STATE OF THE ENERGY MARKET 2018

AER
AUSTRALIAN
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Cover image by istock Photo

PREFACE

Since 2007, the Australian Energy Regulator has reported on the state of the energy market in this flagship report. We aim to provide independent and accessible information to policy-makers, industry and the community on Australia's wholesale electricity and gas markets, the transmission and distribution networks, and the rapidly evolving energy retail market.

Our stakeholders constantly remind us how much they value this publication as a ready source of unbiased and up-to-date information. Energy markets are complex, and media reporting, public commentary and political debate on energy issues can be conflicting and confusing. This report aims to give readers a working understanding of how the markets operate so they can make their own assessment of the issues.

Among the most debated issues in 2018 have been why retail energy bills are higher than in the past, how renewable generation is changing the market, how Australia's gas industry is balancing the needs of foreign and domestic customers, how energy networks can be managed to meet changing customer expectations, and the impact of government intervention in the market.

State of the energy market is evolving as the market itself evolves. In 2019 we aim to publish the report's most frequently requested data sets online. We will also look to update key data series on a quarterly basis.

We hope you find this year's report interesting, and that it contributes to informed and productive policy debate.

Paula Conboy—Chair
December 2018

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SNAPSHOT

Retail energy markets

- Electricity and gas retail prices rose in 2017 on the back of rising wholesale costs, and remained elevated in 2018. Only in Queensland did prices remain relatively stable.
- Large 'headline' discounts widened the price gap between 'standing' and market retail offers, with retailers profiting from customer inertia and confusion.
- Customers on the most expensive electricity offers in Victoria, NSW and South Australia pay more than double what customers on the cheapest offers pay (per unit of electricity).
- Rising wholesale costs for electricity and gas were the main driver of energy retail prices since 2016. Retail costs and margins also rose.
- Only 39 per cent of consumers trust the retail market and 25 per cent of consumers are confident it works in their interests—lower than for telephone, internet, insurance, water and banking services.
- 67 per cent of customers in eastern and southern Australia buy their energy from a 'big 3' retailer—AGL, Origin or EnergyAustralia—but smaller retailers are gaining ground.
- Perceptions the retail energy market is not working in the interests of consumers led the Australian and Victorian Governments to announce regulated pricing in 2019.
- Around 20 commercial websites offer energy price comparisons, but most cover less than half the retail brands in the market. The AER (www.energymadeeasy.gov.au) and Victorian Government (compare.energy.vic.gov.au) websites cover all readily available offers.

National Electricity Market

- Coal fired generators are being retired as they reach the end of their economic life, withdrawing 4200 MW of capacity from the market since 2014. But 4300 MW of large scale wind and solar capacity was added over the same period. The pace of this investment is rising, with renewable capacity additions averaging almost 200 MW per month (plus another 100 MW per month in rooftop solar PV) since July 2017.
- More expensive black coal, gas and hydroelectric generators filled part of the supply gap in 2017 following the exit of Victoria's Hazelwood power station. Price offers by some black coal generators rose more than underlying costs.
- State Government intervention helped lower Queensland prices by 28 per cent in the year to June 2018. But Victorian prices set a new state record at almost $100 per MWh after the Hazelwood closure.
- Forecast power shortages over 2017–18 were averted by generation businesses returning mothballed plant to service, increased wind, hydro and rooftop solar PV generation, new plant and battery projects in South Australia, and a relatively mild summer.
- Almost 2 million Australian households and businesses have become energy producers by installing rooftop solar PV systems.
- Despite prices being high enough to signal new entry for lower cost plant technologies, barriers to entry stalled generation investment, other than in renewables.
- Investors cited a lack of stability and predictability in government energy policy, market interventions, government ownership in the industry, difficulties in obtaining finance, vertical integration and contract market liquidity as barriers to investment.
- Reforms are helping to better integrate wind, solar and battery technologies into the market to manage risks of power system security issues. The NEM's first grid–scale battery and new demand response initiatives lowered South Australia frequency management costs over summer, enabling significant savings for consumers.

SNAPSHOT

Eastern Australian gas markets

- Queensland's LNG export industry has caused disruptive price increases in the eastern Australian gas market.
- Southern gas was often more expensive than Queensland gas, due to rising gas production in Queensland, difficulties in sourcing southern gas, and demand for gas generation in southern Australia.
- Market intervention by the Australian Government in 2017 led LNG producers to commit to increasing gas supplies to the domestic market on reasonable terms.
- Gas contract prices in 2018 eased off the peaks recorded in early 2017, but remained two to three times above historical levels.
- New gas flows will enter the market from the Northern Territory in 2019.
- Reforms making it easier to negotiate gas pipeline access and free up underused pipeline capacity are being implemented.
- Legal restrictions and regulatory hurdles continue to impede onshore gas exploration and development in Victoria, NSW, South Australia and Tasmania.

Regulated energy networks

- Revenue forecasts for electricity networks are 16 per cent lower in current periods than in previous periods, mainly because network decisions from 2016–18 allowed an average rate of return of 6 per cent, compared with over 10 per cent in decisions from 2009–11.
- Current AER decisions are forecast to reduce electricity distribution charges in residential energy bills by 1–2.5 per cent per year.
- Revenues are forecast to fall in current periods for gas distribution networks in NSW, South Australia and the ACT. Higher revenues are forecast for some Victorian networks to cover new gas connections and mains replacement costs.
- AER incentives and benchmarking policies encouraged networks businesses to more efficiently managing their operating costs.
- Distribution network productivity rose by 5 per cent over the two years to 2017.
- Several network businesses are moving to engage more closely with their customers in framing regulatory proposals, and the AER is also trialing new engagement processes with stakeholders.
- Electricity distributors are phasing in cost-reflective network tariffs, with 12 per cent of small customers on these tariffs in 2018.

Image courtesy of Hydro Tasmania

MARKET OVERVIEW

The energy market in 2018 was again characterised by high prices and rapid change, with widespread concerns about affordability, reliability and security of supply, and the industry's carbon emissions. These concerns have prompted major market reviews led by the Australian Energy Regulator (AER), other energy market bodies and the Australian Competition and Consumer Commission (ACCC) which led to important reforms being announced or implemented. The ACCC's broad inquiry powers also shed light on a number of issues where market intelligence was previously limited.

Additionally, governments at all levels are influencing outcomes in energy markets, including through public infrastructure investments, incentives for private investment, and directions to the market about how it should operate.

Retail energy markets

Rising electricity and gas prices, coupled with poor perceptions of retailer behaviour, have heightened focus on retail energy markets over the past two years. Assessments by governments, regulators and other bodies have identified significant issues in the market, and presented recommendations for reform to improve consumer outcomes.

Prices

Electricity retail prices in 2017 increased in most regions on the back of rising wholesale costs, and remained elevated in 2018 (figure 1). Prices also rose in gas markets.

Electricity prices rose by 56 per cent in real terms over the 10 years to 2017–18.[1] Outcomes varied across regions, with Queensland having the largest price rise (71 per cent) and Tasmania the lowest (39 per cent). Australian electricity prices, traditionally low by global standards, are now around 10 per cent above the European average.

Despite this, customer *electricity bills* rose by a lower (but still significant) rate of 35 per cent over this period. The difference is explained by customers achieving savings by switching to energy efficient appliances, changing their behaviour to reduce their electricity use, and meeting some of their energy needs from rooftop solar photovoltaic (PV) systems.

Network costs were the largest driver of retail electricity prices for several years (discussed below). But since 2016, wholesale cost increases have been the main driver. The retirement of large brown coal fired generators in South Australia (2016) and Victoria (2017) made the market more reliant on black coal and gas generation at a time when black coal and gas fuel prices were rising.

Retail costs and margins also rose over this period, contributing 8 per cent and 13 per cent respectively to the increase in retail electricity prices. Both are high by world standards, raising questions about whether retail competition is delivering benefits for consumers. Fuelling these concerns are increasing costs of competing (marketing and commission costs to gain or retain customers) and retailer margins. These costs are highest in Victoria, the market where retail contestability has been in place the longest.[2]

Analysis of retail *gas prices* found an average rise of 46 per cent in real terms over the 10 years from 2007 to 2017. In mainland regions, the average increase ranged from 27 per cent in New South Wales (NSW) to 51 per cent in Victoria.[3]

Rising wholesale costs from 2015–17 were the primary driver of these rises, with gas contract and spot prices reaching historically high levels that persisted into 2018. The diversion of gas supplies from the domestic market to liquefied natural gas (LNG) projects, moratoria on onshore gas exploration in some states, and declining production in some established gas basins all contributed to higher gas costs.

The impact of high energy prices varies between customers. Customers on the most expensive offers in Victoria, NSW and South Australia were paying more than double the amount paid for each unit of electricity consumed by those on the cheapest offers.[4]

Retailers' offers of large 'headline' discounts have widened the price gap between 'standing' and competitive market offers. While some market offers appear to reflect efficient costs, others appear to be set at levels designed to profit from customer inertia and confusion, and from the inability of some customers to meet discount conditions.

Figure 2 compares standing and market offers in Sydney, Melbourne, Brisbane and Adelaide. In all cities, the median standing offer is considerably higher than the median market offer, and this gap appears to be widening. By 2018 a typical standing offer customer in Melbourne was

1 ACCC, *Restoring electricity affordability and Australia's competitive advantage, Retail Electricity Pricing Inquiry—Final Report*, June 2018.

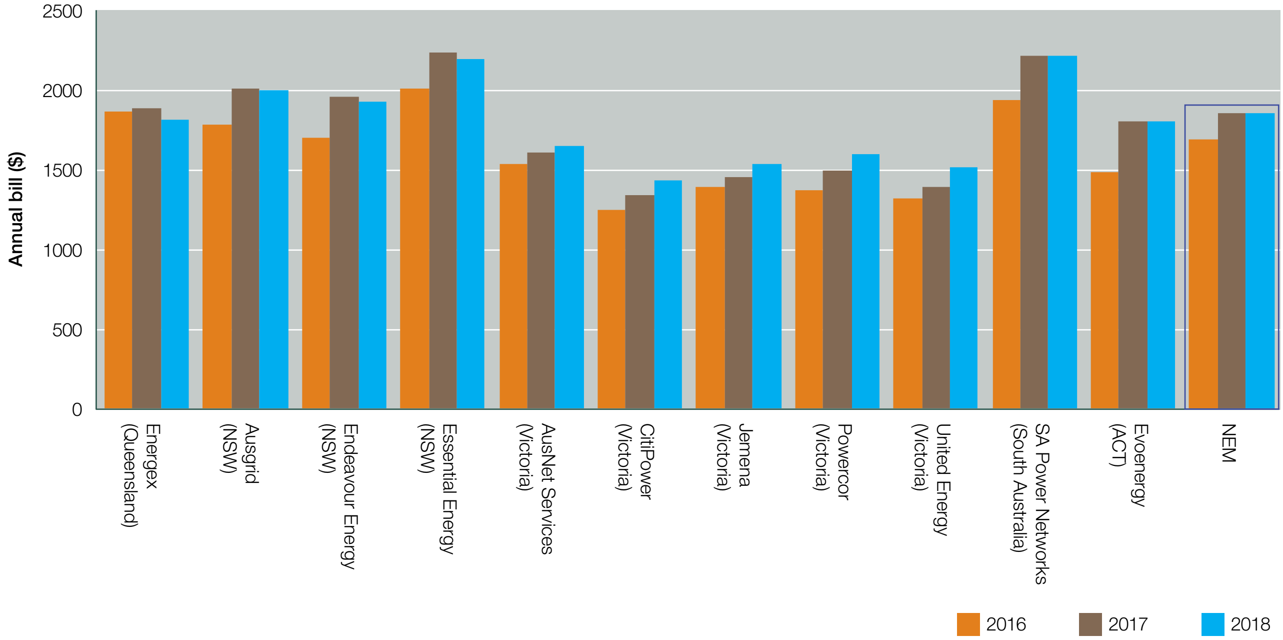
2 ACCC, *Restoring electricity affordability and Australia's competitive advantage, Retail Electricity Pricing Inquiry—Final Report*, June 2018.

3 Oakley Greenwood, *Gas price trends review 2017*, March 2018.

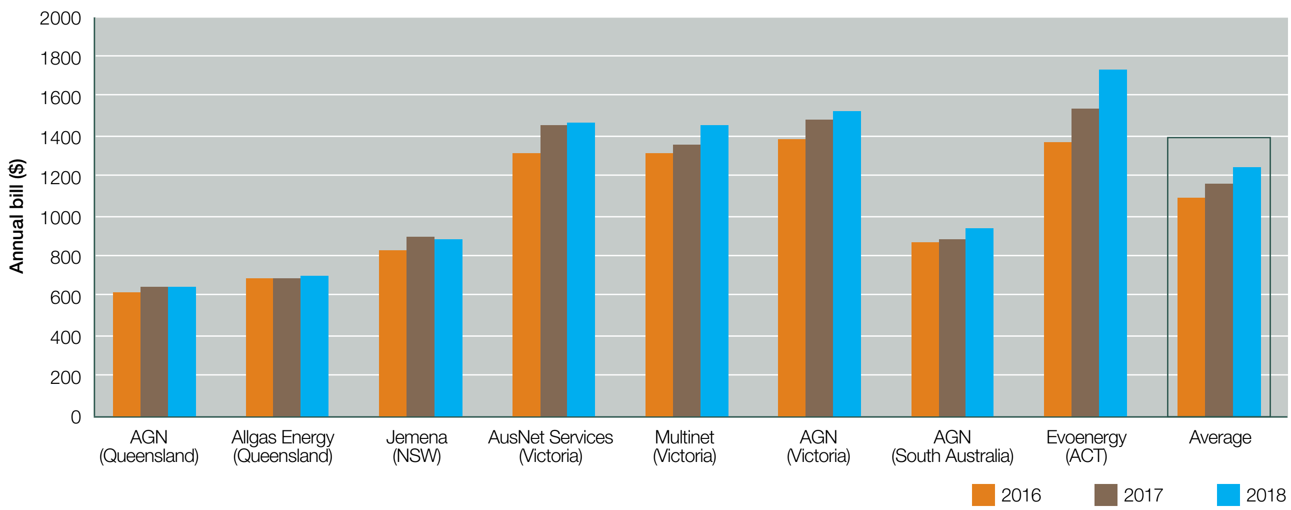
4 ACCC, *Restoring electricity affordability and Australia's competitive advantage, Retail Electricity Pricing Inquiry—Final Report*, June 2018, p. 262.

Figure 1
How retail bills have moved

Electricity



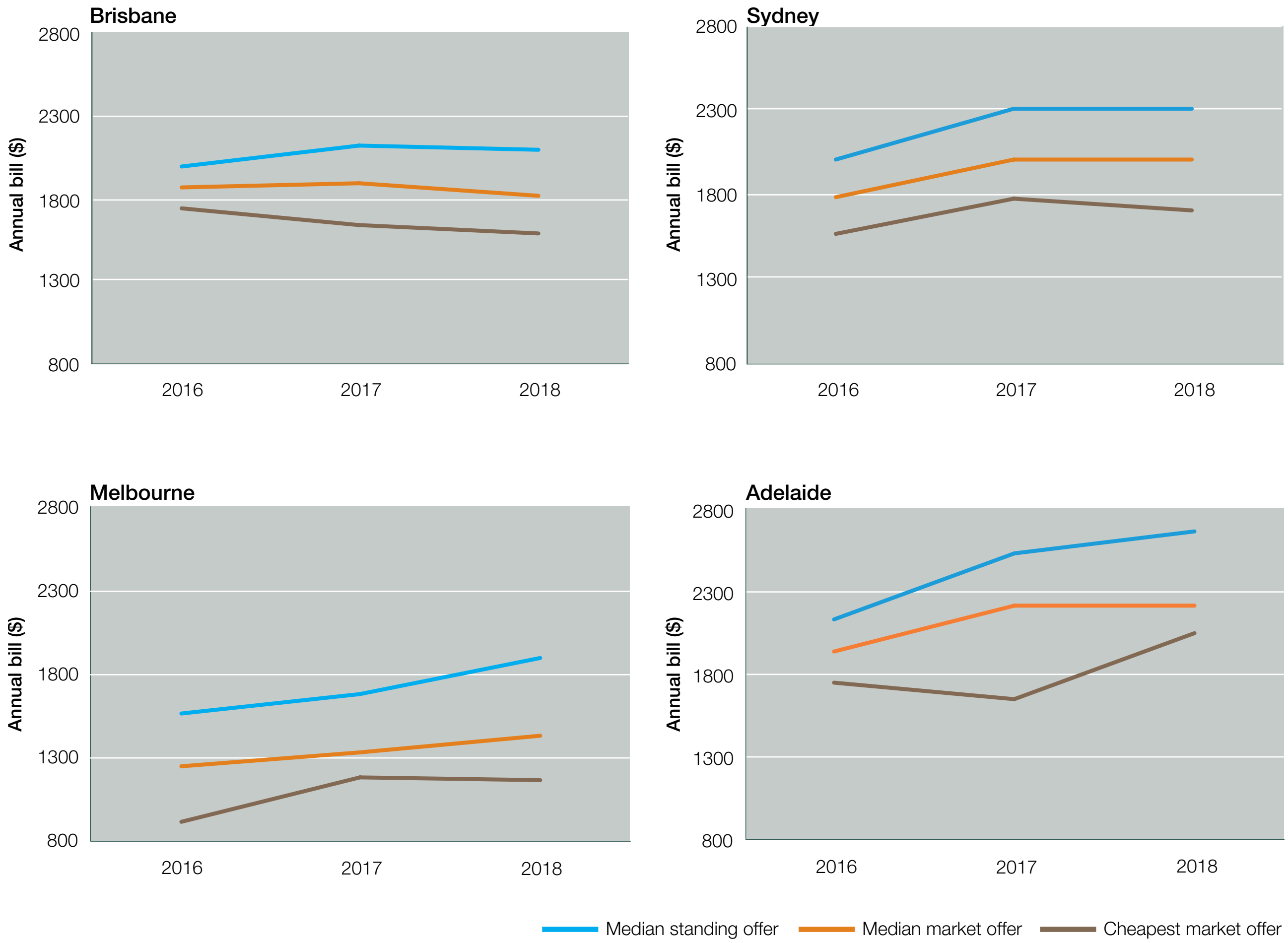
Gas



Note: Median market offers in each calendar year. Data includes all generally available offers for residential customers using a 'single rate' tariff structure at December 2016, December 2017 and August 2018. Annual bills based on average consumption in each jurisdiction: NSW 6130 kWh (electricity), 22 860 MJ (gas); Queensland 5950 kWh, 7870 MJ; Victoria 4810 kWh, 57 060 MJ; South Australia 5100 kWh, 17 500 MJ; ACT 7010 kWh, 42 080 MJ; NEM/national 5590 kWh, 39 030 MJ.

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

Figure 2
Electricity price dispersion—standing and market offers in capital cities



Note: Includes all generally available offers for residential customers in distribution networks in capital cities (Energex in Brisbane, Ausgrid in Sydney, CitiPower in Melbourne and SA Power Networks in Adelaide) using a 'single rate' tariff structure. Annual bills and price changes based on median market and standing offers at December 2016, December 2017 and August 2018, using average consumption in each jurisdiction: NSW 6130 kWh; Queensland 5950 kWh; Victoria 4810 kWh; South Australia 5100 kWh. Market offer prices factor in all conditional discounts.

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

paying $460 above the median market offer on their annual electricity bill. The gap was $450 in Adelaide, $320 in Sydney and $280 in Brisbane.[5] Even greater savings were available under retailers' cheapest market offers.

Even within market offers, price dispersion is increasing. The gap between the median and cheapest market offer in 2018 was $160 in Adelaide, $270 in Melbourne, $230 in Brisbane and $290 in Sydney.[6]

While the proportion of customers on standing offers is declining (from 25 per cent to 20 per cent for electricity, and from 17 per cent to 15 per cent for gas, during the period 2015–18), the pricing of some offers illustrate the risks faced by customers who do not regularly engage in the market. As discounts in market offers are frequently of limited duration, customers may find themselves returning to prices closer to standing offer levels unless they switch regularly. Yet around a third of energy customers have never switched retailer.[7]

5 Based on offers identified on the AER's Energy Made Easy website at August 2018, and the Victorian Government's Victorian Energy Compare website at June 2018.

6 Assumptions are set out in note to figure 2.

7 ECA, *Energy Consumer Sentiment Survey*, December 2017.

Customer outcomes

Recent assessments of energy retail competition concluded the market has not delivered for consumers. The ACCC found the 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'.[8] Likewise, the Australian Energy Market Commission (AEMC) found 'competition in the retail energy market … is currently not delivering the expected benefits to consumers.'[9]

Poor conduct by a number of retailers and their agents in marketing and signing up customers has contributed to low levels of customer satisfaction and trust in retail energy markets. In a 2018 survey, only 39 per cent of consumers 'trusted' the market (down from 50 per cent in 2017), and only 25 per cent of consumers were confident the market was working in their interests (down from 35 per cent). Similarly, satisfaction with value for money of energy was down across most regions in 2018, at 40–50 per cent for electricity and around 50–65 per cent higher in gas. The results are well below customer satisfaction rates for services such as telephone, internet, insurance, water and banking.[10]

Policy developments

Perceptions that the retail energy market is not working in the interests of consumers has increased government and community focus on the sector. In October 2018 the Australian Government adopted an ACCC recommendation for a default market offer price to be set by the AER. The default price is intended to take effect from 1 July 2019, and act as a cap on standing offer prices in jurisdictions where price regulation does not otherwise exist.

The ACCC recommended the default offer should not mirror the lowest price, or be close to the lowest price in the market, to avoid incentivising consumers to disengage. It recommended the default offer should cover efficient costs, including customer acquisition and retention costs, and a reasonable margin. This default price will also inform a 'reference bill' on which any advertised discounts promoted by electricity retailers must be based. This requirement seeks to provide consumers with meaningful information to compare offers.

8 ACCC, *Restoring electricity affordability and Australia's competitive advantage, Retail Electricity Pricing Inquiry—Final Report*, June 2018, p. 134.

9 AEMC, *2018 Retail Energy Competition Review*, June 2018, p. i.

10 ECA, *Energy Consumer Sentiment Survey*, June 2018.

The Victorian Government also committed to introducing a regulated price from 1 July 2019, to be set by the Essential Services Commission. Like the default offer adopted by the Australian Government, the regulated price will reflect the efficient costs of a retail business operating in a contestable market.

Other changes to the regulatory framework already implemented or being considered include:

- requirements that retailers notify small customers before making any change to their benefits or price
- prohibiting quoting discounts off rates that are above a retailer's standing offer
- mandatory provision of clearer summary contract and pricing information to customers (including showing indicative bills for different household sizes).[11]

'Power of Choice' reforms are being implemented to provide electricity customers with opportunities to benefit from advances in metering, energy generation, management and storage technologies that are changing how energy markets work. Key reforms include retailers leading a rollout of smart meters and introducing cost reflective network pricing.

The pricing reforms create incentives for customers to minimise energy use at times of high system cost, and result in a more equitable allocation of costs across customers. At June 2018, around 35 per cent of small customers had metering capable of supporting cost reflective tariffs (including smart meters and manually read interval meters). Despite this, only around 12 per cent of small customers in 2018 were on new tariff structures. In those networks with opt-in arrangements, few small customers have elected to move voluntarily to a new tariff structure.

Distributors can advance reforms in this area by simplifying tariff offerings, linking tariffs more closely to how customer use affects network costs, requiring customers to move to a new tariff unless they opt out, and integrating network pricing with planning and demand management policies. Retailers also have a significant role in some of these areas.

Price comparator services

Customer use of comparator websites for energy deals has increased as customers try to reduce bill shock from higher prices and navigate the market's complexity.

The AER operates an online price comparison website—Energy Made Easy—to help residential and small business customers compare retail offerings in jurisdictions that have

11 These reforms are being implemented via rule changes made by the AEMC or through AER guideline reviews.

implemented the National Energy Retail Law (Retail Law)—Queensland, NSW, South Australia, Tasmania and the Australian Capital Territory (ACT). The Victorian Government operates a similar website—Victorian Energy Compare—in Victoria.

The AEMC identified 19 commercial energy offer comparison websites at March 2018. While these websites and brokers can provide customers with a quick and easy way of engaging in the market, the ACCC found some services did not operate in the best interests of customers. Around 80 per cent of commercial comparator websites cover less than half the retail brands in the market.[12]

Additionally, retailers typically pay commissions or subscription fees to commercial comparator sites, which are often not clearly disclosed on the website. The websites may have incentives to promote offers that provide the largest benefit to the comparator business, rather than the cheapest offer for the customer.

The ACCC recommended a prescribed mandatory code to ensure price comparator and broker services act in the best interests of the consumer, to overcome the potential for customers to be misled.[13] Under the code, it would be mandatory to disclose commissions from retailers, show results from cheapest to most expensive, disclose the number of retailers and offers considered, and also show a link to government comparator websites.

In 2018 the ACCC issued infringement notices against One Big Switch—a service negotiating better energy offers for its registered members—for alleged false and misleading energy price representations relating to advertised discounts and savings.

Vulnerable customers

High energy prices have increased financial pressures on vulnerable consumers. Provisions in retail contracts that tie low priced offers to paying on time are a financial risk for vulnerable customers. Over one quarter of residential customers (and over half of hardship customers) do not achieve conditional discounts.[14] This outcome often means they pay hundreds more dollars than if they had achieved the conditional discount. The ACCC recommended capping such discounts to reduce the risk of vulnerable customers being penalised for not meeting the terms of conditional discount offers.

12 AEMC, *2018 Retail Energy Competition Review*, June 2018.
13 ACCC, *Restoring electricity affordability and Australia's competitive advantage, Retail Electricity Pricing Inquiry—Final Report*, June 2018.
14 ACCC, *Restoring electricity affordability and Australia's competitive advantage, Retail Electricity Pricing Inquiry—Final Report*, June 2018.

Support for vulnerable customers varies across retailers, but is often well below best practice. The AER reported in December 2018:

- fewer residential customers are on payment plans and those that are have a higher amount of debt
- more than half of all payment plans are cancelled by retailers
- fewer people are successfully graduating from hardship programs and more people are being excluded from hardship programs
- electricity and gas disconnections continue to rise.[15]

The AER identified deficiencies in how retailers implement their hardship policies in its 2017 Hardship Policy Review, and in 2018 proposed a rule change to the AEMC to strengthen obligations on retailers to help customers in financial hardship.[16] The AEMC in November 2018 amended the rules, and the AER in 2019 will publish binding guidelines to strengthen hardship arrangements, and make the policies more transparent and consistent.[17]

Wholesale electricity market

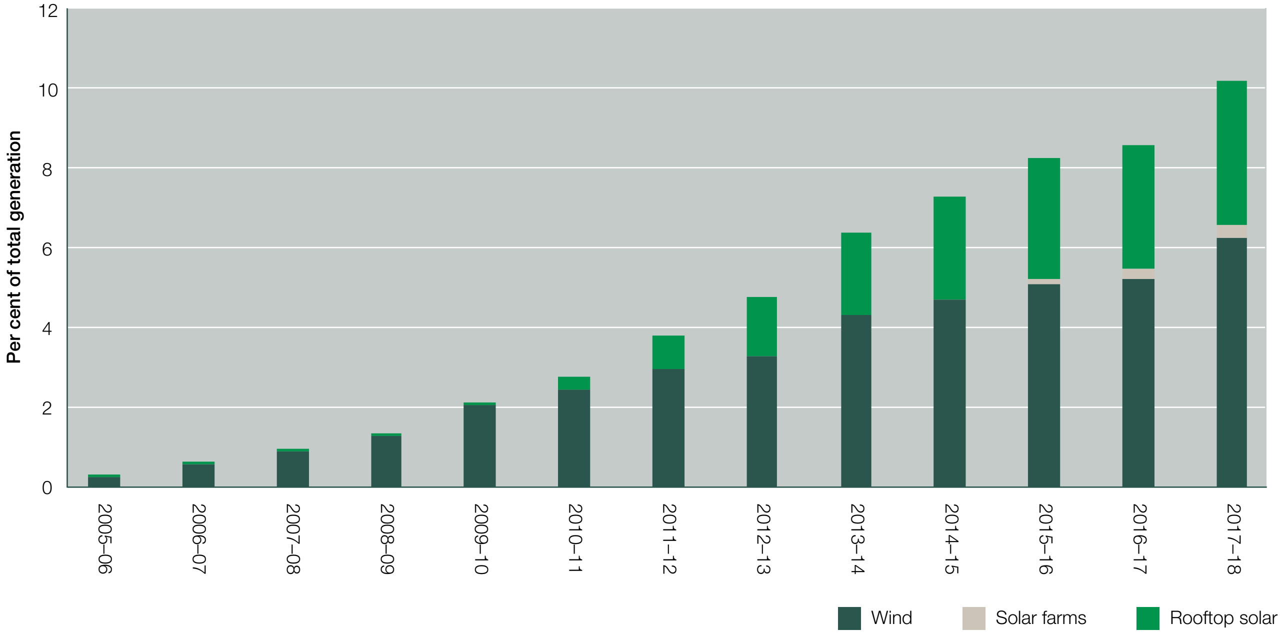
Wholesale electricity in eastern and southern Australia is traded through the national electricity market (NEM), a spot market in which supply and demand conditions determine prices in real time. Over 230 large scale power stations sell electricity into the market, which is transported along 40 000 kilometres of transmission lines to almost 10 million energy customers.

Market evolution

The energy market is rapidly evolving. Wind and solar generation are replacing older coal fired generators as they retire from the market (figure 3). Around 2 million Australian energy customers have become energy producers by installing rooftop solar PV systems, and selling surplus production back into the grid. In the year to 30 June 2018 alone, rooftop PV installations grew by 20 per cent in the residential sector and almost 60 per cent in the business sector.[18]

15 AER, *Annual report on compliance and performance of the retail energy market 2017–18*, December 2018.
16 AER, *Strengthening protections for customers in financial hardship*, media release, March 2018.
17 AEMC, *National energy retail amendment (strengthening protections for customers in hardship) rule 2018*, Final rule determination, November 2018.
18 AEMO, *2018 electricity statement of opportunities*, August 2018, p. 5.

Figure 3
Wind and solar generation share of total generation in the NEM



Note: Rooftop solar output estimates derived from CER data on installed capacity, and AEMO system output assumptions.
Source: Grid generation (AER, AEMO); Rooftop solar (AER, CER, AEMO (www.nemweb.com.au/#rooftop-pv-actual)).

Government incentives—such as the Small-scale Renewable Energy Scheme and premium feed-in tariffs—have resulted in Australia having one of the world's highest per capita installations of rooftop solar PV. Solar penetration is highest in South Australia and Queensland, where over 30 per cent of households have installed PV systems.[19]

In coming years, customers will increasingly meet their energy needs by drawing on electricity stored in batteries. They will also be able to contract with an energy provider to earn income (or reduce their energy bills) by lowering their energy use or injecting stored electricity into the grid. On a larger scale, South Australia in December 2017 commissioned the world's largest lithium ion battery at the Hornsdale wind farm. Large scale storage is also being pursued through proposed investments in pumped hydroelectricity projects in the Snowy Hydro scheme and in Tasmania. The technology involves pumping water into a raised reservoir when energy is cheap, and releasing it to generate electricity when prices are high.

Despite these changes, coal fired generation remains the dominant supply technology in the NEM, supplying 73 per cent of output in 2017–18, when it operated at its highest summer output in a decade. But older generators are reaching the end of their life and closing—most recently Alinta's Northern power station in South Australia (2016) and ENGIE's Hazelwood power station in Victoria (2017). The aging plants had become increasingly unprofitable due to rising maintenance costs, coal supply issues, and market penetration by other plant technologies.

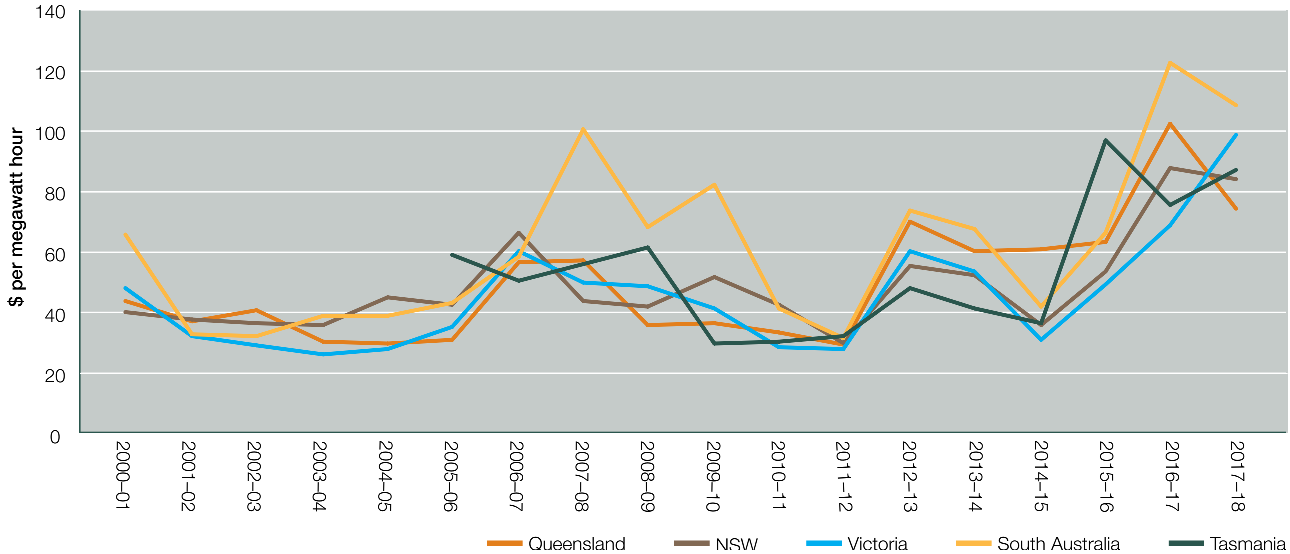
Hazelwood was over 50 years old, and was Australia's most emissions intensive power station. But its closure was significant given it supplied 5 per cent of the NEM's total output. Further coal plant closures are likely in the future. AGL plans to retire its Liddell power station (1680 megawatts (MW)) in NSW in 2022, replacing it with a mix of renewable generation, gas peaking capacity, batteries, and an upgrade to its Bayswater power station.[20] Participants including AGL, ENGIE and Origin Energy have signalled they have no plans to invest in new coal plant.

Renewable generation—wind, hydroelectric and solar—have filled much of the supply gap left by the closures. Wind generation rose by 20 per cent in 2017–18. Favourable weather conditions on 7 July 2018 resulted in record levels of wind generation. Its role is especially significant in South

19 AEMO, *2018 electricity statement of opportunities*, August 2018, p. 27.

20 AGL, *NSW generation plan*, media release, December 2017.

Figure 4
Wholesale electricity prices



Note: Volume weighted annual averages of 30 minute spot prices.

Source: AER analysis, AEMO data.

Australia, where wind generation met 40 per cent of the state's electricity requirements during the year. Rooftop solar penetration is also highest in South Australia, where it supplies around 8 per cent of the state's electricity needs.

Challenges of an evolving market

As the NEM evolves, new and emerging generation, storage, and demand management technologies are being connected to the grid in a way not contemplated when the power system was designed.

While the surge in renewable generation investment may be placing downward pressure on wholesale prices, it can create challenges for managing the power system. Resources such as solar PV create two-way flows on an energy network (power is both injected and withdrawn at customer connection points). Increasingly, electricity supply and demand are influenced by factors such as wind speed and cloud cover, posing challenges for demand forecasting and power system security. While solar PV systems reduce strain on the electricity grid when the sun is present, the market can lose 200–300 MW of power if cloud covers a major city, for example.

Solar generation raises particular challenges for coal plant. When solar generation is high in the middle of the day, the demand for dispatchable generation can significantly fall. This phenomenon challenges the economics of coal fired generators, which are engineered to run fairly continuously at or near full capacity to be profitable.

The wholesale market in 2017–18

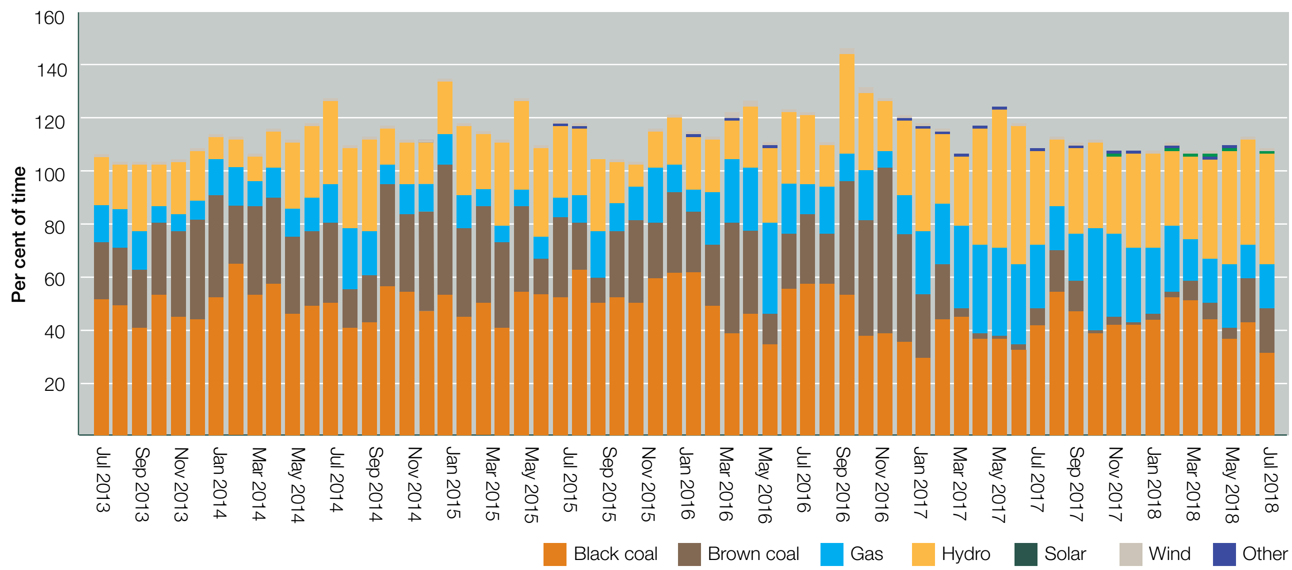
Price pressure intensified following the closure of coal fired plant in South Australia (in May 2016) and Victoria (in March 2017) (figure 4). These retirements followed years of stagnant investment in dispatchable generation, leaving the market without an efficient mix of generation. The removal of low cost supply was initially replaced by output from more expensive black coal, gas and hydroelectric generation, although wind and solar generation took more of this share in 2018, and will likely further rise in 2019.[21]

High gas prices and coal supply issues put further pressure on wholesale electricity prices in 2017. Volatility was exacerbated by a series of outages affecting aging coal and gas generators, and interconnector constraints limiting trade between Victoria and other regions.

Prices in NSW, Queensland and South Australia peaked in summer 2016–17, but eased to some degree in 2017–18. Market intervention by the Queensland Government in July 2017 to constrain offer prices by its state owned Stanwell generator contributed to regional prices being 28 per cent

21 AER, *Electricity wholesale performance monitoring, Hazelwood advice*, March 2018; AEMO, *2018 electricity statement of opportunities*, August 2018.

Figure 5
Price setting in Victoria by fuel type



Note: Charts show more than 100 per cent because the price can be set by more than one generator at a time.

Source: AER analysis, AEMO data.

lower in 2017–18 than a year earlier. Prices also eased in South Australia (by 12 per cent) and NSW (by 4 per cent), as black coal and gas fuel costs stabilised and renewable generation (hydroelectricity, wind and solar) increased. Despite this, NSW prices in 2017–18 were 55 per cent higher than two years earlier. And South Australia recorded triple digit average prices for a second consecutive year.

Wholesale prices in Victoria set a regional record in 2017–18, averaging almost $100 per megawatt hour (MWh). Hazelwood's closure has diminished the role of brown coal in price setting in Victoria (figure 5). Over summer 2017–18 brown coal set the dispatch price less than 2 per cent of the time, compared with 24 per cent over the previous summer. Outages at Loy Yang A and Yallourn in late 2017, and at Loy Yang B in January 2018, contributed to this shift. Despite Victoria's tight market, electricity imports from NSW were constrained 30 per cent of the time over summer, limiting supply to Victoria and pushing its wholesale prices 43 per higher than NSW prices.[22]

Tasmania's prices rose by 14 per cent in 2017–18, partly reflecting higher prices on the mainland following the closure of Hazelwood. Additionally, dry conditions affected hydro generation in 2017, but good rainfall reversed this trend in 2018.

Futures (contract or derivatives) markets operate parallel to the wholesale electricity market. Energy retailers and electricity generators manage the risk of volatile wholesale prices by locking in prices they will trade electricity for in the future. Comprehensive data on futures markets is not publicly available. While regular trade occurs in Queensland, NSW and Victoria, contract market liquidity is poor in South Australia. Traded volumes also appear to be declining across the market.

The decline in trade may be partly due to increasing levels of variable generation (wind and solar) that is not suitable for contracting because its output is weather dependent. Flat electricity demand and less price volatility in the wholesale market may also be contributing. Another reason for the decline in trade is the extent of vertical integration, which allows businesses to internally manage risk by operating both generation and retail arms, limiting their need to contract with third parties.

Futures prices for supply in 2019 and beyond tended to ease over 2017 and through the first half of 2018, reflecting expectations that a large influx of new renewable generation planned to come online in 2018–19 would exert downward pressure on wholesale prices. However, futures prices have remained well above historical levels, and began trending higher from mid-2018. Between May and November 2018, futures prices for summer (quarter one) 2019 supply rose by 35–40 per cent in NSW and Victoria, and 25 per cent in

22 AEMO, *Quarterly energy dynamics, Q1 2018*, p. 10.

Queensland and South Australia.[23] These rises reflect market concerns about drought impacting coal and hydroelectric plant availability over summer, and expectations gas fuel costs are likely to remain high.

Reliability and security concerns

The *Independent review into the future security of the NEM* (Finkel review) found the closure of coal fired plants may pose risks to power system reliability and security, in part because the variable (weather dependent) wind and solar plant replacing them has not been well integrated into the system.[24]

The concepts of reliability and security should be carefully distinguished. Power system *reliability* relates to having sufficient generation capacity to meet demand, while *security* refers to the system's technical capability in terms of frequency, voltage, inertia and similar characteristics.

Over 95 per cent of supply interruptions originate in local distribution networks, and relate to local power line issues. The most serious recent outage occurred on 28 September 2016 in South Australia when a combination of severe weather, catastrophic failure of transmission infrastructure and the performance of a number of generators caused the state to be blacked out for several hours. The AER published a comprehensive report on this event in December 2018.[25]

In September 2017, AEMO raised concerns the market would be at risk of generation shortfalls over summer 2017–18, especially in Victoria and South Australia where plant closures had occurred.[26] The market provided additional capacity with the return to service of mothballed gas powered generators in South Australia, Queensland, Tasmania and NSW. AEMO took further action to manage supply risk, including by securing over 1100 MW of back-up reserves through the Reliability and Emergency Reserve Trader (RERT) mechanism at a cost of over $51 million. Reserves were put on standby twice over summer 2017–18, but were ultimately not required. AEMO also worked with industry to avoid outages due to plant and network maintenance, and to secure fuel supplies for the summer.

AEMO in August 2018 raised similar concerns for summer 2018–19. It forecast a higher risk of load shedding (cutting power supply) over summer 2018–19 than a year earlier, based on modelling that showed ageing coal and gas powered plants have become less reliable. It is working with the Victorian Government to contract additional reserves under the RERT mechanism to again manage these supply risks.[27]

More long term solutions are also being proposed. AEMO's integrated system plan (ISP) forecasts transmission system requirements for the NEM over the next 20 years. The inaugural plan, released in 2018, recommended $450–650 million of immediate investment in transmission networks, including upgrading cross-border interconnectors between Victoria, NSW and Queensland, to manage reliability risks. It recommended further major investment by the mid-2020s (including the Riverlink interconnector between NSW and South Australia) and later (including Snowylink between NSW and Victoria).[28]

Market bodies are reviewing the role of the ISP in driving transmission investment, including the use of cost–benefit testing to assess the efficiency of new investment proposals. This work also explores broader coordination issues between transmission and generation investment.

Investment in expensive, long lived assets is risky—especially when a market is in transition, and where more flexible and potentially cheaper alternatives are available. The cost–benefit focus of the AER's regulatory investment test provides a robust and transparent model for analysing whether network upgrades provide value for money to energy consumers.

While power system *reliability* incidents rarely result in load shedding, power system *security* issues have become more common, closely linked to higher levels of variable wind and solar generation. The older fossil fuel power plants that are retiring helped maintain power system security by providing frequency, voltage, inertia and system strength services that kept the system in a secure technical state.[29] The capability of variable generation plants replacing them to provide these services, and the types of services required, are still evolving.

AEMO has had to intervene in the market more often to address instability associated with variable generation. In

23 ASX Energy data.

24 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.

25 AER, *The Black System Event*, Compliance report, December 2018.

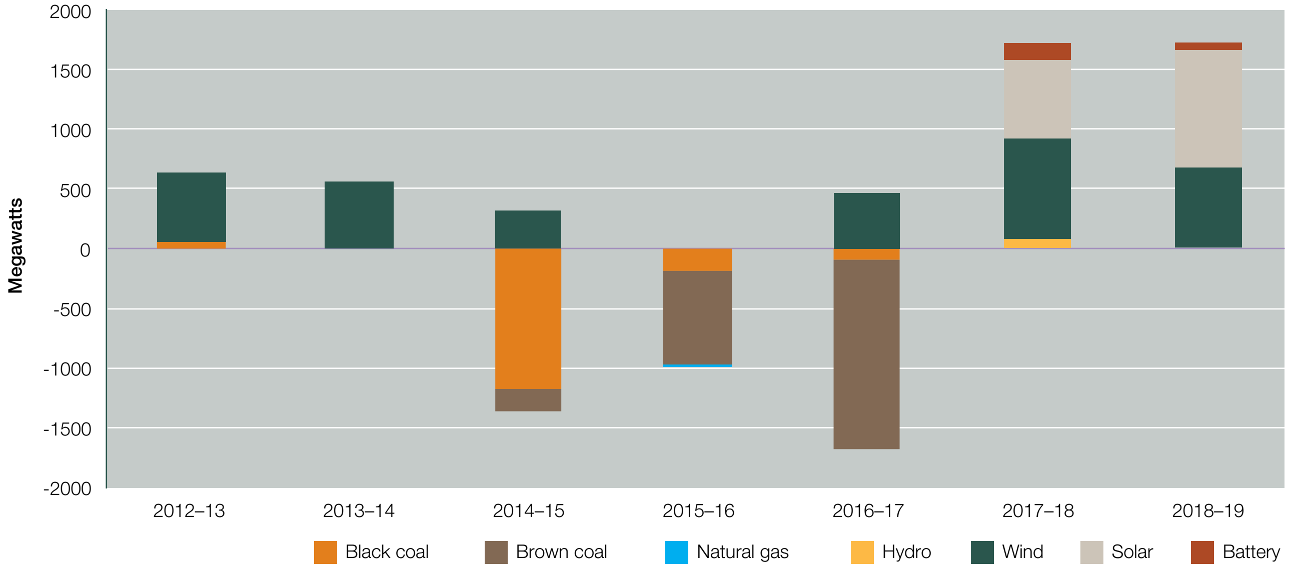
26 AEMO, *Electricity statement of opportunities for the national electricity market*, September 2017.

27 AEMO, *2018 electricity statement of opportunities*, August 2018, p. 3.

28 AEMO, *Integrated System Plan for the National Electricity Market*, July 2018.

29 Synchronous generators—including hydroelectric and thermal plant such as coal, gas and solar thermal generators—can provide these services. The generators' heavy spinning rotors provide synchronous inertia that slows down the rate of change of frequency. They help with voltage control by producing and absorbing reactive power and also provide high fault current that improves system strength.

Figure 6
New investment and capacity withdrawals in the NEM



Note: 2018–19 data is to 31 October 2018 only. An additional 2076 MW of committed capacity (1178 MW of wind, 873 MW of solar, 24 MW of biomass and 2 MW of battery storage) is expected to be commissioned in 2018–19.

Source: AEMO, Generation information, 2 November 2018.

2018, for example, it 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 loads from the power system for several minutes at a time.[30]

Market bodies are focusing on ways to better integrate variable generators and distributed energy resources to improve system security. Measures include encouraging investment in resources with flexibility to manage sudden demand or supply fluctuations and short term forecasting uncertainty.

The AEMC in 2017 introduced reforms to allow batteries and demand response aggregators to provide frequency control services. It is also exploring reforms to allow wider use of demand response and aggregation of small scale generation in the wholesale market. Another reform requires generators to provide three years' notice prior to closing a plant to allow more time for the market to adjust to the change. New standards are also being applied to ensure the technical standards of new generators match local power system needs.

30 AEMO, *Power system requirements*, March 2018, p. 8.

Investment response

The Finkel review argued years of inconsistency in government policies on energy and carbon emissions have hampered investment. Financers are wary of backing energy assets when policy settings affecting those assets may change.[31] There is a widespread view among market participants that the failure to implement consistent, enduring environmental policy in the electricity sector has caused significant investment uncertainty.

This inconsistency has contributed to private sector investment not keeping pace with the loss of generation capacity due to plant closures. While 2200 MW of new generation investment was added to the NEM over the five years to June 2017, almost 4000 MW of capacity was withdrawn over the same period (figure 6).[32]

Over 90 per cent of new investment over this period was in renewable (wind and solar) capacity, driven in part by subsidies available under the Large-scale Renewable Energy Target and funding by the Australian Renewable Energy Agency and the Clean Energy Finance Corporation. No material coal fired or gas powered generation has been

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

32 AER, *Wholesale electricity market performance report*, December 2018.

added to the market since a 240 MW upgrade to the Eraring power station in NSW was completed in 2013.

Despite ongoing uncertainty, investment has gained pace over the past 18 months. Renewables continue to be the focus, with almost 3000 MW of new wind, solar and battery capacity added to the NEM between July 2017 and November 2018. A further 2300 MW is committed for 2018–19.

The business case for investing in gas plant has been weakened by a threefold rise in gas prices since 2014. AEMO also found a reduction in the number of spot electricity prices above $300 per MWh in recent years has affected the revenue potential of gas peaking plant, which rely on selling cap contracts to customers insuring against high prices.[33] The AER's December 2018 wholesale market report found current elevated wholesale prices strengthen signals to invest in combined cycle gas plant, although this signal may not be sustained given the forecast influx of new renewable capacity.[34]

The proposed National Energy Guarantee (NEG) achieved support among industry and policy bodies as a way to reduce investment risk and encourage an efficient generation mix, by aligning carbon emissions and reliability targets into a coherent policy framework. Progress on the NEG stalled in August 2018 when the Australian Government removed the policy's emissions component. The government abandoned the NEG as a package, but retained the reliability component as part of a new energy policy.

The lack of a clear, agreed national policy has led governments at all levels to invest in state owned generation projects, offer financial incentives for private generation, and issue directions to the market on how it should operate. In late 2018 over 20 such measures were operating, had been committed or announced as policy (appendix 1). The initiatives included:

- major investments in publicly owned generation and storage
- a pricing direction to state owned generators
- a threat of compulsory divestment of private generation assets
- national and state level renewable energy targets
- programs offering financial assistance for grid scale renewable projects or residential solar and battery systems
- a market wide reliability guarantee.

Other government interventions are occurring in the electricity retail and transmission sectors.

Among major initiatives, the Australian Government undertook a feasibility study into expanding Snowy Hydro (which it owns) using pumped hydroelectric technology. The proposal would increase Snowy Hydro's hydroelectric generation capacity by around 2000 MW—a rise of 50 per cent. A final investment decision on the project is scheduled for late 2018, with generation from the project commencing in late 2024 if it proceeds.

In April 2017, the Australian and Tasmanian governments announced a feasibility study into expanding the Tasmanian hydroelectric system through schemes that could deliver up to 2500 MW of pumped storage capacity, and through possible expansions of the Tarraleah and Gordon power stations.

On a smaller scale, 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 and currently the world's largest lithium ion battery. The battery's ability to assist with sudden market issues was demonstrated in December 2017 when it provided frequency support within four milliseconds on two separate occasions when coal fired generators tripped.[35] The battery has also helped lower the cost of frequency control services needed to keep the power system secure.

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 in the long term. While noting, for example, that the Queensland Government's direction to put downward pressure on wholesale prices improved short term outcomes for consumers, the ACCC argued interventions of this kind should not be a substitute for structural reform.[36]

Competition issues

High prices have boosted profits for many generators and renewed focus on the state of competition in the wholesale energy market. Earnings of large generation businesses rose sharply in most regions from 2014–15 to the end of 2017,

33 AEMO, *Operational and market challenges to reliability and security in the NEM*, March 2018.

34 AER, *Wholesale electricity market performance report*, December 2018.

35 AEMO, *Initial operation of the Hornsdale Power Reserve battery energy storage system*, April 2018.

36 ACCC, *Restoring electricity affordability and Australia's competitive advantage, Retail Electricity Pricing Inquiry—Final Report*, June 2018, pp. 87, 92.

resulting in profit margins rising over that period, and several generators earning margins above 30 per cent. Even the least profitable of the assessed businesses earned a margin of at least 14 per cent in late 2017.[37]

In December 2018 the AER published its first NEM wide assessment of competitive conditions in the wholesale market, after previously reporting on conditions in the NSW market and the impact of Hazelwood's closure in Victoria.[38] The reports analyse whether generators (especially those vertically integrated with retailers) are exercising market power to impact prices.

The AER found structural features of the market make it vulnerable to the exercise of market power, and may have driven prices higher than would be expected based on changes in generation mix and underlying costs of supply. A few large vertically integrated participants control significant generation capacity and output in each region of the NEM. Ownership among fast response 'flexible' generation is also concentrated. The output of these participants is necessary to meet demand a significant proportion of the time, providing them potential to exercise market power.

Three generators—AGL Energy, Origin Energy and EnergyAustralia—have expanded their market share in NEM generation capacity from 15 per cent in 2009 to 46 per cent in 2018. In NSW, Victoria and South Australia, six businesses control 90 per cent of generation capacity.

The AER did not identify short term generator bidding behaviour (such as rebidding, withholding capacity and lowering ramp rates) as significantly contributing to recent energy price rises. In Queensland, for example, the incidence of generators rebidding to disrupt prices has declined since the Queensland Government in July 2017 directed Stanwell to lower its prices.

But the AER did identify longer term trends that warrant monitoring. Bidding by some black coal generators in NSW and Queensland has risen more than underlying costs, for example. In addition, participant conduct in South Australian frequency control ancillary services markets suggests evidence of the exercise of market power.

The report found while wholesale prices in the NEM have risen to a level that should signal new entry for some lower cost technologies, some barriers to investment remain. Stakeholders raised concerns about a lack of policy stability and predictability, government intervention aimed at maintaining reliability or lowering prices, and government ownership in the industry. They also cited challenges faced by non-vertically integrated and new entrant generators in obtaining finance and managing their market exposure. Challenges include having to contract with competing gentailers, and poor liquidity in some contract markets. The report also noted particular issues for 'flexible' plant (such as open cycle gas turbines) due to price spikes in the market becoming less frequent.

Eastern Australian gas markets

While Queensland's LNG export industry has brought significant investment and growth to the state, it has also caused disruptive price increases in the eastern Australian gas market. The industry, launched in January 2015, increased both demand for Australian produced gas and pressure on gas reserves in southern Australia.

High gas demand for electricity generation following the closure of coal fired generators, regulatory restrictions on developing new gas supplies, and impediments to pipeline access for transporting gas, all further intensified market pressures. The ACCC described the gas market in 2017 as 'dysfunctional'.[39]

Market intervention

Market pressures peaked in early 2017, when forecasts indicated the market could face a supply shortfall by 2018.[40] Responding to these concerns, the Australian Government launched the Australian Domestic Gas Security Mechanism (ADGSM). The ADGSM allows the government to direct LNG projects to limit exports or find new gas source if their gas consumption causes a domestic supply shortfall.[41] To avoid triggering the mechanism, LNG producers in October 2017 committed to divert enough gas to the domestic market to avoid a shortfall, and to make it available on reasonable terms. They also committed to offer any uncontracted gas to the domestic gas market on competitive terms, before offering it to international buyers.[42]

37 ACCC, *Restoring electricity affordability and Australia's competitive advantage, Retail Electricity Pricing Inquiry—Final Report*, June 2018. Earnings before interest and tax as a share of revenue, based on information from seven large mainland generators.

38 AER, *Electricity wholesale performance monitoring, NSW electricity market advice*, December 2017; AER, *Electricity wholesale performance monitoring, Hazelwood advice*, March 2018; AER, *Wholesale electricity market performance report*, December 2018.

39 ACCC, *Gas inquiry 2017–2020, July 2018 interim report*, August 2018.

40 AEMO, *2018 Gas statement of opportunities for eastern and southern Australia*, August 2018; ACCC *Gas inquiry 2017–2020, September 2017 interim report*.

41 Department of Industry, Innovation and Science, *Australian Domestic Gas Security Mechanism,* available at www.industry.gov.au.

42 *Heads of Agreement—The Australian East Coast Domestic Gas Supply Commitment*, 3 October 2017.

The ACCC reported in 2018 that the LNG producers' commitment is 'clearly influencing their decisions about supplying gas to domestic customers'.[43] EnergyQuest estimated Queensland's supply of gas to the domestic market in April–June 2018 was equivalent to 16 per cent of gas used for LNG exports—a similar ratio to that applied in Western Australia under the state's domestic gas reservation policy.[44]

Supply outlook

The ACCC in July 2018 found the risk of a gas supply shortfall in 2019 is substantially lower than seemed likely in 2017.[45] The government's threat to activate the ADGSM has contributed to the improved outlook. Other contributing factors include lower forecast demand for gas powered generation in 2019 (due to higher levels of renewable generation), stronger gas production forecasts in Victoria (including supplies from Cooper Energy's new Sole project) and new gas flows entering the market from the Northern Territory. Queensland supply should also stabilise with the completion of all operational testing on the LNG projects, and the likelihood of rising oil prices providing funds for new development projects.

In these improved conditions, AEMO in June 2018 forecast no supply gap on the east coast is likely to materialise until at least 2030. EnergyQuest queried this conclusion, arguing it relies on all current proved and probable resources being successfully developed, and early development of contingent resources from around 2021, despite limited recent investment having occurred that might enable this.[46]

Wholesale gas prices

Despite improved conditions, the domestic gas market remained tight in 2018. Contract prices eased off the peaks of early 2017, but settled at $8–11 per gigajoule (GJ), which is two to three times above historical levels. Commercial and industrial customers were the hardest hit in 2017, with quoted prices reaching as high as $22 per GJ for 2019 supply. Domestic prices in 2017 were often well above LNG netback levels (the comparable price a producer could earn from exporting gas), but in 2018 eased below export prices (figure 7).

Improved pricing was mirrored in gas spot markets, which tend to be shaped by short term factors such as electricity demand and timing of LNG shipments. Gas spot prices did not reach the same heights as contract prices in 2017, and eased somewhat for much of 2018. Prices hit their usual seasonal peaks in the winter months, and were also affected by gas plant outages at Longford in Victoria. Average prices for 2017–18 in Sydney, Victoria and Adelaide averaged above $8 per GJ for the second year in succession. By late 2018, gas spot prices were again moving higher and aligned fairly closely with export prices.

A significant differential between spot gas prices in Queensland (Wallumbilla and Brisbane) and the southern states emerged for much of 2017. Southern gas was more expensive for much of this period, reflecting contrasting conditions in the two regions. In Queensland, rising gas production at Roma increased supply while outages at LNG plants suppressed gas requirements. But gas demand in southern Australia was high, especially for gas powered generation. Difficulties in sourcing local gas resulted in gas being shipped from Queensland, which incurred pipeline charges. Southern spot prices reflected this, often being $2–3 per GJ above Queensland prices.

The differential eased in late 2017 following the Australian Government's market intervention (discussed above), but gas plant outages in Victoria in 2018 periodically caused it to return. Price largely converged from March 2018, in part because swap agreements between Queensland producers and southern buyers increased supply in southern markets but avoided pipeline costs.

