Wholesale electricity market performance report 2022

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AUSTRALIAN ENERGY REGULATOR

Australian Government

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Executive summary

The National Electricity Market (NEM) continues to transition from a system dominated by large thermal generators to one that incorporates an increasing volume of widely dispersed intermittent renewable generators. Since our last report in 2020, this has proceeded with significant new entry of large-scale solar and wind generation increasingly putting downward pressure on prices and reducing market concentration.

However, over the past year, NEM prices have increased to unprecedented levels across all regions as supply-side conditions put pressure on the market. Sharp increases in international fuel prices, significant outages of thermal generation and fuel supply problems strained the generation fleet. The resulting volatility led to extraordinary interventions to maintain reliability and security of the system. In June 2022 sustained high wholesale electricity prices triggered an administered price cap in all mainland regions for the first time ever. This combined with high fuel costs, contributed to several generators withdrawing capacity from the market. The resulting supply shortfalls prompted the Australian Energy Market Operator to increasingly direct generators to provide electricity and, ultimately, take the unprecedented step to simultaneously suspend the market in all mainland regions of the NEM to ensure reliable supply. The price cap and suspension were lifted around a week later as supply issues were resolved.

Events in 2022 highlighted that the NEM is still heavily reliant on coal, and its offers have significant influence on market outcomes. Dispatchable generation continues to play a pivotal role in balancing fluctuations in demand and supply, and more flexible generation like gas and hydro has set the price more often in peak demand periods. Flexible generation plays a particularly vital role when the market is under stress. Despite its significant role, ownership of dispatchable generation remains concentrated during peak periods, leaving the market potentially susceptible to the exercise of market power and the business management strategies of individual generators.

The electricity contract market has also experienced unprecedented volatility since the sharp rise of spot prices in early 2022. There are clear signs that liquidity has fallen, which can impact the sustainability of existing participants and create barriers to entry and expansion. Through the volatility in spot and contract market prices, generator earnings varied significantly depending on outages, fuel costs, contract positions, and consequently participants' ability to capitalise on high prices.

We continue to observe significant structural barriers to entry, as well as impediments to efficient price signalling. Governments are also increasingly needing to intervene in markets. While we have seen price signals for investment in a range of technologies, most of the recent and projected entry has been supported by government programs.

We are tasked with identifying impediments to effective competition and efficiency in the NEM

The Australian Energy Regulator (AER) has conducted this review on the performance of the wholesale electricity market under the National Electricity Law. We analyse and identify whether there is effective competition in the NEM and whether there are market features that may be detrimental to effective competition or the efficient functioning of the market. We are also empowered under the law to advise Energy Ministers on any legislative or regulatory reform to address key risks in the market.

This 2022 report is our third report covering all NEM regions. It presents a comprehensive picture of the state of wholesale competition, and analyses how the performance of the NEM has changed over the past 5 years, with a particular focus on outcomes since our last report released in 2020.

Through our analysis of market performance, we have identified key considerations for policy makers to support a smooth transition and a future market that delivers efficient outcomes.

Renewables are reducing concentration during the day, but the market remains concentrated at peak times

Elements of the NEM make it vulnerable to the exercise of market power. Despite continued penetration of renewables, overall the market remains concentrated, with a few large participants controlling significant generation capacity and output in each region of the NEM. This concentration provides a number of participants with the potential to exercise market power. However, concentration is significantly lower in the middle of the day, as a result of the contribution from intermittent renewables like wind and solar where there is more diversity of ownership.

Supply conditions largely explain increases in offers, but there is evidence suggestive of exercise of market power

Since our 2020 report, rising fuel costs, fuel supply issues, weather events and significant outages have caused many participants in wholesale markets to shift their offers to higher price bands. How participants responded to these events seems to have been heavily influenced by the composition of their portfolios and by the supply-chain pressures on the fuel types to which they are exposed.

However, while supply-side factors are a major driver of higher offers, they may not explain all of the shifts we have observed. New analysis suggests there may be evidence of sustained exercise of market power through economic withholding in some instances. Economic withholding (offering capacity higher than cost with the intention to increase prices) is not necessarily illegal by itself, but it does put upward pressure on prices and may indicate that competition in the market is ineffective. Our results require further analysis to test the potential drivers of the behaviour we have observed and to assess the significance on market outcomes. In addition, access to information on contract markets is vital to enable effective scrutiny of participant incentives and behaviour.

The impact of recent events on participant behaviour has highlighted key linkages in the NEM which should be kept in mind in the coming years. The NEM is still dependent on coal for baseload supply, but coal generators are facing reliability and fuel supply challenges. When black coal outages coincide with periods of low wind and solar output, more expensive gas-powered and hydro generation is needed to meet demand. Gas offers in the NEM are closely linked to gas spot prices, which soared in 2022. Hydro offers, which are closely linked to gas and black coal offers, also rose. While wind and solar offers are generally low priced, output is dependent on weather conditions and frequency markets.

Coal exit is accelerating and most entry has been supported by government programs

The NEM has seen significant new entry in large-scale wind and solar since our last report. We expect further investment in these technologies, as well as some entry from battery storage, pumped hydro and gas. Thermal generators have continued to leave the market and significant further exits are imminent. Planned exits are also accelerating as generators shift their scheduled closure dates earlier.

Market price signals persist for investment in wind, large-scale solar, gas and a variety of storage technologies. However, the majority of new investment in these assets is tied to some level of government support from state and territory governments and the Australian Government. It extends from directly funding or underwriting investment, to supporting more market-based incentives like certificate schemes or grants for project development.

There are structural and artificial barriers to entry and impediments to efficient price signalling

There are persistent structural barriers to investment in the NEM. Investment in high-cost, long-lived assets requires some level of revenue confidence. However, uncertainty is difficult to avoid in a complex, rapidly transforming market and uncertain macroeconomic and policy environment. Beyond these barriers, there are increasing indications of impediments to efficient price signalling in the market. These include the events of June 2022, as well as increased congestion, and a greater use of directions and emergency reserves.

In addition, governments are increasingly intervening in markets to meet environmental, economic, social, and reliability needs, as well as responding to a lack of private investment resulting from structural barriers in the market. Market participants and potential investors report that this in itself is a barrier to entry because it crowds out market-led investment, leads investors to wait for opportunities to receive support, and risks excessive or inefficient investment. As a result, interventions in the market carry the risk of dampening further private investment if they are prolonged or if regulation does not respond to changing economic conditions.

Current reforms to market design aim to address some of the structural issues and instil effective price signals in the future NEM, including through enabling sufficient dispatchable generation, facilitating efficient use of transmission networks, and enabling least-cost procurement of essential system services. Our assessment of the events of June 2022 has also highlighted areas of possible reform that could better balance commercial imperatives with system security in times of market stress. In addition, Energy Ministers have started work to introduce an emissions objective into the framework that governs the NEM.

New entry in the markets for managing frequency has improved competitive outcomes, but costs have been high

Over the past 2 years, frequency control ancillary services markets have attracted investments in grid-scale batteries, virtual power plants and demand response aggregators. These investments have displaced gas and coal generation and improved the competitive landscape for a number of frequency service markets. In particular, grid-scale batteries have secured a proportion of revenue on entry and have become the dominant provider for most frequency services. However, extreme local costs in 2021–22 and more recently in November 2022 highlight the vulnerability of regional markets to transitory network and plant outages.

We have identified recommendations that will support an effective transition

Through our assessment of competition and efficiency in the wholesale electricity market, we have identified initial recommendations to support policy makers to deliver an effective transition. These include:

- Enabling a contract monitoring function for the AER, to ensure we can accurately scrutinise the behaviour of participants, as well as more clearly identify impediments to competition and efficiency to inform policy makers. This is also a key recommendation of the ACCC's Inquiry into the National Electricity Market and is currently being progressed by Energy Ministers.
- Providing a clear and coordinated pathway to reduce the significant uncertainty that currently exists in the NEM, create confidence for investors and facilitate a smoother transition. An action that may support this would be to explore the increased regulation of coal-fired generators in some form, as its viability and exit pathway is a significant source of uncertainty.
- Facilitating competition during and beyond the transition to enable the NEM to function efficiently at lowest cost to consumers and reduce the exposure of market outcomes to the strategies or supply chains of individual participants. As an example, where governments have choice over their investments or underwriting, consideration should be given to actions to diversify the operation of dispatchable generation where possible, as its significant role will continue to drive market outcomes.

We believe these suggestions will help policy makers enable future investment and efficiency and secure the best outcomes for consumers. We also may identify further recommendations as we deepen our analysis over coming months.

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 third comprehensive report covering competition and efficiency in all regions in the National Electricity Market (NEM), following on from our previous reports released in 2018 and 2020.
- 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.

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 2022 report is our third 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
- 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 undertook targeted consultation with select industry participants to obtain insights on competition and efficiency issues. The unprecedented market events in Q2 2022, though, meant that consultation was limited.

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

In 2022 we have applied the same approach as our 2020 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 market performance monitoring – 2022* Focus paper provide detail on this framework and the areas we identified for focus in 2022. We also published a series of documents setting out more detail on the calculations and methods we applied in this report, including the *Wholesale electricity market performance report 2022 – Methods and assumptions, the LCOE & LCOS modelling approach, limitations and results, and the Economic withholding approach, limitations and results*.

1.3.2 We have expanded our analysis in this report

Building on the work in our 2020 report, in 2022 we have expanded our analysis in several areas to inform our assessment of the performance of the market. This includes:

- Extending our analysis of how individual participants offer their portfolio of assets across and within different NEM regions.
- Exploring new methods with support from NERA Economic Consulting to consider whether there is evidence of economic withholding that may suggest the sustained exercise of market power.
- Examining data and stakeholder reporting to understand whether the existing range of risk management products are working to support competitive and efficient markets.
- Exploring the role of interconnectors in providing a competitive constraint to participants in a region.

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 – challenges facing contract markets
- Chapter 5 – whether participants are exercising market power
- Chapter 6 – whether there is evidence of economic and physical withholding
- Chapter 7 – the prospects for new investment
- Chapter 8 – barriers to entry and impediments to efficient price signalling
- Chapter 9 – understanding competition in FCAS markets
- Chapter 10 – key findings and recommendations.

2. Market conditions and change drivers

Key points

- Prices in the National Electricity Market (NEM) reached unprecedented levels, as supply conditions put pressure on the market. In 2022 we saw considerable increases in international fuel prices combined with significant outages of thermal generation, fuel supply problems and an early winter, which increased demand. This resulted in extraordinary interventions to ensure reliability and security of the system.
- The market transformation to renewable generators and storage technologies is continuing, placing increasing importance on flexible output that can address variations in demand, generation, and price throughout the day.
- Since our last report, the contribution of renewable sources has continued to grow to a quarter of generation output in 2021–22. In particular, rooftop solar contributed more to the NEM's electricity requirements than gas or hydro for the first time.
- Through the volatility in spot market prices, generator earnings varied significantly depending on outages, fuel costs, contract positions and, consequently, participants' ability to capitalise on high prices.
- Frequency control ancillary services (FCAS) prices have increased over the last 2 years, as upgrades to the Queensland to NSW interconnector restricted the amount of available FCAS in Queensland, increasing local prices.

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 transformation is accelerating, as low-emissions solar and wind generation sources gain increasing market share and influence on pricing dynamics. The move to these intermittent renewables has resulted in flexible output becoming more important to firm that generation. Further, unprecedented market events have highlighted that the market continues to rely on dispatchable generation and is vulnerable to 'energy squeezes' – that is, when there is enough capacity technically available to the market, but high input costs and supply constraints mean there are limitations of how much is effectively available.

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 242 power stations (comprising around 334 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 13 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 that 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 5 minutes. Participants can offer their capacity at any level between the price floor (-$1,000 per megawatt hour (MWh)) and the price cap ($15,500 per MWh). The highest priced offer needed to meet demand sets the spot price every 5 minutes. 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 are also engaging in long-term offtake agreements (i.e., power purchase agreements) and 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.

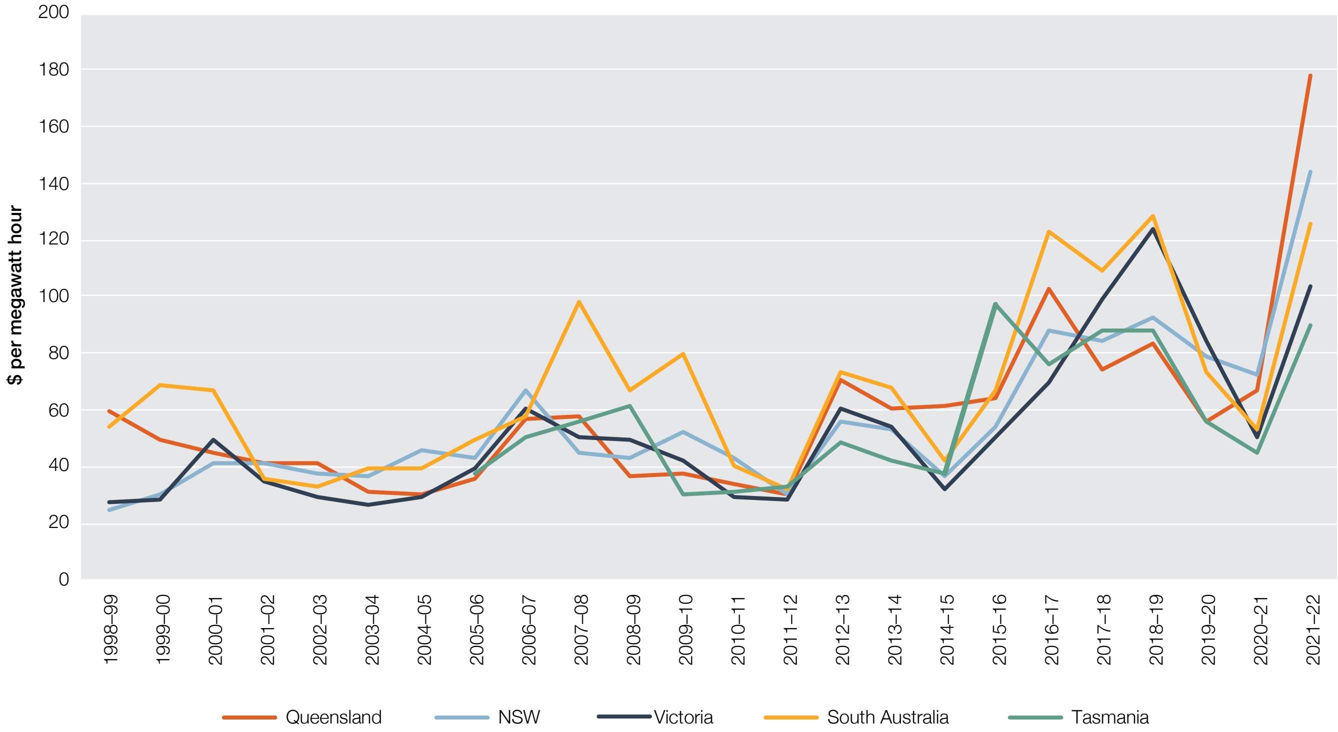
2.1 Average annual wholesale prices increase drastically

Across the NEM average volume weighted annual wholesale prices hit unprecedented levels in the last quarter of 2021–22, triggering protective price caps and subsequent market interventions (section 2.1.2) (Figure 2.1). In 2022, concurrent supply-side issues led to an ‘energy squeeze’, due to significant outages of thermal generation, fuel supply problems in coal and gas markets, and an early winter increasing demand. This put pressure on remaining generation to offer more into the market at a time of increasing domestic and international fuel prices. Increased demand for gas to generate electricity and meet winter demand, combined with tight domestic supply conditions, caused domestic gas prices to surge. At the same time coal generators increasingly needed to source additional fuel from suppliers that would otherwise be exporting, meaning they were more exposed to international prices. Simultaneously, hydro generators faced environmental constraints that limited their available output and further contributed to high prices.

These record highs came after significantly lower prices in 2019–20 and 2020–21, when multiple regions saw some of the lowest prices in nearly 5 years. Subdued prices through this period were driven by milder temperatures, reduced demand during the pandemic and the increasing influence of low-cost renewable generation in the generation mix.

- 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 compared with 2018–19. Across the NEM, 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.
- In 2020–21 average annual prices continued to fall in all regions except for Queensland. Prices fell by between 20% and 40% in Tasmania, South Australia and Victoria and by around 10% in NSW. In Queensland prices increased by 19%, with prices particularly high in May and June 2021 following the major failure at the Callide C coal station. However, all regions were priced below $75 per MWh and Tasmania continued to be the lowest priced region in the market.
- In 2021–22 average annual prices increased drastically in every region, with Queensland and NSW reaching all time market records of $178 per MWh and $144 per MWh, respectively. Prices in all regions more than doubled, and almost tripled in Queensland. High average annual prices were primarily driven by very high prices in the last quarter of the financial year as the market faced an energy squeeze. However, increases in international coal and gas prices as well as the upgrade of the Queensland to NSW Interconnector (QNI) saw price increases in Queensland, NSW and South Australia from September 2021.

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



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

Source: AER analysis using NEM data.

The performance of the wholesale market can have a significant impact on retail prices and electricity bills, but it can be difficult to measure the extent of that impact (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. Historically wholesale costs average around 30% of a residential electricity bill.[3]

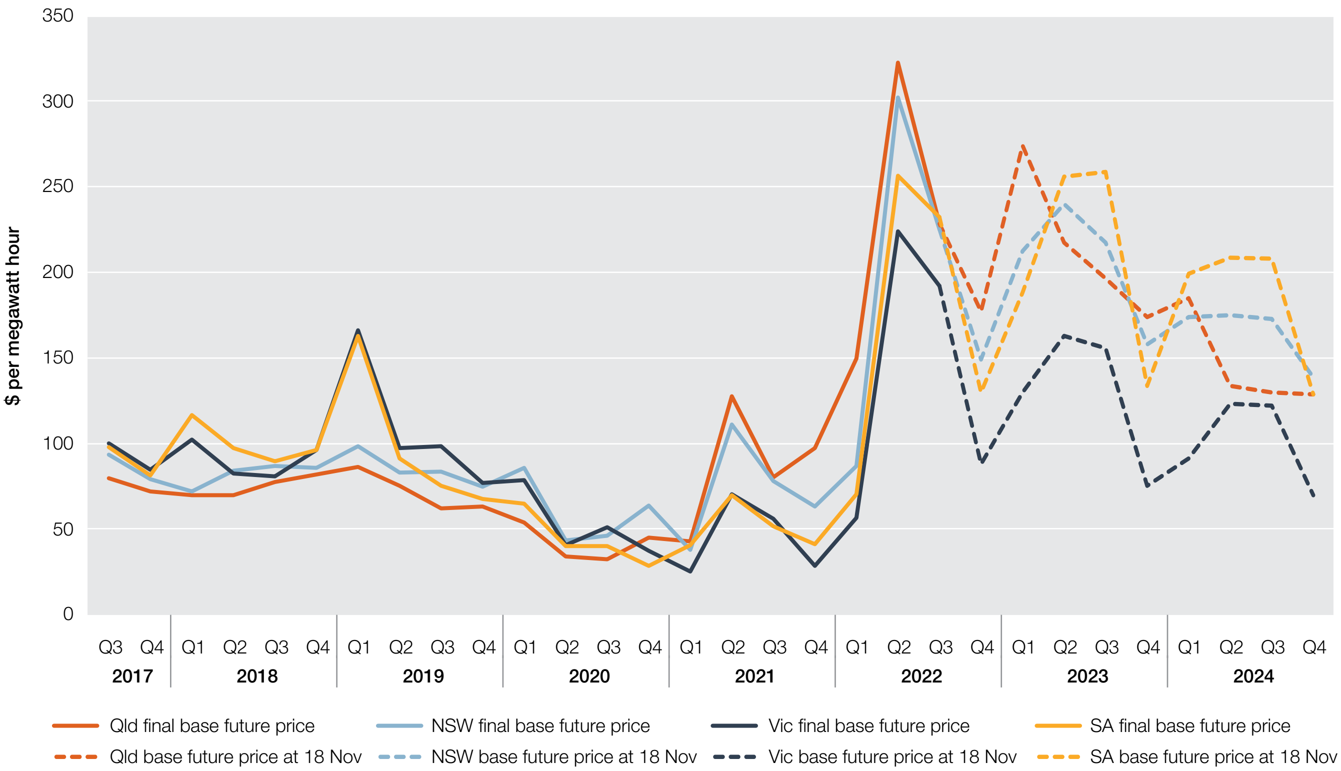
Electricity retailers purchase electricity in the wholesale spot market and sell it to consumers packaged with network services. The final price to consumers also includes additional costs of wholesale electricity, such as frequency services and (in rare cases) compensation payments when the market is suspended.

Retailers and generators manage the risk of wholesale prices fluctuating by entering into financial hedge contracts (Box 4.1). The degree to which the wholesale market impacts retail prices and electricity bills can be difficult to measure as 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 several factors, including how exposed individual retailers are to the spot price, how they structured their portfolios and when their contracts were entered into or expire.

2.1.1 Contract prices increased drastically in line with spot prices

Retailers and generators manage the risk of wholesale prices fluctuating by entering into financial hedge contracts (Box 4.1). In line with spot price trends, after a period of low and steady price outcomes contract prices increased significantly following the sharp increases in spot prices in the last quarter of 2021–22 (Figure 2.2). Final contract prices for base futures set a new record in all regions in Q2 2022, with final prices ranging from $224 per MWh in Victoria to $323 per MWh in Queensland. These increases were dramatic, with contract prices increasing by 232% to 686% compared with prices only 6 months earlier.

Figure 2.2 Final and current quarterly base future contract prices



Note: Final contract prices are equal to the cash settlement price, calculated by taking the arithmetic average of the wholesale electricity spot prices over the contract term. Non-final prices are the daily settled price for the quarterly base future contract on 28 October 2022.

Source: AER analysis using ASX data.

3 ACCC, Inquiry into the National Electricity Market, November 2022, p 115.

While final contract prices for Q3 2022 fell slightly, ranging from $192 per MWh to $232 per MWh, the current forward prices for 2023 and 2024 suggest that high electricity prices are expected to continue into the coming years. As of 18 November 2022, calendar year contracts for 2023 were trading at prices in line with or higher than the calendar year 2022 prices. Price expectations for 2024 are 11% to 33% lower than 2023 but remained elevated compared with all previous years.

High contract prices were driven by several factors. A significant driver is uncertainty around international gas and coal prices due to the impact of the war in Ukraine. There is also increased uncertainty around the reliability of aging coal generators (section 2.2), leading to a reduction in available contracts offered from these generators. In addition, several major coal generators are scheduled to exit in the next few years (section 7.1.3), starting with AGL closing the final 3 Liddell units on 1 April 2023, which will remove an additional 1,500 MW of base load generation in NSW.

2.1.2 Extreme market prices led to unprecedented intervention

Sustained high prices in the wholesale electricity markets in Q2 2022 triggered a protective price cap of $300 per MWh in every mainland region for the first time ever. During this time, some generators revised their market availability and/or withdrew capacity from the market. This contributed to forecast supply shortfalls, and along with generation units being offline for planned maintenance and repairs, ultimately led to AEMO having to intervene heavily in the market by issuing numerous directions to market participants to make capacity available for dispatch. AEMO formed the view that this became unworkable and suspended the NEM from 15 to 23 June 2022.[4]

Following negotiations with generators and the resolution of plant outages, by 23 June, directions to generators were no longer required and AEMO shifted from the Market Suspension Pricing Schedule to dispatch pricing. On 24 June, the market suspension was lifted entirely.

There are various compensation mechanisms available to participants, including for directions, market suspension and intervention pricing. These are administered by AEMO and the AEMC and claims are currently under review.[5]

We have investigated whether generator behaviour at this time breached the National Electricity Rules (NER). While the conduct is unlikely to have breached the Rules in the circumstances, we did find that certain generator conduct in this period made the operation of the spot market more difficult, and we have identified a number of measures for consideration that may improve the operation of the market and the effectiveness of the supporting regulatory framework (section 8.1.7).

2.2 Market transformation is accelerating

The NEM has continued to transition away from coal, towards lower emission, renewable generators and storage technologies. The technology mix is evolving due to changes in the relative fuel and capital costs of different plant, technological advances that make some plant more efficient and government policies to reduce carbon emissions. The exit of coal-fired generators and investment into new wind and solar generation and battery storage is increasing the proportion of generation from renewables. Despite this, the NEM is still heavily reliant on dispatchable technologies and the events of 2022 have highlighted the increasing roles of flexible generation and storage, as intermittent generation continues to connect to the grid.

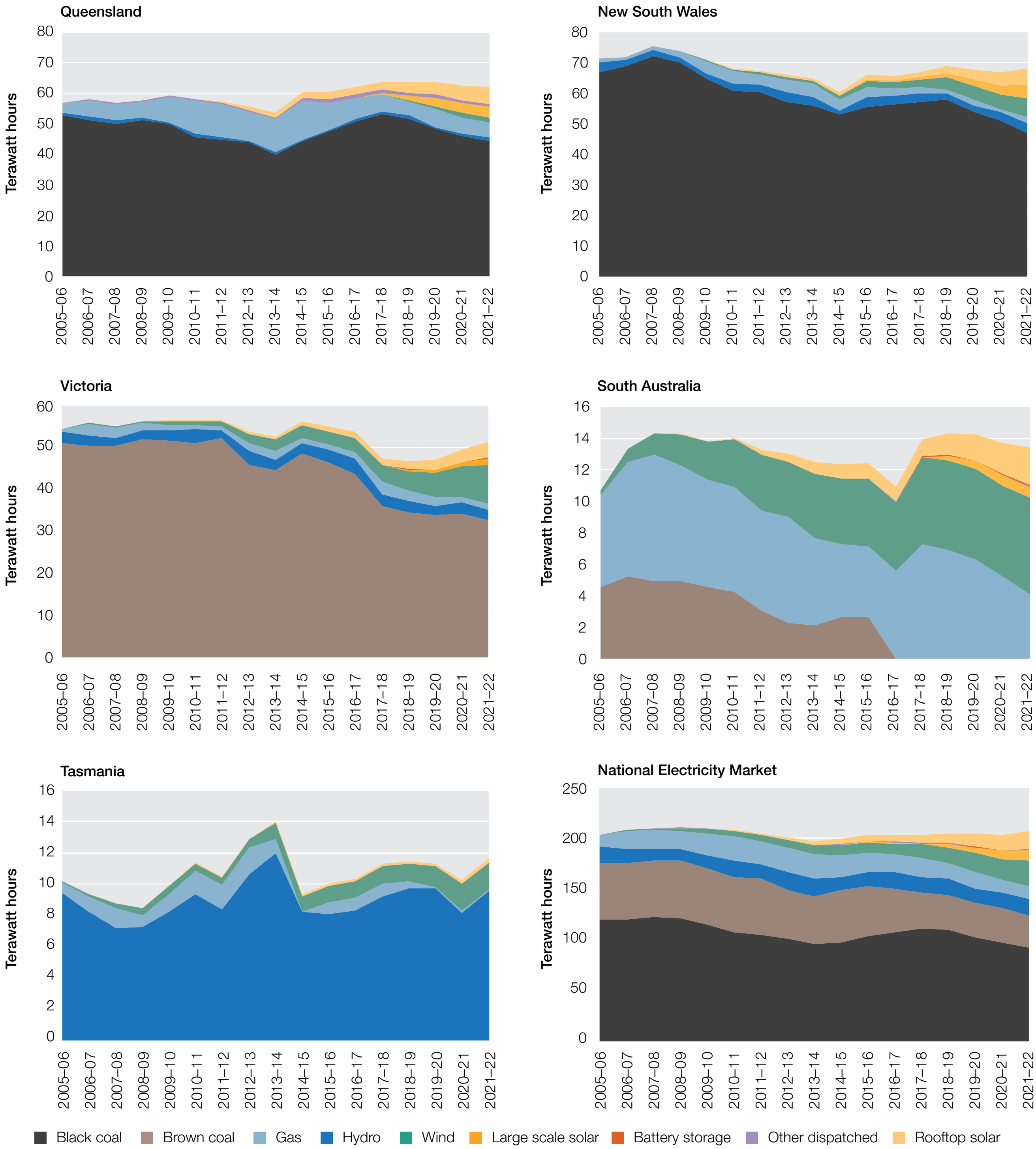
2.2.1 Coal remains the prevailing fuel source

Coal remains the dominant fuel source in Queensland, NSW and Victoria (Figure 2.3). Black and brown coal supplied 60% of total output in the NEM in 2021–22, down from 67% in 2019–20 due to the penetration of renewables and exit of coal generation. In 2021–22, 500 MW of coal-fired capacity retired from the market and further closures are scheduled for 2023 and 2025 (section 7.1.3).

4 AEMO, NEM Events and Reports, accessed 1 November 2022.

5 AEMC, Administered pricing compensation claims, accessed 1 November 2022; AEMO, NEM Events and Reports, accessed 1 November 2022.

Figure 2.3 Generation output by fuel type



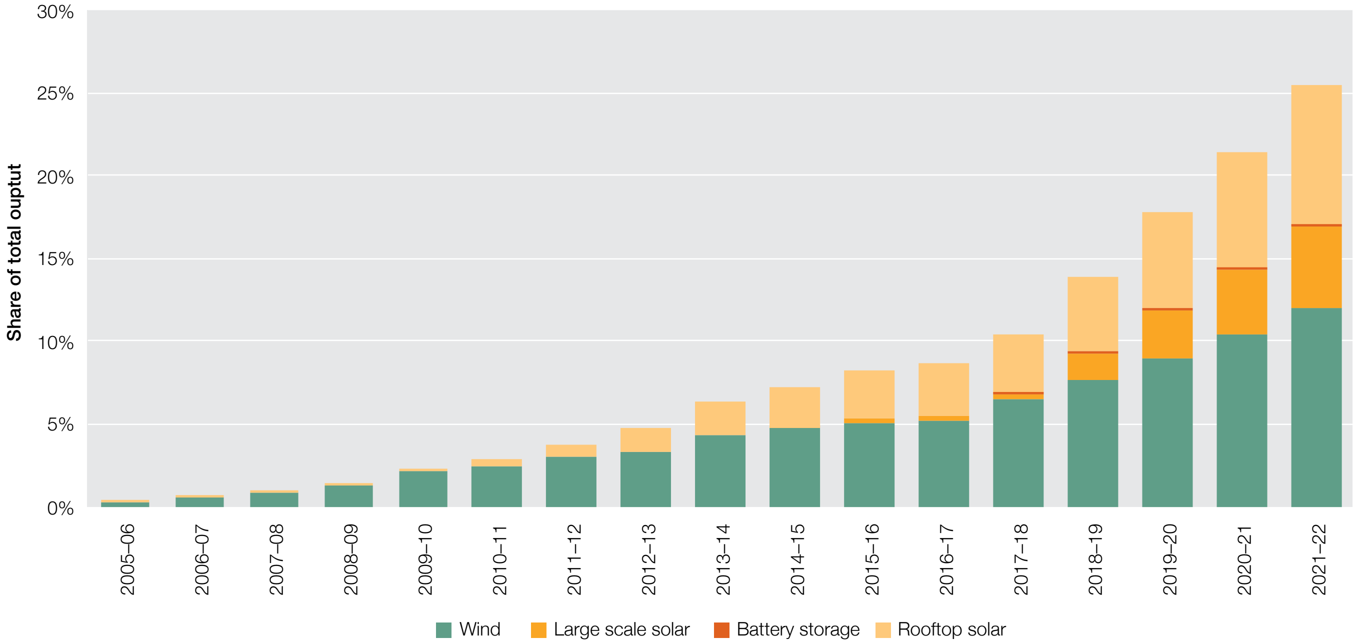
Note: Sum of generation by financial year. Other dispatched includes generation from bagasse, biomass, diesel, liquid and waste gas fuels.

Source: AER analysis using NEM data.

2.2.2 Share of renewables is growing

Generation from renewable sources, including rooftop solar, is steadily increasing and reached 25% of total output in the NEM in 2021–22, up from 17% in 2019–20 (Figure 2.4). New battery storage installations in Queensland and NSW have meant there has been battery output from these regions for the first time. As a result, all mainland regions now have battery storage, with more entry anticipated. However, batteries only comprised 0.1% of output in 2021–22.

Figure 2.4 Wind and solar generation share of total output



Note: Sum of generation as share of total output by financial year.
Source: AER analysis using NEM data.

Generation from wind rose to contribute 12% of total output in the NEM in 2021–22, up from 9% in 2019–20, as around 2,100 MW of new capacity registered in the market. Wind generation now has the highest output in the NEM after black and brown coal. Wind penetration continues to be strongest in South Australia, meeting around 45% of the state's electricity requirements in 2021–22. Investment in new wind generation is continuing, with significant wind projects expected to enter the market in the next couple of years.

Solar technologies are an important source of generation in the NEM. Household rooftop solar is not dispatched in the wholesale market, but rather reduces the demand that must be met by grid generation. In 2021–22 rooftop solar reached 8.5% of total electricity produced, exceeding generation output from gas (6% of output) and hydro (8%) for the first time.

Large-scale solar generation has grown from less than 1% of total output in 2017–18 to meeting around 5% of the NEM's electricity requirements in 2021–22. Historically, Queensland had the highest penetration of large-scale solar generation. However, since the last report NSW has seen the most solar new entrants (1,603 MW). As a result, the proportion of generation from NSW solar farms at 6.4% of NSW output exceeded Queensland at 5.6%. Another 8 solar projects (over 1,900 MW) are expected to be commissioned across Queensland, NSW, Victoria and South Australia by the end of 2022–23 (section 7.1).

2.3 Higher priced trading intervals are driving higher average prices across the market

Average prices can be driven by a general movement in prices or a more limited number of extreme price events over $5,000 per MWh. Historically, higher average prices in the market were driven by a small number of extreme price events. However, an increase in both extreme price events and higher underlying prices (i.e. those between $100 and $500 per MWh) have pushed average prices higher (Figure 2.5). This uplift in prices has been occurring since Q2 2021 after a particularly low-priced period in most regions in 2020.

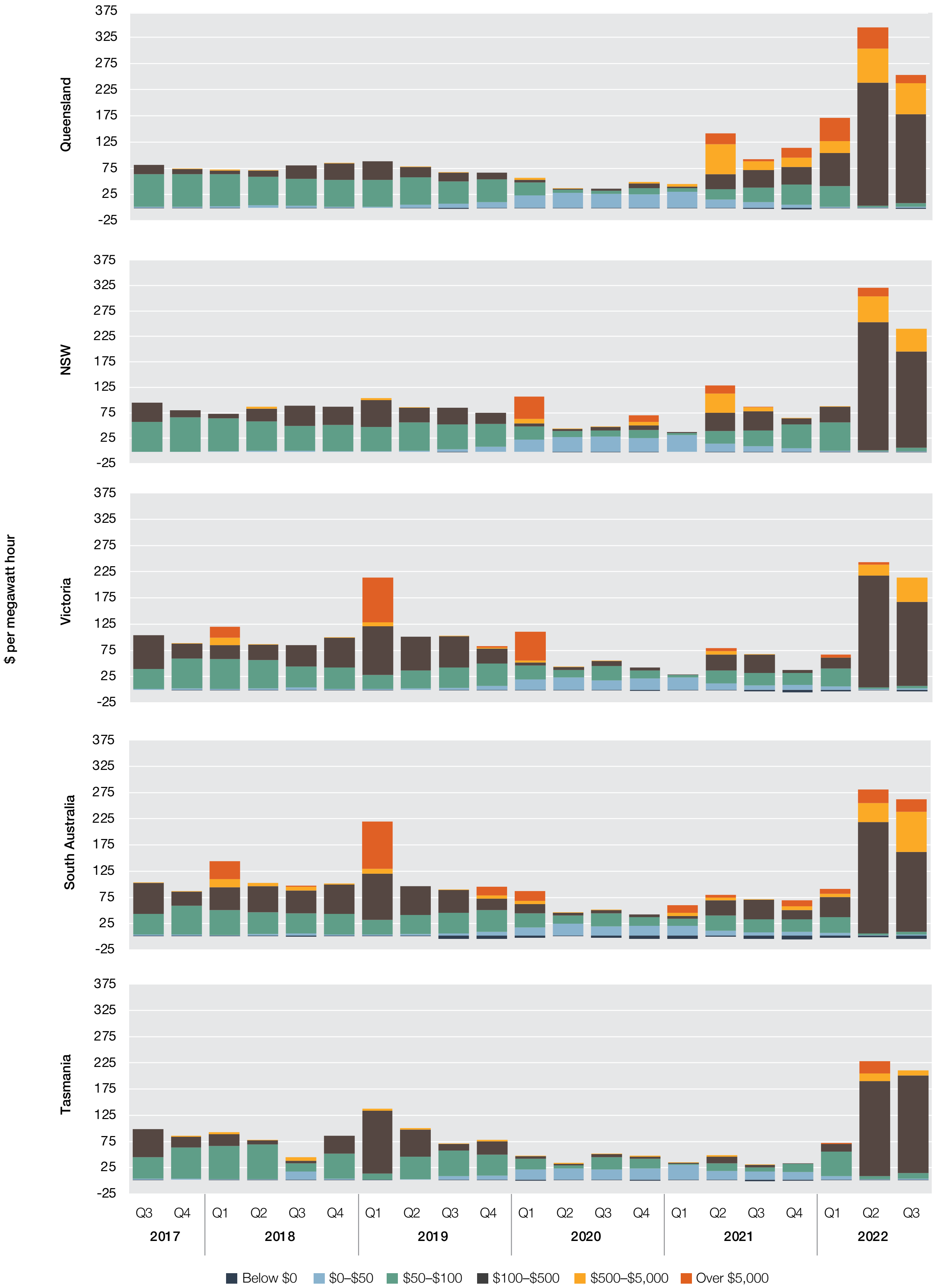
In contrast to previous trends, there has been a significant reduction in trading intervals priced less than $50 per MWh. These are being superseded by prices between the $50 to $500 per MWh price bands. All states have reflected similar trends but it is particularly prominent in Queensland. Comparing Q1 2021 with Q1 2022, prices between $50 to $100 per MWh increased by 514% and prices between $100 to $500 per MWh increased by 2,178%. This trend has generally aligned with significant increases in fuel costs (section 2.4.1).

Prices above $5,000 per MWh continue to have a significant impact on overall outcomes and have been occurring more frequently, especially in Queensland and South Australia across 2021 and 2022. Thermal generator outages were a key driver of the high prices in Queensland, though other factors contributed, including periods of high demand and network constraints that limited the ability to import electricity from NSW.[6] Prices above $5,000 per MWh in South Australia were the result of high demand, low wind generation, reduced imports from Victoria and rebidding capacity from low to high prices.

In Q2 2022 there were $5,000 per MWh prices across all regions, primarily driven by fuel prices, fuel availability and generation outages. However, several instances were also influenced by interconnector constraints, network outages and FCAS requirements.

6 AER, Wholesale markets quarterly – Q4 2021, February 2022.

Figure 2.5 Contribution of different price bands to quarterly wholesale prices

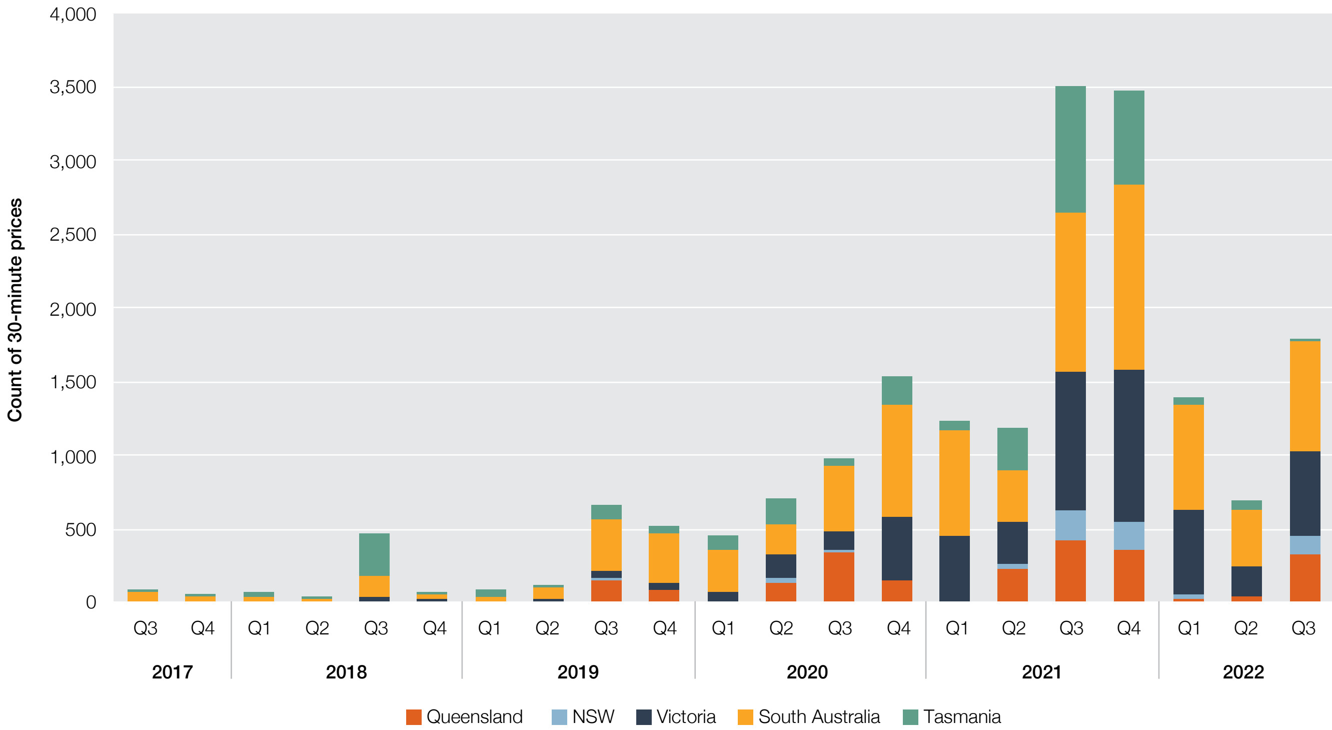


Note: Shows the extent to which different spot prices within defined bands contributed to the volume weighted average wholesale prices in each region.

Source: AER analysis using NEM data.

Instances of negative prices also increased significantly through 2021, though reduced in 2022 (Figure 2.6). The increase in 2021 was primarily driven by renewable generation during the day, when there is high solar generation, while the fall in 2022, particularly between April and June, reflected tighter supply conditions and increases in costs. In 2019–20 there were 2,338 instances of half hour spot prices less than $0 per MWh, rising to 4,931 instances in 2020–21 and further increasing to 9,057 instances in 2021–22 (an 84% increase). Historically, across all regions, lower demand quarters (Q3 and Q4) have the most instances of negative prices and this continued through the last few years.

Figure 2.6 30-minute prices below $0 per MWh



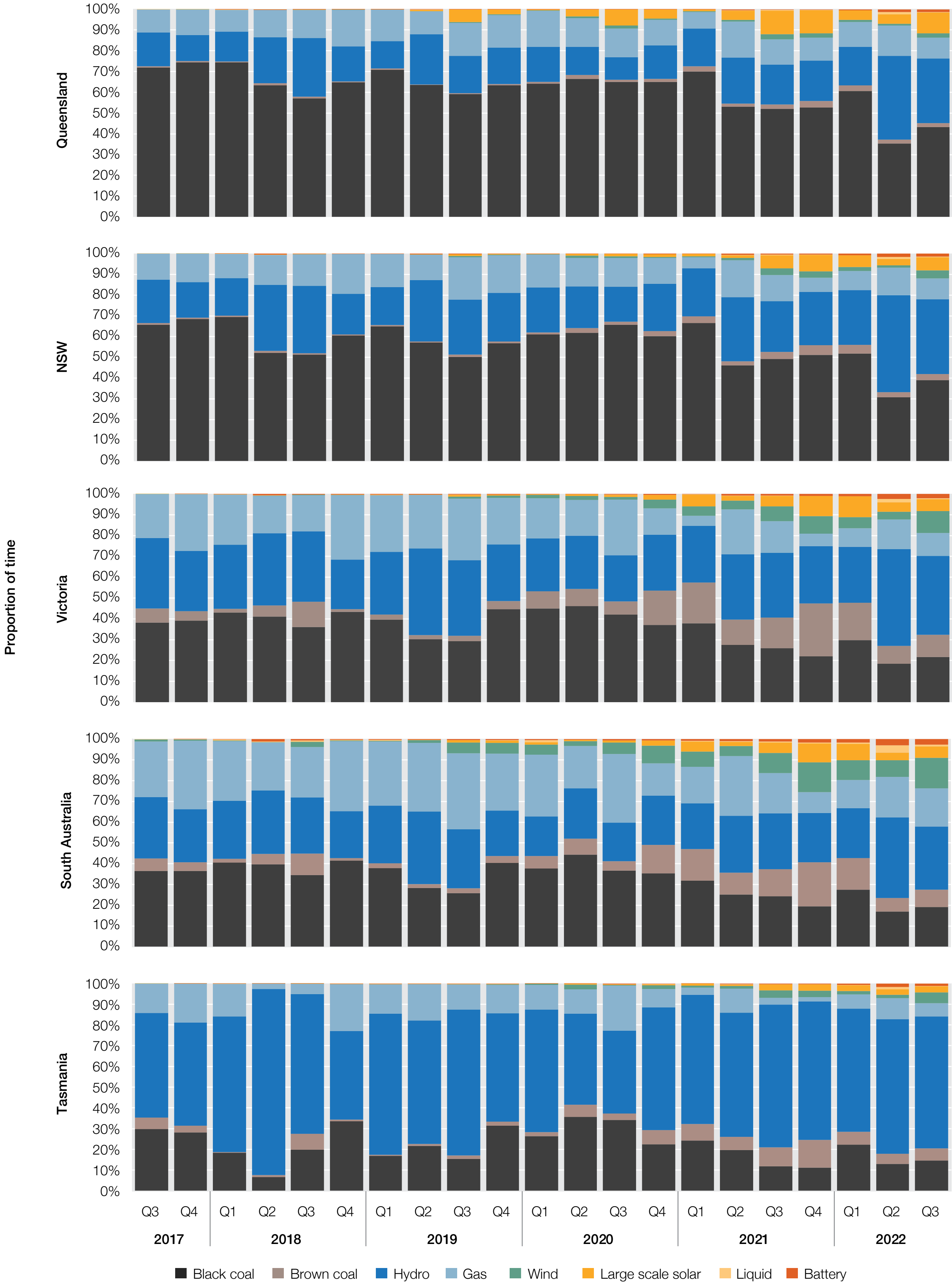
Source: AER analysis using NEM data.

2.4 Supply conditions have been a major driver of the increase 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. In fact, changes in supply conditions have predominately contributed to the sustained increase in prices in 2021–22. These have included the increasing gas and black coal fuel prices, constraints on fuel availability for coal and hydro plants, and significant concurrent outages in major thermal generation.

Since the last report, renewable wind and solar generation has set prices more often across all regions, most often in the middle of the day (Figure 2.7). As a result, the percentage of time that black coal generation set prices continued to trend downwards in all regions. At the same time, black coal faced issues with fuel supply and availability (section 2.4.1), so higher-cost hydro and gas generation has been needed to meet demand, most often during periods of lower renewable generation.

Figure 2.7 Price setter, by fuel type and region



Source: AER analysis using NEM data.

In recent quarters black coal, gas and hydro generators set prices at much higher levels on average, largely due to the removal of low-cost baseload capacity caused by outages, increases in input costs and environmental constraints (section 5.1). In contrast, wind and solar set prices at significantly lower levels than other fuel types, most often in the middle of the day.

2.4.1 Fuel costs increased sharply and fuel supply was constrained

Spot prices for black coal and gas rose significantly in 2021 and 2022. These elevated fuel costs were a major contributor to electricity price increases because the thermal generators exposed to the fuel cost rises priced their capacity higher as a result.

Black coal generators can source their fuel from a range of sources, including directly from an attached mine or through short-term or long-term contracts. NSW black coal generators typically acquire their fuel through 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:

- they require additional coal that their contracts or mines cannot supply (due to supply disruptions from weather or transport congestion or other delays in delivery)
- long-term contract negotiations coincide with fluctuating prices.

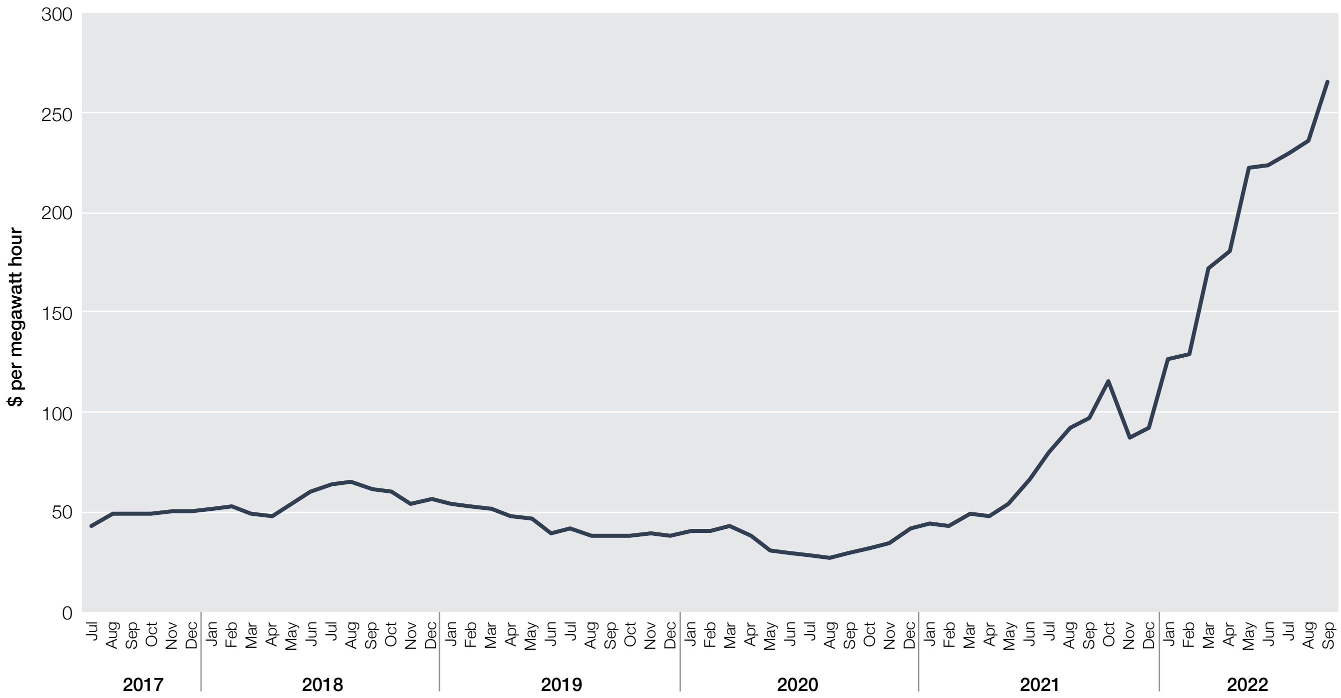
Similarly, gas-fired generators source their fuel from a variety of sources. The opportunity cost of using gas for electricity generation is, among other things, selling it on the Short Term Trading Markets in Adelaide, Brisbane and Sydney, the Declared Wholesale Gas Market in Victoria, or the Gas Supply Hubs at Wallumbilla and Moomba.

The international reference prices for thermal coal rose moderately throughout 2021 and hit the equivalent of around $115 per MWh in October 2021, before more than doubling to over $260 per MWh in September 2022 (Figure 2.8). Gas prices also rose steeply from early 2022, from roughly $10 per gigajoule (GJ) or around $80 per MWh in February to a high of $43 per GJ or around $340 per MWh in July, before falling again (Figure 2.9). Driving the sharp surge in international fuel prices has been a post-COVID recovery in demand, production disruptions and the impact of the potential loss and diversion of some Russian exports from markets.[7] In early 2022, the Russian invasion of Ukraine put upwards pressure on global oil and gas prices. Bans on Russian oil drove countries to diversify their supply and to decrease dependence on Russia for both oil and gas, sending ripple effects across global supply chains.[8]

7 Department of Industry, Science and Resources, Resources and energy quarterly, June 2022.

8 AER, State of the Energy Market 2022, September 2022.

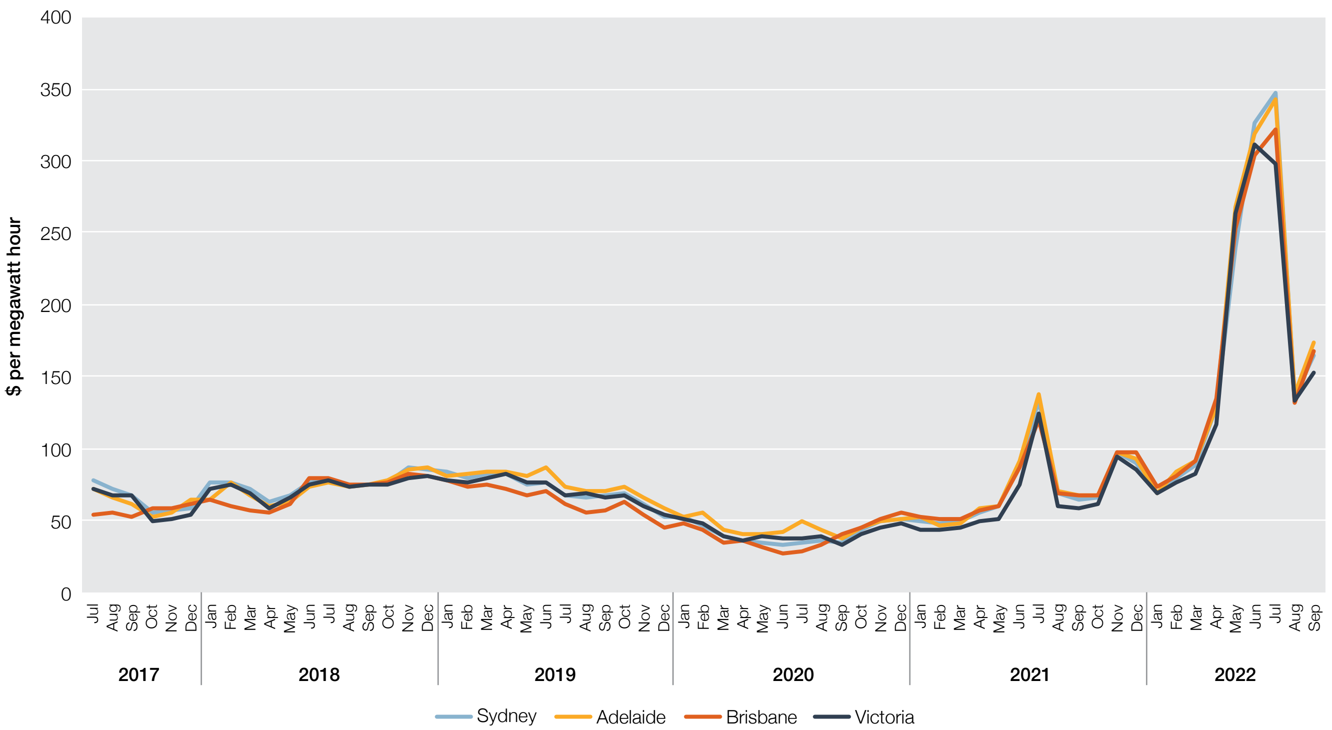
Figure 2.8 Proxy input cost for coal, based off international reference price for spot thermal coal



Note: To convert coal prices from USD$ per tonne to AUD$ per MWh, we use the following formula: $ per MWh = coal cost (USD$ per tonne) divided by the exchange rate (monthly average) x heat rate (GJ per MWh)/low heating value (GJ per tonne). For coal we use a constant heat rate of 9 GJ per MWh and a low heating value of 23 GJ per tonne.

Source: AER analysis of the Newcastle thermal coal index using data from GlobalCOAL.

Figure 2.9 Proxy input costs for gas in all regions, based off domestic spot gas prices



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. To convert the gas prices from per GJ to per MWh, we use the following formula: $ per MWh = gas cost x heat rate (GJ per MWh). For gas we use an average constant heat rate for combined cycle gas turbine (CCGT) units of 8 GJ per MWh. However, it is important to note that open cycle gas turbine (OCGT) units are more likely to set the price in periods of peak demand, and as they operate less efficiently than CCGT they have higher heat rates and so the cost of gas in terms of $ per MWh are higher.

Source: AER analysis using gas market data.

On top of higher fuel prices, many generators faced challenges accessing fuel in 2022. Severe rain in NSW and Queensland drove delays in coal deliveries, slowed mining production and compromised coal quality. Other logistical constraints, including available transportation, made it difficult for generators to access supplementary coal quickly. Consequently, many generators had low stockpiles in June and July 2022, which led to plants pricing their capacity higher in an effort to conserve fuel. Gas-fired generators also had limited fuel quantities as a result of the tight supply-demand balance in east coast gas markets. Brown coal did not face any major production issues in 2022.

The wet weather also affected hydro generation. In Q2 2022 Snowy Hydro faced particular challenges managing its generation within environmental constraints. These included managing storage levels in Blowering Reservoir, as well as limiting the amount of water it could release into the Tumut River without risking downstream flooding.[9] As a result, while hydro generation ran harder to compensate for high levels of coal outages, Snowy Hydro's ability to further increase its output was limited. These events highlighted the potential energy constraints even pumped hydro generators face (section 5.1).

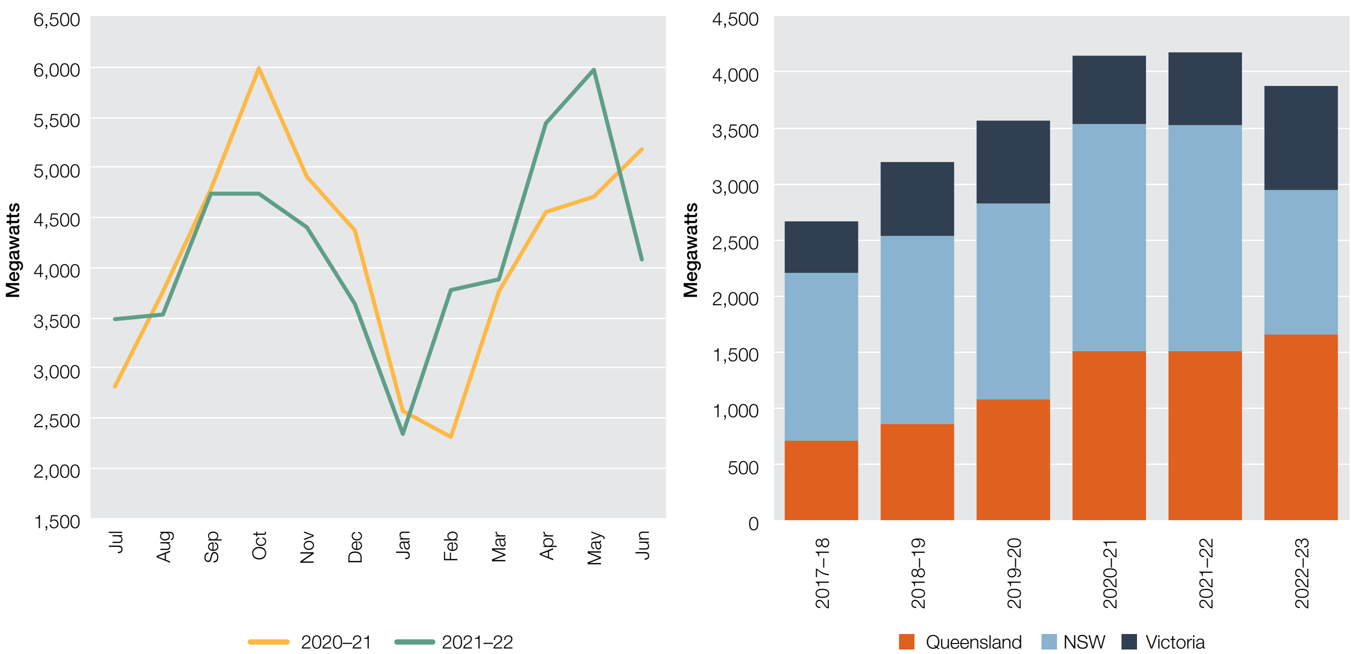
2.4.2 Baseload generator outages have increased and reliability is declining

A major contributor to the tight supply conditions over 2022 was a reduction in baseload generation availability as instances of outages increased.[10] Outages to baseload generators have grown in the past 5 years, particularly in Queensland (Figure 2.10). Over the past 2 years since July 2020 there have been significant planned and unplanned outages:

- Liddell units in NSW had cumulatively 819 days of outages across its 4 units (each with a registered capacity of 500 MW).[11]
- Yallourn units in Victoria had cumulatively 694 days of outages across its 4 units (each with a registered capacity between 360 MW and 380 MW).
- Callide C unit 4 in Queensland suffered a significant failure in May 2021, and so had cumulatively 466 days of outages and has been completely offline since then (registered capacity of 420 MW).

