State of the energy market 2022

AUSTRALIAN ENERGY REGULATOR

Australian Government

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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, energy retail markets and consumer experiences.

For the first time, we are publishing this report alongside the Energy Security Board's (ESB) annual report on the Health of the NEM. The Health of the NEM is the ESB's evaluation on how the NEM is performing against the objectives set by energy ministers in the Strategic Energy Plan. The State of the energy market focuses on the past year and provides in-depth analysis of recent outcomes, which the Health of the NEM report draws on. In combination, the reports should help readers to understand the market as it is now and the challenges we face as our energy markets transition.

As we release this report, we are concerned that energy is becoming less affordable for consumers. During 2022 wholesale markets have surged to record high prices. This was reflected in increases across all customer types in all regions in our decision on the Default Market Offer for 2022–23, released in May.

Depending on the extent and duration of these pressures, we are likely to see fewer and more expensive retail offers available to consumers. In that environment, it is more important than ever that shopping around is as simple as possible.

Our Energy Made Easy website offers free, impartial price comparisons for energy consumers. It was accessed by almost 2 million users over the past year in more than 4.9 million sessions.

Importantly, not all consumers will have the same opportunities to manage energy costs and those opportunities may not be enough. Some consumers will experience periods of vulnerability as they grapple with increasing energy bills in an environment of high inflation following years of subdued wage growth.

The AER recognises the need to respond to these issues across our work.

We are supporting consumers to make more confident decisions by implementing the Better Bills Guideline and improving our Energy Made Easy website, so that consumers can find and switch to a better plan more easily. We are also working with stakeholders on a sector-wide, 'game changing' reform initiative to address consumer vulnerability in the energy sector more broadly. These actions, and others, will be outlined in more detail in our first ever consumer vulnerability strategy, scheduled for release in October.

Our compliance and enforcement work is a central part of our role. Each year it is guided by a set of priorities which, over the past year, included the effective identification of residential consumers in payment difficulty and the offering of payment plans reflecting consumers' capacity to pay. This remains a priority for the forthcoming year.

Our work has been supported by the Federal Court, which ordered a record $35 million in civil penalties under national energy laws in 2021–22. This is an almost ten-fold increase on the next highest year and reflects the culmination of several longstanding processes. In addition to these penalties, we accepted 4 enforceable undertakings and agreed to an administrative resolution of a 'hardship' investigation, which saw an energy retailer waive $1 million of customer debt.

In 2020–21 consumers on average spent less on the network component of their bills, continuing a recent trend of reductions. In coming years, we expect upward pressure on network costs as inflation and rising costs of capital combine with significant upcoming network investments.

We are committed to making network determinations that reflect the input of consumers and support efficient investments in the future of energy networks, but do so at the least possible costs to consumers. Through work such as our Better Resets Handbook, our review of incentive schemes and our imminent completion of the second binding rate of return instrument, we are improving the tools we use to regulate networks.

In August 2022, energy ministers established the National Energy Transformation Partnership. This is a major development in the energy sector. The first act under the Partnership will be to include an emissions objective in the rules and laws governing the market and our work. This reiterates the vital connection between Australia's energy markets and its journey towards decarbonisation.

We also see this journey happening in the everyday lives of consumers, with more households than ever installing solar PV on rooftops and consumer energy resources (CER) accounting for 8% of demand in the NEM – the highest ever proportion.

I recommend the *State of the energy market 2022* 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
September 2022

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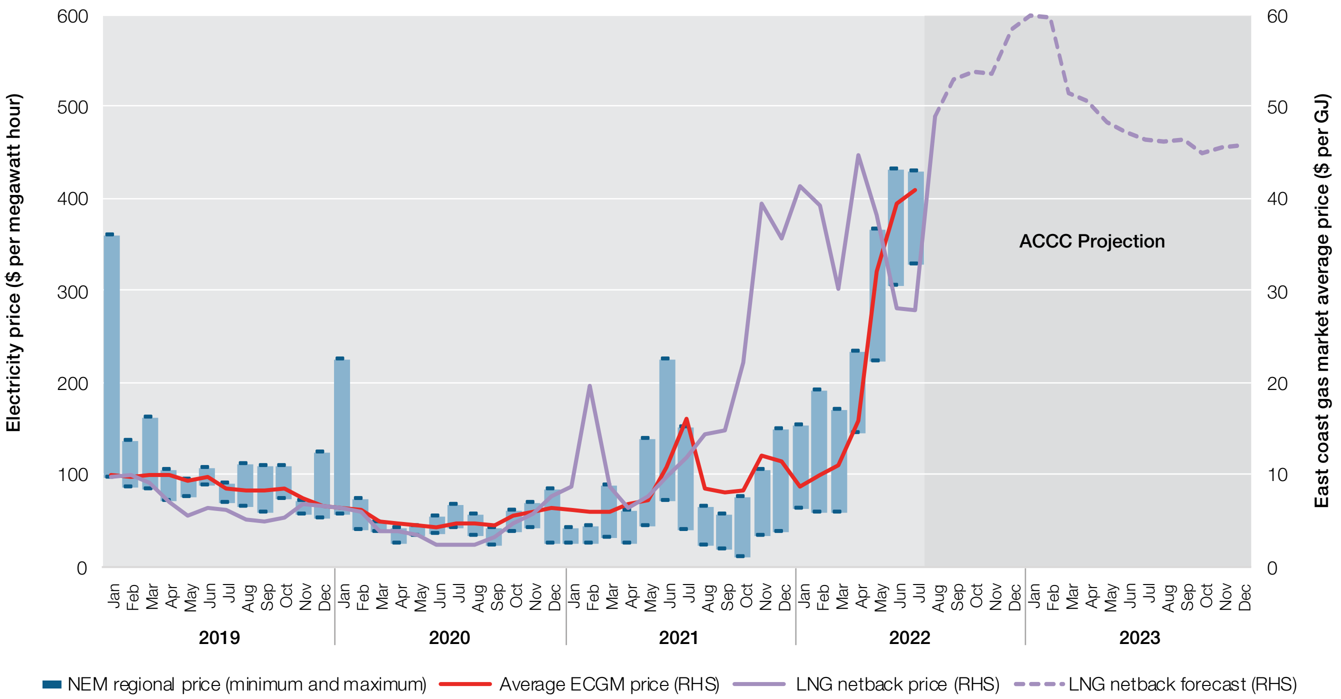
Image source: Shutterstock.

1 Market overview

Australia's energy markets are undergoing a profound transformation. The National Electricity Market (NEM) is moving from a centralised system of large fossil fuel (coal and gas) generation towards an array of smaller scale, widely dispersed wind and solar generators, hydroelectric generation, grid-scale batteries and demand response. We have observed over the last 12 months that the transition continues to accelerate.

Electricity and gas wholesale market prices were relatively low at the start of 2021 but have since surged to record and persistent highs, driven by a perfect storm of supply-side constraints. At the peak of recent market turbulence, the Australian Energy Market Operator (AEMO) simultaneously suspended all mainland regions of the NEM for the first time ever. In parallel, it invoked the Gas Supply Guarantee for the first 2 instances ever. Electricity contract markets alongside coal and LNG netback projections suggest those high prices will persist over at least the next 2 years.

Figure 1.1 Wholesale electricity prices, east coast and international gas market prices



Note: The range between the minimum and maximum NEM regional price shows the range of average monthly volume weighted wholesale electricity prices across the NEM regions. A large column illustrates a large variation between regions, while a short column highlights that prices are relatively similar across regions. NEM prices reflect the administered price caps on prices (limiting prices to $300 per megawatt hour) from 15 to 24th June. Average ECGM price is the average monthly east coast gas market price. The prices in May onwards include periods of price setting and administered price caps.

Source: AER analysis using NEM data and gas data.

Network price pressures have remained low in recent years and continued to be low in 2021–22. However, upward pressures are expected. Network costs are updated annually for consumer price index (CPI), and recent high CPI outcomes will contribute to increasing network costs throughout 2023 and likely into 2024. Recent low costs of capital also appear to be increasing. These are the costs networks face to raise equity and debt capital for investment and are a major driver of network costs to consumers.

Consumers are not well-placed to absorb the higher retail prices that will flow from increased costs. Retailers typically update their offers in July, and the impact of updated offers will begin to impact consumers over the months until October depending on the length of their billing cycles. Slow wage growth compared with the growth of energy costs means that the number of consumers facing energy debt and the levels of that debt were increasing even before the current market events.

The AER is concerned about the impact of these market developments on consumers experiencing vulnerability. Later in 2022 we will publish a strategy to better address the needs of consumers experiencing vulnerability. This will include actions to reduce barriers to participation, support consumers experiencing payment difficulty, ensure consumer voices are heard in market reforms and improve affordability by reducing the cost to serve energy consumers.

1.1 National Electricity Market (Chapter 2)

In 2022 overlapping factors combined to put extreme upward pressure on prices in the NEM. These included multiple supply-side problems experienced by generators – coal plant outages, coal supply issues, domestic gas supply shortfalls and hydro generating constraints. These supply-side constraints increased the NEM's reliance on gas and hydroelectric generation at a time of record high gas prices and when hydroelectric generators were also facing environmental constraints. High international coal and gas prices put pressure on domestic fuel costs, amplifying the impacts of generators being required to source additional fuel through spot markets.

At the start of 2021 prices were low in all regions due to an abundance of cheap renewable generation and mild summer conditions. Nevertheless, supply-demand conditions were tight and the explosion at the Callide C power station in May 2021 was sufficient to lift prices in all regions. Queensland and NSW saw the largest price increases, because they also faced network outages that restricted access to lower priced imports from neighbouring regions.

Wholesale prices remained high for the remainder of 2021, as international pressures added to existing domestic pressures. The war in Ukraine exacerbated pressures caused by the global energy crisis in Europe and China. International fuel prices rose to unprecedented levels and Australian coal and gas was worth more in export than in domestic markets.

Many other factors combined from May 2022 onwards to drive record wholesale electricity prices.

Coal-fired generation in Australia experienced high levels of coal plant outages as well as coal supply and transport problems. Heavy rain impacted open cut mines in NSW and Queensland, geological issues reduced output from others and some generators needed to manage low stockpiles.

Winter 2022 was early and cold, which increased demand for heating. Reduced coal-fired output meant the NEM was reliant on very expensive gas generation to meet daily energy needs, despite gas price increases. The unanticipated increase in gas demand put upward pressure on gas prices at the same time as local gas markets were being used to cover short-term spot exposure over the higher demand winter period. LNG exporters in Queensland were exporting near record volumes for the April to June quarter, and flows of domestic gas were primarily being transported from south to north until June.

Generators exposed to higher coal and gas prices offered capacity at higher prices to cover costs. Some generators buying coal on the spot market reported they needed a price of more than $300 per megawatt hour (MWh) to break even. Gas generators buying fuel on the spot market needed around $400 per MWh.

Sustained high prices in the wholesale electricity markets in June triggered a protective price cap of $300 per MWh in every mainland region for the first time ever. The price cap, combined with high fuel costs, contributed to a number of generators withdrawing capacity from the market, which resulted in forecast supply shortfalls in Queensland and NSW. To ensure reliable supply, AEMO took the extraordinary step of suspending the spot markets in all regions. It also activated emergency reserves to reduce demand.

While underlying conditions explain these market outcomes to a large degree, the AER is investigating whether bidding behaviour breached any rules and legislation. The AER will also examine whether generator conduct and market outcomes were consistent with an efficient and competitive market serving the long term interest of consumers.

The high and volatile spot prices impacted contract markets. In Queensland and NSW, base futures prices (for Q2 2022) increased six-fold in 12 months. Traded volumes visible through the ASX fell sharply in June and July.

Contract outcomes indicate the market expects that high prices will continue beyond 2022–23. Factors such as persistently high fuel costs, generation closures and gas supply issues will contribute to this.

The NEM generation mix also continued to evolve. Key coal-fired generators announced earlier closure dates and over 4.5 gigawatts of new renewable generation has entered the market since January 2021. New entry included the NEM's largest wind farm, its largest solar farm, largest battery and record levels of rooftop solar.

Growing rooftop solar output continued to carve out demand from the grid in the middle of the day. Record low levels of minimum demand were reported across spring in 2021 and are expected to break more records again this spring. Although middle of the day prices fell during periods of low demand and high solar output, evening peak prices remained high.

Maintaining system security continued to be challenging and costly. Even though the outlook has improved (because of recent rule changes for system strength and frequency and the installation of synchronous condensers in South

Australia), there is still a risk of high frequency control costs. In 2021 Queensland experienced record local frequency control ancillary services (FCAS) costs of $234 million because of extended constraints on the NSW-Queensland interconnector, meaning FCAS had to be sourced from within the state.

Significant market reforms were implemented in 2021. In October 2021, 5-minute settlement was applied to the NEM to provide better price signals to fast response generation such as batteries, gas peaking plants and demand response. Battery capacity in the NEM tripled in 2021 and participants registered demand response capacity for the first time.

A wholesale demand response mechanism was also introduced in October 2021. Demand response allows consumers, either directly or through aggregators, to offer and be rewarded for reducing their load during peak periods. It can also be used to help keep the power system stable. Adoption of demand response in Australia is still limited, but by June 2022 Enel X had registered 60 MW of demand response facilities. These units participated in the market in May and June at times of high prices.

1.2 Gas markets in eastern Australia (Chapter 4)

Domestic prices remained below soaring international prices in late 2021, but events from May 2022 onwards, including unprecedented increases in wholesale electricity prices, pushed domestic spot gas prices above export parity levels. The depletion of local legacy gas fields supplemented by diminishing local gas storage supplies further tightened the supply–demand balance, as a particularly cold start to winter drove increased domestic demand and led to numerous unprecedented market outcomes across both the gas and electricity sectors.

East coast exports increased to record levels from late 2020 and continued to exceed previous records into 2022 as the conflict in Europe put pressure on global gas demand and drove up international oil and gas prices.

Gas prices were capped in the Sydney and Brisbane short-term trading markets following the failure of Weston Energy—a large gas retailer in NSW—with the failure of Weston Energy resulting in a Retailer of Last Resort (RoLR) event. Separately, prices were also capped in the Victorian and Sydney markets when high price thresholds were breached in May and June.

To secure additional gas supplies from gas producers to support gas-powered electricity generation in the NEM, AEMO activated the Gas Supply Guarantee (GSG) in July. The market operator also limited the operations of 2 gas-powered generators in Victoria as low storage levels presented a threat to system security.

High local and international demand for gas resulted in record east coast production levels, with gas flows transporting southern supply towards Queensland despite rising local spot market prices.[1] The increased pressure on sourcing gas supply also resulted in record spot market trade levels[2] and a rebound in trade on the Gas Supply Hub. Record quantities were also won on the day-ahead auction (DAA) to transport gas across the east coast transmission system. This assisted in bringing gas south following activation of the GSG, with activity shifting to change the direction of interregional gas flows from June.

With a lack of new supply coming online in the short term, pipeline expansions should increase supply options to southern markets over winter. AEMO forecasts that these capacity expansions alongside reductions in peak-demand are crucial in mitigating the risks of potential supply shortfalls as early as 2023.[3] As projected output from reserves in the Gippsland Basin decline, the delay in bringing new supply sources online, such as the Port Kembla import terminal in NSW, has left southern markets reliant on northern supply for requirements outside long-term supply arrangements.

In the immediate term, southern markets are facing acute risks from declining gas storage. Victoria has become increasingly reliant on gas storage inventory from Iona. In 2021 east coast storage levels fell to their lowest point since reporting commenced. A similar trend occurred over winter 2022, leading AEMO to issue a notice of a threat to system security due to low storage levels in Victoria.[4] Recent upgrades have improved supply rates, but this has led to storage inventory being drawn down earlier than in previous years. With low storage levels, there is a higher risk of supply being insufficient to meet demand on peak days.

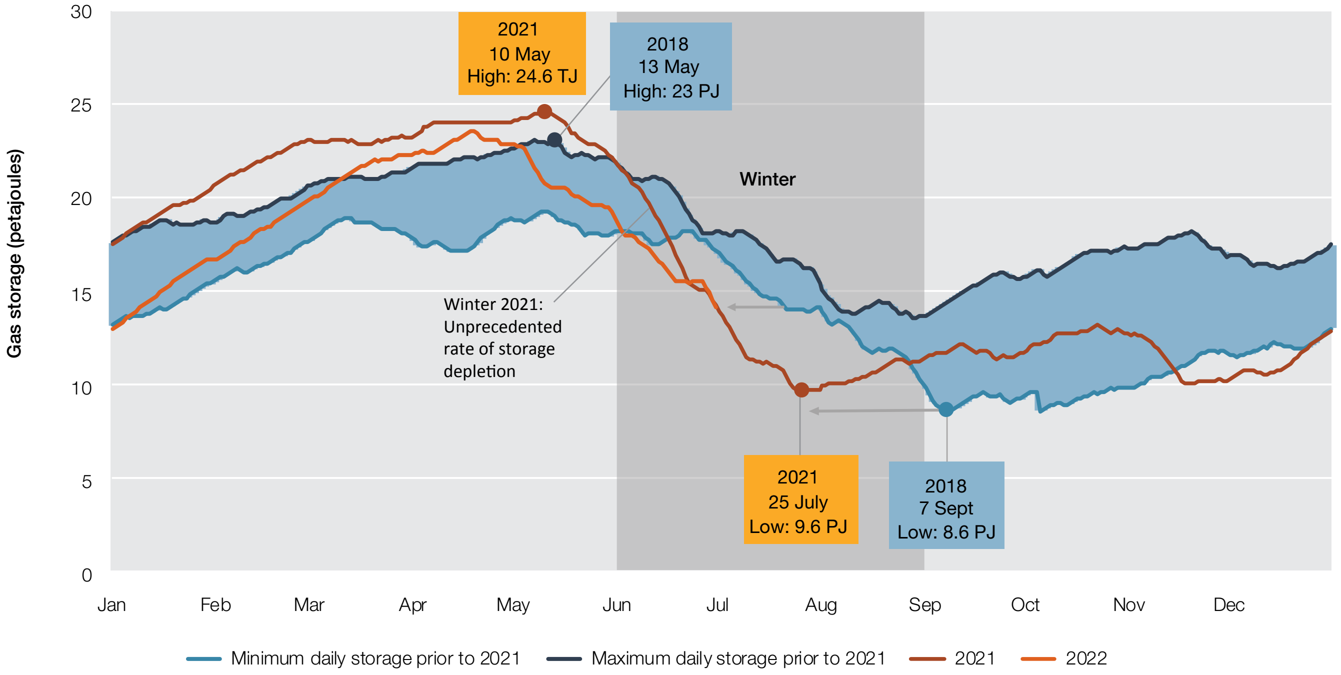
1 Close to 10 PJ of gas was transported north from southern supply sources over April-May to feed international exports.

2 Over the April to June quarter of 2022, record net trade quantities in Victoria and Sydney drove east coast market trade to the highest levels observed since the gas markets commenced, exceeding 20 PJ.

3 AEMO, Gas statement of opportunities, March 2022, p 58.

4 The AEMO notice was issued on 11 July, indicating the facility at current usage rates would decrease to 6 PJ by 31 July. This would result in reduced injection capability due to low pressure, increasing the risk of curtailment on peak demand days.

Figure 1.2 Iona underground storage, low storage levels in winter 2021 and 2022



Source: AER analysis, Gas Bulletin Board data.

In response to ongoing supply uncertainty, government initiatives have been launched to encourage new supply projects. In recent years, this has included:

- the Queensland Government offering areas for additional 'domestic only' exploration tenements
- the Australian Government and NSW Government signing a memorandum of understanding to bring new supplies to the domestic market
- a Heads of Agreement between the Australian Government and east coast LNG exporters to assist local users in procuring gas supply at competitive rates from exporters.

There is significant risk that new gas projects will not come online in time to prevent expected supply shortages. Sustained high prices are likely if forward contracts incorporate international price pressures.

In August the Australian Government confirmed it is taking steps to secure domestic gas availability, including renegotiating the Heads of Agreement alongside reviewing and extending the Australian Domestic Gas Security Mechanism to 2030.

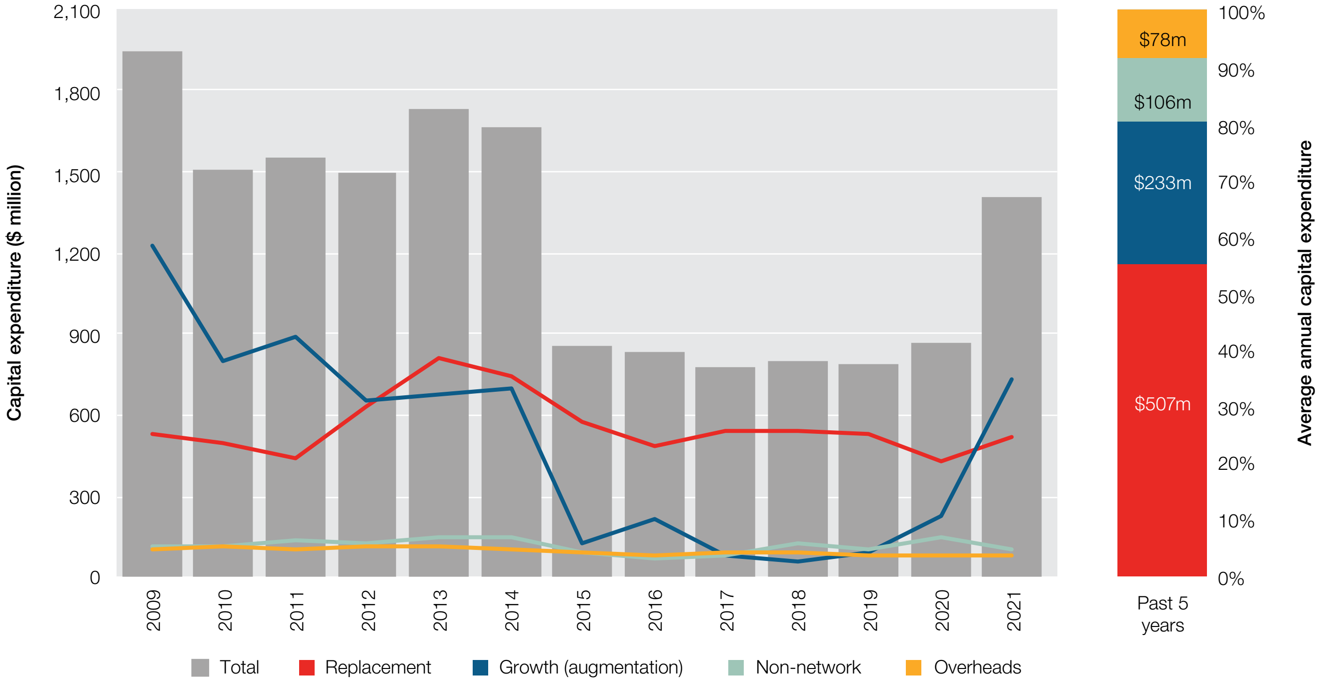
1.3 Electricity and gas networks (Chapters 3 and 5)

Consumers spent less on network costs in 2020–21 than in 2019–20 for both electricity networks and regulated gas pipelines. This reflected improvements in our regulatory approach, improved efficiency from the regulated networks and historically low costs of capital to finance the networks' asset bases.

Despite spending less on network services, reliability outcomes continued to improve. Electricity consumers faced the fewest and shortest unplanned outages ever, excluding the impacts of major events. Consumers on gas pipelines continued to experience very few outages.

In recent years, investment in electricity networks has been used to replace ageing assets. In 2020–21 growth expenditure exceeded replacement expenditure for transmission networks for the first time since 2012 (Figure 1.3). This was driven by Transgrid's expenditure on Project Energy Connect. This is a major new interconnector between NSW and South Australia. It is one of the upgrades listed under AEMO's integrated system plan, among other major transmission infrastructure upgrades. As these projects ramp up, the AER expects to see this significant growth expenditure continue.

Figure 1.3 Drivers of capital expenditure – electricity transmission networks



Note: All data are adjusted to June 2022 dollars, based on forecasts of the consumer price index (CPI). The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018). Augmentation of the Victorian transmission network is carried out by AEMO; hence, AusNet Services reports $0 expenditure for augmentation carried out on the transmission network.

Source: Category analysis regulatory information notice (RIN) responses.

Investment in gas pipelines was slightly down on the previous year and continues to be driven by expenditure on new gas connections, and by several major programs to replace old steel or cast-iron distribution pipes with plastic pipes. The AER initiated a consultation process to encourage wider dialogue about gas investment decisions given the uncertainty about the future of gas pipelines. That future could vary significantly depending on how the energy transformation proceeds, ranging from wide electrification and declining use for pipelines, to significant development of hydrogen and using pipelines to transport it.

Beyond the significant upcoming investment, emerging price pressures will contribute to higher network costs in years to come. High CPI outcomes in 2022 will feed into higher network costs through annual tariff increase processes from 2023 and onwards. In addition, the costs networks incur as a result of raising capital to finance investment appear to be increasing after several years of historically low rates.

The AER continues to develop its regulatory approach to ensure decisions made during this period of high price pressures are well-informed and reflect genuine engagement with consumers. Regulatory proposals that are developed in this way and meet the AER's expectations for forecast expenditure, depreciation and tariff structure statements are more likely to be accepted at the draft decision stage. This creates a more efficient regulatory process for all stakeholders.

The 4-yearly review of the AER's methodology for estimating the costs of capital is also underway. This sets out how the AER will set this key driver of network revenue over the next wave of electricity and gas regulatory decisions. The AER published its draft rate of return instrument in June and will publish the final instrument by the end of 2022.

1.4 Retail energy markets (Chapter 6)

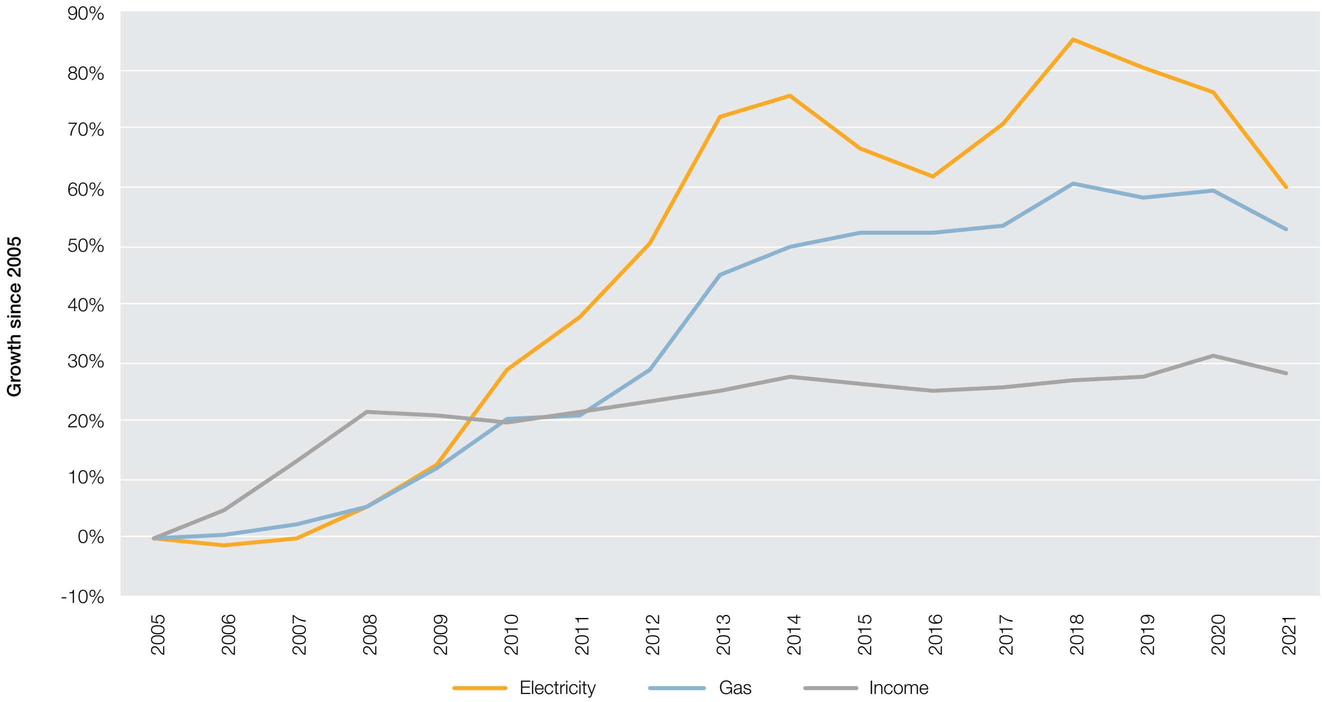
At the start of 2021, subdued energy market conditions drove down the cost of energy. Since then, the impacts of high wholesale prices in 2022 have started flowing through to retail markets and energy bills.

Increased wholesale costs are incorporated in the higher default market offers for 2022–23, which came into effect on 1 July 2022. The DMO is the maximum price an electricity retailer can charge a typical standing offer customer each year. It also acts as a 'reference price' for residential and small business market offers.

Market offers, which are typically adjusted in July, increased to accommodate higher wholesale costs.[5] Bills are likely to increase, commencing from August (for customers with monthly billing cycles) to October 2022 (for customers with quarterly billing cycles). Some customers are not well-placed to absorb these higher prices, with slow wage growth and increasing costs of living reducing their capacity to pay (Figure 1.4).

As a result, we expect energy affordability will decline. This is a major concern, recognising that electricity affordability remains a top cost of living issue for households. We also expect to see consumers' debt levels escalate from late 2022 to early 2023.

Figure 1.4 Energy prices and income



Note: Inflation adjusted.

Source: Electricity and gas index – ABS, Consumer Price Index, various years; income index – ABS, Household Income and Wealth, Australia, various years.

Recent regulatory reforms echo affordability concerns, with the Better Bills Guideline making it easier for consumers to understand how they are charged for energy use and whether they are on the best offer available from their retailer. The AER also recognises that not all consumers are able to shop around for a better deal and that more supports are needed to ensure the energy market is functioning efficiently.

In support of the AER's focus on consumers experiencing vulnerability, the AER is developing its first ever consumer vulnerability strategy, due for release in October. The strategy will be guided by a vision:

- to ensure consumers experiencing vulnerability are offered timely and effective support that works for them and for energy businesses
- to improve energy affordability, help consumers stay connected and reduce energy businesses' cost to serve.

The AER also undertook a range of compliance activities to improve behaviours in the industry to ensure retailers meet their obligations to consumers experiencing vulnerability and help where appropriate. The AER's compliance and enforcement priorities over 2021–22 included a focus on effective identification of consumers in financial difficulty and the offering of payment plans that have regard to the consumers' capacity to pay.

Through 2021, both electricity and gas retail markets continued to attract new entrants and mid-sized (Tier 2) retailers maintained market share. In 2021 the proportion of small customers on market contracts increased and customer switching rates also increased. This suggests small customers were more engaged in the market. However, prolonged high wholesale prices may strain smaller retail market participants and adversely impact the level of retail competition. Tier 1 retailers may regain market share through acquisitions of smaller retailers or through the Retailer of Last Resort scheme, where they may absorb customers from retailers exiting the market.

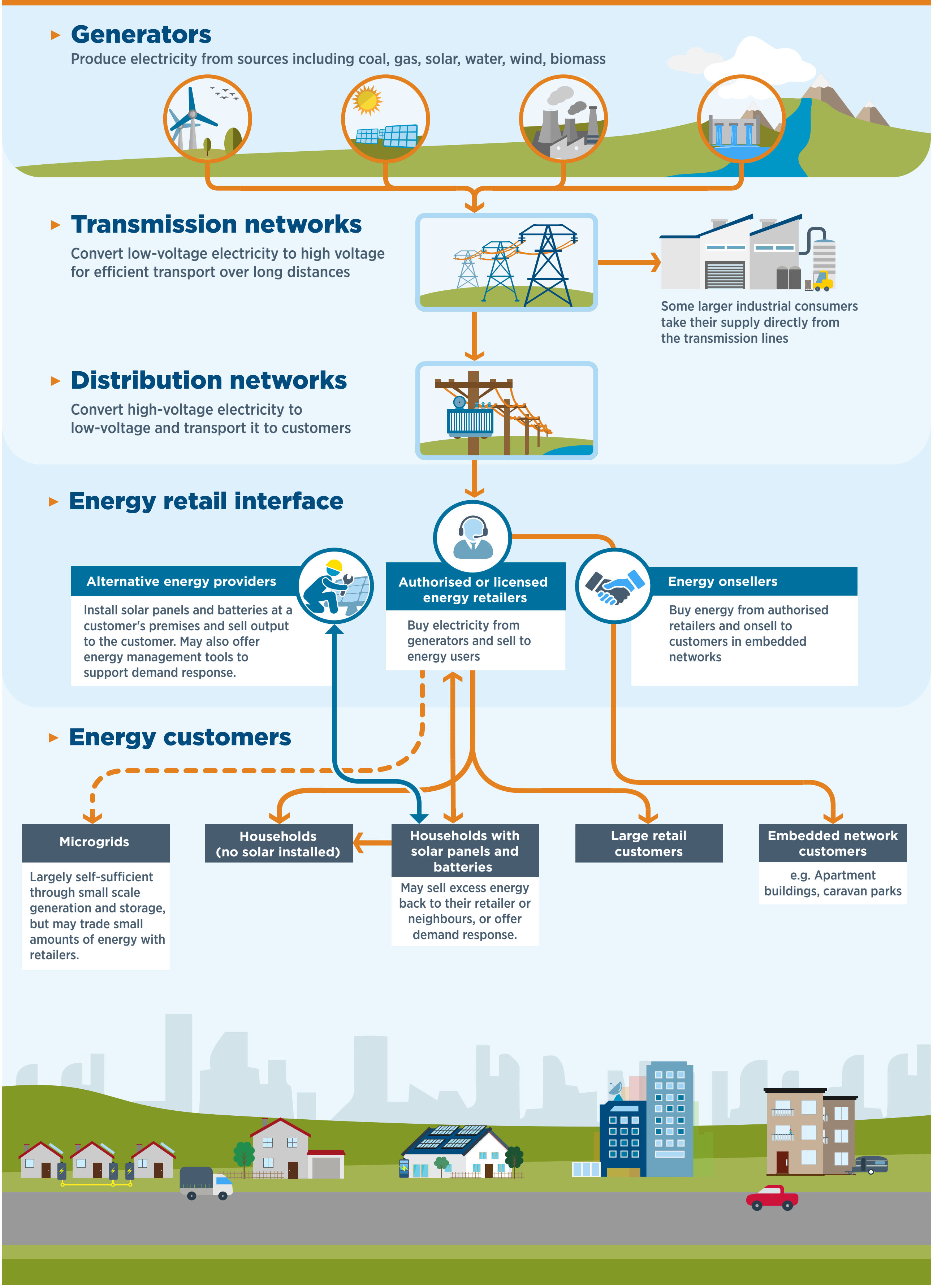
5 Anyalysis of offers for the July 2022 period will be included in the 2022 Annual retail performance report, due in November 2022.

Between May and September 2022, 8 retailers failed, which triggered Retailer of Last Resort (RoLR) processes. This number is significantly above normal, with only 4 retailer failures between 2016 and 2019. Following these failures, the AER transferred customers in each case to a new retailer to ensure the continued supply of essential energy services. The combined customer base of these retailers was almost 22,000, mostly small customers.[6] The AER has raised concerns regarding instances of retailers actively shedding customers as a way of avoiding incurring losses from high wholesale costs, possibly obtaining windfalls from selling lucrative energy contracts that are no longer needed.[7]

6 Retailers include Weston Energy Pty Ltd, Pooled Energy Ltd, Enova Energy Pty Ltd, Apex Energy Holdings, Power Club Limited, Mojo Power East, Social Energy Australia Pty Ltd and Elysian Energy Pty Ltd.

7 Australian Financial Review 'Energy retailers investigated for $100m hedges', 7 July 2022.

Infographic 1 – Electricity supply chain



Infographic 2 – Gas supply chain

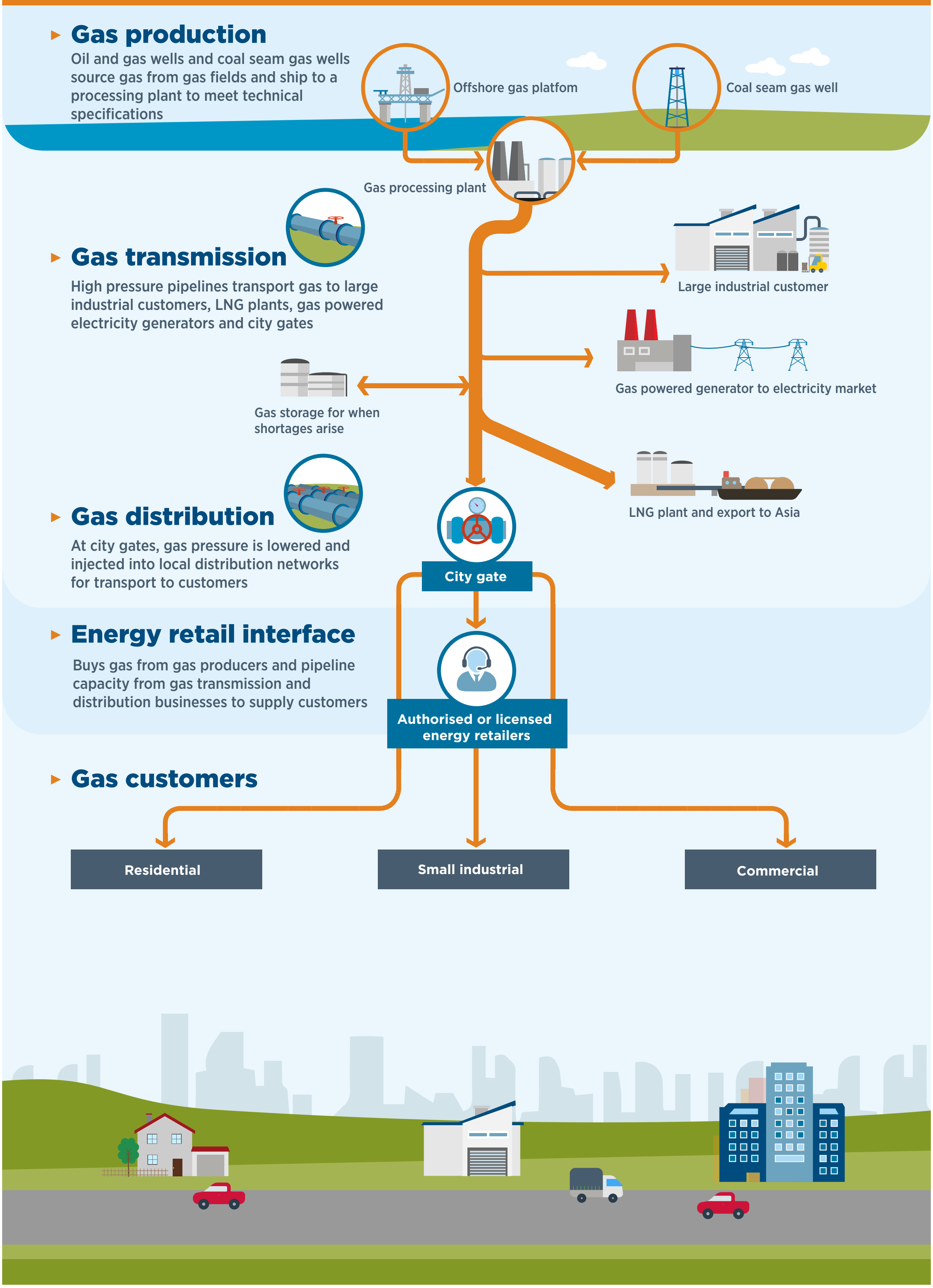


Image courtesy of Neoen

2 National Electricity Market

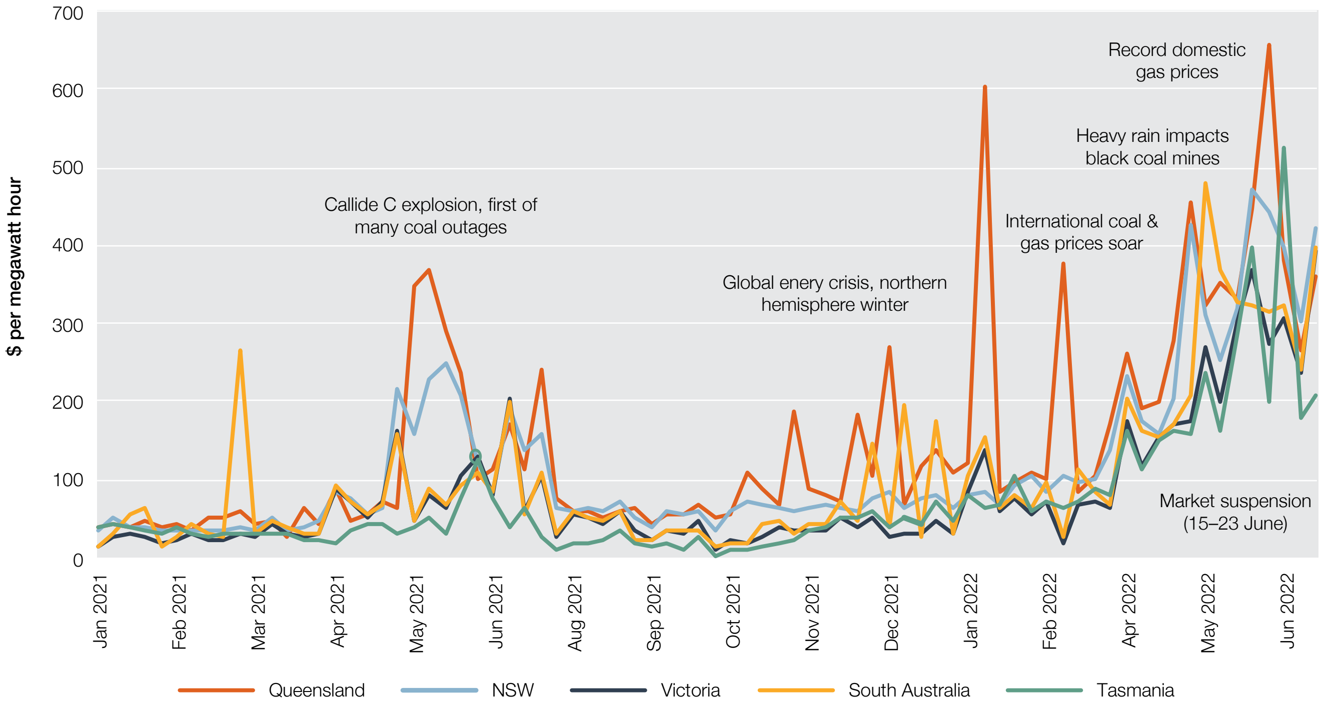
Electricity generated in eastern and southern Australia is traded through the National Electricity Market (NEM). Generators make offers to sell electricity into the market and the Australian Energy Market Operator (AEMO) schedules the lowest priced generation available to meet demand. The amount of electricity generated needs to match demand in real time. The market covers 5 regions – Queensland, New South Wales including the ACT (NSW), Victoria, South Australia and Tasmania. 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.

2.1 NEM snapshot

Since the last *State of the energy market* report:

- Wholesale electricity prices across much of the NEM remained relatively low across 2021 but rose rapidly to record highs in all regions in May, June and July 2022 (Figure 2.1).
- These high and volatile prices were the consequence of a compounding set of drivers in domestic and international markets.
- Coal-fired generation fell due to a high level of outages and coal supply problems, and more expensive hydro and gas-powered generation was needed to fill the gap. At the same time, gas spot prices were at record high levels impacted by international prices and tight domestic supply conditions.
- The need to cover high fuel costs, or to ration fuel or water levels, caused market participants to offer their capacity at progressively higher prices.
- Sustained high prices triggered protective price caps, multiple market interventions, and unprecedented market suspension of the entire NEM.
- Futures markets suggest that NEM prices will remain high (relative to 2021) over the next 2 years.
- Unplanned aging coal plant outages accompanied by early closure announcements highlighted the pressing need for new investment.
- Major reforms are ongoing to transform the NEM's market design to ensure it is best equipped for the post-transition energy market. The Energy Security Board's *Health of the NEM 2022* addresses the greatest risks to the NEM and the actions required to address them.[8]

Figure 2.1 Weekly wholesale electricity prices



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

8 Energy Security Board, Health of the National Electricity Market 2022, September 2022.

2.2 The NEM at a glance

Around 325 generating units produce electricity for sale into the NEM (Figure 2.2). A transmission grid carries this electricity along high voltage power lines to industrial energy users and local distribution networks (chapter 3). Energy retailers complete the supply chain by purchasing electricity from the NEM and packaging it with transmission and distribution network services for sale to residential, commercial and industrial energy users.

Figure 2.2 NEM at a glance

Note: MW: megawatts; TWh: terawatt hours. All data as at January 2022, except customers, which are as at the second quarter of 2020–21, and Victoria customer numbers, which were reported in 2019–20.

Includes energy met by the grid and rooftop solar generation.

Source: AER; AEMO; Clean Energy Regulator; Energy Made Easy website (energymadeeasy.gov.au); Victorian Essential Services Commission, Department of Industry, Science, Energy and Resources, National greenhouse gas inventory.

Box 2.1 How the NEM works

The NEM consists of a wholesale spot market for selling electricity and a transmission grid for transporting it to energy customers.

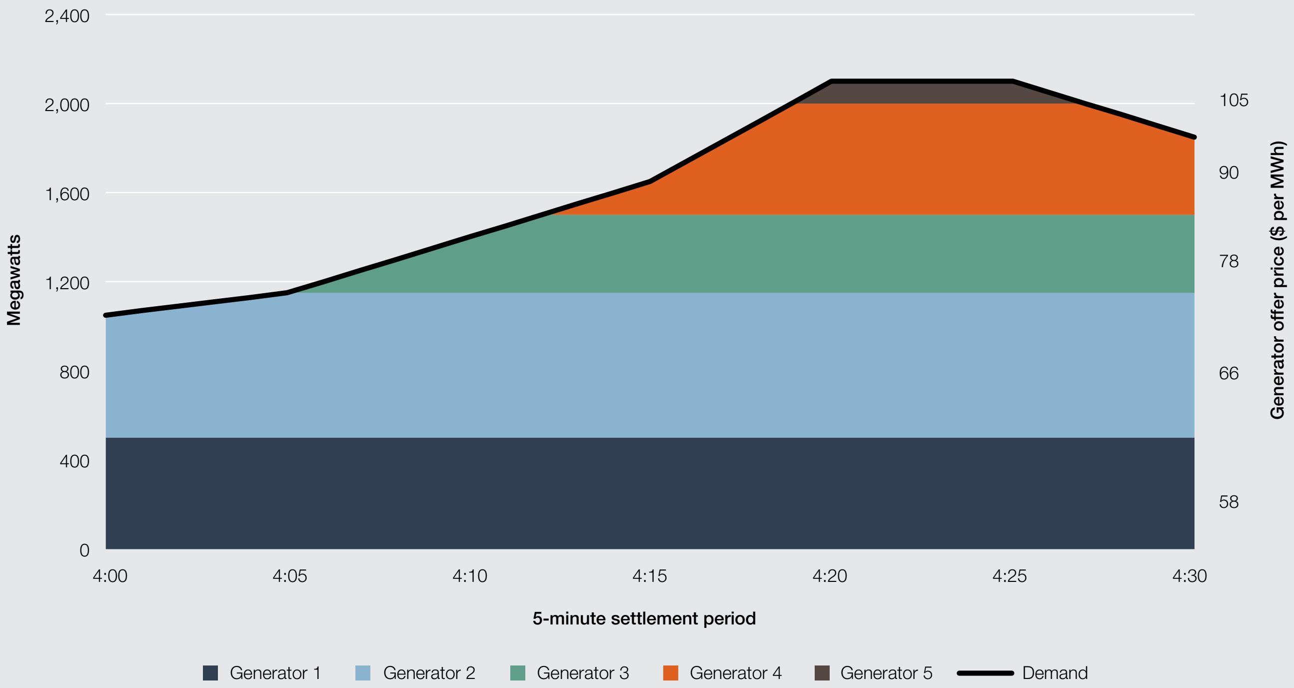
Power stations make offers to supply quantities of electricity in different price bands for each 5-minute dispatch interval. Scheduled loads, or consumers of electricity such as pumped hydro and batteries, also offer into the market. In 2021, for the first time, consumers (either directly or through aggregators) were able to bid demand response directly into the wholesale market as a substitute for generation (section 2.11.3). Electricity generated by rooftop solar systems is not traded through the NEM, but it does lower the demand that market generators need to meet.

A separate price is determined for each of the 5 NEM regions. Prices are capped at a maximum of $15,500 per megawatt hour (MWh) in 2022–23. A price floor of –$1,000 per MWh also applies. The market cap has increased in line with the consumer price index (CPI) each year, but the market floor price remains unchanged.

As the power system operator, AEMO uses forecasting and monitoring tools to track electricity demand, generator bidding and network capability to determine which generators should be dispatched to produce electricity. It repeats this exercise every 5 minutes for every region. 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 price in each region.

Figure 2.3 illustrates how prices are set. In this 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 price paid to all dispatched generators is the price in each 5-minute dispatch interval.

Figure 2.3 Setting the 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 dispatches more expensive (out of merit order) generators instead.

Retailers buy power from the wholesale market and package it 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.

2.3 Wholesale prices and activity

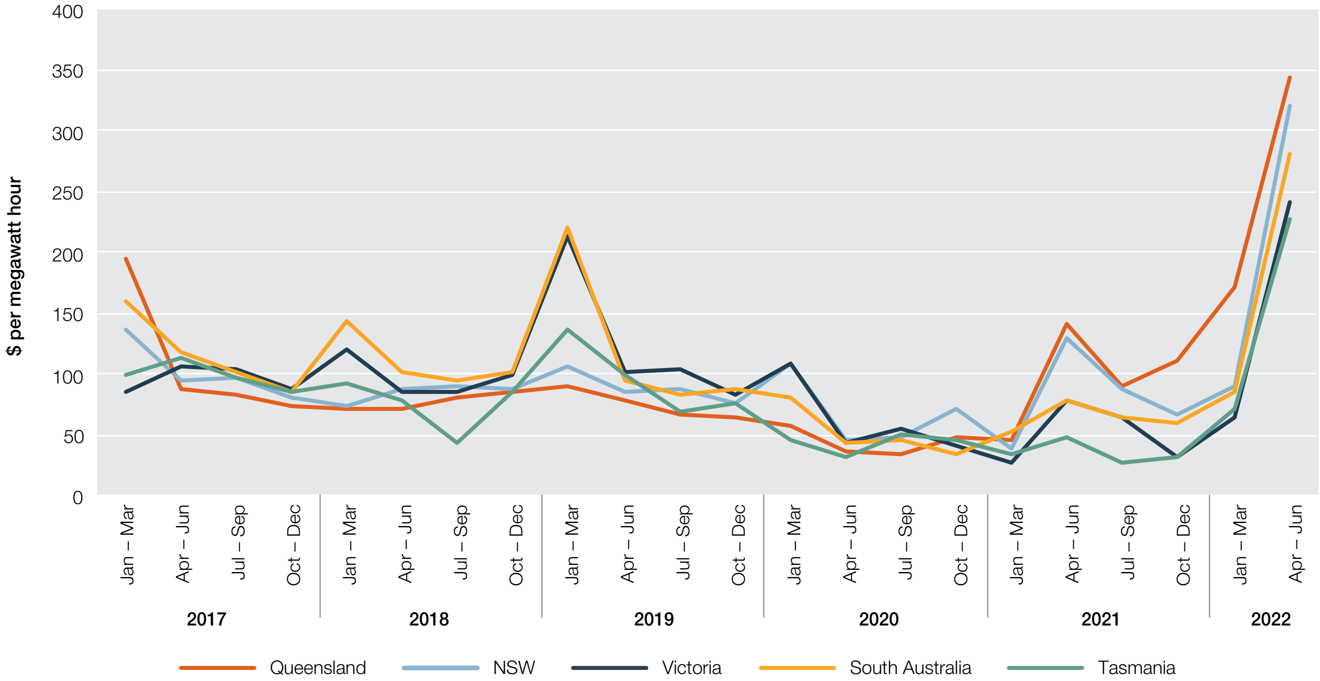
2.3.1 The market in 2022

Wholesale electricity prices rose dramatically in 2022 to reach record levels in all regions.

From January to March (Q1 2022) average prices increased across all regions compared to the same quarter in 2021, at least doubling in most regions and quadrupling in Queensland (Figure 2.4). Demand reached record highs in Queensland as plant outages in Queensland and NSW reduced supply. Network constraints meant that periodically, regions were limited in their ability to import electricity from neighbouring regions, and at the same time, international coal and gas prices started increasing as a result of the Ukraine war.

From April to June (Q2 2022) and continuing into July, supply-side pressures on wholesale prices intensified. Average quarterly 30-minute wholesale electricity prices increased significantly in all regions to reach their highest levels ever. These outcomes were largely the result of underlying high prices (particularly prices between $200 and $500 per MWh) over several months in all regions.

Figure 2.4 Quarterly wholesale electricity prices



Note: Prices are volume weighted quarterly averages.
Source: AER; AEMO (data).

Compounding factors drove these increases in spot market prices:

- very high international coal and gas prices
- ongoing coal plant outages, significant coal supply challenges and higher marginal coal prices
- reduced coal-fired generation causing the market to rely on more expensive sources of generation, such as gas and hydro to meet demand
- high demand for gas-powered generation coinciding with gas supply limits and soaring gas spot prices.
- increased demand due to an early and very cold winter.

A key driver of high prices in the NEM has been the dramatic increase in international prices for coal and gas, which are key fuels for electricity generation. The 2021–2022 global energy crisis led to energy shortages in the United Kingdom and China. European and Asian prices rose to record levels and Australian coal and gas was worth more in export than in domestic markets. In February 2022 Russia invaded Ukraine and global fuel prices rose even further (section 2.3.3). Coal and gas-powered generators needing to source additional fuel were exposed to these high prices.

Numerous coal plants experienced coal supply issues (section 2.6.1). Heavy rain in March impacted open cut mines and rail lines in NSW and Queensland, and geological issues reduced output from others. Prices for marginal coal bought on the spot market rose 4-fold compared to the same time the previous year.

Coal generator outages (planned and unplanned) reduced availability in May and June at the same time an early and very cold start to winter increased demand. At times of low renewable and reduced coal-fired generation, the NEM was reliant on expensive gas and hydroelectric generation to meet daily energy needs. Increased demand for gas to generate electricity and meet winter demand, combined with tight domestic supply conditions caused domestic gas prices to surge (section 4.3). High international gas prices strengthened the incentive for producers to export liquefied natural gas (LNG). By late May, domestic gas spot prices were 2 to 5 times higher than in March.

The soaring cost of fuel and the need for some generators to ration depleted fuel supplies led to a very large shift in bidding by coal and gas generators. Some generators buying coal on the spot market reported they needed a price of more than $300 per MWh to break even. Gas generators buying fuel on the spot market needed around $400 per MWh.

When the offers of coal or gas generators increase, hydro generators generally follow suit or risk overly depleting their water reserves. Thus, hydro offers increased in line with thermal offers. While hydro generation ran hard, Snowy Hydro's ability to further increase its output was limited by the amount of water it could release into the Tumut River, which risked downstream flooding.

The scale of these events and price increases triggered administered price caps and spot market suspensions.

High gas prices trigger price cap

From 24 May to 7 June, following the suspension of a gas market participant, AEMO imposed price caps in the Sydney and Brisbane short-term trading markets. A week later, the cumulative price threshold was reached in Victoria's wholesale gas market and it was placed under an administered price cap, lasting until 1 August when the cumulative price dropped below the threshold. The Sydney short-term market was also placed under an administered price cap from 8 to 14 June when the cumulative price exceeded the threshold.

High electricity prices trigger price cap and subsequent capacity withdrawals lead to market suspension

Between 12 and 14 June 2022, sustained high wholesale electricity prices triggered an administered price cap of $300 per MWh in Queensland, NSW, Victoria and South Australia. The price cap, combined with high fuel costs, contributed to several generators withdrawing capacity from the market. The resulting supply shortfalls prompted AEMO to use its powers to direct generators to provide electricity.

On 15 June, AEMO took the extraordinary step of suspending the wholesale electricity markets to ensure a reliable supply of electricity. NEM operations were not designed to cope with a withdrawal of such large volumes of capacity and AEMO was unable to sustain the level of manual resolution needed. During the market suspension, AEMO determined spot prices and participants were able to apply for compensation if those prices did not cover actual costs.[9]

Following negotiations with generators and the resolution of plant outages, almost 4,000 MW of coal capacity returned to the market. Nevertheless, there were occasions when the market came close to actual supply shortfalls and AEMO activated emergency reserves to reduce demand. On 22 June AEMO removed the price cap and on 23 June it lifted the market suspension.

While underlying conditions explain these market outcomes to a large degree, the AER is investigating whether bidding behaviour breached any rules and legislation. We will also examine broadly if generator conduct and market outcomes were consistent with an efficient and competitive market serving the long term interest of consumers. We will report our conclusions in the *Wholesale electricity markets performance report 2022*, to be released in December 2022.

Wholesale electricity prices eased in August 2022 but were more than double the prices in August 2021.

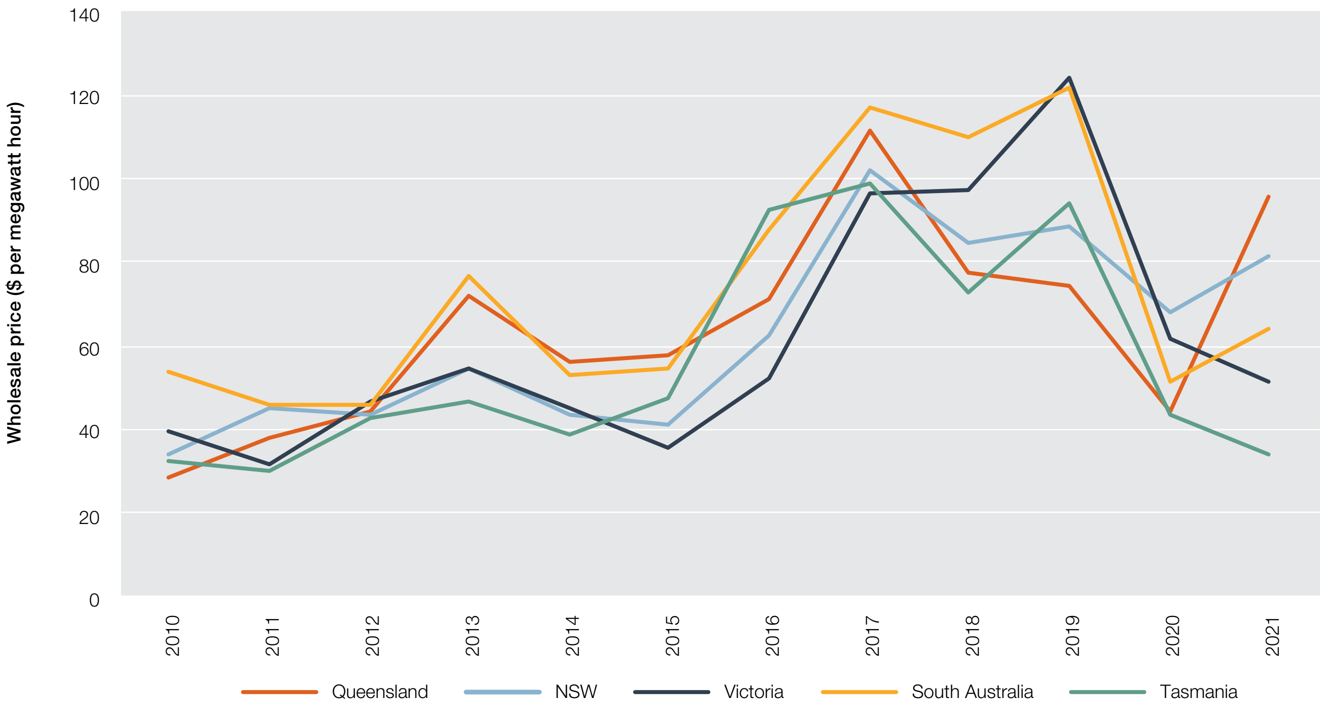
9 AEMO, Market suspension FAQs June 2022, June 2022.

2.3.2 The market in 2021

The outcomes in 2022 represent a dramatic reversal from those a little over a year earlier. Wholesale prices across the NEM were low at the start of 2021, driven largely by new investment in wind and solar and falling coal and gas fuel input costs through to late 2020. Demand was also lower due to increased rooftop solar output and mild summer conditions in 2020–21.

However, the supply-demand balance remained tighter than in the past and the outage at Callide C power station drove higher wholesale prices in Queensland and NSW, particularly in the evenings.

Figure 2.5 Annual wholesale electricity prices



Note: Prices are volume weighted calendar year averages.
Source: AER; AEMO (data).

Average annual prices in 2021 rose in Queensland, NSW and South Australia and fell in Victoria and Tasmania (Figure 2.5):

- Queensland ($96 per MWh) was the NEM's highest priced region. Average prices were affected by price spikes, starting with the long-running Callide outage, and network constraints, which limited the ability to import electricity from NSW.
- NSW ($81 per MWh) recorded the second highest prices in the NEM due to high prices in May and June. At times it was limited in its ability to import cheaper electricity from Victoria due to outages around the transmission lines connecting the 2 regions.
- South Australia ($64 per MWh) prices rose compared with 2020. High prices often occurred at times of low wind output when South Australia was also prevented from importing from Victoria.
- Victoria ($52 per MWh), on the other hand, recorded its second year of falling spot prices. These reflected an increase in low-cost renewable generation and low demand due to mild temperatures and output from rooftop solar.
- Tasmania ($34 per MWh) remained the NEM's lowest price region.

2.3.3 Generator fuel costs and fuel availability

In 2021 and 2022 generator fuel costs increased for many reasons. High prices for Australian coal and gas were fuelled by the global energy crisis, war in the Ukraine, sanctions against Russia, high Asian and European demand, as well as domestic coal supply problems.

Upstream black coal and gas market conditions can affect fuel costs for generators. Although black coal generators do not pay international prices for all 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 determine when long-term contracts are renegotiated. The international export price for black coal quadrupled from the start of 2021, to over $500 per tonne in mid-2022 (Figure 2.6). These prices suggest that the short run marginal cost for coal plants needing to source coal from spot markets is well above $200 per MWh. With future coal prices expected to remain elevated into 2024, there will be a step increase in costs as coal supply contracts are renewed over the next 2 years.

Record La Niña-driven rains impacted open cut coal mines on Australia's east coast, particularly in the Hunter Valley.[10] Pits were flooded and rail lines disrupted. Some mines were unable to deliver forecast levels of coal to associated coal generators. Not all coal meets the correct specifications, and it takes time to purchase coal and create new logistic chains. Further, high export prices caused domestic coal sales in NSW to drop. These conditions resulted in a number of coal generators having low stockpiles going into winter.

The average price set by NSW black coal generators rose from $35 per MWh in Q1 2021 to over $400 per MWh in the week leading up to the administered price cap in June.

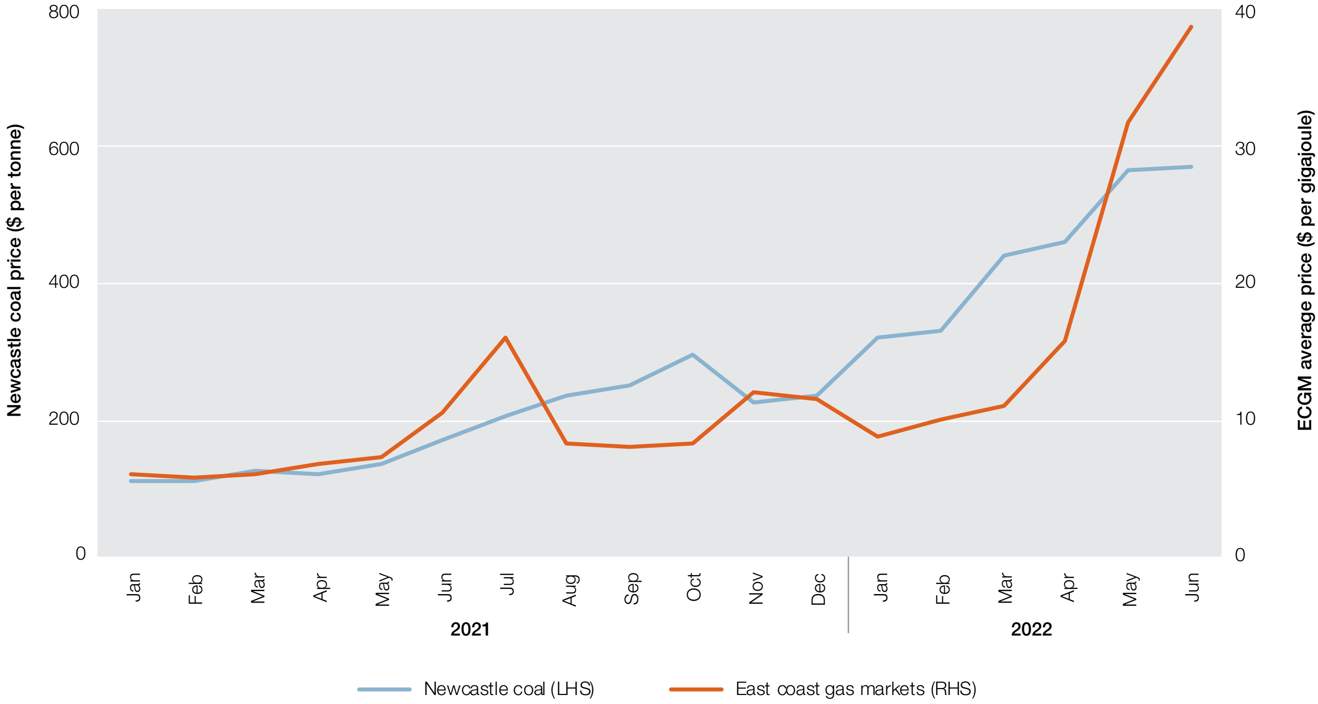
Fuel costs for gas plants also increased across 2021 and 2022. Gas generators are likely to value their fuel at the prevailing gas market price when deciding whether to generate. Record LNG demand driven by a dramatic spike in international LNG prices put upward pressure on domestic gas spot prices. The LNG netback price tripled from the start of 2021 to June 2022.

In May through to June 2022, gas market participants bought record levels of gas off the spot markets, either for gas generation or for other gas customers. These spot purchases were likely to be a relatively small percentage of these participants' total gas demand, most of which is sourced under long term contracts. Nevertheless, the increase in spot market purchases from generators had a significant impact on spot market demand and prices, and ultimately on NEM prices.

The average price set by NSW gas generators rose from around $50 per MWh in Q1 2021 to $325 per MWh in the week leading up to the administered price cap in June.

10 Yancoal, Quarterly Report for the quarter ending 31 March 2022, April 2022.

Figure 2.6 Black coal and gas fuel prices



Note: The black coal price is derived from the Newcastle coal index (US$ per tonne), converted to A$ with the Reserve Bank of Australia exchange rate. The east coast gas market (ECGM) average gas price is the average of gas prices in Queensland, NSW, Victoria and South Australia.

Source: AER analysis using globalCOAL data, and data from the short-term trading market and Victorian declared wholesale gas market.

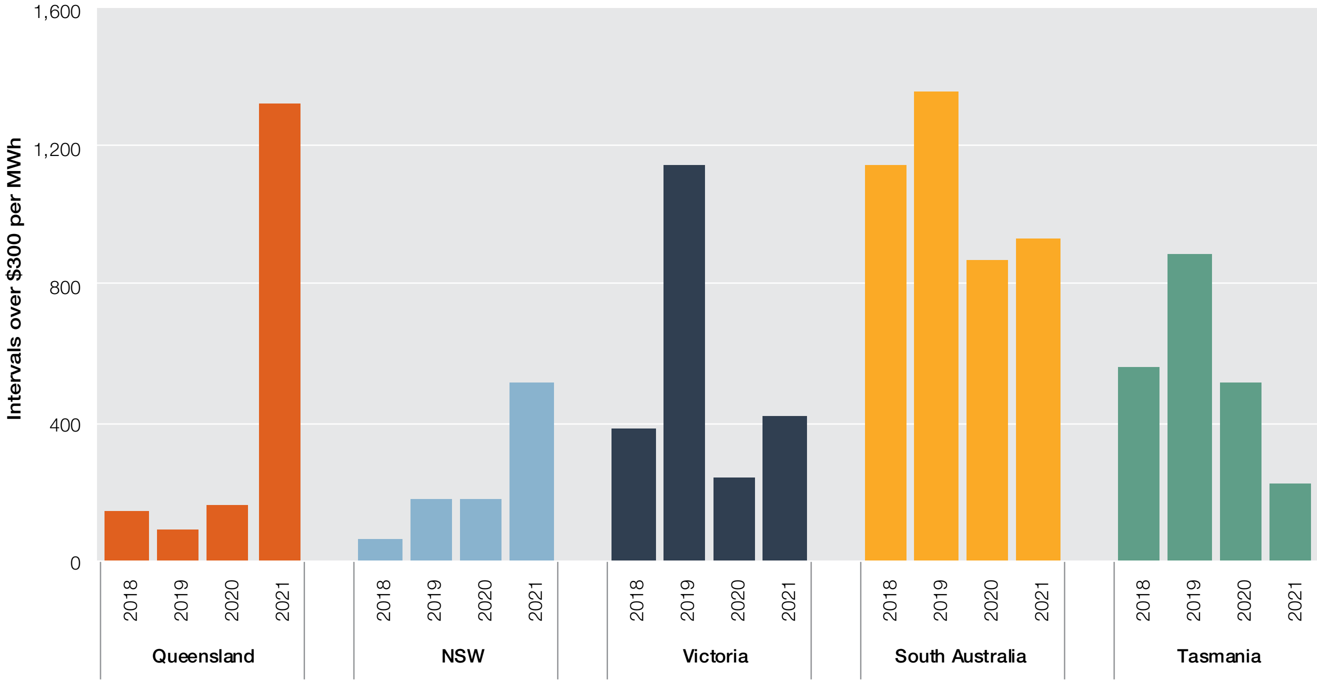
2.3.4 Price volatility

Price volatility is a natural feature of energy markets and can signal to the market that investment in new generation is needed. While price volatility was high in 2021, with more 30-minute prices over $5,000 per MWh in 2021 than in the last decade, price volatility was significantly higher again in 2022.

In 2022, high prices were the largely the result of underlying high prices over several months in all regions but were also increased by high price spikes in Queensland, NSW and South Australia. In the first 8 months of 2022 there were almost 11,000 instances of prices above $300 per MWh (compared to 632 in 2021) and 74 instances of prices above $5,000 per MWh (compared to 43 in 2021).[11]

11 The AER reports on all 30-minute prices above $5,000 per MWh through its Performance reporting.

Figure 2.7 Count of prices above $300 per MWh



Note: Count of 30-minute prices above $300 per MWh.
Source: AER; AEMO (data).

2.3.5 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.[12]

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 start-up or shut down 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 or power purchase agreements, 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 technologies 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 middle of the day when solar resources are producing maximum output and demand is relatively low.[13]

12 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.

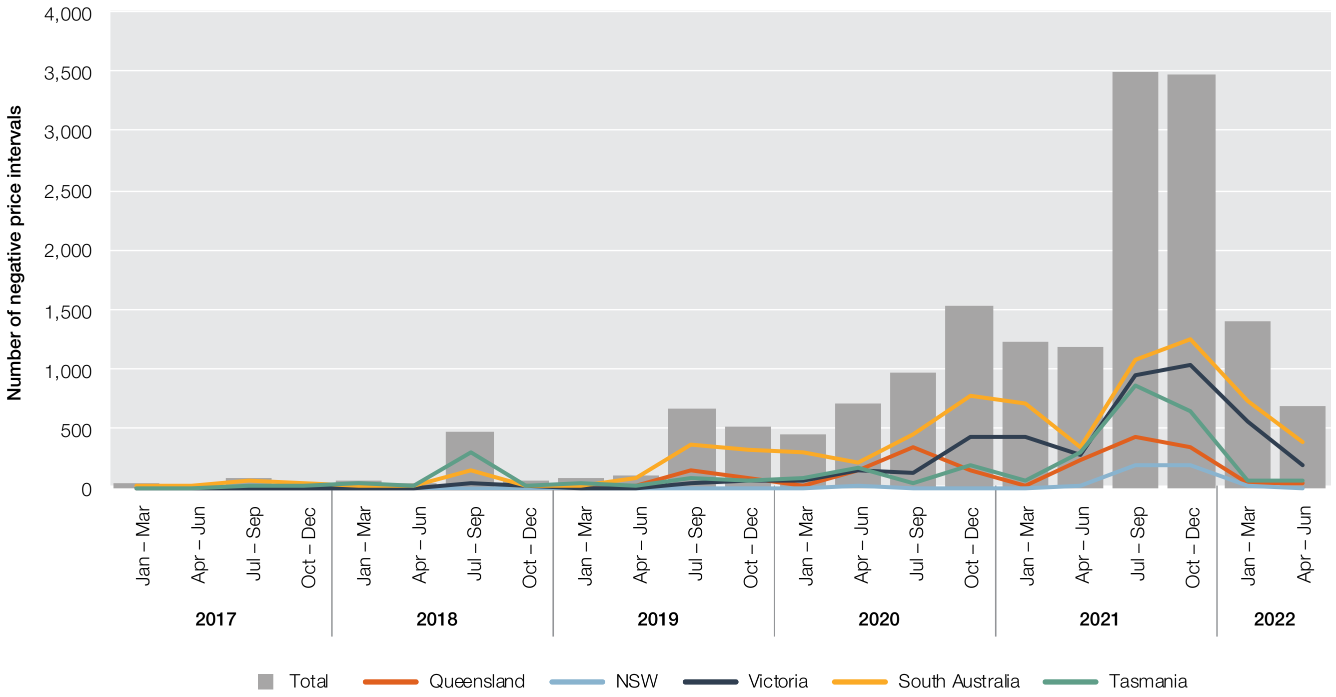
13 AER, Wholesale markets quarterly – Q3 2020, November 2020.

A record number of negative prices were seen NEM-wide in 2021, well over double the number in 2020. Nearly two-thirds occurred in South Australia and Victoria, which have the highest penetration of wind and solar (including grid-scale and rooftop) generation. Instances of negative spot prices were highest when these units were generating.

Over 65% of negative prices in 2021 occurred in the second half of the year, far exceeding the previous quarterly record set in October to December 2020. Between October to December in 2021, prices were negative in South Australia 27% of the time and in Victoria 22% of the time.[14]

In 2022, the instance of negative prices fell, particularly between April and June, reflecting fuel constraints and low renewable generating conditions. This may reverse in the Spring months with low demand and good wind and solar generating conditions.

Figure 2.8 Count of negative prices



Note: Count of 30-minute prices below $0 per MWh.
Source: AER; AEMO (data).

2.4 Electricity contract markets

Contract market prices increased by as much as 300% to 600% since the start of 2022. Market participants did not anticipate such a significant jump. These markets are critical to the ability of retailers to manage price risk on behalf of customers. They are also critical in driving generator behaviour. Contract prices, along with liquidity of contract markets, will drive wholesale outcomes for some time.

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 ('gentailers') to offset 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

14 AER, Wholesale markets quarterly – Q4 2021, February 2022, p 4.

participate in contract markets to manage outstanding exposures, although usually to a lesser extent than standalone generators and retailers do.

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:

- In over-the-counter (OTC) markets, 2 parties contract with each other directly (often assisted by a broker). The terms of OTC trades are usually set out in International Swaps and Derivatives Association (ISDA) agreements.
- In exchange traded markets, electricity futures products are traded on the Australian Securities Exchange (ASX) or through FEX Global (FEX).[15] 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. 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.
- 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.

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

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 manage credit risk by determining the creditworthiness of their counterparties.[16]

2.4.1 Contract market activity

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. To 30 June 2022, only 3 trades have occurred.

Regular ASX trades occur for the Queensland, NSW and Victorian regions of the NEM, but liquidity is poor in South Australia.

Until June 2022, trading levels had increased over the previous 4 financial years due to a material growth in traded volumes on the ASX (Figure 2.9). The increased ASX volumes were driven by increases to options and quarterly base futures. Since 2017–18, the annual traded volume of options increased by more than 500% and quarterly base futures increased by over 150%.

In June and July 2022 there was a marked decline in ASX trade for some contract types, likely resulting from significant market volatility and the resulting cashflow impacts on generators. Retailers might have been hesitant to

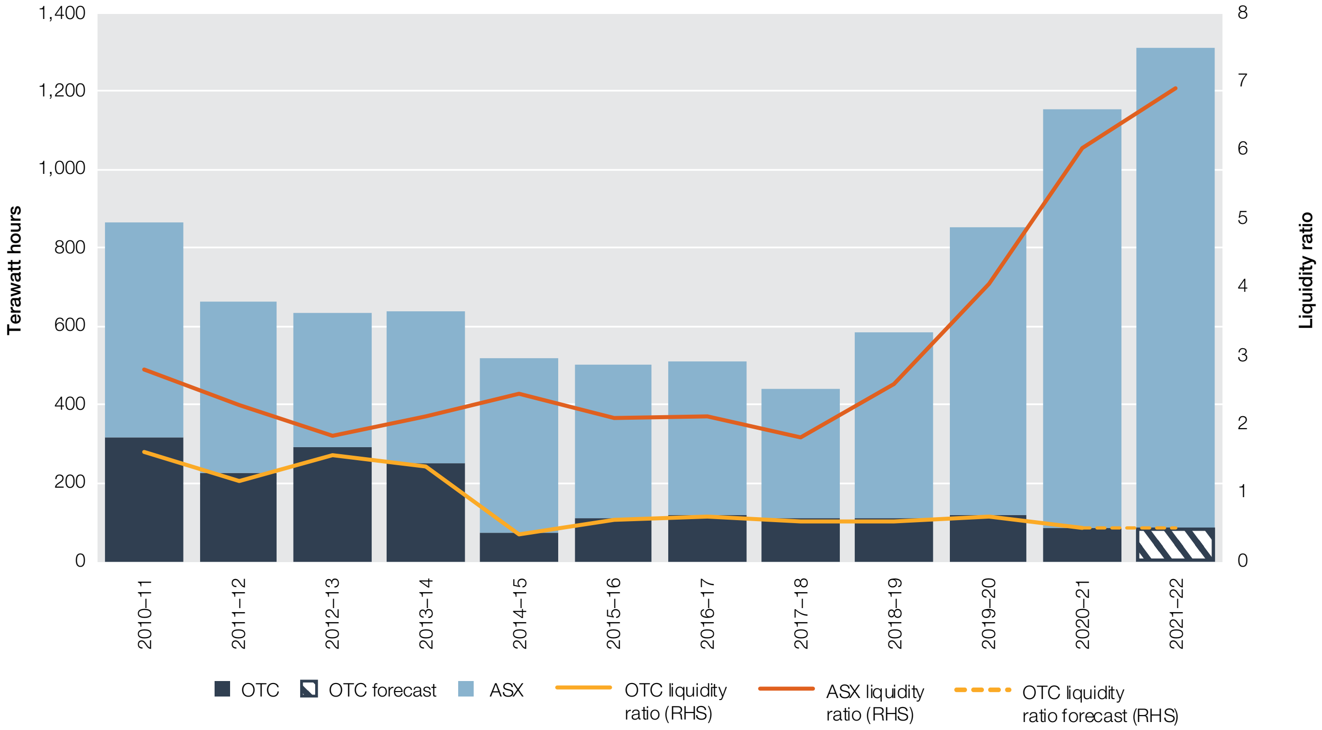
15 FEX launched its futures exchange on 26 March 2021.

16 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.

contract being unwilling to lock in prices at such high levels and instead opted to wait and see if prices would fall in the future. Generators might have been hesitant to contract because additional contracting would expose themselves to potential margin calls.

In August 2022, however, trade volumes were higher than any volume previously traded in the month of August since records began in 2002. The increase in traded volumes after the low levels observed in June and July is a positive sign for liquidity increasing in the contract market.

Figure 2.9 Traded volumes in electricity futures contracts



Note: Exchange trades are publicly reported, while activity in over-the counter (OTC) markets is confidential and disclosed publicly only via voluntary 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. Data for 2021–22 trading of OTC contracts were not available at the time of publication. The OTC liquidity ratio forecast is the liquidity ratio compared the total traded volumes to the native demand across the 4 combined regions.

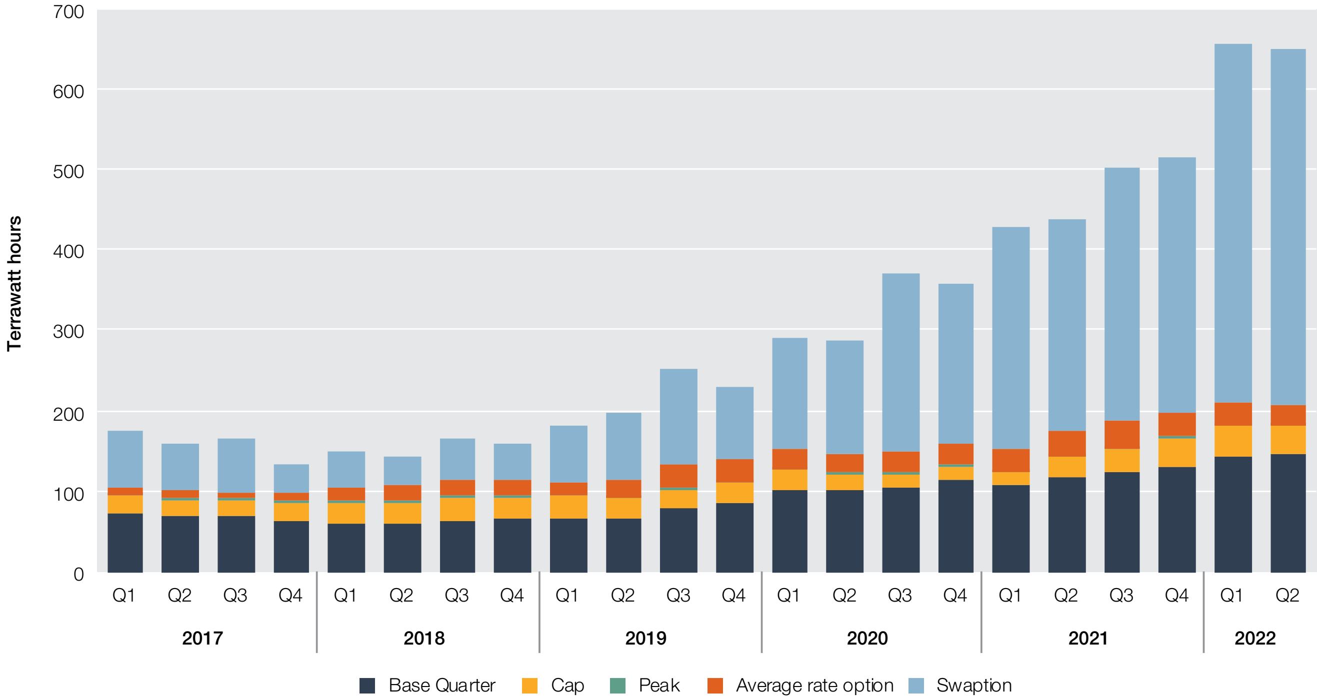
Source: AER; AFMA; ASX Energy.

Importantly, open interest volumes have been increasing (Figure 2.10). In the past 3 years, the total open interest volume for electricity futures and options has quadrupled despite the high contract prices. This indicates that the increase in traded volumes is not just due to higher turnover, but also because participants are holding larger open contract positions.

OTC trade volumes have remained steady or declined. In 2020–21 OTC trade was only 7% of total traded volume.

The growth in trading of ASX contracts until June 2022 continued despite the falling capacity of baseload coal generation and rising share of wind and solar generation in the market. Intermittent renewables generation is not as well suited to the sale of standard contracts as coal generation. This is because its output is uncertain and weather dependent. But ‘firming’ this generation with energy storage or gas-powered plant can help support contract market participation. Several market participants with flexible generation capacity offer firming products targeted at renewable generation.

Figure 2.10 ASX open interest volumes



Source: AER; ASX Energy.

ARENA provided funding support to Renewable Energy Hub, a specialist advisory and technology solutions provider, to establish a firming market platform that offers new hedge products designed for clean energy technologies. The platform aims to fill a gap in risk management products and overcome a market barrier for clean energy technologies.[17] New hedging products introduced by Renewable Energy Hub include:[18]

- 'Solar shape' and 'inverse solar shape' contracts to provide a level of flexibility to manage the intermittency of renewable generation. They are tailored to specific periods of the day and provide an alternative to flat contracts.
- A 'super peak' electricity contract for electricity supply during the high demand hours of the morning, afternoon and evening periods.
- A 'virtual storage' electricity swap for buying and selling 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 cap products. These replaced existing cap products in advance of changes to settle the market every 5 minutes.

Contract market liquidity

Overall, contract liquidity has improved across the NEM in recent years. The liquidity ratio (contract trading relative to underlying demand) across the NEM rose from around 240% in 2017–18 to over 650% in 2020–21 (Figure 2.9), with all regions improving. Trades through just the ASX in 2021–22 equated to 690% of underlying trade in the NEM.

The recent decline in liquidity in June and July 2022 was the result of market conditions including high contract prices, trading limits and margining requirement. Margining may have placed financial pressure on generators, reducing their ability to continue to offer contracts for sale.

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 indicates that substantial trading (and re-trading) occurs in capacity made available for contracting.

Liquidity is poorer in South Australia, where trading volumes are less than underlying electricity demand. For just ASX trades, South Australia was the only region where the liquidity ratio dropped in 2020–21 and again in 2021–22. The region's high proportion of renewable generation and relatively concentrated ownership of dispatchable generation

17 ARENA, Renewable Energy Hub marketplace, ARENA website, May 2020.

18 Renewable Energy Hub, 'New energy contracts for a new energy future', May 2021.

likely contributed 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. Similar reforms were introduced in 2019 under the Retailer Reliability Obligation (RRO) (section 2.4.3).

Composition of trade

Trade increased in Queensland and NSW and accounted for 48% and 30% respectively of ASX contracts traded in 2021–22. Traded volumes decreased in Victoria, accounting for 22% of trades. Trading in South Australia accounted for less than 1% of contract volumes. In the OTC market segment covered by the AFMA survey, Victoria had the highest traded volume, accounting for 40% of the total volume.

For 2021–22, swaptions (51%) were the most traded products on the ASX. The next most traded products were quarterly base futures, accounting for 39% of the traded volume. Average rate options (4%) and caps (6%) are traded at lower rates. Peak products continue to decline in popularity, accounting for only 0.04% of the volume. In the OTC market, swap products (78%) and caps (21%) accounted for most of the reported trading in 2020–21. Options are less popular in the OTC market, accounting for less than 1% of the OTC traded volume.

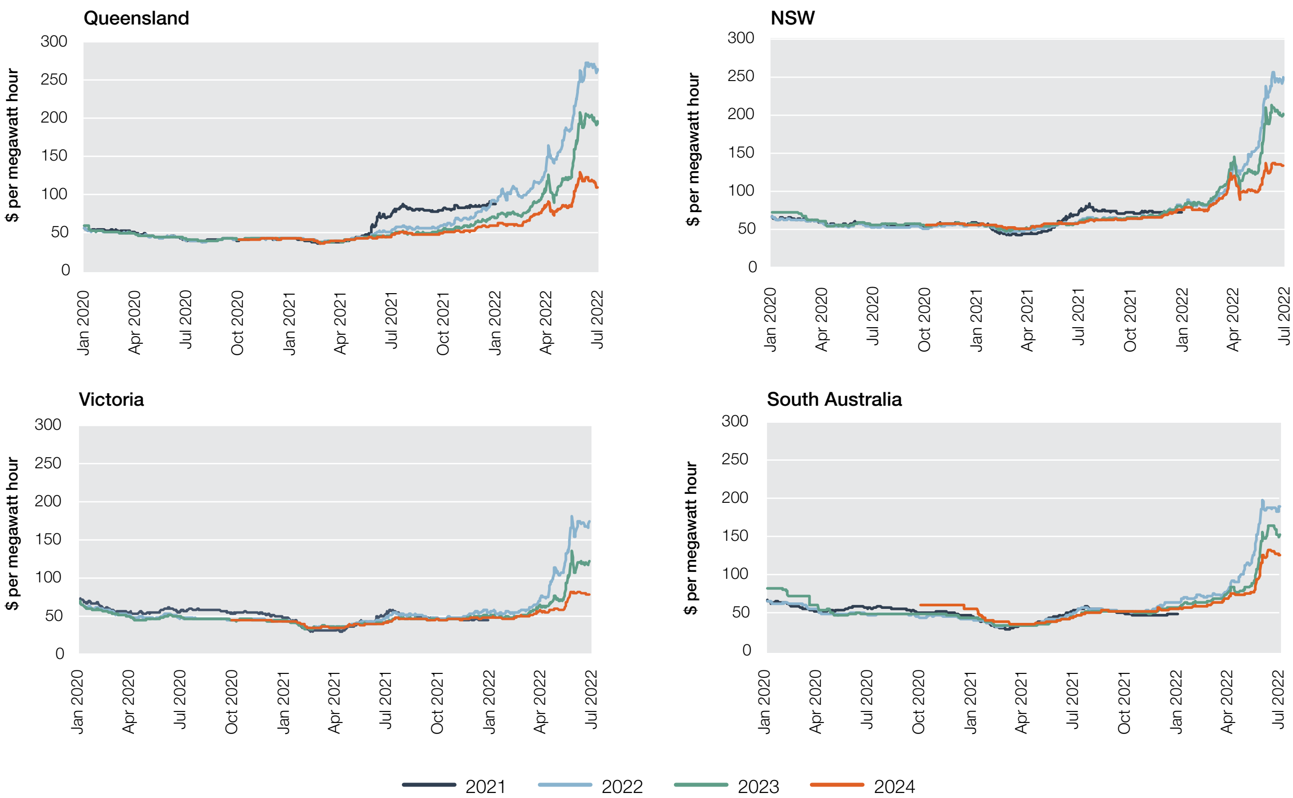
2.4.2 Contract prices

Base futures prices for calendar year 2022 ASX contracts were low at the start of 2021, before increasing in early 2022 and jumping considerably in April and May (Figure 2.11). At 30 June 2022, the calendar year prices for 2022 ranged from $177 per MWh in Victoria to $264 per MWh in Queensland. This is an increase of 360% to 540% since the start of 2021.

Final Q2 2022 contract prices set record highs in all regions. The final Q2 2022 base future prices were the highest ever recorded, not just in Q2 but in any quarter since the NEM commenced. The final Q2 2022 cap prices were the highest Q2 prices ever recorded in all regions. NSW and Queensland also recorded the highest ever final cap price regardless of the quarter.

These increases reflected higher than expected spot market prices due to the increased cost of generation with gas and coal fuel costs at record high prices, coal supply issues and increased opportunity costs with some generators rationing their fuel usage to save fuel for summer.

Figure 2.11 Prices for calendar year base futures

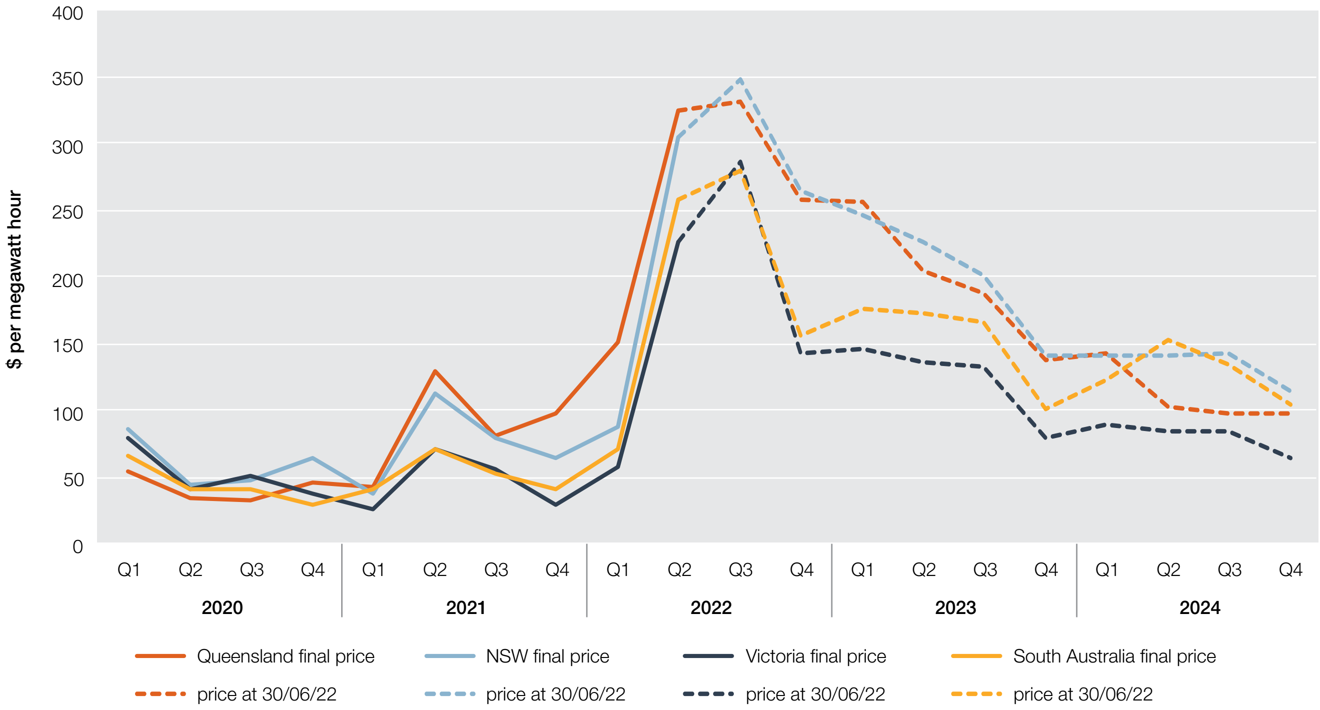


Source: AER; ASX Energy.

The outlook for 2023 and 2024 also increased, with high prices expected to continue into the coming years, but not as high as in 2022. On 30 June 2022, base future prices for 2023 and 2024 were highest in NSW and Queensland, rising to $202 per MWh in NSW and $195 per MWh in Queensland in 2023. NSW and Queensland prices for 2023 were $40–$80 per MWh higher than in South Australia and Victoria. These contract prices indicated that participants might have been anticipating a market impact from the closure of Liddell power station in NSW in 2023.

Quarterly base future prices start falling across 2023 and 2024, but they generally remain above $100 per MWh in every region except Victoria into 2024 (Figure 2.12).

Figure 2.12 Prices for quarterly base futures



Note: Prices for quarterly base future up to and including Q2 2022 are finalised (as they are no longer traded). Prices for quarterly base futures for Q3 2022 and beyond (which are still being traded) are as of 30 June 2022.

Source: AER; ASX Energy.

2.4.3 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 poses a significant risk as contracts offer a degree of control over costs (for retailers) and revenue (for generators).

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 is 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. However, 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 contracts through an exchange. 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 2.2 The AER's role in the National Electricity Market

The AER has regulatory responsibilities in the NEM across the entire supply chain. We regulate competitive markets primarily through monitoring and reporting. At the wholesale level, we oversee and report on spot and contract market activity.

We 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.

2.5 Electricity demand and consumption

'Grid demand' is demand for electricity produced by generators, sold through the wholesale market.[19] Rooftop solar output is treated as an offset against grid demand because it replaces electricity that would otherwise be supplied by large generators. Consumption is a wider concept covering the total amount of electricity used, including rooftop solar generation.

Grid demand has been falling significantly for 5 years, due to the increasing number of electricity customers generating their own electricity using rooftop solar (section 2.6.7). However, consumption fell only slightly in 2020 and 2021, after rising steadily for 5 years. The increase in consumption was largely driven by the expansion of Queensland's coal seam gas (CSG) and LNG industries and air conditioning, while the fall in 2020 and 2021 was mostly due to milder weather reducing the need for air conditioning.

Electricity demand varies by time of day, season and temperature. It typically peaks in early evening, when rooftop solar generation falls and business and residential use overlap. Seasonal peaks occur in winter (driven by heating loads) and summer (for air conditioning), often reaching maximum levels on days of extreme heat. Demand is a key driver of wholesale electricity prices.

2.5.1 Minimum grid demand

Investment in rooftop solar was high in 2021, further reducing grid demand during the middle of the day across the NEM.

