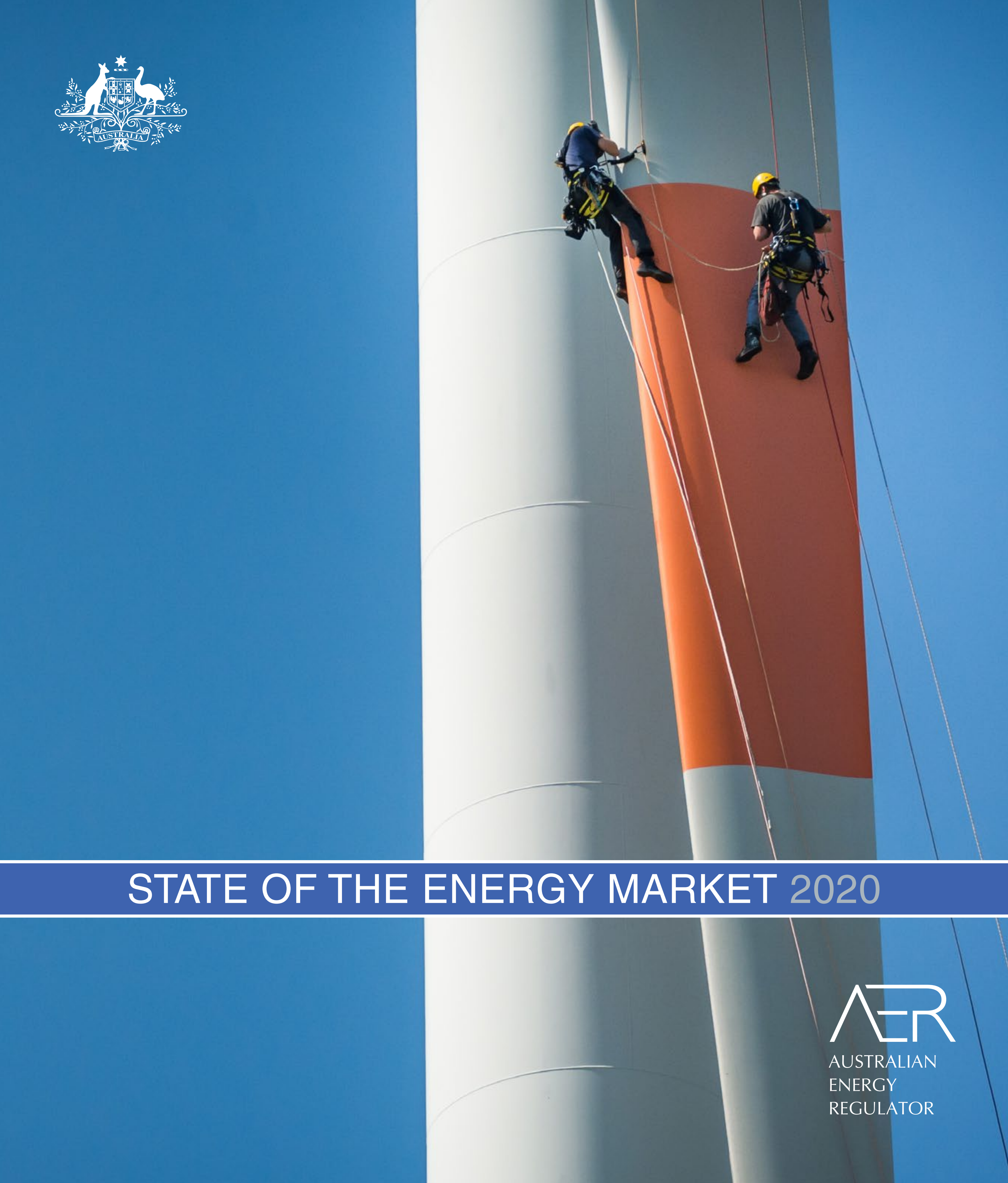

# STATE OF THE ENERGY MARKET 2020

AUSTRALIAN
ENERGY
REGULATOR

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ENERGY
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# PREFACE

Much is written about the energy transition and, indeed, for the first time we have dedicated a chapter to it in *State of the Energy Market 2020*. At the same time, with so many of us home due to COVID-19 and using more power, it's an important reminder that our focus must always remain on the interests of consumers. All of our work over the past year has been underpinned by exceptional market and consumer insight, of which there are few better examples than the AER's signature publication, *State of the energy market*.

Our market and regulatory frameworks exist to serve the long term interests of consumers, but meeting their diverse needs is challenging. There are still many consumers who may not want to, or simply cannot, effectively engage in what is a complicated market. The Australian Government introduced the Default Market Offer as a cap on the price that electricity retailers can charge consumers on standing offer contracts. The AER sets price caps in south east Queensland, NSW and South Australia. From July 2019 to January 2020, standing offer prices for residential consumers fell by 11–13 per cent in NSW, 12 per cent in South Australia, and 10 per cent in south east Queensland.

The AER recently commissioned a study from the Consumer Policy Research Centre on vulnerability. Vulnerability is multi-faceted, and all consumers can move in and out of vulnerability at different points, as demonstrated by COVID-19. Our Statement of Expectations released in the wake of COVID-19 extended payment plans to all residential and small business customers in financial stress and prevented their disconnection. Pleasingly, both networks and retailers quickly adopted these expectations. As reflected in Justice Hayne's commentary in the Royal Commission into banking and financial services, it is no longer enough for businesses to do the bare minimum to comply with the strict letter of the law.

The AER actively monitors and reports on energy market participants, and takes action to ensure compliance with the law and rules. Since 1 July 2019, the AER has issued 25 infringement notices, accepted three enforceable undertakings, commenced eight cases in the Federal Court, and conducted 10 retail audits. This is almost twice as many compliance and enforcement actions as the AER has initiated before.

This year the AER will complete its biennial review of the performance of the wholesale electricity market. Wholesale electricity prices have been the largest contributor to retail price rises over the past few years. This review will analyse longer term trends in wholesale prices and generator costs, and explore a number of emerging market trends.

Fortunately, stubbornly high wholesale electricity prices have finally begun to fall as large volumes of renewable energy enter the market and fuel prices fall. This should bring some relief to consumers in coming years.

The entry of large volumes of renewable energy means we need a stronger grid to support a least cost energy system. The AER has approved two new electricity transmission projects this year (Queensland – NSW, and NSW – South Australia) in record time to ensure we can meet the future needs of consumers.

Those active and engaged consumers among us long for smart homes and appliances that can be used to participate in the emerging energy marketplace. More rooftop solar photovoltaic (PV) and battery systems will require creative and nimble regulatory approaches to ensure the integration of these resources benefit all. More innovative network tariffs—such as the SA Power Networks' 'solar sponge' tariff that the AER approved this year—will be critical. The AER is also supporting investment in demand management innovations that will reduce the need to invest in network assets.

The national gas industry could also undergo significant change as some jurisdictions move towards a zero carbon emissions policy. This could have significant consequences for the future of gas pipeline networks. In response, the AER recently supported the future recovery of Jemena's investment in trialling the production of hydrogen from renewable energy for injection into its Sydney network.

If hydrogen trials such as Jemena's prove successful, the natural gas networks could be re-purposed to distribute hydrogen. If not, the economic life of the assets could be limited, raising questions in price reviews about levels of investment, how quickly assets should be depreciated, and the appropriate path of network prices over time.

Making well informed decisions about energy investment requires confidence in the policy and regulatory environment, along with a deep understanding of the marketplace. The many and varied interventions by governments and regulators are complex for industry and consumers alike. It's incumbent on us all to increase the transparency of and rationale for our evidence based decisions in plain language.

We will continue to build on our strong relationships with industry, consumers, business groups, regulatory counterparts and government stakeholders as we play our part in energy regulation and policy development. We understand there are investment decisions that depend on our decisions, and we will continue to work hard to be open and timely in our engagement.

We will continue to build on communicating the benefits of our website Energy Made Easy, #PowerToCompare, to deliver transparent and independent alternatives for consumers.

The *State of the energy market* has served as a valuable resource for decision makers across the policy, legal and regulatory spheres. I commend this resource to everyone who contributes to the governance, generation, distribution, transmission, supply and demand of energy in Australia.

Clare Savage—Chair
June 2020

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# SNAPSHOT

## National Electricity Market

- As ageing coal generators exit the market, over 93 per cent of investment since 2012–13 has been in wind and solar plant, often located on the fringes of the grid.
- Renewable plant produced record output in 2019. Wind farms accounted for 8 per cent of output, and solar farms for 2.5 per cent. Rooftop solar photovoltaic systems met another 5.2 per cent of the market's electricity needs.
- Investment in wind and solar plant slowed from mid-2019, as technical issues with integrating new plant into the system delayed projects. Coordinated planning reforms aim to better integrate renewable plant, rooftop solar PV, demand response and battery storage into the system, with a focus on ensuring the transmission grid can meet transport needs.
- As the market transitions, intervention to manage power system security and reliability risks has risen, imposing significant costs on energy customers. The Australian Energy Market Operator has directed some generators to operate even when not economic, and constrained some low priced plant from operating. South Australia and, more recently, Victoria and Queensland have been the focus of these interventions.
- Investment in 'firming' capacity (such as fast start generation, demand response, battery storage and pumped hydro plant) is needed to fill supply gaps when a lack of wind or sunshine curtails renewable plant.
- The Reliability and Emergency Reserve Trader mechanism was activated in each of the past three summers to secure back-up supply, at a cost of $126 million. And the Retailer Reliability Obligation, launched in July 2019, was activated in January 2020 (in South Australia).
- Victoria at $126 per megawatt hour (MWh) edged South Australia ($125 per MWh) as the NEM's highest price region in 2019. Wholesale prices peaked early in the year, due to high fuel costs and periods of (weather driven) high demand. Generator outages in Victoria also impacted the market.
- Rising solar generation and weakening fuel costs eased wholesale prices from mid-2019, with prices for the first quarter of 2020 below $110 per MWh in all regions for the first time since 2015. But extreme weather contributed to record frequency control costs ($220 million) for that quarter.

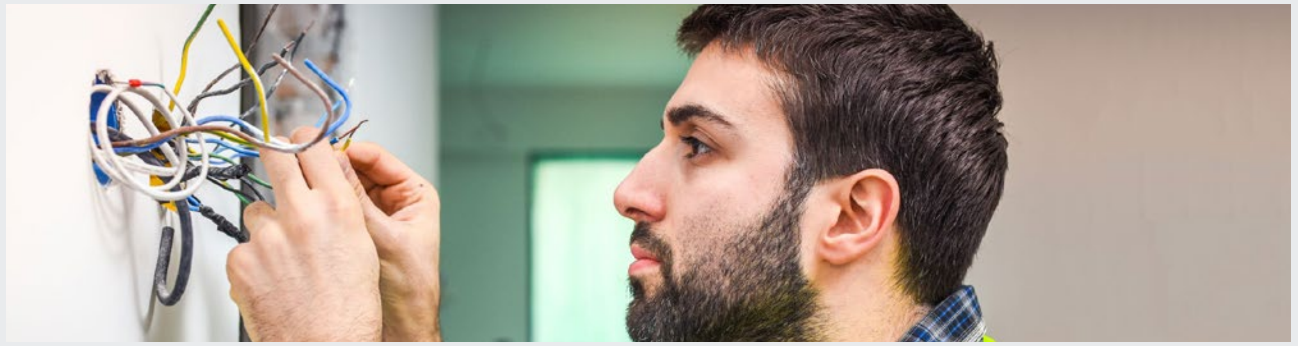
## Eastern Australia gas

- Gas production in the northern gas basins rose to record levels in 2019, in response to (over-optimistic) forecasts of Asian liquefied natural gas (LNG) demand over the 2020 northern hemisphere winter.
- Gas producer agreements with the Australian Government to offer uncontracted supply to the domestic market helped ease domestic supply concerns. New gas supply from the Northern Territory (via the Northern Gas Pipeline) also mitigated risks.
- Policy reforms in 2019 made it easier to access gas pipelines needed to transport gas to markets. The reforms free up contracted pipeline capacity that is not being fully used, either through voluntary trade or mandatory day-ahead auctions. The auctions freed up over 40 petajoules of capacity across 10 pipelines in the first 13 months of operation, with most capacity auctioned at the reserve price of zero.
- LNG prices weakened as new international supply came online at a time when demand was slowing. In March 2020 intense price competition between Saudi and Russian oil producers, and COVID-19 related demand reductions dragged international oil prices to their lowest levels since 2003. Australian exporters reported the uncertainty stemming from COVID-19 and collapsing oil prices limited their ability to strike new gas supply agreements.
- Increased domestic supply, pipeline reforms and weakening global markets flowed through to domestic prices. Spot prices averaged $7–8 per gigajoule (GJ) in the fourth quarter of 2019, down from $10 per GJ a year earlier. Some trades in the first quarter of 2020 were being made at prices below $5 per GJ in southern markets, and below $4 per GJ in northern markets.
- Four LNG import terminals are being considered across South Australia, Victoria and New South Wales (NSW).

# SNAPSHOT

## Regulated energy networks

- Revenue forecasts in current regulatory periods are 13 per cent lower for electricity networks, and 14 per cent lower for gas networks, than in previous periods. Lower rates of return were a key driver of declining revenues.
- Electricity distribution revenue in 2019 hit its lowest point since 2011, and was 23 per cent lower than the peak recorded in 2015. Transmission revenue in 2019 was at its lowest level in over a decade.
- Network investment increased for the third consecutive year in 2019, including a 9 per cent rise for electricity distribution. But investment in 2019 remained 41 per cent below the peak recorded in 2012. The majority of forecast investment in distribution networks is to replace and refurbish old assets, rather than to expand the networks.
- Electricity networks are better managing their operating costs, partly in response to AER incentives and benchmarking. Productivity rose by 1 per cent in distribution networks and 2.2 per cent in transmission in 2018, mainly linked to efficiencies in operating expenditure. Distribution productivity grew for three consecutive years to December 2018, exceeding growth in the Australian economy as a whole.
- Distribution network businesses have managed reliability more effectively over the past decade, although factors such as extreme weather sometimes impact customer experience.
- A number of network businesses are trialing engagement models to identify their customers' needs, to help develop new regulatory proposals. AusNet Services (Victoria) engaged an independent customer forum to negotiate its proposal.
- Cost-reflective network tariffs encourage retailers to incentivise energy customers to switch their energy use from times of high demand to times of lower demand. As an example, SA Power Networks' 'solar sponge' tariff for residential customers offers lower network charges in the middle of the day when solar output is highest.
- The AER is supporting investment in demand management innovations that will reduce the need to invest in network assets. Supported projects include residential and grid scale battery storage projects, technology trials to manage demand through device control, and research into distributed energy platforms for demand management.



## Retail energy markets

- The Australian Government introduced price caps on retailers' electricity standing offers from 1 July 2019. The AER sets the default market offer on standing offer prices in south east Queensland, NSW and South Australia. Victoria introduced a similar arrangement that sets standing offer prices at a level reflecting the costs of an efficient retailer in a contestable market.
- In the seven months to January 2020, standing offer prices for residential customers fell by 14–19 per cent in Victoria, 11–13 per cent in NSW, 12 per cent in South Australia, and 10 per cent in south east Queensland.
- But electricity standing offer prices remain higher than market offers. A customer switching from the median standing offer to the best market offer in their distribution zone could save up to 20 per cent ($300–400 in annual savings) in January 2020.
- Retailers are moving away from discounting towards simpler, more stable pricing. This shift coincided with reforms introduced in 2019 that restricted advertising based on large headline discounts. Offers with conditional discounts accounted for around two thirds of offers in Queensland, NSW, South Australia and the Australian Capital Territory (ACT) in 2018, but less than 20 per cent of offers by 2020.
- Three businesses—AGL Energy, Origin Energy and EnergyAustralia—continue to dominate the retail market, supplying 63 per cent of small electricity customers and 75 per cent of small gas customers in eastern and southern Australia. But smaller retailers are building market share.
- The AER is strengthening frameworks to support customers in vulnerable circumstances. It revised hardship guidelines in 2019, and published research (by the Consumer Policy Research Centre) in 2020 on regulatory approaches to customer vulnerability.
- The AER (www.energymadeeasy.gov.au) and Victorian Government (compare.energy.vic.gov.au) websites provide energy price comparisons of all readily available market offers. Enhancements to the Energy Made Easy website in early 2020 aim to simplify the user experience and increase the site's capability to compare innovative offers.

Source: AER

# MARKET OVERVIEW

The COVID-19 pandemic has overshadowed other aspects of life in 2020, and the energy sector is not immune from its impact. The energy market has an important role to play in protecting and supporting businesses and the community through the pandemic and recovery. In April 2020 the Australian Energy Regulator (AER) released a Statement of Expectations to energy businesses, setting out principles that it expects them to follow during this period to avoid imposing unnecessary hardship on the community.[1]

In its compliance work, the AER is focusing on ensuring customers receive the support that they need, and the protections to which they are entitled. It is closely monitoring business compliance with provisions of the National Energy Retail Law, the National Energy Retail Rules and the exemption guidelines that protect customers facing payment difficulties. Initial commitments by energy retailers and some distribution networks have been encouraging, clearly looking to reduce the financial burden on impacted customers while COVID-19 related restrictions remain in place. But concerns have been raised around some retailers' interpretation of hardship disconnection principles.

The AER recognises the current heightened risks and costs facing energy businesses. For this reason, it is working with stakeholders to appropriately balance the risks and costs across the sector, and to ensure energy businesses receive any assistance they may need to remain viable. The AER in May 2020 proposed an urgent change to the National Electricity Rules to support electricity retailers as they provide payment assistance to customers, by allowing them to defer payments of network charges by up to six months for customers affected by the COVID-19 pandemic. The proposal builds on voluntary support measures being provided by network businesses under Energy Networks Australia's Networks' Relief Package.

Alongside impacts on energy customers and retailers, the COVID-19 outbreak intensified pressures already building in gas markets. In March 2020 international oil prices crashed to their lowest levels since 2003, from the combined impacts of the Saudi Arabia – Russia oil price war and COVID-19 related demand reductions. Domestically, collapsing demand led wholesale spot gas prices in the first quarter of 2020 to settle at their lowest quarterly levels in four years. Wholesale electricity prices also eased from mid-2019, reflecting lower fuel costs for fossil fuel generation and rising levels of renewable generation.

## 1 The electricity market in transition

While dealing with the disruptive impacts of COVID-19, the energy sector is also in the midst of its own transition from a centralised system of large fossil fuel (mainly coal) generation towards a decentralised system of widely dispersed, relatively small scale renewable (mainly wind and solar) generators (figure 1).

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

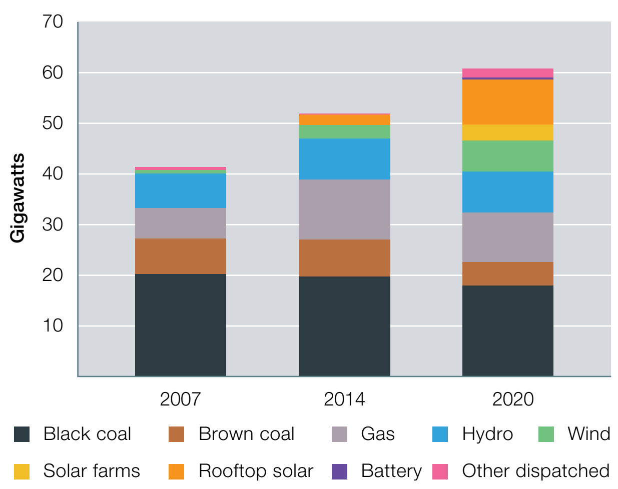
But integration issues have arisen because much of this new generation is located in sunny or windy areas at the edges of the grid with relatively weak transmission network capacity. Further, the fossil fuel plant being replaced traditionally provided critical technical stability services such as inertia and system strength. The ability of wind and solar plant to provide these services has been limited. As a result, the rising proportion of renewable generation is bringing more periods of low inertia, weak system strength, more erratic frequency shifts, and voltage instability.[2] This volatility has consequences, such as the rising cost of procuring market services to keep system frequency within safe limits.

An ongoing challenge is to find the best ways to keep the power system reliable and secure as the generation mix changes. The weather dependent nature of wind and solar generation creates a need for 'firming' capacity (such as fast start generation, battery storage and pumped hydro plant) to fill supply gaps when a lack of wind or sunshine curtails renewable plant. Greater weather driven volatility also requires better demand and supply forecasting, to ensure firming capacity is available when needed.

More frequent market interventions have occurred to maintain a reliable and secure power system. As an example, the Australian Energy Market Operator (AEMO) used the Reliability and Emergency Reserve Trader (RERT) mechanism in each of the past three summers to secure back-up supply, at a cumulative cost to the market (and energy customers) of around $126 million.[3]

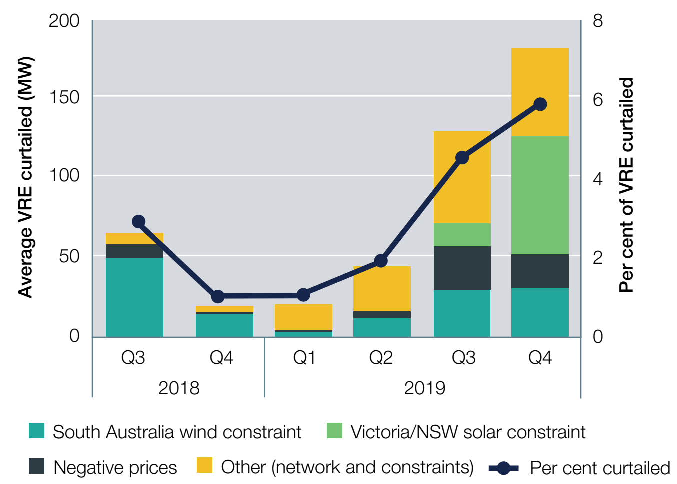
1 AER, *Statement of Expectations of energy businesses: protecting consumers and the market during COVID-19*, 9 April 2020.

**Figure 1**
**A changing generation mix**




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

**Figure 2**
**Curtailment of renewable generation**




MW, megawatt; VRE, variable renewable energy.
Source: AEMO, *Quarterly energy dynamics Q4 2019*, February 2020.

To manage security issues, AEMO has been directing generators to operate even if it is not economic for them to do so, and constraining some low priced plant from operating (figure 2). South Australia and, more recently, Victoria and Queensland have been the focus of these interventions. AEMO also de-energised transmission lines in Victoria.

AEMO instructed load shedding—a last resort option for managing system security—twice in 2019. The load was shed in Victoria on 24 January 2019 (75 megawatts (MW)) and 25 January 2019 (100 MW).

Strategic planning, and policy and regulatory reforms are guiding the energy market transition in ways that will optimise benefits for energy customers. Market bodies are exploring how best to manage reliability risks, with a focus on encouraging investment in resources with the flexibility to manage sudden demand or supply fluctuations. A longer term focus is on expanding the role of demand response to manage risks. To manage more imminent threats, the Retailer Reliability Obligation (RRO) launched in July 2019 requires retailers and large energy customers to cover their electricity requirements by either owning dispatchable generation or securing contracts with third parties, whenever AEMO identifies a reliability gap in the market. The AER enforces compliance with the RRO.

New rules to address technical security risks include an obligation on transmission network businesses to maintain minimum levels of system strength and inertia if AEMO identifies a shortfall. Declared shortages of inertia and system strength are in place in South Australia, and inertia and fault level shortfalls were declared in Tasmania in November 2019. Additionally, AEMO declared fault level shortfalls in north west Victoria and north Queensland in December 2019 and April 2020 respectively.

Another reform requires connecting generators to 'do no harm' to levels of system strength needed to maintain the power system security. And, from June 2020, all capable generators and batteries must provide primary frequency response support whenever called on to manage a supply–demand imbalance. Market bodies are also exploring longer term solutions for sourcing security services, including the development of new markets for inertia, system strength and voltage control. Supporting these developments, the Australian Renewable Energy Agency (ARENA) and Clean Energy Finance Corporation (CEFC) increased their focus on funding technologies and business models that efficiently integrate renewables into the system.

Aside from reliability and security challenges, Australia's energy market transition poses risks to the efficient investment and use of energy infrastructure. Key issues are the efficient location of new generation, and the coordination of generation and transmission investment.

AEMO's Integrated System Plan is a roadmap for the efficient future development of the National Electricity Market (NEM). As part of that development, the plan identifies network investment needed to accommodate anticipated new generation connections. It prioritises the bolstering of the interconnection of NEM regions, to allow more generation trade among regions to reduce energy costs and enhance reliability and security.

Alongside this plan, policy makers are changing elements of the energy market design to improve locational signals for new generation investment, and to coordinate investment across the generation and transmission sectors. Reforms also target the creation of renewable energy zones so clusters of generators can share the costs of connecting to the shared transmission network, and contribute to wider network improvements.

Reforms to make network tariffs more cost reflective will support the more efficient use of networks and demand management, as discussed below.

## 2 National Electricity Market

The transition underway in the electricity market is still in its early stages. Fossil fuel generators continued to produce 77 per cent of electricity in the NEM in 2019. But many older generators are nearing the end of their life and becoming less reliable. Around 15 per cent of the NEM's coal generation capacity in 2010 has since retired, and a further 29 per cent is scheduled to retire by 2035.

The profitability of coal plant has also been challenged by slumping demand for grid supplied electricity in the middle of the day, when rooftop solar PV generation is at its maximum. Despite these pressures, profits and share prices for some coal generating businesses have shown resilience. This resilience may reflect ongoing tightness in the supply–demand balance. The AER is monitoring the market to identify any competition concerns as the market transitions, and will publish its next round of findings in December 2020.

Wind and solar generation are filling much of the supply gap left by coal plant closures. Over 93 per cent of generation investment since 2012–13 has been in wind and solar capacity, driven partly by government subsidies under the renewable energy target scheme, and by funding from ARENA and the CEFC.

Around 4000 MW of grid scale generation was added to the NEM in 2018–19, but capacity additions have since slowed, partly as a result of issues with integrating new plant into the power system. Only 1400 MW of capacity was commissioned in the nine months to March 2020. But rooftop solar investment continued to grow steadily, adding 1600 MW of capacity in 2018–19, and another 1400 MW in the nine months to March 2020.

Wind plant accounted for over 40 per cent of new generation investment in 2019. Wind farms produced 8.2 per cent of the NEM's electricity in 2019, and recorded an 18 per cent year-on-year rise in output. Its penetration is especially strong in South Australia, where it provided 38 per cent of the state's electricity output in 2019.

Commercial solar farms have been slower to develop in Australia, but a pipeline of projects reached commissioning stage in 2019. Solar farms accounted for 2.5 per cent of output in 2019, and that contribution is set to rise as new projects come on stream. Generation by rooftop solar PV systems rose strongly over the past decade, and met 5.2 per cent of the NEM's electricity requirements in 2019.

The closure of two major brown coal power stations—Northern (South Australia) in May 2016 and Hazelwood (Victoria) in March 2017—triggered several years of rising wholesale electricity prices. The Hazelwood closure withdrew 5 per cent of the NEM's total capacity, much of which was usually offered at low prices. After the closure, more expensive black coal and gas plant began to set spot prices more frequently.

Prices remained elevated in most regions through to 2019, when they averaged close to $100 per megawatt hour (MWh)—just short of the record ($105 per MWh) set in 2017 (figure 3).

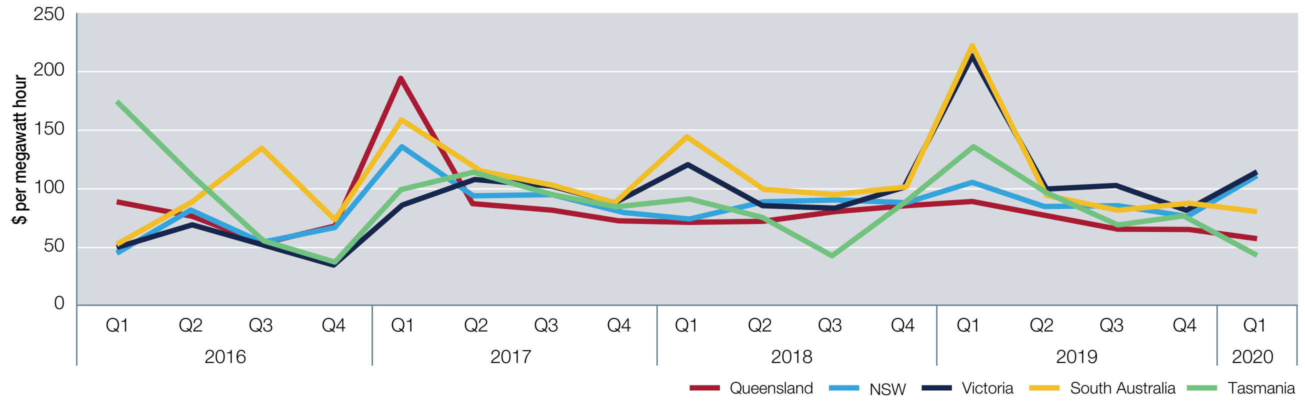
Victoria ($126 per MWh) edged out South Australia ($125 per MWh) as the NEM's highest price region in 2019. The state more than doubled its 2016 average ($52 per MWh) before the closure of Hazelwood. Hot weather combined with plant failures led to Victoria ($216 per MWh) and South Australia ($223 per MWh) setting record prices in the first quarter of 2019. Other contributing factors included dry conditions (which constrained hydrogeneration) and high fuel costs for gas powered generation.

Victorian prices remained unseasonably high for much of 2019, exacerbated by an unplanned outage at Loy Yang A that ran for several months and removed 11 per cent of low cost generation from the region. Outages at the Yallourn and Mortlake power stations compounded the situation, contributing to average prices settling above $100 per MWh in Victoria in the second and third quarters of 2019.

Queensland prices averaged $75 per MWh in 2019, which was the lowest average for any NEM region. A substantial rise in solar capacity contributed to Queensland being the only region with a lower year-on-year average price, despite growth in electricity demand. New South Wales (NSW) prices averaged $89 per MWh in 2019—which was the second lowest average for any NEM region—but were 4 per cent higher than in 2018. Coal supply issues caused



Figure 3
**Quarterly wholesale electricity prices**




Note: Volume weighted average prices.
Source: AER; AEMO (data).

the state's Mount Piper power station to operate at reduced output for several months during the year. In Tasmania, below average rainfall constrained hydrogeneration, and a six week disruption on the Basslink interconnector disrupted trade with the mainland. As a result, the region recorded a 30 per cent price rise, averaging $95 per MWh in 2019.

The market was volatile in 2019, with 397 trading intervals settling above $300 per MWh. Much of this volatility occurred in Victoria, South Australia and Tasmania, linked to extreme weather and high system demand early in the year, and generator outages in Victoria. Significant volatility returned in early 2020, again linked to extreme weather. Bushfires impacted the market, causing transmission lines to trip and limiting generation. At times, the transmission interruptions led to market separation between regions, as occurred between NSW and Victoria on 4 January 2020. Spot prices hit the cap of $14 700 per MWh on multiple days during the bushfire period.

Market volatility also reflected in an increasing occurrence of negative prices. The market set a record number of negative prices in the second half of 2019. These price events typically occur when weather conditions are optimal for renewable generation, and electricity demand from the grid is low. The geographic grouping of renewable generators intensifies the effect, because when conditions are favourable for one wind or solar farm in an area, they tend to be favourable for other wind or solar farms in the area too. The phenomenon is particularly apparent in South Australia and Queensland, which are regions with a high penetration of solar (grid scale and rooftop solar PV) generation (figure 4).

### The market in early 2020

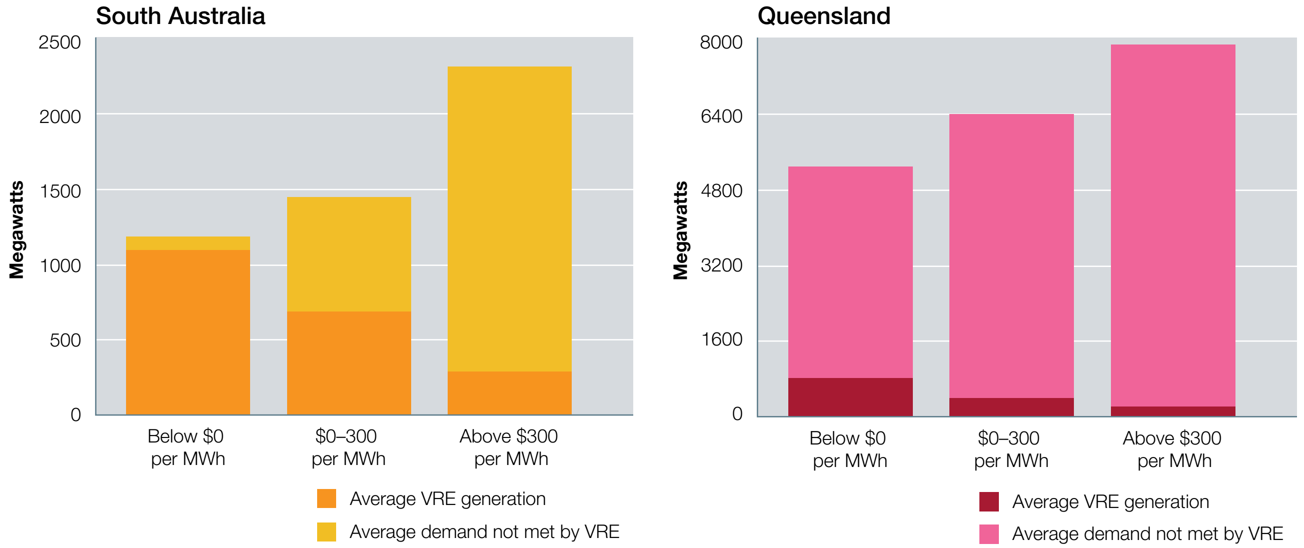
Lower demand—largely driven by a generally mild summer—and lower coal and gas fuel costs caused a reversal in market conditions in early 2020. Wholesale electricity prices in the first quarter were the lowest first quarter prices observed since 2012 in Queensland, 2015 in Tasmania and 2016 in South Australia. More generally, the first quarter of 2020 marked the first time since 2015 that first quarter prices were below $110 per MWh in all regions.

These averages, however, mask exceptional volatility. At the start of the first quarter, extreme weather conditions and bushfires drove short bursts of high prices in January 2020 across NSW, Victoria and South Australia. Yet, weather conditions in the quarter were generally mild, resulting in lower levels of summer demand. In addition, lower gas and coal fuel costs and rising levels of low priced solar generation kept pressure off prices.

In February 2020 South Australia was isolated from the rest of the NEM after storms damaged transmission infrastructure. The separation meant South Australia was required to provide its own frequency stability services, resulting in record quarterly costs of $227 million for frequency control ancillary services (FCAS)—six times the FCAS costs in the first quarter of 2019.

As the quarter progressed, the COVID-19 pandemic began to affect expectations in contract markets. Volumes of electricity futures contracts for the second and third quarters of 2020 fell by 11 per cent in the last two weeks of March 2020. By late March 2020, baseload futures for first quarter 2021 contracts in Victoria and South Australia had eased 30 per cent off their peak in late October 2019.

Figure 4
Renewable generation and negative prices, 2019




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

## 3 Eastern Australian gas markets

The launch of Queensland's liquefied natural gas (LNG) export industry in 2015 placed significant pressure on Australia's eastern gas market. Relatively higher international gas prices began to bear on domestic gas prices at a time when state based moratoriums on gas development limited options for new domestic supply. Higher gas prices weakened gas demand by industrial customers and gas powered generators. In Queensland, gas generation slumped from 22 per cent of electricity output in 2014 to 8 per cent in 2019. A similar squeezing occurred in NSW.

Different conditions prevailed in Victoria and South Australia, where coal generation retirements and outages on remaining plant made gas generation critical to meeting electricity demand despite higher fuel costs. The share of gas powered generation in electricity supply rose between 2015 and 2019 from less than 2 per cent to 7 per cent in Victoria, and from 37 per cent to 48 per cent in South Australia.

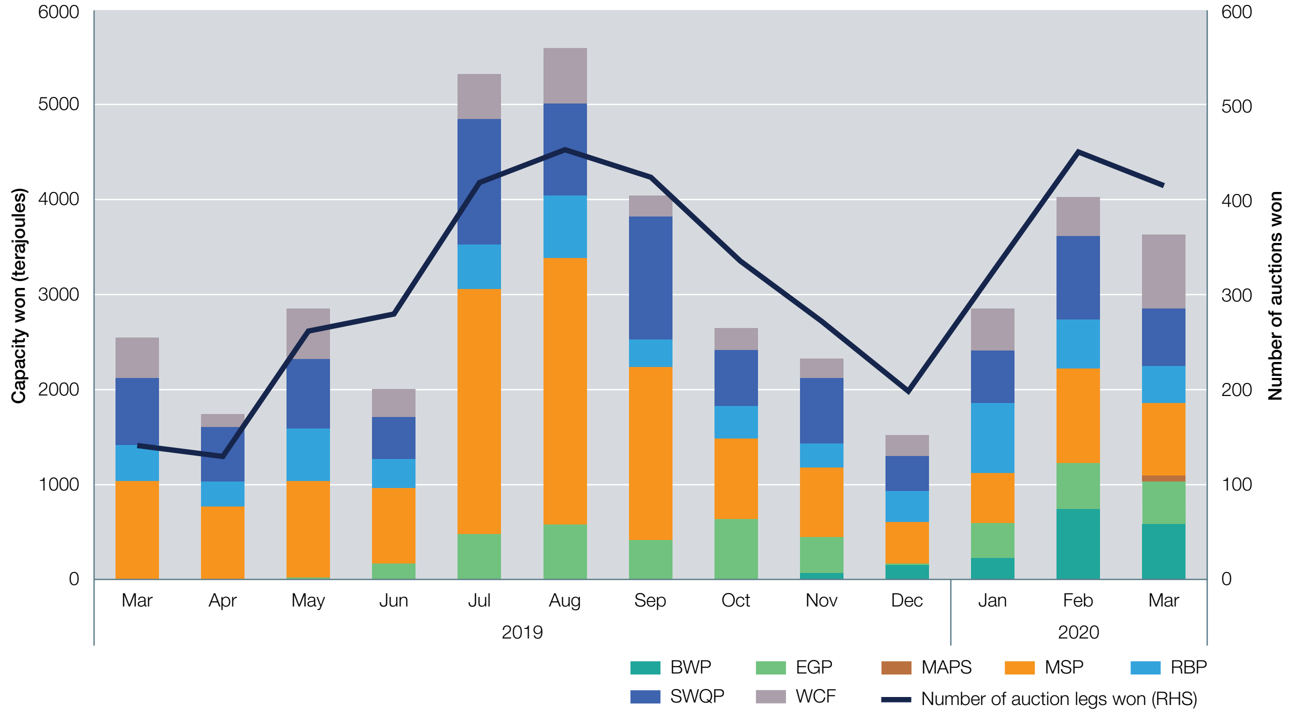
Gas market conditions changed significantly in 2019. Gas production in the northern gas basins rose to record levels, in response to (over-optimistic) forecasts of Asian LNG demand in the northern hemisphere 2019–20 winter. Agreements between gas producers and the Australian Government led to all uncontracted supply being offered to the domestic market on competitive terms before being offered for export. New gas supply from the Northern Territory (via the Northern Gas Pipeline) also improved domestic supply conditions.

Policy reforms making it easier to access critical gas pipelines mitigated pressures in the domestic market too, by enabling gas customers to transport gas at lower cost. The reforms introduced in March 2019 make available to third parties any contracted pipeline capacity that is not being fully used. The capacity may be offered voluntarily in the first instance or failing that, by mandatory day-ahead auction.

The day-ahead auction created access to over 41 petajoules (PJ) of capacity across 10 pipelines in the first 13 months of its operation (figure 5). Over 80 per cent of that capacity was auctioned at the reserve price of zero. Access to low or zero cost pipeline capacity is allowing shippers to move relatively low priced northern gas into southern markets, easing pressure in those markets. The AER estimates the auctions effectively reduced spot gas prices by as much as $0.76 per GJ in Sydney, and up to $0.17 per GJ in Victoria, over the six months to September 2019.[4]

4 AER, *Wholesale markets quarterly—Q3 2019, November 2019*. pp. 52–3.

Figure 5
Day-ahead auction of pipeline capacity




BWP, Berwyndale to Wallumbilla; EGP, Eastern Gas Pipeline; MAPS, Moomba to Adelaide Pipeline; MSP; Moomba to Sydney Pipeline; RBP, Roma to Brisbane; SWQP, South West Queensland Pipeline; WCF, Wallumbilla compression facilities.
Source: AER analysis of AEMO day-ahead auction data.

International market conditions have also shifted. Asian LNG prices weakened significantly in 2019, as new capacity in the United States, Australia and Russia came online at a time when the Chinese economy was slowing and Japan continued its switch away from gas powered generation. In March 2020 international oil prices crashed to their lowest levels since 2003, from the combined impacts of intense price competition between Saudi and Russian oil producers, and COVID-19 related demand reductions. At times, they settled in negative territory. Australian exporters reported the uncertainty stemming from COVID-19 and collapsing oil prices limited their ability to strike new gas supply agreements.[5]

The combination of domestic supply increases, pipeline reforms and weaker international market conditions are flowing through to domestic prices (figure 6). Monthly spot prices averaged $10 per GJ across all markets in the fourth quarter of 2018. By mid-2019 prices had eased in most markets, mirroring the decline in LNG prices that began a few months earlier. By the fourth quarter of 2019, prices in all spot markets averaged around $7–8 per GJ. This trend continued into 2020, with first quarter price averages at their lowest since 2016 in all markets. Some trades were being made at prices below $5 per GJ in southern markets, and below $4 per GJ in northern markets.

As a result of the changed market conditions, forecasts of Australia's supply–demand balance have become more optimistic. The Australian Competition and Consumer Commission (ACCC) in 2020 forecast eastern Australia's gas supply in 2020 to be 2025 PJ—around 200 PJ above forecast domestic and LNG demand.[6] But AEMO forecast supply gaps could emerge by 2024, as Victorian production wanes.[7] Both AEMO and the ACCC argue more exploration and development in southern Australia, pipeline capacity expansions, or the commissioning of LNG import terminals could mitigate the supply risk.

Four LNG import terminals are being considered across South Australia, Victoria and NSW. State governments have also taken steps to expand domestic gas production. The

5 EnergyQuest, *Energy quarterly*, March 2020, p. 53.

6 ACCC, *Gas inquiry 2017–2025, Interim report, January 2020*, February 2020, p. 27. Based on forecast production from proved plus probable (2P) reserves.

7 AEMO, *2020 Gas statement of opportunities*, March 2020, p. 44.

Figure 6
**Eastern Australia gas spot 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.

NSW Government has targeted injection of an additional 70 PJ of gas per year into the NSW market, which could be sourced from local basins or imported. In Victoria, the government will allow conventional onshore gas exploration to recommence from July 2021.

As the compliance and enforcement body for gas markets, the AER is monitoring the introduction of reforms, including the day-ahead trading in underused pipeline capacity and the provision of accurate information to the Gas Bulletin Board. In 2019 it strengthened its reporting on the market by launching online gas industry statistics and quarterly market reports.

## 4 Regulated energy networks

The AER regulates the costs of transporting electricity and gas through transmission and distribution networks. The bulk of these costs, which account for around 40 per cent of a residential customer's energy bill, occur in distribution networks.

Inaccurate energy demand forecasts and stringent energy reliability standards drove over-investment in electricity networks for several years. Coupled with a sharp rise in financing costs (caused by the global financial crisis), this investment drove a 66 per cent real increase in the electricity network revenues over the nine years to 2015.

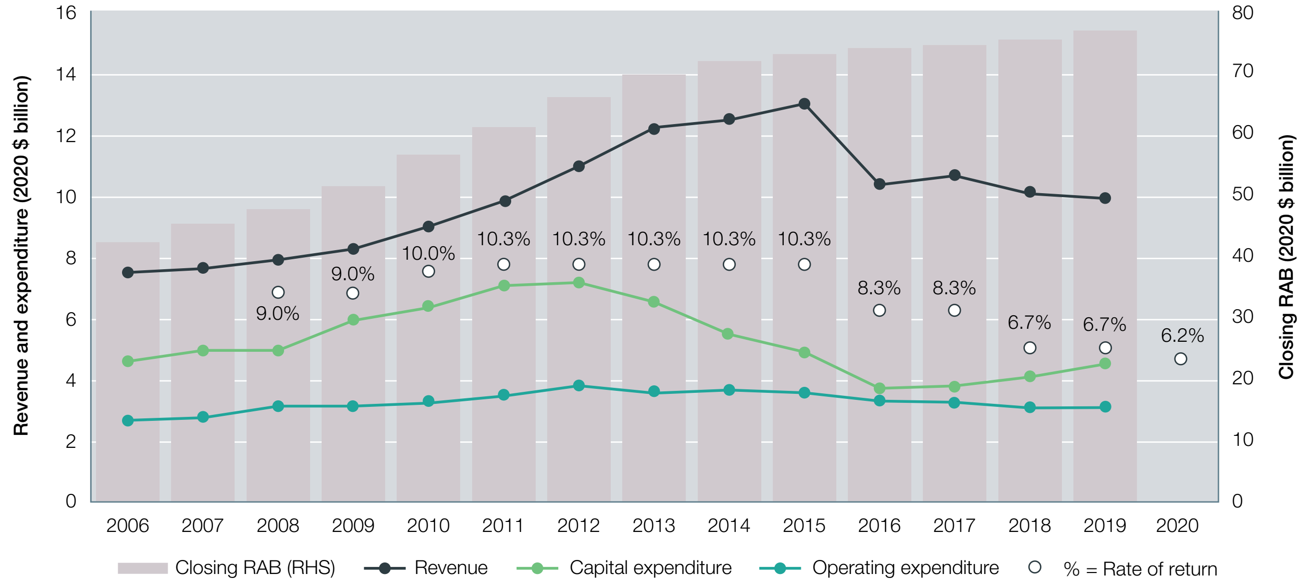
High financing costs similarly impacted gas pipeline revenues in that same period. Financial markets have since stabilised, cutting allowed rates of return for network businesses from as high as 10 per cent for several years from 2009, to around half that level in 2020. Weakening electricity demand forecasts also caused investment projects to be delayed or shelved. And reliability standards were softened, bringing them more into line with values that customers place on reliability.

More recently, electricity networks began to implement operating efficiencies to better control their costs, partly in response to the AER applying benchmarking tools to set operating cost allowances, and launching new incentive schemes.

Higher productivity helped drive lower operating costs in several networks. Productivity rose by 1 per cent in distribution networks and 2.2 per cent in transmission networks in 2018, mainly driven by efficiencies in operating expenditure. Distribution productivity grew for three consecutive years to December 2018, exceeding growth in the Australian economy as a whole.

Improved network reliability also supported high productivity. Most customer outages originate in distribution networks. But distribution outages became less frequent in eight of the past nine years, and the average outage duration remained stable or lessened in nine of the past 10 years.

Figure 7
**Electricity distribution revenue and drivers**




RAB, regulatory asset base.

Note: Victorian network businesses report on a 1 January – 31 December basis. All other network businesses report on a 1 July – 30 June basis. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018).

All data are CPI adjusted to June 2020 dollars.

Rates of return are weighted average cost of capital (WACC) forecasts in AER revenue decisions and Australian Competition Tribunal decisions for transmission networks. The rates of return shown represent the highest rate applicable to the distribution network businesses in each year.

Source: AER modeling, economic benchmarking regulatory information notice (RIN) responses, category analysis RIN responses.

These shifts reflect in all but one of the AER's decisions made since January 2019 setting lower revenues for network businesses than in their previous regulatory periods.

Electricity distribution revenue decreased by 2 per cent in 2019 following a 5 per cent decrease in 2018 (figure 7). Revenue in 2019 hit its lowest point since 2011, and was 23 per cent lower than the peak recorded in 2015. Transmission revenue eased by 1 per cent in 2019 following a 10 per cent decrease in 2018, and is now at its lowest level in over a decade.

Declining network revenue since 2016, combined with rising customer numbers, have translated into lower network charges in retail energy bills for most customers. Current AER decisions reduced distribution charges in residential electricity bills by an average 0.6 per cent across all states and territories. Outcomes are more varied in the transmission sector, which has different cost drivers (figure 8).

While network revenues have decreased since 2015, network investment increased for the third consecutive year in 2019, including a 9 per cent rise for electricity distribution.

Despite this increase, total network investment remained 41 per cent below the peak recorded in 2012.

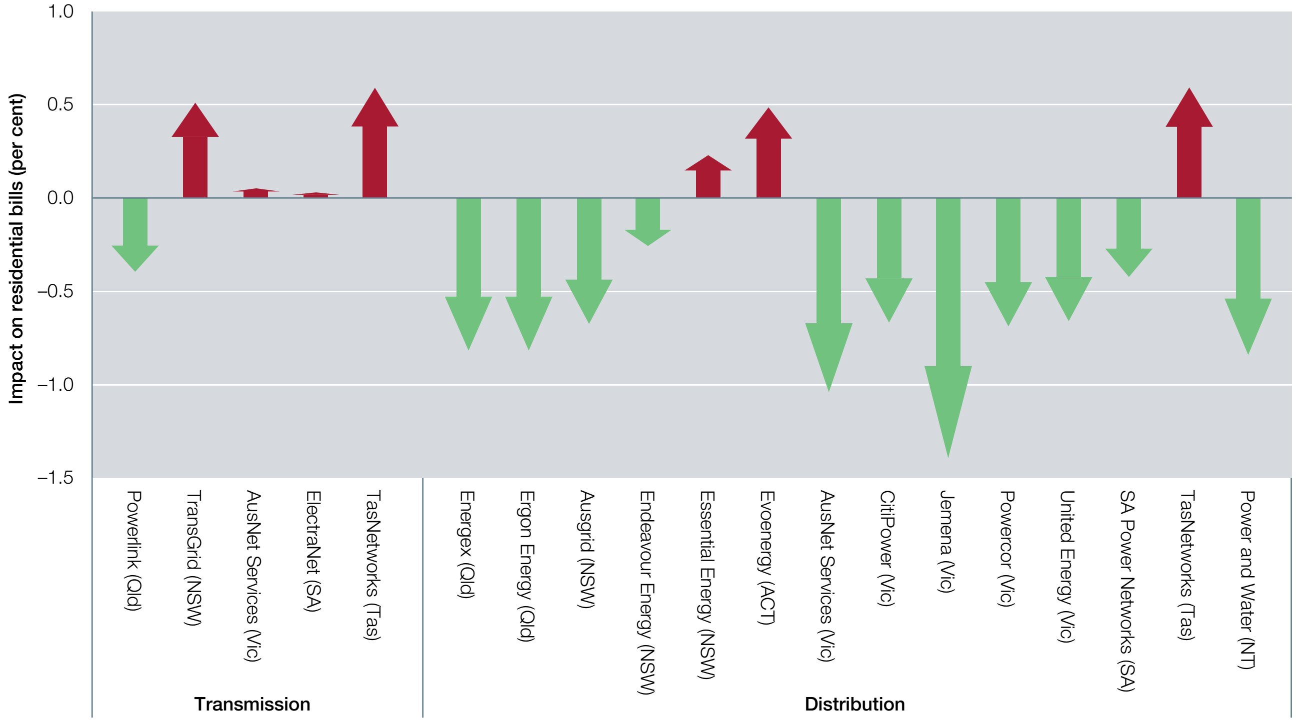
The composition of investment is also changing. The majority of forecast investment in distribution networks is to replace and refurbish old assets, rather than spending on new assets.

Network investment should be driven by how much customers are prepared to pay for a reliable and secure electricity supply. The AER in December 2019 published estimates of the value that customers place on avoiding long unplanned network outages. It found business customers tend to place a higher value on reliability than residential customers do, although residential customers are concerned about long outages, particularly at peak times. The AER will draw on these values when assessing future network proposals for new investment.

### New approaches to regulation

The AER encourages innovative approaches to network regulation to achieve better outcomes for energy customers. A number of businesses are trialling engagement models

Figure 8
**How AER revenue decisions affect residential customer electricity bills**




Note: Estimated impact of latest AER decision on the network component of a residential electricity bill for a customer using 6500 kilowatt hours of electricity per year. Revenue impacts are nominal and averaged over the life of the current decision.

The data account for only changes in 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 and additional AER modeling.

to identify their customers' needs as a basis for developing new regulatory proposals. Agreement between network businesses and their customers can help ensure network design and development reflect customer preferences on issues such as reliability and access to distributed energy resources. It can also expedite the regulatory process, reducing costs for businesses and energy customers alike.

While engagement processes are improving, consumer groups report the quality of engagement varies across network businesses. They argue the businesses should engage in meaningful engagement earlier in the process (such as 'deep dive' workshops), and engagement should be at the 'consult', 'involve' or 'collaborate' end of the spectrum, rather than just 'inform'.

The AER is trialling one early engagement approach in partnership with Energy Networks Australia and Energy Consumers Australia. The first business to trial the model, AusNet Services engaged an independent customer forum to negotiate its regulatory proposal.

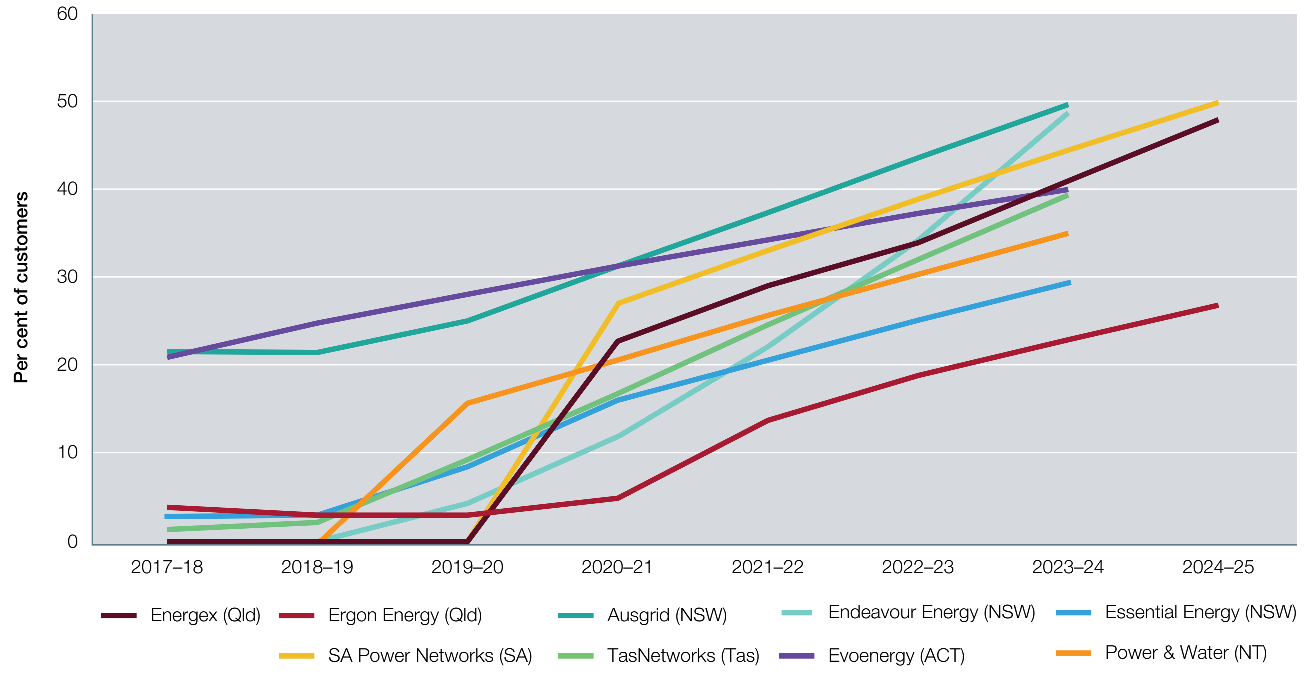
Customer engagement included interviews, field visits, commissioned research, observations (such as focus groups, deep dives, workshops and public forums) and reviews (of complaints data, guaranteed service level data and reliability data, and of AusNet Services customer research). This engagement illustrated the complexity of consumer preferences. As an example, customers supported sensible investment by AusNet Services to allow solar exports, so this energy is not wasted and helps reduce all customers' bills. Further, they supported sharing the costs among customers and with government.[8] AusNet Services lodged its regulatory proposal in January 2020, which the AER is now assessing.

## Adapting to an evolving market

The growth of distributed energy resources, and innovations in network and communications technology are changing the role of energy networks. Regulatory reforms are being rolled out to unlock the benefits of these changes. Electricity



Figure 9
**Projected assignment of cost-reflective tariffs for residential customers**




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

distributors are progressively making their network tariffs more cost reflective, for example. Tariff reforms reduce charges at times of low demand, and raise them at times of peak demand when the networks are under strain. Networks levy the new tariff structures on retailers, which then have discretion to set their charges to customers as they see fit.

Cost reflective prices encourage retailers to incentivise energy customers to switch their energy use away from times of high demand to times of low demand, and to operate distributed energy resources such as rooftop solar PV systems and batteries in ways that minimise network stress. Network businesses forecast that up to half of all customers in NSW, Tasmania, the ACT and Northern Territory will be on cost reflective network tariffs by 2024–25 (figure 9).

The AER is supporting network transformation in other ways. It offers incentives for distribution network businesses to manage demand on their networks in ways that will reduce the need to invest in expensive network assets. In September 2019, the AER approved expenditure on residential and grid scale battery storage projects, technology trials to manage demand through device control, and research into distributed energy platforms for demand management. As an example, it is supporting Essential Energy's involvement in a virtual power plant scheme to help manage peak demand on the business's NSW network.

The proposed introduction of a 'regulatory sandbox' toolkit will make it easier for network businesses to develop and trial innovative energy technologies and business models.[9] The toolkit will allow participants to trial smaller scale innovative concepts under relaxed regulatory requirements, on a time limited basis.

AEMO has targeted investment in strategic electricity transmission projects as being critical for supporting the integration of renewable technologies into the market. The AER is amending the cost–benefit test (that is, the regulatory investment test) that it administers for investment proposals, to fast track it for strategic projects such as interconnectors linking networks in different jurisdictions. In early 2020 it fast tracked its determinations that the test had been satisfied for a new interconnector linking South Australia with NSW, and for an upgrade to the Queensland–NSW Interconnector (QNI). The purpose of the faster assessments was to support the timely completion of these projects.

9 AEMC, *Regulatory sandbox arrangements to support proof-of-concepts trials*, 26 September 2019.

# 5 Retail energy markets

High energy prices and poor perceptions of retailer behaviour have heightened focus on retail energy markets from 2017. Industry assessments found 'competition … is currently not delivering the expected benefits to consumers'[10] and 'the retail market has developed in a manner that is not conducive to consumers being able to make efficient and effective decisions about the range of available offers in the market'.[11]

Regulatory reforms targeting these concerns were progressed in 2018 and 2019, aimed at strengthening customer protections, encouraging customers to engage (to their benefit) in the market, and making it easier for customers to compare retail offers. A central reform was the introduction of price caps on retailers' standing offers from 1 July 2019. Governments introduced a default market offer because standing offer contracts were found to no longer work effectively as a safety net. Standing offer prices had become unjustifiably expensive, and penalised customers who had not taken up a market offer.

The AER sets the default market offer as a cap on standing offer electricity prices in south east Queensland, NSW and South Australia.[12] The price cap is not intended to mirror the lowest price in the market. Rather, it strikes a balance among reducing unjustifiably high prices, allowing retailers to recover costs in servicing customers, and providing customers and retailers with incentives to participate in the market. Victoria introduced a similar but separate default offer that sets standing offer prices at a level that reflects the costs of an efficient retailer in a contestable market. The introduction of price caps has reduced standing offer prices (as intended), but has not been reflected in lower priced market offers by retailers.

Reforms also introduced a 'reference bill' to simplify and standardise how retail offers are presented. Any advertised discounts by retailers must be based against the default offer.

These changes followed reforms in 2018 that require retailers to notify small customers before any change in their benefits, alert customers to any expired benefits, and provide advance notice of any price change under an existing contract. In Victoria, retailers also must inform customers on their energy bills whether they are on the retailer's lowest offer.

Customer trust, or confidence that the market is working in their interests, rose marginally to 33 per cent in December 2019, from 31 per cent a year earlier. Likewise, customer satisfaction with competition in energy markets rose in all markets except south east Queensland, averaging across the NEM a positive rating of 52 per cent.[13]

Since 2018 electricity retail prices for residential customers have plateaued or fallen in most regions, after significant rises in preceding years. The change was due to factors that include new price and advertising regulations, flatter wholesale costs, and reductions in network costs.

Wholesale costs were the main driver of elevated retail electricity prices from 2015 to 2018. Those costs have since moderated in most regions, and tracked lower in Australia in 2019–20 as more low cost renewable generators came online, and as fuel costs for black coal and gas plant eased. This moderation in wholesale prices was yet to be fully reflected in retail prices in January 2020. It can take time for wholesale cost changes to work their way through to retail prices, because retailers typically lock in a portion of their wholesale costs in advance through hedge contracts.

In the seven months to January 2020, standing offer prices for residential customers fell in every region that introduced standing offer price caps in July 2019 (figure 10). Prices fell by 14–19 per cent in Victoria, 11–13 per cent in NSW, 12 per cent in South Australia, and 10 per cent in south east Queensland.[14]

Market offers did not mirror this fall in standing offer prices, remaining relatively steady in NSW, Queensland and South Australia, and increasing in Victoria. Some higher priced market offers that link to standing offer prices did lower, however. But the lowest priced offers also disappeared in some regions. These factors significantly narrowed the price range in available offers between June 2019 and early 2020. In June 2019, for example, the median standing offer by distribution zone was around 28 per cent higher than the median market offer. By January 2020 the gap had narrowed to 6 per cent.

10 AEMC, *2018 retail energy competition review*, *Final report*, June 2018, p. i.
11 ACCC, *Restoring electricity affordability and Australia's competitive advantage, Retail Electricity Pricing Inquiry—final report*, June 2018, p. 134.
12 Other jurisdictions already had price regulation in place.
13 Energy Consumers Australia, *Energy Consumer Sentiment Survey*, December 2019.
14 Both market and standing offer electricity prices rose in those regions with previously established jurisdictional price regulation—namely, Tasmania, the ACT and regional Queensland.



Figure 10
**Movement in energy bills for customers on market and standing offers**


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

Annual bills and price changes are based on median market and standing offers at June 2018, June 2019 and January 2020, using average consumption in each jurisdiction: NSW 5881 kWh (electricity), 22 855 MJ (gas); Queensland 5699 kWh, 7873 MJ; Victoria 4589 kWh, 57 064 MJ; South Australia 4752 kWh, 17 501 MJ; ACT 6545 kWh, 42 078 MJ.

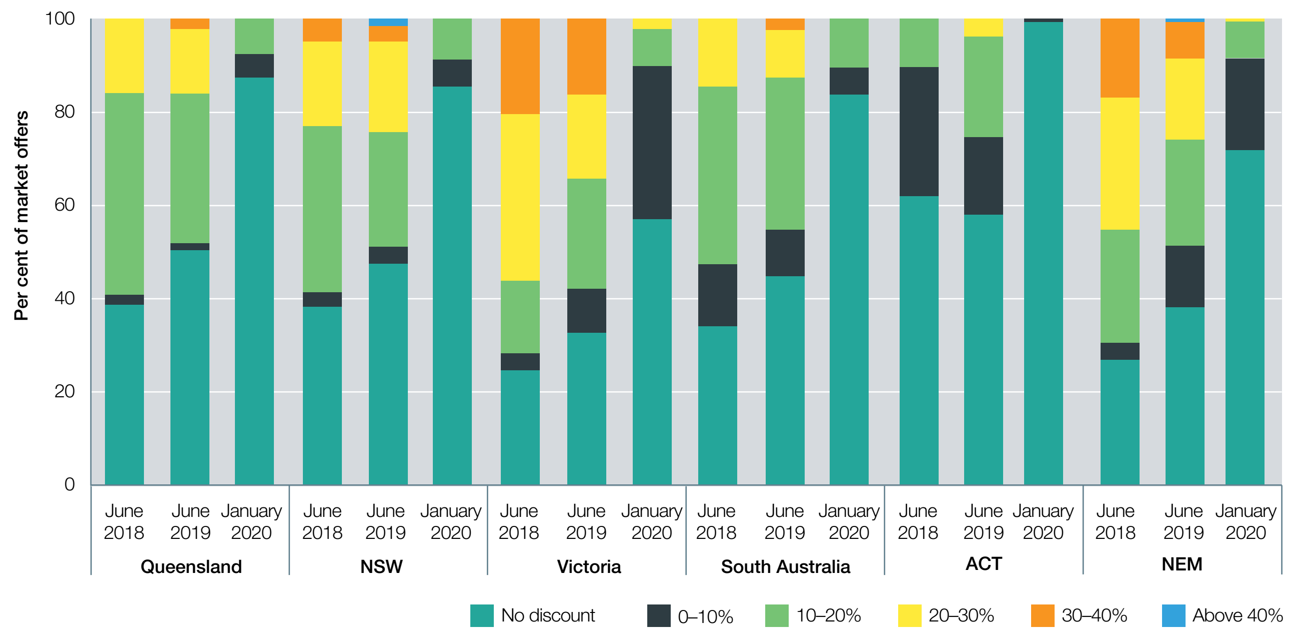
Market offer prices include all conditional discounts.

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

Despite this shift, customers can still benefit by engaging with the market. A customer switching from the median standing offer to the best market offer in their distribution zone could save up to 20 per cent ($300–400 in annual savings) in January 2020. Customers already on market offers could also save, because the lowest priced market offers averaged 7–8 per cent lower than median market offers (and 12–18 per cent lower in Victoria), representing an annual saving of around $100–200.

In gas, recent retail price movements were more varied. Retail prices fell by 6 per cent in the east of Victoria, but rose up to 3 per cent in the west of the state over the seven months to January 2020. In NSW, market offer prices rose by 5 per cent, while standing offer prices were flat. The reverse was true in South Australia, where standing offer prices rose by 6 per cent. Prices in other regions were generally flat. Gas wholesale costs—the key driver of rising retail gas prices from 2015–17—stabilised over 2018 and eased significantly from early 2019.

**Figure 11**
**Conditional discounts for residential electricity market offers**




Note: Advertised discounts in generally available market offers.

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

In gas, the gap between market and standing offer prices remains significant. At January 2020 median market offers were 8–21 per cent lower than median standing offers.

## Competitive environment

Some evidence emerged in 2019 of improved competition in the retail energy market. Market concentration lowered as smaller retailers grew their customer base in established markets, and expanded into new markets. Three businesses—AGL Energy, Origin Energy and EnergyAustralia—continued to dominate in 2019, supplying 63 per cent of small electricity customers and 75 per cent of small gas customers in eastern and southern Australia. But 'second tier' retailers have built significant market share in some regions. Snowy Hydro, Alinta Energy and Simply Energy have emerged as strong 'gentailers', while smaller retailers have gradually built market share (with 8 per cent of electricity customers and 4 per cent of gas customers in 2019).

Retailers are moving away from discounting towards simpler, more stable pricing. This move coincided with reforms introduced in 2019 that restricted advertising based around large headline discounts. Before reform (in 2018), around two thirds of electricity offers offered discounts conditional on the customer meeting terms such as on time payment (figure 11). The discounts offered 10–40 per cent off a customer's bill. By January 2020, offers with guaranteed prices (no conditional discounts) comprised over 80 per cent of offers in Queensland, NSW, South Australia and the ACT. A majority of conditional discounts were for less than 10 per cent off the base price.

Although discounting reforms apply in electricity only, practices in gas followed similar trends.

While the size of discounts has decreased, this change has not worsened outcomes for customers. The size of previous discounts was often deceiving, because retailers measured discounts off different price bases. The size of discounts may reduce further following a rule change in February 2020 that limits conditional discounts to the reasonable cost savings that a retailer could expect if a customer satisfies the conditions attached to the discount.

Additionally, retailers are offering a wider range of products and services, such as leveraging off the uptake of solar PV and battery technology to offer contracts that give customers greater control over their electricity costs. Other retailers are focusing on products that are simple to understand and provide a high level of bill certainty.



These offers include fixed price contracts (where the customer pays a fixed amount regardless of how much energy they use) and subscription offers (where a customer pays a set amount each period to cover their expected electricity use).

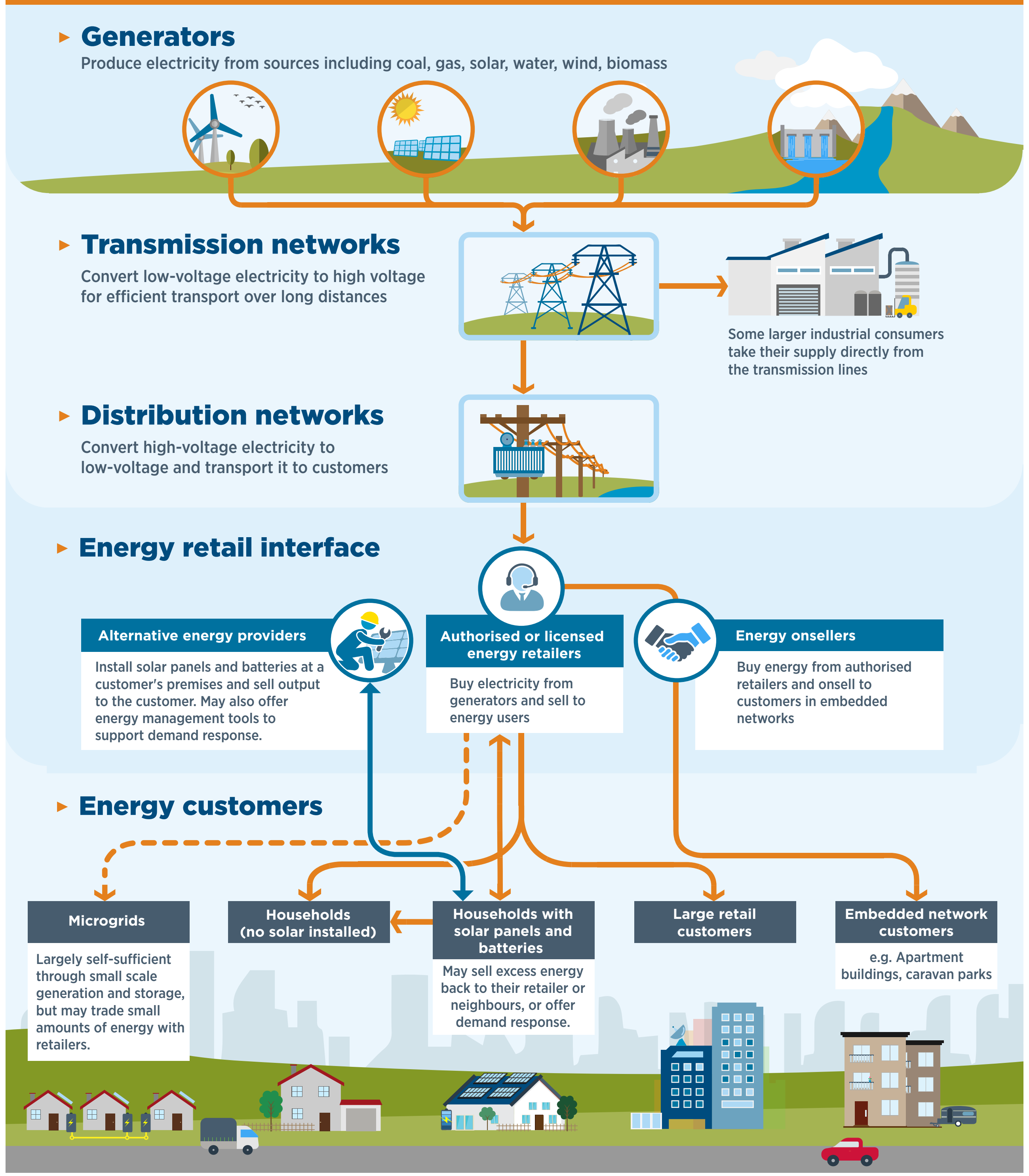
## Customers in vulnerable circumstances

While energy prices have moderated, they continue to be a source of financial pressure for customers in vulnerable circumstances. Payment plans and hardship programs are the key mechanisms in place to support customers facing payment difficulties. The AER has focused on improving frameworks around these tools to promote better customer outcomes, releasing a Sustainable Payment Plans Framework in 2017 and a revised hardship guideline in 2019.

To better understand issues facing customers in vulnerable circumstances, the AER in 2020 published research (by the Consumer Policy Research Centre) on regulatory approaches to customer vulnerability.[15] The report will inform the AER's approach in this vital area.

15 CPRC, *Exploring regulatory approaches to consumer vulnerability, A report for the Australian Energy Regulator*, November 2019.

## Infographic 1—Electricity supply chain




## Infographic 2—Gas supply chain

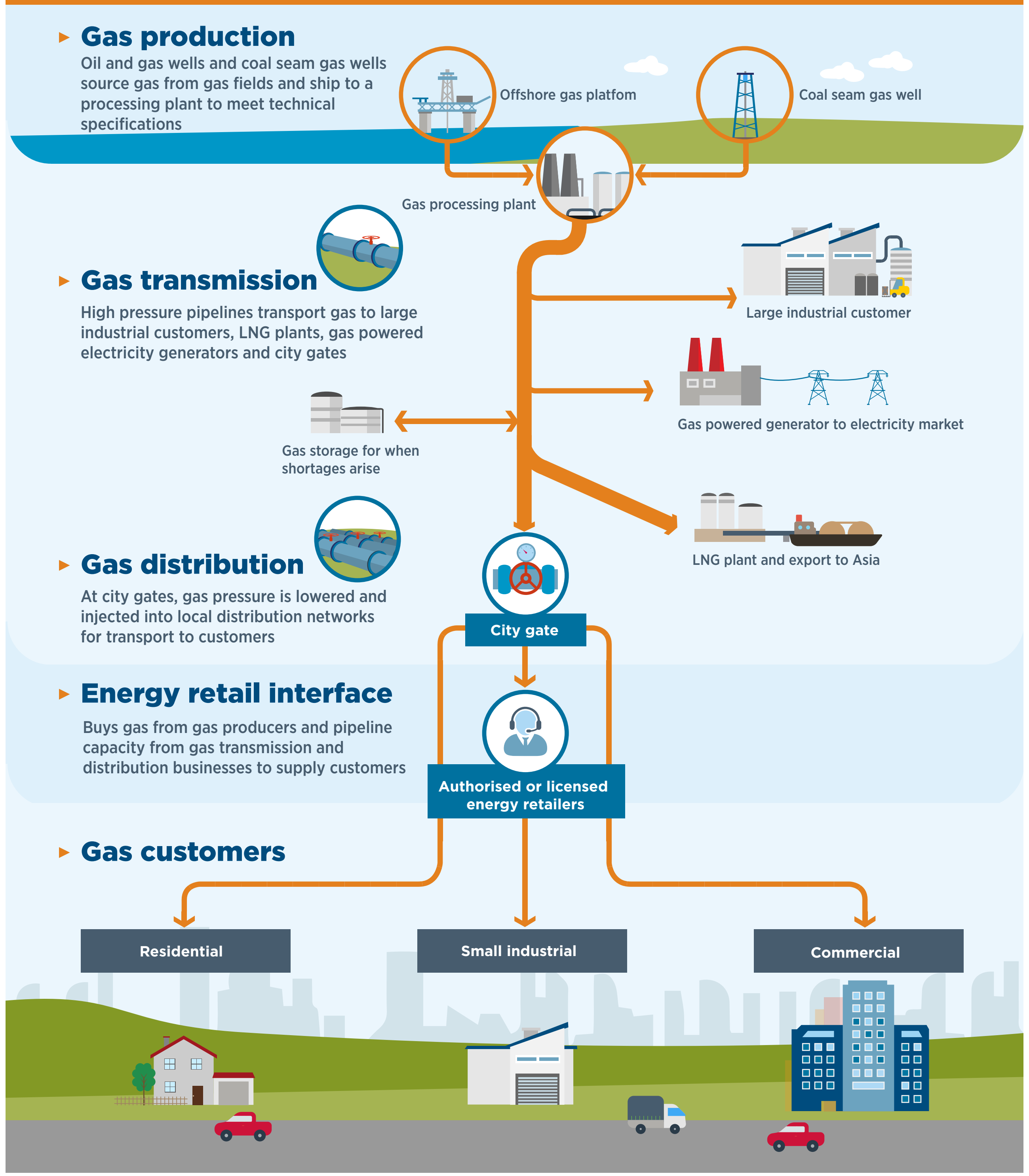
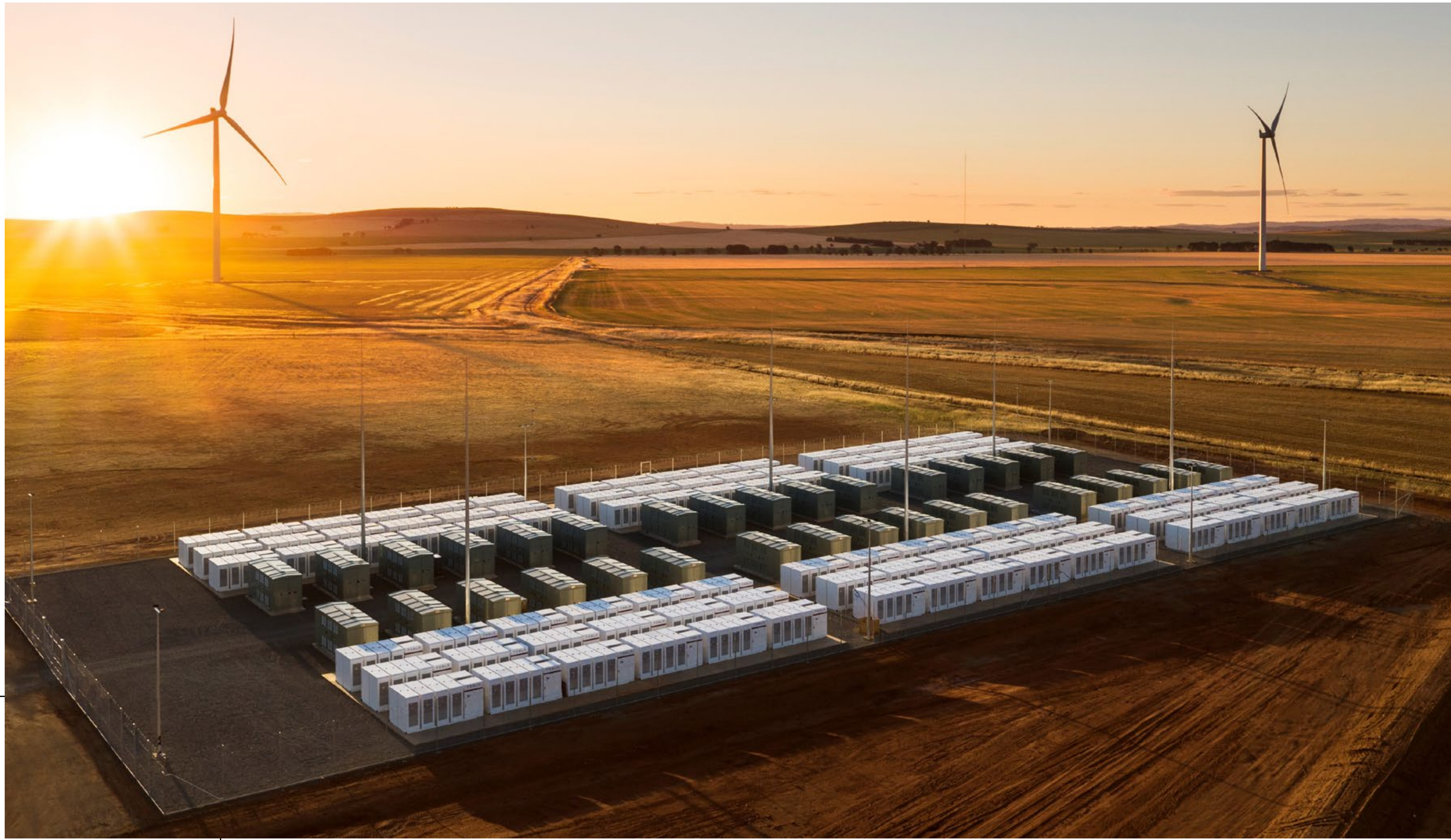


Image courtesy of Neoen



# THE ELECTRICITY MARKET IN TRANSITION

Australia's electricity markets are undergoing a profound transformation from a centralised system of large fossil fuel (coal and gas) generation towards an array of smaller scale, dispersed generators, most of which use wind and solar technologies. The transition is particularly advanced in South Australia, which at times meets all electricity demand from renewables.

Additionally, some energy customers are adopting their own 'behind the meter' energy solutions—namely, distributed energy resources (DER) that include rooftop solar photovoltaic (PV) installations, small batteries, electric vehicles and demand response. Customers may sell power generated from their solar PV systems and batteries into the grid (typically during the day), and draw power from the grid at other times. So, where power once moved in one direction, from large generators through transmission and distribution lines to end customers, two-way flows now occur.

A web of interrelated factors is driving this transition. Community concerns about the impact of fossil fuel generation on carbon emissions were a major catalyst for change, driving action by governments and businesses. In the electricity sector, government incentives for lower emissions generation encouraged investment in wind, solar farms and small scale solar PV systems. An environment of high energy prices gave further impetus to this transition, by driving customers to change their behaviour (to use energy more efficiently and to generate their own power).

As the uptake of renewables rose, economies of scale drove down construction and installation costs. Technologies also improved, further lowering costs. These developments reinforced incentives for further investment. This cycle helped establish Australia's solar PV and wind industries.

While renewable generation investment is growing strongly, some of the major fossil fuel power stations that supplied Australia's electricity over the past 50 years have been retired or announced for retirement as they near the end of their economic life. This transition raises challenges.

The weather dependent nature of renewable generation creates a need for 'firming' capacity (such as fast start generation, battery storage and pumped hydro plant) to fill supply gaps when a lack of wind or sunshine curtails renewable plant. Greater weather driven volatility requires better demand and supply forecasting to ensure firming capacity is available when needed.

The transition also poses risks to the technical security of the power system. The rising proportion of renewable generation is bringing more periods of low inertia, weak system strength, more erratic frequency shifts, and voltage instability.[1] And, with new plants locating in sunny or windy areas at the edges of the grid where network capacity is insufficient to serve them, solutions are needed to deliver energy to customers. Two-way power flows are creating similar pressure points in local distribution networks.

Finding the best ways to keep the power system reliable and secure as the generation mix changes is an ongoing challenge. Improved data and technology services are providing some solutions. New renewables plants, for example, are being engineered to provide synthetic inertia and other system security services that fossil fuel plants traditionally provided. During the transition, however, more frequent market interventions have been needed to maintain a reliable and secure power system. Strategic planning, policy and regulatory reforms are being implemented to guide the transition to optimise benefits for energy customers.

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

## 1.1 Drivers of change

Community concerns about the impact of fossil fuel generation on carbon emissions, technology and cost changes, and an ageing coal fired generation fleet are among the factors driving Australia's energy market transition.

### 1.1.1 Action on climate change

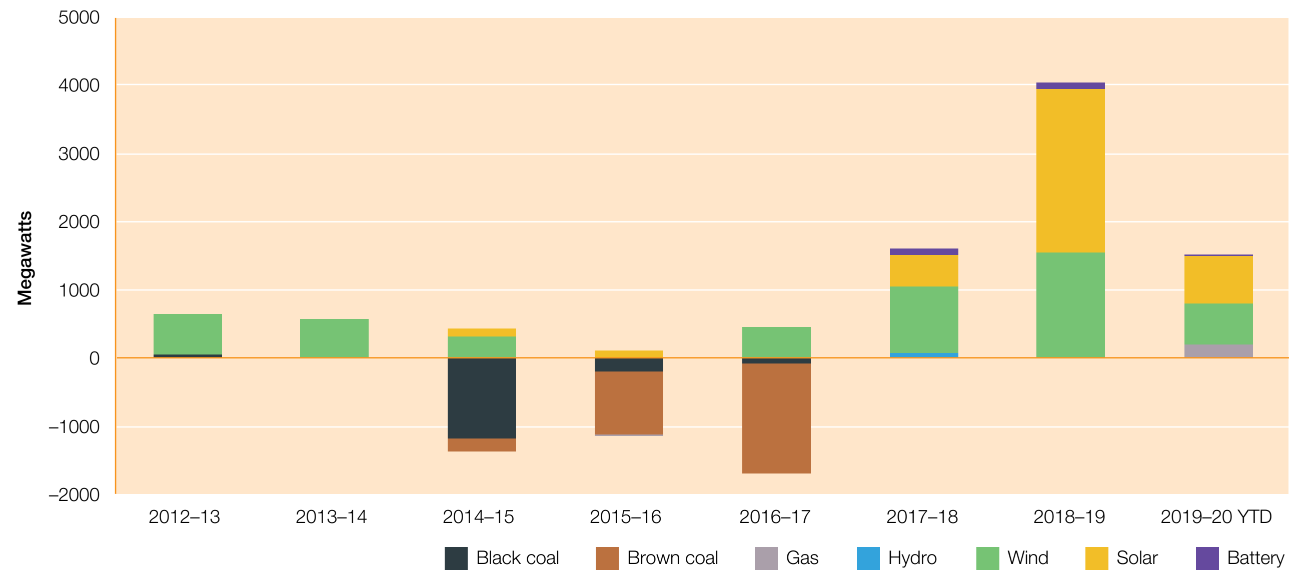
Community concerns about the impact of fossil fuel generation on carbon emissions were a major catalyst for the transition underway in the electricity sector. Energy businesses responded to these concerns by changing their approach to generation investment. No energy business has invested in new coal fired generation in Australia since 2012 (figure 1.1).

1 Box 1.4 defines these terms.





Figure 1.1
**Entry and exit of generation capacity in the NEM**




Note: Capacity includes scheduled and semi-scheduled generation, but not non-scheduled or rooftop PV capacity. 2019–20 YTD includes data to 31 March 2020.

Source: AER; AEMO (data).

Instead, investment is targeting lower emission renewable technologies. Commercial businesses also moved to generate some of their energy requirements through solar PV systems.

Australian governments also took action. At a global level, Australia made international commitments under the Kyoto Protocol (2005) and the Paris Agreement (2016) to reduce its carbon emissions. It committed in Paris to reduce its carbon emissions by 26–28 per cent below 2005 levels by 2030. The agreement set no specific target for the electricity sector.

Australia's carbon emissions have risen since 2016 (figure 1.2). But the electricity sector's contribution lowered over this period, following the closure of coal fired generators in South Australia (in 2016) and Victoria (in 2017), and significant investment in wind and solar generation. Despite this change, the electricity sector remains the largest contributor to national carbon emissions, accounting for 34 per cent of Australia's total emissions.

Victoria's brown coal plants are the most emission intensive power stations in the National Electricity Market (NEM), followed by black coal plants and gas powered generation. Wind, hydroelectric and solar PV power stations generate negligible emissions. Fuel mixes vary across jurisdictions, with Victorian generation (mainly brown coal) having the highest emissions factor, and Tasmania (mainly hydro) having the lowest.[2]

Australia's policy settings to reduce carbon emissions in the electricity sector have changed direction many times. Current government policy focuses on financial incentives for private investment in lower emission generation (box 1.1). The schemes have encouraged significant investment in wind and solar farms, and small scale solar PV systems.

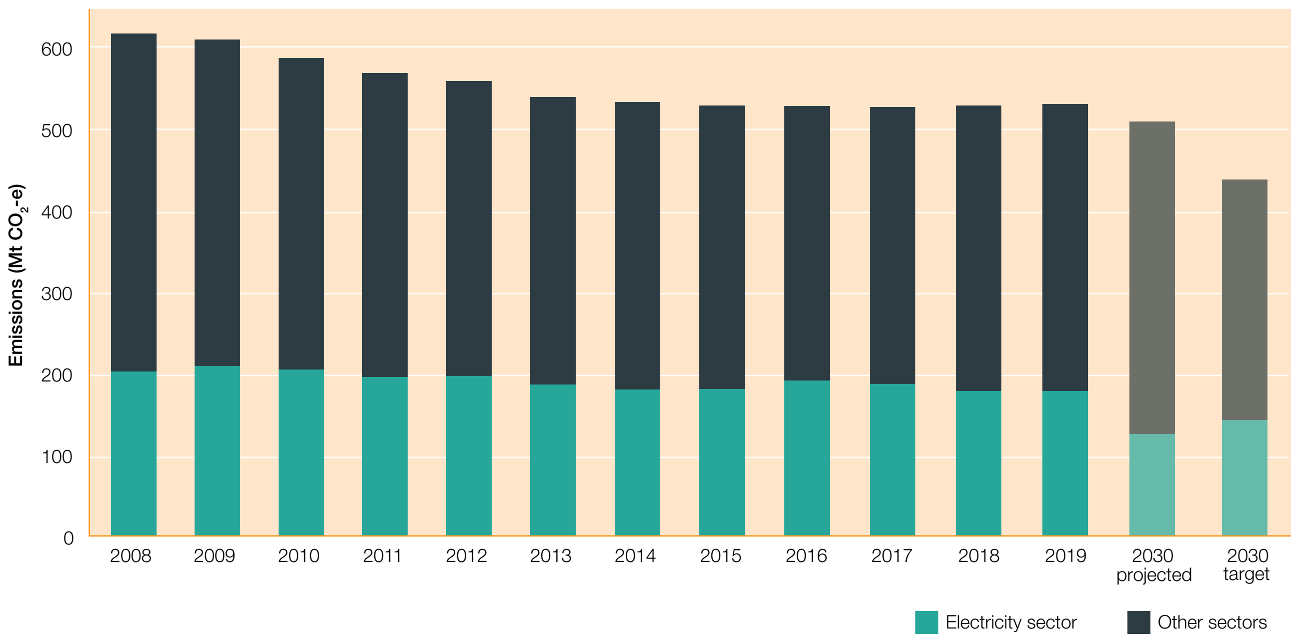
Alongside national policies, several state and territory governments set renewable energy targets that are more ambitious than the national scheme. Programs encouraging new renewable entry typically support these targets.

### 1.1.2 Technology and cost changes in the renewables sector

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

2 Department of the Environment and Energy, *National greenhouse accounts factors, August 2019*, 2019.

Figure 1.2
**Australia's carbon emissions**




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

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

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

Projected 2030 emissions are as forecast by the Department of Industry, Science, Energy and Resources in December 2019 in the absence of policy intervention.

Source: Department of Industry, Science, Energy and Resources, *Quarterly update of Australia's national greenhouse gas inventory*, June 2019; Department of the Environment and Energy, *Australia's emissions projections*, December 2019.

Technological advancements and cost reductions in grid scale wind and solar generation have outpaced predictions made a decade ago. This shift appears to be continuing. The International Renewable Energy Agency (IRENA) reported the global levelised cost of onshore wind generation fell by 35 per cent between 2010 and 2018. Over the same period, it reported the global levelised cost of large scale solar PV fell by 77 per cent. In Australia, the Commonwealth Scientific and Industrial Research Organisation (CSIRO) and Australian Energy Market Operator (AEMO) in December 2019 estimated a levelised cost of electricity (LCOE) in 2020 for large scale solar PV and onshore wind of around $50 per megawatt hour (MWh). They forecast the cost of onshore wind will continue to reduce marginally to 2050, but the cost of large scale solar PV will reduce by almost half in that time.[3]

The substantial cost reductions observed in wind and solar technology have made these renewables the lowest cost option for new build generation. The CSIRO found the cost of those technologies is significantly lower than construction costs for new black coal and brown coal generators (and significantly lower than the cost of coal generation with carbon capture and storage).[4] The lifecycle costs of wind and solar generators are now becoming competitive with the operational costs of the current fleet of conventional generators.

The cost reductions observed in wind generation are largely driven by advancements in turbine technology. Over the past two decades, the diameter of the rotors and hub heights increased significantly, resulting in larger turbines. This development increased capacity factors (the amount of electricity that can be generated over a specific period)

3 CSIRO, *GenCost 2019–20: preliminary results for stakeholder review, Draft for review*, December 2019.

4 CSIRO, *GenCost 2019–20: preliminary results for stakeholder review, Draft for review*, December 2019.



## Box 1.1 Emission reduction policies and the electricity industry

Australia's key policy initiatives in recent years to reduce carbon emissions from electricity generation are outlined below.

### Renewable energy targets

The Australian Government launched a national renewable energy target (RET) scheme in 2001, and has since revised it several times. The scheme applies different incentives for large (such as wind and solar farms) and small (such as rooftop solar photovoltaic (PV)) scale energy supply. It requires energy retailers to buy renewable energy certificates for electricity generated by accredited power stations or from the installation of eligible solar hot water or small generation units. The certificates allow renewable generators to earn revenue above what they earn from selling electricity in the wholesale market.

Amendments to the RET scheme in 2015 set the 2020 target for energy from large scale renewable projects at 33 000 gigawatt hours (GWh). Sufficient renewable generation was committed by September 2019 to meet this target.[a] The Australian Government's policy is to not increase the target beyond the 2020 requirement, and to not extend or replace the target after it expires in 2030.[b]

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

- The Victorian Government set a legislated target of 25 per cent of the state's electricity to be sourced from renewable resources by 2020, and 40 per cent by 2025.
- The Queensland Government has an unlegislated target of 50 per cent renewable generation by 2030.
- The Australian Capital Territory (ACT) has a legislated target of 100 per cent of Canberra's electricity being met by renewable generation by 2020.

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

- The Victorian, Queensland and ACT governments offer 'contracts for difference'[b] to new renewable generation investments, awarded through reverse auctions.[c]
- The Queensland Government established CleanCo, which is a new generation company to directly invest in renewable and gas firming capacity.
- The Victorian, South Australian, Queensland and ACT governments operate schemes that provide grants, rebates or loans to support small scale solar PV and battery systems.

In the past, state and territory governments also offered incentives such as premium feed-in tariffs to support the installation of residential solar PV systems. Those schemes are closed to new entrants. More generally, state and territory governments operate energy efficiency schemes that encourage households and small business customers to reduce their electricity demand.

### ARENA and CEFC

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

From its inception, ARENA has invested around $1.5 billion in close to 500 projects, with a combined value of $5.5 billion. The projects include solar PV, hybrid, solar thermal, bioenergy, ocean, hydrogen, geothermal, grid integration, battery and pumped hydro storage projects. ARENA's focus since 2019 is on projects that integrate renewables into the electricity system, accelerate the development of hydrogen energy supply, and support industry efforts to reduce emissions.[d]

The Clean Energy Finance Corporation (CEFC) was launched in 2012 as a government owned green bank to promote investment in clean energy. The fund provides debt and equity financing (rather than grants) for projects that will deliver a positive return. CEFC finance of around $5.5 billion has delivered 1.6 gigawatts (GW) of large scale solar capacity and 2 GW of wind capacity, and significant investment in storage and energy efficiency.[e]

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

### Carbon pricing

A carbon pricing scheme operated in Australia from 1 July 2012 to 1 July 2014. The scheme placed a fixed price on carbon of $23 per tonne of carbon dioxide equivalent emitted. The emission intensity of National Electricity Market (NEM) generation fell by 4.7 per cent over the two years that carbon pricing was in place. This drop in emission intensity, combined with lower NEM demand, contributed to a 10.3 per cent fall in total emissions from electricity generation over those two years.

### Climate Solutions Fund

Under the Australian Government's Climate Solutions Fund (called the Emissions Reduction Fund until February 2019), the government pays for emission abatement through 'reverse' auctions run by the Clean Energy Regulator. Ten auctions were held to March 2020, with spending of $2.3 billion to abate 193 million tonnes of carbon emissions (an average price of $12.06 per tonne of abatement). Purchases steadily declined over recent auctions, from 50 million tonnes of abatement in the third auction, to an average of less than 2 million tonnes in the past three auctions.[f]

Many funded projects involved growing native forests or plantations, otherwise known as carbon farming. The electricity sector made less than 2 per cent of the carbon abatements under the scheme. Participating electricity projects mostly capture and combust waste methane gas from coal mines for electricity generation.[g]

Following a review of the scheme, the government in May 2020 announced an expansion of the scheme, including the scoping of carbon capture and storage technology.[h]

a. Clean Energy Regulator, '2020 Large-scale Renewable Energy Target capacity achieved', Media release, 4 September 2019.
b. Commonwealth, *Parliamentary Debates*, House of Representatives, 18 September 2018, 9325 (The Hon. Angus Taylor MP, Minister for Energy).
c. Contracts for difference provide a hedge for the holder by locking in future wholesale electricity prices (section 2.7).
d. ARENA, *ARENA at a glance, Q3 2019*, 2019.
e. CEFC, *FY19 investment update—accelerating Australia's sustainable transition to lower emissions*, July 2019.
f. Auction results published by the Clean Energy Regulator, available at: www.cleanenergyregulator.gov.au/ERF/Auctions-results.
g. Projects do not necessarily connect to the NEM.
h. The Hon. Angus Taylor MP (Minister for Energy and Emissions Reduction), 'Building on the success of the Emissions Reduction Fund', Media release, 19 May 2020.

and made areas with lower wind speeds economic for wind generation development.[5]

In 2019 the IRENA reported the maximum size of the wind turbines deployed was 4.3 megawatts (MW). By comparison, the average turbine deployed in 2000 was only 1 MW (figure 1.3). This shift represents a significant increase in the capability of wind generation over the past 20 years.[6]

Solar cost reductions were mainly driven by lower panel costs, and by continued reductions in the costs of supporting equipment (such as inverters, transformers and rack/frame mounts) and installation costs.

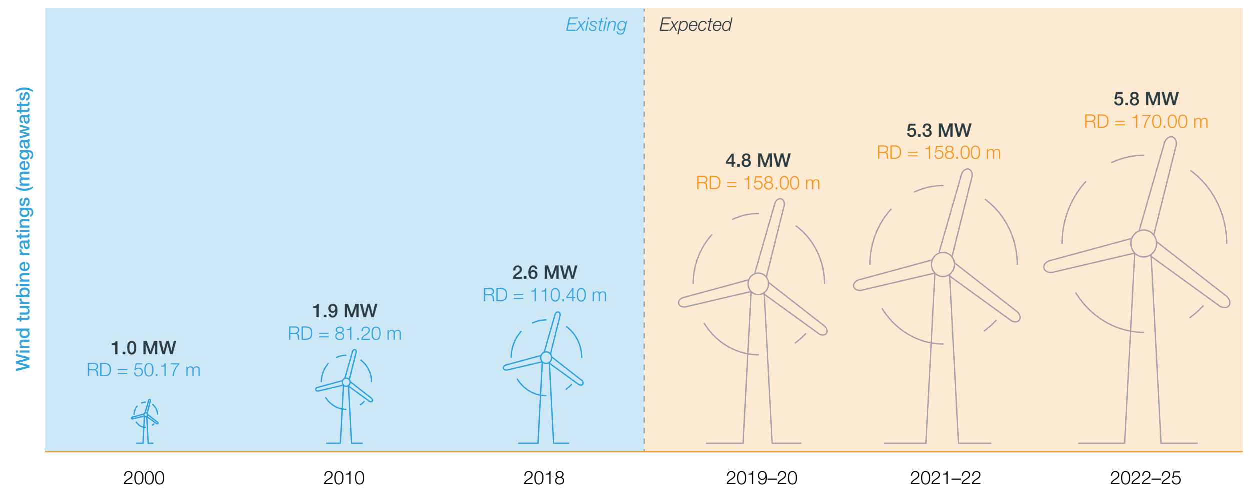
Battery costs have also fallen. Bloomberg estimated lithium ion battery pack prices fell by around 85 per cent between 2010 and 2018.[7] The cost reductions were driven by technology innovation (with increased energy density at the cathode and cell level), improved manufacturing, and economies of scale. The CSIRO projected weaker cost reductions as the technology matures, but considered costs reductions may again accelerate from around 2025 as global capacity for battery manufacturing rises to meet the demand for electric vehicles.[8]

5 IRENA, *Future of wind: deployment, investment, technology, grid integration and socio-economic aspects*, 2019.
6 IRENA, *Future of wind: deployment, investment, technology, grid integration and socio-economic aspects*, 2019.
7 Bloomberg New Energy Finance, *New energy outlook 2019*, 2019.
8 CSIRO, *GenCost 2019–20: preliminary results for stakeholder review, Draft for review*, December 2019.





Figure 1.3
Wind turbine development




MW, megawatts; RD, rotor diameter.

Source: International Renewable Energy Agency, *Future of wind: deployment, investment, technology, grid integration and socio-economic aspects*, 2019.

## 1.1.3 Deteriorating economics of fossil fuel generation

The declining costs of renewable generation coincided with the deteriorating economics of fossil fuel generation, making the latter less competitive in the market:

- The ageing of Australia's coal fired generation fleet is causing more frequent and longer unplanned outages, and higher operating and maintenance costs.
- The rapid escalation of solar PV generation is lowering electricity demand during the day, reducing output from coal fired generators at these times.
- Fuel costs rose significantly for New South Wales (NSW) black coal plant from mid-2016 to late 2018, and for gas plant from 2015 to 2018, but eased for both in 2019.

Despite these challenges, profits and share prices for some coal generators have shown resilience. This resilience may reflect ongoing tightness in the electricity supply–demand balance, particularly following the recent closures of large coal plant in South Australia and Victoria. The Australian Energy Regulator (AER) is monitoring the market to identify any competition concerns as the market transitions, and will publish its next round of findings in December 2020.

### An ageing coal fleet

Australia's coal fired generators are ageing. Some have been retired, and others are nearing the end of their economic life. There are 18 large coal fired power stations operating in the NEM, with a median age of 34 years: five in NSW (median of 38 years), three in Victoria (median of 36 years) and 10 in Queensland (median of 23 years).

Recent closures include the Northern Power Station in South Australia (2016) and Hazelwood in Victoria (2017). The ageing plants had become increasingly unprofitable as a result of rising maintenance costs, coal supply issues, and market penetration by other plant technologies. The Northern and Hazelwood plants closed after 31 and 53 years of operation respectively.

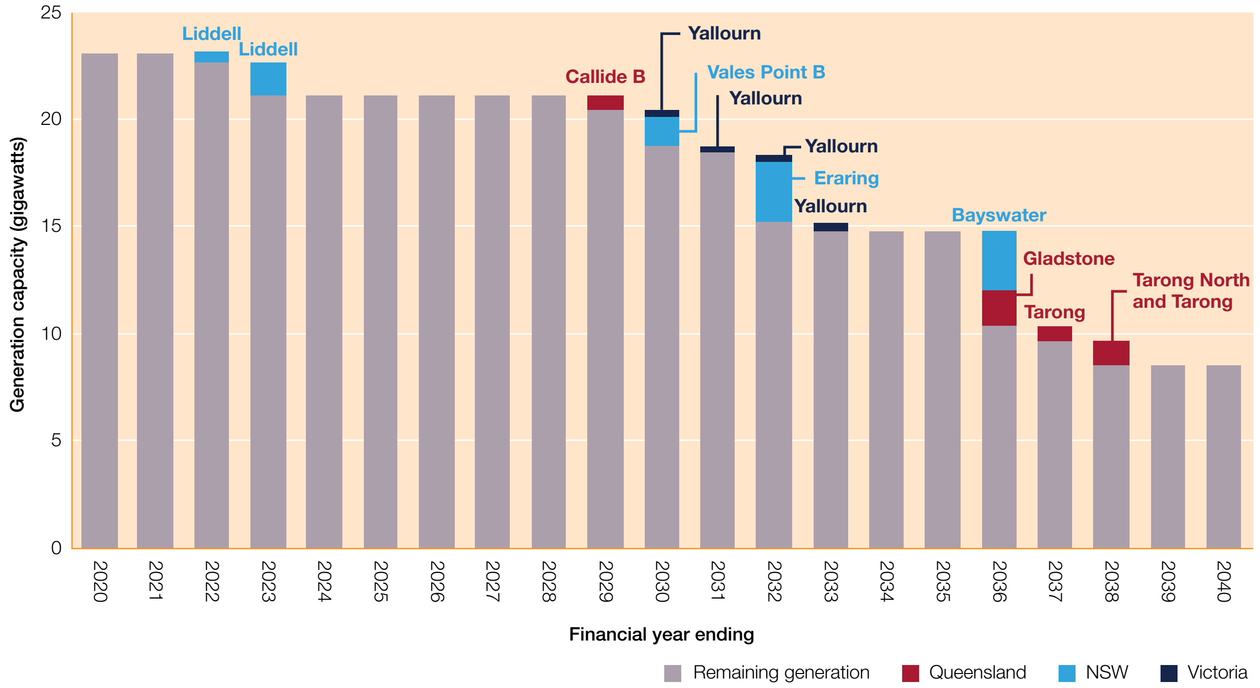
In announcing the closure of Northern, Alinta Energy described the plant as 'increasingly uneconomic', citing declining electricity demand in South Australia, the performance of the plant, and workplace safety considerations.[9] Hazelwood was the most emission intensive power station in the Organisation for Economic Co-operation and Development (OECD) when it closed. Announcing the closure, Hazelwood's owner Engie described the power station as having experienced 'difficult market conditions' and 'reached the end of its productive life'.[10]

Further coal plant closures are foreshadowed, with around two thirds of total coal fired generating capacity announced for closure over the next 15 years (figure 1.4). Those closures would leave Mount Piper in NSW (1320 MW) and

9 ABC, 'Alinta Energy to close power stations at Port Augusta and coal mine at Leigh Cree', Media release, 11 June 2015.
10 Engie, 'Hazelwood power station in Australia to close at the end of March 2017', Media release, 3 November 2016.

Figure 1.4

**Scheduled closure profile of coal fired generators**




Source: AEMO, *Draft 2020 integrated system plan*, December 2019.

Loy Yang B in Victoria (1000 MW) as the last remaining coal fired power stations outside Queensland.

AGL plans to progressively retire its Liddell power station in NSW from 2022, when it reaches its 50th year of operation. It plans to retire one of the plant's four units in April 2022, but delayed closing the three remaining three units until April 2023 to support system reliability over the 2022–23 summer.[11] The plant suffers from regular failures. During a heatwave in February 2017, for example, three of the plant's four turbines broke down.[12] The plant supplies around 10 per cent of NSW electricity, but declining reliability means it often runs at less than half its current rated capacity. AGL intends to replace the plant with a mix of renewable generation, gas peaking capacity, batteries, and an upgrade of its Bayswater power station.[13]

Two gas plants are also scheduled for retirement—AGL's Torrens Island A plant (480 MW) in South Australia (progressively from 2020 to 2022), and the Mackay plant (34 MW) in Queensland (2021). There is speculation on the future of other plants too. In late 2019 CS Energy announced it may close its Callide B (700 MW) coal generator in Queensland a decade earlier (in 2028) than previously planned, due to technical reasons.[14] EnergyAustralia's Yallourn brown coal generator in Victoria may also close earlier than expected, with the timeframe now described as a phased retirement of the generator's four units from 2029 to 2032.[15] At the time of publication, neither plant had provided notice of closure.

### Impacts of solar generation on fossil fuel plant

When rooftop solar PV generation is high in the middle of the day, the demand for electricity from the grid falls significantly (section 1.2.3). This phenomenon drives down prices at these times, challenging the economics of coal fired generators, which are engineered to run continuously.

11 AGL, 'Schedule for the closure of AGL plants in NSW and SA', Media release, 2 August 2019.
12 Angela Macdonald-Smith and Ben Potter, 'The fight about AGL's Liddell power station explained', *Financial Review*, 11 April 2018.
13 AGL, 'AGL announces plans for Liddell Power Station', Media release, 9 December 2017.

14 CS Energy, 'Statement on the future of Callide B Power Station', Media release, 27 October 2019.
15 EnergyAustralia, 'Statement on the Yallourn power station', Media release, 24 June 2019.





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

The ability of generators to manage two-shifting will vary depending on plant age and condition. That is, the increased cycling of output compounds stress on equipment, potentially requiring more frequent maintenance (planned outages) or, in an extreme scenario, earlier retirement (if two-shifting proves uneconomic).

Minimum demand remains sufficient to cover the minimum technical operating levels of most coal plant. But, if demand drops below those levels, coal plant operations may be significantly disrupted.

### Fuel costs

Fuel costs for black coal and gas powered generators surge from time to time as they compete for fuel supplies on the world market. Export prices for Newcastle black coal rose by 50 per cent between July 2013 and July 2018, for example, exposing black coal generators in eastern Australia to higher fuel costs (to the extent that they were not covered by long term contracts). Black coal prices peaked at around US$120 per tonne in June 2018, but eased sharply in 2019 and sat below US$70 per tonne in February 2020.

A similar story occurred for gas powered generation. Gas fuel prices rose significantly from 2015 to 2018, when Queensland's liquefied natural gas (LNG) plants absorbed gas supplies from the domestic market to meet export obligations. Higher fuel costs made gas powered generation less economically viable during this period. Gas prices then eased from mid-2019, before falling significantly at the end of the year. A plunge in global oil markets led domestic gas prices in early 2020 to return to 2015–16 levels.

When fuel costs are high, fossil fuel generators increase the prices at which they offer capacity into the market. While higher prices cushion the impact of fuel costs, they also incentivise new entry by renewable plant. Then, as renewables take a larger share of the generation mix, coal and gas plant is less able to set high dispatch prices.

## 1.2 Features of the transition

Features of the energy market transition include an evolving technology mix in the generation sector, including a rapid uptake of distributed energy resources (DER), and significant changes in electricity demand.

### 1.2.1 A changing generation mix

The mix of electricity generation is changing, both at grid scale and at the individual customer level. Between 2014 and 2020, more than 4000 MW of coal fired generation left the market. No material coal fired or gas powered generation has been added to the market since a 240 MW upgrade to the Eraring power station in NSW was completed in 2013. Over this same period, more than 7000 MW of new renewable supply came online (mainly in the form of wind and large solar) (figures 1.5 and 1.6). Another 3340 MW of renewable capacity is committed for 2020, of which the bulk is wind (56 per cent) and solar (43 per cent) plant. Figure 1.7 illustrates the impact of these shifts on output from different types of plant.

There is also a shift away from the traditional model of having relatively few large power stations congregated close to fossil fuel sources, towards having many small to medium generators spread out across the system. New solar and wind plants are often being constructed in locations with the richest wind and solar resources, but many of these locations are remote areas where the network struggles to cope with more capacity. Sections 1.5 and 1.6 discuss some challenges in managing these issues, and solutions being developed.

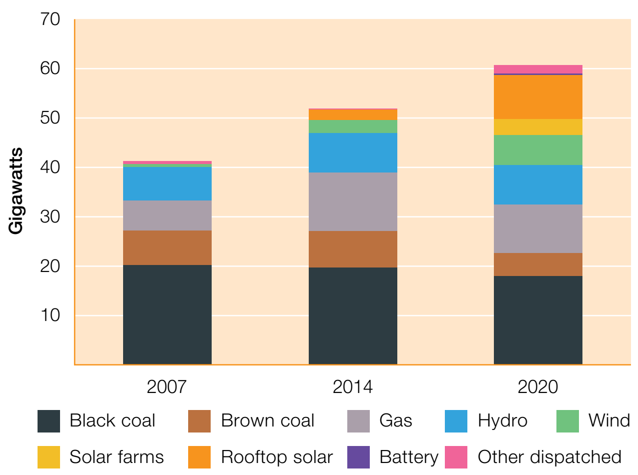
While total capacity in the market has increased, renewable generators have lower utilisation factors compared with conventional plant. For every 1 MW of coal plant retiring, 2–3 MW of new renewable generation capacity is needed, because wind and solar plants can operate only when weather conditions are favourable.[16] For this reason, increased supply from black coal fired stations has been needed to fill much of the supply gap left by the more recent brown coal plant closures in South Australia and Victoria.

Coal fired generation remains the dominant supply source in the NEM, meeting around 68 per cent of energy requirements in 2019.[17] The market at times also uses gas powered generation to manage the variability of renewables' output. As a result, gas plant is being used more often than in the past, at times even when gas fuel costs are high.

Investment in gas powered generation has been negligible, however, with significantly higher gas prices making this plant less economically viable.

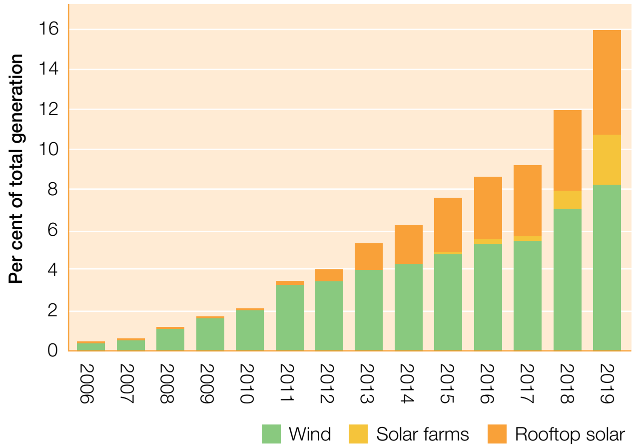
16 AEMO, *Draft 2020 integrated system plan*, December 2019.
17 Based on total generation (including rooftop solar PV) to meet electricity consumption.

Figure 1.5
**Generation capacity, by technology**




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

Figure 1.6
**Renewable generation in the NEM**




Source: AER; AEMO (data).

Fewer spot electricity prices above $300 per MWh may also be impairing the profitability of gas plant, whose business model often relies on selling cap contracts to customers that wish to insure against high prices. But the Australian Government announced support for two gas plant proposals in early 2020, to attract more dispatchable plant into the market (section 1.7.1).

### Increased variability of supply and demand

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

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

As the market transitions, the power system must increasingly respond to sudden changes in renewable output caused by changes in weather conditions and dispatch decisions by plant operators. Figure 1.8 illustrates the increasing scale of hourly changes in renewable output (ramping) in the NEM since 2015, which must be managed by equivalent changes in dispatchable generation or demand. This trend indicates the increasing need for resources (generation, storage and demand response) that can respond quickly to these changes.

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

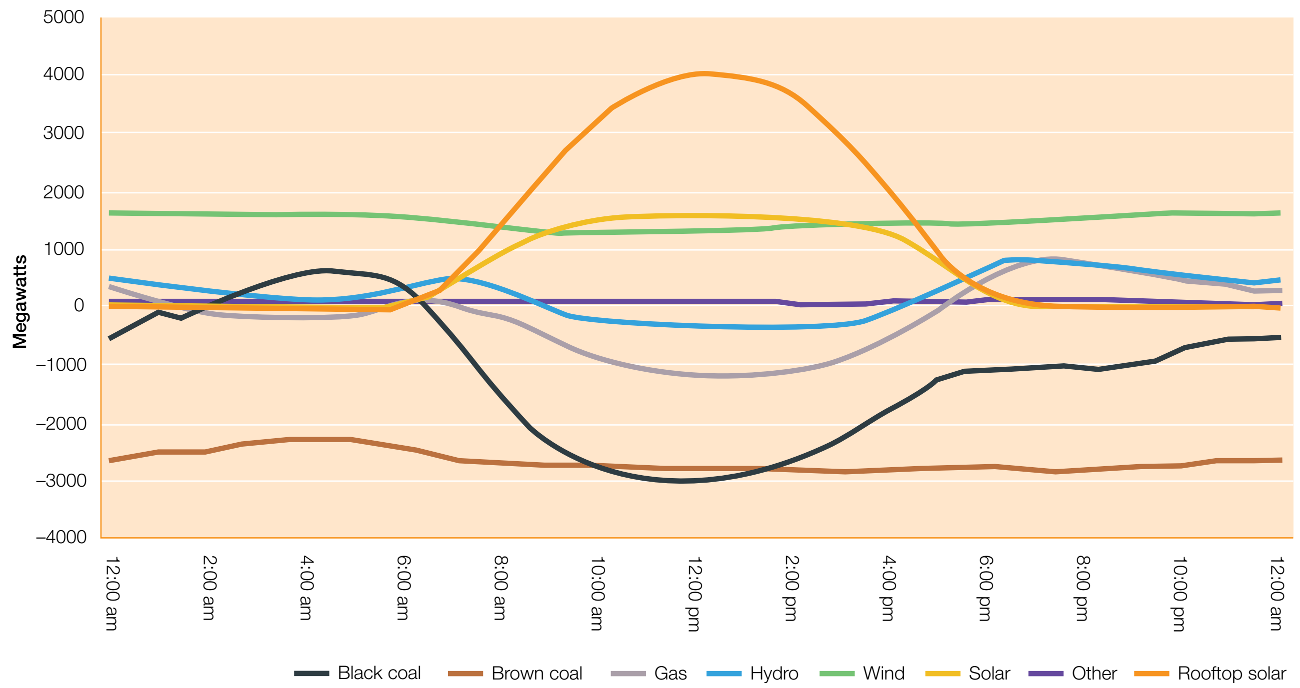
In this environment, accuracy in demand and weather forecasting is critical. Recent work has focused on innovative short term weather forecasting systems for wind and solar generators.[18] The variability of wind and solar farm output is partly offset by a negative correlation between the two: that is, decreasing wind generation is often observed during the morning ramp of rooftop and grid scale solar PV generation, and the opposite is observed in the afternoon. Global-ROAM cited data showing high levels of negative correlation in NSW, but less in other regions.[19]

18 Energy Security Board, *Health of the National Electricity Market 2019*, February 2020, p. 34.
19 Global-ROAM and Greenview Strategic Consulting, *Generator report card*, May 2019.





Figure 1.7
**Changing generation profile, by time of day, 2009–19**




Note: Comparison of average generation by time of day. The 2009 rooftop PV generation is estimated using the average 2009 daily generation, allocated to intervals using 2019 proportions.
Source: AER; AEMO (data).

Dispersing wind and solar resources over a wide geographic base covering different weather zones can also have a balancing impact.

### Grid scale storage

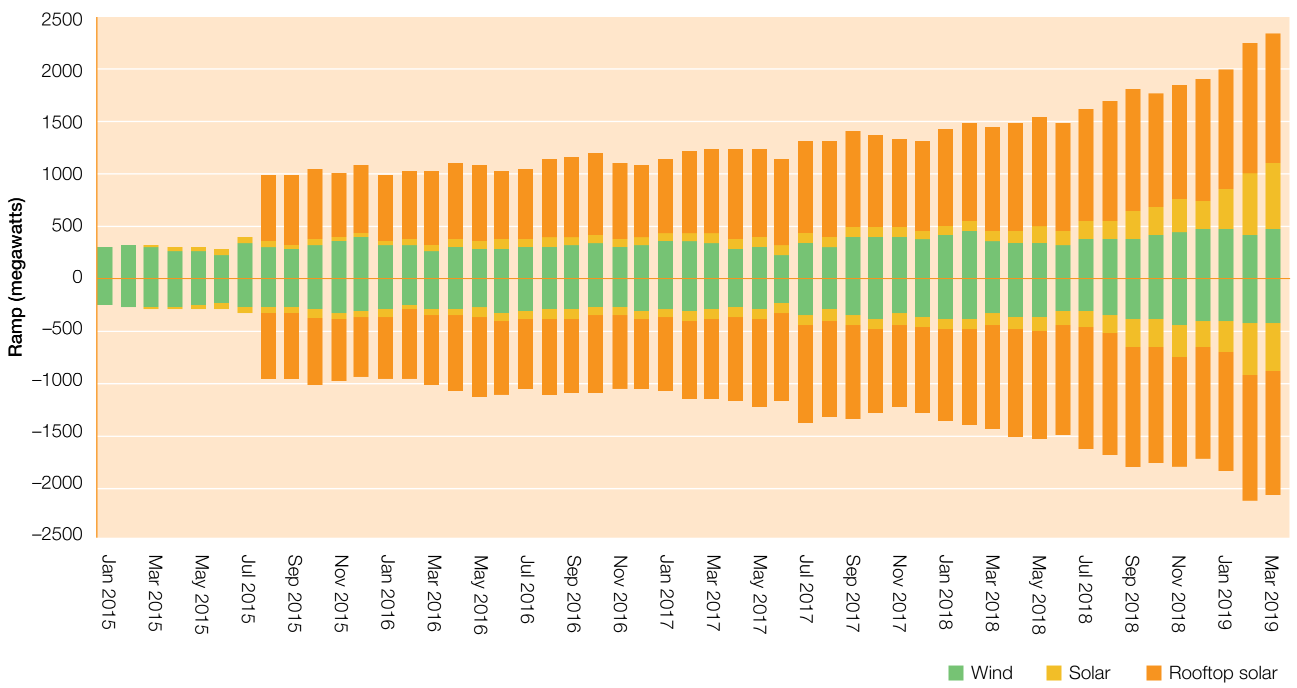
Until recently, storing electricity was not commercially viable, but emerging technologies have changed this. The growth in renewable generation is creating commercial opportunities for storage to offer fast response power system stabilisation services when solar and wind generation fluctuate.

Battery storage is currently best suited to shorter term 'fast burst' storage of energy to help stabilise technical issues in the grid (such as in providing frequency control services). South Australia in 2017 commissioned the world's largest lithium ion battery adjacent to the Hornsdale wind farm. As well as operating in the electricity market, the battery earns significant revenue by supplying stability (frequency) services to the grid. The AER estimated the battery earned around $25 million in 2019 from frequency services—five times its earnings from wholesale energy sales.

A further four battery projects were commissioned in the NEM by January 2020 (table 1.1), including ElectraNet's Dalrymple Battery Energy Storage System (which ARENA partly funded). Some of these battery storage systems are located adjacent to solar and wind farms, and aim to complement and 'firm' generation output from these plants.

Large scale storage is also being pursued through pumped hydroelectricity projects, which allow hydroelectric plant to reuse their limited water reserves. The technology involves pumping water into a raised reservoir when energy is cheap, and releasing it to generate electricity when prices are higher. Pumped hydroelectric technology has operated in the NEM for some time, in Queensland (570 MW at Wivenhoe) and NSW (240 MW at Shoalhaven, 1500 MW at Tumut 3, and 70 MW at Jindabyne). But advances in technology and the rise of intermittent generation are providing opportunities to deploy this form of storage at a larger scale. In particular, pumped hydroelectricity is the basis of the proposed Snowy 2.0 (2000 MW) and Battery of the Nation (2500 MW) projects in NSW and Tasmania respectively (section 1.7.2).

Figure 1.8
**Hourly ramping of wind and solar generation**




Note: Monthly top 1 per cent of up and down 60 minute ramps in the National Electricity Market.
Source: AEMO, *Renewable integration study, stage 1 report*, April 2020.

## 1.2.2 Distributed energy resources

Alongside the major shift occurring at grid level, significant changes are occurring in small scale electricity supply. Most significant is the uptake of which are consumer owned devices that can generate or store electricity, or actively manage energy demand. They include:

- rooftop solar PV units
- storage, including batteries and electric vehicles
- demand response, using load control technologies to regulate the use of household appliances such as hot water systems, pool pumps and air conditioners (section 1.5.3).

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

These DER have varying characteristics—for example, rooftop solar systems are passive, and can generate electricity only when the sun is shining, while active resources such as batteries and electric vehicles can both draw electricity from, and inject it into, the electricity grid at any time. With DER, energy customers are changing from passive consumers to active buyers and sellers of energy services.

### Rooftop solar PV installations

Government incentives and declining installation costs resulted in Australia having one of the world's highest per person rates of rooftop solar PV installation. Around 20 per cent of all customers in the NEM now partly meet their electricity needs through rooftop solar PV generation, and sell excess electricity back into the grid, compared with less than 0.2 per cent of customers in 2007. This production met over 5 per cent of the NEM's total electricity requirements in 2019.

South Australia has operated for periods when wind and solar (grid level and small scale) output was equivalent to 142 per cent of the state's energy requirements (with excess production exported to Victoria). This trend is creating new challenges for the market around reliability and security (sections 1.4 and 1.5).

Table 1.1 **Grid scale battery storage projects**

| STATE | BATTERY NAME | NAMEPLATE CAPACITY (MW) | NAMEPLATE STORAGE (MWh) | STATUS | DATE OF FIRST OUTPUT |
|---|---|---|---|---|---|
| South Australia | Hornsdale Power Reserve | 100 | 122 | In service | November 2017 |
| South Australia | Dalrymple | 30 | 8 | In service | July 2018 |
| Victoria | Gannawarra Energy Storage System | 25 | 50 | In service | November 2018 |
| Victoria | Ballarat Energy Storage System | 30 | 30 | In service | November 2018 |
| South Australia | Lake Bonney | 25 | 52 | In service | October 2019 |
| Queensland | Kennedy Energy Park Phase 1 | 2 | 4 | Committed | August 2020 |
| Victoria | Bulgana Green Power Hub | 20 | 20 | Committed | November 2020 |

MW, megawatt; MWh, megawatt hour.
Note: Date of commissioning refers to the date of first output to the grid, or the expected full commercial use date for committed projects.
Source: AEMO, *NEM generation information*, January 2020.