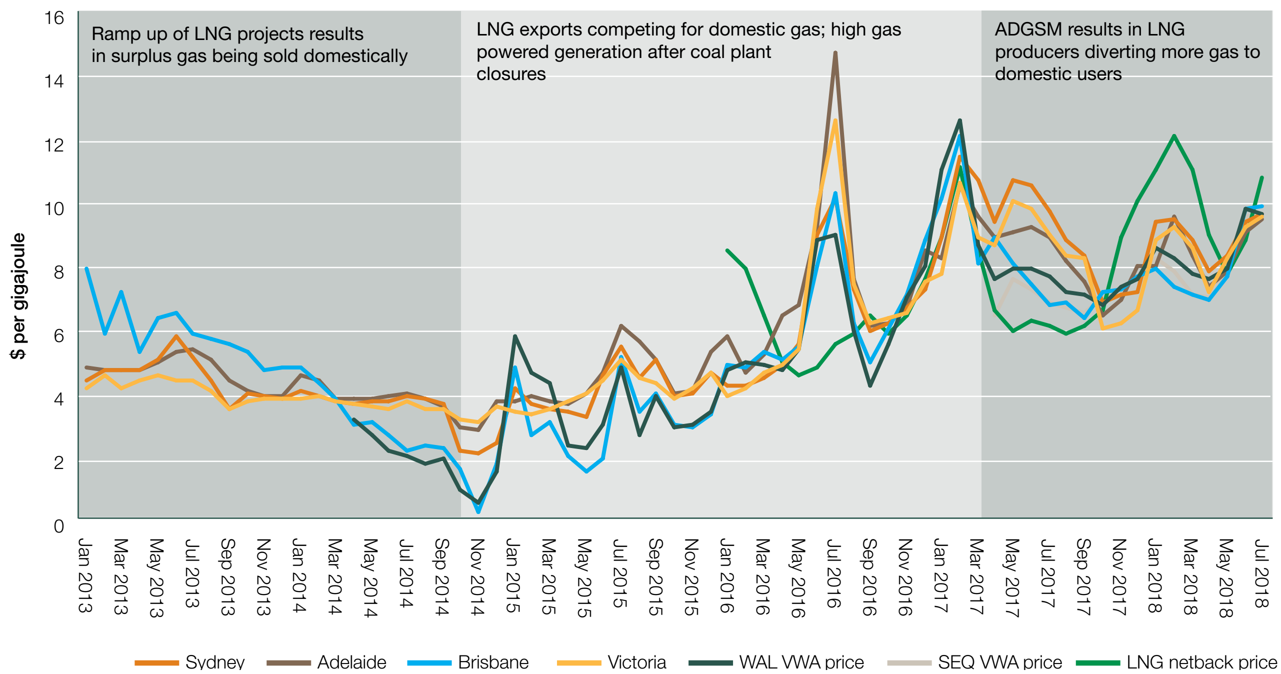
Structural issues in the market

While the ADGSM triggered a significant change in gas supply dynamics, many structural issues in the market remain. 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[47] have led to legislative moratoria and regulatory restrictions on onshore gas exploration and development. Victoria, South Australia, Tasmania and Western Australia each have onshore fracking bans in place, covering all or part of those states. NSW has no outright ban in place, but significant regulatory hurdles have stalled development proposals. In 2018 a fracking ban was lifted in parts of the Northern Territory. Queensland broadly allows the practice.

Gas pipeline access is another structural issue in the market. Transmission pipelines on key north–south transport routes

43 ACCC, *Gas inquiry 2017–2020, July 2018 interim report*, August 2018, pp. 15–19.
44 EnergyQuest, *Energy Quarterly*, September 2018, p. 11.
45 ACCC, *Gas inquiry 2017–2020, July 2018 interim report*, August 2018.
46 EnergyQuest, *Energy Quarterly*, September 2018, p. 12.
47 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.

Figure 7
Spot gas and LNG netback prices



Note: ADGSM, Australian Domestic Gas Security Mechanism; SEQ, south east Queensland; VWA, volume weighted average; WAL, Wallumbilla.

Note: Spot prices are monthly weighted averages. 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; AEMO (spot gas data); ACCC (LNG netback prices).

has become critical to moving gas to demand centres. Gaining access to pipeline capacity has proved difficult for many customers. The ACCC found many pipelines face little competition and charge monopolistic prices.[48] At present, only a handful of pipelines have their prices vetted by the AER. Additionally, several key pipelines have little or no spare capacity, making it difficult to negotiate access.

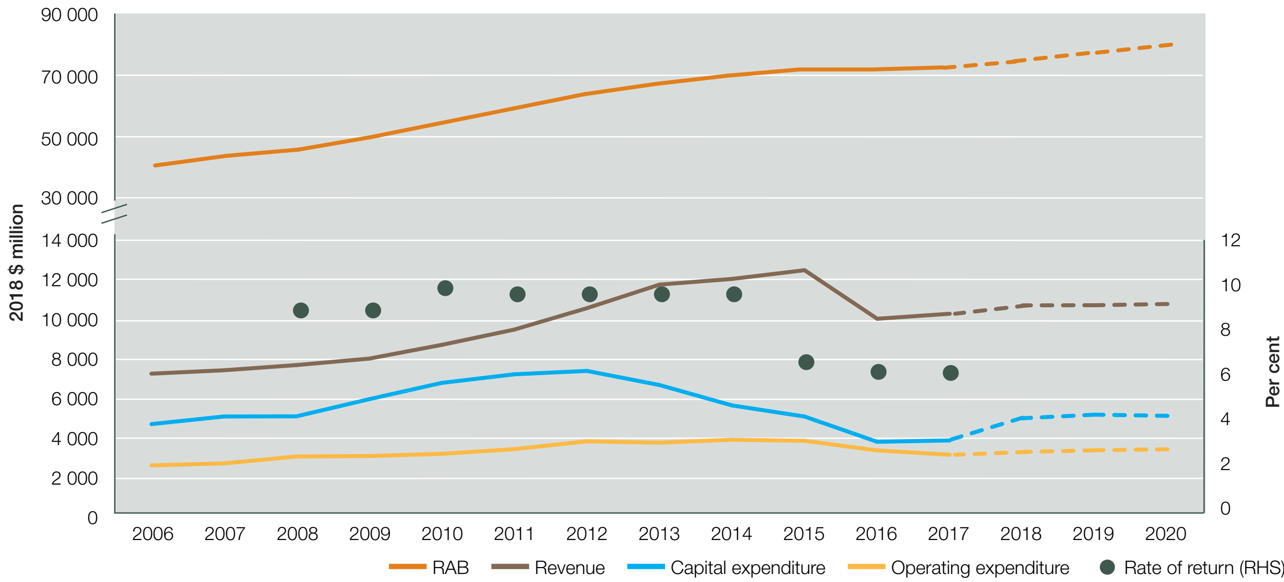
Market reforms

Reforms making it easier for gas customers to negotiate access to underused capacity on transmission pipelines will take effect in 2019. The AER will monitor and enforce compliance with the reforms, which include a voluntary trading platform, backed by the mandatory auction of all remaining contracted capacity that is not in use.

The AER is also helping implement other reforms aimed at making the market more transparent for customers. In 2018 the AER began publishing new data on prices and liquidity in gas markets. And in September 2018 reforms to the Gas Bulletin Board widened and improved reporting coverage, including on gas production, pipelines and storage options. The AER is engaging with industry to ensure the reforms are well understood. The AER will administer new civil penalty provisions that may apply to any breaches that occur.

48 ACCC, *Inquiry into the east coast gas market*, April 2016.

Figure 8
Electricity distribution revenues and key drivers



RAB, regulatory asset base; WACC, weighted average cost of capital.

Note: Revenue, capital expenditure, operating expenditure and RAB data are actual outcomes to 2017, and forecasts for 2018–20. RAB is actual closing data at end of relevant year. Data is shown for the relevant regulatory year on an end of year basis. The Victorian networks report on a calendar year basis. All other networks report on a financial year basis. All data is CPI adjusted to June 2018 dollars. Rates of return (WACC) are weighted average cost of capital forecasts in AER revenue decision and Australian Competition Tribunal decisions.

Source: AER estimates derived from Economic benchmarking regulatory information notices, AER revenue determinations, Australian Competition Tribunal decisions and AER modelling.

Regulated energy networks

The cost of transporting electricity and gas makes up over 40 per cent of a residential customer's energy bill. The bulk of these charges relate to local distribution network costs.

Network revenues and charges

Network charges put significant pressure on retail energy bills for several years, following changes to the energy rules in 2006 that incentivised investment to address concerns about rising demand and, in electricity, to meet tighter reliability and safety standards. Coupled with high financing costs caused by financial market instability, these changes drove a 70 per cent real increase in electricity network revenues over the nine years to 2015 (figure 8).[49]

By 2015, however, financial markets had stabilised, and flat electricity demand was causing new investment projects to be delayed or re-engineered. Reliability standards were also softened, bringing them more into line with values that customers place on reliability.

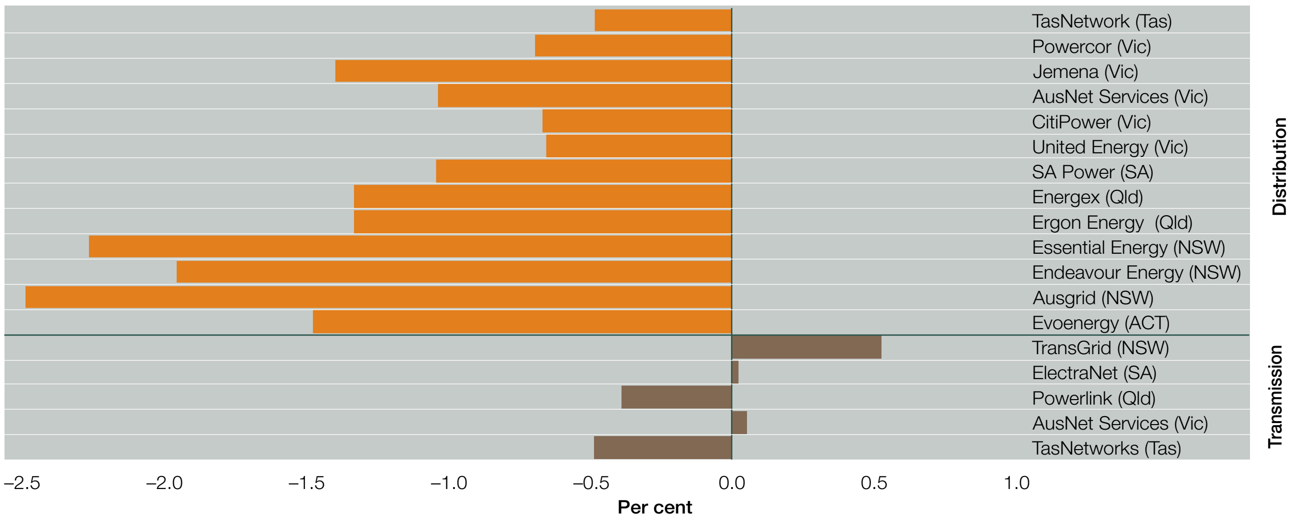
More recently, electricity networks began implementing efficiencies to better control their operating costs, partly in response to the AER applying benchmarking tools to set operating cost allowances, as well as new incentive schemes. Distribution network productivity has risen by 5 per cent over the two years to 2017, though it remains well below 2006 levels.

These shifts are reflected in lower revenue forecasts in current regulatory periods for every transmission network in the NEM and for every distribution network outside Victoria, where the networks had begun implementing efficiencies in previous periods. Overall, revenues are forecast to be 16 per cent lower in current regulatory periods than in previous periods. This trend is helping mitigate some of the recent upward pressure on retail energy bills from other sources.

Current AER decisions reduced distribution charges in residential energy bills by 1–2.5 per cent per year, on average, in all states and territories (figure 9). Transmission charges also eased or remained stable for most networks, with TransGrid (NSW) being an exception. In part, TransGrid's outcome reflects that changes in the investment

49 AER estimate derived from regulatory information notices submitted by electricity network business.

Figure 9
How AER electricity network decisions are affecting retail bills



Note: Estimated impact of latest AER decision on 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. Only the impact of changes in network charges is accounted for. Outcomes will vary among customers, depending on energy use and network tariff structures. The savings for NSW and ACT customers reflect the AER's 2015 decision for those networks. Those savings were partly set aside on appeal by the Australian Competition Tribunal.

Source: AER revenue decisions and additional AER modelling.

and financing environment occurred in its previous regulatory period.

The Grattan Institute called for the asset bases of some electricity networks to be written down to save consumers from paying for historical overinvestment.[50] The ACCC supported this position, particularly for government owned networks in Queensland, NSW and Tasmania.[51]

In gas, revenues are expected to fall in four of the six distribution pipeline networks the AER regulates, including those in NSW, South Australia and the ACT. In gas transmission, prices for the regulated Roma to Brisbane Pipeline will fall by 18 per cent. The only forecast revenue rises are for the Victorian transmission network and two of the state's three distribution networks. Investment in Victorian networks is rising to meet demand for new gas connections and to undertake substantial mains replacement to maintain safety, reliability and security.

The AER continues to scrutinise regulatory proposals carefully and ensure they reflect efficient costs for consumers. The AER's three regulatory decisions for electricity networks in 2018—for transmission networks in NSW, South Australia and a Victoria–South Australia interconnector—accepted elements of the networks' capital expenditure proposals, but some only on a contingent basis, reflecting uncertainty about their need, cost and scope. The networks may only apply for additional revenue to incorporate these projects if a defined trigger event occurs.

Constructive engagement and the New Reg

The AER's approach to setting energy network prices is set out in rules and legislation. But within the rules, it continues to explore innovative approaches to achieve better outcomes for consumers.

A critical reform focus is on the quality of engagement network businesses undertake with their customers and the AER. In electricity, Powerlink (Queensland transmission), ElectraNet (South Australian transmission), SA Power Networks (South Australian distribution) and TasNetworks (Tasmanian networks) are among businesses that developed regulatory proposals in closer consultation with their customers. Evidence of constructive engagement also helped the AER adopt a relatively expedited process in 2018 for remaking decisions on the NSW distribution networks, following directions from the Full Federal Court.

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

51 ACCC, *Restoring electricity affordability and Australia's competitive advantage, Retail Electricity Pricing Inquiry—Final Report*, June 2018, p.171.

The Victorian gas distributors—Multinet, AusNet Services and Australian Gas Networks—also engaged constructively with their customers in developing new access arrangements for 2018–22. The AER's Consumer Challenge Panel particularly commended Australian Gas Networks' genuine commitment to giving consumers—small and large—a say by clearly identifying feedback from stakeholders and how that feedback had been addressed.[52] Transmission businesses have been less proactive, with the panel being critical of APA's approach to consulting on its access arrangement for the Victorian Transmission System.[53]

With some network businesses making encouraging progress to engage with their customers, the next step is a new regulatory model that systemises this approach. The AER is trialling a new regulatory model in a partnership with Energy Networks Australia and Energy Consumers Australia. The *New Reg* involves consumers shaping a business's regulatory proposal *before* it is lodged with the AER.[54] The model offers potential to expedite the regulatory process, reducing costs for businesses and consumers alike.

AusNet Services (Victorian electricity distribution) in 2018 became the first network to actively trial the model to develop its upcoming regulatory proposal. The trial will continue until AusNet Services formally lodges its proposal in July 2019.

Rate of return and other major reviews

The AER has also strengthened its own engagement processes. Its 2018 review of rate of return allowances for network businesses drew on intensive consultation and engagement processes including:

- a consumer reference group comprising academics, energy consumer associations, community and advocacy groups
- a consumer challenge sub-panel
- an investor reference group
- expert 'hot tubbing' sessions to explore areas of disagreement
- an independent review panel.[55]

The outcomes of this review are binding on both the AER and network businesses for four years. The review covered both electricity and gas network businesses.

The AER is also refining the regulatory framework in other ways. In September 2018 it began publishing information about network businesses' profitability to help customer groups make informed assessments of revenue proposals. The initiative responds to calls for greater transparency around actual returns achieved by businesses. Some observers are concerned networks are earning excessive profits, given the market risks they face. The first phase of this initiative was to publish return on assets data for each network business.[56] More comprehensive reporting will follow in 2019.

Another key project is the AER's research into whether taxation allowances for network businesses are consistent with the amount of tax they actually pay. And the AER continues to streamline its approach to benchmarking network businesses, with a review launched in 2018 of operating environment factors unique to particular networks that impact their efficiency data.

Adapting to an evolving market

An important focus of reform is ensuring the network regulation remains fit for purpose in an environment of dynamic market change. In 2017 the AER launched incentives for electricity network businesses to find lower cost alternatives to cope with rising demand on their networks. Complementing this, the AER expanded its demand management innovation allowance to provide funding for projects such as trials of innovative tariffs, customer payments that incentivise customers to reduce their energy use at times of peak demand, and battery storage.

In this environment, the AER has been tasked with calculating the price customers are willing to pay for having a reliable electricity supply (referred to as 'value of customer reliability'). This information will provide valuable input into assessing whether a network's investment proposals are in the best interests of consumers. The AER will survey consumers to estimate reliability values, and update them annually. The first estimates will be published in December 2019.

The AER is also examining whether the regulatory test for assessing electricity network investment proposals remains fit for purpose in the current environment. In particular, it is assessing whether the test adequately accounts for

52 Consumer Challenge Panel Sub-Panel CCP11, *Response to the AER's draft decisions and the revised proposals from AGN, AusNet and Multinet*, September 2017, p. 10.

53 Consumer Challenge Panel Sub-Panel CCP11, *Response to proposals from APA VTS*, September 2017, p. 4.

54 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.

55 AER, *Final rate of return guidelines*, December 2018.

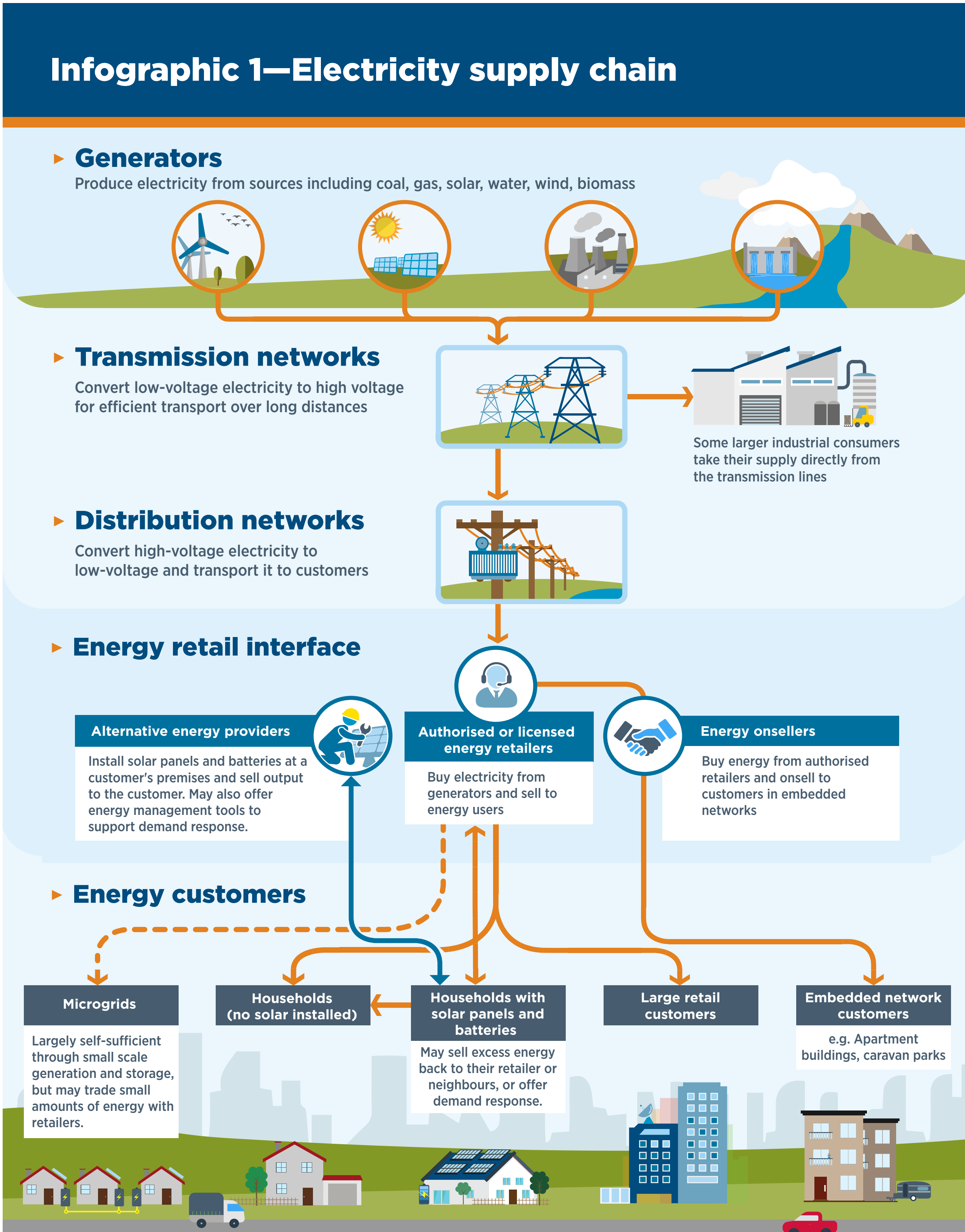
56 AER, *Return on assets, summary data*, September 2018.

system security, emissions reduction goals, and events with a low probability of occurring but a high impact. The AER aims to ensure the test is suitable for assessing whether recent proposals for transmission upgrades and new interconnectors are in the long term interest of consumers. This work follows earlier work by the AER to strengthen the test's focus on ensuring the efficiency of replacement expenditure, which is now the largest component of network investment.

The AEMC in 2018 found the regulatory framework may discourage network businesses from making efficient choices between their capital (capex) and operating expenditure (opex) programs as the market evolves.[57] This effect particularly impacts non-network (demand response) projects offered by third parties. While a traditional network solution to meet increasing consumer demand in an area might be to augment a zone substation, for example, it may be more efficient to purchase services from a battery provider, or an aggregator of many small scale batteries, to reduce peak demand.

The current framework may encourage businesses to favour (expensive) long life capex solutions over cheaper opex alternatives, especially if the business' regulated rate of return is higher than current borrowing costs. AER incentive schemes seek to limit this bias and its 2018 rate of return review also considers the issue. Another option may be a holistic approach to regulatory assessments of capital and operating expenditure programs such as the 'total expenditure' approach used in the United Kingdom. The AEMC in 2019 will consider arrangements for better aligning incentives to ensure an optimal balance between capital and operating expenditure.

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


Infographic 1—Electricity supply chain
Generators
Produce electricity from sources including coal, gas, solar, water, wind, biomass
Transmission networks
Convert low-voltage electricity to high voltage for efficient transport over long distances
Some larger industrial consumers take their supply directly from the transmission lines
Distribution networks
Convert high-voltage electricity to low-voltage and transport it to customers
Energy retail interface
Alternative energy providers
Install solar panels and batteries at a customer's premises and sell output to the customer. May also offer energy management tools to support demand response.
Authorised or licensed energy retailers
Buy electricity from generators and sell to energy users
Energy onsellers
Buy energy from authorised retailers and onsell to customers in embedded networks
Energy customers
Microgrids
Largely self-sufficient through small scale generation and storage, but may trade small amounts of energy with retailers.
Households (no solar installed)
Households with solar panels and batteries
May sell excess energy back to their retailer or neighbours, or offer demand response.
Large retail customers
Embedded network customers
e.g. Apartment buildings, caravan parks

Infographic 2—Gas supply chain

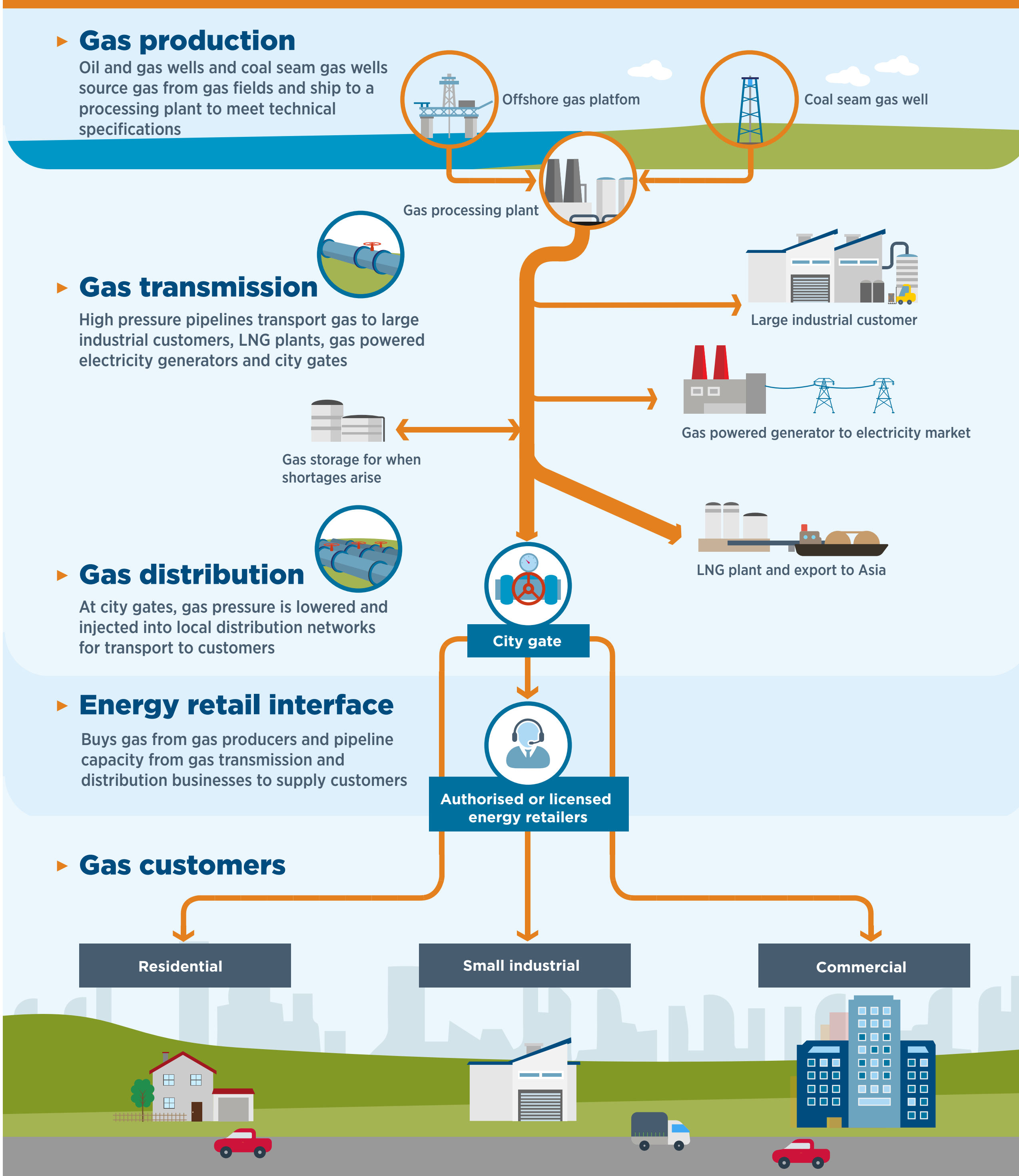


Image courtesy of Pika Energy Island

1 RETAIL ENERGY MARKETS

1.1 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.

But this traditional retail model is evolving as customers become active participants in the market and take greater control over their energy use (figure 1.1). Advances in technology (particularly in the electricity market) and an environment of rising energy prices are driving this change, opening up markets for new types of energy services. Examples include:

- s*mart meters* provide scope for retailers to offer more innovative products, and for new sellers to offer 'add-on' energy management services.
- *rooftop solar photovoltaic (PV) systems* 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 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.

More 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.

1.2 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]

1 Recent changes to the Victorian framework, including recommendations adopted from the Thwaites *Independent Bipartisan Review into the Electricity and Gas Retail Markets in Victoria* (August 2017), have seen greater divergence between the Victorian and national frameworks. The ACCC's *Retail Electricity Pricing Inquiry* (July 2018) recommended Victoria adopt the Retail Law.

The National Energy Retail Law (Retail Law) sets out the regulatory arrangements, and confers wide ranging regulatory responsibilities on the Australian Energy Regulator (AER) (box 1.1). This chapter focuses on the five jurisdictions where the AER has a regulatory role, and also covers the Victorian market where possible. Western Australia and the Northern Territory operate 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 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, though 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. The AER does not currently regulate retail energy prices, but from 1 July 2019 it is expected to set a *default price* that caps standing offers[3] for electricity in jurisdictions without state based price regulation. This price will also inform a reference bill from which any advertised discounts promoted by retailers must be based.[4]

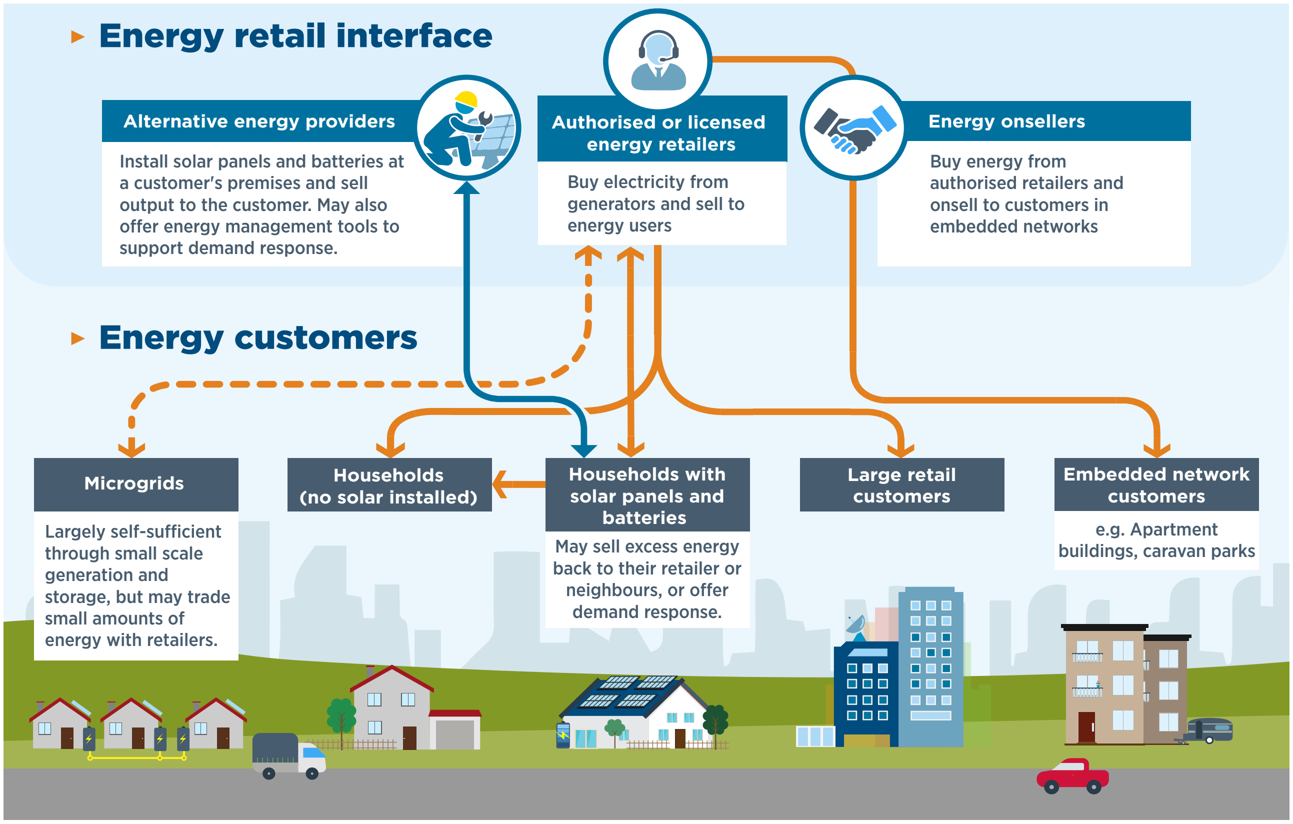
The Australian Energy Market Commission (AEMC) sets the rules for the energy market.

2 For electricity, some jurisdictions have different consumption thresholds to that specified in the Retail Law. In South Australia, for example, small electricity customers are those consuming fewer than 160 MWh per year. In Tasmania, the threshold is 150 MWh per year.

3 Standing offers are applied where a customer does not enter into a market contract. The terms and conditions of standing offers are prescribed in the National Energy Retail Rules.

4 Commonwealth Treasurer, Josh Frydenberg and Minister for Energy, Angus Taylor, *Introduction of a default market offer*, Letter to the AER, 23 October 2018.

Figure 1.1
An evolving retail energy market



1.3 Energy retailers

Energy sellers include those authorised as retailers under the Retail Law, and those holding exemptions from the requirement to be authorised.[5] Additionally, some entities offer energy products and services in markets beyond the scope of the Retail Law, such as energy management services, storage products, and off-grid energy systems. Only customers of authorised retailers enjoy the full set of protections in the Retail Law.

1.3.1 Authorised energy retailers

The Retail Law requires an entity to be authorised to operate as an energy retailer. An authorisation covers energy sales to all customers in participating jurisdictions. Authorised retailers must comply with consumer protection and other obligations under the Retail Law.

In July 2018, 71 businesses held authorisations to retail electricity and 28 held authorisations to retail gas, though not all retailers were active in the market.[6] Since 2017 15 new retailers were authorised to retail electricity, and one to retail gas. Two new authorised retailers commenced offering electricity contracts since 2017. Four established retailers expanded the markets in which they sell electricity, and eight commenced offering gas in new markets.

While many authorised retailers offer energy services to all customers, some target specific market segments—a retailer may focus on offers for large commercial customers or customers in embedded networks, for example. Some retailers also have offers that have particular value for users with certain characteristics, such as customers with swimming pools or those with flexibility in when they use energy.

In choosing which markets to enter, a retailer considers factors such as price regulation (if it applies), market scale,

5 In Victoria, where the Retail Law does not apply, retailers must hold a licence issued by the ESC or seek an exemption from this requirement.

6 Details of all businesses that hold electricity or gas authorisations can be found in the public register of authorised retailers on the AER website.

Box 1.1 The AER's role in retail energy markets

The AER regulates retail energy markets so energy customers (particularly residential and small business customers) can participate confidently in those markets. We undertake this work in Queensland, NSW, South Australia, Tasmania and the 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:

- maintain an energy price comparator website (www.energymadeeasy.gov.au) for residential and small business customers that helps energy users 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 Retail Law, Rules and Regulations
- oversee retail market entry and exit by assessing applications from businesses looking to become energy retailers, grant exemptions from the requirement to hold a retailer authorisation, and administer 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.

From 1 July 2019 we are expected to set a default price that caps standing offers for electricity in jurisdictions without state based price regulation.

competition, the ability to source hedging contracts to manage risk and, for gas retailing, whether wholesale gas contracts and pipeline access are available.

Table 1.1 lists the 36 authorised or licensed retailers selling energy to residential or small business customers in southern and eastern Australia. Around 50 per cent of these retail brands offer both electricity and gas in at least one jurisdiction. Some offer only electricity, while one retailer specialises in just gas. A small number of authorised retailers (not listed in table 1.1) only offer electricity retail services to customers in embedded networks.

Only 15 retail brands offer energy products in all the fully contestable markets without price regulation—south east Queensland, NSW, Victoria and South Australia. The retail brands of three businesses—AGL Energy, Origin Energy and EnergyAustralia—supply over 66 per cent of small electricity customers and 77 per cent of small gas customers in southern and eastern Australia (section 1.7.1).

1.3.2 Exempt energy sellers

An energy seller may apply to the AER for an exemption from the need to be authorised 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 the customer's primary energy connection.

At 1 July 2018 over 3000 businesses held exemptions, typically to onsell energy within an embedded network (that is, a small private network whose owner sells electricity to other parties connected to the network). Hospitals, retirement villages, caravan parks and apartment complexes are examples of entities that might run an embedded network. The AEMC estimates there are over 200 000 embedded network customers.[7] Solar power purchase agreement providers are also covered by the exemptions framework.

Embedded network customers do not enjoy the full set of protections in the Retail Law, and have more limited avenues for dispute resolution.[8] But energy ombudsman schemes are being widened to allow customers of exempt sellers to lodge complaints (section 1.8.5).

7 AEMC, *Review of regulatory arrangements for embedded networks, information sheet*, p. 3.

8 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.

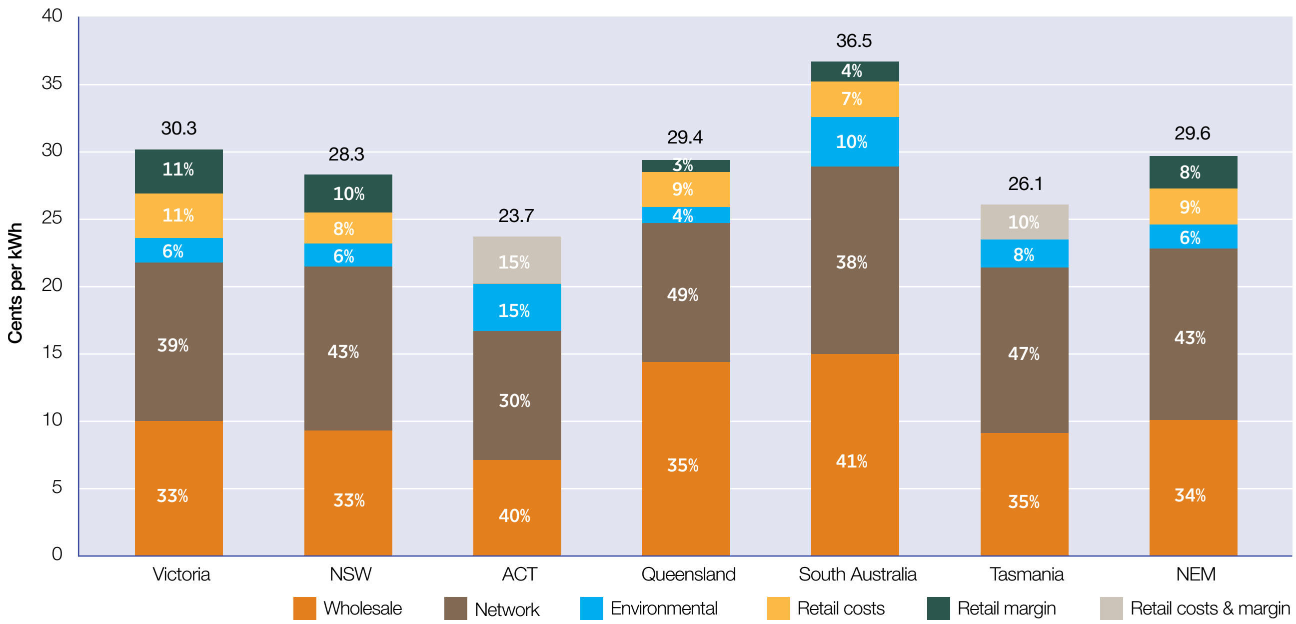
Table 1.1 Retailers offering energy contracts to small customers

Retailer	Ownership	Queensland	NSW	Victoria	South Australia	Tasmania	ACT
1st Energy	1st Energy	Electricity	Electricity	Electricity			
ActewAGL Retail	AGL Energy (ACT Government)		Gas (host), Electricity				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		
Aurora Energy	Aurora Energy					Gas, Electricity (host)	
Blue NRG	Blue NRG		Electricity	Electricity	Electricity		
Click Energy	Amaysim Energy	Electricity	Gas, Electricity	Gas, Electricity	Electricity		
Commander Power & Gas	M2 Energy		Electricity	Electricity	Electricity		Gas, Electricity
CovaU	TPC		Gas, Electricity	Gas, Electricity			Electricity
Diamond Energy	Diamond Energy	Electricity	Electricity	Electricity	Electricity		
Dodo Power and Gas	M2 Energy	Electricity	Electricity	Gas, Electricity	Electricity		Electricity
EnergyAustralia	CLP Group	Electricity	Gas, Electricity (host)	Gas (host), Electricity (host)	Gas, Electricity		
Energy Locals	Energy Locals	Electricity	Gas, Electricity				
Enova Energy	Enova Community Energy		Electricity				
Ergon Energy	Queensland Government	Electricity (host)					
ERM Power	ERM Power		Electricity	Electricity	Electricity	Electricity	
Flow Power	OPTrust	Electricity	Electricity		Electricity		
Globird Energy	Globird Energy			Gas, Electricity			
Lumo Energy	Snowy Hydro	Electricity	Gas, Electricity	Gas, Electricity	Gas, Electricity		
Mojo Power	Mojo Power	Electricity	Electricity				
Momentum Energy	Hydro-Electric (Tansmanian Government)	Electricity	Electricity	Gas, Electricity	Electricity		
Next Business Energy	Next Business Energy	Electricity	Electricity	Electricity			Electricity
Online Power and Gas	Online Power and Gas			Gas, Electricity			
Origin	Origin	Gas (host), Electricity (host)	Gas (host), Electricity (host)	Gas (host), Electricity (host)	Gas (host), Electricity		Gas, Electricity
People Energy	People Energy			Electricity			
Pooled Energy	Efficiency Filters		Electricity				
Powerdirect	AGL Energy	Electricity	Electricity	Electricity	Electricity		Electricity
Powershop	Meridian Energy	Electricity	Electricity	Gas, Electricity			
Qenergy	Qenergy	Electricity	Electricity	Electricity	Electricity		
Red Energy	Snowy Hydri	Gas, Electricity	Gas, Electricity	Gas, Electricity	Gas, 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			Gas, Electricity			
Tango Energy	State Power Investment Corporation			Electricity	Electricity		
Tas Gas Retail	Brookfield Infrastructure					Gas	
TOTAL	**Gas retailer**	3	12	16	7	2	3
	Electricity retailer	22	28	26	20	2	7
	Host retailer (electricity and gas)						

Note: Includes all retailers with generally available offers at August 2018. Retailers servicing only embedded customers are excluded as well as some retailers servicing only rural and regional areas. A host retailer has obligations to supply new customers in a region that do not take up a market offer.

Source: Energy Made Easy; Victorian Energy Compare.

Figure 1.2
Composition of a residential electricity bill



kWh, kilowatt hour.

Note: Data are estimates for 2017–18. Average residential customer prices excluding GST (real $2016–17). Retail costs and margin are combined for the ACT and Tasmania due to data availability.

Source: ACCC, *Restoring electricity affordability and Australia's competitive advantage, Retail Electricity Pricing Inquiry—Final report*, June 2018, p. 8; ACT data from AEMC, *2017 Residential Electricity Price Trends, final report*, December 2017, p. 111.

1.4 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.

1.4.1 Electricity bills

A typical residential electricity retail bill in 2017–18 comprised:

- retailers' **wholesale costs** of buying electricity in spot and hedge markets—34 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—collectively 6 per cent of a bill
- the **retail costs** of servicing customers (including meeting regulatory obligations) and acquiring and retaining customers—9 per cent of the bill
- the **retailer's margin** (profit)—8 per cent of the bill (figure 1.2).[9]

The contribution of the different components of retail electricity bills varies across regions (figure 1.2).

Wholesale costs

The energy retailers sell to customers is purchased in wholesale markets. But prices in the wholesale market can be volatile, while the prices retailers charge customers are generally fixed. To manage this risk, retailers lock in firm prices for electricity they need to buy or sell by entering forward contracts (hedges or derivatives). Alternatively, they might own generation assets, or enter demand response contracts to manage these risks (discussed in sections 1.7.2 and 1.8.4).

Wholesale costs in 2017–18 were highest in South Australia. This reflects both the generation portfolio in the state (which is reliant on higher cost gas powered generation and has relatively concentrated ownership), relatively peaky demand and limited interconnection with other regions.

9 Based on earnings before interest, taxes, depreciation and amortisation (EBITDA).

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 owner and lenders that fund the business.

Network costs (as a percentage of total retail bills) in 2017–18 were highest in Queensland and Tasmania and also high in NSW. Productivity has been consistently lower for the (largely still government owned) networks in these regions than in the privatised networks in Victoria and South Australia.

Environmental costs

Environmental costs include payments to fund the renewable energy target, feed-in tariffs for solar PV installations, and state government operated energy efficiency schemes. Costs associated with the large scale renewable energy target made up around half of all environmental costs. State government premium feed-in tariff schemes were the next largest contributor to environmental costs in most regions. While these schemes are closed to new entrants, eligible households continue to receive payments under the schemes.

South Australian and ACT customers face the highest environmental costs. South Australian costs flow from the state's premium feed-in tariff scheme, given the high penetration of rooftop solar PV. South Australia's energy efficiency scheme also has the largest per customer cost. ACT costs were largely related to the government's feed-in tariff scheme for large scale solar developments.

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 retailer's margin

Retail costs fall into two main categories. *Costs of servicing customers* include managing billing systems and debt, handling customer enquiries, and compliance with regulatory obligations. These costs do not vary significantly across regions.

Customer acquisition and retention costs—marketing to gain or retain customers—are highest in Victoria. These costs tend to be higher in jurisdictions with high rates of customer switching. This outcome highlights a risk that competition may increase energy bills for customers if the costs of competing outweigh the competition benefits of efficiency and innovation.

Retail costs per customer tend to be lower for the big three retailers (AGL, Origin and EnergyAustralia) than other retailers.

Retailers' margins in Victoria and NSW were more than double those in South Australia and south east Queensland (on a dollar per customer basis). The combined retail costs and retailer's margin were lowest in Tasmania (as a percentage of the total bill).

1.4.2 Gas bills

The composition of retail gas bills is opaque. Unlike in electricity, there is no systematic annual reporting of this data. Figure 1.3 shows estimates of the composition of retail gas bills in 2017.

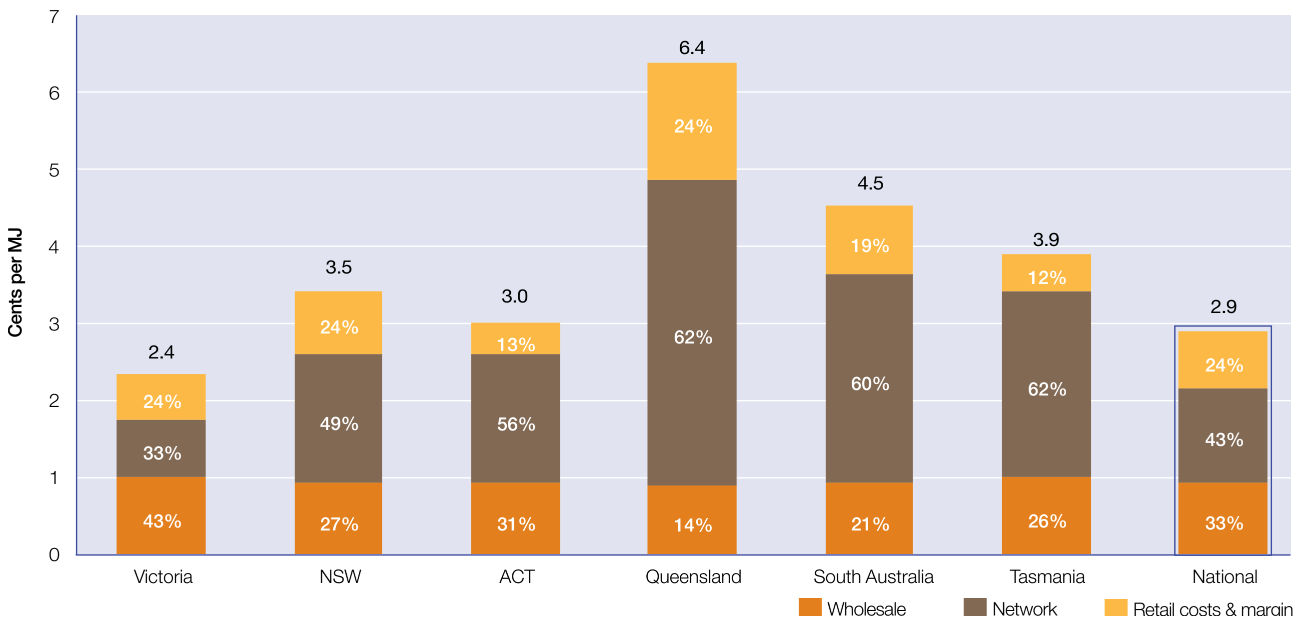
On average, gas pipeline (transportation) charges make up over 40 per cent of a retail gas bill. Distribution charges represent the largest component, at around 35 per cent of retail gas bills, with transmission costs making up around 7 per cent.[10] Wholesale gas prices, which account for around one third of a typical gas bill, have risen sharply since 2015 (chapter 4). Retail costs and margin accounted for the remaining 25 per cent of retail gas bills.

Regional outcomes varied. Victorian residential gas prices were the cheapest on a unit basis—largely due to lower network costs given a high level of gas use per customer and connection penetration. In Tasmania and Queensland, where gas use is less widespread, network costs account for over 60 per cent of gas bills.

Retail costs also varied across regions. On a unit basis, Queensland retail costs were almost double those elsewhere, which may reflect economies of scale in servicing larger customer bases. Retail margins were highest in Victoria and NSW.[11] The Thwaites review found retail costs in Victoria were higher than in an efficient or regulated market.[12] Gas retailers likely face many of the same customer acquisition and retention costs as electricity retailers.

10 Oakley Greenwood, *Gas Price Trends Review 2017*, March 2018, p. 158.
11 Oakley Greenwood, *Gas Price Trends Review 2017*, March 2018, p. 225.
12 Thwaites, T, Faulkner, P, and Mulder, T, *Independent Review into the electricity and gas retail markets in Victoria*, August 2017, p. 23.

Figure 1.3
Composition of a residential gas bill



MJ, megajoule.
Note: Data are estimates at 2017. Average residential customer prices excluding GST (real $2014–15).
Source: Oakley Greenwood, *Gas Price Trends Review 2017*, March 2018.

1.5 How retail prices are set

Energy retailers in southern and eastern Australia offer energy contracts at whatever prices they set. Alongside this deregulated pricing, government agencies in some jurisdictions regulate electricity retail prices for 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 in those jurisdictions require retailers to publish standing offer prices that small customers can access. Retailers may adjust these prices once every six months.

Only the ACT, Tasmania and regional Queensland regulate retail electricity prices for small customers. State regulators use a 'building block' approach to set a price reflecting the costs of an efficient retailer supplying electricity to its customers. The approach adopted to estimate 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).

In gas, NSW was the last jurisdiction to deregulate retail prices for small customers at 1 July 2017—following an AEMC finding in 2016 that gas market customers would benefit from the removal of retail price regulation.[13]

Recent reviews of retail energy markets advocated returning to some form of price regulation in all regions.[14] In October 2018, the Australian Government adopted an ACCC recommendation for a default market offer price to be set by the AER. The default price is intended to take effect from 1 July 2019, and act as a cap on standing offer prices in jurisdictions where price regulation does not otherwise exist.

The ACCC recommended the default offer should not mirror the lowest price, or be close to the lowest price in the market, to avoid incentivising consumers to disengage. It recommended the default offer should cover efficient costs, including customer acquisition and retention costs, and a reasonable margin. This default price will also inform a reference bill on which any advertised discounts promoted

13 AEMC, *2016 Retail competition review, final report*, June 2016, p. 20.
14 Thwaites, T, Faulkner, P, and Mulder, T, *Independent review into the electricity and gas retail markets in Victoria*, August 2017; ACCC, *Restoring electricity affordability and Australia's competitive advantage, Retail Electricity Pricing Inquiry–Final Report*, June 2018.

Figure 1.4

Spread of electricity costs for residential consumers

kWh, kilowatt hour.

Note: Based on effective unit charges paid by residential customers without solar PV systems at June 2017. Data is inflation adjusted, in 2016–17 dollars, and excludes GST. The average is the weighted average unit charge for each region.

Source: ACCC, *Restoring electricity affordability and Australia's competitive advantage, Retail Electricity Pricing Inquiry—Final report*, June 2018, p. 262.

by electricity retailers must be based. This requirement seeks to provide consumers with meaningful information to compare offers.

The Victorian Government also committed to introducing a regulated price from 1 July 2019, to be set by the Essential Services Commission (ESC). Like the default offer adopted by the Australian Government, the regulated price will reflect the efficient costs of a retail business operating in a contestable market, including an allowance for customer acquisition and retention costs.

1.6 Retail prices and customer bills

The amount customers pay for energy services can vary significantly. Customers who regularly change their energy contract usually pay lower prices, reflecting that market offer prices are often cheaper than standing offers (table 1.2).

Energy bills are typically higher for customers in regions with higher average energy use, and in regional and remote areas (where network costs tend to be higher and can be recovered from fewer customers), than for urban customers.

1.6.1 Diversity of customer bills

A customer's energy bill depends on their use and the terms of their contract with their retailer. 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. A customer's contract may change even where they do not initiate a change.

The ACCC in 2018 used its inquiry powers to gather information on the bills paid by different electricity customers. In Victoria, NSW and South Australia, electricity customers on the most expensive offers pay more than double what those on the least expensive offers pay, on a per unit basis (figure 1.4). While potential savings exist for those on expensive offers, it is not always easy for a customer to identify the best contract for their situation.

South Australian customers paid the highest average per unit rates. Victorian customers paid around 10 per cent less than South Australian customers on average, but those on the most expensive offers in Victoria paid more than anyone else in the NEM. ACT customers paid the lowest average per unit rates for electricity, and had the least variation in prices paid.

1.6.2 Headline price movements

Electricity retail prices rose significantly across most regions over the past two years, driven largely by wholesale costs.

In 2017 market offer prices for residential customers rose by 11–17 per cent in NSW, 19 per cent in South Australia and 21 per cent in the ACT. Prices were also affected in South Australia by increasing network costs, and in the ACT by an expansion of the ACT Government's feed-in tariff scheme for large scale solar developments.

In Queensland prices rose by only 1 per cent. While wholesale costs put upward pressure on prices, this effect was partly mitigated by a Queensland Government decision to recover premium feed-in tariff costs through the tax base rather than electricity charges.

In Tasmania, the government capped the wholesale electricity price used to calculate standing offer prices for 12 months from July 2017. A new distribution network determination also took effect with lower allowed revenues for TasNetworks. These changes resulted in stable retail prices in 2017.

Prices rose by 5–9 per cent in Victoria in 2017. While lower than in NSW and South Australia, this outcome reflected the timing of price changes rather than a difference in underlying market conditions (Victorian prices are typically adjusted in January rather than July). Victorian prices rose a further 4–8 per cent in 2018.

Outside Victoria, market offer prices were either stable or fell slightly in 2018. Queensland had the largest price reduction (4.6 per cent) following a fall in network costs.

In gas, retail prices rose in all regions in 2017, with the largest rises in Victoria (13–16 per cent) and the ACT. Victorian prices were affected by rising network costs in both transmission and distribution. Prices were flat in 2018 for NSW and Queensland, but continued to rise in other regions.

In both electricity and gas, prices in standing offers typically rose more (or fell less) than prices in market offers. Table 1.2 (and figure 1 in the Market overview) summarises recent movements in market and standing offer energy prices for residential customers, and estimated annual customer bills.

Energy wholesale costs

Rising energy wholesale costs were the main driver of higher retail prices in 2017 and 2018.

In electricity, the 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 fed into wholesale electricity prices. Additionally, liquidity in electricity financial markets has tightened since traditional generators left the market, putting upward pressure on hedging costs. In combination, these factors led to wholesale electricity prices setting new records in several regions (chapter 2).

While wholesale costs eased in the first half of 2018 in some regions, this cost reduction generally did not flow through to retail prices. This outcome may reflect hedging strategies of retailers that typically lock in a portion of their wholesale costs up to a few years in advance, meaning it takes time for cost changes to work their way into retail prices.

In gas, wholesale costs more than doubled in all regions—and tripled in Queensland—from 2015–17, before stabilising (at high levels) in 2018. This increase was largely due to Queensland's liquefied natural gas (LNG) projects linking 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 (chapter 4).

1.6.3 Longer term price trends

Retail *electricity* prices rose by 56 per cent in real terms for customers in eastern and southern Australia over the 10 years to 30 June 2018 (figure 1.5). Queensland recorded the highest price rise over the decade (71 per cent) and Tasmania the lowest (39 per cent).[15]

However, changes in customer behaviour—switching to energy efficient appliances, meeting some of their energy needs from rooftop solar PV systems, and other changes to reduce their energy use—have moderated the impact of price rises on customer bills. Electricity customer bills rose by a lower (but still significant) rate of 35 per cent over this period, for example.

15 ACCC, *Restoring electricity affordability and Australia's competitive advantage, Retail Electricity Pricing Inquiry—Final report*, June 2018, pp. 10–23.

Table 1.2 **Movement in energy bills for customers on market and standing offers**

JURISDICTION	WHO SETS STANDING OFFER PRICES?	DISTRIBUTION NETWORK AREA	CHANGE IN MEDIAN OFFER (%) 2017 MARKET	2017 STANDING	2018 MARKET	2018 STANDING	ESTIMATED ANNUAL CUSTOMER BILL, 2018 ($) MARKET	STANDING
Electricity								
Queensland	Retailers	Energex	1.0	6.7	-3.5	-1.4	1814	2098
	QCA	Ergon Energy		3.8		-1.5		2012
NSW	Retailers	Ausgrid	12.8	16.2	-0.5	0.0	1997	2315
		Endeavour Energy	15.2	17.2	-1.6	-1.3	1928	2264
		Essential Energy	11.1	10.9	-2.1	3.1	2188	2619
Victoria	Retailers	Citipower	7.5	8.4	7.2	12.0	1431	1891
		Powercor	8.8	4.5	6.8	9.3	1619	2070
		AusNet Services	4.9	3.5	2.5	12.5	1651	2269
		Jemena	4.9	6.9	5.5	10.9	1538	2077
		United Energy	5.1	4.8	9.5	11.5	1518	1972
South Australia	Retailers	SA Power Networks	14.3	19.0	-0.1	5.3	2213	2662
Tasmania	OTTER	Aurora Energy		-0.5		2.1		2455
ACT	ICRC	Evoenergy	21.8	20.8	0.1	6.1	1804	2019
Gas								
Queensland	Retailers	AGN	3.3	4.6	-0.1	2.9	645	688
		Allgas Energy	1.9	4.5	1.0	0.3	702	736
NSW	Retailers	Jemena	7.3	7.8	-0.7	1.9	887	1020
Victoria	Retailers	AusNet Services	15.5	13.6	5.9	16.2	1468	1774
		Multinet	12.9	10.1	5.6	16.2	1449	1757
		AGN	13.7	12.6	6.4	16.6	1527	1846
South Australia	Retailers	AGN	1.1	9.2	6.8	5.7	941	1005
ACT	Retailers	Evoenergy	12.7	17.9	2.2	3.4	1573	1735

Note: Analysis includes all generally available offers for residential customers using a 'single rate' tariff structure. Annual bills and price changes based on median market and standing offers at December 2016, December 2017 and August 2018, using average consumption in each jurisdiction: NSW 6130 kWh (electricity), 22 860 MJ (gas); Queensland 5950 kWh, 7870 MJ; Victoria 4810 kWh, 57 060 MJ; South Australia 5100 kWh, 17 500 MJ; ACT 7010 kWh, 42 080 MJ; NEM 5590 kWh, 39 0301 MJ. Market offer prices include all conditional discounts.

Source: Energy Made Easy; Victorian Energy Compare.

Retail *gas* prices rose by 46 per cent over the 10 years to 2017 (figure 1.6). On the mainland the increase ranged from 27 per cent in NSW to 51 per cent in Victoria. As in electricity, this impact was partly offset by customers using less gas. Average residential gas use fell by 6–7 per cent in NSW and Victoria, and by around 30 per cent in South Australia.

Electricity

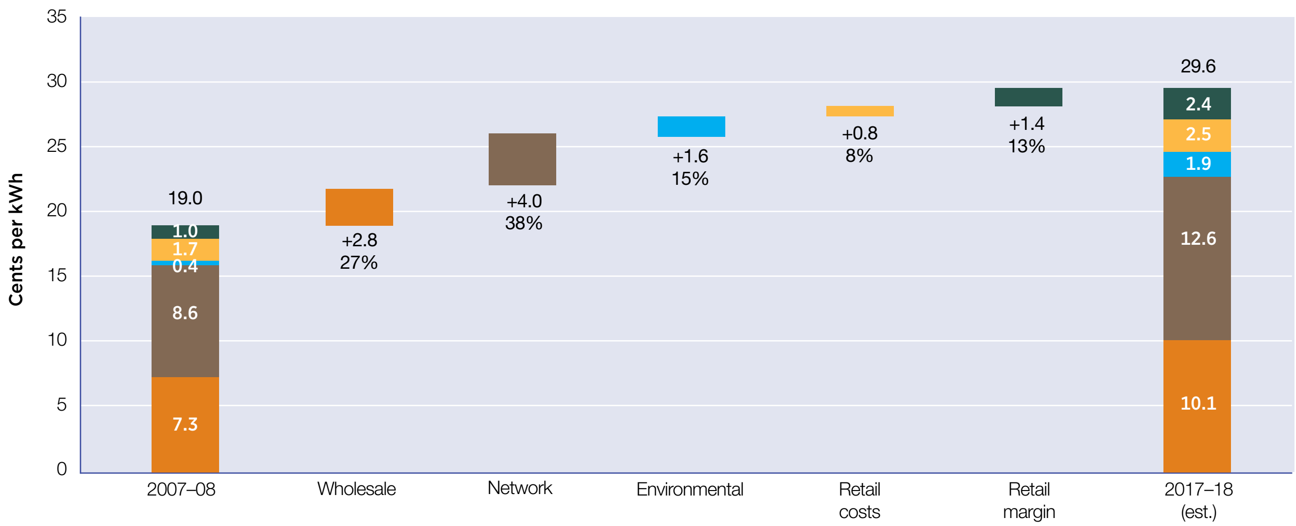
Network costs were the largest driver of retail *electricity* prices over the 10 years to 30 June 2018, accounting for 38 per cent of the growth in retail electricity prices across the NEM. Network costs rose most sharply from 2007–15, when network businesses invested heavily in new assets and financial 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.

