State of the energy market 2021

AUSTRALIAN ENERGY REGULATOR

Australian Government

ACKNOWLEDGEMENTS

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Preface

The Australian Energy Regulator's (AER) flagship *State of the energy market* report has for more than a decade provided a clear, impartial, and comprehensive view of our energy markets from all angles: wholesale electricity and gas markets, the transmission and distribution networks, as well as energy retail markets and consumer experiences.

A fundamental part of our role in regulating the NEM is to provide analysis and insight into the emerging and long-term trends within the energy market. This year's report continues to explore the dominant themes in our energy markets including the need for flexibility to respond to variable market conditions and the ongoing transformative expansion of renewable energy generation.

While this transformation continued throughout 2020, consumers also went through a period of significant change as COVID-19 shifted the way we work and live.

During 2020, the AER responded by initiating the Statement of Expectations of energy businesses, which helped protect more than 61,000 households and small businesses from being disconnected – an 82% drop in disconnections from the previous year – as they weathered the impacts from the pandemic.

Our enhanced reporting of key customer data during COVID-19, including disconnections and energy debt levels, provides timely insight into how energy consumers are faring during the pandemic. We remain concerned about the level of residential debt, as detailed in this report, with a 16% increase in the number of customers in debt at December 2020 compared to the previous year, and their average debt up by more than $200.

We will have a strong focus in the coming year through our compliance and enforcement priorities on ensuring retailers identify customers in financial difficulty and offer payment plans that have regard to the customer's capacity to pay.

Our focus on ensuring compliance with our energy laws and rules was supported by the Federal Court in 2020–21 with the highest civil penalties ordered under national energy laws to date totalling $3.8 million, while the AER issued a further $960,000 in infringement notices.

As highlighted in this report, pressure on electricity prices began to ease during 2020 as reductions in wholesale prices started to flow through to consumers. Prices fell significantly in all regions across 2020, declining by between 23% and 58% compared to 2019 averages.

The annual average price in all regions was below $70 per megawatt hour (MWh) for the first time since 2015. These wholesale price reductions were evident in the AER's Default Market Offer (DMO) final decision for 2021–22 with standing offer prices for residential customers in south east Queensland, NSW and South Australia set to reduce by between 2.7% and 7.4% from 1 July 2021. While short term factors have led to a rise in wholesale prices from May 2021, the longer-term outlook is for prices to remain relatively subdued.

Shopping around remains the best way for consumers to get the best energy deal and it's never been easier to do following the AER's redevelopment of the Energy Made Easy website. Energy Made Easy is aimed at empowering consumers to make the switch to better energy deals. It offers free, impartial price comparisons for energy consumers, and was accessed by more than 2.5 million users over the past year, with more than 4.8 million sessions, a 100% increase on the previous year. We know that if just 5% of people accessing the site switched they could save a total of $7 million.

State of the energy market 2021 charts in detail the growth in renewables, with record investment in rooftop solar. Our energy system is continually adapting as we transition away from a centralised system of large coal and gas generation, towards a mixture of smaller scale, widely dispersed wind and solar generators, and battery storage.

To help the Australian Energy Market Operator (AEMO) more effectively manage system security in a transitioning market, the AER proposed a rule change in 2020 that would stop weather dependent generators from turning off without instruction from AEMO. The extensive consultation undertaken by the AER allowed the Australian Energy Market Commission (AEMC) to fast track the rule change process with the final rule made in March 2021.

In 2020, we also published our second, biennial *Wholesale electricity markets performance report*. This presents a comprehensive picture of the state of wholesale competition in the NEM. It also analyses how the performance of the market has changed since our inaugural report released in 2018. A key finding of this report was that the NEM continues to be concentrated in ownership, despite new entry of wind and solar, and ongoing surveillance will remain important in a rapidly changing market.

While the transformation of the energy market might seem a high level concept, it is clearly visible at a grassroots level by the changes we are seeing in neighbourhoods and communities.

Rooftop solar has dramatically altered the way consumers interact with the market and how the electricity grid functions. Increasingly, we will see households installing their own batteries to store energy, and joining their neighbours in creating virtual power plants. A small but growing fleet of electric vehicles on our roads also continues to prompt policy debate about network charging.

As detailed in this report, in 2020 the total asset value of the electricity network businesses we regulate exceeded $100 billion for the first time. Progressing tariff reform and supporting the integration of distributed energy resources such as solar panels have been key features of the 8 electricity distribution network revenue determinations the AER has completed in the past 18 months. The future of Australia's gas distribution networks has also been central to our 2 gas distribution network decisions.

As this report details, the Integrated System Plan (ISP) is critical to achieving a least-cost development pathway to support the energy transition. In 2020, the AER provided guidance on how large-scale projects should be assessed through the ISP, and implemented changes to the regulatory investment test to streamline the assessment of priority projects identified through that process. The AER has also delivered rapid approvals of a number of critical transmission projects while maintaining rigour in our assessment and ensuring consumers pay no more than necessary for safe and reliable power.

The AER is supporting the Energy Security Board in its important work on NEM 2025, a strategy that will help steer us through the emerging challenges of the transition.

The AER is always listening and engaging with our diverse range of stakeholders particularly as we manage and respond to the significant changes unfolding in the energy sector.

I commend the State of the energy market 2021 report to all stakeholders as a source of key data on the industry, but also as a compelling reminder of our shared responsibility to help make energy consumers better off, now and in the future.

Clare Savage
AER Chair
June 2021

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Image source: iStock.

Market overview

The National Electricity Market (NEM) is undergoing a profound transformation from a centralised system of large fossil fuel (coal and gas) generation towards an array of smaller scale, widely dispersed wind and solar generators, grid scale batteries and demand response. This transition has required adaptation by all participants, from generators through to customers, and is driving a significant package of reforms to ensure the market framework remains fit for purpose.

The gas market is also undergoing a fundamental shift. In 2020 we saw a move to more flexible use of our gas resources to meet the competing demands of Australian industry and households, and liquefied natural gas (LNG) export businesses. Focus has turned to identifying and encouraging development of new sources of gas as the traditional sources decline. Gas network businesses are also balancing meeting short term operational needs against uncertainty about the future demand for gas.

In 2020 the COVID-19 pandemic resulted in social and economic disruption across Australia, with many consumers facing increased financial stress. But the pandemic has had only a moderate impact on broader energy market outcomes. Energy demand reduced due to a drop in commercial load associated with businesses closing during lockdowns, but this was partly offset by a rise in household consumption. Falling international fuel prices flowed through to the domestic markets, contributing to lower energy prices.

National Electricity Market

In 2020 over 3,700 megawatts (MW) of large-scale solar and wind generation capacity entered the NEM, mostly in New South Wales (NSW) and Victoria. There was also record investment in rooftop solar photovoltaic (PV), with almost 2,500 MW of new capacity installed across the NEM in 2020.

This new entry drove record levels of wind and solar generation in 2020, accounting for over 19% of total electricity generation. Wind output exceeded gas generation for the first time.

While wind and solar generation has increased, fossil fuel generation continues to produce over 70% of electricity in the NEM, but this is declining. Many older generators are nearing the end of their operational life and becoming less reliable. The growth in renewable energy is also contributing to financial stress on fossil fuel generators, risking earlier than scheduled plant exits from the market. Broadly, the profitability of black coal and gas plant has been challenged by low or negative prices in the middle of the day, when solar generation is at its maximum.

Over the next 2 decades, 16 gigawatts (GW) of thermal generation (61% of the current coal fleet in the NEM) is expected to retire. Over the same period, 26–50 GW of new large scale wind and solar capacity is forecast to come online, along with 13–24 GW of rooftop solar PV capacity. Energy storage is also expanding, through grid scale and household batteries, and pumped hydrogeneration plant. While still in their infancy, technologies including hydrogen and electric vehicles (EVs) will impact on both electricity supply and electricity demand.

This electricity market transition can deliver significant benefits. Renewable energy is a relatively cheap fuel source and, if integrated efficiently into the power system, can deliver low cost sustainable energy into the future. But the weather-dependent nature of wind and solar generation poses risks. Firming capacity (such as fast-start generation, demand response and battery storage) is needed to maintain a reliable electricity supply, filling supply gaps when a lack of wind or sunshine curtails renewable plant.

Coal and gas powered generators also provide the market with inertia and system strength which help stabilise the grid. The reduction in output from these plants as renewables expand has meant the transmission network is more susceptible to erratic frequency shifts and voltage instability. Shortages of system strength have emerged in South Australia and Tasmania, and parts of Victoria and Queensland. South Australia also faces an inertia shortage. These issues constrain the operation of renewable plant and make it difficult to connect new plant to the grid. The Australian Energy Market Operator (AEMO) issued directions to market participants to maintain system security around one-third of the time in 2020 – a record high level. The volume of frequency control services acquired over 2020 and into early 2021 was also a record high level. South Australia has been the main focus of these interventions.

Market bodies are implementing changes to the market framework to signal the requirement for services alongside energy to maintain system security. For example, new frequency services are being introduced to manage the rising incidence of frequency deviations, and draft reforms announced in April 2021 make transmission networks responsible for providing system strength services.

A further focus of recent reforms has been on planning and coordinating transmission and generation investment to ensure assets are built in the right place at the right time. A key initiative is to cluster new wind and solar projects in hubs, called renewable energy zones (REZs), so that efficient transmission investment can be made to transport energy to customers. REZ locations have been identified through AEMO's Integrated System Plan and are being implemented by state governments.

In tandem with policy reforms underway, the Energy Security Board (ESB) is developing a long term, fit-for-purpose market framework (NEM 2025). The ESB released a consultation paper on its preferred approaches to reform in April 2021, with recommendations to ministers expected to follow later in the year.[1]

Alongside coordinated reforms, governments are directly intervening in the market through various funding mechanisms for new generation or storage capacity to meet short term reliability and security requirements and carbon emissions targets. Recent examples include Victoria's 300 MW 'big battery' (to begin operating in 2021) and the Australian Government's proposed 660 MW gas-powered generator in the Hunter region of NSW (to begin operating in 2023).

The ESB noted in 2021 that a number of government interventions appear to be driven by an intolerance for sustained high prices that may be needed to prompt a market-led investment response. It found that rewarding resources outside the market increases the risk of distortions, especially when interventions are delivered inconsistently and in an uncoordinated way.[2] While the ESB recognised that such schemes are likely to be an enduring feature of the energy sector, it noted that a NEM-wide approach to jurisdictional investment schemes would increase policy certainty.[3]

Assessing whether the energy market is operating efficiently as it transitions to a lower emissions generation mix is difficult. The AER published its second *Wholesale electricity market report* in 2020, which found that the market transformation is having an effect on competition dynamics in the NEM. The transition has reduced market concentration and affected how participants offer their capacity, price signals for new investment, and markets for managing fluctuations in system frequency.

Prices fell significantly in all regions across 2020, declining by between 23% and 58% compared to 2019 averages. The annual average price in all regions was below $70 per megawatt hour (MWh) for the first time since 2015. Prices in Victoria ($62 per MWh) and South Australia ($51 per MWh) fell most dramatically, down from $124 per MWh and $122 per MWh respectively in 2019). NSW ($68 per MWh) had the most modest reduction in prices and was the NEM's highest priced region in 2020. Tasmania ($43 per MWh) and Queensland ($44 per MWh) were the lowest priced regions.

The declines 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.

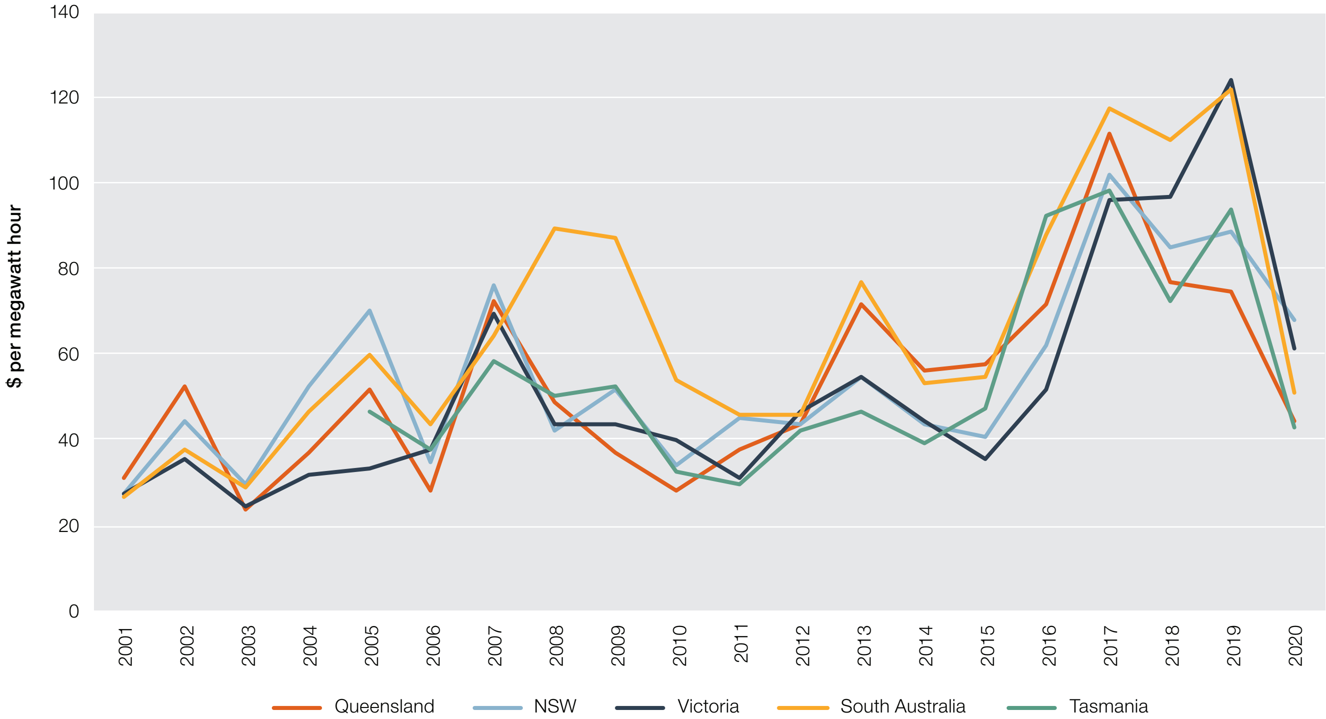
Despite falling across the year, average prices in NSW, Victoria and South Australia were higher than in Queensland and Tasmania – pushed up by a number of high price events. In January 2020, prices spiked above $5,000 per MWh a total of 25 times. Five of these events were the result of high demand and network outages due to bushfires, while 4 others related to unplanned generator outages and lower than forecast wind generation. Prices also spiked 16 times in Victoria and South Australia when extreme storms caused the collapse of transmission towers in Victoria, which led to South Australia being electrically isolated from the rest of the NEM.

1 ESB, *Post 2025 Market Design Options – a paper for consultation*, April 2021.

2 ESB, *Post-2025 Market Design Directions Paper*, January 2021, pp 16, 21, 24.

3 ESB, *Post 2025 Market Design Options – a paper for consultation*, April 2021, pp 25–26.

Figure 1 Wholesale electricity prices



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

Outcomes in 2021 have been more volatile. Prices remained low in early 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). Low grid demand contributed to low prices, with the NEM experiencing unusually mild summer conditions and high levels of rooftop solar PV generation. Mild conditions also meant there were few reliability concerns over the 2020–21 summer. AEMO activated the Reliability and Emergency Reserve Trader once, in NSW on 17 December 2020 in response to a forecast lack of reserve capacity.

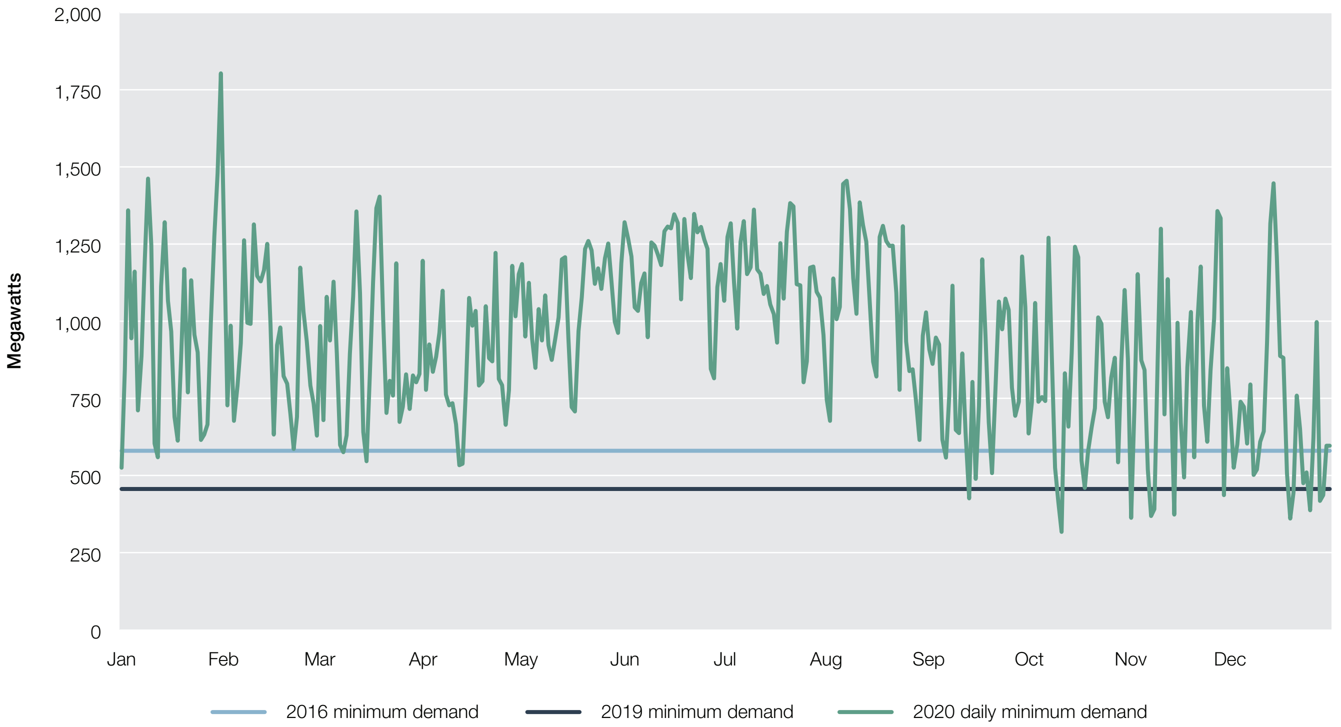
A tighter supply–demand balance from May 2021 drove a change in market outcomes. A fire at Queensland's Callide C power station in May 2021 and a number of plants being offline for maintenance significantly reduced availability of coal fired generation. This coincided with relatively low output from weather-dependent renewables and rising demand associated with winter heating requirements (particularly in NSW). Prices in May 2021 averaged over $130 per MWh in Queensland and NSW, and around $85 per MWh in Victoria and South Australia.

Future price expectations have generally tracked spot market outcomes. Base futures prices for 2021 Australian Securities Exchange (ASX) contracts fell by between 40% and 60% by early 2021 from highs observed in 2018 and 2019. Prices have since risen, particularly in Queensland and NSW. The outlook for 2022 and 2023 is for prices to remain lower than in recent years. Base futures for 2022 and 2023 fell to less than $40 per MWh in March 2021 for all regions except NSW ($49 per MWh) but by June 2021 were up to $10 higher in each region. These contract prices indicate that participants are not currently anticipating any significant market impact from the impending closure of Liddell power station in NSW.

A key challenge for AEMO over 2020 was managing minimum demand. Historically, electricity demand reaches its lowest point in the middle of the night, when most people are sleeping. But rooftop solar PV output is lowering daytime 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.

Minimum demand fell in every NEM region in 2020. The greatest falls were in South Australia and Victoria, where new minimum demand records were set. South Australia beat its previous minimum demand record (set in 2019) on 13 separate days in 2020.

Figure 2 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.

With more low priced renewable generation operating at times of low demand, the incidence of negative prices has increased. In 2020 there was a record number of negative prices NEM-wide, with 3,662 instances of negative spot prices across the 5 regions. Over 40% of these occurred in the fourth quarter, where prices reached a record low daily average in Victoria, South Australia and Tasmania. Nearly half of all instances of negative prices in 2020 occurred in South Australia.

To maintain the security of the power system, AEMO can instruct network operators in South Australia to back off rooftop solar generation, forcing them to draw power from the grid. These powers, which were used for the first time in March 2021, are being considered for other NEM regions due to the continued rapid uptake of rooftop solar PV.

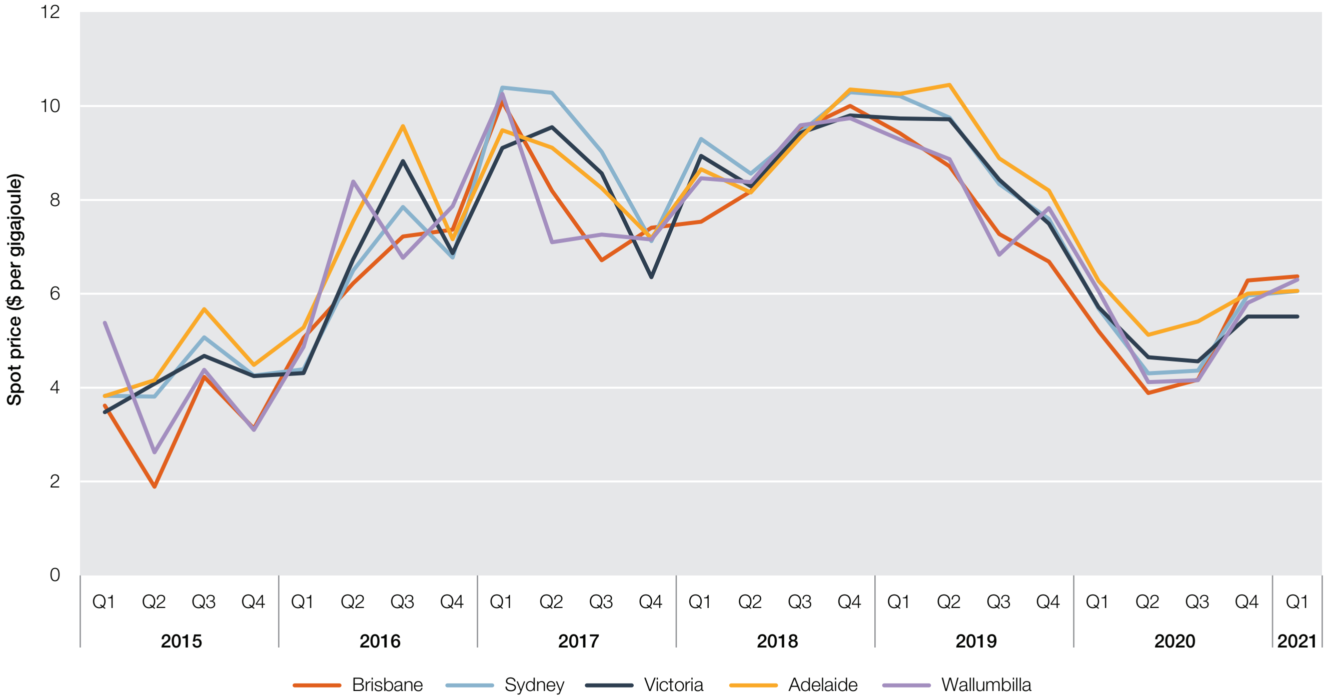
Gas markets in eastern Australia

The development of Queensland's LNG export industry placed significant pressure on the eastern gas market. That pressure, combined with other factors such as state-based moratoriums on gas development, tightened the supply–demand balance. This tightening led to increases in wholesale gas prices from 2017 as international gas prices began to bear on domestic gas prices. However, these price pressures eased over 2020 as Asian LNG spot prices reduced significantly due to intense price competition, reductions in oil price, and COVID-19 related demand reductions.

Ultimately LNG netback prices bottomed out at a record low in July 2020. Late in 2020, Asian LNG demand rebounded during the northern hemisphere winter. From December 2020 to January 2021 a cold snap created unexpectedly strong LNG demand in Asia, causing a sharp spike in international prices. This also coincided with coal supply issues in China, LNG plant outages at key facilities around the world and congestion at the Panama Canal, which caused delays in cargoes reaching Asia from further afield. By mid-February 2021 Asian LNG prices returned to levels similar to before the spike.

Domestically conditions eased significantly in line with international conditions. Although demand for LNG exports reduced in mid-2020, production in Queensland did not. This increase in gas availability coincided with a reduction in gas used for electricity generation to lower domestic prices. Average annual prices fell by more than 40% over 2020 and in the second and third quarters were below $5 per gigajoule (GJ) in all markets except Adelaide.

Figure 3 Eastern Australia gas market prices



Note: The Wallumbilla price is the volume weighted average price for day-ahead, on-screen trades at the Wallumbilla gas supply hub. Brisbane, Sydney and Adelaide prices are ex-ante. The Victorian price is the 6 am schedule price.

Source: AER analysis of gas supply hub, short-term trading market and Victorian declared wholesale gas market data.

With reductions in LNG export flows, producers also seized the opportunity to conduct maintenance and divert flows into storage facilities. While short term conditions improved, Australian exporters reported that the uncertainty stemming from COVID-19 and other international conditions limited their ability to strike new gas supply agreements and finalise investment decisions.

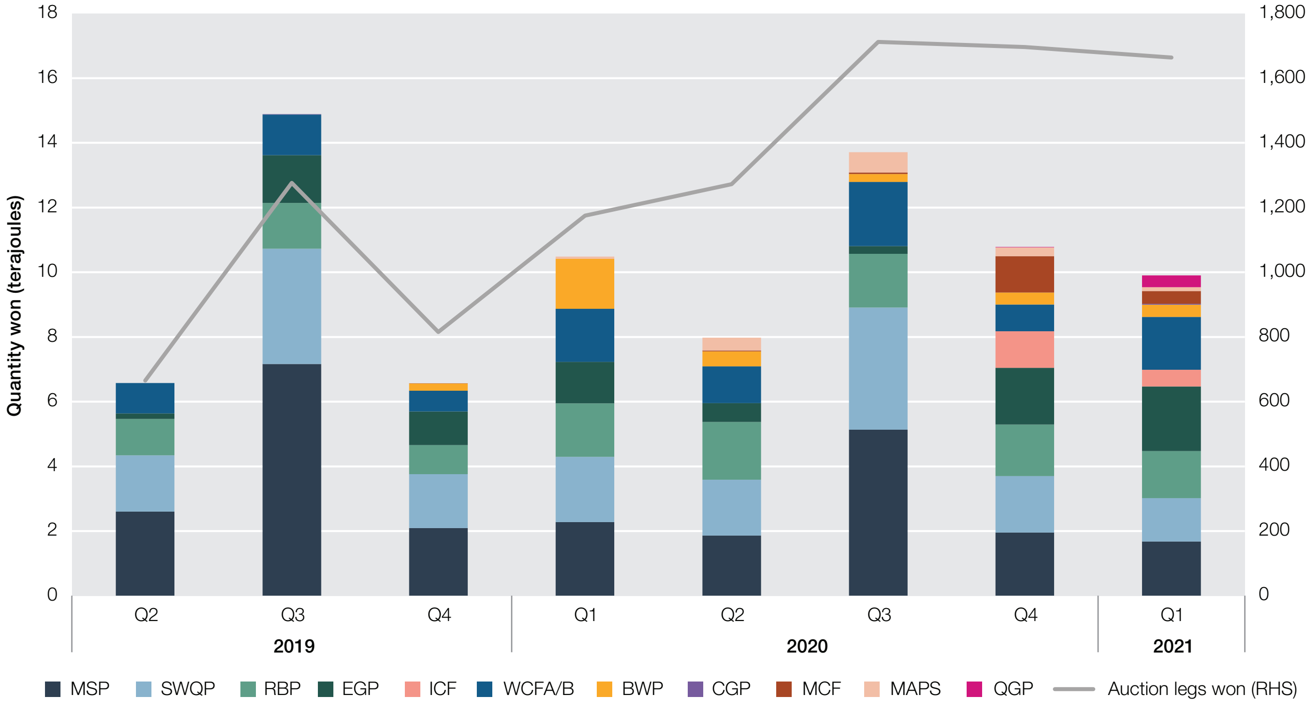
The rebound in demand for LNG late in the year through the Asian winter drove record eastern Australian LNG exports in 2020 (around 1,350 petajoules (PJ)) and record production in Queensland (over 1,500 PJ). But domestic spot prices did not rise to the same degree, as lower summer demand on the east coast mitigated linkages to global spot prices. In particular, gas used for electricity generation continued to fall across the year, particularly in the southern regions, and by early 2021 had fallen to the lowest quarterly level since 2005. As a result of lower demand, the southern markets were less reliant on northern production, and excess gas flowed from south to north.

These flows were supported by capacity purchased by participants through the day-ahead auction, which provided access to over 73 PJ of contracted, but unnominated, pipeline capacity in the 2 years since it launched in March 2019. More generally, the day-ahead auction has improved market dynamics by enhancing competition, especially in southern markets. Access to low or zero cost pipeline capacity is allowing shippers to move gas from relatively low priced markets into other, more expensive markets, easing price pressures. The AER estimated the auctions reduced monthly average spot gas prices by as much as $0.63 per GJ in the Sydney market over the 2 years to December 2020.

While improvements have been made to market transparency and pipeline access, concerns remain that the regulatory framework favours pipeline operators, with shippers facing information asymmetries and being exposed to potential exercises of market power. In May 2021 Energy Ministers set out their preferred approach to improve the regulatory framework.[4]

4 Energy Ministers, *Options to improve gas pipeline regulation, Regulation Impact Statement for Decision*, May 2021.

Figure 4 Day-ahead auction quantities won, by facility



BWP: Berwyndale to Wallumbilla Pipeline; CGP: Carpentaria Gas Pipeline; EGP: Eastern Gas Pipeline; ICF: Iona Compression Facility; MAPS: Moomba to Adelaide Pipeline; MCF: Moomba Compression Facility; MSP: Moomba to Sydney Pipeline; QGP: Queensland Gas Pipeline; RBP: Roma to Brisbane Pipeline; SWQP: South West Queensland Pipeline; WCFA/B: Wallumbilla compression facilities.

Source: AER analysis of day-ahead auction data.

Despite changing market conditions, forecast concerns around eastern Australia's supply–demand balance have persisted as Victorian production wanes. In 2021 the Australian Competition and Consumer Commission (ACCC) forecast that potential supply shortfalls could emerge in the southern states by 2024. Similarly, AEMO forecast supply scarcity risks in the southern states for winter 2023 under certain conditions.

Both AEMO and the ACCC have identified a range of projects that could mitigate the supply risk. The recently approved Narrabri Gas Project has the potential to supply up to 200 terajoules (TJ) of gas per day. Also, in May 2021 APA Group announced it would be expanding key pipelines linking east coast markets to increase capacity by up to 25%. In addition, there are currently 5 LNG import terminals under consideration in NSW, Victoria and South Australia. Of these, the most progressed is Australian Industrial Energy's Port Kembla proposal in NSW, which has the potential to supply up to 500 TJ of gas per day.

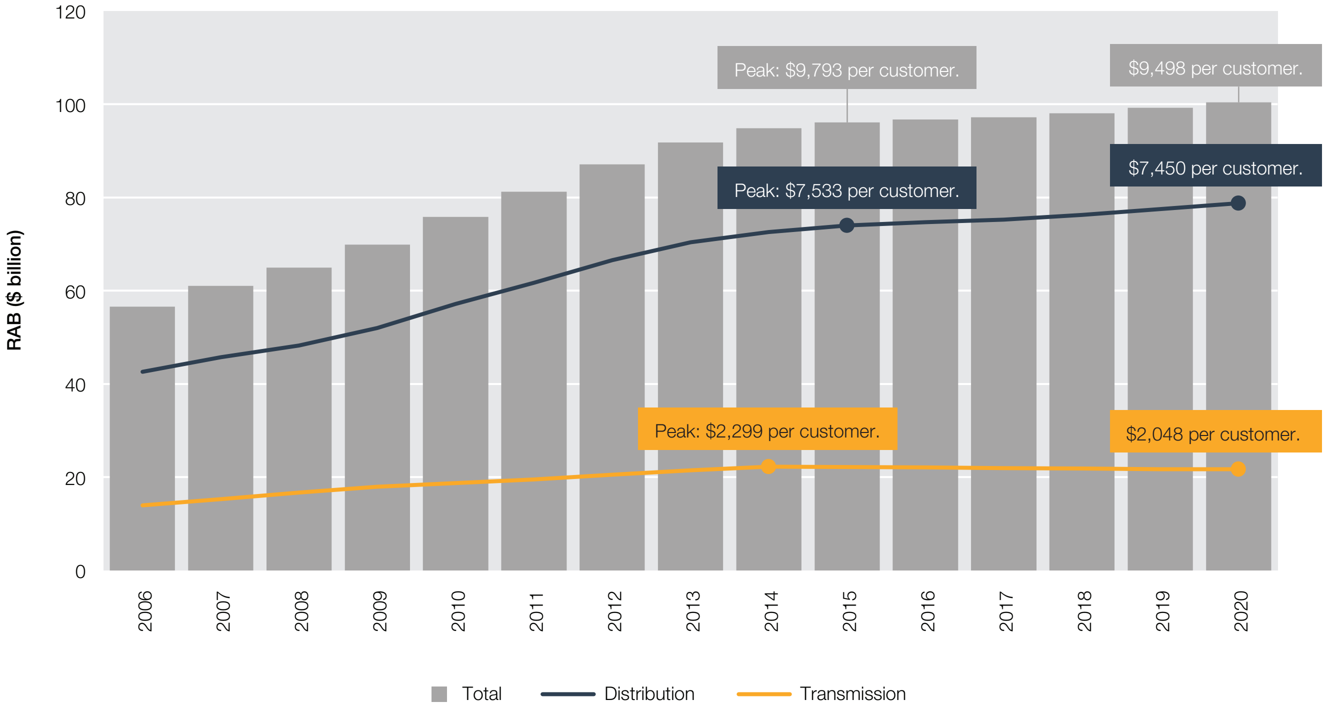
There is a risk that these projects will not come online in time, however, as many have already faced significant delays. The Narrabri Gas Project has faced significant opposition and regulatory hurdles since proposal, and the LNG import terminals slipped from their original timeframes due to planning, environmental and other challenges. While, if completed, projects under development should avert supply issues in the near term, supply gaps could emerge by 2026, or earlier if committed projects experience delays.

In response to ongoing supply uncertainty, the Australian Government and some state governments have launched initiatives to encourage new projects to supply the domestic market. In 2020 the Australian Government announced a number of measures as part of its gas-fired recovery plan to facilitate the development of new sources of supply. These include extending the heads of agreement with Queensland producers, providing funding to support the further development of key gas basins, and exploring a gas reservation scheme. In May 2021 the Australian Government also released its first interim National Gas Infrastructure Plan, which identifies priority projects critical to addressing expected gas supply shortfalls.

Electricity and gas networks

In 2020 the value of the regulatory asset base (RAB) for electricity network businesses exceeded $100 billion for the first time – a 1.2% increase over the previous year. However, growth in customer numbers offset the impact of this increase, with RAB per customer falling to $9,498 in 2020 – 3% lower than its peak in 2015.

Figure 5 Value of electricity network assets (regulatory asset base)



RAB: regulatory asset base.

Note: Closing RABs for electricity networks in the National Electricity Market, consumer price index (CPI) adjusted to June 2021 dollars. Most network businesses report on a 1 July – 30 June basis. The exceptions are Victorian networks: AusNet Services (transmission) reports on a 1 April – 31 March basis, and the Victorian distribution network businesses report on a 1 January – 31 December basis. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018). Transmission networks do not report customer numbers. Per customer metrics for the transmission network were calculated using the total number of distribution customers.

Source: AER modelling; economic benchmarking regulatory information notice (RIN) responses.

In 2020 the average residential electricity distribution customer consumed 0.8% more energy from the distribution network than they did in the previous year – the second consecutive year of mildly increasing consumption. This compares to a trend of decreasing average consumption since 2008, by around 2% per year, due in large part to the rapid uptake of rooftop solar PV systems. The opposite was experienced by business customers, with average electricity use falling by 4.5% over 2020. This marked the largest single annual fluctuation in the past 14 years for these customers.

The COVID-19 pandemic drove a significant change in electricity usage over 2020 as residential customers spent more time at home and many businesses were forced to close or change how they operated. This change was most pronounced in Victoria, which experienced a longer lockdown than other regions. Over 2020 Victorian residential usage increased by around 4%. Victorian business customer usage reduced by over 8% in 2020.

The average network customer experienced significantly more total minutes off supply in 2020 (350) than in the previous year (275). The increase was largely driven by the impact of the devastating bushfires which burned throughout the spring and summer of 2019–20, destroying thousands of homes and burning over 17 million hectares of land across Australia.

Customers also experienced a significant increase in the frequency and duration of planned interruptions to supply in 2020, driven by Ausgrid's (NSW) decision to temporarily pause all live work on its network for safety reasons.

However, in 2020 the distribution businesses generally performed well against their reliability performance targets, which exclude the impact of extreme events.

Network businesses are adapting to a changing operating environment. The impact of storms and bushfires over recent years has emphasised the importance of electricity system resilience as extreme weather events become more frequent and intense. In 2020 a number of distributors applied to the AER to pass through costs linked to extreme weather events that damaged their networks.

Distribution networks are also addressing system security issues from the rapid growth in rooftop solar PV. Until recently, distributors could not charge for export services into the grid, and hosted rooftop solar exports as a 'free' service. In effect, the costs of network congestion and voltage instability caused by rooftop solar PV were paid for by all consumers through higher energy bills.

Distributors have sought to manage the issue through efficient expansion of their networks and by imposing solar export limits, in some cases as low as zero. From February 2021 new minimum technical standards require rooftop solar PV to be able to ride through voltage disturbances. Draft pricing reforms released in March 2021 allow networks to charge for transporting electricity both from the grid and into it to better signal the cost of network services.[5] Proposed new 'solar export charges' would allow network businesses to signal the value of excess electricity produced by rooftop solar PV at different times of the day. The networks will also receive incentives to identify and implement a level of export service valued by their customers.

Market signals should encourage efficient investment in distributed energy resources such as battery storage or EVs that can provide network support services and help manage system demand, particularly when coordinated through virtual power plants. While uptake of these technologies has been slow, trials are underway to identify how best to integrate them into the NEM.

Retail energy markets

Electricity retail prices have become slightly more affordable over the past 3 years as sharply declining electricity wholesale costs since 2019 started to flow through to retail customers. Between June 2018 and February 2021, median market offer prices for residential customers fell by 8–16% in Queensland, 10–18% in NSW, 7–10% in Victoria, 19% in South Australia, and 4% in the Australian Capital Territory (ACT). Tasmania was the only region to record a rise (less than 1%) in market offer prices over this period. Standing offer prices also fell over this period, particularly between 2019 and 2020, when the AER's Default Market Offer (DMO) role (and similar Victorian provisions) commenced to limit the level of standing offers in most regions, removing inflated offers from the market.

Price competition at the lower end of the market intensified over 2020, with prices of the lowest offers in most regions reducing more than the median market or standing offer. The cheapest market offers were typically offered by smaller tier 2 retailers. A residential customer switching from the median electricity market offer to the best market offer in most jurisdictions could save $180–300 annually in February 2021. Potential savings were lower in Victoria, at $110–150 annually.

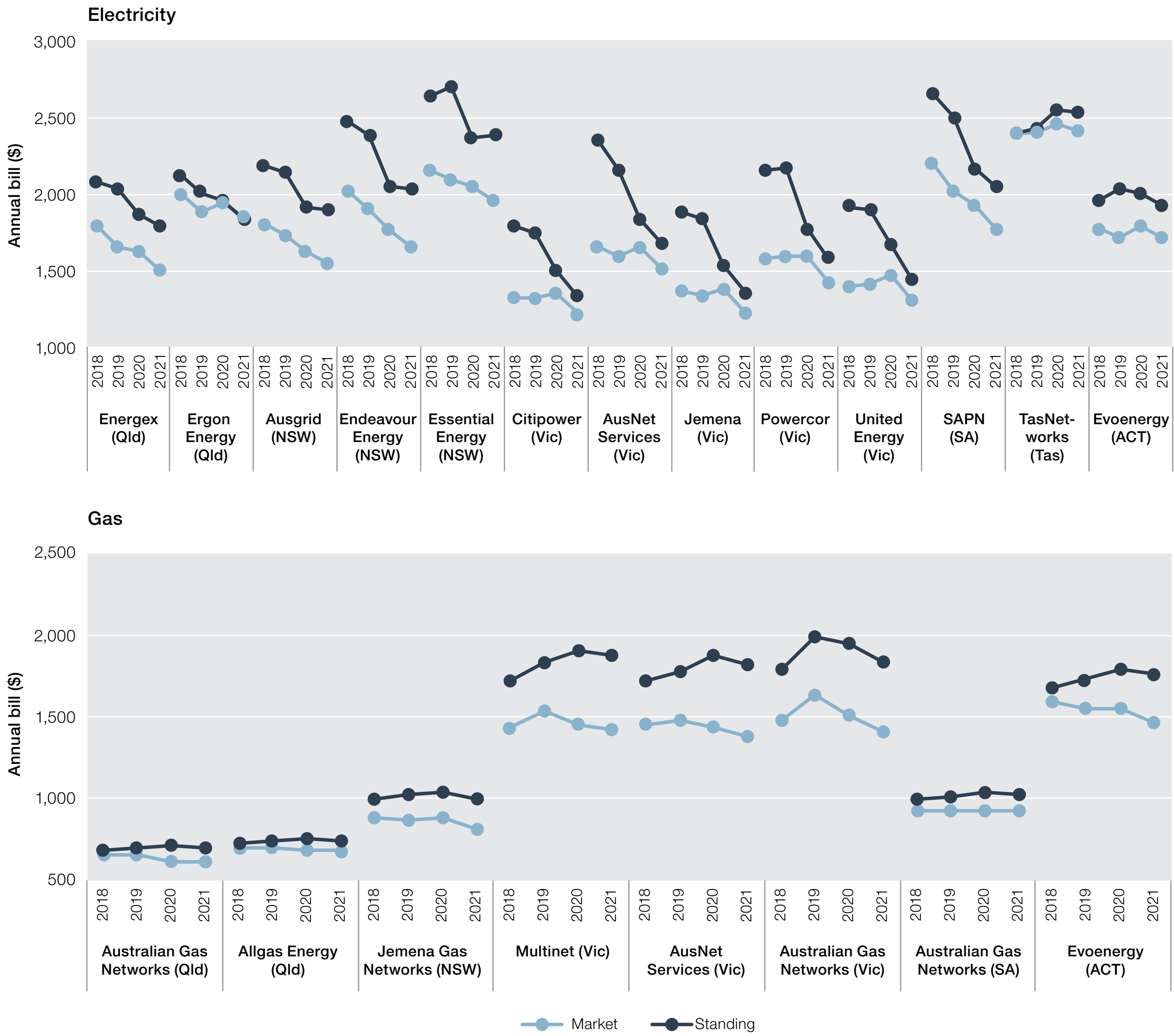
Lower wholesale costs are forecast to drive electricity retail prices even lower. The AER's DMO determination for 2021–22 will reduce the price cap on standing offer prices for residential customers in south east Queensland, NSW and South Australia by between 2.7% and 7.4%. The Australian Government introduced legislation in June 2020 that requires retailers to pass on to customers any sustained and substantial decreases in the costs of electricity.[6]

Gas retail prices have followed a similar path to electricity prices, with lower wholesale gas costs leading to a decline in retail prices since 2018 in most regions. But price reductions were less pronounced than for electricity. Between June 2018 and February 2021 median gas market offer prices fell by 3–8% in Queensland, 8% in NSW, 2–5% in Victoria, and 8% in the ACT. South Australia was the only region to record a rise (of less than 1%) in market prices over this period. A customer switching from the median gas market offer to the best market offer in their distribution zone in February 2021 could save from $50 annually in Queensland to almost $300 in the ACT.

5 AEMC, *National electricity amendment (access, pricing and incentive arrangements for distributed energy resources) rule, draft rule determination*, March 2021.

6 *Treasury Laws Amendment (Prohibiting Energy Market Misconduct) Act 2019*.

Figure 6 Movement in energy bills for customers on market and standing offers



Note: AER estimates based on generally available offers for residential customers on a 'single rate' tariff structure.

Annual bills and price changes are based on median market and standing offers at June 2018, June 2019, June 2020 and February 2021, using average consumption in each jurisdiction: NSW 5,881 kWh (kilowatt hours) (electricity), 22,855 megajoules (MJ) (gas); Queensland 5,699 kWh, 7,873 MJ; Victoria 4,589 kWh, 57,064 MJ; South Australia 4,752 kWh, 17,501 MJ; ACT 6,545 kWh, 42,078 MJ.

Market offer prices include all conditional discounts.

Source: Energy Made Easy (www.energymadeeasy.gov.au); Victoria Energy Compare (compare.energy.vic.gov.au).

Reforms were introduced in 2020 to cap conditional discounts (such as 'pay on time' discounts) in retail offers. Conditional discounts can result in much higher energy bills if the conditions are not met, and opaque advertising of these offers makes it difficult for customers to assess whether an offer is right for them. Customers in financial difficulty are more likely to face higher bills as a result of missed conditional discounts. In 2019–20, 18% of customers in hardship programs or on payment plans failed to meet conditional discounts compared to 11% of all customers.[7]

Caps on conditional discounts, along with earlier reforms that simplified and standardised how offers are presented (including a 'reference bill' against which all offers must be compared; and restrictions on advertising conditional discounts), have led to retailers moving away from this practice. In February 2021, 83–91% of offers in Queensland, NSW, Victoria and South Australia had guaranteed prices (no conditional discounts) – up from 43–60% in 2019. Similar outcomes were seen for gas offers. The size of offered discounts also reduced over this period. In February 2021 conditional discounts were typically less than 10% of the original bill.

While energy prices have moderated in recent years, they continue to be a source of financial pressure for customers in vulnerable circumstances. The COVID-19 pandemic magnified financial stress over 2020 and led to many households facing payment difficulties for the first time as a result of reduced income and higher household energy use.

The AER's Statement of Expectations set out additional customer protections, including a ban on retailers disconnecting any small (residential or small business) customer in financial distress. This protection was in place until August 2020, with disconnections allowed after that date in limited circumstances. Disconnections of residential customers remained well below the previous year in the period following the lifting of restrictions – down more than 70% from October to December 2020.

The number of customers in debt rose over 2020 – up 16% from a year earlier – and 2.9% of customers were in debt at December 2020.[8] But this rise followed a trend of falling numbers of customers in debt since 2015, with the number of customers in debt in 2020 still well below the number between 2015 and 2018.

Along with an increase in the number of customers in debt over 2020, the level of debt held by those customers also increased across all regions. The average value of debt at December 2020 was $1,008 (up from $796 in the previous year). This continued a trend of increasing debt levels since 2015.

Hardship customers had higher levels of debt than other customers. Electricity debt for hardship customers reached record levels by December 2020, averaging $1,584. This was 58% higher than debt levels at December 2018. Gas hardship customer debt levels also increased over the past 2 years, rising 42% to an average $745.

High debt levels of hardship customers are compounded by relatively high average energy usage for these customers. Customers on hardship programs in the third quarter of 2020 consumed on average over 60% more electricity than a typical customer (2,129 kWh per quarter compared to 1,310 kWh).[9] This may reflect that financially vulnerable customers have less access to solar PV systems and are residing in properties and using electrical appliances that are less energy efficient. High ongoing energy costs from this electricity use contributes to around 40% of hardship customers not meeting ongoing usage charges, meaning their debt levels will continue to increase.

Reforms to strengthen customer protections and encourage customers to engage (to their benefit) in the market, and a period of reducing prices, have contributed to improved customer satisfaction in the energy market. But there is much still to do, with only 38% of residential customers expressing confidence in the market in December 2020 (up from 21% in December 2017).[10] Pleasingly, 70% of customers were confident in their ability to navigate the energy retail market – the highest recorded in the 4 years that surveys have been undertaken by Energy Consumers Australia.

This increase in customer confidence has not translated into higher levels of market activity. Small customer switching decreased in 2020 in all regions for electricity customers, with NSW, Victoria and South Australia recording their lowest annual switching rates in the past decade. Customer switching rates peaked in 2018 following the introduction of initiatives to encourage customer engagement, but have declined in recent years.

7 ACCC, *Inquiry into the National Electricity Market, May 2021 report*, June 2021.

8 Energy debt refers to electricity and gas debt that has been outstanding for 90 days or more.

9 ACCC, *Inquiry into the National Electricity Market, May 2020 report*, May 2020.

10 Energy Consumers Australia, *Energy consumer sentiment survey, December* 2020.

Ongoing reform processes will impact on customer engagement. The Australian Government (Treasury) is progressing work to implement a national Consumer Data Right for energy, which will increase access to consumers' data to support comparisons of offers and underpin new energy services. The Consumer Data Right framework for energy is expected to be finalised in 2021.[11] Also, from August 2022, new customer billing rules will provide retailers with more flexibility in how they present information to customers, including through digital platforms.

While customer engagement has reduced over the past year, retailer activity continues to expand. Since the start of 2020, 11 new retailers have been authorised to retail electricity and 2 to retail gas. Five new brands commenced selling electricity.

New products were introduced that reflect the increasing penetration of solar and to cater for early adopters of batteries and EVs. Some of these products have a time-of-use pricing structure but with rates set to encourage charging/discharging of batteries or EVs at specific times. These products may also come with add-on services such as automated systems that learn customers' usage patterns and charge/discharge batteries to maximise value. Some offers allow customers to become part of a virtual power plant that aggregates multiple household solar and battery systems to provide power for network support or frequency control ancillary services or to engage in wholesale price arbitrage.

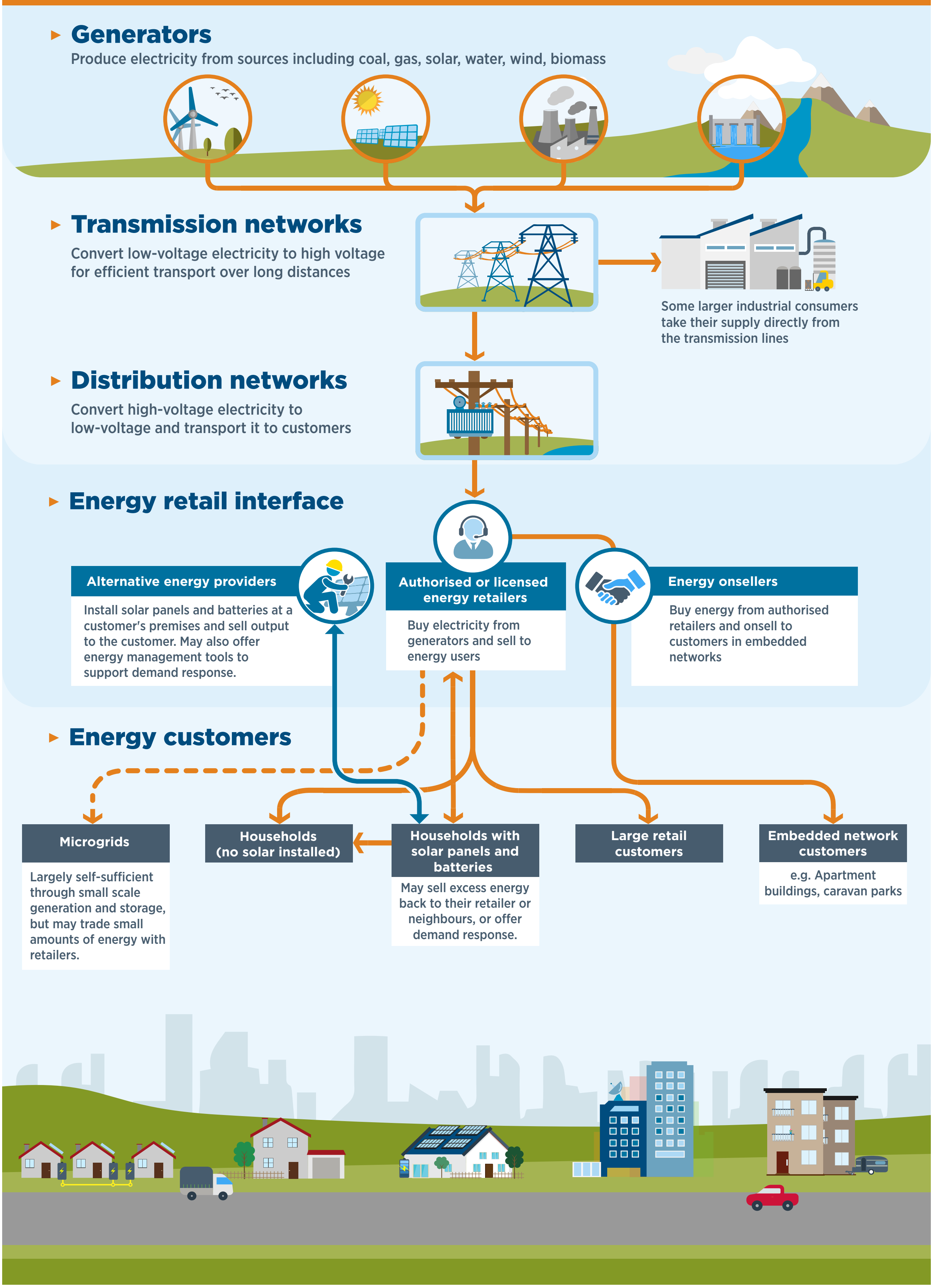
Retailers have also been required to manage the transition to cost-reflective network tariffs underway since 2017. Retailers receive these price signals from networks, but have freedom to decide how to pass on the changes to their customers. The AEMC found that despite progress at the network level, cost-reflective tariff reform at the consumer level has proven to be difficult to implement. The AEMC cited a lack of clarity about how network tariffs could play out through retailers, how retailers will translate tariffs to customers, and what protections will be available for vulnerable consumers as factors contributing to slow progress.[12] Survey responses from members of an AEMC technical working group rated 'retailer support and the extent of pass through into retail tariffs' as the largest cause of delay to the pace of tariff reform.

The limited penetration of smart meters (or manually read interval meters) for residential and small business customers is another factor limiting the uptake of cost-reflective tariffs. At February 2021 around 39% of customers in the NEM had metering capable of supporting cost-reflective tariffs. But installation rates vary across regions. Around 98% of Victorian customers had access to a smart meter. NSW had the next highest penetration of smart or interval meters at around 25% of customers. Installation levels in other regions ranged from 15% of customers in Queensland to 23% of customers in the ACT.

11 ACCC, *Energy rules framework, consultation paper*, July 2020.

12 AEMC, *Electricity network economic regulatory framework 2020 review*, final report, 1 October 2020, p 45.

Infographic 1 – Electricity supply chain



Infographic 2 – Gas supply chain

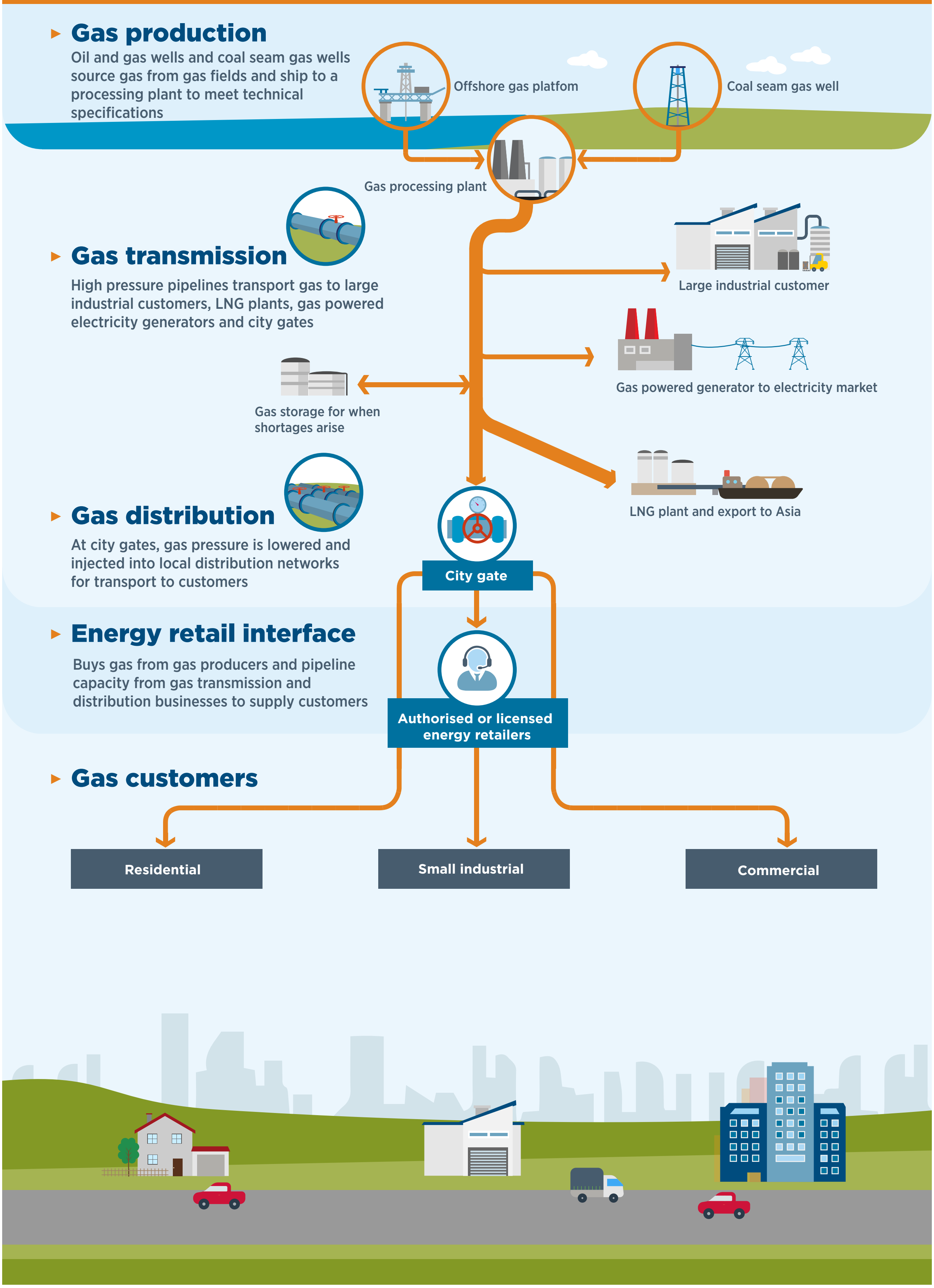


Image courtesy of Powering Australian Renewables.

1

The electricity market in transition

Australia's electricity markets are undergoing a profound transformation from a centralised system of large fossil fuel (coal and gas) generation towards an array of smaller scale, widely dispersed wind and solar generators, grid scale batteries and demand response.

The mix of electricity generation is changing, both at grid scale and at the individual customer level. Ageing coal fired and gas powered generation has left the market and been replaced by large scale wind and solar capacity.

Additionally, some energy customers are adopting their own 'behind the meter' energy solutions – namely, distributed energy resources (DER) that include rooftop solar photovoltaic (PV) installations, small batteries, electric vehicles (EV) and demand response. Where power once moved in one direction, from large generators through transmission and distribution lines to end customers, significant 2-way flows of power now occur. At times electricity demand from the grid is close to zero in some regions.

A web of interrelated factors has driven (and continues to drive) this transition. Community concerns about the impact of fossil fuel generation on carbon emissions are a major catalyst, driving policy initiatives by governments and behavioural change by energy customers and businesses. Government incentives for lower emissions generation encouraged early investment in wind, solar farms and small scale solar PV systems. A trend of rising energy prices over the past decade gave further impetus to this transition by driving customers to use energy more efficiently and to generate their own power. These developments helped establish Australia's solar PV and wind industries.

While government policies on climate change helped drive the surge in renewable energy, the declining costs of renewable plant (both commercial and small scale) have made them the most economic options for new build generation. This cost advantage over thermal plant is forecast to widen over the next 2 decades as economies of scale and technology improvement further reduce costs, particularly for solar plant and batteries.

The weather-dependent nature of renewable generators makes their output variable and sometimes unpredictable. The market needs 'firming' capacity (such as fast-start generation, demand response and battery storage) to fill supply gaps when a lack of wind or sunshine curtails renewable plant. Sophisticated demand and supply forecasting is also required to ensure sufficient firming capacity is available when needed.

Coal and gas powered generators also provide the market with inertia and system strength which help stabilise the grid.[1] Reduced output from these plants as renewables output grows makes the transmission network more susceptible to erratic frequency shifts and voltage instability.[2] And, with new plants locating in sunny or windy areas at the edges of the grid where network capacity is limited, additional measures are needed for efficient supply to customers. Two-way power flows are also creating similar pressure points in local distribution networks.

Finding the best ways to keep the power system reliable and secure as the generation mix evolves continues to be a pivotal challenge. Improved data and technology services provide some solutions. New renewables plants, for example, are now required to provide some system security services traditionally provided by fossil fuel plants. During the transition, however, more frequent market interventions have been needed to maintain a reliable and secure power system.

Strategic planning and policy and regulatory reforms are being implemented to guide the transition to optimise benefits for energy customers. A new fit-for-purpose electricity market framework – NEM 2025 – is being developed to ensure the market signals opportunities for new generation investment and for services needed for system security, and to effectively integrate DER.

A well-managed transition will deliver significant benefits. Renewable energy is a relatively cheap fuel source and, if integrated efficiently into the power system, can deliver low cost sustainable energy. For customers, the uptake of solar PV and battery systems (when supported by appropriate control systems) can help them save on power bills and manage energy use in ways to suit their needs, while also empowering them to take initiative on environmental concerns.

1 Box 1.4 defines these terms.

2 Box 1.4 defines these terms.

1.1 Drivers of change

Community concerns about the impact of fossil fuel generation on carbon emissions, along with technology changes and an ageing coal fired generation fleet, are among factors that have driven and continue to drive Australia's energy market transition.

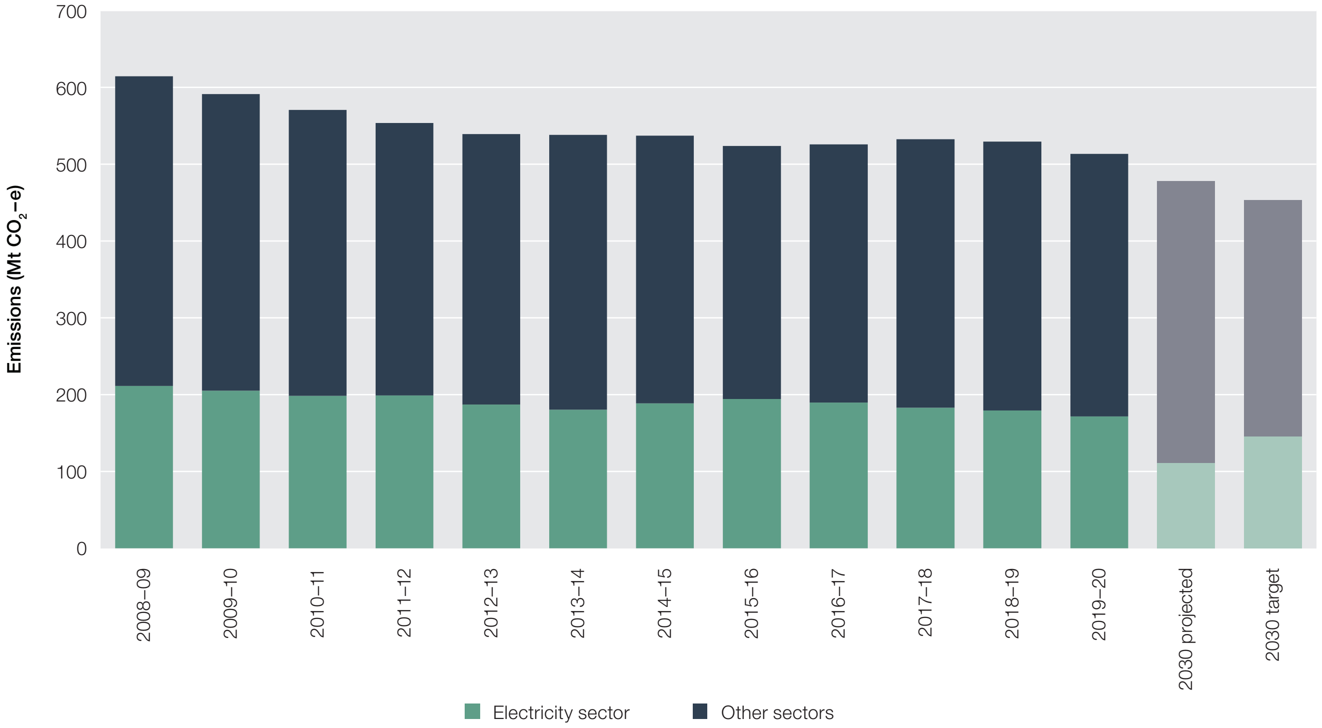
1.1.1 Action on climate change

Environmental concerns were a major catalyst for the transition underway in the electricity sector. Australia has international commitments under the Paris Agreement (2016) to reduce its carbon emissions by 26-28% below 2005 levels by 2030. The agreement set no specific target for the electricity sector.

Australia's carbon emissions have trended down over the past decade (figure 1.1). The electricity sector has become increasingly important in driving this trend, with emissions reductions of almost 12% over the past 5 years. Emissions across other sectors rose by 4% over this period.

Despite this shift, the electricity sector remains the largest contributor to national carbon emissions, accounting for 33% of Australia's total emissions in 2019–20. Victoria's brown coal plants are the most emission-intensive power stations in the NEM, followed by black coal plants in Queensland and New South Wales (NSW) and gas powered generation. Wind, hydroelectric and solar PV power stations generate negligible emissions.[3]

Figure 1.1 Australia's carbon emissions



Mt CO_2-e: million metric tonnes of carbon dioxide equivalent.

Note: Electricity sector emissions exclude stationary energy, transport and fugitive emissions.

The 2030 target is based on Australia's Paris commitment of a 26% reduction on 2005 emissions levels and assumes a proportional contribution by the electricity sector.

Projected 2030 emissions are as forecast by the Department of Industry, Science, Energy and Resources in December 2020 in the absence of policy intervention.

Source: Department of Industry, Science, Energy and Resources, *Quarterly update of Australia's national greenhouse gas inventory*, June 2020; Department of the Environment and Energy, *Australia's emissions projections*, December 2020.

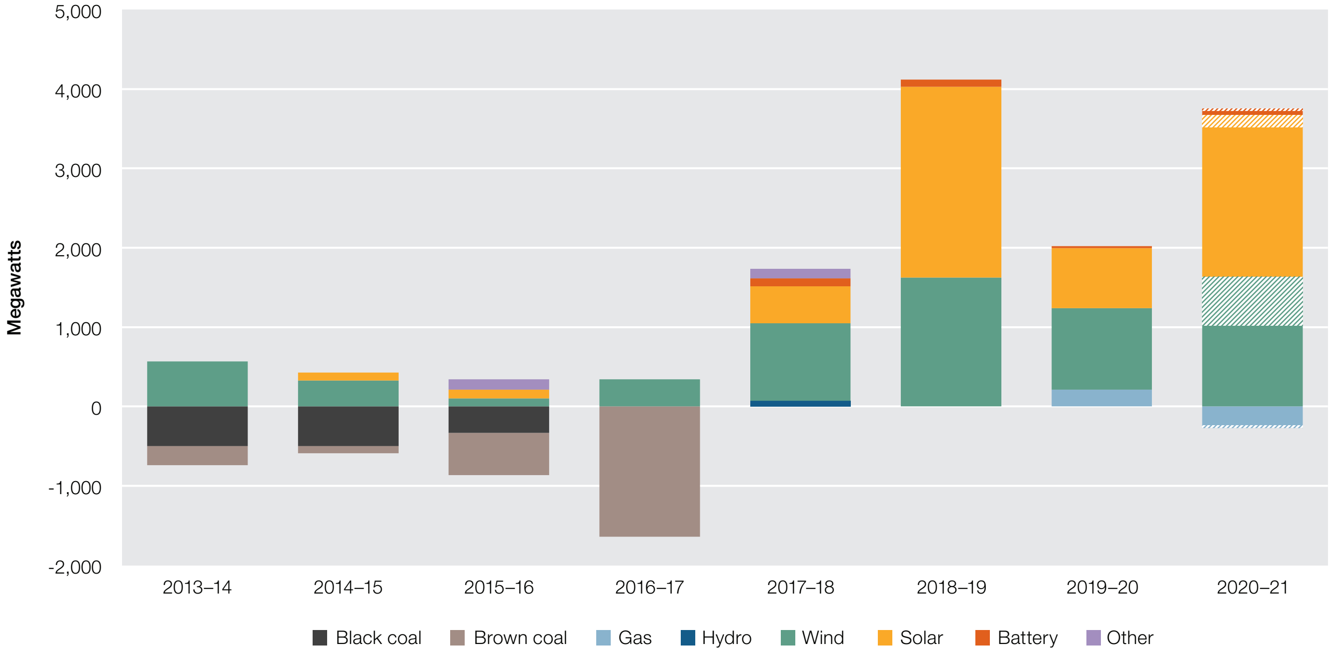
3 Department of the Environment and Energy, *National greenhouse accounts factors,* October 2020.

Australian Government policies to reduce carbon emissions focus on financial incentives for private investment in lower emission generation (box 1.1). The schemes have encouraged significant investment in wind and solar farms and small scale solar PV systems.

Alongside national policies, several state and territory governments set renewable energy targets that are more ambitious than the national scheme. Programs encouraging new renewable entry typically support these targets. More generally, several jurisdictions have launched comprehensive energy plans that include climate change settings and new initiatives to meet targets (section 1.7).

Energy businesses have also responded to concerns about climate change through new strategies for generation investment. No energy business has invested in new coal fired generation in Australia since 2012 (figure 1.2). Commercial businesses are also self-generating more of their energy requirements (mostly through solar PV systems).

Figure 1.2 Entry and exit of generation capacity in the National Electricity Market



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).

Box 1.1 Emission reduction policies and the electricity industry

Australian government policies aimed at reducing carbon emissions from electricity generation are outlined below.

Renewable energy targets

The Australian Government operates a national Renewable Energy Target (RET) scheme that incentivises large (such as wind and solar farms) and small (such as rooftop solar photovoltaic (PV)) scale energy supply. It requires energy retailers to buy renewable energy certificates for electricity generated by accredited power stations or from the installation of eligible solar hot water or small generation units. The certificates allow renewable generators to earn revenue above what they earn from selling electricity in the wholesale market.

The RET scheme set a 2020 target for energy from large scale renewable projects at 33,000 gigawatt hours (GWh). Sufficient renewable generation was committed by September 2019 to meet this target.[4] The Australian Government's policy is to not increase the target beyond the 2020 requirement and to not extend or replace the target after it expires in 2030.[5] As renewable generation capacity in the market has expanded beyond that needed to meet the 33,000 GWh target, renewable energy certificate values have fallen.

Some state and territory governments set renewable energy targets that are more ambitious than the national scheme:

- The Victorian Government set a legislated target of 25% of the state's electricity to be sourced from renewable resources by 2020, 40% by 2025 and 50% by 2030. Victoria met its 25% target in 2020.
- The Australian Capital Territory (ACT) Government achieved its legislated target of 100% of Canberra's electricity being met by renewable generation by 2020. It has a broader target for the ACT to be carbon neutral by 2045.
- The South Australian Government is targeting 100% net renewable energy generation by 2030. It has also announced plans to achieve renewable energy of more than 500% of current local grid demand by 2050.
- The Queensland Government has an unlegislated target of 50% renewable generation by 2030.
- New South Wales (NSW) does not have a renewable energy target but aims to achieve net zero emissions statewide by 2050.

To support these targets, state and territory governments run programs encouraging investment in renewables:

- The Queensland, Victorian, and ACT governments have offered 'contracts for difference' to new renewable generation investments and batteries, awarded through reverse auctions.[6]
- The Queensland Government established CleanCo, a new generation company that directly invests in renewable and gas firming capacity.
- Queensland, NSW and Victoria are developing renewable energy zones to reduce the risks and costs of renewables investment. The NSW Government's Electricity Infrastructure Roadmap proposes underwriting 12 GW of renewable energy across 5 renewable energy zones.
- The Queensland, Victorian, South Australian and ACT governments operate schemes that provide grants, rebates or loans to support small scale solar PV and battery systems.

More generally, state and territory governments operate energy efficiency schemes that encourage households and small business customers to reduce their electricity demand.

4 Clean Energy Regulator, '2020 Large-scale Renewable Energy Target capacity achieved' [media release], CER, 4 September 2019.

5 Commonwealth, Parliamentary Debates, House of Representatives, 18 September 2018, 9325 (The Hon Angus Taylor MP, Minister for Energy).

6 Contracts for difference provide a hedge for the holder by locking in future wholesale electricity prices (section 2.7).

Australian Renewable Energy Agency and the Clean Energy Finance Corporation

The Australian Government funds 2 key renewable energy investment agencies – the Australian Renewable Energy Agency (ARENA) and the Clean Energy Finance Corporation (CEFC).

ARENA was established in 2012 to fund the research, development and commercialisation of renewable technologies. The agency funds innovative projects that would otherwise struggle to attract sufficient funding or be potentially lost to overseas markets.

From its inception to February 2021, ARENA invested $1.7 billion in over 550 projects, with a combined value of $6.9 billion. The projects include solar PV, hybrid, solar thermal, bioenergy, ocean, hydrogen, geothermal, grid integration, battery and pumped hydro storage projects. ARENA's focus since 2019 has been on projects that integrate renewables into the electricity system, accelerate the development of hydrogen energy supply and support industry efforts to reduce emissions.[7]

The CEFC was launched in 2012 as a government-owned green bank to promote investment in clean energy. The fund provides debt and equity financing (rather than grants) for projects that will deliver a positive return. CEFC finance of around $8 billion has supported around 200 large scale projects and 18,000 smaller scale projects, including commercial solar and wind, and storage and energy efficiency projects.[8]

Additionally, ARENA and the CEFC jointly manage the Clean Energy Innovation Fund, which provides debt and equity for clean energy projects at early stages of development that require growth capital.

In September 2020 the Australian Government proposed an amendment to the rules governing ARENA and CEFC to widen the scope of low emissions technologies they may support. It committed to additional funding of $1.9 billion for the agencies to invest in technologies including carbon capture and storage, hydrogen, soil carbon and green steel.

The government also introduced legislation for the CEFC to administer a $1 billion Grid Reliability Fund to fund the Underwriting New Generation Investment (UNGI) program (section 1.7.1). The fund aims to encourage private investment in generation, energy storage and transmission projects to balance the grid and deliver affordable power. The legislation defines gas as a low emissions technology to enable the CEFC to support gas generation projects under the fund. The legislation was before parliament in early 2021.[9]

Climate Solutions Fund

Under the Australian Government's Climate Solutions Fund (called the Emissions Reduction Fund until February 2019), the government pays for emission abatement through 'reverse' auctions run by the Clean Energy Regulator. Twelve auctions were held to April 2021, with spending commitments of $2.5 billion to abate 205 million tonnes of carbon emissions (an average price of $12.32 per tonne of abatement).[10]

In total, around 66 million tonnes of carbon abatement had been delivered by April 2021. Many funded projects involved growing native forests or plantations. The electricity sector made less than 2% of the carbon abatements under the scheme. Participating electricity projects mostly capture and combust waste methane gas from coal mines for electricity generation.[11]

Following a review, in May 2020 the government announced an expansion of the scheme, including the scoping of carbon capture and storage technology.[12] The model for participants to offer abatement under these categories is scheduled for completion by September 2021.

7 ARENA, *ARENA at a glance*, ARENA website, accessed 16 February 2021.

8 CEFC, *2019–20 investment update*, 2020.

9 Parliament of Australia, Clean Energy Finance Corporation Amendment (Grid Reliability Fund) Bill 2020, Australian Parliament House website, accessed 23 March 2021.

10 Auction results published by the Clean Energy Regulator, available at: www.cleanenergyregulator.gov.au/ERF/Auctions-results.

11 Projects do not necessarily connect to the NEM.

12 The Hon Angus Taylor MP (Minister for Energy and Emissions Reduction), 'Building on the success of the Emissions Reduction Fund' [media release], 19 May 2020.

1.1.2 Technology and cost changes

While government policies on climate change helped drive the surge in renewable energy, the declining costs of renewable plant (both commercial and small scale) accelerated the shift. Improvements in plant technologies and the scale benefits of an expanding market are driving these cost improvements.

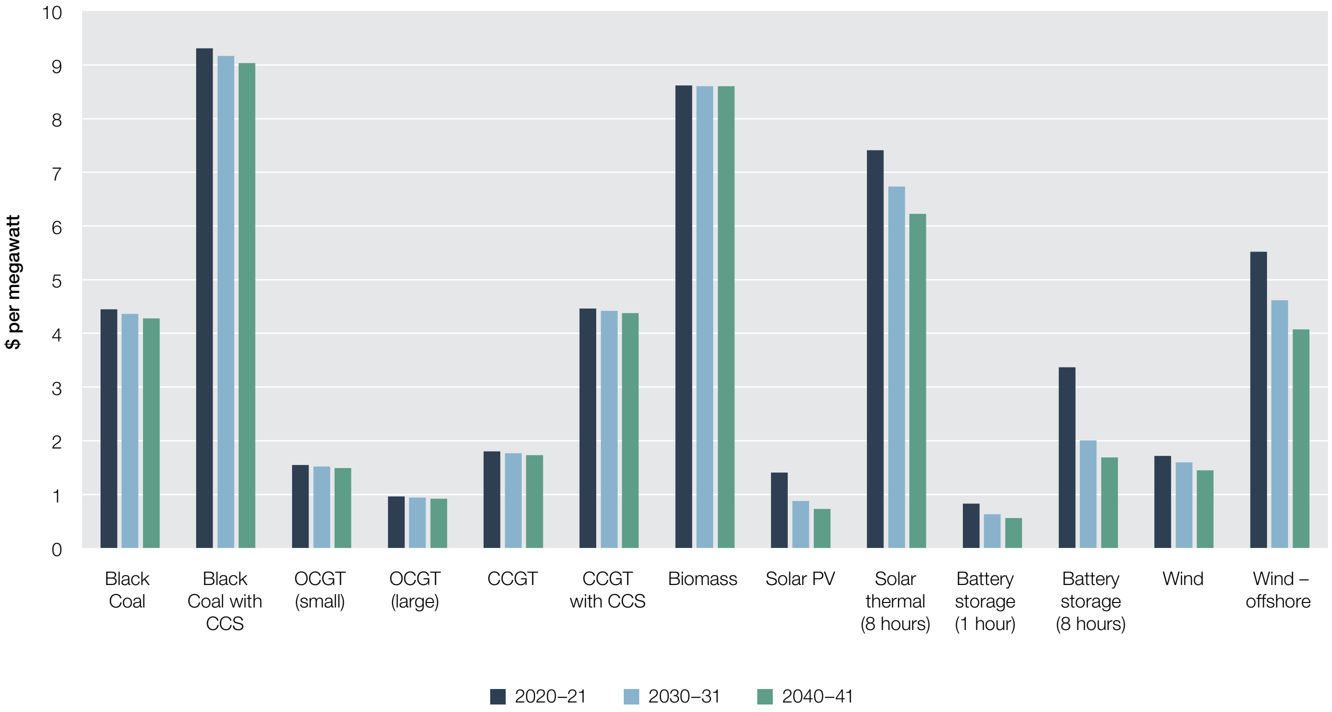
The International Renewable Energy Agency (IRENA) reported the global levelised cost of electricity (LCOE) of onshore wind generation fell by 38% between 2010 and 2019. Over the same period, it reported the global LCOE of large scale solar PV fell by 82%.[13]

In Australia, in December 2020 the Commonwealth Scientific and Industrial Research Organisation (CSIRO) estimated the LCOE in 2020 for large scale solar PV and onshore wind of around $45–70 per megawatt hour (MWh). They forecast the cost of onshore wind will continue to reduce marginally to 2040, but the cost of large scale solar PV will reduce by almost 50% in that time (figure 1.3).[14]

The substantial cost reductions for wind and solar technologies have made them the most economic options for new build generation and competitive with the operational costs of the current fleet of conventional generators. Factoring in storage and transmission costs needed to support up to 90% penetration of weather-dependent renewables, the CSIRO's upper cost estimate for wind and solar technologies was below $90 per MWh. In comparison, costs for new black coal and brown coal generation were estimated at $90–140 per MWh (and $170–300 for coal generation with carbon capture and storage). Gas generation was estimated at $70–120 per MWh. Both coal and gas plants face cost risks relating to fuel prices and uncertain carbon targets.[15]

Battery costs have also fallen. Bloomberg estimated lithium ion battery pack prices fell by around 89% between 2010 and 2020.[16] The CSIRO projected battery costs would fall by 24–40% between 2020 and 2030 (depending on battery size) and up to 50% by 2040 as global capacity for battery manufacturing rises to meet the demand for stationary storage and EVs.[17]

Figure 1.3 Forecast changes in generation capital costs



CCS: carbon capture and storage; CCGT: combined cycle gas turbine; OCGT: open cycle gas turbine; PV: photovoltaic.

Source: CSIRO, *GenCost 2020–21, consultation draft*, December 2020.

13 IRENA, *Power generation costs*, IRENA website, accessed 22 April 2021.

14 CSIRO, *GenCost 2020–21, consultation draft*, December 2020.

15 CSIRO, *GenCost 2020–21, consultation draft*, December 2020.

16 Bloomberg New Energy Finance, *2020 battery price survey*, December 2020.

17 CSIRO, *GenCost 2020–21, consultation draft*, December 2020.

Economics of fossil fuel generation

The declining costs of renewable generation coincide with deteriorating economics for fossil fuel generation, making the latter less competitive in the market and changing their operating patterns:

- The rapid escalation of solar PV generation is lowering electricity demand during the day, reducing wholesale prices and revenues for coal fired generation at these times.
- The ageing of Australia's coal fired generation fleet is causing more frequent and longer unplanned outages and higher operating and maintenance costs.

An ageing coal fleet

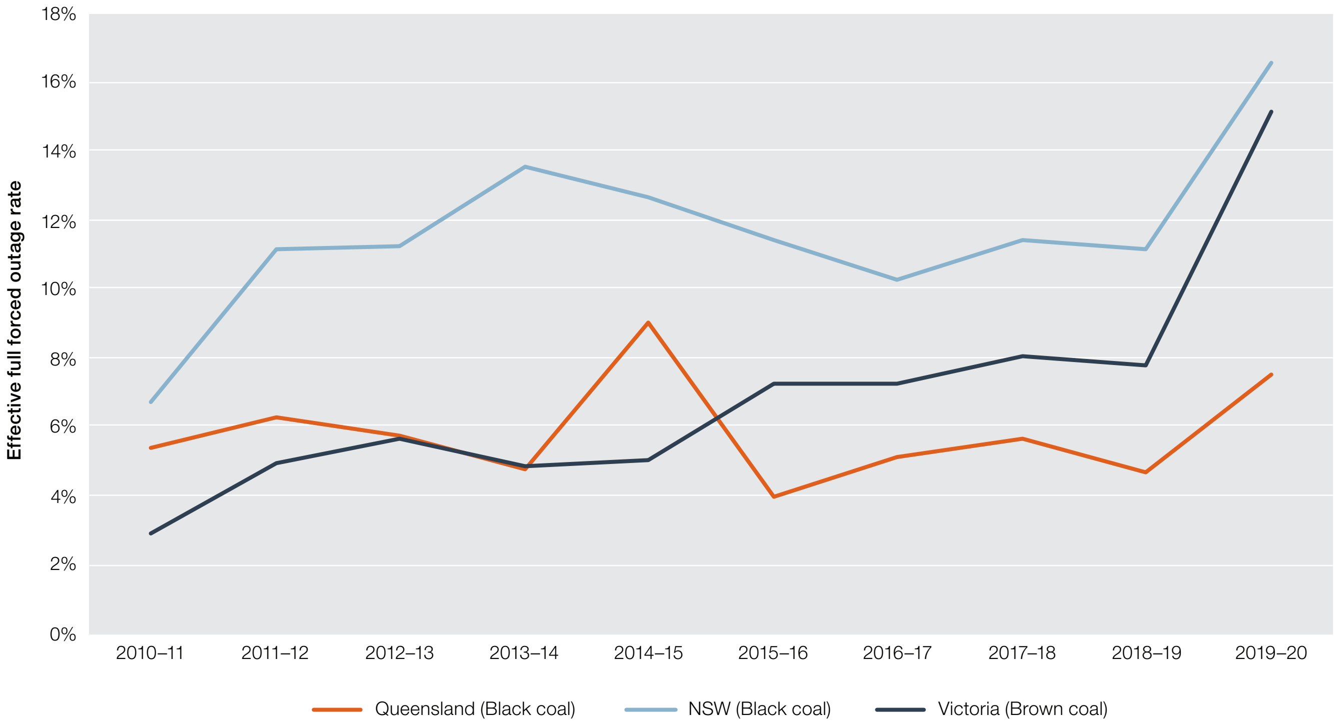
Australia's coal fired generators are ageing. Some have been retired and others are nearing the end of their economic life. Plant closures include Northern in South Australia (2016) and Hazelwood in Victoria (2017), which had become unprofitable due to rising maintenance costs and market penetration by other plant technologies. Further closures are scheduled in the coming years (section 1.2.1).

There are 18 remaining coal fired power stations in the NEM, with a median age of 35 years: 10 in Queensland (median age of 24 years), 5 in NSW (median age of 39 years) and 3 in Victoria (median age of 37 years).

In 2020 the Australian Energy Market Operator (AEMO) reported a trend of rising forced outages among fossil fuel plants due to breakdowns and more frequent and longer planned outages for maintenance and repair work.[18]

For each of the past 5 years, brown coal forced outage rates exceeded long term averages (figure 1.4). There was also a sharp increase in outages across black coal plants in NSW and Queensland in 2019–20.

Figure 1.4 Coal plant outages as a share of capacity



Source: AEMO, *2020 electricity statement of opportunities*, August 2020.

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

Impacts of solar generation on fossil fuel plant

When rooftop solar PV generation is high in the middle of the day, the demand for electricity from the grid falls significantly (section 1.2.3). This phenomenon drives down prices at these times, challenging the economics and operating capability of coal fired generators, which are not engineered to run at low levels of output. Minimum demand remains sufficient to cover the minimum technical operating levels of most coal plant. But, if demand drops below those levels, coal plant operations may be significantly disrupted.

Origin and AGL announced plans to alter the operation of their Eraring and Bayswater plants (NSW) respectively in coming years. Options include shutting some generating units from mid-morning before firing them back up in the evening. This process represents a significant shift in the operation of these plants.

The ability of generators to operate more flexibly varies depending on plant age and condition. The increased cycling of output compounds stress on equipment, potentially requiring more frequent maintenance (planned outages) or, in an extreme scenario, earlier retirement.

In 2021 the Energy Security Board (ESB) noted that recent company results showed owners of large coal fuelled generators are facing commercial difficulties in the current wholesale market. It also noted falling wholesale energy prices may result in retirement decisions on some plants being brought forward. In 2021 EnergyAustralia announced it will retire its Yallourn power station in Victoria in 2028, 4 years earlier than planned.[19]

1.2 Dimensions of the transition

Features of the energy market transition include an evolving technology mix in the generation sector, a rapid uptake of DER, a changing geographical spread of energy resources and significant changes in electricity demand.

1.2.1 A changing generation mix

Since 2014 more than 4 GW of coal fired and gas powered generation left the market. Over this same period, around 12.5 GW of large scale wind and solar capacity and 8.5 GW of rooftop solar PV has begun operating.

This shift is continuing. Over the next 2 decades, another 16 GW of thermal generation (61% of the current coal fleet in the NEM) is expected to retire as plants reach the end of their economic lives. Over the same period, 26–50 GW of new large scale wind and solar capacity is forecast to come online, along with 13–24 GW of rooftop solar PV.[20] To balance this, the NEM will need 6–19 GW of new utility scale, flexible and dispatchable resources by 2040. To put these numbers into perspective, the average NEM demand is currently around 20 GW.[21]

Coal fired plant retirements

No significant coal fired generation has been added to the market since a 240 MW upgrade of Eraring power station in 2012. Since then, several major plants have closed, including Wallerawang (NSW), Hazelwood (Victoria) and Northern (South Australia).

Further closures are foreshadowed (figure 1.5). AGL plans to progressively retire its Liddell power station over the next 2 years. It plans to retire one of the plant's 4 units in April 2022 but close the 3 remaining units in April 2023 to support system reliability over the 2022–23 summer.[22] The plant supplies around 10% of NSW electricity, but declining reliability means it often runs at less than half its current rated capacity. AGL intends to replace the plant with a mix of renewable generation, gas peaking capacity, batteries, and an upgrade of its Bayswater power station.[23]

Planned closure dates for a number of other plants have been brought forward. In March 2021 EnergyAustralia announced it would bring forward the phased closure of its Yallourn brown coal generator from 2032 to 2028.[24] EnergyAustralia will partly offset the reduction in capacity by building a 350 MW, 4-hour battery by 2026.

19 EnergyAustralia, 'EnergyAustralia powers ahead with energy transition' [media release], 10 March 2021.

20 AEMO 2020 ISP – Central and Step Change Scenario – transmission and generation outlook files, cited by ESB, *Post 2025 market design options – a paper for consultation*, April 2021.

21 AEMO 2020 ISP – Central and Step Change Scenario – transmission and generation outlook files, cited by ESB, *Post 2025 market design options – a paper for consultation, part A*, April 2021.

22 AGL, 'Schedule for the closure of AGL plants in NSW and SA' [media release], 2 August 2019.

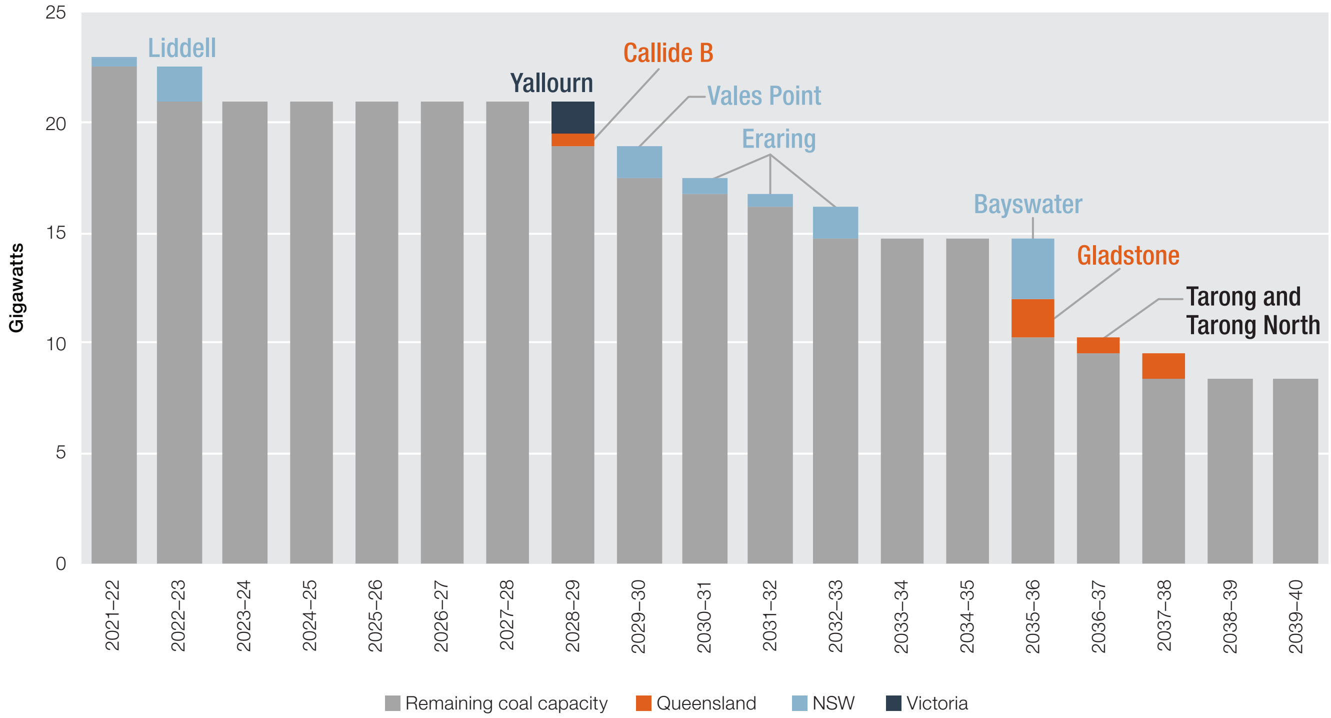
23 AGL, 'AGL announces plans for Liddell Power Station' [media release], 9 December 2017.

24 EnergyAustralia, 'EnergyAustralia powers ahead with energy transition' [media release], 10 March 2021.

AEMO forecast a further 11 GW of coal fired generation capacity in Queensland and NSW will retire between 2028 and 2038. Those closures would leave Mount Piper in NSW (1,320 MW) and Loy Yang A and B in Victoria (3,120 MW) as the NEM's last remaining coal fired power stations outside Queensland.

Despite plant closures, coal fired generation remains the dominant supply source in the NEM, meeting around 66% of energy requirements in 2020.[25] Utilisation rates of some remaining coal plants have risen to cover the supply gap left by the closures.

Figure 1.5 Scheduled closure profile of coal fired generators



Source: AEMO, *2020 Integrated System Plan*, July 2020. Data updated for recent market announcements.

Gas powered generation

Investment in gas powered generation over the past decade has been limited. AGL's 210 MW Barker Inlet power station in South Australia, commissioned in 2019 to replace its Torrens Island A power station (being progressively retired from 2020 to 2022), was the NEM's first new gas plant since 2011.

While gas powered generation output has reduced in recent years, it plays an increasingly important role in managing the variability of output from weather-dependant wind and solar plant. In the past, gas powered generation's critical role was to meet maximum summer demand, but it increasingly supports the market in winter when solar PV generation is lower and coal fired capacity tends to be withdrawn from the market for maintenance.[26]

Around 4 GW of gas powered generation is forecast to retire over the next 2 decades.[27] But multiple proposals for new gas plant are on the table in Queensland, NSW, Victoria and South australia. In May 2021 EnergyAustralia committed to developing a 316 MW gas plant in NSW by 2023–24. The Australian Government has 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 to be operated by Snowy Hydro in the Hunter region of NSW. It has also announced support for 2 gas plant proposals (in Queensland and Victoria), through its Underwriting New Generation Investment (UNGI) scheme (section 1.7.1).

25 Based on total generation (including rooftop solar PV) to meet electricity consumption.

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

27 AEMO, *2020 Integrated System Plan*, July 2020, p 44.

Weather-dependant renewable generation

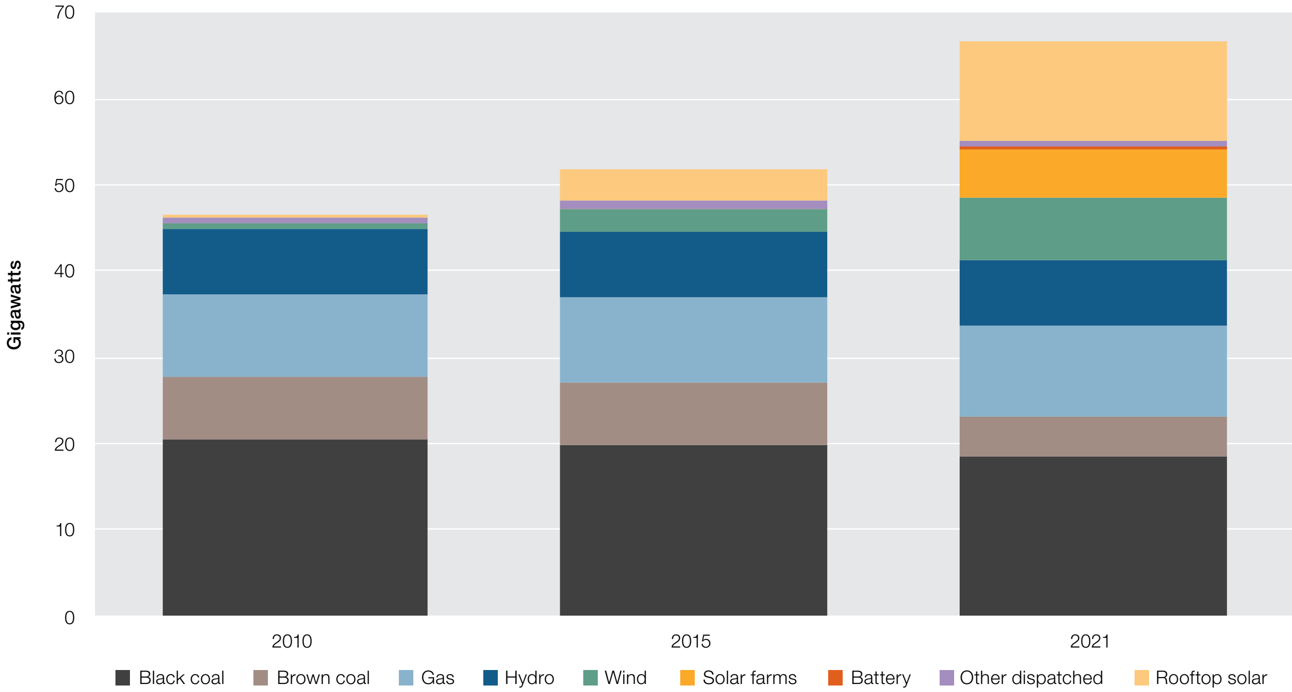
The decline in coal plant capacity since 2014 is in contrast to around 12,500 MW of weather-dependant renewable plant (mainly wind and large solar) coming online (figures 1.6 and 1.7). These technologies account for over 90% of proposed new generation investment. Figure 1.8 illustrates the impact of these shifts on the output of different plant technologies.

A feature of the transition is a shift away from the traditional model of having relatively few large power stations congregated close to fossil fuel sources towards having many small to medium generators spread out across the system. New solar and wind plants are being constructed in windy or sunny parts of the grid, but many of these locations are remote areas where the network capacity is limited.

Sections 1.5 and 1.6 discuss some challenges in managing this issue and solutions being developed.

While total capacity in the market has increased, renewable generators produce less energy for each MW of capacity installed than conventional plant because wind and solar plants can operate only when weather conditions are favourable. For every 1 MW of coal plant retiring, 2–3 MW of new renewable generation capacity is needed.[28]

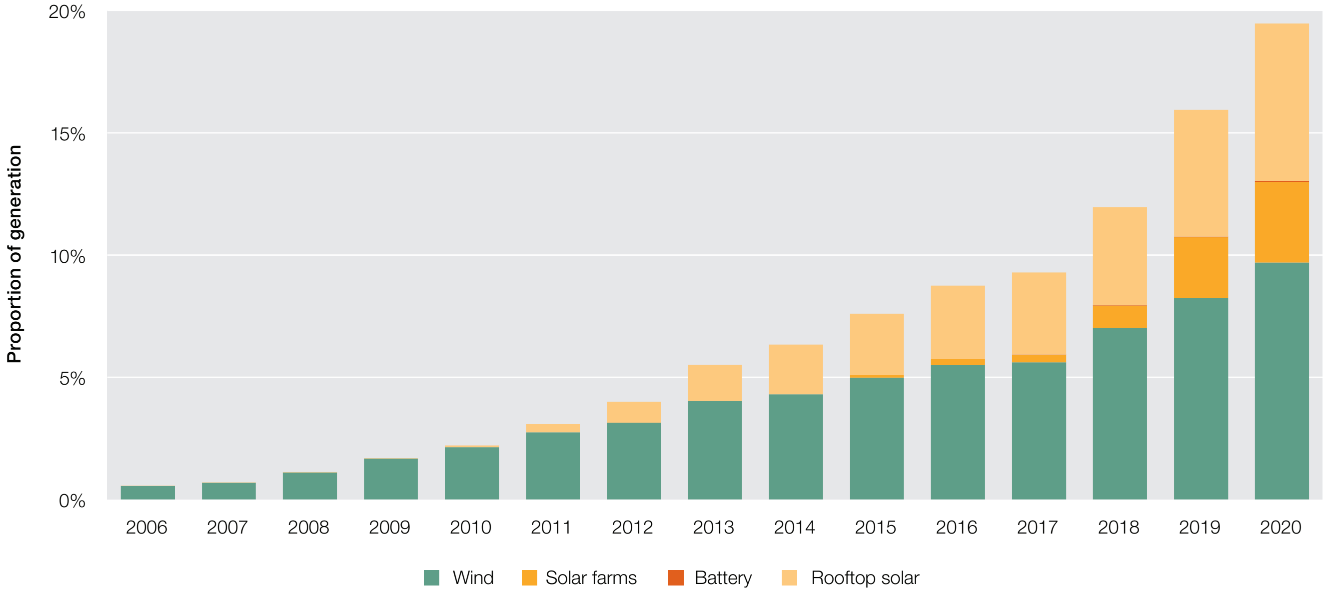
Figure 1.6 Generation capacity, by technology



Note: January (summer) capacity.
Source: AER; AEMO (data).

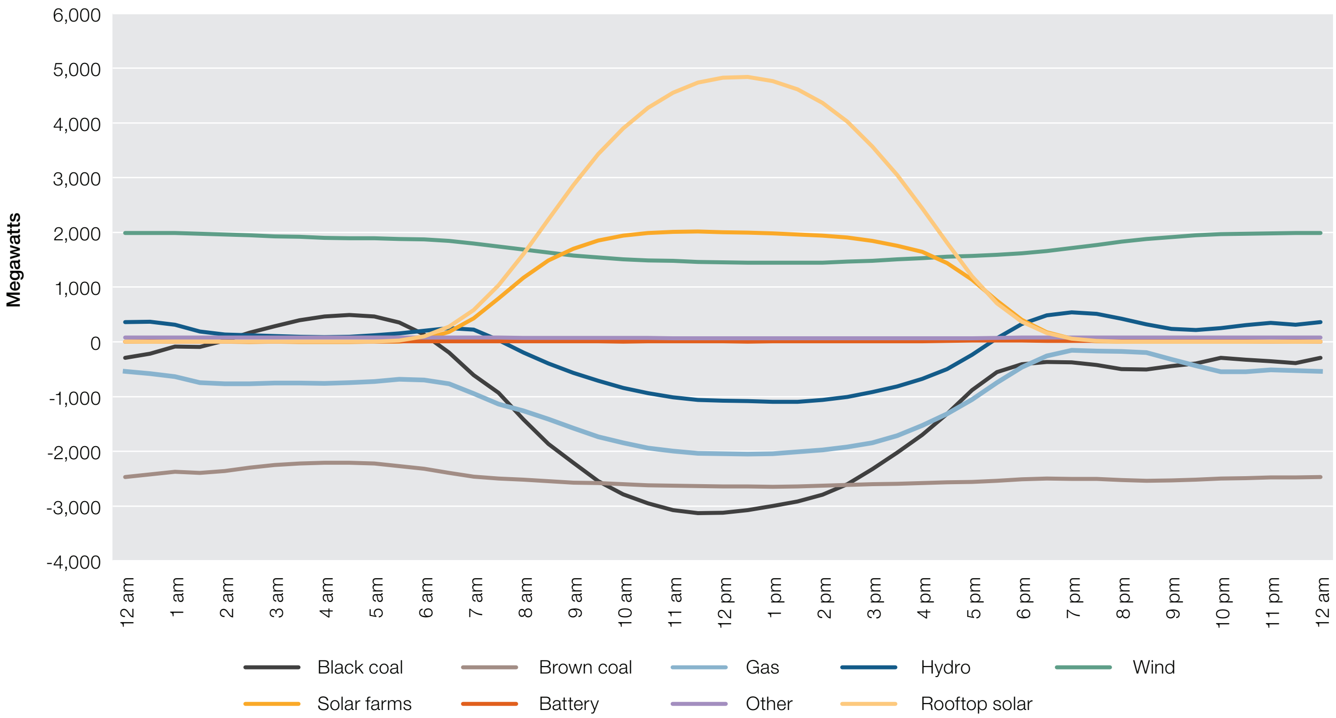
28 AEMO, *Draft 2020 Integrated System Plan*, December 2019.

Figure 1.7 Renewable generation in the National Electricity Market



Source: AER; AEMO (data).

Figure 1.8 Changing generation profile, by time of day, 2010–2020



Note: Comparison of average generation by time of day in 2010 and 2020. The 2010 rooftop PV generation is estimated using the average 2010 daily generation, allocated to intervals using 2020 proportions.

Source: AER; AEMO (data).

Volatility in supply and demand

Increased wind and solar generation in the NEM is creating more volatile supply and demand conditions. Since wind and solar generation relies upon specific weather conditions as a fuel source, its output is variable and can at times be difficult to predict. Solar production depends on the level of light received, so output is lower on cloudy days and in winter, when the days are shorter and the sun is lower in the sky. Wind production varies based on wind speed. By comparison, coal, gas and large hydroelectric generators can stockpile fuel for continuous use. While those plant technologies are also susceptible to outages or fuel shortages, their output when they are operating is more predictable and controllable.

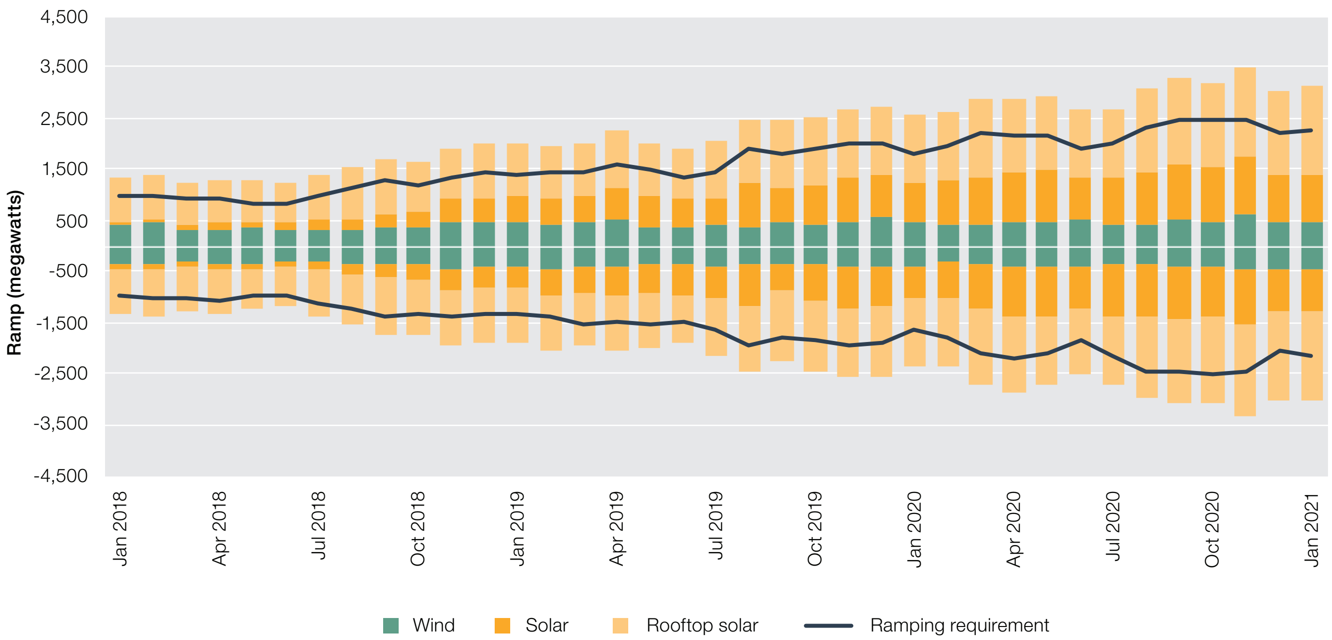
Wind and solar generators typically bid so they can generate when available, with more expensive sources of supply responding to their variability. Apart from variations caused by weather, renewable plant owners can also respond quickly to changes in economic signals (by, for example, switching off a plant if wholesale prices are too low).

As the contribution of weather-dependent generation increases, the power system must respond to increasingly large and sudden changes in output caused by changes in weather conditions and dispatch decisions by plant operators. Figure 1.9 illustrates the increasing scale of hourly changes in renewable output (ramping) in the NEM since 2018, which must be managed by equivalent changes in dispatchable generation or demand. This trend indicates the increasing opportunity for resources (generation, storage and demand response) that can respond quickly to these changes.

Fast-response alternatives are becoming critical to balance supply and demand in this volatile environment. Gas, hydro and batteries are able to respond to the variability of wind and solar because they can frequently alter output while continuing to remain economic. These technologies have been a focus of recent policies designed to stabilise the grid. Demand response can also play an important role in responding to sudden shifts in output from renewable generators.

Accuracy in demand and weather forecasting is critical. Recent work has focused on innovative short term weather forecasting systems for wind and solar generators.[29]

Figure 1.9 Hourly ramping of wind and solar generation



Note: Monthly top 1% of up and down 60 minute ramps in the National Electricity Market.
Source: AEMO, unpublished data.

29 ESB, *Health of the National Electricity Market 2019*, February 2020, p 34.

Grid scale storage

Storing electricity is becoming increasingly commercially viable. The growth in renewable generation is creating more commercial opportunities for storage to offer fast-response power system stabilisation services.

South Australia's Hornsdale battery, commissioned in 2017 and upgraded in 2020 (to 150 MW), was the first large scale battery in the NEM. A further 4 battery projects (totalling 110 MW) have since been commissioned across South Australia and Victoria, and over 7,400 MW of battery storage has been proposed (table 2.2 and figure 2.16). Some of these battery storage systems are located adjacent to solar and wind farms to smooth the contribution from these plants and respond to price opportunities.

Battery storage is currently largely used for shorter term 'fast burst' storage of energy to help stabilise technical issues in the grid (such as in providing frequency control services). The Australian Energy Regulator (AER) estimated batteries earned around $63 million in 2019–20 from frequency services. The Hornsdale battery earned the majority of this revenue ($58 million) – more than 15 times the battery's spot earnings from wholesale energy sales.[30]

Longer term, large scale storage is also being pursued through pumped hydroelectricity 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 higher. Pumped hydroelectric technology has operated in the NEM for some time in Queensland (570 MW at Wivenhoe) and NSW (240 MW at Shoalhaven, 1,500 MW at Tumut 3 and 70 MW at Jindabyne). Increased market price volatility can provide opportunities to deploy this form of storage at a larger scale. 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) and a number of smaller projects in NSW and South Australia.

Hydrogen

There is growing interest in Australia in hydrogen's potential to support the power system. Hydrogen production is an electricity-intensive process that can be quickly ramped up or down to manage fluctuations in renewable generation or provide frequency control ancillary services. Stored hydrogen can also be used as a fuel source for electricity production by flexible generators that offer electricity reliability and stability services.

In 2020 the Australian Government identified clean hydrogen as a priority low emissions technology, with a stretch goal of production under $2 per kilogram (around $15 per gigajoule).[31] It also announced support for 5 regional hydrogen hubs to build demand for clean hydrogen.[32] The CSIRO outlined opportunities for hydrogen to compete favourably on a cost basis by 2025 in Australian applications such as transport and remote area power systems.[33]

State governments are exploring opportunities to use or export hydrogen and ARENA is supporting a number of demonstration-scale renewable hydrogen projects and other hydrogen research.[34]

1.2.2 Distributed energy resources

Alongside the major shift occurring at grid level has been the uptake of small scale DER, which are consumer-owned devices that can generate or store electricity or actively manage energy demand. The growth of rooftop solar PV, the projected growth of battery storage and EVs and continued advances in load control technologies to regulate the use of household appliances such as hot water systems, pool pumps and air conditioners have the combined potential to revolutionise the way many customers receive and use energy.

These DER have varying characteristics – for example, rooftop solar systems are mostly passive and generate electricity only when the sun is shining, while active resources such as batteries and EVs can both draw electricity from, and inject it into, the electricity grid at any time.

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

31 DISER, *Technology Investment Roadmap: first low emissions technology statement – 2020*, September 2020.

32 The Hon Angus Taylor MP, Minister for Energy and Emissions Reduction, 'Jobs boost from new emissions reduction projects' [media release], 21 April 2021.

33 CSIRO, *National hydrogen roadmap*, August 2018.

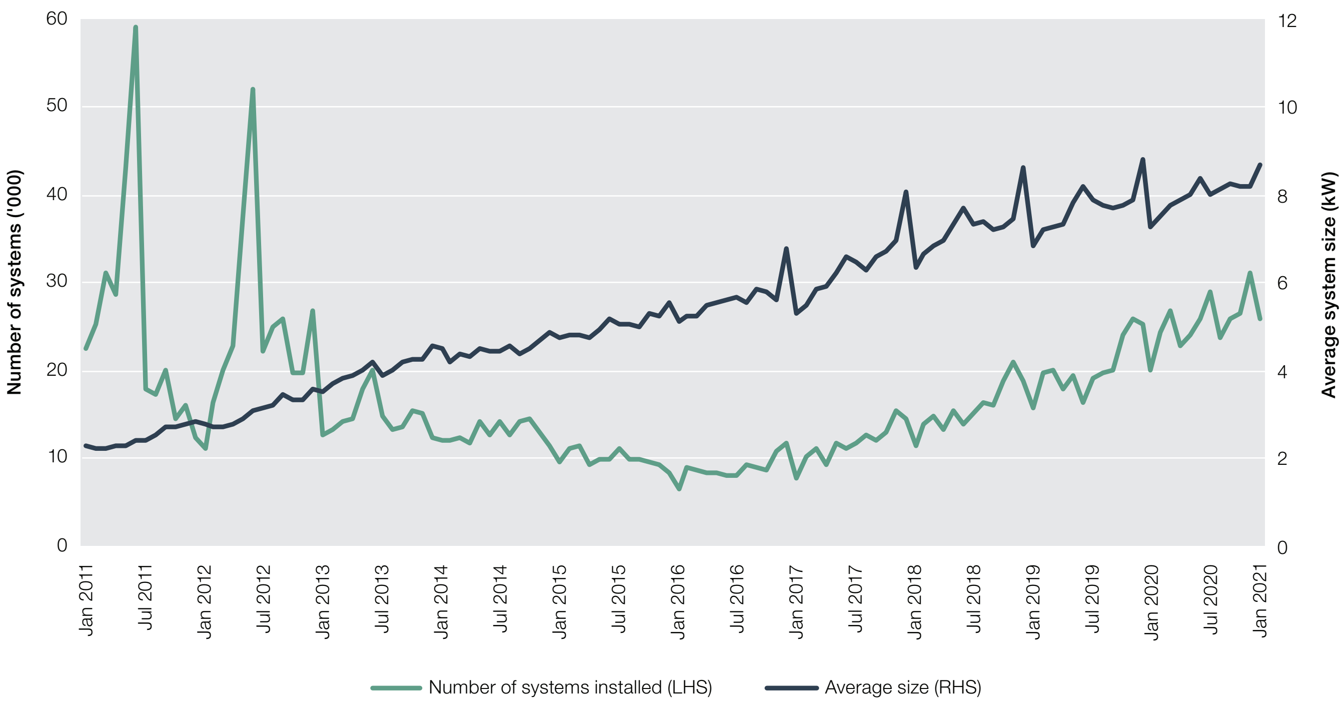
34 ARENA, *Hydrogen projects*, ARENA website, accessed 17 May 2021.

Rooftop solar photovoltaic installations

By far the fastest development has been in rooftop solar PV installations. Government incentives and declining installation costs have resulted in Australia having one of the world's highest per person rates of rooftop solar PV installation. Almost 24% of customers in the NEM partly meet their electricity needs through rooftop solar PV generation, and sell excess electricity back into the grid, compared with less than 0.2% of customers in 2007.[35] The combined capacity of these systems (11.4 GW) is around 17% of the NEM's total generation capacity and 4 times the size of the largest generator in the NEM (but dispersed through the country). Rooftop solar PV met 6.4% of the NEM's total electricity requirements in 2020.

Attractive premium feed-in tariffs offered by state governments drove the initial growth in solar PV installations. Despite the closure of those schemes, subsidies through the Australian Government's Small-scale Renewable Energy Scheme, combined with the falling costs of solar PV systems, has led to sustained strong demand for new installations. Total solar capacity installed in 2020 (2,470 MW) was 30% higher than the previous highest annual capacity in 2019, with both the number of systems installed (over 300,000) and the average system size (8.1 kilowatts (kW)) the highest recorded (figure 1.10).

Figure 1.10 Growth of solar photovoltaic installations in the National Electricity Market



Source: Clean Energy Regulator, *Postcode data for small scale installations, Small generation units—solar*, February 2021.

Batteries and electric vehicles

In coming years, customers will increasingly store surplus energy from solar PV systems in batteries and draw on it when needed. In this way, they will reduce their peak demand for electricity from the grid. The owners of DER can thus better control their electricity use and power bills, while taking initiative on environmental concerns. If DER is properly integrated with the power system, they could also help manage demand peaks and security issues in the grid (section 1.5.3).

But small scale batteries are not yet economic and uptake has been low. Of the 300,000 solar PV systems installed in the NEM in 2020, less than 3% had an attached battery system. The Clean Energy Regulator estimated customers in the NEM had installed 30,000 battery systems by February 2021.

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

The charging profiles of EVs will affect power flows in a similar way to batteries. Price incentives that discourage customers from charging during peak demand periods would ease potential strain on the power system. The Australian Government predicts that EVs will make up 26% of new car sales by 2030, with 1.3 million in use by that date.[36] AEMO forecasts around half that number under current policy settings, with EVs comprising just over 1% of NEM demand by 2029–30.[37]

ARENA is funding different projects to assess different approaches to optimise the use of EVs. For example, in July 2020 ARENA announced funding for ActewAGL Retail (ACT) to demonstrate that a fleet of EVs can provide similar grid services to big batteries and virtual power plants. The EVs used in the trial can be charged from mains power or rooftop solar but can also send electricity back to the grid. In February 2021 Jemena (Victoria) announced funding for a number of networks across the NEM to explore using hardware-based smart charging for dynamic management of residential EVs.

Baringa Consulting estimated that effective integration of DER into the grid, through network tariff reform and direct procurement of network support services, would generate around $2.3 billion of value over the next 20 years from avoided network investment and reduced curtailment.[38]

Standalone power systems

It is increasingly plausible for customers to wholly bypass the traditional energy supply model by going ‘off-grid’ through self-sufficient solar PV generation and battery storage.

Standalone power systems (SAPS) or microgrids – where a community primarily uses locally sourced generation and does not rely on a connection to the main grid – are gaining traction in some areas. The systems typically comprise solar panels, a large battery and a backup diesel generator which can coordinate decisions on charging and discharging and operate independently of the electricity grid. The arrangements mainly occur in regional communities that are remote from existing networks, enabling them to lower costs and increase reliability while also reducing the costs other consumers incur in maintaining distribution network infrastructure.

A SAPS may be privately owned and operated or may be owned and operated by a distribution network. Either way, the system may be operated for profit or community benefit.

Reforms are being implemented to support the growth of off-grid arrangements. Changes to the National Electricity Law and National Energy Retail Law announced in 2021 will allow distribution network providers to offer SAPS (where economically efficient to do so) while maintaining appropriate consumer protections and service standards. The Australian Energy Market Commission (AEMC) expects to deliver implementation measures during 2021.[39]

There is likely to be an increased role for SAPS and microgrids in how distributors meet their supply obligations and manage emergency and fault events. For example, the AER is considering how SAPS and microgrids could be used to reduce bushfire risk and manage network infrastructure replacement at lower cost, with implications for how they should be regulated and the terms of access and pricing.[40]

To support the timely and efficient deployment of SAPS in the early stages of market development, in May 2021 the AER published a draft ring-fencing guideline that exempts distribution networks from ring-fencing requirements for generation services provided through SAPS (up to a revenue cap). While ring-fencing aims to provide a level playing field by preventing network businesses discriminating in favour of related affiliates in competitive markets, existing rules may impede development of SAPS in situations when there are likely to be limited third party providers of SAPS generation services.[41]

36 DISER, *Future Fuels Strategy: discussion paper*, February 2021.

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

38 Baringa Consulting, *Potential network benefits from more efficient DER integration*, report for the ESB, June 2020. The estimate of network benefits is based on a central scenario. Benefits increase to around $11.3 billion under a step-change scenario.

39 AEMC, ‘AEMC welcomes consultation on revised rules to support distributor-led stand-alone power systems’ [media release], 25 March 2021.

40 Farrierswier, *Electricity network economic regulatory framework review 2020 – stakeholder interviews report*, 2020, p 16.

41 AER, *Draft electricity distribution ring-fencing guideline, explanatory statement*, May 2021.

Virtual power plants

Individually, DERs are largely invisible to the market and unable to participate in the wholesale market as a supplier of electricity unless they have sophisticated systems.

Virtual power plants (VPP) allow consumers with active forms of DER (such as battery storage, EVs or demand response) to aggregate with other providers at multiple points across the grid to coordinate decisions on charging and discharging. Aggregation creates opportunities for small scale resources to participate in markets such as those for demand management and frequency control services. A VPP (typically run by a retailer or aggregator) can bundle DER produced or stored electricity along with that of other consumers and then sell this energy.

Though most VPP projects in the NEM are relatively small, at around 5-10 MW of generation or storage capacity, AEMO anticipates up to 700 MW of VPP capacity by 2022.[42]

VPPs are mostly operated as part of trials to integrate the technology in to the NEM. AEMO has run virtual power plant demonstrations to test the technology's capabilities to deliver energy and grid stability services, the operational visibility of these arrangements, and the consumer experience.[43]

The Australian Renewable Energy Agency (ARENA) has provided funding to support trials of virtual power plants, including those run by AEMO. In 2019 ARENA provided funding to a trial by SA Power Networks to demonstrate how higher levels of energy exports from solar and battery systems can be enabled through dynamic, rather than fixed, export limits. In 2020 ARENA partially funded a trial led by Tesla to deploy 3,000 household solar and battery storage systems on residential properties owned by Housing SA. This is part of a larger project to connect up to 50,000 solar and battery systems across South Australia to form the world's largest VPP.

1.2.3 Changing patterns of electricity demand

As more electricity customers generate some of their own electricity needs through rooftop solar PV systems, the demand for grid-supplied electricity is changing. Output from rooftop solar PV systems met 6.4% of the electricity needs in the NEM in 2020 – up from 2.5% in 2015.

On 11 October 2020 South Australia operated for a period where over 100% of its regional demand was met by distributed and grid scale solar PV generation. Distributed solar PV alone met over 76% of regional demand for a few periods that day and over 70% for 4 hours. By 2025 other mainland NEM regions could be regularly operating close to or above 50% instantaneous penetration.

While solar generation is helping to meet energy demand, timing issues limit the extent of this assistance. In summer, daily energy use peaks in the late afternoon or early evening, when temperatures are high and business use overlaps with household use of air conditioning and other appliances. Winter demand peaks at a similar time of day, when households switch on heating appliances. Growth in rooftop solar PV has caused demand for grid-supplied electricity to peak later in the day. With peaks now occurring when solar output is low, scope for further support from solar PV may be limited. Rooftop solar PV systems met just 0.44% of electricity needs in the NEM at times of peak electricity consumption in 2020. The impact on peak demand was most pronounced (but still modest) in South Australia, with rooftop solar meeting 1.75% of peak electricity consumption. However, the impact of solar PV will typically be greater on the highest demand days over summer.

Rooftop solar PV generation is having a more profound impact on the level and timing of *minimum* demand for grid supplied electricity. Historically, demand reached its low point in the middle of the night, when most people are sleeping. But the growth in solar PV output in the middle of the day is lowering daytime grid demand, and minimum grid demand increasingly occurs then. Figure 1.11 shows how demand is falling in absolute terms, represented by the area under the curve, and how this shift is particularly apparent around midday. This hollowing out of demand through daylight hours is often called the 'duck curve'.