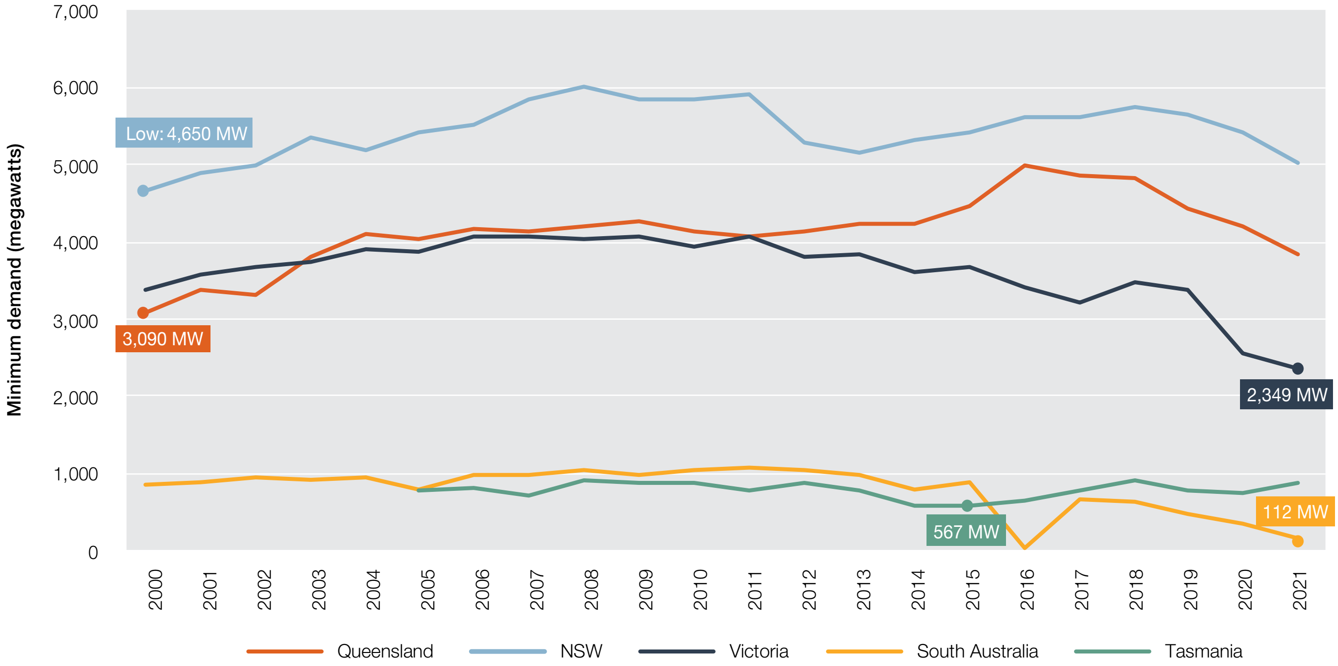
In 2021 demand across the NEM fell to its lowest level since 2005, when Tasmania joined the market.[20] The fall in minimum demand was most pronounced in Victoria and South Australia, where it has been trending down for the past decade. Both regions set new minimum demand records on sunny spring weekend days (Figure 2.13).[21] AEMO reported that for 30 minutes rooftop solar provided 92% of underlying demand in South Australia. It is likely that minimum demand records will be broken again in Spring 2022.

19 More specifically grid demand is demand for electricity produced by scheduled and semi-scheduled generators.

20 Record minimum NEM-wide demand occurred on Sunday 17 October 2021 (13,924 MW, 9% lower than in 2020).

21 South Australia set a new minimum demand record (excluding the System Black event in October 2016) on Sunday 21 November 2021 and Victoria on Sunday 28 November 2021.

Figure 2.13 Minimum grid demand



Note: Minimum 30-minute grid demand (including scheduled and semi-scheduled generation, and intermittent wind and large-scale solar generation) is for any time during the year. Data excludes consumption from rooftop solar systems. Drop in 2016 in South Australia is due to the System Black event in October.

Source: AER, AEMO (data).

As a result of low demand in the middle of the day and high renewable output, prices were negative 27% of the time in South Australia and 22% of the time in Victoria during Q4 2021.

Demand needs to be above certain thresholds for the power system to operate securely. AEMO considers that very low levels of forecast demand in the next 5 years will make it increasingly challenging for it to operate the market with all the required security services.

As the penetration of rooftop solar continues to accelerate, AEMO forecasts a rapid decline in minimum demand, and that:

- minimum operational demand – the lowest level of demand from the grid – will shift from the middle of the night to the middle of the day in all NEM mainland regions in the next 5 years
- the challenges created by falling minimum demand will be experienced earlier than has been expected.[22]

2.5.2 Maximum grid demand

Maximum grid demand fell in all mainland regions in 2021, particularly in Victoria (Figure 2.14). Maximum grid demand has been steady or declining in most regions since 2011, except in Queensland. In Queensland, maximum demand steadily increased due to mining and LNG demand until 2019, before falling in 2020 and 2021. However, in March 2022, with the hot weather and high humidity in Queensland, demand reached over 10 GW, close to the record set in February 2019.

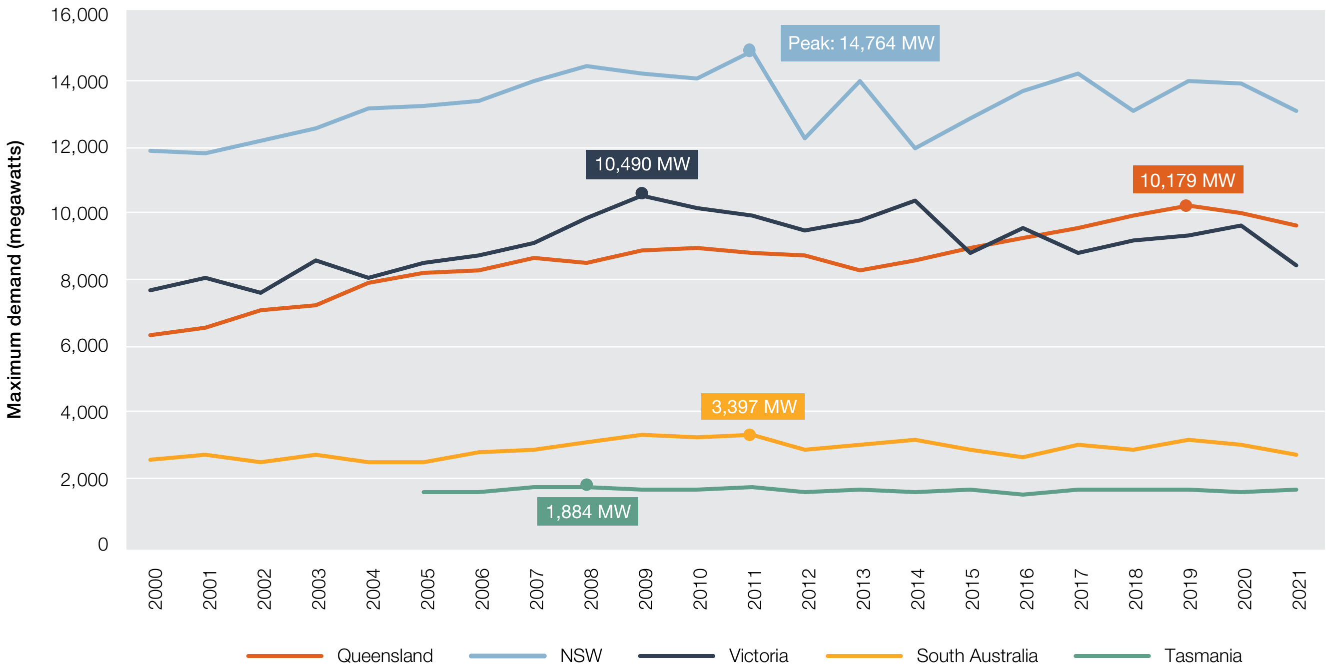
Looking forward, AEMO forecasts maximum demand in every mainland NEM region to be lower in the next 5 years because it expects the business sector's consumption to reduce.[23]

Rooftop solar has a limited impact on maximum demand, which typically occurs in the early evening when solar output ramps down and residential demand increases.

22 AEMO, 2021 Electricity statement of opportunities, August 2021, p 9.

23 AEMO, 2021 Electricity statement of opportunities, August 2021, p 7.

Figure 2.14 Maximum grid demand



Note: Maximum 30-minute grid demand (including scheduled and semi-scheduled generation, and intermittent wind and large-scale solar generation) is for any time during the year. Data excludes consumption from rooftop solar systems.

Source: AER, AEMO (data).

2.6 Generation in the NEM

The NEM's generation fleet uses a mix of technologies to produce electricity. Figure 2.15 and Figure 2.16 compare generation capacity and output across regions.

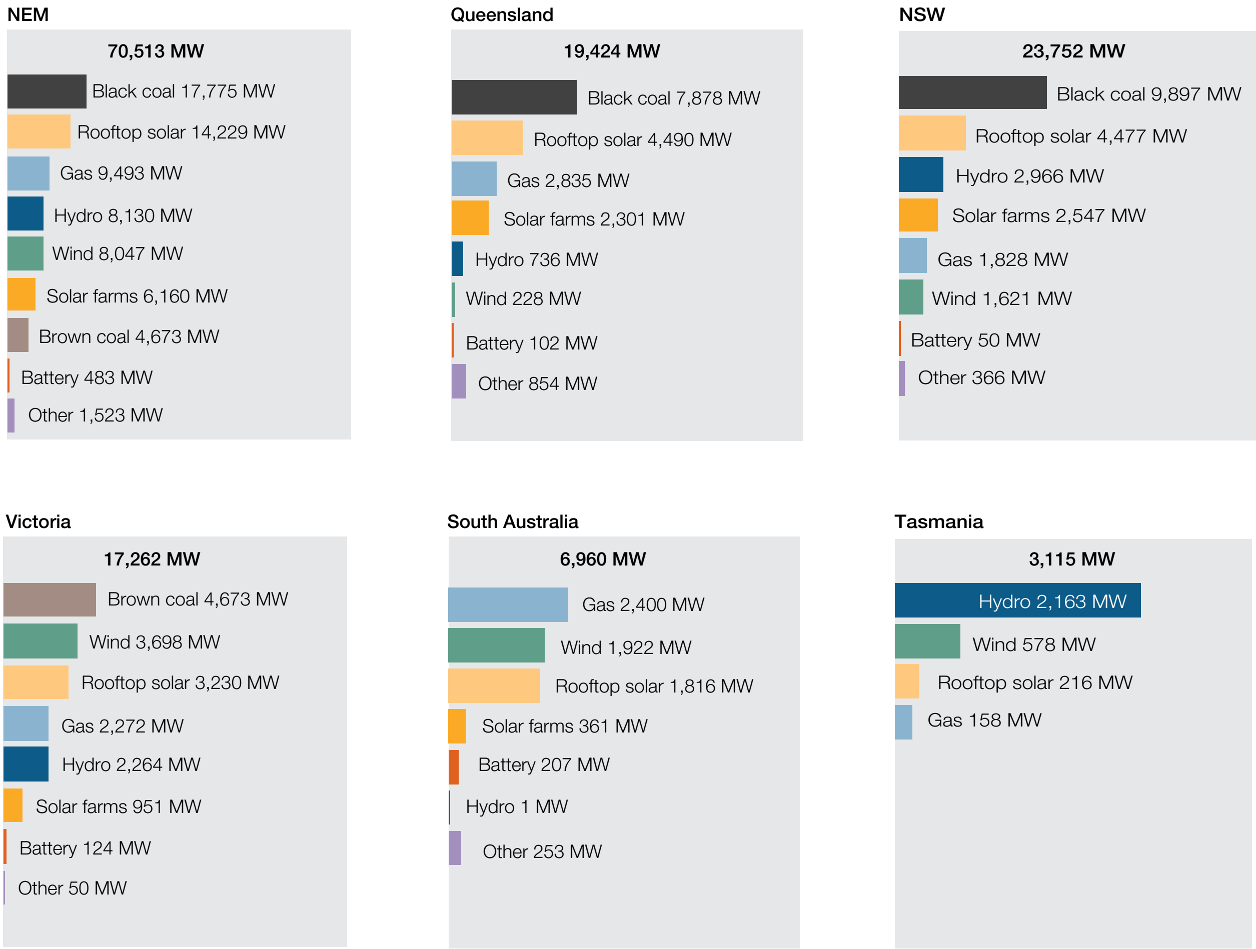
At the end of 2021, black coal provided the most generating capacity in the NEM at over 17 GW, closely followed by rooftop solar with 14 GW of generating capacity. While rooftop solar capacity is not considered as generation in the NEM, its output reduces demand from the grid. Wind and solar farms provided an additional 14 GW.

Looking at output, fossil fuel generators produced 74% of electricity in the NEM in 2021, 6% less compared with 2020.[24] The fall corresponded with an increase in renewable output, which accounted for more than 25% of total grid generation, double that just 4 years earlier.[25]

24 Includes black and brown coal, and gas-powered generation. The total does not include rooftop solar.

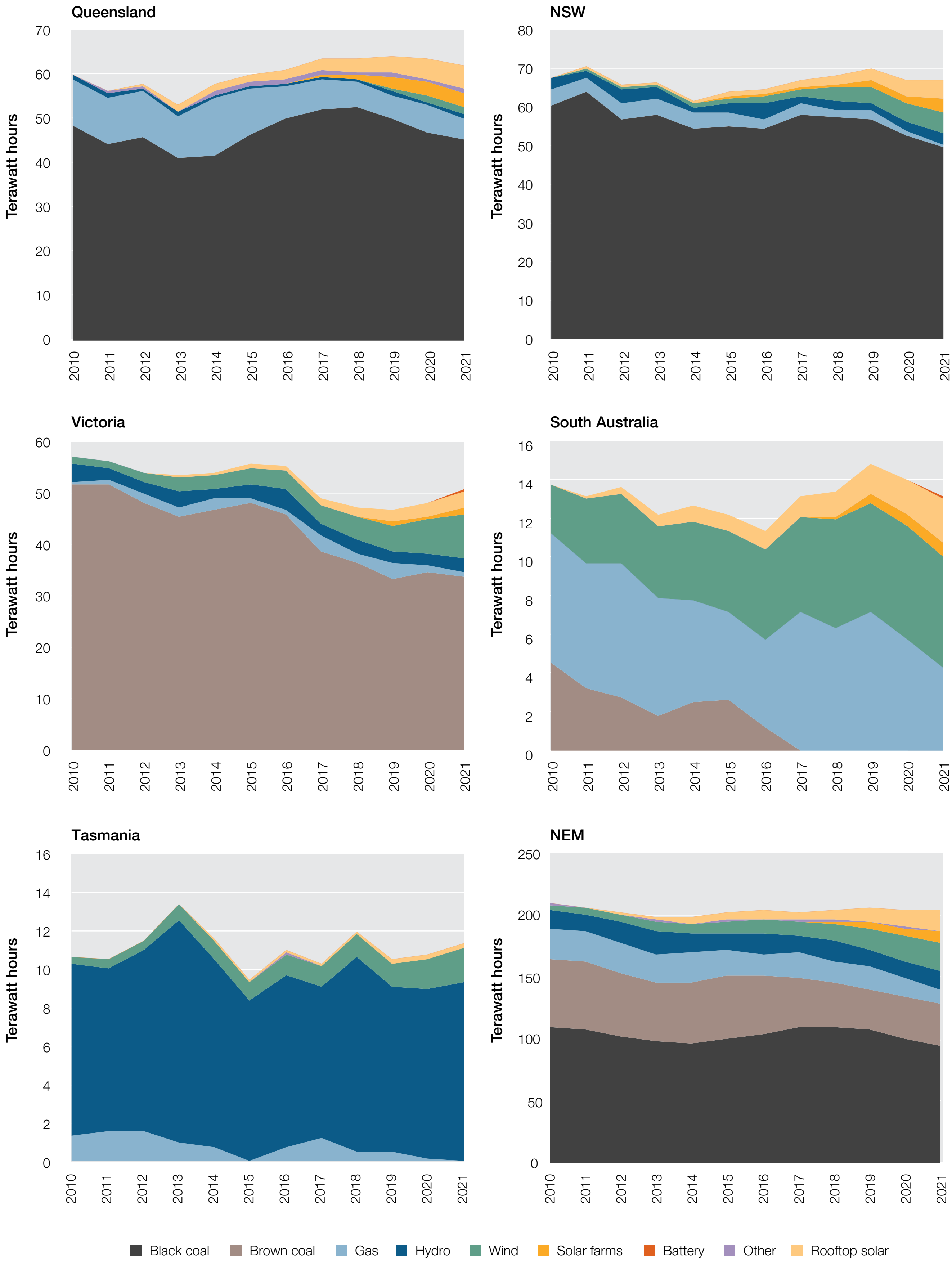
25 AER, Wholesale markets quarterly – Q4 2021, Wholesale electricity markets data, February 2022. Renewable grid generation includes hydro and does not include rooftop solar.

Figure 2.15 Generation capacity, by fuel source



Note: Generation capacity at 1 January 2022. Other dispatch includes biomass, waste gas and liquid fuels.
Source: Grid demand: AER, AEMO; rooftop solar: AER, Clean Energy Regulator, AEMO.

Figure 2.16 Generation output, by fuel source

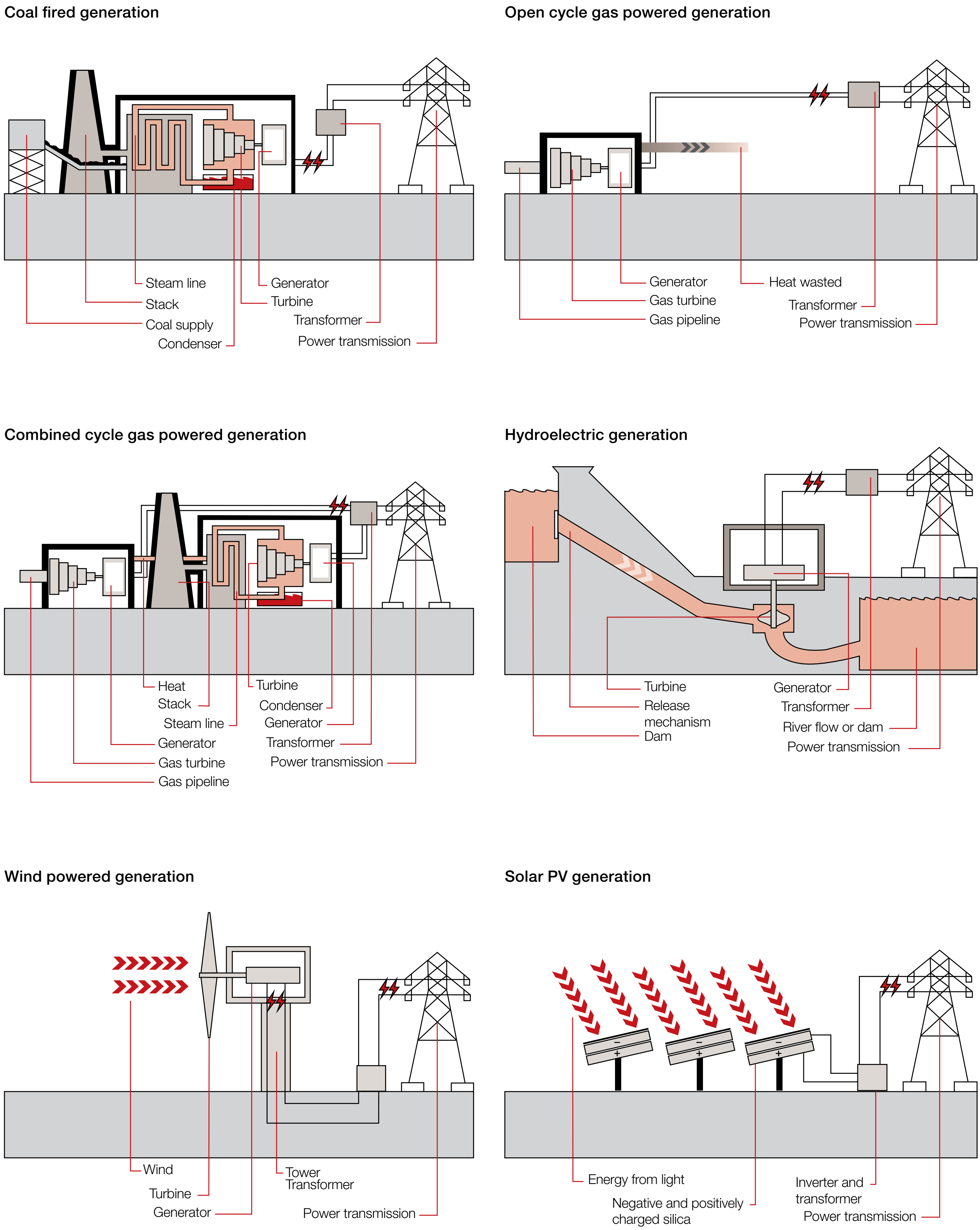


Note: Other dispatch includes biomass, waste gas and liquid fuels.

Source: AER; AEMO (data).

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.

Figure 2.17 NEM generation technologies



2.6.1 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 2.17). Coal-fired generation remains the dominant supply technology in the NEM, producing over two-thirds of all electricity traded through the market in 2021.

Coal plants operate in Queensland, NSW and Victoria. Generators in Queensland and NSW burn black coal, and generators in Victoria depend on brown coal. Black coal produces more energy than brown coal because it has lower water content and produces 30–40% fewer greenhouse gas emissions when used to generate electricity. However, 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 activate, but their operating costs are low. Once switched on, coal plants tend to operate 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.[26]

Impacts of solar generation on coal-fired plant

The rapid influx of grid and rooftop solar over the past 3 years has changed the shape of wholesale electricity prices and demand for baseload (coal) generation during the day. These changing conditions, backed by the global investor and local push to decarbonise, are compromising the economic viability of the NEM's 16 remaining coal-fired power stations. As fossil fuel dependent energy companies pivot toward renewable energy, many of these coal-fired power stations are slated to close earlier than previously announced. Five coal-fired power plants are currently due to close by 2030.

While around 8 GW of the current 23 GW of coal-fired capacity has already been announced to withdraw by 2030, AEMO's most recent integrated system plan (ISP) suggests this number will be closer to 14 GW. That is, it expects 60% of current coal-fired capacity will withdraw by 2030.[27]

The next to exit is Liddell power station in NSW. In April 2022, AGL Energy retired the first Liddell unit, removing 500 MW of black coal generation. The remaining units will be retired in 2023, removing a further 1,500 MW of black coal capacity from the NEM.

This will be followed by the closure of Eraring – Australia's largest power station. In February 2022, Origin Energy announced it would potentially bring forward the retirement of the Eraring black coal power station in NSW by 7 years, from 2032 to 2025.[28]

EnergyAustralia also announced in 2021 that it will retire its Yallourn power station in Victoria in 2028, 4 years earlier than planned. Callide B power station is also expected to close that year and Vales Point B power station is expected to close the following year in 2029. Early in 2022, AGL announced the accelerated closure of its remaining coal-fired power stations of Bayswater (2030–2033) and Loy Yang A (2040–2045).[29]

The economics and operating capability of coal-fired generators have been challenged by the impact of rooftop solar in particular. When rooftop solar generation is high in the middle of the day, the demand for electricity from the grid falls significantly. If demand drops below the minimum technical operating levels of coal plants, which are not engineered to run at low levels of output, plant operations may be significantly disrupted. Options include shutting some generating units from mid-morning before firing them back up in the evening. The ability of generators to operate more flexibly depends on plant age and condition. The increased cycling of output compounds stress on equipment, potentially requiring more frequent maintenance (planned outages) or, as we are seeing more frequently, earlier retirement.

No further investment in new coal plant is proposed for the NEM.

26 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.

27 AEMO, 2022 Integrated system plan, June 2022.

28 Origin Energy, Origin proposes to accelerate exit from coal-fired generation, February 2022.

29 Department of Industry, Statement on early closure of Loy Yang A and Bayswater power stations, February 2022.

Coal outages were high in 2021 and 2022

A high level of coal generation outages contributed to the tight supply conditions across several regions in 2021, starting with the outage at Callide C power station and continuing into 2022. The level of outages was particularly high in April and May 2022, when at times almost 8 GW of capacity was on outage, compared to a normal level of 3 to 4 GW. Black coal outages occurred at Liddell, Eraring, Bayswater and Mount Piper power stations. Brown coal outages occurred at Loy Yang A and B and Yallourn power stations.

The level of planned outages is typically high in these months which are considered a shoulder season and an appropriate time to undertake maintenance. The impact of Covid also changed some of the maintenance schedules, pushing more maintenance into 2022. The level of unplanned outages was also high. Aging coal plants are moving closer to their exit dates. This is impacting long term maintenance decisions and reducing the incentive to undertake expensive overhauls.

The high level of unexpected outages can transfer generation requirements on to other generators (that may not have planned and contracted for this additional workload).

2.6.2 Gas-powered generation

A number of gas generation technologies operate in the NEM. Open cycle gas turbine (OCGT) plants burn gas to heat compressed air that is then released into a turbine to drive a generator (Figure 2.17). In combined cycle gas turbine (CCGT) plants, waste heat from the exhaust of the first turbine is used to boil water and create steam to drive a second turbine (Figure 2.17). The capture of waste heat improves the plant's thermal efficiency, making it more suitable for longer operation than an open cycle plant. Reciprocating engine gas plants use gas to drive a piston that spins a turbine. These plants operate similarly to OCGTs but are more flexible. Some legacy 'steam turbines' – which operate similarly to coal plants – also remain in the market.

Gas plants can operate more flexibly than coal – open cycle plants (and newer CCGT plants and reciprocating engines) need as little as 5 minutes to ramp up to full operating capacity. This has made gas generation more competitive than coal since the start of 5-minute settlement in October 2021.[30]

The ability of gas plants 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 emissions intensive as the most efficient coal-fired plant.[31]

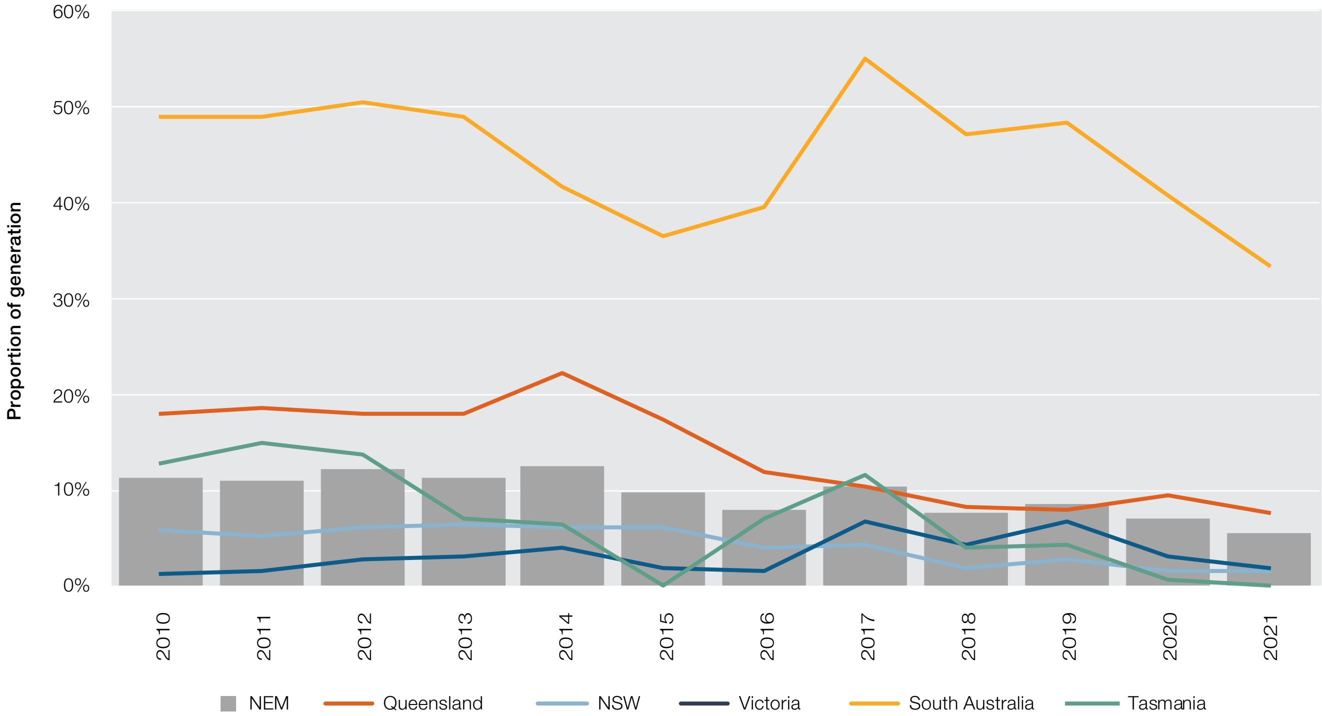
Despite these benefits, gas is a relatively expensive fuel for electricity generation, so gas generators more typically operate as 'flexible' or 'peaking' plant.32 Across the NEM, gas-powered plants supplied only 5% of electricity generated. South Australia relies more on gas-powered generation than other regions. In 2021, the state produced 33% of its local generation from gas plants – the lowest level since 2015 (Figure 2.18).

30 AER, Wholesale markets quarterly – Q3 2021, p 25, November 2021.

31 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.

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

Figure 2.18 Dependence on gas



Note: The share of total regional output produced by gas-powered generators.

Source: AER; AEMO (data).

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.

The interaction between the wholesale electricity and gas markets was particularly prominent in May to July in 2022. A reduction in the availability of coal-fired electricity generation due to outages, lower than expected renewable generation and early winter demand led to an increase reliance on gas-powered generation, despite gas price increases. Spot market prices for gas reached record highs in May as high international gas prices strengthened the incentive for producers to export LNG rather than supply into the domestic market (section 4.3). At the same time, local gas markets were being used to cover short-term spot exposure over the higher demand winter period. Average gas spot prices rose in April to June 2022 to roughly 3 times higher than in the same period in 2021.

As coal-fired generation retires, gas-powered generation is expected to help meet peak demand, particularly during times of low renewable output. It will also provide system services to maintain grid security and stability. AEMO's latest ISP calls for 10 GW of gas-powered generation, or a doubling of current capacity, by 2050 to help firm renewable energy.[33]

There are currently 2 significant proposals for new gas plant in NSW, totalling almost 1,000 MW. Both projects are expected to be operational by the summer of 2023–24.

Snowy Hydro plans to construct a 660 MW open-cycle gas-powered power station at Kurri Kurri in the Hunter Valley. Construction is expected to begin in 2022 and, as a gas peaking plant, it is only expected to operate around 2% of the time.[34] In May 2021, EnergyAustralia committed to developing its Tallawarra B power station (316 MW) in the Illawarra, capable of using a blend of hydrogen and natural gas.[35]

33 AEMO, Integrated system plan 2022, June 2022.

34 Snowy Hydro, Hunter Power Project Overview, September 2020.

35 EnergyAustralia, EnergyAustralia gives green light to Australia's first net zero emissions, hydrogen/gas power plant, May 2021.

2.6.3 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 2.17). Similar to coal and gas plants, hydroelectric generators are synchronous, meaning they provide inertia and other services that support power system security. 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.

Hydroelectric plants have low fuel costs (that is, they do not explicitly pay for the water they use), but 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. Therefore, hydroelectric generators typically operate as 'flexible' or 'peaking' plant, similar to gas-powered generation. While some pumped hydroelectric generation already operates in NSW and Queensland, the construction of Snowy 2.0 will add a further 2,000 MW of pumped hydroelectric capacity in the Snowy Mountains. Snowy Hydro currently expects the pumped hydroelectric storage project will be completed by 2026.[36]

Conditions in the electricity market affect incentives for hydroelectric 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 14% of capacity in the NEM in 2021 and supplied 8% of electricity generated. Tasmania is the region most reliant on hydroelectric generation, with 83% of its 2021 generation coming from that source. NSW and Victoria also have significant hydroelectric generation plants located in the Snowy Mountains region.

In 2021, hydroelectric generation in Queensland increased by 65% compared with the previous year as outages and higher fuel costs impacted black coal and gas generators. This is the highest level of hydroelectric generation in Queensland since at least 2006.

In Q2 2022, hydroelectric generation across the NEM was at the highest level since Q3 2018, and the second highest level since Q1 2015. In NSW, despite pressure to run harder to compensate for the high level of coal outages, generation at Snowy Hydro's biggest power station, Tumut 3, was constrained by environmental concerns. These included high water levels in the release reservoir, Blowering Dam, and the limited release capacity of the Tumut River.[37]

2.6.4 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 2.17).

Renewable generation, including wind, has filled much of the supply gap left by thermal plant closures. Government incentives, including the RET scheme, provided impetus for the growth of wind generation in the NEM. While providing low-cost energy, the weather-dependent nature of wind generators makes their output variable and sometimes unpredictable.

On 4 August 2022, a new record high was set for wind generation in the NEM reaching over 7,300 MW. A new record high was also set for the highest proportion of demand in the NEM met by wind generation. At 1:30am on Friday 5 August one third of all native demand was met by wind generation.

Wind output increased more in 2021 than in any previous year, increasing by 17% from the previous year. Wind farms generated almost 12% of all electricity produced in the NEM and produced twice as much energy as gas-powered generators. With over 1 GW of new wind farms connected in 2021 (accounting for almost a third of all new investment), wind accounted for 14% of the NEM's total capacity.

36 Australian National Audit Office, Snowy 2.0 Governance of Early Implementation, June 2022.

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

Wind penetration is especially strong in South Australia, where it provided 53% of the state's electricity output in 2021. More recently, the focus of wind investment has shifted to NSW and Victoria, where over 40% of capacity installed or committed since July 2017 has occurred. In 2021, after lengthy delays, the NEM's largest wind farm, Stockyard Hill (530 MW) in Victoria, entered the market.

2.6.5 Grid-scale solar farms

Australia has the highest solar radiation per square metre of any continent, receiving an average 58 million petajoules of solar radiation per year.[38] All solar investment to date has been in photovoltaic systems that use layers of semi-conducting material to convert sunlight into electricity (Figure 2.17).

Investment in large-scale solar farms in Australia did not occur at a significant scale until 2018, supported by government incentives under the RET scheme and funding support from the Australian Renewable Energy Agency (ARENA) and Clean Energy Finance Corporation (CEFC). In 2017, commercial solar farms accounted for only 0.5% of total NEM generation capacity and met only 0.3% of the NEM's electricity requirements. But just 4 years later, in 2021, solar farms made up 11% of capacity and 5% of output. In 2021, 18 solar farms, or almost 1.6 GW, entered the market. Most of these were located in Queensland and NSW, including the NEM's largest solar farm, the Western Downs Green Power Hub (500 MW).

Solar output reached record levels in 2021 and continues to grow. In the last quarter of 2021, large-scale solar generation had the highest quarterly output on record – up a massive 41% from a year previous.

2.6.6 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. With less coal-fired generation and more wind and solar generation, increased storage will be essential to manage daily and seasonal variations in output.

Battery storage

Lower costs and expanding opportunities for battery technology has seen a significant increase in battery investment.

Batteries provide multiple benefits to the market. They have fast response times which enable them to help maintain the power system in a secure state faster than other technologies (although they cannot provide sustained generation). They can be co-located with renewable resources to firm output or with gas plant to provide instant energy while the gas plant starts up.

Batteries take advantage of variations in the spot price, typically charging when prices are low, which is often in the middle of the day, and discharging when prices are high. This is often in the morning and evening when demand is high. The greater the difference between these two prices determines how much revenue the battery will make in the spot market. With the increase in negative spot prices this makes storage loads an attractive option.

Batteries in the NEM can also earn significant revenue from operating in frequency control markets.[39]

In 2021, 4 batteries (totalling over 500 MW) entered the NEM. This brought the total number of batteries in the NEM to 9 (totalling over 800 MW). This included the Victorian Big Battery (360 MW), which is now the largest battery in the NEM. The Victorian Big Battery provides support to Victoria's transmission network – allowing for increased wind and solar generation in the region and increased flows over interconnectors with adjacent regions.[40]

An additional 1,700 MW of battery capacity is committed to enter the NEM by 2025. AGL Energy and Origin Energy have announced new batteries to replace capacity lost by the closures of Liddell and Eraring power stations in NSW.[41] [42] These are in addition to the 700 MW Waratah Super Battery the NSW Government has announced.[43]

38 Geoscience Australia, Solar energy, Geoscience Australia website, May 2020.

39 For example, the AER estimated that 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. AER, Wholesale electricity market performance report 2020, December 2020.

40 Victorian Big Battery, Neoen starts operating 300 MW Victorian Big Battery in Australia, December 2021.

41 Origin Energy, Origin proposes to accelerate exit from coal-fired generation, February 2022.

42 AGL, AGL's Hunter Energy Hub takes shape with Liddell grid-scale battery, March 2022.

43 Energy NSW, Waratah Super Battery, May 2022.

Pumped hydroelectricity

Large-scale storage can be provided through pumped hydroelectric projects, which allow hydroelectric plants 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. As with batteries, price arbitrage and the increase in negative prices when demand is low in the middle of the day, may help make pumped hydroelectric more profitable.

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). Use of this technology is limited by the availability of appropriate physical sites, but 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.

2.6.7 Consumer 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 consumer energy resources. These consumer-owned devices can generate or store electricity or actively manage energy demand. Consumer energy resources include:

- rooftop solar
- 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 (section 2.11.3).

By far the fastest development has been in rooftop solar installations, but interest is also growing in battery systems, electric vehicles and demand response.

Rooftop solar generation

Backed by state government incentives, households and businesses have continued to install record volumes of rooftop solar capacity every year since 2015. In 2021, households across Australia installed more than 3 GW of small-scale solar capacity, of which more than 2.7 GW was connected to the NEM.[44]

As of 1 January 2022, rooftop systems in the NEM totalled over 14 GW of capacity, making it second largest fuel type by capacity after black coal (Figure 2.15). By mid–2022 this total had increased to over 15 GW. Around 30% of Australian houses have rooftop solar, a larger share than in any other country. Queensland and NSW have the most installed capacity, but South Australia has the highest capacity per capita.

Output from rooftop solar across the NEM in the first 6 months of 2022 was 19% higher than over the same months in 2021. Output in 2021 had already increased by 24% compared with the year prior, breaking records in every region and meeting 8% of total consumption. A milestone was reached on 14 December 2021 when generation from rooftop solar in the NEM reached 10 GW.

Rooftop solar generation is not traded through the NEM. Instead, installation owners receive reductions in their energy bills for feeding electricity into the grid.

Small-scale storage

Customers are increasingly storing surplus energy from rooftop solar systems in batteries to draw from 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. As charging technologies mature, electric vehicle batteries may also provide electricity back to the grid at times of high demand.

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44 Clean Energy Regulator, Quarterly Carbon Market Report – September Quarter 2021, December 2021. Note there is a reporting time lag with rooftop solar installations, so 2021 data is incomplete.

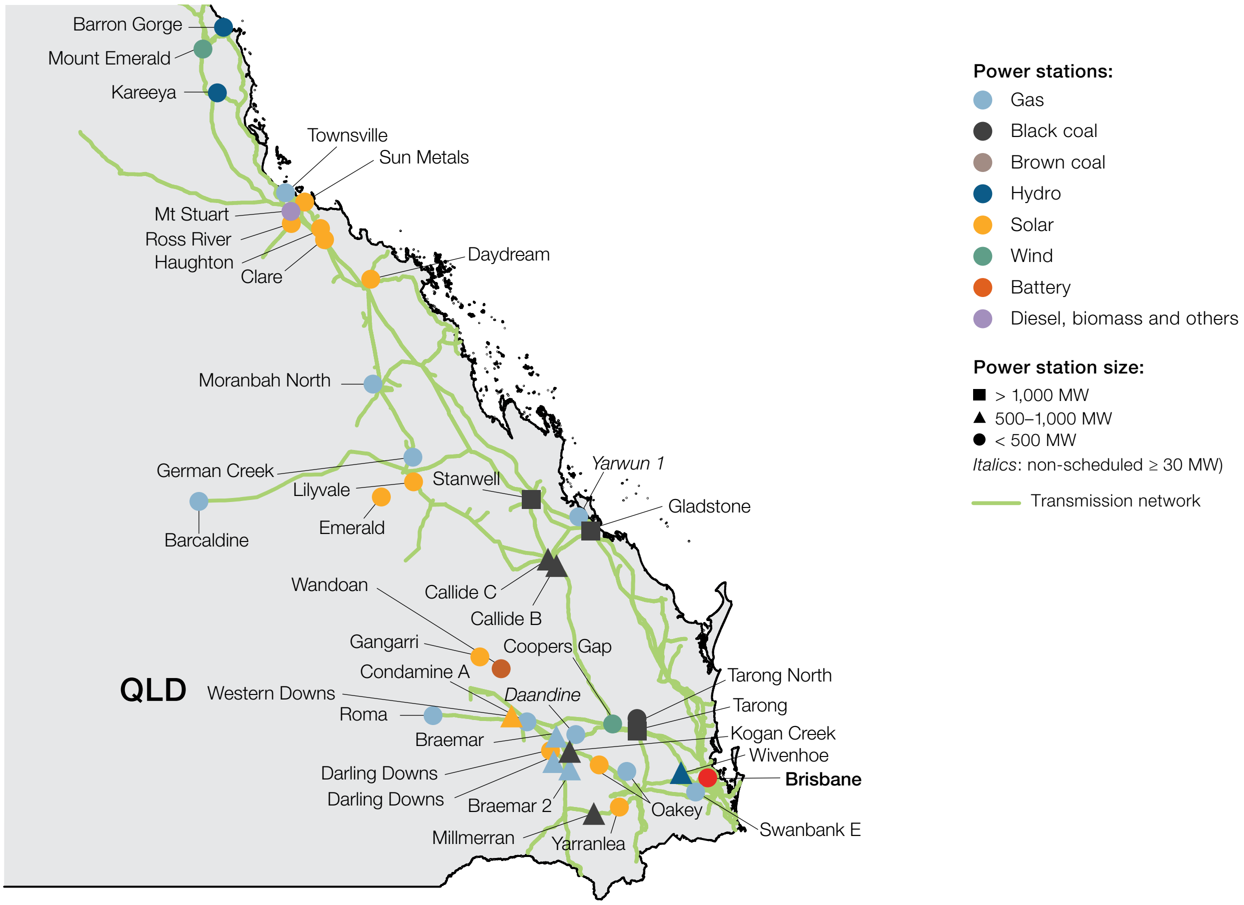
In 2021 small-scale battery installations increased by 33% compared with 2020, continuing the upward trend since 2016.[45]

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

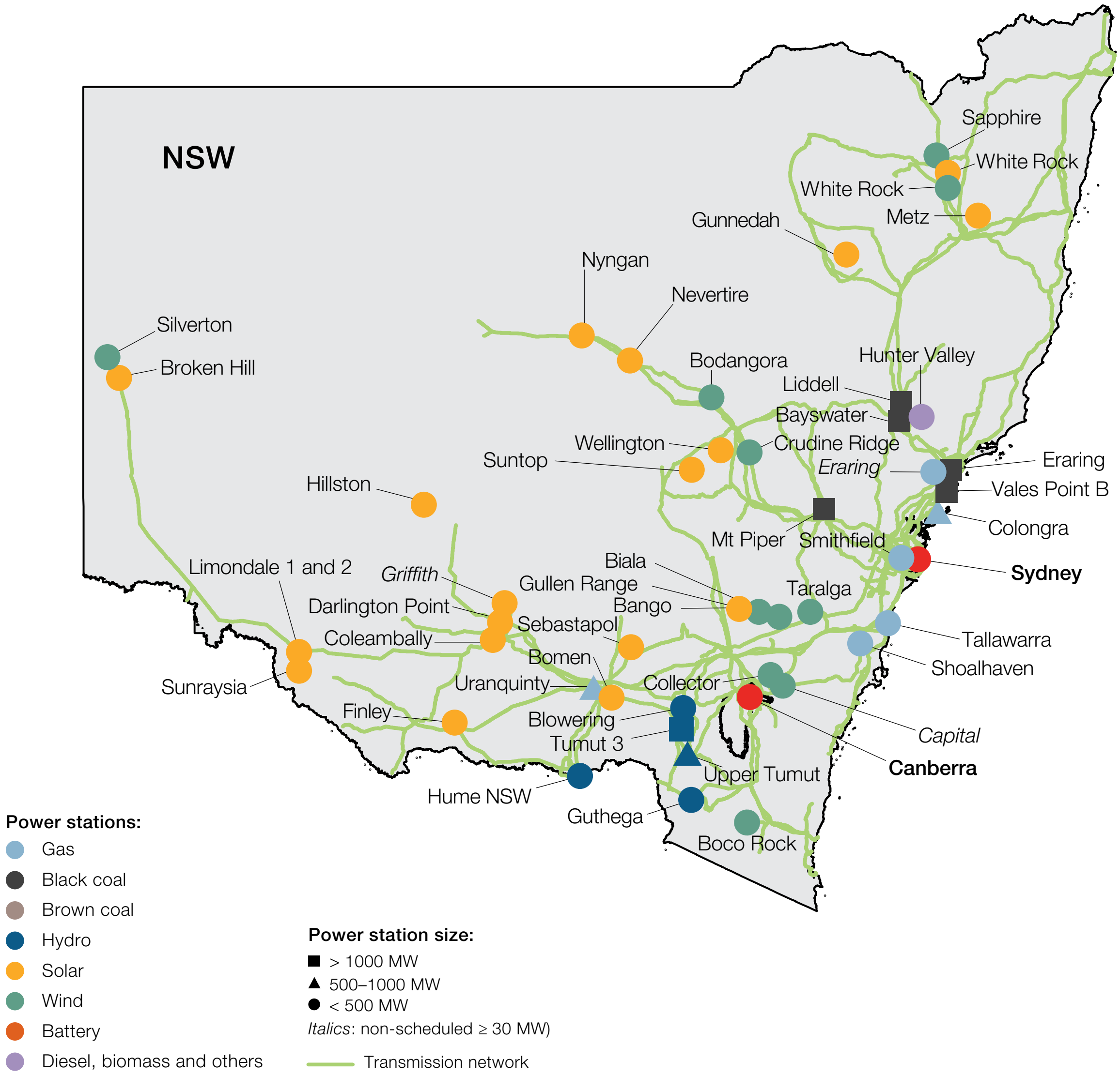
2.6.8 Generator information

Figure 2.19 maps the locations of generation plants and the types of technology in use.

Figure 2.19 Generators in the NEM



45 Data on small-scale battery installations from Clean Energy Regulator, State data for battery installations with small scale systems, Clean Energy Regulator website, March 2022.


NSW
Sapphire
White Rock
White Rock
Metz
Gunnedah
Nyngan
Nevertire
Silverton
Broken Hill
Bodangora
Hunter Valley
Liddell
Bayswater
Wellington
Crudine Ridge
Suntop
Eraring
Eraring
Vales Point B
Hillston
Colongra
Mt Piper
Smithfield
Limondale 1 and 2
Griffith
Biala
Sydney
Gullen Range
Taralga
Darlington Point
Bango
Sebastapol
Coleambally
Tallawarra
Bomen
Shoalhaven
Sunraysia
Uranquinty
Collector
Finley
Blowering
Capital
Tumut 3
Canberra
Upper Tumut
Hume NSW
Guthega
Boco Rock
Power stations:
Gas
Black coal
Brown coal
Hydro
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Power station size:
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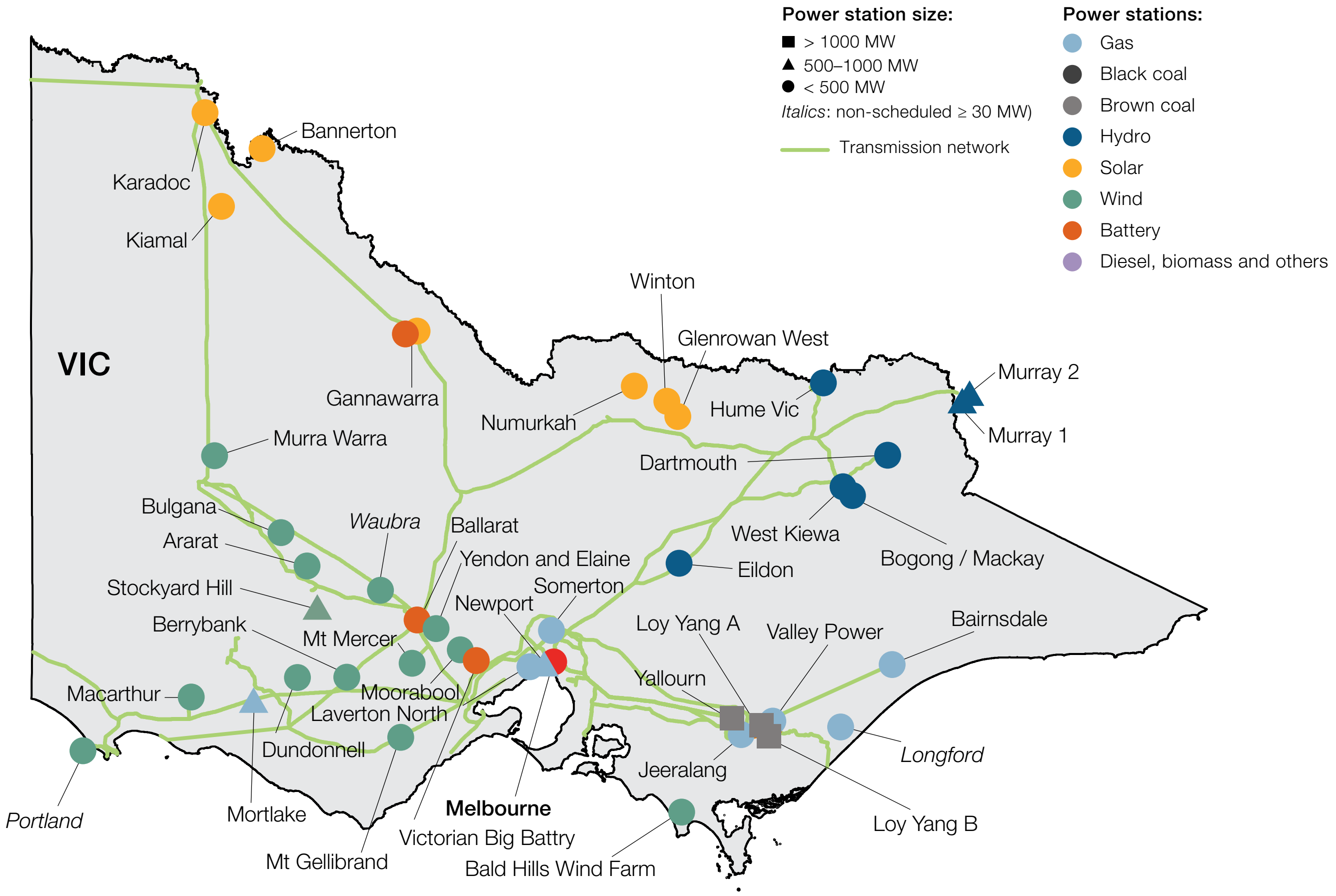
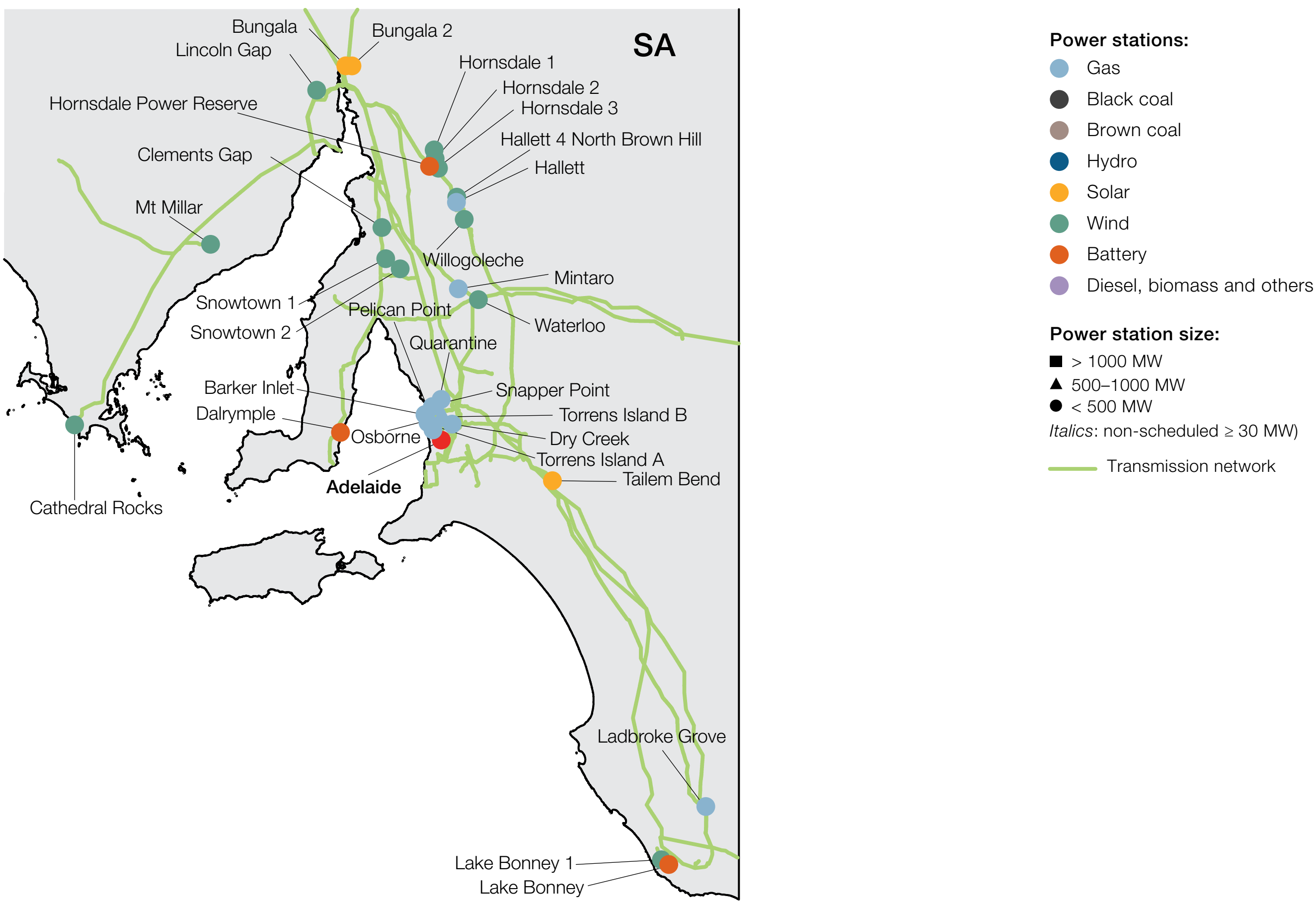
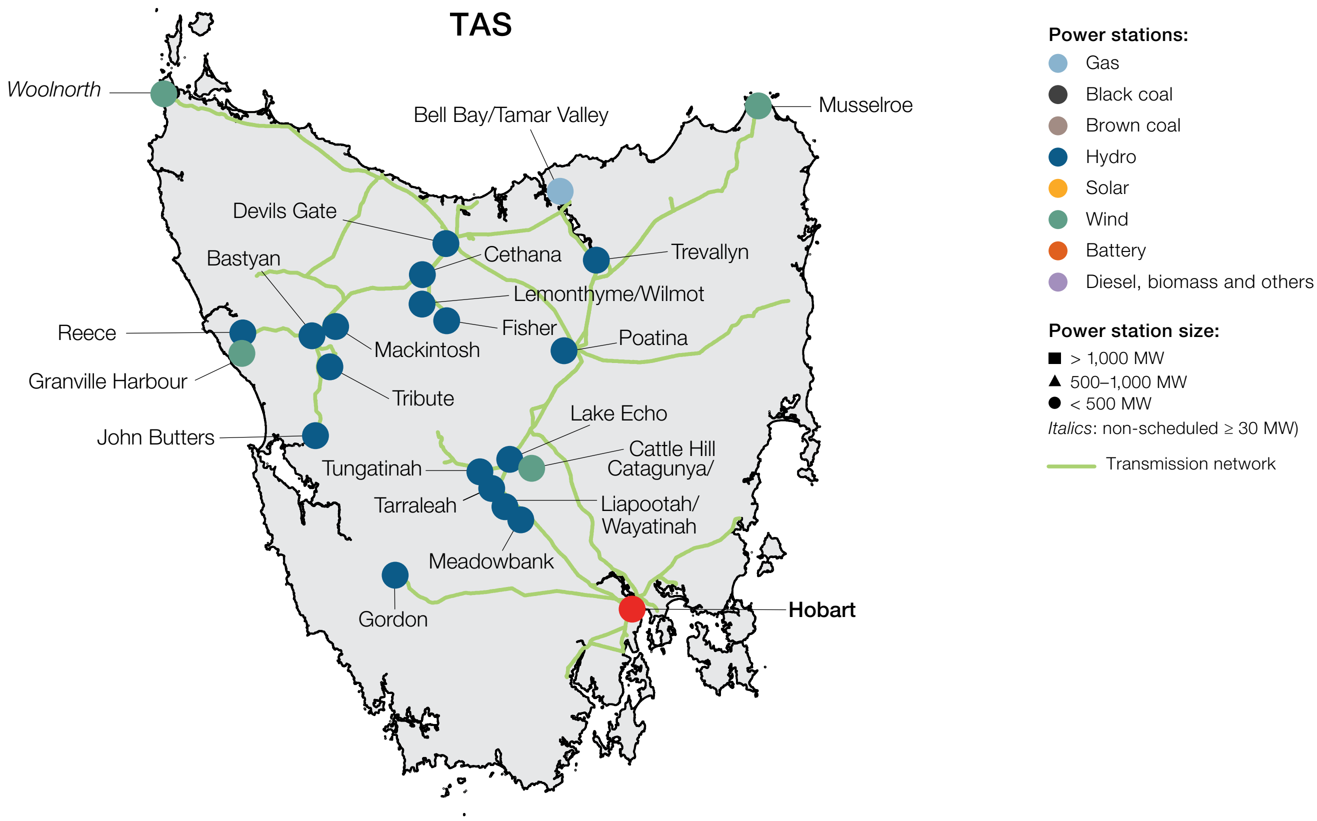
Transmission network



Power station size:
> 1000 MW
500–1000 MW
< 500 MW
Italics: non-scheduled ≥ 30 MW)
Transmission network
Power stations:
Gas
Black coal
Brown coal
Hydro
Solar
Wind
Battery
Diesel, biomass and others
VIC
Bannerton
Karadoc
Kiamal
Winton
Glenrowan West
Murray 2
Murray 1
Gannawarra
Numurkah
Hume Vic
Murra Warra
Dartmouth
Bulgana
Waubra
Ballarat
West Kiewa
Ararat
Yendon and Elaine
Eildon
Bogong / Mackay
Stockyard Hill
Somerton
Newport
Berrybank
Loy Yang A
Valley Power
Bairnsdale
Mt Mercer
Macarthur
Moorabool
Yallourn
Laverton North
Dundonnell
Longford
Jeeralang
Portland
Mortlake
Melbourne
Loy Yang B
Victorian Big Battry
Mt Gellibrand
Bald Hills Wind Farm



Bungala
Bungala 2
Lincoln Gap
SA
Hornsdale 1
Hornsdale 2
Hornsdale Power Reserve
Hornsdale 3
Hallett 4 North Brown Hill
Clements Gap
Hallett
Mt Millar
Willogoleche
Mintaro
Snowtown 1
Pelican Point
Snowtown 2
Waterloo
Quarantine
Barker Inlet
Snapper Point
Dalrymple
Torrens Island B
Osborne
Dry Creek
Torrens Island A
Adelaide
Tailem Bend
Cathedral Rocks
Ladbroke Grove
Lake Bonney 1
Lake Bonney
Power stations:
Gas
Black coal
Brown coal
Hydro
Solar
Wind
Battery
Diesel, biomass and others
Power station size:
> 1000 MW
500–1000 MW
< 500 MW
Italics: non-scheduled ≥ 30 MW)
Transmission network



Note: Excludes solar, wind and diesel/biomass smaller than 100MW registered capacity.
Source: AER.

2.7 Trade across 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. This allows for more efficient use of the generation fleet.

Typically, Queensland has surplus generation capacity, making it a net electricity exporter (Figure 2.20). However, export levels significantly dropped in 2021 compared with previous years because of network outages that were part of the QNI upgrade. In the first 3 months of 2022, for the first time, Queensland imported more than it exported.

NSW has relatively high fuel costs, typically making it a net importer of electricity. Constrained imports from both Queensland and Victoria meant NSW had to source more of its own generation throughout 2021.

Victoria's abundant supplies of low-priced brown coal generation traditionally make it a net exporter of electricity. In 2021, lower prices in Victoria led to more than a doubling in net exports.

Though South Australia had switched from net importer to net exporter from 2019 following increased wind generation, ongoing network outages in South Australia limited its ability to export cheaper generation to Victoria in 2021.

Tasmania's trade position varies with environmental and market conditions. Key drivers include local rainfall (which affects dam levels for hydroelectric generation), Victorian spot prices, and the availability of the Basslink interconnector (which has suffered multiple extended outages in recent years). In 2021 Tasmania was a net exporter, reflecting that it had the lowest volume weighted average (VWA) prices in the NEM.

Figure 2.20 Inter-regional trade

Source: AER; AEMO.

2.7.1 Market alignment and network constraints

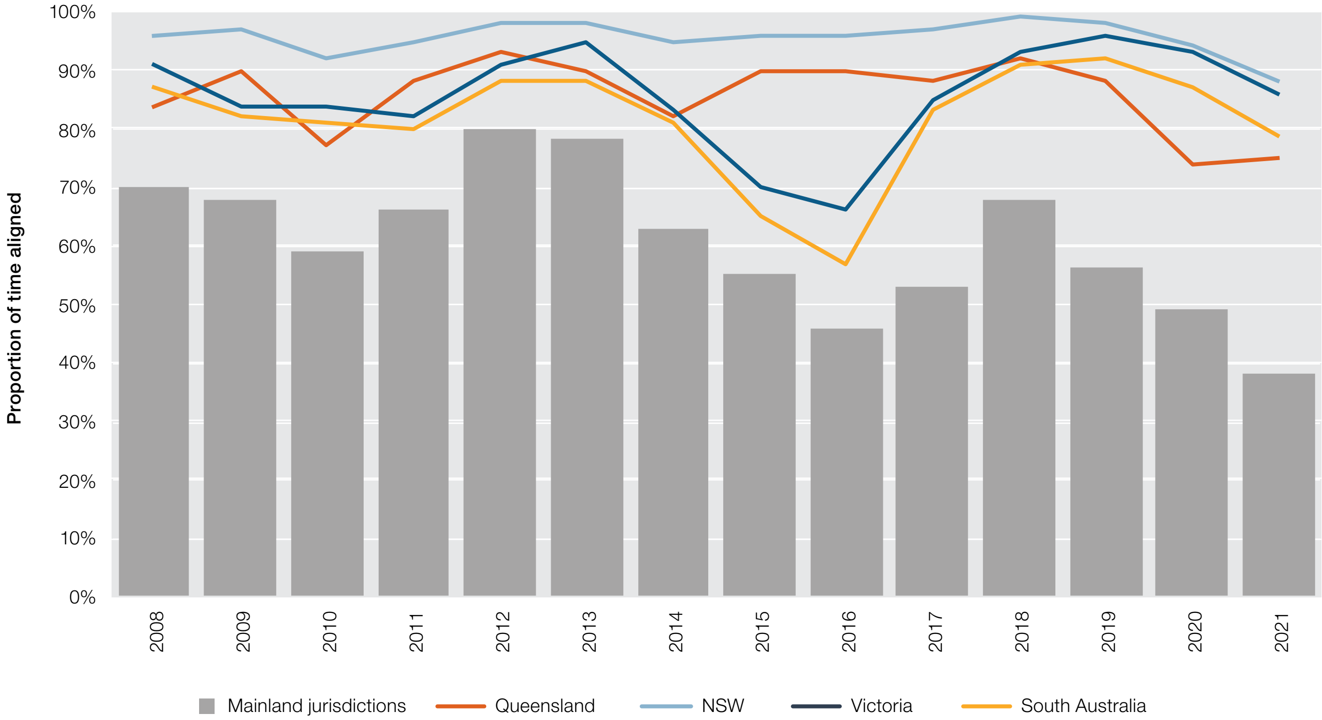
Price alignment in the NEM has fallen over the past 3 years. The market sets a separate spot price for each NEM region. When the interconnectors linking NEM regions are unconstrained, trade brings prices into alignment across all regions (apart from variations caused by physical losses that occur when 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.

NSW and Victoria were the most aligned regions, with prices aligned almost 90% of the time in 2021. Prices in Queensland and South Australia, at either end of the grid, were less aligned, with prices aligned 75% of the time in Queensland and 80% of the time in South Australia.

Queensland's alignment rates declined in 2020 and 2021, driven by work to upgrade NSW interconnector that limited flows between the regions (Figure 2.21). NSW's alignment rates also fell, driven by transmission outages that restricted flows across the Victoria–NSW interconnector.

Price alignment in Victoria and South Australia had been less regular, with congestion on the Victoria – South Australia interconnectors. 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 (Figure 2.21). However, price alignment in Victoria and South Australia also fell in 2021.

Figure 2.21 Price alignment in mainland NEM 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 (data).

2.8 Market structure

Around 200 power stations sell electricity into the NEM spot market. Despite significant new entry over recent years, a few large participants control a significant proportion of generation in each NEM region. Ownership of flexible generation is particularly concentrated.

2.8.1 Market concentration

The 2 largest participants account for around 60% of output (Figure 2.22) in all regions except South Australia.

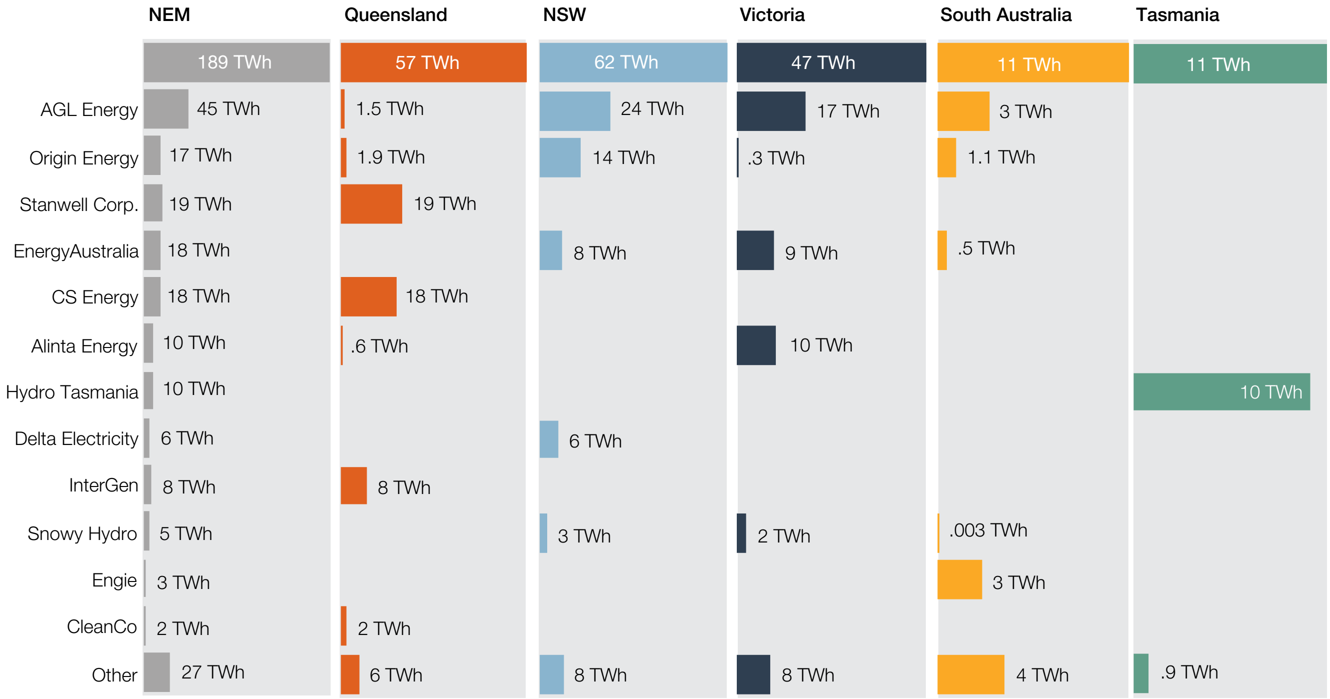
Private entities control most generation output in NSW, Victoria and South Australia:

- In NSW, AGL Energy and Origin Energy produced around 60% of output in 2021 and own over 40% of the region's capacity. EnergyAustralia and Delta are other major players. Snowy Hydro, owned by the Australian government produced 4% of output in the region but owns 19% of its capacity.
- In Victoria, AGL Energy and Alinta produced around 57% of output in 2021 and own over 30% of the region's capacity. EnergyAustralia produced a slightly smaller share of output than Alinta. Snowy Hydro produced 5% of output in the region but owns 16% of its capacity.
- In South Australia, AGL Energy and Engie produced 50% of output in 2021and own 45% of the region's capacity. The other significant entity is Origin Energy.

Government-owned entities control most generation output in Queensland and Tasmania:

- In Queensland, state-owned corporations Stanwell and CS Energy controlled 65% of generation output in 2021 and own 42% of its capacity. A third state-government owned entity, CleanCo, produced 4% of the state's output. It was created in 2019 to increase competition and support growth in renewables. The largest private operator by output is InterGen.
- In Tasmania, the state-owned Hydro Tasmania owns most of the 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.

Figure 2.22 Market shares in generation output



Note: Output in 2021. 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 2021. Data exclude output from rooftop solar systems and interconnectors.

Source: AER; AEMO; company announcements.

Ownership of flexible generation, or generation that can respond quickly to changing market conditions, is particularly concentrated. A few participants control significant flexible generation capacity in NSW, Victoria and Tasmania. Snowy Hydro controls more than 5,000 MW of flexible generation capacity. Most of these assets are located in NSW and Victoria and, as a result, Snowy Hydro controls around 60% of flexible generation in NSW and 50% in Victoria.[46] In addition, Snowy Hydro is developing Snowy 2.0, which would add a further 2,000 MW of flexible capacity to its portfolio. It also plans to construct a 660 MW gas-fired power station near Kurri Kurri. Origin Energy is the second largest provider of flexible generation, with significant capacity across the mainland. Collectively, Snowy Hydro and Origin Energy control almost all flexible capacity in NSW and more than three-quarters in Victoria. Ownership of flexible capacity is less concentrated in the other regions.

Flexible generation is playing an increasingly important role in the market. In the recent high priced market events, this plant played a particularly critical role in meeting demand. We monitor concentration and competition in the supply of flexible capacity, in addition to broader market outcomes, in our *Wholesale electricity market performance report* due to be released in December 2022.

2.8.2 Vertical integration

Most large generators in the NEM are vertically integrated, 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. The 4 largest vertically integrated participants in each region account for the majority of generation output and supply more than half of retail load. Across the NEM, 3 retailers – AGL Energy, Origin Energy and EnergyAustralia – supplied 44% of electricity generation in 2021–22 and supplied 64% of residential energy customers in Q1 2022.

Second tier retailers – Red Energy and Lumo Energy (Snowy Hydro), Simply Energy (Engie) and Alinta – also own major generation assets. These vertically integrated businesses supplied 9% of electricity generation in 2021–22 and 13% of residential energy customers in Q1 2022.

46 AER, Wholesale electricity market performance report, December 2020.

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's share of the retail load is greater than its share of generation output, but they also have a greater share of peaking generation. This allows them to manage the risk of high prices. These differences drive different contracting strategies across the businesses.

Several 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 black coal Vales Point Power Station in NSW and Shell Energy owns the gas-powered 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 most of the generation capacity in Tasmania.

2.9 Generation investment and plant closures

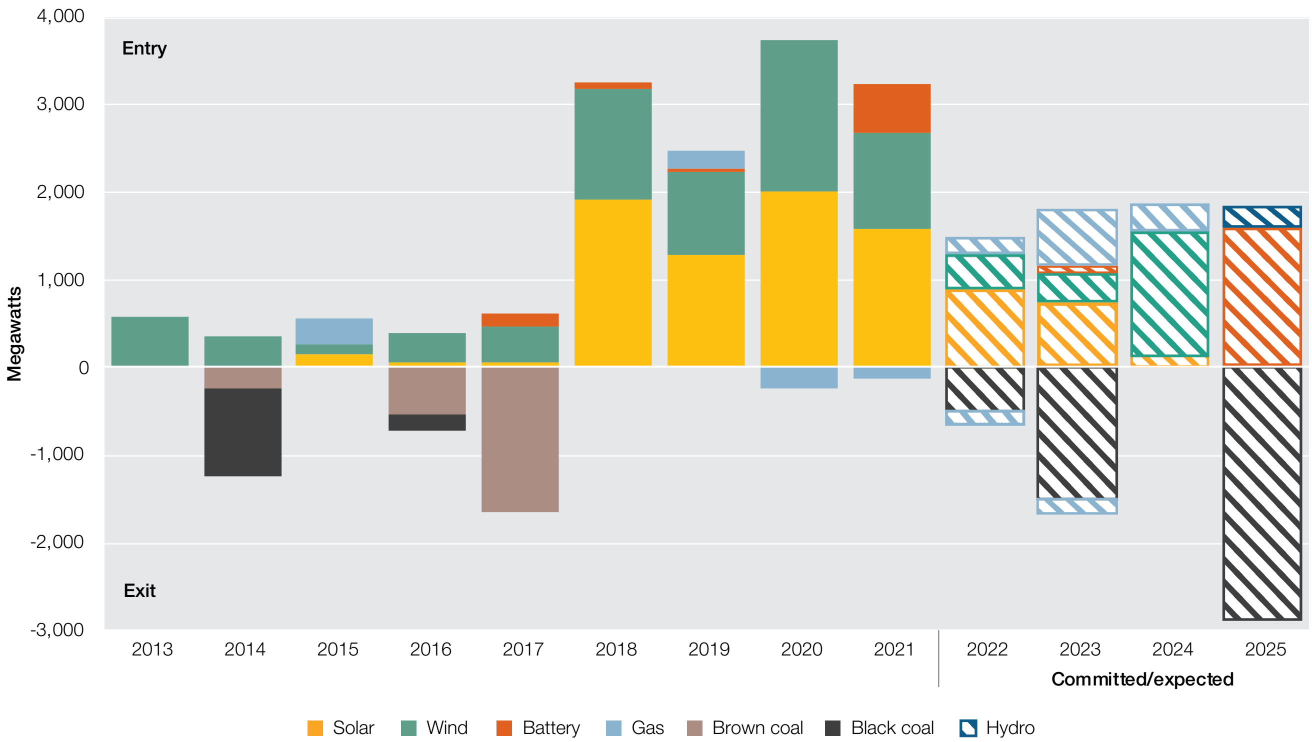
Around 12,500 MW of new utility-scale solar, wind and battery investment was added to the NEM in the 4 years to 2022. Over the same period, a net 150 MW of gas capacity was withdrawn (Figure 2.23).

In 2021, over 3 GW of renewable capacity entered the market, comprising:

› 1.5 GW of solar capacity, which was located mostly in NSW and Queensland
› 1 GW of wind capacity, which was located mostly in Victoria
› 0.5 GW of battery capacity (2 batteries in Victoria, 1 in Queensland and 1 in NSW).

This new entry included the NEM's largest wind farm (Stockyard Hill), largest solar farm (Western Downs Green Power Hub) and largest battery (the Victorian Big Battery). 150 MW of gas capacity exited the NEM in 2021 – namely, the Mackay Gas Turbine (30 MW) in Queensland and the third unit (120 MW) at Torrens Island A Power Station in South Australia.

Figure 2.23 New generation investment and plant withdrawal



Note: Capacity includes scheduled and semi-scheduled generation, but not rooftop solar capacity. Actual and expected investment and closures from 1 January 2022 are shown as shaded components. These include Liddell and Osborne power stations in 2023 and Eraring power station in 2025.

Source: AER; AEMO (data).

More than 5,000 MW of additional capacity is committed to come online in 2022 and 2023. As well as solar and wind, committed new entry includes the 660 MW Kurri Kurri gas-powered power station and over 500 MW of new batteries.

2,300 MW of base load capacity is expected to retire in 2022 and 2023. Exits in 2022 include AGL's Hunter Valley Gas Turbines (50 MW) in January, the first black coal unit (500 MW) at AGL's Liddell Power Station in April (with full closure taking place in April 2023) and AGL's final Torrens Island gas-powered unit (120 MW) in September.

Further fossil fuel plant withdrawals are expected, including 8,200 MW of coal-fired generation expected to retire between 2023 and 2029.

2.10 Power system reliability

Reliability is about the power system being able to consistently supply enough electricity to meet customers' requirements.[47]

The transition in the energy market has increased concerns about reliability. Coal plant closures remove a source of 'dispatchable' capacity that could historically 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. But they may also emerge over winter when solar output is low. Reliability concerns were elevated this winter 2022 due to coal plant outages, fuel constraints and high demand.

Box 2.2 How reliability is 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 reliability standard requires any shortfall in power supply to not exceed 0.002% of total electricity requirements. It has rarely been breached, but AEMO increasingly intervenes in the market to manage forecast supply shortfalls.

While the 0.002% target 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 as a trigger for market mechanisms to prevent forecast supply shortages. From 2020 to 2025 a tighter standard of 0.0006% is used to trigger the RRO and set the threshold where AEMO can procure interim reliability reserves.

The reliability 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.

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.

2.10.1 Managing reliability

The wholesale market remains the primary mechanism for delivering reliability. However, AEMO has powers to mitigate reserve shortfalls, including having emergency reserves on standby.

Reliability and Emergency Reserve Trader

Over the 5 summers up to and including 2021–22, AEMO used the Reliability and Emergency Reserve Trader (RERT) mechanism to maintain reliability. The mechanism allows AEMO to procure additional supply from generators and/or demand management from customers (to reduce their consumption) at times of limited reserves to reduce the risk of load shedding.

47 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 2.11).

Reserves procured under the RERT must be 'out of market'. Specifically, any generator or load that participated in the wholesale market in the previous 12 months may not provide emergency reserves through the RERT.[48]

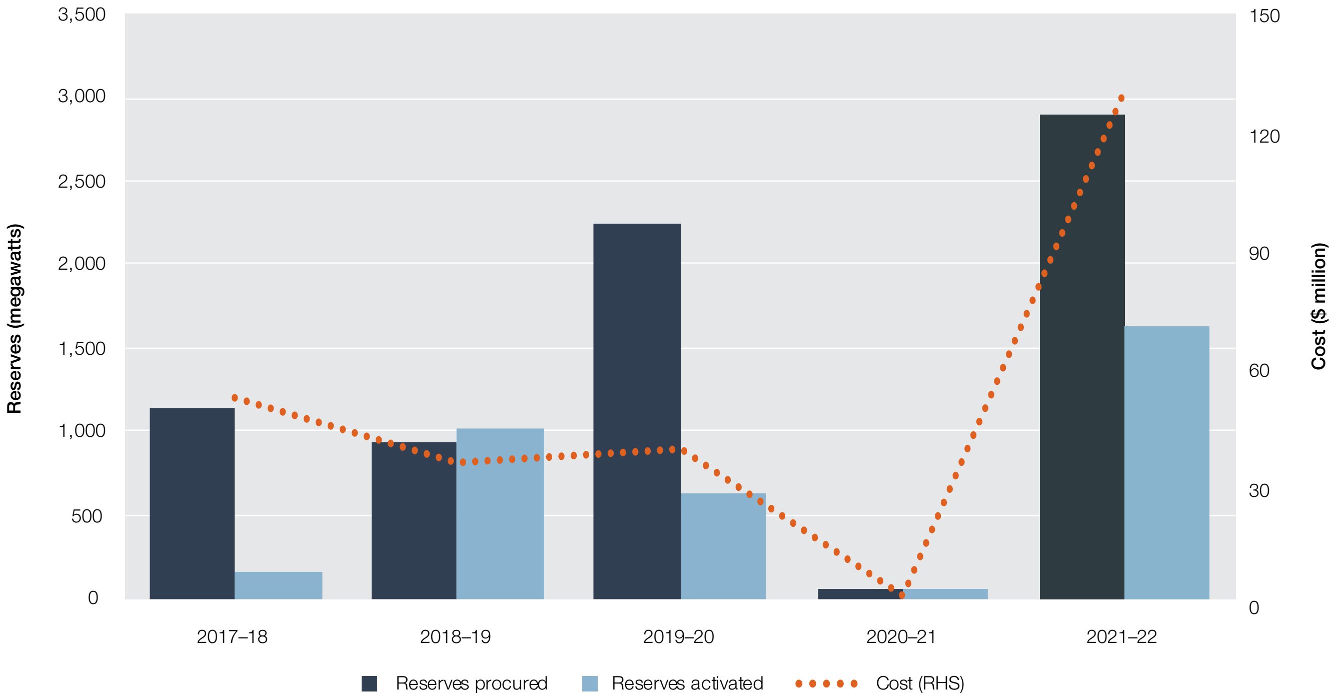
RERT is activated only if required. The RERT scheme is expensive to operate and consumers ultimately bear these costs. AEMO maintains a panel of RERT providers that can provide short notice and medium notice reserve if required. Panel members for short notice RERT agree on prices when appointed to the panel, whereas panel members for medium notice RERT negotiate the price when reserves are required. AEMO may procure long notice reserve through invitations to tender where it has 10 weeks or more notice of a projected shortfall.

Before 2017–18, the RERT mechanism had been used to procure backup capacity only 3 times 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 and again in December 2020. The cumulative cost of the RERT between 2017 and 2020 was around $126 million (Figure 2.24).

In 2021 AEMO activated RERT in Queensland for the first time, following a serious fire at the Callide C power station in May 2021, at a cost of $460,000.[49]

In the first half of 2022, AEMO has relied on RERT to manage reliability more than at any other time at a record cost of over $130 million. In February it activated RERT in Queensland on a hot, humid day with plant outages and low wind generation, at a cost of $50.1 million. In June, it activated RERT following the administrated price cap and subsequent withdrawal of generation capacity. During this period, it activated RERT 3 times in NSW (14, 15 and 16 June) at a cost of $76.2 million and once in Queensland (15 June) at a cost of $3.7 million.[50]

Figure 2.24 RERT reserves and costs



Note: Reliability and Emergency Reserve Trader (RERT) costs include costs for availability, pre-activation, activation and other costs (including compensation costs).

Source: AER analysis of AEMO's RERT reporting.

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

49 AEMO, Reliability and Emergency Reserve Trader End of Financial Year 2020–21 Report, August 2021.

50 AEMO, Reliability and Emergency Reserve Trader End of Financial Year 2021–22 Report, August 2022.

2.10.2 Reliability outlook

In August 2022, AEMO forecast relatively low reliability risks for the coming summer, although risks remain under extreme conditions.[51] These include weather uncertainty or simultaneous generator and/or transmission outages that may reduce available supply when it is required.

A change since last year's forecast and now, is that both South Australia and Victoria could breach the Interim Reliability Standard in 2023–24. AEMO also brought forward the timing for potential gaps in reliable power supply by up to 7 years due to accelerating coal power station closures, delays in transmission projects and expectations of rising demand.

The NEM faces 5 announced coal-fired generator retirements in the next decade. Liddell (NSW) in 2023, Eraring (NSW) as soon as August 2025, Yallourn (Victoria) and Callide B (Queensland) in 2028 and Vales Point B (NSW) in 2029.

As a result, AEMO forecast there will be periods when electricity supply may not meet demand in NSW from as early as 2025–26. The 2022 ISP sets out the scale and urgency of the transmission projects needed to support new generation.[52]

The Health of the NEM 2022 found the best strategy to manage the risk of the transition is to build replacement assets quicky and cost-effectively, in advance of generation retirements.[53] This will reduce our exposure to the shocks of international gas and coal price movements, reduce our reliance on ageing assets, and allow consumers to benefit from renewable energy resources. However, if there are delays in proposed generation, storage or transmission projects, or enabling reform, there is a growing risk of reliability gaps.

2.11 Power system security

Power system security refers to the power system's technical stability in terms of frequency, voltage, inertia and similar characteristics. Historically, the NEM's coal, gas and hydroelectric generators helped maintain a stable and secure system through inertia and system strength services provided as a by-product of producing energy. However, as older synchronous plants retire, or reduce operations in response to falling demand, 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 and 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 will mean 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.

AEMO is more frequently relying on directions to keep the system secure. Directions for system security are intended a last resort intervention, when the market has not delivered the necessary requirements. In South Australia, directions to market participants to take action to maintain or restore power system security have been in place for a substantial amount of time in the past 2 years at a substantial cost. In 2021 total costs for directing South Australian generators for system strength reached $94 million – almost double those costs in 2020.

In South Australia, 4 synchronous condensers, installed by ElectraNet, started operating in October 2021 to provide system strength and inertia. Each has a flywheel with a large amount of momentum. In the event of a disturbance on the network, these provide the electrical inertia to power through the fault. They have reduced the number and cost of market interventions, relaxed constraints on wind and solar output and reduced the amount of gas generation required down to 2 units. Directions in South Australia fell from being in place over 80% of the time in the last quarter of 2021 to below 20% of the time in the first quarter of 2022.[54]

51 AEMO, 2022 electricity statement of opportunities, August 2022.

52 AEMO, Integrated system plan (ISP) 2022, 30 June.

53 ESB, Health of the National Electricity Market 2022, September 2022.

54 AEMO, Quarterly energy dynamics, Q1 2022, April 2022.

Energy rule reforms have widened the pool of providers (such as batteries and demand response) of security services. An initial reform to support more flexible generation saw 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. Three key regulatory changes are expected to improve system security:

- A new system strength framework will apply from December 2022.
- AEMO will implement a very fast ancillary service market in 2023. In July 2021 the AEMC published a rule requiring that AEMO introduce 2 new market ancillary services to help control system frequency and keep the future electricity system secure – namely, very fast raise services and very fast lower services markets, which will facilitate the delivery of fast frequency response services.
- Market reforms for valuing, procuring and scheduling essential system security services are under consultation. Consistent with the broader ESB post-2025 reform program, the AEMC is consulting on rule change requests concerning valuing, procuring and scheduling essential system services to ensure the power system remains secure.[55]

2.11.1 Security performance in the National Electricity Market

As part of AEMO's market operations, it seeks to maintain system frequency within a secure 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. Maintaining system security during the energy transition has been a key focus of the NEM market bodies.

Security performance can be impacted by changing system conditions (including extreme weather), generation volatility and an increase in load. AEMO reports annually on system security needs across the NEM for the coming 5-year period. Its December 2021 report identified system strength shortfalls in NSW and Queensland, and inertia and voltage shortfalls in Queensland and South Australia.[56] AEMO expects the need for additional system security services will only increase over the coming years as power stations that previously supplied these services withdraw from the system. AEMO needs to consider what technologies will be incentivised to provide these services in future, and whether the new market arrangements currently being developed will provide sufficient incentives to do so.

2.11.2 Frequency control markets

AEMO procures some of the services needed to maintain power system stability through markets. 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, which 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 several new participants emerged in recent years. In mid-2022, 10 participants were providing FCAS in Queensland, 12 in NSW, 10 in Victoria, 16 in South Australia and 2 in Tasmania. Demand response aggregators now offer FCAS across all NEM regions, and virtual power plants and battery storage offer services in all mainland regions.[57] Some of these new entrants account for only a small proportion of FCAS trades and others such as batteries have displaced incumbent providers.

In the first quarter of 2022, helped by the Victorian Big Battery which started providing FCAS in November 2021, batteries became the largest provider of FCAS in the NEM, providing almost a third of all FCAS (by volume). This was more than either black coal or hydroelectric. Demand response also provided more FCAS, growing to 14% of FCAS volumes.[58]

55 A more detailed discussion of these essential system services can be found in AEMO and AEMC's Joint Paper on Essential System Services and inertia in the NEM (June 2022) and AEMO's Engineering Framework.

56 AEMO, 2021 System Security Reports, December 2021.

57 AEMO, NEM registration and exemption list, June 2022.

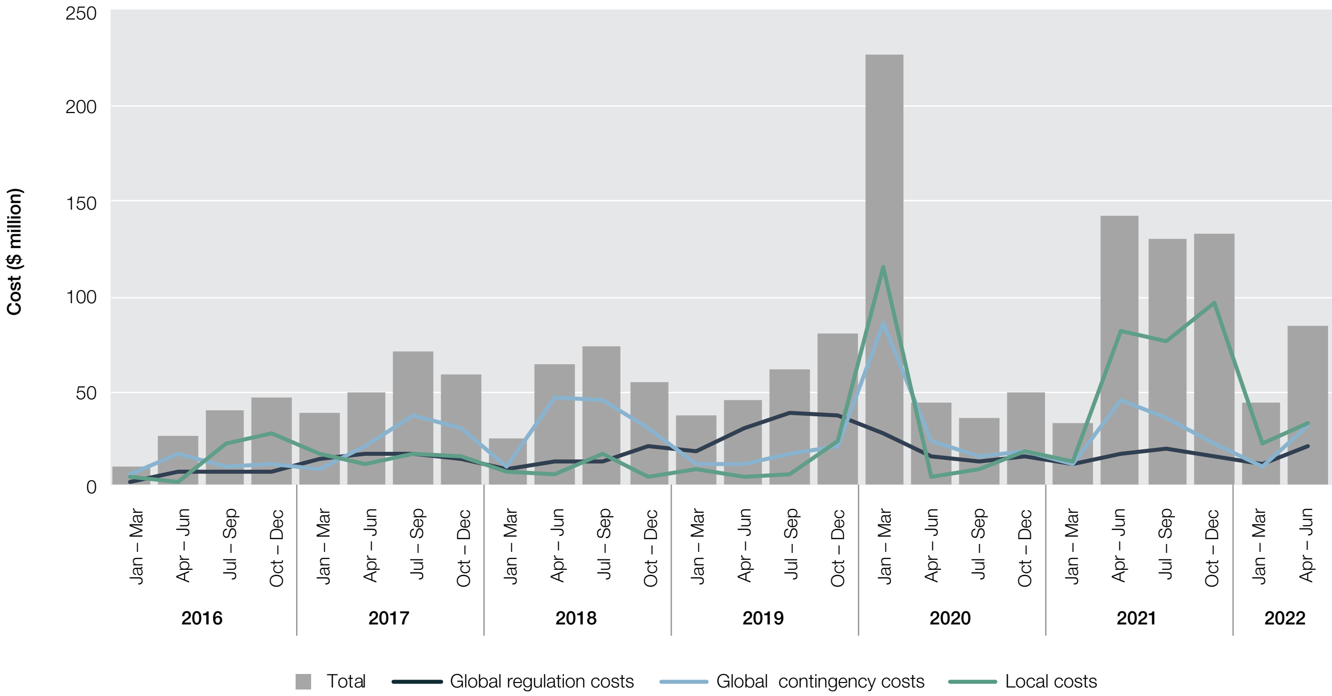
58 AEMO, Quarterly energy dynamics Q1 2022, April 2022.

Historically, FCAS costs were comparatively low in relation to energy costs. However, these costs have risen steadily over the past few years.

Despite low FCAS costs in the first quarter of 2021, FCAS costs rebounded sharply in the second quarter of 2021 and remained high for the remainder of the year. This drove record FCAS costs of $438 million over the year. Most of the cost increase reflected very high local FCAS costs in Queensland, driven by individual days of extreme FCAS price volatility (Figure 2.25). High FCAS prices were caused by a combination of factors. The ongoing upgrade to the Queensland–NSW interconnector meant that at times FCAS requirements in Queensland had to be met exclusively by local supply. Some Queensland FCAS providers had units on outage, which reduced available supply. Further, FCAS prices were also strongly impacted by high energy prices in the region, which reflected the opportunity cost of providing some services. The combination of these factors meant at times it was necessary to dispatch very expensive local capacity.[59]

In 2022 FCAS costs fell from the very high levels of 2021. FCAS prices in Queensland dropped because the region didn't need to provide its own FCAS as often, with fewer outages on the Queensland–NSW interconnector related to the transmission upgrade works. The fall in local FCAS costs was slightly offset by an increase in local Tasmanian FCAS costs at the start of 2022.

Figure 2.25 Frequency control ancillary service costs



Note: Record FCAS costs in the first quarter of 2020 were due to high local costs in South Australia when it was islanded for several weeks following the loss of the Heywood interconnector. In January 2020 bushfires also drove high prices across the NEM.

Source: AER; AEMO (data).

2.11.3 Market reforms

Significant market reforms were implemented in 2021.[60] In October 2021, 5-minute settlement was applied in the NEM to provide better price signals for fast response technologies such as batteries, new gas-peaking plants and demand response. Previously, participants were paid an average 30-minute price.

The wholesale demand response mechanism was also introduced in October 2021.[61] Demand response involves paying energy consumers to cut their use of power. Consumers (either directly or through aggregators) are able to bid demand response directly into the wholesale market at any time, but most likely at times of high electricity prices. It is also used to help keep the power system stable. New Zealand began using demand response in 2007 and now meets over 16% of peak demand through demand response programs.[62] Adoption of demand response in Australia is

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

60 Energy Security Board, *Health of the NEM 2022*, September 2022.

61 AEMO, Wholesale demand response mechanism, August 2022.

62 ARENA, What is Demand Response?, April 2022.

still limited, but by June 2022 Enel X had registered 60 MW of demand response facilities in NSW, Victoria and South Australia. These units participated in the market in May and June at times of high prices.

2.11.4 Future market reforms

Governments, the ESB and market bodies are progressing future reform workstreams, which include:

- a capacity mechanism to create a signal for investment in dispatchable capacity
- initiatives to maintain the system's secure operation, including system strength, frequency, operating reserve and inertia
- improved integration of consumer energy resources to ensure these resources are coordinated and aligned with system and market signals
- supporting the timely and efficient delivery of major transmission projects, as well as consideration of a congestion management mechanism to improve market signals for generator connections.[63]

2.11.5 Compliance and enforcement activities

The AER's compliance and enforcement work ensures that important protections are delivered, and rights are respected. It gives consumers and energy market participants confidence that the energy markets are working effectively and in their long term interests, so that they can participate in market opportunities as fully as possible and are protected when they cannot do so.

Compliance work helps to proactively encourage market participants to meet their responsibilities, and enforcement action is an important tool where breaches occur.

Each year, the AER identifies and publishes a set of compliance and enforcement priorities, some of which relate to participants in the NEM. The challenge to maintain system security has increased our focus on generators' meeting technical standards and providing accurate information to AEMO. Providing inaccurate information undermines AEMO's ability to manage frequency deviations, creating a risk to system security and stability.

Over 2021–22, one priority was to focus on generators' compliance with AEMO dispatch instructions and their ability to comply with their latest offers at all times. The AER released two compliance bulletins providing key guidance to participants and encouraged them to review and update their practices as appropriate.

In September 2021 the AER instituted proceedings against Hornsdale Power Reserve Pty Ltd (HPR) for alleged breaches of the National Electricity Rules. Between July and November 2019 HPR made offers to AEMO and was paid to provide market ancillary services, which allegedly it could not provide including when it was called on to provide those services after a frequency disturbance. On 28 June 2022 HPR was ordered by the Federal Court to pay $900,000 in penalties.[64]

During the recent suspension of the NEM, the AER wrote to market participants reminding them of their obligations around bidding and providing accurate and timely capability information to AEMO. The AER also provided detailed guidance to generators as the market suspension lifted to encourage orderly market conduct. This priority will be expanded in 2022–23 to include a focus on obligations relating to bidding behaviour and providing accurate and timely capability information to AEMO as the east coast energy market continues to face challenges.

More detail on the AER's compliance and enforcement work is outlined in the Annual compliance and enforcement report 2021–22.

63 The AEMC published a draft report as part of the Transmission planning and investment review on 2 June 2022.

64 AER, 'Hornsdale Power Reserve penalised $900,000 for inability to provide contingency services as offered' [media release], June 2022.

Image courtesy of Powerlink

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. This chapter covers the 21 electricity networks regulated by the Australian Energy Regulator (AER), which are located in all Australian states and territories except Western Australia.

3.1 Electricity network snapshot

In 2022, the AER has completed 2 revenue determinations – for Powerlink (Queensland) and AusNet Services (Victoria) transmission – setting target revenue controls for those networks through to 2027.