More recently, weaker electricity demand has eased operating costs and delayed network expansions. Improved financial market conditions further moderated cost pressures on the networks. In these conditions, networks require less revenue to operate efficiently, and the impacts on retail bills have moderated accordingly (chapter 3).

Wholesale costs (including hedging costs to insure against spot market volatility) accounted for 27 per cent of electricity price rises across the NEM, and have been the main driver of rising electricity prices since 2016.

Figure 1.5

Change in average residential electricity customer prices in the NEM



kWh, kilowatt hour.

Note: Based on effective unit charges paid by residential customers. Data is inflation adjusted, in 2016–17 dollars, and excludes GST. 2017–18 data are estimates.

Source: ACCC, *Restoring electricity affordability and Australia's competitive advantage, Retail Electricity Pricing Inquiry—Final report*, June 2018, p. 7.

Environmental costs contributed 15 per cent to the increase in retail electricity prices over the past decade, for reasons including:

- increases in the price of certificates 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 8 per cent and 13 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 overall retail cost increase. Retail margins rose most significantly in NSW and Victoria, and fell in South Australia.

Gas

In *gas*, rising wholesale gas costs contributed around 57 per cent of retail price increases from 2007 to 2017 (figure 1.6). Much of the rise in wholesale costs occurred since 2015.

Retail costs (including margin) 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.

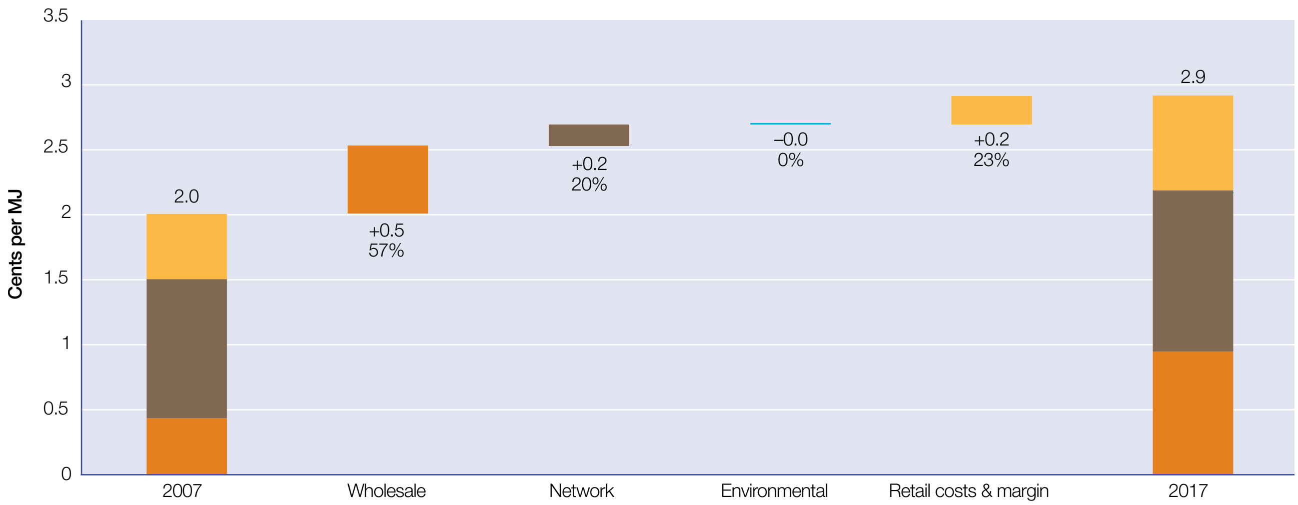
Network costs accounted for around 20 per cent of the increase. They were the largest contributing element in Queensland, South Australia, Tasmania and the ACT. As for electricity networks, increased debt costs due to financial market instability were a significant driver. More recently, gas pipeline charges eased in NSW (2015) and South Australia (2016) (chapter 5).

1.6.4 CPI data on retail energy prices

The ABS tracks movements in energy prices for metropolitan households as an input to the consumer price index (figures 1.7 and 1.8). Electricity prices began to track significantly higher in real terms from around 2008, and rose by around 10 per cent each year (13 per cent in nominal terms) over the five years to June 2013. Prices peaked nationally in March 2014 before easing as a result of falling network costs, an oversupply of generation capacity and the removal of carbon pricing.

Between March 2014 and June 2016, real prices fell by around 6 per cent nationally, with the steepest falls occurring in Canberra and Sydney. Brisbane was the only city to experience price rises over this period, reflecting a delayed

Figure 1.6
Change in average residential gas customer prices in the NEM



MJ, megajoule
Note: Data are estimates at 2017. Average residential customer prices excluding GST (real 2014–15 dollars).
Source: Oakley Greenwood, *Gas Price Trends Review 2017*, March 2018.

pass through of network cost increases, rising gas fuel costs, and costs associated with the Solar Bonus Scheme.

The national trend of declining real prices reversed in 2016, when high electricity wholesale prices began to flow through into retail prices in most cities. A new peak national average retail electricity price level was recorded in June 2018, though prices fell marginally in Brisbane and Hobart.

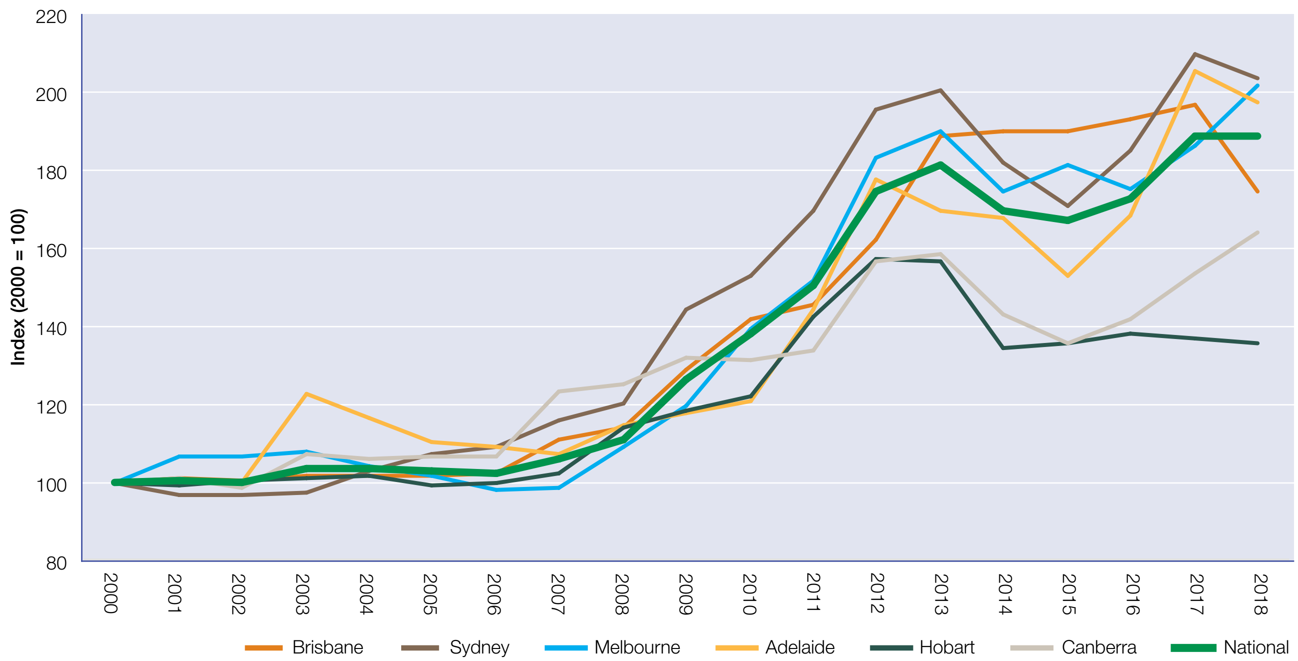
Retail gas prices rose by an average of 7 per cent per year in real terms over the five years to 2012–13 (10 per cent in nominal terms). Prices continued to rise strongly in Sydney, Adelaide and Canberra until new access arrangements lowered gas pipeline charges (2014–15 in Sydney and 2015–16 in the other cities). But prices in those regions have trended upwards since that time. Gas prices in Melbourne dipped following the removal of carbon pricing in 2014, but have overall trended higher. Retail prices in the small residential markets of Brisbane and Hobart were relatively stable. Gas prices at June 2018 were at record levels in all cities except Sydney and Adelaide (which had peak prices in 2015 and 2016 respectively).

1.6.5 International electricity prices

Figure 1.9 compares average Australian household electricity prices with European countries (which historically have had some of the highest electricity prices internationally), based on purchasing power parity. This measure adjusts for differences in the cost of living across countries.

Australian electricity prices were traditionally low by global standards. But increases over the past decade mean average Australian prices are now around 10 per cent above the European average.

Figure 1.7
Electricity retail price index (inflation adjusted)



Note (figures 1.7 and 1.8): Consumer price index electricity and gas series for each region, deflated by the consumer price index for all groups. Data at September quarter each year.

Source (figures 1.7 and 1.8): ABS, *Consumer price index*, cat. No. 6401.0, various years.

Figure 1.8
Gas retail price index (inflation adjusted)

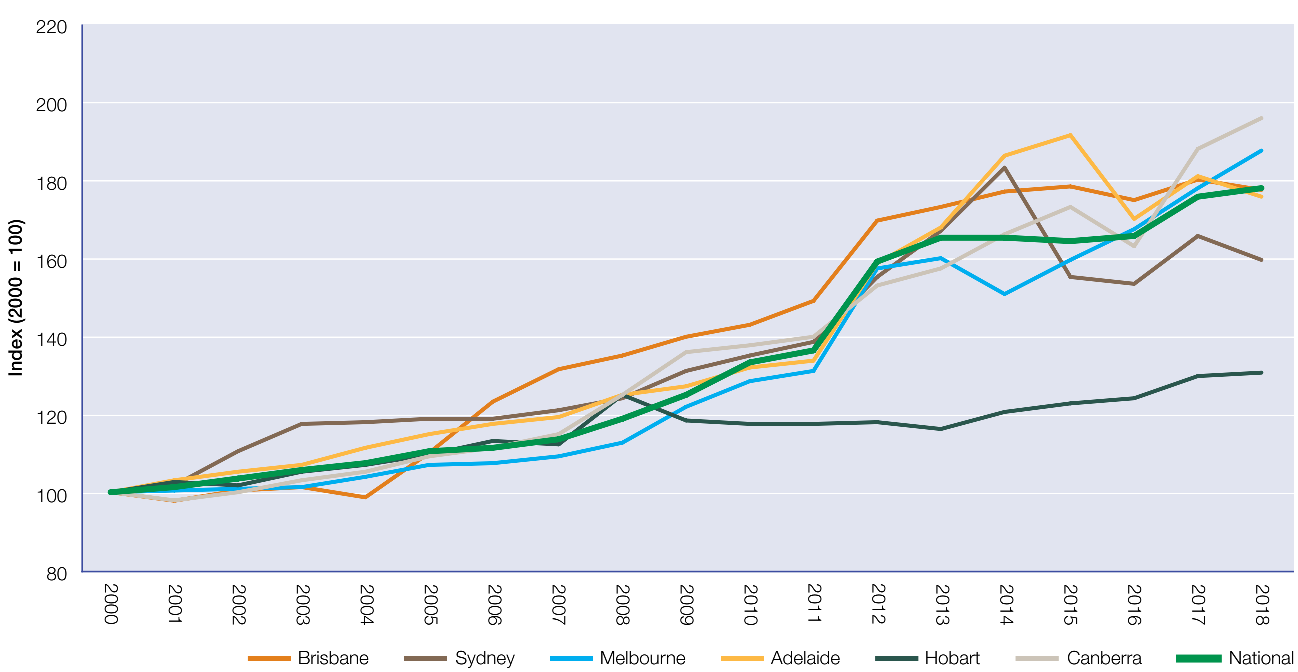
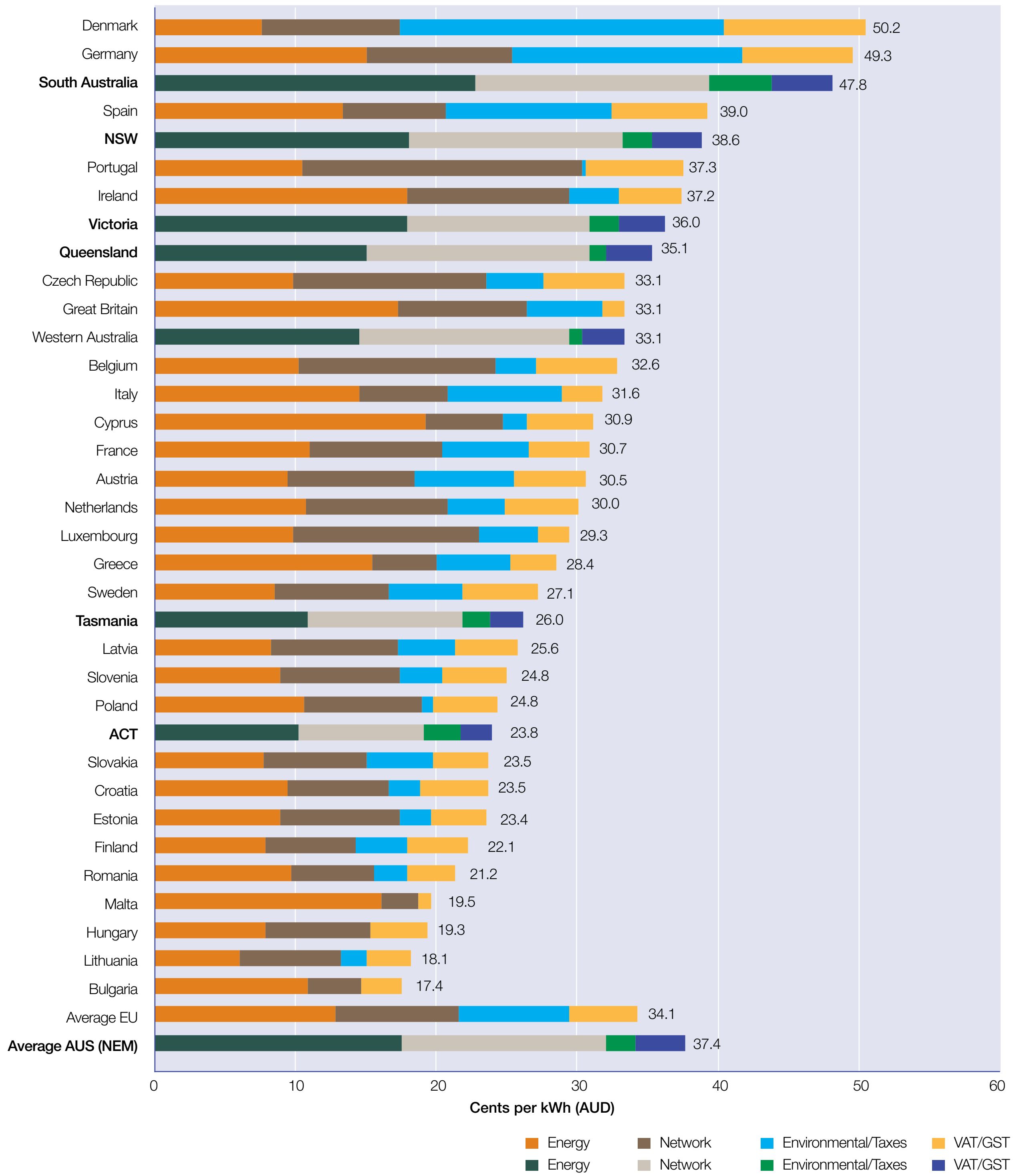


Figure 1.9

International household electricity price comparison



c/kWh, cents per kilowatt hour.

Note: 2018 prices, including GST.

Source: ACCC, *Restoring electricity affordability and Australia's competitive advantage, Retail Electricity Pricing Inquiry—Final report*, June 2018, p. 24.

1.7 Competition in retail energy markets

The AEMC found competition is effective for electricity markets in south east Queensland, NSW, Victoria and South Australia. These markets have characteristics consistent with competitive markets, including high levels of offers, marketing, and customer switching. Barriers to entry are considered low, as evidenced by regular new entry (though contract market issues in South Australia mean barriers are higher in that market). Market concentration has also been falling in these regions, albeit slowly.

Effective competition has yet to emerge in electricity retail markets in the ACT, Tasmania and regional Queensland. The small size of these markets and continued price regulation have potentially contributed to the limited entry of new retailers. Further, 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) makes new entry extremely difficult.

Overall, gas markets are less competitive than electricity markets given the smaller market scale, and difficulties in sourcing gas and pipeline services in some regions. Gas markets in each region are generally more concentrated than electricity markets.

Despite findings of effective competition in some regions, recent assessments have found retail energy markets are not delivering the expected benefits for consumers. The ACCC 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'.[16] Similarly, the AEMC found 'competition in the retail energy market … is currently not delivering the expected benefits to consumers'.[17]

Customer satisfaction with competition in national energy retail markets declined over the year to April 2018. Consumer trust was 39 per cent (down from 50 per cent), and only 25 per cent of consumers were confident the market was working in their interests (down from 35 per cent).[18]

16 ACCC, *Restoring electricity affordability and Australia's competitive advantage, Retail Electricity Pricing Inquiry—Final report*, June 2018, p. 134.

17 AEMC, *2018 Retail energy competition review, final report*, June 2018, p. i.

18 AEMC, *2018 Retail energy competition review, final report*, June 2018, p. vii.

Assessments of the state of competition in retail energy markets should account for a range of indicators, including:

- market concentration and vertical integration
- customer engagement and activity in the market
- retailer behaviour
- product and price differentiation
- competitive pricing.

1.7.1 Market concentration

More than 30 authorised retailers supply small energy customers in southern and eastern Australia (table 1.1). But the retail brands of three businesses—AGL Energy, Origin Energy and EnergyAustralia (the 'big three')—supply over 68 per cent of small electricity customers and 75 per cent of small gas customers (figures 1.10 and 1.11).

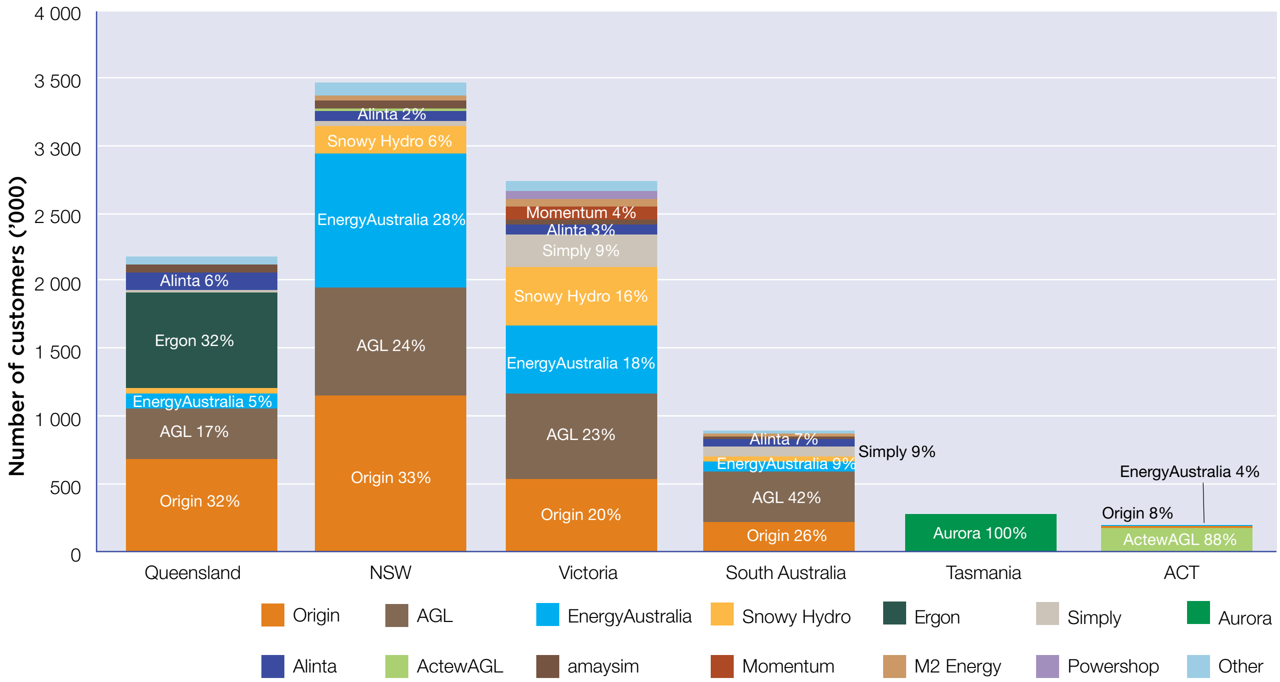
Among the major electricity markets, NSW is the most concentrated. The 'big three' account for 85 per cent of NSW electricity customers. Snowy Hydro (through its Red Energy and Lumo brands) accounts for another 6 per cent of customers. The other 23 retailers competing in NSW have just 9 per cent of the market between them.

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 92 per cent of retail gas customers.

Markets with price regulation are even more concentrated. The dominant retailer in those regions is typically a government owned (or part owned) business with limited operation outside its home region. ActewAGL (a joint venture between the ACT Government and AGL Energy) supplies almost 90 per cent of ACT electricity and gas customers. In Tasmania, Aurora Energy (Tasmanian Government owned) is the only retailer offering electricity to households, but small businesses can also choose ERM Power Retail, which entered the market in 2014. Ergon Energy (Queensland Government owned) supplies most small customers in rural and regional Queensland.

Smaller retailers continue to gain market share from the big three, increasing their market share across the NEM from 28 per cent in 2016 to 33 per cent in 2018. Smaller retailers have had most success in Victoria, where they supply almost 40 per cent of small electricity customers and 32 per cent of small gas customers. This outcome reflects the more mature retail market in Victoria, where prices for gas and electricity were deregulated in 2009.

Figure 1.10
Electricity retail market share (small customers)



Note (figures 1.10 and 1.11): Includes residential and small business customers. All data at June 2018, except Victoria (June 2017).

Source (figures 1.10 and 1.11): AER, *Retail energy market performance report*, December 2018; ESC, *Victorian energy market report 2016–17*, November 2017

1.7.2 Vertical integration

Governments structurally separated the energy supply industry in the 1990s into separate wholesale, network and retail businesses. In electricity, however, many retailers and generators 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, so they have less need to hedge their positions in futures (derivatives) markets. This strategy may be efficient for the business, but can drain liquidity from derivatives markets, posing a barrier to entry or expansion for retailers that are not vertically integrated.

In the NEM, AGL Energy, Origin Energy and EnergyAustralia each have significant market share in both generation and retail markets (figure 1.12). The three businesses:

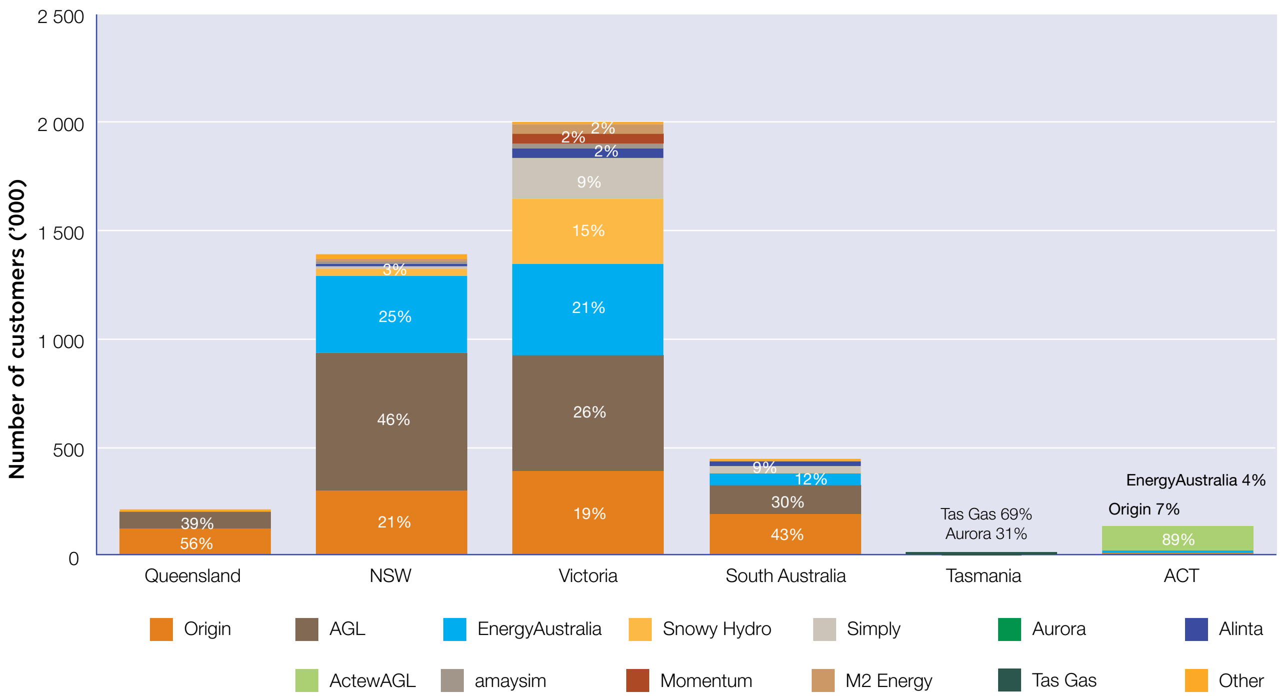
- increased their market share in electricity generation from 17 per cent in 2011 to 45 per cent in 2018
- owned or controlled almost 70 per cent of new generation that entered the market between 2011 and 2017
- supplied over 66 per cent of small electricity customers and 77 per cent of small gas customers in southern and eastern Australia in June 2018.

The businesses also have interests in upstream gas production and storage, complementing their interests in gas fired electricity generation and energy retailing, though some have been scaling back those interests.

Outside the 'big three' retailers, a number of former stand-alone electricity generators established retail arms. The businesses include Engie (which established Simply Energy), Alinta, ERM Power, Meridian Energy (Powershop) and Pacific Hydro (Tango). Government owned generators are also vertically integrated. Snowy Hydro (Australian Government) owns the retailers Red Energy and Lumo Energy, while Hydro Tasmania (Tasmanian Government) owns Momentum Energy.

Few retailers have managed to build a significant electricity customer base without some internal generation capacity. The largest stand-alone electricity retailers operating in the

Figure 1.11
Gas retail market share (small customers)



Note and Source: See figure 1.10.

NEM are amaysim (trading under its own name and as Click Energy) and M2 Energy (trading as Dodo Power and Gas, and Commander Power and Gas) with 1.4 and 1.1 per cent of small customers across the NEM respectively.

1.7.3 Customers with market contracts

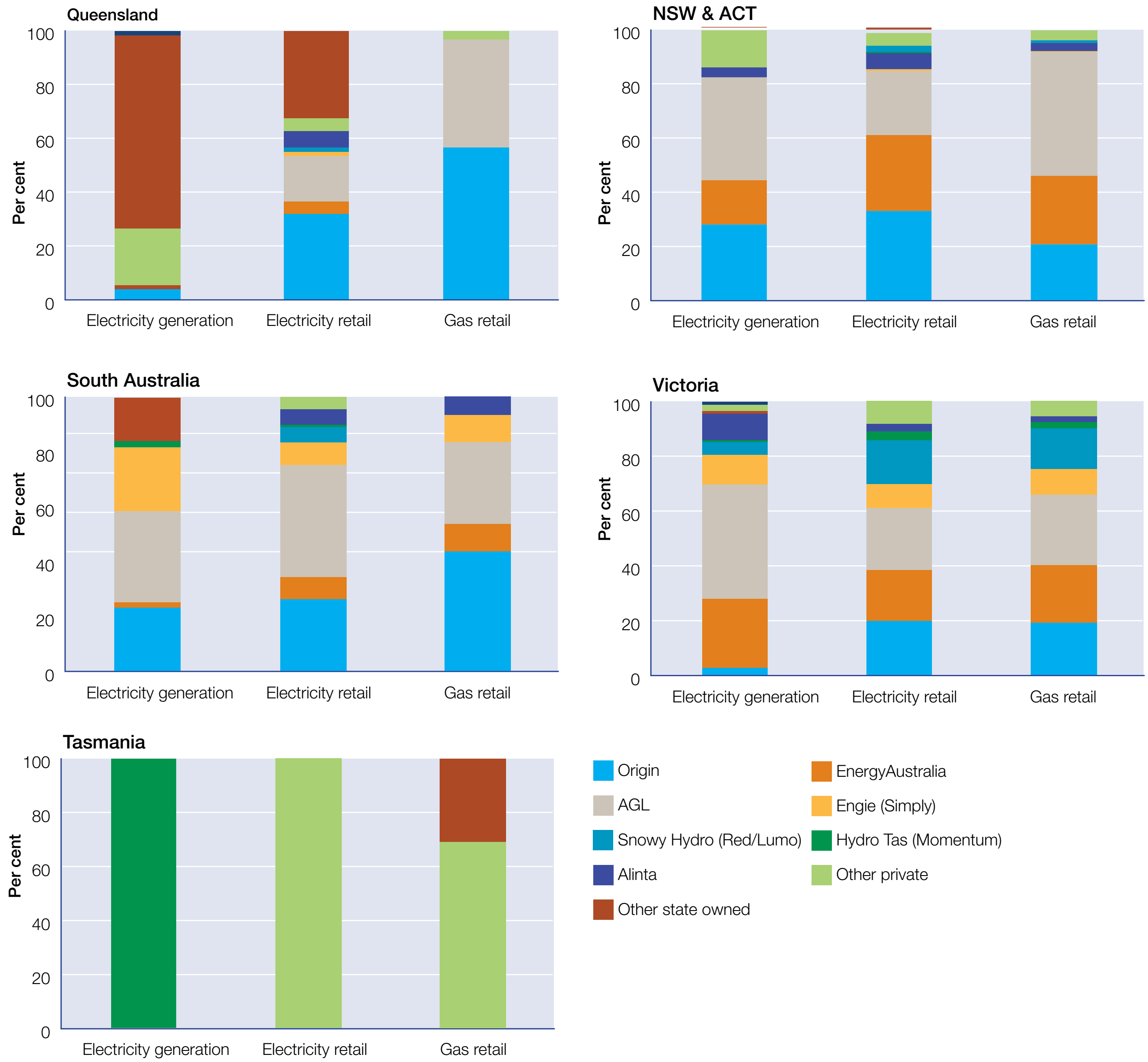
Energy customers are free to enter a market contract with their retailer of choice (figure 1.13). Market contracts allow retailers to tailor their energy offers, subject to meeting regulated requirements. A contract may be widely available or only offered to specific customers. Retailers can shape their 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 (as offered by GreenPower). Retailers must obtain explicit informed consent from a customer before entering a market contract.

Customers without a market contract are placed on a *standing offer* with the retailer that most recently supplied energy at their premises (or for new connections, with a retailer designated for that geographic region). A standing offer is a basic contract with prescribed terms and conditions that the retailer cannot change. It provides a full suite of protections to customers 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. Standing offers have regulated prices set by state or territory governments for electricity in Tasmania, the ACT and regional Queensland. In other jurisdictions for electricity, and in all regions for gas, retailers can set their own standing offer prices.

Victoria, the first state to fully deregulate its energy market, has the highest rate of energy customers on market contracts at around 93 per cent (figure 1.14). South Australia has almost 90 per cent of customers on market offers, which may reflect customers in South Australia searching for cheaper contracts, given the relatively high price of electricity.

In NSW, the shift towards market contracts accelerated after electricity prices were deregulated in 2014, with around 85 per cent of customers on market contracts (up from 76 per cent in 2016). Similarly, the uptake of

Figure 1.12
Vertical integration in NEM jurisdictions

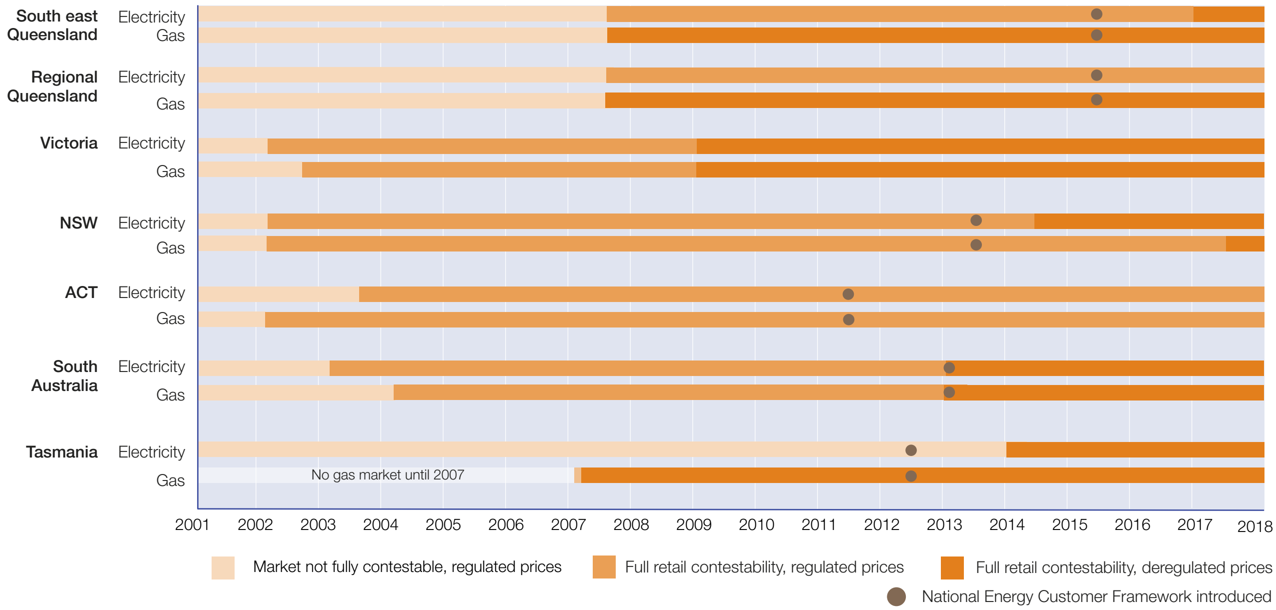


Note: Electricity generation market shares are based on generation capacity owned or controlled at January 2018. Retail market shares are based on number of small customers at June 2018, except Victoria (June 2017).

Source: Retail: AER, *Retail energy market performance report*, December 2018 and ESC, *Victorian energy market report 2016–17*, November 2017. Electricity generation: AER, *Wholesale electricity market performance report*, December 2018.

Figure 1.13

Progress towards customer choice



market contracts in south east Queensland increased after deregulation. Over 80 per cent of customers have switched to a market offer, up from 70 per cent in 2016.

In regional Queensland, Tasmania and the ACT, a minority of customers are on market contracts. ACT has around 40 per cent of customers on market contracts, with recent increases following EnergyAustralia and Origin entering the market. In Tasmania, less than 10 per cent of electricity customers are on a market contract. This figure is lower than in previous years, with some customers opting to revert to the regulated standing offer electricity price.

1.7.4 Customer awareness and engagement

The AEMC reported in 2017 that over 90 per cent of customers in jurisdictions with retail competition were aware they had a choice of retailer.[19] But many customers do not actively participate in the market because they find it confusing and difficult to compare plans. Research for the ACCC found 14 per cent of customers were on a standing offer for an entire 9–13 months survey period in 2017–18.[20]

A range of factors can limit a customer's ability to engage in the market. These include language barriers, cultural background, disabilities, and family violence issues. Low income consumers may lack confidence in finding the best deal for them, and face concerns switching retailers will result in loss of benefits, increased debt, and exit or reconnection fees. Around 19 per cent of customers earning less than $25 000 a year are on a standing offers, compared with 14 per cent across all customers.[21]

Customers who do switch are often unaware when benefits provided through their market offer—such as price discounts—change or end. Large increases in their bills can occur when discounts or favourable terms end. Reforms introduced in 2018 require retailers to notify small electricity and gas customers before any change in their benefits, to alert them to expired benefits. From September 2018 retailers must also provide advance notice of any price change under an existing contract.

Customers are more widely using price comparator websites to reduce bill shock and manage market complexity. Despite this, awareness of independent government comparator websites Energy Made Easy and Victorian Energy Compare remains low.

Commercial switching websites and services are emerging as a way for customers to access better offers with minimal

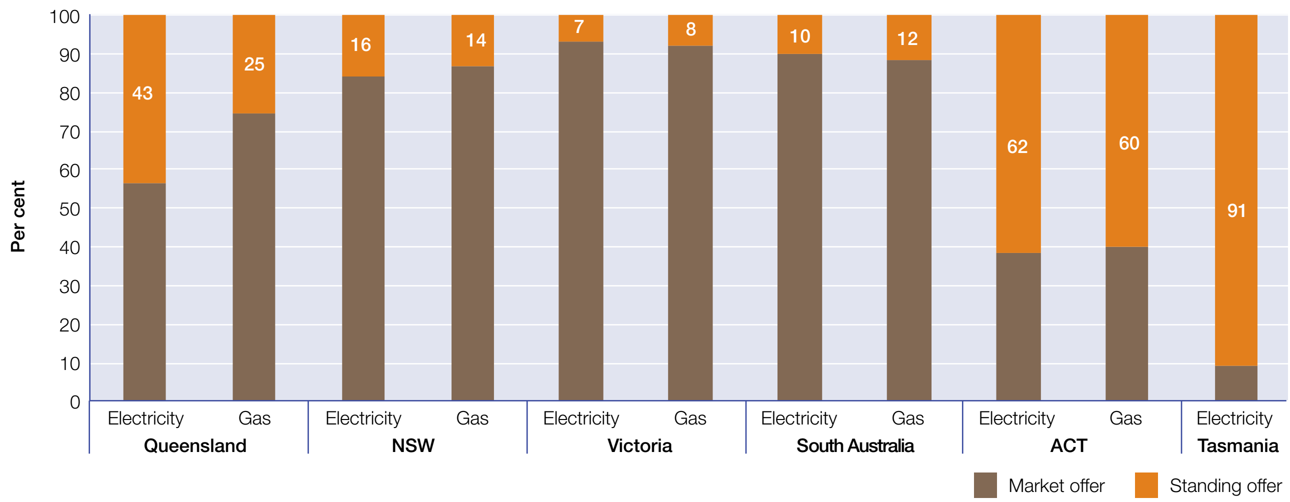
19 AEMC, 2017 Retail energy competition review, final report, June 2017, p. ii.

20 Colmar Brunton, Consumer outcomes in the National Retail Electricity Market, final report for the ACCC, June 2018, p. 30.

21 Colmar Brunton, Consumer outcomes in the National Retail Electricity Market, final report for the ACCC, June 2018, p. 10.

Figure 1.14

Small customers on market and standing contracts, 2018



Note: Standing and market offer shares are based on the number of small customers at June 2018, except Victoria (June 2017). Queensland electricity numbers include customers in regional Queensland who largely remain on standing offers. In south east Queensland (where prices are deregulated), we estimate over 80 per cent of electricity customers are on a market contract.

Source: AER, *Retail energy market performance report*, December 2018; AEMC, *2018 Retail energy competition review, final report*, June 2018.

engagement. But there are risks to consumers in relying on commercial services to navigate energy retail markets (section 1.7.8).

Customer understanding of the market

Customer understanding of the market remains low. The AEMC reported residential customers' confidence in their ability to make good choices in the gas and electricity markets fell to 58 per cent in 2018. Customer confidence that easily understood information is available dropped below 50 per cent in all regions except Queensland.[22] The Queensland result may reflect significant consumer education following price deregulation in that state.

A lack of confidence inhibits customers from seeking out the best offer for their circumstances. In 2018 reforms to help customers make informed decisions were introduced. The reforms prohibit retailers from discounting off rates above their standing offer, and improve summary contract and pricing information that must be provided to customers (including a requirement to show indicative bills for different household sizes).

Market developments, including the rollout of smart metering and cost reflective tariffs, are likely to make it harder for consumers to confidently engage in the market without better tools for comparing offers. The COAG Energy Council and Energy Security Board are developing a framework to increase the availability of and access to electricity data to support customer decision making.[23]

Customer satisfaction

Customers' satisfaction with retail energy markets depends on factors including price, value for money, reliability, customer service of their retailers, confidence in engaging with the market, technology uptake, and ability to switch.

Residential customers' overall satisfaction with their energy supply arrangements fell in Victoria, the ACT and Tasmania in 2018. Satisfaction was around 70 per cent across most regions, but slightly lower in South Australia and Tasmania.[24] Satisfaction with the value for money of energy was down across most regions in 2018, at 40–50 per cent for electricity and 50–65 per cent in gas.

These results are well below those for other industries including phone, internet, insurance, water and banking. The drop in satisfaction followed large energy price increases in most regions.

Higher retail energy prices in 2017 and 2018 negatively affected customer views about the state of competition and

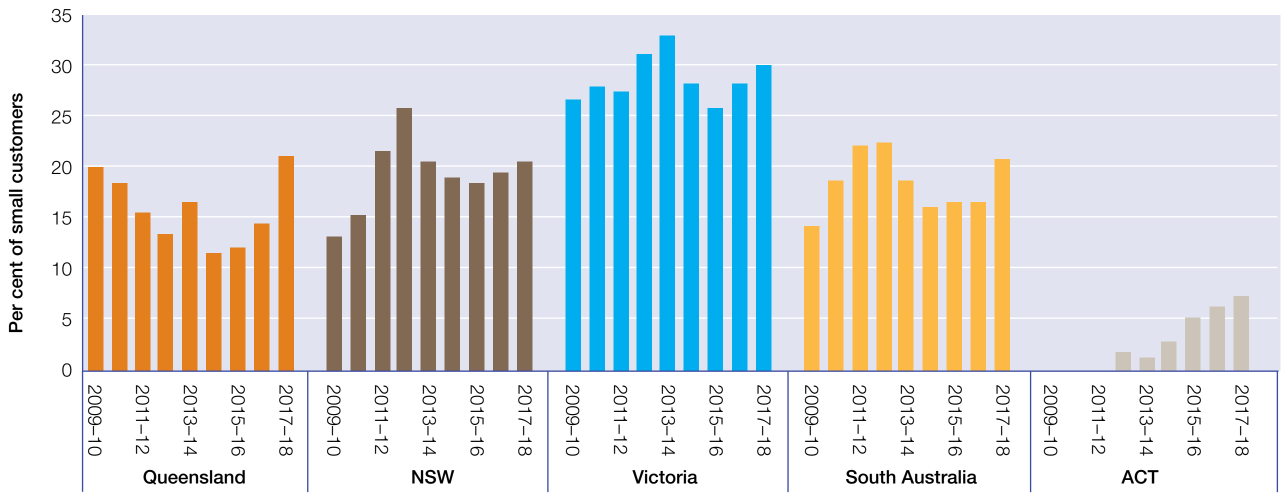
22 AEMC, *2018 Retail energy competition review, final report*, June 2018, p. 90.

23 COAG Energy Council, *Facilitating Access to Consumer Energy Data, consultation paper*, March 2018.

24 ECA, *Energy consumer sentiment survey*, June 2018, p. 14.

Figure 1.15

Small electricity customer switching



Note (figure 1.15 and 1.16): Total annual customer switches in a financial year divided by average customer numbers.

Source (figure 1.15 and 1.16): Customer switches: AEMO, MSATS transfer data to June 2018 and gas market reports, transfer history to June 2018; customer numbers: estimated from energy retail performance reports by the AER and the ESC (Victoria).

operation of the market, which are largely tied to views on value for money. Customer satisfaction with competition fell sharply between 2017 and 2018 in most regions. Satisfaction was highest in south east Queensland (53 per cent) and Victoria (50 per cent). Satisfaction in other regions ranged from 45 per cent in NSW to 9 per cent in Tasmania.[25] Customer confidence the market is working in the long term interests of customers also fell in most regions, to an average of 25 per cent in April 2018.[26]

Customer switching

The rate at which customers switch retailers can indicate their level of engagement in the market. However, these statistics must 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.

Small customer switching increased in 2017–18 in all regions for both electricity and gas customers, except gas customers in Queensland (figures 1.15 and 1.16). This shift coincides with higher prices and increased media scrutiny of the sector.

Residential customers typically switch retailer because they are dissatisfied with value for money or have searched for a better plan on a price comparison website. In South Australia, being approached by a retailer is the most common reason for switching.[27] For business customers, wanting or being offered a better price is the leading factor driving switching.[28]

Electricity switching by small customers was around 23 per cent in 2017–18, and has gradually increased across the NEM since 2014–15. Victoria remains the most active region, with 30 per cent of customers switching in 2017–18. Price spreads in energy offers tend to be higher in Victoria than elsewhere, meaning the potential savings from switching are often greater. A 2018 Victorian Government initiative of a $50 payment to households for visiting the government comparator website, Victorian Energy Compare, will likely drive higher switching activity in 2018.[29]

The largest rise in consumer switching in 2017–18 was in south east Queensland following Alinta's entry into the market, with 21 per cent of customers switching (compared with 14 per cent in 2016–17). The ACT continues to have the lowest switching rates, due to the market's lack of competition, small scale, continued price regulation, and the dominance of the incumbent retailer ActewAGL. But it

25 ECA, *Energy consumer sentiment survey*, June 2018, p. 18.

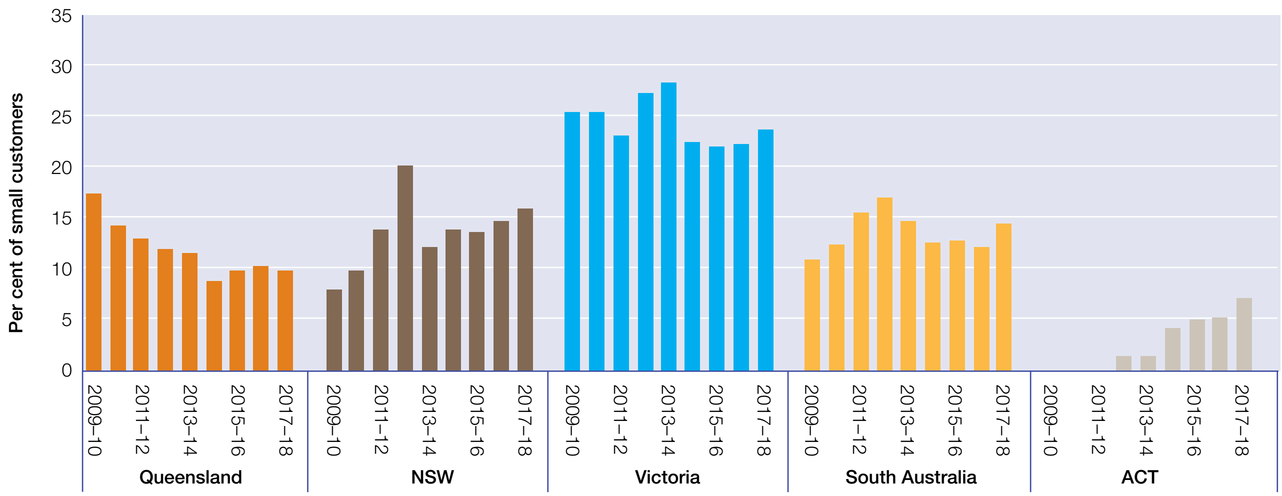
26 AEMC, *2018 Retail energy competition review, final report*, June 2018, p. 91.

27 AEMC, *2018 Retail energy competition review, final report*, June 2018, p. 99.

28 AEMC, *2018 Retail energy competition review, final report*, June 2018, p. 118.

29 Victorian Premier, Daniel Andrews, Busting energy bills with new $50 power savings bonus, media release, July 2018.

Figure 1.16
Small gas customer switching



Note and source: see figure 1.15.

recorded its highest switching rates in 2017–18, at 7 per cent of customers.

Switching rates are lower in gas (averaging around 15 per cent in 2017–18), though rates rose following several stable years. Less active customers in this market may reflect a lower number of retailers participating in gas, meaning less choice and savings available for customers.

Small business customers switched at a similar rate to residential customers in electricity, but higher rates for gas (around 30 per cent).[30]

While overall switching activity is strong, activity is uneven across the customer base. A significant number of customers have never switched retailer. These customers may be satisfied with their current supplier and energy prices, lack trust in the market or lack confidence in making good decisions.

The ECA reported in December 2017 that over a third of customers have never switched. Victoria had the smallest number of customers in this category (32 per cent), followed by South Australia (37 per cent) and NSW (42 per cent). Tasmania and the ACT had the most customers who had never switched (91 per cent and 74 per cent respectively).[31] These outcomes are consistent with other measures of customer engagement.

In most markets, engagement by even a limited number of customers can drive lower prices and product improvements that benefit all consumers. But in energy markets, retailers can easily identify inactive customers and price discriminate against them. 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.

1.7.5 Retailer activity

Changes in retailer marketing activity can impact the level of customer switching. Around 39 per cent of residential customers were directly approached by a retailer in 2017, well down from the peak of 53 per cent in 2014.[32] This outcome reflects a move away from door-to-door sales by larger retailers, following enforcement in this area. However, retailers have been more active in approaching businesses, with a 30 per cent increase in contact in 2018 from 2017.[33] Most of these contacts were in the form of a phone call by the retailer.

Retailers appear to be focusing more on retaining existing customers than expanding their customer base. This strategy—referred to as 'saves' and 'win backs'—involves

30 AEMC, *2018 Retail energy competition review, final report*, June 2018, p. 121.
31 ECA, *Energy consumer sentiment survey*, December 2017, p. 32.
32 AEMC, *2018 Retail energy competition review, final report*, June 2017, p. 89.
33 AEMC, *2018 Retail energy competition review, final report*, June 2018, p. 112.

a retailer offering better deals specifically to customers that have initiated or recently completed a switch to another retailer. The big three retailers have been prominent in making retention offers, which are often cheaper than other available offers.[34] These retailers have relatively large numbers of 'sticky' customers (those who rarely switch), and so have an incentive to retain those customers they consider to be high value. However, the AEMC found smaller retailers are also using this strategy.[35]

The use of digital acquisition channels, including retailers' own websites and price comparison websites, is also growing (section 1.7.8).

While most retailers operate across multiple regions, less than half of electricity retailers operating in south east Queensland, NSW, Victoria and South Australia are active in all four regions. The gas market is even more segregated, with most retailers concentrating on the NSW and Victorian markets.

Since 2017 two new retailers began selling energy, and 10 existing retailers expanded in to new regional markets. The most prominent was Alinta's entry into south east Queensland through a joint venture with the state owned generator CS Energy.

Minimal retailer activity in some markets may reflect perceived barriers to entry or expansion. Retailers commonly cite price regulation and the dominance of incumbent retailers as barriers to entry in some jurisdictions. Limited access to competitively priced risk management contracts for electricity is seen as a significant barrier to entry in South Australia in particular. Regulatory risk was identified as a concern in Victoria (whose retail market operates outside the national framework).[36]

In gas, retailers identified issues with sourcing gas, the small size of the customer base, and the price of gas as barriers to entry and expansion. Other barriers included access to pipeline capacity and state based regulatory issues such as licensing requirements. Recent reforms sought to reduce these barriers by increasing transparency in the gas market, and creating a new a dispute resolution mechanisms to improve access to pipeline capacity (chapter 4).

34 ACCC, *Restoring electricity affordability and Australia's competitive advantage, Retail Electricity Pricing Inquiry—Final report*, June 2018, p. 142.

35 AEMC, *2018 Retail energy competition review, final report*, June 2018, p. 32.

36 AEMC, *2018 Retail energy competition review, final report*, June 2018, pp. 31, 37, 41.

1.7.6 Product differentiation

In a competitive market, retailers offer a range of products and services to attract and retain customers. Energy retailers compete by discounting (section 1.7.7), bundling offers (such as for electricity, gas, phone, internet, pool services), varying contract terms (length and fixed price periods), and offering other incentives (such as sign-up discounts and subscriptions).

Despite the range of offers, most use a basic two-part price structure—a daily supply charge plus a flat consumption charge, though the relative size of these components varies. Most retailers also offer tariffs that charge consumers different prices depending on the time of day or week that electricity is consumed.

Other products offered in the market range from pool pass through arrangements (where the customer takes on the risk of wholesale market volatility) to fixed price contracts (where the customer pays a fixed amount regardless of how much energy they use). Retailers also differentiate their products through 'add-on' services, such as systems to allow customers to track and control their energy use (section 1.8).

New service providers are applying some competitive pressure to traditional retailers through product differentiation, with a focus on new products and services. Over 100 energy businesses offer solar power purchase agreements in jurisdictions applying the Retail Law, for example. Further waves of new products and offers may emerge once battery storage systems become more affordable, and as accessibility of consumer energy data improves.

1.7.7 Price differentiation

Price competition between retailers generally plays out through 'headline' discounts. Across the NEM, 80 per cent of market offers have a discount, around two thirds of which are conditional on the customer meeting terms such as paying on time, e-billing, or paying by direct debit.[37]

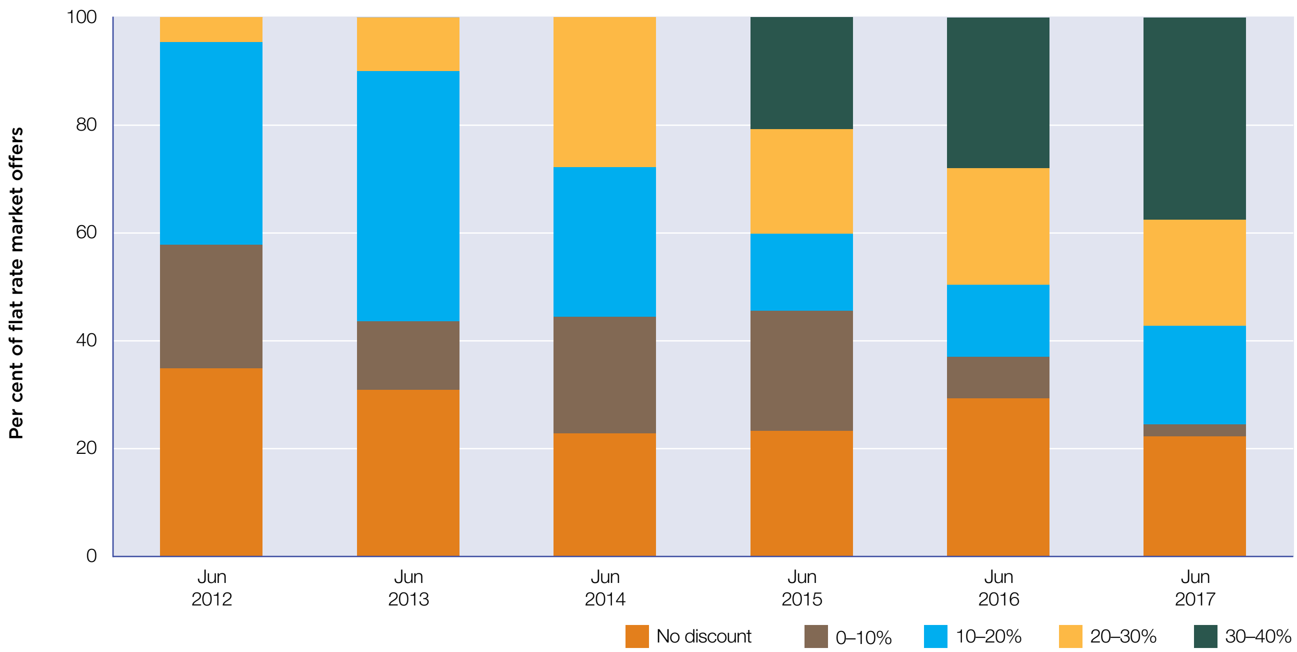
Discounting in market offers has risen. In Victoria, for example, the most common level of discount in 2017 was 30–40 per cent, up from 10–20 per cent in 2012 (figure 1.17). The size of discount offers continued to rise in 2018 for both electricity and gas in most regions.

Discounting has resulted in significant price diversity within individual retailers' offers and across retailers, and increased

37 AEMC, *2018 Retail energy competition review, final report*, June 2018, p. 54.

Figure 1.17

Conditional headline discounts for single rate residential market offers in Victoria



Note: Advertised discounts in generally available market offers.

Source: ACCC, *Restoring electricity affordability and Australia's competitive advantage, Retail Electricity Pricing Inquiry—Final report*, June 2018, p. 257.

the gap between standing and market offers. While the proportion of customers on standing offers is declining, the extent of discounting highlights the risk that customers who do not engage in the market or switch regularly may pay significantly higher prices.

Figures 1.18 and 1.19 set out prices under market and standing offers for residential electricity and gas customers from 2016–18. In Victoria, a retailer's market offers averaged 26–31 per cent lower than the same retailer's standing offer. In NSW, south east Queensland and SA, retailers' market offers averaged 14–19 per cent lower than standing offers, and in the ACT they were 11 per cent lower. A typical customer switching from an electricity standing offer to the best market offer with the same retailer could save $634–787 in Victoria, $416–517 in NSW, $555 in South Australia, $529 in south east Queensland, and $259 in the ACT.

The gap between the least and most expensive offers narrowed in NSW and South Australia in 2018 compared with 2017, but widened in other regions. Victoria had the widest dispersion, with prices under the most expensive standing offer being around 180 per cent higher than the cheapest market offer.

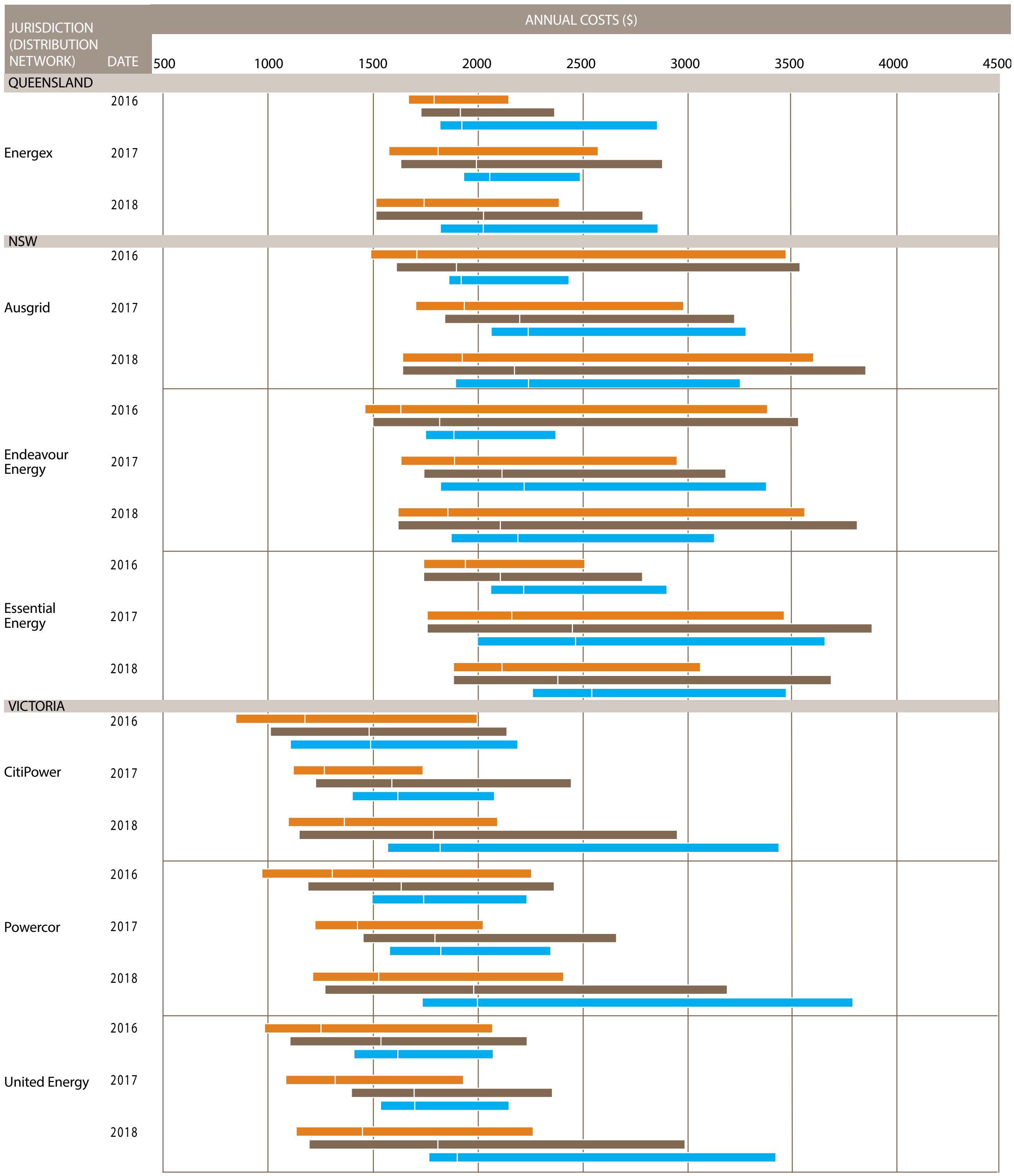
Discounts against standing offers were generally lower in gas than electricity offers in 2018. Gas discounts ranged from 3–7 per cent in Queensland to 18 per cent in Victoria. Annual bill spreads (highest versus lowest offer) ranged from $100–150 in Queensland to almost $1400 in Victoria. In NSW and South Australia the range was $300–350. As in electricity, gas price spreads in 2018 were generally wider than those observed a year earlier, other than in the ACT.