Outages peaked in May 2022, when 6,000 MW of baseload capacity was not available to the market. This was the third highest level seen in the past 5 years and it was one of the factors observed in the lead up to the market suspension in June (section 2.1.2).

Figure 2.10 Baseload outages, by month and by region



Note: Average coal generator outages are calculated based off registered capacity when dispatch for the day is zero. Includes planned and unplanned outages. Actual maximum capacity can differ from registered capacity due to changing performance of units through time and seasonal factors.

Source: AER analysis using NEM data.

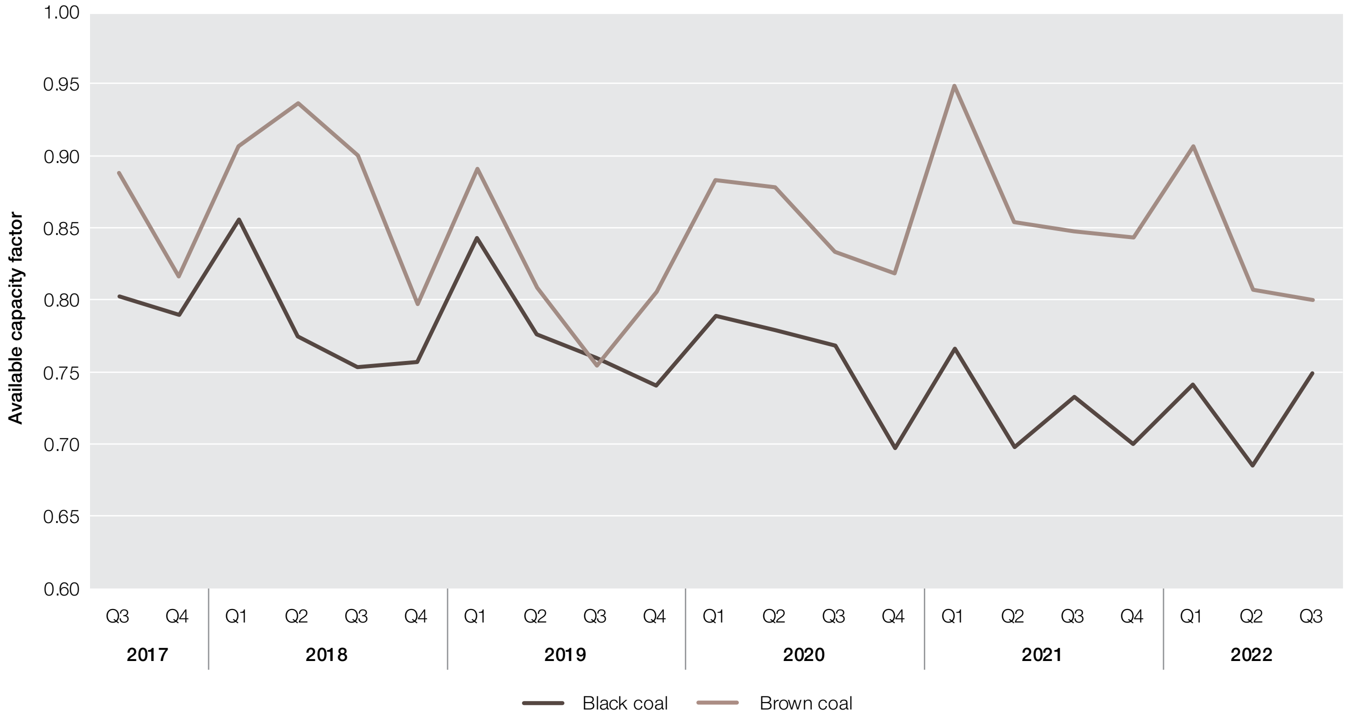
9 Snowy Hydro, Snowy Hydro water releases from Tumut 3 Power Station, 3 June 2022.

10 Baseload generators includes black coal stations in NSW and Queensland and brown coal stations in Victoria, which supply the 'base' capacity to the NEM. Outages refers to instances when a baseload generator is completely offline either due to a planned or unplanned circumstances.

11 Registered capacity is obtained from AEMO. For more detail see, NEM Registration and Exemption List.

The average availability capacity factor, which measures the maximum availability of different types of units over their registered capacity, has declined since 2017 (Figure 2.11). The number and scale of outages have been a major driver of the reduced capacity. The reduction in the availability capacity factor indicates that units are offering a smaller proportion of their registered capacity to the market and that coal reliability has declined. Market participants reported that in some cases it had been challenging to manage maintenance investment (which must be planned several years out), particularly when there were extended periods of very low prices, such as those seen in 2020.

Figure 2.11 Average available capacity factor of baseload generators



Note: The average available capacity factor is calculated by comparing generator availability to registered capacity.

Source: AER analysis using NEM data.

However, the availability factor also reflects offer strategies and a unit's overall efficiency as well as outages, and so it is likely that declining availability is at least partly influenced by generators adapting their operations in response to the increasing penetration of renewables (section 6.2).

2.5 Range of potential operating earnings has grown significantly

The level of operating earnings is a useful input in our assessment of whether generators overall hold a sustainable position in the market. We model operating earnings as potential revenue less operating costs for all mainland generators. To account for the range of costs generators face depending on how much they have contracted their generation and the exposure to fuel spot prices, we model 2 variants of both revenue and cost.[12]

In 2021–22 the range of modelled operational earnings was far greater than previous years (Figure 2.12). Earnings modelled on revenue from the spot market show the potential for high earnings through 2021–22, when there were periods of volatility and high spot prices. Generators that did not contract their generation and had secured fuel at lower prices than in the market had the potential for increased earnings because they could capitalise on high spot market prices.

12 Care must be taken when interpreting modelled operating earnings as an indicator of profits, as our model cannot fully reflect the revenues and costs that a participant may face. Further details on the sources and assumptions we have used are contained in our methodology: AER, Wholesale electricity market performance report 2022 – Methods and assumptions, December 2022.

Figure 2.12 Modelled operational earnings range: spot and contract adjusted revenue and cost, in the mainland NEM

Source: AER, *Wholesale electricity market performance report 2022 – Methods and assumptions*, December 2022

In comparison, generators that had highly contracted output and had more exposure to the increases in fuel costs likely had low or even negative earnings. This is because generators that were highly contracted would have been unable to capitalise on high spot market prices. Similarly, generators that experienced significant unplanned outages would have had more difficulty capitalising on high prices. Where generators needed to pay the spot market price for fuel, the potential for earnings were further reduced.

The modelled findings will not reflect an individual generator's actual situation, but some public information is available on generators' earnings outcomes. Notably, losses from generators have been reported, particularly through the second half of 2021–22. This is because generators dealt with outages and fuel supply constraints, while others that were more diversified could supplement losses in electricity with revenue from other markets.[13]

2.6 Flexible, dispatchable capacity is playing an increasingly significant role

As intermittent renewables penetration increases (section 2.2.2) and the exit of thermal generation accelerates (section 7.1), market dynamics are shifting and generation that can effectively match the variation in intermittent supply is playing an increasingly significant role in the market.

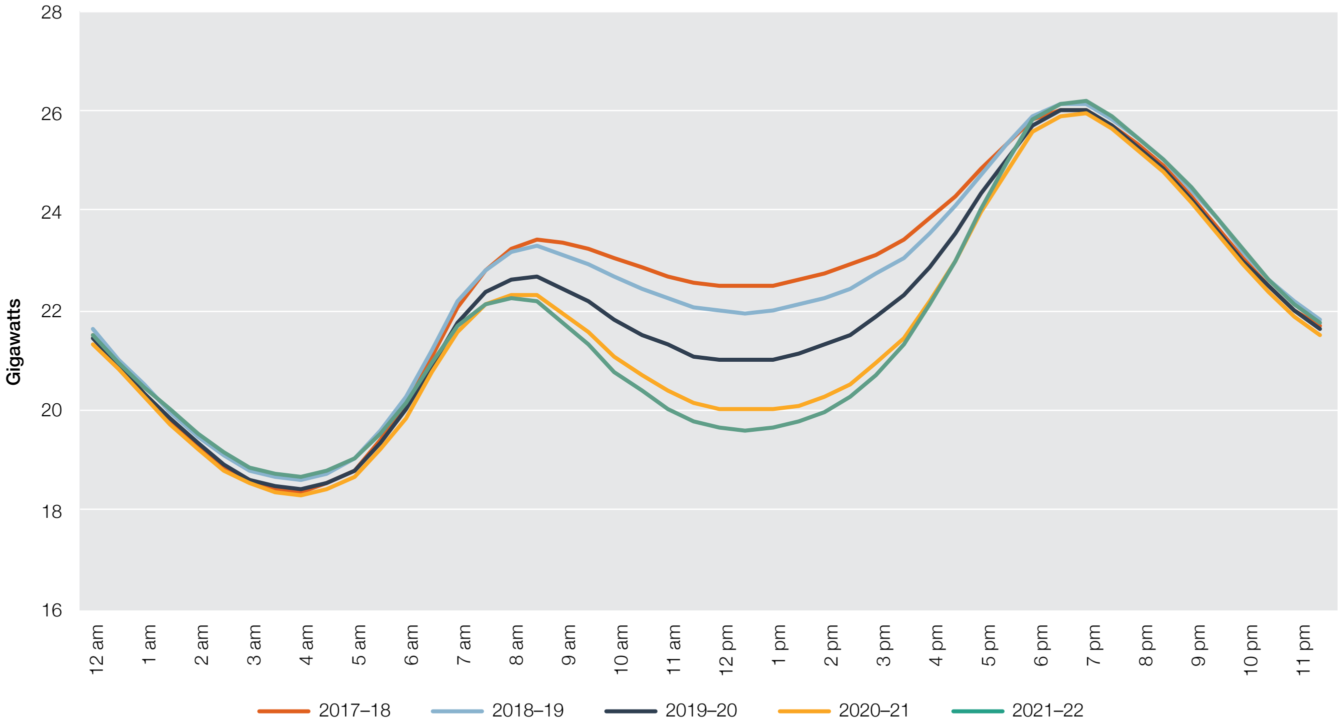
2.6.1 Rooftop solar penetration continues to reduce demand throughout the day

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 2.13). Since our last report, afternoon demand (12 pm to 2 pm) in the NEM dropped by 1,370 MW on average, which is equivalent to around a 7% reduction since 2019–20.

13 AGL Energy, 2022 Annual Report, 19 August 2022; Origin Energy, 2022 Annual Report, 18 August 2022.

Figure 2.13 Average NEM native demand, by time of day



Note: AER defines native demand as the sum of initial supply and total intermittent generation in a region. Figure presents outcomes in NEM time (Australian Eastern Standard Time). Values of y-axis do not start at zero to highlight the changes in demand.

Source: AER analysis using NEM data.

In most regions the uptake of rooftop solar has meant that demand has approached record minimums more frequently, with NSW, Victoria and South Australia setting records since our last report at 4,483 MW, 2,319 MW and 112 MW respectively. In South Australia, minimum demand in 2021–22 breached the original 318 MW record set in 2020 around 19 times. In contrast, regional maximum demand records have not changed, with most regions having set their maximums between 2008 and 2011.

Although rooftop solar reduces grid demand, it also makes demand more variable and uncertain in response to weather patterns. AEMO has reported that the resources necessary to meet large daily demand swings have introduced operational challenges that can be addressed through enhanced forecasting techniques and more flexible generation.[14]

2.6.2 Renewable generation is growing while dispatchable generation is increasingly relied on in the evening peak

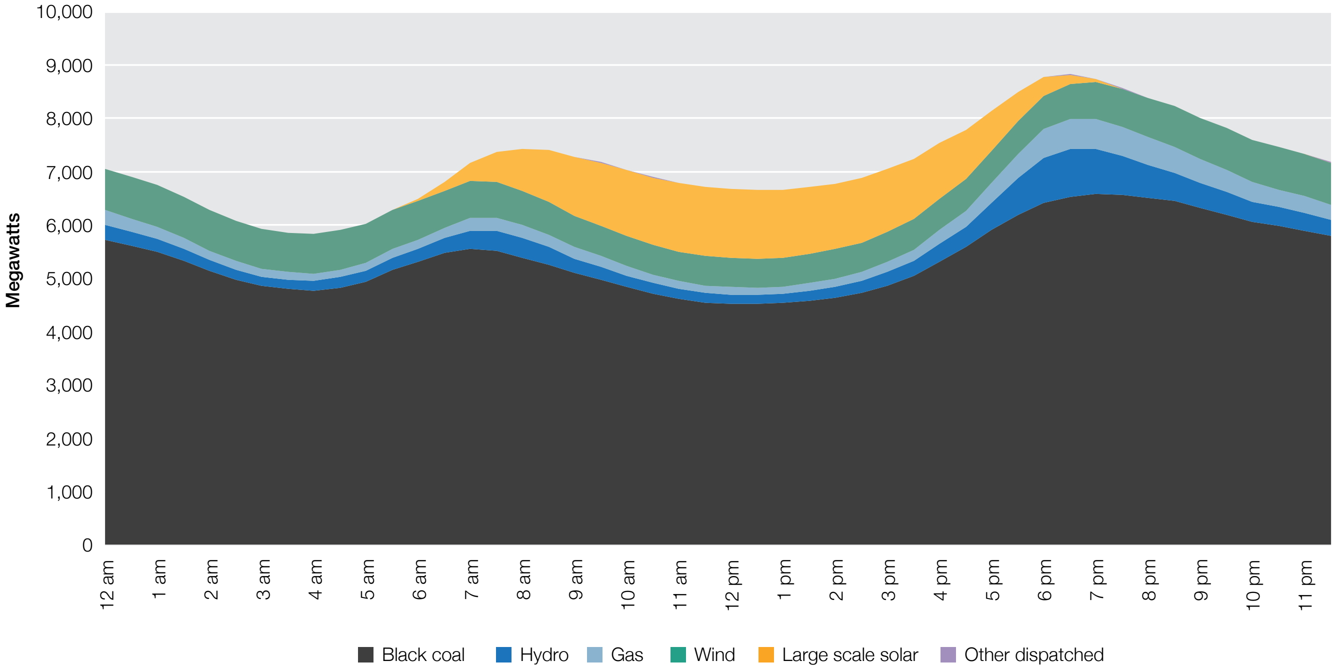
Rooftop and large-scale solar have an even greater impact in the market during the day and dispatchable generation is more prominent in the evening peak. All mainland regions had increased large-scale solar generation, providing 9% to 20% of output on average in the middle of the day.[15] The biggest growth in solar generation has been in NSW, the region with the highest penetration of large-scale solar in 2021–22 (section 2.2.2).

In NSW, large-scale solar generation on average accounted for up to 19% of generation during daylight hours (8 am to 5 pm), up from 8% in 2019–20 (Figure 2.14). At the same time, there has been up to a 5% reduction in total generation in the middle of the day since 2019–20, due to rooftop solar replacing generation required from the grid.

14 AEMO, Quarterly Energy Dynamics Q1 2022, April 2022.

15 In 2021–2022, Victoria had the lowest large-scale solar penetration at peak times, reaching 9% of output between 11.30 am and 12.30 pm, while South Australia had the greatest at 20%.

Figure 2.14 NSW average generation by time of day, by fuel type



Note: Figure presents outcomes in NEM time (Australian Eastern Standard Time).
Source: AER analysis using NEM data.

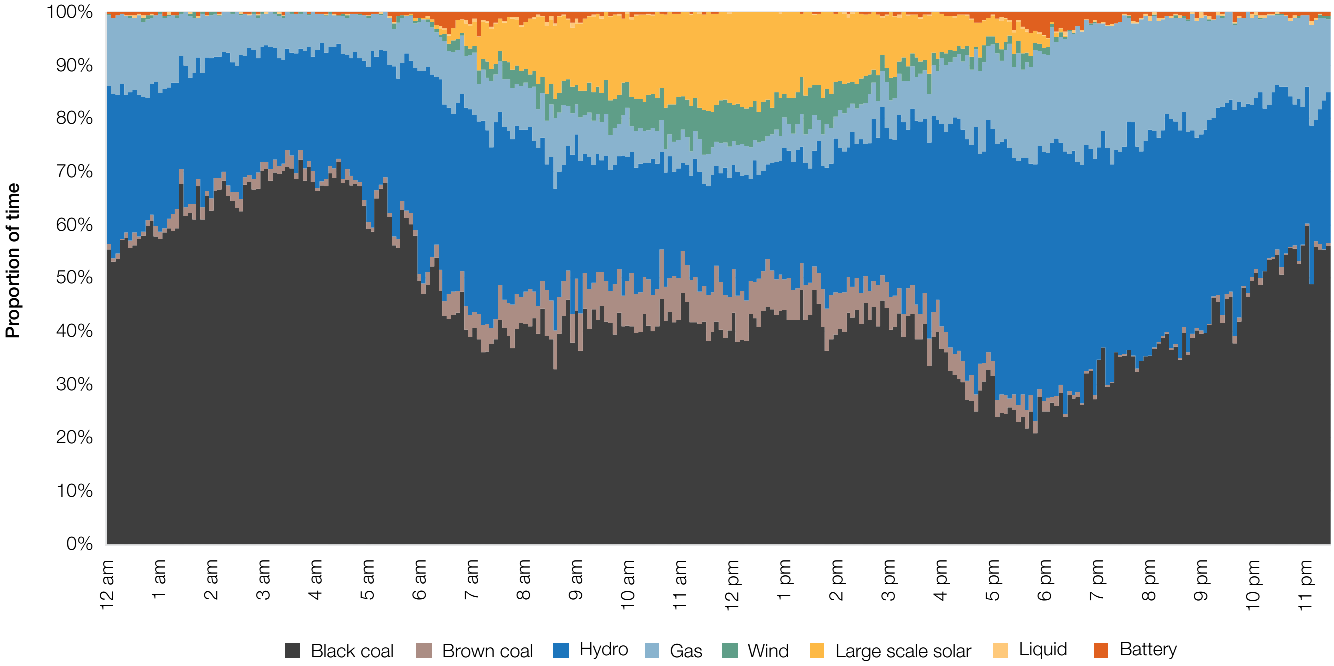
Generation from black coal in NSW decreased by an average of 770 MW for all hours across the day and large-scale solar increased by an average of 670 MW between 8 am and 5 pm. Another contributor to the reduction in coal is from the more than 2 GW of wind that has been installed in the NEM in past 2 years. In NSW, generation from wind increased by around 180 MW on average across the day, while Victoria saw more significant changes, increasing by an average of 420 MW across the day and almost doubling between 6:30 pm and 8 pm.

While solar generation primarily displaced coal and gas generation during the day, there is increased generation from gas and hydro in the evening peaks. In NSW, during the evening hydro and gas increased generation around 200 MW each on average, increasing their contribution to output at this time from 10% in 2019–20 to 15% in 2021–22.

2.6.3 Flexible generation has a greater influence on prices in the evening peak

As changing generation patterns would suggest, renewables are now setting price much more often in the middle of the day. In NSW, wind and large-scale solar set price a quarter of the time at noon in 2021–22 – compared with just 3% of the time in 2019–20 (Figure 2.15). The increase in renewables has meant that black coal, gas and (to a lesser extent) hydro are setting price less often in the middle of the day. At these times, negative prices have become increasingly common (section 2.3).

Figure 2.15 NSW price setter by time of day, 2021–22



Source: AER analysis using NEM data.

However, dispatchable and particularly flexible generation has a much greater influence on prices in the evening peak. Between 6 pm and 7 pm in the evening, gas and hydro set price two-thirds of the time in NSW. Most of the remainder of the time, the price is set by black coal. As such, at these times the market is highly vulnerable to the supply conditions and bidding strategies of dispatchable generators.

Trends in other regions have been similar to NSW. In South Australia and Victoria, relatively higher wind penetration means that wind sets price more often than solar. On the other hand, low wind penetration in Queensland means solar sets price relatively more often in that region. However, in all regions, renewables are setting price more often during the day, but dispatchable generation is still heavily relied on in the evening peak, and batteries are becoming significant at peak times in South Australia.

2.6.4 Changing generation mix has highlighted need for additional market services

The increasing penetration of intermittent renewable generation requires sufficient complementary generation to 'firm' output into the market when renewables are not able to generate. 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 2019–20 over 600 MW of battery storage has entered across the mainland, and new and existing batteries are continuing to have a significant impact on FCAS markets (section 9.2). 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 are 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. Synchronous condensers have been installed in South Australia to provide system strength and inertia services, and the AEMC is considering a mechanism to procure security services.[16] There is also increasing consumer participation being

16 ElectraNet, Power system strength (Synchronous condensers), accessed 1 November 2022; AEMC, Operational security mechanism rule change, accessed 6 November 2022.

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.

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 was implemented from October 2021 to enable consumers to sell demand response in the wholesale market either directly or through specialist aggregators.[17] To date there has been limited market-based demand response in energy, but some uptake in FCAS markets (section 9.3.2).

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.[18] These products are not offered on the Australian Securities Exchange and, although they are available over the counter, there can be challenges in accessing these bespoke products. The market has potential to grow further with Snowy Hydro identifying its ability to offer firming products as one of the benefits of the proposed Snowy 2.0 project.

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

2.6.5 Five-minute settlement has been introduced to provide signals for flexible generation, but the impacts are difficult to assess

Five-minute settlement came into effect in the NEM on 1 October 2021, to facilitate more efficient operational decisions, investment and bidding, and particularly provide market signals for flexible fast response technologies. This reform reduced the time interval for financial settlement from 30 minutes to 5 minutes, aligning the timelines for dispatch and financial settlement.

In the lead-up to 5-minute settlement we observed some investment. Two gas generators in South Australia – Origin Energy's Quarantine power station and EnergyAustralia's Hallett power station – upgraded their equipment to enable them to start up and generate within 5 minutes of receiving a target from AEMO. There is also planned investment in batteries and pumped hydro to enable participants to respond quickly to the 5-minute settlement market.

In response to 5-minute settlement, some generators made changes to their operational strategies by either starting as quickly as possible or keeping units warm and ready to respond, while others began using the technical specifications they provide to AEMO to influence receiving a generation target.[19] We have also observed that disorderly bidding (that is, flooding the market with low-priced offers to take advantage of a high average 30-minute price) has reduced significantly. However, assessing the specific long-term price and investment impacts of 5-minute settlement has been difficult due to the significant market events since its implementation.

17 AEMC, Wholesale demand response mechanism – Final report, 11 June 2020.

18 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.

19 Some generators adjusted their Fast Start Inflexibility Profile after the introduction of 5-minute settlement. For more detail, see AER Wholesale market quarterly – Q3 2021, November 2021.

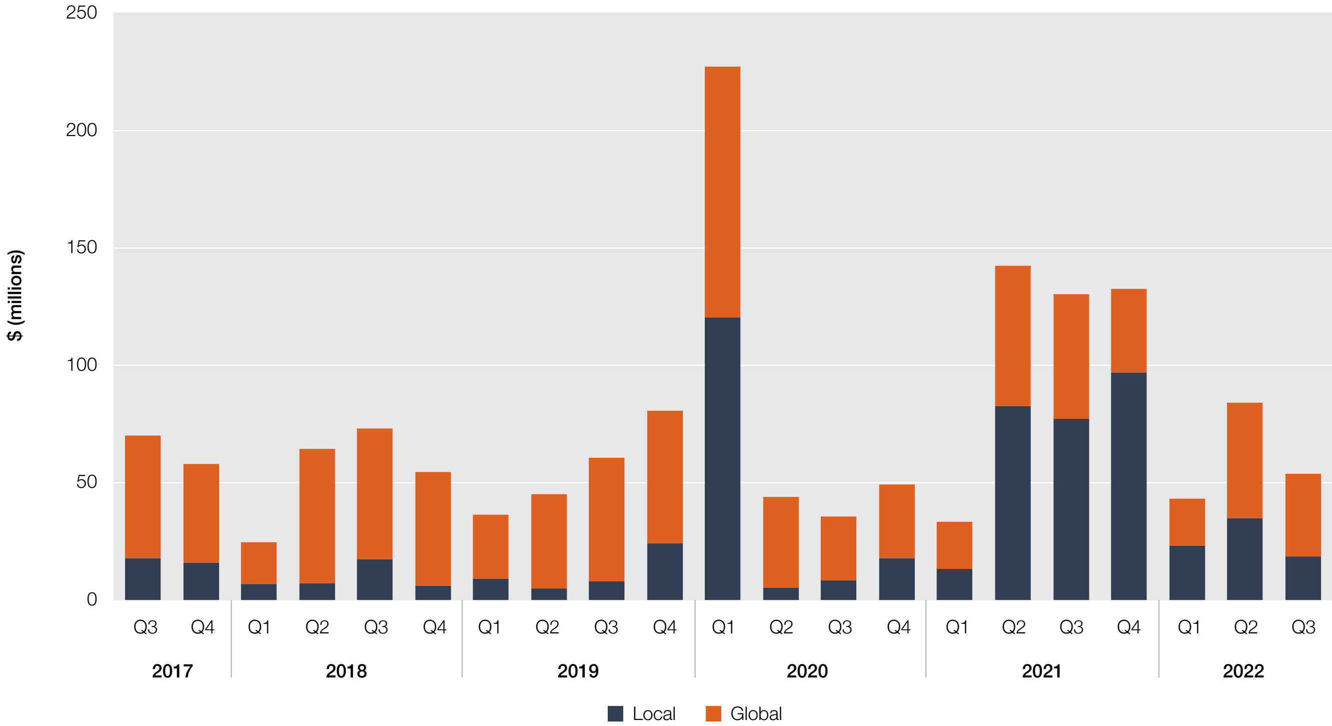
2.7 Extended local markets resulted in record local FCAS costs

FCAS are used to maintain the frequency of the power system (Box 9.1). There are markets for both energy and FCAS, which 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 9.2). 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.

Most of the time, FCAS markets operate as a global market and participants providing FCAS compete across all regions of the NEM. However, if a region is separated or at risk of separation, the ability to transfer FCAS between regions is limited and local markets emerge.

Since our last report there was sustained uplift in FCAS costs, driven by an increase in costs from local markets (Figure 2.16). The cost for local services were greater than global costs for 4 consecutive quarters from Q2 2021 to Q1 2022, an unprecedented trend. These costs were due to an extended local market in Queensland, driven by the planned upgrade of the Queensland to NSW interconnector (QNI), which restricted the amount of FCAS available in the market. Chapter 9 discusses FCAS markets in more detail.

Figure 2.16 Global and local FCAS costs



Source: AER analysis using NEM data.

3. Market structure

Key points

- The market remains concentrated, despite significant new entry. A small number of participants control the majority of generation, and most are vertically integrated.
- Concentration is significantly lower in the middle of the day, as a result of the contribution from intermittent renewables like wind and solar where there is more diversity of ownership. These trends are strengthening year on year as more renewable generation enters the market.
- Ownership among dispatchable generation remains concentrated and a few large participants are often needed to meet demand. However, this reliance has decreased across the National Electricity Market (NEM) over the past 2 years, except in Queensland.
- While interconnectors provide some competitive pressure, congestion on several interconnectors has increased, resulting in less interregional trade and limiting this pressure to neighbouring regions. New interconnector projects in the works may increase interregional competition.
- Participants may have an ability to exercise market power at times, but 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.

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.

3.1 Despite significant new entry, generation ownership remains concentrated

Despite notable new entry, a few large participants continue to control a significant portion of generation capacity in the NEM. This continues to provide incentives for certain participants to exercise market power. Compounding this issue, base load and flexible generation remain particularly concentrated among a small number of participants, potentially diminishing competition during periods of supply stress and at certain times of the day.

We used standard market concentration metrics (Box 3.1) to assess market concentration in each region of the NEM and the extent to which this has changed.

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 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 participant's ability to generate such as network constraints, fuel availability plant conditions and seasonal variations in operational capacity.
- 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. It may under-represent market participants with flexible generation portfolios who use their units to respond to peak prices and so operate them infrequently.

Herfindahl Hirschman Index (HHI)

HHI is a useful measure of market concentration because 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.

Other regulators also use HHI thresholds to assess concentration. The US Federal Trade Commission broadly categorises HHI above 2,500 as highly concentrated. 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. In general, an HHI score of under 1,500 indicates a competitive market, while a score above 2,500 denotes a highly concentrated market. A score of between 1,500 and 2,500 indicates a market is moderately concentrated.

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)

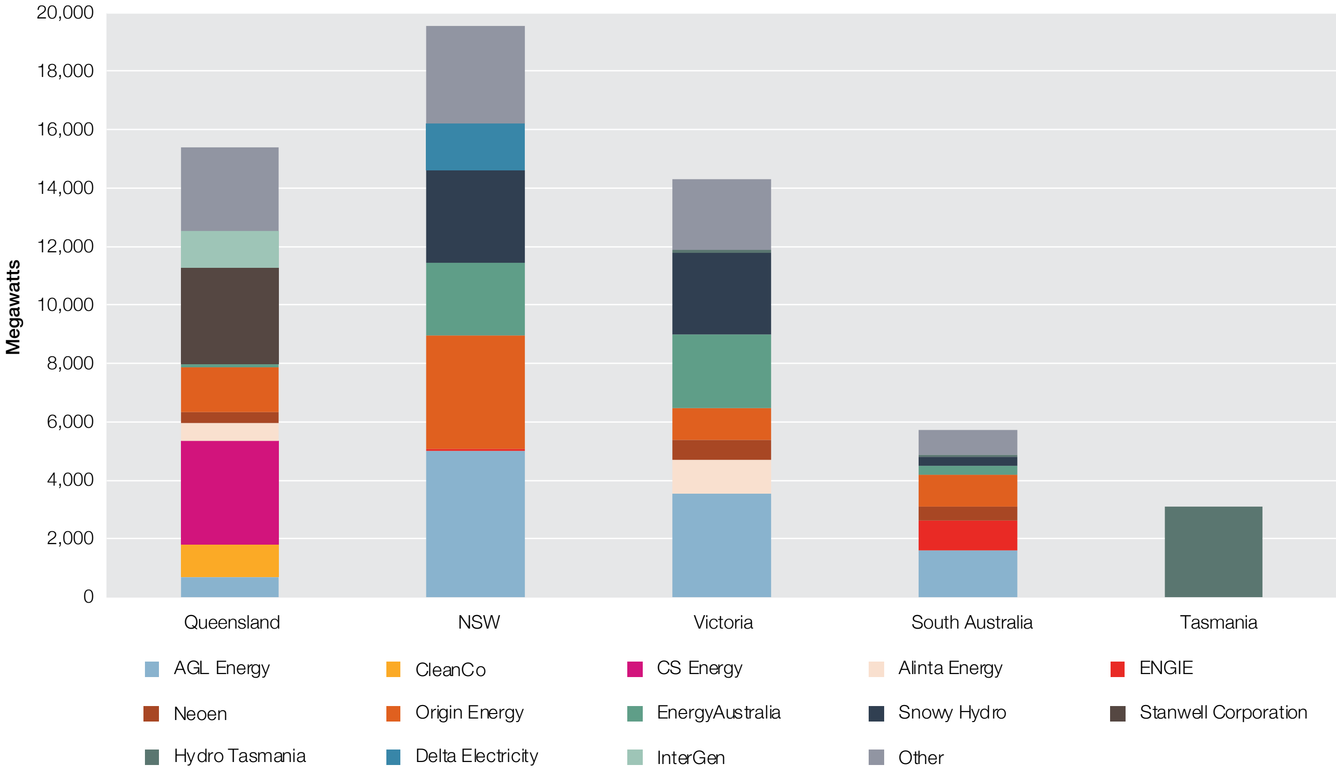
The PST measures the extent to which one or more participants is 'pivotal' to clearing the market. A participant is pivotal if market demand exceeds the capacity of all other participants, accounting for possible imports. In these circumstances, the participant must be dispatched (at least partly) to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

In 2021–22 a few large participants continued to control a significant portion of generation capacity and output in each region of the NEM (Figure 3.1 and Figure 3.2).

- In Queensland, state government owned participants Stanwell Corporation, CS Energy and CleanCo controlled a combined 52% of the region's generation (down from 60%) capacity and 72% of its output.
- In NSW, AGL Energy and Origin Energy's controlled 45% of the region's generation capacity, which was a 5% decrease in market share. AGL Energy's share of registered capacity fell by 9% due to the closure of Liddell Unit 3 and the Hunter Valley gas turbine, while Origin Energy gained 3%. Combined, the 2 participants made up 61% of NSW output in 2021–22.
- In Victoria, AGL Energy, EnergyAustralia and Snowy Hydro controlled 61% of total generation capacity (down from 70% in 2021), driven by falls from AGL Energy and EnergyAustralia. The three participants' share of total output rose to 66% (from 63%).
- In South Australia, AGL Energy, Origin Energy and ENGIE controlled 64% of the region's generation capacity (up from 50%) and 73% of its output.
- The most concentrated region is Tasmania, where state government owned Hydro Tasmania owns almost all generation. Some wind generation assets are not owned by Hydro Tasmania directly but are obligated through power purchase agreements to provide energy to the Tasmanian Government, as such they have been recorded under Hydro Tasmania.

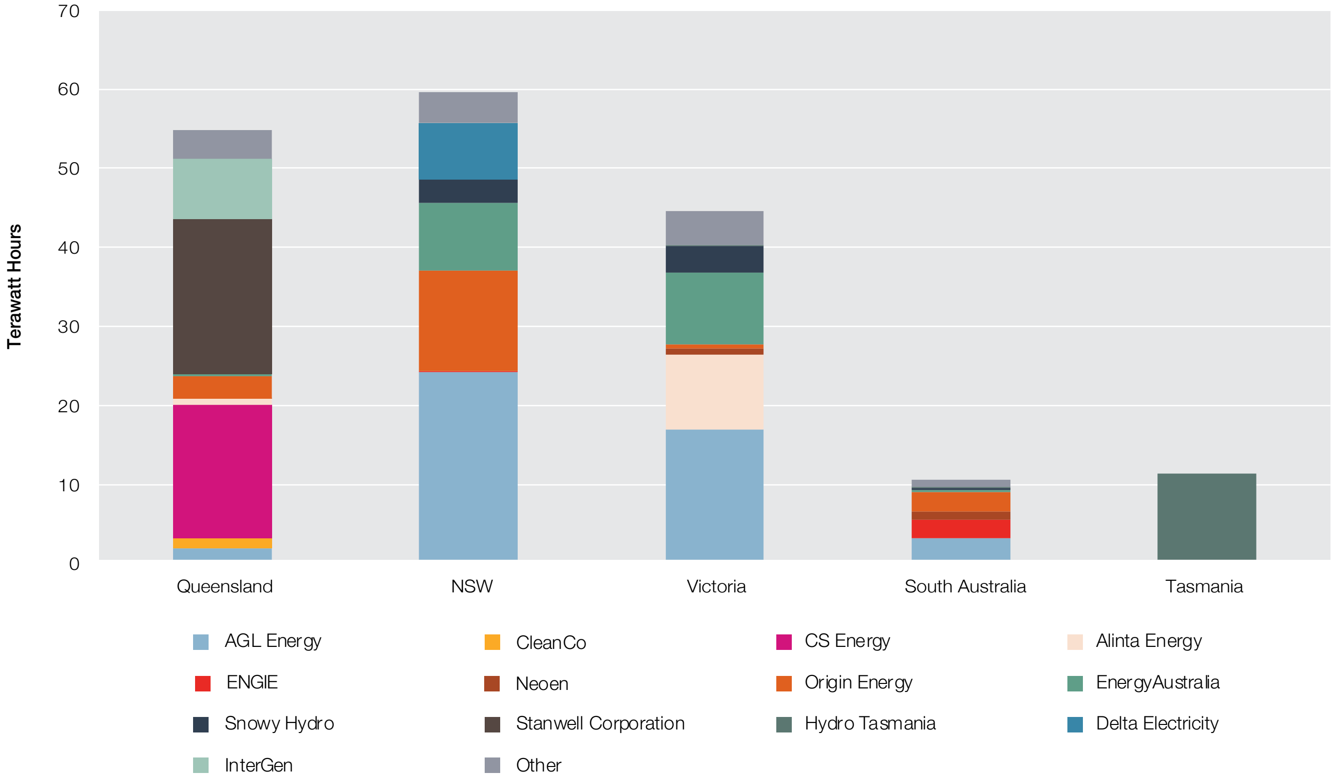
Figure 3.1 Market share by registered capacity, by region, 30 June 2022



Note: Registered capacity share uses registered capacity of all market scheduled generation (excluding market loads) registered as at 30 June 2022. 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.

Source: AER analysis using NEM data.

Figure 3.2 Market share by total generation output, by region, 2021–22



Note: Generation market share uses 30-minute metered data, aggregated for the entire 2021–22 financial year and expressed in terawatt hours. 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.

Source: AER analysis using NEM data.

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

AGL Energy is the largest participant in NSW, South Australia and Victoria and continues to control the most capacity in the NEM. Despite strong investment in new generation assets, AGL Energy's total market share has fallen from more than 20% of capacity in 2019–20 to 18% at the end of 2021–22. However, its share of output has remained consistent at 24%. Origin Energy is the NEM's next largest participant. It has generation across all mainland regions and its market share has remained consistent at 12% of registered capacity and 10% of total 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.

Based on capacity, Snowy Hydro is the third largest participant in the NEM, controlling 10% of registered capacity. Despite its significant generation portfolio, Snowy Hydro accounted for only 4% of output in 2021–22, up from 1.8% in 2019–20. Snowy Hydro's overall share of national output has increased from 1% in 2019–20 to 4% in 2021–22, due to more dispatch from its hydro assets and its acquisition of power purchase agreements for wind and solar farms across NSW, Victoria and South Australia.

Since the last report roughly 6,000 MW of new capacity has entered the market, more than 95% of which was investment in solar, wind or batteries. Around 40% of new registered capacity was acquired by the NEM's largest 4 participants. Of the remaining new capacity Neoen was the largest investor, almost doubling its market share from 1.5% to 2.8%.

Despite significant new entry, there has been little change to the distribution of market share as proportion of the total MW dispatched. This is likely due to the lower operational capacity of incoming renewable generation. For example, AEMO reports in its Integrated System Plan 2022 inputs and assumptions that the average operational capacity factors for solar range from 17% to 58% and wind from 25% to 60%, while coal plants can output up to 75% of registered capacity.[20] Although the declining reliability of coal generation (section 2.2) means the effective capacity utilisation may be much lower than 75%, in general coal still dispatches more volume than wind and solar and thus has greater market share by output (Figure 2.3).

20 AEMO, Integrated System Plan 2022 inputs and assumptions, accessed 12 November 2022. Due to the data available, for wind and solar, the average of all regions and reference years were used, while maximum capacity factor was used for coal.

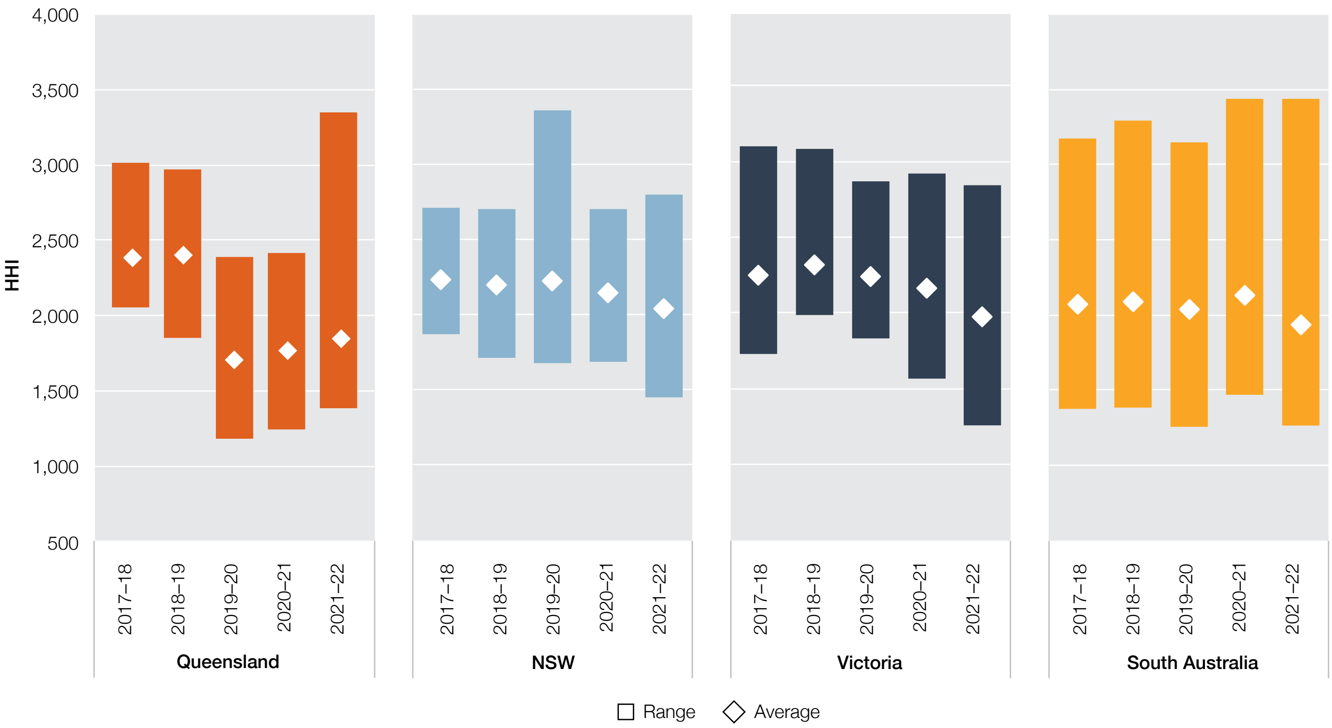
In each mainland region, between 65% and 80% of generation output in 2021–22 was dispatched by one of that region's largest participants, and these participants are still needed to meet demand a significant proportion of the time (section 3.1.5).

3.1.2 The NEM is becoming more competitive on average but still has periods of very high concentration

As well as using market share, we used the Herfindahl Hirschman Index (HHI) to assess the market concentration of the NEM (Box 3.1).

Since our last report, on average all mainland regions except for Queensland saw reduced concentration, although in 2021–22 all regions were still classified as moderately concentrated (Figure 3.3). The reduction in average concentration for NSW, Victoria and South Australia can partly be explained by growth in renewable generation, which saw roughly equal investment from both large and small participants. There is also growing variability in market concentration driven by the output of renewables (section 3.1.3), with South Australia consistently seeing the most.

Figure 3.3 Variability in bid availability Herfindahl Hirschman Index

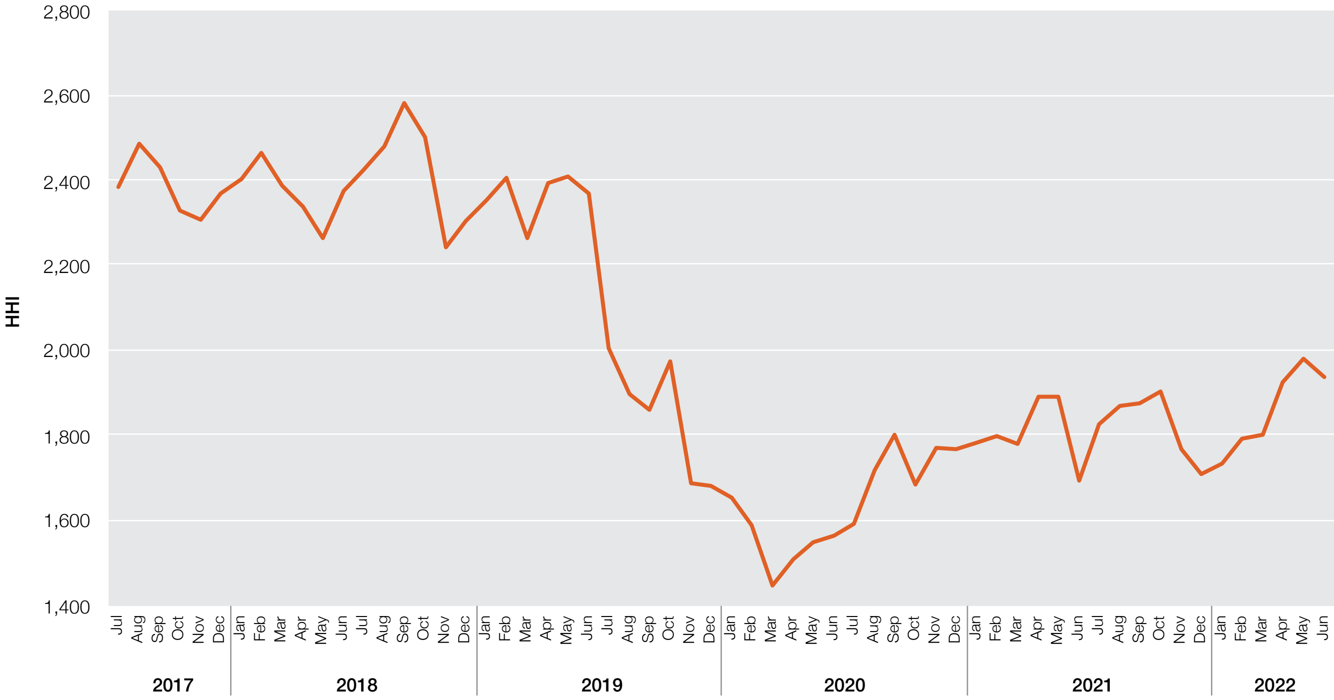


Note: Calculations of HHI exclude the administered pricing period from 12 to 23 June 2022.
Source: AER analysis using NEM data.

In Queensland, after a significant reduction in concentration in 2019–20 with the establishment of CleanCo, average concentration increased significantly over the past 2 years.[21] This was the result of significant outages to CS Energy's black coal units, reducing its effective market share (Figure 3.4). This meant that Stanwell Corporation, the largest generator in Queensland, held a greater market share and the market became more concentrated on average. The effect of these outages on concentration was compounded by frequent constraints on the Queensland to NSW Interconnector (QNI) interconnector, which limited the energy imported into Queensland as it was upgraded from June 2020 (section 3.3.1). Outages are becoming more frequent as the NEM's coal fleet ages, and as observed here can have significant impact on a region's overall availability. We expect market concentration will continue to fluctuate as plants suffer unplanned outages and subsequently return to service.

21 AER, Wholesale electricity market performance report 2020, December 2020, pp 51–52.

Figure 3.4 Queensland average bid availability Herfindahl Hirschman Index



Note: Calculations of HHI exclude the administered pricing period from 12 to 23 June 2022.

Source: AER analysis using NEM data.

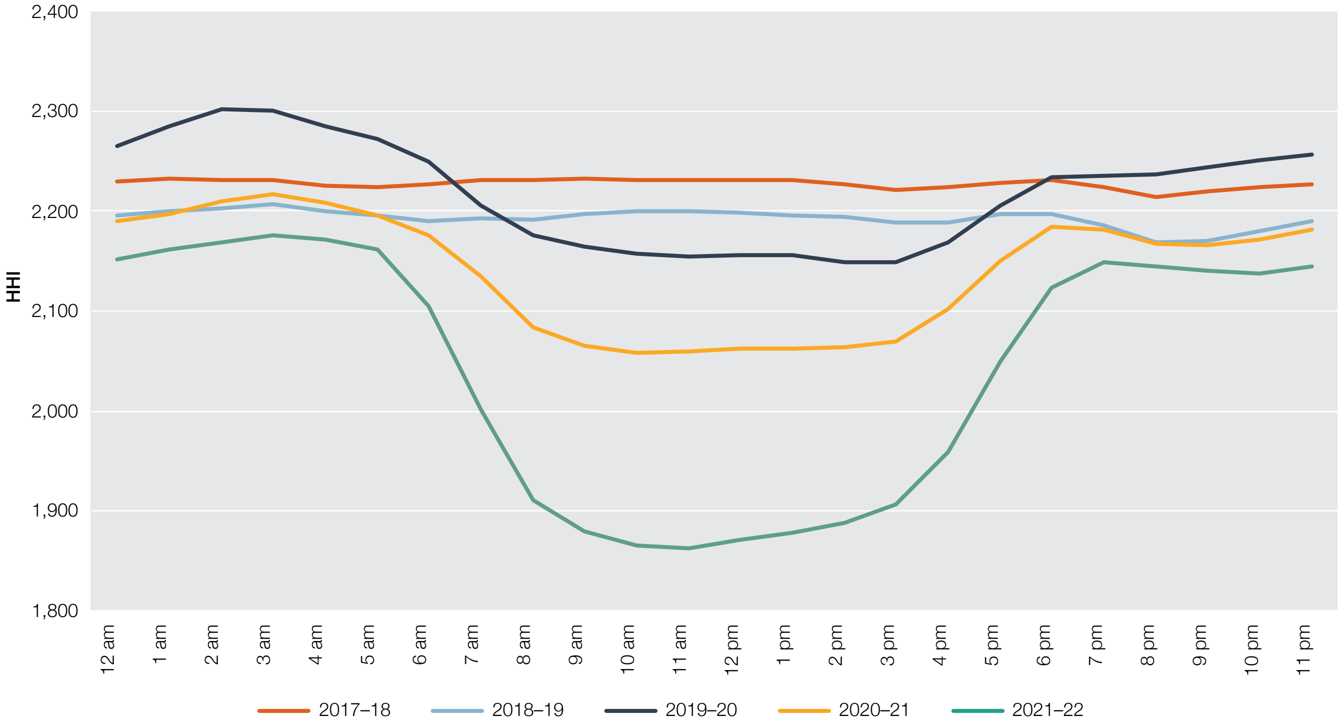
3.1.3 Sub-markets are emerging that depend on generation of intermittent renewables

As discussed in section 3.1.1 recent investment has been dominated by wind and solar, and ownership of these assets is much less concentrated (section 3.1.4). The availability of these generators is quite variable because they are primarily dictated by weather patterns. To understand the impacts of solar generation on concentration we considered the variability of HHI throughout the day. For wind, we compared HHI when wind was above and below its average generation.

Market concentration and thus competitiveness can vary significantly depending on how much wind and solar are generating.

Since the last report NSW saw significant new entry of solar generation, with a regional record 1,085 MW of capacity entering in 2020–21 and an additional 518 MW in 2021–22. As a result, market concentration in NSW has decreased markedly during the middle of the day (Figure 3.5). However, this is a stark difference to concentration in the morning and evening peaks when the market remains moderately concentrated.

Figure 3.5 NSW average bid availability Herfindahl Hirschman Index, by time of day

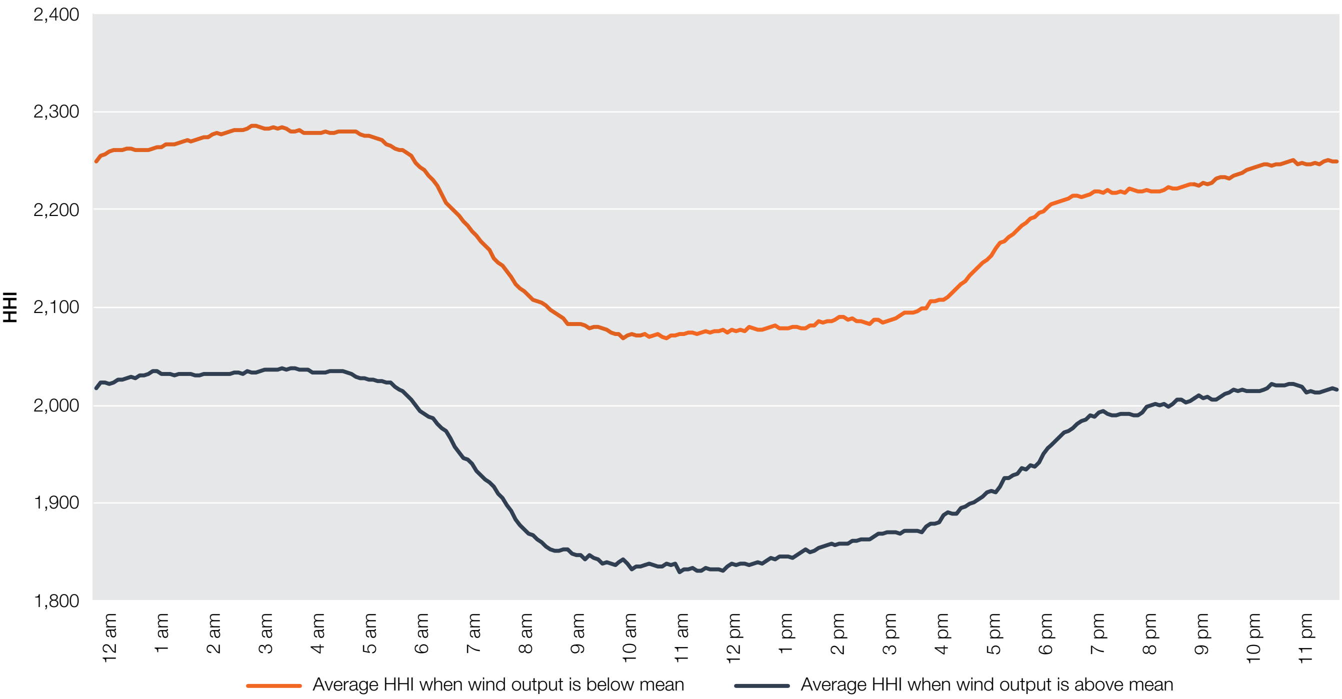


Note: HHI is averaged across all hours of the year. Figure presents outcomes in NEM time (i.e., Australian Eastern Standard Time). Calculations of HHI exclude the administered pricing period from 12 to 23 June 2022.

Source: AER analysis using NEM data.

Victoria has also seen considerable investment in wind generation, 492 MW in 2019–20 and 740MW in 2021–22. The regions wind industry makes up 25% of total generation and consequently wind availability has a significant impact on the regions concentration (Figure 3.6). When wind has above average availability, the Victorian market can be up to 24% less concentrated. Concentration is further reduced in the daylight hours when solar farms are generating.

Figure 3.6 Victoria average bid availability Herfindahl Hirschman Index for above and below average wind output, by time of day, 2021–22



Note: HHI scores by time of day were split and averaged across 2 series – when wind generation above the annual mean and when it was below, then averaged across all hours of 2021–22. Figure presents outcomes in NEM time (i.e., Australian Eastern Standard Time). Calculations of HHI exclude the administered pricing period from 12 to 23 June 2022.

Source: AER analysis using NEM data.

Similar results were observed in all regions, with the shifts in concentration directly proportional to the level of new wind and solar entry.

Overall, renewables generation is a significant contributor to the variability we are seeing across the NEM (section 3.1.2). The entry of intermittent renewables is having a strong positive impact on competition when they are available, but regions can still be significantly concentrated when their output is low.

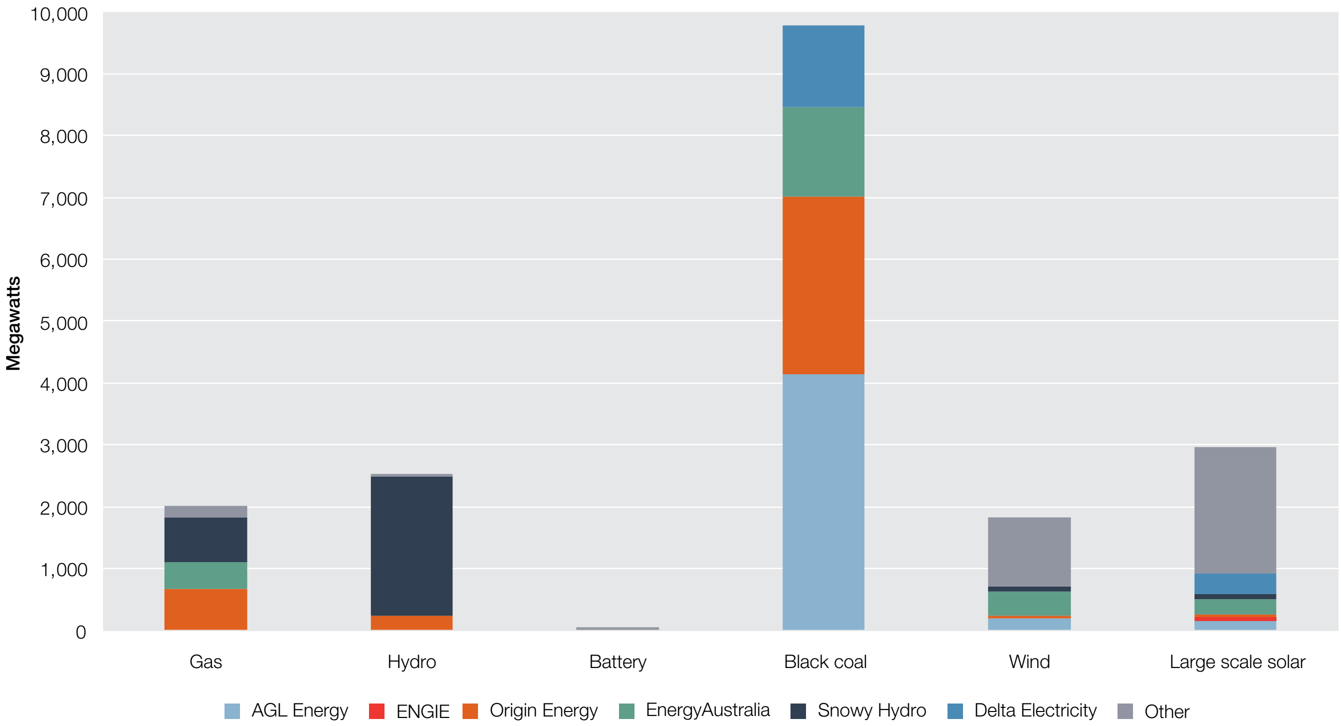
3.1.4 Ownership of dispatchable generation remains concentrated

As outlined in section 3.1.2, the market can still be highly concentrated during periods of low renewables output. This is because at the times when solar and wind generation has constrained availability due to weather constraints, the market must rely on dispatchable generation. This includes thermal fuels like coal and gas, and renewable technologies like hydro and batteries. Unlike coal, which is most efficient running at a steady 'baseload' level of output, hydro, battery and some gas generators also have the additional ability to ramp up and down quickly as 'flexible' technologies.