Attractive premium feed-in tariffs offered by state governments drove the initial growth in solar PV installations. Despite the closure of those schemes, subsidies through the Australian Government's small scale renewable energy scheme, combined with the falling costs of solar PV systems, has led to sustained strong demand for new installations. In 2019 the average size of a rooftop solar installation in the NEM was 7.6 kilowatts (kW), up from 2.5 kW in 2011 (figure 1.9). The total installed capacity of rooftop PV systems in the NEM reached almost 9000 MW in early 2020.

### Batteries and electric vehicles

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

The charging profiles of electric vehicles will similarly affect power flows. Price incentives that discourage customers from charging during peak demand periods would ease potential strain on the power system. Based on current forecasts, however, AEMO expects the uptake of electric vehicles to be relatively small in the next decade.

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

Stand-alone systems or microgrids—where a community primarily uses locally sourced generation and does not rely on a connection to the main grid—are also gaining traction in some areas. These arrangements have mainly developed in regional communities that are remote from existing networks. But improvements in energy storage and renewable generation technology may lead more customers to take up this form of energy supply.

Regulatory and pricing frameworks are being implemented to support the growth of off-grid arrangements. The Australian Energy Market Commission (AEMC) in May 2020 proposed rules making it easier for distribution network providers to offer stand-alone power systems (where economically efficient to do so) while maintaining appropriate consumer protections and service standards.[20]

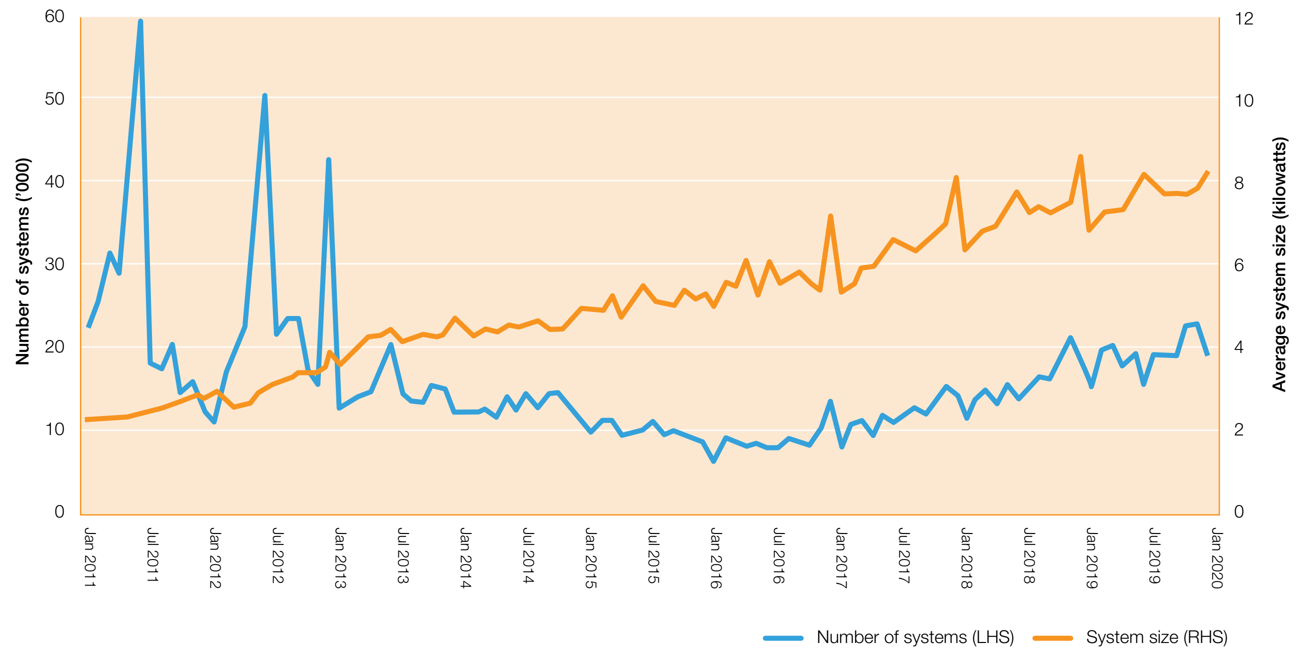
### Virtual power plants

Individually, distributed energy resources are largely invisible to the market, and potentially disruptive to the grid. But solar systems combined with batteries can be aggregated to form a microgrid or virtual power plant that, if coordinated, can charge and discharge on a larger scale. Aggregation creates opportunities for small scale resources to participate in markets such as those for demand management and frequency control services.

The Australian Renewable Energy Agency (ARENA) in May 2019 announced $2.5 million in funding for AEMO to run a virtual power plant trial over a 12–18 month period, to demonstrate the technology's capabilities to deliver energy and grid stability services. AEMO invited existing pilot scale projects to participate, including ARENA funded AGL and Simply Energy pilot scale projects in South Australia.

20 AEMC, *Updating the regulatory frameworks for distributor-led stand-alone power systems, Final report*, May 2020.

Figure 1.9
**Growth of solar PV installations in the NEM**




PV, photovoltaic.

Source: Clean Energy Regulator, *Postcode data for small scale installations, Small generation units—solar*, February 2020.

While virtual power plants are relatively small in scale to date (accounting for round 5–10 MW), AEMO forecast they would contribute up to 700 MW of capacity to the market by 2022.[21]

## 1.2.3 Changing patterns of electricity demand

As more electricity customers generate some of their own electricity needs through rooftop solar PV systems, the demand for grid supplied electricity is changing. Some consumers with solar panels are self-generating much of their daytime power needs, then using the grid when sunlight and solar generation fall later in the day.[22]

While solar generation is helping to mitigate stress on the power system, timing issues limit the extent of this assistance. In summer, daily energy use peaks in the late afternoon or early evening, when temperatures are high and business use overlaps with households using air conditioning and other appliances. Winter demand peaks at a similar time of day, when households switch on heating appliances. But solar PV generation is falling late in the day when these peaks occur, so it can provide only limited support. For this reason, maximum demand for grid supplied electricity continues to rise in most regions, despite the rapid rise of solar PV systems.

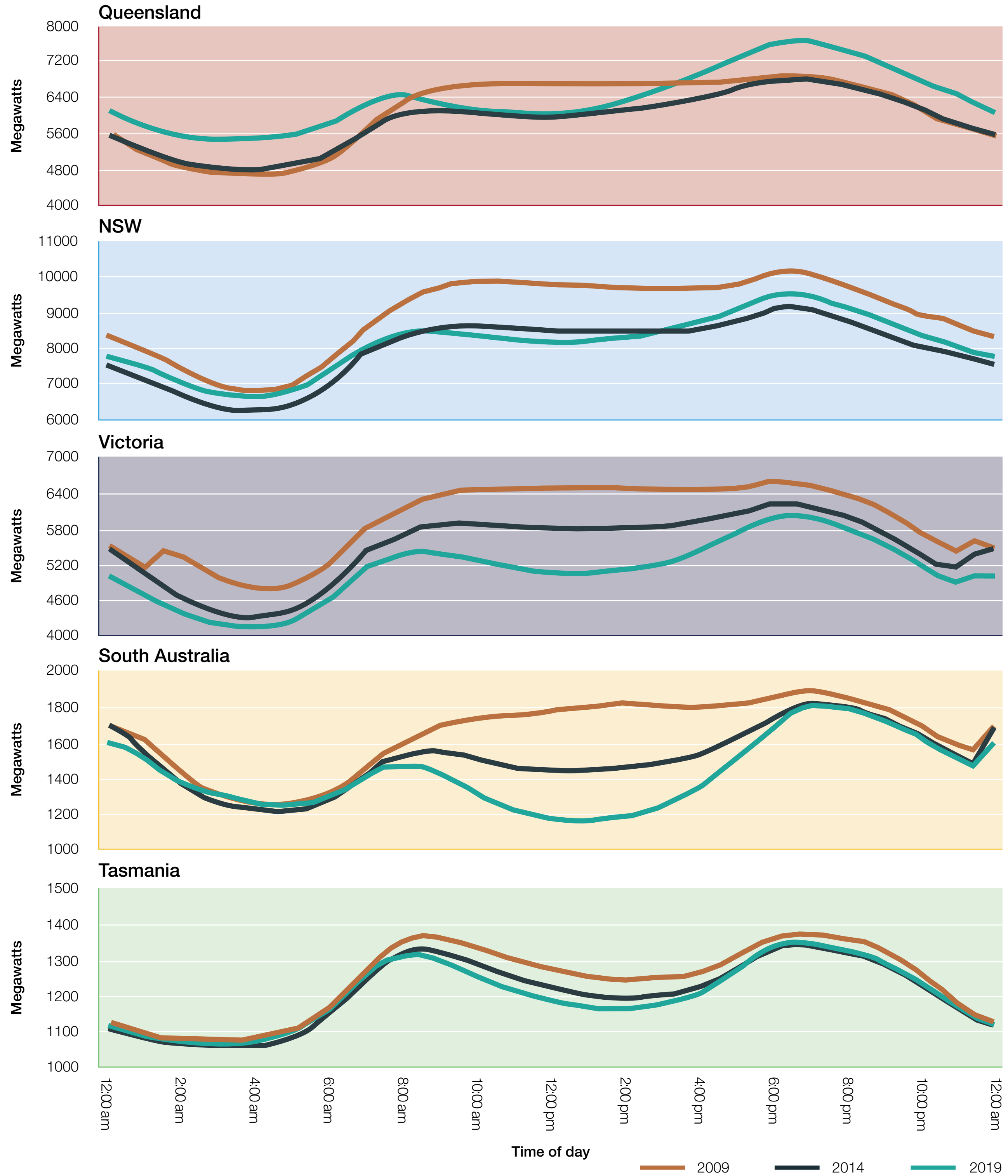
The growth of rooftop solar PV generation is also shifting the level and timing of *minimum* demand for grid supplied electricity. Historically, demand reached its low point in the middle of the night, when most people are sleeping. But the growth in solar PV output in the middle of the day is lowering daytime grid demand, and minimum grid demand increasingly occurs then. Figure 1.10 shows how demand is falling in absolute terms, and how this shift is particularly apparent around midday. Increasing residential rooftop PV uptake is expected to result in all regions experiencing minimum demand in the middle of the day within the next few years.

This hollowing out of demand through daylight hours is often called the 'duck curve'. The total energy consumed is represented by the area under the curve, which is falling over time.

21 ARENA, 'AEMO to trial integrating virtual power plants into the NEM', Media release, 5 April 2019.

22 AEMC, *Economic regulatory framework review, Promoting efficient investment in the grid of the future*, July 2018.

Figure 1.10
**Electricity duck curves**




Note: Average native demand by time of day for 2009, 2014 and 2019.

Source: AER; AEMO (data).

### 1.2.4 Climate change and the power system

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

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

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

Higher ambient temperatures affect the technical performance of thermal plant (coal, gas and liquid fired plant) by reducing cooling efficiency. This issue affects air cooled plant (such as Kogan Creek and Millmerran) and gas turbines in particular, although high temperatures also affect water cooled plant. The performance of wind and solar plant, and batteries may also degrade at higher temperatures.[23]

These issues are most frequent on very hot days when demand is at its highest. When AEMO notified the market about reliability threats in 2018–19, a number of thermal generators were not available, or running at lower capacity, as a result of technical or safety concerns from extreme weather events.[24] More recently, bushfires caused interruptions to the transmission grid over summer 2019–20 (section 2.6.2). Extreme wind also crippled transmission infrastructure in Victoria in early 2020.

The Energy Security Board's 2020 report on the health of the NEM highlighted the importance of electricity system resilience, given extreme weather events will likely become more frequent and intense.[25] AEMO modeling is also factoring in the increased risk of extreme temperatures impacting peak demand, and of drought affecting water supplies for hydro generation and cooling for thermal generation.[26]

23 Global-ROAM and Greenview Strategic Consulting, *Generator report card*, May 2019.
24 AEMC Reliability Panel, *2019 annual market performance review, Final report*, March 2020.
25 Energy Security Board, *Health of the National Electricity Market 2019*, February 2020.
26 AEMO, *2019 electricity statement of opportunities*, August 2019.

## 1.3 Reliability issues

Reliability is about the power system being able to supply enough electricity to meet customers' requirements, in terms of available generation and storage capacity, demand response, and transmission network capacity (box 1.2). Cross-border transmission interconnectors support reliability by allowing resource sharing across regions. Reliability concerns tend to peak over summer, when high temperatures spike demand and increase the risk of system faults and outages.

### 1.3.1 Reliability in a transitioning market

The transition underway in the energy market has increased concerns about reliability. Coal plant closures remove a source of 'dispatchable' capacity that could once be relied on to operate when needed. AEMO raised concerns the market would be at risk of generation shortfalls over each of the past three summers (including 2019–20), especially in Victoria and South Australia where major fossil fuel plant closures occurred.

Additionally, the ageing fossil fuel plants still in the market are becoming more prone to outages, especially in hot weather. AEMO in 2019 reported a trend of rising forced outages among the NEM's ageing thermal generation, due to plant breakdown and more frequent and longer planned outages for maintenance and repair work.

For each of the past four years, brown coal forced outage rates exceeded long term averages (figure 1.11). A particularly significant outage occurred in 2019 at Victoria's Loy Yang A plant.

The surge in wind and solar generation investment over the past few years poses new reliability challenges:

- Because most renewable generation is weather dependent, AEMO cannot depend on it to run unless it is supported by 'firming' capacity such as battery storage.
- The intermittency of renewable generation makes it harder to forecast its output than for other plant types, although forecasting techniques are improving.
- New investment in renewables tends to be financed by long term power purchase agreements, rather than the underwriting of hedge products in contract markets. Over time, this investment approach may drain liquidity from contract markets, potentially posing a barrier to investment in new dispatchable capacity.[27]

27 AEMC Reliability Panel, *2018 annual market performance review, Final report*, April 2019, p. 34.



### Box 1.2 How is reliability measured?

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

The standard excludes outages caused by 'non-credible' threats, such as bushfires and cyclones, because the power system is not engineered to cope with these issues, and the cost of doing so would be prohibitive. It also excludes supply interruptions originating in local distribution networks. Over 95 per cent of a typical customer's power outrages originate in distribution networks, and are caused by local power line and substation issues. While these outages are common, their impact is confined to relatively small cluster of customers in each instance. Section 3.14.3 of this report covers distribution reliability.

In effect, the standard sets a level of unserved energy that balances the cost of providing reliability against the value that customers place on avoiding an unexpected outage. A stricter reliability standard would reduce outages, but then power bills would rise because more generation plant or transmission interconnection would need to be built to ensure peak demand can be met.

### 1.3.2 Managing reliability risks

AEMO has powers to intervene to manage a forecast lack of supply to meet electricity demand. Over the past three summers (up to and including 2019–20), it used the Reliability and Emergency Reserve Trader (RERT) mechanism to manage reliability risks. Under the scheme, AEMO secures contracts with generators (to provide capacity) and/or large customers (to reduce their consumption) when the power system is under stress.

Before 2017–18, the RERT had been used to procure back-up capacity only three times, and was never activated. AEMO activated the RERT for the first time on 30 November 2017 to manage a forecast lack of reserves in Victoria. It again activated the scheme in Victoria and South Australia in January 2018, January and December 2019, and three times in January 2020, at a cumulative cost of around $110 million (section 2.9.1).

### 1.3.3 Market reforms on reliability

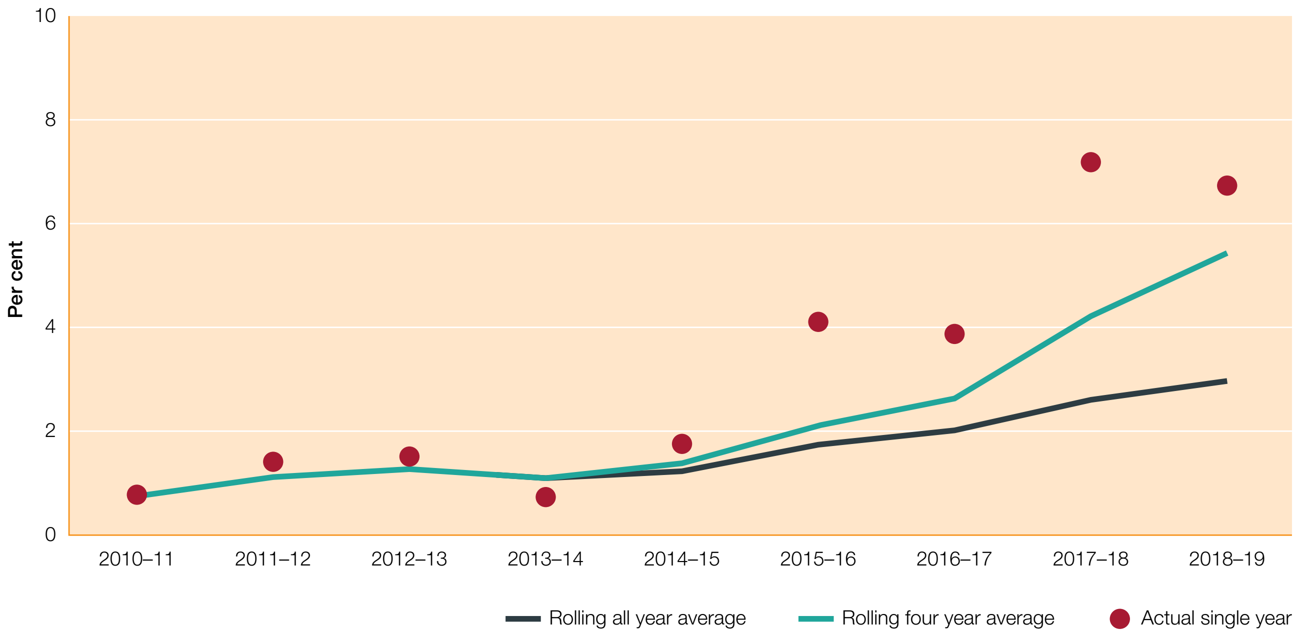
Market bodies are exploring how best to manage reliability risks in an evolving energy market. In doing so, they are looking at investment in resources with flexibility to manage sudden demand or supply fluctuations.

A central reform was the introduction of a Retailer Reliability Obligation (RRO) in July 2019 (box 1.3). The scheme encourages retailers and large energy customers to invest in dispatchable electricity generation in regions where a gap between generation and peak demand is forecast. A longer term focus is on expanding the role of demand response as a cost-effective way of addressing reliability risks (discussed below). Other reliability initiatives include:

- a new rule (from 1 September 2019) that requires generators to provide the market at least 42 months advance notice of their intention to close. The rule aims to improve long term forecasting of plant closures and reduce the reliability risks that closures can impose. When the rule commenced, a number of generators provided formal notice of their impending closure, including AGL Energy's Liddell power station and Torrens Island A power station, and Stanwell's Mackay gas turbine.
- the Energy Security Board's 2020 review of the adequacy of the reliability standard, to account for increased reliability risks from an ageing thermal generation fleet. The Energy Security Board recommended no changes to the reliability standard, but it will explore reforms in the lead-up to a post-2025 NEM design (section 1.6.3). In the short term, it recommended the creation of an out-of-market capacity reserve to be managed by AEMO, at least in part through reverse auctions and offering contract terms of up to three years. It also recommended a lowering of the trigger for activating the RRO.[28]
- From March 2020 AEMO can contract for RERT resources up to 12 months in advance (previously, nine months in advance). And, in Victoria, it can enter multi-year RERT contracts until June 2023, to help address reliability challenges facing that state.

28 CoAG Energy Council, 'Energy Security Board outcomes from 23rd Energy Council Ministerial Meeting', 27 March 2020, web page, available at: www.coagenergycouncil.gov.au/publications/energy-security-board-outcomes-23rd-energy-council-ministerial-meeting.

Figure 1.11
**Coal plant outages as a share of capacity**




Source: AEMO, *2019 electricity statement of opportunities*, August 2019.

To address reliability risks in the longer term, AEMO proposed substantial investment in transmission networks to integrate new renewable generation into the system as that generation comes online (section 1.7.2).[29]

### Expanded role for demand response

Demand response relates to electricity users responding to financial incentives to cut their energy use from the grid temporarily when the power system is under pressure. While demand response can help manage peak demand, it has not been widely used in the NEM. One reason is that only retailers and large industrial customers see the price signals that encourage demand response, and they often prefer to manage this risk through hedge contracts.

The AEMC released rules in 2020 to attract more demand response providers into the market. Under the reform, participants can offer demand reductions through AEMO's central dispatch process, and be paid for any capacity called on. The mechanism will apply from October 2021, but will initially be limited to large customers. The AEMC regards the mechanism as an interim measure in the transition to a two-sided market with participants on both the supply and demand sides participating in dispatch and price setting.[30] The Energy Security Board is developing a two-sided market as part of the NEM framework overhaul that is scheduled to take effect in 2025 (section 1.6.3).

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

## 1.4 Power system security issues

Power system security relates to keeping the power system within technical operating limits needed to keep it safe and stable. Parameters of system security include frequency and voltage stability, and physical properties such as system strength and inertia (box 1.4). An electricity system that operates outside acceptable limits for these parameters may jeopardise the safety of individuals, damage equipment, and lead to blackouts. A secure system can withstand a disturbance (such as the loss of a major transmission line) by quickly returning to a secure operating state.

29 AEMO, *Draft 2020 integrated system plan*, December 2019.

30 AEMC, *Wholesale demand response mechanism final rule, Information sheet*, June 2020.





### Box 1.3 Retailer Reliability Obligation

The Retailer Reliability Obligation (RRO) scheme (launched in July 2019) aims to incentivise retailers and large energy customers to invest in dispatchable electricity generation to meet a forecast reliability risk. The Energy Security Board designed the scheme from an earlier version that formed a limb of the now abandoned National Energy Guarantee.[a] The Australian Energy Retailer (AER) publishes guidelines on the scheme's operation.

The scheme supports reliability by encouraging retailers and large energy users to enter contracts (or own generation capacity) to match their electricity demand in periods when the Australian Energy Market Operator (AEMO) forecasts a reliability gap between generation and peak demand over the coming five years. If a material gap remains three years out, then AEMO will ask the AER to formally trigger the RRO. The trigger level is intended to ensure the electricity system remains reliable during a one-in-10 year summer. The Energy Security Board in March 2020 reduced the trigger for activating the RRO, and introduced more flexibility to initiate the RRO to address forecast reliability gaps at shorter notice.[b]

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

If a forecast gap persists one year out, then liable entities must submit their contract position to the AER for a compliance assessment. AEMO may also start procuring emergency reserves through the Reliability and Emergency Reserve Trader mechanism to address any remaining supply gap.

The RRO's design relies on retailers having access to hedge products. To support contract market liquidity, a market liquidity obligation (MLO) also applies if the RRO is triggered: it requires large generators to perform a 'market maker' role by offering to buy and sell hedge contracts on the Australian Securities Exchange (ASX) within a limited price spread. The obligation aims to ensure smaller participants can access enough contracts to meet their RRO obligations. The AER monitors relevant generators' compliance with the MLO.

AEMO in 2019 identified a supply shortfall in 2019–20 in Victoria, but did not highlight any shortfall three years out (that is, in 2022–23) for any NEM region. So, the RRO was not triggered.

#### South Australia

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

In January 2020 the minister triggered the RRO in South Australia for periods in the first quarters of 2022 and 2023. Large generation businesses in South Australia—Origin, AGL and Engie—must now offer contracts for those periods on the ASX.

a Energy Security Board, *National Energy Guarantee, Final detailed design*, 1 August 2018.

b CoAG Energy Council, 'Energy Security Board outcomes from 23rd Energy Council Ministerial Meeting', 27 March 2020, web page, available at: www.coagenergycouncil.gov.au/publications/energy-security-board-outcomes-23rd-energy-council-ministerial-meeting.

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

### 1.4.1 Security in a transitioning market

The energy market transition impacts system security on many levels. Historically, the normal operation of the NEM's synchronous coal, gas and hydro generators produced inertia and system strength as a byproduct of producing energy, which helped maintain a stable and secure power system. But as older synchronous plants retire, important sources of inertia and system strength are removed from

## Box 1.4 Power system security parameters

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

Synchronous generators (such as hydro, coal and gas plants) produce *inertia*, which is a physical property that helps the power system ride through disturbances. The large rotating mass of a plant's turbine and alternator create this inertia as they rotate in synch with system frequency, which helps resist disturbances caused by a shift in supply or demand. A system with low inertia has a higher risk that frequency deviations will cause generators to disconnect from the power system.

*Voltage* is the electrical force or potential between two points that 'pushes' an electric charge through a wire. Voltage stability is necessary for a healthy power system, whereas large fluctuations in voltage can make it difficult for generators to remain connected to the system. In a healthy power system, the injection and absorption of reactive power manages these fluctuations. Synchronous generators create and absorb reactive power as a byproduct of producing energy, which helps manage voltage instability.

*System strength* is an umbrella term referring to the power system's sensitivity to disturbances such as voltage changes caused by a fault. A strong system can better cope with faults caused by electrical plant malfunctions, or by threats such as lightning and bushfires. With low strength, protection systems in the transmission network are less able to locate and clear faults. Failing to clear faults in a timely manner risks equipment damage, and makes it difficult for generators to remain connected during a disturbance. While inertia can be shared across regions, system strength is a more local phenomenon that requires local solutions.

Frequency, inertia, voltage and system strength interrelate and affect each other. Weak inertia, for example, can lead to frequency instability and weak system strength. In turn, weak system strength intensifies the effects of voltage instability (resulting in deeper, more widespread voltage dips).

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

Wind and solar (non-synchronous) generators are not electro-mechanically coupled to the frequency of the power system. To connect with the system, they use a synthetic power device called an inverter, which simulates an alternating current (AC). Wind and solar generators are limited in their ability to dampen rapid changes in frequency, and have provided little or no fault current to support system strength.

So far, the rising proportion of renewables in the generation mix has meant more periods of low inertia, weak system strength, 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. To help manage this ramping issue, the settlement period for the electricity spot price will change from 30 minutes to 5 minutes. While this change was planned for July 2021, the AEMC in May 2020 was consulting on a delay to July 2022.[31]

Since the closure of South Australia's Northern power station in 2016, and new entry of wind and solar plant, inertia shortfalls have caused more volatile frequency disturbances in the state. AEMO in 2018 declared an inertia shortfall in South Australia. Inertia levels have also fallen in Victoria since the closure of its Hazelwood power station in March 2017, falling at times below acceptable thresholds.

System strength has become an issue on the fringes of the grid, particularly in South Australia, north Queensland, south west NSW, north west Victoria and Tasmania. Weak system strength can lead to overvoltage in parts of the transmission system. AEMO has declared shortfalls in important security services in these regions (section 1.4.4). The uptake of DER is also creating voltage issues in distribution networks (section 1.5.3).

Declining system strength also makes it harder for generating units to meet their performance standards. The operation of inverters—such as those used by wind farms, transmission interconnectors, solar PV systems and battery storage—requires sufficient system strength to ride through faults.

As the generation mix changes, new approaches are required to provide the stability services that we previously took for granted. The capability of wind and solar plants to provide these services is evolving, as are the types of service required. The first wave of wind farms in particular were not well engineered to provide security services. However, some modern inverter based generation has the capability to respond rapidly to sudden changes in electricity supply or demand, and to make a limited contribution to system strength (at the expense of producing energy).

Other technology solutions include synchronous condensers—that is, large spinning machines similar to those used in synchronous generators, but with shafts that spin freely. The motion of the machines creates inertia. They can also supply and absorb fault current to support system strength and maintain voltage stability (section 1.4.3).

The AEMC noted international experience suggests it is not yet possible to operate a large power system without some synchronous inertia, and 'synthetic' inertia from non-synchronous generators does not currently provide a direct replacement.[32]

Power system security was previously achieved as a byproduct of the power system's normal operation. But it increasingly needs careful management. AEMO is responsible for managing power system security in the NEM. It uses market based methods where possible, but it can override the market's normal operation if market measures are inadequate. Further, AEMO and other stakeholders can propose rule changes to address systemic issues (section 1.4.4). At a higher level, market, policy and regulatory bodies are developing reforms of the market's architecture to keep it fit for managing security issues in the longer term (section 1.4.5).

### 1.4.2 Market procurement of security services

Some of the services needed to maintain power system stability can be procured through markets. In particular, AEMO operates markets to procure different types of frequency control services.

#### Frequency control services

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

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

System frequency is deviating from its normal operating range more often than in the past (figure 1.12). Policy reforms—including mandatory primary frequency response—target this issue (section 1.4.4).

Historically, FCAS costs were comparatively low in relation to energy costs. In 2015 FCAS costs totalled $63 million, which represented around 0.7 per cent of NEM energy costs. However, they steadily increased over the past few years (figure 1.13), and they totalled around $223 million in 2019, which was almost four times their total in 2015.[33] For the first quarter of 2020, FCAS costs were higher (at $227 million) than they were over the whole of 2019. The first quarter peak was partly driven by high local costs in South Australia when it was isolated from the rest of the NEM for several weeks. Chapter 2 further describes recent FCAS costs (section 2.10.2).

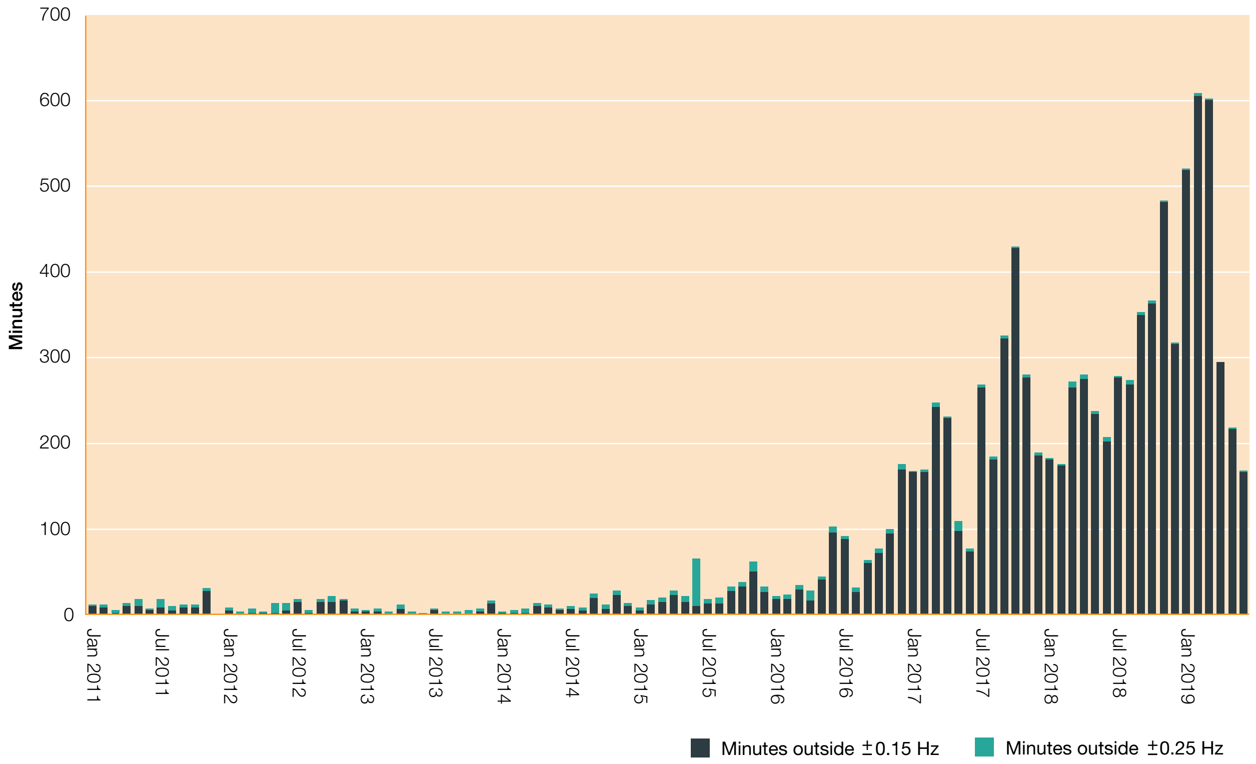
The increase in FCAS prices over the past five years, coupled with technological developments, has driven new types of FCAS provider to enter the market. These new entrants include demand response, virtual power plants,

31 AEMO in April 2020 proposed the delay in response to the potential impact of COVID-19 on the energy industry, to free up human and financial resources that would be under strain during the pandemic.

32 AEMC Reliability Panel, *System security market frameworks review, Final report*, June 2017.

33 AER, *Wholesale markets quarterly—Q4 2019*, February 2020.

Figure 1.12
**NEM mainland frequency excursions**




Hz, hertz.

Source: AEMC Reliability Panel, *2019 annual market performance review, Final report,* March 2020.

wind farms and utility scale batteries. They demonstrate new technologies and business models will have an increasingly important role in maintaining system security. To strengthen transparency around FCAS markets and encourage participation, the AER in 2019 launched quarterly reporting on each market, including an analysis of outcomes.[34]

### Procurement of other security services

Alongside the spot markets for frequency control services, AEMO enters long term contracts to procure two other types of security service:

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

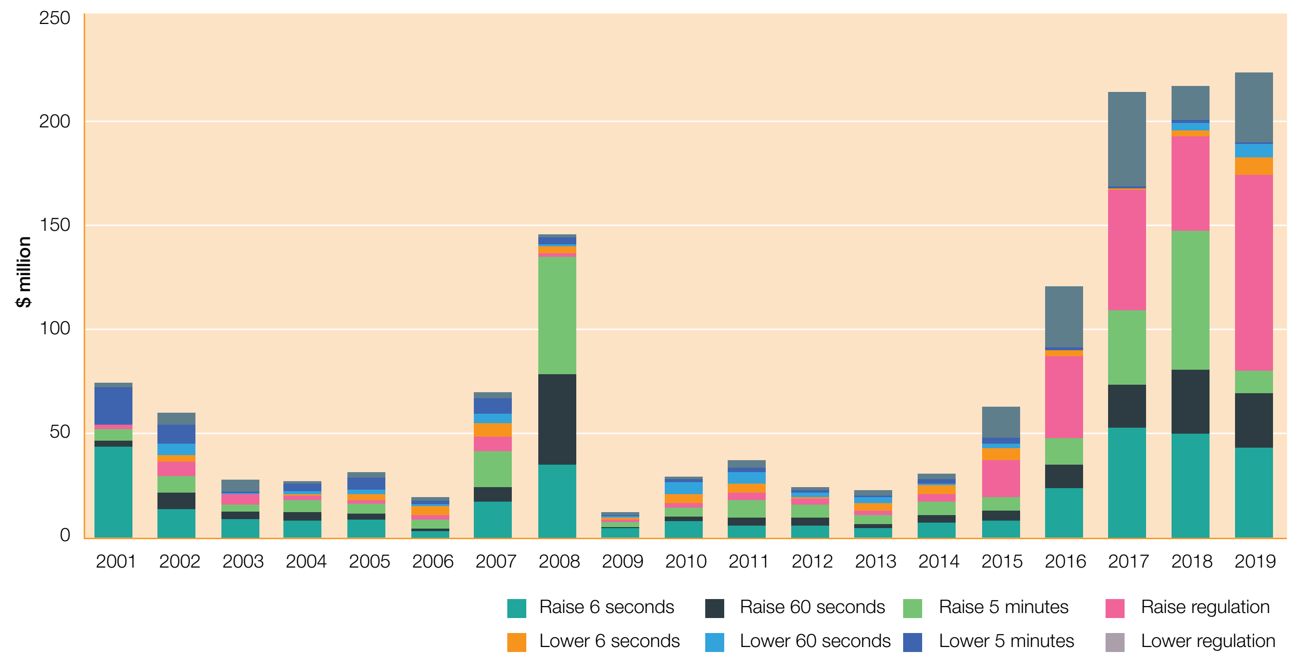
No market yet exists to procure other system services such as inertia and system strength. In the past, these properties were so plentiful that no value was ever placed on them, and no mechanism to procure them was required. But the AEMC is exploring new mechanisms to obtain and pay for these services.

## 1.4.3 Market intervention to manage security

Where no market exists to manage a security issue, AEMO may intervene. The extent of such intervention has risen markedly in recent years. While necessary as a short term measure, this intervention is costly for energy consumers.

34 AEMC, *Monitoring and reporting on frequency control framework, Fact sheet*, July 2019.

Figure 1.13
**Frequency control ancillary service costs**




Note: South Australia's local frequency control ancillary service (FCAS) costs rose from late 2015 through to 2017 as a result of stricter requirements for localised sourcing of those services in that period, and fewer participants offering FCAS.

Source: AER.

AEMO uses a blend of interventions methods, which include:

- directing generators to operate even if it is not economic for them to do so
- preventing some low priced generation plants from operating
- de-energising transmission lines
- as a last resort, instructing load shedding.

Some mechanisms can be applied jointly. In South Australia, for example, AEMO has managed inertia and system strength issues by constraining wind and solar generators, while also directing synchronous (gas) generators to operate. In Victoria, it has managed voltage and system strength by constraining transmission lines and directing gas powered plants to operate.

While AEMO targeted these mechanisms in recent years mainly at security threats, they can also target reliability issues. AEMO's principal mechanism for managing short term reliability risks in the past few years, however, was the RERT mechanism (section 1.3.2).

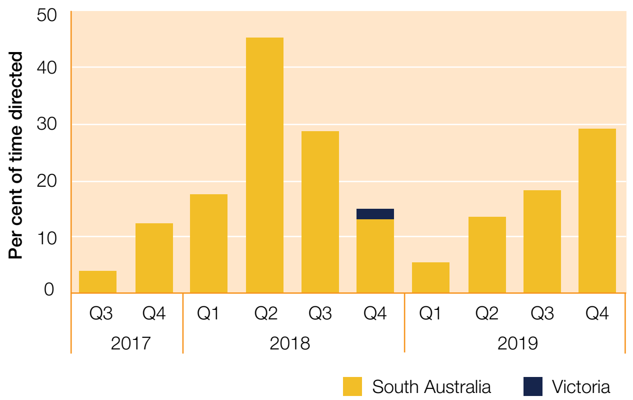
Between 2014 and 2016 AEMO intervened in the market only once each year, for a cumulative total of less than 4 hours. Market interventions to maintain security rose sharply from 2017. South Australia and, more recently, Victoria have been the focus of these interventions.

### Directions

AEMO normally dispatches the lowest cost generators to meet demand, but this dispatch can cause security issues. If, for example, a lack of online synchronous generators causes a lack of system strength, then AEMO may direct one or more synchronous generators to operate, even if this direction overrides the market's normal efficient operation.

The use of AEMO directions has increased markedly in recent years, with most targeting system strength issues in South Australia (figure 1.14). The duration of these directions peaked in 2018, when they were in place for 26 per cent of the time. While this ratio eased to 16 per cent in 2019, AEMO intervened regularly late in the year, and intervention costs in October–December 2019 hit a record $13 million.

Figure 1.14
System security directions




Source: AEMO.

### Constraints

In recent years, AEMO periodically constrained renewable generation to maintain inertia and system strength. Figure 1.15 shows a significant increase in the volume of renewable generation curtailed by constraints and operator decisions in 2019.

Much of this curtailment applied to wind generation in South Australia, particularly in the third quarter each year (July–September), when electricity demand is lowest. Since September 2019 the focus of AEMO's intervention shifted to north west Victoria and south west NSW, where it constrained substantial volumes of solar generation to manage voltage issues (box 1.5).

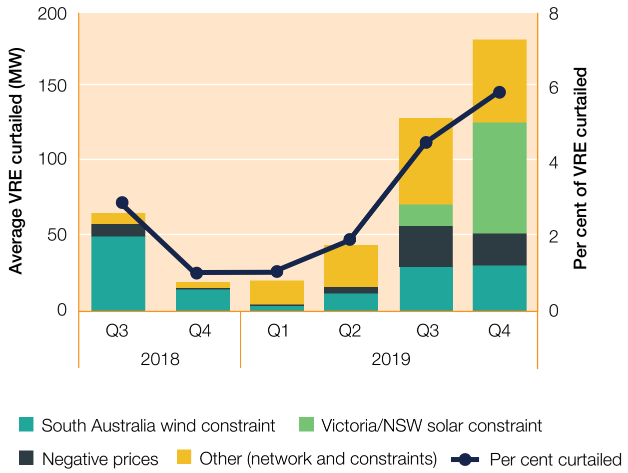
In March 2020 AEMO raised system strength concerns in north Queensland that occur when insufficient coal or hydro plant is operating. It introduced new constraints preventing three renewable generators in the region from operating when coal and hydro output falls below a set threshold.[35]

### Transmission network intervention

While power system intervention often targets the generation sector, some instances target transmission networks. The closure of Victoria's Hazelwood power station in March 2017 removed a generator that historically played an important role in supporting voltage control. Following the closure, AEMO began managing overvoltages at times of minimum demand by de-energising (switching off) high voltage lines (and sometimes also directing a gas powered generator to operate).

35 AEMO, 'Revised system strength limits in north Queensland', Market notice 74987, 19 March 2020.

Figure 1.15
Curtailment of renewable generation




MW, megawatt; VRE, variable renewable energy.
Source: AEMO, *Quarterly energy dynamics Q4 2019*, February 2020.

In November 2018 a significant voltage incident led to AEMO switching off three separate 500 kilovolt (kV) transmission lines in Victoria for the first time in the history of the NEM. AEMO in December 2018 declared a gap for voltage control in Victoria, and entered contracts with synchronous generators for voltage support.

### Load shedding

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

### Intervention costs

Until recently, generators subject to a direction were entitled to claim compensation. The cost of AEMO directions—that is, the compensation recovery amount—was around $15.7 million in 2018–19, and $18.2 million the year before.[36] There are no compensation provisions for generators affected by constraints. Given the scale of these costs, the AEMC in December 2019 abolished compensation payments associated with system security directions.

36 Energy Security Board, *Health of the National Electricity Market 2019*, February 2020.





### Box 1.5 Curtailment of solar farms in Victoria and NSW

In September 2019 the Australian Energy Market Operator (AEMO) began overriding the power system's normal operation to manage system strength and voltage issues in north west Victoria and south west NSW. Many solar farms have been commissioned in the region over a short period.

The area is too remote from synchronous generators for AEMO to manage the issue through directions to gas or coal fired generators. Instead, AEMO intervened by constraining the output of five solar farms (four in Victoria and one in NSW) by 50 per cent of their maximum output at all times. The constraints equated to a loss of up to 170 megawatts of output. The intervention aimed to manage the risk of voltage instability following a contingency such as the loss of a nearby transmission line.[a] Following changes to inverter settings for the affected plants, AEMO lifted the constraints in April 2020.

Limited transmission capacity may still impede the connection of new plant in the region. Another five generators ready to connect to the grid had been placed on hold until a solution to the issue was found. In early 2020 a further 15 generators had committed to connect in the region, and another 25 generators were at the point of applying for connection.

In December 2019 AEMO began a cost–benefit analysis of building new transmission capacity to unlock renewable capacity in the region. It estimated a lead time for this investment of six to seven years. A shorter term option to manage system strength and voltage issues would be to install synchronous condensers.

In December 2019 AEMO declared a 'fault level shortfall' in north west Victoria relating to this issue. AEMO (as the network planner for Victoria) is assessing combinations of synchronous condensers to supply additional fault current, and is looking to have a solution in place by 1 January 2021.

a AEMO, *Notice of Victorian fault level shortfall at Red Cliffs*, December 2019.

Aside from formal compensation, the use of constraints or directions penalises consumers by driving up wholesale electricity prices. By, for example, restricting wind or solar output that might have zero marginal costs, AEMO directions may lead to dispatch from synchronous generators with higher costs. ElectraNet estimated the cumulative effect of system strength directions in South Australia on wholesale market prices exceeded $270 million at September 2018.[37]

## 1.4.4 Rule changes and regulatory reform

While AEMO intervenes in the market to manage short term security issues, AEMO and other stakeholders can propose changes to the Electricity Rules to address more systemic issues. The AEMC considers these proposals, which (if accepted) are then written into the rules. A number of recent rule changes target security issues.

37 ElectraNet, *Addressing the system strength gap in SA, Economic evaluation report*, February 2019.

### System strength and inertia

New rules addressing the issue of declining system strength commenced in 2017 in South Australia, and in July 2018 elsewhere.[38] Under the framework:

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

A separate rule change imposed similar requirements on transmission businesses to maintain minimum levels of inertia (or provide alternative services to meet these levels) if a shortfall is identified.

AEMO declared a system strength gap in South Australia in October 2017, and an inertia shortfall in December 2018. The issue typically arises when low to moderate demand combines with high levels of renewable generation to

38 AEMC, *Managing power system fault levels, Information sheet*, September 2017.

cause low spot electricity prices. If prices are too low for gas powered generators to cover their short run costs, the generators may bid to avoid dispatch. When fewer synchronous generators operate, unacceptably low fault current and weak system strength may occur.

South Australia's transmission business, ElectraNet, plans to partly address the issue by installing four high inertia synchronous condensers (by the end of 2020) to cover the system strength gap. It was exploring options such as contracting with generators or battery providers to cover the remaining inertia shortfall. In the meantime, AEMO will continue to direct synchronous generation to remain online to maintain system strength.

More recently, other regions of the market have experienced shortfalls in important security services. AEMO declared inertia and fault level shortfalls in Tasmania (November 2019), and fault level shortfalls in north west Victoria (December 2019) and north Queensland (April 2020).[39]

The AEMC noted the 'do no harm' rule may be causing issues for the connection of new generators. It is exploring options to value additional system strength and inertia, and to develop a mechanism to pay for these services.[40]

#### Mandatory frequency response

In March 2020 the AEMC ruled all capable generators and batteries must provide primary frequency response support whenever the system needs to respond to a supply–demand imbalance.[41] The response needs to be automatic and almost instantaneous, in the form of either a change in generation or a demand response.

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

The rule commenced in June 2020 and will sunset after three years. During this period, the AEMC will explore the development of payment mechanisms to encourage businesses such as utility scale batteries to provide fast frequency response. Further, it is considering a proposal from AEMO to address perceived regulatory disincentives to generators operating their plant in a frequency response mode during normal operation. The AEMC expects to make a draft decision on the proposal in September 2020.[42]

### 1.4.5 Market architecture reform

Policy makers are exploring reforms to the energy market's design so, in the longer term, it can efficiently deliver services to maintain system security. Work is underway, although many reforms will take time to be implemented.

Market bodies are exploring the development of new markets for services such as inertia, system strength and voltage control, which were traditionally viewed as cost-free byproducts of synchronous generation. The AEMC in 2017 introduced reforms to allow batteries and demand response aggregators to offer services in FCAS markets (section 1.5.3). The rule potentially widens the pool of FCAS suppliers and may stimulate competition between providers.

Technologies such as virtual power plants are increasing opportunities for smaller scale DER to participate in FCAS markets (and the wholesale market), and could widen scope for emerging markets such as voltage control, ramping and demand response. Pilot programs are exploring a new market design for a two-way energy system and marketplace in which DER can participate via aggregators to provide wholesale energy and/or ancillary services to the electricity grid and market.

AEMO is analysing the generation fleet's ability to ramp (adjust) quickly to sudden changes in wind and solar generation. To help manage this ramping, the settlement period for the electricity spot price will change from 30 minutes to 5 minutes.[43] This reform aims to stimulate investment in technologies that are particularly suited to providing a fast ramping response, such as batteries, gas peaking plants and demand response.

## 1.5 Efficiency challenges

Aside from reliability and security challenges, Australia's energy market transition poses risks to the efficient investment and use of energy infrastructure.

Small and geographically dispersed generators are being commissioned each year, often in sunny or windy areas at the edges of the grid, where the transmission network is weak. Connecting new generation to weaker parts of the grid is causing network congestion and security risks to the electricity grid. Yet, current frameworks do not provide accurate signals to connecting generators on the costs and risks of connecting in these locations.

The current regime for connecting new generation plant to the transmission grid raises a number of issues. One issue is that generators connecting to the grid do not pay for their use of the transmission networks, beyond a basic charge to connect to the nearest point on the network. The cost of other work to augment the network to accommodate a new generator with a poor network connection is charged to all energy users.

### 1.5.1 Efficient locating of new renewables plant

Generators consider a number of factors when determining where to locate a new plant. They consider the cost and availability of fuel resources, whether they can connect to the network to sell electricity, the costs of connecting to the grid, and energy losses that will scale down their future earnings. Regulatory frameworks have not encouraged efficient choices in some of these areas.

#### Transmission losses

As a result of the NEM's generation fleet becoming more geographically dispersed, and new plants locating further from the existing grid, energy losses from the system are rising. When electricity is transported across a network of poles and wires, some of it is lost as heat. These losses increase as more generators locate far from demand centres, because power has to travel further to reach customers. Across the NEM, transmission losses equate to around 10 per cent of all electricity transported between power stations and customers.[44]

A generator's earnings from selling electricity are scaled down to reflect this loss of energy. Generators that locate near the end of the line, where transmission is weak, have a relatively higher loss factor. As a result, their earnings can be significantly scaled down. This outcome appropriately signals to developers that locating new plant in a weak network area poses risks to future earnings. In this way, loss factors provide a price signal that discourages investment in inefficient locations.[45]

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

The increase in renewable generation in weaker (often remote) parts of the grid is causing large changes in loss factors in parts of the power system. The planned connection of substantial solar generation in north and central Queensland led to MLFs in the region being scaled back in each of the three years to 2020–21. Loss factors were also scaled back in 2020–21 for some other regions where network limitations constrain generation output, including areas of north west Victoria, south west NSW, the south east and Riverland areas of South Australia, and several parts of Tasmania.[46]

Declining MLFs increase risks for investors in new generation plant (figure 1.16). To help decision making, the AEMC in February 2020 amended the calculation process to increase transparency and improve predictability for investors.[47]

Under rules made in 2018, stricter technical standards applying to connecting generators help mitigate these risks.[48] Transmission networks may impose such technical requirements (generator performance standards) as they see fit. As networks become more constrained in areas with high quality renewable energy resources, requirements placed on connecting generators are becoming increasingly stringent. But the new arrangements have raised concerns among developers, with some reporting that network businesses are delaying the processing of connection applications or altering required standards during negotiations.

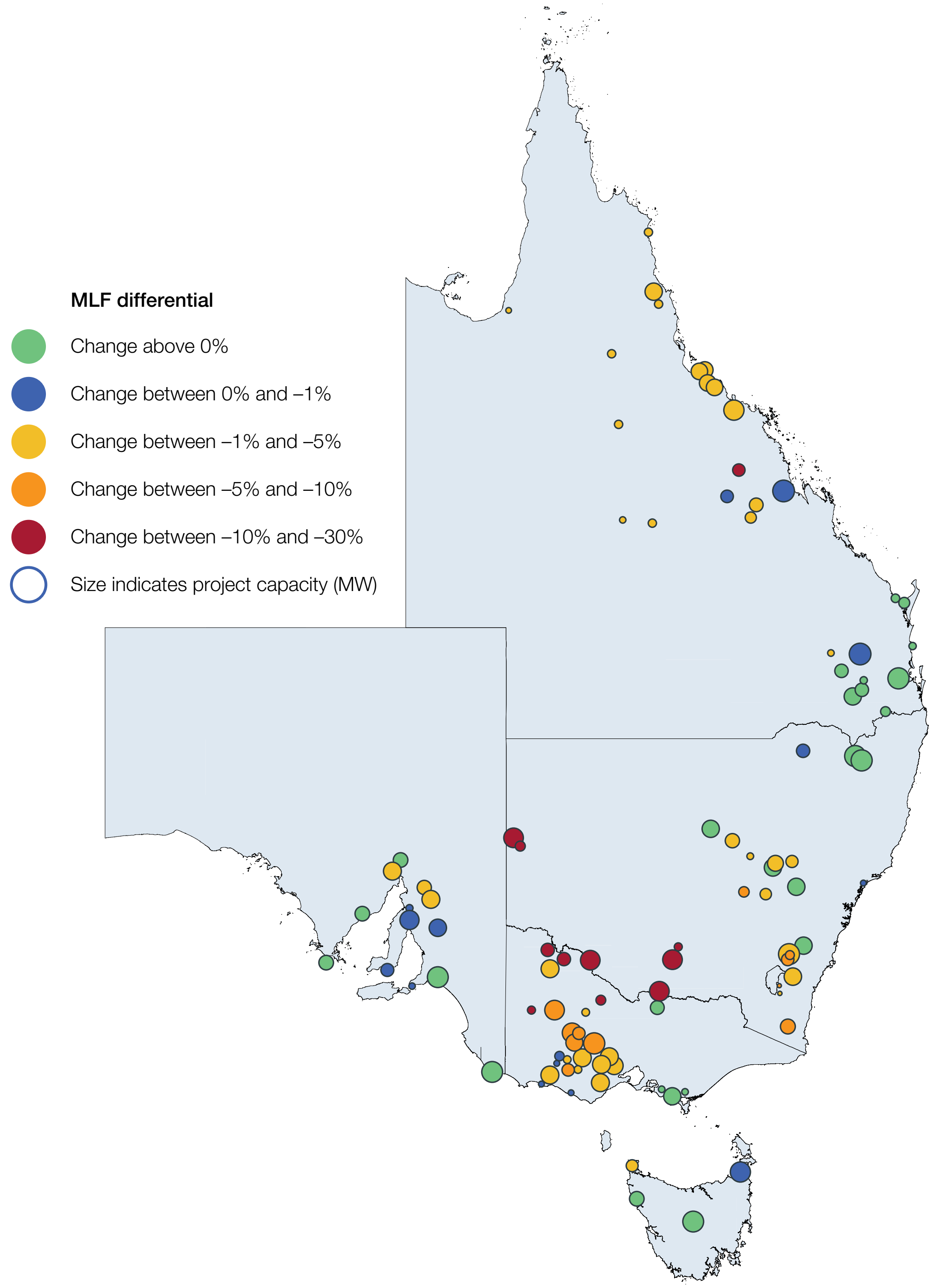
#### Congestion costs

Under current frameworks, a new connecting generator is not penalised for causing network congestion that degrades the quality of access for other generators. Existing generators cannot gain firm network access to avoid this risk. Further, current frameworks do not allocate congestion costs among generators. The MLFs account for transmission losses, but not for congestion caused by a generator connecting in a weak network area.

Rising generation in weaker parts of the grid is causing congestion that weakens network security for all participants. The lack of certainty also poses risks to

39 AEMO, *Notice of inertia and fault level shortfalls in Tasmania*, November 2019; AEMO, *Notice of Victorian fault level shortfall at Red Cliffs*, December 2019; AEMO, 'Revised system strength limits in north Queensland', Market notice 74987, 19 March 2020.
40 AEMC, *Investigation into intervention mechanisms and system strength in the NEM, Consultation paper*, April 2019.
41 AEMC, 'Final rule to better control power system frequency', Media release, 26 March 2020.
42 AEMC, *Primary frequency response rule changes, Fact sheet*, September 2019.
43 While the change was planned for July 2021, the AEMC in May 2020 was consulting on a delay to July 2022.
44 AEMO, 'Loss factors and regional boundaries', web page, available at: https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/market-operations/loss-factors-and-regional-boundaries, viewed 21 May 2020.
45 AEMC, *Transmission loss factors*, Fact sheet, November 2019.
46 AEMO, *Regions and marginal loss factors: FY 2020–21*, April 2020.
47 AEMC, *Transmission loss factors, Final determination*, 27 February 2020.
48 AEMC, *Generator technical performance standards rule determination*, Information sheet, September 2018.

Figure 1.16
Two year change in marginal loss factors, 2018–19 to 2020–21




MLF, marginal loss factor; MW, megawatt.
Source: KPMG for the Australian Energy Council, *Marginal loss factors: the state of play in Australia*, May 2020.

prospective generators that their assets may become unprofitable if subsequent parties connect to the network and create congestion. New rules introduced in 2018 help to some extent by requiring new connections to 'do no harm' to local system strength in the network (section 1.4.4).

### Pricing reforms

The AEMC in 2019 proposed pricing reform to address congestion issues.[49] Every generator and customer in a region receives or pays the same price (adjusted for loss factors), which is determined at a single point in the region called the reference node. Under the proposed reform, generators would instead receive a local price based on the marginal cost of supplying electricity in their specific network area. This localised price would account for congestion and losses in that area. Retailers would continue to pay a single regional price. Customers could elect to pay either the local price or a load weighted regional price.

Financial transmission rights would be available for parties to hedge against price differences caused by network congestion and transmission losses. The hedges would effectively pay a generator the difference between the local and regional price. The AEMC argues the combination of local pricing and financial transmission rights would improve incentives for generators to connect to efficient areas of the network, thereby lowering costs to customers. The Council of Australian Governments' (CoAG) Energy Council will consider the AEMC's proposed pricing model as part of the NEM 2025 reform package at the end of 2020.

### Coordinating generation projects

Transmission network providers are receiving an unprecedented volume of generation connection enquiries from renewable projects in various stages of development. While significant information is available about a generator once it connects to the grid, these projects have limited transparency before the generator signs a connection agreement with a network. This lack of transparency can lead to inefficient outcomes. As an example, multiple generators seeking to connect to a network may each invest in separate connection assets, when a shared asset may be more efficient.

Reforms are underway to improve transparency and coordination. AEMO's *Integrated system plan* (first published in 2018 and updated in 2020) provides information to the market on future generation and network requirements over a 20 year horizon. It also identifies efficient hubs for renewables investment. Called renewable energy zones, these hubs are based on assessments of fuel resources, network connections and proposed network upgrades (section 1.6.2). The Energy Security Board in 2020 was progressing reforms to better coordinate decisions on locating new renewable plant, and support efficient network planning to move energy from renewable energy zones to markets.

More generally, new rules effective from December 2019 require network businesses to share connection information about generation proposals with AEMO, which then publishes this information. The rule provides better and more up-to-date information about what generation projects are in the pipeline, to help developers make better investment decisions on where to locate new generators and to assess project viability.[50]

## 1.5.2 Efficient network investment

Current regulatory arrangements for transmission networks raise a number of efficiency issues, including whether cost allocation is efficient, and whether new investment to support the energy market transition is timely.

### Cost allocation

Under current arrangements, transmission investment is paid for mainly by energy customers in the region where new assets locate. But, in cases such as investment in cross-border interconnectors, customers in other regions may benefit most from this investment.

In November 2019 the CoAG Energy Council tasked the Energy Security Board with considering a fair method for allocating transmission costs to better align the costs and benefits of network investment. The AER in 2020 led an Energy Security Board working group looking into this issue. The board will report back to the CoAG Energy Council in mid-2020, with a final report due in September.[51]

### Timeliness of transmission investment

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

49 AEMC, *Coordination of generation and transmission investment proposed access model*, Discussion paper 14, October 2019.

50 AEMC, *Transparency of new projects, Fact sheet*, December 2019.
51 CoAG Energy Council, 'Energy Security Board outcomes from 23rd Energy Council Ministerial Meeting', 27 March 2020, web page, available at: www.coagenergycouncil.gov.au/publications/energy-security-board-outcomes-23rd-energy-council-ministerial-meeting.

Some delays stem from regulatory processes for transmission investment, which can be lengthy.

The CoAG Energy Council in March 2020 agreed to streamline some regulatory processes (such as the AER's regulatory investment test) to fast track strategic transmission projects. This decision followed an earlier change to streamline processes for priority projects identified in AEMO's first integrated system plan. The changes (scheduled to commence in July 2020) would allow some parts of the regulatory process to run concurrently, and avoid duplicating processes such as modeling in cost–benefit assessments (section 1.6.2).[52]

## 1.5.3 Efficient integration of distributed energy resources

Investment in DER by energy customers poses challenges to the power system, in terms of DER's lack of visibility, and variations in controllability and level of performance. If integrated efficiently, DER has a flexible nature that can help delay the need for large scale generation and network investments, and provide new sources of network support and energy management capabilities. The ability to take advantage of these opportunities depends on how well DER—for example, rooftop solar PV systems, household battery systems, and demand response such as home energy management systems—interact with the system. The CSIRO estimated household bills could lower by as much as $400 per year if these resources are optimised.[53]

### Technical issues for distribution networks

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

While grid scale wind and solar generation raise security issues for transmission networks, distribution networks face similar issues as consumers adopt DER and export electricity into the grid. Some networks are experiencing congestion issues as areas of their networks reach capacity limits on the amount of DER that they can host. Those networks with high penetration of rooftop solar PV systems (such as SA Power Networks and Energy Queensland) are experiencing the greatest impacts.[54]

The export of power from solar generation into distribution networks is causing security issues:

- *voltage* issues may arise when electrical pressure reaches its upper threshold as more and more rooftop solar PV units inject power into the grid
- *thermal limits* are reached when wires and other equipment are unable to carry any more power because the equipment has reached its upper temperature limit.

Voltage control can be a major issue for distribution networks in those cities where rooftop solar penetration exceeds 20 per cent of homes (currently Brisbane and Adelaide). The level of demand for grid power in some feeders, or even in whole suburbs, can drop close to zero in the middle of the day when demand is met by rooftop solar PV generation. In 2018 AEMO reported multiple instances of rooftop generation causing deep voltage dips in the middle of the day, requiring it to remove hundreds of megawatts of nearby load from the power system for several minutes at a time.[55]

AEMO published in 2020 a survey on how DER are impacting distribution networks in the NEM, illustrating the range and complexity of these issues.[56] Distribution businesses identified over- and under-voltage issues; problems with inverter setting at customers' premises; and voltage, phase balancing and thermal capacity issues on feeders and at substations. The extent of integration challenges varies by the size and location of PV clusters in each network, relative to physical network characteristics and load. AEMO's survey findings confirmed South Australia and Queensland experience the most significant challenges due to their high uptake of solar PV systems, exacerbated by some cluster areas in these states having generally weaker network capacity.

To mitigate the risk of DER breaching technical limits, the networks set circuit breakers that interrupt supply if those limits are exceeded. But the performance of inverters connecting DER devices to the network has posed challenges in some regions. AEMO estimated around 15 per cent of rooftop systems in Queensland and 30 per cent in South Australia did not meet the Australian standard for inverters. Work is being undertaken to improve performance standards for newly installed inverters.[57]

52 CoAG Energy Council, Energy Security Board, 'Actionable ISP final rule recommendation', 27 March 2020, web page, available at: www.coagenergycouncil.gov.au/publications/actionable-isp-final-rule-recommendation.

53 CSIRO/AEC, *Electricity network transformation roadmap, Final report*, April 2017.

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

55 AEMO *Power system requirements*, March 2018.

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

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



In the longer term, distribution networks require more visibility over DER to manage frequency and voltage stability. Technical standards for DER devices and smart software can help. In addition, AEMO needs to be able to support better load shaping and localised storage requirements.[58]

### Pricing reforms

Pricing is one mechanism that can be used to optimise the benefits of DER. Reforms introduced in 2017 require electricity distribution businesses to progressively move customers onto network tariffs more closely aligned to the costs of providing the services that they use. The reforms reduce network charges at times of low demand, and raise them at times of peak demand when the networks are under strain.

Networks levy the new tariff structures on retailers, which then have discretion to set their charges to customers as they see fit. Retailers are expected to offer a range of products to suit different customer needs and preferences. Some customers may prefer basic 'insurance' style products that charge the customer one price for energy regardless of when it is used. But, for customers with some flexibility in their energy use, retailers may offer incentives for those customers to switch their energy use to times of low demand, and operate DER such as rooftop solar PV systems and batteries in ways that minimise network stress.

Pricing reform is progressing slowly, with most networks initially adopting 'opt in' models for transferring customers to cost-reflective network tariffs. More recently, distributors are starting to require customers to 'opt out' of cost reflective network tariffs. The AER estimates this shift will result in up to half of all residential customers in NSW, Tasmania, the ACT and Northern Territory being on cost-reflective network tariffs by 2024 (figure 1.17).[59]

The limited penetration of smart meters for residential and small business customers is also limiting tariff uptake. Smart meters (or manually read interval meters) are required to measure customers' electricity use across the day. While around 98 per cent of Victorian customers had access to a smart meter, penetration is much lower in other regions. Outside Victoria, Ausgrid (NSW) had the highest penetration of smart or interval meters at February 2020, at 34 per cent of small customers. In other networks, 10–15 per cent of small customers had a smart or interval meter.

The AER supports network pricing reform through its demand management incentive scheme and demand management innovation allowance (section 3.10.7).

### Pricing of DER exports to the grid

Pricing reforms to date mainly focus on network charges for the use of poles and wires to transport electricity from the grid *to* the consumer. At present, distribution networks cannot charge DER owners for exporting electricity back into the network, beyond a basic charge to connect to the network.

Forward and reverse power flows through a distribution network fluctuate widely during the day. This fluctuation can impact the quality and reliability of power supplies at certain times, especially during periods of very high or low demand, when voltage instability is more likely. These costs affect all customers but are not charged to DER owners, so are not factored into DER investment decisions.

As solar penetration increases to levels that cause network constraints, distributors have the option of expanding the network, and recovering the costs from all consumers through higher charges. But network augmentation is costly. Some consumer groups argue the approach is also inequitable, with the cost of DER integration being borne by all consumers regardless of whether they own DER.[60] Nevertheless, customer research conducted by AusNet Services' found support for sensible investment to allow solar exports, with the cost to be shared among all customers and with government.[61]

Some distributors are managing network constraints by restricting DER exports in constrained parts of their network, with some customers facing very low or zero export limits in areas with high levels of solar penetration.

While scope exists for technical solutions in the short term, the AEMC found flexible export limits offer an alternative. Instead of applying a low static export limit to all consumers (as occurs now), this approach recognises technical issues caused by DER exports to the grid occur infrequently, so blanket restrictions are inefficient. Distributors with a high level of DER penetration, such as SA Power Networks, have already proposed flexible export limits.

In the longer term, the AEMC proposed a 'use of system charge' for DER exports as part of an efficient solution. Network charges for the use of poles and wires to transport electricity could apply to exports to the grid, and to energy taken from it. The reforms could accompany options for

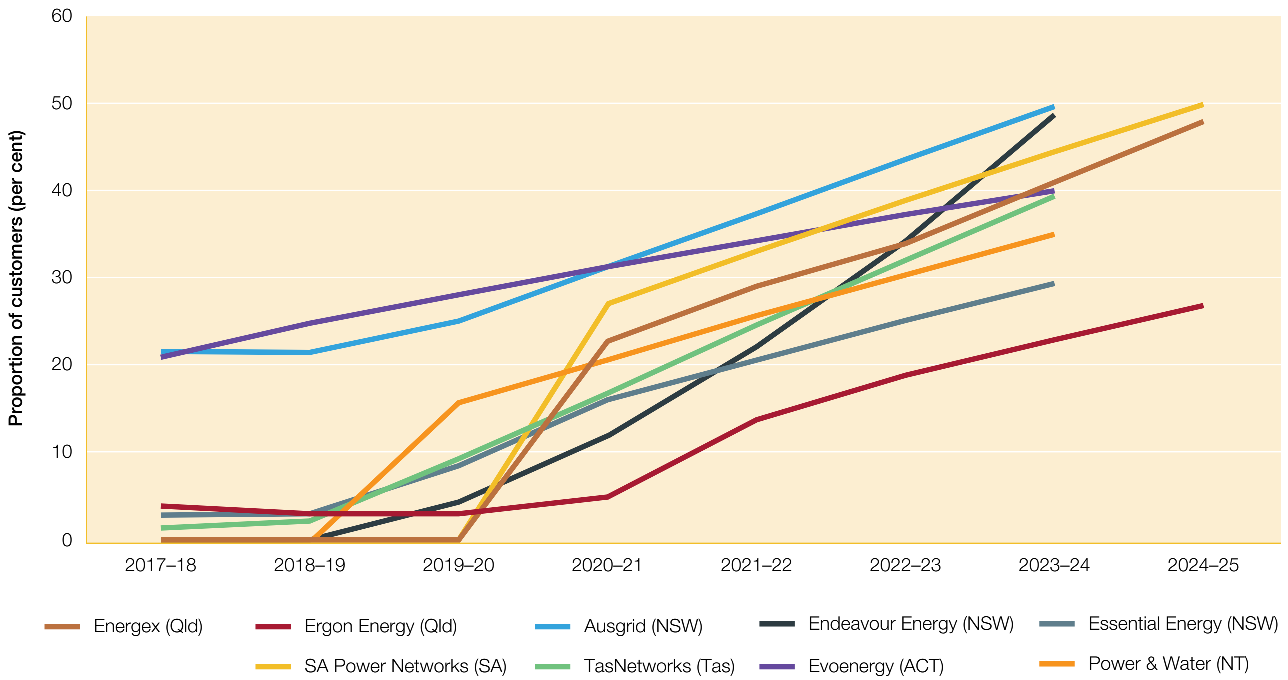
58 Energy Security Board, *Health of the National Electricity Market 2019*, February 2020.

59 AER estimate. Outcomes will depend on the rate at which smart meters are installed for new connections. Source: AER, 'Network tariff reform', web page, available at: www.aer.gov.au/networks-pipelines/network-tariff-reform, viewed 1 April 2020.

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

61 AusNet Services, *2021–2025 Electricity distribution price review, Customer forum final engagement report*, 2020, p. 14.

Figure 1.17
**Projected assignment of cost-reflective tariffs for residential customers**




Source: AER estimates based on distribution network business data.

customers to choose a level of 'firmness'—such as rewards for their solar panels being constrained from exporting to the grid when the network is under pressure.[62]

### DER visibility

More issues arise from DER's inherent lack of visibility, which compromises the market operator's ability to understand DER behaviour and manage the power system. AEMO and Australian distributors have little real time visibility of PV systems less than 5 MW.

As synchronous generators retire, the NEM increasingly relies on emergency control schemes to manage fluctuations in system frequency. Such schemes rely on the visibility of loads and generation to work effectively. But residential rooftop solar PV systems can blur this visibility. Activation of a scheme to disconnect load may unintentionally disconnect distributed generation as well, which could further destabilise frequency and disconnect more loads than intended.

More generally, as passive DER (rooftop solar PV generation) increases, the controllability of the power system reduces.

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

The NEM currently has no means to actively control residential DER, even in emergency situations.[63]

In response to these issues:

- new arrangements announced in September 2018 require AEMO to establish a register of DER in the NEM. The register will give network businesses and AEMO visibility of where DER are connected, to help plan and operate the power system as it transforms.
- demand response and virtual power plant trials are exploring how DER behaves during disturbances, and developing a database of DER installations
- the CoAG Energy Council in March 2020 agreed to incorporate DER technical standards into the National Electricity Rules, and make them nationally consistent through complementary measures across the jurisdictions.[64] The new technical standards will aim to improve DER performance to support energy system security.

63 AEMC Reliability Panel, *2019 annual market performance review, Final report*, March 2020.
64 CoAG Energy Council, 'Energy Security Board outcomes from 23rd Energy Council Ministerial Meeting', 27 March 2020, web page, available at: www.coagenergycouncil.gov.au/publications/energy-security-board-outcomes-23rd-energy-council-ministerial-meeting.

### Demand response technologies

DER can help manage power system disturbances by, for example, aggregating resources into virtual power plants. Automated technologies could help consumers respond to dynamic pricing signals, shifting their use away from high demand periods to when power is available at a lower cost.

As an example, affordable automated home energy management systems with 'set it, forget it' technologies could allow consumers or their service providers to pre-program use parameters that limit adverse effects on their lifestyles. Equipment, appliances and software are already available that use emerging smart grid technologies to save energy and seek the lowest energy rates. Specific loads such as electric hot water, pool pumps and air conditioners can be controlled remotely to reduce costs without significantly impacting consumers' amenity.

These trends will be accelerated by the entrance of new service providers marketing home energy management services. To optimise benefits to consumers, smart home energy management systems need to have access to real time information on network constraints and dynamic operating envelopes, and to price signals at the wholesale level.

The AER supports distribution networks in undertaking innovative projects in this area, through its demand management innovation allowance and demand management innovation scheme (section 3.10.7).

## 1.6 Coordinated reforms

Generation investment equivalent to the current size of the NEM (50 GW) is expected to occur over the next two decades.[65] Coupled with a significant proportion of conventional generation in the NEM retiring over this period, strategic planning is increasingly being used to coordinate the market's requirements to ensure efficient investment in generation plant and network capacity.

Two related processes focusing on the issues at a high level are:

- the AEMC's Coordination of Generation and Transmission Investment (CoGaTI) review, which examines how best to coordinate incentives for investment across both the generation and transmission sectors
- AEMO's integrated system plan, which is a long term plan of the NEM's transmission requirements to support and accommodate the transformation of the energy sector.

65 AEMO, *Draft 2020 integrated system plan*, December 2019.

A longer term reform initiative is the Energy Security Board's work to develop a new market framework (NEM 2025) to apply from the mid-2020s. This work is at an early stage.

Other high level policy workstreams with implications for electricity markets are gas reform and initiatives to develop a hydrogen industry in Australia.

### 1.6.1 Coordination of generation and transmission investment

Policy bodies are progressing reforms to better coordinate planning and investment in transmission and generation, to ensure new assets are built in the right place, at the right time, to serve the long term interests of consumers. The reforms (many of which are discussed in section 1.5) include:

- introducing transmission access reforms to strengthen price signals for generators to more efficiently locate and operate new plant
- facilitating renewable energy zones so clusters of generators can share the costs of connecting to the shared transmission network, or contribute to wider network improvements
- more closely allocating transmission costs to the parties that benefit from it
- simplifying the process for large scale storage systems to connect to the grid
- streamlining regulatory approvals for strategic transmission projects.

The AEMC is developing a model for transmission access reforms. It proposes that generators would receive a local price that reflects generation costs and congestion at their location. Generators would also have access to new products (financial transmission rights) to manage the risks of congestion and transmission losses (section 1.5.1). The CoAG Energy Council will consider the AEMC model as part of the NEM 2025 reform package at the end of 2020.

In 2020 the Energy Security Board was progressing rule changes to support the development of renewable energy zones. The process will include a staged development plan for each priority zone and trial rules for the connection of generators within the zones.

### 1.6.2 Integrated system plan

The integrated system plan (ISP) is a roadmap for the efficient future development of the NEM over a 20 year horizon. The first plan—published by AEMO in 2018 and updated in 2020—arose from recommendations in the Finkel review, following a statewide blackout of South Australia in September 2016.[66]

The ISP forecasts where and when network investment is likely to be needed to accommodate the large amount of new generation likely to connect to the grid in coming years. The 2018 plan focused on upgrading transmission interconnection in targeted locations to promote efficient sharing of energy, storage, and backup supply generation across regions, to reduce energy costs and enhance reliability and security. The draft 2020 plan updates and reclassifies some projects, but its direction is largely unchanged.

The draft 2020 plan forecast by 2040:

- small scale rooftop solar PV generation capacity will likely double or triple
- over 30 GW of new grid scale renewables will likely be needed to replace coal fired generation as it retires, supported by up to 20 GW of flexible, dispatchable resources such as pumped hydro and battery storage. If gas prices materially reduce, then new gas generators may also form part of the mix.
- innovative power system services will be needed to manage security issues such as voltage control, system strength, frequency control and power system inertia
- the transmission grid will require targeted augmentation (including new interconnectors and energy storage) to balance resources and unlock renewable energy zones.

The 2020 draft ISP identified over 15 projects for augmenting the transmissions network in eastern and southern Australia. The projects fall into three groups, by priority. Projects identified for immediate development (if not already underway) include:

- a new interconnector between NSW and South Australia (EnergyConnect) aimed at unlocking stranded renewable investments
- a new interconnector between NSW and Victoria, aimed at accessing planned new capacity at Snowy Hydro and unlocking renewable energy resources in western and north west Victoria
- minor upgrades to the Queensland–NSW and Victoria–NSW interconnectors
- reinforcements to the network in southern NSW to increase transfer capacity from Snowy Hydro to NSW demand centres.

AEMO recommended assessing and planning other major (but less time critical) projects, including a new Tasmania–Victoria interconnector (Marinus Link), upgrades to the Queensland–NSW interconnector supported by grid reinforcements, and infrastructure to support renewable energy zones.

The CoAG Energy Council in March 2020 agreed on an action plan developed by the Energy Security Board to action the ISP and integrate it with existing planning processes. The plan covers, for example, a streamlined process for the AER's regulatory investment test (a cost–benefit test for assessing the efficiency of network investment proposals) for ISP projects.[67]

### 1.6.3 NEM 2025

The CoAG Energy Council has tasked the Energy Security Board with advising on a long term, fit-for-purpose market framework that could apply from the mid-2020s, to support energy reliability and security, and emission reductions. The plan (NEM 2025) will consider opportunities and challenges, including:

- incentivising timely and efficient generation investment (including the right level and mix of technologies), and coordinating it with transmission investment to integrate renewable energy into the grid in a way that maintains system security and reliability
- optimising the contribution of DER to efficiency, security and reliability outcomes
- identifying additional security services such as frequency, inertia and system strength that may be needed in future, and how best to source and pay for those services.

In April 2020 the Energy Security Board identified market frameworks that could meet the project objectives of NEM 2025:

- *Two sided markets*, where consumers signal the value that they place on energy and are active in responding to wholesale prices. Consumer behaviour under this model is transparent, with real time information used to keep the power system operating securely and reliably.[68] This model would build on the wholesale demand response mechanism to be launched in October 2021.
- *'Ahead' markets*, where electricity supply and demand are scheduled (sold) ahead of the real time market. This model provides AEMO with greater visibility of energy market needs and, and it also allows the time to plan accordingly.
- *System services markets*, for products that are not currently valued. They include markets for operating reserves, frequency management (through synchronous inertia and fast frequency response) and system strength.[69]

The Energy Security Board will release a detailed analysis by the end of 2020 on a package of measures to adapt the existing market design.

### 1.6.4 Gas market reform

The launch of Australia's LNG industry, combined with structural issues in the domestic gas market, put significant pressure on domestic gas prices. This price pressure posed challenges for gas powered generation, which had been widely viewed as a key transition technology as coal fired plants close and more renewable generation comes online.

Government initiatives in Australia, including the Australian Domestic Gas Security Mechanism, increased domestic gas supply and eased price pressures, but structural issues in the market remain.[70] Legacy gas fields in southern Australia continue to deplete, and the status of new gas resources is unclear. In some states and territories, community concerns about environmental risks associated with fracking have led to legislative moratoria and regulatory restrictions on onshore gas exploration and development (section 4.10.1).

Gas pipeline access has been another structural issue in the market. Access to transmission pipelines on key north–south transport routes is critical to moving gas to demand centres. But gaining access to pipeline capacity has proved difficult for some customers.

In response to this issue:

- the AER in 2018 began publishing new data on prices and liquidity in gas markets to make wholesale gas markets more transparent for customers
- reforms to the Gas Bulletin Board widened reporting coverage of gas production, pipelines and storage options
- reforms making it easier for gas customers to gain access to underused capacity on transmission pipelines took effect in 2019. The AER monitors and enforces compliance with the reforms, which include a voluntary trading platform, backed by the mandatory day-ahead auction of all contracted capacity that is not in use. Early indications are that the reforms have improved transparency and flexibility in the domestic gas market (section 4.10.4).

### 1.6.5 Hydrogen

Hydrogen is derived primarily by splitting water or by reacting fossil fuels with steam or controlled amounts of oxygen. It can be stored as a gas or liquid, and retains roughly 80 per cent of the energy value of electricity used to produce it, giving it potential as a form of large scale electricity storage.

Hydrogen's storage potential gives it scope to offer electricity reliability and stability services. Grid connected electrolysers (which are energy intensive electrical loads) can be used to quickly ramp up or down the production of hydrogen, to manage fluctuations in renewable generation.

Hydrogen can also be stored in gaseous form in pipelines at concentrations of up to 10 per cent. Potentially, gas distribution networks could blend hydrogen with gas, and eventually transition to hydrogen as a fuel for heating and other industrial feedstock. The CSIRO outlined opportunities for hydrogen to compete favourably on a cost basis by 2025 in Australian applications such as transport and remote area power systems.[71]

In November 2019 the CoAG Energy Council released the National Hydrogen Strategy, with a focus on removing market barriers and efficiently building supply and demand. State governments have also announced initiatives. In 2019 the South Australian and Tasmanian governments established hydrogen plans to explore opportunities for using or exporting hydrogen, provide funding for pilot projects, and establish frameworks and infrastructure.

66 Dr Alan Finkel AO, Karen Moses, Chloe Munro, Terry Effeney and Professor Mary O'Kane, *Independent review into the future security of the National Electricity Market: blueprint for the future* (Finkel review), 2017.

67 CoAG Energy Council, 'Energy Security Board outcomes from 23rd Energy Council Ministerial Meeting', 27 March 2020, web page, available at: www.coagenergycouncil.gov.au/publications/energy-security-board-outcomes-23rd-energy-council-ministerial-meeting.

68 AEMC, 'What next for a two sided market? The implications of venturing behind the meter', Media release, 20 April 2020.

69 Energy Security Board, *System services and ahead markets*, April 2020, available at: https://prod-energycouncil.energy.slicedtech.com.au/sites/prod.energycouncil/files/System%20services%20and%20ahead%20markets%20paper%20-%20COAG%20April%202020.pdf.

70 Department of Industry, Science, Energy and Resources, 'Australian Domestic Gas Security Mechanism', web page, available at: www.industry.gov.au/regulations-and-standards/australian-domestic-gas-security-mechanism.

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

ARENA is supporting a number of demonstration scale renewable hydrogen projects, and 16 research projects. This support includes funding for a Jemena project to produce hydrogen from renewable energy, for injection into the Sydney gas network.[72] The trial will inject a majority of the hydrogen for domestic use, with a portion used for gas powered electricity generation. Some hydrogen will be stored to refuel hydrogen vehicles.

On an international scale, a pilot project in Victoria's Latrobe Valley is demonstrating the full hydrogen supply chain, from production through to export to Japan. The four year project uses a world first purpose-built liquefied hydrogen carrier, and is the world's largest hydrogen demonstration project.[73]

The largest commercial green hydrogen project currently proposed for Australia is a 15 GW wind and solar project in the Pilbara in Western Australia. Up to 3 GW would be dedicated to large energy users in the region, such as mines and mineral processing facilities, while 12 GW would be used to produce green hydrogen for domestic and export markets. Construction is forecast to commence in 2023–24, with first generation in 2025–26.

## 1.7 Government initiatives

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

While government intervention can help manage an identified market issue, its wider market impacts are complex. In particular, intervention can distort market signals, affecting private sector investment decisions. The Energy Security Board argued, for example, government intervention intended to improve reliable supply may also distort the market and lower investor confidence.[74]

The AER in December 2018 reported views of energy market participants that a lack of stability and predictability in government energy policy is a barrier to entry for new generation. Emission policy instability, interventions to address energy policy objectives such as reliability and affordability, and government ownership in the industry were cited as key impediments to investment in the NEM.[75]

72 ARENA, 'Hydrogen to be trialled in NSW gas networks', Media release, 22 October 2018.
73 CoAG Energy Council, *Australia's National Hydrogen Strategy*, November 2019.
74 Energy Security Board, *Health of the National Electricity Market 2019*, February 2020.
75 AER, *Wholesale electricity market performance report*, December 2018.

### 1.7.1 Incentivising private capacity investment

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

#### Underwriting new generation investment

Alongside ongoing funding schemes run by ARENA and the Clean Energy Finance Corporation (CEFC) (box 1.1), the Australian Government launched the Underwriting New Generation Investments program (UNGI) in 2019. The program offers incentives for 'firm' and 'firmed' capacity targeted at lowering prices, increasing competition and increasing reliability. It is stated to be technology neutral, and may include upgrades or life extensions to existing generators. The multi-phased program runs over four years to June 2023.

UNGI support may take various forms. It may include, for example, a guaranteed floor price, contracts for difference, collar contracts, government loans, and other mechanisms. Shortlisted projects may be eligible for support from the Grid Reliability Fund, which the CEFC administers.[76]

The first registrations of interest led to a shortlist of 12 projects, including six pumped hydro projects, five gas projects, and a proposed upgrade of the Vales Point black coal fired generator. From the shortlist, the Australian Government announced two successful projects in January 2020:

- APA Group's proposed 220 MW gas generator in Victoria to provide fast start generation to balance the increase in intermittent renewables in that state
- Quinbrook Infrastructure Partners' 132 MW gas generator in Queensland to help meet peak demand in Queensland and NSW, increase competition, and complement an upgrade to the Queensland–NSW interconnector.[77]

The government previously announced a commitment to develop an underwriting mechanism through the UNGI program for the Battery of the Nation scheme (section 1.7.2).

76 The government will refer UNGI projects to the Grid Reliability Fund only if the referral reflects the CEFC's legislative mandate. The CEFC will not invest in coal projects.
77 The Hon. Angus Taylor MP (Minister for Energy and Emissions Reduction), 'Initial support terms for two new generation projects agreed', Media release, 23 December 2019.

#### Queensland generation feasibility studies

In February 2020 the Australian Government committed funding for a feasibility study into new generation projects in central and northern Queensland. It allocated:

- $4 million to Shine Energy to conduct a feasibility study for a 1 GW 'high efficiency low emissions' coal plant at Collinsville. Shine Energy is seeking government indemnity against a future carbon price.
- $2 million to a pre-feasibility study for a 1.5 GW pumped hydroelectric plant located between Collinsville, Proserpine and Mackay.

The two projects are partly targeted at adding new synchronous generation to address system strength issues in the region (section 1.4.3). If found to be viable, they may be eligible for underwriting through the Australian Government's UNGI program.

### 1.7.2 Public investment in generation capacity

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

#### Snowy 2.0

Among major initiatives, the Australian Government undertook a feasibility study in 2017 for expanding Snowy Hydro (which it owns) by using pumped hydroelectric technology (figure 1.18). The proposal would increase Snowy Hydro's pumped hydroelectric generation capacity by around 2000 MW—a rise of 50 per cent. A final investment decision was made in late 2018, and a contractor was appointed in 2019.

Snowy Hydro's sole shareholder is the Australian Government, after the government purchased the NSW and Victorian governments' shares in March 2018.

The Snowy 2.0 project will construct an underground power station and about 27 kilometres of power waterway tunnels to link the existing Tantangara and Talbingo reservoirs. The underground power station will pump water from the Talbingo reservoir to the Tantangara reservoir when electricity prices are low. When prices are high, it will generate electricity by releasing water from the Tantangara reservoir to flow down through the underground power station back to the Talbingo reservoir.

The proposal adds 2000 MW of energy generation and 175 hours of storage to the NEM. The $5 billion project is forecast to start producing power from the first of six new generators by late 2024.

#### Battery of the Nation

The Australian and Tasmanian governments in April 2017 announced a feasibility study into expanding the Tasmanian hydroelectric system. The expansion would deliver up to 2500 MW of additional capacity through pumped storage and possible expansions of the Tarraleah and Gordon power stations.

#### CleanCo

The Queensland Government in December 2018 launched CleanCo, a state owned corporation focused on meeting Queensland's 50 per cent renewable energy target by 2030, supporting secure and reliable electricity generation, and creating investment and jobs in regional Queensland. CleanCo has a particular focus on low and zero emission technology. Initially, 1000 MW of capacity from hydroelectric and gas power stations transferred to CleanCo from other state owned generators. The Queensland Government will fund CleanCo's investment in a further 1000 MW of renewable capacity by 2025. That investment will involve a mix of building, owning and operating its own assets, and investing in private sector projects.

#### Hornsdale

The South Australian Government developed diesel (convertible to gas) generation and battery storage, including the 100 MW Hornsdale Power Reserve—the first scheduled battery in the NEM. The battery has helped lower the cost of frequency control services in the region. Its capacity was expanded to 170 MW in 2020.

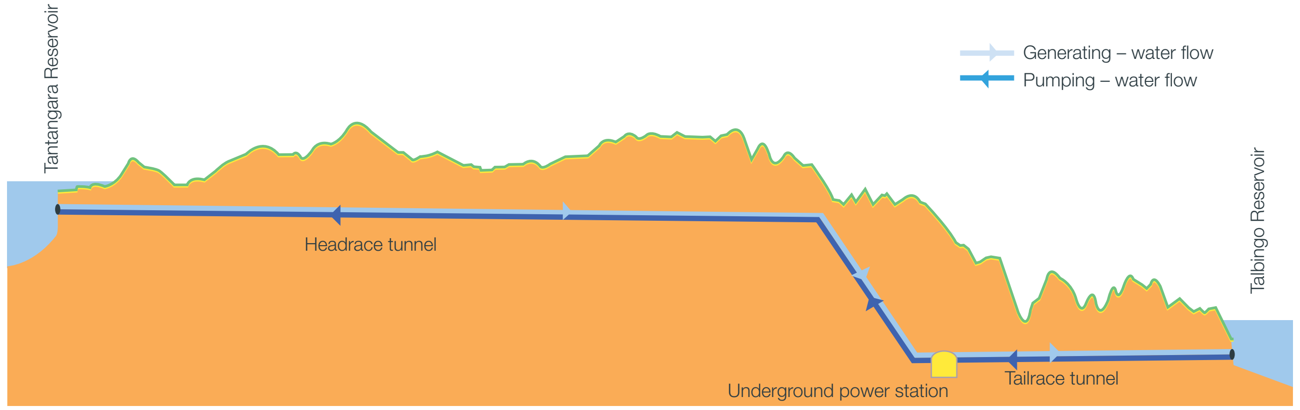
#### NSW electricity strategy

The NSW Government launched a new electricity strategy in November 2019.[78] The strategy has three key elements:

- grants to support grid scale electricity generation and storage projects, to diversify the NSW electricity mix and drive competition in the wholesale market
- support for renewable energy zones, which includes (where appropriate) changing regulatory settings to incentivise generators to cover part of the cost of building new transmission assets. The initial focus will be on a 3000 MW pilot zone in the state's central west.

78 Prime Minister of Australia and Premier of New South Wales, 'NSW energy deal to reduce power prices and emissions', Media release, 31 January 2020.

Figure 1.18
**Snowy 2.0**




Note: Illustration not to scale.

Source: Snowy Hydro.

- a NSW-specific reliability target, accompanied if necessary by additional support (through grants or contracts for output) for new generation, and by fast tracking of priority transmission projects. The NSW Government may also use its emergency response powers and processes.

The strategy follows an earlier NSW Transmission Infrastructure Strategy that looked to accelerate four transmission projects to improve interconnection with Queensland, Victoria, South Australia and the Snowy region.

The Australian governments will support elements of the strategy, along with initiatives to:

- ensure reliability following the planned exit of the Liddell power station, and ensure long term access to coal for the Mount Piper power station
- inject another 70 petajoules (PJ) of gas per year into the NSW market
- ensure access to the $1 billion federal Grid Reliability Fund
- guarantee support for three NSW generation projects under the federal UNGI program.[79]

### Victoria

The Victorian Government in February 2020 introduced legislation to fast track priority projects such as grid scale batteries and transmission upgrades. Amendments to the *National Electricity (Victoria) Act 2005* will allow the government to override the national framework on transmission approvals—the government argues that the framework excessively delays the delivery of transmission projects and fails to account for the full benefits of investments. The changes will focus on projects that increase the state's capacity to import electricity during periods of peak demand.

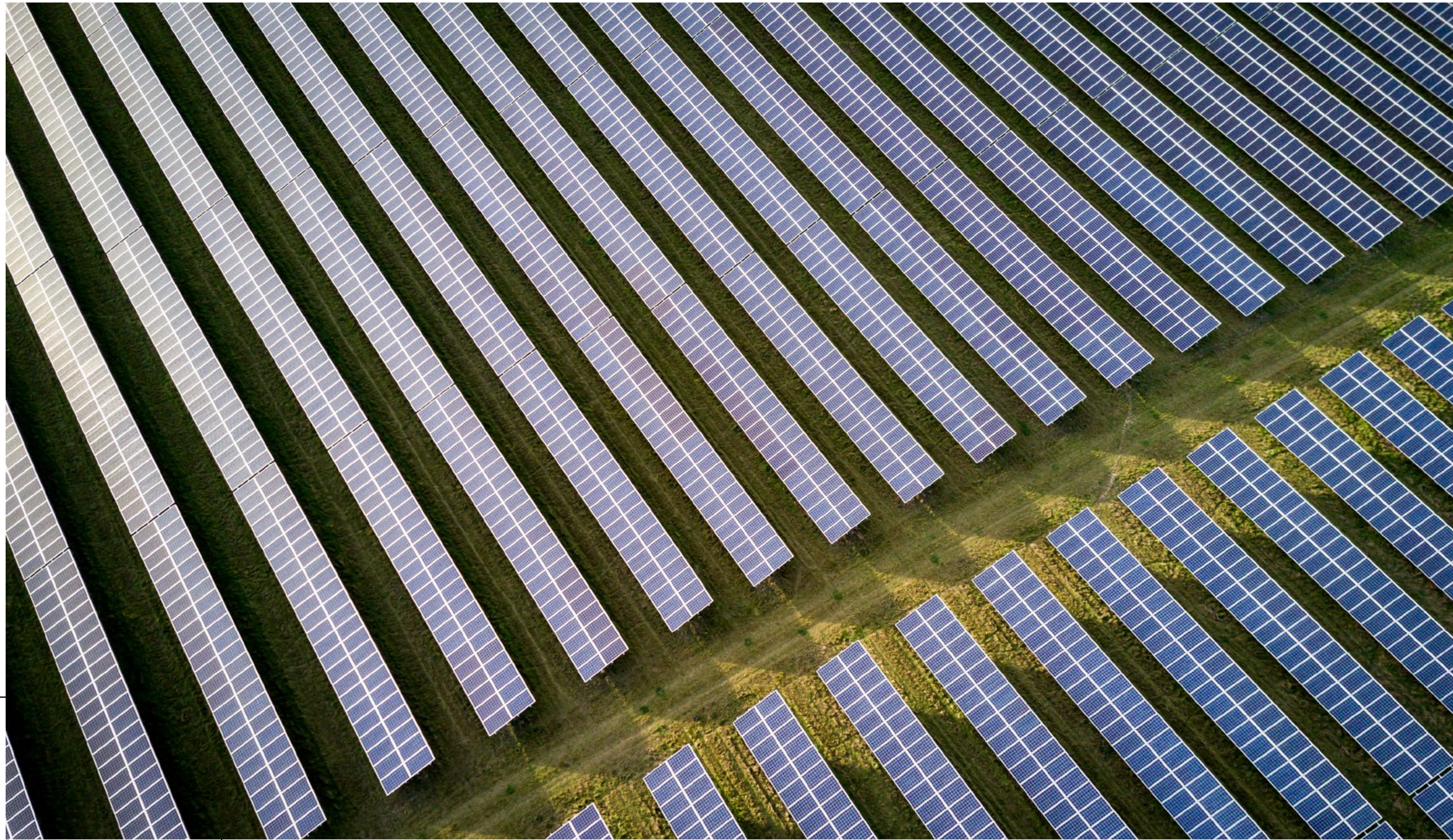
The Victorian Government will work in consultation with AEMO to implement the changes, with an initial focus on expanding the capacity of the Victoria–NSW Interconnector.

The government linked its intervention to the grid's increasing vulnerability to extreme heat, which is causing unprecedented demand for electricity. That demand is putting pressure on the state's ageing coal fired generators, and making the transmission network more vulnerable to bushfires and severe weather events.[80]

79 The Hon. Angus Taylor MP (Minister for Energy and Emissions Reduction), 'Backing reliable energy for commercial and industrial users', Media release, 8 February 2020.

80 Minister for Energy, Environment and Climate Change (Victoria), 'Victoria acts to secure a more reliable energy system', Media release, 18 February 2020.

Source: Shutterstock



# 2 NATIONAL ELECTRICITY MARKET

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

Around 200 large power stations produce electricity for sale into the NEM. A transmission grid carries this electricity along 43 000 kilometres of high voltage power lines and cables to industrial energy users and local distribution networks. Energy retailers complete the supply chain by purchasing electricity from the NEM, and packaging it with transmission and distribution network services for sale to over 10 million residential, commercial and industrial energy users. Infographic 1 shows the electricity supply chain.

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

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

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

## 2.1 Electricity consumption

The market operator defines electricity demand as electricity supplied through the transmission grid, with rooftop solar PV output treated as an offset against demand (because it replaces electricity that would otherwise be supplied through the grid). To avoid confusion, this report refers to that demand as 'grid demand'. Consumption is a wider concept covering the total amount of electricity used, including both grid and rooftop PV generation.

Over 10 million residential and business customers consume electricity across the NEM's five regions. Overall consumption increased steadily from 2014 to almost 206 terawatt hours (TWh) in 2019—its highest level since 2011 (figure 2.2).

The expansion of Queensland's coal seam gas (CSG) and liquefied natural gas (LNG) industries accounts for much of the growth in electricity use since 2014. Elsewhere, consumption moderately increased in NSW, remained flat in South Australia and Tasmania, and fell in Victoria over this period.

Most electricity consumed in the NEM is produced by large generators, sold through a wholesale market, and transported through a network grid to customers. Total grid demand peaked in 2008 at 211 TWh. Following several years of decline, demand levelled out from 2013. Demand in 2019 totalled 195 TWh, similar to levels in the previous six years.

Demand patterns are changing as more electricity customers generate some of their own electricity needs through rooftop solar PV systems. By January 2020 over 2 million households and businesses in the NEM had installed solar PV systems to produce electricity. These systems met around 5 per cent of total energy requirements in the NEM in 2019.

Consumption of grid supplied electricity in the NEM is forecast to decline marginally over the next decade. The Australian Energy Market Operator (AEMO) forecast that rises in consumption associated with population growth and increased mining activity will be more than offset by improvements in energy productivity, growth in rooftop PV and other non-scheduled generation, and a gradual shift away from energy intensive industries.[1]

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

### 2.1.1 Maximum grid demand

The demand for electricity varies by time of day, season and ambient temperature. Daily demand typically peaks in early evening when business and residential use overlap, while seasonal peaks occur in winter (driven by heating loads) and

1 AEMO, *2019 electricity statement of opportunities*, August 2019, p. 8.

## Box 2.1 How the National Electricity Market works

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

**Table 2.1 NEM at a glance**

| | |
|---|---|
| Participating jurisdictions | Qld, NSW, Vic, SA, Tas, ACT |
| NEM regions | Qld, NSW, Vic, SA, Tas |
| NEM installed capacity (including rooftop solar)[1] | 60 824 MW |
| Number of large generating units | 268 |
| Number of customers[2] | 10 million |
| NEM turnover 2019 | $18.6 billion |
| Total electricity consumption 2019[3] | 205.5 TWh |
| National maximum demand 2019[4] | 33 941 MW |

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

1. At January 2020.
2. Customers are at the second quarter of 2019–20, except for Victoria, which reported customers in 2018–19.
3. Includes energy met by the grid and rooftop PV generation.
4. The maximum historical summer demand of 35 551 MW occurred in 2009. The maximum historical winter demand of 34 422 MW occurred in 2008.

Source: AER; AEMO; Clean Energy Regulator; Energy Made Easy website (energymadeeasy.gov.au); Victorian Essential Services Commission.

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

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

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

Generators are paid at the *settlement (or spot) price*, which is the average dispatch price over 30 minutes. All dispatched generators are paid at this price. A separate spot price is determined for each of the five NEM regions. Prices are capped at a maximum of $14 700 per megawatt hour (MWh) in 2019–20. A price floor of –$1000 per MWh also applies. The market cap increases in line with the consumer price index (CPI) each year, but the market floor price remains unchanged.

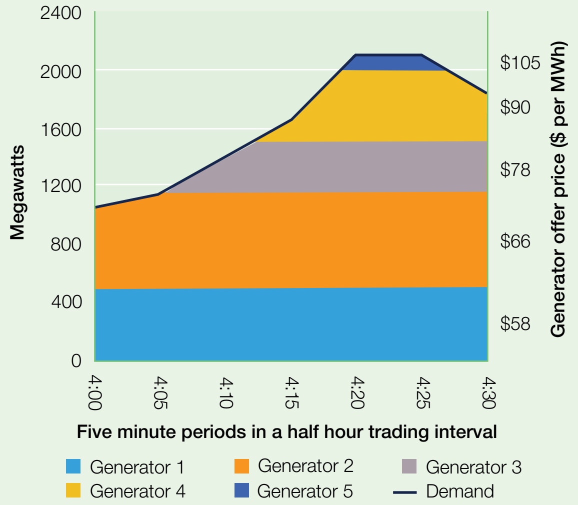
Figure 2.1 illustrates how prices are set. In the example, five generators offer capacity in different price bands between 4.00 pm and 4.30 pm. At 4.15 pm the demand for electricity is 1650 megawatts (MW). To meet this demand, generators 1, 2 and 3 must be fully dispatched, and generator 4 is partly dispatched. The dispatch price is $90 per MWh. By 4.20 pm demand has risen to the point where a fifth generator is needed. This generator has a higher offer price of $105 per MWh, which becomes the dispatch price for that 5 minute interval. The settlement price paid to all dispatched generators for the half hour trading interval is the average of the six dispatch prices over the half hour period—around $89 per MWh.

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, so AEMO deploys more expensive (out of merit order) generators instead.

### Power system management

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

Figure 2.1
**Setting the spot price**



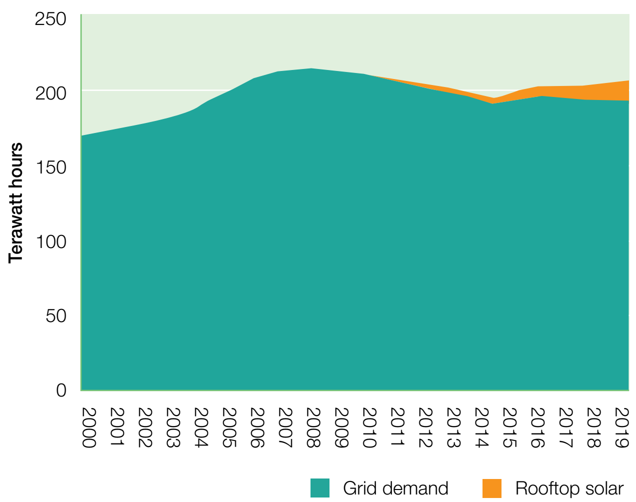

AEMO procures some stability services (such as frequency control) in markets to keep the power system secure. The services are offered by generators and storage facilities that can rapidly adjust output, and demand responders that can rapidly adjust their energy use.

Generators and other participants can offer both energy and stability services into the market. AEMO 'co-optimises' the supply of both services so overall costs are minimised.

Security services such as inertia and system strength are not procured in markets. Instead, AEMO overrides the market's normal operation when issues arise in these areas—for example, it may constrain from operation a generator that contributes to the problem, or direct a generator to operate if it could help alleviate the problem (even if the generator is not the lowest cost available plant). Such interventions are costly, and ultimately consumers pay for them (section 1.4.3).

AEMO can also intervene in the market to manage reliability risks, typically by contracting with back-up generators to ensure reserves are available, or by paying large energy customers to cut their energy use to ease demand (section 2.9.1). If a threat of unserved energy cannot otherwise be avoided, AEMO may direct generators to provide additional supply. If all other avenues have been exhausted, and insufficient generation is available (or cannot be dispatched quickly enough), AEMO may instruct a network business to 'load shed'—that is, temporarily cut power to some customers. This action is rare.

Figure 2.2
**Electricity consumption in the NEM**




Note: Grid demand is operational demand (including scheduled and semi-scheduled generation, and intermittent wind and large scale solar generation). Rooftop solar consumption is based on generation estimates by AEMO.

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

summer (for air conditioning). Demand normally reaches its maximum on days of extreme heat, when air conditioning loads are highest.

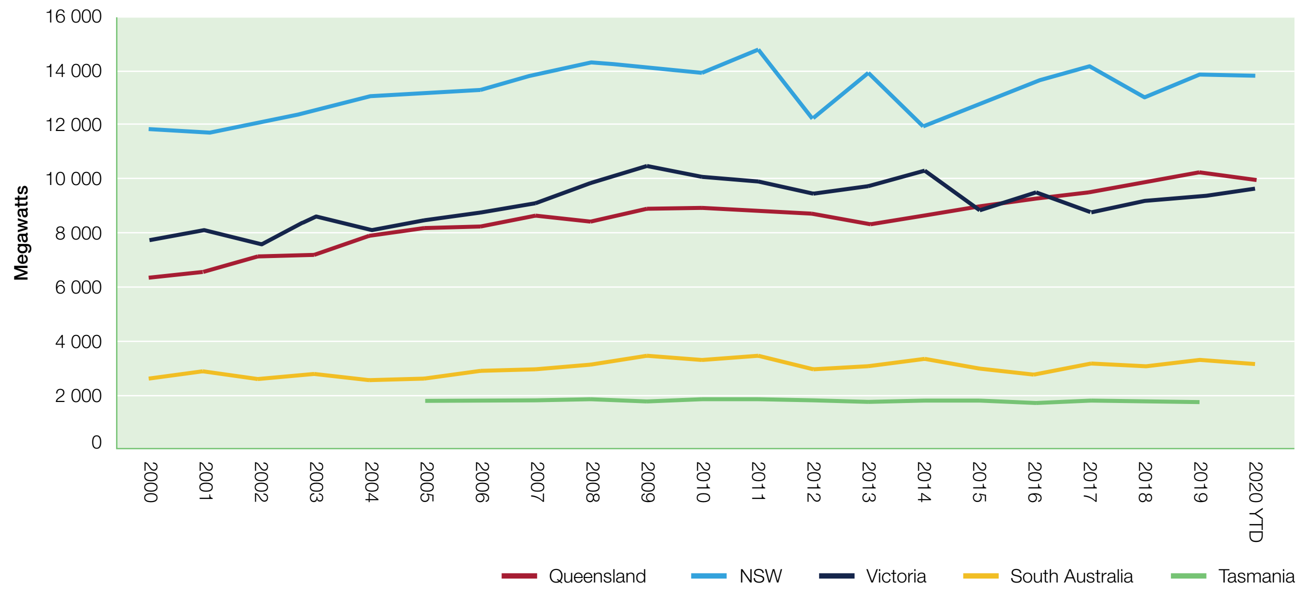
Maximum demand for grid sourced electricity rose steadily until 2009, but then flat lined or declined in all regions except Queensland (figure 2.3). Outcomes in 2019 and early 2020 varied by region. Queensland continued its almost unbroken trend of rising maximum demand, setting a new record on 13 February 2019 during a prolonged heatwave. But, in the 2019–20 summer, Queensland's maximum fell for the first time since 2013.

Victoria, NSW and South Australia also experienced higher maximum demand in 2019 than a year earlier, partly due to a warm summer driving air conditioning use and higher industrial demand for power. Maximum demand fell slightly in Tasmania. The maximums in all regions were well below historical peaks. In the 2019–20 summer, Victoria was the only state with a higher maximum demand than a year earlier.

Maximum demand over the next 10 years is forecast to rise steadily in Queensland, remain flat in NSW and South Australia, and to fall in Victoria. Tasmanian



Figure 2.3
**Maximum grid demand, by region**




YTD, year-to-date.

Note: Maximum operational grid demand (including scheduled and semi-scheduled generation, and intermittent wind and large scale solar generation) is for any time during the year. Data exclude consumption from rooftop solar PV systems. The 2020 year-to-date data include all intervals to 31 March 2020. Tasmania's 2020 maximum is not shown, because Tasmania's maximum demand occurs in winter (from heating loads).

Source: AER analysis of AEMO data.

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

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

Our work in the sector is wide ranging and includes:

- from 1 July 2019, administering and monitoring compliance with the Retailer Reliability Obligation, including participants' activity in electricity contract markets
- reporting on the effectiveness of competition in the NEM. Our second competition report is scheduled for release in late 2020.
- publishing our *Wholesale markets quarterly report,* which launched in November 2019
- publishing the annual *State of the energy market* report, along with interim data updates.

We also monitor the markets to ensure participants comply with the National Electricity Law and 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.

Alongside our wholesale market activity, the AER is the economic regulator for electricity networks in NEM jurisdictions (chapter 3). In retail markets, we hold wide ranging responsibilities in jurisdictions that have passed the National Energy Retail Law—namely, NSW, Queensland, South Australia, Tasmania and the ACT (chapter 6).

maximum demand is forecast rise over the next two years then flatten.[2]

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

### 2.1.2 Minimum grid demand

Historically, electricity demand reached its lowest point in the middle of the night, when most people are sleeping. But the growth of rooftop solar PV capacity means households are exporting electricity to the grid in the middle of the day when the sun is at its highest point. This trend is lowering daytime grid demand, to the extent that minimum grid demand increasingly occurs in the middle of the day. This shift is being driven not by low electricity consumption, but by rising 'behind-the-meter' production by solar PV systems.

The shift also reflects in declining levels of minimum demand. While maximum demand was higher in mainland states in 2019, minimum demand fell in every NEM region. The shift was most apparent in South Australia, which beat its previous record low demand on seven separate days, and set a new historic minimum demand of 456 megawatts (MW) on 10 November 2019. South Australia, Victoria and Queensland all recorded their minimum demand in 2019 around the middle of the day.

Over the next five years, minimum demand is forecast to decline in mainland regions and keep shifting towards the middle of the day as rooftop PV capacity increases. The trend is predicted to occur more slowly in Tasmania, which has a comparatively higher proportion of business load, meaning that minimum demand may still occur overnight.[3]

Section 1.2.3 in chapter 1 further discusses trends in minimum demand.

2 AEMO, *2019 electricity statement of opportunities*, August 2019, p. 9.
3 AEMO, *2019 electricity statement of opportunities*, August 2019.

## 2.2 Generation technologies in the NEM

The NEM's generation plant uses a mix of technologies to produce electricity. Figure 2.17 maps the locations of generation plant, and the types of technology in use. Table 2.2 lists each plant. Figures 2.4–2.6 compare variations across regions, including movements over time.

Fossil fuel generators produce almost 77 per cent of electricity in the NEM. The plants burn coal or gas to power a generator. This combustion process releases carbon emissions as a byproduct into the atmosphere. While large scale, fossil fuel fired synchronous generators still dominate, many older generators are nearing the end of their life, becoming less reliable and closing. Renewable generation is filling much of the gap as Australia transitions to a lower emission economy. Hydroelectric and wind plant use water and wind respectively to drive generators. Solar PV generation does not rely on a turbine; rather, it directly converts sunlight to electricity.

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

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

Despite challenges in integrating wind and solar plant into the grid, the shift to renewable generation has been significant. The technology mix is evolving due to changes in the relative fuel and capital costs of different plant, technological advances that make some plant more efficient, and government policies to reduce carbon emissions. Section 1.1 in chapter 1 analyses these drivers.

### 2.2.1 Coal fired generation

Coal fired generators burn coal to create pressurised steam, which is then forced through a turbine at high pressure to drive a generator (figure 2.7). Coal fired generation remains the dominant supply technology in the NEM, producing 68 per cent of all electricity traded through the market in 2019. But coal plant accounts for only 37 per cent of the market's generation capacity, reflecting that coal generators tend to run fairly continuously.

Figure 2.4
Generation in the NEM, by fuel source, 2019

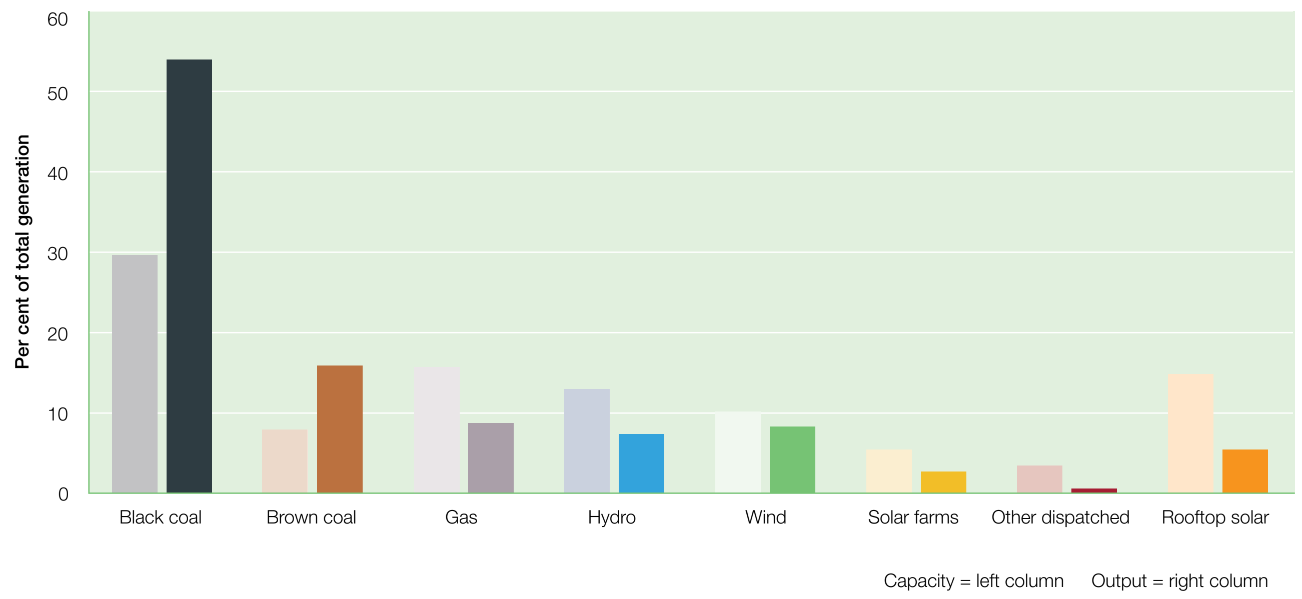
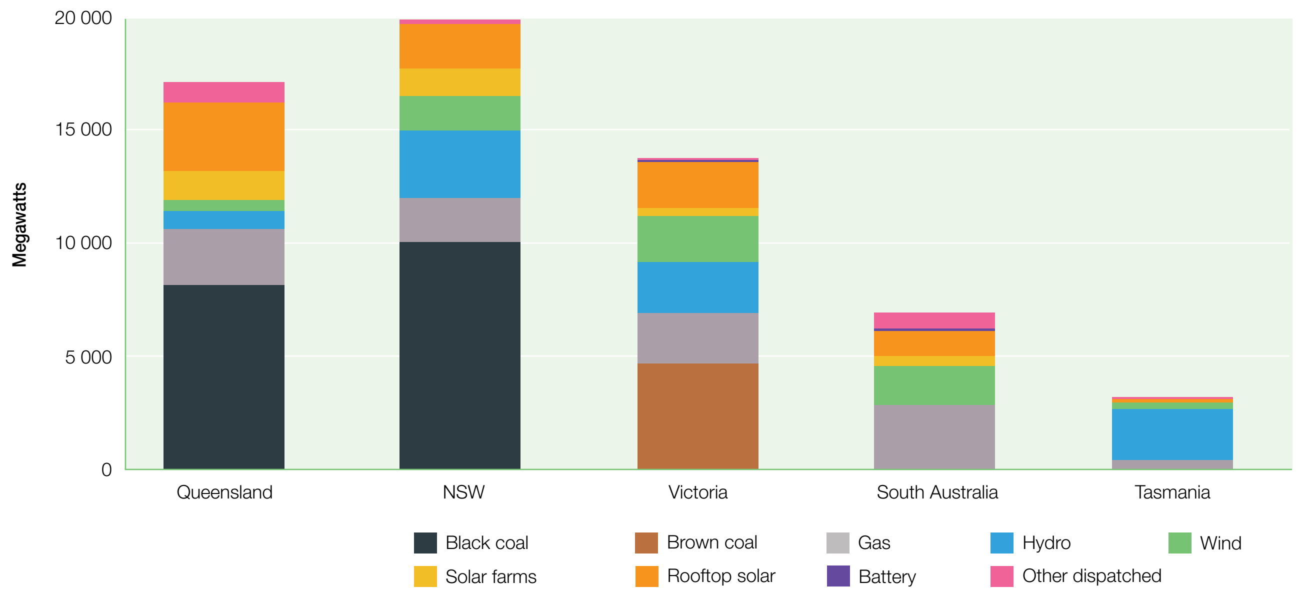
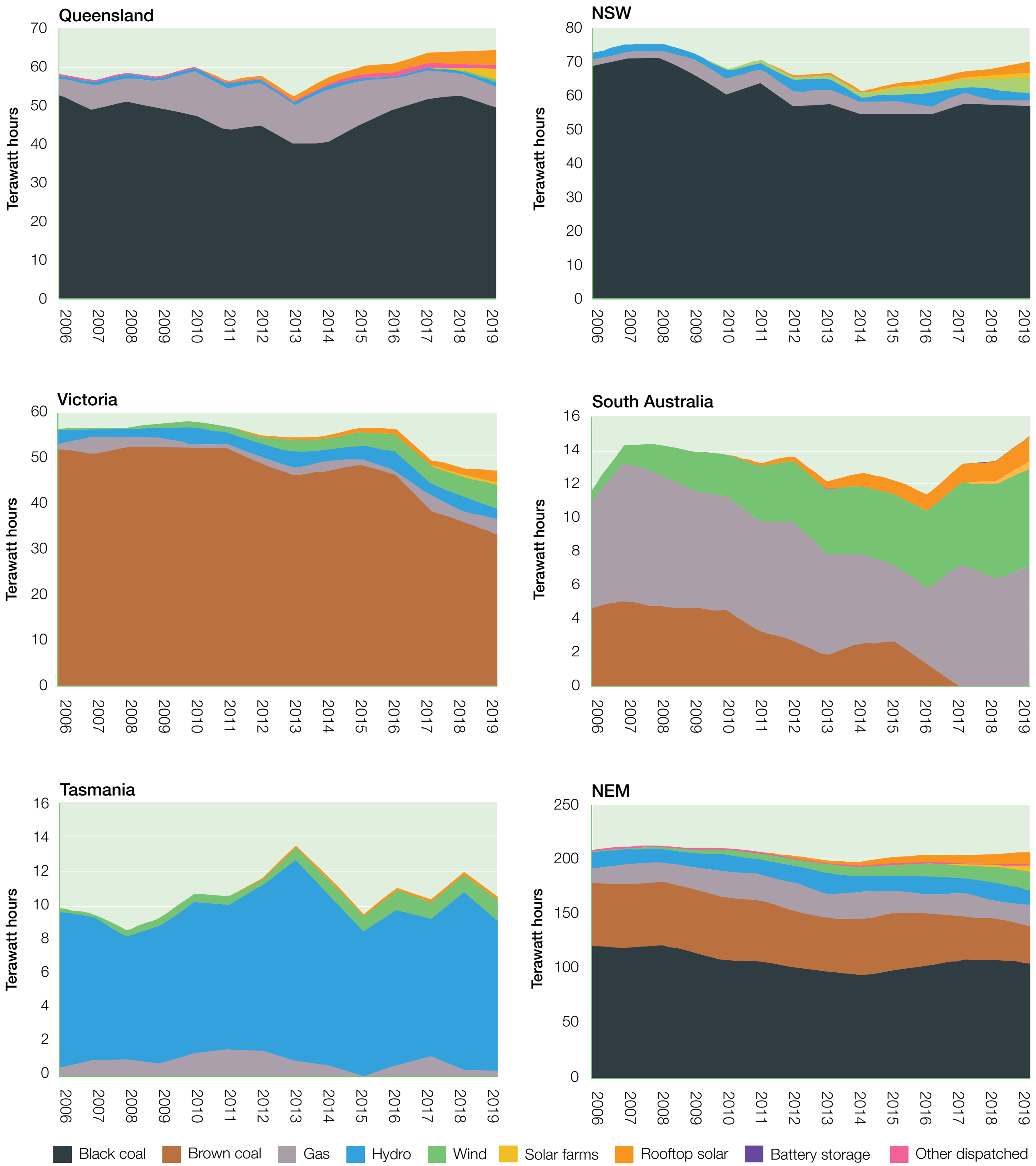



Figure 2.5
Generation capacity in the NEM, by region and fuel source, 2019




Note (figures 2.4 and 2.5): Generation capacity at 1 January 2020. Other dispatch includes biomass, waste gas and liquid fuels. Output is for 2019.
Source: Grid demand: AER, AEMO; rooftop solar: AER, CER, AEMO.

Figure 2.6
**Electricity generation over time, by region and fuel source**




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

Figure 2.7
**Coal fired generation**

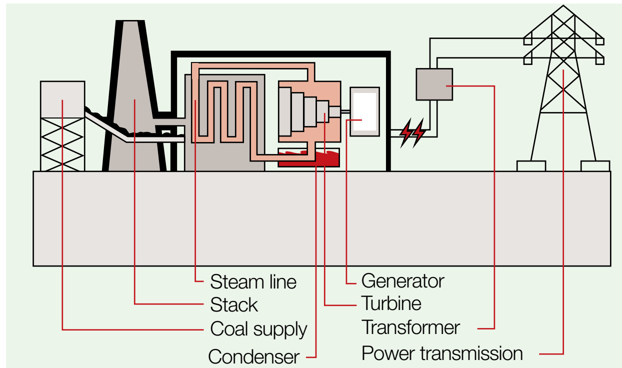
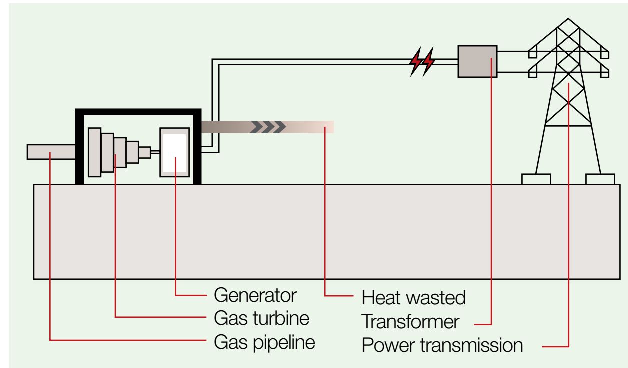



Figure 2.8
**Open cycle gas powered generation**




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

Coal fired generators can require a day or more to start up, so they have high start-up and shutdown costs. But their operating costs are low. These characteristics make it uneconomical to frequently switch coal plant on and off; once switched on, coal plant tends to operate relatively continuously. For this reason, coal fired generators usually bid a portion of their capacity into the NEM at low prices to guarantee dispatch and keep their plant running. Aside from providing relatively low cost electricity to the market, coal fired generators also help maintain power system stability.[4]

Over 4000 MW of coal fired capacity has been retired from the market since 2014. Most recently, in March 2017 Engie retired its Hazelwood power station in Victoria, removing 1600 MW of brown coal generation. The plant was over 50 years old, and was Australia's most emission intensive power station. The closure was especially significant given Hazelwood supplied around 5 per cent of the NEM's total output.

Following the plant closures, the remaining coal fired generation fleet operated at higher output levels. But significant coal generator outages occurred in the past few years. Brown coal in particular has had an increased rate of forced outages, which rose sevenfold between 2010–11 and 2017–18. In 2019 Loy Yang A unit 2 (530 MW) was offline for almost seven months due to an unplanned outage. This situation raised reliability concerns for Victoria going into summer, particularly given the Mortlake gas plant had a coinciding unplanned outage.[5]

Retirements of further coal plant are expected. The most imminent is the planned retirement of AGL Energy's Liddell power station in NSW in stages over 2022 and 2023, which would remove 2000 MW of black coal capacity from the NEM. No further investment in coal plant is proposed for the NEM, other than a potential recommissioning of the Redbank power station in NSW (151 MW) and minor upgrades to Bayswater (Queensland) and Loy Yang A and B (Victoria) power stations, totalling an additional 125 MW.[6]

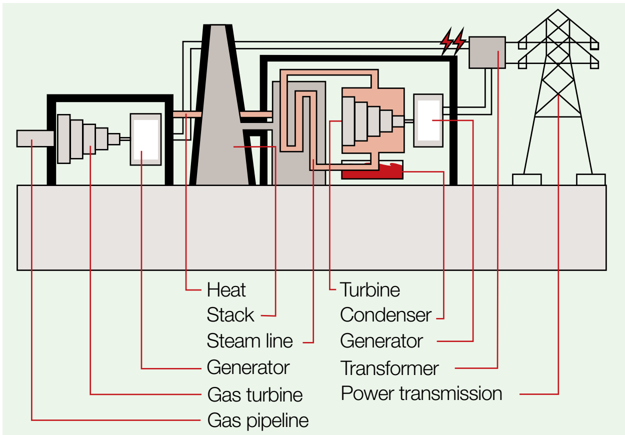
## 2.2.2 Gas powered generation

A number of gas generation technologies operate in the NEM. *Open cycle gas turbine* (OCGT) plant burn gas to heat compressed air that is then released into a turbine to drive a generator (figure 2.8). In *combined cycle gas turbine* (CCGT) plant, waste heat from the exhaust of the first turbine is used to boil water and create steam to drive a second turbine (figure 2.9). The capture of waste heat improves the plant's thermal efficiency, making it more suitable for longer operation than open cycle plant. More recently, the first *reciprocating engine gas plant* was commissioned in South Australia. This technology uses gas to drive a piston that spins a turbine. These plant operate similarly to OCGTs,

4 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.

5 AEMO, *2019 electricity statement of opportunities*, August 2019, p. 72.
6 AEMO, *Generation information April 2020*.

Figure 2.9
**Combined cycle gas powered generation**




but are more flexible. Some legacy 'steam turbines'—which operate similarly to coal plant—also remain in the market.

