Image courtesy of EnergyAustralia

2 National Electricity Market

Electricity generated in eastern and southern Australia is traded through the National Electricity Market (NEM) – a wholesale spot market in which changes in supply and demand determine prices in real time. The market covers 5 regions – Queensland, New South Wales (NSW), Victoria, South Australia and Tasmania. The Australian Capital Territory (ACT) falls within the NSW region. In geographic span, the NEM is one of the world's longest interconnected power systems, stretching from Port Douglas in Queensland to Port Lincoln in South Australia and across the Bass Strait to Tasmania (box 2.1). The Australian Energy Regulator (AER) plays a number of important roles in the market (box 2.2).

Box 2.1 How the National Electricity Market works

The National Electricity Market (NEM) consists of a wholesale spot market for selling electricity and a transmission grid for transporting it to energy customers (table 2.1). Generators make offers to sell power into the market, and the Australian Energy Market Operator (AEMO) schedules the lowest priced generation available to meet demand. The amount of electricity generated (or released from storage) needs to match demand in real time.

Table 2.1 National Electricity Market at a glance

Participating jurisdictions	Qld, NSW, Vic, SA, Tas, ACT
NEM regions	Qld, NSW, Vic, SA, Tas
NEM installed capacity (including rooftop solar)[1]	67,046 MW
Number of large generating units	295
Number of customers[2]	10.2 million
NEM turnover 2020	$10.9 billion
Total electricity consumption 2020[3]	190.1 TWh
National maximum demand 2020[4]	35,043

MW: megawatts; NEM: National Electricity Market; TWh: terawatt hours.

1. At January 2021.
2. Customers are as at the second quarter of 2020–21, except for Victoria, which reported customers in 2019–20.
3. Includes energy met by the grid and rooftop photovoltaic (PV) generation.
4. The maximum historical summer demand of 35,626 MW occurred in summer 2019–20. The maximum historical winter demand of 34,594 MW occurred in 2008.

Source: AER; AEMO; Clean Energy Regulator; Victorian Essential Services Commission.

Large power stations make offers to supply quantities of electricity in different price bands for each 5-minute dispatch interval. Electricity generated by rooftop solar PV systems is not traded through the NEM, but it does lower the demand that market generators need to meet.

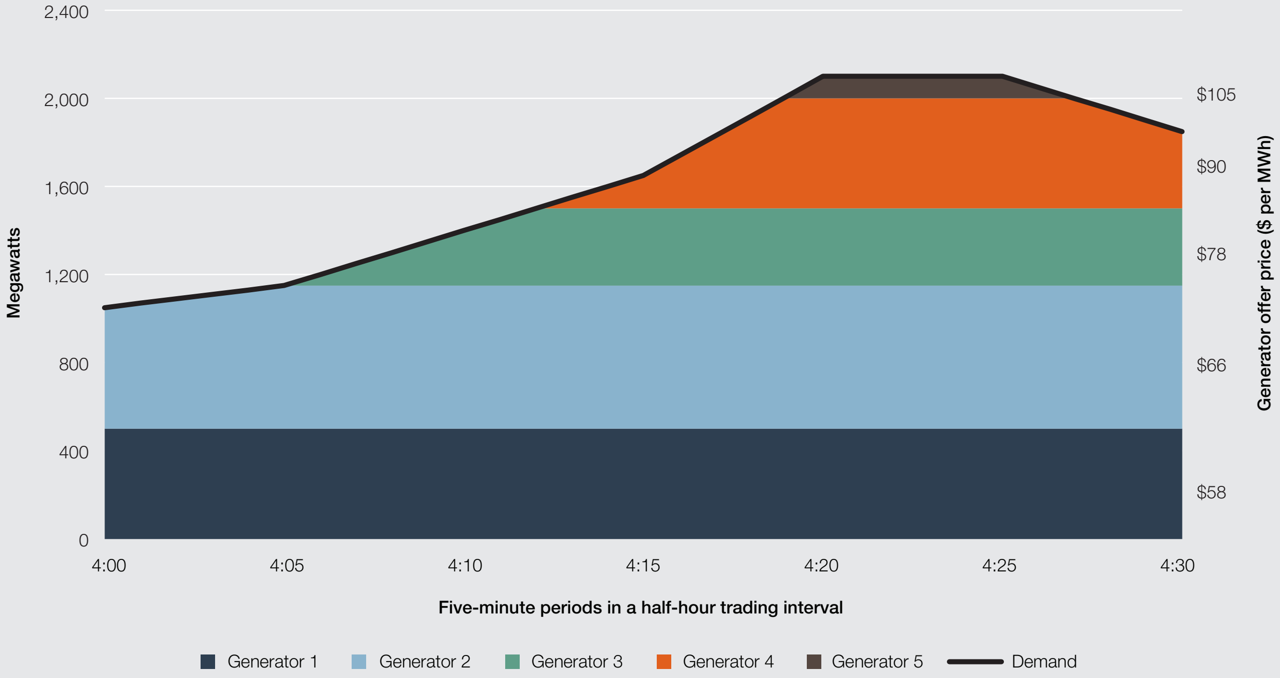
Only large customers (such as energy retailers and major industrial energy users) deal directly with the wholesale market. Retailers buy power from the market, which they package with network services to sell as a retail product to their customers. They manage the risk of volatile prices in the wholesale market by taking out hedge contracts (derivatives) that lock in a firm price for electricity supplies in the future by controlling generation plant or taking out demand response contracts with their retail customers.

As the power system operator, AEMO uses forecasting and monitoring tools to track electricity demand, generator bidding and network capability, allowing it to determine which generators should be dispatched (directed) to produce electricity. It repeats this exercise every 5 minutes. It dispatches the cheapest generator bids first then progressively more expensive offers until enough electricity can be produced to meet demand. The highest priced offer needed to cover demand sets the 5-minute dispatch price.

Generators are paid at the settlement (or spot) price, which is the average dispatch price over 30 minutes. All dispatched generators are paid at this price. A separate spot price is determined for each of the 5 NEM regions. Prices are capped at a maximum of $15,000 per megawatt hour (MWh) in 2020–21 (increasing to $15,100 in 2021–22). A price floor of –$1,000 per MWh also applies. The market cap increases in line with the consumer price index (CPI) each year, but the market floor price remains unchanged.

Figure 2.1 illustrates how prices are set. In the example, 5 generators offer capacity in different price bands between 4.00 pm and 4.30 pm. At 4.15 pm the demand for electricity is 1,650 MW. To meet this demand, generators 1, 2 and 3 must be fully dispatched, and generator 4 is partly dispatched. The dispatch price is $90 per MWh. By 4.20 pm demand has risen to the point where a fifth generator is needed. This generator has a higher offer price of $105 per MWh, which becomes the dispatch price for that 5-minute interval. The settlement price paid to all dispatched generators for the half-hour trading interval is the average of the 6 dispatch prices over the half-hour period – around $89 per MWh.

Figure 2.1 Setting the spot price



While the market is designed to meet electricity demand in a cost-efficient way, other factors can intervene. At times, dispatching the lowest cost generator may overload the network or risk system security, so AEMO deploys more expensive (out of merit order) generators instead.

Power system management

AEMO is responsible for managing the NEM spot market and transmission network. The power system needs to be reliable (having enough generation and network capacity to meet customer demand, plus a safety margin) and secure (being technically stable, even following an unexpected outage of a major transmission line or generator). Security issues, such as frequency and voltage instability, have become more widespread in the NEM in recent years (sections 1.4 and 2.10).

Around 200 large power stations produce electricity for sale into the NEM. A transmission grid carries this electricity along 44,000 kilometres of high voltage power lines and cables to industrial energy users and local distribution networks. Energy retailers complete the supply chain by purchasing electricity from the NEM and packaging it with transmission and distribution network services for sale to over 10.2 million residential, commercial and industrial energy users. Infographic 1 shows the electricity supply chain.

This chapter covers the NEM wholesale market and the derivatives (contract) markets that support it. Chapter 3 covers electricity transmission and distribution networks, while chapter 6 covers electricity (and gas) retailing.

The generation mix in the electricity market continues to evolve as new technologies emerge and as the costs of some generation technologies fall. Wind and solar generation are replacing older coal fired generators as they retire from the market, for example. Energy customers are increasingly bypassing the traditional supply chain by producing some or all of their own electricity, using rooftop solar photovoltaic (PV) systems, and selling surplus production back into the grid.

In coming years, households and businesses may increasingly meet their energy needs by drawing on electricity stored in batteries and be paid by energy suppliers to reduce their energy use or inject stored electricity when the grid is under stress. Technological advances that make battery storage more economical will accelerate this shift.

Box 2.2 The AER's role in the National Electricity Market

The Australian Energy Regulator (AER) has regulatory responsibilities in the National Electricity Market (NEM) across the entire supply chain. At the wholesale level, we oversee spot and contract market activity in all regions of the market (Queensland, New South Wales (NSW), Victoria, South Australia and Tasmania).

Our work is wide ranging and includes:

- administering and monitoring compliance with the Retailer Reliability Obligation, including participants' activity in electricity contract markets
- monitoring and reporting on the effectiveness of competition in the NEM, with our second NEM-wide report released in December 2020
- identifying and reporting on the causes of high price events
- publishing our *Wholesale markets quarterly* and annual *State of the energy market* reports.

We also monitor the markets to ensure participants comply with the National Electricity Law and National Electricity Rules and take enforcement action if necessary. A recent focus is on the provision of accurate and timely information to the Australian Energy Market Operator to help maintain power system security and efficient market outcomes.

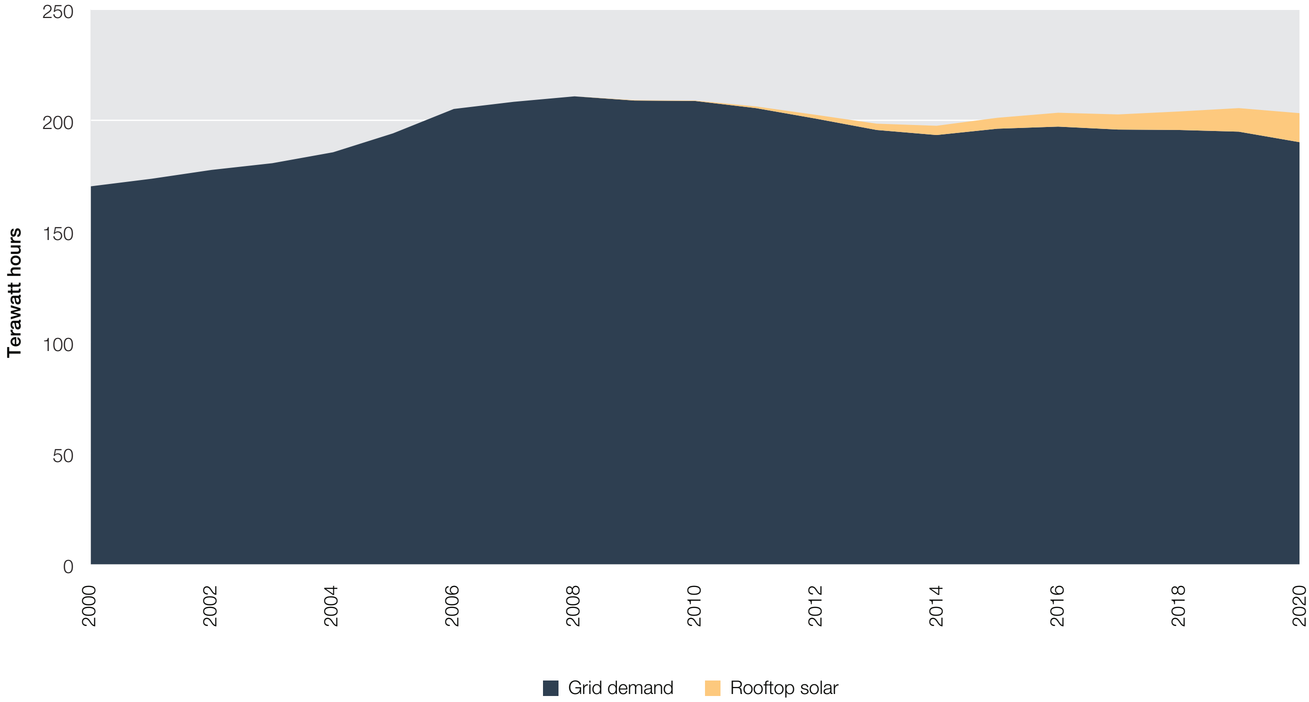
We draw on our monitoring work to advise policy bodies and other stakeholders on market trends, policy issues and irregularities. When appropriate, we also propose or participate in reforms to improve the market's operation.

2.1 Electricity consumption

The market operator defines electricity demand as electricity produced by large generators, sold through a wholesale market and transported through a transmission grid to customers. Rooftop solar PV output, which is supplied directly into local distribution networks, is treated as an offset against demand (because it replaces electricity that would otherwise be supplied through the transmission grid). To avoid confusion, this report refers to that demand as 'grid demand'. Consumption is a wider concept covering the total amount of electricity used, including both grid and rooftop PV generation.

Over 10.3 million residential and business customers consume electricity across the NEM's 5 regions. Electricity consumption peaked in 2008 at 211 terawatt hours (TWh) before a period of decline (figure 2.2). Consumption began to rise again from 2014, reaching 206 TWh in 2019 after 5 years of steady growth. Overall electricity consumption decreased slightly in 2020 to 203 TWh.

Figure 2.2 Electricity consumption in the National Electricity Market



Note: Grid demand is operational demand (including scheduled and semi-scheduled generation; and intermittent wind and large scale solar generation). Rooftop solar consumption is based on generation estimates by the Australian Energy Market Operator (AEMO).

Source: Grid production: AER, AEMO; rooftop solar: AER, AEMO (nemweb.com.au/#rooftop-pv-actual).

The expansion of Queensland's coal seam gas (CSG) and liquefied natural gas (LNG) industries accounts for much of the growth in electricity use from 2014. The reduction of overall consumption in 2020 was largely driven by milder weather. Notwithstanding some extreme weather events, the summer conditions in early 2020 were relatively mild, with fewer days of high demand and hot weather than in 2019.

The COVID-19 pandemic had a modest impact on overall electricity consumption in 2020.[1] Large industrial load was broadly flat, with most factories, mines and smelters continuing their typical operations. Commercial load was initially down due to restrictions limiting business activity, but this was almost offset by an increase in residential load.[2]

Victoria recorded the largest reduction in overall electricity consumption due to the COVID-19 pandemic, with stage 4 restrictions imposed on much of the state from August to October 2020. The Australian Energy Market Operator (AEMO) estimated that in the third quarter of 2020 commercial demand in Victoria fell by approximately 15%, but this was partially offset by an increase in residential demand of 10–15%.[3]

While electricity consumption in 2020 was 3% above 2014 levels, grid demand decreased by almost 2% over the same period. This difference reflects the increase in the number of electricity customers generating some of their own electricity needs through rooftop solar PV systems. By April 2021 over 2.3 million households and businesses in the NEM had installed solar PV systems to produce electricity. Rooftop solar PV systems met around 6% of total energy requirements in the NEM in 2020.

Consumption of grid-supplied electricity in the NEM is forecast to decline marginally over the next decade. The AEMO forecast that rises in consumption associated with population growth and increased mining activity will be more than offset by improvements in energy efficiency, growth in rooftop PV and a continuing gradual shift away from energy-intensive industries. In August 2020 AEMO considered the impact of COVID-19 on consumption over the next decade is uncertain and that reductions in consumption could be more significant if energy-intensive loads permanently close.[4]

Section 1.2.3 in chapter 1 further discusses trends in electricity consumption.

1 Australian Energy Market Operator (AEMO) estimated that for the second quarter of 2020 energy consumption reduced by approximately 2.1% compared with the same time the previous year after adjusting for differences in weather conditions. AEMO, *Quarterly energy dynamics Q2 2020,* July 2020, p 3.

2 AEMO, *Quarterly energy dynamics Q2 2020*, July 2020.

3 AEMO, *Quarterly energy dynamics Q3 2020*, October 2020.

4 AEMO, *2020 electricity statement of opportunities*, August 2020, p 27.

2.1.1 Maximum grid demand

The demand for electricity varies by time of day, season and ambient temperature. Daily demand typically peaks in early evening, when business and residential use overlap and rooftop PV generation falls. Seasonal peaks occur in winter (driven by heating loads) and summer (for air conditioning). Demand normally reaches its maximum on days of extreme heat, when air conditioning loads are highest.

Maximum grid demand rose steadily until 2009 but then flat lined or declined in most regions (figure 2.3). Queensland was an exception, with a trend of rising maximum demand since 2013 leading to a new record on 13 February 2019 during a prolonged heatwave.

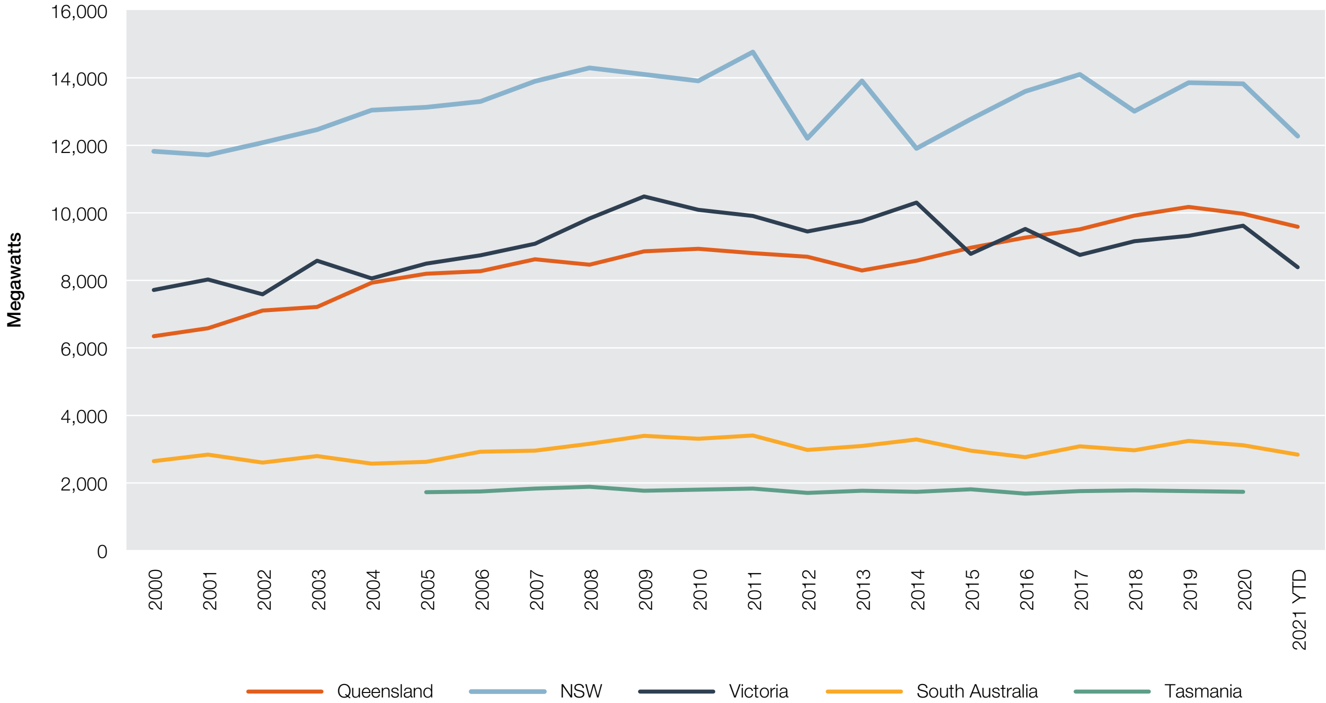
In 2020 all regions except Victoria experienced lower maximum demand than a year earlier. While high temperatures on some days in early 2020 drove demand higher, generally weather conditions over the summer were much milder than the previous year. Victoria recorded its highest maximum demand since 2013 on 31 January 2020, when the temperature reached 43° C in Melbourne. But in 2021 maximum summer demand in Victoria was the lowest since 2004, driven by milder weather.

AEMO forecast that all regions would experience a decline in maximum demand in 2020–21 due to the effects of COVID-19 on economic activity, changing daily demand profiles, and some large industrial customers reducing output in response to economic conditions.

Maximum demand over the next 10 years is forecast to rise in Queensland, South Australia and NSW and remain relatively stable in Tasmania. Victoria is the only state forecast to experience a decline in maximum demand beyond 2020–2021, with the level expected to decline slightly in the first half of the decade before increasing steadily.[5]

Trends in maximum demand are driven by factors similar to those affecting total grid demand (population and economic growth, energy efficiency, and technology). But the impact of changes in these drivers can differ for total grid demand and maximum demand. As an example, the forecast rise in rooftop solar PV capacity over the next decade will significantly reduce total grid demand but will have a more limited impact on maximum demand, which typically occurs in the early evening, when solar is generating at limited capacity.

Figure 2.3 Maximum grid demand by region



YTD: year to date.

Note: Maximum operational grid demand (including scheduled and semi-scheduled generation; and intermittent wind and large scale solar generation) is for any time during the year. Data exclude consumption from rooftop solar photovoltaic (PV) systems. The 2021 year-to-date data include all intervals to 31 March 2021. Tasmania's 2021 maximum is not shown, because Tasmania's maximum demand typically occurs in winter (from heating loads).

Source: AER analysis of AEMO data.

5 AEMO, *2020 electricity statement of opportunities*, August 2020, p 41.

2.1.2 Minimum grid demand

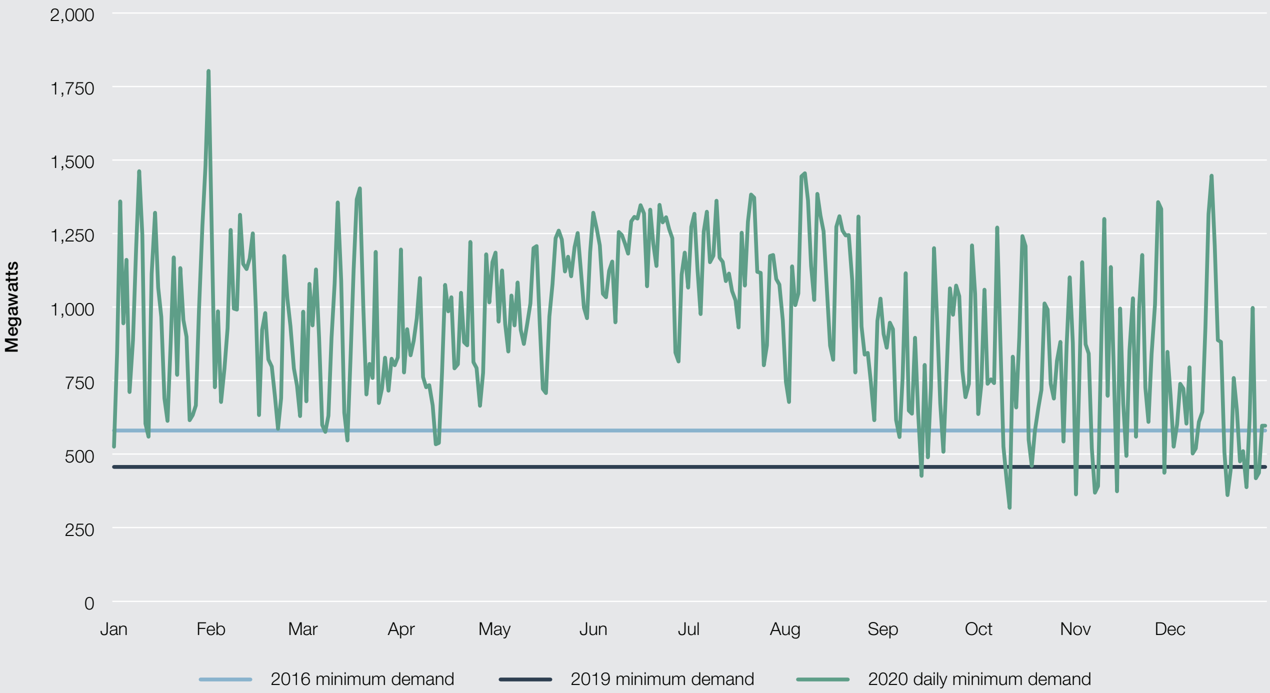
Historically, electricity demand reached its lowest point in the middle of the night, when most people are sleeping. But the growth of rooftop solar PV capacity means households are exporting electricity to the grid in the middle of the day when the sun is at its highest point. This trend is lowering daytime grid demand to the extent that minimum grid demand increasingly occurs in the middle of the day. South Australia, Victoria and Queensland all recorded their minimum demand in 2020 around the middle of the day.

The shift also reflects declining levels of minimum demand. Minimum demand fell in every NEM region in 2019 and continued this trend in 2020. The shift was most apparent in South Australia and Victoria, where new records were set (box 2.3).

Box 2.3 Record low minimum grid demand in South Australia and Victoria

In the second half of 2020 South Australia beat the previous minimum demand record of 456 megawatts (MW) (set in 2019) on 13 separate days (figure 2.4). Of these, the lowest (and the new record minimum) was 318 MW on 11 October 2020.

Figure 2.4 Daily minimum demand in South Australia, 2020



Note: 2016 and 2019 minimum demand levels shown were record minimum demand at the time.

Source: AER analysis of AEMO data.

In Victoria, demand fell to its lowest ever level of 2,539 MW on Christmas day 2020, beating the previous record of 2,614 MW set in 1998. This was the only time demand fell below the previous minimum in 2020.

All these minimum demand events in South Australia and Victoria occurred in the middle of the day, driven by mild temperatures and high rooftop solar generation.

Growth in rooftop solar PV capacity is driving a shift in timing of minimum demand in all NEM regions from overnight to the middle of the day.[6] Over the past 4 years, rooftop solar generation in South Australia has increased by 15–24% each year. On 8 December 2020 both South Australia and Victoria set new records for maximum rooftop solar PV output, generating 1,152 MW and 1,865 MW respectively in the middle of the day.[7]

6 AEMO, *2020 electricity statement of opportunities*, August 2020, p 45.

7 AER, *Wholesale markets quarterly – Q4 2020*, February 2021.

Over the next 5 years, minimum demand is forecast to continue to decline in all regions. The trend is most significant in Victoria and South Australia, with minimum demand forecast to become negative by around 2027 and 2028 due to the rapid uptake of rooftop solar PV. Minimum demand is also forecast to keep shifting towards the middle of the day as rooftop PV capacity increases. By 2025 all regions are expected to experience minimum demand in the daytime rather than overnight. The trend is predicted to occur more slowly in Tasmania, which has a comparatively higher proportion of business load and lower rooftop PV uptake, meaning that minimum demand may still occur overnight.[8]

Section 1.2.3 further discusses trends in minimum demand.

2.2 Generation technologies in the National Electricity Market

The NEM's generation plant uses a mix of technologies to produce electricity. Figure 2.35 maps the locations of generation plant and the types of technology in use.

Table 2.5 lists each plant. Figures 2.5–2.7 compare variations across regions, including movements over time.

Fossil fuel generators produce almost 74% of electricity in the NEM. The plants burn coal or gas to power a generator. This combustion process releases carbon emissions as a by-product into the atmosphere. While large scale, fossil fuel fired synchronous generators still dominate, many older generators are nearing the end of their life, becoming less reliable and closing. Renewable generation is filling much of the gap as Australia transitions to a lower emission economy. Hydroelectric and wind plant use water and wind respectively to drive generators. Solar PV generation does not rely on a turbine; rather, it directly converts sunlight to electricity.

The various generation technologies have differing characteristics. Differences in startup, shutdown and operating costs influence each fuel type's bidding and generation strategies. Technology types also have different implications for power system security, including system strength and frequency.

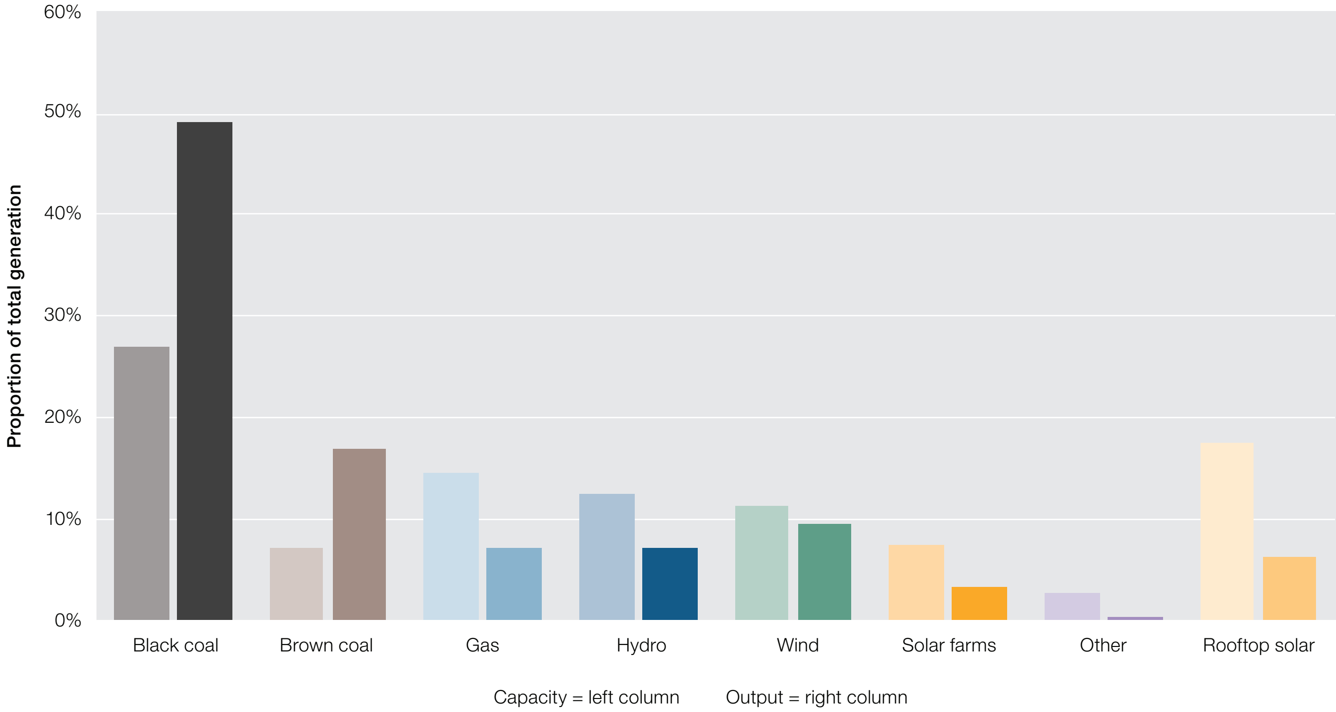
Synchronous generators such as coal, gas and hydro plants possess rotational inertia, which regulates frequency in the power system. Wind and solar plant do not possess this inertia and can pose challenges for power system security. The capability of those technologies to provide inertia and other security services is evolving (section 1.4).