A few participants control the majority of dispatchable generation capacity across the NEM.

In NSW, the major dispatchable fuel source is black coal, making up 51% of NSW's grid generation capacity. Ownership is highly concentrated across only 4 participants, with AGL Energy, Origin Energy and EnergyAustralia accounting for 86% of registered black coal capacity (Figure 3.7). Gas is similarly concentrated, with 91% of capacity owned by Origin Energy, EnergyAustralia and Snowy Hydro. Ownership of hydro generation is the most concentrated of all fuel types, with Snowy Hydro controlling 89% of registered capacity. As a result, Snowy Hydro has a 60% share of flexible capacity in the region. In contrast, wind and solar ownership is very diversified in NSW – the largest 4 participants control no more than 26% across the 2 generation types.

Figure 3.7 NSW market share by registered capacity, by fuel type, 30 June 2022

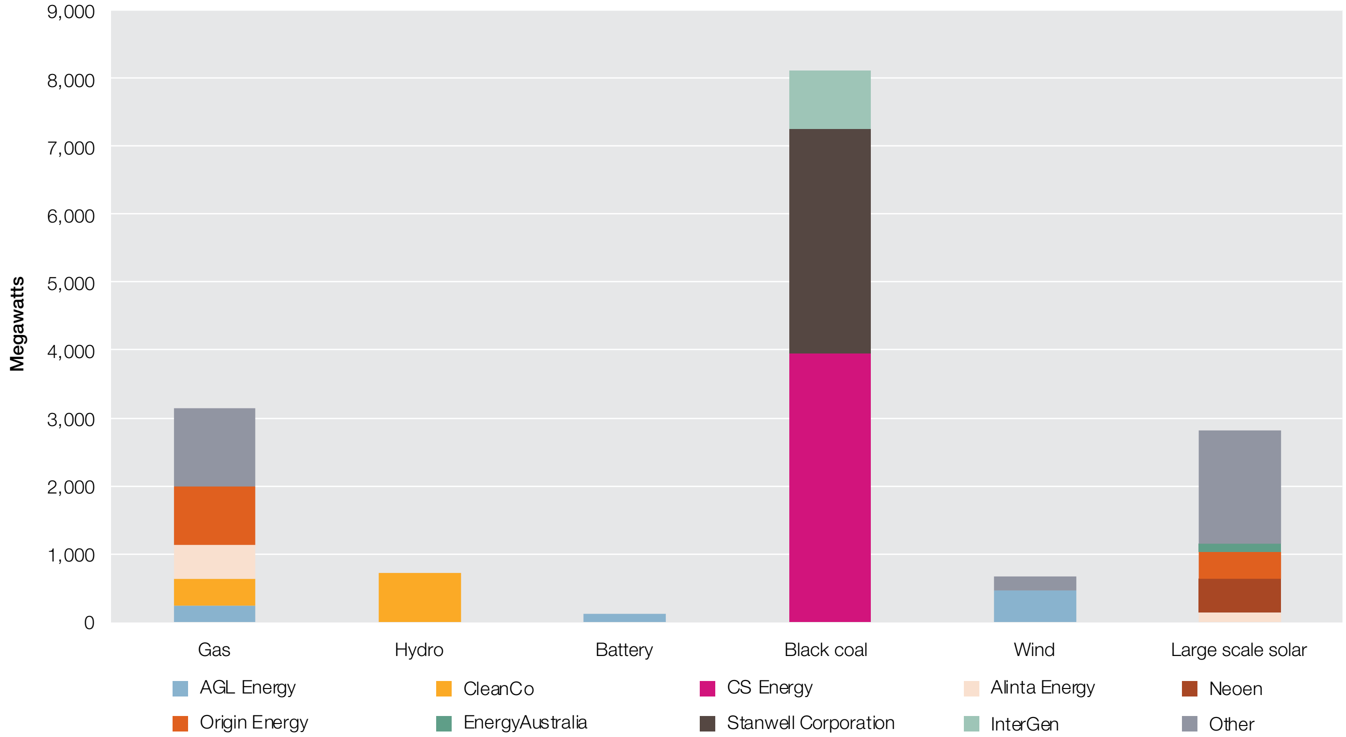


Note: Fuel type capacity share uses registered capacity of all market scheduled generation (excluding market loads) registered as at 30 June 2022. Market shares are determined using ownership declared to AEMO for each unit (DUID). Where an intermediary operates on behalf of the owner, the market share for that capacity is attributed to the intermediary.

Source: AER analysis using NEM data.

Queensland is similarly dominated by black coal, ownership of which is even more concentrated than in NSW (Figure 3.8). Government-owned entities control a significant proportion of dispatchable capacity in this region, with 90% of coal capacity controlled by CS Energy and Stanwell and hydro assets completely controlled by CleanCo. However, gas is more diversified, with ownership spread across 8 participants. As with NSW, control of wind and solar assets are more diversified in Queensland, with the largest 6 participants controlling 51% of intermittent capacity and the remaining split across 19 others.

Figure 3.8 Queensland market share by registered capacity, by fuel type, 30 June 2022

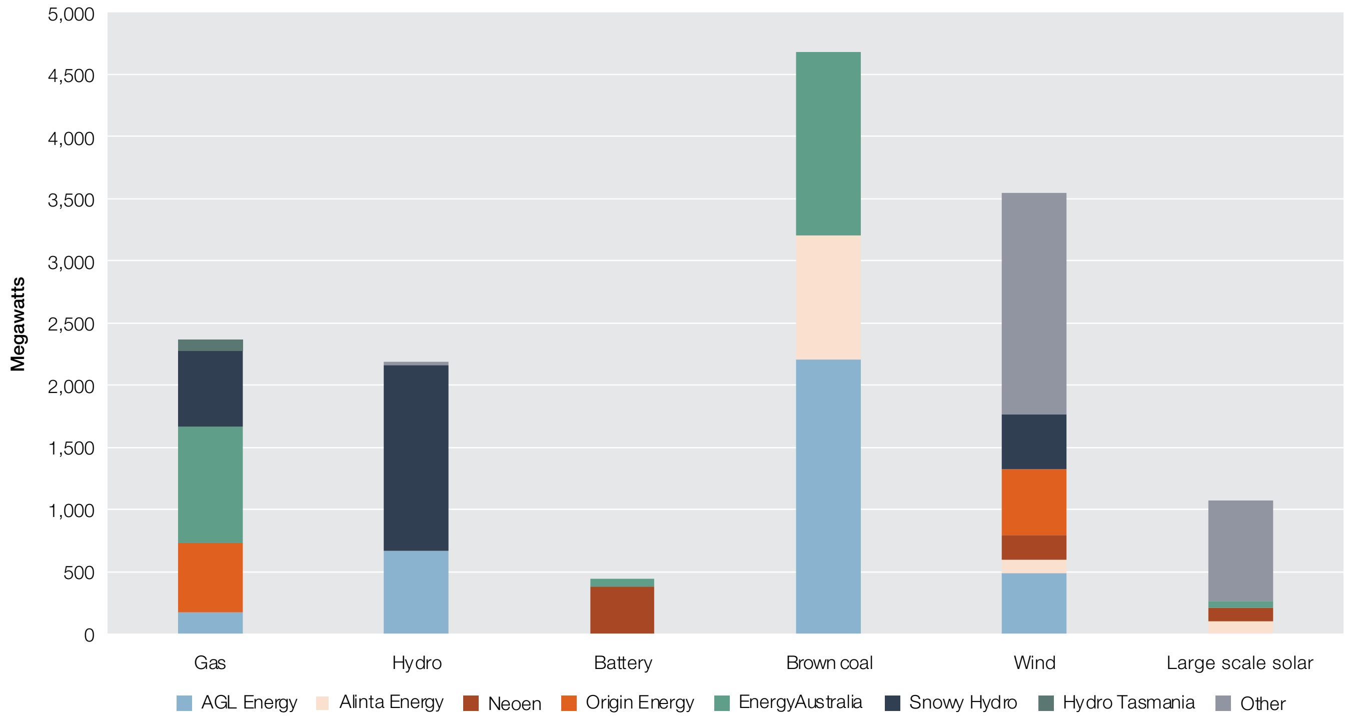


Note: Fuel type capacity share uses registered capacity of all market scheduled generation (excluding market loads) registered as at 30 June 2022. Market shares are determined using ownership declared to AEMO for each unit (DUID). Where an intermediary operates on behalf of the owner, the market share for that capacity is attributed to the intermediary.

Source: AER analysis using NEM data.

Although brown coal is the dominant fuel type in Victoria, other generation capacity is much more significant there than in NSW and Queensland (Figure 3.9). Highly diversified wind capacity now exceeds hydro and gas, but actual output is around 38% of registered capacity (section 3.1.1). Dispatchable generation is also highly concentrated, with AGL Energy, EnergyAustralia and Snowy Hydro controlling 80% of coal, gas, hydro and battery capacity.

Figure 3.9 Victoria market share by registered capacity, by fuel type, 30 June 2022

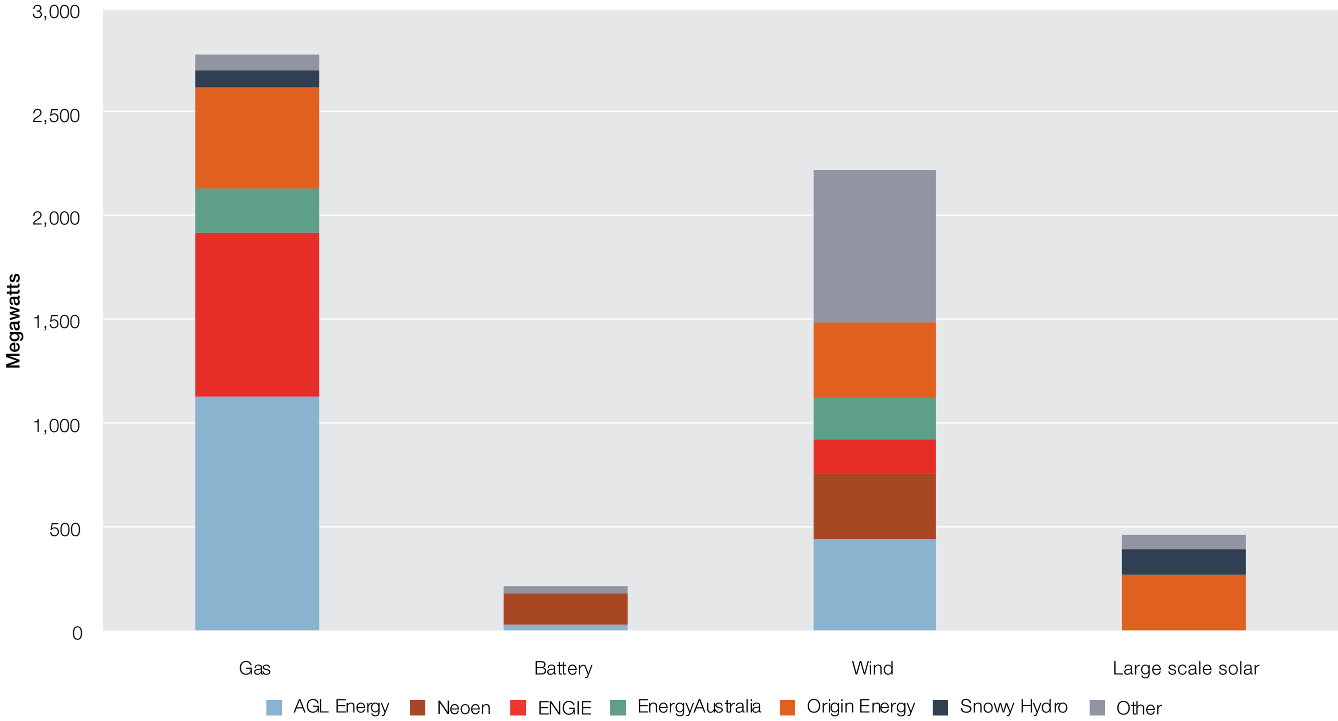


Note: Fuel type capacity share uses registered capacity of all market scheduled generation (excluding market loads) registered as at 30 June 2022. Market shares are determined using ownership declared to AEMO for each unit (DUID). Where an intermediary operates on behalf of the owner, the market share for that capacity is attributed to the intermediary.

Source: AER analysis using NEM data.

Unlike the rest of the mainland, South Australia has a significant renewable capacity and relies primarily on dispatchable gas to firm this generation (Figure 3.10). Ownership of gas is highly concentrated, with 40% of capacity controlled by AGL Energy, ENGIE and Origin Energy. Renewable energy in this region is also more concentrated than elsewhere in the NEM – Origin Energy and AGL Energy control 40% of intermittent wind and solar capacity.

Figure 3.10 South Australia market share by registered capacity, by fuel type, 30 June 2022



Note: Fuel type capacity share uses registered capacity of all market scheduled generation (excluding market loads) registered as at 30 June 2022. Market shares are 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.

Source: AER analysis using NEM data.

Tasmania remains the most concentrated region in the NEM – all of its dispatchable generation is operated by government-owned Hydro Tasmania. However, a few small wind farms in the region are owned by smaller participants.

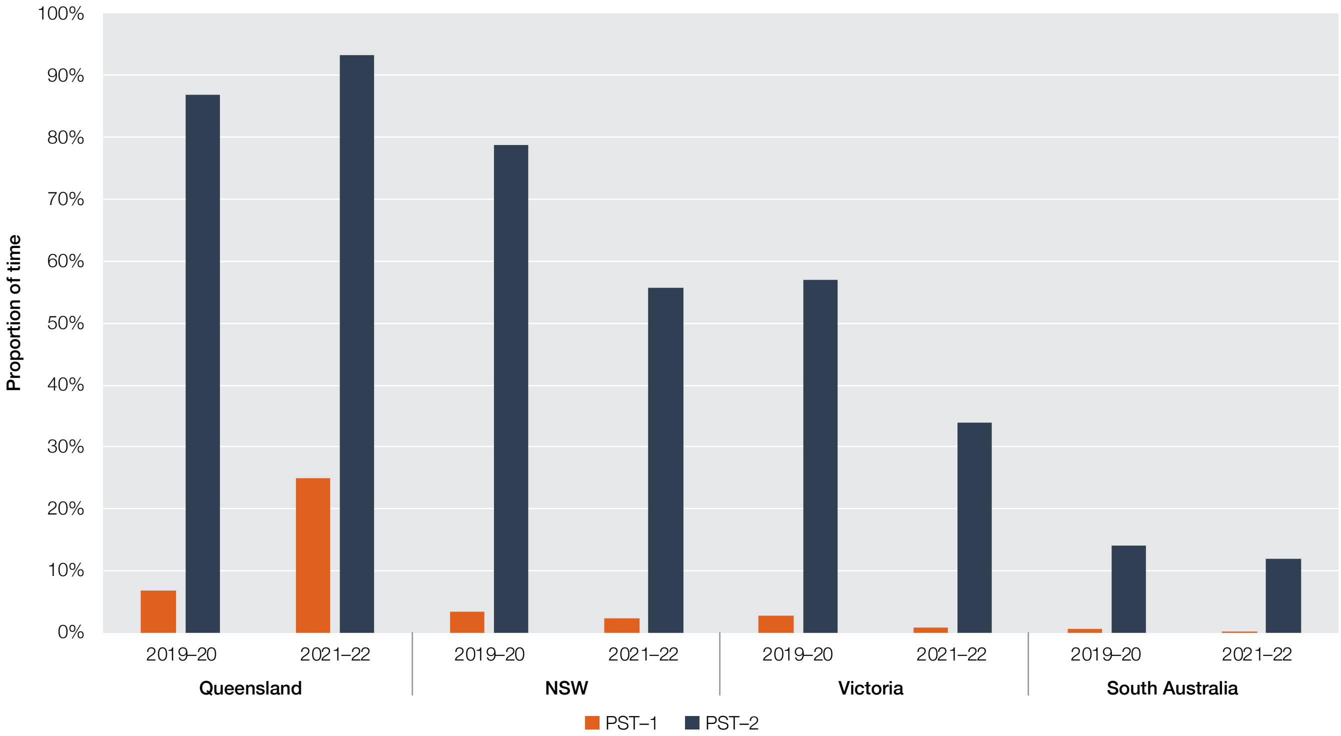
3.1.5 Output of one or two large participants is required to meet demand a significant proportion of time

As a result of the high concentration of dispatchable generation (section 3.1.4), the generation output of a few large participants was necessary to meet demand for a significant proportion of the time in all regions, 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 a participant or participants to exercise market power based on whether they are needed to meet demand. 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.

In the past 2 years, all regions excluding Queensland have become less concentrated (section 3.1.2). As a result, the extent to which the largest generators are pivotal in Victoria, NSW and South Australia reduced (Figure 3.11).

Figure 3.11 Proportion of time some generation from the largest one or 2 participants was needed to meet demand in 2019–20 and 2021–22



Note: PST-1 measures the period during which the available generation of the largest participant was required to meet market demand, while PST-2 measures the period where the 2 largest participants were required to meet demand. Data excludes the administered pricing period from 12 to 23 June 2022.

Source: AER analysis using NEM data.

In Queensland, the time the largest supplier was needed to meet demand almost quadrupled, from 7% in 2019–21 to 27% 2021–22 (corresponding to around 53 days). The 2 largest suppliers (Stanwell Corporation and CS Energy) were required to meet demand 96% of the time – almost the entire year. A major driver of the increased reliance on Stanwell and CS Energy was the upgrades to the Queensland–NSW Interconnector (QNI), which constrained generation from adjoining regions. Consequently, there was less available capacity that could flow from NSW into Queensland, placing greater reliance on the largest local participants.

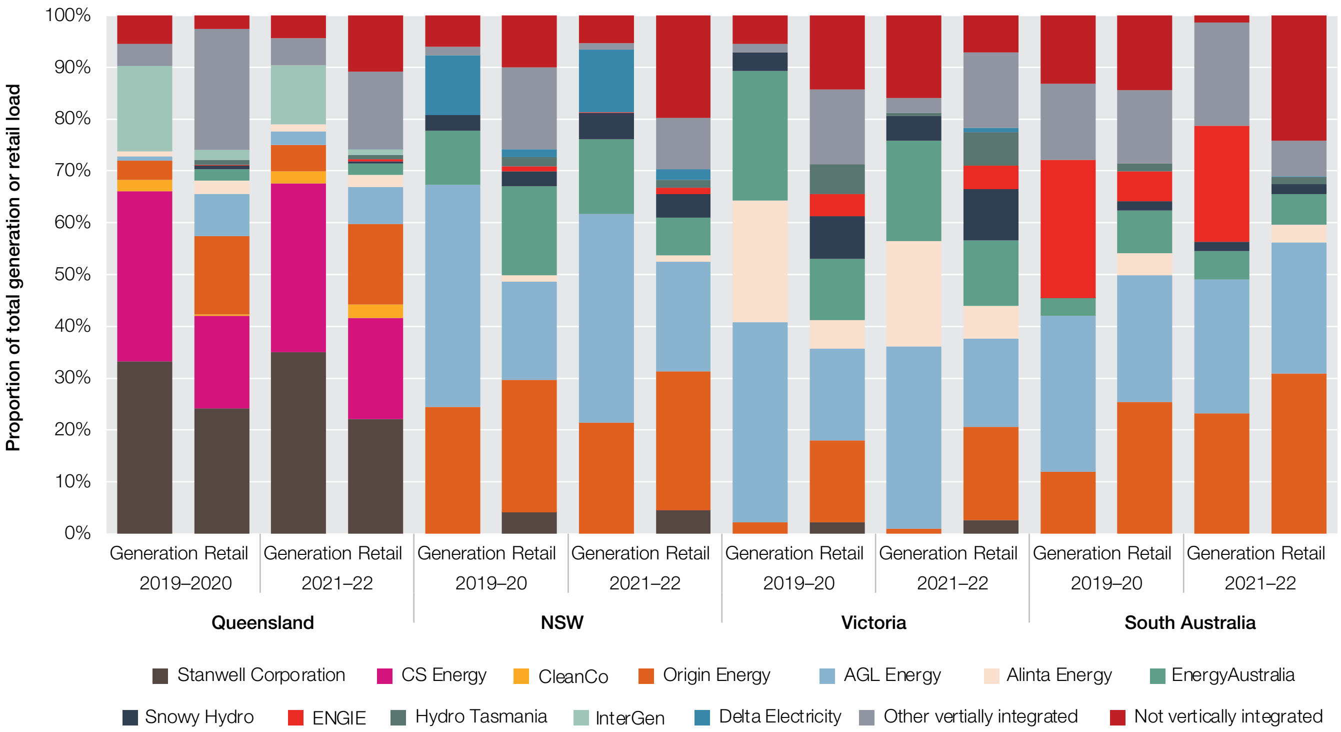
Of the remaining mainland regions, the 2 largest participants were required to meet demand less often than they were 2 years ago. When they were pivotal, less of their generation was needed.

- In NSW, generation from the largest 2 participants was needed to meet demand 56% of the time, almost a 23% drop since 2019–20. The largest suppliers were typically AGL Energy, Origin Energy and Snowy Hydro.
- In Victoria, there was a similar decrease in the PST-2, falling to 34% in 2021–22 from 57% 2 years ago. EnergyAustralia, Snowy Hydro and Alinta were the largest suppliers, although AGL Energy was notably larger than these 3 competitors in respect to available capacity.
- In South Australia, the percentage of time the largest or 2 largest suppliers were pivotal was similar to 2 years ago. However, as Neoen has grown its market share, the largest participants in terms of availability rotated between AGL Energy, ENGIE, Origin Energy and Neoen.

3.1.6 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 3.12).

Figure 3.12 Vertical integration in the NEM, 2019–20 and 2021–22



Note: Vertical integration compares the output capacity MW of each participant with its net retail load MW to determine the extent to which the NEM is vertically integrated.

Source: AER analysis using NEM data.

In 2021–22 the 4 largest vertically integrated participants in each region accounted for the majority of generation output and more than half of retail load:

- In NSW, they accounted for 88% of generation output and 60% of retail load.
- In Victoria, they accounted for 80% of generation output and 58% of retail load. However, Victoria saw a 10% increase in the net load serviced by merchant retailers (those without generation portfolios) from 2019–20 to 2021–22.
- In South Australia, they accounted for 77% of generation output and 65% of retail load. South Australia saw a 12% decrease in output of merchant generators and an increase of 10% in merchant retailers.
- In Queensland, state government owned businesses (CS Energy, Stanwell Corporation and CleanCo) accounted for 70% of total generation output and 44% of load in 2021–22. Distribution of market shares between wholesale and retail sectors remained largely the same, but Stanwell's share of total retail fell by 2%.

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, AGL Energy and Alinta tend to have larger generation portfolios on average, 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, allowing them to manage the risk of high prices.

These differences, along with imbalances between generation and retail load at the regional level, will drive different contracting strategies across the businesses.

3.2 A participant may not have incentive to exercise market power

Section 3.1 indicates that some larger participants may have opportunities to exercise market power in certain circumstances. However, in practice they may not have strong incentives to do so. 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.

3.2.1 Vertical integration and contracting enables participants to manage risk

Vertical integration (section 3.1.6) and contracting (chapter 4) change a participant's exposure to spot prices. Reduced exposure to spot prices also reduces the profitability (and potentially raises the risk to the participant) of any economic or physical withholding (chapter 6).

In theory a participant that is fully contracted with very limited immediate exposure to spot prices is unlikely to profit significantly from a successful withholding strategy, as its revenue is generally determined by the price it sold its contracts at. Chapter 6 outlines how a participant's contracted position can influence its incentives to withhold in more detail.

While vertical integration continues to be a feature of the NEM, the incentives that vertically integrated participants face vary depending on how much generation they control against their retail load. A participant with just enough generation to cover its retail position (a balanced portfolio) would be unlikely to profit from raising spot prices because any additional revenue in its wholesale business would be offset by higher costs in its retail arm. The same may apply if it has less generation than retail load (i.e. 'short' in generation). However, a participant that has more generation than retail load (i.e. 'long') may be able to profit from raising spot prices because 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.

It is difficult to assess 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 insight into the extent to which participants are vertically integrated (section 3.1.6) and therefore their potential risk management, our insights into this are limited because we don't know how balanced their portfolios are in reality. For non-vertically integrated players we have even less insight. Similarly, although we have an understanding of broader contract market dynamics (chapter 4), we do not have access to information on participant contract positions.[22] Where possible we have estimated potential risk management scenarios from public data, including in operational earnings (section 2.5) and as part of our assessment of economic withholding (chapter 6). However, an accurate understanding of how participants manage risk is a significant limitation in assessing participant behaviour.

3.2.2 Government regulation can influence a participant's behaviour

In addition to a participant's exposure to spot prices, government direction and regulation can 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 3.2). 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 3.2 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 March 2021.[23]

In the past there have also been interventions to the offers of government-owned participants in Queensland. 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'.[24] This direction was removed on

22 The ACCC and the Australian Energy Market Commission (AEMC) have made recommendations to improve transparency for over-the-counter transactions. See ACCC, Retail electricity pricing inquiry – Final report, 11 July 2018, p xviii; AEMC, Market making arrangements in the NEM, 19 September 2019.

23 Office of the Tasmania Economic Regulator, Wholesale Contract Regulatory Instrument pricing investigations, accessed 9 November 2022.

24 Queensland Department of Resources, Stabilising electricity prices for Queensland consumers, accessed 8 November 2022.

30 June 2019, ahead of the transfer of generation assets from CS Energy and Stanwell Corporation to CleanCo. With its establishment, CleanCo was given a mandate to increase competition at peak demand times when prices are at their highest.[25] These interventions directly impacted the behaviour of these generators and highlighted how government regulation can alter the incentives of state-owned participants.[26]

The implications of government intervention on investment decisions are discussed in detail in sections 8.1 and 8.2.

3.3 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 3.3). 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.

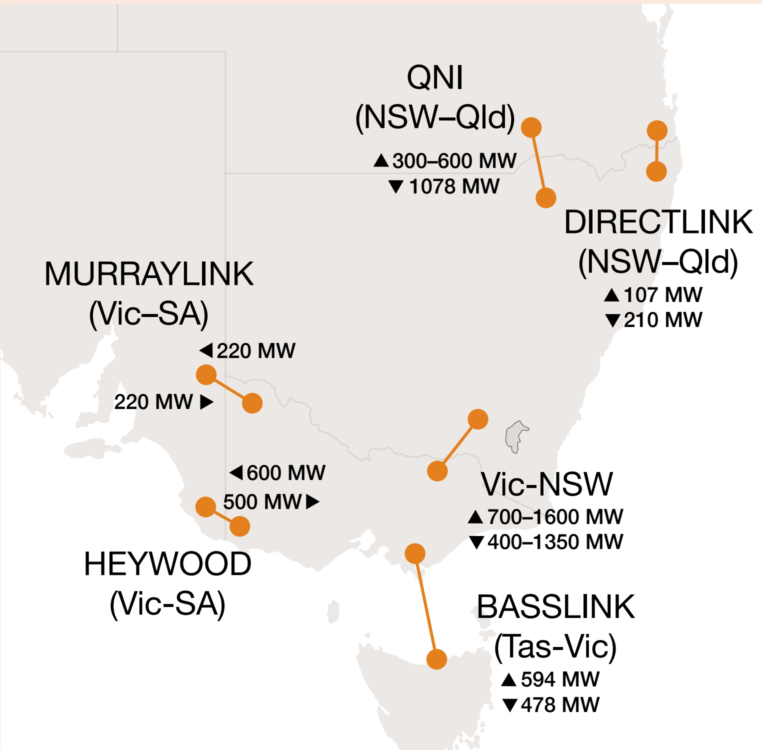
Box 3.3 Interconnectors in the NEM

Transmission interconnectors enable energy transfers between the NEM's 5 regions. Interconnectors generally deliver energy from lower priced regions to higher priced 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 3.13 Interconnectors in the NEM



Source: AER analysis using NEM data.

25 CleanCo, 2018–19 Annual report, August 2019.

26 AER, Wholesale electricity market performance report 2020, 14 December 2020, pp 49–52.

3.3.1 Interregional congestion has increased, driven by network outages

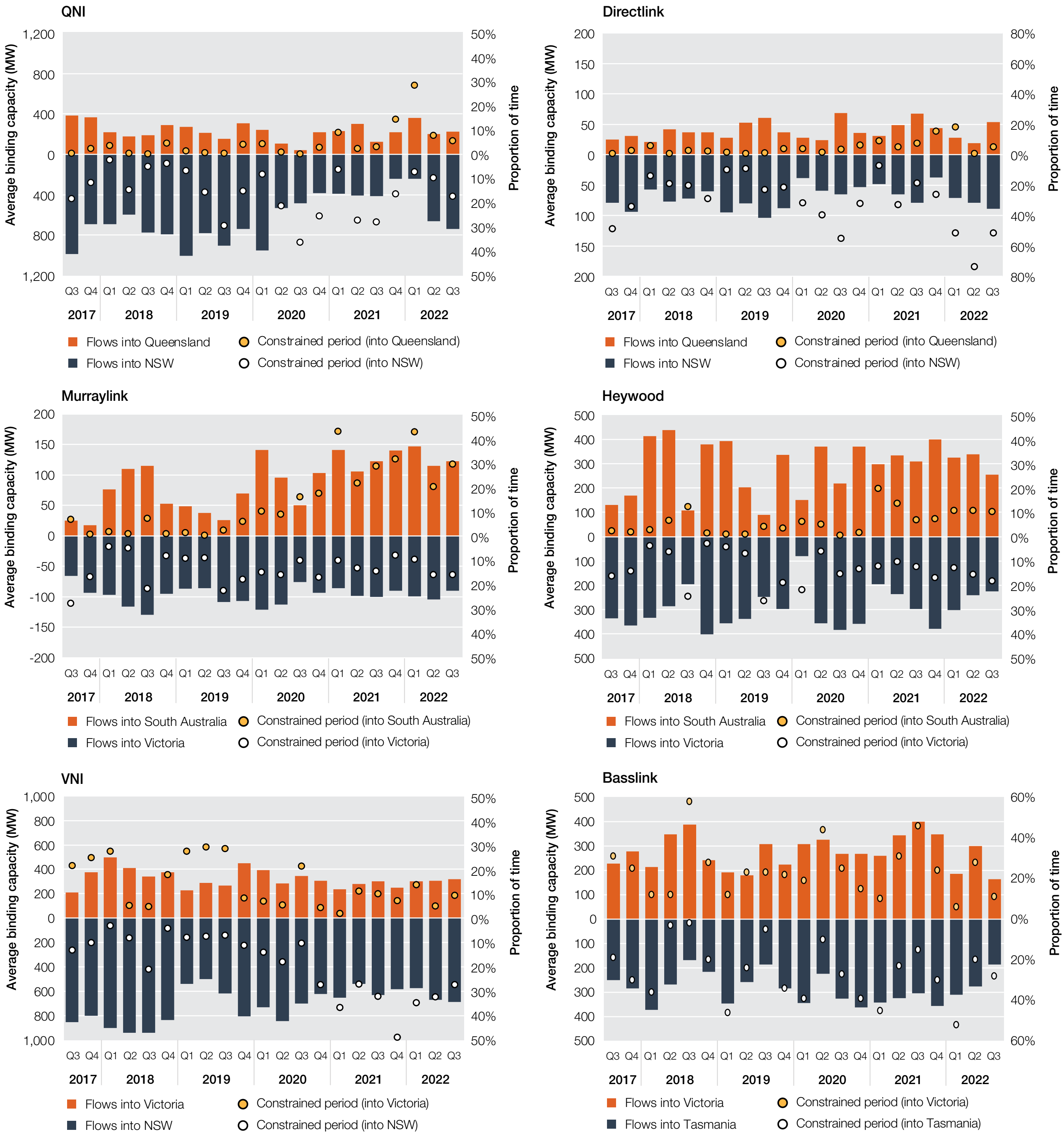
Interregional transfer is an important aspect of the market that promotes effective competition between regions. However, these transfers are impacted by congestion when flows over the interconnectors are constrained by physical or system limitations.[27] Congestion affects market outcomes by distorting the economic dispatch of generators and hence prices. Despite these impacts, a certain level of congestion is expected in an efficient market where the cost of expanding the network to eliminate congestion is greater than the cost of congestion.

Stakeholders have raised that the performance of the network, as measured by factors on constraint equations used in the dispatch engine, appears to be declining over time. This has implications for market efficiency. We explore this by reviewing the time (binding duration) and capacity (binding capacity) congested for each interconnector (Figure 3.14).

- QNI was congested into NSW 16% of the time over the past 5 years. This was driven by system normal constraints in the earlier years but from 2020 it was driven by outage constraints, mostly related to the upgrade of QNI.
- Directlink was congested in NSW 31% of the time, primarily driven by outages. Over the past 5 years there has been an increase in the duration the interconnector was binding, and capacity remained variable.
- VNI was congested into NSW 19% of the time. The congestion was driven by system normal constraints in the earlier years but in 2021 there was a marked increase in outage-related congestion. In 2021 and 2022 the binding duration increased to 31% while binding capacity reduced.
- Heywood was congested into Victoria 13% of the time, primarily driven by outage constraints. In 2021 and 2022 the binding duration increased but the binding capacity remained variable, averaging 270 MW into Victoria.
- Murraylink's congestion into South Australia increased to between 20% and 43% of the time through 2021 and 2022. This was driven by both system normal and outage constraints. The binding capacity also increased considerably, from 57 MW in 2017–18 to 130 MW in 2021–22.
- Basslink was congested into Victoria 24% of the time, primarily driven by system normal constraints. The binding duration varied, typically at high levels compared with other interconnectors. In 2021 there was in increase in binding capacity. This trend did not persist into 2022.

27 There are 2 types of congestion – system normal and outage. System normal is when the network is limited by the normal operation of the grid, while outage congestion is when the network is limited by line outages. Outage congestion often result in the network operating at less capacity compared with that of system normal conditions.

Figure 3.14 Average binding capacity, by interconnector



Source: AER analysis of AEMO data.

In recent years, some increases in congestion were a result of greater competition across regions. This resulted in high periods of congestion but also high flows when the interconnector was constrained, such as seen across Basslink and Murraylink. On the other hand, some increases in congestion are transitory and are linked to interconnector upgrades or network outages, including the events on the QNI and Heywood interconnectors. When this occurs, interconnectors flows are likely to be lower, constraining trade and creating opportunities for exercise of market power. Investment in interconnectors is therefore important for supporting competition but also requires careful coordination and oversight to minimise the opportunity for generators to take advantage of the constrained network, particularly given the scale of investment planned in the energy transition.

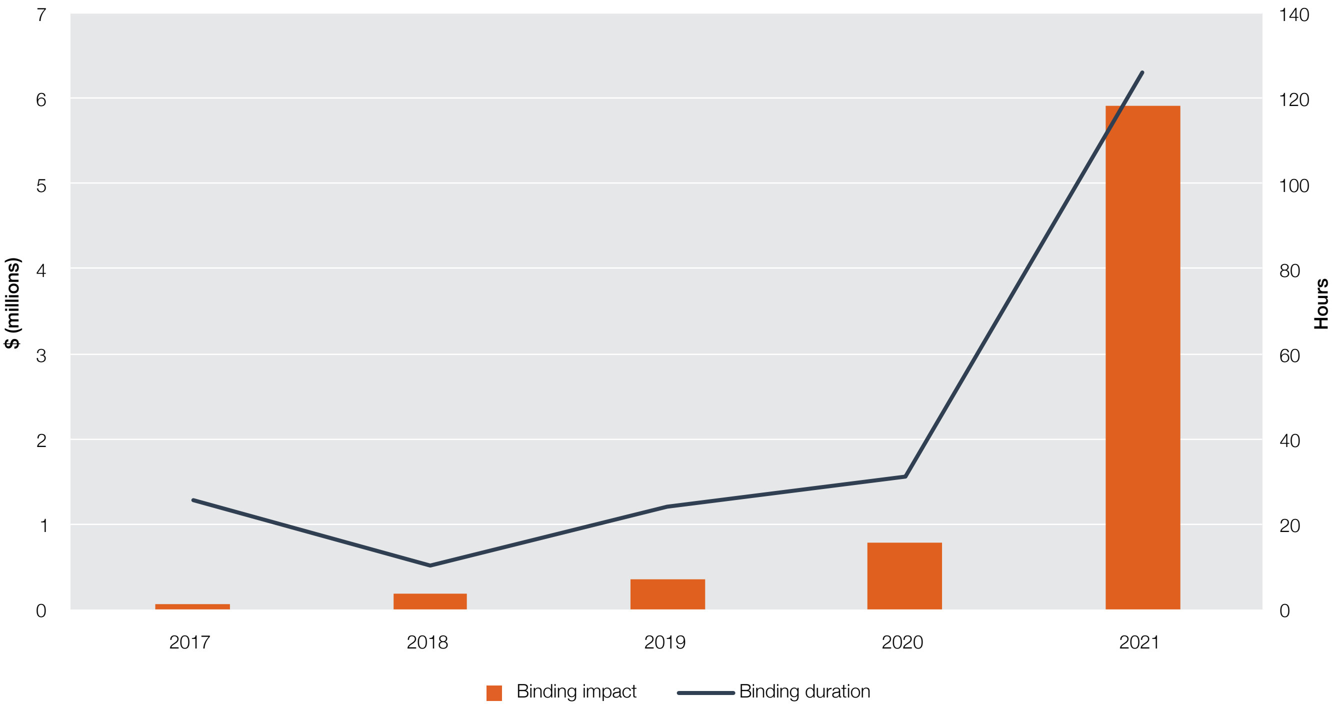
3.3.2 Negative interregional settlement residues have increased

Interregional settlement residues occur when there are energy flows between neighbouring regions and the prices between those regions differ. In the normal course of events, electricity will flow from low priced regions across interconnectors into higher price regions. However, counter-price flows occur when electricity flows in the opposite direction to price in order to manage congestion. This occurs when the NEM dispatch engine determines that the optimal outcome to manage congestion located in one region is to force the flow of electricity into an adjoining region.

When counter-price flows occur, AEMO pays out more money to the generators in the exporting region than it has received from customers/retailers in both the exporting and importing regions. This is known as negative interregional settlement residue. Several inefficiencies are associated with it, including customers paying for energy at a higher price than the marginal generator in their region, and can reduce the value of settlement residue auction units used to manage price risk between regions.

AEMO manages the accumulation of negative interregional settlements by using constraints to limit or 'clamp' exports from the higher priced exporting region into adjoining region(s). The binding duration and binding impact of these constraints provide an indication of the inefficiencies associated with negative settlement residues. The binding impact has increased over the past 5 years, but markedly in 2021 (Figure 3.15).[28] This was primarily driven by the constraints used to manage QNI (into NSW) during the QNI upgrade. This highlights the potential unintended costs of significant network outages at the regional boundaries. The upgrade was completed in mid-2022 and we expect costs associated with the upgrade to decline as the line becomes tested and fully operation over the next year.

Figure 3.15 Negative settlement residues



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 MW. Binding impact represents the financial cost 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. Further details can be found at AEMO congestion information.

Source: AER analysis of AEMO data.

28 AEMO report congestion information annually, generally publishing in March for the previous year. For more detail see AEMO, Statistical Reporting Streams.

3.3.3 Market network service provider Basslink temporarily shifted its bidding behaviour in 2022

During 2022 there were significant changes to ownership and management of Basslink, which resulted in shifts in bidding behaviour and interconnector flows.[29]

Basslink is the only market network service provider in the NEM. This means, unlike other network service providers that have their revenues regulated by the AER, Basslink offers its interconnector capacity into the spot market similar to a generator. However, in practice Basslink entered into a long-term agreement with major generator Hydro Tasmania, which governed its bidding behaviour. This gave Basslink revenue certainty and Hydro Tasmania a large amount of certainty about the capacity available to move energy to and from Victoria. However due to ongoing disputes with Hydro Tasmania and issues from an unsuccessful sale process, Basslink entered into administration in November 2021. As a result, a receiver was appointed to manage its operations. In addition, the service agreement was terminated by Hydro Tasmania in February 2022, with Basslink operators reverting to trading under commercial terms.

The receiver of Basslink changed in mid-June and from July to September 2022 Basslink's offers shifted significantly. The operators bid across a broader range of price bands, offered more capacity at high prices and removed capacity from the market more regularly, often to manage counter-price flows. Without the service agreement, the operators were more exposed to losses when there were instances of counter-price flows (where electricity is exported from a higher priced region into a lower priced region). This behaviour also occurred in June during the market suspension and while the administered price cap was in place, again, likely to minimise losses. However, the shift in behaviour did not appear to have significantly impacted prices in Tasmania or Victoria, with prices falling in both regions across August and September.

As of 30 September 2022, Hydro Tasmania and the receiver established a short-term agreement to make Basslink available at a continuous capacity at a low price. This change would likely also provide more certainty around revenue, rather than trading under commercial terms, potentially a more stable operating structure. In late October 2022 energy infrastructure business APA Group announced it had purchased Basslink. APA Group has stated their intention to convert Basslink to a regulated asset.[30] We will continue to closely monitor Basslink performance and the impact on offers.

3.3.4 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.

To minimise the risk of overinvestment (where consumers pay more than is efficient) or underinvestment (where consumers experience lower reliability or higher than necessary wholesale prices), interconnector investment decisions currently undergo cost-benefit analyses by network service providers.

There are several major interconnector transmission projects currently planned or underway:

- Project Energy Connect, an interconnector connecting South Australia to NSW, was approved in 2021 and construction is currently underway in South Australia. The project is forecast to be completed in the first half of 2026 and aims to deliver greater security and competitive constraint.
- In October 2022 the Australian, Tasmanian and Victorian governments agreed to joint ownership of Marinus Link, a new interconnector connecting Tasmania and Victoria. This will enable an increase in interregional trade between the regions, which will improve the competitive landscape as well as system security. Construction will begin in 2026 and operational in 2028.
- Transgrid and the AEMO Victorian Planning (AVP) are progressing a joint regulatory investment test to assess the viability of expanding the transmission capacity between Victoria and NSW. (VNI West). The interconnector aims to increase the reliability and security of supply for both Victoria and NSW and unlock renewable energy from existing and future renewable energy zones.

29 For more detail see AER, Wholesale markets quarterly – Q3 2022, November 2022, pp 30–32.

30 APA, APA to acquire Basslink, 18 October 2022.

In considering future interconnector planning, we should recognise that energy consumers ultimately bear the cost of new investment. In particular, the full impacts of interconnector investment should be considered. For example, the recent upgrade of the QNI conducted between May 2020 and June 2022 resulted in significant costs in varying areas of the market, including interregional congestion (section 3.3.1), negative settlement residues (section 3.3.2) and FCAS (section 9.1). This highlights opportunities for efficiency improvements for future network upgrades, especially for extended durations on key networks such as interconnectors. It also highlights greater consideration should be placed on impacts of outages on market dynamics and not just energy prices.

4. Contract markets

Key points

- The electricity contract market has experienced unprecedented volatility since the sharp rise of spot prices in early 2022.
- Traded volumes and open interest have increased considerably in the past 5 years. This is mostly driven by the increase in trading of option contracts, a method of hedging utilised almost exclusively by the largest participants and financial speculators. However, in 2022 there are clear signs that liquidity has started to fall, with Q3 2022 volumes the lowest since 2020.
- The outlook for liquidity is concerning. Access to clearing services has tightened while increased margin payments have impacted the cost of trading and holding of contracts. Longer term, the closure of base load generation is also reducing the amount of contracts on offer.
- A lack of liquidity in the contract markets is a significant source of risk. It can impact the sustainability of existing participants and create barriers to entry and expansion.

Some level of volatility in spot prices is an expected feature of a competitive market. Volatility sends price signals for investment, but it also increases 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.

The National Electricity Market (NEM) relies on a liquid contract market operating alongside the spot market, to enable participants to efficiently hedge against price volatility and underpin investment signals (Box 4.1). To enable participants to easily buy and sell contracts to manage their risk, contract markets must be liquid.

Recently, trading in contract markets has declined and contract prices have increased sharply amidst unprecedented volatility in the NEM.

In the immediate term, while legacy contracts remain open, unprecedented market volatility and high prices pose challenges to generators through significant, albeit transient, changes in cash flows arising from margin requirements (section 4.2.2).

In the longer term, as these contracts lapse and participants seek to re-contract, the outlook for contract liquidity is concerning (section 4.2). This poses clear risks for retail competition, but also reduces the level of revenue certainty available to generators. We are concerned this may prove a deterrent to investment required in the NEM.

Box 4.1 Contract markets in the NEM

Prices in the wholesale market can be volatile, rising as high as $15,500 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 contracts are traded on the Australian Securities Exchange (ASX) or FEX Global. Electricity futures contracts are available for Queensland, NSW, Victoria and South Australia. Until recently, the ASX was the sole futures exchange operating in the NEM. FEX Global launched a separate futures exchange in March 2021 offering a similar range of products. At this stage, trading on FEX Global is illiquid with only 3 trades occurring to 30 June 2022.

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 several 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 contracts 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 contracts 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).

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

4.1 Liquidity in contract markets has declined due to unprecedented volatility

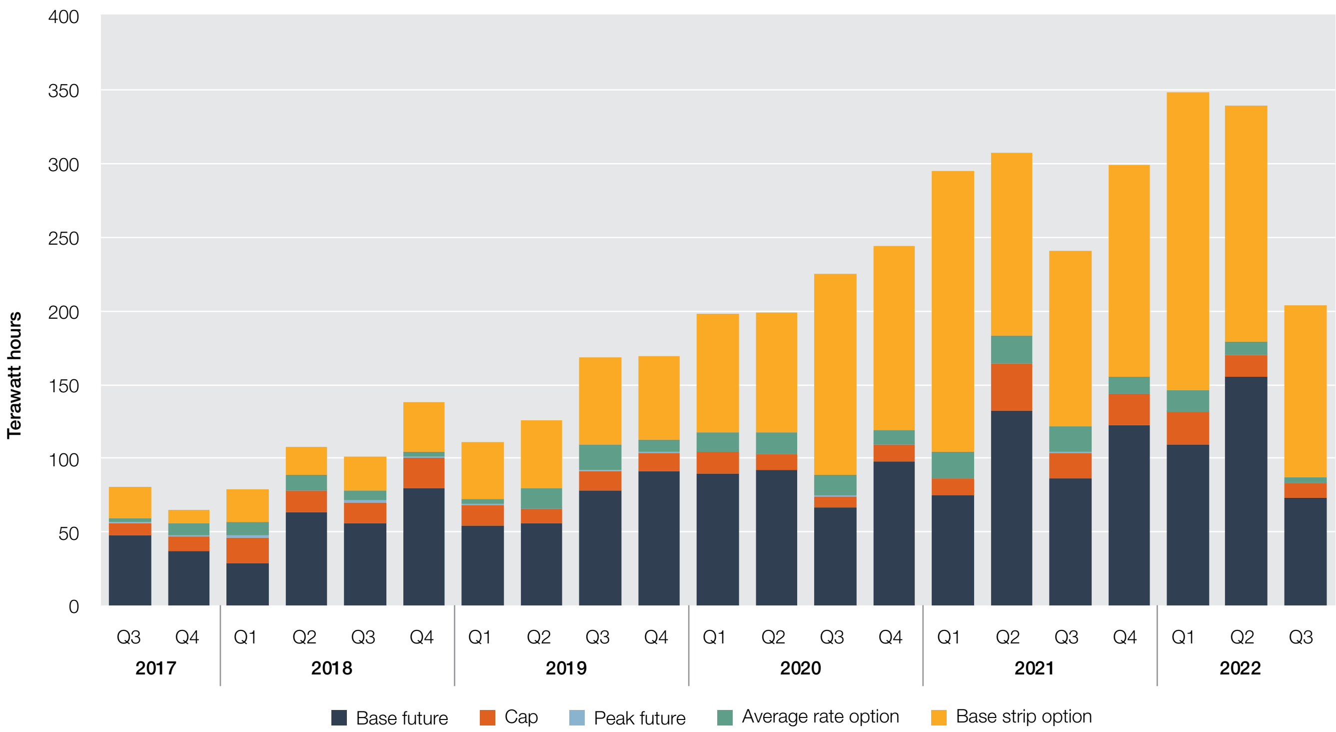
In general, a liquid market is one in which a participant can reasonably expect to buy or sell a contract, within a reasonable price range, without that trade moving the price unreasonably.

4.1.1 Liquidity in exchange traded contracts is declining

Limited public information is available on the contracting arrangements in the NEM. The ASX publishes some information on trading, including the price and volumes traded, but not the parties to transactions.

ASX activity shows that traded volumes have increased significantly in recent years (Figure 4.1). In 2021–22 a record high volume of contracts (1,226 terawatt hours (TWh)) was traded on the ASX, more than triple the volume traded 5 years ago. Most of the growth in traded volume is due to an increase in options being traded. While traded volume has increased steadily, there was a drop-off in volumes in Q3 2022 following the sharp increase in spot prices that occurred during Q2. Concerns about liquidity have been raised with the AER and are discussed in detail in section 4.2.

Figure 4.1 Traded volumes in ASX electricity contracts



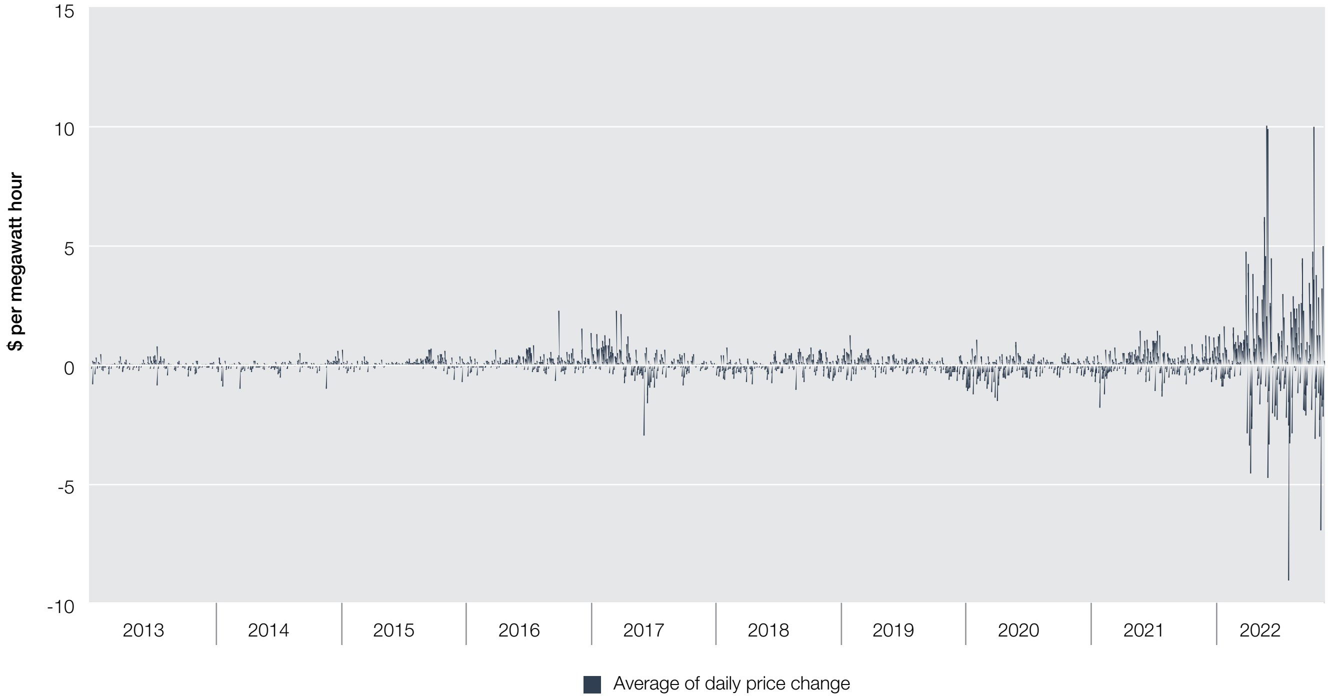
Note: Volume of trades that occurred during the quarter across ASX Energy futures.
Source: AER analysis using ASX data.

Queensland was the most traded region in 2021–22, accounting for 48% of the total volume traded, likely due to less vertical integration and thus less internal hedging. Queensland volumes have increased 415% in the past 5 years. NSW and Victoria have also increased, up 290% and 127% respectively. South Australia is the only region that has seen traded volumes decline in the past 5 years, down 22% compared with 2017–18.

4.1.2 High daily price changes also suggest an illiquid market

Since early 2022 the contract market has experienced many large daily changes in contract prices (Figure 4.2). These daily price movements are unprecedented. While some additional price volatility was observed following the sudden closure of Hazelwood Power Station in 2017, the scale of the volatility from that event is dwarfed by the volatility seen in the market price since early 2022.

Figure 4.2 Average daily price change, base futures contracts



Note: Average daily price changes of all quarterly base futures contracts with a published daily settled price.
Source: AER analysis using ASX data.

Large swings in daily or intra-day contract prices are an indicator of declining liquidity. As the market depth falls due to a lower number of buyers and sellers, contract prices are likely to be more volatile. This is because a solitary buyer or seller in an illiquid market will have a bigger influence on the contract price compared with a market with many buyers and sellers.

4.1.3 Use of over-the-counter markets likely increasing

In contrast, activity in OTC markets is confidential and not disclosed publicly. In the past, the Australian Financial Markets Association (AFMA) has reported 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. From 2021–22 AFMA are no longer reporting on OTC trades.

Stakeholders report a significant increase in the use of over-the-counter contracting, particularly for small retailers. This is corroborated by findings published in the ACCC's Inquiry into the National Electricity Market November 2022 Report.[31] The ACCC reported that smaller retailers have shifted further towards over-the-counter contracts, with a 16% increase in over-the-counter purchases in 2022 (excluding load following swaps). This increase was especially apparent in Q2 2022, which saw a 33% increase from Q2 2021.

A shift to the over-the-counter market decreases the visibility of contract market liquidity and prices. As the wholesale electricity market transitions, transparency and visibility through ongoing contract market monitoring and reporting is integral to inform policy and regulation and ensure effective operation of the energy markets. Access to non-public contracts information would increase the AER's ability to effectively monitor conduct and advise on market outcomes.

31 ACCC, Inquiry into the National Electricity Market, November 2022.

4.1.4 Trade in option contracts is significant and growing, but is a method of hedging unavailable to many participants

In times of uncertainty, options are a prudent hedging tool. As a result, options are increasingly being used by market participants to manage their risk. Base strip options are currently the most popular type (Box 4.2).

Box 4.2 Options

The term option refers to a financial instrument that is based on the value of the underlying asset. An electricity options contract offers the buyer the opportunity to buy or sell, depending on the type of contract they hold, the underlying asset at an agreed strike price, volume and term.

There are 2 types of standard options available through either the ASX or FEX Global.

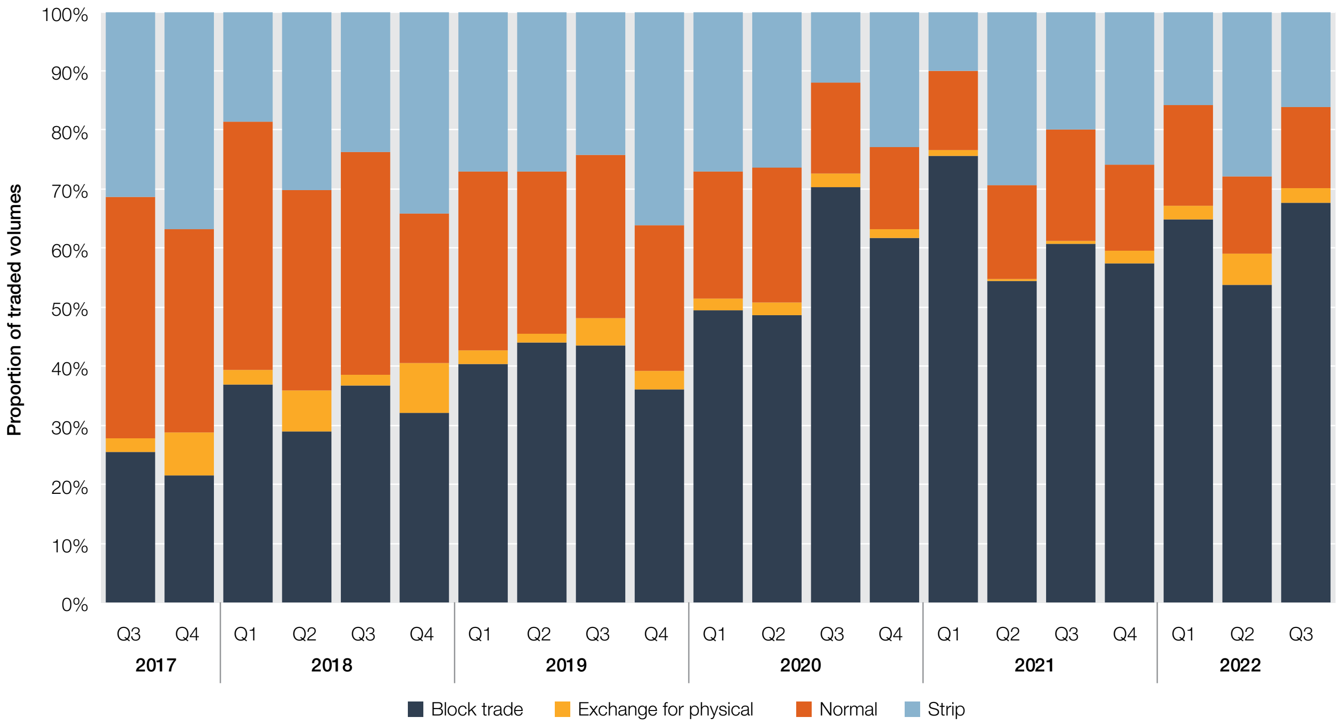
- **Base strip options (also called swaptions) –** are traded for either a calendar year or financial year. The buyer pays a premium up front to have the opportunity, in the future, to buy/sell a set of 4 quarterly base futures contracts at a set price (the strike price). They must exercise their options (convert into the underlying base futures contracts) before the expiry date (swaptions expire 6 weeks before the start of the year). Once an option is exercised the buyer will own the 4 quarterly base futures contracts that make up either the calendar or financial year. The price of a base strip option is intrinsically linked to the price of the underlying base future contracts.
- **Average rate options (also called Asian options) –** are bought/sold for a quarter. The payout for this type of option is based on the average spot price for the quarter measured at the end of the quarter. The buyer of an average rate option pays a premium upfront and the option is auto-exercised at the end of the quarter only if the option is 'in-the-money' (that is, the buyer will receive a payout). An average rate option can be bought and sold until the last day of the quarter.

Options have many advantages for buyers. Firstly, options allow the buyer to lock in a price for futures contracts in advance. This allows the buyer some price certainty without restricting them from achieving a better price if contract prices move in their favour. If the contract prices become more favourable in the time before the option expiry date, the option buyer can let the option expire and only lose the premium that they paid. They are then able to purchase the contracts from the market at the more favourable price. However, if the option price for the contract is more favourable to the buyer than the current market price, they are able to exercise the option and purchase the futures contracts at the agreed price.

Secondly, the buyer of an option is exposed to less cash flow risk from margining requirements. The buyer must pay the option premium but is not exposed to the same initial margins and daily variation margins that the seller is (Box 4.3). The current cash flow squeeze outlined in section 4.2.2 means that options have never been more attractive from a buyer's perspective.