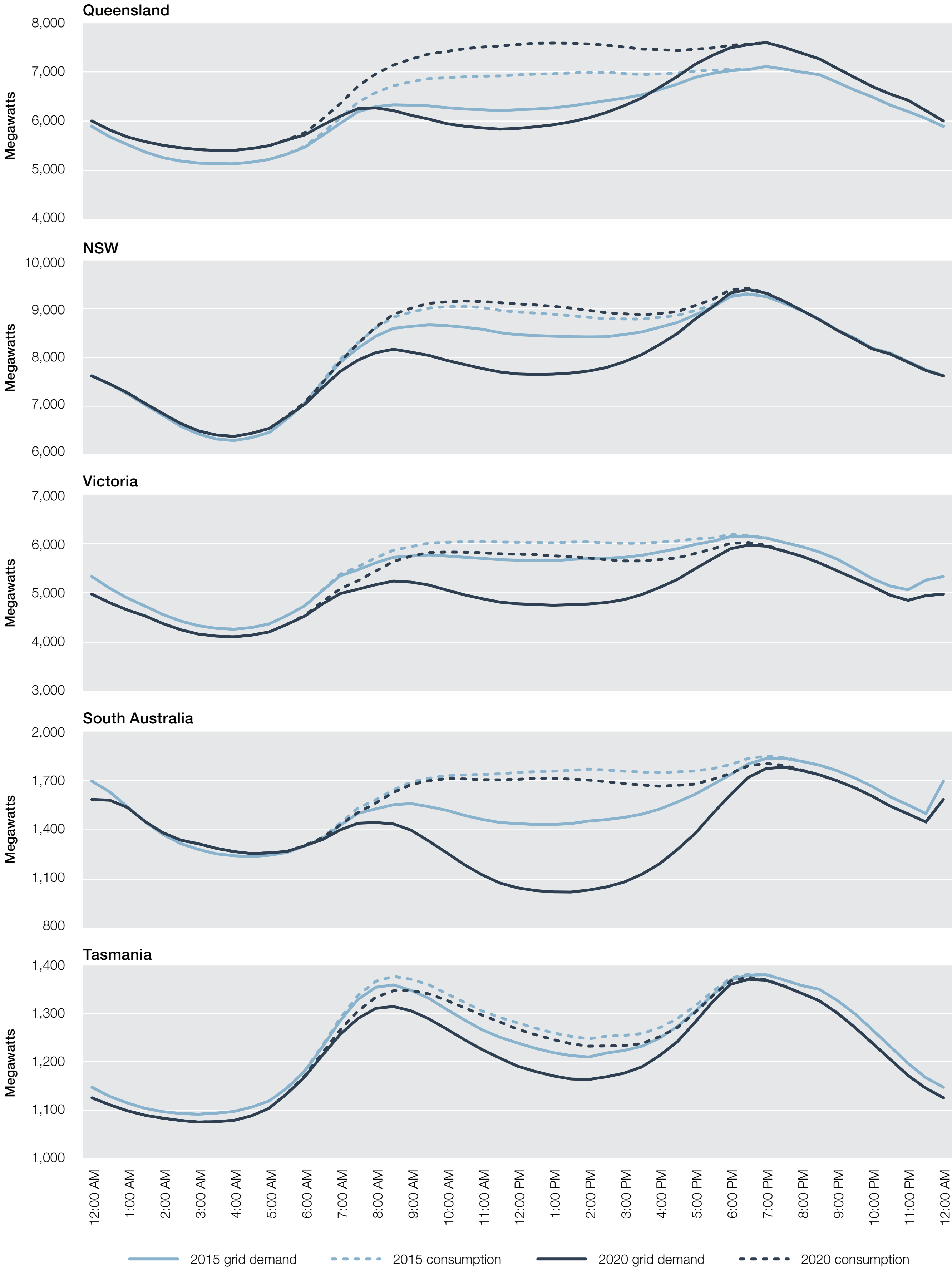
In 2020 midday demand in South Australia was almost 20% lower than the overnight demand. Rooftop solar PV systems in South Australia met over 40% of electricity needs at the time of minimum demand for grid supplied electricity in 2020. Increasing rooftop PV uptake is expected to result in all regions experiencing minimum demand in the middle of the day within the next few years.

Periods when grid demand drops to almost zero are posing serious challenges to the market operator in balancing supply and demand and maintaining the system in a secure operating state.

42 AEMO, *NEM virtual power plant (VPP) demonstrations program – consultation paper*, November 2018, p 3.

43 AEMO, *AEMO virtual power plant demonstrations, knowledge sharing report #3*, February 2021.

Figure 1.11 Electricity duck curves



Note: Average native demand by time of day for 2015 and 2020.

Source: AER; AEMO (data).

1.2.4 Climate change and the power system

Action on climate change was a key driver of the transition underway in the energy sector. But climatic changes already occurring are impacting electricity demand and the performance of generators and energy networks.

Australia's changing climate is creating more volatile patterns of electricity demand as the frequency of extreme heat events increases. Since maximum summer demand is driven by cooling (air conditioning) load, the warming Australian climate means demand peaks are rising relative to average levels of demand.

Extreme weather also stresses generation plant. Drought affects water storages and hydro generation capacity. Tasmania, for example, experienced a fall in water storage in 2015 and 2016. More recently, through 2018 and into 2019 many parts of Australia experienced low rainfall.

Higher ambient temperatures affect the technical performance of thermal plant (coal, gas and liquid fired plant) by reducing cooling efficiency. The performance of wind and solar plant and batteries may also degrade at higher temperatures.[44]

These issues are most frequent on very hot days when demand is at its highest. When AEMO notified the market about reliability threats in 2018–19, a number of thermal generators were not available, or running at lower capacity, as a result of technical or safety concerns from extreme weather events.[45] More recently, bushfires caused interruptions to the transmission grid over summer 2019–20 (section 2.6.2). Extreme wind also crippled transmission infrastructure in Victoria in early 2020.

The ESB's 2021 report on the health of the NEM highlighted that recent horrific bushfires continue to emphasise the importance of electricity system resilience as extreme weather events become more frequent and intense. The ESB argued this needs serious attention in the years ahead as further extreme events, including fire, flood and high temperatures, can be expected.[46] AEMO modelling is also factoring in the increased risk of extreme temperatures impacting peak demand and of drought affecting water supplies for hydro generation and cooling for thermal generation.[47]

Extreme weather also affects distribution networks, imposing costs that are passed on to energy customers. For example, in November 2020 the AER approved AusNet Services recouping $13.9 million from its customers to cover costs associated with the 2019–20 bushfires, which damaged 1,000 kilometres of power lines in its distribution network.[48] The AER also approved Ausgrid recouping $19 million from its consumers to cover costs associated with storms that hit Sydney in 2019–20 and damaged network infrastructure.[49]

1.3 Reliability issues

Reliability refers to the power system being able to supply enough electricity to meet customers' requirements (box 1.2). Reliability concerns tend to peak over summer, when high temperatures spike demand and increase the risk of system faults and outages.

1.3.1 Reliability in a transitioning market

The transition underway in the energy market has increased concerns about reliability. Coal plant closures remove a source of 'dispatchable' capacity that could once be relied on to operate when needed. As the contribution of weather-dependent generation increases, the power system must respond to increasingly large and sudden changes in output caused by changes in weather conditions and dispatch decisions by plant operators.

Reliability risks remain highest over summer, particularly at times when peak demand coincides with low renewable generation, or transmission or plant outages. AEMO has periodically intervened in the market to manage these risks (section 1.3.2).

44 Global-ROAM and Greenview Strategic Consulting, *Generator report card*, May 2019.

45 AEMC Reliability Panel, *2019 annual market performance review, final report*, March 2020.

46 ESB, *Health of the National Electricity Market 2020*, 2021, p 33.

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

48 AusNet Services, *2019–2020 cost pass-through application – 2020 summer bushfires*, 27 May 2020.

49 Ausgrid, *2019–20 storm season pass through application*, 31 July 2020.

AEMO raised concerns the market would be at risk of generation shortfalls over recent summers, especially in Victoria and South Australia. But reliability forecasts improved for summer 2020–21 onwards, due to significant development of large-scale renewable resources, lower forecast peak demand, and minor generation and transmission augmentations.

AEMO forecast that unserved energy would rise in NSW in the period between Liddell closing in 2023 and Snowy 2.0 being commissioned.[50] But the amount of unserved energy is expected to remain below the reliability standard of 0.002%.

Box 1.2 How is reliability measured?

Reliability outcomes are measured in terms of unserved energy – that is, the amount of energy required by consumers that cannot be supplied due to a shortage of capacity. The Australian Energy Market Commission Reliability Panel sets the reliability standard for the generation and transmission sectors. The standard requires any shortfall in power supply to not exceed 0.002% of total electricity requirements. It has rarely been breached, but the Australian Energy Market Operator (AEMO) increasingly intervenes in the market to manage forecast supply shortfalls.

The standard excludes outages caused by 'non-credible' threats, such as bushfires and cyclones, because the power system is not engineered to cope with these issues and the cost of doing so would be prohibitive. It also excludes supply interruptions originating in local distribution networks. Around 95% of a typical customer's power outages originate in distribution networks and are caused by local power line and substation issues. While these outages are common, their impact is confined to relatively small cluster of customers in each instance. Section 3.15.3 of this report covers distribution reliability.

In effect, the standard sets a level of unserved energy that balances the cost of providing reliability against the value that customers place on avoiding an unexpected outage.

While the 0.002% target for unserved energy is used to assess market performance and the appropriateness of reliability settings such as the market price cap, a stricter interim reliability standard is used in planning to trigger 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 (box 1.3) if unserved energy is forecast to exceed 0.0006%.

1.3.2 Managing reliability risks

AEMO has powers to intervene to manage a forecast lack of supply to meet electricity demand. Over the past 4 summers (up to and including 2020–21), it used the Reliability and Emergency Reserve Trader (RERT) mechanism to manage reliability risks. Under the scheme, AEMO secures contracts with generators (to provide capacity) and/or large customers (to reduce their consumption) when the power system is under stress.

Before 2017–18, the RERT had been used to procure backup capacity on only 3 occasions and was never activated. AEMO activated the RERT for the first time in November 2017 to manage a forecast lack of reserves in Victoria; and a further 6 times in Victoria and South Australia over the 2017–18, 2018–19 and 2019–20 summer periods.

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 was activated in Queensland for the first time in May 2021, following a serious fire at the Callide C power station. The cumulative cost of the RERT between 2017 and 2020 was around $110 million. Market reliability outcomes are discussed in section 2.9.

1.3.3 Market reforms on reliability

The ESB is exploring how best to manage reliability risks in an evolving energy market through the NEM 2025 project. In doing so, it is looking at mechanisms that provide long term signals for investment in resources with flexibility to manage sudden demand or supply fluctuations and which can deliver an orderly closure of ageing generation.

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

The ESB's reforms are occurring at a time when the fast moving nature of the transition is creating a level of uncertainty that impacts on participants' willingness to invest in dispatchable resources. Uncertainty is heightened in relation to technology costs, the timing of large scale generation closure, and the ability of retailers to hedge demand risk. While some new investment is being supported by government led initiatives (section 1.7), these can dampen investment signals sent by the NEM spot and contracting markets.

These factors reflect a need for the ESB to consider the adequacy of existing investment signals in the NEM. The ESB is focused on reforms that ensure sufficient dispatchable resources and storage capacity are in place prior to anticipated plant closures and that generator exit does not cause significant price or reliability shocks to consumers.

Key areas being considered by the ESB are changes to the Retailer Reliability Obligation (RRO) scheme (box 1.3), and a NEM-wide approach to integrating jurisdictional underwriting or schemes for new investment. The ESB released a consultation paper on its preferred approaches to reform in April 2021, with recommendations to ministers expected to follow later in the year.[51]

Other recent reforms to policy setting and market rules that have targeted the market's ability to respond to reliability risks include:

› requirements on plant owners to give notice of closure.
› stricter rules for wind and solar plants
› changes to the RERT scheme
› expanding the role of demand response.

Stricter rules for wind and solar plants

The rising incidence of negative spot prices in South Australia and Victoria is encouraging wind and solar farms to curtail their plant for economic reasons, even though weather conditions to operate were suitable. Economic self-curtailment was greater than plant curtailment by AEMO in the first (summer) quarter of 2021, accounting for 58% of all curtailment across the market (by MW).[52]

In response to an AER proposal, in March 2021 the AEMC amended the rules to require semi-scheduled generators (commercial wind and solar plants) to generate according to the available resource and their offer and not turn off without receiving an instruction from the market operator.[53] By requiring semi-scheduled generators to operate in this way, AEMO can more effectively forecast demand and supply and avoid unexpected impacts to system security.[54]

Notice of closure

Since September 2019 generators are obliged to provide the market at least 42 months advance notice of their intention to close. The rule aims to improve long term forecasting of plant closures and reduce the reliability risks that closures can impose. When the rule commenced, a number of generators provided formal notice of their impending closure, including AGL Energy's Liddell and Torrens Island A power stations; and Stanwell's Mackay gas turbine.

The ESB raised concerns in 2021 that the 42-month rule may be insufficient to address reliability risks. It found there may be value in widening the notification rule to cover situations other than plant retirements; for example, significant changes in operation such as mothballing of generator units, as well as changes in contractual positions. It also noted the notice of closure requirements does not address risks arising from the sudden exit of thermal plant – for example, due to catastrophic technical failure.[55]

To address these concerns, the ESB is exploring mechanisms for a more orderly exit of thermal plants as they retire from the system – such as changes to notice of closure requirements, expanding information requirements around mothballing and seasonal shutdowns of generators, regulated or negotiated arrangements with thermal plants for their closure, and contingent scenario planning (such as the Australian Government's Liddell Taskforce, which was established in 2019 to assess the impacts of the planned closure of that plant).[56]

51 ESB, *Post 2025 market design options – a paper for consultation*, April 2021.
52 AEMO, *Quarterly energy dynamics, Q1 2021*, April 2021.
53 AEMC, *Semi-scheduled generator dispatch obligations*, information sheet, March 2021.
54 AER, 'AER requests fast track consideration of proposed rule change to address system security' [media release], 30 September 2020.
55 ESB, *Post-2025 market design directions paper*, January 2021, p 32.
56 ESB, *Post-2025 market design directions paper*, January 2021.

Box 1.3 Retailer Reliability Obligation

The Retailer Reliability Obligation (RRO) scheme (launched in July 2019) creates incentives for retailers and large energy customers to purchase contracts that should support investment in dispatchable electricity generation in regions where a gap between generation and peak demand is forecast. The Australian Energy Retailer (AER) publishes guidelines on the scheme's operation.

The RRO scheme supports reliability by requiring retailers and large energy users to enter contracts (or own generation capacity) to match their electricity demand in periods when the Australian Energy Market Operator (AEMO) forecasts a reliability gap between generation and peak demand. If a material gap is determined 3 years out then AEMO will ask the AER to formally trigger the RRO. The trigger level is intended to ensure the electricity system remains reliable during a one-in-10-year summer. In November 2020 the Energy Security Board (ESB) reduced the trigger for activating the RRO (to a forecast of 0.0006% unserved energy – down from 0.002%).[57]

Once the RRO is triggered, electricity retailers and large energy users (liable entities) are on notice to secure contracts for sufficient generation to cover their expected demand for grid-supplied electricity, based on a one-in-2-year peak demand forecast. Demand response contracts qualify if they are 'in market' and have a direct link to the electricity market to manage exposure to high spot prices.

To support contract market liquidity, a market liquidity obligation (MLO) operates when the RRO is triggered. The MLO requires large generators to perform a 'market maker' role by offering to buy and sell hedge contracts on the Australian Securities Exchange (ASX) or other approved platform with a limited price spread. The obligation aims to ensure smaller participants can access enough contracts to meet their RRO obligations. The AER monitors relevant generators' compliance with the MLO.

If a forecast gap persists one year out then liable entities must submit their contract position to the AER. AEMO may also procure emergency reserves through the Reliability and Emergency Reserve Trader mechanism to address any remaining supply gap. If actual peak demand exceeds the forecast, the AER must assess liable entities' contract positions against their share of system load. Entities without adequate contracts will be required to contribute to the cost of AEMO procuring emergency reserves.

In 2020 AEMO identified a potential supply shortfall in 2023–24 in NSW, triggering the RRO (section 2.7.3).

As part of its NEM 2025 reforms, the ESB is exploring options to enhance the RRO mechanism to ensure retailers implement and maintain supply arrangements with new and existing resources sufficient to meet their customers' needs. The ESB noted that the current RRO provides only muted signals for timely investment, with compliance assessed only if a number of hurdles relating to AEMO forecasts are passed.[58]

The ESB is developing 3 options for modifying the RRO:

› removing the 3-year-out trigger to extend the duration of the price signal for investment and promote more contracting by retailers
› requiring retailers and large loads to meet their RRO targets by acquiring physical certificates rather than hedge contracts. This approach creates an investment signal and a revenue stream that is separate from spot and contract market prices
› allowing state Energy Minsters to trigger the MLO without AEMO identifying a gap.

It is also considering issues around the RRO's complexity and compliance burden.

South Australia

The operation of the RRO differs in South Australia compared with other regions, in that the state Energy Minister can trigger the obligation.

The minister triggered the RRO in South Australia for periods in the first quarters of 2022, 2023 and 2024. The 2022 RRO period was subsequently closed, as AEMO did not identify an enduring reliability gap 1 year ahead.

57 ESB, *Interim reliability measures – RRO trigger, recommendation for National Electricity Amendment (Retailer Reliability Obligation Trigger) Rule 2020*, decision paper, October 2020.

58 ESB, *Health of the National Electricity Market 2020*, 2021, pp 24–25.

Reliability and Emergency Reserve Trader changes

From March 2020 AEMO can contract for RERT resources up to 12 months in advance (previously 9 months in advance).

In August 2020 a rule change by the ESB established a temporary out of market capacity reserve (the Interim Reliability Reserve) that reduces the threshold for procuring capacity under the RERT. Under the Interim Reliability Reserve, in place until March 2025, AEMO can contract for RERT resources between 10 weeks and 12 months in advance if unserved energy in a region is forecast to exceed 0.0006% (compared with the normal reliability standard of 0.002%).

AEMO can enter into reserve contracts of up to 3 years where there is a forecast reliability shortfall in at least 2 of the 3 years. This scheme replaced Victorian specific RERT arrangements introduced in 2020 that allowed for multi-year RERT contracts to help address reliability challenges facing that state.

Expanded role for demand response

While many reforms targeting reliability have focused on the supply side, reforms are also progressing on the demand side to ease reliability risks. Demand response relates to electricity users responding to financial incentives to cut their energy use from the grid temporarily when the power system is under pressure.

New technologies are providing opportunities for smaller scale DER to offer demand response in the wholesale market (and in markets for grid stability services). Initiatives include virtual power plant trials (section 1.2.2) and a proposed AEMO-operated platform on which participants can contract for electricity in the week leading up to dispatch to enable more demand response.

While demand response can help manage peak demand, it has not been widely used in the NEM. One reason is that only retailers and large industrial customers see the price signals that encourage demand response, and they often prefer to manage this risk through hedge contracts.

Reforms that apply from October 2021 aim to attract more demand response providers into the market.[59] Under the reform, customers can offer demand reductions through AEMO's central dispatch process and be paid for whatever load they are called on to reduce. The mechanism will initially be limited to large customers.

The AEMC regards the mechanism as an interim measure in the transition to a 2-sided market with participants on both the supply and demand sides participating in dispatch and price setting. The ESB is developing a 2-sided market as part of the NEM 2025 framework (section 1.5.7).

1.4 Power system security

Power system security relates to maintaining the power system within technical operating limits needed to keep it safe and stable. Parameters of system security include frequency and voltage stability; and physical properties such as system strength and inertia (box 1.4). An electricity system that operates outside acceptable limits for these parameters may jeopardise safety, damage equipment (both network assets and household appliances) and cause blackouts. A secure system needs to be able to withstand a credible disturbance (such as the loss of a major transmission line) by quickly returning to a secure operating state.

System security differs from reliability, but the distinction can sometimes blur. For example, if electricity demand is forecast to exceed available supply (a reliability issue) then the imbalance may also affect the power system's frequency (a security issue). There is also a temporal distinction. Reliability is typically a longer term consideration, while security issues tend to occur closer to real time.

59 AEMC, *National Electricity Amendment (wholesale demand response mechanism) Rule 2020, rule determination*, June 2020.

1.4.1 Security in a transitioning market

The energy market transition impacts system security on many levels. Traditional synchronous generators like coal, gas and hydro plants use spinning turbines that create physical properties called inertia and system strength as a normal by-product of producing energy. These properties play an important role in keeping the power system stable and secure. In the past, these properties were taken for granted and considered 'free' services.

But, as older synchronous plants retire, important sources of inertia and system strength are disappearing from the system. Falling inertia makes it harder to keep frequency within an acceptable band, while falling system strength makes it harder to keep voltage stable. The retirement of synchronous generation is also causing situations where too much reactive power is injected (particularly at times of high renewable output), causing overvoltage.

Wind and solar generators are not synchronised to the frequency of the power system. To connect with the system, they use a synthetic power device called an inverter, which converts the DC current generated by wind and solar plants to the AC current operating in the grid.

The transition to a more renewable generation mix poses twin challenges to system security. First, inverter based resources like wind, solar PV and batteries have only recently been configured to support frequency control and provide system strength in the same way as coal, gas and hydro plant. But more work is required to procure and integrate these services from inverters. Second, those resources require system strength to ride through faults and meet performance standards.

The rising proportion of wind and solar in the generation mix has contributed to more periods of low inertia, weak system strength, volatile frequency and voltage instability, although remedial actions are being taken. The amount of time the power system frequency spent away from the target frequency of 50 Hertz (Hz) rose between 2016 and 2020. AEMO identified this degradation as being driven by a decline in the responsiveness of generation plant to system frequency combined with an increase in the variability of generation and load in the power system (section 1.4.4).[60]

Since the closure of South Australia's Northern power station in 2016, and new entry of wind and solar plant, *inertia* shortfalls have caused more volatile frequency disturbances in the state. In 2018 AEMO declared an inertia shortfall in South Australia. Inertia levels have also fallen in Victoria since the closure of its Hazelwood power station in March 2017, falling at times below acceptable thresholds (box 1.5). The ESB reported that, by 2025, inertia levels on the mainland could drop by 35% compared to its historical average. This will increase the need for frequency services following a disruption.[61]

System strength has become an issue across the fringes of the grid, making it harder for new generators to connect. AEMO has declared system strength gaps and worked with local transmission networks to address shortfalls in South Australia, Tasmania, north west Victoria and north Queensland (section 1.4.5 and box 1.5). The uptake of DER is creating similar issues in distribution networks (section 1.5).

A lack of system strength in parts of the system in recent years has meant that some renewable generators are being constrained off and others have been unable to connect to the grid in a timely manner. The AEMC is considering rule changes that would facilitate the introduction of system strength services in the NEM.

The rising proportion of wind and solar plant also raises challenges to the generation fleet's ability to *ramp* (adjust) quickly to sudden changes in renewable output. The magnitude of peak ramps (upward/downward fluctuations in supply) from renewable generation almost doubled between 2018 and 2020 (figure 1.8). Accurate forecasting of expected ramps is difficult, raising uncertainty and creating a need for greater ramping reserves as wind and solar penetration increases.

Generator ramping capability will be better recognised and rewarded when the settlement period for the electricity spot price changes from 30 minutes to 5 minutes from October 2021. This reform will provide stronger price signals for flexible generation.[62] Similar to system strength, the AEMC is also considering a rule change for the introduction of an operating reserve which is intended to create a market that would address ramping issues.

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60 AEMO, *Primary frequency response incentive arrangements, rule change proposal*, 3 July 2019, p 14.

61 ESB, *Health of the National Electricity Market 2020*, 2021, p 28.

62 The reform was originally scheduled to commence from July 2021. In April 2020 AEMO proposed the delay in response to the potential impact of COVID-19 on the energy industry to free up human and financial resources that would be under strain during the pandemic.

Box 1.4 Power system security

Power system security has a number of parameters, including frequency stability, inertia, voltage stability and system strength.

The power system's *frequency* refers to the rate of oscillations as electricity transmits through the system. Generators require a narrow band of system frequency to operate safely and efficiently. In the National Electricity Market (NEM), the frequency target is 50 cycles per second, or 50 Hertz. Sudden shifts in supply or demand can push frequency away from this level. In the NEM, temporary deviations within 49.85–50.15 Hertz are considered acceptable. Wider deviations, or rapid changes of frequency, can lead to system failures.

Synchronous generators (such as coal, gas and hydro plants) produce *inertia* – a physical resistance that slows the impact of a sudden disturbance to the system. The large rotating mass of a plant's turbine and alternator create this inertia as they rotate in synch with system frequency. A system with low inertia has a higher risk that frequency deviations will cause generators to disconnect from the power system.

System strength is an umbrella term referring to the power system's resilience to voltage changes caused by a system fault. *Voltage* is the electrical force or pressure between 2 points that 'pushes' an electric charge through a wire. Voltage stability is necessary for a healthy power system to push power around the system in a steady, controlled manner. A strong, stable voltage helps protection systems locate and clear faults, such as those caused by plant malfunctions or by threats such as lightning and bushfires. In a strong system, reactive power is injected and absorbed to manage these fluctuations. Wind and solar plants need a smooth and stable voltage wave form to operate properly, so diminishing system strength makes it harder for them to connect to the grid.

The energy market transition is weakening system strength in the NEM. Like inertia, synchronous coal, gas and hydroelectric generators create system strength through the normal spinning operation of their turbines. But newer plant like batteries, wind and solar use electronics – computers and inverters – rather than turbines to couple with the grid.

Technology solutions

As the generation mix changes, new approaches are needed to provide essential system services. The capability of wind and solar plants to provide these services is evolving, as are the types of service required. The first wave of wind farms in particular were not configured to provide security services. However, advanced inverter technologies have the capability to respond rapidly to sudden changes in electricity supply or demand and to make a contribution to system strength.

Other technology solutions include synchronous condensers – that is, large spinning machines similar to the spinning motion in synchronous generators but not driven by the action of a turbine. The rotation of these machines provides inertia and can aid in maintaining voltage stability (section 1.4.3). Smart transmission lines are another approach for energy networks to resist voltage disturbances. Some recently installed renewable plant, and storage solutions including grid scale batteries, pumped hydro and virtual power plants, can also provide services to manage voltage fluctuations and strengthen the network.

Managing system security

AEMO is responsible for managing power system security in the NEM. It uses market-based methods where possible, but it overrides the market's normal operation if market measures are inadequate. The AEMC assesses market rule changes to address systemic issues. A number of recent rule changes target security issues.

At a higher level, the ESB is reviewing the market's architecture as a whole to ensure it meets the requirements of the evolving market. It is scoping reform in conjunction with other agencies, including AEMC rule change processes to introduce of a range of new system security services such as system strength and fast frequency response services.

1.4.2 Market intervention to manage security

Where possible, AEMO operates markets to procure essential system services needed to maintain power system security. To date, these markets exist only for a number of frequency control services. There are currently no market arrangements to procure system strength or inertia (collectively referred to as synchronous services) in the NEM. In the past, these properties were so plentiful that no value was placed on them and no mechanism to procure or schedule them was required.

Where no market exists, or if market solutions are inadequate, AEMO may intervene in the market to manage a security issue. Interventions may be aimed at removing the source of the problem (for example, constraining a generator causing the issue from operating) or creating a solution (for example, directing a generator that may help the situation to operate).

While sometimes necessary as a short term measure, this intervention is costly and ultimately paid for by consumers. It is not sustainable as a long term solution. Policy and rule reforms are progressing to provide longer term solutions.

Key requirements for AEMO to effectively intervene in the market are visibility of participants and an understanding of how participants will respond to market events. 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 allegedly failing to comply with generator performance standards; and proceedings against the Pelican Point gas power station (South Australia) for allegedly failing to submit accurate generator availability information.

In February 2021 CS Energy paid penalties totalling $200,000 for allegedly failing to ensure it was able to comply with its market offers for frequency control services. CS Energy also repaid to AEMO around $1 million it received as payment to provide the services.

Intervention methods

AEMO normally dispatches the lowest cost generators to meet demand, but this dispatch can cause security issues. In these circumstances it may intervene to override the market's normal efficient operation.

For example, if a lack of online synchronous generators causes a lack of inertia and system strength then AEMO may direct one or more synchronous generators to operate, even if it is uneconomic for the plant owners to do so. It may also constrain non-synchronous generators (wind and solar) from operating to ease a drain on system strength and allow the directed synchronous machines to fill the supply gap. On some occasions, it might de-energise transmission lines to change power flows or switch off rooftop solar PV to increase grid demand to address an issue.

The mechanisms can be applied jointly. In South Australia, for example, AEMO has managed weak inertia and system strength by switching off (constraining) wind and solar generators to ease the drain on system strength, while simultaneously directing synchronous gas generators to operate (to create inertia and boost system strength). In Victoria and Queensland it has managed voltage and system strength issues by directing gas plants to operate while simultaneously de-energising a number of transmission lines.

Market interventions to maintain system security have risen sharply in recent years, at significant cost to consumers. South Australia and, more recently, Victoria, Tasmania and Queensland have been the focus of these interventions.

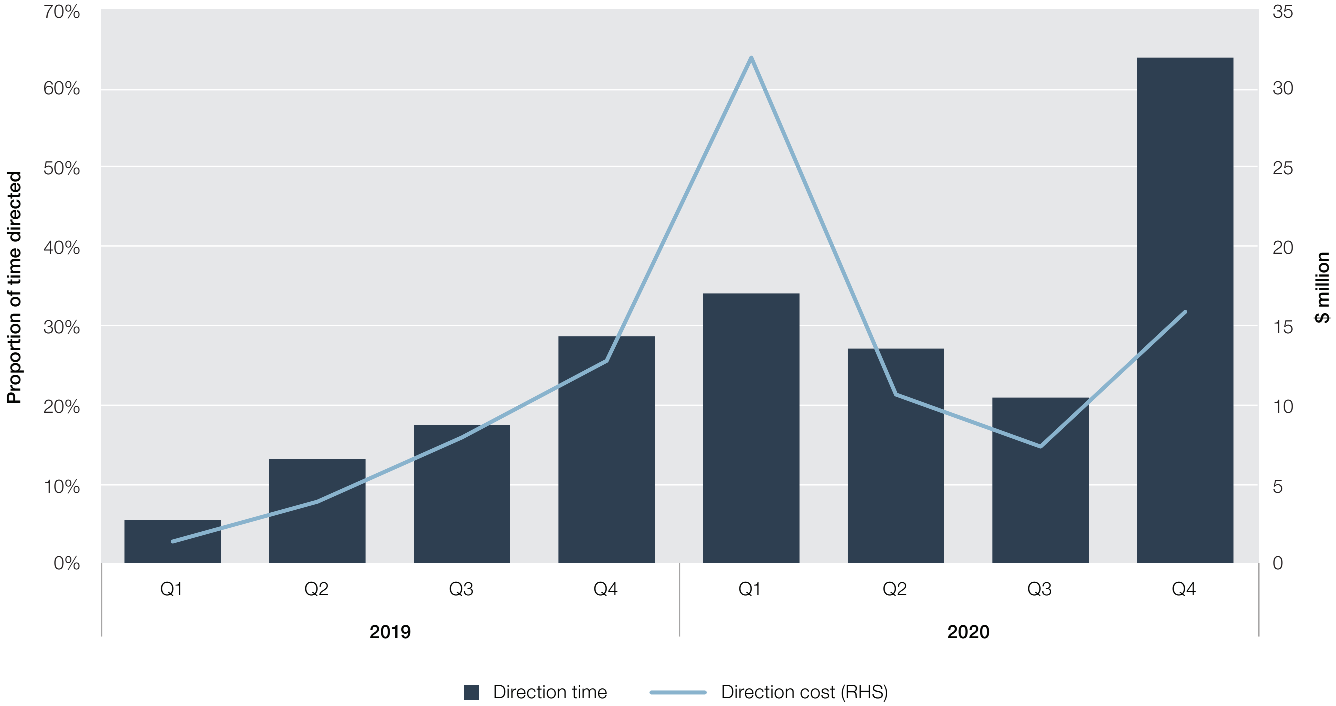
Recent intervention

The use of AEMO directions to manage system security reached a new peak in 2020, when they were in place for more than one-third of the year across the NEM (figure 1.12). Higher than previous use of directions was required in the first quarter to manage 3 separate region separation events.

Late in the year in South Australia, AEMO intervened a record 64% of the time to maintain a minimum level of gas powered generation. This generation was required to provide system strength support at times of low demand.

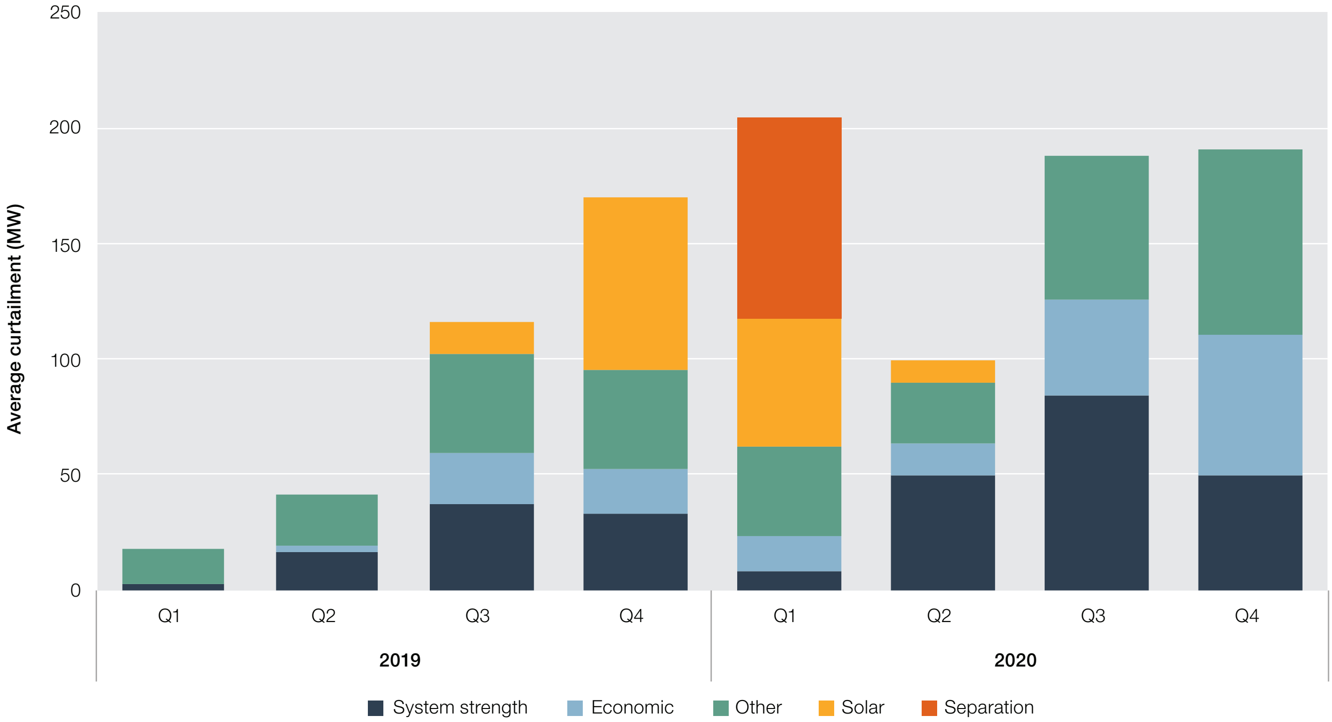
Intervention to curtail renewable generation has risen markedly. Figure 1.13 shows a significant increase in the volume of renewable generation curtailed by system strength constraints over 2019 and continuing throughout 2020. In 2020 there was also an increase in economic curtailment, with renewable generators choosing not to operate at times of negative prices.

Figure 1.12 System security directions



Source: AEMO, *Quarterly energy dynamics Q4 2020*, February 2021.

Figure 1.13 Curtailment of renewable generation



MW: megawatt.

Source: AEMO, *Quarterly energy dynamics Q4 2020*, February 2021.

Intervention costs

Generators subject to certain directions from AEMO are entitled to claim compensation. Compensation costs relating to AEMO directions averaged $25 million in 2018 and 2019.[63] Given the scale of these costs, in December 2019 the AEMC limited compensation payments associated with system security directions (and any other intervention to obtain a service for which no relevant market price applies). Despite this change, direction costs rose to almost $66 million in 2020.[64] Around half of this cost was incurred in the first quarter to manage 3 separate region separation events caused by unplanned transmission outages.

Aside from formal compensation, the use of constraints or directions penalises consumers by driving up wholesale electricity prices. For example, by restricting wind or solar output that might have zero marginal costs, AEMO directions may lead to dispatch from synchronous generators with higher costs.

Load shedding

The most extreme form of intervention occurs when AEMO instructs a network business to load shed (that is, temporarily cut power to some customers). This action is rare and only occurs if all other avenues have been exhausted. In recent years, insecure operating states led AEMO to cut supply to some customers in South Australia (December 2016 and February 2017), NSW (February 2017) and Victoria (twice in January 2019).

AEMO also operates schemes that automatically shed generation or load when system frequency exceeds or falls below safe levels. Generation was shed for the first time under South Australia's over-frequency generation shedding scheme in January 2020, when 3 wind farms tripped off following the islanding of the state from the rest of the NEM. In NSW, 20 MW of load at Tumut (NSW) was disconnected in January 2020 when the network was impacted by bushfires.[65]

1.4.3 Spot markets for frequency control services

Some of the services needed to maintain power system stability can be procured through markets. Currently, spot markets exist only for a number of frequency control services. There are currently no market arrangements to procure essential system services such as system strength or inertia.

AEMO also enters long term contracts for:

- network support and control ancillary services, for controlling voltage at different points of the network, controlling power flow on network elements and maintaining transient and oscillatory stability after major power system events
- system restart ancillary services, for restarting the electrical system after a complete or part system blackout.

Frequency control services

AEMO operates markets to procure different types of frequency control ancillary services (FCAS) to maintain stable system frequency. Participants make offers to provide these services in a similar way to how they provide energy offers. AEMO determines which generators will be dispatched to jointly provide energy and FCAS at the lowest cost (known as co-optimisation). The costs are recovered from generators and consumers, partly through a 'causer pays' mechanism.

Eight different FCAS markets operate, each providing a different type of service. *Regulation services* are procured to manage frequency deviations within the normal operating frequency band, while contingency services are procured to arrest any major variations caused by events such as the loss of a generating unit or a significant electricity transmission line. *Contingency services* are available over a range of response speeds (from 6 seconds to 5 minutes). Separate markets operate to raise and lower frequency for each type of service.

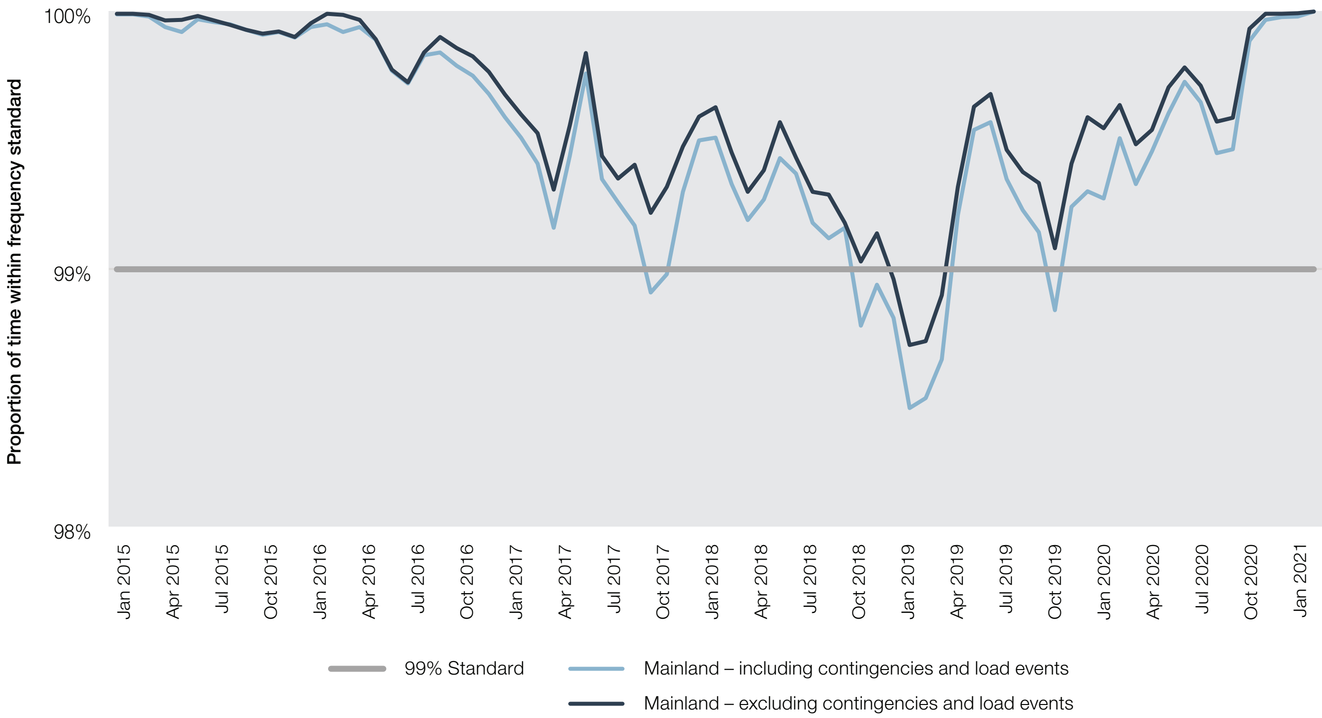
Between 2016 and 2020 the control of power system frequency during normal operation degraded, such that the power system frequency spent more time outside the target frequency of 50 Hz than was historically the case (figure 1.14). Since reforms introduced in 2020, system frequency performance has improved (section 1.4.4).

63 AEMO, *Quarterly energy dynamics Q1 2020*, April 2020.

64 AEMO, *Quarterly energy dynamics Q4 2020*, February 2021.

65 AEMO, *Final report – New South Wales and Victoria separation event on 4 January 2020*, September 2020.

Figure 1.14 Proportion of time National Electricity Market mainland frequency is within normal operating band



Note: AEMO calculates daily the percentage of time that frequency remained inside the normal operating frequency band in the preceding 30-day window. Data represents the minimum daily estimate from each month.

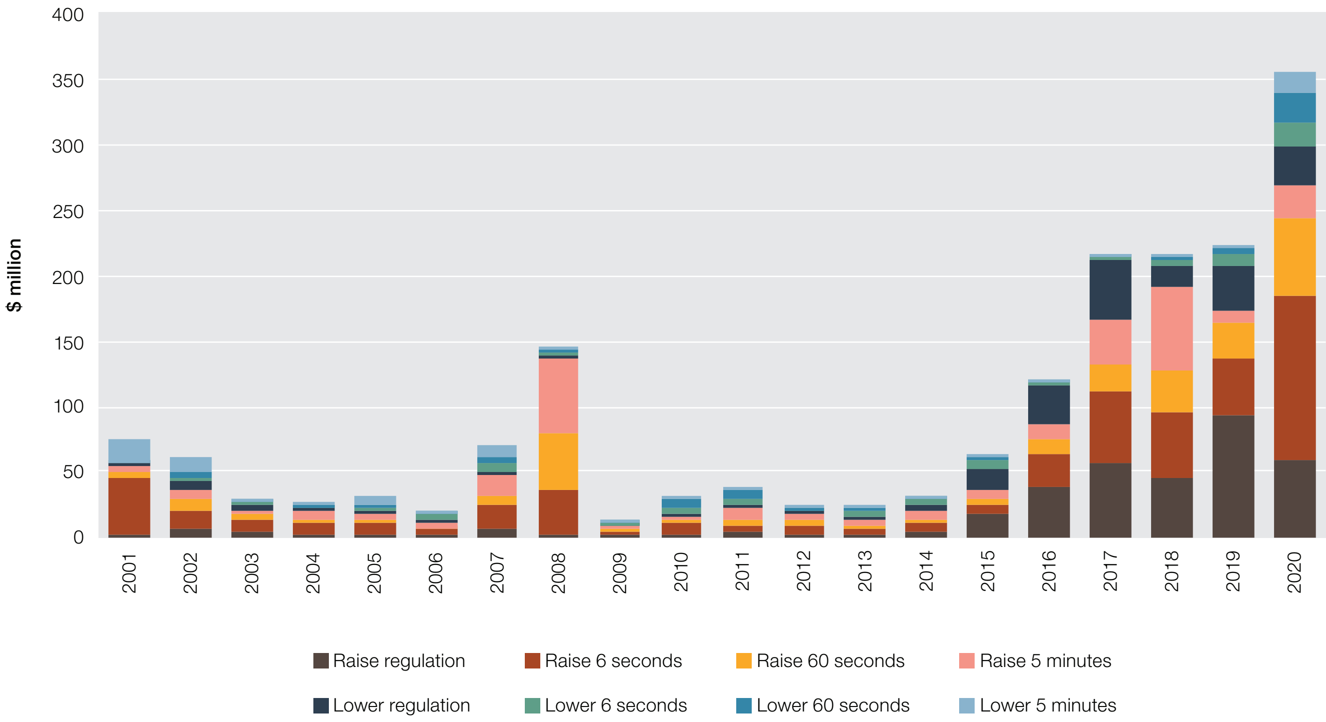
Source: AEMO, *Frequency and time error monitoring – quarter 4 2020*, February 2021.

The degradation in frequency control was reflected in higher FCAS costs. Historically, FCAS costs were low in relation to energy costs. Between 2015 and 2019 FCAS costs rose fourfold to over $220 million (figure 1.15).[66] And in 2020 costs rose further, to over $350 million. FCAS costs for the first quarter of 2020 were higher than they were over the whole of 2019, mainly due to high local costs in South Australia when it was isolated from the rest of the NEM for several weeks. Costs reduced to their lowest level since 2016 for the remainder of 2020 despite an increase in the volume of regulation and contingency services purchased (section 2.10.2).

Reforms in 2017 widened the potential pool of FCAS providers by allowing batteries and demand response aggregators to offer services in those markets. Demand response aggregators now offer FCAS across all NEM regions, VPPs offer services in all mainland regions and batteries offer services in South Australia and Victoria. Some wind farms also offer FCAS. These new technologies and business models will have an increasingly important role in maintaining system security. To strengthen transparency around FCAS markets and encourage participation, the AER publishes quarterly reports on activity in FCAS markets.

66 AER, *Wholesale markets quarterly – Q4 2019*, February 2020.

Figure 1.15 Frequency control ancillary service costs



Source: AER.

1.4.4 Addressing gaps in frequency control services

While spot markets operate for 8 types of FCAS service in the NEM, gaps have emerged in recent years, both in system normal conditions and in circumstances where a very fast response is needed. Reforms are being implemented to address these gaps.

Mandatory frequency response

The power system increasingly needs fast-response frequency services to manage volatile changes in frequency caused by shifts in weather-dependant generation.

Reforms introduced in 2020 require all capable generators and batteries to provide primary frequency response support by responding automatically to small changes in power system frequency, either in the form of a change in generation or a demand response.

In effect, generators must be engineered to vary from their preferred energy dispatch whenever frequency goes outside a specified range. The aim is to ensure an immediate response is available to address an imbalance so that FCAS markets have enough time to deliver frequency services.

The rule commenced in June 2020 as an interim arrangement that will expire in June 2023. During the fourth quarter of 2020, a high proportion of thermal generators changed unit settings, bringing improved frequency performance. There was also a decline in the proportion of regulated FCAS sourced from coal fired generators (from 7% in the third quarter of 2020 to 3% in the fourth quarter of 2020), with corresponding increases in wind and solar farms' share of these costs. Additionally, some generating units registered to provide FCAS services for the first time.[67]

The AEMC is considering a longer term solution (called primary frequency response) that would offer payments to encourage participants such as large batteries to respond to small frequency changes during the market's normal operation. The AEMC expects to publish a draft proposal by September 2021.

In 2021 the AEMC was also considering a proposal from AEMO to enhance incentives for market participants to offer primary frequency response services during normal conditions. A draft determination is scheduled for September 2021.

67 AEMO, *Quarterly energy dynamics Q4 2020*, February 2021.

Very fast frequency response

The AEMC made a draft rule in April 2021 to introduce a payment mechanism to incentivise and reward businesses such as utility scale batteries to provide very fast frequency response. The reform addresses a gap in current arrangements, whereby frequency services can take up to 6 seconds to come online. But the rising incidence of frequency deviations caused by sudden shifts in renewable generation sometimes requires a faster response. Providers of the new service must be able to deliver it within 2 seconds. It can also be provided by inverter-based technologies such as wind, solar PV, batteries and demand response.

To allow participants to adjust to the new rule, its implementation will be delayed to start 3 years after the AEMC's final decision (due July 2021).[68]

1.4.5 Addressing gaps in system strength and inertia

Ensuring the availability of essential system services (frequency response, operating reserves, inertia and system strength) is a pivotal element of the ESB's NEM 2025 reforms.

There are currently no market arrangements to procure system strength or inertia in the NEM. In the past, these properties were so plentiful that no value was ever placed on them and no mechanism to procure or schedule them was required. Despite emerging gaps in inertia and system strength, market solutions have not evolved for their provision.

Inertia is a system-wide property than can, to some extent, be shared across regions. It becomes a local issue only if a region is islanded from the rest of the market. Because of this, the ESB's preferred long-term approach is to develop a real-time spot market for inertia, with structured procurement as an interim solution.

By contrast, system strength is a relatively localised phenomenon, and a shortage requires local solutions. The ESB notes that the localised nature of system strength makes it currently unsuitable to a spot market, but it is scoping options for a market solution to supply inertia in the longer term.

Until recently, gaps in system strength and inertia were addressed purely through market intervention by AEMO. In particular, AEMO has used its directions power to direct synchronous (usually gas) plant to operate to raise inertia and system strength and/or constrain off weather-dependant generation that is draining strength from the system.

Reforms in 2017 in South Australia and in July 2018 elsewhere introduced a new approach requiring generators and transmission networks to play an active role in managing system strength.[69] In particular, if AEMO identifies a system strength shortfall in a region:

- transmission network businesses must maintain minimum levels of system strength for generators connected to the network
- new connecting generators must 'do no harm' to the level of system strength needed to maintain the security of the power system. This rule applies to all new connecting generators in the NEM. In effect, new plant must be able to operate to specific system strength levels before it can connect to the system.

Similar requirements were imposed on transmission businesses to maintain minimum levels of inertia (or provide alternative services to meet these levels) if a shortfall is identified.

68 AEMC, *National electricity amendment (fast frequency response market ancillary service) rule, draft rule determination (Infigen energy)*, April 2021.

69 AEMC, *Managing power system fault levels*, information sheet, September 2017.

In April 2021 the AEMC found current arrangements for managing system strength (the 'do no harm' rule and obligations on transmission networks) to be ineffective and cause inefficient delays in connecting new generators. It announced draft reforms to make it simpler, faster and more predictable for new generation – renewables in particular - to connect to the grid.[70] The reforms:

- require transmission networks, working with AEMO, to provide system strength when and where it is needed. The network would consider options for providing system strength, such as building network assets, contracting with existing synchronous generators, retuning existing generators and other solutions. Identified solutions would then be assessed for market benefit through the regulatory investment test (RIT-T) (section 3.12.6). The AER would assess the efficient cost of providing system strength services through its periodic reviews of each network's revenue requirements
- introduce new access standards for generators connecting to the grid to ensure they only use efficient amounts of system strength
- introduce a new charging mechanism for system strength so that those parties who use the service pay for it. New generators would have the choice of paying the network for the system strength it provides or creating their own system strength. The AER would set charges through published guidelines on pricing methods.

The AEMC's development of these rule changes has been informed by the ESB's work and direction through the NEM 2025 project. The draft reforms are consistent with the ESB's preferred approach of 'structured procurement'[71] of system strength.

In 2021 the AEMC was separately considering the launch of scheduling and deployment mechanisms for system strength, including consideration of a short term market for these services to complement structured procurement.[72]

New services

Market bodies are exploring the potential need for a fast-responding ramping service in the NEM to manage variability and uncertainty as the NEM progresses towards very high shares of weather-dependent supply. In particular, the market is facing a growing need to ramp (adjust) quickly to sudden changes in wind and solar generation.

Beyond this, market bodies are considering the introduction of a new service for operating reserve provision. To date, operating reserves have been provided by AEMO's dispatch process keeping 'headroom' on operating generators.

In January 2021 the AEMC concluded that a new operating reserve service may be needed to address changes in net demand that were not forecast and therefore unexpected by market participants.[73] It expects to release a draft determination later in 2021. The ESB is working closely with the AEMC on this matter as part of its NEM 2025 project.

The project is considering the need to explicitly value operating reserves to encourage resources with capability to ramp up or down quickly and provide flexibility to the grid. It is also considering a price signal for reserves that would reflect their real value at any point in time.

While these reforms to security service provision focus on the supply side, reforms progressing on the demand side may also ease the pressures causing security issues. A new demand response market, commencing in October 2021, will allow participants to offer demand reductions through AEMO's central dispatch process, and be paid for any capacity called on (section 1.3.3).

70 AEMC, *National electricity amendment (efficient management of system strength on the power system) rule 2021*, draft rule determination, proponent: TransGrid, 29 April 2021.

71 'Structured procurement' involves AEMO sourcing a resource outside spot markets. It is currently used for the RERT mechanism and voltage control; and for minimum levels of system strength and inertia.

72 AEMC, *National electricity amendment (efficient management of system strength on the power system) rule 2021, draft rule determination, proponent: TransGrid*, 29 April 2021.

73 AEMC, *Reserve services in the National Electricity Market*, directions paper, proponents: Infigen Energy, Delta Electricity, January 2021.

Box 1.5 System strength and inertia issues across the National Electricity Market

South Australia has been the epicentre of inertia and system strength issues in the National Electricity Market (NEM) for a number of years. More recently issues have emerged in Victoria, Queensland and Tasmania.

South Australia

The Australian Energy Market Operator (AEMO) declared a system strength gap in South Australia in October 2017 and an inertia shortfall in December 2018. The issues intensified following the closure of a major coal fired power station in 2016 and a rapid escalation in grid scale wind and solar generation. The problem is acute when low to moderate demand combines with high levels of renewable generation to cause low spot electricity prices. When prices are too low for gas powered generators to cover their short run costs, the generators bid high to avoid dispatch. With fewer synchronous generators operating, inertia levels and system strength levels fall.

South Australia's transmission business ElectraNet, which must address the issues, is installing 4 high inertia synchronous condensers to cover the system strength and inertia gaps. ElectraNet expects all the devices to be in place by 2021.

In 2020 total costs for directing South Australian generators for system strength reached $49 million (or $4 per megawatt hour (MWh)) – almost double those costs in 2019.[74] In the first quarter of 2021 AEMO directed gas powered generators to be online 70% of the time. With low spot electricity prices prevailing for much of the summer, it was uneconomic for gas powered generators to operate in these periods. Around 30% of all gas powered generation in the state was made under direction during the quarter.[75]

In August 2020 AEMO declared a new inertia shortfall in South Australia following the islanding of South Australia earlier in the year, in anticipation of continued growth in rooftop PV and declining minimum daytime demand. ElectraNet is procuring fast frequency response to meet the shortfall.

Victoria

In late 2019 system strength issues emerged in north west Victoria and south west NSW, where a large number of solar farms were being commissioned over a short period, causing system strength and voltage issues. In December 2019 AEMO declared a system strength shortfall in north west Victoria. The area is too remote from synchronous generators for AEMO to manage the issue through directions to gas or coal fired generators. Instead, AEMO intervened by constraining the output of 5 solar farms (4 in Victoria and 1 in NSW) by 50% of their maximum output. The constraints equated to a loss of up to 170 megawatts (MW) of output. The intervention aimed to manage the risk of voltage instability following a contingency such as the loss of a nearby transmission line.

Following changes to inverter settings for the affected plants, AEMO lifted the constraints in April 2020. AEMO (as the network planner for Victoria) also assessed combinations of synchronous condensers to supply additional system strength. As a longer term strategy, AEMO conducted a cost–benefit analysis of building new transmission capacity to unlock renewable capacity in the region. It estimated a lead time for this investment of 6 to 7 years.

In 2020 AEMO, on behalf of the Victorian Government, procured 250 MW from Neoen's 300 MW battery to increase the capability of the Victoria to New South Wales Interconnector and respond to unexpected network outages in Victoria from November 2021. AEMO procured sufficient resources to meet system strength requirements until August 2022. It is assessing the need for further intervention beyond that time.

74 AEMO, *Quarterly energy dynamics, Q4 2020*, February 2021.

75 AEMO, *Quarterly energy dynamics, Q1 2021*, April 2021.

Queensland

In April 2020 AEMO announced a system strength shortfall in northern Queensland. The issue occurs when insufficient coal or hydro plant is operating. It introduced new constraints preventing 3 renewable generators in the region from operating when coal and hydro output falls below a set threshold. As an interim solution, the transmission provider Powerlink entered into an agreement with CleanCo Queensland to provide system strength services using CleanCo assets in Far North Queensland. Powerlink is required to provide a longer term solution by August 2021.[76]

Changed inverter settings at wind and solar farms in the north of the state, as well as increased demand, resulted in system strength curtailment falling to near zero in the first quarter of 2021.

Also in 2020 Powerlink committed to install a synchronous condenser for which the costs would be recovered from committed and future connecting renewable generators. This was a first for the 'system strength as a service' model for new connecting generators.[77]

Tasmania

In 2019 AEMO declared inertia and system strength shortfalls in Tasmania over the period 2020 to 2025. In response, the transmission network (TasNetworks) procured services to meet the shortfalls by contracting with existing synchronous machines and through delivery of new operating procedures and processes.

Also in Tasmania, hydro generation units were directed to be online for system strength for the first time since NEM start due to a temporary shortfall in late 2020 following a transmission outage.[78]

1.5 Efficient integration of distributed energy resources

Over the past decade, many customers have sought to reduce their energy costs, and support renewable energy, by investing in DER – for example, rooftop solar PV systems, household battery systems and demand response such as home energy management systems – at their household or business. The CSIRO and Energy Networks Australia estimated household bills could lower by as much as $400 per year if these resources are optimised.[79]

When integrated efficiently, DER offers flexibility that can help delay the need for large scale generation and network investments and can provide new sources of network support and energy management capabilities. According to estimates published by AEMO and developed by Energy Synapse, in 2020 the NEM had around 4.3 GW of potential demand flexibility. When small scale solar PV and battery capacity is added, the pool expands to around 15 GW and is forecast to reach up to 21 GW by 2022.[80]

Reforms introduced in 2017 aimed to tap into this pool by allowing batteries and demand response aggregators to offer services in FCAS markets (section 1.5.3). Technologies such as virtual power plants are increasing opportunities for smaller scale DER to participate in FCAS markets and potentially the wholesale market through demand response and emerging markets such as voltage control and ramping. Pilot programs are exploring a new market design for a 2-way energy system and marketplace in which DER can participate via aggregators to provide wholesale energy and/or ancillary services to the electricity grid and market.

But the ability of DER to benefit customers and support the power system depends on how well those resources interact with the system. The growth in DER is making electricity demand more volatile due to variations in controllability (changes in weather conditions can be sudden and frequent) and levels of performance. Additionally, limited visibility over the scale and distribution of DER resources makes it difficult to anticipate and manage issues when they arise. These issues are leading to more curtailment of those resources because of network congestion and insufficient services like frequency control system strength, voltage control and ramping. The ESB reported that, without further action, the maximum instantaneous penetration of renewable resources could be limited to 50–60%.[81]

76 AEMO, *2020 system strength and inertia report*, December 2020.

77 ESB, *Health of the National Electricity Market 2020*, 2021, p 31.

78 AEMO, *Quarterly energy dynamics, Q4 2020*, February 2021.

79 CSIRO/ENA, *Electricity network transformation roadmap, Final report*, April 2017.

80 Cited in ESB, *Health of the National Electricity Market 2020*, 2021, p 74.

81 ESB, *Post 2025 market design options – a paper for consultation*, April 2021, p 16.

On the customer side, it remains difficult for small consumers to access markets to deliver energy or system services that could reward them for shifting their demand over the course of a day or several days.

The ESB considers that current market arrangements, along with those for metering and connection, do not adequately support consumers wanting to participate in the market and are complex to navigate. Today, people can contract with one retailer only and not with other intermediaries (such as aggregators) in the energy market. Furthermore, retailers are limited in what they are permitted to offer to customers. The ESB aims to reduce barriers to participation in the market so that consumer benefits can be unlocked without the need for consumers to engage in the market more than they do currently. The ESB and market bodies have been carrying out research on this and are also working with ARENA to commission studies to better understand the potential for flexible demand under a range of scenarios and conditions.[82]

1.5.1 Distributed energy resources and distribution network security

Distribution networks were historically engineered to transport electricity one way – that is, from large generators to energy customers. But, with the continued uptake of rooftop solar PV systems and other types of DER, the networks now increasingly support multi-directional energy flows. Customers can generate electricity, store it and export it to their local distribution network.

While grid scale wind and solar generation raise security issues for transmission networks, distribution networks face similar issues as consumers adopt DER and export electricity into the grid. Some networks are experiencing congestion as areas of their networks reach capacity limits on the amount of DER that they can host. Congestion tends to manifest through voltage issues where electrical pressure reaches its upper threshold as more and more rooftop solar PV units inject power into the grid.

In 2020 AEMO published a survey on how DER are impacting distribution networks in the NEM, illustrating the range and complexity of these issues.[83] Distribution businesses identified voltage issues; problems with inverter settings at customers' premises; and phase balancing and thermal capacity issues on feeders and at substations. The issues vary by the size and location of PV clusters in each network, relative to physical network characteristics and load. AEMO's survey findings confirmed South Australia and Queensland experience the most significant challenges due to their high uptake of solar PV systems, exacerbated by some cluster areas in these states having generally weaker network capacity.

The performance of some inverters connecting DER devices to the network has posed challenges. AEMO estimated around 15% of rooftop systems in Queensland and 30% in South Australia did not meet the Australian standard for inverters to ride through faults.

In February 2021 the AEMC introduced minimum technical standards for DER, including rooftop solar PV inverters, on their ability to ride through short-duration under-voltage disturbances.[84] This is a priority in South Australia following recent power system events linked to the tripping of solar PV systems.

1.5.2 Static and flexible export limits

As solar penetration increases to levels that cause network constraints, distributors have the option of expanding the network and recovering the costs from all consumers through higher charges. But network augmentation is costly. Some consumer groups argue the approach is also inequitable, with the cost of DER integration being borne by all consumers regardless of whether they own DER.[85] Nevertheless, customer research conducted by AusNet Services found support for some investment to allow solar exports, with the cost to be shared among all customers and with government.[86]

82 ESB, *Post 2025 market design options – a paper for consultation*, April 2021, p 57.

83 AEMO, *Renewable integration study, Stage 1*, Appendix A, April 2020.

84 AEMC, *National Electricity Amendment (Technical Standards for Distributed Energy Resources) Rule 2021, determination, proponent: AEMO*, February 2021.

85 AEMC, *Economic regulatory framework review, integrating distributed energy resources for the grid of the future*, September 2019.

86 AusNet Services, *2021–2025 electricity distribution price review, customer forum final engagement report*, 2020, p 14.

An immediate challenge is the rising instances of distribution networks applying static export limits that restrict DER exports in constrained parts of their network. While these measures help balance the system, outcomes are not efficient for customers – in particular, DER owners. Some customers in areas with high levels of solar penetration are facing very low or zero export limits. In Victoria, several thousand customers have been constrained to zero exports across 4 of the 5 distributors.[87] South Australia may need to introduce reduced or zero export limits in parts of Adelaide's southern suburbs.[88]

Flexible export limits offer a better solution than applying a static export limit to all consumers (as occurs now). Flexible export limits are based on the premise that technical issues caused by DER exports to the grid occur infrequently, so blanket restrictions are unnecessary for most of the time they are imposed.

Distributors with a high level of DER penetration are already shifting towards flexible export limits. SA Power Networks will offer new solar customers the option to export up to 10 kW from their solar panels but agree to be constrained as required to maintain system security; or have a fixed export limit of 1.5 kW.[89] The option will be offered to new or upgrading solar customers in some congested areas from mid-2021.

For most of the time, customers choosing the flexible option would have the opportunity to export more than they would on a lower fixed export limit, even in highly overloaded parts of the network. Export limits will only be lowered periodically when necessary to avoid overloading the network and to help maintain a reliable electricity supply.

More broadly, AEMO has the power to direct a full or partial reduction in output from solar systems in South Australia during electricity security emergencies. All solar installations in South Australia since September 2020 are required to have flexible export limit capability. This power was used for the first time in March 2021 to switch off around 12,000 solar systems at a time of near-record minimum demand. These powers are being considered for other NEM regions due to the continued rapid uptake of rooftop solar PV. AEMO is also working with electricity distributors to establish real-time visibility requirements for distributed solar PV systems available for curtailment, and consistent real-time visibility for all new commercial scale systems.

1.5.3 Pricing of solar exports to the grid

Pricing reform has become another focus to manage distribution network congestion caused by rooftop solar PV. At present, distribution networks earn revenue by charging for the use of poles and wires to transport electricity *from* the grid *to* the consumer. At present, distribution networks cannot charge solar PV owners for exporting electricity back into the network, beyond a basic charge to connect to the network. In effect, exporting solar output into the grid is treated as a 'free' service provided by the network that is paid for by all consumers through higher energy bills.

The AEMC concluded a 'use of system charge' for DER exports is part of an efficient solution to optimise the benefits of DER, while managing the risks and costs of congestion at times of oversupply from small scale (solar PV) generation. Under draft reforms made in March 2021, distribution network services will in future be regulated as 2-way services and be able to charge to transport electricity both from the grid and into it.

The draft reforms are not mandatory. Networks will be allowed to develop flexible pricing that allocates costs in a more equitable and efficient way, accounting for their capability, customer preferences and jurisdictional policies. The aim is to reward customers for actions that better use the network or improve its operations. For example, a customer could choose a level of 'firmness' that rewards them for reducing their exports to the grid at times when there is limited network capacity.

The AEMC found that, if networks introduce export charges, around 80% of customers (those without solar systems) would see their bills drop because they would no longer pay for solar export services they were not using.

For the 20% of customers with solar, export charges would reduce their earnings from solar exports. A 4–6 kW system, for example, would still earn on average $900 – about $70 less than now. Even without export charges, solar owners would face a similar drop in earnings if they are constrained from exporting energy just 10% of the time.[90]

87 Clay Lucas, 'Power failure: homes hit by solar limits as distributors protect network, and profits', *The Age*, 14 March 2021. Estimates are based on information provided by Victorian distributors.

88 SA Power Networks, 'Working with industry to boost customer solar options' [media release], 14 April 2021.

89 SA Power Networks, 'Working with industry to boost customer solar options' [media release], 14 April 2021.

90 AEMC, *National Electricity Amendment (Access, Pricing and Incentive Arrangements for Distributed Energy Resources) Rule, draft rule determination*, March 2021.

The reforms would also introduce incentives for distribution networks to deliver export services that customers value. The AER would be required to review the scope of its service target performance incentive scheme (STPIS) to reward or penalise networks for the quality of their export service provision, and to develop a method to calculate customer export curtailment values to help guide efficient network expenditure. These values aim to measure the detriment to customers and the market from having exports curtailed (and so provide a guide to the pricing of DER exports that might avoid this scenario).

To support the transitional introduction of export tariffs the AEMC modified revenue recovery arrangements to allow distributors to trial alternative tariff structures.

1.5.4 Visibility of distributed energy resources

As we move towards a system of millions of DER, issues arise from DER's inherent lack of visibility, which compromises the market operator's ability to understand DER behaviour, forecast electricity demand, schedule dispatch and manage power system security. In particular, the market operator and distribution networks have little real-time visibility of PV systems less than 5 MW, including rooftop solar.

In response to these issues:

- arrangements announced in September 2018 require AEMO to establish a register of DER in the NEM. The register gives network businesses and AEMO visibility of where DER are connected to help plan and operate the power system as it transforms
- demand response and VPP trials are exploring how DER behaves during disturbances and developing a database of DER installations
- new technical standards for DER finalised in 2021 aim to improve DER performance to support energy system security
- the ESB is looking at ways to improve DER visibility over the longer term to support efficient forecasting and scheduling through its NEM 2025 project.

1.5.5 Distribution network pricing

While pricing of DER exports into the grid is a major reform focus in 2021, longer term reforms to retail energy prices also impact DER and its efficient use. Most retail customers are still on some form of fixed retail tariff that takes little account of how their energy use affects the network. Market bodies have been progressing a shift towards cost-reflective tariffs that more closely account for how a customer's energy consumption pattern affects the network. Cost-reflective network tariffs should be structured to fall at times of low demand (when the network has spare capacity) and rise at times of peak demand when the networks are under strain.

Reforms introduced in 2017 require electricity distributors to progressively shift retailers, aggregators and other third-party providers onto network tariffs that more closely reflect the true costs of their customers' use of the distribution network. The reform operates by requiring networks to levy the new tariffs on *their* customers (mainly energy retailers) but leaves it open to retailers to decide how to pass on the changes to their residential and business customers.

Retailers may offer different price arrangements to suit different customer preferences. Some customers may prefer traditional pricing with a single price for energy regardless of when it is used. But, for customers with some flexibility in their energy use, retailers can offer incentives to switch their energy use to times of low demand and operate DER such as rooftop solar PV systems and batteries in ways that minimise network stress.

The AEMC found that, despite progress at the network level, cost-reflective tariff reform at the consumer level has proven to be difficult to implement. The AEMC cited a lack of analysis of the impact on various consumer groups, including a lack of clarity about how network tariffs could play out through retailers, how retailers will translate tariffs to customers and what protections and supports will be put in place for vulnerable consumers, as factors contributing to slow progress.[91] Survey responses from members of an AEMC technical working group rated 'retailer support and the extent of pass through into retail tariffs' as the largest cause of delay to the pace of tariff reform.[92] Retailer feedback to the AER suggests retailers are still working on developing more innovative offers.

91 AEMC, *Electricity network economic regulatory framework 2020 review*, final report, 1 October 2020, p 45.

92 farrierswier, *Effectiveness of the TSS process and options for implementing export charges*, March 2021.

The limited penetration of smart meters for residential and small business customers is one factor limiting the uptake of cost-reflective tariffs. Smart meters (or manually read interval meters) measure customers' electricity use across the day. At February 2021 around 39% of customers in the NEM had metering capable of supporting cost-reflective tariffs. But installation rates vary across regions. Around 98% of Victorian customers had access to a smart meter. NSW had the next highest penetration of smart or interval meters at around 25% of customers. Installation levels in other regions ranged from 15% of customers in Queensland to 23% of customers in the ACT.[93]

Even accounting for the ongoing rollout of smart meters, uptake of cost-reflective tariffs has been slow. Less than 23% of customers outside of Victoria with advanced meters have cost-reflective network tariffs. Tasmania and NSW have seen the greatest take-up of these tariffs (at 46% and 39% of customers respectively), with much lower rates in Queensland (1% of customers), South Australia (6% of customers) and the ACT (4% of customers).[94]

South Australian and Queensland distributors proposed to shift all customers with smart meters onto cost-reflective network pricing from 1 July 2021. The proposed shift would significantly step up the progress of tariff reform in those states.

1.5.6 Demand management incentives

The AER supports distributors to implement strategies to manage the impact of DER on their networks through a demand management incentive scheme and demand management innovation allowance (section 3.12.9). Among projects recently supported through the scheme are large and small scale storage projects, microgrids and load control projects. The scheme has also funded research on subjects including future grid and EV demand; and studies on the use of energy trading and distributed energy platforms.

1.5.7 A 2-sided market

The efficient integration of DER into the power system is a priority reform in the ESB's NEM 2025 project. The focus is to enable the integration of DER such as rooftop solar and distributed storage into the system so they can provide services to networks, the wholesale market and other consumers. A key element is to appropriately value flexible demand to incentivise the owners of distributed resources to respond to price signals on the system's need for them.

Alongside reforms already being progressed by the AEMC, the ESB is focused on rewarding customers for building flexibility into their energy use. To provide these opportunities to customers, it needs to be made easier for innovative new retailers and service providers to enter the market and offer different choices to customers.

In 2021 the ESB is exploring options for the NEM to operate in the longer term as a 2-sided market in which traditional participant categories such as retailers, generators and aggregators would be replaced by 2 categories – those who use electricity and those who sell it on behalf of end users. This would make it easier for new types of traders to enter the market. It could also mean that single end users could be their own trader for some services – and use other traders to buy or provide other services for them.[95]

A 2-sided market has all its participants responding to price signals and being exposed to market outcomes. Energy customers could use metering and other evolving technologies to set up arrangements for how they wish to participate, either through a retailer or aggregator.

The AEMC is taking steps toward making these reforms operable through its review of integrating energy storage systems into the NEM. The AEMC aims to release a draft decision in July 2021.[96]

The ESB is also considering the introduction of flexible trading arrangements, including a new participant category called 'scheduled lite', so that those resources that do not normally participate in the market can offer services such as demand response.[97]

93 Estimates derived from AER market intelligence.

94 AER, *Retail energy market performance update for Quarter 2, 2020–21*, April 2021.

95 ESB, *Moving to a two-sided market*, April 2020.

96 AEMC, 'Integrating energy storage – new date for draft National Electricity Rules changes' [media release], 29 April 2021.

97 ESB, *Post 2025 Market Design Options – a paper for consultation*, April 2021, p 71.

1.6 Efficient investment and access

Aside from reliability and security challenges, Australia's energy market transition poses risks to efficient investment in, and use of, energy infrastructure. The market lacks a coordinated framework to locate generators efficiently and provide transmission capacity where it is needed.

Transmission network providers are receiving an unprecedented number of connection enquiries from renewable projects seeking to locate in sunny or windy locations on the edges of the grid, where transmission capacity is weak. Connecting new plant in these areas can cause network congestion, which weakens system security for the grid as a whole. Congestion can prevent generators in an affected area from being dispatched efficiently.

A lack of transparency intensifies the problem. While significant information is available about a generator once it connects to the grid, projects have limited transparency before the generator signs a connection agreement with a network. Progress has been made in this area. New rules effective from December 2019 require network businesses to share connection information about generation proposals with AEMO, which then publishes this information. The rules provide developers with up-to-date information about generation projects in the pipeline to help guide investment decisions on where to locate new generators and to assess project viability.[98]

Reforms introduced in 2018 apply stricter technical standards to connecting generators to help mitigate the risks of new plant causing congestion (section 1.4.5).[99] Transmission networks may impose such technical requirements (generator performance standards) as they see fit. But, as networks become more constrained in areas with high quality renewable energy resources, requirements placed on connecting generators are becoming increasingly stringent. Many project proponents find grid connection (access) difficult to negotiate. The arrangements have raised concerns among developers, with some reporting that network businesses are delaying the processing of connection applications or altering required standards during negotiations.

Current access frameworks also fail to address perverse outcomes that can occur. For example:

› multiple generators seeking to connect to a network may each invest in separate connection assets when a shared asset may be more efficient. In 2021 the AEMC has been consulting on draft reforms to enable a generator, or a group of generators, to fund shared network assets and have those assets subject to a special access regime.[100] Development of REZs will also address this issue (section 1.6.1)

› a new connecting generator is not penalised for causing network congestion that degrades the quality of access for other generators. Existing generators cannot gain firm network access to avoid this risk.

These issues are difficult to address without pricing reforms. Current frameworks do not provide accurate signals to new generators on the costs and risks of connecting to weaker parts of the grid. Generators connecting to the grid do not pay for their use of the transmission networks, beyond a basic charge to connect to the nearest point on the network. The cost of other work needed to augment the network to accommodate a new generator with a poor network connection is charged to all energy users. Further, current frameworks do not allocate congestion costs among generators.

In 2021 the ESB assessed that, without reforming access arrangements, new generation will locate and operate in ways that exacerbate congestion, reducing efficiency and raising costs for consumers. Alongside piecemeal reforms to the market's architecture, 2 major reform strands aim to make access to transmission networks more efficient. The immediate focus is on coordinated generation and transmission planning. A longer term focus is on pricing reforms and congestion management tools.

98 AEMC, *Transparency of new projects*, fact sheet, December 2019.

99 AEMC, *Generator technical performance standards rule determination*, information sheet, September 2018.

100 AEMC, *National electricity amendment (connection to dedicated connection assets), draft rule determination, proponent: AEMO*, November 2020.

1.6.1 Coordinating generation and transmission investment

Transmission investment tends to lag behind generation investment, often resulting in delays between the completion of a generation project and the network being ready for the plant to connect. These lags create uncertainty for generation proponents and may delay efficient investment.

The lag in transmission investments is driven by 2 underlying factors:

- The business case for transmission upgrades typically requires evidence of a current, rather than a likely future, market need.
- Approval of transmission projects requires a thorough cost-benefit assessment to ensure customers are getting value for money.

The Victorian Government, concerned that the national framework on transmission approvals excessively delays the delivery of projects and fails to account for the full benefits of investments, introduced new rules in February 2020 that allow priority projects such as grid scale batteries and transmission upgrades to be fast-tracked.

Reforms are progressing to better coordinate planning and investment in transmission and generation to ensure new assets are built in the right place, at the right time, to serve the long term interests of consumers. More coordinated planning will facilitate efficient grid connection and reduce the risk of congestion scaling back generator earnings. Reforms also focus on streamlining the approval process for large transmission projects.

Integrated system planning

The centrepiece of reform to coordinate investment in transmission and generation to serve the long term interests of consumers is AEMO's Integrated System Plan (ISP). The plan (first published in 2018 and updated in 2020) provides information to the market on future generation and network requirements over a 20-year horizon. It is a whole-of-system plan that aims to facilitate strategic transmission investments and deliver the least cost mix of resources to supply secure and reliable energy to consumers.

The ISP forecasts where and when network investment is likely to be needed to accommodate the large amount of new generation likely to connect to the grid in coming years. Elements include upgrading transmission interconnection where needed for efficient sharing of energy, upgrading storage and backup supply across regions.

Renewable energy zones

A key initiative is to cluster new wind and solar projects in hubs called *renewable energy zones* (REZs) so that efficient transmission investment can be made to transport energy to customers. The clustering of renewable plant reduces the amount of transmission investment that would be needed if new renewable plant were widely dispersed. In 2020 AEMO highlighted 35 possible REZs across eastern Australia.

State governments have initiated programs to support the development of REZs identified through the ISP – NSW is developing 5 REZs, Victoria is consulting on 6 proposed REZs, and Queensland has identified 3 REZ corridors (figure 1.16). The ESB prioritised the development of REZ arrangements as a first step in improving transmission access and is working with state governments to efficiently plan, develop and maintain REZs to manage congestion and other risks.[101]

The NSW Government's Electricity Infrastructure Roadmap, launched in November 2020, will underwrite 12 GW of renewable energy across 5 REZs (Central-West Orana, New England, South West, Hunter, Illawarra), support the development of transmission assets and set a pathway for 2 GW of long-duration energy storage (and potentially other firming capacity) by 2030. The development of these assets is intended to be sized and timed to replace capacity lost through the progressive closure of coal fired power stations.

In February 2021 the Victorian Government released a plan to develop 6 REZs across the state, to add 10 GW of new renewable energy. The government will establish a new body – VicGrid – to plan and develop the zones and has allocated $540 million to invest in network infrastructure.[102]

In May 2021 the Queensland Government committed $145 million to establish 3 REZs – the Northern, Central and Southern QREZ. The government will undertake strategic network investments, streamline development of renewable energy projects and facilitate industrial energy demand to capitalise on available renewable energy resources.

101 ESB, *Post 2025 market design options – a paper for consultation*, April 2021, pp 79–80.

102 DELWP, *Victorian renewable energy zones development plan*, directions paper, February 2021.

Transmission investment

The 2020 ISP identified 18 transmissions augmentations to accommodate weather-dependant generation and DER and the phasing out of coal generation. The projects fall into 4 categories:

- *Committed* projects, which are those already approved and underway. They include:
  - the installation of synchronous condensers in South Australia to address inertia and system strength issues (scheduled for completion in 2021)
  - transmission upgrades in western Victoria to unlock capacity from new solar farms in the area (on track to be commissioned in 2 stages, by 2021 and 2025)
  - a minor upgrade to the Queensland–NSW interconnector scheduled for 2021–22. The AER in 2020 fast-tracked its regulatory test assessment on the upgrade, which aims to provide additional import capacity into NSW to supplement local supply following the closure of Liddell power station. The AER determined that the upgrade, estimated at $218 million, will deliver a net economic benefit to Australian energy consumers
- *Actionable* ISP projects, which are those considered by AEMO as critical for immediate development but still undergoing regulatory approvals. The projects, forecast to cost between $6.8 and $12.7 billion over the period 2022–32, include:
  - Project EnergyConnect – a new interconnector linking South Australia and NSW aimed at unlocking stranded renewable investments, for expected completion by 2024–25. TransGrid and ElectraNet committed to the project in June 2021 following AER approval of the project costs.
  - a minor upgrade to the Victoria–NSW Interconnector, to access planned new capacity at Snowy Hydro and unlock renewable energy resources in western and north west Victoria
  - HumeLink – a transmission upgrade to reinforce the NSW southern network and increase transfer capacity between Snowy Hydro and demand centres, with completion due by 2025–26
  - network augmentations to support the Orana REZ in the central west of NSW and upgrade transfer capacity to major load centres, for expected completion in 2024–25[103]
  - Project Marinus – a proposed 1,500 MW capacity interconnector between Tasmania and Victoria to allow increased exports from Tasmania's renewable energy and storage resources
  - the Victoria to NSW Interconnector (VNI) West project, to allow for additional renewable generation in north west Victoria and address grid congestion and system strength issues
- third and fourth categories, which relate to projects that have been identified as potentially contributing to improved system outcomes but are not required immediately or are contingent on other projects or work programs.

Regulatory processes

Proposed transmission investments are subject to a cost-benefit analysis before they can proceed. The RIT-T assesses an investment proposal against credible alternatives, including non-network solutions.

The RIT-T has been streamlined to fast-track strategic transmission projects. The changes (which took effect in 2020) allow some parts of the regulatory process to run concurrently, avoid duplicating processes such as modelling in cost–benefit assessments and allow regulatory requirements to be met *before* dependant generation projects are committed (section 1.6.2).[104] In August 2020 the AER published guidelines on how AEMO should undertake analysis and consultation in the ISP, and on how transmission businesses should apply the RIT-T to actionable ISP projects.

In 2021 the AER published guidance on its approach to assessing the costs of 'actionable' ISP projects for inclusion in the regulatory asset base, to support efficient and timely delivery.[105] In April 2021 the AER approved $45 million to upgrade the Victoria to NSW Interconnector to help secure electricity supply to homes and businesses after Liddell power station's closure in 2023. The upgrade is the first 'actionable project' to progress under new rules governing the ISP. Average residential customers in NSW will pay an estimated extra $1 on their bills in 2022–23 as a result of this decision.[106]

In May 2021 the AER approved funding of $2.3 billion in efficient costs for the proposed South Australia–NSW interconnector (Project EnergyConnect) – 4% less than the proposal from TransGrid and ElectraNet.[107]

103 AEMO, *2020 Integrated System Plan*, July 2020, p 14.

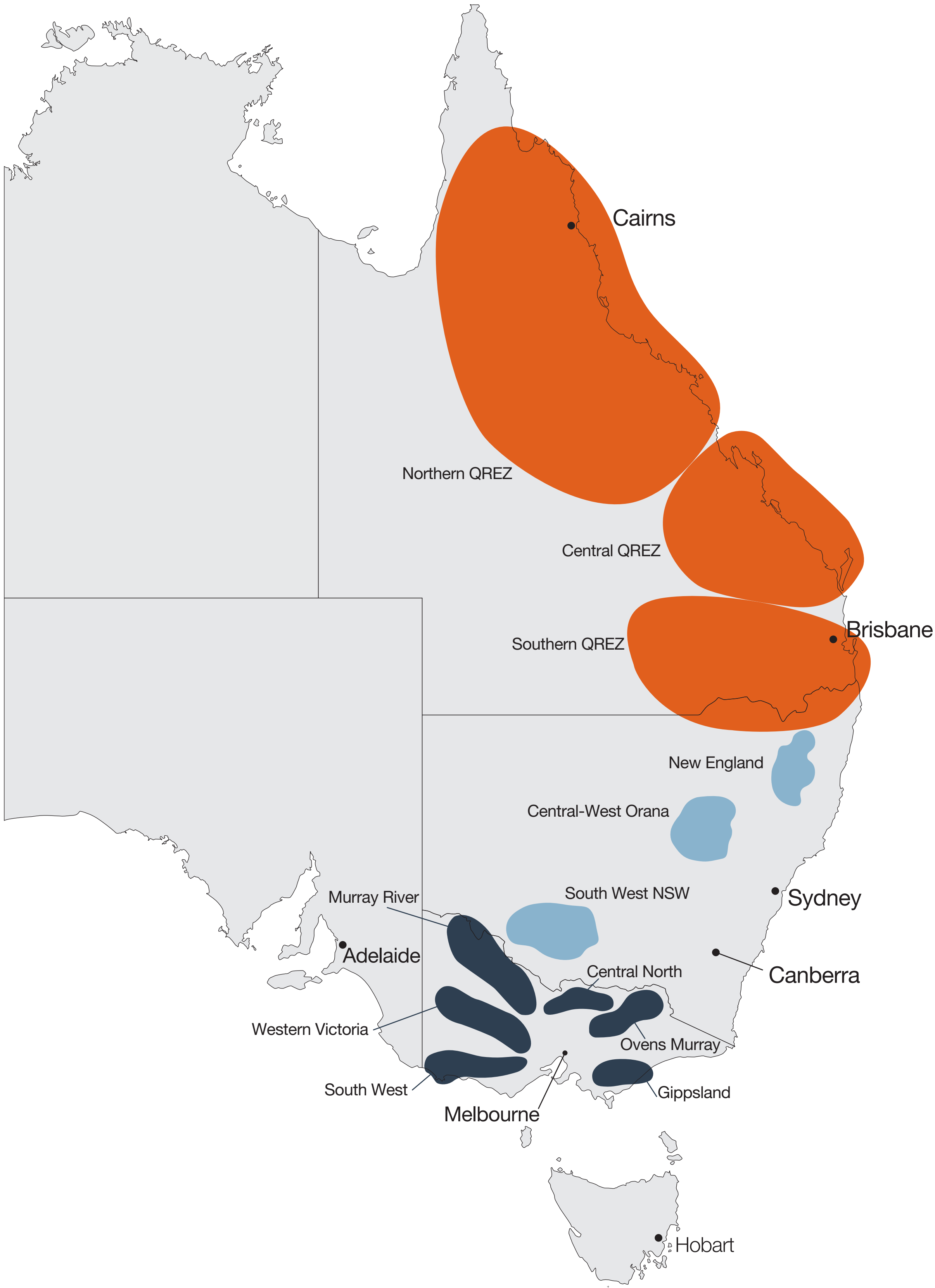
104 CoAG Energy Council, Energy Security Board, 'Actionable ISP final rule recommendation', CoAG website, accessed 27 March 2020.

105 AER, 'Regulation of large transmission projects' [media release], 17 November 2020.

106 AER, 'AER approves costs for Victoria to New South Wales Interconnector' [media release], 13 April 2021.

107 AER, 'AER approves costs for Project EnergyConnect' [media release], 31 May 2021.

Figure 1.16 Renewable energy zones



Note: The NSW Government has not mapped the location of the planned Hunter and Illawarra REZs.

Source: Department of Environment, Land, Water and Planning, Victoria, *Renewable energy zones*, DELWP website, accessed 1 June 2021; NSW Government, *Renewable energy zones*, NSW Government website, accessed 1 June 2021; Department of Energy and Public Works, Queensland, *Queensland renewable energy zones*, DEPW website, accessed 1 June 2021.

Challenges to ISP transmission projects

In 2021 the ESB reported that challenges are emerging in building new actionable ISP projects. These include planning issues, community concerns, biodiversity, Indigenous heritage, difficulties getting access to land and reluctance by networks to take risk and cope with financing very large projects. Unaddressed, these issues have the potential to result in delays and increased costs. In some cases, the Commonwealth and relevant state jurisdictions are underwriting and supporting projects.[108]

TransGrid and ElectraNet raised concerns about the ability of network businesses to finance large transmission projects. In April 2021 the AEMC rejected a rule change proposal in relation to revenue recovery for actionable ISP projects to be developed by these network businesses. The AEMC considered that current arrangements do not pose a barrier to financing actionable ISP projects. The AEMC also considered that making the rule change would likely substantially increase costs to consumers in the near to medium term.[109]

Community concerns can be addressed through a RIT-T dispute process. Upon receiving a dispute, the AER assesses the transmission business's compliance with the RIT-T. In 2019 the South Australian Council of Social Service (SACOSS) lodged a dispute over ElectraNet's application of the RIT-T to the proposed South Australia–NSW interconnector. The AER found that ElectraNet had met the requirements of the test.

Allocating costs of transmission interconnectors

While transmission interconnectors provide national benefits, they are largely paid for by customers who happen to live in the states in which they are built. The approach raises issues of fairness and has come under scrutiny. For instance, the Marinus Link project linking Tasmania with Victoria will only proceed if agreement is reached on how the cost of the project will be recovered. The issue has the potential to delay the project.

There is also a debate as to whether generators should share in the cost of transmission investment. The ESB has provided advice to Energy Ministers on a fair method for allocating transmission costs to better align the costs and benefits of network investment and governments are conducting further analysis.[110]

1.6.2 Access pricing

Coordinating transmission and generation development will help overcome some of the traditional inefficiencies in connecting new plant to the grid. But reform is needed to achieve this coordination.

Price signals for investors as to where the network has spare capacity for new connections are currently limited. Every generator and customer in a region receives or pays the same price (adjusted for loss factors), which is determined at a single point in the region called the reference node. Marginal loss factors provide a limited signal on how connecting in a weak network area might impact future earnings. But marginal loss factors have become increasingly volatile and, therefore, difficult to interpret or rely on (box 1.6).

The ESB is exploring medium term pricing reforms for congestion management as a focus of its NEM 2025 reforms. Options include charges imposed each dispatch interval on generators contributing to network congestion; connection fees for new generators that reflect congestion costs caused by their connection; and generator transmission use of system charges that reflects the relative cost of providing transmission infrastructure at a given point on the network.

The proposed congestion management charge would reflect a generator's marginal impact on the cost of congestion in each dispatch interval. This would remove incentives for 'disorderly bidding' – where generators offer capacity below cost to ensure dispatch – when the network is congested. Money received through the congestion charge would then be rebated to generators based on their availability. To encourage new generation investment within REZs and other areas of new transmission capacity, the rebate could be limited to new generators that locate within these zones.

In the longer term, the ESB is exploring a more comprehensive access solution in the form of locational marginal pricing and financial transmission rights.

108 ESB, *Post 2025 market design options – a paper for consultation*, April 2021, p 78.

109 AEMC, *Rule determination – participant derogation – financeability of ISP project (ElectraNet)*, April 2021.

110 ESB, *Post 2025 market design options – a paper for consultation*, April 2021, p 75.

Under AEMC proposals announced in 2020, generators would receive a local price based on the marginal cost of supplying electricity in their specific network area. The price would account for congestion and losses in that area.

Generators would have access to new hedge products (financial transmission rights) to manage the risks of congestion and transmission losses. The hedges would effectively pay a generator the difference between the local and regional price. The AEMC argued the combination of local pricing and financial transmission rights would improve incentives for generators to connect to efficient areas of the network, thereby lowering costs to customers.

Box 1.6 Existing price signals for new plant

As the National Electricity Market's (NEM) generation fleet becomes more geographically dispersed, and new plants locate further from the existing grid, energy losses from the system are rising. When electricity is transported across a network of poles and wires, some of it is lost as heat. These losses increase as more generators locate far from demand centres, because power has to travel further to reach customers. Across the NEM, transmission losses equate to around 10% of all electricity transported between power stations and customers.[111]

A generator's earnings from selling electricity are scaled down to reflect this loss of energy. Generators that locate near the end of the line, where transmission is weak, have a relatively high loss factor. As a result, their earnings can be significantly scaled down. This outcome appropriately signals to developers that locating new plant in a weak network area poses risks to future earnings. In this way, loss factors provide a price signal that discourages investment in inefficient locations.[112]

In the NEM, this signal is applied through *marginal loss factors* (MLFs), which estimate the percentage of the next (marginal) unit of electricity sent into the grid that is likely to reach customers rather than being lost. The Australian Energy Market Operator (AEMO) forecasts the MLF for each generator annually, based on forecast losses between a generator and the regional reference node (the place in a region where wholesale electricity prices are set).

The increase in renewable generation in weaker (often remote) parts of the grid can cause large changes in loss factors. The planned connection of substantial solar generation in north and central Queensland led to MLFs in the region being scaled back in each of the 3 years to 2020–21. Loss factors were also scaled back in 2020–21 for some other regions where network limitations constrain generation output, including areas of north west Victoria, south west NSW, the south east and Riverland areas of South Australia, and several parts of Tasmania.[113]

MLFs provide a partial price signal on where to invest in new generation. But, with the sheer volume of new renewable generation connecting to the system, the usefulness of MLFs as a price signal is breaking down. Price signals for locating new plant should provide relatively stable longer term guidance, but MLFs have become increasingly volatile. To help decision making, the AEMC in 2020 amended the calculation process to increase transparency and improve predictability for investors.[114]

The MLFs are also only a partial signal. While they account for transmission losses caused by a generator connecting in a weak network area, they do not capture network congestion costs, which are borne by the whole market.

111 AEMO, 'Loss factors and regional boundaries', AEMO website, accessed 21 May 2020.

112 AEMC, *Transmission loss factors*, fact sheet, November 2019.

113 AEMO, *Regions and marginal loss factors: FY 2020–21*, April 2020.

114 AEMC, *Transmission loss factors, Final determination*, 27 February 2020.

1.7 Government schemes

Governments at all levels are undertaking unilateral (or bilateral) policy initiatives to manage aspects of the energy market transition. The schemes include major investments in publicly owned generation and storage, programs offering financial assistance for private grid scale projects, and regulatory interventions to streamline investment approvals.

The schemes often embody broader policy objectives than maintaining reliability and security. Examples include supporting community transition and jobs or delivering low emissions and renewable energy policy targets.[115]

While government intervention can help manage an identified market issue, its wider market impacts are complex. In particular, intervention can distort market signals, affecting private sector investment decisions. The addition of capacity from government-backed schemes places downward pressure on the current and projected energy prices, putting resources not supported by government backing at a competitive disadvantage, making it more difficult for them to attract investment. Lower energy prices also makes it difficult for thermal plants to maintain commercial viability and may lead to exits of thermal plant faster than anticipated.[116]

The AER has previously noted that a key driver behind increased government intervention appears to be the risk that short term price signals may not deliver significant investment in dispatchable generation at the current time.[117]

The ESB noted a number of government interventions appear to be driven by an intolerance for sustained high prices that may be needed to prompt a market-led investment response. The ESB found that rewarding resources outside the market increases the risk of distortions, especially when interventions are delivered inconsistently and in an uncoordinated way.[118]

The ESB recognised that jurisdictional investment schemes are likely to be an enduring feature of the energy sector as governments seek to manage risks associated with the energy transition. It is working with governments and industry on a more consistent NEM-wide approach to the various schemes that preserves the role of spot and contract markets in providing the primary signal for investment.[119]

1.7.1 Incentivising private capacity investment

Australian governments offer a range of financial incentives for private investment in generation and storage capacity. Some schemes offer direct subsidies or grants. Others underwrite investment through debt or equity support or through measures such as selling 'contracts for difference' that provide financial certainty for investors. Some schemes use a mix of approaches.

Underwriting new generation investment

Alongside ongoing funding schemes run by ARENA and the Clean Energy Finance Corporation (CEFC) (box 1.1), the Australian Government launched the UNGI program in 2019. The program offers incentives for 'firm' and 'firmed' capacity targeted at lowering prices, increasing competition and increasing reliability.

The first registrations of interest led to a shortlist of 12 projects: 6 pumped hydro projects (including Battery of the Nation), 5 gas projects, and a proposed upgrade of the Vales Point black coal fired generator (which has since been cancelled).

115 ESB, *Post 2025 market design options – a paper for consultation*, April 2021, p 18.

116 ESB, *Post-2025 market design directions paper*, January 2021, pp 16, 22.

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

118 ESB, *Post-2025 market design directions paper*, January 2021, pp 16, 21, 24.

119 ESB, *Post-2025 market design directions paper*, January 2021, p 29.

From the shortlist, the Australian Government announced 2 successful projects in January 2020:

- APA Group's proposed 220 MW gas generator in Victoria to provide fast-start generation to balance the increase in intermittent renewables in that state
- Quinbrook Infrastructure Partners' 132 MW gas generator in Queensland to help meet peak demand in Queensland and NSW, increase competition and complement an upgrade to the Queensland–NSW Interconnector.[120]

An agreement to fund these projects had not been reached by early 2021 due to stalled progress in implementing the Grid Reliability Fund.[121]

State and territory government schemes

The Victorian Government's Renewable Energy Target, the Queensland Government's Renewable Energy Target and the ACT Government's 100% Renewable Energy Target are backed by programs to underwrite investment. The governments run reverse auctions to secure target levels of new renewable generation capacity, with successful applicants receiving a guaranteed minimum price for generation output from the plant. The NSW Government's Electricity Infrastructure Roadmap also proposes significant underwriting of generation investment.

1.7.2 Public investment in generation capacity

Despite strong investment in renewable capacity, private sector investment in 'firming' or 'dispatchable' capacity in recent years has been negligible. To fill the gap, the Australian Government and some state governments have announced new public sector investment in electricity generation, storage and transmission projects.

Snowy 2.0

Among major initiatives, in 2018 the Australian Government committed to expanding Snowy Hydro by using pumped hydroelectric technology. The expansion will increase Snowy Hydro's pumped hydroelectric generation capacity by around 2,000 MW – a rise of 50% – adding 175 hours of storage to the NEM. The project will construct an underground power station and about 27 kilometres of power waterway tunnels to link existing reservoirs. The underground power station will pump water to the upper reservoir when electricity prices are low. When prices are high, it will generate electricity by releasing water to flow down through the underground power station back to the lower reservoir. Approvals for main works on the project were received in May 2020. The project is forecast to start producing power from the first of 6 new generators by early 2025.

In 2021 the Australian Government also committed funding for Snowy Hydro to build a 660 MW gas powered generator in the Hunter region of NSW by 2023 after declaring that committed private investment is insufficient to fill the gap left by the closure of the Liddell power station.[122]

Battery of the Nation

In April 2017 the Australian and Tasmanian governments announced a feasibility study on expanding the Tasmanian hydroelectric system. The expansion would deliver up to 2,500 MW of additional capacity, including through a pumped hydro project at Lake Cethana and redevelopment of the Tarraleah hydropower scheme. Initial studies of the project have been supported with $5 million in funding from ARENA.

Alongside the Battery of the Nation project, planning is progressing on a new interconnector between Tasmania and Victoria to support an expansion of Tasmania's renewable energy capacity. A business case for the 1,500 MW Marinus Link was completed in 2019, and in 2021 TasNetworks was progressing project design and approvals. The project will only proceed if an agreement is reached on allocating costs of the project across NEM regions.

120 The Hon Angus Taylor MP (Minister for Energy and Emissions Reduction), 'Initial support terms for two new generation projects agreed' [media release], 23 December 2019.

121 The Clean Energy Finance Corporation Amendment (Grid Reliability Fund) Bill 2020 was introduced into the House of Representatives in August 2020 but at May 2021 had not been passed.

122 The Hon Angus Taylor MP, 'Protecting families and businesses from higher energy prices' [media release], 19 May 2021.

CleanCo

In December 2018 the Queensland Government launched CleanCo – a state-owned corporation focused on meeting Queensland's 50% Renewable Energy Target by 2030. CleanCo has a target to support 1,400 MW of new renewable capacity by 2025 through a mix of building, owning and operating assets and investing in private sector projects.

In 2020 the Queensland Government committed $500 million into a Renewable Energy Fund, allowing increased public ownership of commercial renewable projects and supporting infrastructure.[123] In June 2021 the Government increased funding by $1.5 billion to support expansion of the renewable energy and hydrogen industries.[124] Investments from the fund are expected to be made progressively over the next 3 years.

Grid scale batteries

South Australian Government support led to the development of the first scheduled battery in the NEM – the 100 MW Hornsdale Power Reserve. The battery has helped lower the cost of frequency control services in the region. Its capacity was expanded to 150 MW in 2020.

The Victorian Government's first expedited project under its new transmission project approval framework was to fast-track AEMO's procurement of a 300 MW battery to increase import capacity of the Victoria to NSW Interconnector in peak demand periods. The battery will be in place by summer 2021–2022.

In May 2021 the NSW Government entered into a services agreement to underpin development of a 100 MW battery in the south west of the state. The agreement forms part of a long term retail contract with Shell Energy to provide electricity for government-run facilities.

123 Queensland Government, *Budget strategy and outlook 2020–21*, chapter 8, November 2020.

124 The Honourable Annastacia Palaszczuk, Premier and Minister for Trade '$2 billion investment to power more jobs and more industries through cheaper, cleaner energy' [media release], 10 June 2021.

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.

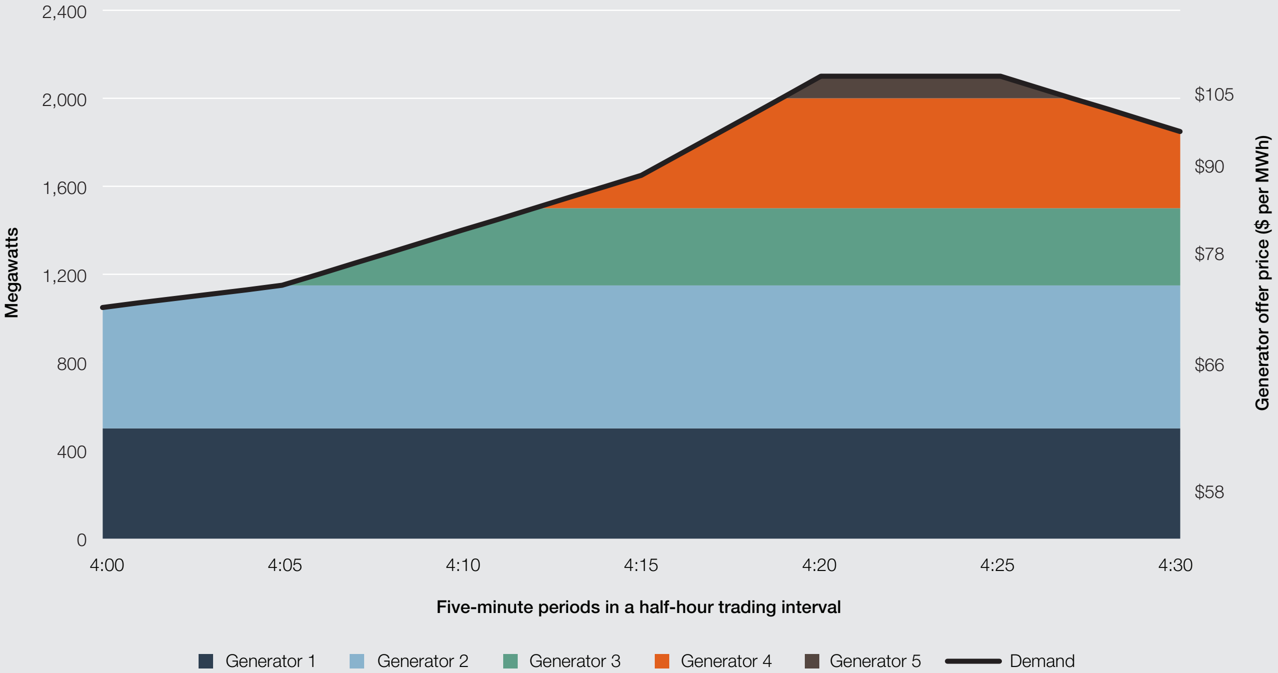
Only large customers (such as energy retailers and major industrial energy users) deal directly with the wholesale market. Retailers buy power from the market, which they package with network services to sell as a retail product to their customers. They manage the risk of volatile prices in the wholesale 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.

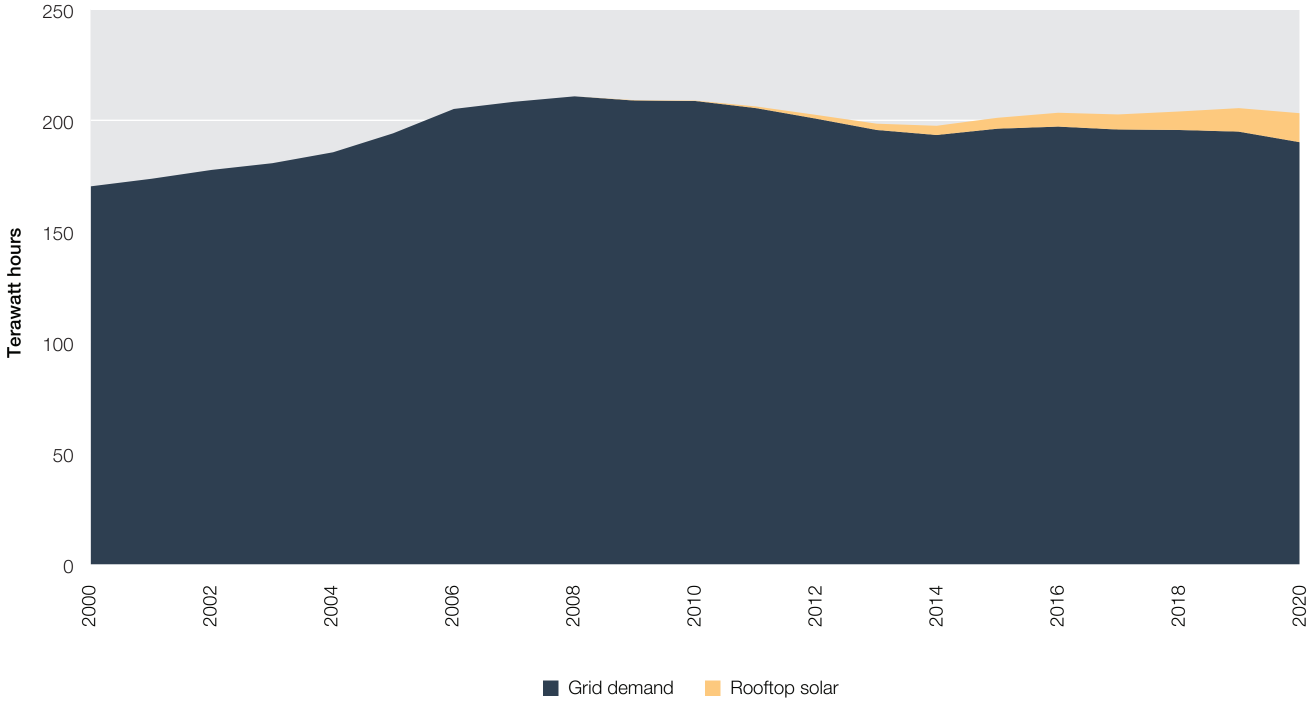
We draw on our monitoring work to advise policy bodies and other stakeholders on market trends, policy issues and irregularities. When appropriate, we also propose or participate in reforms to improve the market's operation.

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.

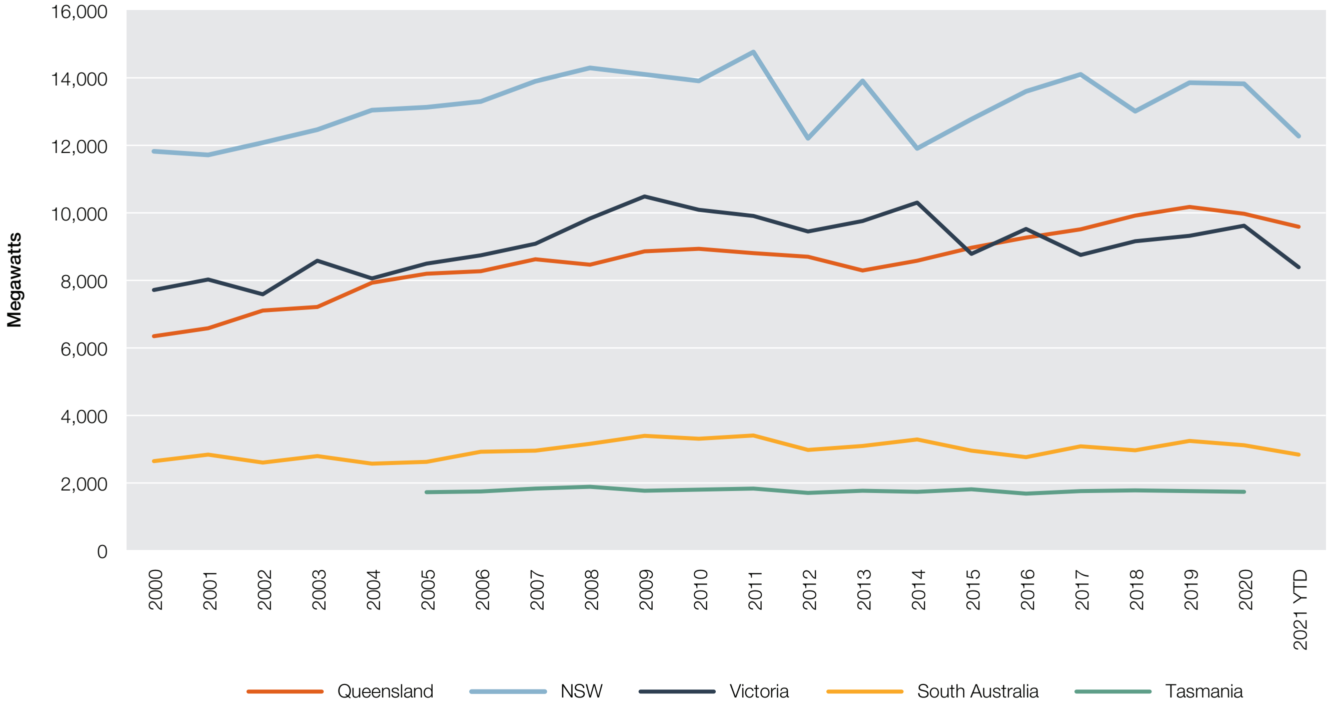
In 2020 all regions except Victoria experienced lower maximum demand than a year earlier. While high temperatures on some days in early 2020 drove demand higher, generally weather conditions over the summer were much milder than the previous year. Victoria recorded its highest maximum demand since 2013 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

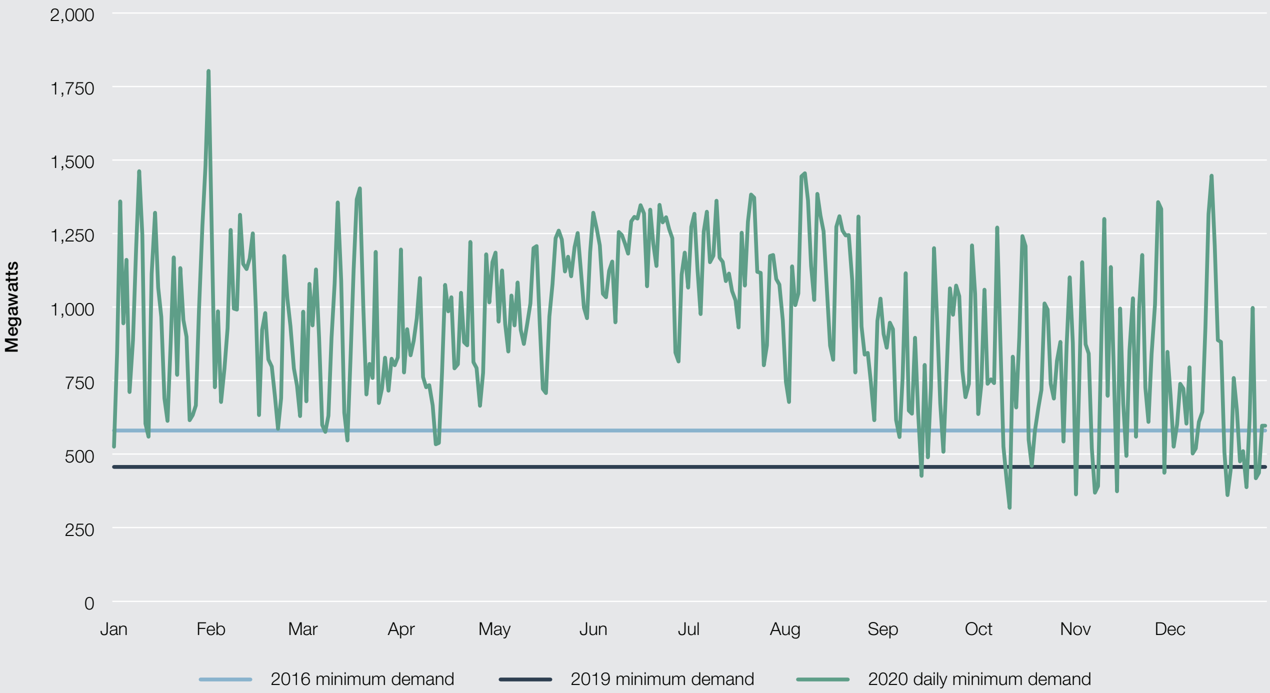
Historically, electricity demand reached its lowest point in the middle of the night, when most people are sleeping. But the growth of rooftop solar PV capacity means households are exporting electricity to the grid in the middle of the day when the sun is at its highest point. This trend is lowering 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.

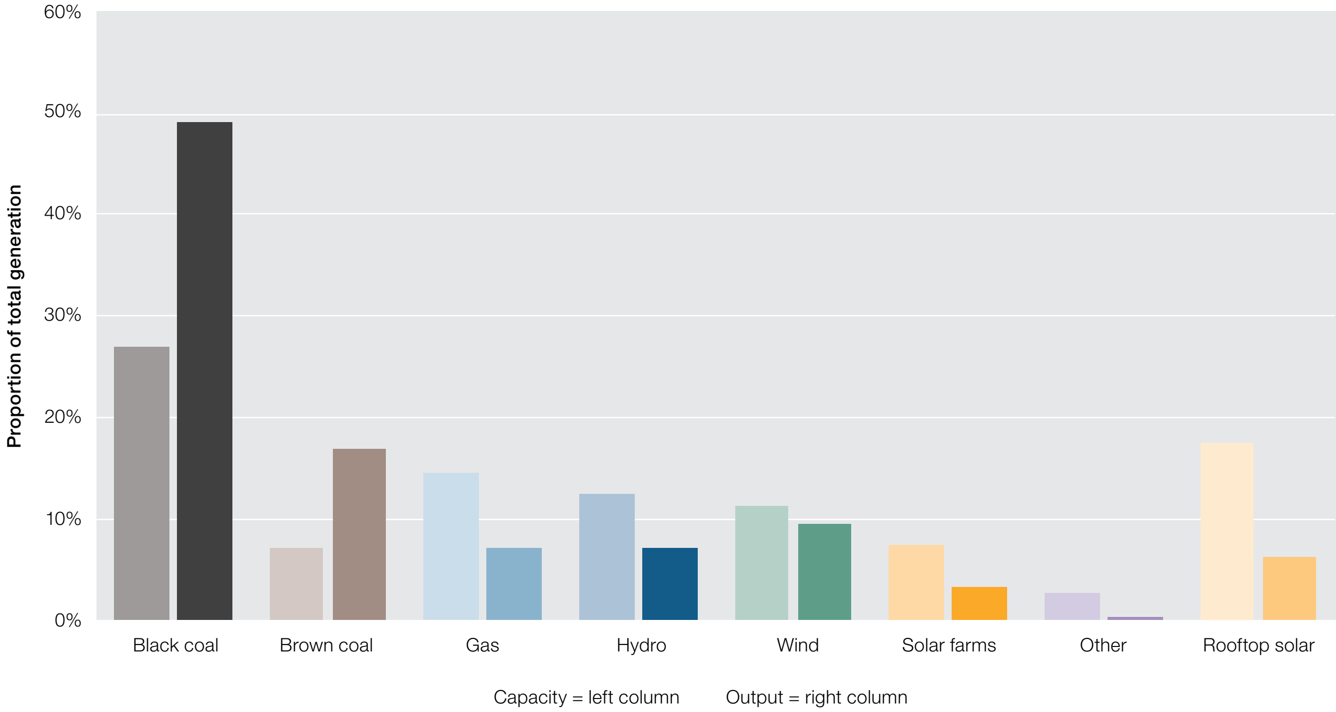
Synchronous generators such as coal, gas and hydro plants possess rotational inertia, which regulates frequency in the power system. Wind and solar plant do not possess this inertia and can pose challenges for power system security. The capability of those technologies to provide inertia and other security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

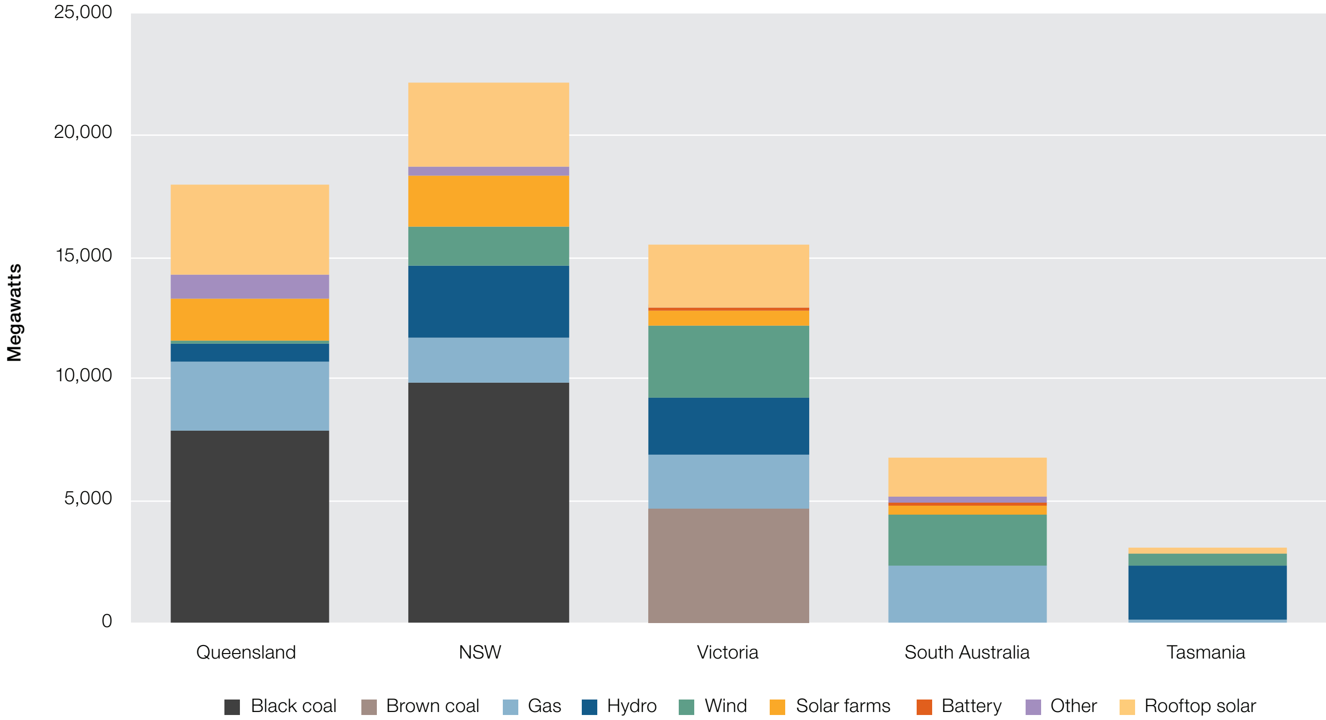
Figure 2.5 Generation output and capacity in the National Electricity Market, by fuel source, 2020



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.