Despite challenges in integrating wind and solar plant into the grid, the shift to renewable generation has been significant. 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.

Section 1.1 in chapter 1 analyses these drivers.

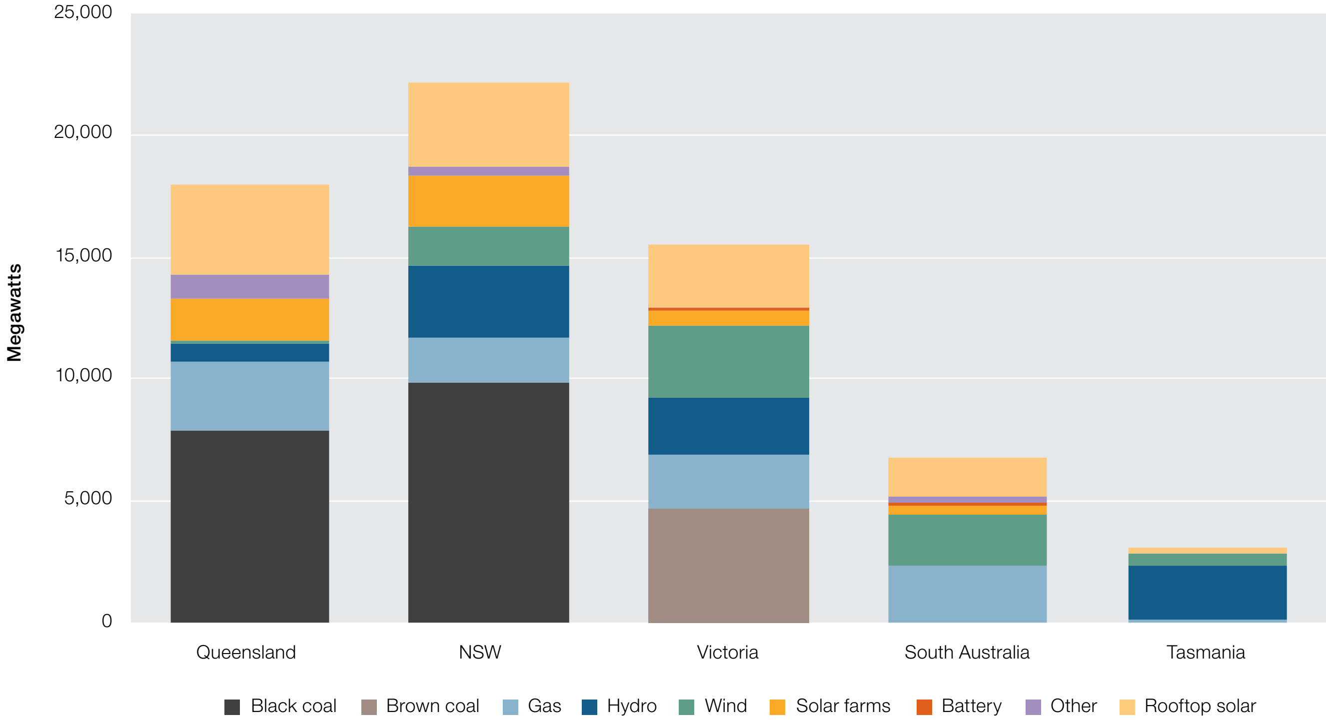
8 AEMO, *2020 electricity statement of opportunities*, August 2020.

Figure 2.5 Generation output and capacity in the National Electricity Market, by fuel source, 2020



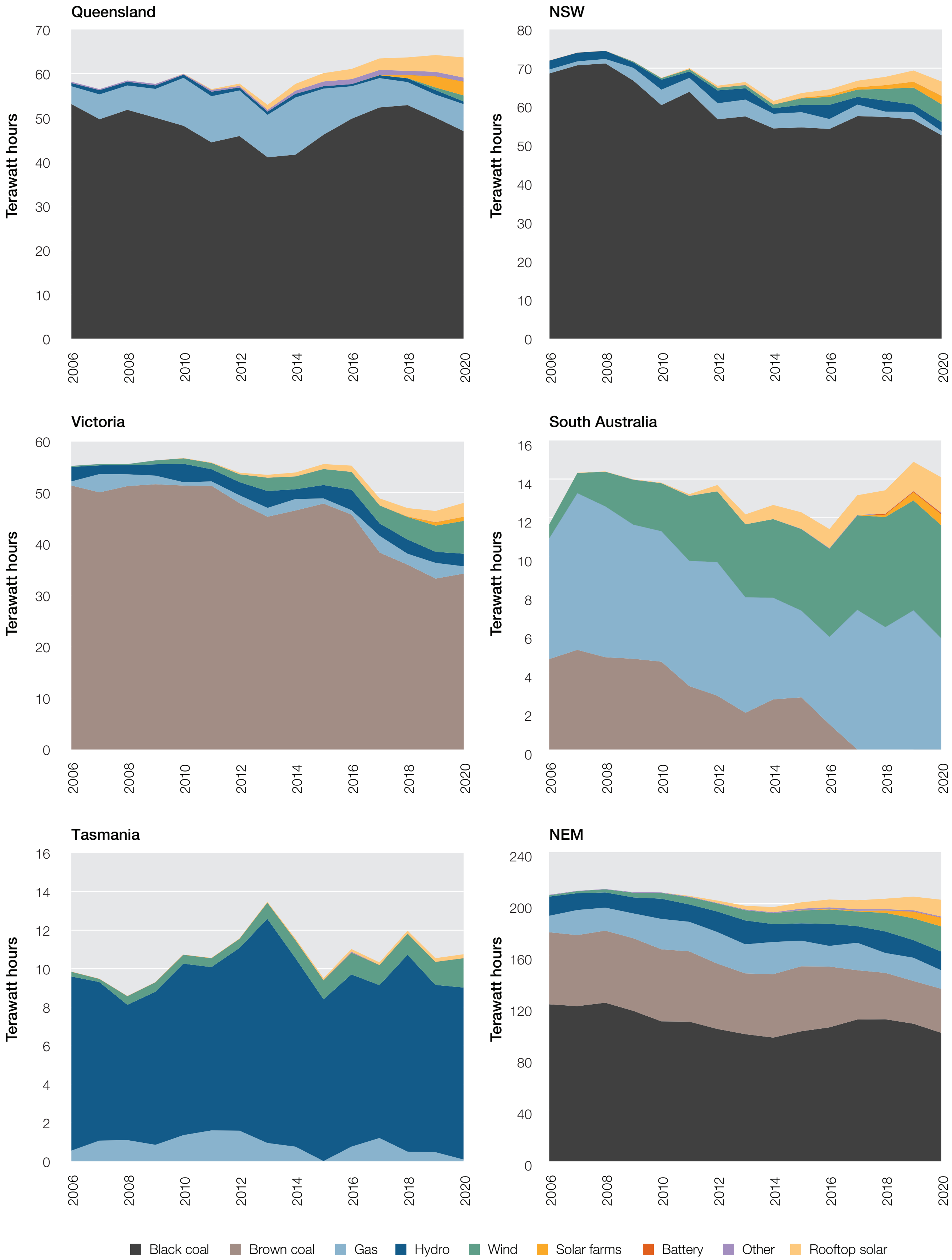
Note: Generation capacity at 1 January 2021. Other dispatch includes biomass, waste gas and liquid fuels. Output is for 2020.
Source: Grid demand: AER, AEMO; rooftop solar: AER, CER, AEMO.

Figure 2.6 Generation capacity in the National Electricity Market, by region and fuel source, 2020



Note: Generation capacity at 1 January 2021. Other dispatch includes biomass, waste gas and liquid fuels.
Source: Grid demand: AER, AEMO; rooftop solar: AER, CER, AEMO.

Figure 2.7 Electricity generation over time, by region and fuel source



Note: Other dispatch includes biomass, waste gas and liquid fuels.
Source: AER; AEMO (data).

2.2.1 Coal fired generation

Coal fired generators burn coal to create pressurised steam, which is then forced through a turbine at high pressure to drive a generator (figure 2.8). Coal fired generation remains the dominant supply technology in the NEM, producing 66% of all electricity traded through the market in 2020. But coal plant accounts for only 34% of the market's generation capacity, reflecting that coal generators tend to run fairly continuously.

Coal plants operate in Queensland, NSW and Victoria. Queensland and NSW generators use black coal, while Victorian generators run on brown coal. Black coal produces more energy than brown coal because it has lower water content, and it produces 30–40% fewer greenhouse gas emissions when used to generate electricity. But Victorian brown coal is among the lowest cost coal in the world, because the Gippsland region has abundant reserves in thick seams close to the earth's surface.

Coal fired generators can require a day or more to start up, so they have high start-up and shutdown costs. But their operating costs are low. These characteristics make it uneconomical to frequently switch coal plant on and off; once switched on, coal plant tends to operate relatively continuously. For this reason, coal fired generators usually bid a portion of their capacity into the NEM at low prices to guarantee dispatch and keep their plant running. Aside from providing relatively low cost electricity to the market, coal fired generators also help maintain power system stability.[9]

Over 4,000 megawatts (MW) of coal fired capacity has been retired from the market since 2014. Most recently, in March 2017 Engie retired its Hazelwood power station in Victoria, removing 1,600 MW of brown coal generation (that supplied around 5% of the NEM's total output).

Following the plant closures, the remaining coal fired generation fleet operated at higher output levels. But significant coal generator outages occurred in the past few years. Both brown and black coal had an increased rate of forced outages, with reliability falling to historically low levels for NSW coal plant in 2019–20.[10]

Major unplanned outages in 2020–21 included Yallourn unit 1 (360 MW), offline for 4 months from July; Stanwell Unit 2 (365 MW), offline for almost 3 months from 20 December 2020; and Liddell Unit 3 (500 MW), offline for most of the 2020–21 summer following a significant transformer incident on 17 December. Network and generation outages in NSW, including the Liddell Unit 3 outage, contributed to AEMO activating the reliability and emergency reserve trader (RERT) for summer 2020–21 (section 2.9.1).[11]

Retirements of further coal plant are expected. The most imminent is the planned retirement of AGL Energy's Liddell power station in NSW in stages over 2022 and 2023, which would remove 2,000 MW of black coal capacity from the NEM. No further investment in new coal plant is proposed for the NEM.

2.2.2 Gas powered generation

A number of gas generation technologies operate in the NEM. Open cycle gas turbine (OCGT) plant burn gas to heat compressed air that is then released into a turbine to drive a generator (figure 2.8). In combined cycle gas turbine (CCGT) plant, waste heat from the exhaust of the first turbine is used to boil water and create steam to drive a second turbine (figure 2.8). The capture of waste heat improves the plant's thermal efficiency, making it more suitable for longer operation than open cycle plant. More recently, the first reciprocating engine gas plant was commissioned in South Australia. This technology uses gas to drive a piston that spins a turbine. These plant operate similarly to OCGTs but are more flexible. Some legacy 'steam turbines' – which operate similarly to coal plant – also remain in the market.

Gas plant can operate more flexibly than coal, with open cycle plant (and newer CCGT plant and reciprocating engines) in particular needing as little as 5 minutes to ramp up to full operating capacity. The ability of gas plant to respond quickly to sudden changes in the market makes it a useful complement to wind and solar generation, which can be affected by sudden changes in weather conditions. The most efficient gas powered generation is less than half as emission intensive as the most efficient coal fired plant.[12]

9 Synchronous generators – including hydroelectric and thermal plant such as coal, gas and solar thermal generators – contain heavy spinning rotors that provide synchronous inertia, slowing down the rate of change of frequency. They also help with voltage control by producing and absorbing reactive power, and they provide high fault current that improves system strength.

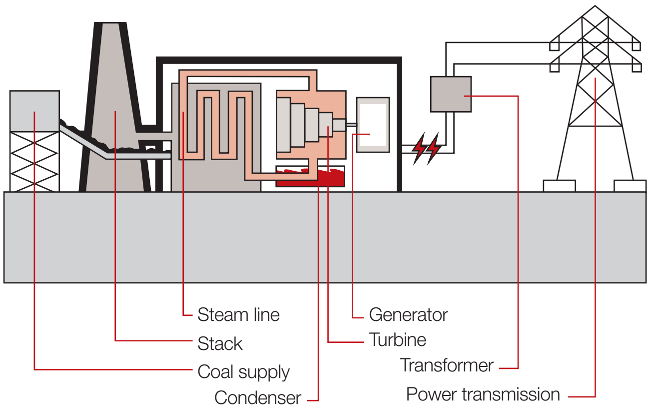
10 AEMO, *2020 electricity statement of opportunities*, August 2020, p 48.

11 AEMO, *Reliability and Emergency Reserve Trader (RERT) quarterly report Q4 2020*, February 2021, p 10.

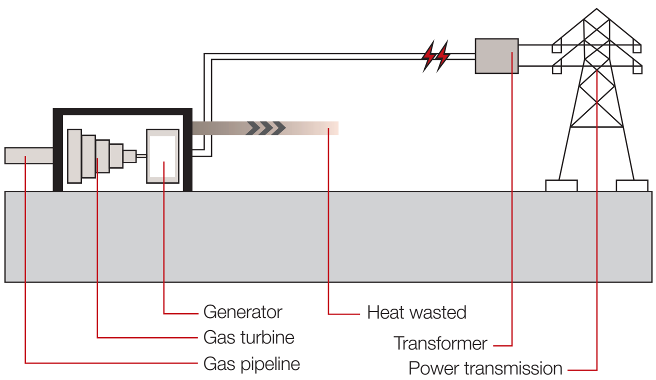
12 Dr Alan Finkel AO, Chief Scientist, Chair of the Expert Panel, *Independent review into the future security of the national electricity market: blueprint for the future*, June 2017, p 109.

Figure 2.8 National Electricity Market generation technologies

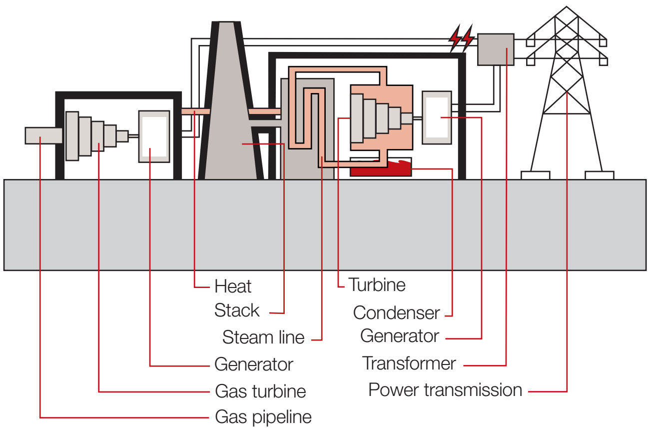
Coal fired generation



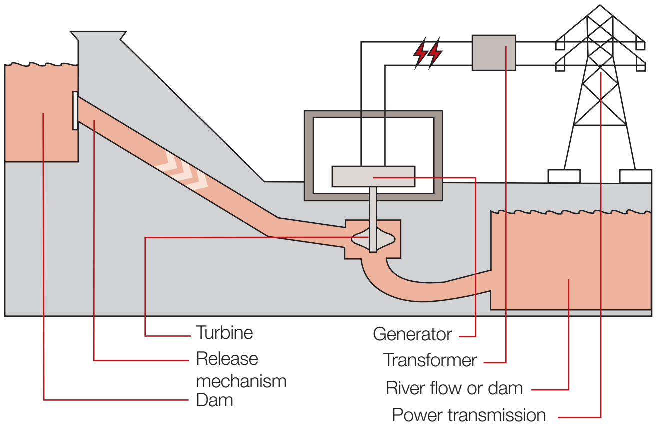
Open cycle gas powered generation



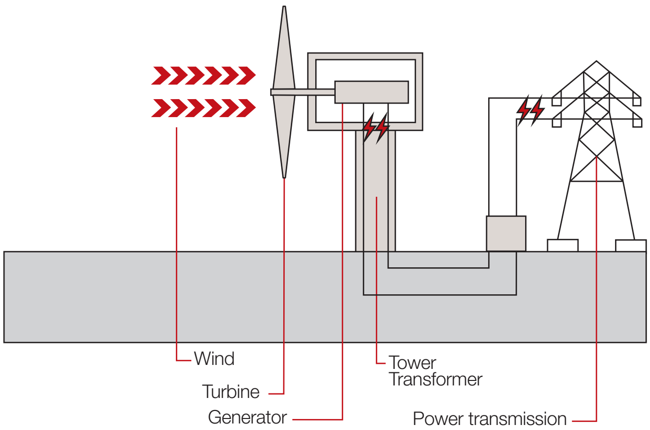
Combined cycle gas powered generation



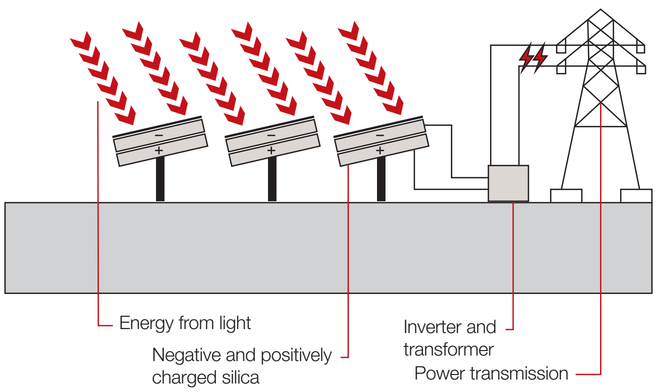
Hydroelectric generation



Wind powered generation



Solar PV generation

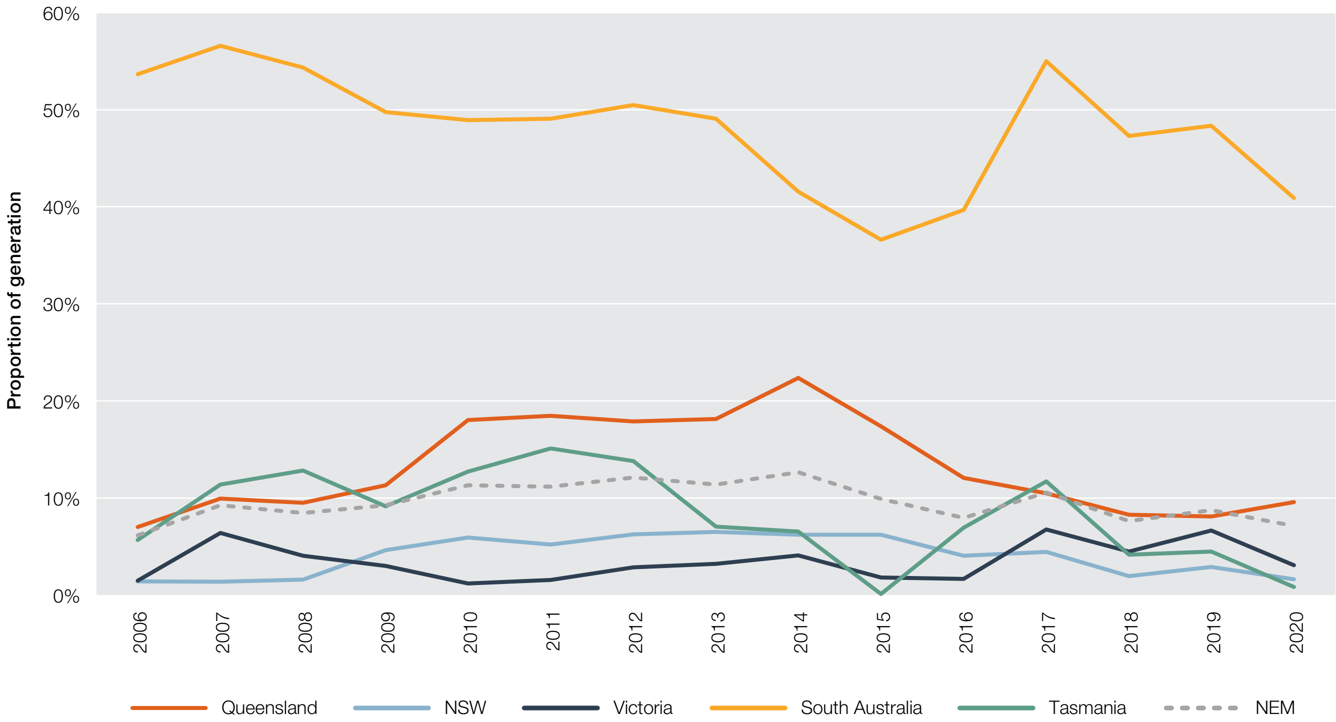


Despite these benefits, gas is a relatively expensive fuel for electricity generation, so gas generators more typically operate as 'flexible' or 'peaking' plant.[13] Across the NEM, gas powered plant accounted for 14% of plant capacity in the NEM in 2020 but supplied only 7% of electricity generated. South Australia relies more on gas powered generation than do other regions. In 2020 the state produced 41% of its local generation from gas plant – the lowest level since 2016.

Gas generation in the NEM tends to be seasonal, peaking in summer (and sometimes winter) when electricity demand and prices are highest. It also varies with the amount of intermittent generation and outages affecting coal fired generators. AEMO forecasts that gas generation will increasingly support the market in winter when solar PV generation is lower and coal fired capacity is withdrawn for maintenance.[14]

Higher gas fuel costs linked to Queensland's LNG industry, along with a lack of new gas supplies, slowed demand for gas powered generation from 2015 (figure 2.9). This shift was reinforced by the Queensland Government in July 2017 directing its major state-owned coal generator to lower its offer prices (making gas generation less competitive). These conditions were reflected in gas powered generation slumping from 22% of Queensland's electricity output in 2014 to under 10% since 2018.

Figure 2.9 Gas powered generation



Source: AER; AEMO (data).

A similar squeezing of gas powered generation was apparent from 2018 in NSW. The state's gas output in 2020 was 1.6% of total electricity generation – its lowest level since 2008.

The retirement of coal generators in Victoria and South Australia made gas generation critical to meeting electricity demand whenever renewable generation is low in those regions. Gas generation increased in both states for several years following the closure of the Hazelwood and Northern power stations in 2017 and 2016. But lower grid demand and higher wind and solar output reversed this trend in 2020, with gas generation 54% lower in Victoria and 15% lower in South Australia than the previous year.

AGL commissioned new gas plant in South Australia in 2019 at Barker Inlet (210 MW), replacing the Torrens Island plant that is retiring in stages from 2020 to 2022. This was the first new gas plant investment in the NEM since Origin commissioned the Mortlake power station (566 MW) in Victoria in 2011.

Multiple proposals for new gas plant are on the table in Queensland, NSW, Victoria and South Australia. The Australian Government announced support for 2 gas plant proposals (and shortlisted a further 3) through its Underwriting New Generation Investment (UNGI) scheme (section 1.7.1).

13 Flexible or peaking plant can be turned on at short notice and is often turned on during high price periods.

14 AEMO, *Gas statement of opportunities 2021*, p 37.

The Australian Government has also signalled the need for new gas powered generation in NSW to fill the gap left by Liddell's exit and has backed a new 660 MW plant by Snowy Hydro in the Hunter region of NSW. Also in NSW, in May 2021 EnergyAustralia committed to developing its Tallawarra B power station (316 MW), which is capable of using a blend of hydrogen and natural gas, by 2023–24. And Goldwind Australia plans to build gas reciprocating engines (72 MW) and a 12 MW battery alongside an existing renewables farm with support from the NSW Government under its Emerging Energy Program.

2.2.3 Hydroelectric generation

Hydropower uses the force of moving water to generate power. The technology involves channelling falling water through turbines. The pressure of flowing water on the blades rotates a shaft and drives an electrical generator, converting the motion into electrical energy (figure 2.8). Similar to coal and gas plant, hydroelectric generators are synchronous, meaning they provide inertia and other services that support power system security. And, because their fuel source is usually available (except in drought conditions), they are 'dispatchable' plants that can switch on as required.

Most of Australia's hydroelectric plants are large scale projects that are over 40 years old. A number of 'mini-hydro' schemes also operate. These schemes can be 'run of river' (with no dam or water storage) or use dams that are also used for local water supply, river and lake water level control, or irrigation.

While hydroelectric plants have low fuel costs (that is, they do not explicitly pay for the water they use), they are constrained by storage capacity and rainfall levels to replenish storage, unless pumping is used to recycle the water. For this reason, the opportunity cost of fuel is comparatively high. Hydroelectric generators typically operate, therefore, as 'flexible' or 'peaking' plant, similar to gas powered generation. Some pumped hydroelectric generation already operates in NSW and Queensland, but larger scale projects are also being explored (section 1.7.2).

Conditions in the electricity market affect incentives for hydro generation. Subject to environmental water release obligations, hydroelectric generators tend to reduce their output when electricity prices are low and run more heavily when prices are high. Incentives under the Renewable Energy Target (RET) scheme also affect incentives to produce.

Hydroelectric generators accounted for 12% of capacity in the NEM in 2020 and supplied 7% of electricity generated. Tasmania is the region most reliant on hydro generation, with 83% of its 2020 generation coming from that source. NSW and Victoria also have significant hydro generation plant located in the Snowy Mountains region.

Hydro generation levels in recent years varied due to weather conditions, market incentives to generate, and subsidy arrangements under the RET scheme.[15] In 2020 hydro generation in the NEM increased 5.5% over the previous year but remained well below recent peak output in 2018 that stemmed in part from a Basslink interconnector outage that required Tasmania to be self-sufficient in generation.

In 2019 there was record hydro generation output in Queensland following high rainfall in northern Queensland, where the region's 2 main plants are located. But in 2020 hydro generation in Queensland fell 38%, returning to levels more consistent with longer term trends.

2.2.4 Wind generation

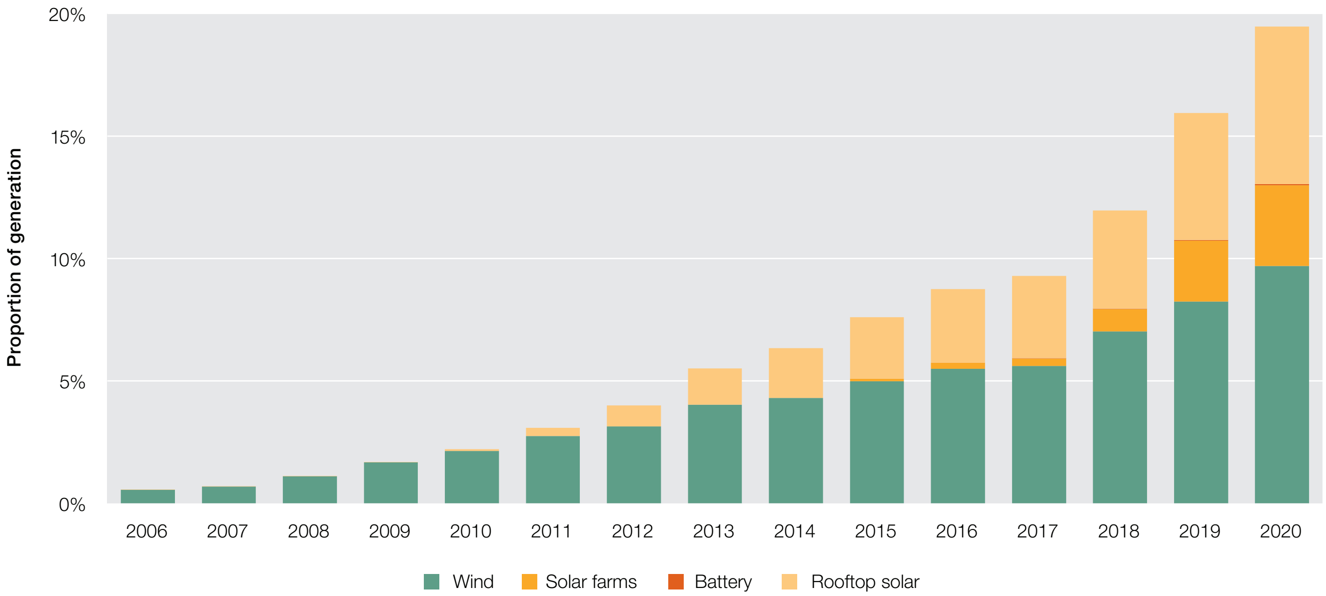
Wind turbines directly convert the kinetic energy of wind into electricity. The wind turns blades that spin a shaft connected (directly or indirectly via a gearbox) to a generator that creates electricity (figure 2.8).

Renewable generation, including wind, has filled much of the supply gap left by thermal plant closures (figure 2.10). Government incentives, including the RET scheme, provided impetus for the growth of wind generation in the NEM.

Wind generators accounted for 11% of the NEM's capacity in 2020. Over 1,000 MW of new capacity was added since July 2020 (accounting for almost 35% of all new investment). During 2020 wind generated almost 10% of all electricity in the NEM, with total output generated up 17% since 2019 and 73% since 2017.

15 Box 1.1 in chapter 1 describes the RET scheme.

Figure 2.10 Wind, solar and battery generation share of total generation



Source: Grid generation: AER, AEMO; rooftop solar: AEMO (nemweb.com. au/#rooftop-pv-actual).

Wind penetration is especially strong in South Australia, where it provided 42% of the state's electricity output in 2020. More recently, the focus of wind investment has shifted to NSW and Victoria, where over 70% of capacity installed or committed since July 2017 has occurred. Queensland had no large scale wind generators until 2018, but now has 2 in operation, with Coopers Gap set to be one of the largest in the country (453 MW) when completed. Queensland has significantly less wind generation than other mainland states, however.

Weather conditions affect wind generation levels. Favourable conditions on 22 August 2020 resulted in record levels of wind output, peaking at 5,242 MW. On that day, wind generation accounted for 20% of all electricity generated in the NEM.

Wind generation accounts for around 25% of the NEM's proposed and committed generation projects, at nearly 24,000 MW. Three wind projects, comprising over 650 MW of capacity, are scheduled to be fully commissioned by the end of 2021 (table 2.3).