Traded volumes of base strip options have increased fivefold in recent years, only a small percentage of these trades are occurring 'on screen' (trades made by matching buy and sell offers for contracts through the exchange). Instead, 94% of the trades in 2021–22 were done off-market (via a block trade), direct with other parties, which is then cleared via the ASX and contributes to the traded volume. This limits access for those without means to trade directly. Across all energy contracts traded on the ASX, 59% of the volume was traded via a block trade in 2021–22, up from 29% in 2017–18 (Figure 4.3).

Figure 4.3 ASX traded volume percentage, by trade type



Note: Normal trades are made by matching buy and sell offers for contracts through the exchange. Strip trades comprise a bundle of the 4 quarters of the year (either calendar or financial).

Source: AER analysis using ASX data.

Block trades have a minimum trade size of 25 MW, which is larger than the average size futures contracts are generally traded. In 2021–22, 74% of all base strip option trades were traded in lot sizes of 25 MW or higher. The high volume of these large trades indicates that base strip options are primarily traded between the largest market participants and are less available to smaller participants. Base strip options are attractive to financial participants – those without retail or generation – and act to inflate the overall volumes traded.

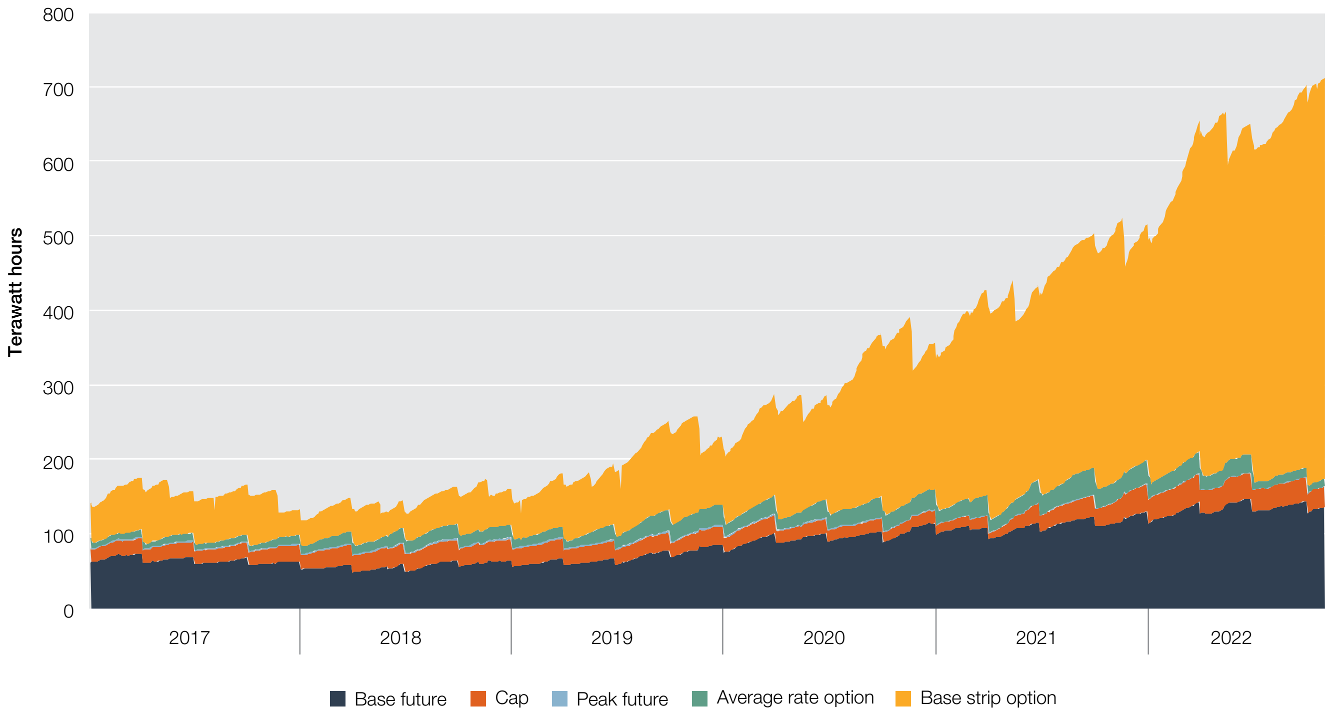
In recent months there has also been an increase in the volume of exchange for physical (EFP) trades. An EFP is an off-market transaction that involves swapping (or exchanging) a futures position on the exchange to an OTC position. As a result, futures positions are transferred to an OTC position or the reverse. An increase in the volume of EFP trades is a sign that market participants are looking to reduce their cash outlay by moving their contracts away from the ASX.

EFP transactions increased in March 2022 and remained elevated through to June. Although a movement of contracts from the exchange to OTC can help ease cash flow constraints, market participants face a trade-off because they are agreeing to take on more third-party credit risk (the risk that the counterparty is unable to meet their contractual arrangements).

4.1.5 Decline in contract trading not yet evident in currently held contract volumes

Open interest for ASX contracts has increased significantly, from less than 200 TWh in 2018 to more than 700 TWh at the end of October 2022 (Figure 4.4). Open interest indicates how many open contracts are being held by market participants on the ASX at a given point in time. Higher levels of open interest indicate more contracts are available for trade and being held to the end of the contract term. Most of the open interest growth is due to the increased volume of base strip options being traded.

Figure 4.4 Monthly open interest



Note: Open interest for all ASX Energy contracts.
Source: AER analysis using ASX data.

4.2 Outlook for liquidity is concerning

The increase in traded volumes and open interest could be interpreted as an indicator of improved liquidity. However, market participants have raised concerns with the AER about the declining liquidity in the contracts market, particularly since the sharp increase in spot prices in April 2022 (section 2.1). While the contract traded volumes have generally increased in recent years, traded volumes fell in Q3 2022 to the lowest level since Q2 2020. The following factors have combined to raise concerns around liquidity in the short to medium term.

4.2.1 Reduced access to clearing services

To transact on either the ASX or FEX Global, a market participant requires a clearer to clear and settle the transaction.

Exchanges, like the ASX, facilitate trades between counterparties and take on risk as they are a counterparty to all trades. The ASX Clearing House manages their risk by imposing margin requirements on their contracting counterparties, the clearing participants. The clearing participants then pass on these margin requirements to retailers and generators.

In November 2022 there were only 5 clearing service providers for electricity derivatives approved by the ASX.[32]

On 14 October 2022 it was reported that Bell Potter had withdrawn its clearing services for ASX electricity derivatives.[33] Affected clients have had varying degrees of success in finding an alternative, with some informing the AER that they have not been able to secure a new clearer despite contacting all listed service providers. Participants without access to the ASX or FEX Global will be forced to hedge using OTC contracts, either through a broker or negotiated directly with a counterparty. An OTC trade negotiation can be time-consuming and small retailers may find the credit requirement imposed on them by counterparties to be onerous.

It was also reported that Macquarie had moved to restrict clearing services for electricity futures for would be clients while existing customers will continue to be able to clear electricity futures.[34]

The exit of Bell Potter and restriction of Macquarie's services illustrates the risks of having such a small pool of clearing service providers. This is especially true at times of high electricity prices, when clearers are forced to take

32 ABN Amro, BNP Paribas, JP Morgan, Macquarie Bank, Societe Generale, see ASX Clearing Contacts.

33 Financial Review, Energy retailers struggle for hedges as Bell Potter withdraws, 14 October 2022.

34 Financial Review, Energy chaos grows as Macquarie restricts clearing services, 14 October 2022.

on more risk due to the volatile daily price fluctuations and risk that the client is unable to make the daily margin payment. The limited clearing pool is also a risk for new exchanges. FEX Global has confirmed to the AER that it considers the scarcity of available clearers as currently the most significant barrier that new customers face when seeking access to FEX Global products and services.

4.2.2 Rising spot prices impact margins, credit and cash flow

Increasing spot prices have resulted in substantial increases in contract prices, as well as high daily variations in the daily settlement price of these contracts (section 4.1.2). While contract prices have generally increased (section 2.1.1), there have been large fluctuations – both up and down – in daily settlement prices (section 4.1.2). This has resulted in significant daily variation margin payments.

Box 4.3 Margin requirements

The role of the margin payment is as a security to cover any shortfall if the market participant is unable to pay at contract settlement. The clearing service provider then passes some or all of these payments onto the ASX Clearing House. The individual clearing service providers manage their own risk by imposing their own margin requirements on the retailers and generators, on top of those margins paid to the ASX Clearing House.

There are 2 types of margins:

- Initial margins are paid on entering into the contract and provide security to cover any reasonable price changes that can occur in a 3-day window. This gives the ASX 3 days to find a buyer for any contracts in the case that a retailer or generator can't afford to continue holding the contract. The initial margin is based on modelled scenarios but is linked to the contract price. If the price of the contract increases, the associated initial margin increases. The initial margin can be either cash, collateral or a guarantee.
- Variation margins are based on the daily changes to the settled price for each contract. When a futures contract increases in price, the seller must pay the difference between yesterday's price and today's price in the form of a variation margin. The buyer of the contract will receive the variation margin. The opposite is true when the price of the contract falls. The variation margin must be paid in cash within a day of the price movement.

Given the current volatility of contract prices, variation margins are having a material impact on cash flow. Contract prices have increased by as much as 680% since the start of 2022 (section 2.1.1). Each time the contract price increases, the seller of a futures contract is required to make a variation margin payment. The biggest sellers of futures contracts are typically the largest generators in the NEM. These participants have had the largest daily margin calls over the past 6 months. Generators posting large variation margins can make back this money as they are selling their generation into the spot market at elevated prices. However, this poses a real cash flow issue because margins are paid now on contracts for generation that won't be sold into the spot market for months or years in the future. There is also the possibility that these contracts were sold with the assumption that fuel (coal and gas) could be sourced at much lower prices than are available now, resulting in a higher cost to generate that may or may not be covered by the agreed to contract strike price.

Cash flow is not only an issue for generators that have sold multiple contracts. As contract prices increase and become more volatile, the initial margin paid by all buyers and sellers is increasing. Retailers and generators also have internal risk positions – that is, they set their own limits on the amount of risk they are exposed to through either the contract market or spot market. With margin requirements increasing, many participants have informed the AER that they are at or near their risk limits. This limits the amount of contracting they can engage in.

Some participants are choosing to move volume to the OTC markets. This brings with it additional hurdles, particularly for smaller participants, in the form of credit requirements. In times of high contract prices and increased volatility, the credit requirements are likely to be more onerous. It was recently reported that several retailers have been shocked by the collateral, or capital requirements, asked of them. One industry source was quoted as saying 'we got asked for capital requirements that we've never been asked for before. It will be a serious challenge for us'.[35]

35 Financial Review, Energy retailer squeeze worsens as hedging costs spike, 24 October 2022.

4.2.3 Generator exit, reliability and fuel costs create uncertainty

Market participants have informed the AER that the combination of coal closures, concerns about reliability of baseload plant, concerns about coal supply and uncertainty around fuel costs has led them to reduce the number of hedge contracts sold off the back of this baseload plant compared with past years. This will be an ongoing challenge as the transition to renewables accelerates in the coming decade.

Traditionally, base futures contracts have predominantly been sold by the owners of baseload generation. As this generation is retired, the owners will consequently offer fewer contracts. The replacement renewable generation is not as well suited to fixed load contracts and will require firming by dispatchable generation or through complementary contracts. Coal unit closures will reduce the amount of hedging contracts offered from these units (section 7.1.3). Liddell (AGL) and Eraring (Origin) are both due to close in the coming years. Historically, both AGL and Origin would either have used this generation as an internal hedge or sold excess generation into the contract market. The replacement of coal generation with renewables will not result in the same level of contracting and both AGL and Origin may need to buy more contracts compared with previous years to account for this lost baseload generation. Coal closures will continue to impact liquidity for years to come with Callide B, Yallourn and Vales Point all scheduled to close before 2030.

The number of baseload outages has increased each year since 2017–18 (section 2.4.2). As coal generators near the end of their life, they are likely to be more unreliable. To manage the risk associated with selling contracts backed by this generation, some generators have told the AER that they are offering less contracts due to reduced reliability.

Some long-term fuel agreements have also expired in recent years and the replacement fuel contracts are now negotiated on a shorter-term basis. Given the increasing cost of fuel and uncertainty around fuel prices for gas and coal, both nationally and internationally, generators have told the AER that they are unable to sell contracts off the back of their generation assets as far into the future as they once did.

4.2.4 Standard cap contracts are not as attractive to sellers

Cap contracts are widely used to manage a retailer's exposure to high spot prices. The standard cap contract offered on the ASX has had the same strike price since inception at $300 per MWh. Unprecedented spot prices in Q2 and Q3 2022 saw sustained periods of spot prices exceeding the strike price of $300 per MWh, resulting in cap sellers having to pay out record amounts. Given the recent market conditions, cap sellers are likely to offer less contracts into the market or turn to the OTC market where they can sell contracts with a higher strike price. FEX Global has already moved to list a cap contract with a $500 per MWh strike price.

4.2.5 Retailer Reliability Obligation aims to support liquidity

The Retailer Reliability Obligation (RRO) scheme (launched in July 2019) creates incentives for retailers and large energy customers to purchase contracts that support investment in dispatchable electricity generation in regions where a gap between generation and peak demand is forecast. To support contract market liquidity, a market liquidity obligation (MLO) operates when the RRO is triggered. The MLO requires large generators to perform a 'market maker' role by offering to buy and sell hedge contracts on the ASX or FEX Global.

The RRO has been triggered in NSW in summer 2024 and 2026 and South Australia in all summer periods from 2022 to 2025. The first T-1 reliability instrument was issued in October 2022, with liable entities required to submit their net contract positions for Q1 2024 to the AER in mid-2023.

The significant events in wholesale spot and contract markets across 2022 make it difficult to assess the direct impacts of the RRO on liquidity. However, because the MLO requires some level of market making, it does provide a guarantee to market participants that some contracts will be available to trade.[36] This is likely to be of greater importance in some markets than others, and particularly important in South Australia due to the lower liquidity there.

36 AEMC, Market making arrangements in the NEM, September 2019.

4.3 Low liquidity creates challenges for new and existing participants

A lack of liquidity in the derivative contract markets is a significant source of risk. It can impact the sustainability of existing participants and create barriers to entry and expansion.

Market participants, both retailers and generators, use electricity contract markets to manage their exposure to spot prices. Current pressure on the financing costs involved in contracting, access to clearing services and a less liquid market means participants are less likely to be able to manage their risk in the same way they have previously. If alternative contracting arrangements cannot be undertaken, for example via the OTC market, it may result in market participants having greater exposure to spot prices in the future. This can further increase the risks these participants face in meeting current financial costs and appropriate levels of cash flows to satisfy a number of requirements they need to meet to remain in the market.

If a larger proportion of the market shifts to contract via OTC, transparency in both prices and volumes will reduce. The OTC market presents greater challenges, especially for smaller players. Without the benefit of confidentiality that occurs when purchasing contracts via the ASX (where the counterparty to trades is unknown), the OTC market generally provides smaller participants with less bargaining power than the larger counterparties. The ACCC found that over-the-counter contracts in most NEM regions traded at a premium over ASX equivalents in 2022 relative to 2021. It also found that smaller retailers bought proportionally larger volumes of over-the-counter swap contracts than larger generators and gentailers when prices were high.[37] Smaller participants will also need to spend more time and incur more costs on sourcing potential trading partners, while relying on larger players' willingness to trade with them given the current tight credit conditions.

A decrease in liquidity can often result in an increase in market price volatility, because the lack of market depth makes it difficult to set a price point based purely on demand and supply of contracts. For example, some participants currently find it difficult to understand large daily and intra-day movements in contract prices, which is adding additional concern to trading via ASX energy futures markets.

These issues impacting liquidity could persist through the transition and compromise the competitiveness and efficiency of the NEM. The dynamics of contract markets are an important influence on the performance of the wholesale electricity market. The events of 2022 have highlighted the need for ongoing monitoring of contract market outcomes. Governments need information to understand drivers behind events like those experienced in 2022 in order to ensure the market design and regulatory landscape is fit for purpose as we transition to a low-emissions future.

37 ACCC, Inquiry into the National Electricity Market, November 2022.

5. Participant conduct

Key points

- In our 2020 report, we observed that participants offered capacity at lower prices following reductions in fuel input costs, and that there was competitive pressure from new low-cost solar and wind generation.
- Since then, rising fuel costs, fuel supply issues, weather events and significant outages have caused many participants to shift their offers to higher prices or offer less capacity into the market. Participant responses to supply conditions can largely be explained by the composition of their portfolios and by the supply-chain pressures on the fuel types to which they are exposed. However, we have found supply-side factors may not explain all increases in offer prices.
- Increasing, low-cost wind and solar are continuing to displace existing thermal generators, with coal generators shifting some capacity to high prices in the middle of the day to avoid uneconomic dispatch.
- The impact of recent events on participant behaviour has highlighted key linkages in the National Electricity Market (NEM) which should be kept in mind in the coming years. The NEM is still dependent on coal for baseload supply, but coal generators are facing reliability and fuel supply challenges. When black coal outages coincide with periods of low wind and solar output, more expensive gas-powered and hydro generation is needed to meet demand. Gas offers in the NEM are closely linked to gas spot prices, which soared in 2022. Hydro offers, which are closely linked to gas and black coal offers, also rose. Wind and solar offers are generally low priced, but their availability is naturally weather-dependent.

A participant may have the ability and incentive to exercise market power. But that does not necessarily mean it will do so in a way that harms effective competition. Participants can exercise market power in several ways (Box 5.1).

Box 5.1 How participants can 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 they may engage in longer term strategies. The strategies we assess in chapters 5 and 6 include:

- offering capacity at prices materially higher than efficient costs to increase prices (economic withholding) – this activity could include shadow pricing for example, where a participant reprices capacity to just under the costs of the next highest price unit
- reducing the amount of capacity offered to the market or not offering capacity at all (physical withholding) – this 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.

However, some behaviours that appear to be a potential exercise of market power may also be efficient responses to changing market conditions or a plant's technical requirements. This is something we consider in our analysis.

The factors we must have regard to under the National Electricity Law requires that when assessing effective competition, we focus on the extent to which market power is sustained.[38] A few isolated instances of transient market power alone are not sufficient to conclude that competition in the NEM is not effective – when barriers to entry are low, temporary higher prices provide a signal for new investment. However, sustained market power indicates there is likely an issue with competition in the market. For this reason, we focused on whether behaviour significantly affected price outcomes and whether that behaviour was sustained.

We assess participant conduct in each region over the long term to see if changes in offers can be explained by underlying supply conditions, whether participants' behaviour contributed significantly to price increases or market

38 National Electricity Law Section 18B.

volatility, and whether market power has been exercised.[39] This analysis includes case studies of participants that exemplified market dynamics or had notable shifts in behaviour. We also explore how the events of 2022 and the transition towards lower emission, renewable generation have impacted the operation and behaviour of different fuel types. In chapter 6 we extend our analysis to screen for potential economic and physical withholding behaviour, and we assess how rebidding has contributed to high prices.

5.1 Shifts in offers to higher prices generally reflected supply conditions

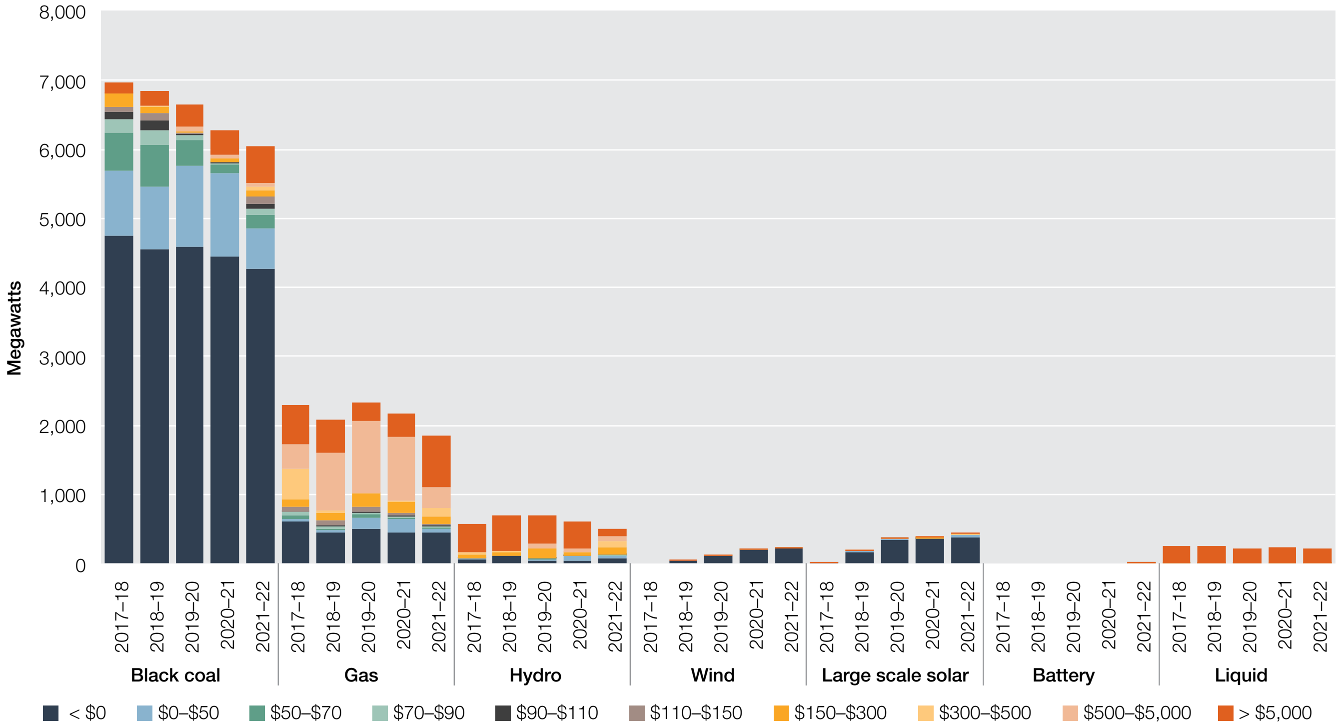
In our 2020 report we observed that participants offered more lower priced capacity following reductions in fuel input costs. We also observed that the entry of low-cost solar and wind generation provided additional competitive pressure, particularly in the middle of the day.

We have seen a significant reversal in offer behaviour since then. In 2022 particularly, we saw considerable increases in international fuel prices combined with significant outages of thermal generation, fuel supply problems and an early winter, which increased demand. In response to these supply-side issues, to cover higher fuel costs or manage limited fuel supplies, participants progressively shifted offers into higher prices. This mostly came from capacity that had previously been offered between $0 and $50 per MWh.

5.1.1 Queensland impacted by outages and supply issues, which contributed to higher offers from coal and gas

Queensland depends heavily on black coal generation (Figure 5.1). Outages, heavy rainfall and increases in black coal prices substantially impacted the region's overall offers.

Figure 5.1 Queensland offers, by fuel type



Note: Financial year average offered capacity by Queensland generators within price bands.
Source: AER analysis using NEM data.

Queensland recently faced significant coal outages, starting with Callide C power station in May 2021 (section 2.4.2). These outages contributed to a reduction in total offers in Queensland in 2021–22. For example, 600 MW less capacity was offered in Q2 2022 than in Q2 2020.

39 When output is sold to a third party (as through PPAs), the operator of a generator and the owner of its output may differ, and there can be limited transparency about the arrangements that determine offers. Therefore, while analysis of market share in chapter 3 aims to reflect the owners of the output of generation (or 'trading rights'), for simplicity our analysis of offers in this chapter reflects the operators (or 'corporation').

Costs vary between black coal generators depending on how they source their fuel. Most black coal generators in Queensland are 'mine-mouth'. These generators have lower fuel costs because they receive their coal directly from an on-site mine. In contrast, generators that source their coal from third parties are more exposed to higher export coal prices, because those parties could otherwise be selling that coal internationally. No matter the source, if a generator secures a long-term contract, they generally pay less for coal than export prices, depending on the timing of the contract. Short-term supply contracts for coal are likely to reference the prevailing international coal price.

Most Queensland black coal mines were impacted by heavy rainfall in 2022, which impacted coal quality and mining operations. Significant outages of thermal units also meant that remaining generation had to run harder to meet demand, depleting their coal stockpiles. As a result, participants shifted offers above $5,000 per MWh to preserve fuel. These stresses on coal supply also meant some participants sourced additional coal on the spot market at a time of rising prices. Coal generators shifted low-priced offers to progressively higher price bands to reflect their increasing exposure (section 2.4.1).

Gas faced similar issues, with a significant reduction in gas generator availability in the region. This was driven by an outage at CleanCo's Swanbank E gas power station in December 2021, which removed 350 MW of gas capacity from Queensland's supply until it returned to service in September 2022.

While gas and coal faced supply issues, which drove offers higher, hydro generation was offered at lower prices. This was driven by CleanCo, the only hydro participant in Queensland. To compensate for the outage at Swanbank E, CleanCo moved some of its hydro offers from above $5,000 per MWh to below $500 per MWh to ensure more hydro capacity was dispatched to cover its contract position and retail load.

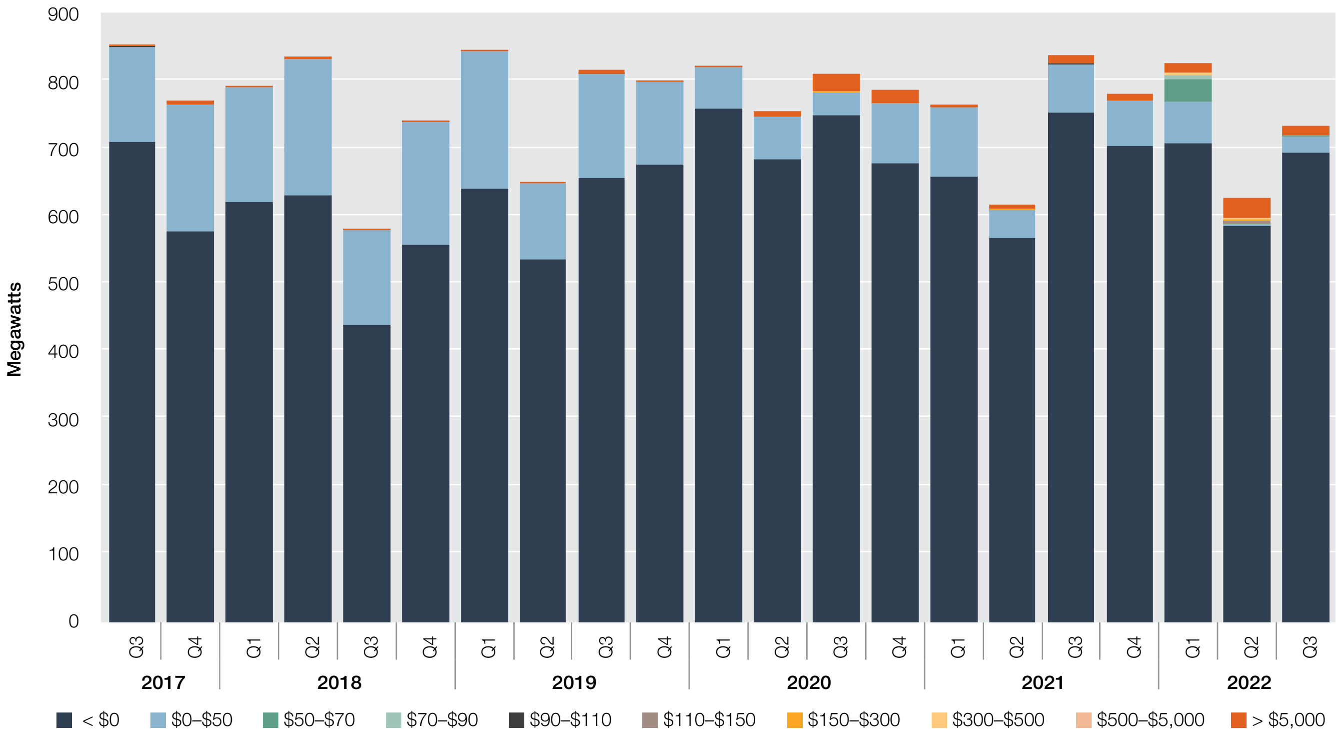
Case Study 1 – InterGen shifted offers in response to supply issues and renewables

Although InterGen is a relatively small coal generator in Queensland, its behaviour highlights how challenges to coal supply even for mine-mouth generators have impacted offers.

InterGen owns the coal mine at its Millmerran power station and generally benefits from low-cost fuel supply. As a result, over the last 2 years InterGen offered 89% of its capacity below $0 per MWh and offered most of the remainder below $50 per MWh (Figure 5.2).

However, InterGen reported that heavy rainfall in 2022 interrupted mining operations and meant that wet coal was supplied, which impacted plant reliability and increased the maintenance required. Outages drove a reduction in total offers, and the need to conserve fuel caused InterGen to shift more of its capacity above $5,000 per MWh in Q2 2022.

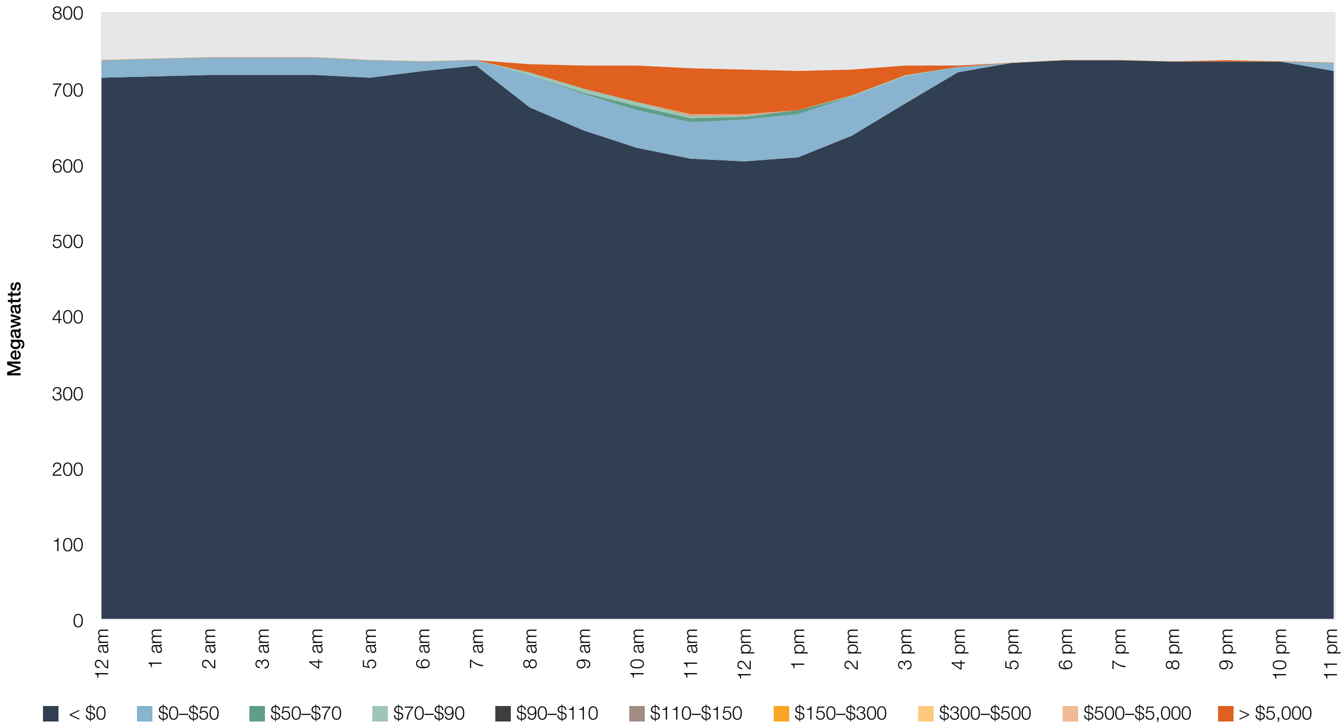
Figure 5.2 InterGen quarterly offers



Note: Quarterly average offered capacity by InterGen within price bands.
Source: AER analysis using NEM data.

The behaviour of InterGen also highlights how coal generators are adjusting offers in response to increased renewables. Coal generation is designed for continuous operation, so ramping output up and down (and particularly turning off and on) can stress the units and result in more frequent maintenance (section 5.2.1). As a result, coal generators offer most capacity under $50 per MWh to cover their retail and contract load, and some capacity at higher price bands to minimise the costs of ramping and conserve fuel for the morning and evening peaks. InterGen's offers reflect this trend (Figure 5.3). InterGen reported that generally when it offers capacity above $5,000 per MWh, it does so in response to low and negative spot prices in the middle of the day and to conserve fuel.

Figure 5.3 InterGen offers, by time of day, Q3 2022



Note: Quarterly average offered capacity by InterGen within price bands, average for all hours of the day.

Source: AER analysis using NEM data.

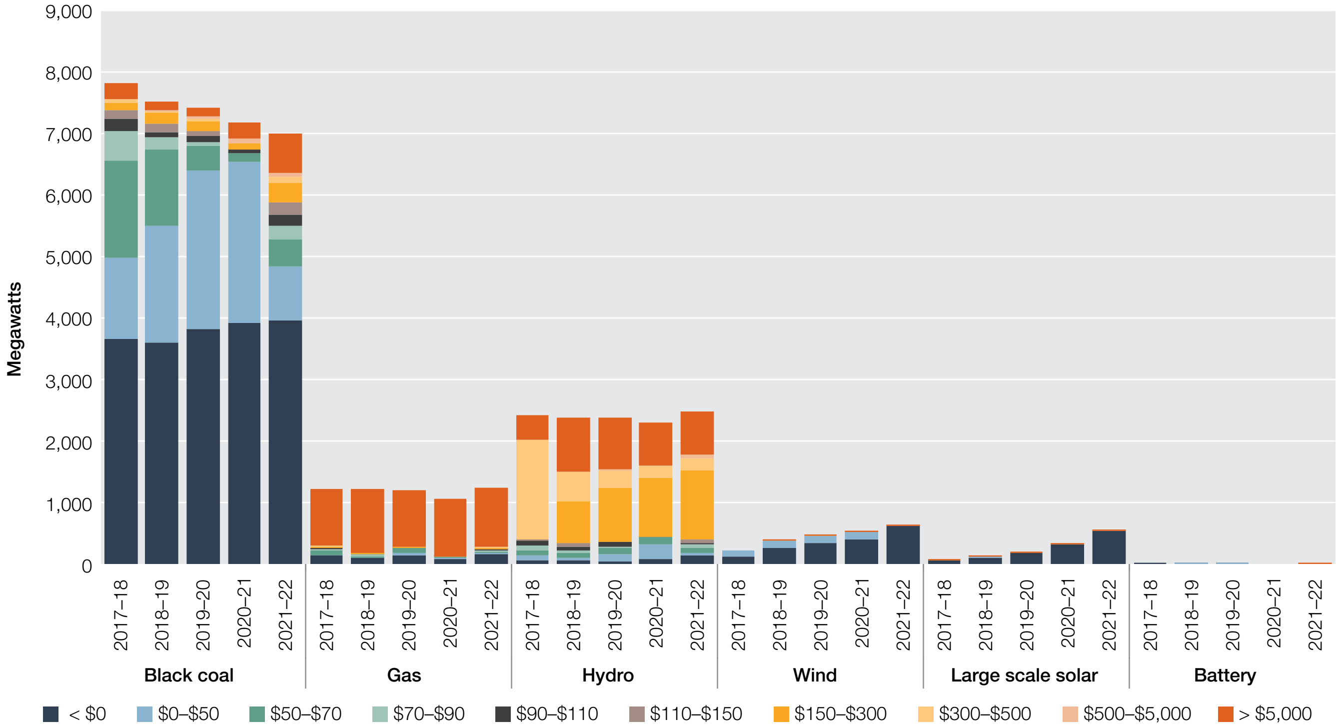
This repricing of black coal capacity to high prices has intensified in recent years as solar generation has increased. However, this trend can leave the market vulnerable to short periods of high prices where rapid changes in conditions occur. Sudden changes in demand, falls in intermittent renewable generation or drops in output when plants trip off mean fast-start generation is needed to meet demand, which is often higher cost.

5.1.2 NSW impacted by outages, high fuel costs and fuel supply challenges, which contributed to higher offers

Like Queensland, NSW is reliant on black coal generation and was exposed to significant outages. This, and the closure of Liddell's first 500 MW unit in April 2022, reduced availability from these generators (Figure 5.4). Some participants in NSW also faced an undersupply of coal in Q2 2022, due to transportation and weather challenges. For example, Origin Energy reported that ongoing challenges with fuel supply impacted Eraring power station, with material under delivery of coal compared with expectations.[40] This undersupply meant some NSW generators were more exposed to high international prices.

40 Origin Energy, Investors media update on operating conditions and guidance, 1 June 2022.

Figure 5.4 NSW offers, by fuel type



Note: Financial year average offered capacity by NSW generators within price bands.
Source: AER analysis using NEM data.

As a result of these issues, in 2021–22 black coal participants in NSW significantly reduced the amount of capacity they offered between $0 and $50 per MWh and progressively shifted it to higher price bands. This is a reversal of our observations reported in 2020 – between 2017–18 and 2019–20, participants increased the amount of capacity offered at prices between $0 per MWh and $50 per MWh.

The majority of gas in NSW is usually offered above $5,000 per MWh. Reduced coal-fired output meant the market was more reliant on very expensive gas generation to meet daily energy needs, despite gas price increases. This drove an unanticipated increase in gas demand putting upward pressure on gas prices at the same time as local gas markets were being used by other gas customers to cover the higher demand winter period. In 2022 these high gas spot prices, as well as challenges in accessing gas supply, drove some generators to move capacity to higher prices.[41] While some generators that needed to cover their portfolio position offered some gas at lower prices, overall gas set much higher prices in 2022 because expensive gas was needed to meet demand.

More capacity was also offered at negative prices in NSW. This was largely driven by the new entry of wind and large-scale solar farms, which on average offered almost 640 MW more capacity below $0 per MWh in 2021–22 than they did in 2019–20.

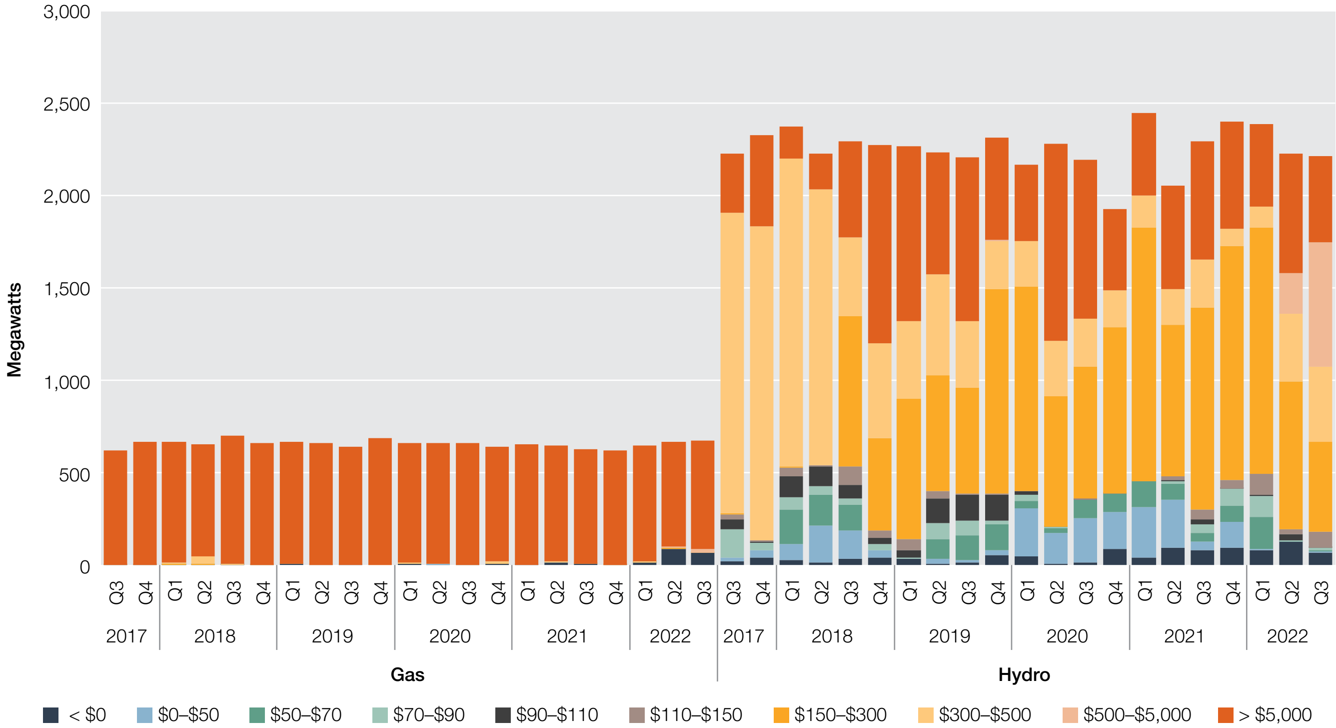
Case Study 2 – Snowy Hydro offered less hydro and more gas at lower prices

Snowy Hydro operates a significant share of flexible capacity in NSW, owning almost 80% of regional hydro capacity and 40% of gas capacity. As a result, its offers are a significant contributor to regional outcomes. This has been particularly consequential in 2022 as hydro set the price more often and at much higher prices.[42]

Snowy Hydro's fast start generation assets and large storages means they generate at times of peak demand, providing firming capability for renewable energy as well as cap contracts insuring retailers against price volatility.[43] Snowy Hydro offers the majority of its flexible generation capacity above $150 per MWh (Figure 5.5).

41 AER, Wholesale markets quarterly – Q2 2022, 6 September 2022, pp 23–24.
42 AER, Wholesale markets quarterly – Q2 2022, September 2022, and Wholesale markets quarterly – Q3 2022, November 2022.
43 Snowy Hydro, Good business makes good business: The Case for Snowy 2.0, 10 January 2018.

Figure 5.5 Snowy Hydro NSW offers, by fuel type



Note: Quarterly average offered capacity by Snowy Hydro in NSW by fuel type within price bands.
Source: AER analysis using NEM data.

Because of reduced thermal availability, Snowy Hydro increased its output in the first half of 2022. A variety of factors impact the value of water and how Snowy Hydro offers its capacity into the market (section 5.2.3). Snowy Hydro faces annual environmental water release limits and in periods of very high rain it is restricted by how much water it can safely release. Higher rainfall in 2022 meant its lower dams were full and Snowy Hydro had to further restrict its water use. Further, when coal generators shifted offers to higher prices, Snowy Hydro needed to increase its offers to ensure it was not dispatched over its limits. Finally, Snowy Hydro faced increasing energy prices to pump water at its pumped hydro power stations.

Snowy Hydro shaped its offers in response to these opportunity and monetary costs, shifting capacity higher to prices above $300 per MWh in Q2 and Q3 2022. This was a significant shift from its historical offers – for example, across Q2 2021 to Q1 2022 Snowy Hydro offered 42%, on average, of its hydro capacity above $300 per MWh, but in Q2 and Q3 2022 this rose to 63%.

Despite shifting its offers to higher prices to manage water use, Snowy Hydro was dispatched at record levels in order to meet market demand. Hydro generators can receive further revenue in renewable energy certificates (RECs) if their output exceeds their ‘eligible renewable power baseline’. For Snowy Hydro this is around 4.5 TWh across its hydro portfolio.[44,45]

Snowy Hydro generally uses its hydro assets to cover the majority of its contract position and retail load and only uses its gas assets at times of very high prices or when hydro output is restricted.[46] Over the past 5 years, Snowy Hydro offered 98% of its gas capacity above $5,000 per MWh. However, in Q2 and Q3 2022 it offered 10% of its gas at negative prices in response to restrictions in its hydro generation and to cover its contracts.[47]

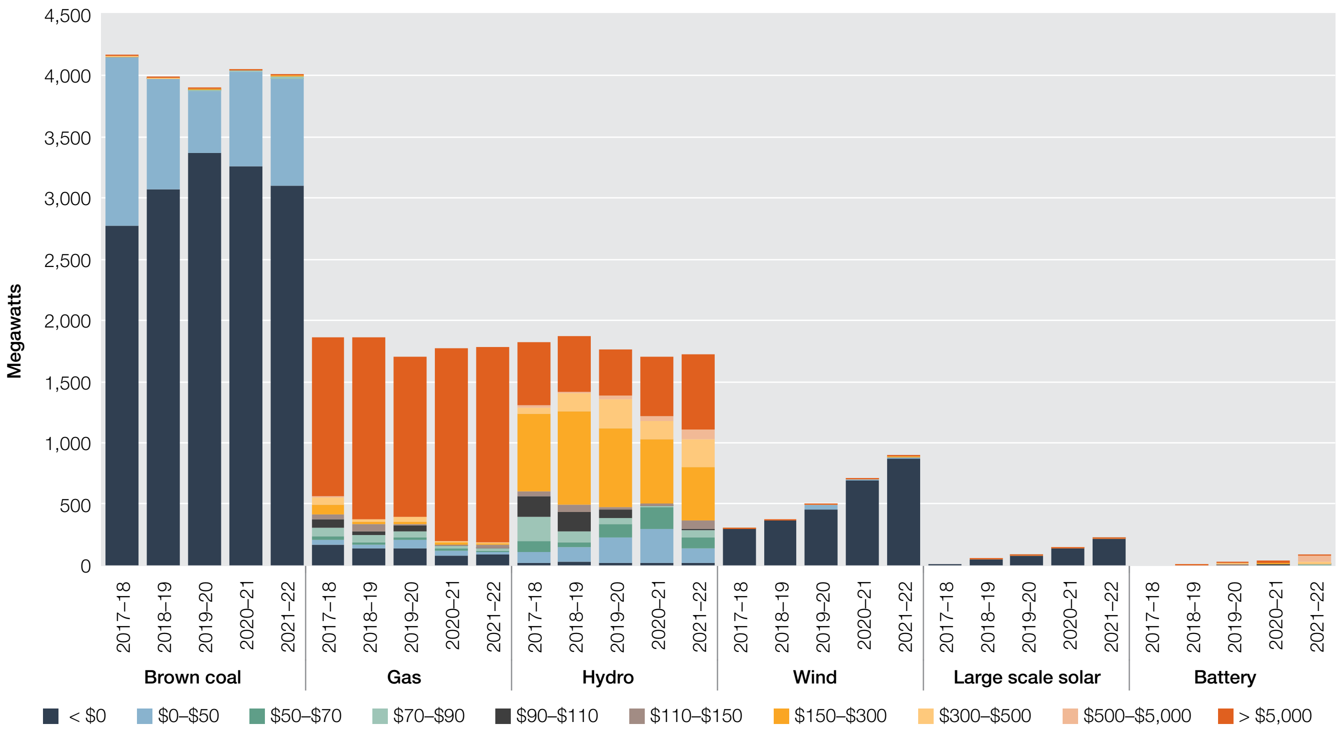
5.1.3 In Victoria, brown coal did not face major supply issues

Victoria has significant brown coal capacity, which did not face the same supply issues impacting black coal in Queensland and NSW. Brown coal is low quality and not suitable for export, which means it is not exposed to international prices and so did not face the same cost pressures as black coal. Brown coal offers nearly all of its capacity below $50 per MWh (Figure 5.6), with most of that offered below $10 per MWh. Case Study 3 highlights

44 Clean Energy Regulator, Large-scale generation certificate general formula, 29 October 2019.
45 Clean Energy Regulator, Register of accredited power stations, accessed 1 October 2022.
46 Snowy Hydro, Optimising our Energies, accessed 1 October 2022.
47 AEMO, Quarterly Energy Dynamics – Q2 2022, 29 July 2022, p 26.

a brown coal participant shifting offers higher than can be explained by supply conditions. But, because price increases were substantially driven by other fuel types, the overall impact on the market was not significant.

Figure 5.6 Victorian offers, by fuel type



Note: Financial year average offered capacity by Victorian generators within price bands.

Source: AER analysis using NEM data.

In contrast to brown coal generators, gas and hydro generators in Victoria faced similar issues to the other regions and shifted offers to higher prices.

Gas generators in Victoria all operate as peaking plants and offer most of their capacity above $5,000 MW in order to generate only during periods of very high prices. Over the past 5 years the proportion of lower priced gas capacity in Victoria has steadily decreased, with only 11% offered below $5,000 per MWh on average in 2021–22. This is likely driven by the increasing penetration of renewables, as gas peakers want to avoid uneconomic dispatch and minimise incurring high start-up, running and maintenance costs for only short periods of high prices. However, we saw a significant shift in offers in Q2 2022. Victorian gas generators faced similar access and cost issues to those in NSW, with additional restrictions as Australian Energy Market Operator (AEMO) directed that gas generators sourcing gas from the Victorian market not come on in order to preserve sufficient capacity in the Iona gas storage facility.[48] Despite this, around 21% of gas capacity was offered below $300 per MWh, half of which was offered at negative prices. As a result, gas output in Q2 2022 was almost double the same period in the previous year.

Victorian hydro generators faced the same issues as those in NSW and in 2021–22 reduced the amount of capacity offered below $300 per MWh, shifting it into higher price bands.

New entry of wind, solar and batteries has increased the available capacity in Victoria since the last report. The volume of overall offers below $0 per MWh rose with the increasing contribution of low-cost wind and solar generation.

Due to the technical characteristics of batteries, historically they have been used mainly in frequency control ancillary services (FCAS) markets with minimal participation in energy. This was reflected in their offers, with over 60% of capacity priced over $500 per MWh over the past 2 years. However, with increases in overall prices in the energy market, batteries adjusted their offers in 2021–22, shifting capacity from over $5,000 per MWh to below $500 per MWh in order to be dispatched. In addition, the entry of the Victorian Big Battery resulted in an increase in battery capacity in Victoria, with availability in 2021–22 almost triple that offered in 2020–21 (though from a low base).[49] Most of this additional capacity was offered at $500 to $5,000 per MWh. Higher prices and increased

48 AEMO, Notice of a Threat to System Security – Iona, 19 July 2022.

49 AER, Wholesale markets quarterly – Q4 2021, 23 February 2022, p 19.

dispatch meant battery revenue from energy across the NEM reached record high levels and exceeded that from FCAS for the first time (section 9.4.3).

Case Study 3 – Increase in brown coal offers in Victoria not explained by market conditions

Brown coal is a low-cost fuel. The 3 brown coal power stations – Loy Yang A (AGL), Loy Yang B (Alinta) and Yallourn (EnergyAustralia) – are located close to brown coal mines, which minimises transportation problems. As outlined above, brown coal is not exposed to international prices. While there can be challenges with the reliability of these stations, over the past year brown coal has not faced the same widespread supply-side issues as black coal.

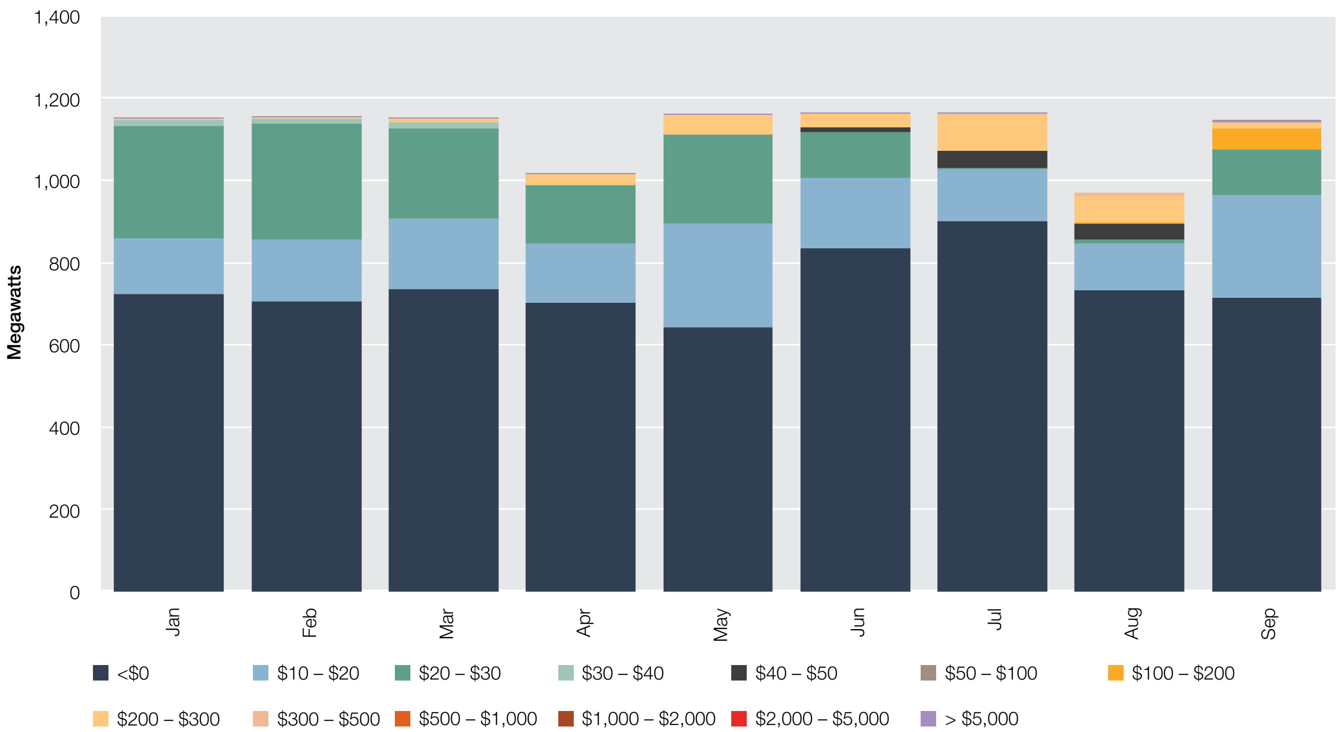
Although these participants did not face higher fuel costs or major supply issues, offers from brown coal participants have started to mirror trends in black coal. Brown coal is offering more capacity higher outside of the evening peak and particularly in the middle of the day when solar output is high. As a result, we observe brown coal on occasion setting prices above $100 per MWh and sometimes as high as $300 per MWh. This has driven an increase in the average price set by these generators. For example, in Q2 2022 brown coal set price on average at $40 per MWh in Victoria, while over 2020–21 the highest quarterly average price set was $14 per MWh in Victoria.[50]

Given the considerable rise in market prices in 2022, we consider that this behaviour did not significantly contribute to recent price outcomes. However, in a sufficiently competitive market, we expect participants will need to offer their capacity close to cost or risk being displaced. Participants significantly changing their offer behaviour, and setting higher prices as a result could suggest a lack of competitive pressure on brown coal generators.

The shift in offers and price setting we have observed was driven by a change in the behaviour of Alinta Energy.

From April 2022 onwards, Alinta Energy (which typically offered all of its brown coal capacity below $20 per MWh) shifted growing amounts to above $100 per MWh (Figure 5.7). This peaked in July, when Alinta offered around 8% of its Loy Yang B capacity above $100 per MWh. In contrast, AGL Energy and EnergyAustralia did not significantly change their offers over this period. Alinta reported that its offers reflect their position in the contracts market and how they value capacity from time to time. Further, they reported adjusting their offers in response to a boiler tube leak at one of its units in July and August.

Figure 5.7 Alinta brown coal offers, by price band



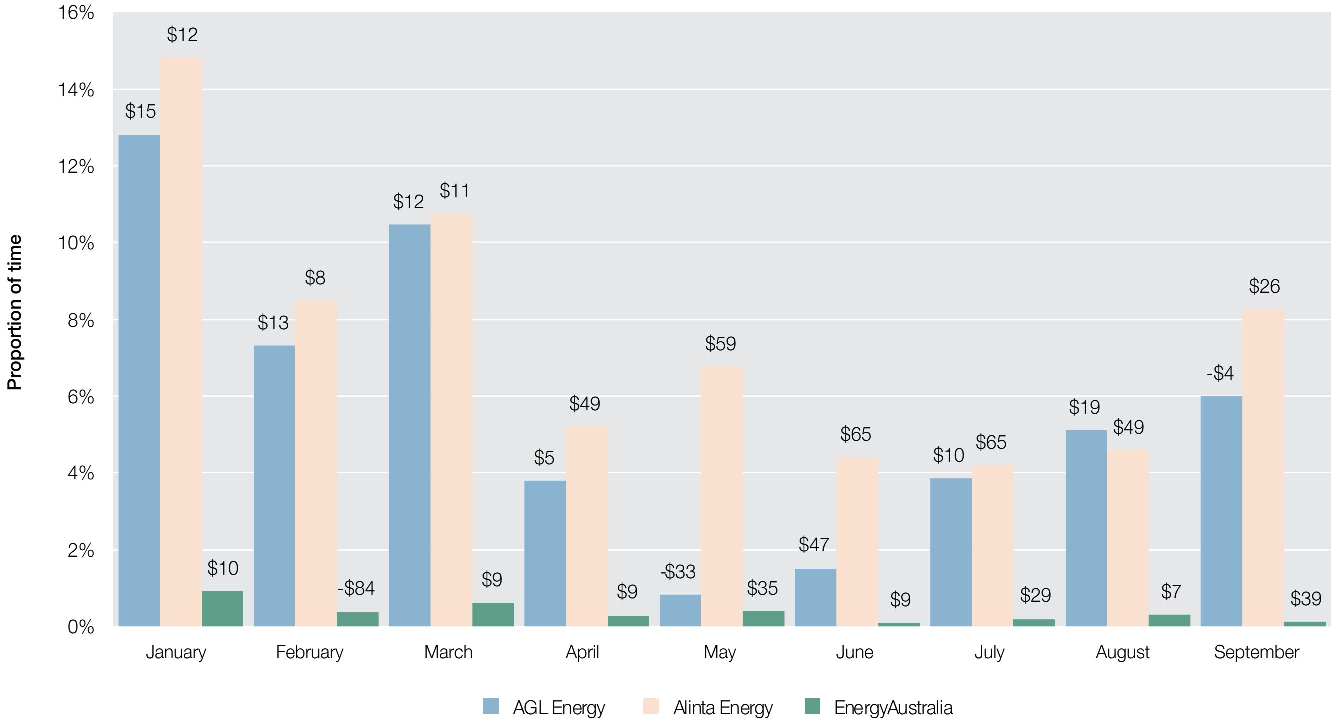
Note: Monthly average offered capacity by Alinta Energy's brown coal generation within price bands.

Source: AER analysis using NEM data.

50 AER, Quarterly price setter and average price set by fuel source – Victoria and Quarterly price setter and average price set by fuel source – NSW, accessed 8 December 2022.

Following the repricing of its capacity into higher price bands, Alinta Energy set prices less often but at significantly higher prices than in previous months, and higher than the prices set by other brown coal generators (Figure 5.8). For example, in June and July 2022 Alinta set the price at $65 per MWh on average, compared with $8 per MWh in February. The higher average was driven by Alinta occasionally setting prices between $100 and $300 per MWh, often in the middle of the day when there can be rapid changes in demand or availability.

Figure 5.8 Average price set by brown coal generation in Victoria, 2022



Note: Monthly average price set in Victoria by brown coal participants and the proportion of time they set price.
Source: AER analysis using NEM data.