Across all electricity networks, reporting over the 12-month period to 30 June 2021:

- Revenue earned by network businesses was 5% lower than in the previous year (the fourth consecutive year of decreased revenue) (section 3.9).
- Expenditure on investment projects was the highest since 2015; 8% higher than in the previous year and 12% higher than the average investment expenditure over the previous 5 years (section 3.13).
- Asset bases continued to grow, driven by investment projects on the Transgrid (NSW) and ElectraNet (South Australia) transmission networks. Asset bases are forecast to grow at an accelerated rate as several major transmission projects progress (sections 3.11 and 3.13.6).
- Expenditure on operating costs was at its lowest since 2017; 0.8% lower than in the previous year and 7% lower than the average operating expenditure over the previous 5 years (section 3.14).
- Customers experienced fewer and shorter (normalised) network outages than in any time in the past. Despite this, major weather events continued to have an impact on the overall customer experience (section 3.16).

3.2 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.

Electricity distributors transport and deliver electricity to customers, but 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 systems are now embedded within distribution networks, resulting in 2-way electricity flows along the networks. Energy users with rooftop solar systems can now source electricity from the distribution network when they need it and sell the surplus electricity they generate at other times. Electricity generated using rooftop solar systems is also increasingly being stored using battery storage systems. Due to the versatility and falling cost of battery technology, its use is expected to continue to grow over the coming years.[65]

Alongside the major distribution networks, smaller localised 'embedded' networks distribute energy to sites such as apartment blocks, retirement villages, caravan parks and shopping centres. Electricity is delivered from the distribution network 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.

65 Australian Renewable Energy Agency, 'Battery costs falling fast, wind and solar still cheapest new electricity', ARENAWIRE, 17 June 2021, accessed 29 March 2022.

3.3 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) are owned by the state governments and 3 interconnectors (Directlink, Murraylink and Basslink) are privately owned (Figure 3.2). 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.[66] Customers 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 (Figure 3.1 and Figure 3.3).

The Northern Territory has 3 separate networks – the Darwin–Katherine, Alice Springs and Tennant Creek systems – all owned by Power and Water Corporation (Power and Water). The 3 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 and Tasmania. It also regulates the Northern Territory's distribution network.

The combined value of the regulatory asset bases (RABs) for the electricity networks regulated by the AER is around \$105 billion.[67] This comprises 7 transmission networks valued at \$22.8 billion and 14 distribution networks valued at \$82.6 billion. In total, the networks operate almost 800,000 kilometres of lines and deliver electricity to more than 10.6 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.[68]

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

67 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.

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

Figure 3.1 Electricity networks regulated by the AER – distribution

Note: QNI is the Queensland–NSW Interconnector. The AER does not regulate the Basslink Interconnector.
Source: AER.

Figure 3.2 Electricity networks regulated by the AER – transmission

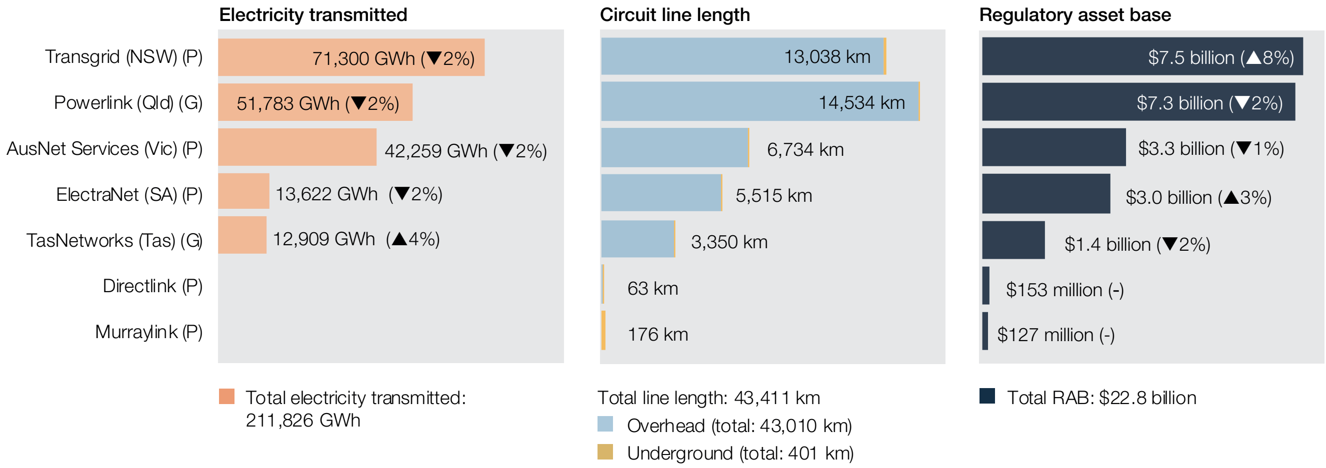
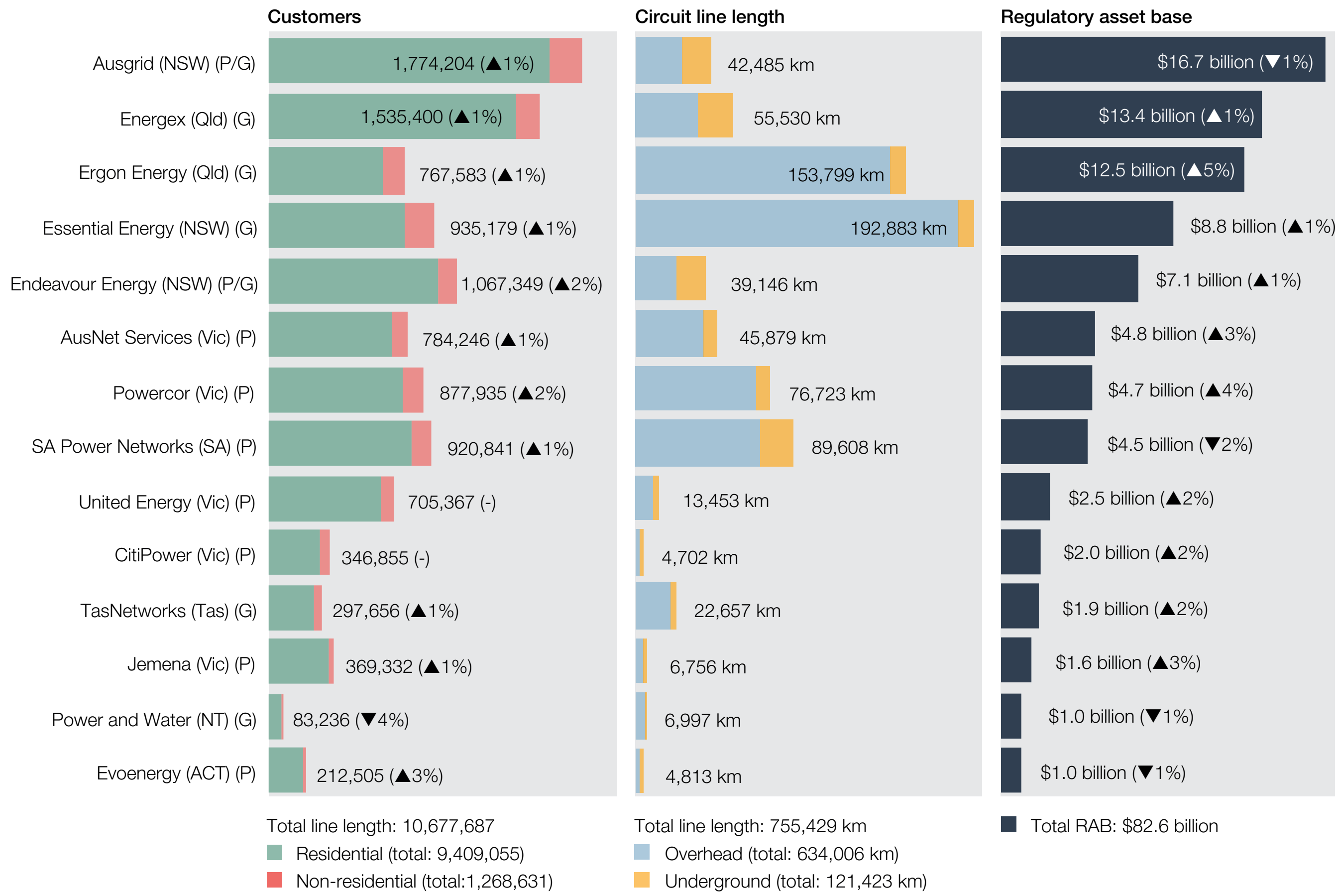


Figure 3.3 Electricity networks regulated by the AER – distribution



(G): state government owned; (P): privately owned; GWh: gigawatt hours; km: kilometres; % values represent change from previous year.

Note: Regulatory asset base is adjusted to June 2022 dollars based on forecasts of CPI. Line length and asset base are as at 30 June 2021 (31 March 2021 for AusNet Services transmission). Electricity transmitted is for the year to 30 June 2021 (year to 31 March 2021 for AusNet Services). Customer numbers, line length and asset base are as at 30 June 2021 for the distribution networks. 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).

3.4 Network ownership

Australia's electricity networks were originally government owned, but many jurisdictions have now partly or fully privatised the assets. Ownership of the partly or fully 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 (section 5.2).

Electricity networks in Queensland, Tasmania, the Northern Territory and Western Australia remain wholly government owned. In 2016 the Queensland Government 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. In such cases, ring-fencing arrangements are in place to ensure the network businesses do not use revenue from regulated services to cross-subsidise their unregulated products (section 3.8.2). For example, Queensland's state-owned Ergon Energy provides both distribution and retail services in regions outside south-east Queensland.

3.5 How network prices are set

Electricity networks are capital intensive and require significant investment in order to install and operate the required infrastructure. This 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 higher prices than they could charge in a competitive market. This environment poses serious risks to consumers, given network charges currently make up around 50% of a residential electricity bill (Figure 6.2 in chapter 6). To counter these risks, the role of the AER as economic regulator is to replicate the incentives that network businesses would face in a competitive market (that is, to control costs, invest efficiently and not overcharge consumers).

3.5.1 Regulatory objective and approach

One of the AER's key objectives is to deliver efficient regulation of monopoly infrastructure while incentivising networks to become platforms for energy services.[69]

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 electricity supply, and the reliability, safety and security of the national electricity system.

The AER's regulatory toolkit to pursue this objective is wide ranging (Box 3.1), but one of its fundamental roles 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 the amount of 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.[70]

69 ACCC and AER, 'Corporate plan 2021–22', 31 August 2020, accessed 29 March 2022.

70 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

Every 5 years the AER sets a cap on the revenue that a network business can earn from its customers. Alongside this central role, we undertake broader regulatory functions, including:

- assessing distribution 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 final 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
- promoting and enforcing compliance with regulations, including connections policies and ring-fencing.

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

- adopting a more consumer-centric approach to setting network revenues (section 3.7)
- reviewing and refining our incentive schemes and guidelines to ensure they remain relevant and fit for purpose
- publishing information on network profitability
- reviewing how rates of return and taxation allowances are set for energy networks (section 3.12).

The AER has also been appointed as regulator of the NSW Renewable Energy Zones (REZs). The AER will make revenue determinations for network infrastructure projects authorised by the independent Consumer Trustee for each REZ. The AER's determinations will include calculating the prudent, efficient and reasonable capital costs of each NSW REZ project, as well as:

- determining annual contributions from NSW electricity distribution businesses to fund the framework
- approving a risk management framework developed by the Consumer Trustee
- reviewing tender rules regarding long-term energy service agreements.

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

To form a view on a network business's capital expenditure forecast, the AER assesses the drivers of the proposed expenditure. The AER does not determine the capital programs or projects for a network business. Once the AER determines a capital expenditure forecast, it is up to the network business to prioritise its investment program.

Unlike capital expenditure, a network business's operating costs are largely recurrent and predictable. As such, the AER begins its review by assessing the actual operating expenditure incurred in the (then) current regulatory period. The AER uses several assessment techniques to determine whether this base expenditure is efficient before applying a rate of change 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 expenditure and applying incentives.[71]

Sections 3.10, 3.14 and 3.16 examine the incentive schemes in more detail. Past AER *Electricity network performance reports* have focussed on the impact incentive schemes have had on network businesses' behaviour.[72]

71 AER, 'Guidelines, schemes, models & reviews', AER website, accessed 1 February 2022.

72 AER, 'Electricity network performance report', September 2020, accessed 5 April 2022.

In conducting its review of a network business's revenue proposal, 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 business lodges a formal proposal.

Electricity network businesses continue to significantly improve how they engage with consumers. The regulatory process increasingly focuses on how network businesses engage with their customers in shaping regulatory proposals. In December 2021, the AER published its *Better Resets Handbook*.

The objective of this process is to contribute to high-quality regulatory proposals based on genuine engagement with consumers. Where network proposals are developed in line with these expectations, the AER will be able to undertake a targeted review of the proposal rather than the standard more detailed approach.

The AER previously trialled the 'New Reg' process with Victorian electricity distributor AusNet Services in developing its regulatory proposal for the 5-year period ending 31 June 2026. The New Reg process offers an enhanced, more open approach to how network businesses incorporate consumer perspectives in developing their regulatory proposals.

Additionally, the AER's Consumer Challenge Panel – 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
- how consumer views are reflected in the development of network businesses' proposals.[73]

3.5.2 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:

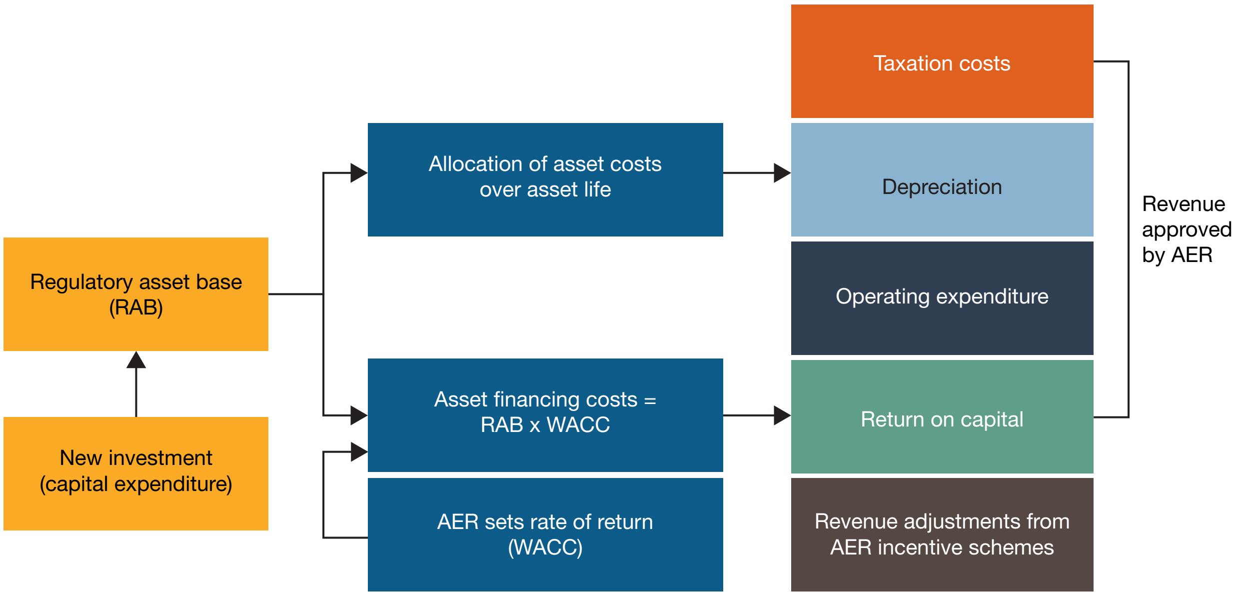
- a commercial return to investors that funds the network's assets and operations
- efficient operating and maintenance costs
- asset depreciation costs
- taxation costs.

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.

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 and 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 (Figure 3.4).

73 AER, 'Consumer Challenge Panel', AER website, accessed 2 February 2022.

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.

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:

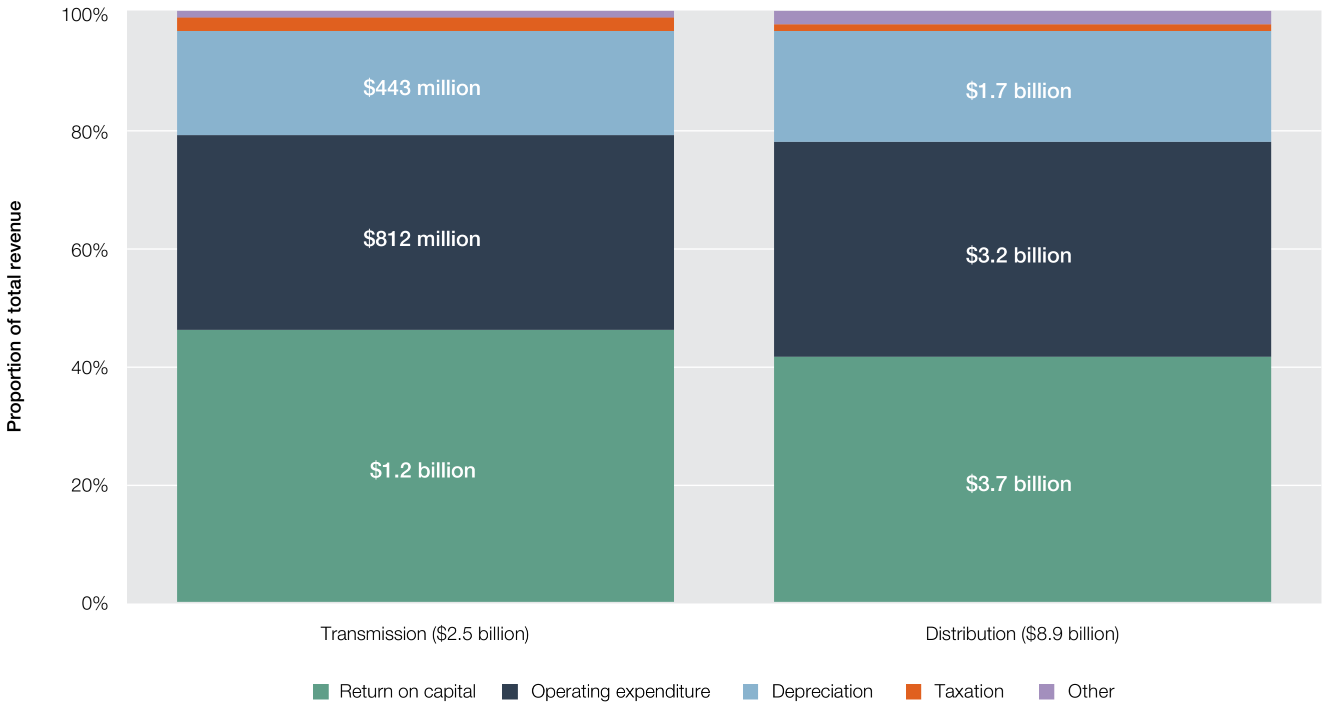
- the value of the network's RAB
- the rate of return that the AER allows based on the forecast cost of funding those assets through equity and debt.[74]

Overall, the return on capital takes up the largest share of network revenue, accounting for 43% of total revenue across all networks (Figure 3.5).

Sections 3.11 to 3.14 examine major cost components in more detail.

74 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.

Figure 3.5 Composition of average annual electricity network revenue



Note: Composition of average annual electricity network revenue – current periods as at June 2022. Consumer price index (CPI) adjusted to June 2022 dollars.

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

3.6 Recent AER revenue decisions

In 2022 the AER published its final revenue decisions for Victorian transmission network AusNet Services for the 5-year period ending 31 March 2027 and Queensland transmission network Powerlink for the 5-year period ending 30 June 2027 (Figure 3.6).

Figure 3.6 Recent AER electricity network revenue decisions

	Revenue	Capital Expenditure	Operating Expenditure	Annual impact on residential bill
Powerlink (QLD)	$3.5b (▼19%)	$892m (▼3%)	$1.1b (▼0.5%)	▲0.1%
AusNet Services (Vic)	$2.6b (▼8%)	$819m (▲4%)	$513m (▲0.9%)	▲0.1%

Note: Changes in revenue and expenditure are in relation to forecasts from the previous regulatory periods. 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.

The key driver of the lower forecast revenues for AusNet Services and Powerlink is the allowed rate of return, which is lower than the rate applied in the previous period.[75] This reflects a decrease in interest rates compared with those in the previous period, meaning the networks businesses can obtain the capital needed to run their businesses more cheaply. Forecast revenues were also affected by a decrease in tax allowance – predominately as a result of lower return on equity, higher gamma and the new regulatory tax approach applied following our 2018 tax review.[76]

75 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.

76 AER, 'Regulatory tax approach review 2018', AER website, accessed 25 April 2022.

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. The AER's setting of lower forecast revenue allowances for the current period acknowledged that network businesses are rationalising their operations and will continue to build on operational efficiencies. Lower revenue allowances benefit customers by locking in efficiency gains.

3.7 Refining the regulatory approach

The regulatory framework is not static. In December 2021 the AER published its *Better Resets Handbook*, which aims to incentivise network businesses to develop high-quality proposals driven by genuine engagement with consumers.[77]

The handbook outlines what the AER expects should be included in a high-quality, consumer-centric regulatory proposal. Regulatory proposals that are developed through genuine engagement with consumers and meet the AER's expectations for forecast expenditure, depreciation and tariff structure statements are more likely to be largely or wholly accepted at the draft decision stage, creating a more efficient regulatory process for all stakeholders.

The handbook should also lead to many other benefits, including improved relationships and understanding between networks and consumers, greater trust between all parties in regulatory processes, and the generation of new ideas and regulatory approaches that benefit both customers and networks.

3.7.1 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 informative documents – including fact sheets that simplify technical language – and holds public forums. The AER's Consumer Challenge Panel also provides a mechanism for consumer perspectives to be voiced and considered.

Several 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.

Early engagement offers the potential to expedite the regulatory process, reducing costs for businesses and consumers. Effective consumer consultation, along with agreement with its customers, can lay the foundations for the AER to accept major elements of a network business's revenue proposals.

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

In 2021 Powerlink (Queensland) was awarded the ENA/ECA Consumer Engagement Award for its 2022–27 revenue determination engagement process. Powerlink received the award for its outstanding engagement practice which, according to ECA, demonstrated a new standard for customer consultation.

ECA was particularly impressed with Powerlink's willingness to undertake a genuine co-design process together with consumers, market bodies and executive teams within the business. ENA recognised the importance of integrating consumer engagement into energy networks' business planning.[78] Ergon Energy (Queensland) was also shortlisted as a finalist for the award for its consumer-developed load control tariffs.

3.7.2 Changes to revenue setting approaches

The AER frequently reviews and updates key aspects of its revenue setting approaches.

In January 2022 the AER published a report detailing the outcomes of its transparency review of AEMO's draft 2022 integrated system plan (ISP).[79] The ISP is a whole-of-system plan for eastern Australia's power system (section 3.13.6). The AER concluded that AEMO had adequately explained most of its inputs and assumptions and how they contribute to the draft ISP outcomes. The National Electricity Rules require the AER to finalise a transparency review of AEMO's draft ISP one month following its publication. Transparency in understanding AEMO's approach

77 AER, 'Better Resets Handbook – Towards consumer centric network proposals', AER website, 9 December 2021.

78 Powerlink, 'Powerlink wins 2021 Consumer Engagement award', Powerlink website, 4 November 2021, accessed 20 March 2022.

79 AER, 'AER completes transparency review of draft 2022 Integrated System Plan', AER website, 7 January 2022, accessed 3 February 2022.

is important because it promotes stakeholder understanding of key outcomes in the draft 2022 ISP, which in turn promotes confidence in the ISP. The ISP and RIT-Ts are discussed in section 3.13.

The 2022 ISP also brought into effect guidelines the AER published in August 2020 to make the ISP actionable. The guidelines include a cost-benefit analysis guideline, a forecasting best practice guideline and updates to the regulatory investment test for transmission (RIT-T) instrument and application guidelines.[80] The guidelines are part of broader reforms led by the Energy Security Board (ESB), with changes made to the National Electricity Rules to streamline the transmission planning process while retaining rigorous cost-benefit analyses.

In late 2022 the AER will publish its new Rate of Return Instrument, which will apply to all regulatory determinations made in the subsequent 4 years. As a milestone in that process, the AER published a Draft Instrument in June 2022. The Instrument sets out the AER's approach for estimating the rate of return and comprises the return on debt and the return on equity, as well as the value of imputation credits.

In December 2021, the AER commenced a review of the incentive schemes and guidelines that apply to regulated electricity networks to ensure they remain relevant and fit for purpose.[81] This forms part of the AER's strategic objectives for 2020–2025 to improve its approach to regulation by being more efficient and focusing on outcomes that matter most to consumers.

The AER also continues to review and incrementally refine elements of its benchmarking methodology and data. The aim of this work is to continually improve the reliability of the benchmarking results we publish and use in our network revenue determinations.

In addition, the AER has developed new models for forecasting capital expenditure, which standardise and streamline presentation of information about capital projects and programs. These models map forecast capital expenditure into a format consistent with the post-tax revenue model (PTRM), which is used to calculate the annual revenue requirement for each year of a regulatory period. The new model streamlines the resources and consultation required and increases consistency across regulatory proposals.[82]

3.8 Power of Choice

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 delay the need for costly network investment. Moreover, since demand for energy imports is increasingly at its minimum when solar generation is high, shifting consumption to these off-peak periods can help reduce the costs of supply, manage minimum demand constraints (such as voltage issues) and draw more energy from a low emissions fuel source.

'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 3.8.1), and incentives for demand management as a lower cost alternative to network investment (section 3.13.9).

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.[83] A separate trial, led by Jemena (Victoria) with the collaboration of AusNet Services, Evoenergy, TasNetworks and United Energy, is exploring using hardware-based smart charging to dynamically manage residential electric vehicles.[84]

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 consumer energy

80 AER, 'Guidelines to make the integrated system plan actionable', AER website, August 2020, accessed 29 March 2022.

81 AER, 'Review of incentive schemes for regulated networks', AER website, 4 August 2022.

82 AER, 'Standardised model for standard control services capital expenditure (standardised SCS capex model)', AER website, 16 December 2021, accessed 19 April 2022

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

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

resources, including benefits from access and pricing reforms.[85] The DEIP has also run a series of task forces to explore issues relating to integrating EVs into the energy system.

Improvements in energy storage and renewable generation technology are making it increasingly possible for some consumers to go 'off-grid'. Standalone 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 that are remote from existing networks.

In 2020 the Australian Energy Market Commission (AEMC) proposed rule changes to enable distributors to supply their customers using standalone power systems where it is cheaper than maintaining a connection to the grid.[86] The AEMC identified additional benefits of these systems, including improved reliability and reduced bushfire risks.[87] Following a series of changes in the national electricity and retail laws over 2021, these changes were made to the rules in February 2022.[88]

Under the reforms, customers who receive standalone 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 standalone systems will flow through to all users of the distribution network through lower network prices.

3.8.1 Tariff structure reforms

Traditionally, households and small businesses have been charged the same electricity tariff for their use of the distribution network regardless of how and when they use energy (that is, flat/single rate or non-cost-reflective network tariffs). Because flat tariffs are independent of when and how electricity is used, they don't reflect the true costs of using the network. This means some consumers, such as those who use electricity at peak periods, may not pay their full share of network costs under single rate tariff structures, while other consumers may pay more than their full share.

Distribution network businesses do not charge network tariffs directly to end customers. Rather, distributors charge retailers, who then package network tariffs together with other costs (such as the cost of wholesale energy) in their retail price offers to end customers. It is up to the end customer to choose a retail offer that suits their needs.

The National Electricity Rules require distributors to make network tariffs more cost-reflective, to signal to retailers the true cost of their customers' use of the network.[89] The AER supports and encourages the reform to more cost-reflective tariffs and tariff reform through the tariff structure statement process.

Tariff reform can encourage more efficient use of networks, delay the need for network augmentation and investment, and spread network costs more equitably. 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 consumer energy resources – such as rooftop solar, batteries and EVs – into distribution networks. This includes sending price signals to customers to encourage the use of solar energy in the middle of the day to avoid excess solar (minimum demand) on the network.

Distributors are required to submit their tariff structure statements to the AER every 5 years, as part of the wider distribution revenue determination process. With each tariff structure statement, distributors progressively move towards more cost-reflective tariffs. Distributors are now moving into their third round of tariff structure statements.

Progress towards increasing the number of customers seeing, and responding to network costs has included:

- simplifying tariffs and modifying peak windows to provide clear, consistent signals
- designing tariffs that more closely reflect network costs
- applying an 'opt-out' or mandatory assignment policy that increases the number of end customers 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 trialing alternative approaches.

85 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.

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

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

88 AEMC, New rules allow distributors to roll out stand-alone power systems in the NEM, February 2022.

89 AEMC, 'National Electricity Amendment (Distribution Network Pricing Arrangements) Rule 2014, rule determination', November 2014.

To better manage minimum demand issues, support effective consumer energy resources integration, and enable future market designs, the AEMC made a rule change in August 2021 to remove a prohibition on distributors charging for exports and to expand the definition of 'network services' to include exports of consumer energy resources.[90] Distributors may now signal the cost of serving energy export as well as energy consumption, where provision of the export service imposes a cost on the network (also called 2-way pricing). This rule change required the AER to publish Export Tariff Guidelines for the implementation of any 2-way pricing that may be introduced in the distributors' next round of tariff structure statements.[91]

Under the National Electricity Rules, subject to revenue recovery limits, distributors can trial alternative tariff structures (sub-threshold tariffs) during the regulatory period to support the introduction of innovative tariff structures. Distributors have responded with a broad range of trials to explore innovative approaches, covering solar sponges, critical peak pricing and 2-way pricing. Examples of trials include:

- Ausgrid (NSW): a community battery tariff trial with critical peak pricing, a residential 2-way tariff trial with export rewards and charges and a residential flexible load tariff trial aimed at electric vehicle users.
- Essential Energy (NSW): an export tariff trial with rebates (rewards for customers) for exporting between 5 pm and 8 pm, an export tariff trial for batteries, a weekly demand tariff trial aimed at peaky load large customers and an education only trial to determine whether education alone can shift customer behaviour.
- CitiPower (Victoria): a daytime saver trial aimed at customers with pool pumps and EVs to incentivise customers to use more electricity around midday, and community battery tariff trials (aimed at both distributor-owned and non-distributer-owned batteries).
- Evoenergy (ACT): a residential battery tariff trial aimed at residential customers with batteries and EVs, and a highly cost-reflective large-scale battery tariff trial.[92]

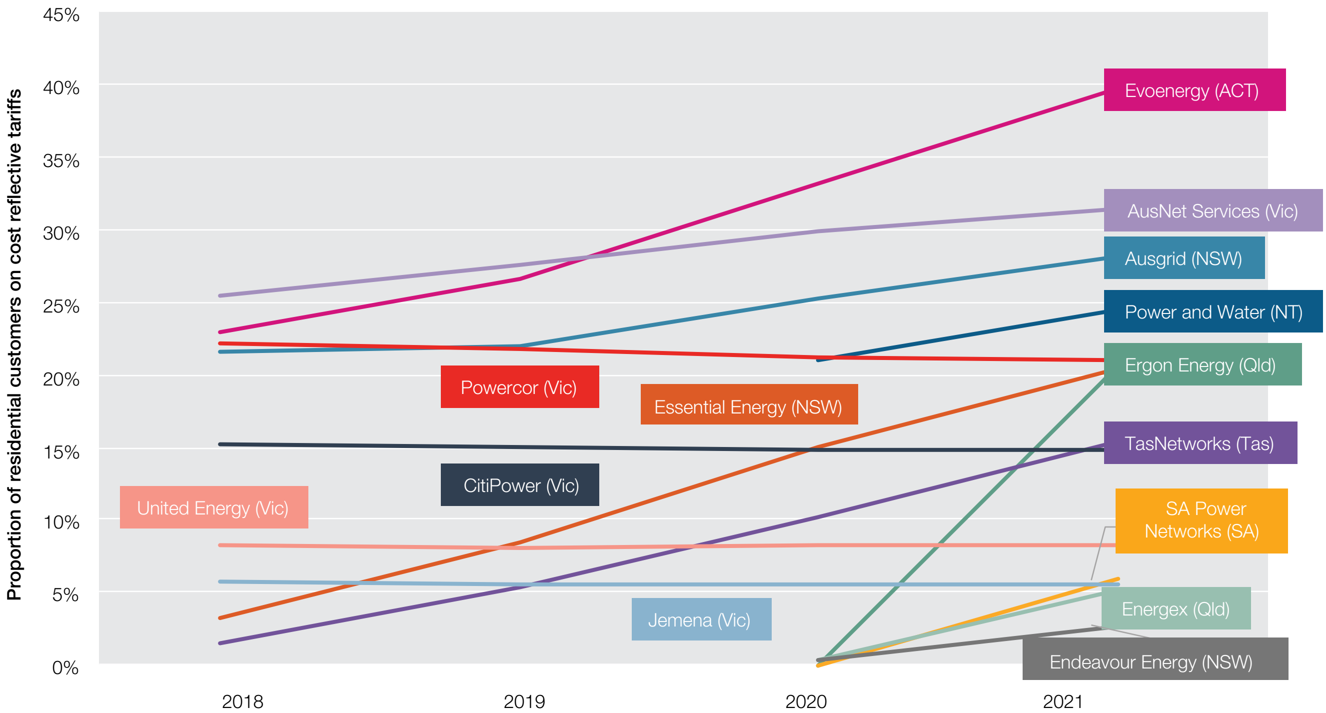
As an example of progress to cost reflectivity, in 2020 the AER approved SA Power Networks' use of a 'solar sponge' tariff for its residential customers. This network tariff offers a lower charge during the middle of the day, when solar output is highest, to encourage customers to use more electricity when it is plentiful and less costly. Raising demand for grid-supplied electricity in the middle of the day can help manage voltage issues and thermal overloads associated with minimum demand, while shifting demand away from the evening peak when there is heavy strain on the network and costs are higher. SA Power Networks also introduced a demand tariff that offers discounted time of use rates and a seasonal peak demand component. This provides a clear example of the progress that has been made around tariff structures.

90 AEMC, 'Final determination – Access, pricing and incentive and incentive arrangements for distributed energy resources', 12 August 2021, accessed 20 January 2022.

91 AER, Export Tariff Guidelines, 19 May 2022.

92 All current tariff trial notifications are available on the AER website: https://www.aer.gov.au/networks-pipelines/network-tariff-reform/tariff-trials.

Figure 3.7 Residential customers on cost-reflective tariffs



Source: Annual RIN responses.

Although distributors are moving towards more cost-reflective tariffs, the limited uptake of smart meters for residential and small business consumers outside Victoria has been a barrier to cost-reflective network tariffs. Smart meters, which measure electricity use in 30-minute blocks, are essential for most cost-reflective network tariffs to be applied.

In jurisdictions other than Victoria, where almost 100% of small consumers have smart meters, the rollout of smart meters is market-led. Installation rates vary across jurisdictions. New and replacement meters installed for residential and small business consumers must now be smart meters and other consumers can negotiate for a smart meter as part of their electricity retail offer. At 30 June 2021, around 53% of residential customers in the NEM had metering capable of supporting cost-reflective tariffs (including smart meters and manually readable interval meters). Outside Victoria, the penetration of smart or interval meters ranged from as low as 23% in Queensland to 36% in Tasmania.

Changes to the National Electricity Rules in 2017 transferred responsibility for metering from distributors to retailers. Additionally, from February 2019 retailers are required to provide consumers with electricity meters within 6 business days of a property being connected to the network or with replacement meters within 15 days.[93]

In December 2020 the AEMC announced a review of the regulatory framework for metering. As at June 2022, the AEMC was working with stakeholders to develop a package of measures to fast-track the deployment of smart meters in the NEM. The AEMC indicated the measures will include a target, which may be based on a range of geography, age and other factors.[94]

3.8.2 Ring-fencing

When a network business offers services in a contestable market, robust ring-fencing arrangements must be in place to ensure the business competes fairly with other service providers.

The objective of ring-fencing is to provide a regulatory framework that promotes the development of competitive markets. It does this by providing a level playing field for third party providers in new and existing markets for contestable services.[95] Effective ring-fencing arrangements are an important mechanism for promoting increased choice for consumers and more competitive outcomes in markets for energy services.

93 AEMC, 'National Energy Retail Amendment (Metering Installation Timeframes) Rule 2018', rule determination, December 2018, accessed 14 February 2022.

94 AEMC, 'Review of the regulatory framework for metering services', December 2020, accessed 26 April 2022.

95 The 2015 Power of Choice reforms (section 3.8) required the AER to develop the distribution ring-fencing guideline.

Ring-fencing aims to prevent network businesses from using revenue from regulated services to cross-subsidise their unregulated products, and/or discriminate in favour of affiliated businesses.

The AER publishes separate ring-fencing guidelines for transmission networks and for distribution networks. Under the guidelines, network businesses identify and separate the costs and business activities of delivering regulated network services from the delivery of other services.

Under the distribution ring-fencing guideline, all distributors are required to annually report on their compliance to the AER. Since 2017–18 the AER has generally observed fewer compliance issues and breaches. 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 has continued to help encourage improved compliance.

On 3 November 2021 the AER published an updated ring-fencing guideline for electricity distribution networks.[96] A key change in the updated guideline is inclusion of a provision for ring-fencing interactions with standalone power systems and energy storage devices. Distribution network businesses have been required to comply with this version of the guideline since 3 February 2022.

In July 2022 the AER released its final interim draft ring-fencing guideline for electricity transmission networks.[97] The interim guideline contains minor changes made to reflect amendments to the NER since publication of the prevailing Guideline and remains substantively the same.

3.9 Revenue

Network businesses earn revenue for providing services to consumers. While some services are regulated, others are provided through competitive markets. For transmission network businesses, we focus exclusively on components of their revenue associated with delivering prescribed transmission services. For distribution network businesses, we focus exclusively on revenues associated with providing core distribution services – standard control services.[98]

Figure 3.8 to Figure 3.12 provide a breakdown of the revenue network businesses earned in 2021 and how this compared with previous years and targets.

Figure 3.8 Revenue in 2021 – key outcomes

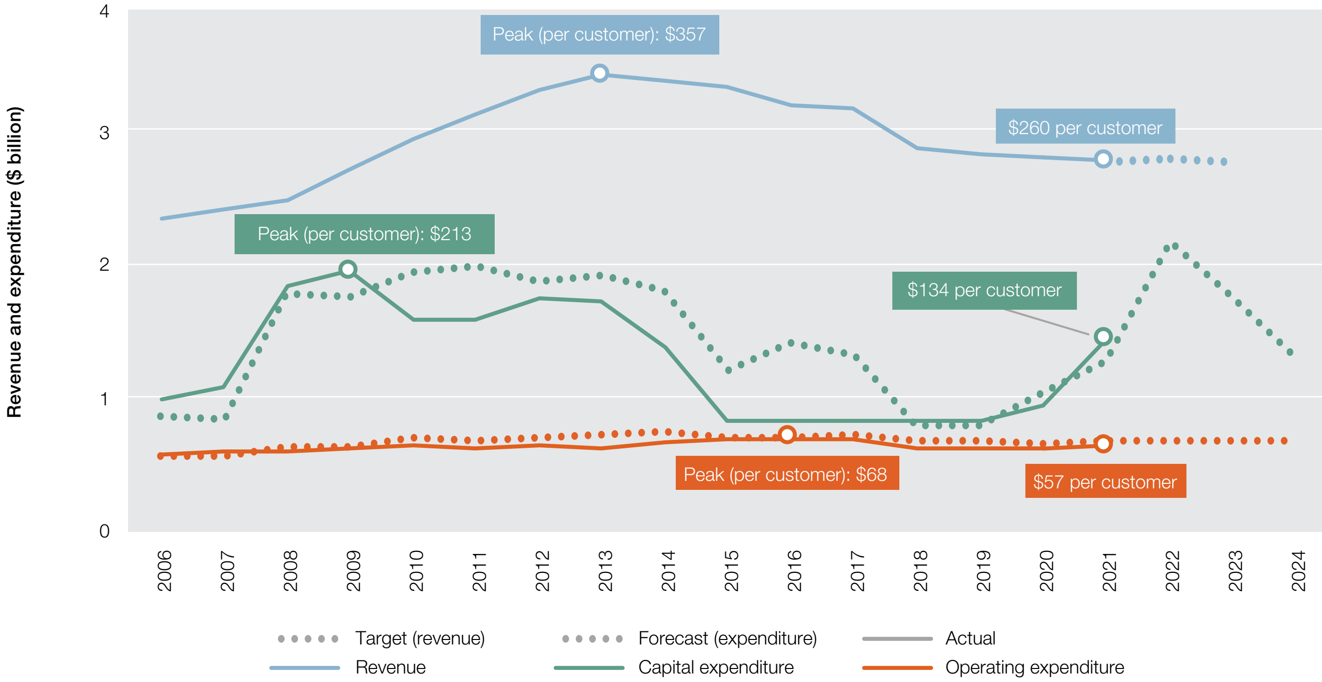
	2021 (actual)	Compared to 2020	Compared to peak (year)
Transmission	$2.8b	▼$38m (▼1.3%)	▼19% (2013)
Distribution	$9.6b	▼$631m (▼6%)	▼29% (2015)
Total	$12.3b	▼$669m (▼5%)	▼27% (2015)

96 AER, 'Ring-fencing guideline – electricity distribution – version 3', AER website, November 2021, accessed 5 April 2022.

97 AER, 'Ring-fencing guideline – electricity transmission – interim', AER website, accessed 5 April 2022.

98 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.

Figure 3.9 Revenue and key drivers – electricity transmission networks

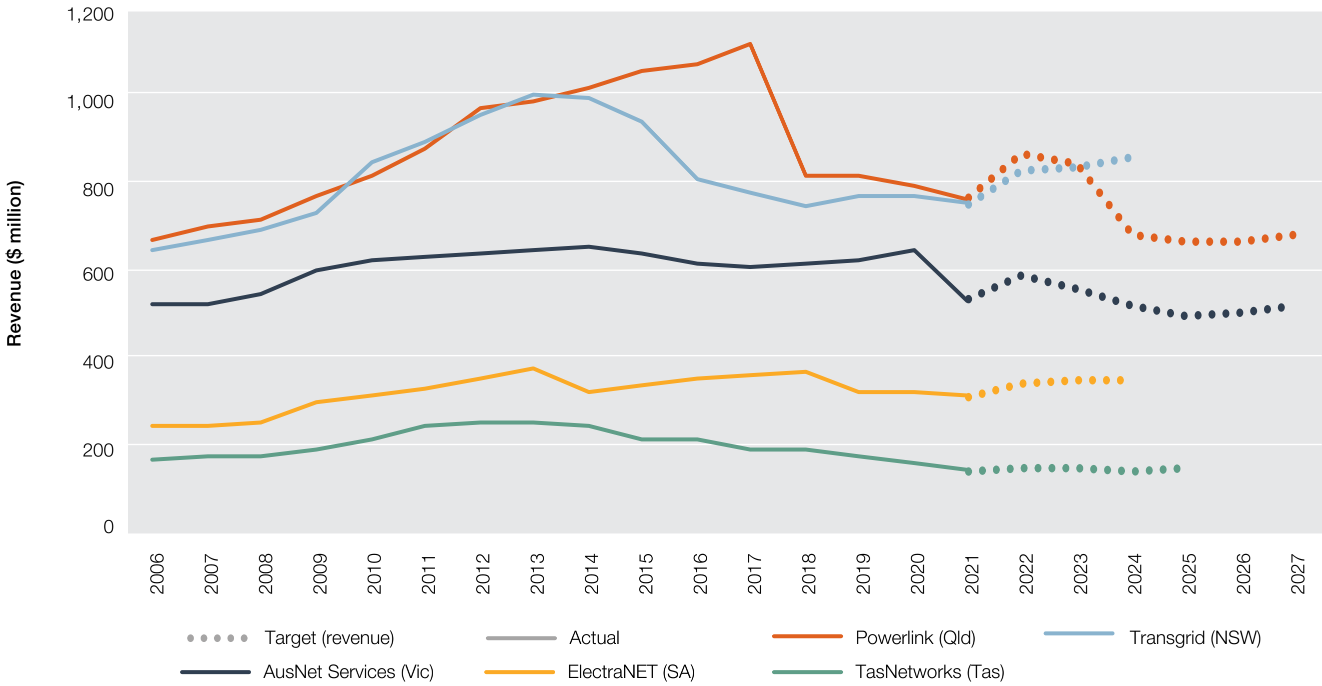


Note: All data are adjusted to June 2022 dollars, based on forecasts of CPI. Most network businesses report on a 1 July – 30 June basis. The exception is AusNet Services (Victoria), which reports on a 1 April – 31 March basis. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018). 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 considered in determining the target revenues used to set prices each year.

Transmission networks do not report customer numbers. Per customer metrics for the transmission networks were calculated using the total number of distribution customers in the relevant jurisdictions.

Source: Revenue: economic benchmarking RIN responses; capital expenditure: AER modelling, category analysis RIN responses; operating expenditure: AER modelling, economic benchmarking RIN responses.

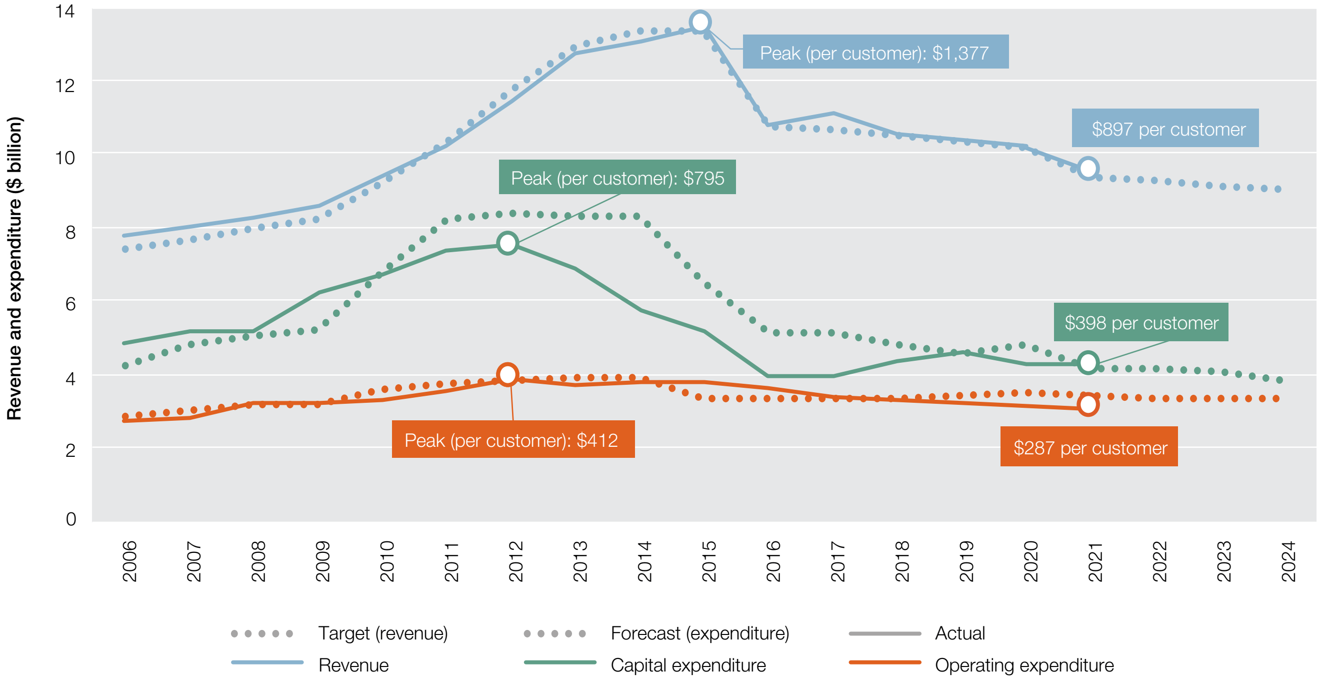
Figure 3.10 Revenue – electricity transmission networks



Note: All data are adjusted to June 2022 dollars, based on forecasts of CPI. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018). Assumptions are set out in Figure 3.9 notes.

Source: AER modelling; annual reporting RIN responses.

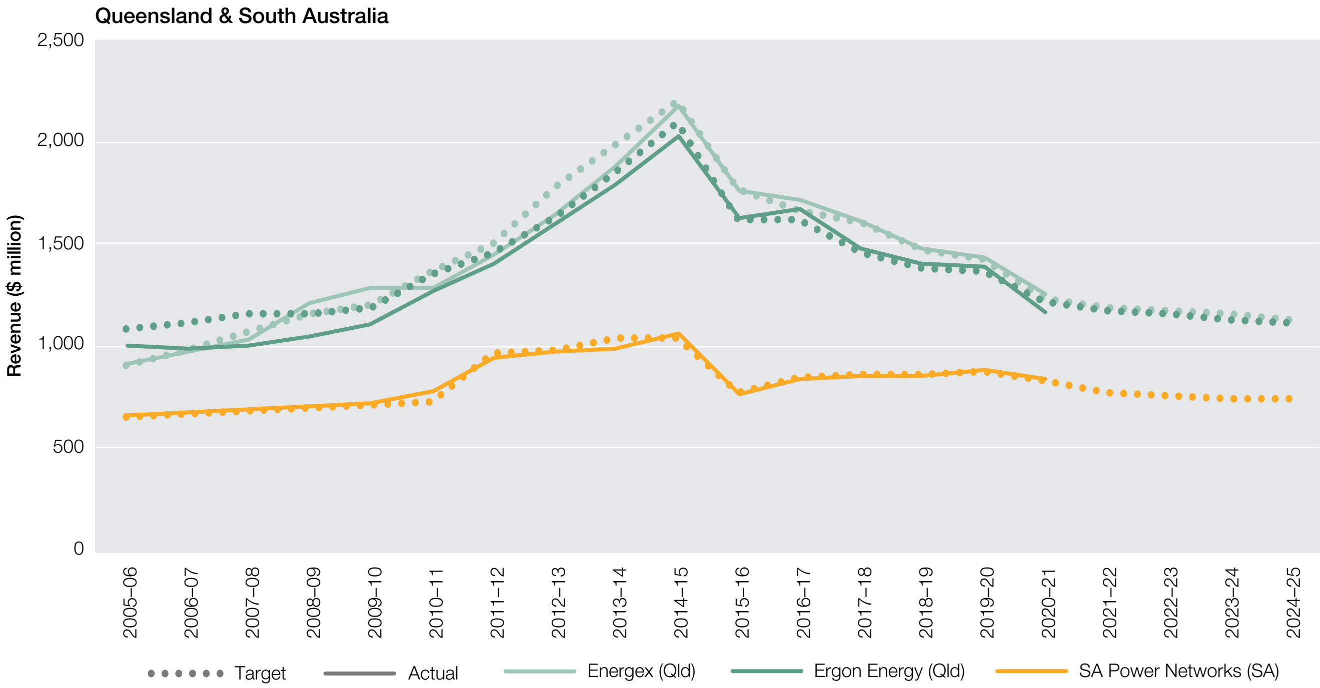
Figure 3.11 Revenue and key drivers – electricity distribution networks

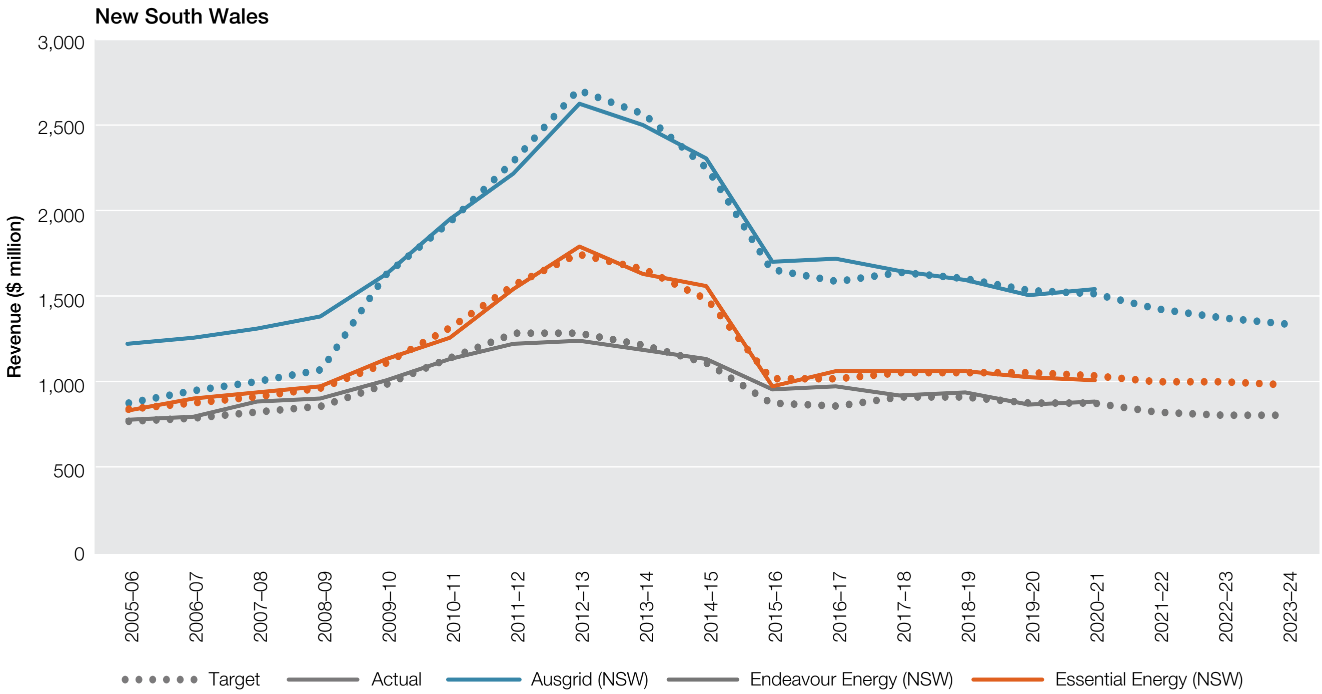


Note: All data are adjusted to June 2022 dollars, based on forecasts of CPI. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018). Target revenue is derived from regulatory decisions but adjusted to present it on a comparable basis to actual revenues. The adjustments include rewards and penalties from incentive schemes, cost pass-throughs and other factors that are considered in determining the target revenues used to set prices each year. Target revenue for the Victorian distribution networks for the 2021 year has been derived from the transitional year (1 January – 30 June 2021). To enable reporting on equivalent terms these values have been doubled.

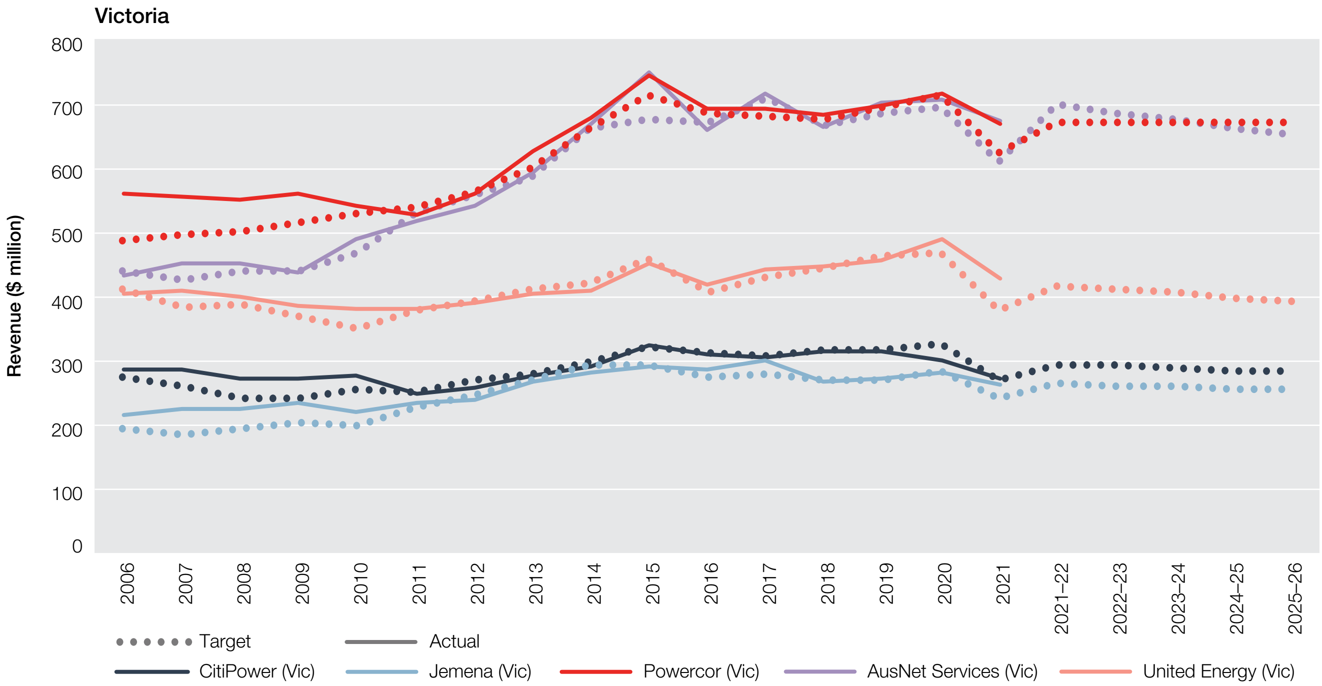
Source: Revenue: economic benchmarking RIN responses; capital expenditure: AER modelling, category analysis RIN responses; operating expenditure: AER modelling, economic benchmarking RIN responses.

Figure 3.12 Revenue – electricity distribution networks

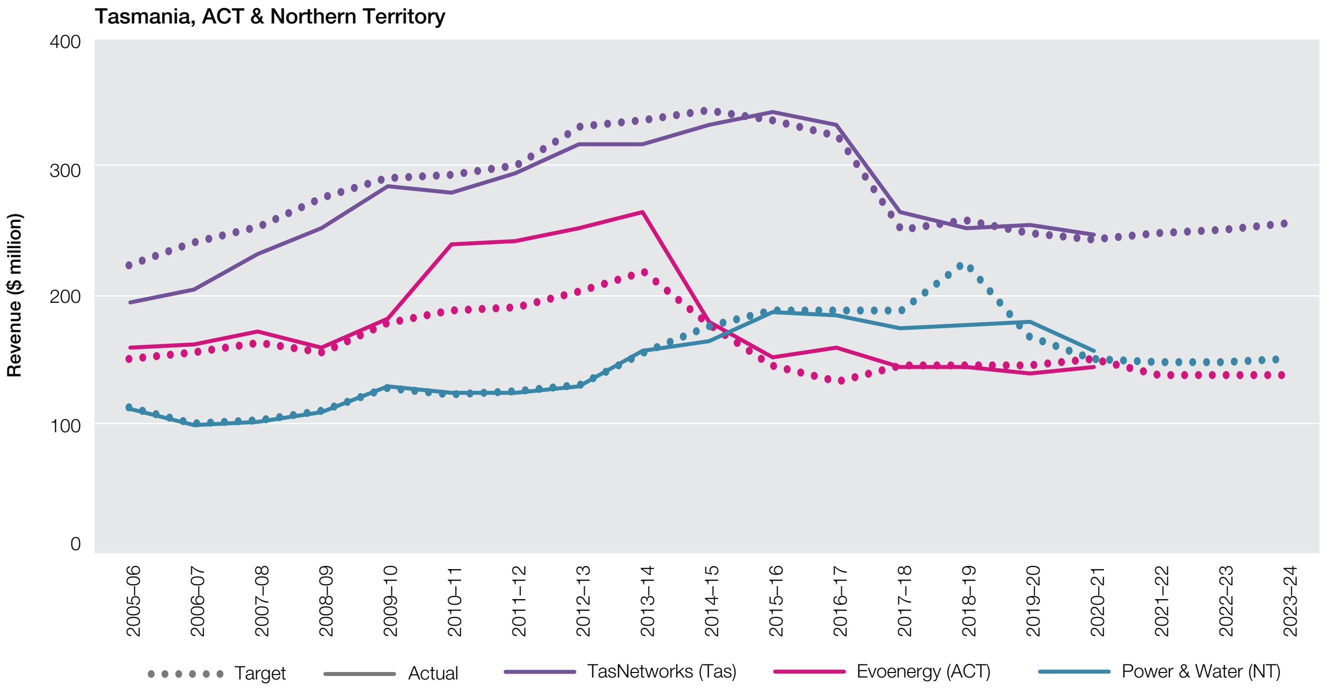




New South Wales
3,000
2,500
2,000
1,500
1,000
500
0
Revenue ($ million)
2005–06
2006–07
2007–08
2008–09
2009–10
2010–11
2011–12
2012–13
2013–14
2014–15
2015–16
2016–17
2017–18
2018–19
2019–20
2020–21
2021–22
2022–23
2023–24
Target
Actual
Ausgrid (NSW)
Endeavour Energy (NSW)
Essential Energy (NSW)



Victoria
800
700
600
500
400
300
200
100
0
Revenue ($ million)
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2021–22
2022–23
2023–24
2024–25
2025–26
Target
Actual
CitiPower (Vic)
Jemena (Vic)
Powercor (Vic)
AusNet Services (Vic)
United Energy (Vic)



Note: All data are adjusted to June 2022 dollars, based on forecasts of CPI. Most network businesses report on a 1 July – 30 June basis. The exception is the Victorian networks which have reported 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 for the Victorian distribution networks for the 2021 year has been derived from the transitional year (1 January – 30 June 2021). To enable reporting on equivalent terms these values have been doubled.

Source: AER modelling; annual reporting RIN responses.

Actual network revenues increased by around 7% per year from 2006 to 2015, when network charges accounted for around 43% of retail electricity bills. This significant growth in network revenues led to an increase in retail electricity bills over the period. From 2015 revenues decreased, driven by a 22% reduction in target revenue for the NSW networks in 2015 and an 11% reduction for the Queensland networks in 2016.

A 68% increase in the value of the total transmission and distribution RAB from 2006 to 2014 was a key contributor to the increase in revenue. The increase in RAB was driven by increased investment, in part caused by more strict jurisdictional reliability standards.

Since 2014 the level of investment has decreased, but the impact of past overinvestment remains in the asset base (section 3.11). The inflating RAB 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 it did elsewhere. In Queensland, it grew by 11% per year from 2006 to 2015; in NSW, it rose by 13% from 2006 to 2013. A key cost driver was the stricter reliability standards imposed by state governments, which required new investment and operating expenditure to meet the new standards. Revenue growth was less pronounced in Victoria, increasing by a relatively stable 4% per year from 2006 to 2015.

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, allowed rates of return approved for some network businesses fell to around 4.6% in 2022 (section 3.12).

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.

A combination of these factors reduced the revenue needs of network businesses. Decreasing investment and rates of return gradually often lowered network businesses' revenue as they entered a new 5-year regulatory cycle. However, 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.[99] The Australian Competition and Consumer Commission (ACCC) supported this position, particularly for government-owned networks in Queensland, NSW and Tasmania.[100]

Consumer groups and some industry observers remain concerned that 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. The AER also releases its *Annual electricity network performance report*, which provides detailed analyses of key operational and financial trends and key profitability measures. The AER's report enables stakeholders to make more informed assessments of the returns earned by each network business.

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 led to the expenditure on capital projects dropping to a comparable level with operating costs. Operating expenditure later eased as network businesses (especially distributors) implemented efficiency programs (section 3.14).

Figure 3.13 provides a summary of key financial indicators for electricity networks on a per customer basis, which allows for greater comparability across networks.[101] [102] The data in Figure 3.13 reports actual network revenue and expenditure over the past 5 years, which covers a full regulatory period and also reduces the potential for single year bias.

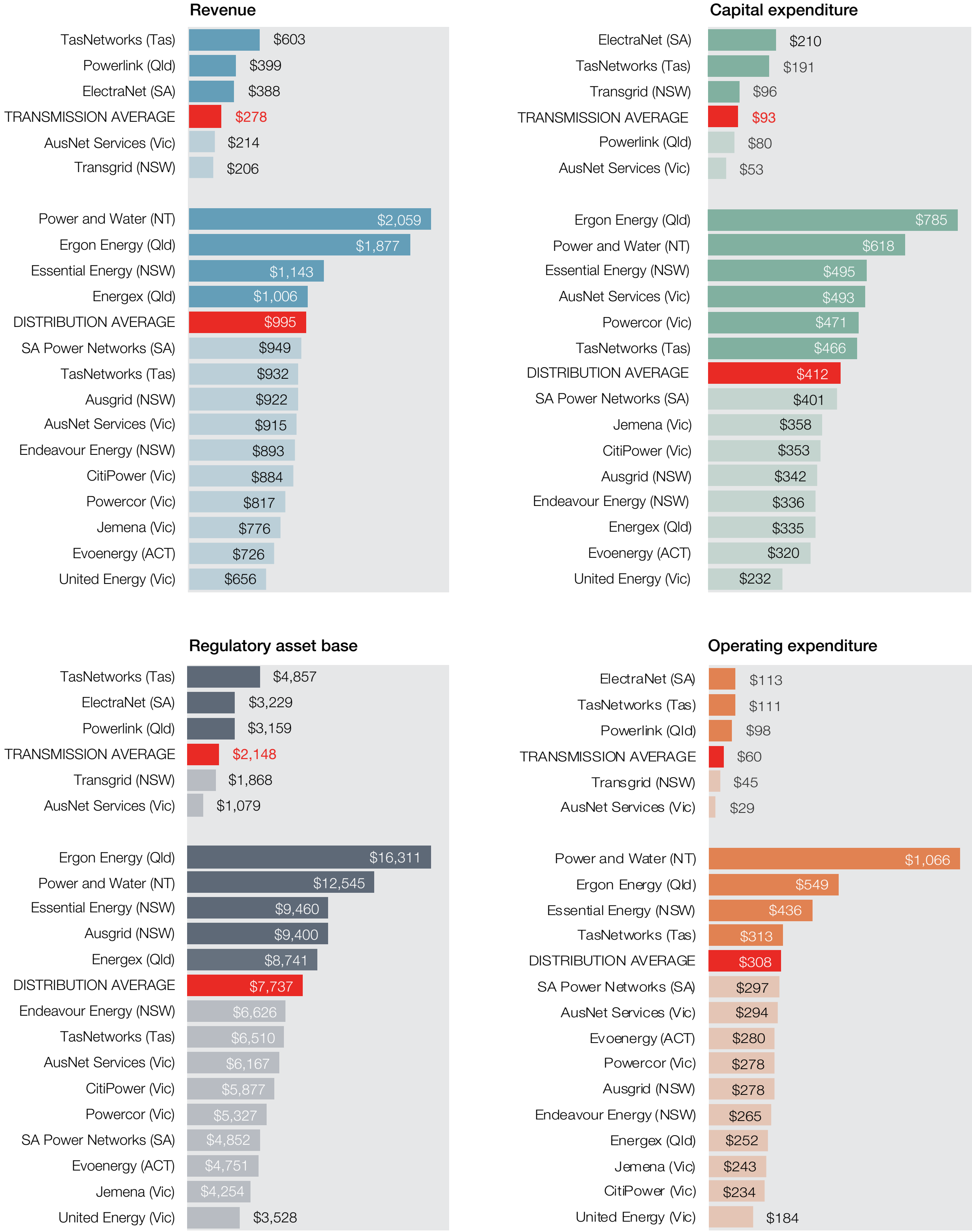
99 T Wood, D Blowers, K Griffiths, 'Down to the wire – a sustainable electricity network for Australia', Grattan Institute, March 2018.

100 ACCC, 'Retail Electricity Pricing Inquiry – final report', 11 July 2018.

101 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.

102 Transmission networks do not report customer numbers. Per customer metrics for the transmission networks were calculated using the total number of distribution customers in the relevant jurisdictions.

Figure 3.13 Per customer financial metrics – electricity networks



Note: All data are adjusted to June 2022 dollars, based on forecasts of CPI. In 2021 residential customers (a customer who purchases energy principally for personal, household, or domestic use) accounted for 88% of total customers on the distribution network. Of the remaining customers, 10% were non-residential and 1.4% were unmetered or 'other'. While these proportions differed across network businesses – for example, 91% residential for Energex (Qld) and 83% for Essential Energy (NSW) – the differences did not materially affect the 'per customer' metric. Revenue, capital expenditure and operating expenditure are the annual averages over the 5 years to 30 June 2021. RAB is the actual closing RAB at 30 June 2021. For regulatory purposes, Northern Territory transmission assets are treated as part of the distribution system.

Source: AER revenue decisions and economic benchmarking RINs.

Figure 3.14 provides a snapshot of the key forecasts from the AER's revenue decisions for the current regulatory periods and how they compare with the forecasts from the previous period.

Figure 3.14 AER electricity network revenue decisions – current regulatory period

	Revenue	Capital expenditure	Operating expenditure	Annual impact on residential bill
Transmission	\$12.6b (▼5%)	\$7b (▲61%)	\$3.2b (▼3%)	▲0.3%
Distribution	\$46.3b (▼14%)	\$19.9b (▼19%)	\$16.9b (▲0.6%)	▼0.4%
Total	\$58.9b (▼12%)	\$26.9b (▼7%)	\$20.2b (▲0.04%)	▼0.2%

Note: The current regulatory period is the period in place at 1 July 2022. Changes in revenue and expenditure are in relation to forecasts from the previous regulatory periods. 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.

Revenue for transmission businesses is locked in at the beginning of the regulatory period. 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.

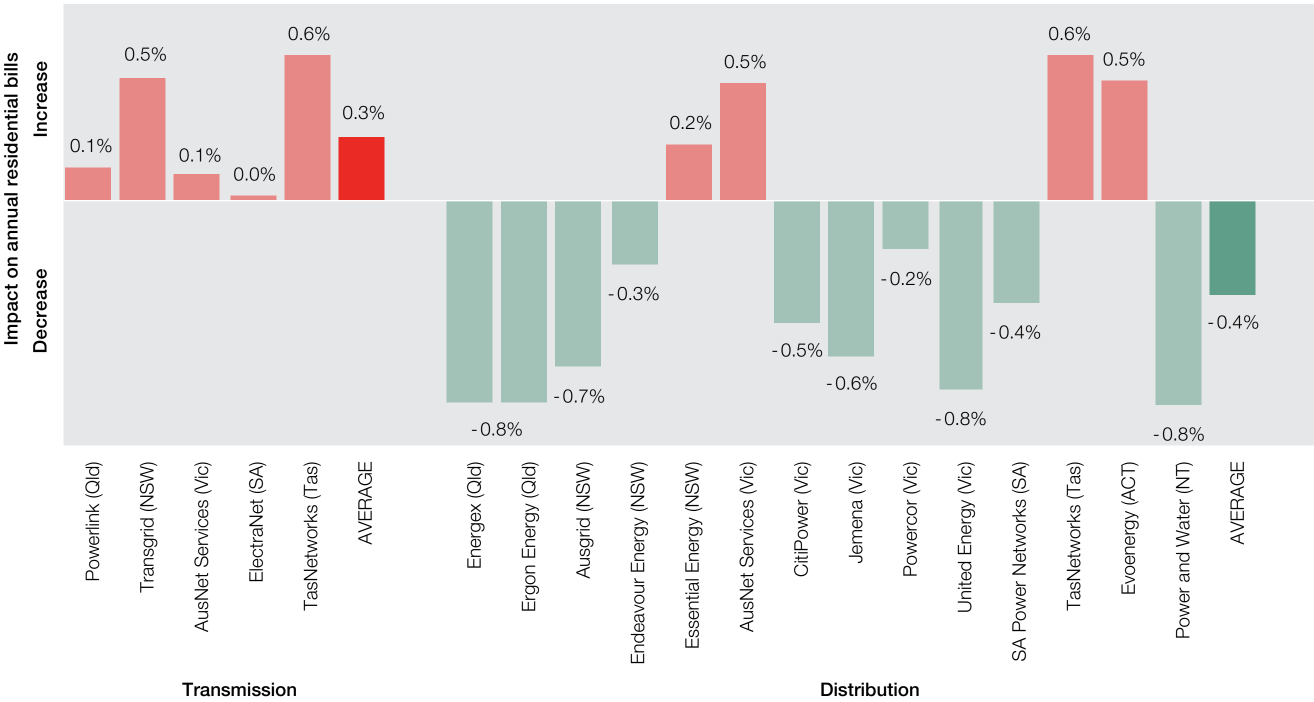
The key driver behind lower revenues for most of the transmission and distribution networks is the change in the return on capital. The rate of return has decreased between regulatory periods; this has been driven by the decrease in interest rates. This means network businesses can now obtain the capital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

3.10 Network charges and retail bills

Electricity network charges made up 40% to 50% of a residential customer's energy bill in 2021 (section 6.6.1 in chapter 6). Distribution networks account for most of the costs (73% to 78%), and transmission network costs (up to 21%) and metering costs make 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 3.15). 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.

Figure 3.15 Impact of AER revenue decisions on residential customer electricity bills



Note: Estimated 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.

The AER's most recent revenue decisions decreased residential energy bills by an average of 0.2% per year across all states and territories. This is the culmination of an average 0.3% 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.

Electricity distributors submit annual pricing proposals to the AER, outlining proposed prices to take effect in the following year. These proposed prices must be consistent with the distributor's approved revenues but can account for additional costs associated with transmission and jurisdictional schemes.

Amongst other factors, those annual processes update prices for changes in the consumer price index (CPI). Since June 2021, CPI has increased significantly. For example, over the twelve months to June 2022, CPI increased by 6.1%. The RBA forecasts CPI growth will continue to be high through the end of 2022 and into 2023.[103] As these inflation results feed into annual pricing over coming years they will put upward pressure on prices.

3.11 Regulatory asset base

The RAB for a network business represents the total economic value of assets that provide network services to customers.[104] The value of the RAB substantially impacts a network business's revenue requirement, 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 on 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.

103 RBA, Statement of Monetary Policy, Forecast table, August 2022.

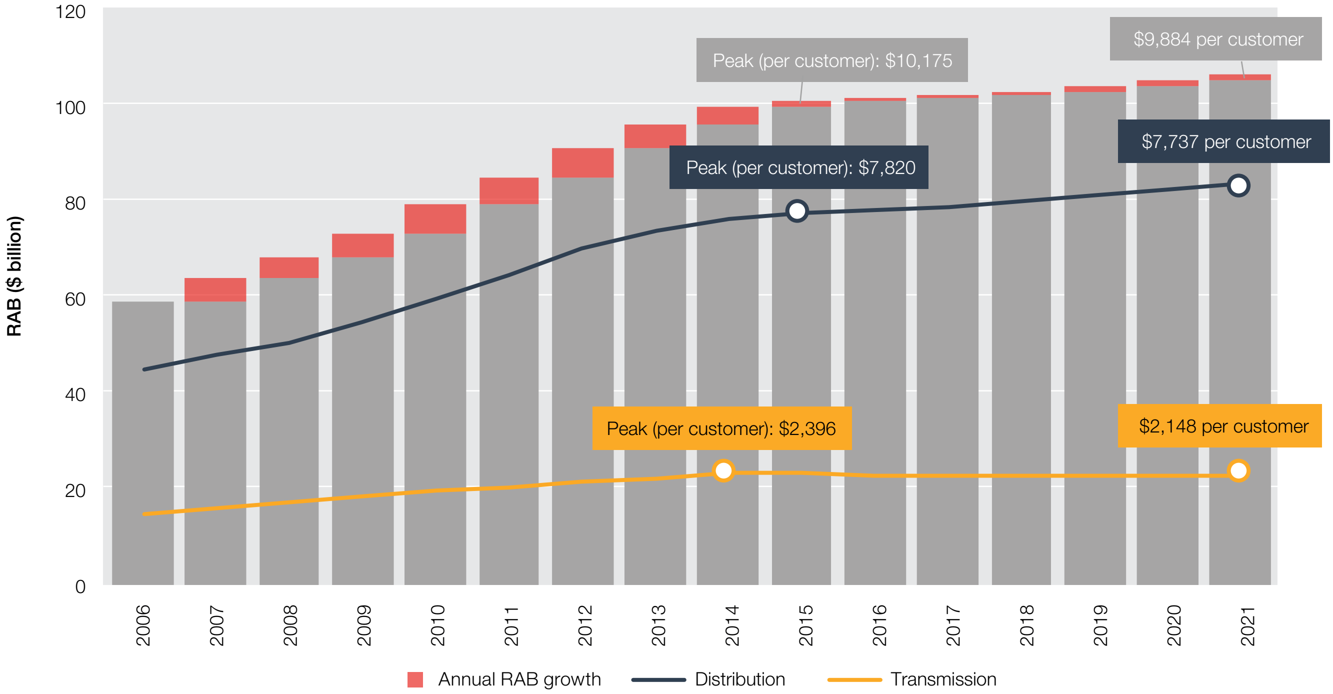
104 To the extent that they are used to provide such services.

Escalating investment inflated the value of the total network RAB from $58.8 billion in 2006 to $98.5 billion in 2014 – an increase of around 8% per year. Since 2014 network investment has steadied, as has the growth in the value of the total network RAB. From 2014 to 2021 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 continues to grow, the recent trend has differed between transmission and distribution networks.

3.11.1 Regulatory asset base in 2021

As at 30 June 2021 the value of the RAB for electricity network businesses was $105.4 billion, an increase of $1.4 billion (1.3%) from the previous year (Figure 3.16).

Figure 3.16 Value of electricity network assets (regulatory asset base)



Note: All data are adjusted to June 2022 dollars, based on forecasts of CPI. 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 modelling; economic benchmarking RIN responses.

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 3.9). Under reforms introduced in 2015 the AER may remove inefficient investment from a network's asset base if the network overspent its allowance, to ensure customers do not pay for it.

3.11.2 Overhead support structures

The value of a network business's RAB includes many assets, which can be disaggregated into several categories. Overhead network assets represent the most observable component of electricity network infrastructure and account for the greatest proportion (around 35%) of the total network RAB. This is not surprising given the network spans almost 800,000 kilometres of line, 85% of which is above ground (Figure 3.2 and Figure 3.3).

Transmission towers and distribution poles are installed by network businesses to support overhead powerlines. Transmission towers are predominately made of steel, but distribution poles can be made of wood, concrete, steel or composites like fiberglass. The differing environmental conditions faced by each network business can influence their choice of material. For example, in some parts of Australia, wooden poles are more quickly destroyed by termites, so metal poles are used instead.

Stobie poles – which are unique to South Australia – consist of 2 perpendicular lengths of steel-channel section held apart by bolts and the intervening space is filled with concrete, which protects the steel from corrosion. The poles – which were patented in 1924 – came about as an engineering solution to South Australia's lack of tall, termite-resistant hardwood for poles to carry powerlines and telephone wires.[105]

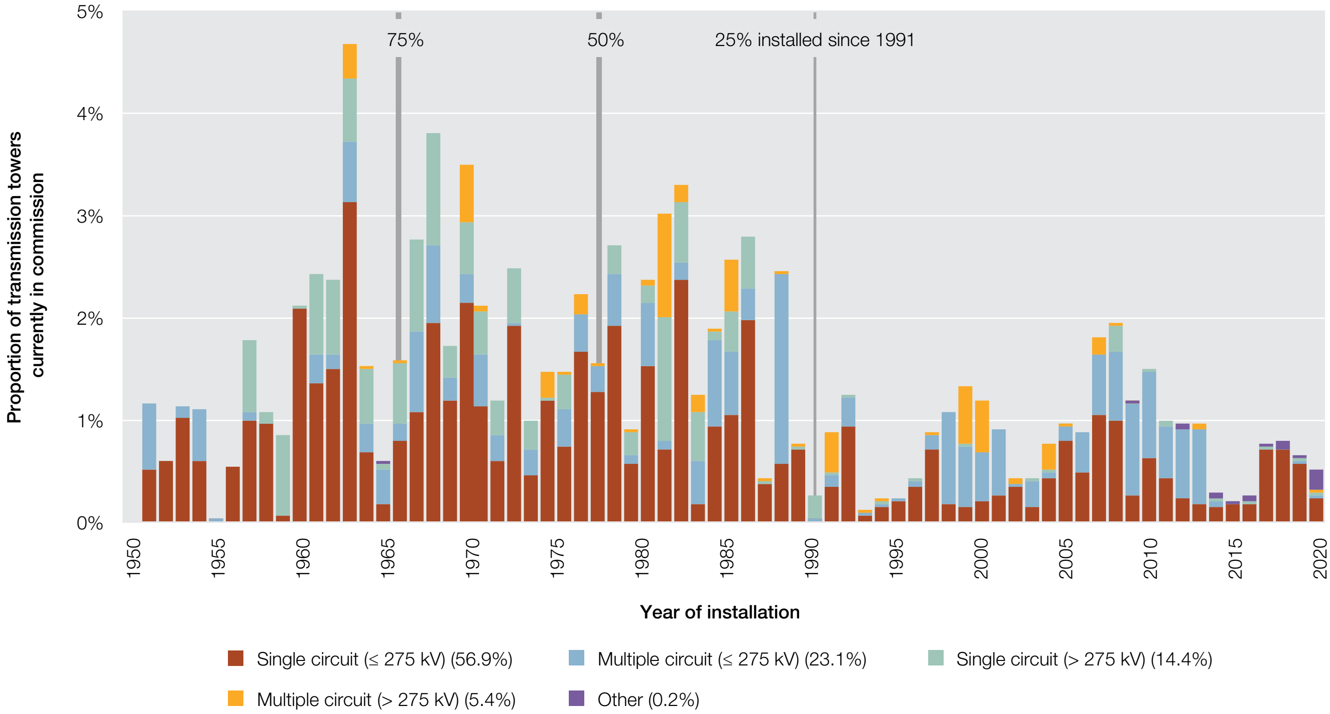
SA Power Networks' distribution network consists of more than 70,000 kilometres of overhead powerlines. However, overhead network assets only make up around 18% of the value of SA Power Networks' RAB. This relatively low representation of overhead assets in SA Power Networks' RAB is uncommon among network businesses given the considerably large size of the network's service area.

Due to the hard-wearing and near-indestructible nature of the distribution poles used in South Australia, SA Power Networks' poles in commission are significantly older than the poles in commission in any other network in the NEM. As such, a significant proportion of SA Power Networks' overhead assets are no longer included in the RAB. This unique feature makes SA Power Networks somewhat of an anomaly in the NEM and has the impact of providing cost savings for its current customers.

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. It is not surprising that predominately rural networks are more reliant on overhead poles than the networks operating in predominately urban environments.

The transmission tower and distribution pole age profiles shown in Figure 3.17 and Figure 3.18 provide an overview of the total towers and poles currently in commission. However, we note the asset age and tower/pole types differ considerably between the network businesses.

Figure 3.17 Overhead support structures – electricity transmission towers

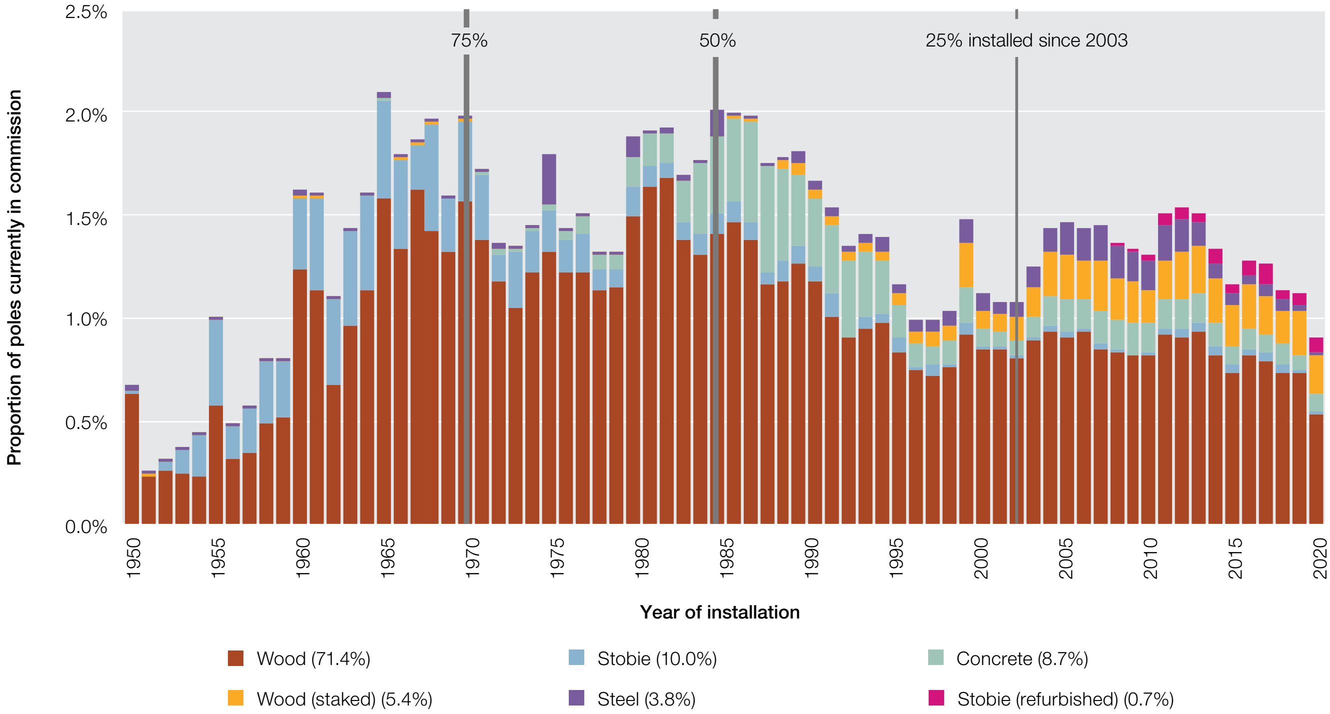


kV: kilovolt.

Source: Category analysis RIN responses.

105 P Sumerling and W Prest, 'Stobie Poles', SA History Hub, History Trust of South Australia, accessed 14 December 2020.

Figure 3.18 Overhead support structures – electricity distribution poles



Note: 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 RIN responses.

3.12 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 financial returns that a network business's financiers require to justify investing in the business. It is a weighted average of the return needed to attract both equity and debt funding. Equity funding is the dividends paid to a network business's shareholders and debt funding relates to 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 difference can be due to several 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.[106]

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.

Because electricity networks are capital intensive, returns to investors typically make up 30% to 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 allowed WACC will increase revenues by around 8%, which would increase average household bills by around 4%.[107] For this reason, prior to the abolition of limited merits review and the introduction of the binding rate of return instrument, the allowed rate of return was often the most contentious part of the AER's individual revenue decisions.

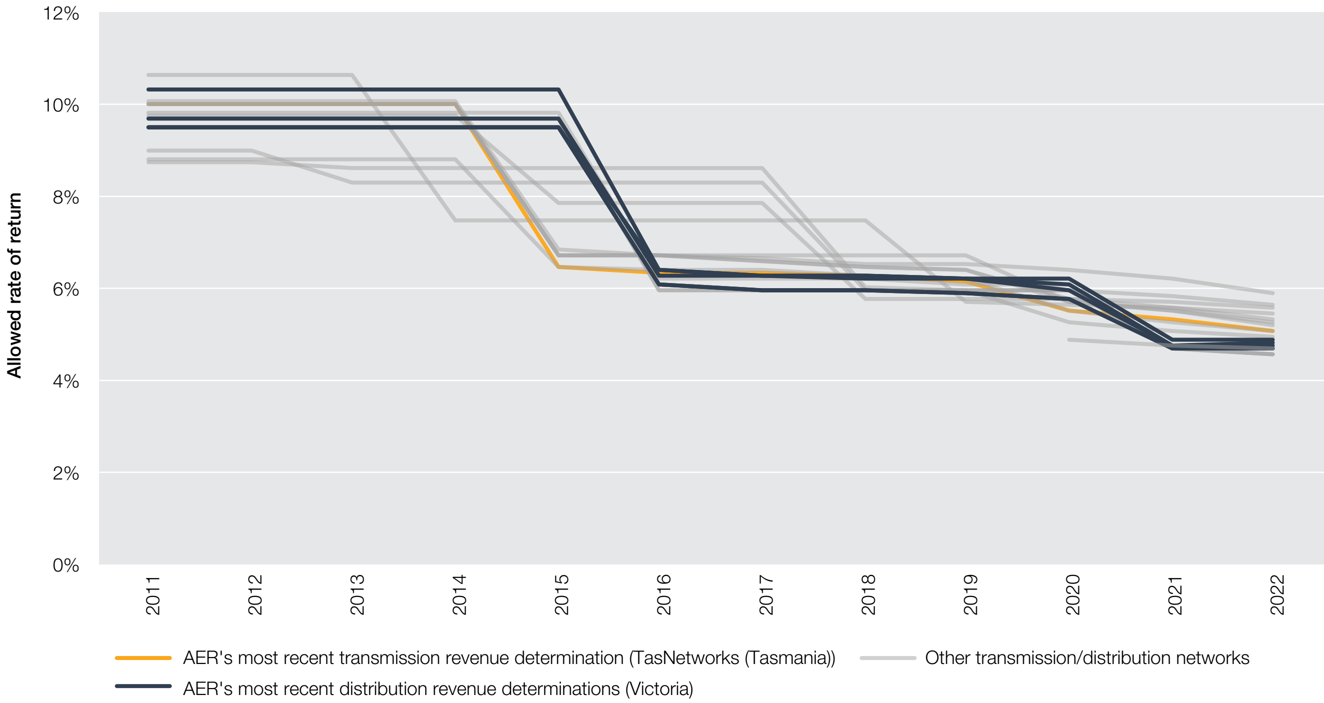
Conditions in financial markets are a key determinant of the allowed rate of return. The AER's revenue decisions from 2009 to 2012 took place against a backdrop of the global financial crisis, an uncertain period associated with reduced liquidity in debt markets and high-risk perceptions. In revenue decisions made during this period the allowed rate

106 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.

107 Average household bill calculation assumes: $2,000 average household bill, 50% network component (transmission + distribution), ignores demand impacts.

of return was more than 10%, reflecting the conditions in financial markets (Figure 3.19). The Australian Competition Tribunal increased some allowed rates of return following appeals by the network businesses.

Figure 3.19 Allowed rate of return



Note: Rate of return is the nominal vanilla WACC.

Source: AER decisions on electricity network revenue proposals; AER decisions following remittals by the Australian Competition Tribunal or Full Federal Court.

Since 2015 the AER has updated the allowed return on 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 (Figure 3.9 and Figure 3.11).

In recent months, some key inputs into rates of return have increased. For example, the risk-free rate is an important driver of allowed returns on equity and is estimated using required returns on Commonwealth Government Securities (CGSs), also known as Australian government bonds. Annual yields on 10-year CGSs were as low as 0.6% in March 2020, but over 2022 to the end of August have averaged roughly 3%. Similarly, annual yields on 5-year CGSs were as low as 0.25% in November 2020 but over 2022 to the end of August have averaged roughly 2.7%.[108] If risk-free rates, or other key inputs, remain at levels above lower recent rates, this will put upward pressure on network revenue over coming years.

In recent years the AER has estimated network businesses' actual returns for comparison against network businesses' allowed returns. This analysis suggests that actual returns have often exceeded the AER's allowed returns. This is not unexpected given that the premise of a revealed efficient cost framework is to encourage network businesses to become more efficient, allowing for short-term profits to be earned above the allowed rate.[109]

3.13 Investment

Electricity network businesses invest in capital equipment such as towers, 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 when 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.

108 RBA, Capital Market Yields – Government Bonds – Daily – F2, accessed 6 September 2022.

109 AER, 'Electricity network performance report', September 2021, investigates network profitability and provides a more thorough analysis of actual returns as opposed to allowed/forecast returns.

Figure 3.20 to Figure 3.22 break down the amount of investment network businesses undertook in 2021 and how this compared with previous years' expenditure and forecasts.

Figure 3.20 Capital expenditure in 2021 – key outcomes

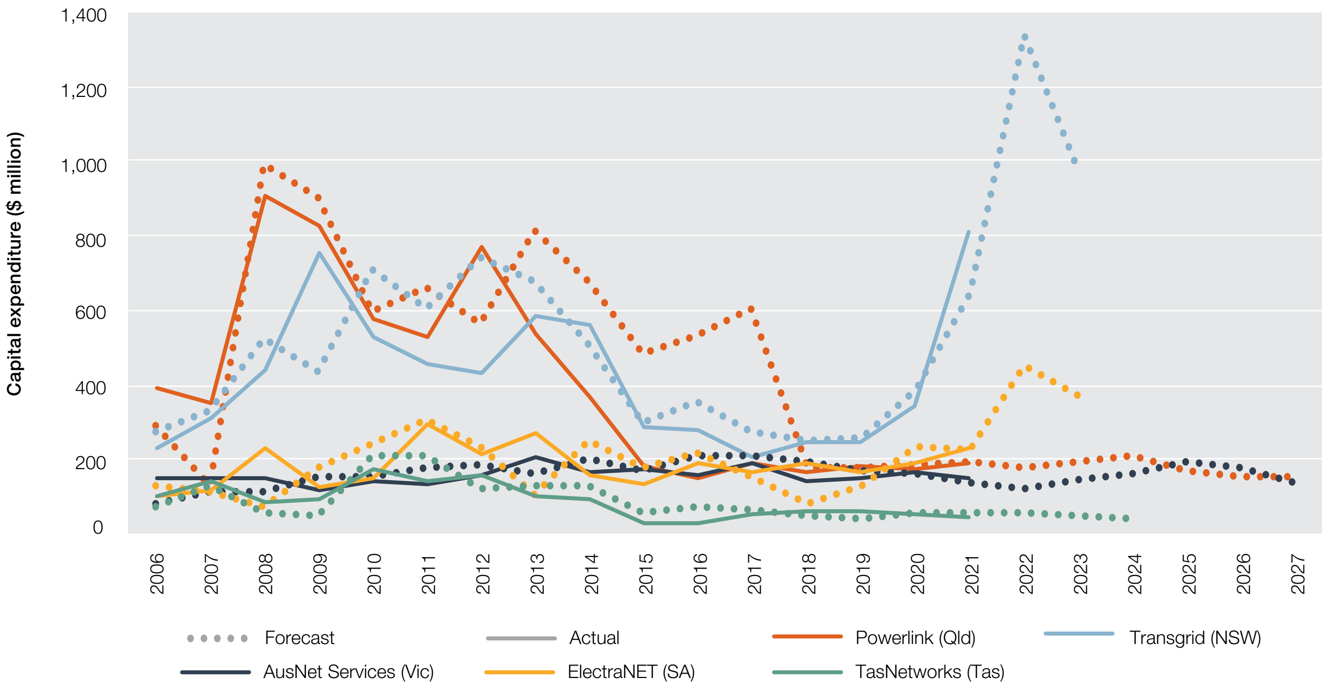
	2021 (actual)	Compared to 2020	Compared to forecast	Compared to peak (year)
Transmission	$1.4b	▲$494m (▲53%)	▲$157m (▲12%)	▼26% (2009)
Distribution	$4.2b	▼$56m (▼1.3%)	▲$96m (▲2%)	▼44% (2012)
Total	$5.7b	▲$438m (▲8%)	▲$253m (▲5%)	▼39% (2012)

Note: Excludes AER decisions on transmission interconnectors.

Significant investment in the transmission network is forecast to continue over the next few years (Figure 3.21). Between 2022 and 2026 the modelled cost of actionable ISP projects under the 2020 ISP – specifically Project EnergyConnect (Transgrid and ElectraNet) and the Queensland–NSW interconnector (QNI) project (Transgrid) – is around $12.8 billion (Figure 3.27).[110]

Further significant investment is also forecast for Transgrid's HumeLink project – a new 500 kilovolt transmission line that will connect Wagga Wagga, Bannaby and Maragle. Transgrid expects to commence construction on HumeLink in 2024.[111]

Figure 3.21 Capital expenditure – electricity transmission networks



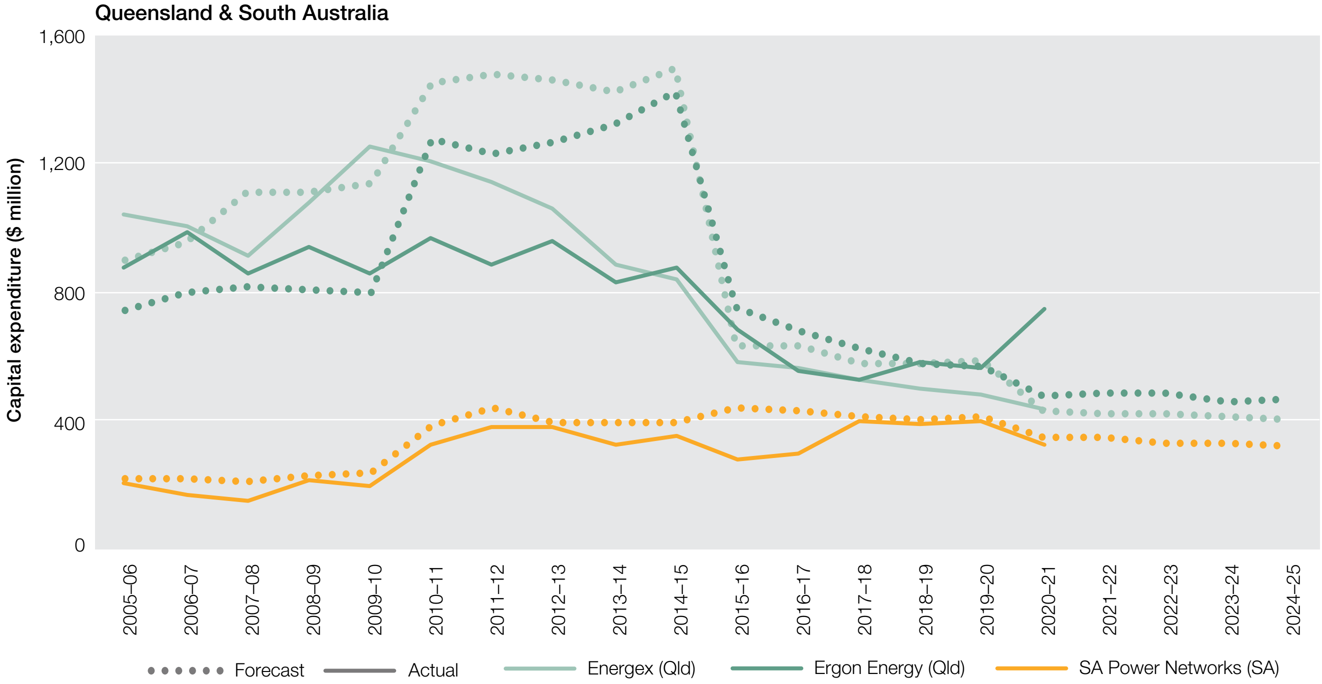
Note: Actual outcomes, CPI adjusted to June 2022 dollars. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018). Assumptions are set out in Figure 3.9 notes.