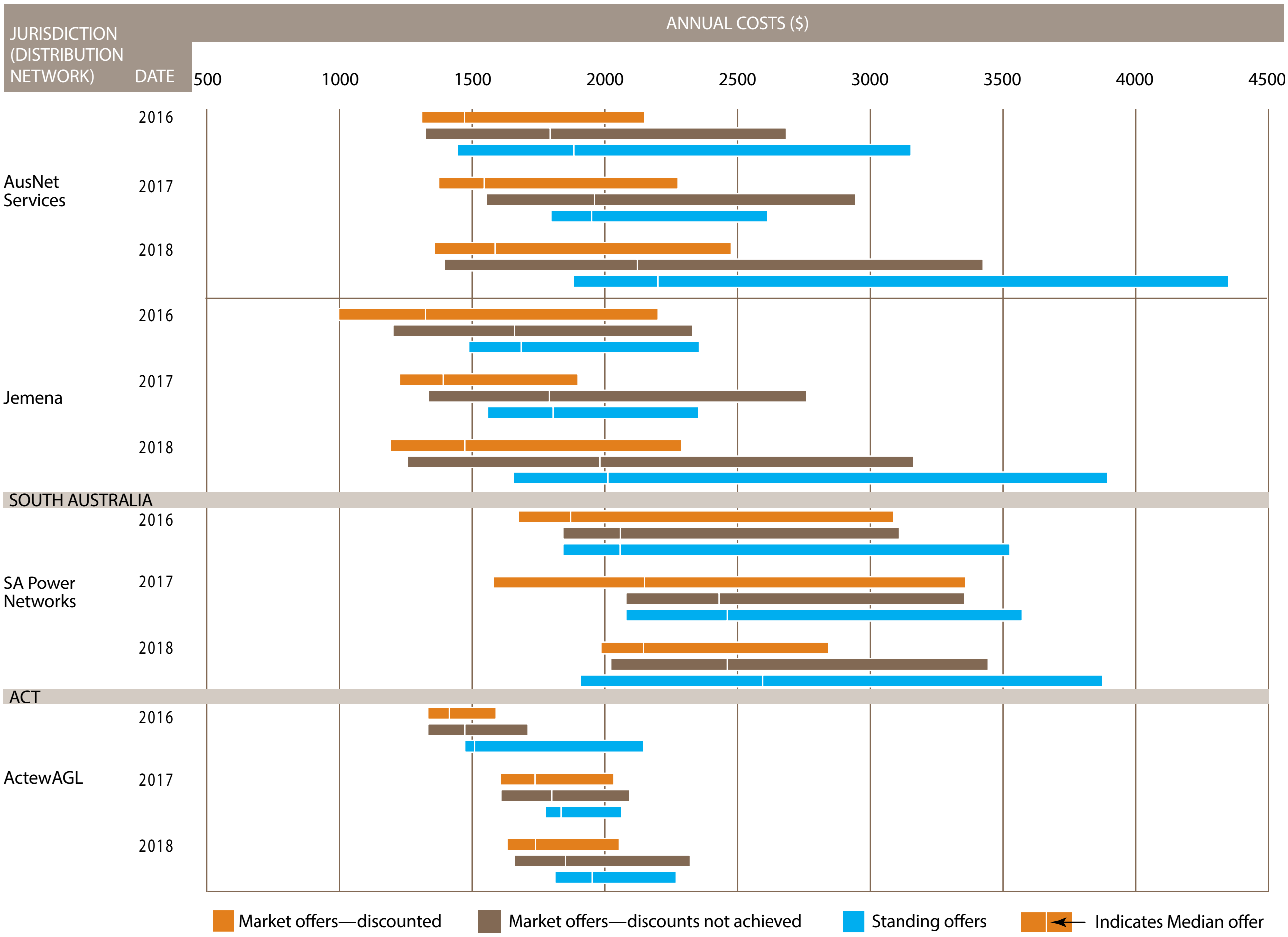
Navigating headline discounts

While price competition across retailers generally plays out through headline discounts, a large discount does not necessarily mean a low electricity price. The size of a discount may be deceiving, because retailers measure and apply discounts in different ways. Retailers set the base rate against which a discount is applied, making it difficult to compare effective prices. Further, some retailers apply discounts off the entire bill, while others only apply it to usage charges.

On average, customers on market contracts pay less than those on standing contracts, and a larger headline discount generally results in cheaper electricity. However, while Victorian customers on all discount tiers paid less than the standing offer price on average, customers on 'no discount'

Figure 1.18
Price diversity—electricity





Note (figures 1.18 and 1.19): Data includes all generally available offers for residential customers using a 'single rate' tariff structure at December 2016, December 2017 and August 2018. Annual bills based on average consumption in each jurisdiction: NSW 6130 kWh (electricity), 22 860 MJ (gas); Queensland 5950 kWh, 7870 MJ; Victoria 4810 kWh, 57 060 MJ; South Australia 5100 kWh, 17 500 MJ; ACT 7010 kWh, 42 080 MJ.

Source (figures 1.18 and 1.19): AER, Energy Made Easy (www.energymadeeasy.gov.au); Victoria Energy Compare (compare.energy.vic.gov.au).

market offers were typically better off than customers on offers with discounts of up to 20 per cent. And in NSW, customers on market offers with discounts up to 5 per cent typically paid more than those on standing offers.[38] These perverse outcomes highlight the often misleading nature of advertised discounts in retail energy market offers.

The range of prices across offers within each discounting tier also varies significantly. Some customers in Victoria on an offer with a 30 per cent or larger discount are paying more than some standing offer customers (figure 1.20), for example, despite the average price of offers in that discount tier being almost 29 per cent below the average standing offer price.

To improve comparability of offers, the ACCC recommended all discounting should be off a common 'reference bill'. The AER is developing a reference bill as part of its role in setting a default market offer price (section 1.5).

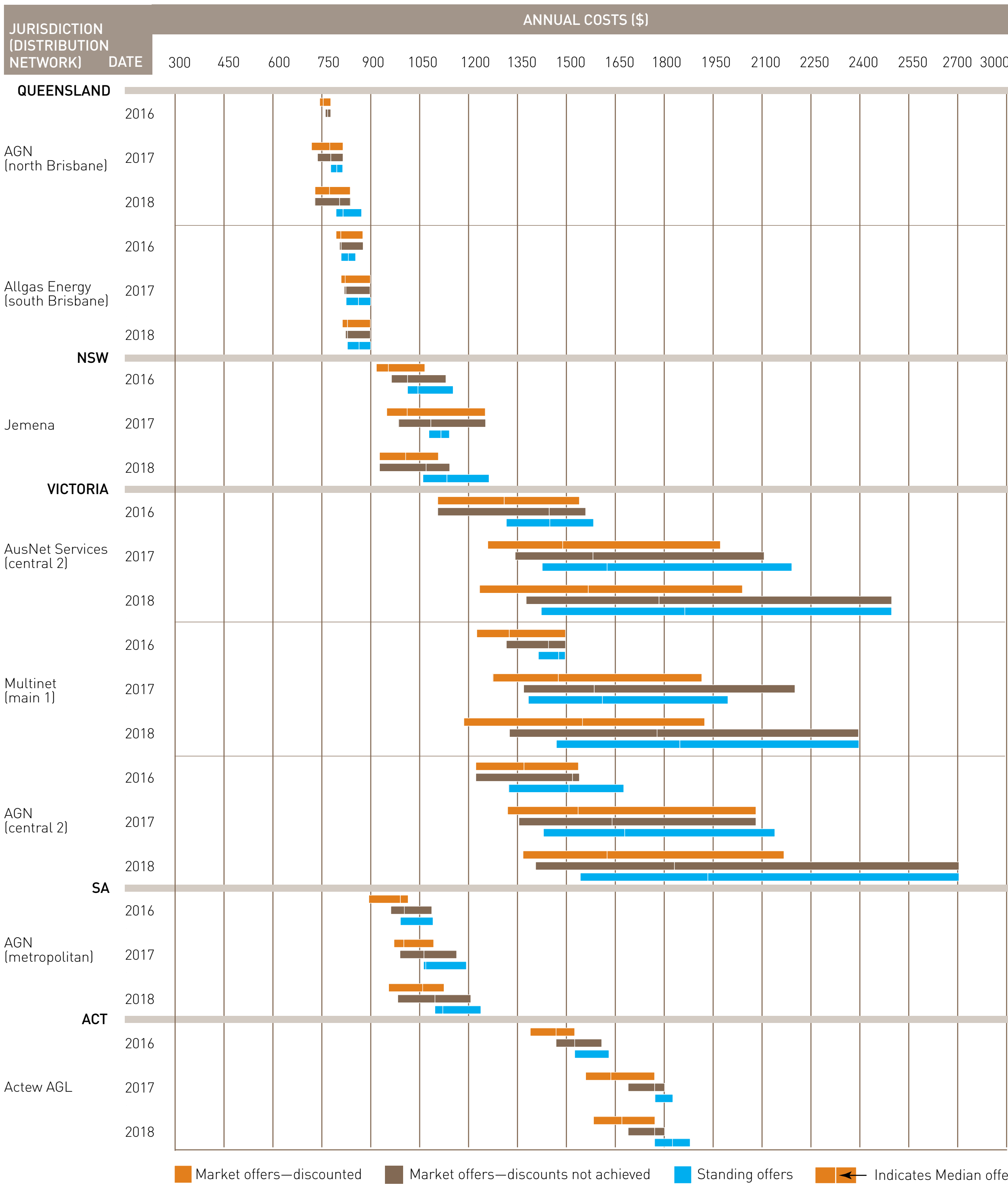
Many discounts are conditional on the customer meeting certain terms, the most common being a requirement to pay on time. Over a quarter of residential customers (and over half of hardship customers) do not receive their conditional discounts.[39] This outcome often means they end up paying hundreds more dollars than if they had met the

38 ACCC, *Restoring electricity affordability and Australia's competitive advantage, Retail Electricity Pricing Inquiry—Final report*, June 2018, pp. 12–20.

39 ACCC, *Restoring electricity affordability and Australia's competitive advantage, Retail Electricity Pricing Inquiry—Final report*, June 2018, p. 29.

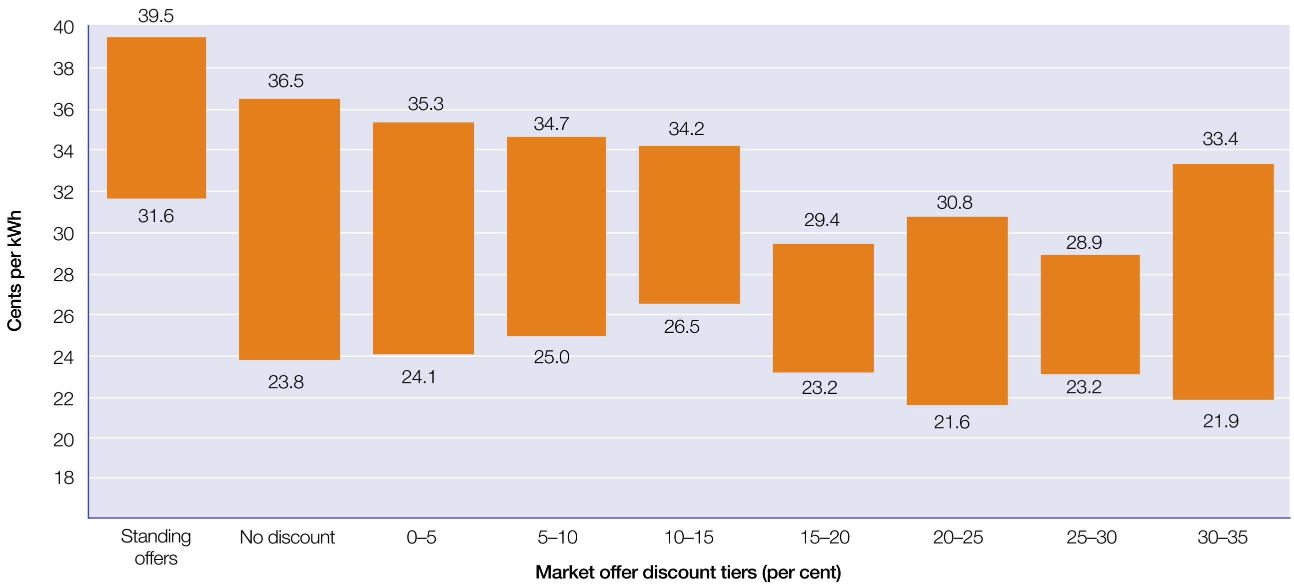
Figure 1.19

Price diversity—gas



Note and source: see figure 1.18

Figure 1.20
Range of average unit charges paid by Victorian residential customers



Note: Based on effective unit charges paid by residential customers without solar PV systems in 2016–17. Data is inflation adjusted, in 2016–17 dollars, and excludes GST.

Source: ACCC, *Restoring electricity affordability and Australia's competitive advantage, Retail Electricity Pricing Inquiry—Final report*, June 2018, p. 262.

conditions. The prevalence of conditional discounts means these customers are not seeing the full benefits of price competition in the market.

To protect vulnerable customers being penalised, the ACCC recommended conditional discounts be no greater than the reasonable savings to the retailer from the customer meeting the discount conditions.[40] If this recommendation leads to more unconditional discounting, these customers will benefit from lower effective prices.

1.7.8 Price comparison websites and switching services

The variety of product structures, discounts and other inducements makes direct price comparisons between retail offers difficult. Customers have begun using 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 an electricity use benchmarking tool that allows households 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 website allowing Victorian customers to compare market offers—Victorian Energy Compare.

Various private entities also offer online price comparison services. The AEMC identified 19 separate comparison websites in 2018.[41] 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 only show offers of retailers affiliated with the site, for example. Of the 19 commercial comparator websites reviewed by the AEMC, 15 websites showed offers for less than half the retail brands in the market.[42]

Comparison websites also typically require retailers to pay a commission per customer acquired or a subscription fee to

40 ACCC, *Restoring electricity affordability and Australia's competitive advantage, Retail Electricity Pricing Inquiry—Final report*, June 2018, p. 269.

41 AEMC, *2018 Retail energy competition review, final report*, June 2018, p. viii.

42 AEMC, *2018 Retail energy competition review, final report*, June 2018, p. 103.

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.

To address these issues, the ACCC recommended the government prescribe a mandatory code of conduct to ensure price comparator and broker services act in the best interests of the consumer.[43] 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 these issues by listing all generally available offers in the market. However, knowledge about independent government comparator sites is low, with only 9 per cent of customers being aware of Energy Made Easy.[44] The AER in 2018 upgraded Energy Made Easy to improve its usability and add value to customers. It also campaigned to increase awareness of the website. In 2018 the Victorian Government ran an awareness campaign for its comparison site, offering households $50 to visit the website.[45]

New business models are emerging to help consumers find and switch to better energy offers. In 2018 CHOICE launched an automatic switching service—Transformer. For a fixed annual fee, Transformer compares all generally available offers to a customer's current energy plan, and switches the customer where a better price is identified. In addition to offer comparison services, new services offer to arrange energy connections for customers moving into a new property.

1.8 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 switch retailers, and enabling wider use of demand response. The COAG Energy Council in 2017 requested industry bodies form a working group to develop a code of practice to support consumer protections for new energy products and services. The working group released a draft code in November 2018.[46]

1.8.1 New price structures

Most energy 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 used by a customer, regardless of how and when they use energy. Some customers—such as those with airconditioners or solar PV systems—are not exposed to their full network costs under these tariff structures, resulting in other customers paying more than they should.

Power of choice reforms introduced in 2017 require electricity distribution businesses to move customers onto network tariffs more closely reflecting the efficient costs of providing the services they use. The reforms make charges higher at times of peak demand when the networks are most under strain. Charging in this way creates incentives for customers to minimise energy use at times of high system cost, and results in a more equitable allocation of costs across customers.

Different pricing structures can meet this requirement, including:

- *time-of-use tariffs* that apply different pricing to electricity use in 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* that 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* factor in a low electricity usage charge for most of the year but much higher tariffs during a few short 'critical peaks' each year. Customers get prior notice of critical peak periods, which typically are when electricity networks forecast they will need to operate at, or near, full capacity.

Each tariff structure reflects a trade-off between cost reflectivity and simplicity. Both elements are needed to

43 ACCC, *Restoring electricity affordability and Australia's competitive advantage, Retail Electricity Pricing Inquiry—Final report*, June 2018, p. 282.

44 AEMC, *2018 Retail energy competition review, final report*, June 2018, p. 89.

45 Victorian Premier, Daniel Andrews, *Busting energy bills with new $50 power savings bonus*, media release, July 2018.

46 BTM working group, *Behind the meter distributed energy resources provider code, consultation draft*, November 2018.

ensure customers face appropriate incentives around their energy use, and understand how these incentives work.

Distributors are phasing in the new tariff structures over time. For the initial pricing period, most networks adopted a form of demand tariff. The NSW distribution businesses Ausgrid and Endeavour Energy, however, introduced time-of-use tariffs.

Retailers initially pay the new network charges, then decide whether to pass on those costs to customers and in what form. Most networks are offering the new cost reflective structures on an opt-in basis (that is, a customer may choose to adopt the new pricing). But some networks are making the tariffs mandatory for new customers, or those with smart meters. Retailers generally mirror the network tariff structure in their retail tariff, as doing so removes any price risk for the retailer.

At August 2018 most retailers offered a range of flat and time-of-use tariffs to customers across all regions. Demand tariffs were available from a small number of retailers across the NEM. Victoria had the highest number of demand tariff offers. Five retailers offered demand tariffs under market contracts, while other retailers only offered demand tariffs under standing offer contracts. This outcome indicates there is little interest on the part of retailers to promote these tariff structures to customers.

At June 2018 30 per cent of customers in the NEM had metering capable of supporting cost reflective tariffs (including smart meters and manually read interval meters). Despite this, only around 12 per cent of small customers were on new tariff structures (mostly time-of-use tariffs),[47] Very few small customers have elected to voluntarily opt-in to a new tariff structure.

Distributors are required to progress towards full cost reflective pricing through their tariff structure statements, which the AER vets within the network revenue determination process. They can meet this requirement by:

- simplifying tariff offerings
- designing tariffs that more closely reflect how customer use affects the network's costs
- implementing an opt-out approach requiring customers to move to a new tariff unless they elect not to
- integrating network pricing with broader management policies (such as network planning and demand management).

47 ACCC, *Restoring electricity affordability and Australia's competitive advantage, Retail Electricity Pricing Inquiry—Final report*, June 2018, p. 177.

1.8.2 Smart meters

The rollout of smart meters is fundamental to changes to more cost reflective pricing structures. Smart meters measure electricity use in half hour blocks, and allow for remote reading and connection/disconnection. The detailed information about a customer's energy use throughout the day provides scope for more innovative offers from retailers, and for new energy management services from third parties.

Victoria was the first jurisdiction to progress metering reforms, with its electricity distribution businesses rolling out smart meters across 2009–14. Over 97 per cent of Victorian customers now have a smart meter.[48]

In other jurisdictions, the rollout of smart meters is occurring on a market led basis. Responsibility for metering was transferred from network businesses to retailers in 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.

Responsibility for metering was transferred to retailers so they could use meter functionality to develop new energy services for customers. But apart from an initial push to install smart meters in NSW for residential customers with solar PV systems, most retailers have shown little interest in driving a rollout beyond new or replacement meters.

Outside Victoria, only around 5 per cent of customers had access to a smart meter in June 2018. A further 6 per cent of customers in these regions (mostly in NSW) had access to an interval meter providing half hourly consumption readings but without remote reading and connection capabilities.

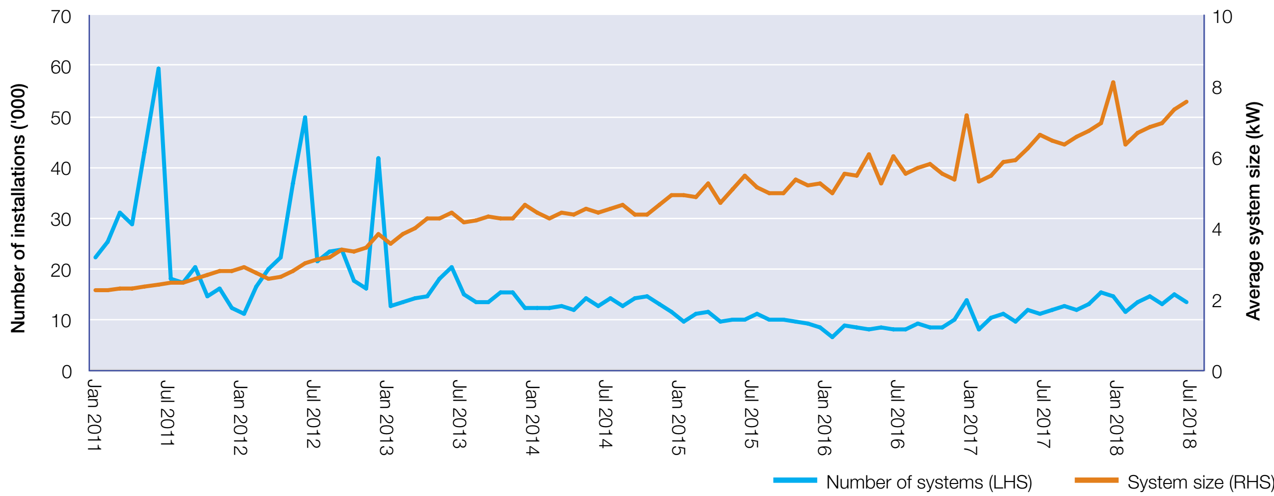
The transition to retailer responsibility for metering coincided with large delays in meter installations in some regions. The AEMC in August 2018 noted there had been 'customer complaints in some regions about delays in installing meters … [and] instances where the customer service from retailers and metering businesses has been poor'.[49]

Customers in South Australia have been most affected. The South Australian Energy and Water Ombudsman found the average time taken to provide meters at new connections under the new arrangements was four weeks in metropolitan areas, with delays of up to four to six months for rural and regional customers.

48 Victorian Department of Economic Development, Jobs, Transport and Resources, *Smart meters: End of rollout, fact sheet*, March 2015.

49 AEMC, *Smart meter installations across the national electricity market update*, media release, August 2018.

Figure 1.21
Growth of solar PV installations



kW, kilowatts.

Note: Data at 31 October 2018.

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

This outcome compares to requirements under the previous framework for meter installations to occur within six days. Causes of the delays identified by market participants include:

- poor coordination and data provision between network businesses, retailers and metering coordinators
- inadequate retailer systems, processes and controls
- poor resourcing leading to a backlog of jobs.

In September 2018 the AEMC released a draft rule change requiring retailers to provide customers with new electricity meters within six business days after a property has been connected to the network, or replacement meters within 15 days.[50]

1.8.3 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 June 2018 almost 2 million rooftop solar PV systems had been installed throughout Australia, the majority of which were on residential households. Over 12 per cent of customers in the NEM received some of their electricity supply through a solar PV system, compared with less than 0.2 per cent of customers in 2007–08.

New installations of residential solar PV systems peaked in 2011 (figure 1.21) due to attractive premium feed-in tariffs offered by state governments. Despite the closure of these schemes, ongoing subsidies provided through the Australian Government's small scale renewable energy scheme, combined with falling costs of solar PV systems, has seen continued strong demand for new installations. The average size of installations has also grown. Total solar capacity installed in 2017 (870 MW) exceeded the capacity installed in 2011 (750 MW), despite less than half of the number of systems being installed.

While energy from solar PV systems is available for use only at the time it is generated, battery storage and smart appliances allow customers to better match their electricity generation and use over time. The amount of power that customers withdraw from and inject into the network throughout the day is, therefore, reduced.

Of the 332 000 solar PV systems installed since 2017, 2.6 per cent have had an attached battery system.[51] Though still low, penetration of battery installations is expected to increase due to 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

50 AEMC, *National energy retail amendment (metering installation timeframes) rule 2018, draft rule determination*, September 2018.

51 Clean Energy Regulator, *Solar PV systems with concurrent battery storage capacity by year and state/territory*. Data at 31 October 2018.

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 usually produce enough energy to meet all their requirements, and buy the balance from a retailer. But the lower volumes that they require make these customers less profitable for the retailer. Battery storage may further reduce energy purchases by these users.

1.8.4 Demand response

Smart meters provide customers with opportunities to participate in demand response programs run by retailers, distribution network businesses or third party energy providers (box 1.2). A retailer might offer customers a financial incentive to lower their energy consumption on a peak demand day to limit the retailer's exposure to peak energy costs, for example.

The simplest approach to demand response is for a customer to switch off or not use appliances after receiving an alert from their energy provider. More sophisticated approaches 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, and allow customers to provide electricity back to the grid, rather than just reducing their load.

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. These products and services can also reduce or defer the need for new investment in both network and large scale generation.

1.8.5 Customers in embedded networks

An increasing number of customers are being supplied energy through embedded networks (where a group of customers are located behind a single connection point to the main distribution network). The supply of energy in embedded networks occurs on a similar basis to that for customers directly connected to a distribution network. The customer experience in an embedded network, however, can be significantly different. In particular, these customers may not have the same access to the competitive market or to customer protections as customers supplied through a distribution network.

Many embedded network customers currently cannot buy energy from a provider other than their network operator, or can only do so at significant cost. New energy rules took effect in December 2017 to give embedded network customers better access to retail market offers from electricity retailers. These changes require embedded networks to have an embedded network manager, authorised by the AEMC, who can link customers to the Australian Energy Market Operator's (AEMO) electricity market systems. This is a necessary first step for customers to access retail market offers.

These new rules only apply in jurisdictions where embedded networks customers are able to access a competitive retail market and for networks with over 30 customers. Despite these changes, there remain very few retailers who are willing to serve customers on embedded networks.

Customers in embedded networks typically have access to a reduced level of consumer protections, and more limited avenues for dispute resolution, than customers of energy retailers. However, energy ombudsman schemes in NSW, Victoria and South Australia now require exempt sellers to become scheme members and allow customers of exempt sellers to lodge complaints. The Queensland Government is considering a similar arrangement.

1.8.6 Beyond the grid

It is becoming increasingly viable to bypass the traditional energy supply model altogether, by going 'off grid' through self-sufficient solar PV generation and battery storage.

Stand-alone systems or microgrids—where a community is primarily supplied by locally sourced generation and does not rely on a connection to the main grid—are also starting to gain traction in some areas. These arrangements have largely been limited to regional communities a long distance

Box 1.2 Demand response in the NEM

Retailers including Mojo Power and Powershop are trialling demand response programs with their customers. These programs offer customers financial incentives to reduce consumption when wholesale prices are forecast to reach the price cap and the Australian Energy Market Operator notifies a risk of power cuts.

Network operators are also engaging in demand response programs with their customers. United Energy's 'Summer Saver' program operates in the same way as the retailer programs discussed above. Under Energex's 'PeakSmart' program, a signal receiver is attached to appliances such as air conditioners. The appliance can then be switched to economy mode during peak demand, which might only be a few times a year. Customers receive an upfront rebate on installation of approved devices.

New entrants that were not traditionally part of the energy market are also engaging in this area. Reposit offers technology solutions to manage electricity demand for customers with solar panels and batteries. Batteries can be recharged during off-peak times (when electricity is cheaper) and run down to sell energy to retailers at peak times when prices are higher.

from the electricity network. But improvements in energy storage and renewable generation technology are likely to see more customers take up this form of energy supply.

Current regulatory and pricing frameworks are possible impediments to the growth of these energy supply arrangements. Geographically averaged (postage stamp) network prices, for example, mean price signals that would encourage high cost customers to explore alternative supply arrangements don't exist. Consumer protections under the Retail Law also do not extend to these supply arrangements.

1.9 Energy affordability

Energy affordability relates to customers' ability to pay their energy bills. It depends on their energy use, the energy prices they pay, their incomes and their other living costs.

A customer's energy use depends on how many people they live with, housing and appliance quality, their heating and cooling needs, their lifestyle, and whether they also have access to gas. Energy prices depend on where a customer lives, the network services required to supply their energy, competition between retailers in their area, and whether they are eligible for a concession or rebate to help manage their energy costs.

The AEMC undertook research to identify customers likely to be vulnerable to energy affordability issues. Low income customers (12 per cent of customers) face clear risks associated with energy affordability. However, these customers tend to be familiar with support services to help them manage energy costs. The most vulnerable group tends to be 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 (8 per cent of customers).[52]

The AER publishes an annual affordability report on energy bill trends, with a focus on low income households. Figure 1.22 provides an energy affordability snapshot for a typical low income household.

In the year to July 2018, the AER found electricity affordability worsened for low income households in all jurisdictions except Queensland and Tasmania.[53] Gas affordability for low income households deteriorated over the same period in NSW, the ACT and Victoria. These changes mainly reflect higher retail prices for gas and electricity.

For a typical low income household receiving energy bill concessions, at July 2018:

- electricity costs accounted from 4.7–9.5 per cent of disposable income on the mainland (up from 3–5 per cent in 2016), and around 8 per cent (up from 6.4 per cent) for Tasmanian households.
- gas costs accounted for around 2.6–5.4 per cent of disposable income for low income households.

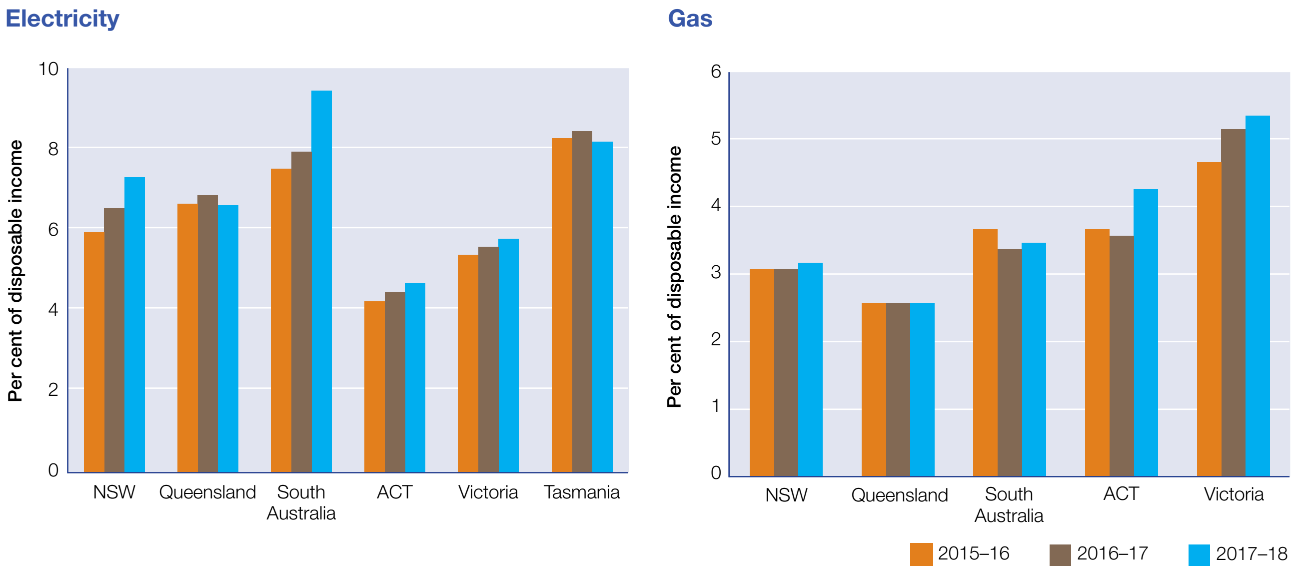
South Australia had the highest electricity bill to income ratio in low income households, despite having the second lowest electricity use in the NEM. This outcome reflects the high costs of electricity in that state. Tasmanian customers also experienced relatively high electricity bill to income ratios. This reflects Tasmania having the highest average use of electricity—due to a cold climate creating a high demand for heating, and low gas penetration. However, high concessions and relatively low electricity charges partly offset this factor.

52 Newgate Research, *Understanding vulnerable customer experiences and needs, consumer research report prepared for the AEMC*, June 2016.

53 Based on the percentage of household disposable income spent on the median retail offer.

Figure 1.22

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 accounts for available concessions and rebates. Income data is equivalised disposable income (adjusted lowest income quintile) as reported by the ABS in 2015–16, adjusted to 2016–17 and 2017–18 dollars using CPI.

Source: AER, *Annual Report on Compliance and Performance of the Retail Energy Market 2017–18*, December 2018.

Despite the ACT having the second highest electricity use, it had the most affordable electricity bills as a percentage of disposable income—a result of relatively low electricity charges and high incomes.

In gas, the high use jurisdictions of Victoria and ACT had the highest bills (across market and standing median offers) as a percentage of disposable income.

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 energy affordability. Most jurisdictions also offer emergency bill support. The potential savings vary by jurisdiction and depend how the concession is applied, but can be several hundred dollars a year for each fuel.

In the past year, there has been a renewed focus on concessions to help manage the increasing bill burden of energy prices on consumers, with jurisdictions increasing help to vulnerable customers. Most jurisdictions offer concessions as a fixed annual dollar amount. Victoria, however, applies the concession as a percentage of a customer's energy bill.

The ACCC found the way concessions are applied may reduce their effectiveness in helping customers reduce their energy costs.[54] In South Australia, for example, a customer must reapply for a concession each time they change retailer. This may discourage customers 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 1–3 years.[55]

While concessions represent an important saving for eligible households, many households can achieve significant savings simply by switching to a cheaper offer. Price differentiation across offers is discussed in section 1.7.7.

1.9.1 Assisting customers in debt

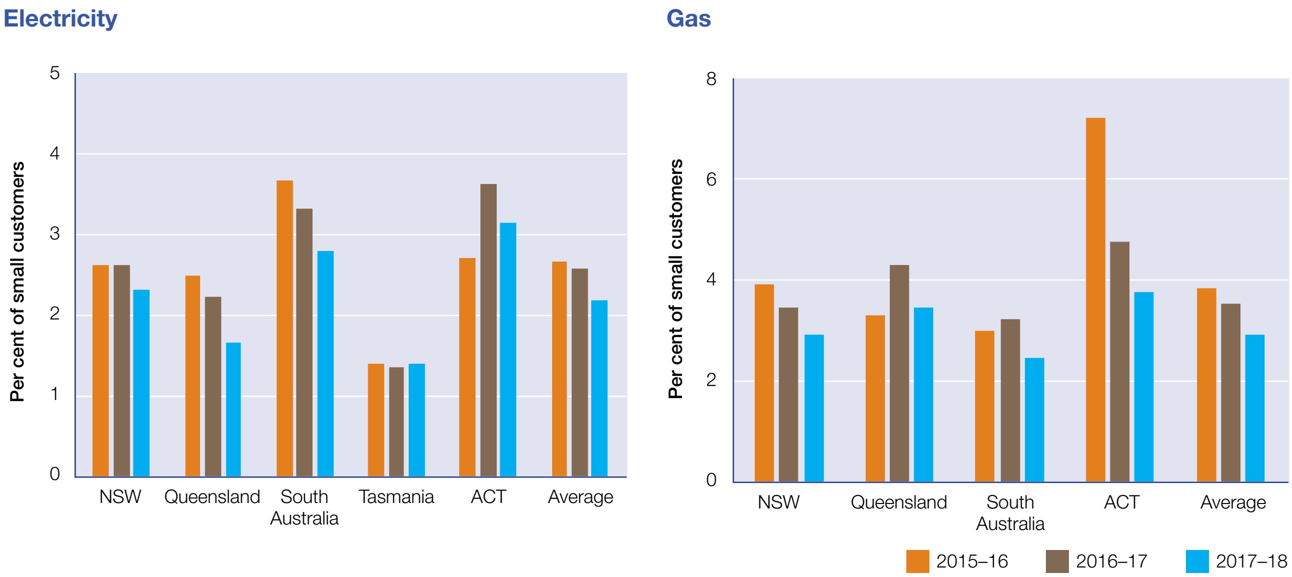
Energy affordability issues can lead customers into debt. A household's energy bill debt is measured as amounts owing to a retailer that has been outstanding for 90 days

54 ACCC, *Restoring electricity affordability and Australia's competitive advantage, Retail Electricity Pricing Inquiry—Final report*, June 2018, pp. 297–303.

55 Information on these schemes is available from government departments and ombudsmen websites.

Figure 1.23

Small customers in debt



Note: Based on customers with an amount owing to a retailer that has been outstanding for 90 days or more, at 30 June 2018.

Source: AER, *Annual Report on Compliance and Performance of the Retail Energy Market 2017–18*, December 2018.

or more. Average electricity and gas debt increased for residential customers in 2017–18.

Despite having the lowest electricity costs as a percentage of income, the ACT had the highest percentage of residential electricity customers in debt at June 2018—3.8 per cent of customers (figure 1.23). Queensland and Tasmania had the lowest number of electricity customers in debt at around 2 per cent. The ACT also had the highest percentage of gas customers in debt (6.1 per cent). South Australia had the lowest rate of gas customer debt, at around 2.8 per cent of residential customers.

The number of electricity customers in debt in 2017–18 was up from recent years in the ACT and Tasmania, but lower elsewhere. In gas, the percentage of customers in debt in 2017–18 was lower in all regions except the ACT.

Debt numbers in some jurisdictions are seasonal, particularly for gas customers. In the ACT, for example, gas debt worsens in the December and March quarters as winter heating bills are paid off.

The AER introduced a voluntary Sustainable Payment Plans Framework in 2016 to guide retailers in negotiating affordable payment plans with customers needing assistance to repay debt.[56] The framework sets out good practice principles that encourage open, clear and ongoing engagement based on trust, respect and empathy. The principles promote constructive, long term customer relationships. Eighteen retailers have signed on to the framework, covering over 90 per cent of customers.

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 number of customers on payment plans has steadily risen in both gas and electricity, despite a slight fall in 2017–18.

Referral to a hardship program may be warranted if a customer's payment difficulties are chronic or severe. The Retail Law requires energy retailers to develop and maintain a customer hardship policy that underpins how they identify and assist customers facing difficulty paying their energy bills.

56 AER, *Sustainable payment plans, a good practice framework for assessing customers' capacity to pay*, July 2016.

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.

Among jurisdictions in which the Retail Law applies, South Australia continues to have the highest proportion of residential customers on hardship programs—2 per cent of electricity customers and 1.3 per cent of gas customers at June 2018.

The ACT had the smallest proportion of customers on hardship programs—around 0.5 per cent for electricity and gas—despite having a relatively high percentage of customers with electricity debts. There was, however, a large increase in the number of ACT customers on hardship programs compared with the previous year.

Facilitating entry into a hardship program is an important role for retailers. But not all customers on hardship programs appear to be receiving the support they require. There is a trend towards excluding (removing) customers from hardship programs and transferring them to another retailer, for example. Excluding customers from hardship programs for not meeting their payment obligations rose from 54 per cent in 2014–15 to 65 per cent in 2017–18. Successful completion of hardship policies (customers clearing their debt) is low, averaging 21 per cent across all retailers.

The AER identified deficiencies in how retailers implement their hardship policies and in 2018 proposed a rule change that would enable it to develop a new hardship policy guideline, enforceable by civil penalties.[57] The AEMC in November 2018 amended the rules, and the AER will publish new guidelines in 2019.

Victoria operates a state-based hardship program. In 2019 new minimum standards of assistance will be introduced for customers who anticipate or face payment difficulties.[58] Hardship protections under the Victorian framework are more prescriptive than those in the Retail Law

1.9.2 Disconnecting customers for non-payment

Energy retailers are required to help customers in financial hardship before considering disconnecting 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, when a customer on a hardship program is meeting their obligations, or when a customer's debt is below $300.

The AER reports on disconnection rates resulting from failure to pay an energy bill. Queensland and South Australia had the highest rates of electricity disconnections in 2017–18, at around 1.4 per cent of customers. Around 1 per cent of NSW customers were disconnected, and 0.4 per cent of customers in the ACT and Tasmania (figure 1.24). Queensland and NSW had the highest rates of gas disconnections at around 1 per cent. South Australia and the ACT had gas disconnection rates of 0.4 per cent. Victoria typically has disconnection rates of around 1 per cent of electricity and gas customers.

Disconnection rates have been relatively stable over recent years, with the exception of gas disconnections in the ACT. Disconnection rates in the ACT averaged 1.2 per cent until 2015–16, before falling below 0.4 per cent over the past two years. This shift reflected a policy change by a retailer in that jurisdiction.

Less than 0.1 per cent of *hardship* customers in electricity and gas were disconnected in 2017–18 following a failure to meet the terms of their hardship program, compared with 1 per cent of all customers. This illustrates the benefit of customers raising payment difficulties with their retailer and negotiating a sustainable approach to repaying debt. In many cases, disconnection occurs because customers are unwilling or unable to engage with retailers about their financial difficulties.

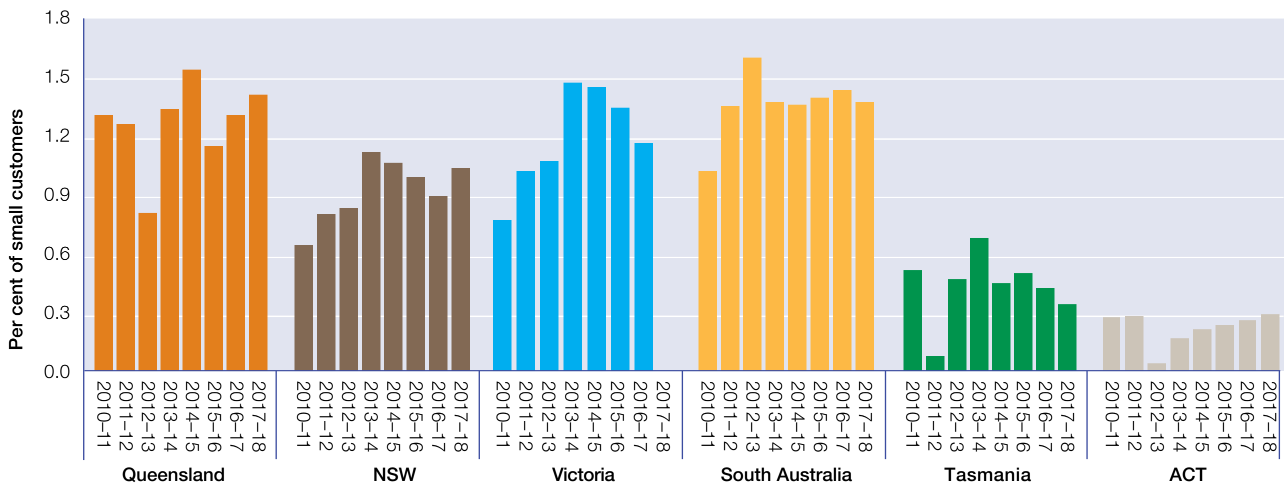
Repeated disconnection of the same customers has become more common. In 2017–18, 39 per cent of disconnected electricity customers and 33 per cent of disconnected gas customers had been disconnected in the previous 12 months. This suggests customers experiencing long term or severe financial difficulties are not being adequately supported through hardship programs.

57 AER, *Strengthening protections for customers in financial hardship, media release*, March 2018.

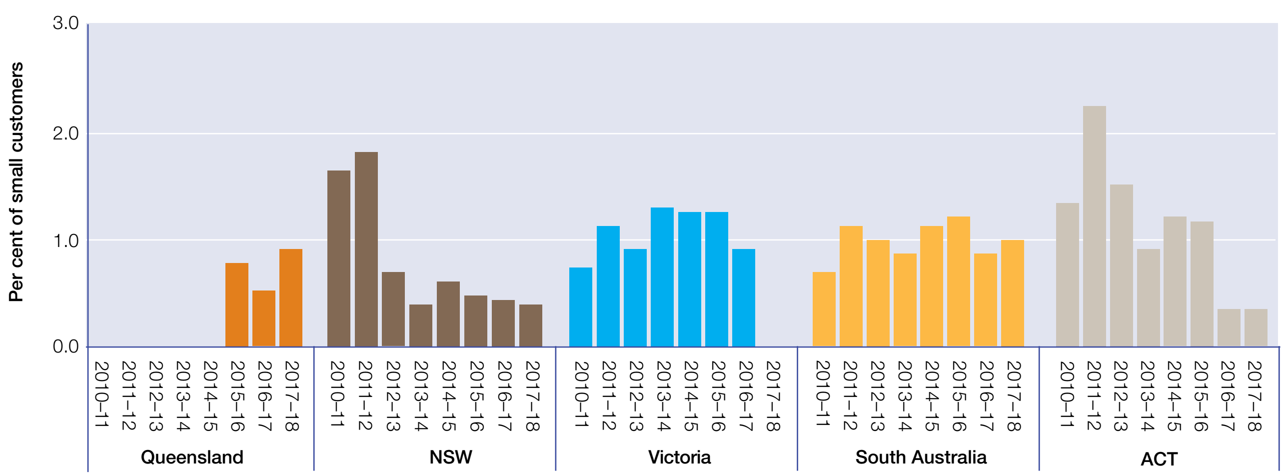
58 ESC, *Amendments to the energy retail code: payment difficulties*, October 2017.

Figure 1.24
Disconnection of residential customers for failure to pay amount due

Electricity



Gas



Note: Data not available for Victoria for 2017–18.

Source: AER, *Annual Report on Compliance and Performance of the Retail Energy Market 2017–18*, December 2018.

1.10 Customer complaints

Consumer trust in the energy sector reached new lows in 2017–18, driven by high prices and lack of transparency in the market. This level of dissatisfaction is reflected in the number of customer complaints to energy retailers.

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.

In the first instance, customers can lodge a complaint directly with their retailer. If unable to resolve an issue with their retailer, a customer can 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 may reflect unfairly on energy retailers, for example. For this reason, the manner in which complaints are handled can be a more meaningful measure of retailer performance than the number of complaints received.

Retailers with effective customer service generally resolve complaints without the need for escalation to energy ombudsman schemes.

The number of complaints to ombudsman schemes rose in NSW, South Australia and Victoria in 2017–18, to around 1 per cent of customers (figure 1.25). Rates are typically lower in Queensland, and fell in 2017–18 to 0.3 per cent of customers.

Gas complaints are generally lower than in electricity. NSW and Victoria have the highest complaint rates at around 0.5 per cent of customers. Gas complaints fell in NSW and South Australia in 2017–18, but rose in Victoria and Queensland.

The ombudsman schemes in Victoria and South Australia saw less complaints from 2013–14, with levels halving by 2017–18. Performance in those regions now aligns with outcomes in NSW, but remains higher than in Queensland.

Billing issues drove 40 per cent of all complaints in 2017–18. Credit issues—including disconnection following a 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 (less than 10 per cent of complaints in most regions, but around 30 per cent in NSW).

1.11 Enforcement action in retail markets

Poor conduct by a number of energy retailers and their agents relating to marketing and signing up customers has contributed to low levels of customer satisfaction and trust in retail energy markets. 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 Australian Consumer Law (enforced by the ACCC) also protects customers from improper sales or marketing conduct relating to unsolicited sales, misleading and deceptive conduct, and unconscionable conduct.

The AER issued multiple infringement notices against retailers since 2017 for alleged breaches relating to failure to obtain explicit informed consent from new customers. Simply Energy was issued three notices in 2017 and Alinta was issued two notices in 2018. The penalty for each infringement notice was $20 000.

The ESC regulates the Victorian energy market. The ESC took action against Alinta in 2018 for transferring customers onto contracts on 15 separate occasions without their explicit informed consent. Alinta paid penalties of $300 000.[59]

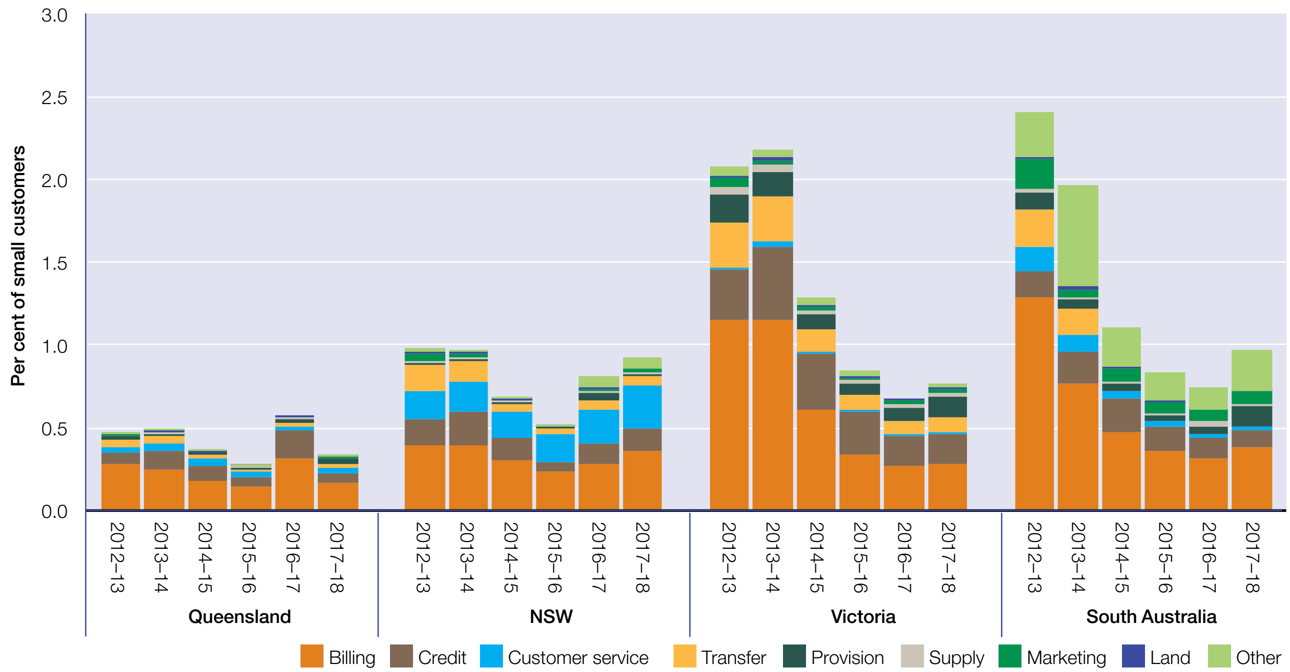
The ACCC monitors how businesses promote discounts and savings under their energy offers, following concerns that consumers have been misled about the extent of savings available. Action taken by the ACCC since 2017 includes:

- requiring Alinta to compensate customers who switched based on misleading price comparisons
- issuing an infringement notice to Lumo Energy for a false or misleading representation about the size of energy discounts
- instituting proceedings in the Federal Court against Amaysim (trading as Click Energy) for misleading marketing claims about discounts and savings that customers could obtain
- issuing two infringement notices against One Big Switch, a service negotiating better energy offers for its registered members, for false and misleading price representations relating to advertised discounts and savings.

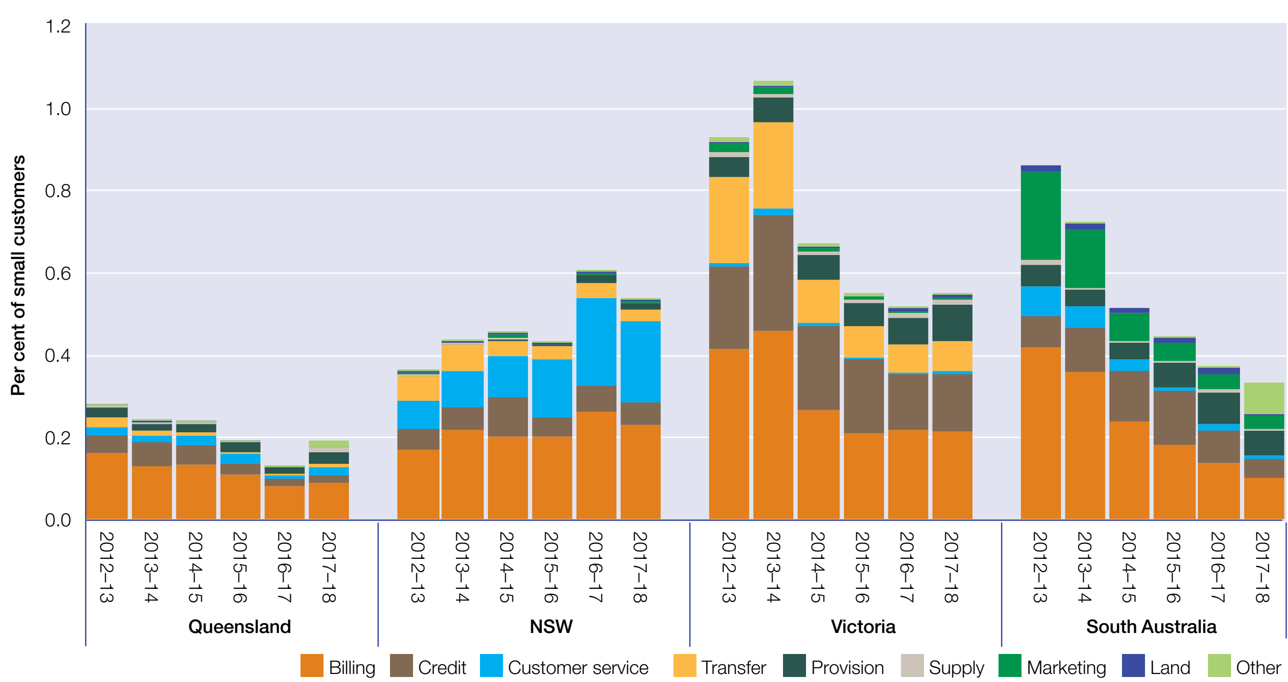
59 ESC, *Alinta Energy pays $300 000 for allegedly failing to obtain consent to switch*, media release, August 2018.

Figure 1.25
Complaints to ombudsman schemes

Electricity



Gas



Source: Annual reports by ombudsman schemes in Queensland, NSW, Victoria and South Australia.

The AER also monitors and enforces broader compliance with the Retail Law. Action taken by the AER for alleged breaches of the Retail Law since 2017 includes:

- three infringement notices to Taplin for selling energy without an appropriate authorisation or exemption
- three infringment notices to AGL for failing to inform more than 1000 customer that their fixed term contract was about to end. Retailers must disclose to a customer what happens if they choose not to enter into a new contract
- two infringement notices to Origin Energy for allegedly failing to offer hardship assistance to a residential customer experiencing payment difficulties, and wrongfully disconnecting that customer. Retailers must implement their hardship policies, and use best endeavours to contact a customer before disconnecting their energy supply
- two infringement notices to Alinta, one to EnergyAustralia and one to Origin Energy for failing to submit correct performance reporting data.

Image courtesy of Tesla

2 NATIONAL ELECTRICITY MARKET


TESLA

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 (box 2.1). 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 (figure 2.19).

Around 150 large power stations (comprising around 240 plant units in total) produce electricity for sale into the NEM. A transmission grid carries this electricity along 40 000 kms 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 almost 10 million residential, commercial and industrial energy users. The electricity supply chain is illustrated in infographic 1.

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 1 covers electricity (and gas) retailing.

The generation mix in the energy market continues to evolve as new technologies emerge and the costs of generation from some technologies fall. Wind and solar generation are replacing older coal fired generators as they retire from the market. 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.

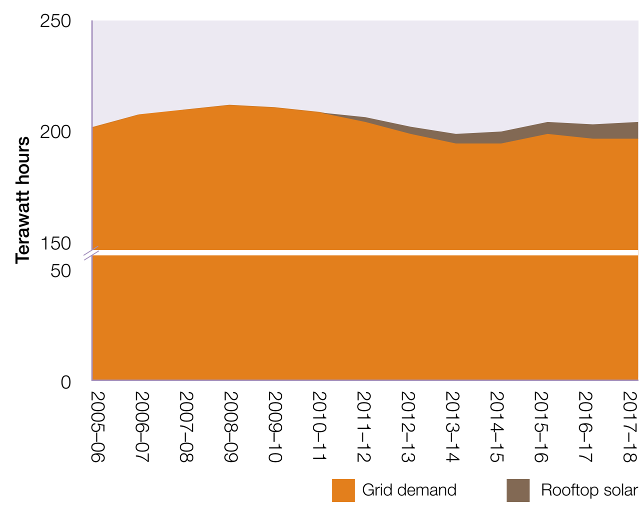
In coming years, customers may increasingly meet their energy needs by drawing on electricity stored in batteries, and be paid by energy suppliers to reduce their energy use or inject stored electricity when the grid is under stress. Technological advances making battery storage more economical will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

2.1 Electricity demand

Almost 10 million residential and business customers consume electricity across the NEM's five regions. Traditionally, all electricity was produced by large scale registered generators, sold through the NEM spot market, and supplied to customers through a transmission and distribution network grid. Consumers produced little of their own electricity until 2010, but by October 2018 almost two million households and businesses had installed solar PV systems to produce electricity. This production met almost 4 per cent of the NEM's total electricity requirements in 2017–18 (figure 2.1).

Figure 2.1

Electricity consumption in the NEM



Note: Grid consumption is native demand (including scheduled and semi-scheduled generation, and intermittent wind and large scale solar generation). Rooftop solar output estimates derived from CER data on installed capacity, and AEMO system output assumptions.

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

2.1.1 Grid consumption

Most electricity consumed in the NEM is produced by registered generators and transported through the NEM transmission grid. Grid consumption peaked in 2008–09 at 210 terawatt hours (TWh). Following several years of declining consumption, demand levelled out from 2013–14. Demand in 2017–18 totalled 196 TWh, similar to levels in the previous five years (figure 2.1).

Electricity consumption from the grid continues to grow in Queensland, mainly due to escalating energy requirements for the state's coal seam gas and liquefied natural gas (LNG) industries. This growth is likely to moderate now the LNG plants are fully operational. Projected demand growth is weakest for South Australia, mainly due to the state's rising rooftop solar PV generation.[1]

Box 2.1 How the NEM 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 needs to match demand in real time.

Table 2.1 National electricity market at a glance

Participating jurisdictions	Qld, NSW, Vic, SA, Tas, ACT
NEM regions	Qld, NSW, Vic, SA, Tas
NEM installed capacity (including rooftop solar PV)	55 590 MW
Number of large generating units	240
Number of customers	9.7 million
NEM turnover 2017–18	$17 billion
Total electricity demand 2017–18[1]	203 TWh
National maximum demand 2017–18[2]	32 469 MW

MW, megawatts; PV photovoltaic; TWh, terawatt hours.

1 Includes total energy met by grid connected generation, including rooftop solar PV.

2 The maximum historical summer demand of 35 551 MW occurred in 2009. The maximum historical winter demand of 34 422 MW occurred in 2008.

Around 150 large power stations (comprising around 240 plant units in total) make offers to supply quantities of electricity in different price bands for each five minute *dispatch interval*. Electricity generated by rooftop solar photovoltaic systems is not traded through the NEM, but it does lower the demand needed to be met by market generators.

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. Retailers 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 through demand response contracts with their retail customers.

AEMO, the power system operator, works with constantly varying information to make a continuum of decisions. It uses forecasting and monitoring tools to track electricity demand and generator bidding, allowing it to determine which generators should be dispatched (directed) to produce electricity. It repeats this exercise every five 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 five 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 $14 500 per megawatt hour (MWh). A price floor of –$1000 per MWh also applies.

Figure 2.2 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 3500 megawatts. To meet this, generators 1, 2 and 3 must be fully dispatched and generator 4 is partly dispatched. The dispatch price is $51 per MWh. By 4.25 pm demand has risen to the point where a fifth generator is needed. This generator has a higher offer price of $60 per MWh, which becomes the dispatch price for that five 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 $54 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.

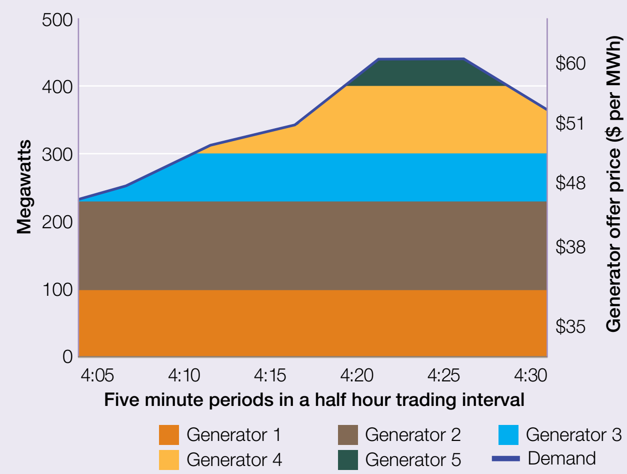
Power system management

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). AEMO may enter contracts with generators or large customers to ensure back-up reserves are available. But, if system issues or an unexpected rise in demand pose a threat of unserved energy, AEMO can direct generators to provide additional supply, or may directly intervene as a last resort.

AEMO also procures *ancillary services* from market participants to keep the power system secure. Frequency control ancillary services maintain system frequency within a safe range. 'Regulation' services correct for minor deviations in load or generation within each five minute dispatch interval. AEMO procures 'contingency' services to maintain safe power flows and voltage levels following a major disturbance such as the loss of a transmission line. These services are offered by generators (including battery storage) that can rapidly adjust output and industrial customers able to rapidly adjust their energy use.