Gas plant can operate more flexibly than coal, with open cycle plant (and newer CCGT plant and reciprocating engines) in particular needing as little as 5 minutes to ramp up to full operating capacity. The ability of gas plant to respond quickly to sudden changes in the market makes it a useful complement to wind and solar generation, which can be affected by sudden changes in weather conditions. The most efficient gas powered generation is less than half as emission intensive as the most efficient coal fired plant.[7]

Despite these benefits, gas is a relatively expensive fuel for electricity generation, so gas generators more typically operate as 'flexible' or 'peaking' plant.[8] Across the NEM, gas powered plant accounted for 19.8 per cent of plant capacity in the NEM in 2019, but supplied only 8.7 per cent of electricity generated. South Australia relies more on gas powered generation than do other regions. In 2019 the state produced 48 per cent of its local generation from gas plant, similar to its long term average.

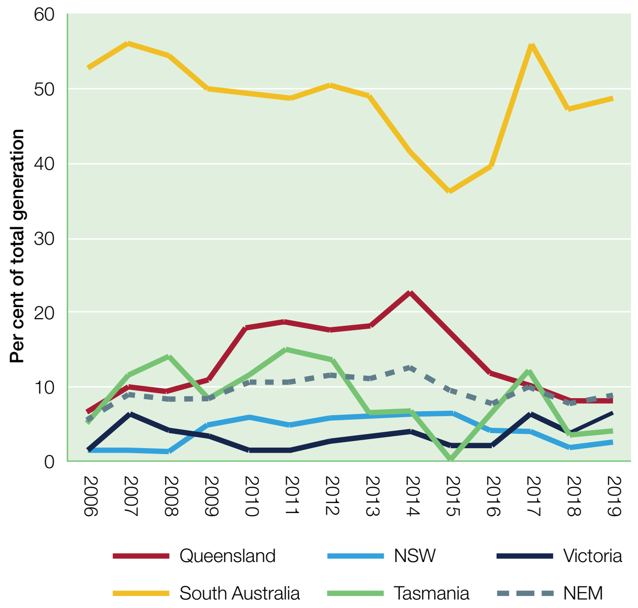
Gas generation in the NEM tends to be seasonal, peaking in summer (and sometimes winter) when electricity demand and prices are highest. It also varies with the amount of intermittent generation and outages affecting coal fired generators.

Higher gas fuel costs linked to Queensland's LNG industry, along with a lack of new gas supplies, slowed demand for

7 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.

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

Figure 2.10
**Gas powered generation**




Source: AER; AEMO (data).

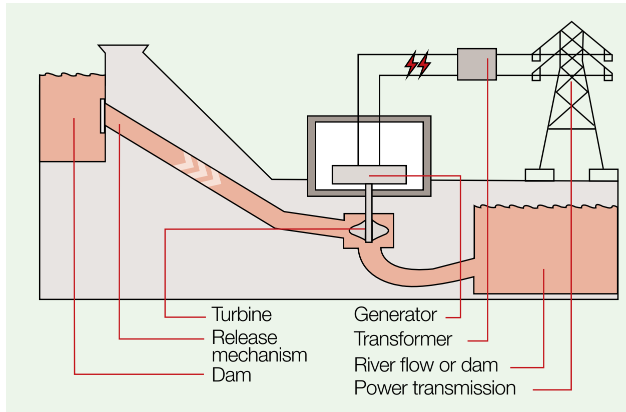
gas powered generation from 2015 (figure 2.10). This shift was reinforced by the Queensland Government in July 2017 directing its major state owned coal generator to lower its offer prices (making gas generation less competitive). These conditions were reflected in gas powered generation slumping from 23 per cent of Queensland's electricity output in 2014 to under 9 per cent in 2018 and 2019.

A similar squeezing of gas powered generation was apparent from 2018 in NSW. The state's gas output in 2018 was 60 per cent below the average output over the previous decade, providing only 2 per cent of total electricity generation. Output was higher in 2019, but remained well below previous years.

In contrast, the retirement of coal generators in Victoria and South Australia made gas generation critical to meeting electricity demand whenever renewable generation is low in those regions. This dependency was reflected in gas generation from 2017 to 2019 being 107 per cent higher in Victoria than in the previous three years, and 46 per cent higher in South Australia.

AGL commissioned new gas plant in South Australia in 2019 at Barker's Inlet (210 MW), replacing the Torrens Island plant that it is retiring. No new gas plant investment had previously occurred in the NEM since Origin commissioned the Mortlake power station (566 MW) in Victoria in 2011. Further new gas plants have been announced for Victoria and Queensland

Figure 2.11
**Hydroelectric generation**




as part of the Australian Government's Underwriting New Generation Investment (UNGI) program (section 1.7.1).

## 2.2.3 Hydroelectric generation

Hydropower uses the force of moving water to generate power. The technology involves channelling falling water through turbines. The pressure of flowing water on the blades rotates a shaft and drives an electrical generator, converting the motion into electrical energy (figure 2.11). Similar to coal and gas plant, hydroelectric generators are synchronous, meaning they provide inertia and other services that support power system security. And, because their fuel source is usually available (except in drought conditions), they are 'dispatchable' plants that can switch on as required.

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

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

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

Hydroelectric generators accounted for 12.9 per cent of capacity in the NEM in 2019, and supplied 6.7 per cent of electricity generated. Tasmania is the region most reliant on hydrogeneration, with 84 per cent of its 2019 grid generation coming from that source. NSW and Victoria also have significant hydrogeneration plant located in the Snowy Mountains region.

Hydrogeneration levels in recent years varied due to weather conditions, market incentives to generate, and subsidy arrangements under the RET scheme.[9] Hydrogeneration tracked higher in 2018, up 29 per cent over the previous year. This rise stemmed in part from a Basslink interconnector outage that required Tasmania to be self-sufficient in generation.

In 2019 hydrogeneration dropped 18 per cent from 2018 levels, with lower output in all major producing regions—Tasmania, NSW and Victoria. These changes reflected low rainfall in Victoria and NSW, and a return to more typical generation levels in Tasmania. In contrast, Queensland recorded record hydrogeneration output in 2019, following high rainfall in northern Queensland where the region's two main plants are located.

## 2.2.4 Wind generation

Wind turbines directly convert the kinetic energy of wind into electricity. The wind turns blades that spin a shaft connected (directly or indirectly via a gearbox) to a generator that creates electricity (figure 2.12). Wind turbines are typically designed to operate to wind speeds up to 90 kilometres per hour. They shut down automatically in high winds until speeds return within the turbine's operations range.

Renewable generation, including wind, has filled much of the supply gap left by thermal plant closures (figure 2.13). Government incentives, including the RET scheme, provided impetus for the growth of wind generation in the NEM.

Wind generators accounted for 10 per cent of the NEM's capacity in 2019, with over 1000 MW of new capacity added during the year (accounting for almost 40 per cent of all new investment). Wind generation rose 18 per cent on a

9 Box 1.1 in chapter 1 describes the RET scheme.

Figure 2.12
**Wind powered generation**

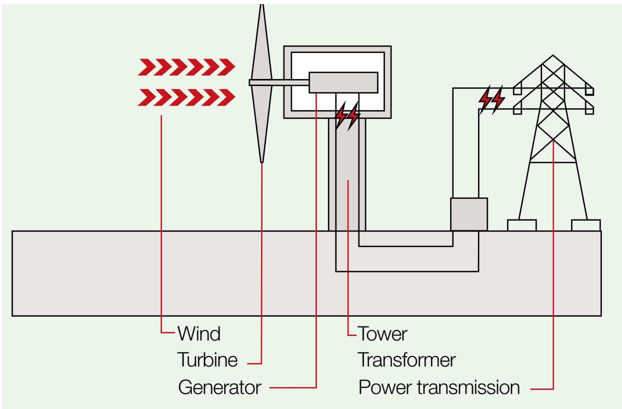
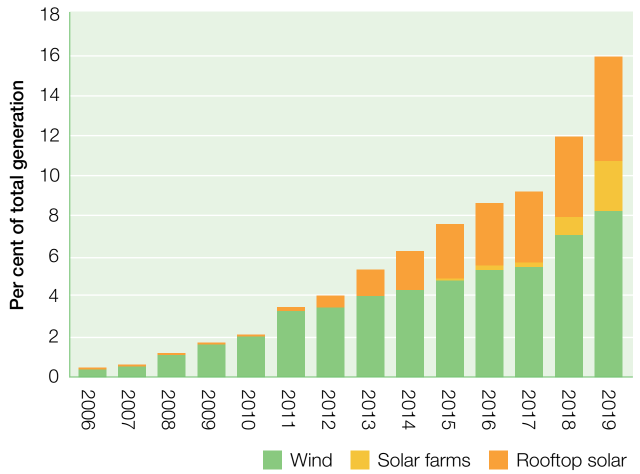



Figure 2.13
**Wind and solar generation share of total generation**

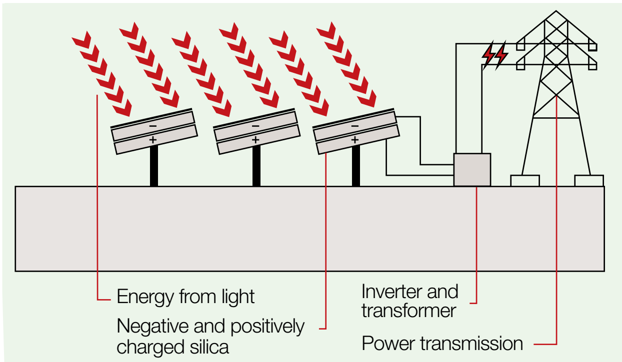



Source: Grid generation: AER, AEMO; rooftop solar: AEMO (nemweb.com.au/#rooftop-pv-actual).

year-on-year basis in 2019, and during the year generated 8.2 per cent of all electricity.

Wind penetration is especially strong in South Australia, where it provided 38 per cent of the state's electricity output in 2019. More recently, the focus of wind investment has shifted to NSW and Victoria, where over 70 per cent of capacity installed or committed since July 2017 has occurred. Queensland had no large scale wind generators until 2018, but now has two in operation, with Cooper's Gap set to be one of the largest in the country (453 MW) when completed. Queensland has significantly less wind generation than other states, however.

Figure 2.14
**Solar PV power plant**




Weather conditions affect wind generation levels. Favourable conditions on 11 July 2019 resulted in record levels of wind output, peaking at 4624 MW. On that day, wind generation accounted for 17 per cent of all electricity generated in the NEM.

Wind generation accounts for around one third of the NEM's proposed and committed generation projects, at over 20 000 MW. Ten wind projects, comprising over 1500 MW of capacity, are scheduled to be commissioned by the end of 2020 (table 2.4).

## 2.2.5 Grid scale solar farms

Large scale solar plant is a relatively new entrant in the NEM. Australia has the highest solar radiation per square meter of any continent, receiving an average 58 million petajoules of solar radiation per year.[10] All solar investment to date has been in PV systems that use layers of semi-conducting material to convert sunlight into electricity (figure 2.14). Concentrated solar thermal (CST) is an alternative technology that uses lenses, towers, dishes and reflectors to concentrate sunlight, heating fluid to produce steam that drives a turbine.[11]

Despite eligibility for government incentives under the RET scheme, and funding support from the Australian Renewable Energy Agency (ARENA) and Clean Energy Finance Corporation (CEFC),[12] investment in large scale solar farms in Australia did not occur at a significant scale until 2018. Commercial solar farms accounted for only 0.5 per cent of total NEM generation capacity in 2017, and met only 0.3 per cent of the NEM's electricity requirements in 2017. But by 2019 they made up 5.2 per cent of capacity and 2.5 per cent of output.

Thirty-four solar farms began generating in 2018 and 2019 (totalling 3157 MW),[13] and a further 13 projects (1570 MW) were scheduled to begin output by the end of 2020.

While NSW was the initial focus for solar plant development, the majority of new capacity has been located in Queensland. The largest operating plant at March 2020 is Daydream solar farm in Queensland (168 MW).

10 Geoscience Australia, 'Solar energy', web page, available at: www.ga.gov.au/ scientific-topics/energy/resources/other-renewable-energy-resources/ solar-energy.

11 There are no operating solar thermal plants in the NEM, and only one proposed—a 150 MW plant in South Australia. This project changed ownership in 2019, and an expected commissioning date is unclear.

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

## 2.2.6 Grid scale storage

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

### Battery storage

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

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

Batteries in the NEM tend to earn a majority of their profits from operating in frequency control markets. The AER estimated South Australia's Hornsdale battery earned around $25 million for frequency services in 2019—five times the battery's earnings from wholesale energy sales.

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

13 The 3157 MW encompasses the new farms' total registered capacity on completion. Some farms are not yet operating at that full capacity, as construction continues.

### Pumped hydroelectricity

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

Pumped hydroelectric technology has been available in the NEM for some time, with generation in Queensland (570 MW at Wivenhoe) and NSW (240 MW at Shoalhaven and 1500 MW at Tumut 3). While use of this technology is limited by the availability of appropriate physical sites, advances in technology and the rise of intermittent generation are providing new opportunities for deploying this form of storage at a larger scale. In particular, pumped hydroelectricity is the basis of the proposed Snowy 2.0 (2000 MW) and Battery of the Nation (2500 MW) projects in NSW and Tasmania respectively (section 1.7.2).

## 2.2.7 Distributed energy resources

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

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

By far the fastest development has been in rooftop solar PV installations, but interest is also growing in battery systems, electric vehicles and demand response. Small scale battery installations in 2019 were over tenfold those in 2014, although their penetration is much lower than rooftop PV installations.

### Rooftop solar PV generation

While large scale solar generation was slow to develop in Australia, consumers began installing rooftop solar PV panels from around 2010. Rooftop systems now account for over one third of renewable capacity in the NEM. In 2019 solar PV systems met 5.2 per cent of the NEM's electricity requirements. Their contribution is highest in South Australia, where they met over 10 per cent of electricity requirements.

Queensland has the highest number of installations and the highest installed capacity (almost 3000 MW).

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

By early 2020, NEM customers had installed over 2 million solar PV rooftop systems.[14] The total installed capacity of these systems was 8.8 gigawatts (GW), which was equivalent to over 14 per cent of the NEM's total generation capacity.

The uptake of rooftop solar PV is driven by opportunities for energy customers to reduce their electricity bills and earn income by feeding surplus generation back into the grid. Government incentives—such as rebates through the Small-scale Renewable Energy Scheme and premium feed-in tariffs—strengthened incentives to install the systems.

The rate of installation of solar PV systems has risen each year since 2016. Combined with larger system sizes for newer installations, a record amount of solar PV capacity was installed in 2019—over 2000 MW of capacity, compared with 1400 MW in 2018.

The average size of systems installed in 2019 more than tripled that in 2011, rising from 2.5 kilowatts (kW) to 7.7 kW. This shift to larger systems reflects the lower installation costs and the higher uptake of solar PV systems by commercial businesses (figure 1.9 in chapter 1). In the year to 30 June 2019, for example, solar PV installations grew by almost 35 per cent in the business sector, compared with 20 per cent in the residential sector.[15]

#### Small scale storage

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

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

Australian households already show significant interest in and awareness of batteries. Nearly half of customers with solar PV systems are interested in using batteries.[16] The Clean Energy Regulator estimates Australians had installed 21 000 battery systems by January 2020.[17]

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

In May 2019 ARENA announced $2.5 million in funding for AEMO to run a virtual power plant trial over a 12–18 month period, to demonstrate the technology's capabilities to deliver energy and grid stability services. AEMO invited existing pilot scale projects to participate, including ARENA funded AGL and Simply Energy pilot scale projects in South Australia.

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

## 2.3 Trade across NEM regions

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

Queensland has surplus generation capacity, making it a net electricity exporter (figure 2.15). Victoria's abundant supplies of low priced brown coal generation also traditionally made it a net exporter of electricity. But Hazelwood's closure in 2017 eliminated Victoria's trade surplus, with Victoria becoming a net importer for the first time in 2019.

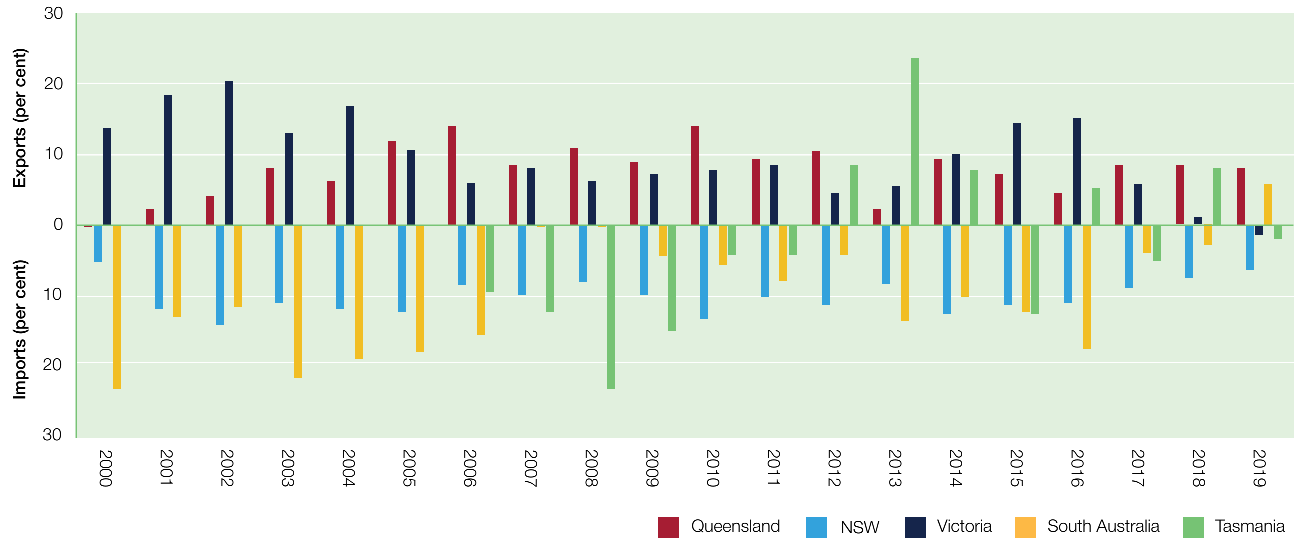
NSW has relatively high fuel costs, typically making it a net importer of electricity. Its trading position tends to be relatively stable, although declining imports from Victoria led to its net imports recording a historic low in 2019.

14 Data on small generation units (solar) from: Clean Energy Regulator, 'Postcode data for small scale installations', web page, available at: www.cleanenergyregulator.gov.au/RET/Forms-and-resources/Postcode-data-for-small-scale-installations.
15 AEMO, *2019 electricity statement of opportunities*, August 2019, p. 9.
16 Energy Consumers Australia, *Energy consumer sentiment survey*, December 2019.
17 Data on solar PV systems with concurrent battery storage capacity by year and state/territory from: Clean Energy Regulator, 'Postcode data for small scale installations', web page, available at: www.cleanenergyregulator.gov.au/RET/Forms-and- resources/Postcode-data-for-small-scale-installations.





Figure 2.15
**Interregional trade as a percentage of demand**




Note: Net interregional trade (exports less imports) divided by regional (native) demand.
Source: AER; AEMO.

South Australia was traditionally an electricity importer, due to its lack of low cost local supply. Coal plant withdrawals increased the region's trade dependency, making it proportionally the NEM's highest importer in 2016. But surging local wind generation, combined with the reduced availability of brown coal generation in Victoria, made it more self-sufficient from 2017. As a result, the state had its first energy trade surplus in 2019.

Tasmania's trade position varies with environmental and market conditions. Key drivers include local rainfall (which affects dam levels for hydrogeneration), Victorian spot prices, and the availability of the Basslink interconnector (which has suffered multiple extended outages in recent years). Tasmania was proportionally the NEM's largest net exporter when carbon pricing made hydroelectric generation more competitive in 2012–14. But the abolition of carbon pricing and drought reversed this position.

### 2.3.1 Market alignment and network constraints

The market sets a separate spot price for each NEM region. When the interconnectors linking NEM regions are unconstrained, trade brings prices into alignment across all regions (apart from variations caused by physical losses that occur when transporting electricity). At these times, the NEM acts as a single market rather than as a collection of regional markets, and generators within a region are exposed to competition from generators in other regions.

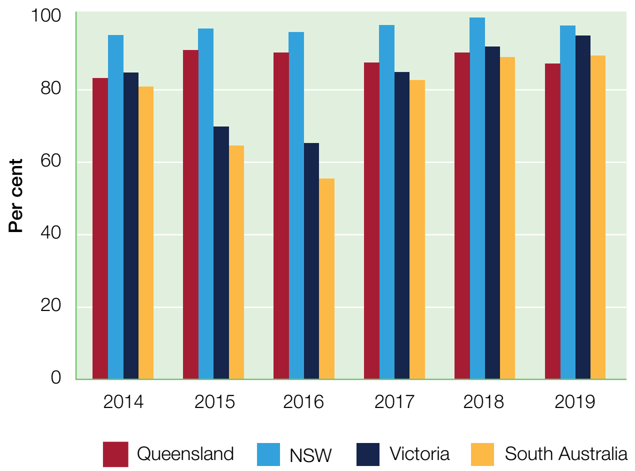
Historically, Queensland and NSW had high alignment rates, with a fairly stable duration of network congestion on interconnectors linking the regions. Price alignment between Victoria and South Australia has been less regular, with congestion on the Victoria–South Australia interconnectors more than doubling in frequency between 2013 and 2017. Heywood was the NEM's most congested interconnector over this period, partly because its capacity was constrained during a major upgrade.

But the completion of the Heywood upgrade and the closure of Victoria's Hazelwood power station in 2017 (which reduced Victorian exports of electricity to South Australia) reduced congestion between the regions. Victoria and South Australian prices aligned over 90 per cent of the time in 2018 and 2019, up from a low of 57 per cent in 2016 (figure 2.16).

But interpreting alignment rates as an indicator of competition between regions requires care. The improved alignment rates between South Australia and Victoria do not necessarily indicate a change in competitive conditions.[18]

18 AER, *Wholesale electricity market performance report*, December 2018, p. 27.

Figure 2.16
**Price alignment in mainland NEM regions**




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

Source: AER; AEMO.

## 2.4 Market structure

Around 200 registered generators sell electricity into the NEM spot market. Table 2.2 lists the major generators, plant technologies and ownership arrangements (including the entities that control each plant's dispatch). Figure 2.18 maps each plant's location.

### 2.4.1 Generation businesses

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

Section 2.8 examines the market's structure and competitiveness.

### 2.4.2 Market concentration

A few large participants control a significant proportion of generation in each NEM region. The two largest participants account for over half of total capacity (figure 2.17) and two thirds of output (figure 2.19) in all regions except South Australia.

Queensland, NSW and Victoria account for a higher concentration of output than capacity, given the high utilisation rates of black and brown coal plant, which make up the bulk of capacity held by the major participants. South Australia's largest participants rely on gas powered generation (which operates less often than coal plant).

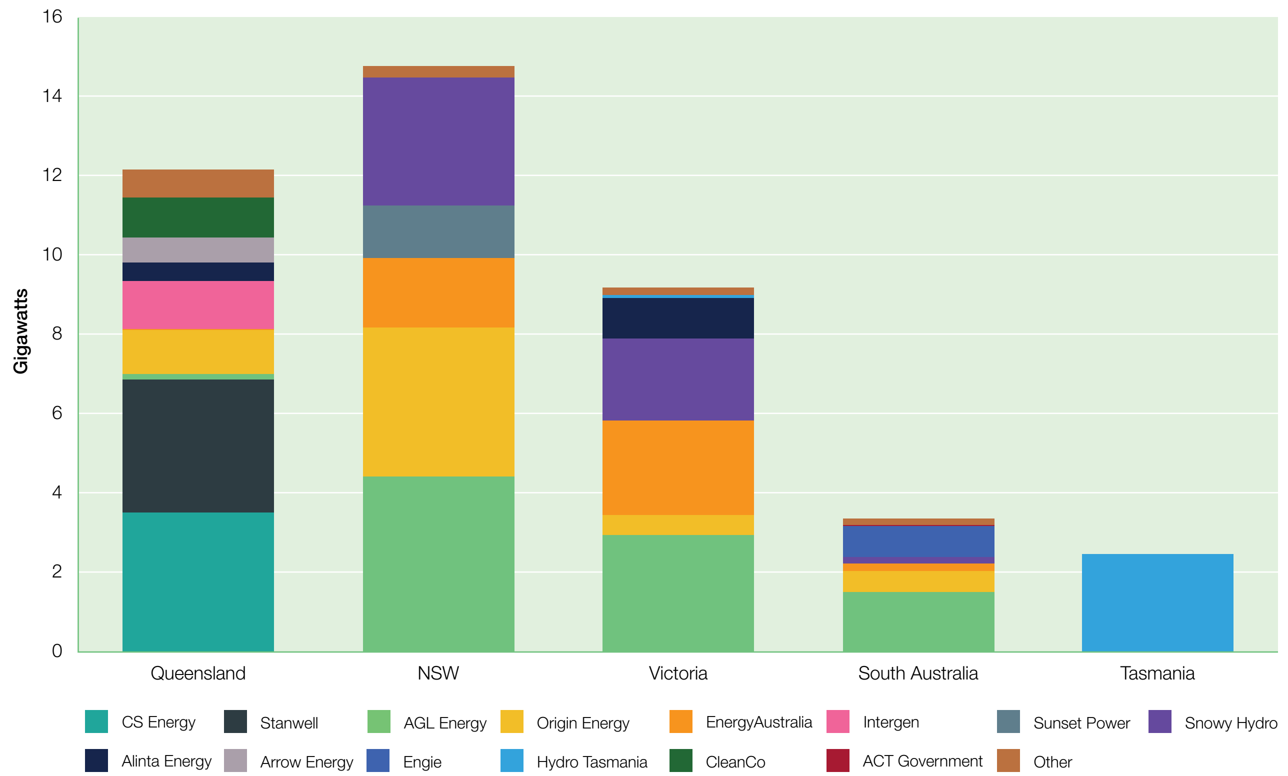
Private entities own most generation capacity in Victoria, NSW and South Australia:

- In Victoria, AGL Energy (32 per cent) and EnergyAustralia (26 per cent) control a majority of capacity. The Australian Government owned Snowy Hydro (23 per cent) is the next largest participant. Engie controlled over 20 per cent of the market until decommissioning its Hazelwood plant in March 2017.
- In South Australia, AGL Energy is the dominant generator, with 45 per cent of capacity. Other significant entities are Engie (23 per cent), Origin Energy (15 per cent) and EnergyAustralia (6 per cent). Before retiring its Playford (2012) and Northern (2016) power stations, Alinta had around 20 per cent market share in South Australia.
- In NSW, AGL Energy (30 per cent) and Origin Energy (26 per cent) became the leading plant owners following the privatisation of state owned generators in 2015. Snowy Hydro (22 per cent), EnergyAustralia (12 per cent) and Sunset Power (9 per cent) are other major players.

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

- In Queensland, state owned corporations Stanwell and CS Energy control 56 per cent of generation capacity, including power purchase agreements over privately owned capacity (such as the Gladstone power station). This market share is lower than in 2018, because some of CS Energy's and Stanwell's assets were transferred to a third state owned corporation, CleanCo, in October 2019. CleanCo was created to increase wholesale market competition and support growth in the state's renewable energy industry. It controls 8 per cent of the state's capacity, including all hydropower plant. The largest private operators are InterGen (10 per cent of capacity) and Origin Energy (9 per cent).
- In Tasmania, the state owned Hydro Tasmania owns all generation capacity. To encourage competition in the retail market, the Office of the Tasmanian Economic Regulator regulates the prices of four safety net contract products offered by Hydro Tasmania, and ensures adequate volumes of these products are available.

Figure 2.17
**Market shares in generation capacity**




Note: Generation capacity based on 2019–20 summer capacity, except for wind and solar, which are adjusted based on AEMO's 'firm contribution' estimates to account for generation likely to be operational during periods of maximum demand. Capacity is allocated to the business that controls the trading rights for each generator. Import capacity via interconnectors and rooftop solar PV capacity is excluded.

Source: AER; AEMO.

AGL Energy is the largest participant by capacity and output in NSW, Victoria and South Australia. On a NEM-wide basis, it accounts for 21 per cent of capacity and 26 per cent of output.

Snowy Hydro contributed only 3 per cent of output in NSW and Victoria, despite holding over 20 per cent of capacity in each region. This outcome arose because Snowy Hydro's hydroelectric generators have limited water availability, and its gas peaking gas plant operates infrequently.

### 2.4.3 Vertical integration

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

Vertical integration has become the primary business structure for large electricity retailers in the NEM. Three retailers—AGL Energy, Origin Energy and EnergyAustralia—supply 63 per cent of small retail electricity customers in the NEM. The same entities expanded their market share in NEM generation capacity from 17 per cent in 2011 to 46 per cent in 2019.

Second tier retailers—Red Energy and Lumo Energy (Snowy Hydro), Simply Energy (Engie) and Alinta—also own major generation assets. These vertically integrated businesses account for another 17 per cent of small residential customers across the NEM, and 18 per cent of generation capacity.

**Table 2.2 Generation plant in the NEM, 2020**

| TRADING RIGHTS | CAPACITY (MW) | POWER STATION (MW) | OWNER |
|---|---|---|---|
| QUEENSLAND | 15 345 | | |
| Stanwell Corporation | 3 333 | Stanwell (1460); Tarong (1400); Tarong North (443); Mackay (30) | Stanwell Corporation (Qld Government) |
| CS Energy | 3 124 | Callide B (700); Kogan Creek (744); Gladstone (1680) | CS Energy (Qld Government) |
| Origin Energy | 1 541 | Darling Downs (644); Mount Stuart (419); Roma (80)<br>Daydream (167)<br>Darling Downs (121)<br>Clare (110) | Origin Energy<br>Blackrock 90%; Edify Energy 10%<br>APA Group<br>Clare Solar Farm |
| CleanCo | 1 106 | Swanbank (385); Kareeya (91); Barron Gorge (60); Wivenhoe (570) | CleanCo (Qld Government) |
| InterGen | 852 | Millmerran (852) | China Huaneng Group 71%; InterGen 29% |
| CS Energy 50%; InterGen 50% | 840 | Callide C (840) | CS Energy (Qld Government) 50%; InterGen 50% |
| AGL Energy | 560 | Moranbah North (63); German Creek (45)<br>Coopers Gap (452) | Energy Developments (DUET Group)<br>Powering Australian Renewables Fund |
| Arrow Energy | 552 | Braemar 2 (519)<br>Daandine (33) | Arrow Energy (Shell 50%, PetroChina 50%)<br>Energy Infrastructure Investments (MMCIF 49.9%, Osaka Gas 30.2%, APA Group 19.9%) |
| Alinta Energy | 546 | Braemar 1 (504)<br>Collinsville (42) | Alinta Energy (CTFE)<br>Braemar Power Project |
| ERM Power | 345 | Oakey (288)<br>Hamilton (57) | ERM Power<br>Wircon 94.9%; Edify Energy 5.1% |
| Ergon Energy | 335 | Mount Emerald (180); Barcaldine (37)<br>Lilyvale (118) | Ergon Energy (Qld Government)<br>Fotowatio Renewable Ventures |
| Arrow Energy 50%; AGL Energy 50% | 242 | Townsville (242) | RATCH Australia (Ratchaburi Electricity Generation 80%, Ferrovial 20%) |
| RTA Yarwun | 154 | Yarwun (154) | Rio Tinto Alcan |
| ESCO Pacific | 149 | Susan River (85); Childers (64) | Elliott Green Power |
| Shell | 144 | Condamine (144) | Queensland Gas Company (Shell) |
| Queensland Government | 107 | Whitsunday (57)<br>Kidston (50) | Wircon 94.9%; Edify Energy 5.1%<br>Genex Power |
| Pacific Hydro | 132 | Haughton (132) | Pacific Hydro (State Power Investment Corporation) |
| EnergyAustralia 80%; ESCO Pacific 20% | 128 | Ross River (128) | Pallisade Investment Partners |
| Risen Solar | 121 | Yarranlea (121) | Risen Solar |
| Sun Metals Corporation | 124 | Sun Metals (124) | Sun Metals Corporation |
| Wilmar International | 118 | Pioneer Sugar Mill (68)<br>Invicta Sugar Mill (50) | Wilmar International<br>Stanwell Corporation (Qld Government) |
| Simec Zen Energy | 92 | Clermont (92) | Wircon |
| Telstra | 88 | Emerald (88) | Lighthouse Infrastructure Management |
| Adani Renewables | 83 | Rugby Run (83) | Adani Australia |
| Foresight | 65 | Oakey 2 (65) | Diamond Energy |
| Diamond Energy | 63 | Oakey 1 (30); Maryrorough (33) | Diamond Energy |
| Edify Energy | 57 | Hayman (57) | Edify Energy |
| Mackay Sugar | 48 | Racecourse Mill (48) | Mackay Sugar |
| Renewable Power Australia | 30 | Rocky Point Cogeneration Plant (30) | Heck Group |
| *Non-scheduled plant < 30MW* | 266 | *Misc.* | |
| NSW | 18 046 | | |
| AGL Energy | 5 043 | Bayswater (2640); Liddell (2000); Hunter Valley (50)<br>Broken Hill (53); Nyngan (102); Silverton (198) | AGL Energy<br>Powering Australian Renewables Fund (QIC 80%, AGL Energy 20%) |
| Origin Energy | 3 960 | Eraring (2880); Shoalhaven (240); Uranquinty (664); *Eraring (42)*<br>Moree (57)<br>Gunning (47)<br>*Cullerin Range (30)* | Origin Energy<br>Fotowatio Renewable Ventures<br>Acciona Energy<br>Energy Developments (DUET Group) |
| Snowy Hydro | 2 980 | Tumut 3 (1500); Colongra (724); Upper Tumut (616); Blowering (80); Guthega (60) | Snowy Hydro (Australian Government) |
| EnergyAustralia | 2 394 | Mount Piper (1400); Tallawarra (440)<br>Gullen Range (275); Gullen Range (10)<br>Taralga (106)<br>Boco Rock (113)<br>Manildra (50) | EnergyAustralia (CLP Group)<br>Beijing Jingneng Clean Energy 75%; Goldwind 25%<br>Pacific Hydro (State Power Investment Corporation)<br>Electricity Generating Public Company<br>New Energy Solar |
| Delta Electricity | 1 320 | Vales Point (1320) | Sunset Power International (Waratah Power 50%, Vales Point Invesments 50%) |
| Infigen Energy | 373 | *Capital (140)*; Woodlawn (48); Smithfield (185) | Infigen Energy |
| CWP/Partners Group 67%; ACT Government 37% | 270 | Sapphire (270) | CWP Renewables and Partners Group |
| EnergyAustralia 67%; Neoen 33% | 180 | Coleambally (180) | Neoen |
| White Rock Wind Farm | 175 | White Rock (175) | CECEPWP 75%; Goldwind 25% |
| BlueScope Steel 66%; John Laing 34% | 162 | Finley (162) | John Laing Group |
| Elliott Green Power | 132 | Nevertire (132) | Elliott Green Power |
| Flow Power 69%; Westpac 26%; Spark Infrastructure 5% | 121 | Bomen (121) | Spark Infrastructure |
| EnergyAustralia 60%; Infigen Energy 40% | 113 | Bodangora (113) | Infigen Energy |
| NSW Government 70%; Kelloggs 30% | 98 | Beryl (98) | New Energy Solar |
| Stanwell Corporation | 96 | *Appin (55); Tower (41)* | Energy Developments (DUET Group) |
| ACT Government | 96 | Crookwell 2 (96) | Global Power Generation Australia (Naturgy 75%, Kuwait Investment Authority 25%) |
| Capital Dynamics | 68 | *Broadwater/Condong (68)* | Cape Byron Power (Cape Byron Infrastructure LP) |
| Engie | 55 | Parkes (55) | Neoen (Impala 54%, Omnes Capital 23%, Bpifrance 14%, other 9%) |
| Essential Energy | 50 | *Broken Hill (50)* | Essential Energy (NSW Government) |
| Innogy | 38 | Limondale (38) | Innogy |
| Meridian Energy | 29 | Hume (29) | Meridian Energy |
| Goldwind | 22 | White Rock (22) | Goldwind |
| *Non-scheduled plant < 30 MW* | 271 | *Misc.* | |

| TRADING RIGHTS | CAPACITY (MW) | POWER STATION (MW) | OWNER |
|---|---|---|---|
| VICTORIA | 12 467 | | |
| AGL Energy | 3 539 | Loy Yang A **(2210)**<br>Macarthur **(420);** Oaklands Hill **(67);** West Kiewa **(62);** Somerton **(170);** Eildon **(125);** Dartmouth **(185);** Mackay/Bogong **(300)** | AGL Energy<br>AGL Hydro Partnership |
| EnergyAustralia | 2 527 | Yallourn **(1480);** Jeeralang A **(204)** and B **(228);** Newport **(500);** Ballarat **(30);** Gannawarra **(30);**<br>Gannawarra **(55)** | EnergyAustralia (CLP Group)<br>Wircon 94.9%; Edify Energy 5.1% |
| Snowy Hydro | 2 112 | Murray **(1500)**; Laverton North **(312)**; Valley Power **(300)** | Snowy Hydro (Australian Government) |
| Alinta Energy | 1 206 | Loy Yang B **(1000);**<br>Bald Hills **(106);**<br>Bannerton **(100)** | Alinta Energy |
| Origin Energy | 566 | Mortlake **(566)** | Origin Energy |
| Snowy Hydro 50%; Victorian Government 37%; Tilt Renewables 13% | 335 | Dundonnell **(335)** | Tilt Renewables |
| Acciona Energy | 330 | *Waubra* ***(192)***; Mount Gellibrand **(138)** | Acciona Energy |
| ACT Government 33%; Ararat Wind Farm 67% | 241 | Ararat **(241)** | RES; GE; Partners Group; OPTrust |
| Telstra | 231 | Murra Warra **(231)** | Partners Group |
| Pacific Hydro | 230 | *Yambuk* ***(30)****; Challicum Hills* ***(52)****; Portland* ***(148)*** | Pacific Hydro (State Power Investment Corporation) |
| Simec Zen Energy | 209 | Numurkah **(112)**<br>Wemen **(97)** | Neoen<br>Wircon |
| Meridian Energy | 160 | Mount Mercer **(131);** Hume **(29)** | Meridian Energy |
| Orora | 144 | Yendon **(144)** | Northleaf 40%; InfraRed Capital Partners 40%; Macquarie 20% |
| Carlton & United Breweries | 104 | Karadoc **(104)** | BayWa r.e. Renewable Energy |
| Hydro Tasmania | 94 | Bairnsdale **(94)** | Alinta Energy |
| Pacific Hydro 67%; Melbourne Renewable Energy Project 33% | 79 | Crowlands **(79)** | Pacific Hydro (State Power Investment Corporation) |
| Powershop | 54 | Salt Creek **(54)** | Tilt Renewables |
| Infigen Energy | 31 | Kiata **(31)** | John Laing Group 72.3%; Windlab Australia 25%; Local community 2.7% |
| *Non-scheduled plant < 30 MW* | 275 | *Misc.* | |
| SOUTH AUSTRALIA | 6 082 | | |
| AGL Energy | 1 963 | Torrens Island A **(480)** and B **(800)** Barker Inlet **(211);** Hallett 1 **(95);** Hallett 2 **(71);** Wattle Point **(91);** North Brown Hill **(132);** The Bluff **(53)**<br>Dalrymple North **(30)** | AGL Energy<br>ElectraNet |
| Origin Energy | 1 128 | Snowtown **(99)**; Snowtown North **(144)**; Snowtown South **(126)**<br>Quarantine **(229)**; Ladbroke Grove **(80);** Osborne **(180)**<br>Bungala One **(135)** and Two **(135)** | Tilt Renewables<br>Origin Energy<br>Enel Green Power |
| Engie | 1 025 | Pelican Point **(478)**; *Canunda* ***(46)****;* Dry Creek **(156)**; Mintaro **(90)**; Port Lincoln **(73)**; Snuggery **(63)**<br>Willogoleche **(119)** | Engie 72%; Mitsui 28%<br>Engie |
| ACT Government | 316 | Hornsdale 1–3 **(316)** | Neoen |
| EnergyAustralia | 283 | Hallet **(217)**<br>*Cathedral Rocks* ***(66)*** | EnergyAustralia (CLP Group)<br>EnergyAustralia (CLP Group) 50%; Acciona Energy 50% |
| SA Government | 277 | *Temporary Generation North* ***(154)****; Temporary Generation South* ***(123)*** | SA Government |
| Snowy Hydro | 237 | Port Stanvac **(58)**; Angaston **(50)**; Lonsdale **(21)**<br>Tailem Bend **(108)** | Snowy Hydro (Australian Government)<br>Vena Energy |
| Infigen Energy | 223 | Lake Bonney 2 **(159)** and 3 **(39);** Lake Bonney **(25)** | Infigen Energy |
| EnergyAustralia 50%; Hydro Tasmania 50% | 130 | Waterloo **(130)** | Palisade Investment Partners 74%; Northleaf Capital Partners 26% |
| ERM Power | 126 | Lincoln Gap 1 **(126)** | Nexif Energy |
| SA Government 70%; Neoen 30% | 100 | Hornsdale Power Reserve **(100)** | Neoen |
| Essential Energy | 81 | *Lake Bonney 1* ***(81)*** | Infigen Energy |
| Meridian Energy | 70 | *Mount Millar* ***(70)*** | Meridian Energy |
| Pacific Hydro | 57 | Clements Gap **(57)** | Pacific Hydro (State Power Investment Corporation) |
| Hydro Tasmania | 35 | *Starfish Hill* ***(35)*** | RATCH Australia (Ratchaburi Electricity Generation 80%, Ferrovial 20%) |
| *Non-scheduled plant < 30 MW* | 31 | *Misc.* | |
| TASMANIA | 3 154 | | |
| Hydro Tasmania | 2 906 | Gordon **(432)**; Poatina **(300)**; Reece **(232)**; Tamar Valley **(208)**; Catagunya/Liapootah/Wayatinah **(173)**; Mussleroe **(168)**; John Butters **(144)**; *Woolnorth* ***(140)***; Tungatinah **(125)**; Bell Bay **(105)**; Trevallyn **(93)**; Tarraleah **(90)**; Cethana **(85)**; Tribute **(83)**; Lemonthyme/Wilmot **(82)**; Bastyan **(80)**; Mackintosh **(80)**; Devils Gate **(60)**; Fisher **(43)**; Meadowbank **(40)**; Lake Echo **(32)**;<br>Granville Harbour **(111)** | Hydro Tasmania (Tas Government)<br>Palisade Investment Partners |
| Goldwind Australia | 148 | Cattle Hill Wind Farm **(148)** | Goldwind Australia; Power China Group |
| *Non-scheduled plant < 30 MW* | 100 | *Misc.* | |

Misc., miscellaneous; MW, megawatts.

Fuel types: black coal; brown coal; gas; hydro; wind; solar; battery; other (e.g diesel, bagasse).

*italics*: non-scheduled.

Note: Capacity as published by AEMO for summer 2019–20, except for non-scheduled plant, for which nameplate capacity is used.

Source: AER; AEMO; company announcements.

Figure 2.18
**Generators in the NEM**

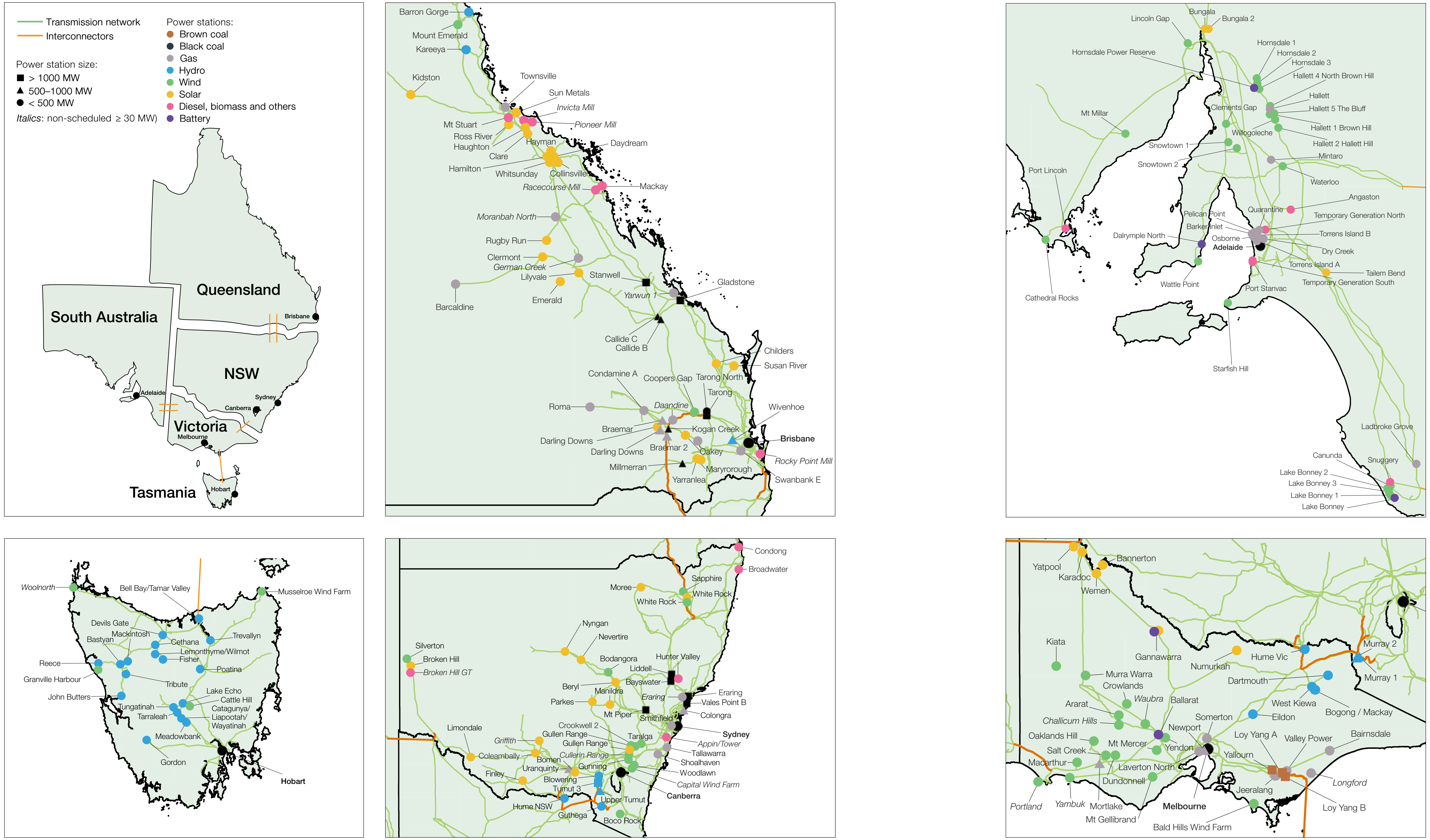
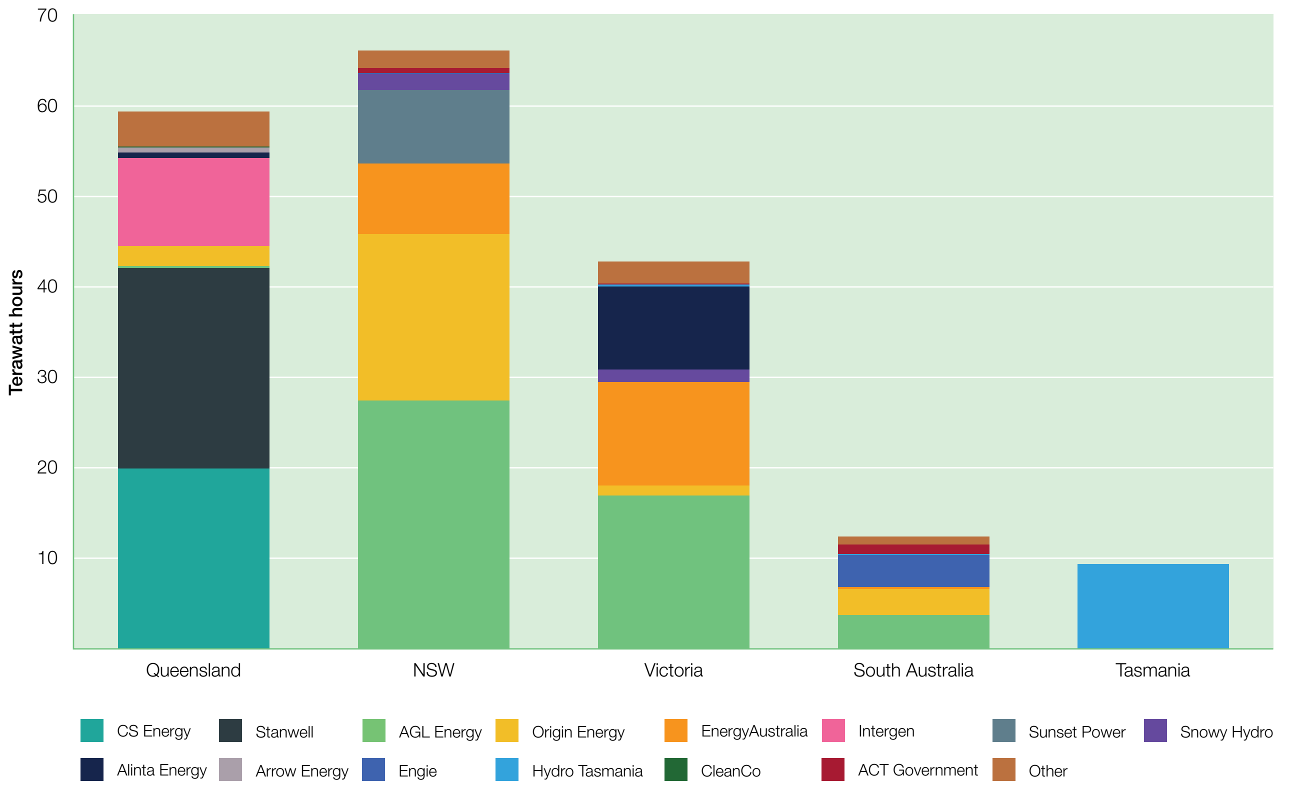


Figure 2.19
**Market shares in generation output**




Note: Output in 2019. Ownership is attributed by trading rights at the time. Output is split on a pro rata basis if ownership changed in 2019. Data exclude output from rooftop solar PV systems and interconnectors.

Source: AER; AEMO; company announcements.

Across NSW, Victoria and South Australia, these seven retailers jointly own around 90 per cent of generation capacity.

A number of smaller retailers are also vertically integrated:

- Powershop and Tango Energy each have a portfolio of wind and hydroelectric generation operated by their respective parent companies, Meridian Energy and Pacific Hydro.
- Momentum Energy is backed by Hydro Tasmania, which owns the vast majority of generation capacity in Tasmania.

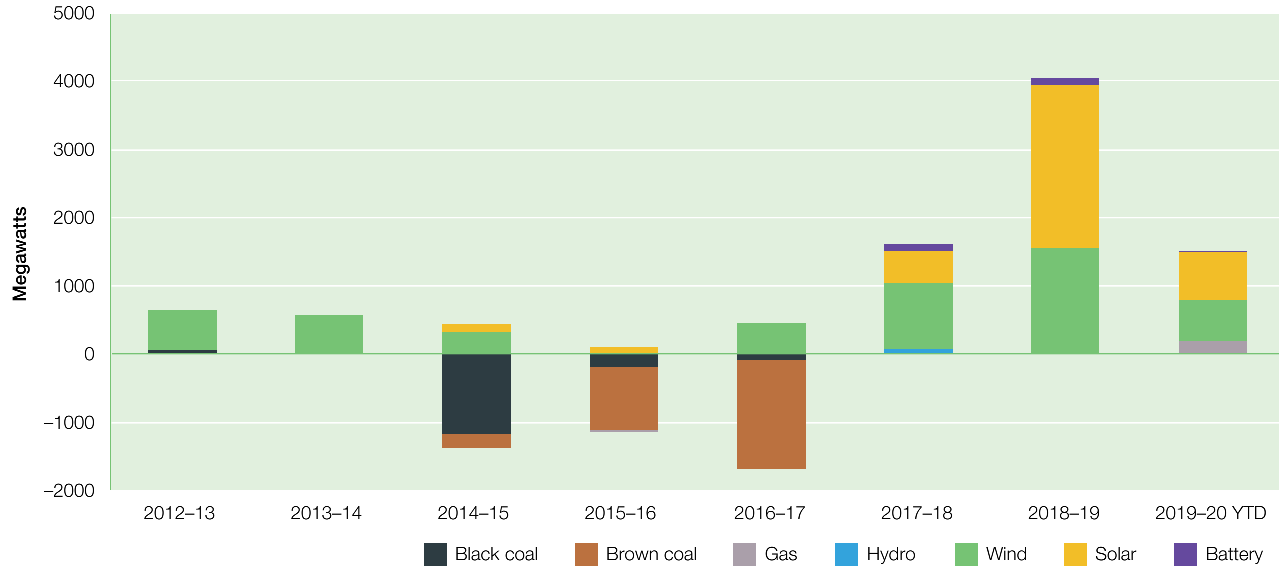
## 2.5 Generation investment and plant closures

Investment in generation plant outpaced the growth in electricity demand for several years, resulting in significant surplus capacity from around 2009 to 2015. In response, new investment slowed and some generators permanently or temporarily removed capacity from the market. While 2200 MW of new generation investment was added to the NEM over the five years to June 2017, over 4000 MW of capacity was withdrawn over the same period (figure 2.20).

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

Two gas plants are also listed for retirement—AGL's Torrens Island A (480 MW) in South Australia (retiring progressively in 2020–21) and Mackay (34 MW) in Queensland (retiring in 2022). In Tasmania, the Tamar Valley plant (208 MW) is unavailable for much of the time, but can be returned to service with less than three months notice.[19]

Figure 2.20
**New generation investment and plant withdrawals**

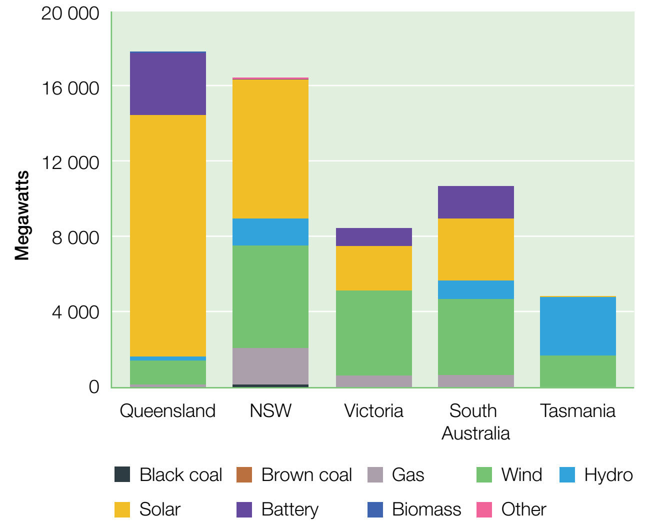



YTD, year to date.

Note: 2019–20 data are to 31 March 2020. An additional 2817 MW of committed capacity (1461 MW of wind, 1334 MW of solar and 22 MW of battery storage) is expected to be commissioned in 2020.

Source: AER; AEMO (data)

Figure 2.21
**Announced generation proposals at March 2020**




Source: AEMO, *Generation information April 2020*.

19 AEMO, *2018 electricity statement of opportunities*, August 2018, p. 55.

The plant closures significantly reduced capacity in the NEM and led to AEMO signalling risks of summer power outages. The private sector responded with significant investment in renewable generation, but investment in other technologies has been limited. High gas fuel costs, less frequent high electricity spot prices, and policy uncertainty have been cited as reasons for the lull in gas plant investment.[20] Barker Inlet (South Australia, 210 MW) is the NEM's first material addition of fossil fuel capacity since an upgrade to Eraring in 2012. The gas plant was commissioned to replace capacity lost by the retirement of Torrens Island A.

Over 93 per cent of generation investment since 2012–13 has been in renewable (wind and solar) capacity, partly driven by RET scheme subsidies, and ARENA and CEFC funding. Investment in renewables picked up strongly after the Australian Government confirmed in 2015 the RET scheme would continue until 2030. Over 5900 MW of new wind, solar and battery capacity was added to the NEM between June 2017 and December 2019 (table 2.3). Another 3000 MW of capacity is committed to come online by 2021 (table 2.4).

20 AER, *Wholesale electricity market performance report*, December 2018; ACCC, *Restoring electricity affordability and Australia's competitive advantage, Retail Electricity Pricing Inquiry—final report*, June 2018, p. 100.

**Table 2.3 New generation investment, January 2018 – March 2020**

| TRADING RIGHTS | POWER STATION | TECHNOLOGY | CAPACITY (MW) | FIRST DISPATCH DATE |
|---|---|---|---|---|
| QUEENSLAND | | | 2406 | |
| Origin Energy | Clare | Solar | 110 | April 2018 |
| Origin Energy | Darling Downs | Solar | 121 | July 2018 |
| ERM Power | Hamilton | Solar | 57 | July 2018 |
| Sun Metals | Sun Metals | Solar | 124 | July 2018 |
| Queensland Government | Whitsunday | Solar | 57 | July 2018 |
| Alinta Holdings | Collinsville | Solar | 42 | August 2018 |
| Ergon Energy | Mount Emerald | Wind | 180 | August 2018 |
| Telstra | Emerald | Solar | 88 | September 2018 |
| EnergyAustralia | Ross River | Solar | 128 | September 2018 |
| Origin Energy | Daydream | Solar | 167 | October 2018 |
| ESCO Pacific | Susan River | Solar | 85 | December 2018 |
| Edify Energy | Hayman | Solar | 57 | January 2019 |
| ESCO Pacific | Childers | Solar | 64 | February 2019 |
| Ergon Energy | Lilyvale | Solar | 118 | March 2019 |
| Diamond Energy | Oakey | Solar | 30 | March 2019 |
| Pacific Hydro | Haughton | Solar | 132 | May 2019 |
| Adani Renewables | Rugby Run | Solar | 83 | May 2019 |
| AGL Energy | Coopers Gap | Wind | 452 | June 2019 |
| Simec Zen | Clermont | Solar | 92 | June 2019 |
| Foresight | Oakey 2 | Solar | 65 | September 2019 |
| Risen Solar | Yarranlea | Solar | 121 | January 2020 |
| Diamond Energy | Maryrorough | Solar | 33 | March 2020 |
| NSW | | | 1535 | |
| Engie | Parkes | Solar | 55 | February 2018 |
| CWP/Partners Group 67%; ACT Government 37% | Sapphire | Wind | 270 | February 2018 |
| EnergyAustralia | Manildra | Solar | 50 | May 2018 |
| AGL Energy | Silverton | Wind | 198 | May 2018 |
| EnergyAustralia 60%; Infigen Energy 40% | Bodangora | Wind | 113 | August 2018 |
| ACT Government | Crookwell 2 | Wind | 96 | August 2018 |
| EnergyAustralia 67%; Neoen 33% | Coleambally | Solar | 180 | September 2018 |
| Goldwind | White Rock | Solar | 22 | October 2018 |
| NSW Government 70%; Kelloggs 30% | Beryl | Solar | 98 | April 2019 |
| BlueScope Steel 66%; John Laing 34% | Finley | Solar | 162 | August 2019 |
| Elliott Green Power | Nevertire | Solar | 132 | December 2019 |
| Innogy | Limondale 2 | Solar | 38 | December 2019 |
| Flow Power 69%; Westpac 26%; Spark Infrastructure 5% | Bomen | Solar | 121 | March 2020 |
| VICTORIA | | | 1509 | |
| EnergyAustralia | Gannawarra | Solar | 55 | April 2018 |
| Acciona Energy | Mount Gellibrand | Wind | 138 | June 2018 |
| Powershop | Salt Creek | Wind | 54 | June 2018 |
| Alinta Holdings | Bannerton | Solar | 100 | July 2018 |
| Carlton & United Breweries | Karadoc | Solar | 104 | October 2018 |
| EnergyAustralia | Ballarat | Battery | 30 | November 2018 |
| Simec Zen | Wemen | Solar | 97 | November 2018 |
| EnergyAustralia | Gannawarra | Battery | 30 | November 2018 |
| Pacific Hydro 67%; Melbourne Renewable Energy Project 33% | Crowlands | Wind | 79 | December 2018 |
| Telstra, in consortium | Murra Warra stage 1 | Wind | 231 | April 2019 |
| Simec Zen | Numurkah | Solar | 112 | May 2019 |
| Orora | Yendon | Wind | 144 | June 2019 |
| Snowy Hydro 50%; Victorian Government 37%; Tilt Renewables 13% | Dundonnell | Wind | 335 | March 2020 |
| SOUTH AUSTRALIA | | | 889 | |
| Origin Energy | Bungala One | Solar | 135 | May 2018 |
| AGL Energy | Dalrymple North | Battery | 30 | July 2018 |
| Engie | Willogoleche | Wind | 119 | August 2018 |
| Origin Energy | Bungala Two | Solar | 135 | October 2018 |
| Snowy Hydro | Tailem Bend | Solar | 108 | February 2019 |
| ERM Power | Lincoln Gap stage 1 | Wind | 126 | May 2019 |
| AGL Energy | Barker Inlet | Gas | 211 | October 2019 |
| Infigen Energy | Lake Bonney | Battery | 25 | October 2019 |
| TASMANIA | | | 256 | |
| Goldwind | Cattle Hill | Wind | 144 | January 2020 |
| Hydro Tasmania | Granville Harbour | Wind | 112 | February 2020 |

MW, megawatts.

Source: AER; AEMO, *Generation information April 2020*.

Almost 60 000 MW of additional capacity is proposed but not formally committed (figure 2.21). The bulk of proposed projects are in solar (43 per cent) and wind (31 per cent) plant.

Offsetting new capacity, further fossil fuel plant withdrawals are expected (figure 1.4 in chapter 1). Among these withdrawals, AGL plans to retire its Liddell coal plant in NSW (2000 MW) in stages over 2022 and 2023, and replace it with a mix of renewable gas generation, batteries, and an upgrade to the Bayswater power station.

## 2.6 Wholesale prices and activity

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

Alongside this seasonal pattern, longer term trends show an upward movement in wholesale prices after the closure of

**Table 2.4 Committed investment projects in the NEM at March 2020**

| OWNER | POWER STATION | TECHNOLOGY | CAPACITY (MW) | PLANNED COMMISSIONING |
|---|---|---|---|---|
| QUEENSLAND | | | 244 | |
| Windlab/Eurus | Kennedy Energy Park | Solar | 15 | 2020 |
| Windlab/Eurus | Kennedy Energy Park | Battery | 2 | 2020 |
| Windlab/Eurus | Kennedy Energy Park | Wind | 43 | 2020 |
| University of Queensland | Warwick | Solar | 64 | 2020 |
| Shell | Gangarri | Solar | 120 | 2021 |
| NSW | | | 3340 | |
| Fotowatio Renewable Ventures | Goonumbla | Solar | 70 | 2020 |
| Edify Energy; Octopus Investments | Darlington Point | Solar | 275 | 2020 |
| Innogy | Limondale 1 | Solar | 220 | 2020 |
| John Laing/Maoneng Group | Sunraysia | Solar | 229 | 2020 |
| Beijing Jingneng Clean Energy | Biala | Wind | 111 | 2020 |
| RATCH Australia | Collector | Wind | 227 | 2020 |
| TEC-C Investments | Molong | Solar | 30 | 2020 |
| CWP Renewables | Crudine Ridge | Wind | 138 | 2021 |
| Snowy Hydro | Snowy 2.0 | Pumped hydro | 2040 | 2025 |
| VICTORIA | | | 1734 | |
| Northleaf 40%; InfraRed Capital Partners 40%; Macquarie 20% | Elaine | Wind | 84 | 2020 |
| John Laing Group | Cherry Tree | Wind | 58 | 2020 |
| Total Eren | Kiamal stage 1 | Solar | 200 | 2020 |
| BayWa r.e. | Yatpool | Solar | 94 | 2020 |
| Neoen | Bulgana Green Power Hub | Battery | 20 | 2020 |
| Goldwind | Stockyard Hill | Wind | 532 | 2020 |
| Goldwind | Moorabool | Wind | 320 | 2020 |
| Wirtgen Invest | Glenrowan West | Solar | 106 | 2020 |
| Neoen | Bulgana Green Power Hub | Wind | 204 | 2021 |
| Fotowatio Renewable Ventures | Winton | Solar | 85 | 2021 |
| Enel Green Power | Cohuna | Solar | 31 | 2020 |
| SOUTH AUSTRALIA | | | 86 | |
| Nexif Energy | Lincoln Gap stage 2 | Wind | 86 | 2020 |

MW, megawatts.

Source: AER; AEMO, *Generation information April 2020*.

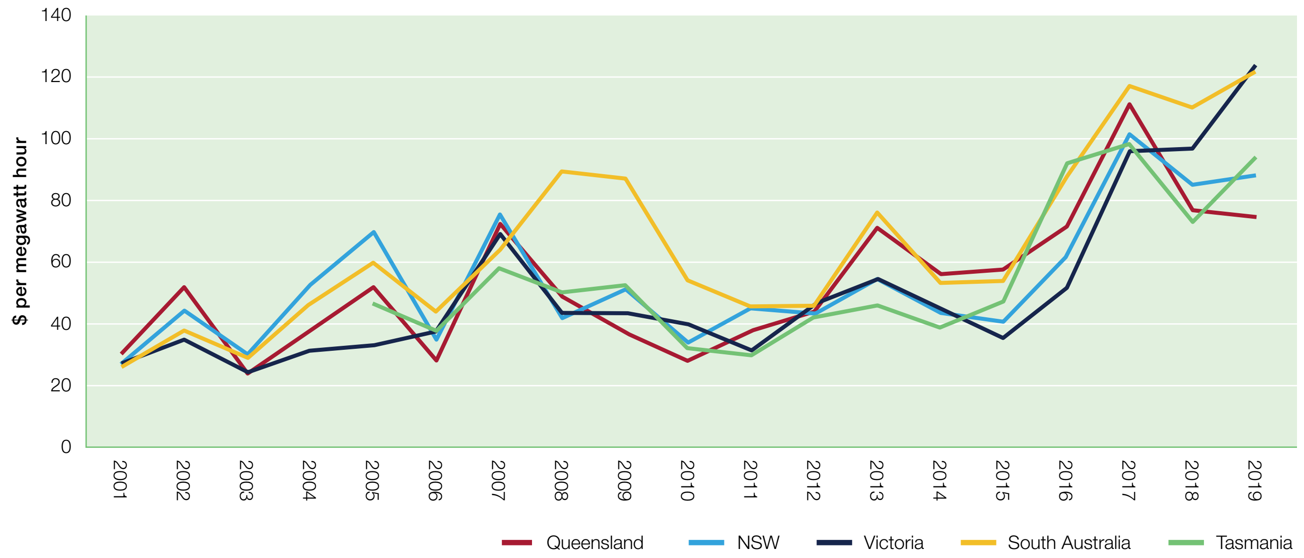
two brown coal power stations—Northern (South Australia) in May 2016 and Hazelwood (Victoria) in March 2017. The Hazelwood closure withdrew around 5 per cent of the NEM's total capacity, much of it usually offered at low prices. From that point, more expensive black coal and gas plant began to set spot prices more often. Between July 2015 and July 2017, the average offer price for the cheapest 20 000 MW of capacity in the NEM increased from $50 per megawatt hour (MWh) to almost $100 per MWh. Prices generally remained elevated in 2017 and 2018.

Queensland prices followed a different trend. In June 2017 the Queensland Government directed the state owned generation business, Stanwell, to put downward pressure



Figure 2.22

**Wholesale electricity prices**




Note: Volume weighted annual averages.

Source: AER; AEMO (data).

on wholesale electricity prices.[21] The state has since moved from having some of the highest average prices in the NEM to generally having the lowest average price. The government direction remained in place until 30 June 2019.

## 2.6.1 The market from 2019

The following is a high level summary of market conditions from 2019. The AER's *Wholesale markets quarterly*, launched in 2019, analyses price trends and underlying causes in more detail.

In 2019 wholesale prices across the NEM (on a volume weighted average basis) averaged close to $100 per MWh, up from $90 per MWh in 2018, but slightly lower than the 2017 average of $106 per MWh (figures 2.22 and 2.23):

- Victoria ($126 per MWh) edged out South Australia ($125 per MWh) as the NEM's highest price region. The state more than doubled its 2016 average ($52 per MWh) before the closure of Hazelwood.
- South Australia recorded its third consecutive year of triple digit average prices, and more than doubled its 2015 average before the closure of the region's last brown coal generator, Northern.
- Queensland ($75 per MWh) and NSW ($89 per MWh) were the lowest price regions.
- Tasmania recorded a 30 per cent year-on-year rise in spot prices—the largest for any region, with prices averaging $95 per MWh.

These calendar year averages mask a distinct shift in market outcomes over 2019. Prices were elevated in the first quarter (setting records in some regions), then eased in the second quarter, before moving lower in the second half of the year. This downward shift continued into 2020.

In the first quarter of 2019, weather events combined with plant failures led to Victoria ($216 per MWh) and South Australia ($223 per MWh) setting record prices. Temperatures on some days neared 50°C in parts of South Australia. During the quarter, Victoria and South Australia experienced 16 and 15 trading intervals respectively of prices exceeding $5000 per MWh. The number for South Australia was a quarterly record.

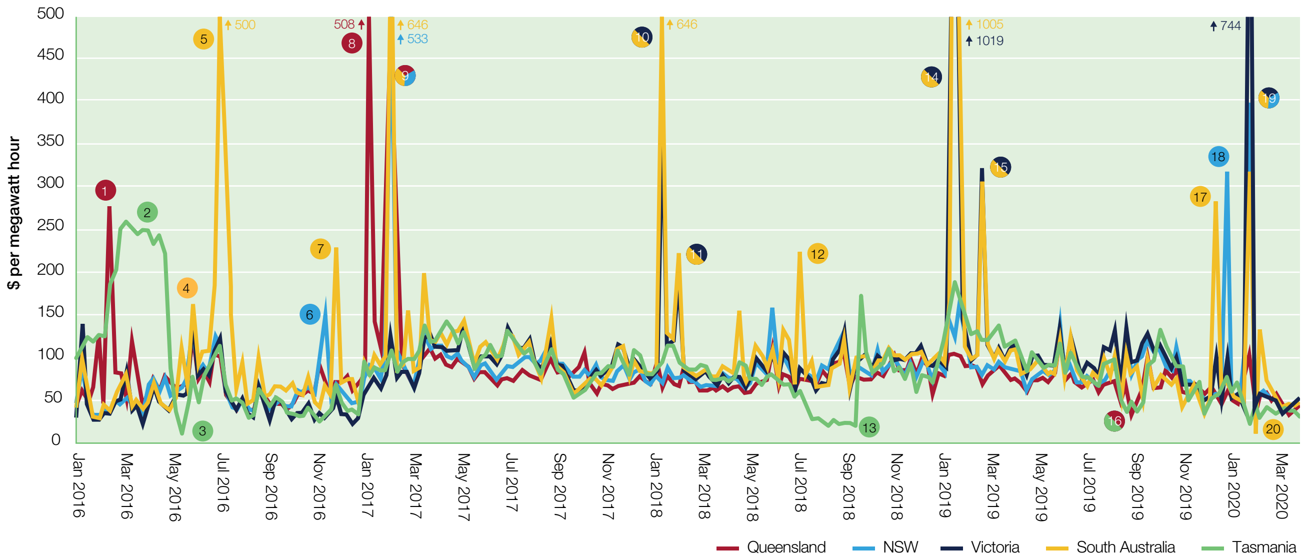
Eleven of the high price events occurred on 24 January 2019. Record temperatures in South Australia (48°C) following three days of temperature above 35°C, and high temperatures in Victoria, caused a surge in demand. This surge coincided with unexpected equipment failures, causing forecast demand to exceed available supply in both regions. Prices reached the market cap ($14 500 per MWh at the time) in both regions.[22]

On 25 January, continued high temperatures in Victoria drove high demand. Prices reached the cap in Victoria,

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

22 AER, *Electricity spot prices above $5000/MWh, Victoria and South Australia, 24 January 2019*, March 2019.

Figure 2.23
**Wholesale electricity prices—volume weighted weekly averages**




**Price events**

1 Record high demand and rebidding
2 Basslink outage and record low rainfall and dam levels
3 High rainfall increased hydro output
4 Coal plant closures and extensive coal outages reduced supply. Coincided with high gas prices
5 Heywood interconnector outage due to planned maintenance. Coincided with low wind and plant closures
6 Rebidding behaviour and network constraints on the Victoria-NSW interconnector
7 Rebidding behaviour and an unplanned outage of the Heywood interconnector
8 High temperatures led to record Queensland demand, plant restrictions, rebidding and limited imports
9 Extremely high temperatures led to high demand across the NEM. Extensive coal generator outages in Queensland and NSW. Load shedding in SA because demand exceeded forecasts and wind output was low
10 High temperatures led to high demand in Victoria and South Australia, coincided with a plant outage in Victoria
11 High temperatures led to high demand
12 Planned outages on the Heywood interconnector. Coincided with low wind output
13 High rainfall increased hydro output
14 High temperatures led to high demand in Victoria and South Australia, and load shedding in Victoria coincided with a plant outage in Victoria
15 High temperatures led to high demand in Vic and SA at a time of low wind output
16 Record low demand and an increase in solar output drove negative prices in Queensland during the middle of the day. High hydro output in Tasmania
17 High temperatures drove demand close to record levels. Coincided with limited import capacity on the Murraylink interconnector and low wind output
18 Bushfires led to Victoria-NSW interconnection being disrupted. Coincided with high demand
19 Extreme storm conditions led to South Australia being isolated from the NEM. Tight supply conditions and high demand driven by high temperatures in Victoria and NSW. Another price event in South Australia and Victoria due to high demand, low wind generation and a plant outage
20 South Australia unable to export energy due to interconnector disruptions, resulting in excess supply

Note: Volume weighted weekly averages.

Source: AER; AEMO (data).

and exceeded $11 000 per MWh in South Australia.[23] The high price events over the two days contributed around $40 to the quarterly price in Victoria and South Australia. Coincident high temperatures in Victoria and South Australia again drove prices above $5000 per MWh on 1 March in both regions.

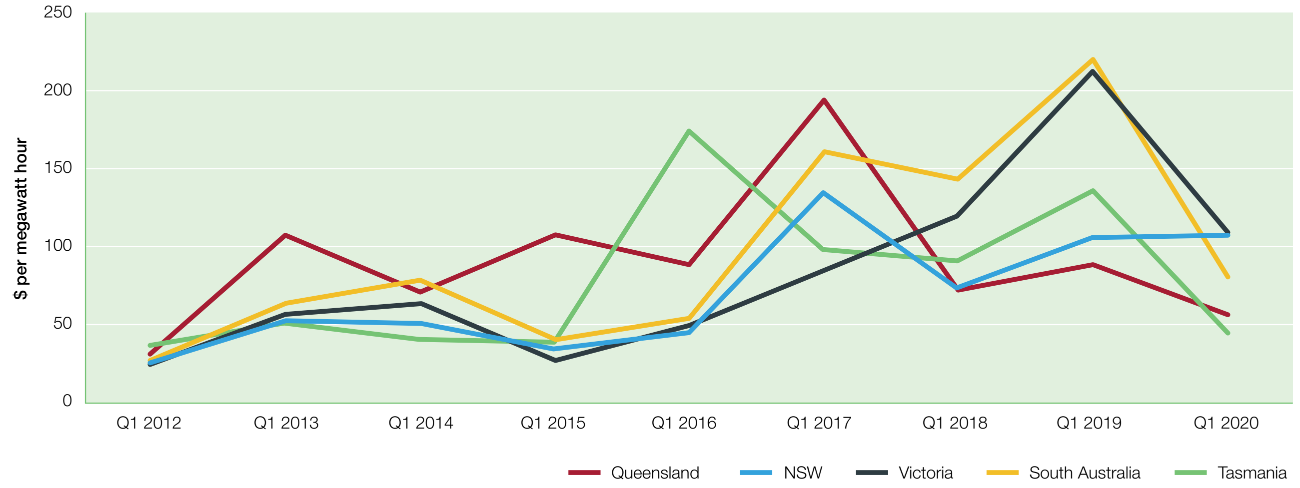
Tasmania also recorded high prices during the quarter, driven by high demand and below average rainfall affecting offers from hydro generators. Overall, hydro generation was around 15 per cent lower in 2019 than a year earlier.

Wholesale prices remained elevated in some regions during the second quarter of 2019, compared with the same quarter in 2018. Prices were higher in Victoria than elsewhere, partly due to planned and unplanned outages reducing brown coal generation. An unplanned outage at Loy Yang A ran from May to December 2019, removing 11 per cent of low cost generation from the region. Loy Yang B unit 2 was also unavailable, due to a planned upgrade. Outages at the Yallourn and Mortlake power stations compounded the situation, resulting in Victoria setting record prices of over $100 per MWh in the second and third quarters of 2019.

23 AER, *Electricity spot prices above $5000/MWh, Victoria and South Australia, 25 January 2019*, March 2019.



Figure 2.24
**First quarter wholesale electricity prices**




Note: Volume weighted quarterly averages.

Source: AER; AEMO (data).



Prices generally eased in the second half of 2019 as new renewable generation came online, and fuel costs for coal and gas generators fell (see below). South Australia and Queensland recorded their lowest third quarter averages since 2016. A fault on the Basslink interconnector between Tasmania and Victoria meant the connection was unavailable for around six weeks in August–September 2019, contributing to Tasmania having higher third quarter prices than a year earlier.

By the fourth quarter, prices across the market had entered a discernible downward trend, averaging below $90 per MWh in every region for the first time in two years. Queensland and Victorian prices in the fourth quarter recorded their lowest quarterly averages since 2016 (figure 2.24). The easing of Victorian prices was assisted by the return to service of Yallourn and Loy Yang A.

## 2.6.2 The market in early 2020

Prices continued to ease in 2020, when first quarter prices fell to their lowest average since 2012 in Queensland, 2015 in Tasmania, 2016 in South Australia, and 2017 in Victoria. Notably, first quarter prices were below $110 per MWh in all regions for the first time since 2015.[24]

This outcome appeared unlikely in January 2020, when most regions experienced bushfires and periods of extreme weather that caused bursts of high prices in NSW, Victoria and South Australia. On 4 January high demand and network outages due to bushfires resulted in NSW spot prices rising above $5000 per MWh between 4 pm and 6 pm.[25] On 30 January higher than forecast demand, lower than forecast wind generation and generator outages meant evening prices in Victoria and South Australia rose above $10 000 per MWh.

On 31 January the Heywood interconnector connecting Victoria to South Australia failed when a localised storm collapsed six transmission towers. As a result, South Australia was isolated from the rest of the NEM until 17 February, when a temporary 500 kilovolt (kV) line was installed (the interconnector returned to full operation on 3 March). Prices exceeded $5000 per MWh in NSW, Victoria and South Australia immediately following the interconnector failure as a result of constraints invoked by AEMO, tight supply and demand conditions driven by hot weather, and technical plant issues.[26]

While mainland regions recorded their highest weekly prices for the quarter in the week commencing 26 January, Tasmania recorded its lowest weekly average in the same week. It appears Tasmania's generation capacity was being offered in a way to ensure it was dispatched to take advantage of high prices on the mainland.[27]

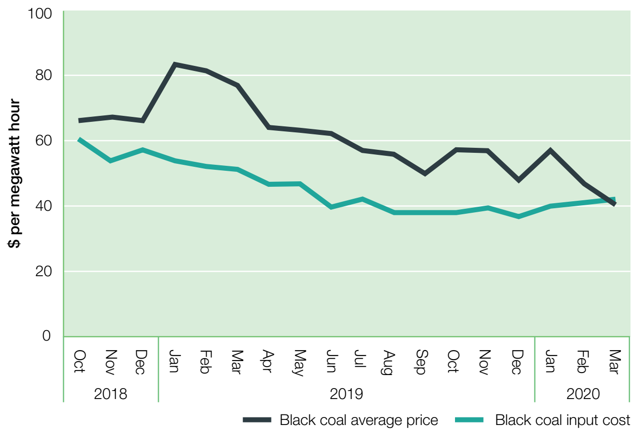
24 All prices are volume weighted averages.

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

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

27 AER, *Wholesale markets quarterly—Q1 2020*, May 2020.

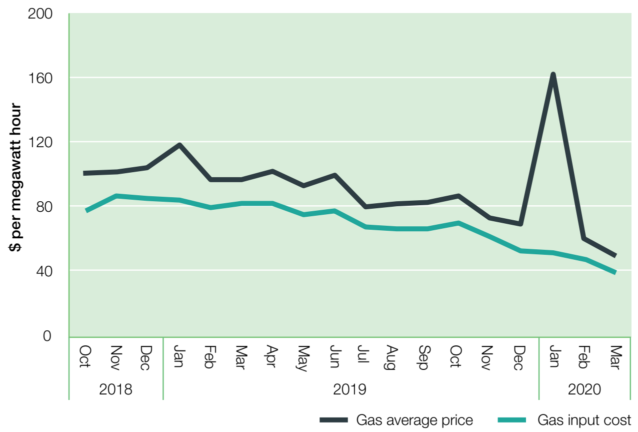
Figure 2.25
Black coal fuel costs, NSW




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

Source: AER analysis using globalCOAL data.

Figure 2.26
Gas fuel costs, Sydney




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

Source: AER analysis using NEM and gas price data.

From the week beginning 16 February, generally milder weather reflected in relatively low summer demand. Prices in all regions progressively converged and remained below $74 per MWh for the remainder of the quarter. Subdued demand also reflected in average generation in the NEM being 4 per cent lower in the first quarter of 2020 than in the same quarter of 2019, with the largest reductions being for black coal and gas generation.

But longer term factors that began around mid-2019 also contributed to benign market conditions. Two key factors were a downward shift in generator fuel costs, and rising levels of renewable generation.

### 2.6.3 Generator fuel costs

Fuel costs for black coal and gas generators eased significantly after the first quarter of 2019. In NSW, for example, fuel costs for black coal generators hovered around $60 per MWh in January 2019, but then steadily declined to $40 per MWh by June 2019, where they have since stabilised (figure 2.25). Prices set by black coal plants generally tracked falling international coal prices over this period. In March 2020 the average price set by black coal generators in NSW ($47 per MWh) was at its lowest level since late 2016. This shift occurred despite coal supply and plant availability issues at Bayswater and Mount Piper that constrained black coal generation. Over a period of several months in 2019, coal supply issues cut Mount Piper's output to less than half of what the plant generated in the same period in 2018.

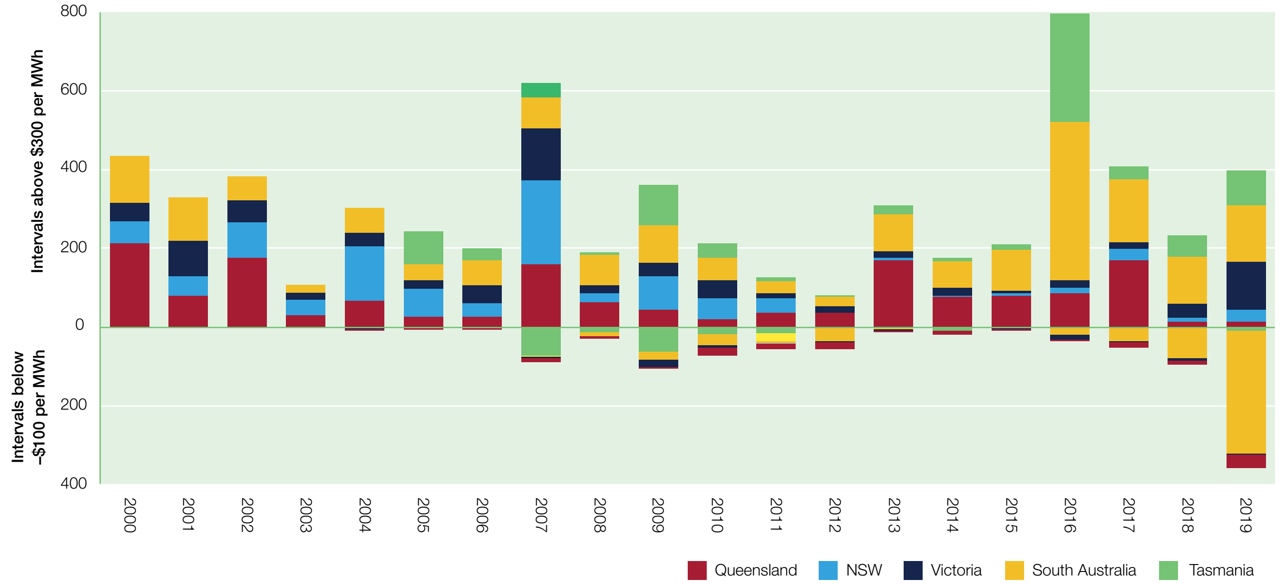
Fuel costs for gas plant also lowered in 2019. Again taking NSW as an example, fuel costs for gas plant eased from around $80 per MWh in January 2019 to around $60 late in the year (figure 2.26). The trend continued into 2020, with fuel costs falling to around $40 per MWh by March 2020. This decline generally reflected in wholesale electricity prices set by gas generators trending downwards since early 2019. January 2020 was an exception, when bushfires and high temperatures in NSW allowed generators to set some prices above $5000 per MWh.

More generally, coal and gas generation set lower wholesale electricity prices in the first quarter of 2020 than in the same quarter of 2019 in all regions except South Australia. Notably, black coal generators in NSW offered nearly all their capacity at less than $50 per MWh. This reduction in offer price is significant because black coal sets the price in NSW, Queensland and Victoria around 70, 60 and 40 per cent of the time respectively.

### 2.6.4 Renewable output

Another factor driving lower prices from the second half of 2019 was the increased renewable output from the recent influx of new wind and solar plant in the market. Over the 12 months to 31 March 2020, around 1550 MW of wind

Figure 2.27
Prices above $300 per MWh and below –$100 per MWh




Source: AER; AEMO (data).

capacity entered the market, of which almost half was installed in Victoria. Over the same period, almost 1200 MW of grid scale solar capacity entered the market, mostly in Queensland and NSW. A substantial rise in solar capacity contributed to Queensland being the only region with a lower year-on-year average price in 2019, despite electricity demand in the region continuing to grow.[28]

Wind generation in the first quarter of 2020 was 18 per cent higher than in the same quarter of 2019, and in South Australia it periodically displaced gas generation. Over the same period, solar generation was 54 per cent higher. Hydro generation was also higher (by 17 per cent), with the increase occurring mostly in Tasmania and NSW. This growth of renewable output is easing price pressures in the market, and contributed to a record number of negative prices during the third quarter of 2019. The number of negative prices in the first quarter of 2020 was also a first quarter record (section 2.6.2).

### 2.6.5 Price volatility

Spot price volatility is a natural feature of energy markets, and can signal to the market a need for investment in new generation (figure 2.27). Following record volatility in 2016 and 2017, the NEM recorded a marked reduction in the number of trading intervals with spot prices over $300 per MWh in 2018, with 232 instances (down from 409 the previous year).

Volatility returned in 2019, with 397 trading intervals exceeding $300 per MWh. Much of this volatility occurred in Victoria, South Australia and Tasmania, and was associated with extreme weather and high system demand early in the year, as well as generator outages in Victoria in mid-2019. Significant volatility was also observed in early 2020, again linked to extreme summer weather.

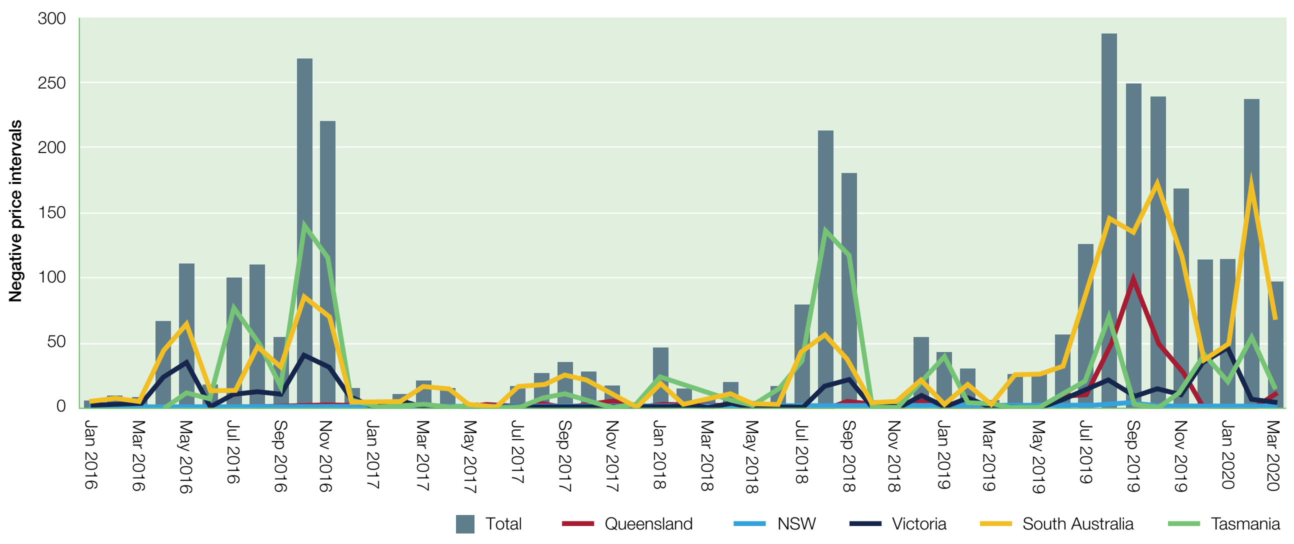
Bushfires and storms also impacted the market, causing transmission lines to trip and suddenly cut off available generation. At times, these events led to market separation between regions, as occurred between NSW and Victoria on 4 January 2020, and between Victoria and South Australia from 31 January to 17 February 2020. Spot prices hit the cap of $14 700 per MWh on multiple days during the bushfire period.

#### Negative prices

A relatively recent aspect of market volatility is a rising incidence of negative prices. Generators in the NEM can offer capacity as low as the market floor price of –$1000 per MWh. Negative bids essentially signal a generator's willingness to pay to produce electricity rather than switch

28 On 13 February 2019, Queensland set a new record for the region's maximum demand, at 10 179 MW.

Figure 2.28
**Negative spot price count**




Source: AER; AEMO (data).

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.[29]

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 shutdown costs, and have running costs close to zero. If generating conditions are optimal, they may bid capacity at negative prices to guarantee dispatch.

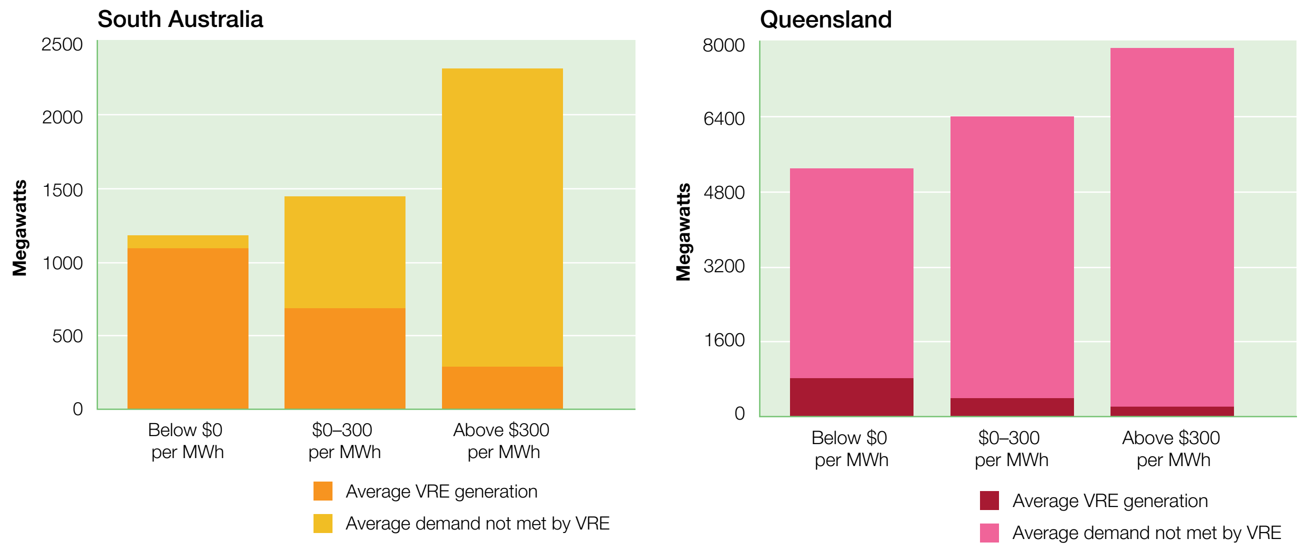
If electricity demand is low, the market has surplus capacity, and the chances of the market settling at a negative price are higher. The geographic grouping of renewable generators can intensify the effect, because when conditions are favourable for one generator in the area, conditions tend to be favourable for others too. With multiple generators of similar technology competing for dispatch, the likelihood of negative prices increases.

While some renewable generators are insulated from negative spot prices through power purchase agreements, other generators may adjust their bidding and shift capacity to higher prices to avoid being dispatched at a negative price. Some wind and solar generators also source revenue from the sale of renewable energy certificates, so they may operate profitably even when wholesale prices are negative.

The instances of negative spot prices increased markedly in the second half of 2019, compared with the same period in 2018 and 2017 (figure 2.28). The third quarter of 2019 exceeded the previous record of the number of negative spot prices, with over 650 negative price intervals across the five regions. Negative prices tended to occur when electricity demand was low and weather conditions were optimal for renewable generation. While historically occurring overnight, they are now more common during the day when solar resources are producing maximum output. The phenomenon was particularly apparent for South Australia and Queensland—regions with a high penetration of wind and solar (grid scale and rooftop) generation (figure 2.29).

29 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 six dispatch prices within that half hour.

Figure 2.29
**Renewable generation and negative prices, 2019**




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

The first quarter of 2020 had over four times as many negative prices (450) as the previous first quarter record in 2014. In that quarter, South Australia accounted for almost two thirds of all negative prices, and over 80 per cent of prices under –$100. Over 40 per cent of its negative prices occurred while South Australia was separated from the rest of the NEM, and coincided with mild temperature and high wind generation. The high incidence of negative prices reduced the average spot price in South Australia by around $5 per MWh during the quarter.

## 2.7 Electricity contract markets

Futures (contract or derivatives) markets operate parallel to the wholesale electricity market. Prices in the wholesale market can be volatile, posing risks for market participants. Generators face the risk of low settlement prices reducing their earnings, while retailers risk paying high wholesale prices that they cannot pass on to their customers. A retailer may expand its operation and sign up a significant number of new customers at a particular price, only to then incur unexpectedly high prices in the wholesale market, ultimately leaving the retailer substantially out of pocket.

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

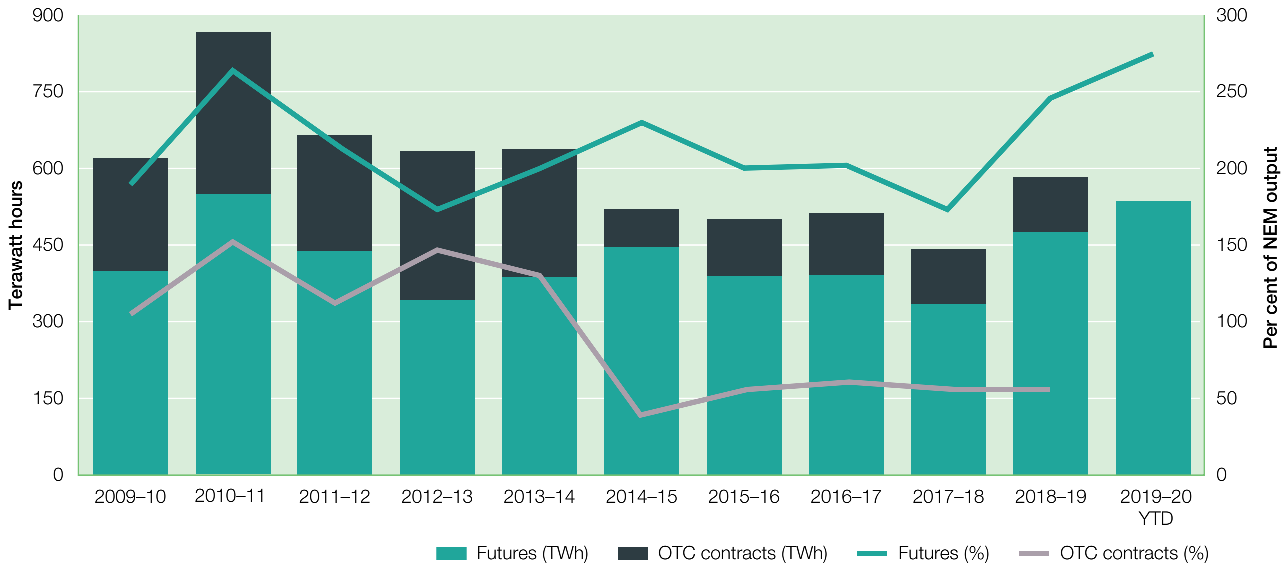
Typically, vertically integrated 'gentailers' are imperfectly hedged—their position in generation may be 'short' (not enough generation) or 'long' (too much generation) relative to their retail position. For this reason, gentailers participate in contract markets to manage outstanding exposures, although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

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

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

- Over-the-counter (OTC) markets, in which two 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.

Figure 2.30
**Traded volumes in electricity futures contracts**




NEM, National Electricity Market; OTC, over-the-counter; TWh, terawatt hours; YTD, year-to-date.

Note: Data for the full 2019–20 financial year trading of OTC contracts were not available at the time of publication. ASX data for 2019–20 are year to date at 31 March 2020.

Source: AER; AFMA; ASX Energy.

- The exchange traded market, in which electricity futures products are traded on the Australian Securities Exchange (ASX). Participants include generators, retailers, speculators, banks and other financial intermediaries. Electricity futures products are available for Queensland, NSW, Victoria and South Australia.

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

- *ASX 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 four quarters of a year. Futures contracts are settled against the average quarterly spot price in the relevant region—that is, when the spot price exceeds the strike price, the seller of the contract pays the purchaser the difference, and when the spot price is lower than the strike price, the purchaser pays the seller the difference. In OTC markets, futures are known as swaps or contracts for difference.
- *Caps* are contracts setting an upper limit on the price that a holder will pay for electricity in the future. Cap contracts on the ASX have a strike price of $300 per MWh. When the spot price exceeds the strike price, the seller of the cap (typically a generator) must pay the buyer (typically a retailer) the difference between the strike price and the spot price. Alternative (higher or lower) strike prices are available in the OTC market.
- *Floors* are contracts that operate on the opposite principle of a cap contract, because they set a lower price limit. They are typically purchased by generators to ensure a minimum level of revenue for output.
- *Options* are contracts that give the holder the right—without obligation—to enter a contract at an agreed price, volume and term in the future. The buyer pays a premium for this added flexibility. An option can be either a call option (giving the holder the right to buy the underlying financial product) or a put option (giving the holder the right to sell the underlying financial product). Options are available on futures and cap products.



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

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

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

## 2.7.1 Contract market activity

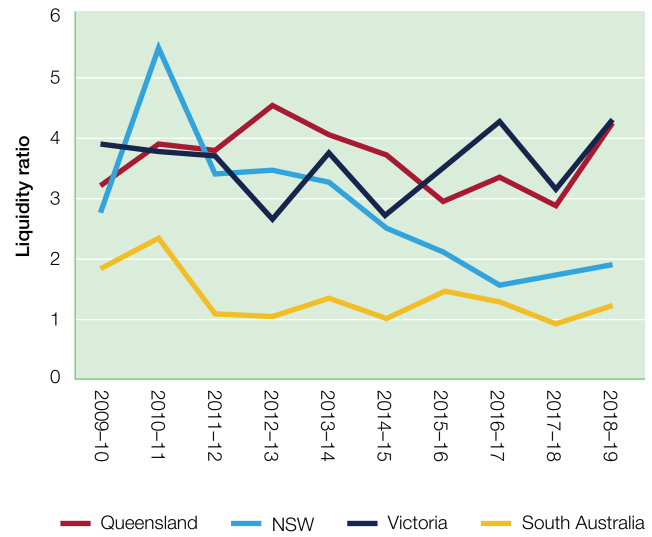
As noted, ASX trades are publicly reported, while activity in OTC markets is confidential and disclosed publicly only via participant surveys in aggregated form. The OTC data are published on a financial year basis. To allow some comparability across OTC and ASX data, this section refers to financial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

Regular ASX trades occur for the Queensland, NSW and Victorian regions of the NEM, but liquidity is poor in South Australia. A decline in trade volumes across the market from 2014 to 2017 may link to flat electricity demand and an oversupply of generation creating less price volatility in the wholesale market, which likely weakened demand for cap contracts. But volumes increased after hitting a low point in 2017–18 (figure 2.30).

In 2018–19 there were trades of 476 TWh of electricity contracts on the ASX, up 43 per cent on the previous financial year and the highest volume traded since 2010–11. These trades represented 243 per cent of underlying NEM demand. Trading levels rose again in 2019–20, with volumes traded in the nine months to 31 March 2020 already exceeding the 2018–19 total.

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

Figure 2.31
**Liquidity ratio in NEM regions**



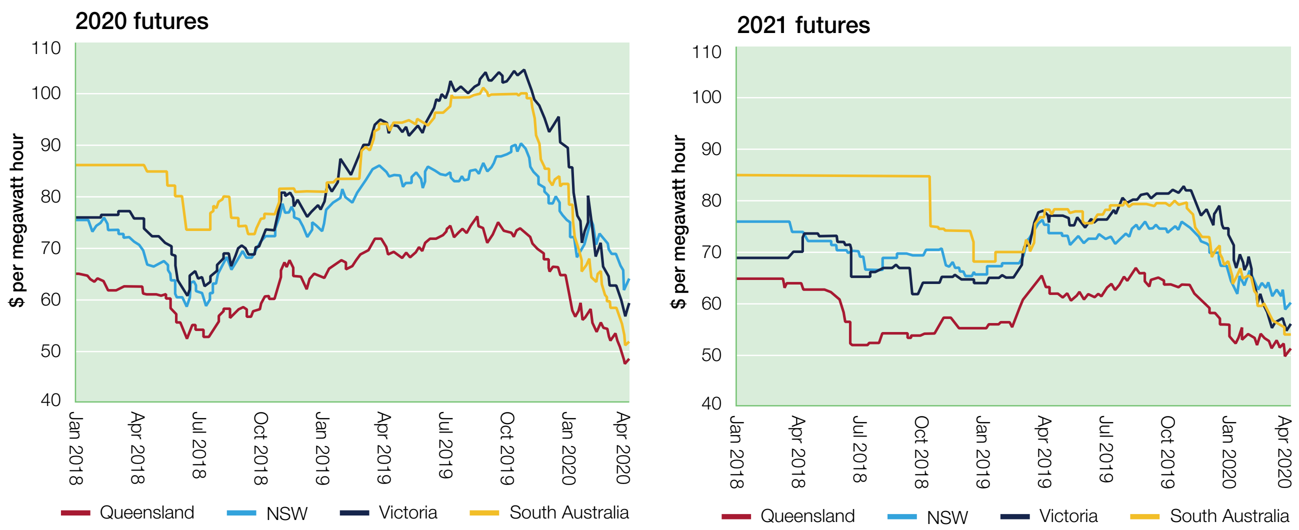

Source: AER; AFMA; ASX Energy.

More recently, ARENA in February 2020 provided funding support to Renewable Energy Hub to establish a firming market platform that offers new hedge products designed for clean energy technologies. The project aims to fill a gap in risk management products and overcome a market barrier for clean energy technologies.[30] In April 2020 Renewable Energy Hub introduced a new 'super peak' electricity contract for electricity supply during the high demand hours of the morning, afternoon and evening periods.[31] Snowy Hydro became the first participant to offer this product.

OTC trade volumes have reduced substantially from levels of a few years ago, making up less than 25 per cent of contract volumes since 2013–14. Leading up to and during the period of carbon pricing from 2012 to 2014, participants sought greater contract flexibility to manage risk through wider participation in the OTC market, and OTC trade volume peaked at 46 per cent of total trade in 2012–13.

30 ARENA, 'Renewable Energy Hub marketplace', web page, available at: https://arena.gov.au/projects/renewable-energy-hub-marketplace/, viewed 1 May 2020.
31 Renewable Energy Hub, 'New era for renewables as first new super peak firming contract signed', Media release, 14 April 2020.

Figure 2.32
Prices for calendar year base futures




Source: AER; ASX Energy.

### Contract market liquidity

Overall, contract liquidity has improved across the NEM in recent years as participants seek additional price protection. The liquidity ratio (contract trading relative to underlying demand) across the NEM rose from around 230 per cent in 2017–18 to 300 per cent in 2018–19 (figure 2.30), with all regions showing improvement (figure 2.31).

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

Liquidity is poorer in South Australia, where trading volumes tend to roughly match underlying electricity demand. The region's high proportion of renewable generation and relatively concentrated ownership of dispatchable generation likely contribute to this weaker liquidity. Given South Australia's liquidity issues, the Australian Competition and Consumer Commission (ACCC) recommended the imposition of a 'market maker' obligation, under which large vertically integrated retailers must make offers to buy and sell hedge products within a capped price spread. Reforms to similar effect were introduced in 2019 under the Retailer Reliability Obligation (RRO) (section 2.7.3 and box 1.3 in chapter 1).

### Composition of trade

Victoria, NSW and Queensland each accounted for 25–37 per cent of ASX contracts traded in 2018–19. Trading in South Australia accounted for only 2 per cent of contract volumes. In the OTC market, the majority of reported OTC trading (63 per cent) occurred in Queensland. NSW and Victoria each accounted for 17 per cent of trading, with South Australia accounting for 4 per cent.

Quarterly futures made up the majority (67 per cent) of ASX trading in 2018–19, with 98 per cent of those futures being baseload products. Peak products accounted for only 2 per cent. The next most commonly traded products were ASX options (21 per cent) and caps (11 per cent). In the OTC market, swap products (83 per cent) and caps (13 per cent) accounted for most of the reported trading.

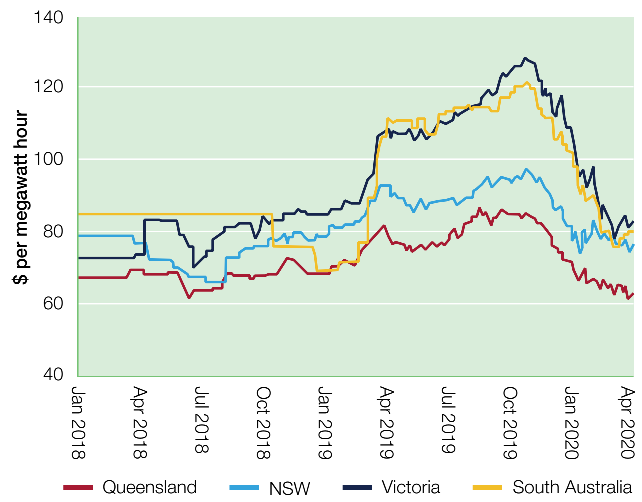
## 2.7.2 Contract prices

Base futures prices for 2020 ASX contracts began rising in the second half of 2018 in the lead up to the summer period, before easing during the summer (figure 2.32). Prices again moved upwards in early 2019 and continued for much of the year. In November 2019 prices began what would become a significant decline across all NEM regions, with falls of almost 50 per cent for Victorian and South Australian futures. The falls coincided with weakening wholesale market prices, linked to falling generator fuel costs and rising renewable generation (section 2.6).





Figure 2.33
Prices for first quarter 2021 base futures




Source: AER; ASX Energy.

The outlook for 2021 prices is relatively stable, with prices following a downward trajectory since November 2019, although the decline has been more gradual than for 2020 base futures.

Futures prices for the first quarter 2021 contracts have been more volatile (figure 2.33). Prices in Victoria and South Australia rose sharply in March 2019, following record high quarterly wholesale prices in each region over the summer. They continued to rise through to October 2019, peaking at $121 and $128 respectively. Prices for Queensland and NSW first quarter 2021 contracts rose to a lesser extent, peaking at $86 and $97 respectively in 2019.

Prices declined for all regions late in the year, and by April 2020 had eased 30 per cent off their 2019 peaks in Queensland, Victoria and South Australia, and 20 per cent in NSW. These movements mirrored spot market outcomes, where prices generally eased in the fourth quarter of 2019, and remained subdued over the first quarter of 2020. As noted, lower generator fuel costs and rising renewable generation contributed to this shift in the market. The market appears to expect these changes in market dynamics to continue through to the summer of 2020–21.

## 2.7.3 Access to contract markets

Access to contract markets, either on the ASX or in OTC markets, can pose a significant barrier to retailers and generators looking to enter or expand their presence in the electricity market. This barrier is a risk because contracts offer a degree of control over costs (for retailers) and revenue (for generators). The ACCC identified potential barriers to small or new retailers accessing hedge products in ASX and OTC markets, with significantly fewer trade options available to these retailers.[32]

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

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

AEMO's assessment in 2019 did not identify a shortfall in any NEM region over the relevant period, so the RRO was not triggered. The operation of the RRO differs in South Australia, where the local energy minister can trigger the obligation. In January 2020 the minister triggered the RRO in South Australia for specific periods in the first quarters of 2022 and 2023. Large generation businesses in South Australia—Origin, AGL and Engie—must now offer contracts for those periods on the ASX. By May 2020 there had been trade during the MLO trading windows of 32 MW of contracts covering those reliability gap periods. These contracts represented 55 per cent of all trades relating to the reliability gap periods.

## 2.8 Market competition

The AER monitors the performance of the wholesale electricity market, and assesses whether it is effectively competitive. It is required to report on the performance of

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

the wholesale electricity market every two years. The AER published its first *Wholesale electricity market performance report* in December 2018, and expects to publish its second report by the end of 2020.

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

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

Opportunistic bidding by large generators can be profitable because dispatch and settlement prices are determined over different time frames—that is, the 30 minute settlement price is the average of six of the 5 minute dispatch prices. This timing allows generators to rebid capacity late in a trading interval to capture high prices, while giving competing generators little time to respond. To help manage this risk, the settlement period for the electricity spot price will change from 30 minutes to 5 minutes to align the timeframes for dispatch and settlement prices. The reform was expected to take effect in July 2021, but the AEMC in early 2020 was consulting on a delayed introduction to July 2022.[33]

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

The exit of low cost coal generation plant in 2016 and 2017 contributed to higher electricity prices. With less capacity available at low prices, higher cost black coal, gas and hydroelectric generators were more frequently setting electricity prices. This period also coincided with high gas costs.

33 AEMO in April 2020 proposed the delay in response to the potential impact of COVID-19 on the energy industry, to free up human and financial resources that would be under strain during the pandemic.

But certain features of the market make it vulnerable to the exercise of market power, and at times may drive prices higher than recent changes in the generation mix and underlying supply costs can explain. A few large participants control significant generation capacity and output in most NEM regions. Their output is typically needed at times of high demand, creating opportunities to exercise market power at these times (box 2.3).

## 2.9 Power system reliability

Reliability is about the power system being able to supply enough electricity to meet customers' requirements, drawing on available generation and storage, demand response, and transmission network capacity to transport power to customers.[34] Cross-border transmission interconnectors support reliability by allowing power sharing across regions. Reliability concerns tend to peak over summer, when high temperatures spike demand and increase the risks of system faults and outages.

Chapter 1 looks at how the current energy market transition is affecting reliability. This section focuses mainly on recent outcomes. It refers to the reliability of wholesale electricity supply through the transmission system. The current reliability standard for these sectors requires any shortfall in power supply to not exceed 0.002 per cent of total electricity requirements.

### 2.9.1 Managing reliability

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

AEMO raised concerns that the NEM's wholesale electricity supply would face reliability risks over each of the past three summers (including 2019–20), especially in Victoria and South Australia where major coal (and gas) plant closures have occurred. The closures removed significant 'dispatchable' capacity from the generation fleet that previously could be relied on when needed. Exacerbating the risk, the remaining coal plants have become more prone to outages, especially in hot weather (section 1.3.1).

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

### Box 2.3 Competition metrics

The market structure of the generation sector affects opportunities and incentives for generators to exercise market power. In particular, a market structure dominated by a handful of generators—especially in a region with limited in-flow interconnector capacity—is likely to be less competitive than a market with diluted ownership. Market shares are a simple illustrator of the degree of concentration in a market. Figures 2.18 and 2.19 illustrate generation market shares in 2019.

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

Figure 2.34 compares market concentration over time in mainland National Electricity Market (NEM) regions. The average HHI is over 2000 for each region, and did not vary significantly in recent years. But significant variation from the average occurs in some dispatch intervals, reflecting plant outages, fuel availability and bidding behaviour in response to demand and prices.

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

While NSW, Victoria and South Australia recorded their lowest minimum HHI values, the maximum HHI value in those regions rose from 2018 levels. NSW recorded a significant rise, with outages in the third quarter of 2019 leading to greater market concentration at that time.

In most regions, the output of a few large participants is necessary to meet demand at times of high demand, even allowing for import capacity from other regions. At these times, those participants are 'pivotal' to meeting demand and may be able to exercise market power. The residual supply index (RSI) quantifies when the largest participants are pivotal to meeting demand in a region.

An RSI-1 greater than 1 means demand can be fully met without dispatching the largest participant. Similarly, RSI-2 and RSI-3 measure the ratio of demand that can be met by all but the two or three largest participants. Various factors may cause the RSI to deteriorate, including a rise in demand, a decrease in generation, or an increase in the share of generation controlled by the largest participants.

It is easier for one pivotal participant to exercise market power than for two or three participants to do so. But RSI-2 and RSI-3 can indicate the risk of participants coordinating behaviour to influence market outcomes.

A limitation of RSI analysis is its focus on whether a participant can raise prices, rather than on its incentives to do so. Many factors can influence a participant's incentives, including the extent to which it is vertically integrated, and its contract position. RSI analysis also fails to account for market intricacies such as transmission constraints and ramp rate limitations.

Figure 2.35 shows the percentage of trading intervals in each the past five years when RSI values were below 1—that is, when at least some generation from the one, two or three pivotal participants was needed to meet demand.

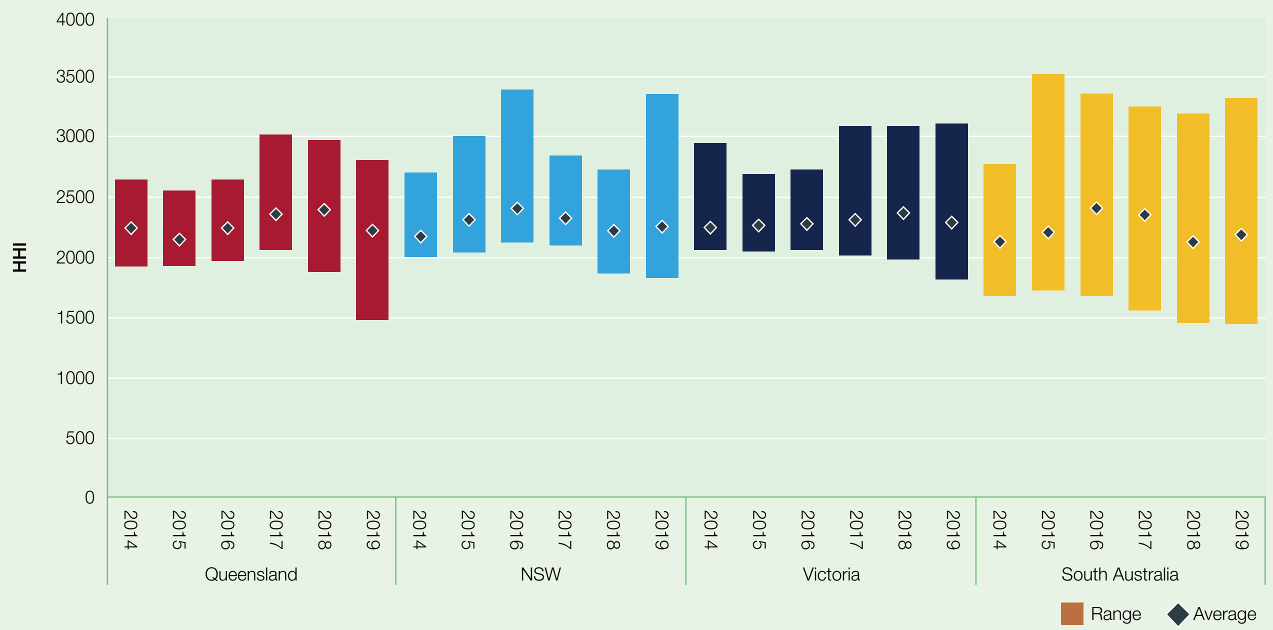
In 2019 the largest participant in Queensland (whether Stanwell or CS Energy) was pivotal 14 per cent of the time—more often than the largest participant in any other region. But this outcome significantly improved on 2018, when Queensland's largest participant was pivotal 22 per cent of the time. For the first time since 2014, Queensland also had periods in 2019 when neither of its two largest generation participants was pivotal. This situation occurred 3 per cent of the time.

In NSW and Victoria, the largest participant was needed to meet demand around 4 per cent of the time (around 15 days per year). The two largest participants were needed to meet demand 74–80 per cent of the time. Some output from one of the three largest participants is always needed to meet demand.

South Australian generators were pivotal less often than were those elsewhere. Output from the region's largest generator was rarely required to meet demand in 2019. The high penetration of rooftop solar PV installations in South Australia in recent years also meets much of the region's demand during daylight hours.

Outcomes for Tasmania are straightforward: Hydro Tasmania is always needed to meet demand.

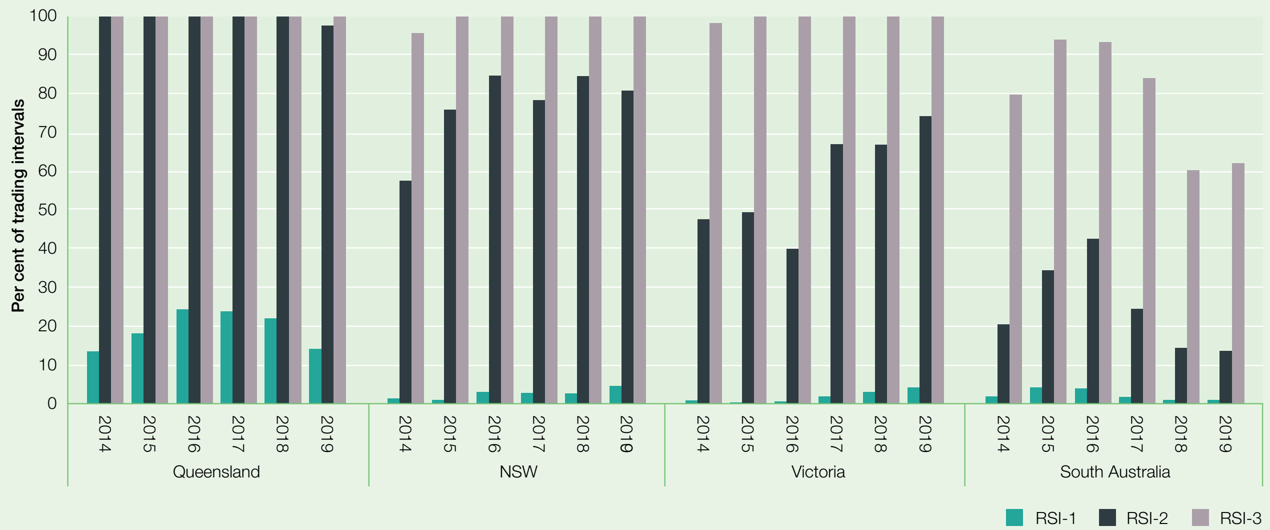
Figure 2.34
**Herfindahl–Hirschman Index**




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

Source: AER.

Figure 2.35
**Pivotality of largest generators**




RSI, residual supply index.

Note: The percentage of trading intervals when the one, two and three largest generators are pivotal. Allocations are based on the control of trading rights. Data are based on real time (half hourly) bid availability, and include maximum possible imports as available capacity. If an interconnector is forced to export, then it is treated as additional demand in the region.

Source: AER.

### Reliability and Emergency Reserve Trader

Over the past three summers (up to and including 2019–20), AEMO intervened in the market to manage forecast risks of available generation not being sufficient to meet demand. In each year, it activated the Reliability and Emergency Reserve Trader (RERT) mechanism, which acts as a safety net to maintain reliability when electricity demand is forecast to exceed supply. The mechanism allows AEMO to procure (via competitive tender) additional supply from generators and/or demand management from customers (to reduce their consumption) at times of system stress, to reduce the risk of load shedding.

Reserves procured under the RERT must be 'out of market.' This feature seeks to preserve economic signals for new investment or demand response by market participants. Procuring reserves from existing market generators could perversely incentivise participants to withhold supply from the market in an attempt to obtain a better price through a RERT procurement. This feature was underlined by a rule change in 2019 that specifies any scheduled generator or load that participated in the wholesale market in the previous 12 months may not provide emergency reserves through the RERT.[35] It ensures the wholesale market remains the primary mechanism for delivering reliability.

The RERT scheme is expensive to operate, and consumers ultimately bear these costs. The costs include availability costs (capacity payments to secure the service over a specified timeframe), pre-activation payments (because some services incur costs to be on standby), and activation costs (for the actual use of the reserves). Other costs include administration costs and compensation payments to participants.[36]

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

Before 2017 AEMO entered contracts with RERT providers on only three occasions, but RERT capacity was never dispatched. The RERT was activated for the first time in November 2017 in Victoria. It was activated twice in January 2018 in Victoria and South Australia, and twice again in those states in January 2019. On two occasions, back-up reserves activated under the RERT were insufficient, and load shedding was required.

AEMO issued 31 low reserve warnings over the summer of 2019–20, and activated RERT reserves on five occasions. The RERT was activated in NSW for the first time in January 2020. No load shedding occurred over the summer of 2019-20. The RERT has never been used in Queensland or Tasmania. Table 2.5 sets out instances of reserves being activated under the RERT.

The total cost of the RERT was over $30 million in each of the past two summers, and around $50 million in the 2017–18 summer (figure 2.36).

## 2.9.2 Reliability outlook

AEMO in August 2019 forecast relatively low reliability risks over the 2020–21 and 2021–22 summers, based on its expectations of nearly 5 GW of new generation and upgrades to existing generators coming online by that time.[37] But it noted 'uncontrollable, but increasingly likely' high impact events (such as prolonged or coincident generator outages) could threaten reliability over the next 10 years, given forecast continued reliability risks over the next decade unless new investment replaces ongoing fossil fuel plant retirements.

AEMO forecast a higher reliability risk for NSW than for other regions over the medium term, particularly in the window between the closure of the Liddell power station in 2023–24 and the expected commissioning of Snowy 2.0 in 2025. Even with increased import capacity from proposed upgrades to the Queensland–NSW and Victoria–NSW interconnectors, AEMO forecast NSW could be exposed—if high summer demand coincided with unplanned generator outages—to significant supply gaps and involuntary load shedding if no mitigation action is taken.

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

# 2.10 Power system security

Power system security refers to the power system's technical stability in terms of frequency, voltage, inertia and similar characteristics.[38] Historically, the NEM's synchronous coal, gas and hydro generators helped maintain a stable

35 AEMC, *Rule determination: National Electricity Amendment (Enhancement to the Reliability and Emergency Reserve Trader) Rule 2019*, May 2019.
36 AEMC, *Rule determination: National Electricity Amendment (Enhancement to the Reliability and Emergency Reserve Trader) Rule 2019*, May 2019.
37 AEMO, *2019 electricity statement of opportunities*, August 2020.
38 Box 1.4 in chapter 1 defines these terms.