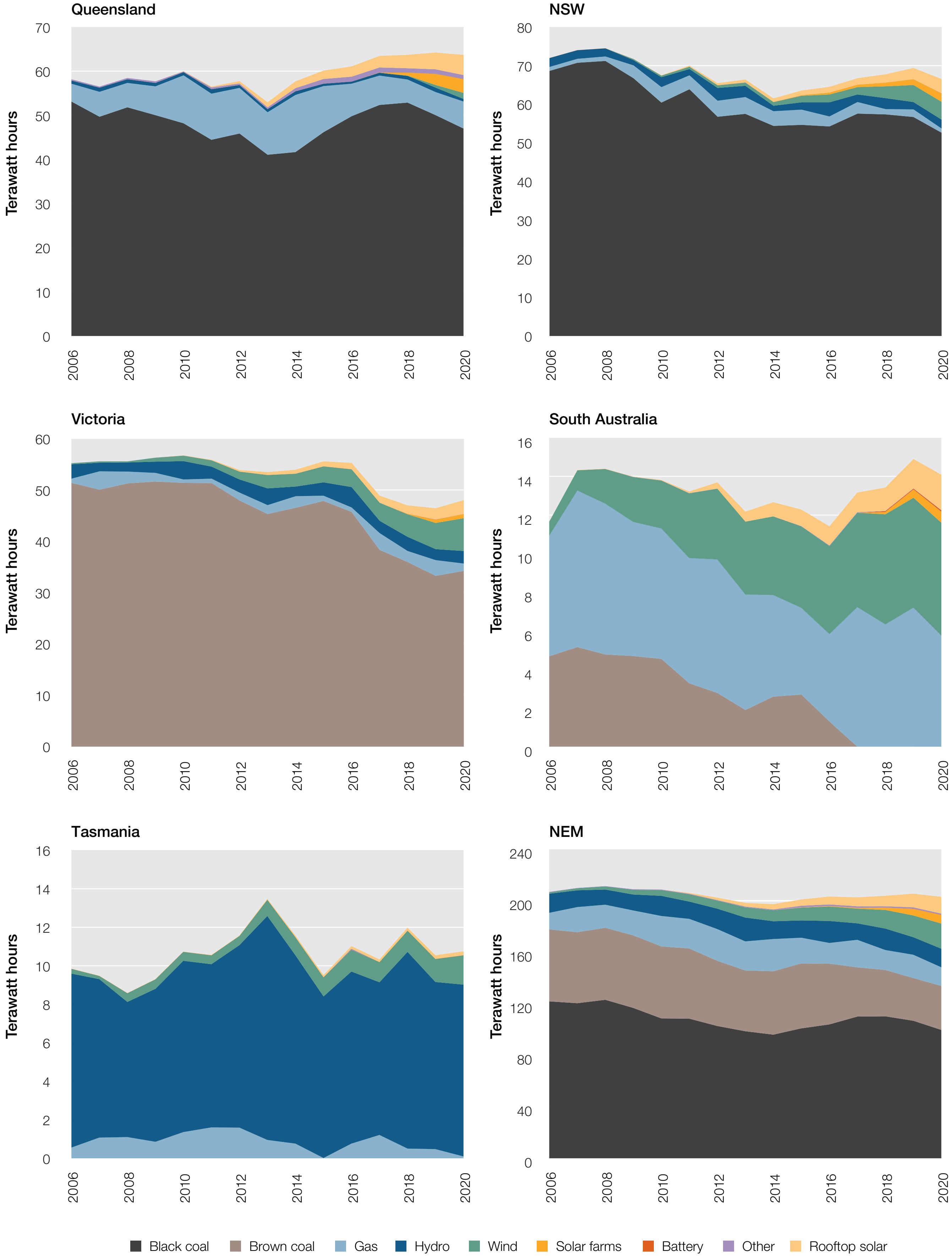
Figure 2.6 Generation capacity in the National Electricity Market, by region and fuel source, 2020



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]

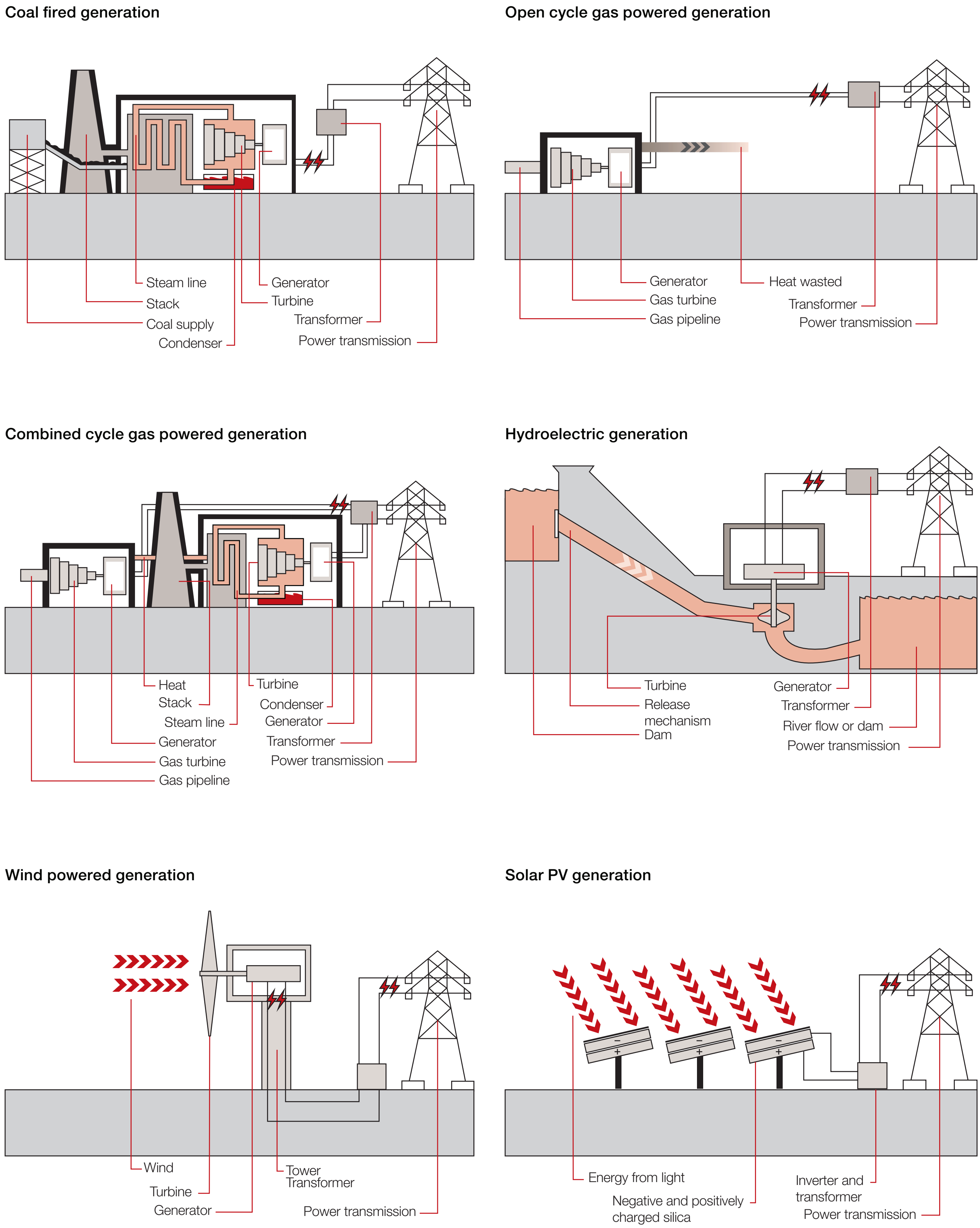
9 Synchronous generators – including hydroelectric and thermal plant such as coal, gas and solar thermal generators – contain heavy spinning rotors that provide synchronous inertia, slowing down the rate of change of frequency. They also help with voltage control by producing and absorbing reactive power,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

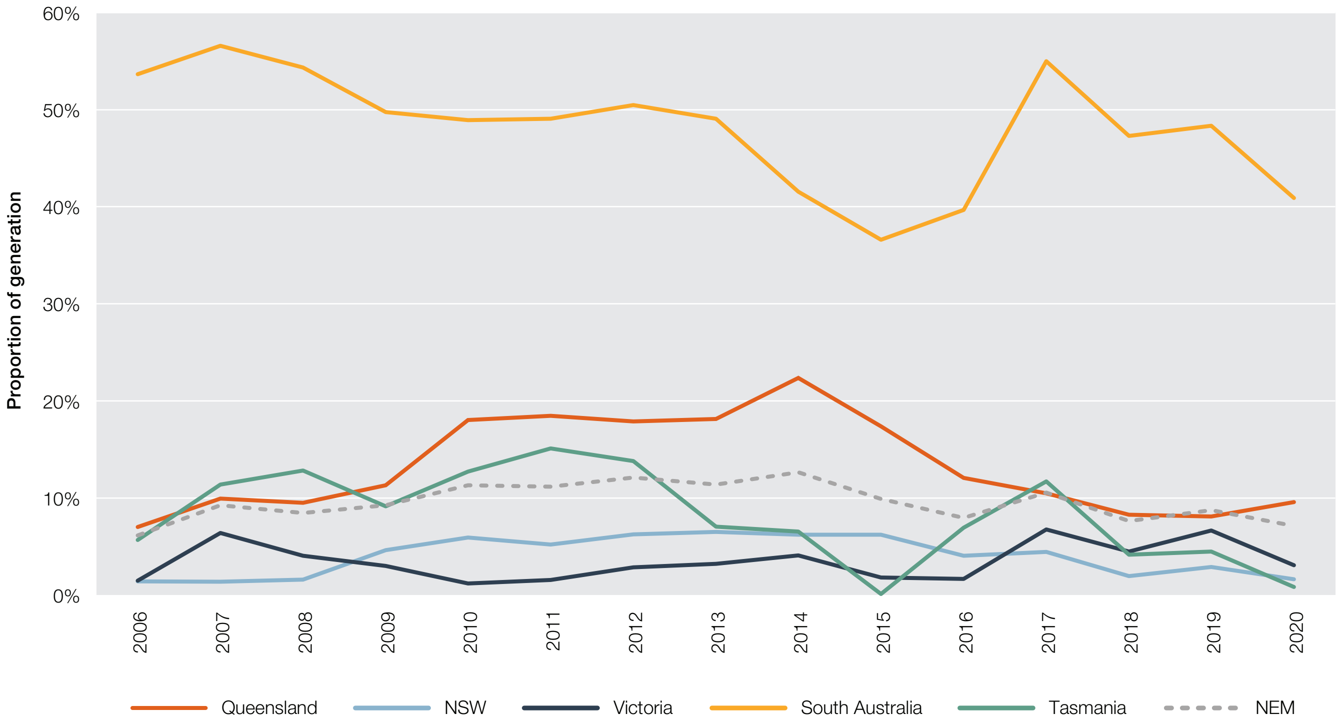


Despite these benefits, gas is a relatively expensive fuel for electricity generation, so gas generators more typically operate as ‘flexible’ or ‘peaking’ plant.[13] Across the NEM, gas powered plant accounted for 14% of plant capacity in the NEM in 2020 but supplied only 7% of electricity generated. 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).

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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

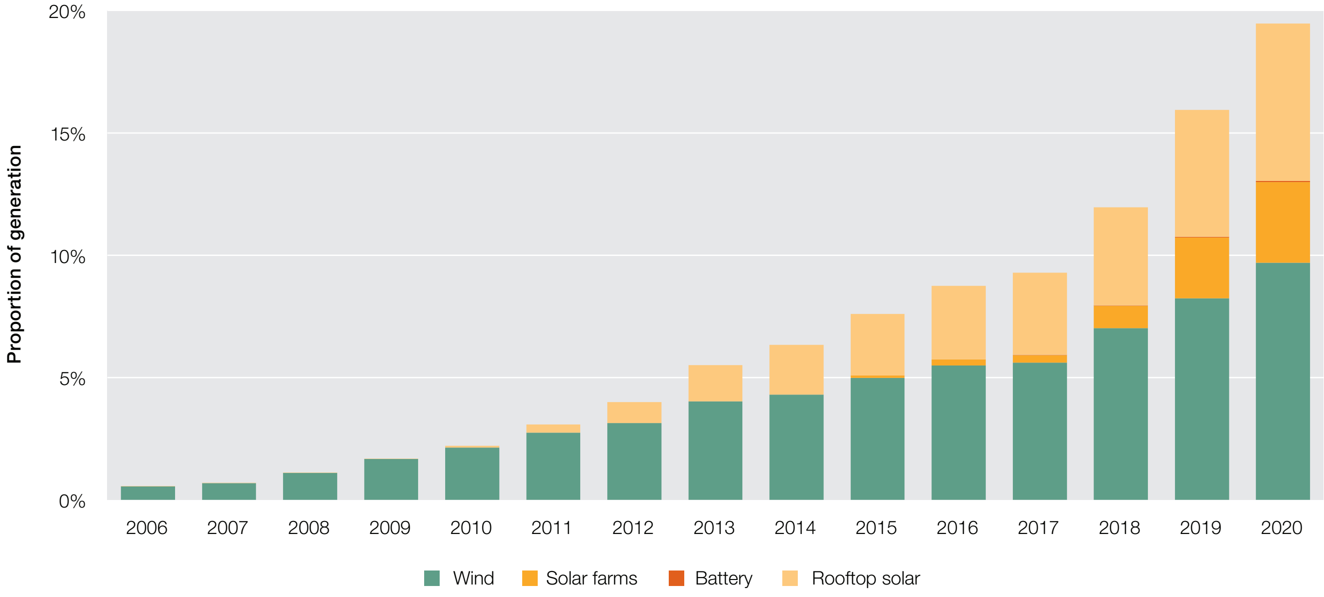
Wind turbines directly convert the kinetic energy of wind into electricity. The wind turns blades that spin a shaft connected (directly or indirectly via a gearbox) to a generator that creates electricity (figure 2.8).

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

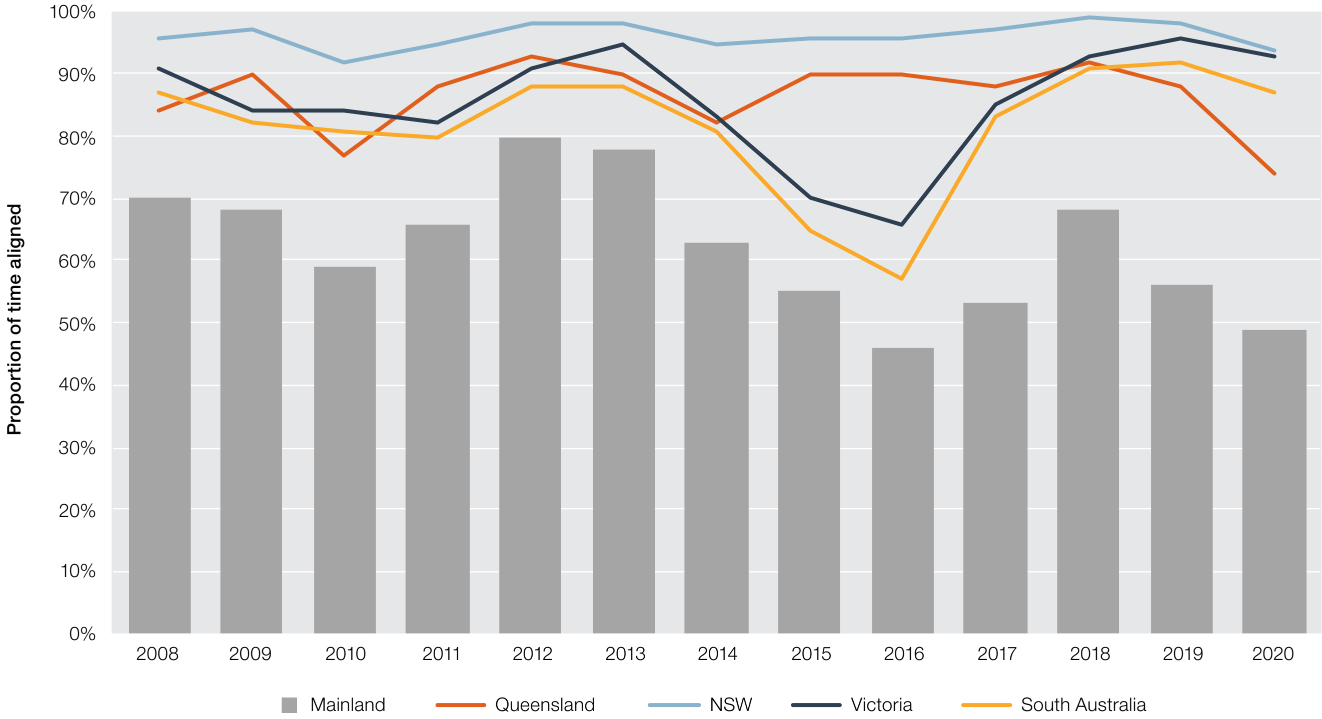
The market sets a separate spot price for each NEM region. When the interconnectors linking NEM regions are unconstrained, trade brings prices into alignment across all regions (apart from variations caused by physical losses that occur when transporting electricity). At these times, the NEM acts as 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.

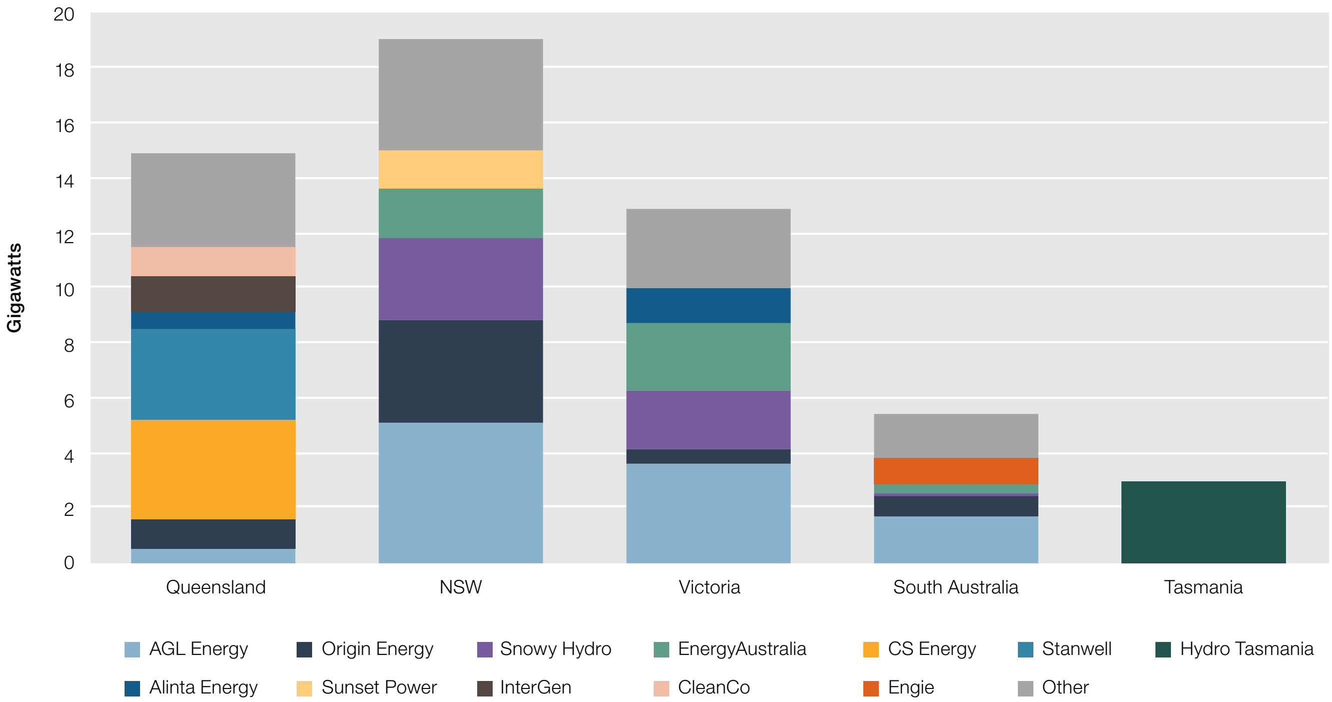
But government-owned corporations own or control the majority of capacity in Queensland and Tasmania:

- 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.

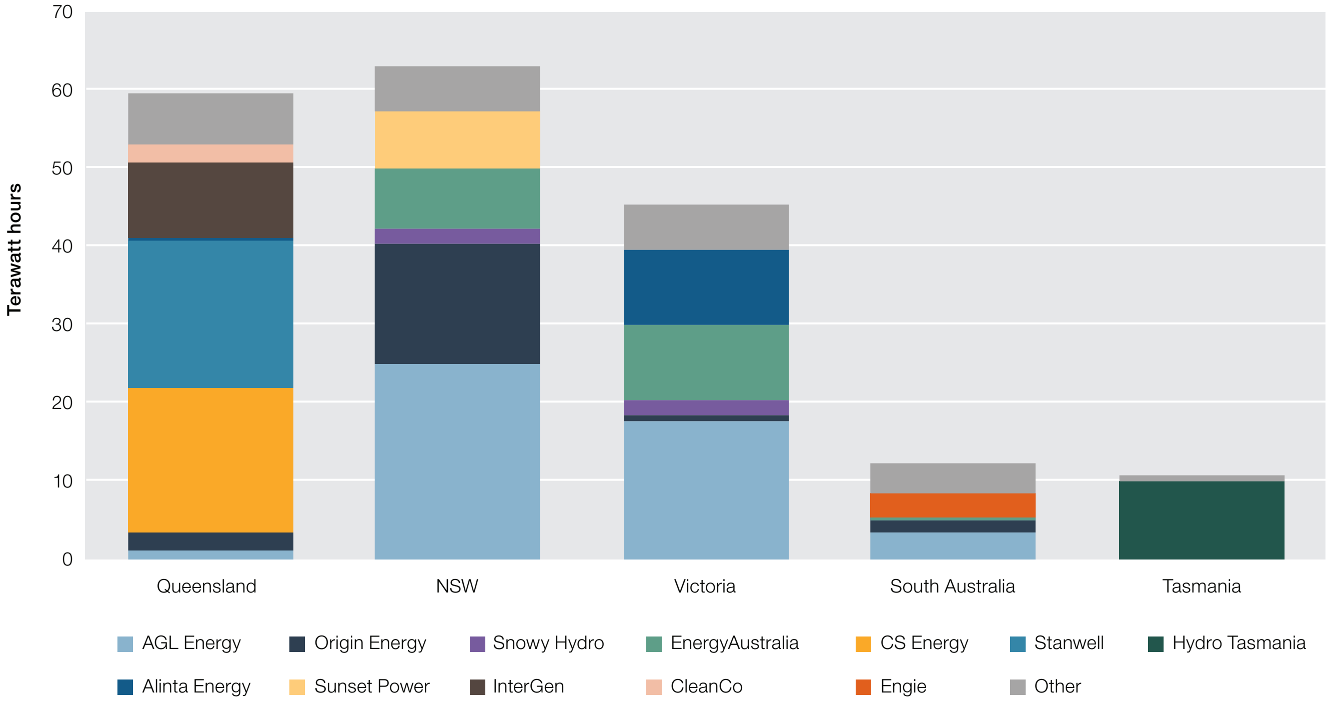
Figure 2.13 Market shares in generation capacity



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.

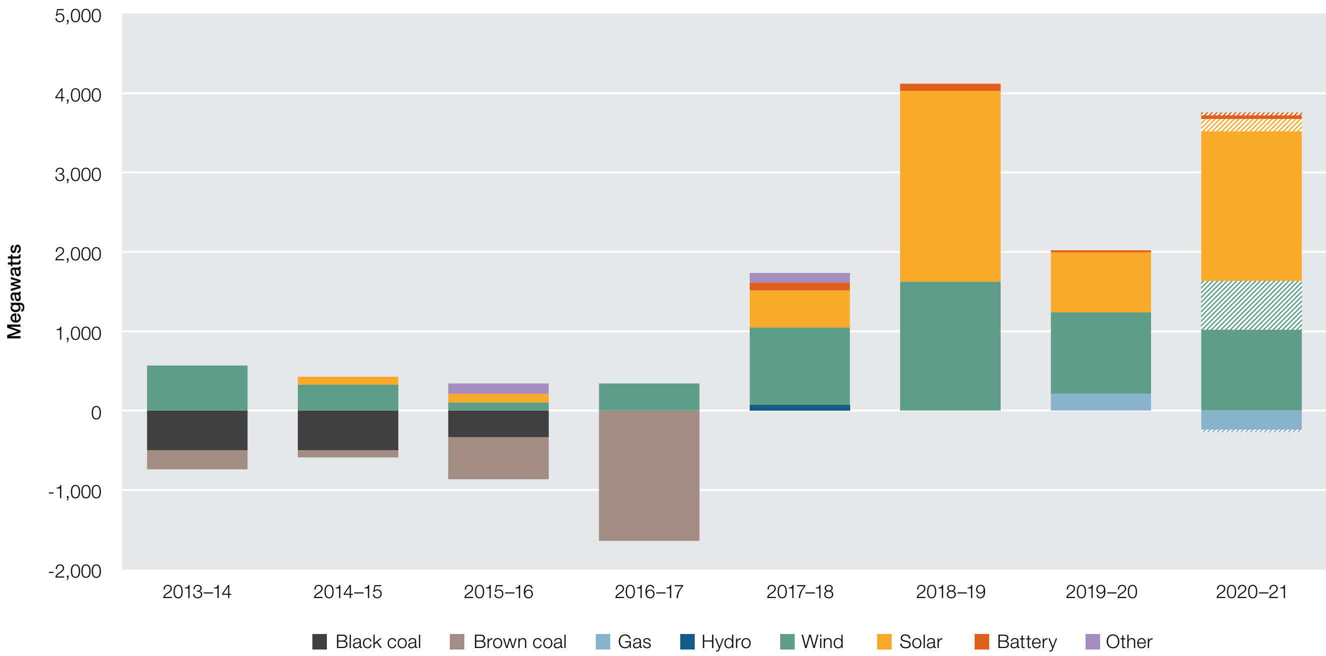
2.5 Generation investment and plant closures

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

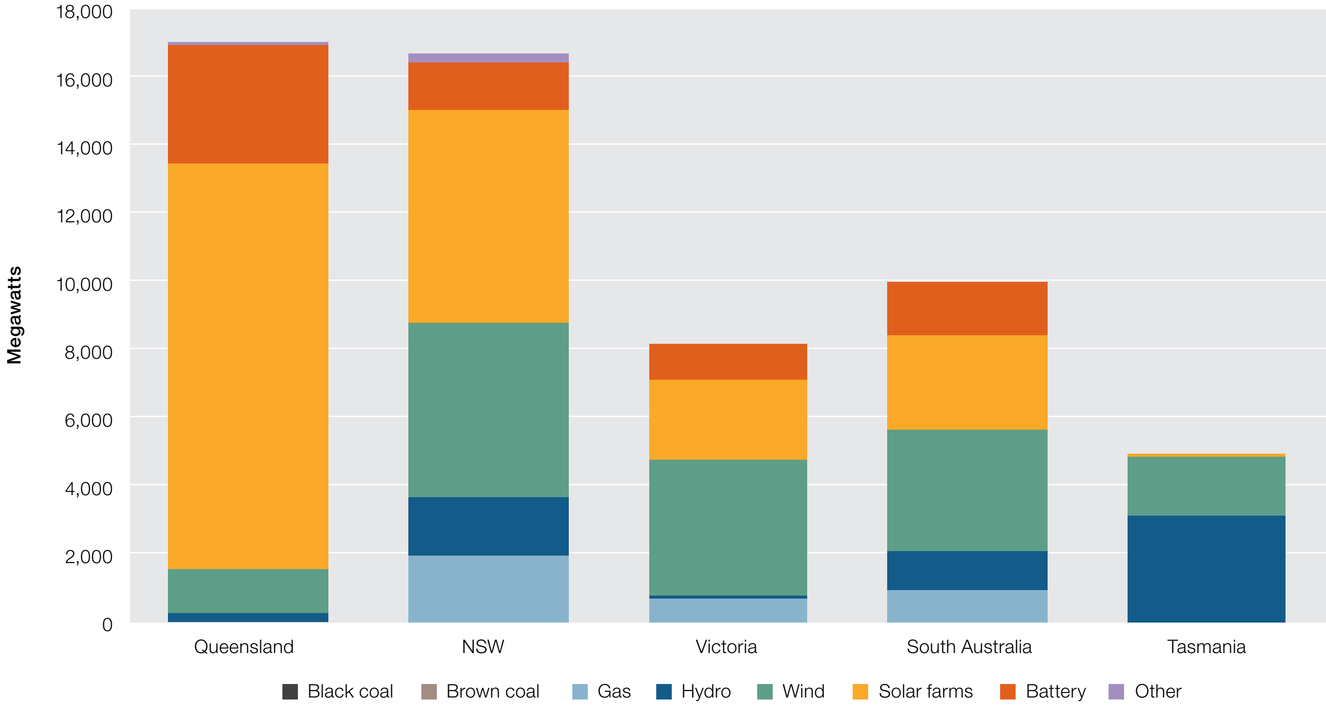
OWNER	POWER STATION	TECHNOLOGY	CAPACITY (MW)	PLANNED COMMISSIONING
QUEENSLAND			**891**	
Shell	Gangarri	Solar	120	June 2021
Windlab / Eurus	Kennedy Energy Park – Phase 1	Solar	15	July 2021
Windlab / Eurus	Kennedy Energy Park – Phase 1	Wind	43	July 2021
The University of Queensland	Warwick	Solar	63	December 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.

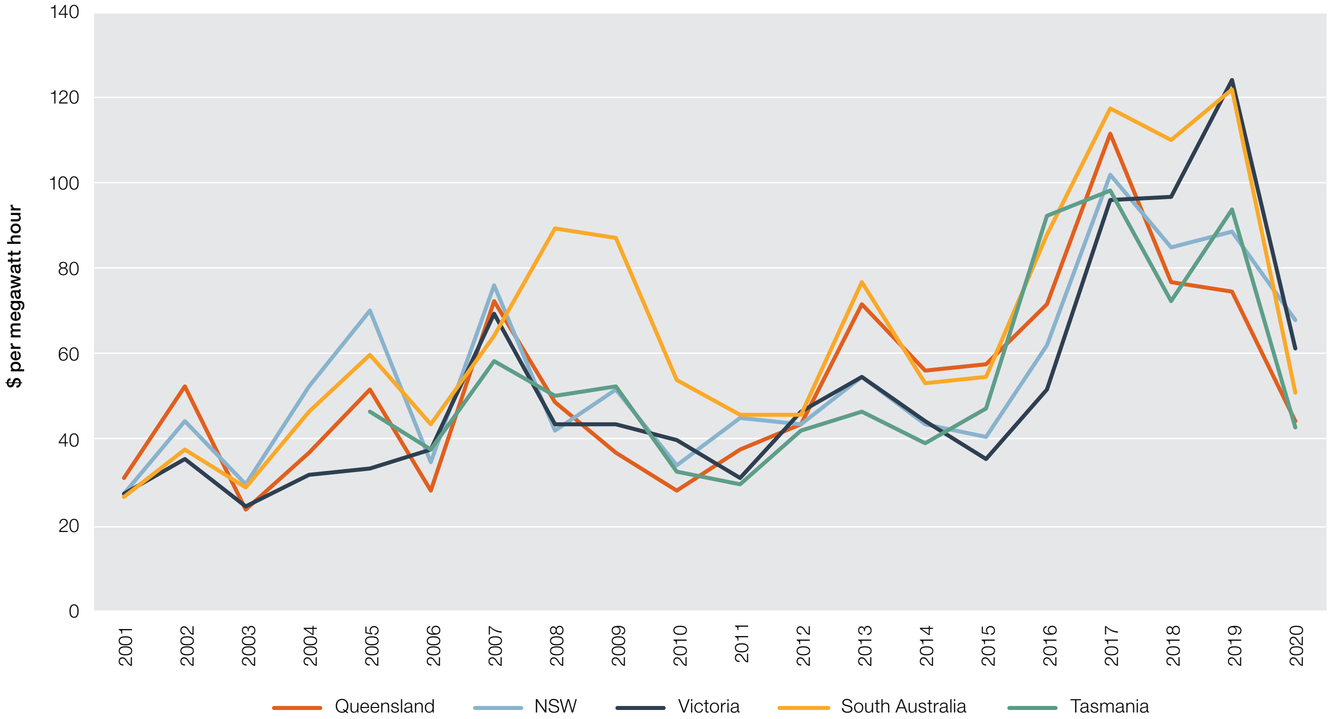
Alongside this seasonal pattern, longer term trends show an upward movement in prices for several years, followed by a sharp reduction in 2020 (figure 2.17). Rising fuel input costs and the closure of 2 brown coal power stations – Northern (South Australia) in May 2016 and Hazelwood (Victoria) in March 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.

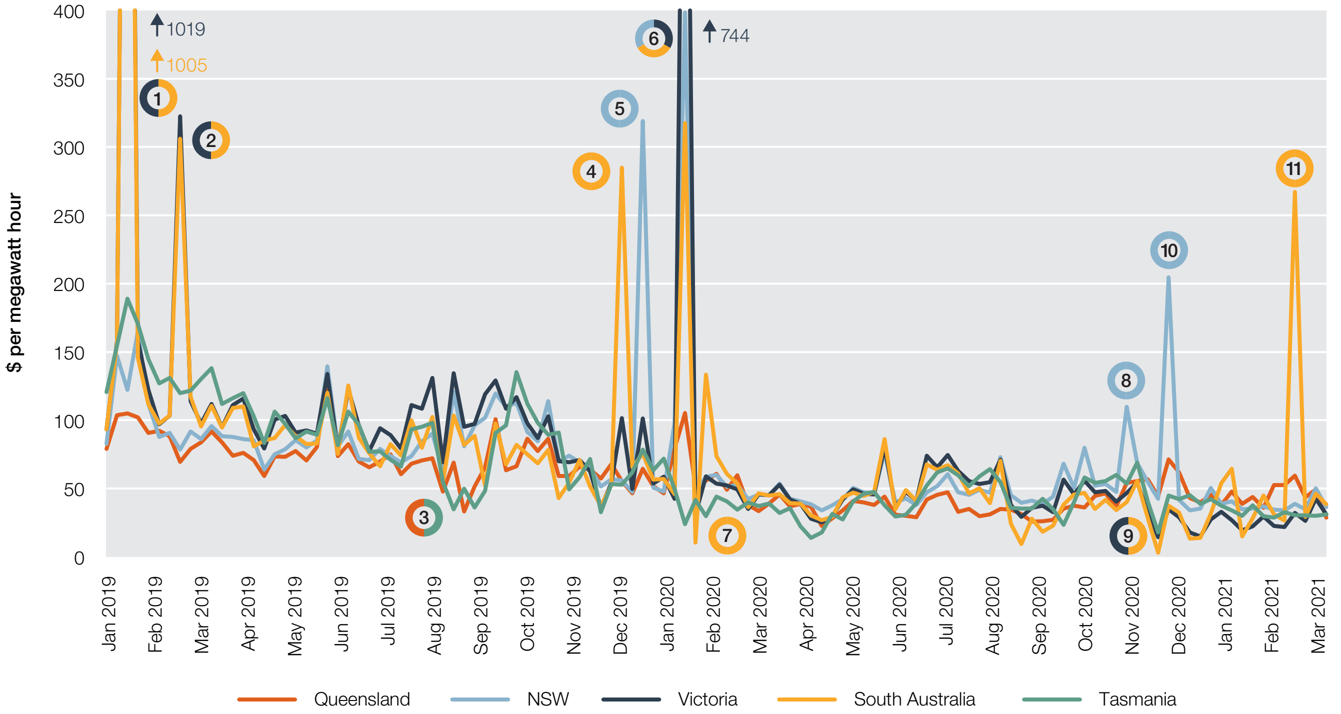
› South Australia ($51 per MWh) recorded the biggest percentage drop in its average, falling 58% from the 2019 record high of over $120 per MWh. The 2020 average was the lowest recorded for that state since 2012 and followed 4 years of relatively high prices since the 2016 closure of the region's last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

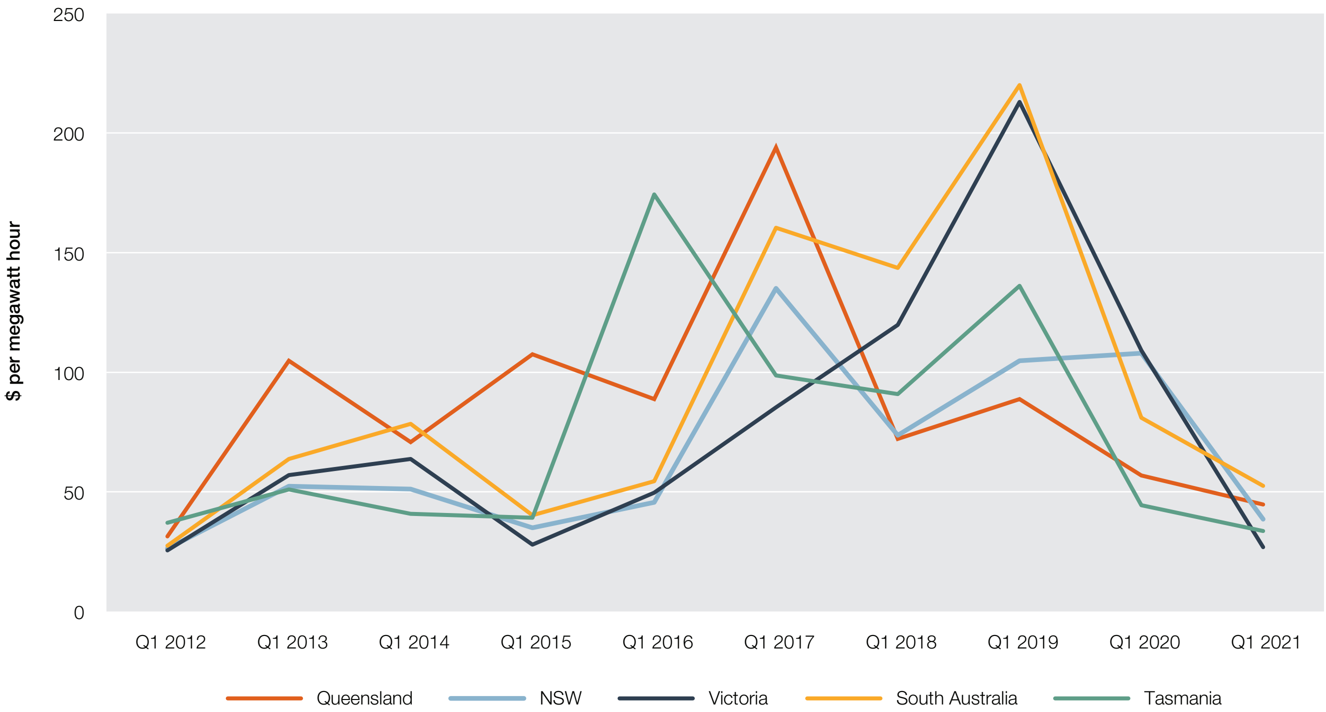
NSW, along with Victoria and South Australia, had higher average prices than elsewhere in the NEM, driven by a number of high price events. During January 2020 NSW and Victoria both experienced 11 trading intervals of prices exceeding $5,000 per MWh, while South Australia experienced 3.

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.

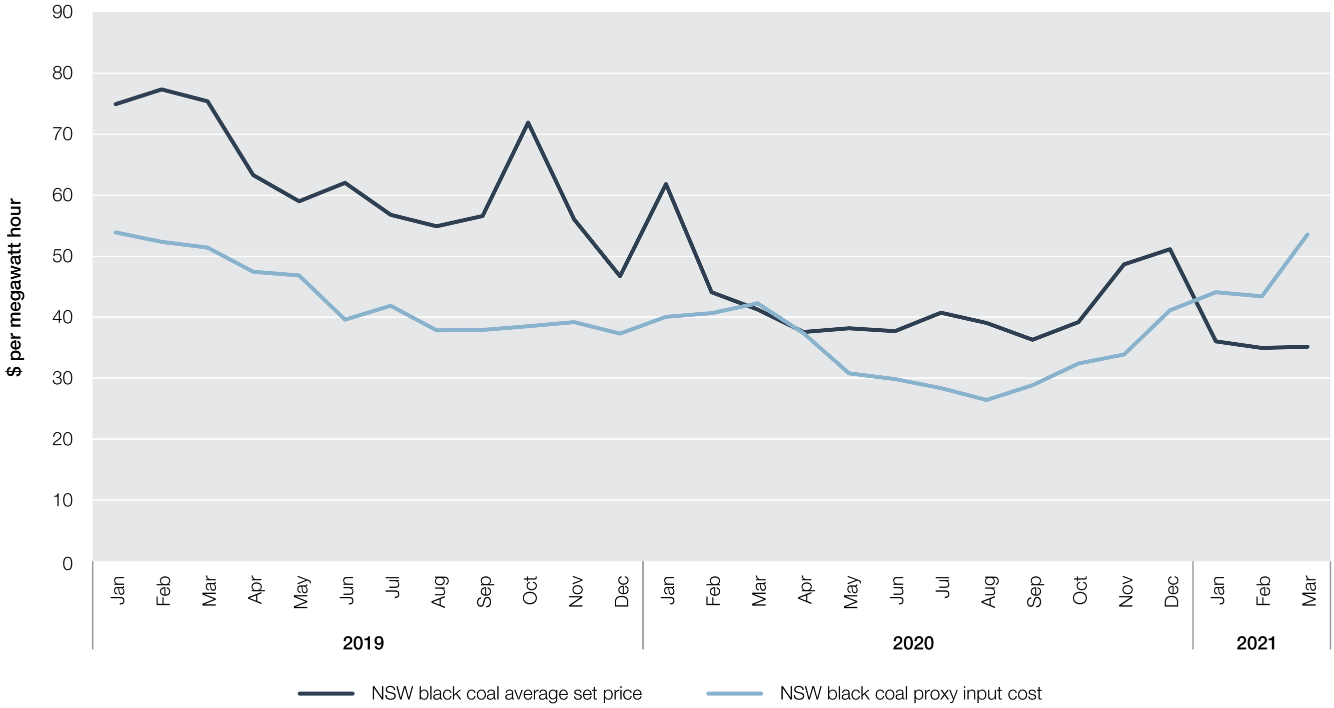
38 AER, *Wholesale electricity market performance report – 2018*, December 2018.

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.

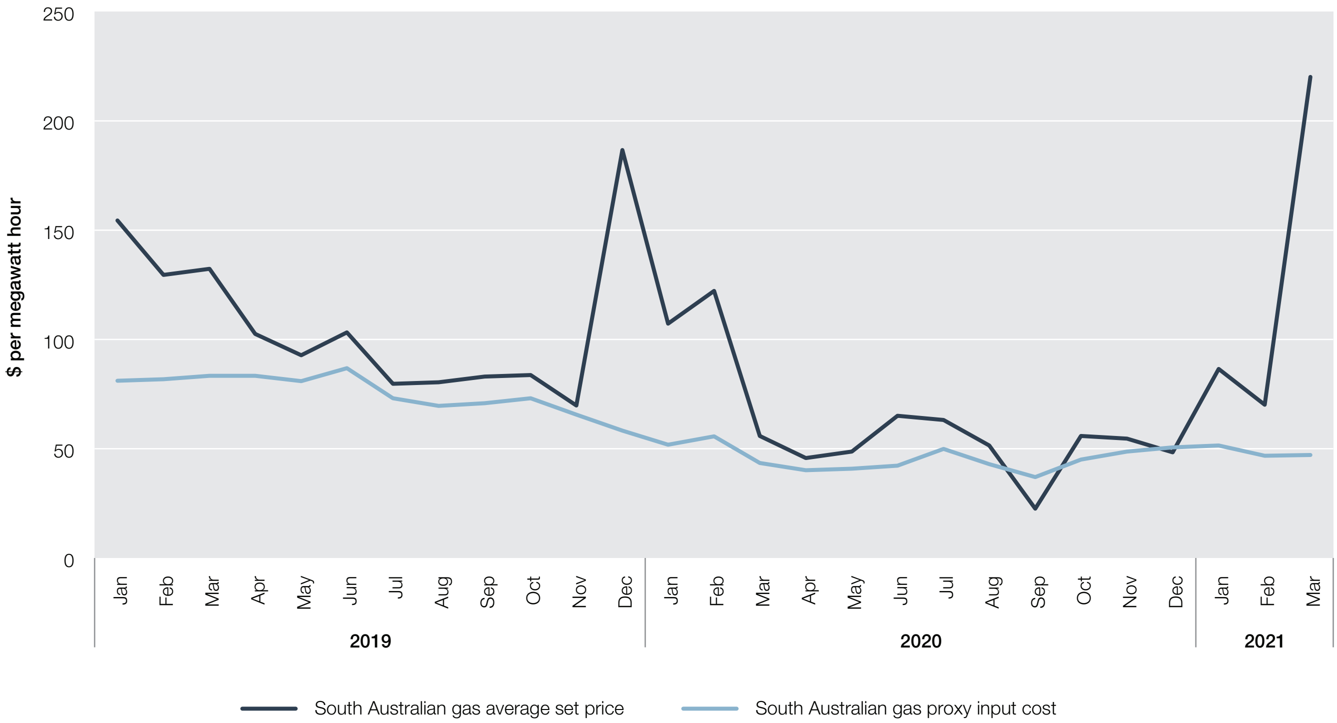
Figure 2.20 Black coal fuel costs, NSW



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.

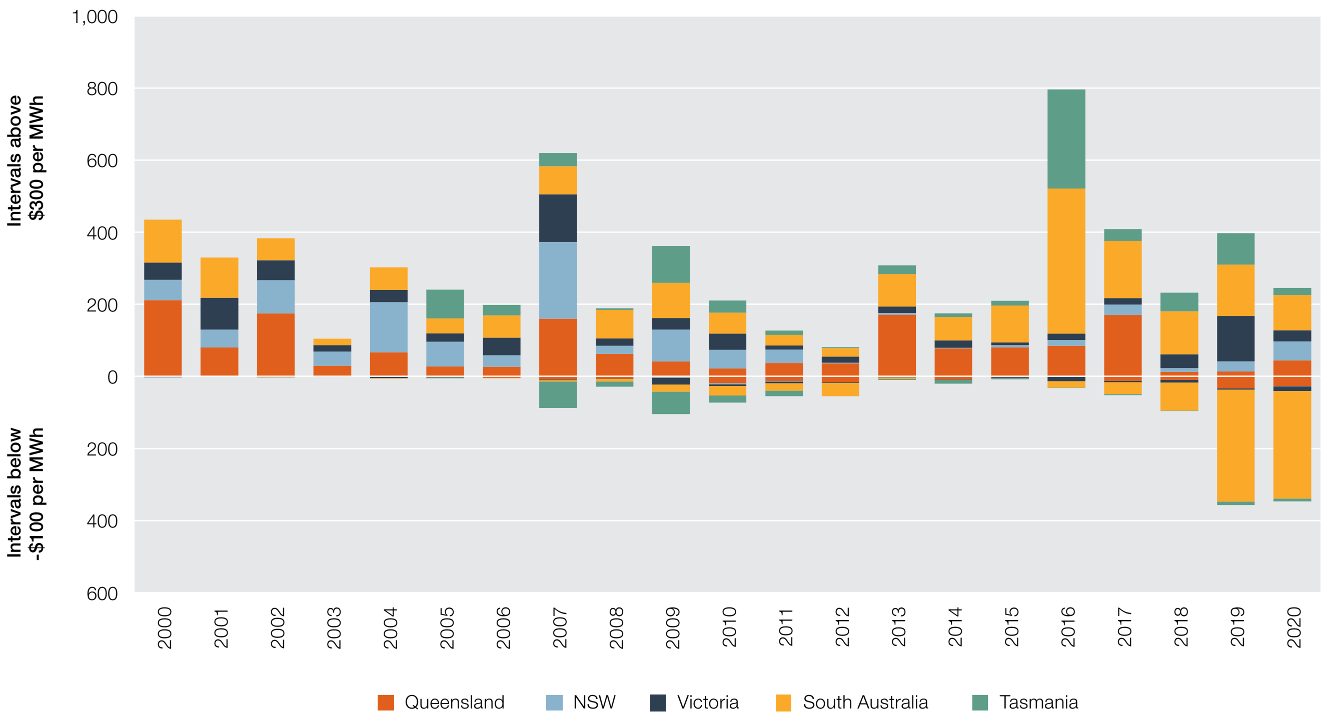
This growth in renewable output is contributing to higher instances of negative prices than ever before (section 2.6.5).

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).

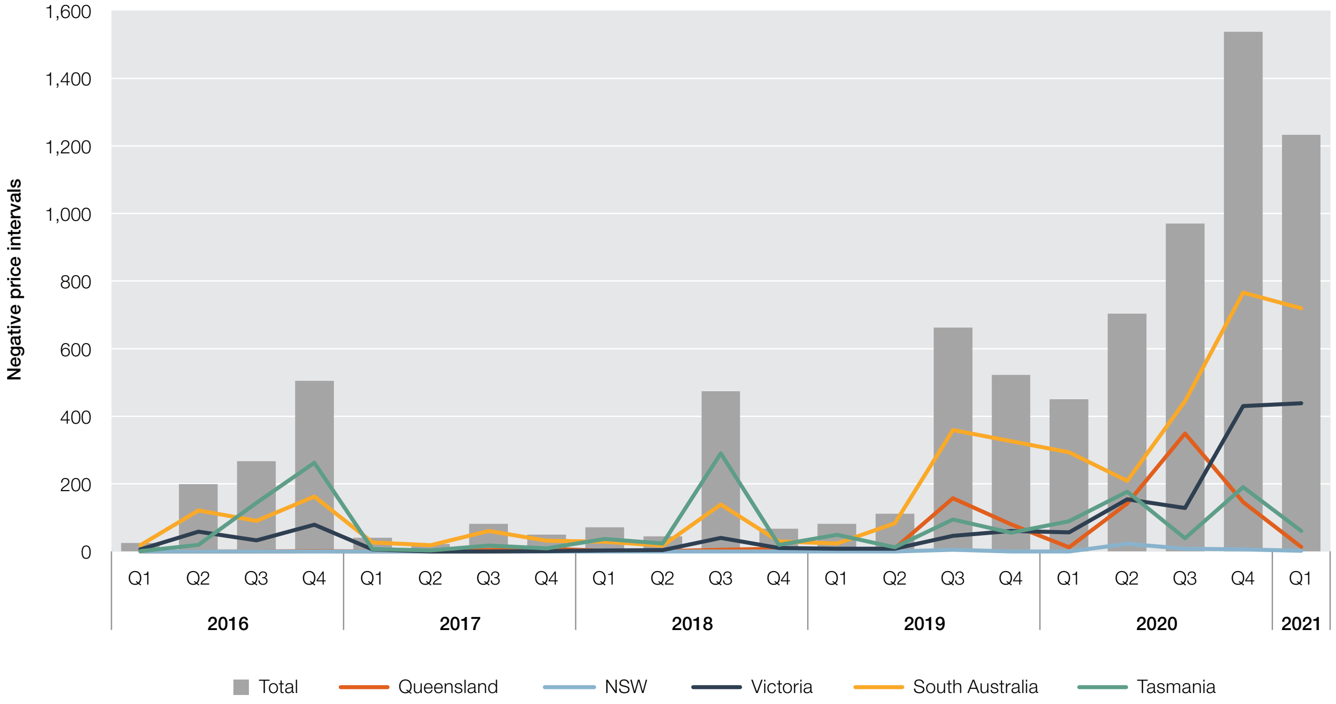
Over 40% (1,538) of negative prices in 2020 occurred in the fourth quarter, exceeding the previous quarterly record of the number of negative spot prices set in the third quarter of 2020. On 6 December 2020 prices reached a record low daily average of –$30 per MWh in Victoria, –$46 per MWh in South Australia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

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.

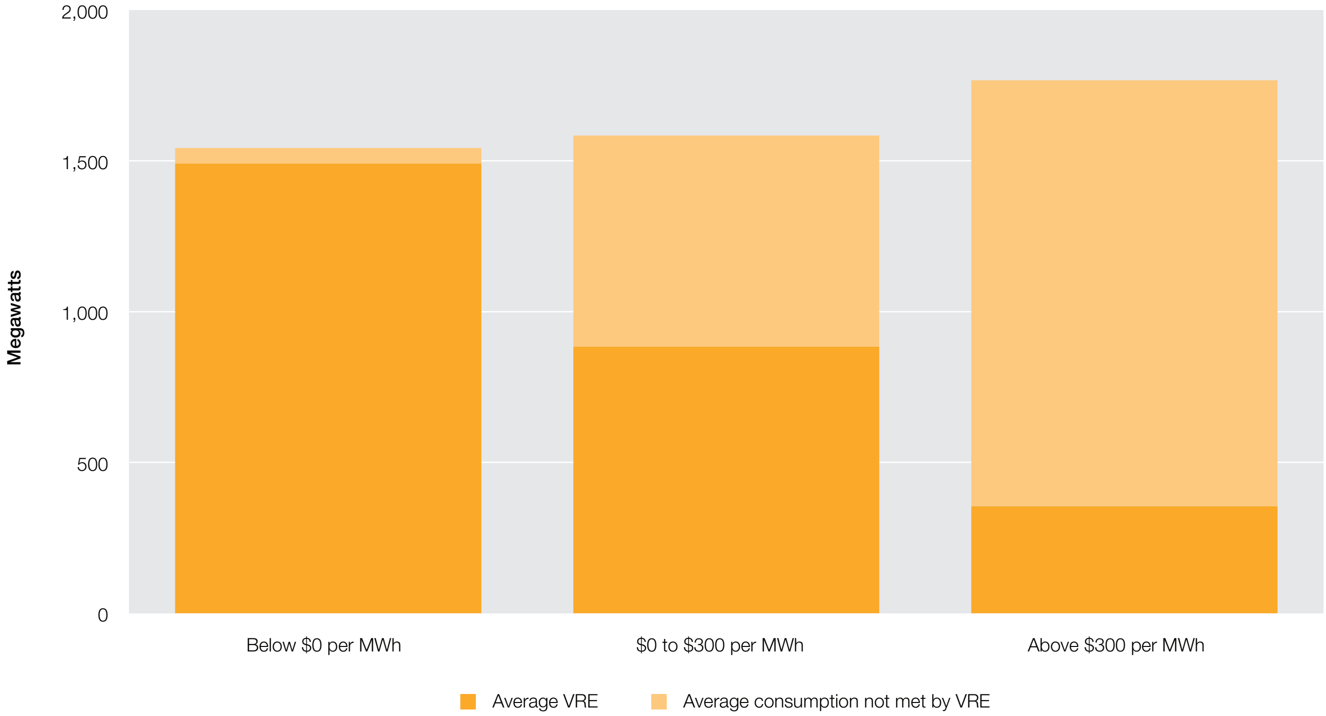
44 AER, *Wholesale markets quarterly – Q4 2020*, February 2021, p 6.

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.

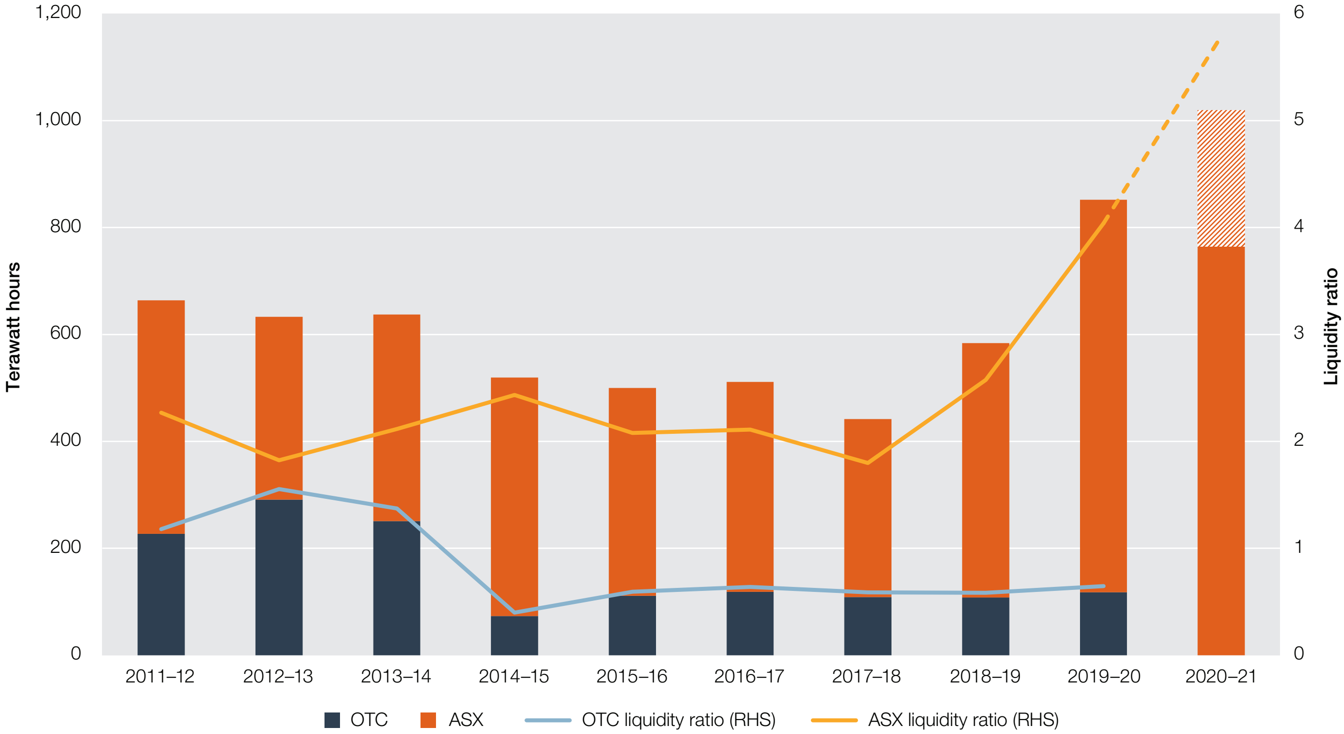
2.7.1 Contract market activity

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.

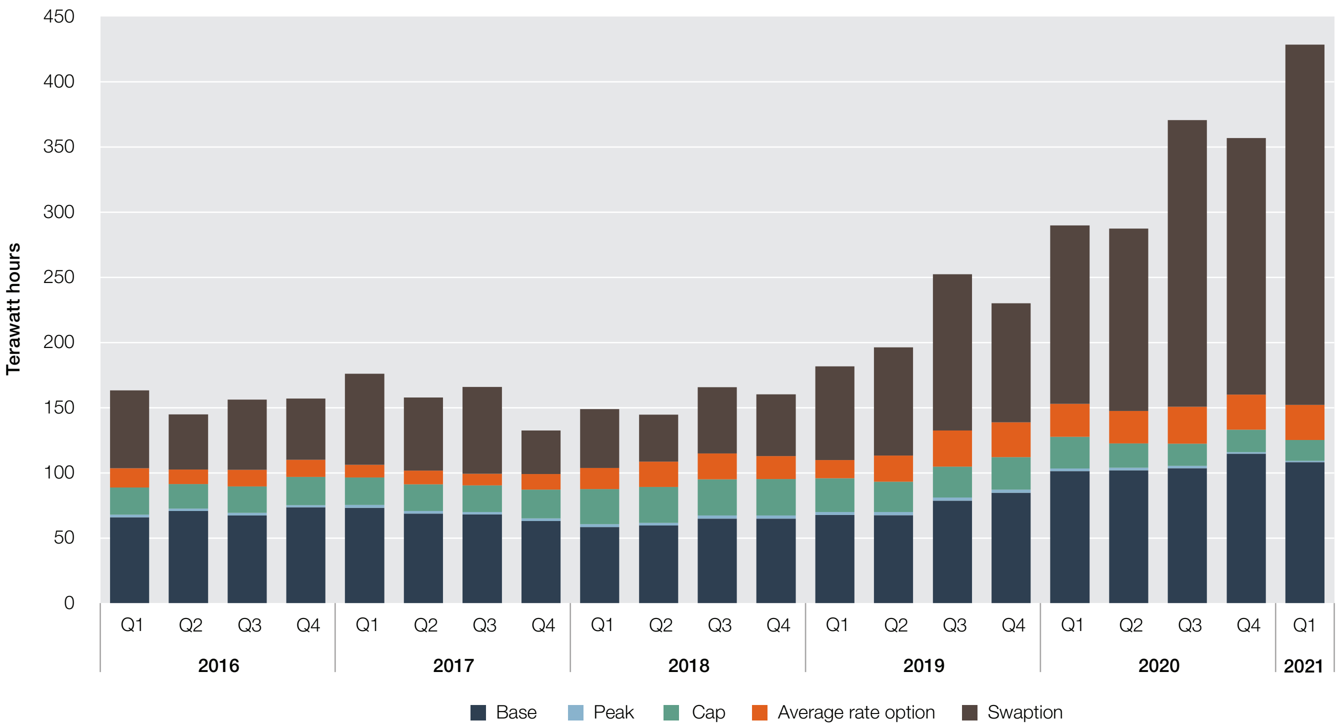
Source: AER; AFMA; ASX Energy.

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.

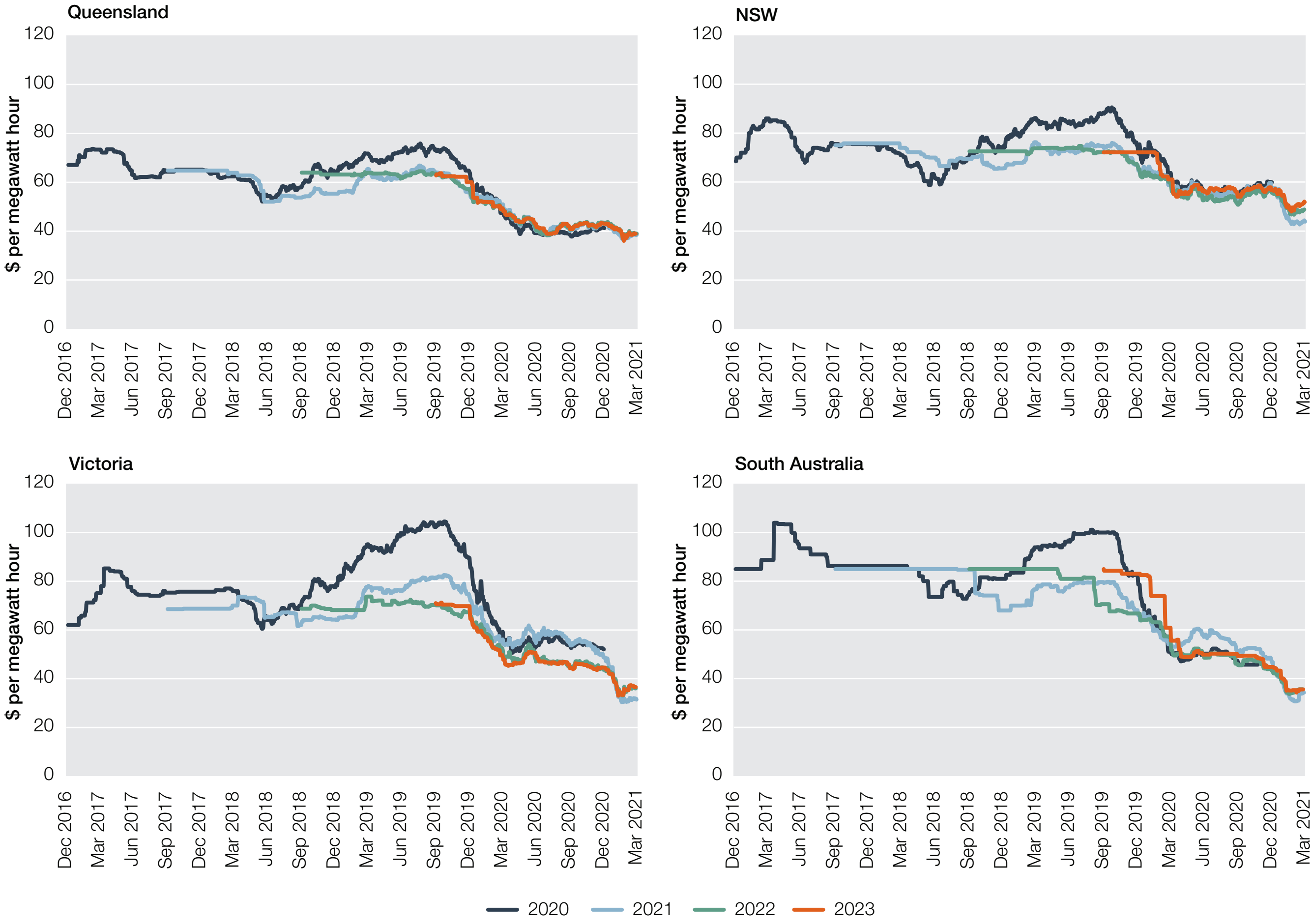
2.7.2 Contract prices

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.

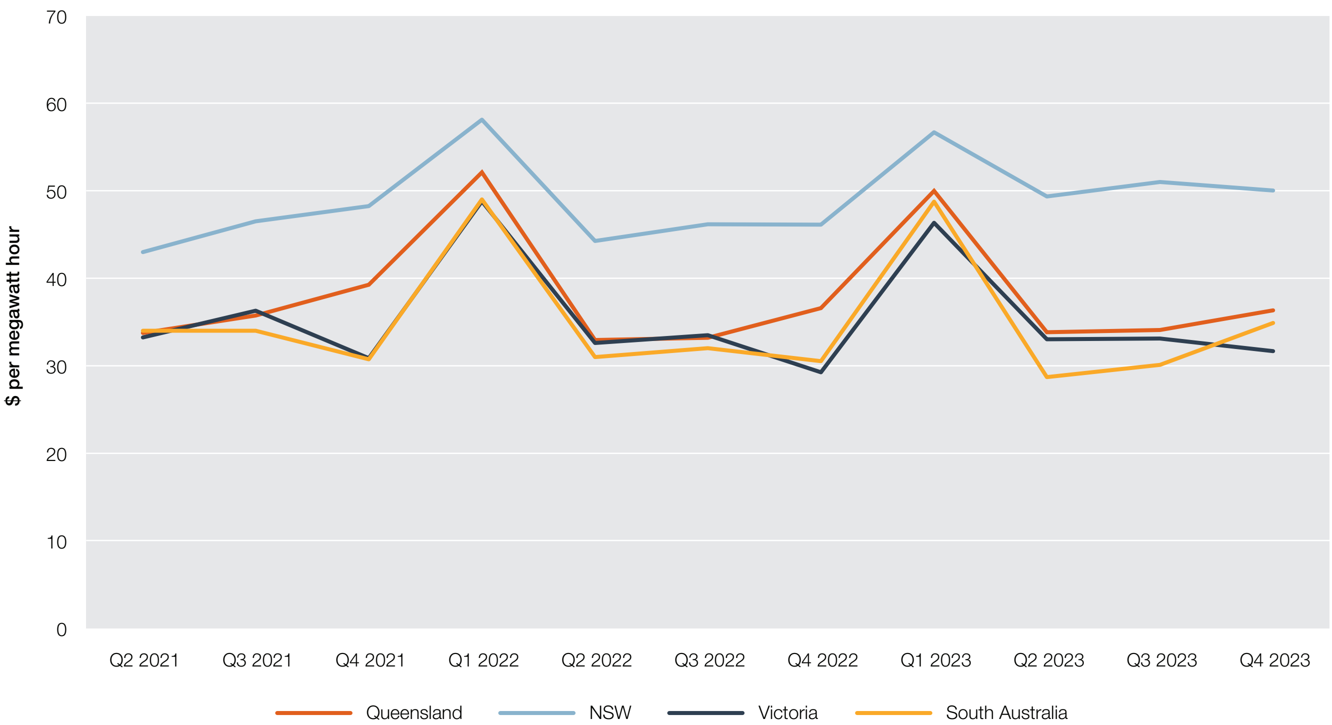
First quarter 2022 and 2023 contract prices were slightly higher but did not exceed $60 per MWh in any region (figure 2.28).

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:

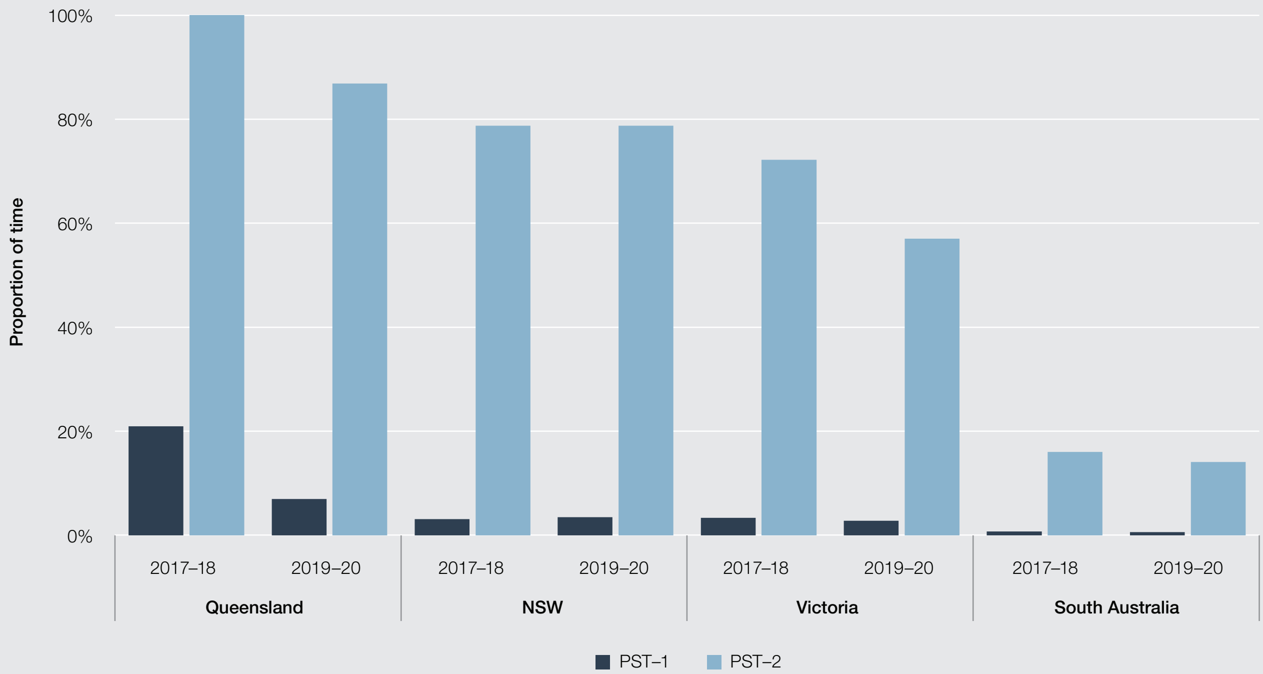
- In Queensland, CS Energy and Stanwell Corporation were jointly pivotal around 87% of the time in 2019–20 – down from 100% of the time in 2017–18. The entry of large scale solar and the creation of CleanCo meant that this change occurred during daylight hours. In the evening peak, when demand is highest, 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.

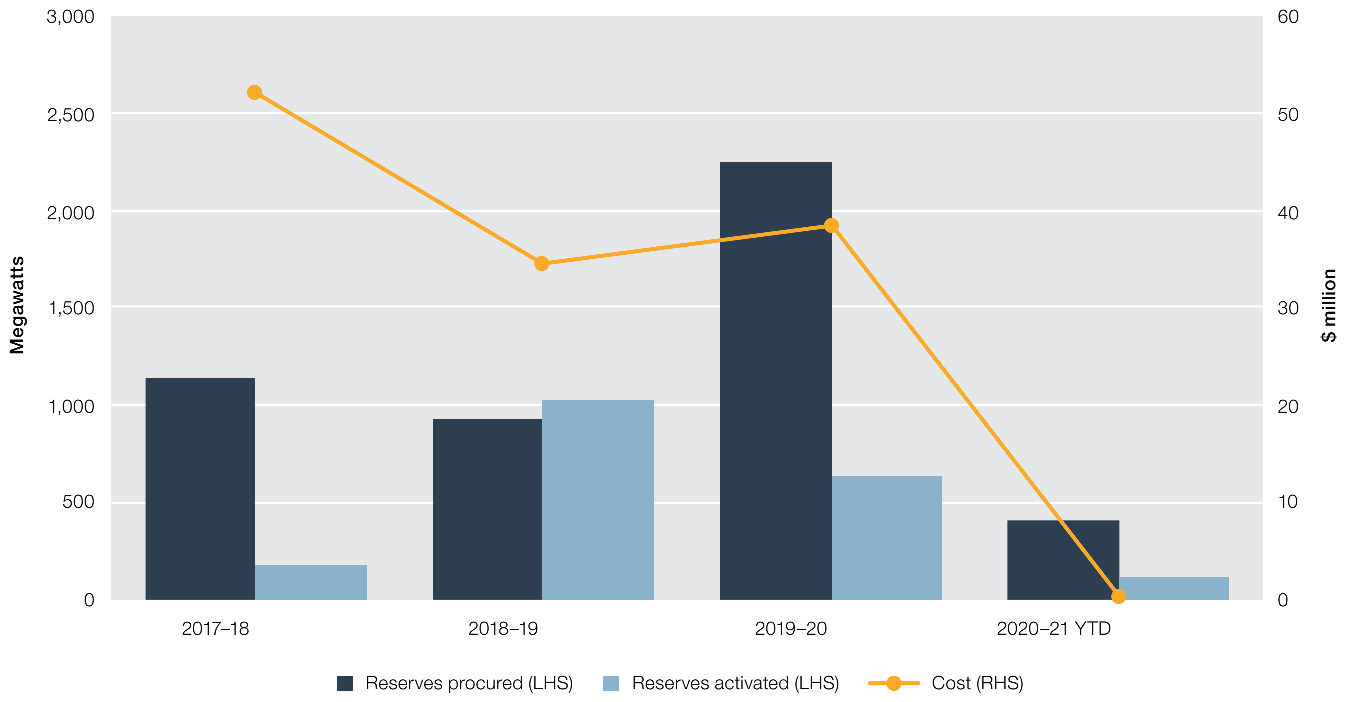
53 AEMC, *National Electricity Amendment (Enhancement to the Reliability and Emergency Reserve Trader) Rule 2019, rule determination*, May 2019.

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

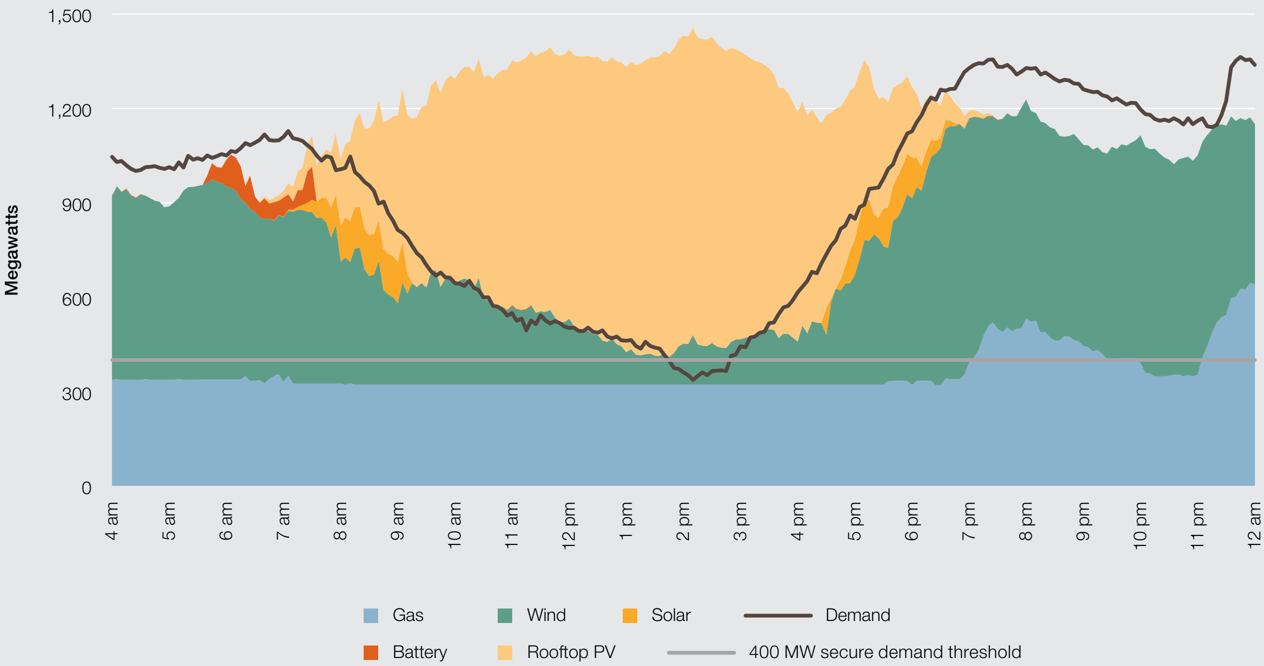
On 14 March 2021 the Australian Energy Market Operator (AEMO) instructed the network operators in South Australia to turn off 67 megawatts (MW) of solar generation to increase grid demand and maintain a secure power system. This was the first time AEMO has issued such an instruction.

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.

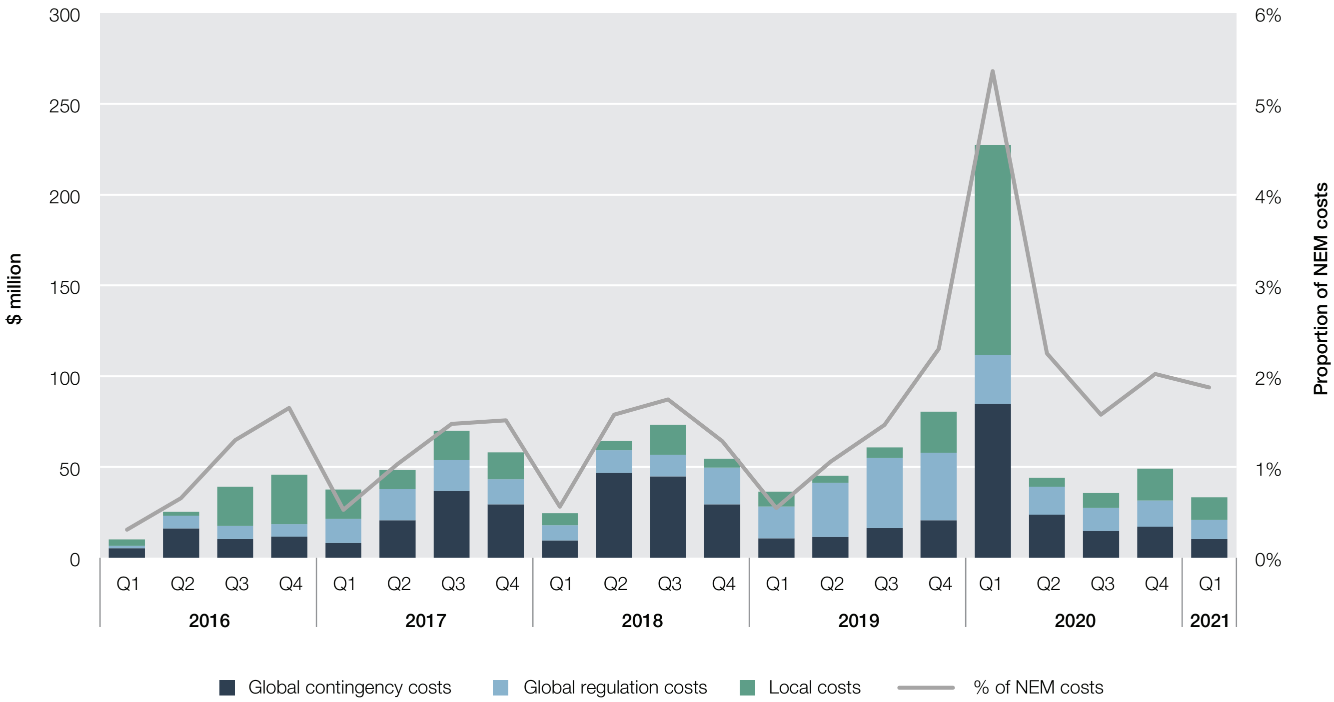
AEMO also introduced a stricter approach to assessing sourcing requirements for contingency services. This led to a step increase of around 300 MW in enabled contingency FCAS across 2020 as compared with 2019.

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).

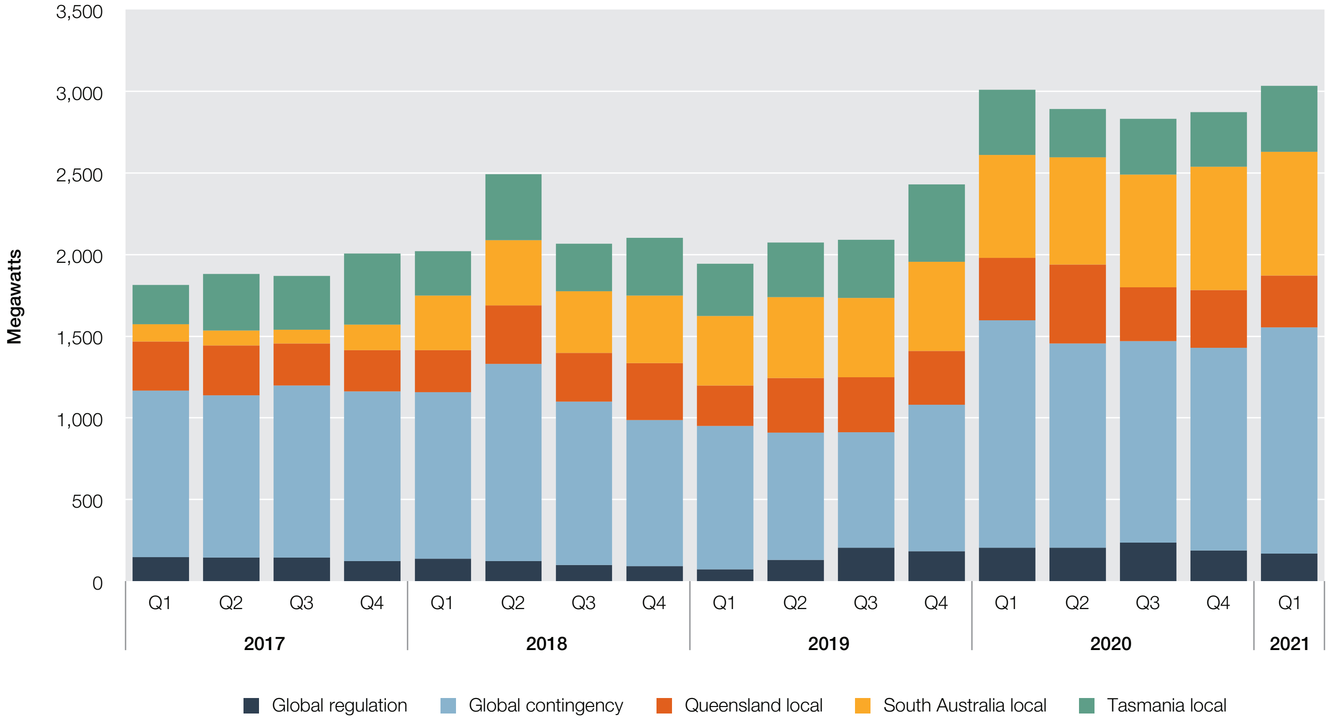
Figure 2.33 Frequency control ancillary service costs



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

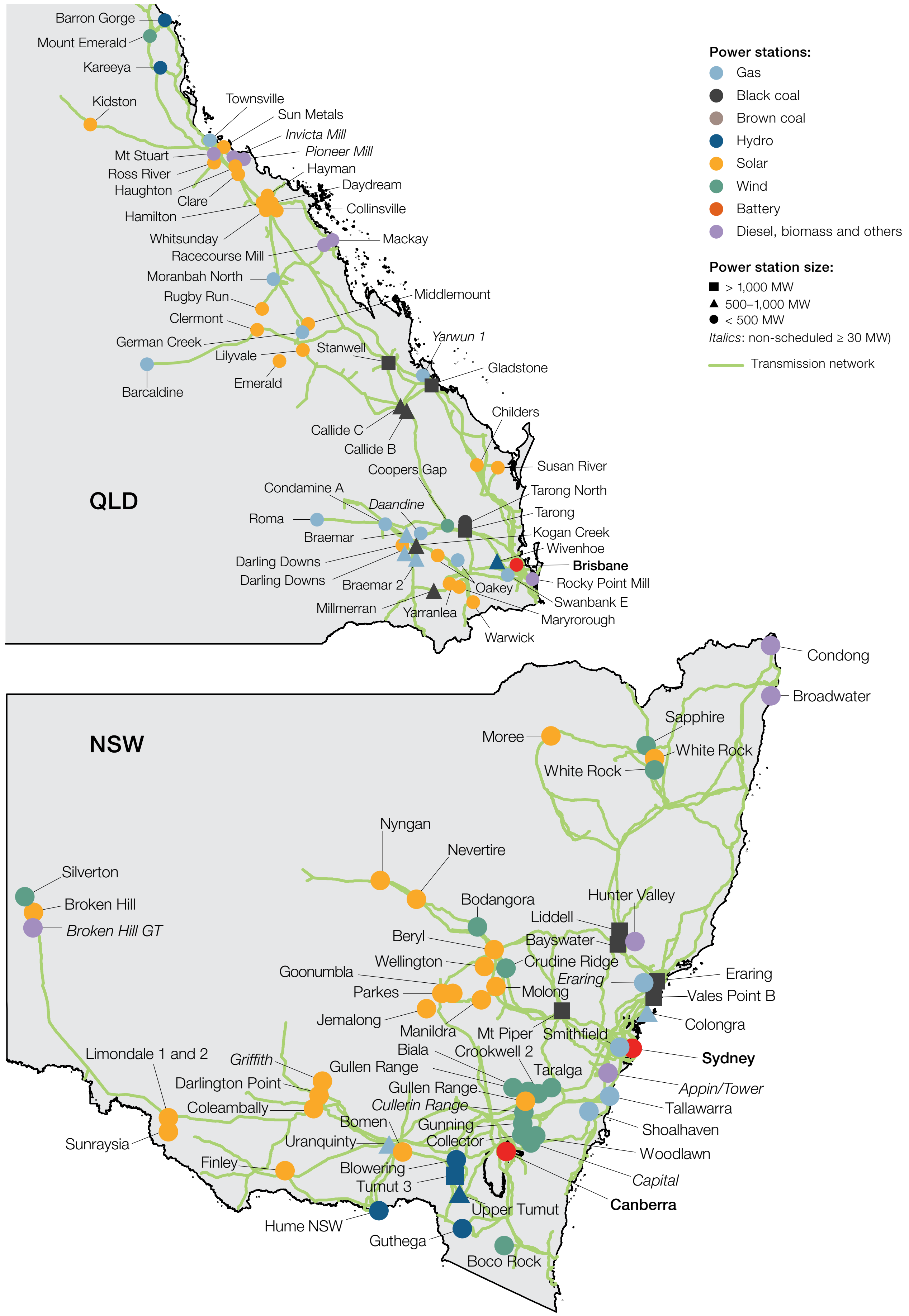
	LOWER				RAISE				TYPE OF PROVIDER
	5 min	60 sec	6 sec	Reg	5 min	60 sec	6 sec	Reg	
Queensland	6	8	7	8	8	9	9	8	Gas, black coal, hydro, pump, demand aggregator, liquid, virtual power plant
NSW	8	8	7	5	10	10	10	5	Black coal, demand aggregator, virtual power plant, hydro
Victoria	6	6	5	5	7	7	7	5	Brown coal, 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

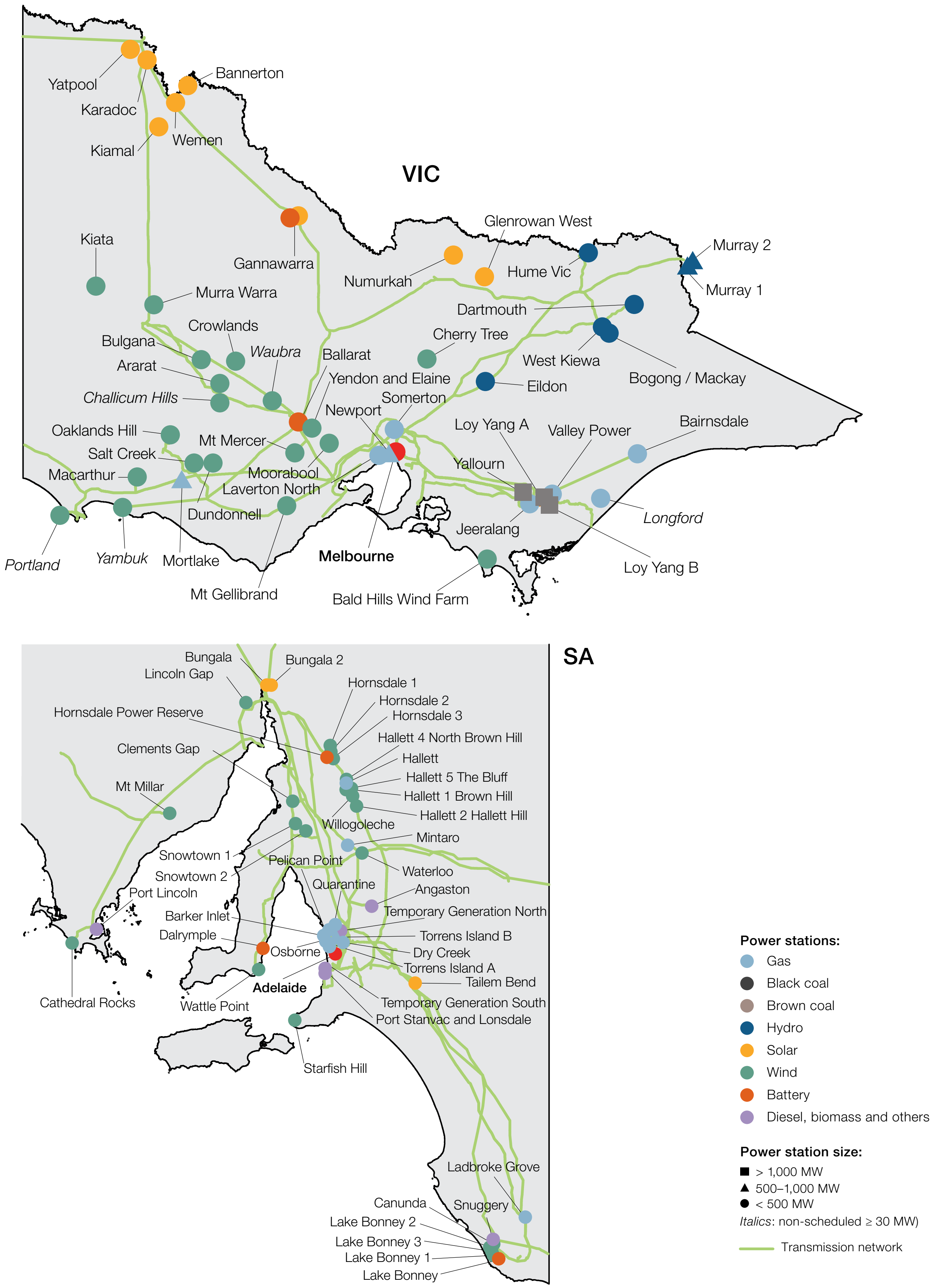
min: minutes; Reg: regulation; sec: seconds.

Source: AER; AEMO (data).

2.11 Generator information

Figure 2.35 Generators in the National Electricity Market




VIC
Yatpool
Karadoc
Bannerton
Wemen
Kiamal
Kiata
Gannawarra
Murra Warra
Numurkah
Glenrowan West
Hume Vic
Murray 2
Murray 1
Dartmouth
Crowlands
Bulgana
Waubra
Ararat
Ballarat
Cherry Tree
West Kiewa
Bogong / Mackay
Yendon and Elaine
Eildon
Challicum Hills
Somerton
Newport
Oaklands Hill
Mt Mercer
Loy Yang A
Valley Power
Bairnsdale
Salt Creek
Macarthur
Moorabool
Laverton North
Yallourn
Dundonnell
Longford
Jeeralang
Portland
Yambuk
Mortlake
Melbourne
Loy Yang B
Mt Gellibrand
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
Mt Millar
Hallett 1 Brown Hill
Hallett 2 Hallett Hill
Willogoleche
Mintaro
Snowtown 1
Pelican Point
Snowtown 2
Waterloo
Quarantine
Port Lincoln
Angaston
Temporary Generation North
Barker Inlet
Torrens Island B
Dalrymple
Dry Creek
Osborne
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

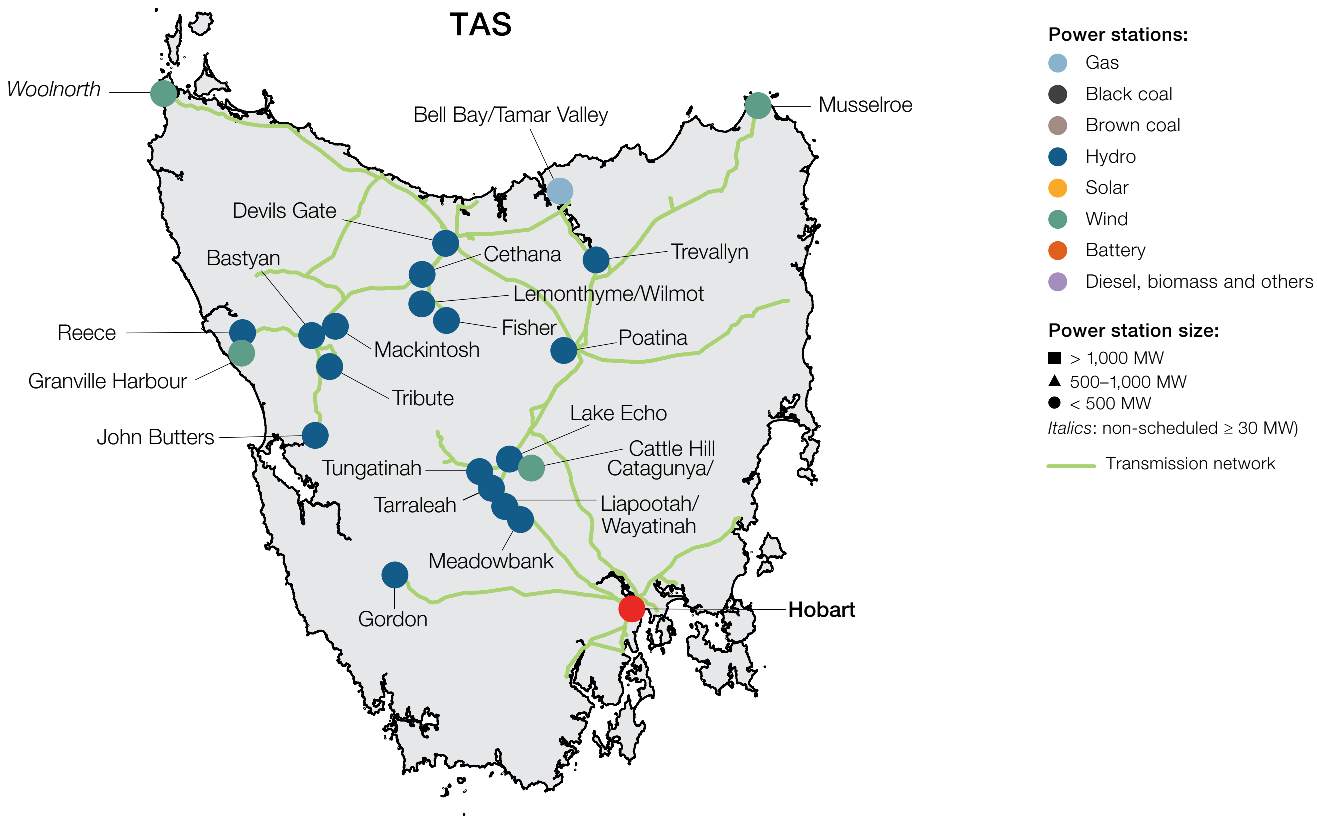

TAS
Woolnorth
Bell Bay/Tamar Valley
Musselroe
Devils Gate
Bastyan
Cethana
Trevallyn
Lemonthyme/Wilmot
Reece
Fisher
Poatina
Mackintosh
Granville Harbour
Tribute
Lake Echo
John Butters
Cattle Hill
Tungatinah
Catagunya/
Tarraleah
Liapootah/
Wayatinah
Meadowbank
Gordon
Hobart
Power stations:
Gas
Black coal
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.

Image courtesy of TransGrid

3 Electricity networks

Australia's electricity network infrastructure consists of transmission and distribution networks, as well as smaller standalone regional systems. Together these networks transport electricity from generators to residential and industrial customers (infographic 1). This chapter covers the 21 electricity networks regulated by the Australian Energy Regulator (AER), which are located in all Australian states and territories other than Western Australia.

3.1 Electricity network characteristics

Transmission networks provide the link between power generators and customers by transporting high-voltage electricity to major load centres. Electricity is injected from points along the transmission grid into the distribution networks that deliver electricity to residential homes and commercial and industrial premises. When electricity enters a distribution network, it is stepped down to lower voltages for safe delivery to customers. Distribution networks consist of poles and wires, substations, transformers, switching equipment, and monitoring and signalling equipment.

While electricity distributors transport and deliver electricity to customers, they do not sell it. Instead, retailers purchase electricity from the wholesale market and package it with network services to sell to customers (chapter 6).

Electricity networks have traditionally provided a one-way delivery service to customers. However, the role of electricity networks is evolving as new technologies change how electricity is generated and used. Many small scale generators such as rooftop solar photovoltaic (PV) systems are now embedded within distribution networks, resulting in 2-way electricity flows along the networks. Energy users with solar PV systems can now source electricity from the distribution network when they need it and sell back the surplus electricity they generate at other times. Electricity generated using solar PV systems is also increasingly being stored using battery storage systems. Due to the versatility and falling cost of battery technology their use is expected to continue to grow over the coming years.[1]

Alongside the major distribution networks, small embedded distribution networks deliver energy to sites such as apartment blocks, retirement villages, caravan parks and shopping centres. Electricity is delivered to a single connection point at these sites, then sold by the embedded network operator to tenants or residents. The revenues of embedded networks are not regulated.

3.2 Geography

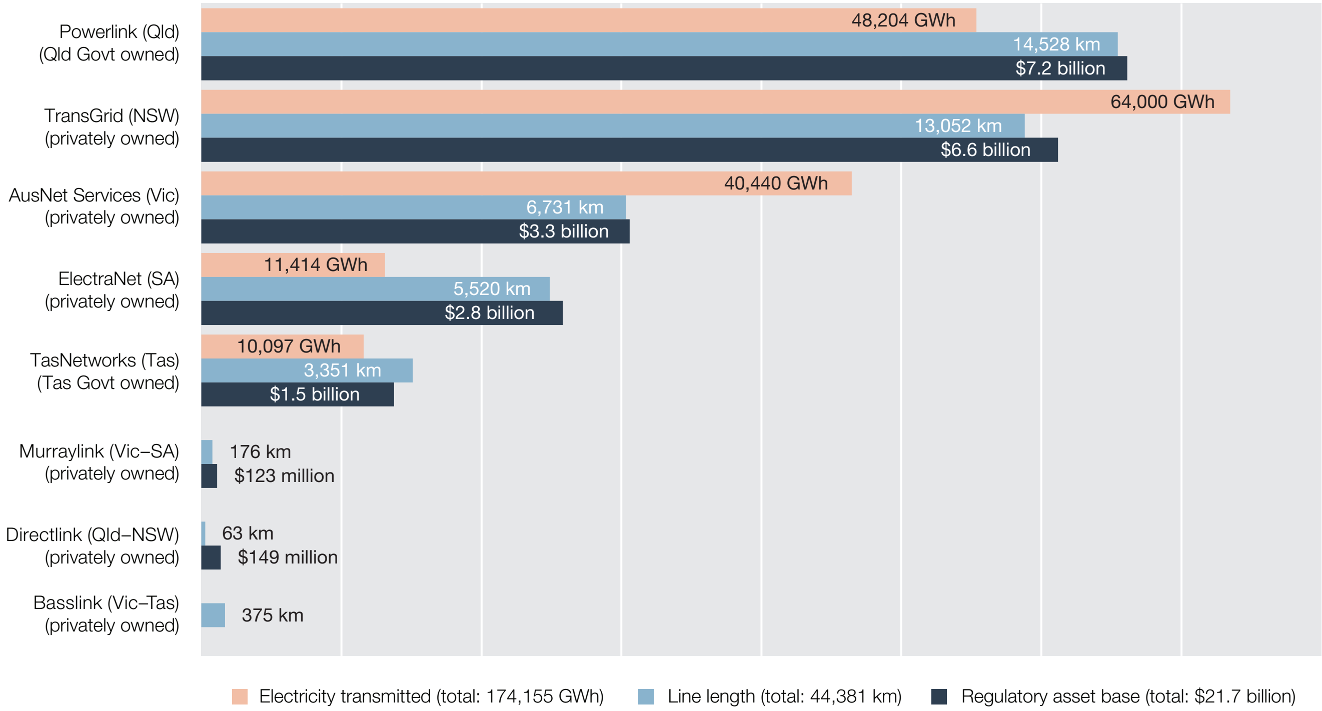
Electricity networks in Queensland, New South Wales (NSW), Victoria, South Australia, Tasmania and the Australian Capital Territory (ACT) create an interconnected grid forming the National Electricity Market (NEM). The NEM transmission grid has a long, thin, low density structure, reflecting the dispersed locations of electricity generators and demand centres. The 5 state-based transmission networks are linked by cross-border interconnectors. Three interconnectors (Queensland–NSW, Heywood, and Victoria–NSW) form part of the state-based networks, while 3 other interconnectors (Directlink, Murraylink and Basslink) are privately owned (figure 3.1). The transmission network also directly supplies energy to large industrial customers such as Alcoa's aluminium smelter in Portland (Victoria).

The transmission grid connects with 13 distribution networks.[2] Consumers in Queensland, NSW and Victoria are serviced by multiple distribution networks, each of which owns and operates its network within a defined geographic region. South Australia, Tasmania and the ACT are serviced by single distribution networks operating within each jurisdiction (figures 3.2 and 3.3).

1 Australian Renewable Energy Agency, *Battery storage*, AREA website, accessed 16 May 2021.

2 Some jurisdictions also have small networks that serve regional areas.

Figure 3.1 Electricity networks regulated by the AER – transmission



GWh: gigawatt hours; km: kilometres.

Note: Line length and asset base are as at 30 June 2020 (30 March 2020 for AusNet Services). Figure shows electricity transmitted in 2019–20 (year to March 2020 for AusNet Services). Regulatory asset base is adjusted to June 2021 dollars based on forecasts of the consumer price index (CPI). Northern Territory transmission assets are treated as part of the distribution system for regulatory purposes.

Source: AER revenue decisions and economic benchmarking regulatory information notices (RINs).

The Northern Territory has 3 separate networks – the Darwin–Katherine, Alice Springs and Tennant Creek systems – that are all owned by Power and Water Corporation (Power and Water). The networks are classified as a single distribution network for regulatory purposes but do not connect to each other or the NEM. The AER regulates all major networks in the NEM, other than the Basslink interconnector linking Victoria with Tasmania. It also regulates the Northern Territory's distribution network.

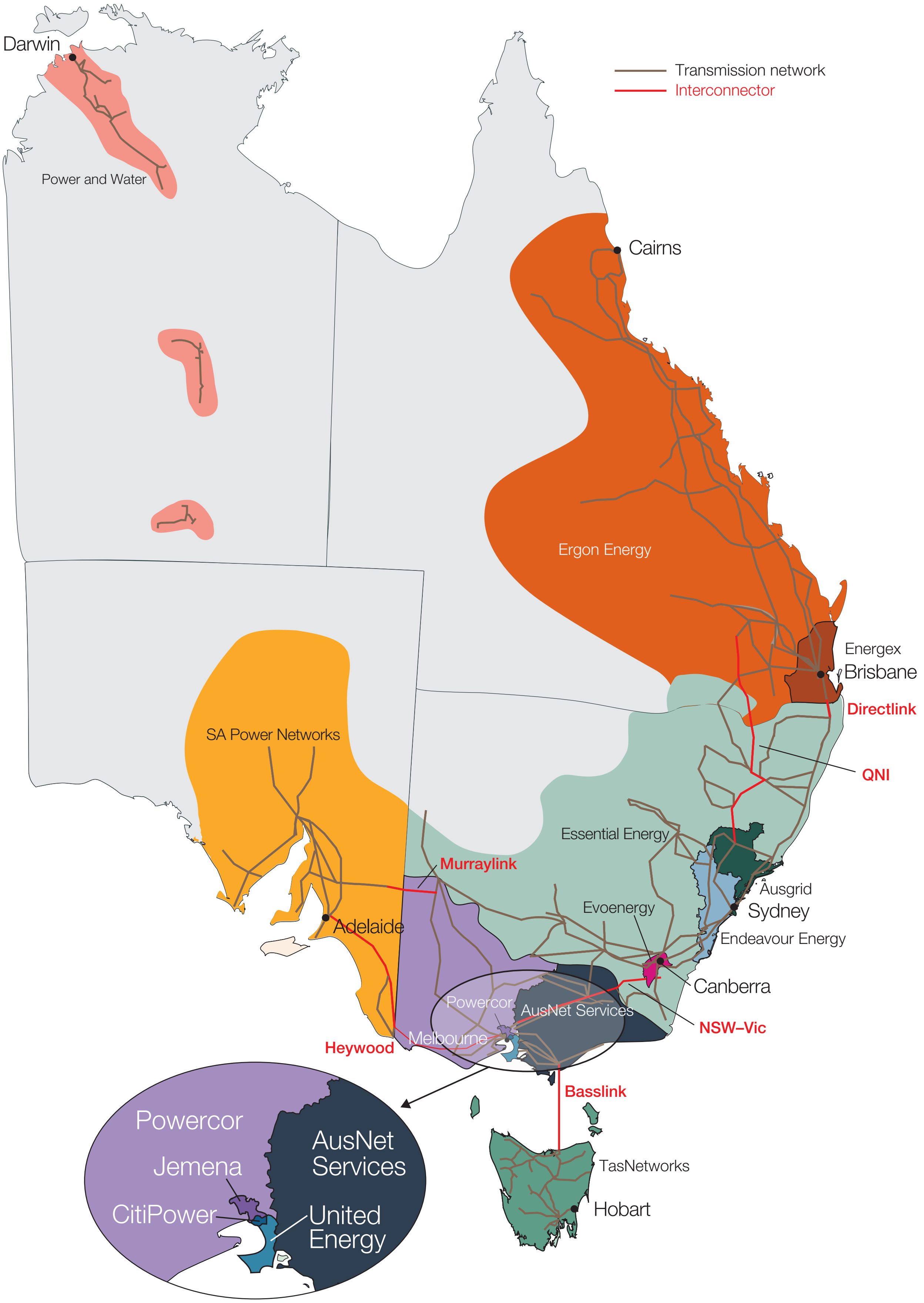
The combined value of the regulatory asset bases (RABs)[3] for the electricity networks regulated by the AER is a little over $100 billion. This comprises 7 transmission networks valued at $21.7 billion and 14 distribution networks valued at $78.8 billion. In total, the networks span almost 790,000 kilometres of line and deliver electricity to more than 10 million customers.

The AER does not regulate electricity networks in Western Australia, where the Economic Regulation Authority (ERA) administers state-based arrangements. Western Power (owned by the Western Australian Government) is the state's principal network, covering the populated south west region, including Perth. Another state-owned corporation – Horizon Power – services Western Australia's regional and remote areas.[4]

3 RABs capture the total economic value of assets that are providing network services to customers. These assets have been accumulated over time and are at various stages of their economic lives.

4 For further information, see the Department of Treasury (http://www.treasury.wa.gov.au) and ERA (http://www.era.wa.gov.au) websites.

Figure 3.2 Electricity networks regulated by the AER – distribution

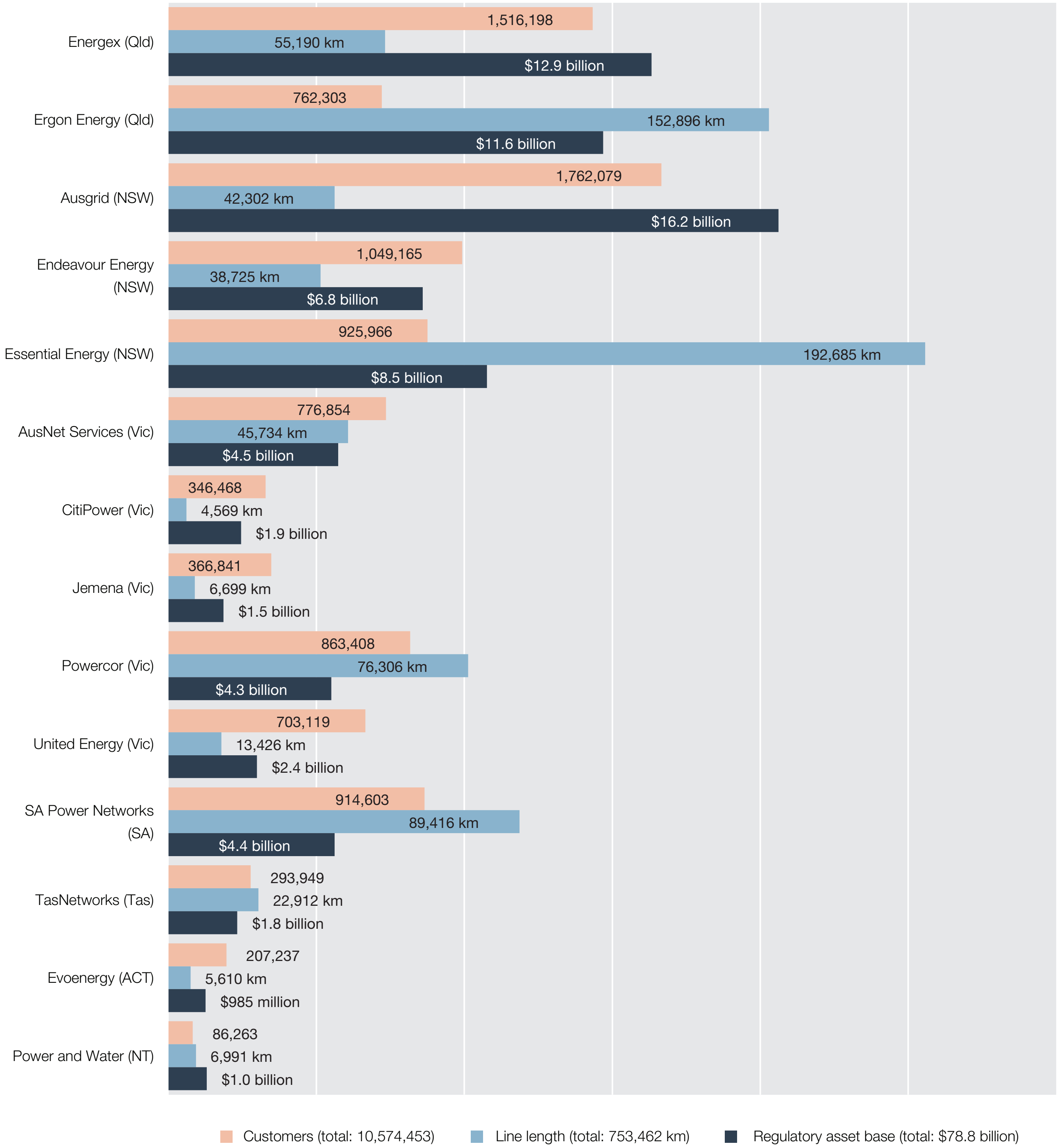


QNI: Queensland–NSW Interconnector.

Note: The AER does not regulate the Basslink Interconnector.

Source: AER.

Figure 3.3 Electricity networks regulated by the AER – distribution



km: kilometres.

Note: Customer numbers, line length and asset base is as at 30 June 2020 (31 December 2020 for Victorian businesses). Regulatory asset base is adjusted to June 2021 dollars based on forecasts of the consumer price index (CPI). For regulatory purposes, Northern Territory transmission assets are treated as part of the distribution system.

Source: AER revenue decisions and economic benchmarking regulatory information notices (RINs).

3.3 Network ownership

Australia's electricity networks were originally government owned, but many jurisdictions have now partly or fully privatised the assets. Privatisation of the electricity networks began in Victoria, which sold its transmission and distribution networks to private entities in the 1990s.[5]

In 2000 the South Australian Government privatised its transmission network and leased its distribution network. In the same year, a joint venture between the ACT Government and private equity holders was established to operate the ACT distribution network.[6]

In November 2015 the NSW Government leased its transmission network (TransGrid) to private interests. It then leased 50.4% of 2 distribution networks – Ausgrid in 2016 and Endeavour Energy in 2017 – to private interests. The predominately rural Essential Energy network remains government owned and operated.

Ownership of the privatised networks in NSW, Victoria and South Australia is concentrated among relatively few entities. These entities include Hong Kong's Cheung Kong Infrastructure Holdings (CKI Group) and Power Assets Holdings, Singapore Power International, and State Grid Corporation of China. Fund managers such as Spark Infrastructure and Hastings also have substantial equity in the sector. Significant ownership links exist across the electricity and gas network sectors (section 5.2).

Electricity networks in Queensland, Tasmania, the Northern Territory and Western Australia remain wholly government owned. The Queensland Government in 2016 merged state-owned electricity distributors Energex and Ergon Energy under a new parent company, Energy Queensland.

In some jurisdictions, ownership of electricity networks overlaps with other industry segments, with ring-fencing for operational separation. Queensland's state-owned Ergon Energy, for example, provides both distribution and retail services in regions outside south east Queensland.

3.4 How network prices are set

Electricity networks are capital intensive, so their average costs will fall as output rises. This characteristic gives rise to a natural monopoly industry structure, where it is more efficient to have a single network provider than to have multiple providers offering the same service.

Because monopolies face no competitive pressure, they have opportunities and incentives to charge unfair prices. This environment poses serious risks to consumers, given network charges can make up close to 50% of a residential electricity bill (figure 6.8 in chapter 6). To counter these risks, the role of the AER as economic regulator is to mimic the incentives that network businesses would face in a competitive market (that is, to control costs, invest efficiently and not overcharge consumers).

3.4.1 Regulatory objective and approach

The National Electricity Law and the National Electricity Rules set the framework for regulating electricity networks, and the AER applies that framework. The regulatory objective of the National Electricity Law is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to price, quality, safety and reliability and security of supply of electricity; and the reliability, safety and security of the national electricity system.

The AER seeks to ensure the delivery of a reliable, secure, affordable and low emissions energy supply in an efficient and timely way that meets the expectations of energy consumers and the community. Its regulatory toolkit to pursue this objective is wide ranging (box 3.1), but its central role is to set the maximum revenue that a network business can earn from its customers for delivering electricity. The AER fulfils this role via a periodic determination process, in which it assesses how much revenue a prudent network business would need to cover its efficient costs. Network revenues are then capped at this level for the regulatory period, which is typically 5 years.[7]

5 In Victoria, ownership of the transmission network is separated from planning and investment decision making. AusNet Services owns the state's transmission assets, but the Australian Energy Market Operator (AEMO) plans and directs network augmentation (expansion). AEMO also purchases bulk network services from AusNet Services for sale to customers.

6 The ACT has no transmission assets.

7 While a 5-year regulatory period helps to create a stable investment environment, it poses risks of locking in inaccurate forecasts. The National Electricity Rules include mechanisms for dealing with uncertainties – such as cost pass-through triggers and a process for approving contingent investment projects – when costs were not clear at the time of the revenue determination.

Box 3.1 The AER's role in electricity network regulation

The Australian Energy Regulator (AER) sets a cap every 5 years on the revenue that a network business can earn from its customers. Alongside this central role, we undertake broader regulatory functions, including:

- assessing network charges each year to ensure they reflect underlying costs and do not breach revenue limits
- providing incentives for network businesses to improve their performance in ways that customers value
- assessing whether any additional costs not anticipated at the time of our original decision should be passed on to customers
- publishing information on the performance of network businesses, including benchmarking and profitability analyses
- monitoring whether network businesses properly assess the merits of new investment proposals.

We also help implement reforms to improve the quality of network regulation and achieve better outcomes for energy customers, such as:

- Power of Choice reforms empowering customers to make informed choices about their energy use, which ultimately help keep network costs down (sections 3.7 and 1.8)
- adopting a more consumer centric approach to setting network revenues (section 3.6)
- publishing information on network profitability
- reviewing how rates of return and taxation allowances are set for energy networks (section 3.11).

As part of the determination process, a network business submits a proposal to the AER setting out how much revenue it will need to earn to cover the costs of providing a safe and reliable electricity supply. The AER then assesses the reasonableness of the network business's forecasts and the efficiency of expenditure proposals. If the AER concludes a business's proposal is likely to be unreasonably costly, it may ask for more detailed information or a clearer business case. Subsequently, the AER may amend a network's proposal to ensure the approved cost forecasts are efficient.

In forming a view on the prudency of a network business's capital expenditure forecast, the AER assesses capital expenditure drivers for that business. The AER does not determine which capital programs or projects a network business can invest in. Once the AER sets a capital expenditure forecast, it is up to the network business to prioritise its investment program. However, the network business must undertake a cost–benefit analysis (CBA) for new investment projects that meet cost thresholds (section 3.12.7).

As operating cost are largely recurrent and predictable, the AER starts its review process by assessing the actual operating expenditure a business incurred in the (then) current regulatory period. The AER uses its assessment techniques to determine whether this base expenditure is efficient and applies a rate of change to this base to account for changes in prices, productivity and the outputs the business is required to deliver.

The AER publishes guidelines on its approach to assessing capital and operating costs and applying incentives.[8]

Sections 3.9, 3.13 and 3.15 examine the incentive schemes in more detail. The AER's *Electricity network performance report* details the impact incentive schemes have had on network businesses' behaviour.[9]

In conducting its revenue assessment, the AER draws on a range of inputs, including expenditure forecasts, benchmarking and revealed costs from past expenditure. It engages closely with stakeholders from the earliest stage of the process, including before the network businesses lodge a formal proposal.

Electricity network businesses have made, and continue to make, significant improvements to the ways in which they engage with consumers. The regulatory process increasingly focuses on how network businesses engage with their customers in shaping regulatory proposals. As part of this focus, the AER has recently trialled the 'New Reg' process – an enhanced, more open approach to how network businesses incorporate consumer perspectives in developing their regulatory proposals – with Victorian distribution network AusNet Services (box 3.2).

8 AER, Guidelines, schemes & models, AER website, accessed 1 March 2021.

9 AER, *Electricity network performance report,* September 2020.

Additionally, the AER's Consumer Challenge Panel (CCP) – comprising experienced and highly qualified individuals with consumer, regulatory and/or energy expertise – provides input on issues of importance to consumers. It advises the AER on whether the revenue proposals submitted by network businesses are in the long term interests of consumers; the effectiveness of network businesses' engagement with their customers; and how consumer views are reflected in the development of the network businesses' proposals.[10]

Box 3.2 Trialling the New Reg model

The Australian Energy Regulator (AER), along with Energy Consumers Australia and Energy Networks Australia, launched the New Reg initiative in June 2017 to explore ways to improve sector engagement and identify opportunities for regulatory innovation. The vision of the New Reg initiative is to ensure that customers' preferences drive energy network businesses' proposals and regulatory outcomes.

Victorian distributor AusNet Services trialled the New Reg initiative and negotiated parts of its 2021 to 2026 regulatory proposal with a customer forum. The AER engaged Cambridge Economic Policy Associates (CEPA) to conduct an evaluation of AusNet Services' trial of New Reg.

CEPA's interim evaluation concluded that the overall vision for New Reg appeared to have been largely realised. CEPA also identified some learnings for future engagement processes.[11]

CEPA's final evaluation of the New Reg trial will inform the AER's future work in relation to network consumer engagement. As part of the New Reg trial the AER is also considering potential reforms to ensure regulatory outcomes reflect consumer preferences and priorities. These included increasing flexibility to better reflect consumer–network agreed price and service combinations and desired incentives. The AER also identified reforms to support and empower consumers and reward effective engagement.[12]

3.4.2 Building blocks of network revenue

The AER uses a 'building block' approach to assess a network business's revenue needs. Specifically, it forecasts how much revenue the business will need to cover:

- a commercial return to investors that fund the network's assets and operations
- efficient operating and maintenance costs
- asset depreciation costs
- taxation costs.

The AER also makes revenue adjustments for over- or under-recovery of revenue made in the past; and for rewards or penalties earned through any applicable incentive schemes (figure 3.4).

While network businesses are entitled to earn revenue to cover their efficient costs each year, this revenue does not include the full cost of investment in new assets made during the year. Network assets have a long life, so investment costs are recovered over the economic life of the assets, which may run to several decades. The amount recovered each year is called depreciation, and it reflects the lost value of network assets each year through wear and tear and technical obsolescence.

Additionally, the shareholders and lenders that fund these assets must be paid a commercial return on their investment. The AER sets the allowed rate of return (also called the weighted average cost of capital (WACC)). The size of this return depends on:

- the value of the network's RAB, which captures the total economic value of assets that are providing network services to customers plus positive adjustments for forecast new capital expenditure and negative adjustments for depreciation on existing assets
- the rate of return that the AER allows based on the forecast cost of funding those assets through equity and debt.[13]

10 AER, *Consumer Challenge Panel*, AER website, accessed 1 March 2021.

11 CEPA, *New Reg: AusNet Services trial – interim evaluation report*, 4 December 2020.

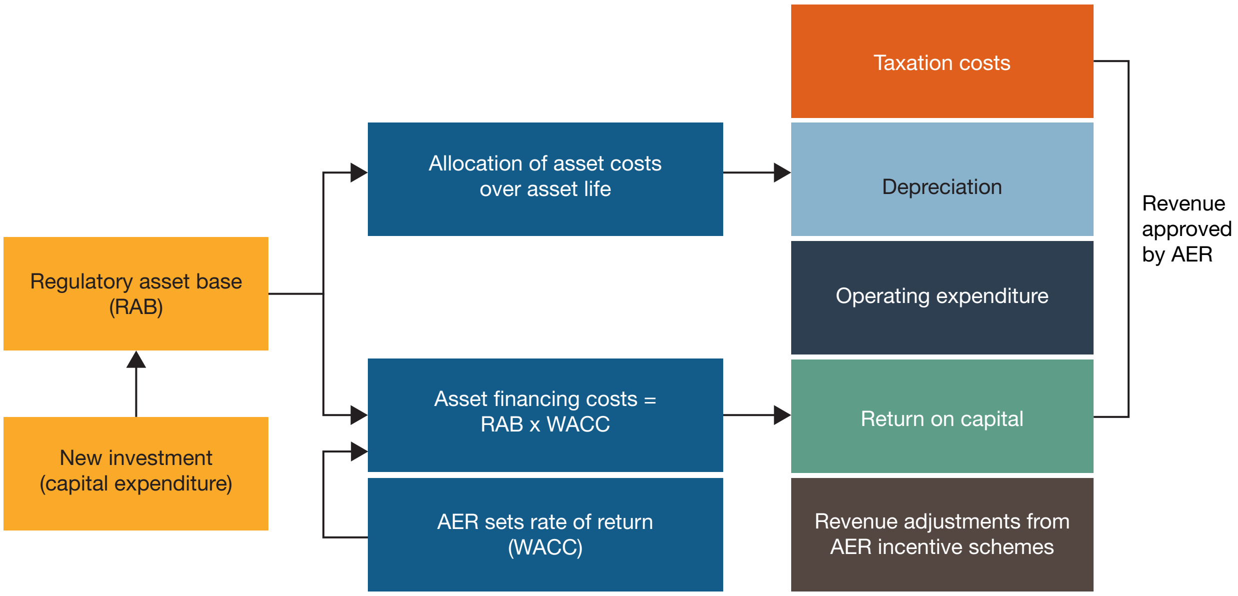
12 AER, ECA, ENA, *Submission to electricity network economic regulatory framework 2020 review*, July 2020.

13 The return on equity is the return that shareholders of the business will require for them to continue to invest. The return on debt is the interest rate that the network business pays when it borrows money to invest.

Overall these returns take up the largest share of network revenue, accounting for 43% across all networks (49% for transmission and 42% for distribution) (figure 3.5).

Operating costs – such as maintenance costs and overheads – absorb 35% of revenue across all networks (30% for transmission and 36% for distribution). Depreciation absorbs another 18%, while taxation and other costs account for the remaining 3% of network revenue. Sections 3.10 to 3.13 examine major cost components in more detail.

Figure 3.4 Forecasting electricity network revenues

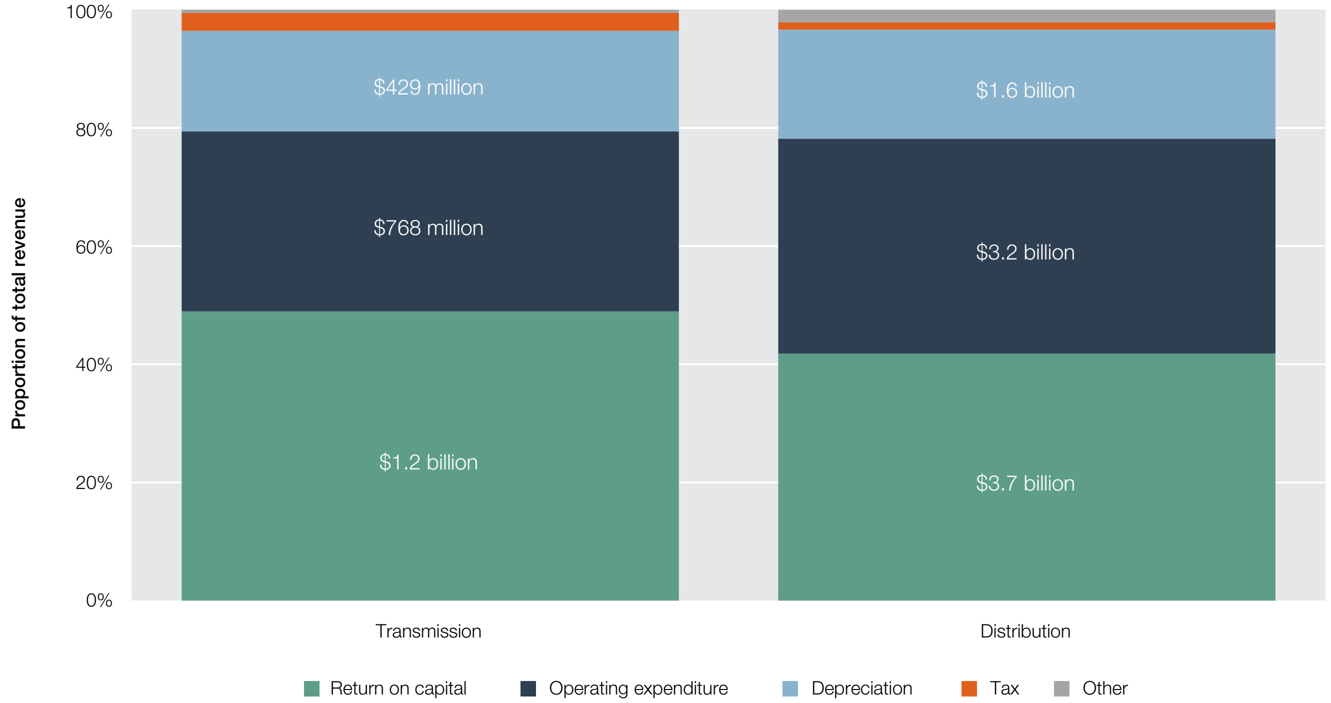


AER: Australian Energy Regulator; RAB: regulatory asset base; WACC: weighted average cost of capital.

Note: Revenue adjustments from incentive schemes encourage network businesses to efficiently manage their operating and capital expenditure, improve services provision to customers, and adopt demand management schemes that avoid or delay unnecessary investment.

Source: AER.

Figure 3.5 Composition of average annual electricity network revenue – current periods



Source: Post-tax revenue modelling used in AER determination process.

3.4.3 Timelines and process

The National Electricity Law and the National Electricity Rules set the regulatory framework and process, which is both lengthy and highly consultative. The process begins around 3 years before the beginning of a regulatory period, when the AER works with stakeholders on a review framework and approach. The next step is for a network business to propose the revenue that it considers it needs to earn to cover the efficient costs of meeting its service and reliability obligations. Network businesses engage with their customers in framing the revenue proposal.