2.2.5 Grid scale solar farms

Large scale solar plant is a relatively new entrant in the NEM. Australia has the highest solar radiation per square metre of any continent, receiving an average 58 million petajoules of solar radiation per year.[16] All solar investment to date has been in PV systems that use layers of semi-conducting material to convert sunlight into electricity (figure 2.8). Concentrated solar thermal is an alternative technology that uses lenses, towers, dishes and reflectors to concentrate sunlight, heating fluid to produce steam that drives a turbine.[17]

Despite eligibility for government incentives under the RET scheme, and funding support from the Australian Renewable Energy Agency (ARENA) and Clean Energy Finance Corporation (CEFC),[18] investment in large scale solar farms in Australia did not occur at a significant scale until 2018. Commercial solar farms accounted for only 0.5% of total NEM generation capacity in 2017 and met only 0.3% of the NEM's electricity requirements. But by 2020 they made up 7.4% of capacity and 3.3% of output.

Forty-eight solar farms began generating from 2018 to the end of 2020 (totalling 5,215 MW),[19] 4 projects (229 MW) commenced by the first quarter of 2021, and a further 9 projects (452 MW) were scheduled to begin output by the end of 2021. The majority of new capacity has been located in NSW – the largest operating plant at March 2021 is Darlington Point Solar (324 MW).

16 Geoscience Australia, *Solar energy*, Geoscience Australia website, accessed 14 May 2020.

17 There are no operating solar thermal plants in the NEM.

18 Box 1.1 in chapter 1 outlines the RET scheme's operation and the role of ARENA and the CEFC.

19 The 5,215 MW encompasses the new farms' total registered capacity on completion. Some farms are not yet operating at that full capacity, as construction continues.

2.2.6 Grid scale storage

Stored energy can be used to support system reliability by being injected into the grid at times of high demand and providing stability services to the grid by balancing variability in renewable generation. Storage technologies in the NEM include batteries and pumped hydroelectricity.

Battery storage

Grid scale batteries were not commercially viable until recently in Australia. But lower costs and expanding opportunities for this technology saw a recent uptick in battery investment.

In December 2017 South Australia commissioned the (at the time) world's largest lithium ion battery at the Hornsdale wind farm in response to a need for 'firming' capacity to manage variability in wind and solar generation. In 2020 the battery's capacity was expanded by 50% (to 150 MW). Other battery projects since commissioned include those at Gannawarra (25 MW) and Ballarat (30 MW) in Victoria; and Dalrymple (30 MW) and Lake Bonney (25 MW) in South Australia. The projects complement and 'firm' solar and wind farm generation.

Batteries in the NEM tend to earn a majority of their profits from operating in frequency control markets. For example, the AER estimated South Australia's Hornsdale battery earned around $58 million for frequency services across 2019–20 – more than 15 times the battery's spot earnings from wholesale energy sales.[20] This represents the majority of FCAS revenue earned by all battery participants for the 2019-20 financial year, which was just over $63 million.

Trials are underway to aggregate household battery systems to create grid scale 'virtual' power plants (section 1.2.2).

Pumped hydroelectricity

Large scale storage can be provided through pumped hydroelectric projects, which allow hydroelectric plant to reuse their limited water reserves. The technology involves pumping water into a raised reservoir when energy is cheap and releasing it to generate electricity when prices are high.

Pumped hydroelectric technology has been available in the NEM for some time, with generation in Queensland (570 MW at Wivenhoe) and NSW (240 MW at Shoalhaven and 1,500 MW at Tumut 3). While use of this technology is limited by the availability of appropriate physical sites, advances in technology and the rise of intermittent generation are providing new opportunities for deploying this form of storage at a larger scale. In particular, pumped hydroelectricity is the basis of the proposed Snowy 2.0 (2,000 MW) and Battery of the Nation (2,500 MW) projects in NSW and Tasmania respectively (section 1.7.2).

2.2.7 Distributed energy resources

Alongside major shifts occurring in the technology mix at grid level, significant changes are occurring in small scale electricity supply with the uptake of distributed energy resources (DER). These consumer-owned devices can generate or store electricity or actively manage energy demand. DER include:

- rooftop solar PV units
- storage, including batteries and electric vehicles
- demand response, which uses load control technologies to regulate the use of household appliances such as hot water systems, pool pumps and air conditioners.

By far the fastest development has been in rooftop solar PV installations, but interest is also growing in battery systems, electric vehicles and demand response. Small scale battery installations in 2020 were over 15 times higher than those in 2014, although their penetration is much lower than rooftop PV installations.[21]

Rooftop solar photovoltaic generation

While large scale solar generation was slow to develop in Australia, consumers began installing rooftop solar PV panels from around 2010. Rooftop systems account for over one-third of renewable capacity in the NEM. In 2020 solar PV systems met 6.4% of the NEM's electricity requirements. Their contribution is highest in South Australia, where they met over 13% of electricity requirements. Queensland has the highest number of installations and the highest installed capacity (almost 3,700 MW).

20 AER, *Wholesale electricity market performance report 2020*, December 2020.

21 Data on small scale battery installations from Clean Energy Regulator, *State data for battery installations with small scale systems*, CER website, accessed 1 May 2021.

Rooftop solar PV generation is not traded through the NEM. Instead, installation owners receive reductions in their energy bills for feeding electricity into the grid. AEMO measures the contribution of rooftop PV generation as a reduction in energy demand – because it reduces electricity demand from the grid – rather than as generation output.

By April 2021 NEM customers had installed almost 2.4 million solar PV rooftop systems.[22] The total installed capacity of these systems was 11.4 gigawatts (GW), which was equivalent to over 17% of the NEM's total generation capacity.

The uptake of rooftop solar PV is driven by opportunities for energy customers to reduce their electricity bills and to contribute to positive environmental outcomes. Government incentives – such as rebates through the Small-scale Renewable Energy Scheme and premium feed-in tariffs – strengthened incentives to install the systems.

The rate of installation of solar PV systems has risen each year since 2016. Combined with larger system sizes for newer installations, a record amount of solar PV capacity was installed in the NEM in 2020 – over 2,500 MW of capacity compared with 1,900 MW in 2019.

The average size of systems installed in 2020 more than tripled that in 2011, rising from 2.5 kilowatts (kW) to 8 kW. This shift to larger systems reflects the lower installation costs and the higher uptake of solar PV systems by commercial businesses (figure 1.9).

Small scale storage

In coming years, customers will increasingly store surplus energy from solar PV systems in batteries and draw on it when needed, thus reducing their demand for electricity from the grid. Home battery systems may play an important role in meeting demand peaks in the grid, depending on the extent to which technology improvements can reduce installation costs.

The pace of uptake of electric vehicles will potentially have a significant impact on electricity demand and supply. Charging the batteries of electric vehicles will likely generate significant demand for electricity from the grid. These batteries may also provide electricity back to the grid at times of high demand.

Australian households and small businesses already show significant interest in and awareness of batteries. Around a third of small businesses and a quarter of household consumers who do not currently have battery storage say they intend or are interested in purchasing a battery system.[23] The Clean Energy Regulator estimates customers in the NEM had installed over 30,000 battery systems by April 2021.[24]

Individually, distributed storage is largely invisible to the market. But, if aggregated and operated together as a microgrid or virtual power plant, the devices can potentially enhance reliability and power system security.

Section 1.2.2 in chapter 1 further discusses distributed storage, including batteries and virtual power plants. Section 1.4.5 discusses the potential role for DER in the future of the market, including as a provider of grid stability services.

2.3 Trade across National Electricity Market regions

Transmission interconnectors (mapped and listed in chapter 3) link the NEM's 5 regions, allowing trade to take place. Trade enhances the reliability and security of the power system by allowing each region to draw on generation plant from across the market, and it allows for more efficient use of the generation fleet.

Queensland has surplus generation capacity, making it a net electricity exporter (figure 2.11). Victoria's abundant supplies of low priced brown coal generation also traditionally made it a net exporter of electricity. But Hazelwood's closure in 2017 reduced Victoria's trade surplus, and significant brown coal plant outages in 2019 contributed to Victoria becoming a net importer for the first time in 2019. In 2020 lower grid demand and increased wind and solar output contributed to Victoria switching back to being a net exporter of electricity.

NSW has relatively high fuel costs, typically making it a net importer of electricity. Net imports steadily declined for several years, reaching an historic low in 2019, but increased again in 2020.

22 Data on small generation units (solar) from Clean Energy Regulator, *Postcode data for small scale installations*, CER website, accessed 1 May 2021.

23 Energy Consumers Australia, *Energy consumer sentiment survey*, June 2020.

24 Data on solar PV systems with concurrent battery storage capacity by year and state/territory from Clean Energy Regulator, *Postcode data for small scale installations*, CER website, accessed 1 May 2021.

Figure 2.11 Inter-regional trade

Source: AER; AEMO.

South Australia was traditionally an electricity importer due to its lack of low cost local supply. Coal plant withdrawals increased the region's trade dependency, making it proportionally the NEM's highest importer in 2016. But increasing local wind generation, combined with the reduced capacity and availability of brown coal generation in Victoria, reduced its net imports from 2017. As a result, the state had an energy trade surplus in 2019. Victoria continued to be a net exporter in 2020, but its net trade surplus fell.

Tasmania's trade position varies with environmental and market conditions. Key drivers include local rainfall (which affects dam levels for hydro generation), Victorian spot prices, and the availability of the Basslink interconnector (which has suffered multiple extended outages in recent years). Tasmania was proportionally the NEM's largest net exporter when carbon pricing made hydroelectric generation more competitive in 2012–2014. But Tasmania's exports fell following drought and the abolition of carbon pricing. In 2020 Tasmania's net trading position was almost in balance, recording a small deficit.

2.3.1 Market alignment and network constraints

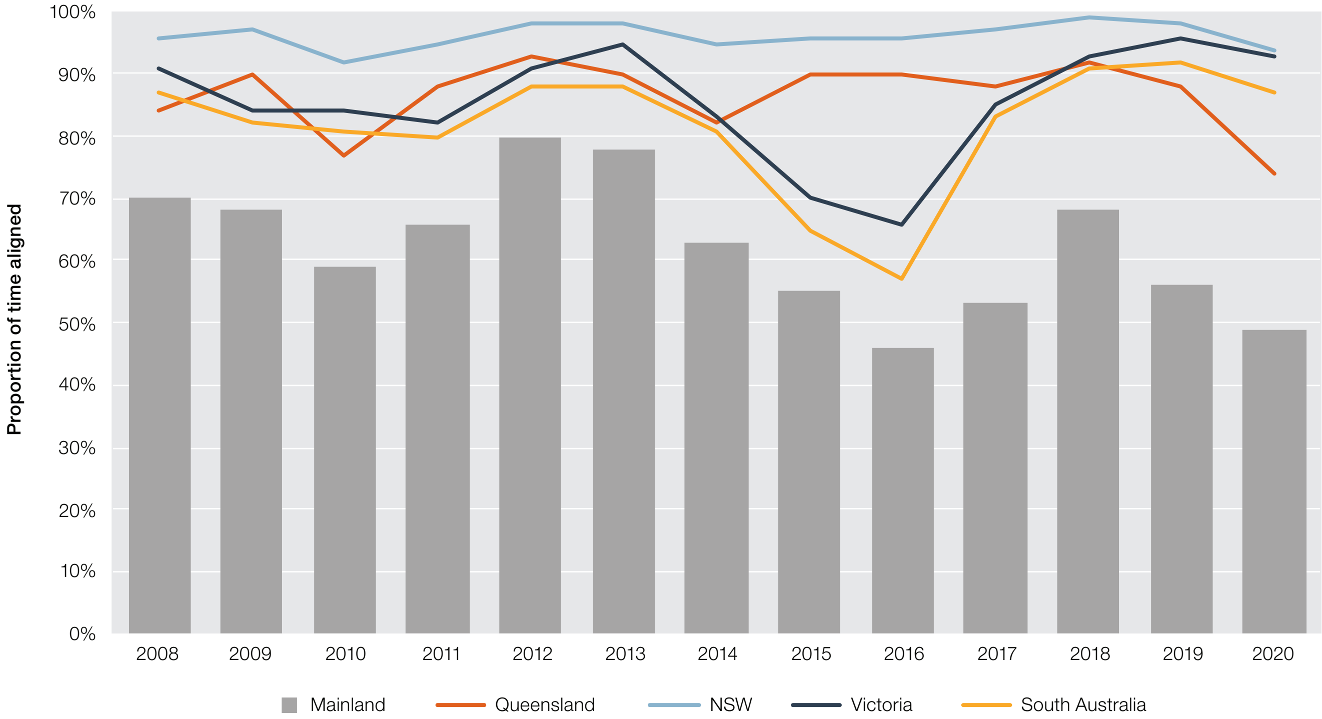
The market sets a separate spot price for each NEM region. When the interconnectors linking NEM regions are unconstrained, trade brings prices into alignment across all regions (apart from variations caused by physical losses that occur when transporting electricity). At these times, the NEM acts as a single market rather than as a collection of regional markets, and generators within a region are exposed to competition from generators in other regions. But interpreting alignment rates as an indicator of competition between regions requires care. For example, improved alignment rates between South Australia and Victoria from 2017 did not necessarily indicate a change in competitive conditions.[25]

Historically, Queensland and NSW had high alignment rates, with a fairly stable interconnector capacity linking the regions. Queensland's alignment rates declined in 2020, driven by work to upgrade NSW interconnector that limited flows between the regions (figure 2.12).

Price alignment in Victoria and South Australia has been less regular, with congestion on the Victoria – South Australia interconnectors more than doubling in frequency between 2013 and 2017. Heywood was the NEM's most congested interconnector over this period, partly because its capacity was constrained during a major upgrade. But the completion of the Heywood upgrade and the closure of Victoria's Hazelwood power station in 2017 (which reduced Victorian exports of electricity to South Australia and NSW) reduced congestion between the regions. South Australia's alignment rates returned to more typical levels from 2018, with prices aligning with Victoria between 87% and 92% of the time – up from a low of 57% in 2016. Victoria's alignment rate has been above 90% since 2018.

25 AER, *Wholesale electricity market performance report*, December 2020, p 35.

Figure 2.12 Price alignment in mainland National Electricity Market regions



Note: Inter-regional price alignment shows the proportion of the time that prices in one NEM region are the same as those in at least one neighbouring region, accounting for transmission losses.

Source: AER; AEMO.

2.4 Market structure

Around 200 power stations sell electricity into the NEM spot market. Table 2.5 lists the major stations, plant technologies and ownership arrangements (including the entities that operate each plant). Figure 2.35 maps each plant's location.

Private entities own most generation capacity in Victoria, NSW and South Australia. AGL Energy, EnergyAustralia, Origin Energy, Snowy Hydro and Engie are among the largest plant owners, although the scale of each business varies across regions. Government-owned corporations own or control the majority of capacity in Queensland and Tasmania.

Section 2.8 examines the market's structure and competitiveness.

2.4.1 Market concentration

A few large participants control a significant proportion of generation in each NEM region. The 2 largest participants account for over 40% of total capacity (figure 2.13) in all regions and 60% of output (figure 2.14) in all regions except South Australia. Queensland, NSW and Victoria account for a higher concentration of output than capacity, given the high utilisation rates of black and brown coal plant, which make up the bulk of capacity held by the major participants. South Australia's largest participants rely on gas powered generation.

Private entities own most generation capacity in, NSW, Victoria and South Australia:

- In Victoria, AGL Energy (27%) and EnergyAustralia (19%) control a majority of capacity. The Australian Government owned Snowy Hydro (16%) is the next largest participant.
- In South Australia, AGL Energy is the largest plant owner, with 30% of capacity. Other significant entities are Engie (18%), Origin Energy (14%) and EnergyAustralia (6%).
- In NSW, AGL Energy (26%) and Origin Energy (20%) are the largest plant owners. Snowy Hydro (16%), EnergyAustralia (10%) and Sunset Power (7%) are other major players.

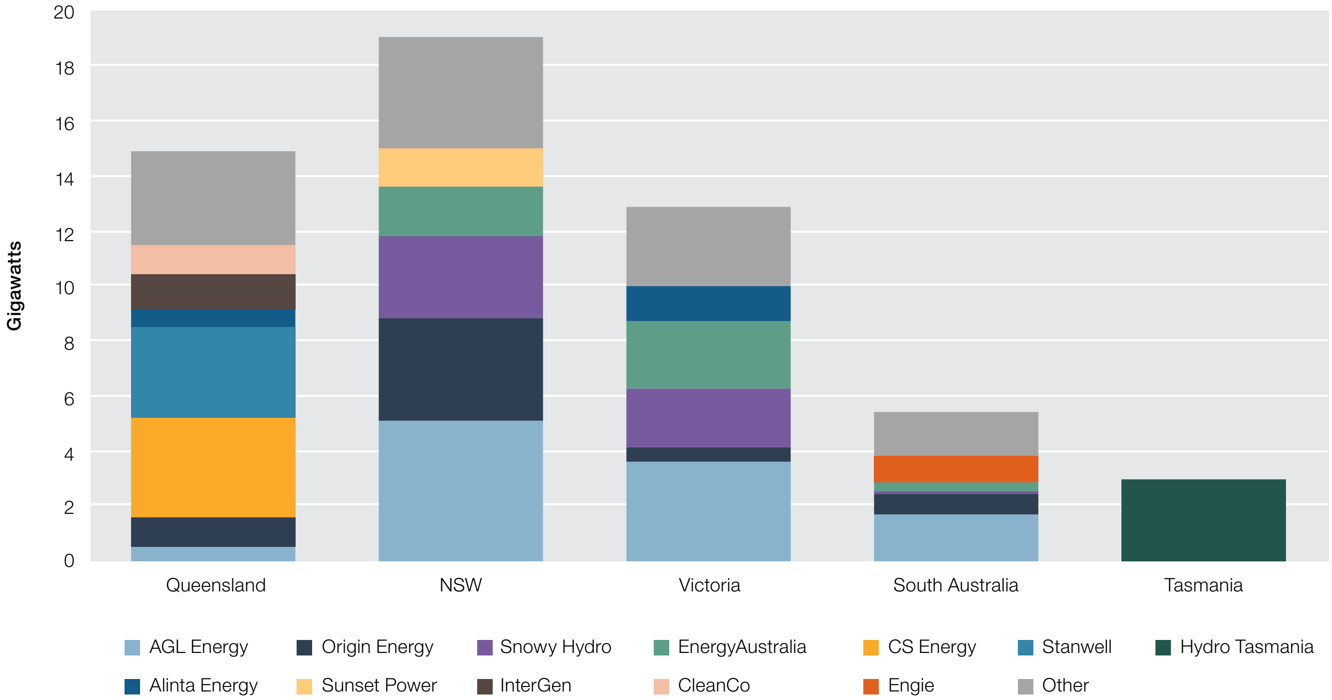
But government-owned corporations own or control the majority of capacity in Queensland and Tasmania:

- In Queensland, state-owned corporations Stanwell and CS Energy control 46% of generation capacity, including power purchase agreements over privately owned capacity (such as the Gladstone power station). This market share fell in October 2019 when some of CS Energy's and Stanwell's assets were transferred to a third state-owned corporation, CleanCo. CleanCo was created to increase wholesale market competition and support growth in the state's renewable energy industry. It controls 7% of the state's capacity, including all hydropower plant. The largest private operators are InterGen (9%) and Origin Energy (8%).
- In Tasmania, the state-owned Hydro Tasmania owns all generation capacity. To encourage competition in the retail market, the Office of the Tasmanian Economic Regulator regulates the prices of 4 safety net contract products offered by Hydro Tasmania and ensures adequate volumes of these products are available.

AGL Energy is the largest participant by capacity and output in NSW, Victoria and South Australia. On a NEM-wide basis, it accounted for 19% of capacity and 25% of output in 2020.

Snowy Hydro contributed only 2% of output in NSW and Victoria, despite holding over 16% of capacity in each region. This outcome arose because Snowy Hydro's hydroelectric generators have limited water availability, and its gas peaking plant operates infrequently.

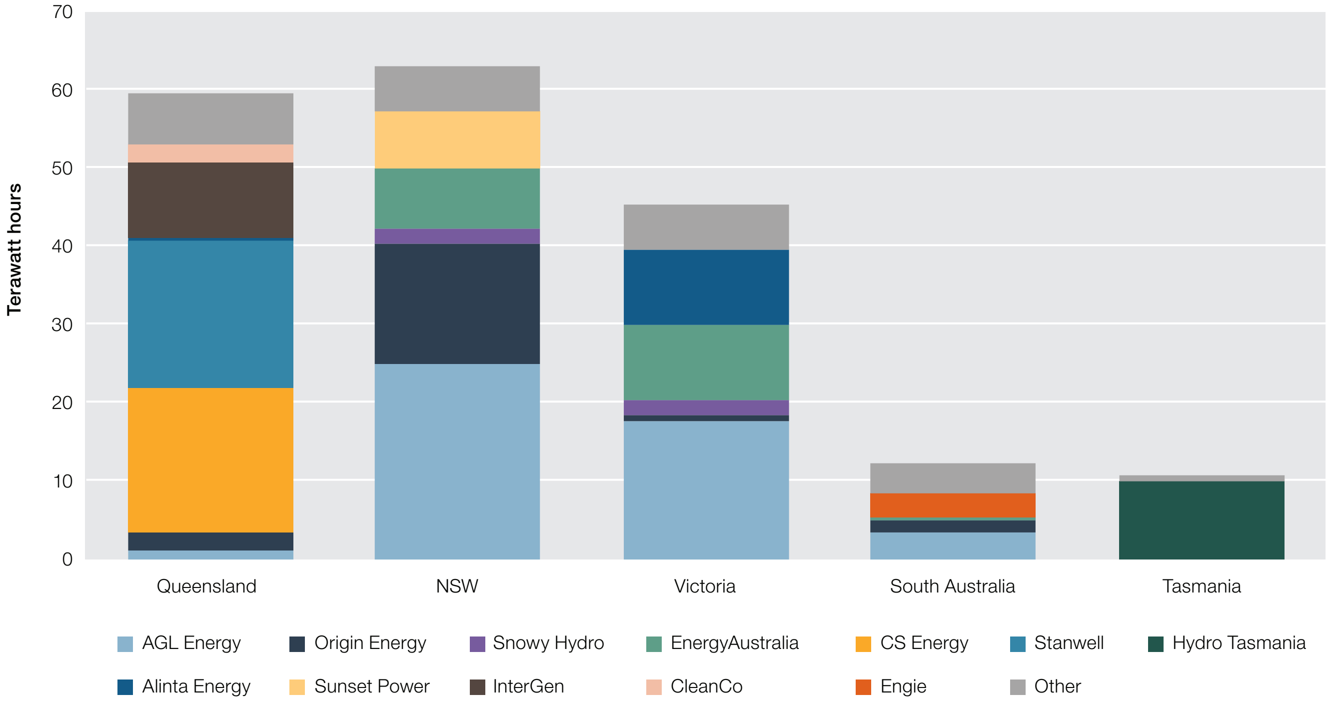
Figure 2.13 Market shares in generation capacity



Note: Generation capacity based on registered capacity of market scheduled and semi-scheduled generators at 31 January 2021. Market shares are attributed to the owner of the plant or the intermediary (should one be declared to AEMO).

Source: AER; AEMO.

Figure 2.14 Market shares in generation output



Note: Output in 2020. Market shares are attributed to the owner of the plant or the intermediary (should one be declared to AEMO). Output is split on a pro rata basis if the owner or intermediary changed in 2020. Data exclude output from rooftop solar PV systems and interconnectors.

Source: AER; AEMO; company announcements.

2.4.2 Vertical integration

While governments structurally separated the energy supply industry in the 1990s, many retailers later reintegrated with generators, forming 'gentailers' with portfolios in both generation and retail. Vertical integration allows generators and retailers to insure internally against price risk in the wholesale market, reducing their need to participate in hedge (contract) markets. But the reduced participation in contract markets reduces liquidity in those markets, posing a potential barrier to entry and expansion for generators and retailers that are not vertically integrated.

Vertical integration has become the primary business structure for large electricity retailers in the NEM. In 2020 the 4 largest vertically integrated participants in each region accounted for the majority of generation output and supplied more than half of retail load. Across the NEM 3 retailers – AGL Energy, Origin Energy and EnergyAustralia – supply 44% of retail load and electricity generation.

Second tier retailers – Red Energy and Lumo Energy (Snowy Hydro), Simply Energy (Engie) and Alinta – also own major generation assets. These vertically integrated businesses supply a further 8% of retail load to customers across the NEM and supply 9% of generation output.

The retail and generation profiles of these vertically integrated businesses across the NEM vary significantly. AGL Energy and Alinta have larger generation portfolios, while EnergyAustralia and Engie have more balanced portfolios. Origin Energy and Snowy Hydro service a larger retail load than supplied by their generation fleet, but they also have a greater share of peaking generation which allows them to manage the risk of high prices.

A number of smaller retailers are also vertically integrated:

› Sunset Power and Shell Energy (formerly ERM Power) provide retail services to large customers across the NEM. Sunset Power owns the Vales Point black coal power station in NSW, and Shell Energy owns the gas fired Oakey Power station in Queensland.

› Powershop and Tango Energy each have a portfolio of wind and hydroelectric generation operated by their respective parent companies, Meridian Energy and Pacific Hydro.

› Momentum Energy is backed by Hydro Tasmania, which owns the vast majority of generation capacity in Tasmania.

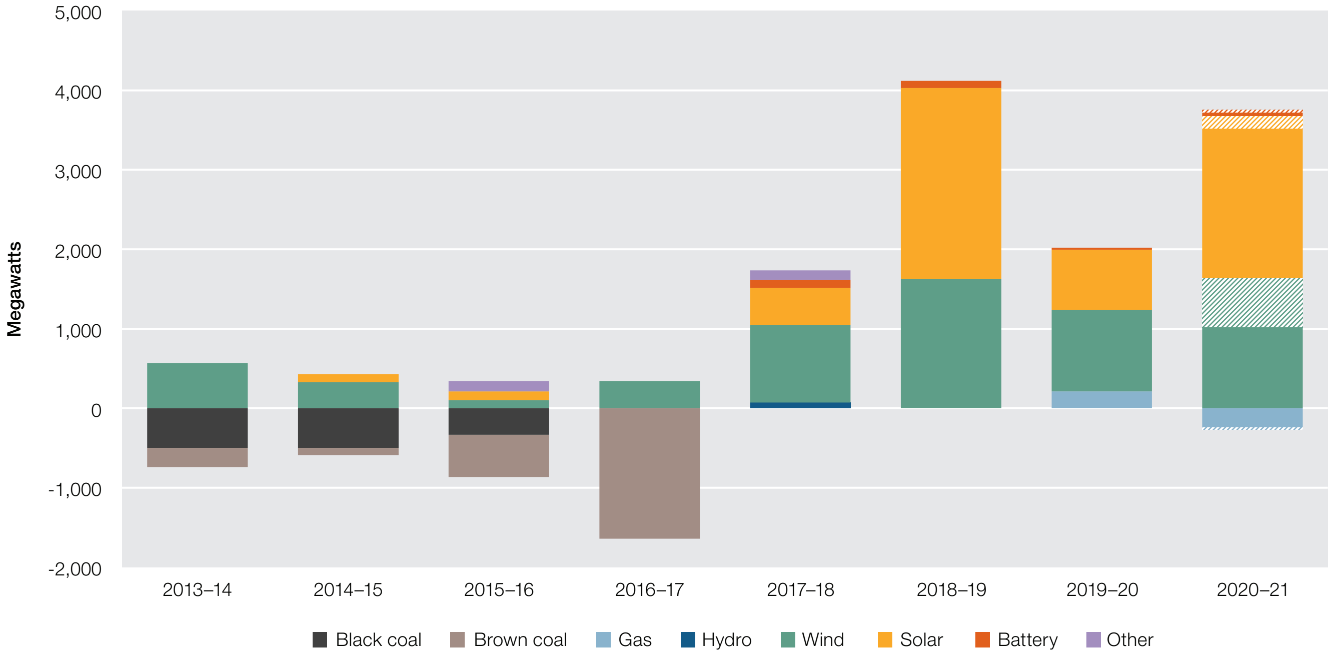
2.5 Generation investment and plant closures

Investment in generation plant outpaced the growth in electricity demand for several years, resulting in significant surplus capacity from around 2009 to 2015. In response, new investment slowed and some generators permanently or temporarily removed capacity from the market. While around 1,670 MW of new generation investment was added to the NEM in the 4 years to June 2017, over 3,800 MW of capacity was withdrawn over the same period (figure 2.15).

Plant closures were coal fired plant, following commercial decisions by owners to exit the market (section 1.1.3 in chapter 1). These ageing plants had become increasingly unprofitable, partly as a result of rising maintenance costs. The Wallerawang plant in NSW closed after 38 years of operation; the Northern and Playford plants in South Australia closed after 31 and 55 years of operation respectively; and the Hazelwood power station in Victoria closed after 53 years.

A further two plants have also recently retired or are in the process of retiring – AGL's Torrens Island A (480 MW) gas plant in South Australia (retiring progressively until 2022) and Stanwell's Mackay GT (34 MW) oil (formerly gas) plant in Queensland (retired in 2021).

Figure 2.15 New generation investment and plant withdrawals



Note: Capacity includes scheduled and semi-scheduled generation, but not non-scheduled or rooftop PV capacity. 2020–21 data are at 31 March 2021. Investment and closures expected between 1 April and 30 June 2021 are shown as shaded components.

Source: AER; AEMO (data).

The plant closures significantly reduced capacity in the NEM and led to AEMO signalling risks of summer power outages. The private sector responded with significant investment in renewable generation, but investment in other technologies has been limited. The risks of investing in these technologies are significant in an environment of uncertainty about future technology costs, an unclear path for the exit of large incumbent generators, and demand uncertainty (particularly around large loads).[26] In January 2021 the Energy Security Board (ESB) reported widespread concern among stakeholders around policy uncertainty affecting incentives to invest.[27]

Barker Inlet (South Australia, 211 MW) is the NEM's first material addition of fossil fuel capacity since an upgrade to Eraring in 2012. The gas plant was commissioned to replace capacity lost by the retirement of Torrens Island A.

Over 90% of generation investment since 2012–13 has been in renewable (wind and solar) capacity, partly driven by RET scheme subsidies and ARENA and CEFC funding. Investment in renewables picked up strongly after the Australian Government confirmed in 2015 the RET scheme would continue until 2030. Over 10,400 MW of new wind, solar and battery capacity was added to the NEM from July 2017 to March 2021 (figure 2.15). The majority of new investment since January 2020 has been located in NSW (1,891 MW) and Victoria (1,409 MW) (table 2.2). More than 1,400 MW of capacity is committed to come online by the end of 2021 (table 2.3).