Table 2.5 **RERT activation and costs**

| DATE | REGION | QUANTITY PRE-ACTIVATED (MW) | QUANTITY ACTIVATED (MW) | RERT COSTS ($ MILLION)[1] | CAUSE OF EVENT |
|---|---|---|---|---|---|
| SUMMER 2019–20 | | | | | |
| 31 January 2020 | NSW<br>Victoria | 390<br>110 | 134<br>185 | 10.9<br>7.5 | In NSW, high temperatures and humidity saw forecast demand reach 13 025 MW. Coupled with this demand, 2800 MW of scheduled generation was unavailable due to unplanned outages and temperature driven limitations.<br>In Victoria, severe winds caused the collapse of several transmission towers, resulting in the region seperating from South Australia, and 1100 MW of generation being unavailable to Victoria. |
| 23 January 2020 | NSW | 406 | 152 | 7.5 | Significant capacity was not available at Mount Piper and Bayswater, and an additional 700 MW unavailable due to temperature-driven limitations. |
| 4 January 2020 | NSW | 368 | 68 | 8.4 | Bushfires caused the loss of several transmission lines in southern NSW and islanded part of NSW and Queensland from the rest of the NEM. This outcome led to an disconnection of a generator and loss of customer load in NSW, and reduced available generation capacity by over 2200 MW. |
| 30 December 2019 | Victoria | 80 | 92 | 4.9 | A transmission outage reduced import capacity to Victoria from NSW by over 1000 MW. |
| SUMMER 2018–19 | | | | | |
| 25 January 2019 | Victoria | na[2] | 396 | 24.5 | Unplanned outages and temperature driven generation capacity limitations reduced Victorian supply by 1600 MW. AEMO activated the RERT and also requested AusNet Services to shed 100 MW of customer load at 11:00 am, and a further 150 MW at 11:30 am. |
| 24 January 2019 | Victoria<br>South Australia | na[2] | 625 | 9.9 | Unplanned outages and generation capacity limitations reduced supply at a time of high temperature driven demand. AEMO also instructed AusNet Services to shed 75 MW of customer load in Victoria. |
| SUMMER 2017–18 | | | | | |
| 19 January 2018 | Victoria<br>South Australia | 500<br>na[2] | 130<br>6.5 | 24.1 | Elevated temperatures coincided with plant outages. These conditions were compounded by extended recall times of some generation, capacity reductions on the Basslink interconnector, and bushfires near the Heywood interconnector. |
| 30 November 2017 | Victoria | na[2] | 32 | 0.9 | Unseasonably warm weather spiked demand and coincided with significant generation capacity being unavailable. |

AEMO, Australian Energy Market Operator; MW, megawatts; na, not available; NEM, National Electricity Market; RERT, Reliability and Emergency Reserve Trader.

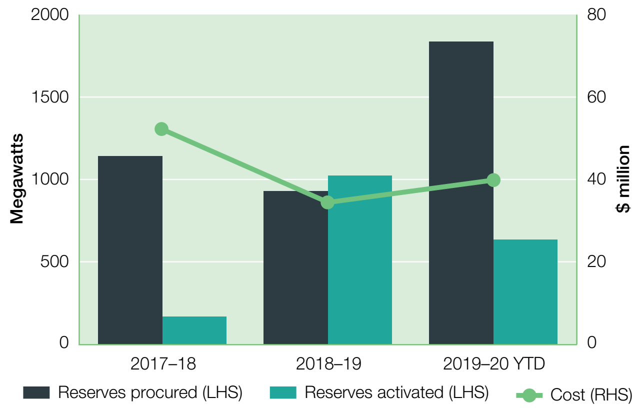
1 2017–18 and 2018–19 RERT costs include costs for pre-activation, and activation, and other costs (including compensation costs). 2019–20 costs also include ongoing availability costs, which do not apply to any one specific event.

2 AEMO reporting for RERT activation did not itemise pre-activation quantities for this event.

Source: AER analysis of AEMO's RERT reporting.



Figure 2.36
**RERT reserves and costs**




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

Note: Calculations for the 2020 component of the 2019-20 data are based on AEMO's initial estimates of RERT costs in January 2020. Includes costs for availability, pre-activation, activation and other costs (including compensation costs). 2019–20 YTD is data to 31 March 2020.

Source: AER analysis of AEMO's RERT reporting.

and secure system through inertia and system strength services provided as a byproduct of producing energy. But, as older synchronous plants retire, these sources of inertia and system strength are being removed from the system. Falling inertia makes it harder to keep frequency within an acceptable band, while falling system strength makes it harder to keep voltages stable.

The wind and solar generators entering the market are less able to support system security. For this reason, the rising proportion of renewable plant in the NEM's generation portfolio reflects in more periods of low inertia, weak system strength, more volatile frequency and voltage instability. It also raises challenges to the generation fleet's ability to ramp (adjust) quickly to sudden changes in renewable output. To help manage these challenges, the settlement period for the electricity spot price will change from 30 minutes to 5 minutes. The reform was expected to take effect in July 2021, but the AEMC in early 2020 was consulting on a delay to July 2022.[39]

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

39 AEMO in April 2020 proposed the delay in response to the potential impact of COVID-19 on the energy industry, to free up human and financial resources that would be under strain during this pandemic.

In the longer term, energy rule reforms aim to widen the pool of providers (such as batteries and demand response) of security services. At a higher level, market policy and regulatory bodies are developing reforms of the energy market's architecture, to manage security risks in the context of an evolving energy market. Sections 1.4.4 and 1.4.5 discuss recent reform initiatives.

## 2.10.1 Security performance in the NEM

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

Power system security has degraded in recent years, and this trend continues. In 2019 the market experienced:

- 28 instances on the mainland when the system frequency did not meet the operating standard requirements. Another 180 events were recorded in Tasmania over the same period.
- A continuing system strength shortfall in South Australia, as well as emerging shortfalls in Victoria, Queensland and Tasmania.

The NEM experienced a major security event on 31 January 2020, islanding South Australia from the national market (box 2.4). Security issues persisted during the 18 day separation, and elevated reliability risks in Victoria and NSW.

## 2.10.2 Frequency control markets

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

Frequency control ancillary services (FCAS) are used to maintain the frequency of the power system close to 50 Hertz. The NEM has eight FCAS markets that fall into two 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

## Box 2.4 Islanding of South Australia on 31 January 2020

On 31 January 2020 storms damaged six transmission towers connected to the Heywood interconnector. Heywood connects the Victorian and South Australian power grids, and the outage separated South Australia from the rest of the National Electricity Market (NEM) for 18 days.[a] The Australian Energy Market Operator (AEMO) constrained a second interconnector linking the regions, Murraylink, to avoid the risk of catastrophic system failures. A second outage occurred on 2 March, but with a shorter duration.

Electricity supply was sufficient to meet demand during the 18 day separation. But, with South Australia unable to trade electricity with Victoria, the system at times faced security risks due to the high level of renewable generation in South Australia. The separation caused system frequency in South Australia to rise above acceptable limits, causing several generators and batteries to trip or reduce output. Demand for grid supplied electricity was high at the time of the separation, and rose further when output from rooftop solar photovoltaic (PV) generation fell as a result of the high frequency.

AEMO was required to manage South Australia as an extended island (South Australia and elements of Victoria), which called for significant intervention. Between 1 February and 17 February 2020, AEMO intervened in the market 100 per cent of the time to maintain system strength in the region.

South Australia was required to provide its own frequency control ancillary services (FCAS) during the separation, resulting in record FCAS costs for the quarter (section 2.10.2). The separation also raised reliability threats in Victoria and NSW, resulting in AEMO dispatching Reliability and Emergency Reserve Trader (RERT) reserves in those regions (section 2.9.1).

Wind generators offered less capacity during the weeks of separation. AEMO constrained wind output to maintain system security, but some plants repriced their offers in the market to avoid the double penalty of being dispatched at negative prices and having to pay high FCAS costs. Before the separation, wind generators offered nearly all their capacity below $0 per megawatt hour (MWh). But, during the separation event, they shifted significant capacity into higher price bands, including over $5000 per MWh.

South Australia's battery storage units also offered significantly less capacity during the separation, following AEMO directions that they hold a constant state of charge and not dispatch. During the separation weeks, batteries shifted nearly all capacity offers to over $5000 per MWh.

a AEMO, *Preliminary report—Victoria and South Australia separation event, 31 January 2020*, April 2020.

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. In early 2020 there were seven major FCAS providers in NSW, nine in Queensland, eight in South Australia, seven in Victoria, and one in Tasmania. A number of new participants emerged in recent years (table 2.6). Demand response aggregators now offer FCAS across all mainland regions; virtual power plants offer services in NSW and South Australia; and battery storage offers services in South Australia and Victoria. But these new entrants account for only a small proportion of FCAS trades. To strengthen transparency around FCAS markets and encourage participation, the AER in 2019 launched quarterly reporting on market activity.[40]

40 AEMC, *Monitoring and reporting on frequency control framework, Fact sheet*, July 2019.

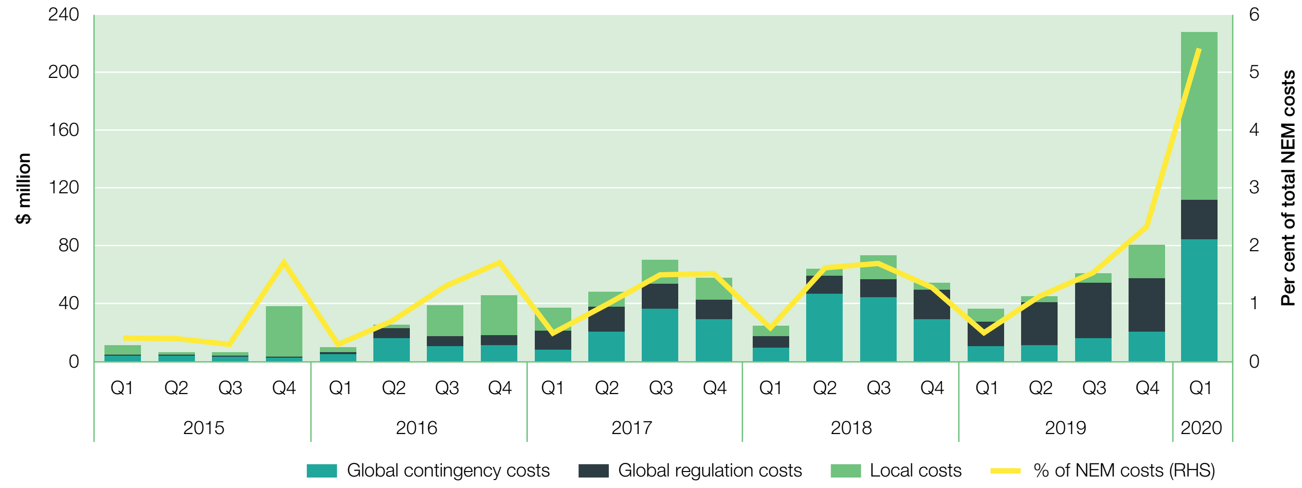
Historically, FCAS costs were comparatively low in relation to energy costs—in 2015 FCAS costs totalled $63 million, which represented around 0.7 per cent of NEM energy costs. However, these costs rose steadily over the past few years. In 2019 FCAS costs totalled around $223 million, almost four times their level in 2015 (figure 2.37).

Following deteriorating frequency performance, AEMO in 2019 increased sourcing requirements for base regulation services on the mainland by 70–75 per cent.[41] AEMO also introduced a stricter approach to assessing sourcing requirements for contingency service.[42] The amount of time that frequency remained within the normal operating

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

42 The change in AEMO's approach to enabling FCAS contingency services resulted in an increase of over 300 MW compared with the same period in 2018.

Figure 2.37
**FCAS costs**




FCAS, frequency control ancillary services; NEM, National Electricity Market.

Source: AER; AEMO (data).

**Table 2.6 Number of providers of FCAS in each market**

| | LOWER | | | | RAISE | | | | TYPE OF PROVIDER |
|---|---|---|---|---|---|---|---|---|---|
| | 5 min | 60 sec | 6 sec | Reg | 5 min | 60 sec | 6 sec | Reg | |
| Queensland | 4 | 6 | 5 | 8 | 6 | 7 | 7 | 8 | Gas, black coal, hydro, pump, demand aggregator, liquid |
| NSW | 6 | 6 | 6 | 5 | 6 | 6 | 6 | 5 | Black coal, demand aggregator, virtual power plant, hydro |
| Victoria | 5 | 5 | 5 | 5 | 6 | 6 | 6 | 5 | Brown coal, hydro, gas, battery, demand aggregator, load (smelter), pump |
| South Australia | 5 | 6 | 6 | 5 | 6 | 7 | 7 | 5 | Gas, demand aggregator, virtual power plant, battery, wind, liquid |
| Tasmania | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | Hydro, pump, gas |

min, minutes; reg, regulation; sec, seconds.

Source: AER; AEMO (data).

band subsequently improved, but regulation FCAS costs rose to record levels. Costs also increased in Tasmania when an outage on the Basslink interconnector in August–September 2019 reduced the availability of services. Once the interconnector was restored, frequency performance improved, but it remained below the standard.

Costs for both regulation and contingency services reached record levels in the first quarter of 2020, at over $220 million (equivalent to 5.4 per cent of energy costs). First quarter FCAS costs were higher than total costs for the whole of 2019. Local regulation services in South Australia accounted for almost half of these costs, mainly due to the region being islanded for several weeks following the loss of the Heywood interconnector. Also, in January 2020 the impact of bushfires on transmission networks drove record prices for contingency services across the NEM. FCAS prices exceeded $5000 per MW several times over the quarter.

AEMO's concerns about the sourcing of frequency services led the AEMC in March 2020 to introduce a mandatory requirement for generators to provide primary frequency response. The new requirement commences in June 2020 (section 1.4.4).

Source: Shutterstock

# 3 ELECTRICITY NETWORKS

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

## 3.1 Electricity network characteristics

*Transmission* networks transport electricity at high voltages from generators to major load centres. They consist of towers and wires, underground cables, transformers, switching equipment, reactive power devices, and monitoring and telecommunications equipment.

Electricity is injected from points along the transmission grid into *distribution* networks that distribute electricity to residential homes, and commercial and industrial premises. Distribution networks consist of poles and wires, substations, transformers, switching equipment, and monitoring and signalling equipment. Electricity is stepped down to lower voltages when it enters a distribution network, for safe delivery to customers.

While electricity distributors are responsible for transporting and delivering electricity to customers, they are not responsible for selling it. Instead, retailers purchase electricity from the wholesale market, and network services from network service providers, and sell them as a package to customers (chapter 6).

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

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

## 3.2 Geography

Electricity networks in Queensland, New South Wales (NSW), Victoria, South Australia, Tasmania and the Australian Capital Territory (ACT) create an interconnected grid forming the National Electricity Market (NEM). The AER regulates all major networks in the NEM, other than the Basslink interconnector linking Victoria with Tasmania.

The electricity networks regulated by the AER (listed in tables 3.1 and 3.2, and mapped in figure 3.1) have a combined valuation of $98.5 billion, and comprise seven transmission networks (valued at $21.4 billion) and 14 distribution networks ($77.2 billion). In total, the networks span almost 800 000 kilometres of line.

The NEM transmission grid has a long, thin, low density structure, reflecting the dispersed locations of electricity generators and demand centres. The grid consists of five state based networks linked by cross-border interconnectors. Three interconnectors (Queensland–NSW, Heywood, and Victoria–NSW) form part of the state based networks, while the other three (Directlink, Murraylink and Basslink) are separately owned (table 3.1).

The transmission grid connects with 13 distribution networks, which transport electricity to residential homes and commercial and industrial premises.[1] Consumers in Queensland, NSW and Victoria are serviced by multiple distribution networks, each of which operates and maintains its network within a defined geographic region. Consumers in South Australia, Tasmania and the ACT are serviced by a single distribution network operating within each jurisdiction (table 3.2). The transmission grid also delivers electricity directly to some industrial customers (such as aluminium smelters).

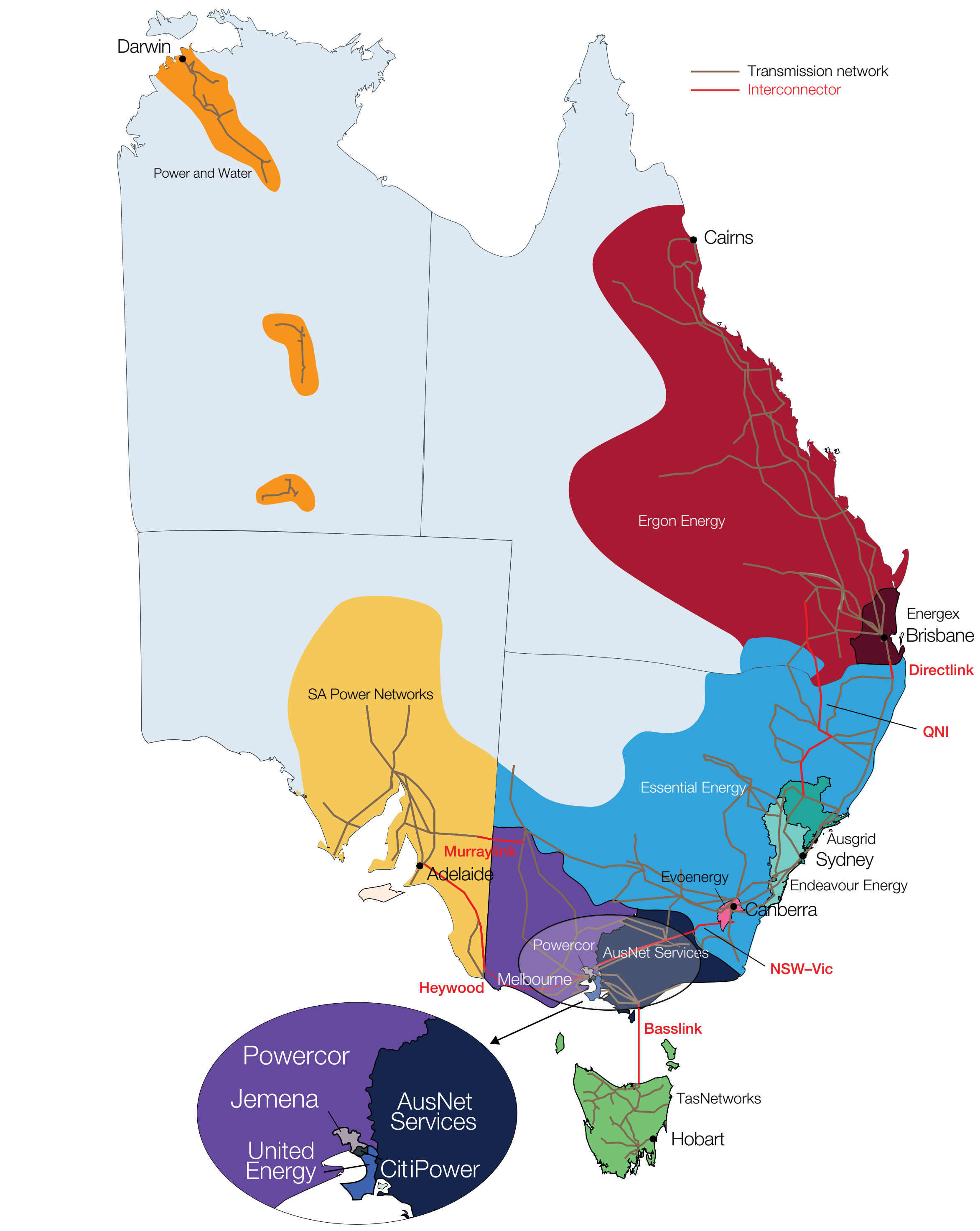
The Northern Territory has three separate networks—the Darwin–Katherine, Alice Springs and Tennant Creek systems—that are all owned by Power and Water. The networks are classified as a single distribution network for regulatory purposes, but do not connect to each other or the NEM.

The AER 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,

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



**Figure 3.1**
**Electricity distribution networks regulated by the AER**




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

including Perth. Another state owned corporation—Horizon Power—services regional and remote areas.[2]

## 3.3 Network ownership

Australia's electricity networks were originally government owned, but many jurisdictions have now either partly or fully privatised the assets. Privatisation of the electricity networks began in Victoria, which sold its transmission and distribution networks to private entities in the 1990s.[3]

In 2000 the South Australian Government privatised its transmission network and leased its distribution network. In the same year, a joint venture between the ACT Government and private equity holders was established to operate the ACT distribution network.[4]

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

Ownership of the privatised networks in NSW, Victoria and South Australia is concentrated among relatively few entities. These entities include Hong Kong's Cheung Kong Infrastructure Holdings Limited (CKI Group) and Power Assets Holdings, Singapore Power International, and State Grid Corporation of China (tables 3.1 and 3.2). Fund managers such as Spark Infrastructure and Hastings also have significant equity in the sector. Significant ownership links exist across the electricity and gas network sectors (section 5.2).

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

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

## 3.4 How network prices are set

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

Because monopolies face no competitive pressure, they have opportunities and incentives to charge unfair prices. This environment poses serious risks to consumers, given network charges can make up close to 50 per cent 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 mimic the incentives that network businesses would face in a competitive market to control their costs, invest efficiently, and not overcharge consumers.

### 3.4.1 Regulatory objective and approach

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

The AER seeks to ensure consumers pay no more than necessary for the safe and reliable delivery of electricity. Its regulatory toolkit to pursue this objective is wide ranging (box 3.1), but its central role is to set the maximum revenue that a network business can earn from its customers for delivering electricity. The AER undertakes this role via a periodic determination or reset process, in which it assesses how much revenue a prudent network business would need to cover its efficient costs. Network revenues are then capped at this level for the regulatory period, which is typically five years.[5]

2 For further information, see the Western Australian Department of Treasury (www.treasury.wa.gov.au) and ERA (www.era.wa.gov.au) websites.

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

4 The ACT has no transmission assets.

5 While a five 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 reset.



**Table 3.1 Electricity transmission networks in the NEM**

| NETWORK | LOCATION | LINE LENGTH (KM)[1] | ELECTRICITY TRANSMITTED (GWH)[2] | MAXIMUM DEMAND (MW)[3] | ASSET BASE ($ MILLION)[1] | CURRENT REGULATORY PERIOD[4] | OWNER |
|---|---|---|---|---|---|---|---|
| STATE NETWORKS[5] | | | | | | | |
| Powerlink | Qld | 14 526 | 53 765 | 12 201 | 7 300 | 1 July 2017 – 30 June 2022 | Queensland Government |
| TransGrid | NSW | 13 052 | 74 400 | 18 700 | 6 600 | 1 July 2018 – 30 June 2023 | Hastings 20%; Spark Infrastructure 15%; other private equity 65% |
| AusNet Services / AEMO | Vic | 6 628 | 41 480 | 9 668 | 3 300 | 1 April 2017 – 31 March 2022 | Listed company (Singapore Power 31.1%, State Grid Corporation 19.9%) |
| ElectraNet | SA | 5 513 | 13 787 | 3 527 | 2 600 | 1 July 2018 – 30 June 2023 | State Grid Corporation 46.6%; YTL Power Investments 33.5%; Hastings Investment Management 19.9% |
| TasNetworks | Tas | 3 545 | 12 885 | 2 353 | 1 500 | 1 July 2019 – 30 June 2024 | Tasmanian Government |
| TOTAL | | 43 264 | 196 317 | | 21 400 | | |
| STANDALONE INTERCONNECTORS | | | | | | | |
| Directlink | Qld–NSW | 63 | | | 144 | 1 July 2020 – 30 June 2025 | Energy Infrastructure Investments (Marubeni Corporation 49.9%, Osaka Gas 30.2%, APA 19.9%) |
| Murraylink | Vic–SA | 180 | | | 117 | 1 July 2018 – 30 June 2023 | Energy Infrastructure Investments (Marubeni Corporation 49.9%, Osaka Gas 30.2%, APA 19.9%) |
| Basslink | Vic–Tas | 375 | | | | Unregulated | Keppel Infrastructure Trust |
| INTERCONNECTORS FORMING PART OF STATE NETWORKS | | | | | | | |
| Queensland to NSW (QNI) | Qld–NSW | 235 | | | | As for Powerlink and TransGrid | Powerlink and TransGrid |
| Heywood | Vic–SA | 200 | | | | As for ElectraNet and AusNet Services | ElectraNet and AusNet Services |
| Victoria to NSW | Vic–NSW | 150 | | | | As for AusNet Services and TransGrid | AusNet Services and TransGrid |

GWh, gigawatt hours; km, kilometres; MW, megawatts.

1. Line length and asset base at 30 June 2019 (30 March 2019 for AusNet Services).

2. Electricity transmitted in 2018–19 (year to March 2019 for AusNet Services).

3. Non-coincident, summated maximum demand in 2018–19 (year to March 2019 for AusNet Services).

4. Current regulatory period at 1 July 2020.

5. Northern Territory transmission assets are treated as part of the distribution system for regulatory purposes.

Source: AER revenue decisions and economic benchmarking regulatory information notices (RINs); Australian Securities Exchange (ASX) release; company websites; company annual reports.

As part of the reset process, a network business submits a proposal to the AER, setting out how much revenue it will need to cover the costs of providing a safe and reliable electricity supply in the upcoming regulatory period. If the AER concludes a business's proposal is likely to be unreasonably costly, it may ask for more detailed information or a clearer business case.

Subsequently, the AER may amend a network's proposal to ensure the network's cost forecasts are efficient.

While the AER determines efficient operating and capital expenditure, it does not approve or disapprove individual projects. Each network business prioritises its own spending programs, but it must undertake a cost–benefit analysis for any new investment project (section 3.10.5).

**Table 3.2 Electricity distribution networks regulated by the AER**

| NETWORK | CUSTOMER NUMBERS[1] | LINE LENGTH (KM)[1] | CUSTOMER DENSITY (CUST/KM) | CURRENT REGULATORY PERIOD[2] | OWNER |
|---|---|---|---|---|---|
| QUEENSLAND | | | | | |
| Energex | 1 496 317 | 54 777 | 27.3 | 1 July 2020 – 30 June 2025 | Queensland Government |
| Ergon Energy | 765 924 | 152 279 | 5.0 | 1 July 2020 – 30 June 2025 | Queensland Government |
| NSW AND ACT | | | | | |
| Ausgrid | 1 746 274 | 42 007 | 41.6 | 1 July 2019 – 30 June 2024 | NSW Government 49.6%; IFM Investors 25.2%; AustralianSuper 25.2% |
| Endeavour Energy | 1 027 586 | 38 284 | 26.8 | 1 July 2019 – 30 June 2024 | Private sector consortium 50.4%; NSW Government 49.6% |
| Essential Energy | 916 471 | 192 538 | 4.8 | 1 July 2019 – 30 June 2024 | NSW Government |
| Evoenergy | 198 432 | 5 435 | 36.5 | 1 July 2019 – 30 June 2024 | Icon Distribution Investments 50%; Jemena 50% (State Grid Corporation 60%, Singapore Power 40%) |
| VICTORIA[2] | | | | | |
| AusNet Services | 762 382 | 45 494 | 16.8 | 1 January 2016 – 31 December 2020 | Listed company (Singapore Power 31.1%, State Grid Corporation 19.9%) |
| CitiPower | 345 009 | 4 558 | 75.7 | 1 January 2016 – 30 December 2020 | Cheung Kong Infrastructure / Power Assets Holdings 51%; Spark Infrastructure 49% |
| Jemena | 354 452 | 6 628 | 53.5 | 1 January 2016 – 30 December 2020 | Jemena (State Grid Corporation 60%, Singapore Power 40%) |
| Powercor | 853 771 | 75 815 | 11.3 | 1 January 2016 – 30 December 2020 | Cheung Kong Infrastructure / Power Assets Holdings 51%; Spark Infrastructure 49% |
| United Energy | 697 594 | 13 408 | 52.0 | 1 January 2016 – 30 December 2020 | Cheung Kong Infrastructure 66%; Jemena 34% (State Grid Corporation 60%, Singapore Power 40%) |
| SOUTH AUSTRALIA | | | | | |
| SA Power Networks | 906 198 | 89 298 | 10.1 | 1 July 2020 – 30 June 2025 | Cheung Kong Infrastructure / Power Assets Holdings 51%; Spark Infrastructure 49% |
| TASMANIA | | | | | |
| TasNetworks | 290 446 | 22 862 | 12.7 | 1 July 2019 – 30 June 2024 | Tasmanian Government |
| NORTHERN TERRITORY | | | | | |
| Power and Water[3] | 85 743 | 7 103 | 12.1 | 1 July 2019 – 30 June 2024 | Northern Territory Government |
| TOTAL | 10 446 598 | 750 487 | 13.9 | | |

km, kilometres; cust/km, number of customers per km of power line.

1. Customer numbers, line length and asset base as at 30 June 2019 (31 December 2019 for Victorian businesses).

2. The Victorian government has indicated it's intention to bring Victoria into alignment with the other NEM states to operate on a financial year—rather than calendar year—basis. The intention is for this change to come into effect for the 1 July 2021 to 30 June 2026 regulatory control period. It will mean extending the current regulatory period by six months.

3. For regulatory purposes, Northern Territory transmission assets are treated as part of the distribution system.

Source: ASX releases; company websites; company annual reports.

The regulatory framework also allows network businesses to earn bonus revenue (or incur a revenue penalty) under incentive schemes operated by the AER.

The schemes encourage businesses to:

- efficiently manage their operating and capital expenditure
- improve service provision in ways that customers value
- adopt demand management schemes that take strain off the network, and avoid or delay network investment.

## Box 3.1 The AER's role in electricity network regulation

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

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

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

- adopting a more consumer centric approach to setting network revenues (section 3.6)
- implementing the Power of Choice reforms, which empower customers to make informed choices about their energy use, and ultimately help keep network costs down (sections 3.7 and 1.8)
- publishing more information on network profitability (section 3.8.1)
- reviewing how rates of return and taxation allowances are set for energy networks (section 3.11).

The AER publishes guidelines on its approach to assessing costs and applying incentives. Sections 3.10, 3.12 and 3.14 examine the incentive schemes in more detail.

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

The regulatory process increasingly focuses on how network businesses engage with their customers in shaping regulatory proposals. As part of this focus, the AER is trialling the 'New Reg' process—an enhanced, more open approach to how network businesses incorporate consumer perspectives in developing their regulatory proposals—with Victorian distribution network AusNet Services (box 3.3).

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; and how consumer views are reflected in the development of the network businesses' proposals.

### 3.4.2 Building blocks of network revenue

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

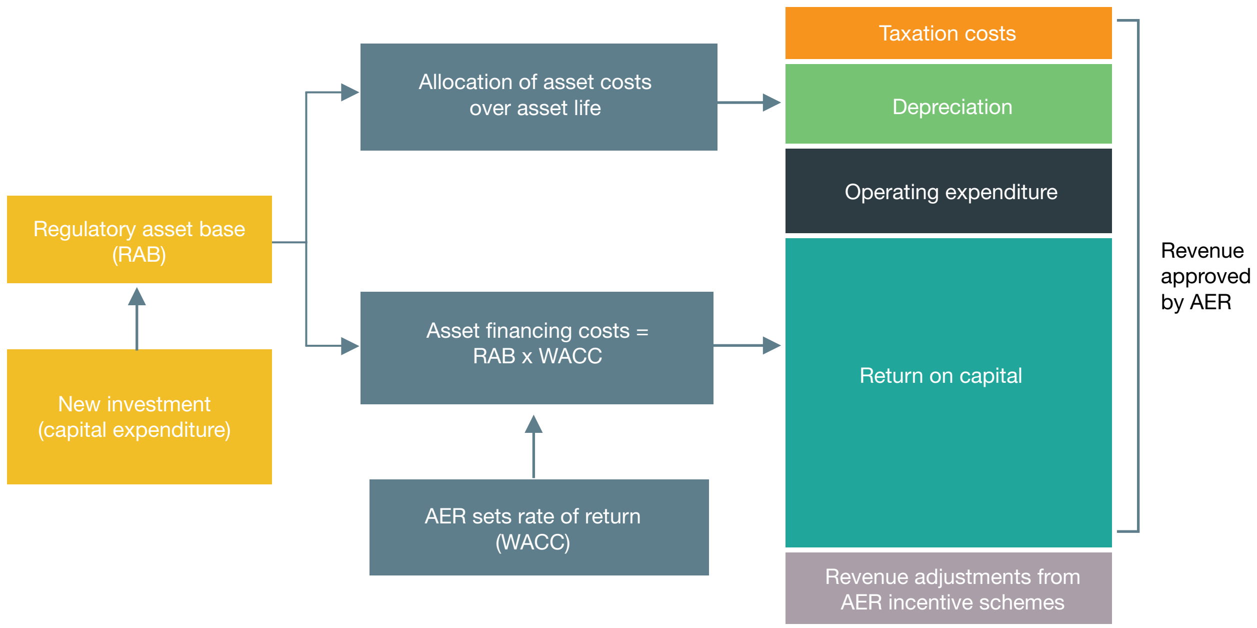
- efficient operating and maintenance costs
- asset depreciation costs
- forecast taxation costs
- a commercial return to investors that fund the network's assets and operations.

The AER also makes revenue adjustments for over- or under-recovery of revenue made in the past, and for incentive schemes (figure 3.2).

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

Additionally, the shareholders and lenders that fund these assets must be paid a commercial return on their investment. The AER sets the rate of return (also called the

Figure 3.2
**Forecasting network revenue**




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.

weighted average cost of capital, or WACC). The size of this return depends on:

- the value of the network's assets, measured by the regulatory asset base (RAB) plus forecast new capital expenditure
- the rate of return that the AER allows based on the forecast cost of funding those assets through equity and debt.[6]

These returns take up the largest slice of revenue, accounting for 45 per cent across all networks (49 per cent for transmission networks, and 44 per cent for distribution networks) (figure 3.3).

Operating costs—such as maintenance costs and overheads—absorb 35 cent of revenue across all networks (30 per cent for transmission, and 36 per cent for distribution). Depreciation absorbs another 17 per cent of revenue. Taxation and other costs account for the remainder of network revenue. Sections 3.10–3.12 examine major cost components in more detail.

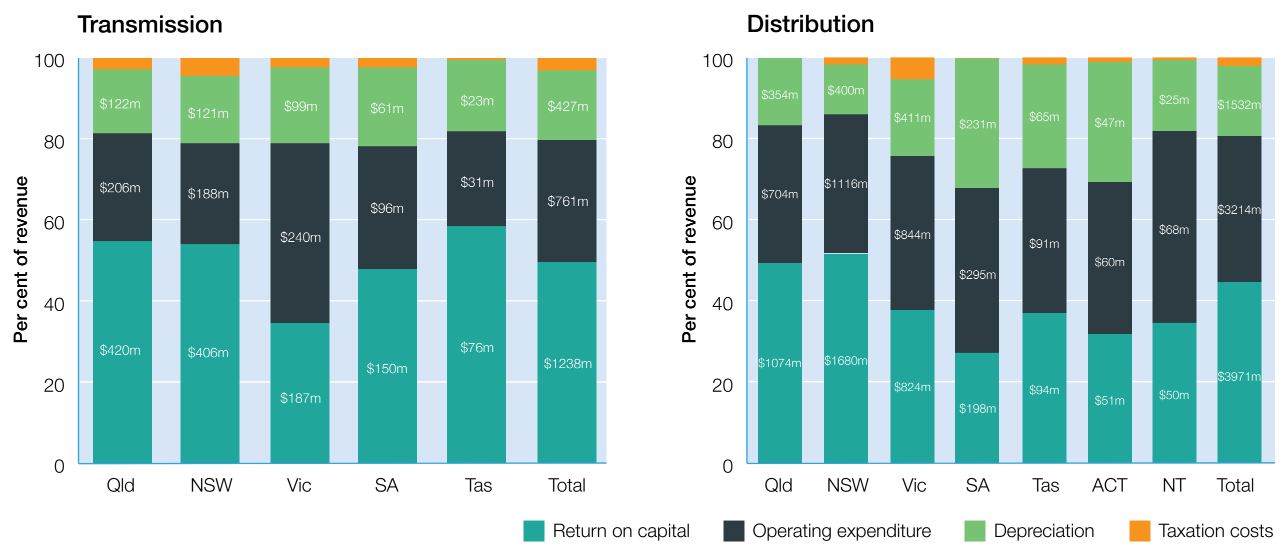
6 The return on equity is the return that shareholders of the business will require for them to continue to invest. The return on debt is the interest rate that the network business pays when it borrows money to invest.

### 3.4.3 Timelines and process

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

The AER has 15 months to formally review a revenue proposal before releasing a final decision. The AER's review includes an assessment of the reasonableness of the network business's forecasts and the efficiency of expenditure proposals. It consults widely with energy customers, consumer representatives, government, investment groups, network businesses and other stakeholders. This consultation includes issues papers, draft decisions and public forums. The timing of the AER reviews is staggered to avoid bunching (figures 3.4 and 3.5).

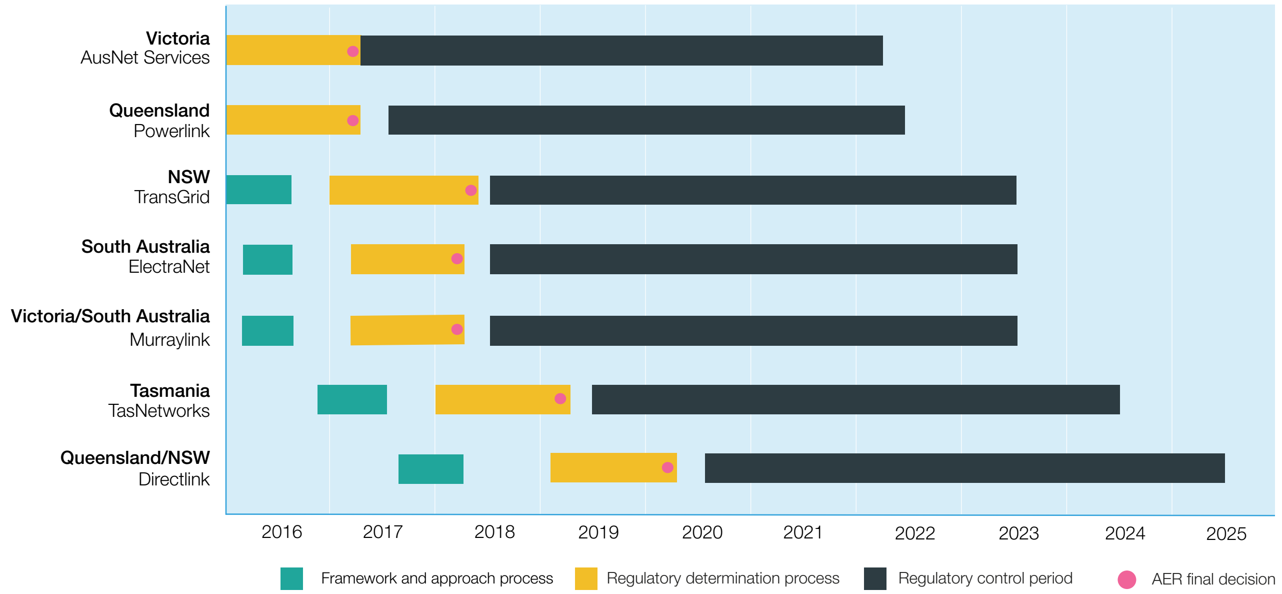
Figure 3.3
**Composition of average annual network revenue**




Note: Network businesses also receive bonuses or penalties that impact on annual network revenues. These bonuses/penalties are not material and are not considered in this chart.

Source: Post tax revenue modeling used in AER determination process.

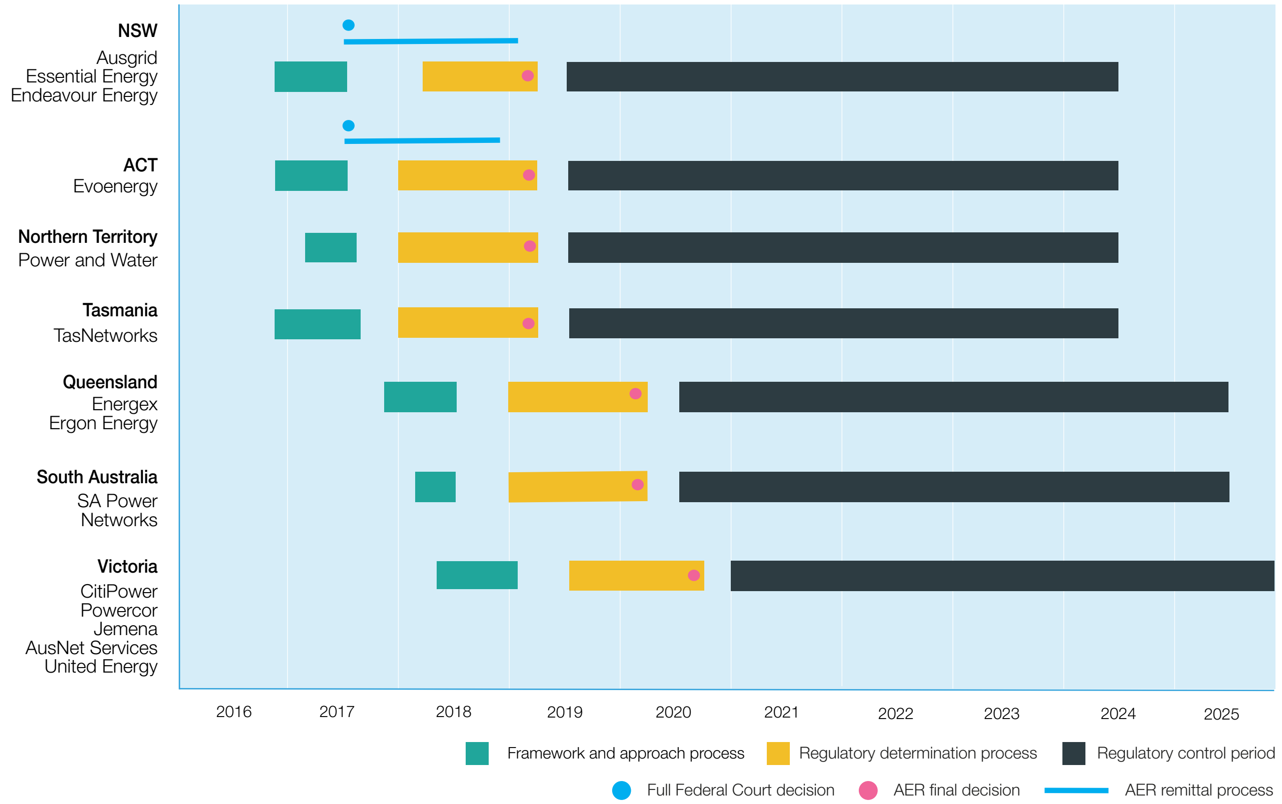
Figure 3.4
**AER decision timelines—electricity transmission networks**




Note: Timelines for AER decisions effective at 1 July 2020. The latest information is available at www.aer.gov.au/networks-pipelines/determinations-access-arrangements.

Source: AER.

Figure 3.5
**AER decision timelines—electricity distribution networks**




Note: Timelines effective at June 2020. The Victorian Government has noted its intention to shift network periods to a financial year—rather than calendar year—basis, commencing with the 1 July 2021 to 30 June 2026 regulatory control period. It will mean extending the current regulatory period by six months. The latest information is available at www.aer.gov.au/networks-pipelines/determinations-access-arrangements.

Source: AER.

Following its review, the AER makes a final decision setting the maximum revenue that a network business can earn from its customers through network charges.[7] While the decision sets network revenues rather than prices, the two are closely related. Network businesses set prices by spreading their allowed revenue across the customer base.[8] As part of the regulatory process (section 3.7.1), the AER assesses tariff structure statements that set out a network's pricing policies, and annually reviews prices to ensure they are consistent with the revenue decision and reflect efficient costs.

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

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

## 3.5 Recent AER revenue decisions

Since January 2019 the AER has finalised revenue decisions for electricity distribution networks in Queensland (Energex and Ergon Energy), NSW (Ausgrid, Endeavour Energy and Essential Energy), South Australia (SA Power Networks), Tasmania (TasNetworks), the ACT (Evoenergy), and the Northern Territory (Power and Water). The AER also finalised its revenue decision for the electricity transmission network in Tasmania (TasNetworks) and for the Directlink interconnector between NSW and Queensland. These decisions all cover a five year regulatory period (table 3.3).

Each of the AER's distribution decisions since January 2019 approved *lower* revenues than in the previous regulatory period. The AER's decisions for the previous regulatory 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 revenue allowances for the current period acknowledged network businesses are rationalising their operations and will continue to build on operational efficiencies. Lower revenue allowances benefit customers by locking in efficiency gains.

As an example, for the regulatory period commencing July 2019, the AER approved capital expenditure for Ausgrid (NSW) that was 6 per cent lower than the network business invested over the previous regulatory period. This lowering of capital expenditure will reduce Ausgrid's RAB and the revenue that it recovers from customers to service those assets.

The AER's 2020 decisions for the Queensland and South Australian distribution networks were made against the backdrop of the COVID-19 pandemic. The full effect of the pandemic was uncertain at the time of the AER's determinations. The AER based its decisions on information and forecasts that could reasonably be made at the time, but it recognised there are uncertainties around how COVID-19 will affect the operations and costs of the Queensland and South Australian distribution networks during the regulatory period. If it becomes clear that the impacts of COVID-19 are substantial, then a rule change would need to be considered to enable the AER to re-open existing revenue determinations.

Table 3.3 **Recent AER revenue decision—key outcomes**

| NETWORK | LOCATION | DECISON DATE | FORECAST CHANGE FROM PREVIOUS REGULATORY PERIOD: REVENUE (%) | OPERATING EXPENDITURE (%) | CAPITAL EXPENDITURE (%) | RATE OF RETURN (%)[1] | ANNUAL RETAIL BILL IMPACT (%)[2] |
|---|---|---|---|---|---|---|---|
| TRANSMISSION NETWORKS | | | | | | | |
| TasNetworks | Tas | 30 April 2019 | ↓ 27.8 | ↓ 11.9 | ↑ 9.1 | 5.5 | ↑ 0.6 |
| DISTRIBUTION NETWORKS | | | | | | | |
| Energex | Qld | 5 June 2020 | ↓ 26.5 | ↓ 4.3 | ↓ 23.7 | 4.7 | ↓ 0.8 |
| Ergon Energy | Qld | 5 June 2020 | ↓ 23.3 | ↓ 8.6 | ↓ 17.8 | 4.7 | ↓ 0.8 |
| Ausgrid | NSW | 30 April 2019 | ↓ 20.0 | ↓ 17.4 | ↓ 5.8 | 5.7 | ↓ 0.7 |
| Endeavour Energy | NSW | 30 April 2019 | ↓ 15.4 | ↓ 1.5 | ↑ 9.0 | 5.7 | ↓ 0.3 |
| Essential Energy | NSW | 30 April 2019 | ↓ 12.3 | ↓ 7.3 | ↓ 6.2 | 5.8 | ↑ 0.2 |
| SA Power Networks | SA | 5 June 2020 | ↓ 8.2 | ↑ 10.4 | ↓ 6.2 | 4.8 | ↓ 0.4 |
| TasNetworks | Tas | 30 April 2019 | ↓ 3.1 | ↑ 6.5 | ↓ 1.0 | 5.3 | ↑ 0.6 |
| Evoenergy | ACT | 30 April 2019 | ↓ 19.6 | ↑ 3.9 | ↓ 17.4 | 5.5 | ↑ 0.5 |
| Power and Water | NT | 30 April 2019 | ↓ 15.8 | ↓ 20.9 | ↑ 14.4 | 4.9 | ↓ 0.8 |

1. Rate of return is the nominal vanilla rate for the first year of a determination. The rate is updated annually to reflect changes in debt costs.

2. Retail 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.

### 3.5.1 Legal reviews of AER decisions

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

From 2008 to 2017, network businesses and other parties applied for limited merits review of 33 of the AER's 52 electricity network decisions. Network businesses often succeeded in having their rates of return and revenues increased, whereas consumer representatives and governments were invariably unsuccessful in arguing that network revenues should be decreased.[9]

From 2008 to 2014, Tribunal decisions added $3.2 billion to network revenues. In later decisions, network businesses sought a further $6 billion in revenue above what the AER had determined (box 3.2).

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

9 AER, *Review of the limited merits review framework, AER submission to CoAG Energy Council*, October 2016.

## Box 3.2 Legal reviews of AER decisions on NSW and ACT networks

One of the longest running appeal processes (with ongoing ramifications in 2020) related to the Australian Energy Regulator's (AER) revenue decisions in 2015 for five New South Wales (NSW) and Australian Capital Territory (ACT) energy networks. While the Australian Government abolished limited merits review in October 2017, legal processes and their regulatory impacts on those five networks ran for several years.

The decisions covered three NSW electricity distributors (Ausgrid, Endeavour Energy and Essential Energy), the ACT electricity distributor Evoenergy, and NSW gas distributor Jemena Gas Networks. The five businesses sought a review of the AER's decisions, seeking to recover around $5 billion in additional revenue from customers.

The Australian Competition Tribunal in February 2016 found in favour of the network businesses in several areas. In 2017 the Federal Court upheld the Tribunal's findings on some matters, and instructed the AER to remake its five revenue decisions.

The lengthy process posed unique challenges. To manage price uncertainty for energy customers, the AER accepted enforceable undertakings from the five network businesses to limit rises in distribution charges to consumer price index (CPI) changes for the three years to 30 June 2019.

The AER remade its revenue decisions on all five network businesses by January 2019. Following the original decisions, each business had embarked on reforms to reduce its operating costs, without compromising network reliability and security. The AER's remade decisions accounted for the businesses' constructive engagement with their stakeholders—including consumer groups and affected distribution businesses—to reach a common position on key issues. The AER also recognised the proposals provided certainty and price stability to customers, and allowed a timely resolution to an unusually lengthy process.

All final decisions resulted in approved revenues below what had been recovered from customers while the remittals were being finalised. The networks are returning excess revenue to customers through lower charges over the regulatory period, which began in July 2019.

## 3.6 Refining the regulatory approach

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

The AER continues to refine its approach to economic benchmarking in assessing a network's proposed operating expenditure. In 2019, for example, it reviewed alternative approaches to assessing information and communication technology (ICT) expenditure. ICT is increasingly a more integral component of energy services delivery. In its review, the AER assessed whether its existing ICT expenditure assessment tools were fit for purpose.

Another ongoing focus is the quality of network businesses' engagement with their customers and with the AER (section 3.6.2). The AER continues to improve incentive schemes and guidelines—for example, it introduced in 2017 a guideline for demand management incentives (section 3.10.7).

### 3.6.1 Aligning business and consumer interests

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

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

A number of network businesses are experimenting with early engagement models to better reflect consumer



## Box 3.3 Trialing the New Reg model

The Australian Energy Regulator (AER), along with Energy Consumers Australia and Energy Networks Australia, launched the New Reg joint initiative in June 2017 to explore ways to improve sector engagement and identify opportunities for regulatory innovation. The primary objective of the New Reg process is for consumers (represented by a customer forum) and the network business to agree the revenue proposal reflects consumer perspectives and preferences, before the business lodges the proposal for AER assessment. The vision of the initiative is for energy consumers' priorities and stated preferences to drive, and be seen to drive, energy network businesses' proposals and regulatory outcomes.

AusNet Services was the first network business to trial the new initiative, engaging an independent customer forum to represent the perspectives of its customers. The customer forum negotiated with AusNet Services on aspects of the network's proposal, to reach a number of outcomes. To represent accurately the perspectives of customers, AusNet Services and the customer forum undertook extensive consumer engagement, including interviews, field visits, commissioned research, observations (such as focus groups, deep dives, workshops and public forums) and reviews (of complaints data, guaranteed service level and reliability data, and AusNet Services customer research).[a]

By April 2020 the New Reg trial was in its third stage, following AusNet Services' submission of its revenue proposal and the customer forum's final engagement report to the AER in January 2020.[b] The AER is now assessing AusNet Services' proposal.

The AER engaged farrierswier consultancy to monitor the AusNet Services trial, and the Centre for Efficiency and Productivity Analysis (CEPA) to evaluate it. The evaluation will continue as the AER assesses the network's regulatory proposal.

a AusNet Services Customer Forum, *AusNet Services 2021–2025 electricity distribution price review—customer forum final engagement report*, 31 January 2020.
b AusNet Services Customer Forum, *AusNet Services 2021–2025 electricity distribution price review—customer forum final engagement report*, 31 January 2020; AusNet Services, *Electricity distribution price review 2022 to 2026*, 31 January 2020.



interests and perspectives in framing their regulatory proposals. The AER is trialing one such approach—the New Reg—in partnership with Energy Networks Australia and Energy Consumers Australia (box 3.3).[10]

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

Many network businesses are increasing their focus on consumer engagement—for example, they may run 'deep dive' workshops before lodging a proposal. Also, the businesses are increasingly looking to maintain open and ongoing dialogue with stakeholders throughout the regulatory period, as opposed to engaging intensively once every five years when a proposal is being considered.

Essential Energy's (NSW) regulatory proposal for the period commencing July 2019 is an example of a well targeted and implemented engagement program. Energy Networks Australia recognised the network's efforts, with Essential Energy winning the 2018 Energy Network Consumer Engagement Award. TasNetworks (Tasmania) and Power and Water (Northern Territory) also undertook comprehensive engagement in developing their most recent regulatory proposals.

While engagement is improving, consumer feedback indicated the processes undertaken by some businesses can improve. Consumer groups argued, for example, that recent processes by Ausgrid (NSW), Endeavour Energy (NSW) and Evoenergy (ACT), would have benefited from more meaningful engagement earlier in the process (such as 'deep dive' workshops) rather than engagement compressed towards the end of the process.

The Consumer Challenge Panel was generally supportive of the quality of engagement by network businesses for three

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

regulatory decisions published by the AER in 2020. It noted SA Power Networks ran a well resourced engagement model that other utilities should consider.[11]

The Panel found engagement from the Queensland businesses—Energex and Ergon Energy—to be responsive, inclusive and transparent.[12] However, it found engagement to be less effective on the structure of tariffs and the impact of its proposal on customer bills. The Panel also noted Ergon Energy did not inform its consumers of the full costs of its proposed safety related investment and the available alternatives. The Queensland Council of Social Service observed the Queensland businesses did not set out a clear rationale for tariff reform.[13]

## 3.7 Power of Choice reforms

Innovations in network and communication technology—including 'smart' meters, interactive household devices, and energy management and trading platforms—are driving change in energy markets. These innovations allow consumers to access real time information about, and make informed decisions in managing, their energy use. If consumers choose to reduce their energy use voluntarily in peak periods, that behaviour can potentially delay the need for costly network investment.

Power of Choice reforms are being progressively rolled out to unlock the potential benefits of these innovations. The reforms include a market led rollout of smart meters, supported by more cost-reflective network pricing (section 3.7.1), and incentives for demand management as a lower cost alternative to network investment (section 3.10.7).

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

The Australian Energy Market Commission (AEMC) in December 2019 released draft rules to address regulatory and pricing barriers to off-grid arrangements. The application of these rules should make it easier for distribution network providers to offer stand-alone power systems where economically efficient to do so,

11 CCP14, *Submission on SA Power Networks' revised proposal 2020–25, Revised*, February 2020, p. 7.
12 CCP14, *Submission on Energex's draft decision and revised proposal 2020–25, Revised*, March 2020, p. 14.
13 QCOSS, *Submission on Energex's draft decision and revised proposal 2020–25*, January 2020, p. 1.

while maintaining appropriate consumer protections and service standards.[14]

The Distributed Energy Integration Program (DEIP)—a collaboration of government agencies, market authorities, industry and consumer associations—aims to enhance customers' benefits from using distributed energy resources, including benefits from access and pricing reforms.[15]

### 3.7.1 Tariff structure reforms

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

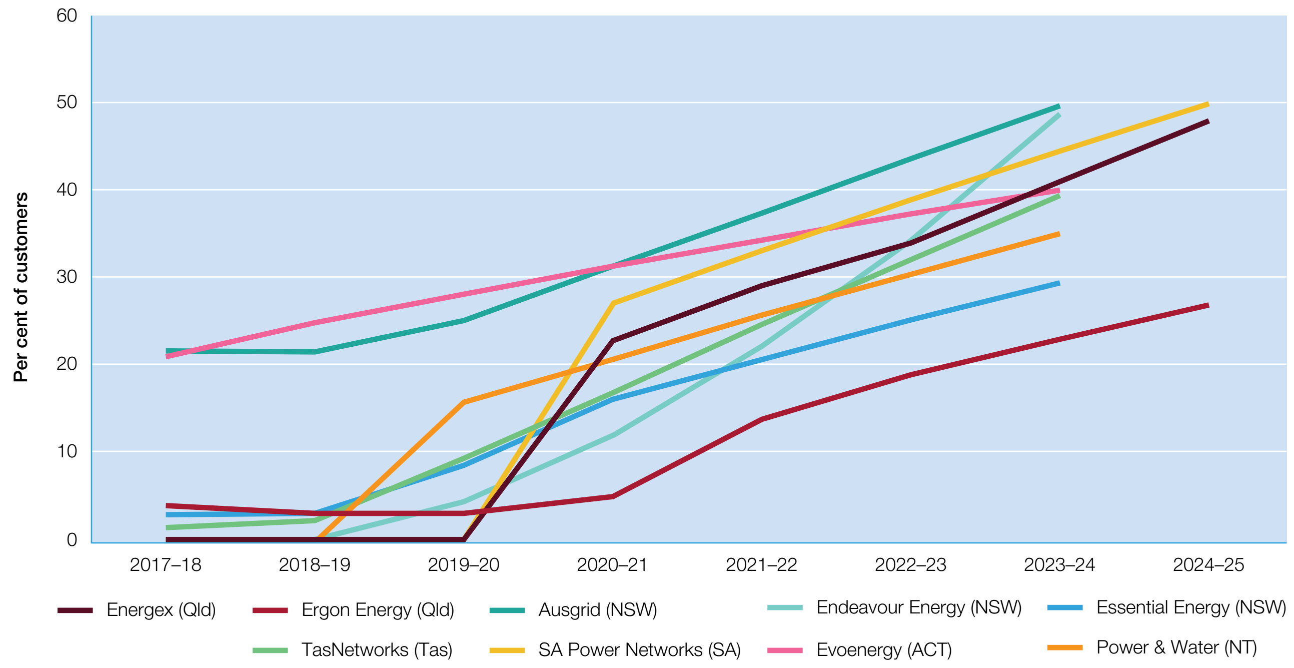
National Electricity Rule changes that took effect in 2017 require distributors to make their tariffs more cost-reflective, to signal to retailers the cost of their customers' use of the network and investment in distributed energy resources (DER). Retailers are the focus of tariff reform, because they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

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

As an example, the AER in 2020 approved SA Power Networks' (South Australia) use of a 'solar sponge' tariff for its residential customers. This tariff offers a lower network charge during the middle of the day when solar output is highest, to encourage shifting of electricity use to those times. Raising demand for grid supplied electricity in the middle of the day can help manage voltage issues and thermal overloads associated with low demand, while

14 AEMC, *Updating the regulatory frameworks for distributor-led stand-alone power systems*, December 2019.
15 The DEIP's Access and Pricing Working Group is developing a rule change proposal on the prohibition on export charging, which it expects to submit to the AEMC by mid-2020.

Figure 3.6
**Projected assignment of cost-reflective tariffs for residential customers**




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

shifting demand away from the evening peak that can put heavy strain on the network. SA Power Networks also introduced a demand tariff that offers discounted time-of-use rates and a seasonal peak demand component.[16]

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

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

Initially, distribution network businesses offered cost-reflective structures on an opt-in basis (that is, a retailer or

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

customer had to choose to adopt the new pricing, or would otherwise stay on the old flat price structure). More recently, however, network businesses are moving to an opt-out or mandatory assignment approach, which is expected to widen the use of these tariffs considerably.

Distribution network businesses outside Victoria forecast the proportion of their residential customers assigned to cost-reflective network tariffs will increase from 2020 (figure 3.6).

The limited uptake of smart meters for residential and small business customers has been a barrier to cost-reflective network tariffs being implemented in distribution networks outside Victoria. Smart meters, which measure electricity use in half hour blocks, are essential for cost-reflective tariffs to be applied.

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

In other jurisdictions, the rollout of smart meters is occurring on a market led basis, following National Electricity Rule changes that applied from December 2017. All new and replacement meters installed for residential and small businesses consumers must now be smart meters, and other customers can negotiate for a smart meter as part of their electricity retail offer.

The new rules also transferred responsibility for metering from distribution network businesses to retailers. The transition to retailer responsibility coincided with large delays in meter installations in some regions. Participants indicated reasons for the delays included poor coordination and data provision among network businesses, retailers and metering coordinators; inadequate retailer systems, processes and controls; and poor resourcing. But from February 2019 new rules required retailers to provide customers with electricity meters within six business days from a property being connected to the network, or with replacement meters within 15 days.[17]

Outside Victoria, Ausgrid (NSW) had the highest penetration of smart or interval meters at February 2020, at 34 per cent of customers. In other networks, 10–15 per cent of customers had a smart or interval meter.[18] This share is expected to increase to a range from 30 per cent for Essential Energy (NSW) and 63 per cent for TasNetworks (Tasmania) by 2025, reflecting the requirement for new meters—including end-of-life replacements—to be smart meters.

### 3.7.2 Ring-fencing

When a network business offers metering or other services in a contestable market, robust ring-fencing must be in place to ensure the business competes fairly with other providers. The AER publishes a ring-fencing guideline that requires distribution networks to separate their regulated network services (and the costs and revenues associated with them) from unregulated services such as metering, and solar PV and battery installations. Unregulated services must be offered through a separate entity.

The ring-fencing rules aim to ensure network businesses do not use revenue from regulated services to cross-subsidise their unregulated products. They also deter discrimination in favour of affiliate businesses.[19]

All distribution network businesses are required to comply with the AER's guideline and annually report on their compliance to the AER. The AER observed a number of serious breaches in 2017–18, but found fewer compliance issues and breaches in 2018–19.

A number of distributors have worked effectively to remediate breaches, and strengthen systems and processes to support compliance. But compliance could still be improved in a number of areas, particularly in separating staff between the distributor and its affiliates, protecting confidential electricity information about the network, and ensuring any shared costs are appropriately allocated between the distributor and an affiliate. However, when breaches have occurred, distributors have mostly communicated promptly with the AER, acted quickly to contain any potential harms from those breaches, and put in place plans to prevent breaches from recurring.

In 2019 the AER reviewed the ring-fencing guideline to strengthen some obligations, and to simplify compliance. The new guideline is scheduled to take effect from July 2020. Civil penalties introduced in February 2020 should help to encourage improved compliance.

## 3.8 Network revenue

Since 2006 revenues earned by network businesses have shown two distinct trends—rapid growth for several years (until around 2013 in transmission and 2015 in distribution), followed by a significant downturn. The revenue downturn was more gradual for transmission network businesses than for distribution (figures 3.7 and 3.8).

Key revenue drivers between 2006 and 2019 included:

- the value of network assets (the RAB), on which revenues are paid each year to cover depreciation and finance costs. New investment adds to the asset base each year (resulting in higher depreciation and finance costs). Surging investment from 2006 to 2013 led the network industry's asset base to rise by 62 per cent. Investment then weakened, but the impact of past over-investment remains in the asset base (section 3.10).
- the rate of return paid to network owners and lenders, which finance the business's operations. Rates of return peaked at over 10 per cent from 2009 to 2013, but by 2020 had eased to around half that level (section 3.11).

Operating, maintenance and other costs correlate less closely with market conditions than do other revenue drivers, and show relatively stable trends. These costs in 2009 were about one third the size of asset investment, but by 2015 weakening investment resulted in the two being at comparable levels. Operating expenditure later eased, as network businesses (especially distributors) implemented efficiency programs (section 3.12).

17 AEMC, *Rule determination: National Energy Retail Amendment (Metering Installation Timeframes) Rule 2018*, December 2018.
18 Estimates based on AER market intelligence.
19 The ring-fencing reforms apply to demand management incentives too (section 3.10.7).

Figure 3.7
**Transmission revenue and key drivers**

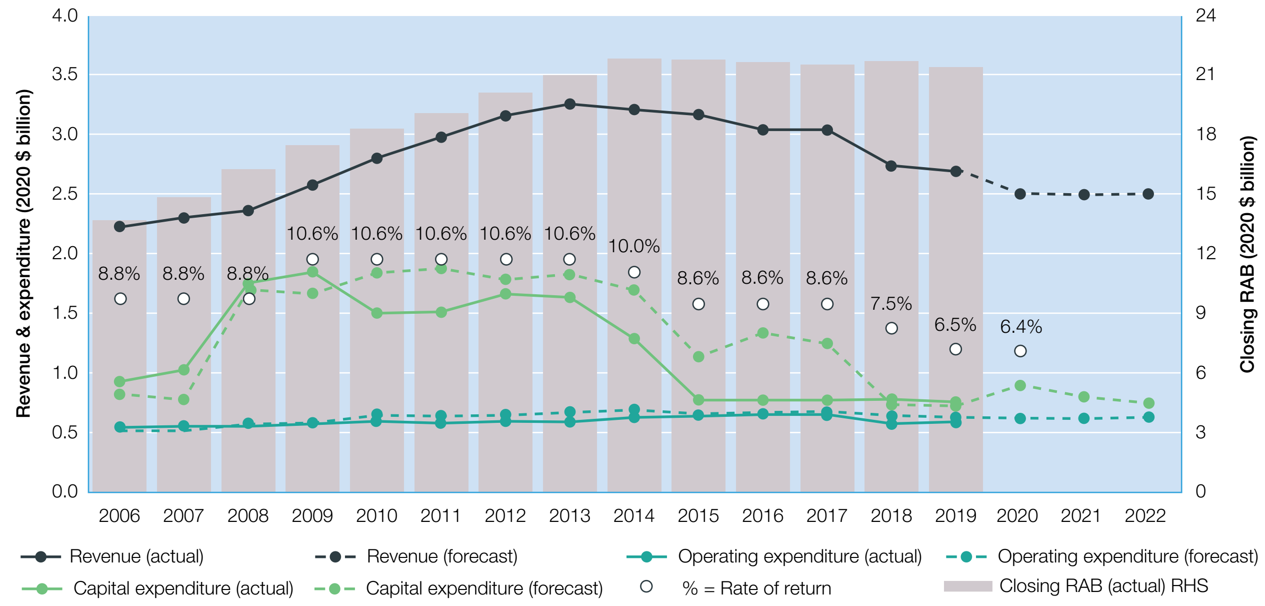
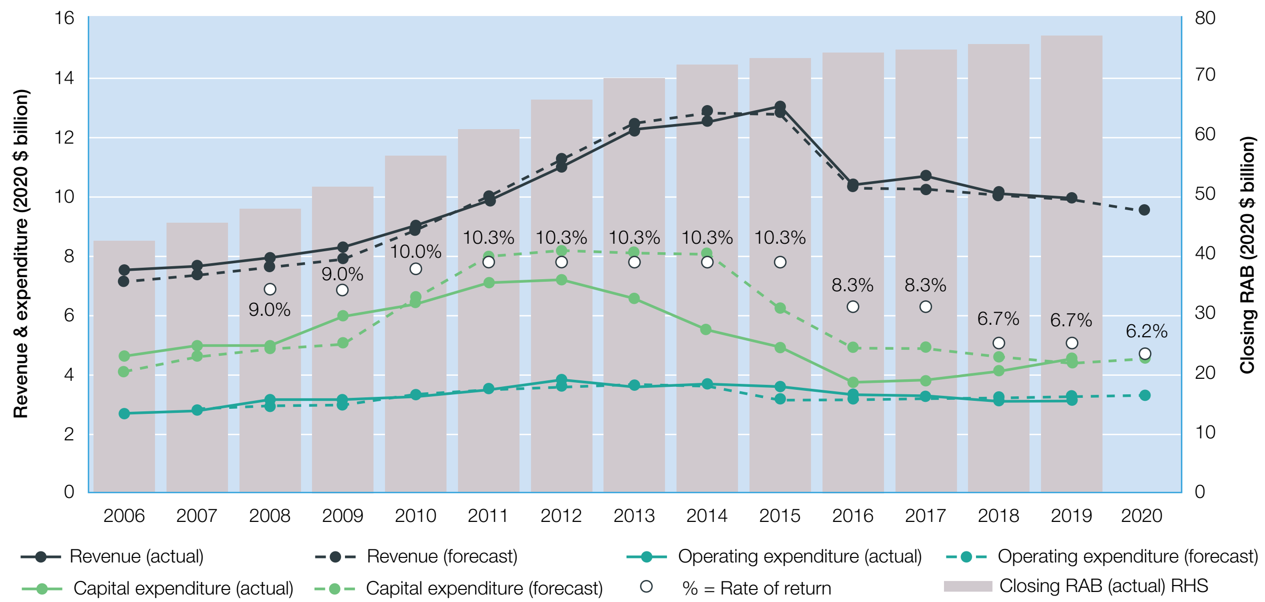



Figure 3.8
**Distribution revenue and key drivers**




RAB, regulatory asset base.

Note (figures 3.7 and 3.8): Most network businesses report on a 1 July – 30 June basis. The exceptions are Victorian networks: AusNet Services (transmission) reports on a 1 April – 31 March basis, and the Victorian distribution network businesses report on a 1 January – 31 December basis. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018).

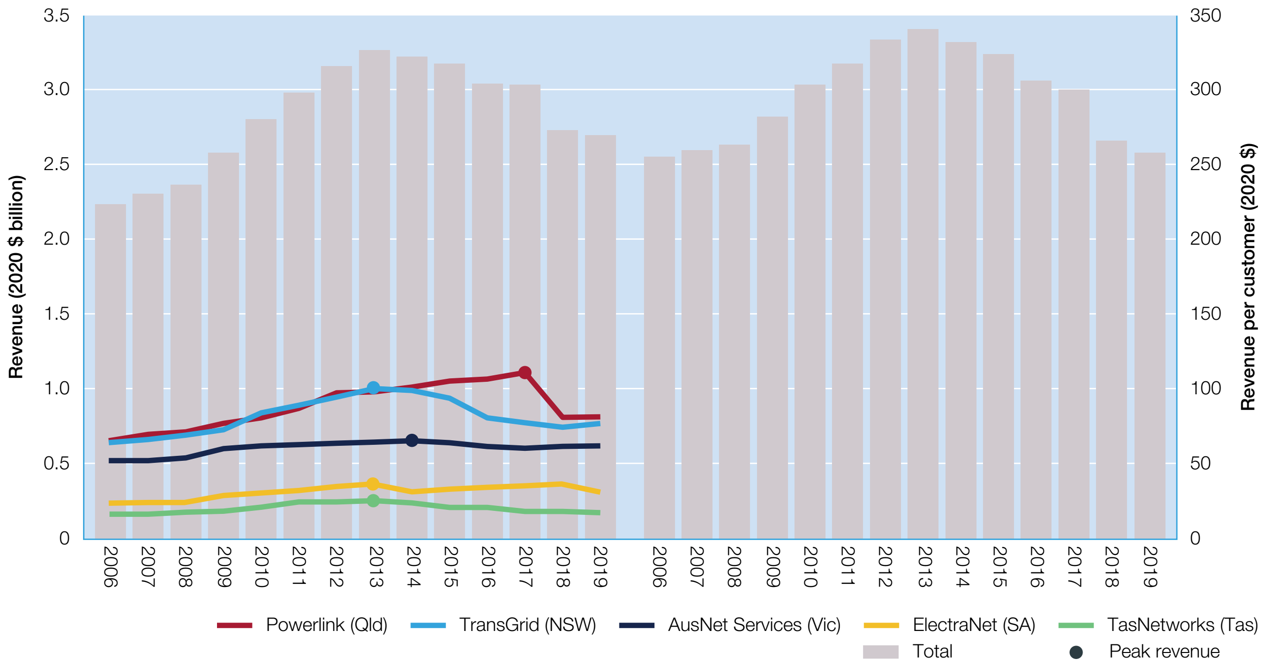
All data are consumer price index (CPI) adjusted to June 2020 dollars. Rates of return are weighted average cost of capital (WACC) forecasts in AER revenue decisions and Australian Competition Tribunal decisions. The rates of return shown represent the highest rate that applied to network businesses each year.

Operating expenditure methodology for transmission network businesses has changed since 2018. Forecast transmission revenues are subject to adjustments over which the AER has limited visibility.

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

Figure 3.9

**Transmission network revenue**




Note: Actual outcomes, CPI adjusted to June 2020 dollars. Most transmission network businesses report on a 1 July – 30 June basis. The exception is AusNet Services (Victoria) which reports on a 1 April – 31 March basis. The data show the outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018).

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

Source: Economic benchmarking regulatory information notice (RIN) responses.

The AER forecasts network revenue and investment will plateau between 2020 and 2022, although continuing distribution investment will likely further raise the industry RAB over this period.

## 3.8.1 Long term revenue trends

Network revenues rose each year from 2006 to 2015 by an average 7 per cent. Figures 3.9 and 3.10 chart transmission and distribution revenue from 2006 to 2019. With network charges absorbing around 43 per cent of retail customer bills, this growth led to escalating retail electricity bills over the period.

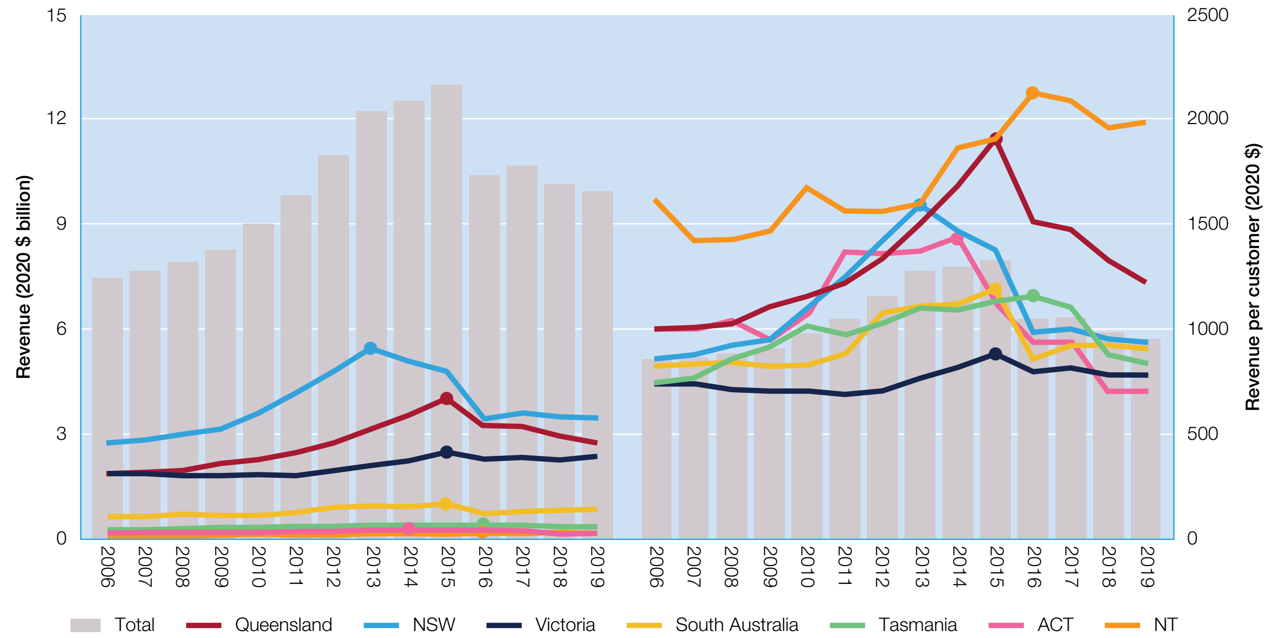
A 62 per cent increase in the value of the RAB (caused by surging investment) was a key contributor. The ballooning asset base increased financing costs and depreciation charges, resulting in higher revenue allowances to cover these costs. Rising interest rates due to the global financial crisis compounded the impact on revenue. Operating expenditure also increased every year from 2006 to 2012, by an average 7 per cent, further boosting network revenue. Further, many AER decisions faced legal challenges over this period, often resulting in court decisions that increased network revenue (box 3.2).

Revenue rose higher in Queensland and NSW than elsewhere. In Queensland, it more than doubled between 2006 and 2015; in NSW, it rose by 90 per cent from 2006 to 2013. Revenue growth was less dramatic in Victoria, at 32 per cent from 2006 to 2015. A key cost driver in Queensland and NSW was the stricter reliability standards imposed by state governments, which required new investment and operating expenditure to meet the new standards.

Cost pressures began to ease when electricity demand from the grid plateaued, causing new investment to scale back from 2013. This easing stemmed several years of rapid growth in network assets and their associated depreciation and finance costs. The changing demand outlook coincided with government moves to allow network businesses greater flexibility in meeting reliability requirements.

Figure 3.10

**Distribution network revenue, by region**




Note: Actual outcomes, CPI adjusted to June 2020 dollars. Victorian distribution network businesses report on a 1 January – 31 December basis. All other distribution network businesses report on a 1 July – 30 June basis. The data show the outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018).

Source: Annual reporting regulatory information notice (RIN) responses; economic benchmarking RIN responses; regulatory accounts.

The financial environment also improved after 2012, easing borrowing and equity costs. After peaking at over 10 per cent between 2009 and 2013, rates of return approved for some network businesses were below 5 per cent in 2020.

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

In combination, these factors reduced the revenue needs of network businesses. But the five year regulatory cycle meant lower investment and rates of return often lowered revenue only after a significant lag. More generally, consumers will continue to pay for the over-investment in network assets from 2006 to 2013 for 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 over-investment.[20] The Australian Competition and Consumer Commission (ACCC) supported this position, particularly for government owned networks in Queensland, NSW and Tasmania.[21]

Consumer groups and some industry observers remain concerned the regulatory framework enables network businesses to earn excessive profits. In response to calls for greater transparency around the actual returns earned by the network businesses, the AER in 2018 began publishing information on the businesses' profitability. From 2020 the AER will expand its coverage of profitability indicators.[22] This initiative will help stakeholders make more informed assessments of the returns earned by each network business.

Table 3.4 summarises recent financial indicators for distribution networks on a per customer basis, to allow comparability across networks.[23]

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

21 ACCC, *Retail Electricity Pricing Inquiry—final report*, June 2018

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

23 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.

**Table 3.4 Electricity distribution networks—financial indicators**

| NETWORK | CUSTOMER NUMBERS[1] | CUSTOMER DENSITY (CUST/KM) | DOLLARS PER CUSTOMER[1] REVENUE[2] | OPERATING EXPENDITURE[2] | CAPITAL EXPENDITURE[2] | ASSET BASE[2] | RATE OF RETURN (%)[3] |
|---|---|---|---|---|---|---|---|
| QUEENSLAND | | | | | | | |
| Energex | 1 496 317 | 27.3 | 951 | 241 | 316 | 8 496 | 6.0 |
| Ergon Energy | 765 924 | 5.0 | 1 756 | 525 | 715 | 14 815 | 6.0 |
| NSW AND ACT | | | | | | | |
| Ausgrid | 1 746 274 | 41.6 | 881 | 262 | 472 | 9 145 | 6.4 |
| Endeavour Energy | 1 027 586 | 26.8 | 872 | 249 | 398 | 6 468 | 6.7 |
| Essential Energy | 916 471 | 4.8 | 1 110 | 451 | 537 | 9 006 | 6.4 |
| Evoenergy | 198 432 | 36.5 | 701 | 285 | 371 | 4 085 | 6.2 |
| VICTORIA[2] | | | | | | | |
| AusNet Services | 762 382 | 16.8 | 887 | 275 | 521 | 5 793 | 6.2 |
| CitiPower | 345 009 | 75.7 | 884 | 232 | 357 | 5 562 | 5.9 |
| Jemena | 354 452 | 53.5 | 744 | 252 | 353 | 4 154 | 6.2 |
| Powercor | 853 771 | 11.3 | 784 | 270 | 429 | 4 866 | 5.9 |
| United Energy | 697 594 | 52.0 | 631 | 164 | 235 | 3 373 | 6.2 |
| SOUTH AUSTRALIA | | | | | | | |
| SA Power Networks | 906 198 | 10.1 | 913 | 300 | 416 | 4 759 | 6.1 |
| TASMANIA | | | | | | | |
| TasNetworks | 290 446 | 12.7 | 840 | 277 | 369 | 6 210 | 6.0 |
| NORTHERN TERRITORY | | | | | | | |
| Power and Water[4] | 85 743 | 12.1 | 1 985 | 1 067 | 506 | 11 426 | 4.2 |
| TOTAL | 10 446 598 | 13.9 | 947 | 297 | 433 | 7 385 | |

1. In 2019 residential customers (a customer who purchases energy principally for personal, household or domestic use) accounted for 88 per cent of total customers on the distribution network. Of the remaining customers, 11 per cent were non-residential (including high voltage customers who were connected at higher than 415 volts, and low voltage customers who were connected at 240 or 415 volts), and 1 per cent were unmetered or 'other'. While these proportions differed across network businesses—91 per cent residential for Energex (Queensland) and 83 per cent for Essential Energy (NSW), for example—the differences did not materially affect the 'per customer' metric.
2. Revenue, capital expenditure, operating expenditure and asset base are actual outcomes for the regulatory year ending in 2019. Distribution networks businesses report on a financial year basis (to 30 June), except in Victoria, where they report on calendar year basis.
3. Rate of return is the nominal vanilla rate for 2019. The rate is updated annually to reflect changes in debt costs.
4. For regulatory purposes, Northern Territory transmission assets are treated as part of the distribution system.

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

### 3.8.2 Recent revenue outcomes

Energy network businesses earned a total of $12.6 billion ($1211 per customer) in 2019:

- Distribution network businesses earned around 79 per cent of all network revenue. They earned just under $10 billion ($953 per customer) in revenue in 2019, which was 2 per cent lower than the previous year, and 23 per cent lower than the revenue peak of $13 billion ($1324 per customer) in 2015 (figure 3.10).
- Transmission network businesses earned around 21 per cent of all network revenue. They earned $2.7 billion ($258 per customer) in revenue in 2019, which was 1 per cent lower than the previous year, and 17 per cent lower than the revenue peak of $3.3 billion (or $340 per customer) in 2013 (figure 3.9).

#### Current AER decisions

Transmission network revenues are forecast to be around 15 per cent lower on average in current regulatory periods compared with previous periods. Distribution network revenues are forecast to be around 13 per cent lower on average in current regulatory periods compared with previous periods (figure 3.11).[24]

Victoria's distribution networks differ from the general industry trend, with revenues in the current period forecast at 7–12 per cent *higher* than in the previous period, due to forecast increases in operating costs and replacement expenditure (sections 3.10 and 3.12). The current Victorian distribution determinations were made in May 2016.

24 The current regulatory period is the period in place at 1 July 2020.



The AER in early 2020 was consulting on the Victorian distribution networks' revenue proposals for the regulatory period commencing January 2021.[25]

## 3.9 Network charges and retail bills

Electricity network charges made up around 43 per cent of a residential customer's energy bill in 2018–19 (figure 6.2 in chapter 6). The bulk of these charges relate to distribution network costs.

Declining network revenue since 2015, combined with rising customer numbers, has translated into lower network charges in retail energy bills for most customers (figure 3.12). This lowering of network charges is helping to mitigate some of the recent pressure (caused by higher wholesale electricity costs) on retail energy bills.

Current AER distribution decisions reduced residential energy bills by an average 0.6 per cent across all states and territories. Changes to network charges mostly arise in the first year of a regulatory period, and range from a 9.1 per cent reduction for Power and Water (Northern Territory) to a 0.2 per cent increase for Essential Energy (NSW). This initial change is generally followed by stable prices or modest increases in later years.

The reduction in network charges reflects factors such as lower finance costs, lower demand for electricity (so less need for new investment), operating efficiencies implemented by network businesses (partly in response to AER incentive schemes), and regulatory refinements such as the AER's wider use of benchmarking to assess efficient costs.

Current AER *transmission* decisions reduced network charges in Queensland, but allowed increases in NSW, Victoria, South Australia and Tasmania.

## 3.10 Electricity network investment

Electricity network businesses invest in capital equipment such as poles, wires and other infrastructure needed to transport electricity to customers. Investment drivers vary among networks, and depend on a network's age and technology, load characteristics, the demand for new connections, and reliability and safety requirements. Substantial investment is needed to replace old equipment as it wears out or becomes technically obsolete. Other investments may be made to augment (expand) a network's capability in response to changes in electricity demand.

25 The Victorian Government indicated its intention to align with the other NEM states, and operate on a financial (rather than calendar) year basis. This change is intended to come into effect for the 1 July 2021 to 30 June 2026 regulatory period. It will mean extending the current regulatory period by six months.

### 3.10.1 Investment and the regulatory asset base

As part of the revenue determination process, the AER forecasts a network business's efficient investment requirements over the upcoming regulatory period. Efficient investment approved by the AER gets added to the RAB, while depreciation of existing assets gets deducted.

A network's asset base will grow over time if approved new investment exceeds depreciation. The regulated network industry's aggregate RAB grew each year from 2006 to 2019. As the RAB grows, the returns paid to shareholders and lenders that fund those assets also grow. This cost is passed on to customers. 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.

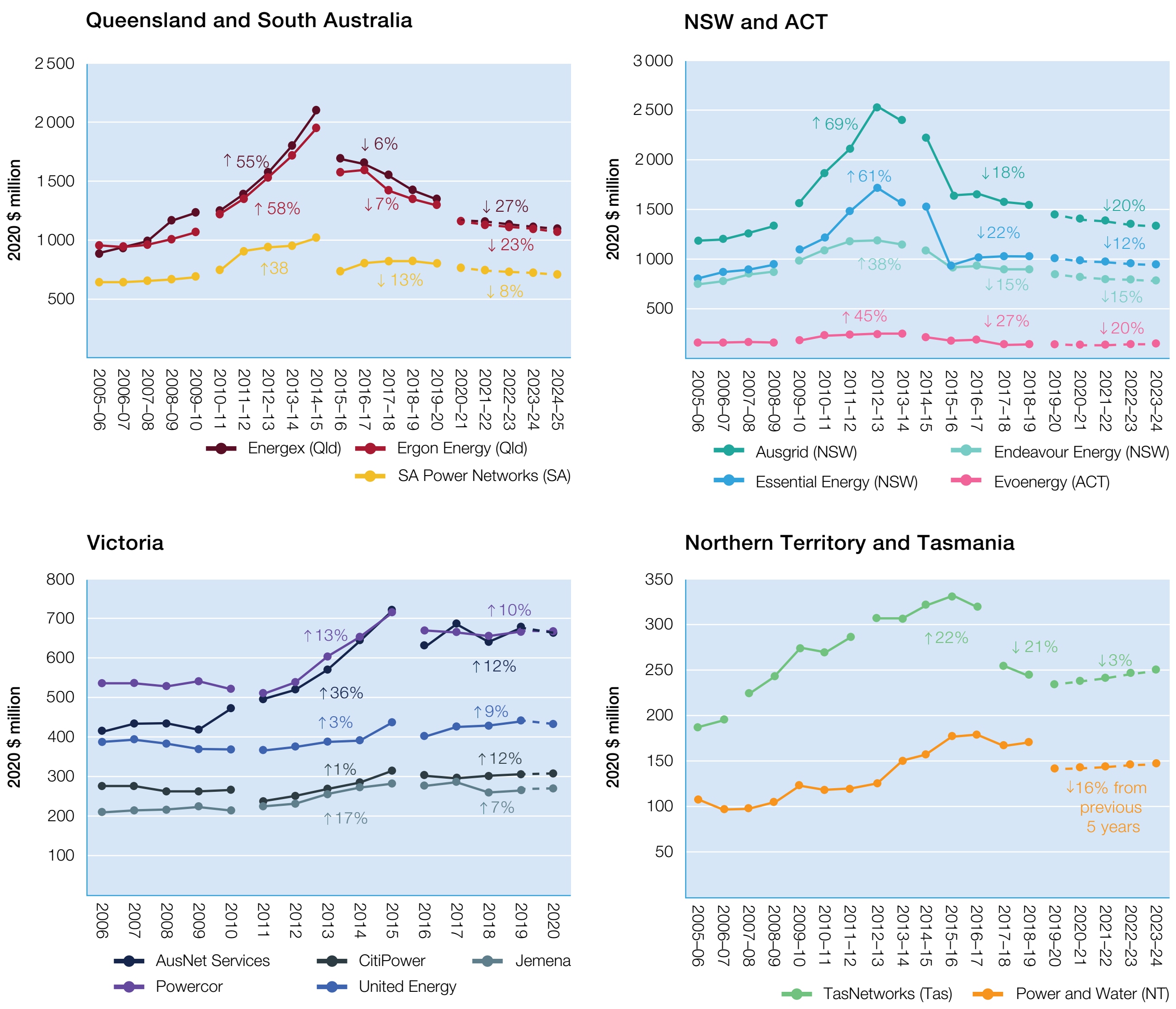
Network businesses receive a guaranteed return on their RAB. For this reason, they have an incentive to over-invest if their allowed rate of return exceeds their actual financing costs. Previous versions of the energy rules enabled significant over-investment in network assets, which partly drove the sharp rise in network revenue from 2006 to 2015 (section 3.10.2). Under reforms introduced in 2015, the AER can remove inefficient investment from a network's asset base if the network overspent its allowance, to ensure customers do not pay for it.

In 2015 the AER also launched new incentives for network businesses to keep their capital expenditure within approved forecasts (box 3.4).

### 3.10.2 Historical investment trends

Network investment grew by an average of 8 per cent per year from 2006 until it peaked at $8.9 billion in 2012 (figure 3.13). From 2006 to 2009, actual investment was 11 per cent above the approved forecast level. This growth responded to concerns at the time that investment was not keeping pace with high projected growth in electricity demand. More stringent reliability standards imposed by some state governments also spurred higher investment.

Figure 3.11
Distribution network revenue, by network business




Note: Percentage values reflect growth from the previous regulatory period. Dollar values are CPI adjusted to June 2020 dollars.

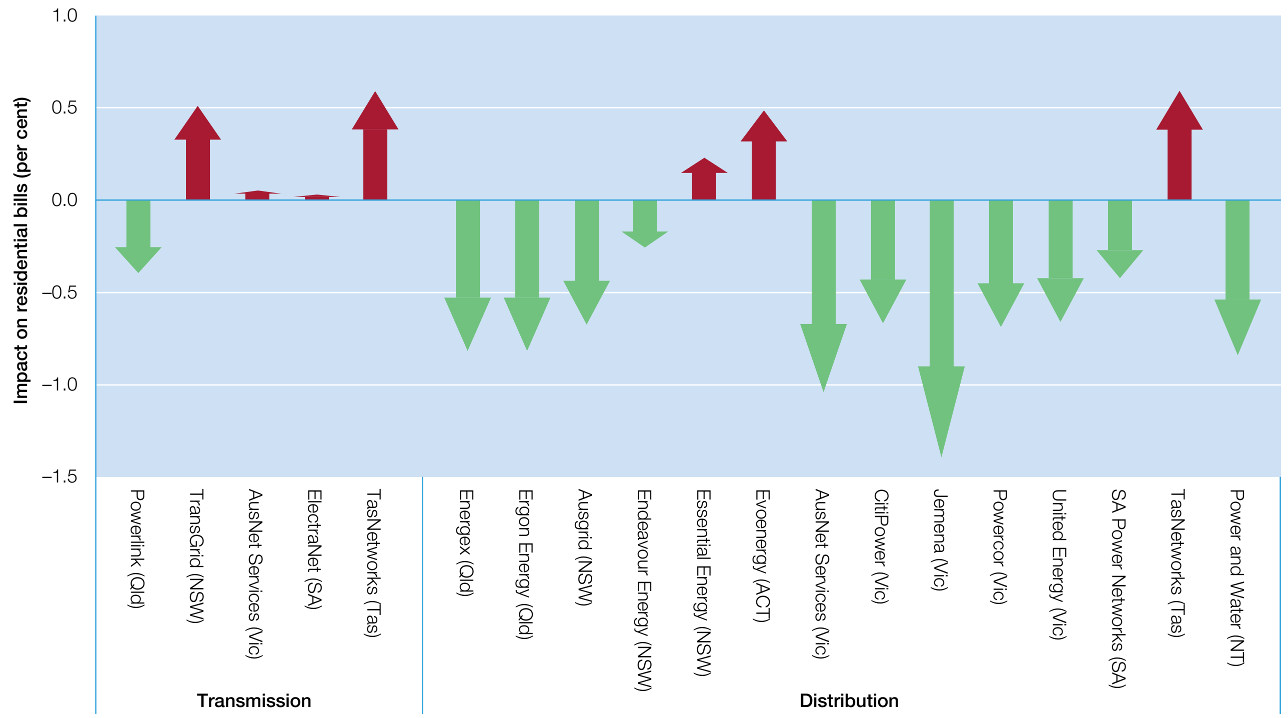
Assumptions are set out in figure 3.8 notes.

Source: AER regulatory decisions; annual reporting regulatory information notice (RIN) responses; economic benchmarking RIN responses; regulatory accounts.

But lower demand for electricity began to reverse this trend from 2013. Many projects were postponed or abandoned when it became clear that earlier projections of sustained demand growth would not eventuate. Further, a shift in government policy towards less stringent reliability obligations on network businesses made some projects redundant, leading to several proposals being scaled back or deferred. Network businesses underspent on capital projects (compared with approved AER forecasts) by $12.9 billion (18 per cent) between 2010 and 2018.

Investment levels further eased from 2015 when AER reforms protecting consumers from funding inefficient network projects began. Plus, a capital expenditure sharing scheme (CESS) offered financial incentives for network businesses to avoid investment above forecast levels. In 2019 network businesses overspent on capital projects by

Figure 3.12
How AER decisions affect residential customer 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 modeling.

## Box 3.4 Capital expenditure sharing scheme

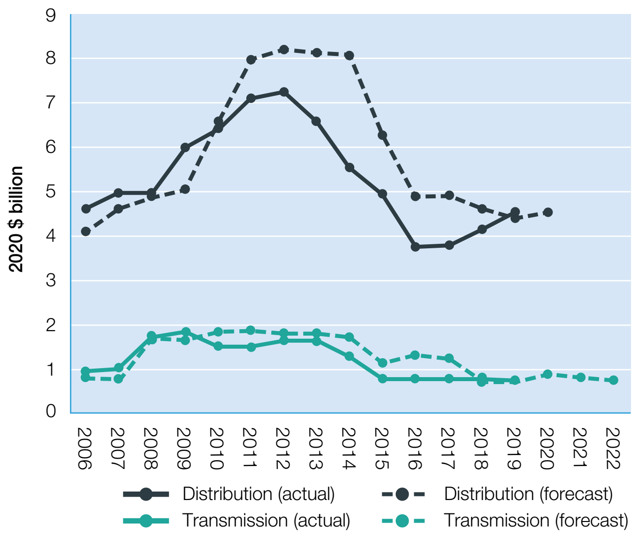
The Australian Energy Regulator's (AER) capital expenditure sharing scheme (CESS) creates an incentive for network businesses to keep new investment within forecast levels approved in their regulatory determination. The CESS rewards efficiency savings (spending below forecast) and penalises efficiency 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 five years, depending on when the spending occurs). In the following regulatory period, the network business must pass on 70 per cent of underspends to its customers as lower network charges. The business retains the remaining 30 per cent of the efficiency savings.

After the regulatory period, the AER conducts an ex-post review of the network's spending. Approved capital expenditure is added to the regulatory asset base (RAB). However, if a network business overspends its capital allowance, and the AER finds the overspending was inefficient, then 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 businesses may inflate their original investment forecasts. To manage this risk, the AER assesses whether proposed investments are efficient at the time of each reset. 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 3.5) and service quality (box 3.6). This balancing of schemes encourages network businesses to make efficient decisions on their mix of expenditure so as to provide reliable services in ways that customers value (section 3.14.1).

Figure 3.13
**Network investment**




Note: Actual outcomes, CPI adjusted to June 2020 dollars. Most network businesses report on a 1 July – 30 June basis. The exceptions are Victorian networks: AusNet Services (transmission) reports on a 1 April – 31 March basis, and the Victorian distribution network businesses report on a 1 January – 31 December basis. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018).

Source: AER modeling; annual reporting regulatory information notice (RIN) responses.

3 per cent (compared with approved AER forecasts). It was the first year of overspending since 2009 (box 3.4).

## 3.10.3 Recent capital expenditure outcomes

Electricity networks invested $5.3 billion (or $505 per customer) in network assets in 2019, which was an 8 per cent increase (6 per cent per customer) on the previous year's investment. While network investment in 2019 rose for third consecutive year, expenditure was still 41 per cent lower than the $8.9 billion ($937 per customer) invested in 2012 (figures 3.14 and 3.15).

Distribution networks accounted for around 86 per cent of total network investment in 2019:

- Distribution network businesses invested $4.5 billion ($433 per customer) in network assets in 2019, which was a 9 per cent increase (8 per cent per customer) on the previous year's investment but 37 per cent less (43 per cent per customer) than peak investment of $7.2 billion in 2012.
- Transmission network businesses invested $756 million ($72 per customer) in network assets in 2019, which was a 2 per cent decrease (4 per cent per customer) on the previous year's investment and 59 per cent less (64 per cent per customer) than peak investment of $1.8 billion in 2009.

AER decisions in place at 1 July 2020 forecast distribution network investment to be 8 per cent lower on average over the current five year regulatory period compared with the previous period. Transmission investment is forecast to be 15 per cent lower.[26]

### Recent AER decisions

Since January 2019 the AER has made eight revenue decisions on electricity distribution networks. All but two of those decisions approved *lower* investment expenditure allowances for distribution network businesses in the current regulatory period than in the previous period. The majority of forecast investment for distribution network businesses is to replace and refurbish old assets.

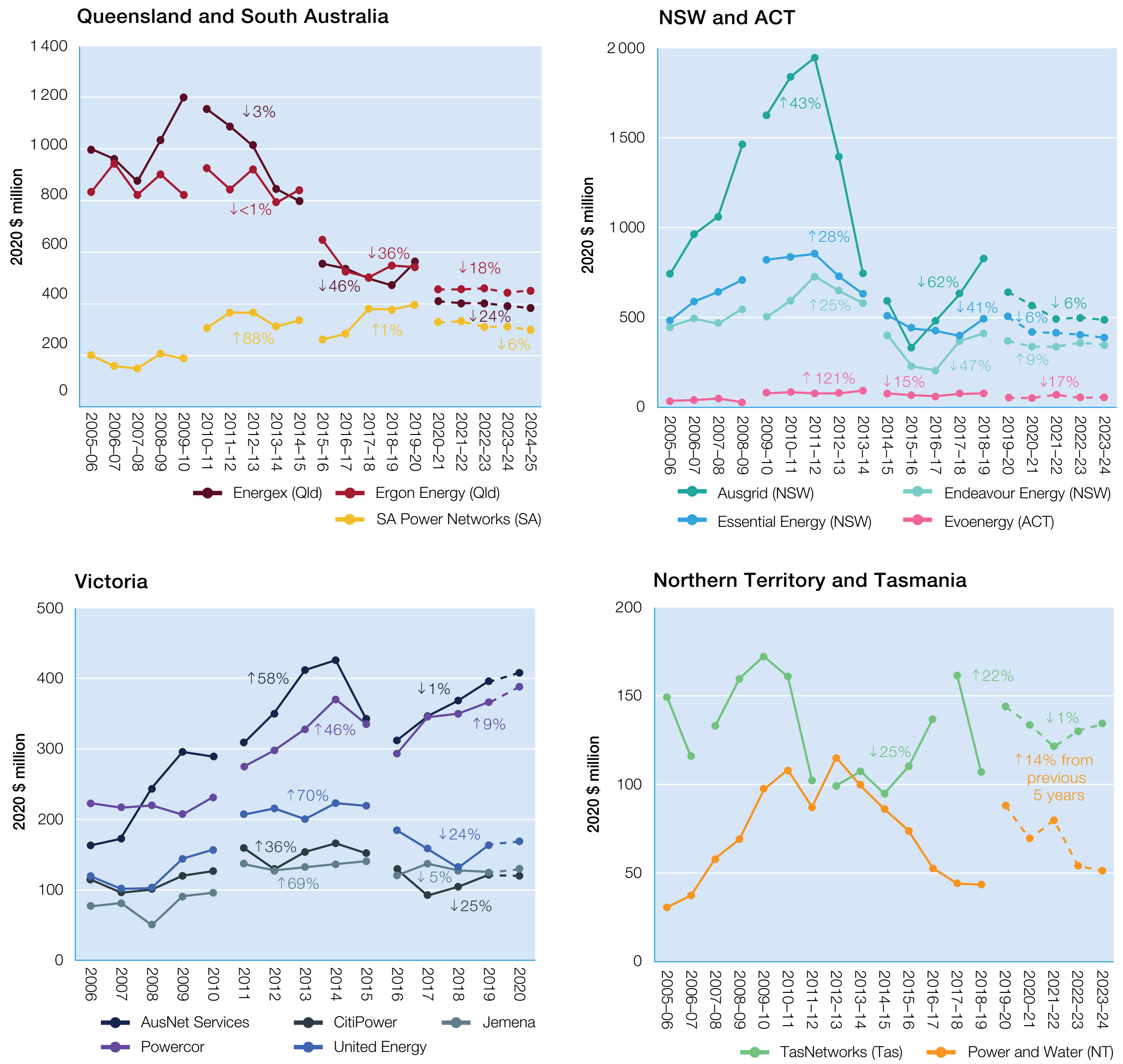
Additionally, in April 2019 the AER made a revenue decision jointly covering Tasmania's transmission and distribution networks, and in June 2020 it made a revenue decision on the NSW–Queensland Directlink interconnector.[27]

For distribution networks in NSW, over the regulatory period commencing July 2019:

- stakeholders—including the AER's Consumer Challenge Panel, the Energy Users Association of Australia, and the Public Interest Advocacy Centre—considered Ausgrid's revised investment proposals to be 'reasonable and supportable'
- Essential Energy's investment was balanced against the costs of past investment needed to meet NSW Government licensing conditions for network security and reliability
- Endeavour Energy's approved investment was 9 per cent higher than in its previous regulatory period, to accommodate growth, replace ageing infrastructure, and invest in technology to transform the business and improve customer service. Endeavour Energy was one of two distribution network businesses—the other being Power and Water (Northern Territory)—granted investment approvals that were higher than spending in the previous period.

26 Excludes AER decisions on transmission interconnectors.
27 Decisions covering several major transmission networks in 2018 are discussed in the 2018 edition of this report.

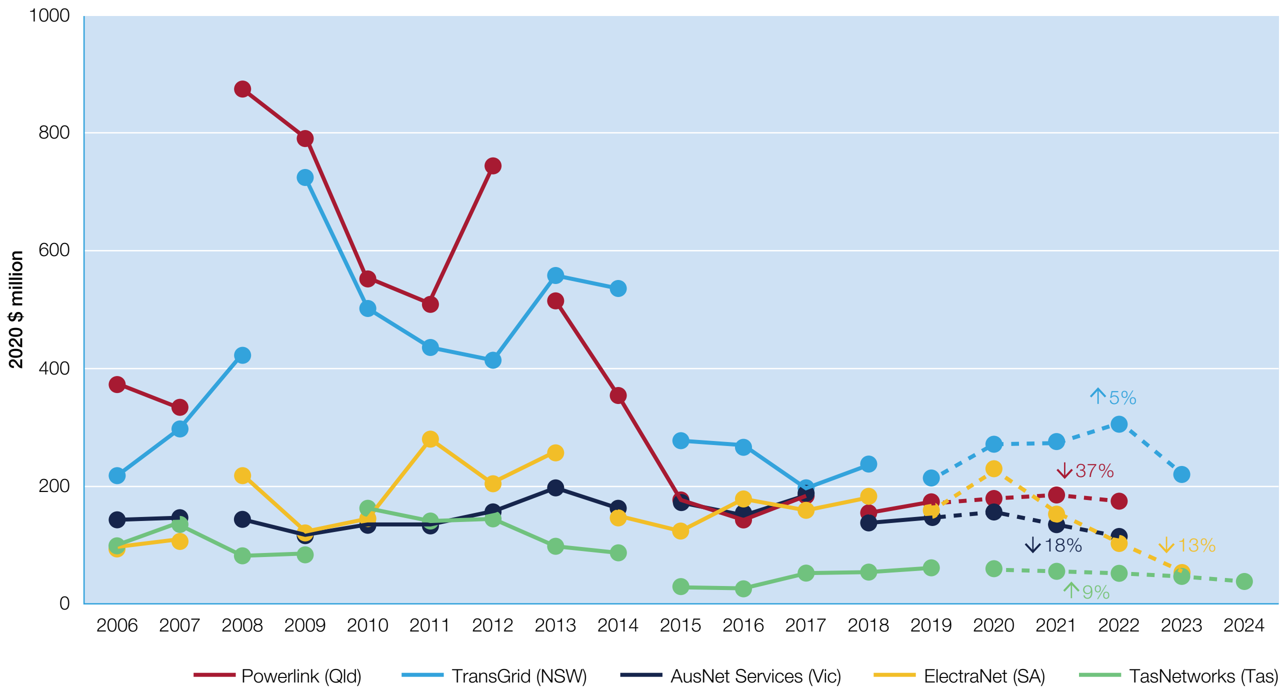
Figure 3.14
**Distribution network investment**




Note: Percentage values reflect growth from the previous regulatory period. Actual outcomes, CPI adjusted to June 2020 dollars. Assumptions are set out in figure 3.8 notes.

Source: AER modeling; annual reporting regulatory information notice (RIN) responses.

Figure 3.15
**Transmission network investment**




Note: Actual outcomes, CPI adjusted to June 2020 dollars. Assumptions are set out in figure 3.7 notes. Most transmission network businesses report on a 1 July – 30 June basis. The exception is AusNet Services (Victoria), which reports on a 1 April – 31 March basis. The data show the outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018).

Source: AER modeling; annual reporting of regulatory information notice (RIN) responses.

Evoenergy's (ACT) allowance for the regulatory period commencing July 2019 will allow it to manage its ageing asset base to meet safety and reliability standards, accommodate urban developments, and meet the ACT Government's requirements on planning and system security.

In Tasmania, TasNetworks targeted increased investment for the regulatory period commencing July 2019 in assets in poor condition, system security, and the transition to clean energy.[28] The AER scaled back some proposals, but approved capacity that would enable Tasmanian generators to export more electricity to the mainland. It approved three projects (each costing between $278 million and $1 billion) on a 'contingent' basis, requiring trigger events such as the construction of a second interconnector to the mainland to occur.

In Queensland, the AER approved less distribution investment for Energex over the regulatory period commencing July 2020 than in the previous regulatory period. Energex consulted widely on its proposal, and provided quantitative cost–benefit analyses for major projects, which allowed the AER to better assess the prudency and efficiency of the proposal. The AER did not accept Ergon Energy's proposed increase in capital expenditure for the same period, finding the business overestimated costs associated with managing risk (particularly those relating to safety). Instead, the AER adopted an approach consistent with its previous decisions, which approved expenditure to address safety risks where the business provides robust evidence of need.

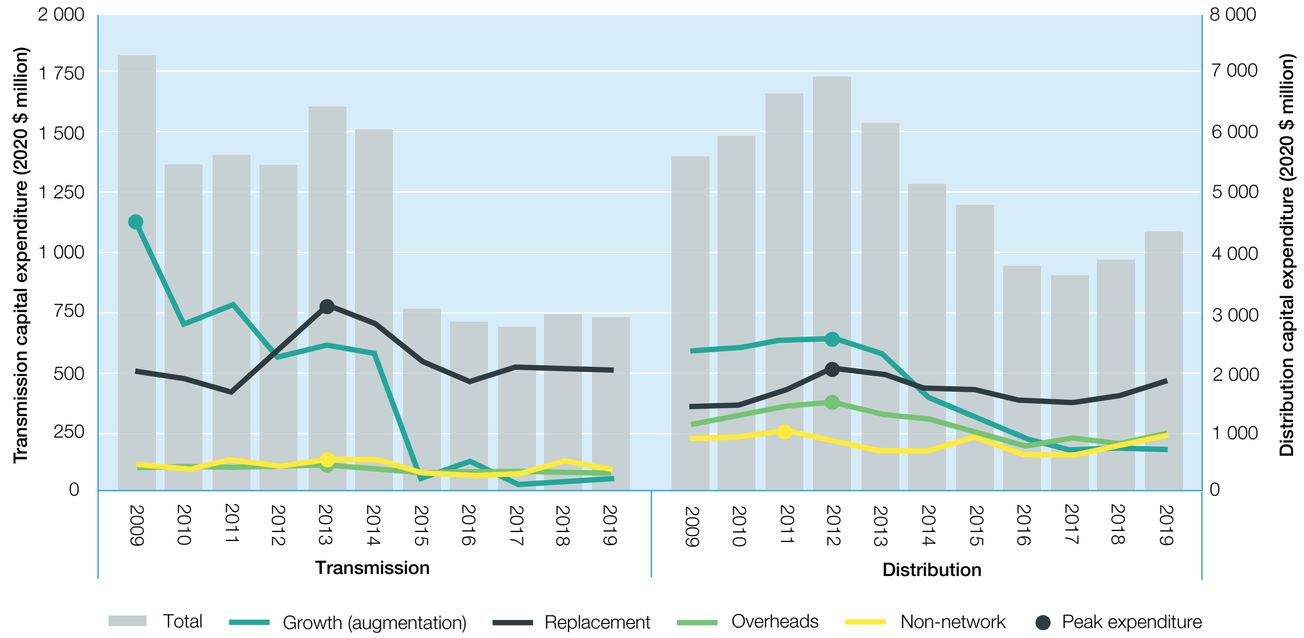
In South Australia, SA Power Networks' investment proposal for the period commencing July 2020 focused on maintaining the network rather than building new infrastructure.[29] The AER did not accept elements of the proposal relating to replacement and property expenditure, and found a lack of stakeholder support for a reliability related augmentation program.

28 The TasNetworks decision jointly covers distribution and transmission investment.

29 SA Power Networks, *2020–25 regulatory proposal, An overview for South Australian electricity customers*, January 2019.



Figure 3.16
**Capital expenditure, by driver**




Note: Actual outcomes, CPI adjusted to June 2020 dollars. Most network businesses report on a 1 July – 30 June basis. The exceptions are Victorian networks: AusNet Services (transmission) reports on a 1 April – 31 March basis, and the Victorian distribution network businesses report on a 1 January – 31 December basis. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018).

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

In the Northern Territory, the AER accepted Power and Water's revised capital expenditure proposal for the period commencing July 2019. Power and Water identified new methods and data that resulted in some adjustments to its replacement expenditure forecast.

## 3.10.4 Changing composition of investment

Over the past decade, the composition of network investment has changed markedly. Until recently, significant network investment occurred in growth (augmentation) expenditure to support new connections (such as new substations) and expand capacity to cope with forecast rising demand. In 2009, for example, growth expenditure accounted for 62 per cent of transmission investment and 41 per cent of distribution investment.

But weaker demand for electricity, along with less stringent reliability obligations, led many network owners to shelve or delay growth related projects in the following years. By 2019 growth related investment had shrunk to 15 per cent of distribution network investment and 8 per cent for transmission. In dollar terms, growth investment declined from $3.5 billion in 2009 to $732 million in 2019 (figure 3.16).

In contrast, over the same time period, replacement expenditure on ageing or degraded assets remained fairly constant at $1.9–2.7 billion. But, as a proportion of shrinking total investment, replacement investment rose strongly. In distribution, replacement investment rose from 24 per cent of total investment in 2009 to 42 per cent in 2019. In transmission, it rose from 27 per cent to 69 per cent of total investment over the same period.

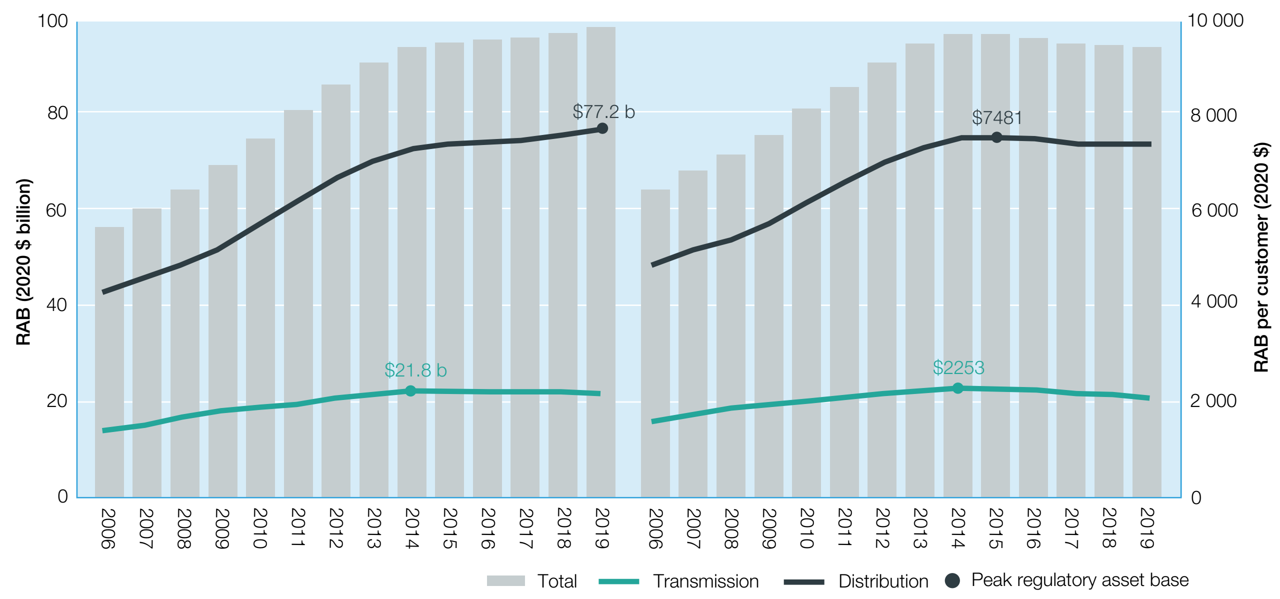
Since 2018 investment in augmentation has been lower than investment in replacement projects, overheads and non-network assets (for example, ICT, buildings and property, fleet and plant, minor asset tools and equipment, and motor vehicles). In each year from 2009 to 2016, investment in augmentation exceeded expenditure on overheads and non-network programs/projects.

### Impact on the regulatory asset base

Capital investment approved by the AER gets added to a network business's RAB, on which the business earns returns. Escalating investment inflated the industry RAB by

Figure 3.17

**Value of network assets**




Note: Closing regulatory asset bases (RABs) for electricity networks in the NEM, CPI adjusted to June 2020 dollars. Most network businesses report on a 1 July – 30 June basis. The exceptions are Victorian networks: AusNet Services (transmission) reports on a 1 April – 31 March basis, and the Victorian distribution network businesses report on a 1 January – 31 December basis. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018).

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

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

around 8.9 per cent per year over the seven years to 2013. From 2014 to 2019 lower network investment flattened RAB growth to around 1.4 per cent per year.

The industry RAB for distribution networks continues to rise, reaching a peak value of $77.2 billion in 2019. However, a greater proportional increase in the number of customers on the distribution networks meant the RAB per customer in 2019 ($7385) was 0.3 per cent lower than its peak of $7481 per customer in 2016.

But, in transmission, the RAB fell to $21.4 billion in 2019—the fifth consecutive year of decline since its peak in 2014 ($21.8 billion) (figure 3.17).

## 3.10.5 Regulatory tests for efficient investment

The AER assesses a network business's efficient investment requirements every five 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). A network business must apply the test when considering an investment project. It must evaluate credible alternatives to network investment (such as generation investment or demand response) that might achieve the required outcome at lower cost. The business should select whatever option delivers the highest net economic benefit, considering any relevant legislative obligations. This assessment requires public consultation.

There are separate tests for transmission networks (RIT–T) and distribution networks (RIT–D). The AER publishes guidelines on how to apply the tests,[30] and monitors businesses' compliance with the tests. It also resolves disputes over whether a network business has properly applied a test.

Until 2018 the regulatory tests applied to only growth investment, which until 2014 was the biggest component of network investment. But, with replacement expenditure overtaking growth investment in most networks (section 3.10.4), the test now applies to replacement projects too. Other revisions were made to the test to ensure it adequately considers system security, emissions reduction goals, and low probability events that would have a high impact.

30 AER, *Application guidelines—regulatory investment test for transmission/distribution*, December 2018.

The AER in December 2018 published the current version of the RIT application guidelines. The review of the preceding guidelines focused on improving guidance for applying RITs under the current regulatory framework. Civil penalties apply to network businesses that do not comply with the RIT requirements (including the required consultation procedures).

The AER is developing new RIT guidelines to make the Australian Energy Market Operator's (AEMO) integrated system plan actionable, as part of broader reforms to strengthen links with transmission planning.[31] Once in place, these guidelines will influence transmission planning by triggering RITs, and replace some elements of the RIT–T process.

The AER began consulting on the changes in November 2019, with a view to having the new guidelines take effect by 30 June 2020.

### Recent regulatory test activity

A focus of recent RIT activity has been interconnector projects linking transmission networks in different jurisdictions.

ElectraNet (South Australia) in 2019 conducted a RIT–T for a major network interconnector project linking South Australia with NSW. The project involves a new interconnector between Robertstown in South Australia and Wagga Wagga in NSW, with a spur to Red Cliffs in Victoria. The estimated cost is $1.53 billion (in nominal terms), with completion due between 2022 and 2024.

The South Australian Council of Social Service in 2019 lodged a dispute against ElectraNet's RIT–T process. It claimed ElectraNet did not adequately address system security risks from the retirement of South Australian gas plants. The AER reviewed the dispute and was satisfied with ElectraNet's application of the test.[32]

The AER in January 2020 determined ElectraNet had satisfied the requirements of the RIT–T for the project, and had identified the credible option that maximises economic benefits. ElectraNet and TransGrid (NSW) (the other project proponent) will likely lodge a joint contingent project application to seek regulatory approval of the project's efficient costs, to enable the recovery of costs from customers.

31 AER, *Guidelines to make the integrated system plan actionable*, November 2019.

32 AER, *South Australian energy transformation, determination on dispute—application of the regulatory investment test for transmission*, June 2019.

The AER in March 2020 also approved the RIT–T for a proposed $230 million capacity upgrade on the Queensland–NSW Interconnector (QNI).[33] The proposal allows more electricity exports from Queensland to NSW, thus avoiding the need for new generation investment in NSW. It also helps manage system security issues and alleviate upward pressure on wholesale electricity prices.

In April 2020 the AER amended TransGrid's revenue determination to allow it to recover the efficient capital costs required to deliver this project. The AER fast tracked its consideration to support the timely completion of this project. TransGrid expects delivery in September 2021 and completion of inter-network testing by June 2022.

In March 2020 the Victorian Government introduced legislation to fast track priority energy projects such as grid scale batteries and electricity transmission upgrades. The legislation allows the government—in consultation with AEMO—to bypass elements of the RIT process.[34] The government indicated it would first apply the fast tracking process to a project that is working to increase capacity on the Victoria–NSW Interconnector.

## 3.10.6 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.

33 AER, *Expanding NSW–QLD transmission transfer capacity, Decision*, March 2020.

34 The Hon. Lily D'Ambrosio MP (Victorian Minister for Energy, Environment and Climate Change), 'Victoria acts to secure a more reliable energy system', Media release, 18 February 2020.

### 3.10.7 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 reduce upward pressure on network charges. It can also increase the reliability of supply and reduce wholesale electricity costs.

The AER offers incentives for distribution network businesses to find lower cost alternatives to new investment to help cope with changing demands on the network and manage system constraints. The *demand management incentive scheme* (DMIS) incentivises distribution businesses 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 per cent 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* (DMIA). This is a research and development fund to help distribution businesses develop innovative ways to deliver ongoing reductions in demand or peak demand for network services. An objective of the innovation allowance is to enhance industry knowledge of practical approaches to demand management. Published annual activity reports set out details of projects undertaken by each business. The AER assesses expenditure claims to ensure distribution businesses appropriately use their funding. Any underspent or unapproved spending is returned to customers through revenue adjustments.

Over the two years to 30 June 2019 (31 December 2018 for Victorian distributors),[35] almost $10 million of innovation allowance funding was approved. Figure 3.18 sets out funding by project type. The largest component of funding related to battery storage. Supported projects included:

- Energex (Queensland) installing a commercial battery and solar PV system
- TasNetworks (Tasmania) trialling an aggregation of customer batteries to manage network constraints on Bruny Island
- Endeavour Energy (NSW) trialling an aggregation of residential batteries to manage peak demand, improve power quality and defer capital investment; and installing a grid connected battery for peak shaving, reliability support, and improved quality of supply
- Ausgrid (NSW) running a feasibility study on community batteries.

Other significant funding was allocated to microgrids, air conditioning and pool pump load control projects, and tariff studies. Projects funded in these areas include:

- Ergon Energy and Energex's (Queensland) Centralised Energy Storage System project for a 100 kilowatt energy storage system to encourage customer owned renewable generation and develop microgrid functionality
- Powercor's (Victoria) 'Energy Partner' program, which used air conditioning load control to alleviate peaky load on the network in the Bellarine Peninsula and reduce load at risk
- TasNetworks's (Tasmania) 'emPOWERing You' tariff trial project on how customers respond to new tariff designs.

Research funding covered projects to, for example, laboratory test devices, make algorithms, look into future grid and electric vehicle demand, and fund scholarship studies. Supported projects include Ausgrid's (NSW) Power2U (demand management for replacement needs), which explored the viability of non-network options to manage risk associated with retiring network assets. Other funded projects included studies on the use of energy trading and distributed energy platforms for demand management.

Some network businesses have undertaken demand management projects outside the DMIS and DMIA framework. United Energy's Summer Saver program, for example, targets network areas with highly utilised distribution transformers and low voltage circuits at high risk of overloading during summer months. Customers participating in the program are offered financial rewards to reduce electricity use voluntarily when asked by United Energy. United Energy reported in November 2019 that the program had led to the deferral of more than $10 million in capital expenditure.[36]

In addition to managing network constraints, demand response solutions can help manage wholesale electricity demand during extreme peaks. In September 2019 the University of Technology Sydney published findings on a trial demonstrating how customers can help the grid host rooftop solar power.[37] The joint industry project, partly funded by the Australian Renewable Energy Agency (ARENA),[38] involved the installation of solar PV and energy storage at around 90 sites across three locations to form a virtual power plant. Surplus generation was stored for later use to reduce peak demand on Essential Energy's (NSW) network. The innovation allowance allowed Essential Energy $107 548 in 2017–18 for its cost contribution to this project, and $171 248 in 2018–19.

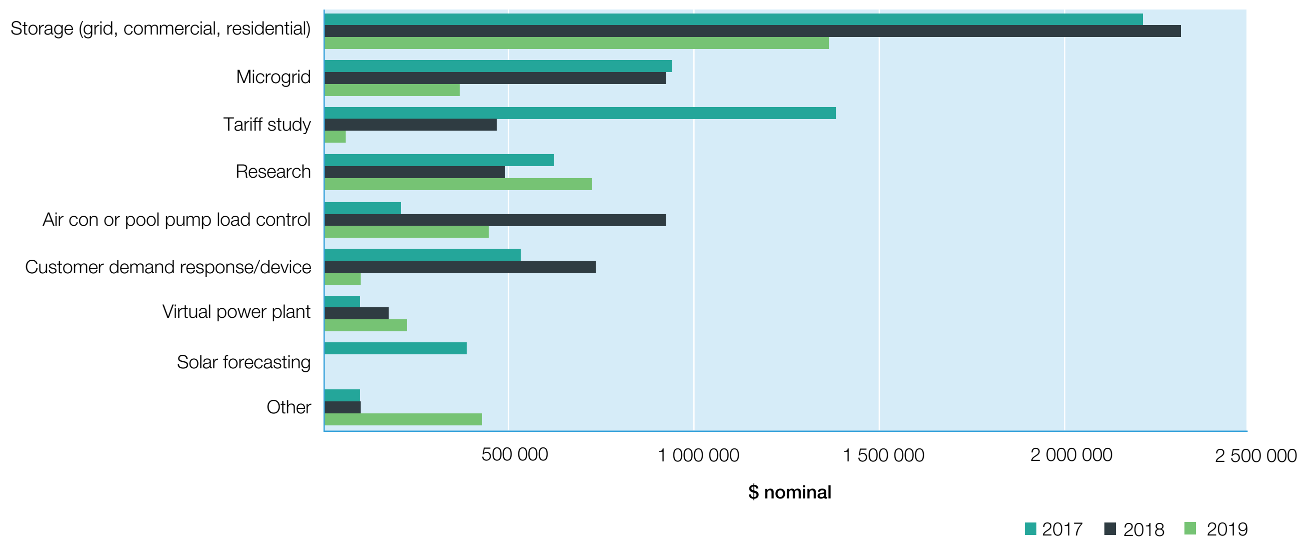
35 At the time of publishing, the AER had not assessed claims by Victorian distribution businesses for expenditure incurred in 2019.

36 United Energy, *Re: Application for the revised DMIS to start from 1 November 2019*, 7 June 2019.





Figure 3.18
**Funding of demand management innovations**




Note: Victorian distribution network businesses report on a 1 January – 31 December basis. All other distribution network businesses report on a 1 July – 30 June basis. The data show the outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018). 2019 data excludes expenditure incurred by Victorian distribution businesses.

Source: AER, *Approval of Demand Management Innovation Allowance expenditures by distributors*, September 2019; AER, *Approval of Demand Management Innovation Allowance (DMIA) expenditures by non-Victorian electricity distributors in 2018–19*, May 2020.

## 3.11 Rates of return

The shareholders and lenders that finance a network business expect a commercial return on their investment. The AER sets an allowed rate of return, but a network's actual returns can vary from the allowed rate. The variance can be due to the impact of incentive schemes, forecasting errors, revenue over- or under-recovery under a revenue cap, or smoothing processes, for example.