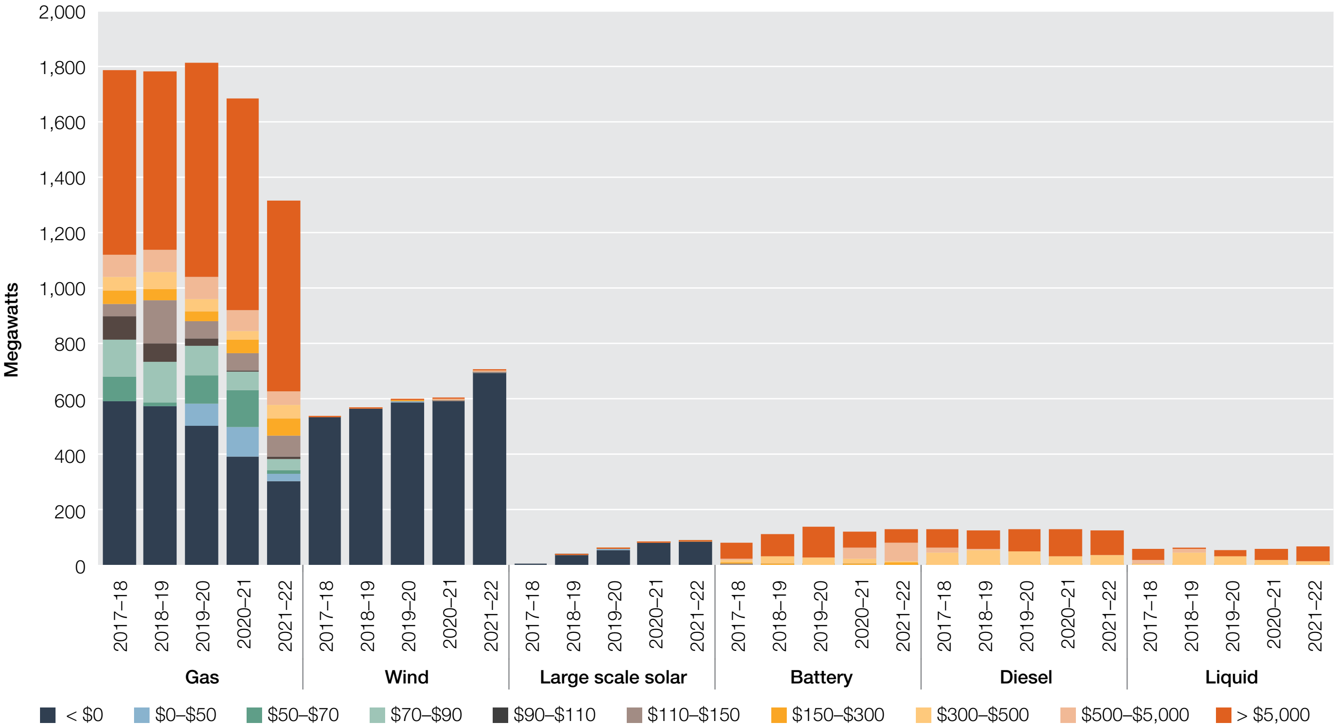
5.1.4 In South Australia exit of gas generation drove higher prices

South Australia has a high penetration of renewable generation and falling levels of minimum demand (sections 2.2.2 and 2.6.1). These factors have complicated the economics of existing gas generation.

The worsening economics for the state's gas generation resulted in AGL Energy closing Torrens Island A power station units in 2020 and 2021.[51] In November 2022, AGL Energy also announced the accelerated closure of Torrens Island B, now planned to exit in 2026 instead of 2035.[52] The closure of Torrens Island A resulted in a reduction of almost 750 MW of gas availability since Q3 2020 (Figure 5.9). Most of the capacity removed through gas closures was previously offered at low prices. Since Q3 2020 gas capacity priced less than $150 per MWh decreased by over 600 MW, while capacity offered at prices greater than $150 per MWh only decreased by about 100 MW.

51 The first Torrens Island A units closed in September 2020, and the last unit closed in September 2022.
52 AGL Energy, Torrens Island 'B' Power Station to close in 2026, 24 November 2022.

Figure 5.9 South Australian offers, by fuel type



Note: Financial year average offered capacity by South Australian generators within price bands.
Source: AER analysis using NEM data.

As with NSW and Victoria, South Australian generators also faced challenges accessing gas. The failure of large gas retailer Weston Energy meant AGL Energy acquired significant gas customer load under the Retailer of Last Resort scheme.[53] AGL reported that this meant it had to source additional fuel to meet their contracts and load across the electricity and gas markets, some of which had to be sourced at high gas spot prices.[54]

Overall wind capacity offered into the market continued to grow due to the entry of a new wind farm in Port Augusta and, from Q1 2022, some existing non-scheduled units (such as Starfish Hill and Wattle Point) began to offer into the market. Almost all wind and solar capacity continued to be offered less than $0 per MWh. Increases in offered wind and solar capacity were not able to completely offset the reduction in gas availability, which meant from Q3 2020 total availability in the region fell by 515 MW.

Since our last report, overall capacity offered by batteries remained relatively constant. Neoen's Hornsdale Power Reserve expanded its capacity by 50 MW to 150 MW in September 2020, but it appears most of this was offered into FCAS markets (section 9.4.2). However, since 2019–20 batteries have shifted offers lower, from above $5,000 per MWh to between $500 and $5,000 per MWh. This may have been driven by higher prices in the energy market, providing more opportunities for revenue and changing the value trade-off between FCAS and energy (Box 9.2).

5.1.5 Tasmanian offers driven by weather conditions

In contrast to the other regions, all generation in Tasmania is controlled by one participant (Hydro Tasmania). As a result, Hydro Tasmania's behaviour determines offers in the region.[55] The majority of Hydro Tasmania's portfolio consists of hydro generation, supplemented by wind and gas-fired generation, which comprise around 17% of Hydro Tasmania's capacity.[56]

Tasmanian prices generally follow similar trends to those in other regions (section 2.1) and offers typically follow a cyclical pattern based on the season. Tasmania as a region is generally distinct from the rest of the NEM in that it experiences peak demand over winter because milder summers mean there is less need for cooling. The greatest

53 AER, AER ensures continued supply for former Pooled Energy and Weston Energy customers, 25 May 2022.

54 Financial Review, AGL demands gas supplies to serve Weston customers, 12 July 2022.

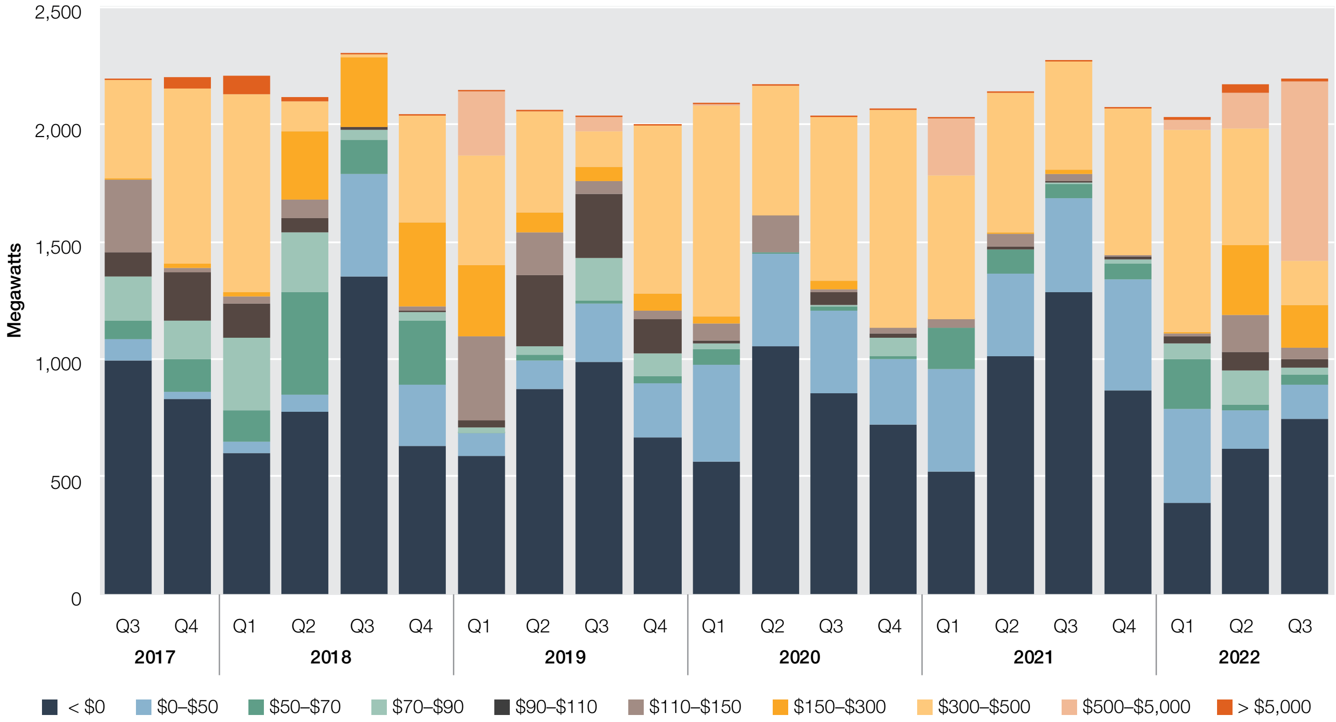
55 Hydro Tasmania has long-term offtake agreements for generation it doesn't own in Tasmania, which gives it control over the output. Since 2018 some new generation has followed this arrangement, including the new Granville Harbour and Cattle Hill wind farms.

56 Tamar Valley, its gas-fired generator, has not been used in several years as hydro capacity is usually sufficient to cover local demand.

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.

Since our last report, Hydro Tasmania's offers from its hydro generation have mostly followed this general pattern (Figure 5.10). The greatest amount of negatively priced capacity, and the most capacity overall, was offered in Q3 2021 as winter rainfalls led to healthy dam storage levels.[57] The 2021 Tasmanian winter was relatively warm, which led to some very low prices and increased exports into Victoria (section 3.3.1).

Figure 5.10 Tasmanian quarterly offers



Note: Quarterly average offered capacity by Tasmanian generators within price bands.
Source: AER analysis using NEM data.

Tasmanian offers can also be influenced by the availability of the region's interconnector to the mainland – Basslink. For example, 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 at prices greater than $300 per MWh. However, since then we have not observed significant shifts in Hydro Tasmania's offers related to Basslink availability. Even when changes in Basslink ownership drove changes in the interconnector's offers from July 2022, this did not appear to significantly impact prices in Tasmania or Victoria.

In Q2 and Q3 2022, Hydro Tasmania shifted offers higher, from below $70 per MWh to between $110 per MWh and $300 per MWh. In Q2 2022 this likely reflected a NEM-wide uplift in energy prices and an associated increase in Hydro Tasmania's valuation of its water. In Q3 2022 Hydro Tasmania shifted a large amount of capacity even higher to above $500 per MWh, likely driven by low 2022 rainfall.

57 AER, Wholesale markets quarterly – Q3 2021, 17 November 2021, p 11.

5.2 Recent events have highlighted interdependencies of the market

Recent supply side pressures on participant behaviour have highlighted possible future challenges as we move through the transition to a low-emissions NEM. In particular:

- the market is still dependent on black coal for baseload supply, at a time when black coal generators face reliability and fuel supply challenges
- when demand for energy is high or there are substantial limitations on supply, gas and electricity markets are increasingly linked due to the firming role that gas plays
- hydro is constrained by water availability and its opportunity costs and offers are closely linked to the offers of other fuel types
- wind and solar offers are generally low priced, but output is intermittent and the way FCAS costs are allocated has influenced offers.

5.2.1 Black coal offers are a key driver of market outcomes

Despite increasing renewable capacity and major exits, black coal still plays a pivotal role in the market, contributing 60% of total generation in the NEM in 2021–22. As highlighted in our assessment of regional outcomes, the market's dependence on black coal means that issues with its supply and reliability can have a significant impact on market outcomes.

Black coal plays a significant role in setting prices, especially in NSW and Queensland, where it is the dominant fuel type. In these regions, black coal sets prices almost half of the time. In all other regions, through interconnector flows, black coal still sets prices around 25% of the time.[58]

Ownership of black coal generation is highly concentrated – 5 participants control almost 90% of its registered capacity in the NEM. This means the market can be influenced by the supply conditions, plant reliability and offer behaviour of a few participants, either through the exercise of market power or exposing the market to the business management decisions of individual participants.

Coal generators are designed for continuous operation, due to their high start-up and shutdown costs and minimum generating requirements. Coal generators also face lower fuel costs than gas or hydro generation. All the generators have some retail load (section 3.1.6), with AGL, Origin and EnergyAustralia having the most significant retail presence. Given this, coal-fired generators often offer significant capacity at low prices to ensure dispatch to meet their retail load and contract position, as well as to keep their plant running. Over the last 5 years, black coal participants offered 80% of capacity below $50 per MWh.

However, over the past year low-priced offers have decreased significantly (section 5.1).

Black coal plants have experienced reliability issues

As discussed in section 2.4.2, baseload generator outages have increased over the past 5 years. Some participants have told us that underinvestment in maintaining aging coal stations has affected the reliability of black coal generators. This has occurred for several reasons:

- COVID-19 impacted staff and contractor availability and delivery of parts, which delayed maintenance.
- Maintenance must be scheduled well in advance and it can be hard to justify significant investment in maintenance, especially for plants that are exiting in the short to medium term.
- Spot price volatility makes it challenging to plan maintenance. Planning for major works can begin several years out. When assessing what and how much is needed, participants must weigh the costs and benefits of maintenance against projected future revenue. When future revenue is projected to be low (as may be expected during extended low prices like those seen in 2020), or generally unclear, this can make it difficult to optimise maintenance schedules.

58 Regions without black coal generators can have their price set by black coal from another region when the interconnector between them is not constrained. For example, when the last MW of generation needed to meet Victorian demand is from a NSW black coal generator, that NSW black coal generator sets the price in Victoria.

- Limited generation from elsewhere in the market, including the increases in outages since Callide exploded in May 2021 and constraints on hydro, meant the remaining coal generation has had to run harder than expected further stressing plants.

As a result of these reliability issues, there was less low-priced capacity offered into the market from black coal generators and more expensive fuels like gas and hydro filled the gap. Although some of these challenges are transient (like COVID-19), others are likely to persist through the transition.

Black coal output was disrupted by fuel supply issues

Black coal can be vulnerable to issues with coal supply, availability, transportation and quality. Although participants can manage the risks of these issues through stockpiling coal, when the issues are widespread it can significantly impact offers.

Black coal participants experienced significant supply issues in 2022 driven by heavy rainfall, which impaired mining production, train lines and coal quality. They were also running harder than anticipated so were drawing on their stockpiles faster than expected. Numerous participants told us that they were left with critically low stockpiles, which could take up to a year to replenish.

As a result, some generators needed to source additional coal on the spot market, which exposed them to very high prices linked to international coal prices. Participants shifted offers to higher prices to cover high fuel costs and to conserve fuel but were still being dispatched, contributing to very high market prices.

The events of 2022 also highlighted how coal fuel supply issues can disrupt the market. Coal fuel shortages cascaded into greater pressure on gas-fired generation to run at a time when international fuel prices were already exerting upward pressure on domestic gas prices.

The Energy Security Board has concluded that transparency around energy availability will be important in supporting market resilience in the future.[59]

Future coal supply may be contracted at high prices

Many participants were only partially exposed to the recent increases in international coal prices due to having long-term fuel contracts in place. However, as these multi-year contracts roll over, participants may face material increases in fuel costs if current high prices persist. In addition, participants anticipating the closure of their black coal assets may be engaging in shorter term contract arrangements at a higher cost.

Some stakeholders also reported that as mines reach the end of their supply there can be challenges around exploration or expansion of existing mines, due to the costs and approvals required. It is difficult to determine how significant an impact this may have, because it will depend on the supply of existing mines as well as government policy, but these issues could possibly create further cost challenges for generators.

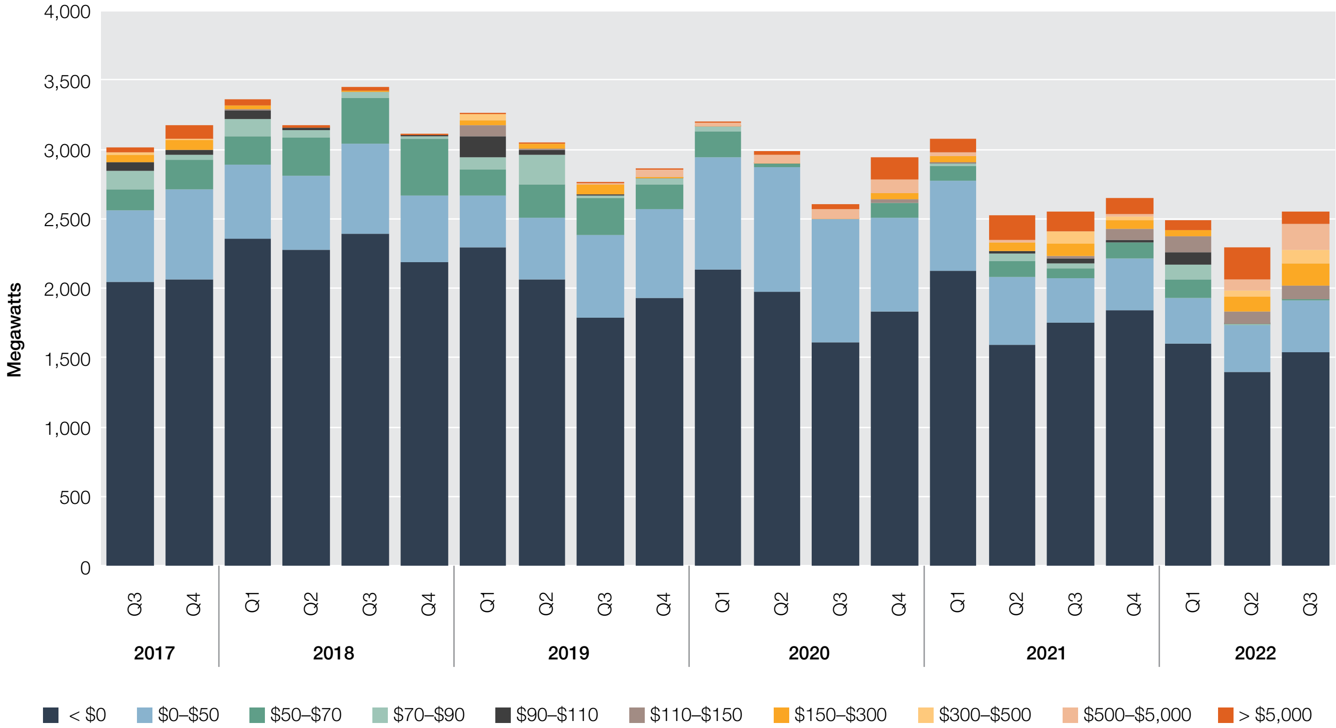
Case Study 4 – How black coal issues have affected different portfolios

Not all participants offer their black coal capacity in the same way. We have assessed how 2 of the largest black coal operators, CS Energy and AGL Energy, have adopted different offer strategies.

CS Energy's portfolio is currently comprised entirely of black coal, so it was significantly affected by the pressures on black coal supply (section 5.1). For CS Energy, these pressures began with the explosion at Callide C power station in May 2021, which reduced its total offers by almost 550 MW. Consequently, coal supply issues saw availability of their portfolio continue to fall (Figure 5.11). It also led CS Energy to re-price offers from below $50 per MWh to progressively higher price bands to cover rising fuel costs, as well as shift some capacity above $5,000 per MWh to preserve stockpile levels.

59 ESB, Health of the National Electricity Market 2022, September 2022, p 26.

Figure 5.11 CS Energy black coal offers



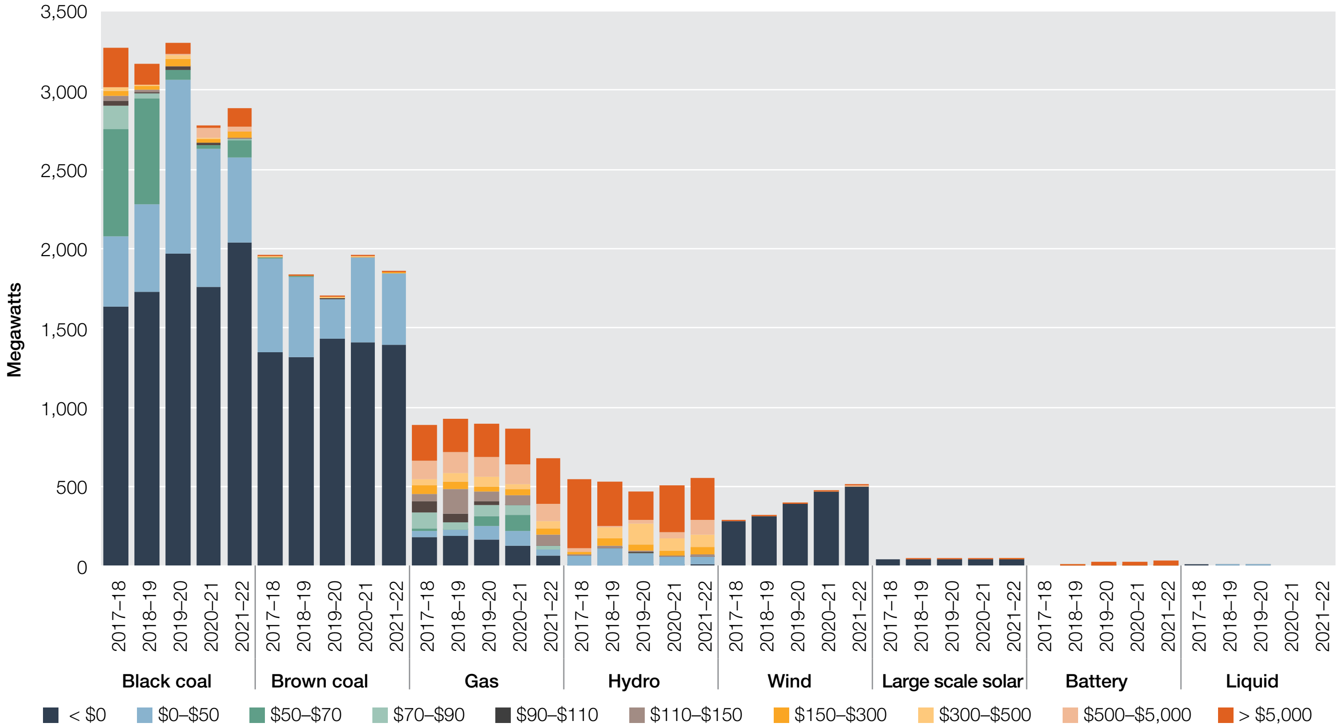
Note: Quarterly average offered capacity by CS Energy within price bands.
Source: AER analysis using NEM data.

In contrast to CS Energy, AGL Energy's portfolio is comprised of 7 different fuel types, giving it greater flexibility in meeting its retail load and contract position when dealing with changes in market conditions.

In 2021–22 AGL Energy decreased the amount of gas priced below $0 per MWh (Figure 5.12), driven by the exit of its Torrens Island units (section 5.1.4). This has been offset by an increase in wind capacity available, which AGL Energy consistently offers at negative prices. In addition, although outages and the closure of a Liddell unit meant AGL Energy's black coal offers were much lower than in 2019–20, the proportion of capacity priced below $0 per MWh increased. These changes highlight how AGL Energy was likely using the breadth of its portfolio to cover its retail load and contract position.

Of the rest of AGL Energy's portfolio brown coal, battery and solar offers did not change significantly. Hydro capacity shifted to lower prices, but still at levels above a majority of its fleet. This suggests that AGL Energy's hydro assets may be used more as 'insurance' in case it cannot get dispatched in other fuel types and to cover exposure to high prices.

Figure 5.12 AGL Energy offers, by fuel type



Note: Financial year average offered capacity by AGL Energy within price bands.
Source: AER analysis using NEM data.

The events of 2022 have highlighted increasing issues with reliability, potential challenges with securing fuel supply at reasonable cost, and increasing complexity of operating in a renewables-heavy market. Given the significant role coal still plays, if issues such as these persist or recur, they could significantly impact on market outcomes, even as coal transitions out of the market.

5.2.2 Gas and electricity markets can be strongly interlinked in certain circumstances

Gas peaking generation is one of the most expensive fuel types in the NEM but can increase and decrease production quickly. This characteristic makes gas generators suited to providing generation when prices are high, usually in the evening peaks. It also makes it suitable for firming intermittent generation, including for longer periods when other storage options might be exhausted.

Over the past 5 years, gas generation has declined by over 30%. In 2021–22 gas-powered plants contributed only 6% of NEM generation but set prices about 13% of the time in mainland regions.

Gas plays a pivotal firming role in the NEM

Winter 2022 has underscored the electricity market's dependence on gas when there is not enough coal or renewable generation to meet demand. It has also highlighted how demand from electricity can put pressure on gas prices when local gas markets are already facing high demand periods or have price and supply tensions.[60] For example, in Q2 2022 baseload generation outages coupled with limits on hydro generation and constraints on the supply and transportation of coal put upwards pressure on demand for gas-powered electricity generation. This increased demand for electricity generation coincided with limited gas supply to domestic markets and drove gas prices to record highs. The combination of these factors put the market at risk of gas shortfalls, and some gas generators were restricted from generating despite high electricity prices.

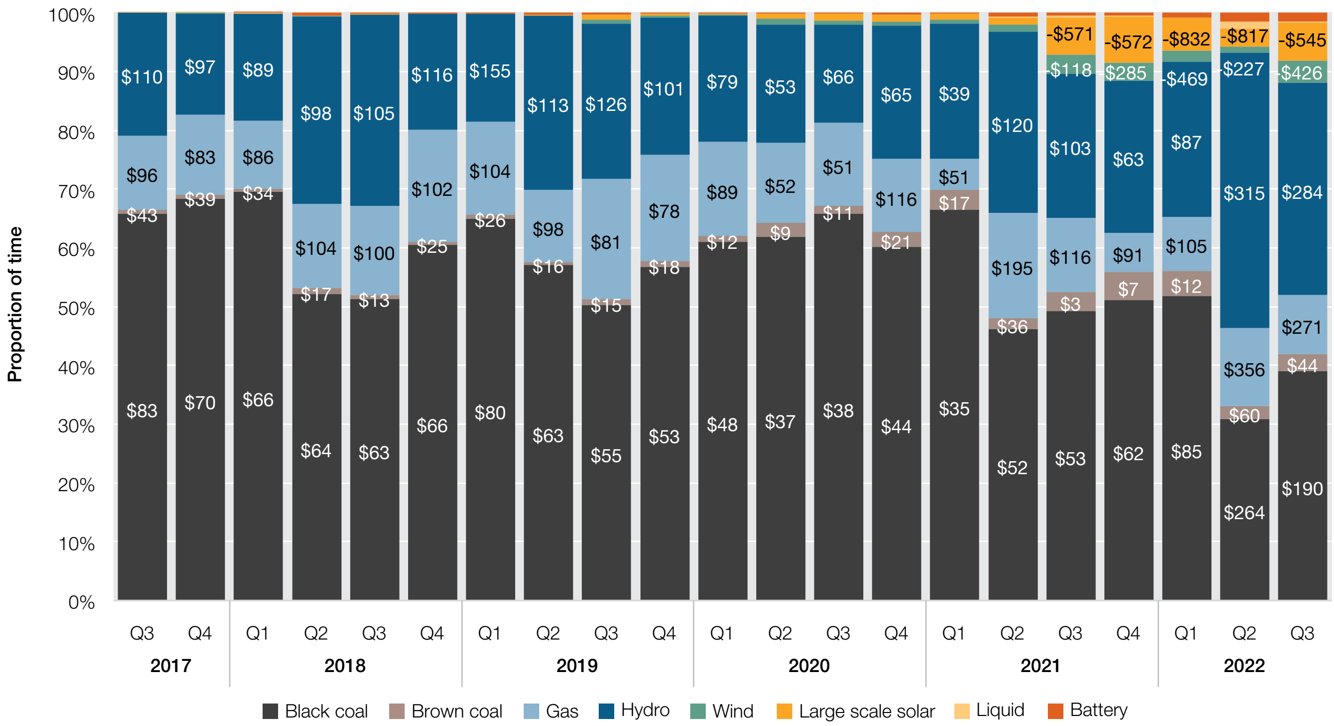
As the market transitions and coal generation exits the market, when there are periods of low renewable output the reliance on dispatchable generation like gas will increase. If gas-powered generation is to continue to play an important part in the future NEM, it is important to note the interactions between demand for gas from electricity generation and demand from gas customers and international export, and the impact this can have on prices across both markets.

60 AER, Wholesale markets quarterly – Q3 2022, 16 November 2022, pp 2, 6–7.

Gas generation is a major influence on how hydro generation offers its capacity

Gas can also have an influence on the behaviour of other generators. Gas and hydro generation set similar prices because both fuel types tend to target similar sections of the market. Hydro generation tends to offer between coal and gas depending on how much it is aiming to be dispatched. As a result, even though gas infrequently sets prices, the price it offers its capacity at influences how hydro generation is offered. When the offers of gas or coal generators increase, hydro generators generally follow suit (section 5.2.3). Over the last 4 years, the average price set by hydro has tended to be above coal, and, depending on how often they wanted to be dispatched, either just above or below gas (Figure 5.13).

Figure 5.13 NSW price setter, by fuel type



Note: The height of each bar is the percent of time each fuel type sets the price and the number within each bar is the average price set by that fuel type when it is marginal (that is, setting the price).

Source: AER analysis using NEM data.

In mid-2022 gas generators buying fuel on the gas spot markets shifted their electricity offers into much higher price bands (as did coal as outlined above) and hydro generators followed suit. As a result, both gas and hydro set prices above $300 per MWh in Q2. Gas input prices fell in August and September due to reduced electricity demand for gas as coal outages resolved and renewable generation increased, and gas storage levels improved.[61] Consequently, the prices that gas and hydro set fell as well.

5.2.3 Hydro is playing a growing role as the market transitions but is energy constrained

Hydro generation plays a significant role in the NEM. It provides renewable, flexible generation and can provide long-term energy storage (like a big battery) when power is needed the most. It can be available to the market to meet sudden changes in demand, falls in intermittent renewable generation or drops in output when plants trip off. Like gas, it will play an increasingly pivotal role in providing generation as the market becomes more dependent on intermittent renewable generation and as baseload generation exits.

The ability to store water in a dam effectively stores energy like a battery, which can be discharged when needed. Pumped hydro generation can pump water from a low reservoir back up to a higher dam to be stored again, generating when the spot price is high during the morning and evening peaks and pumping when the spot price is low during the day or overnight. The price difference must compensate for the efficiency loss of pumping water up to a higher dam.

61 AER, Wholesale markets quarterly – Q3 2022, 16 November 2022, p 17.

In 2021–22 hydro generation contributed 8% of total generation in the NEM yet set prices more than a quarter of the time in all regions. In Q2 2022, at the peak of the black coal supply issues (section 5.1), hydro set the price substantially more often than black coal in NSW (Figure 5.13). This shows the reliance that will be placed on hydro generation as we transition away from coal towards renewable generation.

Snowy Hydro has the largest portfolio of hydro capacity, controlling almost half of the hydro generation in the NEM and the majority on the mainland.

Hydro generation is fuel constrained

As section 5.1.2 outlined, the events of 2022 demonstrate how hydro generation is constrained by water availability and environmental release limits. Generation must also be carefully managed around projected water availability, electricity demand and availability of other generation. As a result, the marginal offers from hydro generators can be influenced by the behaviour of other fuels, particularly coal and gas.

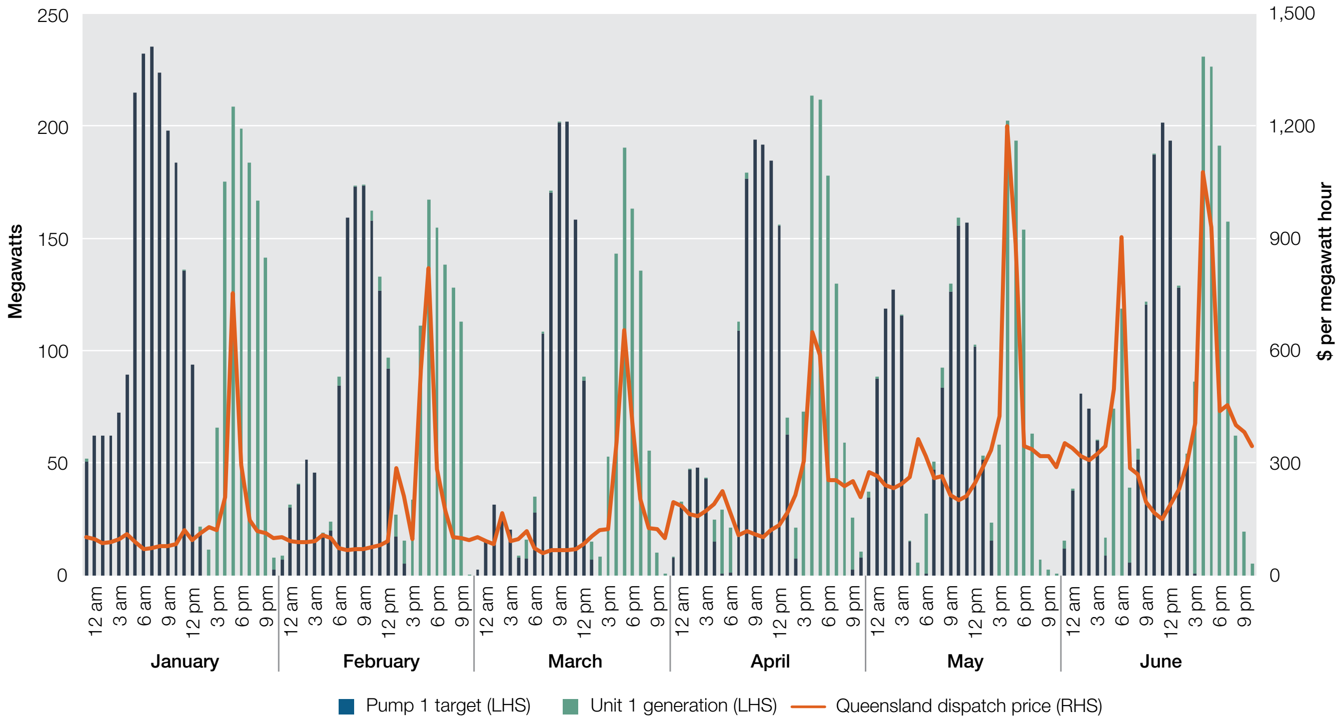
Pumped hydro is exposed to prevailing wholesale prices

Hydro generators do not pay directly for their water, but pumped hydro generators need to purchase electricity off the spot market to refill their dams. This exposes pumped hydro generators to spot prices and influences how they offer their capacity. Generally, participants try to minimise their costs by pumping at low or negative prices at times of low demand and high wind and solar output. When pumping costs are low, hydro generators have more flexibility on the prices they can offer their output. However, when there is an uplift in spot prices driven by other fuels, pumped hydro units need to increase the price they offer their generation to account for higher pumping costs, which puts further upwards pressure on prices.

Case Study 5 – CleanCo changed when it pumps water in response to higher prices

CleanCo's offers in the first half of 2022 highlighted the price pressures that emerged for hydro generation (Figure 5.14). From January to March, CleanCo's Wivenhoe power station pumped water during lower priced periods, generally in the middle of the day, and generated in the evening peak. Over this period, on average CleanCo paid around $96 per MWh to pump and received prices around $180 per MWh. In April, as prices started to increase in the morning and middle of the day, CleanCo adjusted its offers to maximise its pumping load during the lowest priced times but was forced to pay higher prices. As prices continued to rise through May and June, Wivenhoe was paying $270 per MWh on average to pump overnight and selling at around $400 per MWh on average.

Figure 5.14 Average price, pumping and generation, by time of day for CleanCo's Wivenhoe hydro station, January to June 2022



Note: Shows when Wivenhoe hydro station was pumping and generating and the average price in the region by time of day. Pumping and generating behaviour is based on pump 1. Pump 2 is operated in a similar manner to pump 1.

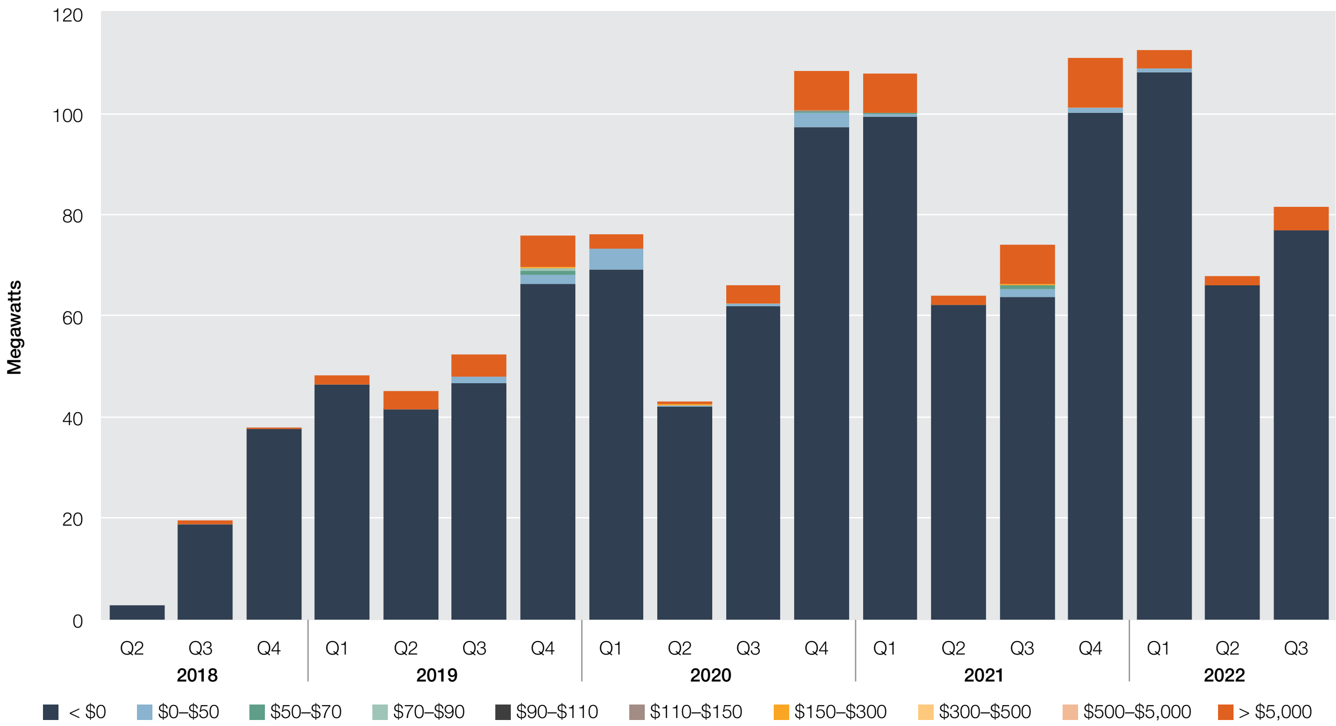
Source: AER analysis using NEM data.

5.2.4 Wind and solar generation provide low-priced capacity but FCAS costs influence offers

Most wind and solar generation is offered at very low or negative prices. In 2021–22 wind and solar generators offered 97% of their capacity at negative prices on average. They can do this because they have a very low marginal costs and receive RECs for every MW they generate.[62] Over the last 5 years, REC prices have ranged from around $28 to $90 per MWh.[63] Participants generally sell their output through power purchase agreements, which further minimises their exposure to low or negative prices.

This low-priced capacity has put downward pressure on prices, especially in the middle of the day. However, while most wind generation is offered at low or negative prices, we observed that solar generators in South Australia and Queensland have offered some generation at prices above $5,000 per MWh (Figure 5.15).

Figure 5.15 Quarterly South Australian solar offers



Note: Quarterly average offered capacity by South Australian solar farms within price bands. There were no solar offers in SA pre-Q2 2018.
Source: AER analysis using NEM data.

These high-priced offers were likely driven by participants trying to minimise FCAS costs. Due to the low costs and revenue sources outlined above, solar and wind participants typically generate at the maximum level the prevailing weather conditions allow. As a result, they typically don't offer FCAS that requires them to increase generation (i.e. raise services), because this means they may miss out on more reliable energy income.

However, when contingency raise services are enabled, the costs are recovered based on how much participants are generating at the time (Box 9.1). This means solar and wind generators can incur a share of raise FCAS costs, without receiving any offsetting revenue from providing those services. The result is that during a time of high contingency raise prices and low energy prices it may be uneconomic for these units to continue generating electricity because the FCAS costs outweigh the revenue from generating electricity.

62 Clean Energy Regulator, Large-scale generation certificates, 29 October 2019.

63 Clean Energy Regulator, QCMR data workbook – September Quarter 2022, accessed 9 December 2022.

5.3 Changes in supply conditions explain most but not all offer behaviour

Since our last report there have been significant shifts in the supply conditions in the NEM, and this seems to have flowed through to some participant conduct. This has highlighted key linkages in the market which should be kept in mind in the coming years.

In general, we find that most changes in offer behaviour are explained by the changes in supply conditions. However, supply-side factors may not explain all increases in offers. In chapter 6 we build on our analysis to systematically screen for economic withholding behaviour, and we assess the trends of physical withholding and rebidding in participant behaviour.

It is important to note that it is challenging to assess the drivers of participant behaviour without insight into their contract positions, and these can significantly impact the costs and revenues that participants face. Access to information on contract markets is key to enable effective scrutiny of participant behaviour.

6. Economic and physical withholding

Key points

- The Australian Energy Regulator (AER) monitors the offers of generators for potentially harmful market conduct. This includes economic and physical withholding, which can drive inefficiently high prices. Although this behaviour is not necessarily illegal, it may indicate that competition in the market is ineffective.
- In chapter 5, we found that most changes in offer behaviour are explained by the changes in supply conditions. However, supply-side factors may not explain all increases in offers. To further test for potentially harmful market conduct, we developed new metrics to indicate whether participants may be withholding capacity to influence wholesale prices.
- Our analysis indicates that rising fuel costs and the entry of renewables may have altered participant incentives, by creating a more sensitive and less predictable relationship between price and surplus capacity in the market. This may have led to a greater incentive for participants to withhold capacity.
- We have not identified widespread or systemic patterns of economic withholding. However, we have identified individual plants that may exhibit behaviour consistent with economic withholding. These plants appear to offer capacity at higher prices both when the estimated incentive to withhold is higher and when prices are higher than we might expect, given the level of surplus capacity in the market.
- We have also found that participants are withdrawing more capacity from the market. This conduct may not constitute physical withholding, as higher renewables penetration is likely changing how generators need to manage their capacity.
- Over the past 2 years, participants rebidding from low to high prices has more frequently been a factor contributing to prices above $5,000 per MWh. At times, this may constitute opportunistic economic withholding, though we have not identified participants that regularly displayed this behaviour.
- Our results require further analysis to understand the drivers of the behaviour we have observed and the magnitude of their impact on market outcomes. In addition, access to information on contract markets is vital to enable effective scrutiny of participant incentives and behaviour.

In an efficient, competitive market, with low barriers to entry, we expect prices to move broadly in line with underlying costs. Firms in these markets are price-takers and cannot influence the price by altering their output. Price-takers are incentivised to offer capacity to the market at their marginal cost of production or risk losing revenue to other firms.

A participant with market power may have the ability to influence the price through its offers (Box 6.1). One way a firm can do this is by economically withholding – that is, by offering its capacity above its marginal cost with the intention of influencing the price. Because it has market power, it has greater ability to influence the price and lower risk of losing revenue if it offers capacity above cost. Deviations between prices and costs are possible indicators of market power. If participants can exercise market power on a sustained or systematic basis, this may compromise the efficiency of the market and lead to higher prices for consumers over the longer term.

In chapter 5 we began our assessment of market conduct by analysing participant offers at a region, fuel type and portfolio level. However, this analysis can be enhanced by systematically assessing whether offer behaviour may be linked to incentives to withhold and whether actions by generators with market power could be driving higher prices.

In this chapter we extend our assessment of behaviour by using new metrics to build on our offers analysis. We focus particularly on economic withholding. This behaviour is not illegal by itself but can be both inefficient and harmful for consumers because it leads to higher prices that do not reflect costs. Our analysis represents a first step towards identifying possible economic withholding behaviour without access to direct cost information. We screen for periods when the price is higher than we might expect given the level of surplus capacity in the market, and examine generator behaviour in these periods. We also estimate generator incentives to withhold in each period and examine conduct in periods of potentially higher incentive.

This chapter also examines physical withholding, which involves removing capacity from the market altogether. Lastly, we examine trends in high prices related to rebidding capacity.

6.1 We developed new metrics to assess participant behaviour for indications of economic withholding

The most direct way to assess economic withholding is to compare the prices at which a participant offers a station's capacity against that station's costs. In lieu of direct information on participant costs, we developed 3 metrics (Box 6.1) that together might provide an indication of potential economic withholding:

- a screen for periods when **outcomes** could be consistent with economic withholding (surplus capacity-price relationship)
- a method to estimate the **incentive** for generators to withhold in any given period (returns from withholding capacity)
- a measurement for generator **actions** to identify whether changes in behaviour occur when outcomes or incentives reflect potential economic withholding (quantity weighted offer price).

Box 6.1 Metrics used to assess economic withholding behaviour

With support from NERA Economic Consulting, we developed 3 metrics to help us assess economic withholding behaviour. We did this by researching the approaches of other energy regulators and economists worldwide and adapting techniques that were most appropriate to our context.

The most direct way to measure economic withholding is to compare a station's offer price to its short-run marginal cost. However, since we have limited access to direct information on participant costs, we have developed alternative techniques to test for economic withholding. This is a common issue that energy regulators are confronted with globally, and we have drawn from their approaches where possible. The techniques we use have limitations, the most significant of which are outlined in section 6.1.1 and explored further in our methodology. However, our view is these metrics could still provide an indication of potential withholding behaviour and could help target where more in-depth analysis is needed.[64]

The metrics we have developed are as follows:

- **Surplus capacity** (or supply cushion) is the capacity in a region that is available but not dispatched. Our analysis focuses on the relationship between surplus capacity and the dispatch price.[65] The surplus capacity-price relationship identifies 'outlier' periods where prices are higher than this relationship would typically predict. A low level of surplus capacity represents tight market conditions. In a competitive market we would expect prices to be higher at these times because this is when higher cost generation is required to be dispatched. Periods when the price is higher than typical for the level of surplus capacity may indicate participants offering capacity above marginal cost to influence the price, but these periods may be caused by other factors, such as constraints.
- **Returns from withholding capacity** estimates a generator's potential gains from economic withholding behaviour. This measure is comprised of a 'price effect' multiplied by a 'portfolio effect'. The price effect estimates the impact on the price of reducing the supply of energy by a given amount. We calculate this based on the slope of the surplus capacity-price relationship, meaning that a steeper relationship implies a greater incentive. The portfolio effect represents the amount of energy the participant is generating in each period and thus the size of the portfolio that stands to benefit from an increase in the price. Returns from withholding capacity aims to provide an indication of the incentive to withhold and we refer to it as 'the incentive' in our analysis. We also note that a participant's incentives can be impacted by its contract position and retail load, which we have attempted to account for in our analysis using public information.
- **Quantity-weighted offer price –** Generators offer into the market across 10 different price bands. The quantity-weighted offer price calculates an average across the offered price bands, weighted by the capacity offered in each price band. We analysed this at a station level, which allowed us to assess how participants are changing offers across their portfolio. This provides a potential indication of how generators contributed to market outcomes and responded to incentives to withhold capacity. In our discussion, we often refer to the quantity-weighted offer price as an 'average offer' and to changes in this average offer as participants 'bidding higher' or 'bidding lower'.

For a more detailed explanation of how we calculate these metrics, together with a summary of our review of the relevant literature, see AER, *Wholesale electricity market performance report 2022 – Economic withholding approach, limitations and results*, December 2022.

64 AER, *Wholesale electricity market performance report 2022 – Economic withholding approach, limitations and results*, December 2022.

65 See Brown and Olmstead 2016, 'Measuring market power and the efficiency of Alberta's re-structured electricity markets: An energy-only market design'.

In this chapter we analyse recent shifts in surplus capacity-price dynamics and the impact of these shifts on our estimated incentives to withhold. We then assess whether participant conduct may reflect intentions to influence the price by examining changes in generator offers at times when we estimate the withholding incentive to be greater. Finally, to assess whether participant conduct may be driving higher prices, we examine generator offers at times when prices are higher than we might expect given the level of surplus capacity. To the extent that a participant's station flags on both assessments, this may represent stronger evidence of the participant's incentive and ability to exercise market power.

In our assessments we used analysis of market outcomes and participant incentives and actions from 2017–18 to 2021–22 in all mainland regions. We exclude Tasmania from our analysis because the state government regulates wholesale electricity contracts to reduce Hydro Tasmania's incentive to exercise market power to increase prices (Box 3.2). Moreover, we focus our analysis on coal, gas and hydro generators due to limited evidence that wind and solar generators engage in offer behaviour that contributes to higher prices.

6.1.1 Limitations and simplifying assumptions

This analysis involves some simplifying assumptions and limitations. Given we are making our assessment from public data, we cannot compare participants' offers to actual costs. Instead, we examine a generator's offers in periods of high prices or incentive to see if its offers differ in these periods. This approach may help us identify withholding 'actions' by generators but could mask systematic economic withholding if a generator always offers its capacity above marginal cost.

Similarly, fluctuations in a generator's short-run marginal cost could affect our results. To account for this, we take steps to factor a generator's running capacity and changes in input costs into our average offer assessment. However, this may be insufficient to fully control for all relevant factors.

Another limitation of the quantity-weighted offer price measure is that the process of averaging across price bands could mask relevant information. For example, a generator could offset a shift of some of its capacity to a higher price band by simultaneously shifting capacity to a lower price band. In this way, it could withhold capacity without its average offer increasing.[66]

A participant's incentives are significantly impacted by both its level of vertical integration and its contracted position (section 3.2). The retail arm of a vertically integrated generator must pay more if the spot price is higher, offsetting gains to the generation arm. Similarly, a contracted generator will need to compensate the buyer if the spot price is above the agreed price. To account for this, we have used the usual dispatch level of each participant to estimate the contract positions plus customer load of generators (see section 6.2.2). However, to accurately account for the impact on incentives, we would require access to the actual contract positions of participants.

For practicality, we estimate the price effect based on the surplus capacity relationship over a year (controlling for the share of wind and solar generation), instead of calculating the actual price effect in each period. We do this in part because, before the advent of 5-minute settlement in October 2021, participant incentives did not directly align to the dispatch price in any 5 minutes.[67] Estimating the price effect based on the surplus capacity-price relationship allowed us to smooth over the distortions caused by disorderly bidding (section 8.1.5). These factors mean the actual price effect in each period may vary from our estimate. We unpack this limitation in more detail in our methodology.

Our analysis of surplus capacity is conducted at a region level, which is a simplification given the NEM is interconnected. In practice, a given region may have a larger surplus capacity if it can access imports from other regions (or a smaller surplus capacity if exports are forced). In the development of our analysis, we experimented with accounting for actual and potential interconnector flows, but this introduced significant complexity. As such, it is not included in this stage of our metric development.

Finally, if participants respond to incentives by removing capacity from supply (that is, physical withholding) rather than repricing it high, this may skew our economic withholding results because capacity could be withheld without an increase in the quantity-weighted offer price. Nevertheless, we would expect participants to typically prefer economic to physical withholding, as this allows the possibility of being dispatched at a high price.[68] We perform analysis of potential physical withholding in section 6.4.

66 To illustrate this, imagine a plant that is offering all its capacity at its marginal cost of $100 per MWh (and thus has a quantity-weighted offer price of $100 per MWh). When it enters a period of more sensitive market conditions, this plant might drop half its capacity to -$500 per MWh (to ensure continued dispatch) and raise half its capacity to $700 per MWh (with intent to influence the price). In this case, the generator's actions could lead to a price increase despite the average offer remaining unchanged at $100 per MWh.

67 Before 5-minute settlement, prices were set every 5 minutes but settlements occurred every 30 minutes. Generators were paid for their output using the average price across the 6 dispatch intervals in each 30-minute trading interval. As such, a 5-minute price spike would incentivise generators to 'race-to-the-floor' to ensure dispatch for the rest of the trading interval, to guarantee revenue from the price spike.

68 See for example D. Biggar, 'The theory and practice of market power in the Australian National Electricity Market', 2011, p 11.

Our view is that, despite these limitations, this analysis is useful as an initial screen for potential economic withholding. It provides a possible indication of when participants have ability and incentive to engage in economic withholding, and may help identify potentially harmful behaviour. We aim to build on this analysis in the future to mitigate some of the limitations. In our methodology, we set out more information on our approach including supplementary figures for NEM regions not featured in this chapter.[69]

6.2 Shifting surplus capacity-price dynamics have led to increased estimate incentive to withhold

We have analysed how surplus capacity-price dynamics have changed over the past 5 years and how this may have impacted the incentive to withhold capacity. This analysis allows us to identify periods when the price may not be explained by supply conditions and thus when economic withholding may be occurring.

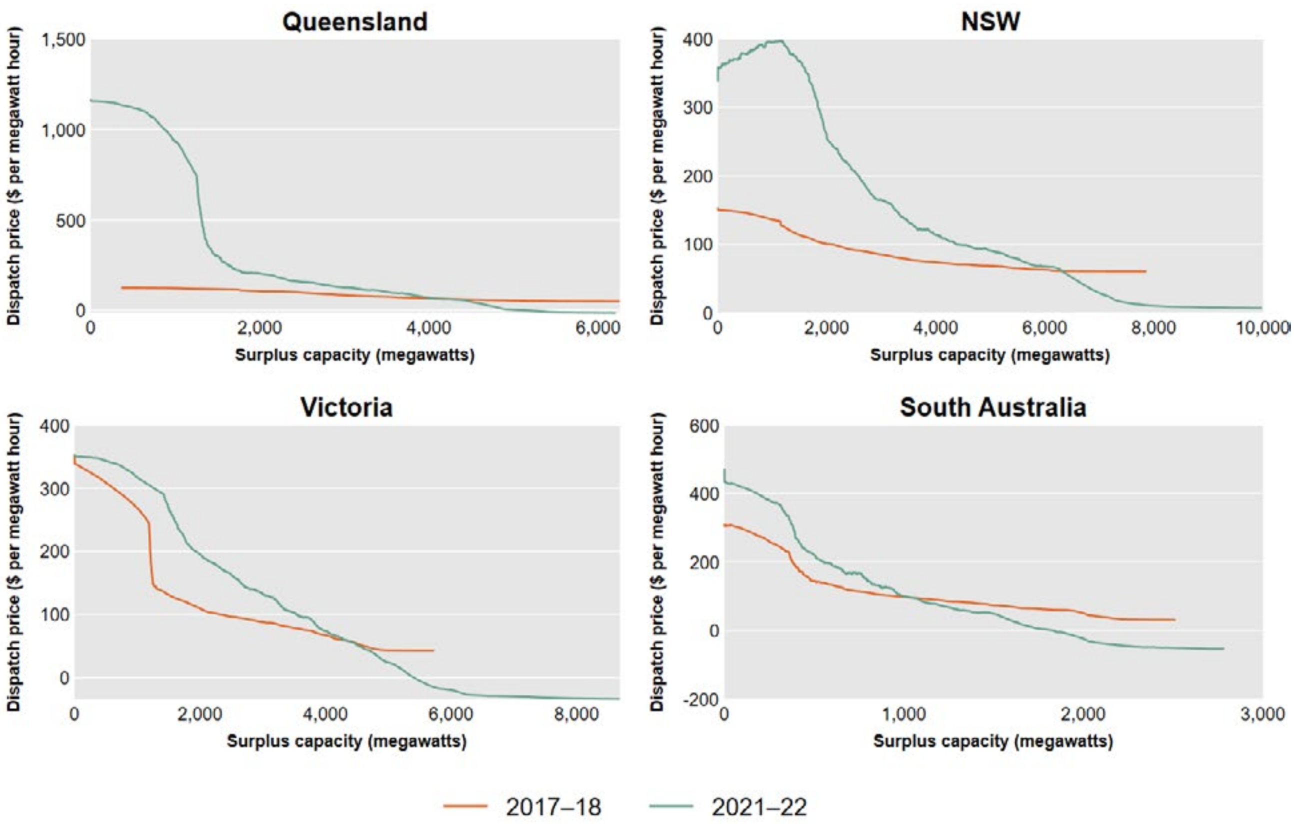
We find that the surplus capacity-price relationship may have become more sensitive over time, meaning that a given reduction in generation (or increase in load) generally leads to a larger increase in price. From this we estimate a greater estimated incentive to withhold capacity.

6.2.1 Changing cost structure of the market has transformed surplus capacity-price dynamics

Our analysis indicates a significant shift in the relationship between price and surplus capacity over the past 5 years.

The surplus capacity-price relationship has changed over time and is generally more sensitive (steeper) in 2021–22 compared with 2017–18 (Figure 6.1). This means that a one megawatt increase in load (or reduction in generation) now leads to a larger increase in the dispatch price. This is reflected in the increased price volatility in the NEM, with more frequent negative prices in recent years as well as very high prices in 2021–22.[70]

Figure 6.1 Surplus capacity-price relationship by region, 2017–18 and 2021–22



Note: The figure plots the relationship between the dispatch price and the level of surplus capacity for every dispatch interval in a financial year. A steeper line indicates a more sensitive relationship between surplus capacity and price. For a more detailed explanation, see AER, *Wholesale electricity market performance report 2022 – Economic withholding approach, limitations and results*, December 2022.

Source: NERA analysis for the AER, using NEM data.

69 AER, *Wholesale electricity market performance report 2022 – Economic withholding approach, limitations and results*, December 2022.

70 See, for example, AER Wholesale Markets Quarterly – Q3 2021, p 5.

However, there are differences across regions over time. For example, in 2017–18 the relationship was less sensitive in Queensland – which at the time had plenty of surplus capacity and low diversity of fuels setting price. However, it was more sensitive in Victoria, amid the Hazelwood closure and generally tight market conditions. In 2021–22 the Queensland surplus capacity-price relationship was much more sensitive, driven by significant outages and fuel supply issues. In contrast, Victoria did not face supply challenges to the same extent and the sensitivity of the relationship did not shift in the same way.

A more sensitive surplus capacity-price relationship increases our estimated incentive to withhold capacity. This is because withdrawing one megawatt of capacity can lead to a larger increase in the dispatch price (increasing the price effect). In turn, such a price increase leads to higher returns on any uncontracted generation capacity in a participant's portfolio.[71]

More sensitive surplus capacity-price relationship driven by entry of low-cost renewables and by rising fuel costs

A key driver of the more sensitive relationship between surplus capacity and price is the increased diversity of fuels setting price, with an increasingly large gap between higher and lower marginal cost fuels. In particular, we have seen a steady increase in output from wind and solar generators (section 2.2.2), which are able to offer capacity below $0 per MWh due to low marginal costs and off-market revenue from renewable energy certificates. This differs considerably from the much higher marginal costs of coal, gas and hydro generation. Having fuels with widely varying marginal costs setting price at different times means that prices can increase sharply when a higher cost fuel is required to be dispatched. Moreover, periods of low prices when wind and solar output is high could mean that thermal generation needs to recover its fixed costs over a shorter period of operation time, resulting in higher prices when wind and solar output is low.