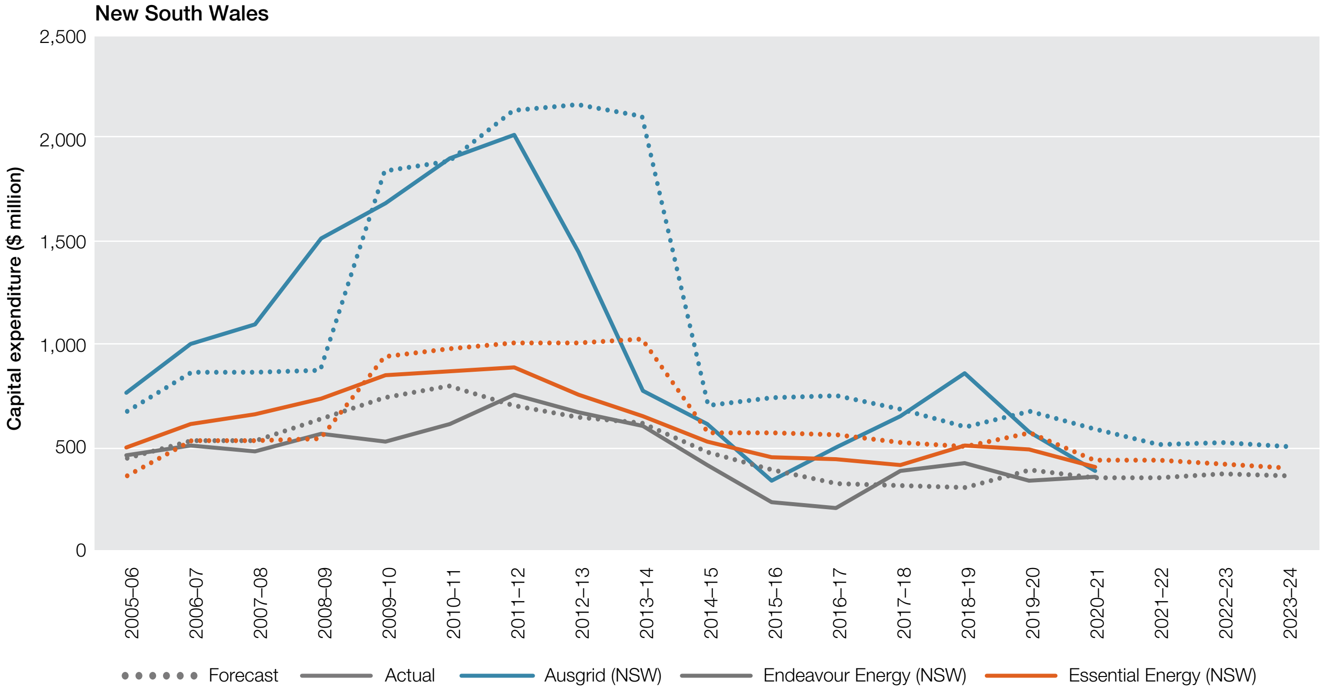
Source: AER modelling; annual reporting RIN responses.

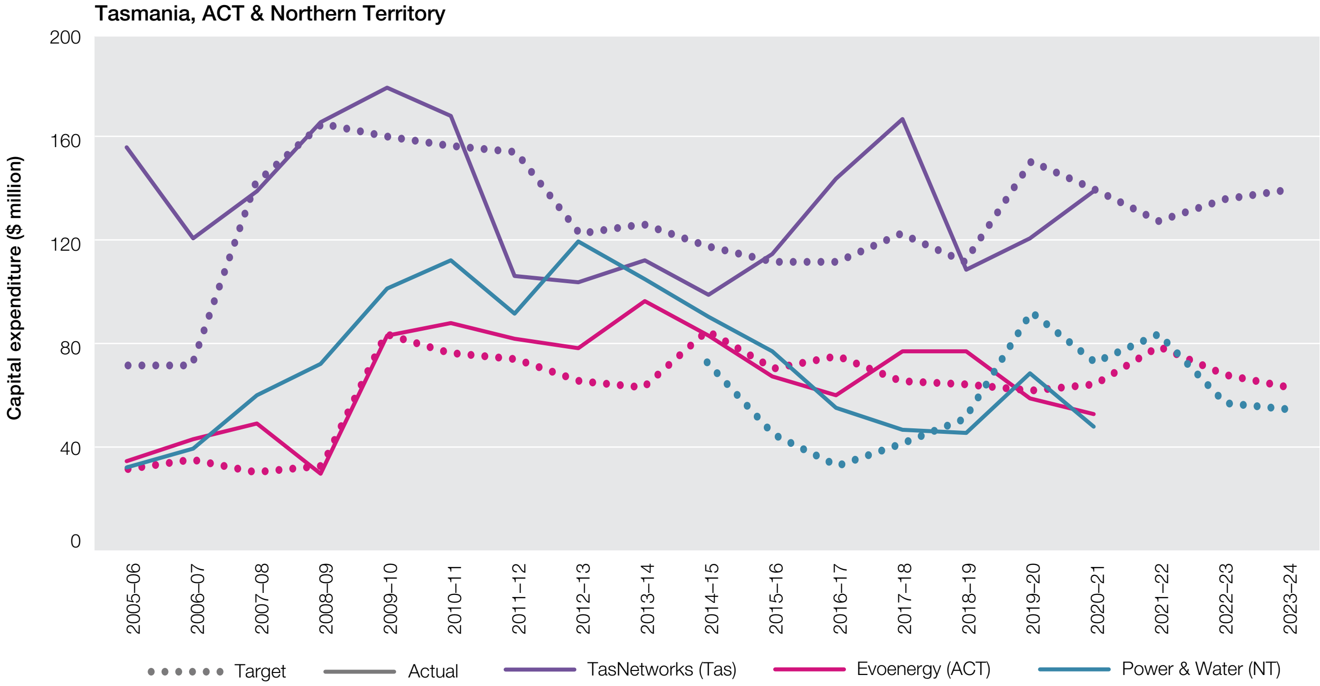
110 AEMO, '2022 Integrated System Plan' June 2022, p. 15

111 Transgrid, 'HumeLink – fact sheet', accessed 30 March 2022

Figure 3.22 Capital expenditure – electricity distribution networks







Note: Actual outcomes, CPI adjusted to June 2022 dollars. Assumptions are set out in Figure 3.11 notes.

Source: AER modelling; annual reporting RIN responses.

3.13.1 Investment trends

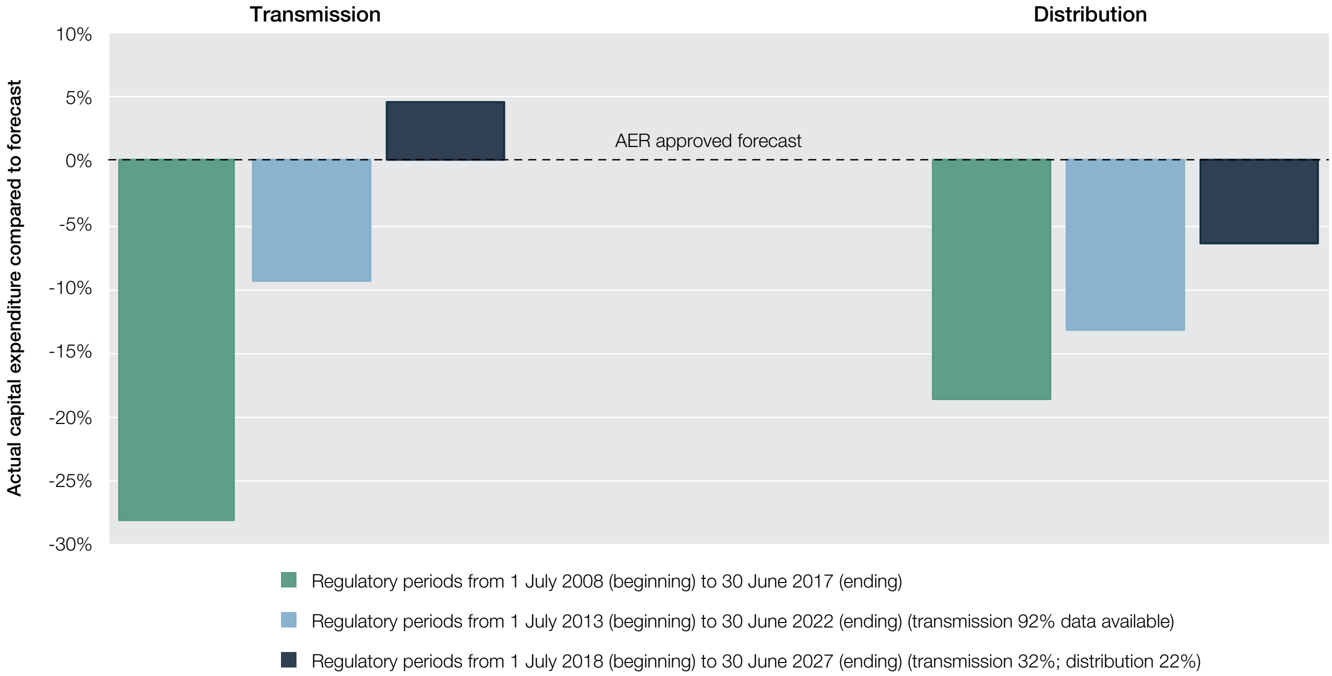
Total investment in the electricity networks increased by an average of 7% per year from 2006 to 2013, when it peaked at $9.3 billion (Figure 3.9 and Figure 3.11).

Network businesses underspent heavily against the forecast over the regulatory periods from July 2008 to June 2017. Network businesses in Queensland were the most significant contributors to the underspend, with Powerlink (transmission) underspending by 54%, Ergon Energy underspending by 31% and Energex (distribution) underspending by 30%. Network businesses in NSW also contributed, with Transgrid (transmission) underspending by 21%, Ausgrid by 23% and Essential Energy (distribution) by 19%.

Investment levels eased in the following regulatory periods[112], when AER reforms to protect consumers from funding inefficient network projects began. Although the trend in underspending continued, it did so at a lesser rate. The Victorian distribution networks were most responsible, led by CitiPower (31% underspend), Jemena (22%) and United Energy (22%).

Network business are still collectively in the early stages of their respective current regulatory periods, but the gap between actual and forecast capital expenditure is continuing to narrow (Figure 3.23).

Figure 3.23 Capital expenditure against forecast



Data availability (%) refers to the proportion of actual capital expenditure data available at the time of publication.

Note: Data used in Figure 3.23 includes actual expenditure for the regulatory year 2021. The timing of regulatory periods differs among network businesses. For example, while 2020–21 reflects the third year of ElectraNet's (transmission) current regulatory period, it reflects the fourth year of Powerlink's (transmission) previous regulatory period. This explains why a proportion of data is available for the current regulatory period even though the dataset from the last regulatory period is not yet complete.

Source: AER modelling; annual reporting RIN responses.

The AER assesses capital expenditure drivers when forming its view on the prudency of a network business's capital expenditure forecast. The AER does not determine which capital 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 cost-benefit analysis for new investment projects that meet cost thresholds.

In the AER's most recent revenue decisions the most significant driver of forecast investment expenditure was the replacement of assets that are reaching the end of their life, and infrastructure that supports the delivery of electricity transmission services.

In 2015 the AER introduced the capital expenditure sharing scheme (CESS), which offered financial incentives for network businesses to avoid investment above forecast levels (Box 3.2).

112 Which ranged from 1 July 2013 – 30 June 2018 for ElectraNet (South Australia) to 1 July 2012 – 30 June 2022 for several network businesses.

Box 3.2 Capital expenditure sharing scheme

The AER's capital expenditure sharing scheme (CESS) creates an incentive for network businesses to keep new investment within forecast levels approved in their regulatory determination. 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 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 3.3) and service quality (Box 3.4). This balancing of schemes encourages network businesses to make efficient decisions on their mix of expenditure to provide reliable services in ways that customers value (section 3.16.1).

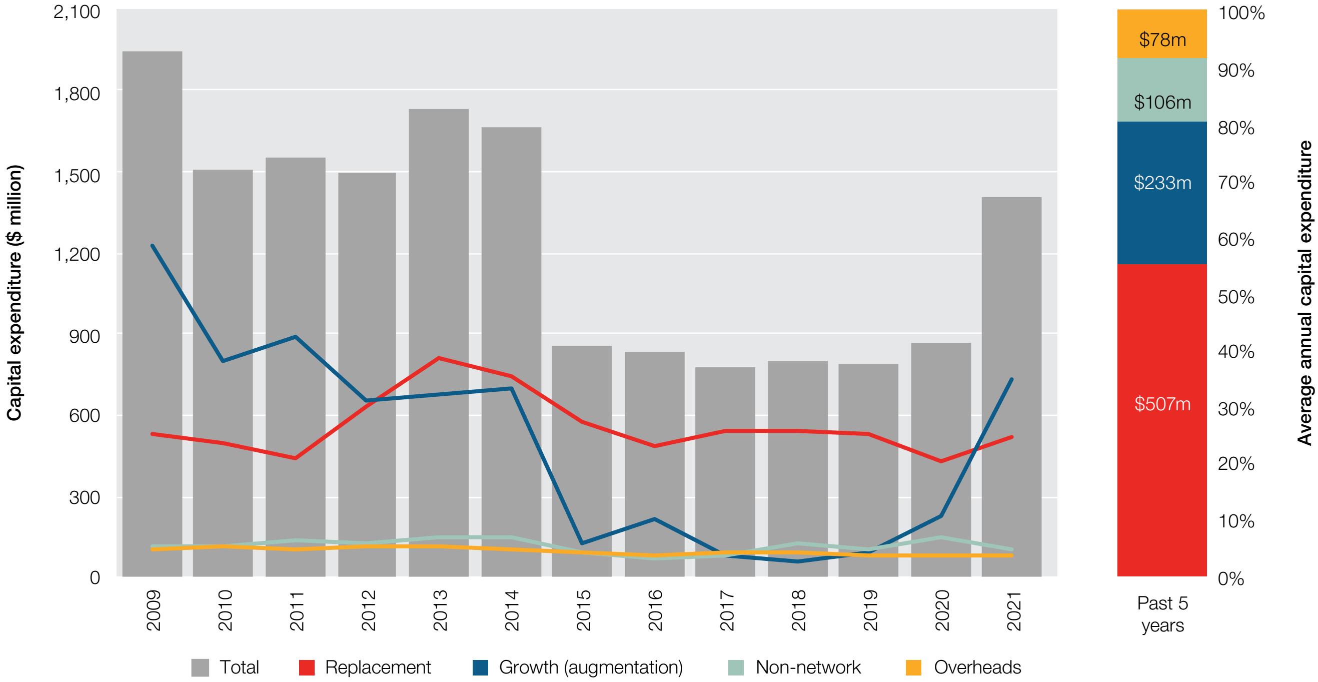
3.13.2 Changing composition of investment

For the last decade, network investment has been driven by replacement expenditure rather than growth-related expenditure (Figure 3.24 and Figure 3.25). Weaker than forecast demand for electricity, along with less stringent reliability obligations, led many network owners to postpone or abandon growth-related projects.

However, in 2021, electricity networks invested $1.6 billion in growth-related projects, an increase of $590 million (59%) over the previous year. This significant increase was not spread evenly across the networks. It was primarily the result of Transgrid (NSW) investing $619 million – driven by Project EnergyConnect – an increase of $535 million (632%) over Transgrid's growth-related expenditure in the previous year.

Despite the significant increase in growth-related expenditure in 2021, the replacement of existing assets continues to be the primary driver of capital expenditure.

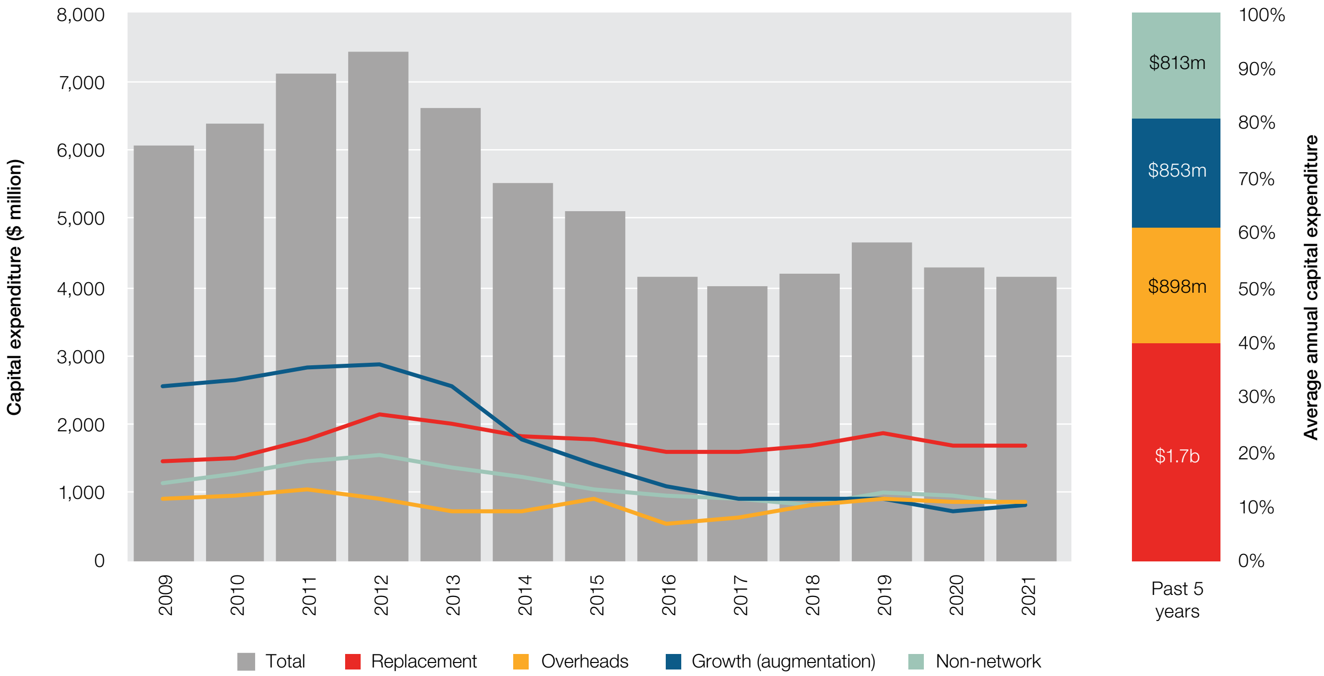
Figure 3.24 Drivers of capital expenditure – electricity transmission networks



Note: All data are adjusted to June 2022 dollars, based on forecasts of CPI. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018). Augmentation of the Victorian transmission network is carried out by AEMO; hence, AusNet Services reports $0 expenditure for augmentation carried out on the transmission network.

Source: Category analysis RIN responses.

Figure 3.25 Drivers of capital expenditure – electricity distribution networks



Note: All data are adjusted to June 2022 dollars, based on forecasts of CPI. 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 RIN responses.

3.13.3 Pass through events – natural disasters

In November 2020 Transgrid (NSW) submitted a cost pass through application to the AER, seeking to recover $55.5 million in costs over a 2-year period in relation to the 2019–20 bushfires. The bushfires impacted 9% of the length of Transgrid's transmission line and 2,681 of its transmission structures.

The AER determined some of the costs proposed by Transgrid should not be included and that the pass through amount should be recovered over a longer time frame. The AER approved a pass through amount of $49.8 million to be recovered by Transgrid over the 3 regulatory years to 30 June 2025.[113]

In September 2021 Essential Energy (NSW) submitted a cost pass through application to the AER, seeking to recover costs in relation to the 2019–20 bushfires. The bushfires burnt more than 3.4 million hectares in Essential Energy's network area or over 60% of the total fireground in NSW, resulting in power outages to over 104,000 customers.

The AER determined that, in this case, the 2019–20 bushfires did not constitute a single natural disaster event, but 2 separate natural disaster events (northern NSW and southern NSW). The AER approved a positive pass through amount of $11.1 million for the northern NSW bushfire and $20.2 million for the southern NSW bushfire to be recovered by Essential Energy over the 2 regulatory years to 30 June 2024.[114]

In November 2021 AusNet Services (Victoria) submitted a cost pass through application to the AER, seeking to recover costs in relation to storms that occurred on 9 and 10 June 2021. The storms caused extensive damage to AusNet Services' electricity distribution network and interrupted supply to over 230,000 customers.

The AER was satisfied that the June 2021 storms met the definition of a natural disaster pass through event and that the damage sustained was material. The AER approved a positive pass through amount of $39.1 million to be recovered by AusNet Services over the 4 regulatory years to 30 June 2026.[115]

In March 2022 AusNet Services (Victoria) submitted a cost pass through application to the AER, seeking to recover costs in relation to the storm that occurred on 29 October 2021. This severe storm event caused extensive damage to AusNet Services' electricity distribution network and interrupted supply to over 230,000 customers.[116]

The AER was satisfied the October 2021 storm met the definition of a natural disaster pass through event and that the damaged sustained was material. The AER approved a positive pass through amount of $6.2 million to be recovered by AusNet Services over the 3 regulatory years to 30 June 2026.[117]

3.13.4 Valuing distributed energy resources

The uptake of rooftop solar systems has grown exponentially over the past decade (Figure 3.26). As a result of this rapid growth, integration of consumer energy resources now presents a significant, emerging area of expenditure.

113 AER, 'Decision – cost pass through Transgrid's 2019–20 bushfire natural disaster event', 4 May 2021, accessed 4 April 2022.

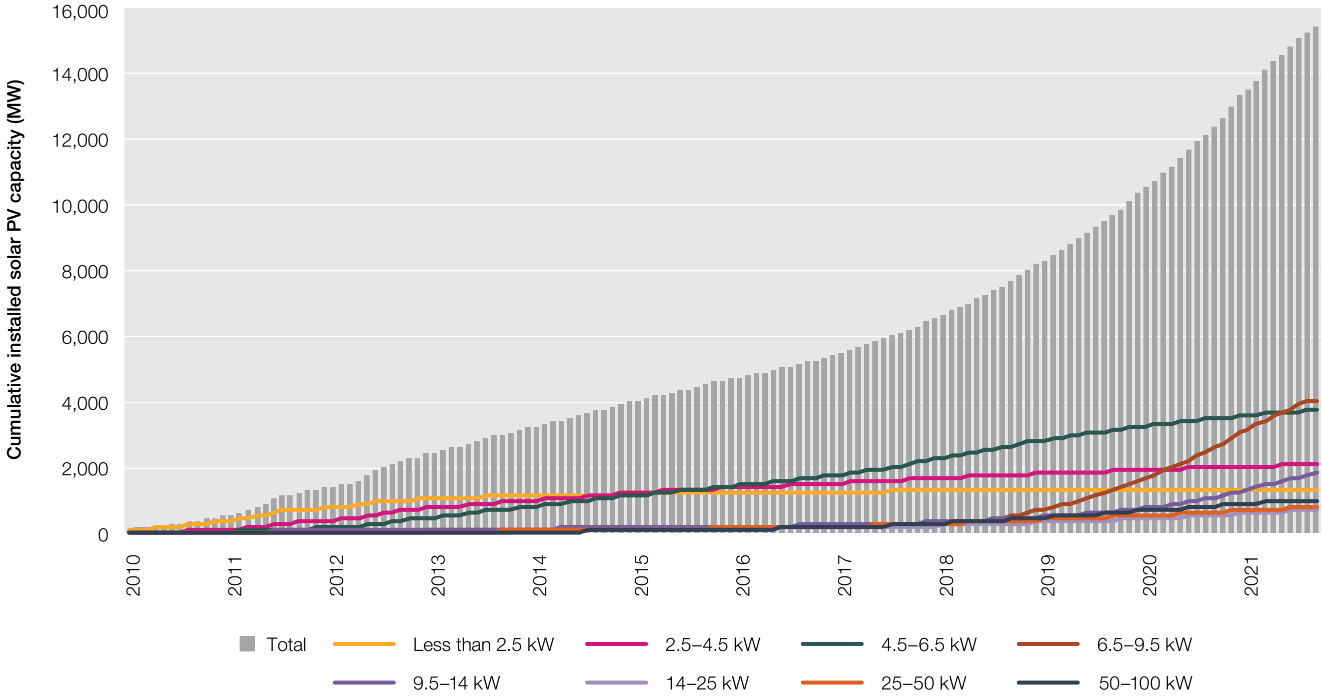
114 AER, 'Determination cost pass through Essential Energy's 2019–20 bushfire natural disaster events', 21 March 2022, accessed 4 April 2022.

115 AER, 'Determination June 2021 storms cost pass through – AusNet Services', 16 March 2022, accessed 4 April 2022.

116 AusNet Services, 'Cost pass through application', 10 March 2022, accessed 4 April 2022.

117 AER, 'AusNet Services – Cost pass through – October 2021 storm', 22 June 2022, accessed 26 June 2022.

Figure 3.26 Cumulative installed small-scale solar 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 6 February 2022.

In November 2019 the AER began developing guidance around assessing proposed integration of expenditure for consumer energy resources. As part of this process, the AER sought stakeholder views on the current and predicted effects consumer energy resources are having on networks and whether its current set of expenditure assessment tools are fit for purpose.

In 2020 the AER released a report (by the CSIRO and Cutler Merz) on potential methodologies for determining the value of consumer energy resources.[118] 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 consumer energy resources installed by customers.

The findings and recommendations of the report were reviewed and considered as part of the AER's draft consumer energy resources integration expenditure guidance note published in July 2021.[119]

The AEMC, in its *Electricity network economic regulatory framework review (2020)*, noted that the central roles of networks in a future with high levels of consumer energy resources 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 several key respects. In particular, how the electricity distribution network is operated and the services provided by distributors could change.

An environment with high levels of consumer energy resources 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 consumer energy resources 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.[120]

118 CSIRO and CutlerMerz, 'Value of distributed energy resources: methodology study – final report', October 2020. Note: Consumer energy resources and distributed energy resources are used interchangeably.

119 AER, 'Draft DER integration expenditure guidance note', AER website, 6 July 2021.

120 AEMC, 'Electricity network economic regulatory framework 2020 review', 1 October 2020.

3.13.5 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 transmission projects that have an estimated capital cost of greater than $7 million and distribution projects that have an estimated capital cost of 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 the option that 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 including fines apply to network businesses that do not comply with some of the RIT requirements (including the required consultation procedures).

Until 2017 the regulatory tests only applied to growth investment, which was the biggest component of network investment until 2014. Replacement expenditure has since overtaken growth investment on most networks (section 3.13.2), so the test now also applies to replacement projects. 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 its *Cost benefit analysis guidelines* (for transmission projects initiated by AEMO's integrated system plan (ISP)) and updated the RIT-T application guidelines (for other projects).[121] [122] The guidelines are part of a broader reform to streamline the transmission planning process while retaining rigorous cost benefit analysis. The new rules were effective from 1 July 2020, but the new guidelines came into effect through the 2022 ISP.[123]

3.13.6 AEMO's integrated system plan

The ISP provides a coordinated whole-of-system plan for efficient development of the power system to ensure power system needs are met in the long-term interests of consumers. The ISP 'actions' key projects by triggering RIT-T applications (section 3.12.6).

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 $12.8 billion.[124]

Under new rules, the ISP is subject to additional governance arrangements through binding cost benefit analysis 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 with flexibility in how it identifies the optimal pathway for the NEM when developing the ISP.

The AER's cost-benefit analysis 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 guidelines also apply to RIT-Ts for actionable ISP projects.[125]

A 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 remain largely unchanged for non-ISP projects, such as asset replacements.

121 AER, 'Cost benefit analysis guidelines', AER website, August 2020.

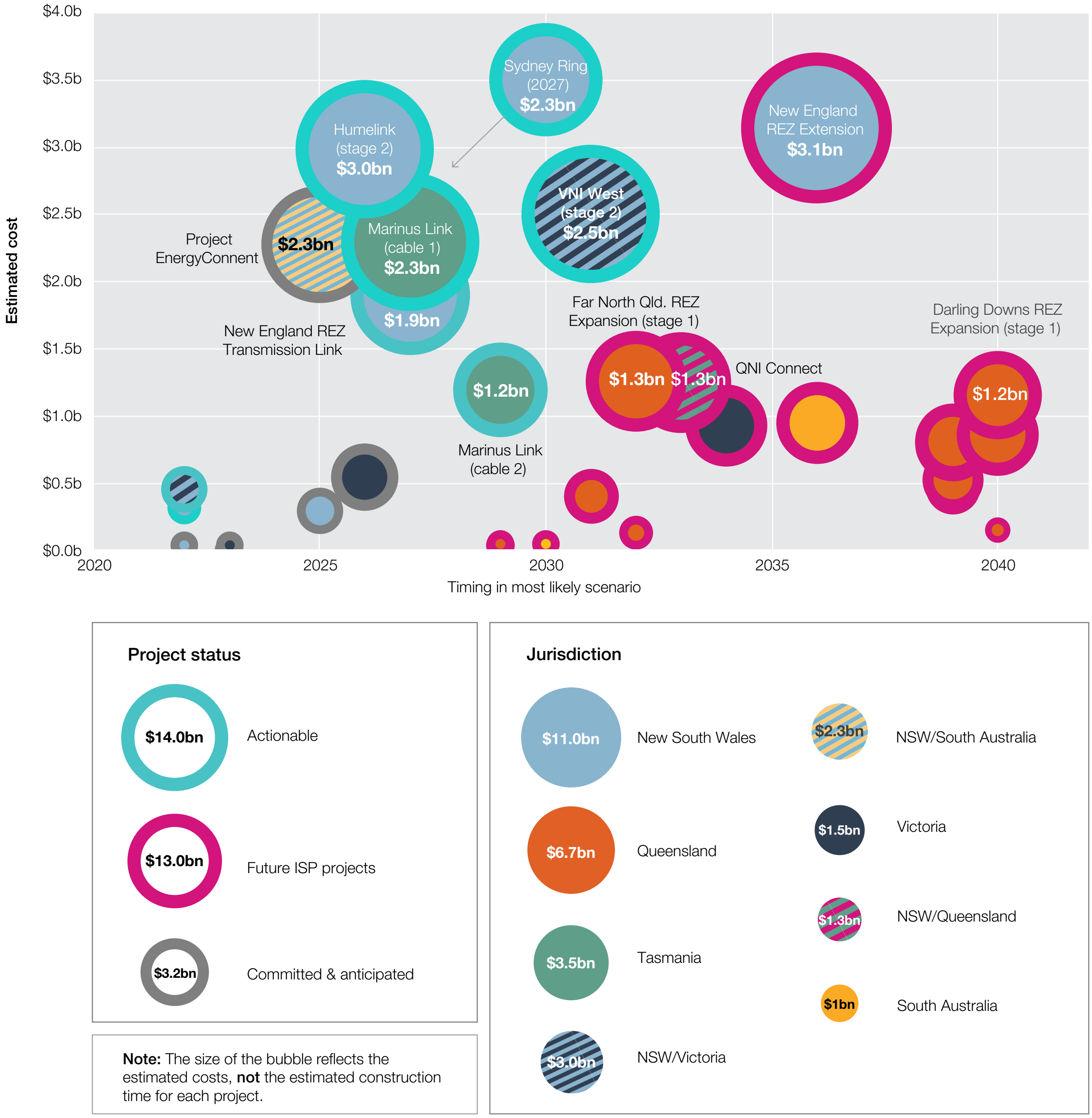
122 AER, 'Application guidelines – regulatory investment test for transmission', AER website, August 2020.

123 AER, 'Final decision – guidelines to make the Integrated System Plan actionable', AER website, August 2020.

124 AEMO, '2022 Integrated System Plan' June 2022, p 15.

125 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.

Figure 3.27 AEMO's integrated system plan



Source: AER analysis, AEMO integrated system plan, June 2022

3.13.7 Recent activity – regulatory tests

In August 2022, Energy Ministers announced the establishment of the National Energy Transformation Partnership (the Partnership). Amongst the initial priorities identified under the Partnership, Ministers have committed to identify and declare transmission of national significance (including the actionable projects in the ISP – Marinus, VNI West (via Kerang), and Humelink) to accelerate the timely delivery of these critical projects and ensure better community consultation.

There are numerous ongoing RIT-T processes across the transmission networks. This section highlights major developments amongst actionable ISP projects.

VNI West is a proposed new high capacity 500 kilovolt double-circuit overhead transmission line between Victoria and NSW. AEMO and Transgrid published the project assessment draft report (PADR) for VNI West in July 2022.[126] The PADR is a major milestone in the RIT-T process, in which the proponents identify a preferred option for consultation and feedback. VNI West was identified as the preferred option, with an estimated market benefit of $687 million in present value.

TasNetworks has completed a RIT-T for Project Marinus, which is a proposed undersea electricity connection between Tasmania and Victoria (Marinus Link) and supported by transmission network developments in north-west Tasmania. In June 2021, TasNetworks published the Project Assessment Conclusions Report, identifying a preferred option made up of 2,750 MW undersea cables, staged over 2029 and 2031, supported by AC network upgrades. This concludes the RIT-T process.

In August 2022, the AER approved Transgrid's proposed contingent project costs of $321.9 million to undertake early works for HumeLink.[127] HumeLink is a transmission upgrade connecting the Snowy Mountains Hydroelectric Scheme to Bannaby in NSW, expanding transmission capacity in southern NSW. The range of early work activities to be delivered by 2024 include project design, stakeholder engagement, land-use planning and approvals and acquisition, procurement activities, and project management to reinforce the transmission network in southern NSW.[128] This follows completion of the RIT-T process in December 2021 following resolution of a dispute on the RIT-T.[129]

The 2 remaining actionable projects identified under the 2022 ISP are the NSW REZ transmission link and the Sydney Ring project.[130] These 2 projects will progress under the Electricity Infrastructure Investment Act 2020 (NSW) rather than the ISP framework, so we do not expect RIT-T processes for these projects.

3.13.8 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.[131] This results in network businesses providing data on geographic constraints to assist third parties in offering non-network solutions and to inform connection decisions at the transmission level.[132]

3.13.9 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.

126 AEMO and Transgrid, Victoria to New South Wales Interconnector West: Project Assessment Draft Report, 29 July 2021.

127 AER, Determination: Humelink Early Works Contingent Project, August 2022.

128 TransGrid, 'Reinforcing the NSW Southern Shared Network to increase transfer capacity to demand centres (HumeLink) – Project assessment conclusions report', 29 July 2021.

129 AER, Humelink: Decision on RIT-T Dispute, November 2021.

130 AEMO, 2022 Integrated System plan, June 2022.

131 AER, 'Final decision: Distribution annual planning report template v1.0', June 2017; AER, 'Final decision: Transmission annual planning report guidelines', December 2018.

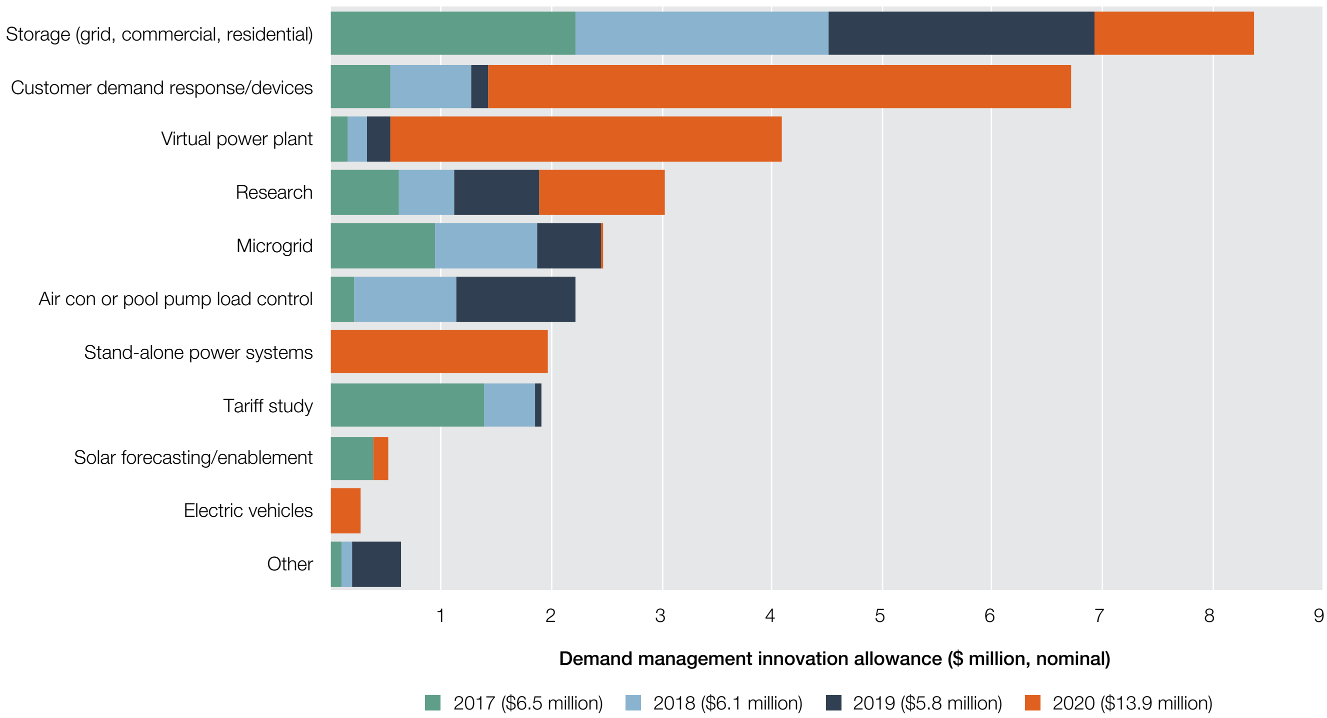
132 For an example of the constraint data available, see the datasheets under Ausgrid, 'Distribution and transmission annual planning report' and data map, accessed 28 July 2022.

The AER offers incentives for distributors to find lower cost alternatives to new investment to help cope with changing demands on the network and to 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 operates a demand management innovation allowance mechanism (DMIAM). The DMIAM provides funding for distributors to undertake research and development works to help them to 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. Network businesses publish annual activity reports setting out the details of projects they have undertaken. 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 June 2021 almost $20 million of innovation allowance funding was approved (Figure 3.28). [133]

Figure 3.28 Funding of demand management innovations – electricity distribution networks



Note: 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, Approval of demand management innovation allowance (DMIA) expenditure reports.

3.14 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 businesses to recover the efficient costs of supplying electricity to customers. The allowance accounts for forecasts of electricity demand, productivity improvements, changes in input prices and changes in the regulatory environment. The AER is guided by the forecasts in each business's regulatory proposal but if the AER considers those forecasts are unreasonable then it may replace them with its own forecasts.

Alongside this assessment, the AER's efficiency benefit sharing scheme encourages network businesses to explore opportunities to lower their operating costs (Box 3.3).

133 For further information on demand management allowances see the biannual reports published by the AER. AER, 'Demand management innovation allowance (DMIA) compliance reporting', AER website.

Box 3.3 Efficiency benefit sharing scheme

The AER runs an efficiency benefit sharing scheme (EBSS), which 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 3.2) – 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 3.4) to encourage network businesses to make efficient holistic choices between capital and operating expenditure in meeting reliability and other targets.

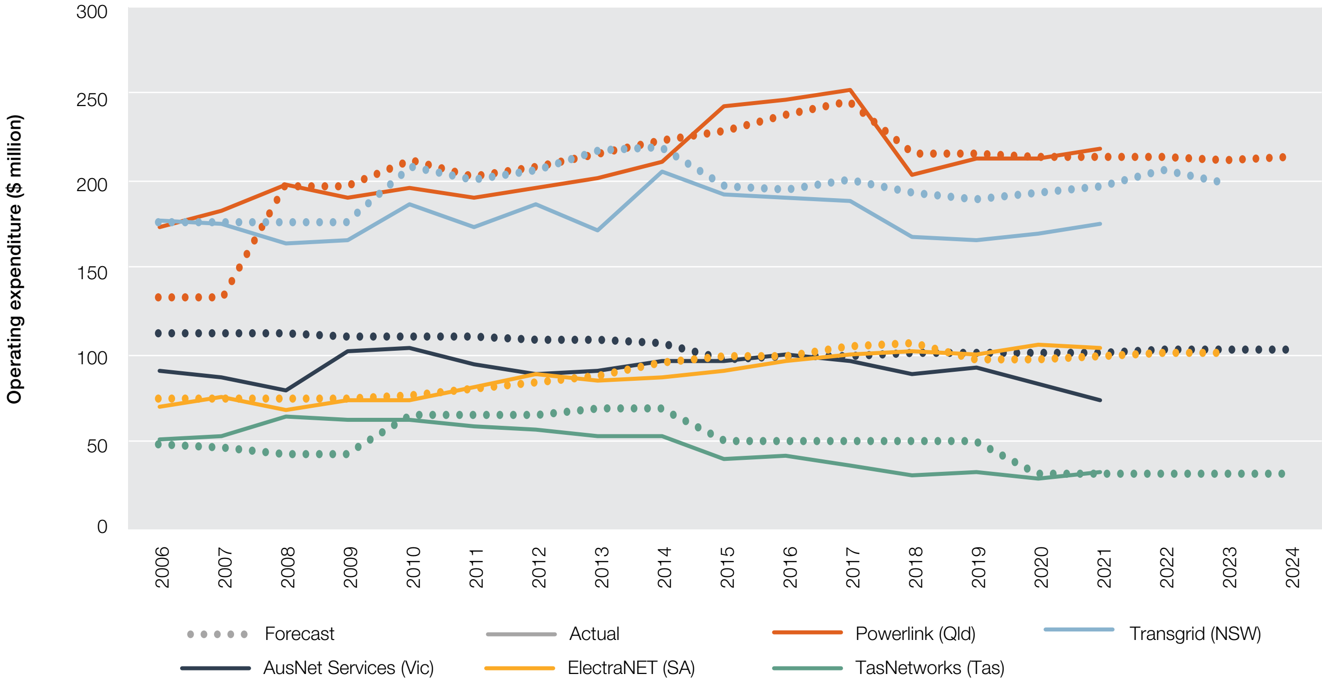
Figure 3.29 to Figure 3.31 provide a breakdown of network businesses' operating costs in 2021 and how this compared with previous years' expenditure and forecasts.

Figure 3.29 Operating expenditure in 2021

	2021 (actual)	Compared to 2020	Compared to forecast	Compared to peak (year)
Transmission	$604m	▲$4m (▲0.7%)	▼$43m (▼7%)	▼11% (2016)
Distribution	$3.1b	▼$34m (▼1.1%)	▼$376m (▼11%)	▼22% (2012)
Total	$3.7b	▼$30m (▼0.8%)	▼$419m (▼10%)	▼19% (2012)

Note: Excludes AER decisions on transmission interconnectors.

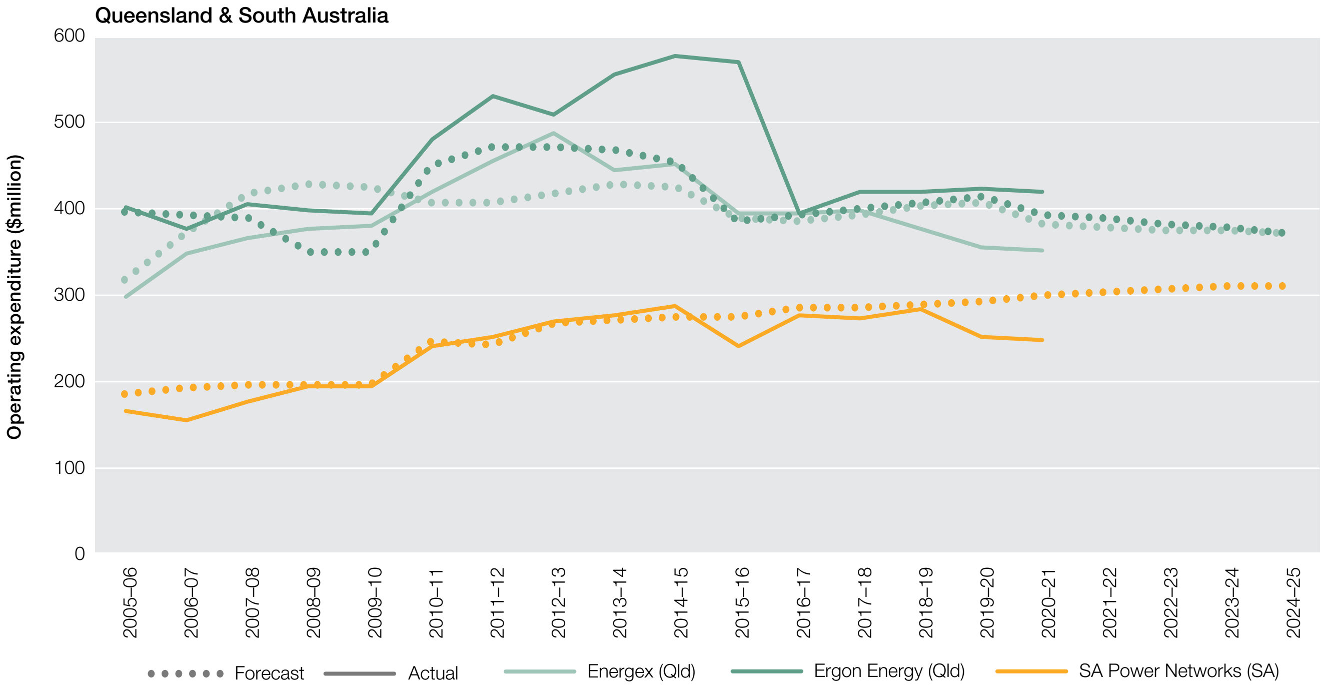
Figure 3.30 Operating expenditure – electricity transmission networks

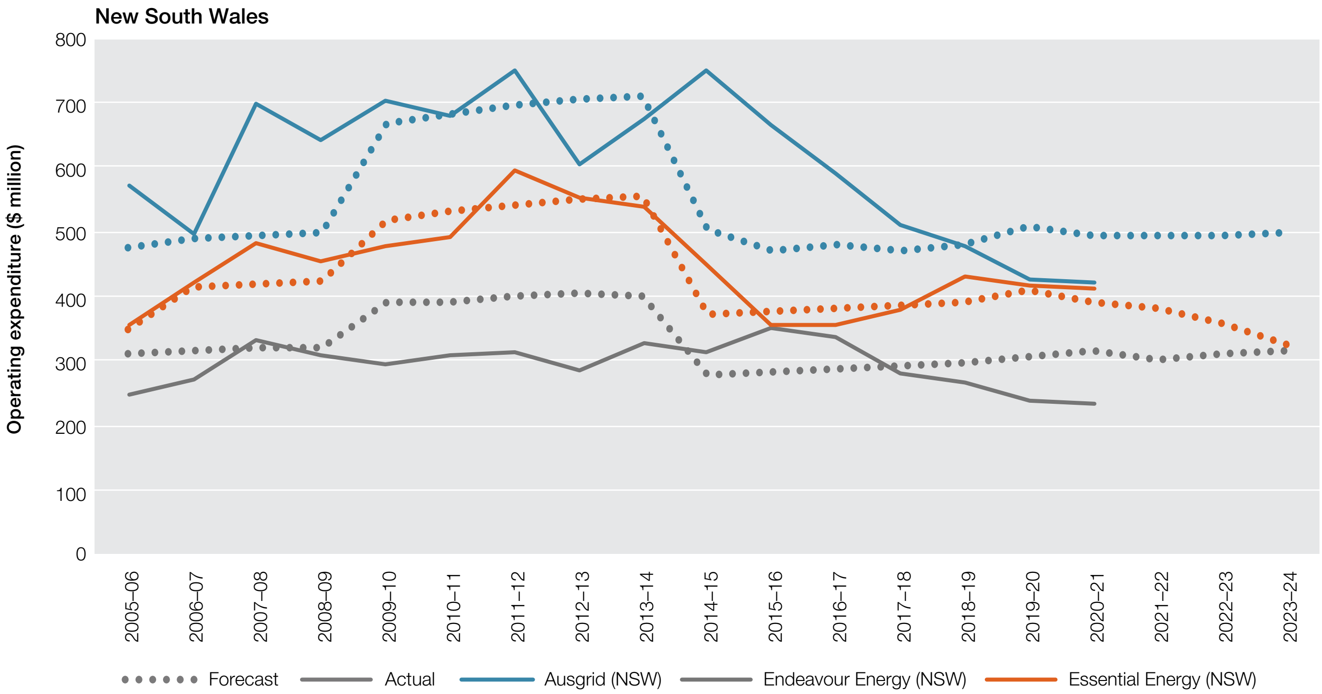


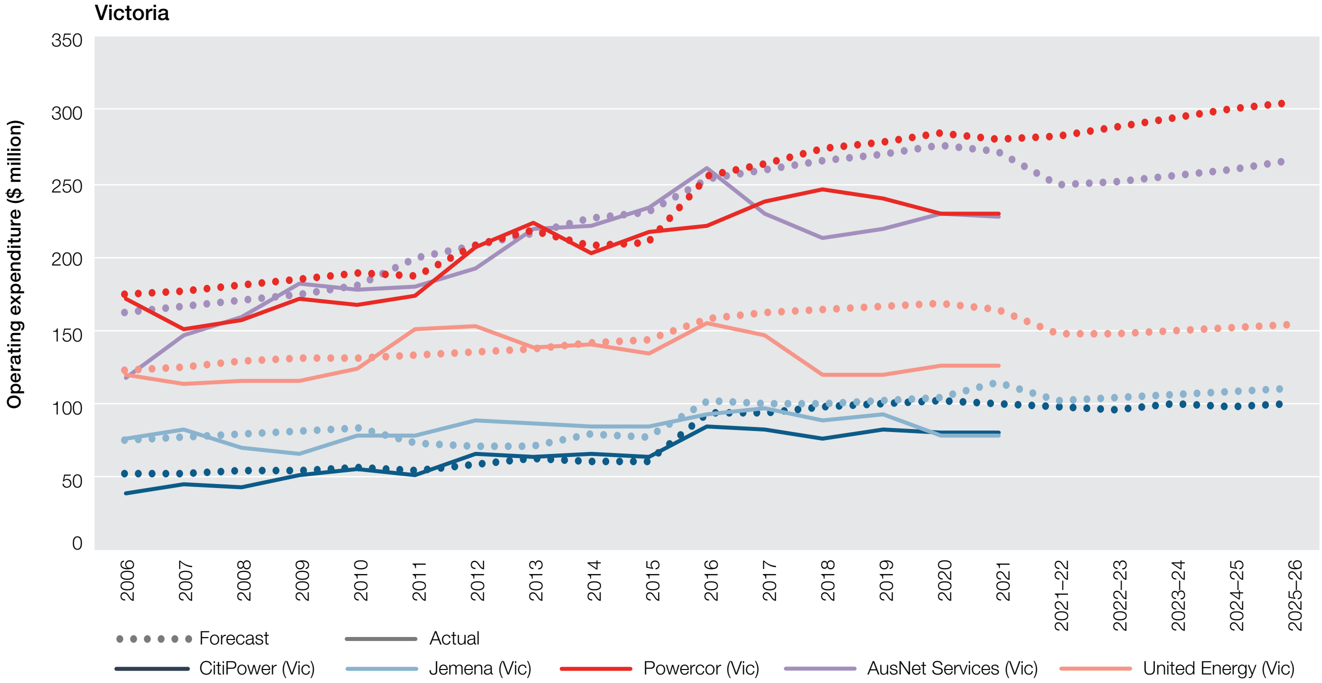
Note: Actual outcomes, CPI adjusted to June 2022 dollars. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018). Assumptions are set out in Figure 3.9 notes.

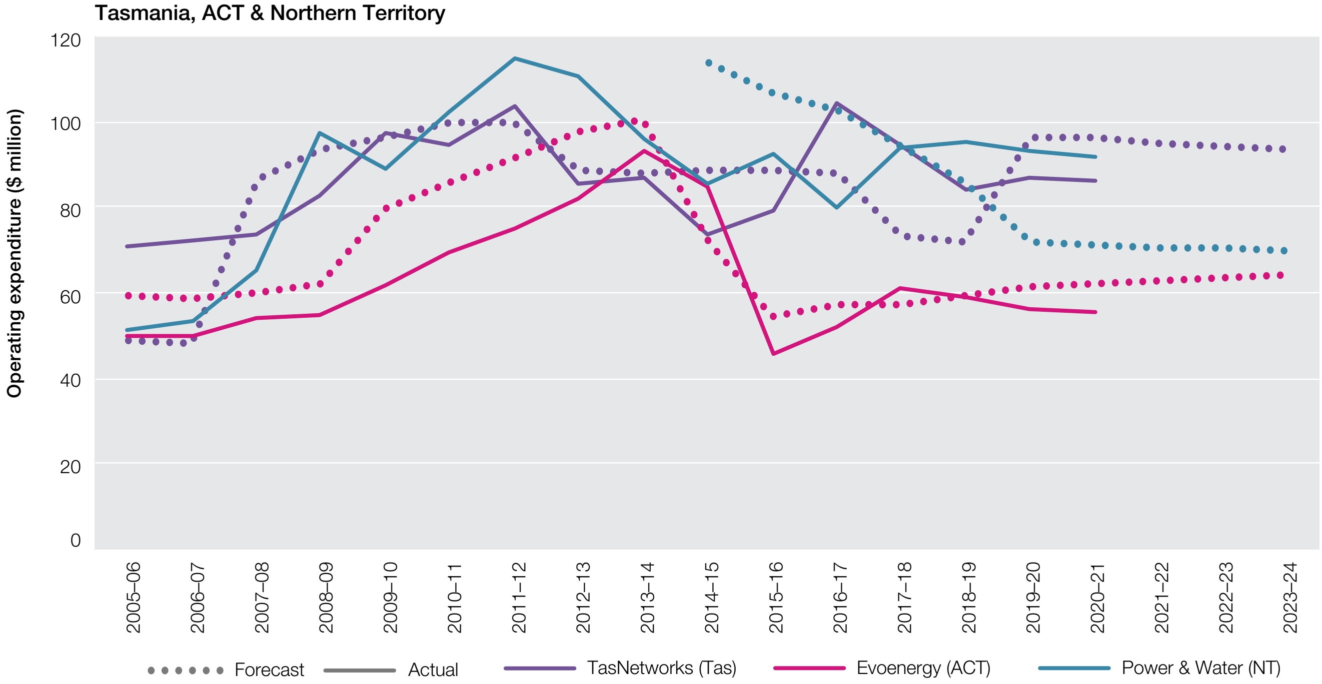
Source: AER modelling; annual reporting RIN responses.

Figure 3.31 Operating expenditure – electricity distribution networks




New South Wales
Operating expenditure ($ million)
800
700
600
500
400
300
200
100
0
2005–06
2006–07
2007–08
2008–09
2009–10
2010–11
2011–12
2012–13
2013–14
2014–15
2015–16
2016–17
2017–18
2018–19
2019–20
2020–21
2021–22
2022–23
2023–24
Forecast
Actual
Ausgrid (NSW)
Endeavour Energy (NSW)
Essential Energy (NSW)


Victoria
Operating expenditure ($ million)
350
300
250
200
150
100
50
0
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2021–22
2022–23
2023–24
2024–25
2025–26
Forecast
Actual
CitiPower (Vic)
Jemena (Vic)
Powercor (Vic)
AusNet Services (Vic)
United Energy (Vic)



Note: All data are adjusted to June 2022 dollars, based on forecasts of CPI. Assumptions are set out in Figure 3.11 notes.

Source: AER modelling; annual reporting RIN responses.

3.14.1 Operating cost trends

Total operating costs for the electricity network businesses increased by an average of 6% per year from 2006 until 2012, when it peaked at $4.5 billion (Figure 3.9 and Figure 3.11).

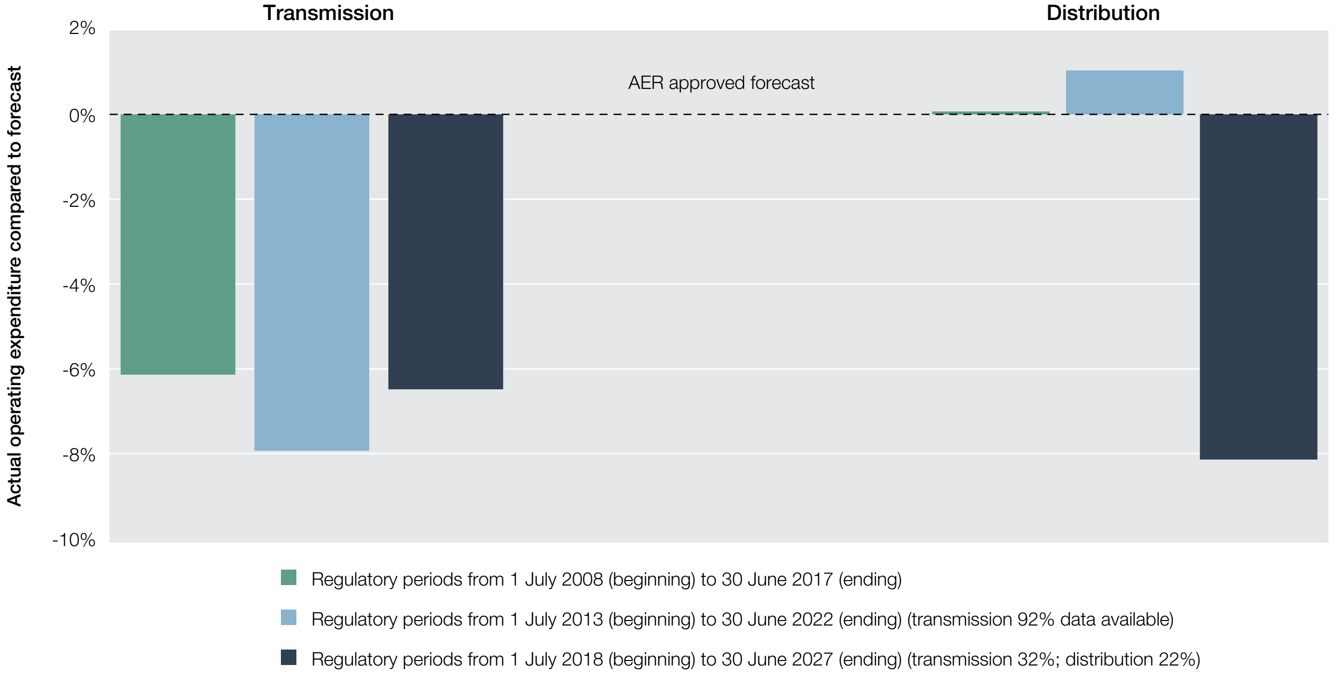
In recent years operating costs have decreased largely due to network businesses implementing more efficient operating practices. However, the decrease in operating costs has been less marked than it was for capital expenditure. Operating and maintenance costs are largely driven by the number of customers 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.

Unlike capital expenditure, a network business's operating costs – such as rent, equipment, marketing, payroll, insurance, step costs and funds allocated for research and development –are largely recurrent and predictable. However, other factors such as reporting obligations, changes to connections charging arrangements, pricing reforms, and greater use of non-network options (section 3.8) can also impact costs.

As such, actual operating expenditure against forecast has been far more stable over the past few regulatory periods than it has been for capital expenditure (Figure 3.32).

Figure 3.32 Operating expenditure against forecast



Note: Data availability (%) refers to proportion of actual operating expenditure data available at time of publication. Data used in igure 3.32 includes actual expenditure for the regulatory year 2021. The timing of regulatory periods differs among network businesses. For example, while 2020–21 reflects the third year of ElectraNet's (transmission) current regulatory period, it also reflects the fourth year of Powerlink's (transmission) previous regulatory period. This explains why a proportion of data is available for the current regulatory period even though the dataset from the last regulatory period is not yet complete.

Source: AER modelling; annual reporting RIN responses.

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 Queensland and NSW. Those savings – for example, from the uptake of technology solutions and from changes to management practices – are now locked in for customers.

3.15 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).[134] Productivity will rise if the network's outputs rise faster than the resources used to maintain, replace and augment energy networks. Benchmarking provides a useful tool for comparing network performance, but some productivity drivers – for example, adhering to 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.[135]

When forecasting a network's efficient operating costs, the AER 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.[136]

134 The AER applies a multilateral total factor productivity approach to benchmark network businesses.

135 AER, 'Annual benchmarking report, electricity distribution network service providers', November 2021, pp 45–52.

136 AER, 'Forecasting productivity growth for electricity distributors', 8 March 2019.

3.15.1 Network productivity trends

Productivity for most networks in the NEM declined from 2006 to 2015, especially in the distribution sector. This decline in productivity was largely driven by:

- rising capital investment (inputs) at a time when electricity demand (output) had plateaued or was declining in Australia
- rising operating costs and declining reliability (for most networks)
- rising expenditure on the distribution networks to meet stricter reliability standards in Queensland and NSW, and regulatory changes following bushfires in Victoria.

However, the privately operated networks in South Australia and Victoria consistently recorded higher productivity scores over this period than those of government-owned or recently privatised networks in other regions.

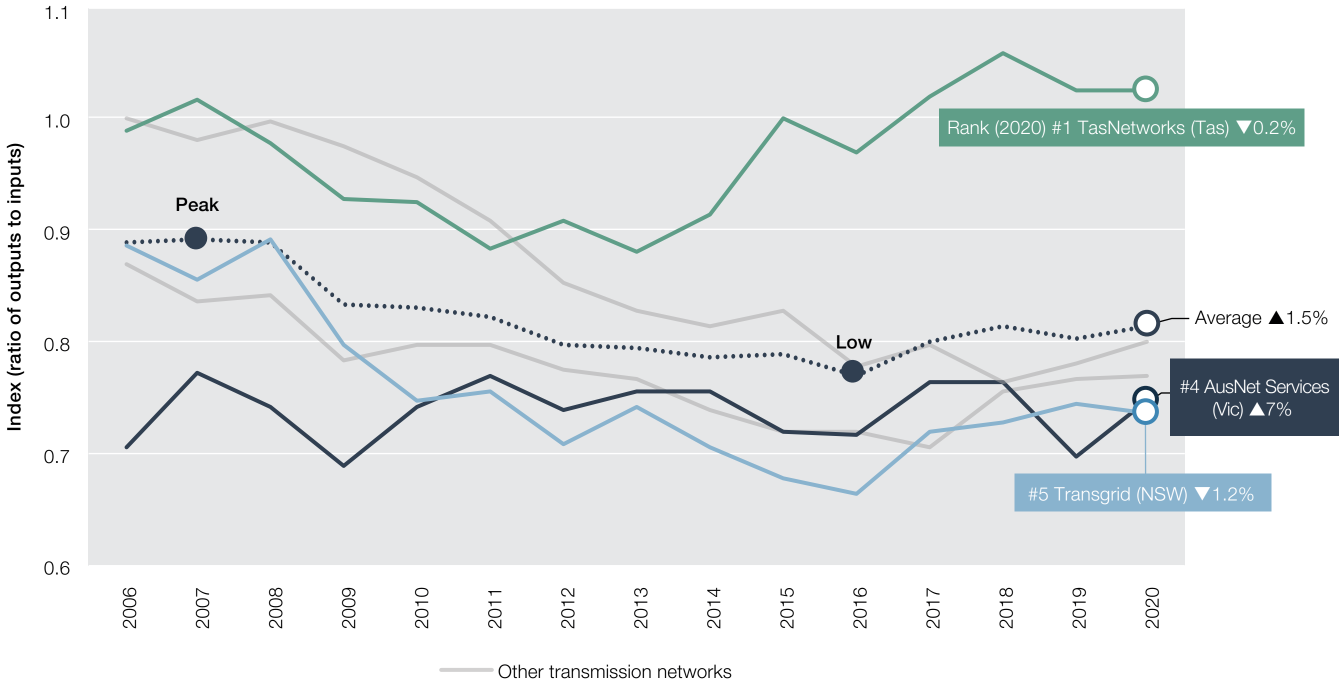
Electricity transmission and distribution productivity increased over 2020, in contrast to declining productivity in the overall Australian economy (down 1%) and the utilities sector (down 4%) over the same period.

3.15.2 Transmission network productivity

Electricity transmission productivity increased by 1.7% over 2020, following a 1.8% decline in 2019. Improved network reliability, combined with a reduction in operating expenditure and overhead line capacity, were the main drivers of the productivity increase.[137]

Viewed over a longer time frame, the productivity of transmission networks has declined at an average rate of 0.9% per year in the 14 years since 2006. Capital partial factor productivity – output per unit of capital expenditure – has declined at an average rate of 1.5% per year compared with average operating expenditure efficiency growth – output per unit of operating expenditure – of 0.8% per year over the same period (Figure 3.33).

Figure 3.33 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. 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.

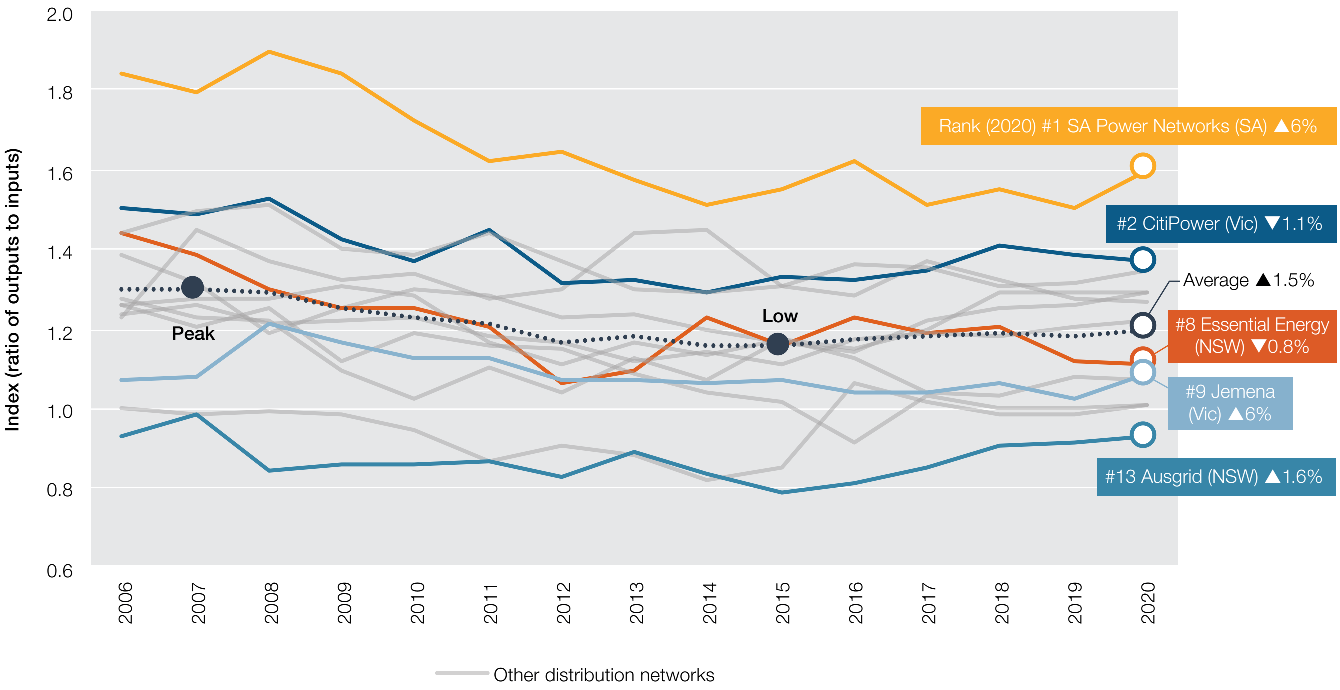
137 As measured by total factor productivity (TFP).

3.15.3 Distribution network productivity

Electricity distribution productivity increased by 1.2% in 2020, following a 1% decrease in 2019.[138] The increase in 2020 was largely driven by ongoing and significant reductions in operating expenditure, with no other individual input or output having a notable impact.

Since 2006 there has been some convergence in the productivity levels of highest and lowest performing distributors. Generally speaking, less productive distributors have improved their productivity since 2012. This has been most evident for United Energy (Victoria), Ausgrid (NSW) and Evoenergy (ACT), which increased their overall productivity, largely because of improvements in operating efficiency. Several middle-ranked distributors, such as Endeavour Energy (NSW), Energex (Queensland), and Essential Energy (NSW), have also improved their productivity and are now closer to the top-ranked distributors. Powercor (Victoria), SA Power Networks (South Australia) and CitiPower (Victoria) have consistently been the most productive distributors in the NEM, but 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 3.34).

Figure 3.34 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. 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.

3.15.4 Network utilisation

A network's utilisation rate indicates the extent to which a network business's assets are being used to meet the needs of customers at times of maximum demand. The utilisation rate can be improved through efficiencies such as using demand response (instead of new investment in assets) to meet rising maximum demand.

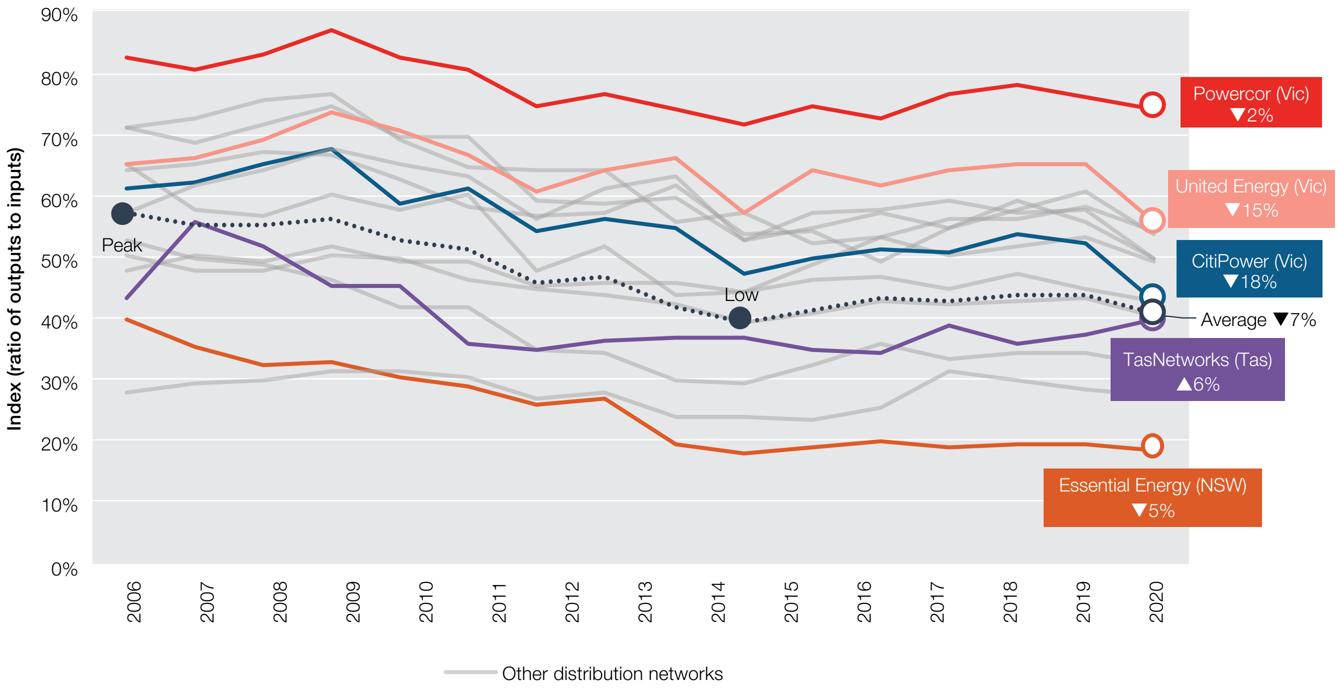
The average level of network utilisation among all distribution networks declined from a high of 57% in 2006 to a low of 39% in 2015.[139] This followed significant investment by many network businesses at a time of weakening electricity maximum demand.

In 2021 maximum demand across the distribution networks dropped by more than 7%, the largest single year decline in demand since 2012. As a result, overall network utilisation dropped by 3 percentage points to 41%, the lowest utilisation rate since 2015 (Figure 3.35).

138 As measured by multilateral total factor productivity (MTFP)

139 The available data does not extend back beyond 2006.

Figure 3.35 Network utilisation – electricity distribution networks



Note: Network utilisation is the non-coincident, summated raw system annual peak demand divided by total zone substation transformer capacity.

Source: Economic benchmarking RIN responses.

In 2021:

- privately owned distributors utilised 54% of network capacity, whereas fully or partly government-owned distributors utilised 36% [140]
- 7 of the 9 most highly utilised distribution networks were privately owned.

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 consumer energy resources (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 because of asset stranding, then electricity consumers – who pay for those assets – may look to opportunities to bypass the grid altogether.[141]

3.15.5 Investment disconnect

The level of network productivity depends on how effectively a network business uses inputs[142] to deliver a range of outputs.[143] Capital expenditure is largely driven by the need to meet the maximum level of demand on the network. While average demand has declined since 2006 (driven in part by improved energy efficiency and increased self-consumption of solar PV), maximum demand has become more variable. While maximum demand has always varied with the weather, the increased use of air conditioners and solar PV has exacerbated this effect.

Since 2006 growth in maximum demand has been somewhat erratic, while the level of average (non-maximum) demand has declined.

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 asset usage rates, which weakens 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 (Figure 3.36).

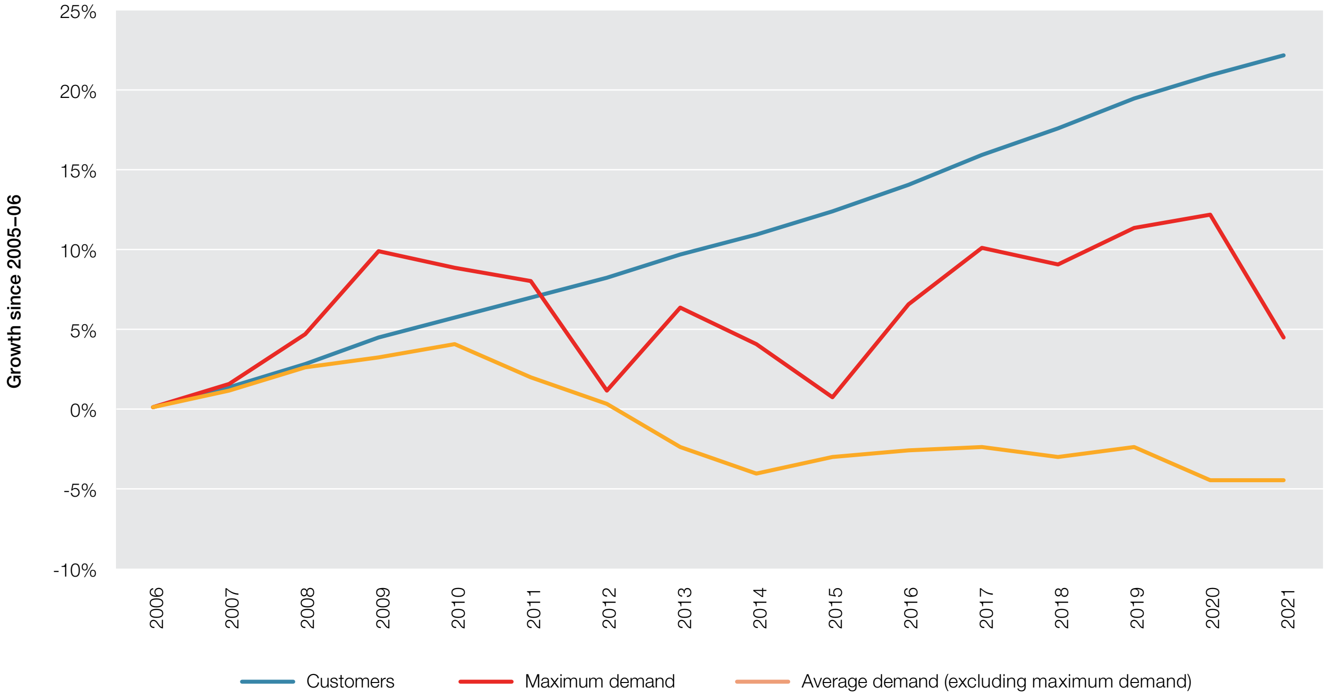
140 Section 3.4 provides information on network ownership.

141 T Wood, D Blowers, K Griffiths, 'Down to the wire – a sustainable electricity network for Australia', Grattan Institute, March 2018.

142 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. Operating expenditure is an example of an intangible input.

143 Outputs include circuit line length; ratcheted maximum demand; energy delivered; customer numbers; and network reliability.

Figure 3.36 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. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018).

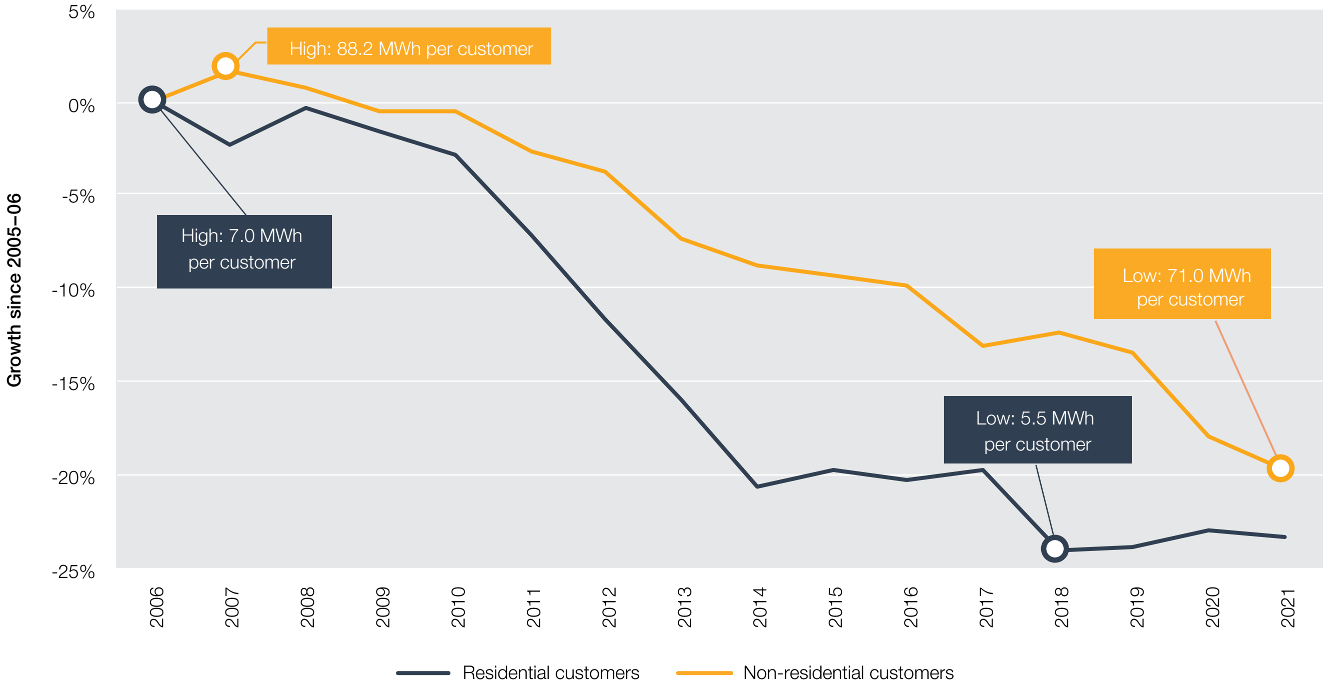
Source: Economic benchmarking RIN responses.

In 2021 the average residential customer consumed 23% 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 17% 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 several factors, including:

- rooftop solar replacing electricity previously sourced from the grid
- housing and appliances becoming more efficient
- consumers reducing their energy use in response to higher prices
- reductions in demand from large industrial customers
- in 2021 the impact of COVID-19 on consumer behaviour (Figure 3.37).

Figure 3.37 Growth in average energy usage per customer – electricity distribution networks



Note: 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 RIN responses.

3.16 Reliability and service performance

In this section, 'reliability' refers to the continuity of electricity supply to customers.[144] 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 powerline 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. Therefore, there is 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. Although 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.

144 The continuity of electricity supply from customers is also an element of service performance for networks with customers that export energy into the grid (for example, energy generated from rooftop solar PV). Reforms are underway to treat export services more clearly as distribution services. See AEMC, 'Rule determination: Access, pricing and incentive arrangements for distributed energy resources', August 2021.

3.16.1 Valuing reliability

Understanding the value that customers place on reliability is important 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; experience of interruptions to supply; and the duration, frequency and timing of interruptions.

The AER develops new estimates of customers' reliability valuations every 5 years and updates these values annually. The values have a wide application, including as an input for:

- cost–benefit assessments, such as those applied in regulatory tests (section 3.13.5) that assess network investment proposals
- assessing bonuses and penalties in the service target performance incentive scheme (Box 3.4)
- setting transmission and distribution reliability standards and targets
- informing market settings, such as wholesale price caps.

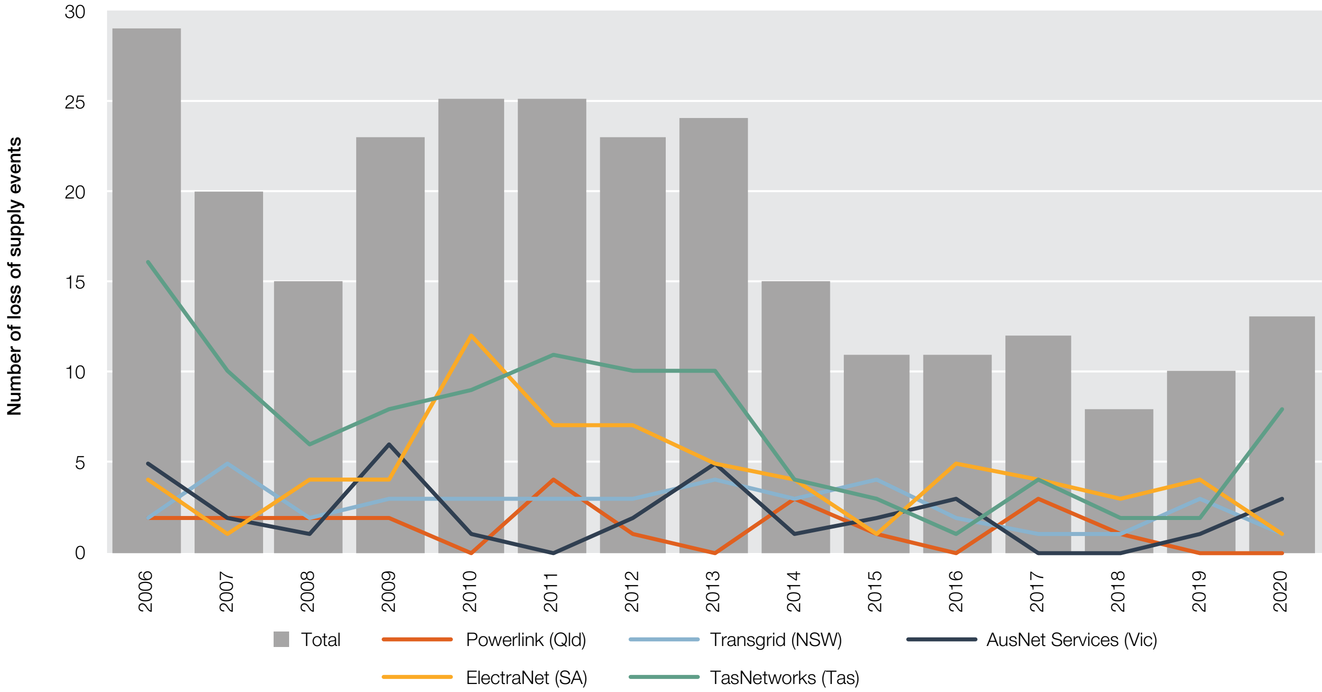
3.16.2 Transmission network performance

Electricity transmission networks are engineered and operated to be extremely reliable, because a single interruption can lead to widespread power outages. To minimise the risk of outages occurring, the transmission networks are engineered with capacity to act as a buffer against credible unplanned interruptions.

In 2020 the NEM experienced 13 loss of supply events due to transmission failures, the most events in any year since 2014. The main driver behind the increase was TasNetworks (Tasmania), which experienced 6 of its 8 events in August 2020. The events were due to a combination of design and operational error, environmental causes and windborne vegetation.[145]

Over the past 5 years, Powerlink (Queensland) has experienced the fewest loss of supply events among the transmission networks (Figure 3.8).

Figure 3.38 Network reliability loss of supply events – electricity transmission networks



Note: Loss of supply events are the times when energy is not available to transmission network customers for longer than a specified duration. 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. 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 RIN responses.

145 TasNetworks, 'Annual Planning Report 2021', accessed 4 April 2022, p 82.

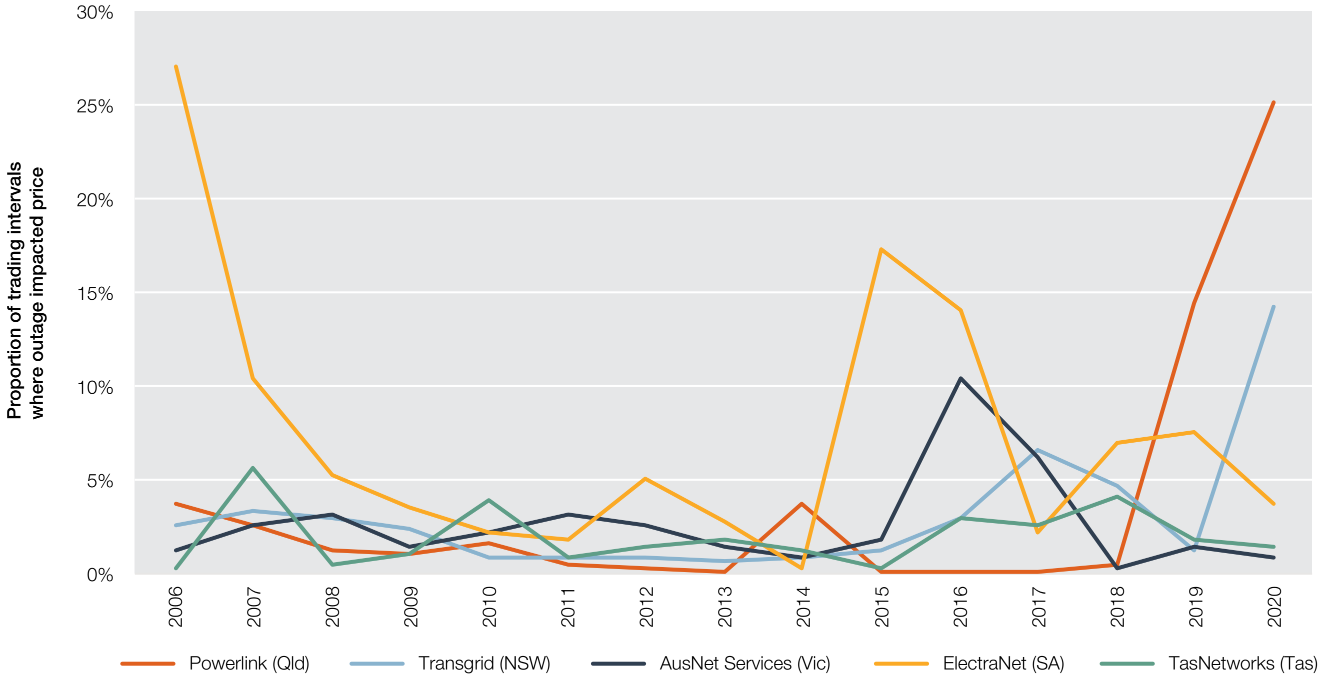
In addition to system reliability, congestion management is another indicator of transmission network performance. All networks are constrained by capability limits, and congestion arises when electricity flows on a network threaten to overload the system. As an example, a surge in electricity demand 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 can cause perverse trade flows, such as a lower 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. But increased 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 have paid for the substantial costs of network investment.

Issues with network congestion re-emerged from 2015 in part due to outages associated with network upgrades in Queensland and 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 (Figure 3.39).

Figure 3.39 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 RIN responses.

Not all congestion is inefficient. 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.

3.16.3 Distribution network reliability

For distribution networks, the reliability of supply – that is, how effectively the network delivers power to its customers – is the main focus of network performance. Around 95% of the interruptions to supply experienced by electricity customers are due to issues in the local distribution network.[146] 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 jurisdictional reliability standards for distribution networks. This required significant investment, driving network costs for several years. In contrast, Victoria placed more emphasis on reliability outcomes and the value that customers place on reliability.

Concerns that reliability-driven investment was driving up power bills led to a different approach to setting distribution reliability targets.[147] This alternative approach considers the likelihood of an interruption occurring and the value that customers place on removing or reducing the impact of an interruption (section 3.16.1). 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.[148]

Interruptions to supply can also be caused by vegetation-related incidents. In the 12-month period to 30 June 2021 vegetation was the third most significant reason for unplanned outages, behind weather events and asset failure. From 1 July 2022, Energy Safe Victoria (ESV) has the power to issue fines to electricity companies that do not keep trees safely clear of powerlines. Prior to this, ESV's powers to take enforcement action for line clearance breaches were limited to issuing warnings or notices to take corrective action or prosecution through the court system.

More than 1,100 power outages are caused by trees touching powerlines in Victoria each year, affecting 400,000 residences and businesses.[149]

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 the average customer experienced each year, while SAIDI measures the total duration – or minutes off supply – the average customer experienced.[150]

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 customer service incentive scheme (CSIS) (Box 3.5). Both the relative frequency and duration of planned interruptions to supply varies considerably among the distribution networks.

The specific characteristics of a distribution network can have a significant impact on its reliability performance. In particular, customer densities and numerous environmental conditions differ across networks. These differences can materially impact the number of customers affected by an outage as well as a network business's response time. Levels of historical investment also affect reliability outcomes.

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 those supplying rural areas. 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.

146 AEMC, 'Final report – 2019 annual market performance review', 12 March 2020, p 51.

147 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.

148 ACCC, 'Retail Electricity Pricing Inquiry final report', 11 July 2018, p 109.

149 Energy Safe Victoria, 'ESV gets new powers to fine for powerline clearance breaches', 30 June 2022 media release.

150 Unplanned SAIDI excludes momentary interruptions (3 minutes or less).

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, comparing network reliability metrices between different distribution networks should be done with care.

3.16.4 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 3.4), 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 (SAIFI) and fewer unplanned minutes off supply (SAIDI). This improvement has occurred despite distribution networks investing $10.4 billion (14%) less than forecast on capital projects from 2010 to 2021 (Figure 3.11).

While the levels of unplanned 'normalised' reliability continue to either improve (SAIFI) or plateau (SAIDI), the absolute level of network reliability (that is, the customer experience) has been less consistent. This is predominately due to annual fluctuations in the impact of unplanned (excluded) events, such as outages caused by major weather events. Figure 3.41 demonstrates the impact and unpredictability of major weather events on network reliability.

Normalising the data (that is, removing the impact of extreme events) provides a more reasonable measure of a distributor's controllable outputs. Figure 3.40 and Figure 3.41 summarise SAIDI and SAIFI outcomes across the NEM, as well as weighted network reliability targets that the AER applies through the STPIS.

3.16.5 Distribution network reliability in 2020–21

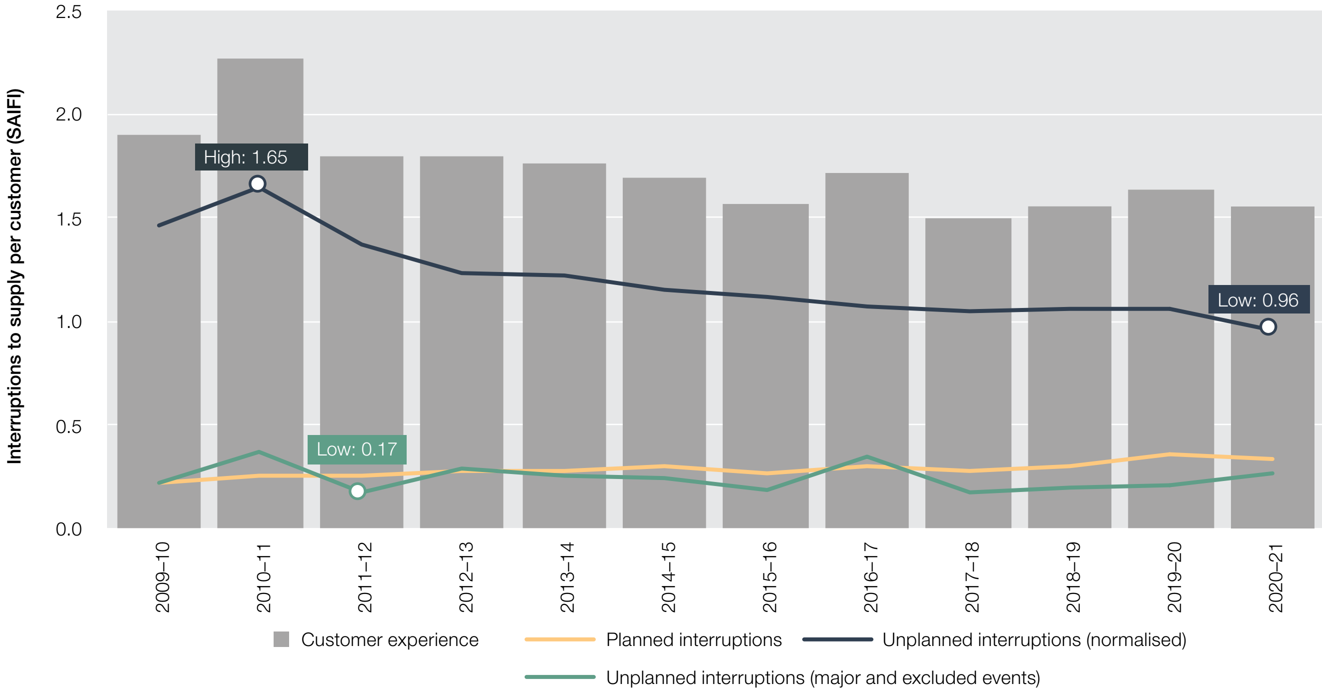
In 2020–21 the average electricity customer experienced 1.56 total interruptions to supply – 9% fewer than in the previous year. This comprised:

- 0.96 unplanned (normalised) interruptions to supply – a new record low and 8% fewer than the previous low in 2017–18
- 0.26 unplanned (excluded) interruptions to supply – 26% more than in the previous year
- 0.33 planned interruptions to supply – 9% less than in the record high set in the previous year.

In 2020–21 the average electricity customer experienced 325.9 total minutes off supply – 8% less than in the previous year. This comprised:

- 105.0 unplanned (normalised) minutes off supply – a new record low and 1.9% fewer than the previous low in 2017–18
- 128.6 unplanned (excluded) minutes off supply – 3% more than in the previous year
- 92.3 planned minutes off supply – 15% less than in the record high set in the previous year.