The AER calculates allowed returns each year by multiplying the RAB by the rate of return set by the AER.[39] Given electricity networks are capital intensive, returns to investors typically make up 30–50 per cent of a network's total revenue allowance.

The rate of return estimates the cost of funds that a network business's financiers require to justify investing in the business. It is a weighted average of the return needed to attract two sources of funding—*equity* (dividends paid to a network business's shareholders) and *debt* (interest paid on borrowings from banks and other lenders). Given this weighting approach, the rate of return is sometimes called the weighted average cost of capital (WACC).

If the AER sets the 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 over-invest, and consumers will pay for a 'gold plated' network that they do not need.

The rate of return is a significant driver of network revenue and a customer's energy bills. A 1 percentage point increase

37 University of Technology Sydney, *Networks renewed: project results and lessons learnt*, September 2019.

38 Participants included the Institute for Sustainable Futures at the University of Technology Sydney, Essential Energy (NSW), AusNet Services (Victoria), United Energy (Victoria), Reposit Power, the Australian Photovoltaic Institute, and the NSW and Victorian governments.

39 If the rate of return is 5 per cent, 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.

in the rate of return for TransGrid (NSW transmission) would increase the business's revenues by around 10 per cent, for example. For this reason, the rate of return is often a contentious part of a revenue decision.

Conditions in financial markets are a key determinant of the allowed rate of return. AER decisions from 2009 to 2012 took place against a backdrop of the global financial crisis, an uncertain period associated with reduced liquidity in debt markets, and high risk perceptions. Reflecting conditions in financial markets, the rate of return peaked at over 10 per cent in revenue decisions made over this period (figure 3.19). The Australian Competition Tribunal increased some rates of return following appeals by the network businesses.

Borrowing and equity costs have since eased. From 2015 the AER has updated the cost of capital annually to reflect changes in debt costs. More stable financial market conditions resulted in rates of return averaging around 6 per cent from 2016. These lower rates became a key driver of lower network revenues and charges over the past few years (figures 3.7 and 3.8).

### 3.11.1 Reforms to setting the rate of return

Outcomes from to the AER's approach to setting rates of return were often adversarial before 2018, with many network businesses arguing for a different approach with different parameters. Regulatory decisions were often challenged. These legal battles were long and costly, and added to uncertainty for network businesses, consumers and investors.

New legislation developed by the Council of Australian Governments (CoAG) Energy Council in November 2018 provided for the AER to make its rate of return determinations binding. The AER released its first Rate of Return Instrument (RRI) in December 2018, setting out how it determines the rate of return on capital in revenue determinations.[40]

In setting the rate of return, the AER balances the need for efficient and stable investment against the need to ensure consumers pay no more than necessary for safe and reliable energy. Because customers pay for the network through their electricity bills, the rate of return must be high enough to attract investment in these long term regulated assets, but not so high that it attracts over-investment.

The RRI sets out the approach by which the AER will estimate the rate of return, and includes the return on debt and the return on equity, as well as the value of imputation credits. The RRI is expected to reduce consumer bills by around $30–40 a year on average, relative to the approach set out in the AER's 2013 rate of return guideline.[41]

The first round of regulatory determinations under the RRI were completed in April 2019. The AER is required to review and replace the RRI by December 2022.[42]

## 3.12 Electricity network operating costs

Electricity network businesses incur operating and maintenance costs that absorb around 35 per cent of their annual revenue (figure 3.3). As part of its five year regulatory review for each network business, the AER sets an allowance for the businesses to recover the *efficient* costs of supplying power to customers. The allowance accounts for forecasts of electricity demand, productivity improvements, changes in input prices, and changes in the regulatory environment. In the first instance, the AER is guided by the forecasts in each business's regulatory proposal. If the AER considers those forecasts are unreasonable, then it may replace them with its own forecasts.

Alongside this assessment, the AER runs an efficiency benefit sharing scheme that encourages network businesses to explore opportunities to lower its operating costs (box 3.5).

### 3.12.1 Historical operating expenditure trends

Operating costs for distribution networks increased by an average 7.1 per cent each year from 2006 ($2.7 billion, or $306 per customer) to 2012 ($3.8 billion, $403 per customer). From 2013 to 2019 operating costs fell by an average 2.6 per cent per year as distribution network businesses implemented more efficient operating practices.

Operating costs for transmission networks peaked at $649 million ($65 per customer) in 2016, but then fell by an average 3.5 per cent per year to $581 ($56 per customer) in 2019 (figure 3.20).

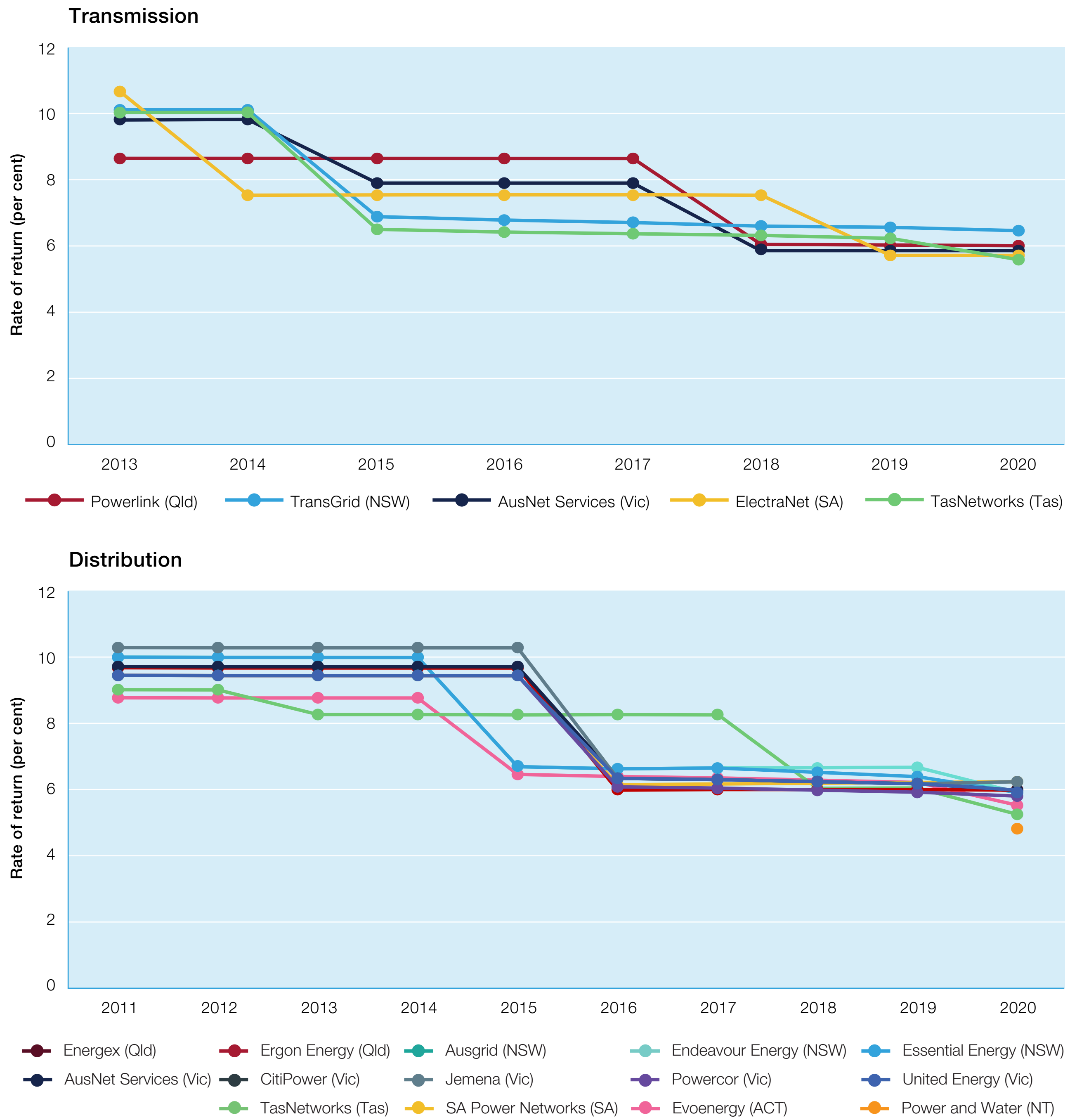
While distribution networks reduced operating expenditure between 2015 and 2019, the reduction was less marked

40 The 2018 RRI specifies the return on debt as a formula, using the trailing average portfolio approach. Network businesses not already applying this method must transition to it over a 10 year period.

41 AER, 'AER releases final decision on rate of return for regulated energy networks', Media release, 17 December 2018.

42 The AER is required to set the RRI every four years.

Figure 3.19
Rates of return for energy networks




Note: Rate of return is the nominal vanilla weighted average cost of capital (WACC).

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

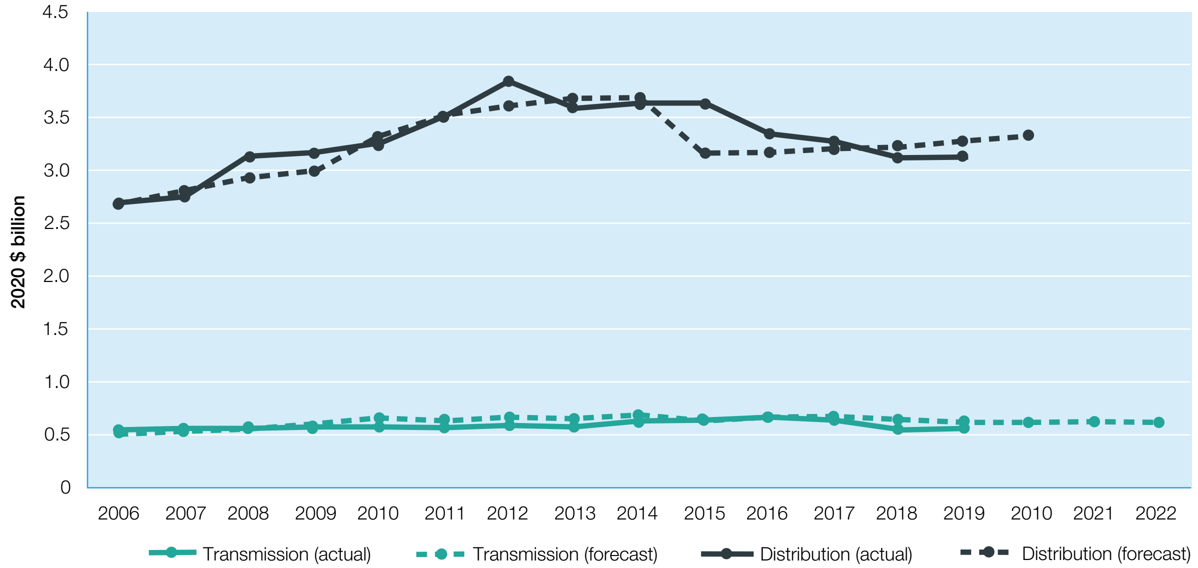
## Box 3.5 Efficiency benefit sharing scheme

The AER runs an efficiency benefit sharing scheme (EBSS) that aims to share the benefits of efficiency gains in operating expenditure between network businesses and their customers. Efficiency gains occur if a network business spends less on operating and maintenance than forecast in its regulatory determination. Conversely, an efficiency loss occurs if the business spends more than forecast.

The EBSS allows a network business to keep the benefit (or incur the cost) if its actual operating expenditure is lower (higher) than forecast in each year of a regulatory period. It effectively allows a network business to retain efficiency gains (or bear the cost of efficiency losses) for the duration of the existing regulatory period, which may be up to five years. In the longer term, network businesses can retain 30 per cent of efficiency savings, but must pass on the remaining 70 per cent (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 3.4)—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 3.6), to encourage network businesses to make efficient holistic choices between capital and operating expenditure in meeting reliability and other targets.

Figure 3.20
**Operating and maintenance expenditure of network businesses**

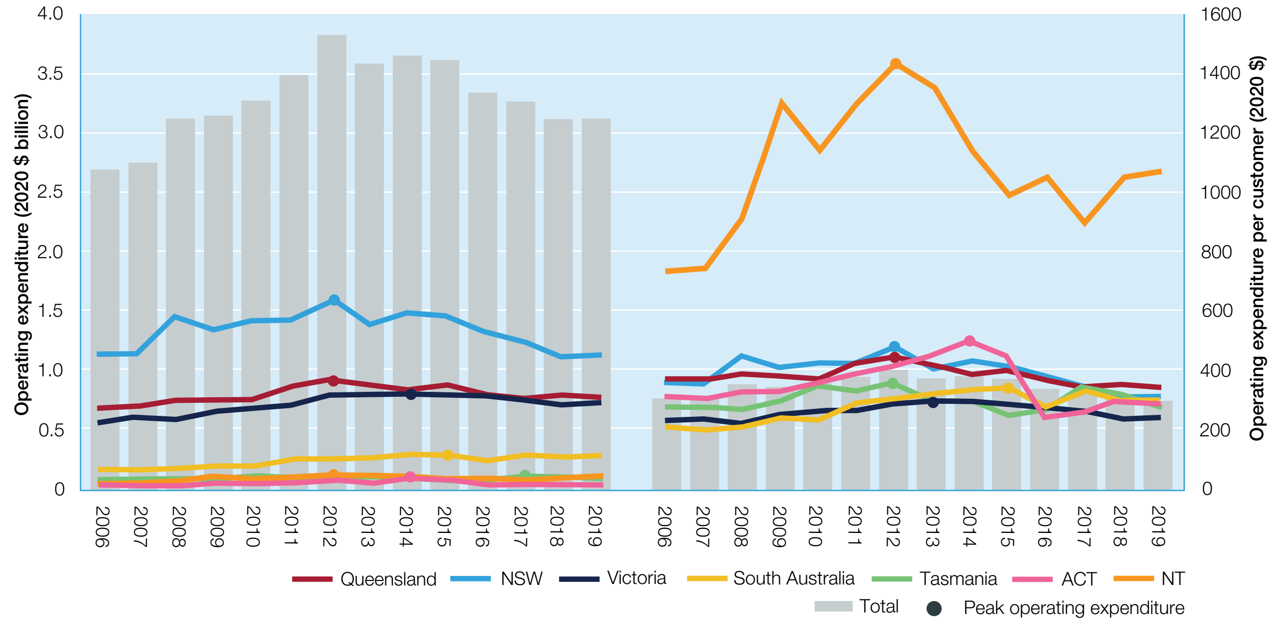



Note: Actual outcomes on an end-of-year basis, CPI adjusted to June 2020 dollars. Most network businesses report on a 1 July – 30 June basis. The exceptions are Victorian networks: AusNet Services (transmission) reports on a 1 April – 31 March basis, and the Victorian distribution network businesses report on a 1 January – 31 December basis. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018).

Source: AER modeling; AER revenue determinations; economic benchmarking regulatory information notice (RIN) responses.



Figure 3.21
**Distribution network operating expenditure, by region**




Note: Actual outcomes on an end-of-year basis, CPI adjusted to June 2020 dollars. Victorian network businesses report on a 1 January – 31 December basis. All other network businesses report on a 1 July – 30 June basis. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018).

Source: AER modeling; AER revenue determinations; economic benchmarking regulatory information notice (RIN) responses.

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 needed to service maximum demand.

## 3.12.2 Recent operating expenditure outcomes

Electricity networks spent $3.7 billion (or $354 per customer) on operating and maintenance in 2019—a 0.2 per cent increase on the previous year's spend. The level of operating and maintenance expenditure in 2019 was $719 million (16 per cent) lower than the $4.4 billion ($466 per customer) spent in 2012.[43]

A number of network businesses implemented efficiencies in managing their operating costs from 2015, when the AER widened its use of benchmarking to identify operating inefficiencies in some networks. The AER also introduced incentives for network businesses to spend efficiently. Not all costs are controllable by network businesses, however. Factors such as reporting obligations, changes to connections charging arrangements, and Power of Choice requirements can also impact costs.

### Distribution

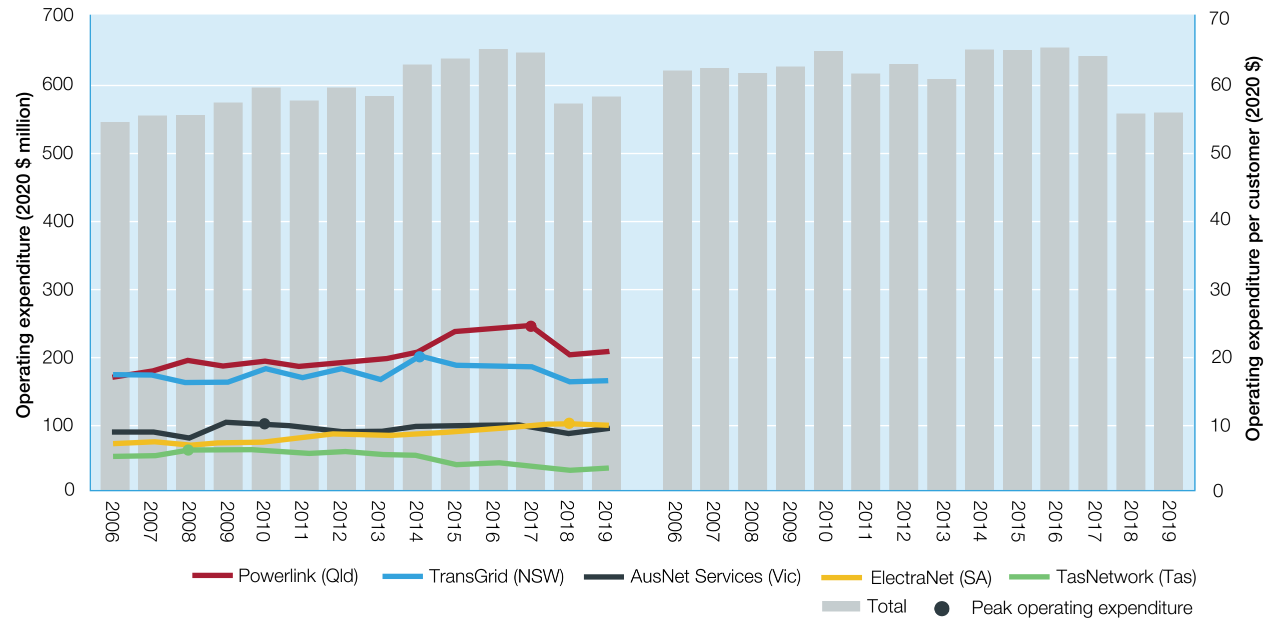
Distribution network businesses spent $3.1 billion ($298 per customer) on operating and maintenance in 2019—a 0.05 per cent decrease on the previous year's spend, and $704 million less than the peak operating and maintenance expenditure of $3.8 billion ($403 per customer) in 2012 (figure 3.21).

AER decisions in place at 1 July 2020 forecast operating expenditure to be 5 per cent lower for distribution networks than in the previous regulatory period, and 2 per cent lower for transmission. Distributors in Queensland, NSW and the Northern Territory are forecast to reduce their operating expenditure in the current regulatory period. But costs are forecast to rise in the South Australian, Tasmanian and ACT networks, and in all but one Victorian network.

Outcomes vary among jurisdictions and networks for a number of reasons. Privately owned networks in South Australia and Victoria tended to implement efficiencies

43 The assumptions underpinning data in this chapter are explained in the figure 3.7 and 3.8 notes. Unless otherwise stated, data refer to actual outcomes, CPI adjusted to 2020 dollars.

Figure 3.22
**Transmission network operating expenditure**




Note: Actual outcomes on an end-of-year basis, CPI adjusted to June 2020 dollars. Most transmission network businesses report on a 1 July – 30 June basis. The exception is AusNet Services (Victoria), which reports on a 1 April – 31 March basis. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018).

Source: AER modeling; AER revenue determinations; economic benchmarking regulatory information notice (RIN) responses.

ahead of other networks (section 3.13). In doing so, they made their levels of expenditure relatively lean, and left less scope for improvement.[44]

Because regulatory periods do not coincide across networks (figure 3.5), timing differences also play a part. Some networks—such as the distribution networks in Victoria—are operating under determinations made several years ago, while others are operating under more recent assessments.

### Transmission

Transmission networks spent $581 million ($56 per customer) on operating and maintenance in 2019—a 1.8 per cent increase on the previous year's spend, and 11 per cent less than peak operating and maintenance expenditure of $649 million ($65 per customer) in 2016 (figure 3.22).

Two transmission network businesses are forecast to reduce operating expenditure in the current regulatory period—TasNetworks (Tasmania) and Powerlink (Queensland)—by 12 per cent and 8 per cent respectively. ElectraNet (South Australia) and TransGrid (NSW) are forecast to increase operating expenditure in the current regulatory period by 5 per cent and 3 per cent respectively, while AusNet Services' (Victoria) operating expenditure is forecast to remain largely the same.

### Latest AER decisions

In decisions on Queensland distributors for the regulatory period commencing July 2020, the AER accepted revised operating expenditure forecasts from Energex and Ergon Energy. While the AER's revealed cost and benchmarking analysis indicated Energex had been relatively inefficient in the past, it also found the network's operating efficiency improved towards the end of the period ending June 2020. The AER found Ergon Energy was historically relatively inefficient, including towards the end of the period ending June 2020. Despite this finding, it accepted Ergon's revised operating expenditure forecast, which was below the business's historical costs.

In South Australia, the AER accepted SA Power Networks' revised operating expenditure forecast for the regulatory period commencing July 2020. The revised proposal included 10 step changes from the previous period, of which the most significant (in dollar terms) was a reclassification of minor repairs from capital to operating expenditure.

A combination of AER incentives and network driven efficiencies has contributed to significant cost reductions, especially among government owned (or recently privatised) distribution network businesses in NSW, Queensland and Tasmania.[45] Those savings—from the uptake of technology solutions, and from changes to management practices, for example—are now locked in for customers.

In its decisions on NSW and ACT distributors for the regulatory period commencing July 2019, the AER accepted revised operating expenditure forecasts by Ausgrid (NSW) and Essential Energy (NSW), but adjusted those submitted by Endeavour Energy (NSW) and Evoenergy (ACT). The main adjustment was the addition of an annual 0.5 per cent productivity requirement, consistent with that applied by Ausgrid and Evoenergy in their revised forecasts.

In the Northern Territory, the AER adjusted Power and Water's forecast operating expenditure for the regulatory period commencing July 2019. Power and Water proposed lower operating expenditure than in the previous period. The AER further reduced the allowance, because it did not consider some costs incurred by Power and Water in the previous period were efficient (figure 3.23).

## 3.13 Electricity network productivity

The AER benchmarks the relative efficiency of electricity network businesses to enable comparisons over time. This benchmarking assesses how effectively each network uses its inputs (assets and operating expenditure) to produce outputs (such as maximum electricity demand, electricity delivered, reliability of supply, customer numbers, and circuit line length).[46] Productivity will rise if the network's outputs rise faster than the resources used to maintain, replace and augment energy networks.

While benchmarking provides a useful tool for comparing network performance, some productivity drivers—for example, reliability standards set by government bodies—are beyond the control of network businesses. More generally, benchmarking may not fully account for differences in operating environment, such as legislative or regulatory obligations, climate and geography.[47]

The AER, when forecasting a network's efficient operating costs, estimates the productivity improvements that an efficient network should be able to make in providing services. In March 2019 the AER published its decision to apply an annual operating expenditure productivity growth rate of 0.5 per cent when reviewing the operating expenditure forecasts of distribution network businesses. This productivity growth rate was applied to all regulatory determinations from March 2019 for electricity distribution businesses.[48]

### 3.13.1 Network productivity

Productivity in most NEM networks declined from 2006 to 2015, especially in the distribution sector (figure 3.24). This outcome was largely driven by:

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

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

The decline in productivity plateaued and then started to improve from 2012 as the NSW and Queensland governments relaxed reliability standards, network businesses implemented operating efficiency reforms and business restructuring, and new energy rules allowed the AER to scale back investment and cost proposals by some networks.

44 AER, *Annual benchmarking report, Electricity distribution network service providers*, November 2019.

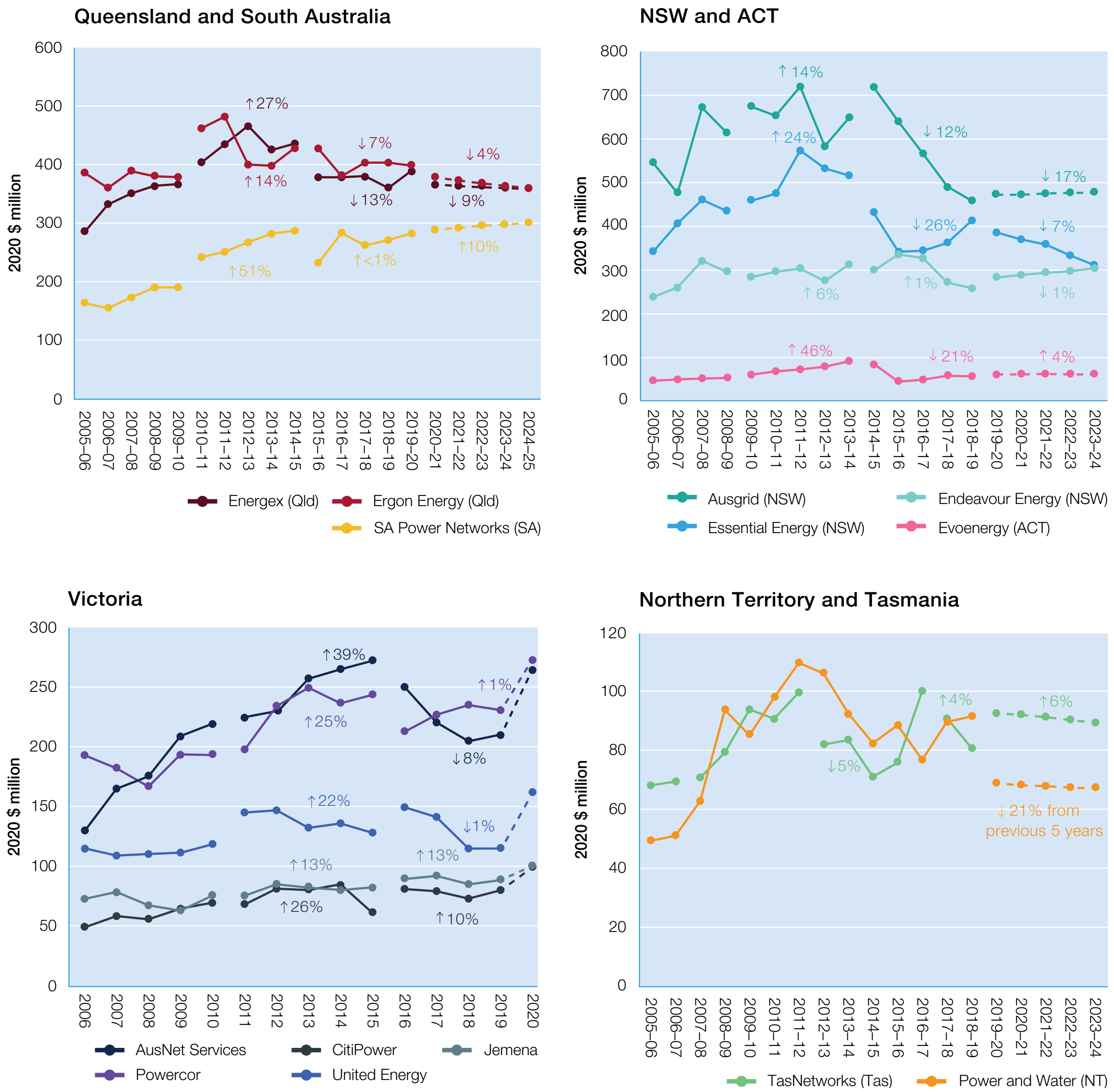
45 As an example, the AER noted TasNetworks (Tasmania) appears to be responding to incentives in the regulatory framework to better manage its costs.

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

47 AER, *Annual benchmarking report, Electricity distribution network service providers*, November 2019, pp. 21–7.

48 AER, *Review of our approach to forecasting opex productivity growth for electricity distributors*, 8 March 2019.

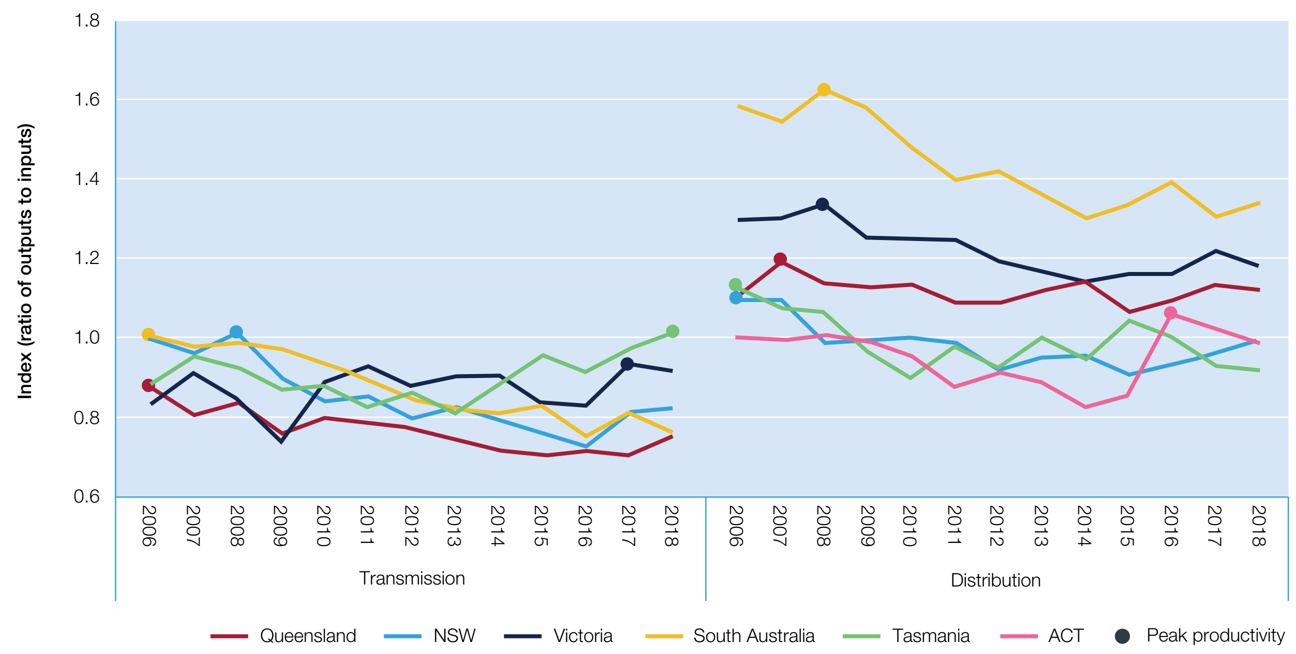
## Figure 3.23
**Distribution network operating expenditure, by network business**




Note: Percentage values reflect growth from the previous regulatory period. Actual outcomes on an end-of-year basis, CPI adjusted to June 2020 dollars. Assumptions are set out in figure 3.8 notes.

Source: AER modeling; AER revenue determinations; economic benchmarking regulatory information notice (RIN) responses.

## Figure 3.24
**Electricity network productivity**




Note: Index of multilateral total factor productivity relative to the 2006 performance of ElectraNet (South Australia) for transmission and Evoenergy (ACT) for distribution. The transmission and distribution indexes cannot be directly compared. Distribution outcomes are averaged for jurisdictions with multiple networks (Victoria, NSW and Queensland). The ACT does not have a transmission network.

Most network businesses report on a 1 July – 30 June basis. The exceptions are Victorian networks: AusNet Services (transmission) reports on a 1 April – 31 March basis, and the Victorian distribution network businesses report on a 1 January – 31 December basis. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018).

Source: AER annual benchmarking reports for electricity transmission and distribution networks.

### 3.13.2 Transmission network productivity

Productivity in the electricity transmission network sector grew by 2.2 per cent in 2018 over the previous year.[49] While this increase was lower than the 5.3 per cent growth achieved in 2017, it is still higher than productivity growth across the electricity, gas, water and waste services (EGWWS) sector and for the overall economy.

Across transmission network businesses in 2018:

- TasNetworks (Tasmania) and AusNet Services (Victoria) continued to be the most productive transmission networks in the NEM
- TasNetworks' productivity level set a new high among transmission businesses, bypassing TransGrid's (NSW) performance in 2008
- AusNet Services' productivity was down slightly from its peak in 2017
- TransGrid reported a significant improvement in productivity for the second consecutive year, continuing to reverse the trend of declining performance
- ElectraNet (South Australia) reported its second worst productivity outcome since 2006, and moved over that period from being one of the most productive networks to one of the least productive
- Powerlink (Queensland) continued to rank lowest on productivity levels, but significantly improved its performance.

The primary reason for productivity growth among transmission network businesses was the reduction in operating expenditure. This reduction alone was responsible for a 3.4 per cent increase in productivity. However, lower energy throughput and a greater number

49 As measured by total factor productivity.

of overhead power lines in use mitigated the net impact on productivity.[50]

### 3.13.3 Distribution network productivity

Productivity in the electricity distribution network sector rose by 1 per cent in 2018 over the previous year. As for transmission, this increase exceeded productivity growth for both the overall economy and the EGWWS sector.

Electricity distribution productivity has now grown for three consecutive years, mainly from networks achieving greater efficiencies in managing their operating expenditure. In 2018 distribution network productivity improved to a level that was comparable to the level in 2011, but still 8.6 per cent lower than the peak recorded in 2006.

Across distribution network businesses in 2018:

- CitiPower (Victoria) and United Energy (Victoria) further increased their productivity, with United Energy experiencing the highest improvement amongst distribution business in the NEM.
- SA Power Networks (South Australia), despite recording the largest fall in productivity of any distributor since 2006, also improved its productivity in 2018 and was the third most productive distributor in the NEM
- Powercor's (Victoria) productivity weakened in 2018, mainly as a result of a poorer reliability outcomes. Despite this fall, Powercor's productivity was still higher in 2018 than in 2015, and it remained in the top four most productive distributors.
- TasNetworks' (Tasmania) distribution productivity level was the lowest in the NEM, which partly reflected its unique network structure[51]
- Ausgrid (NSW), Endeavour Energy (NSW), and Essential Energy (NSW) improved their productivity, after historically being among the least efficient networks in the NEM.[52] The improvements were due to workforce rationalisation, the part privatisation of Ausgrid and Endeavour Energy, reforms in response to the AER's efficiency incentives, and the AER's use of economic benchmarking to set efficient operating costs. In 2018 Endeavour Energy was among the more efficient distributors in the NEM. Ausgrid, however, remained a relatively inefficient network despite significant improvement, partly because it incurred transformation costs to reduce its workforce and become more efficient.

Regulatory incentives too may be contributing to improved outcomes for both transmission and distribution network businesses. In particular, the AER allows network businesses to retain efficiency gains in operating expenditure for up to five years (box 3.5).

### 3.13.4 Investment disconnect

For several years from 2006, a key contributor to poor network productivity was sustained investment growth at a time when electricity demand was falling (figure 3.25). Network investment rose every year from 2006 to 2012, despite the amount of electricity delivered peaking in 2009 for transmission, and in 2010 for distribution. The earlier decline in energy delivered by transmission networks was due to the loss of some industrial loads.

Two key factors drove the mismatch between electricity use and new investment: (1) a growing divide between maximum network demand and total electricity generated, and (2) over-forecasting of maximum demand.

#### Changing demand patterns

The level of productivity depends on how effectively a network business uses inputs to deliver a range of outputs. Capital expenditure is largely driven by the need to meet the maximum level of demand on the network. But, since 2006, maximum demand has risen faster than average demand (figure 3.26).

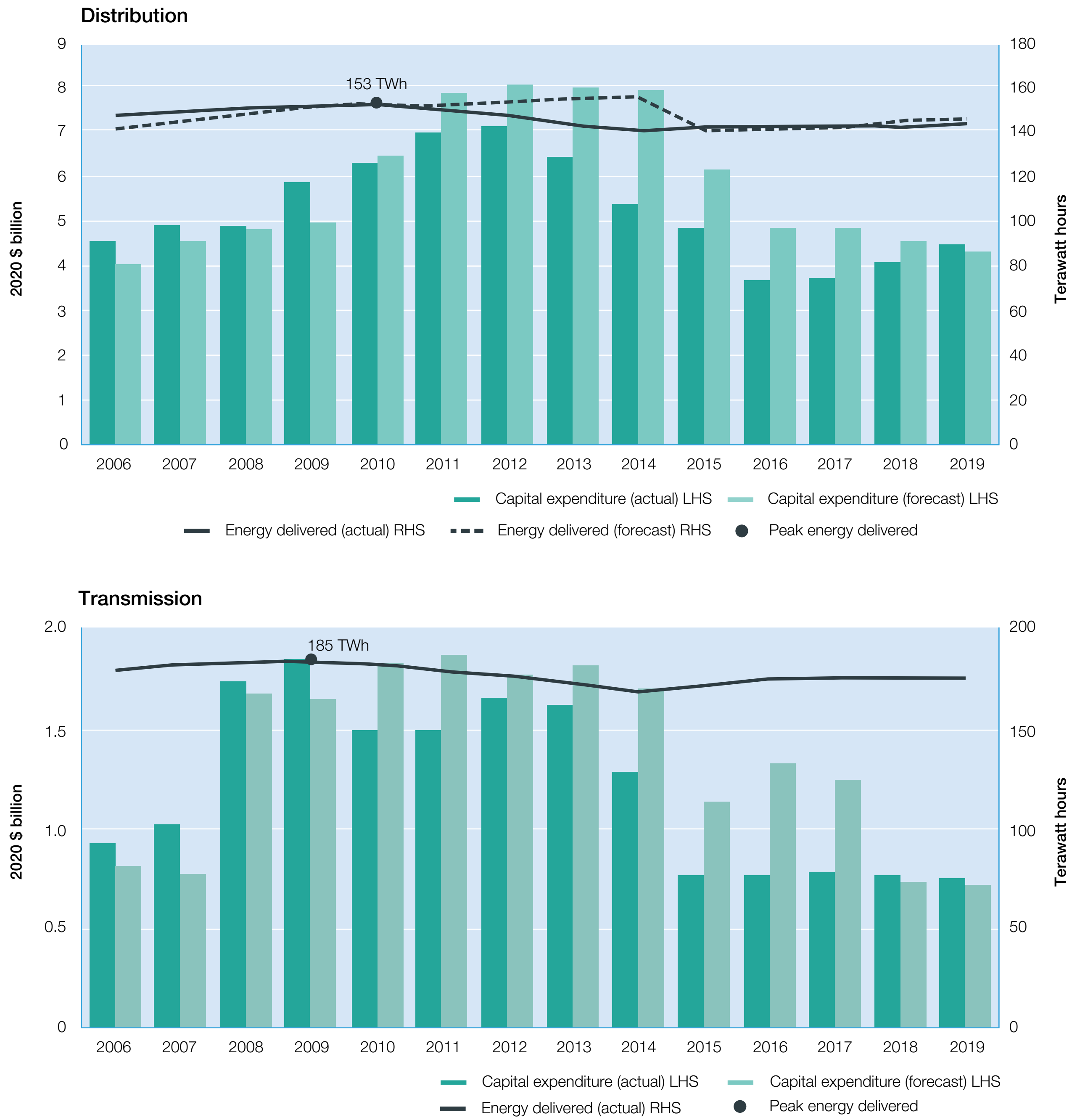
As network demand becomes 'peakier', assets installed to meet demand at peak times—which occur for approximately 0.01 per cent of the year—may sit idle (or be underused) for longer periods. This outcome is reflected in poor use rates, which weaken productivity.

The growth in customers connected to the distribution network has steadily increased by 1.5 per cent per year since 2006, and has outpaced growth in both maximum and average demand.

In 2019 the average residential customer consumed 22 per cent less energy from the distribution network than in 2006. Declining energy use is evident among all distribution networks, with 12 of the 14 distributors reporting declines of more than 15 per cent since 2006 (figure 3.27). Average consumption by business customers also fell over that period, but to a lesser extent.

50 AER, *Annual benchmarking report, Electricity distribution network service providers*, November 2019.
51 Economic Insights, *Memorandum: DNSP MTFP and opex cost function results*, November 2015, p. 4.
52 The lower historical productivity of the three network businesses was due to high operating and capital expenditure when demand for electricity was falling.

**Figure 3.25**
**Investment and energy delivered**



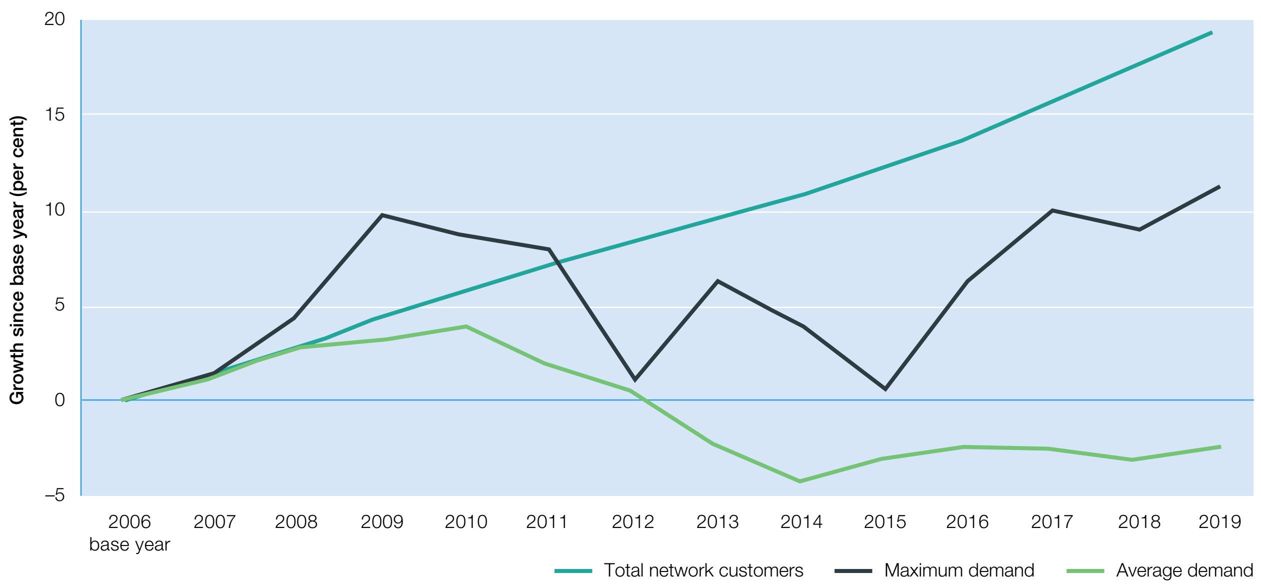

TWh, terawatt hours.

Note: Most network businesses report on a 1 July – 30 June basis. The exceptions are Victorian networks: AusNet Services (transmission) reports on a 1 April – 31 March basis, and the Victorian distribution network businesses report on a 1 January – 31 December basis. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018).

Energy transported through transmission networks includes deliveries to industrial customers that take supply directly off the transmission network. Data exclude energy delivered to other transmission networks via interconnectors. Physical losses account for some differences between transmission and distribution loads.

Source: Annual benchmarking regulatory information notice (RIN) responses.

Figure 3.26
**Growth in customers and demand—distribution networks**




Note: Maximum demand is the network sum of non-coincident, summated raw system maximum demand (megawatts). Average demand is the total energy delivered (gigawatt hours) divided by hours in the year.
Source: Economic benchmarking regulatory information notice (RIN) responses.

### Inaccurate demand forecasting

Forecasts by planning authorities and market participants consistently failed to capture a step decline in electricity use from the grid, and a flattening of maximum demand from around 2009. This decline can be attributed to multiple factors, including solar PV replacing some grid sourced electricity; housing and appliances becoming more efficient; and consumers reducing their energy use in response to higher prices. Electricity use also contracted in the manufacturing sector.[53] More recently, networks have explored demand response to meet short term peaks in demand, as an alternative to investing in long lived assets (section 3.10.7).

Inaccurate demand forecasts fuelled a wave of investment that inflated the electricity networks' RABs, which rose by 75 per cent from 2006 to 2019. This over-investment contributed to poor productivity outcomes. Capital productivity declined for all transmission networks—except AusNet Services (Victoria)—from 2006 to 2018.[54] Over-investment also drove weaker distribution network productivity, but to a lesser extent than did rising operating expenditure. As investment slowed from around 2012, productivity outcomes improved.[55]

## 3.13.5 Adapting to an evolving market

As the market evolves, the regulatory framework needs to encourage network businesses to make efficient choices between capital and operating expenditure solutions for network requirements. A traditional network solution to meet increasing consumer demand in an area might be to augment a zone substation, for example. But a more efficient solution might be to purchase services from a battery provider, or an aggregator of batteries, to manage peak demand.

Regulatory frameworks need to support emerging technologies and business models that have the potential to benefit consumers. Current frameworks encourage network businesses to favour (relatively expensive) long lived capital investment (which gets added to the asset base) over cheaper operating expenditure alternatives, especially if the business's regulated rate of return is higher than its actual borrowing costs.

Network businesses are also having to adapt to a new operating environment, in which distributed energy resources (DER) are changing energy flows and creating new pressure points in the system. These challenges require network businesses to develop innovative solutions to keep the network operating efficiently.

The AEMC in September 2019 recommended the introduction of a 'regulatory sandbox' toolkit to make it easier for network businesses to develop and trial innovative energy technologies and business models.[56] The toolkit allows participants to trial smaller scale innovative concepts under relaxed regulatory requirements, but within time limits and with appropriate safeguards. The proposed reforms were before the CoAG Energy Council in early 2020.

## 3.13.6 Network utilisation

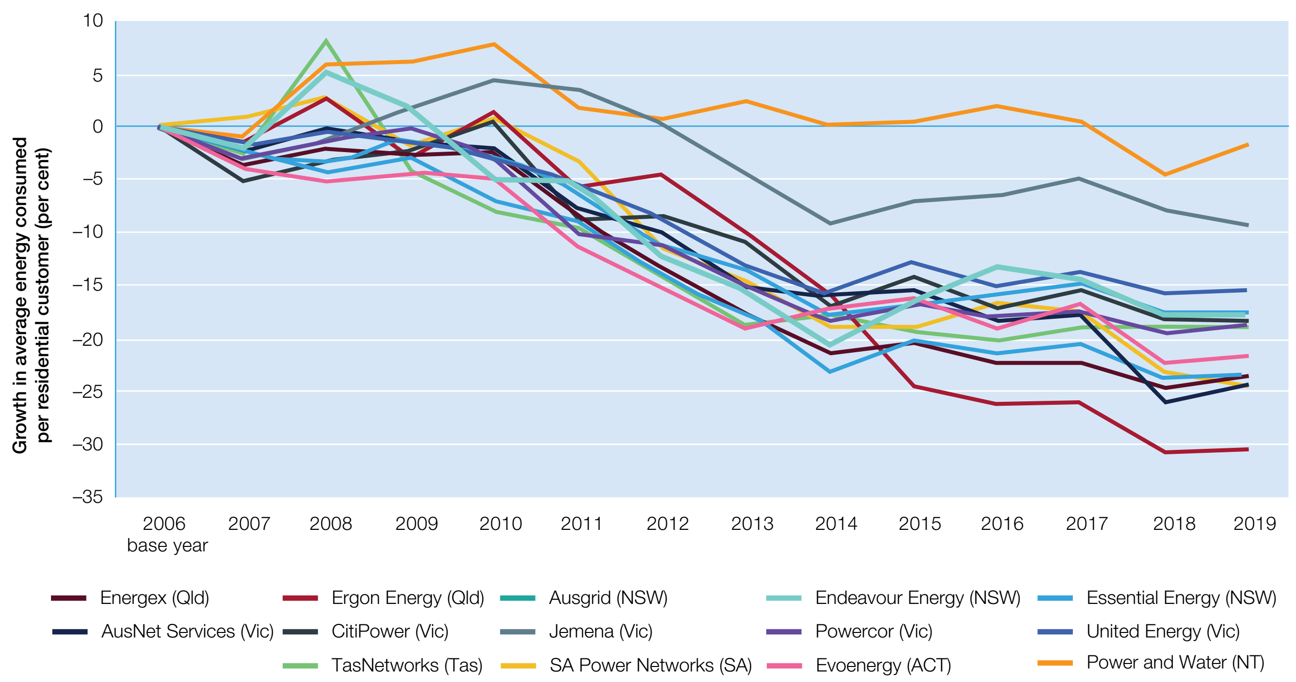
A network's utilisation rate is a part productivity measure, indicating the extent to which a network business's assets are being used to meet maximum demand. The rate can be improved through efficiencies such as using demand response (instead of new investment in assets) to meet rising demand.

Network utilisation rates tend to be higher among privately owned distribution networks (62 per cent in 2019) than in fully or partly government owned networks (37 per cent).[57] In 2019 six of the seven most highly utilised distribution networks were privately owned, with Ergon Energy (Queensland) being the only exception (figure 3.28).

The average network utilisation amongst all distribution networks declined from 56 per cent in 2006 to a low of 39 per cent in 2015, following over-investment by many network businesses at a time of weakening electricity demand. Since 2016 maximum demand has increased by 4 per cent while network capacity has decreased by 2 per cent. In 2019 the average network utilisation among all distribution networks increased to 46 per cent, which was the highest rate since 2013.

Powercor (Victoria) has operated the most highly utilised distribution network in each year from 2006 to 2019,

Figure 3.27
**Energy delivered per residential distribution customer**

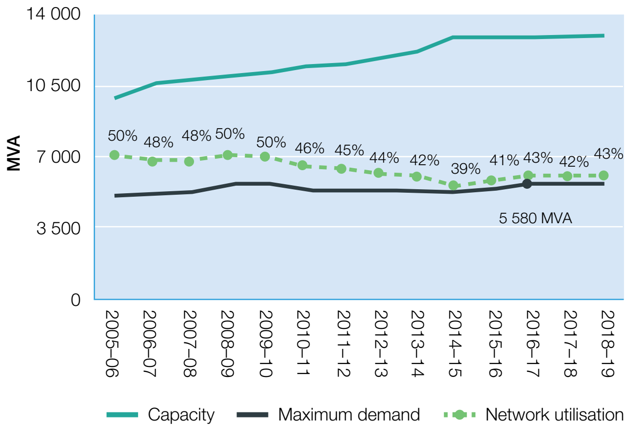



Source: Annual benchmarking regulatory information notice (RIN) responses.

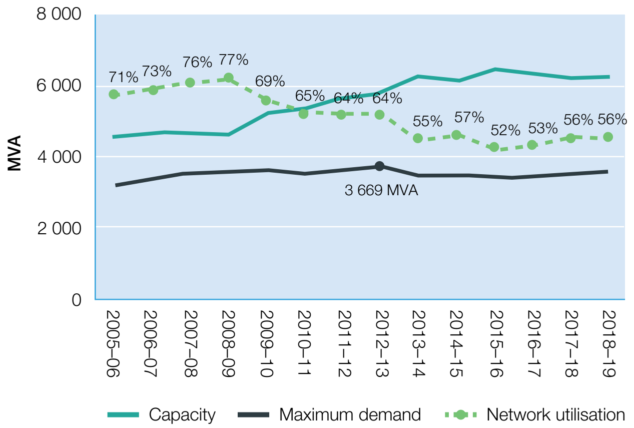
53 AEMC, *Electricity network economic regulatory framework review*, 18 July 2017, pp. 37–8.
54 AER, *Annual benchmarking report, Electricity transmission network service providers*, November 2019, p. 19.
55 AER, *Annual benchmarking report, Electricity distribution network service providers*, November 2019.
56 AEMC, *Regulatory sandbox arrangements to support proof-of-concepts trials*, 26 September 2019.
57 Section 3.3 provides a detailed assessment of network ownership.

Figure 3.28
**Distribution network utilisation**

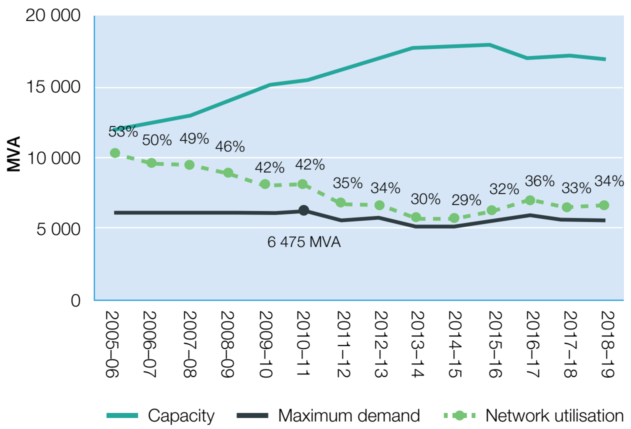
### Energex (Qld)



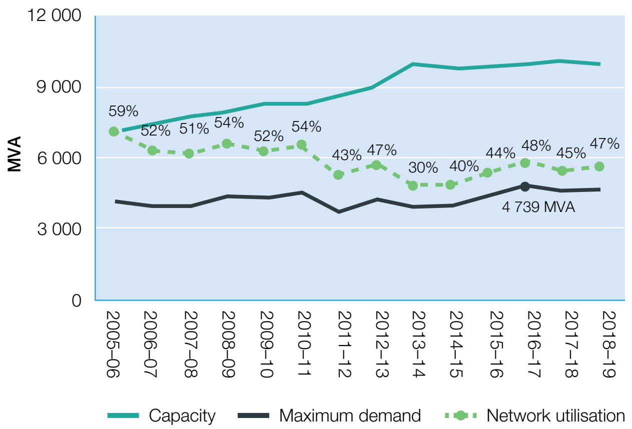

### Ergon Energy (Qld)



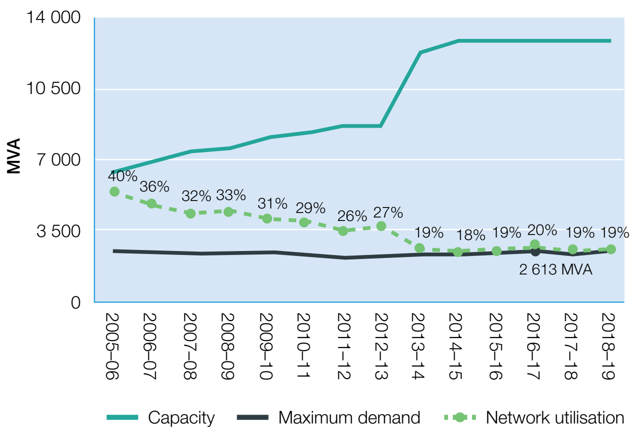

### Ausgrid (NSW)




### Endeavor Energy (NSW)




### Essential Energy (NSW)




### Evoenergy (ACT)

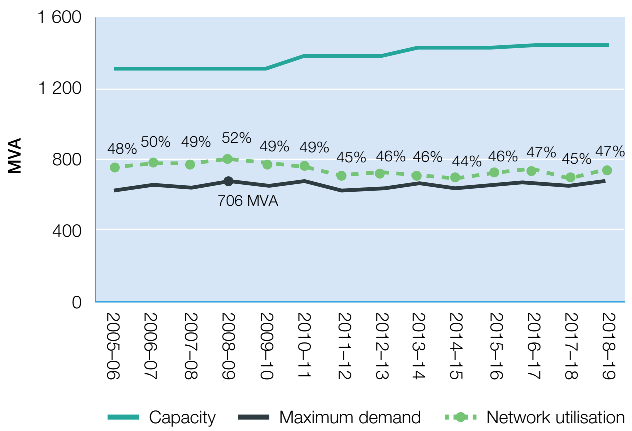
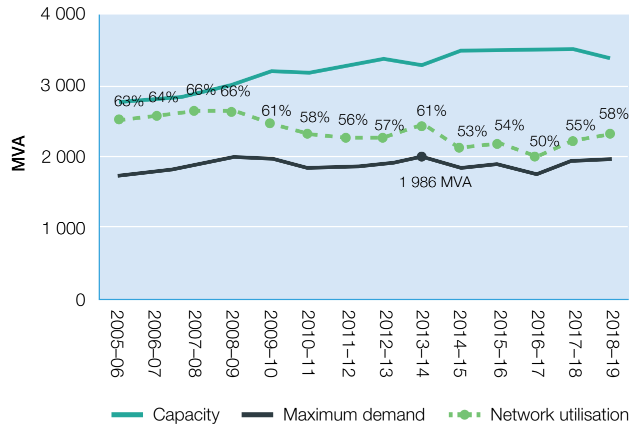
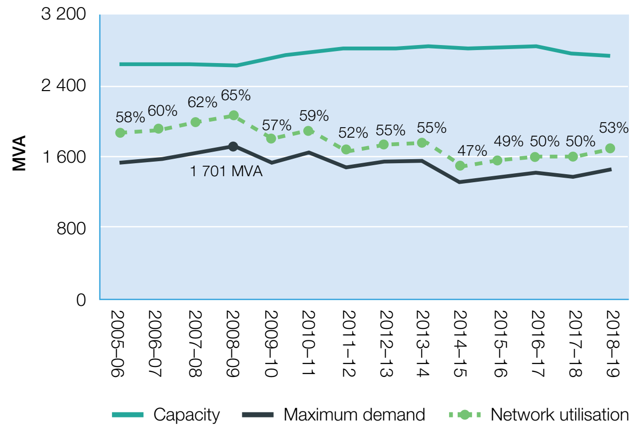



Figure 3.28
**Distribution network utilisation (*cont.*)**

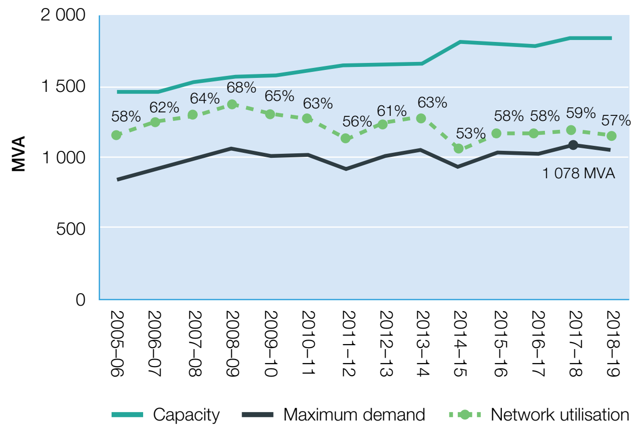
### AusNet Services (Vic)



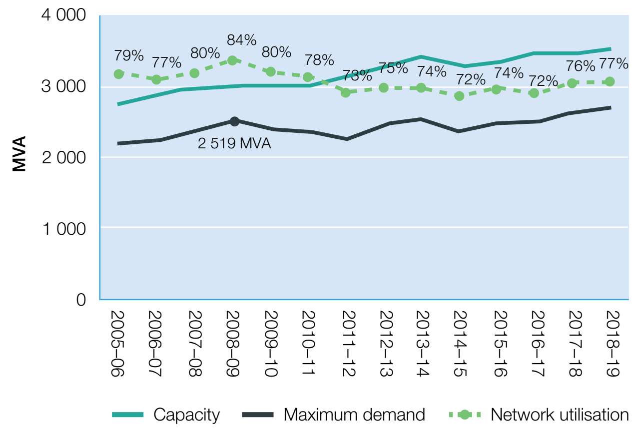

### CitiPower (Vic)



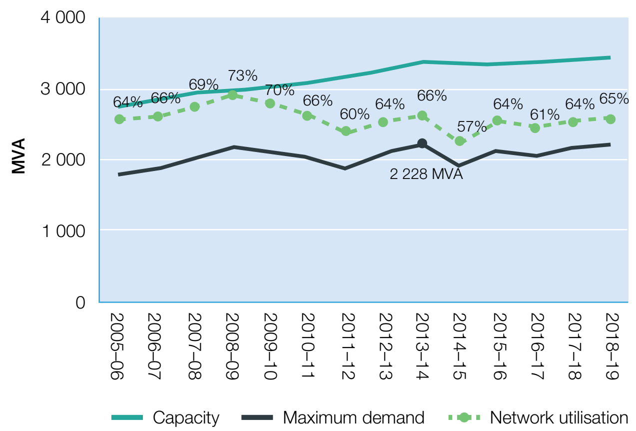

### Jemena (Vic)




### Powercor (Vic)




### United Energy (Vic)




### SA Power Networks (SA)

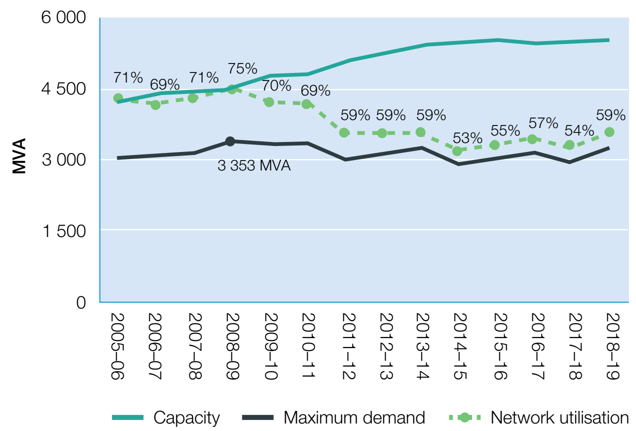
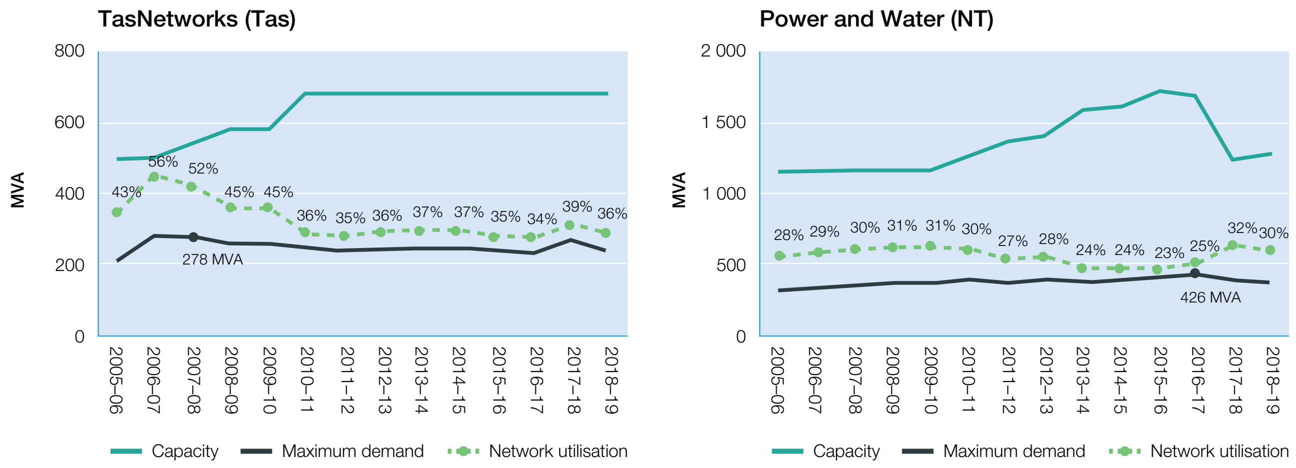


Figure 3.28
**Distribution network utilisation (*cont.*)**




MVA, megavolt amperes.

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

Source: Economic benchmarking regulatory information notice (RIN) responses.

followed by United Energy (Victoria) from 2016 to 2019. Essential Energy (NSW) has been the most underutilised distribution network in each year since 2010, followed by Power and Water (Northern Territory).

Underutilised assets raise the risk of asset stranding—whereby assets are no longer useful—unless network businesses respond to changing conditions. This risk may become more acute as the uptake of DER (such as batteries)—transforms the industry. The electricity rules do not allow for RAB adjustments to remove historical investment in stranded assets. If network charges become inflated as a result of asset stranding, then electricity consumers—who pay for those assets—may look to opportunities to bypass the grid altogether.[58]

## 3.14 Reliability and service performance

Reliability refers to the continuity of electricity supply to customers. Many factors can interrupt the flow of electricity on a network. Supply interruptions may be planned (for example, due to the scheduled maintenance of equipment) or unplanned (for example, due to equipment failure, bushfires, extreme weather events, or the impact of high demand stretching the network's engineering capability).

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

A significant network failure might require the power system operator to disconnect some customers (known as load shedding).

Most supply interruptions originate in distribution networks. They typically relate to power line damage caused by lightning, car accidents, debris such as falling branches, and animals (including possums and birds). Peak demand during extreme weather can also overload parts of a distribution network. Transmission network issues rarely cause consumers to lose power, but the impact when they occur is widespread—for example, South Australia's catastrophic network failures in September 2016 caused an entire state blackout.

Electricity outages impose costs on consumers. These costs include both financial losses resulting from lost productivity and business revenues, and intangible 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. These costs form around 50 per cent of retail electricity bills. There is, therefore, a trade-off between electricity reliability and affordability. Reliability standards and incentive schemes need to strike the right balance by targeting reliability levels that customers are willing to pay for.



State and territory governments set reliability standards for electricity networks that seek to efficiently balance the costs and benefits of a reliable power supply. While approaches to setting standards have varied across jurisdictions, governments recently moved to a more consistent national approach to reliability standards. This approach factors in the value that consumers place on having a reliable power supply.

### 3.14.1 Valuing reliability

Understanding the value that customers place on reliability is an important consideration when setting reliability standards or network performance targets. This value tends to vary among customer types and across different parts of the network. Considerations include a customer's access to alternative energy sources, their past experience of supply interruptions, and the duration, frequency and timing of interruptions.

AEMO estimated the values that customers placed on reliability in 2014, to guide network businesses and planners on the optimal level of investment to meet customer needs.[59] These values were used to set transmission reliability standards in Victoria, South Australia and NSW. The AER also used these values as an input to its regulatory assessments for network businesses.

In July 2018 the AER became responsible for estimating how much customers are prepared to pay for reliable electricity supply. In December 2019 it published valuations for unplanned widespread outages of up to 12 hours in all jurisdictions. It drew on customer surveys and modeling to determine the values, and consulted with governments, energy regulators, industry representatives and customers.[60]

The AER's 2019 estimates were broadly similar to those estimated by AEMO in 2014, but the values varied across sectors. Both reviews found business customers tended to place a higher value on reliability than did residential customers, who were particularly concerned about long outages, and outages at peak times. Differences were also apparent across industries, but these differences changed over time: the 2019 estimates were lower than the 2014 estimates for agricultural and commercial customers, but higher for industrial customers.

The AER will develop new estimates of customers' reliability valuations every five years, and update these values annually. The values will have wide application, including as an input for:

- cost–benefit assessments such as those applied in regulatory tests (section 3.10.5) that assess network investment proposals
- assessing bonuses and penalties in the service target incentive scheme (box 3.6)
- setting transmission and distribution reliability standards and targets
- informing market settings such as wholesale price caps.

59 AEMO, *Value of customer reliability review*, September 2014.
60 AER, *Values of customer reliability, Final report on VCR values*, December 2019.

### 3.14.2 Transmission reliability

Electricity transmission networks are engineered and operated to be extremely reliable, because an interruption can lead to widespread power outages. To avoid this outcome, the transmission networks are engineered with capacity to act as a buffer against credible unplanned interruptions.

Across the NEM, lost supply events due to transmission failures occurred no more than 30 times per year between 2006 and 2018 (figure 3.29). The average number of lost supply events due to transmission failures declined significantly each year from 2013, with no network business reporting more than five loss of supply events in any year between 2014 and 2018.

In 2018 the NEM experienced its fewest (seven) lost supply events due to transmission failures on record, of which ElectraNet (South Australia) experienced three. AusNet Services (Victoria) did not experience a loss of supply event between 2016 and 2018.

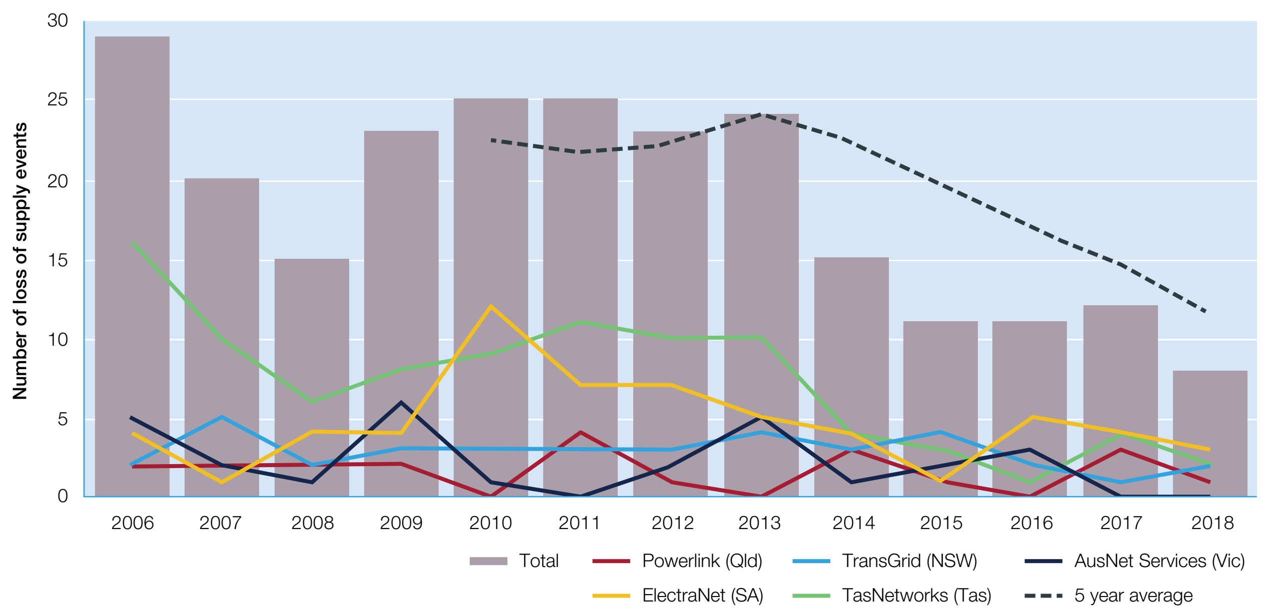
#### Transmission network congestion

In addition to system reliability, congestion management is another barometer of transmission network performance. All networks are constrained by capability limits, and congestion arises when electricity flows on a network threaten to overload the system. As an example, a surge in electricity demand to meet air conditioning loads on a hot day may push a network close to its secure operating limits.

Network congestion may require AEMO to change the generator dispatch order. A low cost generator may be constrained from running to avoid overloading an affected transmission line, and a higher cost generator may be dispatched instead, raising electricity prices. At times, congestion causes perverse trade flows too, such as a low priced NEM region importing electricity from a region with much higher prices.

Figure 3.29

**Transmission reliability—loss of supply events**




Note: Loss of supply events are the times when energy is not available to transmission network customers above a specific time period. The threshold varies across businesses, from 0.05–1.0 system minutes as published in AER decisions on the service target performance incentive scheme (STPIS). The thresholds may also vary between regulatory periods for each network.

Most transmission network businesses report on a 1 July – 30 June basis. The exception is AusNet Services (Victoria), which reports on a 1 April – 31 March basis. The data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018).

Source: Economic benchmarking regulatory information notice (RIN) responses.

Transmission congestion caused significant market disruption in 2006, when rising electricity demand placed strain on the networks (figure 3.30). But network investment from 2006 to 2014—including upgrades to congested lines—eliminated much of the problem. Weakening energy demand reinforced the trend, and for several years network congestion affected less than 10 per cent of NEM spot prices. But, ultimately, consumers paid for the substantial costs of the network investment.

Congestion issues re-emerged from 2015 in Queensland (partly linked to outages associated with network upgrades) and, more recently, on cross-border interconnectors linking Victoria with South Australia and NSW. Not all congestion is inefficient, however. Reducing congestion through investment to augment transmission networks is an expensive solution. Eliminating congestion is efficient only to the extent that the market benefits outweigh the costs of new investment.

Network businesses can help minimise congestion costs by scheduling planned outages and maintenance to avoid peak periods. For this reason, the AER offers incentives for network businesses to reduce the market impact of congestion.

### 3.14.3 Distribution reliability

For distribution networks, the reliability of supply—that is, how effectively the network delivers power to its customers—is the focus of network performance. Around 94 per cent of supply interruptions that electricity customers experience are due to issues in their local distribution network.[61] However, the capital intensive nature of the networks makes it prohibitively expensive to invest in sufficient capacity to avoid all interruptions.

Planned interruptions—when a distribution network business 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 can manage the impact of an interruption.

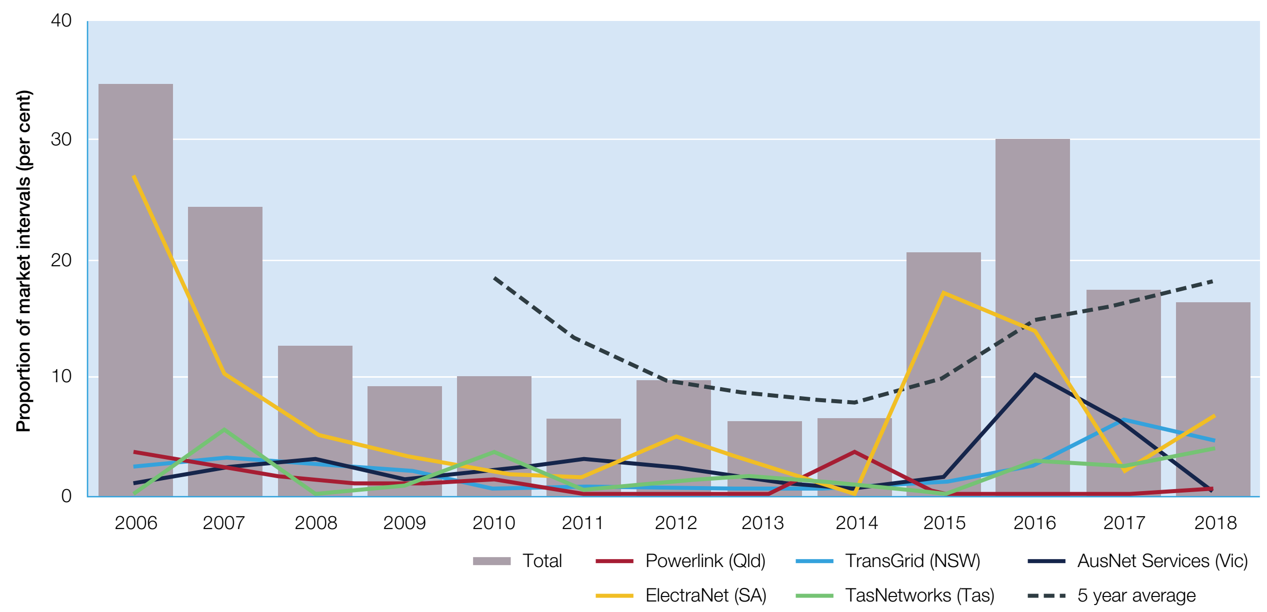
Jurisdictional reliability standards were historically set at high levels to protect customers from the cost and inconvenience

61 AEMC Reliability Panel, *Annual market performance review 2018*, April 2019, p. 80.



Figure 3.30

**Market intervals disrupted by transmission congestion**




Note: Percentage of trading intervals each year when transmission network congestion impacted the NEM spot price by more than $10 per megawatt hour. The data exclude outages caused by force majeure events and other specific exclusions.

Source: Economic benchmarking regulatory information notice (RIN) responses.

of supply interruptions. Following power outages in 2004, the Queensland and NSW Governments in 2005 strengthened reliability standards for distribution networks, requiring significant investment that drove network costs for several years. In contrast, Victoria placed more emphasis on reliability outcomes and the value that customers place on reliability. While Queensland and NSW began to relax reliability standards from 2014, the assets built to meet the high reliability standards remain, and customers continue to pay for them.[62]

Concerns that reliability driven investment was driving up power bills led to a new approach to setting distribution reliability targets.[63] The approach accounts for the likelihood of interruptions, and for the value that customers place on reliability (section 3.14.1).

#### Distribution reliability indicators

Two widely applied measures of distribution network reliability are the system average interruption duration index (SAIDI) and the system average interruption frequency index (SAIFI). SAIDI measures the average *duration of interruptions* experienced by the average customer each year.[64] SAIFI measures the average *number of interruptions* experienced by the average customer each year.

Comparisons across jurisdictions, and between distribution networks within jurisdictions, should be made with care. Customer density and environmental conditions differ across networks, which can impact the number of customers affected by an outage, and a network business's response time. Figure 3.31 shows the varying customer profiles of distribution networks.

Levels of historical investment also affect reliability outcomes. As an example, underground lines protect from pollution, storms, trees, bird life, vandalism, equipment failure, and vehicle collisions with poles, but they are considerably more costly to install than overhead lines. Figure 3.32 illustrates the significant differences in line length across distribution networks, and the networks' proportions of underground and overhead lines.

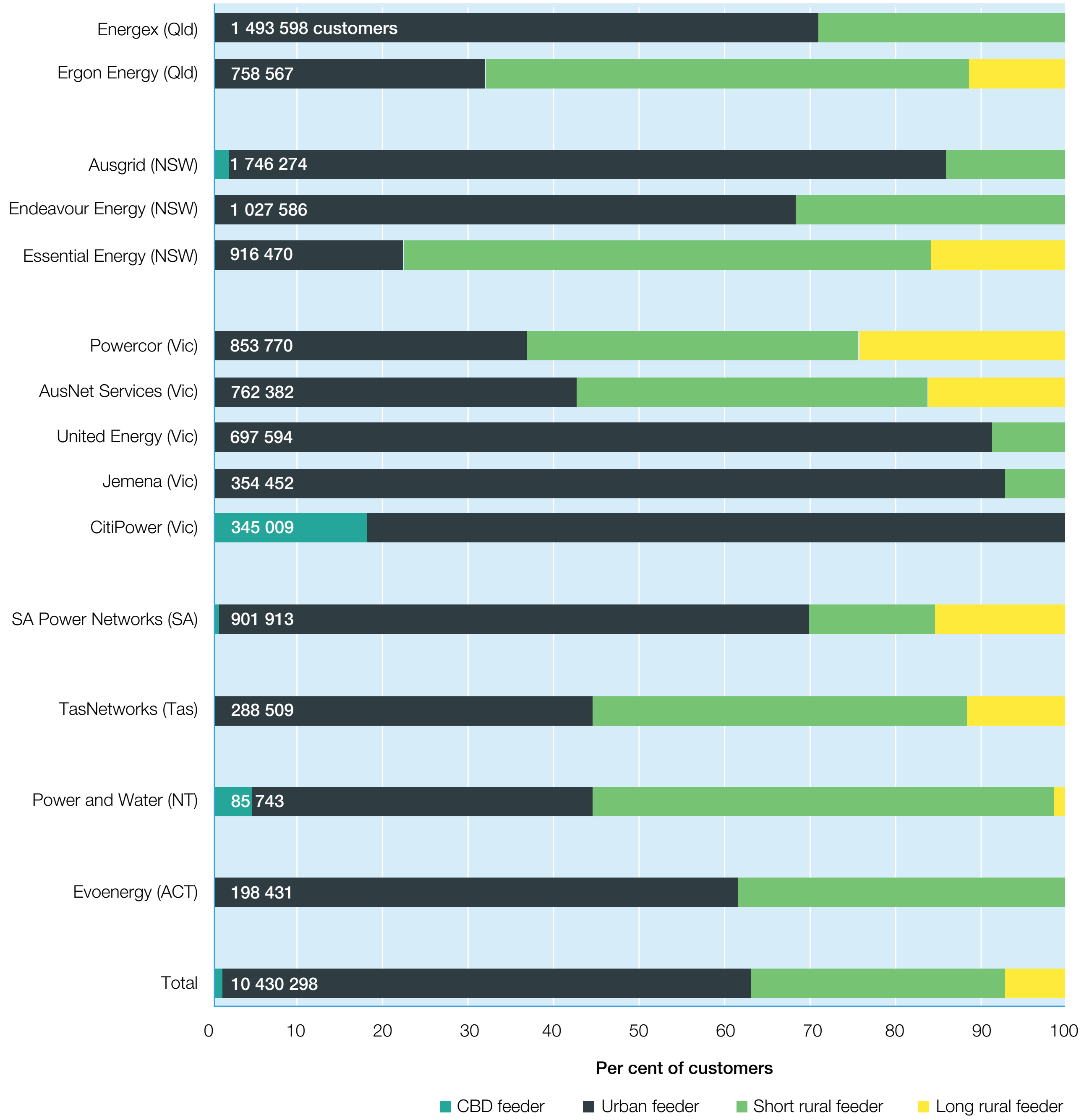
62 ACCC, *Retail Electricity Pricing Inquiry, Final report*, June 2018, p. 109.

63 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.

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

Figure 3.31

**Electricity customer profile—location on network**

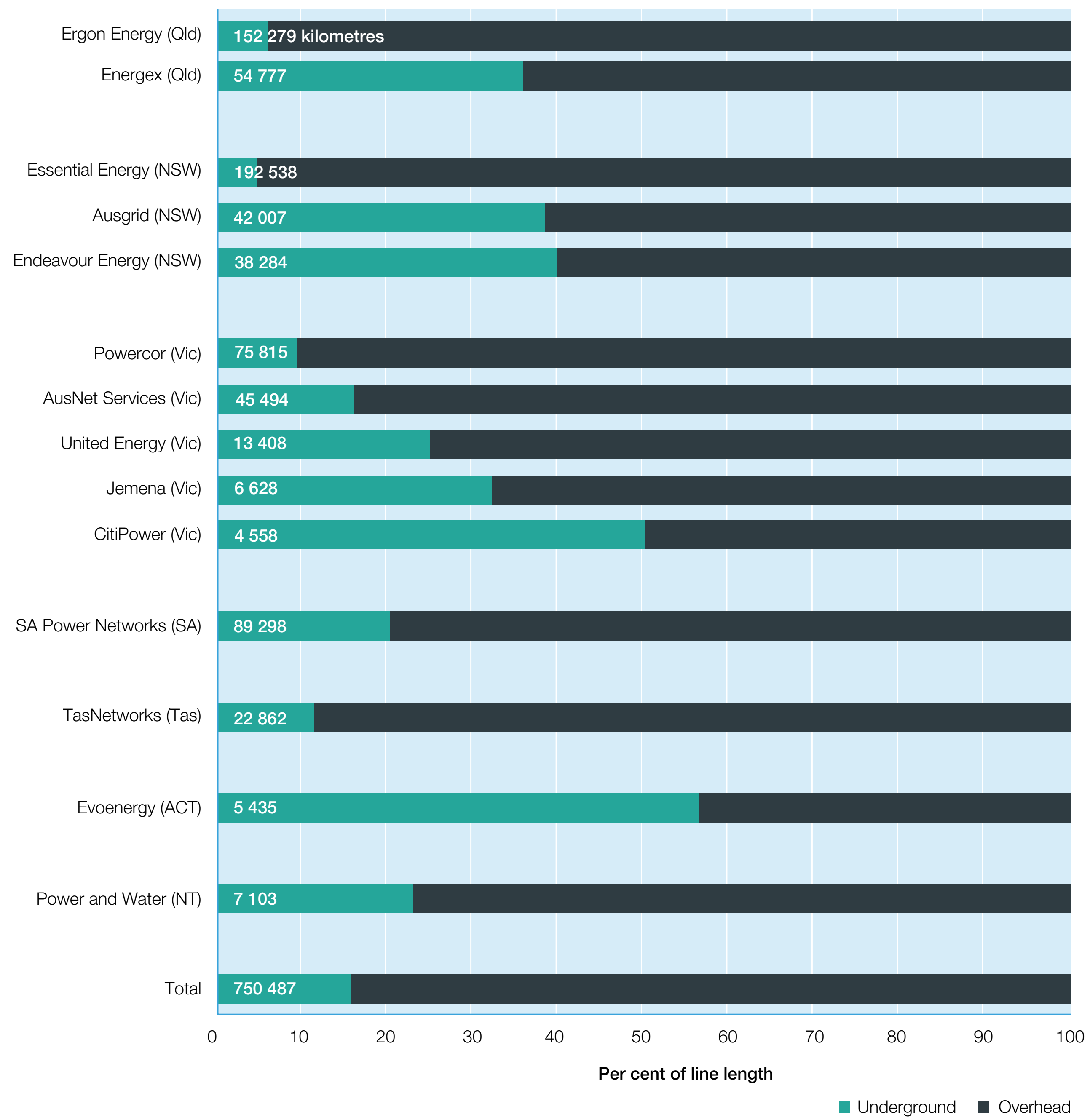



Note: *CBD feeder* is a feeder in the CBD area of a state or territory capital supplying electricity to predominantly commercial, high rise buildings, supplied by a predominantly underground distribution network containing significant interconnection and redundancy compared with urban areas. *Urban feeder* is a feeder that is not a CBD feeder and that has a three year average maximum demand over average feeder route length greater than 0.3 megavolt ampere (MVA) per kilometre. *Short rural feeder* is a feeder that has a total feeder route length less than 200 kilometres, and that is not a CBD feeder or urban feeder. *Long rural feeder* is a feeder that is not a CBD feeder, urban feeder or short rural feeder.

Source: Economic benchmarking regulatory information notice (RIN) responses.

Figure 3.32

**Circuit line length, by electricity distribution network**




Source: Economic benchmarking regulatory information notice (RIN) responses.

In 2019 the average NEM customer experienced:

- 1.4 unplanned interruptions to supply
- 194 unplanned minutes off supply.

The frequency of unplanned interruptions to supply experienced by the average NEM customer was 35 per cent lower in 2019 than in 2009. The duration of interruptions experienced by the average NEM customer has been more erratic, often due to severe weather events (figure 3.33). Examples were:

- network outages associated with bushfires in Victoria in 2009
- network outages caused by strong winds and torrential rain in NSW in April 2015
- reduced reliability for Queensland customers as a result of cyclones and severe flooding in 2011, 2013, 2015 and 2017
- a power outage across almost the whole of South Australia as a result of storm damage to electricity transmission infrastructure in 2016.

Excluding the impact of events deemed beyond the network's control, an average NEM customer in 2019 experienced:

- 1.1 unplanned interruptions to supply
- 119 unplanned minutes off supply.

The AER does not determine a network's operating and capital expenditure allowances to eliminate all supply interruptions. This approach is evident in the AER's service target performance incentive scheme (STPIS) (box 3.6), in which the AER sets 'normalised' reliability targets that do not penalise a network for interruptions considered to be beyond its control.

Across the sector, 'normalised' distribution reliability levels have improved over the past decade, with lower frequency and lower duration of unplanned interruptions to supply. This improvement occurred despite distribution networks spending less than forecast on new capital projects from 2009 to 2018 (figure 3.8).

Figure 3.33 summarises the SAIDI and SAIFI outputs for each jurisdiction, as well as—where applicable—the weighted network reliability targets that the AER applies through the STPIS.

## 3.14.4 Incentivising good performance

Inconsistencies in the measurement of reliability across NEM jurisdictions led the AEMC to develop a more consistent approach. The AER in November 2018 adopted the AEMC's recommended definitions for distribution reliability measures, for purposes such as setting reliability targets in the STPIS.[65] 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.

## 3.14.5 Incentives to avoid fire starts

The AER administers a Victorian Government scheme offering incentives to Victorian distributors to lower the number of fire starts originating from their network, especially in high fire danger zones and at times of heightened fire risk. Available penalties and rewards range from around $1.48 million per fire start in high risk areas on code red days, to $300 in low risk areas on a low fire danger day.

Incentive payments for 2017–18 ranged from around $5000 for the mostly urban United Energy network to almost $1 million for the predominantly rural Powercor network.[66] Victorian distributors received 77 per cent less in rewards in 2017–18 than in the previous year. Rewards were significantly lower for Powercor and AusNet Services (down 79 per cent), and United Energy (down 77 per cent) due to a higher number of fire starts in the period.

The distribution network businesses will continue to receive incentive payments only if they make sustained and continuous improvements in fire start performance. Once they make improvements, their benchmark targets are tightened in future years.

## 3.14.6 Customer service

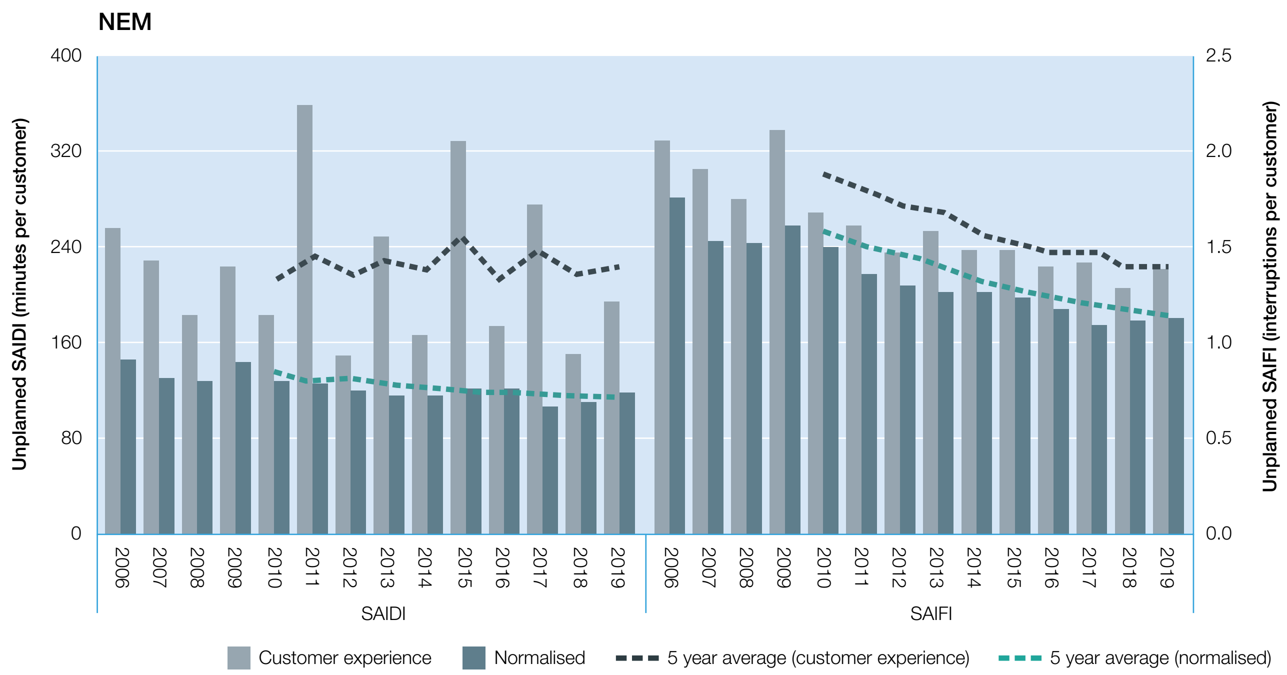
While reliability is the key service consideration for most energy customers, a distribution network's service performance also relates to the business:

- providing timely notice of planned interruptions
- ensuring the quality of supply, including voltage variations
- avoiding wrongful disconnection (including for life support customers) and ensuring quick timeframes for reconnection
- being on time for appointments
- having a fast response to fault calls
- providing transparent information on network faults.

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

66 AER, *Victoria F-factor scheme results for the 2016–20 period*, 28 June 2019.

Figure 3.33
**Distribution network reliability, by region**



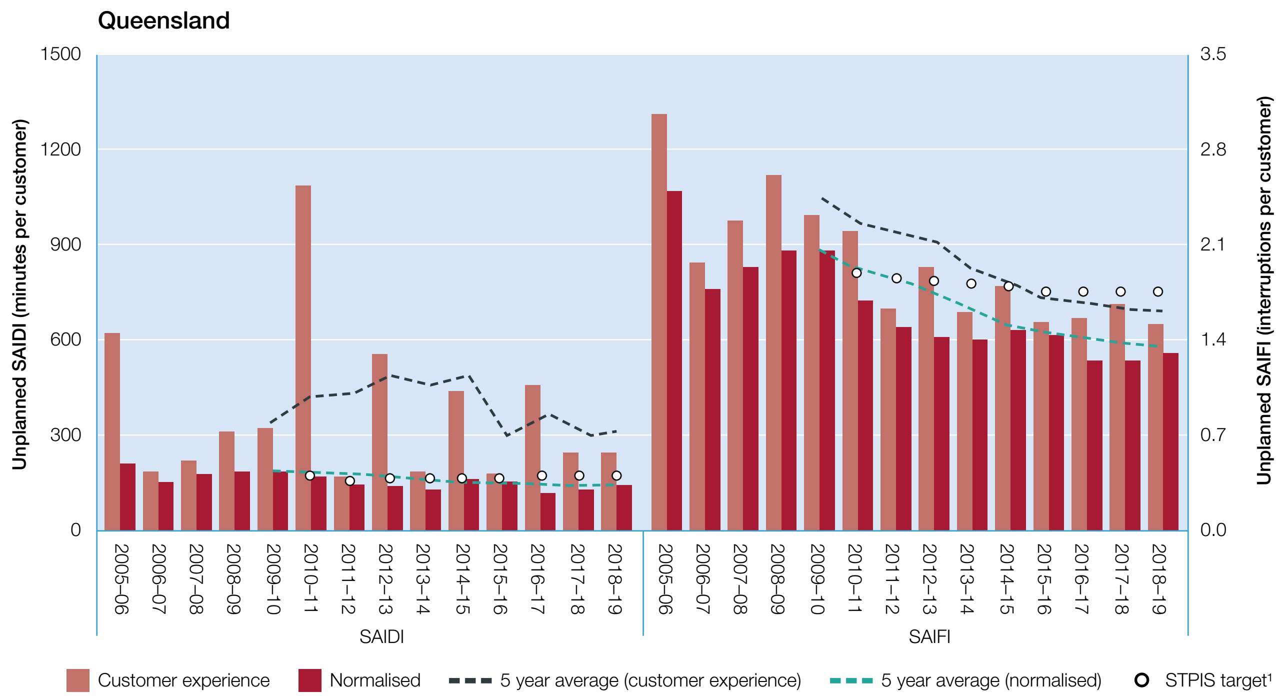
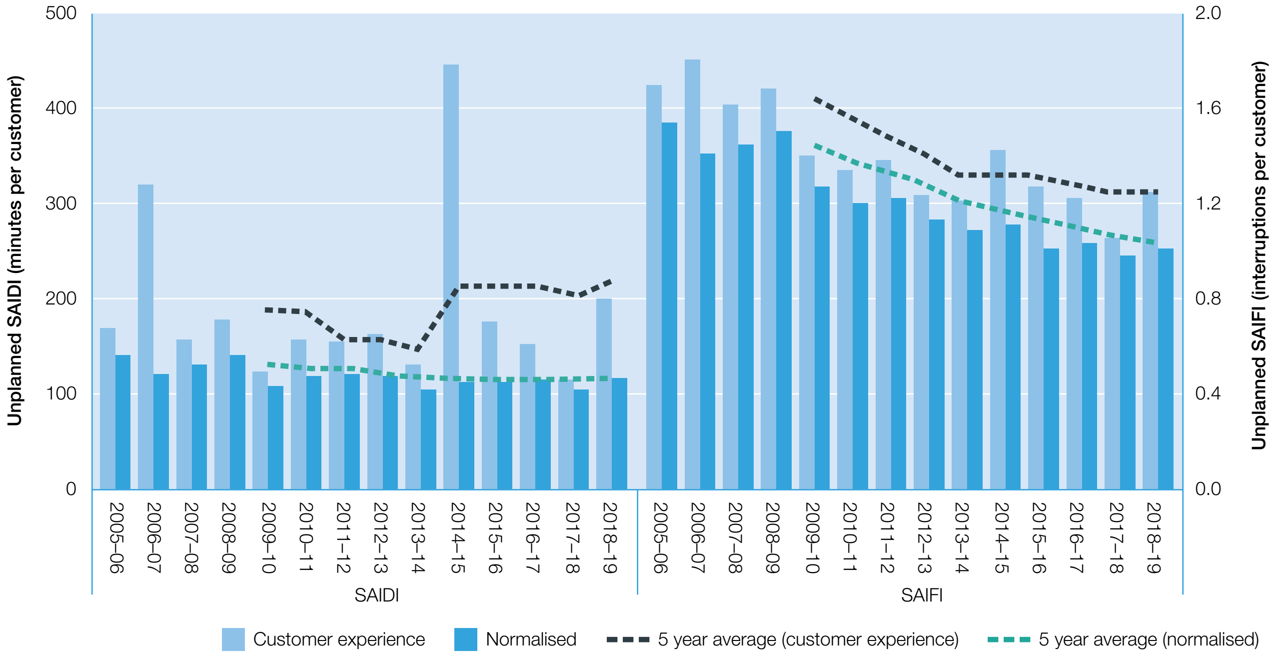



Figure 3.33
Distribution network reliability, by region (*cont.*)

### NSW




### Victoria

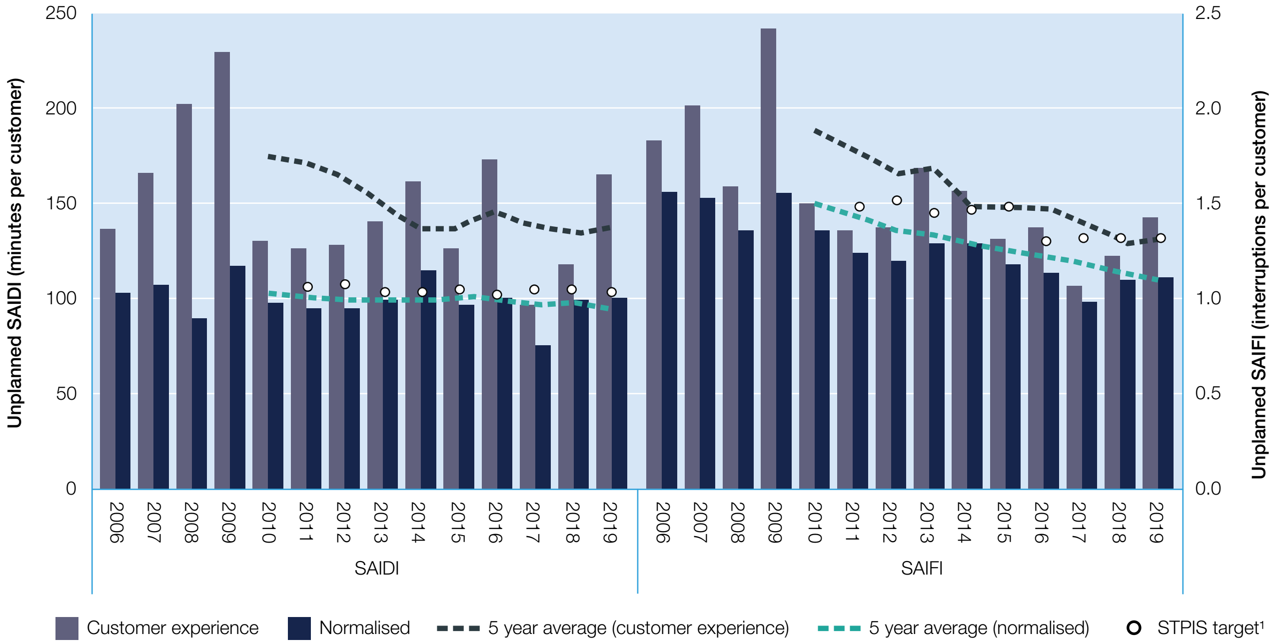
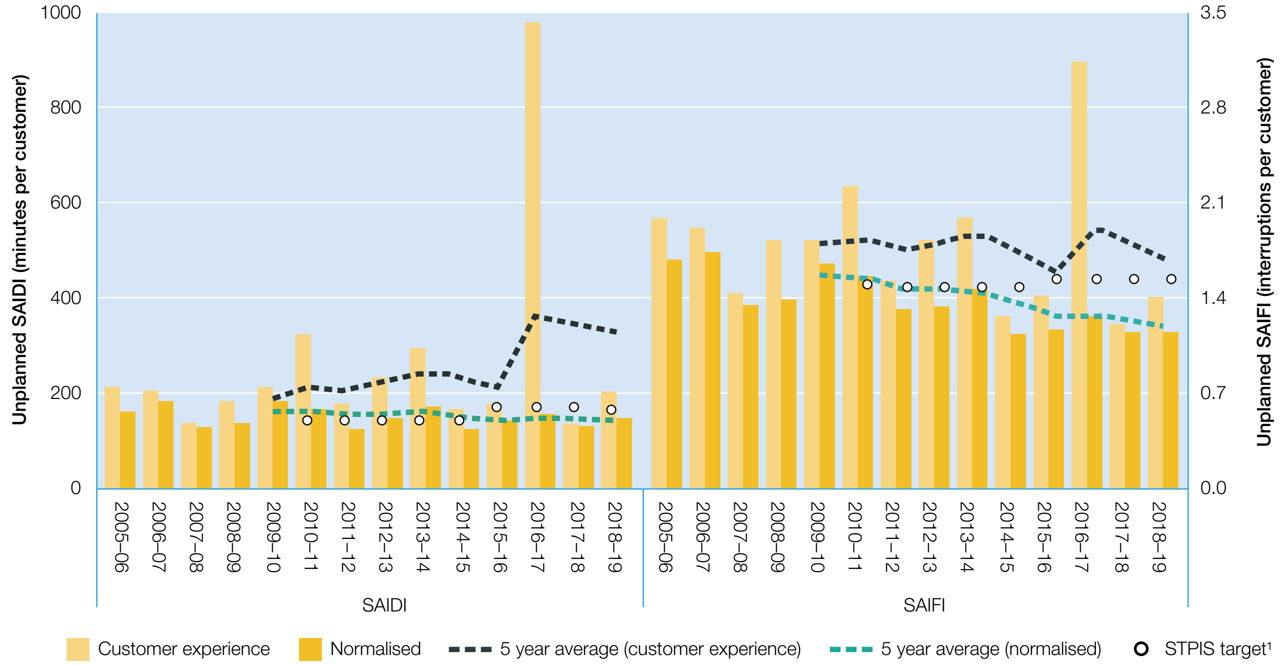



Figure 3.33
Distribution network reliability, by region (*cont.*)

### South Australia




### Tasmania

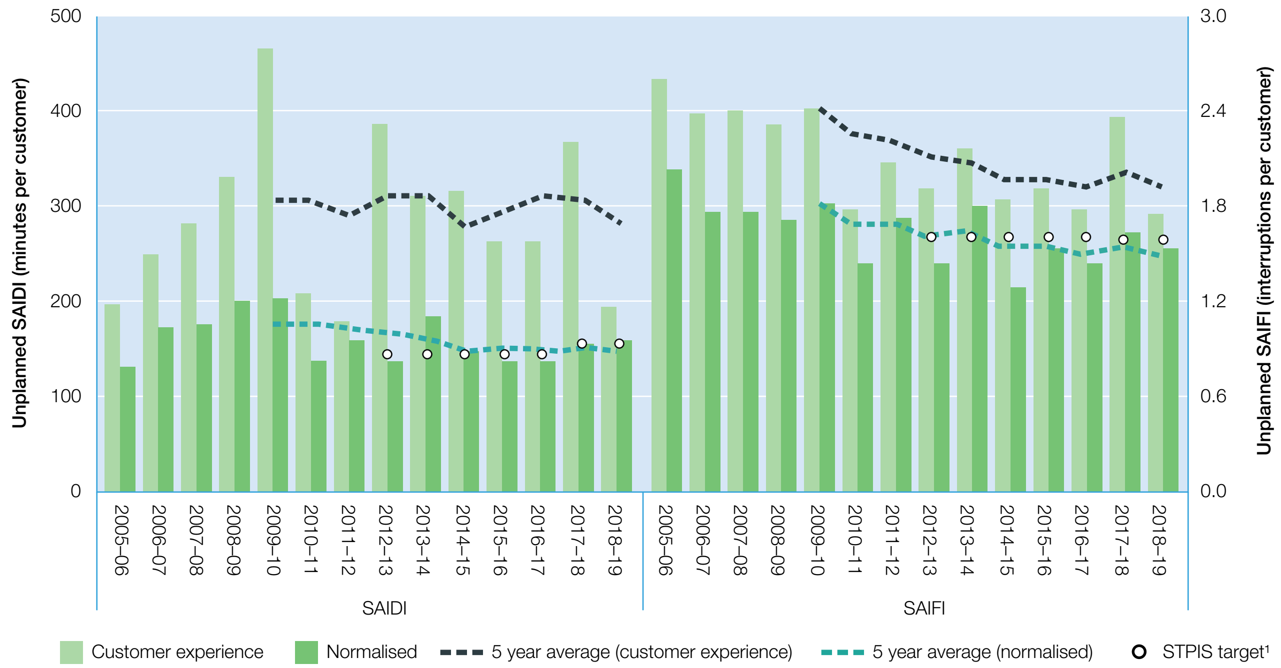
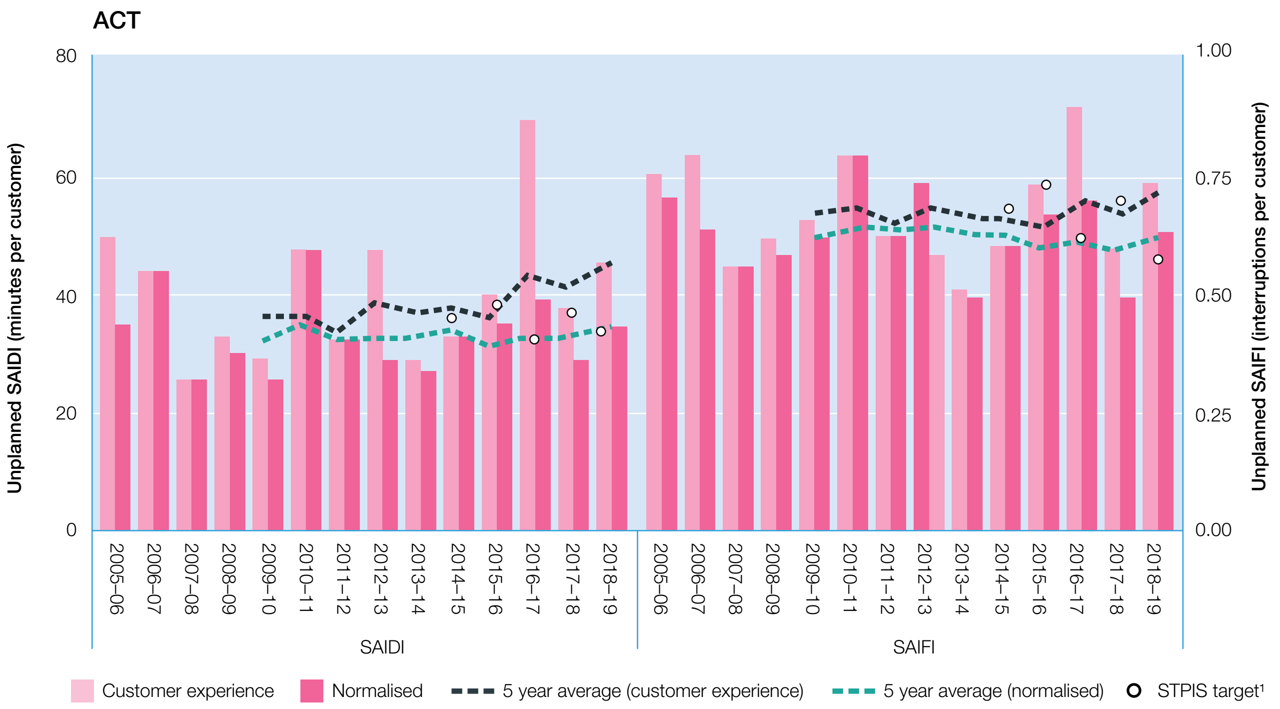


Figure 3.33

**Distribution network reliability, by region (*cont.*)**




SAIDI, system average interruption duration index; SAIFI, system average interruption frequency index; STPIS, service target performance incentive scheme.

1. STPIS targets are set at the feeder level. The STPIS targets shown in figure 3.33 represent weighted network level targets, calculated by multiplying the distributor's feeder level targets by the proportion of its customers on each feeder type.

Note: Victorian network businesses report on a 1 January – 31 December basis. All other network businesses report on a 1 July – 30 June basis. The NEM data show outcomes for the reporting period ending in that year (for example, the 2017–18 reporting year is shown as 2018).

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

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.[67] Victoria reports separately on network performance in that state.[68]

The AER oversees the rules protecting energy customers who rely on life support equipment. Between December 2018 and 31 March 2020, the AER issued seven infringement notices to distribution businesses for failing to provide sufficient notice of outages to life support customers—two notices were issued to Energex (Queensland), and two notices to Evoenergy (ACT). The AER also issued three infringement notices to TasNetworks (Tasmania) for failing to provide life support customers with written notice of planned outages at least four days ahead of the outage.

67 AER, *Annual retail markets report 2018–19*, November 2019.

68 ESC, *Victorian energy market report 2018–19*, November 2019.



## Box 3.6 Service target performance incentive scheme

The Australian Energy Regulator (AER) applies a service target performance incentive scheme (STPIS) to regulated network businesses. The scheme offers incentives for network businesses to improve their service performance to levels valued by customers. It provides a counterbalance to the capital expenditure sharing scheme (box 3.4) and efficiency benefit sharing scheme (box 3.5) by ensuring network businesses do not reduce expenditure at the expense of service quality. A separate STPIS applies to distribution and transmission network businesses.

### Distribution

A distribution network's revenue is increased (or reduced) based on its service performance. The bonus for exceeding (or penalty for failing to meet) performance targets can range to ±5 per cent of a network's revenue.

Currently, the AER applies the distribution STPIS to two 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.

The reliability component sets targets based on a network's average performance over the previous five years. Performance is 'normalised' to remove the impact of supply interruptions beyond the network's reasonable control.

Figure 3.34 shows how distribution network businesses have performed against their reliability targets since the scheme was introduced in 2011. While the reliability performance of each network fluctuates from year to year, network businesses have generally outperformed their targets.

Figure 3.34

**Distribution network performance against reliability targets**

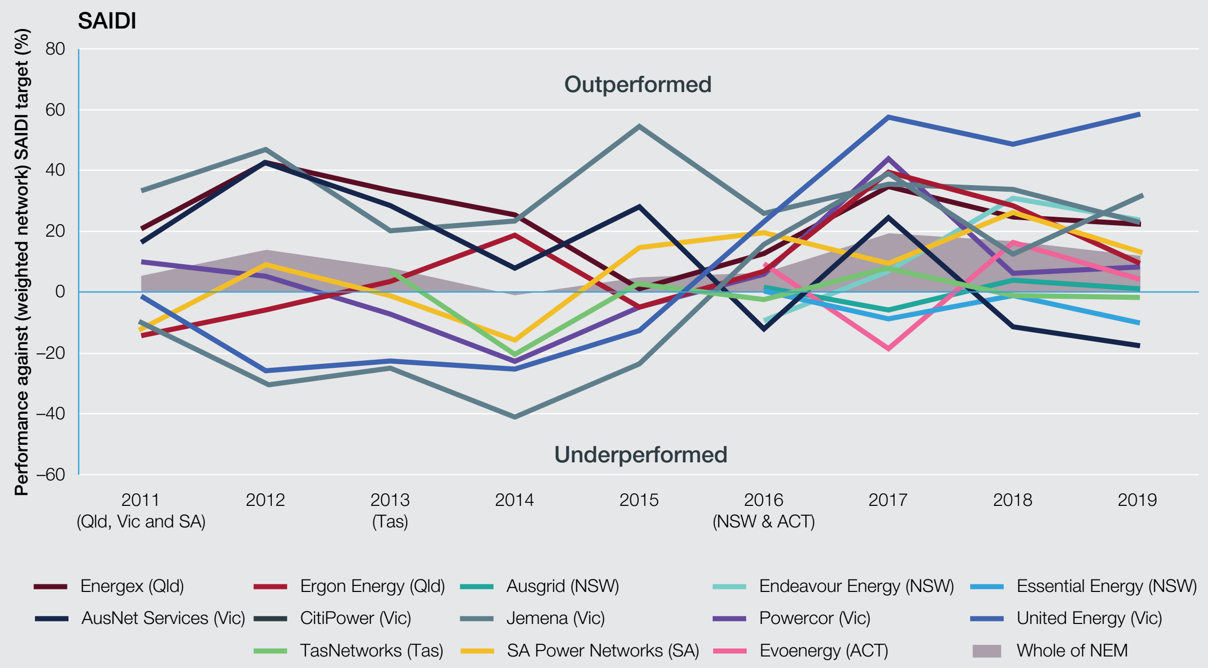
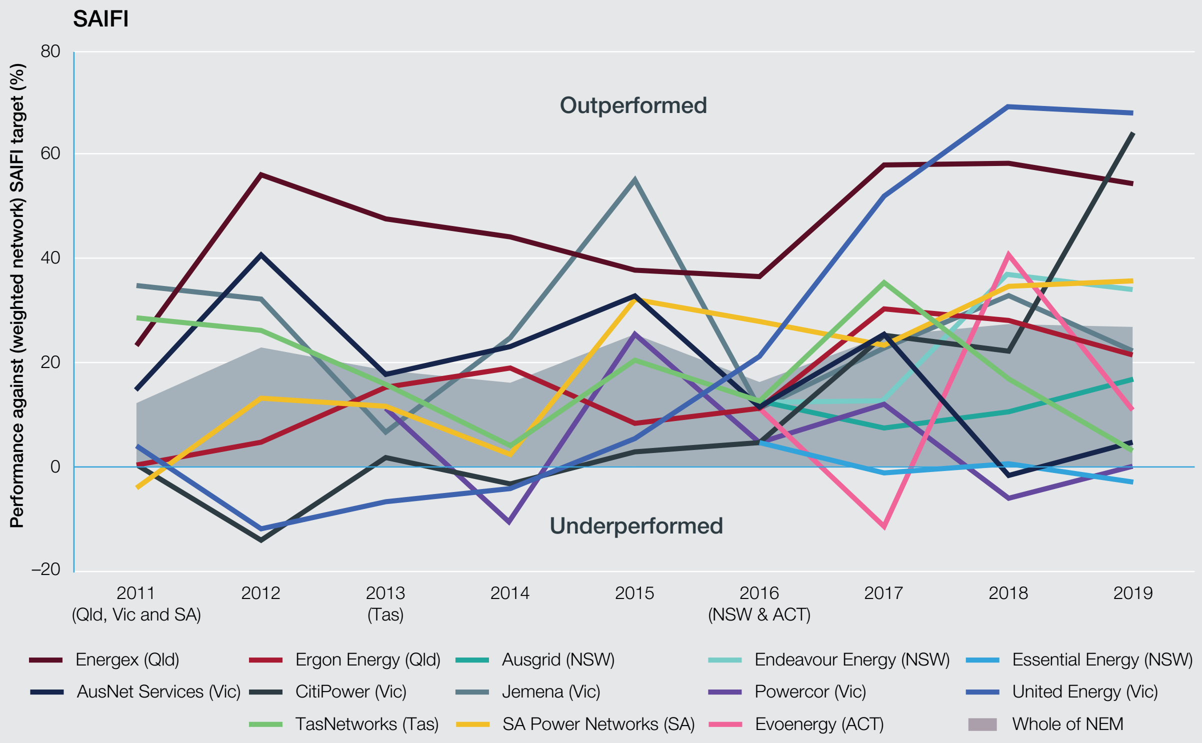


Figure 3.34
**Distribution network performance against reliability targets (*cont.*)**




Source: AER analysis.

## Transmission

The transmission STPIS covers three service components:

- the frequency of supply interruptions, outage duration, and the number of unplanned faults on the network
- rewards for operating practices that reduce network congestion
- funds 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 +4.5 per cent of revenue, or penalties of up to –1 per cent of revenue, are available for exceeding/failing to meet performance targets under the scheme.

Image courtesy of Woodside

# 4 GAS MARKETS IN EASTERN AUSTRALIA

Gas is a fossil fuel consisting mainly of methane, a naturally occurring hydrocarbon. It is created by decomposing plants and animals over millions of years. Reserves tend to be found near other solid and liquid hydrocarbon beds, such as coal and crude oil.

The main types of gas produced in Australia are conventional natural gas and coal seam gas (CSG). Conventional gas is found trapped in underground reservoirs, often along with oil, while CSG is an unconventional form of gas extracted from coal beds. Advancements in extraction techniques have improved the commercial prospects for other forms of unconventional gas, including shale and tight gas.[1]

The supply of gas to energy customers involves several steps (infographic 2). It begins with the exploration and appraisal of potential reserves for commercial viability. Gas discoveries are extracted through wells, then processed to separate the methane and ethane from impurities (such as nitrogen, carbon dioxide and sulphur dioxide), and to remove and treat any water.

In eastern Australia, almost 70 per cent of gas produced is converted to liquefied natural gas (LNG) for export, mainly to Asia. The balance is sold into the domestic market. Some gas is stored (often in depleted gas fields or LNG tanks) and can be used to augment supply at peak times. More recently, domestic gas users have explored options for importing LNG to supplement domestic gas supplies.

Gas sold to domestic customers is transported from production fields to major demand centres or hubs via high pressure transmission pipelines (figure 4.1). The pipelines have wide diameters and operate under high pressure to optimise shipping capacity. They deliver gas to power stations, large industrial and commercial customers, and energy retailers, which sell the gas to their customers. Retailers deliver gas to energy customers' pipelines via distribution networks, which are spaghetti-like networks of smaller pipes that service commercial and residential premises in cities and towns.

1 Shale gas is contained within organic-rich rocks such as shale and fine grained carbonates, rather than in underground reservoirs. The application of horizontal drilling techniques in the past five years is enhancing the economic viability of shale gas development. Tight gas is found in low porosity sandstone and carbonate reservoirs.

## 4.1 Gas markets in eastern Australia

This chapter considers the 'upstream' gas sector, encompassing gas production, wholesale markets for gas, and the transport of gas along transmission pipelines to demand hubs. It focuses on the eastern gas market, in which the Australian Energy Regulator (AER) has regulatory responsibilities (box 4.1).

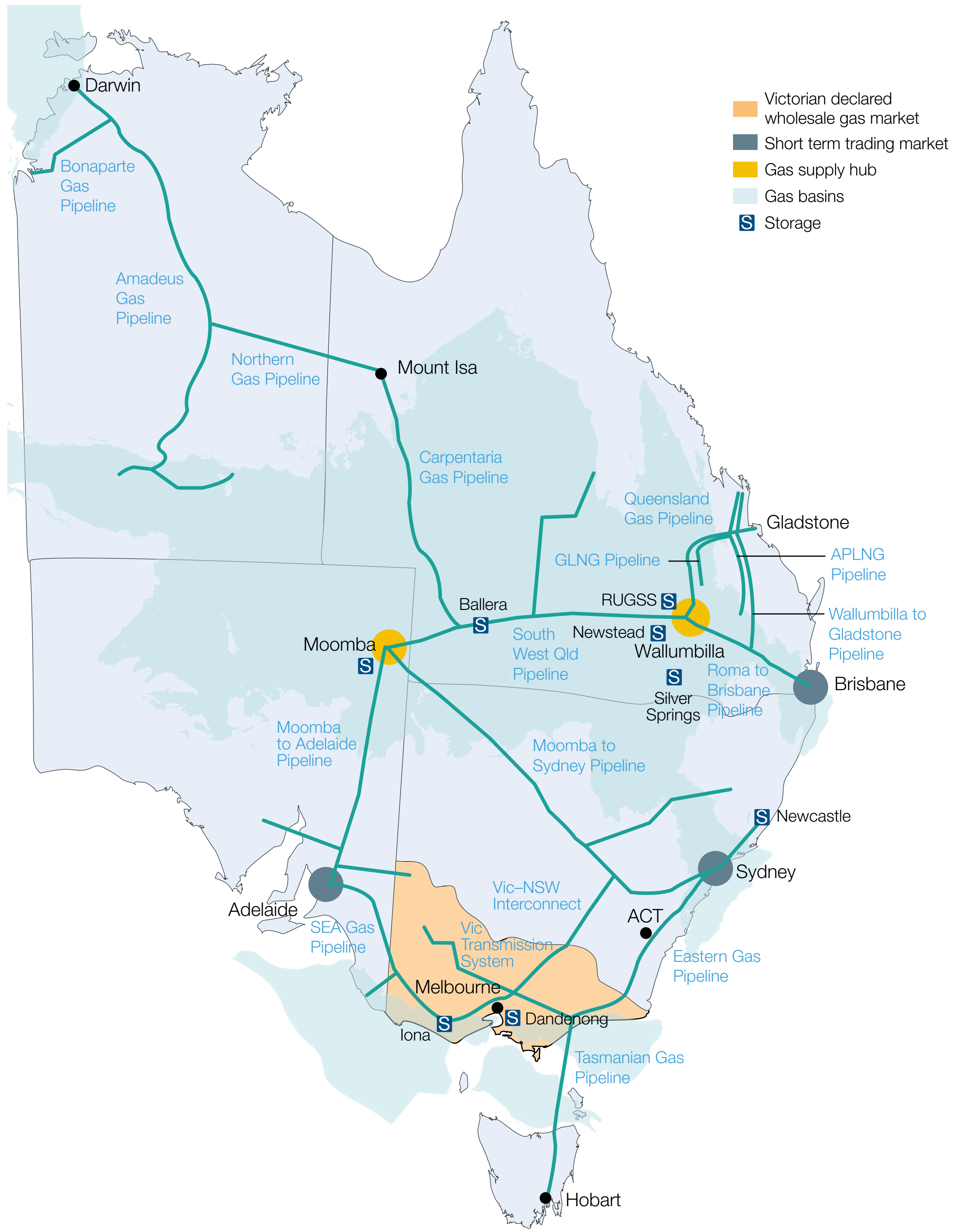
The eastern market encompasses Queensland, New South Wales (NSW), Victoria, South Australia, Tasmania and the Australian Capital Territory (ACT). This market is interconnected by transmission pipelines, which source gas from basins and deliver it to large industrial customers and major population centres. The main production basins are the Surat–Bowen Basin in Queensland, the Cooper Basin in north east South Australia, and three basins off coastal Victoria, the largest being the Gippsland Basin. Since January 2019 the market has also sourced gas from the Northern Territory.

Commercial gas production in eastern Australia began in the 1960s. Relatively low prices at that time encouraged residential, commercial and industrial customers to use gas, which is valued for its clean burning properties. Gas use later expanded into the electricity generation market.

The eastern gas market evolved as separate state based markets, each served by a single gas basin and a single transmission pipeline. Over the past 20 years, new pipelines interconnected these markets, making it possible to transport gas from Queensland to the southern states, and (since key pipelines became bi-directional) vice versa. With the opening in 2019 of the Northern Gas Pipeline, the eastern gas market can also source gas from the Bonaparte Basin off the north coast of Western Australia and the Northern Territory.

Gas became a major export industry in eastern Australia, with the launch in 2015 of Queensland's LNG industry. The industry transformed the eastern gas market by giving producers the choice of exporting gas or selling it domestically. By 2018 around 61 per cent of eastern Australian gas production was being exported. With domestic users now competing with overseas customers to buy Australian gas, prices in the domestic market have risen to align more closely with international gas prices. Higher gas prices also impact electricity markets, which became more reliant on gas powered generation after several coal fired generators closed in 2016 and 2017.

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




Source: AER; Gas Bulletin Board.

## Box 4.1 The AER's role in gas markets

The Australian Energy Regulator (AER) has regulatory responsibilities across the entire gas supply chain in eastern Australia. At the wholesale level, we monitor and report on spot gas markets in Sydney, Brisbane, Adelaide and Victoria; gas supply hubs at Wallumbilla (Queensland) and Moomba (South Australia); and activity on the Gas Bulletin Board, which is an open access information platform covering the eastern gas market.

We monitor the markets and bulletin board to ensure participants comply with the National Gas Law and Rules, and we take enforcement action when necessary. Our compliance and enforcement work aims to promote confidence in the gas market, to encourage participation. We also monitor the markets for particular irregularities and wider inefficiencies. Our monitoring role at the Wallumbilla and Moomba hubs, for example, explicitly looks to detect price manipulation. In 2019 we began a new role as the compliance and enforcement body for a scheme to auction underused capacity in transmission pipelines.

Our gas compliance focus in 2019 included the successful implementation of capacity trading reforms, and enhanced transparency. In particular, market participants are required to submit information to the Australian Energy Market Operator (AEMO) and the AER in a timely and accurate manner.

During the year, we applied more stringent compliance expectations around bulletin board reporting, including administering new civil penalty provisions to enhance the integrity of information provided. Further, to promote compliance with registration and reporting obligations, we engaged with participants that had reporting requirements for the first time. These participants included facility operators in the Northern Territory following its connection to the eastern Australian market in January 2019. Our focus in these areas continues into 2020.

In 2019 we strengthened our monitoring and reporting by publishing gas industry statistics and *Wholesale markets quarterly* reports, covering gas spot market activity, prices and liquidity. The quarterly reports include analysis of eastern Australia's liquified natural gas (LNG) export sector, and its impact on the domestic market.

Looking forward, we continue to engage with the Council of Australian Governments (CoAG) Energy Council's gas reform agenda. Under the agenda, we must administer new reporting obligations to enhance the transparency of market activity.