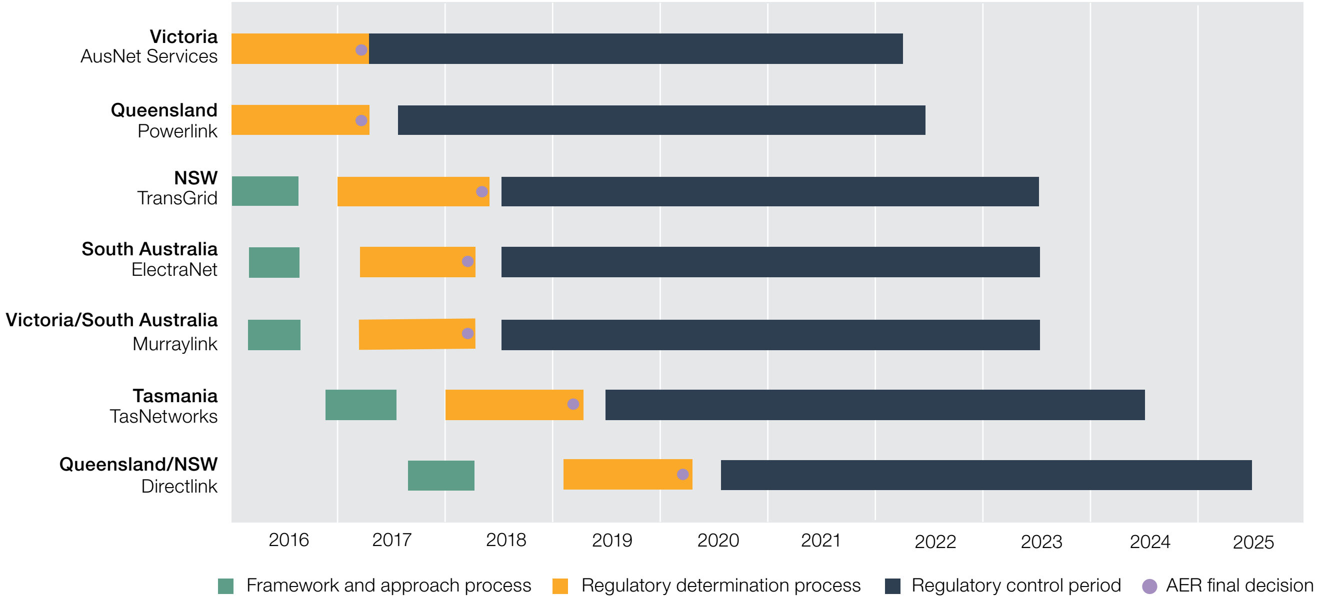
The AER has 15 months to review a revenue proposal before releasing its final decision. It consults widely with energy customers, consumer representatives, government, investment groups, network businesses and other stakeholders. This consultation includes issues papers, draft decisions and public forums. The timing of the AER reviews is staggered to avoid bunching (figures 3.6 and 3.7).

Following its review, the AER makes a final decision setting the maximum amount of revenue that a network business can earn from its customers through network charges.[14]

While the decision sets network revenues rather than prices, the 2 are closely related. Network businesses set prices by spreading their allowed revenue across the customer base.[15]

As part of the regulatory process (section 3.7.1), the AER assesses tariff structure statements that set out a network's pricing policies and annually reviews prices to ensure they are consistent with the revenue decision and reflect efficient costs.

Figure 3.6 AER decision timelines – electricity transmission networks



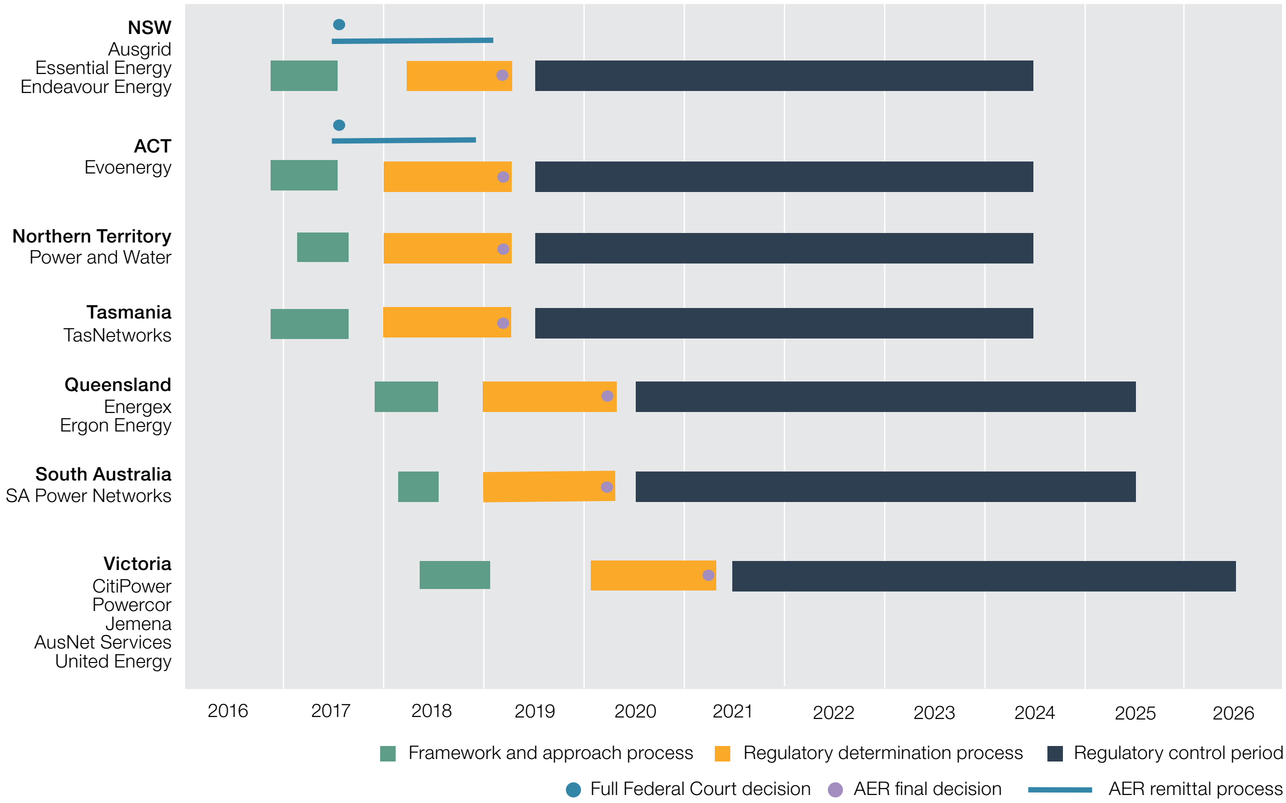
Note: Timelines for AER decisions are effective at 1 July 2021. The latest information is available on the AER website: (https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements).

Source: AER.

14 For transmission networks, the AER determines a cap on the maximum revenue that a network can earn during a regulatory period. For distribution networks, revenue caps apply in all states except the ACT, where an average revenue cap links revenue to volumes of electricity sold.

15 Traditionally, each customer paid a fixed daily charge plus a charge based on actual energy use. These arrangements are evolving under new pricing structures that encourage customers to consider how their energy use impacts network costs. Pricing reforms to address this issue form part of the Power of Choice program (section 3.7).

Figure 3.7 AER decision timelines – electricity distribution networks



Note: Timelines for AER decisions are effective at 1 July 2021. The latest information is available on the AER website: (https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements).

Source: AER.

3.5 Recent AER revenue decisions

In April 2021 the AER published its final revenue decisions for the 5 electricity distribution networks in Victoria – AusNet Services, CitiPower, Jemena, Powercor, and United Energy. These decisions cover the 5-year period ending 30 June 2026 (figure 3.8).

The 5 Victorian distributors are forecast to earn a combined $11.1 billion in revenue over the current period – $313 million (2.7%) less than they were forecast to earn and $392 million (3.4%) less than they actually earned in the previous period. The key driver of the lower forecast revenue is the allowed rate of return, which decreased from around 6.3% for the previous period to 4.7% for the current period.[16] This reflects a decrease in interest rates, meaning the Victorian distributors can obtain the capital they need to run their businesses more cheaply.

In 4 of the 5 decisions, the AER approved lower forecast revenues in the current period than were forecast in the previous period – the exception being AusNet Services. Distribution network charges for AusNet Services' consumers will increase slightly over the current period due to the increase in forecast revenue, combined with a decrease in forecast demand (which causes network charges – revenue per energy unit ($ per kWh) – to increase).

16 The rate of return is a nominal rate of return unless stated otherwise. The real rate of return has also decreased but by a smaller amount. The 4.7% is applied to the first year of the 2021 to 2026 regulatory period. A different rate of return will apply for the remaining regulatory years of the period.

Figure 3.8 Recent AER electricity network revenue decisions – key outcomes

Note: Bill impact is the change in the average annual customer bill compared with the customer bill in the final year of the previous period, adjusted for inflation, assuming retailers pass through outcomes of the decision.

Source: AER estimates.

For the period commencing 1 July 2021 the Victorian distributors are forecast to invest around $5.2 billion in capital projects – $108 million (2%) less than they invested in the previous period. Despite the AER's lower approved capital expenditure allowance the collective value of the Victorian distributors' RABs is forecast to increase by $1.4 billion (10%) by 2026.

The Victorian distributors are forecast to spend around $4.4 billion on operating costs over the current period – $744 million (20%) more than they spent in the previous period.

The AER's decisions for the previous period challenged network businesses to deliver services more efficiently through prudent choices about operating and capital expenditure, without compromising network safety and reliability. In total, the Victorian distributors underspent in the previous period by $1.2 billion (18%) and by $600 million (14%) against their respective approved capital and operating expenditure forecasts. The AER's setting of lower forecast revenue allowances for the current period acknowledged network businesses are rationalising their operations and will continue to build on operational efficiencies. Lower revenue allowances benefit customers by locking in efficiency gains.

3.5.1 Legal reviews of AER decisions

A party can seek judicial review of an AER decision on a network business's revenue. Before October 2017 a party could also apply to the Australian Competition Tribunal (the Tribunal) for a limited merits review of an AER decision.

From 2008 to 2017 network businesses and other parties applied for limited merits review of 33 of the AER's 52 electricity network decisions. Network businesses often succeeded in having their allowed rates of return and revenues increased, whereas consumer representatives and governments were invariably unsuccessful in arguing that network revenues should be decreased.[17] Tribunal decisions added over $3 billion to network revenues.

Following the Australian Government's abolition of limited merits review in October 2017, the AER committed to a more collaborative approach to network regulation, driven by customers' best interests (section 3.6). No appeals for judicial review have since been lodged on any AER decisions on network revenue.

17 AER, *Review of the limited merits review framework, AER submission to Ministerial Forum of Energy Ministers (formerly CoAG Energy Council)*, October 2016.

3.6 Refining the regulatory approach

The regulatory framework is not static. Recent reforms include the AER using benchmarking to assess network costs; offering incentives for network efficiency; and rewarding the network businesses for quality engagement with their customers when they are developing revenue proposals.

The AER continues to review and incrementally refine elements of its benchmarking methodology and data. The aim of this work is to maintain and continually improve the reliability of the benchmarking results it publishes and uses in its network revenue determinations. In 2019, for example, it reviewed alternative approaches to assessing information and communication technology (ICT) expenditure. ICT is increasingly a more integral component of energy services delivery. In its review, the AER assessed whether its existing ICT expenditure assessment tools were fit for purpose.

In 2020 the AER reviewed its treatment of inflation in its regulatory framework. In December 2020 the AER announced that it would adjust its approach to estimate expected inflation from using a 10-year average to a 5-year average of the Reserve Bank of Australia's headline rate to match the 5-year timeframe of a typical regulatory period. The new approach addresses issues highlighted in stakeholder submissions and is more responsive to changing economic circumstances.[18]

In July 2020 the AER released its new Customer Service Incentive Scheme (CSIS), which provides incentives for distributors to provide levels of customer service that align with their customers' preferences (box 3.6).[19] Distributors are encouraged to engage with their customers, identify the customer services they want improved and then set targets to improve those services. The CSIS rewards distributors for improving their customer service and penalises them if service levels deteriorate. The CSIS improves the incentives available for distribution networks to recognise the value of customer service and has been applied to Victorian distributors AusNet Services, CitiPower, Powercor and United Energy in the 2021 to 2026 period.

The AER also implemented changes to regulatory arrangements that sit outside the formal determination process. In June 2020 the AER published its objectives and priorities to be addressed through network service performance reports for regulated electricity and gas network businesses.[20] The AER plans to review these objectives and priorities by 2025 to ensure they remain fit for purpose.

In August 2020 the AER published guidelines to make AEMO's integrated system plan (ISP), a whole-of-system plan for eastern Australia's power system, actionable. The guidelines include a new CBA guideline; a new forecasting best practice guideline; and updates to the regulatory investment test for transmission (RIT-T) instrument and application guidelines.

The guidelines are part of a broader reform led by the Energy Security Board (ESB), with changes made to the National Electricity Rules to streamline the transmission planning process while retaining rigorous CBA. While the new rules were effective from 1 July 2020, the new guidelines will come into effect through the 2022 ISP.[21]

The ISP and RIT-Ts are discussed in section 3.12.

3.6.1 Aligning business and consumer interests

The regulatory process is complex and often adversarial. In this environment, consumers may find it challenging to have their perspectives heard and to assess whether a network business's proposal reflects their interests. In recent processes, the AER and network businesses have trialled new approaches to improve consumer engagement.

To help consumers engage in the regulatory process, the AER publishes documents – including factsheets that simplify technical language – and holds public forums. The AER's Consumer Challenge Panel also provides a mechanism for consumer perspectives to be properly voiced and considered.

A number of network businesses are experimenting with early engagement models to better reflect consumer interests and perspectives in framing their regulatory proposals – for example, running 'deep dive' workshops. The AER has trialled a new approach to customer engagement – the New Reg – in partnership with Energy Networks Australia (ENA) and Energy Consumers Australia (ECA) (box 3.2).[22]

18 AER, *Final position – regulatory treatment of inflation*, December 2020.

19 AER, *Final – Customer Service Incentive Scheme*, July 2020.

20 AER, *Objectives and priorities for reporting on regulated electricity and gas network performance – Final*, June 2020.

21 AER, *Final decision – Guidelines to make the Integrated System Plan actionable*, August 2020.

22 AER, ECA and ENA, *New Reg: towards consumer-centric energy network regulation, a joint initiative of the Australian Energy Regulator, Energy Consumers Australia, and Energy Networks Australia, Directions paper*, March 2018.

Early engagement offers the potential to expedite the regulatory process, reducing costs for businesses and consumers. In particular, effective consumer consultation can lay the foundations for the AER to accept major elements of a network business's revenue proposals. If a business and its customers can agree on key areas then the AER will put significant weight on a proposal reflecting that consensus.

Also, network businesses are increasingly looking to maintain open and ongoing dialogue with stakeholders throughout the regulatory period, as opposed to engaging intensively once every 5 years when a proposal is being considered.

In 2019 Jemena (Victoria) was awarded the ENA/ECA Consumer Engagement Award for its Electricity Network People's Panel. Jemena received recognition because it 'met consumers where they were' – tailored its engagement to them, ensured that translators were on hand, made childcare available and provided transport to ensure that no one was left out of the conversation.[23]

SA Power Networks (South Australia) and Powerlink (Queensland) were also shortlisted as finalists for the award – SA Power Networks for its community engagement on its tariff structure statement and Powerlink for enabling consumer advocates to build an engagement process for its 2023 to 2027 revenue determination.

In 2020 Jemena was again nominated for the ENA/ECA Consumer Engagement Award for its community-focused response to the COVID-19 pandemic. Jemena's diverse customer base presented a unique challenge in how to respond to the pandemic. Jemena identified key customer and community challenges using a consultative, evidence-based approach and delivered solutions in collaboration with industry and the community.[24]

AusNet Services (Victoria) was also nominated for the award for participating in the New Reg trial (box 3.2). As part of the trial AusNet Services established an independent customer forum to represent the perspectives of its customers in negotiating and agreeing price and service offerings, supported by the AER. The forum met with numerous members of AusNet Services' staff over a 2-year period and gained detailed information on the network business, its customers and its plans. The forum also met with many of AusNet Services' customers independently. Agreed outcomes were incorporated in AusNet Services' 2021 to 2026 revenue proposal.

3.7 Power of Choice reforms

Innovations in network and communication technology – including 'smart' meters, interactive household devices, and energy management and trading platforms – are driving change in energy markets. These innovations allow consumers to access real-time information about, and make informed decisions in managing, their energy use. If consumers choose to voluntarily reduce their energy use from the grid in peak periods (by shifting energy use or relying on battery storage), it can potentially delay the need for costly network investment.

Power of Choice reforms are being progressively rolled out to unlock the potential benefits of these innovations. The reforms include a market-led rollout of smart meters, supported by more cost-reflective network pricing (section 3.7.1), and incentives for demand management as a lower cost alternative to network investment (section 3.12.10).

The emergence of electric vehicles (EVs) can also help consumers manage their energy needs. The Australian Renewable Energy Agency (ARENA) is funding projects to assess different approaches to optimise the use of EVs. Projects include ActewAGL Retail (ACT) demonstrating that a fleet of EVs can provide similar services to grid-scale batteries and virtual power plants. The EVs used in the trial can be charged from mains power or rooftop solar but can also send electricity back to the grid.[25] A separate trial, led by Jemena (Victoria), is exploring using hardware-based smart charging for dynamic management of residential electric vehicles.[26]

More generally, the Distributed Energy Integration Program (DEIP) – a collaboration of government agencies, market authorities, industry and consumer associations – aims to enhance consumers' benefits from using distributed energy resources (DER), including benefits from access and pricing reforms.[27] The DEIP has also ran a series of task forces to explore issues relating to integrating EVs into the energy system.

23 Energy Networks Australia, *Consumer engagement report*, 2020.

24 Energy Networks Australia, 'Consumer Engagement Award finalists announced' [media release], 6 October 2020.

25 ARENA, *'"Batteries on wheels" roll in for Canberra storage trial', ARENAWIRE*, 8 July 2020.

26 ARENA, 'Electricity networks gear up to manage electric vehicle demands on the grid', [media release], 5 February 2021.

27 The DEIP's Access and Pricing Working Group developed a rule change proposal on the prohibition on export charging which the AEMC approved in its decision published June 2021.

Improvements in energy storage and renewable generation technology are making it increasingly possible for some consumers to go 'off-grid'. Stand-alone systems or microgrids – where a community is primarily supplied by local generation with no connection to the main grid – are gaining traction, particularly in regional communities remote from existing networks.

In May 2020 the Australian Energy Market Commission (AEMC) proposed rule changes to enable distributors to supply their customers using stand-alone power systems (SAPS)[28] where it is cheaper than maintaining a connection to the grid. The AEMC identified additional benefits of these systems, including improved reliability and reduced bushfire risks.[29]

Under the proposed reforms, customers who receive stand-alone systems will retain all of their existing consumer protections, including access to retail competition and existing reliability and safety standards. Cost savings arising from the use of lower cost stand-alone systems will flow through to all users of the distribution network through lower network prices.

3.7.1 Tariff structure reforms

Under traditional network tariff (price) structures, households and small businesses are charged the same tariffs regardless of how and when they use energy. Some consumers – such as those with air conditioners or solar PV systems – do not pay their full network costs under these structures, while other consumers pay more than they should. Network tariffs for large consumers are typically more cost-reflective.

Changes to the National Electricity Rules which took effect in 2017 require distributors to make their tariffs more cost-reflective so as to signal to retailers the cost of their customers' use of the network and investment in DER. Retailers are the primary focus of network tariff reform, because they act as the interface with consumers. They package network tariffs with other costs (such as wholesale energy) in their retail price offers and decide how to reflect the charges in those offers. It is up to the consumer to choose a retail offer that suits their needs, whether that be a flat rate retail tariff or a more innovative product.

Tariff reform can encourage more efficient use of networks, delay the need for new investment, and reduce the amount of infrastructure that needs to be maintained in the long term. Initially, reform focused on signalling costs during peak demand periods (which historically drove network investment). More recent reform has involved sending price signals to efficiently integrate DER – such as solar PV, batteries and EVs – into distribution networks.

As an example, the AER in 2020 approved SA Power Networks' (South Australia) use of a 'solar sponge' tariff for its residential consumers. This tariff offers a lower network charge during the middle of the day, when solar output is highest, to encourage shifting of electricity use to those times. Raising demand for grid-supplied electricity in the middle of the day can help manage voltage issues and thermal overloads associated with low demand, while shifting demand away from the evening peak that can put heavy strain on the network. SA Power Networks also introduced a demand tariff that offers discounted time of use rates and a seasonal peak demand component.[30]

Distributors are moving towards fully cost-reflective pricing in their second round of tariff structure statements, which the AER considers as part of the revenue determination process. Progress has included:

- simplifying tariff offerings to provide clear, consistent signals
- designing tariffs that more closely reflect how consumers' use of the network affects costs
- applying an 'opt-out' or mandatory assignment policy that increases the number of consumers whose retailers will face these more cost-reflective tariffs
- integrating network pricing with areas such as network planning, demand management and direct procurement of network services; and trialling alternative approaches.

In March 20201 the AEMC released a draft rule change to remove a prohibition on distributors charging for exports and expanded the definition of 'network services' to include DER exports. The AER expects that the next (third) round of tariff structure statements submitted by the distributors in NSW, Tasmania, the ACT and the Northern Territory will signal the cost of serving both consumption and generation.[31] The AER will continue to use an iterative approach to advancing this reform and will consult with stakeholders to produce a non-binding guideline on how export tariffs will be implemented.

28 Usually a combination of solar PV, batteries and a backup generator.

29 AEMC, *Final report – updating the regulatory frameworks for distributor-led stand-alone power systems*, May 2020.

30 SA Power Networks, *2020–25 regulatory proposal, Attachment 17 – tariff structure statement*, January 2019.

31 The tariff structure statements are due in January 2023 and will take effect from 1 July 2024.

To support the transitional introduction of export tariffs the AEMC modified revenue recovery arrangements to allow distributors to trial alternative tariff structures during the regulatory period.

The limited uptake of smart meters for residential and small business consumers has been a barrier to cost-reflective network tariffs being implemented in distribution networks outside of Victoria. Smart meters, which measure electricity use in half-hour blocks, are essential for cost-reflective network tariffs to be applied. At February 2021 around 39% of customers in the NEM had metering capable of supporting cost-reflective tariffs (including smart meters and manually readable interval meters). Installation rates vary across regions.

Victoria was the first jurisdiction to progress metering reforms, with its electricity distribution businesses rolling out smart meters from 2009 to 2014. Around 98% of small consumers in Victoria have a smart meter.

In other jurisdictions, the rollout of smart meters is occurring on a market-led basis, following changes to the National Electricity Rules which have been applicable since December 2017. All new and replacement meters installed for residential and small businesses consumers must now be smart meters, and other consumers can negotiate for a smart meter as part of their electricity retail offer.

The changes to the rules also transferred responsibility for metering from distributors to retailers. The transition to retailer responsibility coincided with large delays in meter installations in some regions. Participants indicated reasons for the delays included poor coordination and data provision among network businesses, retailers and metering coordinators; inadequate retailer systems, processes and controls; and poor resourcing. But from February 2019 new rules required retailers to provide consumers with electricity meters within 6 business days from a property being connected to the network, or with replacement meters within 15 days.[32] In December 2020 the AEMC announced a review of whether additional changes could help smart meters deliver more consumer benefits.[33]

Outside Victoria, in February 2021 NSW had the highest penetration of smart or interval meters, at around 25% of residential and small business customers. Installation levels in other regions ranged from 15% of customers in Queensland to 23% of customers in the ACT.[34] This share is expected to increase, ranging from 30% for Essential Energy (NSW) to 63% for TasNetworks (Tasmania) by 2025, reflecting the requirement for new meters – including end of life replacements – to be smart meters.

In March 2021 the NSW Government lifted restrictions on remote connection and disconnection of smart meters. Relaxing this restriction gives retailers an increased incentive to roll out more smart meters across NSW, delivering benefits to customers, particularly those in regional NSW who face higher fees for technicians to come out to their property.[35]

Around 24% of residential and small business customers outside of Victoria have moved to cost-reflective retail tariffs. Tasmania and NSW have seen the greatest take-up of these tariffs (at 47% and 41% of customers respectively), followed by the ACT (23% of customers). Customer adoption of cost-reflective tariffs remains low in Queensland (1% of customers) and South Australia (7% of customers). Distributors forecast the proportion of their residential consumers assigned to cost-reflective network tariffs will continue to increase from 2020 (figure 3.9).

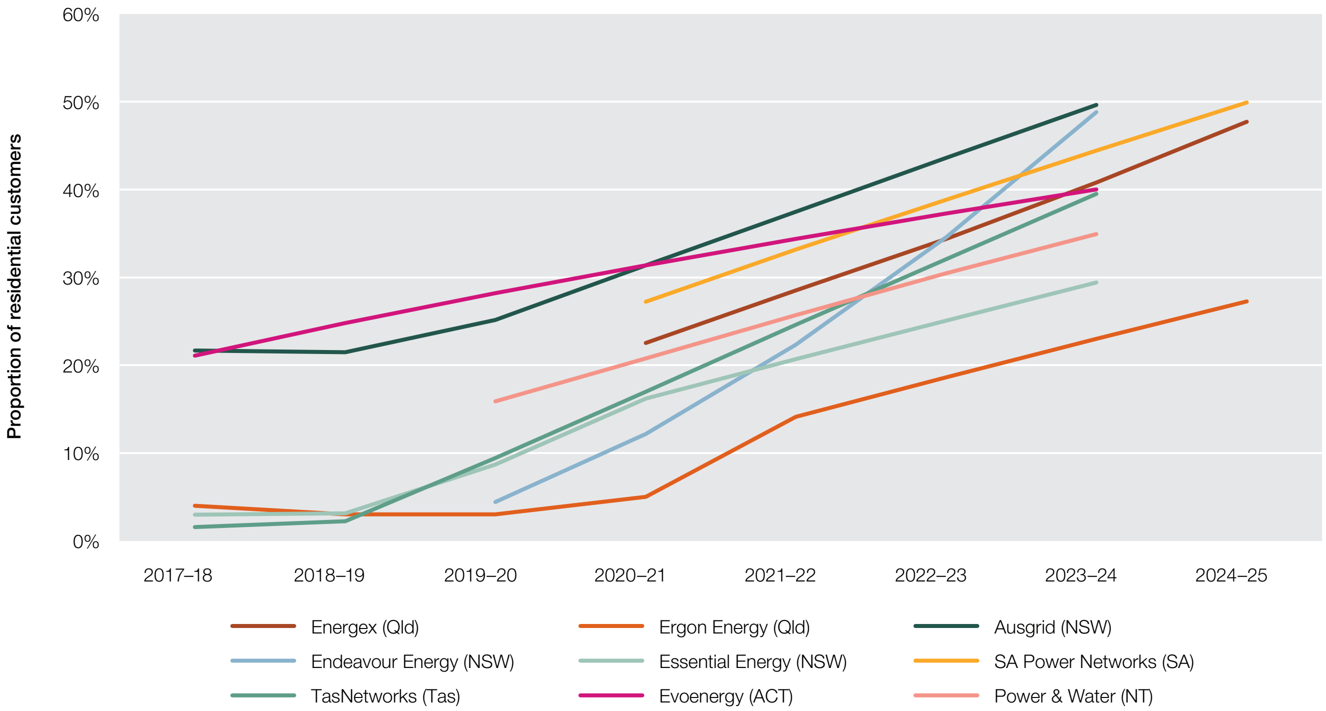
32 AEMC, *National Energy Retail Amendment (Metering Installation Timeframes) Rule 2018, rule determination*, December 2018.

33 AEMC, *Review announced into how electricity smart meters can deliver more customer benefits*, 3 December 2020.

34 Estimates based on AER market intelligence.

35 The National Tribune, 'Cutting red tape for smart meter savings', The National Tribune, 15 March 2021.

Figure 3.9 Projected assignment of cost-reflective tariffs for residential consumers – electricity distribution networks



Source: AER analysis of unpublished forecasts supplied by regulated electricity distribution businesses.

3.7.2 Ring-fencing

When a network business offers metering or other services in a contestable market, robust ring-fencing arrangements must be in place to ensure the business competes fairly with other providers. Ring-fencing aims to ensure network businesses do not use revenue from regulated services to cross-subsidise their unregulated products. It also aims to deter discrimination in favour of affiliated businesses.

The AER administers a ring-fencing guideline that requires distribution network businesses to separate their regulated network services (and the costs and revenues associated with them) from unregulated services, such as metering. Unregulated services must be offered through a separate entity.

All distributors are required to comply with the AER's ring-fencing guideline and annually report on their compliance to the AER. Since 2017–18 the AER has generally observed fewer compliance issues and breaches. However, compliance could still be improved in a number of areas, particularly in relation to protecting confidential information about the network. When breaches have occurred, distributors have generally communicated promptly with the AER, acted quickly to remediate any potential harms, and put a plan in place to prevent breaches from recurring. The introduction of civil penalties in February 2020 will continue to help encourage improved compliance.

In 2019 the AER commenced a review of the current distribution ring-fencing guideline to strengthen some obligations and simplify compliance. The review has since broadened to include consideration of the changing nature of services offered by distribution businesses, including through the use of new technology such as stand-alone power systems and storage devices. The competitive markets for distributor led stand-alone power systems and storage devices are in their infancy and it is unknown how quickly these markets may develop.

Electricity distributors are showing interest in entering these markets to provide contestable services, and to realise efficiencies in using storage devices to provide multiple services. In May 2021, the AER published its draft electricity distribution ring-fencing guideline for stakeholder feedback.[36] The amended guideline is scheduled to be finalised in the third quarter of 2021.

36 AER, *Draft ring-fencing guideline – Electricity distribution – version 3*, May 2021.

3.8 Revenue

Network businesses earn revenue for providing numerous services to consumers. While some of these services are regulated, others are provided through competitive markets. For transmission network businesses we focus on components of their revenue associated with delivering prescribed transmission services. For distribution network businesses we focus on revenues associated with providing core distribution services – standard control services.[37]

Since 2006 the amount of revenue earned by network businesses has seen distinct trends – rapid growth (until around 2013 in transmission and 2015 in distribution), followed by a significant downturn. The downturn in revenue was more gradual for the transmission network businesses than it was for distributors.

3.8.1 Revenue trends

Network revenues increased by around 6% per year from 2006 to 2015. With network charges absorbing around 43% of retail customer bills, this growth led to escalating retail electricity bills over the period.

A 67% increase in the value of the RAB from 2006 to 2014 – caused by surging investment – was a key contributor to the increase in revenue. From 2014 investment weakened, but the impact of past overinvestment remains in the asset base (section 3.10). The ballooning asset base increased financing costs and depreciation charges, resulting in higher revenue allowances to cover these costs. Rising interest rates due to the global financial crisis compounded the impact on revenue. Operating expenditure also increased by an average of 6% per year from 2006 to 2012. Further, many AER decisions faced legal challenges over this period, often resulting in court decisions that increased network revenue.

Revenue rose higher in Queensland and NSW than elsewhere. In Queensland, it grew by 14% per year from 2006 to 2015; in NSW, it rose by 14% from 2006 to 2013. Revenue growth was less dramatic in Victoria, increasing by a relatively stable 4% per year from 2006 to 2015. A key cost driver in Queensland and NSW was the stricter reliability standards imposed by state governments, which required new investment and operating expenditure to meet the new standards.

Cost pressures began to ease when electricity demand from the grid plateaued, causing new investment to be scaled back from 2013. The changing demand outlook coincided with government moves to allow network businesses greater flexibility in meeting reliability requirements. The financial environment also improved after 2012, easing borrowing and equity costs. After peaking at over 10% between 2009 and 2013, rates of return approved for some network businesses were below 5% in 2021 (section 3.11).

Energy rule reforms phased in from 2015 also helped stem growth in network revenue. The reforms, which explicitly linked network costs to efficiency factors, encouraged network businesses to better control their operating costs.

In combination, these factors reduced the revenue needs of network businesses. But the 5-year regulatory cycle meant lower investment and rates of return often lowered revenue only after a significant lag. More generally, consumers will continue to pay for the overinvestment in network assets from 2006 to 2013 for the remainder of the economic lives of those assets, which may be up to 50 years. The Grattan Institute called for the asset bases of some networks to be written down so consumers do not pay for that overinvestment.[38] The Australian Competition and Consumer Commission (ACCC) supported this position, particularly for government-owned networks in Queensland, NSW and Tasmania.[39]

Consumer groups and some industry observers remain concerned the regulatory framework enables network businesses to earn excessive profits. In response to calls for greater transparency around the actual returns earned by the network businesses, in 2018 the AER began publishing information on the businesses' profitability. In September 2020 the AER released its first *Electricity network performance report*,[40] which provides detailed analyses of key operational and financial trends as well as introducing a number of key profitability measures.[41] The report enables stakeholders to make more informed assessments of the returns earned by each network business.

37 Standard control services may include network, connection and metering services. These services make up the bulk of the services provided by distribution businesses and are regulated by the AER.

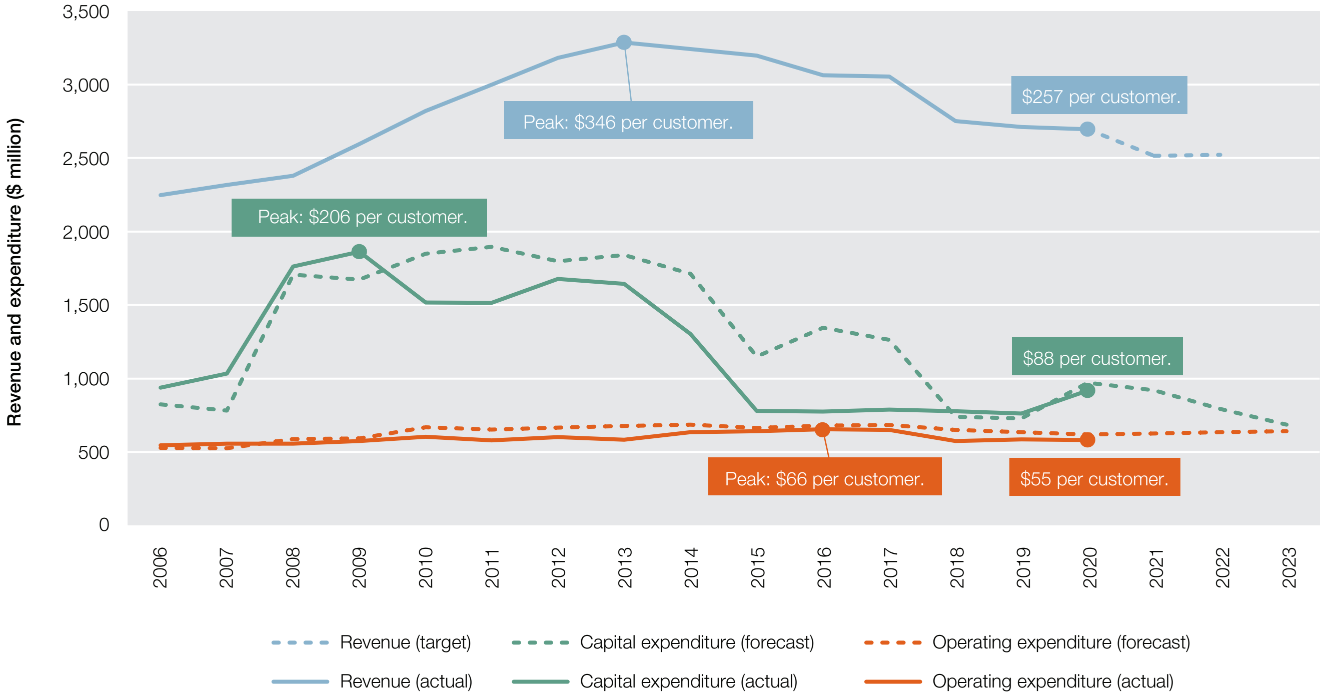
38 Grattan Institute, *Down to the wire – a sustainable electricity network for Australia*, March 2018.

39 ACCC, *Retail Electricity Pricing Inquiry – final report*, June 2018

40 AER, *Electricity network performance report*, September 2020.

41 AER, *Profitability measures for electricity and gas network businesses, final position paper*, December 2019.

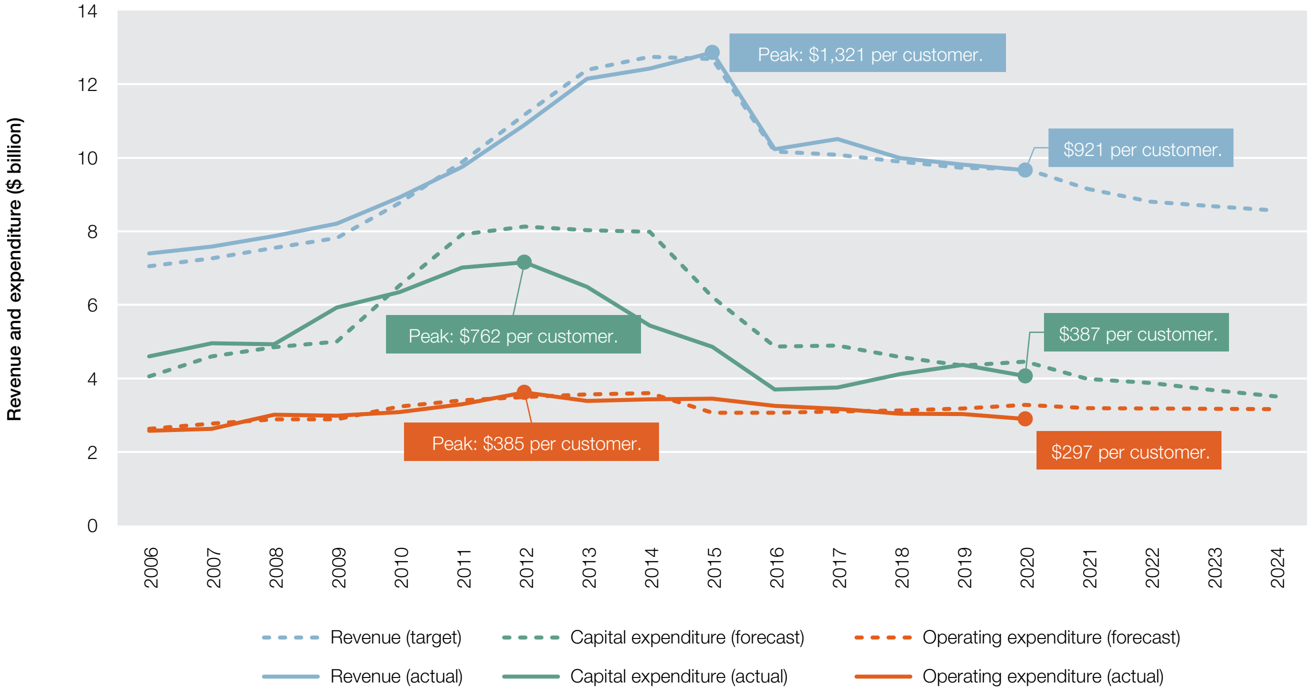
Figure 3.10 Revenue and key drivers – electricity transmission networks



Note: All data are adjusted to June 2021 dollars, based on forecasts of the consumer price index (CPI). Most network businesses report on a 1 July – 30 June basis. The exception is AusNet Services (Victoria), which reports on a 1 April – 31 March basis. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018). Forecast transmission revenues are subject to adjustments over which the AER has limited visibility. Target revenue is derived from regulatory decisions but adjusted to present it on a comparable basis to actual revenues. The adjustments include rewards and penalties from incentive schemes, cost pass-throughs and other factors that are taken into account in determining the target revenues used to set prices each year.

Source: revenue: economic benchmarking regulatory information notice (RIN) responses; capital expenditure: AER modelling, category analysis RIN responses; operating expenditure: AER modelling, economic benchmarking RIN responses.

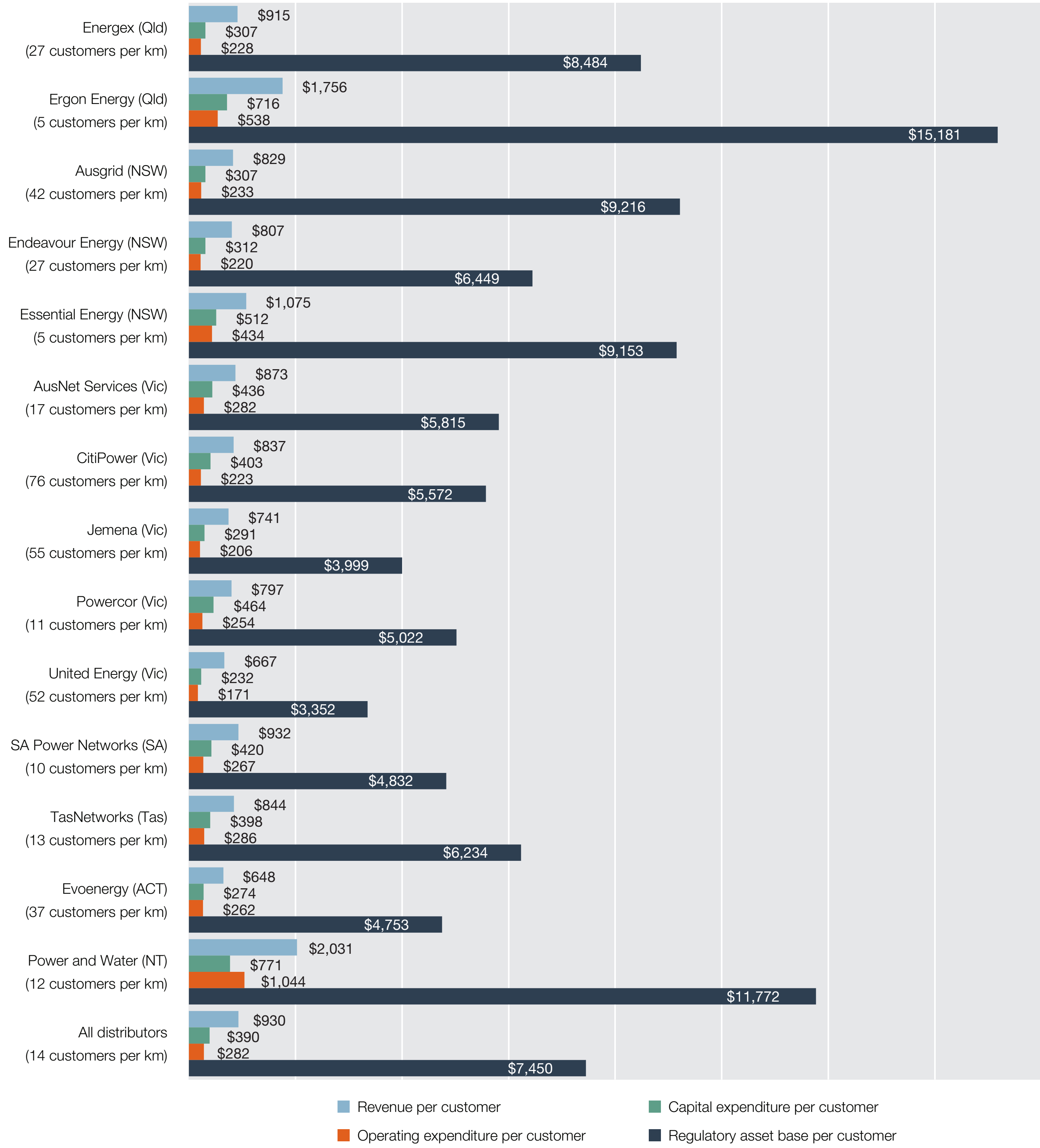
Figure 3.11 Revenue and key drivers – electricity distribution networks



Note: All data are adjusted to June 2021 dollars, based on forecasts of the consumer price index (CPI). Most network businesses report on a 1 July – 30 June basis. The exceptions are the Victorian distribution network businesses, which report on a 1 January – 31 December basis. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018). Target revenue is derived from regulatory decisions but adjusted to present it on a comparable basis to actual revenues. The adjustments include rewards and penalties from incentive schemes, cost pass-throughs and other factors that are taken into account in determining the target revenues used to set prices each year.

Source: revenue: economic benchmarking regulatory information notice (RIN) responses; capital expenditure: AER modelling, category analysis RIN responses; operating expenditure: AER modelling, economic benchmarking RIN responses.

Figure 3.12 Key financial indicators (2020) – electricity distribution networks



Note: In 2020 residential customers (a customer who purchases energy principally for personal, household or domestic use) accounted for 89% of total customers on the distribution network. Of the remaining customers, 10% were non-residential (including high voltage customers who were connected at higher than 415 volts and low voltage customers who were connected at 240 or 415 volts) and 1% were unmetered or 'other'. While these proportions differed across network businesses – 92% residential for Evoenergy (ACT) and 83% for CitiPower (Victoria), for example – the differences did not materially affect the 'per customer' metric. Revenue, capital expenditure, operating expenditure and asset base are actual outcomes for the regulatory year ending in 2020. For regulatory purposes, Northern Territory transmission assets are treated as part of the distribution system.

Source: AER estimates derived from economic benchmarking regulatory information notice (RIN) responses; AER modelling; AER revenue decisions; Australian Competition Tribunal decisions.

Operating, maintenance and other costs correlate less closely with market conditions than do other revenue drivers and show relatively stable trends. In 2009 operating costs were about one-third that of asset investment. However, by 2015 weakening investment had seen the expenditure on capital projects drop to a comparable level with operating costs. Operating expenditure later eased as network businesses (especially distributors) implemented efficiency programs (section 3.13).

Figure 3.12 provides a summary of key financial indicators from 2020 for distribution networks on a per customer basis. This allows for greater comparability across networks.[42]

3.8.2 Revenue in 2020

In 2020 electricity network businesses earned a total of $12.4 billion in revenue. Of this, transmission network businesses earned $2.7 billion, which was 0.6% less than in the previous year and 18% less than the peak in 2013 (figure 3.10). Distributors earned around $9.7 billion, which was 1.5% less than in the previous year and 25% less than its peak in 2015 (figure 3.11).

Network revenue is forecast to continue to fall over the next few years. Beyond that point investment on the transmission networks is likely to increase the industry RAB, pushing revenue higher.

3.8.3 Current AER revenue decisions

Transmission network businesses are forecast to earn around $13.1 billion in revenue over the current periods – $2.1 billion (14%) less than they were forecast to earn in the previous periods. Distribution network businesses are forecast to earn around $44.8 billion – $7.7 billion (15%) less than they earned in the previous periods (figure 3.11).[43]

Unlike the distribution networks, forecast (or target) transmission revenues cannot be directly compared to actual revenues. Actual revenues are subject to adjustments over which the AER has limited visibility. The adjustments include rewards and penalties from incentive schemes, cost pass-throughs and other factors that are taken into account in determining the target revenues used to set prices each year. Revenue for transmission businesses are locked in at the beginning of the regulatory period. The businesses are then incentivised to provide services at the lowest possible cost because their returns are determined by their actual costs of providing services. If the transmission networks reduce their costs to below the estimate of efficient costs, the savings are shared with consumers in future regulatory periods.

In its most recent revenue decisions the AER approved revenue targets for the Victorian distributors which are $313 million (2.7%) less than they were forecast to earn and $392 million (3.4%) less than they actually earned in the previous period (figure 3.8).

The key driver behind lower revenues for the majority of the transmission and distribution networks is the change in the return on capital. The rate of return has decreased between regulatory periods; this has been driven by the decrease in interest rates. This means network businesses can now obtain the capital they need to run their businesses more cheaply.

42 Per customer metrics allow for easier comparison of network businesses of different sizes. But multiple factors other than customer numbers – such as line length and terrain – have an impact on these indicators.

43 The current regulatory period is the period in place at 1 July 2021.

3.9 Network charges and retail bills

Electricity network charges made up 40–50% of a residential customer's energy bill in 2020–21 (section 6.6.1 in chapter 6). Distribution networks account for the majority of costs (73–78%) with transmission network costs (up to 21%) and metering costs making up the balance.

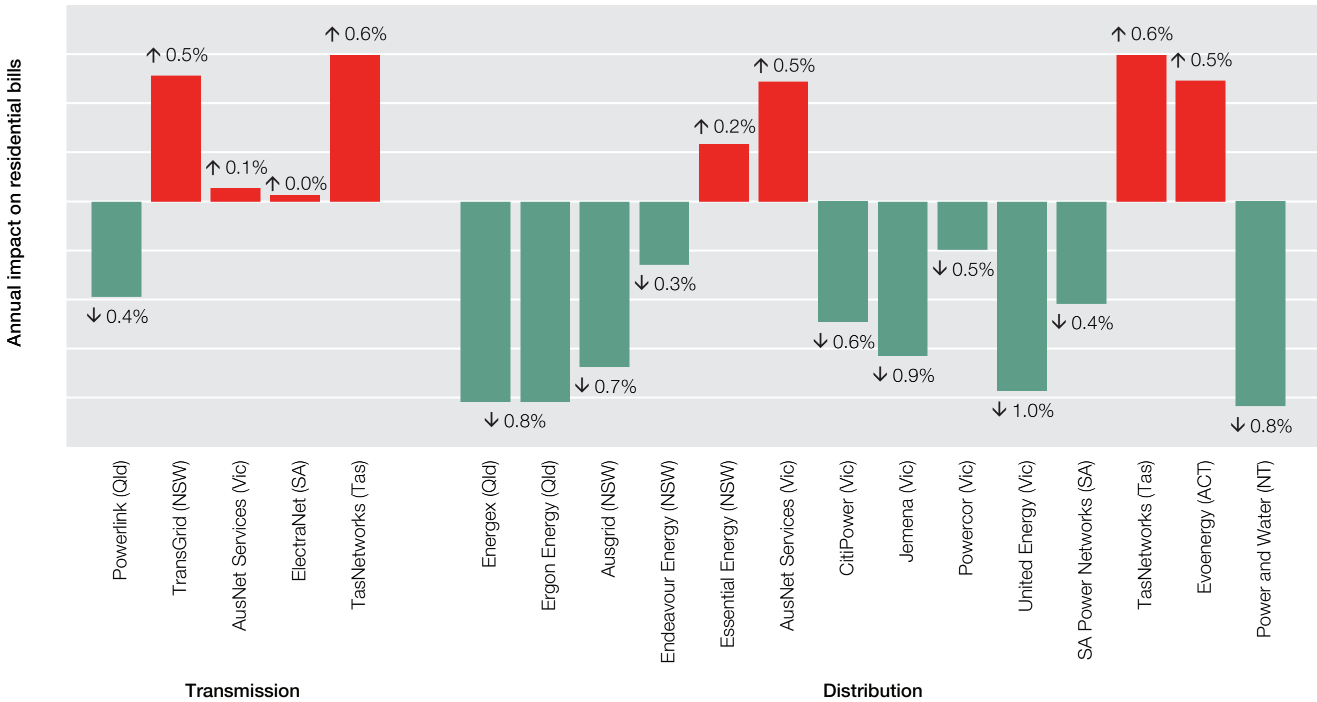
Declining network revenue since 2015, combined with rising customer numbers, has translated into lower network charges in retail energy bills for most customers (figure 3.13). This lowering of network charges helped to mitigate some of the pressure (caused by higher wholesale electricity costs) on retail energy bills between 2017 and 2019.

The AER's most recent revenue decisions decreased residential energy bills by an average of 0.1% per year across all states and territories. This is the culmination of an average 0.2% increase in transmission and an average 0.4% decrease in distribution. Changes to network charges mostly arise in the first year of a regulatory period and range from a 9% reduction for Power and Water (Northern Territory) to a 1.6% increase for AusNet Services (Victoria). Initial changes are generally followed by stable prices or modest increases in later years.

The reduction in network charges reflects factors such as lower finance costs, lower demand for electricity (so less need for new investment), operating efficiencies implemented by network businesses (partly in response to AER incentive schemes), and regulatory refinements such as the AER's wider use of benchmarking to assess efficient costs.

Electricity distributors submit annual pricing proposals to the AER, outlining proposed prices to take effect in the following year. These proposing prices must be consistent with the distributor's approved revenues but are adjusted for factors such as the distributor's performance against incentive schemes and correcting for prior year under- or over-recoveries. The distributors also adjust prices to recover costs from transmission and jurisdictional schemes that are not considered by the AER in setting approved revenues.

Figure 3.13 Impact of AER revenue decisions on annual residential customer electricity bills



Note: Estimated annual impact of latest AER decision on the network component of a residential electricity bill based on AER estimates of retail electricity prices and typical residential consumption in each network. Revenue impacts are nominal and averaged over the life of the current decision.

The data account for changes in only network charges, not changes in other bill components. Outcomes will vary among customers, depending on energy use and network tariff structures.

Source: AER revenue decisions; additional AER modelling.

In May 2021 the AER approved Evoenergy's 2021–22 electricity pricing proposal in accordance with its 2019 to 2024 distribution determination. Evoenergy's pricing proposal generated media attention due to its significant proposed price increases. From 1 July 2021 the network tariff component of the typical annual bill for Evoenergy customers is estimated to be $241 higher for households and $1,476 higher for small business compared with the previous year – an increase of 41%.[44] Evoenergy's charges for jurisdictional[45] taxes and renewables policies drove much of this increase, rising 133% from the charges for 2020–21.[46]

3.10 Regulatory asset base

The RAB for a network business represents the total economic value of assets that provide network services to customers.[47] These assets have been accumulated over time and will be at various stages of their economic lives. Some networks may have relatively older/newer assets than others depending on their growth and the phase of the replacement cycle they are in. The value of the RAB substantially impacts a network service providers' revenue requirements and the total costs a network's consumers ultimately pay. Given some network assets have a life of up to 50 years, network investment will impact retail energy bills long after the investment is made.

As part of the revenue determination process, the AER forecasts a network business's efficient investment requirements over the forthcoming regulatory period. Efficient investment approved by the AER gets added to the RAB on which the business earns returns, while depreciation of existing assets gets deducted. As such, the value of a network's asset base will grow over time if approved new investment exceeds depreciation. The RAB is adjusted at the end of the regulatory period to reflect actual investment.

Escalating investment inflated the value of the total network RAB from $56.6 billion in 2006 to $94.9 billion in 2014 – an increase of around 8% per year. Since 2014 the amount network investment has steadied, as has the growth in the value of the total network RAB. From 2014 to 2020 the value of the total network RAB continued to grow but at a considerably slower rate of around 1% per year. While the value of the total network RAB has continued to grow, the trend has not been the same for both transmission and distribution networks.

3.10.1 Regulated asset base in 2020

In 2020 the combined value of the RABs for network businesses was $100.4 billion, which was 1.2% higher than in the previous year. Of this, the value for the transmission networks was $21.7 billion, which was 0.3% lower than in the previous year and 3% lower than at its peak in 2014. In 2020 the combined value of the RAB for distribution networks reached a new high of $78.8 billion, which was 1.6% higher than in the previous year. However, in recent years the growth in the value of the RAB has been offset by greater increases in the number of customers connected to the networks. As such, the $9,498 RAB per customer in 2020 was 3% lower than its peak in 2015 (figure 3.14).

Network businesses receive a guaranteed return on their RAB. For this reason, they have an incentive to overinvest if their allowed rate of return exceeds their actual financing costs. Previous versions of the energy rules enabled significant overinvestment in network assets, which partly drove the sharp rise in network revenue from 2006 to 2015 (section 3.12.2). Under reforms introduced in 2015 the AER can remove inefficient investment from a network's asset base if the network overspent its allowance, to ensure customers do not pay for it.

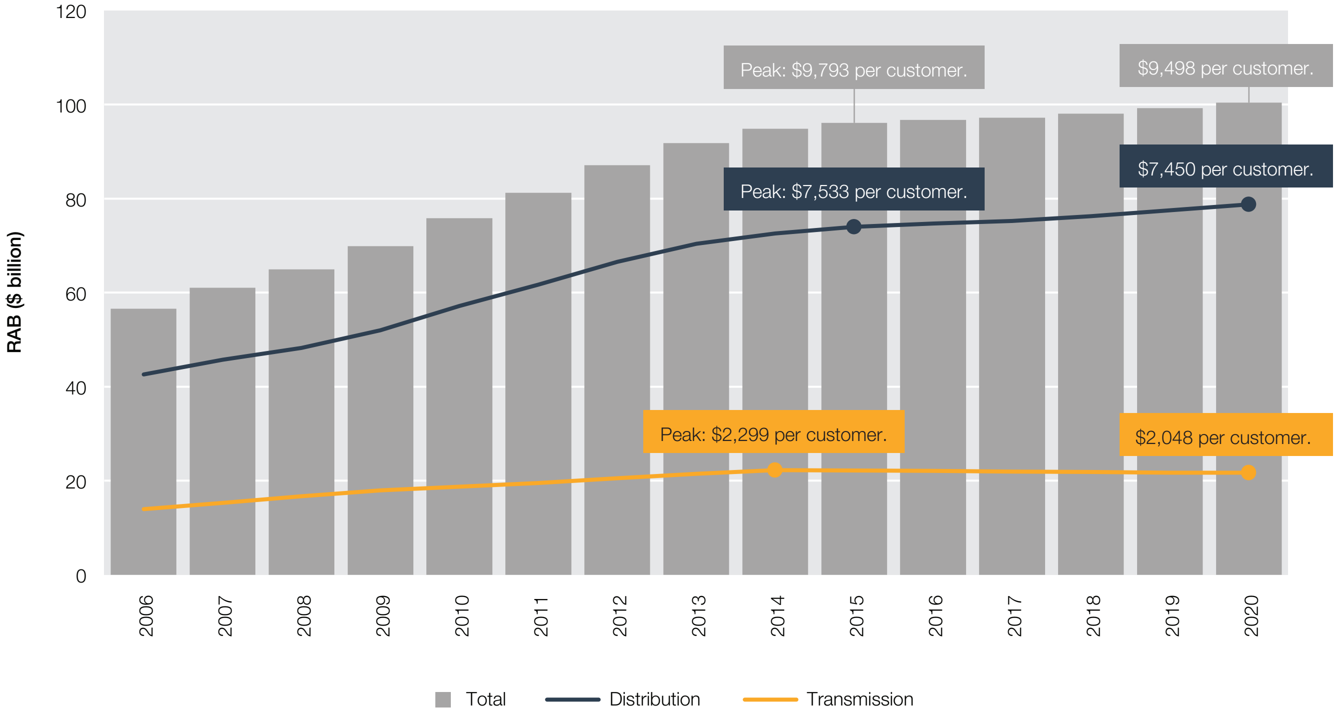
44 AER, *AER approves 2021–22 Evoenergy network tariffs for ACT electricity customers*, AER website, 14 May 2021, accessed 21 May 2021.

45 Jurisdictional schemes are expenses incurred by Evoenergy pursuant to ACT Government requirements, such as the large scale feed-in tariff.

46 Evoenergy, *Network pricing proposal 2021/22*, April 2021.

47 To the extent that they are used to provide such services.

Figure 3.14 Value of electricity network assets (regulatory asset base)



Note: Closing regulatory asset bases (RABs) for electricity networks in the NEM, consumer price index (CPI) adjusted to (forecast) June 2021 dollars. Most network businesses report on a 1 July – 30 June basis. The exceptions are Victorian networks: AusNet Services (transmission) reports on a 1 April – 31 March basis; and the Victorian distribution network businesses report on a 1 January – 31 December basis. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018). Transmission networks do not report customer numbers. Per customer metrics for the transmission network were calculated using the total number of distribution customers.

Source: AER modelling; economic benchmarking regulatory information notice (RIN) responses.

3.10.2 Overhead support structures

The assets that make up a network business's RAB are disaggregated into a number of categories. In 2020 substations, switchyards and transformers were the largest class of assets for transmission businesses (44% of the total transmission network RAB), followed by overhead assets (36%). Overhead network assets were the largest class of assets for distribution businesses (35% of the total distribution network RAB), followed by underground network assets (23%), zone substations and transformers (19%) and distribution substations including transformers (14%).

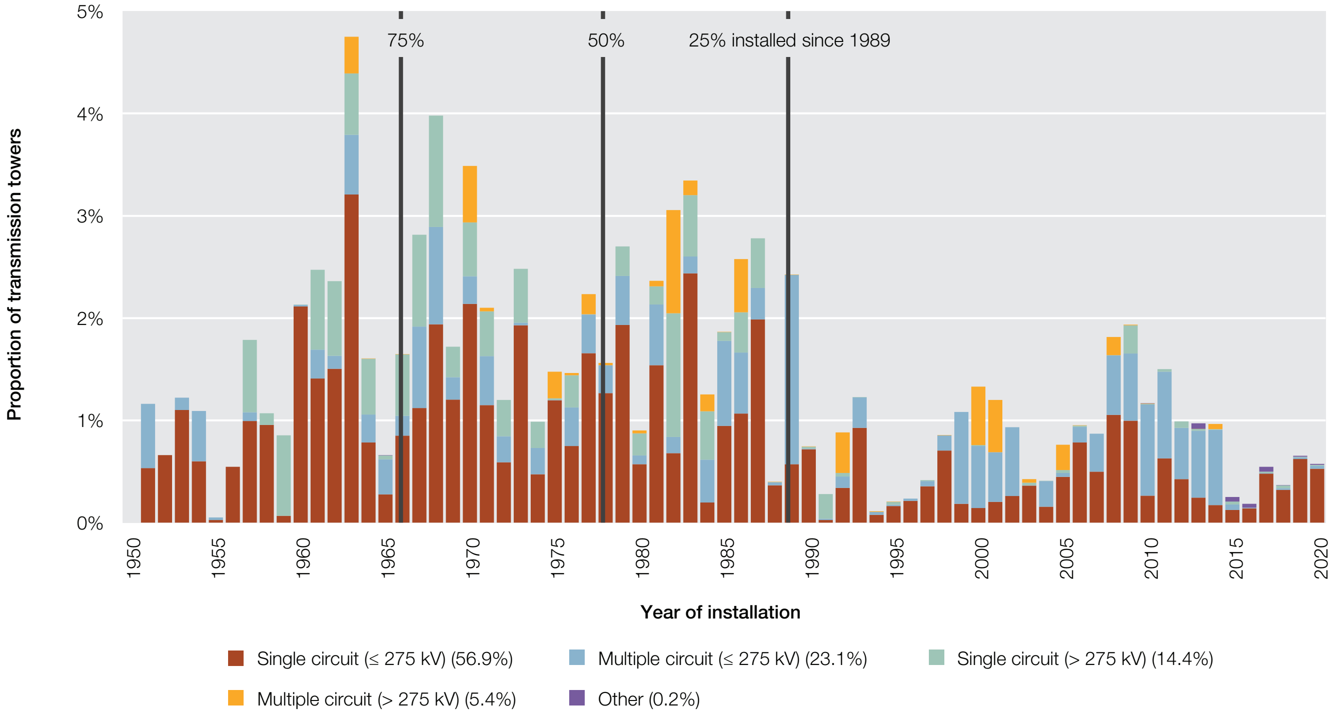
Transmission towers and distribution poles are installed and maintained by network businesses to support overhead power lines. While transmission towers are predominately made of steel, distribution poles are generally made of wood, concrete, steel or composites like fiberglass. Different environmental conditions faced by networks can shape their choice of material. For example, in some parts of Australia, wooden poles are more quickly destroyed by termites, so metal poles must be used instead.

Overhead network assets represent the most observable components of electricity network infrastructure and account for the greatest proportion of the total network RAB (around 35%). This is not surprising given the network spans almost 790,000 kilometres of line, 85% of which is above ground.

There are significant differences in the age and profile of the towers and poles on each network. Some networks, such as Essential Energy (NSW) and Ergon Energy (Queensland) operate larger rural distribution networks that are almost entirely above ground. Conversely, Evoenergy (ACT) and CitiPower (Victoria) operate smaller urban distribution networks that are predominately underground. In these cases the predominately rural networks are more reliant on overhead poles than the networks operating in predominately urban environments.

The overhead network asset age profiles shown in figures 3.15 and 3.16 provide an overview of the different types of towers and poles currently in commission. The individual profiles and characteristics of each network vary significantly from the whole of NEM averages.

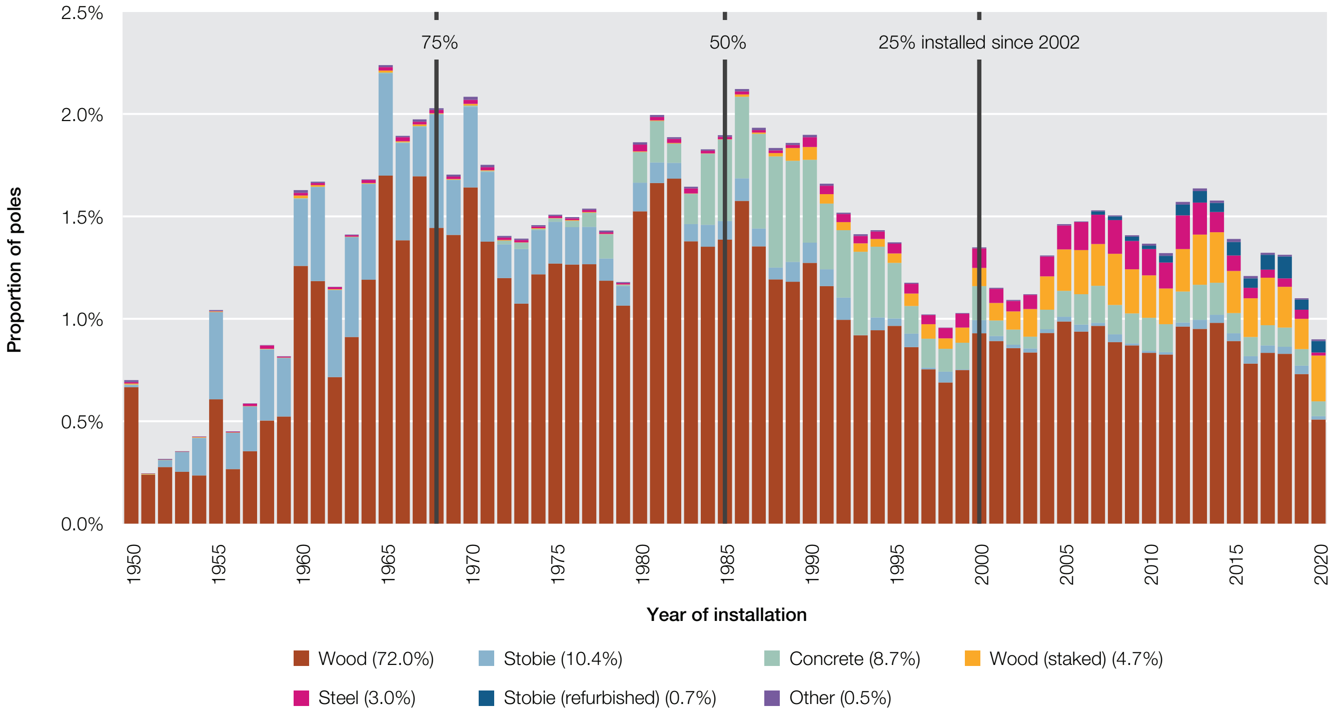
Figure 3.15 Overhead support structures – electricity transmission towers in the National Electricity Market



kV: kilovolt.

Source: Category analysis regulatory information notice (RIN) responses.

Figure 3.16 Overhead support structures – electricity distribution poles in the National Electricity Market



Note: Only includes distributors in the National Electricity Market and does not include Power and Water (Northern Territory). Stobie poles, used almost exclusively in South Australia, are made up of 2 vertical steel posts with a slab of concrete between them.

Source: Category analysis regulatory information notice (RIN) responses.

3.11 Rates of return

The shareholders and lenders that finance a network business expect a commercial return on their investment. The rate of return estimates the cost of funds that a network business's financiers require to justify investing in the business. It is a weighted average of the return needed to attract 2 sources of funding – equity (dividends paid to a network business's shareholders) and debt (interest paid on borrowings from banks and other lenders). Given this weighting approach, the rate of return is sometimes called the weighted average cost of capital (WACC).

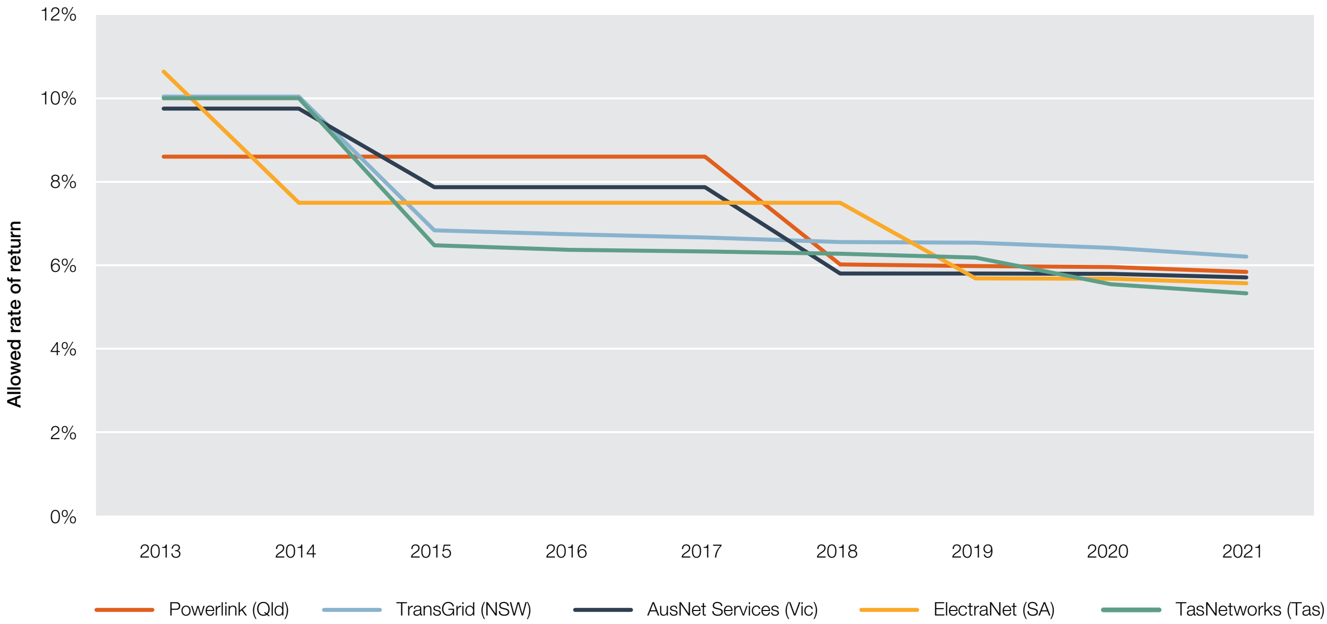
The AER sets an allowed rate of return, but a network's actual returns can vary from the allowed rate. The variance can be due to a number of factors, such as the impact of incentive schemes, forecasting errors, revenue over- or under-recovery under a revenue cap, or the revenue smoothing process. The AER calculates allowed returns each year by multiplying the RAB by the allowed rate of return.[48]

If the AER sets the allowed rate of return too low then a network business may not be able to attract sufficient funds to invest in assets needed for a reliable power supply. If the rate is set too high then the network businesses have a greater incentive to overinvest and consumers will pay for a 'gold-plated' network that they do not need.

As electricity networks are capital intensive, returns to investors typically make up 30–50% of a network's total revenue allowance. A small change in the allowed rate of return can have a significant impact on network revenue and a customer's energy bills. A one percentage point increase in the rate of return for TransGrid (NSW transmission) would increase the business's revenues by around 10%, for example. For this reason, the allowed rate of return is often a contentious part of a revenue decision.

Conditions in financial markets are a key determinant of the allowed rate of return. The AER's revenue decisions from 2009 to 2012 took place against a backdrop of the global financial crisis, an uncertain period associated with reduced liquidity in debt markets, and high risk perceptions. Reflecting conditions in financial markets, the allowed rate of return peaked at over 10% in revenue decisions made during this period (figures 3.17 and 3.18). The Tribunal increased some allowed rates of return following appeals by the network businesses.

Figure 3.17 Allowed rate of return – electricity transmission networks



Note: Rate of return is the nominal vanilla weighted average cost of capital (WACC).

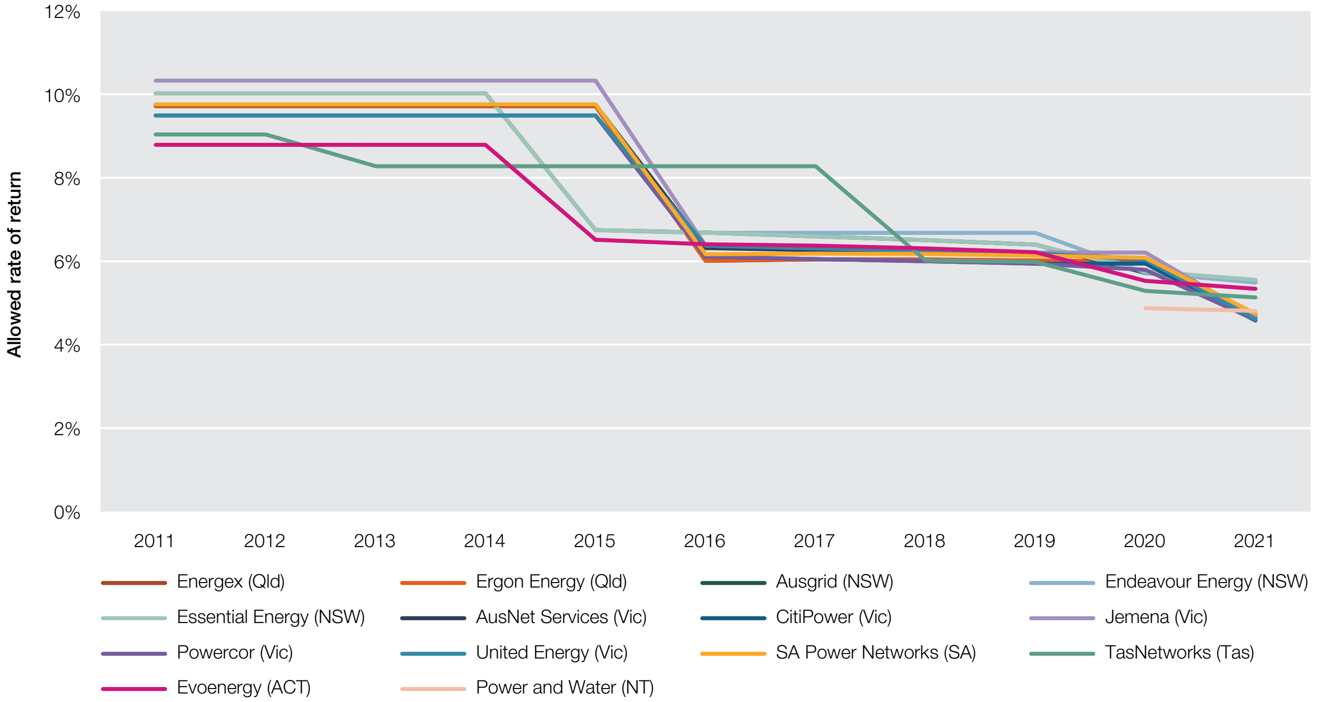
Source: AER decisions on electricity network revenue proposals; AER decisions following remittals by the Australian Competition Tribunal or Full Federal Court.

48 If the rate of return is 5%, and the RAB is $50 billion, for example, then the return to investors is $2.5 billion. This return forms part of a network's revenue needs and must be paid for by energy customers.

Borrowing and equity costs have since eased. From 2015 the AER has updated the cost of capital annually to reflect changes in debt costs. More stable financial market conditions resulted in allowed rates of return averaging around 6% from 2016. These lower allowed rates became a key driver of lower network revenues and charges over the past few years (figures 3.10 and 3.11).

In recent years the network businesses' actual returns have often exceeded the AER's allowed returns. This is not unexpected given the premise of a revealed efficient cost framework encourages network businesses to become more efficient, allowing network businesses to earn short term profits above the allowed rate.[49]

Figure 3.18 Allowed rate of return – electricity distribution networks



Note: Rate of return is the nominal vanilla weighted average cost of capital (WACC). Victorian data for the 2021 year has been derived from the transitional year (6 months data). To enable reporting on equivalent terms it has been doubled.

Source: Post-tax revenue models (PTRMs) developed as part of final regulatory decisions, as made by the AER or jurisdictional regulators, and amended to take into account any updates made after the final decision.

3.11.1 Reforms to setting the allowed rate of return

Outcomes from to the AER's approach to setting allowed rates of return were often adversarial before 2018, with many network businesses arguing for a different approach with different parameters. Regulatory decisions were often challenged. These legal battles were long and costly and added to uncertainty for network businesses, consumers and investors.

New legislation introduced in 2018 provided for the AER to make binding rate of return determinations that apply to all network businesses. The AER released its first Rate of Return Instrument (RRI) in December 2018, setting out how it determines the allowed rate of return on capital in revenue determinations.[50]

In setting the allowed rate of return, the AER balances the need for efficient and stable investment against the need to ensure consumers pay no more than necessary for safe and reliable energy. The RRI sets out the approach by which the AER will estimate the rate of return, and includes the return on debt and the return on equity, as well as the value of imputation credits. The RRI is expected to reduce consumer bills by around $30 to $40 a year on average, relative to the approach set out in the AER's 2013 rate of return guideline.[51]

The first regulatory determinations under the RRI were completed in April 2019. The AER is required to review and replace the RRI by December 2022.[52]

49 The AER's *Electricity network performance report* (September 2020) investigates network profitability in order to better understand actual returns as opposed to allowed/forecast returns.

50 The 2018 RRI specifies the return on debt as a formula, using the trailing average portfolio approach. Network businesses not already applying this method must transition to it over a 10-year period.

51 AER, 'AER releases final decision on rate of return for regulated energy networks' [media release], 17 December 2018.

52 The AER is required to set the RRI every 4 years.

3.12 Electricity network investment

Electricity network businesses invest in capital equipment such as poles, wires and other infrastructure needed to transport electricity to customers. Investment drivers vary among networks and depend on a network's age and technology, load characteristics, the demand for new connections, and reliability and safety requirements. Substantial investment is needed to replace old equipment as it wears out or becomes technically obsolete. Other investments may be made to augment (expand) a network's capability in response to changes in electricity demand.

3.12.1 Investment trends

Total investment in the electricity network grew by an average of 8% per year from 2006 until 2012, when it peaked at $14.1 billion (figures 3.10 and 3.11). From 2006 to 2009 network businesses invested 11% more on capital projects than their approved forecasts. This growth was in response to concerns that investment was not keeping pace with the projected growth in electricity demand. More stringent reliability standards imposed by some state governments also spurred higher than forecast investment.

From 2013 lower demand for electricity began to reverse this trend. Many projects were postponed or abandoned when it became clear that earlier projections of sustained demand growth would not eventuate. Further, a shift in government policy towards less stringent reliability obligations on network businesses made some projects redundant, leading to several proposals being scaled back or deferred.

Investment levels further eased from 2015, when AER reforms that protect consumers from funding inefficient network projects began. Plus, a capital expenditure sharing scheme (CESS) offered financial incentives for network businesses to avoid investment above forecast levels (box 3.3). From 2010 to 2018 network businesses underspent on capital projects (compared with approved AER forecasts) by $13.1 billion (18%).

In 2019 network businesses marginally overspent on capital projects (by 1.2%) compared with approved AER forecasts. However, this proved to be an anomaly, as in 2020 network businesses again underspent on capital projects (by 8%).

Box 3.3 Capital expenditure sharing scheme

The Australian Energy Regulator's (AER) capital expenditure sharing scheme (CESS) creates an incentive for network businesses to keep new investment within forecast levels approved in their regulatory determinations. The CESS rewards efficiency savings (spending below forecast) and penalises efficiency losses (spending above forecast).

The CESS allows a network business to retain underspending against the forecast for the duration of the current regulatory period (which may be up to 5 years, depending on when the spending occurs). In the following regulatory period, the network business must pass on 70% of underspends to its customers as lower network charges. The network business retains the remaining 30% of the efficiency savings.

After the regulatory period, the AER conducts an ex-post review of the network's spending. Approved capital expenditure is added to the regulatory asset base (RAB). However, if a network business overspends its capital allowance, and the AER finds the overspending was inefficient, the excess spending may not be added to the RAB. Instead, the business bears the cost by taking a cut in profits. This condition protects consumers from funding inefficient expenditure.

The scheme poses risks that network businesses may inflate their original investment forecasts. To manage this risk, the AER assesses whether proposed investments are efficient at the time of each revenue determination. Another risk is that the scheme may incentivise a network business to earn bonuses by deferring critical investment needed to maintain network safety and reliability. To manage this risk, the CESS is balanced by separate incentives that focus on efficient operating expenditure (box 3.4) and service quality (box 3.5). This balancing of schemes encourages network businesses to make efficient decisions on their mix of expenditure so as to provide reliable services in ways that customers value (section 3.15.1).

3.12.2 Network investment in 2020

In 2020 electricity network businesses invested $5 billion on capital equipment, which was 3% less than in the previous year and 44% less than its peak in 2012. Of this, transmission network businesses spent $918 million, which was 20% higher than in the previous year but 51% lower than its peak in 2009 (figure 3.10).[53]

Distribution network businesses spent $4.1 billion, which was 7% less than in the previous year and 43% less than its peak in 2012 (figure 3.11).

Significant investment in the transmission network has been proposed over the next few years. Actionable projects under AEMO's 2020 ISP are expected to cost over $11 billion from 2022 to 2026.[54]

3.12.3 Current AER investment allowances

Transmission networks are forecast to invest around $4.1 billion in capital projects over their current regulatory periods. The approved forecasts are $403 million (9%) less than the transmission networks invested in their previous periods, where they underspent by a combined $1.9 billion (33%) against forecast (figure 3.10).[55]

Distribution networks are forecast to invest around $19.1 billion in capital projects over their current regulatory periods. The approved forecasts are $1.4 billion (7%) less than the distributors invested in their previous periods where they underspent by $3.3 billion (14%) against forecast (figure 3.11).

In its most recent revenue decisions the AER approved a combined $5.2 billion of forecast investment for the Victorian distributors over the current regulatory period. The majority of forecast investment for the Victorian distributors is to replace or refurbish old assets. The approved forecast is $108 million (2%) less than the Victorian distributors invested in the previous period.

When forming its view on the prudency of a network business' capital expenditure forecast, the AER assesses capital expenditure drivers. The AER does not determine or set which programs or projects a network business should or should not undertake. Once the AER sets a capital expenditure forecast, it is up to the network business to prioritise its investment program. However, the network business must undertake a CBA for new investment projects that meet cost thresholds.

3.12.4 Changing composition of investment

Over the past decade, the composition of network investment has changed markedly. Until recently, significant network investment occurred in growth (augmentation) to support new connections (such as new substations) and expand capacity to cope with forecast rising demand. In 2009, for example, growth projects accounted for 44% of investment (63% for transmission and 35% for distribution).

But weaker than forecast demand for electricity, along with less stringent reliability obligations, led many network owners to postpone or abandon growth-related projects in the following years. In 2020 growth-related investment accounted for only 7% of investment (26% for transmission and 2% for distribution). Investment on growth-driven projects by transmission networks in 2020 was $965 million (82%) less than at its peak in 2009 (figure 3.19). Likewise, investment on growth-driven projects by distribution networks in 2020 was $1.7 billion (96%) less than at its peak in 2012 (figure 3.20).

Since 2009 expenditure allocated to replacing ageing or degraded assets remained fairly constant at $1.5–2.3 billion. However, as a proportion of decreasing total investment, replacement expenditure has risen considerably. Since 2017 capital (replacement) expenditure has accounted for almost 50% of total network investment (63% for transmission and 46% for distribution).

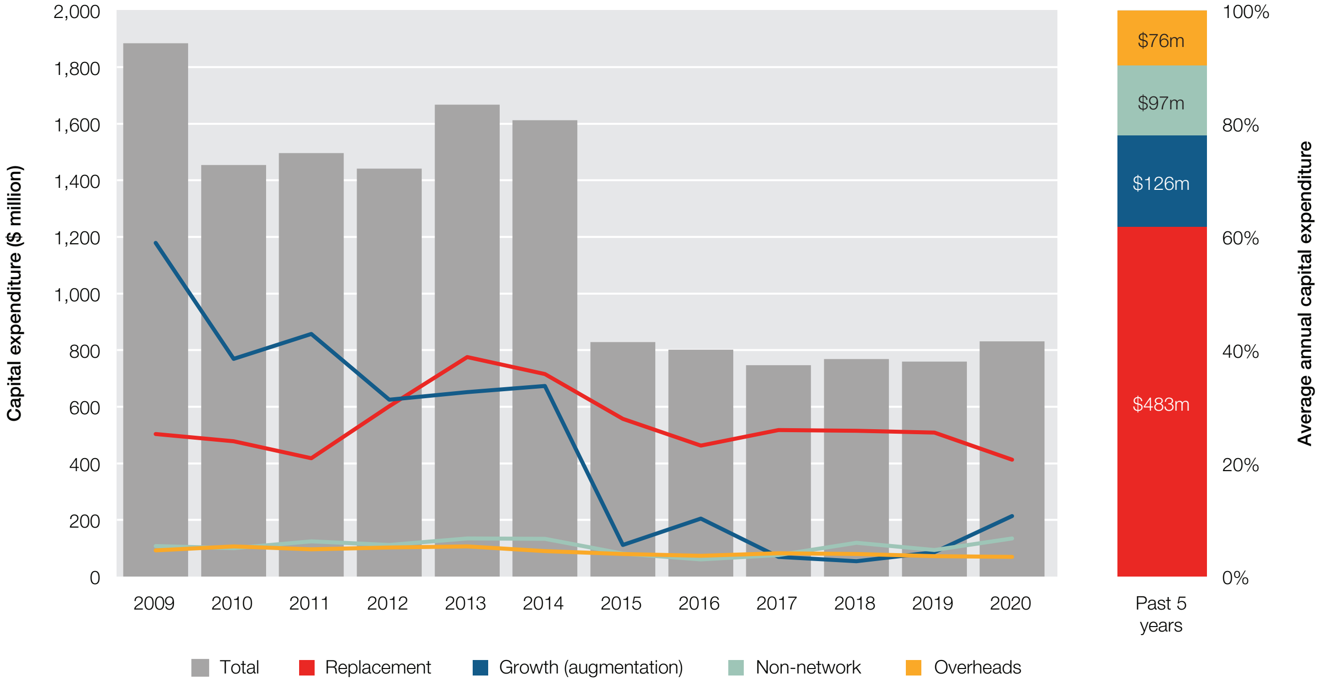
Since 2017 network investment in augmentation has been lower than investment in replacement projects, overheads and non-network assets (for example, ICT, buildings and property, fleet and plant, minor asset tools and equipment, and motor vehicles).

53 Excludes AER decisions on transmission interconnectors.

54 AEMC, *Electricity network economic regulatory framework 2020 review*, 1 October 2020, p 3.

55 The current regulatory period is the period in place at 1 July 2021.

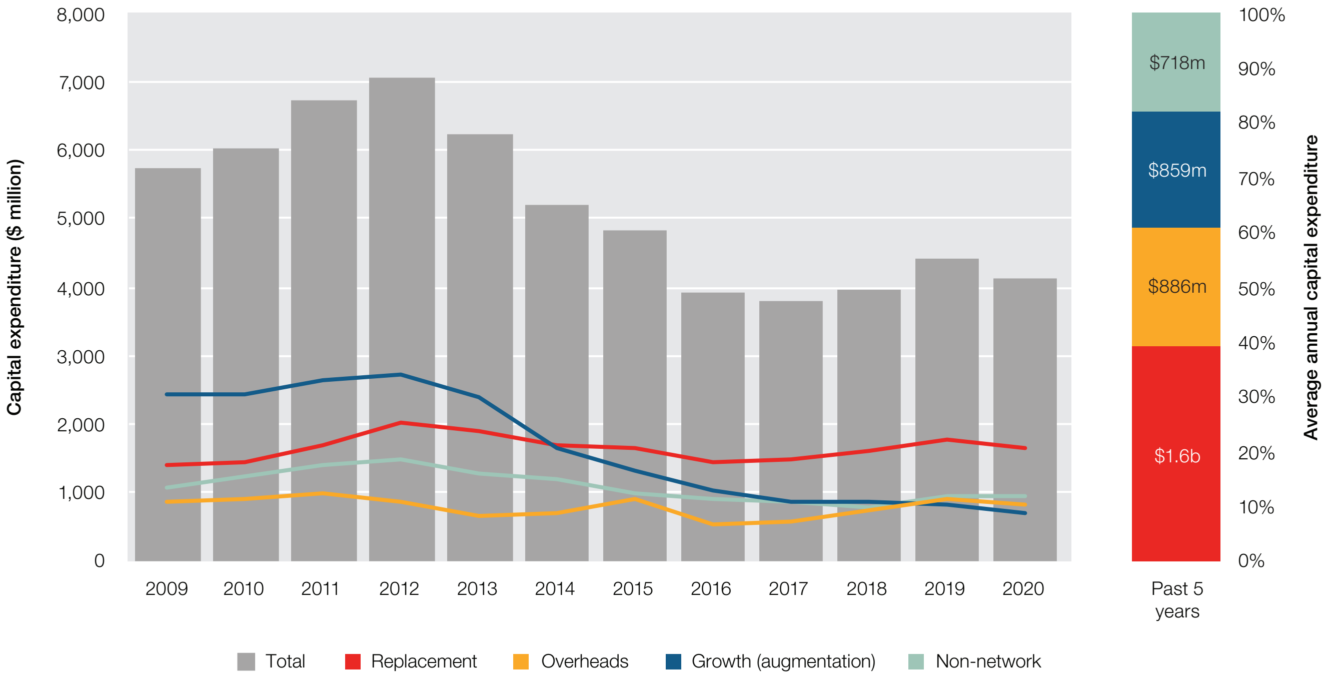
Figure 3.19 Drivers of capital expenditure – electricity transmission networks



Note: Actual outcomes, consumer price index (CPI) adjusted to (forecast) June 2021 dollars. Most network businesses report on a 1 July – 30 June basis. The exception is the Victorian network AusNet Services, which reports on a 1 April – 31 March basis. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018).

Source: Category analysis regulatory information notice (RIN) responses.

Figure 3.20 Drivers of capital expenditure – electricity distribution networks



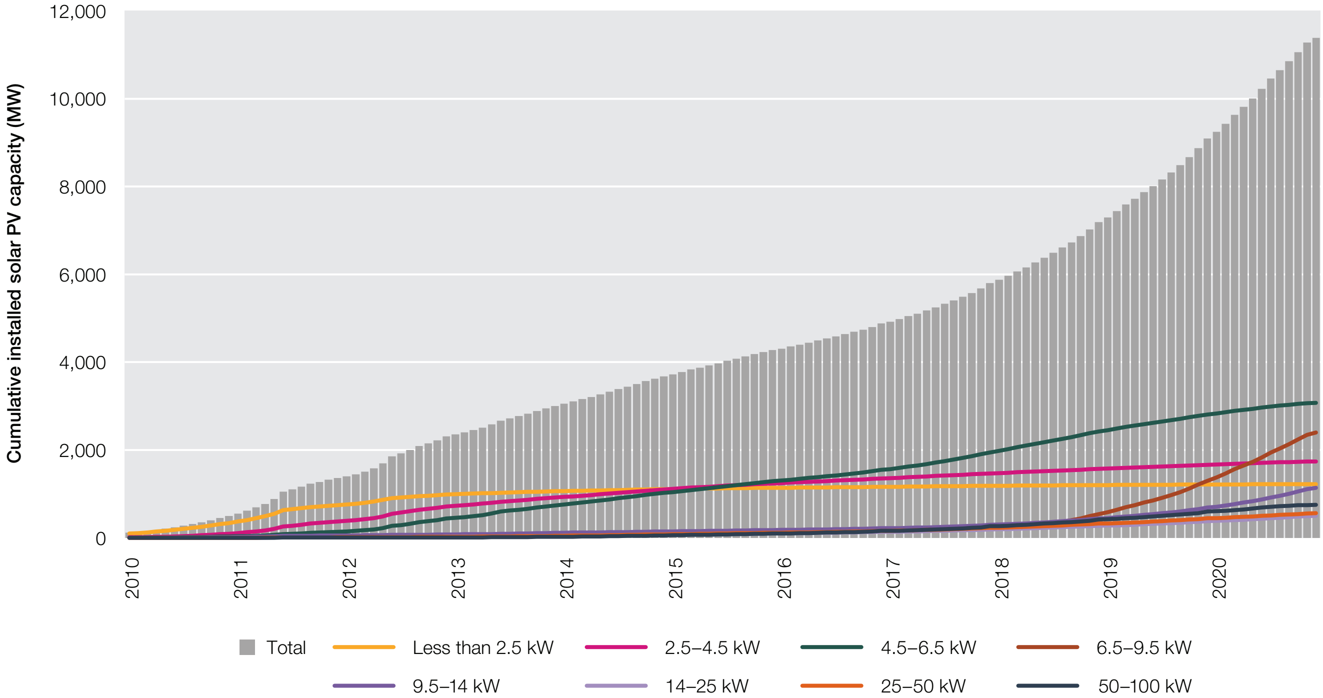
Note: Actual outcomes, consumer price index (CPI) adjusted to (forecast) June 2021 dollars. Most network businesses report on a 1 July – 30 June basis. The exceptions are Victorian networks, which report on a 1 January – 31 December basis. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018).

Source: Category analysis regulatory information notice (RIN) responses.

3.12.5 Valuing distributed energy resources

The uptake of rooftop solar PV systems has grown exponentially in the past decade (figure 3.19). As a result of this rapid growth, DER integration now presents a significant, emerging area of expenditure.

Figure 3.21 Cumulative installed small scale solar photovoltaic capacity



kW: kilowatts; MW: megawatts; PV: photovoltaic.

Note: Includes installations of PV systems up to 100 kW in size. Data covers all of Australia.

Source: AER analysis of postcode data from the Australian PV Institute, collected on 24 February 2021.

In November 2109 the AER began developing guidance around assessing proposed DER integration expenditure. As part of this process, the AER sought stakeholder views on the current and predicted effects DER is having on networks and whether its current set of expenditure assessment tools are fit for purpose.

In November 2020 the AER released a report (by the CSIRO and Cutler Merz) on potential methodologies for determining the value of DER (VaDER).[56] The preferred methodology compares the total electricity system costs from increasing hosting capacity with the total electricity system costs of not doing so. Electricity system costs include the investment costs, operational costs and costs on the system from environmental outcomes of large scale generation, essential system services, network assets and DER installed by customers.

The findings and recommendations of the VaDER report will be reviewed and considered as part of the AER's DER integration expenditure guideline, which is expected to be completed in 2021.

The AEMC, in its *Electricity network economic regulatory framework 2020 review*, noted that the central roles of networks in a high DER future are likely to remain the same as today. Network service providers will continue to be responsible for transporting electricity and providing a safe, secure and reliable supply of electricity as a monopoly service provider. However, how they undertake this role could differ in a number of key respects. In particular, how the electricity distribution network is operated and the services provided by distributors could change.

A high DER environment could mean that distributors need to alter aspects of their operation, from transporting electricity one-way to being platforms for multiple services, facilitating electricity flows in multiple directions and enabling efficient access for DER so that they can provide the greatest benefits to the system as a whole. This change is likely to have implications for some features of the current regulatory framework.[57]

56 CSIRO and CutlerMerz, *Value of distributed energy resources: methodology study – final report*, October 2020.

57 AEMC, *Electricity network economic regulatory framework 2020 review*, 1 October 2020.

3.12.6 Regulatory tests for efficient investment

The AER assesses a network business's efficient investment requirements every 5 years as part of the regulatory process, but it does not approve individual projects. Instead, it administers a cost–benefit test called the regulatory investment test (RIT). The National Electricity Rules require a network business to apply the RIT for projects that have an estimated capital cost greater than $6 million.

A network business must evaluate credible alternatives to network investment (such as generation investment or demand response) that might address the identified need at lower cost. The business should select whatever option delivers the highest net economic benefit, considering any relevant legislative obligations. This assessment requires public consultation.

There are separate tests for transmission networks (RIT-T) and distribution networks (RIT-D). The AER publishes guidelines on how to apply the tests and monitors businesses' compliance with the tests. It also resolves disputes over whether a network business has properly applied a test. Civil penalties apply to network businesses that do not comply with some of the RIT requirements (including the required consultation procedures).

In August 2020 the AER published its CBA guidelines[58] (for transmission projects initiated by AEMO's ISP) and updated the RIT-T application guidelines (for other projects).[59] The CBA guidelines are to be used by AEMO in identifying an optimal development path that promotes the efficient development of the power system, based on a quantitative assessment of the costs and benefits of various options across a range of scenarios. The CBA guidelines also apply to RIT-Ts for actionable ISP projects.[60]

Until 2017 the regulatory tests applied to only growth investment, which until 2014 was the biggest component of network investment. But, with replacement expenditure overtaking growth investment on most networks (section 3.12.4), the test now applies to replacement projects too. Other revisions were made to the test to ensure it adequately considers system security, emissions reduction goals, and low probability events that would have a high impact.

In August 2020 the AER published guidelines to make AEMO's ISP actionable (section 3.6). The guidelines are part of a broader reform to streamline the transmission planning process while retaining rigorous CBA. While the new rules were effective from 1 July 2020, the new guidelines will come into effect through the 2022 ISP.[61]

Under the new rules, the ISP provides a coordinated whole-of-system plan for the efficient development of the power system that meets power system needs in the long term interests of consumers. The ISP 'actions' key projects by triggering RIT-T applications (section 3.12.7). Under the new rules, the ISP is subject to additional governance arrangements through binding CBA guidelines and forecasting best practice guidelines. The RIT-T instrument and associated application guidelines have also been updated to be consistent with the new planning process. In line with the new rules, the guidelines seek to provide AEMO, in developing the ISP, with flexibility in how it identifies the optimal pathway for the NEM.

The distinction between ISP and non-ISP projects was introduced to avoid duplication of project assessments where analysis has already occurred in developing the ISP. The current transmission planning framework will apply largely unchanged for non-ISP projects, such as asset replacements.

Significant investment in the transmission network is forecast over the next few years. Between 2022 and 2026 the modelled cost of actionable ISP projects under the 2020 ISP is around $4.8 billion, with an additional $6.7 billion worth of projects categorised as actionable ISP projects with decision rules.[62] [63]

58 AER, *Cost benefit analysis guidelines*, August 2020.

59 AER, *Application guidelines – regulatory investment test for transmission*, August 2020.

60 Actionable ISP projects are identified in an ISP and trigger RIT–T applications for these projects. Under the RIT–T instrument, RIT–T proponents must identify the credible option that maximises the present value of net economic benefit to all those who produce, consume and transport electricity in the market.

61 AER, *Final decision – guidelines to make the Integrated System Plan actionable*, August 2020.

62 A 'decision rule' refers to a set of conditions or triggers that, if they occurred, may justify a project proceeding.

63 AEMC, *Electricity network economic regulatory framework 2020 review*, 1 October 2020, p 21.

3.12.7 Recent regulatory test activity

TransGrid is undertaking a RIT-T for the HumeLink project to reinforce the transmission network in southern NSW. TransGrid published a project assessment draft report for the project in January 2020[64] and expects to finalise the RIT-T by publishing a project assessment conclusions report in August 2021. If the project is found to have positive net market benefits, TransGrid may then apply to the AER for a contingent project assessment. There are 2 pathways for such an application. The first involves the contingent project trigger events approved in the AER's 2018 to 2023 revenue determination for TransGrid. The second involves the trigger events set out in the National Electricity Rules relating to actionable ISP projects.

TransGrid is also in the final stages of a RIT-T process investigating a new grid-scale storage facility to leverage the significant wind and solar generation around Broken Hill and ensure a more reliable supply. However, as at April 2021 TransGrid had put the project on hold as it sought confirmation from the AER about its approach to estimating non-network option costs.

TasNetworks is undertaking a RIT-T for the Marinus Link project, which is a proposed 1,500 megawatt (MW) capacity undersea electricity connection from Tasmania to Victoria. The increased transmission capacity may be delivered in 2 separate 750 MW developments and will be supported by transmission network developments in north west Tasmania.

In March 2020 the Victorian Government introduced legislation to fast-track priority energy projects such as grid-scale batteries and electricity transmission upgrades. The legislation allows the government – in consultation with AEMO – to bypass elements of the RIT process.[65] In November 2020 the Victorian Government directed AEMO to sign a contract with renewable energy specialist Neoen to build one of the world's largest lithium-ion batteries to boost reliability, drive down electricity prices, and support the state's transition to renewable energy.[66]

3.12.8 Annual planning reports

Network businesses must publish annual planning reports identifying new investment that they consider necessary to efficiently deliver network services. The reports identify emerging network pressure points and options to alleviate those constraints. In making this information publicly available, the reports help non-network providers identify and propose solutions to address network needs.

The AER publishes guidelines and templates to ensure the reports provide practical and consistent information to stakeholders.

3.12.9 Demand management

Distribution network businesses have options to manage demand on their networks to reduce, delay or avoid the need to install or upgrade expensive network assets. Managing demand in this way can minimise network charges. It can also increase the reliability of supply and reduce wholesale electricity costs.

The AER offers incentives for distributors to find lower cost alternatives to new investment to help cope with changing demands on the network and manage system constraints. The *demand management incentive scheme* (DMIS) incentivises distributors to undertake efficient expenditure on alternatives such as small scale generation and demand response contracts with large network customers (or third party electricity aggregators) to time their electricity use to reduce network constraints. The scheme gives distributors an incentive of up to 50% of their expected demand management costs for projects that bring a net benefit across the electricity market.

Complementing this scheme, the AER offers a *demand management innovation allowance* (DMIA). This is a research and development fund to help distributors develop innovative ways to deliver ongoing reductions in demand or peak demand for network services. An objective of the innovation allowance is to enhance industry knowledge of practical approaches to demand management. Published annual activity reports set out details of projects undertaken by each business. The AER assesses expenditure claims to ensure distribution businesses appropriately use their funding. Any underspent or unapproved spending is returned to customers through revenue adjustments. Over the 2 years to 30 June 2020[67] almost $9.5 million of innovation allowance funding was approved (figure 3.22).

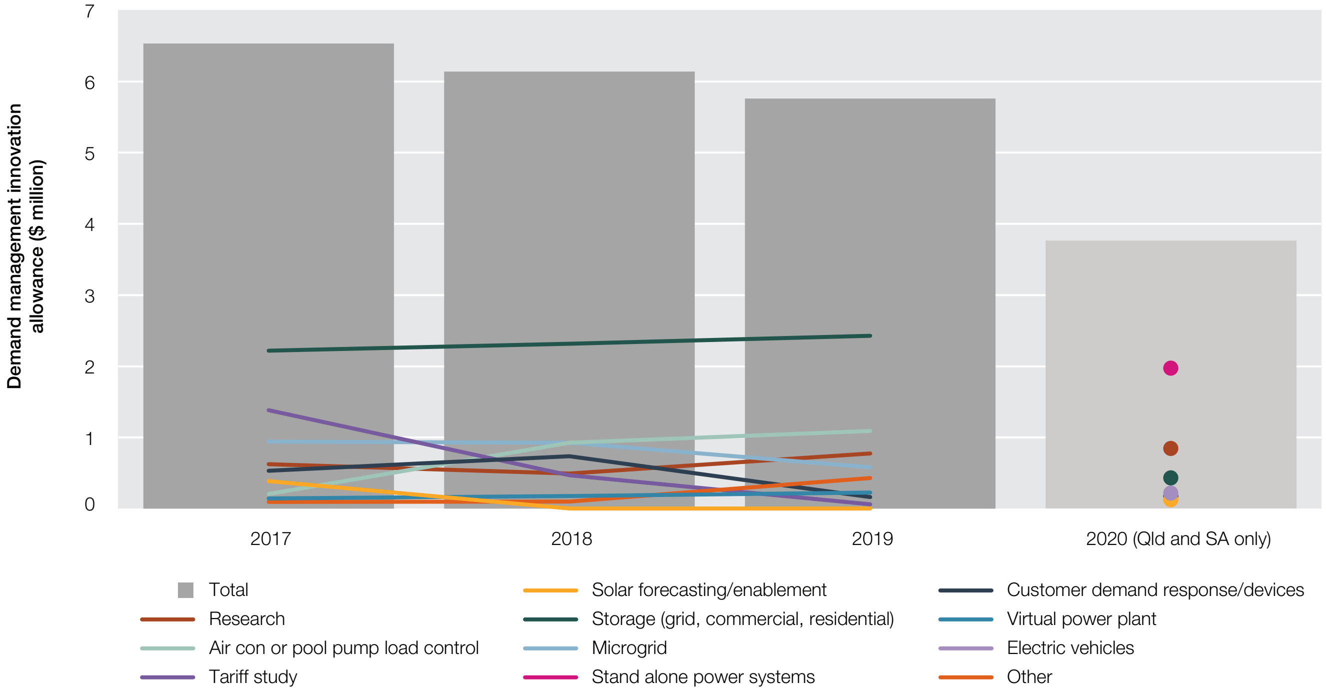
64 TransGrid, *Reinforcing the NSW Southern Shared Network to increase transfer capacity to demand centres (HumeLink)*, 10 January 2020.

65 The Hon Lily D'Ambrosio MP (Victorian Minister for Energy, Environment and Climate Change), 'Victoria acts to secure a more reliable energy system' [media release], 18 February 2020.

66 The Hon Lily D'Ambrosio MP (Victorian Minister for Energy, Environment and Climate Change), 'Victoria to build southern hemisphere's biggest battery' [media release], 5 November 2020.

67 At the time of publishing, the AER had not assessed DMIA claims by Victorian distributors for expenditure incurred in 2020 or claims by the NSW, Tasmanian, ACT, and Northern Territory distributors for 2019–20.

Figure 3.22 Funding of demand management innovations – electricity distribution networks



Note: Victorian distribution network businesses report on a 1 January – 31 December basis. All other distribution network businesses report on a 1 July – 30 June basis. The data show the outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018.

Source: AER, *Approval of demand management innovation allowance (DMIA) expenditures by Victorian electricity distributors in 2019*, November 2020; AER, *Approval of demand management innovation allowance (DMIA) expenditures by distributors*, September 2019; AER, Approval of demand management innovation allowance (DMIA) expenditures by non-Victorian electricity distributors in 2018–19, May 2020.

In 2019–20 the AER approved more than $1.7 million for Ergon Energy's (Queensland) West Leichhardt single-wire earth return project. This project involved the trial of 2 larger scale SAPS as an alternative to grid supply. The outcome of the trial will enable the substitution of costly network components with alternative supply arrangements that provide improved power quality and reliability.

Over 2018 and 2019 the AER approved almost $950,000 for Powercor's (Victoria) Energy Partner program. The demand response program allowed the distributor to directly control its consumers' air conditioners to coordinate the temperature set points for a short time over the 2018–19 and 2019–20 summer periods. Similarly Endeavour Energy claimed around $450,000 over 2017–18 and 2018–19 for its air conditioner control trial using a demand response enabling device.

In 2018–19 the AER approved more than $700,000 for Endeavour Energy's (NSW) Grid Connected Battery Energy Storage System trial. Battery storage can provide several network benefits, primarily peak load lopping, voltage management, load balancing and reliability improvement which may reduce or defer investment decisions. The project allowed Endeavour Energy to identify the functional requirements of the battery energy storage systems (BESS) for connection and operation on its network.

Over 2018 and 2019 the AER approved more than $470,000 for AusNet Services' (Victoria) Mooroolbark Community Mini Grid Trial. The microgrid project was designed to test a future role for AusNet Services' distribution network in an environment of widespread DER that can be coordinated to deliver services and value to both customers and the network. The project encompassed the design, build and operation of an 18-house mini grid in a suburban community that will be monitored and controlled by a cloud-based mini grid control system that can implement distribution system operator control functions and algorithms.

The project also tested the performance of DER systems in providing backup supply to individual customers in case of network outage; and the ability for the mini grid as a whole to operate as an island (grid-separated mode) for short periods of time.

The AER approved almost $400,000 for Energex's (Queensland) Expanded Network Visibility Initiative (ENVI). The purpose of Energex's ENVI research was to build on the work of the Solar Enablement Initiative and LV State Estimation project – former DMIA projects which demonstrated state estimation (use of network data to assess real-time system performance and operational conditions) in operation on Energex's network. ENVI will develop the tools and systems to enable the scale-up of state estimation across Energy and Ergon Energy Network medium and low voltage feeders.

Some successful DMIA trials are being implemented as business as usual activity within their networks. Examples of such projects are:

- AusNet Services' grid energy storage system trial, which was upgraded with various functional enhancements and reliability improvements to enable it to be used to improve power supply reliability in the Mallacoota region
- United Energy's voluntary residential demand response trial (Summer Saver program), which targets network areas with highly utilised distribution transformers and low voltage circuits at high risk of overloading during summer months. Customers participating in the program are offered financial rewards to reduce electricity use when asked by United Energy. The trail period for the program ended in 2019 and United Energy has since implemented it as ongoing expenditure under the new DMIS. United Energy reported in November 2019 that the program had led to the deferral of more than $10 million in capital expenditure.[68]

The AER publishes biannual DMIA reports on its website.[69]

3.13 Electricity network operating costs

Electricity network businesses incur operating and maintenance costs that absorb around 35% of their annual revenue (figure 3.5). As part of its 5-year regulatory review for each network business, the AER sets an allowance for the businesses to recover the efficient costs of supplying power to customers. The allowance accounts for forecasts of electricity demand, productivity improvements, changes in input prices, and changes in the regulatory environment. In the first instance, the AER is guided by the forecasts in each business's regulatory proposal. If the AER considers those forecasts are unreasonable then it may replace them with its own forecasts.

Alongside this assessment, the AER runs an efficiency benefit sharing scheme that encourages network businesses to explore opportunities to lower their operating costs (box 3.4).

Box 3.4 Efficiency benefit sharing scheme

The AER runs an efficiency benefit sharing scheme (EBSS) that aims to share the benefits of efficiency gains in operating expenditure between network businesses and their customers. Efficiency gains occur if a network business spends less on operating and maintenance than forecast in its regulatory determination. Conversely, an efficiency loss occurs if the business spends more than forecast.

The EBSS allows a network business to keep the benefit (or incur the cost) if its actual operating expenditure is lower (higher) than forecast in each year of a regulatory period. It effectively allows a network business to retain efficiency gains (or bear the cost of efficiency losses) for the duration of the existing regulatory period, which may be up to 5 years. In the longer term, network businesses can retain 30% of efficiency savings but must pass on the remaining 70% (as lower network charges) to customers.

The EBSS provides network businesses with the same reward for underspending (or penalty for overspending) in each year of the regulatory period. Its incentives align with those in the capital expenditure sharing scheme (box 3.3) – that is, the 30:70 split between the network business and its customers applies in both schemes. The EBSS incentives also balance against those of the service target performance incentive scheme (box 3.5) to encourage network businesses to make efficient holistic choices between capital and operating expenditure in meeting reliability and other targets.

68 United Energy, *Re: Application for the revised DMIS to start from 1 November 2019*, 7 June 2019.

69 AER, *Demand management innovation allowance (DMIA) assessment 2019–20* (www.aer.gov.au/networks-pipelines/compliance).

3.13.1 Operating cost trends

Total operating costs for the electricity network businesses grew by an average of 5% per year from 2006 until 2012, when it peaked at $4.2 billion (figures 3.10 and 3.11).

Operating costs for transmission networks peaked at $654 million in 2016 but have since fallen by an average of 3% per year. For distribution networks operating costs peaked at $3.6 billion in 2012 and have also since fallen by an average 3% per year. The reduction in operating costs is largely attributed to network businesses implementing more efficient operating practices.

While distribution networks reduced operating expenditure between 2015 and 2019, the reduction was less marked than it was for capital expenditure. Operating and maintenance costs are largely driven by the number of customers that the network business is supplying and the length of line.

A number of network businesses implemented efficiencies in managing their operating costs from 2015, when the AER widened its use of benchmarking to identify operating inefficiencies in some networks. The AER also introduced incentives for network businesses to spend efficiently.

Not all costs are controllable by network businesses, however. Factors such as reporting obligations, changes to connections charging arrangements and Power of Choice requirements can also impact costs.

3.13.2 Network operating costs in 2020

In 2020 electricity network businesses spent a total of $3.5 billion on operating and maintaining the networks. Of this, transmission network businesses spent $580 million, which was 0.9% less than in the previous year and 11% less than its peak in 2016 (figure 3.10).[70]

Distribution network businesses spent $2.9 billion, which was 5% less than in the previous year and 20% less than its peak in 2012 (figure 3.11).

3.13.3 Current AER operating allowances

Transmission networks are forecast to spend around $3.1 billion and distribution around $16.3 billion on operating costs over their current regulatory periods. The approved forecasts are comparable to the actual operating costs incurred in their previous periods, where transmission networks underspent by $178 million (6%) and the distributors overspent marginally (0.4%) against forecast (figures 3.10 and 3.11).[71]

In its most recent revenue decisions the AER approved a combined $4.4 billion of forecast operating expenditure for the Victorian distributors over the current period. The approved forecast is $744 million (20%) more than the Victorian distributors spent on operating costs in the previous period, where they underspent by $601 million (20%) against forecast (figure 3.8).

Distributors in Victoria, South Australia, Tasmania and the ACT are forecast to increase their operating expenditure in their current periods while those in Queensland, NSW and the Northern Territory are forecast to decrease their operating expenditure.

The increase in operating expenditure allowances for the privately owned Victorian and South Australian distributors was largely because they had implement efficiencies ahead of many of the other network businesses (section 3.13). In doing so, they made their levels of expenditure relatively lean and left less scope for improvement.[72]

A combination of AER incentives and network-driven efficiencies has contributed to significant cost reductions, especially among government-owned (or recently privatised) distribution network businesses in NSW, Queensland and Tasmania.[73] Those savings – from the uptake of technology solutions and from changes to management practices, for example – are now locked in for customers.

70 Excludes AER decisions on transmission interconnectors.

71 The current regulatory period is the period in place at 1 July 2021.

72 AER, *Annual benchmarking report, electricity distribution network service providers*, November 2019.

73 As an example, the AER noted TasNetworks (Tasmania) appears to be responding to incentives in the regulatory framework to better manage its costs.

3.14 Electricity network productivity

The AER benchmarks the relative efficiency of electricity network businesses to enable comparisons over time. This benchmarking assesses how effectively each network business uses its inputs (assets and operating expenditure) to produce outputs (such as meeting maximum electricity demand, electricity delivered, reliability of supply, customer numbers and circuit line length).[74] Productivity will rise if the network's outputs rise faster than the resources used to maintain, replace and augment energy networks. While benchmarking provides a useful tool for comparing network performance, some productivity drivers – for example, reliability standards set by government bodies – are beyond the control of network businesses. More generally, benchmarking may not fully account for differences in operating environment, such as legislative or regulatory obligations, climate and geography.[75]

The AER, when forecasting a network's efficient operating costs, estimates the productivity improvements that an efficient network should be able to make in providing services. In March 2019 the AER published its decision to apply an annual operating expenditure productivity growth rate of 0.5% when reviewing the operating expenditure forecasts of distribution network businesses.

This productivity growth rate has been applied in all regulatory determinations since March 2019 for electricity distribution businesses.[76]

3.14.1 Network productivity

Productivity for most networks in the NEM declined from 2006 to 2015, especially in the distribution sector. This outcome was largely driven by:

- rising capital investment (inputs) at a time when electricity demand (output) had plateaued or was declining in Australia
- for most networks, rising operating costs and declining reliability
- for distribution networks, rising expenditure to meet stricter reliability standards in Queensland and NSW; and regulatory changes following bushfires in Victoria.

The privately operated networks in South Australia and Victoria, however, consistently recorded higher productivity scores over this period than those of government-owned or recently privatised networks in other regions.

3.14.2 Transmission network productivity

Electricity transmission productivity declined by 1.8% over 2019 following 2 consecutive years of improvement. This result was driven by a significant worsening in productivity in the AusNet Services (Victoria) and TasNetworks (Tasmania). AusNet Services' decline in productivity growth was largely driven by a single outage event that worsened its reliability performance. TasNetworks remained the most productive transmission network in 2019 despite the decline in its productivity (figure 3.23).

The decrease in productivity in 2019 for AusNet Services and TasNetworks was primarily driven by lower network reliability. However, growth in transformer capacity and operating expenditure were also contributing factors. The decline in electricity transmission productivity was consistent with the decline across both the overall economy and the utility sector (electricity, gas, water and waste services) over the same period. The improvement in transmission productivity over the 2 years prior was be linked to reductions in operating expenditure.

Viewed over a longer timeframe, the productivity of transmission networks has declined at an average rate of 1.1% per year over the 14 years to 2019. Capital partial factor productivity[77] declined at an average rate of 1.8% per year compared to average operating expenditure efficiency growth[78] of 0.7% per year over the same period.

74 The AER applies a multilateral total factor productivity approach to benchmark network businesses.

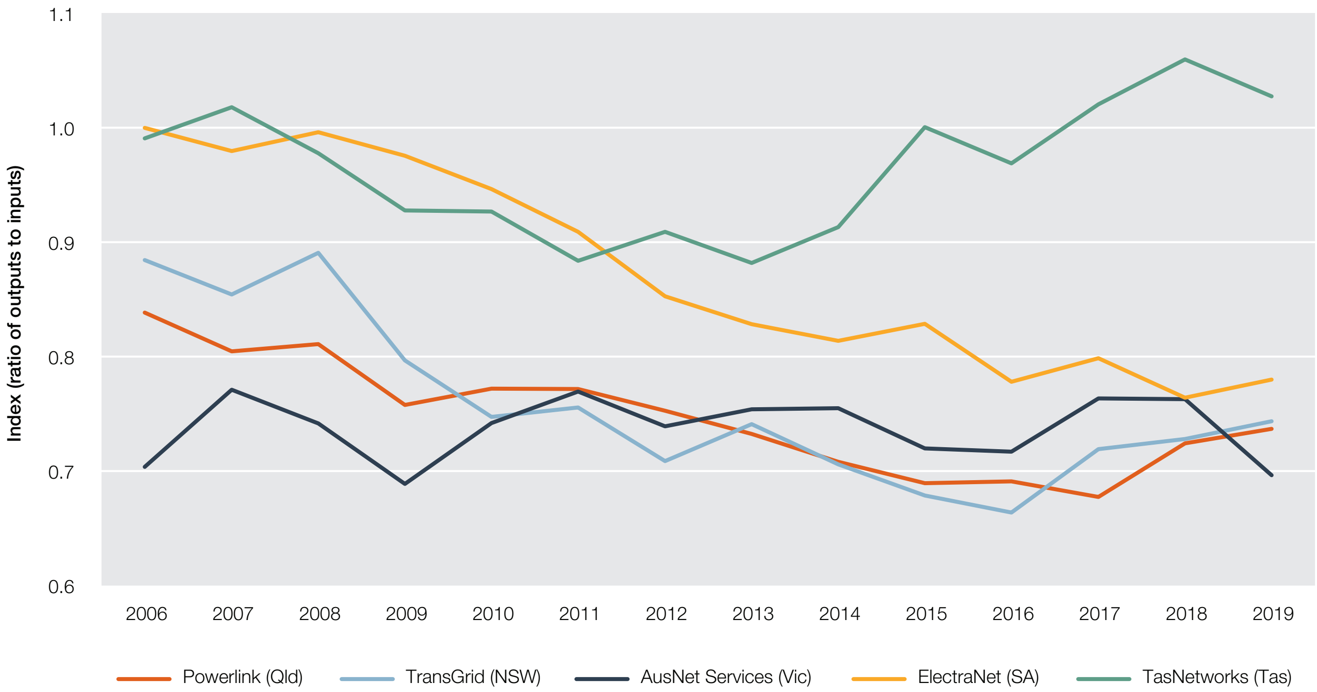
75 AER, *Annual benchmarking report, electricity distribution network service providers*, November 2019, pp 21–27.

76 AER, *Forecasting productivity growth for electricity distributors*, 8 March 2019.

77 Output per unit of capital expenditure.

78 Output per unit of operating expenditure.

Figure 3.23 Productivity – electricity transmission networks



Note: Index of multilateral total factor productivity relative to the 2006 performance of ElectraNet (South Australia). The transmission and distribution indexes cannot be directly compared. Most network businesses report on a 1 July – 30 June basis. The exception is AusNet Services, which reports on a 1 April – 31 March basis. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018).

Source: AER annual benchmarking reports for electricity transmission networks.

3.14.3 Distribution network productivity

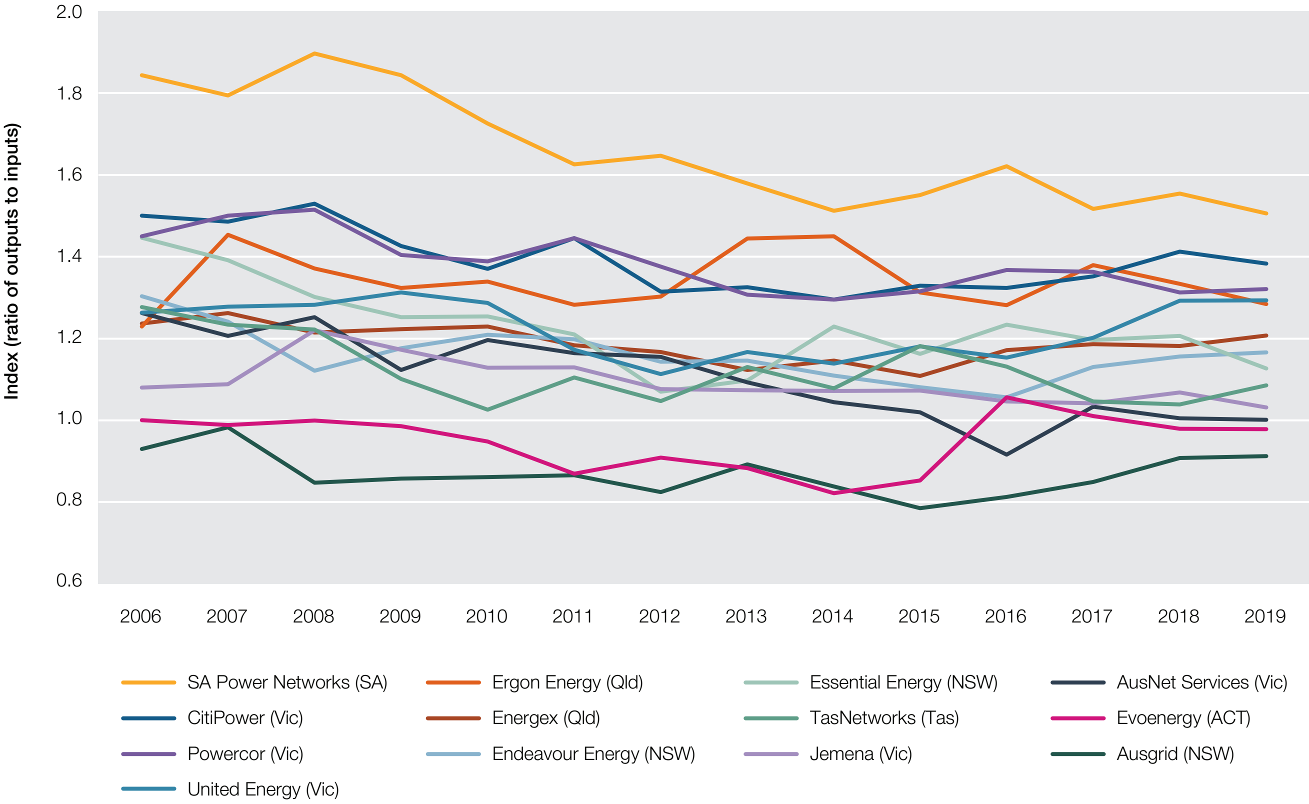
Electricity distribution productivity decreased by 1% in 2019 following 3 years of consecutive improvement. However, productivity outcomes varied across networks. As with the transmission networks the decrease was primarily due to lower network reliability and was consistent with lower productivity growth for the overall economy and the utility sector over the same period.

Across distribution network businesses in 2019:

- 7 distributors were less productive than in the previous year
- Essential Energy (NSW) and Ergon Energy experienced the largest decreases in productivity (6.8% and 3.8% respectively)
- TasNetworks (Tasmania) and Energex (Queensland) showed the most significant increases in productivity (4.4% and 2.1% respectively).

Since 2006 there has been some convergence in the productivity levels of highest and lowest performing distributors (figure 3.24). Generally speaking, less productive distributors have improved their productivity since 2012. In particular, Ausgrid (NSW) and Evoenergy (ACT) have increased their overall productivity, largely as a result of improvements in operating efficiency. Several middle-ranked distributors such as United Energy (Victoria), Endeavour Energy (NSW) and Energex (Queensland), have also improved their productivity and are now closer to the top-ranked distributors. Further, while Powercor (Victoria), SA Power Networks (South Australia) and CitiPower (Victoria) have consistently been the most productive distributors in the NEM they have experienced a gradual decline in productivity. As a result, their productivity is now much more closely aligned with the middle-ranked distributors.

Figure 3.24 Productivity – electricity distribution networks



Note: Index of multilateral total factor productivity relative to the 2006 performance of Evoenergy (ACT). The transmission and distribution indexes cannot be directly compared. Most network businesses report on a 1 July – 30 June basis. The exceptions are the Victorian networks which report on a 1 January – 31 December basis. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018).

Source: AER annual benchmarking reports for electricity distribution networks.