Figure 3.40 Interruptions to supply (SAIFI) – electricity distribution networks

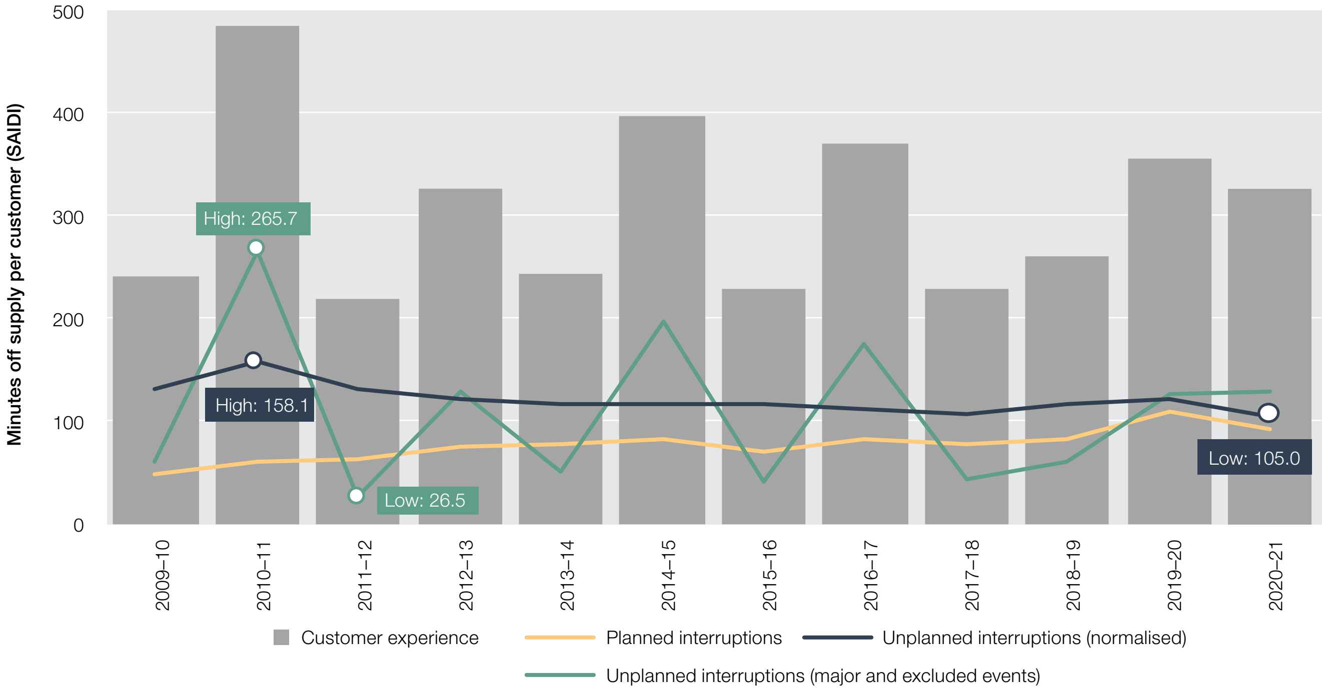


SAIFI: system average interruption frequency index.

Note: Data in Figure 3.40 and Figure 3.39 shows interruptions to supply that lasted longer than 3 minutes. This is consistent with the definition of a sustained interruption in the AER's current service target performance incentive scheme (STPIS) (version 2.0, November 2018). The previous version of the STPIS (May 2009) defined sustained interruptions as those that lasted longer than one minute. Reporting historical SAIFI using a consistent definition allows for greater comparability over time. As such, the values shown above may not reflect outcomes reported in the past. Years reflect 1 July – 30 June.

Source: AER modelling; category analysis regulatory information (RIN) responses.

Figure 3.41 Minutes off supply (SAIDI) – electricity distribution networks



SAIDI: system average interruption duration index

Note: Data in Figure 3.41 shows minutes off supply for interruptions that lasted longer than 3 minutes. This is consistent with the definition of a sustained interruption in the AER's current STPIS (version 2.0, November 2018). The previous version of the STPIS (May 2009) defined sustained interruptions as those that lasted longer than one minute. Reporting historical SAIDI using a consistent definition allows for greater comparability over time. As such, the values shown above may not reflect outcomes reported in the past. Years reflect 1 July – 30 June.

Source: AER modelling; category analysis regulatory information (RIN) responses.

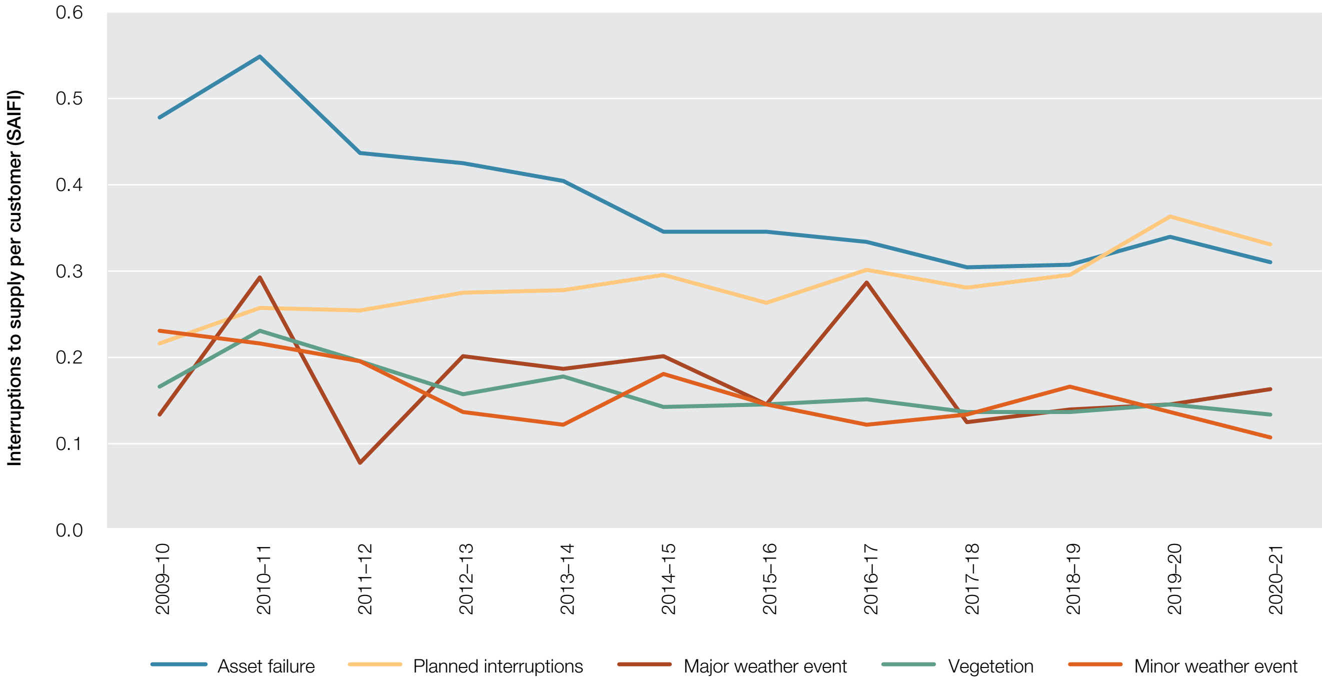
The AER also collects data from networks on the causes of outages. Over the 12-month period to 30 June 2021 asset failure was the most frequently reported reason for unplanned outages, accounting for 25% of all unplanned outages and 16% of all unplanned minutes off supply across the NEM. Over the same period weather events accounted for fewer (22%) unplanned outages, but a greater number of unplanned minutes off supply (59%). This demonstrates the destructive nature of weather events on the electricity network.

Several severe weather events resulted in significant unplanned minutes off supply during this period, including:

- 31 October 2020 – Energex (Queensland) – thunderstorms and extreme wind[151]
- 1 March 2021 – Ergon Energy (Queensland) – severe storm and flooding[152]
- 9–10 June 2021 – AusNet Services (Victoria), Powercor (Victoria) and United Energy (Victoria) – severe storm and flooding.[153]

The June 2021 storm in Victoria was the most disruptive event in the NEM – in terms of minutes off supply – since Tropical Cyclone Yasi caused extensive outages to customers in northern Queensland in early 2011 (Figure 3.42 and Figure 3.43).

Figure 3.42 Key drivers of interruptions to supply (SAIFI) – electricity distribution networks



SAIFI: system average interruption frequency index

Note: Data in Figure 3.42 and Figure 3.39 shows interruptions to supply that lasted longer than 3 minutes. This is consistent with the definition of a sustained interruption in the AER's current STPIS (version 2.0, November 2018). The previous version of the STPIS (May 2009) defined sustained interruptions as those that lasted longer than one minute. Reporting historical SAIFI using a consistent definition allows for greater comparability over time. As such, the values shown above may not reflect outcomes reported in the past. Years reflect 1 July – 30 June.

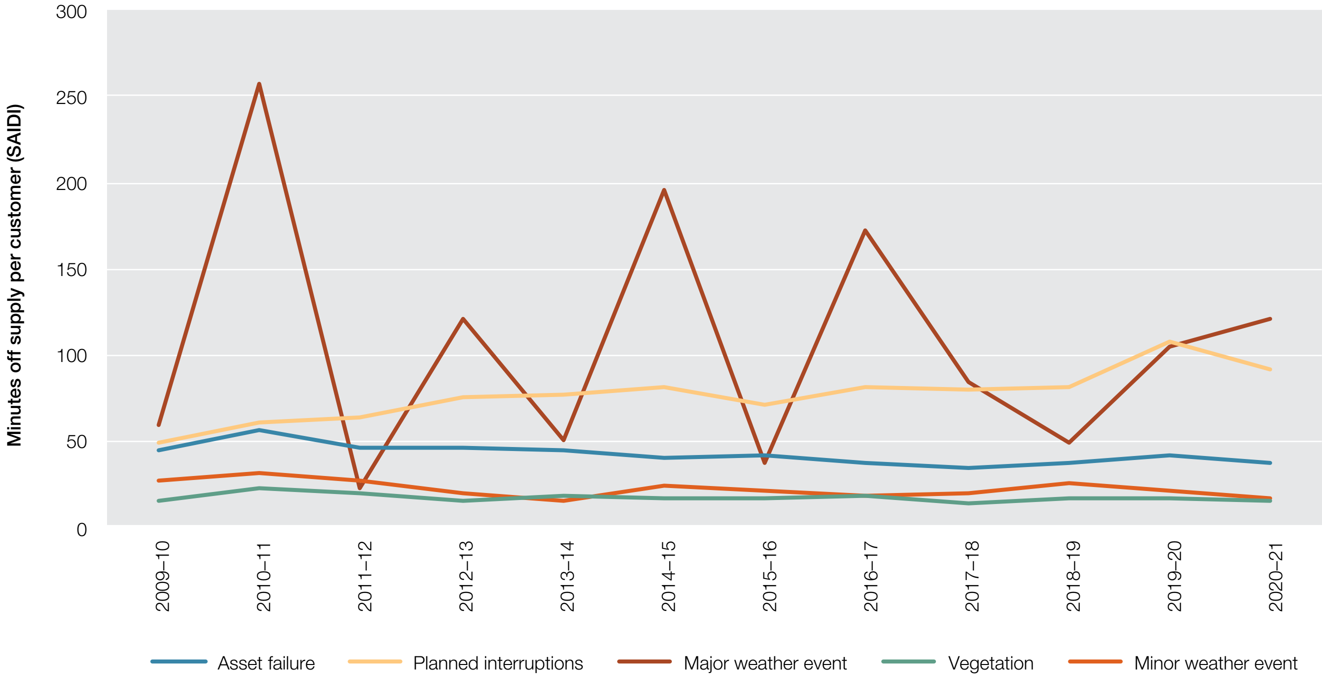
Source: AER modelling; category analysis regulatory information (RIN) responses.

151 ABC News, 'South-east Queensland hit by very dangerous thunderstorms as hail up to 14cm pummels the region', 31 October 2020, accessed 18 December 2021.

152 ABC News, 'Storms swirl across south-east Queensland, cutting power and causing flash flooding', 2 March 2021, accessed 29 June 2022.

153 ABC News, 'Victorians count the cost after violent storm sends trees crashing through homes', 10 June 2021, accessed 18 December 2021.

Figure 3.43 Key drivers of minutes off supply (SAIDI) – electricity distribution networks



SAIDI: system average interruption duration index.

Note: Data in Figure 3.43 shows minutes off supply for interruptions that lasted longer than 3 minutes. This is consistent with the definition of a sustained interruption in the AER's current STPIS (version 2.0, November 2018). The previous version of the STPIS (May 2009) defined sustained interruptions as those that lasted longer than one minute. Reporting historical SAIDI using a consistent definition allows for greater comparability over time. As such, the values shown above may not reflect outcomes reported in the past. Years reflect 1 July – 30 June.

Source: AER modelling; category analysis regulatory information (RIN) responses.

Over the past 2 years customers have experienced significantly more frequent, and longer planned interruptions to supply than in the past. This has been driven by Ausgrid's (NSW) decision to temporarily pause all live work on its network for safety reasons. However, since September 2020 appropriately trained and authorised Ausgrid employees have been able to perform selected live work tasks.[154]

3.16.6 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.[155]

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.

154 Ausgrid, 'Live Work Project', Ausgrid website, accessed 5 May 2022.

155 AER, 'Amendment to the service target performance incentive scheme (STPIS)/Establishing a new Distribution Reliability Measures Guideline (DRMG)', AER website, November 2018.

Box 3.4 Service target performance incentive scheme

The 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 3.2) and efficiency benefit sharing scheme (EBSS) (Box 3.3) 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.[a]

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.

a Since April 2021, the AER has applied the CSIS instead of the STPIS telephone answering parameter to distribution networks whose customers support the change in customer service measurement.

3.16.7 Incentives to avoid fire starts

The AER administers the Victorian Government's f-factor scheme, an initiative that provides financial incentives to Victorian electricity distribution businesses to minimise the number of fire starts within their networks in high fire danger zones and times.

If the number of fire starts increases, the distributor is required to pay a penalty. Likewise, if the number of fire starts decreases the distributor may receive an incentive payment. Payments and penalties are incorporated into distributors' allowable revenue each year.

The penalty or reward rates under this scheme range from around $1.48 million per fire start in high-risk areas on code-red days to $300 in low-risk areas on a low fire danger day.

In 2020 the outcomes varied from a $1.5 million payment for Powercor to a $6,600 penalty for CitiPower. Overall, Victorian electricity distribution businesses received 54% less in total incentive payments under the f-factor scheme in 2020 than in the previous year.

The impact of the incentive payments from 2020 will take the form of adjustments to the distributors' regulated revenues in 2023.

3.16.8 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 time frames 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.[156] Victoria reports separately on network performance.[157]

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 3.5).[158]

Box 3.5 Customer service incentive scheme

The 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 allows for the evolution of customer engagement and 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.[a]

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 first application of the CSIS was for Victorian distributors AusNet Services, CitiPower, Powercor and United Energy for the current period (1 July 2021 – 30 June 2026).

a 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.

156 AER, 'Annual retail markets report 2019–20', November 2020.

157 ESC, 'Victorian energy market update', 31 March 2022.

158 AER, 'Final – Customer Service Incentive Scheme', 21 July 2020.

The AER also oversees the rules protecting energy customers who rely on life support equipment. In June 2022 Endeavour Energy (NSW) paid 7 infringement notices totalling $474,600 for alleged breaches of life support obligations under the National Energy Retail Rules. The breaches included:

- failing to record that there were life support needs at the customer's premises
- not sending information packs
- not notifying the retailer of customers' life support requirements
- not giving the required 4-day notice of planned interruptions.

The AER accepted a court enforceable undertaking from Endeavour Energy, committing to implement new IT systems and to engage an independent expert to conduct an end-to-end review of its life support processes, controls and systems.

4 Gas markets in eastern Australia

This chapter covers upstream gas markets in eastern Australia, encompassing gas production, wholesale markets for gas and the transport of gas along transmission pipelines for export or domestic use.[159]

The main production basin in eastern Australia is the Surat–Bowen Basin in Queensland. There are smaller basins in South Australia, New South Wales, off coastal Victoria and in the Northern Territory. Combined, these basins account for around 37% of Australia's total gas production.[160]

The eastern gas market is interconnected by transmission pipelines, which source gas from these basins and deliver it to liquefied natural gas (LNG) facilities for export and to large industrial customers and major population centres for domestic use.

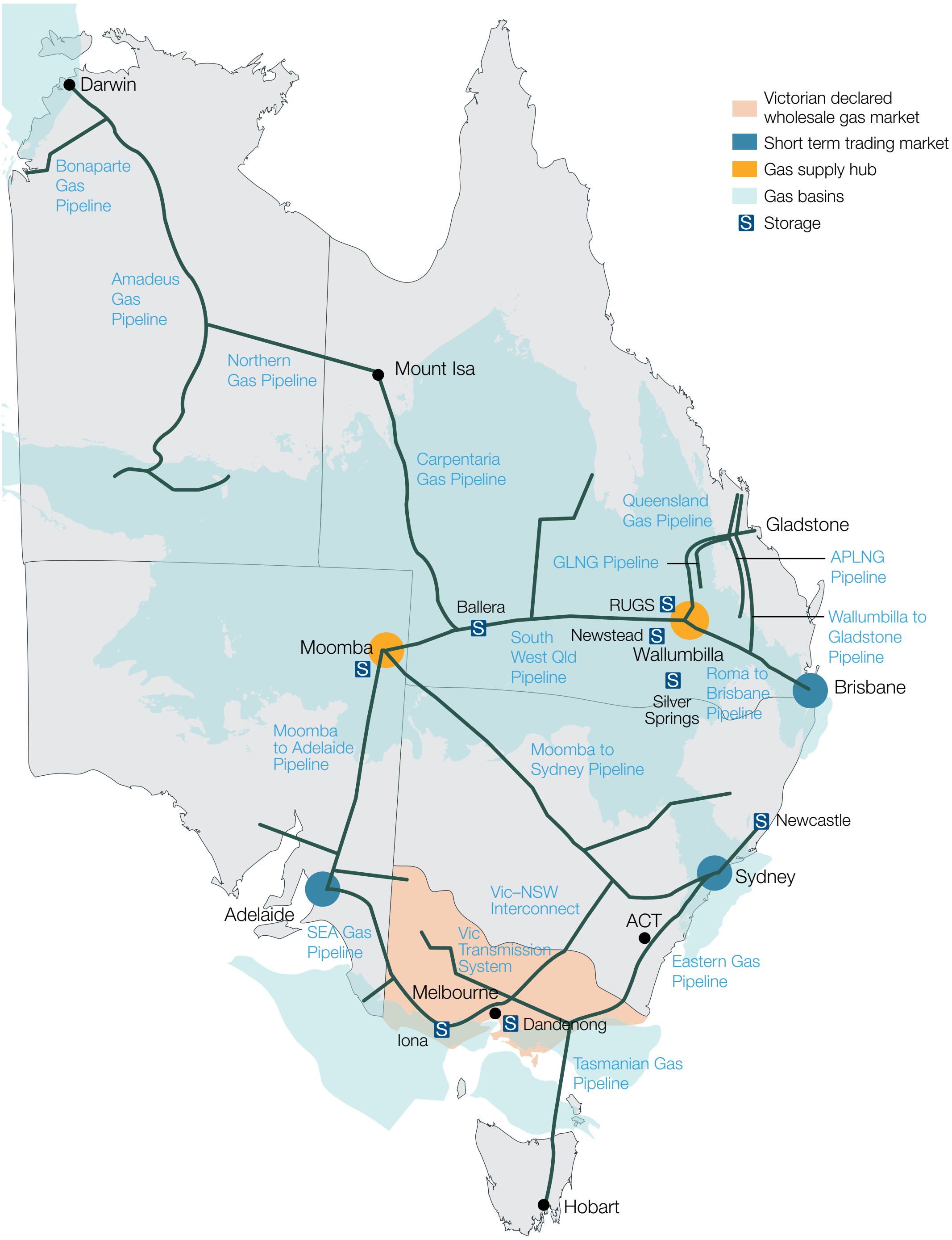
Due to the rapid expansion of the Australian LNG industry on both the east and west coasts, Australia has become one of the world's largest LNG exporters.

Since the launch of the LNG export industry in 2015, gas producers have the choice of exporting or selling gas domestically. Consequently, prices in the domestic market are influenced by international gas prices.

159 The Australian Energy Regulator (AER) has regulatory responsibilities in the eastern Australian gas market in Queensland, NSW, Victoria, South Australia, Tasmania and the ACT.

160 70% of Australia's total gas reserves are conventional gas resources and 30% are unconventional (coal seam gas) resources. Surat-Bowen accounts for most of Australia's coal seam gas (CSG) production, while most of our conventional gas resources are located off the north-west coast of Western Australia and at the end of 2019 they accounted for around 62% of total gas production.

Figure 4.1 Eastern gas basins, markets, major pipelines and storage



Source: AER; Gas Bulletin Board.

Box 4.1 The AER's role in wholesale 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); short-term secondary capacity markets for gas transportation; 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. For example, our monitoring role at the Wallumbilla and Moomba hubs explicitly looks to detect price manipulation. We are also the compliance and enforcement body for a scheme to auction secondary capacity in transmission pipelines.

We publish 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. From December 2022, the AER will report a wider set of information on the export, reserve, storage, and domestic sale and swaps of gas.

The AER also has regulatory responsibilities for transmission and distribution pipelines (chapter 5) and retail markets (chapter 6).

We continue to engage with the energy ministers' gas reform agenda and, when appropriate, we propose or participate in reforms to improve the market's operation. We also draw on our regulatory and monitoring work to advise policy bodies and other stakeholders on market trends, policy issues and irregularities.

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. Facility operators in the Northern Territory must report gas flow activity to the Gas Bulletin Board. We have no regulatory function in Western Australia, where separate laws apply.[a]

a The Economic Regulation Authority is the economic regulator for gas markets and pipelines in Western Australia and AEMO operates a spot gas market there.

4.1 Gas market snapshot

Since the last *State of the energy market* report, east coast gas markets have entered a period of sustained high prices and tight supply. Over late 2021, and particularly since April 2022, gas prices in east coast gas markets have rose to and persisted at record highs.

Southern gas production is continuing to deplete reserves, increasing the risks of shortfalls, and the Iona storage facility dropped dangerously close to minimum reserves for its normal operation this winter.

Overlapping factors in the National Electricity Market from early May – including numerous coal baseload outages and peak gas generation units running for prolonged periods to fill the supply gap – have driven an unanticipated increase in gas demand from this sector despite the gas price increases. This interaction with electricity markets is putting further upwards pressure on gas prices at the same time as local gas markets are being used to cover short-term spot exposure over the higher demand winter period.

With higher gas market demand typical across winter, and the continuing requirement for additional gas generation to make up for supply constraints in baseload coal, gas and electricity prices are not expected to decrease until conditions ease in both local and international markets.[161]

In combination, these market shocks have resulted in extraordinary interventions, including:

- the Australian Energy Market Operator (AEMO) activating the Gas Supply Guarantee twice, including its first ever usage
- AEMO directing two Victorian gas-powered generators not to generate

161 A combination of factors contributed to high prices across both gas and electricity sectors, with price impacts amplified by the fact these drivers were occurring simultaneously. Separate to local market conditions, global drivers impacting fuel costs, including oil, diesel, gas, and coal, have also affected local prices.

› suspension of a market participant
› extended periods with different gas hubs in administered pricing states.

4.2 Structure of the east coast gas market

The east coast gas market is made up of several separate underlying markets and supply hubs, as well as a supporting bulletin board. Around 10% to 20% of gas is traded in these spot markets.[162] All other gas trade is struck under confidential bilateral contracts separate to these markets.

4.2.1 Contract markets

The majority of gas in Australia is traded through bilateral contracts. Contract prices reflect expectations of future market conditions, but the spot markets can reflect short-term shifts in market conditions due to factors such as gas supply and gas storage levels, the timing of LNG shipments and conditions in the electricity market. As a result, the price levels are not always aligned, but they often move in similar directions.

For many domestic users, contract prices are likely to be more indicative of the costs they face.

The 2 main levels of gas contracts (also known as gas supply agreements) 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 on sell it to commercial and industrial (C&I) customers.[163]

Long-term gas contracts traditionally locked in prices and other terms and conditions for several years. In recent years the industry has shifted towards shorter terms (1 to 2 years) for these contracts, with review provisions.[164]

4.2.2 Spot markets

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 – Victoria's declared wholesale gas market, the short term trading market, gas supply hubs and a separate east coast wide market for transportation and compression services.

Victoria's declared wholesale gas market (DWGM)

Victoria's declared wholesale gas market manages gas flows across the Victorian transmission system. Participants submit daily bids ranging from $0 per gigajoule (GJ) (the floor price) to $800 per GJ (the price cap). Prices in the Victorian market cover gas as well as transmission pipeline delivery. AEMO selects the least cost bids needed to match demand to establish a clearing price.

AEMO operates the financial market and manages physical balancing, including by scheduling gas injections at above market price to alleviate short-term transmission constraints.

Short term trading market (STTM)

The STTM is a short-term trading market for gas with hubs in Sydney, Brisbane and Adelaide which allows gas trading on a day-ahead basis. AEMO sets a clearing price at each hub based on scheduled withdrawals and offers by shippers to deliver gas, with a price floor of $0 per GJ and a cap of $400 per GJ. Pipeline operators schedule flows to supply the necessary quantities of gas to each hub.

AEMO operates a balancing service – called market operator services (MOS) – to meet any variations in gas deliveries or withdrawals from the schedule. These services are mainly paid for by the parties causing the imbalance.

162 AER, Wholesale markets quarterly – Q4 2020, February 2021.

163 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. In response, in 2018 the ACCC began publishing gas price data as part of its 2017–2025 gas inquiry.

164 ACCC, Gas inquiry 2017–2020, interim report, July 2018, August 2018, pp 24, 49.

Gas supply hubs

Gas supply hubs at Wallumbilla in Queensland and Moomba in South Australia are a voluntary platform for gas trading. 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. Participants can trade gas up to a year in advance of physical supply.

Wallumbilla is a major pipeline junction linking gas basins and markets in eastern Australia, making it a natural point of trade. A single trading location makes it easier for participants to trade across different pipelines, thus pooling potential buyers and sellers into a single market.

Similar to Wallumbilla, the Moomba hub is located at 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. On 28 January 2021, trade points at Culcairn and Wilton were also introduced to facilitate trades at the Victorian and Sydney gas market locations, respectively.

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.[165]

Day-ahead auction (transportation related services)

An east coast wide market for next day pipeline transport and gas compression has operated since 1 March 2019. Unutilised (contracted but not nominated) capacity for the next day is sold the day before through an auction. This auction has been widely used to move gas between the east coast gas markets since its inception (section 4.6.2).

4.2.3 Gas Bulletin Board

The Gas Bulletin Board is an open access website providing current information on gas production, storage and transmission pipelines in eastern Australia. It plays an important role in making the gas market more transparent, especially for smaller players that 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 bidirectional 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.

Reforms are currently being considered to expand the scope of information reported (section 4.12.1).

4.3 Gas prices

Gas prices in 2022 to date have reached record highs and persisted at high levels for much of the year. This has been particularly evident in spot market prices and to a lesser extent in contract prices.

4.3.1 Gas contract prices

The ACCC has access to gas contract information and reports on these prices through its gas inquiry.

Over previous years (2019 and 2020) domestic gas contract prices tended to track falling international prices, measured using LNG netback prices. However, prices offered for 2022 had stabilised at the beginning of 2021.[166] Although prices have recently increased, the domestic price increase was substantially lower than the increase in international LNG prices, which were up by almost 230%.

165 While most gas trading occurs 'off-screen' (not traded through the gas markets), some of these trades are reported to the market operator and settled through the gas supply hub trading platform.

166 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.

More recently, prices offered by both producers and retailers for 2022 increased to $7–$9.50 per GJ by mid-2021 compared with $6–$8 per GJ in late 2020.[167] Similarly, contract prices agreed to by C&I users increased in 2021 to $7.50–$9.90 per GJ.[168] This likely reflects significantly higher Asian LNG prices across 2021 and changing domestic market conditions from mid-2021.[169]

Producer offers diverged from increased LNG netback prices over 2021. However, improved conditions reported by C&I users, including increased supplier diversity and more flexible contract conditions, dissipated by mid-2021, particularly for supply offered from 2023. Despite forward gas prices easing over 2021, the ACCC reported many C&I users experienced difficulties in procuring supply beyond 2022, with users reporting concerns around future supply resulting in risk premiums being incorporated into contract prices.[170]

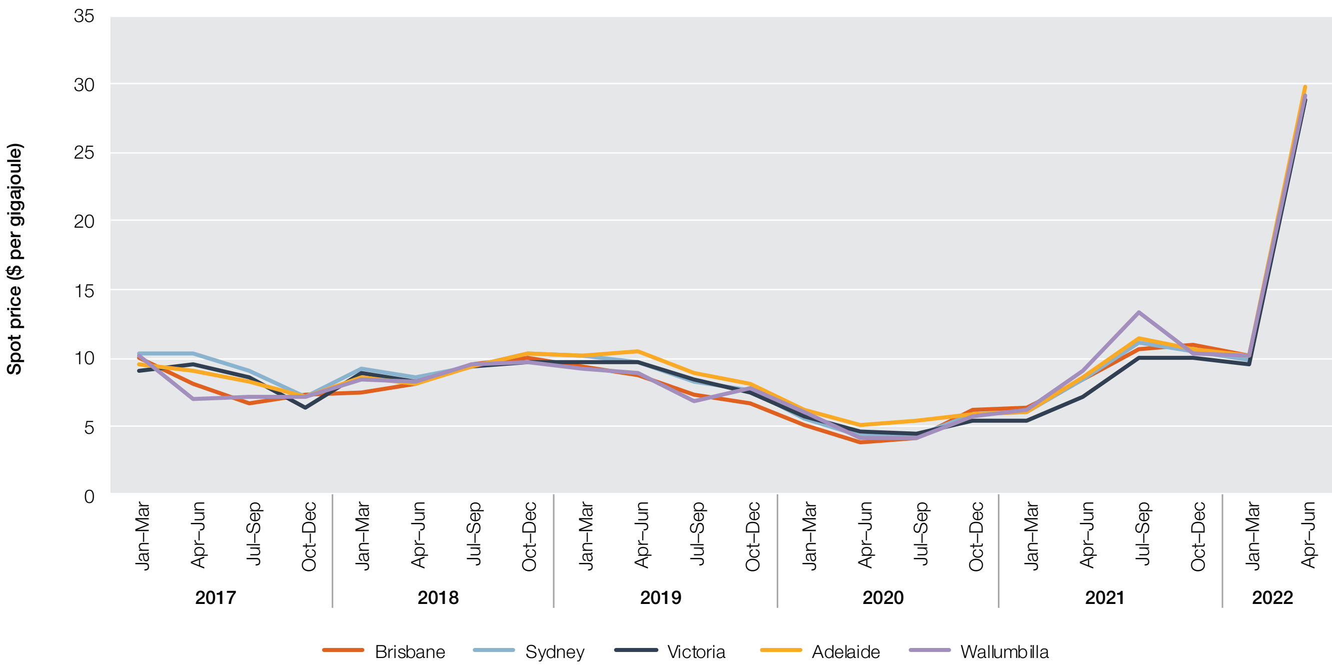
In late 2021 and early 2022, 2023 supply contract offer prices (gas supply agreements) were below international spot LNG and domestic market prices. Spec prices[171] offered for 2023 supply by gas producers increased from between $6.79 and $11.40 per GJ in the first half of 2021 to between $7.33 and $16.33 per GJ in late 2021 and early 2022.[172]

However, the ACCC expressed concern around recent extreme spot price increases in domestic and international markets, and their implications for future contract prices.[173]

4.3.2 Spot market prices

Since May 2022 spot prices have increased rapidly to record high prices, having trended upwards since reaching relatively low levels in 2020 (Figure 4.2).

Figure 4.2 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.

167 ACCC, Gas inquiry 2017–2025, interim report, January 2022, February 2022 p 14.

168 ACCC, Gas inquiry 2017–2025, interim report, January 2022, February 2022 p 111.

169 On 1 December 2021, a voluntary code for negotiations between suppliers and users was announced to improve benefits for users. The code and will be monitored as part of the ACCC gas inquiry.

170 ACCC, Gas inquiry 2017–2025, interim report, January 2021, February 2021, pp 61, 70.

171 Contract offers reflecting indicative prices of gas supply.

172 ACCC, Gas inquiry 2017–2025, interim report, July 2022, August 2022, p 34.

173 ACCC, Gas inquiry 2017–2025, interim report, July 2022, August 2022, p 12.

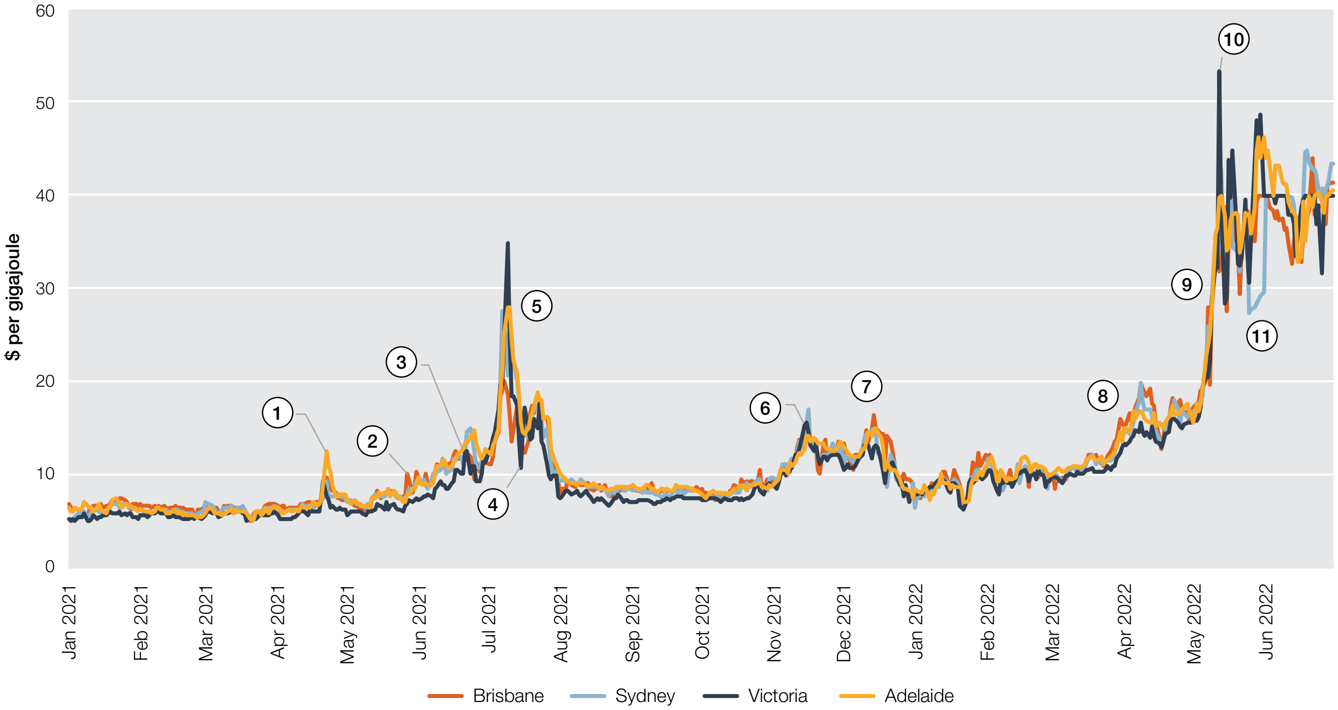
Unprecedented price volatility since May 2022

Following a noticeable increase from late March, when prices are usually subdued prior to winter, spot market prices since May 2022 have reached record highs. This reflects a series of overlapping factors, including:

- high international gas prices and changes to global supply and demand conditions, strengthening the incentive for producers to export LNG rather than supply into the domestic market
- significant demand from gas-powered generators due to other supply-side constraints in the NEM (section 4.4.1).
- demand pressures arising from residential heating demand in southern states.

Figure 4.3 sets out an annotated timeline of key pricing events in 2021 and 2022 to date.

Figure 4.3 Daily gas spot prices



1. 23 April 2021: Moomba production issues on 21 and 22 April, Iona maintenance outage (8 to 31 April) alongside increased demand in Sydney and Victoria, high gas generation demand in all regions (particularly SA) and high NEM prices.
2. From late May 2021: Increased market demand heading into winter, high gas-powered generation usage following the loss of baseload generation in the NEM (Callide power station, Queensland).
3. 19 to 22 June 2021: Victorian demand above 1 PJ and an unplanned production outage at Longford. Adelaide gas generation high during intermittent periods of low wind, gas starts flowing south as southern prices rise above northern prices, with some Callide generation units coming back online.
4. July 2021: High levels of price volatility across the southern markets, resulting in numerous significant price variations occurring (discussed in section 4.3.2).
5. 7 to 10 July 2021: High southern market prices and gas generation demand over periods of low wind. A partial Longford outage and diminishing Iona storage during cold weather (Victoria).
6. 10 to 16 November 2021: Constrained supply and abnormally high end-of-year demand in Victoria due to cold weather, alongside high export demand and elevated gas generation in Queensland.
7. 9 to 21 December 2021: High export demand and gas generation in Queensland with significant gas flows north from southern markets despite continuing capacity restrictions at Longford and historically low storage levels at Iona (Victoria). Elevated gas generation and a Moomba production outage (SA).
8. From late March 2022: Gas prices become increasingly volatile, with drivers of higher prices including a combination of cold weather, low wind levels, coal generation outages and elevated gas-powered generation, with some gas contracts reset at higher prices into the new quarter.
9. From early May 2022: Gas flowing north in contrast to gas flowing south in May 2021, coupled with increased gas demand for electricity generation (14 PJ in May compared to 10 PJ in April on mainland) influenced by baseload outages, with very high NEM prices.
10. 12 May: Consecutive demand forecast increases in Victoria and reduced \$15–\$30 per GJ supply, with 211 TJ of controllable withdrawals further driving up demand.
11. From late May 2022: Administered prices in Brisbane, Sydney and Victoria contribute to unprecedented gas market price volatility.

Source: AER; AEMO (raw data).

Production increased quarter-on-quarter in 2022, exceeding record levels set in 2021. In the north, production at Roma (Queensland) has remained high but output is not keeping up with exports. In addition, Moomba's yearly output (South Australia) is steadily declining. This has resulted in less gas being available for domestic use in 2021 and 2022.

Storage has also been decreasing to levels limiting supply capability (section 4.5.2). These factors have led to a trend of more gas flowing north and decreased supply into southern markets. Queensland continued to source gas supply from Victoria into April and May 2022 despite price increases across the gas markets (section 4.6).

From 24 May 2022 the suspension of a market participant triggered the Retailer of Last Resort (RoLR) provisions, putting Brisbane and Sydney into administered states until 7 June[174]. From 30 May, significant depletion of Iona storage led to an administered price cap in Victoria based on high cumulative prices, when on 14 June it became the only jurisdiction with a price cap in place this led to distorted price signals in the market.

From June, Queensland started providing more gas into southern markets after AEMO activated the Gas Supply Guarantee (GSG) to provide gas to generators in the south for the 2 June gas day.[175] After this, more gas continued to flow south at the same time as the east coast went through a particularly cold start to winter. The gas heating demand load from the cold weather was accompanied by elevated gas-powered generation due to numerous factors (section 4.4.1) driving unprecedented NEM prices (section 4.3.2).

One of the main drivers of supply risk in Victoria into late July was the depletion of Iona's underground storage inventory, where slower draw down over May and June accelerated in July.

This put drawdown rates in line with unprecedented levels observed the previous winter (section 4.5.2).[176] As a result, storage declined because ongoing gas generation demand requirements put increasing pressure on available supply. This then led to multiple notifications about threats to system security in Victoria from 11 July, culminating in the notification of potential shortfalls across the whole south-eastern region from 19 July until the end of September.[177]

Following a conference with industry, the GSG (section 4.11.2) was reactivated out to 30 September and AEMO intervened in the gas markets, directing gas-powered generators to cease taking gas from the Victorian market without supporting gas supply. Exporters agreed to make more supply available to southern markets and, despite a downward trend in prices across the markets from that time, prices over July reached their highest level since the markets commenced.

Administered pricing states

From 24 May, AEMO issued a market suspension notice to Weston Energy, as required under the Gas Rules, when the participant failed to satisfy a margin call made on the previous day. This triggered the Retailer of Last Resort (RoLR) process to transfer Weston's customers over to default retailers, moving them over to the portfolios of AGL and Origin. The process resulted in AEMO declaring a major RoLR event in the Sydney STTM and minor RoLR event in the Brisbane STTM, putting them into administered states where prices were to be set in Sydney at around $30 per GJ for 28 days and capped at $40 per GJ in Brisbane for 10 business days. Following ministerial intervention on 31 May, however, Sydney was downgraded to a minor RoLR classification (with a $40 cap to match Brisbane) and administered states pursuant to the minor RoLR event expired for both on 7 June. However, Sydney remained in an administered state for another week due to the cumulative price exceeding the threshold ($440 per GJ).[178]

In Victoria, the breach of the cumulative price threshold ($1,400 per GJ) from the 10 am schedule on 30 May also triggered administered prices.[179] In the administered price state, the cumulative price is calculated using underlying marginal clearing prices based on participants' market offers. Due to the distorted price signal in the Victorian market, participants have withheld capacity to sure up their own supply, offering gas at market value only up to levels matching their own demand requirements. This has led to shadow prices behind the $40 per GJ administered price cap (APC) frequently reaching the market price cap (MPC) of $800 per GJ, prolonging the administered state. MPC schedule pricing has been driven by higher than expected demand or participants buying off market without

174 Sydney's administered state remained until 14th June because of high prices leading to administered price caps.

175 It is likely in addition some winter contract volumes increased in June for supply of gas to the south, information as to gas sold into (including May when gas went north contrary to daily spot market pricing signals) and out of Queensland will increase partially with requirements on industry to report contract prices and key terms and conditions from 15 December 2022 under new provisions of the National Gas Rules commencing then.

176 While refilling at Iona was limited over this period last year due to a pipeline leak, in 2022 utilisation of Iona and withdrawals to top up storage levels have been influenced by higher-than-expected gas generation requirements and distorted administered state price signals leading to limited market supply being available to schedule controlled market withdrawals.

177 Including New South Wales, Victoria, South Australia and Tasmania, with the direction to take effect until either: generators have sourced gas supply to meet generation demand; the threat to system security has ended; or AEMO determines the direction is no longer required to maintain or improve reliability, system security or in the interest of public safety.

178 The STTM cumulative price threshold (CPT) is calculated from daily market prices over a rolling period measured over the previous 7 days.

179 In Victoria, due to the 5 daily scheduling intervals, the administered price is measured over the previous 35 scheduling intervals (7 days).

providing supply to match their demand requirements. However, this balance has led to contingency gas events when insufficient supply was offered and AEMO could not clear the market, with the Gas Supply Guarantee (GSG) also being invoked to prevent the expected curtailment of electricity generation (section 4.11.2).

2021 local prices and international price trends

Annual prices increased over 2021, rising by 80% from the previous year.[180] Although separate factors influenced higher prices in 2021, including the international price divide, there were numerous similarities to the other drivers of high 2022 prices.

2021 average prices were driven up by particularly high prices over the 4 months of June, July, November and December. These high prices were largely driven by local factors, with record east coast LNG exports putting upward pressure on northern prices. However, the impact of high international prices on northern prices was limited and this created a gap between local and international prices.

Like 2022, record drawdown of gas storage in Victoria and production issues at Longford (Victoria's largest production source) contributed to price volatility in the middle of 2021. Unseasonably cold temperatures over winter drove increased demand and prices later in the year (also driving Iona storage unusually low for that time of year).

4.3.3 Linkages between domestic and international prices

The growth in Queensland's LNG exports from late 2020, combined with other factors including state-based moratoriums on gas development and a tightened supply–demand balance, has placed increasing pressure on east coast domestic markets. This has combined with other factors such as state-based moratoriums on gas development, tightened the supply–demand balance leading to increased wholesale gas prices.

Over 2021, a severe northern winter combined with shipping constraints drove up Asian prices early in the year. Later in the year, competition between Asian, European and South American buyers combined with higher demand from replenishment of European storage levels. This led to higher prices in late 2021 over the following northern winter. In early 2022, the Russian[181] invasion of Ukraine put upwards pressure on global oil and gas prices. Bans on Russian oil drove countries to diversify their supply and to decrease dependence on Russia for both oil and gas, sending ripple effects across global supply chains.

In 2022 further pressure from gas-powered generation heading into the higher demand winter period contributed to driving gas market prices up to unprecedented levels.

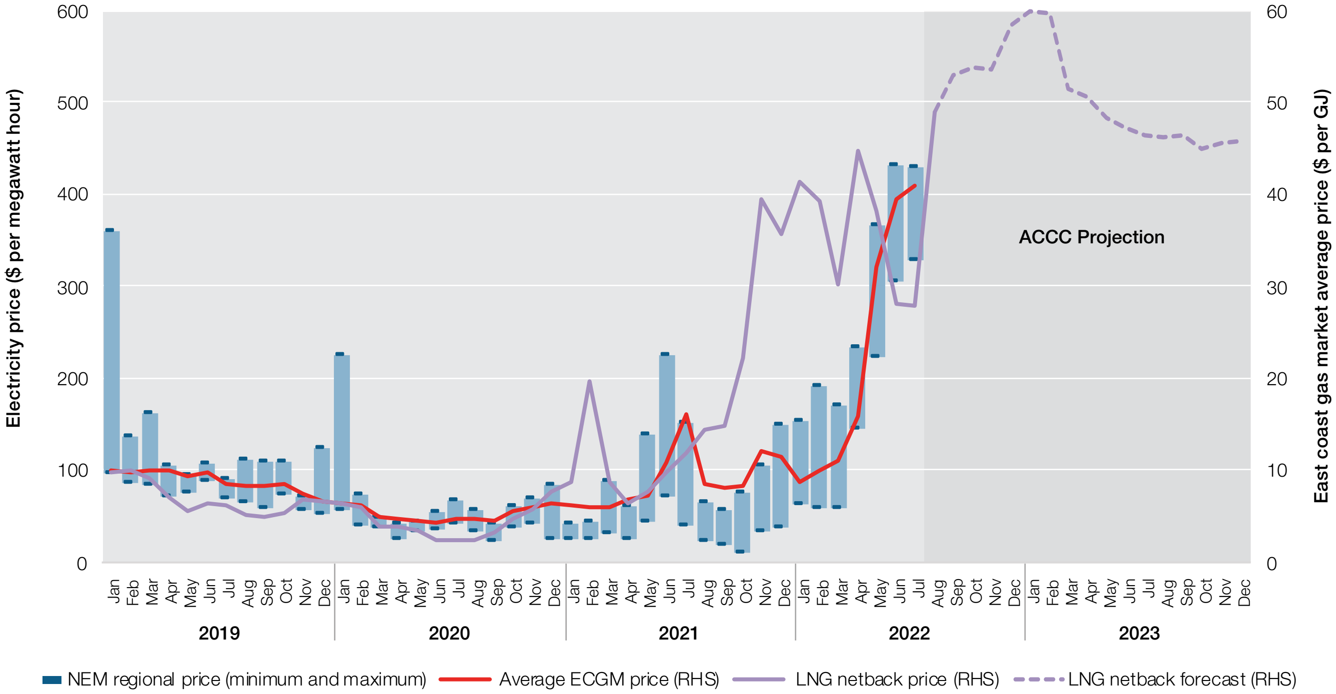
The higher NEM demand coincided with a particularly cold start to winter across the east coast, which put further pressure on the already tight supply–demand balance. Local gas prices increased from a high base of around \$15–\$20 per GJ from April, increasing toward international export parity levels heading into winter and closing the large gap between local and international prices from late 2021 (Figure 4.4). Following Russia's invasion of Ukraine in late February, international oil and gas prices surged, which could flow through to local gas contract pricing – offers from exporters are now starting to factor in export parity prices.[182] However, the more immediate impact to local exports has followed the curtailment of Russian gas supply to Europe, which drove up international LNG demand from alternative supply sources. While Russian gas supply to Europe was maintained and underground storage levels increased, netback prices briefly reduced below \$30 per GJ in mid-2022. However, subsequent Russian supply threats resulting in pipeline flow reductions, and an explosion at Freeport LNG that took a significant amount of US LNG off the market, drove prices back up in August.

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

181 Russia is one of the biggest global producers of both oil and gas commodities.

182 ACCC, Gas inquiry 2017–2025, interim report, July 2022, August 2022, p 12.

Figure 4.4 Comparison of east coast gas market, NEM and LNG netback prices



Note: ECGM is east coast gas market. NEM is National Electricity Market. The LNG netback price calculates the export parity price and subtracts the cost of liquefaction and transport required to produce and deliver LNG to international customers.

Source: AER analysis of NEM, short term trading market, Victorian declared wholesale gas market and ACCC LNG netback price data.

Seasonal factors are also strong drivers of international demand and prices for gas, typically increasing during the northern hemisphere winter. Policy measures that influence gas use and broader economic factors can also be strong drivers of changes internationally.

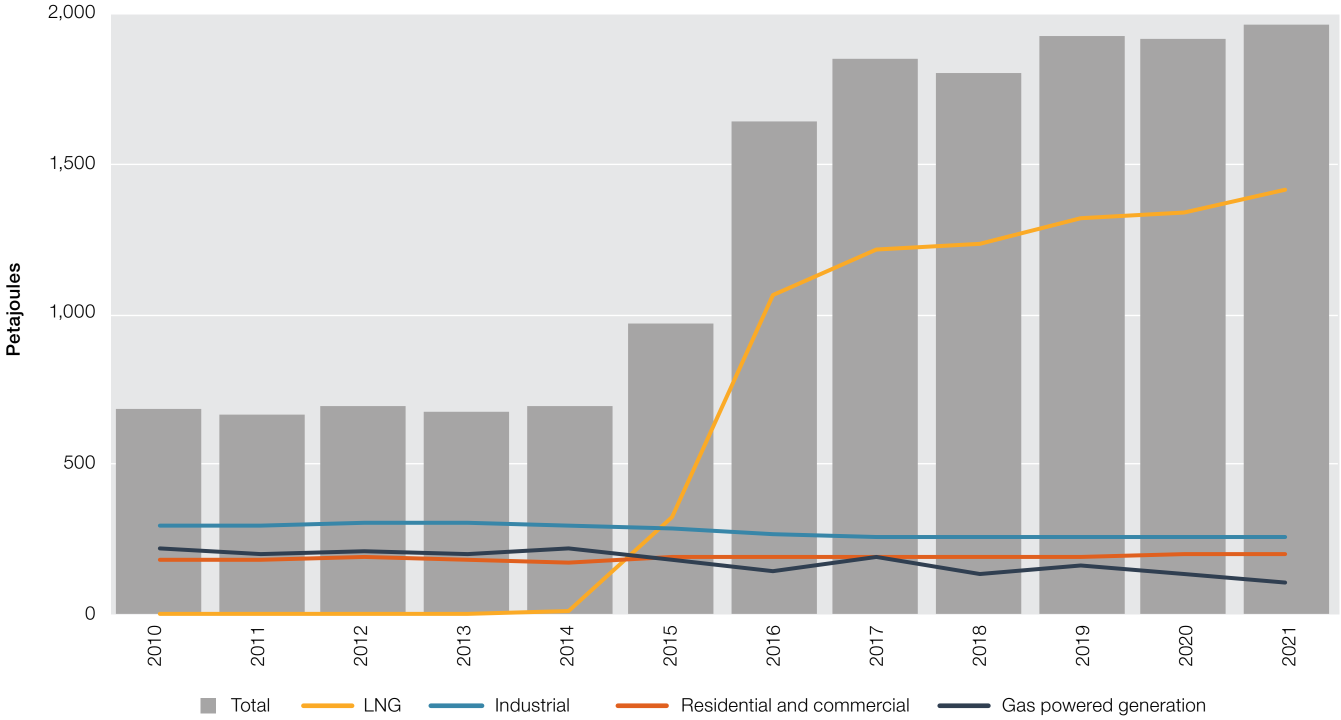
Figure 4.5 LNG netback and Wallumbilla prices

Note: The LNG netback price calculates the export parity price and subtracts the cost of liquefaction and transport required to produce and deliver LNG to international customers.

4.4 Gas demand in eastern Australia

Around 70% of domestic gas production in eastern gas markets (excluding the Northern Territory) is exported and the balance is sold into the domestic market (Figure 4.6).

Figure 4.6 Eastern Australian gas demand



Source: AEMO, 2022 gas statement of opportunities, March 2022.

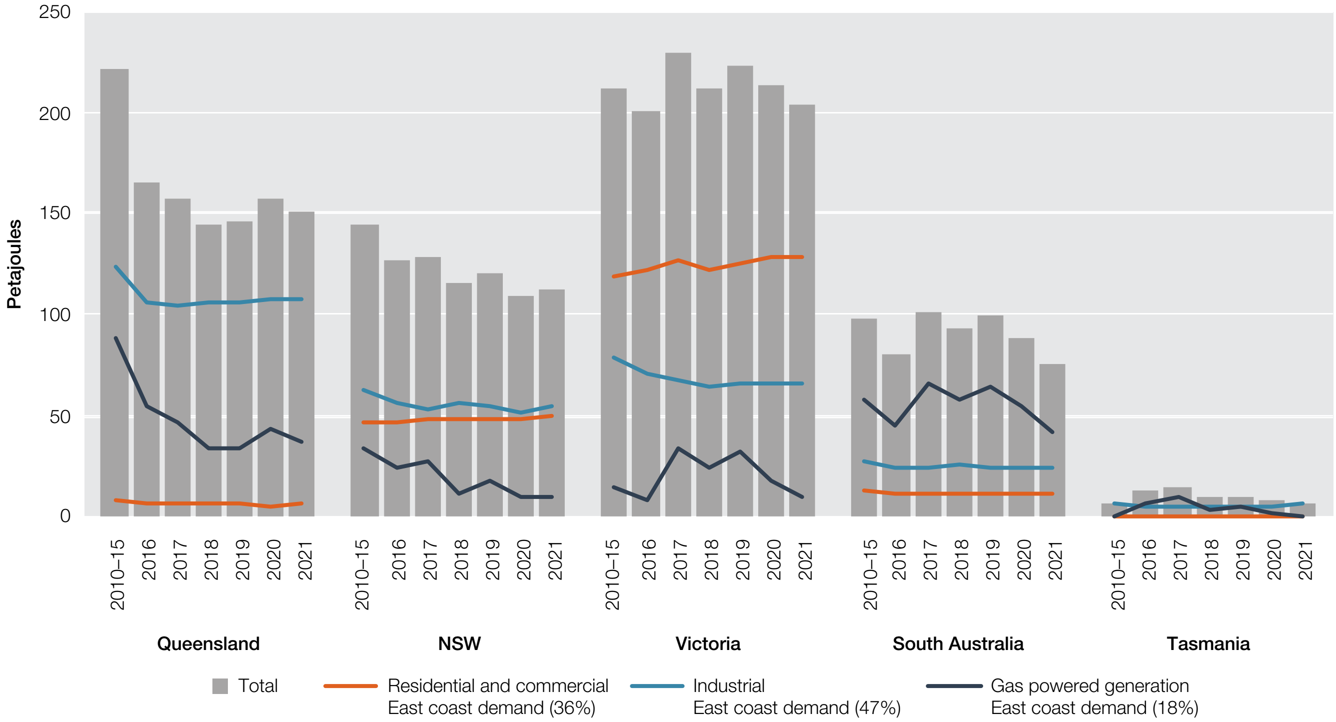
4.4.1 Domestic demand

Domestic customers in eastern Australia used around 550 petajoules (PJ) of gas in 2021 (Figure 4.7).[183] These customers included industrial businesses, electricity generators, commercial businesses and households.

Industrial customers consumed 47% 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.

183 Excludes LNG. AEMO, 2022 gas statement of opportunities, March 2022.

Figure 4.7 Gas consumption in eastern Australia



Note: Data for 2010–15 is average annual consumption over that period.

Source: AEMO, 2021 gas statement of opportunities, March 2021.

Residential and commercial customers accounted for 36% of domestic gas demand, but this share varies from state to state. For example, in Victoria more than 60% of gas is consumed by small residential and commercial customers, who use gas mostly for heating and cooking. In Queensland, where much fewer households are connected to a gas network, the share of gas consumed by residential and commercial customers falls to 4%.

The electricity sector is another major source of gas demand, accounting for 18% of domestic gas use in 2021, down from 29% in 2017. South Australia used the most gas-powered generation in 2021 (42% of gas-powered generation in the National Electricity Market). The rapid responsiveness of gas-powered generators makes them suitable for meeting peak electricity demand and managing variable wind and solar generation. Consequently, the volume of gas used for electricity generation fluctuates with electricity market conditions. Long-term forecasting of expected usage for gas-powered generation in the National Electricity Market (NEM) is difficult due to the unpredictability of factors including unforeseen events.[184]

Domestic gas use in 2022

In 2022, gas-powered generation was up from 2021 levels across the January to March quarter. Queensland remained elevated alongside continuing baseload outages, and baseload outages in Victoria and New South Wales influenced increases from the previous quarter. This occurred alongside warmer weather driving the highest first quarter underlying electricity demand in recent years for Victoria and Queensland, particularly during humid conditions over January and extreme heatwave conditions across northern Queensland in March.[185]

Over the April to June quarter of 2022, numerous baseload generation outages in the NEM contributed to higher demand for gas generation. On top of this, limits on hydroelectric generation output related to recent flooding events and constraints on the supply and transportation of coal put further upwards pressure on demand for gas generation. NEM price spikes from late April into May were also influenced by planned and unplanned network outages limiting Queensland's access to lower priced generation from the rest of the NEM, while a similar situation affected South Australia in mid-May.

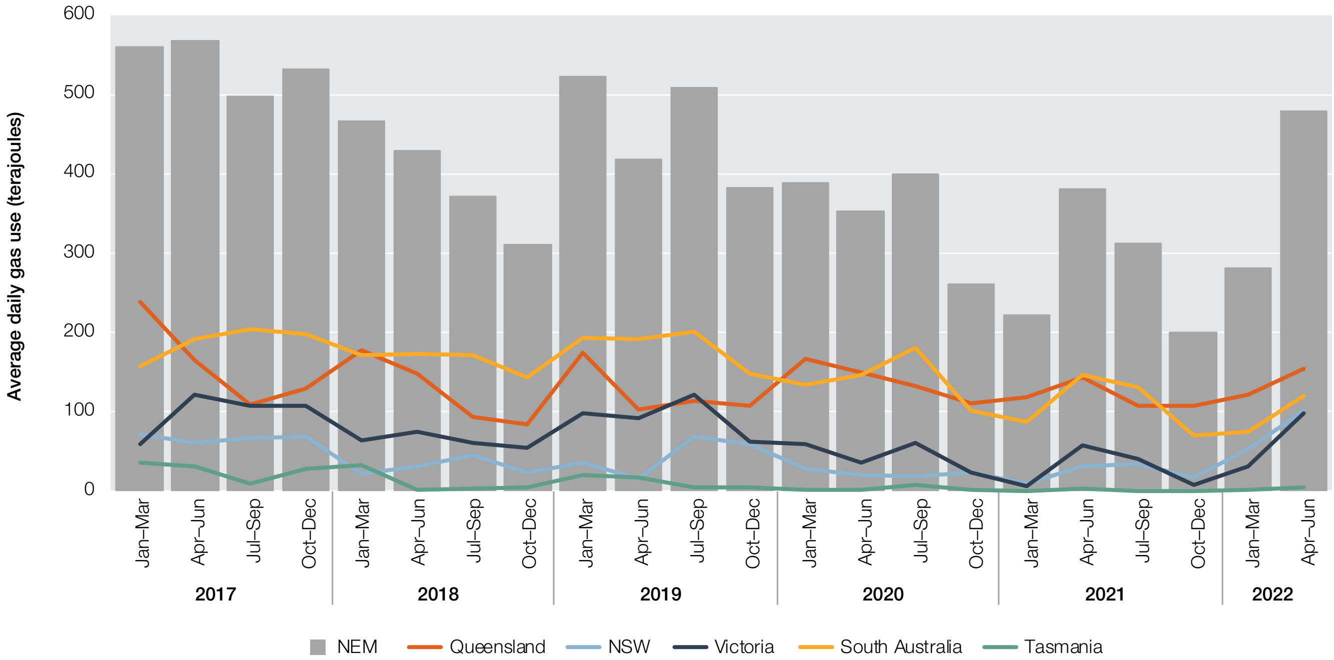
The combination of very high fuel prices, fuel constraints and fuel rationing led to unprecedented NEM prices and AEMO suspending the market (section 4.3). All these factors over the quarter saw gas-powered generation demand increase to the highest level observed for April-June since the shutdown of Victoria's Hazelwood coal-fired generator

184 Multiple events including baseload generation retirement, coal shortages during hot weather, bushfires and flooding, transmission outages, and prolonged coal generation maintenance outages and plant failures, have affected the NEM in recent years.

185 AEMO, Quarterly Energy Dynamics Q1 2022, April 2022, p .7.

in late March 2017 (figure 4.8). On top of this, as the east coast headed into the typically higher winter demand period, it also experienced the coldest start to winter in decades[186], driving up southern gas market demand and putting further pressure on domestic supply given demand for gas-powered generation.

Figure 4.8 Quarterly gas demand for gas-powered generation



Source: AEMO; National Electricity Market (NEM) generation data and heat rates (gigajoules per megawatt hour).

4.4.2 Liquefied natural gas exports

Most of the gas produced in eastern Australia is exported as liquified natural gas (LNG).

In eastern Australia, export gas is liquefied in processing facilities in Queensland to make it economic to store and ship in large quantities (Table 4.1). Australia also operates 5 LNG projects in Western Australia and 2 in the Northern Territory (Figure 4.9).

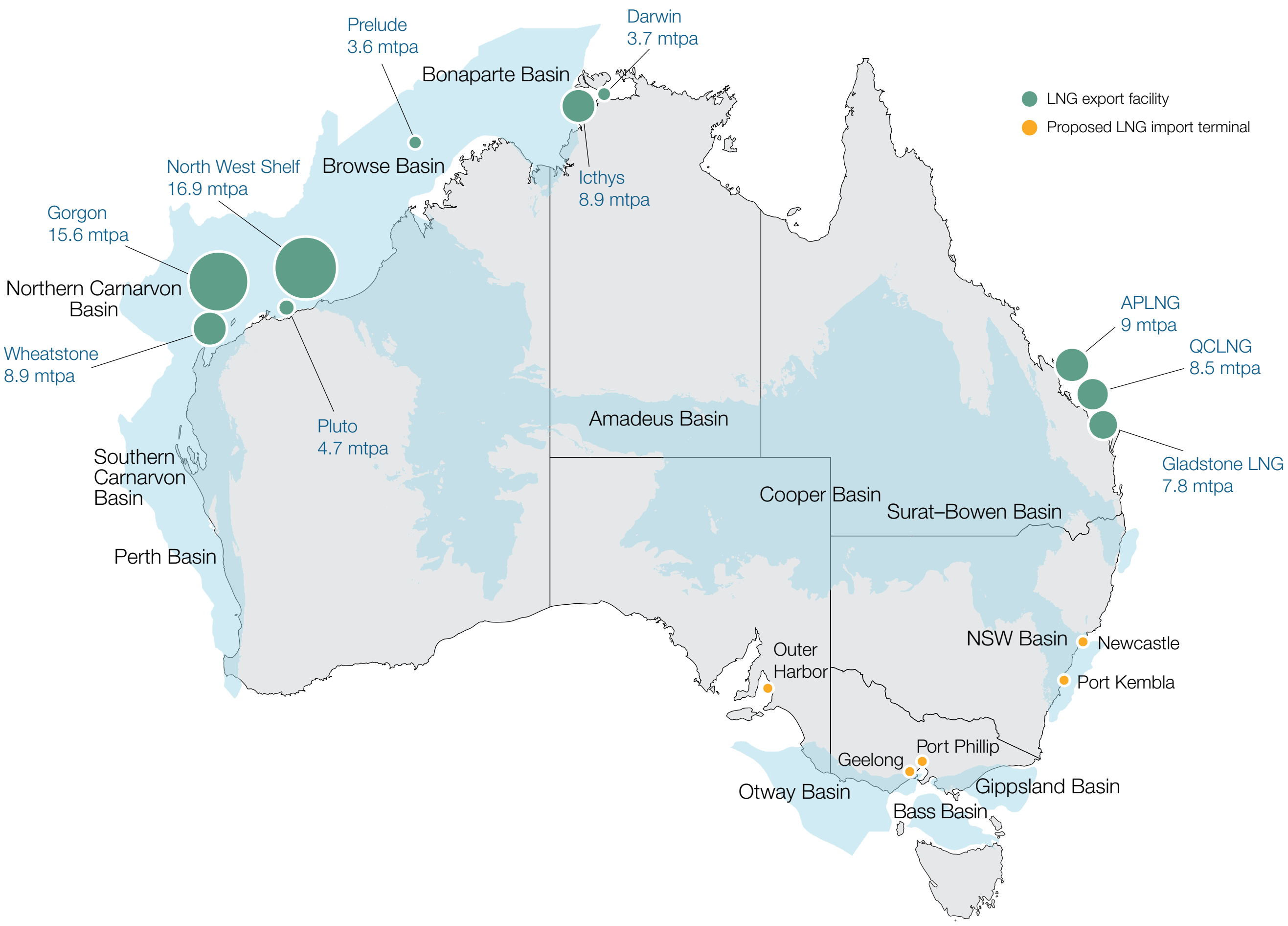
In 2021 LNG exports earned Australia $50 billion, making gas Australia's second largest resource and energy export behind iron ore[187] and Australia one of the world's largest LNG exporters in 2021. These export levels are expected to be overtaken by Qatar and the United States, due to significant growth over the next 5 years.[188]

186 The Guardian, Coldest start to winter in decades for eastern Australia with power grid under strain, June 2022.

187 Department of Industry, Innovation and Science, Resources and energy quarterly, December 2021.

188 EnergyQuest, EnergyQuarterly, March 2020.

Figure 4.9 Australia's LNG export projects



Note: Capacity in million tonnes per annum (mtpa).
Source: AER.

Queensland's LNG industry comprises 3 major projects, which source gas mainly from the Surat–Bowen Basin:

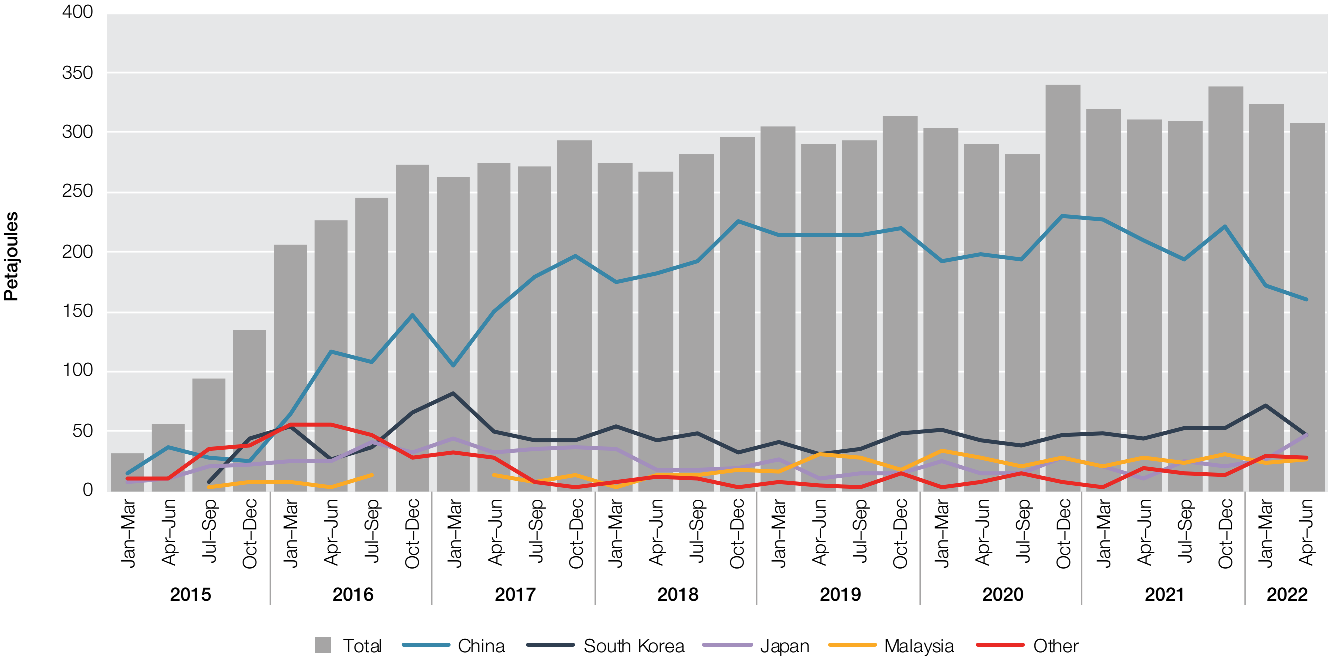
- The Queensland Curtis LNG (QCLNG) project has capacity to produce 8.5 million tonnes of LNG per annum (mtpa). Shell (73.75%), CNOOC (50% equity in Train 1) and Tokyo Gas (2.5% equity in Train 2) own the project.
- The Gladstone LNG (GLNG) project has capacity to produce 7.8 mtpa. Santos (30%), Petronas and Total (27.5% each) and Kogas (15%) own the project.
- The Australia Pacific LNG (APLNG) project has capacity to produce 9 mtpa.[189] Origin Energy and ConocoPhillips (37.5% each) and Sinopec (25%) own the project.

These LNG projects control over 80% of reserves in eastern Australia.[190] They also source gas from other producers through long-term contracts and spot markets. East coast gas exports are typically lower mid-year, when domestic demand increases in winter, and higher over summer as northern winter conditions drive up international demand.

189 APPEA, LNG exports, APPEA website, accessed 29 May 2022.

190 ACCC, Gas inquiry 2017–2025, review of upstream competition and the timeliness of supply, issues paper, 15 September 2021, p 6.

Figure 4.10 Eastern Australian gas exports



East coast LNG exports increased to record levels over 2021 (and the fourth quarter of 2021 reaching close to the record from late 2020).[191] APLNG operated above capacity across most of 2021, contributing to record eastern Australian production levels (figures 4.10 and 4.12).

China is the primary market for eastern Australian LNG, accounting for 67% of exports in 2021 (851 PJ). These exports were 4.4% higher than the previous year's volume following the first decrease since east coast exports commenced, yet they remained lower than 2019 levels (863 PJ). While China's LNG demand is expected to continue to grow, supported by expanded industrial and residential gas use, recent declines in 2022 saw Gladstone exports to China decline to the lowest levels observed since 2017.[192] China has further relaxed macroeconomic policy to support economic growth amidst continued COVID lockdowns, with further measures expected to be introduced to achieve their 2022 growth target.[193] However, with the recent events in Europe, China has sourced additional LNG supply from Russia, increasing imports by 77% in the three months following the invasion of the Ukraine.[194]

Across the January-March quarter of 2022, our other main source of east coast LNG demand from South Korean increased, despite overall lower demand resulting from reduced gas-powered generation that coincided with increased coal-fired generation output. To curb greenhouse gas emissions, South Korea's Government had previously encouraged reduced coal generator output. However, these restrictions appear to have been lifted in April 2022 amidst record-high global LNG prices, with the construction of new nuclear facilities also expected to contribute to restrained growth in gas demand over the coming years.[195] While South Korean demand declined over April-June 2022, Japanese imports increased by a similar amount, yet long-term gas demand from Japan is also expected to decline with rising nuclear and renewable energy generation displacing gas-powered generators.

International price trends outlooks remain uncertain, influenced by potential COVID lockdowns continuing in China and the risk of further curtailments of Russian gas exports to Europe.

Northern Territory and Western Australia exports

The Northern Territory's LNG projects are Darwin LNG (3.7 mtpa capacity) and Ichthys LNG (8.9 mtpa capacity). Both projects connect to the territory's domestic gas market as emergency supply sources but otherwise produce gas for export.

191 DISER, Resources and Energy Quarterly, December 2021, p 77.

192 Chinese gas imports fell 13% over the Jan-March quarter of 2022, with Australia's share down from 7.1 million tonnes in 2021 to 5.6 million tonnes in 2022, and even large declines in US gas imports.

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

194 ibid, p 77.

195 ibid, p 78.

Western Australia has 5 LNG projects with a combined capacity of around 50 mtpa – including the North West Shelf, which is Australia's largest LNG project by capacity (16.3 mtpa). The other projects are Gorgon (15.6 mtpa), Wheatstone (8.9 mtpa), Pluto (4.9 mtpa) and Prelude (3.6 mtpa).

4.5 Gas supply in eastern Australia

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 from the Northern Territory. At times, southern gas is also transported north to meet LNG export demand. Gas from the northern fields is also required to supplement Victorian gas production to meet domestic gas demand in southern Australia over winter.

In 2021 production increased again to 4,163 TJ per day as LNG projects ramped up production, particularly in the second half of 2021, to meet record export demand (Figure 4.10).[196] This continued in 2022 with new record production levels set for both the January-March and April-June quarters, however the east coast increase was driven by higher southern output as northern production tapered off, with significant increases in gas flows into the north over both quarters compared to previous years (Figure 4.18).[197]

To avoid export controls, Queensland's LNG producers have entered into a series of Heads of Agreement with the Australian Government[198], committing to offer uncontracted gas to domestic buyers on competitive terms before offering it for export.[199]

In 2021 and 2022 AEMO forecast an improved gas supply outlook compared to previous years but noted the 5-year forecasts for southern available production were still declining. The improved outlook in 2021 reflected progress in the planning for AIE's Port Kembla LNG import terminal, however development for the project was pushed out past winter-2023. While new greenfield infrastructure solutions are not expected to assist with potential 2023 supply shortfalls[200], brownfield solutions (including an expansion of the South West Pipeline and the duplication of the Winchelsea compressor in Victoria) may improve supply availability.[201] With a reduction in southern reserves (largely due to the decline of the Gippsland basin supplying the largest and most flexible production source)[202], the expansion of the South West Queensland and Moomba to Sydney pipeline corridor is also expected to play an important role in bringing northern gas supply to southern markets next year, with the committed stage 1 of the expansion expected to provide increased transportation capacity before winter-2023 (section 4.9.3).

Despite improved supply forecasts from 2022 in the short run, the longer-term outlook remains uncertain. In addition to further write-downs of 2P reserves reported the previous year, AEMO forecast that south-eastern gas production will drop significantly in 2023, leading to an increased risk of peak day supply shortfalls. By 2026, this is expected to occur more frequently even with no gas generation, while international conflict driving countries to diversify away from Russian gas also drives up risk to accessing LNG imports and the demand for floating storage and regassification units. Similarly, the ACCC reported a broader shortfall in supply from 2P reserves could emerge by 2026. Both AEMO and the ACCC suggested more exploration and development in southern Australia, pipeline expansions and LNG imports could mitigate the supply risks. However, the speculative nature of unsanctioned new domestic supply sources, with a range of barriers including significant investment in infrastructure to bring gas to market, have led to producers finding it increasingly difficult to obtain finance to invest in fossil fuel projects.[203]

Further factors also contribute to uncertainty surrounding long-term supply conditions, including underperformance of developed resources and the potential for southern production to decline faster than expected. Forecasts

196 Each year since 2013, gas production in Queensland has reached record levels.

197 To meet its LNG supply contracts, Santos has sourced substantial volumes of gas from other producers, diverting gas from 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 4.11.1).

198 Department of Industry, Science, Energy and Resources, Securing Australian domestic gas supply, DISER website, accessed 12 July 2022. The new HoA was announced on 21 January 2021.

199 The government is currently negotiating a new Heads of Agreement with gas exporters to safeguard Australia's domestic supplies. 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.

200 AEMO in its Gas Statement of Opportunities (March 2022) and the ACCC in its gas inquiry interim report (July 2022) have both forecast risks of supply shortfalls in 2023, with the ACCC forecasting a probable shortfall of 56 PJ where AEMO's forecast indicated a risk of shortfalls on peak days but sufficient gas available to meet annual demand. The sources of these differences are discussed in: ACCC, Gas inquiry 2017–2020, interim report, January 2022, February 2022, p 19.

201 AEMO, 2022 gas statement of opportunities, March 2022, pp 4, 6 and 11.
Expected Port Kembla development was delayed until late 2023, with insufficient customer contracting impacting the relocation and operation of the floating storage and regassification unit (FRSU), putting an anticipated winter-2024 operation at risk.

202 AEMO, 2022 Victorian gas planning report, March 2022. pp. 47-48.

203 ACCC, Gas inquiry 2017–2020, interim report, January 2022, February 2022, pp 15, 23, 39.

also make assumptions about undeveloped resources with uncertain reserves which are increasingly unreliable, depending on more speculative sources of supply. The decrease in 2P reserves in the Surat basin, where the decline was greatest, has seen substantial volumes of 2P reserves downgraded to 2C resources or revised down for other reasons.[204] [205] 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 4.11).

4.5.1 Gas reserves and production

Eastern Australia had 37,639 PJ of 'proven and probable' (2P)[206] gas reserves in February 2022, having produced over 2,000 PJ of gas in 2021 (Table 4.1).

Ownership is highly concentrated in some gas basins, but more diverse across the market as a whole (Figure 4.11). APLNG owns the majority of reserves in eastern Australia through an incorporated joint venture with Origin Energy, ConocoPhillips and Sinopec.

Table 4.1 Gas basins serving eastern Australia

	GAS PRODUCTION – 12 MONTHS TO DECEMBER 2021			2P GAS RESERVES (FEBRUARY 2022)	
GAS BASIN	PETAJOULES	SHARE OF EASTERN AUSTRALIAN SUPPLY (%)	CHANGE FROM PREVIOUS YEAR (%)	PETAJOULES	SHARE OF EASTERN AUSTRALIA RESERVES (%)
Surat–Bowen (Qld)	1,532	76%	1%	29,020	77%
Cooper (SA–Qld)	91	5%	-10%	1,079	3%
Gippsland (Vic)	290	14%	14%	1,729	5%
Otway (Vic)	35	2%	-5%	685	2%
Bass (Vic)	7	0.3%	-37%	157	0.4%
Sydney, Narrabri, Gunnedah (NSW)	3	0.2%	-8%	11	0.03%
Amadeus (NT)	15	1%	3%	234	1%
Bonaparte (NT)	44	2%	-7%	4,724	13%
EASTERN AUSTRALIA TOTAL	**2,018**	**–**	**2%**	**37,639**	**–**
Domestic gas sales	586	–	-7%	–	–
LNG exports	1,432	–	6%	–	–

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 reserves in other basins are mainly conventional gas.

Source: EnergyQuest, EnergyQuarterly, March 2022.

Queensland's Surat–Bowen Basin holds 77% of gas reserves in eastern Australia and supplied 76% of gas produced in 2021. Queensland's 3 LNG projects produced over 90% of the basin's output in 2021.

Victorian basins account for 7% of eastern Australian reserves, but these reserves are declining largely due to anticipated decreases from Gippsland legacy fields. This is important because Victoria is the highest domestic consumer of gas. AEMO forecasts a steep decline in southern field production after 2022. Of Victorian basins, the Gippsland Basin is the largest while the Bass and Otway basins are smaller basins.

204 2C resources represent the best estimate of contingent gas reserves, which are not yet technically or commercially recoverable.

205 ACCC, Gas inquiry 2017–2020, interim report, January 2022, p 167.

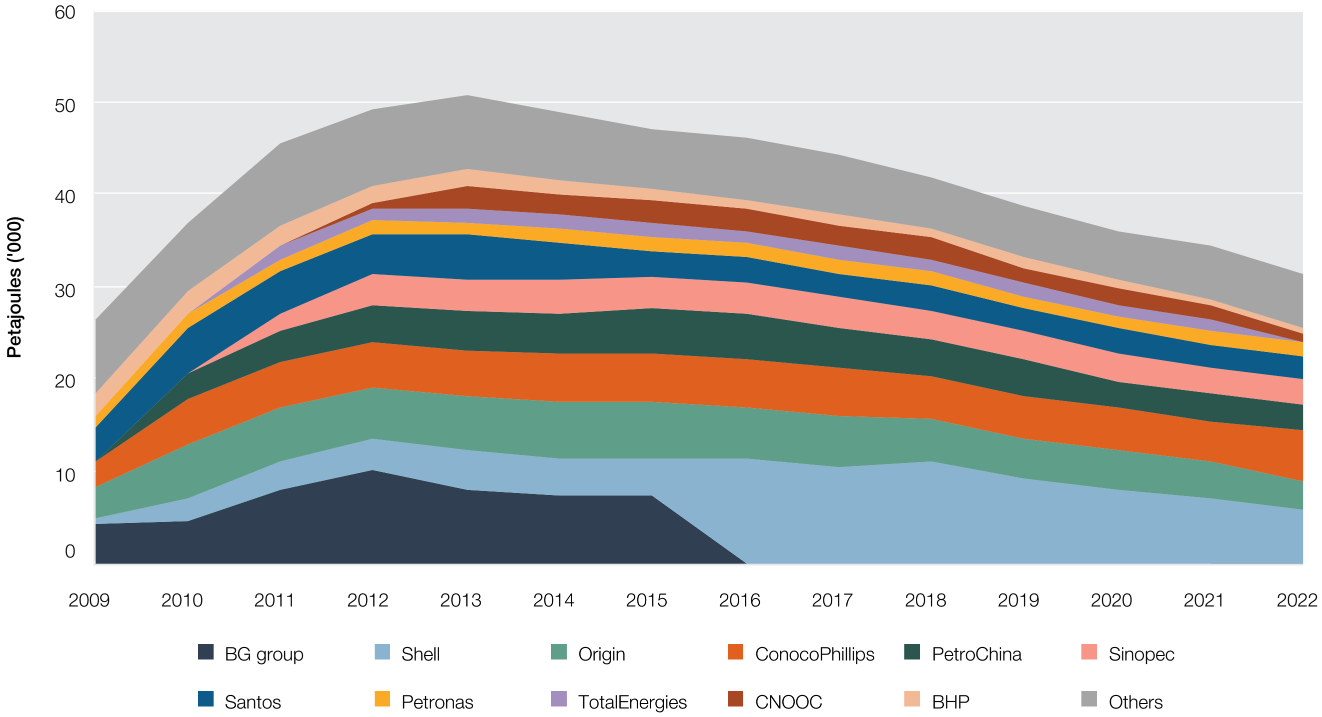
206 2P reserves are proven plus probable reserves estimated to be at least 50% certain of recovery.

The Cooper Basin in central Australia has over 1,000 PJ of eastern Australia's 2P reserves and accounted for 5% of gas production in 2021. Reserves in the basin have declined over the past decade. The Cooper Basin plays an important role as a 'swing' producer in managing seasonal and short-term supply imbalances in the domestic gas market.

NSW has significant contingent resources[207] (around 2,561 PJ) but only 11 PJ of 2P reserves and negligible current production. Santos received approval to develop reserves near Narrabri in the Gunnedah Basin; however, an appeal against the approval led to a 12-month delay of the project, with the final investment decision now expected post-2022 (section 4.9.1).[208]

The Northern Territory has the Bonaparte Basin and the smaller Amadeus Basin. The basins are estimated to have over 4,950 PJ of 2P reserves.[209] Most gas produced is converted to LNG for export.

Figure 4.11 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.

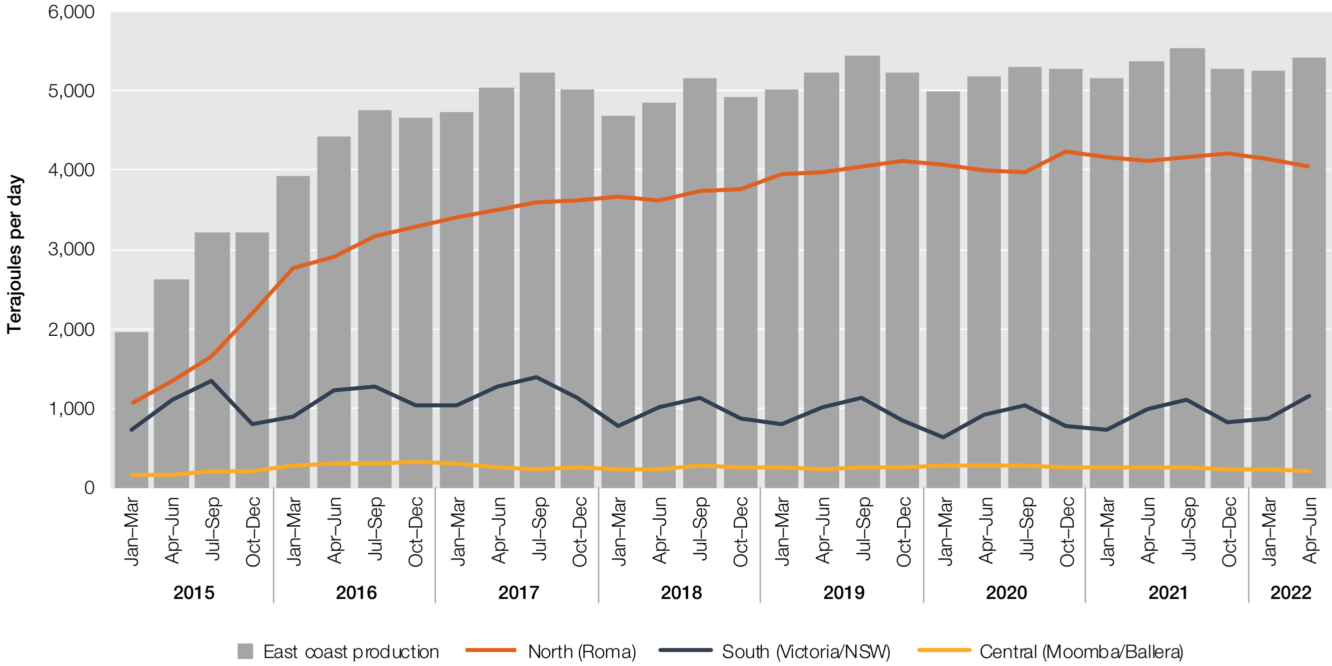
Source: EnergyQuest, EnergyQuarterly (various years).

207 3P contingent resources are reserves estimated to be potentially recoverable from known deposits, but which are not currently considered to be commercially recoverable.

208 EnergyQuest, EnergyQuarterly, December 2021, p 41 and March 2022, p 16.

209 EnergyQuest, EnergyQuarterly, March 2022, p 80. Reserves increased significantly for the Bonaparte basin in the Northern Territory (4,071 PJ). The increase followed a Santos final investment decision on Barossa and the acquisition of Oil Search.

Figure 4.12 Eastern Australia gas production



Source: AER analysis of Gas Bulletin Board data.

Record production levels occurred consecutively across the first 3 quarters of 2021, and the first 2 quarters of 2022 exceeded these levels to set new records.

Gas production in the northern states again rose to record levels in the fourth quarter of 2021 alongside unprecedented high LNG prices (figure 4.4) and record LNG exports (figure 4.10) from Queensland.[210] These export levels were also supplemented by northern gas storage supply and strong gas flows north from southern production sources (Figure 4.18).

In 2021 AEMO reported the accelerated decline of anticipated production in key southern fields,[211] with updated forecast predicting a 36% decrease from 2022-2026.[212] Despite committed new supply contributing an additional 30 PJ (or 100 TJ per day over winter) from 2023, the largest reduction in Gippsland's legacy fields is forecast to occur prior to winter 2023 (section 4.9.1).[213] The depletion of these fields is expected to place immense pressure on the southern markets on peak demand days.

Production in Gippsland is transitioning from old to new fields, but it is not yet clear how much the new gas fields can produce. Production from the Longford plant has been falling and the plant is becoming less reliable with plant constraints and maintenance outages increasingly disrupt production.

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. AEMO and the ACCC have identified the ongoing depletion of southern gas fields as a significant risk to supply in the coming years.

Following government intervention in 2017, LNG producers diverted more gas to the domestic market. Over 2019 and 2020, Surat–Bowen Basin production increased (9%), largely matching LNG export growth (10%), while southern basins decreased by a similar proportion (10%). Over 2021, strong southern supply and gas flows north to support high exports coincided with export levels growing more than Queensland production increases. The drawdown of southern supply has led to a projected shortfall in the south for 2022 and contributed to a 19 PJ surplus in the

210 AER, Wholesale markets quarterly – Q4 2021, February 2022, p v, Queensland exports over 2021 exceeded the previous year's record by about 5%.

211 AEMO, 2021 Victorian gas planning report, March 2021.

212 Total available supply from Gippsland fields is forecast to decline 36% from 312 PJ in 2022 to 200 PJ in 2026, driven by an increase in production from already producing Longford fields and committed new supply from the Kipper field. AEMO, 2022 Victorian gas planning report, March 2022, p 49.

213 Notwithstanding the increase, available Victorian production is forecast to be less than monthly winter consumption (28-30 PJ per month) from winter 2023. ibid, p 52.

north. Projected domestic supply from LNG exporters has also decreased by 52 PJ to half the level of actual supply provided in 2017 and 2018.[214]

4.5.2 Gas storage

Storage facilities have the ability to store surplus gas produced in summer for use during higher demand winter periods, providing supply flexibility and quick delivery capability to meet peak demand requirements. Refill and drawdown rates for these facilities can be impacted by connected pipeline capacity and low storage levels, limiting the amount of gas in storage that can be replenished or delivered. Eastern Australia's gas storage capacity includes:

- large facilities using depleted gas fields in Queensland, Victoria and South Australia:
  - Iona underground storage (Victoria) has a nameplate storage capacity of 23.5 PJ, with a delivery capability of 545 TJ per day[215] – this is the second largest supply source in the south and has the ability to deplete and refill at a much higher rate than other east coast storage facilities
  - Moomba Lower Daralingie Beds (LDB) storage (South Australia) has a nameplate storage capacity of 70 PJ, with a delivery capability of under 15 TJ per day[216]
  - Silver Springs storage (Queensland) has a nameplate storage capacity of 46 PJ, with a delivery capability of 25 TJ per day[217]
  - Roma Underground Gas Storage (RUGS, Queensland) has a nameplate storage capacity of 54 PJ, with a delivery capability of up to 58 TJ per day[218]
- LNG storage in smaller seasonal or peaking facilities located near demand centres – for example, the Newcastle LNG facility in NSW and the Dandenong LNG facility in Victoria[219] – these facilities have relatively high supply rates, but depletion cannot be sustained for many days due to slow refill rates
- short-term peak storage services on gas pipelines, which are mostly contracted by energy retailers – for example, the Tasmanian Gas Pipeline 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, with some storage facilities drawn down to meet LNG export demand and replenished when prices were low. Large gas customers (particularly retailers) have secured their own storage capacity to manage supply risks and seasonal demand. Average storage levels increased over 2020, but steady depletion over 2021 drew down storage to the lowest levels since reporting began. This brought average storage levels below 40% of capacity in late 2021 (Figure 4.13).[220] Iona has replenished significantly into 2022, but draw down of supply from the other large facilities has continued, with declining pressure in the storage wells adding to constraints on supply capability.[221] This winter, Iona storage levels have reduced to lows similar to 2021 in July and Newcastle gas storage reduced all the inventory in their LNG storage tank for the first time since the facility started operating.

214 ACCC, Gas inquiry 2017–2025, interim report, January 2022, February 2022, p 19-21.

215 The maximum supply rate achieved in 2021 with a nameplate capacity of 530 TJ per day was 455 TJ.

216 Progressive depletion of storage levels has reduced delivery capacity to 10 TJ per day from late 2021, with current delivery capabilities now sitting around 6 TJ per day since April.

217 Silver Springs delivery outlooks reduced to around 10 TJ per day from mid-October 2021, and has been sitting around 8 TJ per day or lower over most of 2022.

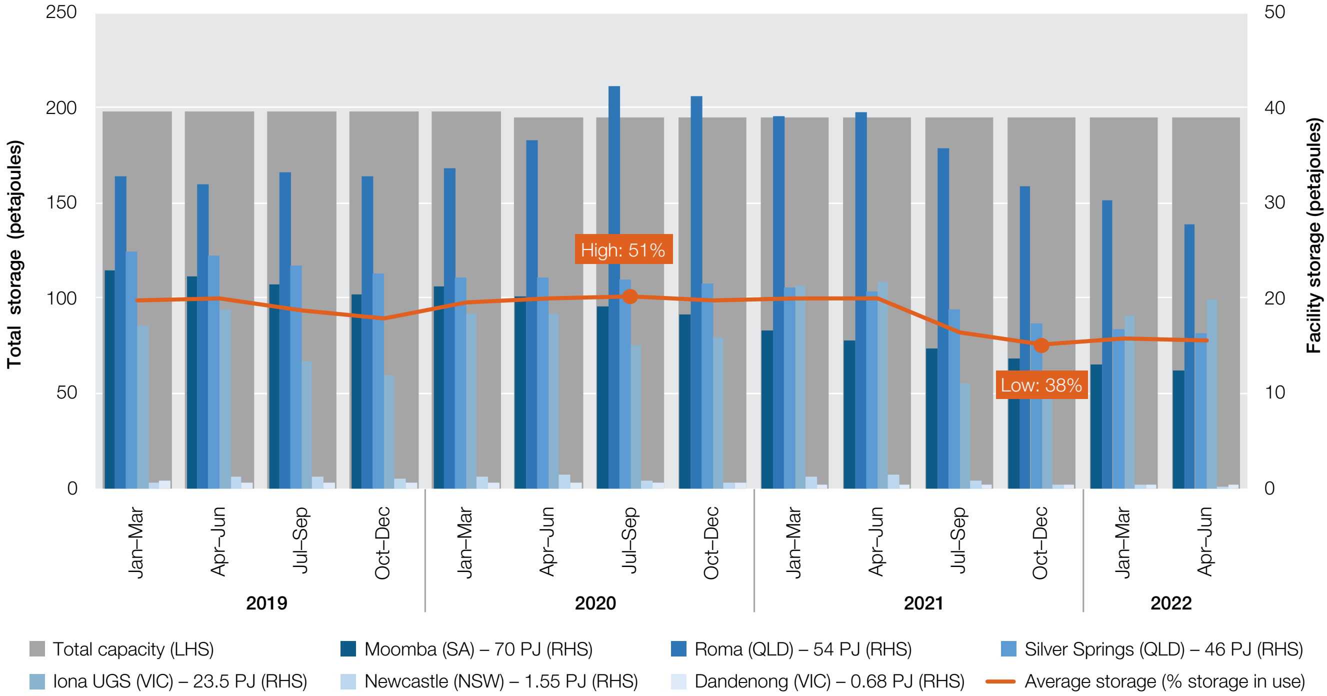
218 Following the continuing depletion of storage levels, short-term outlooks progressively reduced delivery capacity to 50 TJ per day as storage declined to 30 PJ (from 16 March), then 40 TJ per day as storage dropped to 27.6 PJ (from 27 May).

219 The Dandenong LNG storage facility reached record low levels in 2021 (since the commencement of the Declared Wholesale Gas Market in 1999), driven by a reduction in contracted capacity for winter.

220 With the exception of Iona, storage levels fell to record lows across all east coast facilities.

221 Moomba for example, has reduced its nameplate supply capability from 100 TJ per day when it commenced reporting in late 2016, with current storage levels below 13 PJ limiting its physical injection capacity as low as 3 TJ per day over June.

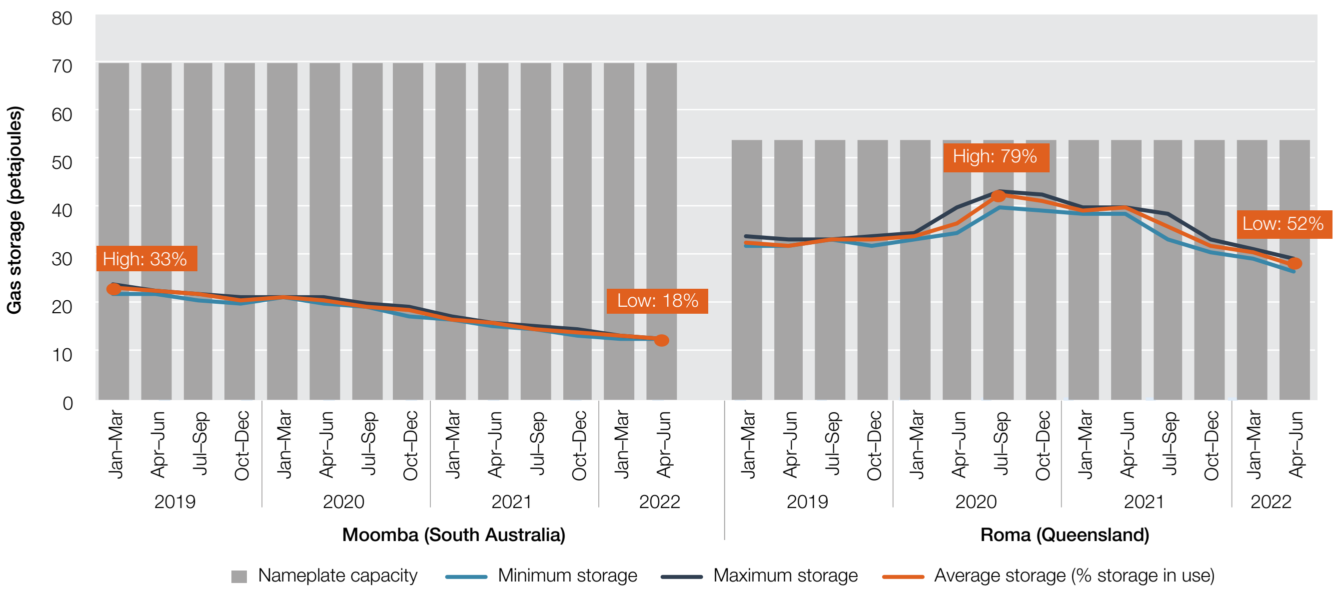
Figure 4.13 Gas storage in eastern Australia



Note: Petajoule (PJ) value next to each facility reflects nameplate capacity.