Another driver of changing surplus capacity-price dynamics is the range of supply side challenges we explored in chapter 5. These include significantly higher fuel costs, fuel supply issues and increased generator outages, and have led to a higher marginal cost of producing electricity through gas and coal (and therefore hydro, as per our discussion in section 5.2.3). Because of this, when coal, gas or hydro are marginal price setting units, the price is often higher than in the past. These fuel types are more likely to set price at times of low wind and solar output and when the supply conditions are tight (that is, at low levels of surplus capacity).

Related to the increased penetration of low-cost wind and grid-scale solar is the impact of rooftop solar. When rooftop PV is generating, demand for generation from the grid decreases. Since rooftop and grid-scale solar generation are highest at the same times, low demand now often combines with high levels of available generation leading to higher levels of surplus capacity in the middle of the day. High levels of surplus capacity generally correlate with lower prices, because high-cost generation is not required to be dispatched and likely also because there is more competitive pressure in the market (section 3.1.3).

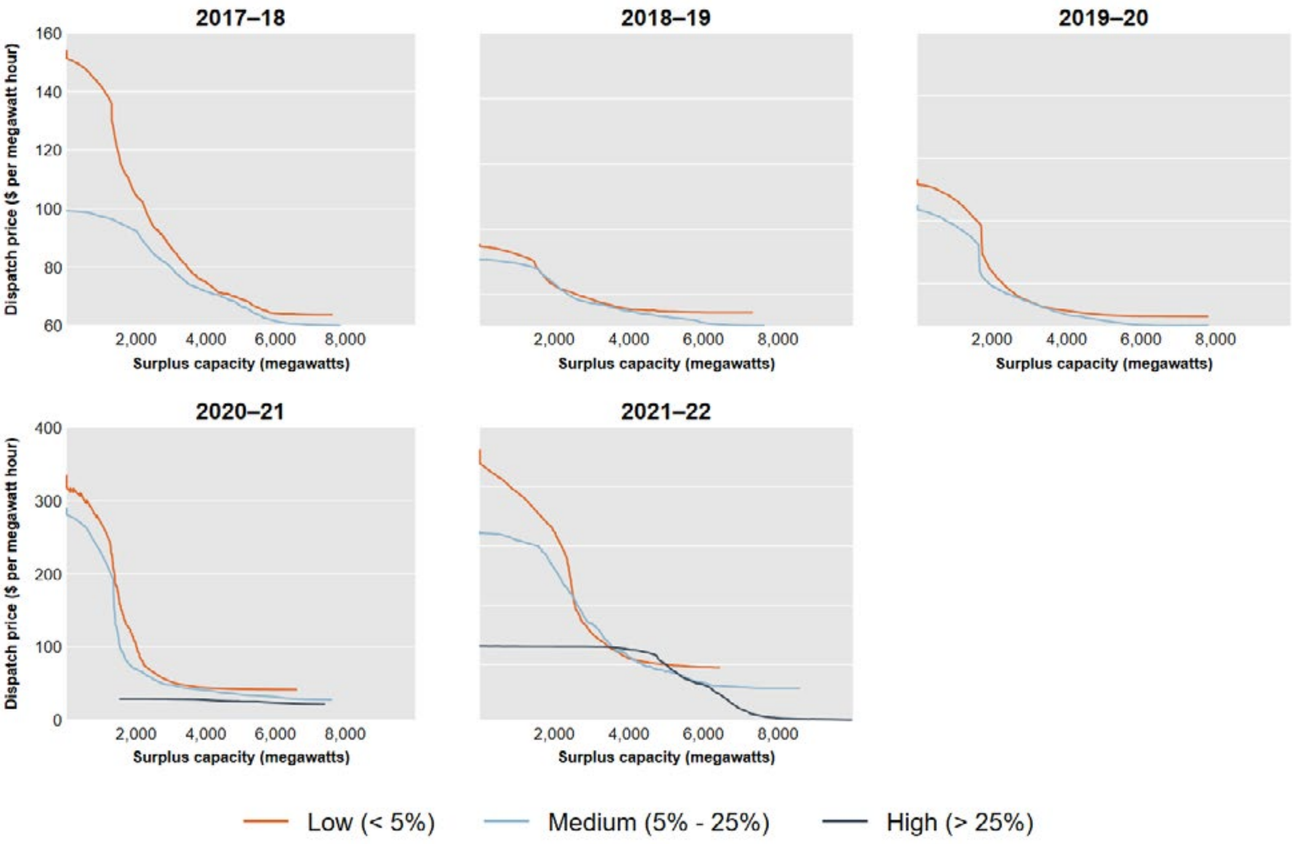
Impact of wind and solar on surplus capacity and price

To better understand how renewable generation impacts surplus capacity-price dynamics, we divided all dispatch intervals according to whether wind and solar output was low (less than 5%), medium (5% to 25%) or high (greater than 25%). We then examined the impacts of this output on the surplus capacity-price relationship. We also take this into account when we calculate our estimated incentive to withhold (section 6.2.2).

When wind and solar generation is high (above 25% of generation), the surplus capacity-price relationship is generally less sensitive. This is consistent across mainland regions and is illustrated by NSW (Figure 6.2). The reduced sensitivity reflects the lower marginal cost of renewable energy compared with other fuel types. Moreover, the level of surplus capacity can be higher at these times because there is typically more available generation and lower demand (due to rooftop solar) when renewable output is high.

71 Note that because we use actual offers and prices the supply cushion-price relationship we observe is the relationship that exists after any withholding actions have been performed. The actual withholding incentive for any participant depends on the slope of the residual demand curve – that is, the market demand not met by other generators.

Figure 6.2 Surplus capacity-price relationship, by wind and solar share of output, NSW



Note: The figure plots the relationship between the dispatch price and the level of surplus capacity for every dispatch interval in a financial year. We group observations according to whether wind and solar output is below 5%, between 5% and 25%, or above 25%. Before 2020–21, wind and solar output did not exceed 25% in NSW for enough periods to define a relationship. A steeper line indicates a more sensitive relationship between surplus capacity and price. For a more detailed explanation, see AER, *Wholesale electricity market performance report 2022 – Economic withholding approach, limitations and results*, December 2022.

Source: NERA analysis for the AER, using NEM data.

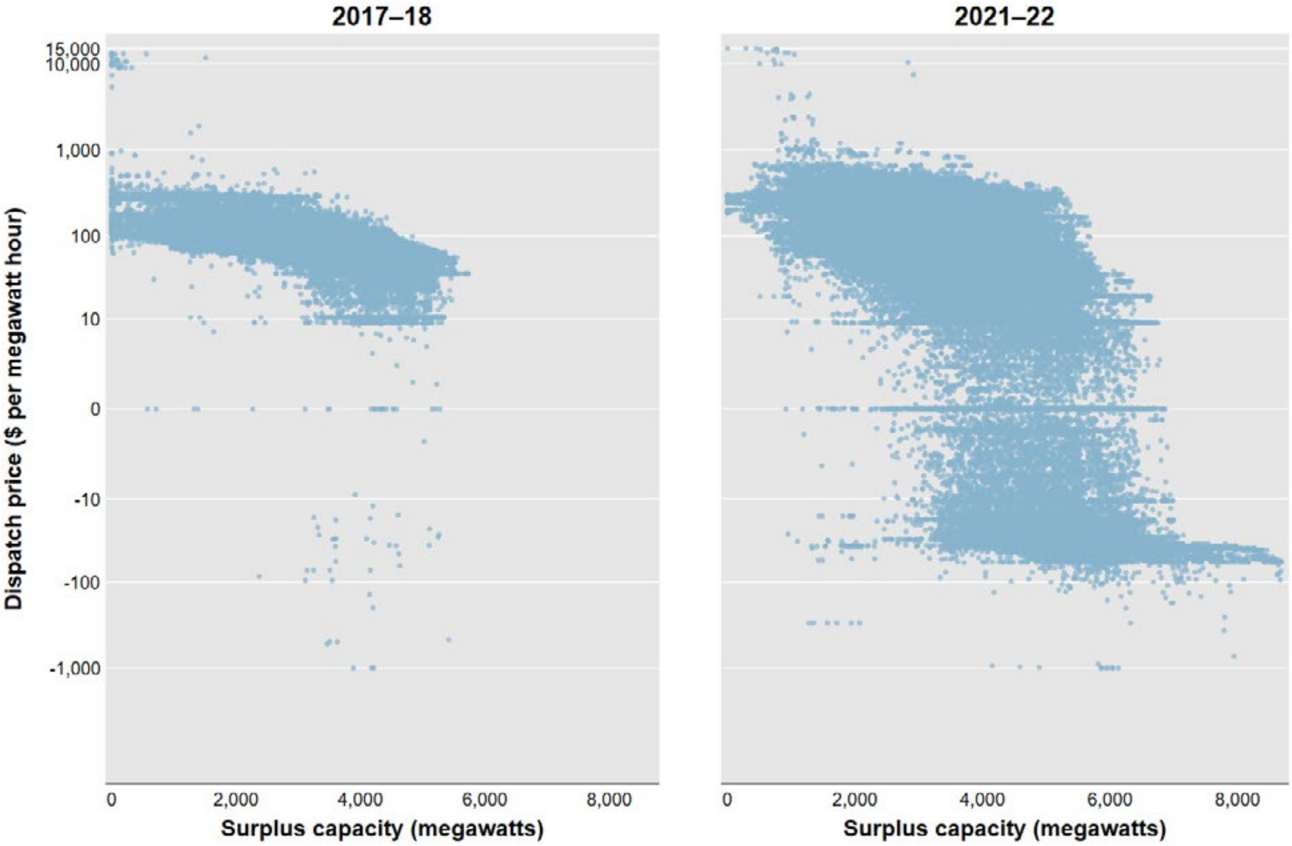
Conversely, in periods of low wind and solar generation, the relationship between surplus capacity and price relationship is more sensitive. This suggests that at times of low wind and solar output – when the market is forced to rely more on coal, gas and hydro – there may be greater incentive to withhold capacity. This is particularly true when conditions are tight – that is, at low levels of surplus capacity. Moreover, in the face of rapidly escalating fuel prices, this already sensitive relationship has become much more pronounced – as shown by the steeper lines for 2020–21 and 2021–22 (Figure 6.2).

The impact of these factors varies according to the region. Victoria and particularly South Australia have experienced the greatest penetration of renewables. In these regions the surplus capacity-price relationship is generally less sensitive. Meanwhile, Queensland and NSW have been most affected by fuel supply and fuel cost issues. As such, the surplus capacity-price relationship can be quite sensitive in these regions, especially when conditions are tight.

Price volatility not always explained by the level of surplus capacity

We have also found increasing volatility in prices that is not driven by changes in surplus capacity. For any given level of surplus capacity, we observe a much larger spread of prices. While this could be an indication of economic withholding, it is more likely to be a consequence of underlying supply conditions relating to the market transition. In Victoria (Figure 6.3) and South Australia in particular, the increased price spread reflects a much higher frequency of negative prices, due to low-cost wind and solar generation setting price. The price volatility also relates to changing fuel availability and increasing variation in fuel costs, with considerable variance over the course of 2021–22 alone, particularly in Queensland and NSW. The intermittent nature of wind and solar can also drive volatility, because brief fluctuations in output can require a response from high-cost fast-response technologies to maintain consistent supply.

Figure 6.3 Surplus capacity price scatterplot, Victoria, all periods in 2017–18 and 2021–22



Note: This figure plots the Victorian dispatch price and the surplus capacity level for all 5-minute dispatch intervals in 2017–18 and 2020–21.
Source: NERA analysis for the AER, using NEM data.

6.2.2 Our estimates of incentives to withhold were highest in 2021–22

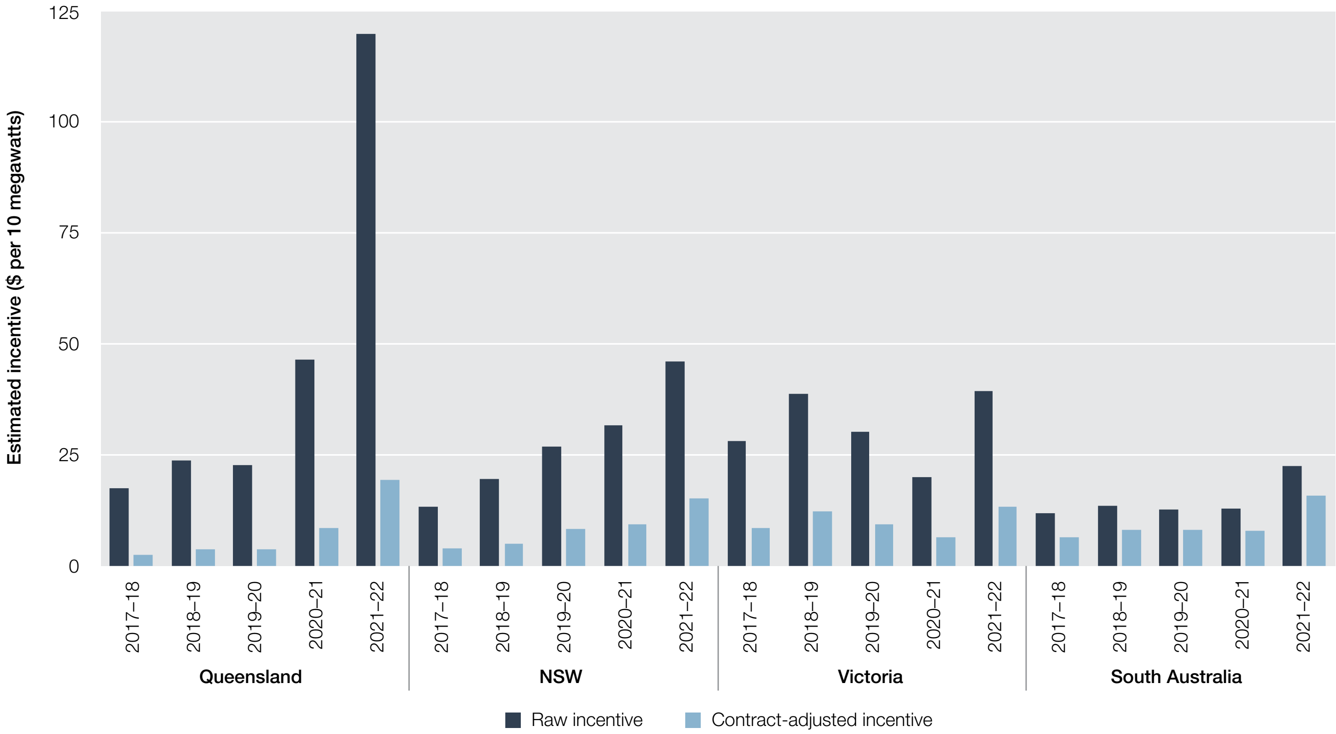
We observe that incentives change based on supply conditions. A more sensitive surplus capacity-price relationship has led to a larger estimated incentive to withhold, particularly in 2021–22. We derived our incentive estimates using 2 methods.

First, we applied a simple framework assuming participants derive all revenue from the spot market and incentives are completely tied to spot prices. We call this the 'raw' incentive. However, we know that the level of contracted capacity can have a major impact on incentives, so we also estimated a contract-adjusted incentive. Generators enter into financial hedge contracts with retailers to manage their risk (Box 4.1). A generator has less incentive to withhold on its contracted capacity because it has effectively agreed on a price with the buyer beforehand, and so fluctuations in spot prices do not impact its revenue for that capacity. In addition, the generator needs to ensure dispatch to cover its contracts (or else buy off the spot market to cover the shortfall), and so has the incentive to offer that capacity at low prices. To estimate the contract-adjusted incentive, we assessed the level of generation each participant consistently dispatches, by time of day for each month. We used this 'consistent dispatch' level as a proxy for a participant's contracted capacity and we assumed participants only have an incentive to withhold on uncontracted capacity.[72]

We estimated the contract-adjusted incentive to withhold to be much less than the raw incentive (Figure 6.4). This is particularly the case for regions with significant coal assets because coal plants tend to contract a significant proportion of their capacity and so have less capacity that would benefit from an increase in spot prices. In regions with fewer coal assets (especially South Australia, which has no coal), the adjustment to the incentive measure was smaller.

72 In theory, a contracted generator can also benefit from withholding capacity if influencing spot prices in the short run allows it to negotiate higher priced contracts in the future. This is complex to assess and is not a focus of this analysis. For detail on how we calculate the consistent dispatch level, see AER, *Wholesale electricity market performance report 2022 – Economic withholding approach, limitations and results*, December 2022.

Figure 6.4 Estimated average incentive to withhold across top 5 firms in each region



Note: 'Raw incentive' denotes the estimated returns from withholding capacity assuming generators derive all income from the spot-market. 'Contract-adjusted incentive' incorporates our estimate of participant contract positions and assumes participants only have an incentive to withhold on uncontracted capacity. We average across the top 5 firms by generation in each region. For a more detailed explanation, see AER, *Wholesale electricity market performance report 2022 – Economic withholding approach, limitations and results*, December 2022.

Source: NERA analysis for the AER, using NEM data.

Nevertheless, we estimate that in all regions both the raw and the contract-adjusted incentive was highest in 2021–22. In Queensland and NSW, this reflected a steady increasing trend over the past 5 years, with the estimated contract-adjusted incentive to withhold in Queensland 7 times higher in 2021–22 than in 2017–18.

These increases in estimated incentives reflect the changes to surplus capacity-price dynamics explored in section 6.2.1. Since the surplus capacity-price relationship is more sensitive, the 'price effect' of withholding is estimated to be higher and thus the incentive is estimated to be greater. An increase in the incentive to withhold does not necessarily mean that economic withholding is occurring. Nevertheless, these results may suggest withholding behaviour is more likely to occur now than a few years ago – particularly in Queensland and NSW.

6.3 Some participants display behaviour consistent with economic withholding

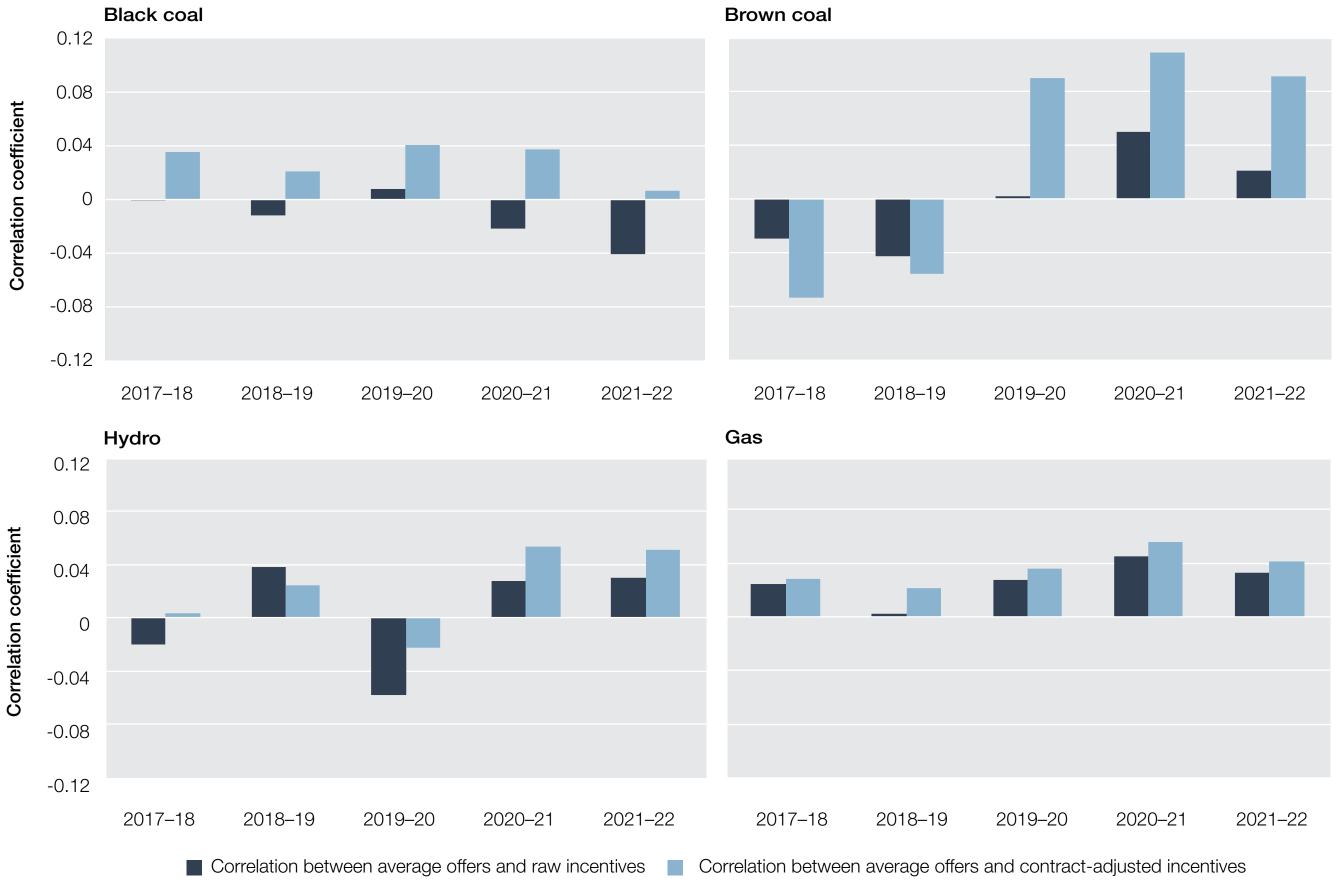
As outlined in section 6.1, to assess potential economic withholding we analysed participant actions against incentives and price outcomes. First, we examined whether participants offered capacity at higher prices when the estimated incentive to withhold was greater. Second, we analysed whether participants offer capacity at higher prices at times when prices are higher than we might expect given the level of surplus capacity. Although economic withholding does not appear to be widespread across the market, the results of our assessment suggest evidence of withholding behaviour by some participants.

6.3.1 Some generators appear to respond to incentives by increasing offers

To explore whether market conduct may reflect intentions to influence the price, we analysed whether generators bid higher when our estimated incentive to withhold is greater. Higher bids at times of greater estimated incentive may indicate economic withholding.

When we assume full spot price exposure (that is, using our 'raw' incentive measure), we found limited evidence of economic withholding. For most fuel types, there was no consistent correlation between raw incentives and average offers (Figure 6.5). When looking across the market, participants were generally just as likely to offer lower at times of greater incentive as they were to offer higher.

Figure 6.5 Average correlation between offers and incentives, by fuel type



Note: This figure plots the average correlation across stations between average offers (or quantity-weighted offer prices – see Box 6.1) and incentives. We do this with both raw incentives (assuming all revenue is derived from the spot) and contract-adjusted incentives (which incorporates an estimate of participant contract positions). Our findings are weighted by unit capacity. A correlation of zero means we typically do not observe a change in offers when the incentive is greater, while a correlation of one means we always see higher offers when the incentive is greater. A negative correlation means participants tend to bid lower when the incentive is greater. For a more detailed explanation, see AER, *Wholesale electricity market performance report 2022 – Economic withholding approach, limitations and results*, December 2022.

Source: NERA analysis for the AER, using NEM data.

When we assume full spot exposure, the portfolio effect (Box 6.1) means that the incentive is greater when a participant's portfolio output is higher. In reality, much of this output could be contracted and actual incentives may be lower. When estimating contract positions, we find that participants appear to be more contracted at times of higher output.

When we account for participant contract positions, the correlation between incentives and offers was stronger than when we assumed full spot exposure. This was apparent for every year since 2017–18 for black coal and gas participants, and during most years for brown coal and hydro participants.

To the extent that our adjustment for contract positions improves the accuracy of our method, these results provide evidence that suggests withholding behaviour may be occurring. Regardless, this highlights that taking steps to account for the limitations of our metrics is important, as they can have a material impact on the results.

At a participant level, we identified several stations that have a stronger relationship between offers and incentives once we adjust for contract positions. Typically, only one or 2 stations in any participant's portfolio displays this kind of behaviour. In the next section we assess if these stations also increase bids during higher-than-expected prices, to determine if they may be economically withholding.

As such, these results provide a possible indication of economic withholding behaviour by some participants with market power.

6.3.2 Offer behaviour during high prices may further suggest withholding by some participants

Having examined participant bids at times of greater estimated incentive, we then looked at offers in periods when prices were higher than we expected given the level of surplus capacity (which we call 'outlier periods'). We identified that a number of generators bid higher during outlier periods, some of which were also identified in section 6.3.1 as bidding higher when the estimated incentive was greater. This provides an indication that these generators may be withholding.

We find that black coal generators bid higher during outlier periods for every year since 2017–18 (Figure 6.6). Moreover, the difference in offers between outlier and non-outlier periods has generally trended upwards, which may suggest that withholding behaviour has become more prevalent. Analysis of individual black coal stations indicates that several consistently bid higher during outlier periods. Moreover, some of these are stations that were identified in section 6.3.1 as bidding higher during periods of greater estimated incentive.

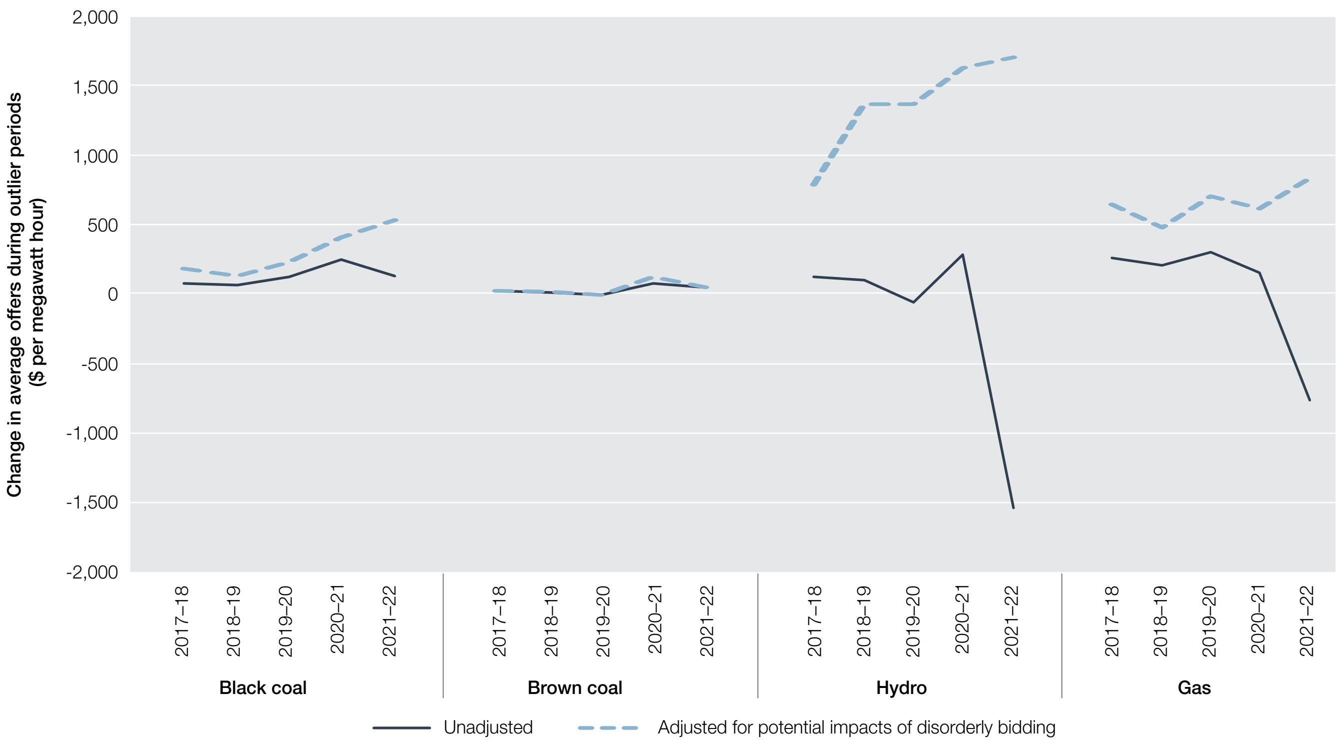
For brown coal, we observed limited change in behaviour during outlier periods, particularly from 2017–18 to 2019–20. This could indicate that the potential withholding behaviour by brown coal flagged in section 6.3.1 did not result in prices that were higher than expected given the level of surplus capacity. Alternatively, it could indicate that only small changes in bids were required to drive higher prices. This correlates with our finding in section 5.1.3 that participants may be withholding capacity, but the behaviour is not a significant contributor to high prices.

For gas and hydro, we observed a range of bidding behaviour across the past 5 years. We found that gas and hydro plants did bid significantly higher in some outlier periods, but also appear to engage in 'disorderly bidding' – dropping offers below marginal cost to ensure dispatch. To mitigate the potential impact of disorderly bidding on our quantity-weighted offer price measure, we removed all the outlier periods where a station's average offer was at least $500 per MWh lower than its average offer across all periods. When we did this, we found that the average offer in outlier periods increased dramatically for some hydro plants.

In general, generators bidding lower so as to be dispatched should lead to lower prices in the market. However, for some stations located close to regional borders, interconnector congestion may allow them to engage in disorderly bidding to be dispatched for a high price in one region while the physical energy is forced over an interconnector into a lower priced region. In such cases, disorderly bidding can lead to harmful outcomes because the market could be supplied at a lower cost if it didn't occur (section 8.1.5).

Regardless, once we exclude periods in which disorderly bidding is more likely, we observe that some hydro and gas stations display behaviour consistent with economic withholding at times.

Figure 6.6 Difference between average offers in outlier periods versus all periods



Note: The unbroken line shows the difference in average offers (or quantity-weighted offer prices) in outlier periods compared with average offers across all periods. If the line is above $0 per MWh, this indicates participants bid higher during outlier periods. The broken line shows what this difference looks like if we exclude outlier periods where a participant bids at least $500 per MWh lower than its overall average offer.

Source: NERA analysis for the AER, using NEM data.

Overall, there is potential evidence that certain participants may be contributing to higher price outcomes due to withholding behaviour. Combining these results with the findings from our previous incentive analysis in section 6.3.1, we identify certain generators who present evidence suggestive of economic withholding. However, to have greater confidence in the drivers of this behaviour we will need to do further analysis – including of actual incentives in each period, technical factors such as ramp rates, and potentially non-public data (such as contract positions). More work is also needed to understand the direct impact of this behaviour on market outcomes. To further evaluate our findings, and before publishing more detailed results, we will give generators the opportunity to provide information and comment.

6.4 Some participants are withdrawing capacity from the market entirely

Participants can also engage in physical withholding, which involves removing capacity from the market entirely with the intention to influence the price.

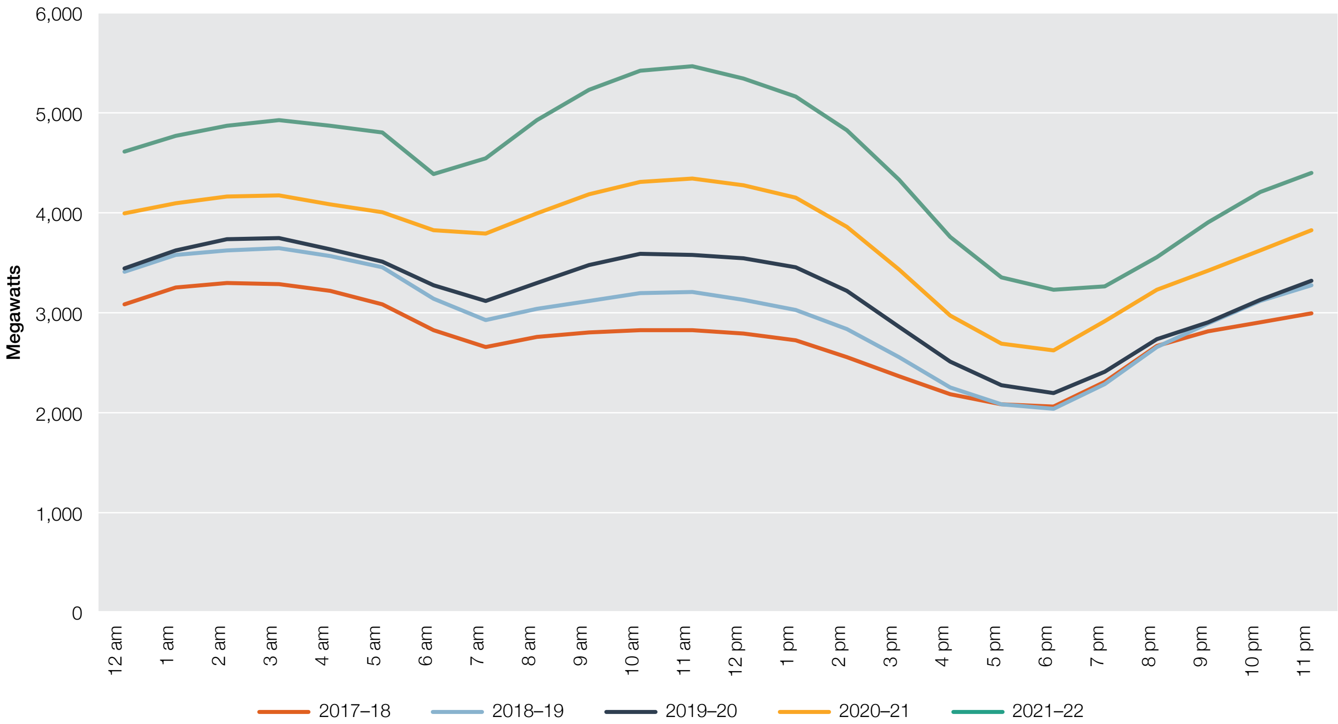
Physical withholding is difficult to accurately assess because participants may have a variety of supply-driven reasons for not offering capacity into the market. It is difficult to distinguish withdrawing capacity to influence the price from withdrawing capacity due to supply conditions, such as a need to conserve fuel or manage start-up costs. However, our screens (Box 6.2) indicate that withdrawal of capacity has increased in recent years.

Box 6.2 How we approximate physical withholding behaviour

Our proxy measure for physical withholding involves comparing participants' Projected Assessment of System Adequacy (PASA) availability with their maximum availability. A participant's PASA availability is the capacity it can supply to the market. By contrast, its 'maximum availability' is the capacity that it actually offers to the market. As such, the difference between PASA availability and maximum availability should reflect the capacity that participants could supply but choose not to. We have conducted this comparison by time of day for each of the past 5 financial years.

The amount of capacity withdrawn from the market has steadily increased over the past 5 years (Figure 6.7). This gap is greatest at off-peak times and has been steadily growing during the middle of the day. There are several reasons this may be occurring.

Figure 6.7 Average capacity withdrawn, by time of day



Note: The figure shows the average NEM-wide capacity withdrawn by time of day. Capacity withdrawn is defined as the difference between Bid PASA and Bid maximum availability.

Source: AER analysis using NEM data.

Participants report that at times they remove capacity from the market to ration fuel. For these generators it makes most sense to remove capacity at off-peak times, when demand and prices are low, so they can make capacity available to the market at peak times. This somewhat explains the high level of withdrawn capacity in 2022, as participants managed significant fuel supply issues particularly during the June administered price period.[73] However, in that case certain generators limiting available capacity did complicate the Australian Energy Market Operator's (AEMO) management of power system security. Despite this, even once we exclude withdrawals in response to administered pricing, 2022 would have been a standout year.

Generators also withdraw capacity to avoid being turned on at times when prices are generally low. Greater renewables penetration, and associated changes to surplus capacity dynamics, have increased the volatility of prices. Peaking plants offering capacity into the market must quickly turn on when the dispatch price reaches their offer price. But since the change to 5-minute settlement in October 2021 (section 2.6.5), a spike lasting only one or 2 dispatch intervals may not be sufficient to recover the costs of turning on (section 5.1.3). We observe that peaking gas plants – which can turn on quickly in response to high prices – are withdrawing much more of their capacity than coal plants or renewables.

Participants may be withdrawing more capacity due to an increased incentive or ability to influence the price. In this case, the behaviour would constitute physical withholding. However, this is unlikely to be a significant driver, given that most withdrawal of capacity occurs in the middle of the day when solar output is highest. High solar output typically corresponds to high levels of surplus capacity, due to a larger amount of available generation and lower demand at these times (section 6.2.1). Moreover, we would expect greater market competition at these times due to a larger number of participants supplying the market. The combination of these dynamics would lead us to expect reduced ability to influence the price through withholding.

Regardless of the reason, withdrawal of capacity can pose a problem if participants are not incentivised to offer the capacity that enables AEMO to operate the market securely and reliably at the lowest cost (section 2.1.2).

6.5 Rebidding by participants is contributing to more high prices

Over the past 2 years we have reported, through our significant price reports, on concrete examples of participants engaging in conduct that has led to high prices. These reports analyse the key drivers of all 30-minute prices above $5,000 per MWh.

In the past 2 years, 9 of the 23 reports we published identified rebidding by participants as a factor contributing to the price outcome. By comparison, in 2020 we identified that out of the 9 reports published in the preceding 2 years, generators rebidding capacity from low to high prices had contributed to 2 events.[74]

Participants rebid for various reasons (Box 6.3). When participants rebid with the intention to influence the price it can constitute economic or physical withholding (depending on whether capacity is shifted to higher prices or removed entirely). Moreover, the rebidding of capacity can represent a further exercise of market power if the rebid occurs close to dispatch, thus limiting the opportunity for other participants to respond.

Over the past 2 years we have observed an increase in instances where participants contributed to high price outcomes through rebidding. Some of the reasons given by participants for these included:

- technical issues
- changes in forecast demand, generation or prices
- conserving fuel
- portfolio rearrangement
- avoiding high FCAS costs.

At times, participants appear to be rebidding for supply-driven reasons; at other times, it is likely that the behaviour constitutes withholding to influence the price. Through our significant price analysis, we have not identified specific participants that regularly displayed this behaviour, but we will continue to analyse these outcomes against our economic withholding findings. Regardless, the increasing prevalence of generators appearing to rebid to influence the price further suggests exercise of market power in the NEM.

73 AER, *June 2022 market events report*, December 2022.

74 AER, Wholesale electricity market performance report 2020, 14 December 2020, p 56.

Box 6.3 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 months in advance or 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. For example, a participant may respond to a higher-than-expected demand forecast 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, which can lead to inefficient outcomes. The National Electricity Rules prohibit participants from making false or misleading offers.

6.6 We have observed potentially harmful conduct from some participants but not systematically across the market

Overall, there is evidence suggestive that some participants may be economically withholding. But the prevalence of this conduct – and the extent to which it reflects an intent to influence the price – is difficult to assess.

When adjusting for contract positions, we found that participants could be offering specific stations at higher prices during times of greater incentives. Moreover, we observed that some of these stations potentially were also offered higher during periods when prices were higher than expected given supply conditions. In some cases, these observations were sustained over time. While we haven’t identified widespread or systemic patterns of economic withholding across the market, the behaviour of these participants is concerning and requires further scrutiny.

We have also identified other conduct that may be harmful to the market. Participants are withdrawing more capacity from the market. This conduct may be a reasonable response to the increased penetration of low-cost renewables but we will continue to analyse these trends. Moreover, we find participants are more frequently contributing to high price events through the rebidding of capacity from low to high prices. At times, this does appear to constitute opportunistic withholding behaviour, though we have not identified participants that regularly displayed this behaviour.

Overall, these results suggest there may potentially be sustained exercise of market power by a number of generators. While we surmise that the significant price increases we have seen in 2021–22 are largely explained by supply conditions, our findings are consistent with a view that prices may be impacted by the sustained exercise of market power, and there may be issues with the effectiveness of competition in the market. However, more analysis is needed to understand the drivers of participant behaviour and the magnitude of the impact. Access to information on contract markets is vital to enable effective scrutiny of participant incentives and behaviour.

As noted above, the exercise of market power to put upward pressure on price is not necessarily illegal but may instead point to problems in market design. We will continue to monitor and analyse this conduct closely, reporting on our findings and referring potentially illegal conduct for investigation as needed.

7. Prospects for new investment

Key points

- The National Electricity Market (NEM) has seen significant new entry in large-scale wind and solar since our last report. We expect further investment in these technologies, as well as some entry from battery storage, pumped hydro and gas.
- Thermal generators have continued to exit and significant further exits are imminent. Planned exits are also accelerating as generators shift their scheduled dates earlier.
- Market price signals persist for wind, large-scale solar, gas and a variety of storage technologies. However, the majority of new investment in these assets is tied to some level of government support. We have not seen significant new investment led purely by the market, suggesting that there may be barriers to this investment.

Understanding entry and exit in the NEM is important for assessing the market's performance over time. Market-led entry and exit promotes dynamic efficiency by ensuring energy is delivered at least cost over time. An efficient wholesale electricity market also typically requires a mix of demand and supply side options.

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 whether investment is occurring in response to these signals is a key part of our assessment.

7.1 Significant new entry in recent years and major exits are imminent

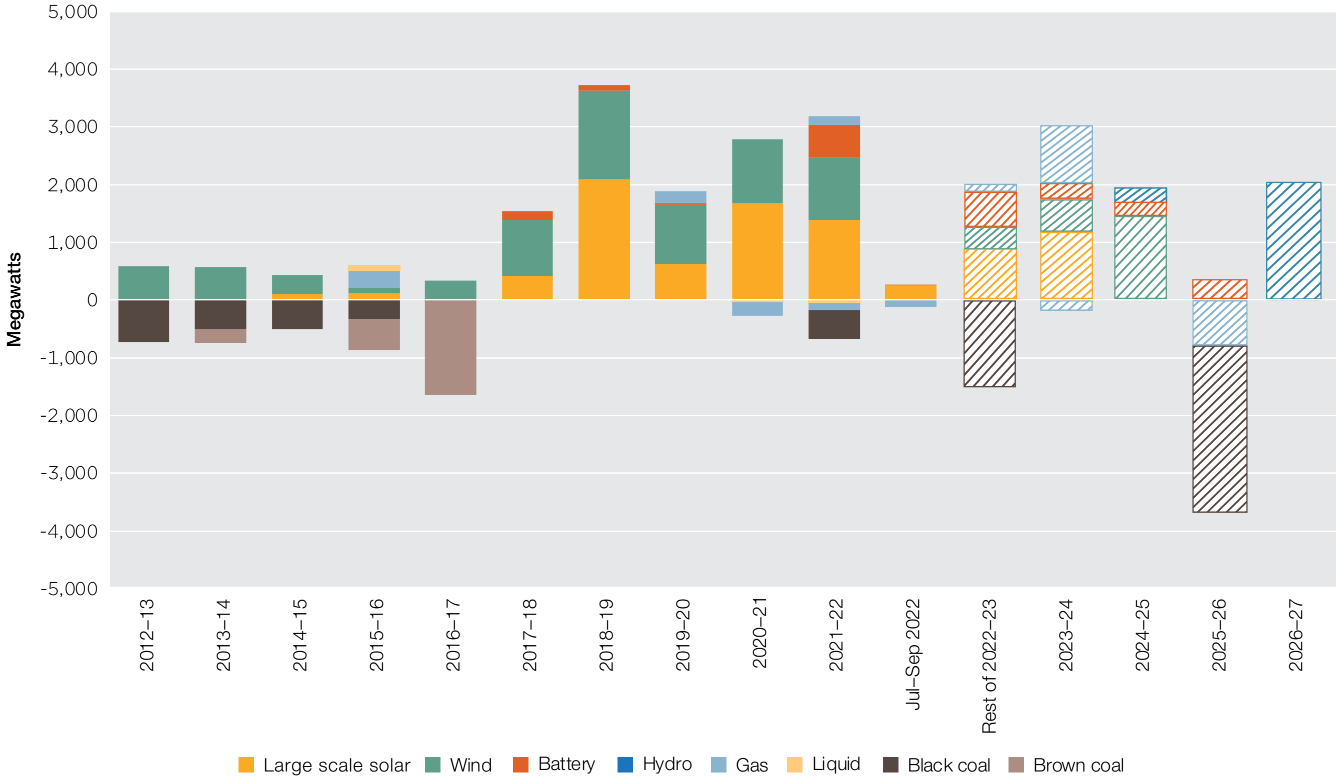
Since our 2020 report, the NEM has seen significant new entry in intermittent renewables and batteries, and the retirement of a number of thermal generators, with further exits expected over the next 3 years. We expect substantial investment in large-scale wind and solar, as well as some in battery storage, pumped hydro and gas, as the market continues through the energy transition.

7.1.1 New entry has primarily been in large-scale wind and solar

Since our previous report, almost all new capacity has been in intermittent renewables and battery storage.

Across 2020–21 and 2021–22 around 3 GW of solar and 2.2 GW of wind capacity entered the market (Figure 7.1). Over the same period, 557 MW of batteries also entered, including 360 MW from the Victorian Big Battery – the largest entry of battery capacity since the NEM commenced. Since July 2022 an additional 248 MW of capacity has been connected to the grid, consisting of the Queanbeyan Battery Energy Storage System (10 MW), Bluegrass Solar Farm (148 MW) and West Wyalong Solar Farm (90 MW).

Figure 7.1 Past and committed investment and withdrawn capacity in the NEM



Note: Capacity includes scheduled and semi-scheduled generation but does not include rooftop solar capacity. Hashed areas reflect committed new entry and planned generator retirements according to the classification in AEMO's NEM Generation Information August 2022. Figure uses registered capacity for every fuel type except for solar, which is based on maximum capacity, to reflect its different technical constraints. Generators are marked as having entered from their first dispatch date and this chart does not reflect stages of commissioning.

Source: AER analysis using NEM data.

New entry over the past 5 years (13.1 GW) was over 6 times greater than that of the 5 years prior (2.5 GW), with almost all of this capacity being in renewables. If exits are considered, this difference is even more stark, with a net gain of 12.1 GW from 2017–18 to 2021–22 compared with a net loss of 1.9 GW over 2012–13 to 2016–17. Nonetheless, while intermittent renewable generation can adequately meet demand and have positive impacts on competition when they are running (section 3.1.3), it is not a like-for-like replacement for thermal generation as these intermittent renewables are not dispatchable. As a result, when conditions are poor for this generation this can put pressure on the supply-demand balance and prices (section 6.2.1).

Looking ahead, significant further new entry of large-scale wind and solar is expected, as well as some dispatchable capacity in the form of batteries and some gas. The increasing role of variable renewable energy in the generation mix combined with the significant exit of coal means that entry of dispatchable capacity is becoming more important. Since the NEM commenced, market participants have delivered around 11.6 GW of investment in new scheduled dispatchable capacity.[75] However, we estimate that only around 1.5 GW of that took place in the past decade.

75 ESB, Capacity mechanism high-level design paper, June 2022, p 9.

7.1.2 The pipeline of upcoming new entry is mostly renewables and some gas

The Integrated System Plan indicates that by 2050 the NEM needs substantial new investment to ensure reliability, including 46 GW of new dispatchable storage capacity and 10 GW of gas-fired generation for peak loads and firming.[76]

About 9.4 GW of new entry is currently committed over the next 5 years, comprising a roughly even mix of intermittent and dispatchable assets:[77]

- 2.1 GW of solar capacity, mostly in NSW[78]
- 2.5 GW of wind capacity
- 1.4 GW of battery storage capacity
- 2.3 GW of pumped hydro, including around 2,000 MW from Snowy Hydro 2.0[79]
- 1.1 GW of gas capacity, including the Kurri Kurri gas-fired power station (660 MW) in 2023–24.

Although the share of new entry capacity owned by the 12 largest participants has dropped, from more than half in the 5 years up to 2016–17 to under one-third in the past 5 years, that share is expected to rise again based on these committed projects.[80]

More projects are likely to be commissioned within the next 5 years, especially in generation types with relatively short construction lead-times.

In addition to committed projects, there is a significant pipeline of future projects in various stages of development, from anticipated – that is, projects that meet some commitment criteria – to publicly announced. In total, 3.4 GW of new generation is classified as 'anticipated' and a further 165 GW of generation capacity has been identified as 'proposed'.[81] This latter category includes projects such as the Eraring Battery (700 MW, expected entry in 2025–26), Waratah Super Battery (700 MW, expected 2025–26) and Liverpool Range Wind Farm (around 1,000 MW, expected 2026–27). By capacity, around two-thirds of future projects are variable renewable energy generation projects, and the remainder are dispatchable assets.[82]

Additionally, an estimated 15 GW of rooftop solar capacity is currently supplying consumers, and this is estimated to reach 69 GW by 2050.[83]

Importantly, a substantial amount of new investment has been supported by government funding or policy, as discussed further in section 8.1.

7.1.3 Thermal capacity will continue to exit the market over the next decade

Thermal generation comprises a substantial portion of generation capacity in the NEM (section 2.2.1) and is currently highly concentrated (section 3.1). As these generators exit the market, we could see more market volatility and uncertainty as the supply-demand balance tightens at certain times, as well as a shift in the competitive landscape depending on how this generation is replaced and by which participants.

Since our last report, thermal generation has continued to exit the NEM. In September 2020, the first and second units at Torrens Island A closed, with the third unit following in September 2021, resulting in 360 MW of withdrawn gas generation. In April 2022 a further 500 MW of black coal exited with the retirement of a black coal unit at Liddell, and the final 120 MW Torrens Island A unit closed in September 2022. These recent exits, along with 80 MW of withdrawn liquid generation, comprise the total 1 GW of capacity withdrawn since July 2017. In the preceding 5 years, 4.5 GW of capacity exited the market – 2.1 GW of black coal and 2.4 GW of brown coal. In the last decade, almost 5.5 GW of scheduled dispatchable capacity exited the NEM, compared with 1.5 GW that has entered.

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76 AEMO, 2022 Integrated System Plan, June 2022, p 50.

77 Based on projects identified by AEMO as committed. See AEMO, NEM Generation Information August 2022, accessed 1 October 2022.

78 Not including rooftop solar capacity.

79 Though media speculation has suggested a likely delay to the project, owner Snowy Hydro has provided unchanged advice regarding the intended commissioning schedule of Snowy 2.0 between 2025–26 and 2026–27.

80 The 12 largest participants include AGL Energy, Alinta Energy, EnergyAustralia, Engie, Ergon Energy, Hydro Tasmania, Iberdrola Australia Limited, Infigen Energy, Neoen, Origin Energy, Shell Energy, and Snowy Hydro.

81 AEMO, 2022 Electricity Statement of Opportunities, August 2022, p 41.

82 AEMO, NEM Generation Information August 2022, accessed 1 October 2022.

83 AEMO, 2022 Integrated System Plan, June 2022, p 39.

Over the next decade, several more thermal power stations are expected to close (Table 7.1). Almost 10 GW of coal and gas-powered generation is scheduled to withdraw – 6.4 GW of black coal, 1.5 GW of brown coal and 1.5 GW of gas. Although recent exits have not been as substantial as in other periods over the past decade, the expected closure of thermal plants is accelerating as projected exit dates are being brought forward. For instance, AGL recently announced that Torrens Island B (800 MW) will close in 2026, 9 years earlier than planned, though one of the four units was mothballed in October 2021.[84] AGL also announced the closure of Loy Yang A (2.2 GW) up to a decade earlier than planned.[85] Additionally, Origin Energy has indicated the potential for early closure of the Eraring power station (2.9 GW) by 7 years.[86] The generators cited the transition to lower cost and low-carbon renewable technology as the reason for these exits, with Origin noting that the transition has put unsustainable pressure on coal-fired power stations.

Table 7.1 Expected thermal generator closure to 2032

EXPECTED CLOSURE YEAR	REGION	STATION	FUEL TYPE	REGISTERED CAPACITY (MW)
2023	NSW	Liddell units 1, 2 and 4	Black coal	500 each
	SA	Osborne	Gas	180
2025	NSW	Eraring units 1, 2, 3, and 4	Black coal	720 each
2026	SA	Torrens Island B units 1, 2, 3, and 4	Gas	200 each
2028	QLD	Callide B units 1 and 2	Black coal	350 each
	VIC	Yallourn W units 1 and 2	Brown coal	360 each
		Yallourn W units 3 and 4	Brown coal	380 each
2029	NSW	Vales Point units 5 and 6	Black coal	660 each
2030	SA	Dry Creek Gas Turbine units 1, 2, and 3	Gas	52 each
		Mintaro Gas Turbine	Gas	90
		Port Lincoln Gas Turbine unit 1	Diesel	50
		Port Lincoln Gas Turbine unit 3	Diesel	23
		Snuggery	Gas	63
2032	SA	Hallett Power Station	Gas	217
2030–2033	NSW	Bayswater units 1, 2, 3, and 4	Black coal	660 each

Since 2019 large generators have been required to provide 42 months' notice before closing[87], to limit the chance of unexpected exit and assist with long-term planning. Numerous generators have notified of several significant upcoming closures. The final 3 units at Liddell, totalling 1,500 MW of black coal capacity, are scheduled to close in April 2023, and the 180 MW Osborne gas-fired power station is scheduled to close in December 2023. A further 2,880 MW of black coal capacity will be withdrawn in 2025 as 4 units at Eraring are retired. This will be the largest exit of capacity from the NEM since its inception.

The exit of thermal generators and their replacement generation has implications for system security (section 2.6.4). Many essential system services that support the stability and security of the grid, including frequency response and inertia, are provided as intrinsic by-products of thermal generation. As thermal generation exits, the system has become vulnerable to low system strength and directions for system security are being issued more frequently. There are currently limited ways for the market to procure system strength outside of directions and the Energy Security Board is exploring reforms to ensure that essential system services can be procured (section 8.1.3).[88]

84 AGL, Torrens Island 'B' Power Station to close in 2026, 24 November 2022.

85 AGL, A clear pathway for a responsible energy transition, accessed 1 October 2022.

86 Origin Energy, Origin proposes to accelerate exit from coal-fired generation, 17 February 2022, accessed 1 October 2022.

87 National Electricity Rules Clause 2.10.1.

88 ESB, Post-2025 Market Design Final advice to Energy Ministers Part A, 27 July 2021.

In terms of ownership, 97% of the capacity that exited in the last 5 years was owned by AGL and all closures expected within the next 5 years are owned by Origin or AGL. Although the projects are yet to meet AEMO's commitment criteria, both firms have announced plans for significant new investment. For example, AGL has announced its intention to roll out 850 MW of battery storage by 2023–24, including 250 MW at Torrens Island, and Origin plans to develop a 700 MW battery at Eraring.[89]

7.2 Price signals are apparent for new entry for several technologies

With major thermal capacity exiting and more new entry needed to replace it, it is important to consider whether market signals for new entry are present and for which technologies. The threat of potential new entry is also an important feature of effectively competitive markets, because it counters participants' ability to exercise sustained market power. If we observe that price signals are apparent (i.e. new entrants would likely be able to recover costs) for a sustained period, we would expect to see new entrants, and market-led investment in response. If we did not see this, then we might be concerned the market was not performing as intended. A lack of new market-led investment may risk too little capacity being available and new capacity arriving too late. It also increases the likelihood that governments intervene to fill the gap of private investment – which, in turn, can create a source of uncertainty for investors (sections 8.1.8, 8.1.9).[90]

We have seen price signals for a range of technologies, as well as significant investment in intermittent assets in particular. However much of the investment, both over the last 5 years and upcoming, has been supported by various government schemes indicating potential barriers to entry and expansion for market-led investments.

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

The National Electricity Law requires us to assess whether prices are determined on a long-term basis by underlying costs.[91]

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 such a market, investors will see an opportunity and enter the market if prices (and therefore revenue) are persistently higher than underlying costs. To the extent this new entry is lower cost, it 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.

To calculate historic potential spot revenues, we assessed spot prices in 2020–21 and 2021–22 in all regions, building on previous reports. 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 7.1).

89 AGL, AGL unveils plans for grid-scale battery in South Australia, 16 November 2020, accessed 1 October 2022; Origin Energy, Eraring Projects, accessed 1 October 2022.

90 ESB, Capacity mechanism – High-level design consultation paper, June 2022, p 13.

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

Box 7.1 Costs and potential revenue are estimated based on how often a new entrant may operate

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 zero to 365 days of production. However, given the significant costs involved we assume that participants would target a minimum level of production. Therefore, we use a minimum of 12 trading days for all storage technologies.

Our cost estimates include both high- and low-cost scenarios for a range of generation and storage technologies. We levelise our cost estimates to create a minimum price a new entrant will need to receive in order to recover its costs.

In undertaking our analysis, the National Electricity Law requires us to use public information in the first instance. Therefore, while it may not provide a complete picture of investment incentives, we used publicly available spot market data to model whether current spot prices reflect the underlying costs of new entry for generation and storage technologies. 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, including future expected revenue, contract arrangements, other market- and non-market sources of revenue, as well as overall market conditions and confidence. Unfortunately, there is limited public information on contract prices, and other factors add significant complexity to our models. Access to contracts information would provide more accurate insight into the actual cost and revenue profiles of different generation technologies and ensure our assessment better reflects the potential cost recovery of new entrants.

We consider the simple analysis a helpful tool for understanding how investment price signals are adjusting over time for a range of technologies. It provides a benchmark that, 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 detailed findings are set out in our methodology.[92]

7.2.2 Price signals for new entry of solar, wind and gas technologies continue

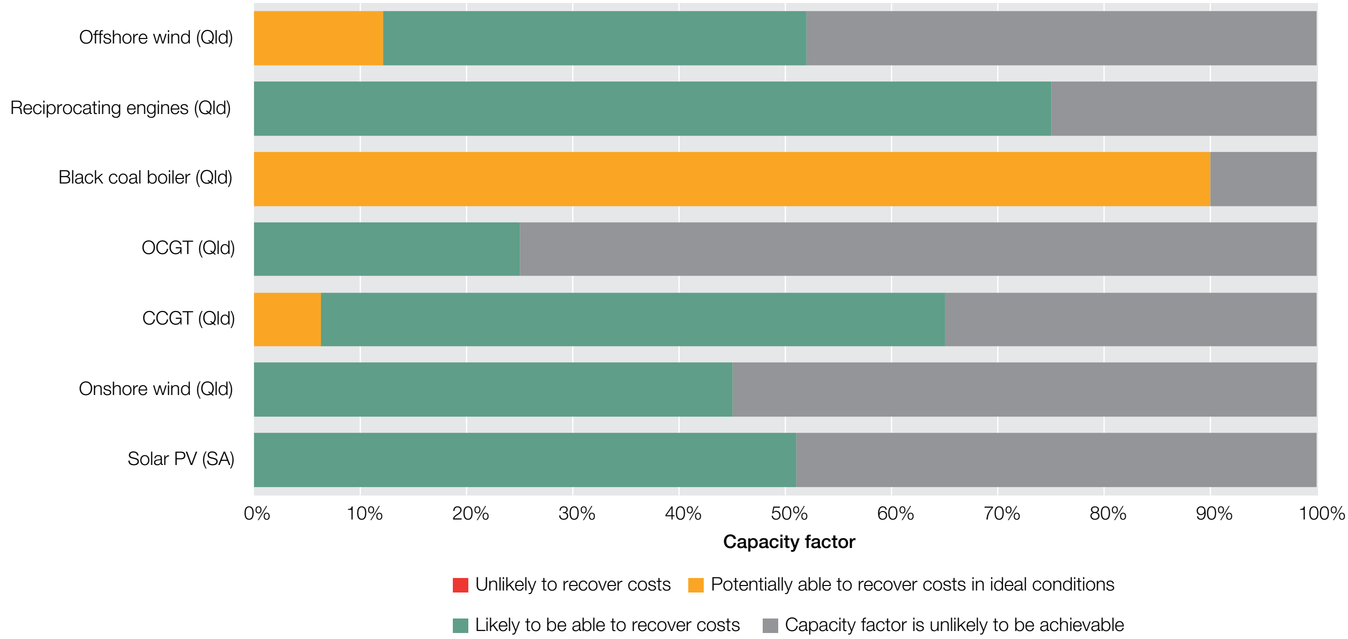
Our findings suggest that price signals for new entry exist for some technologies. While spot prices have fluctuated over the past 2 years, elevated contract forward prices may encourage future investment (section 2.1).