26 AER, *Wholesale electricity market performance report*, December 2020.

27 ESB, *Post 2025 market design directions paper*, January 2021, p 6.

Table 2.2 New generation investment, January 2020 – March 2021

OWNER	POWER STATION	TECHNOLOGY	CAPACITY (MW)	FIRST DISPATCH DATE
QUEENSLAND			**108**	
University Of Queensland	Warwick	Solar	78	September 2020
Capricorn	Middlemount	Solar	30	December 2020
NSW			**1,891**	
Goonumbla Asset	Goonumbla	Solar	85	May 2020
New Gullen Range Wind Farm	Gullen Range 2	Wind	110	June 2020
Limondale Sun Farm	Limondale	Solar	275	July 2020
Darlington Point Solar Farm	Darlington Point	Solar	324	September 2020
RATCH Australia	Collector	Wind	226	November 2020
Sunraysia Solar Project	Sunraysia	Solar	228	November 2020
Molong Property	Molong	Solar	36	November 2020
Lightsource Australia SPV 4	Wellington	Solar	216	November 2020
CRWF Nominees	Crudine Ridge	Wind	141	December 2020
BWF Nominees	Bango 973	Wind	159	January 2021
Genex Power	Jemalong	Solar	55	February 2021
Corowa Operationsco	Corowa	Solar	36	March 2021
VICTORIA			**1,419**	
Northleaf/Infrared/Maquarie Capital	Elaine	Wind	84	April 2020
Cherry Tree	Cherry Tree	Wind	58	May 2020
Bulgana Wind Farm	Bulgana	Wind	182	May 2020
KSF Project Nominees	Kiamal	Solar	239	September 2020
Moorabool Wind Farm Interface	Moorabool	Wind	312	November 2020
Glenrowan Sun Farm	Genrowan West	Solar	132	December 2020
Yatpool Sun Farm	Yatpool	Solar	94	December 2020
Berrybank Development	Berrybank	Wind	180	February 2021
Winton Asset	Winton	Solar	107	March 2021
Cohuna Solar Farm	Cohuna	Solar	31	March 2021
SOUTH AUSTRALIA			**50**	
Neon	Hornsdale upgrade	Battery	50	September 2020

MW: megawatts.

Source: AER; AEMO, Generation information March 2021.

Table 2.3 Committed investment projects in the National Electricity Market at May 2021

OWNER	POWER STATION	TECHNOLOGY	CAPACITY (MW)	PLANNED COMMISSIONING
QUEENSLAND			**891**	
Shell	Gangarri	Solar	120	June 2021
Windlab / Eurus	Kennedy Energy Park – Phase 1	Solar	15	July 2021
Windlab / Eurus	Kennedy Energy Park – Phase 1	Wind	43	July 2021
The University of Queensland	Warwick	Solar	63	December 2021
Western Downs Green Power Hub	Western Downs	Solar	400	March 2022
Genex Power Ltd	Kidston	Pumped hydro	250	February 2025
NSW			**2,697**	
METKA EGN Australia	Junee	Solar	36	June 2021
Wagga Wagga Operationsco	Wagga North	Solar	36	June 2021
Genex Power	Jemalong	Solar	55	September 2021
BWF Nominees	Bango 999	Wind	85	December 2021
Limondale Sun Farm	Limondale	Solar	220	January 2022
Sebastopol Asset	Sebastopol	Solar	90	April 2022
FRV Services Australia	Metz	Solar	135	April 2022
Snowy Hydro	Snowy 2.0	Pumped hydro	2,040	December 2026
VICTORIA			**664**	
Cohuna Solar Farm	Cohuna	Solar	31	June 2021
Winton Asset Co	Winton	Solar	85	June 2021
Bulgana Wind Farm	Bulgana green power hub	Battery	20	September 2021
Stockyard Hill Wind Farm	Stockyard Hill	Wind	528	November 2021
Neoen	Victorian Big Battery	Battery	300	December 2021
Murra Warra Project	Murra Warra – stage 2	Wind	209	July 2022
SOUTH AUSTRALIA			**399**	
South Australian Water Corporation	Adelaide desalination plant	Solar	11	June 2021
South Australian Water Corporation	Adelaide desalination plant	Battery	13	June 2021
Lincoln Gap Wind Farm	Lincoln Gap	Wind	86	February 2022
Iberdrola Renewables Australia	Port Augusta renewable energy park	Solar	79	March 2022
Iberdrola Renewables Australia	Port Augusta renewable energy park	Wind	210	March 2022

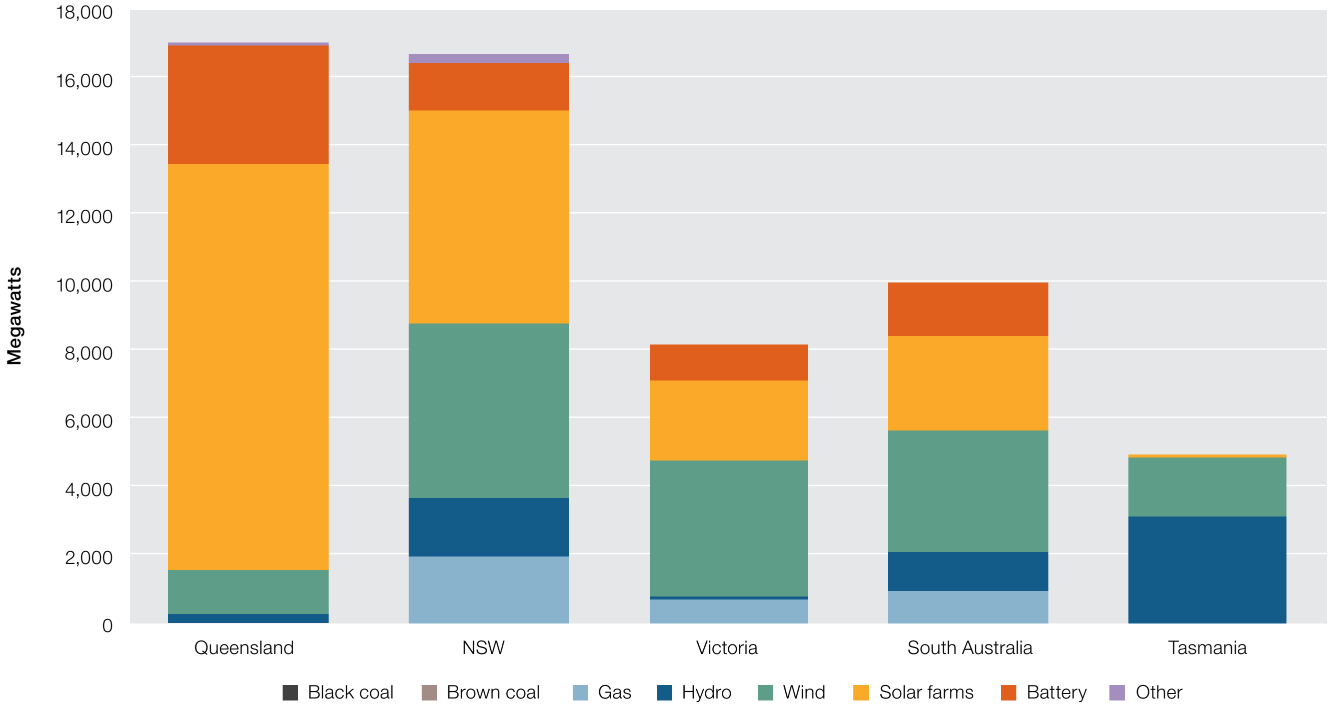
MW: megawatts.

Source: AER; AEMO, Generation information, May 2021.

Around 56,500 MW of additional capacity is proposed but not formally committed (figure 2.16). The bulk of proposed projects are in solar (41%) and wind (28%) plant. Battery storage (13%), hydro capacity (11%) and gas plant (6%) account for the remaining proposals.

Offsetting new capacity, further fossil fuel plant withdrawals are expected (figure 1.4 in chapter 1). The next major planned retirement is of AGL Energy's Liddell coal plant in NSW (2,000 MW) in stages over 2022 and 2023. A further 12,600 MW of coal fired generation is expected to retire between 2028 and 2038.

Figure 2.16 Announced generation proposals at January 2021



Source: AEMO, Generation information January 2021.

2.6 Wholesale prices and activity

Wholesale electricity prices tend move in seasonal cycles linked to the weather. Prices tend to rise in the fourth calendar quarter (October–December) as the weather warms up, then peak in the first quarter, when summer demand for air conditioning is highest, before easing in the cooler second and third quarters.

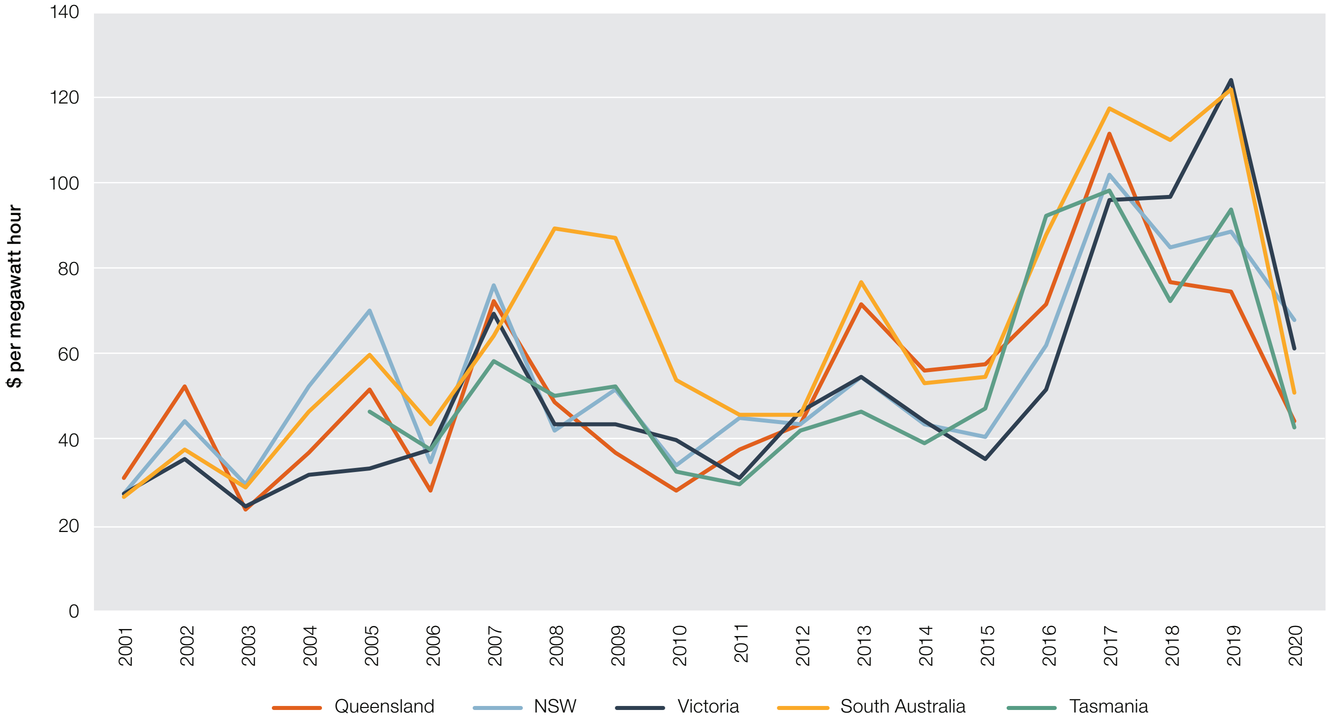
Alongside this seasonal pattern, longer term trends show an upward movement in prices for several years, followed by a sharp reduction in 2020 (figure 2.17). Rising fuel input costs and the closure of 2 brown coal power stations – Northern (South Australia) in May 2016 and Hazelwood (Victoria) in March 2017 – contributed to price rises from 2016. The Hazelwood closure withdrew around 5% of the NEM's total capacity, much of it usually offered at low prices. From that point, more expensive black coal and gas plant began to set spot prices more often at a time when coal and gas input costs were rising.[28] Between July 2015 and July 2017 the average offer price for the cheapest 20,000 MW of capacity in the NEM increased from $50 per megawatt hour (MWh) to almost $100 per MWh. Prices generally remained elevated from 2017 to 2019. Over 2020 and early 2021 changed supply and demand conditions drove prices lower across all NEM regions.

Queensland prices followed a different trend. In June 2017 the Queensland Government directed the state-owned generation business, Stanwell, to put downward pressure on wholesale electricity prices.[29] The state moved from having some of the highest average prices in the NEM to generally having one of the lowest average prices. The government direction remained in place until 30 June 2019, and in 2020 Queensland continues to have some of the lowest average prices in the NEM.

28 AER, *Electricity wholesale performance monitoring – Hazelwood advice*, March 2018.

29 Queensland Government, *Stabilising electricity prices for Queensland consumers*, June 2017.

Figure 2.17 Wholesale electricity prices



Note: Volume weighted annual averages.
Source: AER; AEMO (data).

2.6.1 The market from 2020

The following is a high level summary of market conditions from 2020. The AER's *Wholesale markets quarterly* reports analyse price trends and underlying causes in more detail.

In 2020 wholesale prices across the NEM (on a volume weighted average basis) were below $70 per MWh in all regions for the first time since 2015. Prices were significantly lower than in recent years (figures 2.17 and 2.18):

› NSW ($68 per MWh) was the NEM's highest price region for the first time since 2007 despite its average falling 23% from 2019. Average prices were affected by price spikes in January, November and December caused by generator and transmission outages, rebidding and higher than forecast demand.

› Tasmania ($43 per MWh) edged out Queensland ($44 per MWh) as the NEM's lowest price region. Tasmania recorded a 54% year on year fall in spot prices after recording a 30% rise in 2019.

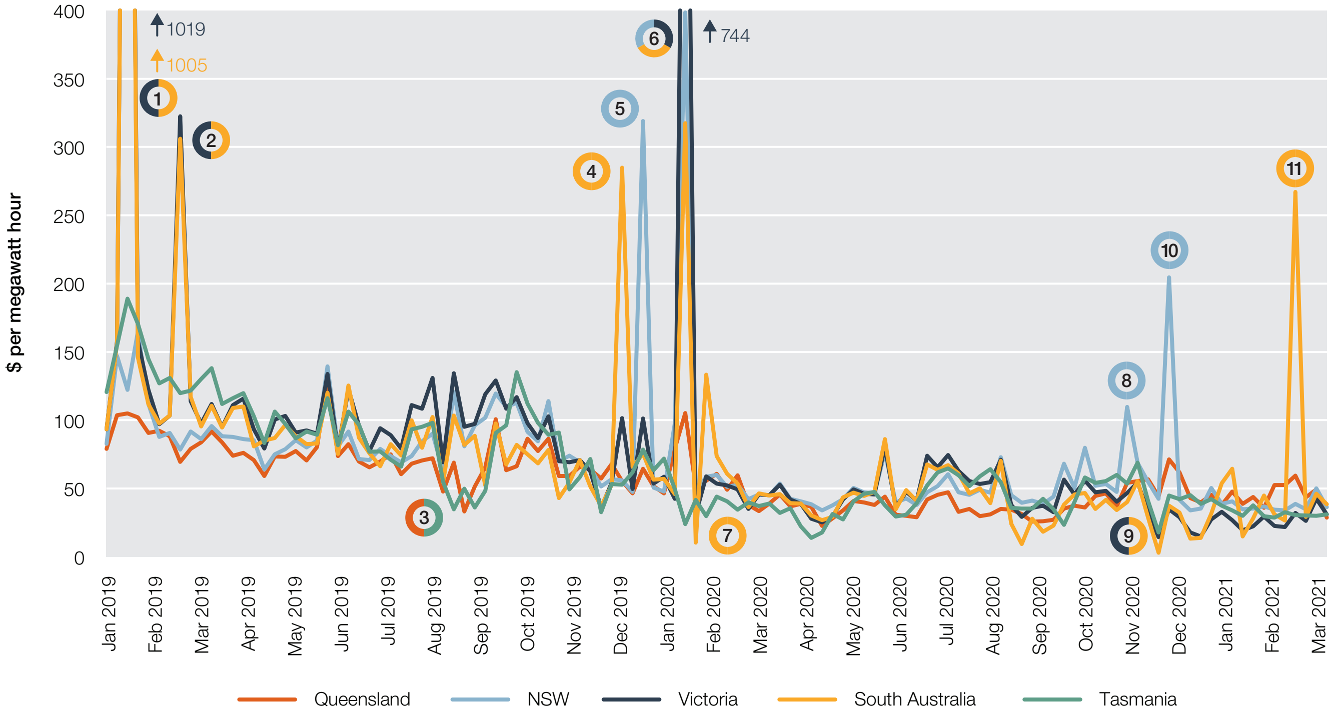
› South Australia ($51 per MWh) recorded the biggest percentage drop in its average, falling 58% from the 2019 record high of over $120 per MWh. The 2020 average was the lowest recorded for that state since 2012 and followed 4 years of relatively high prices since the 2016 closure of the region's last brown coal generator, Northern.

› After 3 successive years of rising spot prices Victoria ($62 per MWh) halved its record 2019 average ($124 per MWh). Despite the fall, Victoria's average was still higher than its 2016 average ($52 per MWh) before the Hazelwood power station closed.

Changed supply conditions were a key driver of these lower prices. Increased capacity from wind and solar generators and falling coal and gas fuel input costs through to late 2020 all contributed to generators offering more capacity at lower prices. Low demand driven by comparatively milder weather conditions and increased rooftop solar PV uptake also contributed.

The falls in calendar year average prices reflect a downward trend in spot prices across the year. All regions except NSW recorded lower average prices across all 4 quarters of 2020 than in the equivalent quarter of the previous year. NSW recorded a slightly higher average for the first quarter of 2020 compared with 2019 but lower averages for the remaining 3 quarters.

Figure 2.18 Wholesale electricity prices – volume weighted weekly averages



1. High temperatures led to high demand in Victoria and South Australia and load shedding in Victoria. Exacerbated by a plant outage in Victoria.
2. High temperatures led to high demand in Victoria and South Australia at a time of low wind output.
3. Record low demand and an increase in solar output drove negative prices in Queensland during the middle of the day. High Hydro output in Tasmania.
4. High temperatures drove demand close to record levels. This coincided with limited import capacity on the Murraylink interconnector and calm wind conditions.
5. Bushfires led to Victoria – NSW interconnection being disrupted amid high demand.
6. Extreme storm conditions led to South Australia being isolated from the NEM. Victoria and NSW faced tight supply conditions and high demand driven by high temperatures. Another price event occurred in South Australia and Victoria due to high demand, low wind generation and a plant outage.
7. South Australia unable to export energy due to ongoing interconnector disruptions resulted in excess supply.
8. Network and generation outages (planned and unplanned) limited availability of low priced generation. High demand conditions and generator rebidding contributed to a second price event.
9. Mild temperatures, record output from rooftop solar and high large scale renewable generation drove a record number of negative prices, resulting in the lowest average weekly price in South Australia ($3 per MWh) and the second lowest in Victoria ($14 per MWh).
10. High demand coincided with reduced supply (driven by planned outages and technical issues). Imports from Queensland were limited due to lightning constraining the interconnector.
11. Switchyard equipment failure resulted in the trip of Barker Inlet power station. Generation issues throughout the evening coincided with reduced import capacity from Victoria due to transmission works.

Note: Volume weighted weekly averages.

Source: AER; AEMO (data).

Average prices were elevated in the first quarter compared with the rest of 2020 but still significantly lower than those experienced during first quarters in recent years. Prices averaged below $110 per MWh in all regions for the first time since 2015 (figure 2.19).

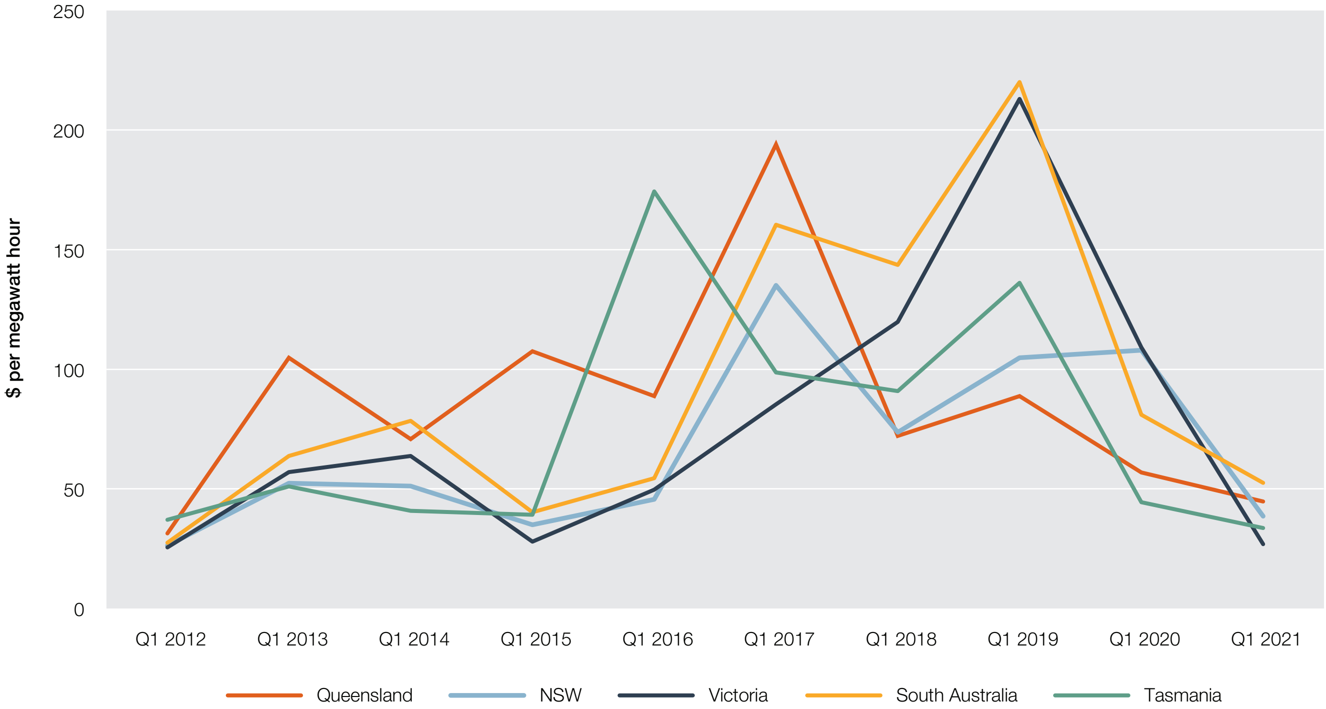
NSW, along with Victoria and South Australia, had higher average prices than elsewhere in the NEM, driven by a number of high price events. During January 2020 NSW and Victoria both experienced 11 trading intervals of prices exceeding $5,000 per MWh, while South Australia experienced 3.

High demand and network outages due to bushfires led to prices in NSW exceeding $5,000 per MWh for 5 trading intervals on 4 January 2020.[30] Victoria and South Australia both experienced a further 2 trading intervals of prices exceeding $5,000 per MWh on 30 January, when demand was higher than forecast and supply was lower than expected due to unplanned generator outages and lower than forecast wind.[31]

30 AER, *Electricity spot prices above $5000/MWh, New South Wales, 4 January 2020*, February 2020.

31 AER, *Electricity spot prices above $5000/MWh, South Australia and Victoria, 30 January 2020*, March 2020.

Figure 2.19 First quarter wholesale electricity prices



Note: Volume weighted quarterly averages.
Source: AER; AEMO (data).

The remaining 16 high price events occurred across 10 trading intervals on 31 January. Prices exceeded $5,000 per MWh in Victoria (9 instances), NSW (6 instances) and South Australia (1 instance). Several factors contributed. Extreme storms caused the collapse of 6 transmission towers in Victoria and led to South Australia being electrically isolated from the rest of the market. AEMO limited the output of several generators to manage the line outage, which resulted in high prices in South Australia. In addition to the network outage, high demand from hot weather and reduced supply due to technical plant issues drove prices higher in NSW and Victoria.[32]

Wholesale prices remained significantly lower in the second quarter of 2020 compared with the same quarter for the previous 4 years. Across the NEM prices averaged between $32 per MWh (Tasmania) and $45 per MWh (NSW). Milder weather conditions, an increase in rooftop solar PV generation and the impact of the COVID-19 pandemic led to lower grid demand during the quarter. There was also more capacity offered at lower prices. Generators across the NEM offered almost 20% more capacity priced below $50 per MWh than a year earlier. Coal generators were responsible for much of the increase, offering an additional 2,000 MW, followed by hydro (900 MW), renewables (500 MW) and gas (400 MW).

Low demand contributed to prices remaining low through the third quarter of 2020. Low demand combined with transfer limits on the Queensland and South Australian interconnectors resulted in a record number of negative prices. There were 47% more negative prices in the third quarter of 2020 than for the same period in 2019. In South Australia spot prices were negative for more than 10% of the time – the highest count ever in any region.

NSW and Queensland prices increased slightly during the fourth quarter but were still significantly lower than in recent years. The quarter on quarter price increase was a function of warmer weather and network and generator outages. Queensland experienced its second warmest November on record, and in December 2020 most of the state experienced heatwave conditions. Higher air conditioning load increased demand for energy and pushed up prices.

32 AER, *Electricity spot prices above $5000/MWh, South Australia, Victoria and New South Wales, 31 January 2020*, March 2020.

The spot price exceeded $5,000 per MWh in NSW on 5 occasions across 3 days of high demand in November and December. On each occasion, a number of coal generators were unavailable due to planned and unplanned outages. Network outages also contributed to the tight supply–demand balance:

- On 16 November lightning led to an unplanned outage of transmission lines in southern NSW, restricting access to generation from Victoria and southern NSW. Access to lower priced capacity in NSW was further limited by works to upgrade the interconnector between Queensland and NSW.[33]
- On 20 November access to lower priced capacity was again limited by planned transmission line upgrades. Higher than forecast demand and erroneous rebidding of Origin Energy's Eraring power station also contributed to the high price event.[34]
- On 17 December the spot price exceeded $5,000 per MWh in NSW on 3 occasions. Access to generation from Queensland was limited due to lightning around the transmission interconnector between the 2 regions. The tight supply–demand balance and associated reliability and security concerns led AEMO to issue lack of reserve notices and activating the RERT to contract off-market capacity (section 2.9.1).[35]

In South Australia and Victoria, mild temperatures and record high rooftop PV solar generation led to continued low demand conditions in the fourth quarter of 2020. Both states recorded their lowest ever minimum demand, with daily minimum demand in South Australia falling below the previous record 9 times during the quarter. The combination of low demand and cheap renewable generation again led to a record number of negative prices.

2.6.2 The market in early 2021

Prices remained low in 2021, when first quarter prices fell to their lowest average since 2011 in Tasmania, 2012 in Queensland and Victoria, and 2015 in NSW and South Australia. Notably, first quarter prices were below $60 per MWh in all regions for the first time since 2012, with prices ranging between $27 per MWh (Victoria) and $53 per MWh (South Australia).[36]

Low grid demand contributed to low prices, with the NEM experiencing unusually mild summer conditions and high levels of rooftop solar PV generation. A high number of negative prices in Victoria and South Australia were recorded during the quarter, with the majority of these instances occurring during daytime hours.

Relatively low cost brown coal, wind and solar generation also increased output during the quarter, squeezing out gas and black coal generation. Brown coal offered more capacity than in any quarter since the Hazelwood power station closed in 2017.

Spot prices exceeded $5,000 per MWh on only 2 occasions during the quarter. On 22 January prices spiked in South Australia at 4 am when the Pelican Point power station tripped and imports from Victoria were reduced to protect the stability of the power system. The spot price again exceeded $5,000 per MWh in South Australia on 12 March when a fire in the Torrens Island power station switchyard disconnected the Barker Inlet power stations and limited output of the Torrens Island B power station. Low wind generation and a planned outage of transmission lines in Victoria further restricted South Australia's access to lower cost generation.[37]

Beyond these events, instances of high spot prices during the quarter were relatively rare, with the NEM recording the lowest number of prices above $300 per MWh for a first quarter since 2012 (45 occasions). The majority were in Queensland (18 occasions) and South Australia (20 occasions), while Tasmania recorded the remaining 7 instances. NSW and Victoria did not record any instances of prices above $300 per MWh.

33 AER, *Electricity spot prices above $5000/MWh, New South Wales, 16 November 2020*, January 2021.

34 AER, *Electricity spot prices above $5000/MWh, New South Wales, 20 November 2020*, January 2021.

35 AER, *Electricity spot prices above $5000/MWh, New South Wales, 17 December 2020*, February 2021.

36 All prices are volume weighted averages.

37 AER, *Electricity spot prices above $5,000/MWh South Australia, 12 March 2021*, 12 May 2021.

2.6.3 Generator fuel costs

Upstream black coal and gas market conditions can affect fuel costs for generators. While black coal generators do not pay international prices for all of their coal supply, the international price can be an important factor. In NSW in particular it can shape prices for short term supply contracts and when long term contracts are renegotiated. In other regions, like Queensland, it can be a less important factor. For those where it is relevant, the international price generally reflects a generator's theoretical maximum cost of some of their coal. Gas generators are likely to value their fuel at the prevailing gas market price when deciding whether to generate.

The international export price for black coal was elevated over 2017 but eased significantly from mid-2018 through to late 2020. Black coal prices hovered around $60 per MWh for several months from June 2018, then steadily declined to below $30 per MWh for several months from June 2020. Coal prices began rising from late 2020 and were over $50 per MWh by March 2021 (figure 2.20).

From late 2016 to early 2018 black coal generators increased their offer prices beyond levels explained by rises in international coal prices. Prices set by black coal generators in NSW increased from around $40 per MWh in 2016 to a peak of over $130 per MWh in February 2017. A range of factors contributed including short term coal supply issues and stockpile management.[38] From 2018 the average price set by NSW black coal generators trended down, in line with falls in the international coal prices and improvements in supply issues, to around $40 per MWh for much of 2020.[39]

In early 2021 the average price set by NSW coal generators remained at these lower levels despite an increase in international export coal prices. This may be due to generators' contract positions or because low demand reduced the need for higher priced coal capacity.[40]

Fuel costs for gas plant also lowered from late 2019. Taking South Australia as an example, fuel costs for gas plant eased from around $80 per MWh in January 2019 to around $60 late in the year (figure 2.21). Over this time, the average price set by gas generators in the region generally trended downwards at a similar rate. Summer 2019–20 was an exception – bushfires and high temperatures allowed generators to set some prices above $5,000 per MWh. And in September 2020 the price set by South Australian gas generators fell significantly below gas market costs to just $22 per MWh. Gas fired generators may offer capacity below the gas market input cost to cover contract commitments or retail loads.