If a serious power system threat 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'—temporarily cut power to some customers. This action is rare. An insecure operating state led AEMO to cut supply to some customers in South Australia on 1 December 2016 and 8 February 2017, and in NSW on 10 February 2017. Extreme weather and infrastructure failures caused the entire state of South Australia to black out for several hours on 28 September 2016, however, this blackout was not at AEMO's direction (section 1.7).

Figure 2.2
Setting the spot price



In other regions (NSW, Victoria and Tasmania), consumption of grid supplied electricity is forecast to remain relatively stable over the next decade. The Australian Energy Market Operator (AEMO) forecast that improvements in energy efficiency and further growth in rooftop PV and non-scheduled generation will largely offset the higher energy use caused by population and economic growth and consumer preferences for energy intensive appliances like home entertainment units and space conditioning. AEMO's demand forecasts factor in how climate change may increase the magnitude and frequency of heatwave conditions that drive peak electricity use.[2]

2.1.2 Maximum grid demand

The demand for electricity varies by time of day, season and ambient temperature (box 2.2). Daily demand typically peaks in early evening, while seasonal peaks occur in winter (driven by heating loads) and summer (for air conditioning). Demand normally reaches its maximum on days of extreme temperature, when air conditioning loads are highest.

Maximum demand for grid sourced electricity rose steadily until 2009, but then flat lined or declined in most regions for several years (figure 2.3). The trend began to reverse in 2015–16, with significantly higher maximum demand in most regions, though it remained well below historical peaks.

Outcomes in 2017–18 varied by region (table 2.2). Queensland continued its almost unbroken trend of rising maximum demand, setting a new record on 14 February 2018 during a prolonged heatwave. Victoria experienced higher maximum demand in 2017–18 than a year earlier, partly due to a warm summer driving air conditioning use and higher industrial demand for power. But the maximum was still 17 per cent below Victoria's demand record, set nine years ago.

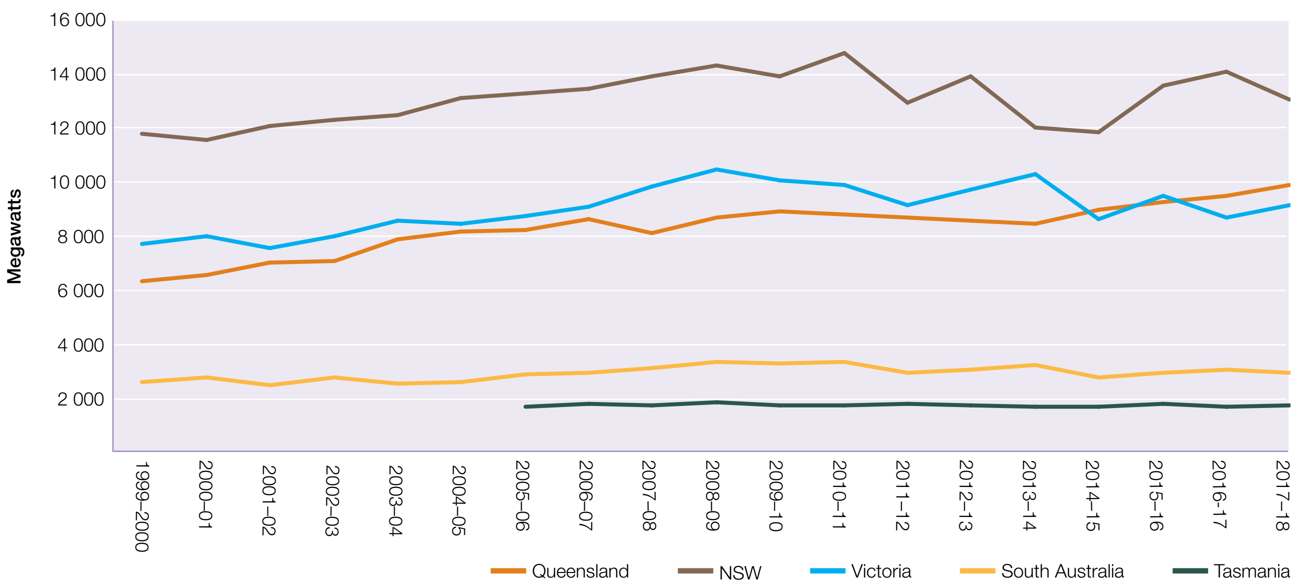
In NSW and South Australia maximum demand was significantly lower in 2017–18 than a year earlier. Demand was steady in Tasmania.

2 AEMO, *2018 electricity statement of opportunities,* August 2018, p. 4–6.

Table 2.2 **Maximum grid demand, by region, 2017–18**

	QUEENSLAND	NSW	VICTORIA	SOUTH AUSTRALIA	TASMANIA
Change from previous year (%)	4.4	–7.3	4.9	–4.0	0.6
Change from historical maximum (%)	0.0	–11.4	–16.8	–0.1	–0.1
Year of historical maximum	2017–18	2010–11	2008–09	2010–11	2008–09

Figure 2.3
Maximum grid demand, by region



Note (table 2.2 and figure 2.3): Maximum native demand (including scheduled and semi-scheduled generation, and intermittent wind and large scale solar generation) occurring at any time during the year. Excludes consumption from rooftop solar systems.

Source: AER; AEMO.

2.2 Generation technologies in the NEM

The NEM's generation plant uses a mix of technologies to produce electricity. Figure 2.19 maps the locations of generation plant, and the types of technology in use. Table 2.3 lists each plant. Figures 2.5–2.7 compare variations across regions, including movements over time.

Fossil fuel generators produce over 80 per cent of electricity in the NEM. The plants burn coal or gas to power a generator. The combustion process releases carbon emissions as a by-product into the atmosphere.

While large scale, fossil fuel fired synchronous generators still dominate, many older generators are nearing the end of their life, becoming less reliable and closing. Renewable generation is filling much of the gap as Australia transitions to a lower emissions 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. Coal fired generators have low operating costs, but are slow (and may be expensive) to start. For this reason, coal fired generators tends to operate relatively continuously.

Some gas powered generators can be switched on and off at short notice, but high operating costs tend to constrain their use. Hydroelectric plant has low operating costs, but finite water to draw on, so it cannot operate continuously. Intermittent generation, such as wind and solar, can operate only if weather conditions are favourable, but their operating costs are low.

Box 2.2 Regional demand patterns

The profile of electricity demand varies across regions. In some regions, grid demand is relatively constant throughout the year, while in others it is more variable. Load duration curves show the frequency of each level of electricity demand over a period of time, and provide an indicator of the variability of this demand. Figure 2.4 illustrates load duration curves for each national electricity market (NEM) region in 2017–18.

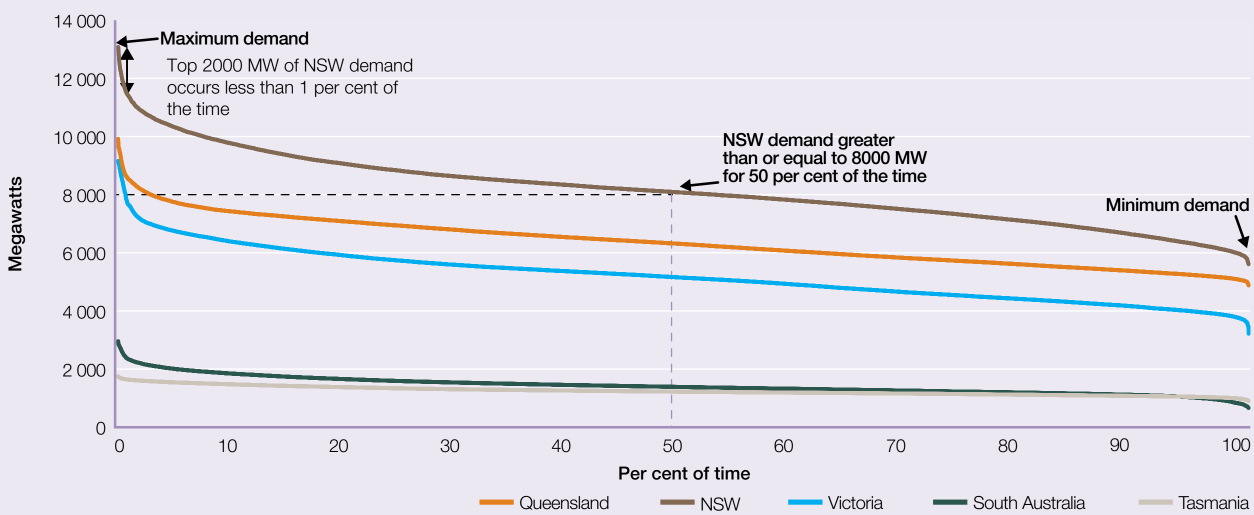
The NEM region with the highest *maximum* demand in 2017–18 was NSW (13 080 megawatts (MW)), followed by Queensland (9920 MW), Victoria (9160 MW), South Australia (2960 MW) and Tasmania (1750 MW). *Minimum* demand ranged from 660 MW in South Australia to 5600 MW in NSW. South Australia's lowest minimum demand now typically occurs in the middle of the day during summer (compared with overnight in most regions). This outcome reflects the region's relatively high output from rooftop solar photovoltaic systems.

Taking NSW as an example, grid demand was below 10 000 MW for more than 90 per cent of the year, as shown by the dotted line in the chart. During the very highest demand periods—occurring 1 per cent of the time, or less than four days a year—demand was up to 2000 MW higher than in the remaining 99 per cent of the year. That is, around 15 per cent (2000 MW) of NSW's generation fleet and transmission network capacity was required for just 1 per cent of the year (shown by the steep segment of the curve highlighted by the arrow in figure 2.4).

Regions with 'peaky' demand profiles benefit from generators such as open cycle gas plant that can be drawn on to meet relatively infrequent demand peaks. Demand response by electricity customers can also play a useful role in helping to reduce maximum demand for short periods.

Figure 2.4

Electricity demand duration



Note: Demand is ordered from maximum on the left to minimum on the right. Each point on the curve represents the percentage of time that demand exceeded that level during 2017–18. Native demand (including scheduled and semi-scheduled generation, and intermittent wind and large scale solar generation).

Source: AEMO; AER.

Figure 2.5
Generation in the NEM, by fuel source, 2017–18

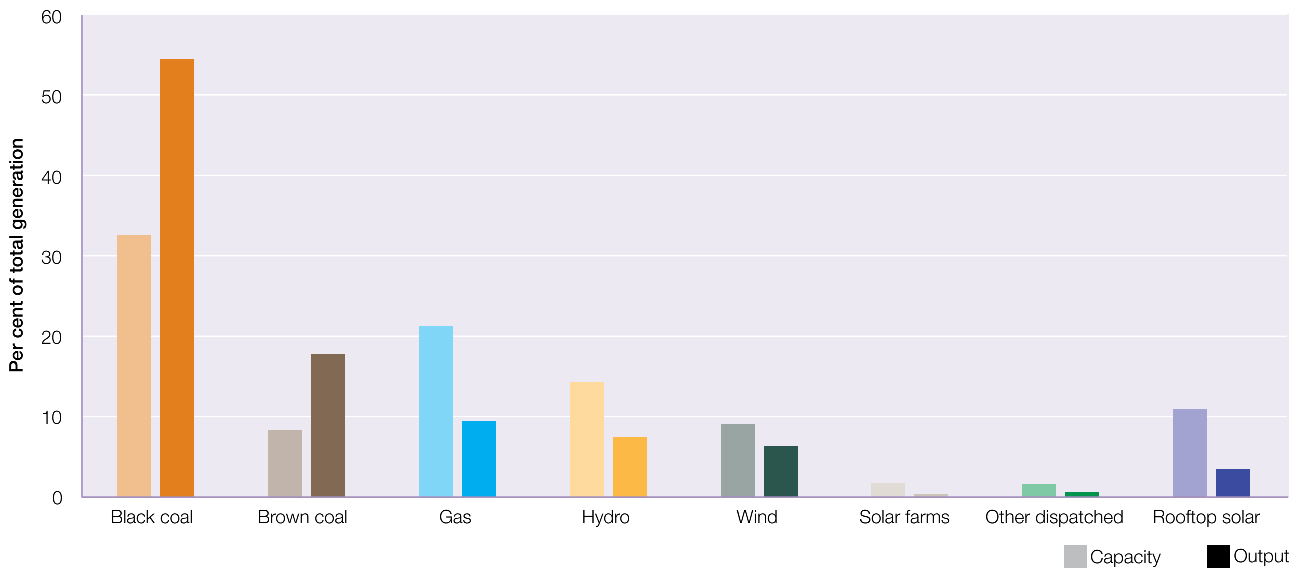
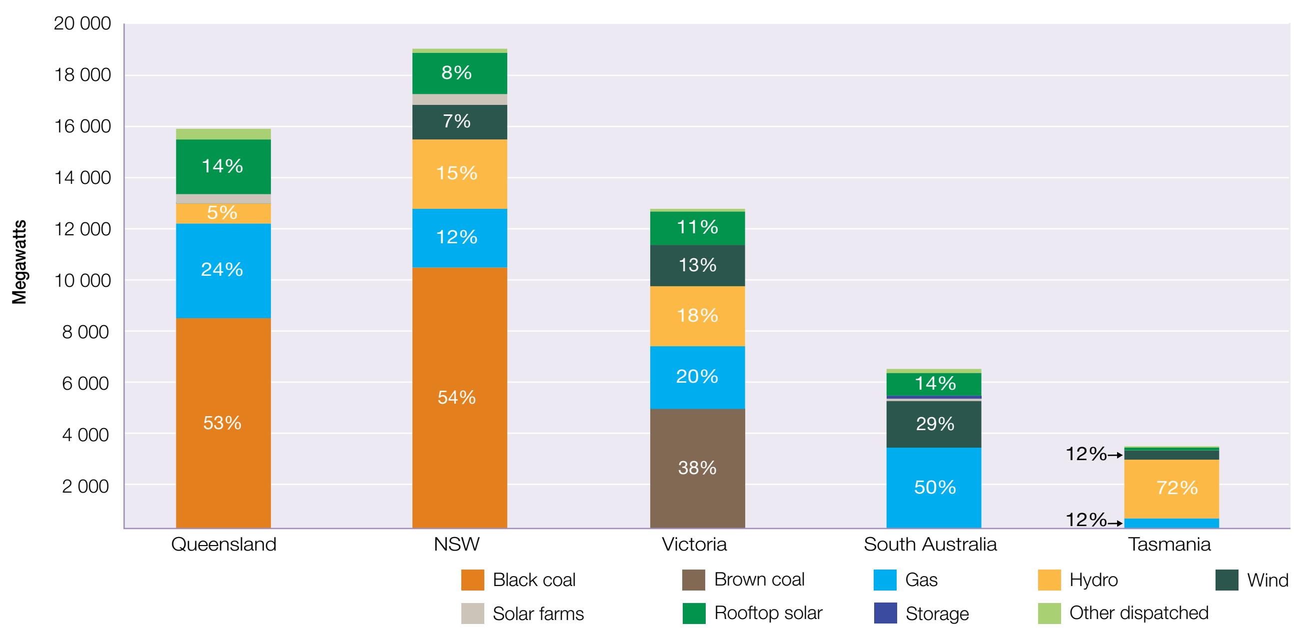


Figure 2.6
Generation capacity in the NEM, by region and fuel source

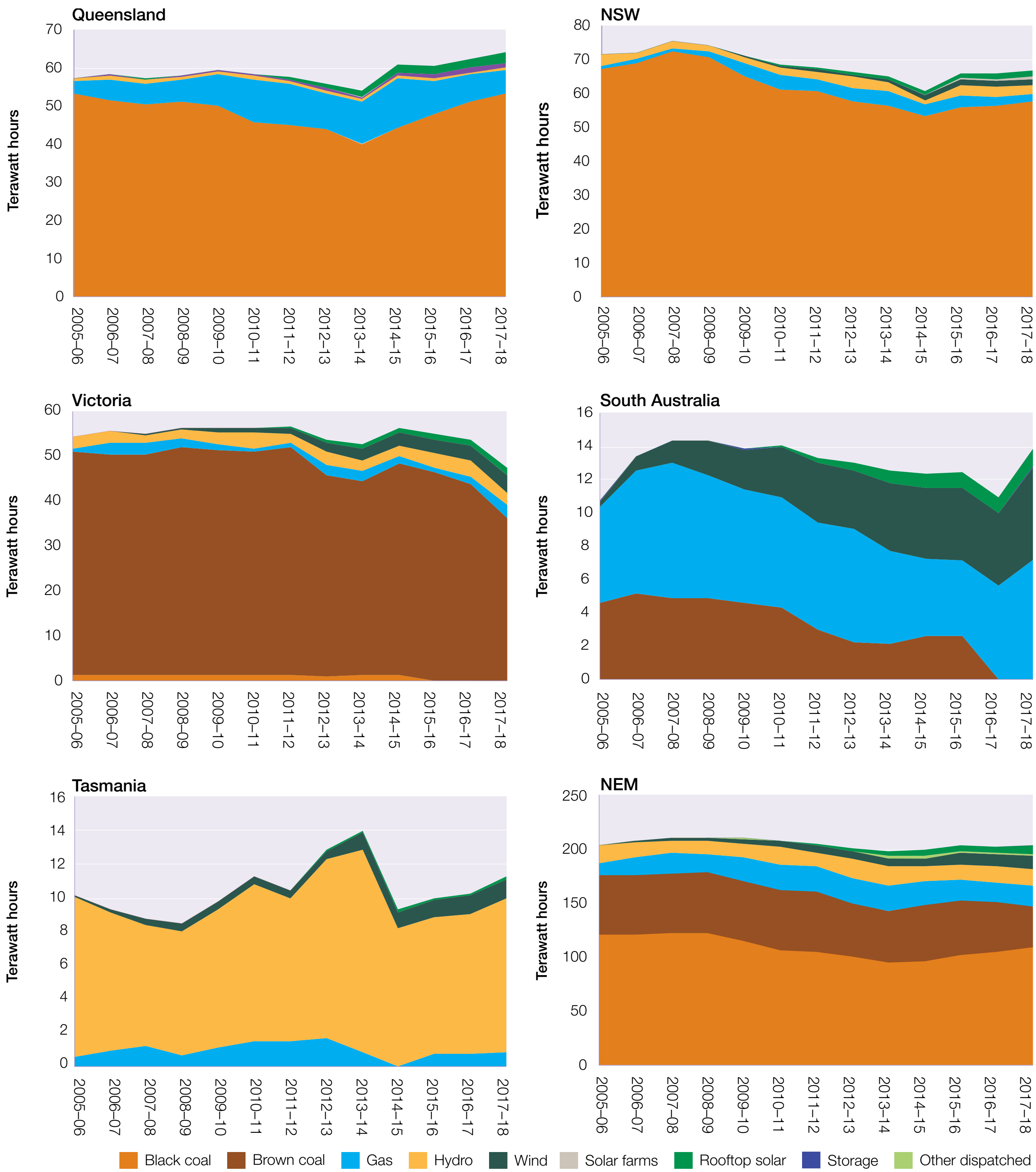


Note (figures 2.5 and 2.6): Generation capacity at 1 July 2018. Rooftop solar output estimates derived from CER data on installed capacity and AEMO system output assumptions. Other dispatch includes biomass, waste gas and liquid fuels. Storage includes only battery storage.

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

Figure 2.7

Changes in electricity generation, by region and fuel source



Note: Rooftop solar output estimates derived from CER data on installed capacity, and AEMO system output assumptions. Other dispatch includes biomass, waste gas and liquid fuels. Storage includes only battery storage.

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

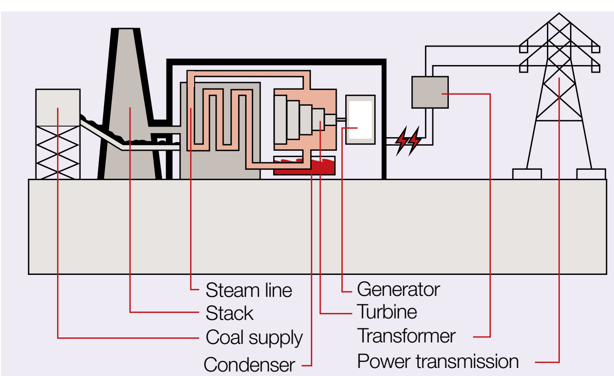
Some intermittent plant can pose challenges for power system security. In particular, the transmission network relies on rotational inertia, system strength, and frequency control mechanisms. But the capability of intermittent generation to provide these services, and the types of services required, are still evolving (section 2.6.3).

Despite challenges in integrating this plant into the grid, the shift to renewable generation continues to gather pace. The technology mix is evolving due to changes in the relative fuel and capital costs or different plant, technological advances making some plant more efficient (such as advances in combined cycle gas plants and thermal solar plants) and government policies to reduce carbon emissions (box 2.3).

2.2.1 Coal fired generation

Coal fired generators burn coal to create pressurised steam, which is then forced through a turbine at high pressure to drive a generator (figure 2.8).

Figure 2.8
Coal fired generation



Coal fired generation remains the dominant supply technology in the NEM, producing 73 per cent of all electricity traded through the market in 2017–18, when it operated at its highest summer output in a decade. But coal plant accounts for only 41 per cent of the market's generation capacity, reflecting that coal generators tend to run fairly continuously.

Coal plant operate in Victoria, NSW and Queensland. Victorian generators run on brown coal, while NSW and Queensland generators use black coal.

Brown coal, also known as lignite, can contain up to 70 per cent water, whereas black (or bituminous) coal has a lower water content and produces more energy than brown coal. Victorian brown coal is cheap to extract as the Gippsland region has abundant reserves in thick seams close to the earth's surface, making Victorian brown coal among the lowest cost coal in the world. But brown coal produces up to 30 per cent more greenhouse gas emissions than black coal when used to generate electricity.

Coal fired generators can require a day or more to start up, so have high start-up and shut-down 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 provide ancillary services that help maintain power system stability.[3]

Significant coal fired capacity has been retired from the market. In May 2016 Alinta retired its Northern power station in South Australia, removing 546 megawatts (MW) of capacity from the market. Then in March 2017 Engie retired its Hazelwood power station in Victoria, removing another 1600 MW of brown coal generation. The plant was over 50 years old, and was Australia's most emissions intensive power station. The closure was especially significant given Hazelwood's size, supplying around five per cent of the NEM's total output.

Following the plant closures, the remaining coal fired generation fleet operated at higher output levels. Over summer 2017–18 it operated at its highest level in a decade.. Black coal generation in particular has played a key role in replacing Hazelwood's generation.[4]

Closures of further ageing coal plant are expected. The most imminent is the planned retirement of AGL Energy's Liddell power station in NSW in 2022, which would remove 1680 MW of black coal capacity from the NEM. Additionally, Engie, Origin Energy and AGL Energy have each signalled they intend to make no further investment in coal plant.

2.2.2 Gas powered generation

Open-cycle gas turbine (OCGT) plant burn gas in a turbine to drive a generator (figure 2.9). 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

3 Synchronous generators—including hydroelectric and thermal plan such as coal, gas and solar thermal generators—can provide these services. The generators' heavy spinning rotors provide synchronous inertia that slows down the rate of change of frequency. They help with voltage control by producing and absorbing reactive power and also provide high fault current that improves system strength.

4 AEMO, *Quarterly Energy Dynamics*, Q1 2018, p. 7.

Figure 2.9

Open cycle gas powered generation

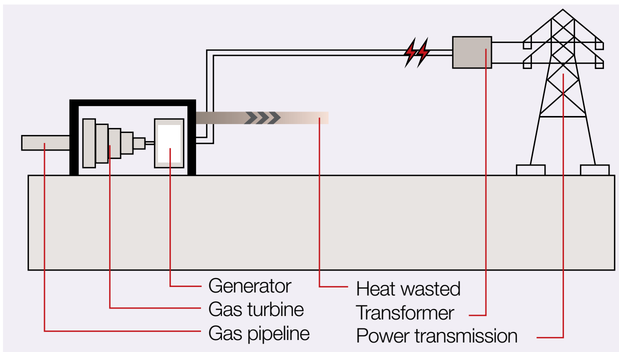
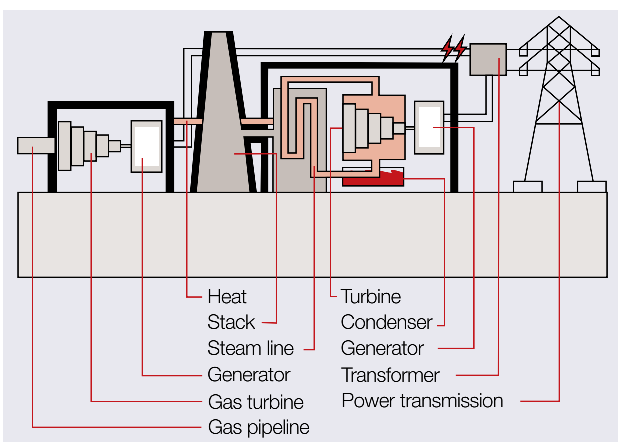


Figure 2.10

Combined cycle gas powered generation



a second turbine (figure 2.10). The capture of waste heat improves the plant's thermal efficiency, making it more suitable for longer operation than open cycle plant.

Gas plant can operate more flexibly than coal, with open cycle plant (and newer CCGT plant) in particular needing as little as five 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 emissions intensive as the most efficient coal fired plant.[5]

Despite these benefits, gas is a relatively expensive fuel for electricity generation, so gas generators more typically operate as 'flexible' or 'peaking' plants. Across the NEM, gas powered plant accounted for 21.3 per cent of plant capacity in the NEM in 2017–18 (up from 19.5 per cent in 2016–17), but supplied only 9.5 per cent of electricity generated (up from 8.8 per cent). The low capacity factor reflects that this plant technology is not widely used to produce baseload power. South Australia relies more on gas powered generation than other regions. In 2017–18, the state produced 56 per cent of its local generation from gas plant.

Gas generation in the NEM tends to be seasonal, peaking in summer (and sometimes winter) when electricity demand and prices are highest (section 4.9.1). It also varies with the amount of intermittent generation and outages affecting coal fired generators.

More recently, sharply higher gas fuel costs linked to Queensland's LNG industry and a lack of new gas supplies slowed demand for gas powered generation from 2015 (figure 2.11). 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 21 per cent of Queensland's electricity output in 2014–15 to just 9 per cent in 2017–18.

A similar squeezing of gas powered generation was apparent for much of 2018 in NSW. Over summer 2017–18 NSW recorded its lowest quarterly level of gas powered generation since 2009—68 per cent below average summer output over the decade.[6] But the retirement of coal generators in Victoria and South Australia has made gas generation critical to meeting electricity demand when renewable generation is low in those regions. This outcome resulted in gas generation in 2017–18 being 270 per cent higher in Victoria than two years earlier, and 160 per cent higher in South Australia.

In 2018 AEMO forecast gas demand for power generation may be 50 per cent lower in 2019 than its year-ahead forecast for 2018. It attributed this reduction to new wind and solar plants coming online and filling more of the supply gap left by the closure of coal plants, reducing the need for gas powered generation.[7]

Hydroelectric generation

Hydropower uses the force of moving water to generate power. The technology involves channelling falling water

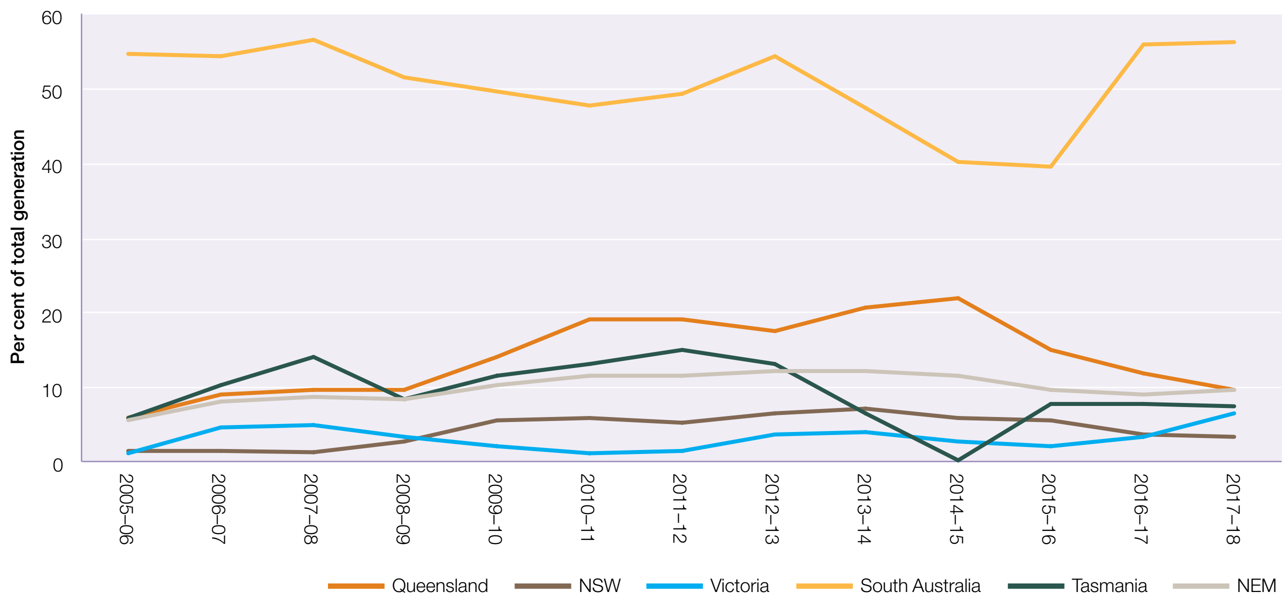
5 Dr Alan Finkel AO, Chief Scientist, Chair of the Expert Panel, *Independent review into the future security of the national electricity market: blueprint for the future*, June 2017, p. 109.

6 AEMO, *Quarterly Energy Dynamics,* Q1 2018, p. 9.

7 AEMO in 2018 forecast gas demand for gas powered generation of 88 PJ in 2019. In 2017 it forecast gas demand for gas powered generation of 176 PJ in 2018. AEMO, *Gas statement of opportunities,* June 2018, p. 15.

Figure 2.11

Gas powered generation



Source: AER; AEMO.

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 2.12). Hydroelectric generators are synchronous generators, providing power that can be dispatched when required and other services that support power system security.

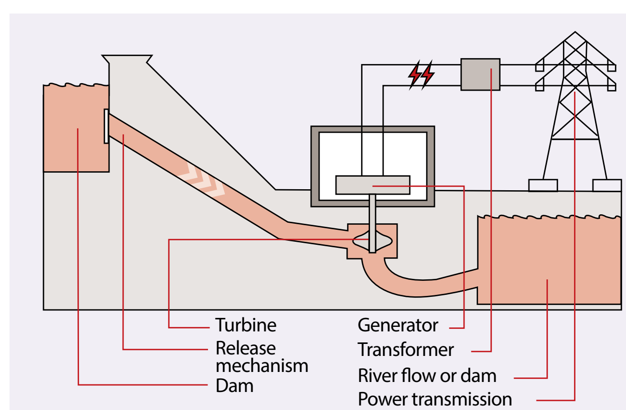
Most of Australia's hydroelectric plants are large scale projects that are over 40 years old. A number of 'mini-hydro' schemes also operate. These schemes can be 'run-of-river' (with no dam or water storage) or use dams that are also used for local water supply, river and lake water level control, or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

While hydroelectric plants have low fuel costs (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. Some pumped hydroelectric generation already operates in the NEM, but larger scale projects are also being explored (section 2.2.6).

Prevailing 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.

Figure 2.12

Hydroelectric generation



Hydroelectric generators accounted for 14.3 per cent of capacity in the NEM in 2017–18, and supplied 7.4 per cent of electricity generated. Tasmania is the region most reliant on hydrogeneration, with 82 per cent of its 2017–18 grid generation coming from that source. Snowy Hydro is a major generator in the NSW and Victoria regions of the NEM. Queensland also has some hydrogeneration (figure 2.6).

Hydrogeneration levels in recent years have varied due to weather conditions, market incentives to generate, and subsidy arrangements under the RET scheme. Hydrogeneration tracked higher in 2018— second quarter output set a new record for that quarter and was the fifth highest output for any quarter since the NEM began.[8]

Tasmania's hydrogeneration output in 2017–18 was 10 per cent higher than a year earlier, in part due to a two month Basslink interconnector outage that suspended imports and required the state to be self-sufficient in generation.

2.2.3 Wind generation

Wind turbines directly convert the kinetic energy of the 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 2.13). Wind turbines are typically designed to operate to wind speeds up to 90 km per hour. They shut down automatically in high winds until wind speeds return within the turbine's operations range.

Renewable generation, including wind, have filled much of the supply gap left by thermal plant closures (figure 2.14). Wind generation has risen under the RET scheme, which subsidises renewable generation (box 2.3).

Wind generators accounted for 9.1 per cent of the NEM's capacity and generated 6.3 per cent of grid supplied electricity in 2017–18. Since 2017 an additional 1800 MW of wind capacity was added to the NEM (around 60 per cent of all investment over this period). Overall, wind generation rose by 20 per cent in 2017–18.

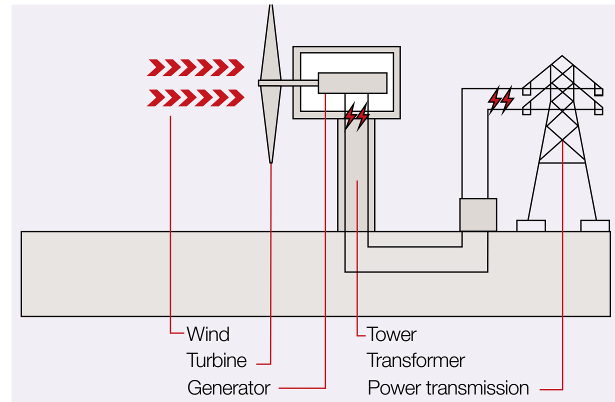
Its penetration is especially strong in South Australia, where it represented 34 per cent of registered capacity and met 40 per cent of the state's electricity requirements in 2017–18. More recently the focus of new wind investment has shifted to NSW and Victoria, with those regions accounting for close to 70 per cent of capacity installed or committed since 2017.

Weather conditions affect wind generation levels. Favourable conditions on 7 July 2018 resulted in record levels of wind output, peaking at 3843 MW. On that day, wind generation accounted for almost 16 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 19 500 MW. Thirteen wind projects, comprising nearly 2500 MW of capacity, are expected to be commissioned by June 2020 (table 2.6).

8 AEMO, *Quarterly Energy Dynamics,* Q1 2018, p. 8.

Figure 2.13
Wind powered generation



2.2.4 Solar generation

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 16 million terawatt hours of solar radiation per year.[9] Most solar investment to date has been in photovoltaic (PV) systems that use layers of semi conducting material to convert sunlight into electricity (figure 2.15).

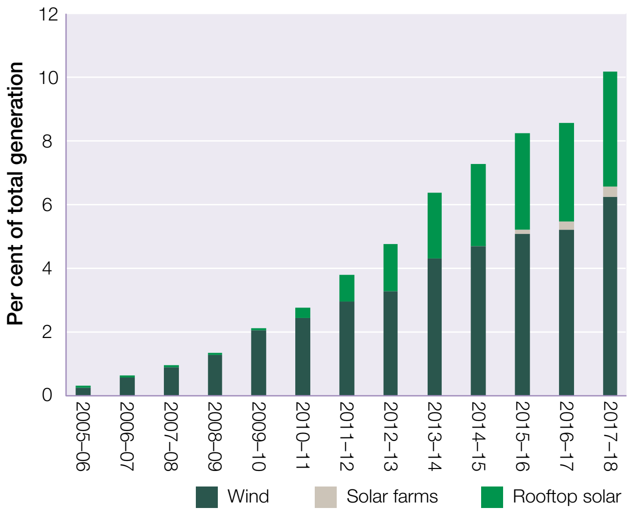
Despite eligibility under the RET scheme, investment in large scale solar farms has been slow to develop in Australia. Commercial solar farms met only 0.3 per cent of the NEM's electricity requirements in 2017–18. But the uptake of rooftop solar PV installations on residential and business premises has been more rapid. These installations met 3.4 per cent of total electricity generation in 2017–18.

Commercial solar farms

Large scale solar generation accounts for less than 1 per cent of total NEM generation. AGL was an early mover, commissioning the Nyngan and Broken Hill solar farms in 2015. The industry continues to grow, supported by funding from the Australian Renewable Energy Agency (ARENA) and the Clean Energy Finance Corporation. At November 2018 large scale solar accounted for around 1850 MW of installed capacity. Sixteen solar farms were commissioned in 2017 and 2018 (totalling 1230 MW), and a further 22 projects (2040 MW) across the NEM were expected to be commissioned by the end of 2019–20.

9 Geoscience Australia, *Solar Energy*, available at: www.ga.gov.au/scientific-topics/energy/resources/other-renewable-energy-resources/solar-energy.

Figure 2.14
Wind and solar generation share of total generation



Note: Rooftop solar output estimates derived from CER data on installed capacity, and AEMO system output assumptions.

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

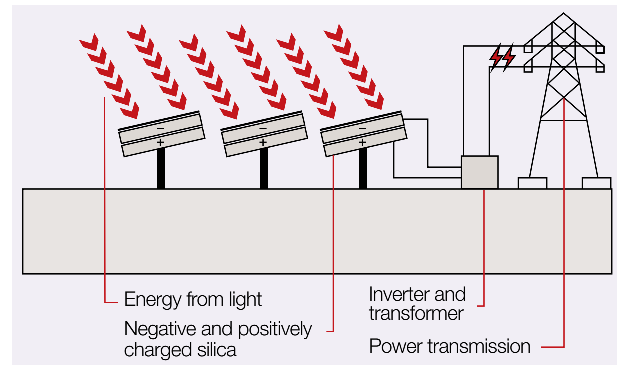
While NSW was the initial focus for solar plant development, the majority of new capacity will be located in Queensland. The largest operating plant at October 2018 is Coleambally solar farm in NSW (180 MW).

Commercial solar farms in Australia produce electricity using arrays of *PV panels*. The conversion of sunlight into electricity takes place in cells of specially fabricated semiconductor crystals. *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.

No solar thermal plant were operating in the NEM in 2018, but two facilities are proposed in South Australia. Construction of the 150 MW Aurora thermal plant was scheduled to begin in 2018, with commissioning expected in 2020 (although the plant was not listed as committed by AEMO at November 2018).[10] Up to 10 hours of storage capacity will enable it to supply dispatchable energy into the grid at any time, including at night.[11] A smaller 60 MW plant has been proposed for Port Augusta, with expected commissioning in 2021.

10 Aurora Solar, *Aurora Solar Energy Project Update,* May 2018.
11 Clean Energy Council, *Clean Energy Australia Report*, 2018, p. 51.

Figure 2.15
Solar photovoltaic power plant



Rooftop solar PV generation

While large scale solar generation has been slow to develop in Australia, consumers are more actively managing their energy supply and consumption by installing rooftop solar PV panels.

Few solar PV systems were installed before 2010, but they account for over 30 per cent of renewable capacity added since that date. In 2018 solar PV systems were meeting 3.4 per cent of the NEM's electricity requirements. Its contribution is highest in South Australia, where it met over 8 per cent of electricity requirements. In South Australia and Queensland, over 30 per cent of households have installed PV systems.[12]

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.

At October 2018 Australians had installed nearly two million solar PV rooftop systems.[13] In the NEM, the total installed capacity of these systems reached 6.6 gigawatt in October 2018, equivalent to 11 per cent of the NEM's total generation capacity.

Australia's 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 the Small-scale Renewable Energy Scheme and premium feed-in tariffs—strengthened incentives to install these systems.

12 AEMO, *2018 electricity statement of opportunities,* August 2018, p. 27.
13 Clean Energy Regulator, *Postcode data for small scale installations*, Small generation units—solar, available at: www.cleanenergyregulator.gov.au/RET/Forms-and-resources/Postcode-data-for-small-scale-installations.

New installations of solar PV systems declined from around 21 000 systems per month in 2011–12 to 13 000 systems per month in 2017–18. But the rate at which capacity is added is rising—1 100 000 MW of solar PV capacity was installed in 2017–18 compared with the previous high of 880 000 MW in 2012–13.

Lower installation costs and uptake of solar PV systems by commercial businesses have seen a shift towards larger systems (figure 1.21 in chapter 1). In the year to 30 June 2018, for example, solar PV installations grew by almost 60 per cent in the business sector, compared with 20 per cent in the residential sector.[14] The average size of systems installed in 2017 more than doubled that in 2011, rising from 2.5 kilowatts (kW) to 5.5 kW.

The uptake of solar PV continues to shift maximum grid demand to later in the day, when the contribution of solar PV is declining. Within the next decade, maximum grid demand in most regions may become so late in the day that adding more PV installations will not materially reduce it further (unless supported by storage).

2.2.5 Storage

Until recently, storing electricity was not commercially viable, but emerging technologies are making storage increasingly attractive. The uptake of battery storage and electric vehicles continues to gather momentum internationally, with declining battery costs and advances in the storage capacity of batteries. The growth in intermittent generation creates business opportunities for storage to offer fast response system security services when solar and wind generation fluctuate.

For smaller customers, storage offers opportunities to store surplus energy from solar PV systems and draw on it when needed, reducing their grid demand. The wider use of cost reflective tariffs may make storage more attractive, by creating incentives to charge batteries during low cost periods and use stored power when prices are high.

Australian households already show significant interest in and awareness of batteries. Nearly three quarters of customers with solar PV systems are interested in using batteries.[15] The Clean Energy Council cited estimates that Australians had installed 28 000 battery systems at January 2018, up from 8000 systems a year earlier. [16] The Clean Energy Regulator's estimates are more conservative at 11 500 battery units installed by November 2018.[17]

On a larger scale, South Australia in December 2017 commissioned the world's largest lithium ion battery at the Hornsdale wind farm (box 2.4). As well as acting operating in the electricity market, the battery provides stability services to the grid.[18]

Other battery projects have since been announced, including at Gannawarra (25 MW) and Ballarat (30 MW) in Victoria. The projects aim to complement and 'firm' solar and wind farm generation.

Aggregation of household battery systems to provide grid scale services is also being explored. Tesla, with support from the South Australian Government, intends to trial a virtual power plant of solar PV and battery systems on 1100 properties to enhance grid security and lower demand. If successful, the trial will be expanded to 50 000 households.[19] ARENA was also supporting trials in South Australia by AGL and Simply Energy of 'virtual power plants' that aggregate the output of household solar and storage systems.

Pumped hydroelectricity

Large scale storage is being explored 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). But advances in technology and the rise of intermittent generation are providing new opportunities for this form of storage to be deployed at a larger scale. In particular, pumped hydroelectricity forms the basis of the proposed 'Snowy 2.0' (2000 MW) and 'Battery of the Nation' (2500 MW) projects in NSW and Tasmania (section 2.7.1).

14 AEMO, *2018 electricity statement of opportunities,* August 2018, p. 5.
15 Energy Consumers Australia, *Energy Consumer Sentiment Survey,* June 2018, p. 36.
16 Clean Energy Council, *Clean Energy Australia Report*, 2018, p. 34.
17 Clean Energy Regulator, *Postcode data for small scale installations*, Solar PV systems with concurrent battery storage capacity by year and state/territory, available at: www.cleanenergyregulator.gov.au/RET/Forms-and-resources/Postcode-data-for-small-scale-installations.
18 AEMO*, Initial operation of the Hornsdale Power Reserve battery energy storage system*, April 2018, p. 4.
19 Government of South Australia, South Australia's Virtual Power Plant: www.virtualpowerplant.sa.gov.au/virtual-power-plant.

Box 2.3 Carbon emissions policies and the electricity sector

Australia has international commitments to reduce its carbon emissions by 26–28 per cent below 2005 levels by 2030. This effort builds on an earlier target of reducing emissions by 5 per cent below 2000 levels by 2020. There is no specific target for the electricity sector.

Australia's carbon emissions have risen continuously since 2015, but the electricity sector's contribution has lowered since the closure of coal fired generators in South Australia (in 2016) and Victoria (in 2017).

Despite this, the electricity sector remains the largest contributor to Australia's carbon emissions, accounting for 35 per cent of all emissions (figure 2.16). Victoria's brown coal plants are the most emissions intensive power stations operating in Australia, followed by black coal plant and gas powered generation. Combined cycle gas plants are less emissions-intensive than open cycle plants. Wind, hydroelectric and solar photovoltaic (PV) power stations generate negligible emissions.

Australia's policy settings to reduce carbon emissions in the electricity sector have changed direction many times. Policies included the Renewable Energy Target (RET) scheme (launched in 2001 and amended several times), carbon pricing (introduced in 2012 but abolished two years later), funding for schemes that abate carbon emissions (launched in 2014 but with little engagement from the electricity sector) and a proposal to integrate emissions and reliability targets through the National Energy Guarantee (NEG) (abandoned in September 2018).

Alongside these schemes, state and territory governments offered subsidies for rooftop solar PV generation, and in some regions set renewable energy targets that are more ambitious than the national scheme.

Renewable Energy Target

The RET scheme requires electricity retailers to source a proportion of their energy from renewable sources developed since 1997. An expert panel in 2014 found the RET scheme had successfully led to the abatement of more than 20 million tonnes of carbon emissions.[a]

The scheme applies different incentives for large scale renewable supply (such as wind and solar farms) and small scale systems (such as solar water heaters and rooftop solar PV systems installed by households and small businesses). It requires energy retailers to buy renewable energy certificates created for electricity generated by accredited power stations, or from the installation of eligible solar hot water or small generation units. The revenue from these certificates is in addition to earnings through the wholesale market.

Amendments to the RET scheme in June 2015 reduced the 2020 target for energy from large scale renewable projects from 41 000 gigawatt hours (GWh) to 33 000 GWh. On current estimates, this target would result in 23.5 per cent of Australia's electricity generation in 2020 being sourced from renewables. Each year the renewable target rises towards the 2020 target; the annual target for 2018 is just over 28 600 GWh. The Australian Government's policy in late 2018 was to not increase the target beyond the 2020 requirement of 33 000 GWh, and to not extend or replace the target after it expires in 2030.[b]

RET certificate prices fluctuate depending on the availability of RET certificates relative to the prevailing target. Large scale generation certificates (LGCs) traded at around $40 in 2011, eased to $22 in June 2014 when the scheme's future was uncertain, then recovered sharply from late 2014 when it became clear that new renewable investment was not keeping pace with the rising target, creating a shortfall in available LGCs.[c] Prices neared $90 in January 2017 close to the effective penalty that a business must pay for failing to surrender LGCs. Prices remained around this level throughout 2017, before easing over 2018 to around $65 in November.

In February 2018 the Clean Energy Regulator announced it was confident there will be sufficient renewable generation by 2020 to meet the RET.[d] This outcome would result in an oversupply of LGCs through to the end of the scheme in 2030. At November 2018, forward contracts for LGCs from 2020 were trading below $30, reflecting this expectation.

Prices for certificates from small scale projects have been steady at around $40 since 2013. The design of the small scale scheme means prices are largely tied to the accuracy of forecasts on qualifying system installations.

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, starting at $23 per tonne of carbon dioxide equivalent emitted. The government intended to replace the fixed price with an emissions trading scheme from July 2014, under which the market would determine a carbon price.

Over the two years of carbon pricing, output from brown coal fired generators declined by 16 per cent (with plant use dropping from 85 per cent to 75 per cent), and output from black coal generators fell by 9 per cent. Coal generation's share of NEM output fell to an historical low of 73.6 per cent in 2013–14, while gas powered, wind and hydroelectric generation shares rose significantly.

Overall, these changes contributed to the emissions intensity of NEM generation falling by 4.7 per cent over the two years that carbon pricing was in place. This drop in emissions intensity, combined with lower NEM demand, contributed to a 10.3 per cent fall in total emissions from electricity generation over those two years.

Emissions Reduction Fund

In 2014 the Australian Government replaced carbon pricing with the Emissions Reduction Fund (ERF), under which the government pays for emissions abatement through auctions run by the Clean Energy Regulator. Seven auctions were held to July 2018, spending $2.3 billion to abate 192 million tonnes of carbon emissions. The reverse auction scheme effectively priced carbon at an average price of $11.97 per tonne of abatement. Purchases have steadily declined over recent auctions, from 50 million tonnes of abatement in the third auction, to under eight million tonnes in the sixth and seventh auctions.[e]

Many ERF projects involve growing native forests or plantations, otherwise known as carbon farming. By the sixth auction in 2018, 12 projects had received funding under the ERF that involved new electricity production or upgrades to existing plant. The total abatement committed under contract for these projects is 3.56 million tonnes CO_2-e. Most of the projects capture and combust waste methane gas from coalmines or landfill for use in electricity generation.[f] The electricity projects represented less than 2 per cent of carbon abatements funded under the scheme.

A safeguard mechanism aims to ensure the reductions purchased through the fund are not offset by increases in emissions elsewhere in the economy. The mechanism requires covered facilities to ensure their net emissions remain below an historical baseline. It currently covers 203 facilities with combined annual emissions of 131.3 million tonnes.[g] In late 2018, less than 10 per cent of the $2.55 billion allocated to the fund remained.[h]

National Energy Guarantee

The Independent Review into the Future Security of the National Electricity Market (the Finkel review) in June 2017 found ongoing uncertainty about Australia's carbon emissions policies had detrimentally affected the electricity sector, particularly relating to investor certainty.[i] The Australian Government rejected the review's recommendation for a clean energy target. Instead, it proposed addressing the market's concerns around reliability and carbon emissions through an integrated policy addressing both issues.

The newly created Energy Security Board developed the National Energy Guarantee (NEG), which comprised:

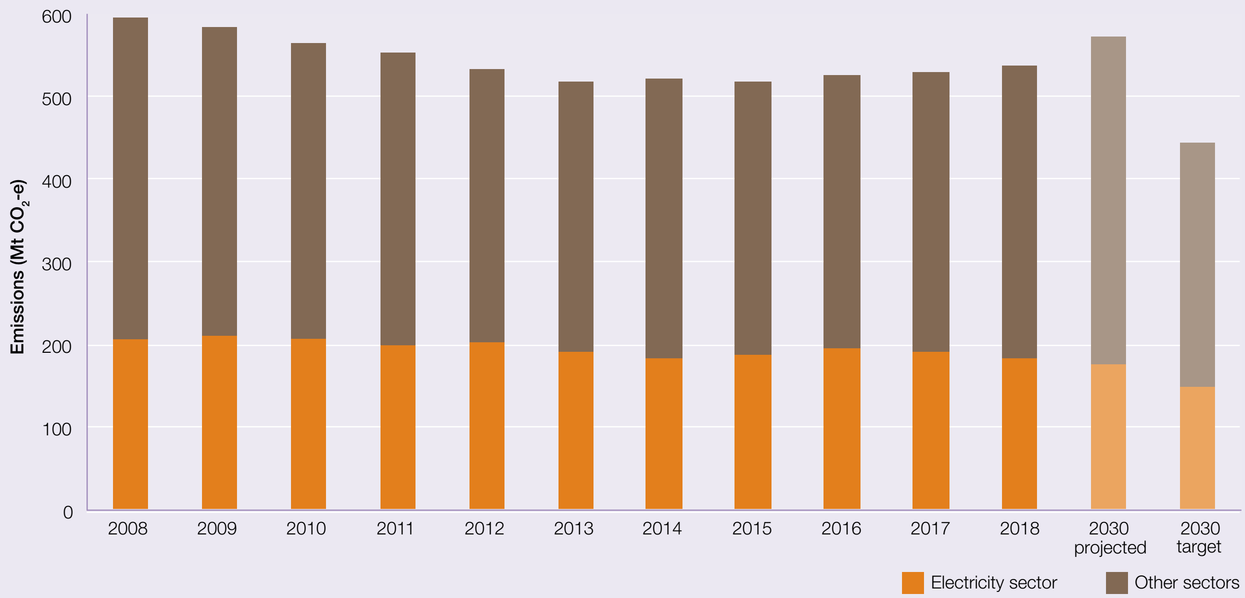
- a reliability guarantee requiring retailers to produce or contract for sufficient dispatchable[j] energy to meet the maximum energy needs of their customers if the Australian Energy Market Operator (AEMO) identifies (and the AER verifies) a risk that the reliability standard will not be met. AEMO could intervene to ensure sufficient dispatchable energy is available, should the market fail to achieve this. The guarantee included measures to increase liquidity in electricity futures (contract) markets.
- an emissions guarantee requiring retailers to produce or contract for electricity in ways that would meet an average emission level over a specified period. The emissions level would be determined by government and enforced by the Australian Energy Regulator.

The twin guarantees aimed to encourage investment in low emissions technologies while ensuring sufficient dispatchable energy is available to ensure the electricity system remains reliable. The scheme's implementation required all national electricity market jurisdictions to ratify the policy.

Progress on the NEG stalled in August 2018 when the Australian Government removed the policy's emissions component. The government abandoned the NEG as a package, but retained the reliability component as part of a new energy policy.

Figure 2.16

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 Energy and Environment in December 2017 in the absence of policy intervention.

Source: Department of the Environment and Energy, *Quarterly Update of Australia's National Greenhouse Gas Inventory*, December 2017.

a Climate Change Authority, *Renewable Energy Target Review—Report,* December 2014, p. 18.

b Commonwealth, *Parliamentary Debates,* House of Representatives, 18 September 2018, 9325 (Angus Taylor, Minister for Energy).

c A certificate represents 1 MWh of output from qualifying renewable generators (or deemed output from small scale generation).

d Clean Energy Regulator, *Surplus of large-scale generation certificates after final surrender*, media release, 22 February 2018.

e Auction results published by the Clean Energy Regulator: www.cleanenergyregulator.gov.au/ERF/Auctions-results.

f Excludes energy efficiency projects that mostly involve upgrades to devices that consume electricity. Projects do not necessarily connect to the NEM. Clean Energy Regulator, Emissions Reduction Fund project map, available at: www.cleanenergyregulator.gov.au/maps/Pages/erf-projects/index.html.

g Clean Energy Regulator, *2016–17 Safeguard facility reported emissions,* five July 2018.

h Clean Energy Regulator, *Auction June 2018*, 31 October 2018, available at: www.cleanenergyregulator.gov.au/ERF/Auctions-results/june-2018

h 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.

j Dispatchable capacity is capable of being supplied when required. It includes coal fired, gas powered and hydroelectric capacity, and intermittent generation such as wind or solar that is supported by battery storage.

2.3 Trade between NEM regions

Transmission interconnectors (figure 3.1 and table 3.1 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 entire market. It also allows each NEM region to access the cheapest available electricity in the market.

Queensland is a net electricity exporter, given its surplus capacity and (traditionally) low fuel prices. Higher fuel costs for gas and black coal reduced Queensland exports in 2015–16 and 2016–17, but improving cost conditions and the loss of brown coal capacity in other regions led to a rise in exports in 2017–18 (figure 2.17).

Victoria's abundant supplies of low priced brown coal generation also traditionally made it a net exporter of electricity. But Hazelwood's closure eliminated Victoria's trade surplus in 2017–18.

NSW has relatively high fuel costs, typically making it a net importer of electricity. Its trading position tends to be relatively stable, although improved black coal availability for its generation fleet in 2017–18, combined with less availability of cheap brown coal generation in Victoria, reduced its imports.

South Australia was traditionally an electricity importer, due to a lack of low cost local supply. Coal plant withdrawals increased the region's trade dependency, making it proportionally the NEM's highest importer in 2016–17. But surging local wind generation, combined with reduced availability of brown coal generation in Victoria, made it more self-sufficient in 2017–18, resulting in a trade surplus.

Tasmania's trade position varies, depending on local and NEM wide conditions. It 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. By late 2015 Tasmania was importing up to 40 per cent of its energy needs, despite outages on the Basslink interconnector to Victoria.

With Basslink back in service and hydroelectric storage returning to normal levels, Tasmania returned to a net exporting position in 2016–17. Rising Victorian wholesale prices further reduced Tasmania's trade dependence, and in 2017–18, it again became a net exporter to the mainland.

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 rates of price alignment, with the duration of network congestion on interconnectors linking the regions fairly stable. Price alignment between Victoria and South Australia has been less regular, with congestion frequency on the Victoria–South Australia interconnectors more than doubling 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 (which increased its capacity) 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 2017–18, up from 60 per cent in the previous year (figure 2.18).

Interpreting alignment rates as an overall 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.[20]

2.4 Generation businesses

Around 150 registered generators (comprising 240 generation units) sell electricity into the NEM spot market. Table 2.3 lists the major generators, plant technologies and ownership arrangements, and figure 2.19 maps their locations.

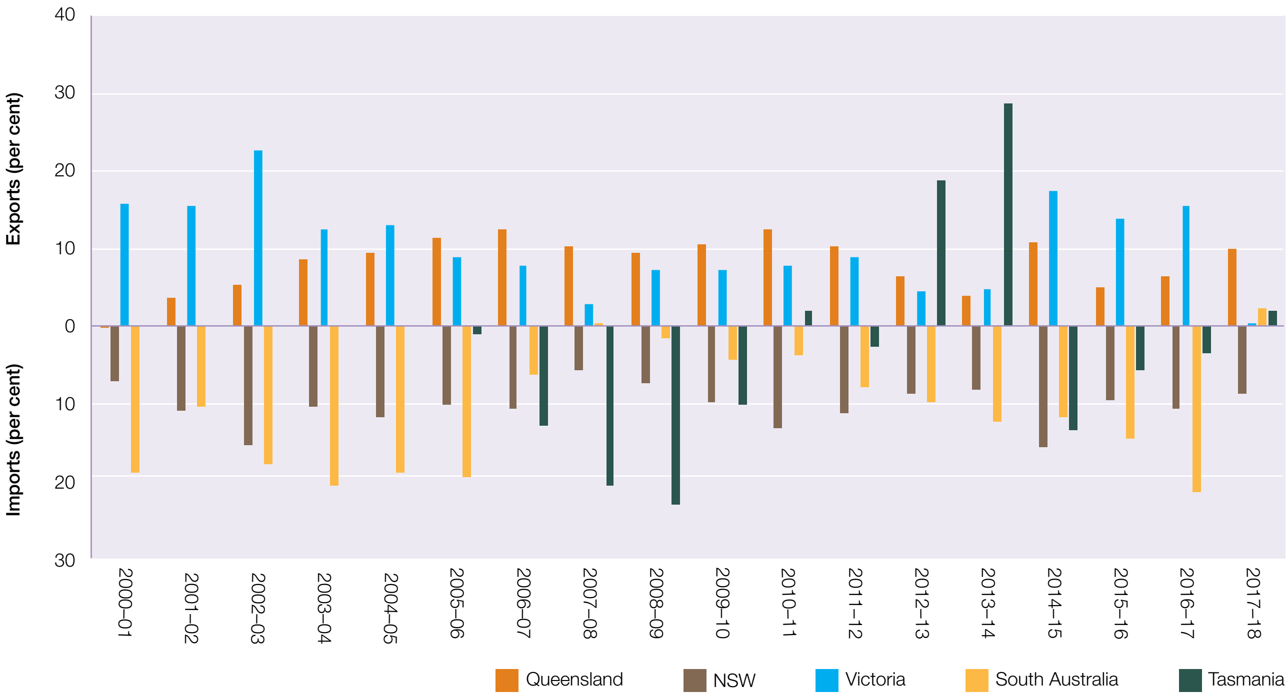
Private entities own most generation capacity in Victoria, NSW and South Australia. AGL Energy, EnergyAustralia, Origin Energy, Snowy Hydro and Engie are among the leading plant owners, although the scale of each business varies between regions. Government owned corporations own or control the majority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

Section 2.8 examines the market structure more closely, and section 2.11 considers the market's competitiveness.

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

Figure 2.17

Interregional trade as a percentage of demand

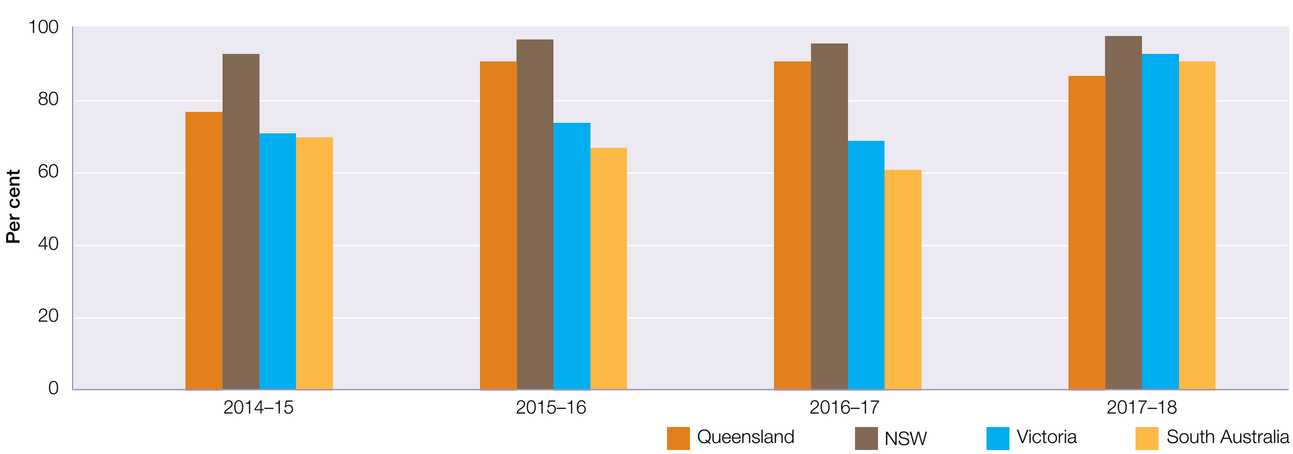


Note: Net interregional trade (exports less imports) divided by regional (native) demand.