In our 2018 report, we found that a signal for the new entry of large-scale solar, wind and combined cycle gas turbines (CCGT) was emerging, and in our 2020 report we saw these signals sustained. Our analysis for 2020–21 and 2021–22 shows that these signals continue as these technologies are likely to be able to recover their costs (Figure 7.2 and Figure 7.3 highlights regions with the strongest signals for each technology). Although costs for new solar PV and wind installations have increased, reversing a decade-long cost reduction trend, prices for natural gas, oil and coal have risen much faster, therefore actually further improving the competitiveness of renewable electricity.[93]

92 AER, *Wholesale electricity market performance report 2022 – LCOE & LCOS modelling approach, limitations and results*, December 2022.

93 International Energy Agency, Renewable Energy Market Update: Outlook for 2022 and 2023, May 2022.

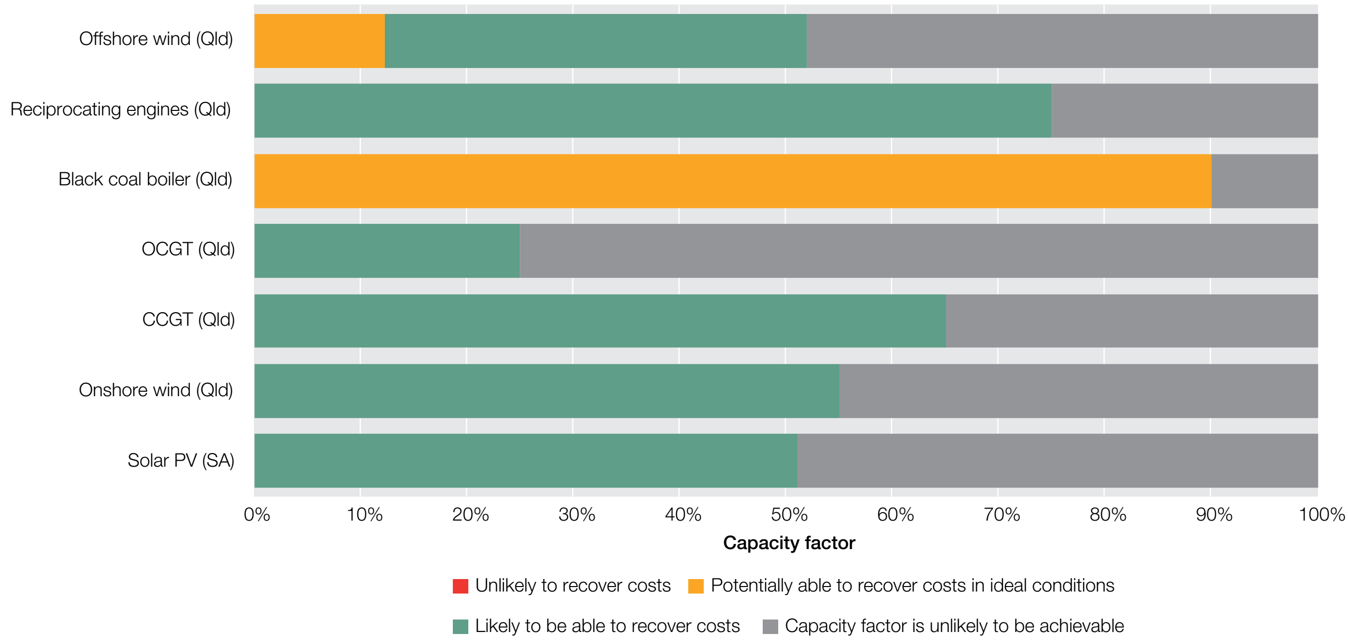
Figure 7.2 Likelihood for new entrant cost recovery for 2020–21, by generation technology type



Note: Figure shows the regions with the strongest price signals; a summary of all regions can be found in our methodology. CCGT: combined cycle gas turbines. OCGT: open-cycle gas turbines.

Source: AER, *Wholesale electricity market performance report 2022 – LCOE & LCOS modelling approach, limitations and results*, December 2022.

Figure 7.3 Likelihood for new entrant cost recovery for 2021–22, by generation technology type



Note: Figure shows the regions with the strongest price signals; a summary of all regions can be found in our methodology. CCGT: combined cycle gas turbines. OCGT: open-cycle gas turbines.

Source: AER, *Wholesale electricity market performance report 2022 – LCOE & LCOS modelling approach, limitations and results*, December 2022.

Our 2020 report also suggested an emerging signal for new entrant open-cycle gas turbines (OCGT) and reciprocating internal combustion engines (RICE).[94] This signal has also been sustained across the past 2 years, with new entrants likely to be able to recover costs. Recent price volatility in the market and high prices in 2021–22 could support investment in the right conditions, because OCGT and RICE generators typically only operate at times of high prices. This has important implications for the market transition. As the NEM shifts to a generation mix that relies increasingly on intermittent renewable generation, there will be a greater need for these forms of fast start, flexible generation that can provide firming services.

94 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.

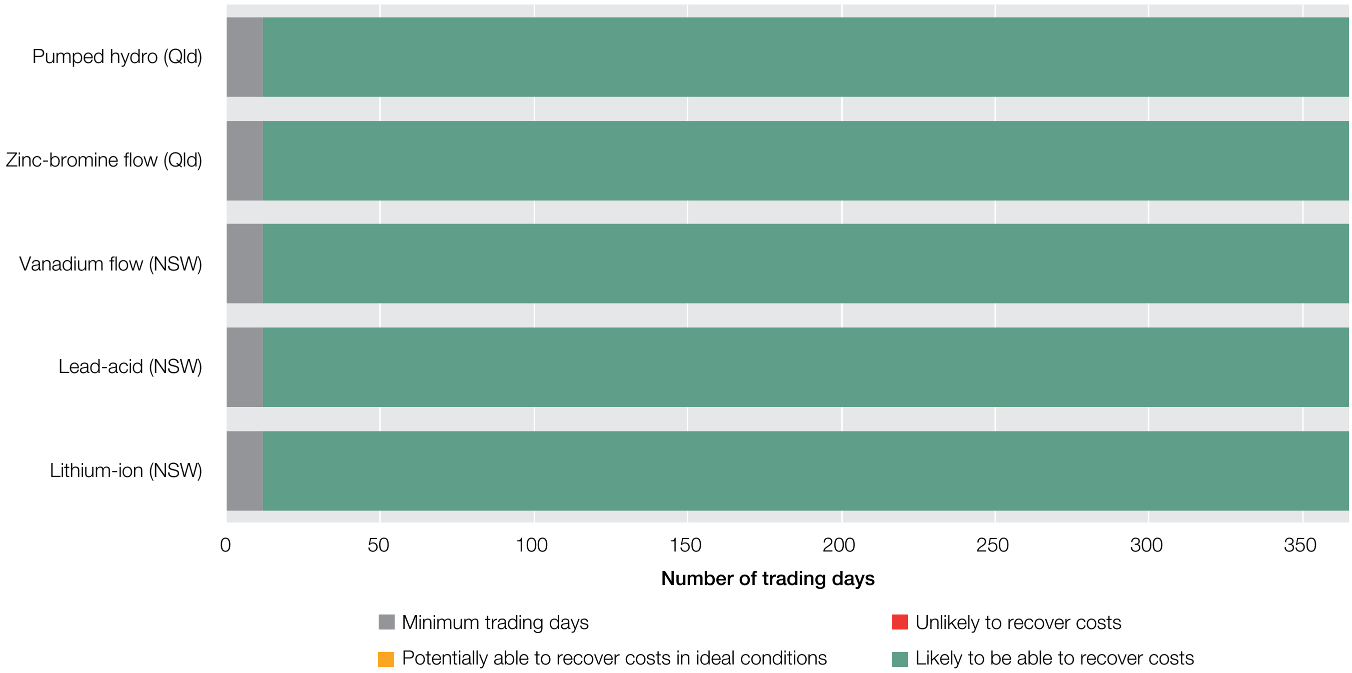
Our analysis also suggests an emerging signal for offshore wind technology. Offshore wind farms can produce more electricity per amount of capacity installed because there are faster and steadier wind speeds available offshore compared with on land. Offshore wind turbines can also be very large, allowing them to produce more electricity, while costs of generation are decreasing.[95] The higher performance of offshore wind farms, along with falling cost of generation may support future investment. In addition, the Australian Government has joined an alliance of government and private organisations to help establish an offshore wind industry in Australia.[96]

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. Further, results for 2021–22 were supported by high prices. If prices normalise to historical averages, we would expect new entrant black coal generators to experience more difficulty recovering costs. 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. In addition, coal-fired generators are designed for continuous operation and are less able to respond to the increasing number of negative prices in the middle of the day without significantly increasing the costs of maintenance. As the market transitions to increased low-cost generation, it will become increasingly difficult for inflexible coal plants to remain viable.

7.2.3 Price signals for new entry are strong 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 2020–21 and 2021–22, including a range of battery types and pumped hydro energy storage (Figure 7.4 and Figure 7.5 show regions with the strongest signals for each technology). Cost recovery for storage technologies depends on variation between minimum and maximum prices each day, and this has been present, noting that volatility has increased over the past few years.

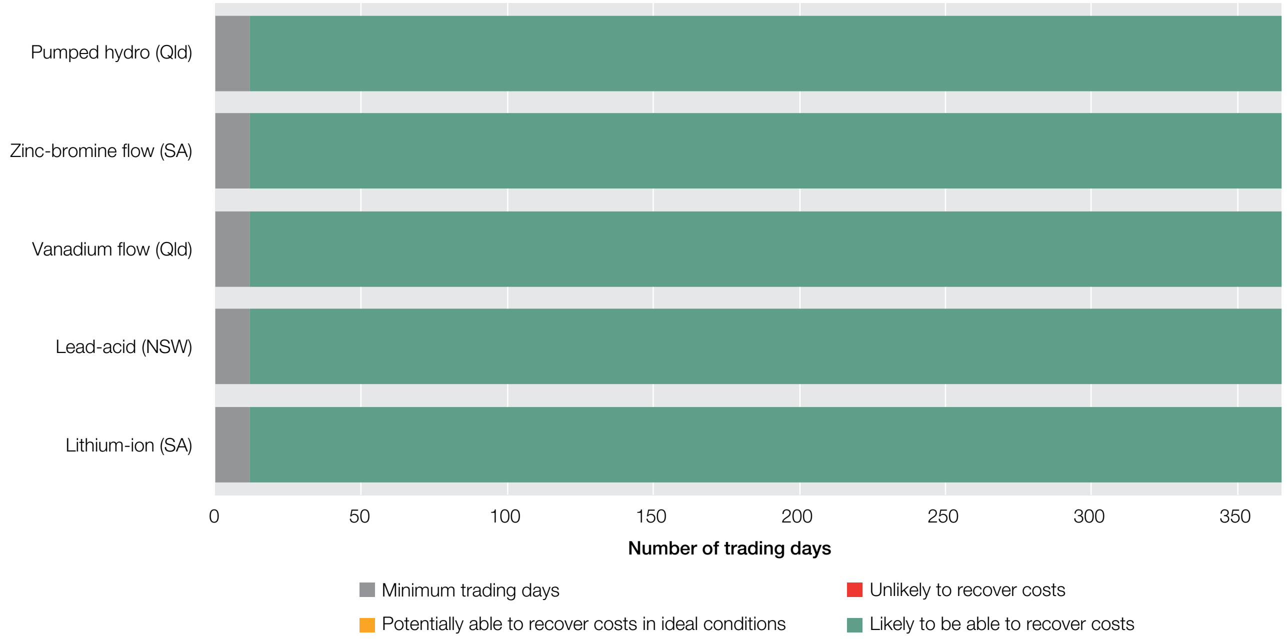
Figure 7.4 Likelihood for new entrant cost recovery for 2020–21 for storage technology type



Note: Figure shows the regions with the strongest price signals; a summary of all regions can be found in our methodology.
Source: AER, *Wholesale electricity market performance report 2022 – LCOE & LCOS modelling approach, limitations and results*, December 2022.

95 Department for Energy and Mining, Offshore Renewable Energy Generation, South Australia State Government, December 2021.
96 Department of Climate Change, Energy the Environment and Water, Australia joins global drive to boost offshore wind, November 2022.

Figure 7.5 Likelihood for new entrant cost recovery for 2021–22 for storage technology type



Note: Figure shows the regions with the strongest signals; a summary of all regions can be found in our methodology.
Source: AER, *Wholesale electricity market performance report 2022 – LCOE & LCOS modelling approach, limitations and results*, December 2022.

Grid-scale batteries are becoming more established in the market and we expect further investment in them. To date all batteries in the NEM are lithium-ion, suggesting that this may currently be the most attractive storage technology for investment. However, some participants have also noted that, due to the popularity of lithium-ion, other battery technologies may get overlooked by investors. This is despite other technologies having different benefits and efficiencies, which may prove better suited to some applications. Our analysis suggests that other battery technologies also exhibited high likelihood of cost recovery.

Our findings also suggest new entrant pumped hydro energy storage is increasingly likely to recover costs. However, not captured in the modelling is that this technology requires a site with adequate storage capacity and elevation differential to be viable, which limits the sites suitable for this technology. Balancing optimal electricity generation with environmental requirements can also be challenging. As a result, the most likely investment in pumped hydro would come from an incumbent participant that already controls, or has the means to develop, the necessary sites and infrastructure, for example Snowy 2.0 or the commitment from the Queensland government to develop new hydro capacity (section 7.3.4).

7.3 Results are consistent with market observations, but much investment is linked to government support

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 research.

As discussed in section 7.2, though, if we observe that price signals are apparent (i.e. new entrants would likely be able to recover costs) for a sustained period, we would expect to see new entrants, and market-led investment in response. If we did not see this, then we might be concerned the market was not performing as intended. For technologies that we have explored, much of the current and planned investment is linked to some form of government support.

This support, from both state and territory and federal governments, ranges from directly funding or underwriting investment, to supporting more market-based incentives like certificate schemes or grants for project development.

7.3.1 Investment in intermittent renewables is consistent with strong price signals, often supported by government

As noted earlier, there has been significant investment in intermittent renewables, and more capacity has been committed for the future. Australia is particularly well suited to wind and large-scale solar due to our abundance of sunshine and strong winds, absence of harsh winters and a seasonal peak in summer when large-scale solar is most effective. Given the strong price signals, we would expect significant market-driven investment. While we have seen considerable investment in wind, large-scale solar and battery storage, much of this has been supported by various government schemes. For example, the Second Victorian Renewable Energy Target auction (VRET2) supported the entry of 6 projects, which will bring forward more than 600 MW of new renewable generation capacity (as well as battery storage).[97]

7.3.2 There has been limited market-led gas investment despite strong price signals

We observed strong price signals for gas generation, and so we would expect to see a range of investment in this technology. These generators can start quickly to take advantage of high prices, but generally operate infrequently due to generally high fuel costs. 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.

To date, we have seen limited market-led investment, and what we have seen is primarily supported by governments. For example, we have observed some investment in OCGT, including Snowy Hydro's plans to construct the Kurri Kurri power station, with funding committed to the project in the 2021–22 Budget.[98] Despite our findings we have observed limited new investment in CCGT and none for RICE. Though we are seeing price signals for gas generation, we are generally not seeing aligned investment, indicating potential structural barriers to entry (section 8.1). For example, CCGT tend to be large capacity and suited to long-term firming roles, requiring significant initial investment which could pose a barrier to new investment. As more coal-fired generators retire, there may be a need for further investment in gas to fill the gap.

7.3.3 There is no new committed investment in coal-fired generation, consistent with declining likelihood of cost recovery

Consistent with our analysis for coal, showing only the potential for cost recovery for investors in ideal conditions, there is no committed new investment in coal-fired generation and the investment environment for this technology looks to be challenging. Typically, coal-fired steam 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 operation costs. The broader shift in the market towards intermittent generation indicates a greater need for plant that can operate flexibly.

7.3.4 Investment in storage technologies is growing and supported by price signals but as yet is not market-led

We have identified price signals for storage technologies, and in line with this, a number of participants have committed or announced investment in pumped hydro energy storage. The majority of these projects, though, are backed or supported by government, rather than purely market-led, as we would expect from such apparent price signals. For example, the Australian Government has committed significant equity for Snowy 2.0, with Snowy Hydro funding the remainder of the project.[99] This project also benefits from existing reservoirs and infrastructure, which are ideal circumstances that a new entrant may not have access to. Further, the Queensland Government has announced development of a pumped hydro scheme that could supply a large amount of Queensland's energy needs, and could replace a significant proportion of coal generation.[100] Governments have also supported investment through providing additional funding for private projects, for example the NSW Government awarded grants to AGL and Idemitsu (through a joint venture) and Energy Australia to advance development of pumped hydro projects.[101,102] While most

97 Department of Environment, Land, Water, and Planning, Second Victorian Renewable Energy Target auction, Victoria State Government, 25 October 2022.

98 Minister Angus Taylor, Protecting families and businesses from higher energy prices, 19 May 2021.

99 Minister Angus Taylor, New construction milestone for Snowy 2.0, 19 March 2021.

100 Queensland Government, World's biggest pumped hydro for Queensland, 28 September 2022.

101 AGL, AGL and Idemitsu Joint Venture Secures Funding to Advance Development Studies for Muswellbrook Pumped Hydro, 02 September 2022.

102 EnergyAustralia, Funding boost for EnergyAustralia's pumped hydro energy storage project, 02 September 2022.

investment in this technology is supported by government funding, there is a small amount of private investment. Genex Power has committed investment in pumped hydro energy storage, with the privately owned project using an abandoned mining site.[103]

Of the other storage technologies, we have seen increasing, though still limited, investment in lithium-ion battery assets in the NEM. We have seen sustained price signals for investment over the past few years and would expect to see market-driven investment in this technology. To date though, most investment has been supported by government programs. For example, the Victorian Big Battery has a 250 MW grid service contract with AEMO under direction from the Victorian Government.[104] The ACT Government has also invested in the 250 MW Capital Battery.[105] Although we have seen investment support from governments – for example, through grant funding or government electricity contracts for battery developments – there is also some private investment on the horizon. A number of privately owned battery projects have been announced, like the Orana Battery Energy Storage System and Wooreen Energy Storage System. We are likely to see further investment in battery technology in the future, with some slated to replace exiting coal generation such as AGL's 500 MW battery on the site of its Liddell power station.[106]

Current investment in battery technology is slow though, when compared with wind and solar, given that we see similarly strong price signals for these technologies. Despite the potential benefits of battery technology, like lower initial costs (when compared to other storage technologies like pumped hydro or gas plants) and the flexibility of batteries to value-stack across services like frequency control ancillary services (FCAS), we are not seeing a significant amount of market-driven investment. Where we do see investment, FCAS has been the primary revenue source for batteries, rather than the energy market (section 9.4). While the market and investment landscape for batteries is complex, this lack of private investment indicates that while price signals are strong there are potential barriers to entry (section 8.1).

7.3.5 Limited market response to price signals may indicate barriers to entry

Overall, while there has been plenty of new entrant large-scale solar and wind generation, we have not seen comparable new entry in flexible technologies like batteries, despite similar strong price signals for these technologies. Further, we are often seeing government support in some form for new investment highlighting potential barriers to entry that could be impacting purely market-driven investment. Stakeholders have also raised concerns that government interventions and investment may crowd out private investment (section 8.1). This limited investment, particularly in flexible dispatchable capacity, has significant ramifications for the market. With more large-scale solar generation in the middle of the day, dispatchable generation is needed to meet demand when intermittent renewable generation is low (section 2.6). Battery technology offers a potential solution, particularly as the technology develops and costs for investment reduce. Advancements in new and existing technologies could also lead to greater diversity in new entrants, which would increase competition in the market. If the current price signals persist for flexible technologies, and we still see limited market led investment in the future, it is likely barriers to entry are persisting. Given the rising importance of flexible firming capacity in the overall generation mix, we will continue to monitor investment trends in these technologies.

103 Genex, 250MW Kidston Pumped Storage Hydro Project (K2-Hydro), accessed 14 November 2022.

104 Neoen, Victorian Big Battery, accessed 14 November 2022.

105 ACT Government, Work begins on the Big Canberra Battery, 25 July 2022.

106 AGL, AGL's Hunter Energy hub takes shape with Liddell grid–scale battery, 19 March 2022.

8. Barriers to entry and impediments to efficient price signalling

Key findings

- We have identified a range of barriers to entry and expansion in the National Electricity Market (NEM). Investment in high-cost, long-lived assets requires some revenue confidence, but such certainty is difficult to provide in a complex, rapidly transforming market and uncertain macroeconomic and policy environment.
- Beyond these barriers, there are increasing indications that there are impediments to efficient price signalling in the market. These include the events of June 2022, as well as increased congestion, and a greater use of directions and emergency reserves.
- In addition, governments are increasingly intervening in markets in order to meet environmental, economic, social, and reliability needs, as well as responding to a lack of private investment from structural barriers in the market. Market participants and potential investors report that this in itself is a barrier to entry as it crowds out market-led investment, leads investors to wait for opportunities to receive support, and risks excessive or inefficient investment. As a result, interventions in the market carry the risk of dampening further private investment if they are prolonged, or if regulation does not respond to changing economic conditions.
- Current reforms to market design could address some of these issues, including providing greater revenue confidence, facilitating efficient use of transmission networks, and enabling least-cost procurement of essential system services. However, these reforms do not address all barriers and impediments in the NEM, and these issues could persist through the transition, which would compromise competition and efficiency.

As highlighted in chapter 7, price signals for new investment appear to be present for a range of technologies, including wind, large-scale solar, gas and a variety of storage technologies. New entry is important for competitive markets because it puts a competitive constraint on incumbent firms. Without new entrants, incumbents have reduced incentives to vigorously compete. This ultimately harms consumers through higher prices, lower quality products, and less innovation.

Our report examines barriers to entry and impediments to efficient price signalling because they are crucial in assessing whether new entry will occur in response to price signals. As in previous reports, when we consider barriers to entry, we review not just barriers to investment for new entrants, but obstacles to expansion and sustainability for incumbent participants, as well as impediments to efficient price signalling.

We have raised a number of these issues in previous reports as they present ongoing challenges for the market.

8.1 We identified a range of barriers to entry and impediments to efficient price signalling

To identify and analyse barriers to entry and impediments to efficient price signalling, we conducted research and engaged with stakeholders.

Broadly, potential barriers fall into 2 types:

- structural or exogenous factors that are not within the control of the market, regulators or government – such as the capital-intensive nature of generation investment and volatile macroeconomic conditions
- more readily controllable factors that arise due to behaviour or governance of the market.

From this research, we identified a range of issues.

8.1.1 Structural features of the market can make entry and expansion challenging

Some structural characteristics inherent to the wholesale electricity market can act as barriers to entry.

Investment in capital-intensive, long-lived assets requires some certainty over future revenue for generation firms to be confident about recovering their costs. Many electricity generation technologies are high-cost, long-term investments. The fact that significant costs associated with these technologies are sunk and may not be recovered acts as a barrier to entry for new generators.[107] These barriers are less present for wind and solar power, as well as battery storage, which tend to be modular and have lower sunk costs. Despite this, we have seen limited new entry in flexible dispatchable generation capacity, like batteries, suggesting that other barriers investment may be present (section 7.3.5).

Under the current market design, revenue streams are generally based on spot and contract market prices. With exchange contracts traded only 3 years out, price signals are relatively short-term compared with the life of a generation asset and are insufficient to underwrite long-term investments.[108] Investors can secure revenues through contracts with longer terms, but these are more bespoke and can be challenging to access.

It is also difficult to provide revenue confidence in an environment of technological change. There is the risk that 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 to us that the potential for future asset stranding leads to a degree of caution when investing.

Rapid technological change also increases supply and demand uncertainty, impacting investment planning. On the supply side, there is doubt around the timing of, and market response to, large generator exits (section 7.1.3). In addition, the increasing penetration of weather-dependent generation has driven increased price volatility (section 2.6). On the demand side, there is uncertainty surrounding the uptake of small-scale distributed energy resources by electricity consumers, the timing and scale of trends like the electrification of transport, and the outlook for energy intensive industries, such as smelters, that make up a substantial proportion of demand.[109] This uncertainty means that a higher return on investment would be required to account for the increased risks of investing, which creates a greater hurdle for new investment.[110]

Long-term revenue uncertainty also impacts the sustainability of thermal generators and can be a barrier to investment in other technologies. Although the exit of coal will create space in the market for new entry, coal generators provide firming services in an increasingly intermittent market, and smooth exit will likely minimise price volatility to consumers. The maintenance schedules for coal-fired power stations need to be planned years in advance and contracting for fuel in a cost-effective way is challenging. Stakeholders have reported considering plant closures because of fuel availability rather than plant reliability. Stakeholders have also reported difficulties in securing funding from coal assets to invest in diversification or maintain current coal assets.

8.1.2 Major shifts in broader economic and market conditions pose risks for investment

Since our last report there have been significant shifts in the macroeconomic environment which are impacting investment conditions.

Large generation and transmission projects by their nature have been challenging to forecast costs for, and have historically been prone to significant unplanned increases in costs. Research shows that a large percentage of capital projects go over budget.[111] This can be due to cost overruns, delays, failed procurement, or unavailability of private financing, but can be corrected with appropriate management of risk through the life of a project.[112]

Difficulties in forecasting costs are heightened in an environment of global inflationary pressures and of competition amongst a finite pool skills and resources necessary to progress investments. This is a potential barrier to entry.

Global and domestic energy markets have recently exhibited unprecedented volatility. Russia's invasion of Ukraine impacted the global supply of oil, coal, and natural gas, resulting in the prices of these commodities

107 Competition Economists Group, Barriers to entry in electricity generation – A report outline for the AEMC, June 2012, p 9.

108 ESB, Post 2025 Market Design – Capacity mechanism – High-level design consultation paper, 20 June 2022, p 13.

109 ESB, Post 2025 Market Design – Capacity mechanism – High-level design consultation paper, 20 June 2022, p 13.

110 Origin Energy, 2022 Annual Report, 18 August 2022, p 45.

111 PwC, Managing capital projects through controls, processes, and procedures, 2014, p 4.

112 McKinsey & Company, A risk-management approach to a successful infrastructure project, November 2013.

rising to extremely high levels. Industry stakeholders have noted the increased risk associated with the volatility of wholesale prices.[113] This heightened risk makes investment in the current market challenging and may delay investment decisions.

The urgency and scope of investment required through the energy transition is likely to intensify competition for scarce inputs, potentially resulting in supply chain issues or skills shortages.[114] A finite pool of labour and suppliers for such projects means there is a risk of supply-chain bottlenecks. For example, the recent placement into administration of Clough, a major civil engineering contractor, may have impacts on the cost and timing of several key transition projects it was involved in, including construction of Snowy 2.0, Project Energy Connect and the Tallawarra B power plant.[115] Challenges accessing plant, skills or resources may be a barrier to entry even where price signals and policy settings otherwise would prompt that investment.

The construction sector is also facing increased pressure on the supply chain and labour market which may undermine an orderly market transition. Analysis from Infrastructure Australia for the Australian Energy Market Operator (AEMO) found that the build out of electricity generation and transmission infrastructure will create pressures on market capacity to deliver the supply of labour and materials required for a smooth, efficient energy system transition.[116] Similarly, the Clean Energy Council has warned that existing labour shortages, especially for engineers and electricians, risks inhibiting the potential for job creation in clean energy over the coming decades.[117]

Inflation is also high globally.[118] This has led to central banks increasing interest rates, potentially dampening investment as it becomes more expensive to borrow money to finance new projects.

During discussions with market participants, the ability to finance new investment was also raised as a concern. Stakeholders indicated it is difficult to attract debt finance to support investment without long-term contracts in place to provide ongoing revenue confidence.

8.1.3 The NEM is complex and undergoing significant change

Stakeholders have reported that the complexity of the NEM is a significant barrier to entry. Relative to international energy markets or other Australian industries, prospective investors indicated that:

- the NEM requires more resources to navigate and monitor assets within the current market, as well as to monitor proposed reform
- monitoring the performance and policy environment of the NEM requires a dedicated analyst within the business – in comparison, where generally an analyst could monitor several other international energy markets simultaneously.

For example, one prospective investor expressed that the effort required to invest in a 200 MW asset in NSW is equivalent to that of a 4 GW asset in Japan.

The volume of reforms underway (Box 8.1) also means that the market is becoming more complex, and the increasing complexity of the market may itself act as a barrier to entry as firms are required to devote more resources to entering or operating in the market. Stakeholders have reported policy uncertainty is a significant investment deterrent. In some cases, it may be efficient for investors to defer investment until reforms have been settled, particularly in the case of significant changes to the market design.

113 AGL, Annual Report 2022, 19 August 2022, p 13.

114 P Hannam, Supply chain delays and steel costs are part of 'perfect storm' stalling renewable energy growth, *The Guardian*, 24 May 2022, accessed 1 November 2022; University of Technology Sydney Institute for Sustainable Futures, Employment, Skills and Supply Chains: Renewable Energy in NSW – Appendices, September 2022.

115 A Macdonald-Smith and J Wiggins, Clough collapse threatens $10b of energy transition projects, *Australian Financial Review*, 6 December 2022

116 Infrastructure Australia, Market Capacity for electricity generation and transmission projects, October 2021.

117 Clean Energy Council, Skilling the Energy Transition, 25 August 2022.

118 Reserve Bank of Australia, Statement on Monetary Policy – November 2022, accessed 17 November 2022.

Box 8.1 Overview of major policy reforms in the NEM

In 2021, the Energy Security Board (ESB) released the *Post 2025 Electricity Market Design*, a suite of reforms which have been endorsed by Energy Ministers.[119]

As part of these, the ESB identified the need for resource adequacy mechanisms to ensure sufficient dispatchable resources and storage capacity are in place before anticipated plant closures, and before generator exits cause significant price or reliability shocks to consumers.[120] This has involved consultation on a number of design considerations, including eligibility, procurement, obligations and cost pass-through.[121] Jurisdictions are now working to develop a framework that delivers adequate capacity, ensures orderly transition, and incentivises new investment in firm renewable energy.[122] The ESB is providing expert support to this work.

In a review of essential system services, the ESB has identified a number of rule changes that are needed to ensure the system has sufficient resources and services to manage the complexity of dispatch and to deliver a secure supply to customers.[123] These include facilitating the valuation, procurement and scheduling of services around frequency, inertia, system strength and operating reserves in a more efficient way, with the goal to minimise expensive interventions like directions (section 8.1.4).

The ESB is also pursuing transmission access reform to improve arrangements for managing congestion (section 8.1.5). This workstream seeks to promote investment certainty, manage access risk, boost operational efficiency and incentivise technologies that alleviate congestion.[124]

In 2022, in recognition of the need to reduce emissions from the energy sector, Energy Ministers agreed to include an emissions objective into the National Energy Objectives. Its inclusion in NEO, which sets out some guiding principles for the framework that governs the NEM, will help to ensure that the transformation to net zero is delivered in the long-term interests of consumers.[125]

8.1.4 Increased directions for system security have compromised market efficiency

Directions are used by AEMO as an emergency backstop to ensure system security and reliability, and can require a market participant to operate in a way that diverges from its original offer strategy. However as thermal generation exits, the system has become vulnerable to low system strength and directions are being issued frequently for system security. There are currently limited ways for the market to procure system strength outside of directions, and a recent investigation found that the market-based setting of the current framework combined with the transition may result in adverse market outcomes.[126] As a result new frameworks are being implemented to address these risks (Box 8.1).

When directions are made, operation of assets is driven by AEMO rather than participants. As directions increase so do AEMO's impact on asset operation, which impedes efficient dispatch based on offers. Although directed participants can recover the costs of directions, stakeholders report that directions make effective management of assets and fuel much more challenging.

In our last report, we identified that increased use of directions, particularly in South Australia may be an impediment to efficient dispatch and price signalling. The costs of directions for system security increased from $7.3 million in Q3 2020 to $35 million in Q4 2021 in South Australia, and, with this, potential inefficiencies to the market also increased. The market intervention framework aims to mitigate this impact through 'intervention pricing' – that is, adjusting the price to a value had the direction not occurred. The application of intervention pricing for these instances has the effect of maintaining the scarcity signal for energy and may encourage new entrants.[127] However, if investments are made without the required system strength capability, directions will continue to occur as will the subsequent distorted price signalling.

119 ESB, Post-2025 Market Design – Final advice to Energy Ministers Part A, 27 July 2021.

120 ESB, Resource adequacy mechanisms and ageing thermal retirement, accessed 17 November 2022.

121 Department of Climate Change, Energy, the Environment and Water, Post 2023 Marker Design – Capacity mechanism – High-level design consultation paper, June 2022.

122 Department of Climate Change, Energy, the Environment and Water, Meetings and communiques, 12 August 2022.

123 ESB, Essential system services and scheduling and ahead mechanisms, accessed 17 November 2022.

124 Department of Climate Change, Energy, the Environment and Water, Transmission access reform Consultation paper, 17 June 2022.

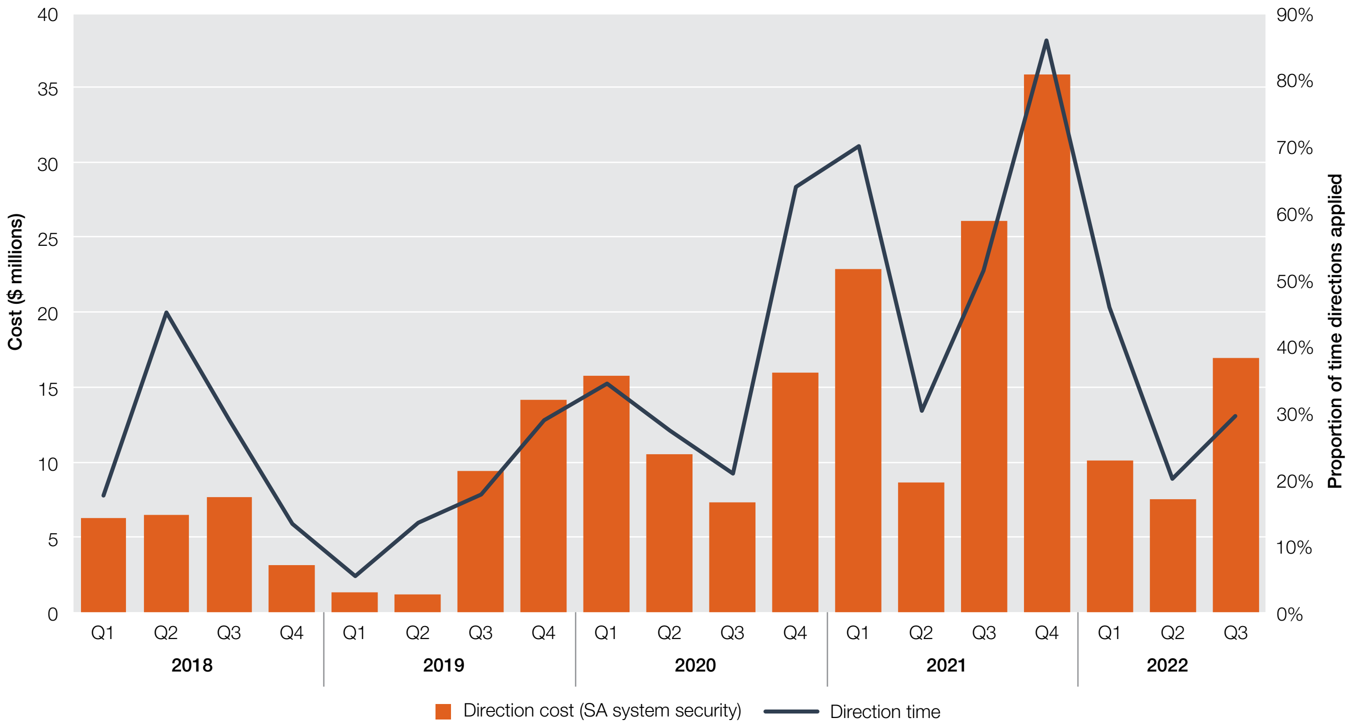
125 Department of Climate Change, Energy, the Environment and Water, Meetings and communiques, 12 August 2022.

126 AER, June 2022 Market Events Report, 2022.

127 AEMC, Investigation into intervention mechanisms in the NEM, August 2019.

In its economic evaluation report, ElectraNet identified that directions for system security were not the most efficient way providing system strength.[128] The report identified that installing synchronous condensers on the transmission network was the most efficient and least cost solution in the short to medium term. In 2019 the AER approved synchronous condensers in South Australia, which reduced the number of minimal thermal plants required to operate in South Australia from 4 to 2. The condensers were completed by Q4 2021 and the costs of directions for system security have since significantly reduced because less plants were required to provide system strength and high energy prices increased thermal generation in South Australia which further reduced the need for directions (Figure 8.1).

Figure 8.1 Cost and proportion of time directions applied in South Australia



Note: Figure presents proportion of time in each quarter that direction(s) applied.
Data not available for 2017.

Source: AER analysis of AEMO data, *Quarterly Energy Dynamics Q4 2021*, Q3 2022.

To provide a market-driven framework for procurement of system services, the ESB has developed an essential services workstream. This aims to proactively identify the current gaps in the market design for system services and provide an efficient long-term solution to procure the services, minimising costs to consumers.[129]

Significant work has progressed in the essential system services workstream over the past 2 years, including rule changes and determinations made for fast frequency response, a system strength framework and an operational security mechanism. Each of these reforms play a role to provide a safe, stable and secure system. This work will address some of the concerns related to the use of directions to procure system strength and will likely significantly reduce the frequency of directions needed as well as the associated inefficiencies. As these reforms are implemented, transparency and monitoring should be prioritised to ensure they are performing as intended.

8.1.5 Network congestion will continue to evolve as the market transitions.

The power system is transitioning from one engineered for a small number of large capacity generators with relatively consistent output to one with more decentralised, diverse and dynamic low-emission generation technologies. This means that pricing signals in the transmission access framework needs to be reconsidered.

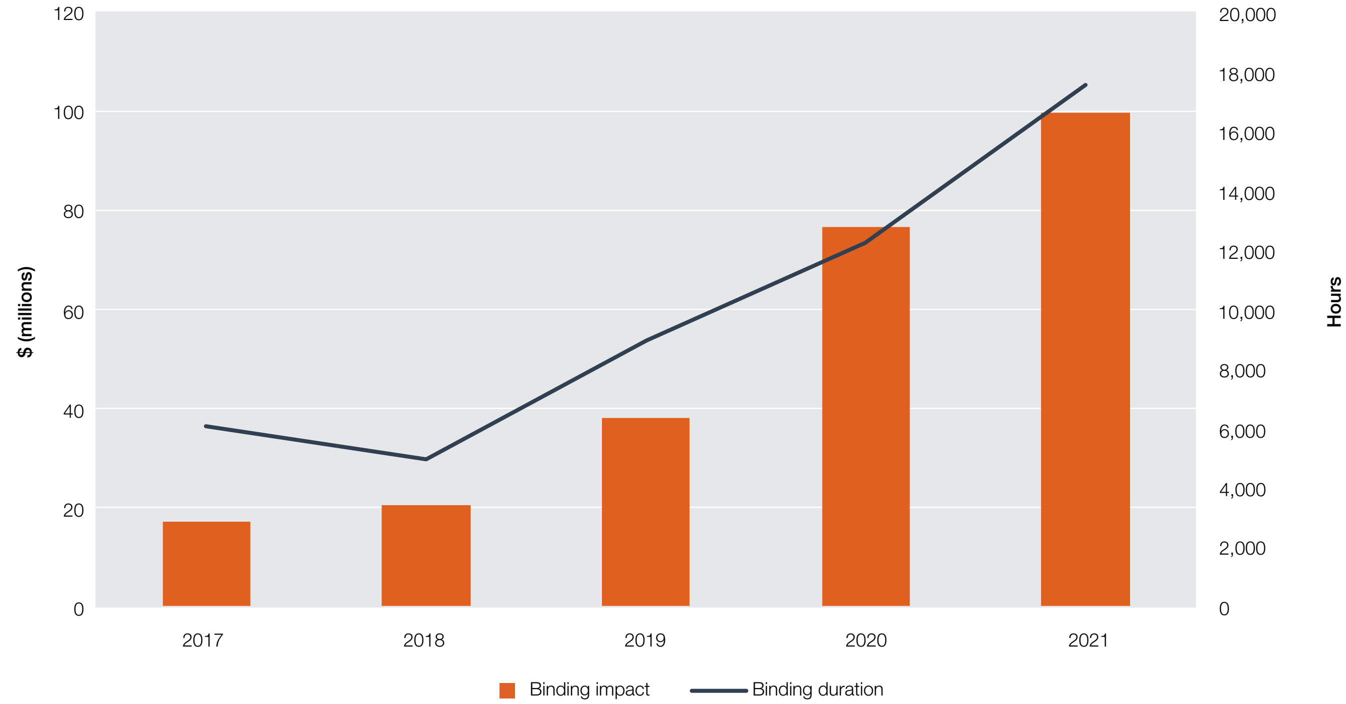
Some level of congestion is a normal feature of an efficient network, but excessive congestion, if sustained, suggests insufficient or absent locational price signals. It results in higher priced capacity being dispatched ahead of lower priced capacity, resulting in consumers facing higher and more volatile prices than is necessary.

128 Electranet, Addressing the system strength gas in SA, February 2019.

129 ESB, Essential system services and scheduling and ahead mechanisms, accessed 6 November 2022.

Network congestion has increased considerably over the past 5 years, and parts of the network are now more heavily used than ever. This is linked to new entrants clustering to certain parts of the grid in an uncoordinated and inefficient way, increasing congestion in those areas. In the past 2 years the costs of congestion have more than doubled, from $38 million in 2019 to $99 million in 2021 (Figure 8.2).

Figure 8.2 Hours and impact from network congestion



Note: Data excludes impacts from FCAS, outages, network support and commissioning constraints. Further details can be found at AEMO congestion information.

The binding hours and impact of system normal constraints provides an indication of network congestion. 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 MW of congestion over the period calculated.

Source: AER analysis of AEMO congestion information.

Congestion can compromise efficiency by driving disorderly bidding and curtailment of low-cost generation. Disorderly bidding occurs when generators have an incentive to offer capacity below cost in order to maximise dispatch.[130] These generators face little risk that they will receive a payment lower than their costs because network congestion usually means that the regional price will be set by a higher price generator. When this occurs higher cost (less efficient) generation capacity may displace lower cost (more efficient) generation, resulting in inefficient dispatch. Curtailment occurs when AEMO reduces the dispatch of particular generation (often low-cost intermittent renewables) to manage system security. Curtailment has more than doubled in the past 2 years, increasing from 211 MW in 2019 to 449 MW in 2021.[131]

The rising costs of congestion highlights the importance of coordination of transmission and generation investments, to minimise system cost and cost to consumers. Transmission access reform is currently underway to encourage more efficient use and orderly connection to the transmission network. This includes consideration of ways to support the timely delivery of ‘strategically important’ transmission investments, as well as access reform through a congestion management mechanism to promote investment certainty and manage access risks. Stakeholders report that there is a risk of unintended barriers to entry emerging due to increased complexity and uncertainty in the system. As these reforms are developed, a focus on simplicity and information transparency would help minimise these risks.

130 AEMC, Fact Sheet – disorderly bidding, accessed 12 December 2022.

131 AEMO, Quarterly Energy Dynamics Q3 2022, April 2022; AEMO, Quarterly Energy Dynamics Q2 2020, April 2022.

8.1.6 Emergency reserves needed more often to maintain system reliability and security

As well as directions, AEMO can also make operational decisions to dispatch under the Reliability and Emergency Reserve Trader (RERT) mechanism. RERT is an intervention under the National Electricity Rules (NER) that allows AEMO to contract for emergency reserves, such as generation or demand response, that are not otherwise available in the market. AEMO uses RERT as one of a number of mechanisms in the event that a critical shortfall in reserves is forecast. RERT is used as an emergency backstop after other market options have been exhausted, typically during periods when the supply demand balance is tight.

Although RERT is an important part of maintaining reliability, it can skew market signals. If the incentives to offer into RERT are higher than the market, potentially lower cost or innovative assets will choose not to participate. This means that the lowest-cost output may not be used first, and could lead to increased costs for consumers, through RERT costs and higher wholesale prices.

In 2021–22 AEMO activated the largest volume of RERT needed in recent years. This is a signal that the market was not operating efficiently during this time, as RERT is an emergency backstop when market options have been exhausted. Three of these interventions occurred during the June 2022 administered pricing periods and market suspension, discussed in further detail in section 8.1.7. In these cases, available wholesale market reserves were insufficient to maintain system reliability.[132] AEMO procured short notice reserves, and then activated these contracts to avoid load shedding.[133] AEMO intervened in the market by activating RERT reserves on 5 occasions in 2021–22 for around 5,456 MWh of volume at a cost of more than $130 million.[134]

This compares with 2020–21, when RERT was activated twice, for around 84 MWh of volume, at a cost of around $662,000, and 2019–20, when RERT was activated five times, for around 2,100 MWh of volume, at a cost of more than $40 million. If the market does not provide sufficient generation when needed, these interventions will continue to be required to ensure system reliability and security.

8.1.7 Events in June 2022 revealed risk of inefficiencies in the market

The unprecedented events of June 2022 (section 2.1.2) and ultimate suspension of the NEM have revealed areas where changes may be considered to improve the overall effectiveness of the regulatory framework.[135] Inefficient operation of the market creates uncertainty and may impede confidence to invest.

The AER investigated reports from a number of stakeholders, including AEMO, that generators were withdrawing capacity during June 2022 in order to be directed on by AEMO which would then enable them to obtain compensation. The AER is of the view that the evidence gathered demonstrated that generator behaviour resulted in poor market outcomes, though under the current framework, generators are likely to be found to have reasonable cause to withdraw capacity in the circumstances. We have identified areas of potential reform that could be considered to improve the overall effectiveness of the regulatory framework, and efficiency of the market.

Under the current legislative framework, commercial considerations appear to be a reasonable cause for generators to cause or contribute to AEMO directions. However, policy makers may wish to consider whether power system security should be the priority during times of system stress. This is because the objective of the compensation provisions, which is meant to incentivise scheduled generators to supply energy, appears to be insufficient in these circumstances.

The AEMC has also determined that the administered price cap (APC) was insufficient to cover the short-run marginal cost of most conventional gas or coal generation in these particular circumstances, despite compensation being available.[136] As a result, the AEMC implemented a transitional rule to lift the APC to $600 per MWh. The increase to the APC should minimise undue reliance on the compensation scheme and reduce additional pass-through compensation costs to consumers.[137]

132 AEMO, Quarterly Energy Dynamics Q2 2022, July 2022, p 38.

133 AEMO, Reliability and Emergency Reserve Trader (RERT) Quarterly Report Q2 2022, August 2022.

134 AEMO, Reliability and Emergency Reserve Trader (RERT) End of Financial Year 2021–22 Report, August 2022.

135 AER, June 2022 Market Events Report, 2022.

136 AEMC, Rule change to help protect consumers against costly blackouts, 17 November 2022.

137 AEMC, Amending the administered price cap, 17 November 2022.

8.1.8 Direct government investment and ownership may contribute to further uncertainty, act as a barrier to entry and distort market signals

The scale of government ownership of generation may also be an impediment to efficient price signalling. These investments may be needed to meet the NEM's future generation requirements, to meet environmental, economic, social and reliability objectives, as well as potentially responding to a lack of private investment from structural barriers in the market. Nonetheless, stakeholders have cited direct government ownership as a significant barrier to entry for market-led investment. This was also identified in our 2018 and 2020 reports.

Currently, in Queensland, government-owned participants Stanwell Corporation, CS Energy and CleanCo control the majority of generation in the region and in Tasmania, government-owned Hydro Tasmania controls almost all generation (section 3.1). Snowy Hydro, the third-largest participant in the NEM by capacity, is owned by the Australian Government.

Since our last report, state and federal governments have also either announced or have implemented direct investment in energy generation on a substantial scale. For instance, the Australian Government has provided $1.38 billion for Snowy Hydro 2.0, a 2000 MW pumped hydro station and up to $600 million for the 660 MW Kurri Kurri gas-fired power plant.[138] The Queensland Government has also announced significant direct investment in pumped hydro and other renewable projects as part of its Energy and Jobs Plan.[139] The Victorian Government aims to revive the publicly owned State Electricity Commission (SEC) as part of a plan to meet its renewable energy target. Under the plan, an initial $1 billion will be invested to deliver 4.5 GW of renewable energy capacity owned by the state.[140] The NSW Government is supporting the Waratah Super Battery Project, which includes the largest standby network battery in the southern hemisphere at 700 MW of capacity.[141]

While investment in government-owned generation can be market driven, our enquiries with market participants indicated it is often not perceived to be the case. Market participants argued that 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. For instance, the Victorian Government's announced revival of the SEC, was met with criticism from some energy generation firms, which warned that it will dampen private investment.[142]

In addition, industry participants and investors have raised concerns that the ability of governments to direct generators they own could distort market signals. For example, stakeholders argued that the Queensland Government's directions to Stanwell Corporation, in effect from 2017 to 2019 not only distorted market signals while they were in effect, but also created a perception that such directions may be re-imposed in the future. This may limit the effectiveness of price signals as a driver of investment decisions in the medium to longer term.

138 Snowy Hydro, About, accessed 1 November 2022; Ministers for the Department of Industry, Science and Resources, Environmental approval for Hunter Power project, 7 February 2022, accessed 1 November 2022.

139 Queensland Government, Department of Energy and Public Works, About the plan, accessed 1 November 2022.

140 A Macdonald-Smith, P Durkin, and C Packham, 'Shocked': Andrews nationalises electricity, Australian Financial Review, 20 October 2022.

141 NSW Government, Waratah Super Battery, accessed 1 November 2022.

142 A Macdonald-Smith, P Durkin, and C Packham, 'Shocked': Andrews nationalises electricity, Australian Financial Review, 20 October 2022.

8.1.9 Other government interventions may also dampen market signals

As well as direct government investment and ownership, stakeholders report that government interventions to underwrite investment potentially mask market signals and make it less predictable to private investors.

As discussed in chapter 7, recent investment has generally been associated with some level of government support. Multiple government schemes have encouraged investment in energy generation and storage. For example, the Renewable Energy Target operates through a certificate scheme to provide financial incentives for the development of large-scale renewable energy projects.[143] Government bodies like the Clean Energy Finance Corporation (CEFC)[144] and Australian Renewable Energy Agency (ARENA) have also supported substantial investment in renewable energy generation.[145] In the 2022–23 Federal Budget, ARENA was allocated additional funding and new budget programs, including $60 million to support large-scale battery projects (at least 70 MW).[146]

At a state level, governments have also developed schemes to support investment, including the Victorian Government's Renewable Energy Target, the Queensland Government's Renewable Energy Target, and the ACT Government's100% Renewable Energy Target. The Queensland Government's Energy and Jobs Plan and NSW Government's Electricity Infrastructure Roadmap also propose significant support of investment.[147] These schemes support private investment by providing financial incentives for investment in renewable generation and storage.

Stakeholders acknowledged the schemes are designed to meet environmental, economic, social and/or reliability objectives, or to accelerate investment in capacity to replace significant upcoming exits. However, they argued that by 'picking winners', government support (rather than market signals) will shape the generation mix in the market.

Stakeholders also highlighted that government decisions on generation investment could lead to inefficiencies, particularly through over-investment. It was argued the risks are heightened where governments pursue other objectives, such as job creation, as part of their investment decision making. Over-investment 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 electricity customers and/or taxpayers.

The scale of support 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 participants responding to government incentives. Even now, stakeholders have reported that they refrain from investment unless it is directly tied to government policy or funding because the risk in the market is otherwise too great.

It is arguable that governments have intervened in the absence of the market delivering new investments. Some stakeholders highlighted that government interventions are one of the factors that may have impacted investment, but others argued that it is not clear that investment would have occurred under the current market design without government support. This, in combination with high structural barriers to entry, means that governments are likely to continue to see a need to act, especially in the face of high costs to consumers. However, they should be mindful of the costs, not just the benefits, that come with intervention.

143 Clean Energy Regulator, Renewable Energy Target – How the scheme works, accessed 1 November 2022.

144 The government-established Clean Energy Finance Corporation (CEFC) supports energy efficiency, renewable energy and low emissions technology projects through loans and equity investments. Since 2012, the CEFC has committed $10.76 billion and catalysed a further $37.15 billion in funding for clean energy projects. See Clean Energy Finance Corporation, Australia's 'green bank' marks 10 years as trailblazing clean energy investor, accessed 1 November 2022.

145 The Australian Renewable Energy Agency (ARENA) was established to support the transition to net zero by accelerating pre-commercial innovation. As of 30 June 2022, it had provided $1.96 billion in grant funding to 632 projects. See Australian Renewable Energy Agency, About, accessed 1 November 2022.

146 Australian Renewable Energy Agency, New funding for ARENA in Federal Budget, October 2022.

147 NSW Government, Electricity Infrastructure Roadmap, accessed 1 November 2022; Queensland Department of Energy and Public Works, Queensland Energy and Jobs Plan, accessed 1 November 2022.

8.2 Impacts of barriers to entry and market impediments to efficient price signalling

Although we observe that there has been significant investment over the past 2 years, and more is projected, much of this was supported some way by Australian and state government schemes. This indicates structural and artificial barriers to entry.

There are prevailing structural characteristics of the market, which will act as a barrier to entry and expansion across the market, but particularly for generation technologies that can have high sunk costs. Investment in these high-cost, long-lived assets requires some revenue confidence, but that can be difficult to provide in a complex, rapidly transforming market and uncertain macroeconomic and policy environment.

Beyond these barriers to entry, there are indications that there are impediments to efficient price signalling in the market. Increased network congestion, the use of directions and emergency reserves are the function of inefficient market signals for investment and operation. However, there are wide-reaching reforms being developed by the ESB and Energy Ministers that aim to address these issues.

The events of June 2022 also revealed the importance of participants complying with market obligations, and that the legislative framework is fit for purpose. When these are compromised, they create impediments to efficient price signalling and can cause adverse market outcomes. In particular, June 2022 highlighted that is it essential for participants to provide high quality and timely information to AEMO to ensure it can maintain a secure and reliable power system. It is also highlighted that rules and policy are currently not sufficient to ensure the efficient operation of the NEM in all circumstances.

Through direct investment or by underwriting projects, governments are increasingly intervening in markets. They are doing so to meet environmental, economic, social and reliability objectives, as well as potentially responding to a lack of private investment from structural barriers in the market. Regardless, stakeholders report that this involvement is distorting market signals by crowding out market-led investment and risking excessive or inefficient investment. As a result, interventions in the market carry the risk of dampening further private investment if they are prolonged or if regulation does not respond to changing economic conditions.

Stakeholders overwhelmingly report that policy certainty would encourage confidence in the energy system and, in turn, help to reduce a significant barrier to entry. Ensuring the market provides the appropriate price signals in the long run will help to deliver the most efficient generation mix in the future market.

9. Frequency control ancillary services markets

Key points

- Over the past 2 years, frequency control ancillary services (FCAS) markets have attracted investments in grid-scale batteries, virtual power plants and demand response aggregators. These investments have displaced gas and coal generation and improved the competitive landscape for a number of frequency service markets.
- Grid-scale batteries have secured a proportion of revenue on entry and have become the dominant provider for most frequency services.
- Local markets are highly concentrated and remain vulnerable to individual participants' strategies. The confluence of events in 2021–22, including an interconnector upgrade, high energy prices and unplanned plant outages, resulted in record local costs reaching $232 million. These surpassed global costs for the first time.
- Extreme local costs in 2021–22 and more recently in November 2022 highlights the vulnerability of local markets to transitory network and plant outages. As the energy market continues to transition, so will FCAS markets and we will continue to closely monitor the efficiency and competitiveness of these markets.

To safely function, the power system must at all times balance the supply of electricity with demand 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 9.1). FCAS markets typically operate as 'global' markets, where participants across the National Electricity Market (NEM) provide FCAS in a single market across interconnectors. However, when a region is electrically separated or at risk of separation from the rest of the NEM, FCAS markets are needed to operate 'locally' and FCAS services can only be procured from within the one region.

Similar to the energy market, participants offer generation into the 8 FCAS markets and are paid for their services. Like in energy, we can assess these markets for effective competition by analysing key outcomes, market structures and participant behaviour.

Box 9.1 Frequency control ancillary services

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. For example, the average raise 6-second service enabled in Q3 2022 was 553 megawatts (MW).

AEMO dispatches services in 8 FCAS markets to maintain system frequency at close to 50 Hz. These services are:

- raise and lower regulation services
- raise and lower 6-second contingency
- raise and lower 60-second contingency
- raise and lower 5-minute contingency.

Regulation costs are recovered from participants that contribute to any deviations in frequency away from a secure operating state, known as causer pays.[148] Participants that operate in a manner that assists in correcting frequency deviations would be assigned a low causer pays factor, while those that operate in a manner that causes the frequency to deviate would be assigned a high factor.[149] The frequency deviation factors are used to determine the payment each participant must make.

Contingency services, like insurance, manage the risk of a large generator or load tripping. Raise contingency costs are recovered from generators, lower contingency costs are recovered from market customers. Each are apportioned a share of local contingency costs based on their share of total generation, or load.

FCAS can refer to global or local requirements:

- Most 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 that 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), where there are less connections to other regions.

Due to the complexities in providing FCAS, there are a number of ways we can analyse the markets. In this chapter we assess:

- 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 every 5 minutes, accounting for trade-offs between FCAS supply and electricity generation
- enablement for regulation services – the volume of FCAS actually provided
- enablement for contingency services – the volume procured in the case of a contingency event (only used if the contingency eventuates).

AEMO's procurement of each FCAS service (in megawatts) depends on several 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.

From October 2023 the FCAS market will expand to include 2 new 'very fast' services to help control power frequency following system events and to foster innovation in faster responding technologies. These new markets are intended to support the transition away from relying on FCAS that are provided by thermal generators as part of their participation in the NEM.