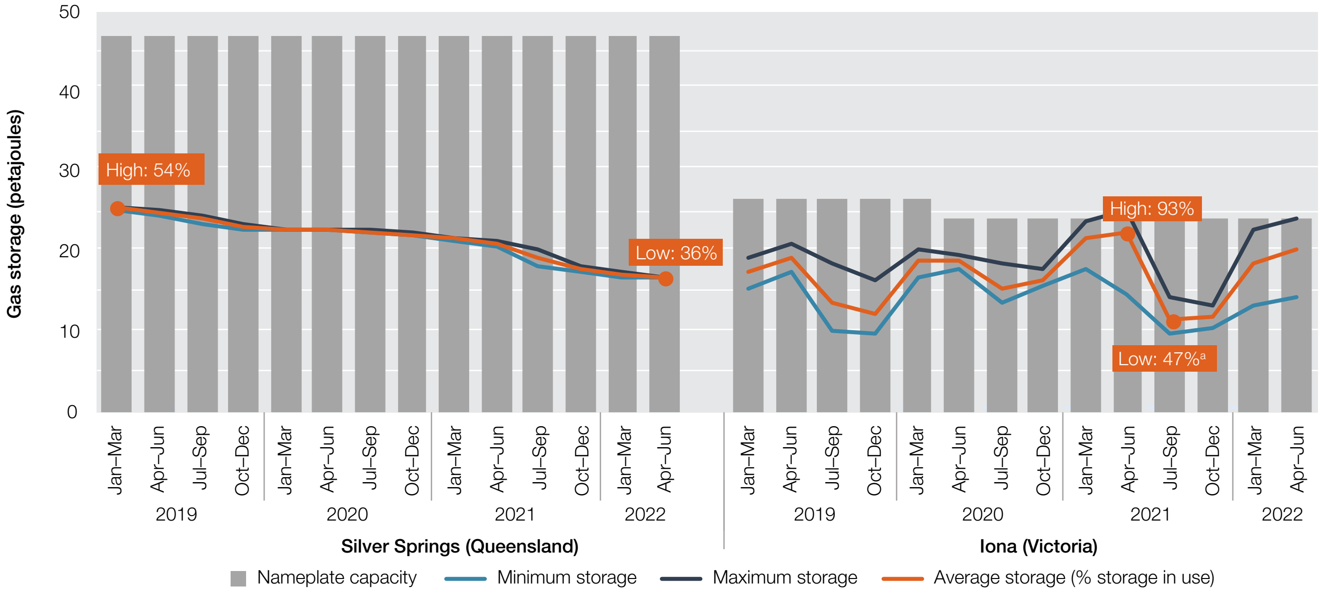
Source: AER analysis of Gas Bulletin Board data.

Figure 4.14 Large gas storage facilities – Moomba (South Australia), Roma (Queensland)



Source: AER analysis of Gas Bulletin Board data.

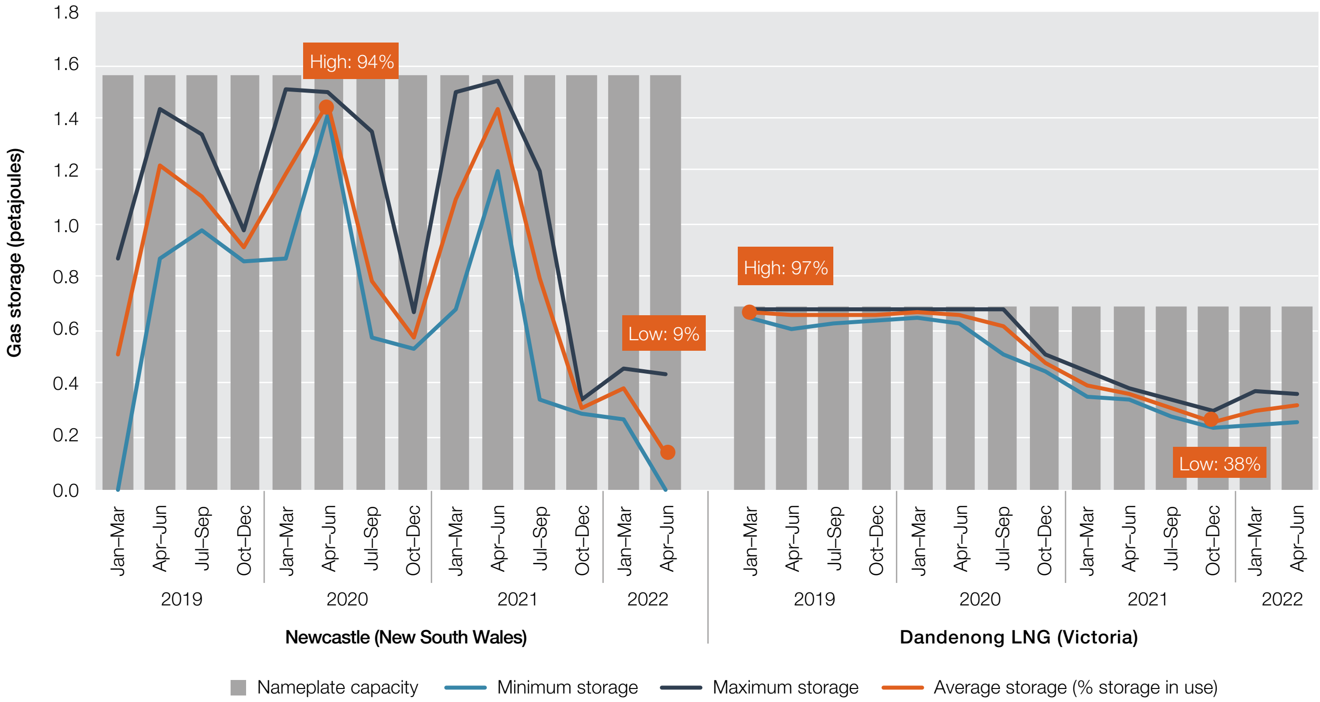
Figure 4.15 Large gas storage facilities – Silver Springs (Queensland), Iona (Victoria)



Note: a Lower storage inventory, lower proportionally for October – December 2018.

Source: AER analysis of Gas Bulletin Board data.

Figure 4.16 Small LNG gas storage facilities – Newcastle (NSW), Dandenong (Victoria)



Source: AER analysis of Gas Bulletin Board data.

Investments to develop or expand storage capacity are under way.[222] Lochard Energy expanded Victoria's Iona facility in 2018 and made further improvements to the gas processing facility that became operational in 2021 and 2022.[223] This operates more dynamically than other storage facilities, with a larger capacity to inject and withdraw gas on any given day. Further expansion of storage capacity is currently taking place[224] and supply capacity is expected

222 ACCC, Gas inquiry 2017–2025, interim report, January 2021, February 2021, p 53.

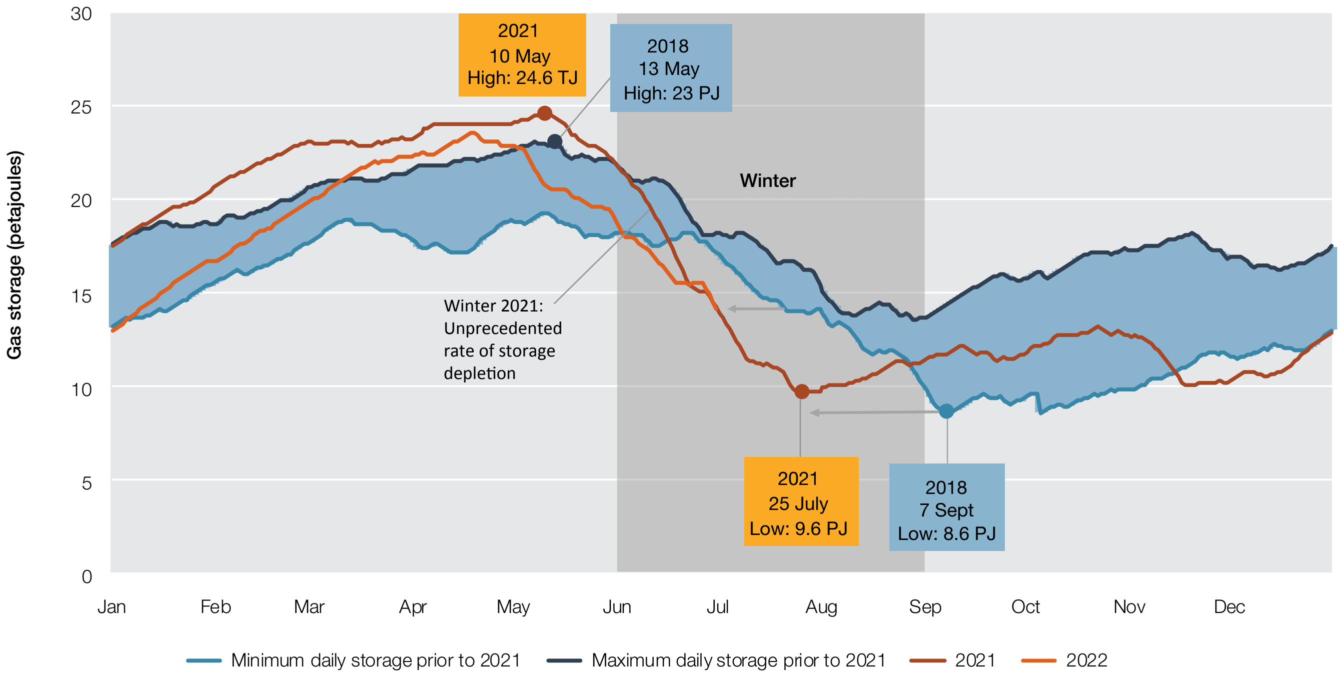
223 Following Lochard's takeover from EnergyAustralia in 2015, storage capacity has expanded significantly from a 390 TJ per day supply capacity to 530 TJ per day (17 March 2021) and 545 TJ per day (28 January 2022).

224 Lochard Energy, Seamer 2 Project – Community Update, 28 January 2022.

to increase from 545 TJ per day to 570 TJ per day in 2022. However, this capability is currently limited by existing pipeline capacity.[225]

In recent years, Victoria has become increasingly reliant on gas storage inventory from Iona. In 2021, storage levels fell to their lowest point since reporting commenced, with a similar trend occurring for winter 2022 heading into July leading AEMO to issue a notice of a threat to system security.[226] Recent upgrades have improved supply rates; however, this has also led to storage inventory being drawn down quicker than previous years. With supply reducing to these low levels earlier into winter (minimum levels have historically been observed from the end of winter), there is an increasing risk of supply being insufficient to meet demand on peak days.

Figure 4.17 Iona underground storage, low storage levels in winter 2021 and 2022



Further to this, the much smaller Dandenong LNG storage facility fell to particularly low levels in June, with recent drops in participants contracting the emergency supply. While much smaller than Iona, the facility plays an important role in mitigating curtailment during potential supply shortfalls, providing critical system security to avoid pressure drops at the Dandenong city gate. There is very high potential for the facility being needed next year as supply at Longford drops off. In August 2022, Energy Ministers submitted an urgent rule change to give the AEMO power to contract underutilised LNG storage capacity in Victoria before winter 2023.[227]

4.6 Inter-regional gas trade

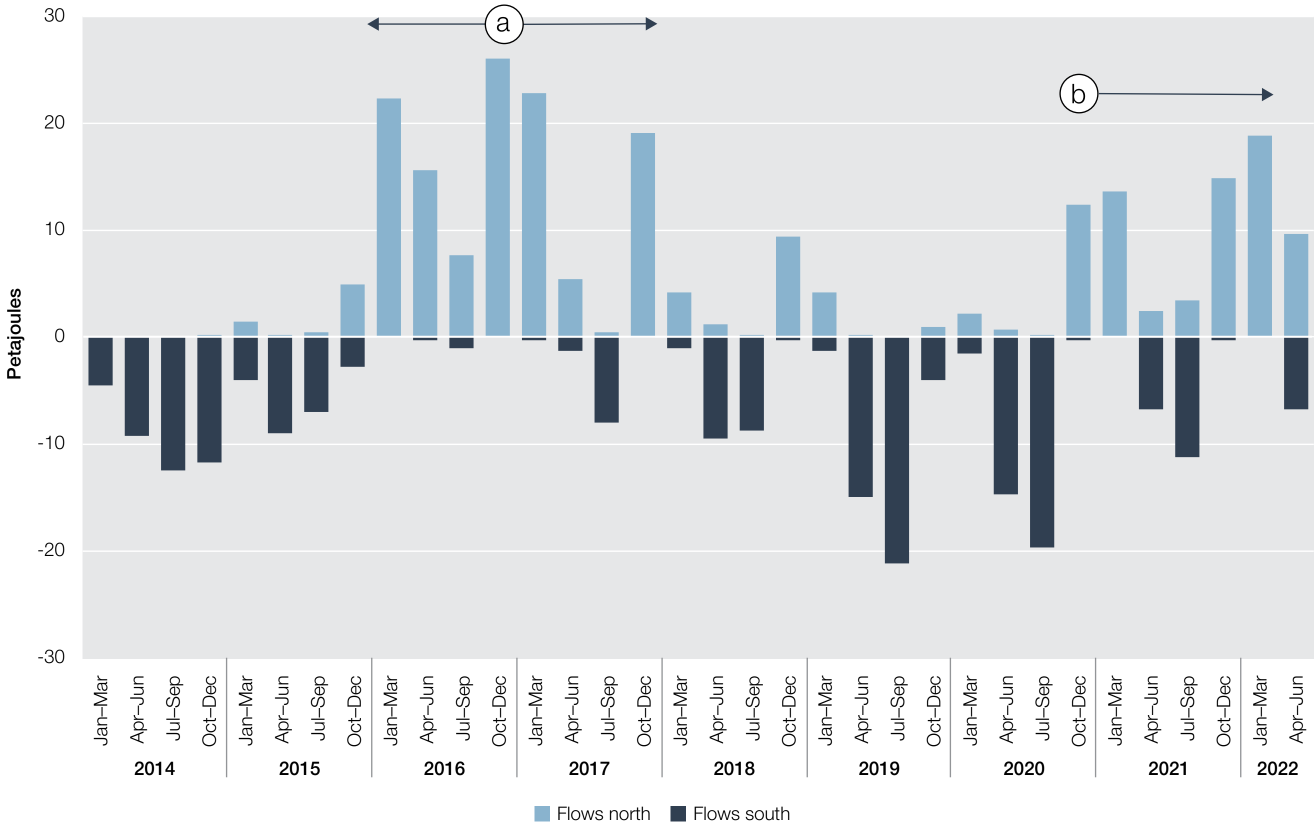
Domestic gas typically flows south in the Australian winter (to meet heating demand) and north in the Australian summer (the northern hemisphere winter) when Asia's LNG demand peaks (Figure 4.18).

225 The South West Pipeline (SWP) is currently undergoing upgrades to increase pipeline capacity that will support higher injection rates from the Iona storage facility. Further expansion of the storage facility could raise supply capacity to 600–700 TJ per day.

226 The AEMO notice was issued on 11 July, indicating the facility at current usage rates would decrease to 6 PJ by 31 July. This would result in reduced injection capability due to low pressure, increasing the risk of curtailment on peak demand days.

227 Energy Ministers Meeting, Communique, 12 August 2022.

Figure 4.18 North–south gas flows in eastern Australia



Note: Flows on the QSN (Queensland / South Australia / New South Wales) Link segment of the South West Queensland Pipeline (flowing through the Moomba location).

[a] 2016-2017: Increased southern production to meet LNG demand

[b] late 2020 onwards: record LNG exports continue to rise

Source: AER analysis of Gas Bulletin Board data.

From the last quarter of 2020, gas flows north increased to the highest level observed over the previous 3 years, in line with increases to east coast LNG export demand (figure 4.10). Flows north increased the following quarter, with larger increases the following year over October to March, while mid-year flows south have notably reduced from 2019 and 2020 levels. The day-ahead auction supported the turnaround in late 2021 as participants bought capacity on routes north. On the South West Queensland Pipeline 95% of all capacity purchased in the fourth quarter of 2020 was on routes north towards Wallumbilla. Recent activity on the auction has reversed this trend, with 61% over the January-March quarter and 85% over the April-June quarter of 2022 won on SWQP routes to transfer supply into southern markets. Since the invocation of the GSG, 99.5% of capacity has been procured through the auction over June to physically transport gas south (section 4.6.2).[228]

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.[229] 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 meet demand in southern Australia.[230] 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 4.12.1).

228 Over the April-June quarter, physical flows moved 6.2 PJ of gas north in April, falling to 3.1 PJ in May. Flows reversed in late May to transport 6.2 PJ of gas south over June. This coincided with AEMO invoking the gas supply guarantee for the first time in early June (section 4.11.2).

229 Santos, 'Santos facilitates delivery of gas into southern domestic market' [media release], August 2017.

230 EnergyQuest, EnergyQuarterly, March 2020.

4.6.1 Gas transmission pipelines

Supply conditions 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 2021 APA announced the first stage of an expansion of the South West Queensland Pipeline and Moomba to Sydney Pipeline to increase delivery capacity from northern fields to southern markets (section 4.9.3).

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 pipeline routes are shown in Figure 4.1). Dozens of smaller pipelines fill out the transmission grid.

The eastern gas market's transmission system has evolved from a series of point-to-point pipelines, each transporting gas from a producing basin to a demand centre, into an integrated network. Many gas pipelines became bidirectional, and gas increasingly flows across multiple pipelines to reach its destination. Additionally, the Northern Gas Pipeline provides eastern Australia's pipeline interconnection with the Northern Territory (section 4.9.5). Access to capacity on key pipelines is important.

Gas production and transmission pipelines assets are owned by separate 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 4.6.2).

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 bidirectional and backhaul shipping, and park and loan services.[231]

Investments to develop or expand transmission capacity are underway (section 4.9.3).

Pipeline ownership

Australia's gas transmission sector is privately owned (chapter 5). The publicly listed APA Group is the largest owner of pipeline assets, with equity in 13 major pipelines, including key routes into Melbourne, Sydney, Brisbane and Darwin. Another major pipeline owner with equity in numerous pipelines is Jemena. The pipelines fall under a range of different regulatory arrangements spanning full regulation to light or no regulation (Table 5.2).[232]

4.6.2 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.

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.

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 most settlements have occurred at no cost.[233]

231 Pipelines with bidirectional 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.

232 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.

233 While participants can win capacity for $0 per GJ, additional charges and registration fees make the real cost slightly higher.

Pipeline capacity trading (day-ahead auction)

In 2022 the AER reported on the continued increase in the popularity of the day-ahead auction.[234] Over the past 3 and a half years over 160 PJ of contracted but nominated pipeline capacity has been won on the Auction across 14 of the 22 auction facilities (since it commenced in March 2019, in conjunction with the Capacity Trading Platform).[235]

Around 80% of all capacity procured was won at the reserve price of zero dollars, and almost 80% of this capacity has been won on 4 key pipelines: the South West Queensland Pipeline (SWQP) and Moomba Sydney Pipeline (MSP) which facilitate gas flows south and north between spot markets; the Eastern Gas Pipeline (EGP) and the Roma Brisbane Pipeline (RBP) which facilitates flows to gas-powered generators.

Over the April – June quarter of 2022, auction quantities exceeded the previous record quarterly trade level by 36%, reaching 20.9 PJ. Of this capacity, 9.4 PJ was traded on gas routes that transport gas between northern and southern markets (SWQP/MSP), while the RPB also saw record trade (3.1 PJ).

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.[236]

The AER's *Pipeline capacity trading – 2 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 NEM.

However, auction activity on some pipeline remains low. In particular, the AER reported on the limited trade on the Moomba to Adelaide Pipeline and SEA Gas Pipeline System supplying the Adelaide market, although participation is increasing.[237] 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 most 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.

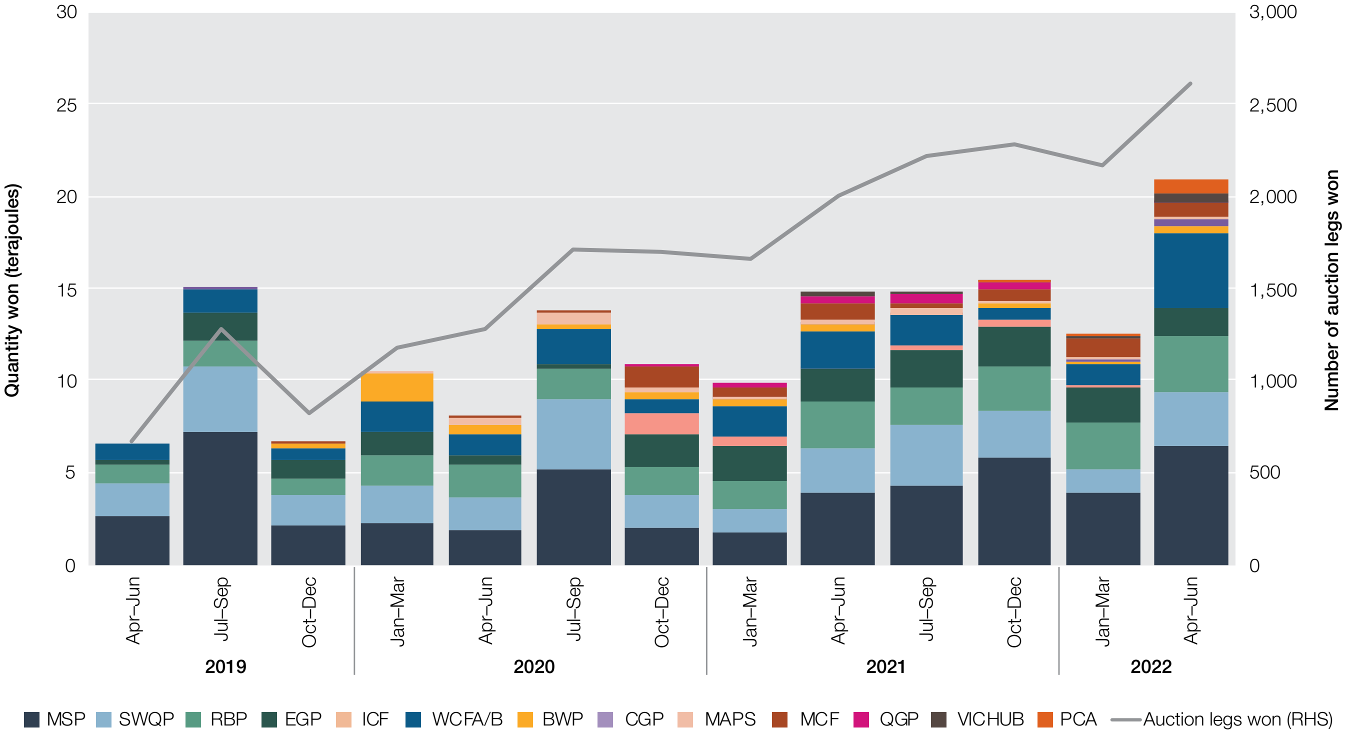
234 AER, Wholesale markets quarterly - Q1 2022 (Pipeline capacity trading update), May 2022, pp 37-48.

235 There has been no significant activity on the voluntary trading platform since its introduction.

236 AER, Pipeline capacity trading – two year review, March 2021, p 23.

237 The Port Campbell to Adelaide pipeline (SEA Gas) had 816 TJ of capacity traded over April – June 2022, the first significant quantity since the auction commenced.

Figure 4.19 Day-ahead auction quantities won, by facility



Note: 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; PCA: Port Campbell to Adelaide Pipeline; QGP: Queensland Gas Pipeline; RBP: Roma to Brisbane Pipeline; SWQP: South West Queensland Pipeline; VicHub (eastern Victoria); WCFA/B: Wallumbilla compression facilities.

Source: AER analysis of day-ahead auction data.

4.7 Trade in east coast gas markets

Gas markets were more liquid in 2021 than in the previous year, with trade levels in the gas supply hub rebounding and trading activity on the day-ahead auction continuing to grow.

In the first half of 2022 the drawdown of southern production reserves left those states more reliant on Queensland gas supplies going forward, yet gas continued to flow north in April and May despite increasing market volatility.

Domestic gas prices increased significantly in April 2022 ahead of the increased southern demand for gas heating over winter, with significant price increases occurring over the following months.[238]

Due to the continued upwards pressure on Victorian and short term trading market prices, and administered prices being applied in Brisbane and Sydney (following the suspension of a market participant) and Victoria (due to high prices), distorted price outcomes and participants wanting to hold on to contracted supply led to reduced supply offers. This compelled contingency market outcomes to mitigate the risks of short-term gas supply shortfalls (involuntary curtailment of uncontrollable load) from late May.

Uncertainty around the availability of sufficient supply levels beyond 2022 has also coincided with delays in bringing new supply sources online.

4.7.1 Victoria's declared wholesale gas market (DWGM)

Around 40 participants traded in the Victorian market in 2021. The market's participants include energy retailers, power generators and other large gas users, and traders.

Like the STTM, volumes traded in the Victorian market rose by 39% in 2021. 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

238 Potential upcoming shortfalls in southern gas supply, due to depleted legacy gas reserves in the Gippsland Basin, may be driving suppliers to set higher prices to limit further run-down of existing supply prior to a possible significant southern supply shortfall over winter 2023. Considering underlying contract positions reviewed in previous ACCC gas inquiry reports, local contract links to international oil and gas prices would potentially be impacted to some extent by international price increases following Russia's invasion of the Ukraine.

operators of gas-powered generation, but other participants have been increasing their deliveries recently, facilitated by the day-ahead auction.

The volume of trade in the Victorian gas futures market increased by 17% in 2021 from the previous year. Ultimately this increase still accounts for only a small proportion (less than 5%) of the total volume traded in the market.

4.7.2 Gas supply hubs (GSH)

In 2021, 17 participants traded at the gas supply hubs, all of which were active, with the entrance of a broker participant also facilitating off market trading.[239] LNG export businesses and gas producers were among the most active participants in 2021, closely followed by gentailers.[240] 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 absorb. Other participants include large industrial users and traders.

In 2021, 16 participants traded on-screen, with 15 actively trading. Similarly, 18 participants traded off-screen, with 17 of them active. On average, participants executed around 190 trades per month in 2021 – a reduction of 13% from 2020.

Wallumbilla hub activity

Users of the Wallumbilla hub include the LNG projects, gas-powered generators and, more recently, trader participants taking advantage of the day-ahead auction to arbitrage prices between Wallumbilla and the downstream markets.

Following a liquidity reduction in 2020, driven primarily by a collapse in on-screen trading, trading rebounded in 2021 with significant growth in off-screen activity (Figure 4.20). Notably, off-screen products tend to involve larger volumes of gas than do on-screen alternatives. In 2022 off-screen trade levels hit a record high, with 8.9 PJ traded in the April-June quarter, driven by higher volumes being traded for longer-term deliveries, including monthly product and strip trades of daily products.[241]

However, ultimately, 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 2021 gas traded through the Wallumbilla hub accounted for 8.8% of total gas flows through pipelines in the Wallumbilla bulletin board zone.

Moomba hub activity

Trade at Moomba has been slow to develop. 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, declining further in 2021.

Victoria and Sydney activity

Trade levels at the Culcairn (Victoria) and Wilton (Sydney) trading locations have occurred in small volumes, reaching a total of 212 TJ and 796 TJ respectively to date.[242]

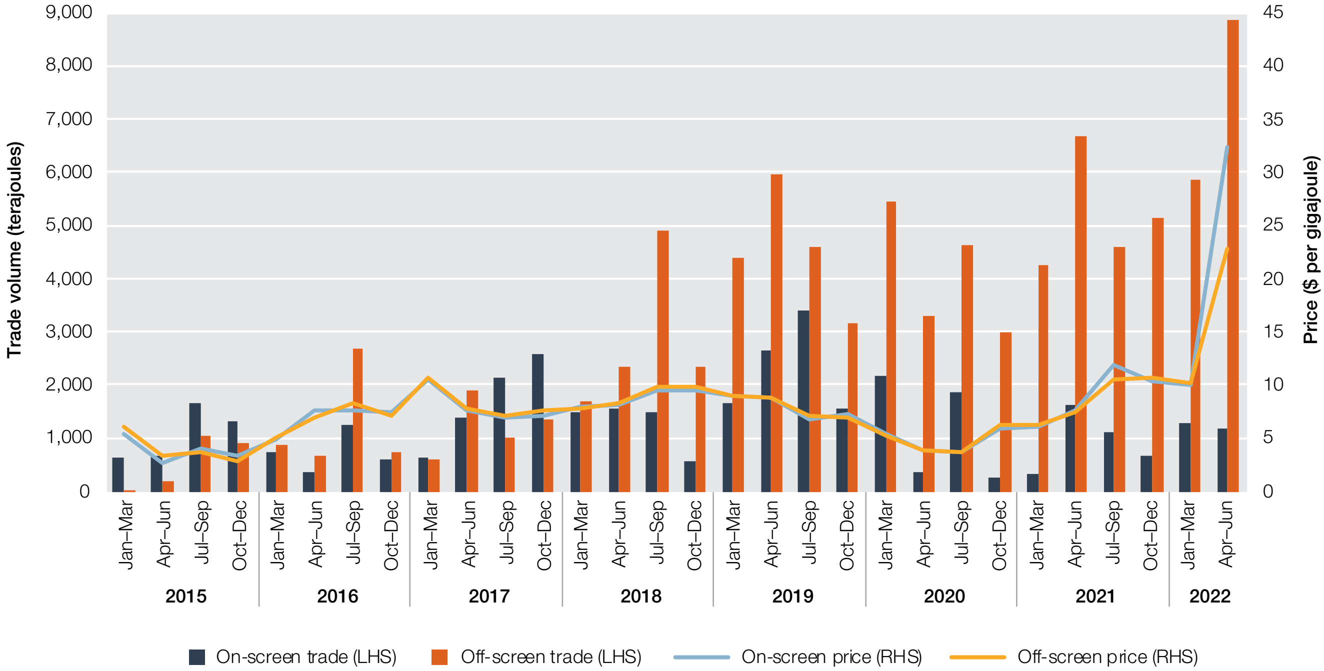
239 We consider a participant 'active' if it makes at least 12 trades in a year. The broker is not included as an active trader.

240 Gentailers are participants that own electricity generation assets and retail market portfolios.

241 Strip trades, introduced in late 2020, allow participants more flexibility, providing the ability to bundle a string of daily products together over a selection of days, which can be traded further out (for delivery periods similar to monthly products).

242 Quantities traded from 2021 up to 30 June 2022.

Figure 4.20 Gas supply hub – on-screen and off-screen price and volume



Source: AER analysis of gas supply hub data.

4.7.3 Short term trading market (STTM)

In 2021 around 38 participants traded in the Sydney STTM, and the Adelaide and Brisbane markets had around 26 and 23 participants, respectively. The participants included energy retailers, power generators, large industrial gas users and traders. The markets are particularly useful for gas-powered generators because they 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 2021, gas traded through the STTM met nearly 24% of demand in Sydney, 20% in Adelaide and around 10% in Brisbane.[243]

Traded volumes at the Sydney market were 19% higher in 2021 than in 2020 and 64% higher at the Brisbane market in 2021. Spot trade in the Adelaide market remained at the same level. The increased spot trade in the Sydney and Brisbane markets has been driven by higher sales volumes from large gas producers, including LNG exporters. In particular, Santos, BHP and Esso have been prominent sellers in recent years.

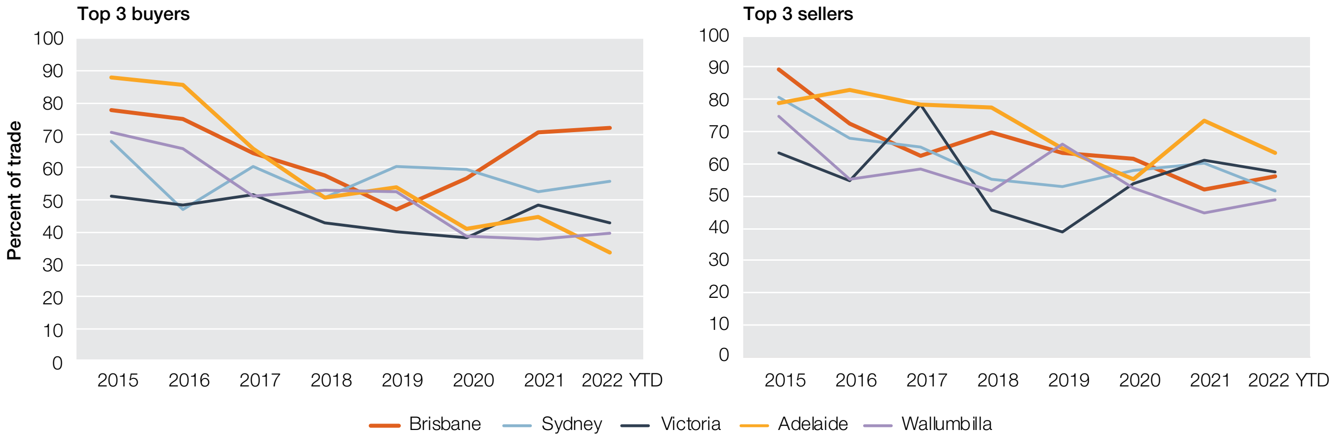
Trading profiles varied across the markets. Concentration across the top 3 sellers fell in Adelaide, Victoria and Sydney from 2021 to 2022 but rose in Brisbane and Wallumbilla (Figure 4.21). Among the top 3 buyers, concentration increased in Brisbane, Sydney and Wallumbilla. Concentration fell in Adelaide and Victoria for the same period. Importantly, the diversity of large suppliers participating in the spot markets is increasing. Similarly, in 2021 trader participants increased their share of gas scheduled into the STTM to record levels. These participants took advantage of cheap capacity won on the day-ahead auction to arbitrage prices between markets.

In 2021 participants used the STTM more heavily, with industrial participants being prominent gas purchasers. Industrial participants accounted for around 24% of trade in the STTM in 2021, compared with around 16% in 2020.

Despite traditionally benefiting from lower spot prices, high spot market exposure can be highly risky for spot market participants. From 1 January to 30 June 2022, spot prices ranged between $6.10 per gigajoule (GJ) and $53.60 per GJ. Over 2021, contract offers for gas delivery in 2022 were between $8.60 per GJ and $11.15 per GJ.

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

Figure 4.21 Top 3 buyers and sellers in eastern Australian gas markets



Note: Year-to-date (YTD) to 30 June 2022.

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

4.8 Development of gas import terminals

Currently, there are no importation terminals operational on the east coast of Australia. This means that Australia currently can export but not import LNG.

In early 2021, 5 LNG import terminals projects were under consideration in NSW, Victoria and South Australia. The intention was to resolve a forecast shortfall in gas supply in the southern states from winter 2023. However, delays have pushed out the potential availability of import supply to winter 2024.

The LNG import projects include:

- Australian Industrial Energy's (AIE) committed terminal at Port Kembla (NSW), which was initially scheduled to commence operating from late 2022.[244] The terminal received planning approval from the NSW Government in April 2019 and EnergyAustralia later signed as a foundation customer.[245 246] The expected commissioning of the facility was delayed and is now expected in late 2023, with gas supply anticipated for winter 2024.[247] Squadron Energy, the private company building the import terminal, has lined up the Hoegh Galleon floating storage and regassification unit (FSRU), but had not lined up gas supply by late March.[248] The facility has planning permission for 130 petajoules (PJ) per year of LNG supply.[249]
- Venice Energy's proposed terminal at Port Adelaide, scheduled to launch by the end of 2022.[250] In late 2020 Venice announced it signed its first customer, as well as advancing a project agreement with Flinders Ports for development of the facility.[251] The project received approvals from the South Australian Government in December 2021 and is on track to begin construction in the second half of 2022 to deliver gas by winter 2024.[252] The terminal would offset supply from the Moomba to Adelaide and SEAGas pipelines providing gas from Moomba (South Australia) and Port Campbell (Victoria). Venice Energy will conduct a feasibility study to upgrade the SEAGas pipeline to flow gas bidirectionally, to enable supply into Victoria.[253]
- 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 awaiting state approval. The project would require duplication of

244 EnergyQuest, EnergyQuarterly, March 2021, p 27.
245 NSW Government, 'Port Kembla gas terminal approved' [media release], April 2019.
246 AIE and EnergyAustralia, 'AIE welcomes foundational customer EnergyAustralia' [media release], May 2019.
247 AEMO, 2022 gas statement of opportunities, March 2022, p 56.
248 Reuters, UPDATE 1-Australia's first LNG import terminal seen ready by late-2023, 22 March 2022.
249 AEMO, Gas statement of opportunities, March 2022, p 74.
250 Venice Energy, 'South Australian LNG import facility advancing' [media release], November 2020.
251 Venice Energy, 'Project agreement signed for LNG import facility at Outer Harbor' [media release], November 2020.
252 Venice Energy, LNG import terminal granted development approval, December 2021.
253 Supply to Victoria would be limited by capacity on the South West Pipeline.

the South West Pipeline.[254] Viva is expected to make a final investment decision on the project by the end of 2022. The terminal is forecast to supply 140 PJ per year with a capacity of 500 to 600 TJ per day.[255]

- Vopak's import terminal in Port Phillip Bay in Victoria. Vopak is considering the feasibility of the terminal and indicated that several gas market participants had signed memoranda of understanding in support of the project.[256]
- Newcastle GasDock, proposed by Energy Projects and Infrastructure Korea. The NSW Government in August 2019 designated the project as critical significant infrastructure.[257] The facility would require multiple pipeline upgrades, expansions or duplications and is not expected to be operating before 2024.[258] While a final investment decision was expected to be made in September 2022, there has been no recent announcements regarding this proposed project.[259 260]

In May 2021 AGL ceased development on its proposed floating terminal at Crib Point (Victoria).[261] This followed a determination in March 2021 by the Victorian Minister for Planning that the proposed terminal would have unacceptable environmental effects.[262] Another project backed by ExxonMobil was abandoned in December 2019.

4.9 Market responses to supply risk

Concerns about potential gas shortfalls have prompted a range of potential market responses. These include further gas development, LNG imports, transmission pipeline solutions and demand response.

4.9.1 Gas field development

Numerous projects are progressing that could bring additional supply to the domestic market:

- In Victoria, Cooper Energy commenced producing supply at the Athena gas plant (formerly Minerva) from mid-December 2021, taking gas from the Casino field that was previously processed at Iona.[263] The new production source processes gas from the Otway Basin's Casino, Henry and Netherby fields, with average production providing around 25 TJ per day since completion of the project.
- Development of the Gippsland Basin Kipper field is also progressing, with additional supply committed from 2024[264] and additional investment announced at the ADGO conference to develop and produce gas from the Kipper and Turrum fields over the next 5 years.[265] However, the depletion of supply from legacy fields contributing to the largest southern source of production has resulted in the decommissioning of fields in the Bass Strait[266], resulting in a significant drop in expected production levels from 2023.
- An increase to Port Campbell production was driven by Beach Energy committing to the development of Geographe, and Thylacine North and West fields, including the drilling of 6 new production wells.[267] Drilling commenced in February 2021 and was completed in July 2022.[268] This followed the successful drilling of the Enterprise-1 well in November 2020 and is expected to assist in returning the Otway Gas Plant to its nameplate capacity of 205 TJ per day.
- Work on existing wells in the Yolla field are also anticipated in the June to September quarter of 2022, with Trefoil supply anticipated from 2025 to increase supply to the Lang Lang Gas Plant (BassGas).[269]

254 AEMO, Gas statement of opportunities, March 2022, p 57.

255 Viva Energy Australia, Viva Energy Gas Terminal Project EES Referral, March 2020.

256 Vopak, 'News: Vopak LNG studies feasibility to develop LNG import terminal for Victoria' [media release], March 2021.

257 NSW Government, 'Newcastle gas terminal given critical status' [media release], August 2019.

258 AEMO, Gas statement of opportunities, March 2022, p 57.

259 ACCC, Gas inquiry 2017–2025, interim report, January 2021, February 2021, p 65.

260 EnergyQuest, EnergyQuarterly, December 2021, p 29.

261 AGL Energy, 'Confirmation of Crib Point impact' [media release], May 2021.

262 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.

263 AEMO, 2022 Victorian gas planning report, March 2022. p 70.

264 ExxonMobil, Esso Australia to Expand Gas Development in the Gippsland Basin, 17 March 2022.

265 ExxonMobil, Opportunities for the Gippsland Basin and Australia's energy transition, 22 March 2022.

266 ExxonMobil, Esso Australia commences technical tender for Bass Strait decommissioning, 17 June 2022.

267 Beach Energy, Otway Offshore Project, 2020-2023 Program, June 2021.

268 ASX Announcement, Otway drilling campaign complete, 12 July 2022.

269 AEMO, 2022 Victorian gas planning report, March 2022. pp 70–71.

- In NSW, Santos proposed to develop 850 wells across its 95,000 hectare Narrabri gas project, which has the potential to supply up to 200 TJ per day.[270] An appeal against the project's approval[271], which delayed the project by 12 months, was dismissed following an unsuccessful challenge. The staged development is expected to provide up to 55 PJ per year in 2026, all of which is voluntarily committed to the domestic market.[272]
- In Queensland, APLNG started an expansion in the Surat Basin to bring 7 PJ per year online from its Murrungama field from 2022. This gas is subject to an Australian domestic manufacturing supply condition.[273]

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.[274] Victoria, South Australia, Tasmania, Western Australia and the Northern Territory have onshore fracking bans in place, with varying degrees of coverage:

- The Victorian Government banned onshore hydraulic fracking and exploration for and mining of CSG or any onshore petroleum until 30 June 2020.[275] In March 2021 the government committed the ban on fracking and CSG exploration to the Victorian Constitution.[276] 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.
- 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.[277]
- The Northern Territory has 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.
- 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.[278] 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.[279] 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.[280]

4.9.2 Liquefied natural gas import terminals

To address future supply concerns, the industry was considering numerous projects to develop LNG import facilities on the east coast. Each project would involve importing LNG through floating storage and regasification units.

- Australian Industrial Energy's (AIE) committed terminal at Port Kembla (NSW) is expected to provide gas before winter 2024. In 2021 AIE and Jemena signed a project development agreement to connect to the Eastern Gas Pipeline, with modifications set to allow bidirectional flows to deliver gas to Sydney and Victoria (section 4.9.3).
- Venice Energy's proposed terminal at Port Adelaide (South Australia) is projected to potentially supply gas by winter 2024. However, gas deliveries to Victoria are currently constrained due to the SEAGas Pipeline, currently only able to flow gas out of Victoria, and the limited available capacity on the South West Pipeline.

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270 Santos, Narrabri Gas Project, Santos website, accessed 28 May 2021.

271 The project was approved by the NSW Independent Planning Commission and the Australia Government. Santos, 'Santos welcomes federal signoff on Narrabri Gas Project' [media release], 24 November 2020.

272 EnergyQuest, EnergyQuarterly, March 2022, p 133.

273 ACCC, Gas inquiry 2017–2025, interim report, January 2022, February 2022, p 55.

274 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.

275 Department of Economic Development, Jobs, Transport and Resources (Victoria), Onshore gas community information, August 2017.

276 Victorian Government, 'Enshrining Victoria's ban on fracking forever' [media release], March 2021.

277 Department of State Growth (Tas), Tasmanian Government policy on hydraulic fracturing (fracking) 2018, DSG website, accessed 28 May 2021.

278 Department of Planning and Environment (NSW), Initiatives overview, July 2018.

279 Department of Planning and Environment (NSW), 'Community views on Narrabri Gas Project to be addressed' [media release], 7 June 2017.

280 Prime Minister of Australia and Premier of New South Wales, 'NSW energy deal to reduce power prices and emissions' [media release], January 2020.

- Viva Energy's Geelong (Victoria) Gas Terminal project is projected to deliver gas as early as 2024. The project would require the duplication of the South West Pipeline. Viva is expected to make a final investment decision on the project by the end of 2022.
- Vopak's import terminal in Port Phillip Bay (Victoria) is undergoing a feasibility assessment.

4.9.3 Transportation capacity expansion

To assist with reducing existing gas supply transportation constraints, pipeline expansions have been progressing to bring more gas south from Queensland, bring more gas from western Victoria into Melbourne, and provide upcoming import supply with the ability to provide gas to New South Wales and Victoria.

South West Queensland and Moomba to Sydney pipelines project

APA has been expanding the pipeline corridor through Queensland into New South Wales by adding additional compression on the South West Queensland Pipeline (SWQP)[281] and the Moomba to Sydney Pipeline (MSP)[282]. The expansion enables more gas flow on pipelines where capacity is fully or close to fully contracted.[283] Stage 1 of the expansion is committed to come online before winter 2023, increasing transportation capacity by 49 TJ on the SWQP (to 453 TJ per day) and by 30 TJ on the MSP (to 475 TJ per day).[284] This will be the first of 3 stages of a 25% increase in transportation capacity.[285] The additional proposed expansion stages include:

- Stage 2 – a 59 TJ per day increase to the nominal capacity from Queensland to the southern markets, with an additional compressor station constructed on both the SWQP and MSP. This will bring the 453 TJ per day increase from stage 1 up to 512 TJ per day on the SWQP, with the 475 TJ per day capacity on the MSP to increase by 90 TJ to 565 TJ per day. Subject to foundation contracts, this stage is expected to be commissioned in the first quarter of 2024.
- Stage 3 – a further 92 TJ per day expansion with increases to capacity on both pipelines is currently in initial design phases and is subject to customer demand and project approval.[286]

South West Pipeline, Western Outer Ring Main (WORM) project

APA is also upgrading the Victorian Transmission System (VTS), building a 51 km high pressure transmission pipeline to address a key capacity constraint currently limiting the connection of existing gas supply from the west of the state to demand in the north and east. The transportation of gas will also be assisted by the upgrade of the existing compressor station at Wollert. The project is expected to be completed in the second quarter of 2023.

The South West Pipeline (SWP) is a bidirectional facility that primarily transports gas from Port Campbell supply (gas from the Otway Basin and Iona underground storage) into Melbourne. The pipeline also supports refilling the Iona reservoir and transports gas west, fuelling the Mortlake power station and South Australia (through the SEAGas pipeline) during periods of lower demand. Limited capacity on the SWP restricts supply being provided from Port Campbell in the state's west. Following the completion of the WORM, the maximum daily capacity will increase from 447 TJ to 476 TJ on peak demand days.[287]

AEMO forecasts show the SWP constraining flows towards Melbourne during peak demand periods, when the full capacity of the Iona underground gas storage (UGS) facility is most needed. Further expansions of the SWP are proposed, to bring its capacity in line with the capacity of Iona UGS (section 4.9.4), following completion of the WORM.

The WORM was one of 4 priority projects implemented to address shortfalls highlighted in the 2021 Victorian gas planning report. However, the tight commissioning schedule presents a risk to the project being completed before winter 2023.

281 The SWQP connects to the Northern Territory through Carpentaria Gas Pipeline and is a gateway between large northern gas fields in Queensland (including the 3 Gladstone LNG projects), and southern regions with highly seasonal demand. AEMO, Gas statement of opportunities, March 2022, p 51.

282 The MSP connects the Moomba hub in South Australia to southern markets in Sydney/ACT, and Victoria (through Young and the Victoria/New South Wales Interconnector). Seasonal (non-peak) capacity on the MSP can be limited by up to 50% due to annual maintenance, while southern haul capacity on the VNI lateral can be limited by dynamic interactions between Young, Sydney and gas-powered generation requirements at Uranquinty.

283 ACCC, Gas inquiry 2017–2025, interim report, January 2022, February 2022, p 15.

284 Stage 1 of the expansion includes an additional compressor on the SWQP and an additional compressor between Moomba and Young on the MSP.

285 AEMO, 2022 Victorian gas planning report, March 2022. pp 76-77.

286 This potential expansion is expected to add a further 25% to the Stage 1 (12%) and Stage 2 (13%) increases. ACCC, Gas inquiry 2017–2025, interim report, January 2022, February 2022, p 67.

287 Based on AEMO modelling of a one-in-20 (5% probability of exceedance) peak system demand day. AEMO, 2022 Victorian gas planning report, March 2022. p 9.

Further expansions are not yet committed because they are subject to approval under APA's Access Arrangement. However, they have been proposed to increase supply capacity from Port Campbell to between 528 and 570 TJ per day through pipeline augmentation (compression or looping) and up to 670 TJ per day with additional looping and/or compression.[288]

Eastern Gas Pipeline expansion project

The Eastern Gas Pipeline (EGP) is a unidirectional pipeline that transports gas from the Gippsland Basin (Victoria) into Sydney. In 2021 Jemena and AIE signed a project development agreement to connect the PKET import terminal (section 4.9.2) at Kembla Grange at a capacity of 522 TJ per day. Jemena plans to modify the pipeline to allow for bidirectional flows, with an initial ability to supply 200 TJ into Victoria and up to 440 TJ towards Sydney per day.[289]

The earliest practical completion of the EGP expansion project in 2024 aligns with the planned completion of the delayed Port Kembla project, with potential future expansion including the installation of a compressor at Kembla Grange to increase daily capacity to supply as much as 323 TJ into Victoria and 550 TJ towards Sydney.

4.9.4 Storage expansion

Iona underground gas storage (UGS)

Lochard Energy is currently upgrading their underground storage facility to increase supply capabilities to 570 TJ per day[290], with 1 PJ of additional storage capacity following the drilling of a new storage well. Well pad construction of the Seamer 2 well in a field adjacent to Iona's existing field was completed in November 2021 before ministerial approval of the operational plan on 28 January 2022.[291] However, daily supply capacity into Melbourne via the South West Pipeline will be constrained to 476 TJ upon the expected completion of the WORM project in mid-2023 (section 4.9.3).

Further upgrades after the development of the Heytesbury Underground Gas Storage (HUGS) project have been proposed to add additional pipeline assets and approximately 3 PJ of additional storage capacity through construction of a new wellsite at Mylor, Fenton Creek and Tregony (MFCT) gas fields.[292] The project would increase capacity following the development of existing depleted reservoirs, with daily supply capacity increasing to 620 TJ.[293] Proposed construction would commence in October 2023 for completion by 2024, but is subject to regulatory approvals and market requirements that could delay the commencement of the project to October 2024.

Golden Beach project

A proposed plant to process gas from the Golden Beach field in the Gippsland Basin could provide additional supply to assist with peak day demand in Victoria in 2024 and 2025, before operating as an underground storage facility. Golden Beach Energy received $32 million from the Australian Government in 2022 to accelerate development of the project.[294] The facility was projected to have a storage capacity of 12.5 PJ, but would require 43 PJ of production to be procured over a 2-year period before being used as a storage facility.[295]

4.9.5 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.[296] This plan would also extend the pipeline to connect the Beetaloo Basin directly to the Wallumbilla gas supply hub.

Last year east coast supply from the Northern Territory averaged around 55 TJ per day until October, before declining in 2022. Supply over the first half of 2022 was down to an average of just over 30 TJ per day. This partially contributed to reduced supply into east coast markets, with gas flowing south on the Carpentaria Pipeline reducing from around

288 AEMO, 2022 Victorian gas planning report, March 2022, p 14.

289 AEMO, 2022 Victorian gas planning report, March 2022, pp 75-76.

290 Nameplate supply capacity increased from 530 TJ per day to 545 TJ per day on 28 January 2022. Storage capacity will increase from 23.5 PJ to 24.5 PJ.

291 Lochard Energy, Seamer 2 Project – Community Update, January 2022.

292 Lochard Energy, Our HUGS Project, April 2022.

293 AEMO, 2022 gas statement of opportunities, March 2022, p 55.

294 The Hon Angus Taylor MP, Unlocking critical local gas production and storage, 21 March 2022.

295 ACCC, Gas inquiry 2017–2025, interim report, January 2022, February 2022, p 68.

296 Jemena, 'Jemena partners with shale gas experts to develop Beetaloo' [media release], November 2020.

90 TJ per day heading into May to around 50 to 60 TJ per day over May and June. The reduction followed NT supply declining by roughly 15 TJ per day heading into 2022, with further drops from mid-March reducing another 15 TJ out to the end of April. The drop in Carpentaria flows preceded a 2-week maintenance outage on the Phillip Creek Compressor Station from 20 May and constrained NT supply.[297]

4.9.6 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 have become direct market participants by engaging in collective bargaining agreements.

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.[298] Some users have lowered their gas use by changing fuels or increasing efficiencies. Others have also deferred large investments.

In addition, some C&I users are considering alternatives to gas, such as renewable energy.[299]

Government initiatives can also play a role in reducing gas demand. The ACT initially removed mandatory gas connection requirements for new homes, before legislating a stop to new gas connections from 2023. Other initiatives, such as the Victorian gas substitution roadmap and energy upgrades program, have identified electrification as the best solution to achieve a short-term reduction to gas consumption levels.[300]

4.10 Compliance and enforcement activities

The AER's compliance and enforcement work ensures that important protections are delivered and rights are respected. It gives consumers and energy market participants confidence that the energy markets are working effectively and in their long-term interests, so that they can participate in market opportunities as fully as possible and are protected when they cannot do so.

Compliance work helps to proactively encourage market participants to meet their responsibilities, and enforcement action is an important tool where breaches occur.

Each year, the AER identifies and publishes a set of compliance and enforcement priorities, some of which relate to participants in east coast gas markets.

Over 2021-22, two of the AER's compliance and enforcement priorities related to gas markets:

› Ensuring service providers meet information disclosure obligations and other Part 23 National Gas Rules obligations
› Ensuring timely and accurate gas auction reporting by registered participants

High-quality market information is vital to improve transparency amongst participants and promote competition.

The AER undertook a range of compliance and enforcement activities in support of these priorities, including:

› An industry-wide review of service provider compliance against part 23 reporting requirements, to form the basis for further engagement with the sector over 2022-23 about issues identified in the review
› Targeted reviews of recovered capital values reported by specific pipeline operators
› Issuing $240,000 of infringement notices for alleged breaches of record-keeping and report requirements under the National Gas Rules relating to the day-ahead auction
› Informing industry of the causes for inaccurate or delayed AQL information through Gas Market Wholesale Consultative forums, along with highlighting new tools to identify potential 'outlier calculations'.

More detail on the AER's compliance and enforcement work is outlined in the Annual compliance and enforcement report 2021-22.

297 The outage coincided with a Blacktip production outage at the Yelcherr/Wadeye production source.
298 ACCC, Gas inquiry 2017–2025, interim report, January 2021, February 2021, pp 73–74.
299 ACCC, Gas inquiry 2017–2025, interim report, January 2020, February 2020, p 74.
300 AEMO, Gas statement of opportunities, March 2022, p 23.

4.11 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 and territory governments have intervened in the market.

4.11.1 Australian Domestic Gas Security Mechanism

The Australian Domestic Gas Security Mechanism empowers the Australian Government Minister for Resources to require LNG projects to limit exports, or find offsetting sources of new gas, if a supply shortfall is likely.[301] 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 agreements with the government committing to offer uncontracted gas on reasonable terms to meet expected supply shortfalls.[302] They also committed to offer gas to the Australian market on competitive market terms before offering any uncontracted gas to the international market.[303] Following a review by the Department of Industry, Science, Energy and Resources[304], the scheme was extended until 2030.

At the time of publishing, the Australian Government is in the process of renegotiating the Heads of Agreement (HoA).[305]

4.11.2 Gas Supply Guarantee (GSG)

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.[306] The mechanism was originally scheduled to finish in March 2020, but the Australian Government extended the guarantee to March 2023.[307]

AEMO triggered the Gas Supply Guarantee for the first time on 1 June 2022.[308] Following activation of the mechanism, gas producers in Queensland diverted gas into the domestic market and AEMO subsequently deactivated the mechanism the next day. AEMO reactivated the mechanism from 19 July following the notification of a threat to system security (TTSS) in Victoria due to insufficient storage, after directing two generators to cease taking gas from the Victorian market until 30 September (with the GSG and TTSS to remain in effect until sufficient supply is available).[309]

4.11.3 State government schemes

To encourage gas exploration, the Queensland Government grants exploration authorities 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.[310] In 2021, the Queensland Government announced it would make 14,100km^2 available for oil and gas exploration.[311]

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.[312]

301 Department of Industry, Innovation and Science, Australian Domestic Gas Security Mechanism, July 2018.

302 Department of Industry, Science, Energy and Resources, Securing Australian domestic gas supply, DISER website, accessed 28 May 2021.

303 The agreement specifically notes that LNG netback prices, as referenced by the ACCC, play a role in influencing domestic gas prices.

304 Department of Industry, Science, Energy and Resources, Australian Domestic Gas Security Mechanism review, January 2020.

305 Energy Ministers Meeting, Communique, 12 August 2022.

306 AEMO, Gas supply guarantee, AEMO website, accessed 28 May 2021.

307 AEMO, Gas supply guarantee guidelines consultation final determination, March 2020.

308 AEMO, Gas supply guarantee, AEMO website, accessed 28 May 2021.

309 AEMO takes further steps to manage tight gas supplies, 19 July 2022, https://aemo.com.au/newsroom/media-release/aemo-takes-further-steps-to-manage-tight-gas-supplies.

310 Queensland Government, 'Queensland gas exploration ramping up' [media release], September 2020.

311 Queensland Government, 2021 Queensland Exploration program, November 2021, accessed 28 Jun 2022.

312 NSW Government, Memorandum of understanding – NSW energy package, 31 January 2020.

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.[313]

4.11.4 ACCC gas inquiry

The Australian Government directed the ACCC to use its compulsory information gathering powers to inquire into wholesale gas markets in eastern Australia. The inquiry was initially tasked to run until 30 April 2020, but in July 2019 the Treasurer extended it to 2025.[314]

4.11.5 Electrification of liquefied natural gas production

On 8 February 2020 the Australian Government announced it would allocate up to $1.5 million to work 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 make available up to 12 PJ of gas for delivery to the domestic market.

4.11.6 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.[315]

4.12 Gas market reform

The Energy Ministers' Meeting and Energy National Cabinet Reform Committee (formerly the COAG Energy Council) direct gas market reforms, which regulatory and market bodies implement.[316] 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.[317]

Reform stems from findings by bodies that include the AEMC, the ACCC and the Gas Market Reform Group. The reforms aim to increase transparency in the gas market, improve the Gas Bulletin Board and improve the availability of information on market liquidity, prices, and gas reserves.

4.12.1 Gas Bulletin Board reforms

The Gas Bulletin Board aims to make the gas market more transparent by providing up-to-date information on gas production, pipelines and storage options in eastern Australia.

Market participants can access detailed information from production and compression facilities on their daily nominations, forecast nominations, intra-day changes to nominations and capacity outlooks. This 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 includes information on flows at key supply and demand locations along pipelines.

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.

In June 2022 states adopted the Gas Market Transparency Act, which will extend reporting to large gas users and LNG processing facilities. These laws give the AER new powers to monitor information related to price and volume in the shorter-term gas market, including how gas is exported overseas and how it is traded here in Australia. In

313 Australian Government, 'Energy and emissions reduction agreement with South Australia' [media release], April 2021.

314 ACCC, Gas inquiry 2017–2025, ACCC website, accessed 28 May 2021.

315 ARENA, Seven shortlisted for $70 million hydrogen funding round, ARENA website, accessed 28 May 2021.

316 Including the Energy Security Board, the AER, the AEMC, AEMO and the ACCC.

317 CoAG Energy Council, Measures to improve transparency in the gas market – decision regulation impact statement, March 2020.

particular, the AER will be able to monitor the export, reserve, storage and domestic sale and swaps of gas to report more comprehensively on competition.

Liquidity information

The AER publishes (on the industry statistics page of its website) quantitative metrics for assessing the liquidity of gas markets, and it regularly updates these metrics. The AER also reports quarterly 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.

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. The ACCC publishes data on LNG netback prices to help gas users negotiate more effectively with gas producers and retailers when entering new gas supply contracts.[318]

The ACCC also publishes data on gas reserves and resources, drawing on information provided by reserve owners. This helps market participants identify future supply issues and plan accordingly.

4.12.2 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. Reforms introduced in March 2019 enabled participants to access unutilised pipeline capacity.

318 ACCC, Gas inquiry 2017–2020 – LNG netback price series, ACCC website, accessed 28 May 2021.

Source: iStock

5

Regulated gas pipelines

Gas pipeline networks transport gas from upstream producers to residential, commercial and industrial customers. Australia's gas pipeline networks consist of:

- long haul transmission pipelines, which carry gas from producing basins to major population centres, power stations, and large industrial and commercial plants
- smaller urban and regional distribution networks, which 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 all states and territories except Tasmania and Western Australia.[319]

Unlike electricity networks, many gas pipelines are unregulated or face only limited regulation. This chapter explains the various tiers of regulation that apply but focuses on 'full regulation' pipelines – those for which the AER sets access (usage) prices.[320] The AER sets access prices for 3 transmission pipelines – the Roma to Brisbane Pipeline (Queensland), the Victorian Transmission System (Victoria) and the Amadeus Gas Pipeline (Northern Territory). In gas distribution, the AER sets access prices for 6 distribution networks in New South Wales (NSW), Victoria, South Australia and the Australian Capital Territory (ACT).

5.1 Gas pipeline snapshot

In 2022 so far, the AER has completed one access arrangement review for a fully regulated pipeline – the Roma to Brisbane pipeline – updating the access arrangement and reference prices for that pipeline through to 2027.

Across the fully regulated pipelines, over the 12-month period to 30 June 2021:

- Revenue earned by network businesses was 6% lower than in the previous year and 6% lower than the average revenue earned over the previous 5 years (section 5.7).
- This overall reduction in revenue was driven particularly by Jemena Gas Networks (JGN) (NSW) who earned 19% less than in the previous year following an access arrangement review which brought actual revenue closer to price cap targets (section 5.7).
- Investment in the fully regulated pipelines was primarily to replace ageing mains pipelines (section 5.10).

5.2 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 provide 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 transport it to export terminals.

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 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.

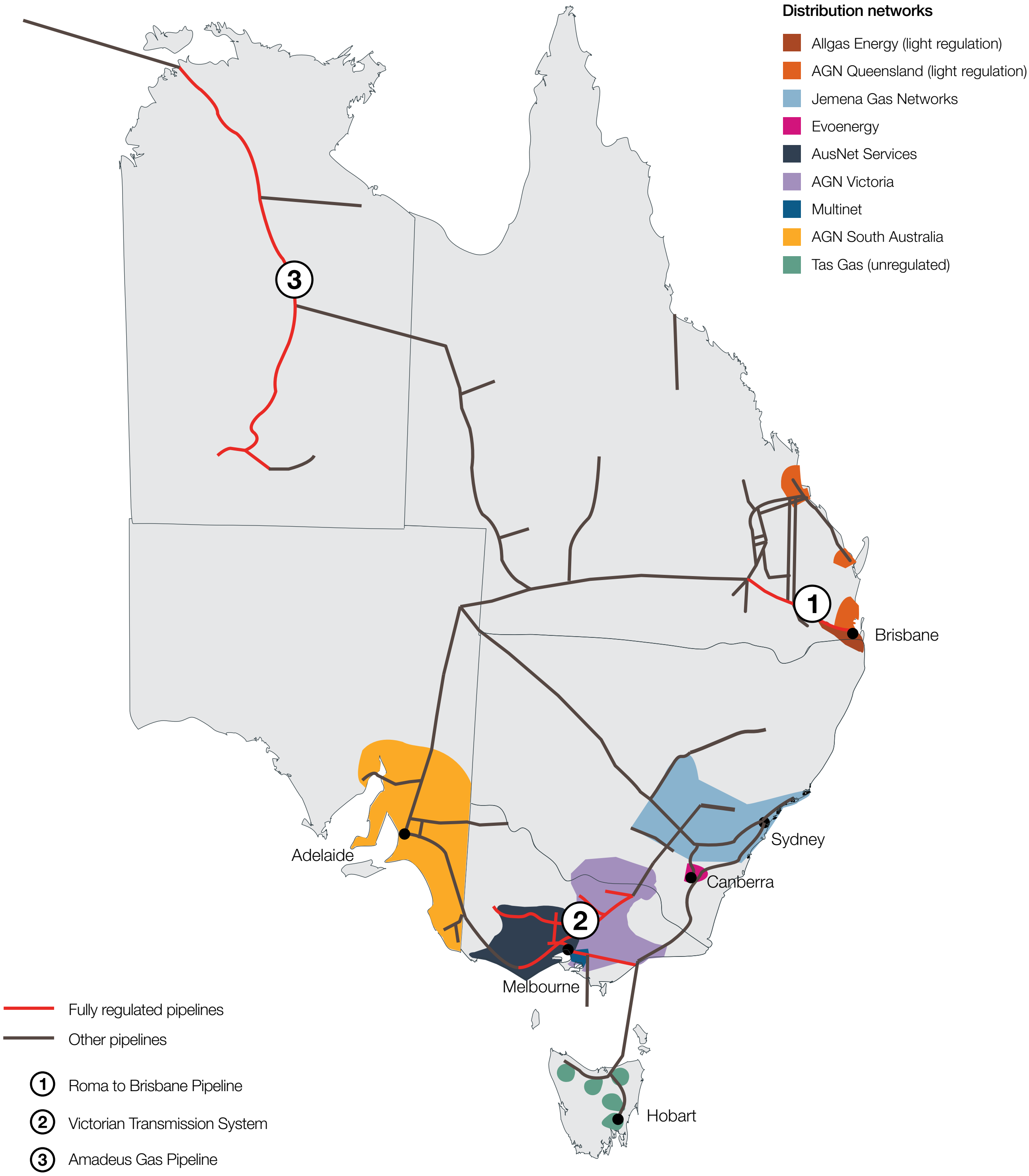
Distribution networks run underground and consist of high, medium and low-pressure pipelines. The high and medium pressure mains provide a 'backbone' that services high demand zones, while the low-pressure pipes lead off high pressure mains to commercial and industrial customers and residential homes. Although the nature of gas transmission services is evolving to meet changing market needs, distribution pipeline businesses tend to offer fairly

319 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).

320 Chapter 4 discusses the wider gas transmission sector, including pipelines not under full regulation.

standard services – namely, allowing gas injections into a pipeline, conveying gas to supply points and allowing gas to be withdrawn.

Figure 5.1 Major gas transmission pipelines and distribution networks



Source: AER.

The total length of gas distribution networks in eastern Australia is around 77,000 kilometres. Gas is distributed to most Australian capital cities, major regional areas and towns. Queensland and Victoria each have multiple distribution networks, while NSW, South Australia, Tasmania and the ACT are each served by a single regulated network.[321]

Gas distributors transport gas to energy customers, but 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.

5.3 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).

Table 5.1 summarises ownership of gas distribution networks, most of which are fully regulated.

Table 5.1 Ownership of gas distribution networks

PIPELINE	LOCATION	LENGTH (KM)	REGULATORY STATUS[1]	OWNER
Jemena Gas Networks	NSW	25,481	Full regulation	Jemena (State Grid Corporation of China 60%, Singapore Power 40%)
AusNet Services	Vic	12,337	Full regulation	Australian Energy Holdings No 4 Pty Limited
Multinet Gas Network	Vic	10,143	Full regulation	CK Infrastructure Holdings
Australian Gas Networks	Vic	11,984	Full regulation	CK Infrastructure Holdings
Australian Gas Networks	SA	8,420	Full regulation	CK Infrastructure Holdings
Evoenergy	ACT	4,614	Full regulation	ICONWater (ACT Government), 50%; Jemena, 50%
Allgas Energy	Qld	3,218	Light regulation	Marubeni, 40%, SAS Trustee Corp, 40%; APA Group, 20%
Australian Gas Networks	Qld	3,463	Light regulation	CK Infrastructure Holdings

Source: AER gas network performance data; corporate websites.

Table 5.2 summarises ownership of key gas transmission pipelines and their forms of regulation.

321 Some networks cross state or territory boundaries. For example, Australian Gas Network's Victorian network and Evoenergy's ACT network both extend into NSW. Some jurisdictions also have smaller unregulated regional networks, such as the Wagga Wagga network in NSW.

Table 5.2 Ownership of key gas transmission pipelines

PIPELINE	LOCATION	LENGTH (KM)	CAPACITY (TJ/DAY)	REGULATORY STATUS[1]	OWNER
Roma (Wallumbilla) to Brisbane	Qld	438	211 (125)	Full regulation	APA Group
Victorian Transmission System (GasNet)	Vic	2,035	1,030	Full regulation	APA Group
Amadeus Gas Pipeline	NT	1,658	120	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 Corporation of China 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 Corporation of China 60%, Singapore Power 40%)
Vic–NSW Interconnect	Vic–NSW		223 (150)	Part 23 regulation	Jemena (State Grid Corporation of China 60%, Singapore Power 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
Northern Gas Pipeline (Tennant Creek to Mount Isa)	NT–Qld	622	90	Part 23 regulation	Jemena (State Grid Corporation of China 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%)

TJ/day: terajoules per day.

Note: For bi-directional pipelines, reverse capacity is shown in brackets.

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.

Source: AER; ACCC, interim reports of gas inquiry 2017–2025; corporate websites; Gas Bulletin Board (www.gasbb.com.au).

5.4 How gas pipelines are regulated

Gas pipelines are capital intensive and require significant amounts of investment to install and operate the required infrastructure. 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 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) and the relevant Minister[322] are 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).

The AER is expected to be responsible for determining the level of regulation for gas pipelines, subject to the passage of the amendments to the National Gas Law, Regulations and the National Gas Rules through the South Australian Parliament.

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, it 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. The AER undertakes 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.

5.4.1 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 all jurisdictions except 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.

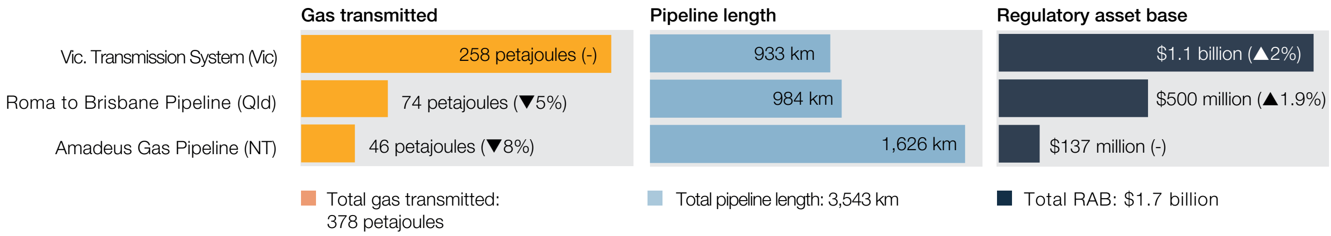
Currently, the AER applies full regulation to 3 gas transmission pipelines and 6 gas distribution networks, with a combined regulatory asset base (RAB) of $12.3 billion (Figure 5.2 and Figure 5.3).[323]

322 Relevant Minister can refer to a state or Commonwealth Minister depending on the pipeline that is under consideration.

323 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.

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 5.4.2). Other pipelines are free from any form of regulation.

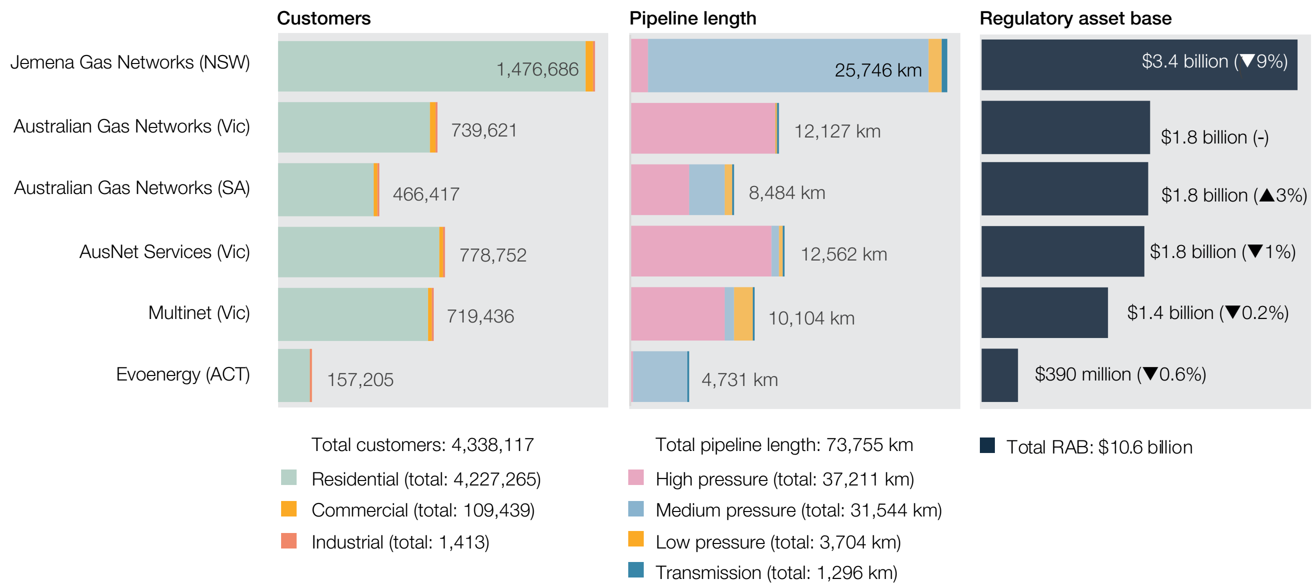
Figure 5.2 Gas transmission pipelines – full regulation



Note: RAB is adjusted to June 2022 dollars based on forecasts of the consumer price index (CPI). The RAB is the forecast value of network assets based on the closing RAB at 30 June 2021, except for the Victorian transmission network (31 March 2021). Excludes gas pipelines in Western Australia, which the Economic Regulation Authority (ERA) regulates.

Source: AER access arrangement decisions and annual regulatory information notices (RINs).

Figure 5.3 Gas distribution networks – full regulation



Note: RAB is adjusted to June 2022 dollars based on forecasts of the CPI. The RAB is the forecast value of network assets based on the closing RAB at 30 June 2021, except for the Victorian distribution networks (31 December 2021). Excludes gas pipelines in Western Australia, which the Economic Regulation Authority (ERA) regulates.

Source: AER access arrangement decisions and annual reporting RINs.

5.4.2 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 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.

5.4.3 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.[324]

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.

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.[325]

A pipeline owner can apply to the AER for an exemption from the disclosure provisions for several reasons, including a pipeline not providing third party access, having only a single shipper or having average daily gas injections of less than 10 terajoules per day. Exemptions may be subject to conditions and varied at the AER's discretion.

In July 2022 the AER announced that one of its key enforcement and compliance priorities for 2022–23 was to ensure service providers meet the information disclosure obligations under Part 23 of the National Gas Rules.

Access disputes

There have 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.[326] The second concerned a dispute between Gas Pipelines Victoria and EnergyAustralia over access to the Carisbrook to Horsham Pipeline in January 2021.[327]

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. 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.

5.4.4 Regulatory reforms to gas pipeline regulation

In May 2021 Commonwealth, state and territory energy ministers agreed on a package of reforms to improve gas pipeline regulation.[328] In September 2021 energy senior officials held public consultation on a draft legal package to give effect to the agreed reforms.[329]

In March 2022 energy ministers agreed to a final package of gas pipeline regulatory reforms, which are intended to provide a simpler regulatory framework and continue to support the safe, reliable and efficient use of, and investment in, gas pipelines. In particular, they are intended to provide:

- more effective constraints on market power of pipeline operators
- better access to pipelines that would not otherwise provide such access
- streamlined governance arrangements
- better support for commercial negotiations between shippers and service providers, through more transparency (including greater price transparency) and improvements to the negotiation framework and dispute resolution mechanisms.

The implementation of the reforms is subject to passage through the South Australian Parliament.

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324 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.

325 AER, 'Part 23 (Access to non-scheme pipelines) exemptions', AER website, accessed 1 February 2022.

326 AER, 'Final access determination – Tasmanian Gas Pipeline', AER website, 12 April 2018, accessed 4 February 2022.

327 AER, 'Access dispute – Carisbrook to Horsham Pipeline', AER website, 28 January 2021, assessed 4 February 2022.

328 Department of Industry, Science, Energy and Resources, 'Energy Ministers release gas pipeline Decision Regulation Impact Statement', 3 May 2021, accessed 5 April 2022.

329 Department of Industry, Science, Energy and Resources, 'Energy Senior Officials gas pipeline draft legal package consultation', 2 September 2021, accessed 5 April 2022.

5.4.5 Gas network performance report

In December 2021 the AER published its first gas network performance report. The report focused on key outcomes and trends in the operational and financial performance data for fully regulated gas distribution pipelines.[330] Subsequent reports will include analysis of the fully regulated gas transmission pipelines.

5.5 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.

5.5.1 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 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 assesses the proposal, and the supporting material, and forms an opinion on the reasonableness of the forecasts and the efficiency of the proposed expenditure. If the AER determines the proposal is likely to be unreasonably costly, it may ask for more detailed information or a clearer business case. Subsequently, the AER may amend the amount of revenue proposed by a gas pipeline to ensure the approved cost forecasts are efficient. Ensuring only efficient costs are included in the calculation of a regulated business's revenue requirement helps protect customers from being charged unreasonable prices.

As with electricity, the AER uses a building block approach to assess the business's efficient costs (section 5.5.5). 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.

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.

5.5.2 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 (chapter 3, Box 3.4), 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 2018–2022 access arrangements. The AER then approved Jemena's (NSW) request for a CESS for its 2020–2025 access arrangement and requests by

330 AER, 'Gas network performance report', December 2021.

AGN (South Australia) and Evoenergy (ACT) for their 2021–2026 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 (chapter 3, Box 3.3). 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 carries a risk of 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.

5.5.3 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 the access price. The assessment period can be extended by up to 2 months, with 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.

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 if the need for it is uncertain at the time of the reset. A pre-approval allows the network business to roll the project into the pipeline's RAB in the forthcoming access arrangement if pre-determined conditions are met.

5.5.4 Customer engagement

As for electricity, an important focus of gas pipeline regulation is how constructively a business engages with its customers in developing an access arrangement proposal. Although 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.

Some recent access arrangement proposals demonstrated better levels of customer engagement:

› Before submitting its 2021–2026 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 that the AER considered to be well-calculated and appropriate.[331]

› Evoenergy submitted a well-informed 2021–2026 access arrangement proposal, underpinned by significant improvements to its consumer engagement approach. 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.[332]

› The AER commended AGN (South Australia) on its consumer engagement approach in developing its 2021–2026 access arrangement proposal. AGN demonstrated meaningful engagement with its customers, which it facilitated

331 AER, 'Final decision – Amadeus Gas Pipeline access arrangement 2021 to 2026', AER website, 30 April 2021, accessed 5 April 2022.

332 AER, 'Final decision – Evoenergy access arrangement 2021 to 2026', AER website, 30 April 2021, accessed 5 April 2022.

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.

However, in its November 2021 draft decision on APTPPL's (Roma to Brisbane Pipeline (Queensland)) 2022–2027 access arrangement proposal, the AER considered there is room for improvement in its overall approach to, and quality of, consumer engagement compared with the high standard set by some of its industry peers.[333]

The AER commented that APTPPL would have benefitted from greater investment in its pre-lodgement processes, including an earlier and sharper focus on planning the proposal and methods to facilitate more meaningful and deeper consumer engagement.[334]

5.5.5 Regulating gas pipelines under uncertainty

In November 2021 the AER published an information paper, 'Regulating gas pipelines under uncertainty', that discusses the potential implications of a decarbonised future energy mix on the long-term gas demand forecast and the expected economic lives of gas pipeline assets.[335]

The information paper explains how these potential implications may affect the AER's regulatory approaches when undertaking access arrangement reviews for full regulation gas pipelines now and in the future. It canvassed a range of potential options, including their costs and benefits, for managing the pricing risk and stranded asset risk that may arise from a potential material decline in gas demand in the future. These options include:

- accelerating asset depreciation
- providing ex-ante risk compensation
- removing redundant assets from capital base
- removing capital base indexation
- revaluating capital base
- introducing exit fees
- increasing fixed charges.

The paper also discusses how the uncertainty in future gas demand can affect specific aspects of the AER's regulatory decisions, such as the assumed payback period of pipeline investment in expenditure assessments, the incentives regulated businesses may have in substituting capital and operating expenditure, the prudency of allowing regulated businesses to recover from customers expenditure that is for repurposing gas assets to potentially transport renewable gases in the future, and the increased demand risk that regulated businesses may face under price cap regulation if gas demand falls persistently.

An example of this uncertainty is the ACT government's decision to cease connecting gas to homes and businesses in Canberra from 1 January 2023.[336]

The paper is intended to inform stakeholders of the longer-term issues facing the gas market and understand the implications on economic regulation for gas pipelines and, therefore, gas prices. This is designed to encourage and facilitate constructive stakeholder debate and engagement during access arrangement review processes, such as the Victorian distribution access arrangement reviews that commenced in July 2022.

333 APT Petroleum Pipelines Pty Limited (APTPPL) owns and operates the Roma to Brisbane Pipeline.

334 AER, 'Draft decision – Roma to Brisbane pipeline access arrangement 2022 to 2027', AER website, 26 November 2021, accessed 5 April 2022.

335 AER, '*Regulating gas pipelines under uncertainty – information paper*', November 2021.

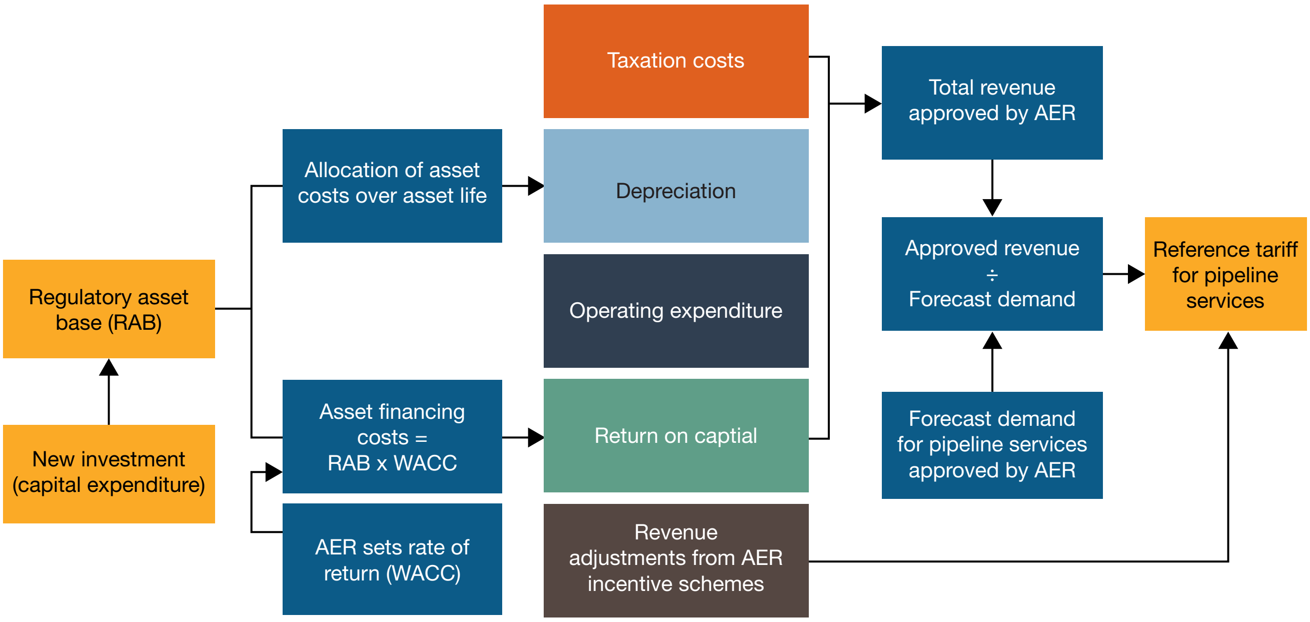
336 ABC News, 'No new gas connections for ACT homes and businesses from 2023 under plan to phase out fossil fuels', 4 August 2022, accessed 16 August 2022.

5.6 Building blocks of gas pipeline revenue

The AER uses a 'building block' approach to assess a gas pipeline business's revenue needs (Figure 5.4). 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.

Figure 5.4 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.

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. Those returns are forecast to absorb around 39% of revenues (54% for transmission and 37% for distribution) in the current access periods. The returns are calculated by multiplying:

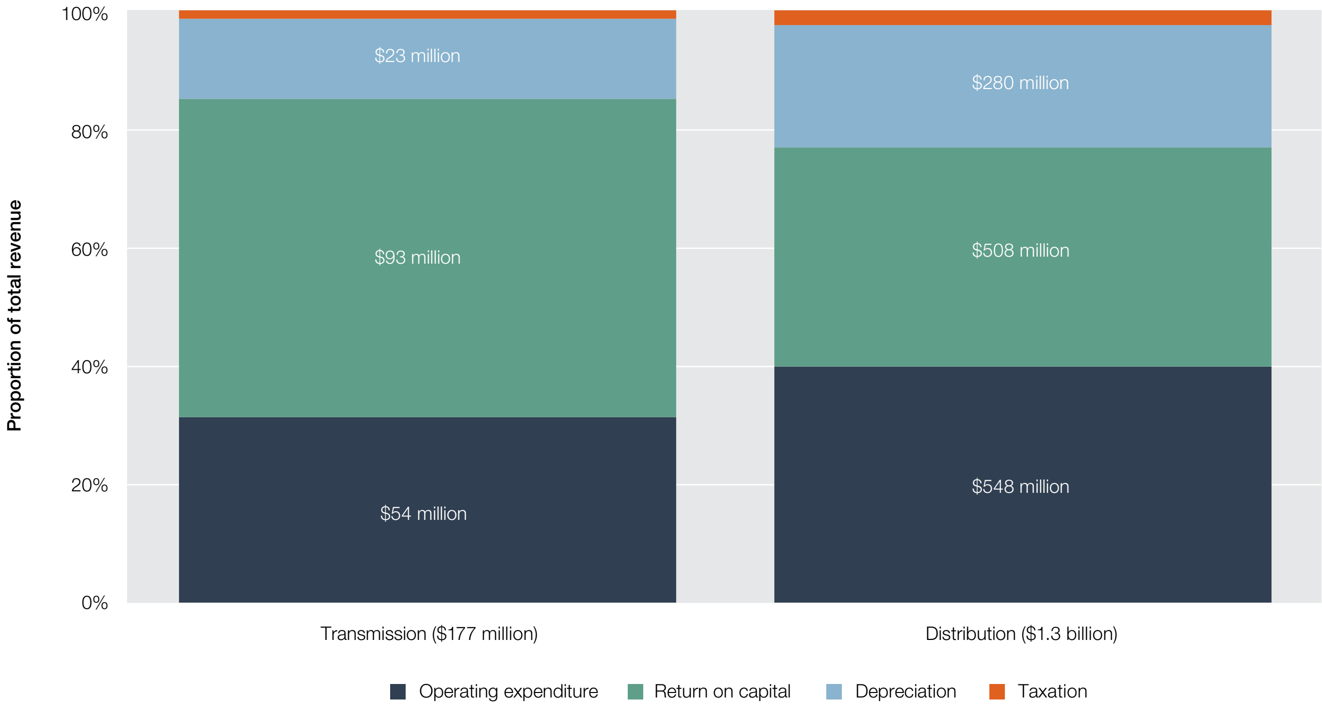
- the value of the network's RAB
- the rate of return that the AER allows based on the forecast cost of funding those assets through equity and debt.[337]

Operating and maintenance costs are also forecast to absorb around 39% of revenues (31% for transmission and 40% for distribution) in the current access periods. Overheads, taxation and other costs account for the remainder of a pipeline's revenue. Figure 5.5 illustrates the composition of pipeline revenues in current gas transmission and distribution decisions.

Gas pipeline businesses can also earn additional revenue through regulatory incentives that encourage the efficient management of operating and capital expenditure programs (section 5.5.2).

337 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.

Figure 5.5 Composition of average annual gas pipeline revenues



Note: CPI adjusted to June 2022 dollars. Gas pipeline businesses also receive bonuses or penalties that impact on annual network revenues. These bonuses/penalties are not material and are not considered in Figure 5.5.

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

5.6.1 Recent AER access arrangement decision

In April 2022 the AER approved a target revenue of $223 million ($45 million per year) for APT's Roma to Brisbane Pipeline (Queensland) for the current access period.[338] This pipeline transports natural gas between the Wallumbilla gas hub, near Roma, and Brisbane and regional centres in between (Figure 5.6).

The target revenue is $21 million (9%) less than the target revenue used to determine tariffs in the 2017–2022 period. The revenue allowance included a reduction in the return on capital and depreciation, which were marginally offset by an increase in operating expenditure.

The AER's final decision affects the component of a customer bill relating to gas transmission tariffs, which represent approximately 3.4% on average of a Queensland retail gas consumer's annual bill.[339]

Figure 5.6 Recent AER access arrangement decision

	Revenue	Capital expenditure	Operating expenditure	Annual impact on residential bill
Roma to Brisbane Pipeline	$233m (▼9%)	$39m (▼47%)	$105m (▲30%)	▲0.1%

338 The current regulatory period is the period in place at 1 July 2022.

339 APTPPL, 'Roma to Brisbane Pipeline 2022–27 access arrangement, Reset RIN Workbook 5 Indicative bill impacts', AER website, 1 July 2021, accessed 5 April 2022.

5.7 Revenue

All fully regulated gas transmission pipelines and distribution networks are regulated under a price cap. Network businesses can earn above or below forecast revenue over time due to changes in demand. If actual demand exceeds forecast demand, the business keeps the additional revenue. Conversely, if actual demand is less than forecast revenue the business is exposed to the shortfall.

Figure 5.7 provides a breakdown of the amount of revenue gas distribution networks earned in 2021 and how this compared with previous years.

Figure 5.7 Revenue in 2021

	2021 (actual)	Compared to 2020	Compared to peak (year)
Transmission	$201m (excl. Amadeus)	▲6.5m (▲3%) (excl. Amadeus)	▼11%(2012) (excl. Amadeus)
Distribution	$1.5b	▼$113m (▼7%)	▼15% (2015)

Note: Amadeus Gas Pipeline's actual revenue is confidential as it contains commercially sensitive information.

Figure 5.8 provides a snapshot of the key forecasts from the AER's revenue decisions for the current regulatory periods and how they compare with forecasts from the previous period.[340]

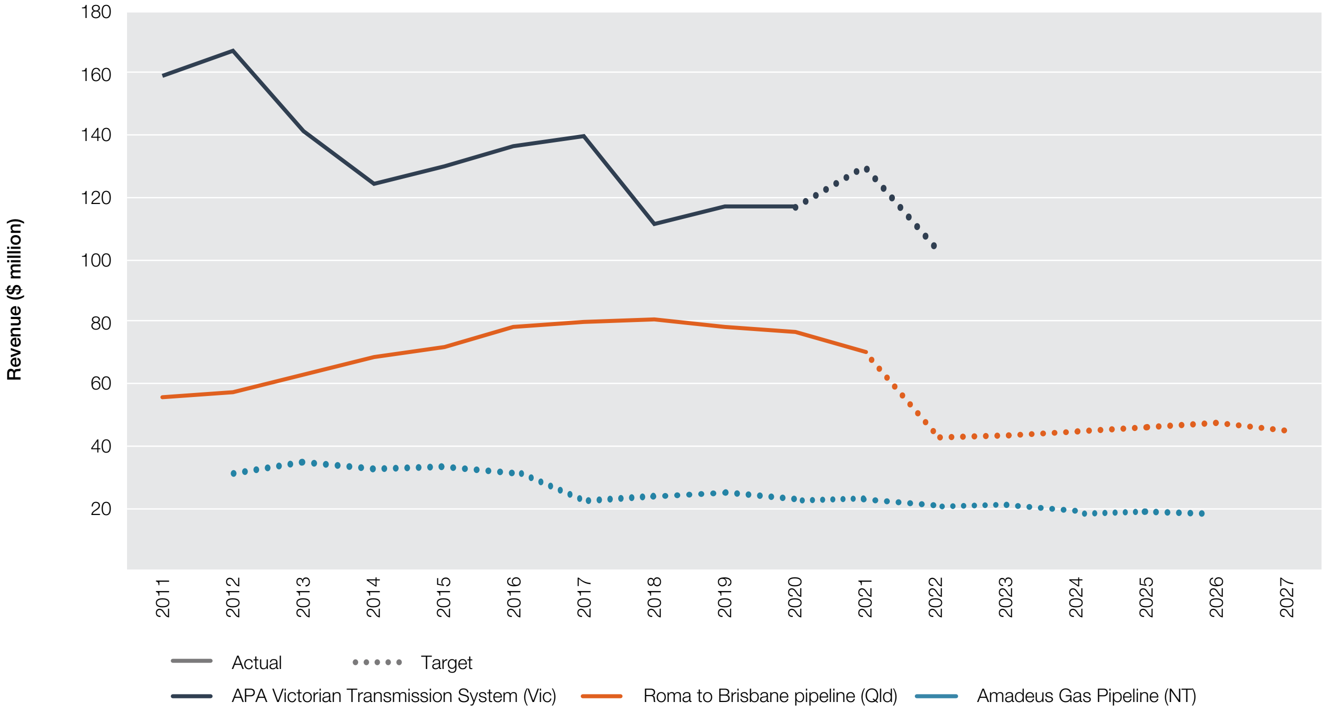
Figure 5.8 AER gas pipeline revenue decisions

	Revenue	Capital expenditure	Operating expenditure
Transmission	$872m (▼3%)	$311m (▲6%)	$296m (▼10%)
Distribution	$6.8b (▼0.6%)	$3.0b (▼4%)	$2.8b (▲8%)
Total	$7.6b (▼0.9%)	$3.3b (▼3%)	$3.1b (▲6%)

Note: Gas pipeline revenue decisions for the current access arrangement periods.

340 The current regulatory period is the period in place at 1 July 2022.

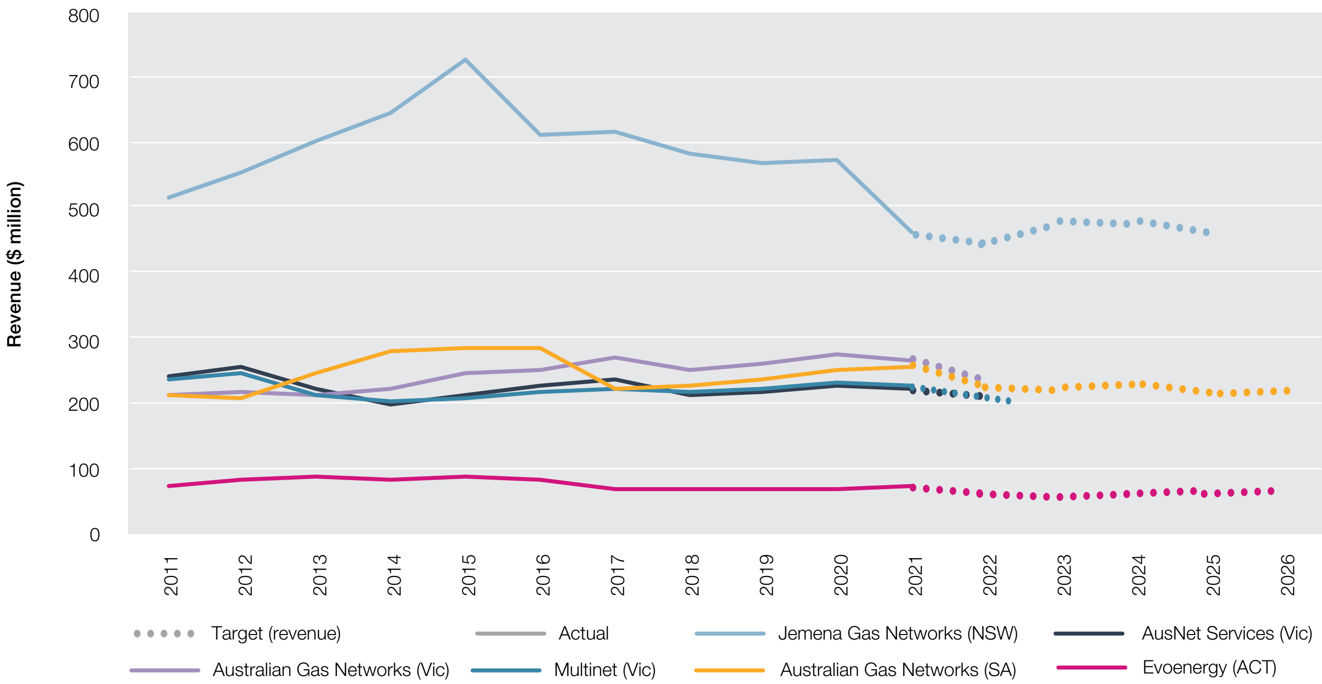
Figure 5.9 Revenue – gas transmission pipelines



Note: All data are adjusted to June 2022 dollars, based on forecasts of the CPI. 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 data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018). Amadeus Gas Pipeline's actual revenue data is confidential.