Source: AER; AEMO.

Figure 2.18

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 at least one neighbouring region, accounting for transmission losses.

Source: AEMO; AER.

Table 2.3 **Generation plant in the NEM, 2018**

TRADING RIGHTS	CAPACITY (MW)	POWER STATION (MW)	OWNER
Queensland	13 261		
Stanwell Corporation	3 839	Stanwell (1440); Tarong (1400); Tarong North (443); Barron Gorge (60); Kareeya (86); Mackay (34); Swanbank (350)	Stanwell Corporation (Qld Government)
CS Energy	3 583	Callide B (620); Kogan Creek (713); Wivenhoe (570)	CS Energy (Qld Government)
		Gladstone (1680)	Rio Tinto 42%; NRG Energy 38%; others 20%
Origin Energy	1 423	Darling Downs (580); Mt Stuart (400); Roma (54)	Origin Energy
		Daydream (150)	Edify Energy
		Darling Downs (109)	APA Group
		Clare (100)	Fotowatio Renewable Ventures
		Daandine (30)	APT Petroleum Pipeline Holdings
CS Energy 50%; InterGen 50%	840	Callide C (840)	CS Energy (Qld Government) 50%; InterGen 50%
InterGen	612	Millmerran (612)	InterGen/China Huaneng Group 59%; KIAMCO/Daelim 35%; others 6%
Alinta Energy	534	Braemar 1 (491); Collinsville (43)	Alinta Energy (Chow Tai Fook Enterprises)
Arrow Energy	495	Braemar 2 (495)	Arrow Energy (Shell 50%; PetroChina 50%)
ERM Power	340	Oakey (282); Hamilton (58)	ERM Group; Wirsol 95%; Edify Energy 5%
RTA Yarwun	180	Yarwun (180)	Rio Tinto Alcan
Arrow Energy 50%; AGL Energy 50%	155	Townsville (155)	RATCH Australia (Ratchaburi Electricity Generation 80%; Ferrovial 20%)
EnergyAustralia	128	Ross River (128)	Pallisade Investment Partners
Sun Metals Corporation	124	Sun Metals (124)	Sun Metals Corporation
Wilmar International	118	*Pioneer Sugar Mill (68);Invicta Sugar Mill (50)*	Wilmar International
AGL Energy	109	*Moranbah North(64); German Creek(45)*	Energy Developments (DUET Group)
Shell	90	Condamine (90)	Queensland Gas Company
Telstra	72	Emerald (72)	Lighthouse Infrastructure Management Limited
Queensland Government	50	Kidston solar (50)	Genex Power Limited
Mackay Sugar	48	*Racecourse Mill(48)*	Mackay Sugar
Ergon Energy	34	Barcaldine (34)	Ergon Energy (Qld Government)
Other non-scheduled plants of < 30 MW	487	*Misc.*	
NSW	16 975		
AGL Energy	4 703	Bayswater (2520); Liddell (1800); Hunter Valley (30)	AGL Energy
		Broken Hill (53); Nyngan (102); Silverton (198)	Powering Australian Renewables Fund (QIC 80%; AGL Energy 20%)
Origin Energy	3 775	Eraring (2720); Shoalhaven (240); Uranquinty (640); *Eraring (42)*	Origin Energy
		Moree (56)	Fotowatio Renewable Ventures
		Gunning (47)	Acciona Energy
		Cullerin Range (30)	Energy Developments (DUET Group)

TRADING RIGHTS	CAPACITY (MW)	POWER STATION (MW)	OWNER
Snowy Hydro	3 178	Tumut 3 (1800); Colongra (648); Upper Tumut (616); Blowering (80); Guthega (34)	Snowy Hydro (Australian Government)
EnergyAustralia	2 112	Mt Piper (1300); Tallawarra (378)	EnergyAustralia (CLP Group)
		Gullen Range (166); Gullen Range (10)	Beijing Jingneng Clean Energy 75%; Goldwind Capital 25%
		Taralga (107)	Pacific Hydro (State Power Investment Corporation)
		Boco Rock (104)	Electricity Generating Public Company
		Manildra (47)	First Solar
Delta Electricity	1 320	Vales Point (1320)	Sunset Power International (Waratah Power 50%, Vales Point Invesments 50%)
Infigen Energy	302	*Capital (141)*; Woodlawn (48); Bodangora (113)	Infigen Energy
White Rock Wind Farm Pty Ltd	193	White Rock (173); White Rock (20)	CECEPWP 75%; Goldwind 25%
CWP/Partners Group 67%; ACT Government 37%	187	Sapphire Wind Farm (187)	CWP Renewables and Partners Group
Neoen	180	Coleambally (150), Griffith (30)	Neoen
Visy Power Generation	109	Smithfield Energy Facility (109)	Visy Power Generation
Stanwell Corporation	97	*Appin (56); Tower (41)*	Energy Developments (DUET Group)
ACT Government	91	Crookwell 2 (91)	ACT Government
Capital Dynamics	68	*Broadwater/Condong (68)*	Cape Byron Power
Engie	51	Parkes Solar Farm (51)	Neoen
Essential Energy	50	*Broken Hill (50)*	Essential Energy (NSW Government)
Trustpower	29	Hume (29)	Trustpower (Infratil 51%, Tauranga Energy Consumer Trust 27%, other 22%)
Non-scheduled plant < 30 MW	530	*Misc.*	
Victoria	11 227		
AGL Energy	3 379	Loy Yang A (2144); West Kiewa (68); Somerton (140); Eildon (100); Dartmouth (165); McKay/ Bogong (300)	AGL Energy
		Macarthur (420)	Morrison & Co. 50%; Malakoff Corporation Berhad 50%
		Oaklands Hill (42)	Challenger Life (Challenger)
EnergyAustralia	2 405	Yallourn (1420)	EnergyAustralia (CLP Group)
		Jeeralang A (189) and B (216); Newport (475)	Ecogen Energy (IFM Investors)
		Gannawarra (50)	Wirsol 95%; Edify Energy 5%
		Ballarat Energy Storage System (30); Gannawarra Energy Storage System (25)	EnergyAustralia (CLP Group)
Snowy Hydro	2 080	Murray (1510); Laverton North (300); Valley Power (270)	Snowy Hydro (Australian Government)
Alinta Energy	1 175	Loy Yang B (980); Bannerton (88)	Alinta Energy (Chow Tai Fook Enterprises)
		Bald Hills (107)	Energy Infrastructure Trust (Infrastructure Capital Group)
Origin Energy	563	Mortlake (518)	Origin Energy
		Longford (45)	BHP 50%; Exxon Mobil 50%
Acciona Energy	324	*Waubra (192)*; Mount Gellibrand (132)	Acciona Energy

TRADING RIGHTS	CAPACITY (MW)	POWER STATION (MW)	OWNER
Pacific Hydro	235	*Yambuk (30); Challicum Hills (53); Portland (152)*	Pacific Hydro (State Power Investment Corporation)
ACT Government 33%; Ararat Wind Farm 67%	195	Ararat (195)	RES; GE; Partners Group; OPTrust
Meridian Energy	131	Mount Mercer (131)	Meridian Energy
Carlton & United Breweries	90	Karadoc (90)	Carlton & United Breweries
Simec Zen Energy	89	Wemen (89)	Simec Zen Energy
Hydro Tasmania	78	Bairnsdale (78)	Alinta Energy (Chow Tai Fook Enterprises)
Tilt Renewables 50%; Meridian Energy 50%	54	Salt Creek (54)	Tilt Renewables
John Laing Group 72%; Windlab Australia 25%; Local community 3%	31	Kiata (31)	John Laing Group 72%; Windlab Australia 25%; Local community 3%
Trustpower	29	Hume (29)	Trustpower (Infratil 51%, Tauranga Energy Consumer Trust 27%, other 22%)
Non-scheduled plant < 30 MW	369	*Misc.*	
South Australia	**5 061**		
AGL Energy	1 599	Torrens Island (1260)	AGL Energy
		Hallett 2 (44); *Wattle Point (91)*	Energy Infrastructure Trust (Infrastructure Capital Group)
		North Brown Hill (82)	Energy Infrastructure Trust (Infrastructure Capital Group) 40%; Osaka Gas 40%; APA Group 20%
		Hallett 1 (59)	Palisade Investment Partners
		The Bluff (33)	Eurus Energy (Toyota Tsusho 60%, Tokyo Electric Power Company 40%)
		ESCRI Dalrymple (30MW)	ElectraNet
Engie	913	Pelican Point (458); *Canunda (46)*; Dry Creek (112); Mintaro (68); Port Lincoln (56); Snuggery (54)	Engie 72%; Mitsui 28%
		Willogoleche (119)	
Origin Energy	908	Snowtown (99); Snowtown North (144); Snowtown South (126)	Tilt Renewables
		Quarantine (189); Ladbroke Grove (68)	Origin Energy
		Osborne (172)	ATCO 50%; Origin Energy 50%
		Bungala One (110)	Enel Green Power
ACT Government	309	Hornsdale (309)	Neoen 70%, John Laing 30%
EnergyAustralia	259	Hallet (193)	EnergyAustralia (CLP Group)
		Cathedral Rocks (66)	EnergyAustralia (CLP Group) 50%; Acciona Energy 50%
SA Government	215	Temporary Generation North (119); Temporary Generation South (96)	SA Government
Infigen Energy	198	Lake Bonney 2 (159) and 3 (39)	Infigen Energy
EnergyAustralia 50%; Hydro Tasmania 50%	131	Waterloo (131)	Palisade Investment Partners 74%; Northleaf Capital Partners 26%
Snowy Hydro	129	Port Stanvac (58); Angaston (50); Lonsdale (21)	Snowy Hydro (Australian Government)
SA Government 70%; Neoen 30%	100	HPRG1 (Hornsdale Power Reserve) (100)	Neoen
Essential Energy	81	*Lake Bonney 1 (81)*	Infigen Energy

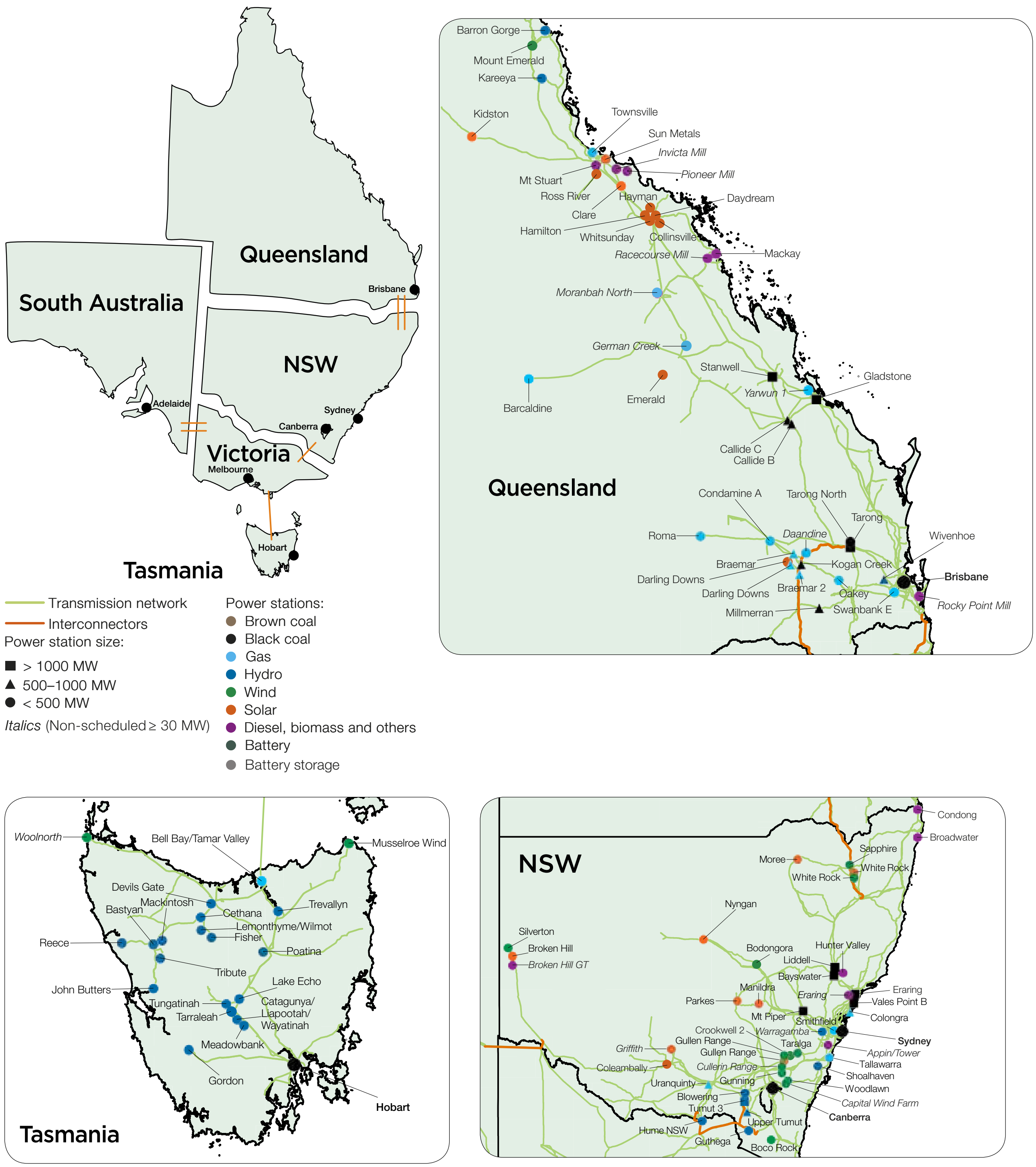
TRADING RIGHTS	CAPACITY (MW)	POWER STATION (MW)	OWNER
Meridian Energy	70	*Mount Millar (70)*	Meridian Energy
Pacific Hydro	57	Clements Gap (57)	Pacific Hydro (State Power Investment Corporation)
Hydro Tasmania	35	*Starfish Hill (35)*	RATCH Australia (Ratchaburi Electricity Generation 80%; Ferrovial 20%)
Non-scheduled plant < 30 MW	57	*Misc.*	
Tasmania	2 723		
Hydro Tasmania	2 601	Gordon (371); Poatina (342); Bell Bay (105); Tamar Valley Peaking (58), others (1475)	Hydro Tasmania (Tas Government)
		Woolnorth(140); Musselroe (168)	Shenhua Clean Energy 75%; Hydro Tasmania 25%
Non-scheduled plant < 30 MW	122	*Misc.*	

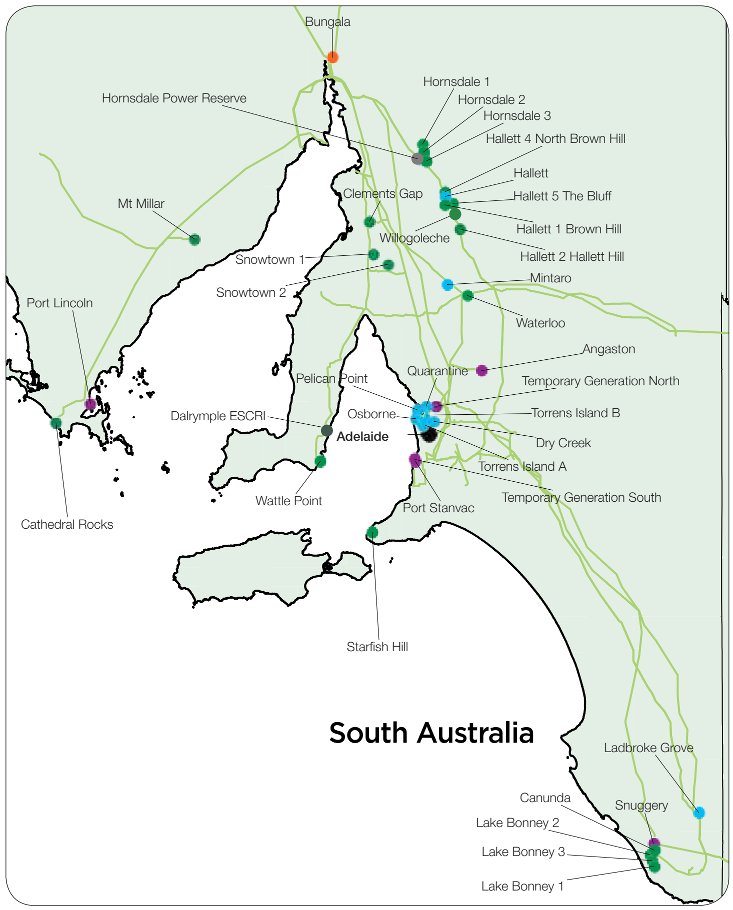
Fuel types: black coal; brown coal; gas; hydro; wind; solar; battery; other (e.g. diesel, bagasse); *italic: non-scheduled.*

Note: Capacity as published by AEMO for summer 2017–18, except for non-scheduled plant, where nameplate capacity is used.

Source: AEMO; AER; company announcements.

Figure 2.19
Generators in the national electricity market




Bungala
Hornsdale Power Reserve
Hornsdale 1
Hornsdale 2
Hornsdale 3
Hallett 4 North Brown Hill
Hallett
Hallett 5 The Bluff
Hallett 1 Brown Hill
Hallett 2 Hallett Hill
Mt Millar
Clements Gap
Willogoleche
Snowtown 1
Snowtown 2
Mintaro
Waterloo
Port Lincoln
Angaston
Quarantine
Pelican Point
Temporary Generation North
Osborne
Torrens Island B
Dalrymple ESCRI
Adelaide
Dry Creek
Torrens Island A
Temporary Generation South
Wattle Point
Port Stanvac
Cathedral Rocks
Starfish Hill
South Australia
Ladbroke Grove
Canunda
Snuggery
Lake Bonney 2
Lake Bonney 3
Lake Bonney 1

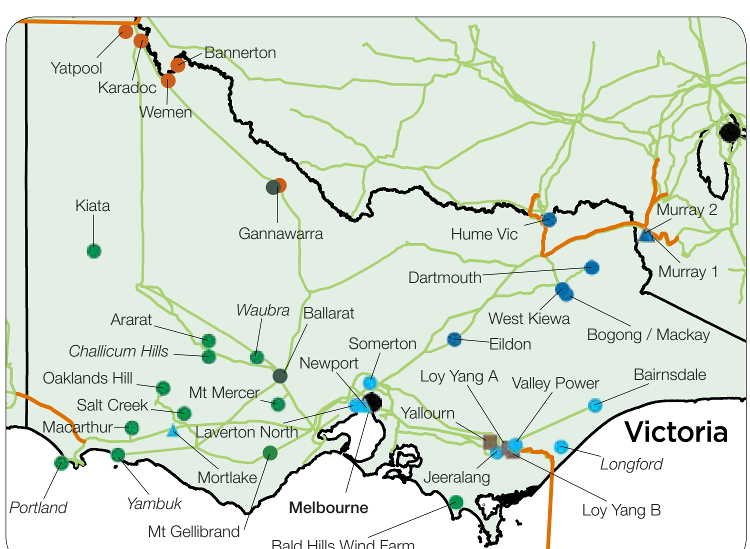

Bannerton
Yatpool
Karadoc
Wemen
Kiata
Gannawarra
Hume Vic
Murray 2
Murray 1
Dartmouth
West Kiewa
Bogong / Mackay
Ararat
Waubra
Ballarat
Challicum Hills
Somerton
Eildon
Newport
Oaklands Hill
Mt Mercer
Loy Yang A
Valley Power
Bairnsdale
Salt Creek
Yallourn
Macarthur
Laverton North
Victoria
Longford
Mortlake
Jeeralang
Portland
Yambuk
Melbourne
Loy Yang B
Mt Gellibrand
Bald Hills Wind Farm

Table 2.4 **Generation withdrawals since 2012–13**

YEAR	POWER STATION	REGION	TECHNOLOGY	CAPACITY (MW)	STATUS
WITHDRAWN				4174	
2014–15	Wallerawang C	NSW	Coal	1000	Retired
2014–15	Morwell, Brix	Vic	Coal	190	Retired
2014–15	Redbank	NSW	Coal	144	Retired
2014–15	Callide A	NSW	Coal	30	Retired
2015–16	Northern	SA	Coal	530	Retired
2015–16	Playford B	SA	Coal	240	Retired
2015–16	Collinsville	Qld	Coal	190	Retired
2015–16	Anglesea	Vic	Coal	150	Retired
2015–16	Barcaldine	Qld	CCGT	20	Downgraded
2016–17	Hazelwood	Vic	Coal	1600	Retired
2016–17	Mt Piper	NSW	Coal	80	Downgraded
ANNOUNCED WITHDRAWAL				2547	
2021	Torrens Island A	SA	Gas	480	Mothballing of units progressively 2019–21
2021	Mackay	Qld	OCGT	34	Retirement
2022	Daandine	Qld	CCGT	33	Retirement
2022	Liddell	NSW	Coal	2000	Retirement

CCGT, combined cycle gas turbine; OCGT, open cycle gas turbine.

Note: Data at November 2018.

Source: AEMO, Generation information, 2 November 2018, available at: www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.

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 2009–15. 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 and table 2.4).

Plant closures were mainly coal fired plant, following commercial decisions by owners to exit the market. The ageing plants had become increasingly unprofitable in part due to rising maintenance costs. The Wallerawang plant in NSW closed after 38 years of operation; the Northern and Playford plant in South Australia after 31 and 55 years of operation respectively; and the Hazelwood power station in Victoria after 53 years.

The plant closures significantly reduced capacity in the NEM and led to AEMO signalling a risk of summer power outages. But the private sector has been slow to respond with new plant investment.

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. Investment in gas powered generation has been negligible, with a threefold rise in gas prices since 2014 making this plant less economically viable.[21] A reduction in the number of spot electricity prices above $300 per megawatt hour (MWh) also affected the revenue potential of gas peaking plant, because these plant rely on selling cap contracts to customers wishing to insure against high prices.[22]

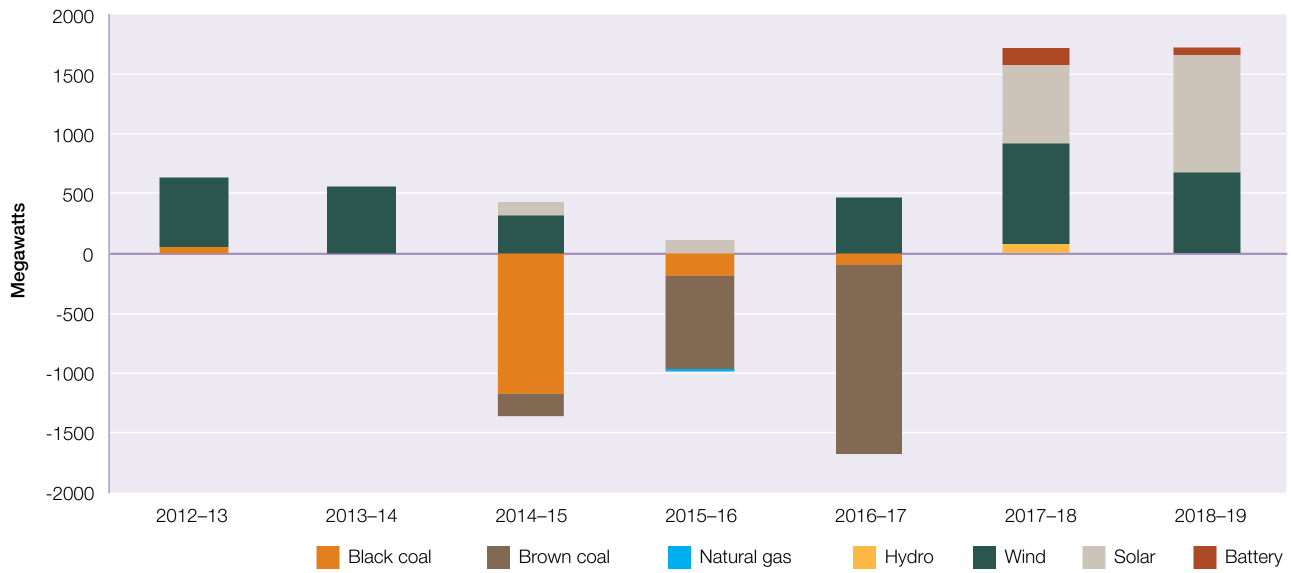
The Independent Review into the Future Security of the National Electricity Market (the Finkel review) argued years

21 The economics depends on prevailing market prices for electricity. See section 2.11.

22 AER, *Wholesale electricity market performance report*, December 2018; AEMO, *Operational and market challenges to reliability and security in the NEM*, March 2018.

Figure 2.20

New generation investment and plant withdrawals



Note: 2018–19 data is to 31 October 2018 only. An additional 2076 MW of committed capacity (1178 MW of wind, 873 MW of solar, 24 MW of biomass and 2 MW of battery storage) is expected to be commissioned in 2018–19.

Source: AEMO, *Generation information,* 2 November 2018, available at: www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.

of uncertainty and change in government policies on energy and carbon emissions have affected investment, making financers wary of backing energy assets when policy settings affecting them are volatile.[23]

Similarly, the AER noted participants identified a lack of energy policy stability and predictability as a barrier to entry for new generation.[24] The Australian Competition and Consumer Commission (ACCC) also noted a widespread view among market participants that the failure to implement consistent, enduring environmental policy in the electricity sector has caused significant investment uncertainty.[25]

Over 90 per cent of investment since 2012–13 has been in renewable (wind and solar) capacity, driven in part by subsidies available under the RET scheme and funding by ARENA and the Clean Energy Finance Corporation. Investment in renewables picked up strongly after an Australian Government review into the RET scheme in 2015 confirmed the scheme would continue until 2030.

Despite ongoing uncertainty, investment has gained pace since 2017 (table 2.5). Renewables continue to be the focus, with over 3500 MW of new wind, solar and battery capacity added to the NEM between January 2017 and October 2018. Another 2000 MW of capacity is committed from November 2018 to June 2019, with 6000 MW beyond 2018–19 (table 2.6).

Almost 50 000 MW of additional capacity has been proposed but not formally committed for development (figure 2.21). The bulk of the proposed projects are for solar (44 per cent) and wind (34 per cent) plant.

Against this additional capacity, further plant withdrawals are also likely. In 2022, AGL plans to retire its Liddell coal plant in NSW (1680 MW) to replace it with a mix of renewable gas generation batteries, and an upgrade to the Bayswater power station.[26]

Two gas plants are listed for retirement—AGL's Torrens Island A plant (480 MW) in South Australia (progressively from 2019–21), and the Mackay plant (34 MW) In Queensland (2021) and in Tasmania, the Tamar Valley plant (208 MW) was unavailable for much of 2018, although can be returned to service with less than three months' notice.[27]

23 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.

24 AER, *Wholesale electricity market performance report*, December 2018.

25 ACCC, *Restoring electricity affordability and Australia's competitive advantage, Retail Electricity Pricing Inquiry—Final Report*, June 2018, p. 100.

26 AGL, *NSW generation plan*, media release, December 2017.

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

Table 2.5 **New generation investment in 2017 and 2018**

OWNER	POWER STATION	TECHNOLOGY	CAPACITY (MW)	DATE COMMISSIONED
NSW			1040	
CECEPWP (75%), Goldwind (25%)	White Rock	Wind	173	July 2017
EnergyAustralia	Gullen Range	Solar	10	September 2017
CWP Renewables (63%), ACT Government (37%)	Sapphire	Wind	187	December 2017
Engie	Parkes	Solar	51	December 2017
AGL Energy	Silverton	Wind	198	February 2018
EnergyAustralia	Manildra	Solar	47	April 2018
Infigen	Bodangora	Wind	113	August 2018
CECEPWP (75%), Goldwind (25%)	White Rock	Solar	20	August 2018
ACT Government	Crookwell 2	Wind	91	August 2018
Neoen	Coleambally	Solar	150	September 2018
QUEENSLAND			1060	
Queensland Government	Kidston	Solar	49	November 2017
Origin Energy	Clare	Solar	100	February 2018
ERM Power	Hamilton	Solar	58	May 2018
Queensland Government	Whitsunday	Solar	58	May 2018
EnergyAustralia	Ross River	Solar	116	June 2018
Origin Energy	Darling Downs	Solar	109	June 2018
Sun Metals	Sun Metals	Solar	124	July 2018
Alinta Holdings	Collinsville	Solar	43	July 2018
Ergon Energy	Mount Emerald	Wind	181	August 2018
Telstra	Emerald	Solar	72	September 2018
Origin Energy	Daydream	Solar	150	October 2018
SOUTH AUSTRALIA			568	
ACT Government	Horsndale Stage 2	Wind	100	February 2017
ACT Government	Horsndale Stage 3	Wind	109	August 2017
South Australian Government (70%), Neoen International SAS (30%)	Hornsdale Power Reserve	Battery	100	November 2017
Origin Energy	Bungala One	Solar	110	May 2018
AGL Energy	Dalrymple North	Battery	30	June 2018
Engie	Willogoleche	Wind	119	July 2018
VICTORIA			832	
Ararat Wind Farm (67%), ACT Government (37%)	Ararat	Wind	240	June 2017
John Laing Group (72%), Windlab (25%), Kiata local community (3%)	Kiata	Wind	31	November 2017
EnergyAustralia	Gannawarra	Solar	50	March 2018
Powershop Australia	Salt Creek	Wind	54	May 2018
Acciona Energy	Mt Gellibrand	Wind	132	June 2018

OWNER	POWER STATION	TECHNOLOGY	CAPACITY (MW)	DATE COMMISSIONED
Alinta Holdings	Bannerton	Solar	88	July 2018
Carlton & United Breweries	Karadoc	Solar	90	October 2018
EnergyAustralia	Ballarat	Battery	30	November 2018
EnergyAustralia	Gannawarra	Battery	29	November 2018
Simec Zen Energy	Wemen	Solar	88	November 2018

Table 2.6 **Committed investment projects in the NEM**

OWNER	POWER STATION	TECHNOLOGY	CAPACITY (MW)	PLANNED COMMISSIONING
NSW			787	
Innogy	Limondale 2	Solar	29	2018–19
FS NSW Project No 1 AT	Beryl	Solar	98	2019–20
CRWF Nominees	Crudine Ridge	Wind	135	2019–20
Elliott Nevertire Solar	Nevertire	Solar	105	2019–20
John Laing, Maoneng Group	Sunraysia	Solar	200	2019–20
Innogy	Limondale 1	Solar	220	2019–20
QUEENSLAND			1208	
Childers Solar	Childers	Solar	56	2018–19
Clermont Asset	Clermont	Solar	93	2018–19
PARF Company 6	Coopers Gap	Wind	350	2018–19
Pacific Hydro	Haughton	Solar	100	2018–19
Edify Energy	Hayman	Solar	50	2018–19
Windlab / Eurus	Kennedy Energy Park	Solar	15	2018–19
Windlab / Eurus	Kennedy Energy Park	Battery	2	2018–19
Windlab / Eurus	Kennedy Energy Park	Wind	43	2018–19
Lilyvale Asset Co	Lilyvale	Solar	100	2018–19
RE Oakey	Oakey 2	Solar	55	2018–19
Canadian Solar	Oakey	Solar	25	2018–19
Adani	Rugby Run	Solar	65	2018–19
Esco Pacific	Susan River	Solar	75	2018–19
MSF Sugar	Tableland Mill	Bagasse (expansion)	24	2018–19
Teebar Clean Energy	Teebar One	Solar	52	2019–20
Risen Energy	Yarranlea	Solar	103	2019–20
SOUTH AUSTRALIA			554	
Enel Green Power	Bungala Two	Solar	110	2018–19
Lincoln Gap Wind Farm	Lincoln Gap—stage 1	Wind	126	2018–19
AGL	Barker Inlet	Gas	210	2019–20
Vena Energy	Tailem Bend	Solar	108	2019–20
TASMANIA			256	

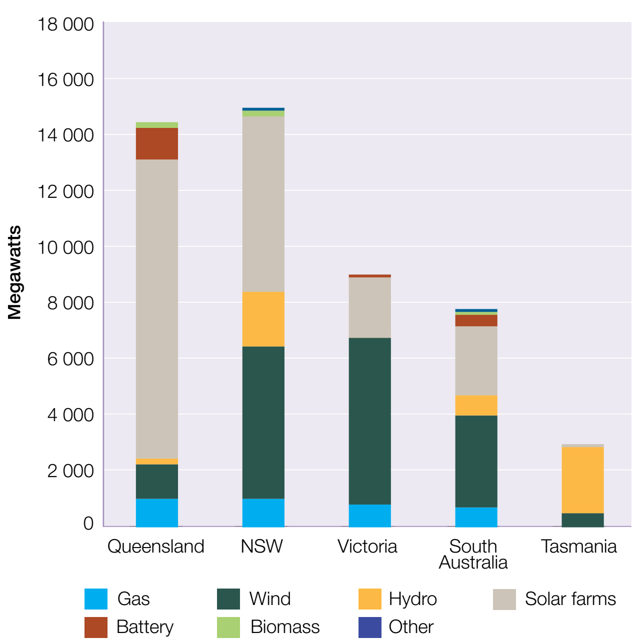
OWNER	POWER STATION	TECHNOLOGY	CAPACITY (MW)	PLANNED COMMISSIONING
Granville Harbour Operations	Granville Harbour	Wind	112	2019–20
Wild Cattle Hill	Wild Cattle Hill	Wind	144	2019–20
VICTORIA			1981	
Bulgana Wind Farm	Bulgana	Wind	194	2018–19
Goldwind	Moorabool	Wind	320	2018–19
Westwind Energy	Lal Lal—Yendon end	Wind	144	2018–19
Neoen	Numurkah	Solar	100	2018–19
Bulgana Wind Farm	Bulgana	Battery	20	2019–20
Pacific Hydro	Crowlands	Wind	80	2019–20
Northleaf, InfraRed, Macquarie Capital	Lal Lal—Elaine end	Wind	84	2019–20
RES Australia	Murra Warra—stage 1	Wind	226	2019–20
Goldwind	Stockyard Hill	Wind	532	2019–20
BayWa r.e Australia	Yatpool	Solar	81	2019–20
Total Eren S.A.	Kiamal—stage 1	Solar	200	2019–20

Note (tables 2.5–2.6): Data at November 2018.

Source: AEMO, Generation information, 2 November 2018, available at: www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.

Figure 2.21

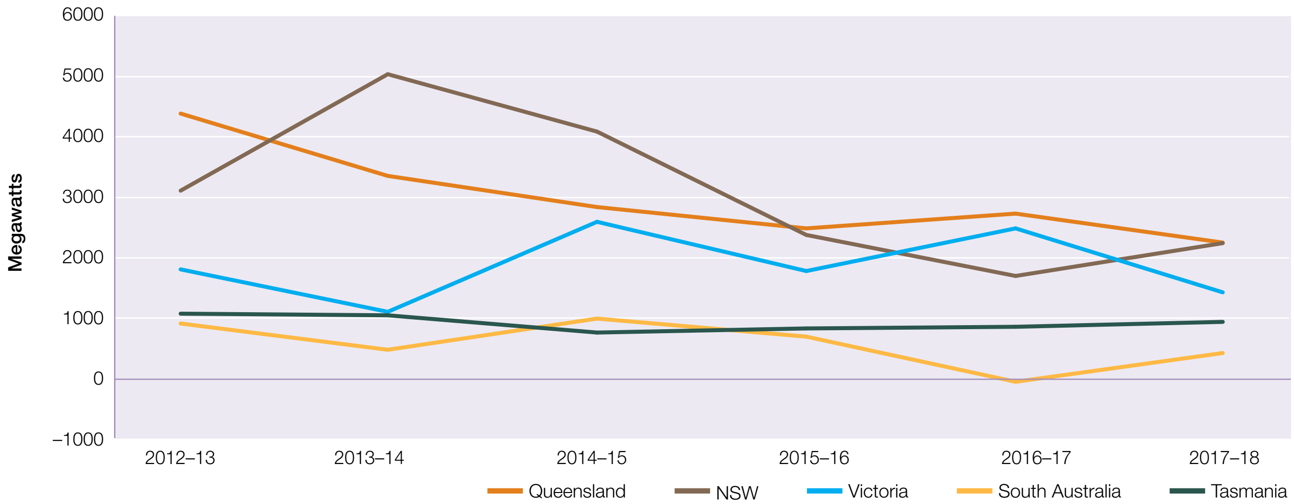
Announced generation proposals at July 2018



Source: AEMO, *Generation information,* 2 November 2018, available at: www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.

Figure 2.22

Surplus generation capacity, by region



Note: Maximum demand in financial year minus summer capacity (nameplate capacity for non-scheduled plant) at 31 January in each region. Summer capacity for 2016–17 in Victoria includes Hazelwood, with closure of the plant reflected in 2017–18 data. Wind and solar summer capacity is de-rated based on AEMO's 'firm contribution' estimates to account for generation likely to be operational during periods of maximum demand.

Source: AEMO, *Generation information*, 31 July 2018, available at: www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.

2.6 Power system reliability and security

The Finkel review found the closure of coal fired plants may pose risks to power system reliability and security, in part because the intermittent (weather dependent) wind and solar plant replacing them has not been well integrated into the system.[28]

The concepts of reliability and security should not be confused. Power system *reliability* relates to having sufficient generation capacity to meet demand. *Security* refers to the system's technical capability in terms of frequency, voltage, inertia and similar characteristics.

2.6.1 Reliability in the NEM

The Reliability Panel sets a *reliability standard* for the generation and transmission sectors, which requires any shortfall in power supply not exceed 0.002 per cent of total electricity requirements. The standard factors in generation required to meet forecast electricity demand on peak days, allowing for a 'safety margin'. The standard has rarely been breached, although AEMO sometimes intervenes in the market to manage forecast supply shortfalls. Consumers do experience supply interruptions, but over 95 per cent of these originate in local distribution networks, and relate to local power line issues.

An over-supply of generation capacity built up for several years in the NEM. But plant retirements, including the closure of major coal fired generators, began to reduce this surplus in Queensland (from 2012–13) and NSW (2013–14), followed by South Australia and Victoria (from 2014–15). The shift was exacerbated from 2013–15 by investment in renewables tailing off due to uncertainty over government policy on the future of the RET scheme.

The retirement of South Australia's Northern power station in 2016 made the state more reliant on imports from other regions to meet peak demand (figure 2.22). The closure of the Hazelwood power station had a similar tightening impact on Victoria in 2017.

AEMO in September 2017 raised concerns the market would be at risk of generation shortfalls over summer 2017–18, especially in Victoria and South Australia where plant closures had occurred.[29] It raised similar concerns

28 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.

29 AEMO, *Electricity statement of opportunities for the national electricity market*, September 2017.

for power outages over summer 2018–19 (section 2.9.8). AEMO took action to manage reliability risks over both summers (sections 2.6.2 and 2.9.8).

2.6.2 Managing reliability risks

AEMO can use the Reliability and Emergency Reserve Trader (RERT) mechanism to manage short term reliability risks in the NEM. The scheme involves AEMO securing contracts with generators (to provide capacity) or large loads (to reduce their consumption) when the power system is under stress. This capacity normally operates outside the NEM. AEMO in 2018 recommended expanding its capacity to secure reserves under the RERT mechanism, arguing it would enhance reliability management.[30]

If a serious reliability threat cannot otherwise be avoided, AEMO may direct generators to provide additional supply or large energy customers to reduce demand. 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'—temporarily cut power to some customers. This action is rare. An insecure operating state led AEMO to cut supply to some customers in South Australia on 1 December 2016 and 8 February 2017, and in NSW on 10 February 2017.

Transmission solutions

AEMO in 2018 proposed major investment in transmission networks that it argued will be necessary to meet the reliability standard as new generation comes online. Its inaugural integrated system plan (ISP) recommended $450–650 million of immediate investment in transmission networks—including upgrading cross-border interconnectors between Victoria, NSW and Queensland—to manage reliability risks. It recommended further major investment by the mid-2020s (including the Riverlink interconnector between NSW and South Australia) and later (including Snowylink between NSW and Victoria).[31]

Market bodies are reviewing the role of the ISP in driving transmission investment, including the use of cost–benefit testing to assess the efficiency of new investment proposals. This work also explores broader coordination issues between transmission and generation investment.

Investment in expensive, long lived assets is risky—especially when a market is in transition, and where more flexible and potentially cheaper alternatives are available.

The cost–benefit focus of the AER's regulatory investment test provides a robust and transparent model for analysing whether network upgrades provide value for money to energy consumers.

2.6.3 Challenges of an evolving market

The surge in intermittent generation investment over the past few years has added capacity to the market. But it can create challenges for managing the power system. In particular, intermittent generation may not be available at a given time due to the uncertain nature of weather conditions. AEMO accounts for this uncertainty by factoring in a plant's region and technology when assessing its contribution to peak demand.

Solar generation raises particular challenges for coal plant. When solar generation is high in the middle of the day, the demand for dispatchable generation can significantly fall. This phenomenon challenges the economics of coal fired generators, which are engineered to run fairly continuously at or near full capacity to be profitable.

While the effects of intermittent wind and solar generation on *reliability* are complex, higher levels of this generation may increase the risk of power system *security* issues. The older fossil fuel power plants that are retiring helped maintain power system security by providing frequency, voltage, inertia and system strength services that kept the system in a secure technical state.[32]

The capability of intermittent generation plants to provide these services, and the types of services required, are still evolving. AEMO noted the rising proportion of wind plant in the NEM's generation portfolio is resulting in more periods with low inertia and low available fault levels, reducing market resilience to extreme events.

The most serious security event to date occurred on 28 September 2016, when a combination of severe weather, catastrophic failure of transmission infrastructure and the performance of a number of generators caused much of South Australia to be blacked out for several hours. The AER published a comprehensive report on this event in December 2018.[33]

A similar event occurred in March 2017, when network faults caused a large and sudden reduction in local

30 AEMO, *AEMO observations: Operational and market challenges to reliability and security in the NEM*, March 2018, p. 26.

31 AEMO, *Integrated System Plan for the National Electricity Market*, July 2018.

32 Synchronous generators—including hydroelectric and thermal plan such as coal, gas and solar thermal generators—can provide these services. The generators' heavy spinning rotors provide synchronous inertia that slows down the rate of change of frequency. They help with voltage control by producing and absorbing reactive power and also provide high fault current that improves system strength.

33 AER, *The black system event*, Compliance report, December 2018.

generation, resulting in voltage instability on the Heywood interconnector. A major blackout was avoided, but South Australia's power system operated in an insecure state for 40 minutes.

AEMO is intervening in the market more often to ensure a minimum level of system security services is maintained. It imposes constraints on generation and uses its directions powers to maintain a balance between synchronous and non-synchronous generation.[34] AEMO issued directions to generators on 25 occasions in 2017, double the number of interventions in the previous seven years combined.[35] In the first five months of 2018 a further 62 directions were issued.[36]

Factors such as wind speed and cloud cover pose challenges for demand and supply forecasting. While solar PV systems reduce strain on the electricity grid when the sun is present, the market can lose 200–300 MW of power if cloud covers a major city, for example.[37] AEMO in 2018 reported multiple instances where rooftop generation caused deep voltage dips in the middle of the day, leading to hundreds of megawatts of nearby loads being removed from the power system for several minutes, before slowly returning.[38]

The uptake of small scale supply, collectively known as *distributed energy resources* pose additional challenges. Distributed energy resources are located within a distribution network but usually operate behind customers' energy meters. They include generation (solar PV systems being the most common form), storage (including batteries and electric vehicles) and demand response. These resources create two-way flows on an energy network (power is both injected in and withdrawn at customer connection points), raising challenges for network design and system security.

Policy responses

The Finkel review in 2017 explored how to better integrate intermittent generators and distributed energy resources into the market to capitalise on its benefits—including its advantages as low cost and low emissions generation.

Many of the review's proposals relate to promoting investment in resources with flexibility to manage sudden demand or supply fluctuations.[39] In the future, resources such as batteries or pumped hydroelectric storage and demand response may become a significant part of the solution to these issues by becoming suppliers of services that maintain power system security. Options may include intelligent wind turbine controllers, batteries and synchronous condensers that could better integrate intermittent plant into the grid.

The Australian Government endorsed most of the review's recommendations. Reforms to ancillary service markets and technical frameworks arising from the recommendations are now being implemented to encourage a more efficient integration of intermittent and distributed generation into the market.

The Australian Energy Market Commission (AEMC) in 2017 introduced reforms to allow batteries and demand response aggregators to provide frequency control services. It is also exploring reforms to allow wider use of demand response and aggregation of small scale generation in the wholesale market. Another reform requires generators to provide three years' notice prior to closing a plant to allow time for the market to adjust to the change. New standards are also being applied to ensure the technical standards of new generators match local power system needs.[40]

2.7 Government intervention in the market

The lack of a clear, agreed national energy policy has led governments at all levels to intervene in the market in a less coordinated way. The interventions include investments in state owned generation projects, financial incentives for private generation, and directions to the market on how it should operate. In late 2018 over 20 such measures were operating, had been committed or announced as policy in the wholesale electricity sector (Appendix 1). The initiatives include:

- major investments in publicly owned generation and storage
- a pricing direction to state owned generators
- a threat of compulsory divestment of private generation assets
- national and state level renewable energy targets

34 AEMO, *AEMO observations: Operational and market challenges to reliability and security in the NEM*, March 2018, pp. 8, 25.

35 AEMO, *AEMO observations: Operational and market challenges to reliability and security in the NEM*, March 2018, p. 26.

36 AEMO, *NEM event—direction* reports, available at: www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Market-notices-and-events/Market-event-reports.

37 Australian Energy Council, *Solar Report, Quarter 1, 2018*, p. 6.

38 AEMO, *Power system requirements*, March 2018, p. 8.

39 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.

40 AEMC, *AEMC system security and reliability action plan*, updated 5 July 2018.

- programs offering financial assistance for grid scale renewable projects or residential solar and battery systems
- a market wide reliability guarantee.

Other interventions are occurring in the electricity retail and transmission sectors.

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 AER in December 2018 reported the views of energy market participants that a lack of stability and predictability in government energy policy is a barrier to entry for new generation. Emissions 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.[41]

2.7.1 Public investment in generation and storage

The Australian Government and some state governments have announced new energy infrastructure projects in generation, storage and transmission.

Among major initiatives, the Australian Government in 2018 undertook a feasibility study into expanding Snowy Hydro (which it owns) using pumped hydroelectric technology. The proposal would increase Snowy Hydro's hydroelectric generation capacity by around 2000 MW—a 50 per cent rise on current capacity. A final investment decision on the project was scheduled for late 2018, with generation from the project commencing in late 2024 if it proceeds.

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

The Queensland Government in 2019 will launch CleanCo, a new state owned generation corporation with a commercial mandate to increase competition in the wholesale market. It will focus on low and no emissions technology. Initially, 1000 MW of hydroelectric and gas power stations will transfer to CleanCo from other state owned generators. The Queensland Government will provide funding for CleanCo to invest in a further 1000 MW of renewable capacity by 2025. Earlier, the Queensland Government invested in recommissioning the state owned Swanbank E generator in December 2017.

On a smaller scale, 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 needed to keep the power system secure.

2.7.2 Market directions

In June 2017 the Queensland Government directed the state owned Stanwell generation business to 'alter its bidding strategies to help put as much downward pressure on wholesale electricity prices as possible'.[42] Stanwell indicated it subsequently adjusted its bidding behaviour in line with the direction, resulting in a significant lowering of Queensland wholesale prices in 2017–18 (section 2.9.1).

In late 2018 the Australian Government drafted legislation to insert a power into the *Competition and Consumer Act 2010* enabling the Courts, on the advice of the Treasurer and ACCC, to order divestiture of an asset by energy companies, or order electricity companies to enter into contracts to supply at specified prices and for specified volumes. The draft legislation listed grounds to force asset divestment, including a retailer's failure to pass on lower wholesale prices to energy customers, or attempts by energy companies to manipulate spot or contract markets.[43]

2.7.3 Renewable energy targets

The Australian, Queensland, Victorian and ACT governments operate renewable energy targets:

- The Australian Government launched a national RET scheme in 2001 and has since revised it several times (box 2.3). The scheme applies different incentives for large (such as wind) and small (such as rooftop solar PV) scale energy supply. The RET scheme targets 33 000 GWh of electricity sourced from large scale renewable projects by 2020, equivalent to 23.5 per cent of Australia's forecast generation at that time.
- The Queensland scheme targets 50 per cent of Queensland's electricity being produced from renewable resources by 2030. It is not a legislated target.
- The Victorian scheme targets 25 per cent of the state's electricity being sourced from renewable resources

41 AER, *Wholesale electricity market performance report*, December 2018.

42 Queensland Government, *Stabilising electricity prices for Queensland consumers*, media release, 2017.

43 Treasury Laws Amendment (Electricity Price Monitoring) Bill 2018, exposure draft.

by 2020, and 40 per cent by 2025. The targets are legislated.

- The ACT Government applies a range of measures to pursue a target of 100 per cent of Canberra's demand being sourced from renewable resources by 2020.

The Victorian, ACT and Queensland governments have (or intend to) run reverse auctions to acquire new private investment in renewable generation to support the targets (section 2.7.4). The Queensland Government's CleanCo generation company will also directly invest in new renewable capacity (section 2.7.1).

2.7.4 Financial incentives for private investment

Governments have introduced a range of programs and schemes offering financial incentives for private investment in generation capacity (appendix 1). Most incentives target investment in renewable energy, but a recent Australian Government initiative focuses on 'dispatchable' 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.

The Australian Government operates three major schemes offering financial support for renewables investment:

- The Australian Renewable Energy Agency (ARENA) was established in 2012 to fund research, development and commercialisation of clean energy technologies. Much of its funding is provided as grants. Its mandate is to advance clean energy technology, rather than generate profit. At 30 June 2018 ARENA had allocated $1 billion in grant funding to 320 projects since 2012, totaling 263 MW of capacity. These projects included 12 large scale solar plants, many with Clean Energy Finance Corporation (CEFC) involvement. Its development pipeline included $2.5 billion worth of additional projects.
- The CEFC launched in 2012 as a government owned green bank to promote investment in clean energy. The fund provides debt and equity financing for projects that will deliver a positive return, rather than grants. The CEFC invested in almost $20 billion of clean energy projects from 2012–18—including 5500 small scale clean energy projects, 20 large scale solar projects, and 10 wind farms.
- The Emissions Reduction Fund launched in 2014 to fund carbons emissions abatement through 'reverse' auctions run by the Clean Energy Regulator. Seven auctions were held to July 2018, spending $2.3 billion to abate 192 million tonnes of carbon emissions. Less than 2 per cent of funding under the scheme was made to the electricity sector. The participating electricity projects mostly capture and combust waste methane gas from coal mines or landfill for electricity generation (box 2.3).

Following an ACCC recommendation, the Australian Government in 2018 proposed underwriting new investment in 'firm' or 'firmed' generation capacity.[44] The support may take the form of a floor price, contracts for difference, collar contracts, government loans, or alternative mechanisms. Expressions of interest are expected to open by January 2019 and proposals will be due by March 2019. Financial support is expected to commence from 1 July 2019.[45]

State governments also operate schemes to support grid scale renewable projects:

- The Queensland Government operates its Renewables 400 and Solar 150 schemes that provide 'contracts for difference' to support the development of renewable and large scale solar generation. Projects are selected through reverse auctions. The Solar 150 scheme has supported 300 MW of new capacity.
- The Victorian Government operates a renewable energy auction scheme, grid scale battery project, and renewable certificate purchasing initiative. The auction scheme has provided support for six projects totaling 928 MW of generation, and the certificate process has supported a further four projects totaling 210 MW. The battery project has supported two batteries totaling 55 MW.
- In 2017 the South Australian Government contracted to source 100 per cent of the government's electricity requirements from the Aurora solar project, a 150 MW solar thermal plant at Port Augusta, due for completion in 2020. The Government's Renewable Technology Fund is also offering $150 million in support for renewables as grants and loans. At November 2018, it had provided funding to three grid scale battery projects.
- The ACT Government introduced a large scale feed in tariff to fund new renewable generation. Projects funded under the scheme are selected through reverse

44 Department of the Environment and Energy, *Underwriting New Generation Investments, Public Consultation Paper*, October 2018. 'Firm' capacity is generation that can be available when needed—for example, coal or gas powered generation or wind generation with onsite storage such as batteries. 'Firmed' capacity encompasses intermittent generation such as wind or solar that is contracted with a certain proportion of firm capacity across the grid.

45 Department of the Environment and Energy, *Underwriting New Generation Investments, Public Consultation Paper*, October 2018.

auction processes. At November 2018 640 MW of new generation had been funded under the scheme.

The Victorian, South Australian, Queensland and ACT governments also operate schemes that provide grants, rebates or loans to support small scale solar PV and battery systems. All state governments have previously operated feed-in tariff schemes to support installation of residential solar PV systems. These schemes are all closed to new entrants.

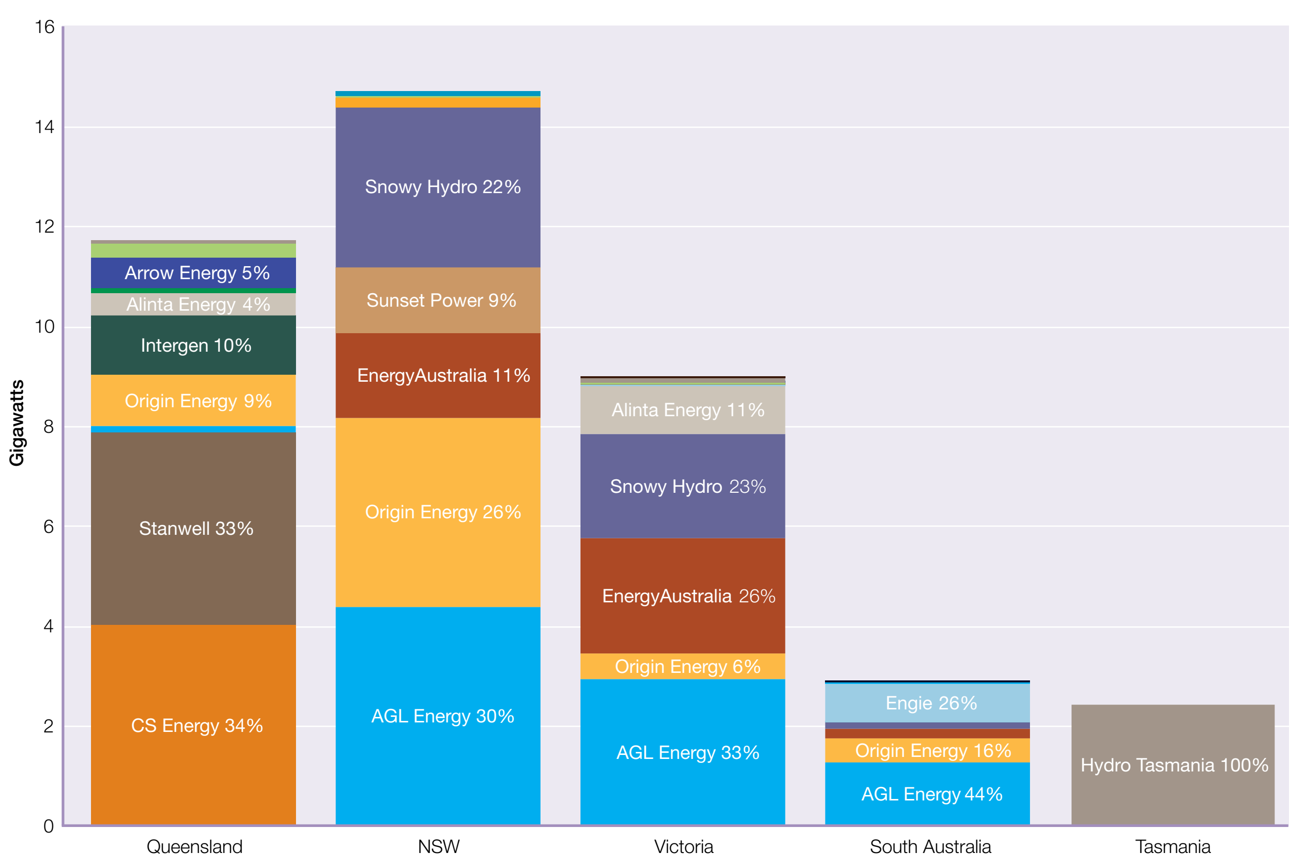
2.8 Market structure

Around 150 registered generation businesses sell electricity into the NEM spot market. Table 2.3 lists the major generators, plant technologies and ownership arrangements (including the entities that control each plant's dispatch).

A few large participants control a significant proportion of generation in each NEM region. The two largest participants in each region account for over half of total capacity (figure 2.23) and two thirds of output (figure 2.24), except in South Australia which is slightly less concentrated.

Higher concentration in output compared to capacity in Queensland, NSW and Victoria reflects the high utilisation rates of black and brown coal plant that make up the bulk of the generation fleet of the largest participants. South Australian outcomes are more even across capacity and output measures, because its largest participants all rely on gas powered generation (which operates less often than coal plant, for example).

Figure 2.23
Market shares in generation capacity



Note: Generation capacity based on 2017–18 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 allocated to the business that controls the trading rights for each generator. Import capacity via interconnectors, and rooftop solar PV capacity are excluded.

Source: AER; AEMO.

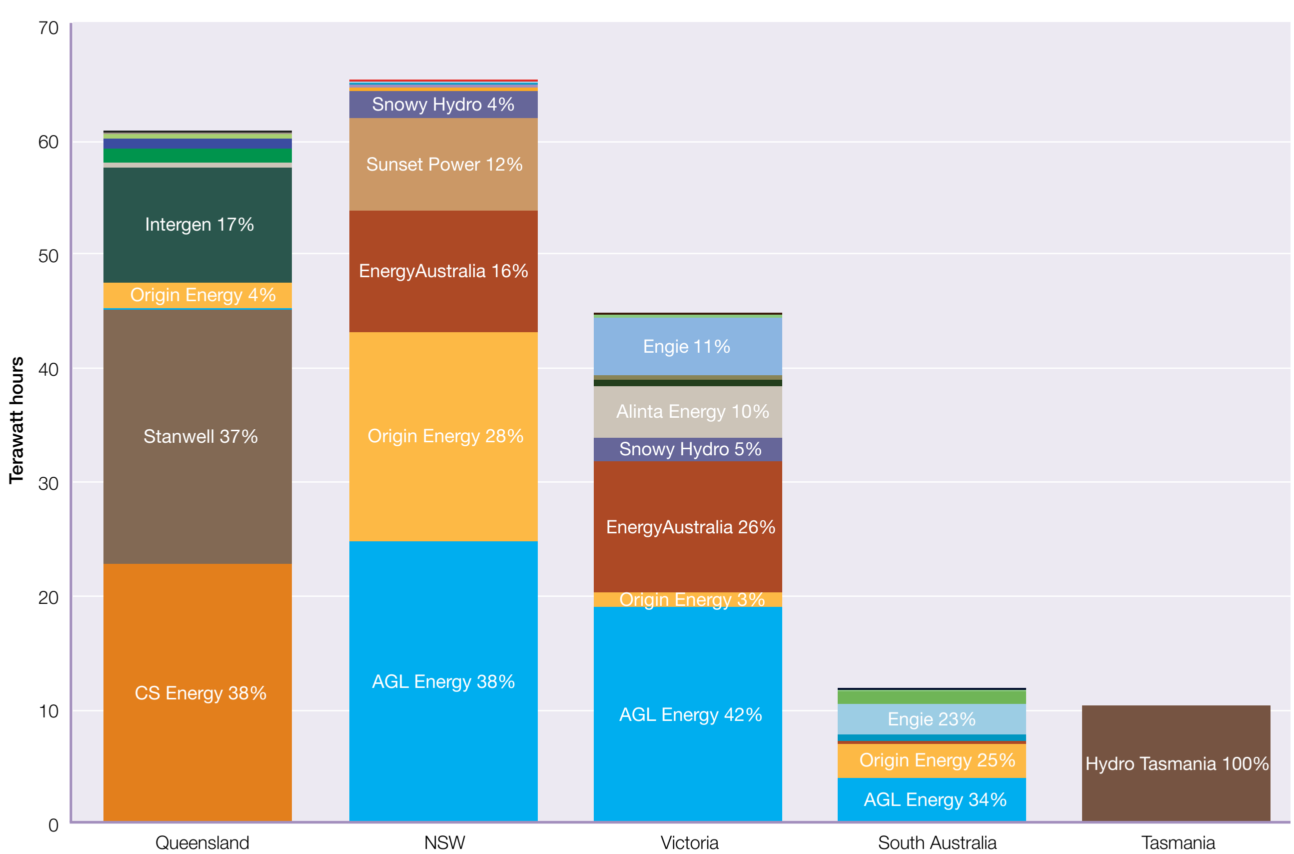
Private entities own most generation capacity in Victoria, NSW and South Australia (figure 2.23):

- In Victoria, AGL Energy (33 per cent), EnergyAustralia (26 per cent) and Snowy Hydro (23 per cent) control a majority of capacity. 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 44 per cent of capacity. Other significant entities are Engie (26 per cent), Origin Energy (16 per cent) and EnergyAustralia (7 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, the privatisation of state owned generation businesses was completed in 2015. AGL Energy (30 per cent), Origin Energy (26 per cent) and Snowy Hydro (22 per cent) emerged as the state's leading generators following the sale process. EnergyAustralia (11 per cent) and Sunset Power (9 per cent) also acquired significant generation capacity.