In late 2020 record LNG demand driven by a spike in international LNG prices put upward pressure on domestic gas prices. This led to an increase in gas market fuel costs and directly impacted the price set by South Australian gas generators.[41] However, lower gas demand for electricity generation in the southern states meant that, despite rising gas costs, the price set by gas powered generation actually fell across the fourth quarter and remained low into the first quarter of 2021. Individual high price events in the NEM caused a divergence between electricity and gas prices in NSW in the fourth quarter of 2020 and in South Australia in the first quarter of 2021. And in the first quarter of 2021 the price set by Queensland gas generators rose to over $70 per MWh due to higher than average temperatures.

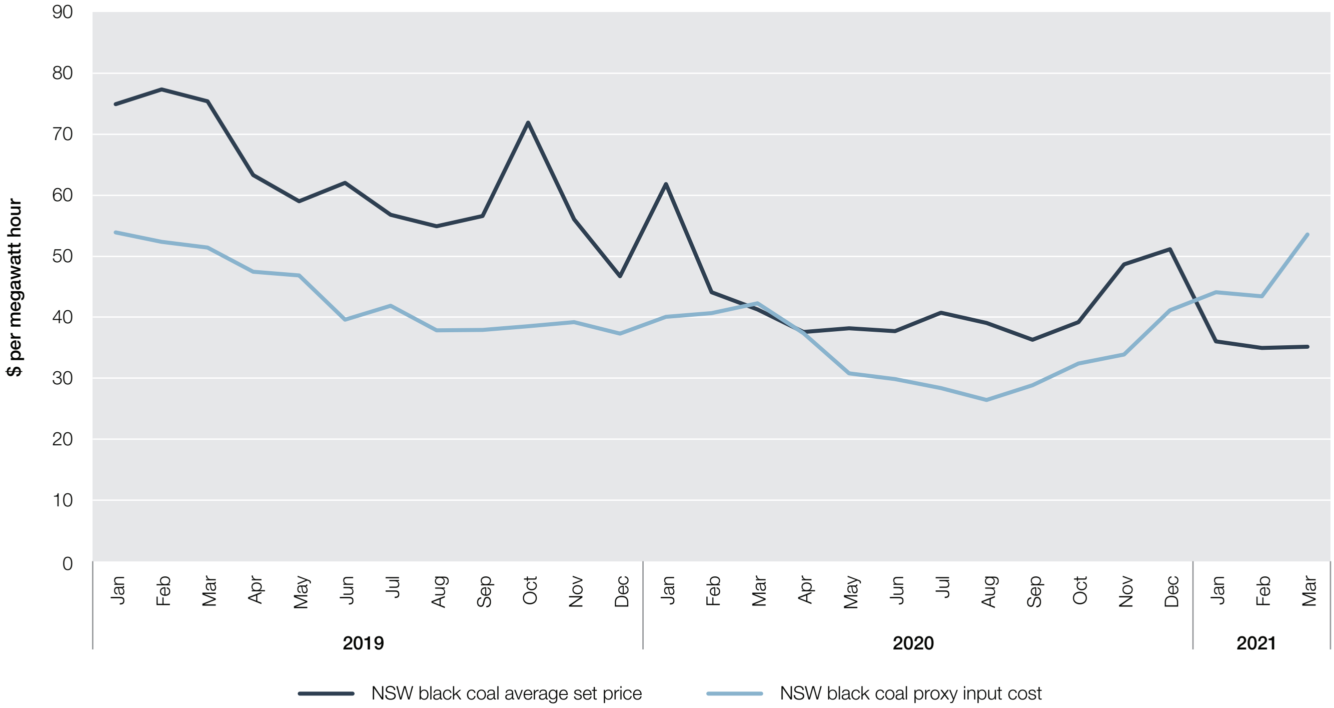
38 AER, *Wholesale electricity market performance report – 2018*, December 2018.

39 AER, *Wholesale electricity market performance report – 2020*, December 2020.

40 AER, *Wholesale markets quarterly – Q1 2021*, May 2021.

41 AER, *Wholesale markets quarterly – Q4 2020*, February 2021.

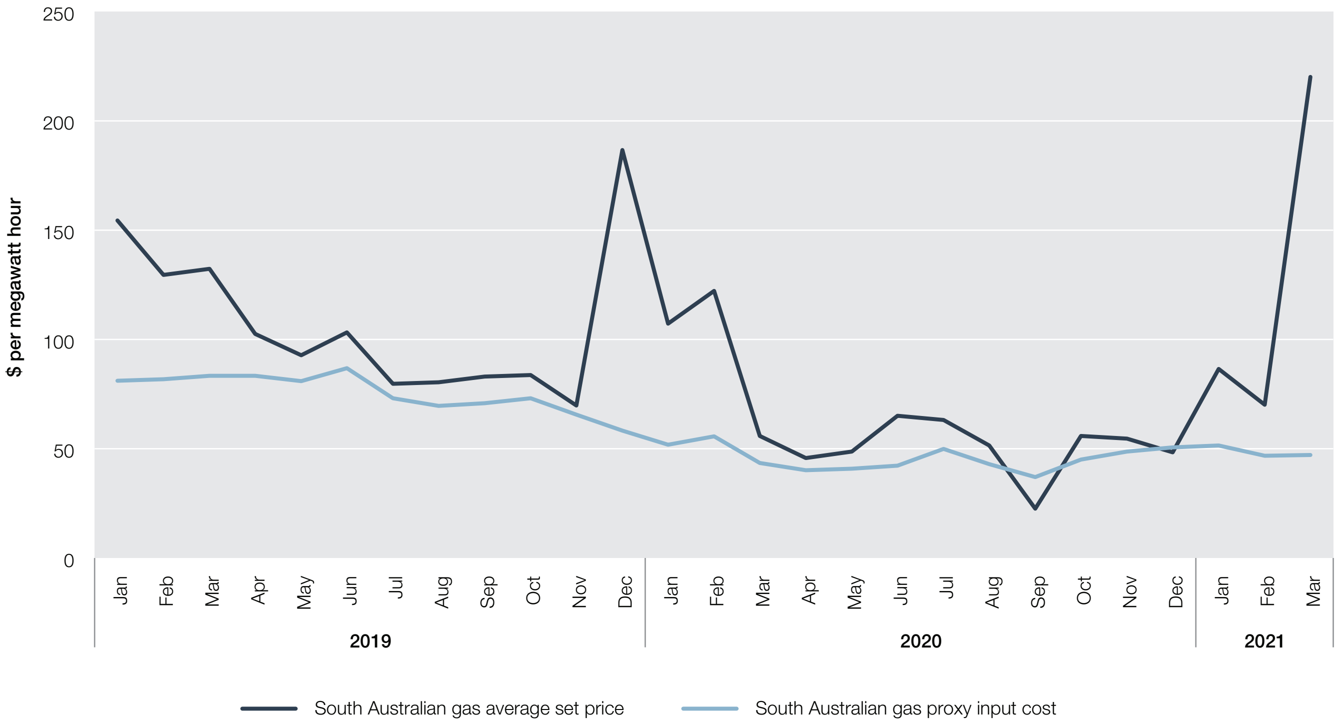
Figure 2.20 Black coal fuel costs, NSW



Note: The international reference price for Newcastle spot thermal coal and the average monthly price when black coal generators set the price in NSW. The black coal input cost is derived from the Newcastle coal index (US$ per tonne), converted to A$ per MWh with the Reserve Bank of Australia exchange rate, and the average heat rate for coal generators.

Source: AER analysis using NEM and globalCOAL data.

Figure 2.21 Gas fuel costs, Adelaide



Note: The Adelaide gas market price and the average monthly price when gas generators set the price in South Australia. The gas input cost is derived from the Adelaide short term trading market (STTM) price (A$ per GJ), converted to A$ per MWh, and the average heat rate for gas generators.

Source: AER analysis using NEM and gas price data.

2.6.4 Renewable output

Another factor driving lower prices is the increased renewable output from the recent influx of new wind and solar plant in the market. Over 2020, 1,705 MW of wind capacity entered the market, of which more than half was installed in Victoria. Over the same period, more than 2,000 MW of grid scale solar capacity entered the market, mostly in NSW.

Wind generation in 2020 was around 16% higher than in 2019. In the fourth quarter of 2020, Victoria experienced record levels of wind generation. Additionally, with lower levels of demand, wind output exceeded gas generation NEM-wide for the first time across 2020.

Similarly, solar output reached record levels in 2020 and continues to grow. In the first quarter of 2021, large scale solar generation had the highest quarterly output on record – up 42% from a year previous.

Hydro generation across the NEM also increased slightly in 2020, up by 4% compared with 2019.

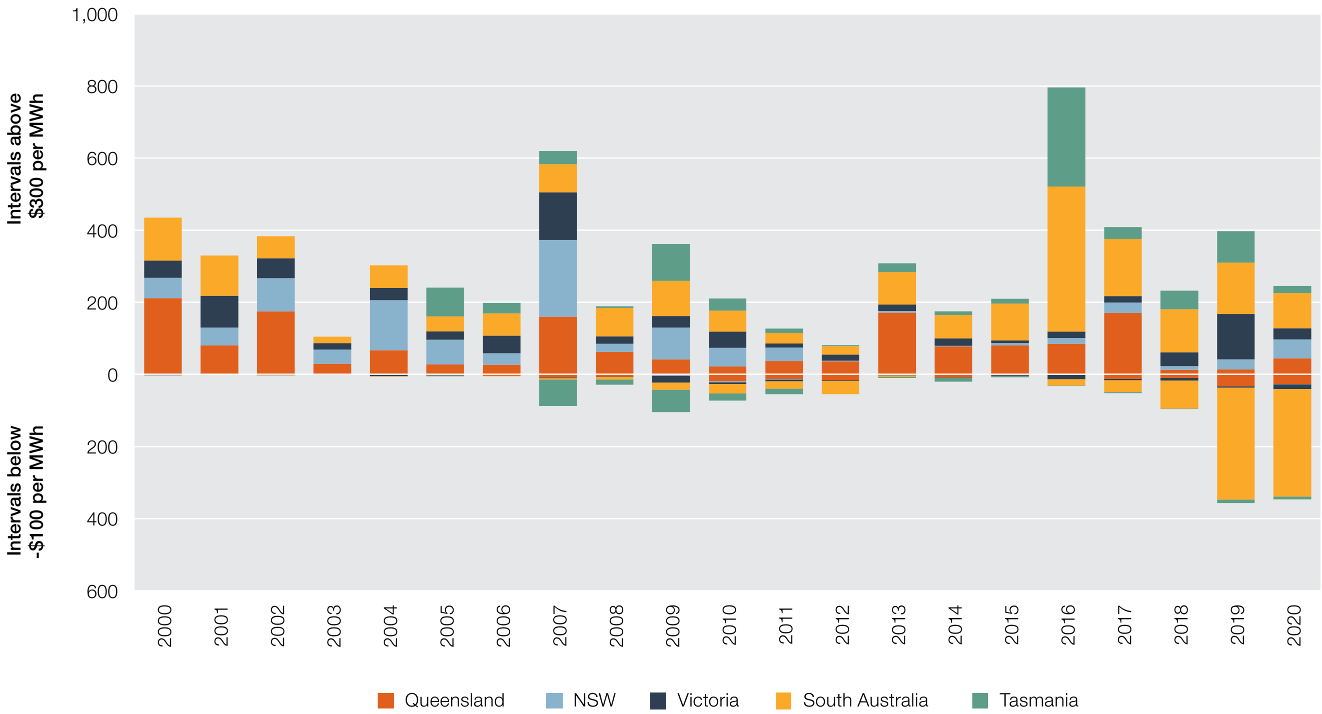
This growth in renewable output is contributing to higher instances of negative prices than ever before (section 2.6.5).

2.6.5 Price volatility

Spot price volatility is a natural feature of energy markets and can signal to the market a need for investment in new generation (figure 2.22). Record price volatility occurred in 2016, with 796 instances of spot prices over $300 per MWh. There has since been a marked reduction in the number of high priced trading intervals, but outcomes in 2017 and 2019 were still above the long term average.

Volatility was down in 2020, with 245 trading intervals exceeding $300 per MWh in 2020 (compared with 397 in 2019). Much of the volatility in 2019 occurred in Victoria, South Australia and Tasmania and was associated with extreme weather and high system demand early in the year, as well as generator outages in Victoria in mid-2019. Volatility observed in 2020 largely occurred in the first quarter, again linked to extreme summer weather. Bushfires and storms also impacted the market, causing transmission lines to trip and cut off available generation. At times, these events led to market separation between regions, as occurred between NSW and Victoria on 4 January 2020 and between Victoria and South Australia from 31 January to 17 February 2020. Spot prices hit the cap of $14,700 per MWh on multiple days during the bushfire period.

Figure 2.22 Prices above $300 per MWh and below –$100 per MWh



Source: AER; AEMO (data).

Negative prices

An aspect of market volatility that has emerged in recent years is a rising incidence of negative prices. Generators in the NEM can offer capacity as low as the market floor price of –$1,000 per MWh. Negative bids essentially signal a generator's willingness to pay to produce electricity rather than switch off. AEMO typically dispatches generators by using the lowest priced offers first, then working its way through the merit order until demand is met. Allowing generators to offer capacity at negative prices increases the chances of the generator being dispatched into the market.[42]

Generators may have various motivations to offer capacity at negative prices. As an example, it may be cost-effective for large baseload coal generators to offer large amounts of capacity at negative prices to ensure continuous operation and avoid the high costs of shutting down and then restarting a few hours later. Once generating, baseload plants generally have low operating costs.

A generator's hedge position in contract markets may also affect its bidding strategies. If a generator has a contract ahead of time that ensures a fixed price for electricity sold into the market, its exposure to negative prices may be minimal.

The ability of wind and solar generators to operate varies with prevailing weather conditions. These generators do not incur high startup or shutdown costs and have running costs close to zero. If generating conditions are optimal, they may bid capacity at negative prices to guarantee dispatch. Some wind and solar generators also source revenue from the sale of renewable energy certificates, so they may operate profitably even when wholesale prices are negative.

If electricity demand is low, the market has surplus capacity, and the chances of the market settling at a negative price are higher. The geographic grouping of renewable generators can intensify the effect because, when conditions are favourable for one generator in the area, conditions tend to be favourable for others too. With multiple generators of similar technology competing for dispatch, the likelihood of negative prices increases. Negative prices tended to occur when electricity demand was low and weather conditions were optimal for renewable generation. While historically occurring overnight, they are now more common during the day when solar resources are producing maximum output.[43]

The instances of negative spot prices increased markedly in the second half of 2019 and have continued that trend into 2020 (figure 2.23). In 2020 there was a record number of negative prices NEM-wide, with 3,662 instances of negative spot prices across the 5 regions. This result was over 3 times higher than 2016. Nearly half of all instances of negative prices in 2020 occurred in South Australia. South Australia has a high penetration of wind and solar (grid scale and rooftop PV) generation and instances of negative spot prices are highest when these units are generating (figure 2.24).

Over 40% (1,538) of negative prices in 2020 occurred in the fourth quarter, exceeding the previous quarterly record of the number of negative spot prices set in the third quarter of 2020. On 6 December 2020 prices reached a record low daily average of –$30 per MWh in Victoria, –$46 per MWh in South Australia and –$35 per MWh in Tasmania as a result of low demand and an excess of low priced wind and solar generation.[44]

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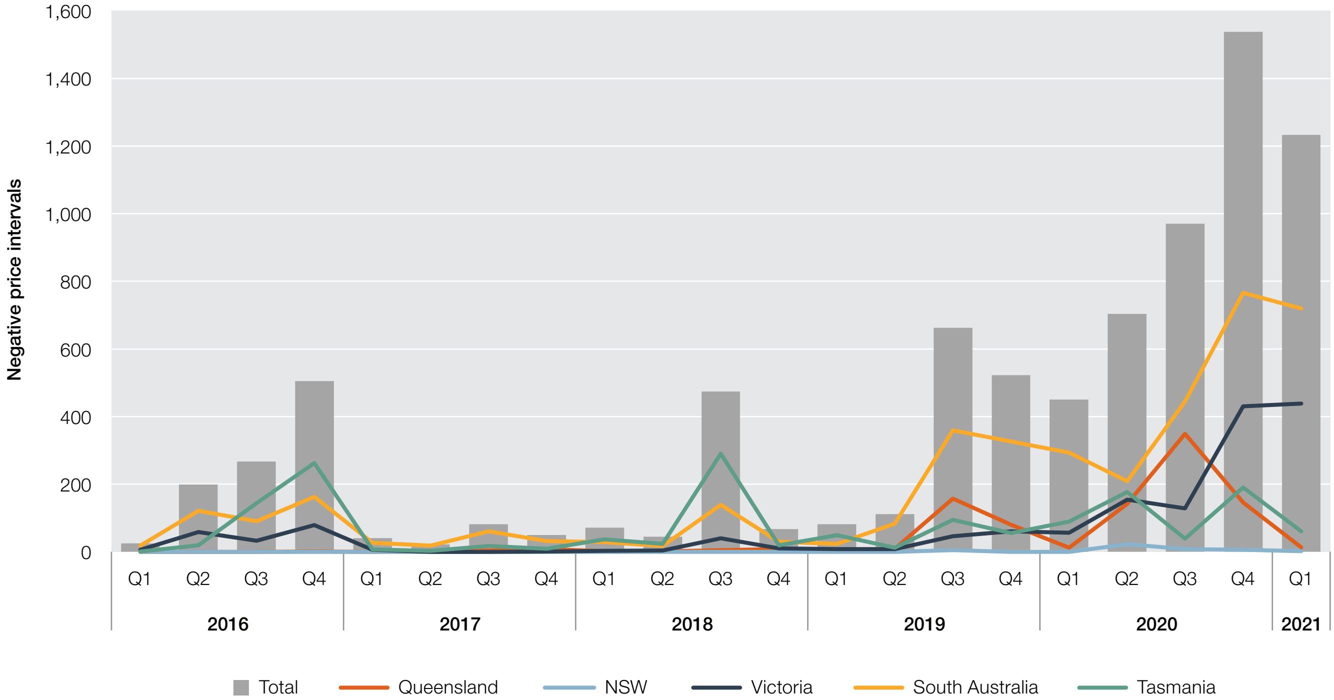
42 While a generator may offer capacity at negative prices, it does not necessarily mean the spot price will settle at a negative price. The dispatch price is determined by the marginal generator required to meet demand every 5 minutes. The spot price is determined every 30 minutes as the average of the 6 dispatch prices within that half hour.

43 AER, *Wholesale markets quarterly – Q3 2020*, November 2020.

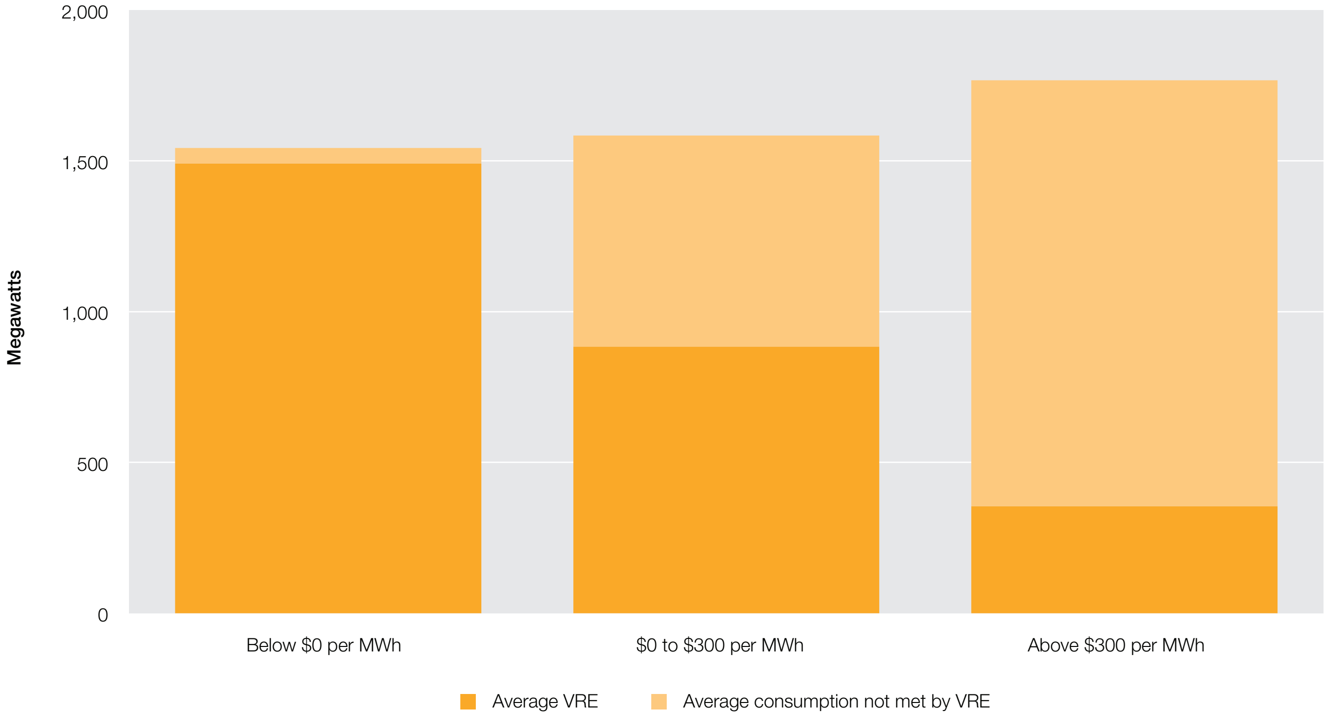
44 AER, *Wholesale markets quarterly – Q4 2020*, February 2021, p 6.

Figure 2.23 Negative spot price count



Source: AER; AEMO (data).

Figure 2.24 South Australia renewable generation and negative prices, 2019



MWh: megawatt hour; VRE: variable renewable energy.
Source: AER; AEMO (data).

2.7 Electricity contract markets

Futures (contract or derivatives) markets operate parallel to the wholesale electricity market. Prices in the wholesale market can be volatile, posing 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. A retailer may expand its operation and sign up a significant number of new customers at a particular price, only to then incur unexpectedly high prices in the wholesale market, ultimately leaving the retailer substantially out of pocket.

Generators and retailers can manage their market exposure by locking in prices for which they will trade electricity in the future. An alternative strategy adopted by some participants is to internally manage risk through vertical integration – that is, operating as both a generator and a retailer to balance the risks in each market.

Typically, vertically integrated 'gentailers' are imperfectly hedged – their position in generation may be 'short' (not enough generation) or 'long' (too much generation) relative to their retail position. For this reason, gentailers participate in contract markets to manage outstanding exposures, although usually to a lesser extent than standalone generators and retailers do. Vertically integrated gentailers in the NEM include AGL Energy, Origin Energy, EnergyAustralia, Snowy Hydro (with retail brands Red Energy and Lumo Energy), Engie (Simply Energy), Alinta Energy, Hydro Tasmania (Momentum), Meridian Energy (Powershop) and Pacific Hydro (Tango).

Alongside generators and retailers, participants in electricity contract markets include financial intermediaries and speculators, such as investment banks. Brokers often facilitate contracts between parties in these markets.

In Australia, 2 distinct financial markets support the wholesale electricity market:

- over-the-counter (OTC) markets, in which 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
- the exchange traded markets, in which electricity futures products are traded on the Australian Securities Exchange (ASX) or through FEX Global (FEX).[45] Participants include generators, retailers, speculators, banks and other financial intermediaries. Electricity futures products are available for Queensland, NSW, Victoria and South Australia.

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

- *Futures* contracts allow a party to lock in a fixed price (strike price) to buy or sell a given quantity of electricity at a specified time in the future. Each contract relates to a nominated time of day in a particular region. Available products include quarterly base contracts (covering all trading intervals) and peak contracts (covering specified times of generally high energy demand). Futures can also be traded as calendar or financial year strips covering all 4 quarters of a year. Futures contracts are settled against the average quarterly spot price in the relevant region – that is, when the spot price exceeds the strike price, the seller of the contract pays the purchaser the difference; and when the spot price is lower than the strike price, the purchaser pays the seller the difference. In OTC markets, futures are known as swaps or contracts for difference.
- *Caps* are contracts setting an upper limit on the price that a holder will pay for electricity in the future. Cap contracts on the ASX and FEX 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.
- *Floors* are contracts that operate on the opposite principle of a cap contract, because they set a lower price limit. They are typically purchased by generators to ensure a minimum level of revenue for output.
- *Options* are contracts that give the holder the right – without obligation – to enter a contract at an agreed price, volume and term in the future. The buyer pays a premium for this added flexibility. An option can be either a call option (giving the holder the right to buy the underlying financial product) or a put option (giving the holder the right to sell the underlying financial product). Options are available on futures and cap products.

While prices are publicly reported for exchange trades, activity in OTC markets is confidential and not disclosed publicly. The Australian Financial Markets Association (AFMA) reports data on OTC markets through voluntary surveys of market participants, providing some information on the trade of standard (or vanilla) OTC products such as swaps, caps and options.

45 FEX launched its futures exchange on 26 March 2021.

Exchange traded contracts are settled through a centralised clearing house, which acts as a counterparty to all transactions and requires daily cash margining to manage credit default risk. In OTC trading, parties rely on the creditworthiness of their counterparties.

Electricity derivatives markets are regulated under the *Corporations Act 2001* (Cth) and the *Financial Services Reform Act 2001* (Cth). The Australian Securities and Investments Commission is the principal regulatory agency.

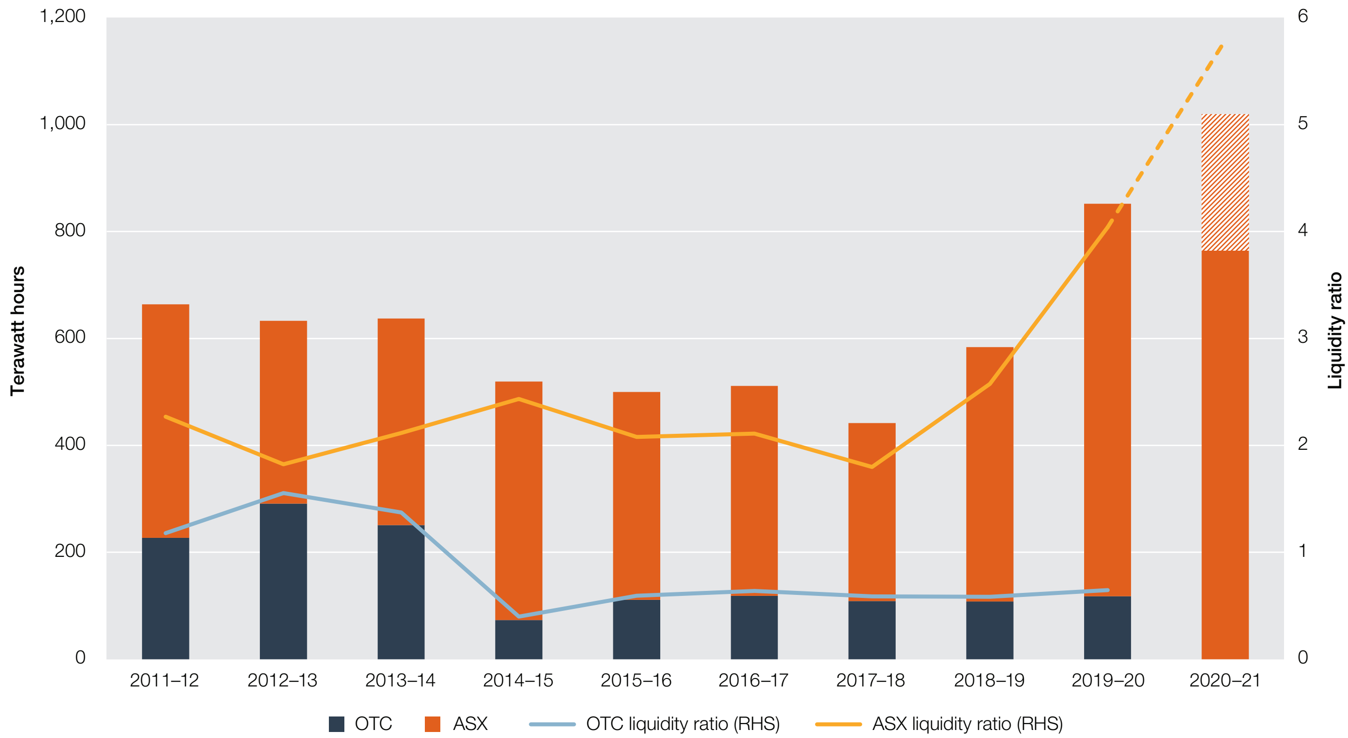
2.7.1 Contract market activity

As noted, exchange trades are publicly reported, while activity in OTC markets is confidential and disclosed publicly only via participant surveys in aggregated form. The OTC data are published on a financial year basis. To allow some comparability across OTC and exchange traded data, this section refers to financial years for both markets.

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. In the first month of operation, no trades occurred on the FEX.

Regular ASX trades occur for the Queensland, NSW and Victorian regions of the NEM, but liquidity is poor in South Australia. A decline in trade volumes across the market from 2014 to 2017 may link to flat electricity demand and an oversupply of generation creating less price volatility in the wholesale market, which likely weakened demand for cap contracts. But volumes increased significantly after hitting a low point in 2017–18 (figure 2.25).

Figure 2.25 Traded volumes in electricity futures contracts



OTC: over-the-counter; RHS: The liquidity ratio compared the total traded volumes to the native demand across the 4 combined regions. TWh: terawatt hours.

Note: Data for 2020–21 trading of OTC contracts were not available at the time of publication. ASX data for 2020–21 are actual data to31 March 2020, and estimated volumes for April to June 2021.