Source: AER modelling; annual reporting RIN responses.

Figure 5.10 Revenue – gas distribution pipelines



Note: All data are adjusted to June 2022 dollars, based on forecasts of the CPI. 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 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; annual reporting RIN responses.

Some key drivers of transmission pipeline and distribution 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 2016 and has since plateaued. Pipeline and network businesses also had higher financing costs due to instability in global financial markets.

In gas transmission, revenues are forecast to fall by 18% for the Amadeus Gas Pipeline (Northern Territory). However, the Victorian Transmission System is forecast to increase revenue by 3%, reflecting an increased RAB following new investment from 2013 to 2017.

In gas distribution, revenues are forecast to increase by 13% for AGN (Victoria), 9% for AGN (South Australia) and 3% for Multinet (Victoria) over the current period. Conversely, revenues are forecast to decrease by 11% for Jemena (NSW), 6% for Evoenergy (ACT) and 1.9% for AusNet Services (Victoria).

Weaker domestic gas demand in recent years – caused by significantly higher gas prices – reduced forecast revenue needs for most pipeline businesses.

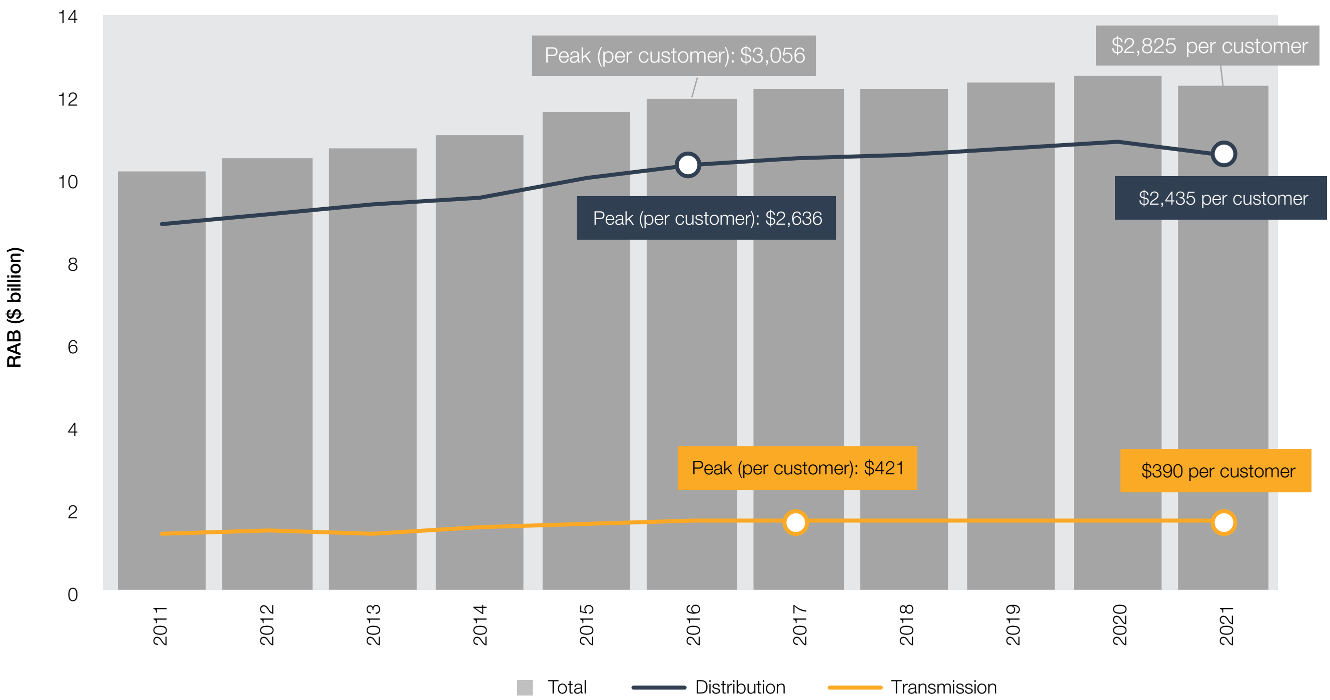
Despite the recent reduction in total gas pipeline and network revenues, additional 'program-specific' revenue is still needed to cover new programs, such as AGN's (South Australia) new Vulnerable Customer Assistance Program (VCAP) during the current access period. The objective of the VCAP is to allow AGN to develop a better understanding of the needs of its vulnerable customers and put in place measures to support these customers.

5.8 Regulatory asset base

The RAB for a gas pipeline business represents the total economic value of assets that provide services to customers. The value of the RAB substantially impacts a gas pipeline owner's revenue requirement.

Capital investment approved by the AER is added to a pipeline's RAB, on which future returns are earned. Reduced investment from 2015 to 2020 slowed RAB growth. Further reductions in investment saw the RAB decrease by $30 million (2%) to $12.3 billion ($1.7 billion for transmission pipelines and $10.6 billion for distribution networks) in 2021 (Figure 5.11).

Figure 5.11 Regulatory asset base – gas pipelines



Note: All data are adjusted to June 2022 dollars, based on forecasts of the CPI. 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 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.

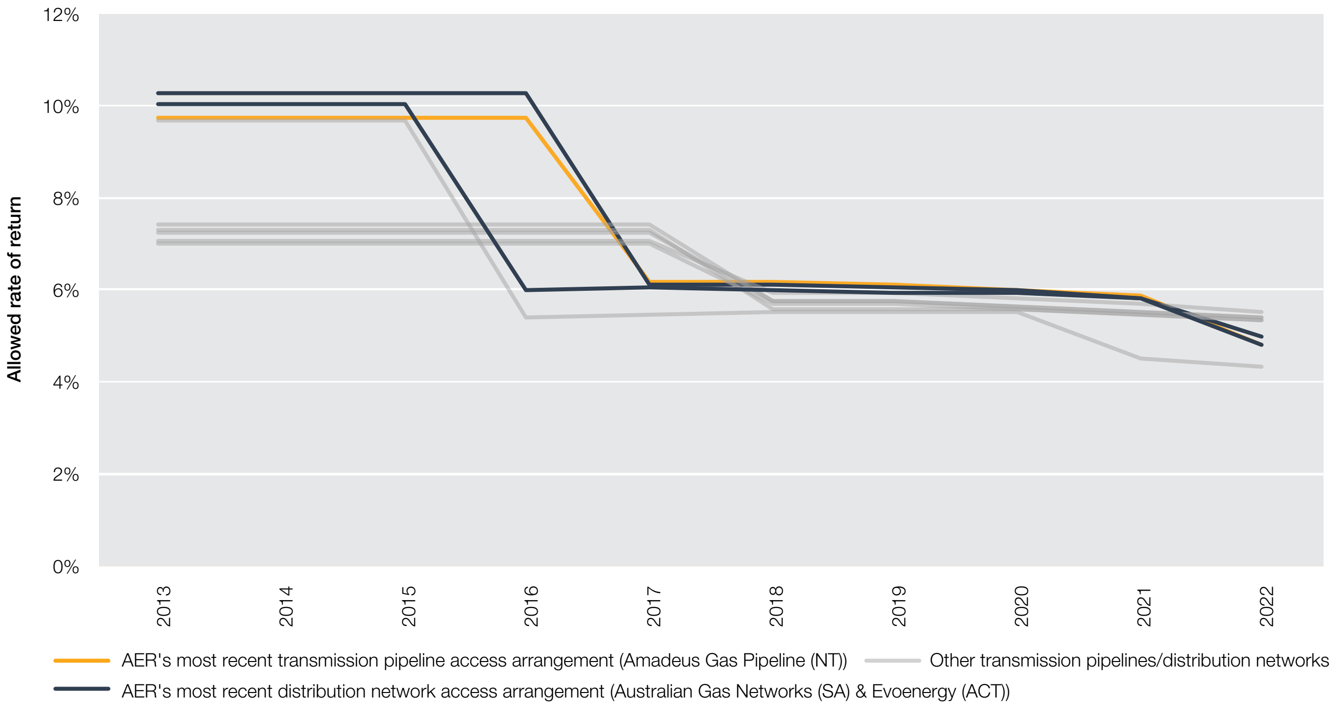
5.9 Rates of return

The shareholders and lenders that finance a gas pipeline business expect a commercial return on their investment. The rate of return estimates the financial return a gas pipeline or network business's financiers require to justify investing in the business. It is a weighted average of the return needed to attract both equity and debt funding. Equity funding is the dividends paid to a network business's shareholders and debt funding relates to 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 difference can be due to several factors, such as the impact of incentive schemes, forecasting errors, revenue over-recovery 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.[341]

Legislation introduced in 2018 provided for the AER to make binding rate of return determinations that apply to all regulated gas pipeline businesses. This change, along with lower financing costs, reduced the average allowed rate of return from around 10% at the beginning of the 2010s, to less than 6% (Figure 5.12). This reduction translated to significantly lower network revenues and gas pipeline charges.

Figure 5.12 Allowed rates of return



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 data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year 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.

In recent months, some key inputs into rates of return have increased. For example, the risk-free rate is an important driver of allowed returns on equity and is estimated using required returns on Commonwealth Government Securities (CGSs), also known as Australian government bonds. Annual yields on 10-year CGSs were as low as 0.6% in March 2020, but over 2022 to the end of August have averaged roughly 3%. Similarly, annual yields on 5-year CGSs were as low as 0.25% in November 2020 but over 2022 to the end of August have averaged roughly 2.7%.[342] If risk-free rates, or other key inputs, remain at levels above lower recent rates, this will put upward pressure on fully regulated pipeline revenue over coming years.

341 For example, if the rate of return is 5% and the RAB is $10 billion, then the return to investors is $500 million. This return forms part of a gas pipeline business's revenue needs and must be paid for by customers.

342 RBA, Capital Market Yields – Government Bonds – Daily – F2, accessed 6 September 2022.

5.10 Investment

Investment requirements differ between the gas transmission and distribution sectors. Gas transmission investment typically involves large capital projects to expand existing pipelines (through compression, looping or extension) or constructing new infrastructure. Additionally, some transmission pipelines have been re-engineered for bi-directional flows.

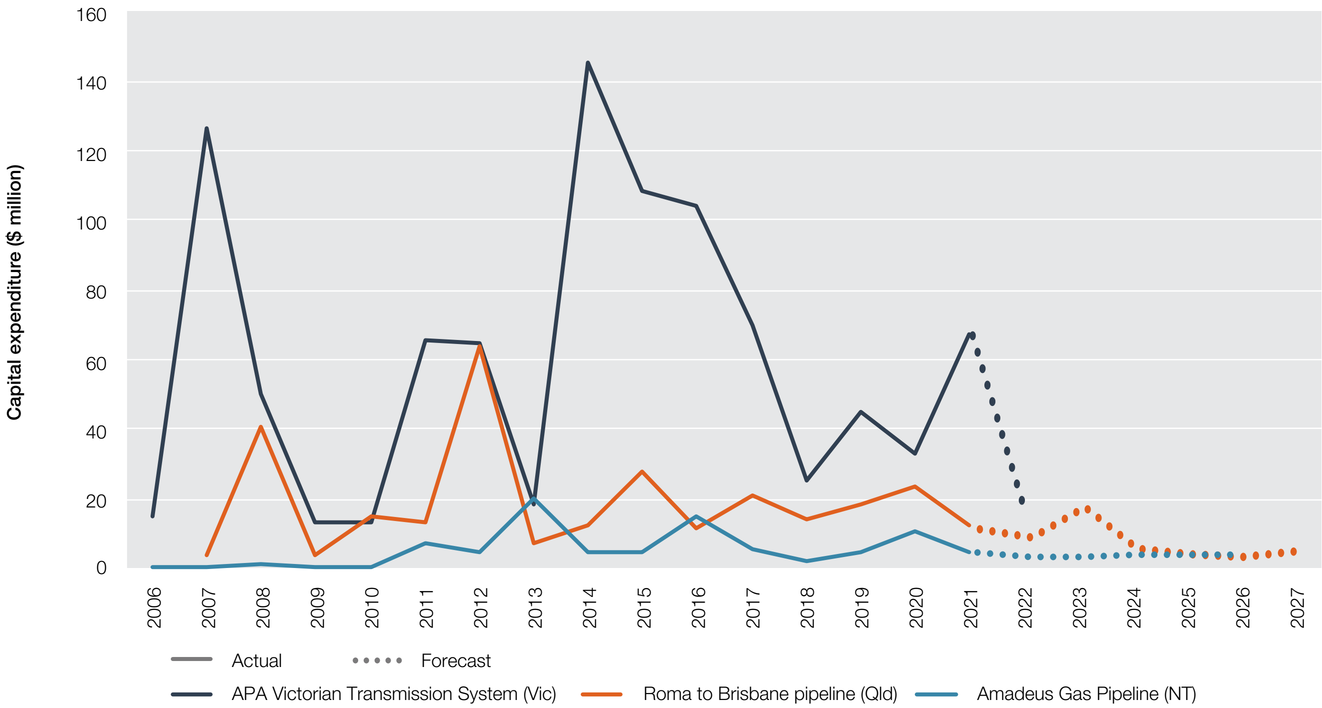
Gas distribution investment mainly comprises augmentation (expansion) of existing systems to cope with new customer connections, as in new housing estate developments. Older networks also require replacement programs for deteriorating infrastructure. For pipelines under full economic regulation (Table 5.2), the AER assesses whether investments are prudent and efficient based on criteria in the National Gas Rules.

Figure 5.13 provides a breakdown of the amount of investment network businesses undertook in 2021 and how this compared with previous years' expenditure and forecasts.

Figure 5.13 Capital expenditure in 2021

	2021 (actual)	Compared to 2020	Compared to forecast	Compared to peak (year)
Transmission	$84m	▲$15m (▲23%)	▲$55m (▲186%)	▼48% (2014)
Distribution	$623m	▼$20m (▼3%)	▲$8m (▲1.2%)	▼17% (2015)
Total	$707m	▲$4m (▲0.6%)	▲$62m (▲10%)	▼20% (2015)

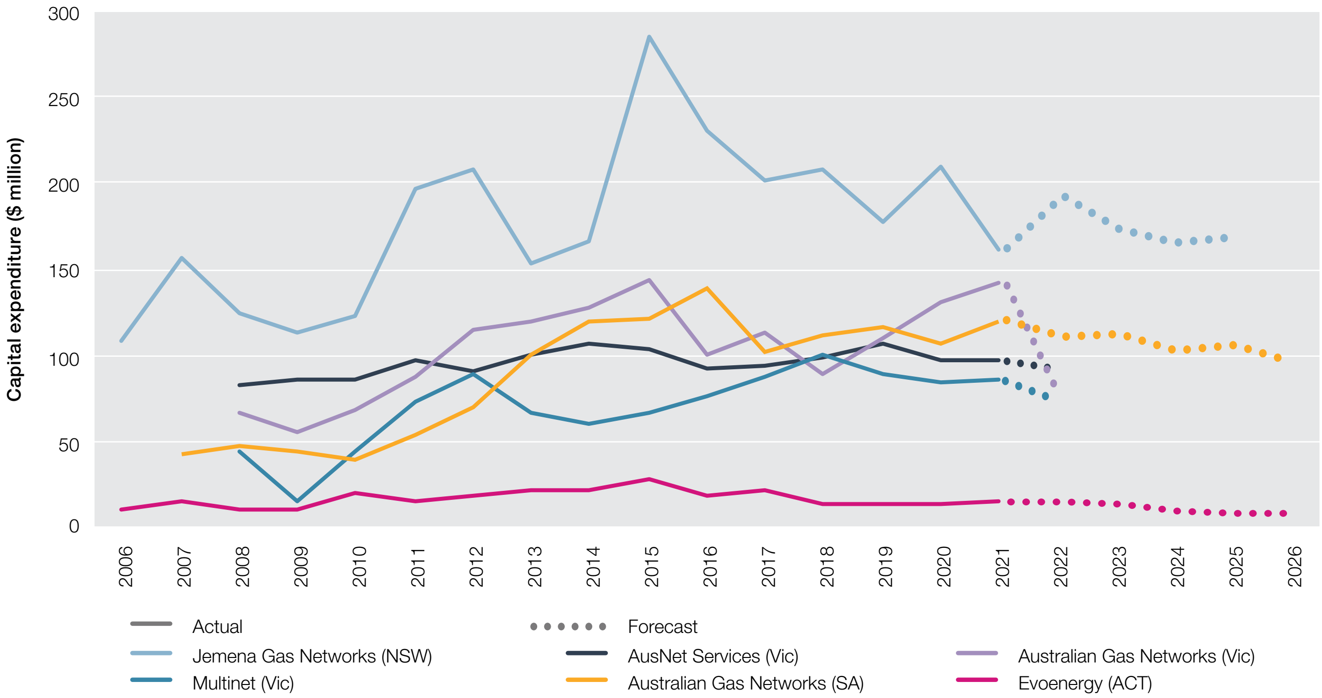
Figure 5.14 Capital expenditure – gas transmission pipelines



Note: All data are adjusted to June 2022 dollars, based on forecasts of the CPI. 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 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; annual reporting RIN responses.

Figure 5.15 Capital expenditure – gas distribution networks



Note: All data are adjusted to June 2022 dollars, based on forecasts of the CPI. 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 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; annual reporting RIN responses.

5.11 Operating costs

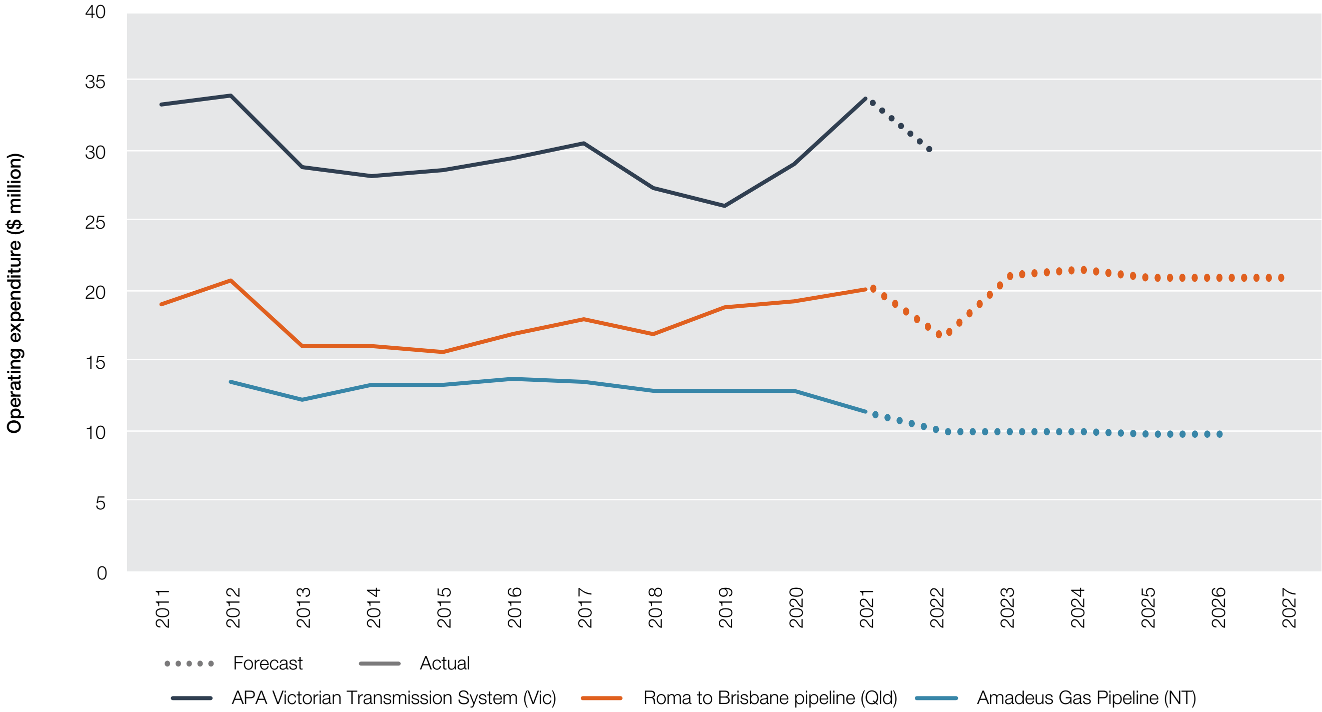
Gas pipelines incur operating and maintenance costs that absorb around 39% of their annual revenue (31% for transmission and 40% for distribution) (Figure 5.5). When assessing a gas pipeline network's efficient operating and maintenance costs, the AER considers cost drivers such as forecast customer growth, expected productivity improvements, changes in labour and materials costs and changes in the regulatory environment. Gas pipelines are subject to an efficiency carryover mechanism, which incentivises them to reduce operating expenditures where efficient to do so.

Figure 5.16 provides a breakdown of network businesses' operating costs in 2021 and how this compared with previous years' expenditure and forecasts.

Figure 5.16 Operating expenditure in 2021

	2021 (actual)	Compared to 2020	Compared to forecast	Compared to peak (year)
Transmission	$65m	▲$4m (▲6%)	▲$6m (▲10%)	▼4% (2012)
Distribution	$468m	▼$19m (▼4%)	▼$85m (▼15%)	▼8% (2012)
Total	$533m	▼$15m (▼3%)	▼$79m (▼13%)	▼8% (2012)

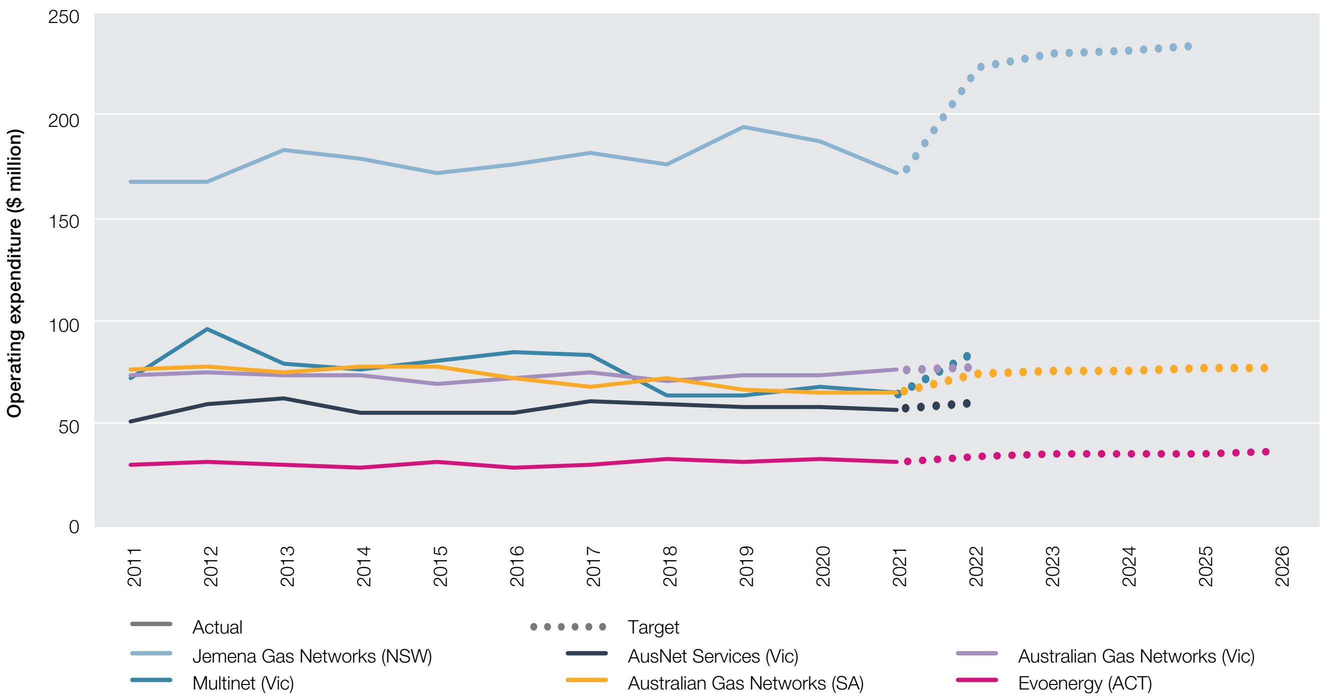
Figure 5.17 Operating expenditure – gas transmission pipelines



Note: All data are adjusted to June 2022 dollars, based on forecasts of the CPI. 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 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; annual reporting RIN responses.

Figure 5.18 Operating expenditure – gas distribution pipelines



Note: All data are adjusted to June 2022 dollars, based on forecasts of the CPI. 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 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; annual reporting RIN responses.

Source: shutterstock

6 Retail energy markets

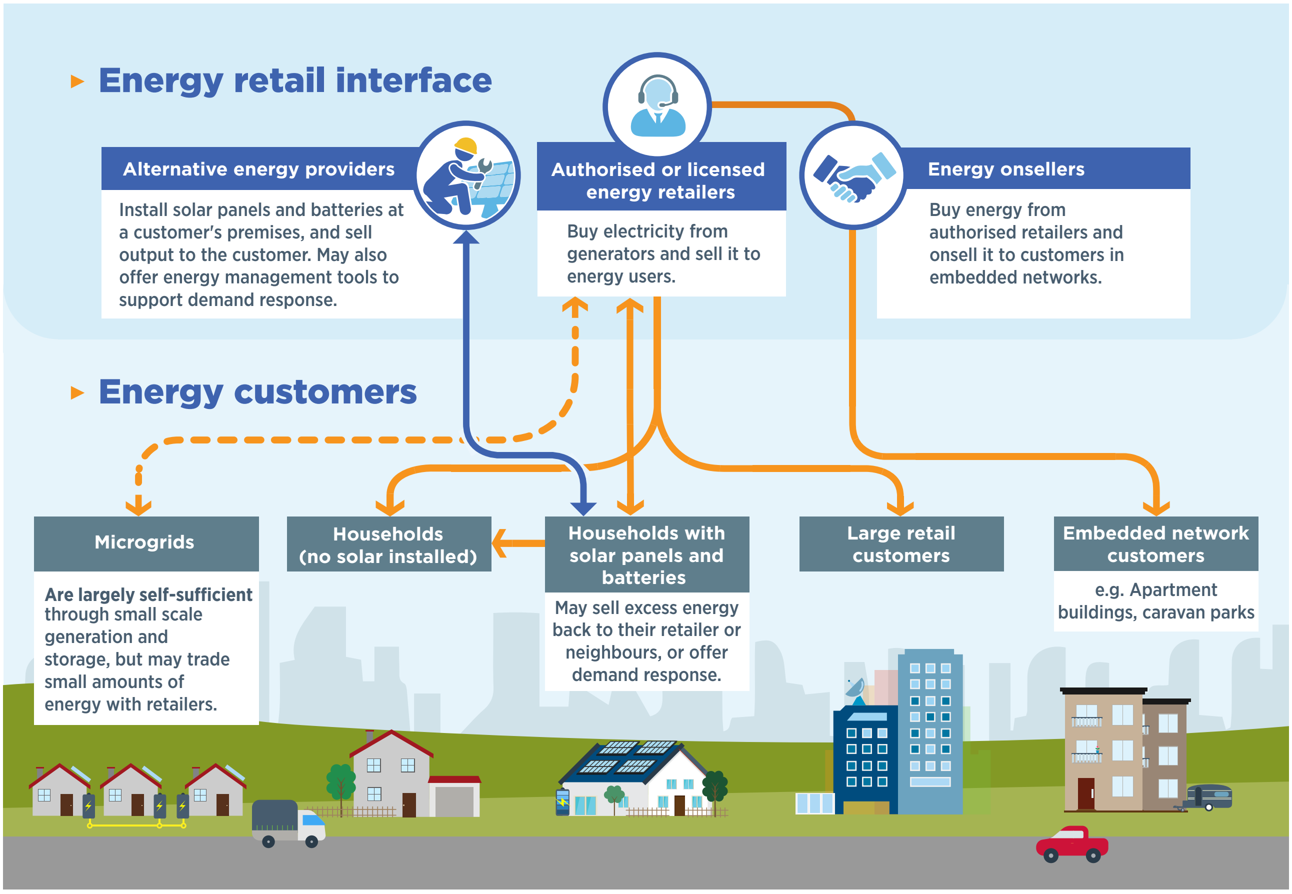
Retail energy markets are the final link in the energy supply chain. Retailers enter into contracts with consumers (such as households and small businesses) to supply energy for an agreed price. The agreed price is used by the retailer to pay for energy it has purchased, as well as the cost of transporting the energy and other system costs.

Retailers purchase electricity and gas either from direct contracts with suppliers or from wholesale markets that use spot pricing based on bids received from energy suppliers.[343] Retailers are exposed to financial risk through spot price volatility in the wholesale electricity and gas markets. To manage this risk, most retailers purchase hedging contracts that limit part, or all of the wholesale price they pay. This is discussed more in section 2.4. Hedging lets retailers offer stable annual prices to consumers, so that consumers have more predictable energy bills instead of bearing the financial risk of energy prices themselves.

A retailer's level of exposure to the very high electricity and gas prices during 2022, and the extent to which these prices will be passed on to its customers, will depend on different factors. These include the sufficiency of the retailers' hedging contracts to protect against the high prices, and expectations around the prices it expects to pay in the future for electricity and gas, including for further hedging or risk mitigation techniques. Contract markets show sharply increased prices for energy derivatives, as well as reduced liquidity in the market. This creates further challenges for retailers to manage their price risk and increases their exposure to the high spot market prices. At the same time, their ability to increase their revenue from their customers is limited until retail contract prices are renegotiated.

The impact of higher wholesale prices on consumers' bills is usually delayed until their energy contract is renewed with new retail prices and the first billing cycle is completed. Many energy contracts (consisting of market offers and standing offers) are determined at the start of the financial year and the billing cycle is usually 90 days. This means that many consumers' energy bills will likely show the impact around October 2022.

Figure 6.1 Retail energy market supply chain



343 Electricity generally must be purchased through the National Electricity Market, but gas is more likely to be purchased directly from suppliers (around 85%) than through the Domestic East Coast Gas Market. See sections 2.3 and 4.3 for more information.

Box 6.1 The AER's role in retail energy markets

The Australian Energy Regulator (AER) regulates retail energy markets so that energy consumers (particularly residential and small business customers) can participate confidently and effectively in those markets to provide protections and support consumers to participate in their energy. We undertake this work for consumers in Queensland, New South Wales (NSW), South Australia, Tasmania and the Australian Capital Territory (ACT).

We aim to enable consumers to make informed decisions on their energy use and to protect consumer rights in the energy market. 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
- 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
- monitor and enforce compliance (by retailers and distributors) with obligations in the National Energy Retail Law, Rules and Regulations
- report on the performance of the market and energy businesses (including information on the cost of energy and its impact on consumers)
- develop hardship guidelines and approve customer hardship policies that energy retailers offer to consumers who are facing financial hardship and seeking help to manage their bills.

6.1 Retail market snapshot

Retail markets have entered a period of significant change:

- As the impacts of high wholesale prices during 2022 flow through to retail markets, retail prices are likely to increase the cost of energy, which had been improving through the end of 2021 (section 6.3.3) based on subdued wholesale market conditions.
- These pressures are reflected in higher default market offers for 2022–23 (section 6.3.2), which mean that standing offers could be revised upwards from 1 July 2022.
- Market offers are typically reset in July each year and these offers will also increase to accommodate the higher wholesale prices, with bills potentially increasing from August (monthly billing cycles) to October 2022 (quarterly billing cycles).
- Through the end of 2021, both electricity and gas retail markets continued to attract new entrants and Tier 2 retailers had maintained market share (section 6.6.1). In 2021 the proportion of small customers on market contracts also increased (section 6.6.5) and an increase in customer switching rates (section 6.6.9) suggests small customers were more engaged in the market. However, prolonged high wholesale prices may exert strain on retail market participants and adversely impact the level of retail competition.
- As of 1 August 2022, 8 retailers have entered the Retailer of Last Resort scheme since 1 May 2022. The combined customer base of these retailers is around 22,000 customers, including almost 20,000 small customers.[344]
- The impact of higher retail prices will flow through to debt levels. We expect to see escalation of consumers' debt levels from late 2022 to early 2023. Worsening of debt levels and other indicators of financial difficulties have already been observed in early 2022 data, demonstrating that consumers are not well placed to absorb further increases in energy costs.
- Recent reforms to retail regulation continue to focus on effective competition – for example, supporting consumers to understand how their bills are calculated and enable them to shop around for a better energy

344 Retailers include Weston Energy Pty Ltd, Pooled Energy Ltd, Enova Energy Pty Ltd, Apex Energy Holdings, Power Club Limited, Mojo Power East, Social Energy Australia Pty Ltd and Elysian Energy Pty Ltd.

contract. These reforms include the release of the AER's Better Bills Guideline (Better Bills)[345] and preparing for greater penetration of consumer energy resources in the NEM through the Energy Security Board's (ESB's) implementation plan for consumer energy resources as part of the Post-2025 Electricity Market Design Project.

The AER is concerned about the impact of these market developments on consumers experiencing vulnerability, recognising that as of March 2022 consumers are already facing higher average levels of debt (section 6.5.3). Consumers experiencing vulnerabilities are also less able to adopt technology and modify their energy use in response to higher prices, or to shop around for a cheaper energy contract. Our strategy focusing on consumers experiencing vulnerabilities will be published this year and will guide our work in responding to these challenges as they emerge.

6.2 Energy market regulation

Five jurisdictions – Queensland, NSW, South Australia, Tasmania and the ACT – apply a common national framework for regulating retail energy markets. The framework applies to electricity retailing in all 5 jurisdictions and to gas retailing in Queensland, NSW, South Australia and the ACT.

The Retail Law operates alongside the Australian Consumer Law to protect small energy consumers in their electricity and gas supply arrangements. It sets out protections for residential consumers and small businesses.[346] Victoria does not apply the national framework but applies similar regulatory provisions.[347]

The Retail Law and equivalent arrangements in Victoria focus on consumer protections related to the traditional retailer–customer relationship. Protections are generally stronger for consumers supplied through an authorised retailer than consumers in embedded networks or entering solar power purchase agreements.

State and territory governments regulate electricity prices in regional Queensland, Victoria, Tasmania and the ACT. Since 1 July 2019 the AER has set caps on 'standing offer' prices[348] for electricity in jurisdictions without state-based price regulation (section 6.4).

This chapter focuses on the 5 jurisdictions where the AER has regulatory responsibilities, but also covers the Victorian market where possible. Western Australia and the Northern Territory apply separate regulatory arrangements and are not covered in this report.

6.2.1 Sellers and resellers of energy services

Market participants that sell and resell energy and services to consumers are classified into:

- those authorised as retailers under the Retail Law
- those exempt from the requirement to be authorised[349]
- 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. Other consumers may be covered by the broader Australian Consumer Law.

6.2.2 Authorised energy retailers

Authorised energy retailers must comply with consumer protection and other obligations under the Retail Law. An authorisation covers energy sales to consumers in all 5 participating jurisdictions.

345 AER, 'Better Bills Guideline', AER Website, 31 March 2022, accessed 15 September 2022.

346 The thresholds for who meets the criteria of a residential customer or small business varies between jurisdictions. For example, in jurisdictions where the Retail Law applies, it includes those consuming fewer than 100 megawatt hours (MWh) of electricity or 1 terajoule (TJ) of gas per year. For electricity, in South Australia, small electricity customers are those consuming fewer than 160 MWh per year. In Tasmania, the threshold is 150 MWh per year.

347 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.

348 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.

349 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.

The AER and the Essential Services Commission (ESC) (Victoria) are responsible for authorising new retailers into the energy market.

6.2.3 Exempt energy sellers

An energy seller may apply to the AER or the ESC (Victoria) for an exemption from authorisation if it only intends to supply energy services to:

- a limited customer group (for example, at a specific site or incidentally through a relationship such as a body corporate)
- supplement its customers' primary energy connection
- sell or supply electricity ancillary to telecommunication services, such as data centres.

At August 2022 over 3,600 businesses were registered in the AER's public register of exemptions, typically to onsell energy within an embedded network (that is, a small private network whose owner sells electricity to other parties connected to the network). Shopping centres, 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 AER's and ESC's exemptions frameworks.

The Australian Energy Market Commission (AEMC) cited stakeholder estimates that up to 500,000 consumers purchase energy through embedded networks.[350] Exemption holders must follow strict conditions and meet a range of obligations to their customers (detailed in the AER's guidelines). Conditions are based on the obligations that apply to authorised retailers and distribution network businesses, but are a lighter, less prescriptive form of regulation.

6.3 Energy bills

The main source of communication between a retailer and a customer is the energy bill. Energy bills set out a customer's energy consumption over a period of time and then how the retailer is charging the customer for that consumption based on the terms of their retail contract. Consumers use bills to understand their energy usage, costs and how to get help. The information in bills also helps consumers to make more confident decisions, such as making sure they are on the best deal for them or shopping around for a better deal.

Finding the best deal or shopping around for a better one can be complicated. Retail contracts or 'offers' can vary significantly, and hundreds of retail offers may be available to customers at any one time. Advertised offers frequently change, as do the terms and 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'. While energy bills can't solve these problems, they can help consumers make more confident decisions by providing them with information to help them understand and compare their energy contract.

6.3.1 Better Bills Guideline

Consumers expect bills to be simple, easy to understand and a source of information about how and when to pay. However, energy bills can be cluttered, complex and confusing, which burdens consumers with cognitive overload and reduces bill comprehension.

In March 2022, the AER released the Better Bills Guideline setting out how retailers must prepare their bills, making it easier for consumers to:

- pay their energy bills
- understand the bill calculation and ensure their bill conforms to their contract
- query their bill
- access interpreter services and seek financial assistance
- report a fault or emergency
- understand their usage to help them use energy efficiently, compare offers and consider new types of energy services.

350 AEMC, 'Updating the regulatory frameworks for embedded networks', AEMC Website, 20 June 2019, accessed 8 April 2022.

The guideline restricts the amount of content allowed on the first page, so it is clean and simple. This will give consumers the essentials at first glance and improve comprehension.

Consumers will now find information on the first page about whether a better offer from their retailer might be available, under the heading ‘Could you save money on another plan?’. Elsewhere on the bill, consumers will also find a simple plan summary that sets out the key features of their plan, including when any benefits are due to expire.

Retailers must comply with the new requirements in the guideline by 31 March 2023.[351] The AEMC is currently consulting on whether the compliance date should be extended by 6 months.

6.3.2 Components of electricity bills

A typical residential electricity retail bill comprises:

- retailers’ wholesale costs of buying electricity in spot and hedge markets
- network costs for transporting electricity through transmission and distribution networks, and metering
- the costs of environmental schemes for promoting renewable generation, energy efficiency and reducing carbon emissions
- the retail costs of servicing customers (including meeting regulatory obligations) and acquiring and retaining customers
- the retailer’s margin (profit).

The contribution of each cost component varies by jurisdiction (Figure 6.2).

Figure 6.2 Composition of a residential bill – electricity

Note: Cost components for the average residential customer in 2021–22, excluding GST Calculated using tends in supply chain components for each jurisdiction and national trends.

Source: AEMC, *Residential electricity price trends 2021*, 25 November 2021 (using data from Energy Made Easy and Victorian Energy Compare on 17 September 2021).

351 AER, ‘Better Bills Guideline’, AER Website, 31 March 2022, accessed 15 September 2022.

6.3.3 Wholesale costs

Retailers purchase energy in wholesale markets for sale to customers. Retailers generally charge their customers fixed prices for energy but need to purchase energy at variable prices in wholesale markets. This means that retailers are exposed to price risk, where they may need to purchase energy at higher prices than they charge their customers. Retailers generally manage this risk by taking into account price volatility when setting retail contract prices and by entering hedge contracts that lock in prices for their future wholesale purchases (section 2.3). Alternatively, they might own generation assets or enter demand response contracts to manage risk (discussed in sections 6.6.4 and 6.7.4).

Wholesale costs typically make up around 32% of the bill. During 2022, wholesale spot prices have increased sharply across all NEM regions. Contract prices for 2022 and 2023 also increased in line with spot prices, particularly in Queensland and NSW.[352] It is expected that spot and contract prices will remain high due to the unknown impact and timing of further coal closures and international pressures.

6.3.4 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. Distribution networks account for the majority of network costs (around 76% across the NEM). Transmission networks account for up to 18% of network costs, with metering accounting for the balance.

Regulated network costs are expected to increase over the 4-year period ending 2023–24, driven by increases in distribution and transmission costs. This will include expenditure to improve the networks' ability to handle higher levels of consumer energy resources, intending to lead to savings for consumers in the longer term.

Customer type (central business district (CBD), urban or rural), area density and local 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 3.15.1).

6.3.5 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 account for over 70% of environmental costs across the NEM (comprising both large-scale and small-scale components of the scheme).

Environmental costs are expected to decrease over the 4-year period ending 2023–24. This forecast is driven by a decrease in Large-scale Renewable Energy Target (LRET) costs, stemming from a reduction in the cost of large-scale generation certificates (LGCs) across several jurisdictions.

ACT and South Australian customers face the highest environmental costs (on a per unit of electricity basis). ACT costs are largely related to the government's feed-in tariff scheme for large-scale solar developments, which accounts for more than 70% of environmental costs. South Australian costs flow from the state's premium distributor 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 Victoria, where the primary cost component was the jurisdictional Small-scale Renewable Energy Scheme (SRES).[353]

6.3.6 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 jurisdictions.

› 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. In theory, these costs should

352 AER, 'Wholesale markets quarterly – Q1 2022', AER Website, 26 May 2022, accessed 15 September 2022.

353 AEMC, 'Residential electricity price trends 2021', AEMC Website, 25 November 2021, accessed 1 February 2022.

be offset by reduced retailer profit margins that are driven down due to competition, but there is a risk that competition may increase energy bills for customers if the costs of competing outweigh competition benefits from efficiency and innovation.

Retailers' margins in 2020–21 were slightly higher than in the previous year, which marked the lowest level we have observed. The default market offer (DMO) (Box 6.2) and Victorian Default Offer (VDO) reforms are likely to have been significant factors in reducing retail margins.[354]

The AEMC estimates that retailer costs and margin made up almost 22% of a customer bill in Tasmania in 2021–22, compared with around 2% in south-east Queensland.[355] Some of the differences between jurisdictions is due to the different methodologies used to set prices by the different regulators.

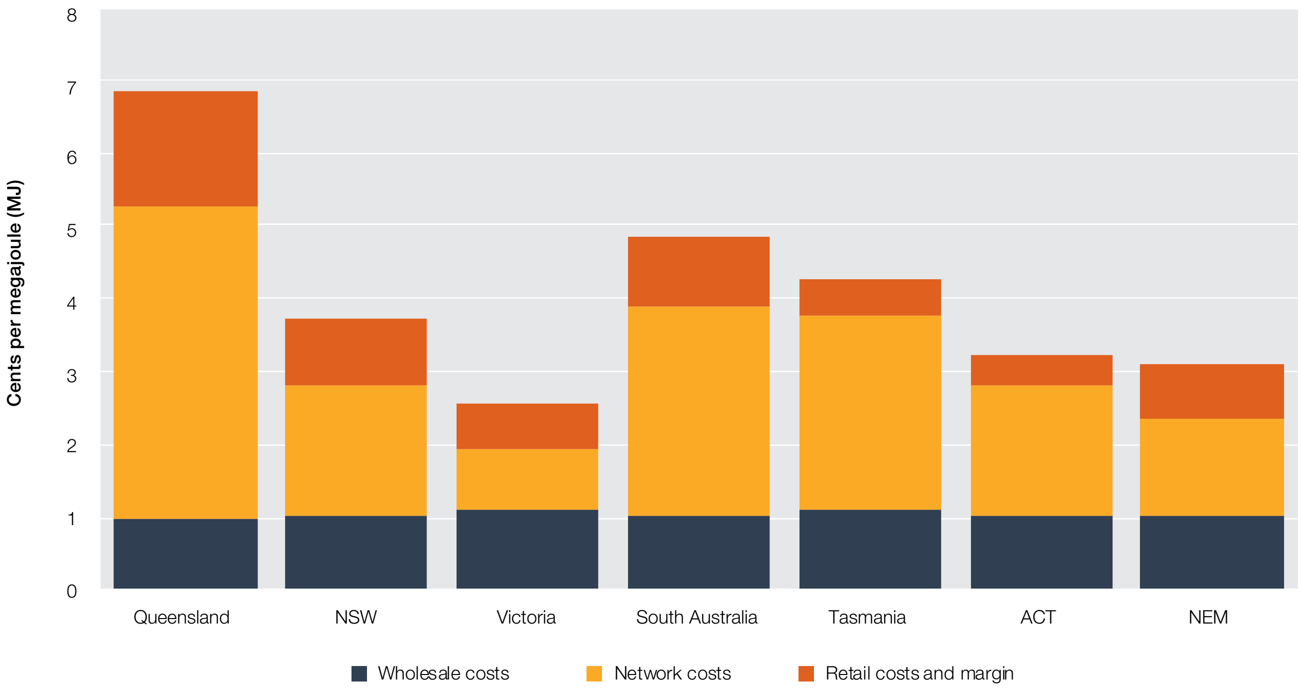
6.3.7 Components of gas bills

The composition of a retail gas bill is less transparent than it is for electricity due to the absence of a regulatory responsibility to regularly analyse the different cost components. Estimates from the most recent comprehensive data (published in 2017) show that gas pipeline charges made up over 40% of a residential gas bill in that year, on average.[356]

Victoria had the cheapest residential gas prices per unit of gas, largely because the state had lower network costs due to a higher level of gas use per residential customer and higher connection penetration. In Queensland, South Australia and Tasmania, where gas use is less widespread, network costs accounted for more than half of the average residential gas bill.

Retail costs also varied across jurisdictions, with Queensland reporting 72% higher retail costs (on a per unit basis) than the next highest jurisdiction (South Australia). This may also reflect the absence of economies of scale for retailers servicing a relatively small customer base (Figure 6.3).[357]

Figure 6.3 Composition of a residential bill – gas



Note: Data are estimates at 2017. Average residential customer prices excluding GST (real $2018–19).
Source: Oakley Greenwood, Gas price trends review 2017, March 2018.

354 ACCC, 'Inquiry into the national electricity market', ACCC Website, 22 November 2021, accessed 3 February 2022.
355 AEMC, 'Residential electricity price trends 2021', AEMC Website, 25 November 2021, accessed 1 February 2022.
356 Oakley Greenwood, 'Gas price trends review 2017', Department of the Environment and Energy Website, March 2018, accessed 15 September 2022, p 158.
357 Oakley Greenwood, 'Gas price trends review 2017', p 225.

6.3.8 How retail prices are set

Energy retailers in southern and eastern Australia are responsible for setting prices for energy market offers. Market offers are energy contracts advertised by retailers that consumers actively enter into. Alongside this market pricing, government agencies regulate prices for electricity standing offers. Standing offers are energy contracts that consumers are placed on by default if they do not enter into a market contract.[358]

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 response to later market reviews.

In 2019 the Australian Government appointed the AER to set a default market offer (DMO) as a cap on standing offer electricity prices in south-east Queensland, NSW and South Australia.[359] The DMO is not intended to mirror the lowest price in the market because this would impede competition among retailers and incentivise consumers to disengage from the market (Box 6.2). Around 7–11% of residential customers and 15–20% of small business customers are on standing offers.[360] The DMO also represents a reference point (or 'reference price') from which any advertised discounts promoted by electricity retailers must be based, providing consumers with meaningful information they can use to compare offers.

The Victorian Government also introduced price controls from 1 July 2019. The 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.

Regional Queensland, Tasmania and the ACT 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 jurisdictions, as does the extent to which the standing offer allows for the recovery of customer acquisition and retention costs (such as advertising). In 2021 the ACT Government announced plans to introduce a reference bill requirement for advertising market offers.

Gas price deregulation occurred along similar time frames to those of electricity price deregulation but was not part of the more recent reintroduction of price controls for electricity. In July 2017 NSW became the last jurisdiction to deregulate retail gas prices for small customers.

In June 2020 the Australian Government introduced further price protections. 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. The ACCC is responsible for investigating contraventions and published guidelines in May 2020.[361] In April 2021, the ACCC published its findings on retailers' compliance with the legislation and stated they had approached retailers who may not have adequately passed on cost savings to their customers.[362]

358 AER, 'Default market offer prices 2022–23 – Final determination', AER Website, May 2022, accessed 15 September 2022, section 3.1.

359 The AER's responsibilities are set out in the Competition and Consumer (Industry Code – Electricity Retail) Regulations 2019.

360 AER, 'Default market offer prices 2022–23 – Final determination', section 3.1.

361 ACCC, 'Guidelines on Part XICA – Prohibited conduct in the energy market', ACCC Website, 11 May 2022, accessed 15 September 2022.

362 ACCC, *$900 million in electricity bill savings available to households* [media release], ACCC, 13 April 2021, accessed 15 September 2022.

Box 6.2 Default market offer

The default market offer (DMO) is the maximum price an electricity retailer can charge a standing offer customer each year. A customer might be on a standing offer if they have never switched to a retailer's market offer or for a range of other reasons.

The scheme was introduced in 2019, 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 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). The AER determines DMO prices each year for residential and small business customers in each of these areas. Victoria operates a separate, but similar, scheme across all its distribution network areas.

The scheme caps how much retailers can charge in their standing offers, but it does not cap customers' bills. Energy bills will vary based on the customer's energy consumption and the specific terms of their retail contract.

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 consumers 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 lower-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.[a] The default price has been updated in 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).

In determining the prices in our 2022–23 DMO (DMO 4) review we considered stakeholder feedback and undertook a holistic review of our price setting methodology. The outcome of our review was to adopt a cost build-up approach for the DMO 4 determination.

We consider a cost build-up approach best achieves the DMO policy objectives. Under this approach we will update the retail operating costs on a yearly basis as new cost information becomes available. This approach addresses retailer concerns with the step-change framework because actual changes in retail costs will be included in future DMO determinations. We expect to continue using this approach in DMO 5 (2023–24) and DMO 6 (2024–25).

Note: a AER, Final determination, Default market offer prices, April 2019.

6.4 Retail energy prices

Retail energy prices fell in 2021, primarily driven by a decrease in wholesale costs. However, retail prices are expected to rise in 2022 and 2023 in response to this year's sharply increased wholesale costs and forward contract prices.

Electricity and gas prices have demonstrated broadly similar trends over time because some key underlying price drivers apply to both fuels (Figure 1.1).

6.4.1 Electricity price movements from 2018 to 2021

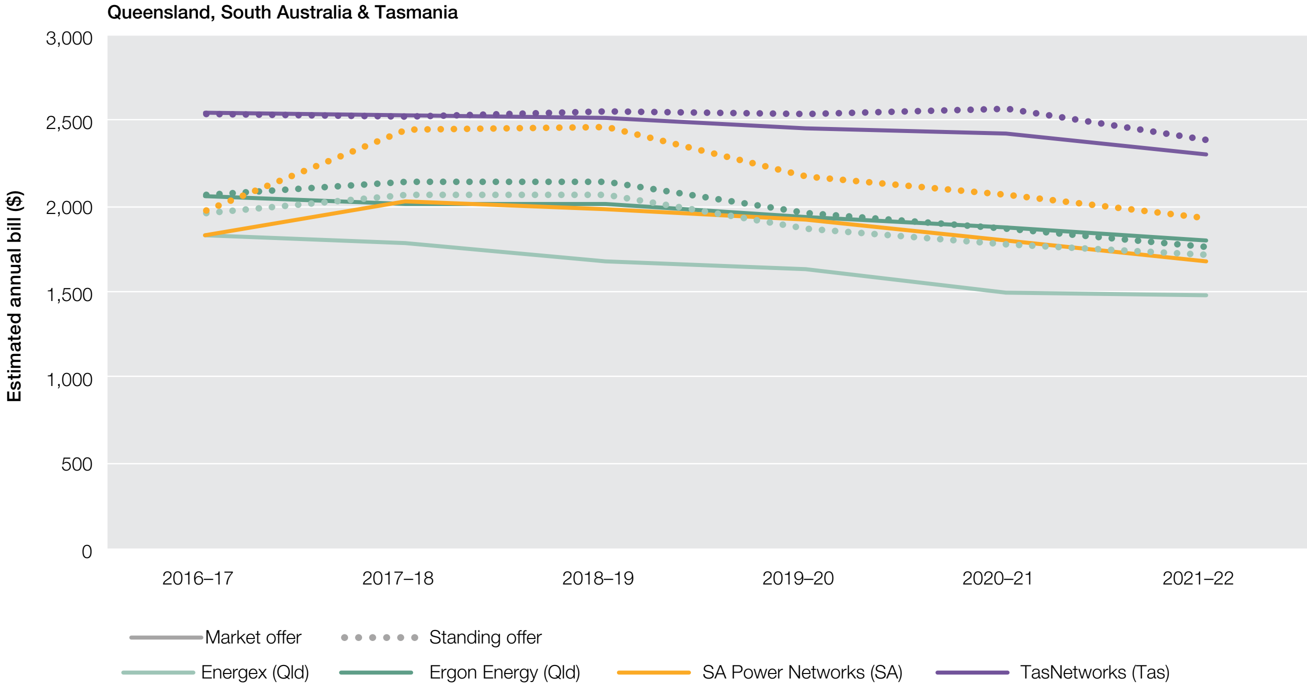
Electricity retail prices fell for the third consecutive year in 2021, dropping by 9% from the previous year and reaching their lowest level since 2012. However, there has been a reversal of this trend in the first half of 2022 due to recent wholesale price increases.

Decreases in market offer prices were most evident in 2020 and 2021 as a lagged response to sharply falling wholesale costs over the previous years 2019 and 2020. Cost reductions were driven by a range of factors, including new low-cost wind and solar farms, low demand due to moderate weather conditions and increased rooftop solar output, and lower coal and gas fuel costs. Lower network costs also contributed to retail price falls in some jurisdictions.

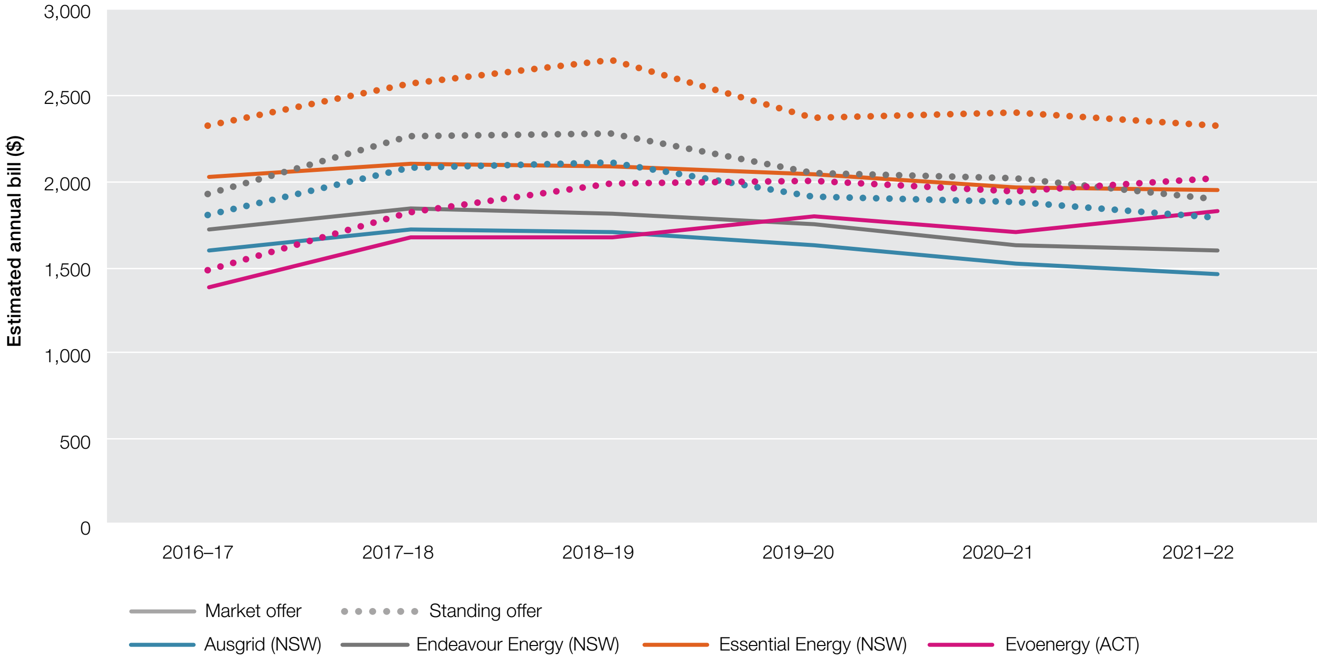
Market offers and standing offers were lower in 2021–22 than they were 3 years ago in every jurisdiction except the ACT, where they increased due to environmental costs (Figure 6.4).

The cheapest market offers in 2021 were typically offered by smaller Tier 2 retailers rather than by one of the 'big 3' retailers (Origin Energy, AGL Energy and EnergyAustralia). 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).

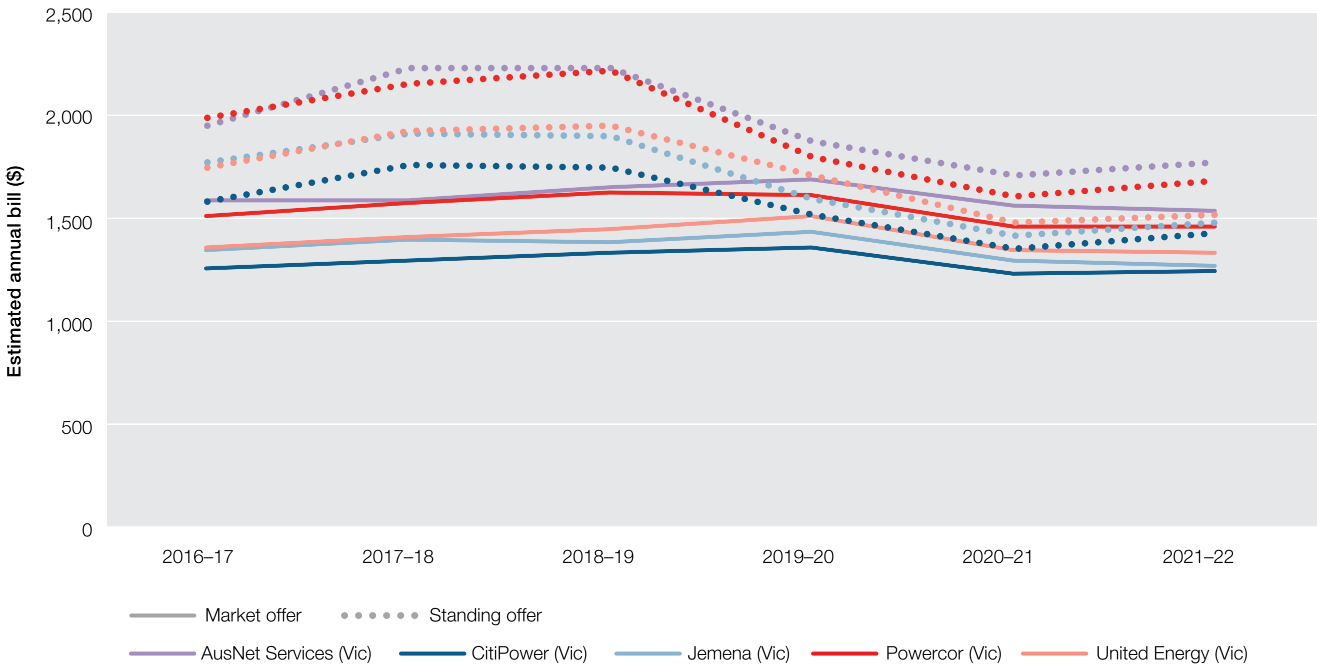
Figure 6.4 Electricity bills for customers on market and standing offers



New South Wales & ACT



Victoria



Note: Ergon Energy's standing offer prices are set by the Queensland Competition Authority (QCA). TasNetworks' are set by the Office of the Tasmanian Economic Regulator (OTTER). Standing offer prices on the Victorian distribution networks are set by the Essential Services Commission (ESC). Evoenergy's are set by the Independent Competition and Regulatory Commission (ICRC). Energex, SA Power Networks, Ausgrid, Endeavour Energy and Essential Energy's standing offer prices are set by the retailers (capped at DMO).

Based on single rate offers for residential customers and average consumption in each distribution area. Average consumption for 2020–21 has been applied to all periods. Some offers listed may not be available to all customers in a distribution area.

The AER will update its analysis on more recent offers for the Annual Retail Performance Report 2022.

On Ergon Energy's network there are few market offers available and some offers are restricted to specific geographic areas.

Source: Victorian Energy Compare (DELWP). Consumption based on Economic benchmarking regulatory information notice (RIN) responses.

6.4.2 Gas price movements from 2018 to 2021

In 2021 gas retail prices fell by 5% from the previous year, reaching the lowest level since 2016. Gas retail prices had been trending down since 2018 in most jurisdictions, driven largely by lower wholesale gas costs. This was similar to the price reductions in electricity, but price reductions were less pronounced in gas (Figure 6.5).

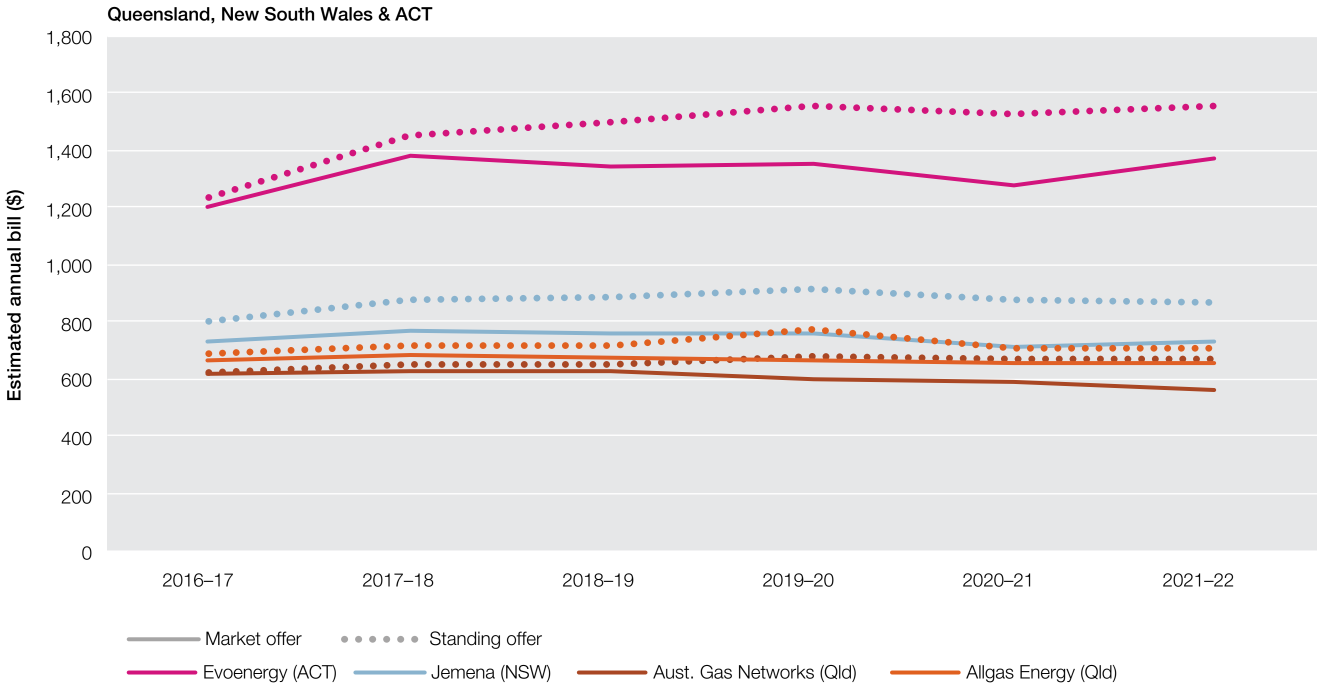
After easing in 2019 and 2020, gas wholesale costs increased significantly over 2021. As a result, average wholesale gas prices in 2021 were 80% higher than they were in 2020 (section 4.3). As in electricity, wholesale cost increases take time to flow through to retail prices, as longer-term contract positions are adjusted, and they may not yet be fully reflected in retail prices observed over 2021. Gas wholesale costs have increased further in 2022 and we expect to see further upward movement in retail prices to reflect this.

Market offers for gas were lower than they were 3 years ago in every jurisdiction, except in South Australia and the ACT (Figure 6.5). Estimated annual customer bills in 2021–22 ranged from $560 in Queensland to $1,369 in the ACT.[363]

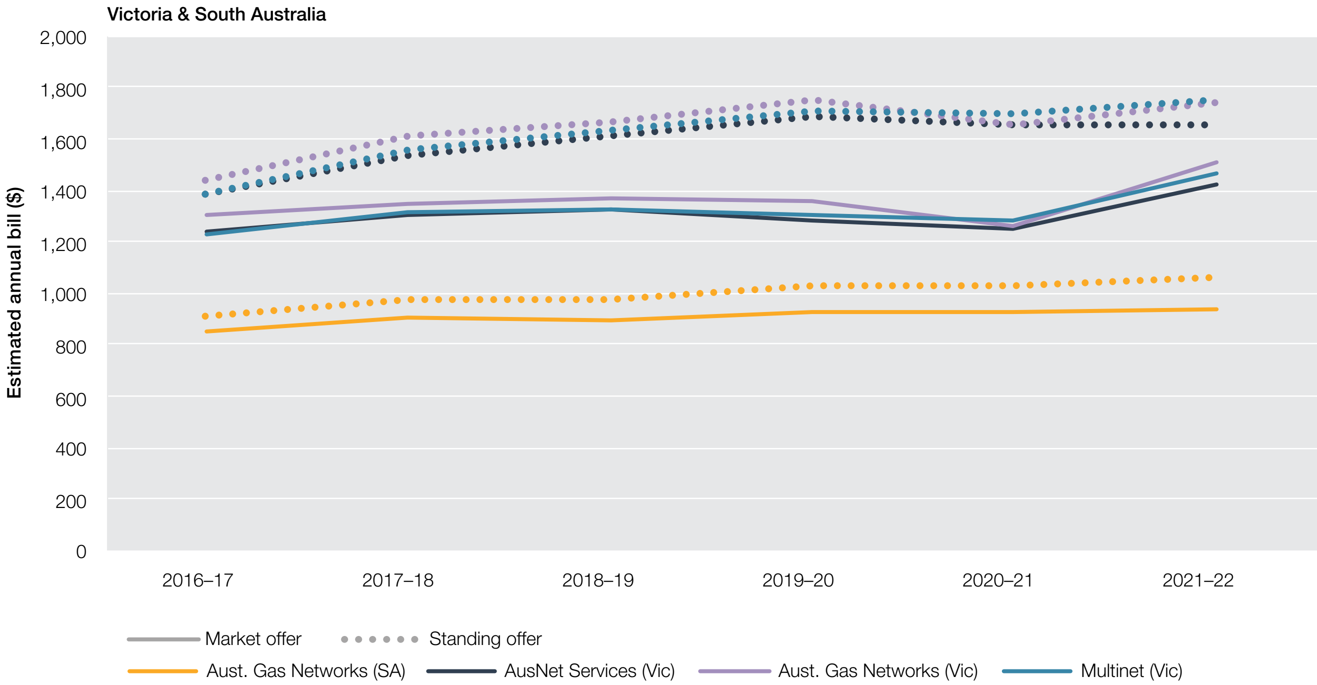
Standing offer prices for gas followed a different trend to market offer prices, with the median price remaining stable or increasing in all jurisdictions between June 2018 and February 2021. Unlike electricity, there is no price regulation of standing offer gas prices.

As at March 2022, the lowest Tier 2 gas market offers in Queensland, SA and the Jemena Gas zone in NSW were $35 to $107 cheaper than the lowest offer from the 'big 3' retailers. In contrast, in the ACT and the AGN and Allgas zones in NSW, one of the 'big 3' retailers had gas market offers that were $17 to $70 cheaper than the lowest offer from Tier 2 retailers. However, with international gas prices increasing sharply over 2022, those retailers offering the cheapest offers may change in future periods.

Figure 6.5 Gas bills for customers on market and standing offers



363 Estimated annual customer bills for generally available flat rate offers, by distribution company.



Note: Based on offers for residential customers and estimated consumption in each jurisdiction.

Source: AER analysis using offer data from Energy Made Easy (AER) and Victorian Energy Compare (DELWP). Consumption based on Frontier Economics report to the AER, *Residential energy consumption benchmarks,* December 2020.

6.4.3 Electricity price forecasts

The AER's final DMO determination for 2022–23 estimates that future retail prices will increase across all DMO regions for all customer types (residential and small business customers). This was mainly due to higher expected wholesale costs in all regions, especially NSW and Queensland. Factors contributing to this include unplanned generator outages, higher coal and gas costs, and increasingly 'peaky' demand driving up the cost of energy contracts for retailers. Analysis in section 2.3 and the AER's Q2 2022 wholesale quarterly report includes more recent market events and confirms even higher than expected wholesale costs in all regions.

As part of our DMO determination, we forecast the cost components of future retail prices such as wholesale costs and network costs. Due to a change in methodology ahead of the 2022–23 determination, the DMO determinations for 2021–22 and 2022–23 are not directly comparable. However, adjusting for the changed approach, our final determination increases the price cap on standing offer prices for residential customers across all DMO regions in 2022–23 by between 1.7% and 12.1% in real terms.[364]

Recent surges in wholesale electricity prices are putting immediate upward pressure on retail prices available to consumers. These surges reflect the combined impacts of:

› reduction in thermal generation resulting from unplanned outages and higher costs
› impacts from the ongoing war in Ukraine, which has led to significant pressure on coal and gas prices globally
› extreme weather in NSW and Queensland, which has affected coal supplies and electricity demand
› increasingly 'peaky' demand driving up the cost of hedging for retailers.

In coming years, high inflation outcomes will flow-through to network costs, and we are seeing evidence of increasing interest rates that may translate to higher required costs for network capital raising. In combination, they will pose continued pressures on electricity prices.

Looking beyond 2022–23, it is difficult to forecast retail costs but they are expected to remain relatively high over the next 2 years. Changes in wholesale costs will depend on the timing and impact of coal closures, international and coal prices, new renewables coming online, additional long-term storage and transmission investment. Higher network costs are forecast to put upward pressure on retail prices in all jurisdictions.

364 AER, 'Default market offer prices 2022–23 – Final determination'.

6.4.4 Energy use

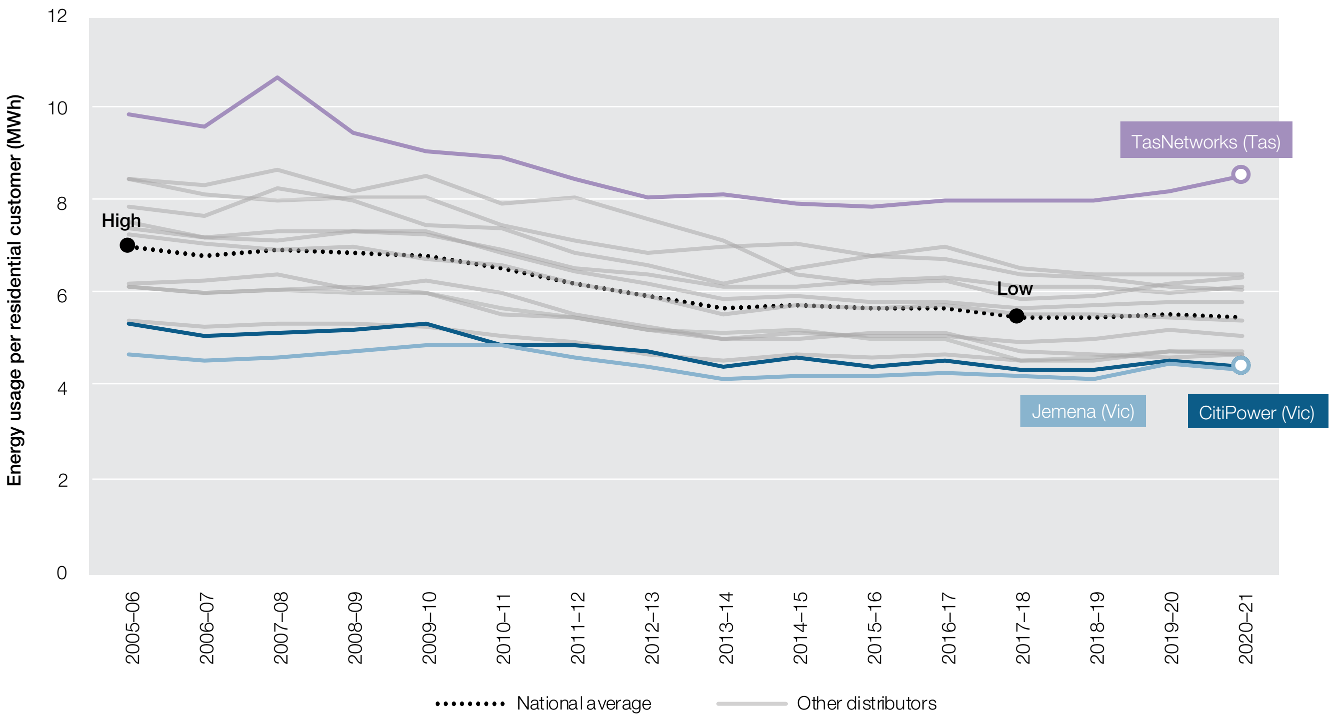
Usage charges (charges accrued per unit of electricity consumed) represent the largest component of energy bills for most households.[365] A consumer's energy use significantly impacts energy affordability (section 6.5). Energy use varies with household size, housing and appliance quality, heating and cooling needs, and lifestyle.

Residential customers in Tasmania and the ACT use the most electricity (per customer) in the NEM. Conversely, residential customers on CitiPower's (Victoria) and Jemena's (Victoria) networks use the least. 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. Customers in colder climates such as Victoria and the ACT tend to use the most gas. This largely reflects the use of gas for space heating – gas use in these jurisdictions is 6–7 times higher in winter than over summer.[366] Tasmania has low gas penetration for households so, although it is a colder climate, it uses comparatively less gas than Victoria and the ACT. 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.[367]

Overall, the amount of energy residential consumers are using has reduced across jurisdictions over the past 10 years. This has helped to moderate the impact on consumers of significantly higher retail energy prices compared with 2012, although average household electricity use has remained stable over the past 3 years in some jurisdictions. The longer-term trend of lower electricity use has been largely driven by the uptake of rooftop solar PV systems. Improving energy efficiency of new homes and appliances also contributed. In addition to these changes in consumer behaviour, switching from gas to electricity means that average gas use has trended downwards (Figure 6.7).

Given these drivers of lower energy use, the reported average outcomes likely obscure a widening gap between use for those households with the capacity to adopt new technology or modify energy use and those unable to do so (due to 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, and these customers are likely spending more on electricity compared with 10 years ago. Figure 6.6 and Figure 6.7 show the differences in energy consumption in different regions up to 2021. The AER's Annual retail market report 2022 will include more detailed analysis of energy use across different demographics and is due to be released in November 2022.

Figure 6.6 Energy use per residential customer – electricity



MWh: megawatt hour.

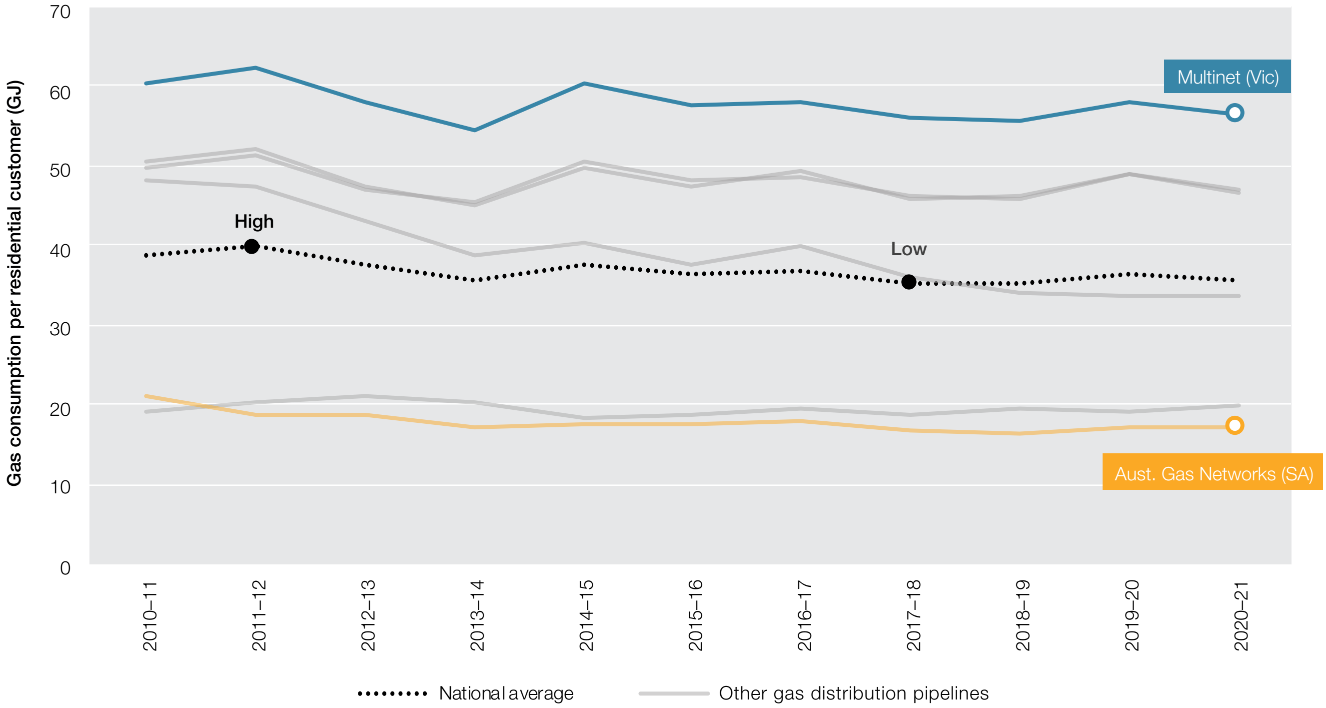
Source: Regulatory information notices (RIN) responses.

365 Most energy offers include usage charges as well as a fixed supply charge. Some offers also include membership fees or additional charges for metering.

366 Frontier Economics, 'Residential energy consumption benchmarks, final report for the Australian Energy Regulator', AER Website, December 2020, accessed 15 September 2022, p 26.

367 Frontier Economics, 'Residential energy consumption benchmarks, final report for the Australian Energy Regulator', p 25.

Figure 6.7 Energy use per residential customer – gas



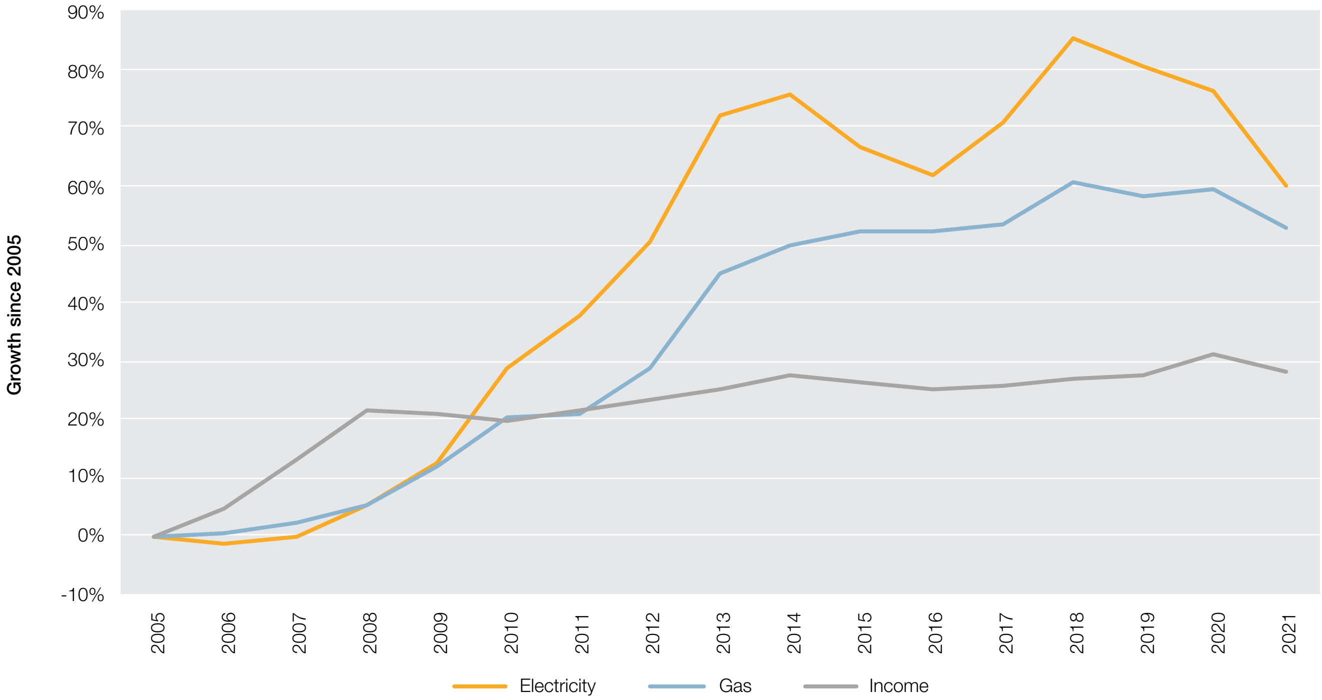
GJ: gigajoule.

Source: Regulatory information notices (RIN) responses.

6.5 Energy affordability

Energy affordability relates to customers' ability to pay their energy bills. A customer's energy use, energy contract and prices, income and other living costs affect affordability. Energy bills can be a significant burden for households even in times of relatively low electricity prices.

Figure 6.8 Energy prices and income



Note: Inflation adjusted.

Source: Electricity and gas index – ABS, Consumer Price Index, various years; income index – ABS, Household Income and Wealth, Australia, various years.

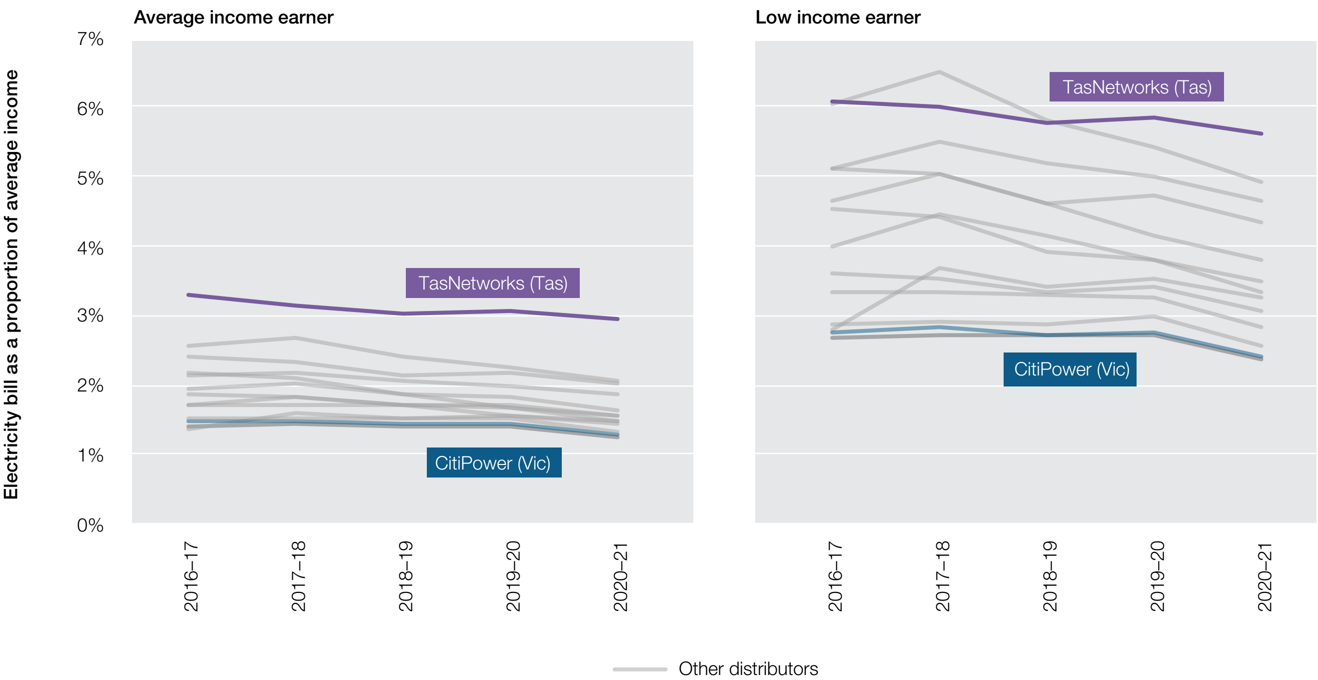
Subdued wholesale market conditions over the past few years (prior to 2022) did flow through to retail prices, which had a positive impact on affordability across all jurisdictions in 2020–21 (Figure 6.9). However, consumers are still recovering from the economic impacts of COVID-19 and slow wage growth since the early 2000s. This means that consumers are not well-placed to absorb the current sharp increases in wholesale energy prices, as well as the forecast increases in network costs to fund the necessary longer-term investments. We expect to observe worsening outcomes for consumers regarding energy affordability for the foreseeable future.

Retail energy prices paid by consumers 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.

This means that affordability challenges are not split evenly across all consumer types. The evidence suggests that affordability differs substantially across consumers based on differences in both retail energy prices and energy use. For example, 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.

On the mainland, estimated annual customer electricity bills in 2021–22 ranged from $1,243 for a customer in urban Victoria to $1,951 for a customer in rural NSW.[368] This is likely driven by both electricity prices and the different energy use profiles.

Figure 6.9 Affordability of median market offer – electricity



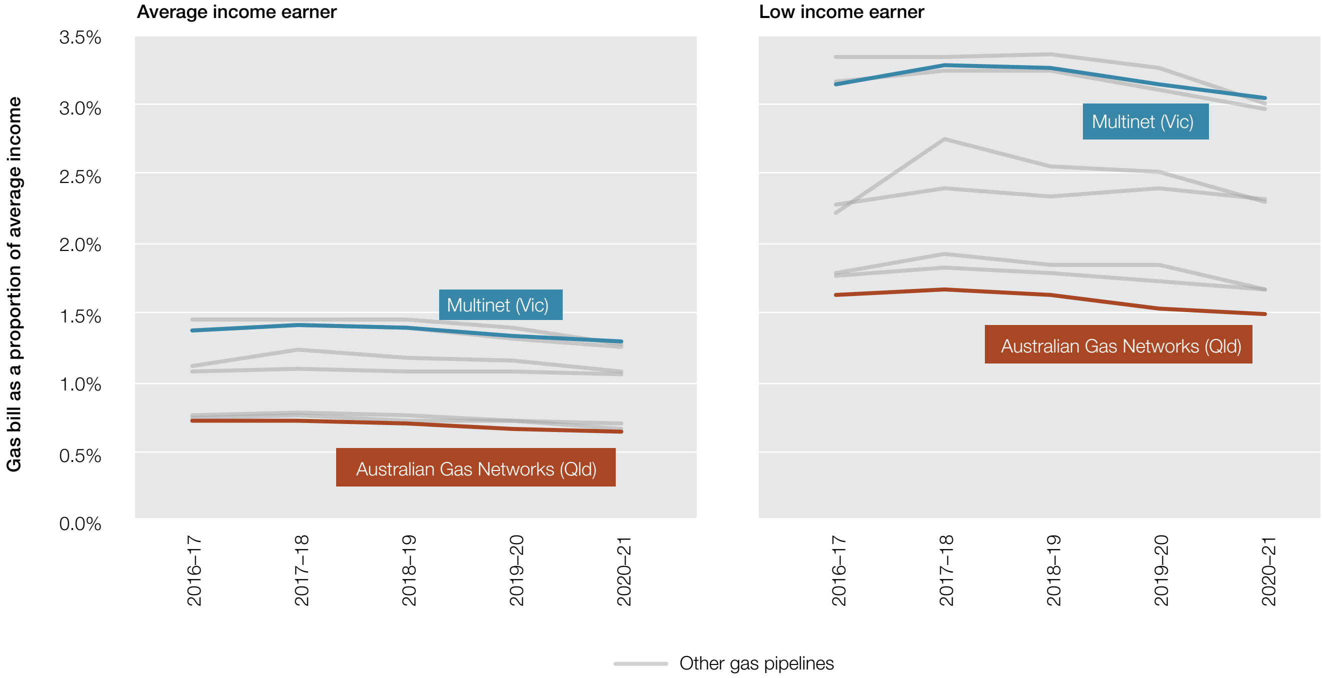
Note: Based on offers for residential customers in each jurisdiction. Average household consumption for the financial year ending June of each period was used in annual bill calculations. Proportion refers to mean disposable income. Use of average incomes across jurisdictions may overstate affordability in regional areas, where average incomes are typically lower than across the jurisdiction more broadly.

Source: Offer data from Energy Made Easy (AER) and Victorian Energy Compare (DELWP). Consumption estimates based on Economic benchmarking regulatory information notice (RIN). Income data are unpublished ABS estimates of household disposable income.

While the DMO and VDO provide price protections, other recent reforms to improve affordability focus on price competition at the retail level, such as rules on conditional discounting, and the role of the DMO as a reference price, which helps consumers more easily compare offers by different retailers.

368 Estimated annual customer bills for generally available flat rate offers by distribution company.

Figure 6.10 Affordability of median market offers – gas



Note: Based on single rate offers for residential customers and average consumption in each distribution area. Using mean disposable income for all and low-income households by state or territory. Use of average incomes across jurisdictions may overstate affordability in regional areas, where average incomes are typically lower than across the jurisdiction more broadly.

Source: Offer data from Energy Made Easy (AER) and Victorian Energy Compare (DELWP). Income data are unpublished ABS estimates of household disposable income. Consumption based on Frontier Economics report to the AER, Residential energy consumption benchmarks, December 2020.

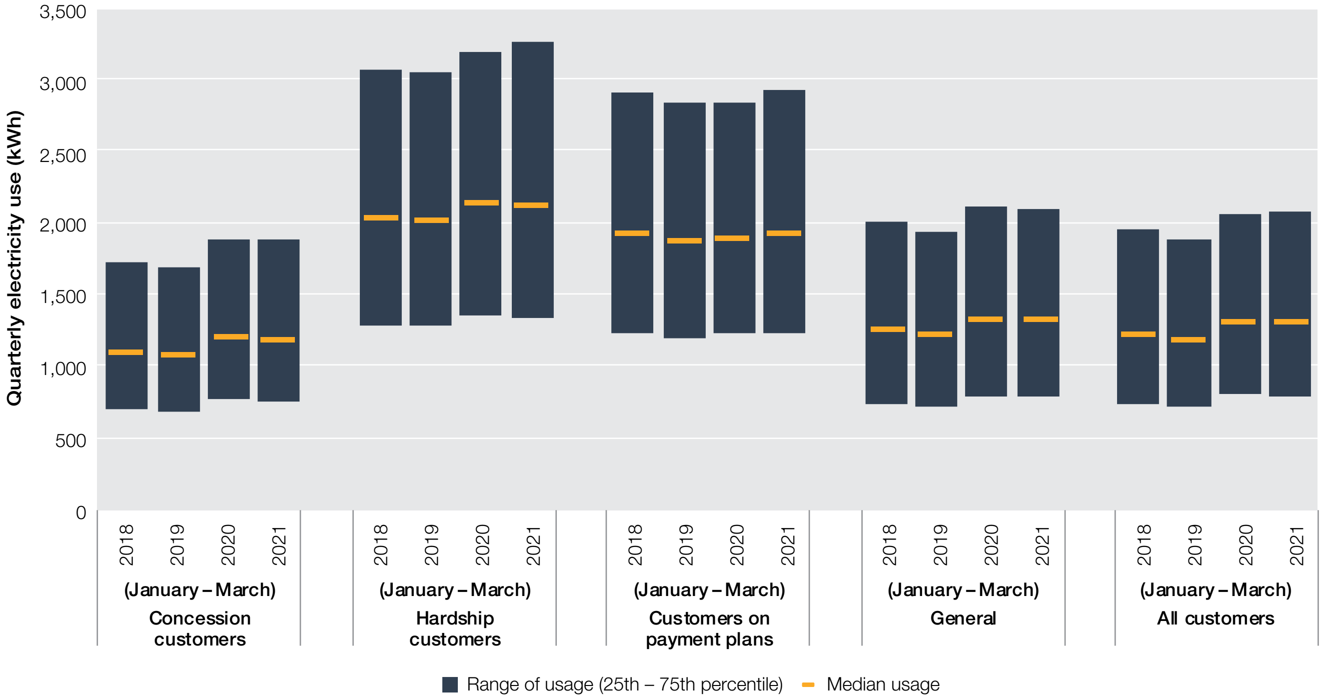
Nonetheless, electricity affordability remains a top cost of living issue for households.[369] Many households can achieve savings simply by switching to a cheaper offer, but the range of offers and the pricing structure can be too complex and a barrier to consumers. Recent regulatory reforms have focused on improving Energy Made Easy, switching processes and the creation of the Better Bills Guidelines to better support consumers' ability to switch.

Autonomy and resources to address energy use also plays an important role in energy affordability. For example, customers on hardship programs in 2021 consumed on average over 60% more electricity than a typical customer (Figure 6.11). This likely reflects 2 aspects:

- consumers who don't have access to energy saving or self-generating measures, such as solar PV systems, have high consuming appliances and live in less energy efficient dwellings face higher bills – therefore, they are more likely to experience financial hardship
- consumers who live in rental properties may be reliant on property owners to make the needed property improvements before they can reduce their energy use, and property owners may lack incentives to make these improvements, leading to a waste of energy resources that could be absorbed back into the system.

369 In a survey of households by Energy Consumers Australia (ECA), 86% said that they were highly or moderately concerned that electricity and gas will become unaffordable for them in the next 3 years. ECA, 'Pulse Survey June to August 2022', ECA Website, August 2022, accessed 15 September 2022.

Figure 6.11 Electricity use, by residential customer type



kWh: kilowatt hour.
Source: ACCC, Inquiry into the National Electricity Market, May 2022 report, May 2022.

To effectively improve energy affordability, measures need to be targeted at increasing the efficient use of energy and lowering energy prices, with a focus on measures that can be accessed by low-income households.

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 energy efficiency heating and cooling systems for low-income households and energy upgrades of social housing properties. The program also includes a one-off $250 Power Saving Bonus to help households that have at least one resident receiving payments under an eligible concession program.
- In the ACT, the free ActSmart Household Energy Efficiency Program, delivered by St Vincent de Paul, offers practical ways for people in lower-income households to reduce their energy and water bills. Energy efficiency assessors visit homes to help consumers find ways to reduce energy and water use and save money.
- 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. The South Australian Government has also supported a virtual power plant project that supplies, installs and maintains solar and home battery systems on Housing SA tenants at no cost to the tenant.[370]

The AER's *Annual retail markets report* provides more in-depth assessments of affordability.

In addition to targeted measures for low-income households, the AER's strengthened focus on the broader population of consumers experiencing vulnerability is also intended to improve energy affordability for the consumers that will benefit most.

6.5.1 Improving our approach to consumer vulnerability

The AER is broadening its focus on consumers experiencing vulnerability and continues to engage with energy retailers on their hardship policies. The AER has developed a strategy that focuses on consumers experiencing vulnerability, to better inform our work and how we consider consumer issues.