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 67 per cent of generation capacity, including power purchase agreements over privately owned capacity (such as the Gladstone power station). The most significant 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 it ensures adequate volumes of these products are available.

Figure 2.24
Market shares in generation output



Note: Output in 2017–18. Ownership is attributed by trading rights at the time. Output split on a pro-rata basis where ownership changed during 2017–18. Excludes output from rooftop solar PV systems.

Source: AEMO; AER; company announcements.

AGL Energy is the largest participant by capacity and output in NSW, Victoria and South Australia. On a NEM-wide basis, it accounts for 20 per cent of capacity and 25 per cent of output.

Snowy Hydro contributed only 4 per cent of output in NSW and five per cent in Victoria, despite holding over 20 per cent of capacity in each region. This outcome is because its fleet comprises hydroelectric generators with limited water availability and peaking gas plant, which typically operate less frequently.

2.8.1 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 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 (section 2.10).

Vertical integration has become the primary business structure for large electricity retailers in the NEM. Three retailers—AGL Energy, Origin Energy and EnergyAustralia—supply 66 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 2018.

Red Energy and Lumo Energy (Snowy Hydro), Simply Energy (Engie) and Alinta also own major generation assets. These vertically integrated businesses account for another 15 per cent of small residential customers across the NEM and 19 per cent of generation capacity.

In NSW, Victoria and South Australia, those six businesses jointly own at least 90 per cent of generation capacity.

A number of smaller retailers are also vertically integrated:

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

2.9 Market activity

Price pressure in the NEM intensified following the closure of coal fired plant in South Australia (in May 2016) and Victoria (in March 2017). These retirements followed years of stagnant investment in dispatchable generation.

The closure of the Hazelwood power station withdrew around five per cent of the NEM's capacity. This low cost supply was initially replaced more expensive gas and hydroelectric generation output. But wind and solar generation took more of this share in 2018, and this share will further rise in 2019.[46]

Brown coal generators—traditionally the cheapest thermal supply source—now rarely set electricity prices because the market rarely has enough brown coal capacity to meet demand.[47] More expensive black coal and gas plant now more often set prices. Between July 2015 and July 2017, the offer price for the cheapest 20 000 MW of capacity in the NEM increased from $50 per MWh to almost $100 per MWh.[48]

A significant factor in this shift was NSW and Queensland black coal generators raising their offer prices. This change in bidding behaviour partly reflected a rise in black coal costs and issues around coal supply availability. A large increase in gas fuel costs also reduced competitive restraints on black coal plant, allowing them to periodically price closer to gas plant prices. The AER found average offers from some black coal generators in NSW and Queensland increased more than underlying costs.[49]

Market volatility was exacerbated by outages affecting coal and gas generators, and interconnector constraints limiting trade between Victoria and other regions. These conditions resulted in spot prices setting records or near-records in most NEM regions in 2016–17 (figures 2.25 and 2.26).

Prices eased in Queensland, NSW and South Australia in 2017–18. Market intervention by the Queensland Government contributed to that region's prices being 28 per cent lower in 2017–18 than a year earlier. Improved gas and black coal supply conditions and increased renewable plant coming online improved outcomes in some regions.

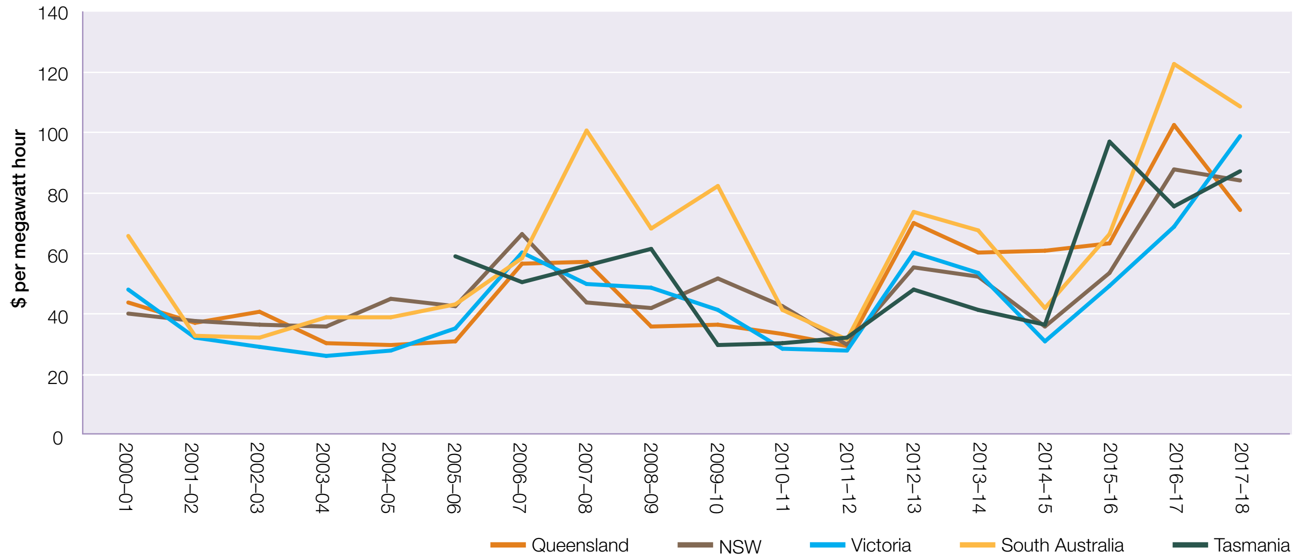
46 AER, *Electricity wholesale performance monitoring, Hazelwood advice*, March 2018; AEMO, *2018 electricity statement of opportunities*, August 2018.

47 AER, *Electricity wholesale performance monitoring, Hazelwood advice*, March 2018, p. 16.

48 ACCC, *Restoring electricity affordability and Australia's competitive advantage, Retail Electricity Pricing Inquiry—Final Report*, June 2018, p. 55.

49 AER, *Electricity wholesale performance monitoring, NSW electricity market advice*, December 2017.

Figure 2.25
Annual NEM electricity prices



Note: Volume weighted averages of spot prices.
Source: AER; AEMO.

But prices rose 43 per cent to a new record in Victoria, averaging almost $100 per MWh.

Several years of high wholesale prices have boosted profits for many generators.[50] Large generation businesses in most regions were earning profit margins of around 20–22 per cent in 2014–15, but by the end of 2017, several generators had margins above 30 per cent. Even the least profitable of seven businesses assessed by the ACCC was earning at least a 14 per cent margin in the first half of 2017–18.[51]

2.9.1 Queensland

Queensland prices averaged $75 per MWh in 2017–18, the lowest for any NEM region. Prices were 27 per cent lower than a year earlier, the largest reduction for any region. Market intervention by the Queensland Government played a key role in this outcome.

The government in July 2017 directed the state owned Stanwell generation business to 'alter its bidding strategies to help put as much downward pressure on wholesale electricity prices as possible'.[52] This intervention contributed to generators shifting capacity previously bid at over $5000 per MWh to lower prices, typically below $300 per MWh. The volume of capacity offered at low prices (below $50 per MWh) has remained relatively stable (figure 2.27).

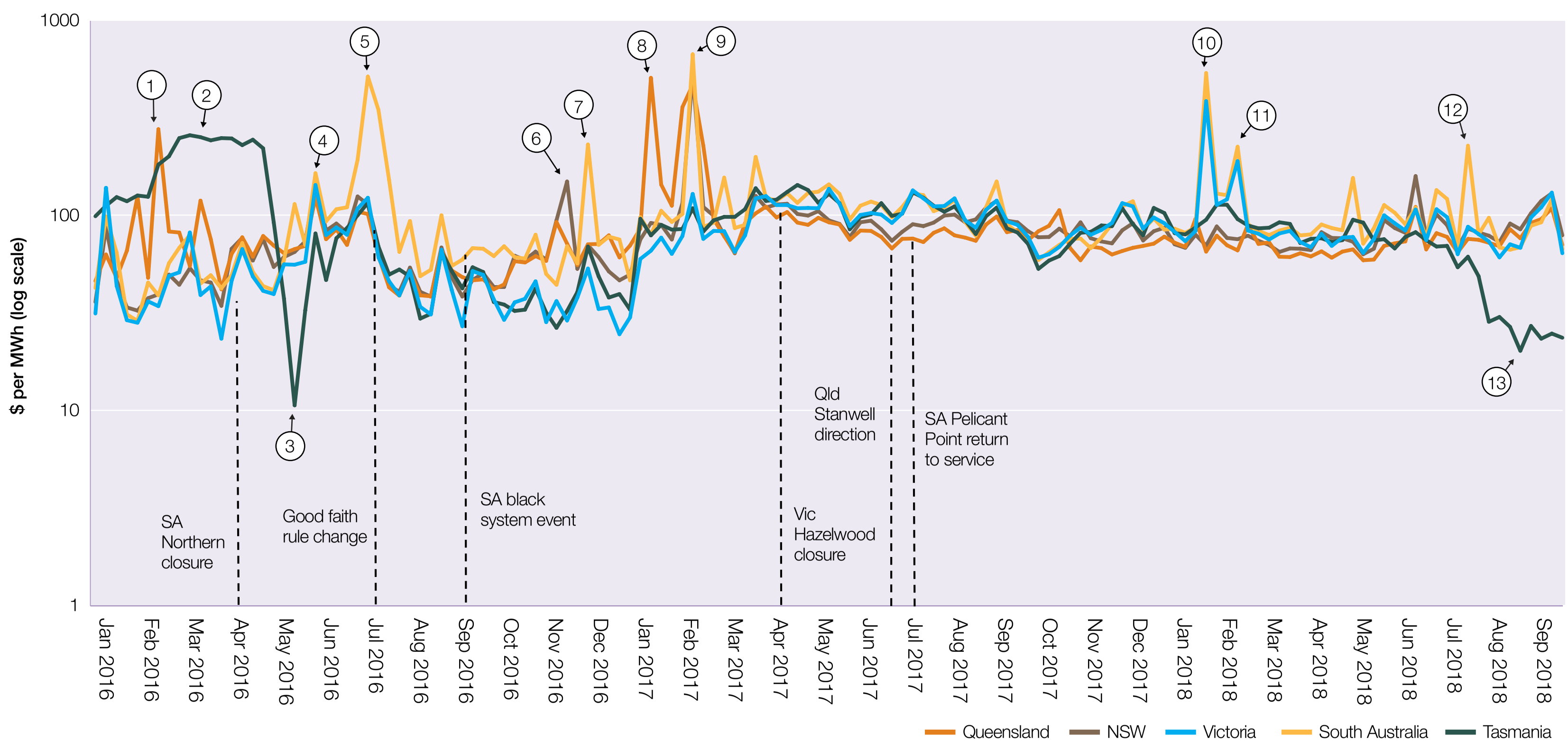
Despite maximum demand setting a new record during a heatwave in February 2018, summer conditions were generally relatively mild, contributing to lower prices. Other contributing factors included the return to service of the mothballed Swanbank E generator.

The Queensland Government intervention took place after a year of extremely high prices. Queensland prices averaged over $100 per MWh in 2016–17, a record high for the region. In that year, higher fuel costs for gas and supply issues affecting black coal put pressure on market prices. These changes coincided with Queensland's black coal generators in 2017 shifting significant capacity from $20–50 per MWh price bands to $50–100 per MWh bands.[53]

But the AER found some black coal generators raised their average supply offers more than can be explained

50 ACCC, *Restoring electricity affordability and Australia's competitive advantage, Retail Electricity Pricing Inquiry—Final Report*, June 2018, p. 50.
51 Earnings before interest in tax as a share of revenue, based on information from seven large mainland generators.
52 Queensland Government, *Stabilising electricity prices for Queensland consumers*, media release, 2017.
53 ACCC, *Restoring electricity affordability and Australia's competitive advantage, Retail Electricity Pricing Inquiry—Final Report*, June 2018, p. 55

Figure 2.26
Weekly spot prices

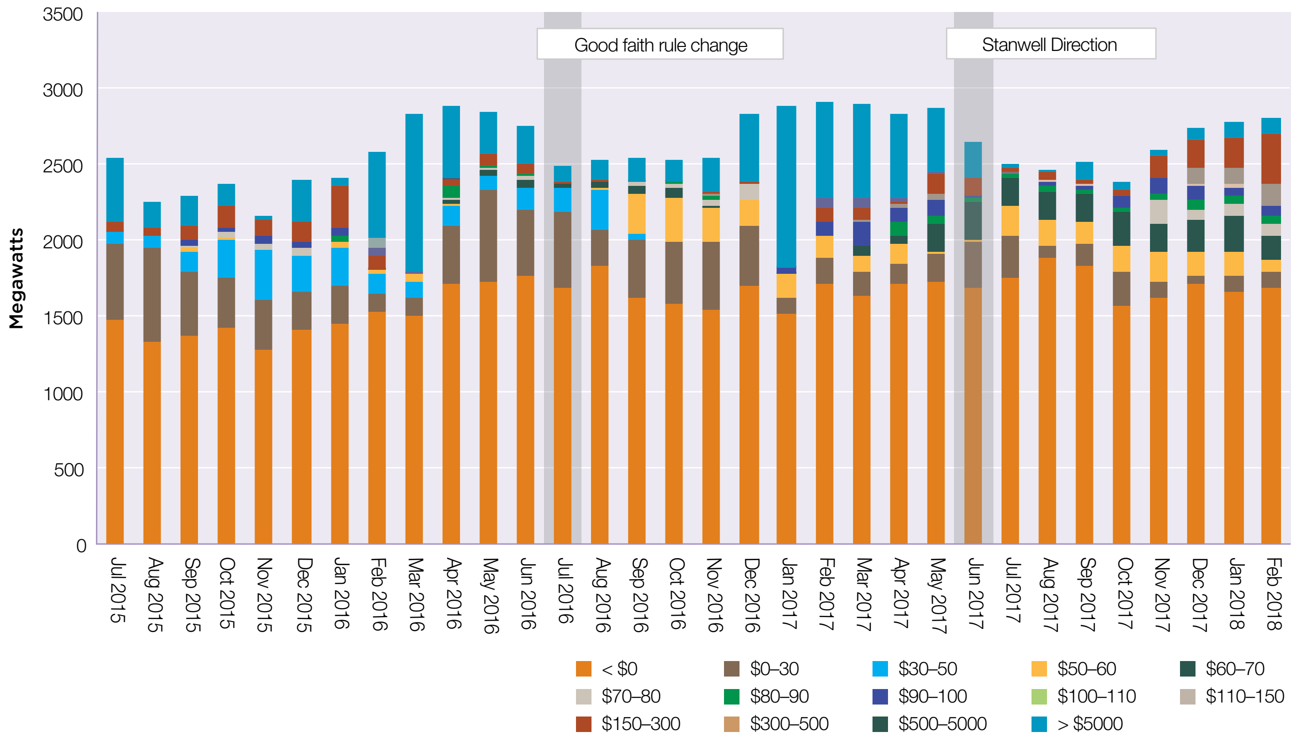


1 Record high demand and rebidding.
2 Basslink outage and record low rainfall and dam levels.
3 High rainfall increased hyrdo output.
4 Coal plant closures and extensive coal outages reduce supply. Coincided with high gas prices.
5 Heywood interconnector outage due to planned maintenance coincided with low wind and plant closures.
6 Rebidding behaviour and network constraints on the Vic–NSW interconnector.
7 Rebidding behaviour and an unplanned outage of the Heywood interconnector .
8 High temperatures led to record Qld demand, plant restrictions, rebidding and limited imports.
9 Extremely high temperatures led to high demand across the NEM. Extensive coal generator outages in Qld and NSW. Load-shedding in SA as demand exceeded forecasts and wind output was low.
10 High temperatures led to high demand in Vic and SA. Exacerbated by a plant outage in Vic.
11 High temperatures drove high demand. No significant generator or network outages.
12 Planned outages on the Heywood interconnector coincided with low wind output.
13 High rainfall increased hyrdo output.

Source: AER.

Figure 2.27

Stanwell Corporation's monthly offered capacity by price band—Stanwell and Tarong power stations



Note: Monthly average capacity offered by price band.

Source: AER; AEMO.

by higher costs alone.[54] The ACCC found Queensland's highly concentrated market structure and a reduction in competitive constraints on Queensland generators since the closure of the Hazelwood power station contributed to record prices in the region.[55]

2.9.2 NSW

NSW prices averaged $85 per MWh in 2017–18, the second lowest for any NEM region, and 3 per cent lower than a year earlier.

NSW is a relatively import-dependent region, and its electricity prices are affected by events across the NEM. The region recorded a 62 per cent rise in prices in 2016–17, partly due to higher fuel costs for gas powered generators and fuel availability issues affecting black plant. In these conditions, NSW generators shifted some of their capacity offers to higher prices (figure 2.28).

But as in Queensland, the AER found the average offers from some black coal generators in NSW increased more than underlying costs. Electricity imports from Victoria were also more expensive following the closure of Victoria's Hazelwood plant in March 2017. The closure lessened competitive pressures on NSW generators, allowing them to bid into the market at higher prices.

Market intervention by the Queensland Government in July 2017 to lower prices in that region also increased competitive pressure on NSW generators. Improved access to black coal and gas fuel availability also took some pressure off NSW prices.

Hydroelectric plant played a significant role in setting prices during the year. Similar to black coal generators a year earlier, Snowy Hydro from early 2017 shifted capacity from prices under $50 per MWh into higher price bands. This behaviour persisted for much of the year.[56] But an increase in hydrogeneration over summer 2017–18 and a relatively mild summer helped to stabilise prices. By autumn 2018

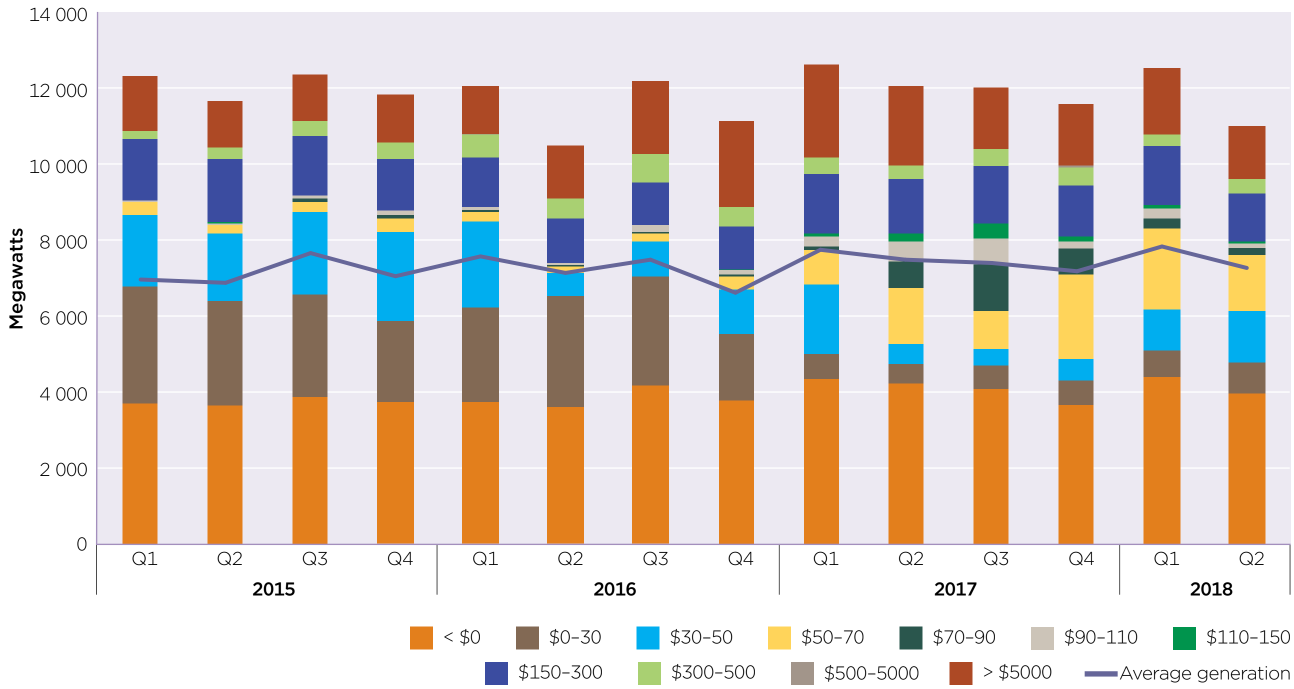
54 AER, *Electricity wholesale performance monitoring, NSW electricity market advice*, December 2017.

55 ACCC, *Restoring electricity affordability and Australia's competitive advantage, Retail Electricity Pricing Inquiry—Final Report*, June 2018, pp. 66–70.

56 AEMO, *Quarterly Energy Dynamics,Q1 2018*.

Figure 2.28

NSW generators' average quarterly offered capacity by price band



Note: Quarterly average capacity offered by price band.

Source: AER, Electricity wholesale performance monitoring—NSW advice, December 2017.

lower priced hydroelectricity offers (from Snowy and Hydro Tasmania) helped to ease wholesale prices.[57]

2.9.3 Victoria

Victorian prices averaged $100 per MWh in 2017–18, a record high for the state. Prices were 43 per cent higher than a year earlier and 30 per cent higher than in any year since the NEM began. Victoria was traditionally a relatively low cost electricity producer, but in 2017–18 was second only to South Australia as the NEM's most expensive region.

Victorian prices moved sharply higher following the closure of its low cost Hazelwood generator in March 2017, which diminished the role of brown coal in price setting in the region. Over summer 2017–18, brown coal set the dispatch price less than 2 per cent of the time, compared with 24 per cent in the previous summer (figure 2.29).

Outages at Loy Yang A and Yallourn in late 2017, and at Loy Yang B in January 2018, contributed to supply and price volatility. Adding to market pressures, Victoria was the only mainland region to record higher average summer demand in 2018 than a year earlier. Warm summer conditions and increased industrial load drove this demand.[58]

With the closure of Hazelwood, only 28 per cent of Victorian spot prices in 2017–18 were set by generators located in Victoria, compared with over 36 per cent of prices three years earlier. AGL's Bayswater black coal station (NSW), Torrens Island gas power station (South Australia) and Origin's Eraring black coal station (NSW) were among frequent price setters for Victoria during the year.

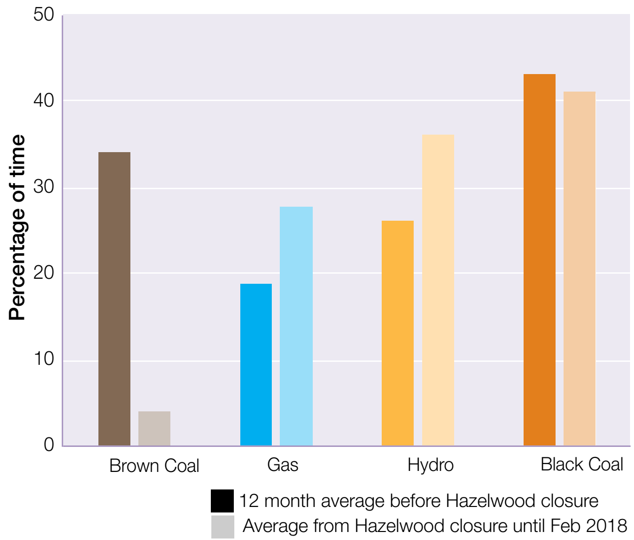
Despite Victoria's increased reliance on electricity imports, interconnector issues constrained imports from NSW 30 per cent of the time over summer 2017–18, pushing the region's average wholesale prices 43 per higher than NSW prices.[59]

57 AEMO, *Quarterly Energy Dynamics Q2 2018*.

58 AEMO, *Quarterly Energy Dynamics, Q1 2018*, p. 3.

59 AEMO, *Quarterly Energy Dynamics, Q1 2018*, p. 10.

Figure 2.29
Price setting in Victoria by fuel type since Hazelwood closure



Note: Hazelwood closure in March 2017. Data is for the periods March 2016 to February 2017 and March 2017 to February 2018. Victorian prices can be set by generation located outside Victoria.

Source: AER, Electricity wholesale performance monitoring—Hazelwood advice, March 2018.

2.9.4 South Australia

South Australian prices averaged $111 per MWh in 2017–18, the highest for any NEM region. Despite prices easing by 12 per cent from a year earlier, South Australia recorded triple digit prices for a second consecutive year.

The closure of Alinta's Northern power station in May 2016 removed significant capacity from the South Australian market. Gas powered generators now represent about two thirds of dispatched generation in South Australia, and often sets prices, despite gas fuel costs being at historically high levels. South Australia is more sensitive to gas price shifts than other regions.

Supply conditions improved in 2017–18 with the return to service of a previously mothballed unit of the Pelican Point plant, and the launch of the Hornsdale Power Reserve (section 2.9.8). A slight easing in gas fuel costs also cushioned prices somewhat.

Intermittent generation plays an increasingly significant role in setting South Australian prices. Periods of low wind generation contributed to the state's record prices in 2016–17, but its contribution increased in 2017–18 and helped ease prices. The increasing contribution of solar PV generation was apparent when South Australia recorded its lowest ever summer grid demand on 1 January 2018.

2.9.5 Tasmania

Tasmania prices averaged $88 per MWh in 2017–18—the state's third highest average since joining the NEM in 2005. Tasmania was one of only two NEM regions to record higher prices in 2017–18 than a year earlier (the other region being Victoria). Tasmanian prices rose on average by 14 per cent.

Tasmanian prices fluctuate depending on conditions for hydrogeneration and electricity market conditions on the mainland. Issues with the Basslink interconnector also affect prices.

Tasmania's higher prices in 2017–18 partly reflect the closure of the Hazelwood power station reducing the availability of cheap electricity imports from the mainland. Dry conditions also affected hydrogeneration for some of the year, but good rainfall in 2018 reversed this trend.

2.9.6 Price volatility

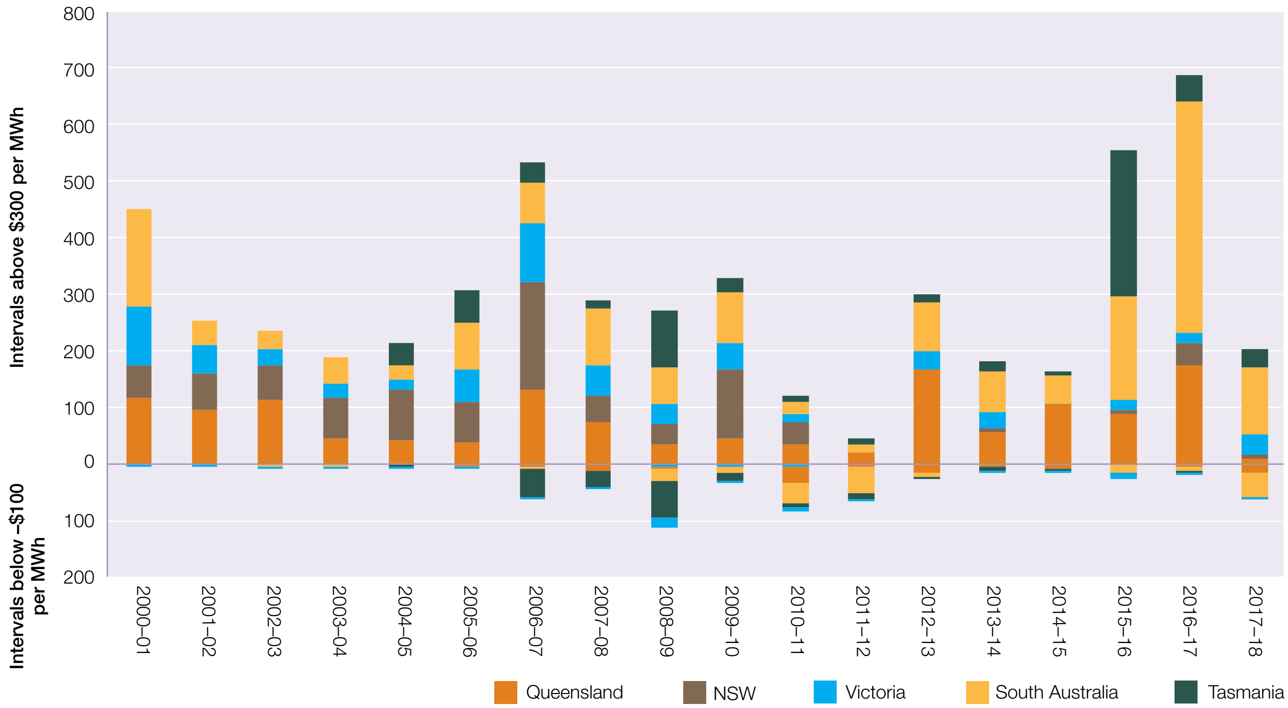
After two years of record volatility, NEM prices were generally more stable in 2017–18 (figure 2.30). Queensland and NSW experienced negligible price volatility despite record high demand in Queensland on 14 February 2018. Queensland recorded only nine prices above $300 per MWh in 2017–18, compared with 176 events the year before. In NSW, the number fell from 39 events in 2016–17 to eight in 2017–18. Directions by the Queensland Government to its generators to lower prices contributed to these outcomes. Queensland and NSW also benefited in 2017–18 from more stable fuel prices, the return to service of mothballed capacity at Swanbank E, increased hydroelectric generation in NSW, and a generally mild summer.[60]

South Australia recorded a majority of the NEM's prices above $300 per MWh in 2017–18 (116 out of a total 205 events). Victoria recorded 38 events, its highest count in a decade. Tasmania recorded 34 events. The high prices in Victoria and South Australia mostly occurred on three days of coincident hot weather, high demand and low wind output—18 and 19 January and 7 February 2018. A plant outage at Loy Yang B on 18 January contributed to this volatility.

Despite a reduction in the number of extremely high prices, the NEM in 2017–18 recorded its highest incidence of extreme negative prices (below –$100 per MWh) since 2011–12. A majority of the events (44 out of 61 events) occurred in South Australia, and usually coincided with high wind and solar PV generation.

60 AEMO, *Quarterly Energy Dynamics, Q1 2018*, p. 3.

Figure 2.30
Market volatility



Note: Total number of intervals where spot prices exceeded $300 per MWh or fell below –$100 per MWh.

Source: AER; AEMO.

2.9.7 FCAS prices

Frequency control ancillary services (FCAS) are required to maintain the frequency of the power system within safe operating standards. Regulation FCAS continuously adjust to balance small changes in frequency during normal operation of the power system, while contingency services manage larger frequency changes associated with sudden unexpected shifts in supply or demand.

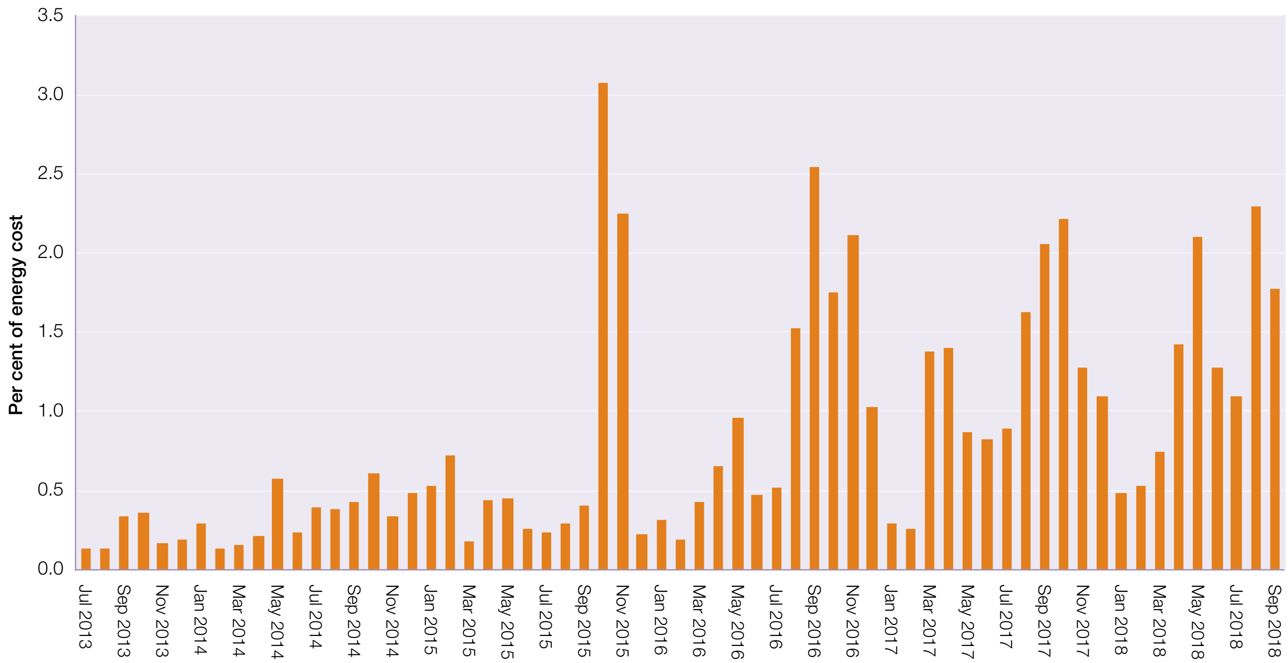
AEMO acquires FCAS through a market that is co-optimised with the wholesale energy market (offers from generators and other participants are coordinated in both markets to minimise overall costs), and consumers ultimately pay the costs. Historically, FCAS costs were small compared with energy costs—before September 2015, FCAS costs averaged less than 0.5 per cent of NEM energy costs. But more recently FCAS costs have often accounted for 1–2 per cent of costs (figure 2.31)

Costs rose for both regulation and contingency services. South Australia in particular experienced significantly higher FCAS costs following stricter requirements for localised sourcing of those services in 2015. This change coincided with a reduction in the number of local suppliers of FCAS. The requirement for additional local FCAS was later removed. New sources of FCAS have also begun operating in South Australia, including the Hornsdale Power Reserve and a provider of demand response services (box 2.4).

The NEM's changing generation mix has contributed to rising FCAS costs. Some thermal generators that traditionally provided FCAS (such as the Northern power station in South Australia) have exited the market. Many older renewable generators (wind and solar) were not engineered to provide these services, but newer plant is required to have this capability.

A reduction in FCAS offered by Tasmania also contributed to higher FCAS costs. Unplanned outages on the Basslink interconnector between Tasmania and the mainland (from December 2015 to June 2016 and again from March to June 2018) reduced FCAS supply. AEMO also imposed limits on the amount of FCAS regulation services Tasmania may provide to the mainland.

Figure 2.31
FCAS costs as a percentage of energy cost,



Note: Based on total wholesale and FCAS market costs each month.
Source: AEMO; AER.

2.9.8 Power system reliability and security

Power system reliability refers to having sufficient generation capacity to meet demand, while security refers to the system's technical capability in terms of frequency, voltage, inertia and similar characteristics (section 2.6). Reliability concerns tend to peak over summer, when high temperatures spike electricity demand and increase risks of system faults.

AEMO in September 2017 raised concerns the market was at risk of power outages over summer 2017–18, especially in Victoria and South Australia where plant closures had occurred.[61] Its concerns were exacerbated by an increasing number of outages affecting fossil fuel generators.

While AEMO issued 31 low reserve warnings over summer 2017–18, none led to load shedding. Outages were averted, partly because maximum demand was significantly lower than a year earlier in NSW and South Australia.

The market had also increased supply by returning mothballed gas powered generators to service in South Australia, Queensland, Tasmania and NSW.[62] In South Australia, the government also invested in nine hybrid diesel–gas generators (276 MW) and in a 100 MW grid connected battery at Hornsdale (box 2.4).

Other factors that helped avert reliability issues were high levels of hydroelectric and other renewable generation over summer 2017–18. Rooftop solar PV generation also contributed, operating at its highest quarterly output on record.[63] Coal plant also operated at relatively high capacity, partly due to increased plant availability in Victoria and an easing of black coal supply concerns in NSW.[64]

61 AEMO, *Electricity statement of opportunities for the national electricity market*, September 2017.

62 In Queensland, Swanbank E returned to service in Q1 2018 after having been mothballed in October 2014. In South Australia, Pelican Point returned to full station capacity on 1 July 2017 after operating at half capacity since March 2013. Additionally, the planned mothballing of Torrens A was deferred from June 2016 until July 2019 In Tasmania, Hydro Tasmania recommissioned the Tamar Valley Power Station in 2016 following its announced in August 2015 to decommission and sell the plant. In NSW, Smithfield returned to service in summer 2017–18 after being originally scheduled for retirement in July 2017.

63 AEMO, *Quarterly Energy Dynamics, Q1 2018*, p. 8.

64 AEMO, *Quarterly Energy Dynamics, Q1 2018*, p. 7.

AEMO also took advance action to manage forecast supply risks over summer 2017–18 by securing over 1100 MW of back-up reserves through the Reliability and Emergency Reserve Trader (RERT) mechanism at a cost of over $51 million. The reserves included generation and storage capacity as well as demand response whereby large energy customers are paid to reduce their load when the power system is under stress.

Low reserve forecasts led AEMO to activate the RERT mechanism by calling on reserves twice over summer 2017–18, but those reserves were ultimately not required. AEMO put reserves on standby on 30 November 2017 in Victoria, a day of unseasonably warm weather and generator unavailability that coincided with a major gas facility outage.[65] It also activated the mechanism in South Australia and Victoria on 19 January 2018, a day of high temperatures coupled with a Victorian generator outage and bushfire risks.[66]

A series of planned and unplanned generation outages led AEMO to issue 'lack of reserve' notices in NSW in June 2018, although no involuntary load shedding occurred. Grid demand was unusually high for June for several days, due to thick cloud cover and rain limiting rooftop solar output.[67] AEMO also issued several directions to keep the power system in a secure operating state, including the curtailment of some wind generation.

On 25 August 2018 a fault due to a suspected lightning strike on the NSW–Queensland interconnector separated Queensland from the rest of the NEM. To maintain frequency levels across the NEM, South Australia was also separated from the rest of the NEM, and load shedding occurred in NSW, Victoria, and Tasmania.

Reliability outlook

AEMO in August 2018 again raised reliability concerns for summer 2018–19, forecasting a higher risk of power outages than for the previous summer. It forecast a 1-in-3 chance of some power outages for Victoria if temperatures reach 40 degrees Celsius—particularly if high temperatures occur towards the end of the day, when business demand is relatively high, residential demand is increasing, and rooftop PV's contribution is declining.

Under these conditions, AEMO forecast around 380 MW of additional resources would be needed across Victoria and South Australia to avoid outages, which it proposed to tender for under the RERT scheme. The reserves may include a combination of additional supply capacity, energy storage, and demand response.[68]

AEMO's modelling of the risk of power outages over summer 2018–19 accounted for the market's ageing coal and gas powered plants becoming less reliable. It also factored in drought risks affecting water availability for hydroelectric generation and cooling for thermal generation in NSW.[69]

Beyond summer 2018–19, AEMO forecast an improved reliability outlook, based on expectations of committed new generation and storage capacity coming online and existing plants being upgraded.[70]

2.10 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 settlement prices reducing their earnings, while retailers risk having to pay high prices they cannot pass on to their customers. A retailer may sign up new customers at a particular price but then incur higher than expected prices in the wholesale market, for example, leaving the retailer substantially out of pocket.

Market participants need to manage their exposure to these risks to ensure their financial solvency. Three energy retailers went into administration in recent years—GoEnergy in 2016, Urth Energy in 2017 and COZero in 2018—due to exposure to high wholesale prices.

Generators and retailers can manage their market exposure by locking in prices they will trade electricity for in the future. An alternative strategy adopted by some participants is to internally manage risk through vertical integration—operating both generation and retail arms to balance out the risks in each market. When the retail arm of the business pays high prices for wholesale energy, for example, the generation arm benefits from high prices.

Typically, vertically integrated 'gentailers' are imperfectly hedged—their position in generation may be 'short' or 'long' relative to their position in retail. For this reason, gentailers participate in contract markets to manage outstanding exposures, but usually to a lesser extent than stand-alone generators and retailers.

65 AEMO, *Summer 2017–18 operations review*, May 2018.
66 AEMO, *Activation of unscheduled reserves for Victoria and South Australia—19 January 2018*, May 2018.
67 AEMO, *New South Wales 7 June*, media release, 10 June 2018.
68 AEMO, *2018 electricity statement of opportunities*, August 2018, p. 8.
69 AEMO, *2018 electricity statement of opportunities,* August 2018, p. 3.
70 AEMO, *2018 electricity statement of opportunities*, August 2018, p. 3.

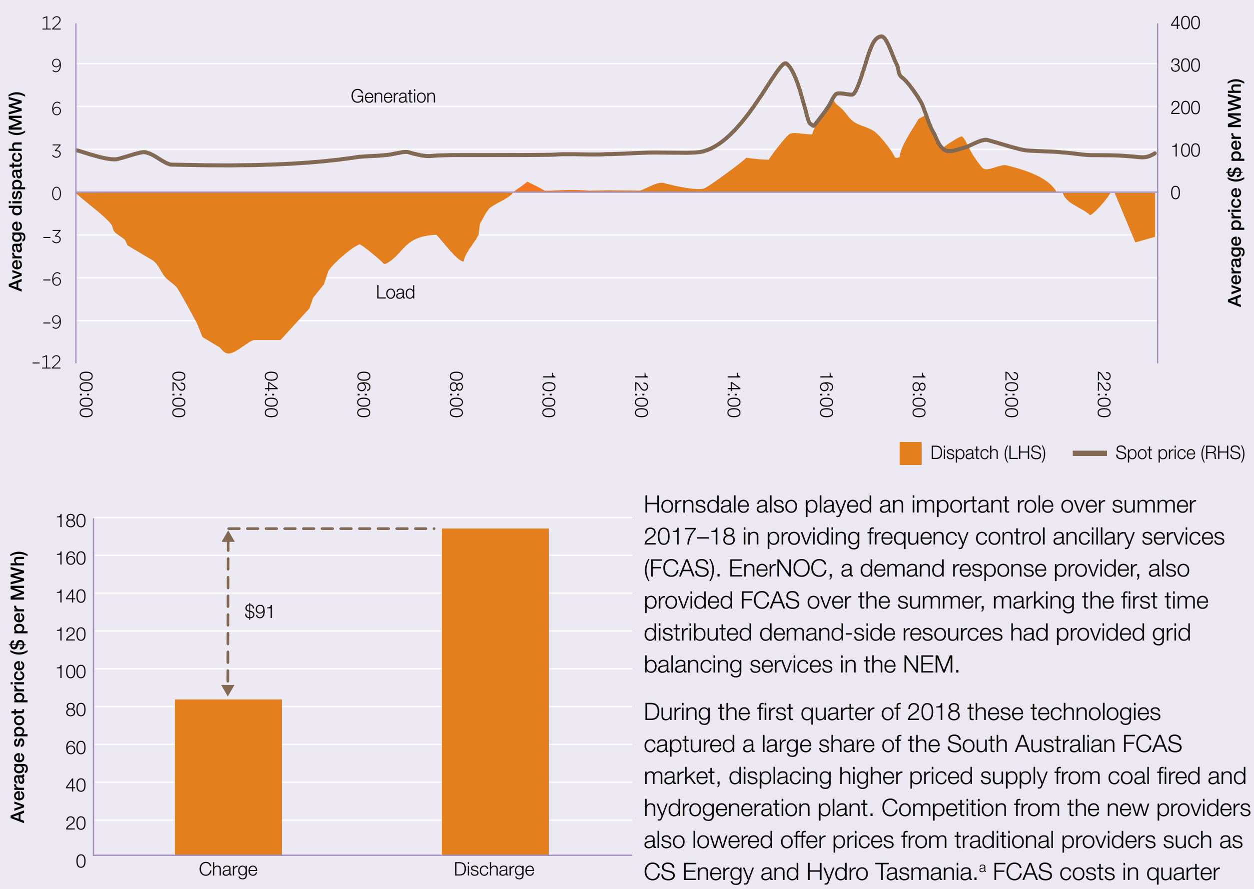
Box 2.4 Hornsdale Power Reserve

The Hornsdale Power Reserve—the NEM's first scheduled battery—played a significant role in the wholesale market over summer 2017–18. It consumed energy (for charging) during 38 per cent of trading intervals in January–March 2018, and was dispatched as a generator in 32 per cent of intervals. The battery was typically charged in the early hours of the morning, when energy prices are low, and power discharged (sold into the grid) in the late afternoon, when prices are higher (figure 2.32).

The difference between the average charge and discharge prices earned the battery an average price arbitrage of over $90 per MWh over this period. Three days of price volatility in South Australia (18 and 19 January, and 7 February 2018) largely accounted for this spread. South Australia prices settled at above $5 000 per MWh in nine trading intervals on these days.

Figure 2.32

Performance of Hornsdale Power Reserve



Source: AEMO, *Quarterly energy dynamics*, Q1 2018, p. 14.

Hornsdale also played an important role over summer 2017–18 in providing frequency control ancillary services (FCAS). EnerNOC, a demand response provider, also provided FCAS over the summer, marking the first time distributed demand-side resources had provided grid balancing services in the NEM.

During the first quarter of 2018 these technologies captured a large share of the South Australian FCAS market, displacing higher priced supply from coal fired and hydrogeneration plant. Competition from the new providers also lowered offer prices from traditional providers such as CS Energy and Hydro Tasmania.[a] FCAS costs in quarter one 2018 averaged 57 per cent lower than in the previous quarter, despite similar volumes of FCAS being required.

Following the success of Hornsdale, other grid scale battery installations have been announced across the NEM to complement and 'firm' solar and wind farm generation.

a AEMO, *Quarterly energy dynamics*, Q1 2018, p. 14.

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 also include financial intermediaries and speculators such as hedge funds. 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 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 Victoria, NSW, Queensland and South Australia.

While ASX trades are publicly reported, activity in OTC markets is confidential and not disclosed publicly, which impairs market information on prices and liquidity. The Australian Financial Markets Association (AFMA) reports data on OTC markets through voluntary surveys of market participants. The AEMC and ACCC both recommended data on OTC electricity contracts be made available to the market in a form that enhances transparency.[71] The ACCC considered this outcome could be achieved through a repository of trades that is disclosed publicly in a de-identified format.

Various products are traded in electricity contract markets. Similar types of 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 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. In OTC markets, futures are known as *swaps* or *contracts for difference*.
- *Options* are a type of contract giving 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.
- *Caps* are contracts setting an upper limit on the price a holder will pay for electricity in the future (typically set at $300 per MWh, while floors are contracts setting a lower price limit. Caps can be traded either as futures or 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. Increasingly, OTC negotiated contracts are cleared and registered through block trading on the ASX.

Electricity derivatives markets are regulated under the *Corporations Act 2001* (Cth) and the *Financial Services*

Box 2.5 Contracting and the reliability guarantee

The reliability guarantee originally proposed as part of the NEG (box 2.3) included an important role for contract (hedge) markets.

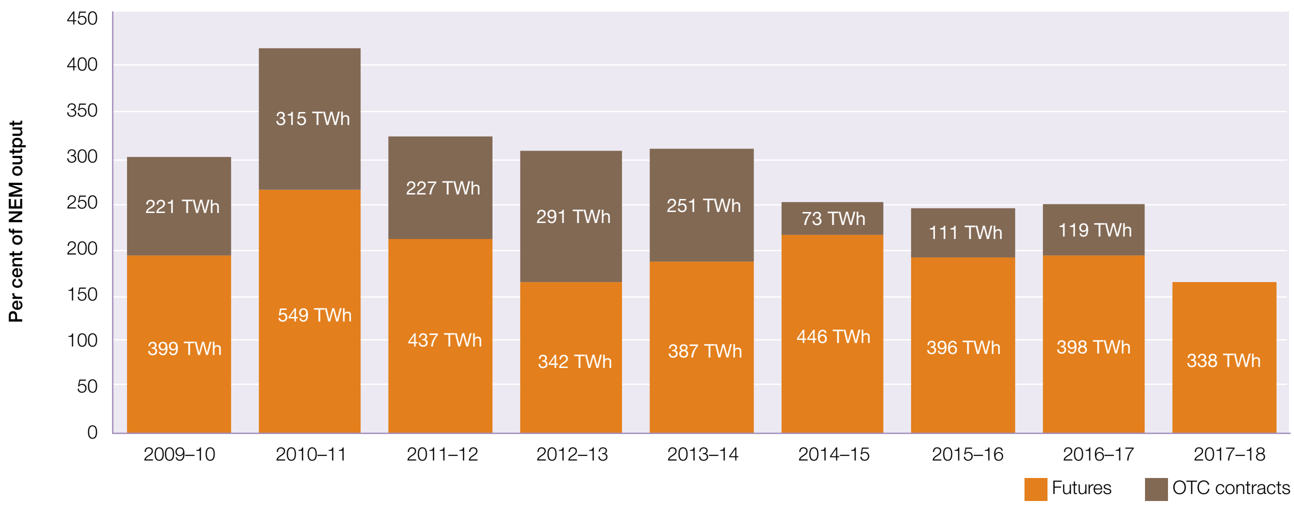
If implemented, the reliability guarantee would require AEMO to forecast the supply-demand balance out 10 years ahead. The guarantee would be activated if AEMO identifies (and the AER verifies) a shortfall in supply that risks the NEM not achieving the reliability standard. Retailers (and other liable entities) would then need to demonstrate they have hedge contracts in place to encourage sufficient generation to meet their expected demand. Hedge contracts with a direct link to the electricity market— including futures (swaps) and caps—would qualify

The guarantee's design relies on retailers having access to hedge products. To support contract market liquidity, the reliability guarantee design requires that if a supply shortfall is identified, large vertically integrated retailers must perform a 'market-maker' role by offering to buy and sell hedge products within a limited price spread.

In December 2018 the Australian and state governments were progressing work on the reliability guarantee through the COAG Energy Council.

71 AEMC, *2018 Retail energy competition review*, June 2018; ACCC, *Restoring electricity affordability and Australia's competitive advantage, Retail Electricity Pricing Inquiry—Final Report*, June 2018, p. 122.

Figure 2.33
Traded volumes in electricity futures contracts



Note: Data for 2017–18 OTC contracts were not available at the time of publication.
Source: AER; AFMA; ASX Energy.

Reform Act 2001 (Cth). The Australian Securities and Investments Commission is the principal regulatory agency.

2.10.1 Contract market activity

As noted, comprehensive data on electricity futures is not publicly available. While ASX trades are publicly reported, activity in OTC markets is confidential and only disclosed publicly via participant surveys in aggregated form.

In ASX markets, regular trade occurs in Queensland, NSW and Victoria, but liquidity is poor in South Australia. Traded volumes also appear to be declining across the market generally (figure 2.33).

In 2017–18 contracts covering 338 TWh of electricity were traded on the ASX, equivalent to 172 per cent of underlying NEM demand. Volumes were down by 15 per cent from 2016–17 levels, when concerns about the impacts of the Hazelwood closure prompted a rise in trading. The 2017–18 data continues a longer term trend of declining activity in the ASX electricity futures market, and was 38 per cent below the peak trading year of 2010–11.

AFMA data based on voluntary reporting suggests OTC trading has increased since 2014–15, but remains well below previous levels. Activity switched from ASX to OTC markets during the period of carbon pricing (2012–14), when participants sought greater contract flexibility, but OTC trading has since weakened. The number of intermediaries (financial market participants without a position in the underlying electricity market) in the market also appears to have reduced.

Declining volumes in electricity futures trades may be partly due to higher levels of intermittent generation, which is not suitable for contracting because its output is weather dependent. But ‘firming’ of this generation through storage or gas may support contract market participation. A number of market participants with flexible generation capacity are already offering firming products targeted at renewable generation. In April 2018, ERM launched a solar firming product and AGL launched a similar wind firming product.[72]

Flat electricity demand and less price volatility in the wholesale market may also have contributed to lower volumes in contract markets, particularly for cap contracts. As discussed previously, vertical integration—which allows businesses to internally manage risk by operating both generation and retail arms—also limits businesses’ need to contract with third parties.

Composition of trade

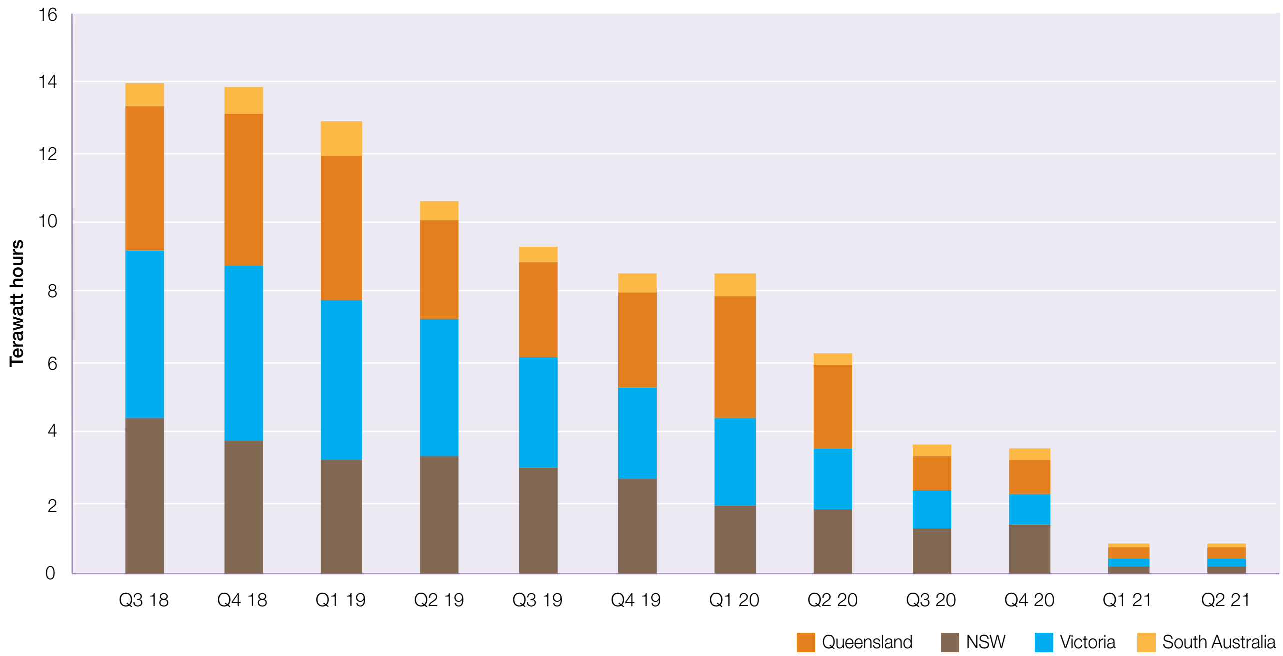
Victoria, NSW and Queensland each accounted for 30–33 per cent of open ASX electricity futures in November 2018. Liquidity was much lower in South Australia, with 6 per cent of open contracts.

The most heavily traded ASX products in 2017–18 were baseload quarterly futures (55 per cent of traded

72 AER, *Wholesale electricity market performance report* December 2018.

Figure 2.34

Open interest in ASX electricity derivatives



Note: Data at November 2018.

Source: AER; ASX Energy.

volume), followed by options (31 per cent) and cap futures (13 per cent). In the OTC market, the vast majority of transactions are for flat swap products.

Liquidity is highest in products traded 12–24 months out. Open interest (the number of contracts) in the market at November 2018 mostly related to contracts out to the first quarter of 2020, with liquidity rapidly tailing off beyond then (figure 2.34).

2.10.2 Contract market liquidity

Contract volumes traded in Victoria and Queensland (across ASX and OTC markets jointly) generally exceed demand for electricity, while NSW trade volumes and electricity demand are generally balanced. 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. Several retailers indicated to the ACCC they consider liquidity in contract markets in Victoria, Queensland and NSW is adequate.

South Australia, by contrast, has trading levels well below regional demand for electricity, which is consistent with claims by retailers that the region's contracting market is highly illiquid. The region's high proportion of renewable generation and relatively concentrated ownership of dispatchable generation likely contributes to this illiquidity. The ACCC also found South Australia is the only region where traded volumes are higher in the OTC than ASX market.[73]

Given South Australia's liquidity issues, the ACCC recommended a 'market-maker' obligation be imposed in South Australia.[74] Similar to the proposed obligation under the reliability guarantee, this obligation would require large vertically integrated retailers to make offers to buy and sell hedge products, with a capped price spread.

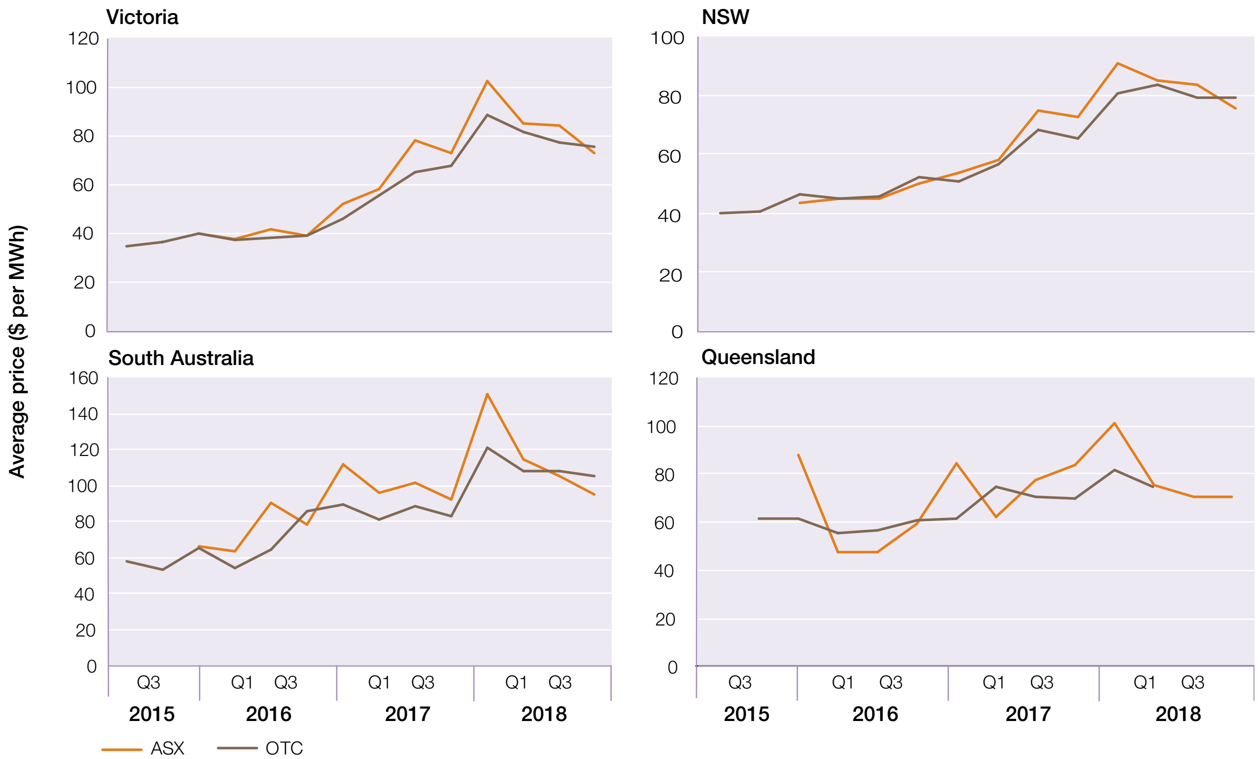
The ACCC also noted retailers' concerns about a reduction in offerings of 'load following' contracts in the OTC market generally. These contracts remove volume risk, and are particularly sought by smaller or new retailers without extensive wholesale market capacity.

73 ACCC, *Restoring electricity affordability and Australia's competitive advantage, Retail Electricity Pricing Inquiry—Final Report*, June 2018, p. 119.

74 ACCC, *Restoring electricity affordability and Australia's competitive advantage, Retail Electricity Pricing Inquiry—Final Report*, June 2018, p. 130.

Figure 2.35

ASX and OTC average contract prices for base swaps



Note: Average prices by maturity dates ranging from Q3 2015 to Q3 2018.

Source: ACCC, *Restoring electricity affordability and Australia's competitive advantage, Retail Electricity Pricing Inquiry—Final Report*, June 2018.

While comparisons of price outcomes in OTC and ASX markets are not generally available, the ACCC conducted a comparative study for trading over several quarters. It found prices of OTC contracts were generally lower than for comparable products traded on the ASX, regularly trading at $10–20 per MWh less. This differential was most evident in Victoria, NSW and South Australia. No clear trend was evident for Queensland (figure 2.35).

2.10.3 Recent contract prices

Price movements for electricity base futures for calendar years 2018, 2019 and 2020 are presented in figure 2.36.

Base futures prices rose steadily prior to the closure of Victoria's Hazelwood power station in March 2017, reflecting expectations of how the closure would affect wholesale prices.

Futures prices for supply in 2019 and beyond tended to ease over 2017 and through the first half of 2018. This easing reflected expectations that a large influx of renewable generation planned to come online in 2018–19 would exert downward pressure on wholesale prices. However, futures prices remained well above historical levels, and began trending higher from mid-2018.