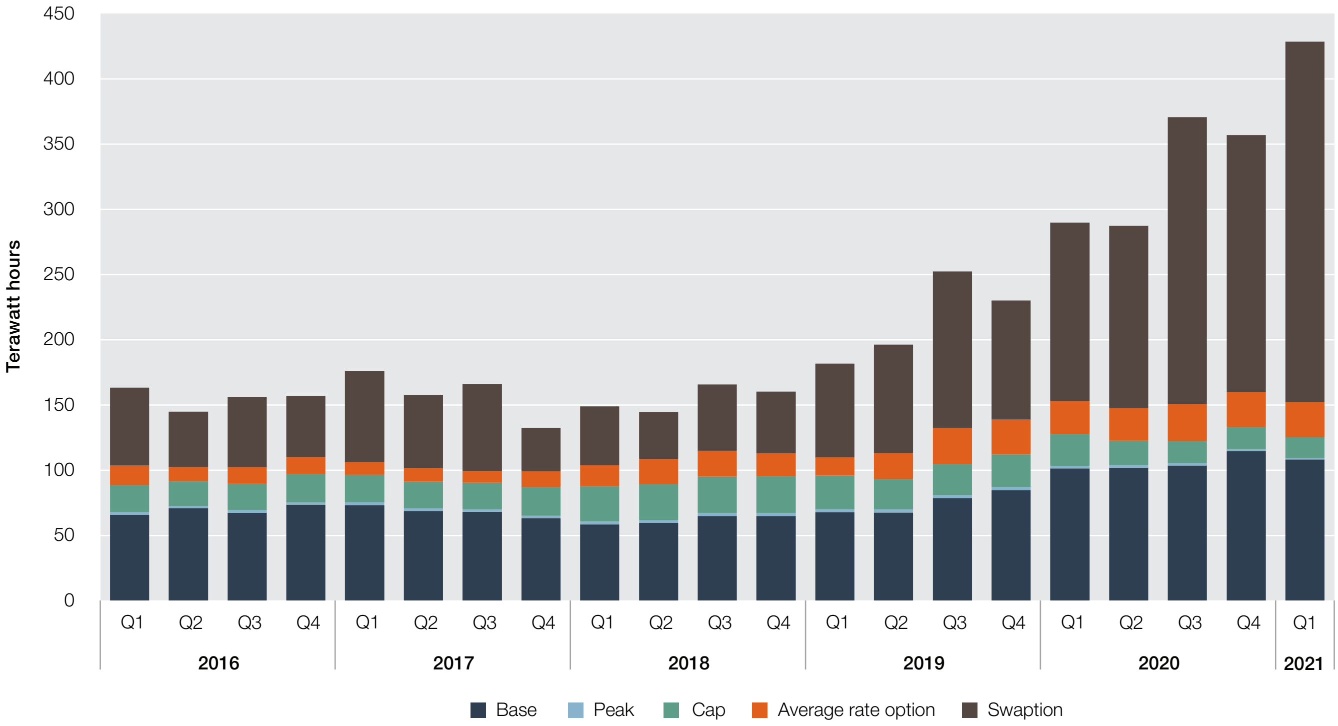
Source: AER; AFMA; ASX Energy.

In 2019–20 participants traded nearly 735 TWh of electricity contracts on the ASX – up 54% on the previous financial year and the highest ever volume traded. These trades represent more than 400% of underlying NEM demand. Trading levels rose again in 2020–21, with volumes traded in the 9 months to 31 March 2020 already exceeding the 2019–20 total. Using past volume profiles as a guide, estimates suggest total trades for 2020–21 may exceed 1,000 TWh. Importantly, open interest volumes are also increasing (figure 2.26). This indicated that the increase in traded volumes is not just due to higher turnover; but also because participants are holding larger open contract positions.

The recent growth in trading of ASX futures occurred despite the rising share of wind and solar generation in the market. This intermittent renewables generation is not well suited to contracting because its output is weather dependent. But 'firming' this generation by backing it with storage or gas powered plant can support contract market participation. A number of market participants with flexible generation capacity offer firming products targeted at renewable generation.

OTC trade volume peaked at 46% of total trade in 2012–13 as participants sought greater contract flexibility to manage risk leading up to and during the period of carbon pricing. Since then, OTC trade volumes have reduced substantially, making up less than 25% of contract volumes since 2013–14. In 2019–20 OTC trade was 14% of total trade.

Figure 2.26 ASX open interest volumes by product type



Source: AER; ASX Energy.

In February 2020 ARENA provided funding support to Renewable Energy Hub to establish a firming market platform that offers new hedge products designed for clean energy technologies. The project aims to fill a gap in risk management products and overcome a market barrier for clean energy technologies.[46] New hedging products introduced by Renewable Energy Hub include:

- a 'super peak' electricity contract for electricity supply during the high demand hours of the morning, afternoon and evening periods[47]
- a 'virtual storage' electricity swap for the buying and selling of stored energy. The price of the product is set at the spread of the agreed charge and discharge prices.

Products on the traditional exchanges are also adapting to market changes. In March 2021 the ASX began offering 5-minute settlement (5MS) cap products. These replaced existing cap products in advance of changes to settle the market every 5 minutes.

46 ARENA, *Renewable Energy Hub marketplace*, ARENA website, accessed 1 May 2020.

47 Renewable Energy Hub, 'New era for renewables as first new super peak firming contract signed' [media release], 14 April 2020.

Contract market liquidity

Overall, contract liquidity has improved across the NEM in recent years as participants seek additional price protection. The liquidity ratio (contract trading relative to underlying demand) across the NEM rose from around 240% in 2017–18 to over 460% in 2019–20 (figure 2.25), with all regions improving. Trades just through the ASX in 2020–21 are forecast to equate to around 580% of underlying trade in the NEM.

Total contract volumes across ASX and OTC markets exceed the underlying demand for electricity by a significant margin in Queensland, Victoria and NSW. Given the extent of vertical integration in Victoria and NSW, this outcome indicates substantial trading (and re-trading) occurs in capacity made available for contracting.

Liquidity is poorer in South Australia, where trading volumes tend to roughly match underlying electricity demand. For just ASX trades, South Australia was the only region where liquidity dropped in 2019–20 compared with the previous year. And for 2020-21 to date, liquidity in the region has continued to fall. The region's high proportion of renewable generation and relatively concentrated ownership of dispatchable generation likely contribute to this weaker liquidity. Given South Australia's liquidity issues, the Australian Competition and Consumer Commission (ACCC) recommended the imposition of a 'market maker' obligation, under which large vertically integrated retailers must make offers to buy and sell hedge products within a capped price spread. Reforms to similar effect were introduced in 2019 under the Retailer Reliability Obligation (RRO) (section 2.7.3 and box 1.3 in chapter 1). South Australian trade in OTC markets, however, increased over the same period.

Composition of trade

Victoria and Queensland accounted for 38% and 42% respectively of ASX contracts traded in 2020–21 to the end of March 2021. NSW trade declined from the previous year and represented only 19% of total trade. Trading in South Australia accounted for less than 1% of contract volumes. In the OTC market, the majority of reported OTC trading in 2019–20 (77%) occurred in Queensland and Victoria. NSW and South Australia each accounted for 18% and 6% of trading respectively.

For 2020–21 to date, swaptions (59%) were the most traded products on the ASX. The next most commonly traded product were quarterly futures, with 99% of those futures being baseload products. Peak products accounted for only less than 1%. Average rate options (6%) and caps (4%) were traded at lower rates. In the OTC market, swap products (74%) and caps (20%) accounted for most of the reported trading in the 2019–20 financial year.

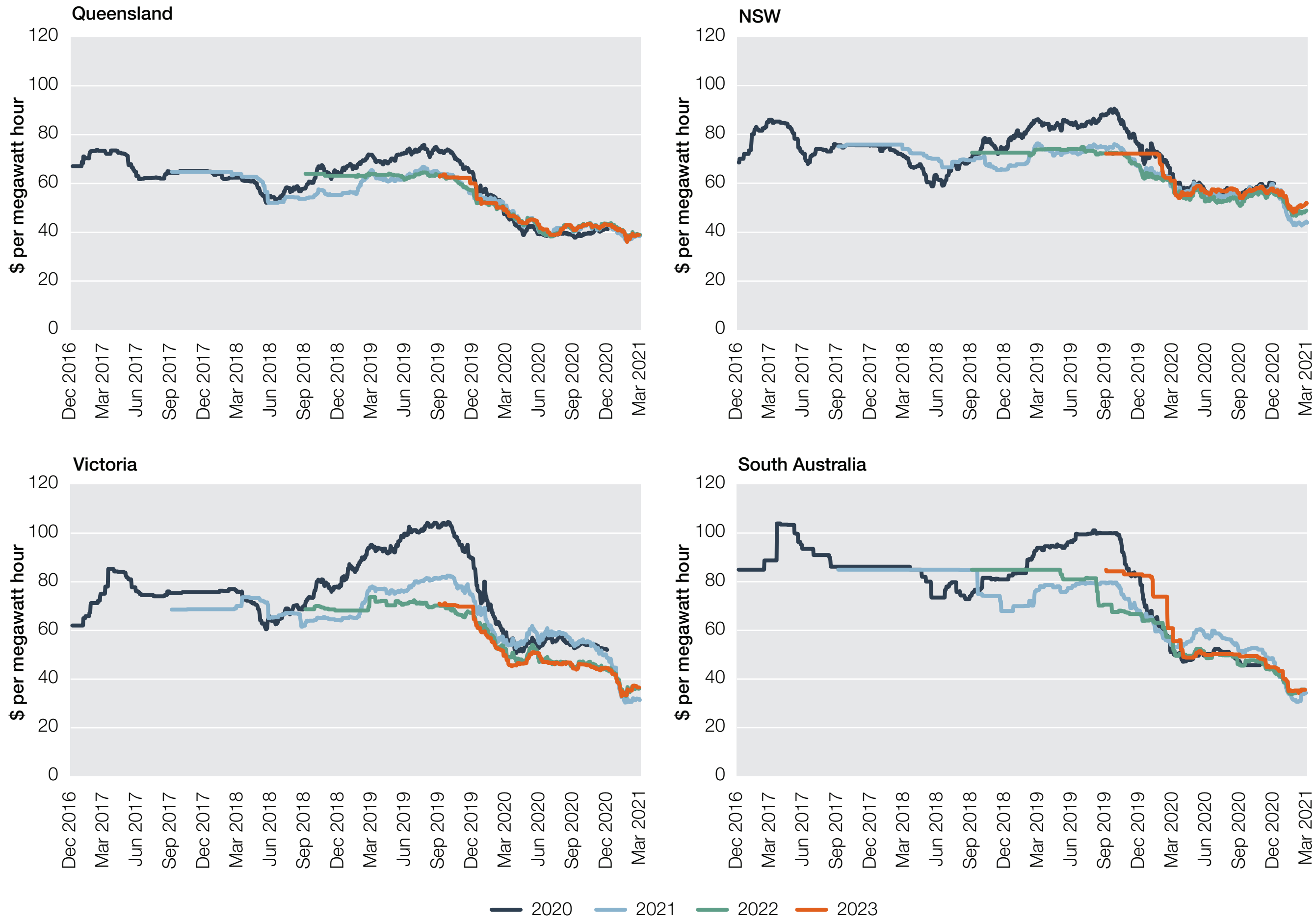
2.7.2 Contract prices

Base futures prices for 2021 ASX contracts peaked in 2018 and 2019, ranging from $67 per MWh in Queensland to $85 per MWh in South Australia (figure 2.27). But by the end of the first quarter of 2021 prices had fallen 40–60% from those peaks, ranging from $31 per MWh in Victoria to $44 per MWh in NSW. These falls reflect lower than expected spot market prices linked to rising renewable generation and subdued demand in some NEM regions (section 2.6).

The outlook for 2022 and 2023 is similar, with low prices expected to continue. Base futures for 2022 and 2023 fell to less than $40 per MWh in March 2021 in all regions except NSW, where prices were around $49 per MWh for 2022 and $52 per MWh for 2023. These contract prices indicate that the participants are not currently anticipating any significant market impact from the closure of Liddell power station over 2022 and 2023.

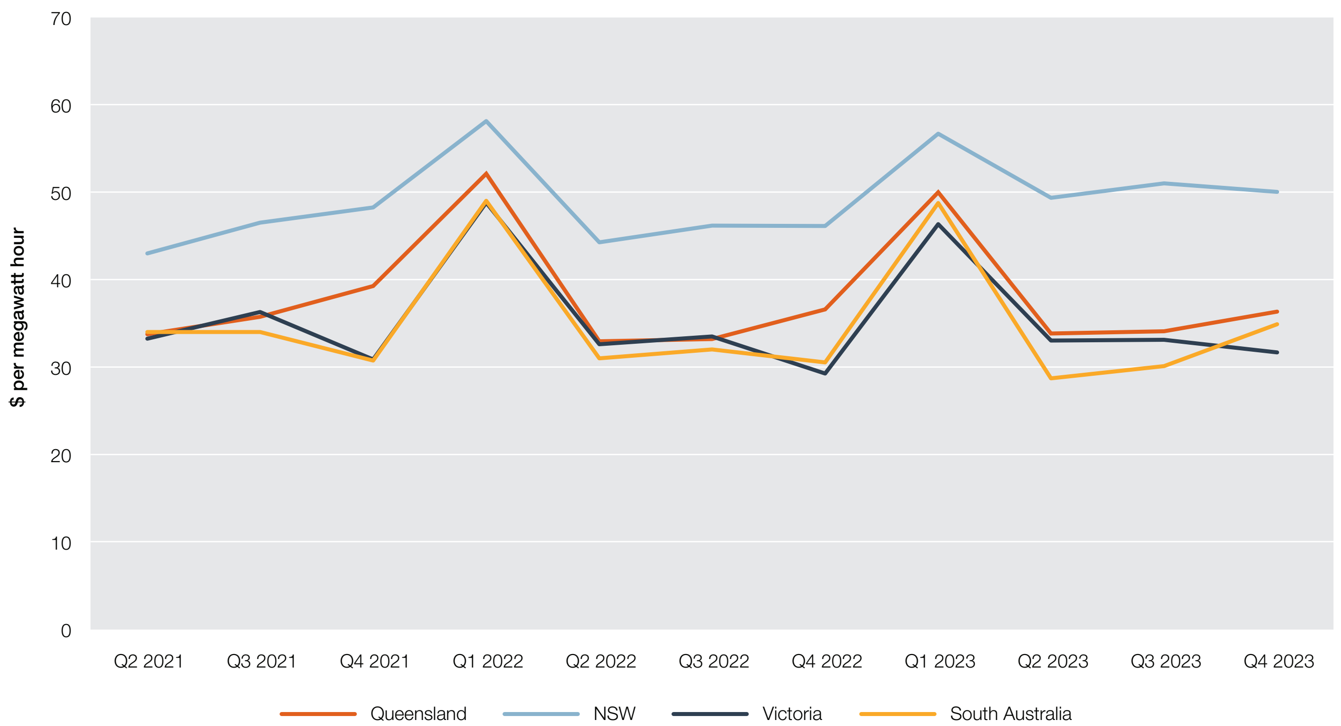
First quarter 2022 and 2023 contract prices were slightly higher but did not exceed $60 per MWh in any region (figure 2.28).

Figure 2.27 Prices for calendar year base futures



Source: AER; ASX Energy.

Figure 2.28 Prices for quarterly base futures



Source: AER; ASX Energy.

2.7.3 Access to contract markets

Access to contract markets, either on the ASX or in OTC electricity markets, can pose a significant barrier to retailers and generators looking to enter or expand their presence in the market. This barrier is a risk because contracts offer a degree of control over costs (for retailers) and revenue (for generators). The ACCC identified potential barriers to small or new retailers accessing hedge products in ASX and OTC markets, with significantly fewer trade options available to these retailers.[48]

In the ASX market, the credit requirements of clearing houses and daily margining of contract positions also impose significant costs on retailers. The use of standardised products with a minimum trade size of 1 MW may be too high for smaller retailers, which may be better served with the kind of 'load following' hedges accessible through the OTC market. These OTC hedge contracts remove volume risk and are particularly sought by smaller or new retailers without extensive wholesale market capacity. But credit risk can act as a barrier to smaller retailers in the OTC market, with counterparties likely to impose stringent credit support requirements on them. Before entering an OTC contract, the parties must generally establish an ISDA agreement, which is a costly process to set up. Further, the retailer must establish a separate agreement with each party with whom it contracts, resulting in further costs.

The RRO scheme introduced in July 2019 includes features aimed at improving access to contract markets. It includes a market liquidity obligation (MLO) on specified generators to post bids and offers in contract markets in the period leading up to a forecast reliability gap, to help smaller retailers meet their requirements. Box 1.3 in chapter 1 outlines the scheme's operation.

In November 2020 AEMO identified a reliability gap in the first quarter of 2024 in NSW, triggering the RRO and requiring Origin, AGL and Snowy Hydro to offer contracts for this period on the ASX.

Despite AEMO not identifying any reliability shortfall in South Australia, the RRO was also triggered in that state for specific periods in the first quarters of 2022, 2023 and 2024 (with the 2022 period since revoked). The operation of the RRO differs in South Australia, where the local energy minister can trigger the obligation. Large generation businesses in South Australia – Origin, AGL and Engie – are required to offer contracts for those periods.

As at the end of March 2021 there had been trade during the MLO trading windows for all identified RRO periods. However, as these periods are still distant, it is too soon to determine the impact on liquidity.

2.8 Market competition

The AER monitors the performance of the wholesale electricity market and assesses whether it is effectively competitive. It is required to report on the performance of the wholesale electricity market every 2 years. The AER published its second *Wholesale electricity market performance report* covering all NEM regions in December 2020.

In an effectively competitive energy market, prices should reflect demand and underlying cost conditions, at least in the longer term. Barriers to entry and exit must be sufficiently low so investors can respond efficiently to price signals. Relatively short periods of high prices driven by tighter supply and demand conditions may occur, allowing generators to recover their fixed costs and earn a return on their investment. But a sustained period of high prices provides clear signals for new generation to enter the market. Likewise, a fall in demand relative to supply should put downward pressure on prices and prompt higher cost generators to exit the market.

Assessing whether the energy market is operating efficiently as it transitions to a lower emissions generation mix is difficult. The market will take time to adjust to the changing role of fast-response 'flexible' generators, demand management and storage, for example.

The 2020 performance report found that the transformation of the market from a system dominated by large thermal generators to one that incorporates an increasing volume of widely dispersed renewable generators is having an effect on competition dynamics in the NEM. The transformation has also affected how participants offer their capacity, price signals for new investment, and markets for managing fluctuations in system frequency.

Significant entry of new large scale solar and wind generation has slightly reduced market concentration. Despite this, the output of a few large generators is necessary to meet demand in most regions a significant proportion of the time, particularly during evening peaks (box 2.4).

48 ACCC, *Restoring electricity affordability and Australia's competitive advantage, Retail Electricity Pricing Inquiry – final report*, June 2018.

But our 2020 review did not identify any concerning exercise of market power. Reductions in input costs were reflected in lower average generator offers, and short term price spikes were driven by extreme weather and high demand.[49] Opportunistic bidding was not a major factor in outcomes (box 2.3).

While new wind and large scale solar generation continues to enter the market, investment in other generation technology has been limited. A range of potential barriers to entry exist. Investment in capital-intensive, long-lived assets requires some confidence over future prices. The risks of investing in these technologies are significant in an environment of uncertainty about future technology costs and demand (particularly for large loads) and an unclear path for the exit of large incumbent generators.[50]

Separately, there are a number of other developments that could significantly impact the future direction of the NEM. There are concerns from governments that the market may not deliver sufficient new generation in an acceptable timeframe, and as a result they are intervening in the market. Also, the existing market design is being reconsidered, and this could fundamentally alter the investment landscape.

Box 2.3 Opportunistic bidding

The Australian Energy Regulator (AER) has previously highlighted periodic evidence of opportunistic bidding in National Electricity Market (NEM) regions. Its reporting on these issues supported reforms to generator bidding rules which the Australian Energy Market Commission (AEMC) implemented. The reforms require market participants to ensure offers, bids and rebids are not false or misleading.

Opportunistic bidding by large generators can be profitable because dispatch and settlement prices are determined over different timeframes – that is, the 30-minute settlement price is the average of 6 of the 5-minute dispatch prices. This timing allows generators to rebid capacity late in a trading interval to capture high prices, while giving competing generators little time to respond. To help manage this risk, the settlement period for the electricity spot price will change from 30 minutes to 5 minutes to align the timeframes for dispatch and settlement prices. The reform will take effect in October 2021.

Box 2.4 Competition metrics

The market structure of the generation sector affects opportunities and incentives for generators to exercise market power. In particular, a market structure dominated by a handful of generators – especially in a region with limited in-flow interconnector capacity – is likely to be less competitive than a market with diluted ownership.

Market shares are a simple illustrator of the degree of concentration in a market (figures 2.13 and 2.14).

The Herfindahl–Hirschman Index (HHI) accounts for the relative size of firms when analysing market structure by tallying the sum of squared market shares in a market. The index can range from zero (in a market with many small firms) to 10,000 (that is, 100 squared) for a monopoly. By squaring market shares, the HHI emphasises the impact of large firms.

In the National Electricity Market (NEM), the average HHI is over 2,000 for each region except Queensland, with little variation in recent years (figure 2.29). However, there is significant variation from the average in some dispatch intervals, reflecting plant outages, fuel availability and bidding behaviour in response to demand and prices.

South Australia had the largest range of HHI values in 2019, similar to previous years. This outcome reflects the significant variability in renewable output in that state. Victoria, South Australia and Queensland recorded their lowest minimum HHI values over the assessed period, indicating the market is more competitive at certain times. Queensland recorded the largest improvement following the introduction in 2019 of a third state-owned generation business in that state – CleanCo. More generally, the 2020 results coincided with higher levels of wind and solar generation across the NEM, as well as a more frequent occurrence of negative spot prices in Queensland, South Australia and Victoria.

49 AER, *Wholesale electricity market performance report – 2020*, December 2020

50 AER, *Wholesale electricity market performance report – 2020*, December 2020

While South Australia recorded its lowest minimum HHI value, the maximum HHI value in that region rose from 2019 levels. NSW recorded a significant reduction in its maximum HHI value from 2019 levels, when outages in the third quarter of 2019 led to greater market concentration at that time.

In most regions, the output of a few large participants is necessary to meet demand at times of high demand, even allowing for import capacity from other regions. At these times, those participants are 'pivotal' to meeting demand and may be able to exercise market power. The pivotal supplier test (PST) measures the extent to which one or more participants is pivotal.

A participant is pivotal if market demand exceeds the capacity of all other participants, accounting for possible interconnector flows. In these circumstances the participant must be dispatched (at least partly) to meet demand. Measuring the extent to which the largest (PST-1) or 2 largest (PST-2) participants are pivotal is a useful indicator for identifying the structural elements of market power.

In the mainland regions of the NEM, there are periods where the single largest participant is needed to meet demand. In 2019–20 the largest participant in a region was needed to meet demand 1% of the time in South Australia and up to 7% of the time in Queensland (figure 2.30). For Queensland this was equivalent to around 25 days, and it occurred primarily in the morning and evening peaks. In Tasmania, Hydro Tasmania is always pivotal to meeting demand.

In most regions, the 2 largest participants are pivotal to meeting demand a majority of the time. However, there have been signs of improvement since 2017–18:

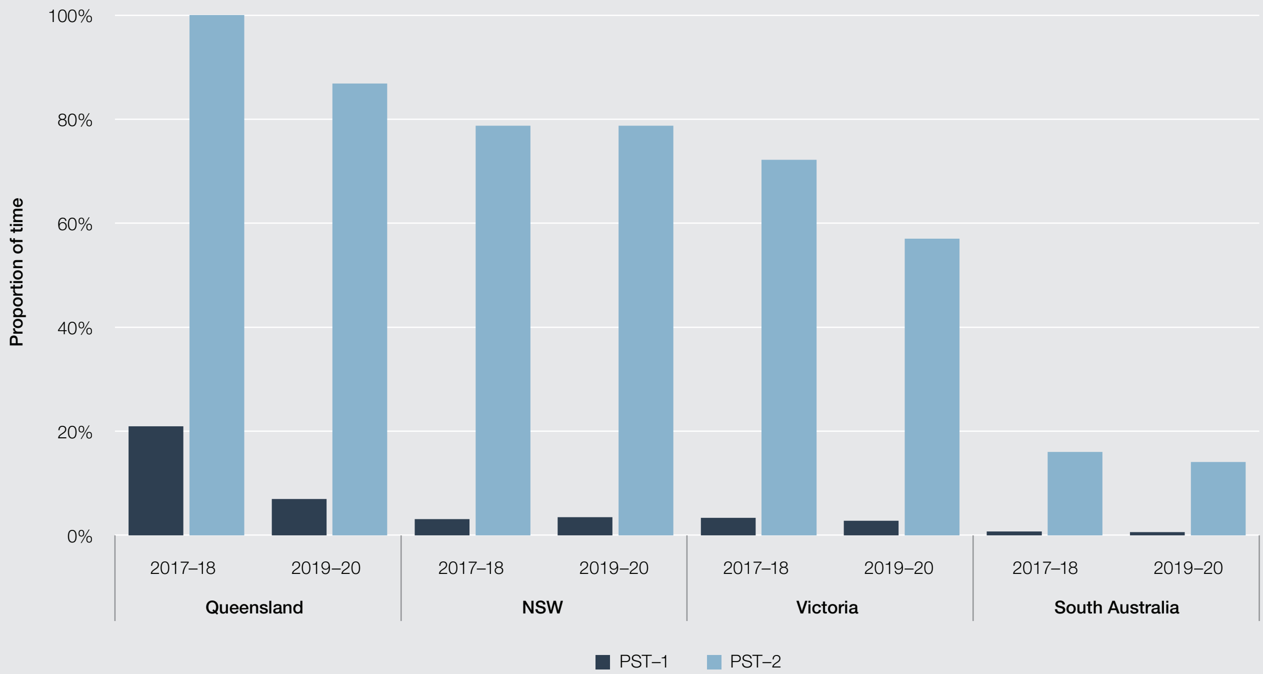
› In Queensland, CS Energy and Stanwell Corporation were jointly pivotal around 87% of the time in 2019–20 – down from 100% of the time in 2017–18. The entry of large scale solar and the creation of CleanCo meant that this change occurred during daylight hours. In the evening peak, when demand is highest, these generators remain pivotal 100% of the time.
› In Victoria, generation from the 2 largest participants was needed to meet demand 58% of the time in 2019–20 – down from 72% in 2017–18. Depending on availability, the largest suppliers were most likely to be AGL, Snowy Hydro, Alinta Energy and EnergyAustralia.
› In NSW outcomes were unchanged from 2017–18 to 2019–20, with generation from the 2 largest participants needed 79% of the time.
› In South Australia, generation from AGL and Engie was needed to meet demand 14% of the time in 2019–20 – down from 16% in 2017–18. Significant wind resources in the region mean there is large variability in what other participants can provide. As a result, these generators are most needed at times of low wind output.

Figure 2.29 Herfindahl–Hirschman Index

Note: Based on bid availability or the capacity that each generator offered, every 5 minutes. Bid availability accounts for outages, fuel availability and bidding behaviour, and provides a dynamic assessment of the levels of concentration in the market based on changing market conditions. The data do not account for imports, so overstate the risks of uncompetitive outcomes. South Australian results for 2016–17 are adjusted to remove outcomes when the market was suspended following the black system event in September 2016.

Source: AER.

Figure 2.30 Pivotality of largest generators



PST: pivotal supplier test.

Note: Figure shows the proportion of time that generation from the largest (PST-1) or 2 largest (PST-2) participant(s) was needed to meet demand in the 2017–18 and 2019–20 financial years. Generation units are attributed to the owner of the plant or the intermediary (should one be declared to AEMO).

Source: AER analysis using NEM data.

2.9 Power system reliability

Reliability is about the power system being able to supply enough electricity to meet customers' requirements, drawing on available generation and storage, demand response, and transmission network capacity to transport power to customers.[51] Cross-border transmission interconnectors support reliability by allowing power sharing across regions. Reliability concerns tend to peak over summer, when high temperatures spike demand and increase the risks of system faults and outages.

Chapter 1 looks at how the current energy market transition is affecting reliability. This section focuses mainly on recent outcomes. It refers to the reliability of wholesale electricity supply through the transmission system. The current reliability standard for these sectors requires any shortfall in power supply to not exceed 0.002% of total electricity requirements. In November 2020 the COAG Energy Council introduced a stricter interim reliability standard to be used as a trigger for market mechanisms to prevent forecast supply shortages. The interim targets allows AEMO to trigger the Reliability and Emergency Reserve Trader (section 2.9.1) and Retailer Reliability Obligation (section 2.7.1) if unserved energy is forecast to exceed 0.0006%.

2.9.1 Managing reliability

The reliability standard has rarely been breached, although AEMO intervenes in the market to manage any forecast shortfalls. Around 94% of supply interruptions experienced by consumers originate in distribution networks and relate to local power line issues. Section 3.14.3 in chapter 3 discusses distribution reliability.

AEMO forecast relatively low reliability risks for the 2020–21 summer. But it had previously raised concerns that the NEM's wholesale electricity supply would face reliability risks over each of the summers from 2017–18 to 2019–20, especially in Victoria and South Australia, where major coal (and gas) plant closures have occurred. The closures removed significant dispatchable capacity from the generation fleet that previously could be relied on when needed. Exacerbating the risk, the remaining coal plants were more prone to outages, especially in hot weather (section 1.3.1).

Reliability and Emergency Reserve Trader

Over the past 4 summers (up to and including 2020–21), AEMO intervened in the market to manage forecast risks of available generation not being sufficient to meet demand. In each year, it activated the RERT mechanism, which acts as a safety net to maintain reliability when electricity demand is forecast to exceed supply. The mechanism allows AEMO to procure (via competitive tender) additional supply from generators and/ or demand management from customers (to reduce their consumption) at times of system stress to reduce the risk of load shedding.

Reserves procured under the RERT must be 'out of market'. This feature seeks to preserve economic signals for new investment or demand response by market participants. Procuring reserves from existing market generators could perversely incentivise participants to withhold supply from the market in an attempt to obtain a better price through a RERT procurement. This feature was underlined by a rule change in 2019 that specifies any scheduled generator or load that participated in the wholesale market in the previous 12 months may not provide emergency reserves through the RERT.[52] It ensures the wholesale market remains the primary mechanism for delivering reliability.

The RERT scheme is expensive to operate, and consumers ultimately bear these costs. The costs include availability costs (capacity payments to secure the service over a specified timeframe), pre-activation payments (because some services incur costs to be on standby), and activation costs (for the actual use of the reserves). Other costs include administration costs and compensation payments to participants.[53]

Changes introduced in 2019 and 2020 provide more flexibility and transparency in the use of the RERT. A key change was to increase AEMO's lead time to purchase reserves from 9 to 12 months. In Victoria, AEMO can enter multi-year contracts of up to 3 years under the long notice RERT mechanism. This arrangement helps address short term reliability challenges facing that state, and it applies until June 2023.