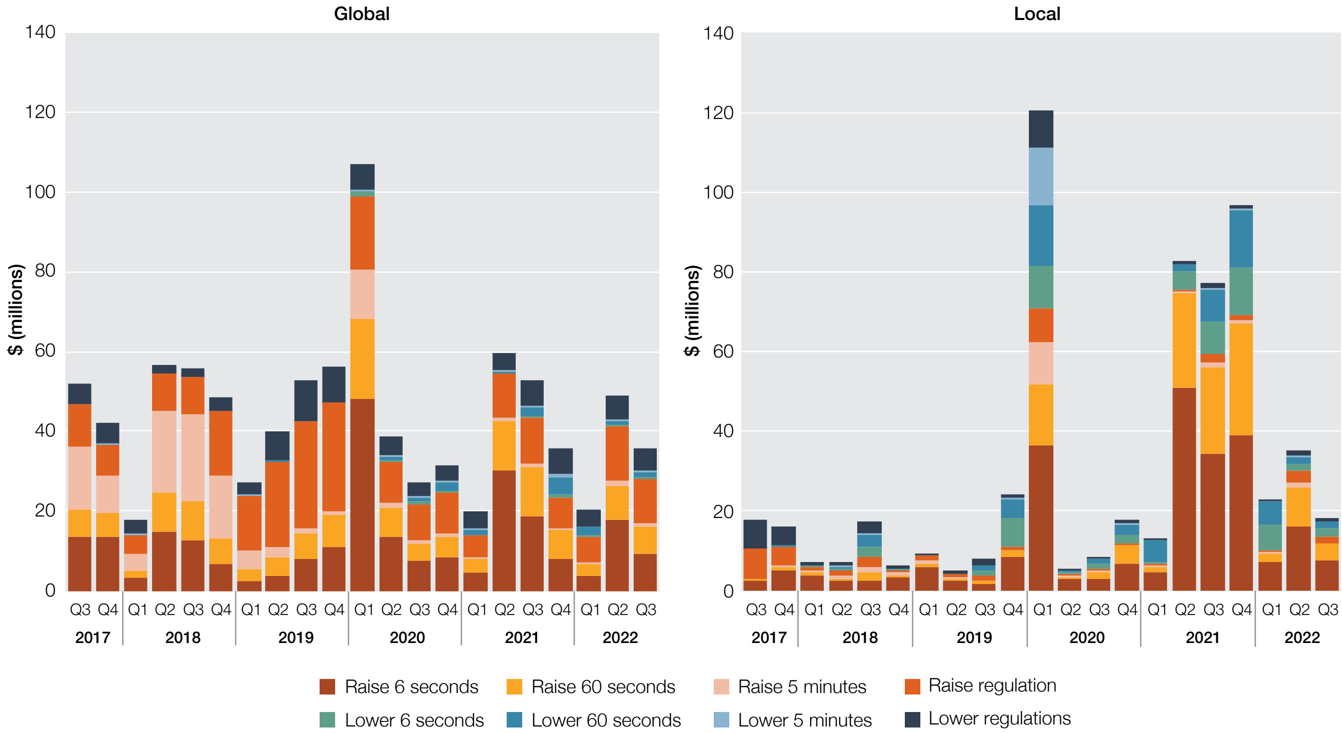
148 EMC, Security of the Power system, accessed 1 November 2022.

149 AEMO, Guide to Ancillary Services in the National Electricity Market, November 2021.

9.1 Interconnector upgrades resulted in record local costs

Since our last report, FCAS costs have significantly increased, driven by an increase in costs of local markets (section 2.7). In 2021–22 local costs surpassed global costs for the first time, reaching a record $232 million (Figure 9.1). Planned transmission outages for the Queensland–NSW Interconnector (QNI) upgrade resulted in Queensland occasionally at risk of being electrically islanded from the rest of the NEM. At these times, Queensland was unable to import FCAS services from NSW and had to provide its own FCAS. This local requirement combined with significant plant outages and the trade-off between energy and FCAS (Box 9.2) resulted in extreme FCAS prices and costs in 2021.

Figure 9.1 Local and global FCAS costs



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.

Source: AER analysis of NEM data.

Box 9.2 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 can 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 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.

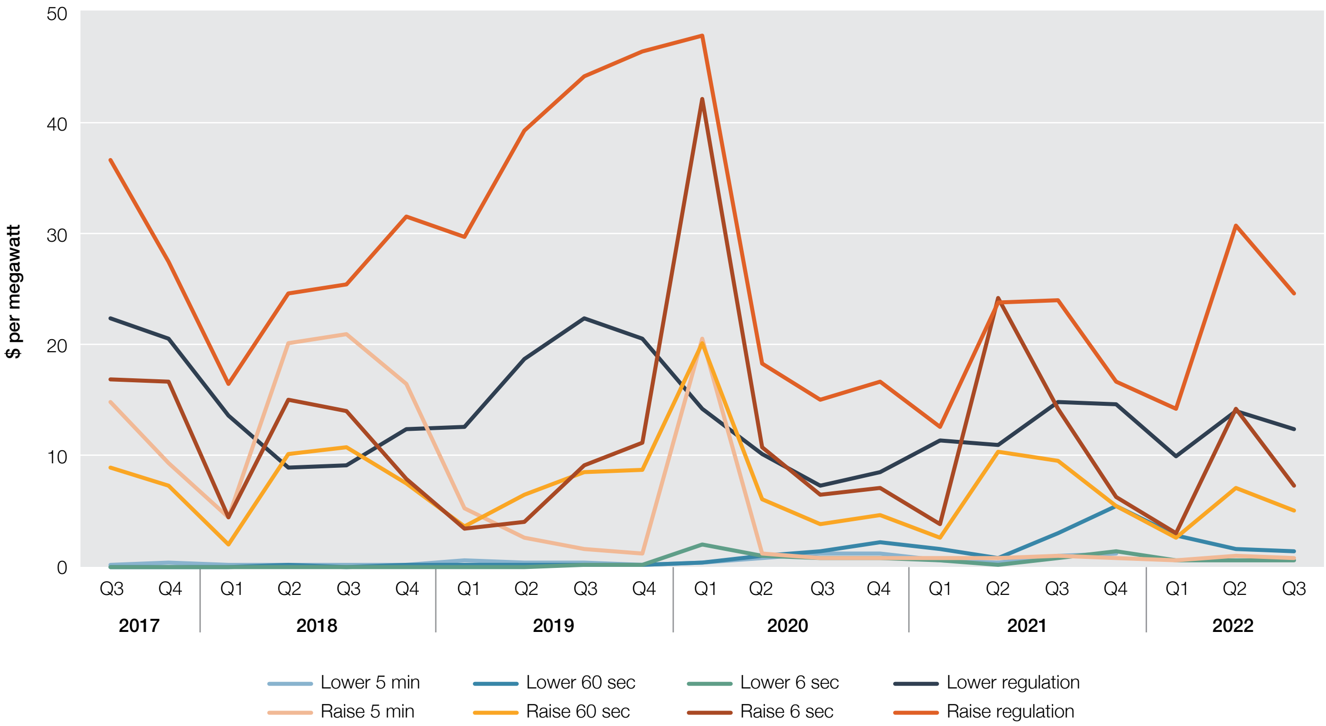
Technologies such as batteries and hydro generators can provide FCAS without providing energy at the same time. This can make them more flexible in responding to signals in FCAS markets.

Of the $232 million local costs, AEMO recovered $162 million from generators for raise contingency services, $60 million from retailers for lower contingency services and $10.4 million from both retailers and generators for regulation services. Regardless of the recovery mechanism, these costs are generally passed on to consumers through retail pricing or generation offers.

Local markets emerge only when a region is electrically separated or at risk of separation from the rest of the NEM. These occurrences are relatively infrequent. In Queensland and South Australia, local markets typically occur less than 6% of the year.[150] However, as observed over the past 2 years, local markets can have significant costs when major events like network outages or interconnector upgrades create risk of separation. These continue to occur – the separation of South Australia from the rest of the NEM in November 2022 led to the breach of the cumulative price threshold for lower 60 second, raise 60 second, raise 5 minute, lower regulation and raise regulation services.[151]

Over the past 2 years, global costs were similar to historic levels with no significant changes to demand for global FCAS. Higher costs accrued in Q2 to Q4 2021, when Queensland participants were not able supply the global FCAS markets and there were several planned thermal plant outages in the remaining NEM regions. This steepened the global supply curve and resulted in an increase in global prices during this time (Figure 9.2).

Figure 9.2 Global FCAS price



Source: AER analysis of NEM data.

From June 2020, all scheduled and semi-scheduled generators in the NEM were required to support the secure operation of the power system by responding automatically to changes in power system frequency.[152] Although it can be difficult to assess the direct impact of policy changes on markets due to the number of factors that influence outcomes, broadly we have observed a slight reduction in raise regulation requirements and therefore lower costs, but no significant impact on lower regulation services.

9.2 Concentration has increased for raise services markets

Since our last report the amount of capacity registered increased, reaching 9,534 MW in 2021–22. This was 749 MW more than 2 years ago and was registered across a range of new and existing participants.[153] However, only a portion of this capacity is actually offered into the market and an even smaller portion is 'effectively available' to meet the dynamic requirements of FCAS (Figure 9.3). This is because of trade-offs between the provision of energy and FCAS (Box 9.2).

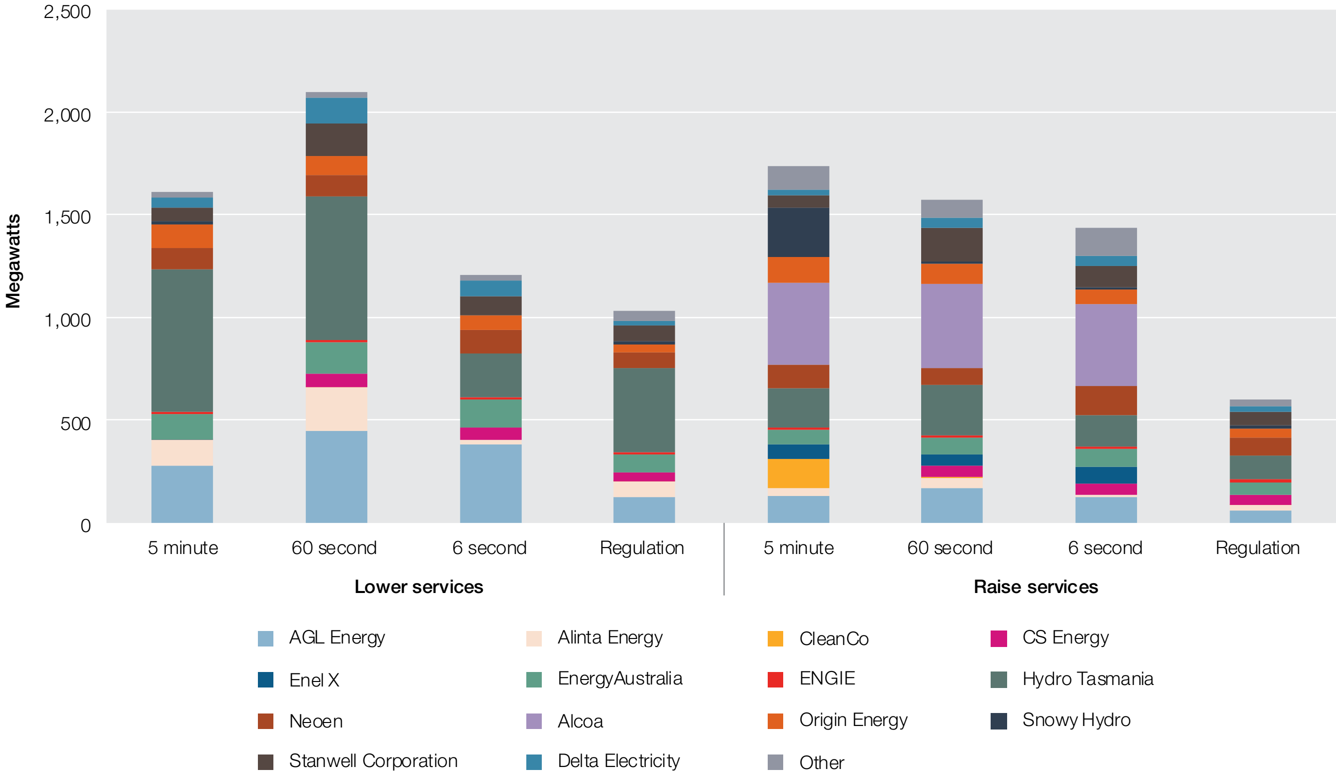
150 Local markets formed in Tasmania at least 50% of the time, primarily due to Basslink being a DC electrical line. The characteristics of this type of connection mean that for safe operation whenever frequency approaches certain levels, FCAS must be sourced locally from within Tasmania.

151 AEMO, Preliminary Report – Trip of South East – Tailem Bend 275kV lines, 12 November 2022.

152 AEMC, Mandatory primary frequency response, rule change, 26 March 2020.

153 As at September 2022, there was a significant amount of capacity across the NEM registered to provide FCAS. For contingency services: 9,382 MW (lower 5 minute), 8,167 MW (lower 60 second), 3,918 MW (lower 6 second), 8,684 MW (raise 5 minute), 9,534 MW (raise 60 second) and 5,345 MW (raise 6 second). For regulation services: 8,845 MW (lower) and 8,877 MW (raise).

Figure 9.3 Market share, by average effective availability, 2021–22



Note: Average effective availability for all participants registered to provide FCAS for the period from 1 July 2021 to 30 June 2022.
Source: AER analysis of NEM data.

Over the past 2 years the average effective availability for lower services remained relatively stable and was between 12% and 31% of registered capacity in 2021–22 depending on the market. Over the same period, average effective availability for raise services increased, most notably in raise contingency services. In 2021–22 effective availability for raise services was between 7% and 27% of registered capacity, depending on the market. Drivers of the low effective availability include participants' trade of FCAS for energy dispatch, plant outages and network outages that impact plant output. When there is low effective availability, FCAS markets becomes more concentrated regardless of how much capacity has been added.

We assess market concentration by applying the Herfindahl-Hirschman Index (HHI) to participants' market shares (Box 3.1) based on average annual effective availability. The higher the index the greater the market concentration. Since our last report, the changes in market entry, exit and expansion have seen an increase in concentration for raise services and a decrease for lower services. Despite the changes to the different services, all FCAS markets remain moderately concentrated.

Plants that have left the market in the past 2 years include Torrens Island A unit (AGL), Liddell power station (AGL) and Mackay power station (Stanwell). In 2019–20 the average effective availability for these plants was between 24 MW and 50 MW across all services.

In the past 2 years, 6 participants have entered the market – Boral Cement, Discover Energy, Viotas, Firmus Grid, Shine Hub and Sonnen Australia. These participants in total accounted for less than 1.1% (16 MW) of effectively available capacity in 2021–22 across all services.

Several incumbent generators also expanded their portfolio by investing in new plants or setting up virtual power plants (VPPs).[154] Neoen's Victorian Big Battery was the largest new plant and was operational in late 2021. This expansion resulted in the increase of Neoen's average effective availability from 37 MW in 2019–20 to 103 MW in 2021–22. Generation from new plants by incumbent generators accounted for between 4% and 11% of effectively available capacity across the markets. Over the same period, Stanwell and Alcoa Portland (load) increased their offers by 60 MW and 330 MW, respectively.

Historically, FCAS market have been small area of the overall energy market. However FCAS price pressures over the last few years have triggered investment from new and existing participants which have altered FCAS market

154 Virtual power plant is a network of distributed energy resources such as wind, solar and battery, working together as a single power plant. Operators can remotely deploy energy from participating resources for a range for services, such a frequency control ancillary services and network support.

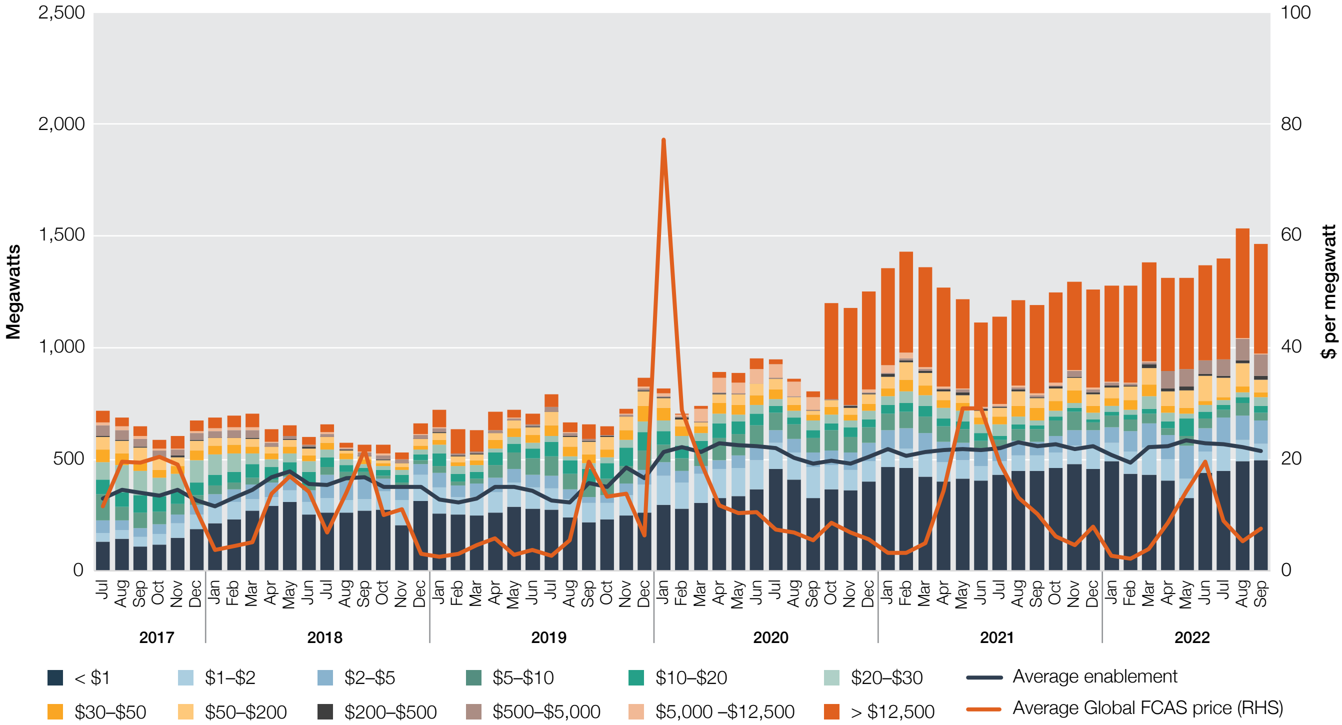
dynamics. In coming years, expected new plants and interconnectors will likely continue to improve the competitive landscape for FCAS.

9.3 New entrants provided pricing pressure in raise contingency services

Offers vary for different frequency services and are impacted by energy market dynamics. The AER analyses the price levels of FCAS offers to better understand how the markets are functioning.

Over the past 2 years, the offers in raise contingency services have trended together. All had more capacity priced below $10 per MW and an increase in total effective availability, mostly driven by the expansion by incumbent generators and increases in offers made by Alcoa Portland Smelter (Figure 9.4). $10 per MW is roughly the price level at which participants' supply curves begin to steepen and where small changes in enablement can lead to large changes in price. The increase in low price offers was also evident in raise regulation services in 2020–21.

Figure 9.4 Raise 6-second effective availability



Source: AER analysis of NEM data.

Raise 6-second services have been one of the more costly services to operate and are the most responsive service used when a large generator or interconnector is suddenly not available. In this section we examine the offers for this service. In describing changes in capacity we refer to effective available capacity, the amount of FCAS on offer that can be dispatched, accounting for trade-offs between FCAS supply and electricity generation.

Over the past 5 years the capacity offered below $10 per MW, in raise 6-second service, steadily increased, reaching an average of 518 MW in 2019–20, 650 MW in 2020–21 and 659 MW in 2021–22. Total availability also increased slightly in the earlier years with a notable (393 MW) increase in October 2020. This increase was a result of Alcoa Portland Smelter (load) offering more to the market. However, this increase did not have a significant impact on the competitive landscape of the market because it was all offered at the price cap.

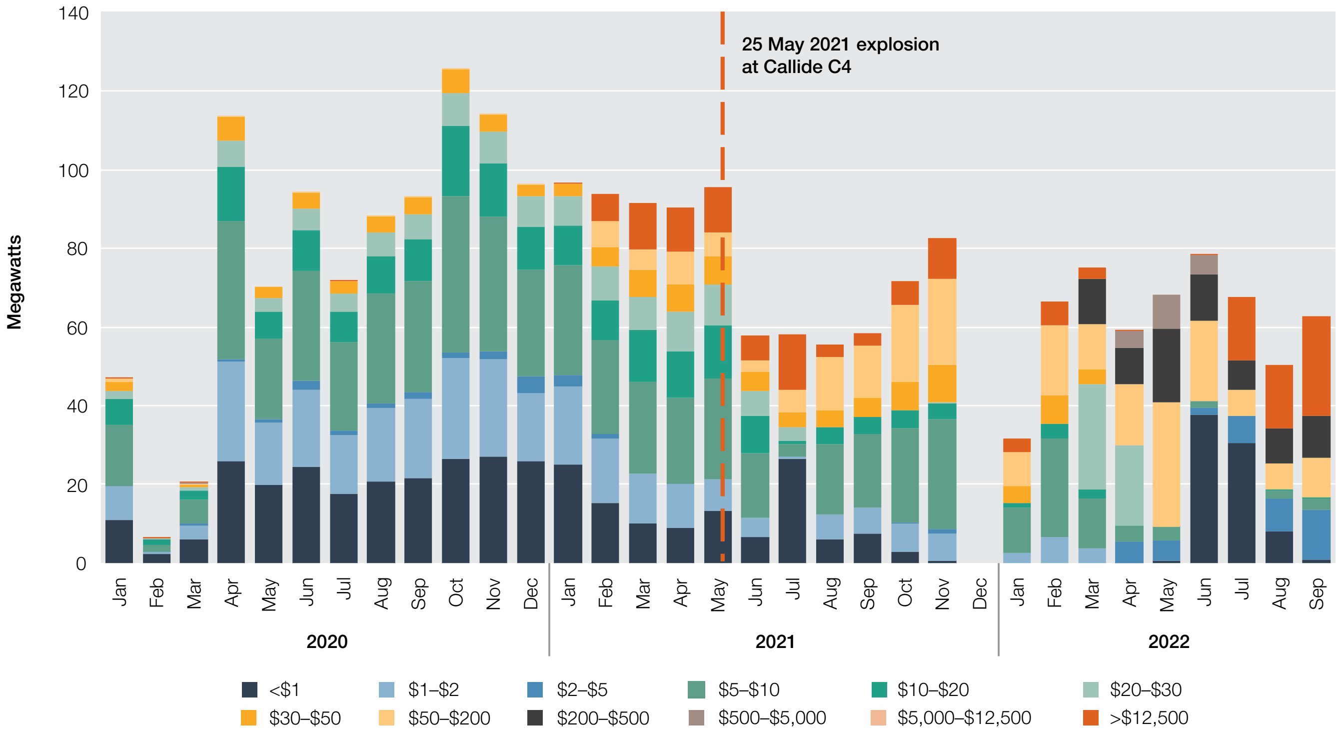
High energy prices and fuel supply issues in May 2022 resulted in several participants repricing capacity from below $5 per MW to between $10 and $20 per MW, driving high FCAS prices that month. High prices in June 2022 were the result of high energy prices caused by fuel supply issues.

9.3.1 Offers in Queensland affected by plant outages and contributed to high local costs

In 2021–22 extreme FCAS costs accrued, driven by local costs in Queensland. In this section we examine offers made by 2 significant FCAS providers in Queensland, CS Energy and Stanwell, with a particular focus on the high costs from Q2 to Q4 2022 and raise 6-second offers (the service with the greatest cost).

In 2021–22 CS Energy had a 33% share in the local raise 6-second market in Queensland. During this high-cost period, CS Energy offered less FCAS overall and particularly offered less capacity at low prices. This steepened the region's supply curve and contributed to high prices (Figure 9.5). The reduced availability from CS Energy was largely driven by the explosion at the Callide C4 plant on 25 May 2021. The explosion caused a significant disturbance to the power system and resulted in the triggering of protection systems and tripping of 9 significant generators in the region (including CS Energy's 3 Gladstone units, Callide B2 and C3 units).[155] The loss of Callide C4 had significant impact on CS Energy's supply in June and July 2021. This reduced supply was reflected in CS Energy's offers. Furthermore, CS Energy also changed its offer strategy, with less capacity offered below $5 per MW for the rest of the year (except for July), steepening the supply curve.

Figure 9.5 Raise 6-second effective availability – CS Energy

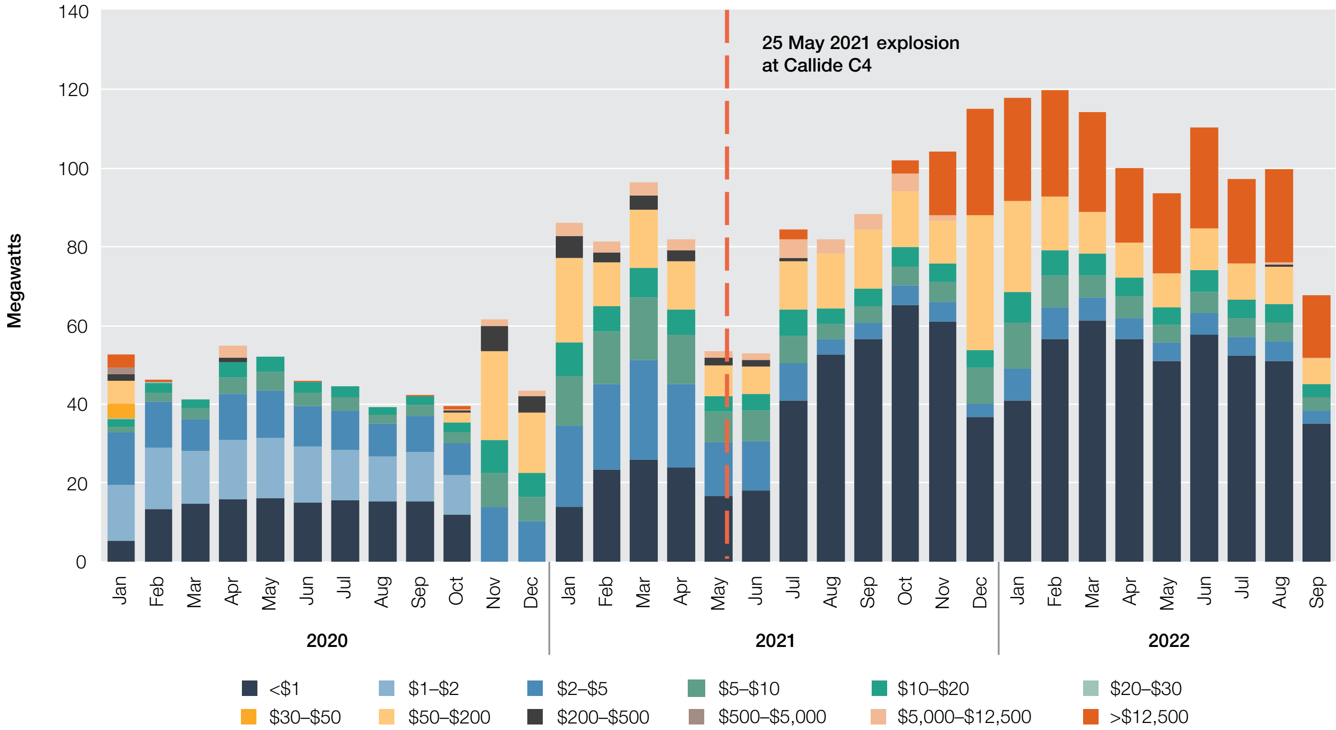


Source: AER analysis of NEM data.

In 2021–22 Stanwell had a 57% share of the local raise 6-second services market in Queensland. From January to April 2021, there was an average of 57 MW priced below $10 per MW (Figure 9.6). This reduced to 38 MW for May and June 2021 due to the tripping of 3 Stanwell plants as a result of the explosion at Callide. By July 2021 most of these plants returned to service and the average capacity priced below $10 per MW for July to December 2021 increased to 67 MW. Despite the increase in low priced offers, the overall supply curve for Queensland remained steep and resulted in high local FCAS prices. Local markets were less prominent in 2022 when QNI was in its final stages of completion and there were less constraints causing local FCAS requirements.

155 AEMO, Trip of multiple generators and lines in Central Queensland and associated under frequency load shedding on 25 May 2021, October 2021.

Figure 9.6 Raise 6-second effective availability – Stanwell



Source: AER analysis of NEM data.

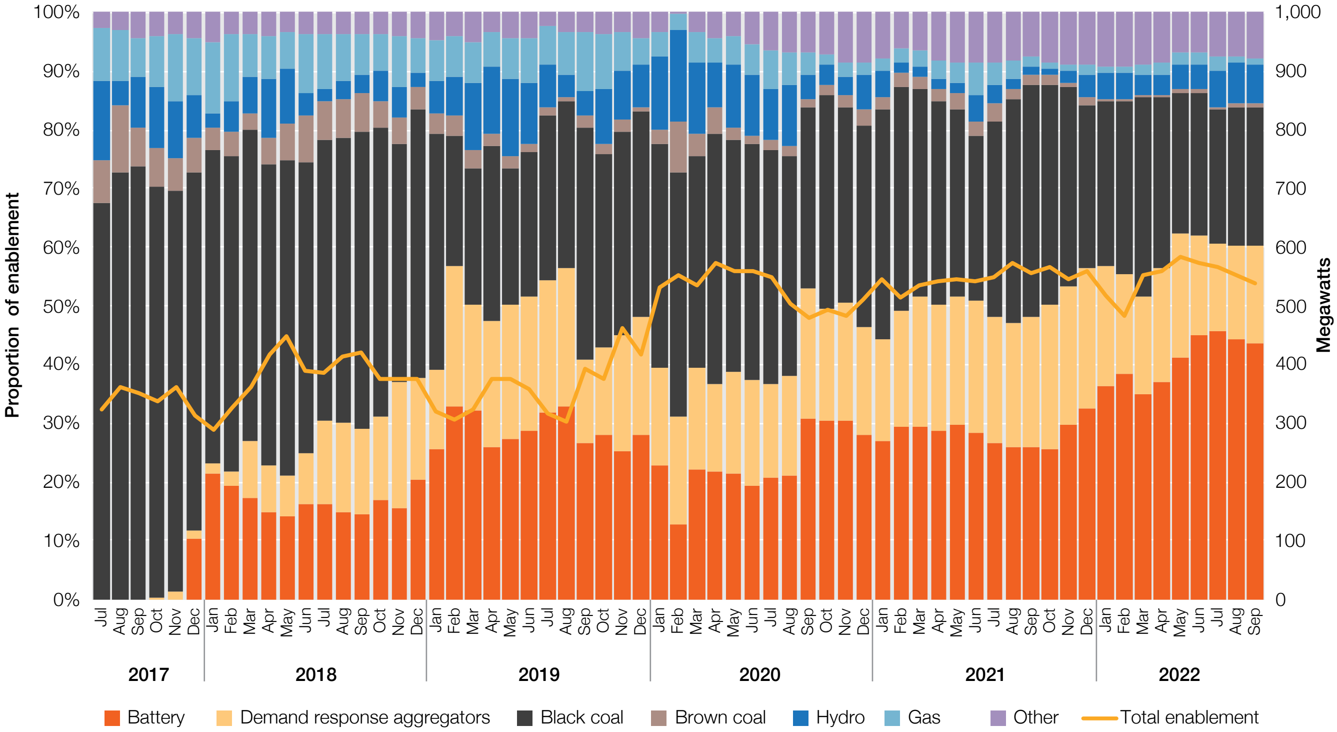
9.3.2 Battery and demand response aggregators have displaced coal and gas generation

As discussed in section 9.2, over the past 2 years there were 6 new participants in VPPs, battery or demand response technologies. These participants 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 more flexible and responsive. Importantly, the efficiencies inherent in these technologies, such as lower marginal cost to operate and lower capital costs, allowed them to offer at mostly low prices. As a result, over the past 2 years they were dispatched for the majority of what they offered. This encouraged some incumbent participants, such as black coal generators, to shift capacity to lower prices to compete when it was economical to do so.

Since June 2020 the average output from grid-scale batteries has increased by 57 MW across all FCAS services. Average output from demand response aggregators (DRA) has also increased, but to a smaller extent (16 MW) and predominately in raise contingency services.

Energy sourced from grid-scale batteries has significantly increased over the past 2 years, surpassing that sourced from coal and gas generators in a number of services. In the case of raise 6-second services, the energy sourced from battery increased from 19% in June 2020 to 45% in June 2022 (Figure 9.7). This displaced thermal generation, where the energy sourced from coal and gas decreased from 47% to 26% over the same period. There is also a notable increase in the 'other' category, which was partly driven by the output from virtual power plants.

Figure 9.7 Raise 6-second service enablement, by fuel type



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. Other category includes VPP, solar and wind.

Source: AER analysis of NEM data.

9.4 FCAS market revenue increased

As FCAS costs have increased, so too has the revenue made from providing those services. An individual participant's costs and profits from providing FCAS are complex and are influenced by a variety of factors including contract positions and the FCAS cost recovery process (Box 9.1). To provide a general indication of market share we have examined the gross FCAS spot revenue participants made over the past 5 years.[156]

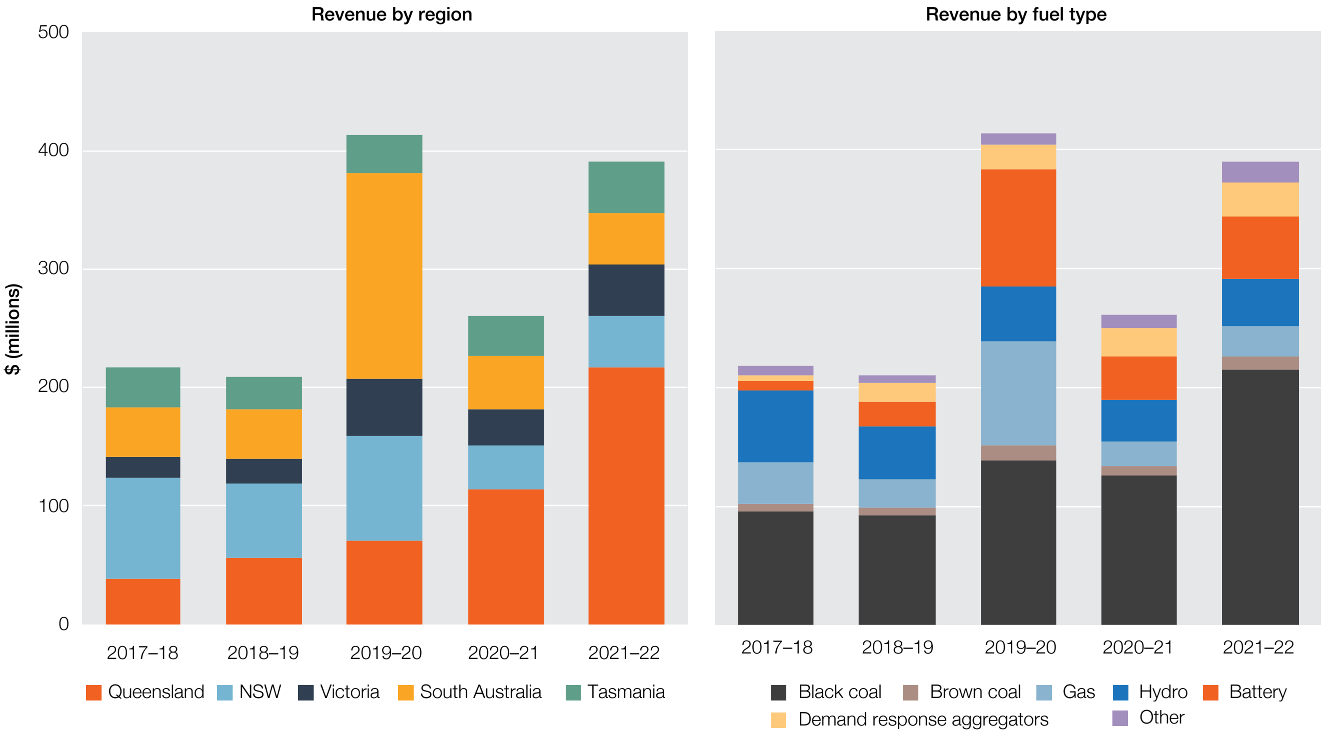
9.4.1 Record FCAS revenue earned by Queensland participants in 2021–22

Over the past 5 years, FCAS revenue fluctuated significantly (Figure 9.8). In 2017–18 and 2018–19 revenue was around $210 million, the majority of which was earned by gas and coal plants in South Australia, Queensland and NSW. The revenue then almost doubled in the following year, reaching a record $413 million. The significant earnings in 2019–20 were driven by the revenue earned in South Australia ($170 million) when the region was islanded from the rest of the NEM. In addition, in 2019 AEMO increased procurement of regulation and contingency FCAS services.[157] This permanently shifted the demand curve up, which contributed to the amount of revenue earned.

156 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.

157 AER, Wholesale electricity market performance report 2020, 14 December 2020, p 92.

Figure 9.8 Total FCAS revenue, by region and fuel type



Note: Revenue was determined by multiplying each unit's 5-minute dispatch target by the FCAS price, then dividing it by 12. Each unit's revenue was then grouped up to the regional level or by their fuel type.

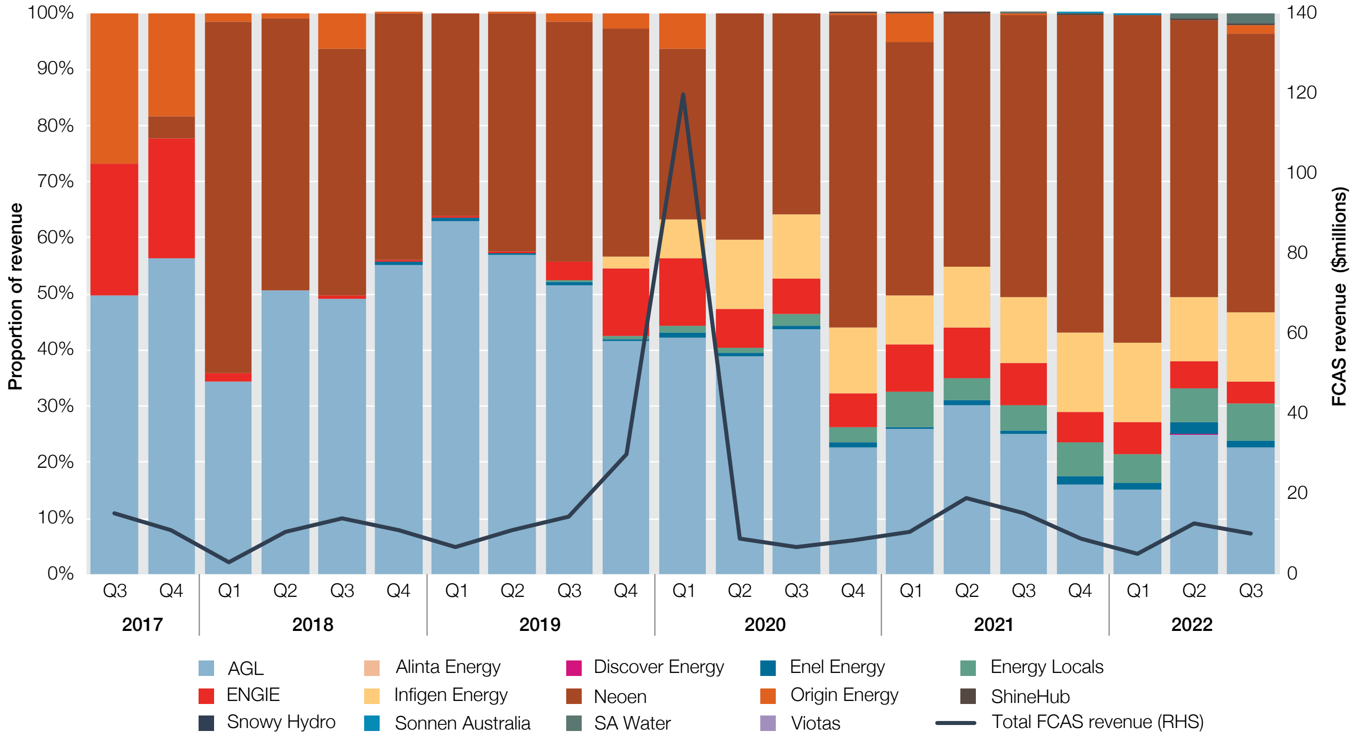
Source: AER analysis of NEM data.

In 2020–21 FCAS revenue reduced to $260 million, driven by lower energy prices and an increase in supply (including the expansion of Hornsdale Power Reserve by 50%), although this was $50 million greater than 2 years prior. In 2021–22 the FCAS revenue earned was driven by the local markets in Queensland and reached $390 million. Queensland participants earned a record revenue of $217 million, as discussed in section 9.1. Black coal is the dominant fuel type in Queensland and the leading provider of FCAS services. As a result, these participants earned significant FCAS revenue in 2021–22.

9.4.2 Participants with batteries earn the greatest revenue and demand response is growing

In December 2017 Neoen entered the market in South Australia with its Hornsdale Power Reserve grid-scale battery. Upon entry it displaced the FCAS earnings of the 2 incumbent providers, Origin and Engie, almost entirely (Figure 9.9). Since then, Neoen has continued to compete with the incumbent generators by offering at lower prices than its competitors and, as a result, has been dispatched for the majority of what it offered. Neoen also expanded the Hornsdale Power Reserve by 50% in 2020, which further solidified its position in the market.

Figure 9.9 Proportion of total FCAS revenue earned, by participant in South Australia



Note: Revenue was determined by multiplying each unit's 5-minute dispatch target by the FCAS price, then dividing it by 12. Each unit's revenue was then grouped by ownership.

Source: AER analysis of NEM data.

Over the past 2 years Neoen has continued to displace incumbent generators, particularly AGL, whose proportion of revenue decreased from 43% in 2019–20 to 21% in 2021–22. There has also been an increased presence from VPP provider Energy Locals, earning 6% of revenue in Q3 2022.

Despite being displaced in South Australian FCAS markets, AGL entered the Queensland market for the first time in Q3 2022 with its Wandoan Battery. It quickly earned 10% of revenue in this quarter, highlighting the competitive advantages that batteries have in FCAS markets.

9.4.3 Historically, FCAS is the primary revenue source for batteries, but the trend may reverse

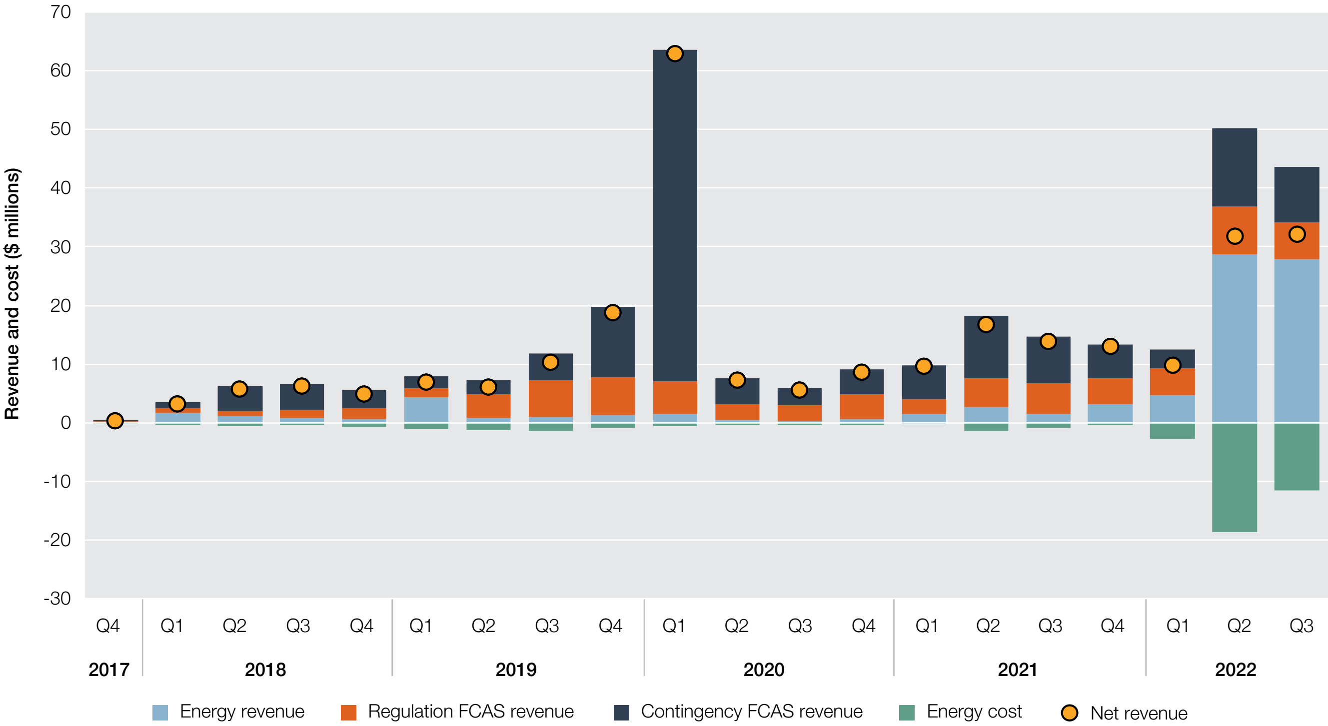
As highlighted in section 9.4.2, batteries are playing an increasingly significant role in FCAS markets. However, to date their impact has been limited in the energy market (Figure 2.7). This is primarily because the technology is well suited to FCAS (section 9.3.2) and batteries can only store limited amounts of energy (compared with generators) before their supply is depleted.

In 2021 more than 80% of gross revenue from battery units was from providing FCAS (both contingency and regulation) while the remaining revenue was from supplying the energy market. This trend was consistent across prior years (around 95% in 2020 and 80% in 2019).

Importantly though, through Q2 and Q3 of 2022 this trend reversed. As other sources of generation faced issues, batteries were able to perform energy arbitrage, storing energy for use during peak periods and obtaining high levels of revenue during periods of extreme wholesale prices. Compared with Q3 2021, battery net revenue was almost 2 and a half times higher in Q3 2022, with the energy market the primary source of revenue (Figure 9.10).[158]

158 Data is from AEMO, and includes marginal loss factors, dispatch prices and dispatch loads (dispatch data from AEMO's monthly data archive). It is important to note, the revenue calculation for FCAS uses the reserve target for calculation, while the revenue for the spot energy market is only an estimation, as we do not know the actual energy generation and consumption for batteries in the spot market alone.

Figure 9.10 Estimated battery spot revenue and cost



Note: The revenue calculation for FCAS uses the reserve target for calculation, while the revenue for the spot energy market is only an estimation, based on target values, because we do not know the actual energy generation and consumption for batteries in the spot market alone. There is no battery data before Q4 2017 as the first grid-sized battery started operation in November 2017.

Source: AER analysis of NEM data.

The potential for high revenues from battery in the energy market may be attractive for investors, potentially leading to new entrants and increasing competition. However, if investors feel these revenues are temporary, they may not provide the incentive needed for new entry. We will continue to monitor whether the recent changes to long-term battery revenue trends continue.

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

Over the last 2 years we have generally seen improvements to the level competition in FCAS markets, as they have continued to attract new entrants and expansions from established participants. Entry has mostly been in innovative technologies such as VPP, demand response aggregators and grid-scale batteries. These have competed by offering at low prices and have successfully displaced gas and coal generation.

We observe that the technological advantages from grid-scale batteries enable them to quickly secure market share and revenue on entry. As a result they have become the dominant provider for most frequency services. However participants have expressed that as more grid-scale batteries enter and FCAS revenues are competed away, there will be a stronger need to optimise revenue across a variety of markets. This means that at some point in the future battery investments are more likely to be driven by energy market dynamics, and participation in FCAS may be of secondary factor.

On the other hand, local markets remain highly concentrated and are vulnerable to the exercise of market power. We have seen local costs reach record levels at $232 million in 2021–22 due to an interconnector upgrade, high energy prices and unplanned plant outages. In theory these high costs should provide a signal for new investment, and at these levels cost recovery could occur very quickly. For example the total local costs in Queensland across 2020–21 and 2021–22 ($279 million) exceeded the costs of building two 100 MW/150 megawatt hour (MWh) battery storage systems ($120 million per unit).[159] However the infrequency and unpredictability of local markets makes them difficult to forecast prices and returns, which creates revenue uncertainty. As a result, investors have reported they are unlikely to enter the market purely due to high local prices, and lack of competition could be a barrier to efficiently priced FCAS services.

159 Vena Energy Australia, Wandoan South BESS project, accessed 3 November 2022.

As the energy market faces significant change in the short and medium term, the competitive landscape of FCAS markets will continue to evolve. Over the next 5 years, a number of thermal generators are expected to exit, whilst significant grid-scale batteries enter (section 7.1). A new interconnector between South Australia and NSW is underway and very fast frequency service markets will be introduced in 2023. These are likely to have a substantial impact on FCAS markets, but at this stage it is difficult to determine what these will be. We will continue to closely monitor the performance of FCAS markets as we move through the energy transition.

10. Key findings and recommendations

Key points

- Since our last report the National Electricity Market (NEM) has seen significant upheaval as supply conditions stressed the market and led to unprecedented high prices and interventions. Through our analysis of market performance over this time we have identified initial recommendations to support policy makers to deliver an effective transition
- The events of 2022 have emphasised the need for contract market monitoring powers for the AER, to enable us to accurately scrutinize the behaviour of participants, and more clearly identify impediments to competition and efficiency to inform policy makers.
- A clear and coordinated pathway would reduce the significant uncertainty that currently exists in the NEM, create confidence for investors and facilitate a smoother transition. An action which may support this would be to explore the increased regulation of coal-fired generators in some form, as its viability and exit pathway is a significant source of uncertainty.
- Facilitating competition during and beyond the transition would enable the NEM to function efficiently at lowest cost to consumers, and reduce the exposure of market outcomes to the strategies or supply chains of individual participants. As an example, consideration should be given to actions to diversify the operation of dispatchable generation where possible, as its significant role will continue to drive market outcomes.

Under the National Electricity Law (NEL) we may advise the Australian and state governments on the performance of the wholesale electricity markets, including whether there are features of the market which are detrimental to competition and efficiency, and identify whether legislative or regulatory reform is required.[160] In this report we made a number of observations on the performance of the NEM. This chapter discusses our key findings and identifies policy principles and recommendations to facilitate competition and efficiency through the transition.

10.1 The NEM has seen significant upheaval since 2020

The performance of the NEM has worsened from when we reported in 2020. Across all regions, wholesale prices have risen to unprecedented levels as supply conditions put pressure on the market. Considerable increases in international fuel prices combined with significant outages of thermal generation and fuel supply problems strained the generation fleet, and ultimately led to extraordinary interventions to ensure reliability and security of the system.

The transition to renewable generation has continued apace, with increased output from solar and wind putting downward pressure on prices. As there is more diversity of ownership of these assets, concentration has significantly decreased in the middle of the day. Lower concentration combined with access to additional non-market revenue from renewable energy certificates has meant that wind and solar have continued to offer capacity into the market at low or negative prices. Batteries are incrementally gaining purchase in the energy market, though continue to play a significant and influential role in frequency control ancillary services (FCAS) markets. In FCAS, concentration has reduced in some areas, but costs of these services have been high when regions are at risk of separation.

Despite the increasing contribution of renewables, coal is still a significant part of the market, while becoming less reliable and potentially more expensive. Across the market, prices have become increasingly vulnerable to energy constraints, with coal and gas subject to supply and cost challenges, hydro generation limited by water availability, and intermittent renewables heavily dependent on weather. In 2020 we identified that flexible generation like gas and hydro will play an increasingly significant firming role as the market transitions. This manifested in 2022, as the market was put under stress from rising cost and supply challenges, gas and hydro generation set prices more often and at higher levels than the preceding few years.

Our analysis found that supply conditions largely explain the increase in offer prices since our last report, and individual participant responses to those conditions were driven by the composition of their portfolios and by the supply-chain pressures on the fuel types to which they are exposed. However, supply-side factors may not explain all increases in offers. We have found some evidence suggestive of systemic economic withholding by particular generators. Economic withholding is not necessarily illegal by itself, but may indicate that competition in the market is

160 National Electricity Law Section 18C.

ineffective. Our results require further analysis to test the potential drivers of the behaviour we have observed, and to assess the significance on market outcomes. In addition, access to information on contract markets is vital to enable effective scrutiny of participant incentives and behaviour.

Although there are market signals for investment, most of the entry over the past 5 years has been supported by government programs in some form. We have identified a range of barriers to investment, including having confidence in revenues in a complex, rapidly transforming market and an uncertain macroeconomic and policy environment. Volatility and supply changes in the spot market have created issues in financial markets as well, which is likely to further create challenges for investment.

Beyond these barriers, there are indications that there are impediments to efficient price signalling in the market, and governments are increasingly intervening. Although they are doing so to meet environmental, economic, social and reliability objectives, as well as responding to structural barriers, market participants and prospective investors report that government involvement is distorting market signals, making them reluctant to invest without support and risking excessive or inefficient investment. As a result, interventions in the market carry the risk of dampening further private investment if they are prolonged or if regulation does not respond to changing economic conditions.

There is currently comprehensive policy work in train which aims to address the gaps and structural barriers within the current market design while considering the long-term interactions and costs of reform. These include mechanisms to create market signals for sufficient dispatchable generation, procurement of essential system services, and operational efficiency of transmission networks. In addition, Energy Ministers have started work to introduce an emissions objective into the framework that governs the NEM. Our assessment of the events of June 2022 has also highlighted areas of possible reform in order to balance commercial imperatives with system security in times of market stress. Policy confidence in these areas would further address a significant barrier to investment, as well as promote confidence in the energy system.

10.2 Recommendations to support an effective transition

Through our assessment of competition and efficiency in the wholesale electricity market, we have identified a set of recommendations to address the key risks we observe in the market and to support policy makers to deliver an effective transition. We may identify further recommendations as we deepen our analysis over coming months.

10.2.1 Insight into contract markets is a key enabler to effective scrutiny of participant behaviour and market performance

In August 2022, Energy Ministers began consultation towards a package of reforms that would expand the AER's gas and electricity wholesale market functions to include monitoring of the contract market. We strongly support and recommend the implementation of these reforms.

To ensure consumers and policy makers have confidence in our energy system, it is vital to understand the drivers and impact of participant behaviour and subsequent market outcomes. Where possible we have analysed these outcomes from available public information. However, participants' risk management strategies are a key element underpinning behaviour. Detailed analysis of financial incentives and risks depends fundamentally on confidential contract information. The current constraints to collect this information have limited our scope to reach definitive findings on contract market outcomes in this report, and in turn on our analysis of participant conduct, potential economic withholding and investment signals.

In particular, contract market powers will provide key insight to enable us to more accurately scrutinize incentives and ability to exercise market power. This will assist us to ensure participants are operating in accordance with the current rules and law. It will also more clearly identify impediments to competition and efficiency to better inform policy makers on where further reform may be needed. In its November 2022 report on its inquiry into the NEM, the ACCC reiterated its support for implementation of these reforms on the basis it provides crucial insights into the strength and resilience of generators and retailers.[161]

161 ACCC, Inquiry into the National Electricity Market – November 2022 Report, 23 November 2022, p 6.

10.2.2 A clear and coordinated pathway will create confidence for investors

The framework supporting the NEM is, like the NEM itself, undergoing an unprecedented transition.

Governments are implementing major policy and legislative changes across an increasing number of interrelated mechanisms. These combined with increasingly volatile market outcomes, and a backdrop of broader economic and geopolitical turmoil, creates an environment of significant uncertainty for future investment (chapter 8).

In consultation for this report, stakeholders told us that:

- the biggest barrier to investment is uncertainty, particularly around market design and future revenue (sections 8.1.1–8.1.3)
- investors are increasingly refraining from investment unless directly tied to government policy or funding because the risk is too great that market-led investments will not be optimised in any new frameworks in an increasingly uncertain investment environment (section 8.1.3).

Some level of uncertainty is inevitable when planning long-lived investment at a time of rapid technological change. Nonetheless, to support a transformative wave of much-needed investment, it is important that we, the other market bodies and governments minimise unnecessary uncertainty wherever possible, and that changes to energy policy and market design are clear, predictable, consistent and harmonised. Even where jurisdictional policies cannot be synchronised, a focus on providing confidence and being as coordinated as possible will help to minimise barriers to investment.

To smooth the transition, increased regulation of coal-fired generators in the lead up to exit could be explored

We have seen significant entry of intermittent renewables since the last report and this is increasing competition in certain operating conditions and helping constrain prices (sections 2.4, 3.1.3). However, to date new entry of dispatchable technologies has been minimal, though there are large projects in the pipeline as the result of direct government investment (section 7.3). Events in 2022 have highlighted how reliant the market remains on coal at times when dispatchable generation is needed and underscores the significant influence coal still has on market outcomes (sections 2.4, 5.1–5.2).

Coal generators have highlighted increasing challenges around plant reliability and planning for maintenance, securing fuel supply at low cost, and funding investment in current and future assets (section 5.2.1). Recognizing that the timeline for the exit of coal is near and accelerating, there is a significant risk that the market faces high prices and a reduction in reliability if these issues persist or grow.

To encourage the smoothest possible transition for the NEM, certainty around timing of coal exit and fuel supply would help coal to withdraw at a rate consistent with the entry of new generation, smoothing the transition. Policy makers have a range of options to achieve this, including contracts between governments and coal generation or some form of economic regulation framework. Any response will have benefit if it enables revenue confidence, offers clearer timeframes in which to plan maintenance, contract fuel, and facilitate future investment in lower emission technologies, while also meeting the broader reliability needs of the system and ensuring an orderly and timely exit to support the transition to net zero emissions.

10.2.3 Facilitating competition will enable efficient allocation in the short and long run

Diverse ownership of generation assets and vigorous competition are important factors to enable the NEM to function efficiently at lowest cost to consumers. Competition also mitigates risk through reducing the exposure of market outcomes to the strategies or supply chains of individual owners.

While we are in an environment of significant upward pressure on costs, where competition is effective it is already imposing some countervailing downward pressure on prices. For example, we are seeing highly competitive sub-markets emerge in the middle of the day, with increased competitive pressure from renewables (section 3.1.3). This is leading to less efficient technologies to shift their offer strategies in response (section 5.1.1).

Nonetheless, ownership of dispatchable generation remains concentrated (section 3.1.4), and this is a particular issue when the output from renewable generation sources is low (section 3.1.3). We also see some evidence suggestive of economic withholding from certain generators with high market share (section 6.3). This could be an increasing risk during and beyond the transition, especially if ownership of dispatchable generation continues to be highly concentrated. In our view, this reiterates the important of maintaining and increasing competitive pressure to spread risk and encourage innovation.

Where governments have choice, diversification of the ownership and operation of future dispatchable generation should be considered

The NEM today has a mix of government and private ownership (section 3.1.1). With the significant investments announced by States and the Commonwealth (sections 8.1.8–8.1.9), this is set to continue. While these investments serve broader environmental, economic, social, and reliability objectives, it is important that, along with the models in which they operate, they are made in such a way as to maximise diversity and competition wherever possible.

Diversity in ownership and operation encourages competition, and subsequently innovation and efficient allocation of resources, as well as reducing the risk of exposing the market to individual participant strategies. Diversification of operation can occur within a framework of public ownership – for example the formation of CleanCo in Queensland meant renewable generation was offered more often and at lower prices and facilitated competitive pressure on the incumbent participants.[162] It can also involve different operating models such as multi-trading rights over a large generating unit.

The most pressing need for diversification and competition is amongst dispatchable generation. Dispatchable generation is already a very concentrated part of the market (section 3.1.4), and it will become more so as coal generation exits unless it is replaced with new and diverse alternatives. Recent and announced major investments in dispatchable generation are largely concentrated amongst a small number of owners (section 7.3). This increases the exposure of the NEM to exercise of market power, or the strategies of individual participants.

In turn, diversification in operations is crucial for consumers because our analysis shows that dispatchable generation is increasingly important and influential on outcomes, particularly in peak periods and when the market is under stress as it has been in 2022 (section 2.4).

162 AER, Wholesale electricity market performance report 2020, 14 December 2020, pp 51–52.

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