3.14.4 Investment disconnect

For several years from 2006, a key contributor to poor network productivity was sustained growth in investment at a time when electricity demand was falling (figures 3.25 and 3.26). Network investment rose every year from 2006 to 2012, despite the amount of total electricity delivered peaking in 2009 for transmission and in 2010 for distribution. The earlier decline in total energy delivered by transmission networks was due to the loss of some industrial loads.

Two key factors drove the mismatch between electricity usage and new investment:

› a growing divide between maximum network demand and total electricity generated
› over-forecasting of maximum demand.

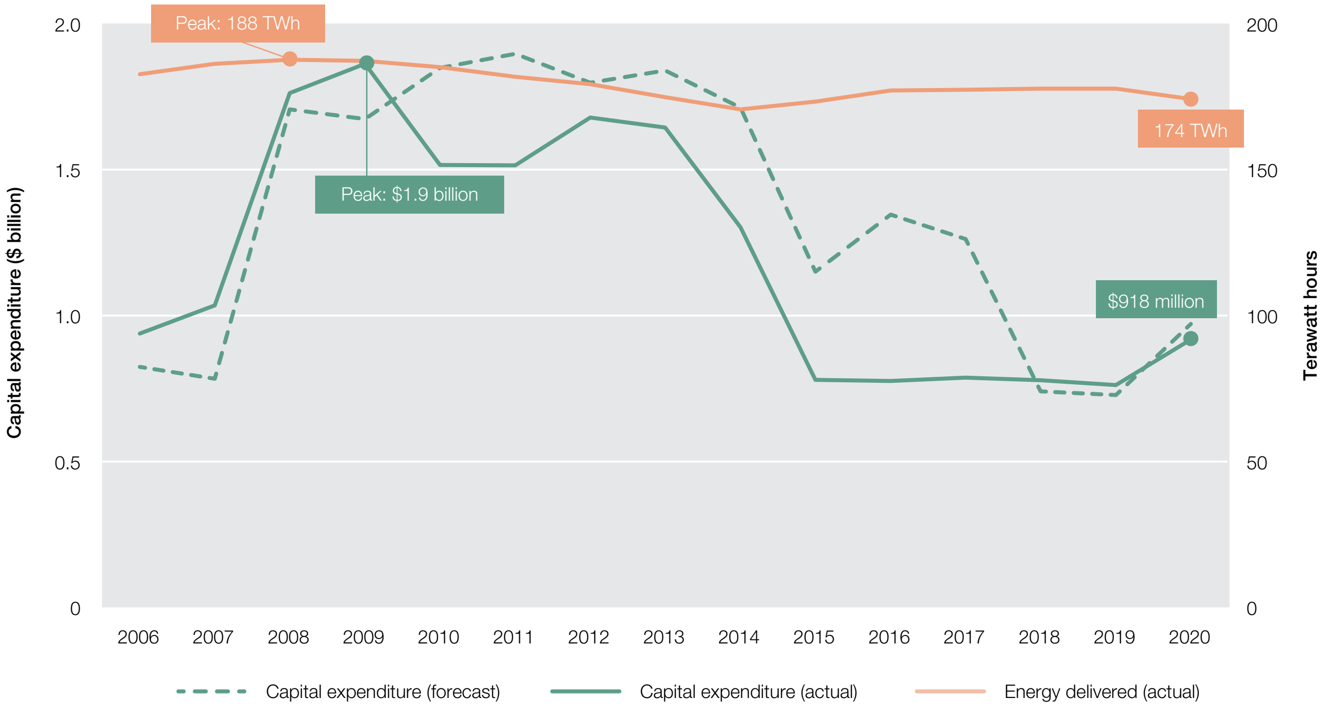
The level of productivity depends on how effectively a network business uses inputs[79] to deliver a range of outputs.[80] Capital expenditure is largely driven by the need to meet the maximum level of demand on the network. But, since 2006, maximum demand has grown, while average (non-maximum) demand has declined (figure 3.27).

As network demand becomes 'peakier', assets installed to meet demand at peak times – which occur for approximately 0.01% of the year – may sit idle (or be underused) for longer periods. This outcome is reflected in poor usage rates, which weaken productivity. The number of customers connected to the distribution network has steadily increased by 1.5% per year since 2006 and has outpaced growth in both maximum and average demand.

79 Types of physical capital assets transmission networks invest in to replace, upgrade or expand their networks are transformers and other capital; overhead lines; and underground cables. Operatingexpenditure is an example of an intangible input.

80 Outputs include circuit line length; ratcheted maximum demand; energy delivered; customer numbers; and network reliability.

Figure 3.25 Investment and energy delivered – electricity transmission networks

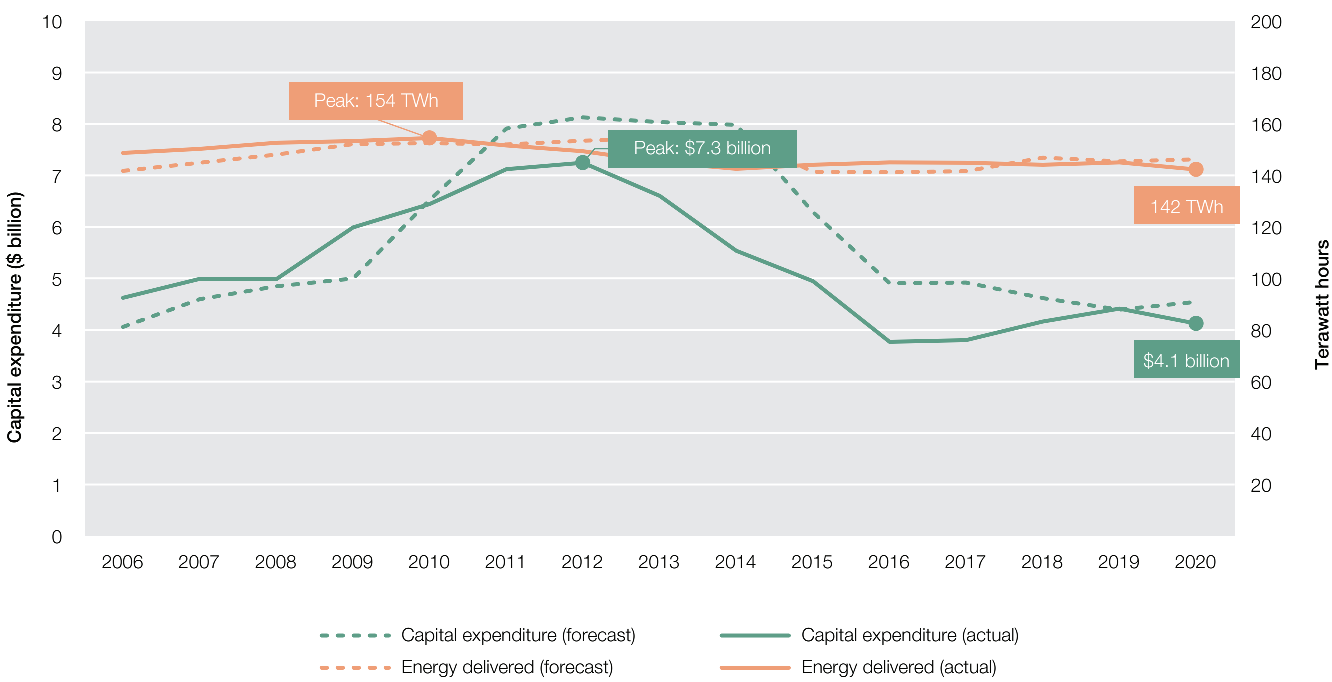


TWh: terawatt hours.

Note: Most network businesses report on a 1 July – 30 June basis. The exceptions are Victorian networks: AusNet Services (transmission) reports on a 1 April – 31 March basis. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018). Data exclude energy delivered to other transmission networks via interconnectors. Physical losses and deliveries to industrial customers directly from the transmission network account for some differences between transmission and distribution loads.

Source: Annual benchmarking regulatory information notice (RIN) responses.

Figure 3.26 Investment and energy delivered – electricity distribution networks

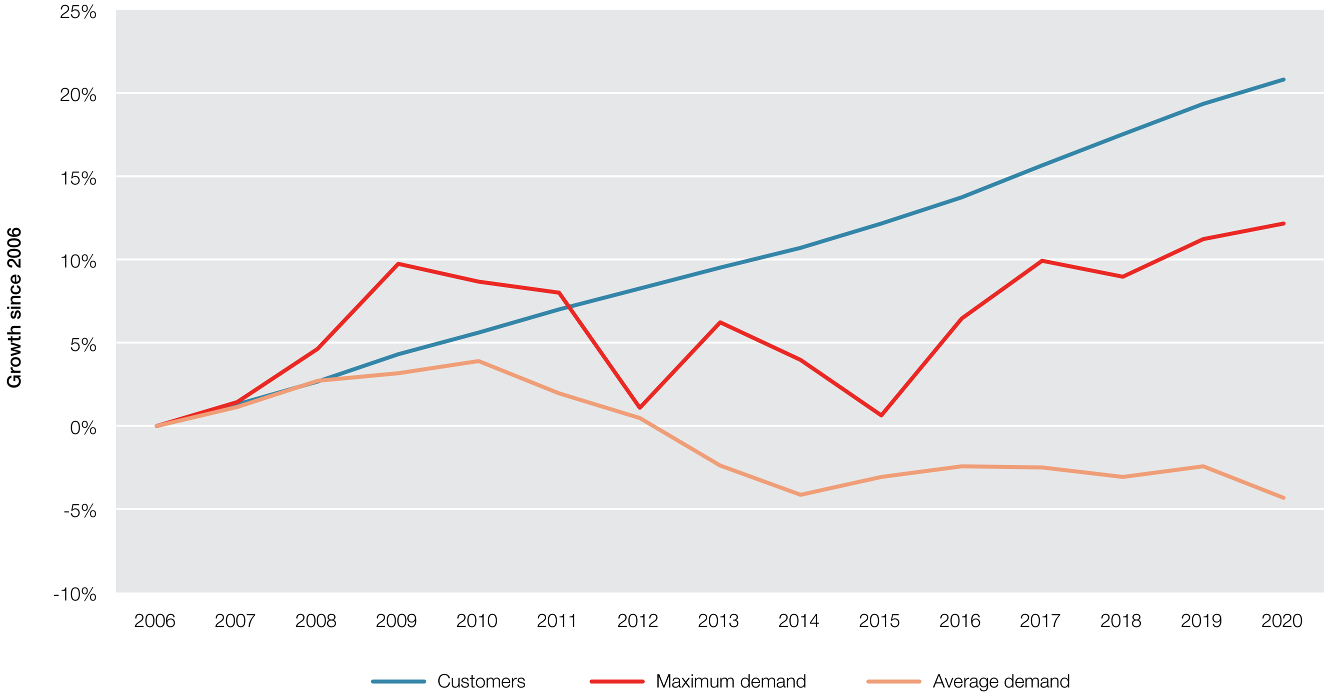


TWh: terawatt hours.

Note: Most network businesses report on a 1 July – 30 June basis. The exceptions are Victorian networks, which report on a 1 January – 31 December basis. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018). Data exclude energy delivered to other transmission networks via interconnectors. Physical losses and deliveries to industrial customers directly from the transmission network account for some differences between transmission and distribution loads.

Source: Annual benchmarking regulatory information notice (RIN) responses.

Figure 3.27 Growth in customers and demand – electricity distribution networks



Note: Maximum demand is the network sum of non-coincident, summated raw system maximum demand (megawatts). Non-maximum demand is the total energy delivered (gigawatt hours) for the year excluding the energy delivered at the time of maximum demand divided by hours in the year minus one.

Source: Economic benchmarking regulatory information notice (RIN) responses.

In 2020 the average residential customer consumed 21% less energy from the distribution network than in 2006. Declining energy use by residential customers is evident among all distributors, with 11 of the 14 distributors reporting declines of more than 15% since 2006. Average consumption by business customers has also fallen over that period but to a lesser extent.

The overall decline in energy consumption from the grid can be attributed to multiple factors, including solar PV replacing some grid sourced electricity; housing and appliances becoming more efficient; consumers reducing their energy use in response to higher prices; reductions in demand from large industrial customers; and in 2020 the impact of COVID-19 on consumer behaviour (figure 3.28).

Forecasts by planning authorities and market participants consistently failed to capture a step decline in electricity use from the grid and a flattening of maximum demand from around 2009. This decline can be attributed to multiple factors, including solar PV replacing some grid sourced electricity; housing and appliances becoming more efficient; and consumers reducing their energy use in response to higher prices. Electricity use also contracted in the manufacturing sector.[81] More recently, networks have explored demand response to meet short term peaks in demand as an alternative to investing in long lived assets (section 3.12.10).

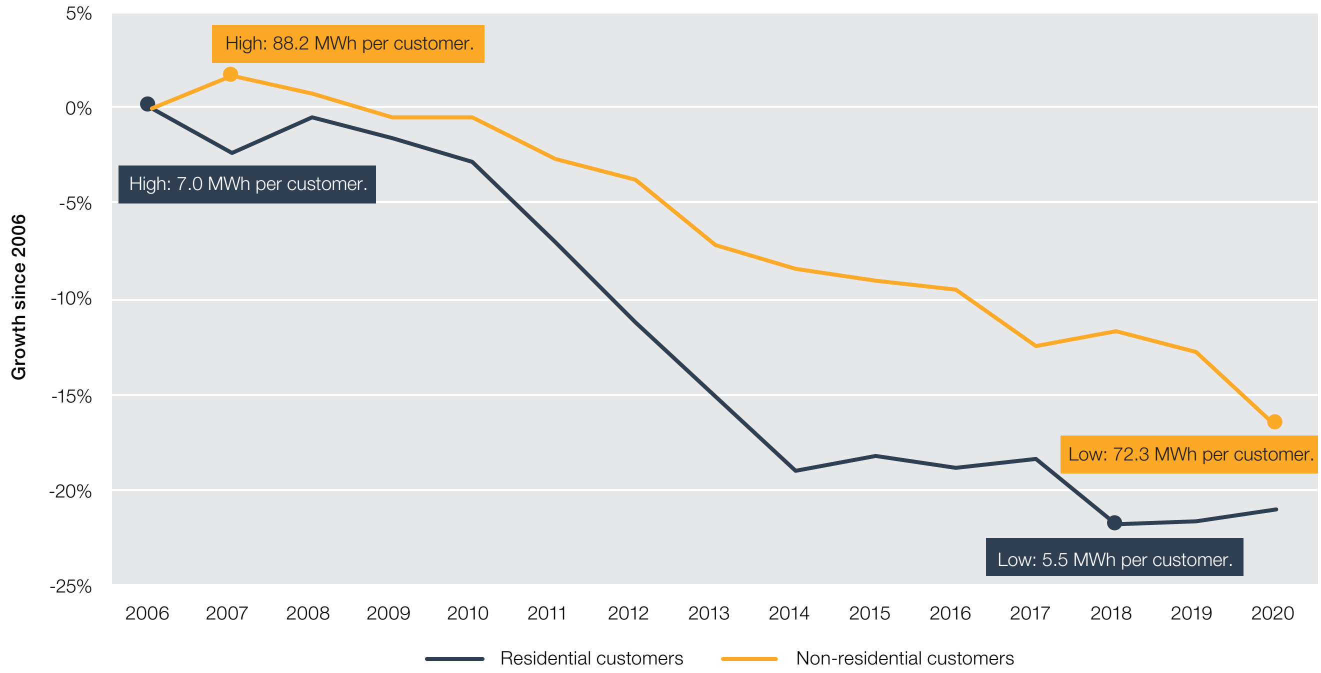
Inaccurate demand forecasts fuelled a wave of investment that inflated the electricity networks' RABs, which increased by 78% from 2006 to 2020. This overinvestment contributed to capital productivity declining for all transmission network businesses since 2006, although since 2013 the rate of decline has slowed.[82]

Overinvestment also drove weaker distribution network productivity but to a lesser extent than did rising operating expenditure. Capital productivity amongst the distribution networks has consistently declined since 2006, with little convergence amongst the individual distribution businesses. All of the distribution networks showed lower capital productivity in 2019 than in 2006, and many were only marginally better than in 2012, when distribution network capital productivity was at its lowest.

81 AEMC, *Electricity network economic regulatory framework review*, 18 July 2017, pp 37–38.

82 AER, *Annual benchmarking report – electricity transmission network service providers,* November 2020, p 22.

Figure 3.28 Change in average energy usage per customer – electricity distribution networks



Note: Most distribution network businesses report on a 1 July – 30 June basis. The exception is the Victorian businesses which report on a 1 January – 31 December basis. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018).

Source: Economic benchmarking regulatory information notice (RIN) responses.

3.14.5 Adapting to an evolving market

As the market evolves, the regulatory framework needs to encourage network businesses to make efficient choices between capital and operating expenditure. A traditional network solution to meet increasing consumer demand in an area might be to augment a zone substation, for example. But a more efficient solution might be to purchase services from a battery provider, or an aggregator of batteries, to manage peak demand.

Regulatory frameworks need to support emerging technologies and business models that have the potential to benefit consumers. Current frameworks encourage network businesses to favour (relatively expensive) long-lived capital investment (which gets added to the asset base) over cheaper operating expenditure alternatives, especially if a business's regulated rate of return is higher than its actual borrowing costs.

Network businesses are also having to adapt to a new operating environment, in which DER is changing energy flows and creating new pressure points in the system. These challenges require network businesses to develop innovative solutions to keep the network operating efficiently.

In March 2020 the AEMC recommended a package of rule changes aimed at making it easier for network businesses to develop and trial innovative approaches to providing energy services to consumers.[83] The rules would implement 'regulatory sandbox' arrangements in the national electricity and gas markets, where participants can test innovative concepts in the market under relaxed regulatory requirements at a smaller scale, on a time-limited basis and with appropriate safeguards in place.[84]

In October 2020 ElectraNet (South Australia) and TransGrid (NSW) submitted a rule change request to the AEMC seeking an exception to the applicability of the rules in relation to the financeability of its share of actionable ISP projects.

In April 2021 the AEMC rejected the rule change request. The AEMC considered that the regulatory framework does not create a barrier to financing ElectraNet's or TransGrid's actionable ISP projects (currently Project EnergyConnect) and that the proposed rule would not provide the right investment incentives and would likely substantially increase costs to consumers in the near to medium term.[85]

83 AEMC, *Final report – regulatory sandboxes – advice to Ministerial Forum of Energy Ministers (formerly CoAG Energy Council) on rule drafting*, 26 March 2020.

84 The Ministerial Forum of Energy Ministers (formerly CoAG Energy Council) will separately develop law changes and conduct stakeholder consultation before the law changes are submitted to the South Australian Parliament. The AEMC's recommended rule drafting will then be updated to reflect the final form of law changes.

85 AEMC, *Participant derogation – financeability of ISP project (TransGrid), rule determination*, 8 April 2021.

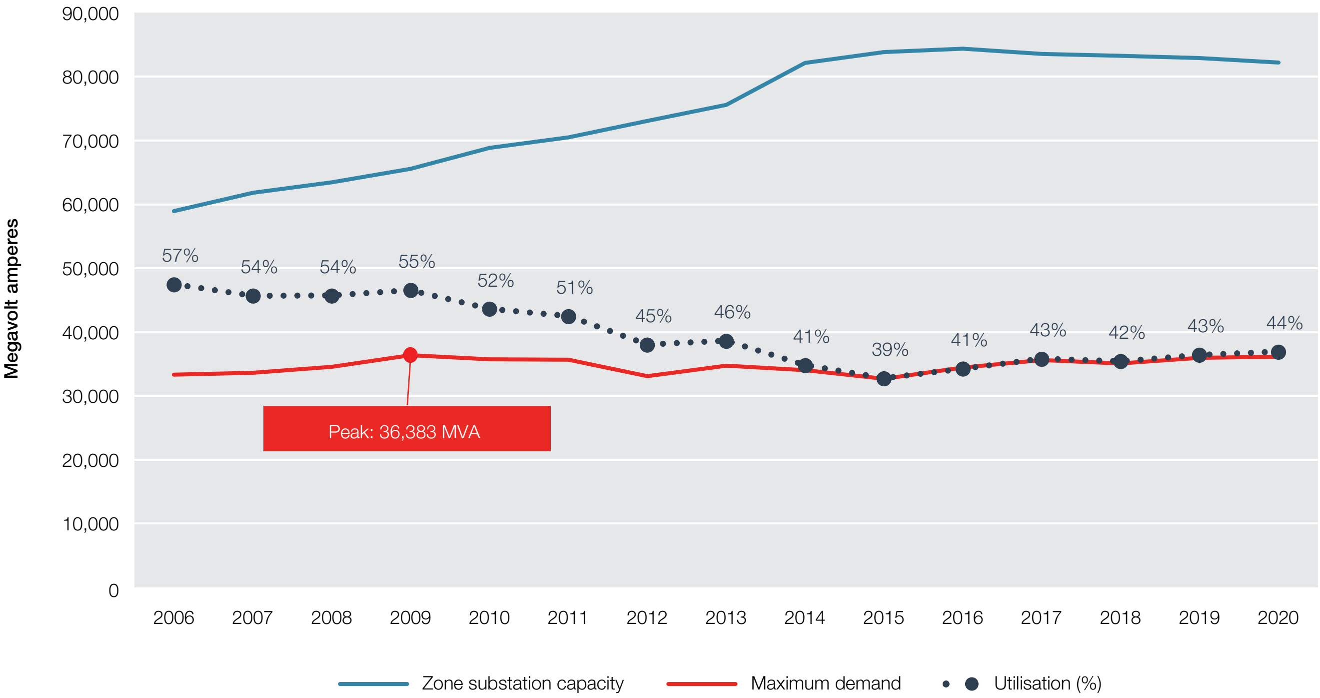
3.14.6 Network utilisation

A network's utilisation rate is a part productivity measure, indicating the extent to which a network business's assets are being used to meet maximum demand. The rate can be improved through efficiencies such as using demand response (instead of new investment in assets) to meet rising maximum demand.

The average network utilisation amongst all distribution networks declined from a high of 56% in 2006[86] to a low of 39% in 2015 following overinvestment by many network businesses at a time of weakening electricity maximum demand. Maximum demand has since increased, rising 11% between 2015 and 2020 (reaching its highest point since 2009). While maximum demand has been increasing, network capacity has been decreasing – down 2% since its peak in 2016. When combined, these events have resulted in the average network utilisation amongst the distribution networks steadily increasing over the past 5 years. In 2020 network utilisation reached 44% – the highest rate since 2013 (figure 3.29).

Network utilisation rates tend to be higher among privately owned distribution networks (62% in 2020) than in fully or partly government owned networks (38% in 2020).[87] In 2020, 5 of the top 6 most highly utilised distribution networks were privately owned, with Ergon Energy (Queensland) being the only exception.

Figure 3.29 Network utilisation – electricity distribution networks



MVA: megavolt amperes.

Note: Network utilisation is the non-coincident, summated raw system annual peak demand divided by total zone substation transformer capacity.

Source: Economic benchmarking regulatory information notice (RIN) responses.

Powercor (Victoria) has operated the most highly utilised distribution network in each year since 2006, followed by United Energy (Victoria) from 2016 to 2020. For the past decade Essential Energy (NSW) has consistently been the most underutilised distribution network, followed by Power and Water (Northern Territory).

Under-utilised assets raise the risk of asset stranding – whereby assets are no longer useful – unless network businesses respond to changing conditions. This risk may become more acute as the uptake of DER (such as batteries) transforms the industry. The National Electricity Rules do not allow for RAB adjustments to remove historical investment in stranded assets. If network charges become inflated as a result of asset stranding then electricity consumers – who pay for those assets – may look to opportunities to bypass the grid altogether.[88]

86 The available data does not extends back beyond 2006.

87 Section 3.16 provides a detailed assessment of network ownership.

88 Grattan Institute, *Down to the wire – a sustainable electricity network for Australia*, March 2018.

3.15 Reliability and service performance

Reliability refers to the continuity of electricity supply to customers. Many factors can interrupt the flow of electricity on a network. Supply interruptions may be planned (for example, due to the scheduled maintenance of equipment) or unplanned (for example, due to equipment failure, bushfires, extreme weather events or the impact of high demand stretching the network's engineering capability).

A significant network failure might require the power system operator to disconnect some customers (known as load shedding).

Most interruptions to supply originate in distribution networks. They typically relate to power line damage caused by lightning, car accidents, debris such as falling branches, and animals (including possums and birds). Peak demand during extreme weather can also overload parts of a distribution network. Transmission network issues rarely cause consumers to lose power, but the impact when they occur is widespread; for example, South Australia's catastrophic network failures in September 2016 caused a state-wide blackout.

Electricity outages impose costs on consumers. These costs include both economic losses resulting from lost productivity and business revenues and non-economic costs such as reduced convenience, comfort, safety and amenity.

Household and business consumers desire a reliable electricity supply that minimises these costs. But maintaining or improving reliability may require expensive investment in network assets, which is a cost passed on to electricity customers. There is, therefore, a trade-off between electricity reliability and affordability. Reliability standards and incentive schemes need to strike the right balance by targeting reliability levels that customers are willing to pay for.

State and territory governments set reliability standards for electricity networks that seek to efficiently balance the costs and benefits of a reliable power supply. While approaches to setting standards have varied across jurisdictions, governments recently moved to a more consistent national approach to reliability standards. This approach factors in the value that consumers place on having a reliable power supply.

3.15.1 Valuing reliability

Understanding the value that customers place on reliability is an important consideration when setting reliability standards or network performance targets. This value tends to vary among customer types and across different parts of the network. Considerations include a customer's access to alternative energy sources; their past experience of interruptions to supply; and the duration, frequency and timing of interruptions.

In July 2018 the AER assumed from AEMO responsibility for estimating how much customers are prepared to pay for reliable electricity supply. In December 2019 it published valuations for unplanned widespread outages of up to 12 hours in all jurisdictions. It drew on customer surveys and modelling to determine the values and consulted with governments, energy regulators, industry representatives and customers.[89]

The AER's 2019 estimates were broadly similar to those estimated by AEMO in 2014, but the values varied across sectors. Both reviews found business customers tended to value reliability more highly than residential customers, who were particularly concerned about long outages and outages at peak times. Differences were also apparent across industries, but these differences changed over time: the 2019 estimates were lower than the 2014 estimates for agricultural and commercial customers but higher for industrial customers.

The AER will develop new estimates of customers' reliability valuations every 5 years and update these values annually. The values will have wide application, including as an input for:

- cost–benefit assessments such as those applied in regulatory tests (section 3.12.7) that assess network investment proposals
- assessing bonuses and penalties in the service target incentive scheme (box 3.5)
- setting transmission and distribution reliability standards and targets
- informing market settings such as wholesale price caps.

In March 2020 the AER published a draft model[90] to estimate the costs of widespread and long duration outages (WALDO). As a result of stakeholder feedback the AER decided to discontinue the WALDO model and methodology but is considering avenues for future work, such as research partnerships with universities.

89 AER, *Values of customer reliability, final report on VCR values*, December 2019.

90 Developed with ACIL Allen.

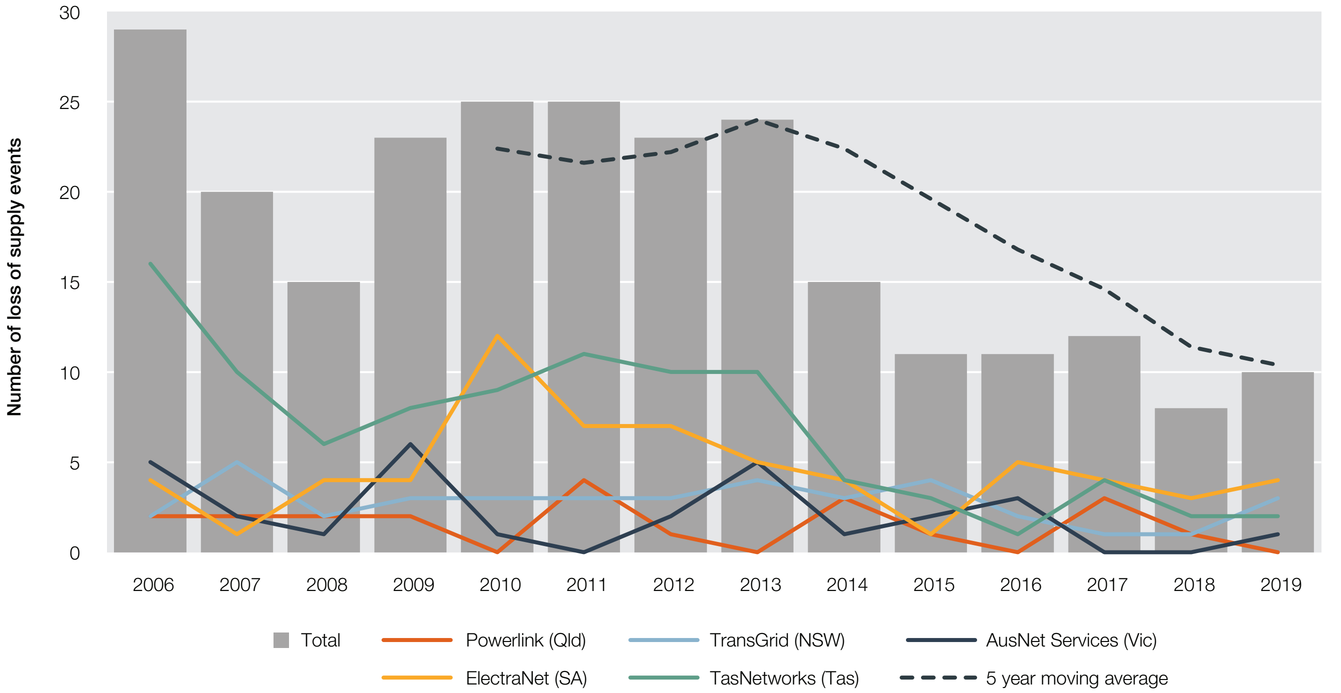
3.15.2 Transmission network performance

Electricity transmission networks are engineered and operated to be extremely reliable, because an interruption can lead to widespread power outages. To avoid this outcome, the transmission networks are engineered with capacity to act as a buffer against credible unplanned interruptions.

Across the NEM, lost supply events due to transmission failures have occurred no more than 25 times in any year since 2006. The 5-year average number of lost supply events due to transmission failures continues to decline, with no network business reporting more than 5 loss of supply events in any year since 2013.

In 2019 the NEM experienced 10 loss of supply events due to transmission failures. Over the past 5 years Powerlink (Queensland) and AusNet Services (Victoria) have consistently experienced the fewest loss of supply events amongst all of the transmission networks in the NEM (figure 3.30).

Figure 3.30 Network reliability loss of supply events – electricity transmission



Note: Loss of supply events are the times when energy is not available to transmission network customers above a specific time period. The threshold varies across businesses, from 0.05–1.0 system minutes as published in AER decisions on the service target performance incentive scheme (STPIS). The thresholds may also vary between regulatory periods for each network.

Most transmission network businesses report on a 1 July – 30 June basis. The exception is AusNet Services (Victoria), which reports on a 1 April – 31 March basis. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018).

Source: Economic benchmarking regulatory information notice (RIN) responses.

In addition to system reliability, congestion management is another barometer of transmission network performance. All networks are constrained by capability limits, and congestion arises when electricity flows on a network threaten to overload the system. As an example, a surge in electricity demand to meet air conditioning loads on a hot day may push a network close to its secure operating limits.

Network congestion may require AEMO to change the generator dispatch order. A low cost generator may be constrained from running to avoid overloading an affected transmission line and a higher cost generator may be dispatched instead, raising electricity prices. At times, congestion causes perverse trade flows too, such as a low priced NEM region importing electricity from a region with much higher prices.

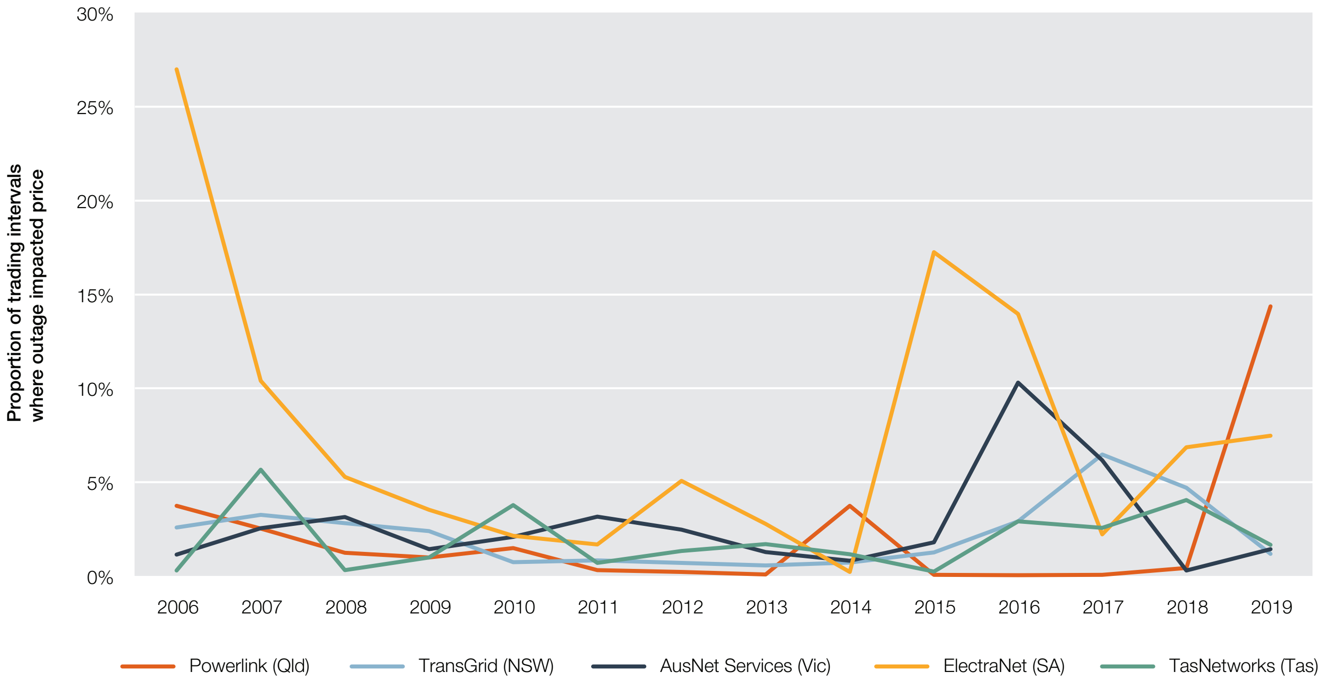
Transmission congestion caused significant market disruption in 2006, when rising electricity demand placed strain on the networks (figure 3.31). But network investment from 2006 to 2014 – including upgrades to congested lines – eliminated much of the problem. Weakening energy demand reinforced the trend, and for several years network congestion affected less than 10% of NEM spot prices. But, ultimately, consumers paid for the substantial costs of the network investment.

Issues with network congestion re-emerged from 2015 in part due to outages associated with network upgrades in Queensland and on cross-border interconnectors linking Victoria with South Australia and NSW. The level of congestion dropped in South Australia in 2017 following completion of an interconnector upgrade.

Not all congestion is inefficient, however. Reducing congestion through investment to augment transmission networks is an expensive solution. Eliminating congestion is efficient only to the extent that the market benefits outweigh the costs of new investment.

Network businesses can help minimise congestion costs by scheduling planned outages and maintenance to avoid peak periods. For this reason, the AER offers incentives for network businesses to reduce the market impact of congestion.

Figure 3.31 Market impact of loss of supply events – electricity transmission networks



Note: Percentage of trading intervals each year when transmission network congestion impacted the National Electricity Market spot price by more than $10 per megawatt hour.

The data exclude outages caused by force majeure events and other specific exclusions.

Source: Economic benchmarking regulatory information notice (RIN) responses.

3.15.3 Distribution network reliability

For distribution networks, the reliability of supply – that is, how effectively the network delivers power to its customers – is the focus of network performance. Around 95% of interruptions to supply that electricity customers experience are due to issues in their local distribution network.[91] The capital intensive nature of the networks makes it prohibitively expensive to invest in sufficient capacity to avoid all interruptions.

Planned interruptions – when a distributor needs to disconnect supply to undertake maintenance or construction works – can be scheduled for minimal impact, and the network business must provide timely notice to customers of its intention to interrupt supply. Unplanned outages – such as those resulting from asset overload or damage caused by extreme weather – provide no warning to customers, so they cannot prepare for the impact of an interruption.

Jurisdictional reliability standards were historically set at higher levels to protect customers from the cost and inconvenience of supply interruptions. Following power outages in 2004, the Queensland and NSW governments in 2005 tightened reliability standards for distribution networks, requiring significant investment that drove network costs for several years. In contrast, Victoria placed more emphasis on reliability outcomes and the value that customers place on reliability.

91 AEMC, *Final report – 2019 annual market performance review*, 12 March 2020, p 51.

Concerns that reliability-driven investment was driving up power bills led to a different approach to setting distribution reliability targets.[92] The approach accounts for the likelihood of interruptions and for the value that customers place on reliability (section 3.15.1). While the Queensland and NSW governments began to relax reliability standards from 2014, the assets built to meet the previously high standards remain, and customers continue to pay for them.[93]

Two widely applied measures of distribution network reliability are the system average interruption frequency index (SAIFI), and the system average interruption duration index (SAIDI). SAIFI measures the frequency – or number – of interruptions to supply experienced by the average customer each year, while SAIDI measures the total duration – or minutes – off supply experienced by the average customer.[94]

The characteristics of a distribution network can have a significant impact on its reliability performance. In particular, customer densities (figure 3.12) and environmental conditions differ across networks. This can materially impact the number of customers affected by an outage and a network business's response time.

Central business district (CBD) and urban network areas have higher load and customer connection density. Distribution lines supplying urban areas are generally significantly shorter than rural lines. CBD and urban areas also tend to have a higher proportion of underground cables (which are protected from pollution, storms, trees, bird life, vandalism, equipment failure and vehicle collisions) and more interconnections with other urban lines. Restoration times following interruptions to supply are usually quicker for distributors operating in urban areas than in rural areas.

Conversely, rural areas generally have lower load and lower customer connection densities and often include customers living in smaller population centres remote from supply points. Distribution lines supplying customers in rural areas tend to cover wider geographic areas. This increases exposure to external influences such as storm damage, trees and branches and lightning. Further, rural lines are generally radial in nature, with limited ability to interconnect with nearby lines. These characteristics tend to result in more frequent and longer duration interruptions.

For these reasons comparisons across distribution networks should be made with care. Levels of historical investment also affect reliability outcomes.

The SAIFI and SAIDI metrics have generally been used to focus on the impact of unplanned outages. However, the impact planned outages have on a customer must also be considered when assessing 'customer experience'. The AER has acknowledged this and has incorporated the impact of planned outages into its recent regulatory determinations through the CSIS (box 3.6). Both the relative frequency and duration of planned interruptions to supply varies considerably amongst the distribution networks.

Distribution reliability trends

The AER does not determine a distributor's operating and capital expenditure forecasts to eliminate all supply interruptions. This is evident in the AER's service target performance incentive scheme (STPIS) (box 3.5), in which the AER sets 'normalised' reliability targets that do not penalise a network for interruptions considered to be beyond its control.

Across the distribution sector, 'normalised' levels of reliability have improved over the past decade, delivering fewer unplanned interruptions to and fewer unplanned minutes off supply. This improvement has occurred despite distribution networks investing $11 billion (16%) less than forecast on capital projects from 2010 to 2020 (figure 3.11).

Normalising the data removes the impact of extreme events and provides a more reasonable measure of a distributor's controllable outputs. Figures 3.32 and 3.33 summarise SAIDI and SAIFI outcomes across the NEM, as well as weighted network reliability targets that the AER applies through the STPIS.

92 Ministerial Forum of Energy Ministers (formerly CoAG Energy Council), *Response to the Australian Energy Market Commission's review of the national framework for distribution reliability and review of the national framework for transmission reliability*, December 2014.

93 ACCC, *Retail Electricity Pricing Inquiry, final report*, June 2018, p 109.

94 Unplanned SAIDI excludes momentary interruptions (3 minutes or less).

While unplanned 'normalised' reliability continues to improve (SAIFI), or plateau (SAIDI), the absolute level of network reliability (that is, 'customer experience') has varied. This is predominately due to year on year fluctuations in the impact of unplanned (excluded) events, such as outages caused by major weather events. Figure 3.33 demonstrates the impact and unpredictability of major weather events on network reliability. For example, the average network customer experienced 87% fewer unplanned (excluded) minutes off supply in 2012 than they did in the previous year, when northern Queensland was lashed by Tropical Cyclone Yasi. Further examples of unplanned (excluded) events include:

- network outages associated with bushfires in Victoria in 2009
- network outages caused by strong winds and torrential rain in NSW in April 2015
- reduced reliability for Queensland customers as a result of cyclones and severe flooding in 2013, 2015 and 2017
- a power outage across almost the whole of South Australia as a result of storm damage to electricity transmission infrastructure in 2016.

Distribution network reliability in 2020

In 2020 the average electricity customer experienced 1.66 total interruptions to supply – 0.7% fewer than in the previous year. This comprised:

- 1.08 unplanned (normalised) interruptions to supply – 3% fewer than in the previous year and a new record low (0.2% fewer than the previous low in 2017)
- 0.21 unplanned (excluded) interruptions to supply – 16% fewer than in the previous year but 36% more than the low recorded in in 2012
- 0.37 planned interruptions to supply – 21% more than in the previous year.
- In 2020 the average electricity customer experienced 350.1 total minutes off supply – 27% more than in the previous year. This comprised:
- 119.5 unplanned (normalised) minutes off supply – 0.7% more than in the previous year and 12% more than the low recorded in 2017
- 124.4 unplanned (excluded) minutes off supply – 64% more than in the previous year and 318% more than the low recorded in in 2012
- 106.2 planned minutes off supply – 32% more than in the previous year.

The average customer experienced significantly more total minutes off supply in 2020 than in the previous year. The increase was largely driven by the impact of the devastating bushfires which burned throughout the spring and summer of 2019–20, destroying thousands of homes and burning over 17 million hectares of land across NSW, Victoria, Queensland, ACT, Western Australia and South Australia.[95]

Customers also experienced a significant increase in the frequency and duration of planned interruptions to supply in 2020. The increase was primarily driven by Ausgrid's decision to temporarily pause all live work on its network for safety reasons.[96]

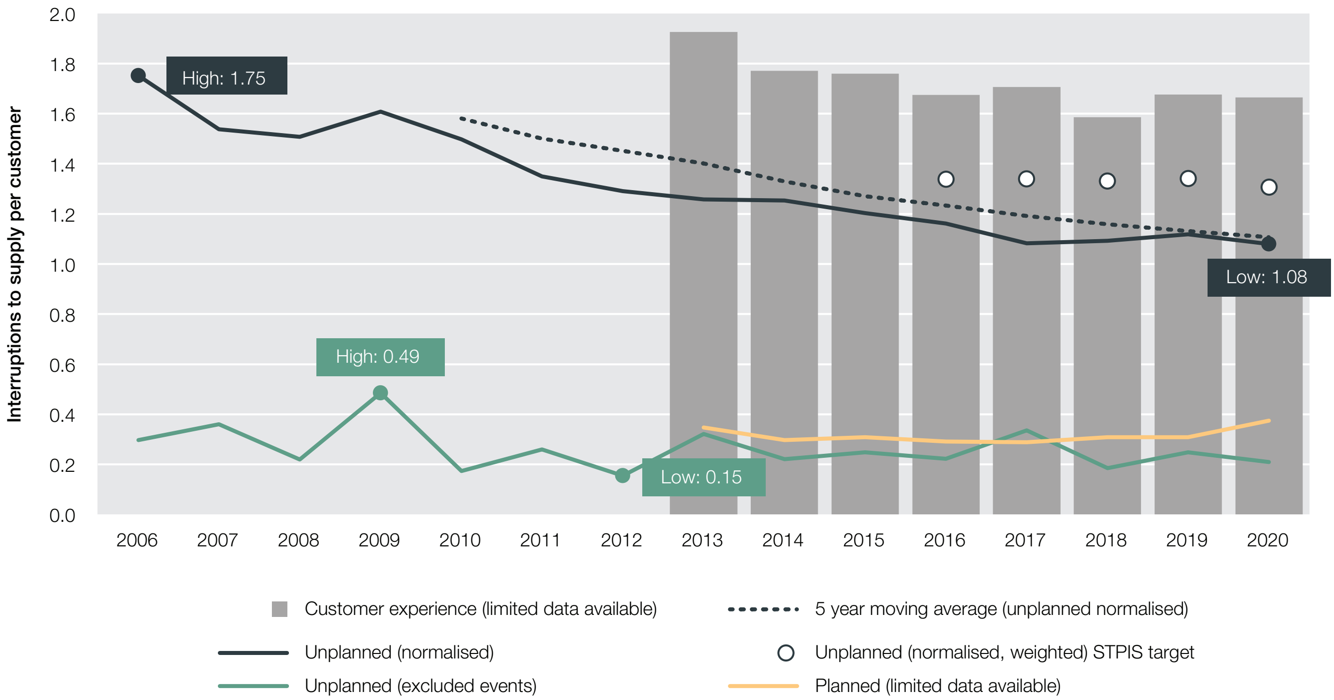
As distribution networks are so heavily impacted by the occurrence of severe weather events, it is more prudent to assess network performance over a rolling 5-year averaging period than it is on a year by year basis. When using a 5-year rolling average network customers experienced 2% fewer unplanned (normalised) interruptions to supply in 2020 than at any time in the past, while the average unplanned (normalised) minutes off supply were only 0.5% higher than at the record low point in 2018.

On average, in 2020 the distributors performed 17% better than their (weighted) SAIFI targets and 3% better than their (weighted) SAIDI targets.

95 Australasian Fire and Emergency Service Authorities Council, 'Cumulative seasonal summary' [tweet], AFESAC, 28 February 2020 (https://twitter.com/AFACnews).

96 Ausgrid, *Live Work Project*, Ausgrid website, accessed 5 May 2021 (www.ausgrid.com.au).

Figure 3.32 Interruptions to supply (SAIFI) – electricity distribution networks

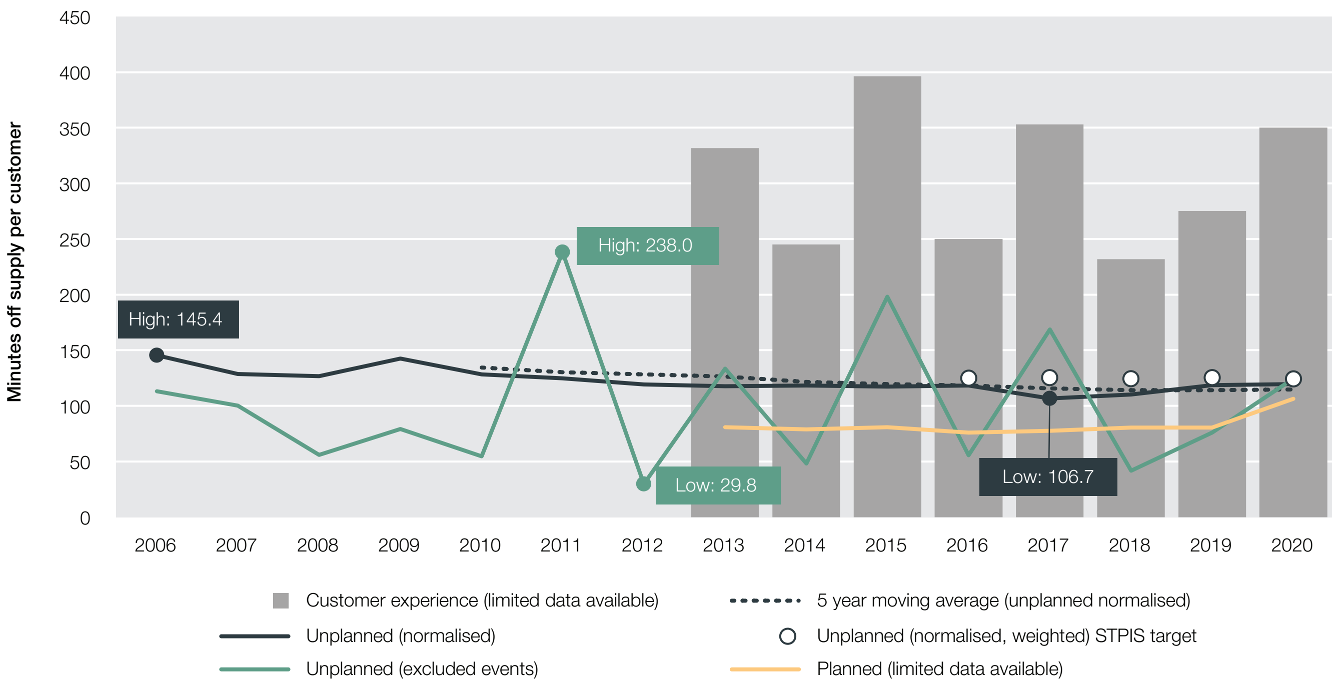


SAIFI: system average interruption frequency index; STPIS: service target performance incentive scheme.

Note: STPIS targets are set at the feeder level. The STPIS targets shown represent weighted network level targets, calculated by multiplying the distributor's feeder level targets by the proportion of its customers on each feeder type. Victorian network businesses report on a 1 January – 31 December basis. All other network businesses report on a 1 July – 30 June basis. The NEM data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018).

Source: AER modelling; economic benchmarking regulatory information (RIN) responses.

Figure 3.33 Minutes off supply (SAIDI) – electricity distribution networks



SAIDI: system average interruption duration index; STPIS: service target performance incentive scheme.

Note: STPIS targets are set at the feeder level. The STPIS targets shown represent weighted network level targets, calculated by multiplying the distributor's feeder level targets by the proportion of its customers on each feeder type. Victorian network businesses report on a 1 January – 31 December basis. All other network businesses report on a 1 July – 30 June basis. The National Electricity Market data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018).

Source: AER modelling; economic benchmarking regulatory information (RIN) responses.

Incentivising good performance

Inconsistencies in the measurement of reliability across NEM jurisdictions led the AEMC to develop a more consistent approach. In November 2018 the AER adopted the AEMC's recommended definitions for distribution reliability measures for purposes such as setting reliability targets in the STPIS.[97]

More generally, the AER reviewed the STPIS to align with the AEMC's recommendations – for example, it amended the scheme to encourage distributors to reduce the impact of long outages experienced by customers at the end of rural feeders.

Box 3.5 Service target performance incentive scheme

The Australian Energy Regulator (AER) applies a service target performance incentive scheme (STPIS) to regulated network businesses. The STPIS offers incentives for network businesses to improve their service performance to levels valued by their customers. It provides a counterbalance to the capital expenditure sharing scheme (CESS) (box 3.3) and efficiency benefit sharing scheme (EBSS) (box 3.4) by ensuring network businesses do not reduce expenditure at the expense of service quality. A separate STPIS applies to distribution and transmission network businesses.

Transmission

The transmission STPIS covers 3 service components:

- the frequency of supply interruptions, duration of outages and the number of unplanned faults on the network
- rewards for operating practices that reduce network congestion
- funding for one-off projects that improve a network's capability, availability or reliability at times when users most value reliability or when wholesale electricity prices are likely to be affected.

Financial bonuses of up to +4% of revenue, or penalties of up to –1% of revenue, are available for exceeding/failing to meet performance targets under the scheme.

Distribution

A distributor's allowed revenue is increased (or decreased) based on its service performance. The bonus for exceeding (or penalty for failing to meet) performance targets can range to ±5% of a distributor's allowed revenue.

Currently, the AER applies the distribution STPIS to 2 service elements:

- reliability of supply – unplanned (normalised) system average interruption duration index (SAIDI), unplanned (normalised) system average interruption frequency index (SAIFI), and momentary interruptions to supply (MAIFI)
- customer service – response times for phone calls, streetlight repair, new connections and written enquiries.[98]

The reliability component sets targets based on a network's average performance over the previous 5 years. Performance measures are 'normalised' to remove the impact of supply interruptions deemed to be beyond the distributor's reasonable control. While the reliability performance of each network fluctuates from year to year, network businesses have generally performed better than their STPIS targets.

97 AER, *Amendment to the service target performance incentive scheme (STPIS) / Establishing a new Distribution Reliability Measures Guideline (DRMG)*, November 2018.

98 The AER's Customer Service Incentive Scheme (CSIS) (box 3.6) will replace the STPIS telephone answering parameter for regulatory determinations made from 30 April 2021 onwards.

Incentives to avoid fire starts

The AER administers a Victorian Government scheme (f-factor scheme) offering incentives to Victorian distributors to lower the number of fire starts originating from their network, especially in high fire danger zones and at times of heightened fire risk. Available penalties and rewards range from around $1.48 million per fire start in high risk areas on code red days to $300 in low risk areas on low fire danger days.

Incentive payments for 2018–19 ranged from around $62,000 for the mostly urban United Energy network to more than $3.7 million for the predominantly rural Powercor network.[99]

Victorian distributors received almost 3 times more in f-factor rewards in 2018–19 than in the previous year. Rewards were significantly higher for United Energy (up 1,124%), Powercor (up 276%) and AusNet Services (up 28%) due to a lower number of fire starts in the period.

The AER will continue to administer the f-factor scheme to all Victorian distributors in the 2021 to 2026 period. The distributors will continue to receive incentive payments if they make sustained and continuous improvements in fire start performance. Once they make improvements, their benchmark targets are tightened in future years.

3.15.4 Customer service

While reliability is the key service consideration for most energy customers, a distribution network's service performance also relates to the business:

- providing timely notice of planned interruptions
- ensuring the quality of supply, including voltage variations
- avoiding wrongful disconnection (including for life support customers) and ensuring quick timeframes for reconnection
- being on time for appointments
- having a fast response to fault calls
- providing transparent information on network faults.

Individual jurisdictions set different standards for these performance indicators. Some jurisdictions apply a guaranteed service level (GSL) scheme that requires network businesses to compensate customers for inadequate performance. Because reporting criteria vary by jurisdiction, performance outcomes are not directly comparable. The AER provides an annual summary of outcomes against some of these measures for networks in NSW, Queensland, South Australia, Tasmania and the ACT.[100] Victoria reports separately on network performance.[101]

In July 2020 the AER released its new CSIS, which provides incentives for distributors to provide measurable levels of customer service that align with their customers' preferences (box 3.6).[102]

The AER also oversees the rules protecting energy customers who rely on life support equipment. Between December 2018 and 31 March 2020 the AER issued 7 infringement notices to distribution businesses for failing to provide sufficient notice of outages to life support customers – 3 notices were issued to TasNetworks (Tasmania) and 2 notices were issued to Energex (Queensland) and Evoenergy (ACT).

In the period 31 March 2020 to mid-May 2021 the AER did not issue any infringement notices to distribution businesses for failing to provide sufficient notice of outages to life support customers.

99 AER, *Victoria F-factor scheme results for the 2016–20 period*, 30 June 2020.

100 AER, *Annual retail markets report 2019–20*, November 2020.

101 ESC, *Victorian energy market update*, March 2021.

102 AER, *Final – Customer Service Incentive Scheme*, July 2020.

Box 3.6 Customer Service Incentive Scheme

The Australian Energy Regulator's (AER's) Customer Service Incentive Scheme (CSIS) is designed to encourage electricity distributors to engage with their customers and provide a level of service which corresponds with their customers' preferences. The AER sets customer service performance targets for network businesses as part of the 5-year revenue determination process. Under the CSIS, distributors may be financially rewarded or penalised depending on how well they perform against the designated customer service targets. The revenue at risk under the scheme is capped at ±0.5%.

The CSIS is a flexible 'principles based' scheme that can be tailored to the specific preferences and priorities of a distributor's customers. This flexibility will allow for the evolution of customer engagement and adapt to the introduction of new technologies.

The CSIS provides safeguards to ensure the financial rewards/penalties under the scheme are commensurate with actual improvements/detriments to customer service. The incentives target areas of service that customers want to see improved.

The AER generally sets performance targets under the CSIS at the level of current performance. However, it may adjust the performance targets if the level of current performance is not considered to provide a good outcome for consumers.[103]

The incentive rates are tested with customers to confirm that they align with the value that customers place on the level of performance improvement/decline. This means that, even if a distributor performs exceptionally well against its targets, customers will still benefit. In subsequent regulatory periods, the targets under the scheme will be adjusted and set in accordance with any improved level of customer service.

The AER applies the CSIS through a selection of the following performance parameters:

- communication of unplanned outages
- frequency, duration and/or communication of planned outages
- customer service for new connections (basic and standard)
- customer service in managing complaints.

For each parameter, customer satisfaction is measured using a survey.

The first application of the CSIS is for Victorian distributors AusNet Services, CitiPower, Powercor and United Energy for the 2021 to 2026 period.

103 AusNet Services' historical performance for the complaints parameter was not considered acceptable. In this case using targets based on historical performance would not have the desired effect. As such, the performance target was calculated using industry-leading performance; therefore, AusNet Services will only be rewarded for material improvements to customer service.

Image courtesy of APPEA

4

Gas markets in eastern Australia

The main types of gas produced in Australia are conventional natural gas and coal seam gas (CSG). Conventional gas is found trapped in underground reservoirs, often along with oil, while CSG is an unconventional form of gas extracted from coal beds. Advancements in extraction techniques have improved the commercial prospects for other forms of unconventional gas, including shale and tight gas.[1]

The supply of gas to energy customers involves several steps (infographic 2). It begins with the exploration and appraisal of potential reserves for commercial viability. Gas discoveries are extracted through wells, then processed to separate the methane and ethane from impurities (such as nitrogen, carbon dioxide and sulphur dioxide) and to remove and treat any water.

In eastern Australia around 70% of gas produced is converted to liquefied natural gas (LNG) for export, mainly to Asia. The balance is sold into the domestic market. Some gas is stored (often in depleted gas fields or LNG tanks) and can be used to augment supply at peak times. More recently, domestic gas users have explored options for importing LNG to supplement domestic gas supplies.

Gas sold to domestic customers is transported from production fields to major demand centres or hubs via high pressure transmission pipelines (figure 4.1). The pipelines have wide diameters and operate under high pressure to optimise shipping capacity. They deliver gas to power stations, large industrial and commercial customers, and energy retailers, which sell the gas to their customers. Retailers deliver gas to energy customers' pipelines via distribution networks, which are spaghetti-like networks of smaller pipes that service commercial and residential premises in cities and towns.

4.1 Gas markets in eastern Australia

This chapter considers the 'upstream' gas sector, encompassing gas production, wholesale markets for gas, and the transport of gas along transmission pipelines to demand hubs. It focuses on the eastern gas market, in which the Australian Energy Regulator (AER) has regulatory responsibilities (box 4.1). Chapter 5 covers regulated transmission and distribution pipelines, while chapter 6 covers gas (and electricity) retailing.

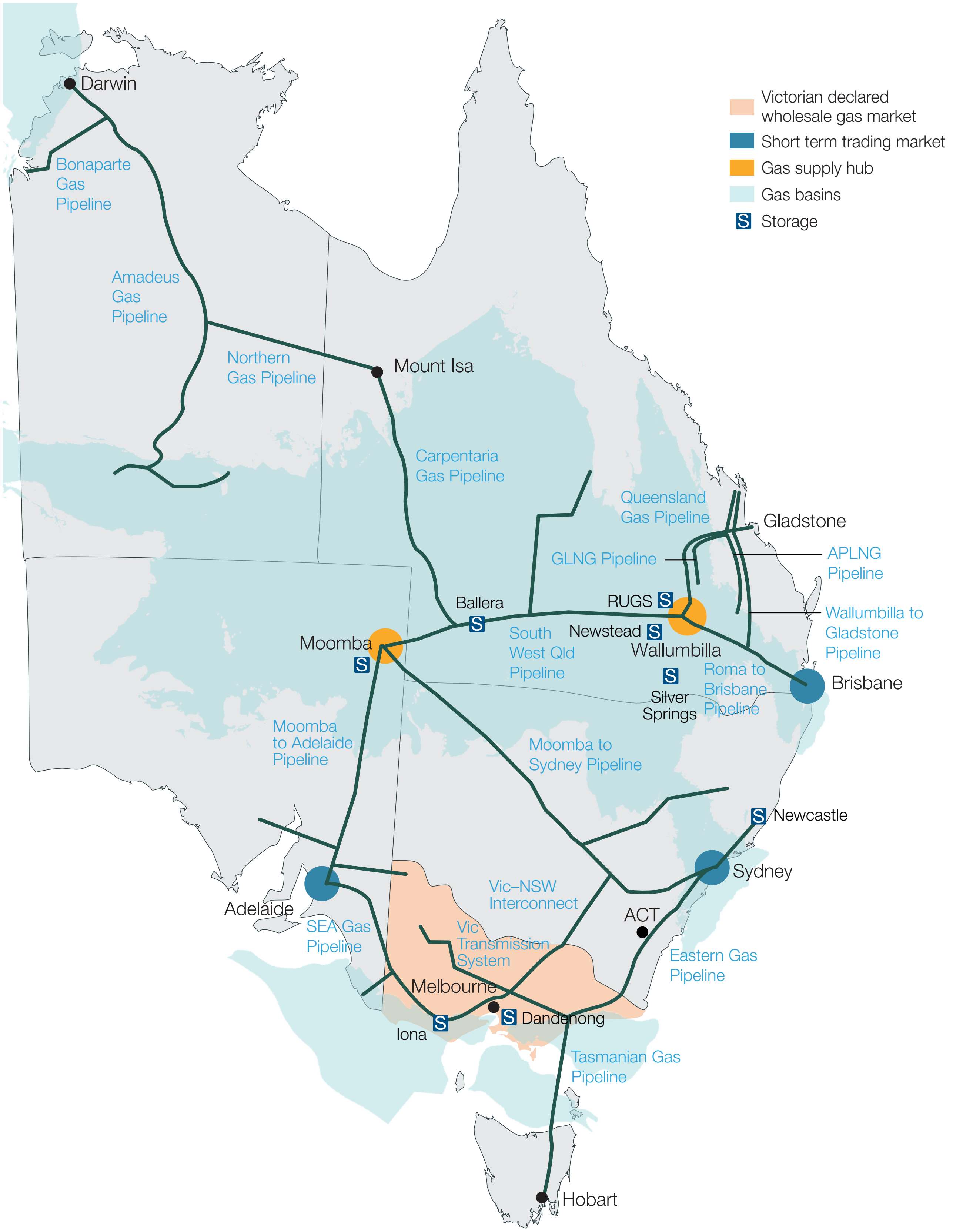
The eastern gas market encompasses Queensland, New South Wales (NSW), Victoria, South Australia, Tasmania and the Australian Capital Territory (ACT). This market is interconnected by transmission pipelines, which source gas from basins and deliver it to large industrial customers and major population centres. The main production basins are the Surat–Bowen Basin in Queensland, the Cooper Basin in north east South Australia, and 3 basins off coastal Victoria, the largest being the Gippsland Basin. Since January 2019 the market has also sourced gas from the Northern Territory.

The eastern gas market evolved as separate state-based markets, each served by a single gas basin and a single transmission pipeline. Over the past 20 years, new pipelines interconnected these markets, making it possible to transport gas from Queensland to the southern states and (since key pipelines became bi-directional) vice versa. With the opening in 2019 of the Northern Gas Pipeline, the eastern gas market can also source gas from the Bonaparte Basin off the north coast of Western Australia and the Northern Territory.

In 2015 gas became a major export industry in eastern Australia with the launch of Queensland's LNG industry. The industry transformed the eastern gas market by giving producers the choice of exporting gas or selling it domestically. By 2018 over 60% of eastern Australian gas production was being exported. With domestic users now competing with overseas customers to buy Australian gas, prices in the domestic market have shifted to align more closely with international gas prices. Shifting gas prices also impact electricity markets, which rely on gas powered generation to firm output from weather-dependent renewable generation and at times of peak electricity demand.

1 Shale gas is contained within organic-rich rocks such as shale and fine grained carbonates, rather than in underground reservoirs. The application of horizontal drilling techniques in the past 5 years is enhancing the economic viability of shale gas development. Tight gas is found in low porosity sandstone and carbonate reservoirs.

Figure 4.1 Eastern gas basins, markets, major pipelines and storage



Source: AER; Gas Bulletin Board.

Box 4.1 The AER's role in gas markets

The Australian Energy Regulator (AER) has regulatory responsibilities across the entire gas supply chain in eastern Australia. At the wholesale level, we monitor and report on spot gas markets in Sydney, Brisbane, Adelaide and Victoria; gas supply hubs at Wallumbilla (Queensland) and Moomba (South Australia); and activity on the Gas Bulletin Board, which is an open access information platform covering the eastern gas market.

We monitor the markets and bulletin board to ensure participants comply with the National Gas Law and National Gas Rules, and we take enforcement action when necessary. Our compliance and enforcement work aims to promote confidence in the gas market, to encourage participation. We also monitor the markets for particular irregularities and wider inefficiencies. Our monitoring role at the Wallumbilla and Moomba hubs, for example, explicitly looks to detect price manipulation. In 2019 we began a new role as the compliance and enforcement body for a scheme to auction underused capacity in transmission pipelines.

Our gas compliance focus in 2020 included the successful implementation of capacity trading reforms and enhanced transparency. In particular, market participants are required to submit information to the Australian Energy Market Operator (AEMO) and the AER in a timely and accurate manner. During the year, we gave significant focus to the day-ahead auction, which facilitates the daily trade of contracted but un-nominated pipeline capacity. We closely monitored auction activity, monitoring for misconduct and for compliance with record keeping requirements. We will continue this focus throughout 2021.

In 2020 we continued our monitoring and reporting activities, publishing weekly reports, gas industry statistics and our *Wholesale markets quarterly* reports, which cover gas spot market activity, prices and liquidity. The quarterly reports also include analysis of eastern Australia's liquefied natural gas (LNG) export sector and its impact on the domestic market.

Looking forward, we continue to engage with the Energy Ministers' gas reform agenda. Under the agenda, we must administer new reporting obligations to enhance the transparency of market activity.

Alongside our work in gas wholesale markets, the AER is the economic regulator for 2 major transmission pipelines in eastern Australia and one pipeline in the Northern Territory. We also arbitrate disputes relating to 'light regulation' pipelines, and we may appoint an arbitrator to settle disputes affecting other pipelines.[2]

In the downstream gas industry, the AER sets reference prices for distribution networks in NSW, Victoria, South Australia and the ACT (chapter 5). In retail gas markets, we hold wide-ranging responsibilities in jurisdictions that have passed the National Energy Retail Law – namely, Queensland, NSW, South Australia and the ACT (chapter 6).

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

Outside the eastern gas market, the AER is the gas pipeline regulator for the Northern Territory but plays no role in the territory's wholesale market. However, facility operators in the Northern Territory must report gas flow activity to the Gas Bulletin Board, which the AER oversees. We have no regulatory function in Western Australia, where separate laws apply.[3]

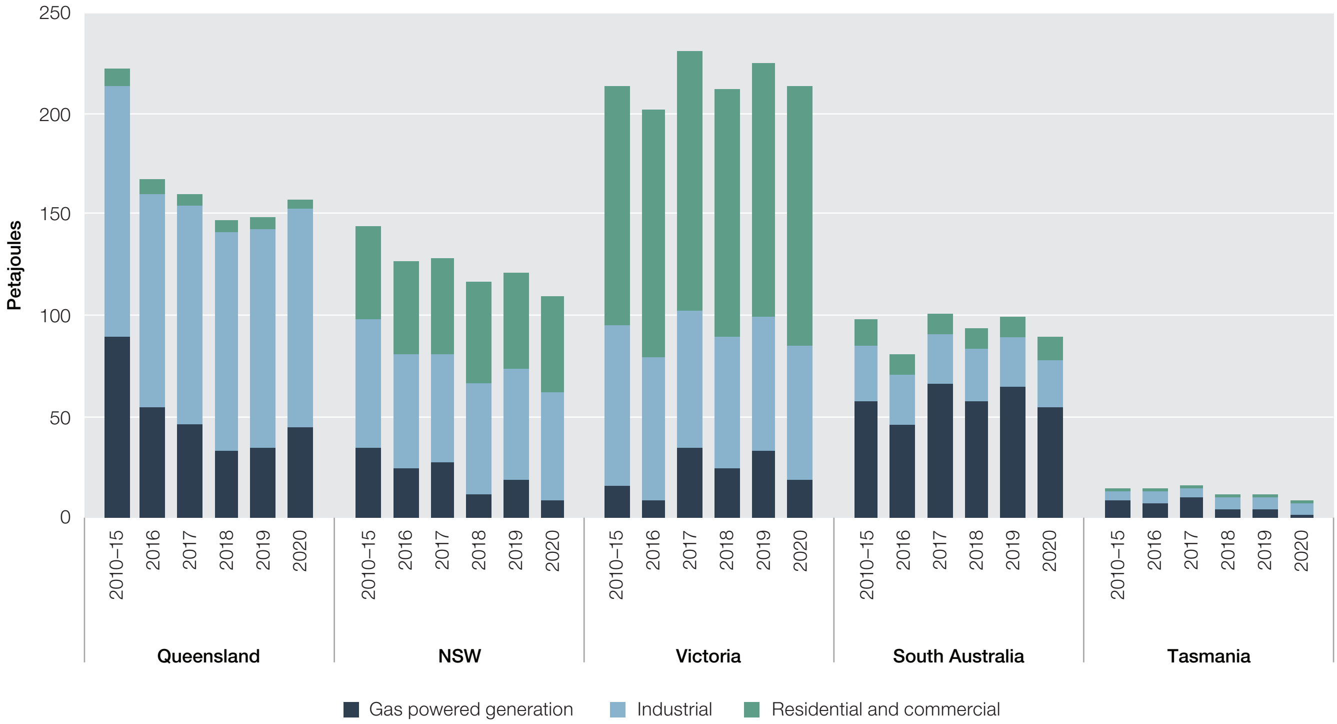
2 Chapter 5 outlines the different tiers of pipeline regulation.

3 The Economic Regulation Authority is the economic regulator for gas markets and pipelines in Western Australia, and AEMO operates a spot gas market there.

4.2 Gas demand in eastern Australia

Domestic customers in eastern Australia used around 580 petajoules (PJ) of gas in 2020 (figure 4.2).[4] These customers included industrial businesses, electricity generators, commercial businesses and households. Industrial customers are the biggest users, consuming 45% of gas sold to the domestic market. They use it as an input to manufacture pulp and paper, metals, chemicals, stone, clay, glass and processed foods. Gas is also a major feedstock in ammonia production for fertilisers and explosives.

Figure 4.2 Gas consumption in eastern Australia



Note: Data for 2010–15 are average annual consumption over that period.

Source: AEMO, 2021 gas statement of opportunities, March 2021.

The electricity sector is another major source of demand. The rapid responsiveness of gas powered turbines makes them suitable for peak electricity generation. Gas powered generation also plays an important role in managing fluctuations in wind and solar generation. With gas generation often used to fill supply gaps in the electricity market, its level can fluctuate significantly. Gas powered generation accounted for 21% of domestic gas use in 2020, down from 29% in 2017 when gas generators helped fill the supply gap caused by the closure of Victoria's Hazelwood power station. South Australia has the highest demand for electricity generation, accounting for 43% of eastern Australian gas powered generation demand in 2020.

Residential and commercial customers are the third major source of gas demand. Overall, they account for 34% of domestic gas demand. Victoria is the only state where a majority of demand (more than 60%) is from small residential and commercial customers, who use gas mostly for heating and cooking. In 2016 over 80% of Victorian households were connected to a gas network. That same year residential gas penetration was around 80% in the ACT, 60% in South Australia, 45% in NSW, 10% in Queensland and 6% in Tasmania.[5] More recently some regions look to be reducing gas connections. In 2020 in the ACT, for example, policy changes mean new developments are no longer required to connect to the gas network.[6]

In the overall energy mix, gas reliance is highest in South Australia, where it accounts for 35% of primary energy consumption, followed by Victoria and Queensland (around 20% in each state). It is lower in NSW, where it accounts for less than 10% of energy consumption.[7] South Australia's high degree of reliance on gas reflects its dependence on gas powered electricity generation.

4 Excludes LNG. AEMO, *2021 gas statement of opportunities*, March 2021.

5 AEMO, *National gas forecasting report*, December 2016.

6 ACT Government, 'Now we're cooking with … electricity! Gas no longer a requirement in Canberra suburbs' [media release], January 2020.

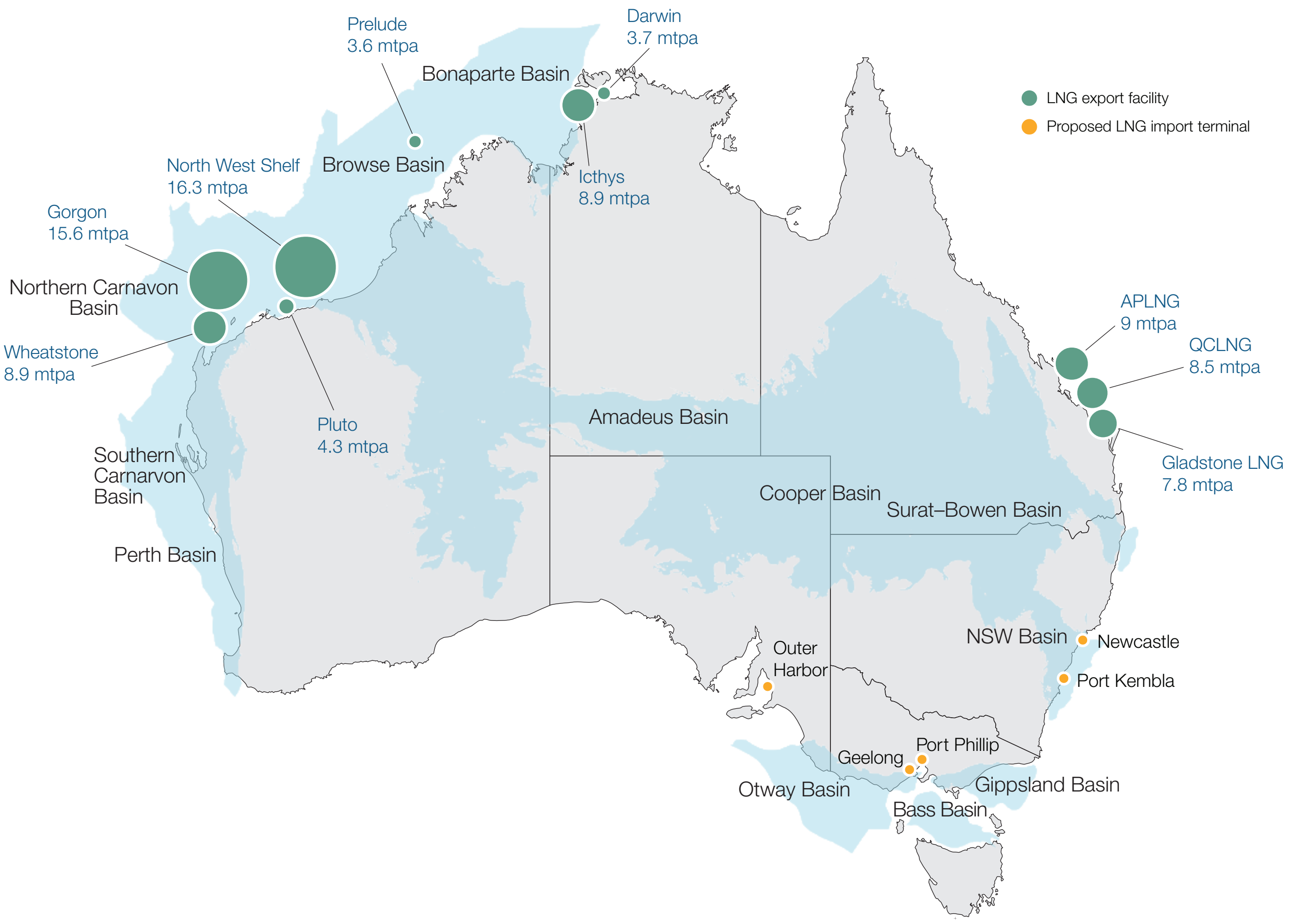
7 Department of Industry, Science, Energy and Resources, *Australian energy update 2020, Australian energy statistics*, September 2020, Table C.

4.3 Liquefied natural gas exports

A majority of gas produced in eastern Australia is liquefied in processing facilities in Queensland for shipping to export markets (table 4.1). The gas is chilled to –162° C, which shrinks volume by 600 times and makes it economic to store and ship in large quantities. Most Australian LNG is shipped to Asia.

Alongside Queensland's LNG industry, Australia operates 5 LNG projects in Western Australia and 2 in the Northern Territory (figure 4.3). In 2019–20 LNG exports earned Australia nearly $50 billion, making gas Australia's second largest resource and energy export behind iron ore.[8] Australia became the world's largest LNG exporter in 2019.[9]

Figure 4.3 Australia's LNG export projects



Note: Capacity in million tonnes per annum (mtpa).
Source: AER.

4.3.1 Queensland liquefied natural gas industry

Queensland's LNG industry comprises 3 major projects, which liquefy gas sourced mainly from the Surat–Bowen Basin. The projects were made possible by the basin's vast CSG reserves and are the world's first to convert CSG to LNG. The LNG projects control over 80% of reserves in eastern Australia (mostly CSG), and they use these reserves to meet a majority of their LNG requirements.[10] They also source gas from other LNG producers, as well as producers in central Australia and Victoria, and acquire it through long term contracts and spot markets:

- The Queensland Curtis LNG (QCLNG) project has capacity to produce 8.5 million tonnes of LNG per annum (mtpa). It began exporting LNG in January 2015 and has 2 trains (liquefaction and purification facilities). Shell is the principal owner (73.75%).

8 Department of Industry, Innovation and Science, *Resources and energy quarterly*, December 2020.
9 EnergyQuest, *EnergyQuarterly*, March 2020.
10 ACCC, *Gas inquiry 2017–2025, interim report, January 2021*, February 2021, p 35.

- The Gladstone LNG (GLNG) project has capacity to produce 7.8 mtpa. It began exporting in October 2015 and has 2 trains. Santos (30%), Petronas and Total (27.5% each) and Kogas (15%) own the project.
- The Australia Pacific LNG (APLNG) project has capacity to produce 9 mtpa.[11] It began exporting gas in January 2016 and has 2 trains. Origin Energy and ConocoPhillips (37.5% each) and Sinopec (25%) own the project.

4.3.2 Northern Territory and Western Australia

The Northern Territory's LNG industry began in 2006 with the commissioning of Darwin LNG (3.7 mtpa capacity), which relies on gas from the Bonaparte Basin in the Timor Sea. A second project – Ichthys LNG (8.9 mtpa capacity) – launched in 2018. Both projects connect to the territory's domestic gas market as emergency supply sources but otherwise produce gas solely for export.

Western Australia has 5 LNG projects with a combined capacity of around 50 mtpa. The industry began with the North West Shelf project, and the first cargo left the facility for sale to Japan in 1989. The North West Shelf project has 5 trains and remains Australia's largest LNG project by capacity (16.9 mtpa).

Western Australia's second LNG project, Pluto, was commissioned in 2012. Rising LNG prices provided the impetus for 3 more recent projects – Gorgon (2016), Wheatstone (2017) and Prelude (2019).[12]

4.4 Gas reserves in eastern Australia

Gas reserves are unexploited accumulations of gas that are expected to be commercially recoverable. Data on gas reserves are an important input to forecasting supplies of gas that may enter the market.

Different measures of gas reserves are quoted based on geological, engineering and commercial analysis of the likelihood of successful recovery:

- Proven reserves (1P) are estimated to be at least 90% certain of successful commercial recovery.
- Proven plus probable reserves (2P) are estimated to be at least 50% certain of successful commercial recovery.
- A third category (3P) includes all reserves deemed at least 10% likely to be commercially recoverable.

Lower levels of probability attach to contingent resources, which are resources considered potentially recoverable from known accumulations that are not yet technically or commercially recoverable.

This probabilistic approach to measuring gas reserves results in frequent, and sometimes substantial, adjustments. Queensland's 2P reserves, for example, were downgraded by over 7,177 PJ between June 2017 and June 2020.[13]

Data on Australian gas reserves is collected through various disconnected mechanisms and bodies, resulting in a lack of clear, consistent and accurate reporting. Data standards and aggregation across these sources are inconsistent, and the assumptions underlying the data are often not transparent.[14]

The Australian Securities Exchange (ASX) requires listed companies to report limited data on gas reserves, but unlisted companies and those listed overseas are not obliged to report. State and territory governments each have reporting requirements, and the Australian Government collects some information (particularly on offshore resources), but much of this information is commercial-in-confidence.

Market analysts such as EnergyQuest and Energy Edge publish reserves estimates, drawing on available sources. The Australian Competition and Consumer Commission (ACCC) also reports on the gas market and began publishing reserves and resources information in December 2018.

In 2020, Energy Ministers were progressing reforms that would require all participants to report information on gas reserves via the Gas Bulletin Board (section 4.14.1).

11 APPEA, *LNG exports*, APPEA website, accessed 28 May 2021.

12 Department of Jobs, Tourism, Science and Innovation (WA), *Western Australia liquefied natural gas profile*, February 2020.

13 ACCC, *Gas inquiry 2017–2025, interim report, January 2021*, February 2021, p 31.

14 ACCC, *Inquiry into the east coast gas market*, April 2016.

4.4.1 Distribution of reserves in eastern Australia

EnergyQuest estimated eastern and southern Australia's 2P gas reserves stood at 35,444 PJ in February 2021 but noted this estimate is subject to uncertainty (table 4.1).[15] Reserve ownership is highly concentrated in some basins but more diverse across the market as a whole (figure 4.4). Arrow Energy (jointly owned by Shell and PetroChina) is the single largest holder of 2P reserves in eastern Australia (17%). Other major reserve holders include Origin Energy, ConocoPhillips, Sinopec and Santos.[16]

Table 4.1 Gas basins serving eastern Australia

	GAS PRODUCTION – 12 MONTHS TO DECEMBER 2020			2P GAS RESERVES (FEBRUARY 2021)	
GAS BASIN	PETAJOULES	SHARE OF EASTERN AUSTRALIAN SUPPLY (%)	CHANGE FROM PREVIOUS YEAR (%)	PETAJOULES	SHARE OF EASTERN AUSTRALIA RESERVES (%)
Surat–Bowen (Qld)	1,513	76%	2%	30,637	86%
Cooper (SA–Qld)	101	5%	11%	1,048	3%
Gippsland (Vic)	255	13%	0%	1,924	5%
Otway (Vic)	37	2%	–37%	745	2%
Bass (Vic)	11	1%	–2%	166	0%
Sydney, Narrabri, Gunnedah (NSW)	4	0%	–8%	14	0%
Amadeus (NT)	15	1%	–26%	247	1%
Bonaparte (NT)	47	2%	–9%	663	2%
Eastern Australia total	**1,983**		**0%**	**35,444**	
Domestic gas sales	631		–2%		
LNG exports	1,352		1%		

2P: proven plus probable reserves estimated to be at least 50% sure of successful commercial recovery.

Note: Totals may not add to 100% due to rounding. Most production and reserves in the Surat–Bowen and NSW basins are coal seam gas. Production and 2P reserves in other basins are mainly conventional gas.

Source: EnergyQuest, EnergyQuarterly, March 2021, p 82.

Surat–Bowen Basin

Queensland's Surat–Bowen Basin is the largest basin in eastern Australia, with over 85% of all gas reserves. Reserves from the basin are mainly converted to LNG for export, but the basin also supplies some gas to the domestic market.

Victorian basins

The Gippsland Basin is the most significant of the 3 producing basins in Victoria, accounting for around 5% of eastern and southern Australian reserves.[17] The Bass and Otway basins together account for 2% of reserves. Total reserves across the Victorian basins are declining.

From December 2019 to February 2021, 2P reserves fell by nearly 22% in the Gippsland Basin. Over the same period, 2P reserves fell by 5% in the Bass Basin and rose by 16% in the Otway Basin. Because the Otway Basin is smaller in scale, this increase did not offset the reductions in the Bass and Gippsland basins.

A joint venture between Esso (ExxonMobil) and BHP controls a large majority of reserves in the Gippsland Basin.

15 EnergyQuest, *EnergyQuarterly*, March 2021, p 82.

16 EnergyQuest, *EnergyQuarterly*, March 2021, Table 27, p 83.

17 EnergyQuest, *EnergyQuarterly*, March 2021, Table 26, p 82.

Cooper Basin

The Cooper Basin in central Australia has over 1,000 PJ of 2P reserves, which accounts for 3% of eastern Australia's 2P reserves. In 2010 Santos entered an agreement to supply one of the Queensland LNG projects with 750 PJ of gas over 15 years, which accelerated the depletion of the basin's conventional reserves. Reserves declined by 5% between December 2019 and February 2021.[18]

NSW basins

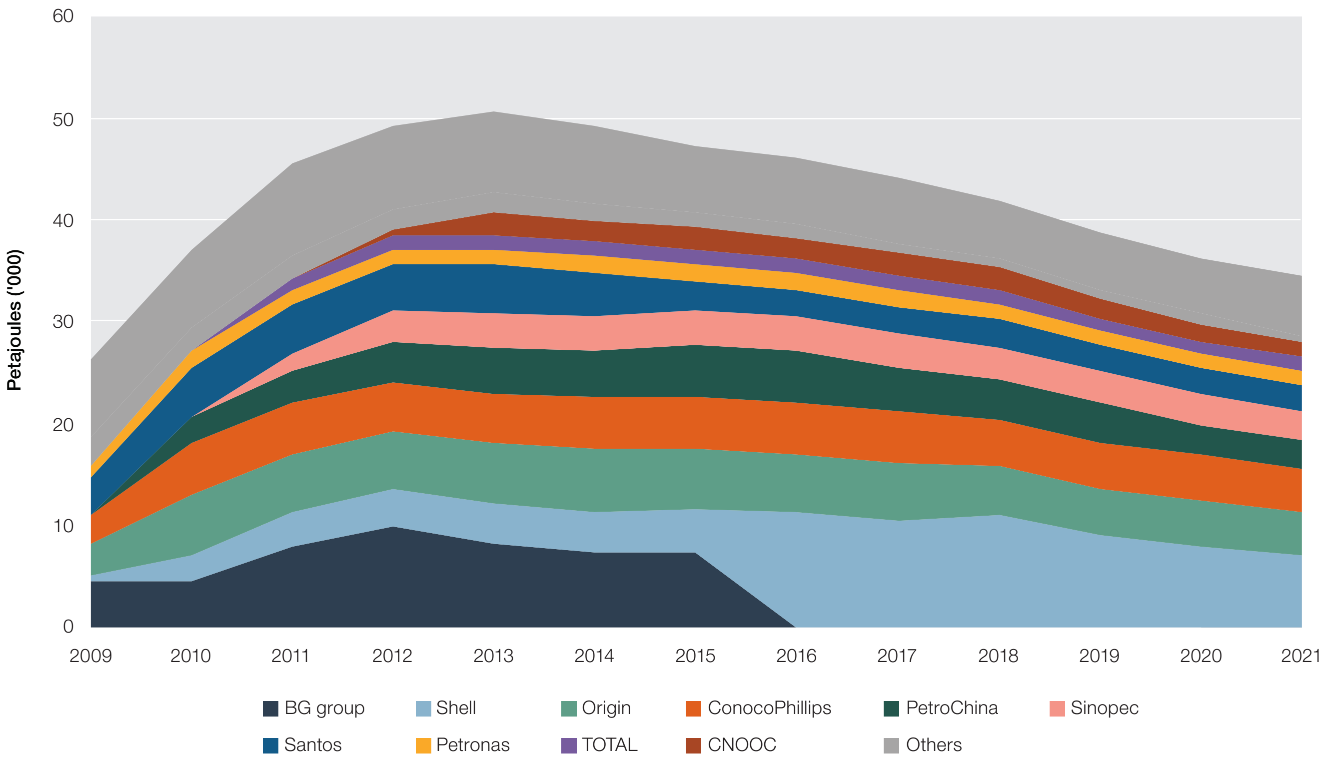
NSW has significant contingent resources (around 1,300 PJ) but only 14 PJ of 2P reserves and negligible current production. In 2017 Santos applied to develop reserves near Narrabri in the Gunnedah Basin. After encountering widespread opposition on environmental grounds, the project received consent from the NSW Independent Planning Commission in September 2020.[19] In November 2020 the Minister for the Environment granted approval to the project, and a final investment decision is expected in late 2021 or early 2022 (section 4.12.1).[20]

Northern Australia

Northern Australia was historically separate from the eastern gas market, but the commissioning of the Northern Gas Pipeline in January 2019 linked gas fields in the Bonaparte Basin (offshore of Darwin in the Timor Sea) and the Amadeus Basin (southern Northern Territory) with Queensland.

The Bonaparte Basin was developed to support the Northern Territory's LNG industry, which is based in Darwin. The basin is estimated to have over 650 PJ of 2P reserves. Most gas produced in the basin is converted to LNG for export. The Amadeus Basin is smaller, with just under 250 PJ of estimated 2P reserves.

Figure 4.4 Market shares in 2P gas reserves in eastern Australia



Note: Aggregated market shares in 2P (proven and probable) gas reserves in the Surat–Bowen, Gippsland, Cooper, Otway, Bass and NSW basins. 2P reserves are those for which geological and engineering analysis suggests at least a 50% probability of commercial recovery.

Source: EnergyQuest, EnergyQuarterly (various years).

18 EnergyQuest, *EnergyQuarterly*, March 2021, Table 26, p 82.

19 Department of Planning, Industry and Environment (NSW), *Narrabri gas*, DPIE website, accessed 28 May 2021.

20 Santos, 'Santos welcomes federal signoff on Narrabri Gas Project' [media release], November 2020.

4.5 Gas production

In 2020 eastern Australia produced almost 2,000 PJ of gas. The majority (68%) was exported as LNG and the remainder was sold to the domestic market (table 4.1).

Queensland's Surat–Bowen Basin supplied 76% of gas produced in eastern Australia in 2020, including much of the gas earmarked for LNG export. Participants in Queensland's 3 LNG projects produced around 90% of the basin's output in 2020. As well as supplying their LNG facilities, the LNG participants sell some gas into the domestic market.

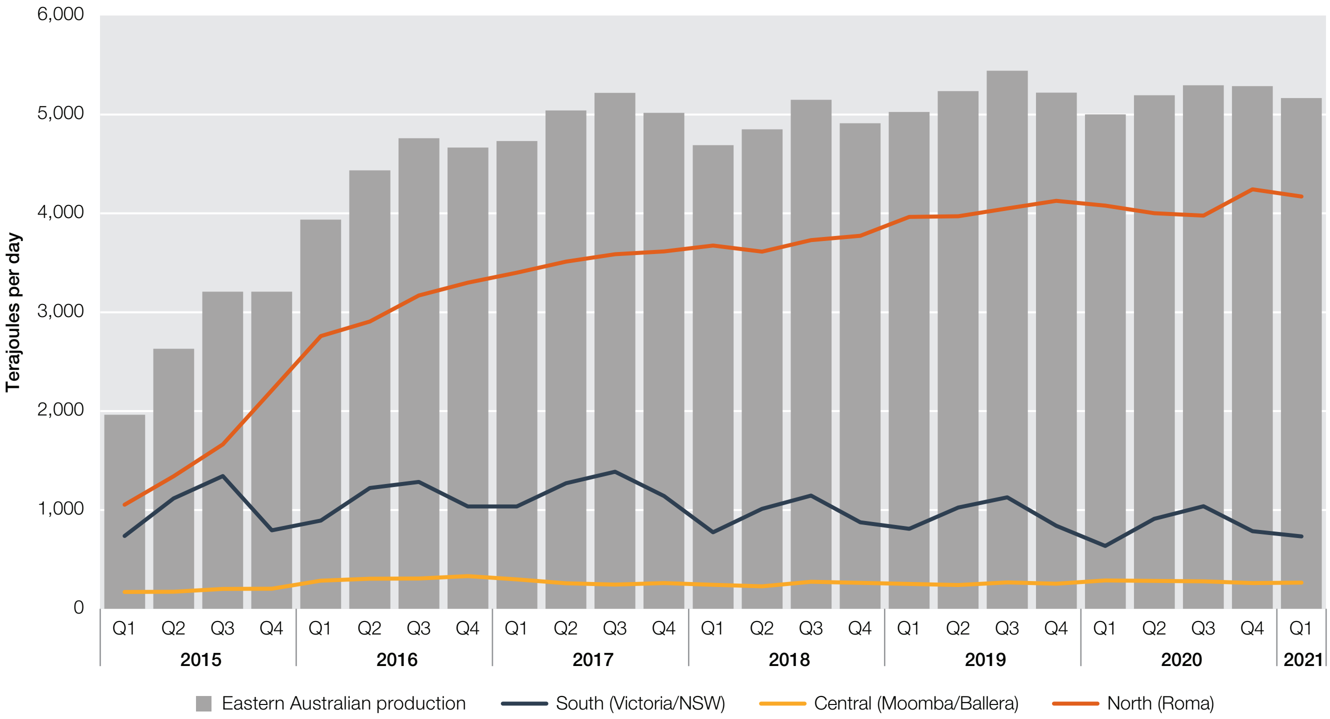
Outside Queensland, the basins off coastal Victoria meet most of the remaining demand in the eastern states. The Gippsland Basin is the most significant of the 3 producing basins in Victoria, meeting 13% of demand in 2020. The smaller Otway and Bass basins jointly supplied 3% of the market.

The Longford Gas Plant, servicing the Gippsland Basin, achieved record high production in 2017, some of which was shipped to Queensland for LNG exports (figure 4.5). But production has since declined. The Australian Energy Market Operator (AEMO) forecasts a steep decline in southern field production after 2022 as a number of Gippsland Basin fields cease production in 2023 and 2024. However, it anticipates that the commissioning of the proposed Port Kembla (NSW) LNG import facility in 2023 will offset this reduction in the short term.[21]

The Cooper Basin in central Australia accounted for 5% of eastern Australian gas production in 2020. The basin plays an important role as a 'swing' producer in managing seasonal and short term supply imbalances in the domestic gas market.

With the opening of the Northern Gas Pipeline in January 2019, the Northern Territory's offshore Bonaparte Basin and onshore Amadeus Basin became new suppliers to the eastern gas market. In 2020 the Northern Gas Pipeline delivered around 56 terajoules (TJ) per day on average into the eastern market – around 62% of its capacity (90 TJ per day).

Figure 4.5 Eastern Australia gas production



Source: AER analysis of Gas Bulletin Board data.

21 AEMO, *2021 gas statement of opportunities*, March 2021, p 44.

4.5.1 Changing basin profiles

Activity in all gas basins across eastern Australia has evolved to meet the needs of the LNG industry. Production from the Surat–Bowen Basin is mainly earmarked for export. But supply from other eastern Australian basins rose between 2015 and 2017 to help LNG projects meet their export contracts. This shift accelerated a depletion of gas reserves in southern basins. High production rates in Victoria also strained production plants, causing outages.

Following government intervention in 2017, LNG producers diverted more gas to the domestic market. In the year to June 2018, Surat–Bowen Basin production growth exceeded LNG export growth. As supplies from the north increased, southern basin production eased from the peaks recorded in 2017. From December 2018 to December 2020, Surat–Bowen Basin production increases (9%) have largely matched LNG export growth (10%). In turn, production in southern basins decreased by a similar proportion (10%). In particular, AEMO and the ACCC have identified the ongoing depletion of southern gas fields as a significant risk to supply in the coming years.

4.6 Gas storage

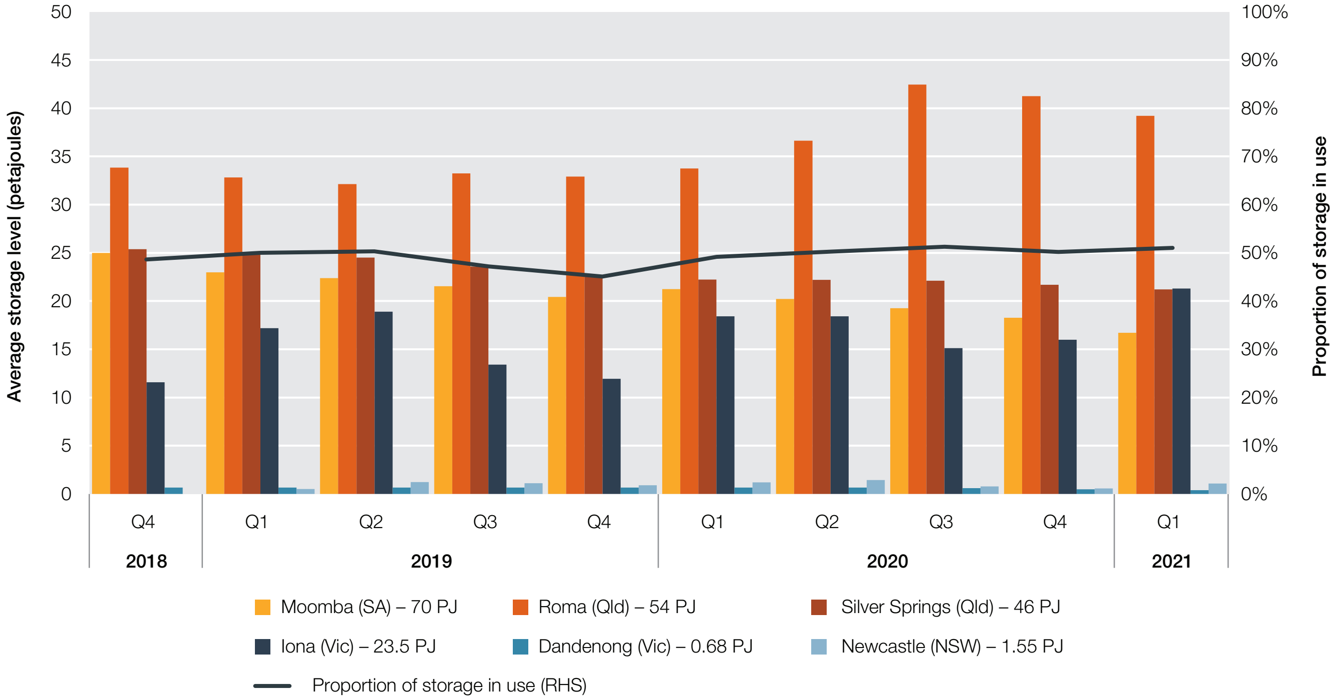
Storage provides a means of conserving surplus gas production for quick delivery when needed. Gas can be stored in its natural state in depleted underground reservoirs and pipelines; or post liquefaction as LNG in purpose-built facilities. Transmission pipelines can also provide gas storage services.

Eastern Australia's gas storage capacity includes:

- large facilities using depleted gas fields in Queensland, Victoria and South Australia
- smaller seasonal or peaking storage facilities located near demand centres – for example, the Newcastle LNG facility in NSW and the Dandenong LNG facility in Victoria
- short term peak storage services on gas pipelines, which are mostly contracted by energy retailers. The Tasmanian Gas Pipeline, for example, stores gas that can be sold into the Victorian market at times of peak demand.

The importance of storage in managing supply and demand has risen since the LNG industry began operating. Storage levels at the Roma underground, Moomba and Silver Springs facilities have been consistently drawn down to meet LNG export demand. Against this trend, Roma underground storage levels increased from 2019, rising significantly in 2020 when prices were low (figure 4.6). More generally, average storage levels in 2020 were higher than in 2019 despite depleting slightly in late 2020 to assist in meeting record LNG export demand.

Figure 4.6 Gas storage in eastern Australia



Note: Petajoule (PJ) value next to each facility reflects nameplate capacity.
Source: AER analysis of Gas Bulletin Board data.

Large gas customers (particularly retailers) have secured their own storage capacity to manage supply risks. For example, AGL contracted to use some of the Iona underground storage facility's capacity from January 2021 to manage seasonal demand. In June 2018 Lochard Energy began to expand its Iona capacity, expecting this storage would help manage future peak demand periods.[22] The Iona facility operates more dynamically that other storage facilities, with a larger capacity to inject and withdraw gas on any given day. As an example, during the third quarter of 2020, Iona storage helped meet South Australian gas demand for electricity generation during a period of low wind output and refilled during a period of milder weather.[23]

In 2021 the ACCC reported on investments to develop or expand storage capacity under consideration.[24] It noted Lochard Energy's expansion at Iona will continue, with a further expansion under consideration. Lochard Energy also purchased depleted shore reservoirs near Iona, which it could use for storage development. Further, production is anticipated shortly from the Golden Beach gas field in the Gippsland Basin, which may include a storage facility that could inject gas into the Victorian transmission system at Longford. A final investment decision on the storage component of this project is anticipated in 2021, with storage capacity becoming accessible from 2023.[25]

4.7 Gas transmission pipelines

Wholesale customers buy capacity on transmission pipelines to transport their gas purchases to destination markets. Around 20 major transmission pipelines transport gas to the eastern gas market (key pipelines are listed in table 4.2, with routes shown in figure 4.1). Dozens of smaller pipelines fill out the transmission grid.

Historically the eastern gas market's transmission system was a series of point-to-point pipelines, each transporting gas from a producing basin to a demand centre. Over time the system evolved into an integrated network covering eastern and southern Australia. Many gas pipelines became bi-directional, and gas increasingly flows across multiple pipelines to reach its destination. These changes mean access to capacity on key pipelines is more important than ever.

Investment in transmission pipelines is expensive and normally underwritten by foundation shippers through long term contracts. After its initial construction, a pipeline can be incrementally expanded to meet rising demand through compression, looping (duplication of parts of the pipeline) and extensions.

In recent years significant transmission investment occurred to meet the needs of Queensland's LNG industry, which included expanding existing pipelines and constructing new pipelines to ship gas to LNG processing facilities. Among recent developments, the Roma North Pipeline and the Atlas Gas Pipeline were commissioned in 2019, and other pipelines are proposed to bring additional supply to the eastern markets. Additionally, Jemena's Northern Gas Pipeline (which began operations in January 2019) provides eastern Australia's pipeline interconnection with the Northern Territory, making it possible to ship gas produced in the territory basins to eastern Australia (section 4.12.3).

The range of services provided by transmission pipelines is expanding to meet the needs of industry as the market evolves. Pipeline operators no longer simply transport gas from a supply source to a demand centre. Gas customers now seek more flexible arrangements such as bi-directional and backhaul shipping, and park and loan services.[26]

Transmission pipelines are separately owned from gas production companies. A gas customer must negotiate with a gas producer to buy gas, and separately contract with one or more pipeline businesses to get the gas delivered. This separation adds a layer of complexity to sourcing gas, especially for smaller customers (section 4.10.4).

4.7.1 Pipeline ownership

Australia's gas transmission sector is privately owned (table 4.2). The publicly listed APA Group is the largest player, with equity in 13 major pipelines, including key routes into Melbourne, Sydney, Brisbane and Darwin. Other major pipeline owners include Jemena and Singapore Power International.

22 The Hon Daniel Andrews MP (Premier of Victoria), 'Securing gas for future winter warmth' [media release], June 2018.

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

24 ACCC, *Gas inquiry 2017–2025, interim report, January 2021*, February 2021, p 53.

25 EnergyQuest, *EnergyQuarterly*, March 2021, Table 5, p 27.

26 Pipelines with bi-directional flows can ship gas in both directions. Backhaul shipping is the 'virtual transport' of gas in a direction opposite to the main flow of gas. Parking gas is a way of temporarily storing gas in the pipeline by injecting more than is to be withdrawn. Loaning gas allows users to inject less gas into the pipeline than is to be withdrawn.

Table 4.2 Key gas transmission pipelines in eastern and northern Australia

PIPELINE	LOCATION	LENGTH (KM)	CAPACITY (TJ/DAY)	REGULATORY STATUS[1]	OWNER
Roma (Wallumbilla) to Brisbane	Qld	438	211 (125)	Full regulation	APA Group
South West Queensland Pipeline (Wallumbilla to Moomba)	Qld–SA	937	404 (340)	Part 23 regulation	APA Group
Queensland Gas Pipeline (Wallumbilla to Gladstone)	Qld	627	140 (40)	Part 23 regulation	Jemena (State Grid 60%, Singapore Power 40%)
Carpentaria Pipeline (South West Qld to Mount Isa)	Qld	840	119	Light regulation	APA Group
GLNG Pipeline (Surat–Bowen Basin to Gladstone)	Qld	435	1,430	15 year no coverage	Santos 30%, PETRONAS 27.5%, Total 27.5%, KOGAS 15%
Wallumbilla Gladstone Pipeline	Qld	334	1,588	Part 23 and 15 year no coverage	APA Group
APLNG Pipeline (Surat–Bowen Basin to Gladstone)	Qld	530	1,560	15 year no coverage	Origin Energy 37.5%, ConocoPhillips 37.5%, Sinopec 25%
Moomba to Sydney Pipeline	SA–NSW	2,029	489 (120)	Partial light regulation / partial Part 23 Regulation[2]	APA Group
Moomba to Adelaide Pipeline	SA	1,184	241 (85)	Part 23 regulation	QIC Global Infrastructure
Eastern Gas Pipeline (Longford to Sydney)	Vic–NSW	797	358	Part 23 regulation	Jemena (State Grid 60%, Singapore Power 40%)
Vic–NSW Interconnect	Vic–NSW		223 (150)	Part 23 regulation	Jemena (State Grid Corporation 60%, Singapore Power International 40%)
SEA Gas Pipeline (Port Campbell to Adelaide)	Vic–SA	680	314	Part 23 regulation	APA Group 50%, Retail Employees Superannuation Trust 50%
Tasmanian Gas Pipeline (Longford to Hobart)	Vic–Tas	734	129 (120)	Part 23 regulation	Palisade Investment Partners
APA Victorian Transmission System	Vic	1,992	1,030	Full regulation	APA Group
Northern Gas Pipeline (Tennant Creek to Mount Isa)	NT–Qld	622	90	Part 23 regulation	Jemena (State Grid 60%, Singapore Power 40%)
Bonaparte Pipeline	NT	287	80	Part 23 exemption	Energy Infrastructure Investments (APA Group 19.9%, Marubeni 49.9%, Osaka Gas 30.2%)
Amadeus Gas Pipeline	NT	1,626	120	Full regulation	APA Group

km: kilometres; TJ/day: terajoules per day.

1 Full regulation pipelines have their prices assessed by the AER. Light regulation pipelines do not have their prices assessed by the AER, but parties can seek arbitration to address a dispute. Part 23 pipelines are subject to information disclosure and arbitration provisions. Exempt pipelines are subject to no economic regulation. Chapter 5 outlines the various tiers of regulation.

2 The Moomba to Sydney Pipeline is subject to Part 23 regulation only from Moomba to Marsden. Light regulation applies to the remainder of the pipeline.

Note: For bi-directional pipelines, reverse capacity is shown in brackets.

Source: AER; ACCC, interim reports of gas inquiry 2017–2025; corporate websites; Gas Bulletin Board (www.gasbb.com.au).

4.8 Gas imports

In early 2021, 5 LNG import terminals projects were under consideration in NSW, Victoria and South Australia. The intention is to resolve a forecast shortfall in gas supply in the southern states from winter 2023. While some of the facilities were to be operational from as early as 2020, all projects have slipped from their original timeframes because planning, environmental and other challenges have delayed their development.

The LNG import projects include:

- Australian Industrial Energy's (AIE) proposed terminal at Port Kembla (NSW), which is the most advanced project, is scheduled to commence operating from late 2022.[27] The terminal received planning approval from the NSW Government in April 2019, and EnergyAustralia later signed as a foundation customer.[28] [29] While a final investment decision has not been formally announced, AEMO considered the project as committed in its forecasts. AIE has a long term lease with NSW Ports for the terminal's site and an agreement with Jemena to connect the terminal to the Eastern Gas Pipeline[30] [31]
- Venice Energy's proposed terminal at Port Adelaide, scheduled to launch by the end of 2022.[32] In late 2020 Venice announced it has signed its first customer, as well as advancing a project agreement with Flinders Ports for development of the facility.[33] The South Australian State Commission Assessment Panel is expected to make a decision on the development in 2021[34]
- Newcastle GasDock, proposed by Energy Projects and Infrastructure Korea, scheduled to commence operations in mid-2023.[35] The NSW Government in August 2019 designated the project as critical significant infrastructure[36]
- Viva Energy's Gas Terminal project, which is expected to deliver gas as early as 2024. The terminal would be co-located with Viva's Geelong oil refinery and is currently undergoing an environmental assessment[37]
- a potential import terminal in Port Phillip Bay in Victoria. In March 2021 Vopak announced it was considering the feasibility of the terminal.[38] As part of its announcement it indicated that several gas market participants have signed memoranda of understanding in support of the project. It anticipates submitting a proposal to the Victorian Government in the third quarter of 2021.

At April 2021 a final investment decision had not been made for any of the proposed LNG import projects.

In May 2021 AGL ceased development on its proposed floating terminal at Crib Point (Victoria).[39] This followed a determination by the Victorian Minister for Planning in March 2021 that the proposed terminal would have unacceptable environmental effects.[40] Another project backed by ExxonMobil was abandoned in December 2019.

27 EnergyQuest, *EnergyQuarterly*, March 2021, p 27.

28 NSW Government, 'Port Kembla gas terminal approved' [media release], April 2019.

29 AIE and EnergyAustralia, 'AIE welcomes foundational customer EnergyAustralia' [media release], May 2019.

30 AIE, NSW Ports, 'Long term lease for gas terminal another key step towards supply security for NSW and economic boost for Illawarra' [media release], November 2020.

31 AIE, Jemena, 'AIE signs critical gas pipeline deal with Jemena' [media release], November 2020.

32 Venice Energy, 'South Australian LNG import facility advancing' [media release], November 2020.

33 Venice Energy, 'Project agreement signed for LNG import facility at Outer Harbor' [media release], November 2020.

34 Venice Energy, *Outer Harbor LNG project*, Venice Energy website, accessed 28 May 2021.

35 EnergyQuest, *EnergyQuarterly*, March 2021, p 29.

36 NSW Government, 'Newcastle gas terminal given critical status' [media release], August 2019.

37 Viva Energy, *Gas terminal project*, Viva Energy website, accessed 28 May 2021.

38 Vopak, 'News: Vopak LNG studies feasibility to develop LNG import terminal for Victoria' [media release], March 2021.

39 AGL Energy, 'Confirmation of Crib Point impact' [media release], May 2021.

40 Department of Environment, Land, Water and Planning (Vic), *Crib Point: AGL APA gas import jetty and Crib Point – Pakenham gas pipeline*, DELWP website, accessed 28 May 2021.

4.9 Contract and spot gas markets

Wholesale gas is traded in 2 distinct types of market. A majority of gas sales in eastern Australia are struck under confidential bilateral contracts. Around 10–20% of gas is traded in spot markets, with the variation reflecting differences between those markets.[41]

4.9.1 Contract markets

Gas contracts (also known as gas supply agreements) are wholesale supply deals negotiated between sellers and buyers. In contract markets, the 2 main levels of supply offers are:

- offers by gas producers to very large customers such as major energy retailers and gas powered generators
- offers by retailers and aggregators that buy gas from producers and onsell it to commercial and industrial (C&I) customers. Prices quoted to C&I customers tend to be higher than those quoted to very large customers, partly to cover the aggregator's margins. But the ACCC found prices to C&I customers have been unreasonably high due to a lack of competition at times (section 4.11.1).

Long term gas contracts traditionally locked in prices and other terms and conditions for several years. In recent years the industry shifted towards shorter terms for these contracts, with review provisions. In 2019 the ACCC observed the majority of recent offers for gas supply had durations of either one or 2 years.[42]

Public information about contract prices is unclear. Much of the pricing is private, and negotiated contract outcomes are often bespoke. There is also disparity between the type of information available to large participants that are frequently active in the market and that available to smaller players. This imbalance favours large incumbents in price negotiations.

Until recently, no accurate and useful indicative wholesale price was readily available to the market. In response, in 2018 the ACCC began publishing gas price data as part of its 2017–2025 gas inquiry (section 4.14.1).

4.9.2 Spot markets

While most gas is traded under confidential contracts, spot markets allow wholesale customers to trade gas without entering long term contracts. Spot market trading can be a useful mechanism for participants to manage imbalances in their contract positions.

Three separate spot markets operate in eastern Australia. The oldest of the 3 is Victoria's *declared wholesale gas market*, established in 1999. A *short term trading market* for gas was launched in 2010, with hubs in Sydney, Brisbane and Adelaide. More recently, *gas supply hubs* launched in 2014 at Wallumbilla, Queensland, and in 2016 at Moomba, South Australia. The 3 spot markets operate under different rules, follow different procedures, do not interact with each other and have different purposes (box 4.2).

In June 2017 the Australian Energy Market Commission (AEMC) found that having multiple market designs inhibits trading between regions, increases complexity and imposes transaction costs. It recommended that the markets transition in the longer term to a single market design based on the gas supply hub model.[43] As a first step, the gas day start times were harmonised for all east coast markets in 2019 (section 4.14.3). Progress towards harmonising the markets is otherwise slow.

An information platform – the Gas Bulletin Board – was launched in 2008 to provide transparency about gas market conditions and encourage participation in the spot markets. The following sections explain the workings of each spot market and the bulletin board. Section 4.11.2 outlines price trends in the markets.

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

42 ACCC, *Gas inquiry 2017–2020, interim report, July 2018*, August 2018, pp 24, 49.

43 AEMC, *Review of the Victorian declared wholesale gas market – final report, factsheet*, June 2017.

Box 4.2 How the different spot markets work

The gas supply hubs

The gas supply hubs take the form of a voluntary electronic platform for the 'upstream' wholesale trading of gas. Participants using the gas supply hubs can lodge trades either 'on-screen' or 'off-screen'. On-screen trades are matched anonymously through the hubs' electronic trading platform. Each price struck is unique to a particular trade – that is, no market clearing price applies to all participants. Off-screen trades are agreed to by participants bilaterally and then lodged through the hub for settlement. Purely bilateral 'off-market' trades are not reported.

There are 5 standard product lengths that participants can use when trading at the gas supply hubs: balance of day, daily, day ahead, weekly and monthly. As in the other spot markets, the gas supply hubs complement bilateral contracts rather than replace them. But participants can trade gas up to a year in advance of physical supply rather than only on a daily basis as in the other markets.

A significant proportion of trade occurs off-screen, which allows participants to use brokers to match trades on their behalf or leverage their existing bilateral arrangements to facilitate spot trades.[44] Such trades can be negotiated directly over the phone and then lodged through the hubs for settlement, which can be faster if on-screen bids and offers do not match. However, new entrant participants are unable to enjoy these benefits to the same degree, because they do not have legacy arrangements. These participants are more likely to rely on the anonymous on-screen trading platform.

The short term trading markets

The short term trading market allows gas trading on a day-ahead basis. The Australian Energy Market Operator (AEMO) sets a day-ahead clearing price at each hub based on scheduled withdrawals and offers by shippers to deliver gas, with a price floor of $0 per gigajoule (GJ) and a cap of $400 per GJ. All gas supplied according to the schedule is settled at this price. The market provides incentives for participants to keep to their schedules, and the rules oblige participants to bid in 'good faith'. Pipeline operators schedule flows to supply the necessary quantities of gas to each hub. As gas requirements become better known closer to the time of delivery, shippers may renominate quantities with pipeline operators (depending on the terms of their contracts).

If gas deliveries and/or withdrawals from a hub do not match the day-ahead nominations then AEMO procures balancing gas – called market operator services (MOS) – to meet any shortfalls. Conversely, it procures storage on transmission pipelines with capacity to manage an oversupply. Participants make offers to supply MOS, which AEMO calls on in order of lowest to highest price when balancing gas is needed. The parties causing the imbalances mainly pay for the gas procured under this mechanism. The Australian Energy Regulator (AER) has reported instances of abnormally high MOS payments in parts of the market, resulting in some investigations.[45]

Generally, prices in the short term trading markets are volatile, reflecting short term shifts in supply and demand, including conditions in liquefied natural gas (LNG) export markets. Given its responsiveness to short term conditions, the markets are not necessarily indicative of prices that would be struck under contracts. No Australian Securities Exchange derivatives market has developed for the short term trading markets.

The Victorian declared wholesale gas market

The Victorian declared wholesale gas market manages gas flows across the Victorian transmission system. Participants submit daily bids ranging from $0 per GJ (the floor price) to $800 per GJ (the price cap). At the beginning of each day, AEMO selects the least cost bids needed to match demand. This process establishes a clearing price. In common with the short term trading markets, only net positions are traded.

The Victorian market differs from the short term trading market in a number of ways. In the short term trading market, AEMO operates the financial market but does not manage physical balancing (which remains the responsibility of pipeline operators). In the Victorian market, AEMO undertakes both roles and can schedule additional gas injections (typically LNG from storage facilities) at above market price to alleviate short term transmission constraints. Also, the short term trading market is for gas only, while prices in the Victorian market cover gas as well as transmission pipeline delivery.

44 AER market intelligence.

45 AER, *State of the energy market 2017*, 2018, p 76.

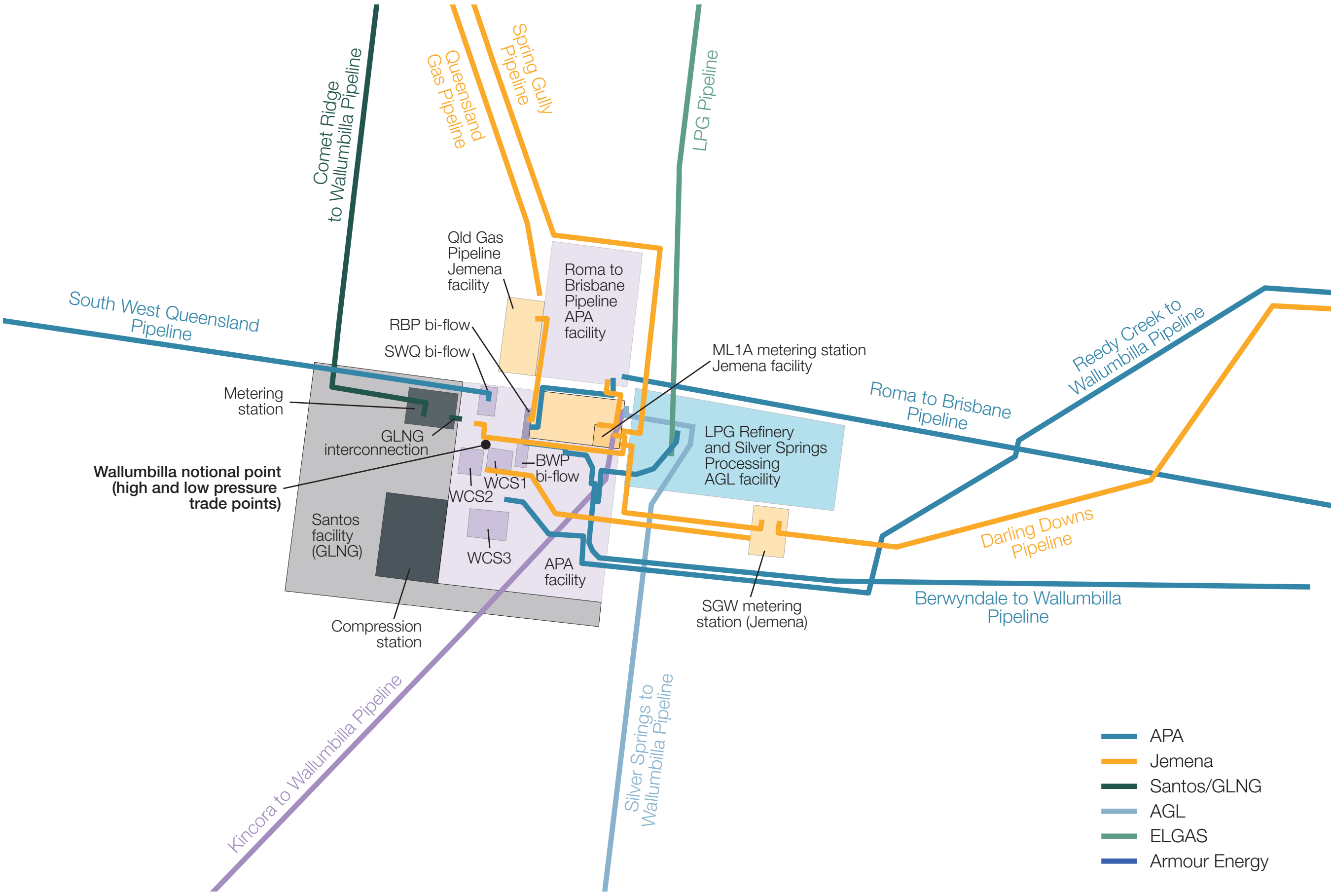
4.9.3 Gas supply hubs at Wallumbilla and Moomba

AEMO launched the gas supply hub model at Wallumbilla, Queensland, in 2014. Wallumbilla is a major pipeline junction linking gas basins and markets in eastern Australia, making it a natural point of trade (figure 4.7).

Until 2017 at the Wallumbilla hub, separate prices were set at 3 major delivery points – the South West Queensland, Roma to Brisbane, and Queensland Gas pipelines. But splitting trade across 3 locations hampered liquidity and trading. Additionally, participants needed access to the transmission pipelines serving the hub, to move gas between those 3 points. This access proved problematic because, while all the pipelines connect with the hub, they do not all physically interconnect with one another.

In March 2017 AEMO replaced the Wallumbilla hub's 3 trading locations with a single Wallumbilla product that groups all delivery points. A single trading location improves liquidity by making it easier for participants to trade across different pipelines, thus pooling potential buyers and sellers into a single market. A separate south east Queensland product was also launched, which provides virtual delivery within the Roma to Brisbane Pipeline.

Figure 4.7 Wallumbilla hub



Source: AER, accounting for consultations with APA Group and public information supplied by APA Group, Santos, AGL, the Queensland Government, Geoscience Australia and AEMO.

Separately, AEMO launched a second gas supply hub at Moomba in central Australia in June 2016. Similar to Wallumbilla, Moomba is a major junction in the gas supply chain serving eastern Australia. Three critical pipelines – the South West Queensland, Moomba to Sydney, and Moomba to Adelaide pipelines – connect to the hub, along with several smaller pipelines and storage facilities. The Moomba hub uses the same model as the Wallumbilla hub, with trade taking place at a central Moomba location.

In 2020, 19 participants traded at the gas supply hubs, of which 17 were active, including 4 new participants.[46] LNG export businesses and gas producers were among the most active participants in 2020. LNG producers are large suppliers of gas into the hubs, although operational issues can limit their participation. In addition, the physical interconnection of LNG facilities allows them to trade easily among themselves. Some market participants have suggested the scale of the LNG producers' operations may involve greater volumes than the hubs can currently

46 We consider a participant 'active' if it makes at least 12 trades in a year.

absorb.[47] Other participants include large retailers, gas powered generators, large industrial users and traders. Activity by traders (including brokers and investors) rose to 20% on average in 2020, up from 12% in 2019.[48]

In 2020, 18 participants traded on-screen, but only 15 traded actively. Similarly, 18 participants traded off-screen, but only 15 were active. On average, participants executed around 220 trades per month in 2020 – a reduction of 27% from 2019 levels.

Wallumbilla hub activity

Trade at Wallumbilla increased progressively since its launch in 2014 but has reduced more recently. The LNG projects use the hub from time to time to manage variations in production and LNG plant performance. Gas powered generators are also significant users of the hub. Most recently, trader participants have increased their activity, taking advantage of the day-ahead auction to arbitrage prices between Wallumbilla and the downstream markets.

In 2020 liquidity at the Wallumbilla hub reduced following significant growth and change in previous years. Traded volumes for 2020 fell from the highs in 2019, primarily due to a collapse in on-screen trading, but remained higher than 2018 levels for all products (figure 4.8). Notably, off-screen products tend to involve larger volumes of gas than do on-screen alternatives. There was also a shift in product preferences in 2020, with most gas traded in daily and monthly products, compared to 2019, where most gas was traded in day-ahead and balance of day products.