51 Reliability should be distinguished from security, which refers to the power system's technical stability in terms of frequency, voltage, inertia and other characteristics (section 2.10).

52 AEMC, *National Electricity Amendment (Enhancement to the Reliability and Emergency Reserve Trader) Rule 2019, rule determination*, May 2019.

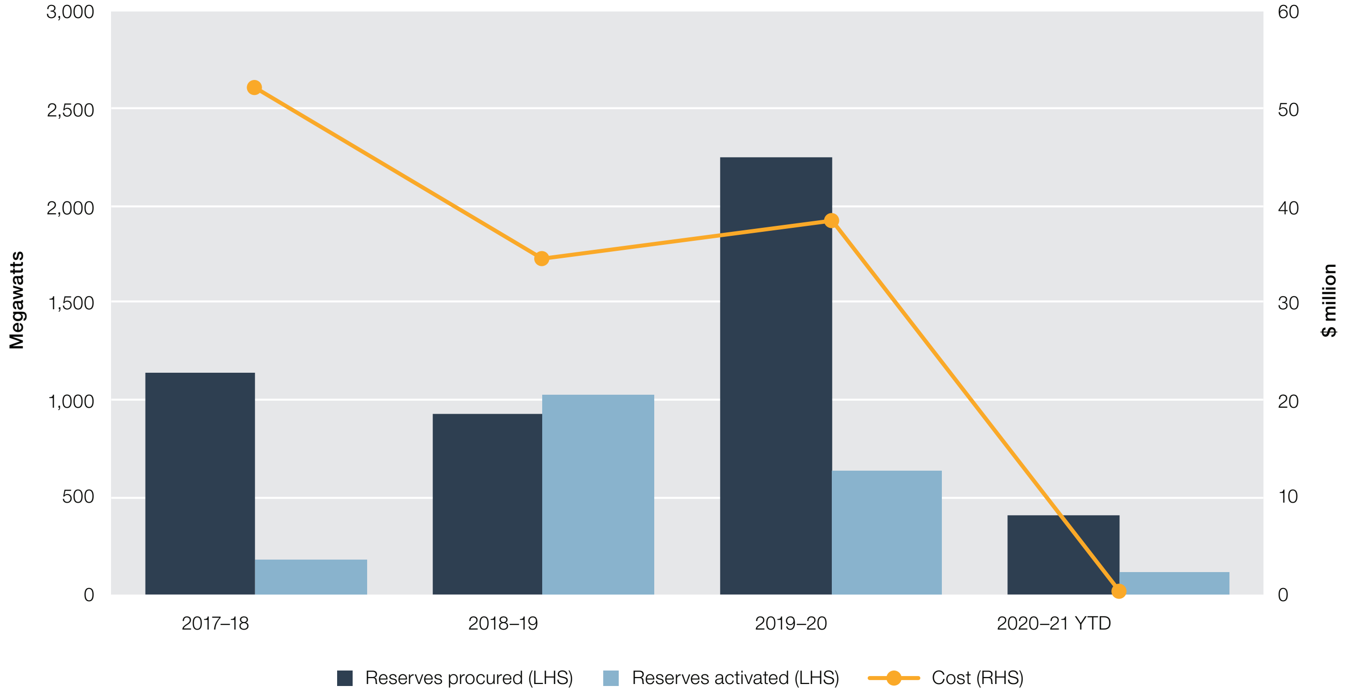
53 AEMC, *National Electricity Amendment (Enhancement to the Reliability and Emergency Reserve Trader) Rule 2019, rule determination*, May 2019.

The RERT was activated for the first time in November 2017 in Victoria and a further 6 times in Victoria and South Australia over the 2017–18, 2018–19 and 2019–20 summer periods. On 2 occasions in 2019, backup reserves activated under the RERT were insufficient, and load shedding was required.

The RERT was activated in NSW for the first time in January 2020, where it was activated on 3 separate occasions. AEMO activated RERT reserves once more in NSW, in December 2020. The RERT has never been used in Queensland or Tasmania.

The total cost of the RERT was around $50 million in the 2017–18 summer and over $30 million in each of the 2018–19 and 2019–20 summers (figure 2.31). The December 2020 activation was estimated to cost around $200,000.[54]

Figure 2.31 RERT reserves and costs



RERT: Reliability and Emergency Reserve Trader; YTD: year-to-date.

Note: Includes costs for availability, pre-activation, activation and other costs (including compensation costs). 2020–21 YTD is data to 31 March 2021.

Source: AER analysis of AEMO's RERT reporting.

2.9.2 Reliability outlook

In August 2020 AEMO forecast relatively low reliability risks over 2020–21 and across the next 5 years. AEMO's forecast was based on its expectations of lower peak demand, significant development of large scale renewable resources, and other minor generation and transmission investments.[55] But the uncertainty of the forecast had increased compared with previous years due to the possible impacts of COVID-19 on demand or delays in the return to service of generators on forced outage or deferred maintenance.

AEMO had previously identified a higher reliability risk for NSW than for other regions over the medium term, particularly in the window between the closure of the Liddell power station in 2023 and the expected commissioning of Snowy 2.0 in 2025.[56] In its most recent assessment, the reliability outlook in NSW for the 2022–23 summer and beyond improved with the planned upgrade of the Queensland–NSW interconnector and the development of 900 MW of renewable generation. But if this investment does not progress, NSW remains vulnerable to high demand, generator outages and low renewable generation.

Market bodies are exploring how best to manage reliability risks in the context of an evolving energy market. Focus areas include encouraging investment in resources with flexibility to manage sudden demand or supply fluctuations. Section 1.3.3 discusses recent reform initiatives.

54 AEMO, *Reliability and Emergency Reserve Trader (RERT) quarterly report Q4 2020*, February 2021.

55 AEMO, *2020 electricity statement of opportunities*, August 2020.

56 AEMO, *2019 electricity statement of opportunities*, August 2019.

2.10 Power system security

Power system security refers to the power system's technical stability in terms of frequency, voltage, inertia and similar characteristics.[57] Historically, the NEM's synchronous coal, gas and hydro generators helped maintain a stable and secure system through inertia and system strength services provided as a by-product of producing energy. But, as older synchronous plants retire, these sources of inertia and system strength are being removed from the system. Falling inertia makes it harder to keep frequency within an acceptable band, while falling system strength makes it harder to keep voltages stable.

The wind and solar generators entering the market are less able to support system security. For this reason, the rising proportion of renewable plant in the NEM's generation portfolio reflects in more periods of low inertia, weak system strength, more volatile frequency and voltage instability. It also raises challenges to the generation fleet's ability to ramp (adjust) quickly to sudden changes in renewable output.

The impact of these new generators on the market can be significant and has required AEMO to intervene more frequently to maintain system security. It has also increased focus on generators' meeting technical standards and providing accurate information to AEMO. In 2019, following an investigation of the circumstances of the 'black system' event in 2016, the AER brought proceedings in the Federal Court against 4 wind farm operators in South Australia for failing to comply with generator performance standards. Snowtown 2 wind farm was ordered to pay $1 million in penalties for breaching the National Electricity Rules.[58] Proceedings are continuing against the 3 other wind farm operators. Also in 2019 the AER brought proceedings against the Pelican Point power station (South Australia) for failing to submit accurate generator availability information.

AEMO uses market-based methods when possible to manage system security in the NEM. If market measures are unavailable or insufficient for some services, AEMO may intervene in the operating decisions of generation businesses. Intervention of this sort has risen sharply in recent years, particularly in South Australia and, more recently, Victoria (section 1.4.3).

In the longer term, energy rule reforms aim to widen the pool of providers (such as batteries and demand response) of security services and to recognise the value of these services. An initial reform to support more flexible generation will see the settlement period for the electricity spot price change from 30 minutes to 5 minutes from 1 October 2021. Market policy and regulatory bodies are developing broader reforms of the energy market's architecture to manage security risks in the context of an evolving energy market. Sections 1.4.4 and 1.4.5 discuss reform initiatives.

2.10.1 Security performance in the National Electricity Market

Section 1.4 discusses security issues in the NEM, including intervention mechanisms and reform initiatives. This section is a summary of recent performance.

As part of AEMO's market operations, it seeks to maintain system frequency within the applicable normal range (between 49.85 and 50.15 Hertz). Any deviations from this range should not exceed more than 1% of the time over any 30-day period. Market performance against this measure declined since 2015 for mainland regions and failed to be met over the first 4 months of 2019 (figure 1.14).[59]

This degradation in performance occurred as a result of changing system conditions (including extreme weather), generation volatility, an increase in load, and a reduction in the amount of frequency control services procured.[60] In response, AEMO implemented a range of measures, including increasing the base amount of 'regulation' frequency control services required across the mainland, reducing the level of assumed load response to frequency changes on the mainland, and progressively increasing the amount of 'contingency' frequency control services required. The AEMC also implemented a new rule requiring all scheduled and semi-scheduled generators to automatically respond to small changes in frequency.[61]

57 Box 1.4 in chapter 1 defines these terms.

58 AER, 'Snowtown 2 to pay penalty of $1 million for rule breach' [media release], 22 December 2020.

59 AEMO, *Frequency and time error monitoring – quarter 4 2020*, February 2021.

60 Frequency control services are discussed in section 2.10.2.

61 AEMC, *National Electricity Amendment (Mandatory Primary Frequency Response) Rule 2020, rule determination*, 26 March 2020.

The result of these changes was a significant improvement in the frequency performance of the mainland over 2020. Over the year, the NEM experienced one major security event on 31 January 2020, when South Australia islanded from the national market. Security issues persisted during the 18-day separation and elevated reliability risks in Victoria and NSW.

Separately, increasing volumes of rooftop solar are impacting security. As more households rely on rooftop solar to meet their own electricity needs, demand from the grid falls. This increases the risk that minimum demand falls below levels required to support operation of local generation from units that are able to respond to minor voltage and frequency fluctuations. This risk is most acute in South Australia.

In 2020 the South Australian Government provided AEMO with new powers to temporarily increase demand when necessary:

- AEMO can direct South Australian network providers to trip existing solar installations (to reduce exports of solar energy to the grid).
- From 28 September 2020 consumers installing or replacing rooftop solar PV must assign an agent who can remotely disconnect and reconnect that system from the distribution network when instructed to do so.

AEMO exercised its new powers for the first time in March 2021, instructing South Australian network operators to reduce rooftop solar generation, thereby increasing grid demand (box 2.5).

2.10.2 Frequency control markets

AEMO procures some of the services needed to maintain power system stability through markets (section 1.4.2 in chapter 1). In particular, it operates markets to procure various types of frequency control services.

Frequency control ancillary services (FCAS) are used to maintain the frequency of the power system close to 50 Hertz. The NEM has 8 FCAS markets that fall into 2 categories: regulation services and contingency services. Regulation services operate continuously to balance minor variations in frequency caused by small changes in demand or supply during normal operation of the power system. Contingency services manage large frequency changes from sudden and unexpected shifts in supply or demand, and they are used less often.

Costs for regulation services are recovered from participants that contribute to frequency deviations (causer pays); costs for raise contingency services are recovered from generators; and costs for lower services are recovered from market customers (usually retailers). AEMO acquires FCAS through a co-optimised market that coordinates offers from generators and other participants in both energy and FCAS markets to minimise overall costs.

Fewer participants operate in FCAS markets than in the wholesale electricity market, but a number of new participants emerged in recent years (table 2.4). In early 2021 there were 10 FCAS providers in Queensland, NSW and South Australia, 8 in Victoria, and 2 in Tasmania. Demand response aggregators now offer FCAS across all NEM regions; virtual power plants offer services in all mainland regions; and battery storage offers services in South Australia and Victoria. While some of these new entrants account for only a small proportion of FCAS trades, batteries have displaced incumbent providers of FCAS in South Australia.[62] To strengthen transparency around FCAS markets and encourage participation, in 2019 the AER launched quarterly reporting on market activity.[63]

Historically, FCAS costs were comparatively low in relation to energy costs – in 2015 FCAS costs totalled $63 million, which represented around 0.7% of NEM energy costs. However, these costs have risen steadily over the past few years. In 2020 FCAS costs totalled around $356 million – more than 5 times their level in 2015 (figure 2.33).

Following deteriorating frequency performance, in 2019 AEMO increased sourcing requirements for base regulation services on the mainland by 70–75% (figure 2.34).[64] The amount of time that frequency remained within the normal operating band subsequently improved, but regulation FCAS costs rose to record levels in 2019. Benign market conditions over much of 2020 resulted in regulation FCAS costs falling 31% from that peak level, despite a higher volume of services procured.

62 AER, *Wholesale electricity market performance report 2020, December 2020*, p 96.

63 AEMC, *Monitoring and reporting on frequency control framework, fact sheet*, July 2019.

64 AEMO, *Frequency and time error monitoring 2nd quarter 2019*, November 2019.

Box 2.5 Reducing solar generation in South Australia on 14 March 2021

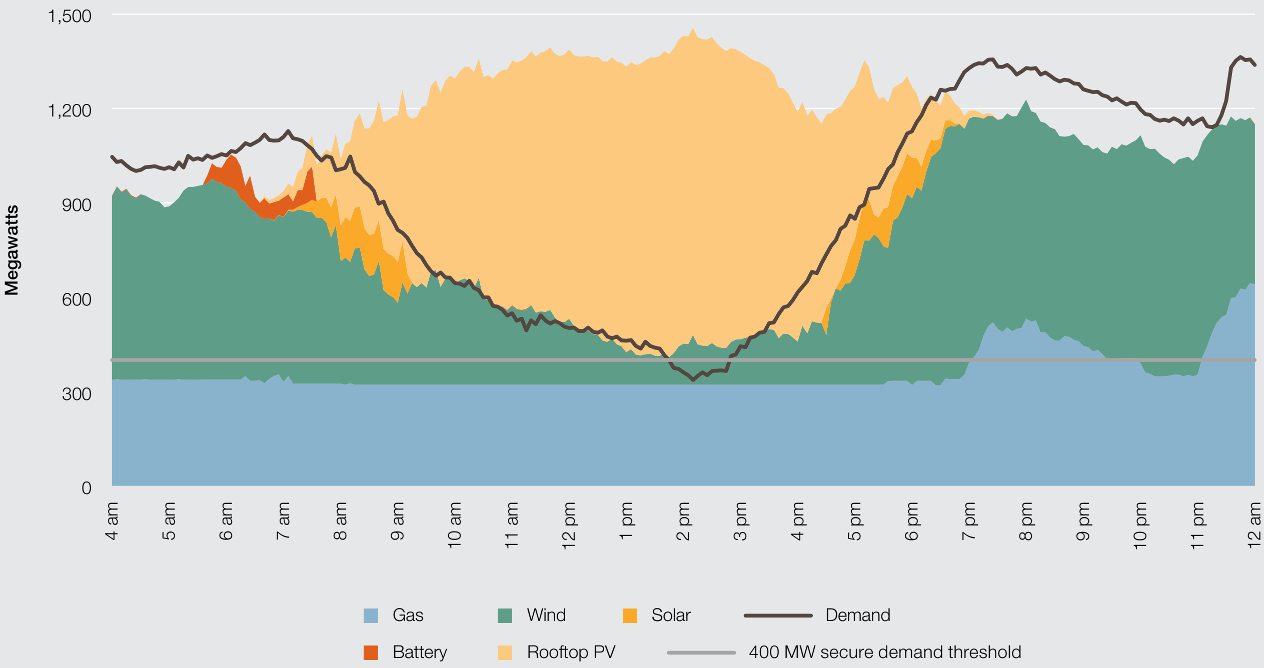
On 14 March 2021 the Australian Energy Market Operator (AEMO) instructed the network operators in South Australia to turn off 67 megawatts (MW) of solar generation to increase grid demand and maintain a secure power system. This was the first time AEMO has issued such an instruction.

On the day, South Australia was approaching near record low levels of grid demand. The temperature was around 21° C in Adelaide and skies were clear. Cool sunny days are ideal conditions for rooftop solar production, and generation increased steadily through the day. The mild weather also reduced the need for electricity for heating and cooling, and commercial load was low, as it was a Sunday.

At 8 am, AEMO announced forecast demand was below minimum operating levels in the afternoon and it may intervene to protect the security of the power system. Each region requires a minimum amount of local generation so that it can respond in the event that region separates from the market.

AEMO had earlier reduced the minimum demand level in South Australia to 400 MW in response to a week-long planned outage of transmission lines feeding the Heywood transmission interconnector between South Australia and Victoria. The outage was to restore transmission towers damaged from extreme weather conditions in January 2020. During the afternoon, network constraints on the Heywood interconnector forced electricity to flow into South Australia. These constraints prevented excess generation from leaving the region and also increased supply into South Australia from Victoria. To maintain security of the power system, AEMO reduced renewable generation in South Australia and issued directions to thermal units to stay online. Grid demand continued to fall in the middle of the day, driven by climbing rooftop solar output (figure 2.32).

Figure 2.32 South Australia local generation mix and grid demand 14 March 2020



Source: AER analysis of AEMO data.

At 2.30 pm AEMO instructed network operators in the region to increase South Australian demand to above 400 MW. A total of 67 MW of rooftop solar generation was backed off for about an hour. More than 10 MW of rooftop solar generation was backed off under rules that require new solar customers to appoint an agent to manage solar disconnections on request (the 'smarter homes' initiative). The local network distribution business, SA Power Networks, tripped a further 40 MW of rooftop solar generation by increasing the voltages at 7 substations. This action did not affect the customer's electricity connection but meant they drew their power from the grid rather than their solar photovoltaic (PV) system. AEMO backed off a further 17 MW of commercial solar through its control systems.

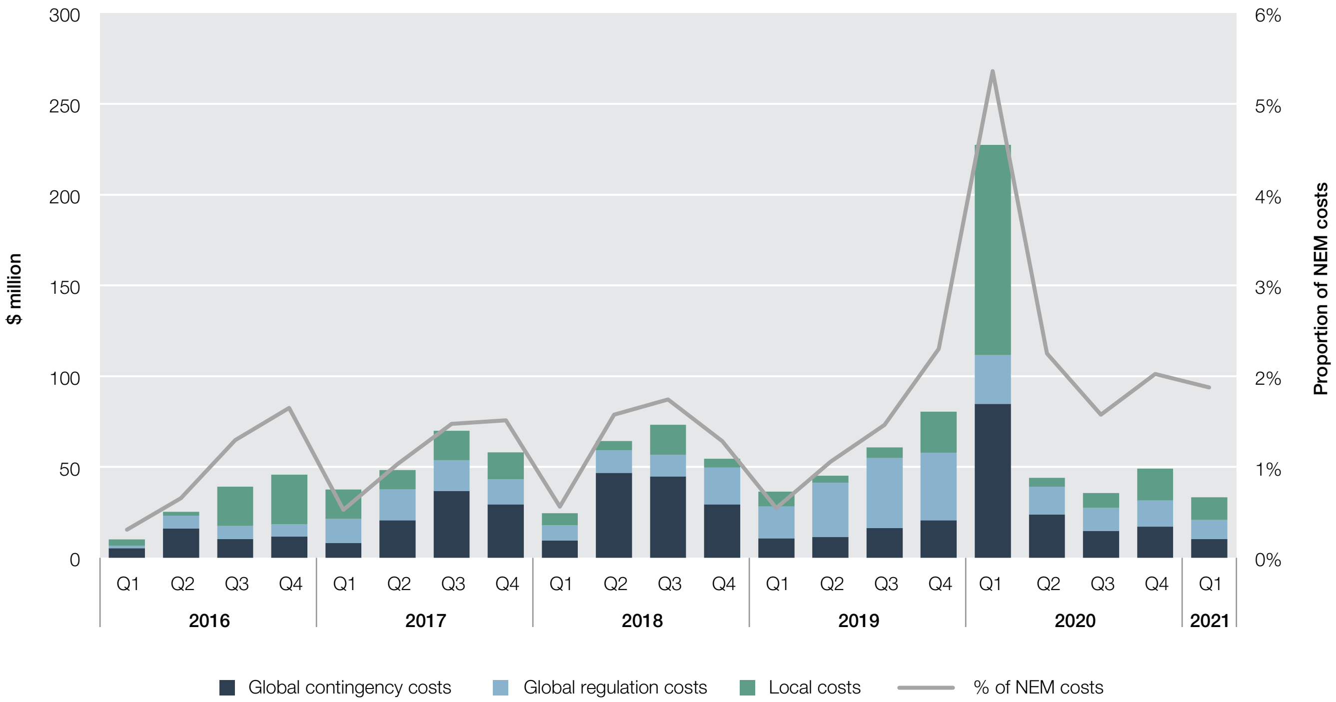
AEMO also introduced a stricter approach to assessing sourcing requirements for contingency services. This led to a step increase of around 300 MW in enabled contingency FCAS across 2020 as compared with 2019.

Costs for both regulation and contingency services reached record levels in the first quarter of 2020, at over $220 million (equivalent to 5.4% of energy costs). First quarter contingency FCAS costs were higher than total costs for the whole of 2019 and over 3 times higher than the previous quarterly record. Local services in South Australia accounted for almost half of FCAS costs over the quarter, mainly due to the region being islanded for several weeks following the loss of the Heywood interconnector. Also, in January 2020 the impact of bushfires on transmission networks drove record prices for contingency services across the NEM. FCAS prices exceeded $5,000 per MW several times over the quarter.

FCAS costs returned to lower levels over the remainder of 2020 and into 2021 as prices fell. These price falls were quite significant in particular FCAS markets. Raise regulation service prices, for example, were $15 per MW in the third quarter of 2020 – down from $44 per MW a year earlier. Across all markets, quarterly average prices were below $20 per MW for the rest of the year, which had not been the case since the first quarter of 2018. Into 2021 prices remained low, with raise regulation prices in the first quarter at their lowest level in 5 years.

Separately, AEMO's concerns about the sourcing of frequency services led the AEMC in March 2020 to introduce a mandatory requirement for generators to provide primary frequency response. The new requirement commenced in June 2020 and has contributed to improved system security performance (section 2.10.1).

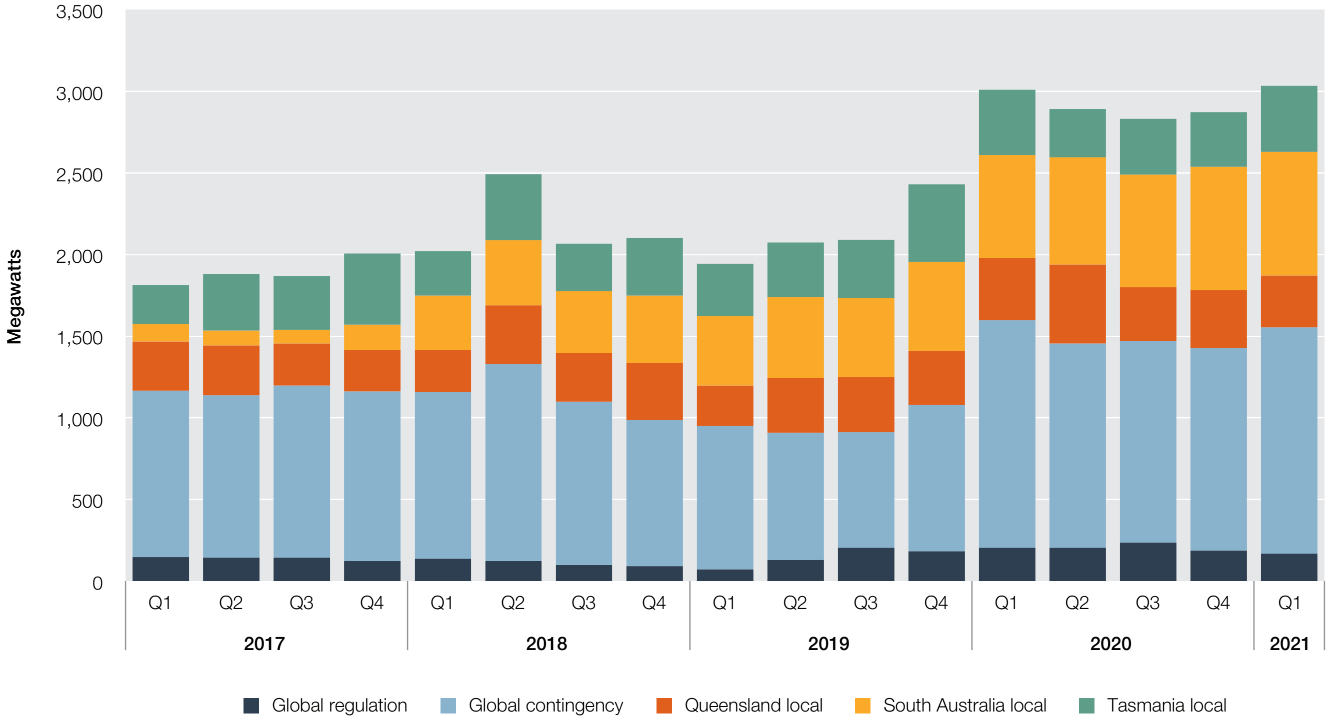
Figure 2.33 Frequency control ancillary service costs



NEM: National Electricity Market.

Source: AER; AEMO (data).

Figure 2.34 Frequency control ancillary service volumes



Source: AER; AEMO (data).

Table 2.4 Number of providers of frequency control ancillary services in each market

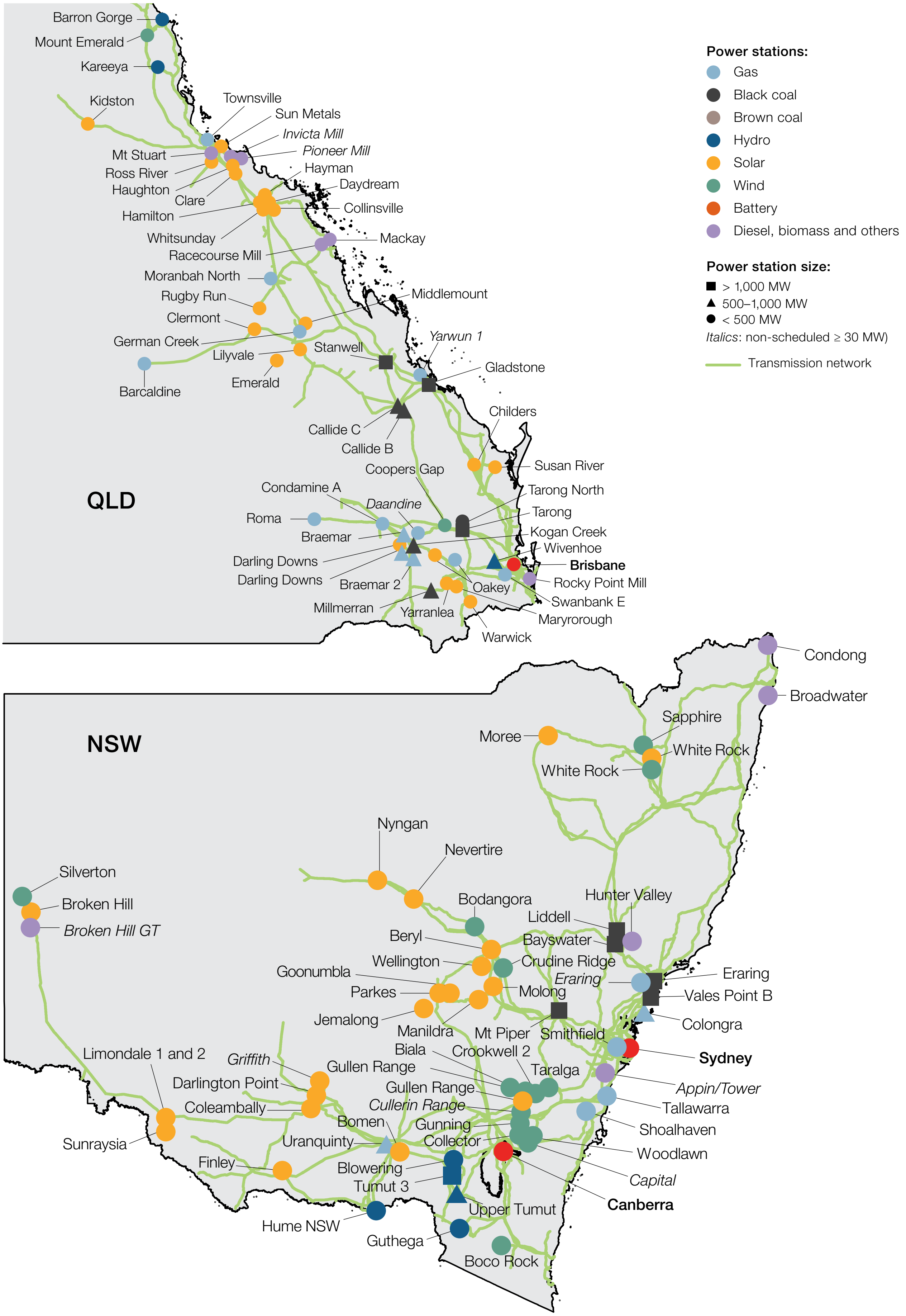
	LOWER				RAISE				TYPE OF PROVIDER
	5 min	**60 sec**	**6 sec**	**Reg**	**5 min**	**60 sec**	**6 sec**	**Reg**	
Queensland	6	8	7	8	8	9	9	8	Gas, black coal, hydro, pump, demand aggregator, liquid, virtual power plant
NSW	8	8	7	5	10	10	10	5	Black coal, demand aggregator, virtual power plant, hydro
Victoria	6	6	5	5	7	7	7	5	Brown coal, hydro, gas, battery, demand aggregator, load (smelter), pump
South Australia	8	8	8	6	9	9	9	6	Gas, demand aggregator, virtual power plant, battery, wind, liquid
Tasmania	1	1	1	1	2	2	2	1	Hydro, demand aggregator, gas, pump

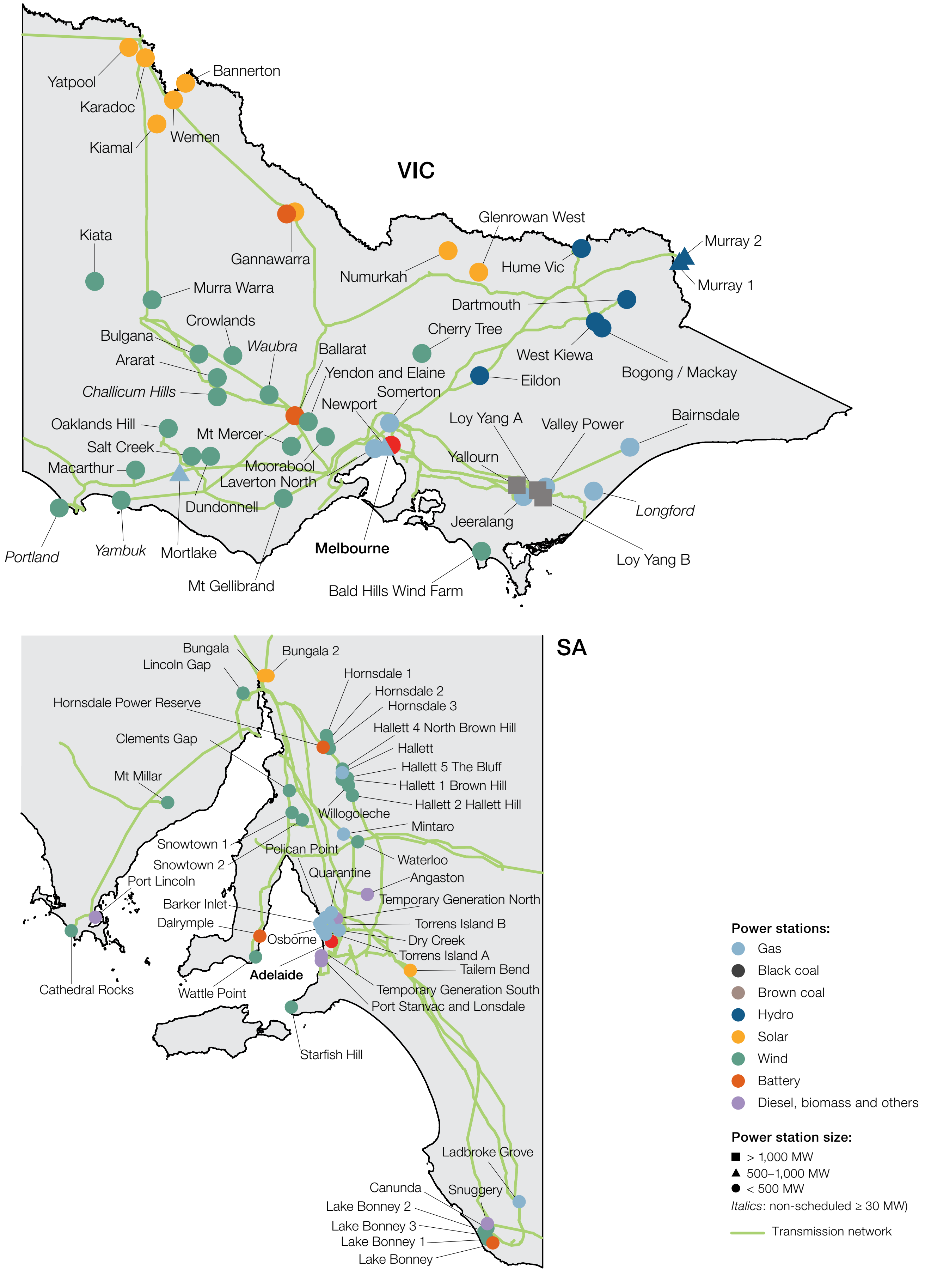
min: minutes; Reg: regulation; sec: seconds.