Alongside our work in gas wholesale markets, the AER is the economic regulator for two major transmission pipelines in eastern Australia. We also arbitrate disputes relating to 'light regulation' pipelines, and we may appoint an arbitrator to settle disputes affecting other pipelines.[a]

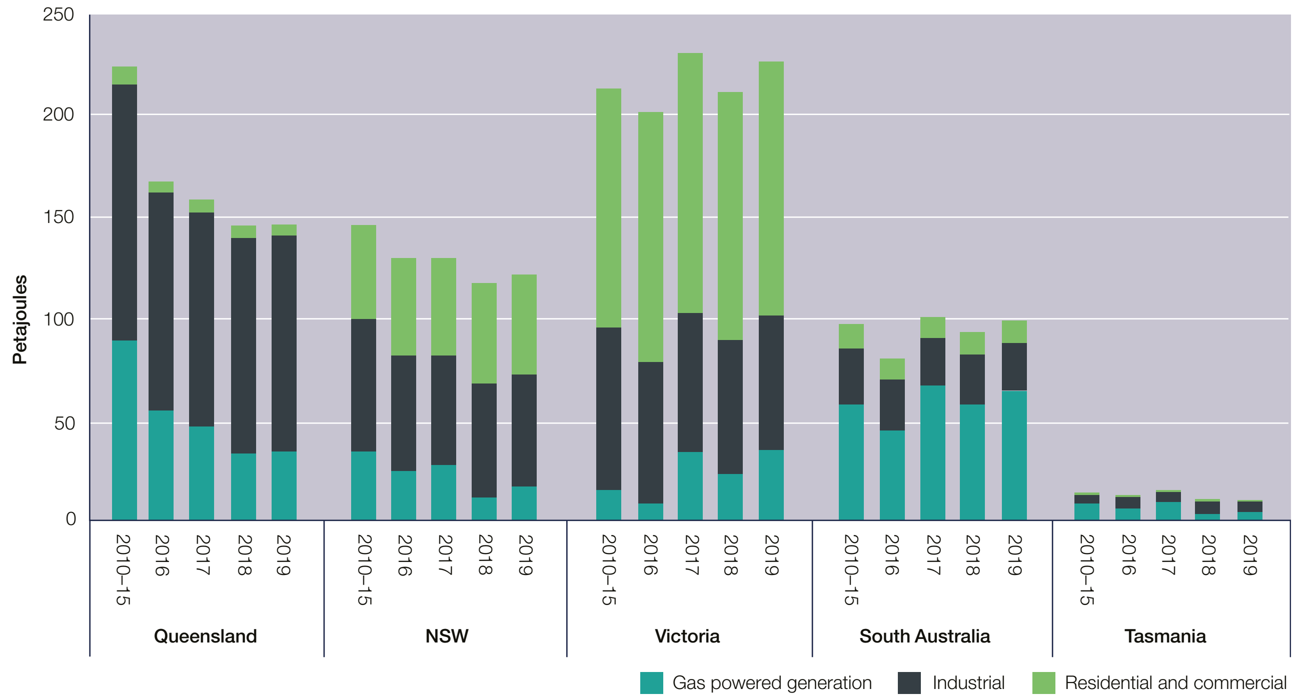
In the downstream gas industry, the AER sets reference prices for distribution networks in NSW, Victoria, South Australia and the ACT (chapter 5). In retail gas markets, we hold wide ranging responsibilities in jurisdictions that have passed the National Energy Retail Law—namely, Queensland, NSW, South Australia and the ACT (chapter 6).

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

Outside the eastern market, the AER is the gas pipeline regulator for the Northern Territory, but plays no role in the territory's wholesale market. However, facility operators in the Northern Territory must report gas flow activity to the bulletin board, which the AER oversees. We have no regulatory function in Western Australia, where separate laws apply.[b]

a Chapter 5 outlines the different tiers of pipeline regulation.
b The Economic Regulation Authority is the economic regulator for gas markets and pipelines in Western Australia, and AEMO operates a spot gas market there.

**Figure 4.2**
**Gas consumption in eastern Australia**




Note: Data for 2010–15 are average annual consumption over that period.
Source: AEMO, *2020 gas statement of opportunities*, March 2020.

## 4.2 Gas demand in eastern Australia

Domestic customers in eastern Australia used around 600 petajoules (PJ) of gas in 2019 (figure 4.2).[2] These customers included industrial businesses, electricity generators, commercial businesses and households. Industrial customers are the biggest users, consuming 43 per cent 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. In Queensland, industrial customers are the main source of domestic gas demand.

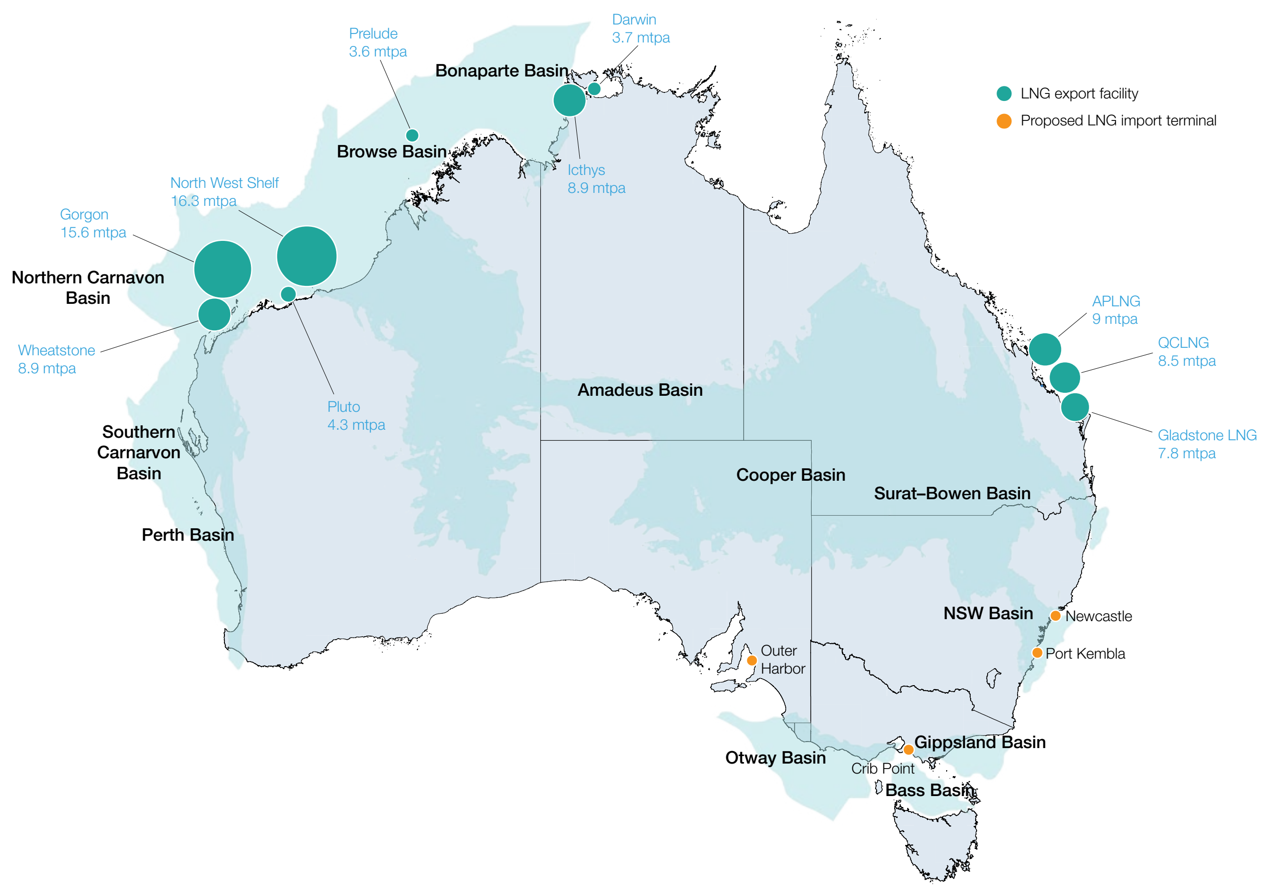
The electricity sector is another major source of demand. The rapid responsiveness of gas powered turbines makes them suitable for peak electricity generation. Gas powered generation also plays an important role in managing fluctuations in wind and solar generation. With gas generation often used to fill supply gaps in the electricity market, its level can fluctuate significantly. Gas powered generation accounted for 26 per cent of domestic gas use in 2019, down from 29 per cent in 2017 when gas generators helped fill the supply gap caused by the closure of Victoria's Hazelwood power station. South Australia has the highest ratio of gas demand for electricity generation, accounting for 42 per cent of gas demand in 2019.

Residential and commercial customers are the third major source of gas demand. Overall, they account for 31 per cent of domestic gas demand. Victoria is the only state where a majority of demand (around 60 per cent) is from small residential and commercial customers, who use gas mostly for heating and cooking. Over 80 per cent of Victorian households are connected to a gas network.[3] Around 35 000 new residential gas connections were made in Victoria each year from 2014 to 2018, mainly as part of new housing developments.[4] Residential gas penetration is around 80 per cent in the ACT, 60 per cent in South

2 AEMO, *2020 gas statement of opportunities*, March 2020.

3 AEMO, *National gas forecasting report*, December 2016.
4 AEMO, *Winter 2018—Victorian gas operations outlook*, 8 May 2018.

**Figure 4.3**
**Australia's LNG export projects**




Note: Capacity in million tonnes per annum (mtpa).
Source: AER.

Australia, 45 per cent in NSW, 10 per cent in Queensland, and 6 per cent in Tasmania.[5]

In the overall energy mix, gas reliance is highest in South Australia, where it accounts for 38 per cent of primary energy consumption, followed by Victoria and Queensland (around 20 per cent in each state). It is lower in NSW, where it accounts for less than 10 per cent of energy consumption.[6] South Australia's high degree of reliance on gas reflects its dependence on gas powered generation since the closure of the state's coal fired generators.

## 4.3 Liquefied natural gas exports

A majority of gas produced in eastern Australia is liquefied as LNG for shipping to export markets (table 4.1). The gas is chilled to –162 degrees Celsius, which shrinks volume by 600 times and makes it economic to store and ship in large quantities. Most Australian LNG is shipped to Asia, where it is stored, regasified and injected into local gas pipeline networks.

LNG projects require major investment in processing plants, port and shipping facilities. The magnitude of this investment requires access to substantial reserves of gas, which may be sourced through the project owner's interests in gas fields, joint venture arrangements with gas producers, and/or contracts with third party producers.

5 AEMO, *National gas forecasting report*, December 2016.
6 Department of the Environment and Energy, *Australian energy statistics 2018–19*, Table C, 2019.



Alongside Queensland's LNG industry, Australia operates five LNG projects in Western Australia, and two in the Northern Territory (figure 4.3). In 2018–19 LNG exports earned Australia $50 billion, making gas Australia's third largest resource and energy export, behind coal and iron ore.[7] Australia became the world's largest LNG exporter in 2019.[8]

### 4.3.1 Queensland LNG industry

Queensland's LNG industry comprises three major projects, which liquefy gas sourced mainly from the Surat–Bowen Basin. The projects were made possible by the basin's vast CSG reserves, and are the world's first to convert CSG to LNG. While all projects meet a majority of their LNG requirements from reserves that they control, they also rely on third party gas. They source this gas from other LNG producers, as well as producers in central Australia and Victoria, and acquire it through long term contracts and spot markets:

- The Queensland Curtis LNG (QCLNG) project has capacity to produce 8.5 million tonnes of LNG per annum (mtpa). It began exporting LNG in January 2015, and has two trains (liquefaction and purification facilities). Shell is the principal owner (74 per cent).
- The Gladstone LNG (GLNG) project has capacity to produce 7.8 mtpa. It began exporting in October 2015 and has two trains. Santos (30 per cent), Petronas and Total (27.5 per cent each), and Kogas (15 per cent) own the project.
- The Australia Pacific LNG (APLNG) project has capacity to produce 9 mtpa.[9] It began exporting gas in January 2016 and has two trains. Origin Energy and ConocoPhillips (37.5 per cent each), and Sinopec (25 per cent) own the project.

### 4.3.2 Northern Territory and Western Australia

The Northern Territory's LNG industry began in 2006 with the commissioning of Darwin LNG (3.7 mtpa capacity), which relies on gas from the Bonaparte Basin in the Timor Sea. A second project—Ichthys LNG (8.9 mtpa capacity)—launched in 2018. Both projects connect to the territory's domestic gas market as emergency supply sources, but otherwise produce gas solely for export.

Western Australia has five LNG projects with a combined capacity of around 50 mtpa. The industry began with the North West Shelf project, and the first cargo left the facility for sale to Japan in 1989. The North West Shelf project has five trains and remains Australia's largest LNG project by capacity (16.9 mtpa).

Western Australia's second LNG project, Pluto, was commissioned in 2012. Rising LNG prices provided the impetus for three more recent projects—Gorgon (2016), Wheatstone (2017) and Prelude (2019).[10]

## 4.4 Gas reserves in eastern Australia

Gas reserves are unexploited accumulations of gas that are expected to be commercially recoverable. Data on gas reserves are an important input to forecasting supplies of gas that may enter the market.

Different measures of gas reserves are quoted, based on geological, engineering and commercial analysis of the likelihood of successful recovery:

- Proven reserves (1P) are estimated to be at least 90 per cent certain of successful commercial recovery.
- Proven plus probable reserves (2P) are estimated to be at least 50 per cent certain of successful commercial recovery.
- A third category (3P) includes all reserves deemed at least 10 per cent likely to be commercially recoverable.

Lower levels of probability attach to *contingent* resources, which are resources considered potentially recoverable from known accumulations that are not yet technically or commercially recoverable.

This probabilistic approach to measuring gas reserves results in frequent, and sometimes substantial, adjustments. Queensland's 2P reserves, for example, were downgraded by over 4400 PJ between June 2017 and June 2019.[11]

Data on Australian gas reserves is collected through various disconnected mechanisms and bodies, resulting in a lack of clear, consistent and accurate reporting. Data standards and

7 Department of Industry, Innovation and Science, *Resources and energy quarterly*, December 2019.
8 EnergyQuest, *Energy quarterly*, March 2020.
9 APPEA, 'Australian LNG projects', web page, available at: www.appea.com.au/oil-gas-explained/operation/australian-lng-projects/.
10 Department of Jobs, Tourism, Science and Innovation (Western Australia), *Western Australia liquefied natural gas profile*, February 2020.
11 ACCC, *Gas inquiry 2017–2025, Interim report*, January 2020, February 2020.

aggregation across these sources are inconsistent, and the assumptions underlying the data are often not transparent.[12]

The Australian Securities Exchange (ASX) requires listed companies to report limited data on gas reserves, but unlisted companies and those listed overseas are not obliged to report. State and territory governments each have reporting requirements, and the Australian Government collects some information (particularly on offshore resources), but much of this information is commercial-in-confidence.

Market analysts such as EnergyQuest and Energy Edge publish reserves estimates, drawing on available sources. The Australian Competition and Consumer Commission (ACCC) is also working in this area, and began publishing reserves and resources information in December 2018.

The CoAG Energy Council in 2020 was progressing reforms that would require all participants to report information on gas reserves via the Gas Bulletin Board (section 4.14.1).

### 4.4.1 Distribution of reserves in eastern Australia

EnergyQuest estimated eastern and southern Australia's 2P gas reserves stood at 36 116 PJ in February 2020, but noted this estimate is subject to uncertainty.[13] Reserve ownership is highly concentrated in some basins, but more diverse across the market as a whole (figure 4.4). Arrow Energy (16 per cent) is the largest holder of 2P reserves in eastern Australia. Other major reserve holders include Shell, Origin Energy, ConocoPhillips and Santos.[14]

#### Surat–Bowen Basin

Queensland's Surat–Bowen Basin is the largest basin in eastern Australia, with over 85 per cent of all gas reserves (table 4.1). Reserves from the basin are mainly converted to LNG for export, but the basin also supplies some gas to the domestic market. The LNG projects control over 80 per cent of reserves in eastern Australia, which are mostly CSG.[15]

#### Victorian basins

The Gippsland Basin is the most significant of the three producing basins in Victoria, accounting for around 7 per cent of eastern Australian reserves.[16] The Bass and Otway basins together account for 2 per cent of reserves. Total reserves across the Victorian basins are declining, mainly due to a depletion of reserves in the Gippsland Basin.

From December 2017 to February 2020, 2P reserves fell by nearly 17 per cent in the Gippsland Basin. Over the same period, 2P reserves more than doubled in the Bass Basin, and rose by more than 80 per cent in the Otway Basin. Because the Bass and Otway basins are smaller in scale, these increases did not offset the reductions in the Gippsland Basin.

A joint venture between Esso (ExxonMobil) and BHP controls a large majority of reserves in the Gippsland Basin, although Esso in September 2019 signaled an interest in selling its gas assets in the region.

#### Cooper Basin

The Cooper Basin in central Australia has over 1000 PJ of 2P reserves, which accounts for 3 per cent of eastern Australia's 2P reserves. In 2010 Santos entered an agreement to supply one of the Queensland LNG projects with 750 PJ of gas over 15 years, which accelerated the depletion of the basin's conventional reserves. But reserve levels stabilised recently, and rose by over 15 per cent between December 2018 and February 2020.[17]

#### NSW basins

NSW has significant contingent resources (around 2000 PJ) but only 7 PJ of 2P reserves, and negligible current production. Santos in 2017 applied to develop reserves near Narrabri in the Gunnedah Basin. The project has encountered widespread opposition on environmental grounds. At March 2020, it was still progressing through the NSW Government's planning process (section 4.12.1).

#### Northern Australia

Northern Australia was historically separate from the eastern gas market, but the commissioning of the Northern Gas Pipeline in January 2019 changed this situation by linking gas fields in the Bonaparte Basin (offshore of Darwin in the Timor Sea) and the Amadeus Basin (southern Northern Territory) with Queensland.

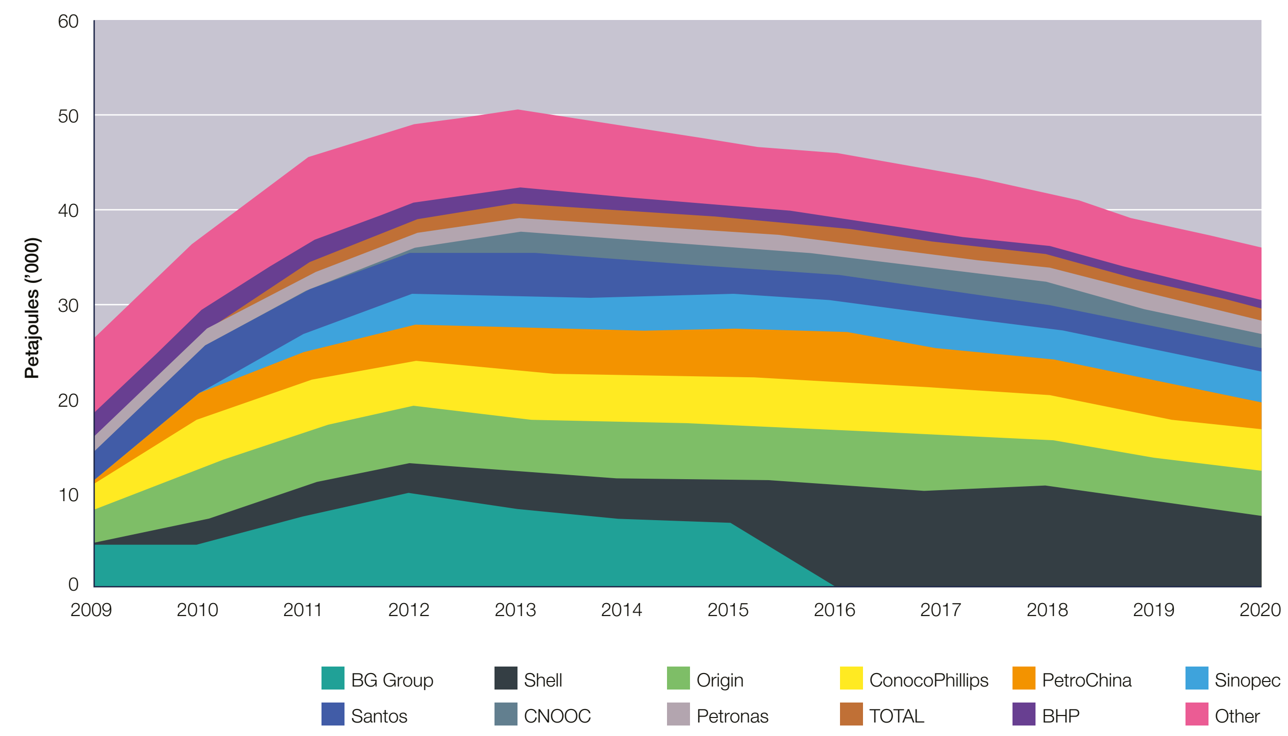
The Bonaparte Basin was developed to support the Northern Territory's LNG industry, which is based in Darwin. The basin is estimated to have over 700 PJ of 2P reserves. Most gas produced in the basin is converted to LNG for export.

12 ACCC, *Inquiry into the east coast gas market*, April 2016.
13 EnergyQuest, *Energy quarterly*, March 2020, p. 68.
14 EnergyQuest, *Energy quarterly*, March 2020, Table 25, p. 70.
15 ACCC, *Gas inquiry 2017–2025, Interim report*, *January 2020*, February 2020, p. 45.
16 EnergyQuest, *Energy quarterly*, March 2020, Table 23, p. 68.

17 EnergyQuest, *Energy quarterly*. March 2020, Table 23, p. 68.



**Figure 4.4**
**Market shares in 2P gas reserves in eastern Australia**




Note: Aggregated market shares in 2P (proven and probable) gas reserves in the Surat–Bowen, Gippsland, Cooper, Otway, Bass and NSW basins. 2P reserves are those for which geological and engineering analysis suggests at least a 50 per cent probability of commercial recovery.

Source: EnergyQuest, *Energy quarterly* (various years).

## 4.5 Gas production

In 2019 eastern Australia produced almost 2000 PJ of gas. The majority (69 per cent) was exported as LNG, and the remainder was sold to the domestic market (table 4.1).

Queensland's Surat–Bowen Basin supplied 77 per cent of gas produced in eastern Australia in 2019, including much of the gas earmarked for LNG export. Participants in Queensland's three LNG projects produced around 90 per cent of the basin's output in 2019. As well as supplying their LNG facilities, the LNG participants sell some gas into the domestic market.

Outside Queensland, the basins off coastal Victoria meet most of the remaining demand in the eastern states. The Gippsland Basin is the most significant of the three producing basins in Victoria, meeting 13 per cent of demand in 2019. The smaller Otway and Bass basins jointly supplied 4 per cent of the market.

The Longford Gas Plant, servicing the Gippsland Basin, achieved record production in 2017, some of which was shipped to Queensland for LNG exports (figure 4.5). But production has since declined. The Australian Energy Market Operator (AEMO) forecasts a steep decline in southern field production after 2022 as a number of Gippsland Basin fields cease production in 2023 and 2024.[18]

The Cooper Basin in central Australia accounted for 5 per cent of eastern Australian gas production in 2019. The basin plays an important role as a 'swing' producer in managing seasonal and short term supply imbalances in the domestic gas market.

With the opening of the Northern Gas Pipeline in January 2019, the Northern Territory's offshore Bonaparte Basin and onshore Amadeus Basin became new suppliers to the eastern gas market. In 2019 the Northern Gas Pipeline delivered over 65 terajoules (TJ) per day on average into the eastern market.

18 AEMO, *2020 gas statement of opportunities,* March 2020, p. 5.

Table 4.1 **Gas basins serving eastern Australia**

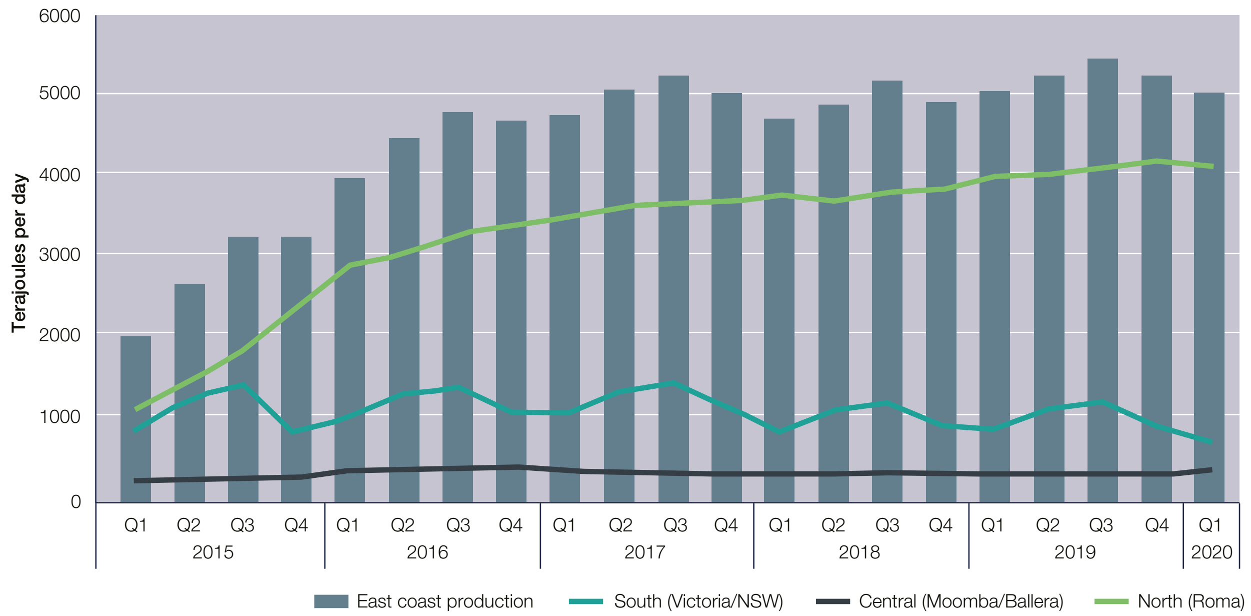
| | GAS PRODUCTION—12 MONTHS TO DECEMBER 2019 | | | 2P GAS RESERVES (FEBRUARY 2020) | |
|---|---|---|---|---|---|
| GAS BASIN | PETAJOULES | SHARE OF EASTERN AUSTRALIAN SUPPLY (%) | CHANGE FROM PREVIOUS YEAR (%) | PETAJOULES | SHARE OF EASTERN AUSTRALIA RESERVES (%) |
| Surat–Bowen (Queensland) | 1 485 | 75 | 7 | 31 706 | 86 |
| Cooper (South Australia – Queensland) | 91 | 5 | 4 | 1 102 | 3 |
| Gippsland (Victoria) | 262 | 13 | 4 | 2 481 | 7 |
| Otway (Victoria) | 60 | 3 | –11 | 644 | 2 |
| Bass (Victoria) | 11 | 1 | –31 | 175 | 0 |
| Sydney, Narrabri, Gunnedah (NSW) | 5 | 0 | –11 | 7 | 0 |
| Amadeus (Northern Territory) | 20 | 1 | 120 | 226 | 1 |
| Bonaparte (Northern Territory) | 51 | 3 | 24 | 734 | 2 |
| Eastern Australia total | 1 985 | | 6 | 37 076 | |
| Domestic gas sales | 645 | | 3 | | |
| LNG exports | 1 340 | | 8 | | |

2P, proven plus probable reserves estimated to be at least 50 per cent sure of successful commercial recovery.

Note: Totals may not add to 100 per cent due to rounding. Most production and reserves in the Surat–Bowen and NSW basins are coal seam gas. Production and 2P reserves in other basins are mainly conventional gas.

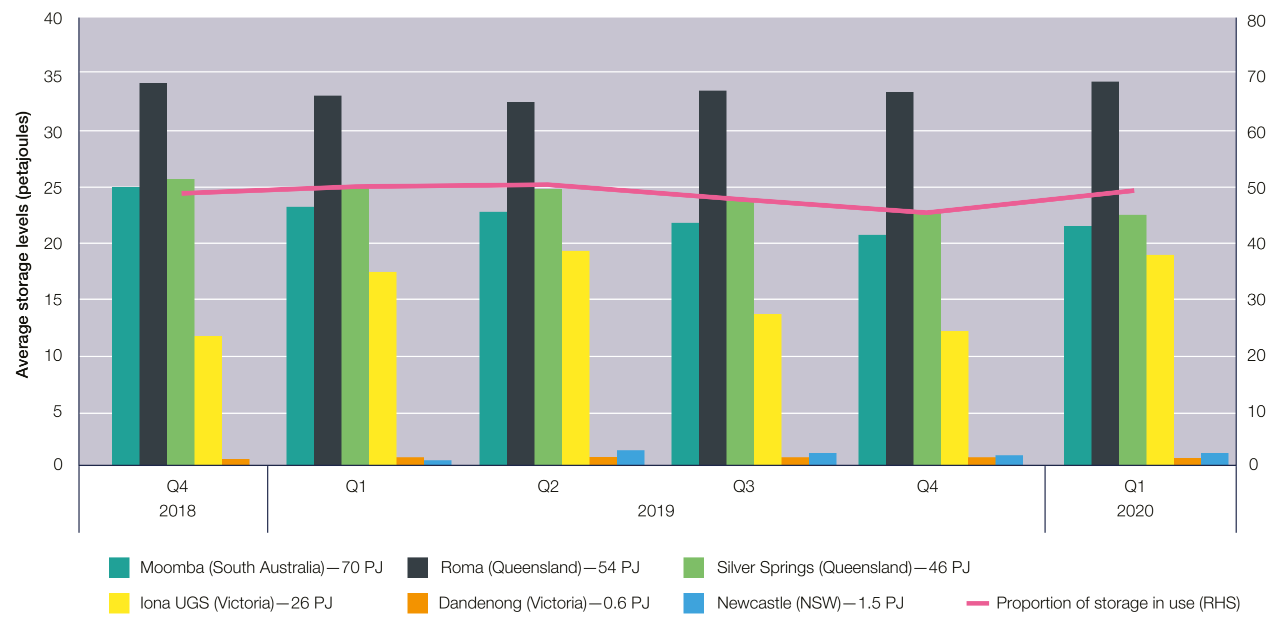
Source: EnergyQuest, *Energy quarterly*, March 2020.

Figure 4.5
**Eastern Australia gas production**




Source: AER analysis of Gas Bulletin Board data.

Figure 4.6
**Gas storage in eastern Australia**




Note: Petajoule (PJ) value next to each facility reflects nameplate capacity.

Source: AER analysis of Gas Bulletin Board data.

### 4.5.1 Changing basin profiles

Activity in all gas basins across eastern Australia has evolved to meet the needs of the LNG industry. Production from the Surat–Bowen Basin is mainly earmarked for export. But supply from other eastern Australian basins rose during the period 2015–17 to help LNG projects meet shortfalls in production, to meet their export contracts. This shift accelerated a depletion of gas reserves in southern basins. High production rates in Victoria also strained production plants, causing outages.

Following government intervention in 2017, LNG producers diverted more gas to the domestic market. In the year to June 2018, Surat–Bowen Basin production growth exceeded LNG export growth. As supplies from the north increased, southern basin production eased from the peaks recorded in 2017. In 2019 Surat–Bowen Basin production rose by 7 per cent, almost matching LNG export growth (8 per cent). As a result, production in southern basins held relatively steady.

## 4.6 Gas storage

Storage provides a means of conserving surplus gas production for quick delivery when needed. Gas can be stored in its natural state in depleted underground reservoirs and pipelines, or post liquefaction as LNG in purpose built facilities. Transmission pipelines can also provide gas storage services.

Eastern Australia's gas storage capacity includes:

- large facilities using depleted gas fields in Queensland, Victoria and South Australia
- smaller seasonal or peaking storage facilities located near demand centres—for example, the Newcastle LNG facility in NSW, and the Dandenong LNG facility in Victoria
- short term peak storage services on gas pipelines, which are mostly contracted by energy retailers. The Tasmanian Gas Pipeline, for example, stores gas that can be sold into the Victorian market at times of peak demand.

The importance of storage in managing supply and demand has risen since the LNG industry began operating. Storage levels at the Roma underground, Moomba and Silver Springs facilities have been consistently drawn down to meet LNG export demand. Against this trend, Roma underground storage levels increased from the start of 2019 (figure 4.6), possibly due in part to LNG plant outages during the year.

Large gas customers (particularly retailers) have secured their own storage capacity to manage supply risks. AGL commissioned an LNG storage facility at Newcastle in 2015, and contracted to use 50 per cent of the Iona underground storage facility's capacity from January 2021 to manage seasonal demand. In June 2018 Lochard Energy began to expand its Iona capacity, expecting this storage would help manage future peak demand periods.[19] During the third quarter of 2019, this expanded gas storage helped meet Victorian gas demand on peak winter demand days, especially when they coincided with high levels of gas demand for electricity generation.[20]

The ACCC in 2020 reported few investments to develop or expand storage capacity were on the table. It noted, however, Lochard Energy's expansion at Iona will continue until 2021, with a further expansion under consideration. Lochard Energy also purchased depleted shore reservoirs near Iona, which it could use for storage development. Further, the Golden Beach gas field in the Gippsland Basin may include a storage facility that could inject gas into the Victorian transmission system at Longford. Golden Beach Energy aims to supply its first gas to the market in the second half of 2021.[21]

## 4.7 Gas transmission pipelines

Wholesale customers buy capacity on transmission pipelines to transport their gas purchases to destination markets. Around 20 major transmission pipelines transport gas to the eastern gas market (key pipelines are listed in table 4.2, with routes shown in figure 4.1). Dozens of smaller pipelines fill out the transmission grid.

Historically, the eastern gas market's transmission system was a series of point-to-point pipelines, each transporting gas from a producing basin to a demand centre. Over time, the system evolved into an integrated network covering eastern and southern Australia. Many gas pipelines became bi-directional, and gas increasingly flows across multiple pipelines to reach its destination. These changes mean access to capacity on key pipelines is more important than ever.

Investment in transmission pipelines is expensive, and normally underwritten by foundation shippers through long term contracts. After its initial construction, a pipeline can be incrementally expanded to meet rising demand through compression, looping (duplication of parts of the pipeline) and extensions.

In recent years, significant transmission investment occurred to meet the needs of Queensland's LNG industry, which included expanding existing pipelines and constructing new pipelines to ship gas to LNG processing facilities. Among recent developments, the Roma North Pipeline and the Atlas Gas Pipeline were commissioned in 2019, and other pipelines are proposed to bring additional supply to the eastern markets. Additionally, Jemena's Northern Gas Pipeline (which began operations in January 2019) provides eastern Australia's first pipeline interconnection with the Northern Territory, making it possible to ship gas produced in the territory basins to eastern Australia.

The range of services provided by transmission pipelines is expanding to meet the needs of industry as the market evolves. Pipeline operators no longer simply transport gas from a supply source to a demand centre. Gas customers now seek more flexible arrangements such as bi-directional and backhaul shipping, and park and loan services.[22]

Transmission pipelines are separately owned from gas production companies. A gas customer must negotiate with a gas producer to buy gas, and separately contract with one or more pipeline businesses to get the gas delivered. This separation adds a layer of complexity to sourcing gas, especially for smaller customers (section 4.10.4).

### 4.7.1 Pipeline ownership

Australia's gas transmission sector is privately owned (table 4.2). The publicly listed APA Group is the largest player, with equity in 13 major pipelines, including key routes into Melbourne, Sydney, Brisbane and Darwin. Other major pipeline owners include Jemena and Singapore Power International.

Cheung Kong Infrastructure (CKI) in 2018 led a $13 billion takeover bid for APA Group. The ACCC did not oppose the proposed acquisition, on condition that CKI divest significant gas assets in Western Australia to address competition issues.[23] After consulting the Foreign Investment Review Board, the Australian Government blocked the bid on grounds the acquisition 'would be contrary to the national interest' because 'it would result in a single foreign company group having sole ownership and control over Australia's most significant gas transmission business'.[24]

19 The Hon. Daniel Andrews MP (Premier of Victoria), 'Securing gas for future winter warmth', Media release, June 2018.
20 AER, *Wholesale markets quarterly—Q3 2019*, November 2019.
21 ACCC, *Gas inquiry 2017–2025, Interim report, January 2020,* February 2020, pp. 93–4.

22 Pipelines with bi-directional flows can ship gas in both directions. Backhaul shipping is the 'virtual transport' of gas in a direction opposite to the main flow of gas. Parking gas is a way of temporarily storing gas in the pipeline by injecting more than is to be withdrawn. Loaning gas allows users to inject less gas into the pipeline than is to be withdrawn.
23 ACCC, 'ACCC will not oppose acquisition of APA', Media release, 12 September 2018.
24 The Hon. Josh Frydenberg MP (Treasurer), 'Final Decision on the proposed acquisition of APA', Media release, 20 November 2018.

**Table 4.2 Key gas transmission pipelines in eastern and northern Australia**

| PIPELINE | LOCATION | LENGTH (KM) | CAPACITY (TJ/DAY) | REGULATORY STATUS[1] | OWNER |
|---|---|---|---|---|---|
| Roma (Wallumbilla) to Brisbane | Qld | 438 | 211 (125 reverse) | Full regulation | APA Group |
| Queensland Gas Pipeline (Wallumbilla to Gladstone) | Qld | 627 | 140 (40 reverse) | Part 23 regulation | Jemena (State Grid Corporation 60%, Singapore Power International 40%) |
| South West Queensland Pipeline (Wallumbilla to Moomba) | Qld–SA | 937 | 404 (340 reverse) | Part 23 regulation | APA Group |
| Carpentaria Pipeline (South West Qld to Mount Isa) | Qld | 840 | 119 | Light regulation | APA Group |
| GLNG Pipeline (Surat–Bowen Basin to Gladstone) | Qld | 435 | 1430 | 15 year no coverage | Santos 30%, PETRONAS 27.5%, Total 27.5%, KOGAS 15% |
| Wallumbilla Gladstone Pipeline | Qld | 334 | 1588 | Part 23 regulation and 15 year no coverage | APA Group |
| APLNG Pipeline (Surat–Bowen Basin to Gladstone) | Qld | 530 | 1560 | 15 year no coverage | Origin Energy 37.5%, ConocoPhillips 37.5%, Sinopec 25% |
| Moomba to Sydney Pipeline | SA–NSW | 2 029 | 489 (120 reverse) | Partial light regulation / partial Part 23 Regulation[2] | APA Group |
| Moomba to Adelaide Pipeline | SA | 1 184 | 241 (85 reverse) | Part 23 regulation | QIC Global Infrastructure |
| Eastern Gas Pipeline (Longford to Sydney) | Vic–NSW | 797 | 358 | Part 23 regulation | Jemena (State Grid Corporation 60%, Singapore Power International 40%) |
| Vic–NSW Interconnect | Vic–NSW | | 223 | Part 23 regulation | Jemena (State Grid Corporation 60%, Singapore Power International 40%) |
| SEA Gas Pipeline (Port Campbell to Adelaide) | Vic–SA | 680 | 314 | Part 23 regulation | APA Group 50%, Retail Employees Superannuation Trust 50% |
| Tasmanian Gas Pipeline (Longford to Hobart) | Vic–Tas | 734 | 129 (120 reverse) | Part 23 regulation | Palisade Investment Partners |
| Victorian Transmission System (GasNet) | Vic | 2 035 | 1030 | Full regulation | APA Group |
| Nothern Gas Pipeline (Tennant Creek to Mount Isa) | NT–Qld | 622 | 90 | Part 23 regulation | Jemena (State Grid Corporation 60%, Singapore Power International 40%) |
| Bonaparte Pipeline | NT | 287 | 80 | Part 23 exemption | Energy Infrastructure Investments (APA Group 19.9%, Marubeni 49.9%, Osaka Gas 30.2%) |
| Amadeus Gas Pipeline | NT | 1 658 | 120 | Full regulation | APA Group |

km, kilometres; TJ/day, terajoules per day.

1. *Full regulation pipelines* have their prices assessed by the AER. *Light regulation pipelines* do not have their prices assessed by the AER, but parties can seek arbitration to address a dispute. *Part 23 pipelines* are subject to information disclosure and arbitration provisions. *Exempt pipelines* are subject to no economic regulation. Chapter 5 outlines the various tiers of regulation.
2. The Moomba to Sydney Pipeline is subject to Part 23 regulation only from Moomba to Marsden. Light regulation applies to the remainder of the pipeline.

Source: AER; ACCC, interim reports of gas inquiry 2017–2025; corporate websites; Gas Bulletin Board (www.gasbb.com.au).

## 4.8 Gas imports

In early 2020 four LNG import terminals projects were under consideration in NSW, Victoria and South Australia. The intention is to resolve a forecast shortfall in gas supply in the southern states from winter 2024. While some of the facilities were to be operational from as early as 2020, all projects have slipped from their original timeframes because planning, environmental and other challenges have delayed their development.

The LNG import projects include:

- AGL's proposed floating terminal at Crib Point (Victoria), scheduled to begin delivering gas in early 2022[25]
- a proposed terminal at Port Kembla (NSW) by a consortium that includes Squadron Energy and JERA, scheduled to commence operations in the first half of 2021.[26] The terminal received planning approval from the NSW Government in April 2019,[27] and EnergyAustralia later signed as a foundation customer.[28]
- Venice Energy's proposed terminal at Port Adelaide, scheduled to launch by the end of 2021[29]
- Newcastle GasDock, proposed by Energy Projects and Infrastructure Korea, scheduled to commence operations in the first half of 2021.[30] The NSW Government in August 2019 designated the project as critical significant infrastructure.[31]

At March 2020 final investment decisions had not been made for any of the four LNG import projects. A fifth project backed by ExxonMobil was abandoned in December 2019.

## 4.9 Contract and spot gas markets

Wholesale gas is traded in two distinct types of market. A majority of gas sales in eastern Australia are struck under confidential bilateral contracts. Around 10–20 per cent is traded in spot markets, with the variation reflecting differences between those markets.[32]

25 AGL, 'AGL Gas Import Jetty Project', web page, available at: www.agl.com.au/about-agl/how-we-source-energy/gas-import-project.
26 ACCC, *Gas inquiry 2017–2025, Interim report, January 2020*. February 2020, p. 29.
27 NSW Government, 'Port Kembla gas terminal approved', Media release, April 2019.
28 AIE and EnergyAustralia, 'AIE welcomes foundational customer EnergyAustralia', Media release. May 2019.
29 *Australian Financial Review*, 'SA LNG import project delayed, but still "in the game"', 11 December 2019.
30 ACCC, *Gas inquiry 2017–2025, Interim report, January 2020*, February 2020, p. 29.
31 NSW Government, 'Newcastle gas terminal given critical status', Media release, August 2019.

### 4.9.1 Contract markets

Gas contracts (also known as gas supply agreements) are wholesale supply deals negotiated between sellers and buyers. In contract markets, the two main levels of supply offers are:

- offers by gas producers to very large customers such as major energy retailers and gas powered generators
- offers by retailers and aggregators that buy gas from producers and on-sell it to commercial and industrial (C&I) customers. Prices quoted to C&I customers tend to be higher than those quoted to very large customers, partly to cover the aggregator's margins. But the ACCC found prices to C&I customers have been unreasonably high at times (section 4.11.1).

Gas contracts traditionally locked in prices and other terms and conditions for several years. More recently, the industry shifted towards shorter term contracts with review provisions. The ACCC reported in 2018 that recent contract offers favoured durations of either one or two years. Between January 2017 and April 2018 over 70 per cent of offers from producers and over 55 per cent of wholesale offers from retailers to supply gas in 2019 were part of contracts with a duration of two years or less.[33]

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 what is available to smaller players. This imbalance favours large incumbents in price negotiations.

Until recently, no accurate and useful indicative wholesale price was readily available to the market. In response, the ACCC in 2018 began publishing gas price data as part of its 2017–25 gas inquiry (section 4.14.1).

### 4.9.2 Spot markets

While most gas is traded under confidential contracts, spot markets allow wholesale customers to trade gas without entering long term contracts. Spot market trading can be a useful mechanism for participants to manage imbalances in their contract positions.

32 AER, *Wholesale markets quarterly—Q4 2019*. February 2020.
33 ACCC, *Gas inquiry 2017–2020, Interim report*, *July 2018*, August 2018, pp. 24, 49.



Three separate spot markets operate in eastern Australia. The oldest of the three is *Victoria's declared wholesale gas market*, established in 1999. A *short term trading market* for gas was launched in 2010, with hubs in Sydney, Brisbane and Adelaide. More recently, *gas supply hubs* launched in 2014 at Wallumbilla, Queensland, and in 2016 at Moomba, South Australia.

The three spot markets operate under different rules, follow different procedures, do not interact with each other, and have different purposes. The Australian Energy Market Commission (AEMC) in June 2017 found having multiple market designs inhibits trading between regions, increases complexity, and imposes transaction costs. It recommended the markets transition in the longer term to a single market design, based on the gas supply hub model.[34] As a first step, the gas day start times were harmonised for all east coast markets in 2019 (section 4.14.3). Progress towards harmonising the markets is otherwise slow.

An information platform—the Gas Bulletin Board—was launched in 2008 to provide transparency about gas market conditions and encourage participation in the spot markets. The following sections explain the workings of each spot market and the bulletin board. Section 4.11.2 outlines price trends in the markets.

### 4.9.3 Gas supply hubs at Wallumbilla and Moomba

AEMO launched the gas supply hub model at Wallumbilla, Queensland, in 2014. Wallumbilla is a major pipeline junction linking gas basins and markets in eastern Australia (figure 4.7). Three critical pipelines—the South West Queensland, Roma to Brisbane, and Queensland Gas pipelines—connect, along with several smaller transmission pipelines, with or near the hub. The diversity of supply options, contract positions, and participants around Wallumbilla create a natural point of trade.

The gas supply hub takes the form of an electronic trading platform. Participation is voluntary. Gas producers (including LNG producers), large retailers, gas powered generators, large industrial users and traders are among the participants. Gentailers (combined generation and retail businesses) and gas powered generators were among the most active participants in 2019. Activity by traders (including brokers and investors) rose to 12 per cent on average in 2019, up from 7 per cent in 2018.[35]

There were 16 active participants in the hub by the end of 2019, including two new participants. The trades are split across a range of product types (such as intra-day, day-ahead, weekly and monthly), and they can be on-screen (traded through the anonymous exchange) or off-screen (bilateral trades settled through the exchange).[36] Purely bilateral off-market trades are not reported to the hub.

In 2019 all 16 participants traded off-screen, but only 13 participated in *active* on-screen trading.[37] On average, participants executed over 300 trades per month in 2019, more than double the rate in 2018.

LNG producers are the largest suppliers of gas into the hub, 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 hub can currently absorb.[38]

The gas supply hub brokerage model allows buyers and sellers to place anonymous offers or bids for quantities of gas at nominated prices, which can be a matched on the exchange to make trades. Each price struck is unique to a particular trade. That is, no market clearing price applies to all participants.

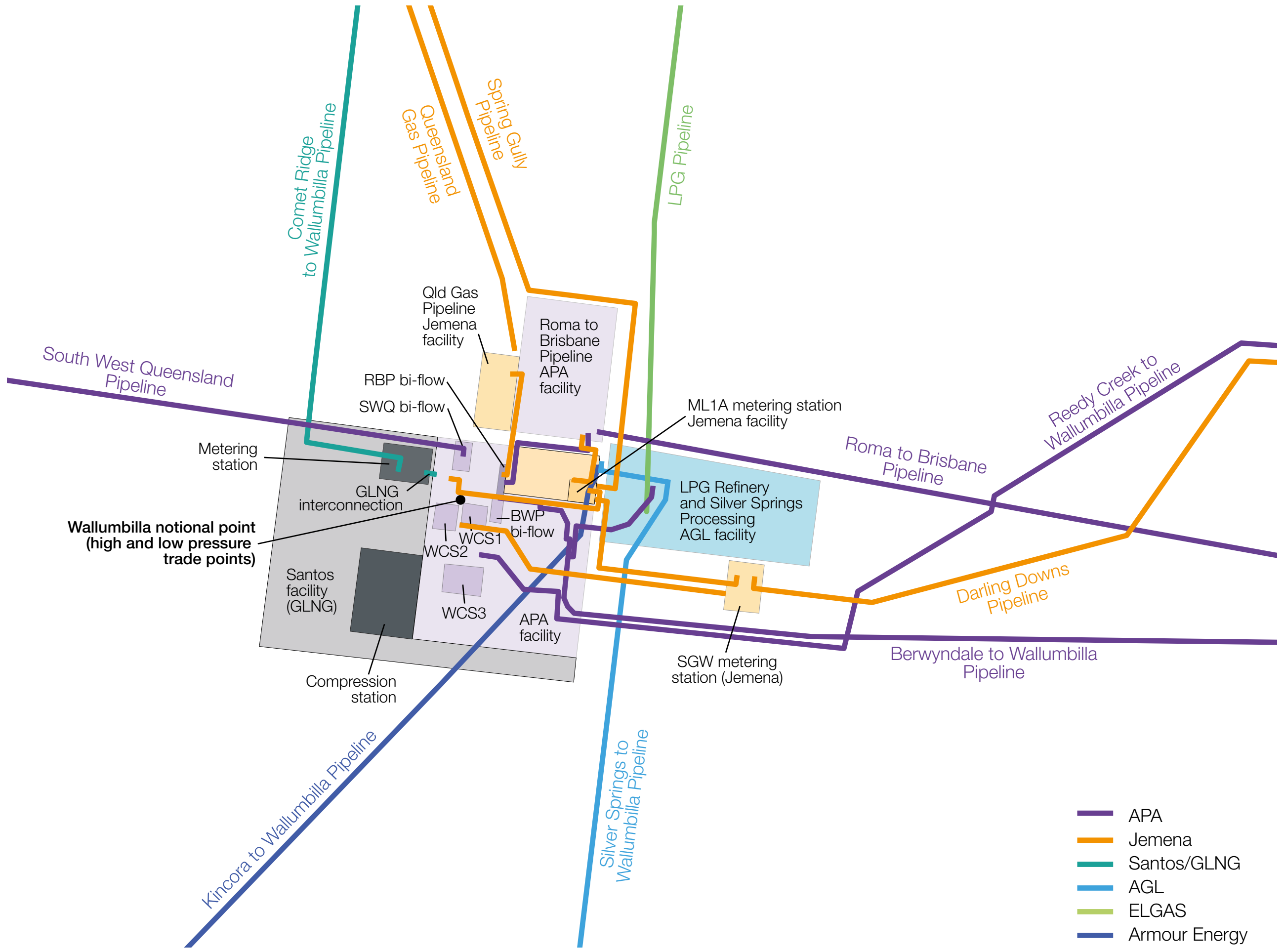
As in the other spot markets, the gas supply hub complements bilateral contracts rather than replaces them. But it allows participants to trade gas up to several months in advance of physical supply, rather than only on a daily basis as in the other markets.

Until 2017 separate prices were set at three major delivery points—the South West Queensland, Roma to Brisbane, and Queensland Gas pipelines. But splitting trade across three locations hampered liquidity and trading. Additionally, participants needed access to the transmission pipelines serving the hub, to move gas between those three points. This access proved problematic because, while all the pipelines connect with the hub, they do not all physically interconnect with one another.

In March 2017 AEMO replaced the hub's three trading locations with a single Wallumbilla product that groups all delivery points. A single trading location improves liquidity by making it easier for participants to trade across different pipelines, thus pooling potential buyers and sellers into a single market. A separate south east Queensland product

34 AEMC, *Review of the Victorian declared wholesale gas market—final report*, Factsheet, June 2017.
35 AER, *Wholesale markets quarterly—Q3 2019*. November 2019.
36 AER, 'Wholesale statistics', web page, available at: www.aer.gov.au/wholesale-markets/ wholesale-statistics.
37 An 'active' participant is one that completes at least 12 trades per year.
38 AER market intelligence.

**Figure 4.7**
**Wallumbilla hub**




Source: AER, accounting for consultations with APA Group and public information supplied by APA Group, Santos, AGL, the Queensland Government, Geoscience Australia and AEMO.

was also launched, which provides virtual delivery within the Roma to Brisbane Pipeline.

Despite these reforms, significant gas trading around Wallumbilla occurs bilaterally and off-market to avoid the pipeline costs of transporting gas to Wallumbilla. Participants also sometimes arrange downstream delivery points to avoid these costs.

Some participants have suggested a preference for off-screen trading, which allows them to use brokers to match trades on their behalf, or leverage their existing bilateral arrangements to facilitate spot trades.[39] Such trades can be negotiated directly over the phone and then lodged through the hub for settlement. In this way, transactions can be accelerated if on-screen bids and offers do not match.

However, new entrant participants are unable to enjoy these benefits to the same degree, because they do not have legacy arrangements. These participants are more likely to rely on the anonymous on-screen trading platform.

39 Two participants with a legacy arrangement can draw on it to quickly organise an off-screen trade, because the agreement between them is already set up. Participants without such agreements need to set up contract arrangements to process deals in the same way.



#### Wallumbilla hub activity

Trade at Wallumbilla has progressively increased since its launch in 2014. The LNG projects use the hub from time to time to manage variations in production and LNG plant performance. Gas powered generators are also significant users of the hub.

In 2019 liquidity at the Wallumbilla hub improved as it experienced significant growth and change. Traded volumes for 2019 were more than twice the volumes in 2017, primarily off the back of significant increases in gas traded off-screen (figure 4.8). Notably, off-screen products tend to involve larger volumes of gas than do on-screen alternatives. Also, in 2019 more participants were active off-screen than on-screen for the first time. There was also a shift in product preferences in 2019, with significant increases in the volume of gas traded through day-ahead and balance-of-day products.

Part of this growth may reflect new arrangements to auction underused pipeline capacity, which increases access to key pipeline routes such as the often congested South West Queensland Pipeline (section 4.10.4). Despite this growth, however, gas traded through the Wallumbilla hub represents only a small share of total gas traded, because many participants continue to favour bilateral arrangements. In 2019 gas traded through the Wallumbilla hub accounted for 9.1 per cent of total gas flows through pipelines in the Wallumbilla bulletin board zone.[40]

#### Moomba hub activity

AEMO launched a second gas supply hub at Moomba in central Australia in June 2016. Similar to Wallumbilla, Moomba is a major junction in the gas supply chain serving eastern Australia. Trade at Moomba has been slow to develop. While there have been offers and bids for gas at Moomba, fewer transactions have occurred there, compared with Wallumbilla.

The first trade was executed in September 2017, with 141 trades executed in 2019. Interestingly, trades at the Moomba location increased markedly from the second quarter of 2019. In particular, the number of day-ahead products greatly increased. As with trades at Wallumbilla, this increase may reflect the introduction of the pipeline capacity trading reforms (section 4.10.4).

40 AER, *Wholesale markets quarterly—Q4 2019*, February 2020.

### 4.9.4 Short term trading market

A short term trading market for gas operates at three locations in eastern Australia—Sydney, Adelaide and Brisbane. AEMO operates the market, which launched in 2010. The market has a floor price of $0 per gigajoule (GJ) and a cap of $400 per GJ. Each market is scheduled and settled separately, but all three operate under the same rules (box 4.2).

Prices are volatile, reflecting short term shifts in supply and demand, including conditions in LNG export markets. Given its responsiveness to short term conditions, the market is not necessarily indicative of prices that would be struck under contracts. No ASX derivatives market has developed for the short term trading market.

In 2019 around 30 participants traded in the Sydney market, while the Adelaide and Brisbane markets each had around 15 participants. The participants included energy retailers, power generators, large industrial gas users, and traders. The markets are particularly useful for gas powered generators, because the generators can source gas at short notice when electricity demand is high (and offload surplus gas if electricity demand is low).

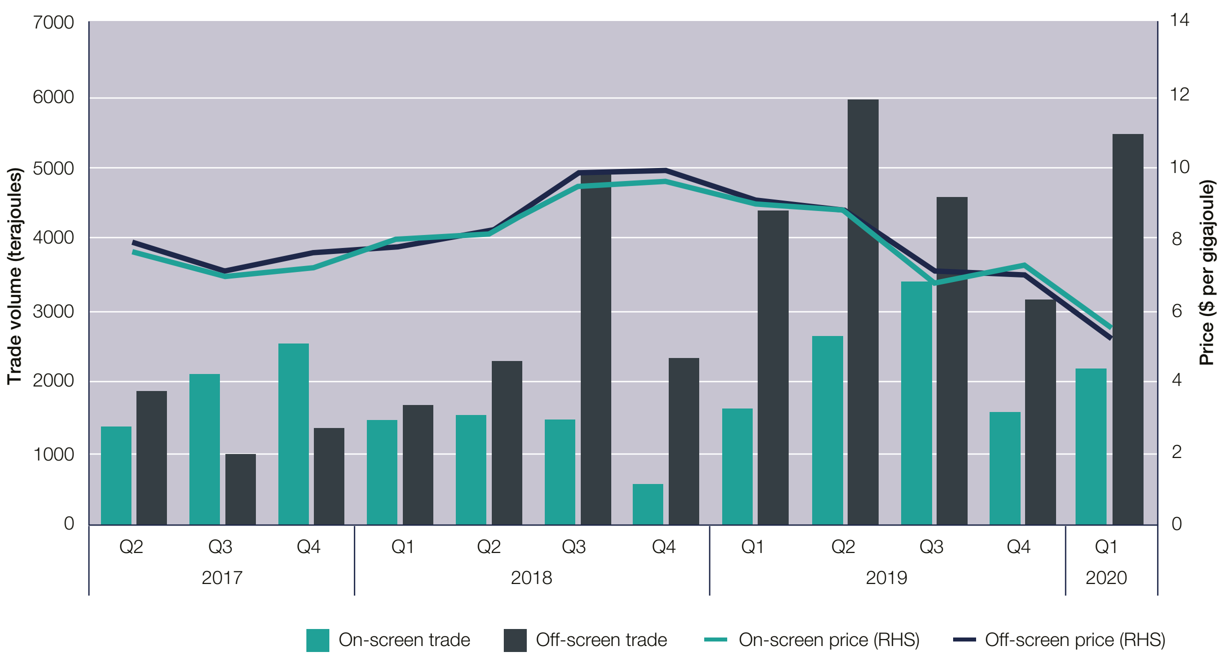
Shippers deliver gas for sale into the market, and users buy the gas for delivery to energy customers. Many participants operate both as shippers and users, but in effect trade only their net positions—that is, the difference between their scheduled gas deliveries into and out of the market. In the fourth quarter of 2019, gas traded through the short term trading market met around 20 per cent of demand in Sydney, more than 22 per cent in Adelaide, and around 8 per cent in Brisbane.[41]

Traded volumes at the Sydney market were 54 per cent higher in 2019 than in 2018, and 17 per cent higher at the Brisbane market. Volumes at the Adelaide market fell by 11 per cent across the same period. Trading profiles varied across the markets. Benefiting from increased participation, all markets experienced less concentration across the top three sellers from 2018 to 2019 (figure 4.9). Concentration among the top three buyers increased in the Sydney and Adelaide markets for the same period.

In 2018 the ACCC reported evidence of C&I customers engaging more heavily in the short term trading market to manage their gas supply, with some users switching to the market to cover their entire demand. Those who switched found they were generally ahead (in pricing terms) of where they would have been with contracts offered to them in 2017 for 2018 supply. More generally, customers

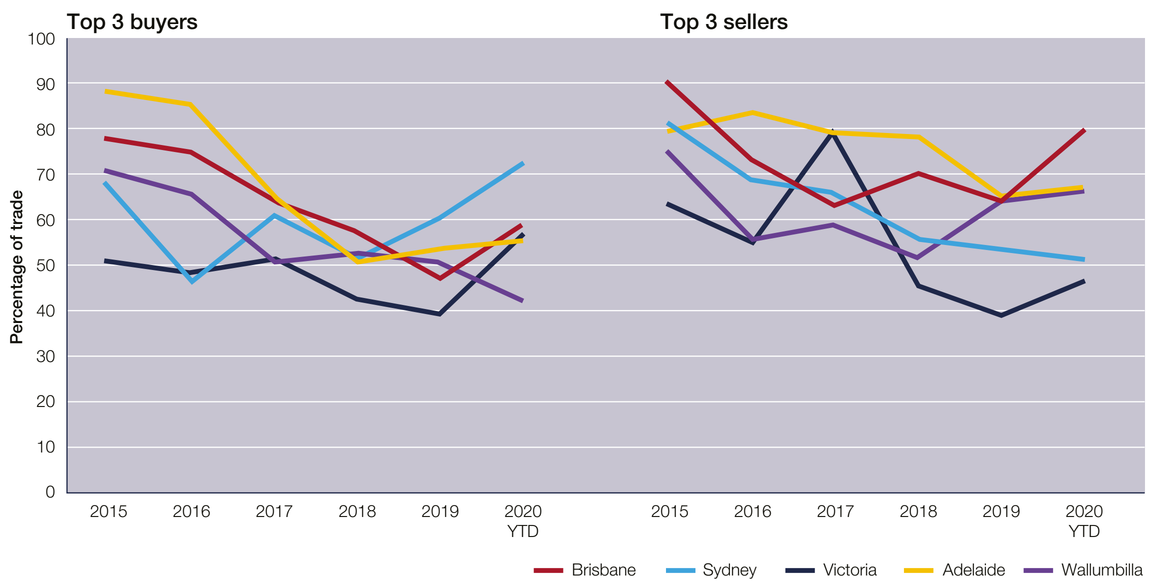
41 AER, *Wholesale markets quarterly—Q4 2019*, February 2020.

Figure 4.8
Gas supply hub—on-screen and off-screen price and volume




Source: AER analysis of gas supply hub data.

Figure 4.9
Top three buyers and sellers in eastern Australian gas markets




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



### Box 4.2 How the short term trading market works

The short term trading market allows gas trading on a day-ahead basis. The Australian Energy Market Operator (AEMO) sets a day-ahead clearing price at each hub, based on scheduled withdrawals and offers by shippers to deliver gas. All gas supplied according to the schedule is settled at this price. The market provides incentives for participants to keep to their schedules, and the rules oblige participants to bid in 'good faith'. Pipeline operators schedule flows to supply the necessary quantities of gas to each hub. As gas requirements become better known closer to the time of delivery, shippers may renominate quantities with pipeline operators (depending on the terms of their contracts).

If gas deliveries and/or withdrawals from a hub do not match the day-ahead nominations, then AEMO procures balancing gas—called market operator services (MOS)—to meet any shortfalls. Conversely, it procures storage on transmission pipelines with capacity to manage an oversupply. Participants make offers to supply MOS, which AEMO calls on in order of lowest to highest price when balancing gas is needed. The parties causing the imbalances mainly pay for the gas procured under this mechanism. The Australian Energy Regulator (AER) has reported instances of abnormally high MOS payments in parts of the market, resulting in some investigations.[a]

a AER, *State of the energy market 2017*, 2018, p. 76.

found participating in the short term market improved their negotiating power in the contract market, enabling them to wait for a suitable contract offer rather than accepting an unsatisfactory one.[42]

### 4.9.5 Victoria's declared gas market

Victoria launched Australia's first spot gas market—the declared wholesale gas market—in 1999, partly to help manage flows on the Victorian Transmission System. Participants submit daily bids ranging from $0 per GJ (the floor price) to $800 per GJ (the price cap). At the beginning of each day, AEMO selects the least cost bids needed to match demand. This process establishes a clearing price. In common with the short term trading market, only net positions are traded. AEMO can schedule additional gas injections (typically LNG from storage facilities) at above market price to alleviate short term transmission constraints.

The market's participants include energy retailers, power generators and other large gas users, and traders. The AEMC reported smaller retailers and new entrants to the gas market tend to favour the spot market for sourcing gas, given the spot market's flexibility and relatively low transaction costs.[43]

As in the short term trading market, participants primarily use the market to manage imbalances in their forecast supply and demand schedules, and prices reflect day-to-day fluctuations in supply and demand. No gas producer currently uses the market as a major outlet for their supply.

Over 30 participants traded in the Victorian market in 2019. As volumes traded in the Victorian market rose in 2019 (up 65 per cent), trading concentration among the top three buyers and sellers continued to fall (figure 4.9). In 2019 the top three sellers accounted for around 40 per cent of total trade volume, down from nearly 80 per cent in 2017.

A small futures market has developed for the Victorian market, with the ASX launching a Victorian gas future product in 2013. But, there was little trade until mid-2018. Since the start of 2019, activity and trade volumes have increased significantly. Ultimately, this increase still accounts for only a small proportion (around 5 per cent or less) of the total volume traded in the market. However, increasing levels of open interest and increased spot trading in short term markets are encouraging signs.

The Victorian market differs from the short term trading market in a number of ways:

- In the short term trading market, AEMO operates the financial market but does not manage physical balancing (which remains the responsibility of pipeline operators). In the Victorian market, AEMO undertakes both roles.
- The short term trading market is for gas only, while prices in the Victorian market cover gas as well as transmission pipeline delivery to the hub.

42 ACCC, *Gas inquiry 2017–2020, Interim report, July 2018*, August 2018.
43 AEMC, *Final report: biennial review into liquidity in wholesale gas and pipeline trading markets*, August 2018, p. 14.

### 4.9.6 Gas Bulletin Board

The Gas Bulletin Board (www.gasbb.com.au) is an open access website providing current information on gas production, storage and transmission pipelines in eastern Australia. Market participants—gas producers, pipeline businesses and storage providers—supply the information to AEMO, which then publishes it. The AER monitors participants' compliance with their obligations to submit accurate data, acting when necessary to enforce compliance.

The bulletin board plays an important role in making the gas market more transparent, especially for smaller players who may not otherwise be able to access day-to-day information on demand and supply conditions. It supplies information such as:

- pipeline capabilities (maximum daily flow quantities, including bi-directional flows), pipeline and storage capacity outlooks, and nominated and actual gas flow quantities
- daily production capabilities and capacity outlooks for production facilities
- gas stored, gas storage capacity (maximum daily withdrawal and holding capacities), and actual injections/withdrawals.

The bulletin board includes an interactive map showing gas plant capacity and production data, and gas pipeline capacity and flow at any point in a network.

The bulletin board's coverage has progressively widened. Significant reforms in 2018 removed reporting exemptions, mandated greater detail for covered facilities, and lowered the reporting threshold to encompass smaller facilities (section 4.14.1). To encourage compliance, the reforms made reporting obligations subject to civil penalties. Reporting obligations were also extended to gas facility operators in the Northern Territory, following the territory's connection to the eastern gas grid in January 2019.

## 4.10 State of the eastern gas market

The development of Queensland's LNG export industry placed significant pressure on the eastern gas market. The pressure, combined with other factors such as state based moratoriums on gas development, tightened the supply–demand balance. This tightening led to increases in wholesale gas prices across 2017–18 as international gas prices began to bear on domestic gas prices. However, in 2019 the price pressure showed signs of easing.

Gas production in the northern states rose to record levels in 2019, peaking in October. However, agreements between gas producers and the Australian Government required this additional uncontracted gas to be offered to the domestic market on competitive terms before being offered for export. This requirement—along with a sharp fall in Asian LNG prices, increased participation in the eastern market, and reforms to improve access to critical pipelines—contributed to prices falling across the year and into early 2020.

### 4.10.1 Supply conditions

While a majority of eastern Australia's gas reserves are located in Queensland's Surat–Bowen Basin, those reserves are largely committed to the LNG export industry. Gas production in Queensland reached record levels in 2019, averaging just over 4000 TJ per day, as LNG projects ramped up production to meet record export demand.

Queensland's LNG projects originally planned to source their gas requirements from their own (newly developed) reserves in the Surat–Bowen Basin. But the development of gas wells by Santos's GLNG project was slower than expected. To meet its LNG supply contracts, therefore, Santos sourced substantial volumes of gas from other producers, diverting gas from the domestic market.

The tightening supply–demand balance following the commencement of LNG exports led to concerns in 2017 that gas production may not be sufficient to meet domestic demand. In response, the Australian Government threatened to instruct LNG producers to supply more gas to the domestic market. The Australian Domestic Gas Security Mechanism empowers the Energy Minister to require LNG projects to limit exports or find offsetting sources of new gas if a supply shortfall is likely (section 4.13.1).

To avoid export controls, Queensland's LNG producers entered a Heads of Agreement with the Australian Government in October 2017, and a second agreement in September 2018. Under the agreements, they commit to offer uncontracted gas to domestic buyers on competitive terms before offering it for export.

The LNG projects use various methods to sell more gas domestically, including: selling short term gas on the Wallumbilla Gas Supply Hub; launching expression of interest (EOI) processes for customers for long term gas contracts; and entering bilateral arrangements for short term and long term gas contracts. APLNG in 2019, for example, entered new supply agreements with gas powered generators and other large domestic customers.[44]

44 Australia Pacific LNG, 'Australia Pacific LNG delivers new gas supplies to domestic manufacturers', Media release, 4 July 2019; Australia Pacific LNG, 'Australia Pacific LNG continues strong support of domestic gas market', Media release, 26 September 2019.



More recently, gas supply concerns have eased. The ACCC forecast eastern Australia gas supply in 2020 to reach 2025 PJ—around 200 PJ *above* its forecast for domestic and LNG demand.[45] Production by LNG projects above their contractual commitments accounted for around 140 PJ of this forecast surplus.

Despite improved forecasts in the short run, the longer term outlook is uncertain. AEMO forecast that supply gaps could emerge by 2024, as Victorian production wanes.[46] Both AEMO and the ACCC suggested more exploration and development in southern Australia, pipeline expansions and/or LNG imports could mitigate the supply risks.

Long term supply conditions are uncertain for a number of reasons. First, some developed resources may underperform, and southern production may decline faster than expected.

Second, forecasts make assumptions about undeveloped gas fields with uncertain reserves. These assumptions are increasingly unreliable, as the long term security of supply for the east coast increasingly depends on more speculative sources of supply. That is, 75 per cent of 2C resources in early 2020 were located in fields that were not yet in production or approved for development, and some 2P reserves and resources in Queensland have been written down.[47,48] While some development proposals in eastern Australia show promising signs, others face significant regulatory hurdles linked to environmental concerns.

In response to this ongoing supply uncertainty, the Australian Government and some state governments launched initiatives to encourage new projects to supply the domestic market (section 4.13).

**Supply conditions in the northern region**

Gas supply to the northern gas market is largely supplied from Queensland's Surat-Bowen Basin. But gas is also sourced from the Cooper Basin in South Australia and, since 2019, from the Northern Territory (via the Northern Gas Pipeline). At times, southern gas is also transported north to meet LNG export demand.

Gas production in the Surat–Bowen Basin rose exponentially from 2014 to 2017 to meet the demands of Queensland's LNG export industry. While production continued to rise, this growth tended to level out once all LNG projects reached full operation.

Despite this levelling out, Queensland production in 2019 rose to record levels of just over 4000 TJ per day. In the fourth quarter of 2019, Queensland facilities produced 4126 TJ of gas per day, compared with 3762 TJ per day in the fourth quarter of 2018. This production growth coincided with Queensland LNG exports reaching record levels (section 4.10.2). High Asian LNG prices in late 2018—when production decisions were likely made—meant record production occurred despite Asian LNG prices in 2019 being significantly lower than those in 2017 or 2018.[49]

Supply conditions also depend on the availability of transmission pipeline capacity to transport gas to customers. Improving this availability, new transmission capacity began operating in 2019:

- Jemena's Northern Gas Pipeline provides eastern Australia's first pipeline interconnection with the Northern Territory, allowing gas from territory basins to reach eastern Australia. The pipeline on average delivered over 65 TJ per day to the eastern market in 2019.[50] Jemena is assessing a proposed expansion of the Northern Gas Pipeline and has committed to develop further pipelines in northern Queensland. This commitment by Jemena includes connecting its Queensland Gas Pipeline to the Galilee Basin, which would bring further supply to the market.[51]
- The Roma North Pipeline and the Atlas Gas Pipeline were commissioned. Senex's Atlas project is dedicated entirely to supply the domestic market, under Queensland Government initiatives to improve supply to industrial customers.[52]

**New entry**

In 2018 and 2019 the number of suppliers in the eastern market rose, and producers such as Shell Energy Australia expanded their presence.[53] Also, the growth of retailers and aggregators in downstream spot gas markets disrupted dominant players and provided C&I customers with competitive alternative sources of gas.

45 ACCC, *Gas inquiry 2017–2025, Interim report*, *January 2020,* February 2020, p. 27. Based on forecast production from 2P reserves.
46 AEMO, *2020 gas statement of opportunities*. March 2020, p. 44.
47 2C resources represent the best estimate of contingent gas reserves, which are not yet technically or commercially recoverable.
48 Queensland reserves were downgraded (on a net basis) by more than 4400 PJ between 1 July 2017 and 30 June 2019. See ACCC, *Gas inquiry 2017–2025, Interim report*, *January 2020,* February 2020.

49 AER, *Wholesale markets quarterly—Q4 2019*, February 2020.
50 National Gas Bulletin Board data.
51 Jemena, 'Proposed route for the Galilee Gas Pipeline revealed', Media release, 30 July 2019.
52 Senex, available at: www.senexenergy.com.au/operations/surat-basin-gas/project-atlas/.
53 AER, *Wholesale markets quarterly—Q4 2019*, February 2020, p. 22.

Additionally, five new projects are expected to commence operations in Queensland over the next four years. The operators of these projects include APLNG, Arrow Energy, Comet Ridge and Senex. As a result, supply options to C&I gas users appear to be improving.

### Supply conditions in the southern region

The Victorian gas basins and the Cooper Basin in central Australia remain pivotal to meeting domestic gas demand in southern Australia. Cooper Basin gas is largely committed to the LNG operators, but contributes to southern supply through swap agreements with independent gas producers in Queensland.[54] It is uncertain whether these agreements will continue beyond 2020.

Production in Gippsland is transitioning from old to new fields, but it is not yet clear how much the new gas fields can produce. After achieving record production levels in 2017, production from the Longford plant servicing the Gippsland Basin fell. The plant is becoming less reliable because it is run harder for longer, and plant constraints and maintenance outages increasingly disrupt production.

AEMO reported a short term increase in Victorian production forecasts as a number of projects reached financial investment decision. Yet, forecasts remain significantly below 2017 levels, and are expected to fall further as some key fields cease production in 2023 and 2024.[55]

Cooper Energy's Sole project in the Gippsland Basin, initially scheduled for commissioning in 2019, began commercial operation in March 2020. The project is the first new production well drilled in offshore Victoria since 2012, and is expected to produce around 25 PJ per year. Another project, the West Barracouta joint venture between Esso Australia and BHP Billiton, achieved final investment decision in late 2018, and is scheduled to be operational by 2021.

While these and other projects should provide additional supply into the southern region, the scope to increase production in the short to medium term is limited, and AEMO still identified a potential gas shortfall from 2024.[56]

### 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.[57] Victoria, South Australia, Tasmania, Western Australia and the Northern Territory have onshore fracking bans in place, with varying degrees of coverage:

- In 2017 the Victorian Government banned onshore hydraulic fracking, and exploration for and mining of CSG or any onshore petroleum until 30 June 2020.[58] While maintaining its ban on onshore exploration, the government in May 2018 announced the release of oil and gas acreage in the Otway Basin for exploration and development, including potential drilling from onshore, subject to regulatory approvals.[59] In March 2020 the government committed the ban on fracking and CSG exploration to the Victorian Constitution, but announced onshore conventional gas exploration could recommence from July 2021.[60]
- South Australia in 2018 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. Unconventional gas extraction is, however, 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.
- The Northern Territory in 2018 made 51 per cent of the territory eligible for hydraulic fracturing. The decision covers much of the Beetaloo Basin, which holds most of the territory's shale gas resources.

Queensland does not restrict fracking. NSW has no outright ban on onshore exploration, but significant regulatory hurdles have stalled development proposals. Regulatory restrictions include exclusion zones, a gateway process to protect 'biophysical strategic agricultural land', an extensive aquifer interference policy, and a ban on certain chemicals and evaporation ponds.[61] 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.[62] 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.[63]

54 A domestic gas retailer also acquires some Cooper Basin gas.
55 AEMO, *Victorian gas planning report update,* March 2020, pp. 4–5.
56 AEMO, *2020 Gas statement of opportunities*, March 2020, p. 8.

57 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.
58 Department of Economic Development, Jobs, Transport and Resources (Victoria), *Onshore gas community information*, August 2017.
59 Department of Industry, Innovation and Science, *The 2018 offshore petroleum exploration acreage release*, available at: www.petroleum-acreage. gov.au/.
60 Premier of Victoria, 'Backing the science, protecting farmers and boosting jobs', Media release, 17 March 2020.

## 4.10.2 Demand conditions

Historically, demand for eastern Australian gas derives from three main domestic sources—C&I gas users, gas powered generators and residential customers. However, with the launch of LNG exports in 2015, international customers became a new source of demand competing to buy eastern Australian gas (figure 4.10).

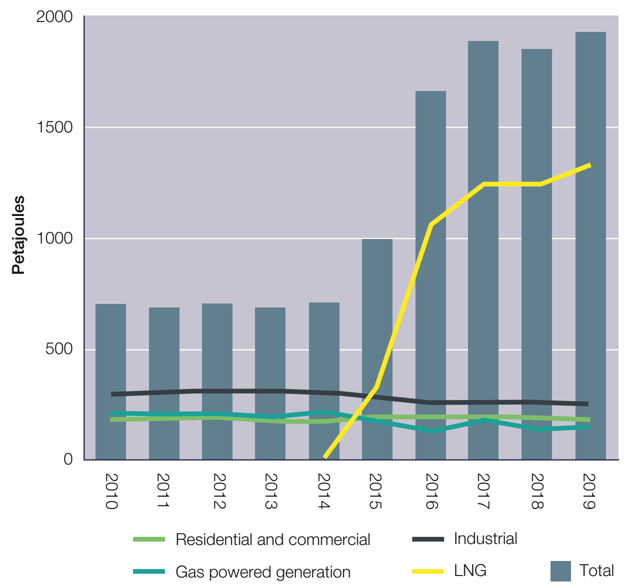
### Domestic gas use

Higher gas prices have weakened gas demand by industrial customers since 2014. In 2019 the closure of Remapak in Sydney and Claypave in Brisbane were linked to high gas prices.[64] Separately, AEMO reported consumption by Victorian C&I customers had declined as a result of increased domestic gas prices, and noted the closure of Dow Chemicals in Melbourne as an example of the impact of high prices.[65]

Other C&I customers have implemented strategies to reduce their gas demand, including energy efficiency improvements and fuel switching.[66] But the ACCC reported in 2020 that energy efficiency measures for C&I customers are now largely exhausted.[67]

Among domestic sources of demand, gas powered generation is the most volatile source of demand (figure 4.11). Gas is a relatively expensive fuel for electricity generation, so gas generators typically operate as 'flexible' or 'peaking' plants that can be switched on at short notice to capture high prices in the electricity market. Gas demand for power generation, therefore, tends to be seasonal, peaking in summer (and sometimes winter) when electricity demand and prices are higher. It also varies with the amount of renewable generation available (which is cheap but weather dependent).[68]

**Figure 4.10**
**Eastern Australian gas demand**




Source: AEMO, *2020 gas statement of opportunities*, March 2020.

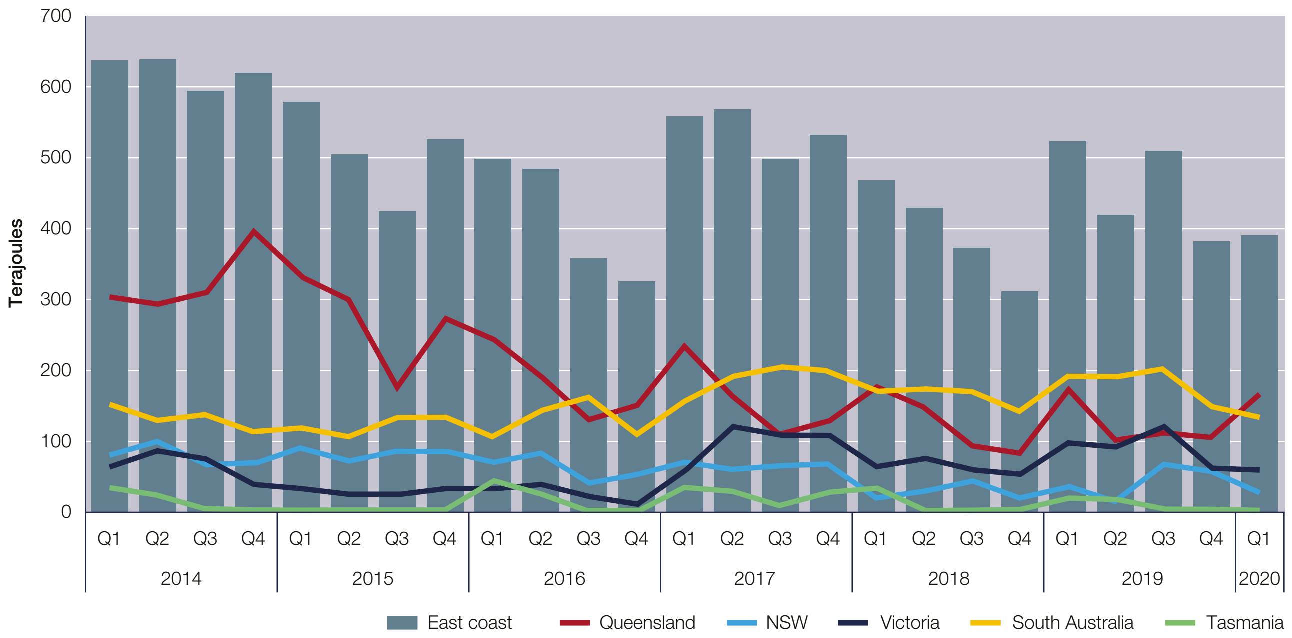
Rising gas fuel costs linked to Queensland's LNG industry, along with a shortage of gas supplies linked to state based moratoriums on gas exploration and production, stalled demand for gas powered generation in the state from 2015 to 2018. Gas powered generation slumped from 18 per cent of Queensland's electricity output in 2015 to 9 per cent in 2019. A similar squeezing off occurred in NSW.

Different conditions prevailed in Victoria and South Australia, where coal generation retirements and rising outages among remaining plant made gas generation critical to meeting electricity demand. In particular, when Hazelwood power station closed in 2017, gas powered generation rose in both states. Across 2019 some major coal generators experienced lengthy, unexpected outages. These outages required gas powered generation to increase output to cover the shortfall. Compared with 2018, gas powered generation rose from 5 to 7 per cent in Victoria, and from 52 to 54 per cent in South Australia.

61 Department of Planning and Environment (NSW), *Initiatives overview*, July 2018.
62 Department of Planning and Environment (NSW), 'Community views on Narrabri Gas Project to be addressed', Media release, 7 June 2017.
63 Prime Minister of Australia, and Premier of New South Wales, 'NSW energy deal to reduce power prices and emissions', Media release, January 2020.
64 ACCC, *Gas inquiry 2017–2025, Interim report*, *January 2020*, February 2020.
65 AEMO, *Victorian gas planning report update*, March 2020, p. 20.
66 ACCC, *Gas inquiry 2017–2020, Interim report*, *July 2019*, August 2019.
67 ACCC, *Gas inquiry 2017–2025, Interim report*, *January 2020*, February 2020.

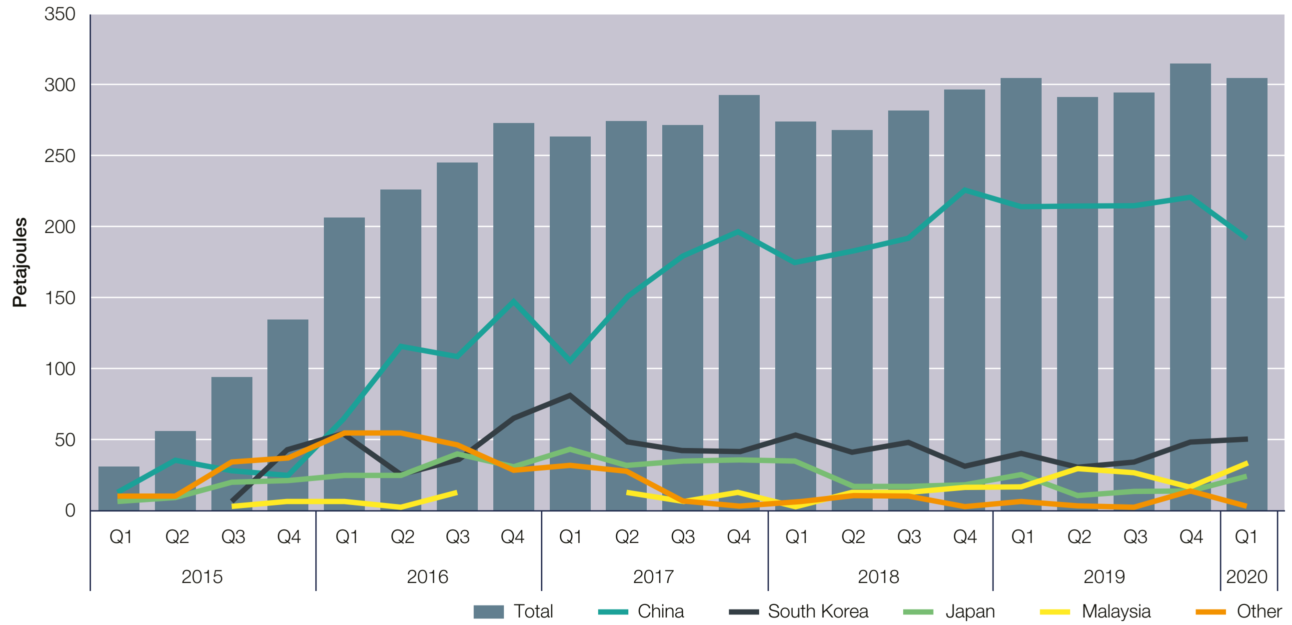
68 EnergyQuest found a –89 per cent correlation between gas and hydroelectric generation; and a –48 per cent correlation between gas and wind generation over 42 months to June 2018. See EnergyQuest, *Energy quarterly*, September 2018, p. 35.

Figure 4.11
Quarterly gas demand for gas powered generation




Source: AEMO; National Electricity Market (NEM) generation data and heat rates (gigajoules per megawatt hour).

Figure 4.12
Eastern Australian gas exports




Source: Gladstone Ports Corporation; trade statistics.

More recently, domestic spot prices for gas fell significantly (section 4.11.2). While the full impact of this price reduction on demand will take time to fully realise, it may provide relief for some customers after several years of high prices.

**LNG exports**

Exports continue to grow, with record volumes over 2019 (and a record quarterly volume in the fourth quarter of 2019) contributing to Australia overtaking Qatar as the world's largest exporter of LNG. Accordingly, both APLNG and QCLNG projects operated at or near capacity in 2019, contributing to record eastern Australian production levels in 2019 (figure 4.12).

China is the primary market for eastern Australian LNG, accounting for 72 per cent of exports in 2019. Chinese demand has grown each year since LNG exports commenced, with the 2019 volume (863 PJ) up 11 per cent on the previous year's volume. A key Chinese policy initiative underpinning LNG demand has been to mandate targets for switching heating fuels from coal to gas, to reduce carbon emissions and improve air quality.[69] Malaysian demand for LNG also increased year on year (with 92 PJ delivered in 2019) despite the country being a major LNG exporter.

In contrast, Japan and South Korea's demand for eastern Australian LNG fell to 220 PJ in 2019, from 365 PJ in 2017. Greater use of nuclear reactors (as well as some additional coal and solar plant) for electricity generation contributed to this shift.

Strong demand caused a surge in LNG spot prices from mid-2017. Monthly Asian spot prices reached around $14 per GJ in December 2017 and remained elevated throughout 2018. But new LNG capacity in the United States, Australia and Russia came online in 2019, creating an oversupply and driving prices lower. Delivery programs and production decisions for 2019 were set in late 2018 when LNG spot prices were high, so LNG volumes were not significantly affected.

A slowing Chinese economy, Japan's ongoing switch away from gas powered generation, and further increases in US export capacity kept downward pressure on prices in late 2019 and early 2020. Also in early 2020, the outbreak of COVID-19 contributed to reduced Asian LNG demand and weaker spot LNG and oil prices.[70] This price downturn coincided with intense price competition among oil exporting countries, which further reduced oil prices, and may ultimately affect prices for oil-linked LNG contracts. Australian exporters reported the uncertainty stemming from COVID-19 and collapsing oil prices limited their ability to strike new gas supply agreements and finalise investment decisions.[71]

While the potential exists for delays to LNG cargoes, it was not reported in the first quarter of 2020. Given the limited ability to reduce production from fields once developed and committed under long term contracts, LNG production and export volumes tend to lag a change in spot prices. Slowing production from the Surat–Bowen Basin from November 2019 is consistent with LNG exporters expecting softer demand conditions in 2020, as buyers exercise downward quantity limits in long term contracts in favour of spot cargoes at lower prices.

### 4.10.3 Interregional gas trade

A signature feature of the domestic gas market since 2014 is the role of interregional gas trades to manage the supply–demand balance. Key pipelines have been re-engineered as bi-directional, enabling them to respond more flexibly to regional supply and demand conditions.

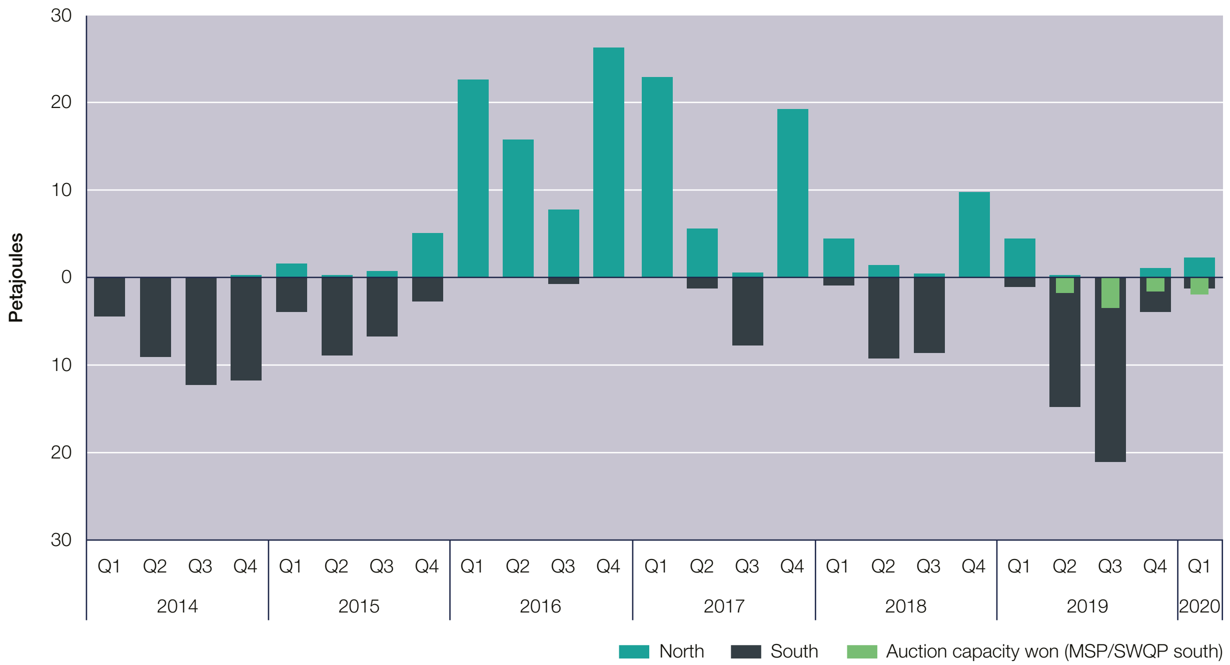
With the launch of Queensland's LNG projects in 2015, the projects began drawing substantial volumes of gas from Victoria and South Australia to cover shortfalls in their reserve portfolios. Flows then settled into a cycle of gas flowing south in the Australian winter (to meet heating demand), and north in the Australian summer (the northern hemisphere winter) when Asia's LNG demand peaks (figure 4.13).

More recently, the cycle appears to be shifting towards net southern flows—that is, less gas flowing north in summer, and more flowing south in winter. In the fourth quarter of 2019, net flows were southward. The introduction of the pipeline capacity reforms (section 4.10.4) is contributing to this shift, and significant southbound flows can be linked to pipeline capacity won at auction for routes on the key South West Queensland and Moomba to Sydney pipelines.

Conditions in the domestic electricity market also affect trade flows. Following the closure of coal fired generators in the southern states, increased demand for gas powered generation in those states drew gas south, especially during the Australian winter when heating demand peaks. In 2018

69 Department of Industry, Innovation and Science, *Resources and energy quarterly*, December 2019, p. 57.
70 EnergyQuest, *Energy quarterly*, March 2020, p. 14.
71 EnergyQuest, *Energy quarterly*, March 2020, p. 53.

Figure 4.13
**North–south gas flows in eastern Australia**




MSP, Moomba to Sydney Pipeline; QSN, Queensland / South Australia / New South Wales; SWQP, South West Queensland Pipeline.

Note: Flows on the QSN Link section of the South West Queensland Pipeline. Northbound flows are from the southern states into Queensland. Southbound flows are exports from Queensland to the southern states.

Source: AER analysis of Gas Bulletin Board data.

and 2019, gas flows turned southbound even before the onset of winter.

The threat of government intervention in the gas market (section 4.13) also impacted flows from late 2017. To avoid triggering intervention, Queensland's LNG producers began offering more gas to the domestic market, which increased southbound trade flows. Exporters committed to the Australian Government to first offer any uncontracted gas to the domestic market on a competitive basis.

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.[72] 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.[73] 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.

### Gas flows into NSW

NSW produces little of its own gas, so it is highly trade dependent. Previously supplied by Victorian sources, NSW became more reliant on its northern neighbour as Queensland production fields ramped up and sent more gas south. As a result, gas volumes shipped along the Moomba to Sydney Pipeline and the South West Queensland Pipeline rose significantly.

The critical role of these pipelines in delivering gas to NSW on peak days highlights the risk of capacity constraints. The South West Queensland Pipeline in particular has little uncontracted capacity between Wallumbilla (Queensland) and Moomba (South Australia), which is the origin point of the Moomba to Sydney Pipeline. But capacity trading reforms introduced on 1 March 2019 eased pressures somewhat (section 4.10.4). In addition, proposals for LNG import terminals and gas pipelines that may open flows from Queensland could improve gas availability in NSW.

72 Santos, 'Santos facilitates delivery of gas into southern domestic market', Media release, August 2017.
73 EnergyQuest, *Energy quarterly*, March 2020.



## 4.10.4 Pipeline access

Wholesale gas customers buy capacity on transmission pipelines to transport their gas purchases from gas basins. Gas production companies and gas pipelines are separately owned, so a gas customer must negotiate separately with producers to buy gas, and pipeline businesses to have the gas delivered. To reach its destination, gas may even need to flow across multiple pipelines with different owners.

Since LNG exports began in 2015, gas flows from the southern states to Queensland, and sometimes the reverse, have helped manage interregional supply–demand imbalances. For this reason, access to transmission pipelines on key north–south transport routes is critical for gas customers. But many critical pipelines have little or no spare, uncontracted capacity, making it difficult to negotiate access. In addition, many pipelines face little competition and charge monopolistic prices.

The ACCC in 2015 found a majority of transmission pipelines on the east coast were using market power to engage in monopoly pricing.[74] Reforms were implemented to address this issue, including a new information disclosure and arbitration framework that came into effect in August 2017, and changes to full and light regulation, which came into effect in March 2019 (section 5.3).

Reforms introduced in March 2019 made it easier to access pipeline capacity that is not fully used. Capacity on some pipelines is fully contracted to gas shippers, who do not fully use it. The reforms give other parties an opportunity to access this capacity through trading platforms.

Capacity can be acquired in two ways. First, the *Capacity Trading Platform* is a voluntary market where shippers can sell any capacity they do not expect to use. Second, any unused capacity not sold in this way must be offered at a mandatory *day-ahead auction*. Any shipper can bid at the auction, which is finalised shortly after the nomination cut-off time a day in advance of the relevant gas day.

Auction revenues go to the pipeline, or facility operator, rather than the shippers that own the capacity rights. The auctions have a reserve price of zero, and the majority of settlements in 2019 occurred at no cost.

To promote transparency, the Gas Bulletin Board publishes prices and other key terms from all voluntary trades and auctions. The AER monitors compliance with capacity trading regulations and the proper reporting of trades, and oversees the resolution of any cost recovery disputes.

74 ACCC, *Inquiry into the east coast gas market*, April 2016, p. 18.

### Outcomes of capacity trading reform

The day-ahead auction provided access to over 41 PJ of unused, contracted pipeline capacity (across 10 pipelines) in the 12 months after it launched on 1 March 2019 (figure 4.14). Over 80 per cent of this capacity was won at the reserve price of zero. No trades occurred on the voluntary platform in 2019, with the first trade recorded in February 2020. The ACCC reported shippers expect activity in the capacity trading platform to increase over time.[75]

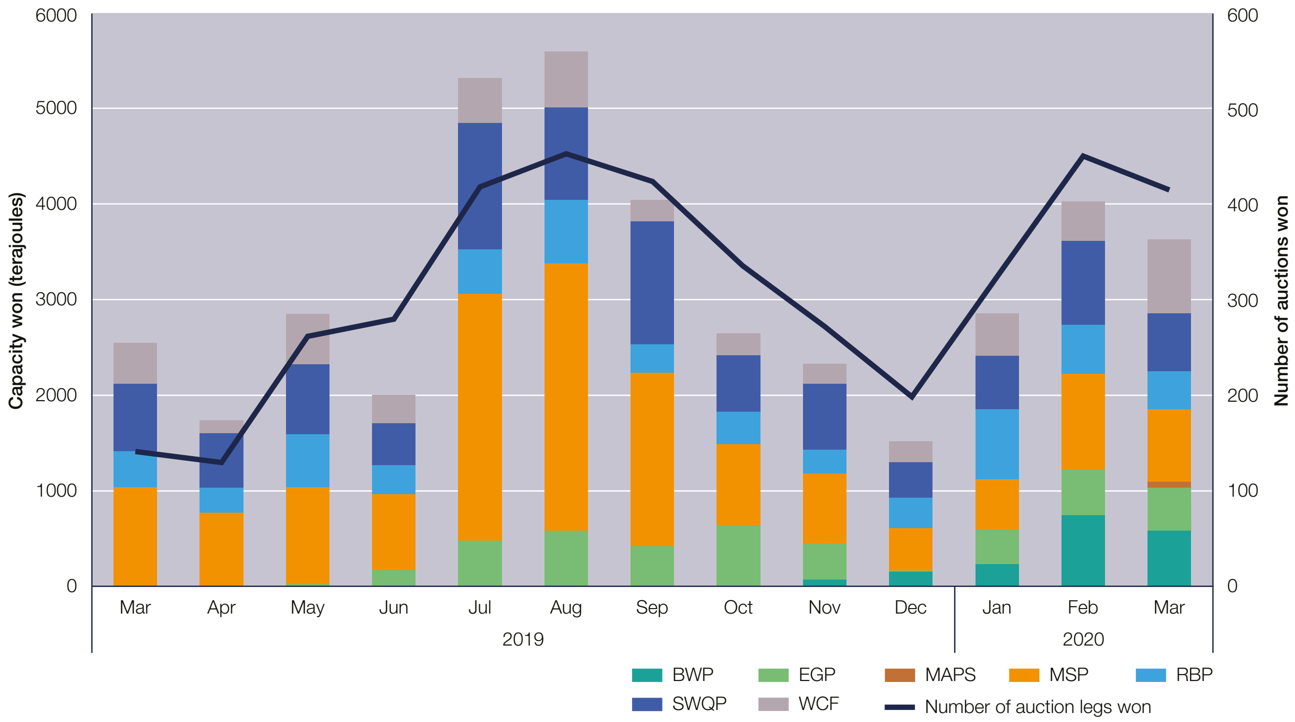
The day-ahead auction has improved market dynamics by enhancing competition, especially in southern markets. Access to low or zero cost pipeline capacity is allowing shippers to move relatively low priced northern gas into southern spot markets, easing price pressure in those markets. The AER estimated the auctions effectively reduced spot gas prices by as much as $0.76 per GJ in Sydney, and up to $0.17 per GJ in Victoria, over the six months to September 2019.[76]

The AER's *Wholesale markets quarterly* reports found day-ahead auctions increased liquidity at the Wallumbilla hub, as well as the Sydney and Victorian spot markets.[77] Separately, the ACCC reported shippers' expectations that spot market prices would more closely align as participants exploit arbitrage opportunities made possible by cheap capacity procured at auction.[78] It also indicated the auctions could indirectly ease supply costs for some gas powered generators in the National Electricity Market (NEM). As an example, the day-ahead auction delivered record capacity (317 TJ) on 31 January 2020, which facilitated gas delivery during South Australia's electrical separation from the NEM.[79]

The ACCC noted, however, some shippers consider pipeline operators may be using the capacity trading reforms to reduce the level of service flexibility provided to shippers, or to require shippers to pay more for this flexibility. Some shippers cited fixed charges levied by major pipelines servicing South Australia as a potential reason for the capacity reforms not being used in the state in the first eight months of operation.[80]

75 ACCC, *Gas inquiry 2017–2025, Interim report, January 2020*, February 2020, pp. 103–4.
76 AER, *Wholesale markets quarterly—Q3 2019*, November 2019, pp. 52–53.
77 AER, *Wholesale markets quarterly—Q3 2019*, November 2019, pp. 44, 52–4
78 ACCC, *Gas inquiry 2017–2025, Interim report, January 2020,* February 2020, p. 101.
79 AER, *Wholesale markets quarterly–Q1 2020,* May 2020, p. 58.
80 ACCC, *Gas inquiry 2017–2025, Interim report*, *January 2020,* February 2020, pp. 6–7.

Figure 4.14
**Day-ahead auction price and quantity**




BWP, Berwyndale to Wallumbilla Pipeline; CGP, Carpentaria Gas Pipeline; EGP, Eastern Gas Pipeline; MAPS, Moomba to Adelaide Pipeline; MSP; Moomba to Sydney Pipeline; RBP, Roma to Brisbane Pipeline; SWQP, South West Queensland Pipeline; WCF, Wallumbilla compression facilities.

Source: AER analysis of day-ahead auction data.

## 4.11 Gas prices

The launch of LNG exports from Queensland in 2015 linked domestic gas prices (which were traditionally fairly stable) to more volatile international oil and gas prices. This link drove prices higher in 2016 and 2017, but operated in reverse in 2019 and 2020 when lower Asian prices helped drive falls in domestic spot prices.

Other factors contributing to lower domestic prices across 2019 included high levels of Queensland gas production, competition in spot gas markets, and the introduction of pipeline capacity auctions. The auctions in particular allowed some shippers to move gas from northern to southern markets at near zero transportation costs.

### 4.11.1 Gas contract prices

A majority of gas prices are agreed in confidential bilateral contracts, either between gas producers and large customers, or between retailers/aggregators and C&I customers (section 4.9.1).

Domestic gas contract prices historically averaged around $3–4 per GJ. But, when Queensland's LNG projects began sourcing gas from Victoria and South Australia, this demand drove contract prices higher. By early 2017, domestic prices of $22 per GJ were being quoted for a one or two year contract—almost $10 per GJ above export prices.[81] At their peak in March 2017, domestic prices offered by retailers nearly doubled LNG netback prices (box 4.3).

Following the Australian Government's market intervention in 2017 (section 4.10.1), Queensland producers began offering more gas to the domestic market at lower prices. By 2018 contract offers had eased into the high $8–11 per GJ range, aligning them more closely with Asian LNG netback prices. By late 2018 domestic gas prices were around $3 per GJ *lower* than export prices, although some customers reported some suppliers' use of EOI processes made it difficult to compare offers.[82]

81 ACCC, *Gas inquiry 2017–2020, Interim report, July 2018*, August 2018.
82 ACCC, *Gas inquiry 2017–2020, Interim report, July 2018*, August 2018.

### Box 4.3 Liquefied natural gas netback prices

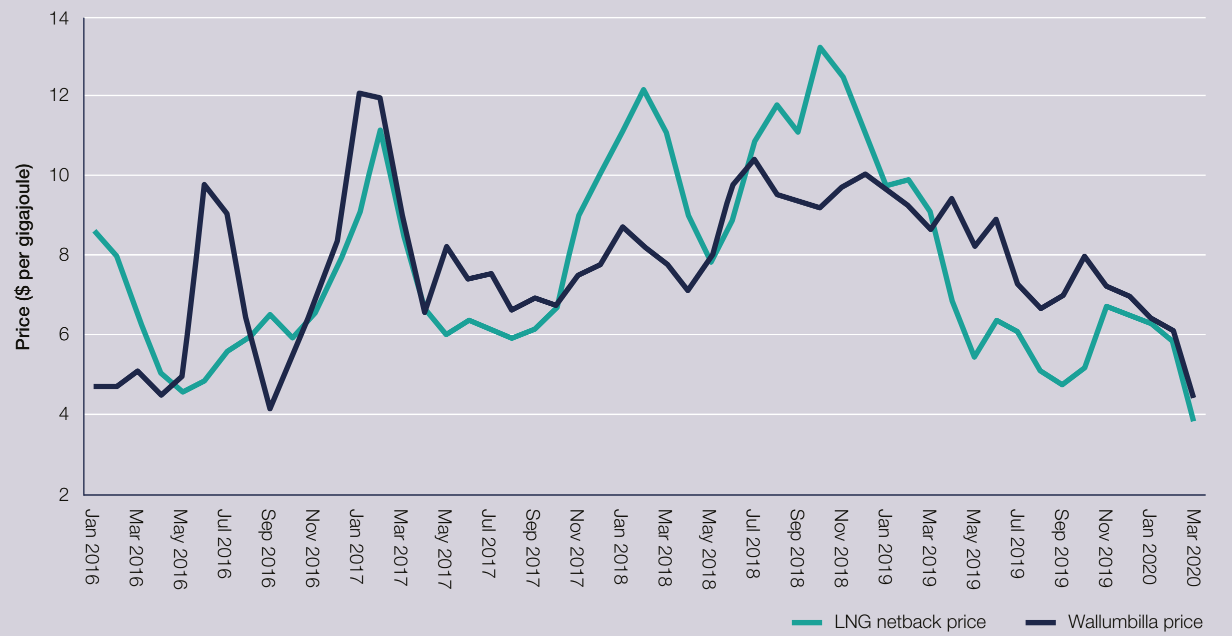
Liquefied natural gas (LNG) netback prices estimate the export parity price that a domestic gas producer would expect to receive from exporting its gas rather than selling it domestically. It is calculated as the price for selling LNG (based on Asian spot prices) and subtracting or 'netting back' the costs of converting gas to LNG and shipping it overseas. The costs include liquefaction at Gladstone, waterborne shipping to Asia, and regasification in Asia.

If LNG netback prices exceed domestic prices, then it becomes more profitable to export gas than to sell it locally. At times in 2017 the reverse situation prevailed in eastern Australia—that is, domestic gas prices exceeded LNG netback prices (figure 4.15). This situation was indicative of a dysfunctional market, where price signals were not addressing a demand–supply market imbalance.

The Australian Competition and Consumer Commission (ACCC) publishes LNG netback prices to improve transparency in the eastern gas market. The prices tend to peak during the northern hemisphere winter, when LNG demand is highest. They peaked at $13.21 per GJ in October 2018 before falling across 2019, reaching $5.19 per GJ a year later in October 2019.

Despite a slight rebound to around $6 per GJ during the northern hemisphere's winter, the LNG netback price was expected to remain suppressed into 2020, reaching as low as $3.85 per GJ in March 2020.[a]

Figure 4.15
**LNG netback prices and Wallumbilla prices**

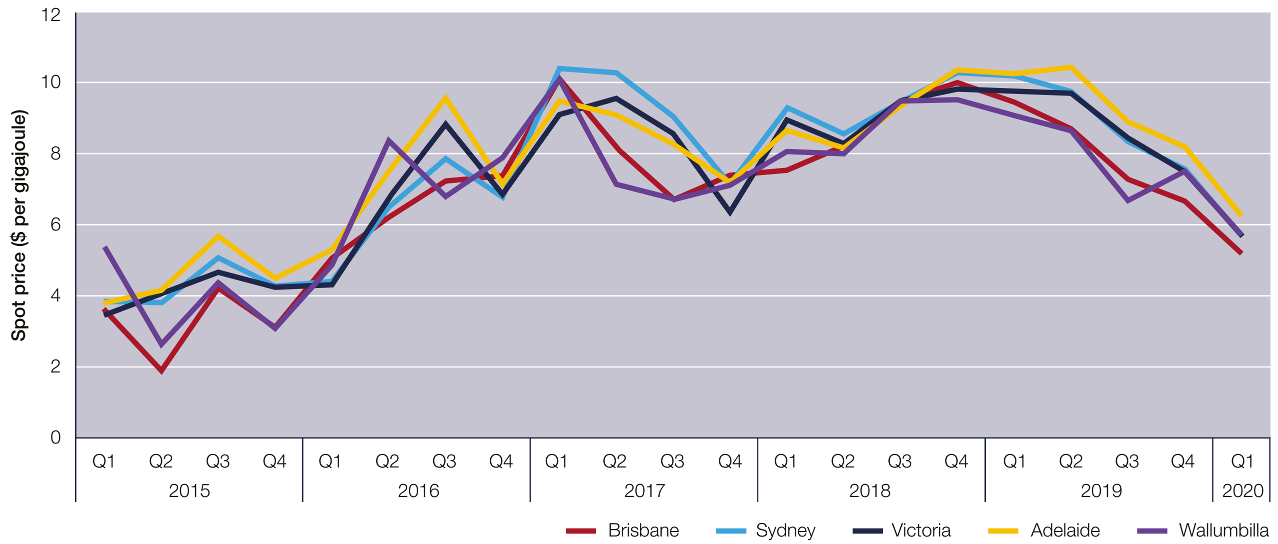



Note: The Wallumbilla price is the monthly volume weighted average price at the Wallumbilla hub for day-ahead, on-screen trades. LNG netback prices are based on domestic spot market prices on the first day each month, and expected netback prices for LNG cargoes to Asia in the following month. The 1 April LNG netback price, for example, is based on domestic spot prices for the 1 April gas day, and the netback on expected LNG spot prices for cargoes to Asia in the following month.

Source: AER analysis of gas supply hub data; ACCC (LNG netback prices).

a ACCC, *LNG netback price series*, March 2020.

**Figure 4.16**
**Eastern Australia gas market prices**




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

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

Prices offered by Queensland gas producers for 2020 supply were mostly in the $9–10 per GJ range over 2019, but retailer offers to C&I users were in the range of $8–12 per GJ.[83] Smaller C&I customers generally have fewer options to buy gas directly from producers, and tend to face more difficulties acquiring pipeline capacity to ship the gas. Some contract prices agreed by C&I users in the first half of 2019 were higher than in the first half of 2017, when market conditions were at their tightest. Flexibility in contract terms and conditions also reportedly decreased in 2019.[84]

That said, the ACCC reported many C&I users are looking to procure gas from other sources, including directly from producers. In addition, the Queensland Government has released tenements exclusively for domestic supply, resulting in direct agreements between customers and producers.[85]

In early 2019 producer offers were broadly in line with expected 2020 LNG netback prices. But, from May 2019, producer price offers remained steady while expected 2020 LNG netback prices eased. By August 2019 producer prices were almost 25 per cent above expected 2020 LNG netback prices. In some instances, producer offers included a new fixed price component, on top of the usual LNG spot price linked component.[86]

Consistent with price trends in the north, average prices offered by producers and retailers in the southern states in 2019 were above expected 2020 LNG netback prices (factoring in pipeline costs). The ACCC noted the disparity might have reflected a tight supply–demand balance in southern states.[87]

### 4.11.2 Spot market prices

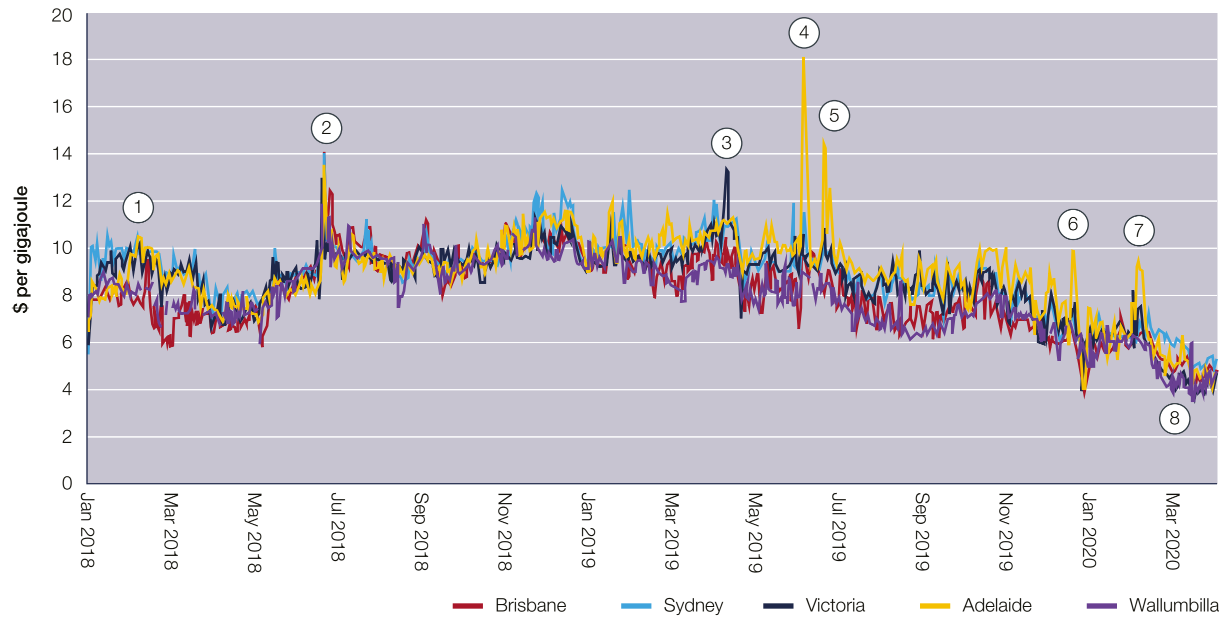
As discussed in section 4.9, three separate spot markets for gas operate in eastern Australia—gas supply hubs at Wallumbilla, Queensland, and Moomba, South Australia; the short term trading market for gas, with hubs in Sydney, Brisbane and Adelaide; and Victoria's declared wholesale gas market. The three spot markets operate under different sets of rules, do not interact with each other, and have different purposes. Price outcomes in the spot markets do not align with contract prices, although they often move in similar directions. Contract prices reflect expectations

83 ACCC, *Gas inquiry 2017–2025, Interim report, January 2020*, February 2020, p. 5.
84 ACCC, *Gas inquiry 2017–2025, Interim report, January 2020*, February 2020, pp. 5–6.
85 ACCC, *Gas inquiry 2017–2025, Interim report, January 2020*, February 2020, p. 78.
86 ACCC, *Gas inquiry 2017–2025, Interim report, January 2020*, February 2020, pp. 1, 44.
87 ACCC, *Gas inquiry 2017–2025, Interim report, January 2020*, February 2020, p. 44.





**Figure 4.17**
**Daily gas spot prices**




| | | |
|---|---|---|
| 1 | January to April 2018 | Lower Queensland demand for gas powered generation (following Queensland Government's direction to increase coal generation) led to more of the state's production being diverted south. |
| 2 | 17–22 June 2018 | Longford outages constrained Victorian supply, coinciding with high gas powered generation demand in South Australia, Victoria and Queensland, and a Queensland pipeline outage. |
| 3 | 11 April 2019 | Longford production was constrained. |
| 4 | 6 June 2019 | Low wind generation and production outages occurred in Victoria. |
| 5 | 20 June 2019 | Low wind generation and high winter gas demand occurred in Victoria and Adelaide. |
| 6 | 16–20 December 2019 | Temperatures were high in the southern states. |
| 7 | 2–7 February 2020 | Gas generation was directed on in South Australia following the outage of the Heywood interconnector in the National Electricity Market (NEM). |
| 8 | March 2020 | An LNG export train outage occurred, along with excess gas supply, and low gas generation demand. |

Source: AER; AEMO (raw data).

of future market conditions, but the spot markets reflect short term shifts in market conditions relating to factors such as the timing of LNG shipments, and conditions in the electricity market.

Spot prices vary seasonally, both within and across the markets. Prices can peak in summer but more typically peak in winter. In summer, gas demand for electricity generation may push up domestic spot prices. Australia's summer also coincides with the northern hemisphere winter, when Asian demand for LNG peaks. In the Australian winter, household gas demand tends to rise in the southern states for heating purposes. This increase in demand tends to push southern prices above northern prices during the winter months as southern customers pay the cost of northern gas *plus* domestic transportation costs (box 4.4).

In recent years, prices have varied significantly (figure 4.16). Along with other factors, the launch of LNG exports in January 2015 caused spot prices to increase in 2016 and 2017 as LNG producers competed with domestic customers for gas supplies (figure 4.17). While prices stabilised somewhat across late 2017 to 2018, they remained at historically high levels.

Monthly spot prices averaged around $10 per GJ in all markets in the fourth quarter of 2018. By the end of the second quarter of 2019, however, prices had already begun to fall in all markets except Adelaide, as the domestic market started mirroring the decline in LNG netback prices a few months earlier. At the same time, Queensland production continued to increase, and the newly implemented day-ahead auction of spare capacity started to provide cheap avenues for participants to bring that gas south, to compete in the Sydney, Adelaide and Victorian markets.

These factors continued to drive prices down through winter and into summer. By the fourth quarter of 2019, all

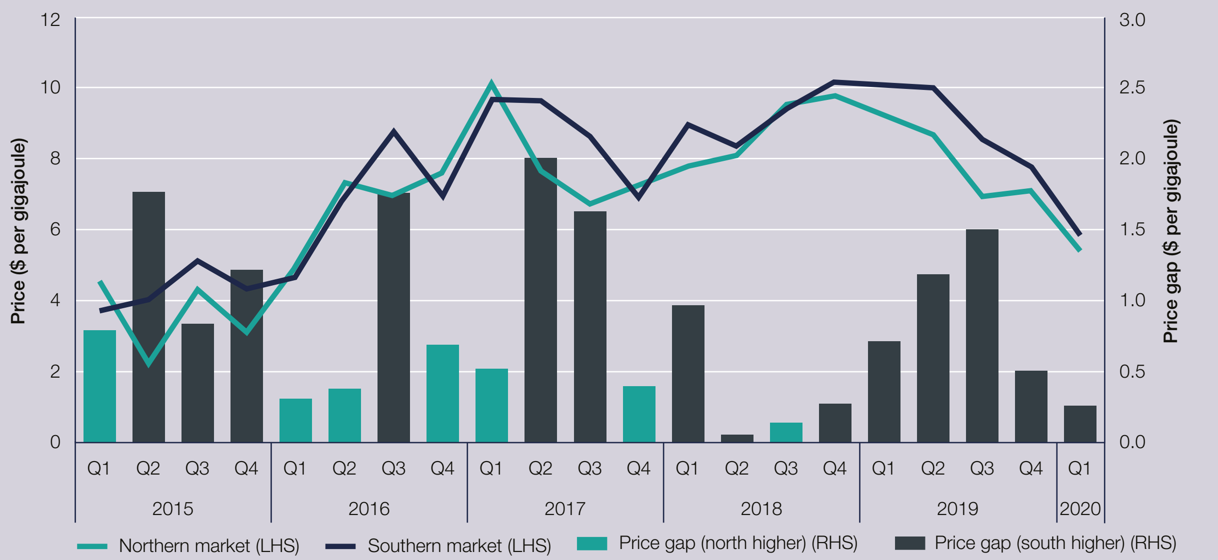
## Box 4.4 North–south price divide

A significant differential between spot gas prices in Queensland (Wallumbilla and Brisbane) and the southern states was evident for much of 2019 (figure 4.18). The differential reflects contrasting demand and supply conditions in the two regions. In Queensland, higher production improved supply. But gas demand for power generation was high in the south, and gas storage levels were falling.

Historically, price gaps tend to emerge each winter as southern gas demand for heating increases. The gap is often around $2 per gigajoule (GJ), roughly the cost of transporting Queensland gas to the southern states.

But, in 2019 the day-ahead auction reforms kept the price gap narrower than it might have been. Access to cheap (or free) pipeline capacity allowed some participants to sell northern gas to southern markets at more competitive prices. Without this cheap pipeline access, southern prices would likely have been higher (section 4.10.4).

Figure 4.18
**North–south gas price divide**




Note: The southern market is the average of NSW, Adelaide and Victorian spot prices. The northern market is the average of Brisbane and Wallumbilla spot prices. The Wallumbilla price used for calculation is the volume weighted average price for day-ahead, on-screen trades at the Wallumbilla gas supply hub.

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

states were averaging prices of around $7–8 per GJ. This downward trend continued into 2020, with average prices at their lowest quarterly levels since the first quarter of 2016 in all markets.

In the first quarter of 2020, the northern markets experienced a number of trades less than $4 per GJ. In the week starting 23 February 2020, the Wallumbilla hub had the lowest weekly average price, and the lowest priced individual trade since the south east Queensland trade location was introduced in March 2017.[88]

In that same quarter, the southern markets also experienced falls in spot prices, with all southern markets seeing trades for less than $5 per GJ. Compared with the same quarter in 2019, the prices in these markets fell by around 40 per cent on average. Notably, prices in all downstream markets except Adelaide have been lower than the equivalent price for on-screen, day-ahead products at the Wallumbilla hub since the last quarter of 2019. This situation highlights a reduction in the price difference between northern and southern markets (box 4.4).

More broadly, these significant reductions in spot prices will ease pressures on C&I customers that previously high prices affected (section 4.10.2).

88 AER, *Gas weekly report, 23–29 February 2020*, March 2020.



## 4.12 Market responses to supply risk

Market responses to concerns about a shortage of domestic gas in coming years are being explored, including further gas development, LNG imports, transmission pipeline solutions, and demand response.

### 4.12.1 Gas field development

Exploration and development in a number of gas fields have increased since international oil and gas prices began to rise in 2017. Additionally, domestic gas prices and government funding improved the economics of some resources and projects. Governments across jurisdictions are offering financial or regulatory incentives for projects that target gas supplies to the domestic market (section 4.13).

The Australian Government's Gas Acceleration Program (GAP), the South Australian Government's Plan for Accelerating Exploration grant programs, and Queensland's 'domestic only' exploration tenement release are among the schemes being implemented.

Many efforts to increase gas supply focus on unconventional projects, which often face community opposition due to environmental concerns. Legislative moratoriums on onshore exploration and fracking have impeded the development of gas projects in Victoria, South Australia and Tasmania (section 4.10.1). Elsewhere, stringent regulatory processes apply, as highlighted by the stalled process for Santos's Narrabri gas project in NSW. Against this trend, the Northern Territory in April 2018 lifted its moratorium on fracking in 51 per cent of the jurisdiction.

Despite the various moratoriums and constraints in place, and sharply lower international oil prices in 2020, a number of projects are progressing that could bring additional supply to the domestic market:

- In Victoria, Cooper Energy's Sole gas field in the Gippsland Basin commenced operation in late March 2020. The gas is processed at the Orbost plant, which can produce up to 68 TJ per day after recommissioning upgrades. By late March 2020 the plant was producing at about 25 per cent capacity (17 TJ).[89] After developing Sole, Cooper Energy plans to develop its Manta gas field.
- In the Otway Basin, Beach Energy delivered its first gas in February 2020 from its Haselgrove-3 project.[90] Gas from the project, which has a capacity of 10 TJ per day, feeds into the new Katnook gas processing facility (South Australia), which the GAP scheme partly funded.
- In NSW, Santos proposed to develop 850 wells across its 95 000 hectare Narrabri gas project, which has potential to supply up to 200 TJ per day.[91] Environmental and community groups opposed the project's environmental impact. Over 23 000 submissions were made in response to the environmental impact statement, mostly in opposition.[92] The project has faced various regulatory delays. In March 2020 the NSW Government referred the project to the Independent Planning Commission to determine whether it can proceed.[93]
- In Queensland, the Kincora project (Armour Energy) began processing gas from surrounding wells in December 2017.[94] Armour Energy expanded its activity in the region after receiving a $6 million grant under the GAP scheme in March 2018. Kincora also won a Queensland Government 'domestic only' tenement release for gas exploration, based on a commitment to supply gas to the domestic market (section 4.13.5).[95] Kincora produced at an average rate of 7.5 TJ per day in the fourth quarter of 2019. Armour Energy targeted output of 20 TJ per day by the end of 2020, but production growth has been restricted.[96]
- Other Queensland projects participating in the GAP scheme include Westside's Greater Meridian project, in the Bowen Basin, and Tri-Star Fairfield's development of four new wells west of Rolleston.
- Also in Queensland, Santos and its partners launched its Roma East project in September 2019, producing around 119 TJ per day.[97] The partners invested a further $400 million in the Arcadia gas project, which launched in the third quarter of 2019 and was producing 15 TJ per day by the end of 2019.[98]

89 AER, *Gas weekly report, 22–28 March 2020*, April 2020, p. 1.
90 EnergyQuest, *Energy quarterly*, March 2020, p. 105.
91 Santos, 'Narrabri Gas Project', web page, available at: www.narrabrigasproject.com.au/ask-us-categories/the-project/.
92 Department of Planning and Environment (NSW), 'NSW Government assessment of the Narrabri Gas Project proposal update', Media release, 23 April 2018.
93 Santos, 'Narrabri Gas Project referred to Independent Planning Commission for public hearings and determination', Media release, 12 March 2020.
94 Armour Energy, 'Kincora Gas Project', web page, available at: www.armourenergy.com.au/kincora-gas-project.
95 Armour Energy, 'Kincora Gas Project', web page, available at: www.armourenergy.com.au/kincora-gas-project.
96 EnergyQuest, *Energy quarterly,* March 2020, p. 108.
97 EnergyQuest, *Energy quarterly,* December 2019, p. 114.
98 EnergyQuest, *Energy quarterly*, March 2020, p. 116.