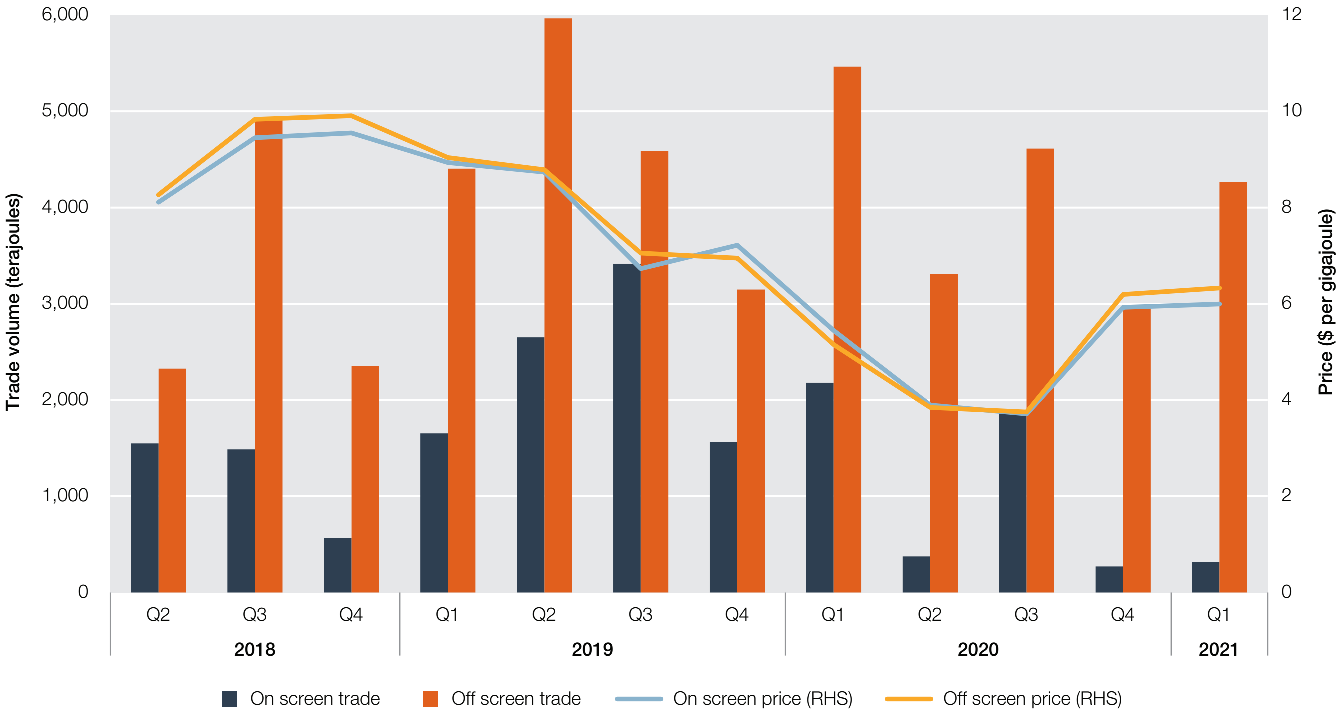
Ultimately, however, gas traded through the Wallumbilla hub represents only a small share of total gas traded, because many participants continue to favour bilateral, off-market arrangements. In 2020 gas traded through the Wallumbilla hub accounted for 6.8% of total gas flows through pipelines in the Wallumbilla bulletin board zone.[49]

Moomba hub activity

Trade at Moomba has been slow to develop. While there have been offers and bids for gas at Moomba, fewer transactions have occurred there compared with Wallumbilla.

The first trade was executed in September 2017, with 141 trades executed in 2019. Similar to Wallumbilla, trades at the Moomba location decreased significantly in 2020.

Figure 4.8 Gas supply hub – on-screen and off-screen price and volume



Source: AER analysis of gas supply hub data.

47 AER market intelligence.

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

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

4.9.4 Short term trading market

In 2020 around 30 participants traded in the Sydney short term trading market (STTM), while the Adelaide and Brisbane markets each had around 20 participants. The participants included energy retailers, power generators, large industrial gas users, and traders. The markets are particularly useful for gas powered generators, because the generators can source gas at short notice when electricity demand is high (and offload surplus gas if electricity demand is low).

Shippers deliver gas for sale into the market, and users buy the gas for delivery to energy customers. Many participants operate both as shippers and users but in effect trade only their net positions – that is, the difference between their scheduled gas deliveries into and out of the market. In the fourth quarter of 2020, gas traded through the STTM met nearly 25% of demand in Sydney, more than 22% in Adelaide and around 8% in Brisbane.[50]

Traded volumes at the Sydney market were 25% higher in 2020 than in 2019, 53% higher at the Brisbane market and 19% higher at the Adelaide market. This increased spot trade has been supported by higher sales volumes from large gas producers, including LNG exporters, with Santos and BHP prominent sellers across 2020. Increased gas availability was due to a combination of excess supply from high production levels in Queensland and generally lower LNG exports in the middle of the year.

Trading profiles varied across the markets. Concentration across the top 3 sellers fell in Brisbane and Adelaide from 2019 to 2020 but rose in Sydney (figure 4.9). Among the top 3 buyers, concentration increased in Brisbane, fell in Adelaide and remained steady in Sydney market for the same period. Importantly, the diversity of large suppliers participating in the spot markets is increasing. Similarly, in 2020, trader participants increased their share of gas scheduled into the STTMs to record levels. These participants took advantage of cheap capacity won on the day-ahead auction to arbitrage prices between markets.

In 2018 the ACCC reported evidence of C&I customers engaging more heavily in the STTM to manage their gas supply, with some users switching to the market to cover their entire demand. This trend has continued. In 2020 the AER reported that participants are using the STTM more heavily, with industrial participants being prominent gas purchasers.[51] This is reflected in new registrations, with more new industrial users registering to participate in the domestic markets than any other participant type since 2018.

Sourcing gas from the spot markets can be to those users' benefit. For example, between late 2019 and mid-2020, spot prices ranged between $4.50 per gigajoule (GJ) and $6 per GJ. Over the same period contract offers for gas delivery in 2020 and 2021 were between $8 per GJ and $11 per GJ.[52] In addition, collective buyer groups have emerged, which improves the purchasing power of the constituent members and helps secure better deals for both spot and contract purchases.

4.9.5 Victoria's declared gas market

Over 30 participants traded in the Victorian market in 2020, including energy retailers, power generators and other large gas users, and traders. From 2019 to 2020, while trading concentration among the top 3 buyers fell slightly, concentration among the top 3 sellers rose significantly from 39% to 54% (figure 4.9). Despite this increased concentration, there is evidence of improving competition between participants driving lower prices in Victoria.[53]

Like the STTMs, volumes traded in the Victorian market rose in 2020, although more modestly (up 2%), after a more significant increase the previous year. Since mid-2019 there has been a consistent increase in quarterly flows of gas into Victoria through the Culcairn injection point. The majority of this is by operators of gas powered generation, but other participants have been increasing their deliveries recently, facilitated by the day-ahead auction.

A small futures market has developed for the Victorian market, with the ASX launching a Victorian gas future product in 2013. But there was little trade until mid-2018. Since the start of 2019, activity and trade volumes have increased and remained consistent. Ultimately this increase still accounts for only a small proportion (around 5% or less) of the total volume traded in the market. However, increasing levels of open interest and increased spot trading in short term markets are encouraging signs.

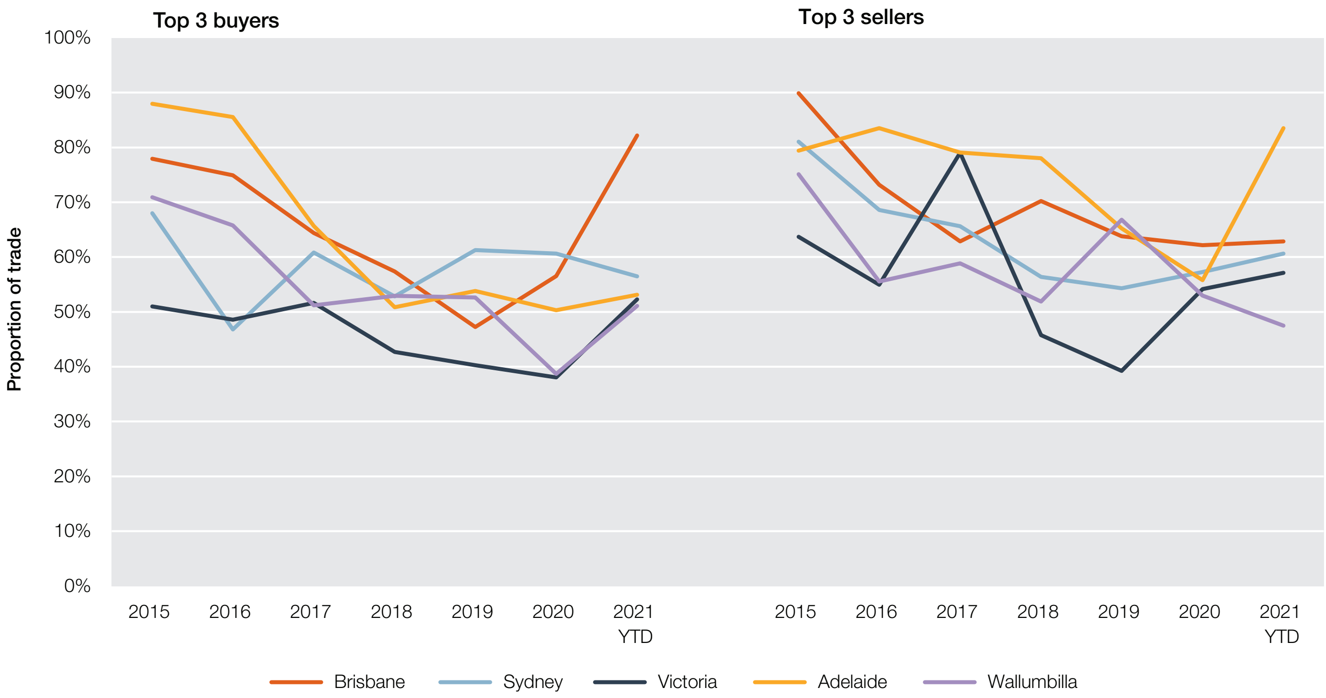
50 AER, *Wholesale markets quarterly – Q4 2020*, February 2021.

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

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

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

Figure 4.9 Top 3 buyers and sellers in eastern Australian gas markets



Source: AER analysis of data from the gas supply hub, short term trading market and Victorian declared wholesale gas market.

4.9.6 Gas Bulletin Board

The Gas Bulletin Board (www.gasbb.com.au) is an open access website providing current information on gas production, storage and transmission pipelines in eastern Australia. Market participants – gas producers, pipeline businesses and storage providers – supply the information to AEMO, which then publishes it. The AER monitors participants' compliance with their obligations to submit accurate data, and enforces compliance.

The bulletin board plays an important role in making the gas market more transparent, especially for smaller players who may not otherwise be able to access day-to-day information on demand and supply conditions. It supplies information such as:

- pipeline capabilities (maximum daily flow quantities, including bi-directional flows), pipeline and storage capacity outlooks, and nominated and actual gas flow quantities
- daily production capabilities and capacity outlooks for production facilities
- gas stored, gas storage capacity (maximum daily withdrawal and holding capacities), and actual injections/ withdrawals.

The bulletin board includes an interactive map showing gas plant capacity and production data; and gas pipeline capacity and flow at any point in a network.

The bulletin board's coverage has progressively widened. Significant reforms in 2018 removed reporting exemptions, mandated greater detail for covered facilities and lowered the reporting threshold to encompass smaller facilities (section 4.14.1). To encourage compliance, the reforms made reporting obligations subject to civil penalties. Reporting obligations were also extended to gas facility operators in the Northern Territory, following the territory's connection to the eastern gas grid in January 2019. Additional reforms are currently under consideration to expand the scope of information reported (section 4.14.1).

4.10 State of the eastern gas market

The development of Queensland's LNG export industry placed significant pressure on the eastern gas market. The pressure, combined with other factors such as state-based moratoriums on gas development, tightened the supply–demand balance. This tightening led to increases in wholesale gas prices from 2017 as international gas prices began to bear on domestic gas prices. However, these price pressures eased over 2020 as international gas prices fell. Also, reforms introduced in 2019 to improve access to critical pipelines allowed a wider range of participants to access cheap transportation, contributing to lower wholesale gas prices in 2020.

Despite COVID-19 dampening LNG exports in the middle of the year, gas production in the northern states again rose to record levels in the fourth quarter of 2020. In the same quarter LNG export demand rebounded, as a spike in international prices drove exports to record levels. This did not have a significant impact on the domestic markets, however, as domestic demand declined and excess gas flowed north to meet demand. The day-ahead auction supported participants' flexibility in responding to prevailing conditions.

4.10.1 Supply conditions

While a majority of eastern Australia's gas reserves are located in Queensland's Surat–Bowen Basin, those reserves are largely committed to the LNG export industry. Each year since 2013, gas production in Queensland has reached record levels. In 2020 production increased again to nearly 4,075 TJ per day as LNG projects ramped up production, particularly in the fourth quarter, to meet record export demand.

Queensland's LNG projects originally planned to source their gas requirements from their own (newly developed) reserves in the Surat–Bowen Basin. But the development of gas wells by Santos's GLNG project was slower than expected. To meet its LNG supply contracts, therefore, Santos sourced substantial volumes of gas from other producers, diverting gas from the domestic market.

The tightening supply–demand balance following the commencement of LNG exports led to concerns in 2017 that gas production may not be sufficient to meet domestic demand. In response, the Australian Government threatened to instruct LNG producers to supply more gas to the domestic market. The Australian Domestic Gas Security Mechanism empowers the Energy Minister to require LNG projects to limit exports or find offsetting sources of new gas if a supply shortfall is likely (section 4.13.2).

To avoid export controls, Queensland's LNG producers have entered a series of heads of agreement with the Australian Government since October 2017, with the most recent agreement in December 2020.[54] Under the agreements, they commit to offer uncontracted gas to domestic buyers on competitive terms before offering it for export.

The LNG projects use various methods to sell more gas domestically, including selling short term gas on the Wallumbilla gas supply hub; launching expression of interest (EOI) processes for customers for long term gas contracts; and entering bilateral arrangements for short term and long term gas contracts. In 2019, for example, APLNG entered new supply agreements with gas powered generators and other large domestic customers.[55]

In 2021 AEMO forecast an improved gas supply outlook compared to previous years. This improved outlook reflected progress in the planning for AIE's Port Kembla LNG import terminal. While a final investment decision is still forthcoming, the project appears committed and is estimated to be capable of delivering up to 500 TJ per day into the southern region. If the project is commissioned ahead of winter 2023, alongside other committed field development and pipeline expansions, AEMO forecast that the additional supply will be sufficient to offset significant reductions in Victorian production.

Despite improved supply forecasts in the short run, the longer term outlook is uncertain. AEMO forecast that, even with the addition of the Port Kembla import terminal, supply gaps could emerge by 2026.[56] Similarly, the ACCC reported a broader shortfall in supply from 2P reserves could emerge by 2026.[57] Both AEMO and the ACCC suggested more exploration and development in southern Australia, pipeline expansions and LNG imports could mitigate the supply risks.

54 Department of Industry, Science, Energy and Resources, *Securing Australian domestic gas supply*, DISER website, accessed 28 May 2021.

55 Australia Pacific LNG, 'Australia Pacific LNG delivers new gas supplies to domestic manufacturers' [media release], 4 July 2019; Australia Pacific LNG, 'Australia Pacific LNG continues strong support of domestic gas market' [media release], 26 September 2019.

56 AEMO, *2021 gas statement of opportunities*, March 2021, p 5.

57 ACCC, *Gas inquiry 2017–2020, interim report, January 2021*, February 2021.

Long term supply conditions are uncertain for a number of reasons. First, some developed resources may underperform, and southern production may decline faster than expected. Second, forecasts make assumptions about undeveloped gas fields with uncertain reserves. These assumptions are increasingly unreliable, as the long term security of supply for the east coast increasingly depends on more speculative sources of supply – that is, 75% of 2C resources in early 2020 were located in fields that were not yet in production or approved for development, and some 2P reserves and resources in Queensland have been written down.[58] [59] While some development proposals in eastern Australia show promising signs, others face significant regulatory hurdles linked to environmental concerns.

In response to this ongoing supply uncertainty, the Australian Government and some state governments launched initiatives to encourage new projects to supply the domestic market (section 4.13).

Supply conditions in the northern region

Gas supply to the northern gas market is largely supplied from Queensland's Surat–Bowen Basin. But gas is also sourced from the Cooper Basin in South Australia and, since 2019, from the Northern Territory (via the Northern Gas Pipeline). At times, southern gas is also transported north to meet LNG export demand.

Gas production in the Surat–Bowen Basin rose exponentially from 2014 to 2017 to meet the demands of Queensland's LNG export industry. While production has continued to rise since 2017, the year on year growth was less dramatic and has levelled out now all LNG projects have reached full operation.

Despite this levelling out, northern production in 2020 rose to record levels of almost 4,500 TJ per day. In the fourth quarter of 2020, Queensland facilities produced a record 4,240 TJ of gas per day – a slight increase from the previous record of 4,126 TJ per day in the fourth quarter of 2019. This record production coincided with record levels of LNG exports in the fourth quarter of 2020 as Asian LNG prices spiked, despite generally low international gas and oil prices across the year.[60]

Supply conditions also depend on the availability of transmission pipeline capacity to transport gas to customers. Improving this availability, pipeline operators are considering a range of upgrades to extend or expand existing infrastructure. For example, in 2020 APA announced that it was investigating adding compression to both the South West Queensland Pipeline and Moomba to Sydney Pipeline to increase delivery capacity from northern fields to southern markets.[61]

New entry

Across 2020 the number of suppliers in the eastern market rose, and some producers expanded their presence in downstream markets.[62] Also, the growth of traders participating in eastern Australian gas markets disrupted dominant players and provided C&I customers with competitive alternative sources of gas.

Five new projects are expected to commence operations in Queensland over the next 4 years. The operators of these projects include Arrow Energy, Denison Gas and QGC.[63] As a result, supply options to C&I gas users appear to be improving.

Supply conditions in the southern region

Historically, the Victorian gas basins and the Cooper Basin in central Australia were pivotal to meeting domestic gas demand in southern Australia. Since 2018 gas from the northern fields has been required to supplement Victorian gas production and balance southern gas demand.

Production in Gippsland is transitioning from old to new fields, but it is not yet clear how much the new gas fields can produce. After achieving record production levels in 2017, production from the Longford plant, servicing the Gippsland Basin, fell. The plant is becoming less reliable because it is run harder for longer, and plant constraints and maintenance outages increasingly disrupt production.

58 2C resources represent the best estimate of contingent gas reserves, which are not yet technically or commercially recoverable.

59 Queensland reserves were downgraded (on a net basis) by more than 4,400 PJ between 1 July 2017 and 30 June 2019. See ACCC, *Gas inquiry 2017–2025, interim report, January 2020*, February 2020.

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

61 APA, 'APA response to 2020 GSOO' [media release], May 2020.

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

63 ACCC, *Gas inquiry 2017–2025, interim report, January 2021*, February 2021, p 39.

In 2021 AEMO reported the anticipated decline in production in key southern fields had accelerated, with the fields expected to deplete by winter 2023.[64] The depletion of these fields will place greater pressure on the southern markets and reduce peak day supply capacity. But new projects are expected to be address this supply concern.

Cooper Energy's Sole project in the Gippsland Basin began commercial operation in March 2020. The project is the first new production well drilled in offshore Victoria since 2012, and it can produce up to 25 PJ per year. However, production from this field has been impacted by problems at the Orbost gas plant.[65] Another project, the West Barracouta joint venture between Esso Australia and BHP Billiton, is scheduled to be operational in 2021.

Production from these new projects is likely to be supported by new supply from AIE's planned 500 TJ per day Port Kembla LNG import terminal. While other import terminal projects exist, Port Kembla appears to be the most progressed. With commitments the terminal will be operational ahead of winter 2023, AEMO deferred previously forecast supply shortfalls to at least 2026. As part of planning for the Port Kembla LNG import terminal, Jemena is proposing an extension and upgrade to the Eastern Gas Pipeline. This project would connect the terminal to the eastern Australian gas markets and allow delivery of significant gas volumes into both NSW and Victoria.[66] Jemena is also considering extending the pipeline into the Hunter Valley to support proposed gas powered generation in the region.[67]

Regulatory barriers to gas development

In some states and territories, community concerns about environmental risks associated with fracking led to legislative moratoria and regulatory restrictions on onshore gas exploration and development.[68] Victoria, South Australia, Tasmania, Western Australia and the Northern Territory have onshore fracking bans in place, with varying degrees of coverage:

- In 2017 the Victorian Government banned onshore hydraulic fracking and exploration for and mining of CSG or any onshore petroleum until 30 June 2020.[69] In March 2021 the government committed the ban on fracking and CSG exploration to the Victorian Constitution.[70] Onshore conventional gas exploration will recommence from July 2021.
- In 2018 South Australia introduced a 10-year moratorium on fracking in the state's south east. It introduced the moratorium by direction and announced its intention to legislate it. However, unconventional gas extraction is allowed in the Cooper and Eromanga basins. South Australia has no restrictions on onshore conventional gas.
- In 2015 the Tasmanian Government banned fracking for the purpose of extracting hydrocarbon resources (including shale gas and petroleum) until March 2020. This has since been extended to 2025.[71]
- In 2018 the Northern Territory made 51% of the territory eligible for hydraulic fracturing. The decision covers much of the Beetaloo Basin, which holds most of the territory's shale gas resources.

Queensland does not restrict fracking. NSW has no outright ban on onshore exploration, but significant regulatory hurdles have stalled development proposals. Regulatory restrictions include exclusion zones, a gateway process to protect 'biophysical strategic agricultural land', an extensive aquifer interference policy, and a ban on certain chemicals and evaporation ponds.[72] The state's regulations also require community consultation on environmental impact statements; and a detailed review process for major projects, as highlighted by the protracted process for Santos's Narrabri gas project.[73] Under an agreement reached in early 2020, the NSW and Australian governments set a target of increasing supply to the NSW market by 70 PJ per year.[74]

64 AEMO, *2021 Victorian gas planning report*, March 2021.

65 EnergyQuest, *EnergyQuarterly*, March 2021.

66 Jemena, 'More gas for Victoria by 2023' [media release], March 2021.

67 Jemena, 'Jemena reveals plans to extend Eastern Gas Pipeline' [media release], September 2020.

68 Hydraulic fracturing, also known as fracking, is a process that involves injecting a mixture of water, sand and chemicals at high pressure into underground rocks to release trapped pockets of oil or gas. A well is drilled to the depth of the gas or oil bearing formation, then horizontally through the rock. The fracturing fluid is then injected into the well at extremely high pressure, forcing open existing cracks in the rocks, causing them to fracture and breaking open small pockets that contain oil or gas. The sand carried by the fluid keeps the fractures open once the fluid is depressurised, allowing oil or gas to seep out.

69 Department of Economic Development, Jobs, Transport and Resources (Victoria), Onshore gas community information, August 2017.

70 Victorian Government, 'Enshrining Victoria's ban on fracking forever' [media release], March 2021.

71 Department of State Growth (Tas), *Tasmanian Government policy on hydraulic fracturing (fracking) 2018*, DSG website, accessed 28 May 2021.

72 Department of Planning and Environment (NSW), Initiatives overview, July 2018.

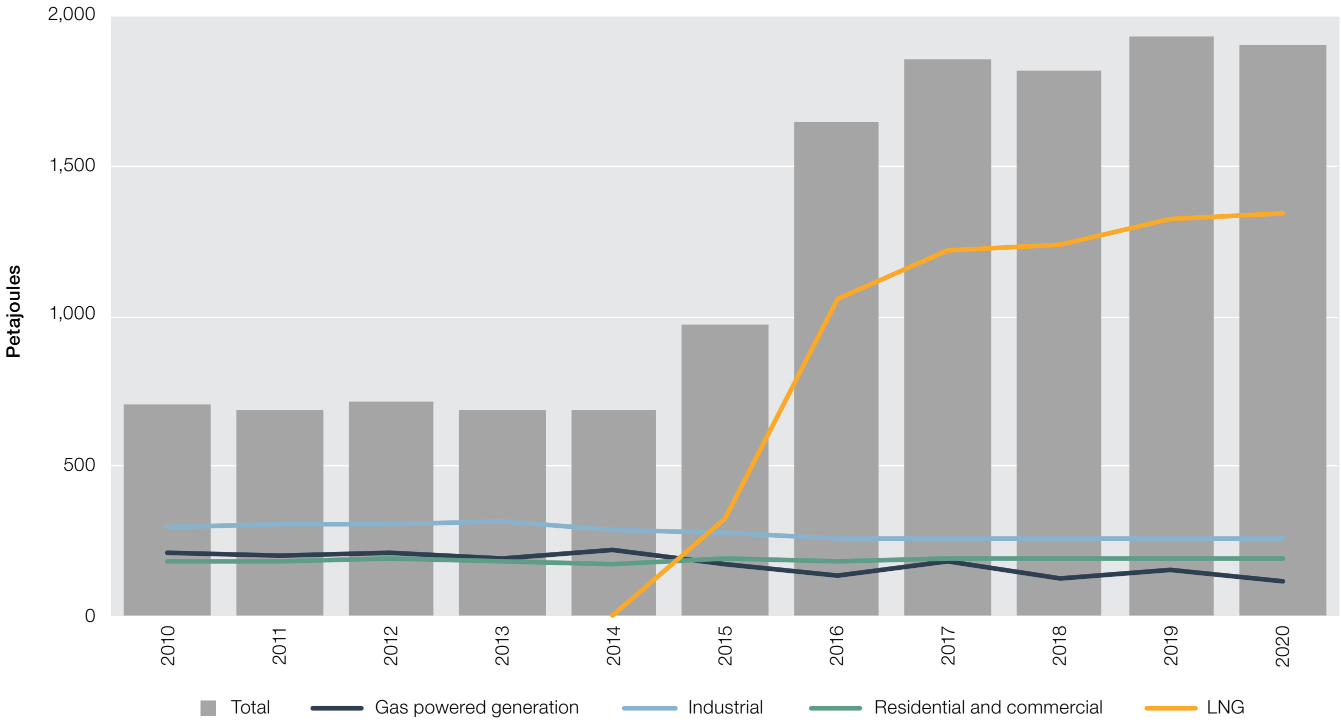
73 Department of Planning and Environment (NSW), 'Community views on Narrabri Gas Project to be addressed' [media release], 7 June 2017.

74 Prime Minister of Australia and Premier of New South Wales, 'NSW energy deal to reduce power prices and emissions' [media release], January 2020.

4.10.2 Demand conditions

Historically, demand for eastern Australian gas derives from 3 main domestic sources – C&I gas users, gas powered generators and residential customers. However, with the launch of LNG exports in 2015, international customers became a new source of demand competing to buy eastern Australian gas (figure 4.10).

Figure 4.10 Eastern Australian gas demand



Source: AEMO, 2021 gas statement of opportunities, March 2021.

Domestic gas use

Higher gas prices have weakened gas demand by industrial customers since 2014. Despite this trend, industrial demand remained relatively steady across 2020, supported by easing prices. The COVID-19 pandemic did not appear to have a significant effect on demand from industrial customers.[75] However, the impact of COVID-19 on other areas of these users' businesses may lead to heightened sensitivity regarding future gas prices and affect consumption.

Despite improving conditions over 2020, longer term concerns still exist and participants are exploring strategies to manage the risk of high prices, including forming buyers groups and using brokers to secure favourable contract arrangements.

Among domestic sources of demand, gas powered generation is the most volatile (figure 4.11). Gas is a relatively expensive fuel for electricity generation, so gas generators typically operate as 'flexible' or 'peaking' plants that can be switched on at short notice to capture high prices in the electricity market. Gas demand for power generation, therefore, tends to be seasonal, peaking in summer (and sometimes winter) when electricity demand and prices are higher. It also varies with the amount of renewable generation available (which is cheap but weather dependent).[76] Gas generation is forecast to play an increasingly important role over winter when solar photovoltaic generation is lower and coal fired capacity may be withdrawn for maintenance.[77]

Rising gas fuel costs linked to Queensland's LNG industry, along with a shortage of gas supplies linked to state-based moratoriums on gas exploration and production, stalled demand for gas powered generation in the state from 2015 to 2019. Gas powered generation slumped from 17% of Queensland's electricity output in 2015 to 8% in 2020. A similar squeezing-off occurred in NSW.

75 ACCC, *Gas inquiry – January 2021 interim report*, January 2021.

76 EnergyQuest found a –89% correlation between gas and hydroelectric generation; and a –48% correlation between gas and wind generation over 42 months to June 2018. See EnergyQuest, *EnergyQuarterly*, September 2018, p 35.

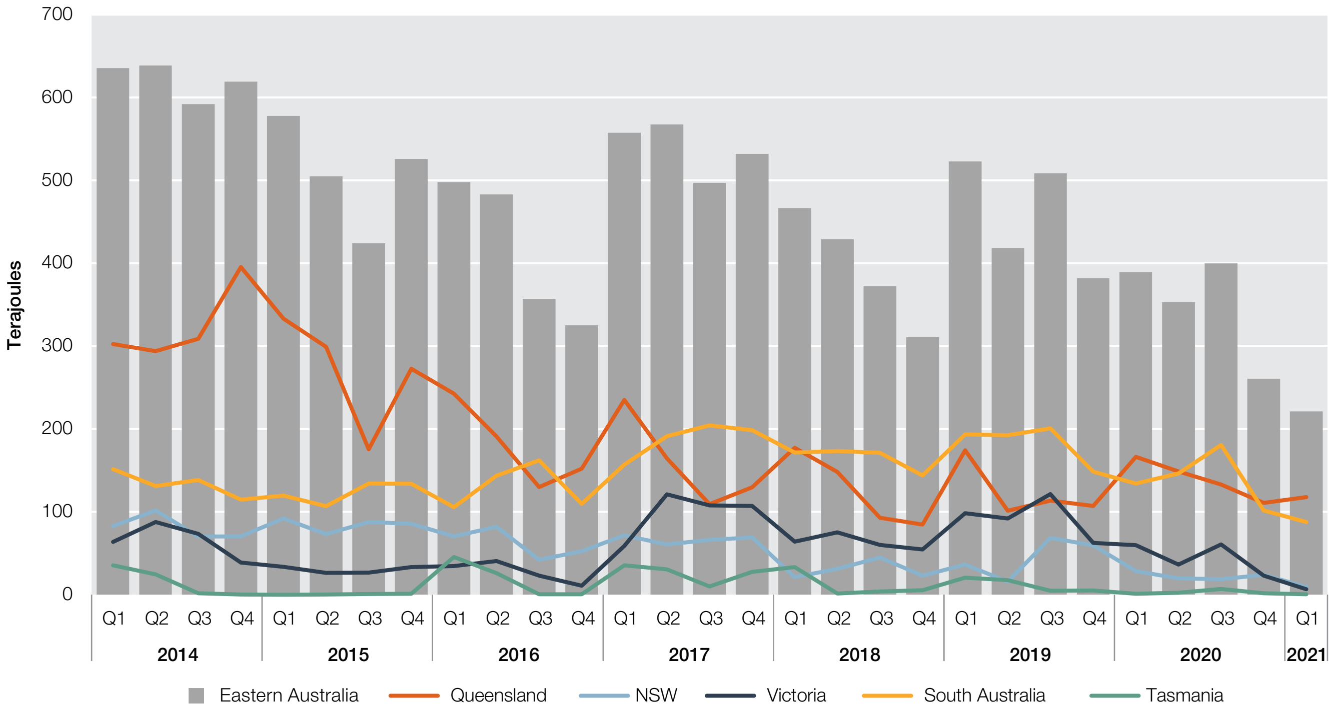
77 AEMO, *Gas statement of opportunities 2021*, p 37.

Different conditions prevailed in Victoria and South Australia, where coal generation retirements and rising outages among remaining plant made gas generation critical to meeting electricity demand. In particular, when Hazelwood power station closed in 2017, gas powered generation rose in both states. As a result, demand for gas powered generation rose across 2017 to 2019.

In 2020 gas powered generation fell in all southern regions due to constrained demand and low electricity prices. Gas powered generation fell from 3% to 2% of electricity generation in NSW, 7% to 3% in Victoria, and 48% to 41% in South Australia. The reduced generation South Australia coincided with the closure of 2 units at the Torrens Island A power station in September 2020. While gas generators offered more capacity in Victoria, it was priced at higher levels so was dispatched less. Over the same period, gas powered generation increased from 8% to 10% of all electricity generation in Queensland as a result of greater generation at Swanbank E power station. This reflected a change in operation of the plant following its transfer to CleanCo.

Gas used for gas powered generation continued to decline in the first quarter of 2021, recording the lowest quarterly level since 2006.[78] However, AEMO expects gas powered generation to fill an electricity supply gap across 2021 caused by higher coal generator outages.[79]

Figure 4.11 Quarterly gas demand for gas powered generation



Source: AEMO; National Electricity Market (NEM) generation data and heat rates (gigajoules per megawatt hour).

Liquefied natural gas exports

LNG exports continue to grow, with record volumes over 2020 (and a record quarterly volume in the fourth quarter of 2020) contributing to Australia remaining the world's largest exporter of LNG.[80] Both APLNG and QCLNG projects operated at or above capacity in 2020, contributing to record eastern Australian production levels (figure 4.12).

China is the primary market for eastern Australian LNG, accounting for 67% of exports in 2020 (815 PJ). Chinese exports were 6% lower than the previous year's volume, marking the first year that Chinese demand decreased since LNG exports commenced. Despite this reduction, China's LNG demand is expected to continue to grow, supported by expanded industrial and residential gas use.[81]

78 AER, *Wholesale markets quarterly Q1 2021*, May 2021.

79 AEMO, *Gas statement of opportunities*, March 2021, p 37.

80 EnergyQuest, *EnergyQuarterly*, March 2021.

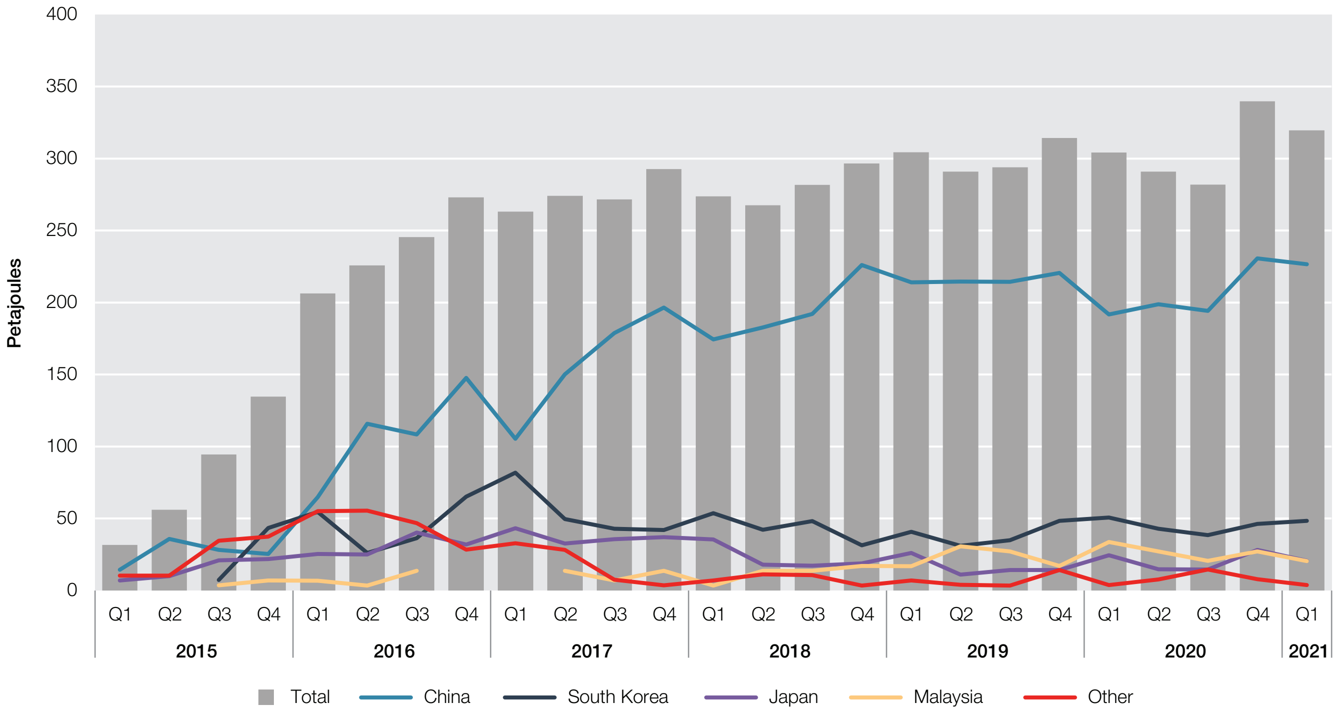
81 Department of Industry, Science, Energy and Resources, *Resources and energy quarterly*, December 2020.

The other main sources of demand for eastern Australian LNG increased in 2020, offsetting the decrease in Chinese demand. Japan's demand grew by 26% in 2020 to 82 PJ and South Korean demand rose by 15% to 178 PJ. Government policies restricting coal fired generation may buoy gas demand in South Korea over the coming decade, but greater use of nuclear reactors for electricity generation will likely reduce longer term gas demand from both Japan and South Korea. Malaysian demand for LNG also increased 17% in 2020 to 108 PJ.

Strong demand caused a surge in LNG spot prices from mid-2017. Monthly Asian spot prices reached around $14 per GJ in December 2017 and remained elevated throughout 2018. But new LNG capacity in the United States, Australia and Russia came online in 2019, creating an oversupply and driving prices lower.

A slowing Chinese economy, Japan's ongoing switch away from gas powered generation, and further increases in US export capacity kept downward pressure on prices in late 2019 and early 2020. Also in early 2020 the outbreak of COVID-19 contributed to reduced Asian LNG demand and weaker spot LNG and oil prices.[82] This price downturn coincided with intense price competition among oil exporting countries. Australian exporters reported that the uncertainty stemming from COVID-19 and collapsing oil prices limited their ability to strike new gas supply agreements and finalise investment decisions.[83]

Figure 4.12 Eastern Australian gas exports



Source: Gladstone Ports Corporation; trade statistics.

The COVID-19 pandemic resulted in changes to supply–demand profiles, project deferrals and asset sales; and sustained downward pressure on prices. Despite this, the eastern Australia LNG industry remained resilient. As LNG export flows decreased, producers seized the opportunity to conduct maintenance and divert flows into storage facilities.

Late in 2020 Asian LNG demand rebounded during the northern hemisphere winter. From December 2020 to January 2021 a cold snap created unexpectedly strong LNG demand in Asia, leading to high international prices. This also coincided with coal supply issues in China, and congestion at the Panama Canal, which caused delays in cargoes reaching Asia from further afield. This drove record eastern Australian LNG exports in 2020.

This volatility was short lived, however. By mid-January 2021 Asian LNG prices returned to levels similar to before the spike. Eastern Australian LNG exports fell slightly in the first quarter of 2021, but remained at high levels buoyed by continued winter heating and generation needs and robust industrial demand.

82 AER, *Wholesale markets quarterly – Q1 2020*, May 2020.

83 AER, *Wholesale markets quarterly – Q1 2020*, May 2020.

4.10.3 Inter-regional gas trade

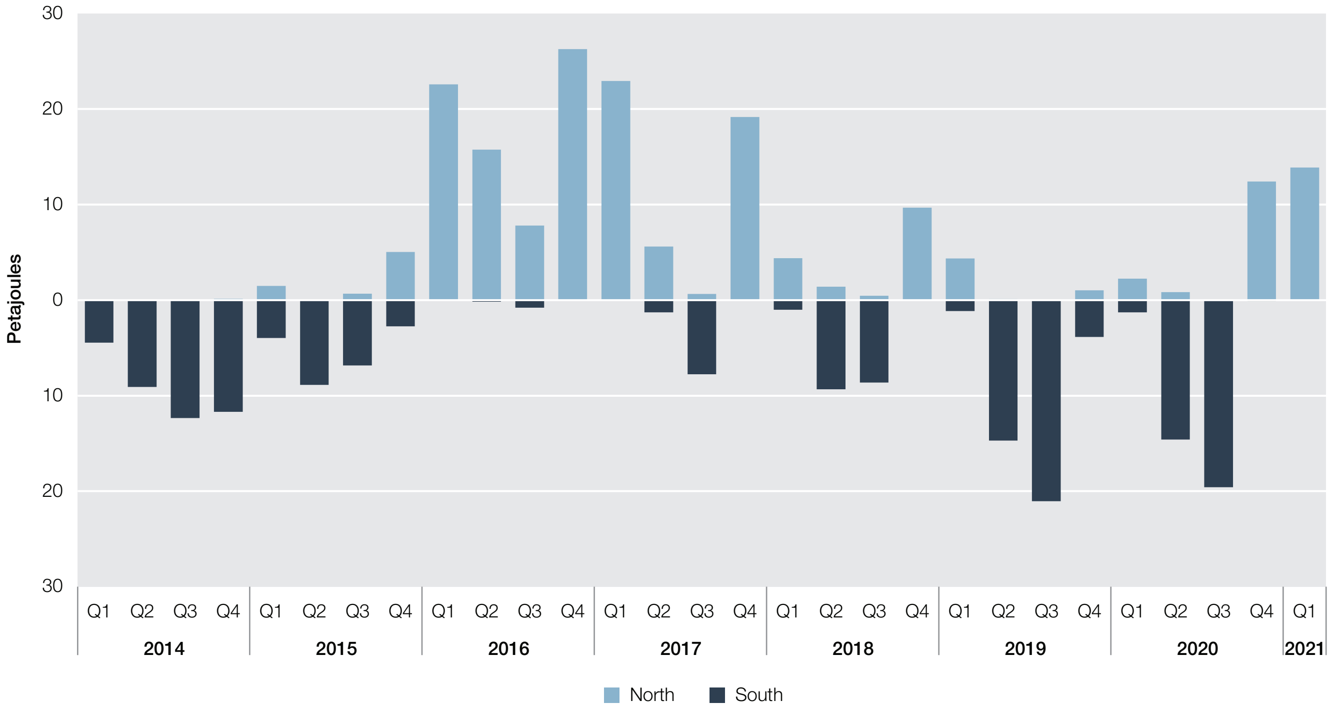
A signature feature of the domestic gas market since 2014 is the role of inter-regional gas trades to manage the supply–demand balance. Key pipelines have been re-engineered as bi-directional, enabling them to respond more flexibly to regional supply and demand conditions.

With the launch of Queensland's LNG projects in 2015, the projects began drawing substantial volumes of gas from Victoria and South Australia to cover shortfalls in their reserve portfolios. Conditions in the domestic electricity market also affect trade flows. Following the closure of coal fired generators in the southern states, increased demand for gas powered generation in those states drew gas south, especially during the Australian winter, when heating demand peaks. In recent years, gas flows turn southbound even before the onset of winter.

The threat of government intervention in the gas market (section 4.13) also impacted flows from late 2017. To avoid triggering intervention, Queensland's LNG producers began offering more gas to the domestic market, which increased southbound trade flows. Exporters committed to the Australian Government to first offer any uncontracted gas to the domestic market on a competitive basis.

Following these events, flows settled into a cycle of gas flowing south in the Australian winter (to meet heating demand) and north in the Australian summer (the northern hemisphere winter) when Asia's LNG demand peaks (figure 4.13).

Figure 4.13 North–south gas flows in eastern Australia



MSP: Moomba to Sydney Pipeline; QSN: Queensland / South Australia / New South Wales; SWQP: South West Queensland Pipeline.

Note: Flows on the QSN Link section of the South West Queensland Pipeline. Northbound flows are from the southern states into Queensland. Southbound flows are exports from Queensland to the southern states.

Source: AER analysis of Gas Bulletin Board data.

More recently, the cycle appears to be shifting towards net southern flows – that is, less gas flowing north in summer and more flowing south in winter. Across most of 2020, net flows were southward. However, in the fourth quarter of 2020, net flows north were at the highest level in 3 years in response to increase LNG export demand. The day-ahead auction supported this turnaround as participants bought capacity on routes north (section 4.10.4). Notably, on the South West Queensland Pipeline 95% of all capacity purchased in the fourth quarter of 2020 was on routes north towards Wallumbilla

Data on trade flows may understate the extent of north–south gas trading. Some gas producers enter swap agreements to deliver gas to southern gas customers without physically shipping it along pipelines. An example is Shell's agreement with Santos to swap at least 18 PJ of gas.[84] Under the agreement, Shell draws on its CSG reserves to meet part of Santos's LNG supply obligations in Queensland, while Santos diverts gas from the Cooper Basin to

84 Santos, 'Santos facilitates delivery of gas into southern domestic market' [media release], August 2017.

meet demand in southern Australia.[85] The swap allows the producers to increase supply to the domestic market, while enabling Shell to avoid transporting gas on the South West Queensland Pipeline, which is contracted to near full capacity. To improve transparency, from 2021 participants' reporting requirements are expected to expand to encompass a range of bilateral arrangements, including physical swaps (section 4.14.1).

Gas flows into NSW

NSW produces little of its own gas, so it is highly trade dependent. Previously supplied by Victorian sources, as Queensland production fields ramped up and sent more gas south, NSW became reliant on Queensland gas to supplement declining Victorian gas production. As a result, gas volumes shipped along the Moomba to Sydney Pipeline and the South West Queensland Pipeline rose significantly.

The critical role of these pipelines in delivering gas to NSW on peak days highlights the risk of capacity constraints. The South West Queensland Pipeline in particular has little uncontracted capacity between Wallumbilla (Queensland) and Moomba (South Australia), which is the origin point of the Moomba to Sydney Pipeline. But capacity trading reforms introduced on 1 March 2019 eased pressures somewhat (section 4.10.4). In addition, proposals for LNG import terminals, and gas pipelines that may open flows from Queensland, could improve gas availability in NSW. In particular, the Port Kembla import terminal is significantly progressed and is expected to alleviate short term supply concerns.

4.10.4 Pipeline access

Wholesale gas customers buy capacity on transmission pipelines to transport their gas purchases from gas basins. Gas production companies and gas pipelines are separately owned, so a gas customer must negotiate separately with producers to buy gas and with pipeline businesses to have the gas delivered. To reach its destination, gas may even need to flow across multiple pipelines with different owners.

Since LNG exports began in 2015, gas flows from the southern states to Queensland, and sometimes the reverse, have helped manage inter-regional supply–demand imbalances. For this reason, access to transmission pipelines on key north–south transport routes is critical for gas customers. But many critical pipelines have little or no spare, uncontracted capacity, making it difficult to negotiate access. In addition, many pipelines face little competition and charge monopolistic prices.

In 2015 the ACCC found a majority of transmission pipelines on the east coast were using market power to engage in monopoly pricing.[86] Reforms were implemented to address this issue, including a new information disclosure and arbitration framework that came into effect in August 2017; and changes to full and light regulation, which came into effect in March 2019 (section 5.3).

Reforms introduced in March 2019 made it easier to access pipeline capacity that is not fully used. Capacity on some pipelines is fully contracted to gas shippers, who do not fully use it. The reforms give other parties an opportunity to access this capacity through trading platforms.

Capacity can be acquired in 2 ways. First, the capacity trading platform allows shippers to sell any capacity they do not expect to use. Second, any unused capacity not sold in this way must be offered at a mandatory day-ahead auction. Any shipper can bid at the auction, which is finalised shortly after the nomination cut-off time a day in advance of the relevant gas day.

Auction revenues go to the pipeline, or facility operator, rather than the shippers that own the capacity rights. The auctions have a reserve price of zero, and the majority of settlements in 2020 occurred at no cost.[87]

To promote transparency, the Gas Bulletin Board publishes prices and other key terms from all voluntary trades and auctions. The AER monitors compliance with capacity trading regulations and the proper reporting of trades; and oversees the resolution of any cost recovery disputes.

85 EnergyQuest, *EnergyQuarterly*, March 2020.

86 ACCC, *Inquiry into the east coast gas market*, April 2016, p 18.

87 While participants can win capacity for $0 per GJ, additional charges and registration fees make the real cost slightly higher.

Pipeline capacity trading

In 2021 the AER reported on how the day-ahead auctions provided access to over 73 PJ of contracted but un-nominated pipeline capacity (across 12 facilities) in the 2 years after it launched on 1 March 2019 (figure 4.14). Of this, around 80% of this capacity was won at the reserve price of zero.

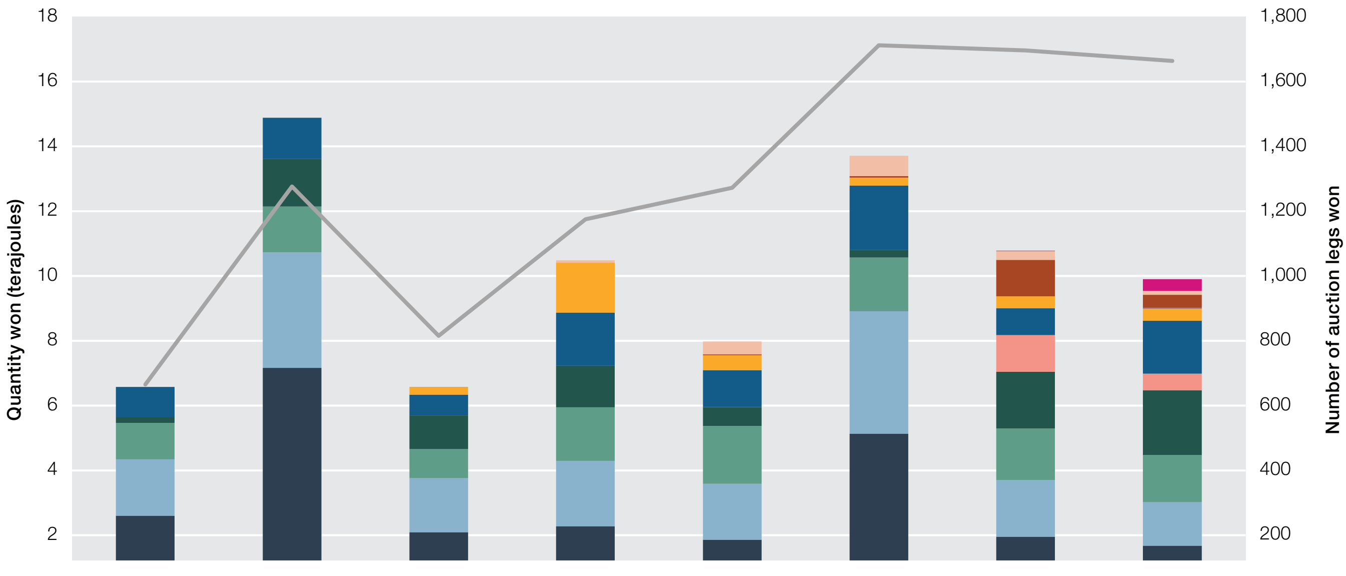
In the 2 years to March 2021 there has only been one trade on the voluntary capacity trading platform: 1 TJ of capacity for $0.02 per GJ. The ACCC reported shippers expect activity in the capacity trading platform to increase over time.[88]

The day-ahead auction has improved market dynamics by enhancing competition, especially in southern markets. Access to low or zero cost pipeline capacity is allowing shippers to move relatively low priced northern gas into southern spot markets, easing price pressure in those markets. The AER estimated the auctions effectively reduced monthly average spot gas prices by as much as $0.63 per GJ in Sydney over the 2 years to December 2020.[89]

The AER's *Pipeline capacity trading – two year review* found day-ahead auction capacity increased liquidity in both upstream and downstream markets. It also reported on how the auction can indirectly ease supply costs for some gas powered generators in the National Electricity Market (NEM). As an example, on 24, 25 and 26 August 2020, when electricity spot prices were high in Victoria, participants used the day-ahead auction to secure additional capacity in response to gas generators running harder than anticipated. Participants win most auction capacity in winter months, particularly on the Moomba to Sydney and South West Queensland pipelines, to assist delivery of gas to southern markets.[90]

However, auction activity on some pipeline remains low. In particular, the AER reported that no capacity has been purchased for the SEA Gas Pipeline System despite there being auction capacity available.[91] The other pipeline connecting to the Adelaide market, the Moomba to Adelaide Pipeline System, has also seen limited trade, although participation is increasing. Under-utilisation of these pipelines may result from higher fees and lower activity levels in Adelaide compared to other markets. Auction fees can discourage smaller players in particular. While the majority of capacity is won at the reserve price of $0 per GJ, the total cost is higher, as participants need to pay pipeline and storage operators for facility use (which can include both fixed and variable fees). Smaller participants also may be required to provide credit support, or collateral to use auction services, and in some cases these costs can be significant.

Figure 4.14 Day-ahead auction quantities won, by facility



BWP: Berwyndale to Wallumbilla Pipeline; CGP: Carpentaria Gas Pipeline; EGP: Eastern Gas Pipeline; ICF: Iona Compression Facility; MAPS: Moomba to Adelaide Pipeline; MCF: Moomba Compression Facility; MSP: Moomba to Sydney Pipeline; QGP: Queensland Gas Pipeline; RBP: Roma to Brisbane Pipeline; SWQP: South West Queensland Pipeline; WCFA/B: Wallumbilla compression facilities.

Source: AER analysis of day-ahead auction data.

88 ACCC, *Gas inquiry 2017–2025, interim report, January 2020*, February 2020, pp 103–104.

89 AER, *Pipeline capacity trading – two year review*, March 2021, p 23.

90 AER, *Wholesale markets quarterly – Q3 2020*, November 2020, p 30.

91 AER, *Pipeline capacity trading – two year review*, March 2021.

4.11 Gas prices

The launch of LNG exports from Queensland in 2015 linked domestic gas prices (which were traditionally fairly stable) to more volatile international oil and gas prices. This link drove prices higher in 2016 and 2017, but operated in reverse in late 2019 and 2020 when lower Asian prices helped drive falls in domestic spot prices.

Other factors contributing to lower domestic prices across 2020 included high levels of Queensland gas production, increased competition in spot gas markets, decreased demand for gas powered generation, and the availability of cheap capacity through the day-ahead auction. The auction in particular allowed some shippers to move gas from northern to southern markets at near zero transportation costs.

4.11.1 Gas contract prices

A majority of gas prices are agreed in confidential bilateral contracts, either between gas producers and large customers or between retailers/aggregators and C&I customers (section 4.9.1).

Domestic gas contract prices historically averaged around $3–4 per GJ. But, when Queensland's LNG projects began sourcing gas from Victoria and South Australia, this demand drove contract prices higher. By early 2017 domestic prices of $22 per GJ were being quoted for a one or 2-year contract – almost $10 per GJ above export prices.[92] At their peak in March 2017, domestic prices offered by retailers nearly doubled LNG netback prices (box 4.3).

Following the Australian Government's market intervention in 2017 (section 4.10.1), Queensland producers began offering more gas to the domestic market at lower prices. By 2018 contract offers had eased into the high $8–11 per GJ range, aligning them more closely with Asian LNG netback prices. In late 2018 domestic prices separated significantly from Asian LNG netback prices due to a short term international price spike as domestic prices flattened out. Across 2019 and 2020 these prices generally decreased together, resulting in falls in contract offer prices.

Prices offered by both producers and retailers for 2021 supply were mostly in the $6–8 per GJ range over 2020.[93] This was a significant reduction from a year previous. Similarly, contract prices agreed to by C&I users decreased notably in 2020, falling to under $8 per GJ. This likely reflects depressed Asian LNG prices across 2020.

Across 2019 producer offers diverged from LNG netback prices as netback prices fell at a more rapid pace. In some instances, producer offers included new pricing structures, such as a fixed price component, on top of an LNG spot price linked component.[94] This trend continued across 2020, although the price disparity narrowed somewhat in the second half of the year.

In contrast with price trends in the north, average prices offered by producers and retailers in the southern states in 2020 fell below expected LNG netback prices (factoring in pipeline costs). The ACCC noted an improvement in the competitive dynamic over 2020 has contributed to this fall in prices, amongst other factors.[95]

Despite gas prices easing, the ACCC reported many C&I users are experiencing difficulties in procuring gas beyond 2022. Where suppliers have provided offers, users report concerns around future supply resulting in risk premiums being incorporated into contract prices.[96]

92 ACCC, *Gas Inquiry 2017–2020, interim report, July 2018*, August 2018.

93 ACCC, *Gas inquiry 2017–2025, interim report, January 2021*, February 2021, p 7.

94 ACCC, *Gas inquiry 2017–2025, interim report, January 2020*, February 2020, pp 1, 44.

95 ACCC, *Gas inquiry 2017–2025, interim report, January 2021*, February 2021, p 61.

96 ACCC, *Gas inquiry 2017–2025, interim report, January 2021*, February 2021, p 70.

Box 4.3 Liquefied natural gas netback prices

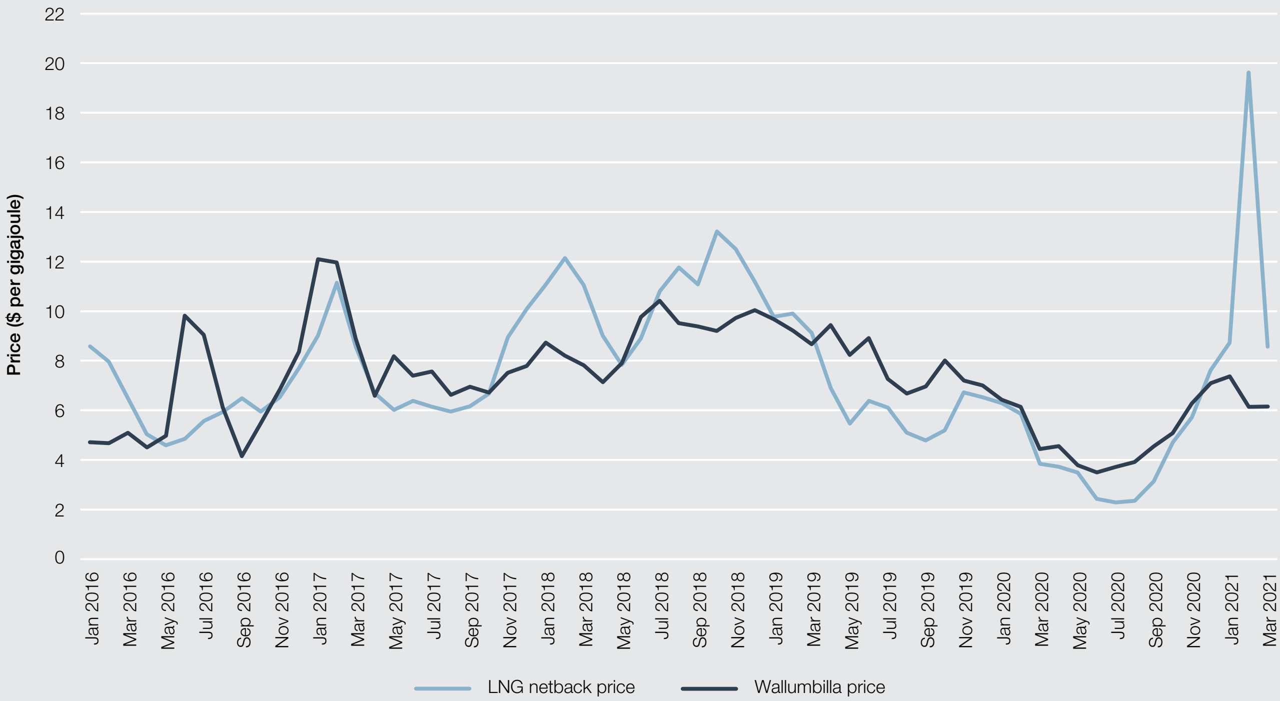
Liquefied natural gas (LNG) netback prices estimate the export parity price that a domestic gas producer would expect to receive from exporting its gas rather than selling it domestically. It is calculated as the price for selling LNG (based on Asian spot prices) and subtracting or 'netting back' the costs of converting gas to LNG and shipping it overseas. The costs include liquefaction at Gladstone, waterborne shipping to Asia, and regasification in Asia.

If LNG netback prices exceed domestic prices then it becomes more profitable to export gas than to sell it locally. At times in 2017 the reverse situation prevailed in eastern Australia – that is, domestic gas prices exceeded LNG netback prices (figure 4.15). This situation was indicative of a dysfunctional domestic market, where price signals were not addressing a demand–supply market imbalance.

The Australian Competition and Consumer Commission (ACCC) publishes LNG netback prices to improve transparency in the eastern gas market. The prices tend to peak during the northern hemisphere winter, when LNG demand is highest. After falling across most of 2019, netback prices were volatile in 2020. They bottomed out at a record minimum of $2.29 per GJ in July 2020 before rising sharply to a record high of $19.62 per GJ in February 2021.

Since peaking, LNG netback prices have fallen significantly from that record, returning to $8.56 per GJ in March 2021. It is expected to remain at levels higher than seen across 2020 for the rest of the year.[97]

Figure 4.15 LNG netback prices and Wallumbilla prices



Note: The Wallumbilla price is the monthly volume weighted average price at the Wallumbilla hub for day-ahead, on-screen trades. LNG netback prices are a simple average, based on domestic spot market prices on the first day each month, and expected netback prices for LNG cargoes to Asia in the following month. The 1 April LNG netback price, for example, is based on domestic spot prices for the 1 April gas day and the netback on expected LNG spot prices for cargoes to Asia in the following month.

Source: AER analysis of gas supply hub data; ACCC (LNG netback prices).

97 ACCC, LNG netback price series, April 2021.

4.11.2 Spot market prices

As discussed in section 4.9, 3 separate spot markets for gas operate in eastern Australia – gas supply hubs at Wallumbilla, Queensland, and Moomba, South Australia; the STTMs in Sydney, Brisbane and Adelaide; and Victoria's declared wholesale gas market. The 3 spot markets operate under different sets of rules, do not interact with each other and have different purposes. Price outcomes in the spot markets do not align with contract prices, although they often move in similar directions. Contract prices reflect expectations of future market conditions, but the spot markets reflect short term shifts in market conditions relating to factors such as the timing of LNG shipments and conditions in the electricity market.

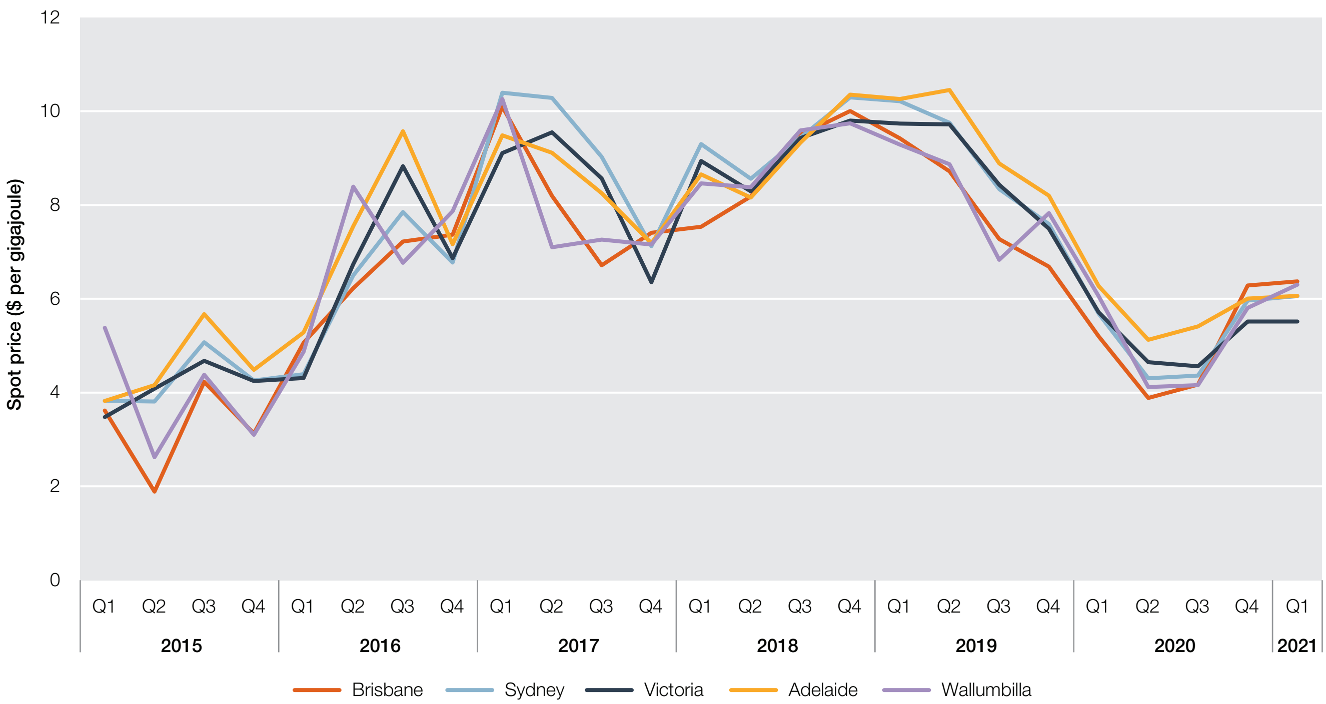
Spot prices vary seasonally, both within and across the markets. Prices can peak in summer but more typically peak in winter. In summer, gas demand for electricity generation may push up domestic spot prices. Australia's summer also coincides with the northern hemisphere winter, when Asian demand for LNG peaks. In the Australian winter, household gas demand tends to rise in the southern states for heating purposes. This increase in demand tends to push southern prices above northern prices during the winter months as southern customers pay the cost of northern gas plus domestic transportation costs (box 4.4).

In recent years, prices have varied significantly (figure 4.16). Along with other factors, the launch of LNG exports in January 2015 caused spot prices to increase in 2016 and 2017 as LNG producers competed with domestic customers for gas supplies (figure 4.17). While prices stabilised somewhat across late 2017 to 2018, they remained at historically high levels before reducing across late 2019 and into 2020.

In the fourth quarter of 2019 spot prices averaged around $8 per GJ. However, by the end of the second quarter of 2020 prices had fallen significantly to below $5 per GJ in all markets except Adelaide ($5.13 per GJ). As demand for LNG exports fell from record highs, Queensland production did not decline in a similar fashion. This, combined with a reduction in gas used for electricity generation, lowered domestic prices. At this time, the gap between the northern and southern markets narrowed significantly as a result of low southern demand and access to cheap capacity through the day-ahead auction.

This steep reduction in domestic prices also mirrored falls in international LNG prices. A greater available supply of LNG combined with intensive price competition and reduced demand due to COVID-19 resulted in the ACCC's LNG netback price falling to $2.29 per GJ in July 2020 – down from $6.72 per GJ in November 2019.

Figure 4.16 Eastern Australia gas market prices



Note: The Wallumbilla price is the volume weighted average price for day-ahead, on-screen trades at the Wallumbilla gas supply hub. Brisbane, Sydney and Adelaide prices are ex-ante. The Victorian price is the 6 am schedule price.

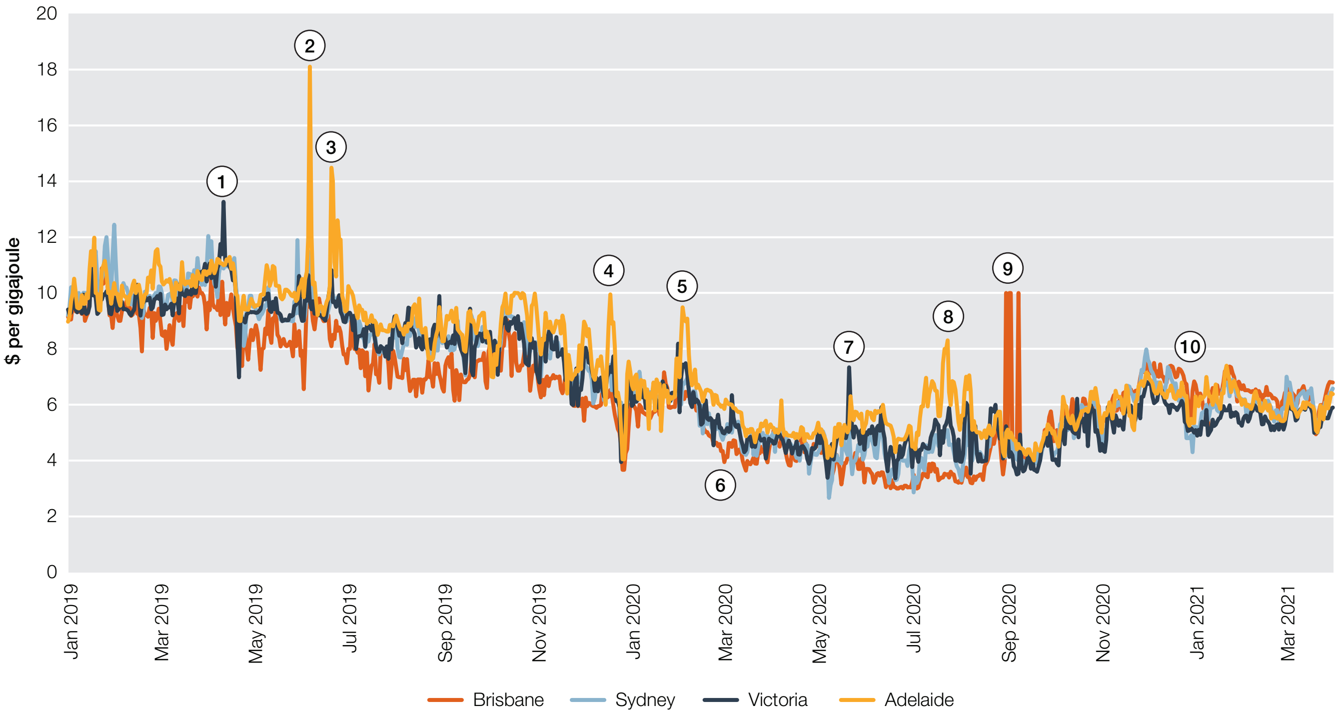
Source: AER analysis of gas supply hub, short term trading market and Victorian declared wholesale gas market data.

Domestic prices levelled off in the third quarter of 2020 as international prices rebounded. Higher demand in winter, particularly in the southern states, resulted in quarterly average prices rising in all spot markets except Victoria. During the first week of August 2020, cold weather affected most of southern Australia, with some areas experiencing their lowest winter minimum or maximum temperatures on record. On 4 and 6 August 2020 AEMO declared a threat to system security as winter demand peaked. This drove record high demand in the Sydney market on 6 August of 382 TJ (surpassing the previous record of 377 TJ set 9 years earlier) as participants withdrew gas from Sydney to inject into Victoria. Despite these dynamics, there was not a significant impact on average Sydney or Victorian prices.

By the end of 2020 prices had rebounded in all markets to levels similar to the start of the year. In the fourth quarter of 2020 northern market prices exceeded southern market prices for the first time in more than 2 years. This continued into early 2021, coinciding with a sharp spike in demand for LNG exports in December 2020 and January 2021 as a result of an unexpected cold snap in Asia (section 4.10.2). Over this time, LNG netback prices peaked at nearly $20 per GJ before falling again by the start of February 2021.[98]

Despite the magnitude of this international price spike, a number of factors meant domestic price rises were more moderate. First, to meet record export demand, LNG exporters increased production from already high levels to record output, averaging over 4,240 TJ per day. At the same time, domestic demand fell as gas used for electricity generation was lower. As a result of lower demand, the southern markets were less reliant on northern production, and excess gas flowed from south to north.

Figure 4.17 Daily gas spot prices



1. 11 April 2019: Longford constrained.
2. 6 June 2019: Low wind generation and production outages in Victoria.
3. 20 June 2019: Low wind generation and high winter gas demand in Victoria and Adelaide.
4. 16–20 December 2019: High temperatures in southern states.
5. 2–7 February 2020: Gas generation directed on in South Australia following the outage of the Heywood interconnector in the NEM.
6. March 2020: LNG export train outage, excess gas supply and low gas generation demand.
7. 21 May 2020: Market demand forecast revised upwards in Victoria during a cold front affecting south east Australia. Uncertainty around demand levels due to COVID-19 impacts (demand profiles deviating from historical trends)
8. 13 July to 8 August 2020: Period of high gas powered generation in South Australia, with significant balancing gas allocations resulting from the diversion of scheduled gas supply towards generation assets. Victorian price spikes linked to high demand due to cold weather.
9. 2–8 September 2020: An unplanned outage at the Dalby compressor station on the Roma to Brisbane Pipeline resulted in high ex ante market prices and capacity constraint pricing.
10. October to December 2020: High domestic prices coincided with international price increases and a significant ramp-up in LNG exports across the fourth quarter of 2020.

Source: AER; AEMO (raw data).

98 ACCC LNG netback price, February 2021. Price assessments take place over the monthly window leading up to about 6 weeks before expected delivery.

4.12 Market responses to supply risk

Market responses to concerns about a shortage of domestic gas in coming years are being explored. Options include further gas development, LNG imports, transmission pipeline solutions, and demand response.

4.12.1 Gas field development

Exploration and development in a number of gas fields have increased since international oil and gas prices began to rise in 2017. Additionally, domestic gas prices and government funding improved the economics of some resources and projects. Governments across jurisdictions are offering financial or regulatory incentives for projects that target gas supplies to the domestic market (section 4.13).

The Australian Government's gas fired recovery plan, the South Australian and NSW governments' plans to unlock additional gas supply, and Queensland's 'domestic only' exploration tenement release are among the schemes being implemented.

Many efforts to increase gas supply focus on unconventional projects, which often face community opposition due to environmental concerns. Legislative moratoriums on onshore exploration and fracking have impeded the development of gas projects in Victoria, South Australia and Tasmania (section 4.10.1). Elsewhere, stringent regulatory processes apply, as highlighted by the extensive process for Santos's Narrabri gas project in NSW. Against this trend, in April 2018 the Northern Territory lifted its moratorium on fracking in 51% of the jurisdiction.

Despite the various moratoriums and constraints in place, sharply lower international oil prices in 2020 and impact of COVID-19, a number of projects are progressing that could bring additional supply to the domestic market:

- In Victoria, Cooper Energy's Sole gas field in the Gippsland Basin commenced operation in late March 2020. The gas is processed at the Orbost plant, which can produce up to 68 TJ per day after recommissioning upgrades. Across 2020 production varied significantly as the plant faced issues.[99] Cooper Energy is also exploring opportunities in the Gippsland and Otway basins for development in 2022.
- In the Otway Basin, in February 2020 Beach Energy delivered its first gas from its Haselgrove-3 project.[100] Gas from the project, which has a capacity of 10 TJ per day, feeds into the new Katnook gas processing facility (South Australia), which the Australian Government's Gas Acceleration Program (GAP) scheme partly funded.
- In NSW, Santos proposed to develop 850 wells across its 95,000 hectare Narrabri gas project, which has potential to supply up to 200 TJ per day.[101] Environmental and community groups opposed the project's environmental impact: over 23,000 submissions were made in response to the environmental impact statement, mostly in opposition.[102] As a result, the project has faced various regulatory and legal delays. In September 2020 the project received approval from the NSW Independent Planning Commission, and in November 2020 the Australian Government also delivered its approval.[103]
- In Queensland, the Kincora project (Armour Energy) began processing gas from surrounding wells in December 2017.[104] Armour Energy expanded its activity in the region after receiving a $6 million grant under the GAP scheme in March 2018. Kincora also won a Queensland Government 'domestic only' tenement release for gas exploration, based on a commitment to supply gas to the domestic market (section 4.13.5).[105] Armour Energy targeted output of 20 TJ per day by the end of 2020, but production growth has been restricted. It produced on average 6 TJ per day in the fourth quarter of 2020.[106]

Participants delayed some projects in response to economic conditions over 2020. In March 2020 Santos announced a 38% reduction in 2020 capital expenditure as a result of COVID-19 and other factors.[107] Similarly, in April 2020 Origin Energy announced a pause in exploration activities in the Beetaloo Basin and a reduction in APLNG development and exploration as a result of changing conditions.[108]

99 EnergyQuest, *EnergyQuarterly,* March 2021, p 27.
100 EnergyQuest, *EnergyQuarterly*, March 2020, p 105.
101 Santos, *Narrabri Gas Project*, Santos website, accessed 28 May 2021.
102 Department of Planning and Environment (NSW), 'NSW Government assessment of the Narrabri Gas Project proposal update' [media release], 23 April 2018.
103 Santos, 'Santos welcomes federal signoff on Narrabri Gas Project' [media release], 24 November 2020.
104 Armour Energy, *Surat Basin*, Armour Energy website, accessed 28 May 2021.
105 Armour Energy, *Surat Basin*, Armour Energy website, accessed 28 May 2021.
106 EnergyQuest, *EnergyQuarterly*, March 2021, p 99.
107 Santos, 'Santos, COVID-19 response and business update' [media release], 23 March 2020.
108 Origin Energy, 'Operational and financial update' [media release], 6 April 2020.

4.12.2 Liquefied natural gas import terminals

To address future supply concerns, the industry is considering at least 5 projects to develop LNG import facilities on the east coast (section 4.8). Each project would involve importing LNG through floating storage and regasification units.

4.12.3 Northern Territory gas

Jemena's Northern Gas Pipeline began delivering gas from the Northern Territory to Queensland in January 2019. Current nameplate capacity of the pipeline is 90 TJ per day, but Jemena plans to increase this to 200 TJ per day by 2025.[109] This plan would also extend the pipeline to connect the Beetaloo Basin directly to the Wallumbilla gas supply hub.

4.12.4 Demand response

Volatile markets and the expiry of legacy gas supply agreements are prompting C&I customers to take a more active role in gas procurement. Some customers are becoming direct market participants by engaging in collective bargaining agreements. As an example, in November 2017 the ACCC granted authorisation to the Eastern Energy Buyers Group of agribusinesses to establish a joint energy purchasing group to run gas and electricity supply tenders for 11 years. The arrangement allows the group to access wholesale markets at better prices than would be possible if the agribusinesses acted individually.[110]

Some C&I users are exploring or implementing options such as purchasing gas directly from producers rather than retailers, using brokers to secure supply agreements, participating in gas markets, and investing in new LNG import facilities.[111] Further, some users have lowered their gas use by changing fuels or increasing efficiencies. Others have also deferred large investments. The ACCC reported one C&I user citing high gas prices as a major factor in delaying a $15 million expansion.[112]

Joint ventures between gas customers and producers are also occurring.[113] Incitec Pivot, with Central Petroleum, won a tender for a CSG tenement release by the Queensland Government and aims to be producing by 2022.[114]

In addition, some C&I users are considering alternatives to gas. Incitec Pivot, for example, is investigating the use of renewable energy instead of natural gas for expanding future ammonia production. Similarly, Australian Paper is developing a waste-to-energy plant, which could reduce its gas use by 4 PJ per year.[115]

109 Jemena, 'Jemena partners with shale gas experts to develop Beetaloo' [media release], November 2020.

110 ACCC, *The Eastern Energy Buyers Group – authorisations – A91594 & A91595*, August 2017.

111 ACCC, *Gas inquiry 2017–2025, interim report, January 2021*, February 2021, pp 73–74.

112 ACCC, *Gas inquiry 2017–2025, interim report, January 2020*, 18 February 2020, p 75.

113 AEMO, *2018 gas statement of opportunities*, June 2018.

114 EnergyQuest, *EnergyQuarterly*, March 2020, p 108.

115 ACCC, *Gas inquiry 2017–2025, interim report, January 2020*, February 2020, p 74.

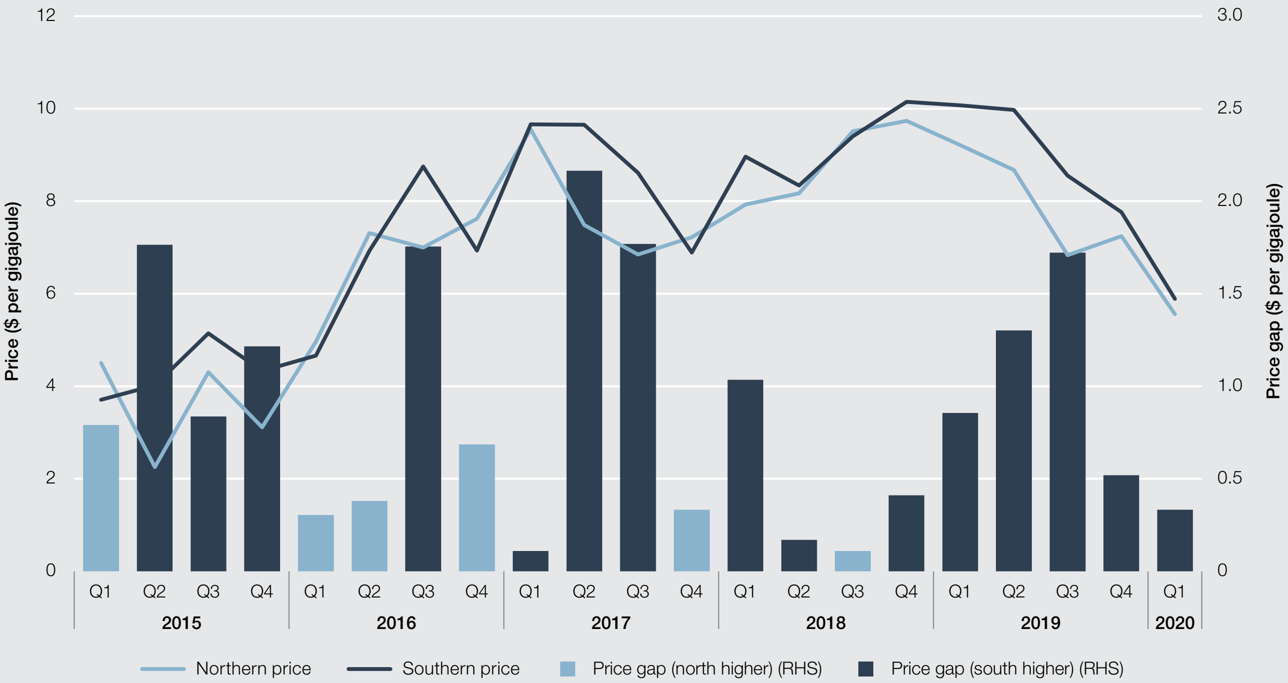
Box 4.4 North–south price divide

The differential between spot gas prices in Queensland (Wallumbilla and Brisbane) and the southern states fluctuated across 2020 (figure 4.18). The differential reflects contrasting demand and supply conditions in the 2 regions. With reduced demand for liquefied natural gas (LNG) exports across mid-2020, Queensland producers diverted gas to domestic markets, resulting in lower northern prices. But late in the year LNG export demand spiked sharply, and as a result significant quantities of gas flowed from south to north. This caused northern market prices to become more expensive than the southern markets for the first time in over 2 years.

Historically, price gaps tend to emerge each winter as southern gas demand for heating increases. The gap can be as much as $2 per gigajoule (GJ), roughly the cost of transporting Queensland gas to the southern states.

But in 2019 and 2020, the day-ahead auction kept the price gap narrower than it might have been. Access to cheap (or free) pipeline capacity allowed some participants to sell northern gas to southern markets at more competitive prices. Without this cheap pipeline access, southern prices would likely have been higher (section 4.10.4).

Figure 4.18 North–south gas price divide



RHS: Shows the price gap between northern and southern markets.

Note: The southern market is the average of NSW, Adelaide and Victorian spot prices. The northern market is the average of Brisbane and Wallumbilla spot prices. The Wallumbilla price used for calculation is the volume weighted average price for day-ahead, on-screen trades at the Wallumbilla gas supply hub.

Source: AER analysis of gas supply hub, short term trading market and Victorian declared wholesale gas market data.

4.13 Government intervention in gas markets

In response to concerns around the adequacy of gas supplies to meet domestic demand, the Australian Government and some state governments have intervened in the market. The interventions are noted throughout this chapter and summarised here.

4.13.1 Gas fired recovery plan

As part of a broader COVID-19 recovery plan, in September 2020 the Australian Government announced a number of measures to facilitate the development of new sources of supply. This plan includes a number of proposed actions, including:[116]

- setting new gas supply targets with states and territories, and enforcing 'use it or lose it' requirements on gas licences
- funding plans for further development of key gas basins and exploring options for a gas reservation scheme
- extending the heads of agreement with Queensland producers
- identifying, through a National Gas Infrastructure Plan, priority pipelines and critical infrastructure and highlight when the government will step in if private sector investment is not forthcoming.

The Australian Government is progressing these commitments. For example, in March 2021 it announced $50 million in grants to support exploration that occurs in the Beetaloo Basin before the end of 2022.[117]

Also, in May 2021 the Australian Government released the *National Gas Infrastructure Plan: interim report*, which identified a range of priority projects that could alleviate expected gas supply shortfalls from 2024.[118] Critical projects identified include the Golden Beach storage facility, expansion of the Iona storage facility and South West Queensland Pipeline, and the development of an LNG import facility. The report also noted that expanded northern production and additional supply from new southern fields, such as the Narrabri Gas Project, would contribute to addressing forecast shortfalls.

4.13.2 Australian Domestic Gas Security Mechanism

In 2017 the Australian Government threatened to direct gas producers to increase gas supplies to the local market. The Australian Domestic Gas Security Mechanism, which took effect on 1 July 2017, empowers the Resources Minister to require LNG projects to limit exports, or find offsetting sources of new gas, if a supply shortfall is likely.[119] The Resources Minister may determine in the preceding September whether a shortfall is likely in the following year and may revoke export licences if necessary to preserve domestic supply.

To avoid export controls, Queensland's LNG producers entered a heads of agreement with the government in October 2017, a second agreement in September 2018 and a third agreement in December 2020.[120] Under the agreements, they committed to offer uncontracted gas on reasonable terms to meet expected supply shortfalls. They also committed to offer gas to the Australian market on competitive market terms before offering any uncontracted gas to the international market.[121] To meet their commitments, the LNG projects adopted a range of strategies to offer more gas domestically (section 4.10.1).

The AEMC reported some stakeholders were concerned that government intervention, while it may increase liquidity in the short term, does not correct participants' lack of confidence that they can source gas where they need it at a reasonable price. Concerns were also raised that intervention may reduce investment certainty and weaken liquidity in the long term.[122]

In 2019 the Department of Industry, Innovation and Science found the scheme had worked effectively to safeguard domestic gas supplies.[123] Following this finding, the scheme was extended until 1 January 2023.

116 Australian Government, 'Gas-fired recovery' [media release], September 2020.

117 Department of Industry, Science, Energy and Resources, *Unlocking the Beetaloo: The Beetaloo strategic basin plan*, DISER website, accessed 28 May 2021.

118 Australian Government, *National gas infrastructure plan interim report*, May 2021.

119 Department of Industry, Innovation and Science, *Australian Domestic Gas Security Mechanism*, July 2018.

120 Department of Industry, Science, Energy and Resources, *Securing Australian domestic gas supply*, DISER website, accessed 28 May 2021.

121 The agreement specifically notes that LNG netback prices, as referenced by the ACCC, play a role in influencing domestic gas prices.

122 AEMC, *Final report: biennial review into liquidity in wholesale gas and pipeline trading markets*, August 2018, p 46.

123 Department of Industry, Science, Energy and Resources, *Australian Domestic Gas Security Mechanism review*, January 2020.

4.13.3 Gas supply guarantee

In March 2017 facility and pipeline operators developed the gas supply guarantee as a mechanism to meet commitments to the Australian Government to ensure enough gas is available to meet peak demand periods in the NEM.[124] The guarantee identified new processes to assess and resolve potential gas supply shortfalls ahead of time.

While the guarantee has not been used, and was due to expire in March 2020, the Australian Government extended the guarantee to March 2023.[125]

4.13.4 National gas reservation scheme

In late 2020, the Australian Government consulted on options for a national gas reservation scheme.[126] It expects to reach a final decision in the first half of 2021.[127]

4.13.5 Gas Acceleration Program

To encourage gas supply, in 2017 the Australian Government launched the $26 million GAP, offering grants of up to $6 million for projects that increase domestic gas flows in the eastern market by 30 June 2020. Four of the 5 successful projects were based in Queensland, including Armour Energy's Kincora expansion, Westside's Greater Meridian project, Tri-Star Fairfield's gas project, and Australian Gasfields' refurbishment of the Eromanga and Gilmore processing facilities. The fifth project was Beach Energy's new Katnook gas processing facility in the Otway Basin.[128]

While all projects have commenced operation, Beach Energy announced that it would be suspending operations at the Katnook Gas Plant during 2021–22 as a result of natural field decline.[129] Beach will assess whether to recommence operations at the plant in future years.

4.13.6 State government schemes

To encourage gas exploration, the Queensland Government offers grants for 'domestic only' exploration tenements.

As part of this grants program, it released almost 70,000 km^2 of land for exploration between 2015 and 2019, of which around 25% was reserved for domestic supply. The Queensland Government released a further 3,000 km^2 of land in September 2020, with over 15% tagged for domestic supply.[130]

In January 2020, through a memorandum of understanding with the Australian Government, the NSW Government committed to bringing new gas supplies to the domestic market. It set a target of injecting an additional 70 PJ of gas per year into the NSW market.[131]

In April 2021 the Australian and South Australian governments announced an agreement to invest in energy infrastructure and reduce emissions in South Australia. As part of this, the state set a target of an unlocking an additional 50 PJ per year by 2023.[132]

4.13.7 ACCC gas inquiry

In April 2018 the Australian Government directed the ACCC to use its compulsory information gathering powers to inquire into wholesale gas markets in eastern Australia. While the inquiry was initially tasked to run until 30 April 2020, the Treasurer extended it in July 2019 to 2025. The ACCC has released several interim reports.[133]

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124 AEMO, *Gas supply guarantee*, AEMO website, accessed 28 May 2021.

125 AEMO, *Gas supply guarantee guidelines consultation final determination*, March 2020.

126 Ministers for the Department of Industry, Science, Energy and Resources (Australian Government), 'Review finds gas policy boosts domestic supply and helps lower prices' [media release], 24 January 2020.

127 Australian Government, *Options for a prospective national gas reservation scheme: issues paper*, October 2020.

128 Department of Industry, Innovation and Science, *Gas Acceleration Program successful applicants*, DIIS website, accessed 19 October 2018.

129 Beach Energy, *FY21 third quarter activities report*, April 2021.

130 Queensland Government, 'Queensland gas exploration ramping up' [media release], September 2020.

131 NSW Government, *Memorandum of understanding – NSW energy package*, 31 January 2020.

132 Australian Government, 'Energy and emissions reduction agreement with South Australia' [media release], April 2021.

133 ACCC, *Gas inquiry 2017–2025*, ACCC website, accessed 28 May 2021.

4.13.8 Electrification of liquefied natural gas production

On 8 February 2020 the Australian Government announced it would allocate up to $1.5 million for working with the Queensland Government and industry on electrifying the Curtis Island LNG facilities. The production facilities currently use their own gas as a power source in production. Partly electrifying these processes would free up to 12 PJ of gas for delivery to the domestic market.

4.13.9 National hydrogen strategy

The Australian Government identified hydrogen as a potential fuel to facilitate cuts to emissions across energy and industrial sectors. As part of this strategy, the government is looking at introducing hydrogen to the gas distribution network as part of the mix with natural gas. Currently, hydrogen can be added to gas pipelines at concentrations of up to 10% to supplement gas supplies, and a number of trials are being explored. In July 2020 the Australian Renewable Energy Agency shortlisted 7 projects to be considered as part of its $70 million fund to develop large scale electrolysers, 3 of which are based in eastern Australia.[134]

4.14 Gas market reform

The Energy National Cabinet Reform Committee (formerly CoAG Energy Council) directs gas market reforms, which regulatory and market bodies implement.[135] A key focus of reform is to address information gaps and asymmetries in the market. Consultation on the latest round of measures took place in 2019, and the CoAG Energy Council delivered the final decision regulation impact statement in late March 2020.[136]

Reform stems from findings by bodies that include the AEMC, the ACCC and the Gas Market Reform Group. In 2016 the AEMC found that the eastern gas market is opaque and participants have low levels of confidence in the information that is available. The reforms aim to increase transparency in the gas market, improving the Gas Bulletin Board and improving the availability of information on market liquidity, prices and gas reserves.

4.14.1 Gas Bulletin Board reforms

The Gas Bulletin Board (www.gasbb.com.au) was launched in 2008 to make the gas market more transparent by providing up-to-date information on gas production, pipelines and storage options in eastern Australia. But its usefulness was compromised by gaps in coverage and, at times, the provision of inaccurate data.

Significant reforms in September 2018 brought the bulletin board closer to being a 'one stop shop' for the eastern gas system. The reforms removed reporting exemptions, mandated the provision of more comprehensive detail for covered facilities and extended reporting obligations to smaller facilities and those in Northern Territory. The reporting threshold for transmission pipelines, production facilities and storage facilities was lowered from 20 TJ per day to 10 TJ per day.

Additionally, more comprehensive reporting was mandated for production facilities. Market participants can now access detailed information from production and compression facilities on their daily nominations, forecast nominations, intra-day changes to nominations, and capacity outlooks. This reporting adds transparency to production outages, which informs market responses and helps maintain security of supply.

In the pipeline sector, operators must submit daily disaggregated receipt and delivery point data. The data include information on flows at key supply and demand locations along pipelines. Reporting obligations were also extended to regional pipelines and facilities attached to distribution pipelines.

To encourage compliance, the reforms made reporting obligations subject to civil penalties. The AER assesses the quality and accuracy of the data submitted by market participants against an 'information standard' to ensure the information presented on the bulletin board has integrity. The AER published a guidance note outlining its approach to enforcement.[137]

134 ARENA, *Seven shortlisted for $70 million hydrogen funding round*, ARENA website, accessed 28 May 2021.

135 Including the Energy Security Board, the AER, the AEMC, AEMO and the ACCC.

136 CoAG Energy Council, *Measures to improve transparency in the gas market – decision regulation impact statement*, March 2020.

137 AER, *Guidance note – natural gas services bulletin board (enhanced information reporting)*, September 2018.

Further reforms have been proposed that would extend reporting to large gas users and LNG processing facilities. The proposed reforms also introduce the reporting of gas reserves, gas sales and swaps, LNG exports and contract prices. Energy Ministers were consulting on the legal package to implement these reforms in late 2020.[138]

Liquidity information

In August 2018 the AER began publishing (on the industry statistics page of its website) quantitative metrics for assessing the liquidity of gas markets, and it regularly updates these metrics. In addition, the AER commenced quarterly reporting, from the third quarter of 2019, on the performance of the east coast gas markets. These quarterly reports build on the liquidity statistics and contain more detailed analysis of key performance indicators across the markets. These indicators have shown signs of improvement in liquidity over time. For example, spot market trade has grown from 10% of east coast demand in the fourth quarter of 2018 to a record high of 15% in the fourth quarter of 2020.[139]

Price and reserves transparency

With gas markets shifting towards shorter term contracts, and suppliers using EOI processes, the transparency of price and other market information is critical. Yet the market lacks a single indicative price for gas and lacks consistent gas reserve and resource information. The ACCC moved to address these issues in late 2018 when it began publishing new data on LNG netback prices.[140] The aim is for the data to help gas users negotiate more effectively with gas producers and retailers when entering new gas supply contracts.

Public information on gas reserves and resources in Australia also tends to lack clarity, consistency and accuracy. As such, market participants are less able to identify future supply issues and plan accordingly. For this reason, in late 2018 the ACCC began publishing data on gas reserves and resources, drawing on information provided by reserve owners.

4.14.2 Pipeline reforms

Gas produced in one region can help address a supply shortfall elsewhere, provided transmission pipeline capacity is available to transport the gas. But a number of key pipelines experience contractual congestion, which arises when most or all of a pipeline's capacity is contracted, making the pipeline unavailable to third parties. Contractual congestion may occur even if a pipeline has spare physical capacity.

Three major pipelines – the South West Queensland Pipeline, the Moomba to Adelaide Pipeline System and the Moomba to Sydney Pipeline – were close to fully contracted in 2018, limiting shippers' ability to transport gas between northern and southern markets.[141]

To manage pipeline congestion issues, some gas producers engage in swap agreements. They bypass the need for transportation arrangements with pipeline operators by 'swapping' rights to gas held in different physical locations. However, the ACCC found that such agreements are complicated, involve extensive negotiations and, by necessity, reveal parties' commercial positions to their competitors. Such agreements are unlikely, therefore, to be an effective long term solution to gas pipeline issues.[142]

Secondary trading in underused capacity

Congestion issues focused policy attention on ensuring any spare physical pipeline capacity is made available to the market. Reforms to launch a voluntary trading platform and a secondary compulsory auction of underused capacity took effect in March 2019. Since its commencement, the day-ahead auction in particular has had a positive impact on the east coast gas markets (section 4.10.4).

To promote transparency, the Gas Bulletin Board publishes prices and other key terms in all voluntary trades, as well as the day-ahead auction results. The AER monitors compliance with capacity trading regulations and the proper reporting of trades.

138 Energy National Cabinet Reform Committee, *Measures to improve transparency in the gas market*, November 2020.

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

140 ACCC, *Gas inquiry 2017–2020 – LNG netback price series*, ACCC website, accessed 28 May 2021.

141 ACCC, *Gas inquiry 2017–2020, interim report, December 2017*, December 2017, p 59.

142 ACCC, *Gas inquiry 2017–2020, interim report, December 2017*, December 2017.

Information disclosure and arbitration

Negotiating a fair price to use a gas pipeline is an ongoing issue, with a number of reviews raising concerns about monopolistic pricing practices.[143] The reviews highlighted a lack of transparency and unequal bargaining power between shippers and pipeline operators.

These concerns led to the introduction of Part 23 of the National Gas Rules in August 2017. Part 23 requires otherwise unregulated pipeline businesses to disclose financial, service and access information, following guidelines published by the AER. Customers can use the disclosed information to negotiate gas transport contracts with pipeline operators. If agreement cannot be reached, an access seeker may apply for arbitration. Chapter 5 details the Part 23 regime.

Scope of pipeline regulation

In July 2018 the AEMC reviewed the effectiveness of current gas pipeline regulation. Various tiers of pipeline regulation apply, including full regulation, light regulation, 15-year exemptions, Part 23 regulation and Part 23 exemptions.[144] The review recommended removing a number of inconsistencies across these tiers.

In late 2019 the CoAG Energy Council consulted on a regulatory impact statement as part of consultation on options for delivering a more efficient, effective and integrated framework for regulating gas pipelines. The Energy National Cabinet Reform Committee delivered a final decision in May 2021.[145] This decision proposed:

› requiring all pipelines to provide third-party access and to be subject to an either ‘stronger’ or ‘lighter’ form of regulation, based on the existing regulation structure, with additional constraints on the exercise of dynamic market power
› a new 15-year ‘greenfields’ exemption from stronger regulation for new pipelines where it can be demonstrated the pipeline is unlikely to have substantial market power over that period
› removing the coverage test from the regulation assessment framework
› new powers to allow regulators to actively monitor pipeline operators for exercises of market power and to refer pipelines for regulation assessment
› introducing a single negotiation framework across all forms of regulation; and additional measures to improve dispute resolution options for smaller shippers
› increased information reporting obligations, including improved price disclosure requirements.

It is anticipated that the new regulatory framework will commence in 2022.

4.14.3 Gas day harmonisation

On 1 October 2019 the gas day start time for each market was standardised to 6.00 am. From their commencement, the different gas markets in the east coast operated with different start times, as a result of historical pipeline arrangements. This difference resulted in unnecessary costs and complexities for participants that operate over multiple locations. Harmonising the gas day start times will reduce these complexities, provide for more interconnection and help the development of standardised market reforms.

4.14.4 Australian gas hub

As part of its gas fired recovery plan, the Australian Government announced plans to reform the Wallumbilla gas supply hub into an Australian gas hub. The plan would include measures to improve liquidity and transparency. In early 2021 the Australian Government was consulting on this proposal ahead of implementation.

143 ACCC, *Inquiry into the east coast gas market*, April 2016, pp 99–106; CoAG Energy Council, *Examination of the current test for the regulation of gas pipelines*, December 2016.

144 Chapter 5 outlines the tiers of gas pipeline regulation.

145 Energy National Cabinet Reform Committee, *Options to improve gas pipeline regulation: regulation impact statement for decision*, May 2021.

Source: iStock

5

Regulated gas pipelines

Gas pipeline networks transport gas from upstream producers to energy customers. Australia's gas pipeline networks consist of:

- long haul transmission pipelines that carry gas from producing basins to major population centres, power stations and large industrial and commercial plant
- urban and regional distribution networks, which are spaghetti-like clusters of smaller pipes that transport gas to customers in local communities.

This chapter covers the 14 gas pipelines and networks regulated by the Australian Energy Regulator (AER), which is the pipeline regulator in states and territories other than Tasmania and Western Australia.[1]

Unlike electricity networks, many gas pipelines are unregulated or face only limited regulation. This chapter discusses the various tiers of regulation that apply but focuses on 'full regulation' pipelines – those for which the AER sets access (usage) prices.[2] The AER sets access prices for 3 transmission pipelines – the Roma to Brisbane Pipeline (Queensland), the Victorian Transmission System, and the Amadeus Gas Pipeline (Northern Territory). In gas distribution, the AER sets access prices for networks in New South Wales (NSW), Victoria, South Australia and the Australian Capital Territory (ACT).

5.1 Gas pipeline services

Gas pipeline businesses earn revenue by providing access (selling capacity) to parties needing to transport gas. Those parties include:

- energy retailers seeking to transport gas to energy users
- commercial and industrial users
- liquefied natural gas (LNG) exporters, which buy gas directly from producers and contract with a pipeline owner to ship it.

An interconnected transmission pipeline grid links gas basins and retail markets in all states and territories other than Western Australia (figure 5.1).

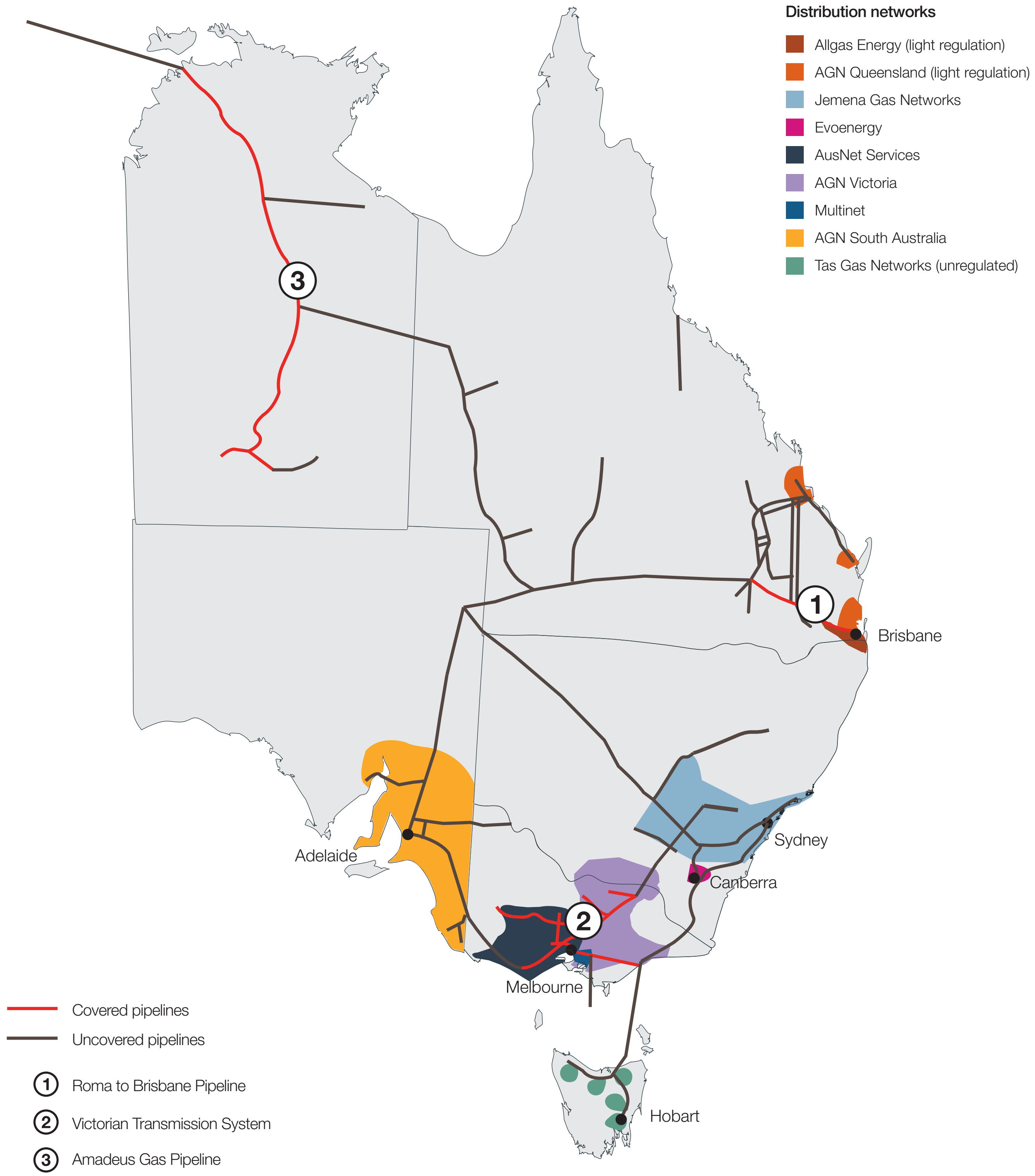
The most common service provided by transmission pipelines is haulage – that is, transporting gas in a forward direction from an injection point on the pipeline to an offtake point further along. Haulage may be offered on a firm (guaranteed) or interruptible (only if spare capacity is available) basis. Some customers seek backhaul too, which is reverse direction transport. Gas can also be stored (parked) in a pipeline on a firm or interruptible basis. As the gas market evolves, more innovative services are being offered, including compression (adjusting pressure for delivery), loans (loaning gas to a third party), redirection and in-pipe trades.

Distribution networks consist of high, medium and low pressure pipelines, which run underground. The high and medium pressure mains provide a 'backbone' that services high demand zones, while the low pressure pipes lead off high pressure mains to commercial and industrial customers and residential homes. While the nature of gas transmission services is evolving to meet changing market needs, distribution pipeline businesses tend to offer fairly standard services – namely, allowing gas injections into a pipeline, conveying gas to supply points and allowing gas to be withdrawn.

1 The Economic Regulation Authority (ERA) administers separate regulatory arrangements in Western Australia (www.erawa.com.au). The Office of the Tasmanian Economic Regulator (OTTER) administers separate regulatory arrangements in Tasmania (www.economicregulator.tas.gov.au/gas).

2 Chapter 4 discusses the wider gas transmission sector, including pipelines not under full regulation.

Figure 5.1 Major gas transmission pipelines and distribution networks



Source: AER.

The total length of gas distribution networks in eastern Australia is around 72,000 kilometres. Gas is distributed to most Australian capital cities, major regional areas and towns. Victoria and Queensland each have multiple distribution networks serving particular areas of the state. NSW, South Australia, Tasmania and the ACT each have a single regulated network.[3]

While gas distributors transport gas to energy customers, they do not sell gas. Energy retailers purchase gas from producers, and pipeline services from pipeline businesses, and sell them as a packaged retail product to their customers. Many retailers offer both gas and electricity products.

5.2 Gas pipeline ownership

Australia's gas pipelines are privately owned. The publicly listed APA Group (APA) is Australia's largest gas pipeline business, with a portfolio mainly in gas transmission. Other sector participants include Jemena Gas Networks (Jemena, owned by State Grid Corporation of China and Singapore Power International) and Cheung Kong Infrastructure Holdings Limited (CKI Group), which operates Australian Gas Networks. State Grid Corporation of China and Singapore Power International also have interests in the publicly listed AusNet Services (Victoria).

State Grid Corporation of China, Singapore Power International and the CKI Group also have ownership interests (some substantial) in the electricity network sector, including distribution networks in Victoria, South Australia and the ACT (chapter 3).

Table 5.1 Gas transmission pipelines and distribution networks – ownership

PIPELINE	JURISDICTION	NETWORK TYPE	REGULATION	OWNER
APA Victorian Transmission System	Vic	Transmission	Full	APA Group
Roma to Brisbane Pipeline	Qld	Transmission	Full	APA Group
Amadeus Gas Pipeline	NT	Transmission	Full	APA Group
Jemena Gas Networks	NSW	Distribution	Full	Jemena (State Grid, Singapore Power)
AusNet Services	Vic	Distribution	Full	Listed company (Singapore Power, 31%; State Grid, 20%)
Multinet	Vic	Distribution	Full	CKI Group
Australian Gas Networks	Vic	Distribution	Full	CKI Group
Australian Gas Networks	SA	Distribution	Full	CKI Group
Evoenergy	ACT	Distribution	Full	Icon Water (ACT Government), 50%; Jemena (State Grid, Singapore Power), 50%
Carpentaria Pipeline (Ballera to Mount Isa	Qld	Transmission	Light	APA Group
Central West Pipeline (Marsden to Dubbo)	NSW	Transmission	Light	APA Group
Moomba to Sydney Pipeline	NSW	Transmission	Light	APA Group
Allgas Energy	Qld	Distribution	Light	Marubeni, 40%; Deutsche AWM, 40%; APA Group, 20%
Australian Gas Networks	Qld	Distribution	Light	CKI Group

3 Some networks cross state or territory boundaries. Australian Gas Network's Victorian network and Evoenergy's ACT network both extend into NSW, for example. Some jurisdictions also have smaller unregulated regional networks, such as the Wagga Wagga network in NSW.

5.3 How gas pipelines are regulated

Gas pipelines are capital intensive, so average costs fall as output rises. Many pipelines are natural monopolies in that it is more efficient to have a single provider than multiple providers offering the same service. Because monopolies face no competitive pressure, they have the opportunity and incentive to charge unfair prices. This poses risks to consumers, because pipeline charges make up a significant portion of residential gas bills (section 6.6.2).

Many pipelines are regulated to manage the risk of monopoly pricing, and different tiers of regulation apply (discussed below). The National Competition Council (NCC) is responsible for decisions on the classification of natural gas pipelines and the form of regulation to be applied to a covered pipeline (that is, full or light regulation). A case-by-case test is undertaken to assess the type of regulation that applies to each pipeline, considering whether:

- the pipeline is a natural monopoly
- regulation would promote competition
- regulation would be cost-effective (that is, the benefits of regulation outweigh the costs).

Box 5.1 summarises the AER's role in gas pipeline regulation. Additionally, the AER monitors participants' compliance with the National Gas Law and National Gas Rules and takes enforcement action when needed. Box 4.1 in chapter 4 outlines the AER's work in this area, including its advocacy for reform to improve access to idle capacity in transmission pipelines.

More generally, the AER advises policy bodies on issues in the gas pipeline sector. It may propose or participate in rule change processes, and it engages in policy reviews to improve regulatory arrangements.

Box 5.1 How the AER regulates gas pipelines

The AER's role in gas pipeline regulation varies depending on the type of regulation applying to a pipeline:

- For *full regulation* pipelines, the AER sets a reference tariff (prices) for at least one service offered by the pipeline following an assessment of the pipeline's efficient costs and revenue needs. We undertake this role for 3 transmission pipelines (in Queensland, Victoria and the Northern Territory), and for all major distribution networks in NSW, Victoria, South Australia and the ACT.
- For *light regulation* pipelines, the AER arbitrates disputes referred by access seekers and monitors pipeline businesses' compliance with their price disclosure obligations.
- For pipelines under *Part 23 regulation*, the AER sets guidelines on the disclosure of financial and pipeline use information and monitors and enforces compliance with these obligations. We establish a pool of experienced arbitrators to deal with disputes, and we can be called on to appoint an arbitrator. We also set conditions for exempting a pipeline from Part 23 obligations.

5.3.1 Full regulation

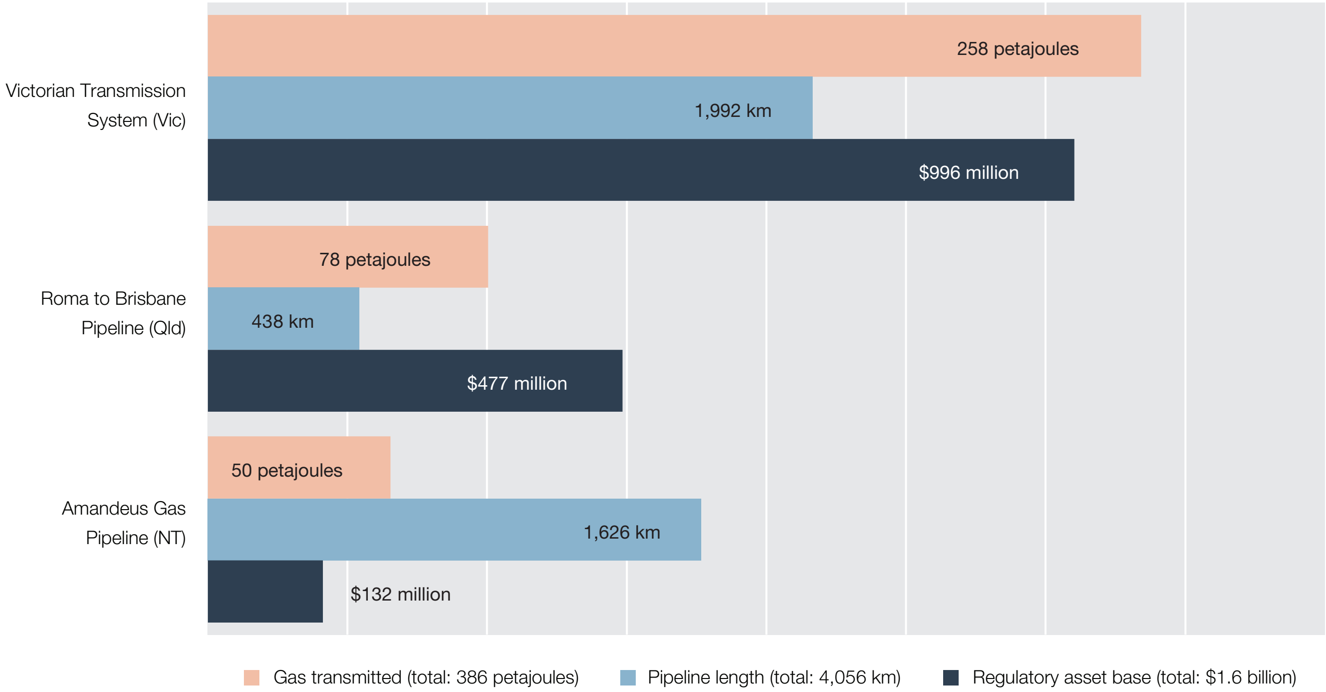
Full regulation is the most intensive form of regulation. It involves the pipeline owner submitting its prices to an independent regulatory body for a detailed economic assessment. The AER undertakes this role in jurisdictions other than Western Australia.

In particular, the AER assesses whether the access tariffs (prices) paid by a third party for using a full regulation pipeline are efficient. Currently, the AER applies full regulation to 3 gas transmission pipelines and 6 gas distribution networks, with a combined regulatory asset base of $12.1 billion (figures 5.2 and 5.3).

Only a handful of transmission pipelines are fully regulated. Full regulation has been removed from many pipelines over the past 20 years, and no new pipeline commissioned in the past 20 years is subject to full regulation. Some pipelines moved to light regulation (section 5.3.2). Other pipelines are free from any form of regulation.

Section 5.4 further discusses full regulation.

Figure 5.2 Gas transmission pipelines – full regulation



km: kilometres.

Note: Excludes gas pipelines in Western Australia, which the Economic Regulation Authority (ERA) regulates. Gas transmitted and pipeline length are most recent data available, retrieved 20 April 2021. The regulatory asset base (RAB) is the forecast value of network assets based on the closing RAB at 30 June 2020, except for the Victorian transmission network (31 March 2020) and Victorian distribution networks (31 December 2020). Values are in June 2021 dollars. Each year the RAB will simultaneously increase due to new investment and decrease due to depreciation and asset disposals.

Source: AER access arrangement decisions; AEMO website; Australian Securities Exchange (ASX) releases; company annual reports; company websites; Gas Bulletin Board.

5.3.2 Light regulation

Light regulation uses a commercial negotiation approach supported by mandatory information disclosure. It requires gas pipeline businesses to publish access prices and other terms and conditions on their website. They cannot engage in inefficient price discrimination or other conduct adversely affecting access or competition in other markets.

If a party is unable to negotiate access to a pipeline, they may request the AER arbitrate a dispute.

The Carpentaria Pipeline in Queensland, the Central West Pipeline in NSW and portions of the Moomba to Sydney Pipeline are subject to light regulation. Queensland's 2 gas distribution networks – Australian Gas Networks (AGN (Queensland)) and Allgas Energy – converted from full to light regulation in 2015.

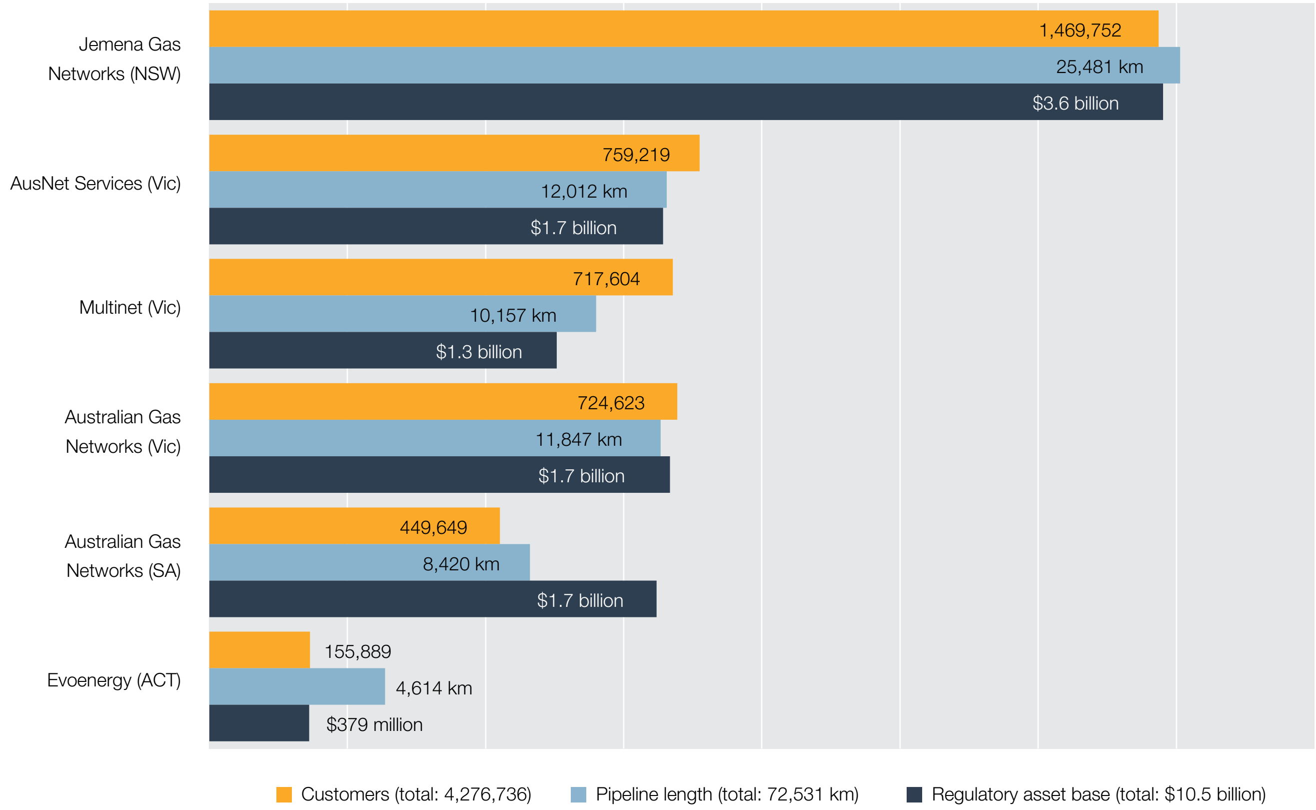
5.3.3 Part 23 regulation

Gas pipelines not subject to full or light regulation are 'unregulated', so they are free to set their own prices and other terms and conditions. A number of independent reviews raised concerns that this allowed monopolistic practices by some pipeline operators.[4]

These concerns led to the introduction of the Part 23 provisions in the National Gas Rules, which took effect in 2018. Part 23 aims to make it easier for gas customers to negotiate access to unregulated pipelines at a reasonable price. The rules require otherwise unregulated pipeline businesses to disclose certain financial, service and access information following guidelines published by the AER.

4 ACCC, *Gas inquiry 2017–2020 interim report*, April 2018; Ministerial Forum of Energy Ministers (formerly CoAG Energy Council), Examination of the current test for the regulation of gas pipelines, December 2016.

Figure 5.3 Gas distribution networks – full regulation



km: kilometres.

Note: Excludes gas pipelines in Western Australia, which the Economic Regulation Authority (ERA) regulates. Customer numbers and pipeline length are most recent data available, retrieved 20 April 2021. The regulatory asset base (RAB) is the forecast value of network assets based on the closing RAB at 30 June 2020, except for the Victorian transmission network (31 March 2020) and Victorian distribution networks (31 December 2020). Values are in June 2021 dollars. Each year the RAB will simultaneously increase due to new investment and decrease due to depreciation and asset disposals.

Source: AER access arrangement decisions; AEMO website; Australian Securities Exchange (ASX) releases; company annual reports; company websites; Gas Bulletin Board.

In 2019 the Australian Competition and Consumer Commission (ACCC) found that, overall, Part 23 is working as intended and having a positive effect on some pipeline prices and the contracting environment. However, the ACCC had significant concerns with some information published by pipeline operators, including information errors and overstated costs and asset values.[5] To address these issues, it recommended improvements to Part 23, which ministers are considering.[6]

In January 2021 the ACCC reported little observed change in most gas transportation and storage prices and emphasised the importance of monitoring and enforcing gas pipeline regulatory compliance under Part 23.[7]

Customers can use the disclosed information under Part 23 to negotiate gas transport contracts with pipeline operators. If the pipeline operator and access seeker cannot reach an agreement, an access seeker can apply for arbitration. The AER uses a pool of experienced arbitrators to determine disputes and liaises with the parties on appointing an arbitrator from the pool. If the parties fail to select an arbitrator, the AER appoints the arbitrator. The AER maintains a register of arbitrated access determinations.[8]

A pipeline owner can apply to the AER for an exemption from the disclosure provisions if, for example, a pipeline does not provide third party access, has only a single shipper or has average daily gas injections of less than 10 terajoules per day. Exemptions may be subject to conditions and varied at the AER's discretion.

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5 ACCC, *Gas inquiry 2017–2020, interim report, July 2019*, August 2019.

6 Ministerial Forum of Energy Ministers (formerly CoAG Energy Council), *Measures to improve transparency in the gas market – decision regulation impact statement*, March 2020.

7 ACCC, *Gas inquiry 2017–2025, interim report, January 2021*, February 2021.

8 AER, 'Part 23 (Access to non-scheme pipelines) exemptions', AER website.

Access disputes

As at March 2021 there had been 2 arbitrated access determinations made under Part 23 rules. The first concerned a dispute between Hydro Tasmania and Tasmanian Gas Pipeline (TGP) over access to the TGP transmission pipeline in April 2018.[9] The second concerned a dispute between Gas Pipelines Victoria and EnergyAustralia over access to the Carisbrook to Horsham Pipeline in January 2021.[10]

In both disputes, the arbitrator made a determination on a valuation method to reflect the value of assets used to provide the relevant transport services required by the access seeker. For the TGP dispute, the arbitrator adopted a 'modified depreciated actual cost' approach, which represented an indexed depreciated actual cost adjusted downwards. For the Carisbrook to Horsham Pipeline dispute, the arbitrator adopted a 'recovered capital' method.[11] Following each dispute, the access seeker gave notice to the AER that it wished to enter an access contract in accordance with the arbitrator's determination.

5.4 How gas pipeline access prices are set

Gas pipeline businesses earn revenue by selling capacity in their pipelines to customers needing to transport gas. A customer buys access to that capacity under terms and conditions that include an access price. The AER sets access prices for full regulation pipelines in eastern Australia and the Northern Territory under broadly similar rules to those applied to electricity networks (chapter 3).

The owners of other pipelines – including those subject to light regulation and the recent Part 23 provisions – are free to set their own prices. Light regulation pipeline owners must publish their prices, but these prices are not independently vetted.

5.4.1 Regulatory objective and approach

The National Gas Law and National Gas Rules lay out the regulatory framework for gas pipelines. The National Gas Law's regulatory objective is to promote efficient investment in, and operation and use of, gas services for the long-term interests of consumers of gas in terms of the price, quality, safety, reliability and security of supply of gas. The National Gas Rules set out revenue and pricing principles, including that pipeline businesses should have a reasonable opportunity to recover efficient costs.

Owners of full regulation gas pipelines must periodically submit a regulatory proposal – called an access arrangement – to the AER. The proposal sets out the pipeline business's forecast revenue and expenditure needs over the forthcoming access arrangement period (typically 5 years) and an access price derived from demand forecasts.

The AER then assesses the proposal, focusing on the business's forecast revenue requirements to cover its efficient costs. As in electricity, the AER uses a building block approach to assess the business's efficient costs (section 5.5). Ensuring only efficient costs are included in the calculation of a regulated business's revenue requirement helps protect customers from being charged unreasonable prices.