370 Government of South Australia, South 'South Australia Virtual Power Plant', n.d., accessed 16 September 2022.

Our strategy envisages 4 overarching outcomes for the energy market:

- Barriers to consumers engaging in the market are reduced and consumers can access the products and services that best meet their needs.
- Consumers facing payment difficulty receive effective, tailored assistance.
- The transitioning and future energy market meets the needs of consumers.
- Energy affordability is improved, including by reducing the cost to serve where possible.

In addition to income levels, experiences of vulnerability can also be due to other factors that prevent consumers from participating fully in the energy market, leading to unnecessarily expensive energy costs. These experiences of vulnerability will only grow as the market transitions to a variable renewable energy model, with a more dynamic approach to energy costs.

The AER anticipates publishing the strategy later in 2022.

6.5.2 Impact of COVID-19

The economic impact of the COVID-19 pandemic has increased financial stress on many energy consumers. To support households impacted by the pandemic, the AER introduced temporary assistance measures 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. These measures were phased out in 2022, when stay-at-home orders reduced across NEM jurisdictions.

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 consumers 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 consumers who would benefit from advocacy and support, including customers requiring life support equipment or who were experiencing financial difficulty
- taking actions 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 a 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 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 and June 2021. From July 2021 a standby Statement of Expectations is available in the event jurisdictions are subject to extended stay-at-home orders. The standby Statement of Expectations applies to specific Local Government Areas (LGAs) and automatically comes into effect when an LGA is subject to stay-at-home orders that last for 7 days or more. The standby Statement of Expectations will continue to apply for 14 days after stay-at-home orders are lifted.

The standby Statement of Expectations is applied at the AER's discretion to all National Energy Customer Framework (NECF) jurisdictions – Queensland, NSW, South Australia, Tasmania and the ACT.

Victorian energy consumers come under the separate protections of the Essential Services Commission, while Western Australia and the Northern Territory have their own separate retail energy market regulation.

Several state and territory governments also introduced COVID-19 support packages for households. For example, in Queensland, 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.

6.5.3 Assisting customers in energy debt

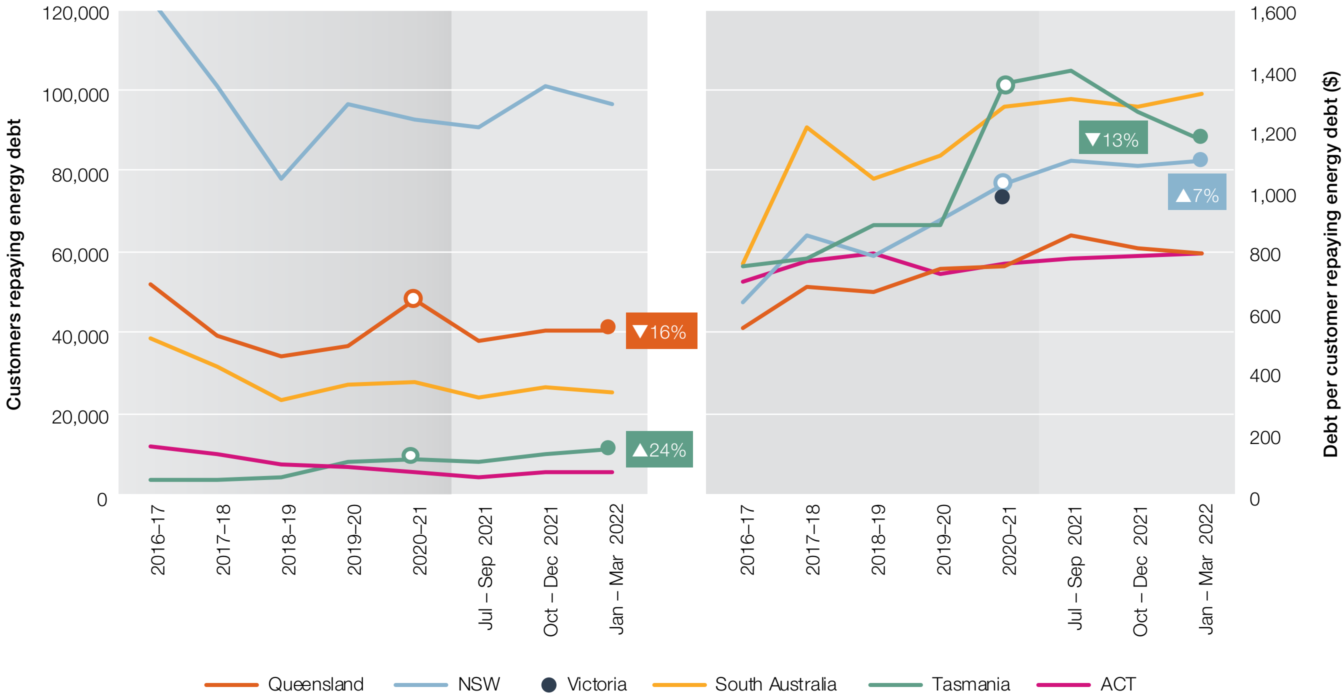
Energy affordability issues can lead customers into energy debt that, if not managed, may result in disconnections. A household's energy debt refers to amounts owing to a retailer for 90 days or more. The COVID-19 pandemic had a significant impact on customers debt levels and their ability to pay their energy bills.

- Both the proportion of residential customers in energy debt and the average debt of residential customers increased during the COVID-19 pandemic.
- Informal bill deferment arrangements, introduced at the start of the pandemic, resulted in fewer customers on payment plans at the end of 2019–20. The number of payment plans has slowly returned to pre-pandemic levels over 2020–21.

- The number of customers on hardship programs dropped at the start of the pandemic because many customers deferred payment of their bill rather than pursuing formal payment assistance. Customers entered hardship programs with higher levels of debt in 2020–21. Average debt of hardship customers also increased, suggesting customers are accumulating more debt while on a hardship program, meaning that some customers on hardship programs are not even meeting their ongoing energy usage costs.
- South Australia and Tasmania have the highest proportion of electricity hardship customers and customers on payment plans, and South Australia has the highest proportion of gas hardship customers. Tasmanian customers were the most likely to be on electricity payment plans in 2020–21 and South Australian customers were the most likely to be on gas payment plans, reflecting lower energy affordability in these jurisdictions.

Since then, as of March 2022, 2.7% of residential customers were in energy debt (Figure 6.12).

Figure 6.12 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.

Source: AER, *Retail markets quarterly*, *Q3 2021–22*, June 2022; ESC, *Victorian energy market report 2020–21*, November 2021.

Along with increases in the number of customers in energy debt, the value of debt held by those customers has also increased across all jurisdictions. The national average value of energy debt at March 2022 was around $1,060 (up $39 (or 3.9%) from the previous year and $131 (or 14%) more than in March 2018).

Energy debt in some jurisdictions is seasonal, particularly for gas customers. For example, in the ACT, gas debt often grows larger after winter because customers may have difficulty in paying off larger winter heating bills. As at March 2022, Tasmania had the highest proportion of residential energy customers in debt (4.3%), while Queensland had the lowest proportion (1.9%).

6.5.4 Payment plans

Payment plans allow settlement of overdue amounts in periodic instalments. They are typically the first assistance offered to customers who show 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.[371]

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 March 2022 was around 5% higher than the previous year, despite retailers also offering other types of COVID-19 support.

371 AER, 'Sustainable payment plans, a good practice framework for assessing customers' capacity to pay, Version 1', AER Website, July 2016, accessed 15 September 2022.

6.5.5 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.[372]

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
- 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
- waiver of late payment fees.

As part of their hardship policies, retailers must take into consideration a customer's capacity to pay.

In 2019 the Victorian Government introduced its payment difficulty framework – a series of rules that provide strong and more consistent hardship assistance for Victorian energy consumers. These rules ensure minimum entitlements to all customers (known as 'standard assistance') and further minimum entitlements to customers with arrears ('tailored assistance').

In 2020–21 the number of residential electricity customers on hardship programs in jurisdictions other than Victoria decreased by 10% over the previous year. The number of Victorian customers on a tailored assistance program increased by 21% (Figure 6.13) but this reflects some retailers offering payment deferrals during March and September 2020 due to COVID-19, temporarily lowering the number of customers on tailored assistance.[373]

The general decrease in hardship customers may reflect the positive effect of increased government supports during the COVID-19 pandemic and a greater ability for some customers to pay off debt. It may also be because of government financial support, such as COVID-19 disaster payments, being offered to households.[374]

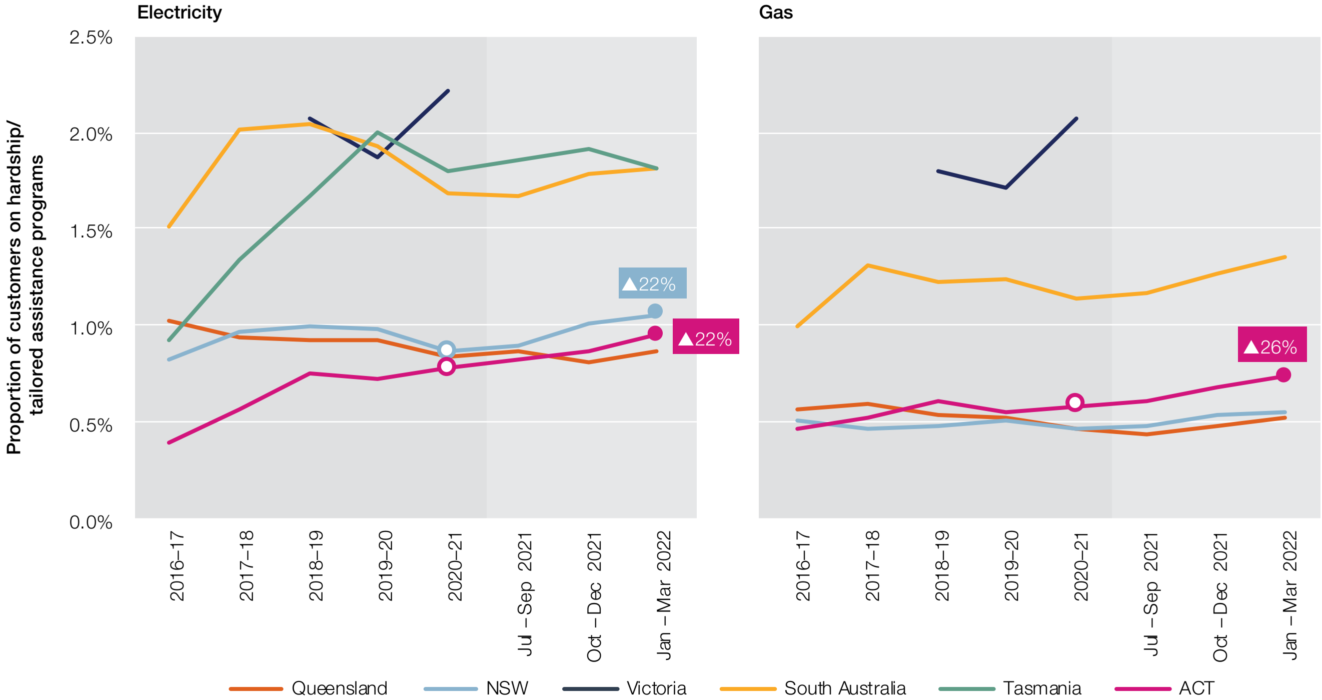
However, the reduction in hardship customers may also have negative implications. The increasing value of customer debt (Figure 6.12) may also reflect changing approaches to debt management, stemming from informal debt management arrangements offered to consumers in response to the COVID-19 pandemic. Retailers have now resumed normal debt management practices and we expect to see the number of customers in hardship increase.

372 AER, Hardship protections a right not a privilege [media release], AER, 29 March 2019, accessed 15 September 2022.

373 For more information, see ESC, 'Victorian Energy Market Report 2020–21', ESC Website, 30 November 2021, accessed 15 September 2022.

374 ACCC, 'Inquiry into the National Electricity Market – November 2021 report' ACCC Website, 13 December 2021, accessed 15 September 2022, p. 36.

Figure 6.13 Small customers hardship/tailored assistance programs



Source: AER, *Retail markets quarterly, Q3 2021–22*, June 2022; ESC, Victorian energy market report 2020–21, November 2021.

The AER's *Annual retail markets report* provides a more in-depth assessment of customers experiencing payment difficulties and hardship.

6.5.6 Disconnecting customers for non-payment

Disconnection for non-payment of bills should be viewed as a last resort and only occur 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 2020–21 disconnections were significantly lower than in previous years, reflecting the AER's Statement of Expectations directing retailers not to disconnect small customers who had been in contact with their retailer or were accessing retailer support (Box 6.3). Where disconnection did occur, customer debt levels at the time of disconnection were higher than in the previous year. Over 2022, disconnections have remained low but are starting to increase again as stay-at-home orders stop applying (Figure 6.14).

Figure 6.14 Disconnection for failure to pay – electricity

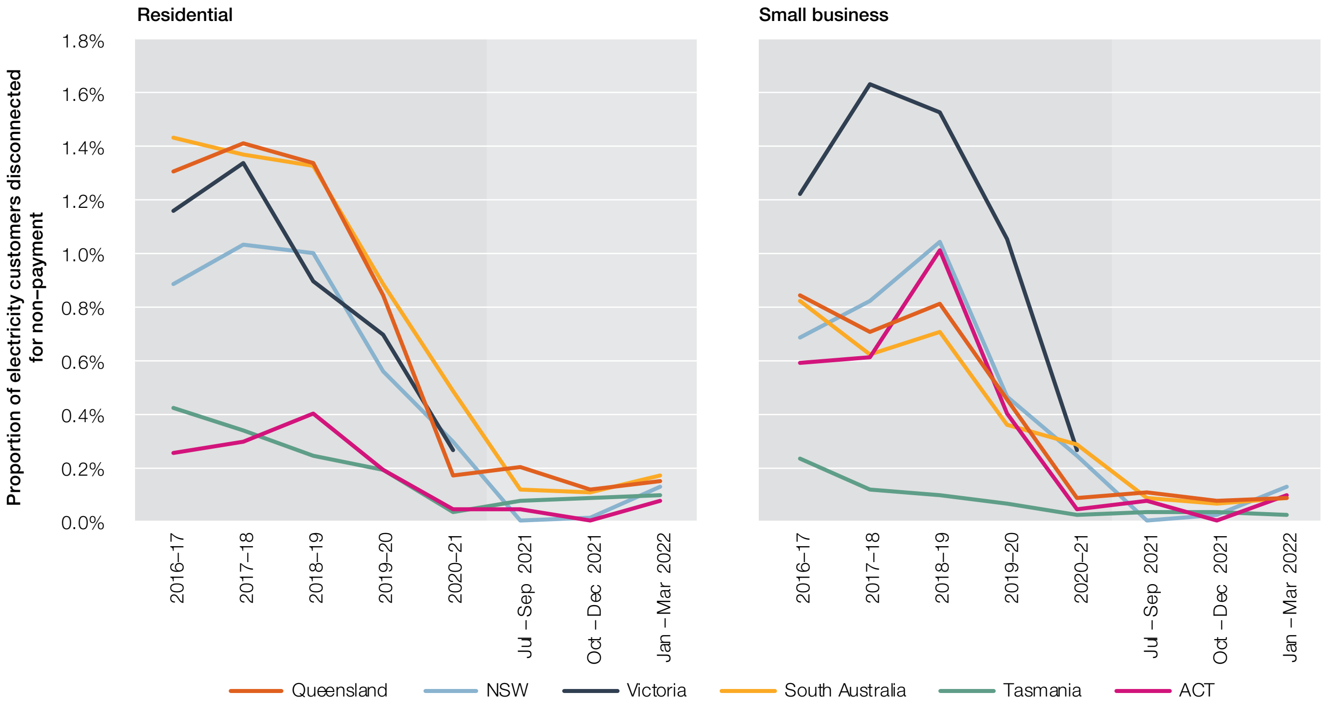


Figure 6.15 Disconnection for failure to pay – gas

Note: Based on customers with an amount owing to a retailer that has been outstanding for 90 days or more, at 31 March 2022 for all states except Victoria, which is at June 2021.

Source: AER, *Retail markets quarterly, Q3 2021–22*, June 2022; ESC, *Victorian energy market report 2020–21*, December 2021.

6.6 Competition in retail energy markets

The purpose of facilitating competition in the retail market is to encourage retailers to innovate and compete for consumers through lower prices and offering better quality products and services. Monitoring the effectiveness of competition is critical to ensure that the market is delivering real, tangible benefits to consumers.

Retail electricity markets in south-east Queensland, NSW, Victoria and South Australia have several key characteristics that are reflective of competitive markets. These include a diversity of sellers making offers, intensive marketing activity and evidence of customer switching. Barriers to entry are considered low, as evidenced by regular new entry (although weaker contract market liquidity means barriers are higher in South Australia).[375] Standalone retailers have identified that access to competitively priced hedging is a barrier to entry and expansion that impacts them more than it does retailers that own generation.[376] These issues in accessing hedging instruments may be exacerbated by recent market events. The AER has raised concerns regarding instances of retailers actively shedding customers as a way of avoiding incurring losses from high wholesale costs, possibly obtaining windfalls from selling lucrative energy contracts that are no longer needed.[377]

However, competition is less effective in electricity retail markets in regional Queensland, Tasmania and the ACT. The smaller 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 persistent issues in sourcing gas and pipeline services in some jurisdictions. Gas markets in all jurisdictions are more concentrated than electricity markets.

Regulatory reforms since 2018 reflect concerns that competition has not delivered sufficient benefit to consumers. The reforms have sought to encourage customers to engage more closely with the market and make it easier to compare retail offers (section 6.7.7) so that existing retailers compete more aggressively on prices.

Despite the reforms, not all consumers can access the benefits of competition. For example, embedded network customers 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.[378] In May 2021 the AER began consultation on the Retail Exempt Selling and Network Exemptions Guidelines in response to concerns raised by stakeholders and published its final Retail Exempt Selling Guideline in July 2022. Key amendments to this guideline include the introduction of a hardship policy condition and other measures to improve customers' access to ombudsman schemes.[379] The Network Exemptions Guideline remains under review.

6.6.1 Market concentration

Origin Energy, AGL Energy and EnergyAustralia (the 'big 3') are the largest energy providers in Australia. The big 3 retailers have a significant share in the residential electricity and gas markets of NSW and South Australia and a lesser but still substantial portion of the Queensland and Victorian markets. Although their market share has declined in recent years, the big 3 still served more than 60% of residential and small business customers at the start of 2022 (Figure 6.17 and Figure 6.18).

Growth in the number of alternative retailers (Tier 2 retailers) supports effective retail competition because it provides more options for consumers, which in turn applies downward pressure on both retail costs and margins.[380] Over 2021 the retail energy market continued to attract new entry – the number of active electricity and gas retailers increased in most jurisdictions in 2020–21. In 2020–21 small energy customers in southern and eastern Australia were served by almost 60 retail brands (Figure 6.16).

However, in 2022 the sharp increases in wholesale energy costs have caused some strain for retailers and will likely subdue interest from new market entrants until wholesale prices stabilise. The market may also experience some decrease in competition from consolidation, where struggling retailers' surrender their licences and customers are

375 AEMC, '2019 Retail Energy Competition Review', AEMC Website, 28 June 2019, accessed 15 September 2022.

376 AEMC, '2020 Retail Energy Competition Review', AEMC Website, 30 June 2020, accessed 15 September 2022.

377 C Packham, 'Energy retailers investigated for $100m hedges', *Australian Financial Review*, 7 July 2022, accessed 16 September 2022.

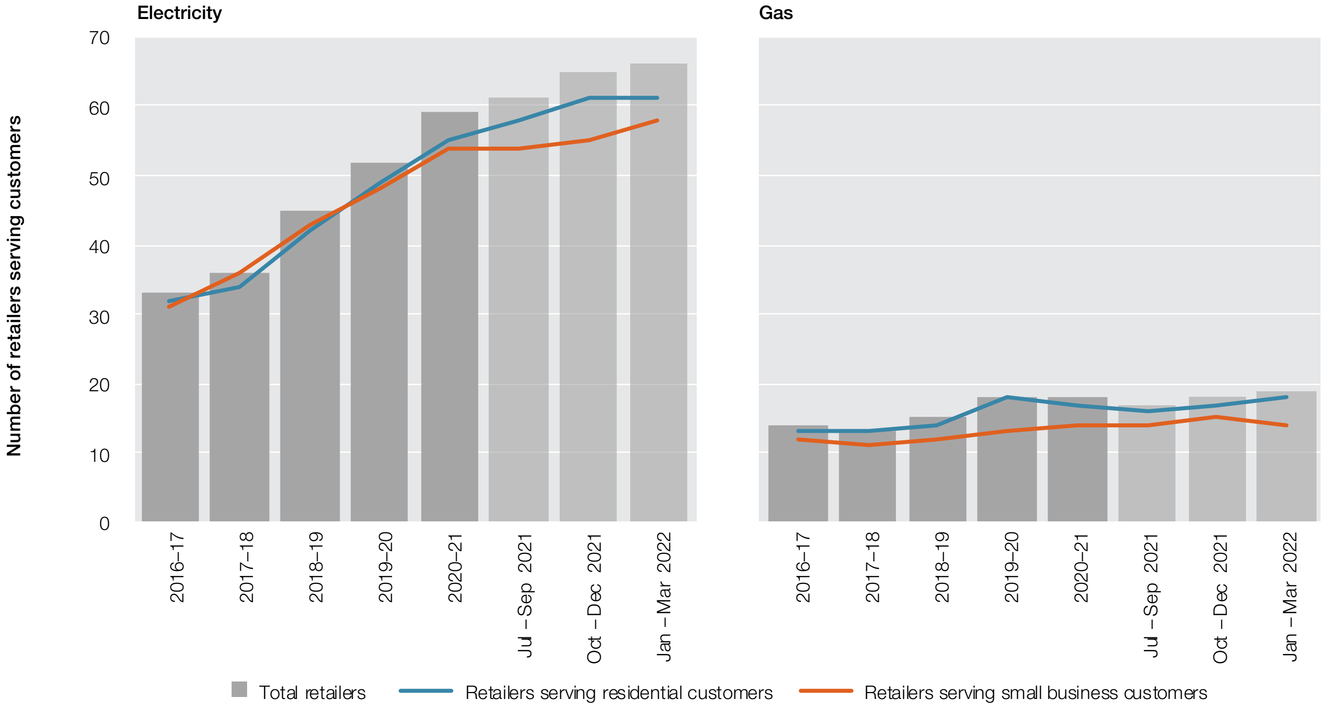
378 AEMC, 'Updating the regulatory frameworks for embedded networks', AEMC Website, 30 June 2019, accessed 15 September 2022.

379 AER, 'Retail Exempt Selling Guideline – July 2022', AER Website, 15 July 2022, accessed 15 September 2022.

380 Tier 2 retailers include any retailer that is not Origin Energy, AGL Energy, EnergyAustralia, nor one of the primary regional government-owned retailers – Ergon Energy (Queensland), ActewAGL (ACT) and Aurora Energy (Tasmania).

transferred to existing retailers. This could lead to Tier 1 retailers increasing their market share because they are the default Retailer of Last Resort retailer in some jurisdictions.

Figure 6.16 Energy market – number of retail brands



Source: AER, *Retail markets quarterly, Q3 2021–22*, June 2022; ESC, *Victorian energy market report 2020–21*, November 2021.

Regional Queensland, Tasmania and the ACT – which have had continuous retail price regulation – are heavily concentrated. The primary regional retailers in these jurisdictions are typically government-owned (or part-owned) businesses with little activity outside their home jurisdiction and were previously the sole regulated provider of retail electricity in that jurisdiction. In 2020–21:

- Ergon Energy (Queensland Government owned) served electricity to 31% of Queensland's total small customers, most of which are in regional Queensland.
- In Tasmania, Aurora Energy (Tasmanian Government owned) served electricity to 97% of Tasmania's total small customers. Before 2019 Aurora Energy was the only retailer offering electricity to households in Tasmania. Customers now have 4 alternative retailers – including 1st Energy, which increased its small customer market share from 1.5% to 2.8% in 2020–21.
- ActewAGL (a joint venture between the ACT Government and AGL Energy) serves 76% of ACT electricity and gas customers.

From January 2021 to March 2022, very few retailers entered and exited the small customer market. However, since May 2022, 8 retailers have exited the market through the Retailer of Last Resort scheme.

The ESC (Victoria), in its *Victorian Energy Market Report 2020–21*, noted the significant market share of larger retailers.[381] The ESC found customer preference to be 'both persistent and striking', given survey responses indicated price is the most important factor when switching and that large energy retailer offers are generally more costly than small and medium retailer offers. This issue is explored further in section 6.6.6.

6.6.2 Electricity

In March 2022 Origin Energy, AGL Energy and EnergyAustralia (the 'big 3') were serving almost 4.7 million (64% of a total 7.4 million) residential and small business customers ('small customers').[382] At the same time, Tier 2 retailers were serving more than 1.5 million (20%) small customers.

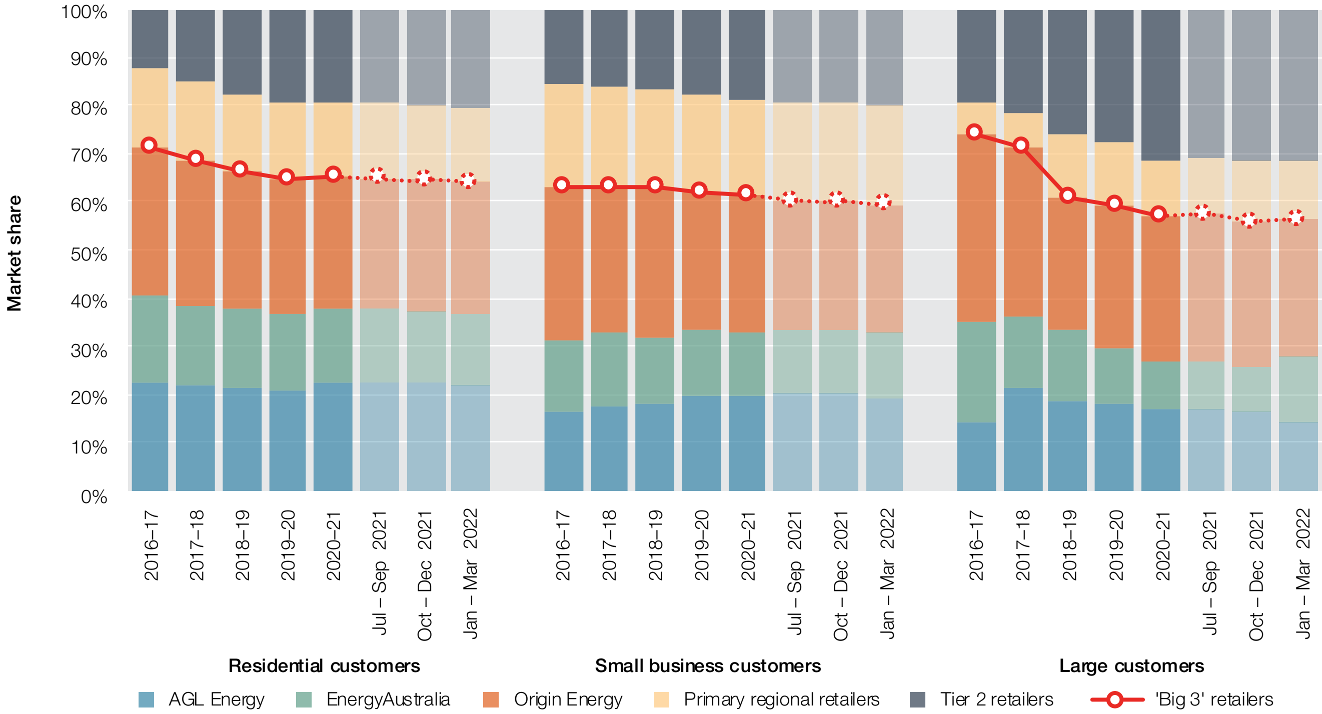
381 Large retailers in Victoria include the big 3 plus Lumo Energy, Red Energy and Simply Energy.

382 Includes customers in Queensland, NSW, South Australia, Tasmania and the ACT. Does not include Victoria.

In the 9 months from June 2021, the big 3 retailers' share of the small customer market decreased by 1.2 percentage points. Conversely, over the same period Tier 2 retailers increased their share of the market by 1.3 percentage points.

Tier 2 retailers have increased their share of small customers in each year since at least 2016–17.[383] Over that period each of the big 3 retailers has lost ground, with Origin Energy the most impacted, falling from 31% in 2016–17 to 27% in March 2022. AGL Energy has seen the smallest decrease, but this was largely driven by the transition of customers following its acquisition of Tier 2 retailer Click Energy (which in 2019–20 served around 150,000 small customers) in October 2020[384] (Figure 6.17).

Figure 6.17 Energy retail market share – electricity



Note: All data at 31 March 2022. Data includes customers in Queensland, NSW, South Australia, Tasmania and the ACT. Some differences may occur between annual and quarterly data to account for retailers revising their data when making their annual submission.

Source: AER, *Retail markets quarterly, Q3 2021–22*, June 2022.

In NSW, the big 3 retailers serve 80% of small electricity customers, making it the most concentrated jurisdiction. Snowy Hydro (owned by the Australian Government and trading as Red Energy and Lumo Energy) serves 7% of small customers, with the remaining 13% served by other Tier 2 retailers.[385]

6.6.3 Gas

As with electricity, AGL Energy, Origin Energy and EnergyAustralia are the dominant retailers in the gas market, serving more than 1.9 million (82% of a total 2.4 million) small customers.[386]

In the 9 months from June 2021, the big 3 retailers' share of the small customer market decreased by 0.7 percentage points. Conversely, over the same period Tier 2 retailers increased their share of the market by 0.8 percentage points. The big 3 retailers have lost 6.8 percentage points of their small customer market share to Tier 2 retailers since 2016–17 (Figure 6.18).

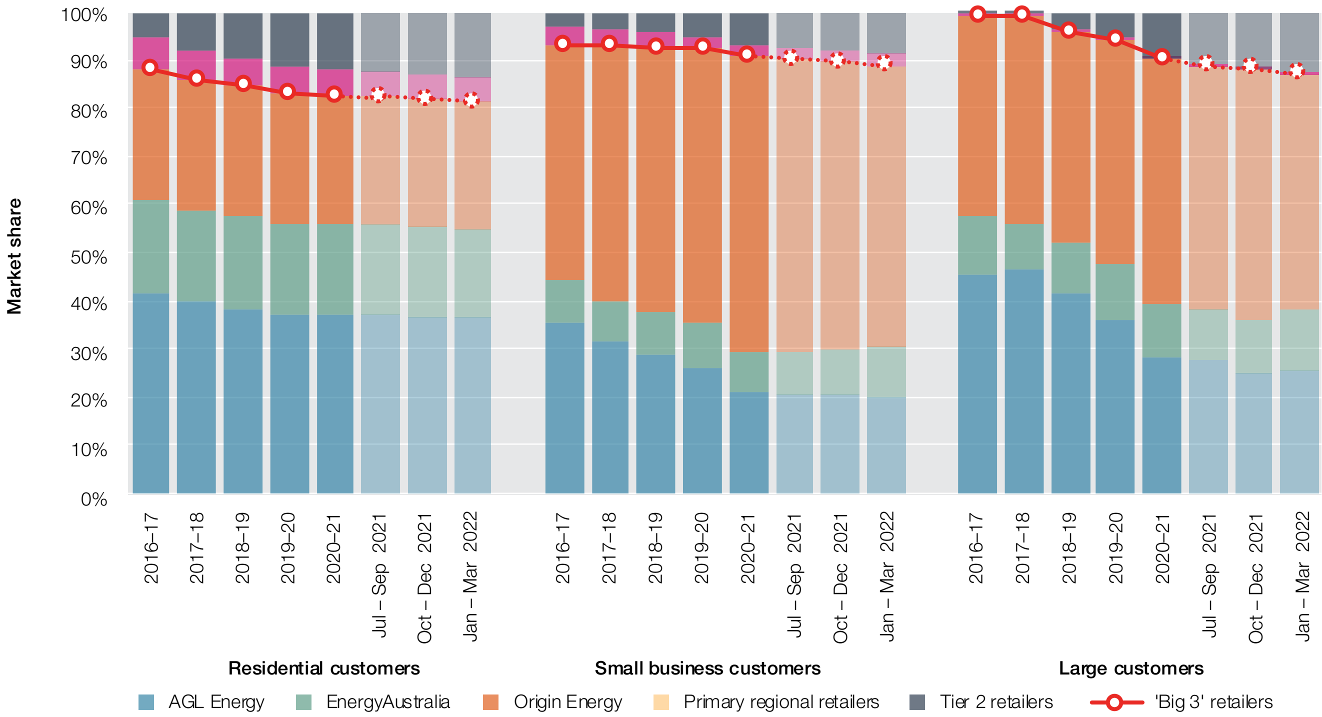
383 Retail customer numbers are not available prior to 2016–17.

384 Click Energy was a subsidiary of Amaysim Australia Limited.

385 Use of state-wide data masks levels of market concentration within some parts of regions with multiple distribution zones (Queensland and NSW). Market concentration is likely to be higher in regional NSW than in Sydney, for example.

386 Includes customers in Queensland, NSW, South Australia and the ACT. Does not include Victoria.

Figure 6.18 Energy retail market share – gas



Note: All data at 31 March 2022. Data includes customers in Queensland, NSW, South Australia and the ACT.

Source: AER, *Retail markets quarterly, Q3 2021–22*, June 2022.

6.6.4 Vertical integration

In the electricity sector, many generators and retailers have integrated to become 'gentailers'. Operating at either end of the energy supply chain is referred to as 'vertical integration', which provides benefits to energy retailers and generators by enabling them to manage price volatility in wholesale markets, with less need to hedge their positions in futures (derivatives) markets. These savings could then be passed through to consumers through lower retail prices. However, this strategy can reduce liquidity in derivatives markets, posing a barrier to entry or expansion for 'independent' retailers that are not vertically integrated.

The big 3 retailers are all gentailers and each have significant market share in generation across NSW, Victoria and South Australia (Figure 6.19).[387] 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), Shell Energy (retailing as Shell Energy Australia and Powershop) and Pacific Hydro (Tango).

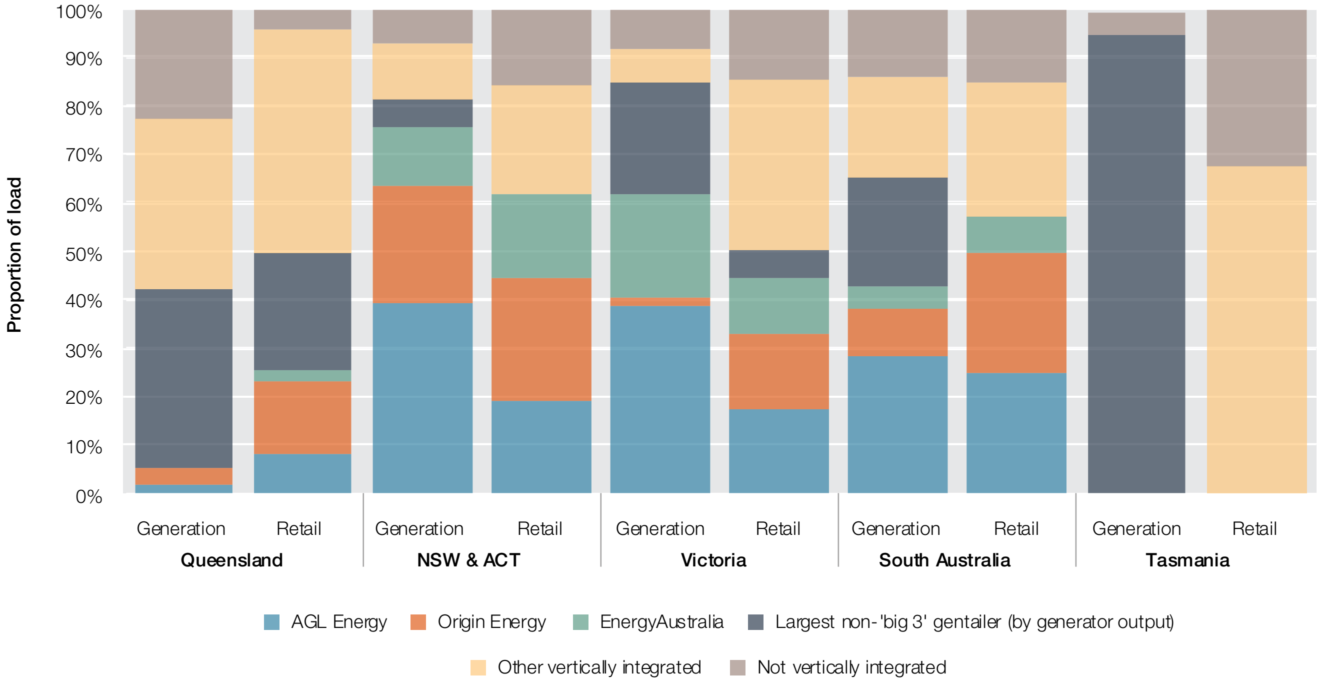
Despite collectively owning more generation than needed to service their retail load, the profiles of gentailers varies significantly. Of the 6 largest gentailers:

- AGL Energy and Alinta Energy have more heavily weighted generation portfolios
- Origin Energy and Snowy Hydro's share of the retail market is greater than its generation market share, but they have significant flexible generation, which helps them manage the risk of high wholesale prices
- EnergyAustralia and ENGIE have relatively balanced generation/load portfolios.

The NEM's largest standalone electricity retailer (without links to a generation business) to small customers is M2 Energy (trading as Dodo Power and Gas) with less than 1% of small customers across the NEM.

387 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. However, on 30 May 2022 the company announced they would withdraw the proposal on the basis that it would not receive sufficient support to meet the needed approval threshold.

Figure 6.19 Vertical integration



Note: Electricity generation market shares are based on generation output in 2021–2022. Retail market shares are based on market load in 2021–2022.

Source: AER, AEMO.

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.

6.6.5 Customers with market contracts

Most energy consumers can enter a market contract with their retailer of choice.[388] 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. Most consumers are currently on a market contract (except small consumers in regional Queensland).

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 consumer protections that the retailer cannot change. Standing offer contracts are generally more expensive than market retail contracts and prices 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 have been set or capped by regulators in all jurisdictions (section 6.3.8) in response to excessively high standing offer prices observed by the ACCC in its 2018 Retail Electricity Pricing Inquiry (REPI). Standing offer prices for gas contracts are not regulated and the prices are set by retailers.

Although customers on market contracts pay less on average than those on standing offers, customers on market contracts do not necessarily receive the best price available. Contracts with expired benefits may be priced close to the standing offer, meaning consumers need to continuously renegotiate or switch market contracts to maintain better prices.

Primary regional retailers – Ergon Energy (Queensland), Aurora Energy (Tasmania) and ActewAGL (ACT) – account for more than 60% of all electricity standing offer customers. These partially government-owned retailers maintain strong market positions in jurisdictions with limited retail competition. In the other jurisdictions, most electricity and gas standing offer customers have contracts with a big 3 retailer. This reflects the position of these retailers as

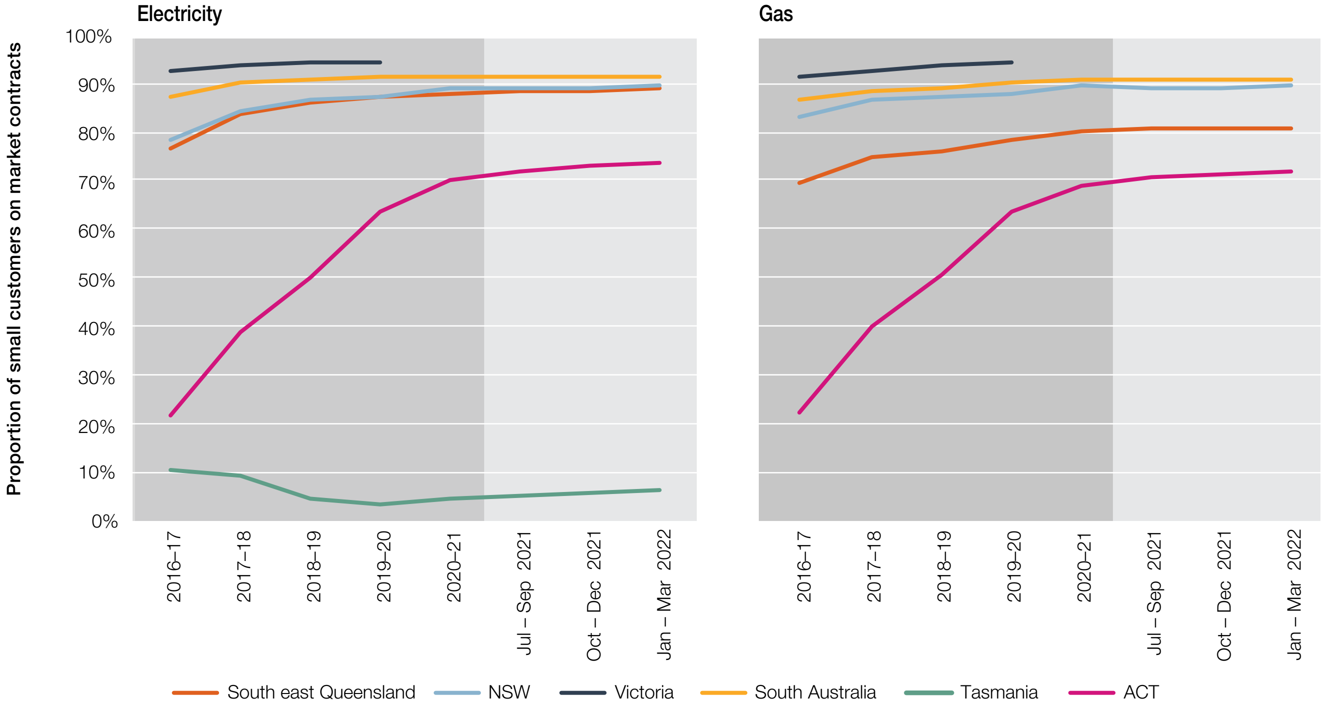
388 While full retail contestability applies in all regions, not all customers can access offers from a retailer other than their host retailer. Further, many customers within embedded networks are still limited to energy supply through their embedded network operator.

incumbents – the retailer that purchased the customer base at the time retail contestability was introduced – allowing them to retain customers that have never taken up a market contract.

Regional Queensland, Tasmania and the ACT have the highest proportion of consumers on standing offer contracts.

- Nearly all small energy customers in regional Queensland are on standing offers.
- The ACT continues to see significant increases in the proportion of small customers on market contracts, in large part due to Origin Energy's increasing share of the market.
- In Tasmania, new entrant retailers have offered market contracts to residential customers since early 2019, but the proportion of customers on market contracts remains comparatively low – the Tasmanian Government set standing offer prices that attracted Aurora Energy's market customers to switch back to the standing offer (Figure 6.20).

Figure 6.20 Small customers on market contracts



Note: Standing and market offer shares are based on the number of small customers at 31 March 2022 except Victoria (June 2020). Queensland electricity numbers exclude customers in regional Queensland, who largely remain on standing offers.

Source: AER, Retail markets quarterly, Q3 2021–22, June 2022; ESC, Victorian energy market report 2019–20, December 2020.

6.6.6 Customer awareness and engagement

Retail competition drives innovation to bring a wider range of products and services to the market to satisfy different customer preferences and demands, but it can also increase complexity. Customers can find it difficult to compare retail offers or understand the risks and benefits of different pricing structures, which can cause them to disengage from the market.

The ESC discussed the challenges of customers shopping around for the best deal in their *Victorian Energy Market Report 2020–21*. The ESC found that while price was indicated as the most important factor when switching, this did not align with customer behaviour in practice as large energy retailer offers are generally more costly than small and medium retailer offers. For example:

- most large retailer customers are not on their current retailer's 'best offer'
- based on customer retention rates, large retailer customers are more loyal despite being presented with more costly offers
- customers who do switch from a large retailer mostly move to another large retailer despite lower prices being offered by small and medium retailers.

Potential explanations for customers' demonstrated preference for large retailers included:

- customers may (incorrectly) believe the lights will go out with a smaller retailer ('supply risk')
- potentially better customer service quality offered by large retailers
- customers' individual experiences in the market
- the economies of scale and broader scope offered by large retailers for 'bundled' electricity and gas (and in some cases, telecommunications) contracts
- brand recognition.

Retailers have added to this complexity by adopting marketing strategies that make it difficult for customers to directly compare offers. Customer surveys regularly report that customers find the energy 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 advertised discounts to be quoted against a 'reference bill', being the default market offer set by the AER (section 6.3.8).

The Better Bills Guideline, which commenced in August 2022, also seeks to make it easier for consumers to engage with the energy market by providing information to help them understand and compare their plan, identify whether their retailer may be able to provide a better offer, or consider options for new types of energy services (section 6.3.1):

These reforms may improve customer engagement, but other inclusion considerations for some customers remain – English as a second or other language; cultural practices; lived experience of disability; low levels of literacy combined with levels of complexity in energy markets, concepts and terms; and status quo bias for consumers to stay with their default retailer or plan. Improving outcomes for all consumers, in particular consumers experiencing vulnerability will need further targeted measures. The AER's strategy that focuses on consumers experiencing vulnerability draws from research by the Consumer Policy Research Centre on understanding experiences of vulnerability and how different regulatory approaches can support consumers experiencing vulnerability.

6.6.7 Customer understanding of the market

Market developments – including the rollout of smart metering and cost-reflective tariffs – are adding additional layers of complexity to the market, making it harder for consumers to confidently engage. Increasingly, more tools are assisting to address the complexity of the market. For example, customers are more widely using price comparator websites. Use of an independent comparator website to find a better offer ranged from 9% of residential customers looking to switch in Tasmania to 26% of customers in Victoria.[389]

The AER and Victorian Government operate comparator websites – Energy Made Easy (www.energymadeeasy.gov.au) and Victorian Energy Compare (compare.energy.vic.gov.au) – to assist users to compare retail 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 6.6.15).

The Australian Government (Treasury) is extending the Consumer Data Right (CDR) to cover the energy sector. This will allow consumers to require their energy retailer to share their data with an accredited service provider such as a comparison site. Giving consumers the right to safely transfer their energy data (such as their current energy deal and consumption patterns) to third parties of their choice should make it easier for them to make good product choices. It should also promote competition between retailers. The government is implementing the CDR for energy in 2 phases – the big 3 retailers will need to comply by October 2022 and the other retailers will need to comply by October 2023.[390]

6.6.8 Customer satisfaction

Customers' level of satisfaction with retail energy markets depends on several factors, including price, perceived value for money, reliability, customer service, confidence in engaging with the market, technology uptake and ability to switch.

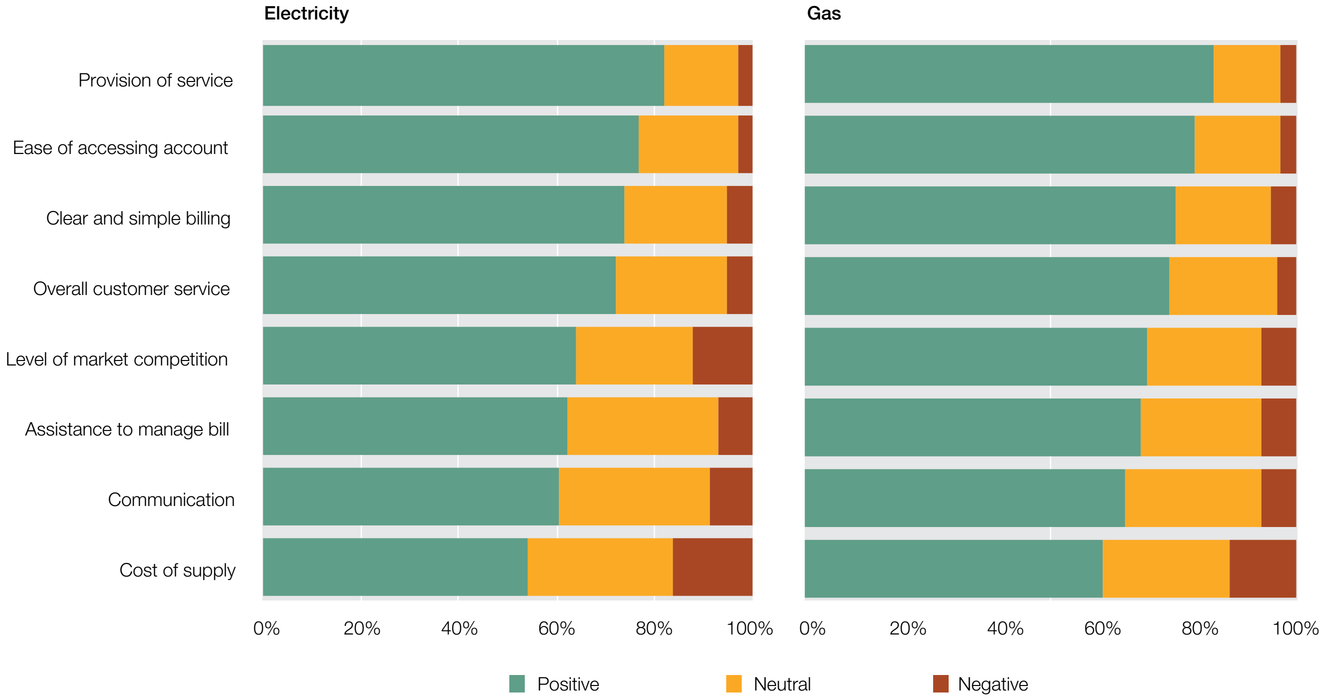
389 ECA, 'Energy Consumer Sentiment Survey', ECA Website, December 2021, accessed 15 September 2022.

390 ACCC, 'Energy rules framework, consultation paper', ACCC Website, July 2020, accessed 15 September 2022.

The behaviour of retailers can have a positive or negative impact on customers' trust and confidence in the market. For customers, an adverse experience with a retailer can create, or increase, barriers between themselves and retailers.

Energy Consumers Australia's consumer sentiment surveys indicate consumer satisfaction and confidence has slightly improved since 2019. Results from the June 2022 survey indicated that the cost of supply was consumers' primary concern, with 'dissatisfaction with value for money' being one of the main reasons for customer switching (Figure 6.21). A majority of respondents (60%) were concerned that electricity and gas will become unaffordable for some Australians over the next 10 years.

Figure 6.21 Responses from energy consumer sentiment survey



Source: Energy Consumers Australia, Energy consumer sentiment survey, June 2022

6.6.9 Customer switching

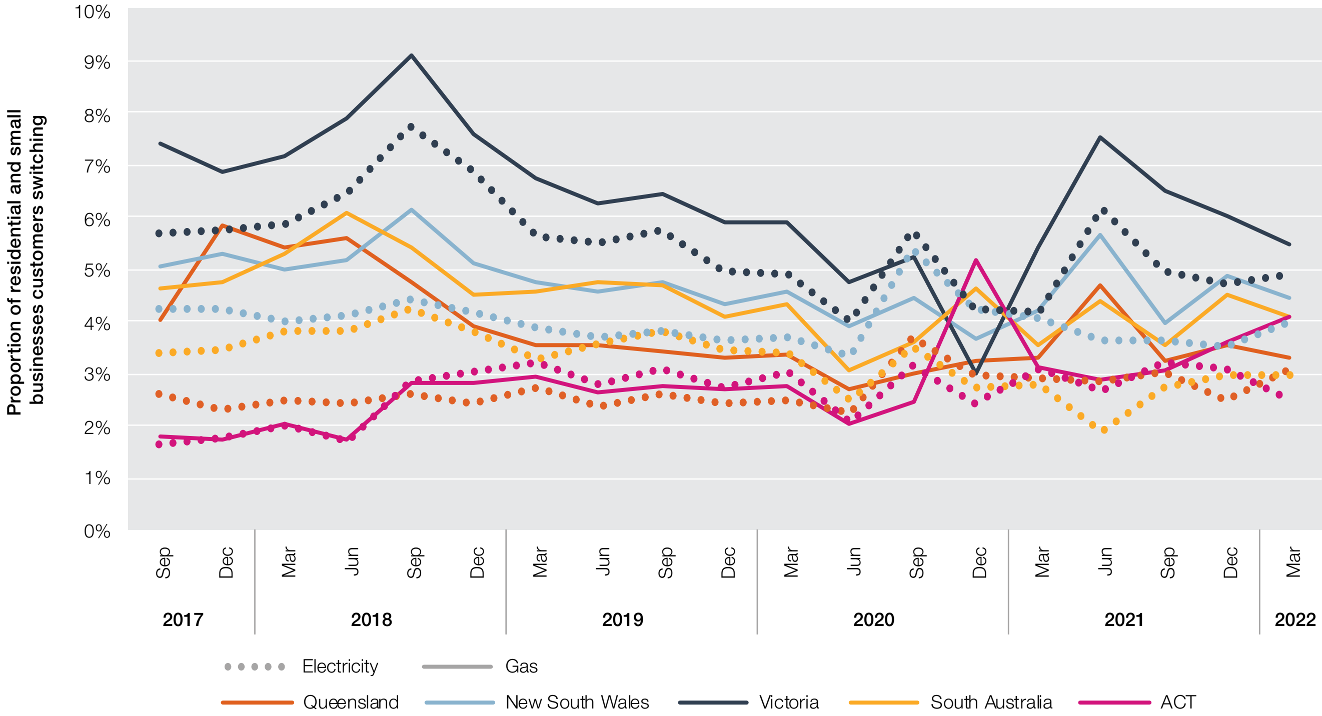
The rate at which customers switch retailers can be used to indicate the level of engagement in the market. But switching rates should be interpreted with care – switching may be low in a competitive market if retailers deliver good-quality, low-priced services that give customers no reason to change. Data on switching rates fails to adequately capture customer movements to new contracts with the same retailer, so it understates customer activity in the market. Conversely, switching data captures when an existing customer moves house and signs a new contract, even if it is with the same retailer (thus overstating customer activity).

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.[391] This process limits retailer 'save' activity (retailers contacting customers who try to switch and giving them a better offer to encourage them to stay) and allows customers faster access to prices and products they want.

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. As a secondary fuel, gas is also typically a lower cost for consumers, so it may not receive the same attention. Overall, the level of switching activity indicates relatively engaged customers – almost half of the surveyed customers have switched retailer at some stage (Figure 6.22).

391 AEMC, 'National Energy Retail Amendment (Reducing Customers' Switching Times) Rule 2019 No. 2', AEMC Website, 19 December 2019, accessed 15 September 2022.

Figure 6.22 Switching activity – small customers



Source: AER, Retail markets quarterly, Q3 2021–22, June 2022

The ESC (Victoria), in its *Victorian energy market report 2020–21*, noted that customers of large retailers are incentivised to search for better offers because large retailers' offers are generally higher than their smaller competitors. The report also referred to 'sticky' customers, who tend to stay with, or return to, particular products or services. This activity can lead to higher customer retention.[392]

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 – customers who do not switch regularly may find themselves paying higher prices than necessary. As a result, a critical part of the AER and other regulators' reform agenda is regulatory reforms to support consumers understanding impending changes in their energy contract and helping them find better offers either with the same or an alternative retailer.

The National Energy Retail Rules require retailers to notify small electricity and gas customers before any change in their benefits and provide advance notice of any price change.[393] In Victoria, retailers must also prominently display their 'best offer'[394] on customers' bills – every 3 months for electricity and every 4 months for gas – along with advice on how to access it. The Better Bills Guideline will bring this requirement to the rest of the NEM jurisdictions.

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. 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.

392 ESC, 'Victorian Energy Market Report 2020–21'.

393 AEMC, 'National Energy Retail Amendment (Notification of the end of a fixed benefit period) Rule 2017 No. 2', 7 November 2017; AEMC, 'National Energy Retail Amendment (Advance notice of price changes) Rule 2018 no. 3', 27 September 2018.

394 Using a customer's past usage and comparing what they pay on their current offer against the cheapest generally available offer.

6.6.10 Retailer activity and barriers to entry

Changes in retailer marketing activity can affect the level of customer switching, most notably through digital acquisition channels, including retailers' websites and price comparison websites (section 6.6.15). Low retailer activity in some markets may reflect barriers to entry or expansion.

Other barriers to entry that retailers have noted include:

- reintroduction of standing offer price caps (section 6.3.8) as a barrier to activity
- limited access for retailers to competitive risk management contracts as a barrier to entry or expansion in South Australia, with almost half of all retailers in 2020 considering that contract market liquidity in South Australia was too low[395]
- application of multiple regulatory frameworks – particularly in Victoria, which has a separate Energy Retail Code – due to the compliance costs this imposes. Retailers considered the divergence of Victorian regulations from other jurisdictions has widened since 2019[396]
- access to reasonably priced gas and pipeline capacity as barriers to entry and expansion, especially in Victoria. The Pipeline Capacity Trading and Day Ahead Auction reforms that commenced in March 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 and a capacity trading platform.

6.6.11 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 6.6.12), retailers are looking to differentiate their products in other ways.

Retailers can differentiate products by offering more price certainty or, alternatively, rewarding customers who are willing to be flexible in how and when they use energy. As technology improves, more products offering energy management services or linking to batteries, solar PV output or electric vehicles, including delivering additional revenue to consumers through virtual power plants, are becoming more common (section 6.7).

Some retailers also 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.

6.6.12 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. Overall, the use of these discounts was not delivering effective outcomes for consumers. The size of a 'discount' was often misleading because retailers applied discounts off a range of price bases. Customers were also exposed to much higher prices if the conditions were not met.

Reforms in 2019 require retailers to now 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 covers retailers in south-east Queensland, NSW and South Australia.[397] Equivalent provisions also 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 satisfied the conditions attached to the discount.

The proportion of offers with conditional discounts has been trending downwards since 2018. As of March 2022, only 17% of electricity offers contain conditional discounts (Figure 6.23).[398]

In 2021 around 9% of residential customers on offers with conditional discounts did not meet the conditions required to receive the discounted price.[399] Customers in financial difficulty were more likely to miss out on the discounts, with 14% of hardship customers and 12% of customers on payment plans not meeting the required conditions.

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395 AEMC, '2020 Retail Energy Competition Review'.

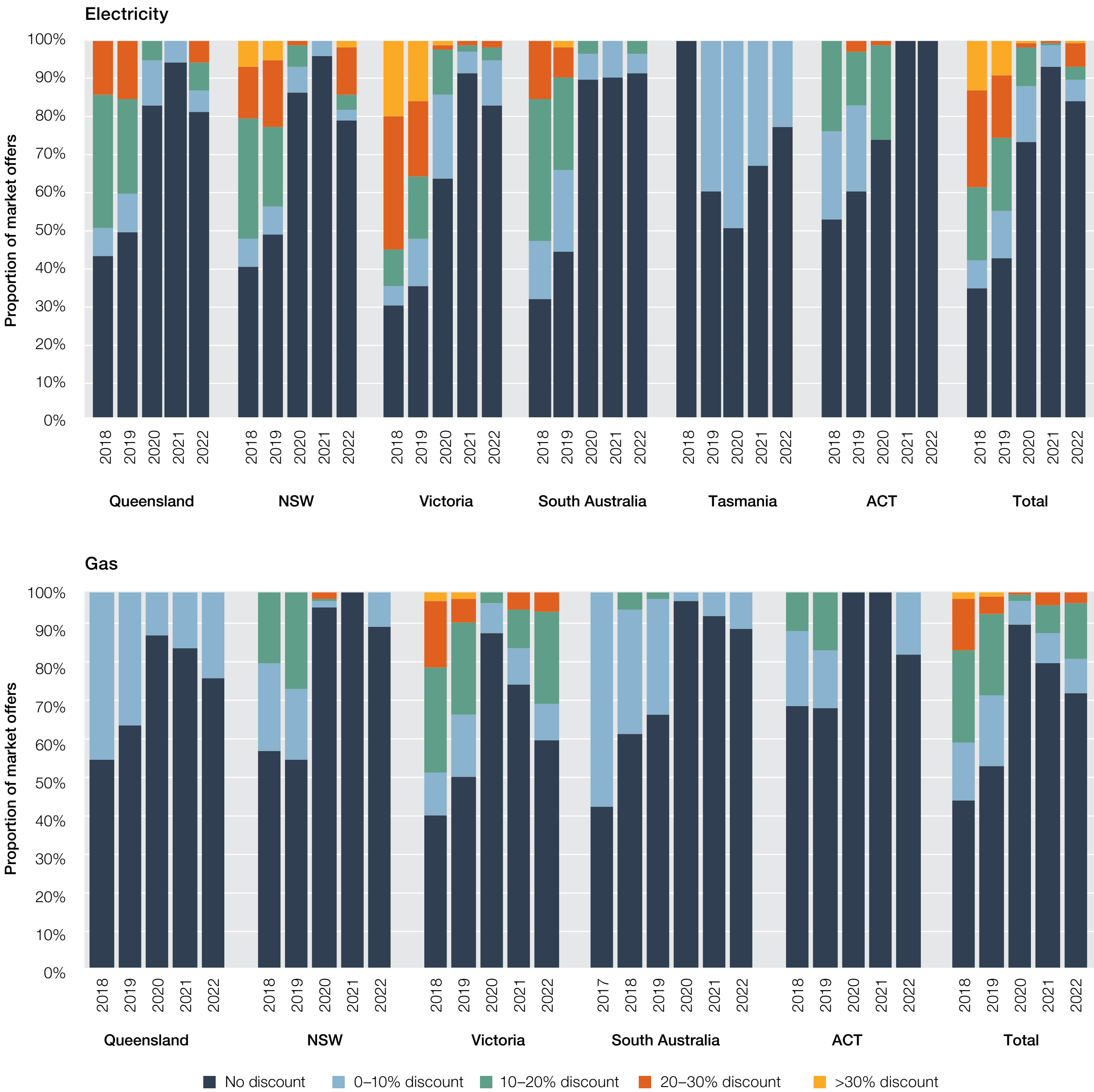
396 AEMC, '2020 Retail Energy Competition Review'.

397 Competition and Consumer (Industry Code – Electricity Retail) Regulations 2019.

398 Some customers will still be receiving them if they are rolling over an existing contract.

399 ACCC, 'Inquiry into the National Electricity Market – May 2022 report', ACCC Website, 20 June 2022, accessed 15 September 2022.

Figure 6.23 Conditional discounts for residential energy market offers



Note: Discounts are advertised conditional discounts in generally available market offers. Data for 2022 reflects offers available in March 2022.

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

The size of discounts being offered has reduced over this period. In 2019, 45% of market offers advertised discounts of greater than 10% off the average bill, with some retailers offering discounts of around 40%. But large-scale discounting has now all but gone, with only around 1% of offers advertising discounts of greater than 10% in September 2021.

Although the reforms only apply to electricity, discounting practices in gas have also changed. At March 2021 over 73% of gas offers did not contain conditional discounts.

6.6.13 Offer structures

Electricity retailers typically use one of 3 tariff structures in their offers:[400]

- Single-rate or 'flat' tariffs apply a daily (fixed) supply charge plus a simple usage charge for the electricity that a consumer uses.
- Time-of-use tariffs apply different pricing to electricity use at peak and off-peak times. Lower prices at off-peak times encourage consumers to shift their energy use to those times. It is intended to better reflect the prices retailers pay for electricity and encourage consumption during cheaper time periods.
- Demand tariffs charge a consumer based on their maximum point-in-time demand at peak times. Consumers 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. This structure is intended to encourage consumers to stagger their energy use and reduce congestion on the network at peak times, also reducing system costs.

Retailers vary the levels of fixed and variable tariff components to appeal to different consumers. For example, consumers with low energy use may prefer an offer with lower fixed charge but higher usage charges, while a consumer with flexibility around when they use energy may prefer an offer with lower 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 consumers to dynamically interact with the wholesale market. These tariffs are best suited to consumers 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 (section 6.7). 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 consumers' electricity use patterns and charge/discharge batteries to maximise value. Some offers allow consumers 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.

Similar to conditional discounting, dynamic products could cost consumers much more if they are unable to conform their energy use to the terms of the agreement.

6.6.14 Non-price competition

In addition to competing on price and tariff structure, many retailers offer other 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.

Several 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 (for example, Alinta Energy partners with Kayo Sports to offer new customers a complimentary subscription to its online streaming service, and Origin Energy partners 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.

6.6.15 Price comparison websites and switching services

The variety of product structures, discounts and other inducements can make 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 and due to the fundamental role shopping around has in delivering savings to consumers. Two independent price comparator websites are run by the AER and Victorian Government.

400 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.

The AER operates an online price comparator – Energy Made Easy (www.energymadeeasy.gov.au) – to help small customers compare market offers. The website shows all generally available offers and has a benchmarking tool that allows consumers to compare their electricity use with similar sized households in their area. The website is available to consumers in jurisdictions that have implemented the Retail Law (Queensland, NSW, South Australia, Tasmania and the ACT).

The Victorian Government operates a similar online price comparator – Victorian Energy Compare (compare.energy.vic.gov.au) – enabling Victorian consumers to compare market offers.

Various commercial entities also offer online price comparison services. The AEMC identified 19 separate comparison websites in 2018.[401] Brokers are also active in the market for larger consumers.

Comparison websites and brokers can provide consumers with a quick and easy way of engaging in the market, but some services may not provide customers with the best outcomes. For example, commercial comparator websites may only show offers of retailers affiliated with the site. Commercial comparators 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.

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.[402] 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. A voluntary code was developed by the Energy Charter[403] that partly addresses the ACCC and AEMC recommendations. For example, while the code does provide for disclosures of commercial interests and other factors that could mislead consumers, it does not provide for sanctions for non-compliance or an independent dispute resolution process.

6.7 The evolving electricity market

Advances in metering and electricity generation, management and storage technologies are changing how the retail market works.

Recent improvements in technology (particularly in the electricity market), high energy prices and environmental concerns are driving some consumers to be more active in the market and to take greater control over their energy use (Figure 6.1). There is also widespread recognition that new technology has a significant role in offsetting system costs and making more efficient use of existing energy generation. New technologies also support more efficient use of longstanding consumer energy resources like rooftop solar photovoltaic (PV) systems, by enabling energy consumers to self-generate electricity and sell excess energy to their retailer or a third party. Technological improvements relating to energy services include:

- smart meters, which provide information on energy use that gives retailers scope to offer more innovative products and ‘add-on’ energy management services, and helps consumers better understand their energy costs and opportunities to reduce them
- batteries, load control devices and similar technologies, which allow consumers greater control over their electricity use and the ability to further engage in the market (for example, by storing electricity and entering demand response contracts)
- electric vehicles, which may significantly increase consumer electricity demand, but can also offer electricity stored in the battery back into the market and could be used to smooth energy demand by charging during times of oversupply of rooftop solar output.

The Power of Choice reforms (section 3.8) and the more recent ESB’s Post-2025 NEM Market Design Project aim to provide consumers with opportunities to benefit from these changes. Reforms include rolling out smart meters, introducing cost-reflective network pricing (section 3.8.1), making it easier for consumers to access their energy data and to compare and switch retailers, enabling wider use of demand response, and better integrating consumer energy resources into the NEM.

401 AEMC, ‘2019 Retail Energy Competition Review’, p 102.

402 ACCC, ‘Restoring electricity affordability and Australia’s competitive advantage, Retail Electricity Pricing Inquiry – final report’, ACCC Website, June 2018, accessed 15 September 2022, p 282; AEMC, ‘2019 Retail Energy Competition Review’, p 282.

403 The Energy Charter, ‘National Customer Code for Energy Comparators & Energy Moving Services’, The Energy Charter Website, May 2022, accessed 15 September 2022.

In December 2019 industry bodies developed a code of practice on standards of consumer protection when businesses offer new energy products and services.[404] 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.

In July 2021 the ESB's Post-2025 Market Design set out recommendations for energy ministers. It included an implementation plan for consumer energy resources, setting out the market, regulatory and technical reforms needed to fully integrate consumer energy resources into the NEM. Reforms include:

› updating technical standards for inverters and meters to ensure the technology can integrate with the NEM and with different retailers so retailers can compete to offer consumers different energy products and services
› providing policy direction and advice on the implementation of flexible export limits, which allow export limits on consumer energy resources to be varied based on available network capacity
› introducing changes to the regulatory framework to allow consumers to engage a separate provider for their consumer energy assets (such as EV charging, solar panels and/or battery devices), and facilitate the active participation of consumer energy resources and flexible demand in the provision of market services
› undertaking a review of the retailer authorisation and exemption framework to ensure it remains fit for purpose in a transitioning retail energy market.

6.7.1 Smart meters

Smart meters frequently measure electricity use in up to 5-minute intervals and allow for remote reading and connecting/disconnecting. The information about a consumer's energy use throughout the day provides scope for innovative offers from retailers and for improved energy management services from third parties or self-management by the consumer.

Victoria was the first jurisdiction to progress metering reforms, with electricity distribution businesses rolling out smart meters to around 98% of Victorian consumers between 2009 and 2014. Elsewhere, the rollout has occurred on a market-led basis. Outside of Victoria, responsibility for metering 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.

Smart meters are key to enabling a more connected, modern and efficient energy system that supports future technologies, services and innovation. Many of the issues addressed in the ESB's Post-2025 Electricity Market Design Project rely on critical upgrades to the energy system through smart meters.[405]

Current arrangements are not supporting the timely roll out of smart meters. Outside Victoria less than 25% of consumers had a smart meter at December 2021. Another 5% of consumers (mostly in NSW) had access to an interval meter providing 30-minute consumption readings but without remote reading and connection capabilities. In addition, retailers in Victoria are not yet making use of smart meters for innovative products. In Energy Consumers Australia's October 2021 Consumer Behaviour Survey, only 67% of respondents in Victoria knew they had a smart meter, despite Victoria installing smart meters in more than 97% of households through a targeted installation scheme.[406]

In December 2020 the AEMC initiated a review of the regulatory framework for metering services. In September 2021 the AEMC published an issues paper proposing several options to improve the current arrangements and increase the penetration of smart meters in jurisdictions outside of Victoria. The AEMC paused this review in November 2021 to focus on the delivery of other priority projects. This review recommenced in April 2022 and the AEMC plans to release a draft report later this year.[407]

6.7.2 Rooftop solar PV and batteries

Many energy consumers partly meet their electricity needs through rooftop solar PV and sell excess electricity into the grid. At January 2022 over 2.6 million households and businesses in the NEM had installed rooftop solar PV systems.

404 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', ACCC Website, December 2019, accessed 15 September 2022.

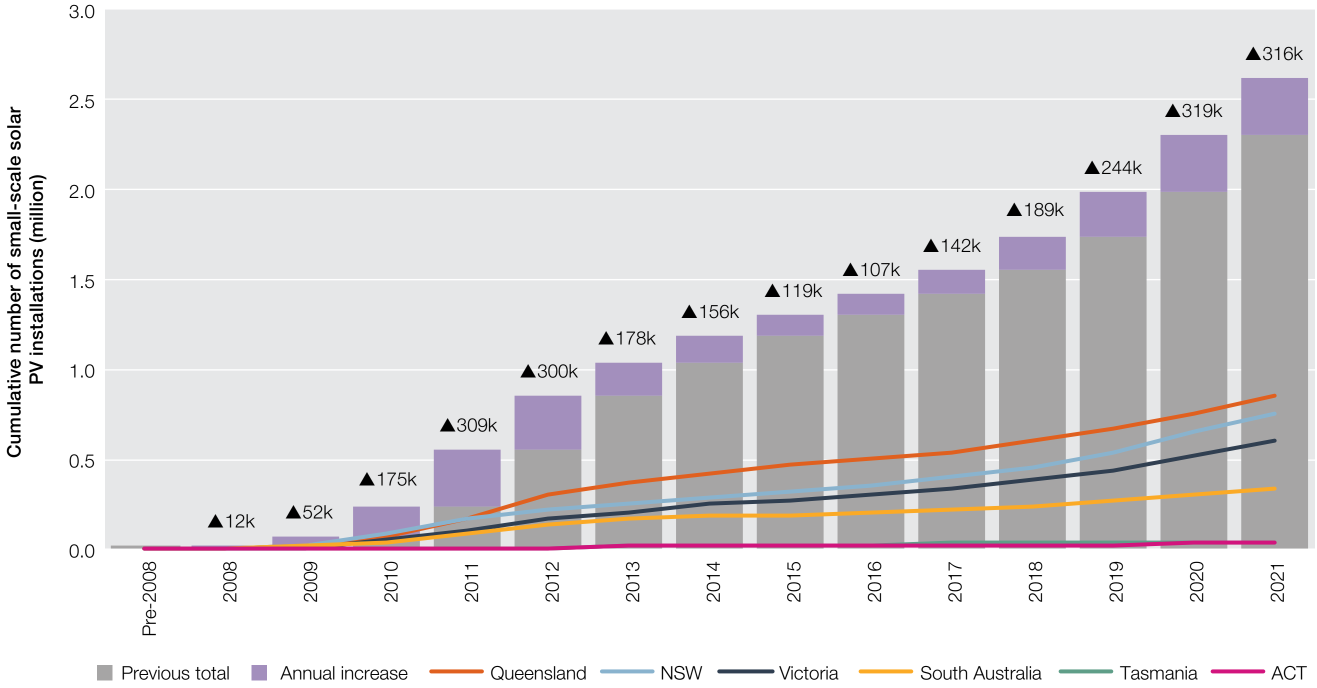
405 AEMC, 'Review of the regulatory framework for metering services – Directions paper', AEMC Website, 16 September 2021, accessed 15 September 2022.

406 ECA, 'Consumer Behaviour Survey', ECA Website, October 2021, accessed 15 September 2022.

407 AEMC, 'National Energy Amendment (Metering installation timeframes) Rule 2018 No. 15', AEMC Website, 6 December 2018, accessed 15 September 2022.

There were over 316,000 new installations of solar PV systems in 2021 (Figure 6.24). Ongoing subsidies provided by the Australian Government and some state governments, combined with falling costs of solar PV systems, have helped to sustain the growth in new installations. The average size of solar PV systems has also grown. Total solar capacity installed in 2021 (2,687 megawatts (MW)) set a new record – 9% higher than the previous record set in 2020 (2,470 MW) and more than 3 times the capacity installed in 2011 (750 MW).

Figure 6.24 Small-scale solar PV installations



Note: Small-scale generation units have a capacity of no more than 100 kilowatts (kW), and a total annual electricity output of less than 250 megawatt hours (MWh).

Source: Clean Energy Regulator, Postcode data for small-scale installations, data at 1 January 2022.

When installed with solar PV systems, battery storage and smart appliances allow consumers to better match their electricity requirements over time, reducing the amount of power they need to withdraw from (and inject into) the network. However, batteries are comparatively more expensive than solar PV systems. Of the 316,000 solar PV systems installed in the NEM in 2021, a little over 3% had an attached battery system.[408]

Solar PV systems can be purchased outright by consumers 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 consumer's home and sells the generated energy to that consumer. In return, the consumer 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 by the consumer to their retailer. Consumers are paid a feed-in tariff for this excess electricity. This tariff is generally a flat per kilowatt hour value and is not linked to the actual value of the excess electricity to the NEM. This means that these consumers are not incentivised to time their exports to when additional energy is needed. 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 consumers can export to the grid. In August 2021 the AEMC made a rule change to integrate consumer energy resources, such as small-scale solar and batteries, more efficiently into the electricity grid. The rule change allows network businesses to charge consumers for any electricity they export at times of network congestion. These charges would act as price signals to encourage consumers to export electricity at times of need and not times of excess electricity supply.[409]

408 Clean Energy Regulator, 'Solar PV systems with concurrent battery storage capacity by year and state/territory', Clean Energy Regulator Website, Data at 1 January 2022, accessed 15 September 2022.

409 AEMC, 'National Energy Retail Amendment (Access, Pricing and Incentive Arrangements for Distributed Energy Resources) Rule 2021', AEMC Website, 12 August 2021, accessed 15 September 2022.

6.7.3 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 21,000 electric vehicles sold in Australia in 2021, up from 6,900 in 2020.[410]

Although electric vehicles are 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. The ESB is considering how to integrate electric vehicles into its implementation plan for consumer energy resources on the expectation that electric vehicle uptake will increase. In July 2022 the ESB published an electric vehicle smart charging issues paper to seek stakeholder input on effective arrangements for electric vehicle smart charging in both domestic and public settings.[411]

6.7.4 Demand response

Smart meters provide consumers 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 consumers to support power system stability.

The simplest demand response programs offer consumers financial incentives to reduce electricity consumption when they receive an alert from their retailer or network service provider. More sophisticated programs include technologies that optimise solar PV and storage systems; and load control devices that automatically reduce power consumption from appliances such as air conditioning, hot water systems or pool pumps if required. Automating consumer participation in these programs is likely to result in increased uptake.

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.

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 (FCAS) 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 consumers to directly offer demand response into the wholesale market commenced in the NEM in October 2021 but is restricted to large customers. Small customers are limited to offering wholesale demand response through programs offered by their retailer.

As the supply of electricity shifts towards variable renewable energy resources, demand needs to shift to become more dynamic to enable us to make efficient use of our electricity resources, reducing the costs of both generation and transmission. However, dynamic demand also increases complexity and puts a heavier burden on retailers and consumers to behave responsively, rather than to passively receive electricity prices as set by AEMO and the NEM Dispatch Engine (NEMDE). Research shows that consumers already have a low level of engagement in the energy market and many do not have the energy literacy to make informed choices that best suit their needs. This then puts further reliance on retailers and other energy service providers to create and innovate energy products and services that either help consumers manage their energy use in response to price signals or make these decisions on behalf of consumers. Where the benefits rely on consumers purchasing different forms of technology, this will exacerbate equity gaps between consumers, for example between consumers who own their home and consumers who rent.

The benefits of integrating consumer energy resources are significant, with potential savings estimated to be up to $6.3 billion over 20 years, which are intended to flow through to consumers through lower system costs and lower electricity prices.[412] The AER is participating in the ESB's working groups to implement the reforms needed to deliver benefits through to consumers. We will be guided by the research on consumers experiencing vulnerability to look at mitigating equity gaps in energy costs and leading a review of the retailer authorisation and exemption framework. This review will consider whether the current consumer protection framework is still fit for purpose in a changing energy market where consumers are offered a variety of new products and services to support consumer energy resources.[413]

410 ESB, 'Electric vehicle smart charging issues paper – for consultation', ESB Website, July 2022, accessed 15 September 2022.

411 ESB, 'Electric vehicle smart charging issues paper – for consultation'.

412 ESB, 'Post-2025 Market Design Final advice to Energy Ministers Part B', ESB Website, 27 July 2021, accessed 15 September 2022.

413 AER, 'Retailer authorisation and exemption review', AER Website, 22 April 2022, accessed 15 September 2022.

6.7.5 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 of their choice other than their network operator or can only do so 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. To address these gaps, in June 2019 the AEMC recommended a new regulatory framework for embedded electricity networks to address these issues.[414] The AER's retailer authorisation and exemption review will build on the AEMC's embedded electricity networks findings and consider the appropriateness of the embedded electricity networks in the context of new products and services supporting consumer energy resources.

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 becoming increasingly prevalent in some areas. These arrangements have mainly developed in regional communities that are remote from existing networks to avoid significant transmission costs. 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 (SAPS) (where economically efficient to do so) while maintaining appropriate consumer protections and service standards.[415]

In November 2021 the AER updated its electricity distribution ring-fencing guideline, which provides the regulatory frameworks and controls to support 2 key emerging markets in Australia's transitioning energy sector – the deployment of batteries, including community-scale batteries, and SAPS.[416]

The AER's ring-fencing reforms also support the new rule to allow network businesses to move customers from a grid connection to a regulated SAPS, improving connection and reliability for customers, particularly those in remote areas. SAPS are fast becoming a cheaper option than waiting for the replacement of aging distribution lines. The updated guideline allows distribution networks to play a greater role in providing standalone generation services and paves the way for faster deployment of regulated SAPS.

6.8 Customer complaints

Customer complaints can cover issues such as 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.

Except for the ACT, the number of electricity and gas complaints received by energy retailers decreased across all jurisdictions in 2020–21, down 30% on the previous year (Figure 6.25). The number of electricity and gas complaints received by energy ombudsmen also decreased in 2020–21, down 19% on the previous year (Figure 6.26).

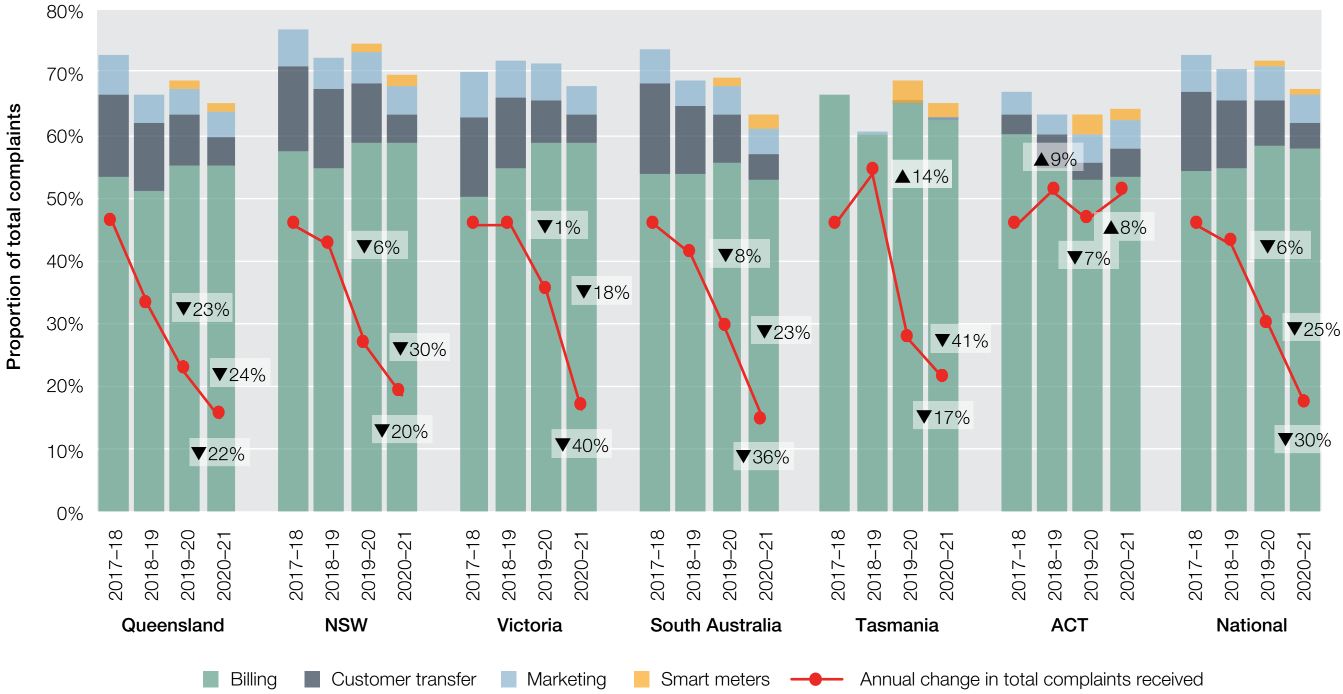
Retailers with effective customer service generally resolve complaints without the need for escalation to energy ombudsman schemes. This means that when viewed together, the data on electricity and gas complaints received by energy retailers and by jurisdictional ombudsmen is useful for assessing the quantity and types of complaints that were not able to be promptly resolved by a retailer.

414 AEMC, 'Updating the regulatory frameworks for embedded networks'.

415 Energy Ministers, 'Stand-Alone Power Systems Priority 1 Rule Amendments, Explanatory note for stakeholder consultation', Department of Climate change, Energy, the Environment and Water Website, March 2021, accessed 15 September 2022.

416 AER, 'Ring-fencing guideline – electricity distribution', AER Website, November 2021, accessed 15 September 2022.

Figure 6.25 Complaints received by energy retailers



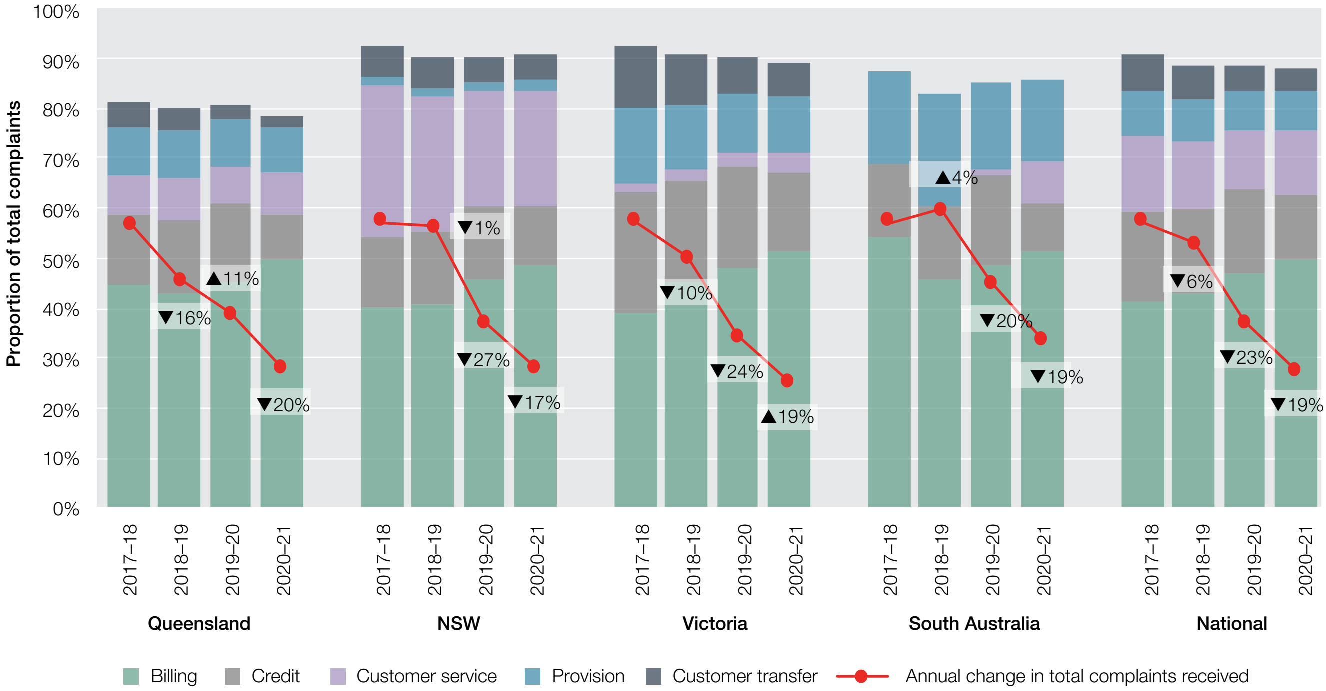
Note: Billing includes complaints about prices, billing errors, payment arrangements and debt recovery practices. Customer transfer includes complaints about timeliness of transfer, disruption of supply due to transfer and billing problems directly associated with a transfer. Marketing includes complaints about sales practices, advertising, contract terms and misleading conduct. Smart meters includes all complaints related to metering contestability. Complaints do not sum to 100% as some customer complaints defined as 'other' are not included in the above data. 'Other' complaints relate to issues outside the retailer's control – for example, complaints about price rises due to wholesale and network costs.

Source: AER, *Retail markets quarterly, Q1 2021–22*, December 2021; ESC, *Victorian energy market report 2020–21*, November 2021.

Billing concerns continued to be the most common cause of complaint, constituting more than half of the total complaints received by both retailers and ombudsmen in 2020–21. Unexpectedly high bills are the primary billing issue. Other billing issues include errors, incorrect tariff, estimation of energy use, fees and charges, and back billing.

The numbers of complaints received has decreased markedly since the introduction of stronger consumer protections in response to the COVID-19 pandemic. The AER's Statement of Expectations (and the equivalent Victorian response) prevented disconnection, debt collection and credit default listing for customers experiencing financial stress. However, as retail energy prices rise, the AER expects to see customer complaints increase.

Figure 6.26 Complaints received by jurisdictional energy ombudsmen



Note: Annual change in total complaints data includes all cases recorded by ombudsman schemes for electricity and gas industries. Annual change in total complaints data includes enquiries and complaints in relation to energy retailers, distribution networks and embedded network operators. Specific complaint type data includes all cases recorded by ombudsman schemes for electricity, gas and water industries. The proportion of water related complaints is immaterial.

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.

Recent reforms to the civil penalties regime under national energy laws now enable the AER to seek penalties of up to $10 million (potentially more for large companies) for alleged breaches of the energy laws.

The AER's compliance and enforcement priorities for 2021–22 focused on protecting consumers experiencing vulnerability, effectively regulating competitive markets and delivering efficient regulation of monopoly infrastructure.

The priorities were:

- effective identification of consumers who experience difficulty to pay and offer of payment plans that consider the consumer's capacity to pay
- ensure exempt seller compliance with exemption conditions, including consumer access to ombudsman schemes
- focus on registered generators' compliance with AEMO dispatch instructions and their ability to comply with their latest offers at all times
- ensure service providers meet information disclosure obligations and other Part 23 National Gas Rules obligations
- ensure timely and accurate gas auction reporting by registered participants.

Significant compliance and enforcement outcomes, including substantially higher penalties under the new penalty regime, have been delivered in 2021–22. As our energy market transitions, it is more important than ever that the AER remains vigilant and takes timely and proportionate enforcement action when harms arise.

6.10 Consumers experiencing vulnerability

6.10.1 Customers in hardship

The AER instituted proceedings in the Federal Court against Origin Energy for systemic failures in implementing its hardship policy and assessing consumers' capacity to pay. Origin Energy was ordered to pay penalties of $17 million in respect of over 90,000 customers. This is the highest civil penalty ordered under national energy laws to date.

The AER investigated concerns that, from September 2019 to March 2020, Alinta Energy may have required consumers experiencing vulnerability to make upfront payments or seek financial counselling, when it should have offered consumers access to payment plans or assistance to join Alinta's hardship program. Following the AER investigation, Alinta Energy waived more than $1 million in customer energy debt and substantially improved its systems.

The AER also undertook a range of compliance activities to improve behaviours in the industry to ensure retailers meet their obligations to consumers experiencing vulnerability, as required under the Retail Law and Retail Rules, and offer individualised assistance where appropriate.

In 2021–22 the AER assessed and approved 6 new and amended retailer hardship policies.

The AER required compliance audits by retailers, including Alinta Energy, Simply Energy, ReAmped Energy and Powershop Australia, of their policies, systems and procedures in relation to hardship and disconnection obligations under the Retail Law and Retail Rules. The audit also considered compliance with the AER Compliance Procedures and Guideline (2018). The audits identified several areas where the audited retailers could strengthen and improve their processes to best support customers in financial difficulty, including:

- reviewing hardship policies and increasing their visibility to customers
- segregating key duties and training staff
- improving compliance reporting and reducing human error through automation of follow-up processes.

The AER has monitored implementation of these plans which have now either been completed or are close to completion.

In November 2021, the AER wrote to 19 retailers requesting information on their practices for consumers experiencing financial hardship or payment difficulty, and the steps retailers will take to support these consumers. Responses from retailers identified some positive practices in the way retailers are assisting consumers in financial difficulty to manage their debt, as well as a number of practices that could be modified or improved. The learnings from both the audits and the information requests were shared by the AER during a panel discussion with energy retailers in June 2022. At this panel discussion, it was emphasised to retailers that, now more than ever, they need to adhere to the hardship and payment plan obligations in the Retail Law and Rules as consumers face higher prices. Retailers were also reminded that former customers are still entitled to hardship and payment plan protections.

6.10.2 Embedded networks

The AER focused on ensuring consumers in embedded networks, who are sold energy by exempt sellers, are not disadvantaged and can access dispute resolution services through ombudsman schemes. This included:

- contacting various industry associations for caravan parks, retirement villages and similar (as well as contacting exempt sellers directly) to share compliance messaging
- formalising a referral process between ombudsman schemes and the AER to ensure non-member exempt sellers are efficiently identified and notified of the requirement
- following up non-member exempt sellers that continued to fail to join the relevant scheme and successfully ensured compliance
- updating its Retail Exempt Selling Guideline to increase protections for consumers living in embedded networks as well as to make exempt sellers' obligations clearer – key changes include:
  - introducing a new condition to require exempt sellers to have a hardship policy
  - introducing a new information provision condition for exempt sellers to provide their customers with an AER fact sheet
  - clarifying our expectations on customer consent for conversions to embedded networks

- introducing a requirement to provide evidence of steps taken to obtain ombudsman scheme membership, as part of the individual exemption application process.

These activities have resulted in a significant increase in the number of exempt sellers that are members of an ombudsman scheme, ensuring the consumers they sell energy to have access to this important dispute resolution service.

The AER decided to defer its release of the draft Network Exemptions Guideline (version 7) while further changes are made to streamline and simplify this guideline. The review of the Network Exemptions Guideline is ongoing and is planned for final release in late 2022.

6.10.3 Life support

The Retail Rules establish critical protections for customers who rely on life support equipment. Failure to deliver these protections could have dangerous and even fatal consequences. All retailers and distributors operating under the Retail Law and Retail Rules are required to comply with these obligations.

The AER has updated the Life support registration guide to reflect new obligations that commenced on 1 August 2021. This follows a rule change published by the AEMC in February 2021, which aims to reduce barriers for life support consumers who switch retailers or move premises by enabling consumers to reuse a previously submitted medical confirmation form. These new rules are designed to allocate clear responsibilities between retailers and distributors to ensure life support registers are accurate and up to date.

- On 1 June 2022 EnergyAustralia was ordered by the Federal Court to pay penalties totalling $12 million for failing to comply with life support obligations for its customers who rely on life-saving health equipment. This conduct occurred over a number of years from 2018.
- Endeavour Energy paid 7 infringement notices totalling $474,600 to the AER on 24 June 2022 for alleged breaches of life support obligations under the Retail Rules. The AER has also accepted a court enforceable undertaking from Endeavour Energy, with Endeavour Energy committing to implement new IT systems and to engage an independent expert to conduct an end-to-end review of its life support processes, controls and systems.

6.10.4 Compliance and enforcement priorities for 2022–23

The AER has settled its compliance and enforcement priorities for 2022–23, which sees the current priorities continued for a further 12 months and some updates to areas of focus:

- effectively identify residential consumers experiencing difficulty to pay and offer payment plans that consider the consumer's capacity to pay
- improve outcomes for consumers in embedded networks, including by enabling access to ombudsman schemes
- focus on registered generators' compliance with offers, dispatch instructions, obligations relating to bidding behaviour and provide accurate and timely capability information to the Australian Energy Market Operator (AEMO)
- ensure service providers meet information disclosure obligations under Part 23 of the National Gas Rules
- ensure timely and accurate gas auction reporting and demand forecasting in downstream wholesale gas markets by registered participants.

In addition, we will continue to act where there are serious issues impacting consumers experiencing vulnerability, including life support customers. We will also continue to act to help shape new or emerging markets and to implement new guidance such as the Better Bills Guideline.

The AER's Annual compliance and enforcement report and Mid-year compliance and enforcement update provide in-depth assessments of the compliance of regulated entities.

6.10.5 Retailer marketing conduct

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 also 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 June 2021 the Federal Court declared that energy retailer Sumo made false or misleading representations in selling electricity plans to Victorian consumers.[417]

The Court declared that Sumo had offered cheap rates and high 'pay on time' discounts to entice consumers to sign up to certain electricity plans and claimed that price increases were solely because of electricity generation costs caused by factors such as climate change, the closure of the Hazelwood power station, network upgrades and fees paid to distributors, when this was not the case.

Sumo was ordered to pay $1.2 million in penalties and to pay consumer redress to 7,700 affected consumers, which on average paid an additional $50 per month. The Court also declared by consent that Sumo had misled consumers by representing that its marketing agents were from an independent company offering a comparison service of electricity plans instead of Sumo.

In January 2022 energy retailer CovaU Pty Ltd paid $33,300 in penalties after the ACCC issued it with 3 infringement notices for alleged contraventions of the Electricity Retail Code. The ACCC alleged that CovaU advertised the prices of 3 residential electricity plans on its website between 27 June and 19 July 2021 without stating a percentage difference to the comparison price set by the government.[418] Since 1 July 2019, retailers have been required to include the percentage difference to the default price in electricity offers to residential and small business customers. This provides a more consistent benchmark to see how a plan compares with other offers from a glance.

417 ACCC, 'Sumo Power to pay $1.2 million for misleading electricity plans' [media release], ACCC Website, 30 June 2021, accessed 15 September 2022.

418 ACCC, 'CovaU pays penalties for allegedly failing to publish comparison pricing on electricity plans' [media release], ACCC Website, 12 January 2022, accessed 15 September 2022.

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
MtCO2-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