Source: AER; AEMO (data).

2.11 Generator information

Figure 2.35 Generators in the National Electricity Market




VIC
Yatpool
Karadoc
Bannerton
Kiamal
Wemen
Kiata
Gannawarra
Murra Warra
Crowlands
Bulgana
Waubra
Ararat
Challicum Hills
Oaklands Hill
Salt Creek
Macarthur
Mt Mercer
Moorabool
Laverton North
Dundonnell
Portland
Yambuk
Mortlake
Mt Gellibrand
Melbourne
Ballarat
Yendon and Elaine
Somerton
Newport
Numurkah
Glenrowan West
Hume Vic
Murray 2
Murray 1
Dartmouth
Cherry Tree
West Kiewa
Bogong / Mackay
Eildon
Loy Yang A
Valley Power
Bairnsdale
Yallourn
Jeeralang
Longford
Loy Yang B
Bald Hills Wind Farm
SA
Bungala
Lincoln Gap
Bungala 2
Hornsdale 1
Hornsdale 2
Hornsdale 3
Hornsdale Power Reserve
Hallett 4 North Brown Hill
Hallett
Clements Gap
Hallett 5 The Bluff
Hallett 1 Brown Hill
Mt Millar
Hallett 2 Hallett Hill
Willogoleche
Mintaro
Snowtown 1
Snowtown 2
Pelican Point
Waterloo
Port Lincoln
Quarantine
Angaston
Temporary Generation North
Barker Inlet
Dalrymple
Torrens Island B
Osborne
Dry Creek
Torrens Island A
Tailem Bend
Adelaide
Cathedral Rocks
Wattle Point
Temporary Generation South
Port Stanvac and Lonsdale
Starfish Hill
Ladbroke Grove
Canunda
Snuggery
Lake Bonney 2
Lake Bonney 3
Lake Bonney 1
Lake Bonney
Power stations:
Gas
Black coal
Brown coal
Hydro
Solar
Wind
Battery
Diesel, biomass and others
Power station size:
> 1,000 MW
500–1,000 MW
< 500 MW
Italics: non-scheduled ≥ 30 MW)
Transmission network

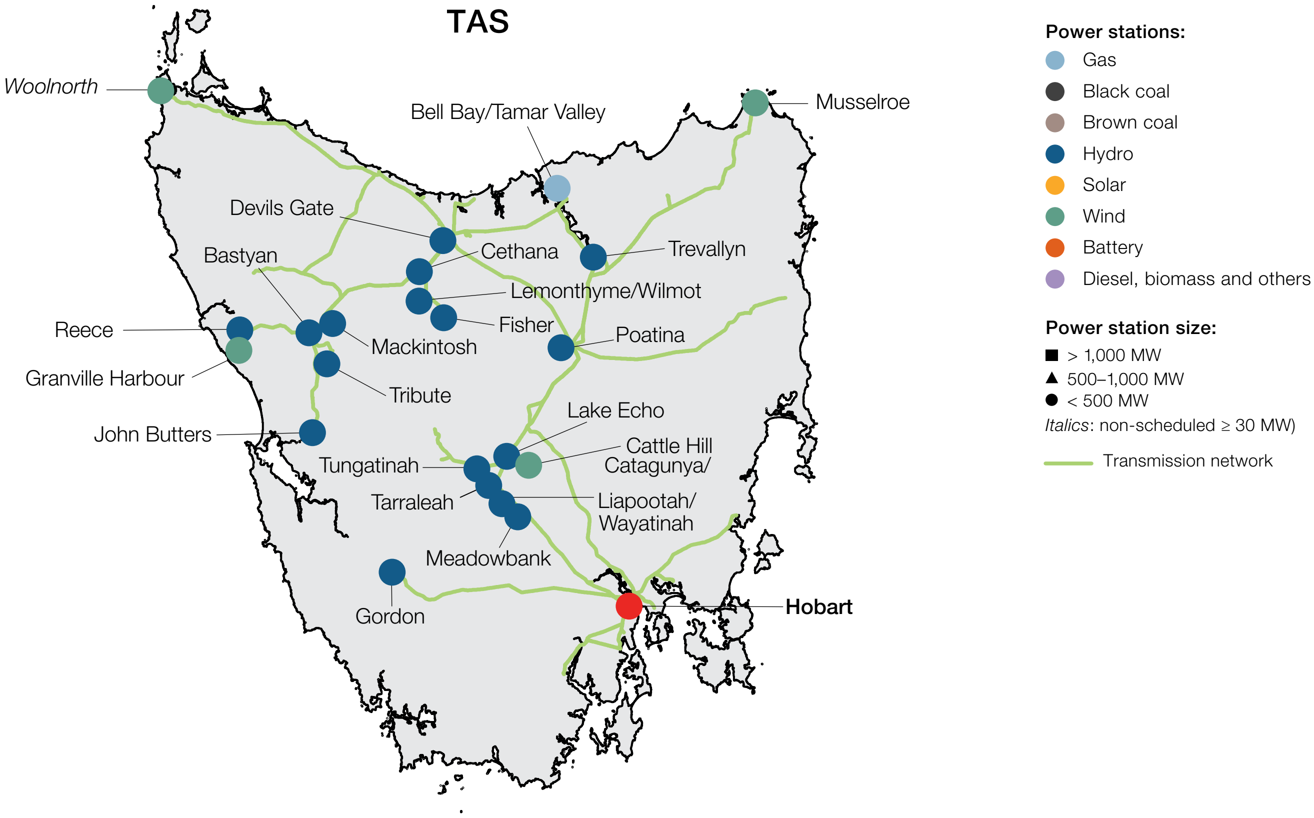

TAS
Woolnorth
Musselroe
Bell Bay/Tamar Valley
Devils Gate
Cethana
Trevallyn
Bastyan
Lemonthyme/Wilmot
Fisher
Reece
Mackintosh
Poatina
Granville Harbour
Tribute
Lake Echo
John Butters
Cattle Hill
Tungatinah
Catagunya/
Tarraleah
Liapootah/
Wayatinah
Meadowbank
Hobart
Gordon
Power stations:
Gas
Black coal
Brown coal
Hydro
Solar
Wind
Battery
Diesel, biomass and others
Power station size:
> 1,000 MW
500–1,000 MW
< 500 MW
Italics: non-scheduled ≥ 30 MW)
Transmission network

Table 2.5 Generation plant in the National Electricity Market, 2020

PLANT OPERATOR	CAPACITY (MW)	POWER STATION (MW)	FUEL TYPE	OWNER
QUEENSLAND	**15,667**			
Stanwell	3,303	Stanwell (1,460)	Black coal	Stanwell Corporation (Queensland Government)
		Tarong (1,400)	Black coal	Stanwell Corporation (Queensland Government)
		Tarong North (443)	Black coal	Stanwell Corporation (Queensland Government)
CS Energy	3,154	Gladstone (1,680)	Black coal	CS Energy (Queensland Government)
		Kogan Creek (744)	Black coal	CS Energy (Queensland Government)
		Callide B (700)	Black coal	CS Energy (Queensland Government)
		Callide A (30)	Black coal	CS Energy (Queensland Government)
Origin Energy	1,143	Darling Downs (644)	Gas	Origin Energy
		Mt Stuart (419)	Other	Origin Energy
		Roma (80)	Gas	Origin Energy
CleanCo	1,106	Wivenhoe (570)	Hydro	CleanCo (Queensland Government)
		Swanbank (385)	Gas	CleanCo (Queensland Government)
		Kareeya (91)	Hydro	CleanCo (Queensland Government)
		Barron Gorge (60)	Hydro	CleanCo (Queensland Government)
InterGen	852	Millmerran (852)	Black coal	InterGen/China Huaneng Group 65%; Daelim/Kiamco 35%
Callide Power Trading	840	Callide C (840)	Black coal	CS Energy (Qld Government) 50%; InterGen 50%
Alinta Energy	629	Braemar 1 (504)	Gas	Alinta Energy (CTFE)
		Rugby Run (83)	Solar	Adani Australia
		Collinsville (42)	Solar	Braemar Power Project
Arrow Energy	519	Braemar 2 (519)	Gas	Arrow Energy (Shell 50%; PetroChina 50%)
AGL Energy	452	Coopers Gap (452)	Wind	Powering Australian Renewables Fund (PARF)
Shell	432	Oakey (288)	Liquid/gas	Shell Energy Australia
		Condamine (144)	Gas	Queensland Gas Company (Shell)
Edify Energy	338	Daydream (167)	Solar	Edify Energy 10%; Blackrock 90%
		Whitsunday (57)	Solar	Wirsol 94.9%; Edify Energy 5.1%
		Hayman (57)	Solar	Edify Energy; Blackrock
		Hamilton (57)	Solar	Wirsol 94.9%; Edify Energy 5.1%
Ergon Energy	335	Mount Emerald (180)	Wind	Ergon Energy (Queensland Government)
		Lilyvale (118)	Solar	Fotowatio Renewable Ventures
		Barcaldine (37)	Gas	Ergon Energy (Queensland Government)
AGL Hydro Partnership	242	Townsville (242)	Gas	RATCH Australia (Ratchaburi Electricity Generation 80%; Ferrovial 20%)
Shell New Energies	162	Gangarri (162)	Solar	Shell Energy Australia
RTA Yarwun	154	Yarwun (154)	Gas	Rio Tinto Alcan
Elliot Green Power	149	Susan River (85)	Solar	Elliott Green Power
		Childers (64)	Solar	Elliott Green Power
EDL Group	144	*Moranbah North (63)*	Gas	Energy Developments (DUET Group)
		German Creek (45)	Gas	Energy Developments (DUET Group)
		Grosvenor (36)	Gas	Energy Developments (DUET Group)

PLANT OPERATOR	CAPACITY (MW)	POWER STATION (MW)	FUEL TYPE	OWNER
Pacific Hydro	132	Haughton (132)	Solar	Pacific Hydro (State Power Investment Corporation)
Diamond Energy	128	Oakey 1 & 2 (95)	Solar	Diamond Energy
		Maryrorough (33)	Solar	Diamond Energy
Ross River Operations	128	Ross River (128)	Solar	Pallisade Investment Partners
Sun Metals	124	Sun Metals (124)	Solar	Sun Metals Corporation
Yarranlea	121	Yarranlea (121)	Solar	Risen Solar
Darling Downs Solar Farm	121	Darling Downs (121)	Solar	APA Group
Wilmar International	118	*Pioneer Sugar Mill (68)*	Other	Wilmar International
		Invicta Sugar Mill (50)	Other	Wilmar International
Clare Solar Farm	110	Clare (110)	Solar	Fotowatio Renewable Ventures
Clermount Asset Co	92	Clermont (92)	Solar	Wirsol
Telstra	88	Emerald (88)	Solar	Lighthouse Infrastructure Management Limited
Warwick Solar Farm	78	Warwick (780	Solar	University of Queensland
Genex Power	50	Kidston (50)	Solar	Genex Power Limited
Mackay Sugar	48	Racecourse Mill (48)	Other	Mackay Sugar
Essential Energy	33	*Daandine (33)*	Gas	Energy Infrastructure Investments (49.9% MMCIF, 30.2% Osaka Gas, 19.9% APA Group)
Rocky Point Power	30	Rocky Point Cogeneration Plant (30)	Other	Heck Group
Capricorn	30	Middlemount (30)	Solar	SUSI Partners
Other non-scheduled plants of < 30 MW	282	*Misc.*		
NSW	**20,031**			
AGL Energy	5,043	Bayswater (2,640)	Black coal	AGL Energy
		Liddell (2,000)	Black coal	AGL Energy
		Silverton (198)	Wind	Powering Australian Renewables Fund (QIC 80%; AGL Energy 20%)
		Nyngan (102)	Solar	Powering Australian Renewables Fund (QIC 80%; AGL Energy 20%)
		Broken Hill (53)	Solar	Powering Australian Renewables Fund (QIC 80%; AGL Energy 20%)
		Hunter Valley (50)	Other	AGL Energy
Origin Energy	3,826	Eraring (2,880)	Black coal	Origin Energy
		Uranquinty (664)	Gas	Origin Energy
		Shoalhaven (240)	Hydro	Origin Energy
		Eraring (42)	Gas	Origin Energy
Snowy Hydro	2,980	Tumut 3 (1,500)	Hydro	Snowy Hydro (Australian Government)
		Colongra (724)	Gas	Snowy Hydro (Australian Government)
		Upper Tumut (616)	Hydro	Snowy Hydro (Australian Government)
		Blowering (80)	Hydro	Snowy Hydro (Australian Government)
		Guthega (60)	Hydro	Snowy Hydro (Australian Government)

PLANT OPERATOR	CAPACITY (MW)	POWER STATION (MW)	FUEL TYPE	OWNER
EnergyAustralia	1,870	Mt Piper (1,430)	Black coal	EnergyAustralia (CLP Group)
		Tallawarra (440)	Gas	EnergyAustralia (CLP Group)
Delta Electricity	1,320	Vales Point (1,320)	Black coal	Sunset Power International (Waratah Power Pty Ltd 50%, Vales Point Invesments Pty Ltd 50%)
Infigen Energy	486	Smithfield Energy Facility (185)	Wind	Infigen Energy
		Capital (140)	Wind	Infigen Energy
		Bodangora (113)	Wind	Infigen Energy
		Woodlawn (48)	Wind	Infigen Energy
Edify Energy	324	Darlington Point (324)	Solar	Edify Energy and Fern Trading Development Limited
Limondale Sun Farm	313	Limondale (313)	Solar	Innogy
Gullen Range	285	Gullen Range (275)	Wind	Beijing Jingneng Clean Energy 75%; Goldwind 25%
		Gullen Range (10)	Solar	Beijing Jingneng Clean Energy 75%; Goldwind 25%
Sapphire	270	Sapphire (270)	Wind	CWP Renewables and Partners Group
BWF Nominees	243	Bango 973 (159)	Wind	CWP Renewables and Partners Group
		Bango 999 (84)	Wind	CWP Renewables and Partners Group
Neoen	235	Coleambally (180)	Solar	Neoen
		Parkes Solar Farm (55)	Solar	Neoen (Impala 54%, Omnes Capital 23%, Bpifrance 14%, other 9%)
Sunraysia Solar Project	228	Sunraysia (228)	Solar	John Laing Group
Collector	226	Collector (226)	Wind	RATCH Australia
Lightsource Australia	216	Wellington (216)	Solar	Lightsource BP Australia
White Rock Wind Farm	197	White Rock (175)	Wind	CECEPWP 75%; Goldwind 25%
		White Rock (22)	Solar	CECEPWP 75%; Goldwind 25%
Finley Solar Farm	162	Finley (162)	Solar	John Laing Group
CRWF Nominees	141	Crudine Ridge (141)	Wind	CWP Renewables and Partners Group
Elliott Green Power	132	Nevertire (132)	Solar	Elliott Green Power
EDL Group	126	*Appin (55)*	Other	Energy Developments (DUET Group)
		Tower (41)	Other	Energy Developments (DUET Group)
		Cullerin Range (30)	Wind	Energy Developments (DUET Group)
Spark Infrastructure	121	Bomen (121)	Solar	Spark Infrastructure
Boco Rock	113	Boco Rock (113)	Wind	Electricity Generating Public Company (EGCO)
Taralga Wind Farm	106	Taralga (106)	Wind	Pacific Hydro (State Power Investment Corporation)
First Solar	98	Beryl (98)	Solar	New Energy Solar
Crookwell Development	96	Crookwell 2 (96)	Wind	Global Power Generation Australia (Naturgy 75%; Kuwait Investment Authority 25%)
Goonumbla Asset	85	Goonumbla (85)	Solar	Fotowatio Renewable Ventures
Cape Byron Management	68	*Broadwater (38)*	Other	Cape Byron Power (Cape Byron Infrastructure LP)
		Condong (30)	Other	Cape Byron Power (Cape Byron Infrastructure LP)
Moree Solar Farm	57	Moree (57)	Solar	Fotowatio Renewable Ventures

PLANT OPERATOR	CAPACITY (MW)	POWER STATION (MW)	FUEL TYPE	OWNER
Genex Power	55	Jemalong (55)	Solar	Genex Power Limited
Essential Energy	50	Broken Hill (50)	Other	Essential Energy (NSW Government)
Manildra Prop	50	Manildra (50)	Solar	New Energy Solar
Acciona Energy	47	Gunning (47)	Wind	Acciona Energy
Corowa Operations	36	Corowa (36)	Solar	METKA EGN
Junee operations	36	Junee (36)	Solar	METKA EGN
Molong Operations	36	Molong (36)	Solar	AMP Energy
Meridian Energy	29	Hume Dam (29)	Hydro	Meridian Energy
Non-scheduled plant < 30 MW	325	*Misc.*		
VICTORIA	**14,001**			
AGL Energy	3,534	Loy Yang A (2,210)	Brown Coal	AGL Energy
		Macarthur (420)	Wind	AGL Hydro Partnership
		Mackay/Bogong (300)	Hydro	AGL Hydro Partnership
		Dartmouth (185)	Hydro	AGL Hydro Partnership
		Somerton (170)	Gas	AGL Hydro Partnership
		Eildon (120)	Hydro	AGL Hydro Partnership
		Oaklands Hill (67)	Wind	AGL Hydro Partnership
		West Kiewa (62)	Hydro	AGL Hydro Partnership
EnergyAustralia	2,516	Yallourn (1,480)	Brown Coal	EnergyAustralia (CLP Group)
		Newport (500)	Gas	EnergyAustralia (CLP Group)
		Jeeralang B (228)	Gas	EnergyAustralia (CLP Group)
		Jeeralang A (204)	Gas	EnergyAustralia (CLP Group)
		Longford (44)	Gas	EnergyAustralia (CLP Group)
		Ballarat Energy Storage (30)	Battery	EnergyAustralia (CLP Group)
		Gannawarra Energy Storage (30)	Battery	EnergyAustralia (CLP Group)
Snowy Hydro	2,182	Murray (1,500)	Hydro	Snowy Hydro (Australian Government)
		Laverton North (312)	Gas	Snowy Hydro (Australian Government)
		Valley Power (300)	Gas	Snowy Hydro (Australian Government)
		Jindabyne Pumps (70)	Hydro	Snowy Hydro (Australian Government)
Alinta Energy	1,300	Loy Yang B (1,000)	Brown Coal	Alinta Energy
		Bald Hills (106)	Wind	Australian Renewables Income Fund
		Bannerton (100)	Solar	CIMIC
		Bairnsdale (94)	Gas	Alinta Energy
Origin Energy	566	Mortlake (566)	Gas	Origin Energy
Dundonell	335	Dundonnell (335)	Wind	Tilt Renewables
Acciona Energy	330	*Waubra (192)*	Wind	Acciona Energy
		Mount Gellibrand (138)	Wind	Acciona Energy
Moorabool Wind Farm	312	Moorabool (312)	Wind	Goldwind Australia

PLANT OPERATOR	CAPACITY (MW)	POWER STATION (MW)	FUEL TYPE	OWNER
Pacific Hydro	309	Portland (148)	Wind	Pacific Hydro (State Power Investment Corporation)
		Crowlands (79)	Wind	Pacific Hydro (State Power Investment Corporation)
		Challicum Hills (52)	Wind	Pacific Hydro (State Power Investment Corporation)
		Yambuk (30)	Wind	Pacific Hydro (State Power Investment Corporation)
Neoen	294	Bulgana Green Power (182)	Wind and Battery	Neoen
		Numurkah (112)	Solar	Neoen
Ararat Wind Farm	241	Ararat (241)	Wind	RES; GE; Partners Group; OPTrust
KSF Project Nominees	237	Kiamal (237)	Solar	Total Eren and CEFC
Telstra	231	Murra Warra (231)	Wind	Partners Group
Lal Lal Wind Farms	227	Yendon (144)	Wind	Northleaf 40%; InfraRed Capital Partners 40%; Macquarie 20%
		Elaine (83)	Wind	LalLal Wind Farm
Berrybank Development	180	Berrybank (180)	Wind	Global Power Generation Australia (Naturgy 75%; Kuwait Investment Authority 25%)
Meridian Energy	160	Mount Mercer (131)	Hydro	Meridian Energy
		Hume (29)	Wind	Meridian Energy
Glenrowan Sun Farm	132	Glenrowan (132)	Solar	WIRTGEN INVEST
Winton Solar Farm	107	Winton (107)	Solar	Fotowatio Renewable Ventures
Iraak Sun Farm	104	Karadoc (104)	Solar	BayWa r.e. Renewable Energy
Wemen Asset	97	Wemen (97)	Solar	Wircon (Wirsol parent company)
Yatpool Sun Farm	97	Yatpool (97)	Solar	BayWa r.e. Renewable Energy
Infigen Energy	57	Cherry Tree (57)	Wind	Iberdrola Australia
Edify Energy	55	Gannawarra (55)	Solar	94.9% Wirsol; 5.1% Edify Energy
Tilt renewables	54	Salt Creek (54)	Wind	Tilt Renewables
Kiata Wind Farm	31	Kiata (31)	Wind	John Laing Group 72.3%; Windlab Australia 25%; Local community 2.7%
Enel Energy Australia	30	Cuhuna (30)	Solar	Enel Green Power
Non-scheduled plant < 30 MW	283	*Misc.*		
SOUTH AUSTRALIA	**5,919**			
AGL Energy	1,723	Torrens Island B (800)	Gas	AGL Energy
		Torrens Island A (240)	Gas	AGL Energy
		Barker Inlet (211)	Gas	AGL Energy
		North Brown Hill (132)	Wind	AGL Energy
		Hallett 1 (95)	Wind	AGL Energy
		Wattle Point (91)	Wind	AGL Energy
		Hallett 2 (71)	Wind	AGL Energy
		The Bluff (53)	Wind	AGL Energy
		Dalrymple North (30)	Battery	ElectraNet

PLANT OPERATOR	CAPACITY (MW)	POWER STATION (MW)	FUEL TYPE	OWNER
Engie	1,025	Pelican Point (478)	Gas	Engie 72%; Mitsui 28%
		Dry Creek (156)	Gas	Engie 72%; Mitsui 28%
		Willogoleche (119)	Wind	Engie 72%; Mitsui 28%
		Mintaro (90)	Gas	Engie 72%; Mitsui 28%
		Port Lincoln (73)	Other	Engie 72%; Mitsui 28%
		Snuggery (63)	Other	Engie 72%; Mitsui 28%
		Canunda (46)	Wind	Engie 72%; Mitsui 28%
Origin Energy	759	Quarantine (229)	Gas	Origin Energy
		Osborne (180)	Gas	Origin Energy
		Bungala One (135)	Solar	Enel Green Power
		Bungala Two (135)	Solar	Enel Green Power
		Ladbroke Grove (80)	Gas	Origin Energy
Neoen	466	Hornsdale 1-3 (316)	Wind	Neoen
		Hornsdale Power Reserve Unit (150)	Battery	SA Government 70%; Neoen 30%
EnergyAustralia	413	Hallet (217)	Gas	EnergyAustralia (CLP Group)
		Waterloo (130)	Wind	Palisade Investment Partners 74%; Northleaf Capital Partners 26%
		Cathedral Rocks (66)	Wind	EnergyAustralia (CLP Group) 50%; Acciona Energy 50%
Trustpower	369	Snowtown North (144)	Wind	Tilt Renewables
		Snowtown South (126)	Wind	Tilt Renewables
		Snowtown (99)	Wind	Tilt Renewables
Infigen Energy	304	Lake Bonney 2 (159)	Wind	Infigen Energy
		Lake Bonney 1 (81)	Wind	Infigen Energy
		Lake Bonney 3 (39)	Wind	Infigen Energy
		Lake Bonney (25)	Battery	Infigen Energy
SA Government	277	*Temporary Generation North (154)*	Other	SA Government
		Temporary Generation South (123)	Other	SA Government
Snowy Hydro	129	Port Stanvac (58)	Other	Snowy Hydro (Australian Government)
		Angaston (50)	Other	Snowy Hydro (Australian Government)
		Lonsdale (21)	Other	Snowy Hydro (Australian Government)
Lincol Gap Wind Farm	126	Lincoln Gap 1 (126)	Wind	Nexif Energy
Vena Energy Services	108	Tailem Bend (108)	Solar	Vena Energy
Meridian Energy	70	*Mount Millar (70)*	Wind	Meridian Energy
Pacific Hydro	57	Clements Gap (57)	Wind	Pacific Hydro (State Power Investment Corporation)
Ratch Australia	35	*Starfish Hill (35)*	Wind	RATCH Australia (Ratchaburi Electricity Generation 80%; Ferrovial 20%)
Non-scheduled plant < 30 MW	58	*Misc.*		

PLANT OPERATOR	CAPACITY (MW)	POWER STATION (MW)	FUEL TYPE	OWNER
TASMANIA	**3,227**			
Hydro Tasmania	2,920	Gordon (432)	Hydro	Hydro Tasmania (Tasmanian Government)
		Poatina (300)	Hydro	Hydro Tasmania (Tasmanian Government)
		Tamar Valley (266)	Gas	Hydro Tasmania (Tasmanian Government)
		Reece (232)	Hydro	Hydro Tasmania (Tasmanian Government)
		Catagunya / Liapootah / Wayatinah (173)	Hydro	Hydro Tasmania (Tasmanian Government)
		Mussleroe (168)	Wind	Hydro Tasmania (Tasmanian Government)
		John Butters (144)	Hydro	Hydro Tasmania (Tasmanian Government)
		Woolnorth (140)	Wind	Hydro Tasmania (Tasmanian Government)
		Tungatinah (125)	Hydro	Hydro Tasmania (Tasmanian Government)
		Bell Bay (105)	Gas	Hydro Tasmania (Tasmanian Government)
		Trevallyn (93)	Hydro	Hydro Tasmania (Tasmanian Government)
		Tarraleah (90)	Hydro	Hydro Tasmania (Tasmanian Government)
		Cethana (85)	Hydro	Hydro Tasmania (Tasmanian Government)
		Tribute (83)	Hydro	Hydro Tasmania (Tasmanian Government)
		Lemonthyme / Wilmot (82)	Hydro	Hydro Tasmania (Tasmanian Government)
		Bastyan (80)	Hydro	Hydro Tasmania (Tasmanian Government)
		Mackintosh (80)	Hydro	Hydro Tasmania (Tasmanian Government)
		Devils Gate (60)	Hydro	Hydro Tasmania (Tasmanian Government)
		Meadowbank (40)	Hydro	Hydro Tasmania (Tasmanian Government)
		Fisher (43)	Hydro	Hydro Tasmania (Tasmanian Government)
		Repulse (34)	Hydro	Hydro Tasmania (Tasmanian Government)
		Paloona (33)	Hydro	Hydro Tasmania (Tasmanian Government)
		Lake Echo (32)	Hydro	Hydro Tasmania (Tasmanian Government)
Wild Cattle Hill	148	Cattle Hill Wind Farm (148)	Wind	Goldwind Australia; Power China Group
Granville Harbour	111	Granville Harbour (111)	Wind	Palisade Investment Partners
Non-scheduled plant < 30 MW	48	*Misc.*		

Italics: non-scheduled.

Note: Capacity is registered capacity at March 2021. 'Other' fuel type includes diesel and bagasse.

Source: AEMO; AER; company announcements.