The AER draws on a range of inputs to assess efficient costs, including cost and demand forecasts and revealed costs from experience. Unlike electricity, the approach is not formalised in published guidelines. An exception is the allowed rate of return assessment, for which a common AER guideline applies to both electricity and gas. New legislation in November 2018 requires the AER to make binding rate of return determinations. In December 2018 the AER released a Rate of Return Instrument (RRI) that sets out its approach (section 3.11.1).

If the AER finds a business's access arrangement proposal to be unnecessarily costly, it may ask the business for more detailed information or for a clearer business case. If these steps fail to satisfy the AER, it may amend the access arrangement to align it with efficient costs.

The AER's final decision sets an access price (reference tariff) for a commonly sought gas pipeline service (reference service) – such as firm haulage – for the duration of the access arrangement. That reference tariff provides a basis for access seekers to negotiate prices to other services. If a dispute arises, a frustrated access seeker can apply to the AER to determine a tariff and other conditions of access.

9 AER, *Final access determination – Tasmanian Gas Pipeline*, 12 April 2018.

10 AER, *Access dispute – Carisbrook to Horsham Pipeline*, 28 January 2021.

11 Under rule 569(4)(b) of the National Gas Rules.

In March 2019 the Australian Energy Market Commission (AEMC) implemented rules to improve information disclosure, support more effective negotiations and improve access to fully regulated pipelines. The rules aim to help pipeline users negotiate lower prices and better deals by:

- setting out a process for determining which services will have reference tariffs set by the AER
- clarifying how the AER calculates efficient costs
- strengthening reporting obligations to support more balanced negotiations
- giving stakeholders more input into AER decisions
- setting a clear trigger for pipeline users to seek arbitration if negotiations fail.[12]

Most of the provisions commenced in March 2019.

5.4.2 Incentive schemes

The National Gas Rules allow scope for gas pipeline businesses to earn bonus revenue by outperforming efficiency targets (and incur penalties for underperformance). An efficiency carryover mechanism allows businesses to retain, for up to 6 years, efficiency savings in managing their operating costs. In the longer term, pipeline businesses must share efficiency gains with their customers by passing on around 70% of the gains through lower access prices. The mechanism is similar to the efficiency benefit sharing scheme (EBSS) in electricity (box 3.5), but it is written into each business's access arrangement rather than being set out in a general guideline.

A number of gas distributors have proposed a capital expenditure sharing scheme (CESS). The National Gas Rules do not mandate such schemes, but they allow the AER to approve their use to incentivise pipeline businesses to efficiently maintain and operate their networks.

The Victorian gas distributors were the first to implement a CESS as part of their 2018 to 2022 access arrangements. The AER then approved Jemena's (NSW) request for a CESS for its 2020 to 2025 access arrangement; and requests by AGN (South Australia) and Evoenergy (ACT) for their 2021 to 2026 access arrangements. To date, no gas transmission business has sought to participate in a CESS.

The CESS for gas pipelines operates in a similar way to the CESS for electricity networks (box 3.4). It allows a pipeline business to earn a bonus by keeping new investment spending below forecast levels (and incur penalties if the business invests above target). In later access arrangements, the business must pass on around 70% of savings to customers as lower pipeline charges.

The CESS risks encouraging pipeline businesses to inflate their investment forecasts. To mitigate this risk, the AER scrutinises whether proposed investments are efficient. The design of the CESS ensures deferred expenditure does not attract rewards so that businesses are not incentivised to defer critical investment needed for safe and reliable network operation. A network health index ensures that rewards depend on the pipeline business maintaining current service standards.

Other incentives applied to electricity networks – such as those relating to service performance and demand management innovations – are not available to gas pipeline businesses. The Victorian gas distributors sought the introduction of a network innovation scheme for the 2018 to 2022 access period. The AER rejected the scheme, arguing the current framework provides sufficient incentives for innovation, particularly since the addition of CESS.[13]

5.4.3 Timelines and process

Once a gas pipeline business submits an access arrangement proposal, the AER has 6 months (plus optional stop-the-clock time at certain stages) to make a final decision on how much revenue the business can recover from its customers. The assessment period can be extended by up to 2 months, but there is a maximum of 13 months to render a decision.

The AER consults with gas pipeline customers and other stakeholders during the process. As part of this consultation, the AER publishes a draft decision, on which it seeks stakeholder input to inform its final decision. At the completion of a review, the AER publishes an access arrangement decision that sets the reference tariff that a gas pipeline business can charge its customers. The AER annually reviews pipeline charges to ensure they are consistent with its decision.

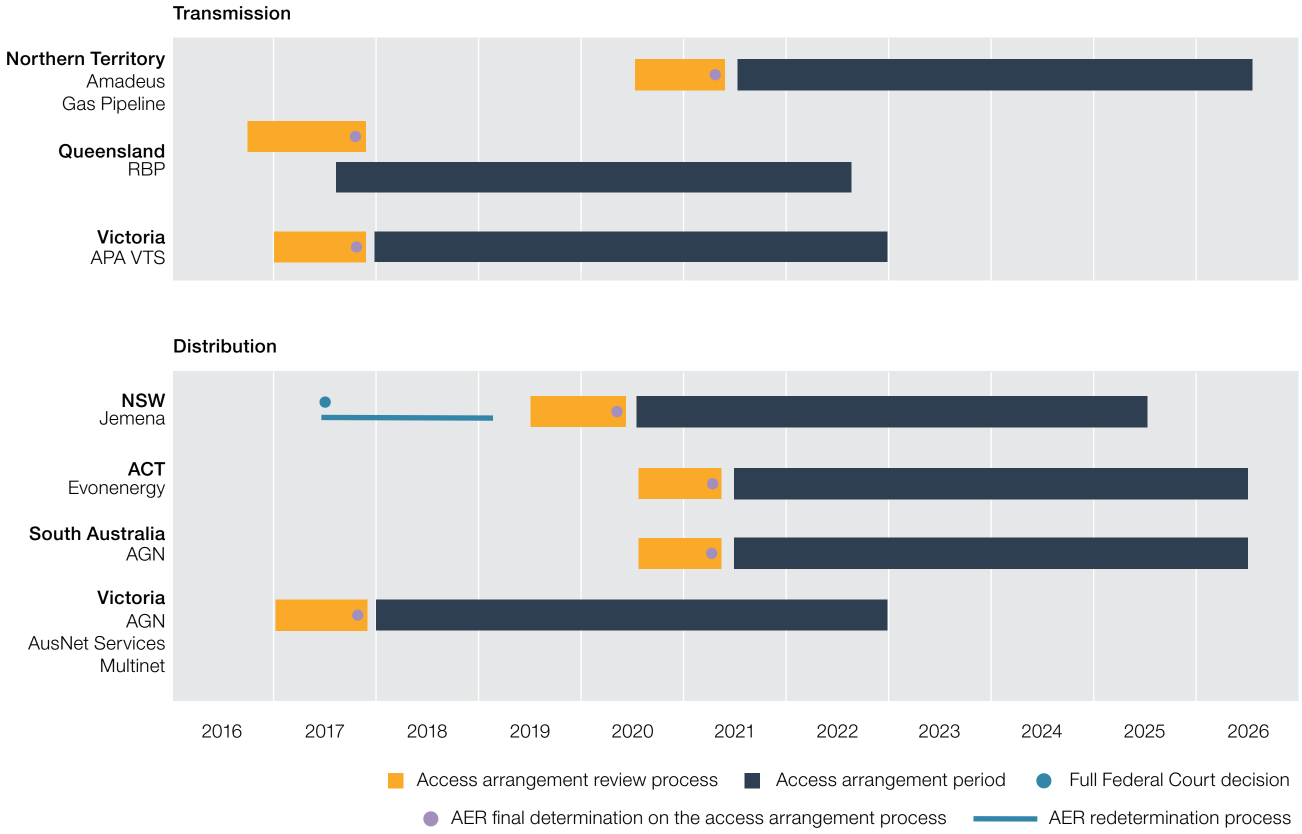
12 AEMC, National Gas Amendment (Regulation of Covered Pipelines) Rule 2019, 14 March 2019.

13 AER, *AusNet Services gas access arrangement 2018–2022, draft decision, attachment 14 – other incentive schemes*, July 2017.

Figure 5.4 sets out timelines for the AER's access arrangement reviews. The AER assesses access arrangements on a rolling cycle, with staggered review timing to avoid bunching. The (typically) 5-year review cycle helps create a stable investment environment but also risks locking in inaccurate forecasts.

Countering this risk, the gas rules include ways of managing uncertainties. The AER can approve cost pass-throughs if a significant event (such as a regulatory change or natural disaster) imposes significant costs that were not forecast. A gas network may also approach the AER to pre-approve a contingent investment project whose need is uncertain at the time of the reset. A pre-approval allows the network business to roll the project into the pipeline's regulatory asset base (RAB) in the forthcoming access arrangement if pre-determined conditions are met.

Figure 5.4 AER decision timelines – full regulation gas pipelines



AGN: Australian Gas Networks; RBP: Roma to Brisbane Pipeline; VTS: Victorian Transmission System.

Note: Times are subject to variation. For the latest information, please check www.aer.gov.au/networks-pipelines/determinations-access-arrangements.

Source: AER.

5.4.4 Customer engagement

As in electricity, an important focus of gas pipeline regulation is how constructively a business engages with its customers in developing an access arrangement proposal. While not mandated in the gas rules, evidence of real constructive engagement can give the AER confidence that the business is genuinely committed to meeting its customers' needs and preferences. It can lay the foundation for the AER to accept elements of an access arrangement proposal, including capital and operating expenditure forecasts.

Recent access arrangement proposals have demonstrated improving levels of customer engagement:

- Before submitting its 2021 to 2026 access arrangement proposal for the Amadeus Gas Pipeline (Northern Territory), APA consulted with stakeholders on the pipeline's asset management plan. APA put forward a well-informed proposal underpinned by sound consumer engagement. The proposal incorporated stakeholder views and included a targeted stakeholder engagement approach which the AER considered to be well calculated and appropriate.[14]

14 AER, *Final decision – Amadeus Gas Pipeline access arrangement 2021 to 2026*, April 2021.

- Evoenergy submitted a well-informed proposal for its 2021 to 2026 access arrangement proposal underpinned by significant improvements to its consumer engagement approach.[15] Its proposal was developed against the backdrop of the ACT Government's Climate Change Strategy 2019–25, including the legislated 2045 net zero greenhouse gas emissions target.[16]

  The impact of evolving ACT policy settings on Evoenergy's future network planning and consumers was a key issue for stakeholders. The AER noted Evoenergy's commitment to put consumers at the centre of its business and to ensure stakeholders' views are reflected in its proposals.[17]

- The AER commended AGN (South Australia) on its consumer engagement approach in developing its 2021 to 2026 access arrangement proposal. AGN demonstrated meaningful engagement with its customers, which it facilitated through workshops held across regional South Australia with residential and business customers. All submissions the AER received on AGN's proposal praised AGN for its quality consumer engagement.

  Further, AGN's (South Australia) consumer engagement program was recognised by the wider industry. In October 2020 AGN was awarded the Energy Network Consumer Engagement Award[18] in recognition of its leadership and innovation in consumer engagement.

5.4.5 Recent AER access arrangement decisions

In April 2021 the AER published its final decisions on access arrangements for gas distribution networks in South Australia (AGN) and the ACT (Evoenergy) and for a major transmission pipeline in the Northern Territory (Amadeus Gas Pipeline). The access arrangements will take effect on 1 July 2021 and remain in place until 30 June 2026.

The AER allowed AGN 16% more revenue in the current period than was used to set tariffs in the previous period. AGN provides natural gas to over 450,000 homes and businesses across South Australia and its revenue makes up around half of an average retail gas customer bill in South Australia. It estimates this change will increase annual retail gas bills for residential and small business consumers in AGN's (South Australia) network area by 0.46% and 0.44% per year respectively over the current access period.

The AER allowed Evoenergy 6% less revenue in the current period than was used to set tariffs in the previous period. The AER accepted Evoenergy's proposal for shorter standard asset lives for new investments in long-lived pipeline assets, which brought forward some revenue. Evoenergy distributes natural gas to approximately 150,000 homes. Around 90% of Evoenergy's consumers are located in the ACT, with the remaining 10% in NSW. Around 98% of Evoenergy's consumers are residential consumers. Evoenergy's revenue makes up around a quarter of the average customer bill in the ACT. The AER estimates the access arrangement will increase annual retail gas bills for residential and small business consumers by 0.63% and 0.69% per year respectively over the current period.

The AER accepted APA's proposed revenue for the Amadeus Gas Pipeline over the current period. The proposed revenue – 18% lower than forecast revenue used to set tariffs in the previous period – was consistent with that of a pipeline which is about halfway through its physical life, with forecast expenditure mainly for corrective maintenance and replacement. APA did not propose expanding the Amadeus Gas Pipeline over the current period.

5.4.6 Legal reviews

An affected party can file an application with the Federal Court for judicial review of an AER access arrangement decision. Until 2017 a party could also apply to the Australian Competition Tribunal for a limited merits review of an AER decision and then appeal the tribunal's decision to the Full Federal Court. The Australian Government abolished this avenue of appeal in October 2017.

After a long-running appeal, in July 2017 the Full Federal Court ordered the AER to remake elements of its access arrangement decision for Jemena (NSW). The AER's remade decision, published in February 2019, approved $18 million of revenue additional to what it approved in 2015. However, adjustments from interim arrangements for the network will result in Jemena returning $169 million to consumers in its current access period (figure 5.14).[19]

15 AER, *Final decision – Evoenergy access arrangement 2021 to 2026*, April 2021, p 6.

16 Environment, Planning and Sustainable Development Directorate, *ACT Climate Change Strategy 2019–25*, 2019.

17 AER, *Final decision – Evoenergy access arrangement 2021 to 2026*, April 2021, p 8.

18 Energy Networks Australia (ENA), in partnership with Energy Consumers Australia (ECA), runs the award, which recognises an Australian energy network business that demonstrates outstanding leadership in consumer engagement.

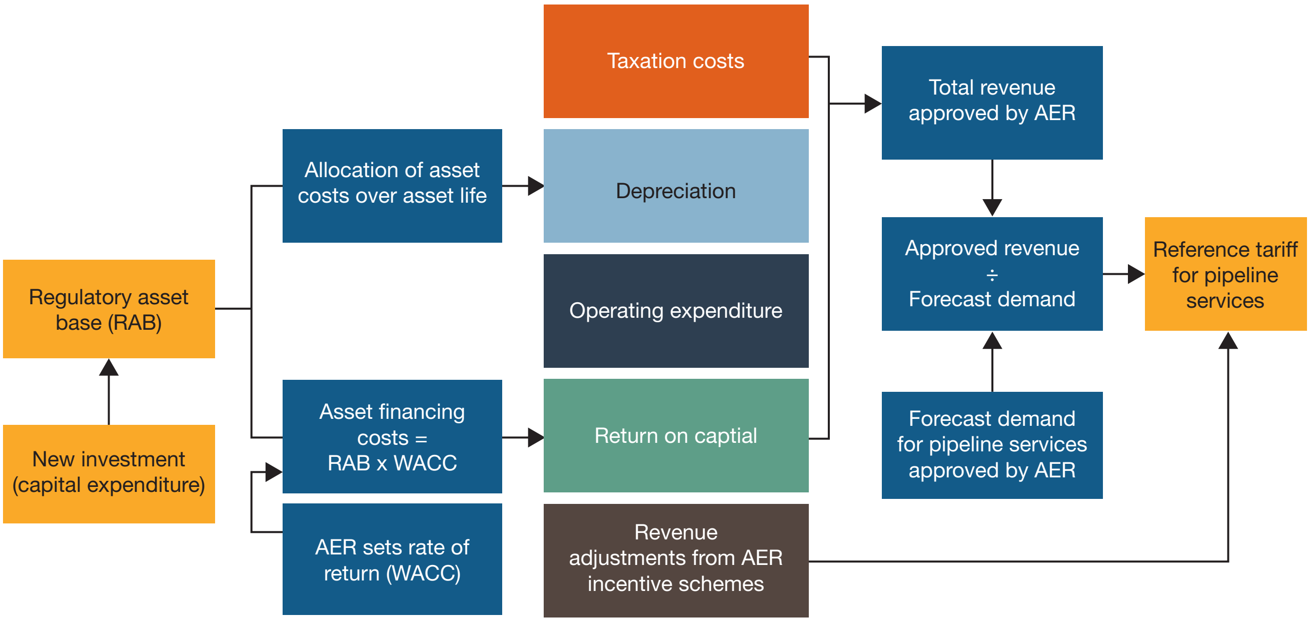
19 AER, *Final decision, Jemena Gas Networks (NSW) Ltd 2015–20 access arrangement*, February 2019.

5.5 The building blocks of gas pipeline revenue

In setting a gas pipeline business's allowed revenue, the AER assesses the efficient costs of operating the business. The AER breaks up its cost assessment into 'building blocks' in order to forecast how much revenue the business is likely to need to cover 4 key cost components (figure 5.5). These components are:

- efficient operating and maintenance costs
- commercial returns to shareholders and investors that fund its operations
- asset depreciation costs
- taxation costs.

Figure 5.5 How gas pipeline revenue and charges are set



WACC: weighted average cost of capital.

Note: Revenue adjustments from incentive schemes encourage pipeline businesses to manage their operating and capital expenditure efficiently, and to innovate.

Source: AER.

The cost of new investment is recovered over the economic life of the asset, which may be several decades. The capital cost recovered each year is called depreciation, and it covers the lost value of assets through wear and tear and technical obsolescence.

The shareholders and lenders that fund network assets must also be paid a commercial return on their investment each year. Those returns are forecast to absorb 54% of transmission revenues and 36% of distribution revenues in the current access periods. The returns are calculated by multiplying:

- the value of the network's RAB,[20] which is adjusted each year for new investment, less asset disposals and depreciation, by
- the rate of return paid to investors that fund those assets, through either equity ownership or debt. The AER sets the allowed rate of return, also called the weighted average cost of capital (WACC).

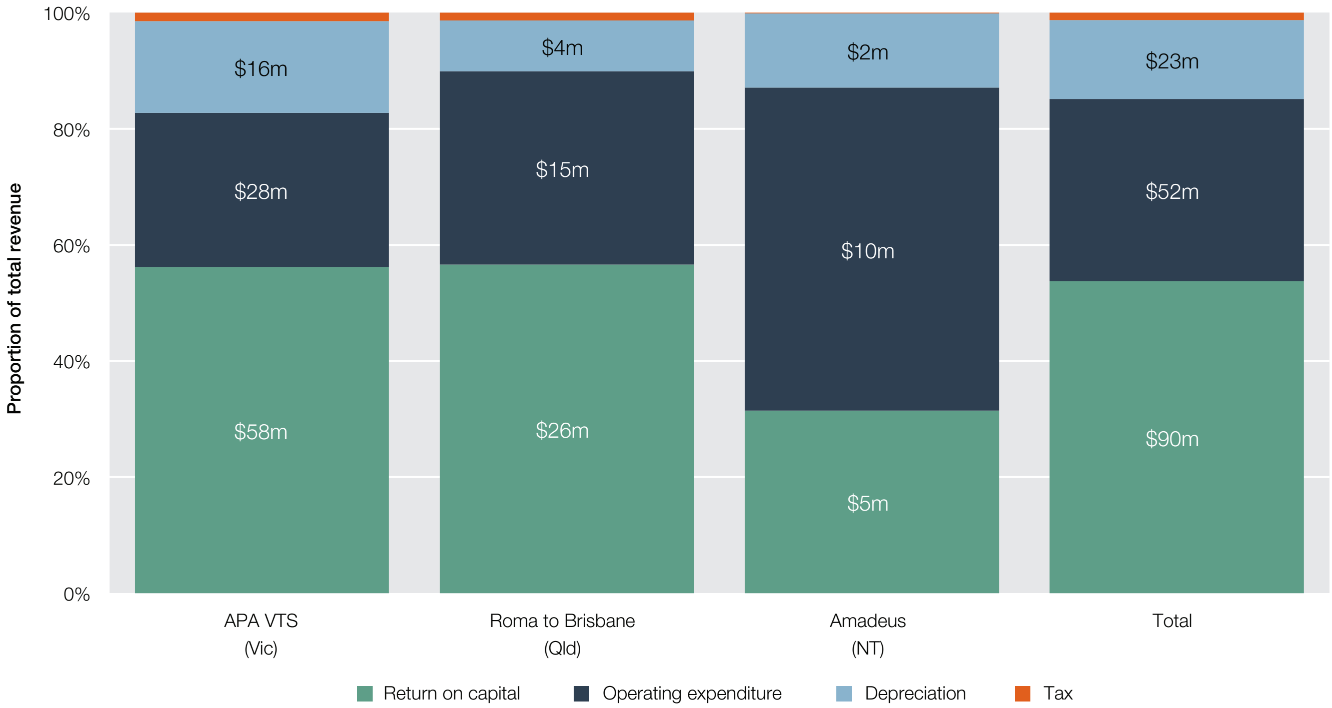
Operating and maintenance costs are forecast to absorb 31% of transmission revenues and 40% of distribution revenues in the current access periods. Overheads, taxation and other costs account for the remainder of a pipeline's revenue.

Gas pipeline businesses can earn additional revenue through regulatory incentives that encourage the efficient management of operating and capital expenditure programs (section 5.4.2).

Figures 5.6 and 5.7 illustrate the composition of pipeline revenues in recent gas transmission and distribution decisions.

20 The regulatory asset base (RAB) is the economic value of a network's assets used to provide network services to customers. These assets have been accumulated over time and are at various stages of their economic life cycle.

Figure 5.6 Composition of average annual gas pipeline revenues – transmission

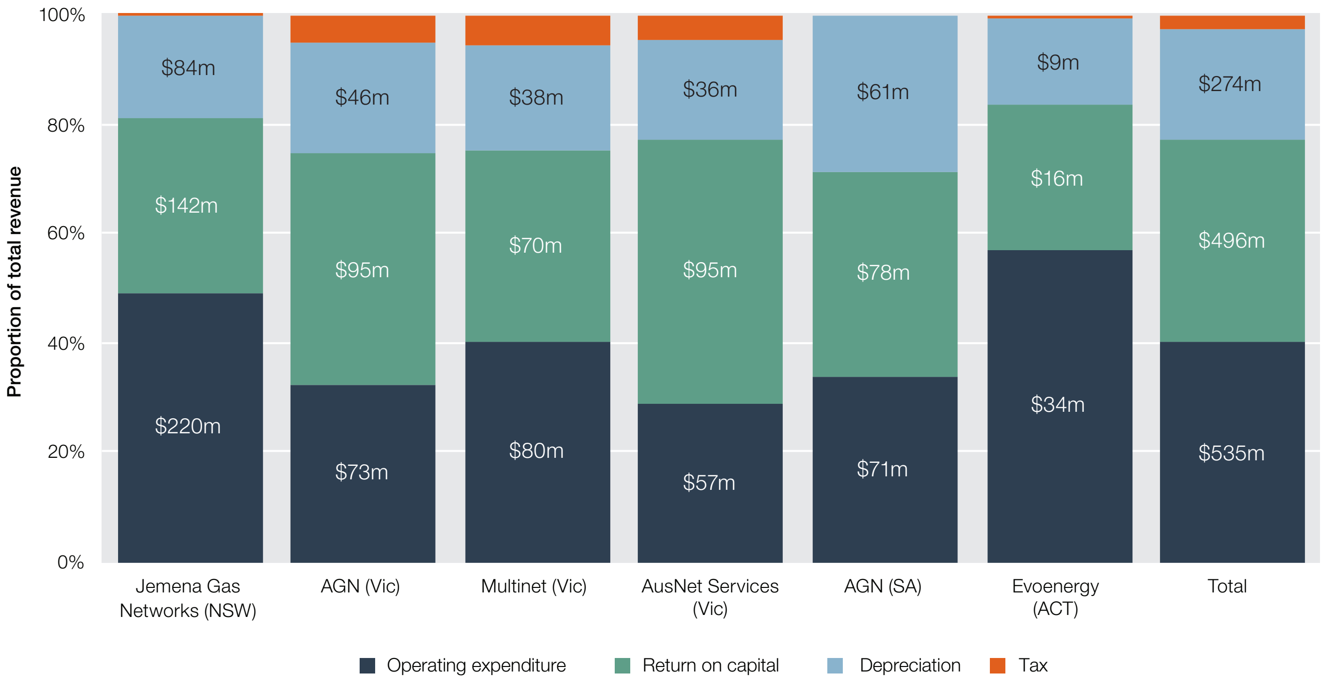


VTS: Victorian Transmission System.

Note: Network businesses also receive bonuses or penalties that impact on annual network revenues. These bonuses/penalties are not material and are not considered in figure 5.6.

Source: Post tax revenue modelling used in AER determination process.

Figure 5.7 Composition of average annual gas pipeline revenues – distribution



AGN: Australian Gas Networks.

Note: Network businesses also receive bonuses or penalties that impact on annual network revenues. These bonuses/penalties are not material and are not considered in figure 5.7.

Source: Post tax revenue modelling used in AER determination process.

5.6 Gas pipeline revenues

Full regulation gas pipelines (figures 5.2 and 5.3) are forecast to earn around $7.6 billion in their current access arrangement periods – 1% more than was forecast in their previous respective periods:

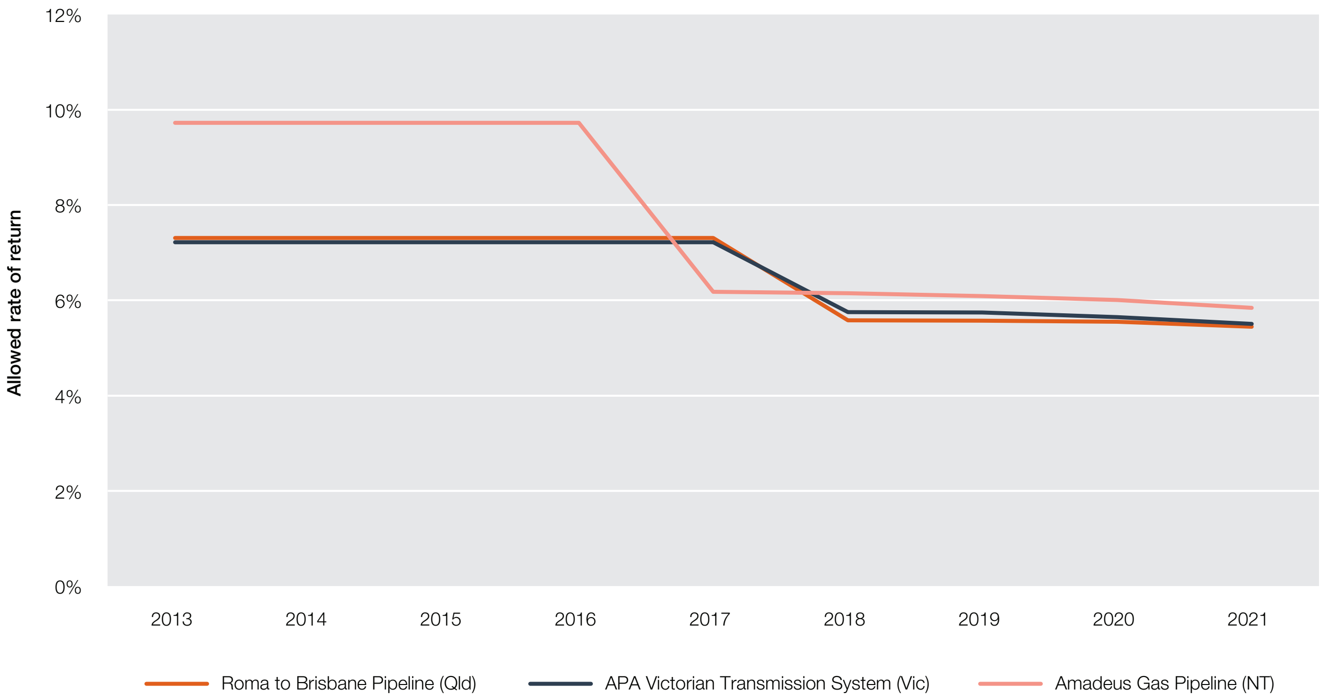
- Full regulation distribution networks are forecast to earn around $6.7 billion[21] in their current access arrangement periods – $136 million (2%) more than forecast in their previous respective previous periods.
- Full regulation transmission pipelines are forecast to earn around $856 million[22] in their current access arrangement periods – $57 million (6%) less than forecast in their previous respective previous periods.

Some key drivers of network revenues have eased in recent years. Previous access arrangements were made at a time of increased pipeline investment in response to ageing assets and forecasts of rising energy demand. However, capital expenditure on both distribution and transmission pipelines decreased in 2015–16 and has since plateaued. Network businesses also had higher financing costs due to instability in global financial markets.

Weaker domestic gas demand in recent years – caused by significantly higher gas prices – reduced forecast revenue needs for most pipeline businesses.

Further, legislation enacted in November 2018 makes the AER's rate of return determinations binding.[23] This change, along with lower financing costs, reduced the average allowed rate of return in the AER's 5 access arrangement decisions made in 2017 to under 6% and the 3 access arrangement decisions made in 2021 to as low as 4.78% (for Evoenergy in the ACT) in 2021–22, compared with over 10% in decisions made from 2008 to 2010 (figures 5.8 and 5.9). This reduction translates to significantly lower network revenues and gas pipeline charges.

Figure 5.8 Allowed rates of return – gas transmission pipeline networks



Note: Allowed rate of return = nominal vanilla weighted average cost of capital (WACC). Victorian pipeline businesses report on a calendar year basis (year ending 31 December). All other pipeline businesses report on a financial year basis (year ending 30 June). The calendar years shown in the charts reflect the later of the 2 relevant years for non-Victorian pipeline businesses (for example, 2017–18 is shown as 2018).

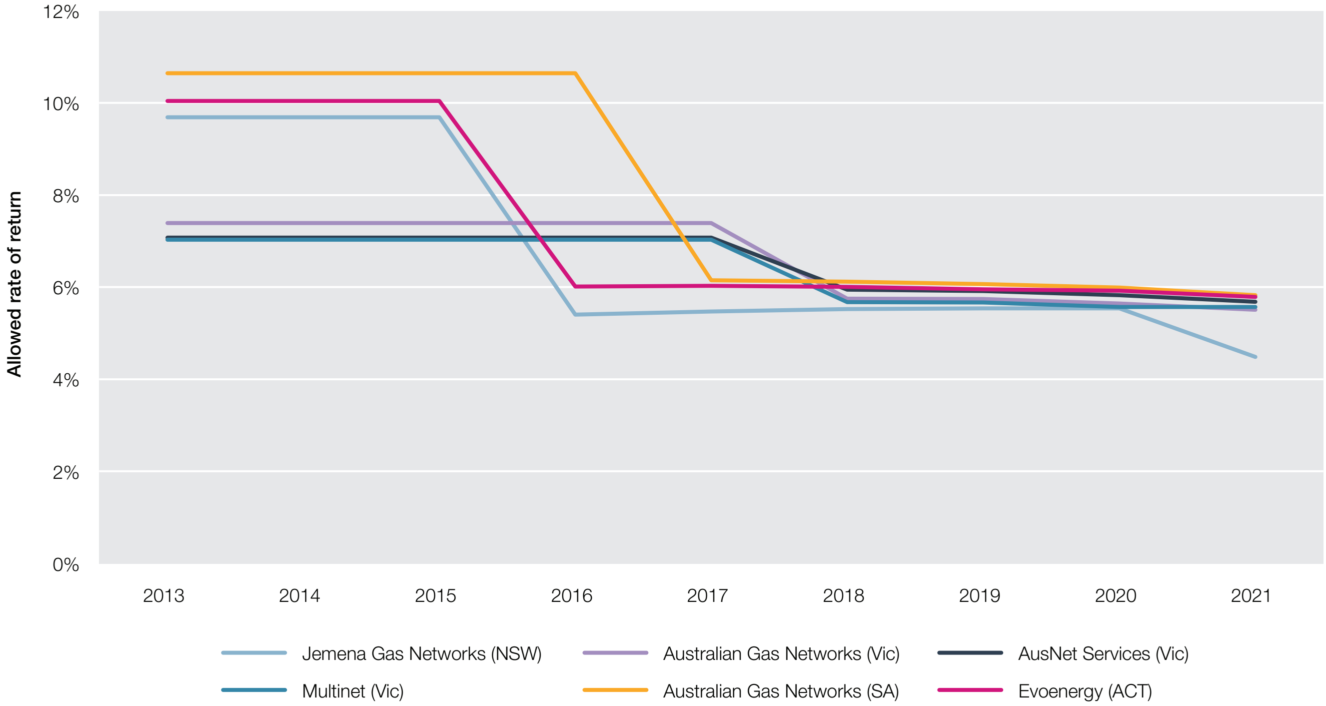
Source: AER decisions on gas pipeline access arrangements; AER decision following the remittal by the Australian Competition Tribunal and Full Federal Court.

21 Excluding revenue adjustments valued at around –$159 million.

22 Excluding revenue adjustments valued at around $26 million.

23 The AER released its first Rate of Return Instrument (RRI) in December 2018, setting out how it determines the allowed rate of return on capital in access arrangement determinations. The 2018 RRI specifies the return on debt as a formula, using the trailing average portfolio approach. Network businesses not already applying this method must transition to it over a 10 year period.

Figure 5.9 Allowed rates of return – gas distribution pipeline networks



Note: Allowed rate of return = nominal vanilla weighted average cost of capital (WACC). Victorian pipeline businesses report on a calendar year basis (year ending 31 December). All other pipeline businesses report on a financial year basis (year ending 30 June). The calendar years shown in the charts reflect the later of the 2 relevant years for non-Victorian pipeline businesses (for example, 2017–18 is shown as 2018).

Source: AER decisions on gas pipeline access arrangements; AER decision following the remittal by the Australian Competition Tribunal and Full Federal Court.

But offsetting these changes has been the need for more revenue to cover new programs, such as AGN's (South Australia) new Vulnerable Customer Assistance Program (VCAP) during the current access period. The objective of the VCAP is to allow AGN to develop a better understanding of the needs of its vulnerable customers and put in place measures to support these customers.

Revenue outcomes vary across network businesses. In gas distribution, revenues are forecast to increase by 16% for AGN (South Australia), 13% for AGN (Victoria) and 4% for Multinet (Victoria). However, Evoenergy (ACT) and Jemena (NSW), had a reduction in forecast revenue of 6% each over the current regulatory period and AusNet Services (Victoria) had a reduction of 1.8%. The relatively stable or increasing revenue for the Victorian networks reflects their higher operating and capital expenditure costs associated with new customer connections, as in new housing estates.

In gas transmission, revenues are forecast to fall by 19% for the Roma to Brisbane Pipeline (Queensland) and 18% for the Amadeus Gas Pipeline (Northern Territory). The Victorian Transmission System, however, is forecast to increase revenue by 3%, reflecting an increased RAB following new investment from 2013 to 2017.

5.6.1 Recent revenue decisions

The AER approved a total allowed revenue of $1,134 million for AGN (South Australia) over the 2021–2026 access period. This allowed revenue is $153 million (16%) more than the forecast revenue used to determine tariffs in the 2016–2021 period. The revenue allowance included reductions in the return on capital and operating expenditure which were marginally offset by an increase in depreciation.

The AER approved revenue of $299 million for Evoenergy (ACT) over the 2021–2026 access period. This allowed revenue is $21 million (6%) less than the forecast revenue used to determine tariffs in the 2016–2021 period. The allowance included reductions in return on capital and corporate income tax which were marginally offset by increases in depreciation and revenue adjustments.

Finally, the AER approved revenue of $98 million for the Amadeus Gas Pipeline over the 2021–2026 access period. This allowed revenue is $20 million (18%) less than the forecast revenue used to determine tariffs in the 2016–2021 period. The revenue allowance included reductions in the building blocks for operating expenditure and return on capital which were marginally offset by an increase in depreciation.

5.7 Gas pipeline investment

Investment requirements differ between the gas transmission and distribution sectors. Gas transmission investment typically involves large, lumpy capital projects to expand existing pipelines (through compression, looping or extension) or construct new infrastructure. Additionally, some transmission pipelines have been re-engineered for bi-directional flows.

Gas distribution investment mainly comprises augmentation (expansion) of existing systems to cope with new customer connections, as in new housing estate developments. Older networks also require replacement programs for deteriorating infrastructure. For pipelines under full economic regulation (table 5.1), the AER assesses whether investments are prudent and efficient based on criteria in the National Gas Rules.

5.7.1 Recent investment

Full regulation transmission pipelines are forecast to invest a total of $332 million in their current access periods – $98 million (42%) more than the forecast investment in their previous periods. Figures 5.11 to 5.19 show investment trends for all pipeline networks regulated by the AER.

APA expects to overspend on its approved capital allowance for the Amadeus Gas Pipeline (Northern Territory) over the previous access arrangement period. The AER approved the overspending, as it qualified as 'conforming capital expenditure'.[24] The AER approved $15 million of proposed total capital expenditure for the current access period – $12 million (45%) below the estimated spend for the previous period. APA did not propose expanding the pipeline over the current access period. This will see its RAB decline over current access period.

Evoenergy (ACT) estimates it will underspend on its total approved capital allowance over the previous access arrangement period. The AER approved a capital expenditure allowance for Evoenergy of $51 million for the current access period. This is $28 million (36%) less than its estimated spend for the previous period. Evoenergy's investment projects over the current access period include meter replacement and replacing facilities and pipes. Evoenergy's RAB is forecast to decrease by 8.4% by 2026.

Following the October 2020 ACT election, the ACT Government confirmed its intention and planned initiatives to phase out natural gas in the ACT.[25] Evoenergy responded to these developments by lowering its forecasts for gas demand and capital expenditure over the current access period.

The AER approved a capital expenditure allowance of $512 million for AGN (South Australia) for the current access period. This was $21 million (4%) less than its estimated spend for the previous period. The allowance is largely to allow AGN to invest in mains replacement and connections. AGN's RAB will initially increase slightly but is expected to stabilise towards the end of the current access period.

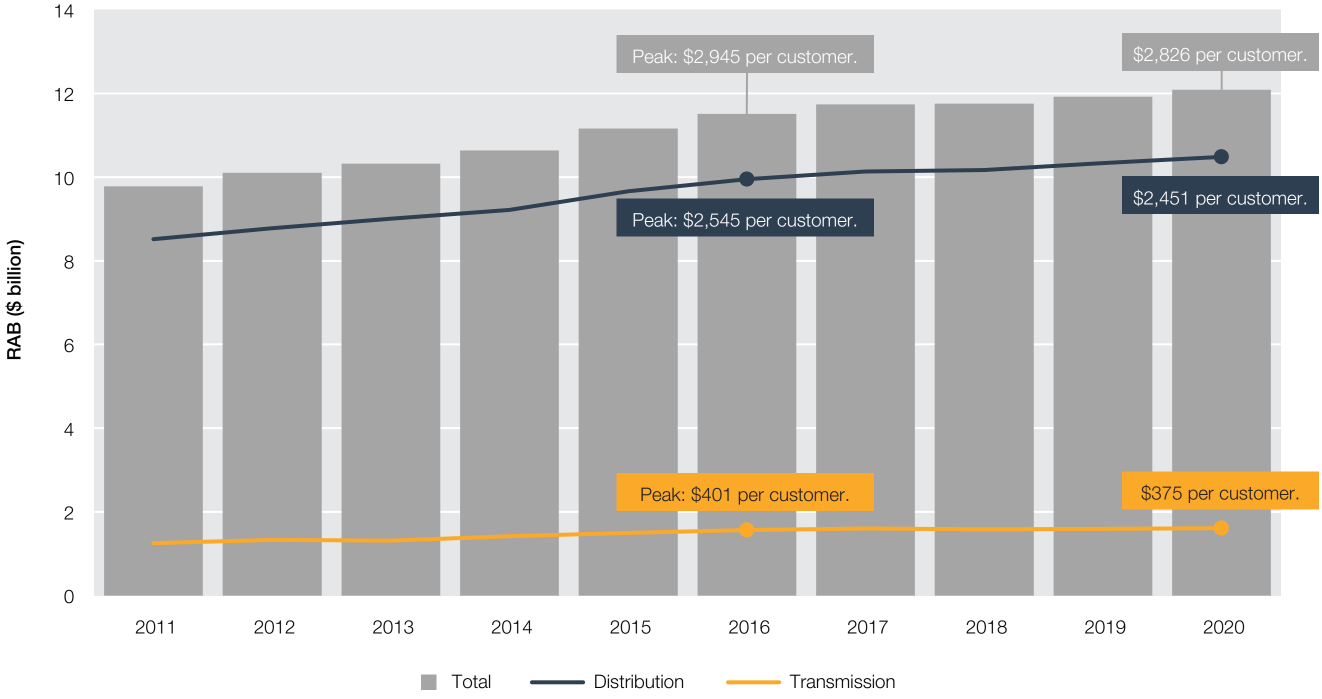
5.7.2 Regulatory asset base

Capital investment approved by the AER is added to a pipeline's RAB, on which future returns are earned. Despite reduced investment since 2014–15, the total RAB for regulated gas pipelines continues to rise, reaching $12.1 billion in 2020 ($1.6 billion for transmission and $10.5 billion for distribution pipelines) (figure 5.10).

24 National Gas Rules, s 79(1).

25 ACT Government, *Parliamentary and Governing Agreement, 10th Legislative Assembly for the Australian Capital Territory*, November 2020, p 7.

Figure 5.10 Regulatory asset base – gas pipelines



RAB: regulatory asset base.

Note: Victorian pipeline businesses report on a calendar year basis (year ending 31 December). All other pipeline businesses report on a financial year basis (year ending 30 June). The calendar years shown in the charts reflect the later of the 2 relevant years for non-Victorian pipeline businesses (for example, 2017–18 is shown as 2018).

Source: AER modelling.

5.8 Gas pipeline operating costs

The AER's assessment of a gas network's efficient operating and maintenance costs accounts for cost drivers such as forecast customer growth, expected productivity improvements, changes in labour and materials costs and changes in the regulatory environment.

Gas distribution networks are forecast to spend around $2.7 billion on operating expenses in the current access arrangement periods – $183 million (7%) more than the forecast in previous periods.

Gas transmission networks are forecast to spend around $261 million on operating expenses in the current access arrangement periods – $53 million (17%) more than the forecast in previous periods.

Figures 5.11 to 5.19 show operating expenditure trends for all pipeline networks regulated by the AER.

In recent AER decisions:

- AGN's (South Australia) approved operating expenditure allowance for the current access period is $368 million – 7% higher than its estimated expenditure in the previous period.
- The AER accepted Evoenergy's (ACT) total operating expenditure forecast for the current access period of $171 million – 8% higher than in the previous access period.
- Amadeus Gas Pipeline's (Northern Territory) operating expenditure allowance over the current access period represents a 19% decrease from its estimated expenditure and a 30% reduction from the approved forecast for the previous access period.

Figure 5.11 APA Victorian Transmission System (Transmission, Victoria)

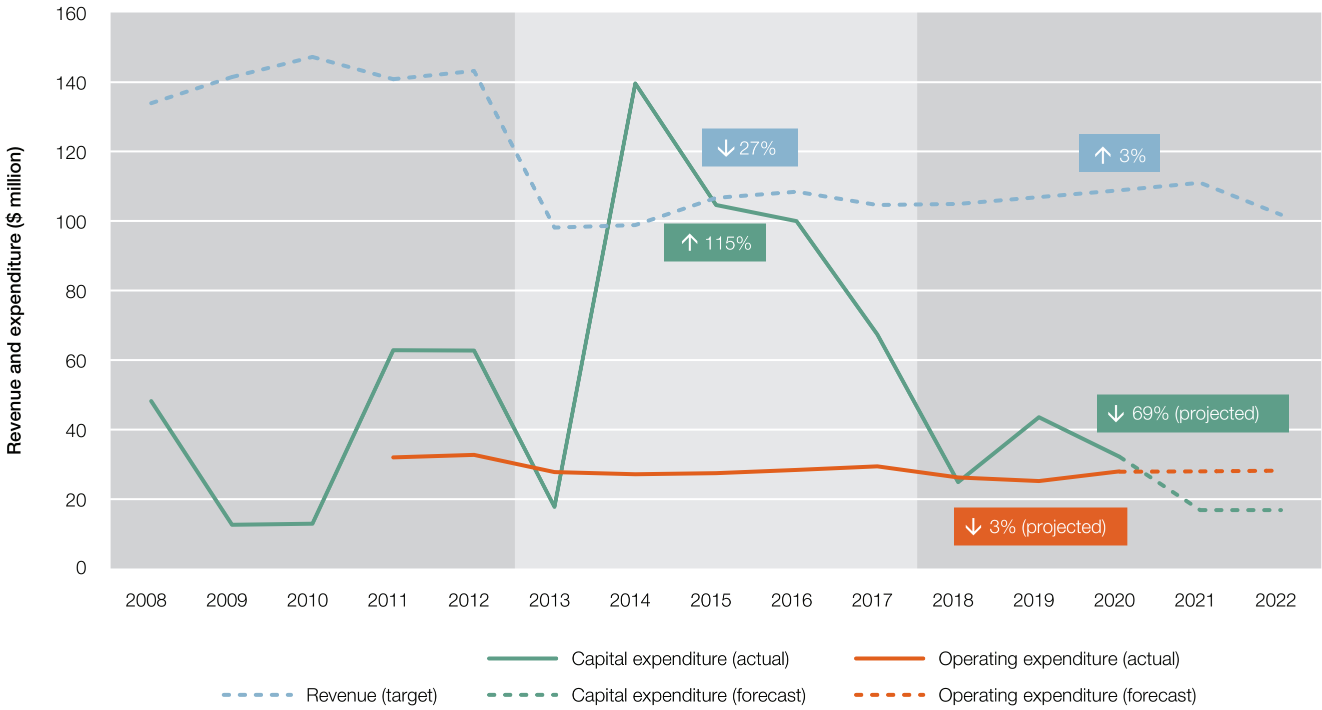


Figure 5.12 Roma to Brisbane Pipeline (Transmission, Queensland)

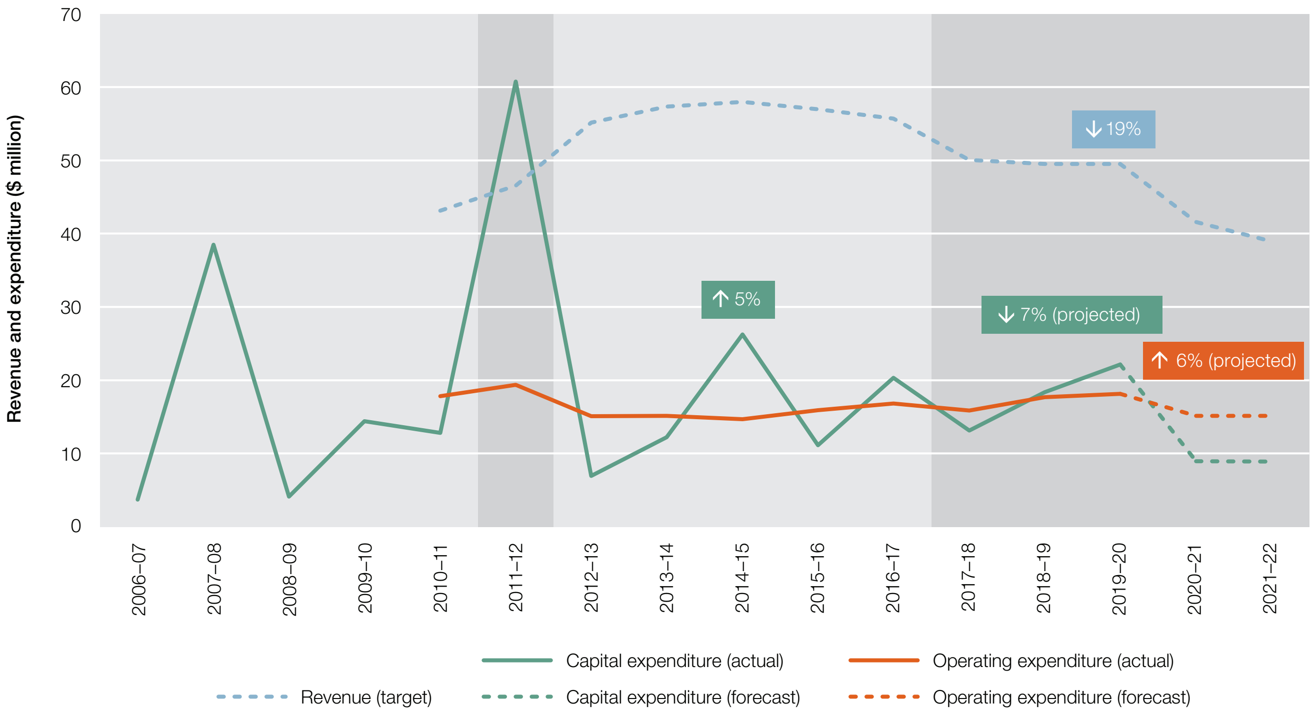


Figure 5.13 Amadeus Gas Pipeline (Transmission, Northern Territory)

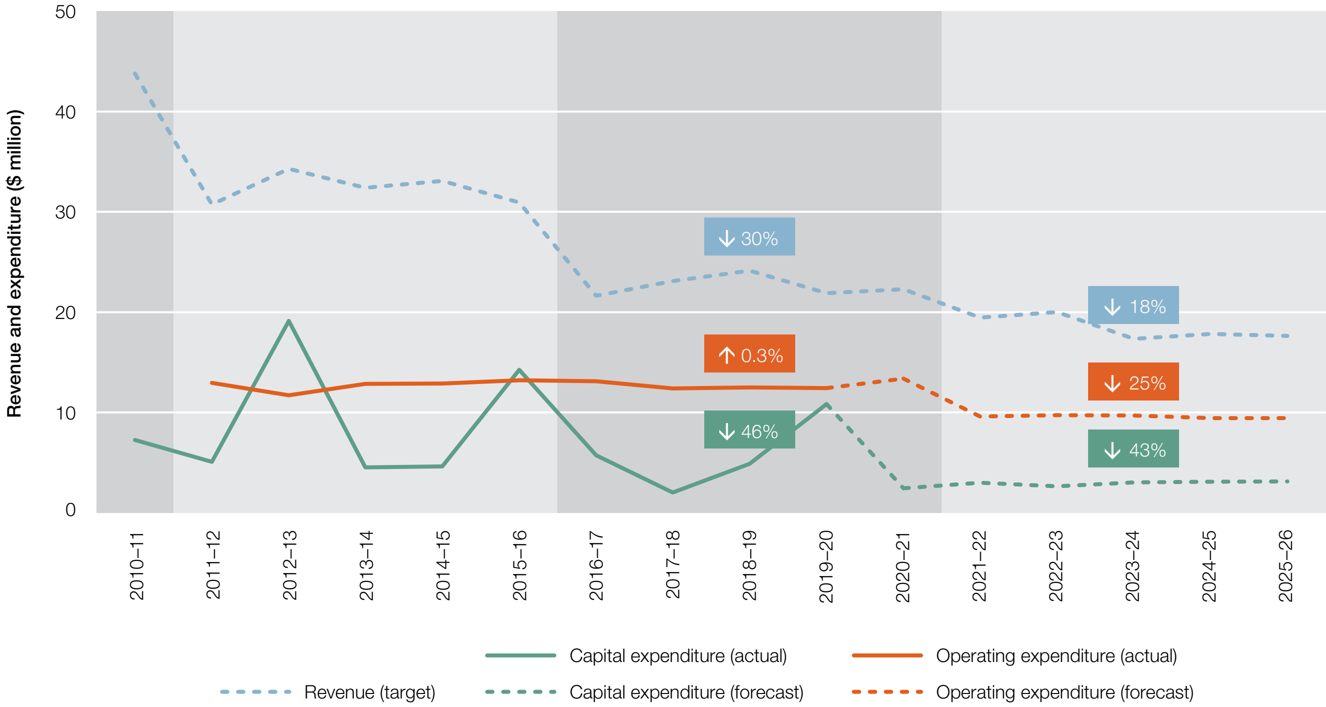


Figure 5.14 Jemena Gas Networks (Distribution, NSW)

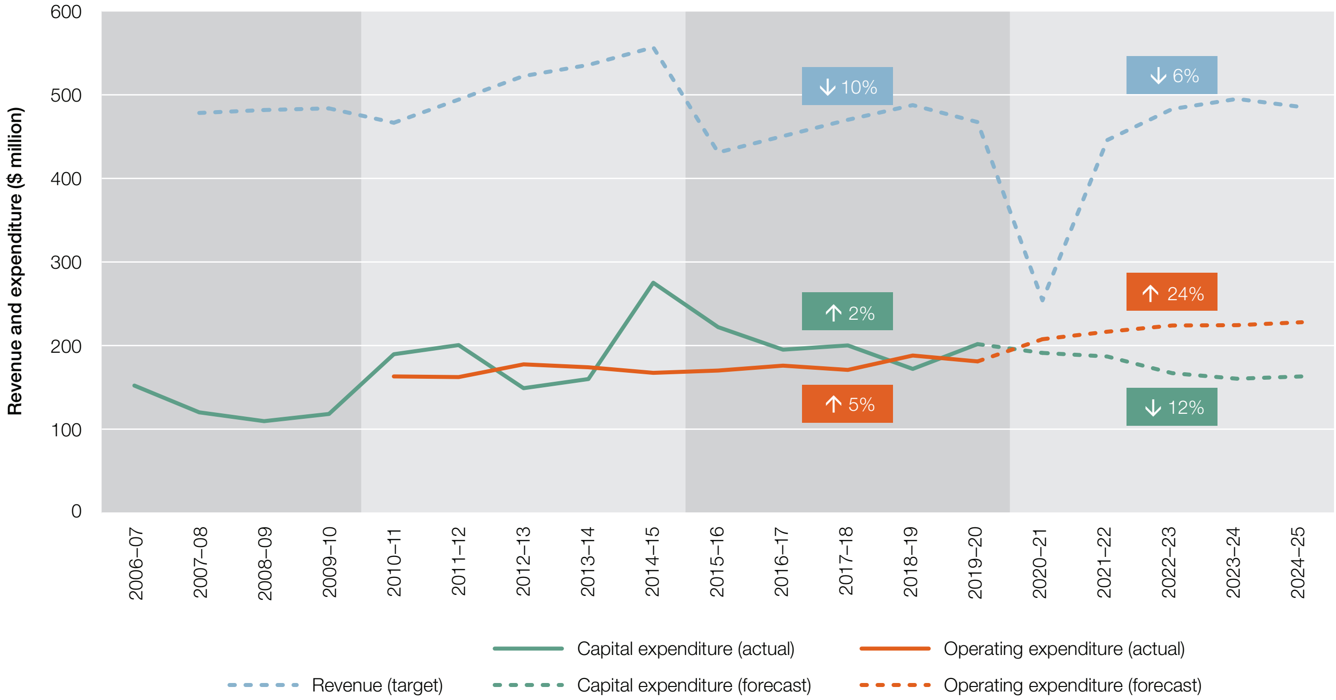


Figure 5.15 Australian Gas Networks (Distribution, Victoria)

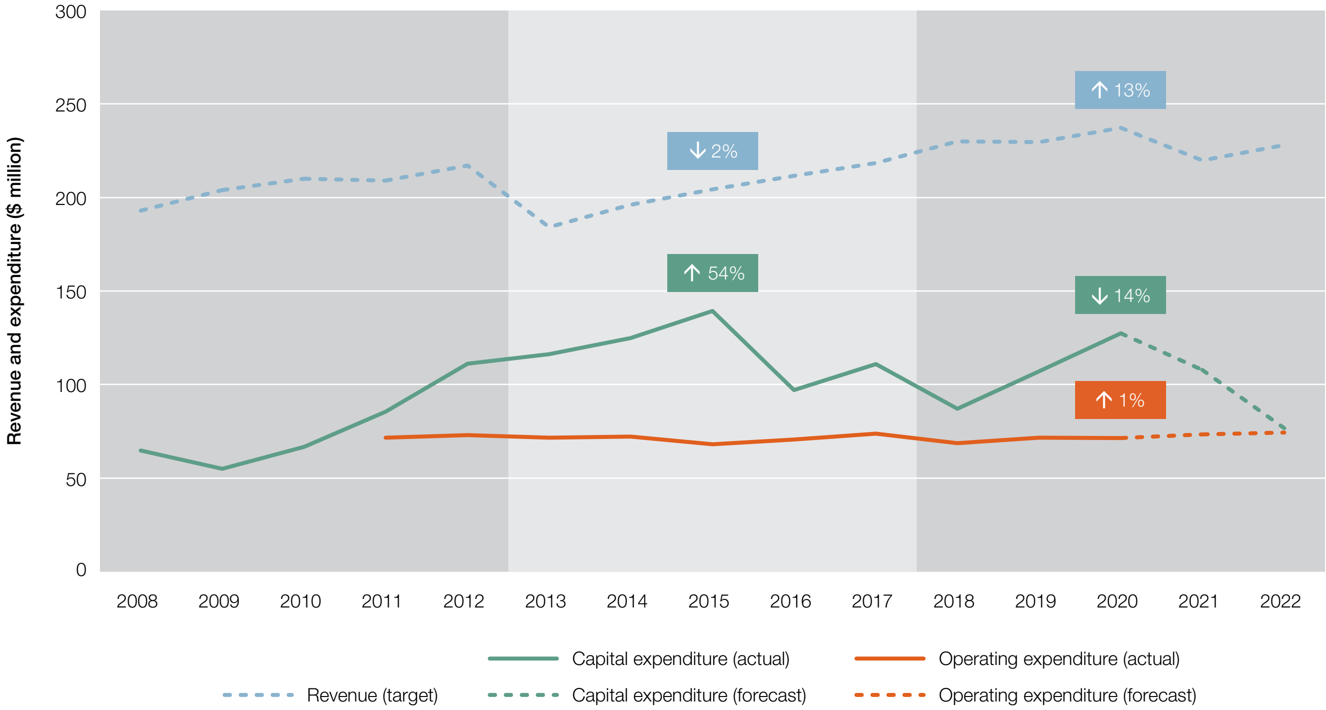


Figure 5.16 Multinet (Distribution, Victoria)

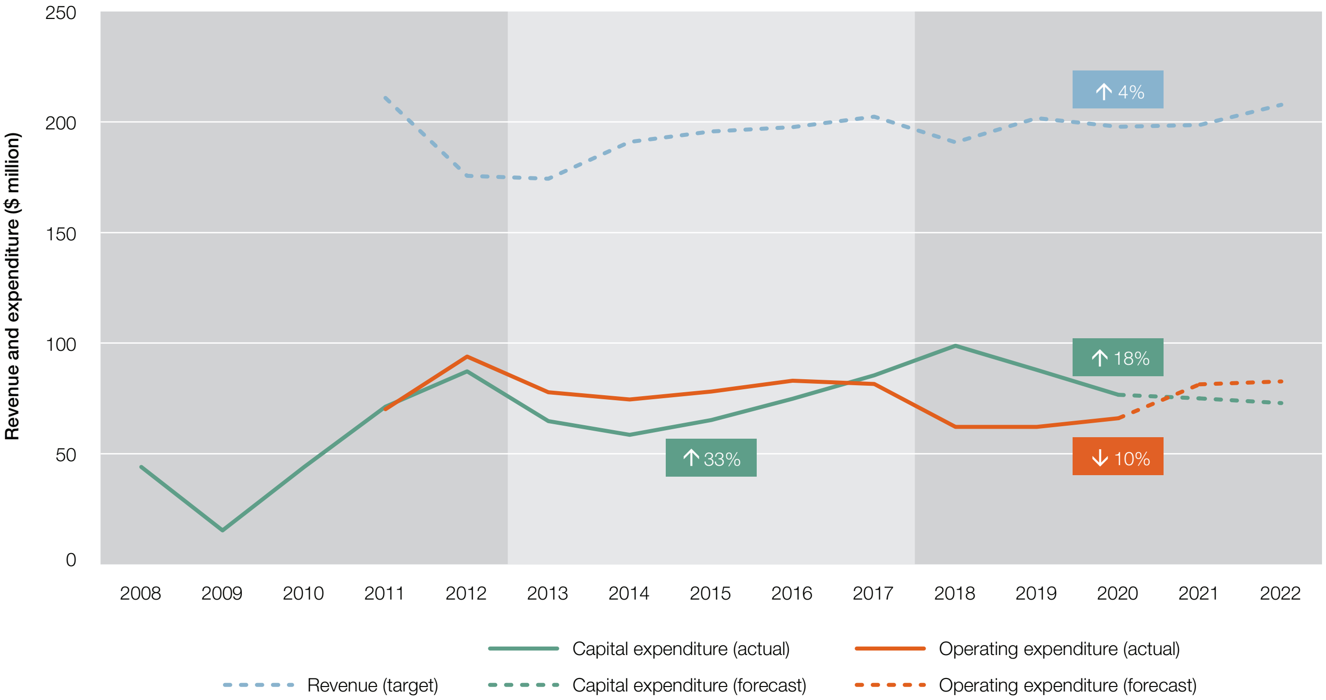


Figure 5.17 AusNet Services (Distribution, Victoria)

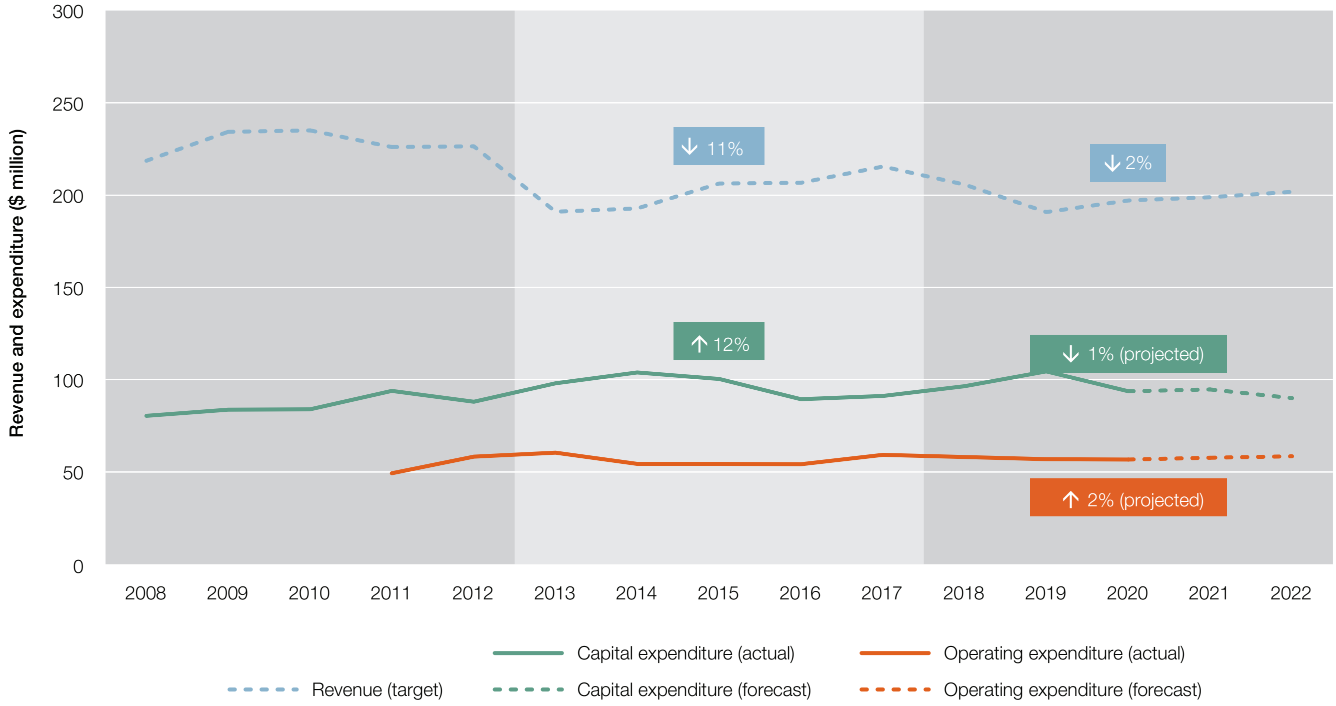


Figure 5.18 Australian Gas Networks (Distribution, South Australia)

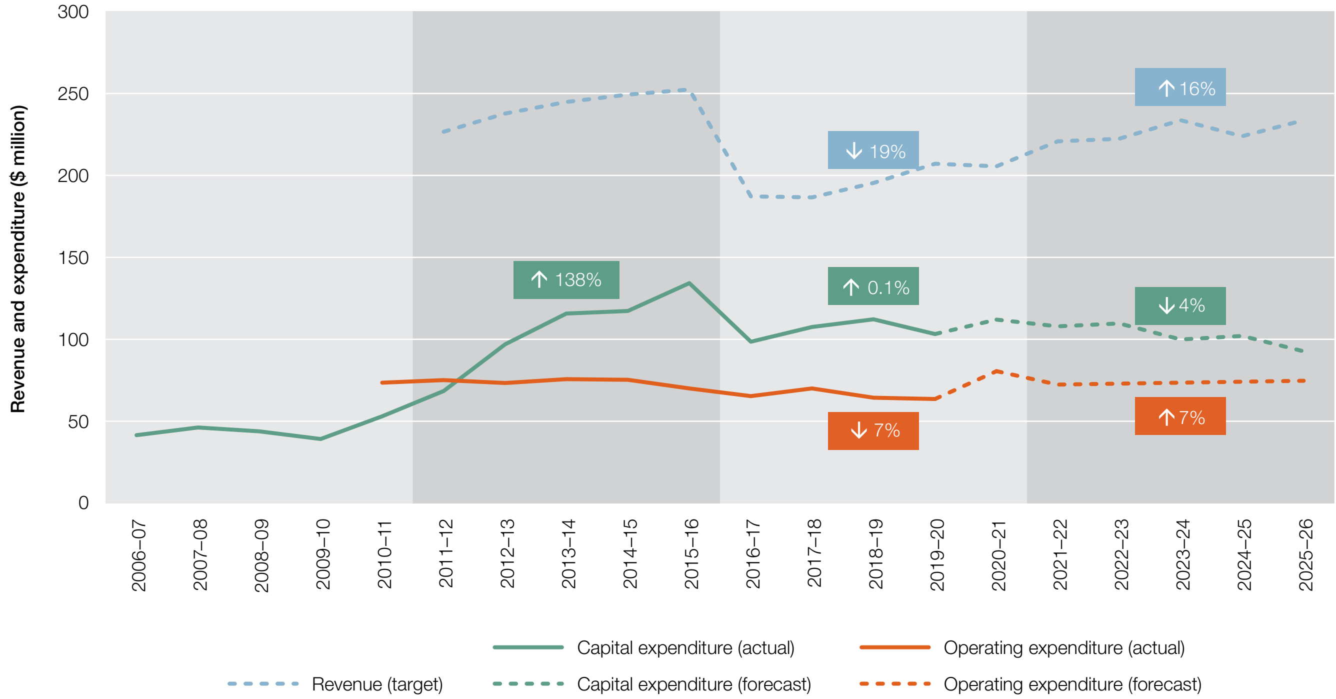
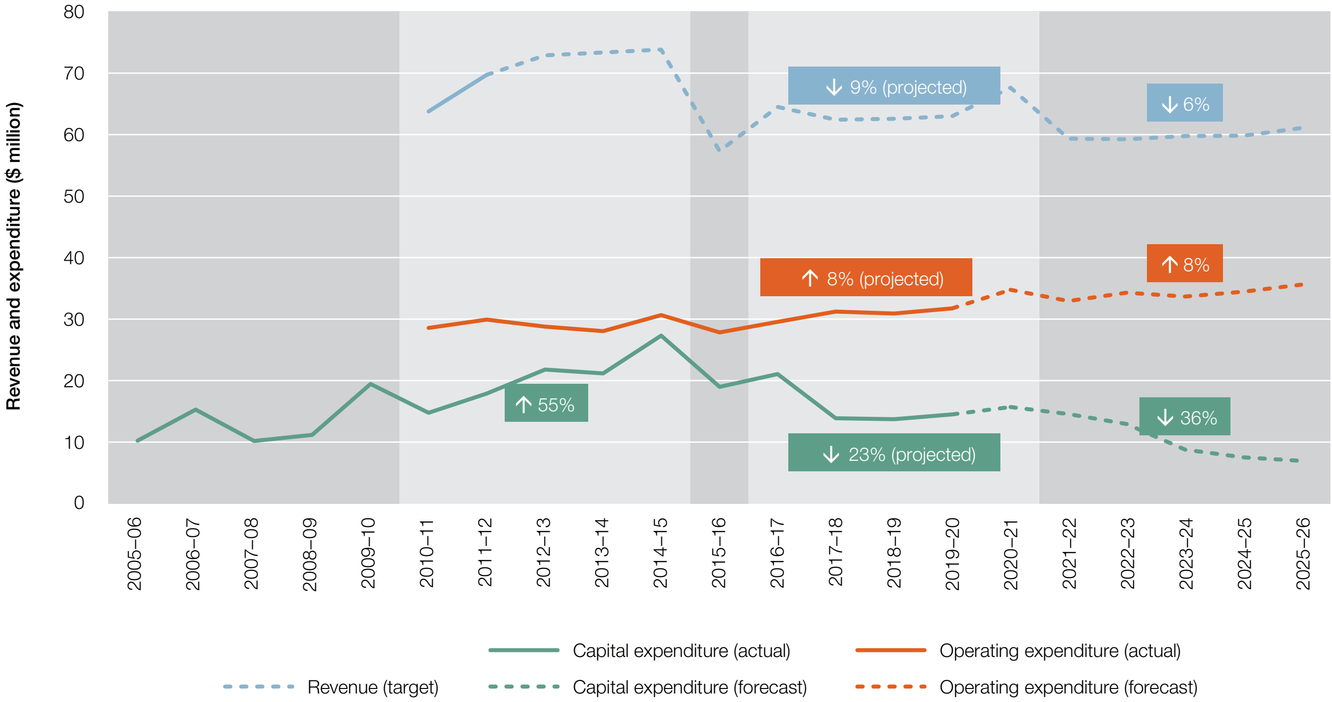


Figure 5.19 Evoenergy (Distribution, ACT)



Note: (figures 5.11 to 5.19): Actual revenue is shown as a solid line; forecast revenue and expenditure is shown as a broken line. Percentages represent the change between periods. Forecasting updates may result in some outcomes varying from those previously reported. Victorian pipeline businesses report on a calendar year basis (year ending 31 December). All other pipeline businesses report on a financial year basis (year ending 30 June).

Source: (figures 5.11 to 5.19): AER.

Source: shutterstock

6

Retail energy markets

6.1 Retail products and services

Most energy customers source their electricity and gas through a retailer that buys energy in wholesale markets and packages it with network services to sell as a bundled product. Retailers monitor and bill customers for the energy they use and manage the risk of price volatility in wholesale markets.

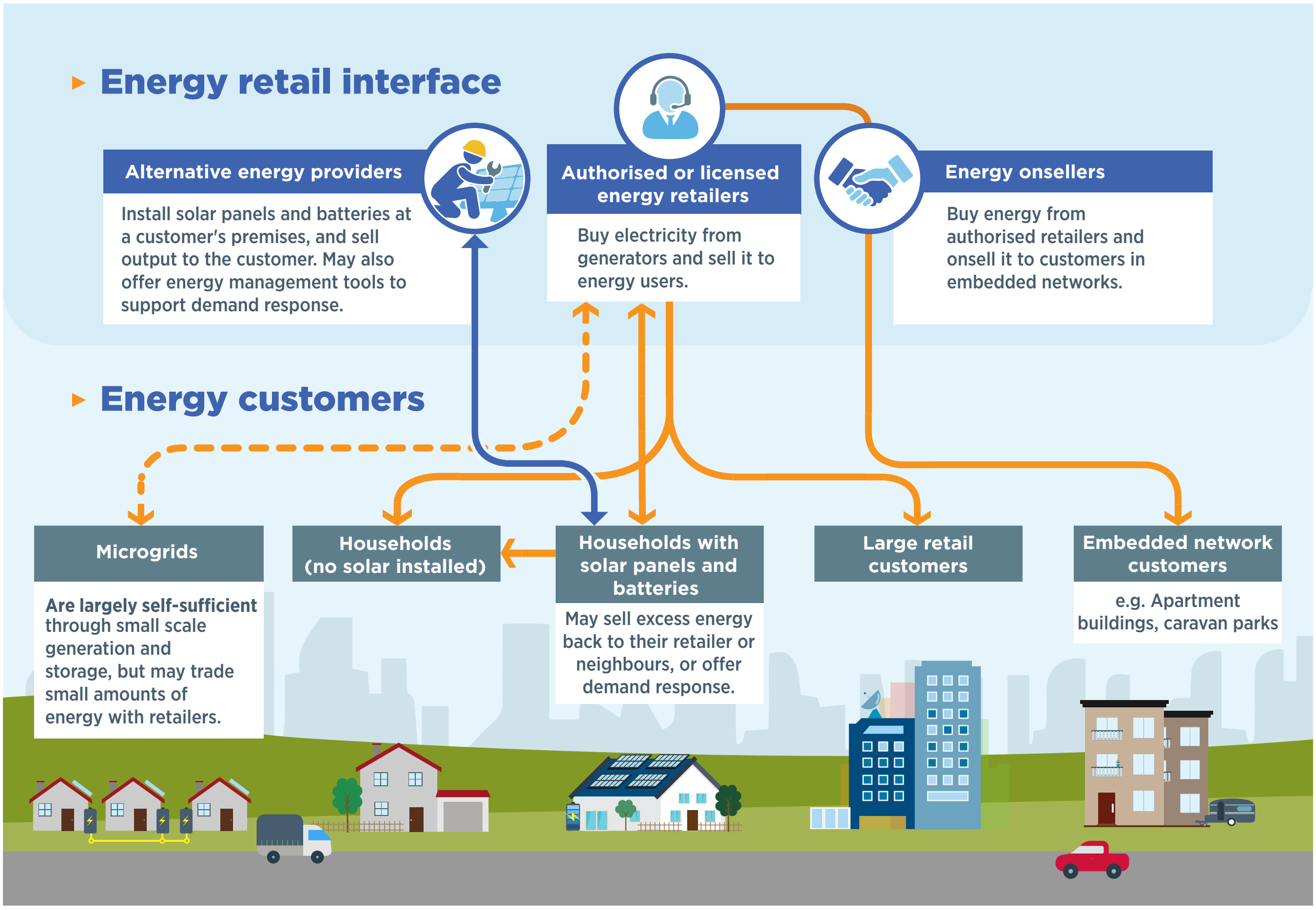
But advances in technology (particularly in the electricity market), high energy prices and environmental concerns are driving customers to be more active in the market and take greater control over their energy use (figure 6.1). Technologies that are opening markets for new types of energy services include:

- smart meters, which provide information on energy use that gives retailers scope to offer more innovative products and for new sellers to offer 'add-on' energy management services
- rooftop solar photovoltaic (PV) systems, which enable energy customers to self-generate electricity and sell any excess back to their retailer or a third party
- batteries, load control devices and similar technologies, which allow customers greater control over their electricity use and the ability to engage in the market in new ways (for example, by storing electricity and entering demand response contracts)
- electric vehicles, which may significantly increase customer electricity demand but can also offer electricity stored in the battery back into the market.

Established energy retailers and new entrant businesses are driving market opportunities for new services.

A small but growing base of customers are bypassing the traditional energy supply model, going 'off-grid' through self-sufficient solar PV generation and battery storage, community based standalone systems or microgrids.

Figure 6.1 An evolving retail energy market



Box 6.1 The AER's role in retail energy markets

The Australian Energy Regulator (AER) regulates retail energy markets so that energy customers (particularly residential and small business customers) can participate confidently and effectively in those markets; and to protect those unable to safeguard their own interests. We undertake this work for Queensland, New South Wales (NSW), South Australia, Tasmania and the Australian Capital Territory (ACT).

We aim to empower customers to make informed decisions on their energy use and protect them when problems arise. As part of this work, we:

- set a price cap on standing offers for electricity in south east Queensland, NSW and South Australia. This cap also acts as a reference price for market offers
- maintain an energy price comparator website (www.energymadeeasy.gov.au) to help residential and small business customers understand the range of offers in the market, make better choices about those offers and be aware of their rights and responsibilities when dealing with energy providers
- monitor and enforce compliance (by retailers and distributors) with obligations in the National Energy Retail Law, Rules and Regulations
- oversee retail market entry and exit by assessing applications from businesses looking to become energy retailers; granting exemptions from the requirement to hold a retailer authorisation; and administering a national retailer of last resort scheme to protect consumers and the market if a retailer fails
- report on the performance of the market and energy businesses (including information on energy affordability)
- develop hardship guidelines and approve customer hardship policies that energy retailers offer to customers who are facing financial hardship and seeking help to manage their bills.

6.2 Energy market regulation

Five jurisdictions – Queensland, New South Wales (NSW), South Australia, Tasmania and the Australian Capital Territory (ACT) – apply a common national framework for regulating retail energy markets. The framework applies to electricity retailing in all 5 of those jurisdictions and to gas retailing in Queensland, NSW, South Australia and the ACT. Victoria does not apply the national framework, but its regulatory arrangements are broadly consistent with it.[1]

The National Energy Retail Law (Retail Law) confers wide-ranging regulatory responsibilities on the Australian Energy Regulator (AER) (box 6.1). This chapter focuses on the 5 jurisdictions where the AER has regulatory responsibilities and also covers the Victorian market where possible. Western Australia and the Northern Territory apply separate regulatory arrangements and are not covered in this chapter.

The Retail Law operates alongside the Australian Consumer Law to protect small energy customers in their electricity and gas supply arrangements. It sets out protections for residential customers and small businesses consuming fewer than 100 megawatt hours (MWh) of electricity or 1 terajoule (TJ) of gas per year.[2]

Small customers make up over 99% of electricity and gas connections, although they account for less than 50% of energy sales by volume.

The Retail Law and equivalent arrangements in Victoria focus on customer protections related to the traditional retailer–customer relationship. Protections are generally stronger for customers supplied through an authorised retailer than, for example, customers in embedded networks or entering solar power purchase agreements.

State and territory governments regulate electricity prices in Victoria, the ACT, Tasmania and regional Queensland. Since 1 July 2019 the AER sets caps on 'standing offer' prices[3] for electricity in jurisdictions without state-based price regulation (section 6.6).

1 Recent changes to the Victorian framework, including recommendations adopted from the Thwaites *Independent review into the electricity & gas retail markets in Victoria* (August 2017), have seen greater divergence between the Victorian and national frameworks.

2 For electricity, some jurisdictions have different consumption thresholds from that specified in the Retail Law. In South Australia, for example, small electricity customers are those consuming fewer than 160 MWh per year. In Tasmania, the threshold is 150 MWh per year.

3 Standing offers apply where a customer does not enter a market contract. The terms and conditions of standing offers are prescribed in the National Energy Retail Rules and include consumer protections not required in market retail contracts, such as access to paper billing, minimum periods before bill payment is due, a set period for reminder notices, and no more than one price change every 6 months.

6.3 Energy retailers

Energy sellers include:

- those authorised as retailers under the Retail Law
- those exempt from the requirement to be authorised[4]
- those offering energy products and services beyond the scope of the Retail Law – such as energy management services, solar and storage products and off-grid energy systems.

Only customers of authorised retailers enjoy the full protections in the Retail Law.

6.3.1 Authorised energy retailers

Authorised energy retailers must comply with consumer protection and other obligations under the Retail Law. An authorisation covers energy sales to customers in all 5 participating jurisdictions.

In April 2021, 98 businesses held authorisations to retail electricity and 37 businesses held authorisations to retail gas.[5] Since the start of 2020, 11 new retailers have been authorised to retail electricity and 2 have been authorised to retail gas. Victoria has 55 licensed electricity retailers and 29 licensed gas retailers, including 5 electricity retailers and 3 gas retailers that are not authorised to provide energy services in other regions.

The number of authorised retailers may differ from the number of brands a customer sees in the market. Not all authorised retailers are active in the market at any time. Some businesses hold multiple authorisations for commercial purposes despite operating under a single brand. In other cases, multiple brands may operate under one authorisation. There has been an increase in 'white-label' retailing – for example, where a business offers energy services under its own name but partners with an authorised retailer to provide the services. Section 6.4 notes recent changes in retailers (brands) active in the market.

While many retailers offer energy services to all customers, some target specific market segments. A retailer may focus on large commercial customers, for example, or those in embedded networks. Some retailers target users with certain characteristics, such as those with swimming pools, solar PV or battery systems, or those with flexibility in when they use energy.

In choosing which markets to enter, retailers consider factors such as price (and broader market) regulation, market scale, competition, the ability to source hedging contracts to manage risk, and (in gas) whether wholesale contracts and pipeline access are available.

Forty-five retail brands sell energy to residential or small business customers in southern and eastern Australia (table 6.1). Twenty of those brands offer both electricity and gas in at least one jurisdiction. Most other brands offer only electricity, but one retailer specialises in gas. A small number of authorised retailers (not listed in table 6.1) only offer electricity retail services to customers in embedded networks.

Twenty-five retail brands offer energy in all 4 of the largest markets – south east Queensland, NSW, Victoria and South Australia. NSW has the largest number of active electricity retailers (40), followed by Queensland (38), Victoria (31) and South Australia (29). Victoria has lower participation, despite it having the most active market on other measures. This outcome may reflect Victoria having its own licensing regime that requires a separate application for authorisation and imposes different regulatory obligations from other jurisdictions.

In gas, however, Victoria has significantly more brands (17) than other regions (7–12). This contrast reflects the importance of gas as a fuel among Victorian households and businesses; and customer preferences for a single retailer across both fuels.

The ACT, Tasmania and regional Queensland have less competitive energy markets, reflecting the relatively small scale of those markets and a continuous history of price regulation. But competition is rising in the ACT, with 10 electricity retailers and 4 gas retailers active in 2021.

4 In Victoria, where the Retail Law does not apply, retailers must hold a licence issued by the Essential Services Commission or seek an exemption from this requirement.

5 Details of all businesses that hold electricity or gas authorisations can be found in the public register of authorised retailers on the AER website.

Table 6.1 Retailers offering energy contracts to small customers

RETAILER	OWNERSHIP	QLD	NSW	VIC	SA	TAS	ACT
1st Energy	1st Energy	Elec: 🏠 🏢	Elec: 🏠 🏢	Gas: 🏠; Elec: 🏠 🏢	Elec: 🏠 🏢	Elec: 🏠 🏢	
ActewAGL Retail	AGL Energy, ACT Govt		Gas: 🏠 🏢; Elec: 🏠 🏢				Gas: 🏠 🏢; Elec: 🏠 🏢
AGL Energy	AGL Energy	Gas: 🏠 🏢; Elec: 🏠 🏢	Gas: 🏠 🏢; Elec: 🏠 🏢	Gas: 🏠; Elec: 🏠 🏢	Gas: 🏠; Elec: 🏠 🏢		
Alinta Energy	Alinta Energy	Gas: 🏠; Elec: 🏠 🏢	Gas: 🏠 🏢; Elec: 🏠 🏢	Gas: 🏠; Elec: 🏠 🏢	Gas: 🏠; Elec: 🏠 🏢		
Amber Electric	Amber Electric	Elec: 🏠	Elec: 🏠	Elec: 🏠	Elec: 🏠		Elec: 🏠
Aurora Energy	Aurora Energy (Tas Govt)					Gas: 🏠 🏢; Elec: 🏠 🏢	
Blue NRG	Blue NRG	Elec: 🏢	Elec: 🏢	Elec: 🏠 🏢	Elec: 🏢		
Bright Spark Power	Bright Spark Power	Elec: 🏠 🏢	Elec: 🏠 🏢				
CovaU	TPC	Gas: 🏠 🏢; Elec: 🏠 🏢	Gas: 🏠 🏢; Elec: 🏠 🏢	Gas: 🏠 🏢; Elec: 🏠 🏢	Gas: 🏠 🏢; Elec: 🏠 🏢		
DC Power Co[1]	DCP Company	Elec: 🏠	Elec: 🏠	Elec: 🏠			
Diamond Energy	Diamond Energy	Elec: 🏠 🏢	Elec: 🏠 🏢	Elec: 🏠 🏢	Elec: 🏠 🏢		
Discover Energy	Discover Energy	Gas: 🏠 🏢; Elec: 🏠 🏢	Gas: 🏠 🏢; Elec: 🏠 🏢	Elec: 🏠 🏢	Gas: 🏠 🏢; Elec: 🏠 🏢		
Dodo Power and Gas	M2 Energy	Elec: 🏠	Gas: 🏠; Elec: 🏠	Gas: 🏠; Elec: 🏠	Elec: 🏠		
Electricity in a Box	Electricity in a Box	Elec: 🏠 🏢	Elec: 🏠 🏢				
Elysian Energy	Elysian Energy	Elec: 🏠 🏢	Elec: 🏠 🏢	Elec: 🏠 🏢	Elec: 🏠 🏢		
Energy Locals	Energy Locals	Elec: 🏠 🏢	Elec: 🏠 🏢	Elec: 🏠 🏢	Elec: 🏠 🏢	Elec: 🏠 🏢	Elec: 🏠 🏢
EnergyAustralia	CLP Group	Elec: 🏠 🏢	Gas: 🏠 🏢; Elec: 🏠 🏢	Gas: 🏠 🏢; Elec: 🏠 🏢	Gas: 🏠 🏢; Elec: 🏠 🏢		Gas: 🏢; Elec: 🏠 🏢
Enova Energy	Enova Community Energy	Elec: 🏠 🏢	Elec: 🏠 🏢				
Ergon Energy	Qld Govt	Elec: 🏠 🏢					
ERM Power	Shell Energy	Elec: 🏢	Elec: 🏢	Elec: 🏢	Elec: 🏢	Elec: 🏢	Elec: 🏢
Future X Power	Future X Power	Elec: 🏠 🏢	Elec: 🏠 🏢		Elec: 🏠 🏢	Elec: 🏠 🏢	
Globird Energy	Globird Energy	Gas: 🏠 🏢; Elec: 🏠 🏢	Gas: 🏠 🏢; Elec: 🏠 🏢	Gas: 🏠 🏢; Elec: 🏠 🏢	Gas: 🏠 🏢; Elec: 🏠 🏢		
Glow Power	Glow Power	Elec: 🏠 🏢	Elec: 🏠 🏢		Elec: 🏠 🏢		
Kogan Energy[1]	Kogan	Elec: 🏠	Elec: 🏠	Gas: 🏠; Elec: 🏠	Elec: 🏠		
Locality Planning Energy	Locality Planning Energy	Elec: 🏠 🏢	Elec: 🏠 🏢				
Lumo Energy	Snowy Hydro			Gas: 🏠 🏢; Elec: 🏠 🏢	Gas: 🏠; Elec: 🏠 🏢		
Mojo Power	Mojo Power	Elec: 🏠	Elec: 🏠				
Momentum Energy	Hydro Tasmania (Tas Govt)	Elec: 🏠 🏢	Elec: 🏠 🏢	Gas: 🏠 🏢; Elec: 🏠 🏢	Elec: 🏠 🏢		
Nectr Energy	Hanwha Energy Retail	Elec: 🏠	Elec: 🏠				
Next Business Energy	Next Business Energy	Elec: 🏢	Elec: 🏢	Elec: 🏢	Elec: 🏢		Elec: 🏢
Origin Energy	Origin Energy	Gas: 🏠 🏢; Elec: 🏠 🏢	Gas: 🏠 🏢; Elec: 🏠 🏢	Gas: 🏠 🏢; Elec: 🏠 🏢	Gas: 🏠 🏢; Elec: 🏠 🏢		Gas: 🏠 🏢; Elec: 🏠 🏢
OVO Energy	OVO Energy	Elec: 🏠	Elec: 🏠	Elec: 🏠	Elec: 🏠		
People Energy	People Energy			Elec: 🏠 🏢			
Pooled Energy	Efficiency Filters		Elec: 🏠 🏢				
Powerclub	Powerclub	Elec: 🏠 🏢	Elec: 🏠 🏢	Elec: 🏠 🏢	Elec: 🏠 🏢		Elec: 🏠 🏢
Powerdirect	AGL Energy	Elec: 🏠 🏢	Elec: 🏠 🏢	Elec: 🏠 🏢	Elec: 🏠 🏢		
Powershop	Meridian Energy	Elec: 🏠 🏢	Elec: 🏠 🏢	Gas: 🏠 🏢; Elec: 🏠 🏢	Elec: 🏠 🏢		
Qenergy	Qenergy	Elec: 🏠 🏢	Elec: 🏠 🏢	Elec: 🏠 🏢	Elec: 🏠 🏢		
Radian Energy	Radian Energy	Elec: 🏠 🏢	Elec: 🏠 🏢				Elec: 🏠 🏢
ReAmped Energy	ReAmped Energy	Elec: 🏠 🏢	Elec: 🏠 🏢		Elec: 🏠 🏢		
Red Energy	Snowy Hydro	Gas: 🏠 🏢; Elec: 🏠 🏢	Gas: 🏠 🏢; Elec: 🏠 🏢	Gas: 🏠 🏢; Elec: 🏠 🏢	Gas: 🏠 🏢; Elec: 🏠 🏢		Gas: 🏠 🏢; Elec: 🏠 🏢
Simply Energy	ENGIE	Elec: 🏠 🏢	Gas: 🏠 🏢; Elec: 🏠 🏢	Gas: 🏠 🏢; Elec: 🏠 🏢	Gas: 🏠 🏢; Elec: 🏠 🏢		
Sumo Power	Sumo Power	Elec: 🏠 🏢	Gas: 🏠 🏢; Elec: 🏠 🏢	Gas: 🏠 🏢; Elec: 🏠 🏢			
Tango Energy	State Power Investment Corporation		Elec: 🏢	Gas: 🏠 🏢; Elec: 🏠 🏢			
Tas Gas Retail	Brookfield Infrastructure			Gas: 🏠 🏢		Gas: 🏠 🏢	
Total	**Gas retailers**	7 🏠 7 🏢	12 🏠 11 🏢	17 🏠 15 🏢	10 🏠 10 🏢	2 🏠 2 🏢	4 🏠 4 🏢
	Electricity retailers	35 🏠 31 🏢	37 🏠 33 🏢	28 🏠 25 🏢	26 🏠 25 🏢	4 🏠 5 🏢	8 🏠 9 🏢

🏠 = Residential 🏢 = Small business

1. DC Power and Kogan Energy offer energy contracts through partnerships with Powershop.

Note: Includes retailers with generally available offers at February 2021. Retailers servicing only embedded network customers are excluded.

Source: Energy Made Easy website (www.energymadeeasy.gov.au); Victorian Energy Compare website (compare.energy.vic.gov.au).

6.3.2 Exempt energy sellers

An energy seller may apply to the AER for an exemption from authorisation if it intends to supply energy services only:

- to a limited customer group (for example, at a specific site or incidentally through a relationship such as a body corporate)
- to supplement its customers' primary energy connection.

At April 2021 over 3,500 businesses held exemptions, typically to on-sell energy within an embedded network (that is, a small private network whose owner sells electricity to other parties connected to the network). Hospitals, retirement villages, caravan parks and apartment complexes are examples of entities that might run an embedded network. Solar power purchase agreement providers are also covered by the exemptions framework.

The Australian Energy Market Commission (AEMC) cited stakeholder estimates that up to 500,000 customers purchase energy through embedded networks.[6] Those customers do not enjoy the full set of protections in the Retail Law and have fewer avenues for dispute resolution.[7] But energy ombudsman schemes have been widened so that customers of exempt sellers can lodge complaints (section 6.8).

6.4 Competition in retail energy markets

Electricity markets in south east Queensland, NSW, Victoria and South Australia have several competitive characteristics, including a diversity of sellers making offers, intensive marketing activity and customer switching. Barriers to entry are low, as evidenced by regular new entry (although weaker contract market liquidity in South Australia means barriers are higher in that market).8 Standalone retailers have identified access to competitively priced hedging as a barrier to entry and expansion that impacts them more than it does retailers which own generation.[9]

Competition is less effective in electricity retail markets in the ACT, Tasmania and regional Queensland. The scale of these markets and continued price regulation may have deterred entry by some retailers. In regional Queensland a subsidy paid to Ergon Energy through the Queensland Government's Uniform Tariff Policy (which other retailers are not able to access) also deters new entry.

Gas markets are generally less competitive than electricity markets, given their smaller scale and issues in sourcing gas and pipeline services in some regions. Gas markets in all regions are more concentrated than electricity markets.

Positive market trends across electricity and gas include:

- decreasing market concentration, with smaller retailers growing their customer base in established markets and expanding into new markets
- retailers winding back confusing discounting practices
- retailers offering a wider range of products and services, including simpler and more stable pricing products; and products leveraging off solar PV and battery technology.

Customer satisfaction with competition in energy retail markets improved in recent years. In December 2020, 59% of consumers across the National Electricity Market (NEM) were satisfied with the state of competition. Consumer trust, or confidence that the market is working in consumers' interests, is lower but improving. In December 2020, 38% of residential customers expressed confidence in the market – this is up from 21% in December 2017.[10]

Regulatory reforms since 2018 aim to address concerns that competition has not delivered sufficient benefit to consumers. The reforms seek to encourage customers to engage more closely with the market and make it easier to compare retail offers (sections 6.4.4 and 6.4.7).

6 AEMC, *Updating the regulatory frameworks for embedded networks*, information sheet, June 2019, p 1.

7 The AER's exemption guideline sets out the classes of exemption. The AER sets customer protections under each class. Details of all businesses that hold a registered or individual exemption can be found in the public register of exemptions on the AER website.

8 AEMC, *2019 retail energy competition review, final report*, June 2019.

9 AEMC, *2020 retail energy competition review, final report*, June 2020.

10 ECA, *Energy consumer sentiment survey, December 2020*, p 12.

Despite the reforms, not all customers can access the benefits of competition. Embedded network customers, for example, often lack retail choice and cannot switch away from a supplier that fails to meet their needs. In June 2019 the AEMC proposed new arrangements that would shift embedded networks into the national regime, improving protections and access to retail market competition for their customers.[11]

In December 2019 the AEMC received a rule change request from Energy Consumers Australia (ECA) which would require retailers to provide information to enable more effective competition assessments. The rule change process had not commenced at May 2021.

6.4.1 Market concentration

Forty-five retail brands supply small energy customers in southern and eastern Australia (table 6.1). Of these, the retail brands of 3 businesses – AGL Energy, Origin Energy and EnergyAustralia (the 'big 3') – supply 64% of small electricity customers and 73% of small gas customers (figure 6.2). Those businesses own at least 2 of the 3 largest retailers in every region except Tasmania. The market share of these businesses has gradually declined over the past decade, but Origin Energy and AGL Energy recorded net growth in electricity customer numbers over 2020. AGL Energy's customer numbers were boosted by its acquisition of amaysim's energy business (including Click Energy) in September 2020.

Three 'tier 2' retailers have significant market share in some regions:

- Snowy Hydro (owned by the Australian Government and trading as Red Energy and Lumo Energy) supplies around 7% of electricity customers and 9% of gas customers – its market share is highest in Victoria, supplying 13% of electricity customers and 14% of gas customers.
- Alinta Energy supplies 5% of electricity customers and 3% of gas customers – its market share is highest in Queensland (where it is the third largest retailer in the south east of the state, with 9% of electricity customers and 1% of gas customers) and South Australia (6% of electricity customers and 5% of gas customers).
- Simply Energy (owned by ENGIE) supplies 4% of electricity customers and 6% of gas customers, including 9–10% of customers in Victoria and South Australia. It is the third largest energy retailer in South Australia.

Smaller retailers have also gained market share in recent years, increasing from 5% of small electricity customers in 2016 to 8% in 2020. This overall market share remained steady in 2020, despite AGL Energy acquiring amaysim. In gas, smaller retailers accounted for 5.9% of small customers in 2020, up from 4.4% in 2019. Smaller retailers have made more inroads in Victoria than elsewhere, supplying 15% of small electricity customers and 10% of small gas customers.

Retail markets tend to be more concentrated in gas than electricity, in part because the markets are smaller in scale. In NSW, for example, the 'big 3' account for 89% of retail gas customers. In Queensland, Origin Energy and AGL Energy account for 92% of retail gas customers.

The ACT, Tasmania and regional Queensland – which have had continuous price regulation –are even more concentrated. The dominant retailers in these regions are typically government-owned (or part-owned) businesses with little activity outside their home region:

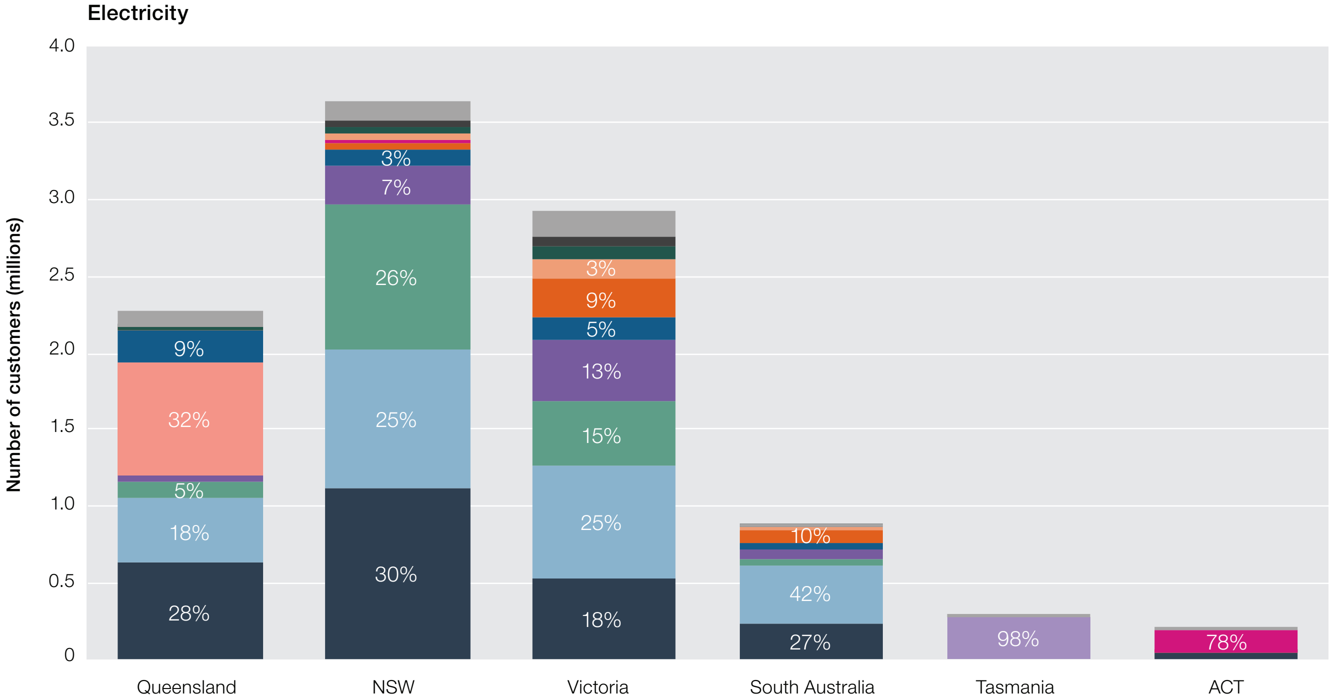
- ActewAGL (a joint venture between the ACT Government and AGL Energy) supplies 78% of ACT electricity and gas customers. Origin Energy (16% of small customers) and EnergyAustralia (5% of small customers) are the other large market players.
- In Tasmania, Aurora Energy (Tasmanian Government owned) was until recently the only retailer offering electricity to households. Since 2019, 4 retailers have begun retailing electricity, and by 2020 they had acquired around 2% of small customers.
- Ergon Energy (Queensland Government owned) supplies electricity to most small customers in regional Queensland.

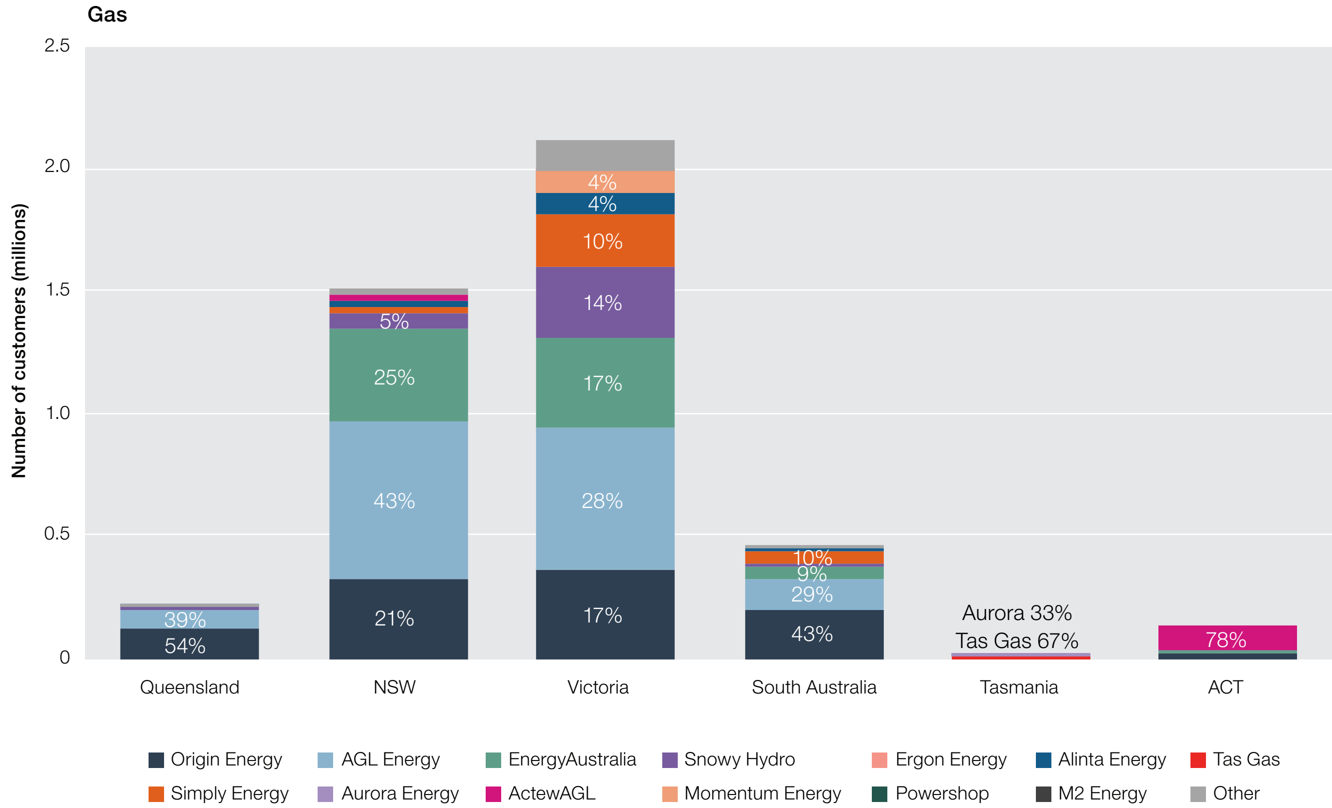
NSW is the most concentrated of the major electricity markets. The 'big 3' account for 81% of NSW electricity customers. Snowy Hydro accounts for another 7% of customers. The other 26 retailers in NSW share 12% of the market.[12]

11 AEMC, *Updating the regulatory frameworks for embedded networks, final report*, June 2019.

12 Use of statewide data masks levels of market concentration within some parts of regions with multiple distribution zones (Queensland, NSW and Victoria). Market concentration is likely to be higher in regional NSW than in Sydney, for example.

Figure 6.2 Energy retail market share (small customers)





Note: Includes residential and small business customers. All data at December 2020, except Victoria (electricity and gas, June 2020) and Tasmania (gas, June 2020).

Source: AER, *Retail markets quarterly, Q2 2020–21*, April 2021; ESC, *Victorian energy market report 2019–20*, December 2020; Office of the Tasmanian Economic Regulator, *Energy in Tasmania report 2019–20*, December 2020.

While most retailers operate across multiple regions, less than half of electricity retailers operating in south east Queensland, NSW, Victoria and South Australia operate in all 4 regions. The gas market is even more segregated, with most retailers concentrating on the Victorian market, followed by the NSW and South Australian markets.

In the year to March 2021, 5 new electricity retail brands entered the small customer market:

- Bright Spark Power
- Electricity in a Box
- Glow Power
- Radian Energy
- Social Energy.

Additionally, 13 existing retailers expanded electricity retailing into another jurisdiction, and 6 commenced or expanded gas retailing into another jurisdiction.

Four retail brands exited the market in the year to March 2021. AGL acquired the customers of amaysim (branded as amaysim and Click Energy) in September 2020. M2 Energy retired its business customer focused Commander Power and Gas brand but continues to retail as Dodo Power and Gas.

6.4.2 Vertical integration

In the 1990s governments structurally separated the energy supply industry into separate wholesale, network and retail businesses. In electricity, however, many generators and retailers have since integrated to become 'gentailers'.

Vertical integration allows retailers and energy producers to manage price volatility in wholesale markets, with less need to hedge their positions in futures (derivatives) markets. This strategy may be efficient for the business but can reduce liquidity in derivatives markets, posing a barrier to entry or expansion for retailers that are not vertically integrated.

The 'big 3' retailers – AGL Energy, Origin Energy and EnergyAustralia – each have significant market share in generation across NSW, Victoria and South Australia (figure 6.3).[13] Most other retailers with a significant retail customer base are also aligned with an electricity generation business – Snowy Hydro (retailing as Red Energy and Lumo Energy), ENGIE (Simply Energy), Alinta Energy, Hydro Tasmania (Momentum Energy), ERM Power, Meridian Energy (Powershop) and Pacific Hydro (Tango).

In 2020 the 4 largest vertically integrated participants in each region (the big 3 plus the next largest gentailer based on generation output) accounted for the majority of generation output and at least half of all retail load:

- In NSW they accounted for 79% of generation output and 65% of load.
- In Victoria they accounted for 83% of generation output and 50% of load.
- In South Australia they accounted for 69% of generation output and 63% of load.

In Queensland, state government owned businesses (CS Energy, Stanwell, CleanCo and Ergon Energy) accounted for 68% of generation output and 56% of load. In Tasmania, state government owned businesses (Hydro Tasmania and Aurora Energy) accounted for 95% of generation output and 62% of load.

Despite collectively owning more generation than needed to service their retail load, the profile of gentailers varies significantly. Among the 6 largest businesses, on average AGL Energy and Alinta Energy tend to have larger generation portfolios, while EnergyAustralia and ENGIE have relatively more balanced portfolios. Origin Energy and Snowy Hydro need to service a larger retail load than their generation fleet accounts for but have significant flexible generation in their portfolios, which allows them to manage the risk of high prices.

The NEM's largest standalone electricity retailer to small customers is M2 Energy (trading as Dodo Power and Gas) with less than 1% of small customers across the NEM.

Vertical integration also occurs in gas, but to a lesser extent. Interests in upstream gas production or storage can complement gas retailing or gas powered electricity generation.

13 In March 2021 AGL Energy announced plans to reduce its level of vertical integration by separating out its coal fired generators into a separate business – PrimeCo.

Figure 6.3 Vertical integration in National Energy Market jurisdictions

Note: Electricity generation market shares are based on generation output in 2020. Retail market shares are based on market load in 2020.
Source: AER, AEMO.

6.4.3 Customers with market contracts

Most energy consumers can enter a market contract with their retailer of choice.[14] Market contracts allow retailers to tailor their energy products, offering different tariff structures, discounted prices, carbon offsets, non-price incentives, billing options, fixed or variable terms and other features. Contracts may be subject to fees and charges, such as establishment or exit fees. Retailers must obtain a customer's explicit informed consent before entering them into a market contract.

Customers without a market contract are placed on a standing offer with the retailer that most recently supplied energy at their premises (or, for new connections, with the retailer designated for that area). Standing offers provide a safety net for customers unable or unwilling to engage in the market, with prescribed terms and conditions and a suite of customer protections that the retailer cannot change. Standing offer prices are generally higher than those offered under market retail contracts and are either set annually under regulation or can be changed no more than once every 6 months. Since 1 July 2019 standing offer electricity prices are set or capped by independent regulators in all jurisdictions (section 6.6.3). Retailers set their own standing offer gas prices, which are not regulated.

While customers on market contracts pay less on average than those on standing offers, market customers do not necessarily receive the best price available. Contracts with expired benefits may be priced close to the standing offer.

Primary regional retailers – ActewAGL, Aurora and Ergon Energy – account for over 60% of all electricity standing offer customers. These (part) government owned retailers maintain dominant market positions in regions with limited retail competition. In the other regions, most electricity and gas standing offer customers have contracts with a 'big 3' retailer. This reflects the position of these retailers as incumbents when retail contestability was introduced, allowing them to retain customers that never took up a market contract.

Victoria – the first state to fully deregulate its energy market – has the highest proportion of energy customers on market contracts, at around 94% (figure 6.4). South Australia has 91% of customers on market offers, which may reflect customers searching for cheaper deals, given the relatively high price of electricity in the state.

NSW and south east Queensland recorded a shift towards market contracts after electricity prices were deregulated in those regions in 2014 and 2016 respectively. The rate of customers shifting to market contracts has since slowed. At January 2021 around 88% of customers were on market contracts in NSW. South east Queensland had similar levels of electricity customers on market contracts (87%), but the level was lower in gas (79% of customers). Nearly all small energy customers in regional Queensland are on standing offers.

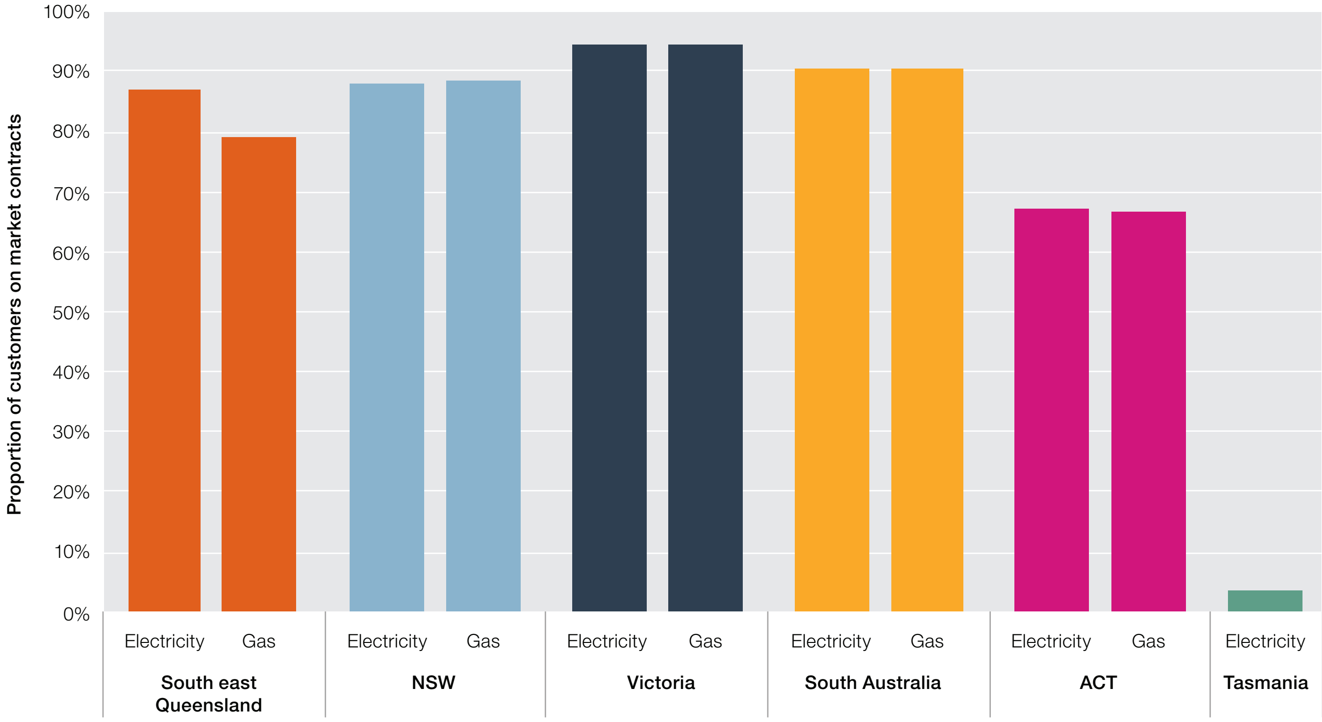
In January 2020, 67% of ACT customers were on market contracts compared with 38% in 2018. The increase follows strong participation by Origin Energy in the market. In Tasmania, new entrant retailers have offered market contracts to residential customers since early 2019. Despite this entry, the proportion of customers on market contracts dropped significantly over 2019 after the Tasmanian Government set standing offer prices that attracted Aurora's market customers to switch back to the standing offer. At January 2021 only 3% of Tasmanian electricity customers were on a market offer.

Financially vulnerable customers are less likely than other customers to be on a standing contract – less than 2% of customers on a hardship program or payment plan compared with over 8% of all customers.[15] This likely reflects reforms requiring retailers to identify the best offer for customers in hardship (section 6.7.2).

14 While full retail contestability applies in all regions, not all customers can access offers from a retailer other than their host retailer. Further, many customers within embedded networks are still limited to energy supply through their embedded network operator.

15 ACCC, *Inquiry into the National Electricity Market, September 2020 report*, September 2020.

Figure 6.4 Small customers on market and standing contracts



Note: Standing and market offer shares are based on the number of small customers at January 2021 except Victoria (June 2020). Queensland electricity numbers exclude customers in regional Queensland, who largely remain on standing offers.

Source: AER, *Retail markets quarterly, Q2 2020–21*, April 2021; ESC, *Victorian energy market report 2019–20*, December 2020.

6.4.4 Customer awareness and engagement

Retail competition can drive innovation to bring a wider range of products and services to satisfy different customer preferences and demands. But competition can also increase complexity. For example, customers have found it difficult to compare retail offers, and this sometimes causes them to disengage from the market. Retailers have added to this complexity by adopting marketing strategies that make it difficult for customers to compare offers. Customer surveys regularly report that customers find the market difficult to navigate. These difficulties impose transaction costs (including time) that customers face when comparing offers, reinforcing a lack of trust and contributing to low levels of engagement.

Reforms in 2019 sought to make it easier for customers to compare offers by simplifying and standardising how retailers must present offers. The reforms require marketed discounts to be quoted against a 'reference bill', being the default market offer set by the AER (section 6.6.3). Some retailers also introduced simpler pricing structures. These changes followed reforms in 2018 requiring retailers to provide customers with advance notice of any change in their energy price or benefits.

Some retailers argue these reforms may lead to customers becoming less engaged. For example, customers may consider there is less value in looking for a better offer if discounts are advertised off a lower baseline or they may take comfort from being on a government-regulated offer.[16]

More recent reforms aim to simplify customer bills.[17] Under new arrangements effective from August 2022, prescriptive billing provisions will be replaced with a guideline to be developed by the AER that offers retailers more flexibility in how they present information to customers. This flexibility will allow retailers to develop tools for their customers to access the key information needed to effectively engage in the market, including through digital platforms.

While these reforms may improve customer engagement, other barriers for some customers remain: language barriers; cultural issues; disabilities; low levels of literacy in energy markets, concepts and terms; and status quo bias for consumers to stay with their default retailer or plan.

16 AEMC, *2020 retail energy competition review, final report*, June 2020.

17 AEMC, *Bill contents and billing requirements, final determination*, March 2021.

Customer understanding of the market

Customer confidence in being able to navigate the energy retail market increased slightly across most regions in 2020. A positive response of 70% on this measure was the highest recorded in the 4 years that surveys have been undertaken by ECA.[18] NSW was the only region to record a fall on this measure in 2020, down 7% to a 65% positive response rate.

Between 2017 and 2019 there was an increase in customer confidence in the availability of easily understood information. This may partly reflect reforms over that period to help customers make informed decisions. Outcomes in 2020 varied, with confidence in Queensland rising by 8% (to 66%) but falling slightly in most other states. Tasmania recorded the largest drop (down 6% to 48%).

Market developments – including the rollout of smart metering and cost-reflective tariffs –will add new layers of complexity to the market, potentially making it harder for consumers to confidently engage. But this added complexity will be offset by better tools for comparing offers. Customers are more widely using price comparator websites, for example. For residential customers looking to switch retailers, use of a comparator website to find a better offer ranged from 25% of customers in Queensland to 38% of customers in Victoria.[19]

Enhancements to the AER's comparator website – Energy Made Easy (www.energymadeeasy.com.au) – in 2020 aimed to simplify the user experience and increase the site's capability to compare innovative offers.

Commercial switching websites and services also allow customers to access better offers with minimal engagement. But there are risks to consumers in relying on commercial services to navigate energy retail markets (section 6.4.7).

The Australian Government (Treasury) is progressing work to implement a national Consumer Data Right for energy, which will allow consumers' data to be shared with trusted third parties. Increasing the availability of and access to electricity data (such as a household's current energy deal and consumption patterns) should support customer decision making by enabling more personalised and precise comparisons of offers. The Consumer Data Right framework for energy is expected to be finalised in 2021.[20]

Customer satisfaction

Customers' satisfaction with retail energy markets depends on factors including price, value for money, reliability, the customer service of their retailers, confidence in engaging with the market, technology uptake and ability to switch.

Around 78% of residential customers were satisfied with their energy supply arrangements in NEM jurisdictions in 2020 (up from 74% in 2019). This result was driven by large improvements in Queensland (up 11% to 83%) and the ACT (up 13% to 80%). South Australia also recorded an increase in overall satisfaction (up 6% to 80%).[21] Satisfaction eased slightly in NSW and Victoria, to 75% and 76% respectively.

Satisfaction with value for money in electricity rose to 57% of household consumers, up 4% over the past year and up 22% since 2017. Satisfaction rates are higher for gas than for electricity (68% in 2020). Satisfaction with both fuels is at the highest or equal highest level since ECA commenced surveys in 2016, reflecting falling or stable energy prices in most regions. But satisfaction with value for money for energy trails services including mobile phone, internet, insurance, water and banking, and this gap widened in 2020.

Customer satisfaction with competition in national energy retail markets improved in recent years. Consumer trust, or confidence that the market is working in consumers' interests, has risen steadily since 2017 but remains low – 38% of residential customers expressed confidence in the market at December 2020, up from 21% in December 2017.[22] Consumer satisfaction with the level of competition in energy markets remained steady over 2020 in all markets except south east Queensland, which recorded an increase in satisfaction to 69% of customers (up from 56% in 2019). On average across the NEM, 58% of consumers were satisfied with competition in their area. Customer satisfaction was lowest in Tasmania at 26%.

18 ECA, *Energy consumer sentiment survey December 2020*, December 2020.

19 ECA, *Energy consumer sentiment survey December 2020*, December 2020.

20 ACCC, *Energy rules framework, consultation paper*, July 2020.

21 ECA, *Energy consumer sentiment survey December 2020*, December 2020.

22 ECA, *Energy consumer sentiment survey, December 2020*, p 12.

Customer switching

The rate at which customers switch retailers can indicate their level of engagement in the market. But these statistics should be interpreted with care – switching may be low in a competitive market if retailers deliver good quality, low priced service that gives customers no reason to change, for example. Switching data fails to capture customer movements to new contracts with the same retailer, so it understates customer activity in the market. Conversely, switching data captures when a customer moves house and signs a new contract, even if it is with the same retailer (thus overstating customer activity). Victorian data for 2019–20 indicates that over half of all switches reflect customers moving properties or setting up new connections.[23]

Reforms introduced in December 2019 make it easier for customers to switch retailer by allowing them to transfer within 2 days of a cooling-off period expiring.[24] This new process limits retailer 'save' activity (retailers contacting customers who try to switch retailer and giving them a better offer to encourage them to stay) and allow customers faster access to prices and products they want.

Small customer switching decreased in 2020 in all regions for electricity customers. NSW, Victoria and South Australia recorded their lowest annual switching rates over the past decade (figure 6.5). Gas switching rates fell in Victoria, South Australia and the ACT but rose slightly in Queensland and NSW. Customer switching rates peaked in 2018 following the introduction of initiatives to encourage customer engagement. Subsequent easing of energy prices, along with the reintroduction of price caps on electricity standing offers, may have contributed to lower switching rates more recently, as customers consider there is less financial gain from changing retailer.

Victoria remains the most active region, with 21% of electricity customers and 19% of gas customers switching in 2020. This outcome occurred despite price spreads in energy offers narrowing significantly in Victoria since 2019, meaning potential savings from switching in 2020 tended to be lower in Victoria than in other regions.

The ACT continues to have the lowest switching rates, with 10% of customers switching retailer in 2020.

Switching rates are typically lower in gas than in electricity. This may reflect fewer retailers participating in gas, meaning less choice and fewer potential customer savings. Gas, as a secondary fuel, is also typically a lower cost for customers, so it may not receive the same attention.

Residential customers were most likely to consider switching retailer because they were dissatisfied with value for money (around one-third of customers who considered switching). Other key drivers of customers considering switching included receiving notice of an energy price change, being approached by another retailer and moving properties.[25]

While overall switching activity indicates relatively engaged customers, over a third of customers reported having never switched retailer or energy plan.[26] Those customers may lack confidence in making decisions – nearly half of consumers in some regions were still not confident that they have access to easily understood information, for example.[27] Alternatively, those customers may be satisfied with their current supplier or unaware they can switch.

Victoria had the smallest proportion of customers who reported having never switched energy company or plan (29%), followed by South Australia (32%), NSW and south east Queensland (each 37%), the ACT (43%) and Tasmania (71%).[28] These outcomes are consistent with other measures of customer engagement.

In many markets, engagement by even a limited number of customers can drive lower prices and product improvements that benefit all consumers. This is less true for energy markets, where retailers can easily identify and price discriminate against inactive customers. Many market offers include benefits that expire after one or 2 years, and customers who do not switch regularly may find themselves paying higher prices than necessary.

23 ESC, *Victorian energy market report 2019–20*, December 2020, p 26.

24 AEMC, *National Energy Retail (Reducing Customers' Switching Times) Rule 2019, rule determination*, 19 December 2019.

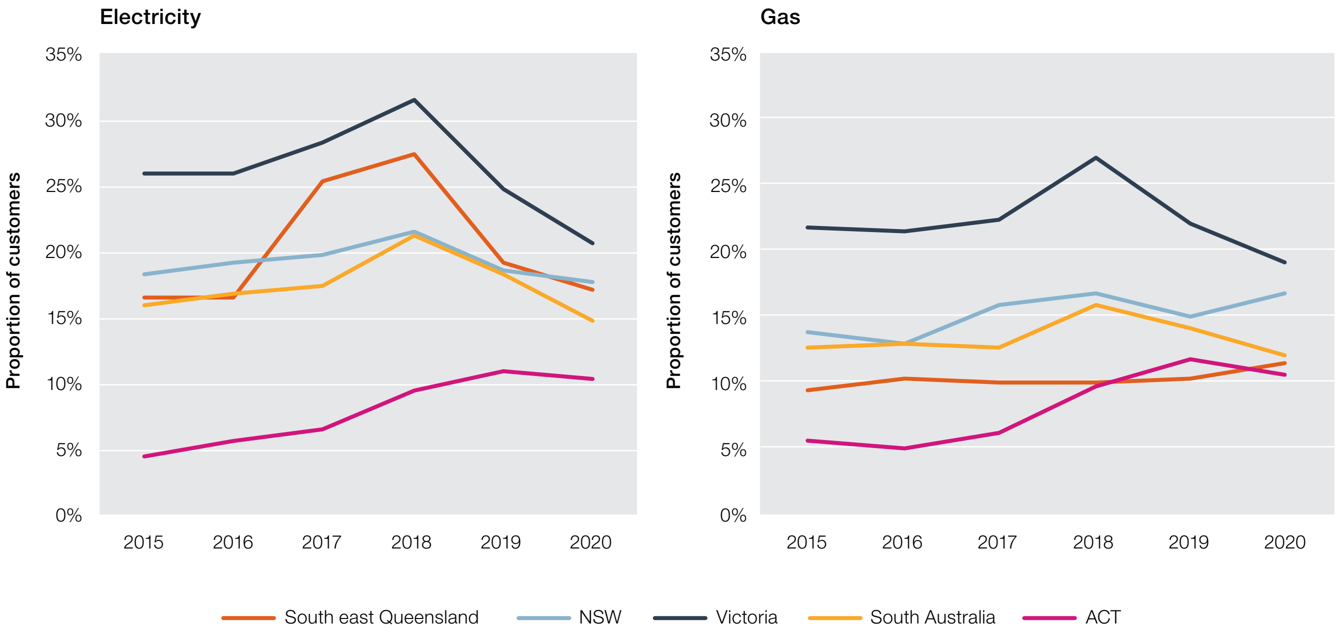
25 ECA, *Energy consumer sentiment survey December 2020*, December 2020.