- In June 2018 Senex and Jemena entered a partnership to bring gas from Senex's Project Atlas in the Surat Basin to the domestic market.[99] This facility and pipeline began operating in late 2019, and is dedicated to supplying domestic customers only, as part of a Queensland Government initiative to boost supply to local industrial customers. The project can deliver up to 48 TJ per day to the Wallumbilla hub.[100]
- In South Australia, Strike Energy is continuing work on its Southern Cooper gas project, which, if successful, would be the deepest CSG well drilled in Australia.[101] Strike Energy undertook pilot operations across 2019 and expects to confirm by mid-2020 whether commercial gas rates can be achieved.[102]

The impact of lower international oil prices and the COVID-19 pandemic on the domestic market is yet to be fully realised, but could delay some projects (section 4.10.2). In March 2020 Santos announced a 38 per cent reduction in 2020 capital expenditure as a result of COVID-19 and other factors.[103] Similarly, in April 2020 Origin Energy announced a pause in exploration activities in the Beetaloo Basin as a result of changing conditions.[104] It also provided guidance that APLNG development and exploration activity would reduce for the same reason, but without materially impacting production.

More broadly, the number of new gas wells drilled in Queensland—a key indicator of the production outlook for CSG producers—declined by around 30 per cent from the fourth quarter 2019 to the first quarter 2020.[105]

### 4.12.2 LNG import terminals

While conditions eased in the east coast gas market in 2019, considerable uncertainty remains. To address these concerns, the industry is considering at least four projects to develop LNG import facilities on the east coast (section 4.8). Each project would involve importing LNG through floating storage and regasification units.

99 Senex Energy, 'Senex and Jemena fast-track Project Atlas gas to domestic market', Media release, 18 June 2018.
100 Senex Energy, 'Project Atlas', web page, available at: www.senexenergy.com.au/operations/surat-basin-gas/project-atlas/.
101 EnergyQuest, *Energy quarterly*, March 2018.
102 Strike Energy, *Half year financial report*, ASX announcement, 14 February 2020.
103 'Santos, COVID-19 response and business update', Media release, 23 March 2020.
104 Origin Energy, 'Operational and financial update', Media release, 6 April 2020.
105 AER, *Wholesale markets quarterly—Q1 2020*, May 2020, p. 53.

### 4.12.3 Northern Territory gas

Jemena's Northern Gas Pipeline began delivering gas from the Northern Territory to Queensland in January 2019. Jemena is evaluating a 1000 kilometre extension to supply Ergon Energy's gas powered Barcaldine power station. It also announced plans for an eight-fold increase in the pipeline's capacity, following the Northern Territory Government's decision to lift a moratorium on hydraulic fracking in 2018.[106] At April 2020 three shippers used the pipeline: Incitec Pivot, Santos and the Northern Territory's Power and Water Corporation. Since its commissioning, pipeline flows have steadily increased. In the fourth quarter of 2019, pipeline deliveries to eastern markets averaged around 72 TJ per day.[107]

### 4.12.4 Demand response

Volatile markets and the expiry of legacy gas supply agreements are prompting C&I customers to take a more active role in gas procurement. Some customers are becoming direct market participants by engaging in collective bargaining agreements. As an example, in November 2017 the ACCC granted authorisation to the Eastern Energy Buyers Group of agribusinesses to establish a joint energy purchasing group to run gas and electricity supply tenders for 11 years. The arrangement allows the group to access wholesale markets at better prices than would be possible if the agribusinesses acted individually.[108]

Some C&I users are exploring or implementing options such as purchasing gas directly from producers rather than retailers, participating in short term trading markets, and investing in new LNG import facilities.[109] Further, some users have lowered their gas use by changing fuels or increasing efficiencies. Others have also deferred large investments. The ACCC reported one C&I user citing high gas prices as a major factor in delaying a $15 million expansion.[110]

Joint ventures between gas customers and producers are also occurring.[111] Incitec Pivot, with Central Petroleum, won a tender for a CSG tenement release by the Queensland Government, and aims to be producing by 2022.[112]

106 AEMO, *2018 gas statement of opportunities*, June 2018.
107 AER, *Wholesale markets quarterly—Q4 2019*, February 2020, p. 38.
108 ACCC, *The Eastern Energy Buyers Group—Authorisations—A91594 & A91595*, August 2017.
109 ACCC, *Gas inquiry 2017–2020, Interim report, July 2018*, August 2018, pp. 62–6.
110 ACCC, *Gas inquiry 2017–2025, Interim report, January 2020*, 18 February 2020, p. 75.
111 AEMO, *2018 gas statement of opportunities*, June 2018.
112 EnergyQuest, *Energy quarterly*, March 2020, p. 108.

In addition, some C&I users are considering alternatives to gas. Incitec Pivot, for example, is investigating the use of renewable energy instead of natural gas for expanding future ammonia production. Similarly, Australian Paper is developing a waste-to-energy plant, which could reduce its gas use by 4 PJ per year.[113]

## 4.13 Government intervention in gas markets

In response to concerns around the adequacy of gas supplies to meet domestic demand, the Australian Government and some state governments have intervened in the market. The interventions are noted throughout this chapter, and summarised here.

### 4.13.1 Australian Domestic Gas Security Mechanism

The Australian Government in 2017 threatened to direct gas producers to increase gas supplies to the local market. The Australian Domestic Gas Security Mechanism, which took effect on 1 July 2017, empowers the Energy Minister to require LNG projects to limit exports, or find offsetting sources of new gas, if a supply shortfall is likely.[114] The Minister may determine in the preceding September whether a shortfall is likely in the following year, and may revoke export licenses if necessary to preserve domestic supply.

To avoid export controls, Queensland's LNG producers entered a Heads of Agreement with the government in October 2017, and a second agreement in September 2018. Under the agreements, they committed to offer uncontracted gas on reasonable terms to meet expected supply shortfalls. They also committed to offer gas to the Australian market on competitive market terms before offering any uncontracted gas to the international market. To meet their commitments, the LNG projects adopted a range of strategies to offer more gas domestically (section 4.10.1).

The AEMC reported some stakeholders were concerned that government intervention, while it may increase liquidity in the short term, does not correct participants' lack of confidence that they can source gas where they need it at a reasonable price. Concerns were also raised that intervention may reduce investment certainty and weaken liquidity in the long term.[115]

The Department of Industry, Innovation and Science in 2019 found the scheme had worked effectively to safeguard domestic gas supplies, and recommended retaining the scheme until 2023.[116] It also recommended a scheme amendment to reference the ACCC's LNG netback price.

113 ACCC, *Gas inquiry 2017–2025, Interim report, January 2020,* February 2020, p. 74.
114 Department of Industry, Innovation and Science, *Australian Domestic Gas Security Mechanism*, July 2018.

### 4.13.2 Gas supply guarantee

In March 2017 facility and pipeline operators developed the gas supply guarantee as a mechanism to meet commitments to the Australian Government to ensure enough gas is available to meet peak demand periods in the NEM.[117] The guarantee identified new processes to assess and resolve potential gas supply shortfalls ahead of time.

While the guarantee has not been used, and was due to expire in March 2020, the Australian Government announced in that month that it would extend the guarantee to March 2023.[118]

### 4.13.3 National Gas Reservation Scheme

The Australian Government announced it would consult in 2020 on options for a National Gas Reservation Scheme.[119] It expects to reach a final decision by February 2021.[120]

### 4.13.4 Gas Acceleration Program

To encourage gas supply, the Australian Government in 2017 launched the $26 million GAP, offering grants of up to $6 million for projects that increase domestic gas flows in the eastern market by 30 June 2020. Four of the five successful projects are based in Queensland, including Armour Energy's Kincora expansion, Westside's Greater Meridian project, Tri-Star Fairfield's gas project, and

115 AEMC, *Final report: biennial review into liquidity in wholesale gas and pipeline trading markets*, August 2018, p. 46.
116 Department of Industry, Science, Energy and Resources, *Australian Domestic Gas Security Mechanism review*, January 2020.
117 AEMO, 'Gas supply guarantee', web page, available at: https://aemo.com.au/en/energy-systems/electricity/emergency-management/gas-supply-guarantee.
118 AEMO, *Gas supply guarantee guidelines consultation final determination*, March 2020.
119 Ministers for the Department of Industry, Science, Energy and Resources (Australian Government), 'Review finds gas policy boosts domestic supply and helps lower prices', Media release, 24 January 2020.
120 The Hon. Josh Frydenberg MP, and the Hon. Angus Taylor MO (Australian Government), 'Government acts to deliver affordable, reliable gas', Media release, 6 August 2019.

Australian Gasfields' refurbishment of the Eromang and Gilmore processing facilities. The fifth project is Beach Energy's new Katnook gas processing facility in the Otway Basin.[121] These projects are expected to deliver an additional 12 PJ by 30 June 2020, and an extra 28 PJ over five years.[122]

The Australian Government also allocated $8.4 million to support feasibility studies of exploration and development in the Beetaloo Basin. This funding would support bringing additional supply from the Northern Territory to the eastern markets.[123]

### 4.13.5 State government schemes

To encourage gas exploration, the Queensland Government offers grants for 'domestic only' exploration tenements. As part of this grants program, it released almost 40 000 square kilometres of land for exploration between 2015 and 2018, of which 20 per cent was reserved for domestic supply. The Queensland Government released a further 30 000 square kilometres of land in November 2019, with over 30 per cent tagged for domestic supply.[124]

In January 2020 the NSW Government committed—through a memorandum of understanding with the Australian Government—to bring 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.[125] Projects that could support the commitment include Santos's Narrabri gas project, a new transmission pipeline to Queensland, and an LNG import terminal.

The South Australian Government offered grants to increase gas supplies in the state and increase competition among suppliers. In 2017 it awarded nine grants for projects in the Cooper and Otway basins, including the drilling of four exploration wells.[126] The government also released over 13 000 square kilometres of land for exploration. The grants scheme has now wound up.

121 Department of Industry, Innovation and Science, 'Gas Acceleration Program successful applicants', web page, available at: www.business.gov.au/Grants-and-Programs/Gas-Acceleration-Program/Successful-applicants, viewed 19 October 2018.
122 ACCC, *Gas inquiry 2017–2025, Interim report, January 2020*, February 2020, pp. 24–5.
123 ACCC, *Gas inquiry 2017–2025, Interim report, January 2020*, February 2020, pp. 24–5.
124 Minister for Natural Resources, Mines and Energy (Queensland), 'Queensland turns up the gas dial', Media release, 30 October 2019.
125 Government of NSW, *Memorandum of understanding—NSW energy package,* 31 January 2020.
126 Government of South Australia, 'PACE gas', web page, available at: www. energymining.sa.gov.au/petroleum/latest_updates/pace_gas, viewed 19 February 2020.

### 4.13.6 ACCC gas inquiry

In April 2018 the Australian Government directed the ACCC to inquire into wholesale gas markets in eastern Australia, using its compulsory information gathering powers. While the inquiry was initially tasked to run until 30 April 2020, the Treasurer extended it in July 2019 to 2025. The ACCC has released several interim reports.[127]

### 4.13.7 Electrification of LNG production

On 8 February 2020 the Australian Government announced it would allocate up to $1.5 million for working with the Queensland Government and industry on electrifying the Curtis Island LNG facilities. The production facilities currently use their own gas as a power source in production. Partly electrifying these processes would free up to 12 PJ of gas for delivery to the domestic market.

### 4.13.8 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 per cent to supplement gas supplies, and a number of trials are being explored. Jemena's Power to Gas Trial, co-funded by the Australian Renewable Energy Agency (ARENA), will generate green hydrogen and inject a small percentage (less than 2 per cent by volume) into part of its gas distribution network.[128]

## 4.14 Gas market reform

The CoAG Energy Council directs gas market reforms, which regulatory and market bodies implement.[129] 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.[130]

127 ACCC, 'Gas inquiry 2017–2025', web page, available at www.accc.gov.au/ regulated-infrastructure/energy/gas-inquiry-2017-2025.
128 ARENA, 'Jemena power to gas demonstration', web page, available at: https://arena.gov.au/projects/jemena-power-to-gas-demonstration/.
129 Including the Energy Security Board, the AER, the AEMC, AEMO and the ACCC.
130 CoAG Energy Council, *Measures to improve transparency in the gas market—decision regulation impact statement*, March 2020.

Reform stems from findings by bodies that include the AEMC, the ACCC and the Gas Market Reform Group. The AEMC in 2016 assessed that the eastern gas market is opaque, and participants have low levels of confidence in the information that is available. The reforms aim to increase transparency in the gas market, improving the Gas Bulletin Board and improving the availability of information on market liquidity, prices and gas reserves.

### 4.14.1 Gas Bulletin Board reforms

The Gas Bulletin Board (www.gasbb.com.au) was launched in 2008 to make the gas market more transparent by providing up-to-date information on gas production, pipelines and storage options in eastern Australia. But its usefulness was compromised by gaps in coverage and, at times, the provision of inaccurate data.

Significant reforms in September 2018 brought the Bulletin Board closer to being a 'one stop shop' for the eastern gas system. The reforms removed reporting exemptions, mandated the provision of more comprehensive detail for covered facilities, and extended reporting obligations to smaller facilities and those in Northern Territory. The reporting threshold for transmission pipelines, production facilities and storage facilities was lowered from 20 TJ per day to 10 TJ per day.

Additionally, more comprehensive reporting was mandated for production facilities. Market participants can now access detailed information from production and compression facilities on their daily nominations, forecast nominations, intra-day changes to nominations, and capacity outlooks. This reporting adds transparency to production outages, which informs market responses and helps maintain security of supply.

In the pipeline sector, operators must submit daily disaggregated receipt and delivery point data. The data include information on flows at key supply and demand locations along pipelines. Reporting obligations were also extended to regional pipelines and facilities attached to distribution pipelines.

To encourage compliance, the reforms made reporting obligations subject to civil penalties. The AER assesses the quality and accuracy of the data submitted by market participants against an 'information standard', to ensure the information presented on the Gas Bulletin Board has integrity. The AER published a guidance note outlining its approach to enforcement.[131]

131 AER, *Guidance note—natural gas services bulletin board (enhanced information reporting)*, September 2018.

Further reforms will likely extend reporting to large gas users and LNG processing facilities from 2021. The reforms will also introduce the reporting of gas reserves and contract prices.

#### Liquidity information

In August 2018 the AER began publishing (on the industry statistics page of its website) quantitative metrics for assessing the liquidity of gas markets, and it regularly updates these metrics. In addition, the AER commenced reporting quarterly on the performance of the east coast gas markets, from the third quarter of 2019. These *Wholesale market quarterly* reports build on the liquidity statistics, and contain more detailed analysis of key performance indicators across the markets. Across 2019 these indicators showed signs of improvement.

#### Price and reserves transparency

With gas markets shifting towards shorter term contracts, and suppliers using EOI processes, the transparency of price and other market information is critical. Yet, the market lacks a single indicative price for gas, and lacks consistent gas reserve and resource information. The ACCC moved to address these issues in late 2018 when it began publishing new data on LNG netback prices.[132] The aim is for the data to help gas users negotiate more effectively with gas producers and retailers when entering new gas supply contracts.

Public information on gas reserves and resources in Australia also tends to lack clarity, consistency and accuracy. As such, market participants are less able to identify future supply issues and plan accordingly. For this reason, in late 2018 the ACCC began publishing data on gas reserves and resources, drawing on information provided by reserve owners.

### 4.14.2 Pipeline reforms

Gas produced in one region can help address a supply shortfall elsewhere, provided transmission pipeline capacity is available to transport the gas. But a number of key pipelines experience contractual congestion, which arises when most or all of a pipeline's capacity is contracted, making the pipeline unavailable to third parties. Contractual congestion may occur even if a pipeline has spare physical capacity.

132 ACCC, 'Gas inquiry 2017–2020—LNG netback price series', web page, available at: www.accc.gov.au/regulated-infrastructure/energy/gas-inquiry-2017-2025/lng-netback-price-series.

Three major pipelines—the South West Queensland Pipeline, the Moomba to Adelaide Pipeline System, and the Moomba to Sydney Pipeline—were close to fully contracted in 2018, limiting shippers' ability to transport gas between northern and southern markets.[133]

To manage pipeline congestion issues, some gas producers engage in swap agreements. They bypass the need for transportation arrangements with pipeline operators by 'swapping' rights to gas held in different physical locations. The ACCC found, however, such agreements are complicated, involve extensive negotiations and, by necessity, reveal parties' commercial positions to their competitors. Such agreements are unlikely, therefore, to be an effective long term solution to gas pipeline issues.[134]

#### Secondary trading in underused capacity

Congestion issues focused policy attention on ensuring any spare physical pipeline capacity is made available to the market. Reforms to launch a voluntary trading platform and a secondary compulsory auction of underused capacity took effect in March 2019. Since its commencement, the day-ahead auction in particular has had a positive impact on the east coast gas markets (section 4.10.4)

To promote transparency, the Gas Bulletin Board publishes prices and other key terms in all voluntary trades, as well as the day-ahead auction results. The AER monitors compliance with capacity trading regulations and the proper reporting of trades.

#### Information disclosure and arbitration

Negotiating a fair price to use a gas pipeline is an ongoing issue, with a number of reviews raising concerns about monopolistic pricing practices.[135] The reviews highlighted a lack of transparency and unequal bargaining power between shippers and pipeline operators.

These concerns led to the introduction of Part 23 in the National Gas Rules in August 2017. Part 23 requires otherwise unregulated pipeline businesses to disclose financial, service and access information, following guidelines published by the AER. Customers can use the disclosed information to negotiate gas transport contracts with pipeline operators. If agreement cannot be reached, an access seeker may apply for arbitration. Chapter 5 details the Part 23 regime.

133 ACCC, *Gas inquiry 2017–2020, Interim report, December 2017*, December 2017, p. 59.
134 ACCC, *Gas inquiry 2017–2020, Interim report, December 2017*, December 2017.
135 ACCC, *Inquiry into the east coast gas market*, April 2016, pp. 99–106; CoAG Energy Council, *Examination of the current test for the regulation of gas pipelines*, December 2016.

#### Scope of pipeline regulation

In July 2018 the AEMC reviewed the effectiveness of current gas pipeline regulation. Various tiers of pipeline regulation apply, including full regulation, light regulation, 15 year exemptions, Part 23 regulation and Part 23 exemptions.[136] The review recommended removing a number of inconsistencies across these tiers by:

- requiring 'light regulation' pipelines to publish prices for each pipeline service, and to report financial information similar to that required of Part 23 pipelines
- requiring the AER set an initial capital valuation for light regulation pipelines, to help users negotiate access to pipeline services. The AER currently undertakes this role only for 'full regulation' pipelines.
- extending the Gas Bulletin Board reporting obligations to all full and light regulation transmission pipelines, and requiring these pipelines to report a 36 month outlook for uncontracted capacity
- requiring full and light regulation distribution pipelines to report capacity and use information similar to that which other distribution pipelines are required to report
- including all pipeline expansions within the regulatory framework of the existing pipeline, rather than them being subject to separate arrangements
- widening the scope of pricing information to cover services, including bi-directional flow, and park and hold services.[137]

The CoAG Energy Council in late 2019 released a regulatory impact statement as part of consultation on options for delivering a more efficient, effective and integrated framework for regulating gas pipelines. A final decision is expected by mid-2020.

### 4.14.3 Gas day harmonisation

On 1 October 2019 the gas day start time for each market was standardised to 6.00 am. From their commencement, the different gas markets in the east coast operated with different start times, as a result of historical pipeline arrangements. This difference resulted in unnecessary costs and complexities for participants that operate over multiple locations. Harmonising the gas day start times will reduce these complexities, provide for more interconnection, and help the development of standardised market reforms.

136 Chapter 5 outlines the tiers of gas pipeline regulation.
137 AEMC, *Review into the scope of economic regulation applied to covered pipelines*, July 2018.

Source: Shutterstock

# 5 REGULATED GAS NETWORKS

Gas pipeline networks transport gas from upstream producers to energy customers. Australia's gas pipeline networks consist of: (1) long haul transmission pipelines that carry gas from producing basins to major population centres, power stations and large industrial and commercial plant, and (2) urban and regional distribution networks, which are spaghetti-like cluster of smaller pipes that transports gas to customers in local communities. This chapter covers the 14 gas pipelines and networks regulated by the Australian Energy Regulator (AER), which are located in states and territories other than Tasmania and Western Australia.[1]

Unlike the electricity network sector, 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 prices.[2] The AER sets access prices for three transmission pipelines—the Roma to Brisbane Pipeline (Queensland), the Victoria Transmission System, and the Amadeus Gas Pipeline (Northern Territory). In gas distribution, the AER sets access prices for networks in New South Wales (NSW), Victoria, South Australia and the Australian Capital Territory (ACT).

## 5.1 Gas pipeline services

Gas pipeline businesses earn revenue by providing access (selling capacity) to parties needing to transport gas. Those parties include (1) energy retailers seeking to transport gas to energy users, and (2) commercial and industrial users, and liquefied natural gas (LNG) exporters, which buy gas directly from producers and contract with a pipeline owner to ship it.

An interconnected transmission pipeline grid links gas basins in Queensland, central Australia and Victoria with retail markets across eastern and southern Australia (figure 5.1). This interconnected network further expanded with the opening in 2018 of the Northern Gas Pipeline linking the Northern Territory with Queensland.

The most common service provided by a transmission pipelines is haulage—that is, transporting gas in a forward direction from an injection point on the pipeline to an offtake point further along. Haulage may be offered on a firm (guaranteed) or interruptible (only if spare capacity is available) basis. Some customers seek backhaul too, which is reverse direction transport. Gas can also be stored (parked) in a pipeline on a firm or interruptible basis. As the gas market evolves, a wider range of services are being offered. These new services include compression (adjusting pressure for delivery), loans (loaning gas to a third party), redirection, and in-pipe trades.

Distribution networks consist of high, medium and low pressure pipelines, and run underground. The high and medium pressure mains provide a 'backbone' that services high demand zones, while the low pressure pipes lead off high pressure mains to commercial and industrial customers, and residential homes. While the nature of gas transmission services is evolving to meet changing market needs, distribution pipeline businesses tend to offer fairly standard services—namely, allowing gas injections into a pipeline, conveying gas to supply points, and allowing gas to be withdrawn.

The total length of gas distribution networks in eastern Australia is around 74 000 kilometres. Gas is distributed to most Australian capital cities, major regional areas, and towns. Victoria and Queensland each have multiple distribution networks serving particular areas of the state. NSW, South Australia, Tasmania and the ACT each have a single network.[3]

While gas distributors transport gas to energy customers, they do not sell gas. Energy retailers purchase gas from producers, and pipeline services from pipeline businesses, and sell them as a packaged retail product to their customers. Many retailers offer both gas and electricity products.

## 5.2 Gas pipeline ownership

Australia's gas pipelines are privately owned. Table 5.2 details ownership arrangements for pipelines regulated by the AER, and chapter 4 includes information for other pipelines.

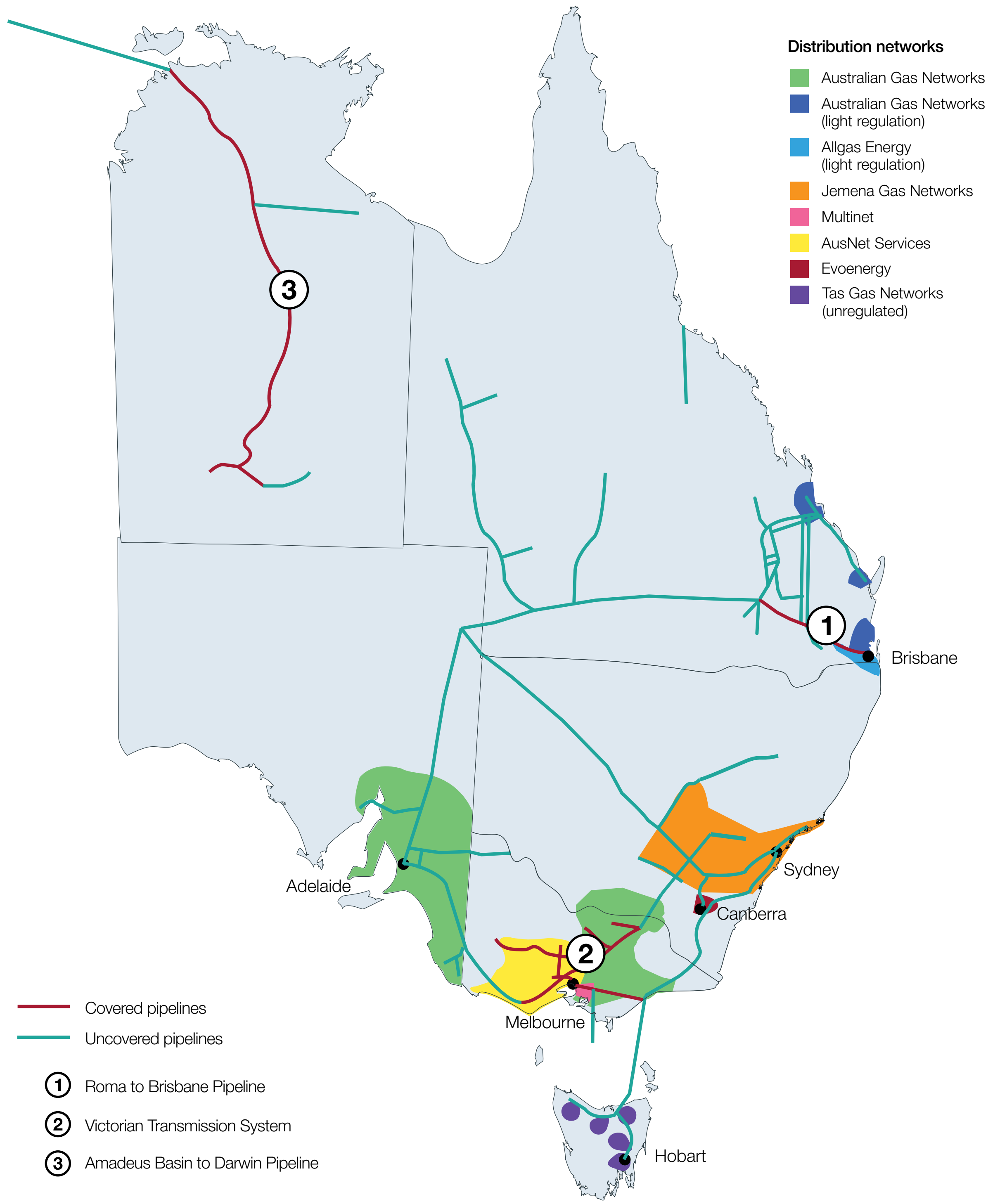
The publicly listed APA Group (APA) is Australia's largest gas pipeline business, with a portfolio mainly in gas transmission. Other sector participants include Jemena (owned by the State Grid Corporation of China and Singapore Power International) and Cheung Kong Infrastructure Holdings Limited (CKI Group) (which operate Australian Gas Networks). The State Grid Corporation of China and Singapore Power International also have interests in the publicly listed AusNet Services.

1 The Economic Regulation Authority (ERA) administers separate regulatory arrangements in Western Australia (www.erawa.com.au). The Office of the Tasmanian Economic Regulator (OTTER) administers separate regulatory arrangements in Tasmania (www.economicregulator.tas.gov.au/gas).

2 Chapter 4 discusses the wider gas transmission sector, including pipelines not under full regulation.

3 Some jurisdictions also have smaller unregulated regional networks, such as the Wagga Wagga network in NSW.

**Figure 5.1**
**Major gas transmission pipelines and distribution networks**




Source: AER.

## Box 5.1 How the AER regulates gas pipelines

The Australian Energy Regulator's (AER) role in gas pipeline regulation varies depending on the type of regulation applying to a pipeline:

- For *full regulation* pipelines, we set a reference tariff (prices) for at least one service offered by the pipeline, following our assessment of the pipeline's efficient costs and revenue needs. We undertake this role for three major transmission pipelines (in Queensland, Victoria and the Northern Territory), and for gas distribution networks in NSW, Victoria, South Australia and the ACT.
- For *light regulation* pipelines, we arbitrate disputes referred to us by access seekers, and monitor pipeline businesses' compliance with their price disclosure obligations.
- For pipelines under *Part 23 regulation*, we set guidelines on the disclosure of financial and pipeline use information, and monitor and enforce compliance with these obligations. We also 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.

The State Grid Corporation of China, Singapore Power International, and the CKI Group also have ownership interests (some substantial) in the electricity network sector, including distribution networks in Victoria, South Australia and the ACT (chapter 3).

In 2018 the CKI Group launched a takeover bid for APA. While the Australian Competition and Consumer Commission (ACCC) cleared the bid of anti-competitive concerns, the Treasurer (on advice from the Foreign Investment Review Board) rejected the bid as 'contrary to the national interest'. The Treasurer cited concerns the takeover would result in an 'undue concentration of foreign ownership by a single company group in [Australia's] most significant gas transmission business'.[4]

## 5.3 How gas pipelines are regulated

Gas pipelines are capital intensive, so average costs will fall as output rises. A natural monopoly industry structure results, 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 opportunity poses a serious risk to consumers, because pipeline charges make up a significant portion of a residential gas bill (section 6.4.2). For this reason, many gas pipelines are regulated to manage the risk of monopoly pricing.

Different tiers of regulation apply to gas pipelines in Australia (discussed below). A case-by-case test assesses the type of regulation that applies to each pipeline, considering whether:

- the pipeline is a natural monopoly
- regulation would promote competition
- regulation would be cost-effective (that is, the benefits of regulation outweigh the costs).

Box 5.1 summarises the AER's role in gas pipeline regulation. Additionally, the AER monitors participants' compliance with the National Gas Law and Rules, and takes enforcement action when needed. Box 4.1 in chapter 4 outlines the AER's work in this area, including work on reforms to facilitate 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 engage in policy reviews with a view to improving gas regulatory arrangements.

### 5.3.1 Full regulation

Full regulation is the most intensive form of regulation. It involves the pipeline owner submitting its prices to an independent regulatory body for a detailed economic assessment. The AER undertakes this role in jurisdictions other than Western Australia.

In particular, the AER assesses whether the access tariffs (prices) paid by a third party for using a full regulation pipeline are efficient. Currently, the AER applies full regulation to three gas transmission pipelines and six gas distribution networks, with a combined value of almost $12 billion (table 5.1).

4 The Hon. Josh Frydenberg MP (Treasurer), 'Proposed acquisition of APA', Media release, 7 November 2018.

Table 5.1
**Full regulation pipelines**

| PIPELINE | JURISDICTION | CUSTOMER NUMBERS [1] | PIPELINE LENGTH (KM)[1] | CAPACITY (TJ/D)[2] | ASSET BASE ($ MILLION)[3] | ANNUAL INVESTMENT ($ MILLION)[4] | ANNUAL REVENUE ($ MILLION)[4] | CURRENT ACCESS ARRANGEMENT [5] | OWNER |
|---|---|---|---|---|---|---|---|---|---|
| TRANSMISSION | | | | | | | | | |
| APA Victorian Transmission System | Vic | na | 1 992 | 1614 | 1074 | 50 | 109 | 1 Jan 2018 – 31 Dec 2022 | APA Group |
| Roma to Brisbane Pipeline | Qld | na | 559 | 211/ 125 | 486 | 14 | 46 | 1 July 2017 – 30 June 2022 | APA Group |
| Amandeus Gas Pipeline | NT | na | 1 658 | 120 | 126 | 4 | 22 | 1 July 2016 – 30 June 2021 | APA Group |
| DISTRIBUTION | | | | | | | | | |
| Jemena Gas Networks | NSW | 1 435 824 | 24 715 | na | 3340 | 172 | 408 | 1 July 2020 – 30 June 2025 | Jemena (State Grid Corporation, Singapore Power) |
| AusNet Services | Vic | 710 000 | 11 650 | na | 1727 | 99 | 175 | 1 Jan 2018 – 31 Dec 2022 | Listed Company (Singapore Power 31%, State Grid Corporation 20%) |
| Multinet | Vic | 687 000 | 9 866 | na | 1321 | 82 | 176 | 1 Jan 2018 – 31 Dec 2022 | CKI Group |
| Australian Gas Networks | Vic | 613 454 | 10 447 | na | 1811 | 114 | 228 | 1 Jan 2018 – 31 Dec 2022 | CKI Group |
| Australian Gas Networks | SA | 423 462 | 7 950 | na | 1693 | 120 | 195 | 1 July 2016 – 30 June 2021 | CKI Group |
| Evoenergy | ACT | 146 000 | 4 911 | na | 419 | 17 | 68 | 1 July 2016 – 30 June 2021 | ACTEW Corporation (ACT Government) 50%, Jemena (State Grid Corporation, Singapore Power) 50% |

km, kilometres; na, not available; TJ/d, terajoules per day.

Note: Excludes gas pipelines in Western Australia, which the Economic Regulation Authority (ERA) regulates.

1. Customer numbers and line length are most recent data available, retrieved 20 April 2020.
2. Where two capacity values appear, the first value represents pipeline capacity for the primary gas flow direction. The second value represents reverse flow capacity for bi-directional pipelines.
3. The asset base is the forecast value of network assets based on the closing regulated asset base (RAB) at 30 June 2019, except for the Victorian transmission network (31 March 2019) and Victorian distribution networks (31 December 2019). Values are in June 2020 dollars. Each year the RAB will simultaneously increase due to new investment, and decrease due to depreciation and asset disposals.
4. Investment and revenue are the annual averages for the current period using actual figures where available, and forecast figures for the remaining years.
5. The current access arrangement period at 1 July 2020.

Source: AER access arrangement decisions; AEMO website; Australian Securities Exchange (ASX) releases; company annual reports; company websites; Gas Bulletin Board.

Only a handful of transmission pipelines are fully regulated. Full regulation has been removed from many pipelines over the past 20 years, and no new pipeline commissioned in the past 20 years is subject to full regulation. Some pipelines moved to light regulation (section 5.3.2). Other pipelines are free from any form of regulation.

Section 5.4 further discusses full regulation.

### 5.3.2 Light regulation

Light regulation uses a commercial negotiation approach supported by mandatory information disclosure. Pipeline businesses must publish access prices and other terms and conditions on their website. They may not engage in inefficient price discrimination or other conduct adversely affecting access or competition in other markets.

If a party is unable to negotiate access to a pipeline they may request the AER arbitrate a dispute.

In eastern Australia, the Carpentaria Pipeline in Queensland, portions of the Moomba to Sydney Pipeline, and the Central West Pipeline in NSW are subject to light regulation (table 5.2). Queensland's two gas distribution networks—Australian Gas Networks and Allgas Energy—became the first distribution networks to convert from full to light regulation in 2015.

### 5.3.3 Part 23 regulation

Gas pipelines not subject to full or light regulation are 'unregulated', so they are free to set their own prices and other terms and conditions. Independent reviews by the ACCC in 2015[5] and for the Council of Australian Governments (CoAG) Energy Council in 2016[6] raised concerns about monopolistic practices by some pipeline operators.

These concerns led to the introduction of new provisions (Part 23) 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.

The ACCC in 2019 found, overall, Part 23 is working as intended and having a positive effect on some pipeline prices and the contracting environment. However, the ACCC had significant concerns with some information published by pipeline operators, including information errors and overstated costs and asset values.[7] It recommended improvements to Part 23 to address these issues, which are being considered as part of the CoAG Energy Council's *Gas pipeline regulation impact statement*.[8]

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.[9]

A pipeline owner can apply to the AER for an exemption from the disclosure provisions if, for example, a pipeline does not provide third party access, has only a single shipper, or has average daily gas injections of less than 10 TJ per day. Exemptions may be subject to conditions and varied at the AER's discretion.

#### Tasmania dispute

At April 2020 only one access determination under the Part 23 rules had been made—a dispute between Hydro Tasmania and Tasmanian Gas Pipeline (TGP) over access to the TGP transmission pipeline in April 2018. The dispute related to the valuation of assets used to provide the services required by the access seeker (firm forward haul services, as available forward haulage). The arbitrator determined a valuation method to reflect the value of assets used in providing the relevant services.[10]

## 5.4 How gas pipeline access prices are set

Gas pipeline businesses earn revenue by selling capacity in their pipelines to customers needing to transport gas. A customer buys access to that capacity under terms and conditions that include an access price. The AER sets access prices for full regulation pipelines in eastern Australia and the Northern Territory under broadly similar rules to those applied to electricity networks (chapter 3).

The owners of other pipelines—including those subject to light regulation and the new Part 23 regime—are free to set their own prices. Light regulation pipeline owners must publish their prices, but these prices are not independently vetted.

### 5.4.1 Regulatory objective and approach

The National Gas Law and National Gas Rules lay out the regulatory framework for gas pipelines. The National Gas Law's regulatory objective is to promote efficient investment in, and operation and use of, gas services for the long term interests of consumers of gas, in terms of the price, quality, safety, reliability and security of supply of gas. The National Gas Rules set out revenue and pricing principles, including that pipeline businesses should have a reasonable opportunity to recover efficient costs.

5 ACCC, *Inquiry into the east coast gas market*, 2018.
6 CoAG Energy Council, *Examination of the current test for the regulation of gas pipelines*, December 2016.
7 ACCC, *Gas inquiry 2017–2020, Interim report, July 2019*, August 2019.
8 CoAG Energy Council, *Measures to improve transparency in the gas market—decision regulation impact statement*, March 2020.
9 AER, 'Part 23 (Access to non-scheme pipelines) exemptions', web page, available at: https://www.aer.gov.au/networks-pipelines/non-scheme-pipelines/part-23-access-to-non-scheme-pipelines-exemptions.
10 AER, *Final access determination—Tasmanian Gas Pipeline*, April 2018.

**Table 5.2**
**Light regulation pipelines**

| PIPELINE | LOCATION | CUSTOMER NUMBERS | PIPELINE LENGTH (KM) | CAPACITY (TJ/D)[1] | OWNER |
|---|---|---|---|---|---|
| TRANSMISSION | | | | | |
| Carpentaria Pipeline (Ballera to Mount Isa) | Qld | na | 942 | 119 | APA Group |
| Central West Pipeline (Marsden to Dubbo) | NSW | na | 255 | 3 | APA Group |
| Moomba to Sydney Pipeline[2] | NSW | na | 2001 | 489/120 | APA Group |
| DISTRIBUTION | | | | | |
| Allgas Energy[3] | Qld | 100 000 | 3218 | na | Marubeni 40%, Deutsche AWM 40%, APA Group 20% |
| Australian Gas Networks[3] | Qld | 92 852 | 2703 | na | CKI Group |

km, kilometres; na, not available; TJ/d, terajoules per day.

Note: The AER does not conduct access arrangement reviews for light regulation pipelines, so limited data are available. Unlisted pipelines are unregulated, except under the Part 23 information disclosure and arbitration provisions introduced in July 2017. Chapter 4 lists major unregulated transmission pipelines. Gas distribution networks in Tasmania and the Northern Territory are unregulated.

1. Part of the Moomba to Sydney Pipeline is subject to light regulation. The pipeline is unregulated from Moomba to the offtake point of the Central West Pipeline at Marsden.
2. Where two capacity values appear, the first value represents pipeline capacity for the primary gas flow direction. The second value represents reverse flow capacity for bi-directional pipelines.
3. Gas distribution pipelines in Queensland converted from full to light regulation in 2015.

Sources: Australian Securities Exchange (ASX) releases; company annual reports; company websites.

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 upcoming access arrangement (which typically covers a five year period), and an access price derived from demand forecasts.

The AER then assesses the proposal—focusing on the business's forecast revenue requirements to cover its efficient costs. As in electricity, the AER uses a building block approach to assess the business's *efficient* costs (section 5.5). Ensuring only efficient costs are included in the calculation of a regulated business's revenue requirement helps protect customers from being charged unreasonable prices.

The AER draws on a range of inputs to assess efficient costs, including cost and demand forecasts, and revealed costs from experience. But it has not formalised the approach through published guidelines. An exception is the rate of return assessment, for which a common AER guideline applies to both electricity and gas. New legislation in November 2018 provided for the AER to make binding rate of return determinations. The AER released its first Rate of Return Instrument (RRI) in December 2018, setting out its approach (section 3.11.1).

If the AER finds a business's access arrangement proposal to be unnecessarily costly, it may go back to the business and ask for more detailed information or for a clearer business case. If these steps fail to satisfy the AER, it may amend the access arrangement to align it with efficient costs.

The AER's final decision sets an access price (reference tariff) for a commonly sought gas pipeline service (reference service)—such as firm haulage—for the duration of the access arrangement. That reference tariff can increase only to cover inflation, and 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.

The Australian Energy Market Commission (AEMC) in March 2019 implemented new rules to improve information disclosure, support more effective negotiations, and improve access to covered pipelines. The new rules are designed to help gas pipeline users negotiate lower prices and better deals.[11] They do so by:

- setting out a process for determining which services will have reference tariffs set by the AER
- clarifying how the AER calculates efficient costs
- strengthening reporting obligations to support more balanced negotiations
- giving stakeholders more input into AER decisions
- setting a clear trigger for pipeline users to seek arbitration if negotiations fail.

Most of these provisions commenced in March 2019.

## 5.4.2 Incentive schemes

The National Gas Rules allow scope for gas pipeline businesses to earn bonus revenue by outperforming efficiency targets (and imposes penalties for underperformance). An efficiency carryover mechanism allows businesses to retain, for up to six years, any 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 per cent of the gains through lower access prices. The mechanism is similar to the efficiency benefit sharing scheme (EBSS) in electricity (box 3.5), but is written into each business's access arrangement rather than being articulated in a general guideline.

A number of gas distributors proposed a capital expenditure sharing scheme (CESS) in their latest access arrangement proposals, including Jemena (NSW) for its 2020–25 access arrangement. The gas rules do not mandate these schemes, but allow the AER to approve the use of such a scheme to incentivise pipeline businesses to efficiently maintain and operate their networks.

The CESS for gas pipelines operates in a similar way to the CESS for electricity networks (box 3.4). It allows a pipeline business to earn a bonus by keeping new investment spending below forecast levels (and penalties apply if the business invests above target). In later access arrangements, the business must pass on around 70 per cent of savings to customers as lower pipeline charges.

To mitigate the risk of encouraging pipeline businesses to inflate investment forecasts, the AER scrutinises whether proposed investments are efficient. The CESS design ensures deferred expenditure does not attract rewards, so businesses are not incentivised to defer critical investment needed for safe and reliable network operation. A network health index ensures rewards depend on the pipeline business maintaining current service standards.

The Victorian gas distributors were the first to implement the CESS scheme, as part of their 2018–22 access arrangements. To date, no gas transmission business has sought to participate in the scheme.

Other incentives applying to electricity networks—on service performance and demand management innovations—are not available to gas pipeline businesses. The Victorian gas distributors sought the introduction of a network innovation scheme in 2018–22. But the AER rejected the scheme, arguing the current framework provides sufficient incentives for innovation, particularly with the addition of the CESS scheme.[12]

## 5.4.3 Timelines and process

After a gas pipeline business submits an access arrangement proposal, the AER has six months (plus optional stop-the-clock time at certain stages) to make a final decision on how much revenue the business can recover from its customers (figure 5.2). The assessment period can be extended by up to two months, but 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.

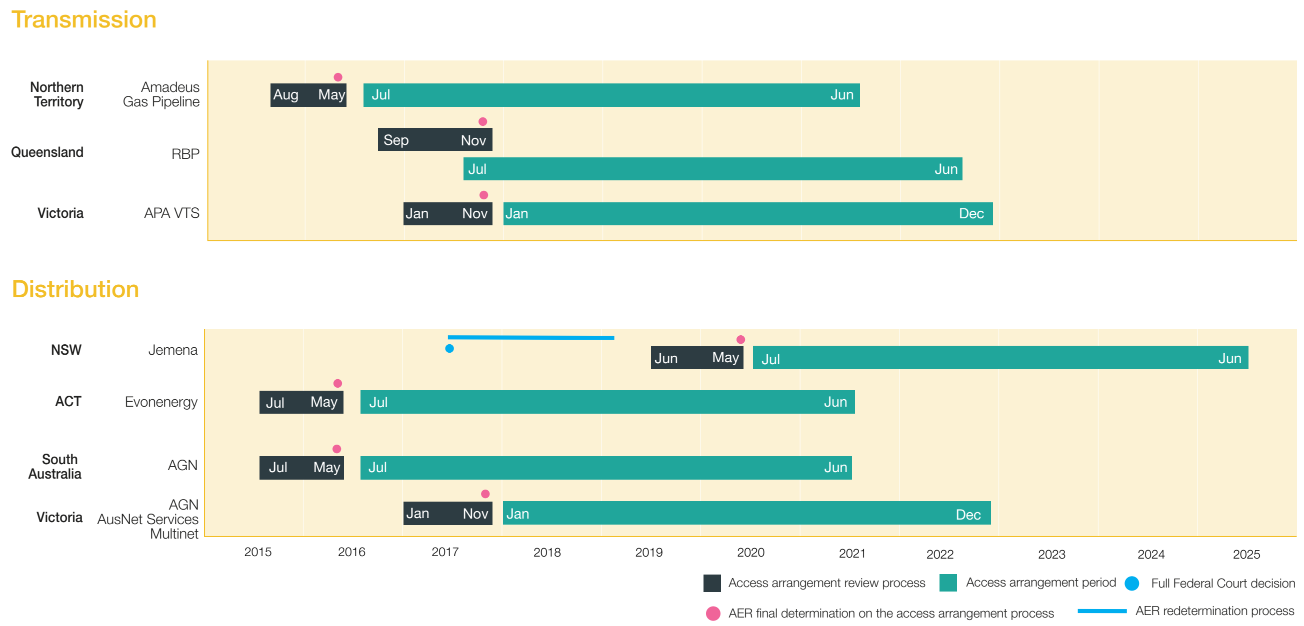
Figure 5.2 sets out timelines for the AER's access arrangement reviews. The AER assesses access

11 AEMC, National Gas Amendment (Regulation of Covered Pipelines) Rule 2019, 14 March 2019.

12 AER, *AusNet Services gas access arrangement 2018–2022, Draft decision, Attachment 14—other incentive schemes*, July 2017.



**Figure 5.2**
**AER decision timelines—full regulation gas pipelines**




AGN, Australian Gas Networks; RBP, Roma to Brisbane Pipeline; VTS, Victorian Transmission System.
Note: Times are subject to variation. For the latest information, please check www.aer.gov.au/networks-pipelines/determinations-access-arrangements.
Source: AER.

arrangements on a rolling cycle, with staggered review timing to avoid bunching. The (typically) five 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 dealing with some uncertainties. The AER can approve cost pass-throughs if a significant event (such as a regulatory change or natural disaster) imposes significant costs that were not forecast. A gas network may also approach the AER to pre-approve a contingent investment project whose need is uncertain at the time of the reset. A pre-approval allows the network business to roll the project into the pipeline's asset base in the forthcoming access arrangement.

## 5.4.4 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. While not mandated in the gas rules, evidence of real constructive engagement can give the AER confidence that the business is genuinely committed to meeting customer 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.

Before submitting its 2020–25 revenue proposal, Jemena (NSW) undertook extensive customer engagement which was well received by stakeholders. Jemena engaged with residential and business customers through forums, study circles, focus groups, data workshops, consumer surveys and consultation drafts.

The AER's Consumer Challenge Panel (CCP) found Jemena demonstrated a genuine commitment to engagement, noting its proposal identified and addressed different views, and demonstrated how engagement shaped its proposal.[13] Jemena was awarded the Energy Networks Australia and Energy Consumers Australia 2019 Consumer Engagement Award for its Gas Networks Deliberative Forum in NSW. Retailers generally commented favourably on Jemena's

13 CCP19, *Submission to the AER on JGN's regulatory proposal*, August 2019, pp. 5–8.

engagement process, but noted it did not resolve some issues with Jemena's Reference Service Agreement.[14]

Customer engagement is more advanced in gas distribution than in transmission. APA Group chose not to undertake stakeholder engagement in developing its 2017–22 access arrangement proposal for the Roma to Brisbane Pipeline. Similarly, the AER's Consumer Challenge Panel was critical of APA Group's commitment to customer engagement on its 2018–22 access arrangement for the Victorian Transmission System.[15] APA Group described the AER's and the Consumer Challenge Panel's consultation expectations as 'unrealistic' and 'ultimately … a waste of time and resources'.[16]

### 5.4.5 Recent AER access arrangement decisions

The AER published in June 2020 its final decision on Jemena's access arrangement proposal for its NSW gas distribution network. This access arrangement will take effect on 1 July 2020 and remain in place until 30 June 2025.

The final decision will lower distribution charges in retail gas bills in NSW. Among residential customers, distribution charges account for around 41 per cent of a typical customer's bill in coastal areas, and 33 per cent in regional areas.

The key driver of Jemena's lower forecast revenue for 2020–25 compared with the previous period was a lower return on capital (reflecting continued downward movements in the rate of return). The decision also factored in Jemena returning $169 million to its customers that was over-recovered in the previous access arrangement period.[17] The remittal outcome is a key driver of the estimated retail gas bill reduction over the 2020–25 period, particularly in the first year (2020–21) with estimated bill reductions of 6 per cent for regional gas customers and 8.3 per cent for coastal gas customers.

14 Origin, *RE: AER draft decision and revised regulatory proposal for Jemena Gas Networks (NSW) access arrangement 2020–25*, February 2020, p. 1; EnergyAustralia, *Jemena Gas Networks (NSW) access arrangement 2020–25*, February 2020, pp. 1–2; AGL, *Jemena Gas Networks (NSW) access arrangement 2020–25*, February 2020, p. 2.
15 CCP11, Response to the AER's draft decisions and the revised proposal from APA VTS for a revenue reset/access arrangement for the period 2018 to 2022, September 2017, p. 4.
16 APA, *Victorian Transmission System access arrangement revised proposal, Submission response to draft decision*, August 2017, p. 8.
17 Jemena's 2015–20 access arrangement was subject to extensive legal appeals and interim arrangements (section 3.5.2). See also: AER, *State of the energy market 2018*, section 5.4.7, 2018; AER, *Final decision, Jemena Gas Networks 2015–20 access arrangement*, February 2019.

The AER accepted the majority of Jemena's proposed capital expenditure, except for expenditure relating to customer connections, and meter and mains replacements. It did not accept Jemena's proposal to approve costs and benefits for new capital assets using an investment horizon to 2070, noting the uncertainties beyond a 30 year horizon. But the AER did approve an increase in operating expenditure on corporate overheads and pipeline inspection costs, and forecast increases in unaccounted for gas.

The full effect of the COVID-19 pandemic on Jemena was uncertain at the time of the AER's determination. The AER based its decision on information and forecasts that could reasonably be made at the time, but it recognised there are uncertainties around how COVID-19 will affect Jemena's operations and costs. If it becomes clear that the impacts of COVID-19 are substantial, then the AER will consider implementing processes to re-open existing access arrangements.

### 5.4.6 Legal reviews

An affected party can file an application with the Federal Court for judicial review of an AER access arrangement decision. Until 2017 a party could also apply to the Australian Competition Tribunal for a limited merits review of an AER decision, and then appeal the Tribunal's decision to the Full Federal Court. The Australian Government abolished this avenue of appeal in October 2017.

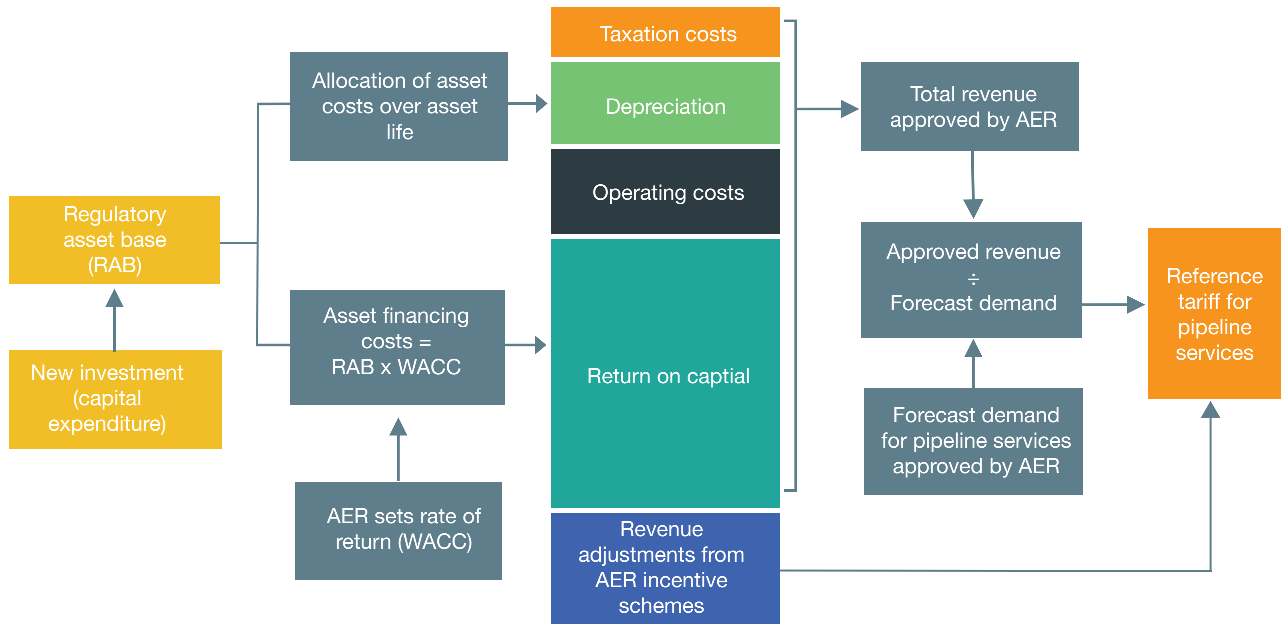
After a long running appeal, the Full Federal Court in July 2017 ordered the AER to remake elements of its access arrangement decision for Jemena (NSW). The AER's remade decision published in February 2019 approved $17.6 million of revenue additional to what it approved in 2015. However, adjustments from interim arrangements for the network will result in Jemena returning $169 million to consumers in the 2020–25 access arrangement period (box 3.2 and section 5.4.5).[18]

## 5.5 The building blocks of gas pipeline revenue

In assessing a gas pipeline business's revenue needs, the AER breaks up its costs into 'building blocks'. Specifically, the AER forecasts how much revenue that the business is likely to need to cover four key cost components.

18 AER, *Final decision, Jemena Gas Networks (NSW) Ltd 2015–20 access arrangement*, February 2019.

**Figure 5.3**
**How gas pipeline revenue and charges are set**




Note: Revenue adjustments from incentive schemes encourage pipeline businesses to manage their operating and capital expenditure efficiently, and to innovate.

Source: AER.

These components are:

- efficient operating and maintenance costs
- commercial returns to shareholders and investors that fund its operations
- asset depreciation costs
- forecast taxation costs.

It also makes adjustments for incentive payments (figure 5.3).

Gas pipeline businesses are entitled to earn revenue to cover their efficient costs each year, Pipelines have a long life, so the cost of new investment is recovered over the economic life of the asset, which may be several decades. The amount recovered each year is called depreciation, and it covers the lost value of assets through wear and tear, and technical obsolescence.

The shareholders and lenders that fund those assets must be paid a commercial return on their investment each year. Those returns are forecast to absorb 52 per cent of transmission revenues, and 38 per cent of distribution revenues in the current access periods.

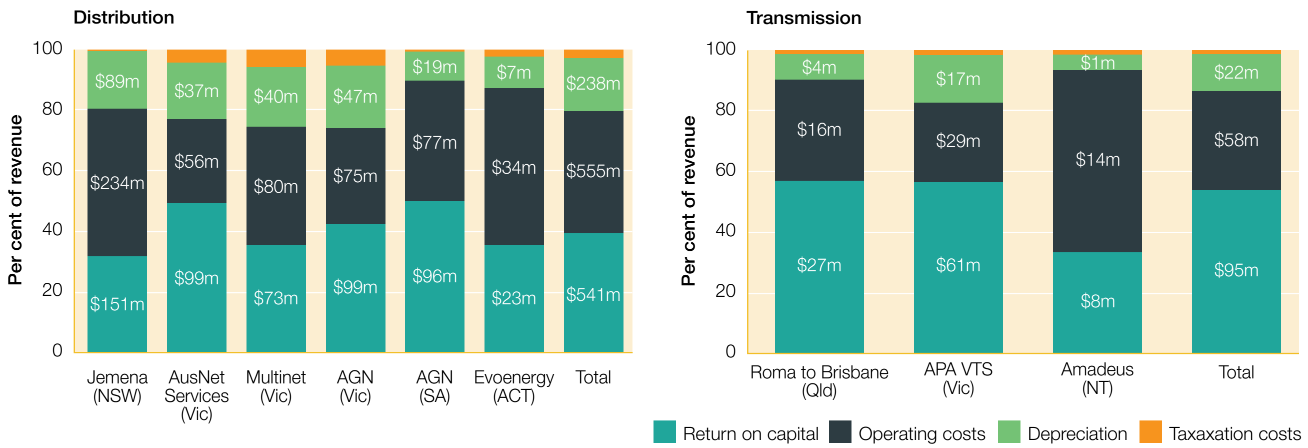
The returns are calculated by multiplying:

- the value of the network's assets calculated as the regulatory asset base (RAB), which is adjusted each year for new investment, less asset disposals and depreciation, by
- the rate of return paid to investors that fund those assets, through either equity ownership or debt. The AER sets the rate of return, also called the weighted average cost of capital (WACC).

Operating and maintenance costs are forecast to absorb 32 per cent of transmission revenues, and 39 per cent of distribution revenues in the current access periods. Overheads, taxation and other costs account for the remainder of a pipeline revenues. Sections 5.6–5.8 examine each component in more detail.

Gas pipeline businesses have scope to earn *additional* revenue through regulatory incentives that encourage the efficient management of operating and capital expenditure programs (section 5.4.2).

Figure 5.4
**Composition of average annual gas pipeline revenues**




AGN, Australian Gas Networks; VTS, Victorian Transmission System.

Note: Network businesses also receive bonuses or penalties that impact on annual network revenues. These bonuses/penalties are not material and are not considered in this chart.

Source: Post tax revenue modeling used in AER determination process.

Figure 5.4 illustrates the composition of pipeline revenues in recent gas transmission and distribution decisions.

## 5.6 Gas pipeline revenues

Full regulation gas pipelines (table 5.1) are forecast to earn around $7.1 billion in current access arrangement periods—14 per cent less than forecast in previous periods:

- Full regulation transmission pipelines are forecast to earn around $887 million[19] in current access arrangement periods—8 per cent less than forecast in previous periods.
- Full regulation distribution networks are forecast to earn around $6.2 billion in current access arrangement periods—15 per cent less than forecast in previous periods.

The previous round of access arrangement decisions were made at a time of increased pipeline investment in response to ageing assets and forecasts of rising energy demand. Network businesses also had higher financing costs due to instability in global financial markets. But these cost pressures have since eased. Lower financing costs and weaker domestic gas demand in recent years—caused by significantly higher gas prices— reduced forecast revenue needs for most pipeline businesses.

Further, legislation enacted in November 2018 provides for the AER to make its rate of return determinations binding. The AER released its first Rate of Return Instrument (RRI) in December 2018, setting out how it determines the rate of return on capital in access arrangement determinations.[20]

These changes reduced the average rate of return in the AER's five access arrangement decisions made in 2017 to under 6 per cent, and its sole access arrangement decision made in 2020 to 4.49 per cent (to be applied to Jemena (NSW) in 2020–21, compared with over 10 per cent in decisions made from 2008 to 2010 (figure 5.5). This reduction translates to significantly lower network revenues and gas pipeline charges.

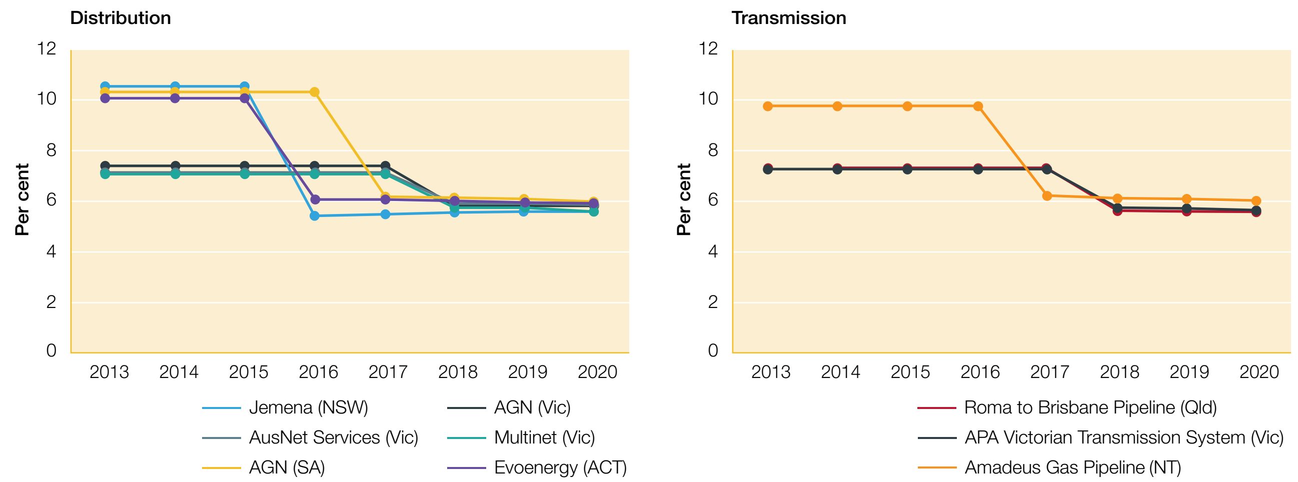
While pipeline revenues are generally falling, the outcomes vary between network businesses. In gas transmission, revenues are forecast to fall in the current access arrangement period by 19 per cent for the Roma to Brisbane Pipeline (Queensland) and 30 per cent for the Amadeus Pipeline (Northern Territory). The Victorian Transmission System, however, is forecast to increase

19 Excluding revenue adjustments valued at around $19.7 million.

20 The 2018 RRI specifies the return on debt as a formula, using the trailing average portfolio approach. Network businesses not already applying this method must transition to it over a 10 year period.



Figure 5.5
**Rates of return for gas pipeline networks**




AGN, Australian Gas Networks.

Note: Rate of return = nominal vanilla weighted average cost of capital (WACC). Victorian pipeline businesses report on a calendar year basis (i.e. year ending 31 December). All other pipeline businesses report on a financial year basis (i.e. year ending 30 June). The calendar years shown in the charts reflect the later of the two relevant years for non-Victorian pipeline businesses (e.g. 2017–18 is shown as 2018).

Source: AER decisions on gas pipeline access arrangements; AER decision following the remittal by the Australian Competition Tribunal and Full Federal Court.

revenue by 5 per cent, reflecting an increased capital base following new investment in 2013–17 by its owner (APA Group).

In gas distribution, revenues are forecast to fall by 8–24 per cent in the current access arrangement periods for five of the six networks for which the AER sets prices. Relatively stable or rising revenue for the Victorian networks reflects their higher operating and capital expenditure costs associated with new customer connections, as in new housing estates (figure 5.6).

## 5.7 Gas pipeline investment

Investment requirements differ between the gas transmission and distribution sectors:

- Gas *transmission* investment typically involves large, lumpy capital projects to expand existing pipelines (through compression, looping or extension) or construct new infrastructure. Additionally, some transmission pipelines have been re-engineered for bi-directional flows.
- Gas *distribution* investment mainly comprises augmentation (expansion) of existing systems to cope with new customer connections, as in new housing estate developments. Older networks also require replacement programs for deteriorating infrastructure.

For pipelines under full economic regulation (table 5.1), the AER assesses whether investments are prudent and efficient, based on criteria in the National Gas Rules.

### 5.7.1 Recent investment

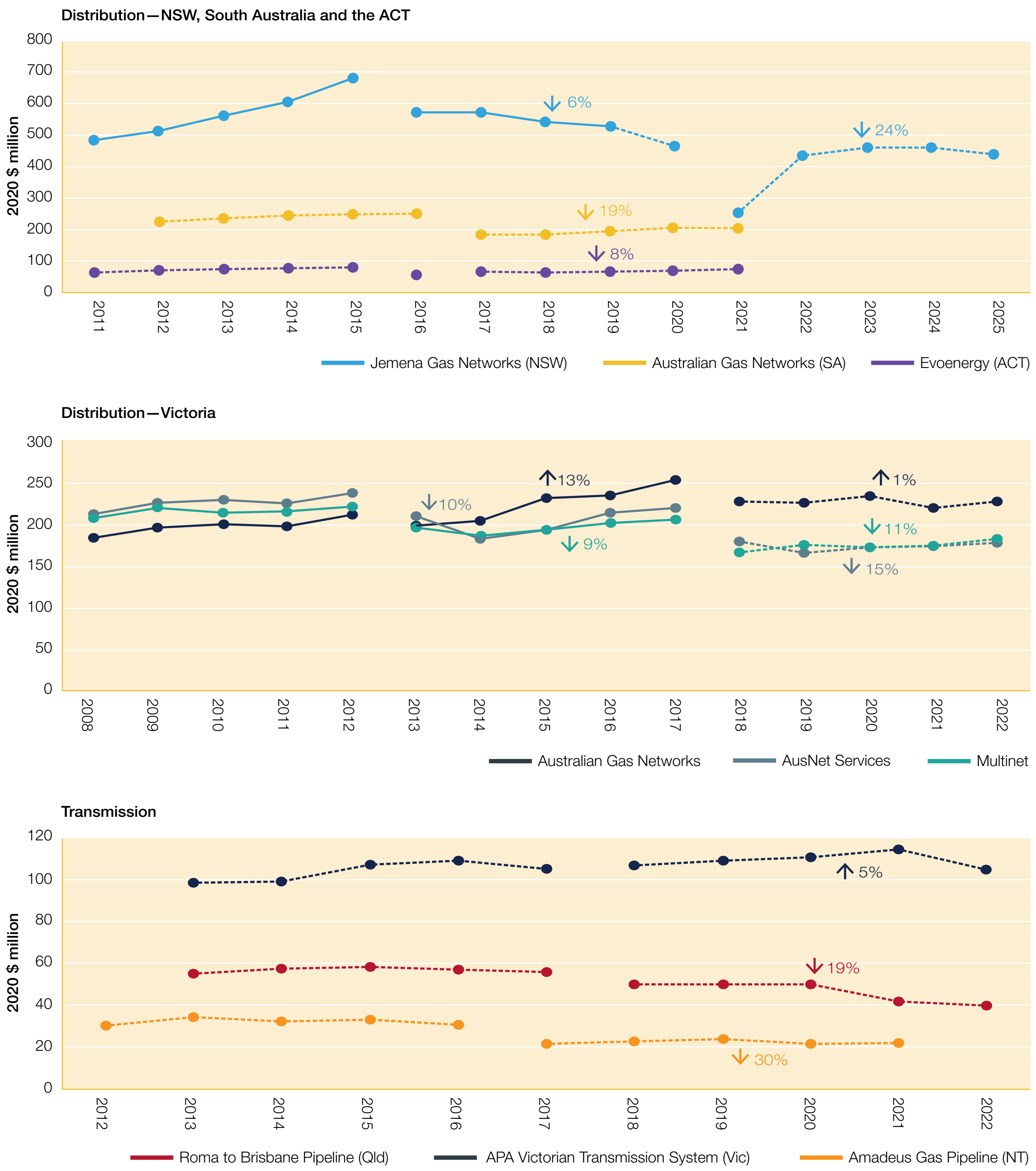
Full regulation transmission pipelines are forecast to invest a total of $335 million in current access arrangement periods, 40 per cent less than the $554 million invested in the previous periods (figure 5.7). Forecast investment is lower than in the previous period for all pipelines:

- Investment in the Roma to Brisbane Pipeline is forecast to fall by 9 per cent in the current period following the completion of a major augmentation program.
- Investment requirements are forecast to fall in the Northern Territory by 62 per cent in the current period following the completion of an integrity works program.
- Investment in the Victorian Transmission System is forecast to fall by 42 per cent. This follows a period of significant overspending against forecast to implement systems to meet new gas market rules, and to augment the Victorian Northern Interconnect Expansion to meet increased demand.[21]

21 AER, *Draft decision, APA VTS Australia Gas access arrangement 2018 to 2022*, July 2017, p. 8.

Figure 5.6

**Gas pipeline revenues**

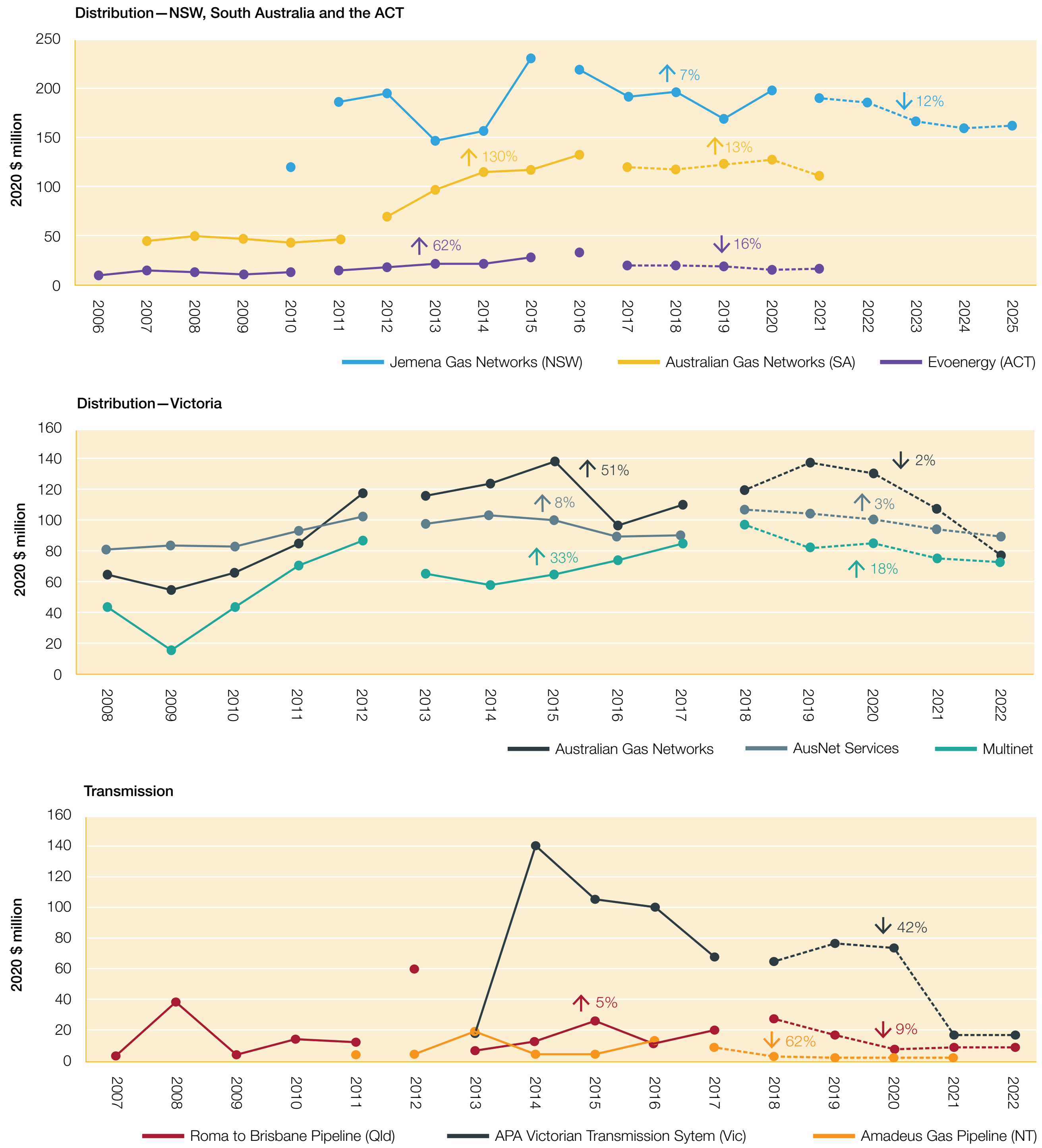



Note: Actual revenue is shown as a solid line; forecast revenue is shown as a broken line. Percentages represent the change between periods. Forecasting updates may result in some outcomes varying from those previously reported. Victorian pipeline businesses report on a calendar year basis (i.e. year ending 31 December). All other pipeline businesses report on a financial year basis (i.e. year ending 30 June). The calendar years shown in the charts reflect the later of the two relevant years for non-Victorian pipeline businesses (e.g. 2017–18 is shown as 2018).

Source: AER.

Figure 5.7

**Gas pipeline investment**

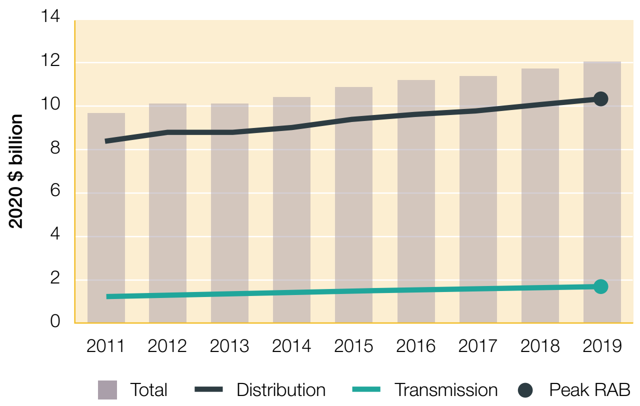



Note: Actual capital expenditure is shown as a solid line; forecast capital expenditure is shown as a broken line. Percentages represent the change between periods. Forecasting updates may result in some outcomes varying from those previously reported. Victorian pipeline businesses report on a calendar year basis (i.e. year ending 31 December). All other pipeline businesses report on a financial year basis (i.e. year ending 30 June). The calendar years shown in the charts reflect the later of the two relevant years for non-Victorian pipeline businesses (e.g. 2017–18 is shown as 2018).

Source: AER.

**Figure 5.8**

**Gas pipeline regulatory asset base**




Note: Victorian pipeline businesses report on a calendar year basis (i.e. year ending 31 December). All other pipeline businesses report on a financial year basis (i.e. year ending 30 June). The calendar years shown in the charts reflect the later of the two relevant years for non-Victorian pipeline businesses (e.g. 2017–18 is shown as 2018).

Source: AER modeling.

Investment in full regulation distribution networks in eastern Australia is forecast at around $3.0 billion in current access arrangement periods, comparable to the amount invested in the previous periods:

- The AER in 2020 approved a 12 per cent reduction in investment in Jemena's (NSW) network in 2020–25, compared with what Jemena invested in the previous period.
- Investment in Victoria's Australian Gas Networks and AusNet Services distribution networks over the 2018 to 2022 access period is steady (a 2 per cent decrease and 3 per cent increase respectively). Multinet is forecast to increase investment by 18 per cent.
- The AER approved a 13 per cent rise in investment in South Australia's Australian Gas Networks in 2017–21 to fund a major mains replacement project.
- The AER approved 16 per cent less investment for the ACT's Evoenergy network in 2017–21, compared with the previous period, after finding a prudent operator would not undertake some augmentation proposals.

### 5.7.2 Regulatory asset base

Capital investment approved by the AER is added to a pipeline's RAB, on which future returns are earned. The RAB for regulated gas pipelines continues to rise, reaching $10.3 billion for distribution networks and $1.7 billion for transmission pipelines in 2019 (figure 5.8).

## 5.8 Gas pipeline operating costs

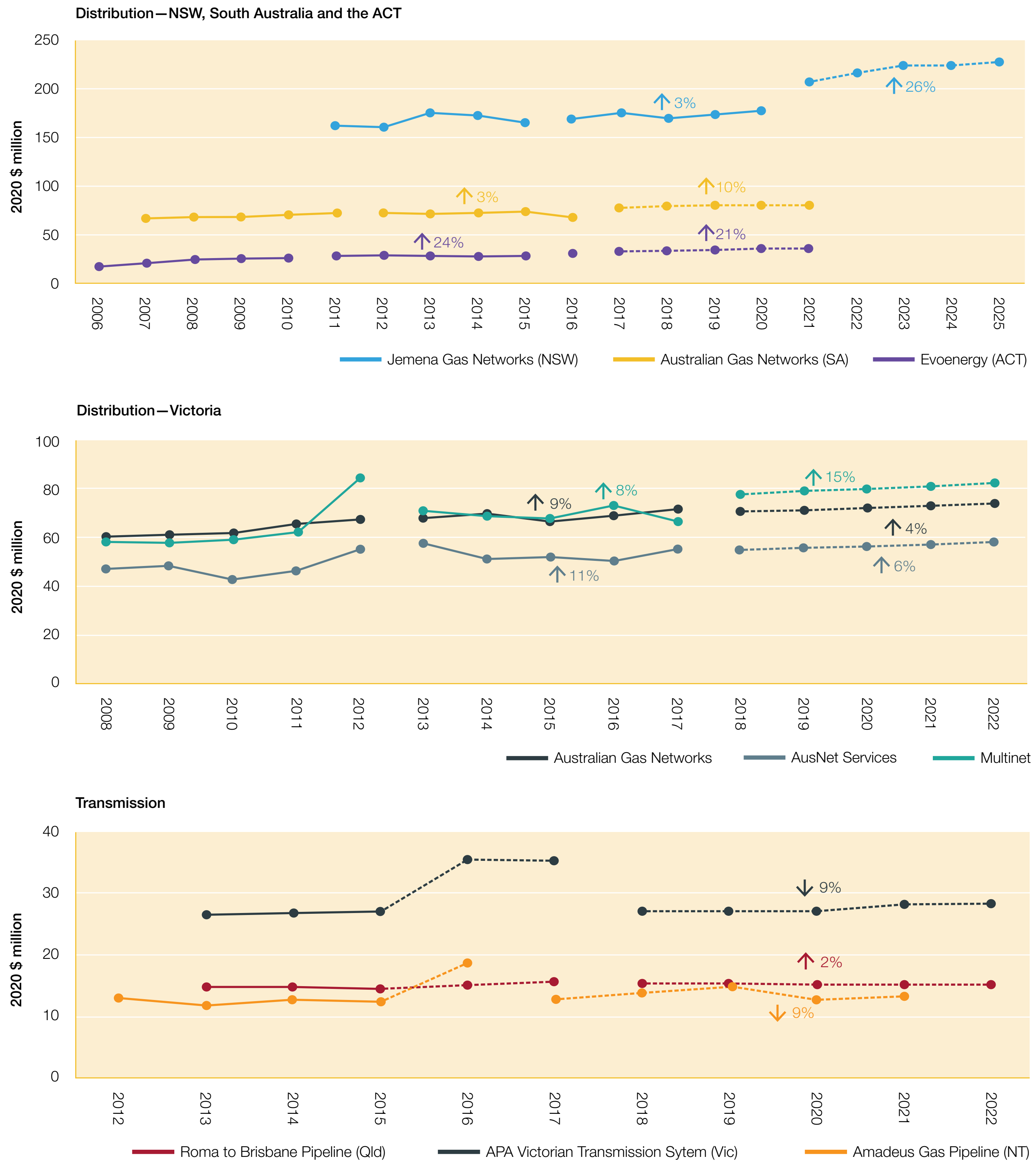
The AER's assessment of a gas network's efficient operating and maintenance costs accounts for cost drivers such as forecast customer growth, expected productivity improvements, changes in labour and materials costs, and changes in the regulatory environment.

Gas transmission networks are forecast to spend around $281 million on operating expenses in the current access arrangement periods—4 per cent less than the $294 million forecast in previous periods.

Gas distribution networks are forecast to spend around $2.7 billion on operating expenses in the current access arrangement periods—16 per cent more than the $2.3 billion forecast in previous periods. The AER in 2020 approved a 26 per cent increase in Jemena's operating expenditure to cover higher corporate overheads and pipeline inspection costs in 2020–25, and expected increases in unaccounted for gas relative to 2015–20 (figure 5.9).

**Figure 5.9**

**Gas pipeline operating costs**




Note: Actual operating expenditure is shown as a solid line; forecast operating expenditure is shown as a broken line. Percentages represent the change between periods. Forecasting updates may result in some outcomes varying from those previously reported. Victorian pipeline businesses report on a calendar year basis (i.e. year ending 31 December). All other pipeline businesses report on a financial year basis (i.e. year ending 30 June). The calendar years shown in the charts reflect the later of the two relevant years for non-Victorian pipeline businesses (e.g. 2017–18 is shown as 2018).

Source: AER.

Source: Shutterstock

# 6 RETAIL ENERGY MARKETS

## 6.1 Retail products and services

Most energy customers source their electricity and gas through a retailer that buys energy in wholesale markets and packages it with network services to sell as a bundled product. Retailers monitor and bill customers for the energy they use, and manage the risk of price volatility in wholesale markets.

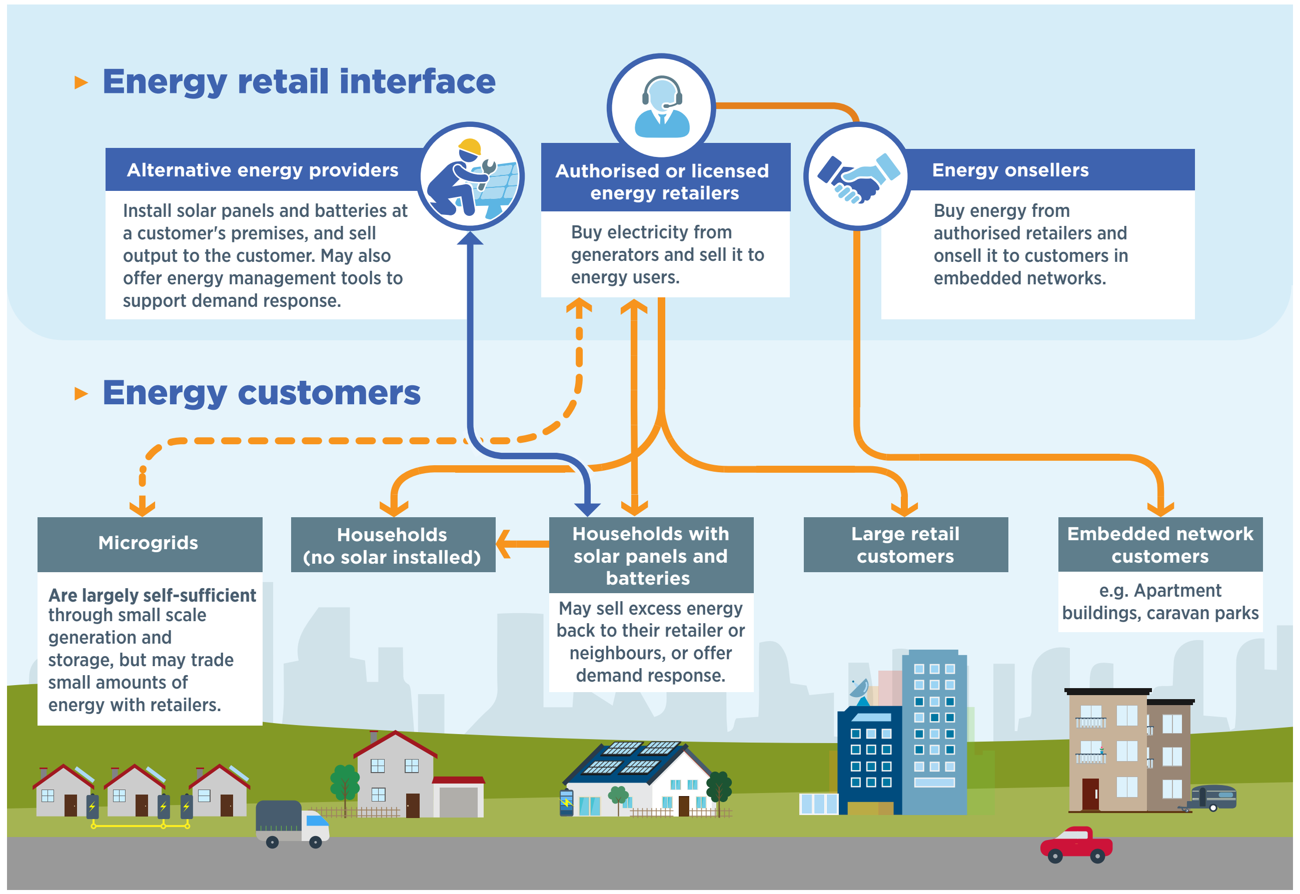
But this traditional retail model is evolving as customers become active participants in the market and take greater control over their energy use (figure 6.1). Advances in technology (particularly in the electricity market), rising energy prices and environmental concerns are driving this change, which is opening markets for new types of energy services. Examples include:

- *smart meters*, which provide information on energy use that gives retailers scope to offer more innovative products, and for new sellers to offer 'add-on' energy management services
- *rooftop solar photovoltaic (PV) systems*, which enable energy customers to self-generate electricity, and sell any excess back to their retailer or a third party
- *batteries, load control devices and similar technologies*, which allow customers greater control over their electricity use and the ability to engage in the market in new ways (for example, by storing electricity and entering demand response contracts).

Established energy retailers and new entrant businesses are driving market opportunities for new services.

A small but growing base of customers are also bypassing the traditional energy supply model, going 'off grid' through self-sufficient solar PV generation and battery storage, community based stand-alone systems, or microgrids.

**Figure 6.1**
**An evolving retail energy market**




### Box 6.1 The AER's role in retail energy markets

The Australian Energy Regulator (AER) regulates retail energy markets so energy customers (particularly residential and small business customers) can participate confidently and effectively in those markets, and to protect those unable to safeguard their own interests. We undertake this work in Queensland, New South Wales (NSW), South Australia, Tasmania and the Australian Capital Territory (ACT).

We aim to empower customers to make informed decisions on their energy use, and protect them when problems arise. As part of this work, we:

- set a price cap on standing offers for electricity in south east Queensland, NSW and South Australia. This cap also acts as a reference price for market offers.
- maintain an energy price comparator website (www.energymadeeasy.gov.au) to help residential and small business customers understand the range of offers in the market, make better choices about those offers, and be aware of their rights and responsibilities when dealing with energy providers
- monitor and enforce compliance (by retailers and distributors) with obligations in the National Energy Retail Law, Rules and Regulations
- oversee retail market entry and exit by assessing applications from businesses looking to become energy retailers, granting exemptions from the requirement to hold a retailer authorisation, and administering a national retailer of last resort scheme to protect consumers and the market if a retailer fails
- report on the performance of the market and energy businesses (including information on energy affordability)
- develop hardship guidelines and approve customer hardship policies that energy retailers offer to customers facing financial hardship and seeking help to manage their bills.

## 6.2 Energy market regulation

Five jurisdictions—Queensland, New South Wales (NSW), South Australia, Tasmania and the Australian Capital Territory (ACT)—apply a common national framework for regulating retail energy markets. The framework applies to electricity retailing in all five jurisdictions and to gas retailing in Queensland, NSW, South Australia, and the ACT. Victoria has not implemented the framework, but its regulatory arrangements are largely consistent with the national framework.[1]

The Australian Energy Market Commission (AEMC) sets the rules for the retail market, which are applied through the National Energy Retail Law (Retail Law). The law confers wide ranging regulatory responsibilities on the Australian Energy Regulator (AER) (box 6.1). This chapter focuses on the five jurisdictions where the AER has regulatory responsibilities, and also covers the Victorian market where possible. Western Australia and the Northern Territory apply separate regulatory arrangements and are not covered in this chapter.

The Retail Law operates alongside the Australian Consumer Law to protect small energy customers in their electricity and gas supply arrangements. It sets out protections for residential customers and small businesses consuming fewer than 100 megawatt hours (MWh) of electricity or 1 terajoule (TJ) of gas per year.[2]

Small customers make up 98 per cent of electricity connections and over 99 per cent of gas connections, although they account for less than 50 per cent of energy sales by volume.

The Retail Law and equivalent arrangements in Victoria focus on customer protections related to the traditional retailer–customer relationship. Protections are generally stronger for customers supplied through an authorised retailer compared with, for example, customers in embedded networks or entering solar power purchase agreements.

State and territory governments regulate electricity prices in the ACT, Tasmania and regional Queensland. From 1 July 2019 the AER began partially regulating retail energy prices,

1 Recent changes to the Victorian framework, including recommendations adopted from the Thwaites *Independent review into the electricity & gas retail markets in Victoria* (August 2017), have seen greater divergence between the Victorian and national frameworks.

2 For electricity, some jurisdictions have different consumption thresholds from that specified in the Retail Law. In South Australia, for example, small electricity customers are those consuming fewer than 160 MWh per year. In Tasmania, the threshold is 150 MWh per year.

by setting a cap on 'standing offer' prices[3] for electricity in jurisdictions without state based price regulation (section 6.5).

## 6.3 Energy retailers

Energy sellers include (1) those authorised as retailers under the Retail Law, (2) those holding exemptions from the requirement to be authorised,[4] and (3) those offering energy products and services beyond the scope of the Retail Law—such as energy management services, solar and storage products, and off-grid energy systems. Only customers of authorised retailers enjoy the full protections in the Retail Law.

### 6.3.1 Authorised energy retailers

Authorised energy retailers must comply with consumer protection and other obligations under the Retail Law. An authorisation covers energy sales to all customers in participating jurisdictions.

In April 2020 89 businesses held authorisations to retail electricity and 35 businesses held authorisations to retail gas.[5] Sixteen new retailers were authorised to retail electricity, and six to retail gas, from the start of 2019.

The number of authorised retailers may differ from the number of brands a customer sees in the market. Not all authorised retailers are active in the market at any time. Some businesses hold multiple authorisations for commercial purposes despite operating under a single brand. In other cases, multiple brands may operate under one authorisation. Section 6.7 notes recent changes in retailers (brands) active in the market.

While many retailers offer energy services to all customers, some target specific market segments. A retailer may focus on offers to large commercial customers, for example, or those in embedded networks. Some retailers target users with certain characteristics, such as those with swimming pools or with flexibility in when they use energy.

In choosing which markets to enter, retailers consider factors such as price regulation (if it applies), market scale, competition, the ability to source hedging contracts to manage risk, and (in gas) whether wholesale contracts and pipeline access are available.

Over 40 retail brands currently sell energy to residential or small business customers in southern and eastern Australia (table 6.1). Eighteen of those brands offer both electricity and gas in at least one jurisdiction. Most other brands offer only electricity, but one retailer specialises in gas. A small number of authorised retailers (not listed in table 6.1) only offer electricity retail services to customers in embedded networks.

Only 22 retail brands offer energy products in all four of the largest markets—south east Queensland, NSW, Victoria and South Australia. NSW has the largest number of active electricity retailers (37), followed by Queensland (31), Victoria (30) and South Australia (27). Victoria has lower participation, despite it having the most active market on other measures. This outcome may reflect Victoria having its own licensing regime that requires a separate application for authorisation and imposes different regulatory obligations from other jurisdictions.

Victoria has significantly more brands (19) selling gas, however, than other regions (3–12). This contrast reflects the importance of gas as a fuel among Victorian households and businesses, and customer preferences for a single retailer across both fuels.

The ACT and Tasmania have limited competition in electricity and gas markets, reflecting the relatively small scale of their markets and greater price regulation.

### 6.3.2 Exempt energy sellers

An energy seller may apply to the AER for an exemption from authorisation if it intends to supply energy services only (1) to a limited customer group (for example, at a specific site or incidentally through a relationship such as a body corporate) or (2) in addition to its customers' primary energy connection.

At March 2020 over 3500 businesses held exemptions, typically to on-sell energy within an embedded network (that is, a small private network whose owner sells electricity to other parties connected to the network). Hospitals, retirement villages, caravan parks and apartment complexes are examples of entities that might run an embedded network. Solar power purchase agreement providers are also covered by the exemptions framework.

3 Standing offers are applied when 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 six months.

4 In Victoria, where the Retail Law does not apply, retailers must hold a licence issued by the Essential Services Commission or seek an exemption from this requirement.

5 Details of all businesses that hold electricity or gas authorisations can be found in the public register of authorised retailers on the AER website.

**Table 6.1 Retailers offering energy contracts to small customers**

| RETAILER | OWNERSHIP | QUEENSLAND | NSW | VICTORIA | SOUTH AUSTRALIA | TASMANIA | ACT |
|---|---|---|---|---|---|---|---|
| 1st Energy | 1st Energy | Electricity | Electricity | Gas, Electricity | | Electricity | |
| ActewAGL Retail | AGL Energy, ACT Government | | Gas, Electricity (host) | | | | Gas (host), Electricity (host) |
| AGL Energy | AGL Energy | Gas (host), Electricity | Gas (host), Electricity | Gas (host), Electricity (host) | Gas, Electricity (host) | | |
| Alinta Energy | Alinta Energy | Electricity | Gas, Electricity | Gas, Electricity | Gas, Electricity | | |
| amaysim Energy | amaysim Energy | Electricity | Gas, Electricity | Gas, Electricity | Electricity | | |
| Amber Electric | Energy Locals | Electricity | Electricity | | Electricity | | Electricity |
| Aurora Energy | Aurora Energy (Tasmanian Government) | | | | | Gas, Electricity (host) | |
| Blue NRG | Blue NRG | Electricity | Electricity | Electricity | Electricity | | |
| Click Energy | amaysim Energy | Electricity | Gas, Electricity | Gas, Electricity | Electricity | | |
| Commander Power & Gas | M2 Energy | | Electricity | Electricity | Electricity | | |
| CovaU | TPC | | Gas, Electricity | Gas, Electricity | | | |
| DC Power Co[1] | DCP Company | Electricity | Electricity | Gas, Electricity | | | |
| Diamond Energy | Diamond Energy | Electricity | Electricity | Electricity | Electricity | | |
| Discover Energy | Discover Energy | Electricity | Electricity | | | | |
| Dodo Power and Gas | M2 Energy | Electricity | Gas, Electricity | Gas, Electricity | Electricity | | |
| Elysian Energy | Elysian Energy | Electricity | Electricity | Electricity | Electricity | | |
| Energy Locals | Energy Locals | Electricity | Electricity | Electricity | Electricity | | Electricity |
| EnergyAustralia | CLP Group | Electricity | Gas, Electricity (host) | Gas (host), Electricity (host) | Gas, Electricity | | Gas, Electricity |
| Enova Energy | Enova Community Energy | | Electricity | | | | |
| Ergon Energy | Queensland Government | Electricity (host) | | | | | |
| ERM Power | Shell Energy | Electricity | Electricity | Electricity | Electricity | Electricity | Electricity |
| Future X Power | Future X Power | Electricity | Electricity | | | | |
| Globird Energy | Globird Energy | | Gas, Electricity | Gas, Electricity | Gas, Electricity | | |
| Kogan Energy[1] | Kogan | Electricity | Electricity | Gas, Electricity | Electricity | | |
| Locality Planning Energy | Locality Planning Energy | Electricity | Electricity | | | | |
| Lumo Energy | Snowy Hydro | | | Gas, Electricity | Gas, Electricity | | |
| Mojo Power | Mojo Power | Electricity | Electricity | | | | |
| Momentum Energy | Hydro Tasmania (Tasmanian Government) | Electricity | Electricity | Gas, Electricity | Electricity | | |
| Nectr Energy | Hanwha Energy Retail | | Electricity | | | | |
| Next Business Energy | Next Business Energy | Electricity | Electricity | Electricity | Electricity | | Electricity |
| Origin Energy | Origin Energy | Gas, Electricity (host) | Gas (host), Electricity (host) | Gas (host), Electricity (host) | Gas (host), Electricity | | Gas, Electricity |
| OVO Energy | OVO Energy | Electricity | Electricity | | | | |
| People Energy | People Energy | Electricity | Electricity | Electricity | Electricity | | |
| Pooled Energy | Efficiency Filters | | Electricity | | | | |
| Powerclub | Powerclub | Electricity | Electricity | Electricity | Electricity | | |
| Powerdirect | AGL Energy | Electricity | Electricity | Electricity | Electricity | | Electricity |
| Powershop | Meridian Energy | Electricity | Electricity | Gas, Electricity | Electricity | | |
| Qenergy | Qenergy | Electricity | Electricity | Electricity | Electricity | | |
| ReAmped Energy | ReAmped Energy | Electricity | Electricity | | | | |
| Red Energy | Snowy Hydro | Gas, Electricity | Gas, Electricity | Gas, Electricity | Gas, Electricity | | Electricity |
| Sanctuary Energy | Living Choice Australia / Sanctuary Energy | Electricity | Electricity | | Electricity | | |
| Simply Energy | ENGIE | Electricity | Gas, Electricity | Gas, Electricity | Gas, Electricity | | |
| Sumo Power | Sumo Power | | Electricity | Gas, Electricity | | | |
| Tango Energy | State Power Investment Corporation | | | Electricity | Electricity | | |
| Tas Gas Retail | Brookfield Infrastructure | | | Gas | | Gas | |
| TOTAL | Gas retailer | 3 | 12 | 19 | 8 | 2 | 3 |
| | Electricity retailer | 31 | 37 | 30 | 27 | 3 | 8 |
| | Host retailer (electricity and gas) | | | | | | |

[1] DC Power and Kogan Energy offer energy contracts through partnerships with Powershop.

Note: Includes retailers with generally available offers or existing customers at March 2020. Retailers servicing only embedded customers are excluded. A host retailer has obligations to supply new customers in a region that do not take up a market offer.

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

The AEMC cited stakeholder estimates of up to 500 000 customers purchasing energy through embedded networks.[6] Those customers do not enjoy the full set of protections in the Retail Law, and have more limited avenues for dispute resolution.[7] But energy ombudsman schemes are being widened to allow customers of exempt sellers to lodge complaints (section 6.10).

## 6.4 Components of energy bills

Retail customers' energy bills cover the costs of producing and transporting energy, costs related to environmental schemes, and retailers' costs and profit margins.

### 6.4.1 Electricity bills

A typical residential electricity retail bill in southern and eastern Australia in 2018–19 comprised:

- retailers' wholesale costs of buying electricity in spot and hedge markets—33 per cent of a bill
- network costs for transporting electricity through transmission and distribution networks, and metering—43 per cent of a bill
- the costs of environmental schemes for promoting renewable generation and energy efficiency, and reducing carbon emissions—8 per cent of a bill
- the retail costs of servicing customers (including meeting regulatory obligations), and acquiring and retaining customers—11 per cent of a bill
- the retailer's margin (profit)—4 per cent of a bill.[8]

The contribution of each component varies by region (figure 6.2).

#### Wholesale costs

Retailers purchase energy in wholesale markets for sale to customers. Prices in wholesale market can be volatile, while the prices that retailers charge their customers are generally fixed. Retailers can manage the risk of wholesale price volatility by entering hedge contracts that lock in prices for their future wholesale purchases (section 2.7). Alternatively, they might own generation assets, or enter demand response contracts to manage these risks (discussed in sections 6.7.2 and 6.8.3).

Wholesale costs rose significantly in all regions from 2015, and were at or near record levels in 2018–19 (section 2.6). Costs are typically highest in South Australia, reflecting the state's significant reliance on relatively expensive gas powered generation, relatively concentrated generator ownership, peaky demand and limited interconnection with other regions. But increased renewable generation and flat demand eased price pressure in South Australia in 2019–20.

#### Network costs

The AER regulates network charges, which cover the efficient costs of building and operating electricity networks, and provide a commercial return to the network's financiers. Network costs in 2018–19 accounted for around 45 per cent of retail bills, but were lower in Victoria (38 per cent) and the ACT (30 per cent).

Customer type (central business district (CBD), urban or rural) and density affect network costs. Tasmania and Queensland have significantly lower proportions of CBD or urban customers (44 per cent and 58 per cent respectively) than other regions (an average 66 per cent). Network productivity levels partly explain cost differences across regions. 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 3.13).

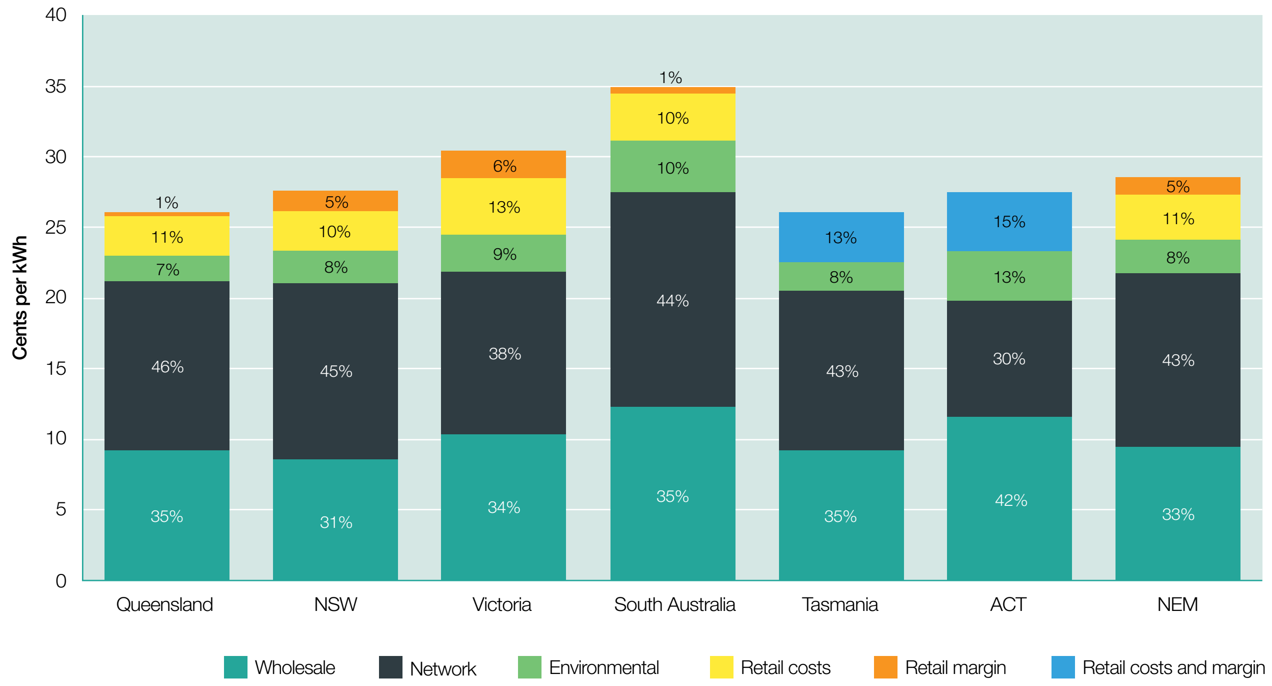
#### Environmental costs

Environmental costs include payments to fund renewable energy targets, feed-in tariffs for solar PV installations, and state government operated energy efficiency schemes. Costs associated with the Australian Government's renewable energy target (box 1.1) account for over 75 per cent of environmental costs nationally (comprising both large scale and small scale components of the scheme). State government premium feed-in tariff schemes are the next largest contributor to environmental costs in Victoria, South Australia and the ACT. While these schemes are closed to new entrants, eligible households continue to receive payments under the schemes.

ACT and South Australian customers faced the highest environmental costs (on a per unit of electricity basis) at 13 per cent and 10 per cent respectively. ACT costs largely related to the government's feed-in tariff scheme for large scale solar developments. South Australian costs flow from the state's premium feed-in tariff scheme, given the high uptake of rooftop solar PV while that scheme was open.

6 AEMC, *Updating the regulatory frameworks for embedded networks, Information sheet*, June 2019, p. 1.
7 The AER's exemption guideline sets out the classes of exemption. The AER sets customer protections under each class. Details of all businesses that hold a registered or individual exemption can be found in the public register of exemptions on the AER website.
8 Based on earnings before interest, taxes, depreciation and amortisation.

**Figure 6.2**
**Composition of a residential electricity bill**




kWh, kilowatt hour.

Note: Data are estimates for 2018–19. Average residential customer prices excluding GST (real $2018–19). Retail costs and margin are combined for the ACT and Tasmania due to data availability. NEM average is based on data for Queensland, NSW, Victoria and South Australia. Percentages may not add to 100 per cent due to rounding.

Source: ACCC, *Inquiry into the National Electricity Market, November 2019 report*, December 2019, p. 40; ACT and Tasmanian data from AEMC, *2019 residential electricity price trends, Final report*, December 2019, p. 9.

Environmental costs were lowest in Queensland, following a state government decision in 2017 to recover premium feed-in tariff costs through the tax base rather than electricity charges. Additionally, Queensland does not operate an energy efficiency scheme targeted at small electricity customers.

#### Retail costs and margin

Retail costs fall into two main categories. Costs of servicing customers include managing billing systems and debt, handling customer enquiries, and complying with regulatory obligations. These costs do not vary significantly across regions.

Customer acquisition and retention costs relate to marketing and other activities to gain or retain customers. These costs tend to be higher in jurisdictions with high rates of customer switching, with Victoria recording the highest costs in 2018–19. This outcome highlights a risk that competition may increase energy bills for customers if the costs of competing outweigh any competition benefits from efficiency and innovation.

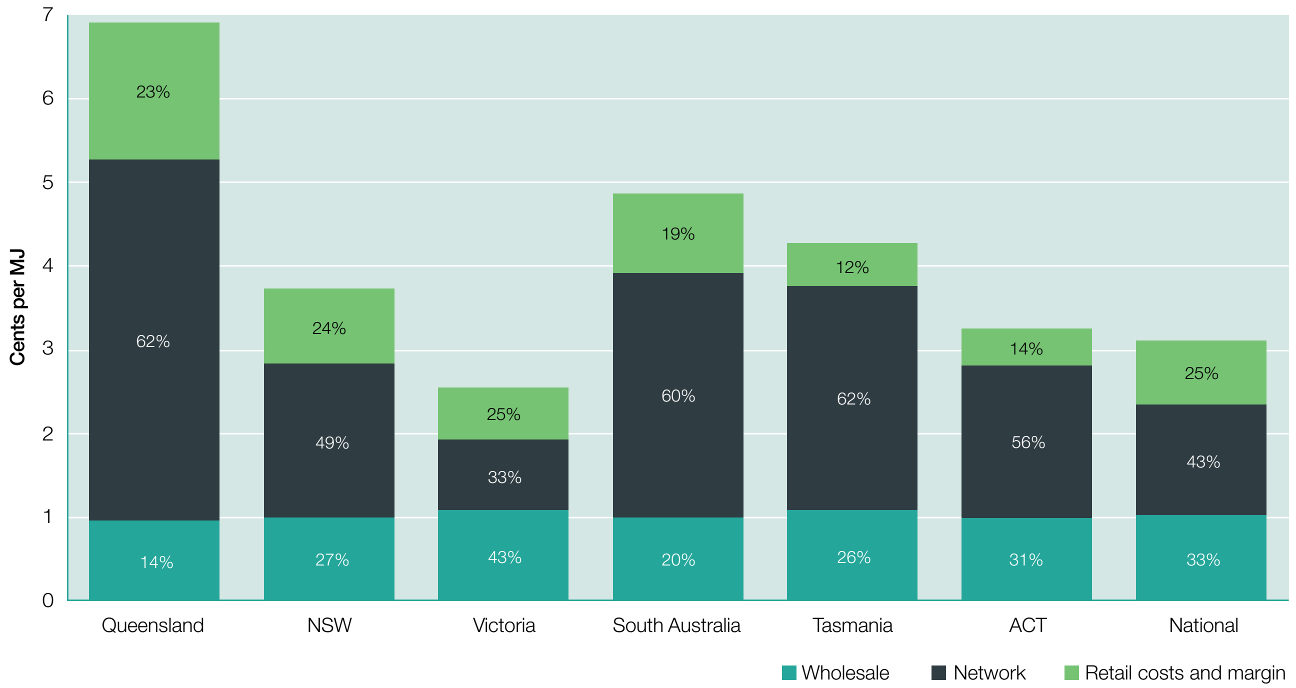
Retail costs per customer tend to be lower for larger retailers, reflecting potential economies of scale in this area. But retailers' profit margins in Victoria and NSW more than doubled those in South Australia and south east Queensland in 2018–19 (on a dollar per customer basis).

### 6.4.2 Gas bills

The composition of retail bills is less transparent in gas than electricity. There is no systematic annual reporting of gas bill data.

Figure 6.3 shows estimates from the most recent comprehensive data published in 2017. On average, gas pipeline (transportation) charges made up over 40 per cent of a gas bill in that year. Distribution charges represented

**Figure 6.3**
**Composition of a residential gas bill**




MJ, megajoule.
Note: Data are estimates at 2017. Average residential customer prices excluding GST (real $2018–19). Percentages may not add to 100 per cent due to rounding.
Source: Oakley Greenwood, *Gas price trends review 2017*, March 2018.

the bulk of this proportion, comprising around 35 per cent of a gas bill.[9] Wholesale gas costs, which accounted for around one third of a typical gas bill, rose sharply from 2015 (chapter 4). Retail costs and margin accounted for the remaining 25 per cent of retail gas bills.

Victoria had the cheapest residential gas prices on a unit basis—largely because the state had lower network costs (33 per cent of gas bills) due to a high level of gas use per customer and high connection penetration. In Tasmania and Queensland, where gas use is less widespread, network costs accounted for over 60 per cent of gas bills.

Retail costs also varied across regions. Queensland retail costs almost doubled those elsewhere on a unit basis, which may reflect the absence of economies of scale from a relatively small customer base. Retail margins were highest in Victoria and NSW.[10]

9 Oakley Greenwood, *Gas price trends* review 2017, March 2018, p. 158.
10 Oakley Greenwood, *Gas price trends review 2017*, March 2018, p. 225.

An independent review found retail costs in Victoria were higher than in an efficient or regulated market.[11] Gas retailers likely face similar customer acquisition and retention costs to those of electricity retailers.

The Australian Competition and Consumer Commission (ACCC) conducted analysis of the costs of AGL Energy, EnergyAustralia and Origin Energy in supplying gas to customers across the east coast, as part of its gas inquiry.[12] The findings were broadly similar to previous analysis, with distribution and transmission costs comprising almost 40 per cent of the delivered price of gas in 2018. However, the wholesale cost faced by these retailers was lower, at 25 per cent of total costs. Gas costs for the three retailers analysed are lower than those of other retailers in part due to low cost gas obtained under long term legacy contracts. But this advantage may be temporary as the retailers enter new contracts at higher market prices to replace expiring contracts. Lower gas costs have allowed these retailers to earn higher margins—retail costs and margins accounted for 36 per cent of the delivered price of gas in 2018, more than half of which was margins.[13]

11 Thwaites, T, Faulkner, P, and Mulder, T, *Independent review into the electricity & gas retail markets in Victoria*, August 2017, p. 23.
12 ACCC, *Gas inquiry 2017–2025, Interim report, January 2020*, 18 February 2020.

## 6.5 How retail prices are set

Energy retailers in southern and eastern Australia are free to set prices for energy market offers. Alongside this market pricing, government agencies regulate prices for electricity standing offers.

Victoria (2009), South Australia (2013), NSW (2014) and south east Queensland (2016) removed retail price regulation for electricity after the AEMC found markets in those states were effectively competitive. But governments reintroduced forms of price control in July 2019.

The Australian Government in 2019 provided for the AER to set a default market offer as a cap on standing offer electricity prices in south east Queensland, NSW and South Australia, following an ACCC recommendation for such a scheme.[14] The default offer is not intended to mirror the lowest price in the market, to avoid impeding competition among retailers and incentivising consumers to disengage from the market (box 6.2). Any advertised discounts promoted by electricity retailers must be based on a reference bill informed by this default offer, providing consumers with meaningful information to compare offers.

The Victorian Government also introduced price controls from 1 July 2019.The Essential Services Commission (ESC) sets the price of standing offers to reflect the efficient costs of a retailer in a contestable market, including an allowance for customer acquisition and retention costs.

The ACT, Tasmania and regional Queensland already had state based arrangements in place to regulate retail electricity prices for small customers in 2019. Price regulation in these regions is based on a 'building block' approach, reflecting the costs of an efficient retailer supplying electricity to its customers. The approach to estimating costs differs across regions, as does the extent to which the standing offer allows for the recovery of customer acquisition and retention costs (such as advertising).

Gas price deregulation occurred along similar timeframes to those of electricity price deregulation. In July 2017 NSW became the last jurisdiction to deregulate retail gas prices for small customers. Recent moves to reintroduce electricity price controls have not been applied in gas.

13 ACCC, *Gas inquiry 2017–2025, Interim report, January 2020*, 18 February 2020, pp. 118–19.
14 ACCC, *Restoring electricity affordability and Australia's competitive advantage, Retail Electricity Pricing Inquiry—final report*, June 2018, p. 252.

### 6.5.1 Price structures

Retailers offers a variety of tariff structures on both market and standing offers. Most customers pay a daily (fixed) supply charge plus a simple usage charge. These single-rate or 'flat' tariffs apply the same charge for all electricity that a customer uses, regardless of how and when they use it.

Power of Choice reforms introduced in 2017 require electricity distributors to move customers onto network tariffs that more closely reflect the efficient costs of providing the services they use. The reforms reduce network charges at times of low demand, and raise them at times of peak demand when the networks are under strain. Networks levy the new tariff structures on retailers, which then have discretion to set their charges to customers as they see fit. Retailers may offer incentives for customers to minimise energy use at times of high system cost. As these reforms progress, more customers will pay prices reflecting this approach.

The new pricing structures include:

- *time-of-use tariffs*, which apply different pricing to electricity use at peak and off-peak times. Higher prices in peak times encourage customers to minimise their use at those times. Customers can reduce their energy costs by reducing use, or by shifting use to off-peak times.
- *demand tariffs*, which charge a customer based on their maximum point-in-time demand at peak times. Customers can reduce their energy costs by shifting demand to off-peak periods. But even one day of high use at peak times will lead to higher charges for the whole billing period.
- *critical peak tariffs*, which factor in a low electricity usage charge for most of the year but much higher tariffs during a few short 'critical peaks' each year. These tariffs are currently available for some larger customers, but not residential customers or small businesses.

Each tariff structure reflects a trade-off between cost reflectivity and simplicity. Balancing these elements ensures customers face appropriate incentives around their energy use, but can understand how the incentives work.

Most retailers offer time-of-use tariffs across all regions. Demand tariffs are available from an increasing number of retailers, but take-up of these tariffs remains low.

## Box 6.2 Default market offer

The Australian Government's default market offer (DMO) scheme, effective from 1 July 2019, sets a cap on what retailers can charge electricity customers on standing offer contracts.

The scheme was introduced following concerns raised by the Australian Competition and Consumer Commission (ACCC) that standing offer contracts:

- were no longer working as a safety net, as originally intended
- were unjustifiably expensive, with retailers having incentives to increase standing offer prices as a basis to advertise artificially high discounts
- penalised customers who had not taken up a market offer, making them a form of 'loyalty tax'.

The ACCC's recommendation for a DMO scheme was implemented through the Competition and Consumer (Industry Code—Electricity Retail) Regulations 2019 under the *Competition and Consumer Act 2010*.

The scheme applies in distribution network areas covered by the Retail Law that are not otherwise subject to retail price regulation—NSW (Endeavour, Essential Energy and Ausgrid), south east Queensland (Energex) and South Australia (SA Power Networks). Victoria operates a separate but similar scheme across all its distribution network areas.

The AER determines DMO prices each year for residential and small business customers in each of the five covered distribution areas. We set prices at a level where standing offer customers will see price reductions, but retailers still have incentives to compete on price, invest and innovate with their market offers.

While the scheme caps what retailers can charge in their standing offers, it does not cap customers' bills. Bills will vary depending on how much electricity customers use and their retailer's specific charges.

The default prices also act as a reference against which retailers must compare their market offers in advertising, on their websites, and elsewhere. This requirement aims to make it easier for customers to compare energy offers across different providers.

The DMO scheme provides a fallback for those who do not engage in the market, rather than providing a low priced alternative to a market offer. It aims to reduce unjustifiably high standing offer prices, while allowing retailers to recover their costs in servicing customers, and providing customers and retailers with incentives to participate in the market.

We 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] We also used these prices as the base for default prices in 2020–21, but adjusted for:

- forecast changes in environmental, wholesale and network costs
- changes in consumer price index (CPI) for residual costs (which includes retail costs).

Our price setting process also includes a 'step change framework' to account for changes in retail costs arising from factors outside the businesses' control, such as regulatory requirements.[b]

a AER, *Final determination, Default market offer prices*, April 2019.
b AER, *Draft determination, Default market offer prices* 2020–21, February 2020.

At February 2020 around 35 per cent of customers in the National Electricity Market (NEM) had metering capable of supporting cost-reflective tariffs (including smart meters and manually readable interval meters). Installation rates vary across regions. Most Victorian customers have advanced metering, with NSW having the next highest penetration at around 21 per cent of customers. Installation levels in other regions ranged from 10–15 per cent of customers.

Around 20 per cent of customers with advanced metering in regions regulated by the AER have moved to cost-reflective retail tariffs. Tasmania and NSW have seen the greatest take-up of these tariffs (at 50 per cent and 35 per cent of customers respectively), but less than 5 per cent of customers have adopted these tariffs in Queensland and South Australia.

Some retailers are trialing other price structures. Subscription tariffs, where customers pay a (yearly or monthly) fee based on their typical electricity use, focus on simplicity rather than cost-reflectiveness. Some retailers suggest these tariffs work to gain customers' trust following evidence of low consumer confidence in the energy market.

At the other end of the pricing spectrum, wholesale market spot price pass-through tariffs allow customers to dynamically interact with the wholesale market. These tariffs are best suited to customers with battery storage that can adjust their use of grid supplied electricity during high price periods.

## 6.6 Customer bills

Customers' energy bills depend on their energy use and the terms of their retail contract. Hundreds of retail offers may be available to customers at any time. Advertised offers frequently change, as do the charges attached to an offer over time. Customers who regularly change their energy contract usually pay lower prices, reflecting that many market offers have terms that see customers revert to a higher price after an initial 'benefit period'. Customers on legacy market offers may pay prices closer to those in standing offers (table 6.2).

Energy bills are typically higher for customers in regional and remote areas (where network costs tend to be higher and can be recovered from fewer customers), than for urban customers. They also tend to be higher in regions with higher average energy use.

### 6.6.1 Headline price movements

Since 2018 electricity retail prices plateaued or fell in most regions, after significant rises in preceding years. This change was due to factors including new price and advertising regulations, relatively stable wholesale costs, and reductions in network costs.

Table 6.2 summarises recent movements in market and standing offer energy prices for residential customers, and estimated annual customer bills for generally available flat rate offers. In the seven months to January 2020, standing offer prices for residential customers fell in all regions that introduced price caps on these offers in July 2019. Prices fell by 14–19 per cent in Victoria, 11–13 per cent in NSW, 12 per cent in South Australia, and 10 per cent in south east Queensland.

Market offers did not mirror this fall in standing offer prices. In Victoria, market offer prices rose 4–11 per cent, reflecting higher network charges from January 2020 and ongoing wholesale price uncertainty. Higher network charges were partly driven by rising land taxes and more power traveling from interstate (the closure of Hazelwood power station in 2017 resulted in Victoria becoming a net importer of electricity).[15]

In NSW, Queensland and South Australia, market offer prices were relatively steady. Prices fell by up to 2 per cent in parts of NSW and Queensland, but rose by up to 1 per cent in South Australia and regional NSW. These variations primarily reflected changes in network tariffs.

In Tasmania, the government caps wholesale electricity charges factored into standing offer prices (and will do so until 2021). Retail prices under both standing and market offers rose by almost 3 per cent to January 2020, reflecting increased metering and wholesale electricity costs but partly offset by lower network and environmental costs.

In the ACT, market and standing offer prices increased by 7 per cent and 1 per cent respectively. These price increases reflected increases in network costs and the cost of the ACT Government's large scale feed in-tariff, although wholesale costs moderated following increases over the past two years.

In gas, retail prices fell by 6 per cent in the east of Victoria, but rose up to 3 per cent in the west of the state over the seven months to January 2020. In NSW, prices in market offers rose by 5 per cent, while standing offer prices were stable. The reverse was true in South Australia, where standing offer prices rose by 6 per cent. Prices in other regions were generally stable.

#### Energy wholesale costs

Rising energy wholesale costs were the main driver of increased retail prices from 2015 to 2018. Those costs have since moderated in most regions, and are tracking lower in 2019–20 (section 2.6).

In electricity, retirement of large coal fired generators in South Australia (Northern, May 2016) and Victoria (Hazelwood, March 2017) tightened the supply–demand balance in generation. Higher gas and coal fuel prices also contributed to high wholesale electricity prices. Additionally, liquidity in electricity financial markets tightened after coal generators left the market, putting upward pressure on hedging costs. These factors combined resulted in wholesale electricity prices setting new records in several regions in 2017 and early 2019.

15 AER, 'AER approves Victorian electricity network charges for 2020', Media release, 11 November 2019.

**Table 6.2** Movement in energy bills for customers on market and standing offers

| JURISDICTION | WHO SETS STANDING OFFER PRICES? | DISTRIBUTION NETWORK AREA | CHANGE IN MEDIAN OFFER (%) JUN 2018 – JUN 2019 MARKET | JUN 2018 – JUN 2019 STANDING | JUN 2019 – JAN 2020 MARKET | JUN 2019 – JAN 2020 STANDING | ESTIMATED ANNUAL CUSTOMER BILL, 2020 ($) MARKET | ESTIMATED ANNUAL CUSTOMER BILL, 2020 ($) STANDING |
|---|---|---|---|---|---|---|---|---|
| **ELECTRICITY** | | | | | | | | |
| Queensland | Retailers (capped at DMO from 1 July 2019) | Energex | –6.7 | 0.0 | –1.3 | –9.9 | 1637 | 1844 |
| | QCA | Ergon Energy | | –5.9 | | 0.1 | | 1846 |
| NSW | Retailers (capped at DMO from 1 July 2019) | Ausgrid | –1.4 | 4.8 | –2.4 | –13.4 | 1785 | 2028 |
| | | Endeavour Energy | –1.9 | 1.4 | –1.5 | –11.1 | 1749 | 1996 |
| | | Essential Energy | –0.8 | 5.1 | 1.0 | –11.3 | 2059 | 2334 |
| Victoria | Retailers (to 30 June 2019); ESC (from 1 July 2019) | Citipower | 1.8 | 0.4 | 6.9 | –14.4 | 1474 | 1568 |
| | | Powercor | 1.2 | 3.2 | 3.7 | –18.9 | 1572 | 1672 |
| | | AusNet Services | 3.5 | 0.6 | 6.2 | –16.4 | 1726 | 1836 |
| | | Jemena | –0.5 | –1.7 | 8.2 | –15.8 | 1560 | 1660 |
| | | United Energy | 1.2 | 2.4 | 11.1 | –13.6 | 1580 | 1680 |
| South Australia | Retailers (capped at DMO from 1 July 2019) | SA Power Networks | –3.5 | 2.4 | 1.1 | –12.5 | 2044 | 2234 |
| Tasmania | OTTER | Aurora Energy | –2.1 | 1.2 | 2.6 | 2.8 | 2414 | 2502 |
| ACT | ICRC | Evoenergy | –0.1 | 9.2 | 6.6 | 0.8 | 1822 | 2047 |
| **GAS** | | | | | | | | |
| Queensland | Retailers | AGN | –2.4 | 1.7 | 1.2 | 2.0 | 650 | 703 |
| | | Allgas Energy | –0.3 | 0.2 | –0.6 | 1.9 | 690 | 753 |
| NSW | Retailers | Jemena | –1.9 | 2.5 | 4.6 | –0.2 | 907 | 1023 |
| Victoria | Retailers | AusNet Services | 1.0 | 2.7 | 0.5 | 3.4 | 1476 | 1880 |
| | | Multinet | 4.5 | 6.3 | –1.0 | 2.4 | 1488 | 1888 |
| | | AGN | 8.5 | 9.1 | –6.0 | –5.1 | 1514 | 1897 |
| South Australia | Retailers | AGN | 0.0 | 0.1 | 0.9 | 5.9 | 932 | 1064 |
| ACT | Retailers | Evoenergy | –2.7 | 3.7 | 0.1 | –0.2 | 1548 | 1733 |

AGN, Australian Gas Networks; DMO, default market offer; ESC, Essential Services Commission; ICRC, Independent Competition and Regulatory Commission; kWh, kilowatt hour; MJ, megajoule; OTTER, Office of the Tasmanian Economic Regulator.