26 ECA, *Energy consumer sentiment survey December 2020*, December 2020.

27 ECA, *Energy consumer sentiment survey December 2020*, December 2020.

28 ECA, *Energy consumer sentiment survey December 2020*, December 2020.

Figure 6.5 Small customer switching activity



Note: Total annual customer switches in a year divided by average customer numbers. Queensland data excludes customers in regional Queensland, who have limited access to competitive market offers.

Source: Customer switches: AEMO, *NEM monthly retail transfer statistics*, December 2020; AEMO, *Gas retail market monthly statistics*, December 2020. Customer numbers: estimates from AER, *Retail markets quarterly, Q2 2020–21*, April 2021; ESC, *Victorian energy market report 2019–20*, December 2020.

The National Retail Energy Rules require retailers to notify small electricity and gas customers before any change in their benefits and provide advance notice of any price change.[29] In Victoria, retailers must also prominently display their 'best offer' on customers' bills (every 3 months for electricity and every 4 months for gas), along with advice on how to access it.

Additionally, at the end of a fixed-term contract, retailers must inform customers in writing about their options, such as setting up a new contract or moving to another retailer. Importantly, retailers must ensure consumers are aware that they will be put onto a standing offer if they choose not to enter a new market contract with their current retailer.

6.4.5 Retailer activity

Changes in retailer marketing activity can affect the level of customer switching. Consumer approaches by retailers appear to have been relatively steady over the past 4 years, with around 20% of customers indicating an approach from a retailer prompted their most recent engagement in the energy market.[30] A peak of 53% of residential customers were directly approached by a retailer in 2014. Enforcement around door-to-door selling by larger retailers has since reduced this activity.[31] But the use of digital acquisition channels, including retailers' websites and price comparison websites, has grown (section 6.4.7).

Low retailer activity in some markets may reflect barriers to entry or expansion. Retailers cited the reintroduction of standing offer price caps (section 6.6.3) as a barrier to activity. Limited access to competitive risk management contracts was also cited as a barrier to entry or expansion in South Australia, with almost half of all retailers in 2020 considering that contact market liquidity in South Australia was too low.[32]

The duplication of regulatory frameworks – notably in Victoria, which has a separate Energy Retail Code – was another barrier due to the compliance costs this imposes. Retailers considered the divergence of Victorian regulations from other regions has widened since 2019.[33]

29 AEMC, *National Energy Retail Amendment (Notification of the End of a Fixed Benefit Period) Rule 2017, rule determination*, 7 November 2017; AEMC, *National Energy Retail Amendment (Advance Notice of Price Changes) Rule, rule determination*, 27 September 2018.

30 ECA, *Energy consumer sentiment survey December 2020*, December 2020.

31 AEMC, *2018 retail energy competition review, final report*, June 2018, p 89.

32 AEMC, *2020 retail energy competition review, final report*, June 2020.

33 AEMC, *2020 retail energy competition review, final report*, June 2020.

In gas, retailers in the past identified access to reasonably priced gas and pipeline capacity as barriers to entry and expansion, especially in Victoria. Reforms in 2018 and 2019 sought to reduce these barriers by increasing transparency in the gas market and improving access to unused pipeline capacity through a day-ahead auction (chapter 4).

6.4.6 Product differentiation

In a competitive market, retailers offer a range of products and services to attract and retain customers. Energy retailers compete primarily on price. But with the introduction of standing offer price caps and restrictions around discounting (section 6.6.3), retailers are looking to differentiate their products in other ways.

Retailers can differentiate products by offering more price certainty; rewarding customers with flexibility in how and when they use energy; or using technology such as batteries or electric vehicles. Some products offer energy management services, including as part of virtual power plants (section 1.2.2).

Some retailers offer other incentives, such as carbon offsets, sign-up discounts and product add-ons and rewards; or they partner with other businesses. Bundling of products such as phone and internet alongside energy has also increased.

Conditional discounts

Until recently, price competition between energy retailers tended to play out through 'headline' discounts, often requiring the customer to meet conditions such as paying on time, e-billing, or paying by direct debit. The size of a 'discount' was often misleading, as retailers applied discounts off a range of price bases. Customers were also exposed to much higher prices if the conditions were not met. In 2020 around 11% of residential customers on offers with conditional discounts did not meet the conditions required to receive the discounted price.[34] Customers in financial difficulty were more likely to miss out on the discounts, with 18% of hardship customers and 17% of customers on payment plans not meeting the required conditions.

Reforms in 2019 require retailers to base any discount advertising off the default price and prohibits them from including conditional discounts in their most prominent advertised price for a market offer. The reform covered retailers in NSW, South Australia and south east Queensland.[35] Equivalent provisions apply in Victoria.

Further reforms in 2020 cap conditional discounts at a level reflecting the reasonable cost savings a retailer would expect if a consumer satisfies the conditions attached to the discount.

Since the reforms, the proportion of electricity offers with guaranteed prices (no conditional discounts) rose significantly. At February 2021 around 90% of offers in Queensland, NSW and South Australia (and all offers in the ACT) had guaranteed prices (up from 44–60% in 2019). The shift was less pronounced in Victoria, where offers with guaranteed prices comprised around 83% of offers at February 2021.

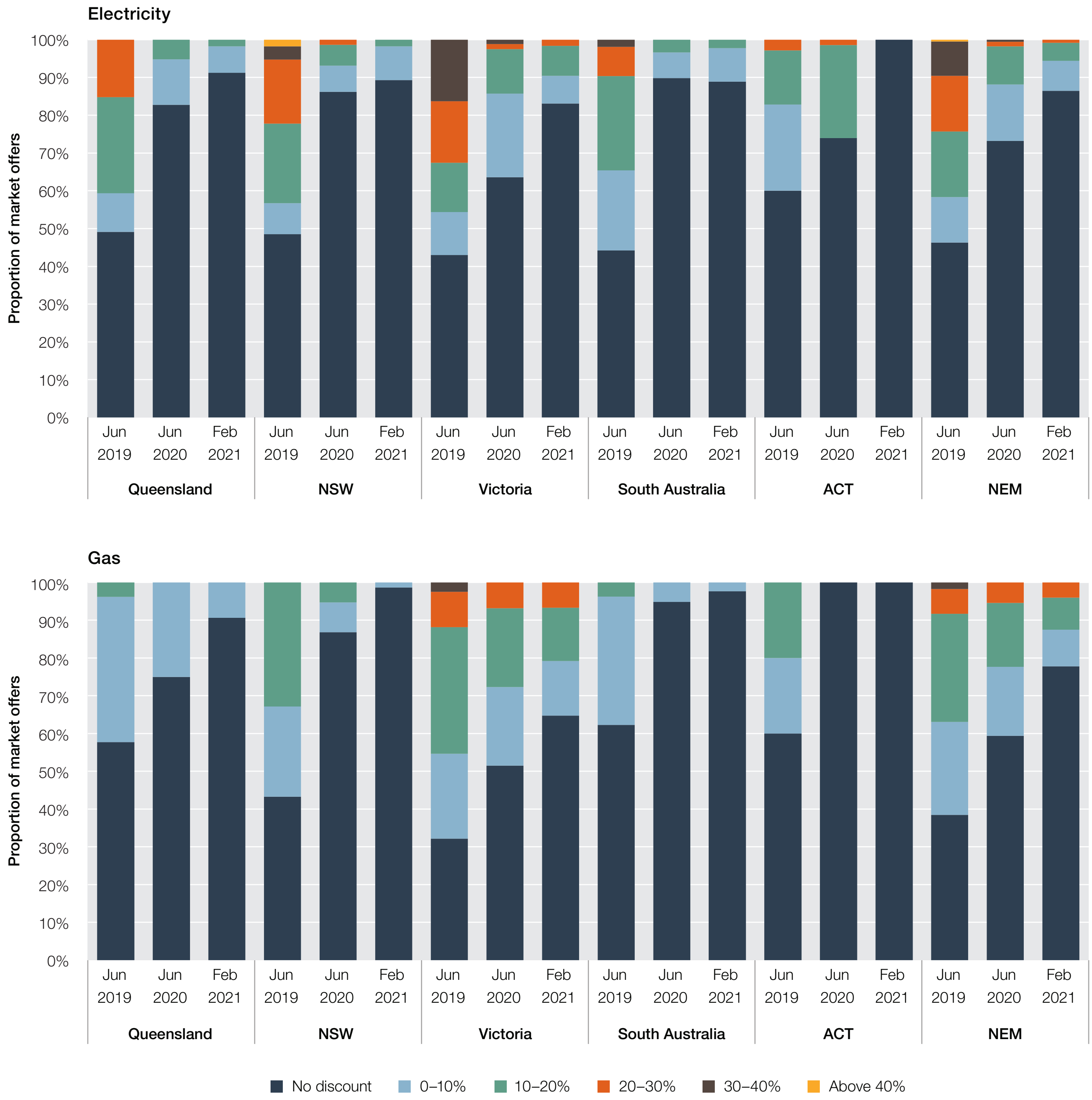
The size of offered discounts also reduced over this period. Most discounts in 2019 offered at least 10% off the original bill, with some offering up to 40% off (figure 6.6). In February 2021, conditional discounts typically offered less than 10% of the original bill, with few discounts offered above 20%.

While the reforms only apply to electricity, discounting practices in gas have also changed. At February 2021 over 90% of gas offers in Queensland, NSW, South Australia and the ACT had a guaranteed price. In Victoria, 65% of offers had a guaranteed price.

34 ACCC, *Inquiry into the National Electricity Market, May 2020 report*, June 2020.

35 Competition and Consumer (Industry Code – Electricity Retail) Regulations 2019.

Figure 6.6 Conditional discounts for residential energy market offers



Note: Discounts are advertised conditional discounts in generally available market offers at February 2021.

Source: Energy Made Easy website (www.energymadeeasy.gov.au); Victorian Energy Compare website (compare.energy.vic.gov.au).

Offer structures

Retailers typically use one of 3 types of tariff structures in their electricity offers:[36]

- single-rate or 'flat' tariffs, which apply a daily (fixed) supply charge plus a simple usage charge for the electricity that a customer uses
- time-of-use tariffs, which apply different pricing to electricity use at peak and off-peak times. Lower prices at off-peak times encourage customers to shift their energy use to those times
- demand tariffs, which charge a customer based on their maximum point-in-time demand at peak times. Customers can reduce their energy costs by shifting demand to off-peak periods. But even one day of high use at peak times will lead to higher charges for the whole billing period.

36 Gas offers have less variability in tariff structure, with flat tariffs typically applied. Usage charges may vary based on the overall volume of gas consumed and the time of year.

Retailers vary the level of fixed and variable tariff components to appeal to different customers. For example, customers with low energy use may prefer an offer with a low fixed charge but higher usage charges, while a customer with flexibility around when they use energy may prefer an offer with low off-peak charges or free weekend energy use.

Some retailers are trialling other price structures. Fixed-price or subscription tariffs, where customers pay a (yearly or monthly) fee based on their typical electricity use, focus on simplicity and bill certainty. At the other end of the pricing spectrum, tariffs that pass through wholesale market spot prices allow customers to dynamically interact with the wholesale market. These tariffs are best suited to customers with battery storage who can adjust their use of grid-supplied electricity during high price periods.

New dynamic products are emerging as battery storage systems and electric vehicles become more affordable and as accessibility to consumer energy data improves. Some of these products have a time-of-use pricing structure but with rates set to encourage charging/discharging of batteries or electric vehicles at specific times. These products may also come with 'add-on' services, such as automated systems that learn customers' electricity use patterns and charge/discharge batteries to maximise value. Some offers allow customers to become part of a virtual power plant that aggregates multiple household solar and battery systems to provide power for network support or frequency control ancillary services or to engage in wholesale price arbitrage (section 1.2.2).

Non-price competition

In addition to competing on price and tariff structure, many retailers offer financial or non-financial incentives to entice customers. Financial incentives may include credit for continuing with a plan for a minimum period, for signing up online or through a partnering business or for referring a friend to the retailer.

A number of retailers offer reward schemes that provide deals and discounts on a range of products and services. Non-financial benefits include carbon offsets for electricity use and product add-ons such as digital subscriptions. Retailers sometimes partner with another business to provide these additional benefits (Alinta Energy partnered with Kayo Sports to provide an energy and streaming offer in 2020, for example; and Origin Energy partnered with Woolworths' Everyday Rewards program).

Retailers increasingly offer products or services alongside electricity and gas to appeal to customers looking for the convenience of a single service provider. Internet and phone services, as well as solar PV and battery products, are offered by a number of energy retailers. AGL Energy also offers an electric vehicle subscription service.

6.4.7 Price comparison websites and switching services

The variety of product structures, discounts and other inducements makes it difficult for energy customers to compare retail offers. Some customers use comparator websites to manage the complexity and range of offers in the market.

The AER operates an online price comparator – Energy Made Easy (www.energymadeeasy.com.au) – to help small customers compare retail offerings. The website shows all generally available offers and has a benchmarking tool allowing customers to compare their electricity use with similar sized households in their area. The website is available to customers in jurisdictions that have implemented the Retail Law (Queensland, NSW, South Australia, Tasmania and the ACT).

The Victorian Government operates a similar website allowing Victorian customers to compare market offers – Victorian Energy Compare (compare.energy.vic.gov.au). The NSW Government also operates a switching service, Energy Switch, which provides a comparison of offers, helps arrange a switch and provides a reminder when it is time to review a plan.

Various private entities also offer online price comparison services. The AEMC identified 19 separate comparison websites in 2018.[37] Brokers are also active in the market for larger customers.

37 AEMC, *2019 retail energy competition review, final report*, June 2019, p 102.

While comparison websites and brokers can provide customers with a quick and easy way of engaging in the market, some services may not provide customers with the best outcomes. Commercial comparator websites may only show offers of retailers affiliated with the site, for example. Comparison websites also typically require retailers to pay a commission per customer acquired or a subscription fee to have their offers shown. These arrangements are opaque to the customer. Commissions may vary across listed retailers, creating incentives for websites to promote offers that will most benefit the comparator business rather than show the cheapest offer for the customer. Government-operated comparison sites avoid this bias by listing all generally available offers in the market.

In October 2020 the ACCC finalised proceedings in the Federal Court against iSelect – a privately operated energy price comparison service – for misleading or deceptive conduct and false or misleading representations. iSelect did not compare all available plans from its partner retailers and did not necessarily recommend the most competitive plan despite claims it would do so on its website. The Federal Court ordered iSelect to pay penalties of $8.5 million.[38]

The ACCC and the AEMC have recommended that the government prescribe a mandatory code of conduct to ensure price comparator and broker services act in the best interests of consumers.[39] The code would require the disclosure of commissions from retailers, show results from cheapest to most expensive, disclose the number of retailers and offers considered and provide a link to government comparator websites.

6.5 The evolving electricity market

Advances in metering and electricity generation, management and storage technologies are changing how the retail market works. Power of Choice reforms aim to provide customers with opportunities to benefit from these changes. Reforms include rolling out smart meters, introducing cost-reflective network pricing (section 3.7), making it easier for consumers to access their energy data and to compare and switch retailers, and enabling wider use of demand response.

Industry bodies developed a code of practice on standards of consumer protection when businesses offer new energy products and services.[40] The New Energy Tech Consumer Code covers all aspects of supply, including marketing, finance, installation, operation, customer service, warranties and complaints handling. The Australian Competition Tribunal authorised the code in September 2020.

6.5.1 Smart meters

Smart meters measure electricity use in half-hour blocks and allow remote reading and connection/disconnection. The information about a customer's energy use throughout the day from smart meters provides scope for innovative offers from retailers and for energy management services from third parties.

Victoria was the first region to progress metering reforms, with its electricity distribution businesses rolling out smart meters to around 98% of customers between 2009 and 2014. Elsewhere, the rollout has occurred on a market-led basis. Responsibility for metering outside of Victoria transferred from network businesses to retailers in December 2017. All new and replacement meters for residential and small businesses consumers must now be smart meters. Outside Victoria less than 17% of customers had a smart meter at February 2021.[41] Another 5% of customers (mostly in NSW) had access to an interval meter providing half hourly consumption readings but without remote reading and connection capabilities.

Retailers are required to provide customers with electricity meters within 6 business days after a property has been connected to the network and with replacement meters within 15 days.[42]

6.5.2 Rooftop solar PV and batteries

Many energy customers partly meet their electricity needs through rooftop solar PV and sell excess electricity back into the grid. At March 2021 over 2.3 million households and businesses in the NEM (23% of customers) had installed rooftop solar PV systems.

38 ACCC, 'iSelect to pay $8.5 million for misleading consumers comparing energy plans' [media release], 8 October 2020.

39 ACCC, *Restoring electricity affordability and Australia's competitive advantage, Retail Electricity Pricing Inquiry – final report*, June 2018, p 282; AEMC, *2019 retail energy competition review, final report*, June 2019, p 282.

40 ACCC, *Determination: Application for authorisation AA1000439 lodged by Australian Energy Council (AEC), Clean Energy Council (CEC), Smart Energy Council (SEC) and Energy Consumers Australia (ECA) (together the Applicants) in respect of the New Energy Tech Consumer Code*, December 2019.

41 AEMO data (unpublished).

42 AEMC, *National Energy Retail Amendment (Metering Installation Timeframes) Rule 2018, rule determination*, 6 December 2018.

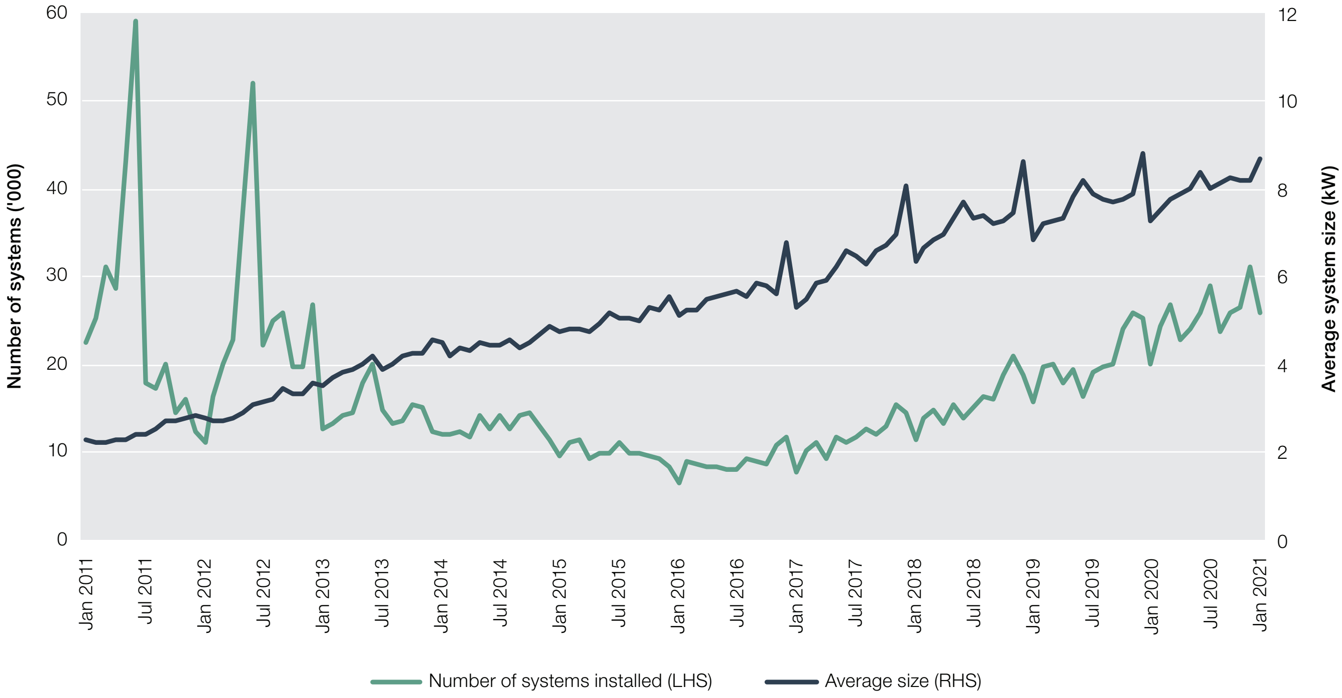
There were over 300,000 new installations of solar PV systems in 2020, exceeding the previous peak level recorded in 2011 (figure 6.7). The 2011 peak was due to attractive premium feed-in tariffs offered by state and territory governments. Those schemes have closed, but ongoing subsidies provided by the Australian and some state governments, combined with falling costs of solar PV systems, sustained growth in new installations. The average size of solar PV systems has also grown. Total solar capacity installed in 2020 (2,470 megawatts (MW)) set a new record – 30% higher than the previous highest annual capacity in 2019 (1,890 MW) and more than 3 times the capacity installed in 2011 (750 MW). NSW and the ACT recorded the strongest growth in installations, with over 40% more installations in 2020 than in 2019.

When installed with solar PV systems, battery storage and smart appliances allow customers to better match their electricity requirements over time, reducing the amount of power they need to withdraw from (and inject into) the network. Of the 300,000 solar PV systems installed in the NEM in 2020, less than 3% had an attached battery system.[43] The uptake of batteries was similar to 2019, despite the increase in the number of solar PV systems installed.

Solar PV systems can be purchased outright by customers or installed under a power purchase agreement. Under a power purchase agreement, an energy provider installs, owns, operates and maintains a solar PV system at a customer's home and sells the generated energy to that customer. In return, the customer pays for the electricity produced by the system, typically at a cheaper rate than an energy retailer would charge for supplying electricity through the grid.

Excess electricity produced by solar PV systems is typically sold back to the customer's retailer. Customers are paid a feed-in tariff for this excess electricity. The recent influx of solar PV capacity has created network constraints that have led to some networks limiting the amount of excess electricity that some customers can export to the grid. In March 2021 the AEMC released a draft rule change that would allow network businesses to charge customers for any electricity they export at times of network congestion (section 1.5.3).[44]

Figure 6.7 Growth of solar PV installations



kW: kilowatts.

Note: Data at January 2021.

Source: Clean Energy Regulator, *Postcode data for small scale installations, small generation units – solar*.

43 Clean Energy Regulator, *Solar PV systems with concurrent battery storage capacity by year and state/territory.* Data at 31 March 2021.

44 AEMC, *National Energy Retail Amendment (Access, Pricing and Incentive Arrangements for Distributed Energy Resources) Rule 2021, draft rule determination*, March 2021.

6.5.3 Electric vehicles

Electric vehicles, like dedicated batteries, have the potential to draw electricity from, and inject it into, the electricity grid. Electric vehicle uptake in Australia has been slower than in other developed countries, but the number of electric vehicles is expected to grow as costs fall and charging infrastructure is expanded. There were around 20,000 electric vehicles in Australia at the end of 2020.

Although still a small part of the market, electricity retailers are beginning to develop offers that reflect the specific needs of electric vehicles, including price incentives to encourage charging and discharging of batteries or electric vehicles at specific times.

6.5.4 Demand response

Smart meters provide customers with opportunities to participate in demand response programs run by retailers, distribution network businesses or third party energy providers. Demand response refers to a temporary shift or reduction in electricity use by customers to support power system stability.

The simplest demand response programs offer customers financial incentives to reduce their electricity use after receiving an alert from their retailer or network business. More sophisticated programs include technologies that optimise solar PV and storage systems; and automated load control devices that reduce power consumption from appliances such as air conditioning, hot water systems or pool pumps when required. Automating customer participation is likely to see greater uptake of these programs.

The Australian Renewable Energy Agency (ARENA) is funding several ‘virtual power plant’ trials that coordinate output from small scale solar and battery systems to provide services equivalent to a large scale generation plant (section 1.2.2).

These opportunities provide a new source of competition across the supply chain. Demand response can be deployed in the wholesale or frequency control ancillary service markets to manage or limit price spikes and can also be used by networks to manage system constraints, for example. A demand response mechanism that allows customers to directly offer demand response into the wholesale market will commence in the NEM in October 2021, but it will be restricted to large customers. Small customers are limited to offering wholesale demand response through programs offered by their retailer.

6.5.5 Customers in embedded networks and standalone power systems

Many customers are supplied energy through embedded networks (where a group of customers are located behind a single connection point to the main distribution network). Energy is supplied on a similar basis to customers directly connected to a distribution network. However, the customer experience in embedded networks can be significantly different. Many customers cannot buy energy from a provider other than their network operator or can do so only at significant cost.

Embedded network customers have less access to the competitive market than customers supplied through a distribution network, despite reforms implemented in 2017. Gaps in consumer protection occur in areas such as connection services, disconnection and reconnection obligations, and life support arrangements. Most customers in embedded networks also have limited avenues for dispute resolution. In June 2019 the AEMC recommended a new regulatory framework for embedded electricity networks to address these issues.[45]

Standalone power systems or microgrids – where a community primarily uses locally sourced generation and does not rely on a connection to the main grid – are also gaining traction in some areas. These arrangements have mainly developed in regional communities that are remote from existing networks. But improvements in energy storage and renewable generation technology may lead more customers to take up this form of energy supply.

These supply arrangements are generally not covered by the Retail Law and Rules. Regulatory and pricing frameworks are being implemented to support the growth of off-grid arrangements. In early 2021 energy ministers began consulting on regulatory changes to make it easier for distribution network businesses to offer standalone power systems (where economically efficient to do so) while maintaining appropriate consumer protections and service standards.[46]

45 AEMC, *Updating the regulatory frameworks for embedded networks, final report*, June 2019.

46 Energy Ministers, *Stand-alone power systems priority 1 rule amendments, explanatory note for stakeholder consultation*, March 2021.

6.6 Energy bills

Customers' energy bills depend on their energy use and the terms of their retail contract. Hundreds of retail offers may be available to customers at any time. Advertised offers frequently change, as do the charges attached to an offer over time. Customers who regularly change their energy contract usually pay lower prices, reflecting that lower priced market offers often revert to higher prices after an initial 'benefit period'. Customers on legacy market offers may pay prices on par with standing offers (table 6.2).

Retail customers' energy bills cover the costs of producing and transporting energy, costs related to environmental schemes, and retailers' costs and profit margins. Energy bills are typically higher for customers in regional and remote areas (where network costs tend to be higher and can be recovered from fewer customers) than for urban customers. They also tend to be higher in regions with higher average energy use.

6.6.1 Components of electricity bills

A typical residential electricity retail bill in southern and eastern Australia in 2020–21 comprised:

- retailers' wholesale costs of buying electricity in spot and hedge markets – 34% of a bill
- network costs for transporting electricity through transmission and distribution networks; and metering – 46% of a bill
- the costs of environmental schemes for promoting renewable generation and energy efficiency and reducing carbon emissions – 9% of a bill
- the retail costs of servicing customers (including meeting regulatory obligations) and acquiring and retaining customers; and the retailer's margin (profit) – 11% of a bill.

The contribution of each component varies by region (figure 6.8).

Wholesale costs

Retailers purchase energy in wholesale markets for sale to customers. Prices in wholesale market can be volatile, while the prices that retailers charge their customers are generally fixed. Retailers can manage their risk by entering hedge contracts that lock in prices for their future wholesale purchases (section 2.7). Alternatively, they might own generation assets or enter demand response contracts to manage risk (discussed in sections 6.4.2 and 6.5.4).

Wholesale costs for 2020–21 were forecast to be lowest in Queensland, which has substantial low cost black coal fired generation. Costs were forecast to be highest in South Australia, reflecting the state's significant reliance on relatively expensive gas powered generation, peaky demand and limited interconnection with other regions.

Increased renewable generation and flat demand across the NEM resulted in lower average wholesale prices than forecast over the first 3 quarters of 2020–21. This outcome will have only a limited impact on current retail prices, given retailers' contract positions for this period were entered into on expectations of higher prices, but it should be reflected in future retail prices.

Network costs

The AER regulates network charges, which cover the efficient costs of building and operating electricity networks and provide a commercial return to the network's financiers. Network costs in 2020–21 accounted for 40–50% of retail bills across most jurisdictions but were lower in the ACT (30%). Distribution networks account for the majority of costs (73–78%). Transmission networks account for up to 21% of network costs, with metering accounting for the balance.

Customer type (central business district (CBD), urban or rural), density and terrain affect network costs. In jurisdictions with multiple distribution networks (Queensland, NSW and Victoria), costs are generally higher in regional networks based on these factors.

Network productivity levels also partly explain cost differences across networks and jurisdictions. Productivity was historically lower for government-owned or recently privatised networks in Queensland, NSW, Tasmania and the ACT than in Victorian and South Australian networks, although this difference has narrowed in recent years (section 3.14).

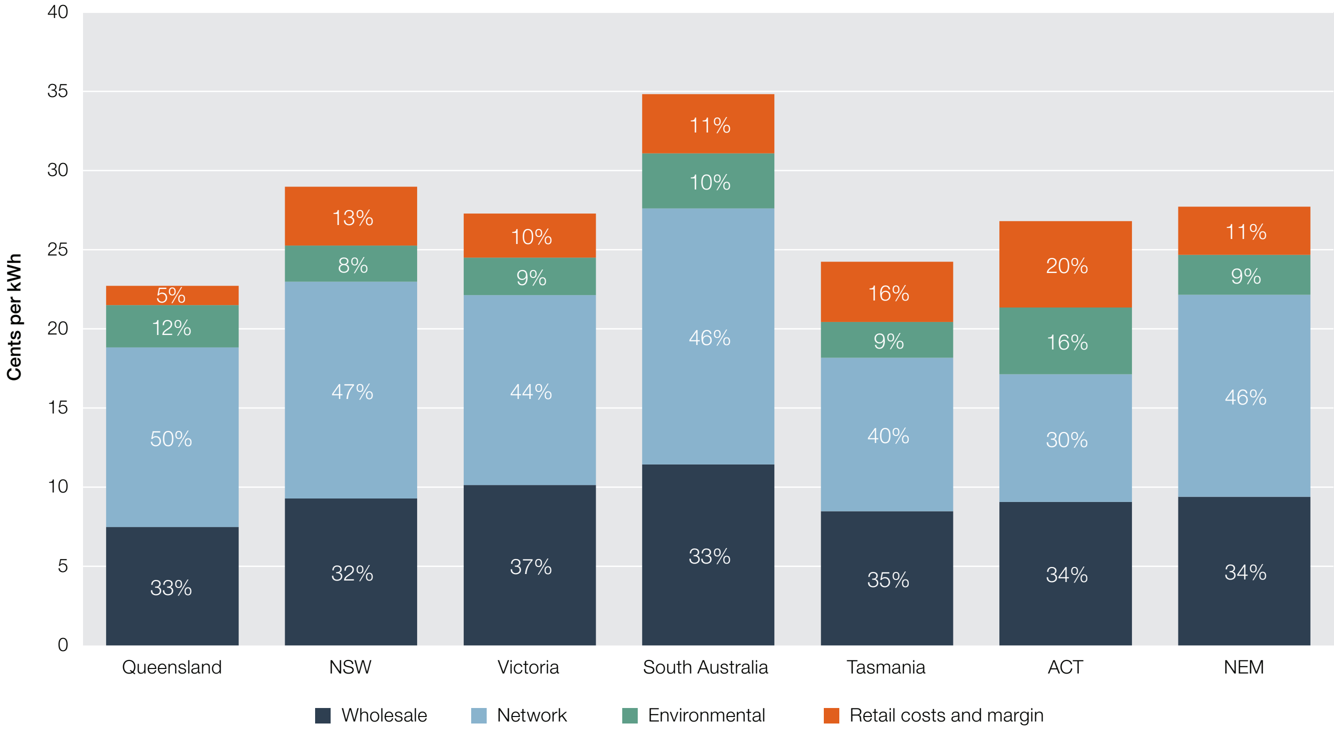
Environmental costs

Environmental costs include payments to fund renewable energy targets, feed-in tariffs for solar PV installations, and state government operated energy efficiency schemes. Costs associated with the Australian Government's Renewable Energy Target (box 1.1) account for almost 70% of environmental costs across the NEM (comprising both large scale and small scale components of the scheme).

ACT and South Australian customers faced the highest environmental costs (on a per unit of electricity basis). ACT costs largely related to the government's feed-in tariff scheme for large scale solar developments, which accounts for around half of environmental costs. South Australian costs flow from the state's premium feed-in tariff scheme for residential solar PV systems, given the high uptake of solar PV while that scheme was open.

Environmental costs were lowest in NSW and Tasmania, with neither jurisdiction having an active feed-in tariff scheme.

Figure 6.8 Composition of a residential electricity bill



kWh: kilowatt hour.

Note: Data are estimates for 2020–21. Average residential customer prices excluding GST. Percentages may not add to 100% due to rounding.

Source: AEMC, *Residential electricity price trends 2020*, Final report, December 2020.

Retail costs and margin

Retail costs fall into 2 main categories. Costs of servicing customers include managing billing systems and debt, handling customer enquiries and complying with regulatory obligations. These costs do not vary significantly across regions.

Customer acquisition and retention costs relate to marketing and other activities to gain or retain customers. These costs tend to be higher in jurisdictions with high rates of customer switching. This outcome highlights a risk that competition may increase energy bills for customers if the costs of competing outweigh competition benefits from efficiency and innovation. But competition should also lead to reduced retailer profit margins. The AEMC estimated that retailer costs and margin in 2020–21 were lowest in Queensland (5% of a retail bill).

6.6.2 Components of gas bills

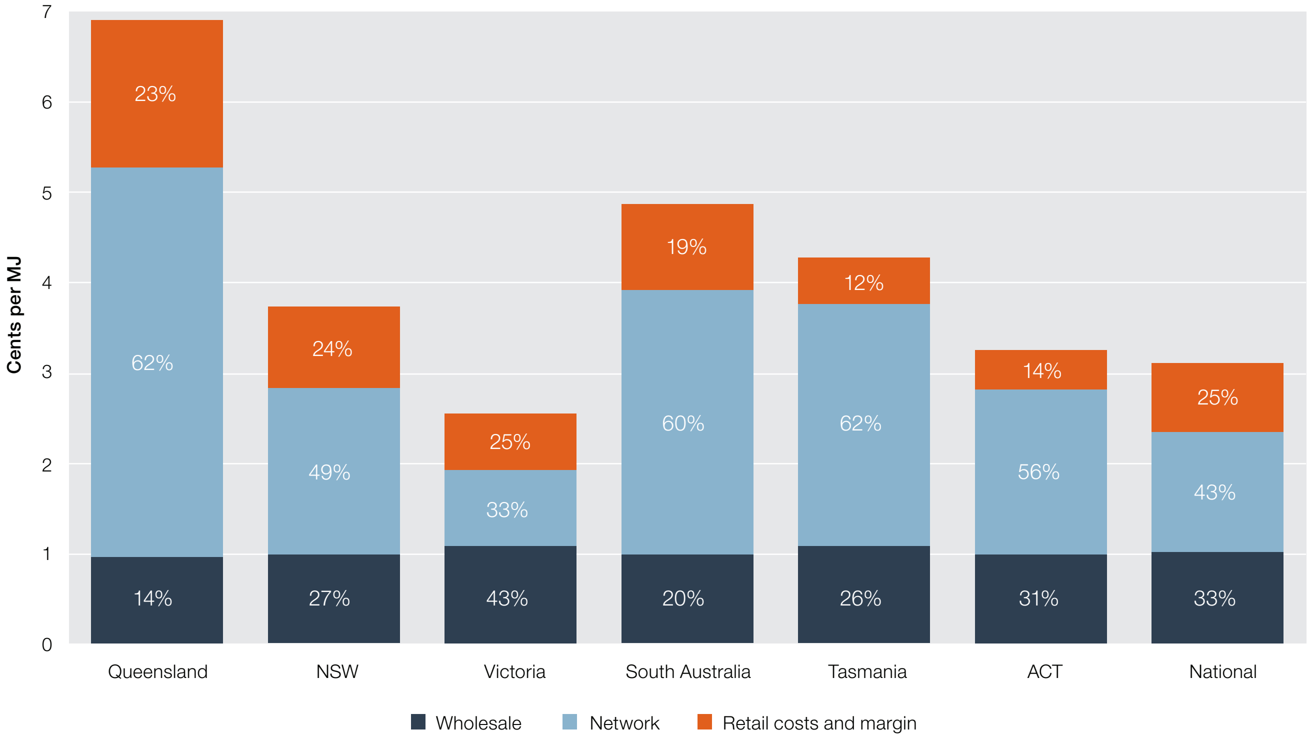
The composition of retail bills is less transparent in gas than electricity. Regulatory bodies provide no systematic annual reporting on gas bill data.

Figure 6.9 shows estimates from the most recent comprehensive data published in 2017. On average, gas pipeline (transportation) charges made up over 40% of a gas bill in that year. Distribution charges represented the bulk of this proportion, comprising around 35% of a gas bill.[47] Wholesale gas costs, which accounted for around one-third of a typical gas bill, rose sharply from 2015 (chapter 4). Retail costs and margin accounted for the remaining 25% of retail gas bills.

Victoria had the cheapest residential gas prices on a unit basis, largely because the state had lower network costs (33% of gas bills) due to a high level of gas use per customer and high connection penetration. In Tasmania and Queensland, where gas use is less widespread, network costs accounted for over 60% of gas bills.

Retail costs also varied across regions. Queensland retail costs almost doubled those elsewhere on a unit basis, which may reflect the absence of economies of scale from a relatively small customer base. Retail margins were highest in Victoria and NSW.[48]

Figure 6.9 Composition of a residential gas bill



MJ: megajoule.

Note: Data are estimates at 2017. Average residential customer prices excluding GST (real $2018–19). Percentages may not add to 100% due to rounding.

Source: Oakley Greenwood, Gas price trends review 2017, March 2018.

47 Oakley Greenwood, *Gas price trends review 2017*, March 2018, p 158.

48 Oakley Greenwood, *Gas price trends review 2017*, March 2018, p 225.

6.6.3 How retail prices are set

Energy retailers in southern and eastern Australia are free to set prices for energy market offers. Alongside this market pricing, government agencies regulate prices for electricity standing offers.

Victoria (2009), South Australia (2013), NSW (2014) and south east Queensland (2016) removed retail price regulation for electricity after the AEMC found markets in those states were effectively competitive. But governments reintroduced forms of price control in July 2019.

In 2019 the Australian Government appointed the AER to set a default market offer as a cap on standing offer electricity prices in south east Queensland, NSW and South Australia.[49] The default offer is not intended to mirror the lowest price in the market – this is to avoid impeding competition among retailers and incentivising consumers to disengage from the market (box 6.2). Any advertised discounts promoted by electricity retailers must be based on a reference bill informed by this default offer, providing consumers with meaningful information they can use to compare offers.

The Victorian Government also introduced price controls from 1 July 2019. The Essential Services Commission (ESC) sets the price of standing offers to reflect the efficient costs of a retailer in a contestable market, including an allowance for customer acquisition and retention costs.

The ACT, Tasmania and regional Queensland have maintained state-based arrangements to regulate retail electricity prices for small customers. Price regulation in these regions is based on a 'building block' approach, reflecting the costs of an efficient retailer supplying electricity to its customers. The approach to estimating costs differs across regions, as does the extent to which the standing offer allows for the recovery of customer acquisition and retention costs (such as advertising). The ACT Government in 2021 announced plans to introduce a reference bill requirement for advertising market offers.

Gas price deregulation occurred along similar timeframes to those of electricity price deregulation. In July 2017 NSW became the last jurisdiction to deregulate retail gas prices for small customers. The recent reintroduction of price controls was not applied in gas.

The Australian Government introduced further price protections in June 2020. Under the *Treasury Laws Amendment (Prohibiting Energy Market Misconduct) Act 2019*, retailers are required to pass on to customers any sustained and substantial decreases in the costs of electricity.

6.6.4 Energy prices

Energy prices have become slightly more affordable over the past 3 years but remain high by historical standards. There has been significant volatility in retail energy prices since 2007, driven largely by changes in input costs. Electricity and gas prices have followed broadly similar trends, as some key underlying price drivers apply to both fuels.

Longer term trends

Prices rose sharply between 2007 and 2013 before plateauing (gas) or falling (electricity) until 2016. Prices again moved sharply upwards in 2017 before moderating in the past few years (figure 6.10).

Network cost increases – driven by network businesses investing heavily in new assets; and financial market instability raising debt costs – were the primary contributor to electricity prices increasing by an average 9% per year, and gas prices increasing by 6% per year, over the 6 years to 2013.

Lower network costs from 2013 eased pressure on prices for both fuels. For electricity, the removal of carbon pricing and an oversupply of generation capacity depressed wholesale electricity prices, with retail prices falling 8% over 2 years.

49 The AER's responsibilities are set out in: *Competition and Consumer (Industry Code—Electricity Retail) Regulations 2019*.

The easing of prices reversed in 2016, when high electricity and gas wholesale prices began to flow through into retail prices in most regions. In electricity, the retirement of large coal fired generators in South Australia (Northern, 2016) and Victoria (Hazelwood, 2017) tightened the supply–demand balance in generation. Higher gas and coal fuel prices also contributed to high wholesale electricity prices. Additionally, liquidity in electricity financial markets tightened after coal generators left the market, putting upward pressure on hedging costs. In gas, the commencement of liquefied natural gas (LNG) exports in Queensland exposed the domestic market to international oil prices and reduced the amount of gas available for the local market. Moratoriums on onshore gas exploration in some states, and declining production in some established gas basins, also contributed to a tighter supply–demand balance. New price peaks for electricity and gas retail prices were recorded in 2017 and 2018.

While not a primary driver of price movements, environmental and retailer costs also added to electricity and gas prices over the decade. Environmental costs related to:

- meeting obligations under the Large-scale Renewable Energy Target
- state-based energy efficiency schemes
- the rapid growth in rooftop solar PV, which increased costs under the Small-scale Renewable Energy Scheme and payments under premium feed-in tariff schemes.

Box 6.2 Default market offer

The Australian Government's default market offer (DMO) scheme, applying since July 2019, sets a cap on what retailers can charge electricity customers on standing offer contracts.

The scheme was introduced following concerns raised by the Australian Competition and Consumer Commission (ACCC) that standing offer contracts:

- were not working as an effective safety net
- were unjustifiably expensive, with retailers having incentives to increase standing offer prices as a basis to advertise artificially high discounts
- penalised customers who had not taken up a market offer, making them a form of 'loyalty tax'.

The ACCC's recommendation for a DMO scheme was implemented through the Competition and Consumer (Industry Code—Electricity Retail) Regulations 2019 under the *Competition and Consumer Act 2010*.

The scheme applies in distribution network areas covered by the Retail Law that are not otherwise subject to retail price regulation – NSW (Endeavour, Essential Energy and Ausgrid), south east Queensland (Energex) and South Australia (SA Power Networks). Victoria operates a separate but similar scheme across all its distribution network areas.

The AER determines DMO prices each year for residential and small business customers in each of the 5 covered distribution areas. We set prices at a level where standing offer customers will see price reductions, but retailers still have incentives to compete on price, invest and innovate with their market offers.

While the scheme caps what retailers can charge in their standing offers, it does not cap customers' bills. Bills will vary depending on how much electricity customers use and their retailer's specific charges.

The default prices also act as a reference against which retailers must compare their market offers in advertising, on their websites and elsewhere. This requirement aims to make it easier for customers to compare energy offers across different providers.

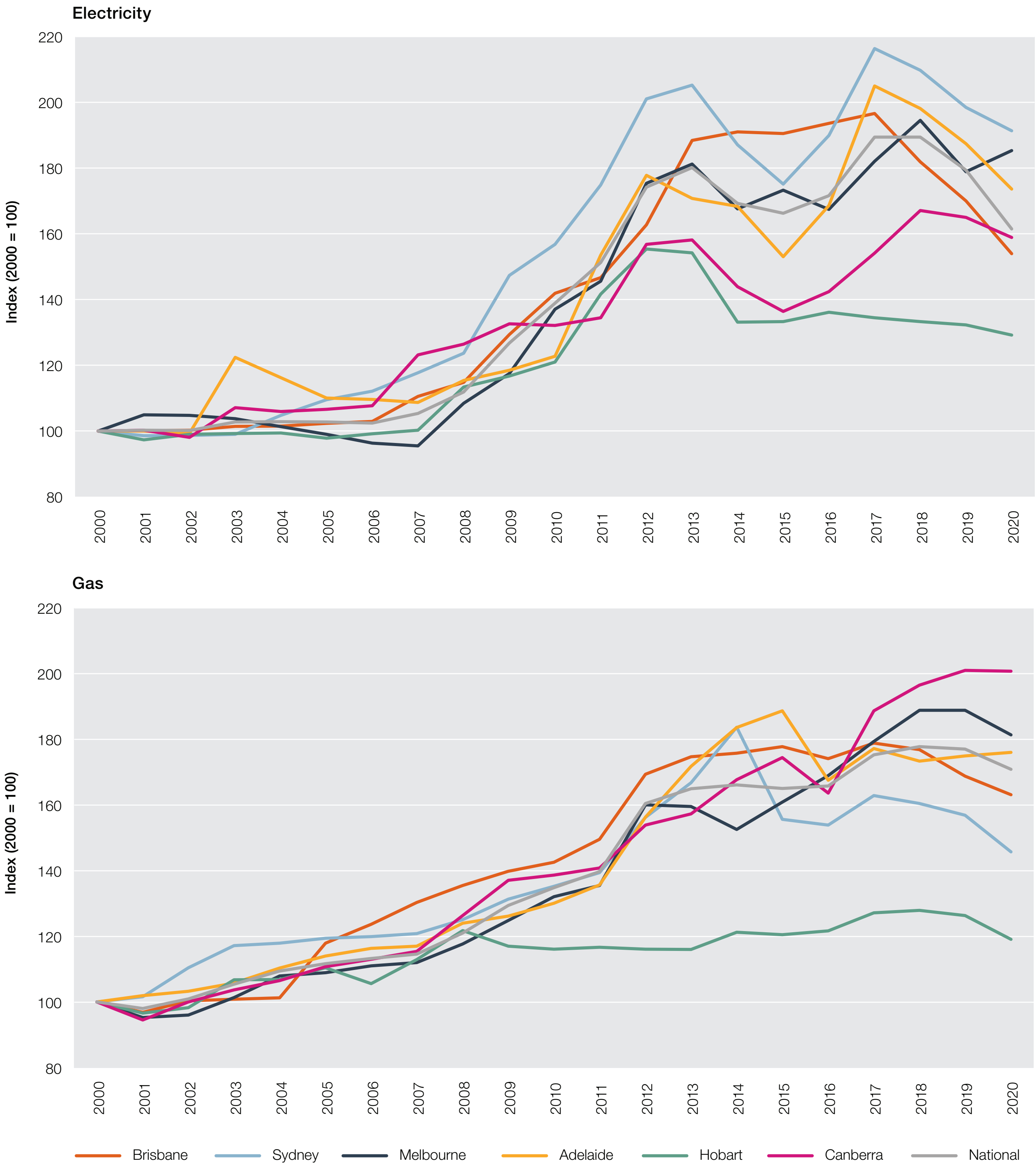
The DMO scheme provides a fallback for those who do not engage in the market, rather than providing a low priced alternative to a market offer. It aims to reduce unjustifiably high standing offer prices while allowing retailers to recover their costs in servicing customers and providing customers and retailers with incentives to participate in the market.

We initially set default prices for 2019–20 at the mid-point (50th percentile) between the median standing offer and median market offer in each distribution zone at October 2018.[50] The default price has been updated each subsequent financial year, with adjustments for:

- forecast changes in environmental, wholesale and network costs
- changes in consumer price index (CPI) for residual costs (which includes retail costs).

50 AER, *Final determination, Default market offer prices*, April 2019

Figure 6.10 Energy retail price indices (inflation adjusted)



Note: Consumer price index electricity and gas series for each region, deflated by the consumer price index for all groups. Data at December quarter each year.

Source: ABS, *Consumer price index*, cat no 6401.0, various years.

Electricity price movements since 2018

Since 2018 electricity retail prices fell in most regions after significant rises in preceding years. *Standing offer* prices fell most dramatically between 2019 and 2020 due to new price regulations that limited the level of standing offers, removing inflated offers from the market. *Market offer* price falls were largest between 2020 and 2021 as a lagged response to sharply falling wholesale costs over 2019 and 2020. These wholesale cost reductions were driven by a range of factors, including the commissioning of low cost renewable generators, moderate weather conditions limiting demand, and lower coal and gas fuel costs. Lower network costs also contributed to retail price falls in some regions.

Environmental costs increased in some regions, offsetting some of the cost reductions from other factors. For example, in 2019 the Queensland Government ended a scheme to recover premium feed-in tariff costs through the tax base rather than electricity charges. But these changes were minor relative to the decrease in wholesale costs.

Table 6.2 summarises recent movements in market and standing offer energy prices for residential customers; and estimated annual customer bills for generally available flat rate offers. Figure 6.11 compares prices under market and standing offers for residential electricity customers at June 2018, June 2019, June 2020 and February 2021.

Between June 2018 and February 2021, median market offer prices fell by 8–16% in Queensland, 10–18% in NSW, 7–10% in Victoria, 19% in South Australia and 4% in the ACT. Tasmania was the only region to record a rise in market prices over this period, of less than 1%.

Changes in the cheapest market offers in each region were even more pronounced over this period, except in Victoria. The lowest market offer price reduced by 8–22% in Queensland, 17–22% in NSW, 26% in South Australia, 4% in the ACT and 8% in Tasmania. The cheapest market offer in Victoria increased by 1% in one network area and reduced by up to 6% in the other 4 network areas.

The cheapest market offers were typically offered by smaller tier 2 retailers. The lowest price offer by a small retailer was typically more than $100 cheaper than the lowest offer from one of the 'big 3' retailers (and up to $270 cheaper).

Gas price movements since 2018

Gas prices have trended down since 2018 in most regions, driven largely by lower wholesale gas costs. But price reductions were less pronounced in gas than in electricity.

Gas wholesale costs have eased significantly since early 2019 (chapter 4). As in electricity, cost reductions take time to flow through to retail prices as longer term contract positions are adjusted, and they may not be fully reflected in prices at February 2021.

Between June 2018 and February 2021, median gas market offer prices fell by 3–8% in Queensland, 8% in NSW, 2–5% in Victoria and 8% in the ACT. South Australia was the only region to record a rise in market prices over this period, of less than 1%. Figure 6.12 compares prices under market and standing offers for residential gas customers at June 2018, June 2019, June 2020 and February 2021.

Reductions in the cheapest market offers were even more pronounced over this period in Queensland, NSW and the ACT, falling by 8–15%. But the lowest price offers in Victoria and South Australia became more expensive.

The cheapest market offers were typically offered by smaller tier 2 retailers. The lowest price offer by a small retailer was between $15 and $90 cheaper than the lowest offer from one of the 'big 3' retailers.

Standing offer prices followed a different trend to market offer prices, with the median price remaining stable or increasing in all regions between June 2018 and February 2021. Unlike in electricity, there is no price regulation of standing offer gas prices.

Table 6.2 Movement in energy bills for customers on market and standing offers

JURISDICTION	WHO SETS STANDING OFFER PRICES?	DISTRIBUTION NETWORK AREA	CHANGE IN MEDIAN OFFER (%) JUN 2019 – JUN 2020 MARKET	CHANGE IN MEDIAN OFFER (%) JUN 2019 – JUN 2020 STANDING	CHANGE IN MEDIAN OFFER (%) JUN 2020 – FEB 2021 MARKET	CHANGE IN MEDIAN OFFER (%) JUN 2020 – FEB 2021 STANDING	ESTIMATED ANNUAL CUSTOMER BILL, FEBRUARY 2021 ($) MARKET	ESTIMATED ANNUAL CUSTOMER BILL, FEBRUARY 2021 ($) STANDING
Electricity								
Queensland	Retailers (capped at DMO)	Energex	–1.7	–7.8	–7.5	–4.4	1,505	1,791
	QCA	Ergon Energy	3.1	–2.0	-5.1	-6.5	1,848	1,840
NSW	Retailers (capped at DMO)	Ausgrid	–6.2	–10.5	–5.0	–0.8	1,543	1,898
		Endeavour Energy	–7.3	–13.7	–5.9	–0.9	1,652	2,035
		Essential Energy	–2.2	–12.2	–4.3	0.5	1,956	2,385
Victoria	ESC	Citipower	1.5	–13.5	–9.1	–10.8	1,227	1,346
		Powercor	0.0	–18.6	–10.4	–10.6	1,431	1,585
		AusNet Services	3.9	–14.6	–8.3	–8.8	1,523	1,682
		Jemena	2.6	–15.9	–10.6	–11.4	1,233	1,366
		United Energy	5.0	–12.4	–11.5	–13.1	1,308	1,449
South Australia	Retailers (capped at DMO)	SA Power Networks	–4.8	–13.3	–7.2	–5.7	1,785	2,051
Tasmania	OTTER	Aurora Energy	2.6	4.9	–1.6	–0.7	2,419	2,536
ACT	ICRC	Evoenergy	4.7	–1.3	–4.6	–3.3	1,711	1,937
Gas								
Queensland	Retailers	AGN	–5.0	2.3	–0.8	–0.7	610	700
		Allgas Energy	–2.1	2.1	0.0	–2.0	680	740
NSW	Retailers	Jemena	0.9	1.0	–7.4	–3.4	810	1,000
Victoria	Retailers	Multinet	–6.0	3.6	–2.4	–1.1	1,414	1,877
		AusNet Services	–3.0	5.1	–3.4	–2.5	1,382	1,825
		AGN	–7.4	–1.9	–6.6	–6.0	1,406	1,830
South Australia	Retailers	AGN	3.6	4.0	2.6	4.9	9,30	1,020
ACT	Retailers	Evoenergy	0.5	3.1	–5.8	–1.7	1,465	1,760

AGN: Australian Gas Networks; DMO: default market offer; ESC: Essential Services Commission; ICRC: Independent Competition and Regulatory Commission; kWh: kilowatt hour; MJ: megajoule; OTTER: Office of the Tasmanian Economic Regulator.

Note: AER estimates are based on generally available offers for residential customers on a 'single rate' tariff structure. Annual bills and price changes are based on median market and standing offers at June 2019, June 2020 and February 2021, using average consumption in each jurisdiction: NSW 5,881 kWh (electricity), 22,855 MJ (gas); Queensland 5,699 kWh, 7,873 MJ; Victoria 4,589 kWh, 57,064 MJ; South Australia 4,752 kWh, 17,501 MJ; ACT 6,545 kWh, 42,078 MJ. Market offer prices include all conditional discounts.

Source: Energy Made Easy website (www.energymadeeasy.gov.au); Victorian Energy Compare website (compare.energy.vic.gov.au).

Price dispersion

Price controls introduced in 2019 reduced electricity prices in standing offers in relevant regions, but the immediate impact on market offers was less clear. Higher priced market offers tend to have lowered in price, given those offers often link to standing offers. Some of the lowest priced offers were removed in some regions, resulting in a significant narrowing of the price range in available offers in 2019.

By February 2021 the median standing offer was around 19% higher than the median market offer in south east Queensland (compared with a 23% difference in June 2019), 22–23% higher in NSW (22–29% in June 2019) and 15% higher in South Australia (24% in June 2019). The Victorian market had the largest contraction in offers, with median standing offers at February 2021 around 10–11% higher than median market offers (compared with a 31–37% difference in June 2019).

Price competition at the lower end of the market intensified over 2020, with prices of the lowest offers in most regions reducing more than the median market or standing offer. In some network areas, the difference between the lowest market offer and median standing offer at February 2021 was larger than at June 2019 (immediately before the Electricity Retail Code was introduced). Victoria was the exception to this recent trend of greater price dispersion, which may reflect the tighter standing offer price cap in that region.

These price differences indicate continued potential for savings for customers who engage in the market. A customer switching from the median electricity market offer to the best market offer in their distribution zone could save between $180 and $300 annually in February 2021. Potential savings were lower in Victoria – between $110 and $150 annually.

In gas, the gap between market and standing offers has widened since 2019. Median standing offers in February 2021 were 9–33% higher than median standing offers, up from 6–22% in June 2019. A customer switching from the median electricity market offer to the best market offer in their distribution zone in February 2021 could save from $50 annually in Queensland to almost $300 in the ACT.

6.6.5 Electricity price forecasts

The AEMC publishes annual forecasts of electricity retail prices based on current expectations, policy and legislation. In December 2020 it forecast electricity prices for a 'representative customer' would fall across the NEM in 2021–22 before increasing in 2022–23.[51] Forecast prices in 2022–23 remain below current levels in all regions except NSW and the ACT. The largest price reductions are forecast for Victoria (with prices in 2022–23 expected to be 9% below current levels) followed by Queensland and South Australia (each 4% lower) and Tasmania (2% lower). Prices are forecast to rise by 3% in NSW and 4% in the ACT.

Lower wholesale costs are forecast as a key driver of lower retail prices. Wholesale costs should continue to ease as new generation capacity comes online, before increasing in 2022–23 following the closure of the Liddell power station in NSW. Environmental costs are also expected to fall across all regions, driven by a decrease in costs for certificates to meet Renewable Energy Target obligations. Higher network costs are forecast to put upward pressure on retail prices in NSW and the ACT.

Consistent with these findings, the AER's DMO determination for 2021–22 will reduce the price cap on standing offer prices for residential customers in south east Queensland, NSW and South Australia by between 2.7% and 7.4%. Wholesale costs and environmental costs were cited as the main factors driving these decreases.[52]

51 AEMC, *Residential electricity price trends 2020, final report*, December 2020.

52 AER, *Default Market Offer prices 2021–22, final determination*, April 2021.

Figure 6.11 Price diversity – electricity offers

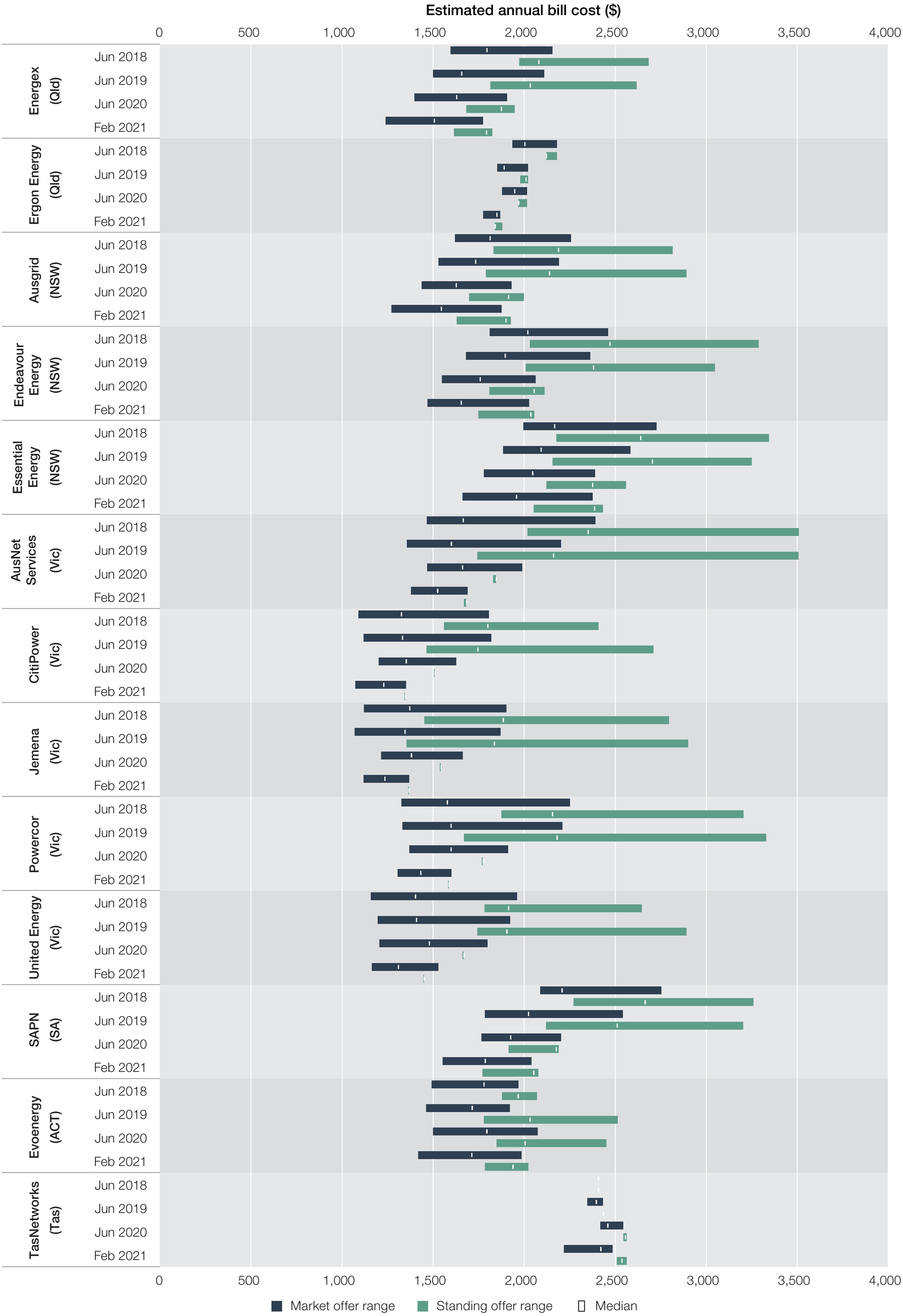
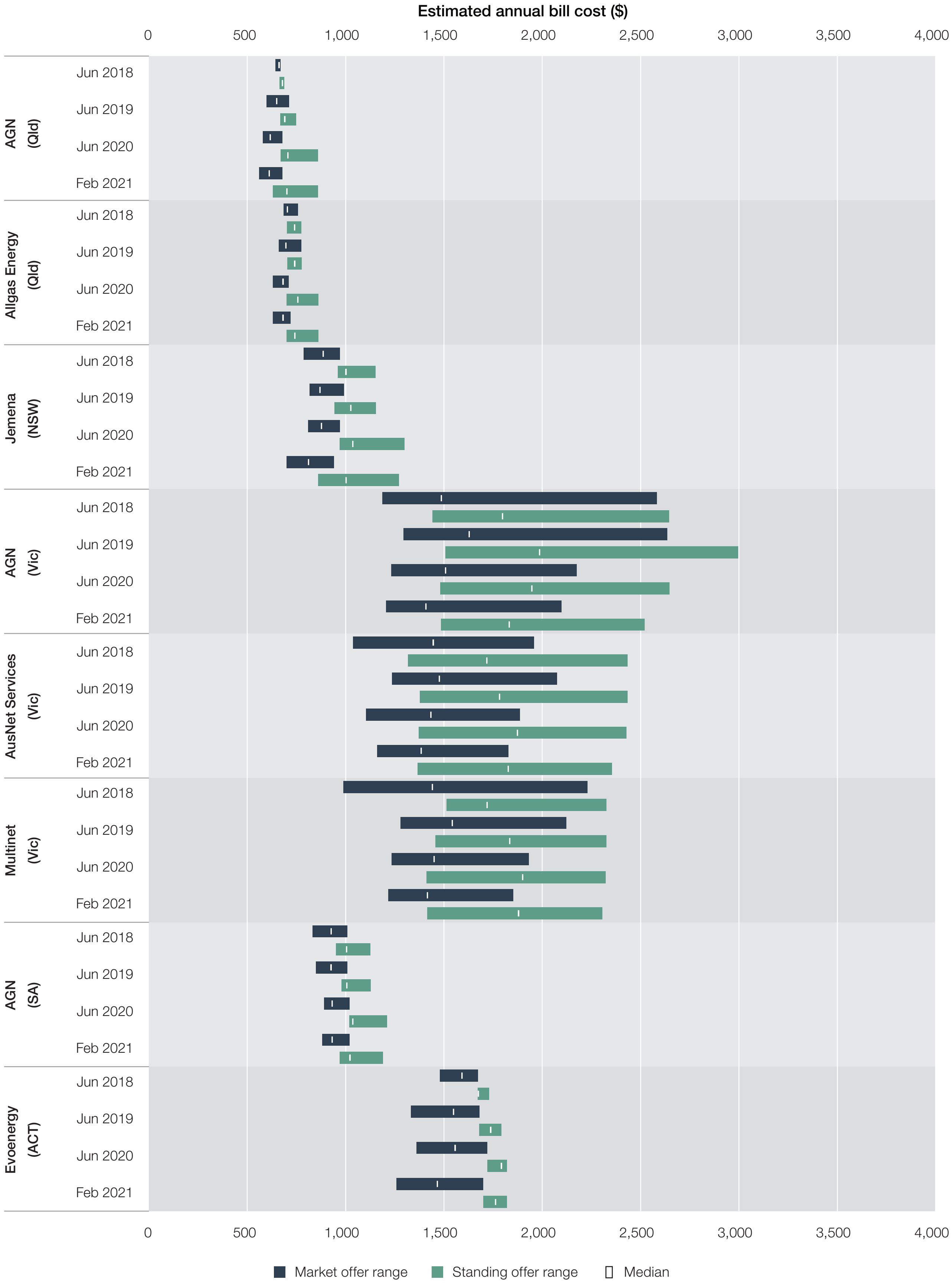


Figure 6.12 Price diversity – gas offers



Note (figures 6.11 and 6.12): Data includes all generally available offers for residential customers using a single-rate tariff structure at June 2018, June 2019, June 2020 and February 2021. Annual bills are based on average consumption in each jurisdiction (table 6.2). Market offer prices include all conditional discounts.

Source (figures 6.11 and 6.12): Energy Made Easy website (www.energymadeeasy.gov.au); Victorian Energy Compare website (compare.energy.vic.gov.au).

6.6.6 Energy use

Electricity use is highest in the ACT and Tasmania. Key drivers of electricity use are climate (with greater heating and cooling requirements in some jurisdictions) and the penetration of gas as an alternative fuel. Tasmania in particular has low gas penetration for households. Conversely, most households in Victoria have both electricity and gas connections, resulting in it having the lowest average household electricity consumption. Benchmark data shows that average electricity use in a Victorian household with gas can be up to 25% lower than for a non-gas household.[53]

While energy prices are significantly higher than a decade ago, reductions in energy use have moderated the impact on customer bills (particularly electricity bills).

Average household electricity use has trended downwards over the past 4 years in most jurisdictions, easing by 5–10% in NSW, South Australia and the ACT. Smaller reductions were recorded in Victoria and Queensland. Tasmania was the only region to record increased electricity use (up 3%).

The trend towards lower electricity use was largely driven by the uptake of rooftop solar PV systems. Improving energy efficiency of homes and appliances also contributed. Given these drivers, average outcomes likely obscure a widening gap between use for those households with the capacity to adopt new technology and those unable to do so (for reasons such as cost or residential tenancy laws). The former group is likely experiencing a substantial reduction in electricity use, while electricity use among other households has likely remained relatively consistent over time.

Gas is primarily used in homes for space heating, water heating and cooking. Customers in colder climates (such as those in Victoria, Tasmania and the ACT) tend to use the most gas. This largely reflects the use of gas for space heating – winter gas use in these regions is 6–7 times higher than over summer.[54]

There is little systematic reporting of gas consumption data in Australia, but changes in customer behaviour, including switching to energy efficient appliances, reducing discretionary energy use and switching from gas to electricity, mean that average gas use has also trended downwards.

6.7 Energy affordability

Energy affordability relates to customers' ability to pay their energy bills. A customer's energy consumption, their energy contract and prices, their income and other living costs affect affordability.

Energy use varies with household size, housing and appliance quality, heating and cooling needs, and lifestyle. Energy prices depend on where a customer lives, the network services required to supply their energy, competition between retailers in their area, the customer's ability to identify an appropriate energy plan, and whether the customer is eligible for a concession or rebate to help manage their energy costs.

The AER reports annually on energy affordability, with a focus on low income households.[55] In 2020 electricity affordability improved for low income households in NSW and South Australia but was unchanged or deteriorated elsewhere (figure 6.13).

Gas affordability for low income households improved in Queensland and Victoria in 2020 but was consistent or deteriorated elsewhere.[56]

Although affordability recently improved in some regions, energy costs remain high in historic terms. Electricity affordability remains a top cost of living issue for households.[57]

53 Frontier Economics, *Residential energy consumption benchmarks, final report for the Australian Energy Regulator*, December 2020, p 25.

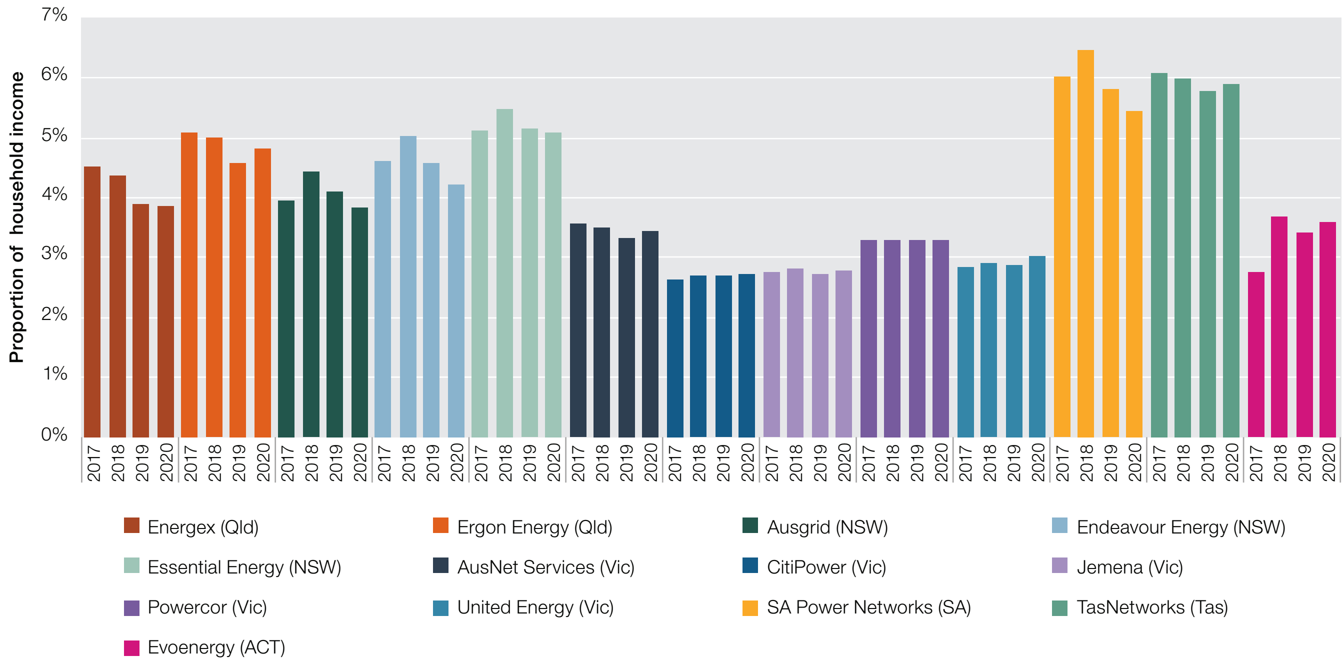
54 Frontier Economics, *Residential energy consumption benchmarks, final report for the Australian Energy Regulator*, December 2020, p 26.

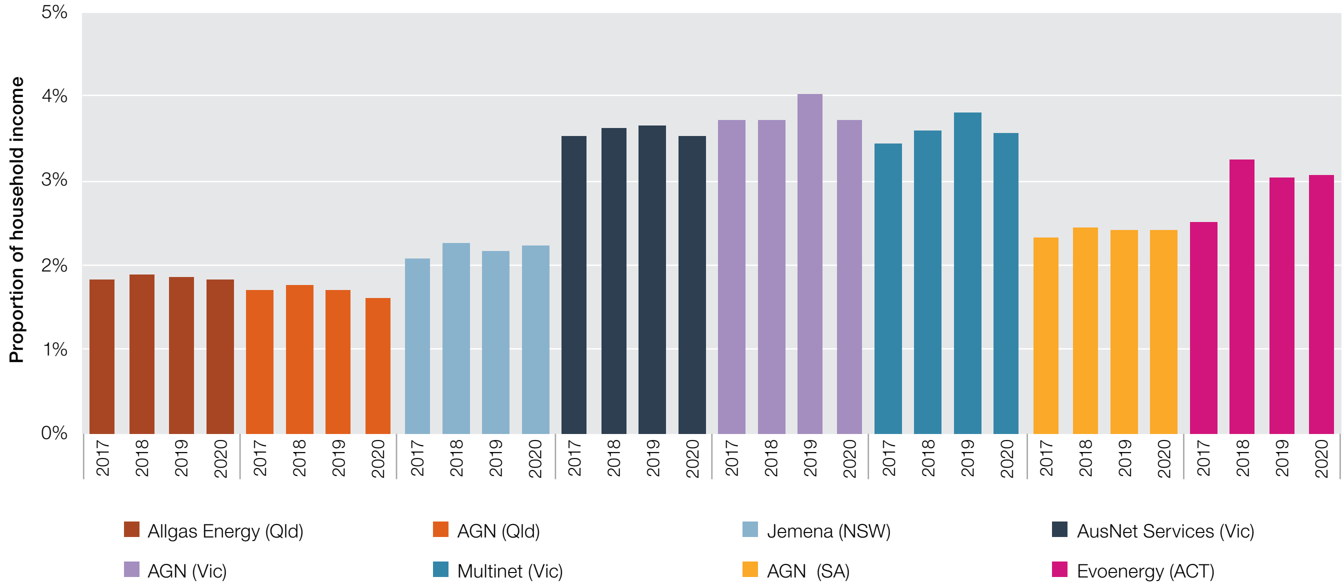
55 AER, *Affordability in retail energy markets*, September 2019.

56 Based on the percentage of household disposable income spent on the median market offer.

57 In a survey of households by Energy Consumers Australia, 25% said that electricity is the bill they were most concerned about, while 73% rated it in their top 3. ECA, *Shock to the system: energy consumers' experience of the Covid-19 crisis*, July 2020.

Figure 6.13 Energy bill burden on low income households





Note: Based on average household consumption data for each state. Energy costs based on the median of generally available single-rate offers (inclusive of discounts) at June each year. The data account for available concessions and rebates. Income data are household disposable income for the adjusted lowest income quintile (on an equivalised income basis) as reported by the Australian Bureau of Statistics for 2015–16 and 2017–18, adjusted for other years using the consumer price index.

Source: AER, *Annual retail markets report 2019–20*, November 2020.

Despite the availability of energy bill concessions offered by state and territory governments, low income households often paid more than double (as a share of income) what households on average incomes paid for their energy. For a typical low income household on the median market offer and receiving energy bill concessions, at June 2020:

- electricity costs accounted for 2.7–5.9% of disposable income (compared with 2.7–5.8% in 2019)
- gas costs accounted for 1.6–3.7% of disposable income (compared with 1.7–4% in 2019).[58]

Bills for customers on standing offers were more expensive than bills for customers on market offers in all networks at June 2020. Customers on the median standing offer would pay up to 1% more of their disposable income on electricity, and up to 1.2% more of their disposable income on gas, than an equivalent customer on the median market offer. While only a small number of customers are on standing offers in most jurisdictions, the role of standing offers as a fallback for customers who are unable to engage in the market means that some of the most vulnerable customers may be exposed to these higher prices.

But not all customers on market offers are getting the lowest prices for electricity and gas. The range of offer prices means that a customer on the highest cost market offer would pay up to 57% more for electricity, and up to 80% more for gas, than a customer on the cheapest market offer. In many cases, customers on high cost market offers would also be paying more than a typical standing offer customer.

Tasmanian customers had the highest electricity bill to income ratio in low income households. This outcome in part reflects Tasmania having the highest average electricity use, as a cold climate creates a high demand for heating, and the state's low gas penetration. High concessions and relatively low electricity charges partly offset this factor. South Australian customers also experienced relatively high electricity bill to income ratio in low income households. While the state has the second lowest electricity use in the NEM, electricity prices were 16–49% higher than other NEM regions.

Despite above average electricity use, the ACT had the most affordable electricity bills as a percentage of disposable income – a result of relatively low electricity prices and high incomes.

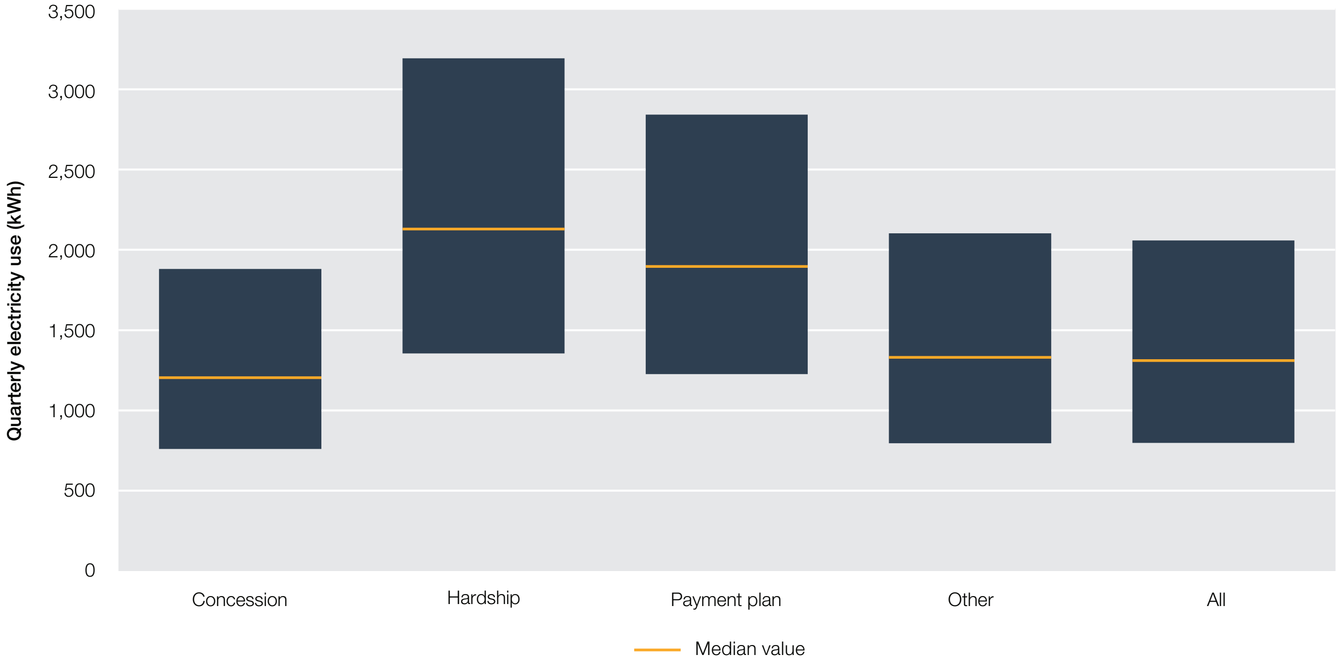
In gas, the high use jurisdictions of Victoria and ACT had the highest bills (across market and standing median offers) as a percentage of disposable income.

While many households can achieve significant savings simply by switching to a cheaper offer, total energy use plays an important role in energy affordability. For example, customers on hardship programs in 2020 consumed on average over 60% more electricity than a typical customer (2,129 kWh per quarter compared to 1,310 kWh) (figure 6.14). This may reflect that the financially vulnerable have less access to solar PV systems and are living in properties and using electrical appliances that are less energy efficient. State and territory governments have implemented initiatives to help low income households improve their energy efficiency or install solar PV systems:

- In Victoria, the Household Energy Savings Package offers high efficiency heating and cooling systems for low income households and energy upgrades of social housing properties. A Home Energy Assist program includes measures such as replacing inefficient electric water heaters and electric heaters in public housing properties; and home energy retrofits, appliance replacement and energy advice for low income households.
- In the ACT, the Actsmart Household Energy Efficiency Program, delivered by St Vincent de Paul, provides a home energy efficiency assessment, draught proofing and an energy savings kit to improve energy efficiency. The Solar for Low Income Program provides eligible households with a subsidy of up to 50% of the cost of a solar system. An Energy Efficiency Improvement Scheme provides products such as LED lighting, insulation, standby power controllers, draught sealers and energy efficient appliances and includes a target for electricity retailers to achieve energy savings for low income households through efficiency measures.
- South Australia's Retailer Energy Productivity Scheme offers free or discounted energy efficiency and energy productivity activities, but it is not specifically targeted at low income households.
- Tasmania's Power$mart Homes helped low income households save money on their bills by providing upgrades such as LED light bulbs, draught sealing and expert energy efficiency advice. The program was discontinued in 2020.

58 AER, *Annual retail markets report 2019–20*, November 2020.

Figure 6.14 Electricity use by customer type



Source: ACCC, *Inquiry into the National Electricity Market, May 2020 report*, June 2020.

6.7.1 COVID-19 issues

In 2020 the economic impact of the COVID-19 pandemic increased financial stress on many energy customers. To support households impacted by the pandemic, the AER introduced temporary assistance measures to be provided by energy businesses (box 6.3). These measures were developed in consultation with energy businesses, consumer organisations and market bodies. The ESC introduced similar measures in Victoria.

6.7.2 Assisting customers in debt

Energy affordability issues can lead customers into debt that, if not managed, may result in disconnections. A household's energy debt refers to amounts owing for 90 days or more to a retailer. The number of customers in debt increased over the period of the COVID-19 pandemic. In December 2020, 2.9% of customers were in debt – 16% more customers than a year earlier. But this rise followed a trend of falling numbers of customers in debt since 2015 in regions other than Tasmania. The number of customers in debt in 2020 remained well below the number over the period from 2015 to 2018.

Tasmania had the highest proportion of residential energy customers in debt at December 2020, at 5.8% of customers (figure 6.15). Queensland had the lowest rate of customers in debt, at around 2.4%.

Along with increases in the number of customers in debt over 2020, the level of debt held by those customers also increased across all regions. The average value of debt at December 2020 was $1,008 (up from $796 in the previous year). This continued a trend of increasing debt levels since 2015 (figure 6.16). The average value of debt was highest in South Australia, at $1,266; and lowest in the ACT, at $744.

Energy debt in some jurisdictions is seasonal, particularly for gas customers. In the ACT, for example, gas debt often grows larger in the December and March quarters because customers may have difficulty in paying off larger winter heating bills.

A retailer's approach to managing customer debt can significantly impact whether a customer navigates a period of financial difficulty. The AER has previously highlighted concerns with retailers disconnecting customers, or referring customers for collection activity, for debt less than $500.[59] Both disconnections and collection referrals reduced significantly over 2020, reflecting that the AER's Statement of Expectations had been in place since March 2020. Residential customer disconnections reduced by 68% and customer referrals for collection activity reduced by 42%.[60]

59 AER, *Annual retail markets report 2018–19*, November 2019.

60 AER, *Retail markets quarterly, Q2 2020–21*, April 2021.

Box 6.3 Responses to COVID-19

In March 2020 the Australian Energy Regulator (AER) released a statement of expectations on how energy businesses should respond to the COVID-19 pandemic, recognising that energy is an essential service. The AER's priorities for supporting customers over the COVID-19 pandemic period included:

- ensuring that retailers met the needs of customers in vulnerable circumstances and that customers could access the energy they need
- protecting customers who may have been unable to safeguard their own interests, including customers requiring life support equipment or who were experiencing financial difficulty
- actions needed to ensure the safety and reliability of energy supply
- being responsive to the rapidly evolving pandemic situation and preparing for our recovery.

Reflecting these priorities, the Statement of Expectations set out principles for energy retailers to follow to avoid imposing unnecessary hardship on the community, including that retailer must:

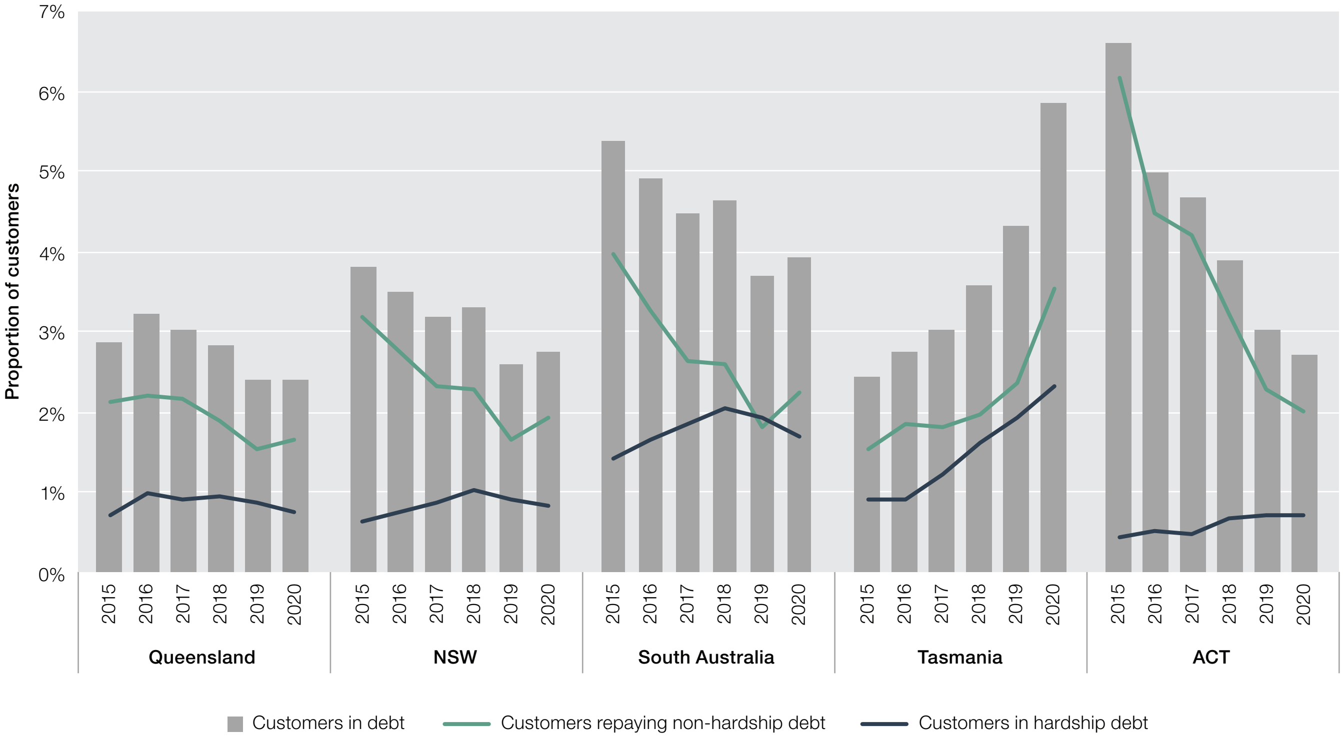
- offer a payment plan or hardship arrangement to all residential and small business customers that indicate they may be in financial stress
- be ready to modify an existing payment plan if a customer's changed circumstances make this necessary
- not disconnect any residential or small business customer in financial stress. Initially a this was a blanket ban on disconnection, but since August 2020 retailers can disconnect customers for non-payment if the customer does not engage with the retailer
- for any customer disconnected for non-payment, reconnect the customer immediately following contact and waive disconnection, reconnection and contract break fees
- defer any referrals of customers to debt collection agencies for recovery actions and credit default listing
- prioritise clear communications with customers about the availability of retailer and other support.

The AER's Statement of Expectations evolved as we moved through the COVID-19 pandemic, with updates released in August and November 2020 and in April 2021. Recent updates have focused on retailers transitioning customers from temporary support to formal payment plans and hardship programs. The Statement of Expectations will expire on 30 June 2021.

To support retailers as they provide payment assistance to customers, a new rule in August 2020 allowed energy retailers to defer payment of network charges for up to 6 months if they related to customers affected by the COVID-19 pandemic. The rule remained in place until February 2021. The rule built on voluntary support measures introduced by some network businesses.

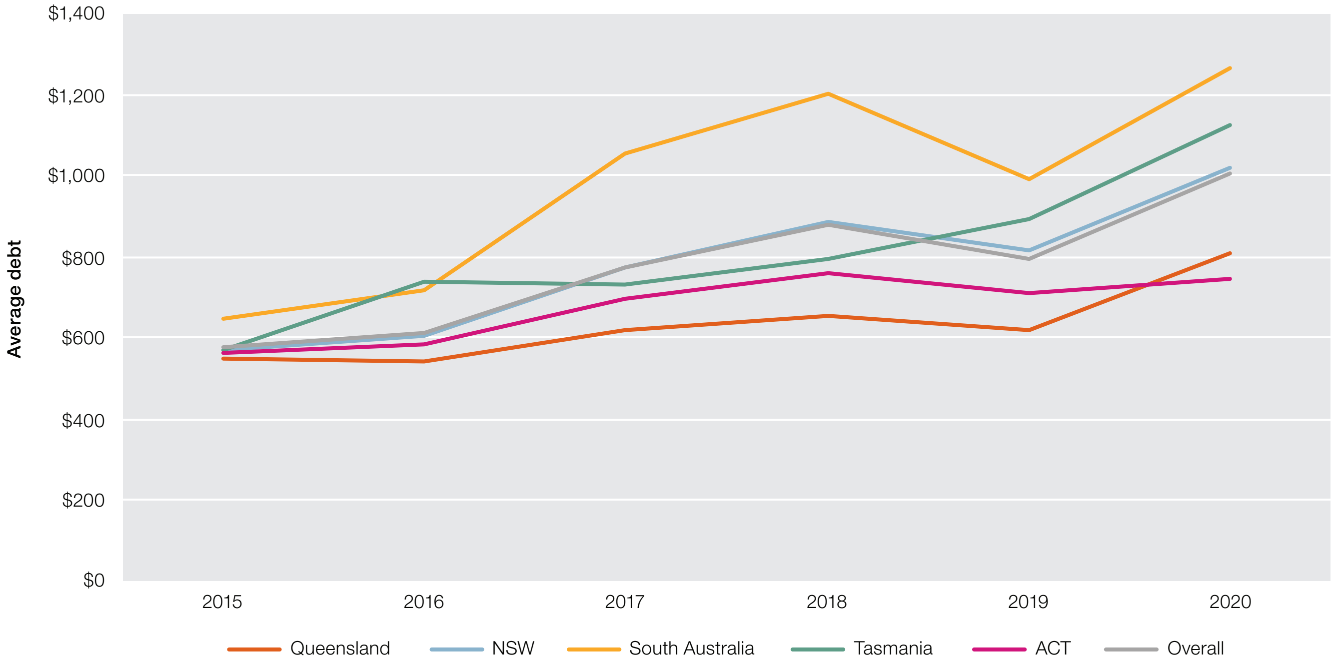
Several state and territory governments also introduced COVID-19 support packages for households. In Queensland, for example, households received a $200 utility payment to assist with their electricity and water bills. In the ACT, holders of a utilities concession received a $200 rebate on their electricity bill. The Tasmanian Government capped price increases in energy bills for 12 months.

Figure 6.15 Residential customers in energy debt



Note: Based on customers with an amount owing to a retailer that has been outstanding for 90 days or more, at 30 December 2020.
Source: AER, *Retail markets quarterly, Q2 2020–21*, April 2021.

Figure 6.16 Average energy debt of residential customers



Note: Average debt of residential customers with an amount owing to a retailer that has been outstanding for 90 days or more, at 30 December 2020.
Source: AER, *Retail markets quarterly, Q2 2020–21*, April 2021.

Payment plans

Payment plans allow settlement of overdue amounts in periodic instalments. They are typically the first assistance offered to customers showing signs of payment difficulties. The AER's Sustainable Payment Plans Framework guides retailers on negotiating affordable payment plans with customers needing assistance to manage debt.[61]

The framework sets out good practice principles of engagement based on trust, respect and empathy to promote constructive, long term customer relationships. The framework has been adopted by retailers that account for around 90% of small customers. The total number of customers on payment plans at December 2020 was around 18% higher than the previous year, despite retailers also offering other types of COVID-19 support.

Customers who fulfil the terms of their payment plan agreement – such as making all repayments under their plan and repaying outstanding debt – are considered to have successfully completed their plan. In 2020 the proportion of payment plans successfully completed increased compared to 2019 for both electricity customers (47% successfully completed, up from 38%) and gas customers (48% successfully completed, up from 32%).

Hardship programs

Referral to a hardship program may be warranted for customers facing payment difficulties. The Retail Law requires energy retailers in Queensland, NSW, South Australia, the ACT and Tasmania to develop and maintain a customer hardship policy that underpins how they identify and assist customers facing difficulty paying their energy bills. The AER's Customer Hardship Policy Guideline requires retailers to ensure their programs are easily accessible and include a standard statement explaining how they will help customers. It puts greater onus on retailers to identify who may need assistance.[62]

Assistance under a retailer's hardship program can include:

- extensions of time to pay a bill, and tailored payment options
- advice on government concessions and rebate programs
- referral to financial counselling services
- a review of a customer's energy contract to ensure it suits their needs
- energy efficiency advice, such as an energy audit and help to replace appliances, to help reduce a customer's bills
- a waiver of any late payment fees.

Customers can enter hardship programs by initiating entry themselves (60–70% of customers), being identified by their retailer (20–30%) or by referral by financial advisers or other agents (around 1%).

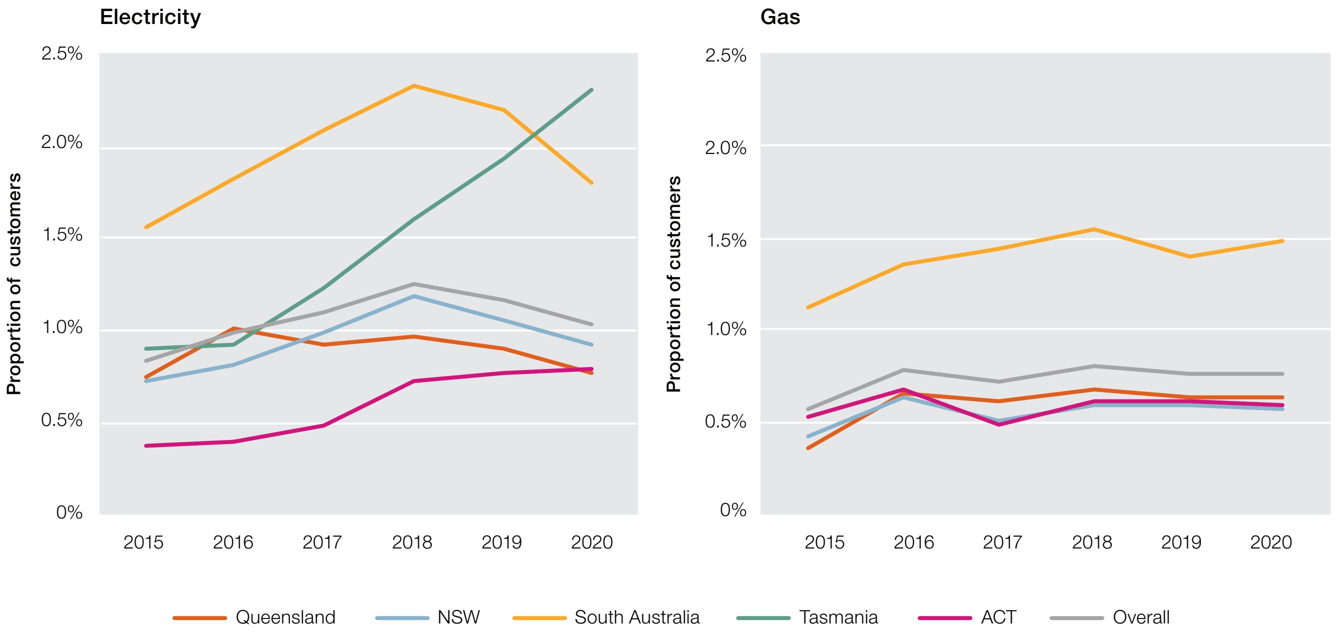
The average proportion of residential electricity customers on hardship programs decreased in 2020 in Queensland, NSW and South Australia, with the proportion at December 2020 being the lowest since 2016 (figure 6.17). Tasmania had a record high number of customers on hardship programs, surpassing South Australia as the region with the highest proportion of residential electricity customers on hardship programs (2.3% of electricity customers at December 2020). The ACT had a slight increase in the proportion of electricity customers on hardship programs in 2020, but its rate remains among the lowest across the regions.

Gas hardship customer numbers remained fairly stable over 2020. South Australia had the highest proportion of customers on a gas hardship program at December 2020 (1.5%). Around 0.6% of customers in other regions were on a gas hardship program.

61 AER, *Sustainable payment plans, a good practice framework for assessing customers' capacity to pay, Version 1*, July 2016.

62 AER, 'Hardship protections a right not a privilege' [media release], 29 March 2019.

Figure 6.17 Proportion of small customers on a hardship program



Source: AER, *Retail markets quarterly, Q2 2020–21*, April 2021.

Customers on hardship programs must typically make payments to cover any outstanding debt and ongoing energy costs. But retailers may allow a customer to make payments that are less than their ongoing costs (or do not take into account arrears), based on the customer's capacity to pay.

In December 2020 the hardship debt of electricity customers reached record levels, averaging $1,584. This was the second year of large debt increases, with 2020 debt levels 58% higher than debt levels at December 2018 (figure 6.18). Gas debt levels also increased over the past 2 years, rising 42% to an average $745.

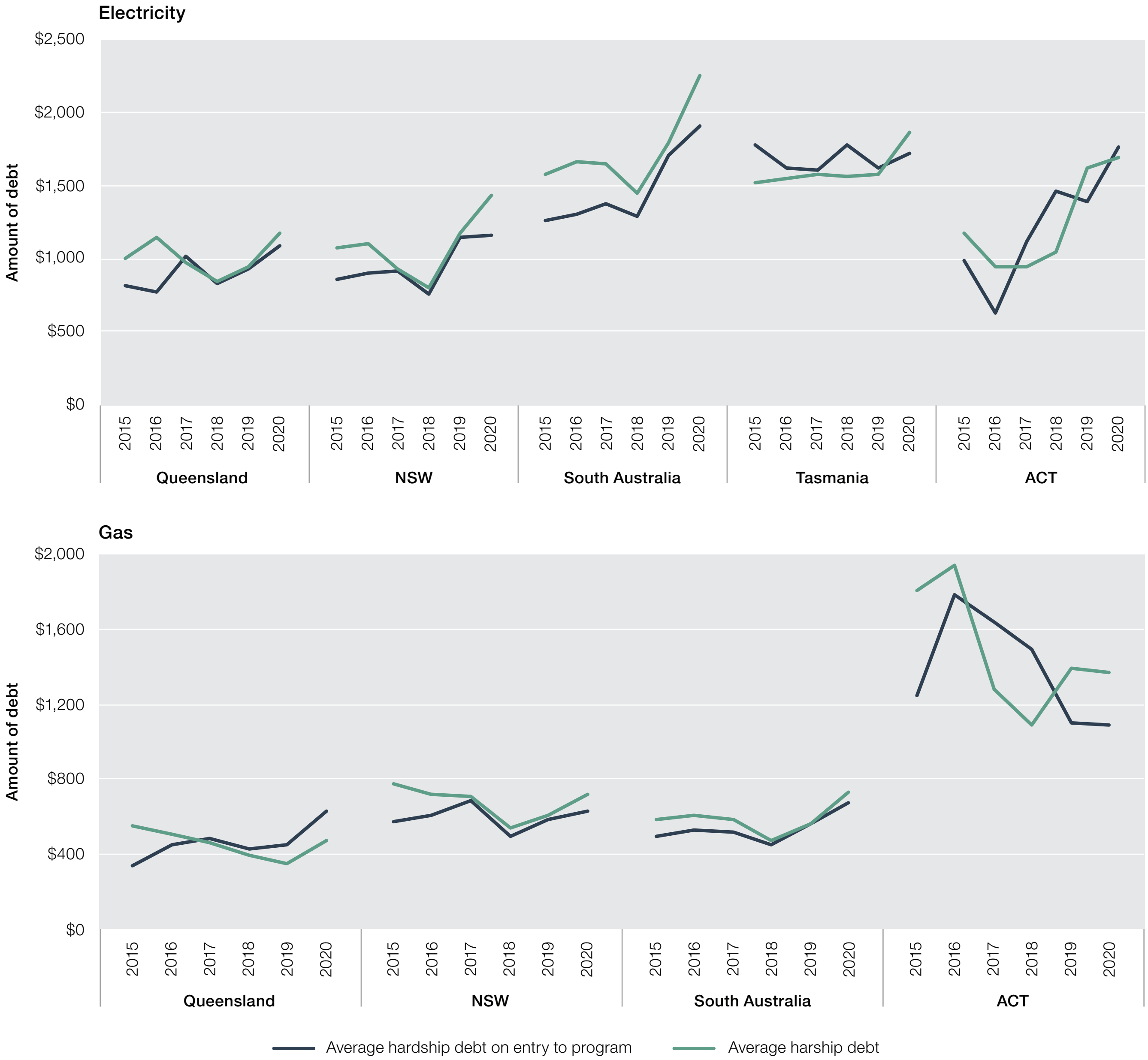
Average debt of customers on entry to hardship programs also increased over the past 2 years. Electricity debt on entry increased by 42% to $1,357, and gas debt on entry increased by 30% to $669. Average debt on entry to hardship programs is lower than average hardship debt in all regions except the ACT (for electricity) and Queensland (for gas). This indicates that, once customers are on a hardship program, on average they tend to accumulate more energy debt, which may become entrenched. Around 42% of electricity customers on hardship payment plans and 36% of gas customers were unable to meet their ongoing usage charges at December 2020.

Average electricity hardship debt and debt on entry to hardship programs was highest in South Australia and lowest in Queensland. Average gas hardship debt and debt on entry in 2020 was significantly higher in the ACT than elsewhere, likely due to the high consumption of gas in the region.

The number of customers exiting hardship programs by paying off their debt is a useful indicator of programs' success. Successful completion of hardship agreements increased from 31% in 2019 to 35% in 2020 after almost doubling between 2018 and 2019. The rate remains low, however, indicating many hardship customers may not be receiving the assistance they require. Of customers who exited hardship programs in 2020, 57% did not successfully meet their payment arrangement. Around 9% of hardship customers exited a program because they transferred to another retailer. Victoria operates its own state-based hardship program. In 2019 it introduced new minimum standards of assistance for customers who anticipate or face payment difficulties.[63]

63 ESC, *Amendments to the Energy Retail Code: payment difficulties*, October 2017.

Figure 6.18 Average debt at time of entry to hardship programs and average hardship debt of small customers



Source: AER, *Retail markets quarterly, Q2 2020–21*, April 2021.

6.7.3 Disconnecting customers for non-payment

Energy retailers are required to help customers in financial hardship before considering whether to disconnect them for non-payment of a bill. Disconnection for non-payment of bills should be viewed as a last resort after payment plans and hardship programs have been attempted and only after the strict processes set out in the Retail Rules have been followed.

Disconnection is not permitted in certain circumstances – such as when a customer's premises are registered as requiring life support equipment, a customer on a hardship program is meeting their payment obligations, or a customer's debt is below $300.

In April 2020 the AER released a Statement of Expectations in response to the COVID-19 pandemic, which included the expectation that retailers do not disconnect any small customer (residential or small business) who 'may be in financial distress'. This restriction was relaxed from August 2020, with retailers allowed to recommence disconnections for those customers who fail to engage with the retailer. Similar restrictions were introduced in Victoria.

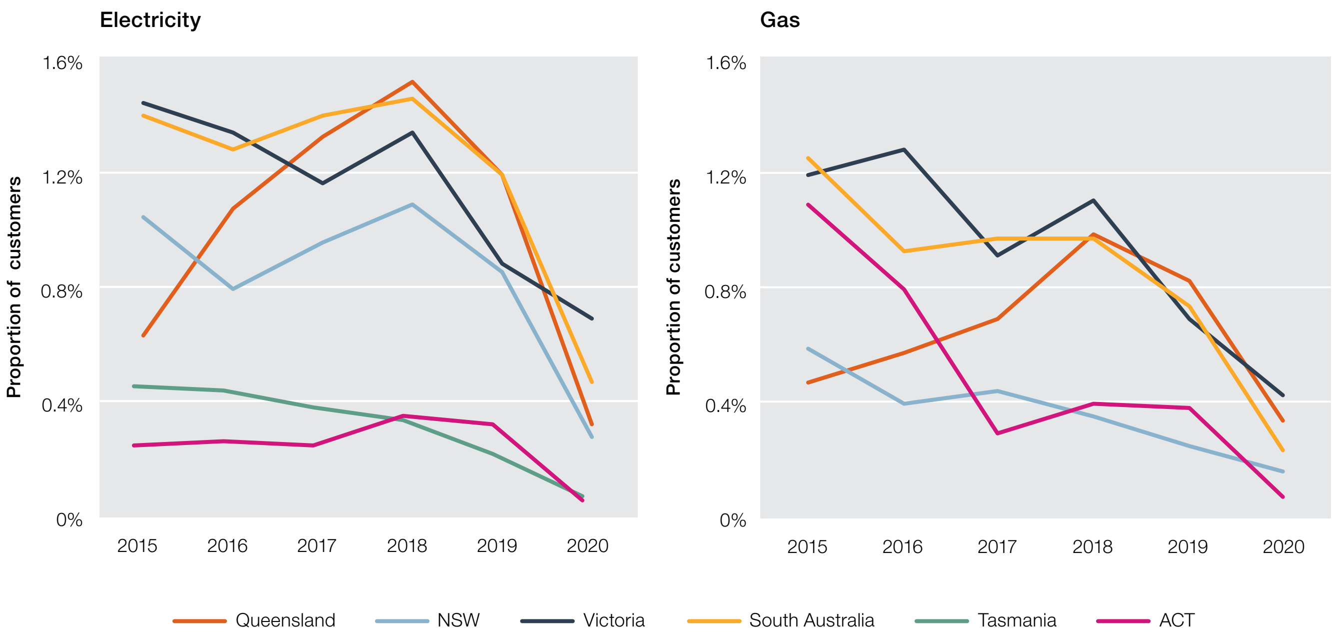
Restrictions on disconnections for much of 2020 resulted in a significant reduction in the proportion of customers disconnected compared with 2019.

South Australia had the highest rate of disconnections of residential electricity customers in 2020, at around 0.5% of customers. Around 0.3% of customers in Queensland and NSW, and less than 0.1% of customers in the ACT and Tasmania, were disconnected (figure 6.19). Disconnection rates presented for Victoria are not comparable with the other regions, as they relate to 2019–20.

Gas customer disconnection rates were around half the level of electricity in NSW and South Australia but similar in Queensland and the ACT.

Almost half of residential customers disconnected in 2020 had outstanding energy debts of between $500 and $1,500. Around 25% of residential electricity customers and 32% of gas customers disconnected had debts of less than $500. Of those residential customers disconnected in 2020, around 16% of electricity customers and 11% of gas customers had been disconnected on another occasion in the previous 24 months.

Figure 6.19 Disconnection of residential customers for failure to pay amount due



Note: Based on customers with an amount owing to a retailer that has been outstanding for 90 days or more, at 30 December 2020 for all states except Victoria, which is at June 2020.

Source: AER, *Retail markets quarterly, Q2 2020–21*, April 2021; ESC, *Victorian energy market report 2019–20*, December 2020.

6.8 Customer complaints

Customer complaints can cover issues including billing discrepancies, wrongful disconnections, the timeliness of transferring a customer to another retailer, supply disruptions, credit arrangements and marketing practices.

Customers can lodge a complaint directly with their retailer in the first instance. If a customer is unable to resolve an issue with their retailer, they can then take the complaint to the jurisdictional energy ombudsman scheme, which offers free and independent dispute resolution.

Some customer complaints relate to issues outside the retailer's control – complaints about price rises due to wholesale and network costs, for example. For this reason, the number of electricity complaints to ombudsman schemes can be a more meaningful measure of retailer performance than the number of complaints received by retailers. Retailers with effective customer service generally resolve complaints without the need for escalation to energy ombudsman schemes.

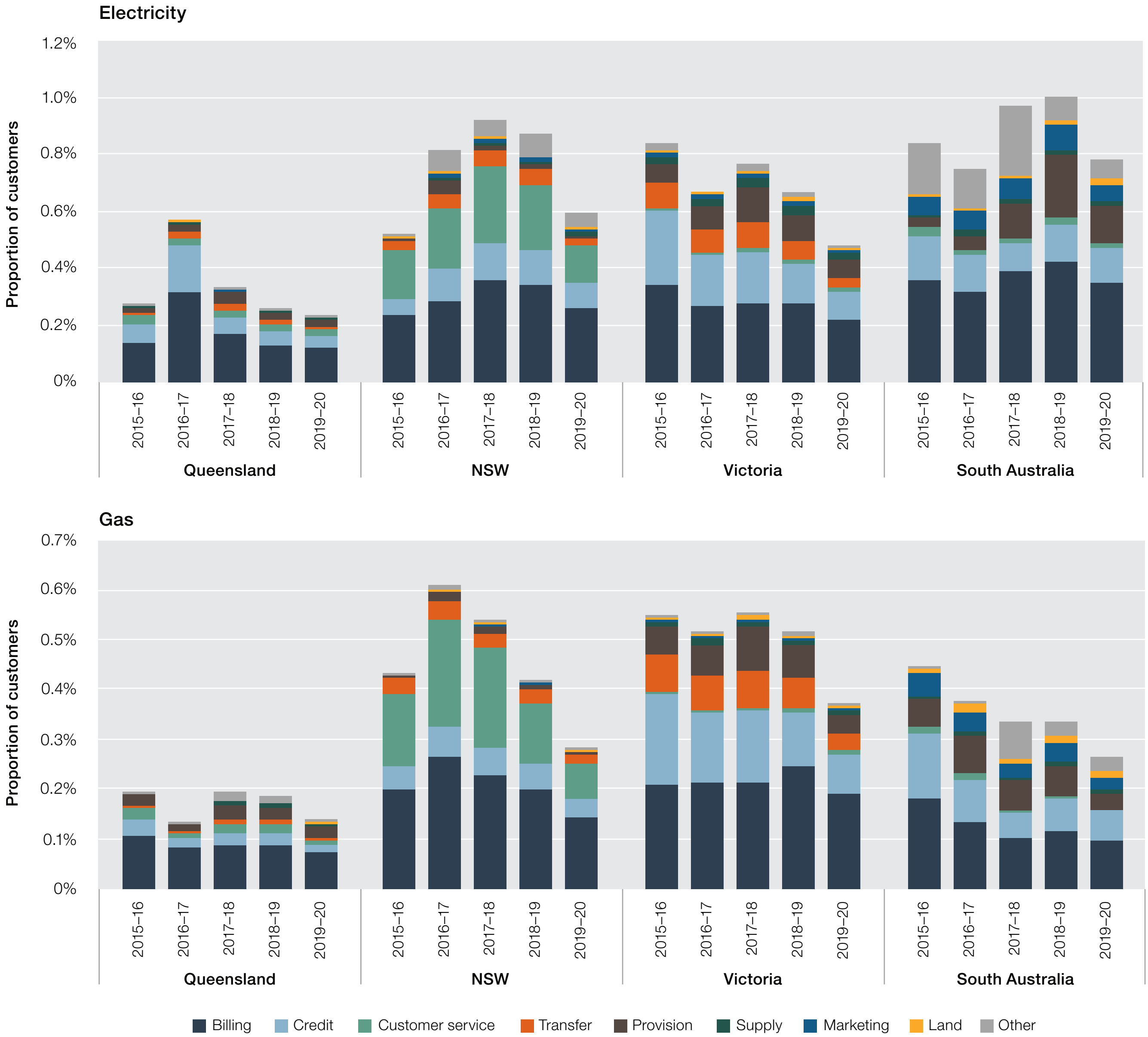
The number of electricity and gas complaints to ombudsman schemes fell in all regions in 2019–20, down 26% on the previous year (figure 6.20).

Complaints levels decreased most markedly following the introduction of stronger consumer protections in response to the COVID-19 pandemic. In particular, the AER's Statement of Expectations (and the equivalent Victorian response) prevented disconnection, debt collection and credit default listing for customers experiencing financial stress. The introduction of the AER's revised Customer Hardship Policy Guideline in October 2019 likely also contributed to a decrease in complaint numbers.

Electricity complaint rates are typically lower in Queensland than in other regions, at 0.23% of Queensland customers in 2018–19 (compared with between 0.48% and 0.77% of customers elsewhere). Gas complaints to ombudsman schemes are generally lower than for electricity. Victoria had the highest complaint rates, at around 0.38% of customers in 2019–20.

Billing concerns generate the largest number of complaints, constituting over 45% of complaints in 2019–20. Unexpectedly high bills are the primary billing issue. Other billing issues include errors, incorrect tariff, estimation of energy use, fees and charges, and backbilling. Credit issues – including the disconnection of customers following non-payment; and the collection of outstanding charges – accounted for another 17% of complaints. Retailers' customer service was another prominent issue (accounting for less than 10% of complaints in most regions but over 22% in NSW).

Figure 6.20 Complaints to ombudsman schemes



Note: Data includes all cases recorded by ombudsman schemes for electricity and gas industries. This includes enquiries and complaints in relation to energy retailers, distribution networks and embedded network operators. 'Other' captures issues including general enquiries, metering and privacy complaints.

Source: Annual reports by ombudsman schemes in Queensland, NSW, Victoria and South Australia.

6.9 Enforcement action in retail markets

The AER's enforcement activity in retail markets recently targeted areas including behaviour towards customers in vulnerable circumstances. Additionally, the ACCC has taken enforcement action against retailers under the Australian Consumer Law, with a focus on marketing practices. In Victoria, the ESC is responsible for enforcement action.

6.9.1 Customers in vulnerable circumstances

The AER's compliance and enforcement priorities include ensuring retailers maintain protections for customers using life support equipment and provide appropriate assistance to customers experiencing payment difficulties.

Following enforcement action initiated by the AER, in November 2020 the Federal Court found that EnergyAustralia had breached provisions relating to customers experiencing payment difficulties. The Federal Court found that, for 8 customers between 2016 and 2018, EnergyAustralia:

- failed to maintain and implement its hardship policy
- failed to provide customers the opportunity to enter into appropriate payment plans
- failed to offer and apply payment plans that had regard to the customer's capacity to pay
- failed to inform customers of EnergyAustralia's hardship policy, and/or
- wrongfully disconnected the customers.

The Federal Court ordered by consent that EnergyAustralia pay penalties of $1.5 million and maintain a compliance program for 3 years.[64]

In November 2020 AGL Energy paid penalties totalling $100,000 for allegedly disconnecting customers who were experiencing payment difficulties, without first offering the customers' payment plans. The AER also required AGL Energy to undertake an independent audit of how it treats its customers in financial difficulty.[65]

In November 2020 Origin Energy paid penalties totalling $120,000 for allegedly wrongfully disconnecting residential customers. Origin Energy initiated the disconnection of 6 customers with outstanding debts. Due to a system error, Origin Energy failed to cancel the disconnection process after the customers paid all amounts owing.[66]

In April 2020 the AER commenced legal proceedings against EnergyAustralia for allegedly failing to comply with life support requirements. The AER alleges that, from February 2018, for a significant number of customers, EnergyAustralia failed to:

- register customers that required life support equipment
- advise the distributor that customers required life support equipment
- provide timely information to life support customers
- keep the registration details of its customers up to date.[67]

The AER also alleges EnergyAustralia failed to establish policies, systems and procedures for registering a premises as requiring life support equipment and did not meet commitments it gave in an undertaking to the AER in August 2019. These commitments included registering customers requiring life support and reviewing customer phone calls within a prescribed timeframe.

In June 2020 Momentum Energy paid penalties totalling $100,000 following the issue of 5 infringement notices by the AER. Momentum Energy allegedly incorrectly removed customers requiring life support equipment from its life support register.[68]

64 AER, 'EnergyAustralia penalised $1.5m for failing to protect hardship customers' [media release], 6 November 2020.

65 AER, 'AGL pay penalties and audited for alleged wrongful disconnection of vulnerable customers' [media release], 4 November 2020.

66 AER, 'AER takes action to protect against wrongful disconnections' [media release], 12 November 2020.

67 AER, 'EnergyAustralia in court for alleged failure to comply with customer life support obligations' [media release], 9 April 2020.

68 AER 'Momentum Energy pays penalties for alleged life support breaches' [media release], 11 June 2020.

In November 2020 Alinta Energy paid penalties totalling $200,000 following the issue of 10 infringement notices by the AER. Alinta Energy admitted that on more than 1,500 occasions it breached requirements around the registration of life support customers. These requirements include registering customers' premises as requiring life support equipment and notifying the energy distributor. The AER accepted a court enforceable undertaking from Alinta Energy for the implementation and independent audit of a compliance improvement action plan.

In Victoria, the ESC took action against Alinta Energy in February 2020 for allegedly requiring customers to provide financial information before they could access payment plans. Alinta Energy paid penalties of $1.125 million.[69]

6.9.2 Marketing

The Retail Law's marketing provisions protect customers by requiring retailers to obtain the customer's explicit informed consent before signing them up to a new energy contract.

The ESC enforces similar provisions in Victoria. The Australian Consumer Law (enforced by the ACCC) also protects customers from improper sales or marketing conduct relating to unsolicited sales, misleading and deceptive conduct, and unconscionable conduct.

The ACCC monitors how businesses notify customers of price changes, and promote discounts and savings under their energy offers, following concerns that consumers may be misled.

In July 2020 Locality Planning Energy paid a penalty of $10,500 for an alleged contravention of the Electricity Retail Code. The ACCC alleged that Locality Planning Energy published an offer on its website that failed to include required information, including a comparison to the reference price, the total amount an average customer would pay, the distribution region and the type of small customer to which the offer applied. This was the ACCC's first enforcement action for a breach of the Electricity Retail Code.

In August 2020 the ACCC instituted proceedings in the Federal Court against Sumo Power for false or misleading representations in relation to its electricity plans. The ACCC alleged Sumo Power promoted electricity plans with low rates and high discounts and represented that it would maintain, or not materially change, prices in these plans for 12 months. But Sumo Power planned to substantially increase the prices charged to those consumers who signed up within a few months, or knew it was likely to do so.[70]

In October 2020 the ACCC finalised proceedings in the Federal Court against iSelect – a privately operated energy price comparison service – for misleading or deceptive conduct and false or misleading representations. iSelect did not compare all available plans from its partner retailers and did not necessarily recommend the most competitive plan, despite claims it would do so on its website. The Federal Court ordered iSelect to pay penalties of $8.5 million.[71]

In December 2020 Origin Energy paid a penalty of $126,000 after the ACCC issued it with an infringement notice. Origin Energy allegedly made a false or misleading representation in a price increase letter sent to residential electricity customers in Victoria.[72]

In December 2020 1st Energy agreed to a court enforceable undertaking in relation to representations made to consumers in Tasmania during unsolicited telemarketing calls. 1st Energy admitted that sales representatives made several representations that were likely to be false or misleading. 1st Energy undertook to contact affected customers and help them exit their contracts, if they wish, without charge. The company will also update its compliance program, staff training and complaints handling system.[73] In Victoria, the ESC took action against Alinta Energy and amaysim in 2020 for transferring customers onto contracts without their consent. The businesses paid penalties of $280,000 and $600,000 respectively.[74]

69 ESC, 'Alinta Energy pays more than $1 million for putting hurdles in way of help' [media release], 4 February 2021.

70 ACCC, 'Sumo Power allegedly misled consumers about electricity pricing' [media release], 5 August 2020.

71 ACCC, 'iSelect to pay $8.5 million for misleading consumers comparing energy plans' [media release], 8 October 2020.

72 ACCC, 'Origin Energy pays penalty for allegedly misleading electricity customers' [media release], 22 December 2020.

73 ACCC, '1st Energy admits it likely misled Tasmanian consumers' [media release], 21 December 2020.

74 ESC, 'Alinta Energy penalised for second time in two years' [media release], 17 March 2020; ESC, 'Amaysim Energy pays $600,000 for alleged sales agent fraud' [media release], 20 April 2020.

6.9.3 Other compliance action

The AER took other compliance action against retailers for alleged breaches of the Retail Law and National Electricity Rules:

- In November 2020 the Federal Court found that AGL Energy failed to submit timely and accurate retail market performance data. The Federal Court ordered AGL Energy to pay penalties totalling $1.3 million.[75]
- In January 2021 AGL Energy paid 8 infringement notices (totalling $160,000) for allegedly failing to promptly appoint metering coordinators to fix customers' faulty meters.[76]

The AER also required retailers EnergyAustralia, Red Energy, 1st Energy and M2 Energy to conduct compliance audits related to performance reporting obligations.

In Victoria the ESC took action against Alinta Energy in August 2020 for allegedly failing to follow the required steps in seeking to recover undercharged amounts from customers. AGL Energy paid penalties totalling $450,000.

In Queensland in November 2020 the Queensland Competition Authority required AGL Energy to reimburse late payment fees it incorrectly charged to more than 24,000 electricity customers between 2015 and 2020.[77]

75 AER, 'AGL to pay $1.3 million penalty for failing to provide performance data on time' [media release], 13 November 2020.

76 AER, 'AER takes action against AGL for not promptly fixing customers' meters' [media release], 19 January 2021.

77 QCA, 'ALG to reimburse customers for late payment charges' [media release], 5 November 2020.

Abbreviations

1P	proven (gas reserves)
2P	proved plus probable (gas reserves)
3P	at least 10 per cent probability of being commercially recoverable (gas reserves)
5MS	5-minute settlement
ABS	Australian Bureau of Statistics
ACCC	Australian Competition and Consumer Commission
ACT	Australian Capital Territory
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AFMA	Australian Financial Markets Association
AGN	Australian Gas Networks
APLNG	Australian Pacific LNG
ARENA	Australian Renewable Energy Agency
ASX	Australian Securities Exchange
BESS	battery energy storage system
C&I	commercial and industrial
CBA	cost–benefit analysis
CBD	central business district
CCGT	combined cycle gas turbine
CCP	Consumer Challenge Panel
CEFC	Clean Energy Finance Corporation
CESS	capital expenditure sharing scheme
CoAG	Council of Australian Governments
COVID-19	coronavirus disease 2019
CPI	consumer price index
CSG	coal seam gas
CSIRO	Commonwealth Scientific and Industrial Research Organisation
CSIS	customer service incentive scheme
DEIP	Distributed Energy Integration Program
DER	distributed energy resources

DMIA	demand management innovation allowance
DMIS	demand management incentive scheme
DMO	default market offer
EBSS	efficiency benefit sharing scheme
ECA	Energy Consumers Australia
ENA	Energy Networks Australia
EOI	expression of interest
ESB	Energy Security Board
ESC	Essential Services Commission
EV	electric vehicle
FEX	FEX Global
FCAS	frequency control ancillary services
GAP	Gas Acceleration Program
GJ	gigajoule
GLNG	Gladstone LNG
GSL	guaranteed service level
GST	goods and services tax
GW	gigawatt
GWh	gigawatt hour
Hz	Hertz
HHI	Herfindahl–Hirschman index
ICT	information and communication technology
IRENA	International Renewable Energy Agency
ISDA	International Swaps and Derivatives Association
ISP	integrated system plan
km	kilometre
kW	kilowatt
kWh	kilowatt hour
LCOE	levelised cost of electricity
LNG	liquefied natural gas
MAIFI	momentary average interruption frequency index
MJ	megajoule
MOS	market operator services
MLF	marginal loss factor
MLO	market liquidity obligation
$MtCO_2$-e	million metric tonnes of carbon dioxide equivalent
mtpa	million tonnes per annum
MW	megawatt
MWh	megawatt hour
NEM	National Electricity Market
NSW	New South Wales

NT	Northern Territory
OCGT	open cycle gas turbine
OTC	over-the-counter
PJ	petajoule
PST	pivotal supplier test
PV	photovoltaic
QCLNG	Queensland Curtis LNG
RAB	regulatory asset base
RERT	reliability and emergency reserve trader
RET	Renewable Energy Target
REZ	renewable energy zone
Retail Law	National Energy Retail Law
RIN	regulatory information notice
RIT	regulatory investment test
RIT–D	regulatory investment test – distribution
RIT–T	regulatory investment test – transmission
RRI	Rate of Return Instrument
RRO	Retailer Reliability Obligation
SAPS	stand-alone power systems
SAIDI	system average interruption duration index
SAIFI	system average interruption frequency index
STPIS	service target performance incentive scheme
STTM	short term trading market
TJ	terajoule
TJ/d	terajoules per day
TW	terawatt
TWh	terawatt hour
UNGI	Underwriting New Generation Investment program
VPP	virtual power plants
WACC	weighted average cost of capital