Note: AER estimates are based on generally available offers for residential customers on a 'single rate' tariff structure. Annual bills and price changes are based on median market and standing offers at June 2018, June 2019 and January 2020, using average consumption in each jurisdiction: NSW 5881 kWh (electricity), 22 855 MJ (gas); Queensland 5699 kWh, 7873 MJ; Victoria 4589 kWh, 57 064 MJ; South Australia 4752 kWh, 17 501 MJ; ACT 6545 kWh, 42 078 MJ. Market offer prices include all conditional discounts.

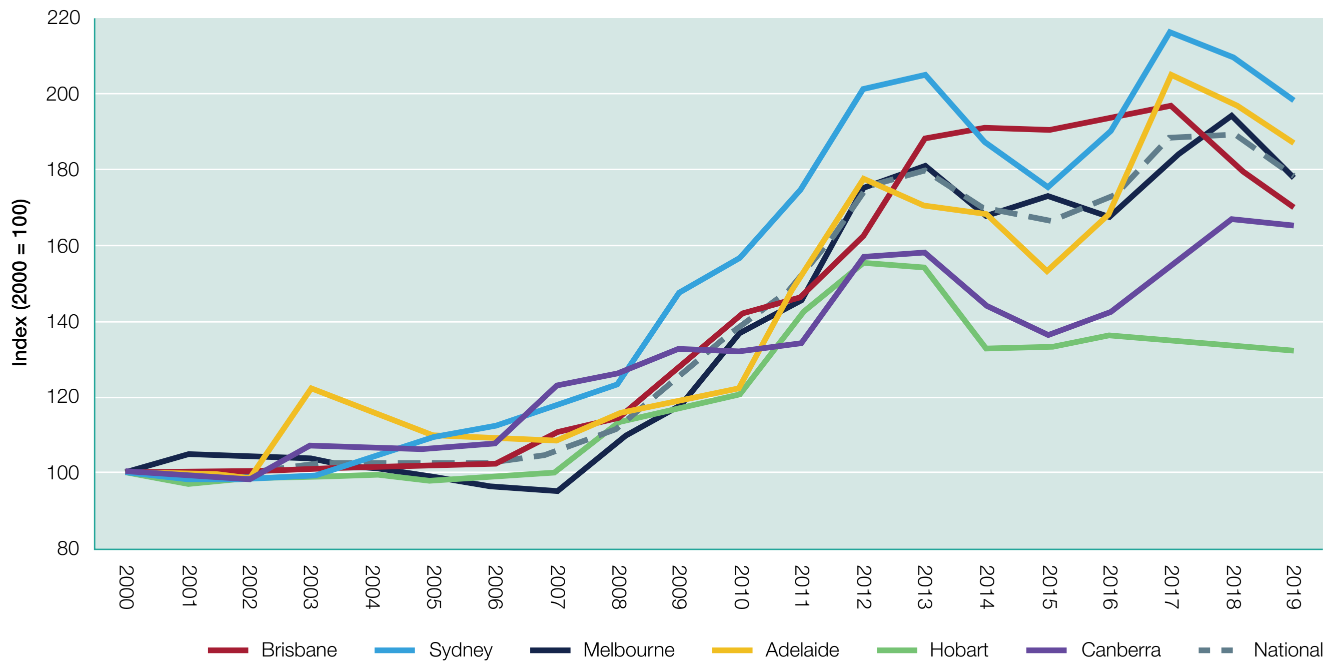
Source: Energy Made Easy website (www.energymadeeasy.gov.au); Victorian Energy Compare website (compare.energy.vic.gov.au).

More recently, commissioning of a large number of lower cost renewable generators has eased supply conditions. Along with lower fuel costs, this easing saw a fall in average wholesale prices in 2019. Supply conditions are volatile, however, including significant generator outages during periods of peak demand.

The moderation in wholesale prices was not fully reflected in reduced retail prices at January 2020. Retailers typically lock in a portion of their wholesale costs up to several years in advance in hedge contract markets, which means it can take time for retail prices to reflect wholesale cost changes.

In gas, wholesale costs more than doubled in all regions—and tripled in Queensland—from 2015 to 2017. This increase was largely due to Queensland's liquefied natural gas (LNG) projects—which link domestic gas prices to international oil prices—and a tighter supply–demand balance. Diversion of gas supplies from the domestic market to LNG projects, moratoriums on onshore gas exploration in some states, and declining production in some established gas basins contributed to this tighter supply–demand balance.

**Figure 6.4**
**Electricity retail price index (inflation adjusted)**




Note: Consumer price index electricity series for each region, deflated by the consumer price index for all groups. Data at December quarter each year.
Source: ABS, *Consumer price index*, cat. no. 6401.0, various years.

Gas wholesale costs stabilised over 2018 and have eased significantly since early 2019 (chapter 4). As in electricity, this cost reduction may take time to flow through to retail prices as longer term contract positions are adjusted, and may not be reflected in prices at January 2020.

## 6.6.2 Longer term price trends

The Australian Bureau of Statistics (ABS) tracks movements in energy prices for metropolitan households as an input to the consumer price index. Retail electricity prices rose by 46 per cent in real terms for customers in eastern and southern Australia over the decade to December 2019 (figure 6.4). Retail gas prices rose by 37 per cent over the decade (figure 6.6).

### Electricity

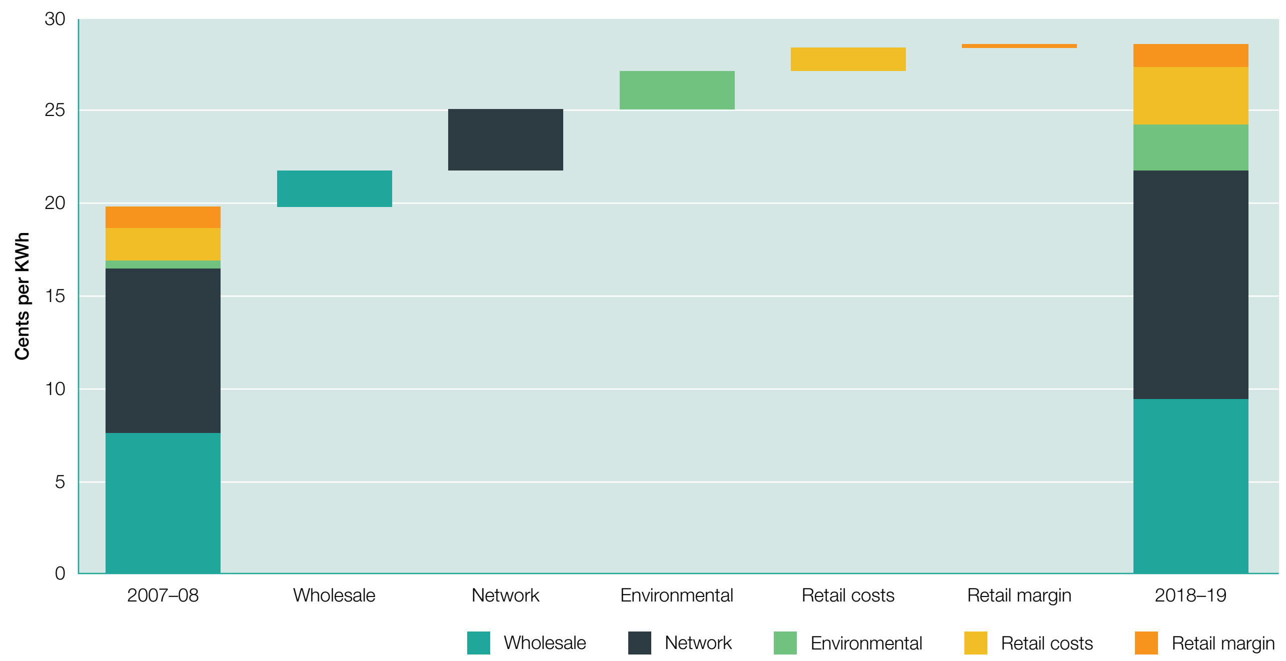
Electricity prices began to track significantly higher in real terms from around 2007 (figure 6.4). Prices increased by an average 11 per cent per year over the five years to 2012, driven by network costs—when network businesses invested heavily in new assets, and financial market instability raised debt costs. In Victoria, the costs of the government led smart meter rollout and new bushfire safety obligations also contributed to cost increases. Prices peaked nationally in 2013, when escalating network charges combined with higher wholesale costs following the introduction of carbon pricing.

Prices eased from 2013–2015, by around 8 per cent nationally in real terms. This easing reflected lower network costs, the removal of carbon pricing, and an oversupply of generation capacity depressing wholesale prices.

The easing of real prices reversed in 2016, when high electricity wholesale prices began to flow through into retail prices in most cities (section 6.6.1). New price peaks were then recorded in 2017 and 2018. Prices fell in all cities during 2019, but they remained significantly above historical levels.

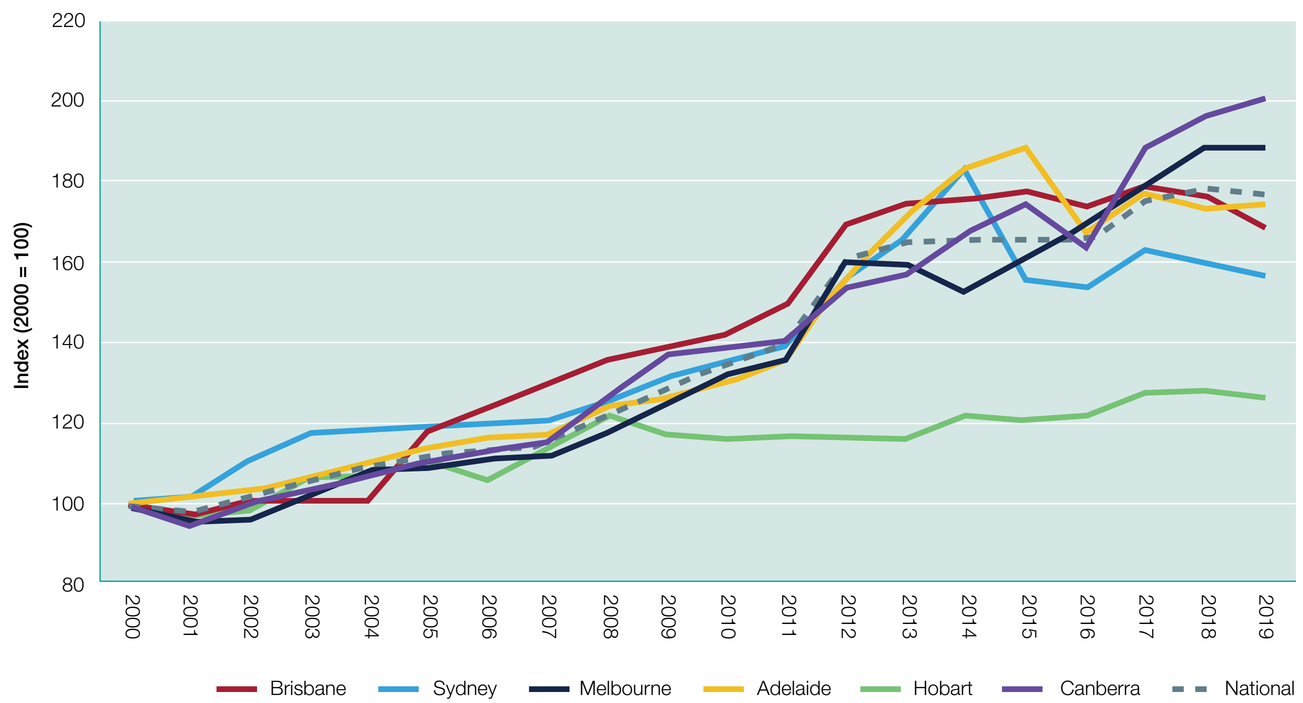
Figure 6.5 illustrates the net drivers of retail electricity prices over the 11 years to 2019 in southern and eastern Australia. Network costs accounted for 38 per cent of the rise in retail electricity prices over this period. Wholesale costs (including hedging against spot market volatility) accounted for 22 per cent of price rises, with most of this rise occurring since 2016.

**Figure 6.5**
**Drivers of change in average residential electricity customer prices in the NEM**




kWh, kilowatt hour.
Note: Based on effective unit charges paid by residential customers. Data are inflation adjusted, in 2018–19 dollars, and exclude GST.
Source: ACCC, *Inquiry into the National Electricity Market*, *November 2019 report*, December 2019, p. 6.

**Figure 6.6**
**Gas retail price index (inflation adjusted)**




Note: Consumer price index gas series for each region, deflated by the consumer price index for all groups. Data at December quarter each year.
Source: ABS, *Consumer price index*, cat. no. 6401.0, various years.

Environmental costs accounted for 22 per cent of the increase in retail electricity prices over the decade, for reasons including:

- increases in the price of certificates needed to meet obligations under the large scale renewable energy target
- the introduction of state based energy efficiency schemes
- the rapid growth in rooftop solar PV, which increased the number of certificates that retailers must acquire under the small scale renewable energy scheme, and the extent of payments under premium feed-in tariff schemes.

Retail costs and margins contributed 16 per cent and 2 per cent to the increase in retail prices respectively. Both are high by world standards, raising questions about whether retail competition is delivering price benefits for consumers. Costs to serve, and acquire and retain, customers made similar contributions to the increase in retail costs.

### Gas

Retail gas prices rose on average by 7 per cent per year in real terms over the five years to 2012 (figure 6.6).

Prices continued to rise strongly in Sydney, Adelaide and Canberra until new access arrangements lowered gas pipeline charges (2014–15 in Sydney and 2015–16 in the other cities). A period of relative price stability followed, before prices began to rise again from 2016 due to tight wholesale supply and constrained access to gas pipelines. Prices reached new record levels in 2018 and 2019.

Rising wholesale costs contributed around 57 per cent of retail gas price increases from 2007 to 2017. Much of the rise in wholesale costs occurred since 2015. Retail costs (including margins) were the next largest contributor to price rises, accounting for around 23 per cent of the national average gas price increase. Increases in these costs are likely to reflect similar drivers to those in the retail electricity market.

Distribution costs accounted for around 19 per cent of the increase in retail gas prices, with most of this impact occurring early in the decade in response to high financing costs brought on by global financial market instability. Pipeline investment increased over this same period to replace aging assets and meet forecasts of rising energy demand (chapter 5). Distribution charges have since eased in most regions as financial market conditions have improved.

## 6.6.3 Energy use

While energy prices are significantly higher than a decade ago, changes in customer behaviour have moderated the impact on customer bills (particularly electricity bills). While electricity prices rose by 45 per cent over the past 11 years, for example, electricity bills rose by only 20 per cent, with a 17 per cent decrease in average electricity use from the grid over this period.

Changes in customer behaviour include switching to energy efficient appliances and reducing their discretionary energy use. But the biggest contributor has been customers meeting some of their energy needs from rooftop solar PV systems. This change raises potential equity issues, because those without access to rooftop solar PV are shouldering a larger proportion of the rise in electricity prices.

There is little systematic reporting of gas consumption data in Australia. Oakley Greenwood estimated a reduction in average household gas use across all regions in the decade to 2016 (ranging from a 4 per cent fall in NSW to a 36 per cent fall in South Australia).[16] This reduction likely reflects a move to more efficient appliances, along with some switching from gas to electricity.

## 6.6.4 Electricity price forecasts

The AEMC publishes forecasts of electricity retail prices each year, based on current expectations, policy and legislation. In December 2019 it forecast electricity prices for a 'representative customer' would fall in all NEM regions over the three years to June 2022. The largest forecast reduction is for Queensland customers (20 per cent), and the smallest is for South Australian customers (2 per cent).[17]

16 Oakley Greenwood, *Gas price trends review 2017*, March 2018.
17 AEMC, *2019 residential electricity price trends*, *Final report*, December 2019.

Forecasts of lower wholesale energy costs are the primary driver of these expectations, as new renewable plants come online and ease prices. Environmental costs are also expected to fall across all regions, driven by a decrease in costs for certificates to meet renewable energy target obligations. Network prices are expected to fall in Queensland and NSW, but to rise elsewhere.

## 6.7 Competition in retail energy markets

The AEMC assessed that electricity markets in south east Queensland, NSW, Victoria and South Australia have characteristics consistent with competitive markets, including high levels of offers, marketing, and customer switching. Barriers to entry were considered low, as evidenced by regular new entry (although contract market issues in South Australia mean barriers are higher in that market).[18]

It assessed competition as less effective in electricity retail markets in the ACT, Tasmania and regional Queensland. The scale of these markets and continued price regulation may have deterred entry by new 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.

The AEMC generally assessed gas markets as being less competitive than electricity markets, given their smaller scale, and difficulties in sourcing gas and pipeline services in some regions. Gas markets in all regions are more concentrated than electricity markets.

Despite those findings, the AEMC found 'competition in the retail energy market … is currently not delivering the expected benefits to consumers'.[19] The ACCC also found retail energy markets were not delivering the expected benefits for consumers. It reported in July 2018 that 'the retail market has developed in a manner that is not conducive to consumers being able to make efficient and effective decisions about the range of available offers in the market'.[20]

A range of regulatory reforms targeting these concerns were progressed in 2018 and 2019, aimed at encouraging customers to engage in the market, and making it easier for them to compare retail offers (sections 6.7.4 and 6.7.7).

While it is too early to assess how the reforms affect customer outcomes, customer satisfaction with competition in national energy retail markets improved slightly in 2019.

Consumer trust, or confidence that the market is working in consumers' interests, rose to 33 per cent in December 2019, up from 31 per cent in December 2018.[21] Likewise, consumer satisfaction with the level of competition in energy markets rose across all markets except south east Queensland. On average across the NEM, the proportion of consumers satisfied with competition in their area rose from 47 per cent in December 2018 to 52 per cent in December 2019.

In its 2019 review, the AEMC identified outcomes that highlight how competition is improving. These include:

- decreasing market concentration, with smaller retailers growing their customer base in established markets, and expanding into new markets
- retailers moving away from discounting practices, and a rise in simpler and more stable pricing products
- retailers offering a wider range of products and services, including leveraging off greater uptake of solar PV and battery technology.

While these findings are broadly positive, the AEMC noted some customer segments may be missing out on the benefits of competition. Embedded network customers, for example, often lack retail choice and cannot switch away from suppliers that do not meet their needs. In June 2019 the AEMC proposed a new regulatory framework that would elevate embedded electricity networks into the national regulatory regime, improving protections and access to retail market competition for their customers.[22]

### 6.7.1 Market concentration

More than 40 retail brands supply small energy customers in southern and eastern Australia (table 6.1). But the retail brands of three businesses—AGL Energy, Origin Energy and EnergyAustralia (the 'big three')—supply 63 per cent of small electricity customers and 75 per cent of small gas customers (figures 6.7 and 6.8). Those businesses own at least two of the three largest retailers in every region except Tasmania. But the market share of these businesses has gradually declined.

18 AEMC, *2019 retail energy competition review, Final report*, June 2019.
19 AEMC, *2018 retail energy competition review, Final report*, June 2018, p. i.
20 ACCC, *Restoring electricity affordability and Australia's competitive advantage, Retail Electricity Pricing Inquiry—final report*, June 2018, p. 134.

21 ECA, *Energy consumer sentiment survey, December 2019*, January 2020, p. 31.
22 AEMC, *Updating the regulatory frameworks for embedded networks, Final report*, June 2019.

**Figure 6.7**
**Electricity retail market share (small customers)**

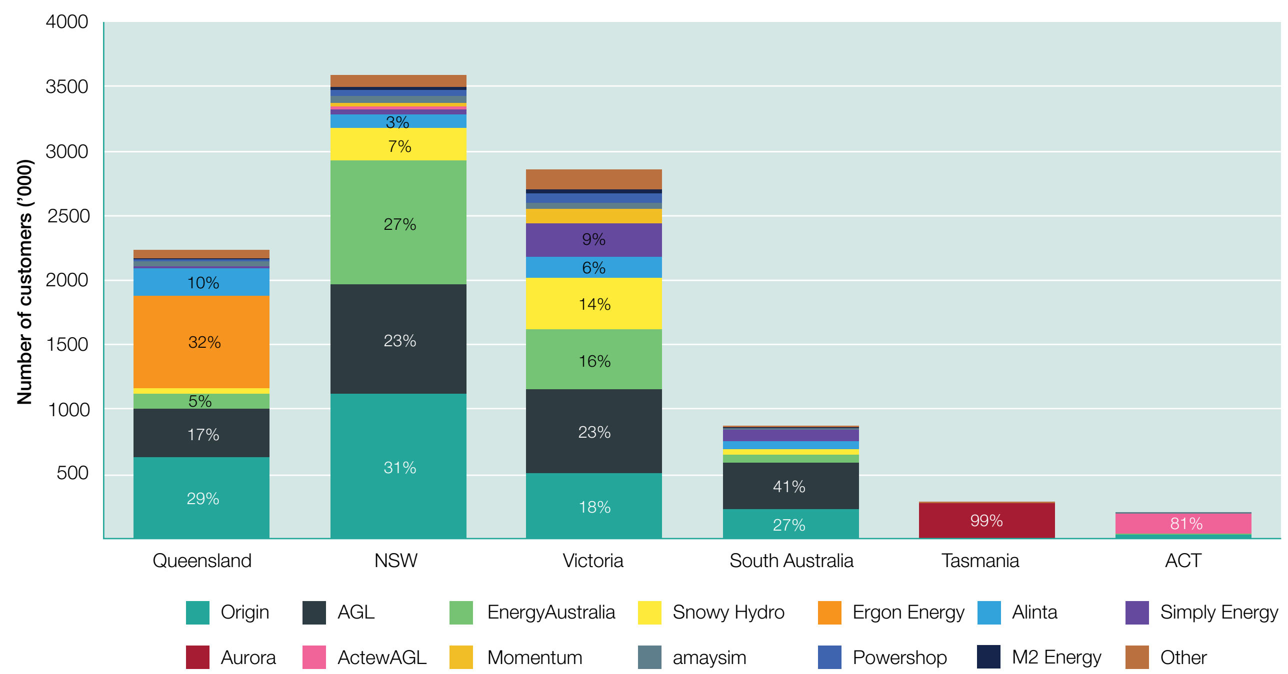
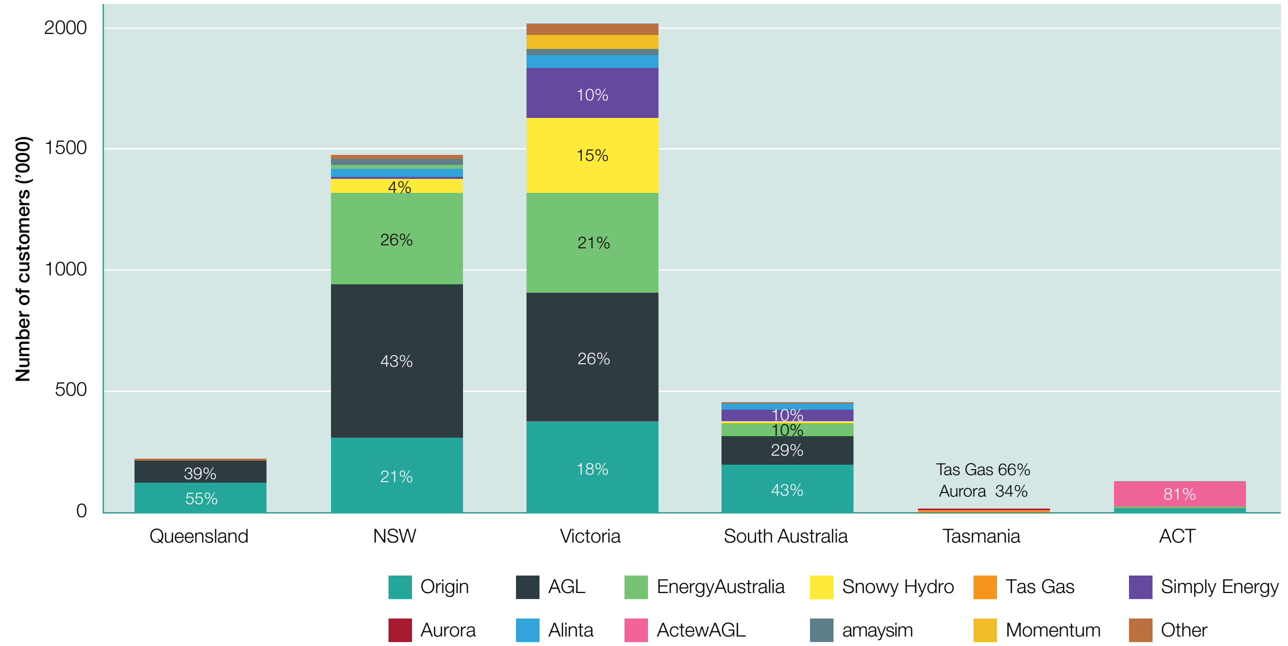



**Figure 6.8**
**Gas retail market share (small customers)**




Note (figures 6.7 and 6.8): Includes residential and small business customers. All data at December 2019, except Victoria (electricity and gas, June 2019) and Tasmania (gas, June 2019).

Source (figures 6.7 and 6.8): AER, *Retail markets quarterly, Q2 2019–20*, March 2020; ESC, *Victorian energy market report 2018–19*, November 2019; Office of the Tasmanian Economic Regulator, *Energy in Tasmania report 2018–19*, February 2020.

Three 'second tier' retailers have built significant market share in some regions:

- Snowy Hydro (owned by the Australian Government and trading as Red Energy and Lumo Energy) supplies around 8 per cent of electricity customers and 9 per cent of gas customers—its market share is highest in Victoria, supplying 14 per cent of electricity customers and 15 per cent of gas customers.
- Alinta Energy (owned by Hong Kong based Chow Tai Fook Enterprises) supplies 5 per cent of electricity customers and 3 per cent of gas customers—its market share is highest in Queensland (10 per cent of electricity customers) and South Australia (7 per cent of electricity customers and 6 per cent of gas customers).
- Simply Energy (owned by French multinational Engie) supplies 4 per cent of electricity customers and 6 per cent of gas customers, including 9–10 per cent of customers in Victoria and South Australia.

Smaller retailers also gained market share, increasing from 5 per cent of small customers in 2016 to 8 per cent in 2019. In gas, smaller retailers accounted for 4.4 per cent of small customers in 2019. Smaller retailers have had more success in Victoria than elsewhere, supplying almost 15 per cent of small electricity customers and almost 7 per cent of small gas customers. This outcome may reflect Victoria's relatively mature market, with prices for gas and electricity deregulated in 2009—earlier than in other regions.

NSW is the most concentrated of the major electricity markets. The 'big three' account for 82 per cent of NSW electricity customers. Snowy Hydro accounts for another 7 per cent of customers. The other 36 retailers in NSW share 11 per cent of the market.

Retail markets tend to be more concentrated in gas than electricity, in part because the markets are smaller in scale. In NSW, for example, the 'big three' account for 89 per cent of retail gas customers. In Queensland, Origin Energy and AGL Energy account for 94 per cent of retail gas customers.

The ACT and Tasmania—jurisdictions that have always had price regulation—are even more concentrated. The dominant retailers in these regions are typically government owned (or part owned) businesses with limited operation outside their home region. ActewAGL (a joint venture between the ACT Government and AGL Energy) supplies almost 81 per cent of ACT electricity and gas customers. However, this market acquired more depth in 2019, when Origin Energy increased its market share to 15 per cent—an increase of 6 per cent from 2018. In Tasmania, Aurora Energy (Tasmanian Government owned) was until recently the only retailer offering electricity to households.

1st Energy entered the Tasmanian electricity market in 2019, but has yet to build a material customer base. Small businesses in Tasmania can also choose ERM Power Retail.

Ergon Energy (Queensland Government owned) supplies electricity to most small customers in rural and regional Queensland.

## 6.7.2 Vertical integration

Governments structurally separated the energy supply industry into separate wholesale, network and retail businesses in the 1990s. In electricity, however, many generators and retailers have since integrated to become 'gentailers'. Vertical integration has also occurred in gas, but to a lesser extent.

Vertical integration allows retailers and energy producers to manage price volatility in wholesale markets, with less need to hedge their positions in futures (derivatives) markets. This strategy may be efficient for the business, but can reduce liquidity in derivatives markets, posing a barrier to entry or expansion for retailers that are not vertically integrated.

The 'big three' retailers—AGL Energy, Origin Energy and EnergyAustralia—each have significant market share in generation across NSW, Victoria and South Australia (figure 6.9). They also have interests in upstream gas production or storage, complementing their interests in gas fired electricity generation.

Outside the 'big three', most retailers with a significant retail customer base are aligned with an electricity generation business—Snowy Hydro (Red Energy and Lumo Energy), Engie (Simply Energy), Alinta Energy, Hydro Tasmania (Momentum Energy), ERM Power, Meridian Energy (Powershop) and Pacific Hydro (Tango).

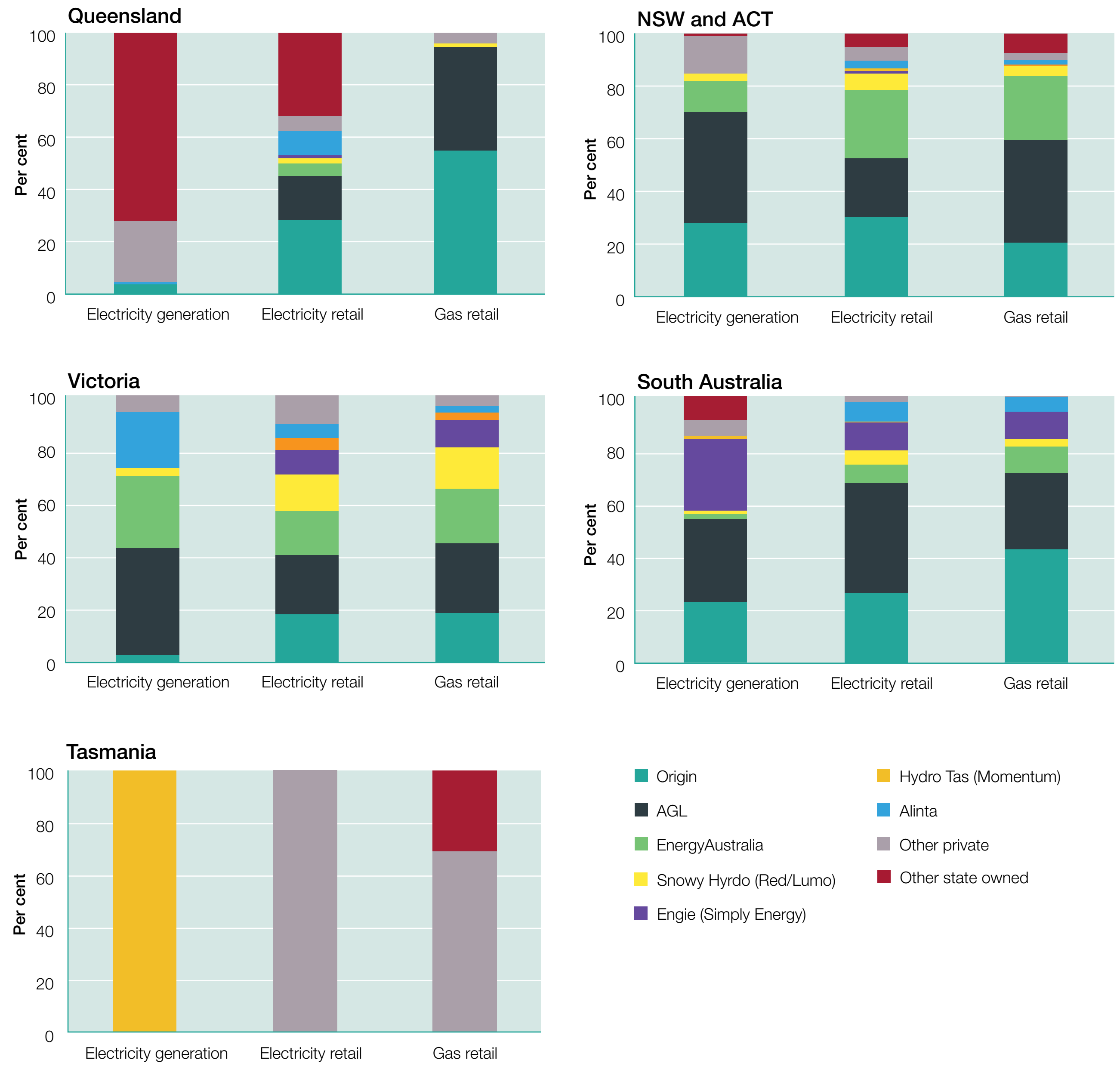
The largest stand-alone electricity retailers in the NEM are amaysim (trading under its own name and as Click Energy) and M2 Energy (trading as Dodo Power and Gas, and Commander Power & Gas) with 1.4 and 1.0 per cent of small customers across the NEM respectively.

## 6.7.3 Customers with market contracts

Most energy consumers can enter a market contract with their retailer of choice.[23] Market contracts allow retailers to tailor their energy offers, subject to meeting regulated requirements. A contract may be widely available or only

23 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.

**Figure 6.9**
**Vertical integration in NEM jurisdictions**




Note: Electricity generation market shares are based on generation capacity owned or controlled at January 2020. Retail market shares are based on number of small customers at December 2019, except Victoria (electricity and gas, June 2019) and Tasmania (gas, June 2019).

Source: AER analysis of retail, electricity generation and trading rights data. Retail: AER, *Retail markets quarterly, Q2 2019–20*, March 2020; ESC, *Victorian energy market report 2018–19*, November 2019; Office of the Tasmanian Economic Regulator, *Energy in Tasmania report 2018–19*, February 2020. Electricity generation: AEMO. Trading rights: AEMO; company announcements.

offered to specific customers. Retailers can shape their contracts by offering different tariff structures, discounted prices, 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. They may also include renewable energy offers. Retailers must obtain a customer's explicit informed consent before entering a market contract with them.

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 geographic area). A standing offer is a basic contract with prescribed terms and conditions that the retailer cannot change. It provides a full suite of customer protections and has no fixed term. Standing offer tariffs are generally higher than those offered under market retail contracts, and can be changed no more than once every six months. Since 1 July 2019 standing offer electricity prices are set or capped by an independent regulator in all jurisdictions (section 6.5). Retailers are free to set their own standing offer gas prices, which are not regulated.

Victoria—the first state to fully deregulate its energy market—has the highest proportion of energy customers on market contracts, at around 93 per cent (figure 6.10). South Australia has 92 per cent of customers on market offers, which may reflect customers searching for cheaper deals, given the relatively high price of electricity in the state.

NSW and south east Queensland recorded a shift towards market contracts after electricity prices were deregulated in those regions in 2014 and 2016 respectively. The rate of customers shifting to market contracts has since slowed. At January 2020 around 87 per cent of customers were on market contracts in NSW, and 83 per cent in south east Queensland. Nearly all customers in regional Queensland were on standing offers.

In January 2020 there were 57 per cent of customers in the ACT on market contracts, compared with 38 per cent in 2018. The recent increase follows strong participation by Origin Energy in the market. In Tasmania, 1st Energy became the state's first new entrant retailer to residential customers in early 2019. Despite the new retailer, the proportion of customers on market contracts dropped significantly over 2019, after the Tasmanian Government set standing offer prices that attracted a majority of Aurora's market customers to switch back to the standing offer. At January 2020 only 2 per cent of Tasmanian electricity customers were on a market offer.

While customers on market contracts pay less on average than those on standing offers, market customers do not necessarily receive the best price available. Contracts with expired benefits may be priced close to the standing offer. No data are currently published on the prices that customers pay under market contracts.

### 6.7.4 Customer awareness and engagement

Retail competition can drive innovation to bring a wider range of products and services to satisfy different customer preferences and demands. But competition can also increase complexity. Customers have found it difficult, for example, to compare retail offers, sometimes causing them to disengage from the market. Retailers have added to this complexity by adopting marketing strategies that make it difficult for customers to compare offers. Customer surveys have regularly found customers find the energy market difficult to navigate. These difficulties impose transaction costs (including time) that customers may face when comparing offers, which reinforces poor customer trust, and contributes to low levels of customer engagement with the market.

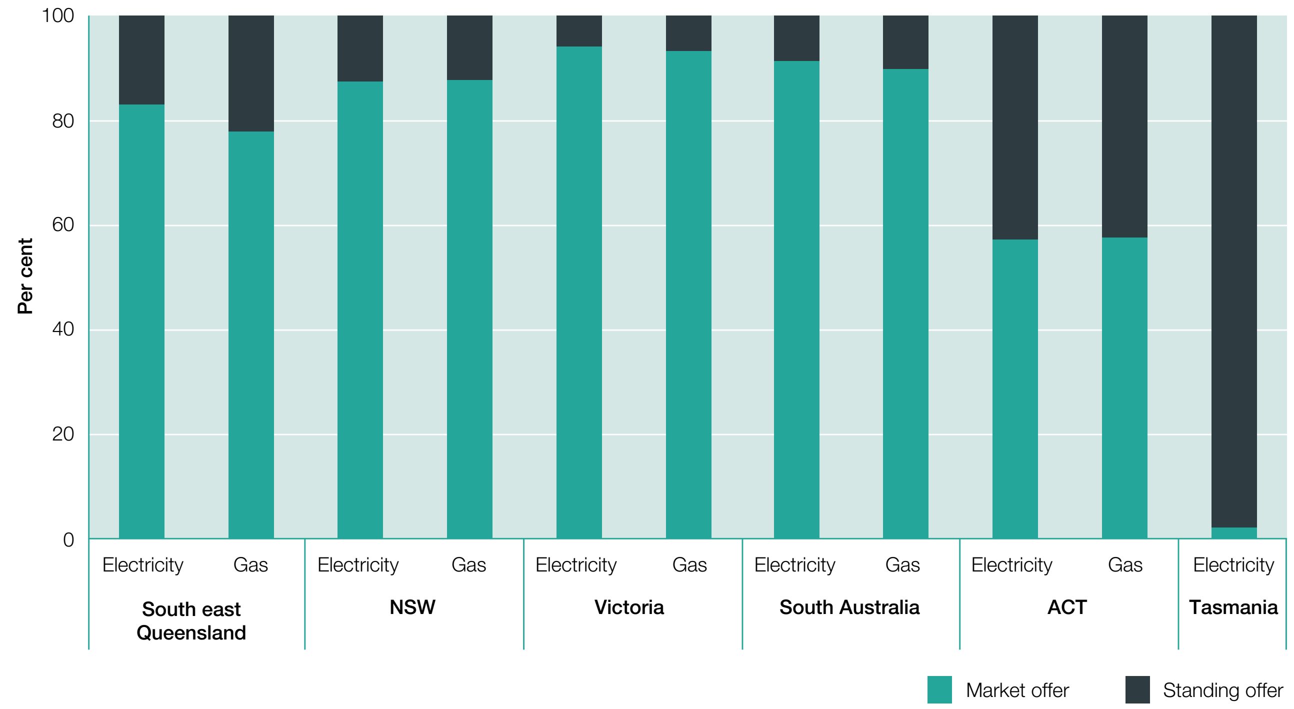
Some of the reforms introduced in the Electricity Retail Code in July 2019 sought to make it easier for customers to compare offers by simplifying and standardising how offers are presented. The reforms require marketed discounts to be quoted against a 'reference bill', being the default market offer set by the AER (section 6.5). Some retailers also introduced simpler pricing structures. These changes followed reforms in 2018 aimed at increasing customer engagement in the market. The 2018 reforms require retailers to notify small customers before any change in their benefits, alert customers to expired benefits, and provide at least five business days advanced notice of any price change under an existing contract.[24]

In Victoria, retailers must also prominently display their 'best offer' on customers' bills (every three months for electricity, and every four months for gas), along with advice on how to access it. The rules—introduced alongside the Victorian default offer in 2019—also require retailers to provide standardised fact sheets for their energy plans, which must include: estimates of how much the plan costs for a small, medium and large household; terms and conditions; discounts and vouchers; and other details specific to the plan.

While these reforms should improve customer engagement, barriers remain for some customers, including: language barriers; cultural issues; disabilities; low levels of literacy in energy markets, concepts and terms; and status quo bias for consumers to stay with their default retailer or plan.

24 AEMC, 'Final rule making retailers warn customers before their energy price change', Media release, 27 September 2018.

**Figure 6.10**
**Small customers on market and standing contracts**




Note: Standing and market offer shares are based on the number of small customers at January 2020, except Victoria (June 2019). Queensland electricity numbers exclude customers in regional Queensland, who largely remain on standing offers.

Source: AER, *Retail markets quarterly, Q2 2019–20*, March 2020; ESC, *Victorian energy market report 2018–19*, November 2019.

#### Customer understanding of the market

Customer confidence in their ability to navigate the energy retail market increased over 2019 in all regions except Tasmania. Energy Consumers Australia reported residential customers' confidence in their ability to make good choices in retail energy markets rose from 63 per cent in 2018 to 69 per cent in 2019. Customer confidence in the availability of easily understood information also rose, from 54 per cent to 60 per cent of households, and from 54 per cent to 63 per cent of small businesses.[25] These improvements may be partly due to recent reforms to help customers make informed decisions.

Market developments—including the rollout of smart metering and cost-reflective tariffs—will potentially add another layer of complexity to the market, making it harder for consumers to confidently engage in the market. But this added complexity will be offset by better tools for comparing offers. Customers are more widely using price comparator websites to reduce bill shock and manage market complexity, for example.

Despite these developments, awareness of independent government comparator websites Energy Made Easy and Victorian Energy Compare remains low. Enhancements to Energy Made Easy made in early 2020 aim to simplify the user experience and increase the site's capability to compare innovative offers. These enhancements coincided with increased promotion of the site.

Commercial switching websites and services have also emerged as a way for 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 6.7.8).

In May 2018 the Australian Government announced it would implement a national consumer data right, which when authorised will allow consumers' data to be shared with trusted third parties. The ACCC is developing arrangements for the energy sector, with the expectation that increasing

25 ECA, *Energy consumer sentiment survey, December 2019*, January 2020, p. 12.

the availability of and access to electricity data (such as a household's current energy deal and consumption patterns) will support customer decision making by enabling more personalised and precise comparison of offers.[26]

### Customer satisfaction

Customers' satisfaction with retail energy markets depends on factors including price, value for money, reliability, the customer service of their retailers, confidence in engaging with the market, technology uptake, and ability to switch.

Around 74 per cent of residential customers were satisfied with their energy supply arrangements in NEM jurisdictions in 2019 (compared with 70 per cent in 2018), but the rate was slightly lower in Queensland and the ACT.[27] Satisfaction with value for money in electricity rose in all regions (to around 52 per cent of customers), with significant increases in the ACT (up 22 per cent) and Tasmania (up 13 per cent). Satisfaction rates tended to be higher for gas than electricity supply (averaging 65 per cent of customers).

Satisfaction with retail competition also rose in most regions, and was highest in NSW and Victoria (both at 60 per cent). Satisfaction elsewhere ranged from 58 per cent in South Australia to 26 per cent in Tasmania.[28] Yet, only one in three households was confident the market is working in their long term interests.[29]

While satisfaction rates were below those in industries such as phone, internet, insurance, water and banking, they were an improvement on recent years. Higher energy prices in 2017 and 2018 negatively affected customer perceptions, which closely tie to views on value for money.

### Customer switching

The rate at which customers switch retailers can indicate their level of engagement in the market. But these statistics should be interpreted with care—switching may be low in a competitive market if retailers deliver good quality, low priced service that gives customers no reason to change, for example. Switching data fails to capture customer movements to new contracts with the same retailer, so understates customer activity in the market. Conversely, switching data captures when a customer moves house and signs a new contract, even if it is with the same retailer (thus overstating customer activity).

Reforms introduced in December 2019 aim to make it easier for customers to switch retailer by allowing them to transfer within two days of a cooling off period expiring.[30] This new process will limit retailer 'save' activity (retailers contacting customers who try to switch retailer, with a better offer to encourage them to stay) and allow customers faster access to prices and products they want.

Small customer switching decreased in 2019 in most regions for both electricity and gas customers (figures 6.11 and 6.12). Switching decreased despite reforms to marketing rules and customer notification requirements that aim to make it easier for customers to compare offers and explore whether better offers are available. The reduction follows increased switching activity in 2018, when greater effort to encourage customer engagement began, and coincides with relatively stable energy prices over 2019. Retailers also maintained their focus on retaining existing customers—of customers who considered switching in 2019, 16–24 per cent were offered a special deal to stay with their current retailer.[31]

Residential customers in NSW, Victoria and South Australia were most likely to switch retailer because they were dissatisfied with value for money. Residential customers in Queensland and the ACT typically switched because they searched for a better plan on a price comparison website.[32] Finding a better plan on a price comparator website was also the leading factor that drove switching for business customers.[33]

While overall switching activity was strong, over a third of customers had never switched retailer.[34] These customers may lack confidence in making decisions—nearly half of consumers were still not confident that they have access to easily understood information, for example.[35] Alternatively, these customers may be satisfied with their current supplier or unaware they can switch.

Victoria had the smallest proportion of customers who had never switched energy company or plan (27 per cent), followed by South Australia (29 per cent) and NSW (32 per cent). South east Queensland and the ACT had the most customers who had never switched (38 per cent and 40 per cent respectively).[36] These outcomes are consistent with other measures of customer engagement.

In other markets, engagement by even a limited number of customers can drive lower prices and product improvements that benefit all consumers. This outcome 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 two years, and customers who do not switch regularly may find themselves paying higher prices than necessary.

Reforms to the energy rules introduced in 2017 and 2018 require retailers to notify small electricity and gas customers before any change in their benefits, and provide advance notice of any price change.[37]

**Figure 6.11**
**Small electricity customer switching activity**

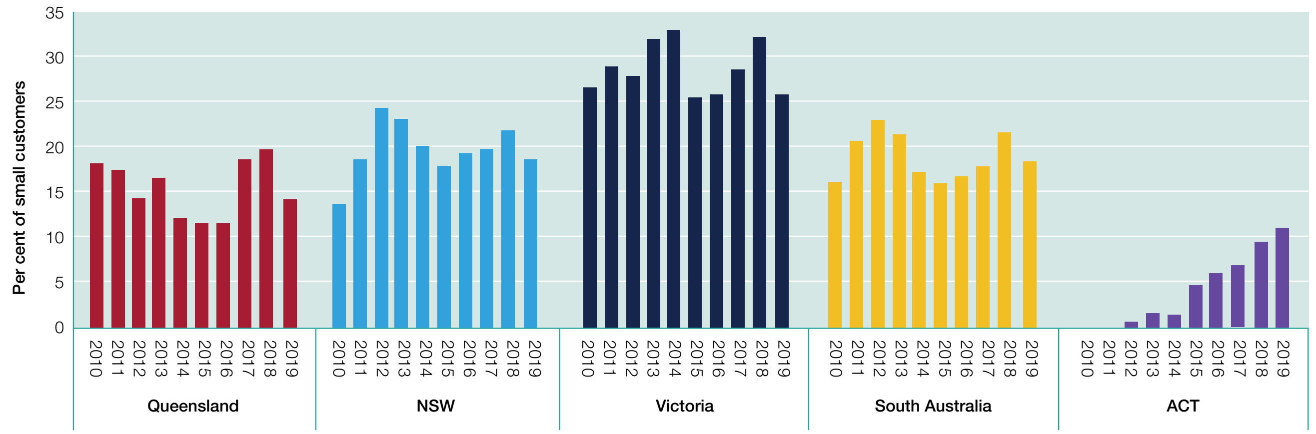
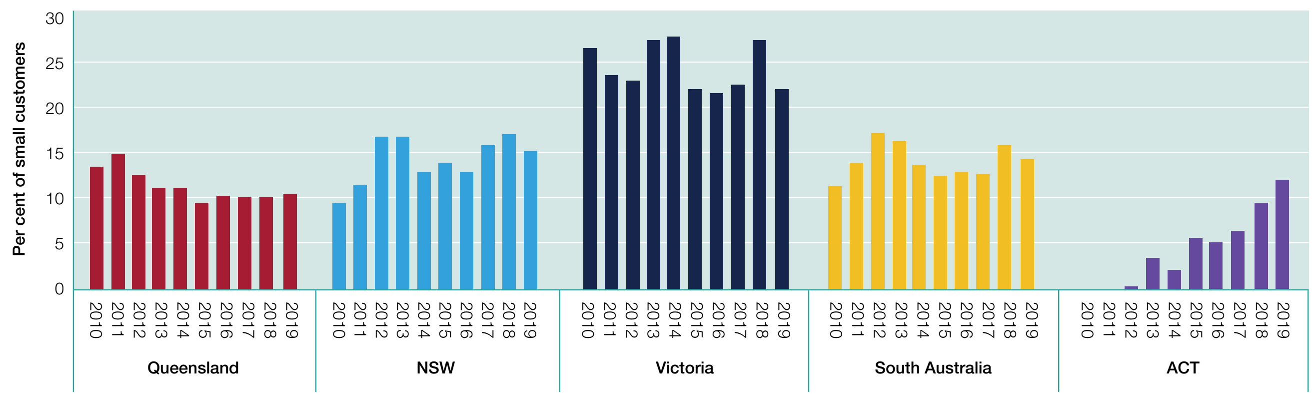



**Figure 6.12**
**Small gas customer switching activity**




Note (figures 6.11 and 6.12): Total annual customer switches in a year divided by average customer numbers.

Source (figures 6.11 and 6.12): Customer switches: AEMO, *NEM monthly retail transfer Statistics*, December 2019; AEMO, *Gas retail market monthly statistics*, December 2019. Customer numbers: estimates from AER, *Annual retail markets report 2018–19*, November 2019; ESC, *Victorian energy market update*, March 2020.

26 ACCC, 'Next step for consumer data right in energy', Media release, 29 August 2019.
27 ECA, *Energy consumer sentiment survey December 2019*, January 2020, p. 14.
28 ECA, *Energy consumer sentiment survey December 2019*, January 2020, p. 18.
29 AEMC, *2019 retail energy competition review, Final report*, June 2019, p. 91.
30 AEMO, *NEM customer switching, Draft report and determination*, December 2019.
31 AECA, *Energy consumer sentiment survey, December 2019*, January 2020, pp. 71, 86, 102, 117.
32 ECA, *Energy consumer sentiment survey, December 2019*, January 2020, pp. 71, 86, 102, 117.
33 ECA, *Energy consumer sentiment survey, December 2019*, January 2020, p. 56.
34 ECA, *Energy consumer sentiment survey, December 2019*, January 2020, p. 55.
35 AEMC, *2019 retail energy competition review, Final report*, June 2019, p. 99.
36 ECA, *Energy consumer sentiment survey, December 2019*, January 2020, pp. 70, 85, 100, 116, 144. Data are not available for regional Queensland or Tasmania.
37 AEMC, *Rule determination: National Energy Retail Amendment (Notification of the End of a Fixed Benefit Period) Rule 2017*, November 2017; AEMC, *Rule determination: National Energy Retail Amendment (Advance Notice of Price Changes) Rule*, September 2018.

These rules add to existing requirements for retailers to inform customers in writing about their options at the end of a fixed term contract, such as setting up a new contract or moving to another retailer. Importantly, retailers must ensure consumers are aware that they will be put onto a standing offer if they choose not to enter a new market contract with their current retailer.

#### Electricity switching

Following an uptick in electricity switching in 2018 (24 per cent of small customers across the NEM), switching in 2019 eased to around 20 per cent—similar to average levels since 2015. Victoria remains the most active region, with 25 per cent of customers switching in 2019. Price spreads in energy offers tend to be higher in Victoria than elsewhere, meaning the potential savings from switching tend to be greater. Switching activity in Victoria eased in 2019, despite the Victorian Government extending its initiative of a $50 payment to households for visiting the government comparator website, Victorian Energy Compare.[38]

Elsewhere, switching eased significantly in south east Queensland. This easing may reflect a return to more normal market conditions after a boost in activity in 2017 and 2018 following Alinta Energy's entry into the market. The ACT continues to have the lowest switching rates, due to the market's lack of competition, its small scale, continued price regulation, and the dominance of the incumbent retailer ActewAGL. But switching activity in the ACT continues to rise, with record switching rates of 11 per cent of customers in 2019.

#### Gas switching

Switching rates in gas eased across the market in 2019, with an average 18 per cent of small customers changing retailer (down from 21 per cent in 2018). But switching rates rose in the ACT and were stable in Queensland. Lower switching activity in gas relative to electricity may reflect fewer retailers participating in gas, meaning less choice and fewer potential customer savings. Gas, as a secondary fuel, is also typically a lower cost for customers, so may not receive the same attention.

The AEMC found in 2019 that small business switching was down across electricity and gas, and generally small business customers tended to switch retailers more than they switched plans.[39]

38 The Hon. Daniel Andrews MP (Premier of Victoria), 'Busting energy bills with new $50 power savings bonus', Media release, 1 July 2018.
39 AEMC, *2019 retail energy competition review, Final report*, June 2019, p. 114.

### 6.7.5 Retailer activity

Changes in retailer marketing activity can affect the level of customer switching. Consumer approaches by retailers appear to have been relatively steady over the past three years, with around 20 per cent of customers indicating an approach from a retailer prompted their most recent engagement in the energy market.[40] A peak of 53 per cent of residential customers were directly approached by a retailer in 2014. Enforcement around door-to-door selling by larger retailers has since reduced this activity.[41] But the use of digital acquisition channels, including retailers' websites and price comparison websites, is growing (section 6.7.8).

Retailers have also been less active in approaching businesses, with 64 per cent of businesses approached by a retailer offering to sell electricity or gas in 2019, down from 79 per cent in 2018.[42] Most contacts were in the form of a phone call by the retailer. Businesses report that retailers' marketing practices have become less aggressive.

While most retailers operate across multiple regions, only around one third of electricity retailers operating in south east Queensland, NSW, Victoria and South Australia operate in all four regions. The gas market is even more segregated, with most retailers concentrating on the NSW and Victorian markets.

Following new entry by two retailers in 2018, seven new retail brands entered the small customer electricity market in 2019:

- Amber Electric
- Elysian Energy
- Future X Power
- Nectr Energy
- OVO Energy
- Discover Energy
- Powerclub.

Additionally, five existing retailers began competing for customers in new jurisdictions:

- Powershop entered the South Australian market.
- 1st Energy entered the Tasmanian market.
- Red Energy entered the ACT market.
- Sumo Power entered the NSW market.
- Energy Locals entered the ACT and South Australian markets.

40 ECA, *Energy consumer sentiment survey, December 2019*, January 2020.
41 AEMC, *2018 retail energy competition review, Final report*, June 2017, p. 89.
42 AEMC, *2019 retail energy competition review, Final report*, June 2019, p. 111.

Minimal retailer activity in some markets may reflect perceived barriers to entry or expansion. Retailers cited the recent introduction of standing offer price caps (section 6.5) as a barrier to activity. Limited access to competitive risk management contracts was also cited as a significant barrier to entry or expansion in South Australia. The duplication of regulatory frameworks—notably in Victoria, which has its own Energy Retail Code—was another barrier due to the additional compliance costs it imposes.[43] Retailers also cited the practice of 'saves and win backs' as barriers to entry in some jurisdictions. 'Saves' refer to a retailer recontracting a customer who has indicated an intention to switch. 'Win backs' refer to retailers enticing a customer back shortly after they have switched to another retailer.

In gas, retailers identified access to reasonably priced gas and pipeline capacity as barriers to entry and expansion, especially in Victoria. Reforms in 2018 and 2019 sought to reduce these barriers by increasing transparency in the gas market and improving access to unused pipeline capacity through a day-ahead auction (chapter 4).

### 6.7.6 Product differentiation

In a competitive market, retailers offer a range of products and services to attract and retain customers. Energy retailers compete primarily on price, but with the introduction of standing offer price caps (section 6.5) and new restrictions around discounting (section 6.7.7), retailers are looking to differentiate their products in other ways.

Retailers can differentiate products by varying contract terms (length and fixed price periods) and offering other incentives (such as sign-up discounts, subscriptions and rewards). Some retailers have begun offering other products alongside electricity and gas (such as phone and internet) as a marketing and acquisition tool. These economies of scope may reduce the cost of customer acquisition and retention.[44]

In recent years, new retailers have offered products aimed at electricity customers with specific needs or preferences—including customers that desire simplicity or transparency, have environmental concerns, or have adopted new technology to regulate their electricity use.

There has been an increase in simple offers that provide a high level of bill certainty, such as fixed price contracts (where the customer pays a fixed amount regardless of how much energy they use) or subscription offers (where a customer pays a set amount each period to cover their expected electricity use).

There has also been an increase in offers with complex tariff structures that reward customers who have flexibility in when and how they use electricity. These structures include pool pass-through arrangements, where the customer takes on the risk of wholesale market volatility. Often these prices and products are accessible to only customers with specific technologies (for example, battery storage). These products may also come with 'add-on' services, such as systems to allow customers to track and control their energy use (section 6.8).

New waves of products and offers may emerge as battery storage systems become more affordable, and as accessibility to consumer energy data improves. But retailers noted the reintroduction of a regulated cap on standing offers may limit product innovation.[45]

### 6.7.7 Price differentiation

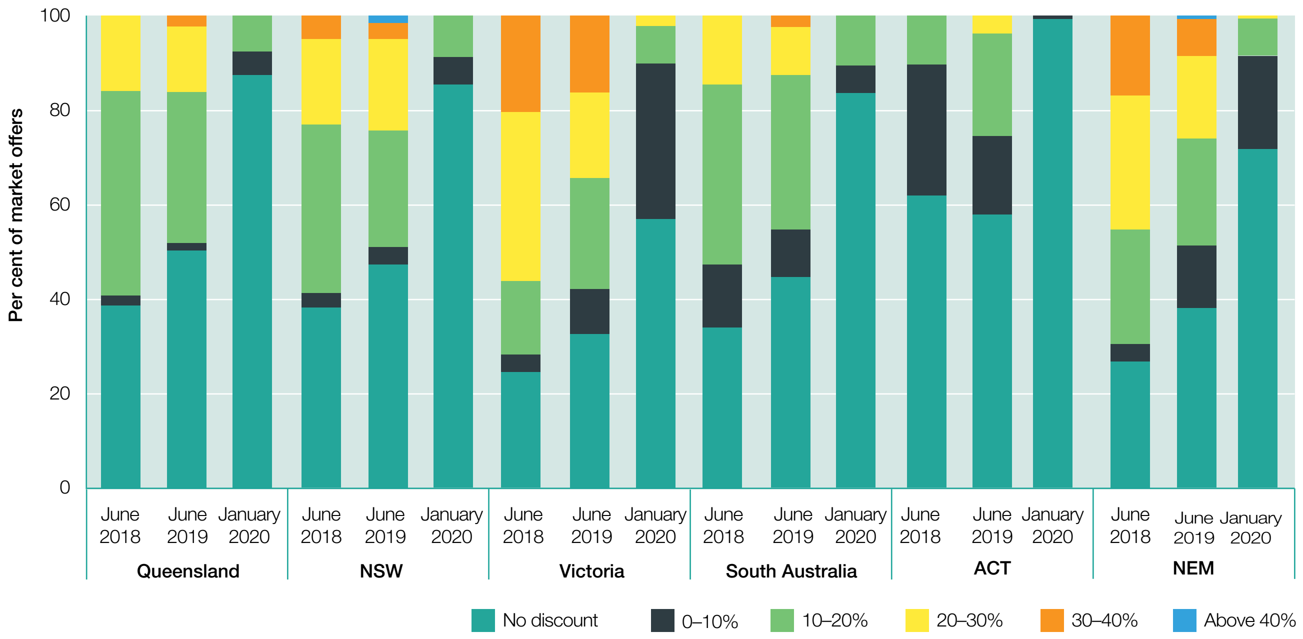
Price competition between retailers tends to plays out through 'headline' discounts. In 2018 around two thirds of offers included discounts that were conditional on the customer meeting terms such as paying on time, e-billing, or paying by direct debit. Most discounts offered at least 10 per cent off the original bill, with some offering up to 40 per cent off (figure 6.13). However, the size of a discount was often deceiving, as retailers measured and applied discounts off different price bases.

Advertising based on conditional discounts is problematic, because customers can be exposed to a much higher price if the conditions are not met. In 2018 over a quarter of residential customers (and over half of hardship customers) on offers with conditional discounts did not meet the conditions required to receive the discounted price.[46] The total number of missed conditional discounts was lower in 2019, but it is unclear if this outcome reflected higher rates of customers achieving discount conditions, or fewer customers on contracts with conditional discounts.

Reforms introduced in 2019 saw the practice of conditional discounting in electricity offers (and the size of discounts) significantly decline across all regions. From 1 July 2019 the Electricity Retail Code covered retailers in South Australia, NSW and south east Queensland.

43 AEMC, *2019 retail energy competition review, Final report*, June 2019, pp. 40, 41, 42.
44 AEMC, *2019 retail energy competition review, Final report*, June 2019, p. 44.
45 AEMC, *2019 retail energy competition review, Final report*, June 2019, p. ii.
46 ACCC, *Restoring electricity affordability and Australia's competitive advantage, Retail Electricity Pricing Inquiry—final report*, June 2018, p. 29.

Figure 6.13
**Conditional discounts for residential electricity market offers**




Note: Discounts are advertised conditional discounts in generally available market offers.
Source: Energy Made Easy website (www.energymadeeasy.gov.au); Victorian Energy Compare website (compare.energy.vic.gov.au).

The code:

- prohibits retailers from charging customers on standing offers more than the default market offer (section 6.5)
- requires retailers to base any discount advertising off the default price
- prohibits retailers from including conditional discounts in their most prominent advertised price for market offers.

The Victorian Government is progressing similar reforms to retailer advertising.

Following the reforms, the proportion of electricity offers with guaranteed prices (no conditional discounts) rose significantly and by January 2020 accounted for over 80 per cent of offers in Queensland, NSW, South Australia and the ACT. In Victoria, they comprised almost 60 per cent of offers.

Although most reforms apply to only electricity, discounting practices in gas follow similar trends. In 2018 almost 80 per cent of gas offers had a conditional discount attached, but that share fell to around 35 per cent in January 2020.

Among energy offers with conditional discounts at January 2020, the majority advertised no more than 10 per cent off the base price. The size of discounts may reduce further following a rule change in February 2020 that limits conditional discounts for both gas and electricity retail offers.[47] The new rule requires offered discounts to be no higher than the reasonable cost savings that a retailer can expect if a consumer satisfies the conditions attached to the discount.

### Recent changes in market offers

The implementation of the Electricity Retail Code reduced prices in standing offers, but the impact on market offers was less clear. Higher priced market offers tended to be lower in price, reflecting that these offers often tie to a retailer's equivalent standing offer. But some of the lowest priced offers were also removed in some regions, leading to a significant narrowing of the price range of available offers from July 2019 to early 2020. Figures 6.14 and 6.15 compare prices under market and standing offers for residential electricity and gas customers at June 2018, June 2019 and January 2020.

The gap between market and standing offers for electricity narrowed in all jurisdictions between July 2019 and January 2020. In Victoria, the median standing offer fell 14–19 per cent over this period across the state's five distribution zones. By January 2020 the median Victorian standing offer was around 6 per cent higher than the median market offer in each zone, compared with a 28 per cent difference in June 2019.

47 AEMC, *Rule determination: National Energy Retail Amendment (Regulating Conditional Discounting) Rule*, 27 February 2020.



These price movements were mirrored elsewhere. In NSW, south east Queensland and South Australia, median standing offers fell 10–13 per cent between June 2019 and January 2020. By January 2020 the median standing offer averaged 9–14 per cent higher than market offers (narrowing from a 23–29 per cent difference in June 2019). In the ACT, the median market offer in January 2020 was 11 per cent lower than the median standing offer, narrowing from 16 per cent in June 2019.

While prices in standing offers and higher priced market offers have declined, customers who engage in the market can still benefit by switching regularly. A customer switching from the median electricity standing offer to the best market offer in their distribution zone could save up to 20 per cent ($300–400 in annual savings) in January 2020.

Customers already on market offers could also save, with the lowest priced market offers averaging 7–8 per cent lower than median market offers (and with a 12–18 per cent saving in Victoria)—an annual saving of around $100–200.

In gas, the gap between market and standing offers has remained stable, with median market offers in January remaining 8–21 per cent lower than median standing offers.

## 6.7.8 Price comparison websites and switching services

The variety of product structures, discounts and other inducements makes direct price comparisons between retail offers difficult. Some customers use comparator websites to manage the complexity and large volume of different offers in the market.

The AER operates an online price comparator—Energy Made Easy—to help small customers compare retail offerings. The website shows all generally available offers, and has a benchmarking tool allowing customers to compare their electricity use with similar sized households in their area. The website is available to customers in jurisdictions that have implemented the Retail Law (Queensland, NSW, South Australia, Tasmania and the ACT).

The Victorian Government operates a similar website allowing Victorian customers to compare market offers—Victorian Energy Compare. In 2018 the NSW Government launched a switching service, Energy Switch, that provides a comparison of offers, helps arrange a switch and provides a reminder when it is time to review a plan.

Various private entities also offer online price comparison services. The AEMC identified 19 separate comparison websites in 2018.[48] Brokers are also active in the market for larger customers.

While comparison websites and brokers can provide customers with a quick and easy way of engaging in the market, some services may not provide customers with the best outcomes. Commercial comparator websites may only show offers of retailers affiliated with the site, for example. Comparison websites also typically require retailers to pay a commission per customer acquired or a subscription fee to have their offers shown. These arrangements are opaque to the customer. Commissions may vary across listed retailers, creating incentives for websites to promote offers that will most benefit the comparator business, rather than the cheapest offer for the customer.

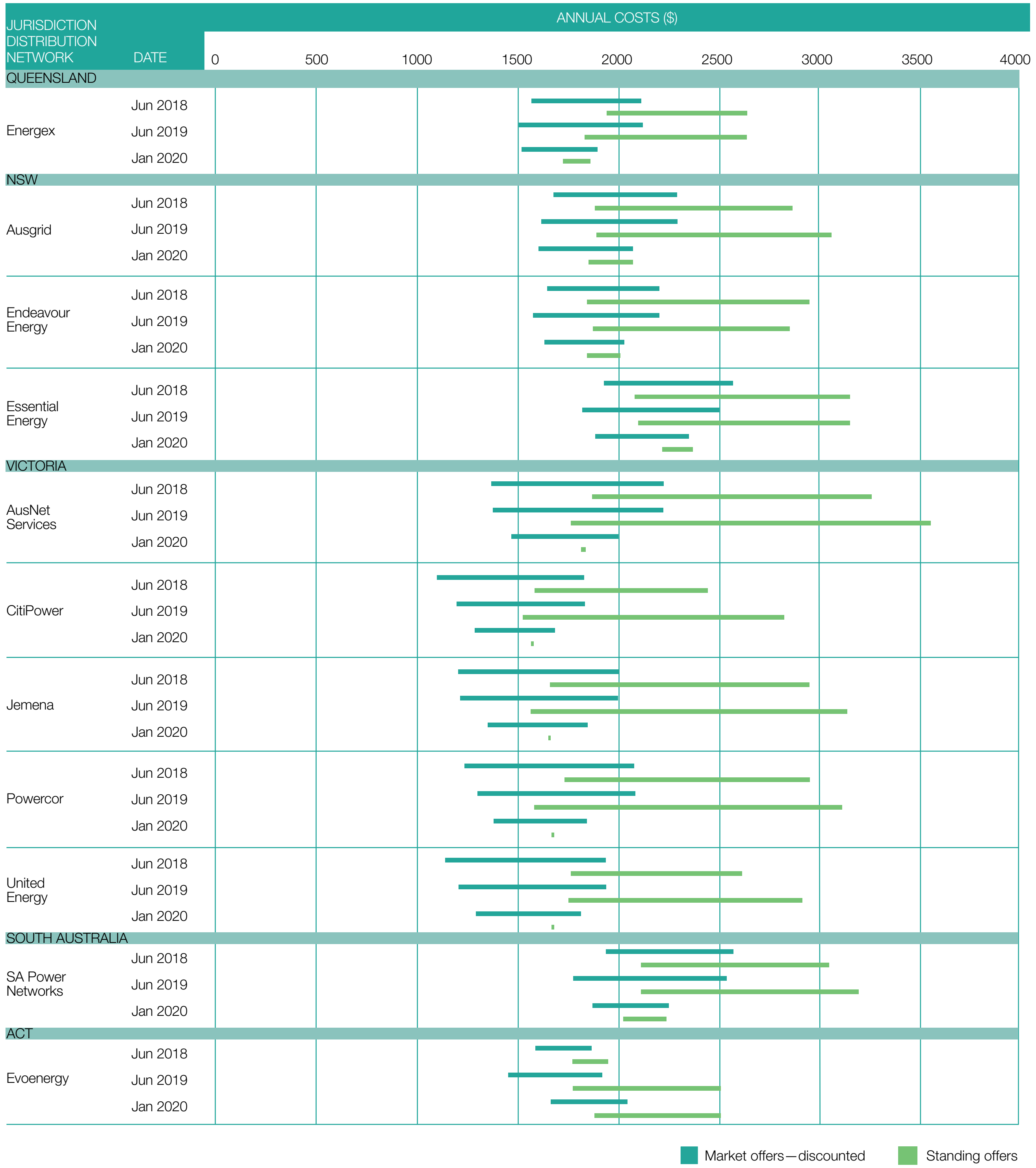
In 2019 the ACCC initiated enforcement action against commercial price comparison site iSelect for allegedly misleading consumers. The ACCC claimed iSelect represented to consumers that it would compare all of the plans available from its partner retailers and would recommend the most suitable plan.[49] In practice, recommendations were allegedly influenced by commercial relationships, and did not involve a comparison of all available plans, and the recommended plans were not necessarily the most competitive.

To address these issues, the ACCC and the AEMC recommended the government prescribe a mandatory code of conduct to ensure price comparator and broker services act in the best interests of consumers.[50] 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.

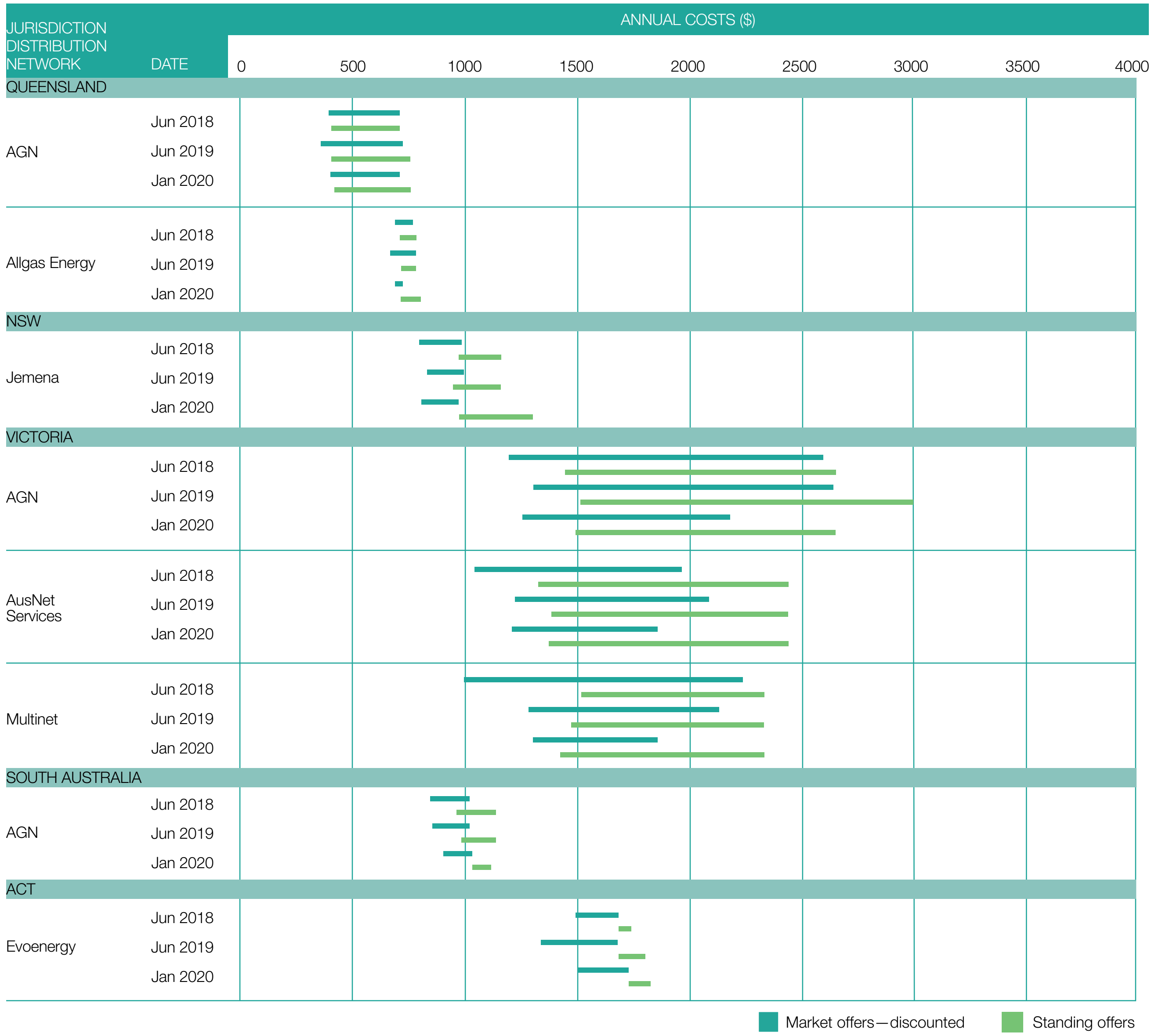
Government operated comparison sites avoid bias by listing all generally available offers in the market. However, knowledge about independent government comparator sites remains low. In 2019 small business awareness of Energy Made Easy decreased by 5 per cent to 24 per cent, for example.[51] In contrast, Victorian business awareness of the state equivalent, Victorian Energy Compare, rose to 55 per cent. This increase is likely due to the Victorian

48 AEMC, *2019 retail energy competition review, Final report*, June 2019, p. 102.
49 ACCC, 'iSelect in court for alleged misleading conduct and claims about energy plan comparison', Media release, 12 April 2019.
50 ACCC, *Restoring electricity affordability and Australia's competitive advantage, Retail Electricity Pricing Inquiry—final report*, June 2018, p. 282; AEMC, *2019 retail energy competition review, Final report*, June 2019, p. 282.
51 AEMC, *2019 retail energy competition review*, *Final report*, June 2019, p. 106.

## Figure 6.14
**Price diversity—electricity offers**




## Figure 6.15
**Price diversity—gas offers**




Note (figures 6.14 and 6.15): Data include all generally available offers for residential customers using a single-rate tariff structure at June 2018, June 2019 and January 2020. Annual bills are based on average consumption in each jurisdiction (table 6.2). Market offer prices include all conditional discounts.

Source (figures 6.14 and 6.15): Energy Made Easy website (www.energymadeeasy.gov.au); Victorian Energy Compare website (compare.energy.vic.gov.au).

Government's $50 bonus for each household or business that uses the website until 30 June 2020.

## 6.8 The evolving electricity market

Advances in metering and electricity generation, management and storage technologies are changing how the retail market works. Power of Choice reforms aim to provide customers with opportunities to benefit from these changes. Reforms include a market led rollout of smart meters, introducing cost-reflective network pricing, making it easier for consumers to compare and switch retailers, and enabling wider use of demand response.

Industry bodies developed a code of practice on standards of consumer protection when businesses offer new energy products and services.[52] The code covers all aspects of supply, including marketing, finance, installation, operation, customer service, warranties and complaints handling. The ACCC authorised the code in December 2019, subject to conditions on the offering of 'buy now pay later' finance arrangements. The authorisation decision was under review by the Australian Competition Tribunal in early 2020.[53]

### 6.8.1 Smart meters

Smart meters measure electricity use in half hour blocks, and allow remote reading and connection/disconnection. The information about a customer's energy use throughout the day from smart meters provides scope for more innovative offers from retailers, and for new energy management services from third parties.

Victoria was the first region to progress metering reforms, with its electricity distribution businesses rolling out smart meters to around 98 per cent of customers across 2009–14. Elsewhere, the rollout has occurred on a market led basis. Responsibility for metering outside of Victoria transferred from network businesses to retailers in December 2017. All new and replacement meters for residential and small businesses consumers must now be smart meters. Outside Victoria, around 12 per cent of customers had a smart meter at February 2020.[54] Another 5 per cent of customers (mostly in NSW) had access to an interval meter providing half hourly consumption readings but without remote reading and connection capabilities.

The transition to retailer responsibility for metering coincided with large delays in meter installations in some regions. Retailers attributed the delays to: poor coordination and data provision among network businesses, retailers and metering coordinators; inadequate retailer systems, processes and controls; and poor resourcing.

Since February 2019 new rules require retailers to provide customers with electricity meters within six business days after a property has been connected to the network, or replacement meters within 15 days.[55]

### 6.8.2 Rooftop solar PV and batteries

Many customers now partly meet their electricity needs through rooftop solar PV, and sell excess electricity back into the grid. At January 2020 over 2 million households and businesses in the NEM (32 per cent of customers) had installed rooftop solar PV systems.

New installations of solar PV systems peaked in 2011 (figure 6.16) due to attractive premium feed-in tariffs offered by state governments. Those schemes have closed, but ongoing subsidies provided by the Australian and some state governments, combined with falling costs of solar PV systems, sustained growth in new installations. The average size of solar PV systems has also grown. Total solar capacity installed in 2019 (1760 MW) was more than double the capacity installed in 2011 (750 MW), despite 25 per cent fewer systems being installed.

When installed with solar PV systems, battery storage and smart appliances allow customers to better match their electricity requirements over time, reducing the amount of power they need to withdraw from the network. Of the 590 000 solar PV systems installed in the NEM since 2017, 3 per cent have had an attached battery system.[56] The uptake of batteries has remained stable over the past three years, despite declining battery costs.

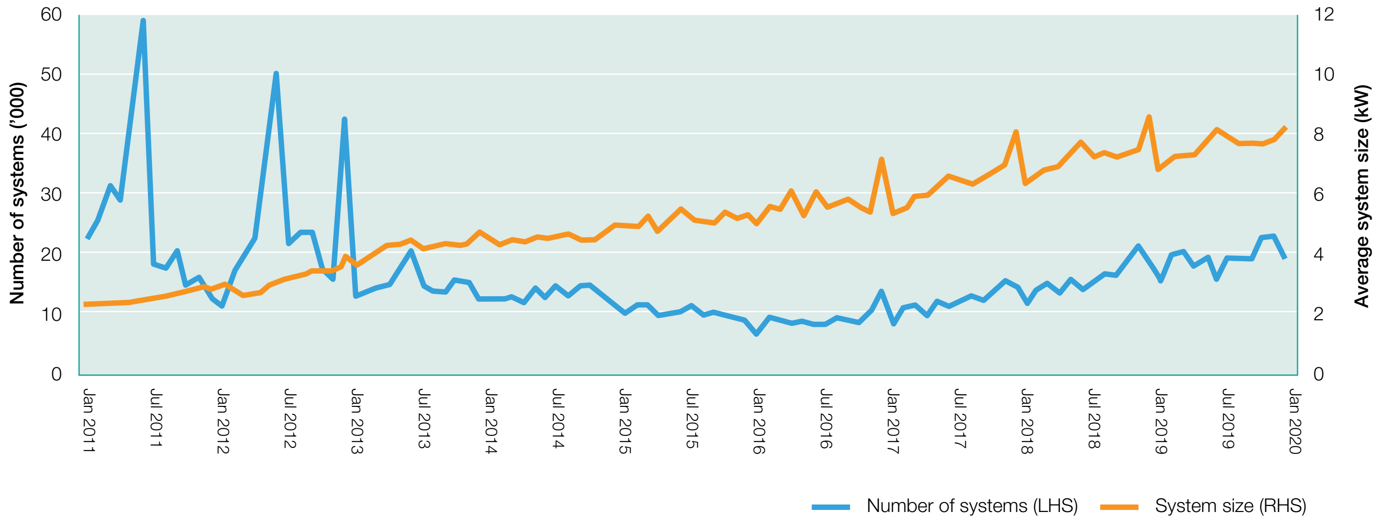
Solar PV systems can be purchased outright by customers, or installed under a power purchase agreement. Under these agreements, an energy provider installs, owns, operates and maintains a solar PV system at a customer's home, and sells the generated energy to that customer. In return, the customer pays for the electricity produced by the system, typically at a cheaper rate than an energy retailer would charge for supplying electricity through the grid. Some agreements transfer ownership of the solar PV system to the customer at the end of a contract.

Excess electricity produced by solar PV systems is typically sold back to the customer's retailer. However, some retailers offer customers the ability to on-sell excess electricity to other customers.

Increasing rates of rooftop solar PV generation pose significant challenges for the traditional retail model. Households with solar PV systems typically do not produce enough energy to meet all their requirements, and buy the balance from a retailer. But the lower volumes they buy make these customers less profitable for the retailer. Battery storage may further reduce energy purchases by these users.

52 ACCC, *Determination: Application for authorisation AA1000439 lodged by Australian Energy Council (AEC), Clean Energy Council (CEC), Smart Energy Council (SEC) and Energy Consumers Australia (ECA) (together the Applicants) in respect of the New Energy Tech Consumer Code*, December 2019.
53 Flexigroup Limited, a provider of finance products for new energy products and services, sought removal of the ACCC imposed conditions on the provision of buy now pay later finance by signatories of the code (see www.competitiontribunal.gov.au/current-matters/act-1-of-2019).
54 AEMO data (unpublished).
55 AEMC, *Rule determination: National Energy Retail Amendment (Metering Installation Timeframes) Rule 2018*, December 2018.
56 Clean Energy Regulator, Solar PV systems with concurrent battery storage capacity by year and state/territory. Data at 31 January 2020.

**Figure 6.16**
**Growth of solar PV installations**




kW, kilowatts.
Note: Data at January 2020.
Source: Clean Energy Regulator, Postcode data for small scale installations, Small generation units—solar.

### 6.8.3 Demand response

Smart meters provide customers with opportunities to participate in demand response programs run by retailers, distribution network businesses or third party energy providers.

The simplest demand response programs offer customers financial incentives to reduce their electricity use after receiving an alert from their retailer or network business. More sophisticated programs include technologies that optimise solar PV and storage systems, and automated load control devices that reduce power consumption from appliances such as air conditioning, hot water systems or pool pumps when required. Automating customer participation is likely to see greater uptake of these programs.

The Australian Renewable Energy Agency (ARENA) is funding a range of 'virtual power plant' trials that coordinate output from small scale solar and battery systems to provide services equivalent to large scale generation plant (section 1.2.2).

These opportunities provide a new source of competition across the supply chain. Demand response can be deployed in the wholesale market to manage or limit price spikes, and can also be used by networks to manage system constraints, for example.

### 6.8.4 Customers in embedded networks

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. The customer experience in embedded networks, however, can be significantly different. Many customers cannot buy energy from a provider 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 December 2017. Gaps in consumer protection occur in areas such as connection services, disconnection and reconnection obligations, and life support arrangements. Most customers in embedded networks also have limited avenues for dispute resolution.

In June 2019 the AEMC recommended a new regulatory framework for embedded electricity networks to address these issues.[57] A Council of Australian Governments (CoAG) Energy Council working group was progressing an implementation framework in 2020.[58]

## 6.9 Energy affordability

Energy affordability relates to customers' ability to pay their energy bills. A customer's energy consumption, their energy contract and prices, their income, and other living costs affect affordability.

A customer's energy use varies with how many people they live with, housing and appliance quality, heating and cooling needs, and lifestyle. Energy prices depend on where a customer lives, the network services required to supply their energy, competition between retailers in their area, the customer's ability to identify an appropriate energy plan, and whether the customer is eligible for a concession or rebate to help manage their energy costs.

Low income customers face heightened affordability risks, but may be familiar with available support services. Middle income households overwhelmed by financial and family commitments, and out of touch with how to access support services such as concessions and payment plans, are also at risk of poor energy affordability outcomes.[59]

To better understand issues facing customers in vulnerable circumstances, the AER in 2020 published research (by the Consumer Policy Research Centre) on the opportunities

57 AEMC, *Updating the regulatory frameworks for embedded networks, Final report*, June 2019

58 CoAG Energy Council, *CoAG Energy Council response, Australian Energy Markets Commission review of the regulatory frameworks for distributor-led stand-alone power systems—priority 1, Final report*, 2 December 2019.

59 Newgate Research, *AEMC 2016 retail competition review: understanding vulnerable customer experiences and needs, Consumer research report*, June 2016.

and benefits of different regulatory approaches to address consumer vulnerability in regulated markets.[60] The report will inform the AER's approach in this vital area.

The AER reports annually on energy affordability, with a focus on low income households.[61] In 2018–19 electricity affordability improved for low income households in all jurisdictions, and especially in South Australia, Queensland and NSW (figure 6.17). Gas affordability for low income households continued to deteriorate in Victoria but improved elsewhere.[62] These outcomes were largely driven by lower retail prices for gas and electricity. However, while affordability has improved, energy costs remain high in historic terms.

Supporting the finding of improved energy affordability, a *Choice* survey in November 2019 found electricity was no longer the expenditure item of most concern to households. While 78 per cent of households said electricity costs were a worry, this response is down from 84 per cent two years ago.[63]

For a typical low income household receiving energy bill concessions, at July 2019:

- electricity costs accounted from 4.8–9.9 per cent of disposable income for low income households (down from 5.2–10.6 per cent in 2018).
- gas costs accounted from 2.6–6.8 per cent of disposable income for low income households (compared with 2.7–6.4 per cent in 2018).[64]

Tasmanian customers had the highest electricity bill to income ratio in low income households. This outcome in part reflects Tasmania having the highest average use of electricity—due to a cold climate creating a high demand for heating, and the state's low gas penetration. High concessions and relatively low electricity charges partly offset this factor. South Australian customers also experienced relatively high electricity bill to income ratio in low income households. While the state has the second lowest electricity use in the NEM, electricity prices are high.

Despite above average electricity use, the ACT had the most affordable electricity bills as a percentage of disposable income—a result of relatively low electricity prices and high incomes.

60 CPRC, *Exploring regulatory approaches to consumer vulnerability. A report for the Australian Energy Regulator*, November 2019.

61 AER, *Affordability in retail energy markets*, September 2019.

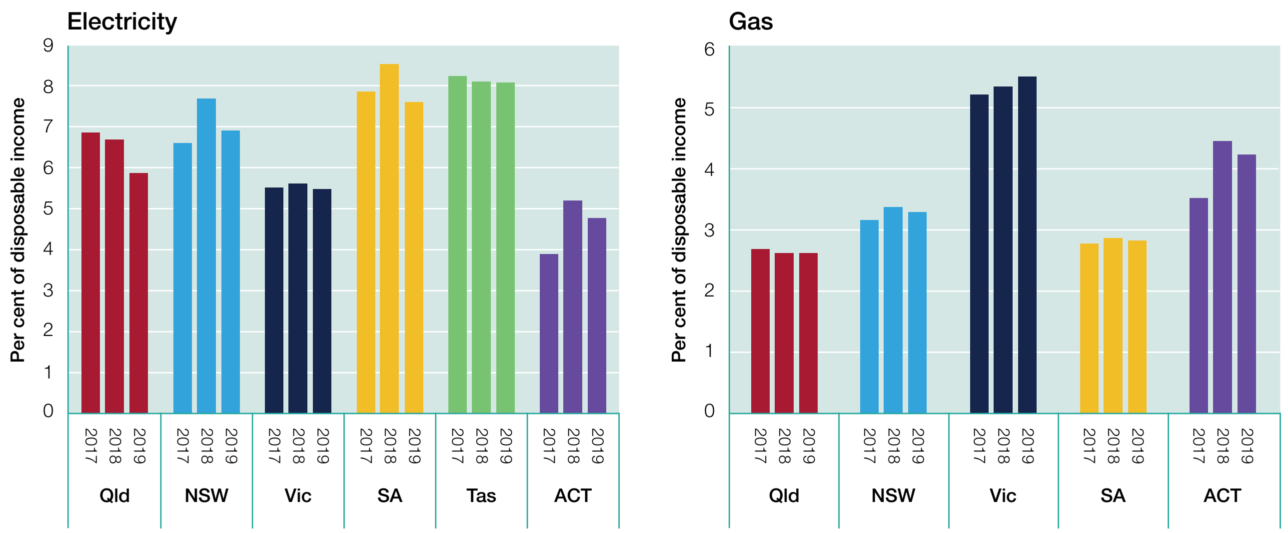
62 Based on the percentage of household disposable income spent on the median retail offer.

63 Kollmorgen, A. 'Two in three Australian households are feeling the pinch', *Choice*, 6 November 2019.

64 AER, *Affordability in retail energy markets*, September 2019.



**Figure 6.17**
**Energy bill burden on low income households**




Note: Based on average household consumption data for each state. Energy costs based on the median of generally available single-rate offers (inclusive of discounts) at June each year. The data account for available concessions and rebates. Income data are equivalised disposable income (adjusted lowest income quintile) as reported by the Australian Bureau of Statistics in 2015–16 and 2017–18, adjusted for other years using the consumer price index.

Source: AER, *Affordability in retail energy markets*, September 2019.

In gas, the high use jurisdictions of Victoria and ACT had the highest bills (across market and standing median offers) as a percentage of disposable income.

Low income households in all jurisdictions often paid more than double (as a share of income) what households on higher incomes paid for their energy. State and territory governments offer energy concessions to eligible low income households, which can significantly improve affordability. Most jurisdictions also offer emergency bill support. The potential savings vary by jurisdiction and depend on how the concession is applied, but can be several hundred dollars per year for each fuel.

Recent policy recommendations have focused on concessions to help manage rising bill burdens on energy consumers. Most jurisdictions offer concessions as a fixed annual dollar amount (ranging from $73 for gas customers in Queensland to $560 for electricity customers in Tasmania). Victoria applies the concession as a percentage of a customer's energy bill (17.5 per cent in 2019).

The ACCC found the way concessions are applied can affect their helpfulness.[65] In South Australia, for example, a customer must reapply for a new concession every

65 ACCC, *Restoring electricity affordability and Australia's competitive advantage, Retail Electricity Pricing Inquiry—final report*, June 2018, pp. 297–303.

time they change retailer—which may discourage them from switching to cheaper offers. Emergency bill support varies across states by amount, eligibility requirements and administration, but usually cannot be accessed more than once every one to three years.[66]

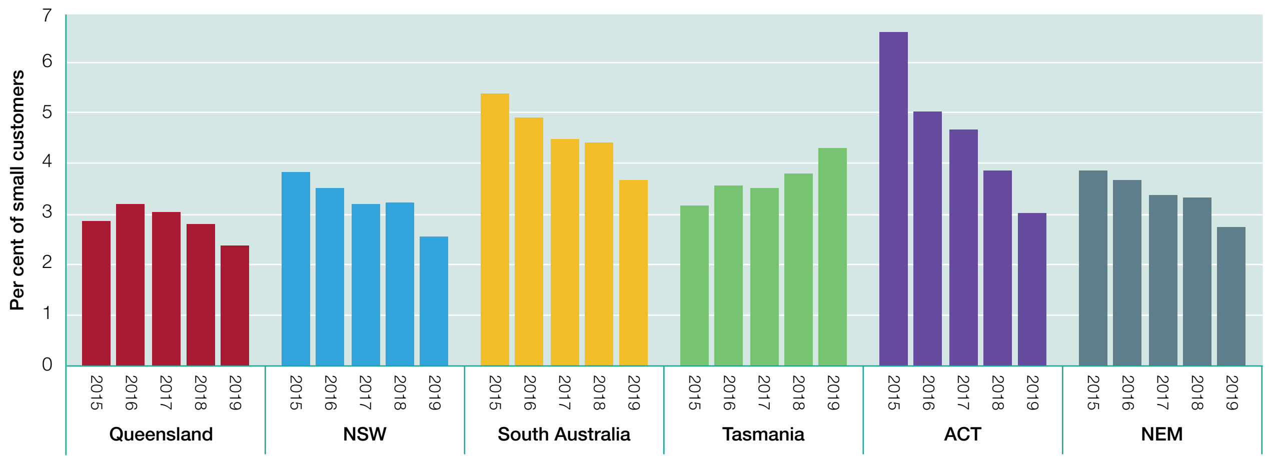
While concessions represent an important saving for eligible households, many households can achieve significant savings simply by switching to a cheaper offer. State governments have implemented initiatives to move low income households onto lower cost offers, or help them improve their energy efficiency:

- South Australia's Concessions Energy Discount Offer, offered through Origin Energy, allows concession customers to receive up to 20 per cent off their electricity bill, and 11 per cent off their gas bill, as part of the offer.
- Victoria's Energy Brokerage Pilot, delivered in partnership with Brotherhood of St Laurence, connected low income households with energy brokers to help them find better energy offers.
- Tasmania's Power$mart Homes helps low income households save money on their bills by providing upgrades such as LED light bulbs, draught sealing and expert energy efficiency advice.

66 Information on these schemes is available from state government departments and ombudsmen websites.

**Figure 6.18**

**Small customers in energy debt**




Note: Based on customers with an amount owing to a retailer that has been outstanding for 90 days or more, at 30 December 2019.
Source: AER, *Retail markets quarterly, Q2 2019–20*, March 2020.

- The ACT's Energy Efficiency Improvement Scheme includes a target for electricity retailers to achieve energy savings for low income households through efficiency measures.

## 6.9.1 COVID-19 issues

In 2020 the COVID-19 pandemic has posed serious financial risks for many energy customers. Retailers, networks and governments have responded with a variety of support programs for customers in vulnerable circumstances (box 6.3).

## 6.9.2 Assisting customers in debt

Energy affordability issues can lead customers into debt that, if not managed, may result in disconnections. A household's energy debt refers to amounts owing for 90 days or more to a retailer. The number of residential electricity and gas customers in debt fell in most regions in 2019, continuing the trend over the past four years.

Tasmania had the highest percentage of residential energy customers in debt at December 2019, at 4.3 per cent of customers (figure 6.18). NSW and Queensland had the lowest rate of customers in debt, at around 2.5 per cent. The average value of debt was highest in South Australia and Tasmania at $955 and $893 respectively, and lowest in Queensland at $607.

Energy debt in some jurisdictions is seasonal, particularly for gas customers. In the ACT, for example, gas debt often grows larger in the December and March quarters because customers may have difficulty in paying off larger winter heating bills.

A retailer's approach to managing customer debt can have a significant impact on whether a customer can successfully navigate a period of financial difficulty. In 2019 the AER highlighted a concerning practice of retailers referring customers for collection activity for debt that is often less than $500.[67] In December 2019 around half of all customers referred for collection activity received a credit default as a result of their unpaid energy debt. A credit default can have a significant negative impact on a customer, including limiting their ability to obtain a credit card or mortgage, or access low cost energy market contracts.

### Payment plans

Payment plans allow settlement of overdue amounts in periodic instalments, and are typically the first assistance offered to customers showing signs of payment difficulties. The AER's Sustainable Payment Plans Framework guides retailers on negotiating affordable payment plans with customers needing assistance to manage debt.[68]

67 AER, *Annual retail markets report 2018–19*, November 2019.
68 AER, *Sustainable payment plans, A good practice framework for assessing customers' capacity to pay, Version 1*, July 2016.



## 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. This statement reiterated energy is an essential service, and the market has an important role in protecting and supporting businesses and the community through the COVID-19 pandemic and recovery. We expect energy retailers to:

- offer payment plans or hardship arrangements to all residential and small business customers who indicate they may be in financial stress, regardless of whether the customer meets the 'usual' criteria for assistance
- not disconnect any residential or small business customers who may be in financial stress (without their agreement) before 31 July 2020 and potentially beyond
- defer referrals of customers to debt collection agencies for recovery actions, or credit default listing until at least 31 July 2020
- waive disconnection, reconnection and/or contract break fees for small businesses that cease operation, along with daily supply charges during periods of disconnection until at least 31 July 2020.

Most retailers, including members of the Australian Energy Council, have committed to similar measures to support customers facing financial distress, including:

- providing support through measures such as payment plans
- helping customers to access available grants and concessions
- ensuring there are no barriers to entering hardship programs
- not disconnecting affected customers who receive hardship assistance if they are unable to afford their energy bills
- pausing any external debt collection and bankruptcy proceedings for customers in the hardship program, and not applying late fees if these customers cannot pay on time.

Together with the Essential Services Commission, we have requested that energy retailers report more frequently on customer outcomes over this period. Data on call centre performance, customer debt levels, credit collection, payment plans and hardship programs will be collected on a weekly or monthly (rather than quarterly or annual) basis.

Due to COVID-19 restrictions and staff shortages, many retailers' call centres have been significantly impacted. As a result, response times have been delayed and/or contact hours limited. However, most retailers have encouraged other means of forms of communication, including through their website, apps, email or online chat.

Energy networks in NSW, Victoria and South Australia have announced measures to support customers enduring hardship as a result of the COVID-19 pandemic. These measures apply to small business and residential customers:

- Network charges will not be applied for small business customers experiencing financial stress and who are mothballing as a result of COVID-19.
- Network charge support will be offered to residential customers who go into default as a result of COVID-19. For customers of small retailers, network charges will be rebated. For customers of larger retailers, network charges will be deferred.
- Support will be offered to retailers to not disconnect residential and small business customers who may be in financial stress.

These measures will apply to network charges for April to June 2020, with rebates to affected customers by September 2020.

The AER recognises the current heightened risks and costs facing energy businesses. For this reason, it is working with stakeholders to appropriately balance the risks and costs across the sector, and to ensure energy businesses receive any assistance they may need to remain viable. The AER in May 2020 proposed an urgent change to the National Electricity Rules to support electricity retailers as they provide payment assistance to customers, by allowing them to defer payments of network charges by up to six months for customers affected by the COVID-19 pandemic. The proposal builds on the voluntary support measures being provided by some network businesses.

Several state governments have also announced COVID-19 specific support packages for households and businesses. In Queensland, for example, households will receive a $200 utility payment to assist with their electricity and water bills, and small businesses consuming less than 100 000 kilowatt hours will receive a $500 utility rebate. In the ACT, holders of a utilities concession will receive an additional $200 rebate on their electricity bill. In Tasmania, Aurora Energy—in conjunction with the state government—capped price increases in energy bills for 12 months, and announced a 100 per cent waiver for small business customers on their next bill after April 2020.

The framework sets out good practice principles of engagement based on trust, respect and empathy to promote constructive, long term customer relationships. Nineteen retailers have signed on to the framework, covering over 90 per cent of customers.

Customers who fulfil the terms of their payment plan agreement—such as making all repayments under their plan and repaying outstanding debt—are considered tosuccessfully complete the plan. In 2019 the proportion of electricity payment plans successfully completed decreased from 44 per cent to 38 per cent, but in gas rose from 31 per cent to 34 per cent. The low success rate indicates repayment schedules may not have been set at appropriate levels.

### 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 identified deficiencies in how retailers implement their hardship policies and in 2019 released a new hardship guideline, enforceable by civil penalties.[69] The guideline requires retailers to ensure their programs are easily accessible and include a standard statement explaining how they will help customers, and puts greater onus on retailers to identify who may need assistance.[70]

Assistance under a retailer's hardship program can include:

- extensions of time to pay a bill, and tailored payment options
- advice on government concessions and rebate programs
- referral to financial counselling services
- a review of a customer's energy contract to ensure it suits their needs
- energy efficiency advice to help reduce a customer's bills, such as an energy audit and help to replace appliances
- a waiver of any late payment fees.

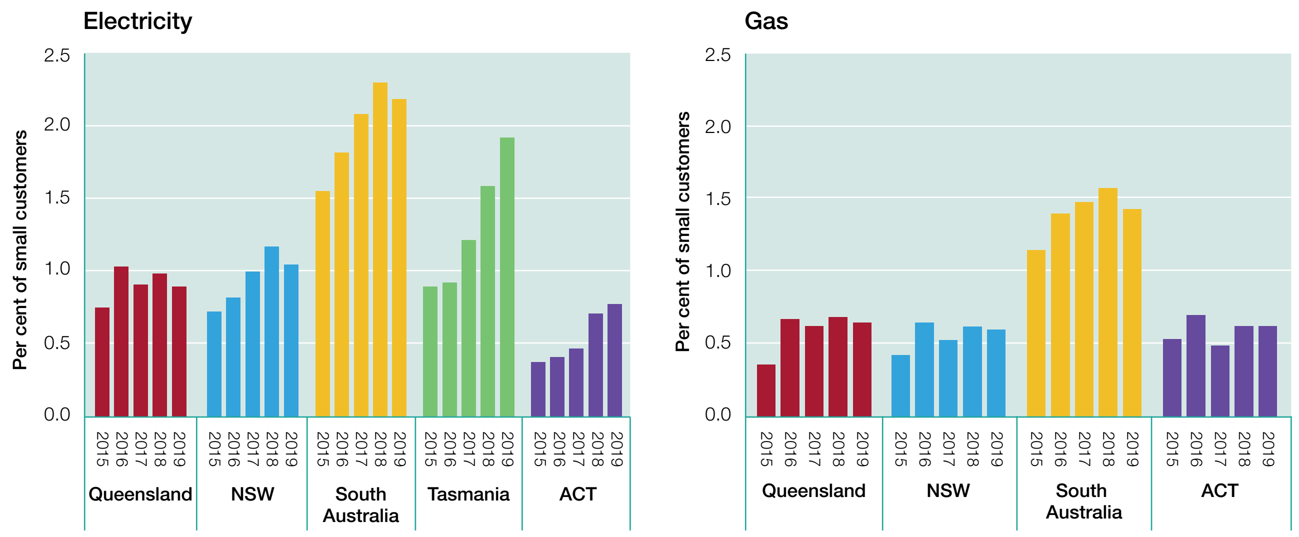
Customers can enter hardship programs by initiating entry themselves (around two thirds of customers), being identified by their retailer (around one third), or by referral by financial advisers or other agents (around 2 per cent). Among jurisdictions in which the Retail Law applies, the average proportion of customers on hardship programs decreased in 2019 (figure 6.19), after increases in previous years. South Australia continued to have the highest proportion of residential customers on hardship programs (2.2 per cent of electricity customers and 1.4 per cent of gas customers at December 2019). The ACT had the smallest proportion at around 0.8 per cent, but the rate has risen since 2017. Gas hardship customer rates in regions outside South Australia were around 0.6 per cent of customers in 2019.

Customers on hardship programs must typically make payments to cover any outstanding debt and ongoing energy costs. But retailers may allow a customer to make payments that are less than their ongoing costs (or do not take into account arrears), based on the customer's capacity to pay.

In 2019 the average hardship debt of electricity and gas customers increased by 16 per cent and 29 per cent respectively. The average electricity hardship debt was around twice the level of gas hardship debt (figure 6.20).

69 AER, *Customer hardship policy guideline, Version 1*, March 2019.
70 AER, 'Hardship protections a right not a privilege', Media release, 29 March 2019.

Figure 6.19
**Proportion of small customers on a hardship program**




Source: AER, *Retail markets quarterly, Q2 2019–20*, March 2020.

Average electricity hardship debt and debt on entry to hardship programs was highest in South Australia and Tasmania, and lowest in Queensland. Outside Tasmania, electricity debt on entry to hardship programs was lower than average debt, indicating consumers accumulate additional energy debt while on hardship programs, which may become entrenched. Around 45 per cent of electricity customers on hardship payment plans and 36 per cent of gas customers were unable to meet their usage costs in 2019.

Average gas hardship debt and debt on entry in 2019 was significantly higher in the ACT than elsewhere, likely due to the high consumption of gas in the region.

The number of customers exiting hardship programs by paying off their debt is a useful indicator of programs' success. Successful completion of hardship agreements almost doubled between 2018 and 2019, to 31 per cent of customers. The rate remains low, however, indicating many hardship customers may not be receiving the assistance they require. Of the 34 742 customers who exited hardship programs in 2019, 58 per cent did not successfully meet their payment arrangement. Around another 10 per cent of hardship customers exited a program because they transferred to another retailer. Victoria operates its own state based hardship program. In 2019 it introduced new minimum standards of assistance for customers who anticipate or face payment difficulties.[71]

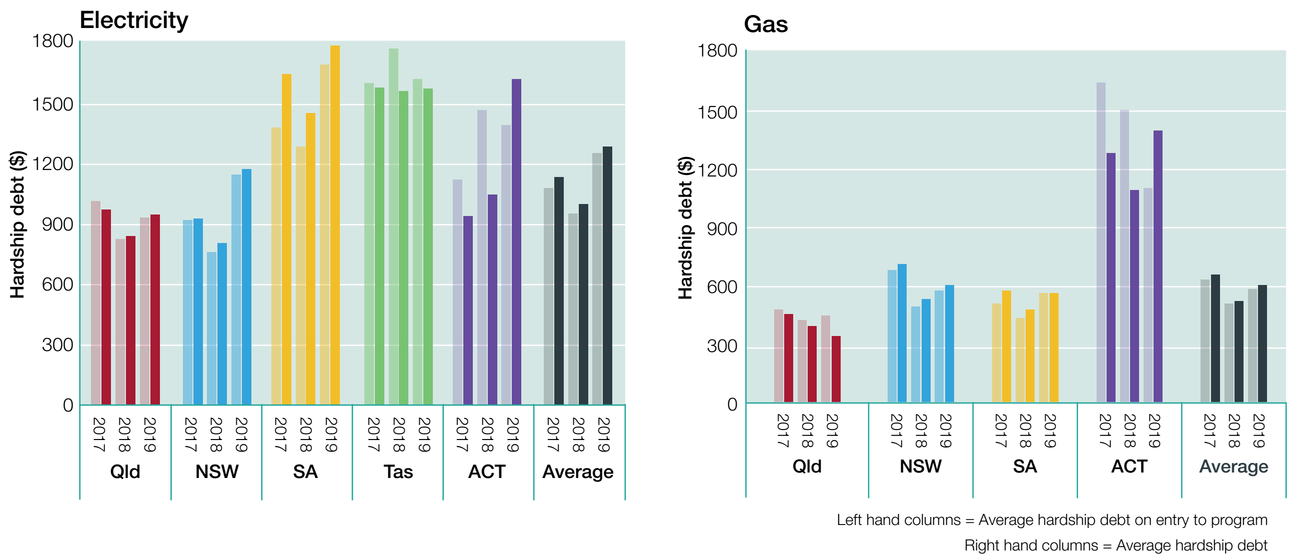
## 6.9.3 Disconnecting customers for non-payment

Energy retailers are required to help customers in financial hardship before considering whether to disconnect them for non-payment of a bill. Additionally, 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. The National Energy Retail Rules set out strict processes that must be followed before a disconnection can occur. In 2019 disconnected customers typically had outstanding energy debts of between $500 and $1500.

Overall, the proportion of residential and small business customers disconnected for failing to pay an energy bill decreased in 2019. Queensland and South Australia had the highest rates of electricity disconnections in 2019, at around 1.2 per cent of customers. Around 0.85 per cent of NSW customers were disconnected, and 0.3 per cent of customers in the ACT and Tasmania (figure 6.21). Disconnection rates were generally lower in gas than

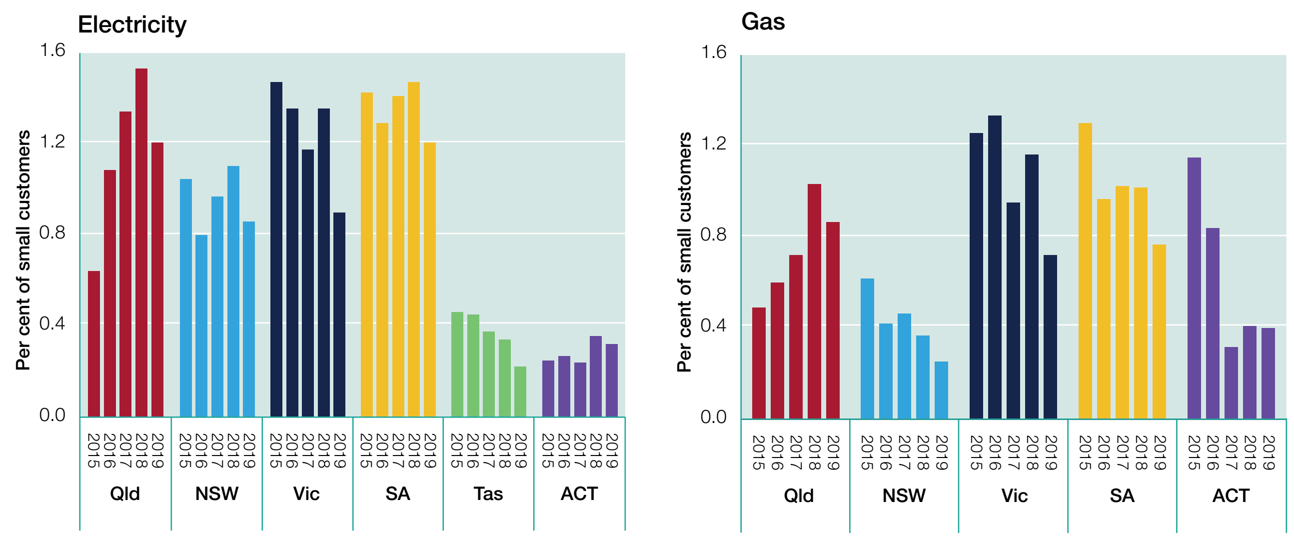
71 ESC, *Amendments to the Energy Retail Code: payment difficulties*, October 2017.

**Figure 6.20**
**Average debt at time of entry to hardship programs and average hardship debt of small customers**




Source: AER, *Retail markets quarterly, Q2 2019–20*, March 2020.

**Figure 6.21**
**Disconnection of residential customers for failure to pay amount due**




Note: Based on customers with an amount owing to a retailer that has been outstanding for 90 days or more, at 30 December 2019 for all states except Victoria, which is at June 2019.

Source: AER, *Retail markets quarterly, Q2 2019–20*, March 2020; ESC, *Victorian energy market report 2018–10*, November 2019.

electricity, ranging from 0.4 per cent of customers in the ACT to 0.8 per cent of customers in Queensland.

Victoria recorded the largest reduction in disconnection rates in both electricity and gas in 2019. This reduction may reflect reforms introduced in January 2019 that raised the minimum amount of debt at which a customer can be disconnected from $120 to $300, and doubled the penalty for wrongful disconnections.

## 6.10 Customer complaints

Customer complaints can cover issues including billing discrepancies, wrongful disconnections, the timeliness of transferring a customer to another retailer, supply disruptions, credit arrangements, and marketing practices.

Customers can lodge a complaint directly with their retailer in the first instance. If unable to resolve an issue with their retailer, a customer can then take the complaint to the jurisdictional energy ombudsman scheme, which offers free and independent dispute resolution.

Some customer complaints relate to issues outside the retailer's control—complaints about price rises due to wholesale and network costs, for example. For this reason, the number of electricity complaints to ombudsman schemes can be a more meaningful measure of retailer performance than the number of complaints received by retailers. Retailers with effective customer service generally resolve complaints without the need for escalation to energy ombudsman schemes.

The number of electricity complaints to ombudsman schemes fell in Queensland, NSW and Victoria in 2018–19 (figure 6.22). South Australia has seen a rise in complaints since 2016–17, reflecting customer dissatisfaction with the implementation of electricity metering competition in that region. Rates are typically lower in Queensland than in other regions, at 0.26 per cent of Queensland customers in 2018–19 (compared with 0.7–1.0 per cent of customers elsewhere).

Gas complaints to ombudsman schemes are generally lower than for electricity. Victoria had the highest complaint rates at around 0.5 per cent of customers in 2018–19, a slight fall from the previous period.

Billing concerns continue to generate the largest number of complaints, constituting about 40 per cent of complaints in 2018–19. Credit issues—including the disconnection of customers following non payment, and the collection of outstanding charges—accounted for another 15 per cent of complaints, but were a larger issue in Victoria than elsewhere. Retailers' customer service was another prominent issue (accounting for less than 10 per cent of complaints in most regions, but around 30 per cent in NSW).

## 6.11 Enforcement action in retail markets

The AER's recent enforcement activity has targeted areas including retailers' marketing practices and behaviour towards customers in vulnerable circumstances. Additionally, the ACCC has taken enforcement action against retailers under the Australian Consumer Law.

### 6.11.1 Marketing

The Retail Law's marketing provisions protect customers by requiring retailers to obtain the customer's explicit informed consent before signing them up to a new energy contract.

The ESC enforces similar provisions in Victoria. The Australian Consumer Law (enforced by the ACCC) also protects customers from improper sales or marketing conduct relating to unsolicited sales, misleading and deceptive conduct, and unconscionable conduct.

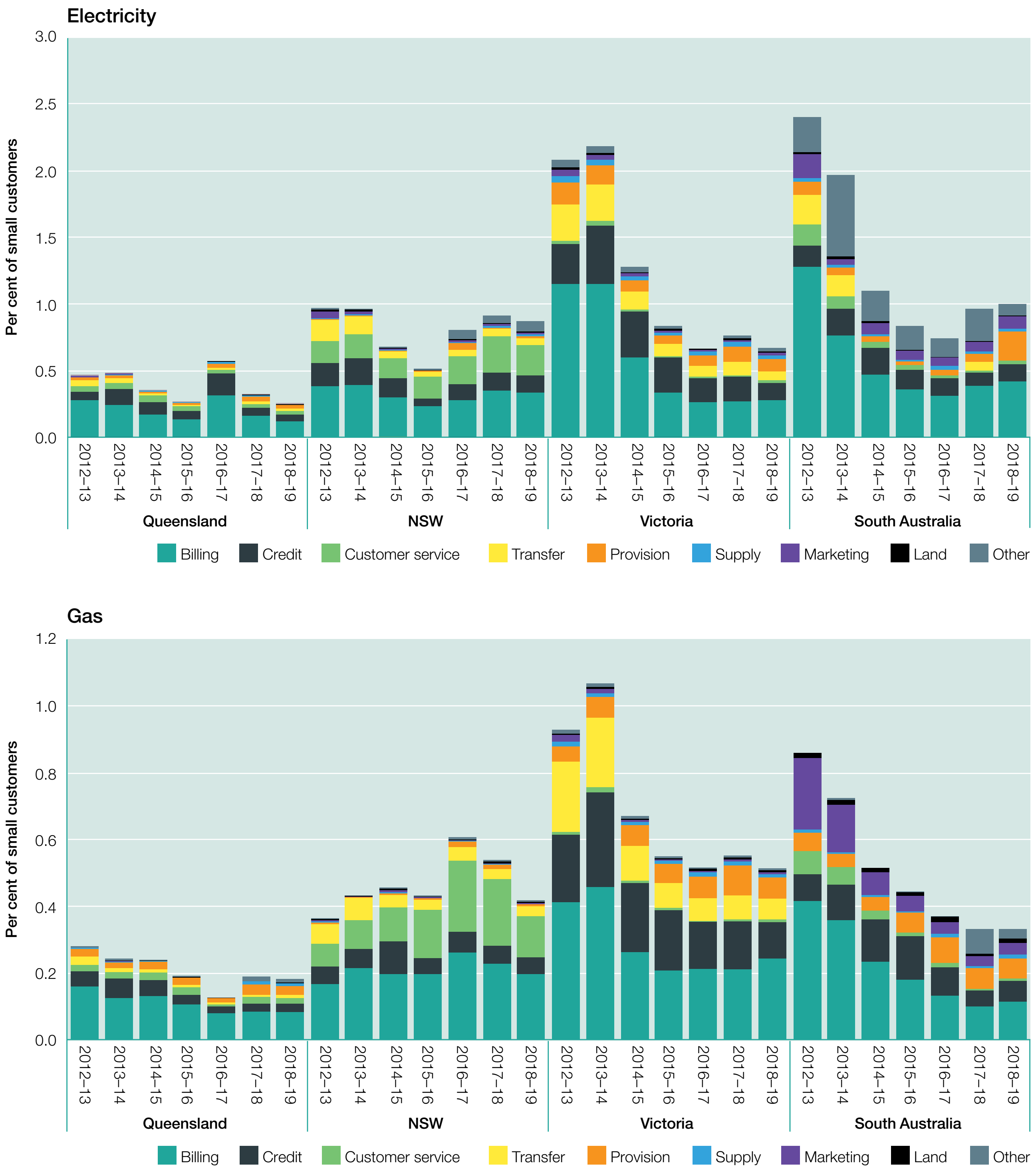
In February 2020 EnergyAustralia paid penalties totalling $80 000 for allegedly failing to obtain explicit informed consent from customers. The AER issued four infringement notices to EnergyAustralia for the alleged breaches.[72]

The ACCC monitors how businesses promote discounts and savings under their energy offers, following concerns that consumers have been misled about the extent of savings available. Since 2019 the ACCC has issued infringement notices against Dodo and CovaU for alleged misleading claims about discounts available on their energy plans, due to advertised discounts being applied to market offers that were above standing offer rates.[73]

In April 2019 the ACCC instituted proceedings in the Federal Court against iSelect—a privately operated energy price comparison service—for misleading or deceptive conduct and false or misleading representations. The ACCC alleged iSelect did not compare all available plans from its partner retailers, and did not necessarily recommend the most competitive plan despite claims it would do so on its website.[74]

72 AER, 'EnergyAustralia pays $80,000 for switching customers without consent', Media release, 27 February 2020.
73 ACCC, 'Dodo and CovaU to refund customers and pay penalties over energy discount claims', Media release, 18 July 2019.
74 ACCC, 'iSelect in court for alleged misleading conduct and claims about energy plan comparisons', Media release, 12 April 2019.

**Figure 6.22**
**Complaints to ombudsman schemes**




Source: Annual reports by ombudsman schemes in Queensland, NSW, Victoria and South Australia.

The ACCC also finalised an earlier Federal Court action against Amaysim (trading as Click Energy) for misleading marketing claims about discounts and savings that customers could obtain. The Court ordered Click Energy to pay penalties of $900 000 for the breach.[75]

In Victoria, the ESC took action against Simply Energy and 1st Energy for transferring customers onto contracts without their explicit informed consent. The businesses paid penalties of $300 000 and $20 000 respectively.[76]

### 6.11.2 Customers in vulnerable circumstances

The AER's compliance and enforcement priorities include ensuring retailers maintain protections for customers using life support equipment, and provide appropriate assistance to customers experiencing payment difficulties.

In November 2019 the AER commenced legal proceedings against EnergyAustralia, alleging for eight customers between 2016 and 2018 that EnergyAustralia:

- failed to maintain and implement its hardship policy
- failed to provide customers the opportunity to enter into appropriate payment plans
- failed to offer and apply payment plans that had regard to the customer's capacity to pay
- failed to inform customers of EnergyAustralia's hardship policy, and/or
- wrongfully disconnected the customers.[77]

In August 2019 Origin Energy paid penalties totalling $80 000 following the issue of infringement notices by the AER. Origin Energy allegedly wrongfully disconnected residential customers receiving hardship assistance and adhering to payment plans, or with energy debts of less than $300. Origin Energy also provided the AER with an enforceable undertaking, committing it to undertake an audit and improve its systems and processes for managing disconnections.[78]

In April 2020 the AER commenced legal proceedings against EnergyAustralia for allegedly failing to comply with life support requirements. The AER alleged EnergyAustralia, for a significant number of customers, failed from February 2018 to:

- register customers that required life support equipment, or advise the distributor that customers required life support equipment
- provide timely information to life support customers
- keep the registration details of its customers up to date.[79]

EnergyAustralia also failed to establish policies, systems and procedures for registering a premises as requiring life support equipment, and did not meet commitments it gave in an undertaking to the AER in August 2019. These commitments included registering customers requiring life support and reviewing customer phone calls within a prescribed timeframe.

In Victoria, the ESC took action against Momentum Energy for allegedly overcharging more than 2500 customers by failing to apply concessions to their bills, and then not notifying them in a timely way. Momentum Energy paid penalties of $900 000 for this infringement.[80] Momentum Energy also agreed to compensate over 800 customers for allegedly failing to inform them they could be disconnected remotely, at a cost of around $530 000.[81]

### 6.11.3 Other compliance action

The AER took other compliance action against retailers for alleged breaches of the Retail Law and National Electricity Rules from 2019:

- The AER commenced legal proceedings against AGL Energy in November 2019 for allegedly failing to submit timely and accurate retail market performance data.
- Discovery Parks paid $40 000 following the issue of two infringement notices, for allegedly selling energy without an appropriate retailer authorisation or exemption.
- Energy Australia paid four infringement notices (totalling $80 000), Origin Energy paid two infringement notices (totalling $40 000) and M2 Energy (trading as Dodo Power and Gas) paid one infringement notice ($20 000) for allegedly failing to promptly appoint metering coordinators following notice of a metering installation malfunction.

75 ACCC, 'Click Energy to pay $900,000 for misleading claims', Media release, 27 March 2019.
76 ESC, 'Simply Energy pays $300,000 in penalties for failing to obtain consent before switching customers', Media release, 16 December 2019; ESC, '1st Energy issued $20,000 in penalties for switching small business customer without consent', Media release, 16 May 2019.
77 AER, 'EnergyAustralia alleged to have wrongly disconnected struggling customers', Media release, 21 November 2019.
78 AER, 'Origin pays penalties for alleged unlawful customer disconnections', Media release, 16 August 2016.
79 AER, 'EnergyAustralia in court for alleged failure to comply with customer life support obligations', Media release, 9 April 2020.
80 ESC, 'Momentum Energy pays $900,000 for overcharging vulnerable Victorians', Media release, 12 November 2019.
81 ESC, 'Momentum Energy agrees to compensate disconnected customers over half a million dollars', Media release, 22 August 2019.

# ABBREVIATIONS

| | |
|---|---|
| 1P | proven (natural gas reserves) |
| 2P | proved plus probable (natural gas reserves) |
| 3P | at least 10 per cent probability of being commercially recoverable (natural gas reserves) |
| ABS | Australian Bureau of Statistics |
| AC | alternating current |
| 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 |
| APGA | Australian Pipelines and Gas Association |
| APIA | Australian Pipeline Industry Association |
| APLNG | Australian Pacific LNG |
| APPEA | Australian Petroleum Production and Exploration Association |
| ARENA | Australian Renewable Energy Agency |
| ASX | Australian Securities Exchange |
| C&I | commercial and industrial |
| CBD | central business district |
| CCGT | combined cycle gas turbine |
| CCP | Consumer Challenge Panel |
| CEFC | Clean Energy Finance Corporation |

| | |
|---|---|
| CESS | capital expenditure sharing scheme |
| CKI | Cheung Kong Infrastructure |
| CoAG | Council of Australian Governments |
| CoGaTI | Coordination of Generation and Transmission Investment |
| COVID-19 | coronavirus disease 2019 |
| CPI | consumer price index |
| CSG | coal seam gas |
| CSIRO | Commonwealth Scientific and Industrial Research Organisation |
| 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 |
| EGWWS | electricity, gas, water and waste services |
| ENA | Energy Networks Australia |
| EOI | expression of interest |
| ESC | Essential Services Commission |
| 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 |
| HHI | Herfindahl–Hirschman index |
| ICT | information and communication technology |
| IPART | Independent Pricing and Regulatory Tribunal |
| 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 |
| LED | light emitting diode |
| LNG | liquefied natural gas |
| MAIFI | momentary average interruption frequency index |
| MJ | megajoule |
| MOS | market operator services |
| MLF | marginal loss factor |
| MLO | market liquidity obligation |
| MSATS | market settlement and transfer solutions |
| $MtCO^2$-e | million metric tonnes of carbon dioxide equivalent |
| mtpa | million tonnes per annum |
| MVa | megavolt ampere |
| MW | megawatt |
| MWh | megawatt hour |
| NEM | National Electricity Market |
| NSW | New South Wales |
| NT | Northern Territory |
| OCGT | open cycle gas turbine |
| OECD | Organisation for Economic Co-operation and Development |
| OTC | over-the-counter |
| PJ | petajoule |
| PV | photovoltaic |
| QCA | Queensland Competition Authority |
| QCLNG | Queensland Curtis LNG |
| QCOSS | Queensland Council of Social Service |
| QNI | Queensland—NSW Interconnector |
| RAB | regulatory asset base |
| RERT | Reliability and Emergency Reserve Trader |
| RET | renewable energy target |
| 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 |
| RoLR | retailer of last resort |
| RRO | retailer reliability obligation |
| RSI | residual supply index |
| SAIDI | system average interruption duration index |
| SAIFI | system average interruption frequency index |
| STPIS | service target performance incentive scheme |
| TGP | Tasmanian Gas Pipeline |
| TJ | terajoule |
| TJ/d | terajoules per day |
| TW | terawatt |
| TWh | terawatt hour |
| UNGI | Underwriting New Generation Investment program |
| VRE | variable renewable energy |
| VTS | Victorian Transmission System |
| WACC | weighted average cost of capital |