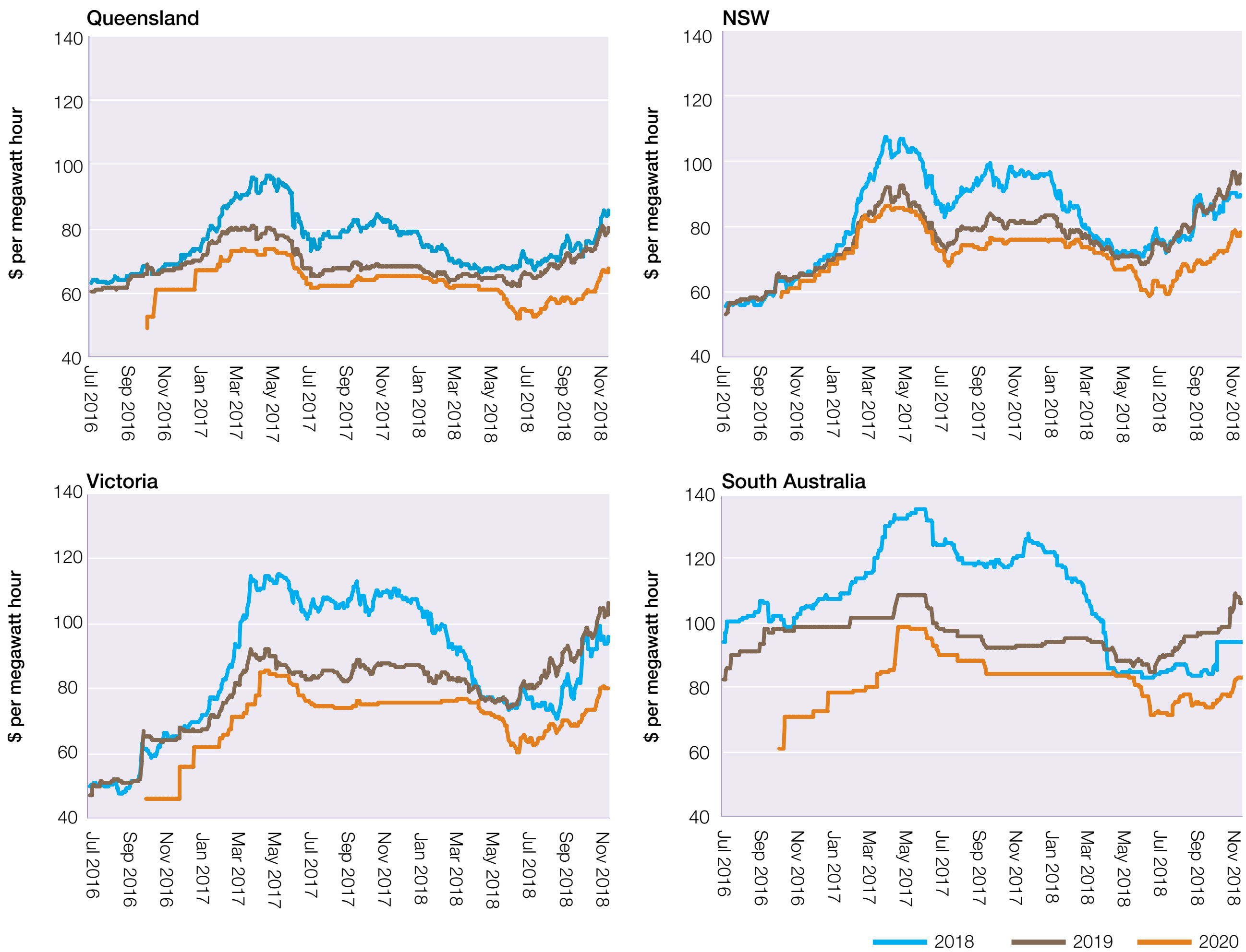
Concerns about electricity market conditions over summer 2018–19 saw futures prices trend higher from mid-2018. Between May and November 2018, futures prices for summer (quarter one) 2019 supply rose by 35–40 per cent in NSW and Victoria, and 25 per cent in Queensland and South Australia. These rises likely relate to market concerns about drought impacting coal and hydroelectric plant availability over summer, and expectations gas fuel costs will likely remain high.

2.10.4 Small retailers' access to contract markets

Lack of effective access to hedging products can pose a barrier to new generators and retailers entering or expanding their presence in the electricity market. The risk is particularly

Figure 2.36

Prices for 2018, 2019 and 2020 base futures



Note: Data at November 2018. Prices for calendar strips, calculated as the average of prices for quarterly base futures for each quarter of the calendar year.

Source: AER; ASX Energy.

high for electricity retailers not vertically integrated with a generator. The ACCC identified potential barriers to small or new retailers accessing hedge products in ASX and OTC markets, with significantly fewer trade options available.[75]

In the ASX market, the credit requirements of clearing houses, and daily margining of contract positions, impose significant costs on retailers. The use of standardised products with a minimum trade size of 1 MW may be too high to meet the contracting requirements of smaller retailers.

75 ACCC, *Restoring electricity affordability and Australia's competitive advantage, Retail Electricity Pricing Inquiry—Final Report*, June 2018, p. 111.

Credit risk is also a barrier to smaller retailers in the OTC market, with counterparties likely to impose more stringent credit support requirements on them. Bilateral trade agreements underpinning OTC trades can also be costly to set up.

Major retailers were found to pay less on average for OTC contracts than smaller retailers. To some extent, this outcome may reflect the higher risk of dealing with smaller retailers. But a lack of transparency in the OTC market, combined with smaller retailers having access to fewer potential trading partners, creates a risk of price discrimination against smaller retailers. Reforms to enhance market transparency would improve outcomes in this area.

2.11 Market competition

The AER monitors the performance of the wholesale electricity market, including whether it is effectively competitive. Prices in an effectively competitive energy market should reflect demand and underlying cost conditions, at least in the longer term.

In an effectively competitive energy only market, 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 tighten supply and demand conditions allow 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.

In previous editions of *State of the energy market,* the AER highlighted periodic evidence of opportunistic bidding in several NEM regions, including by AGL Energy in South Australia, Hydro Tasmania in Tasmania and most recently by state owned generators in Queensland. Our reporting on these issues supported reforms to generator bidding rules, that the AEMC implemented. The reforms, relating to bidding in good faith, require generators to have genuine intent to honour their bids.

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 five minute dispatch prices. This timing difference allows generators to rebid capacity late in a trading interval to capture high prices, while giving competing generators little time to respond.

The AEMC approved a rule change in 2017 to align the timeframes for dispatch and settlement prices to five minutes. It considered removing the time discrepancy would encourage more efficient bidding and operational decisions. The reform will take effect in 2021.

More recently, the AER reported on the effectiveness of competition in NSW in 2016–17[76], impacts of the Hazelwood closure in Victoria in 2017[77], and a NEM wide review over the past five years.[78] The ACCC in 2018 also analysed competition in the NEM.[79]

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.

A key driver of higher electricity prices has been the exit of low cost coal generation plant. With less capacity available at low prices, higher cost black coal, gas and hydroelectric generators are more frequently setting electricity prices. The increased reliance on gas also comes at a time of high gas costs.

These issues may be transitional. But certain features of the market make it vulnerable to the exercise of market power, and may have driven prices higher than recent changes in the generation mix and underlying supply costs can explain. A few large vertically integrated participants control significant generation capacity and output in most NEM regions. This output is needed to meet demand in most regions a significant proportion of the time, which creates opportunities to exercise market power (box 2.6).

Generator bidding

The AER did not identify opportunistic generator bidding behaviour (such as rebidding, withholding capacity or manipulating ramp rates) as significant contributors to recent energy price rises. Some participants periodically used these methods to exercise market power over the past five years, but this behaviour was not apparent recently. Previously observed rebidding behaviour by Queensland generators declined, for example, after a Queensland Government directive to Stanwell in July 2017 (section 2.9.1).

But the AER did identify longer term market trends that warrant surveillance. In particular, average offers from some black coal generators in NSW and Queensland have increased more than underlying costs. The AER also identified participants exercising market power in South Australia's FCAS markets. However, new entrants have since entered that market and regulatory requirements contributing to the problem have been changed (section 2.9.7).

More generally, wholesale electricity prices have risen to a level that should signal new entry for lower cost technologies. Consistent with these findings, significant

76 AER, *Electricity wholesale performance monitoring, NSW electricity market advice*, December 2017.

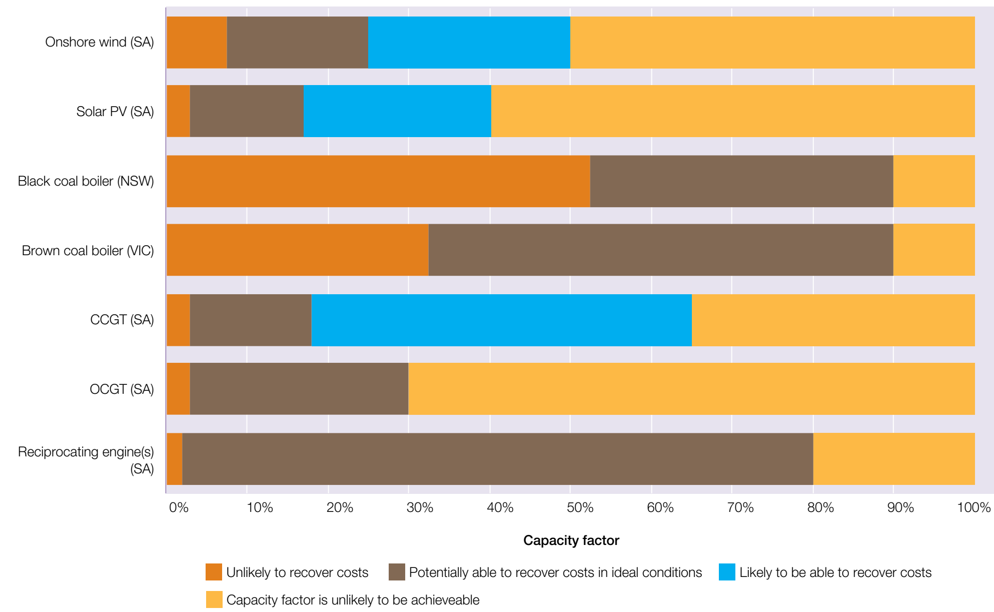
77 AER. *Electricity wholesale performance monitoring. Hazelwood advice*, March 2018.

78 AER, *Wholesale electricity market performance report*, December 2018.

79 ACCC, *Restoring electricity affordability and Australia's competitive advantage, Retail Electricity Pricing Inquiry—Final Report*, June 2018.

Figure 2.37

Likelihood for new entrant cost recovery by technology type



CCGT, combined cycle gas turbine; OCGT, open cycle gas turbine.

Note: Based on spot market outcomes for 2017–18. Cost estimates for new entrants based on publicly available information on generic costs and include both high and low cost scenarios. Cost estimates are levelised, meaning a new entrant generator's lifetime costs are allocated across each megawatt-hour of energy produces over the plant's expected life. New entrants would also consider more site-specific, detailed modelling of costs, risk and production not captured in this analysis.

Source: AER, *LCOE Modelling approach limitations and assumptions*, 2018.

investment in renewable generation is on the horizon (section 2.5). This wind and solar plant investment will create an increasing need for flexible generators or storage able to match variations in intermittent supply.

AER analysis suggested price signals for flexible and firming technologies (such as open cycle gas turbines) are improving. But they remain weaker than for other technologies, because the price spikes these generators need to recover their costs are not occurring frequently enough.

Despite a significant train of recent and planned investment, market participants identified continued barriers to entry for new generation—particularly for flexible capacity. The AER reported views that a lack of stability and predictability in government energy policy is a barrier to entry for new generation. Emissions 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 generation investment.[80]

In addition, there may be barriers to non-vertically integrated or new entrant generation participants to obtaining finance and managing market exposure. These barriers include the need to contract with gentailers with which they would compete, and poor liquidity in contract markets (section 2.10.4).

Signals for new investment

The Australian Energy Regulator assessed the viability of new entrant plant in the NEM based on spot price outcomes in 2017–18 and estimated production costs.

Figure 2.37 summarises results for the regions with the highest potential spot revenue for each technology. The colour indicates the likelihood of cost recovery for a new entrant at different capacity factors.

Based on spot revenues in 2017–18, the results indicate strong price signals to invest in large scale solar and wind plant—even without support from the Renewable Energy Target scheme. Closed cycle gas turbine technologies would also likely recover their costs based on 2017–18 prices, particularly if operating at higher capacity factors. The results indicate improving investment signals for new coal technologies but, based on current prices

80 AER, *Wholesale electricity market performance report*, December 2018.

and cost estimates, those signals are weaker than for other technologies.

Flexible, firming technologies such as open cycle gas turbines could possibly recover their costs in a best case scenario. But investment signals are again weaker than for other technologies, because the price spikes needed to support the low capacity factors of technologies such as open cycle gas turbines are not occurring frequently enough, despite a general uplift in wholesale prices.

Box 2.6 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. Markets with a high proportion of capacity controlled by one or two generators are more likely to be susceptible to the exercise of market power. Figures 2.23 and 2.24 illustrate generation market shares in 2018, based on capacity and output criteria.

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. The higher the HHI, the more concentrated is the market.

Figure 2.38 compares market concentration over time in mainland NEM regions. The average HHI is over 2000 for each region, and has not varied significantly in recent years. But significant variation from the average occurs in some dispatch intervals, due to plant outages, fuel availability and bidding behaviour in response to different levels of demand and prices. South Australia had the highest and lowest single HHI value each year.

Figure 2.38
Herfindahl–Hirschman Index

Note: Based on bid availability or the capacity each generator offered, every five 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 does not account for imports and so overstates 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, *Wholesale electricity market performance report*, December 2018.

In most regions, the output of a few large participants is necessary to meet demand a significant proportion of the time, even allowing for import capacity from other regions. At these times, those participants are 'pivotal' to meeting demand and may have the ability 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 one 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 index to deteriorate, including a rise in demand, a decrease in available generation capacity, or an increase in the proportion of available capacity supplied by the largest participants.

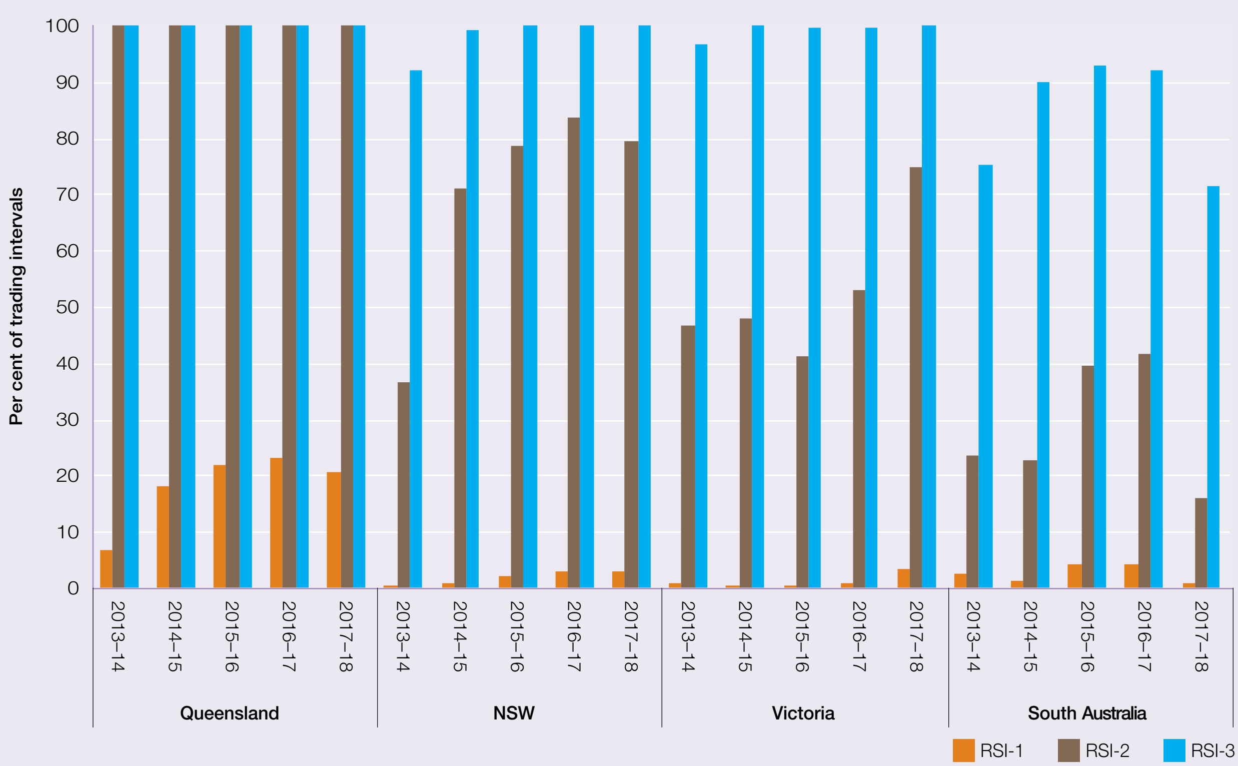
It is easier for one pivotal participant to exercise market power than for two or three participants to do so. But RSI-2 and RSI-3 can indicate the potential risk of multiple participants coordinating behaviour to influence market outcomes.

A limitation of RSI analysis is its focus on whether a participant *can* raise prices rather than 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 2.39 shows the percentage of trading intervals in each the past five years where RSI values were below one—that is, where at least some generation from the one, two or three pivotal participants was needed to meet demand.

Figure 2.39

Pivotality of largest generators



Note: The percentage of trading intervals where the one, two and three largest generators are pivotal. Allocations based on control of trading rights. Based on real time (half hourly) bid availability, Includes maximum possible imports as available capacity. If an interconnector is forced to export, it is treated as additional demand in the region.

Source: AER, *Wholesale electricity market performance report*, December 2018.

In Queensland the largest participant (whether Stanwell or CS Energy) is pivotal— that is, needed to meet demand—more often than the largest generator is pivotal in any other region. In Queensland, the largest generator is pivotal 20 per cent of the time. When Stanwell and CS Energy are jointly considered (RSI-2), some of their combined capacity is needed to meet demand 100 per cent of the time.

In NSW and Victoria, the largest participant is needed to meet demand 3 per cent of the time (around 10 days per year). The two largest participants are needed to meet demand 75–80 per cent of the time. Some output from one of the three largest participants is always needed to meet demand.

South Australian generators are pivotal less often than those in other regions. Output from the largest South Australian generator was rarely required to meet demand in 2017–18. The largest participant(s) was also less pivotal in 2017–18 than previously, in part because a previously mothballed plant at Pelican Point returned to service.

Outcomes for Tasmania are straightforward. In that region, Hydro Tasmania is needed to meet demand 100 per cent of the time.

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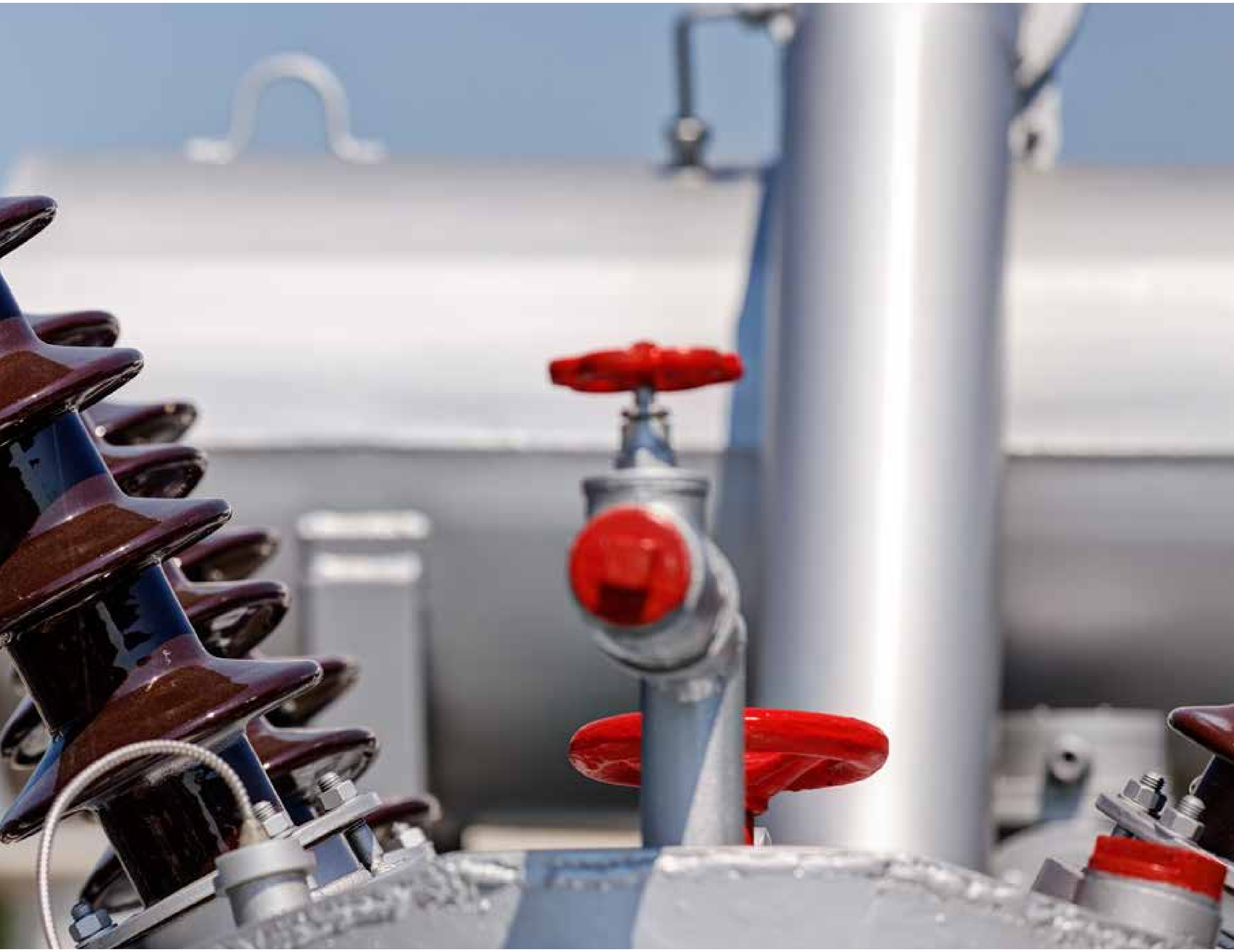
3 ELECTRICITY NETWORKS



Electricity networks transport power from electricity 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 discusses the 21 electricity networks regulated by the Australian Energy Regulator (AER), which are located in 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. The networks 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 carry electricity to residential homes and commercial premises for use by energy customers. 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 transport electricity to customers, they do not sell it. Instead, retailers purchase electricity from the wholesale market and network services from network owners, and sell them as a package to customers (chapter 1).

Electricity networks traditionally provided a one-way delivery service to customers, but their role is evolving as new technologies change how electricity is produced and used. Many small scale generators such as rooftop solar photovoltaic (PV) systems are now embedded within distribution networks, resulting in two-way power flows along the networks. Energy users with solar PV systems can now source power from the distribution network when they need it, and sell back surplus power they produce at other times. Increasingly, they can also store electricity in battery systems.

Alongside the major networks, small *embedded* distribution networks deliver power 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 21 electricity networks regulated by the AER (listed in tables 3.1 and 3.2 and mapped in figure 3.1) span 750 000 km in line length and have a combined valuation of $87 billion. They comprise seven transmission networks (valued at $19 billion) and 14 distribution networks ($68 billion).

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).

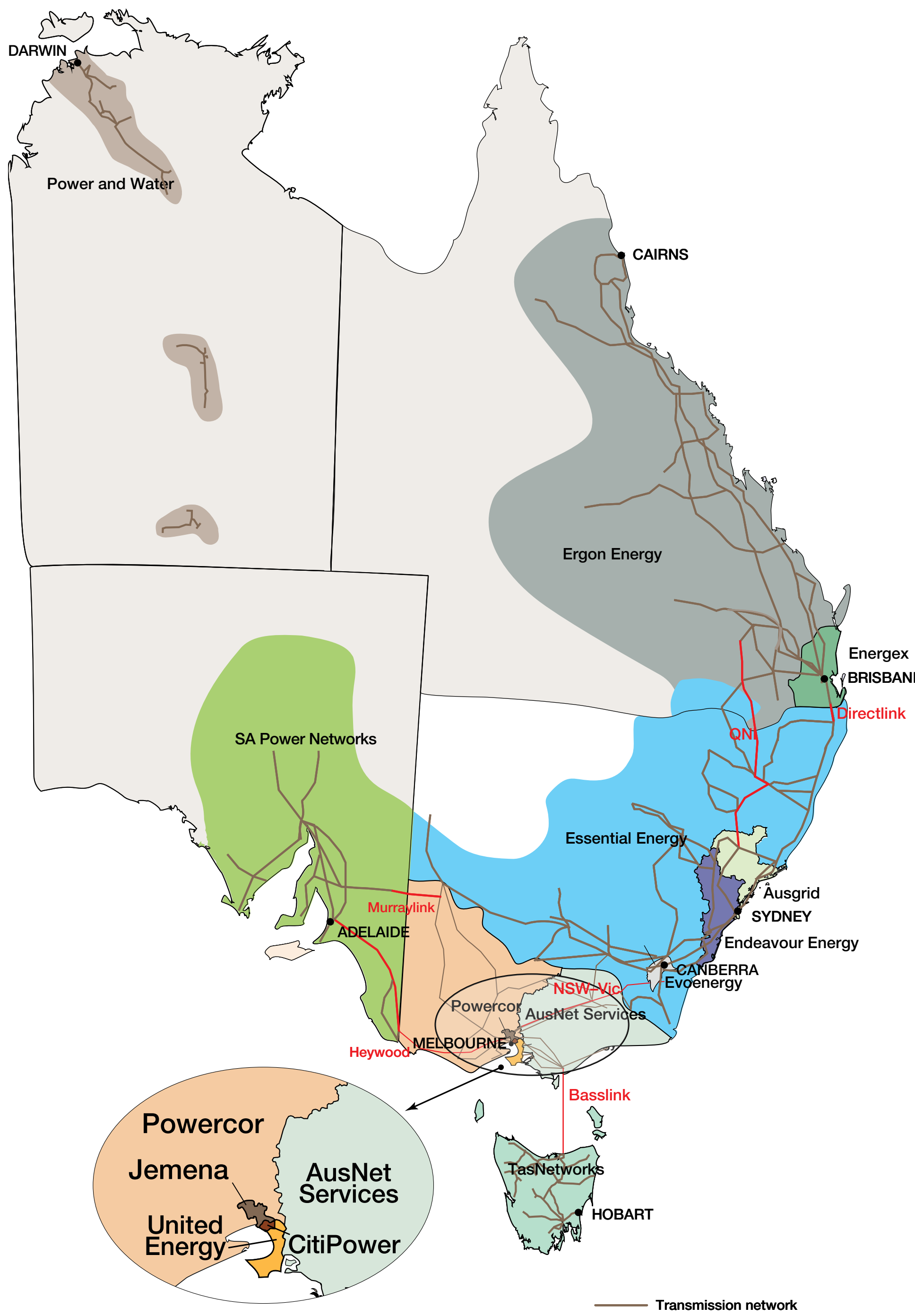
The grid delivers electricity directly to some industrial customers (such as aluminium smelters). It also connects with 13 *distribution* networks, which transport electricity to residential homes and commercial and industrial premises (table 3.2).[1] Queensland, NSW and Victoria each have multiple distribution networks serving particular areas of the state. South Australia, Tasmania and the ACT each have a single network .

Alongside its role in the NEM, in 2016 the AER became the economic regulator for electricity networks in the Northern Territory. The Territory has three separate networks—the Darwin–Katherine, Alice Springs and Tennant Creek systems—all owned by Power and Water (figure 3.1). These networks are classified as a single distribution network for regulatory purposes. The AER published its first draft revenue decision for the network in September 2018.

The AER does not regulate electricity networks in Western Australia, where the Economic Regulation Authority (ERA) administers separate arrangements. Western Power (owned by the Western Australian Government) is the state's principal network, covering the populated south west region, including Perth. Another state owned corporation—Horizon Power—services regional and remote areas.[2]

1 Some jurisdictions also have small networks serving regional areas.
2 For further information, see the Department of Treasury (www.treasury.wa.gov.au) and ERA (www.era.wa.gov.au) websites.

Figure 3.1
Electricity networks regulated by the AER



QNI, Queensland–NSW Interconnector.

Note: Basslink is not regulated by the AER.

Source: AER.

3.3 Electricity network ownership

Australia's electricity networks were originally government owned, but many jurisdictions have partly or fully privatised these assets. Privatisation began in Victoria, which sold its transmission and distribution networks to private entities in the 1990s. In 2000 South Australia privatised its transmission network and leased its distribution network. A joint venture between the ACT Government and private equity holders was established in 2000 to operate the ACT distribution network (the ACT has no transmission assets).

The NSW Government partially privatised its electricity networks through 99 year leases. It leased the 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 rural Essential Energy network remains government owned and operated.

Ownership of the privatised networks in Victoria, South Australia and NSW is concentrated among relatively few entities. These entities include Hong Kong's Cheung Kong Infrastructure (CKI) and Power Assets Holdings, Singapore Power International and State Grid Corporation of China (tables 3.1 and 3.2). Funds 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 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.

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 and their average costs decline as output rises. This gives rise to a *natural monopoly* industry structure, where it is more efficient to have a single network provider than to have multiple providers offering the same service.

But monopolies face no competitive pressure, so have opportunities and incentives to charge unfair prices. This poses serious risks to consumers, because network charges make up close to 50 per cent of a residential electricity bill.

The role of an economic regulator is to mimic the incentives network businesses 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 National Electricity Rules set the framework for regulating electricity networks, which the AER applies. The Law's regulatory objective is to promote efficient investment in, and operation and use of, electricity services for the long term interest of consumers with respect to 1) price, quality, safety and reliability and security of supply, and 2) the reliability, safety and security of the electricity system.

The AER applies this objective by seeking to ensure consumers pay no more than necessary for the safe and reliable delivery of electricity. Our regulatory toolkit to pursue this objective is wide-ranging (box 3.1), but our central role is setting the maximum amount of revenue a network business can earn from its customers for delivering electricity. We do this through a periodic *determination* or *reset* process, in which we assess how much revenue a prudent network business would need to cover its efficient costs. The network's revenues are then capped at this level for the regulatory period—typically five years. A long regulatory period helps create a stable investment environment. But it also poses challenges and risks locking in inaccurate forecasts.[3]

As part of the reset process, an electricity 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. The

3 The rules include mechanisms for dealing with uncertainties—such as cost pass-through triggers and a process for approving contingent investment projects—where costs were not clear at the time of the reset.

Table 3.1 Electricity transmission networks in the NEM

NETWORK	LOCATION	LINE LENGTH (CIRCUIT KM)[1]	ELECTRICITY TRANSMITTED (GWH)[2]	MAXIMUM DEMAND (MW)[3]	ASSET BASE ($2018 MILLION)[1]	CURRENT REGULATORY PERIOD	OWNER
STATE NETWORKS[4]							
Powerlink	Qld	14 533	54 253	11 974	7 281	1 July 2017–30 June 2022	Queensland Government
TransGrid	NSW	13 078	75 000	18 700	6 469	1 July 2018–30 June 2023	Hastings 20%; Spark Infrastructure 15%; other private equity 65%
AusNet Services / AEMO	Vic	6 560	46 829	9 347	3 148	1 April 2017–31 March 2022	Listed company (Singapore Power 31.1%; State Grid Corporation 19.9%)
ElectraNet	SA	5 520	14 525	3 355	2 523	1 July 2018–30 June 2023	State Grid Corporation 46.6%; YTL Power Investments 33.5%; Hastings Investment Management 19.9%
TasNetworks	Tas	3 564	12 427	2 456	1 448	1 July 2014–30 June 2019	Tasmanian Government
TOTALS		43 254	203 034		20 869		
STAND ALONE INTERCONNECTORS							
Directlink	Qld–NSW	63			131	1 July 2015–30 June 2020	Energy Infrastructure Investments (Marubeni Corporation 49.9%; Osaka Gas 30.2%; APA 19.9%)
Murraylink	Vic–SA	180			105	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 2017 (30 March 2017 for AusNet Services).
2. Electricity transmitted in 2016–17 (year to March 2017 for the Victorian business).
3. Non-coincident, summated maximum demand in 2016–17 (year to March 2017 for AusNet Services).
4. 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) releases; company websites; company annual reports.

Table 3.2 Electricity distribution networks regulated by the AER

NETWORK	CUSTOMER NUMBERS[1]	LINE LENGTH (CIRCUIT KM)[1]	ELECTRICITY TRANSMITTED (GWH)[2]	MAXIMUM DEMAND (MW)[3]	ASSET BASE ($2018 MILLION)[1]	CURRENT REGULATORY PERIOD	OWNER
QUEENSLAND							
Energex	1 448 247	53 757	21 355	5 464	12 181	1 July 2015–30 June 2020	Queensland Government
Ergon Energy	745 501	152 491	13 332	3 158	10 758	1 July 2015–30 June 2020	Queensland Government
NSW AND ACT							
Ausgrid	1 706 913	41 642	25 669	5 874	15 038	1 July 2014–30 June 2019	NSW Government 49.6%; IFM Investors 25.2%; AustralianSuper 25.2%
Endeavour Energy	984 230	36 993	16 716	4 635	6 133	1 July 2014–30 June 2019	Advanced Energy 50.4%; NSW Government 49.6%
Essential Energy	891 935	192 103	12 389	2 543	7 725	1 July 2014–3 0 June 2019	NSW Government
Evoenergy	191 482	5 333	2 914	683	933	1 July 2014–30 June 2019	Icon Distribution Investments 50%; Jemena (State Grid Corporation 60%; Singapore Power 40%) 50%
VICTORIA							
AusNet Services	734 644	44 907	7 673	1 715	3 843	1 January 2016–31 December 2020	Listed company (Singapore Power 31.1%; State Grid Corporation 19.9%)
CitiPower	339 400	4 550	5 917	1 399	1 853	1 January 2016–31 December 2020	Cheung Kong Infrastructure / Power Assets Holdings 51%; Spark Infrastructure 49%
Jemena	334 840	6 345	4 264	983	1 327	1 January 2016–31 December 2020	Jemena (State Grid Corporation 60%; Singapore Power 40%)
Powercor	816 349	75 121	10 720	2 450	3 701	1 January 2016–31 December 2020	Cheung Kong Infrastructure / Power Assets Holdings 51%; Spark Infrastructure 49%
United Energy	676 807	13 342	7 844	2 053	2 234	1 January 2016–31 December 2020	Cheung Kong Infrastructure 66%; Jemena (State Grid Corporation 60%; Singapore Power 40%) 34%
SOUTH AUSTRALIA							
SA Power Networks	878 300	88 971	10 215	3 011	4 013	1 July 2015–30 June 2020	Cheung Kong Infrastructure / Power Assets Holdings 51%; Spark Infrastructure 49%
TASMANIA							
TasNetworks	287 652	22 725	4 193	230	1 702	1 July 2017–30 June 2019	Tasmanian Government
NORTHERN TERRITORY							
Power and Water[4]	85 710	8 332	1 780	413	967	1 July 2014–30 June 2019	Northern Territory Government
TOTALS	10 122 009	746 612	155 518		72 407		

GWh, gigawatt hours; km, kilometres; MW, megawatts.

1. Customer numbers, line length and asset base at 30 June 2017, (31 December 2017 for Victorian businesses).
2. Electricity transmitted in 2016–17 (year to March 2017 for the Victorian business).
3. Non-coincident, summated, raw system maximum demand at the zone substation level in 2016–17 (2017 calendar year for Victorian businesses).
4. For regulatory purposes, Northern Territory transmission assets are treated as part of the distribution system.

Source: AER revenue decisions and economic benchmarking RINs; ASX releases; company websites; company annual reports.

AER then assesses the proposal, and if necessary amends it, to ensure revenues only recover *efficient* costs.

The AER's assessment draws on a range of inputs, including cost forecasts, benchmarking and revealed costs from past experience. The AER engages closely with stakeholders from the earliest stage of the process, including before a formal proposal is lodged. It established a *Consumer Challenge Panel* in 2013 to ensure consumer perspectives are properly voiced and considered. 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 new engagement approaches (section 3.6.2).

If the AER's assessment concludes that a business's proposals are unreasonably costly, it may ask for more detailed information or a clearer business case. If a satisfactory outcome is not reached, it may amend a network's proposal to align it with what it considers efficient.

While the AER assesses efficient operating and capital expenditure, it does not approve individual projects. Each businesses prioritises its own spending programs, although it must undertake a cost–benefit analysis for any new investment project (section 3.11).

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 so avoid or delay unnecessary investment.

Sections 3.11, 3.13 and 3.15 examine incentive schemes in more detail.

The AER publishes guidelines on its approach to assessing costs and applying incentives.

Box 3.1 The AER's role in electricity network regulation

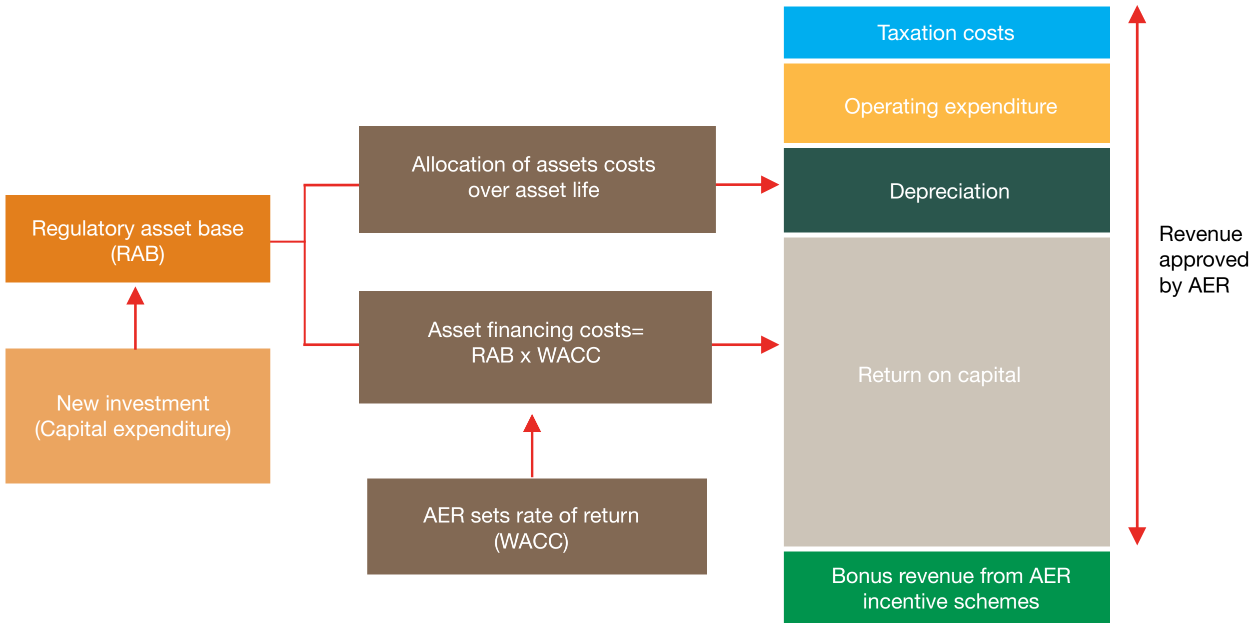
The AER sets a cap every five years on the amount of revenue a network business can earn from its customers. Alongside this central role, we undertake broader regulatory functions including:

- 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 over time 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:

- Power of Choice reforms empowering customers to make informed choices about their energy use, which ultimately help keep network costs down (sections 3.7 and 1.8)
- adopting a more consumer-centric approach to setting network revenues (section 3.6)
- publishing more information on network profitability (sections 3.12.1)
- reviewing how rates of return and taxation allowances are set for energy networks (section 3.12.2).

Figure 3.2
Forecasting network revenues



WACC, weighted average cost of capital.

Note: Bonus revenues 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.

3.4.2 The building blocks of network revenue

The AER uses a 'building block' approach to assess a network'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 who fund the network's assets and operations.

The AER also makes revenue adjustments for past over or under recovery of revenues, and for incentive schemes (figure 3.2).

While network businesses are entitled to earn revenue to cover their efficient costs each year, this does *not* include the full cost of investment in new assets during the year. Network assets have a long life, so the cost of that investment is recovered over the economic life of the asset—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.

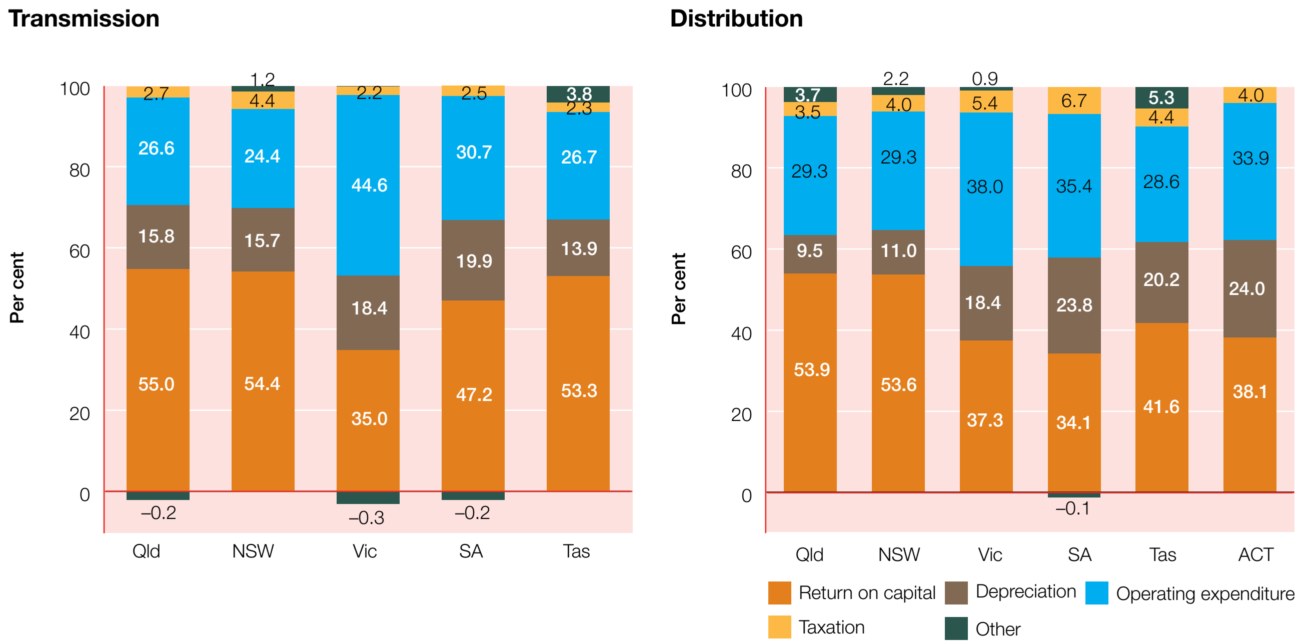
Additionally, the shareholders and lenders who fund those assets must be paid a commercial return on their investment. The AER sets the rate of return (also called the weighted average cost of capital, or WACC). The size of this return depends on:

- the value of the network's assets, measured by the regulated asset base plus forecast new capital expenditure
- the rate of return the AER allows for equity and debt used to fund those assets.

Returns to shareholders and lenders take up the largest slice of revenue for most networks, accounting for over 50 per cent of revenues for most networks in NSW, Queensland and Tasmania (figure 3.3). The rate tends to be lower in the Victorian and South Australian networks. Depreciation absorbs another 10–25 per cent of revenues.

Operating costs—such as maintenance and overheads—absorb 25–35 per cent of revenues for most networks, although the proportions tends to be higher in distribution than transmission. Taxation and other costs account

Figure 3.3
Composition of network revenues



Note: Negative values for ‘other’ revenues represent downward adjustments to reflect penalties for underperforming against incentive schemes, and/or reversing an earlier over-recovery of revenue.

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

for the remainder of network revenues. The AER in May 2018 launched a review into taxation costs in response to concerns about anomalies in the amount of tax paid by some network businesses relative to their forecast taxation costs (box 3.2).

Sections 3.11 to 3.13 examine major cost components in more detail.

3.4.3 Timelines and process

The National Electricity Law and National Electricity Rules set the regulatory framework and process, which is lengthy and highly consultative. It begins around three years before a new regulatory period, when the AER conducts early engagement with stakeholders and works with them on a framework and approach for the review. The next step is for a network business to submit a proposal setting out the revenue needed to cover its efficient costs and investment forecasts.

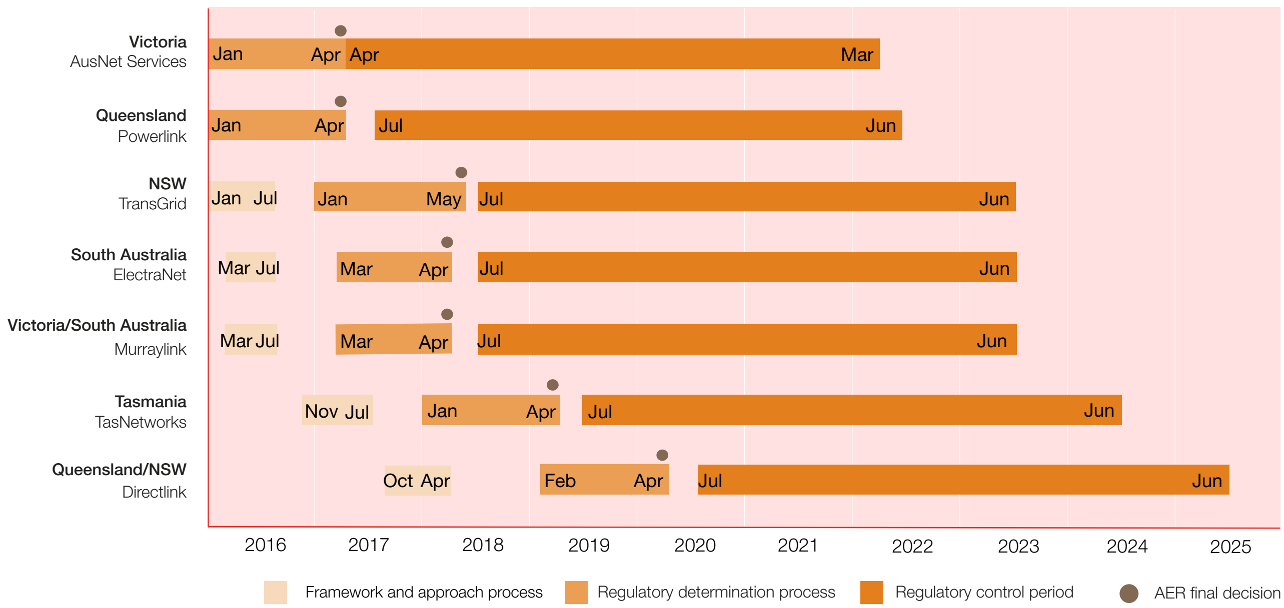
The AER has 15 months to formally review a revenue proposal before releasing a final decision. It consults widely with energy customers, network businesses and other stakeholders, including through issues papers and draft decisions. It conducts public forums and consult with consumer representatives, network businesses, government and investment groups. The timing of reviews is staggered to avoid bunching (figures 3.4 and 3.5).

On completing a review, the AER publishes a decision setting the maximum revenue a network can earn from its customers through network charges.[4] While the decision sets network revenues rather than prices, the two are closely related. Network businesses set their prices by allocating their allowed revenues across the customer base.[5] The AER assesses tariff structure statements on a network’s pricing policies as part of the regulatory process (section 3.7.1), and conducts annual reviews to ensure

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

5 Traditionally, each customer paid a fixed charge per day plus a use charge based on actual energy use. These arrangements are evolving under new pricing structures encouraging customers to factor in how their energy use impacts network costs. Energy demand at peak times (such as to run an airconditioner on a hot day), for example, puts more strain on a network than off-peak demand. Pricing reforms to address this issue form part of the Power of Choice program (section 3.7.1).

Figure 3.4
AER decision timelines—electricity transmission networks



Note: Timelines for AER decisions effective from 2017 or later. The latest information is available at www.aer.gov.au/networks-pipelines/determinations-access-arrangements.
Source: AER.

prices are consistent with the revenue decision and reflect efficient costs.

3.5 Recent AER revenue decisions

The AER in 2018 made final revenue decisions for electricity transmission networks in South Australia (ElectraNet) and NSW networks (TransGrid), and the Murraylink interconnector between Victoria and South Australia. The decisions cover the five year regulatory period 1 July 2018 to 30 June 2023 (table 3.3).

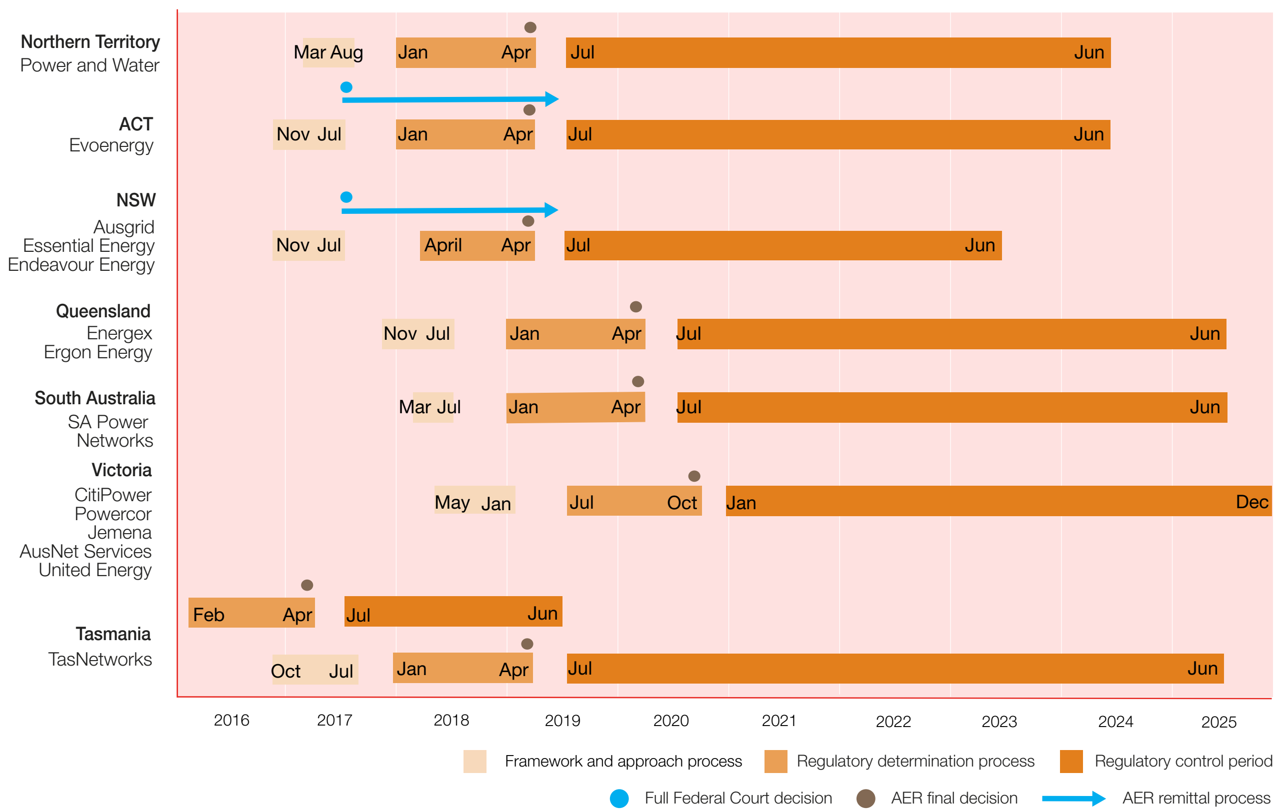
In 2018 the AER also remade revenue decisions for NSW and ACT electricity distribution networks for the regulatory period 2014–19, following orders from the Full Federal Court (section 3.5.2). And it released draft decisions on new revenue proposals for electricity networks in Tasmania, NSW and the ACT, and its first draft assessment for the Northern Territory.

The AER's transmission decisions reduced revenues for ElectraNet by 8.4 per cent and TransGrid by 6.3 per cent (in real terms), compared with revenues in the previous regulatory period. The reductions reflect the network's lower financing costs and less need for new investment due to subdued electricity demand. But the AER's Murraylink decision allowed a revenue increase of 9.4 per cent because higher returns to investors were required to fund major capital investments.

The AER accepted much of ElectraNet's proposal as reasonable, including its operating and capital expenditure forecasts. It also found ElectraNet had engaged constructively with its customers during the review process. Overall, the decision will marginally reduce average transmission charges in South Australia, although the impact on retail customer bills is negligible (partly because transmission charges only comprise 7 per cent of a typical customer bill).

The AER scaled back TransGrid's revised revenue proposal by 1.5 per cent and its capital expenditure forecast by around 20 per cent (though capital expenditure is still likely to be higher than in the previous regulatory period). Despite this, transmission charges in NSW and the ACT will rise because a phased refund to consumers of previously over-recovered revenues will end in 2018. The AER estimated a typical residential electricity bill will be around 0.5 per cent

Figure 3.5
AER decision timelines—electricity distribution networks



Note: Timelines for AER decisions effective from 2017 or later. The latest information is available at www.aer.gov.au/networks-pipelines/determinations-access-arrangements.
Source: AER.

higher in NSW in the new regulatory period than in 2017–18 (in nominal terms).

All three networks forecast the need for major new investment projects in the upcoming period (section 3.11.1). The AER approved some projects outright, but others only on a contingent basis.

3.5.1 Legal reviews of AER decisions

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

From 2008–16 network businesses and other parties applied for limited merits review of 22 of the AER's 35 electricity decisions. Consumers and governments were invariably unsuccessful in arguing that network revenues should be decreased.[6] But network businesses often succeeded in having their rates of return and revenues increased.

From 2008–14, Tribunal decisions added $3.2 billion to network revenues. In later decisions, network businesses sought another $6 billion in revenues above what the AER had determined.[7]

Concerned by the impacts of these appeals on energy customers, the Australian Government in October 2017 abolished limited merits review of AER revenue decisions. Network businesses can no longer dispute discrete elements of an AER decision before the Tribunal. Following the abolition, the AER noted its commitment to a more

6 AER, *Review of the limited merits review framework*, AER submission to COAG Energy Council, October 2016.
7 ACCC, *Retail Electricity Pricing Inquiry—Final Report,* June 2018, p. 114.

Table 3.3 Recent AER revenue decisions—key outcomes

REGION		DECISION DATE	% CHANGE FROM PREVIOUS PERIOD REVENUE	OPERATING EXPENDITURE	CAPITAL EXPENDITURE	RATE OF RETURN (%)[1]	RETAIL BILL IMPACT (%)[2]
TRANSMISSION NETWORKS							
NSW	TransGrid	18 May 2018	-6.3	4.6	8.5	6.5	0.5
South Australia	ElectraNet	30 April 2018	-8.4	4.4	-38.3	5.7	<0.1
Vic–SA interconnector	Murraylink[3]	30 April 2018	9.4	0.2	0.8	5.7	<0.1

1 Rates of return is 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 change in average annual customer bill compared with customer bill in final year of previous period, adjusted for inflation, assuming retailers pass through outcomes of the decision.

3 Murraylink revenue is collected from customers in South Australia and Victoria, and is a small part of the overall transmission charges in those states.

Source: AER estimates.

collaborative approach to network regulation, driven by customers' best interests (section 3.6.2).

While limited merits review is no longer available, various legal proceedings initiated under the regime continued during 2017 and into 2018:

- In May 2017 the Full Federal Court dismissed elements of an appeal by the AER against an earlier ruling by the Tribunal. The Tribunal had found the AER made errors relating to operating expenditure and return on debt in its revenue decisions for five energy networks in NSW and the ACT. The AER's work to remake those decisions continued throughout 2018 (section 3.5.2).
- In October 2017 the Tribunal affirmed the AER's revenue decisions for five Victorian electricity distribution networks and ACT gas distribution pipelines. The Tribunal rejected all grounds of review sought by the businesses to recover an additional $197 million revenue from customers. The AER's original decisions to reduce the revenue the six businesses can recover from consumers therefore stands.
- In January 2018 the Full Federal Court dismissed an appeal by SA Power Networks against an earlier ruling by the Tribunal to affirm the AER's revenue decision for the network. The AER found the network required $3.8 billion to deliver safe, secure and reliable power to South Australian households and businesses. The business sought $4.5 billion.

  Areas of disagreement between the regulator and the network included the rate of return, tax issues and labour cost forecasts. The ruling meant South Australian consumers received the full savings from the AER's 2015 decision, which reduced the network component of consumer bills by around 10 per cent.

The Full Federal Court's ruling on SA Power Networks was the final matter settled under the limited merits review regime.[8]

Many applicants for limited merits review also filed applications with the Federal Court for judicial review of the same AER decisions. Network businesses withdrew all applications following the abolition of limited merits review in October 2017.

3.5.2 Remaking the NSW and ACT revenue decisions

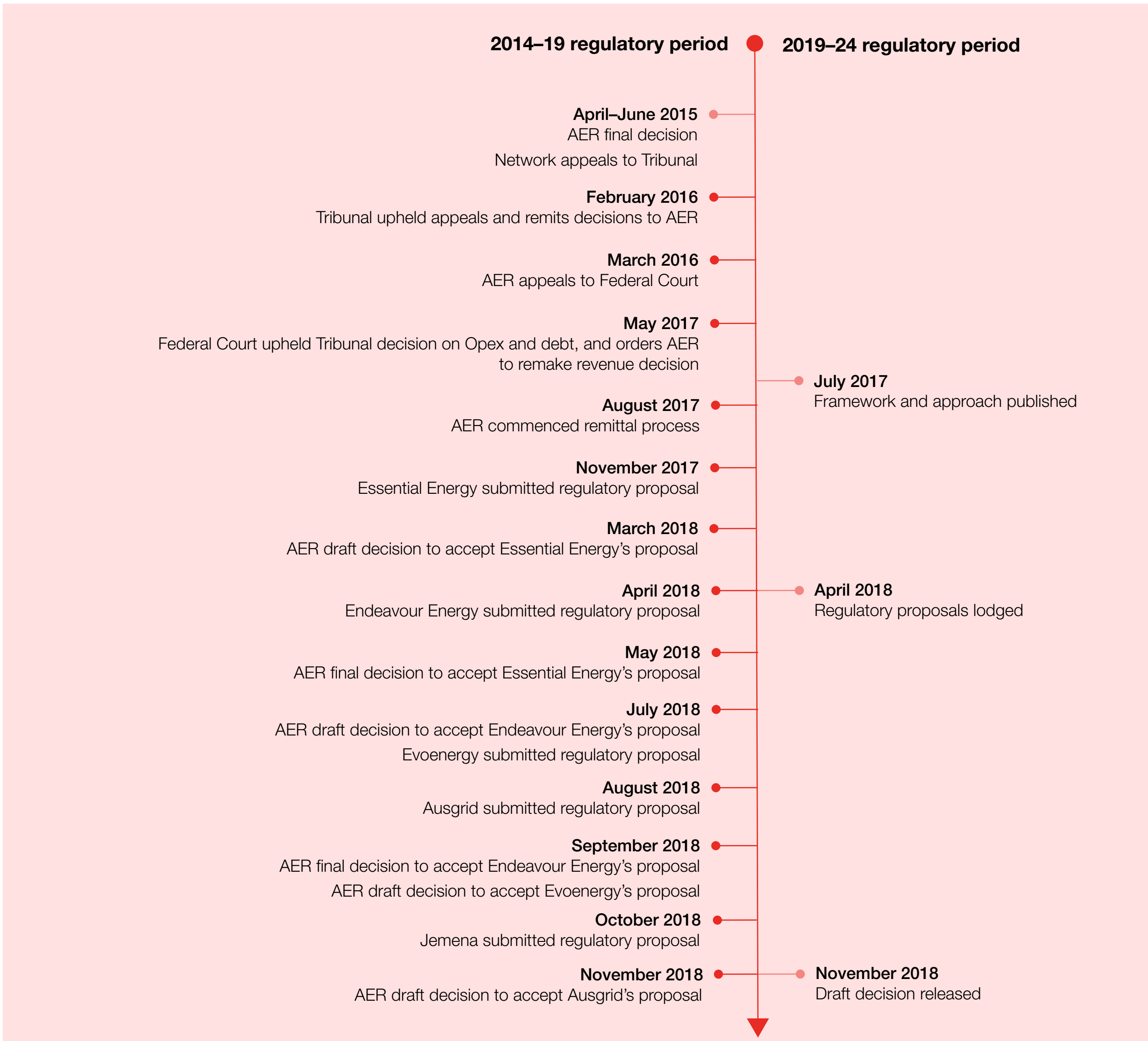
One of the longest running appeal processes (with ongoing ramifications in 2018) related to AER's 2015 revenue decisions for five NSW and ACT energy networks (figure 3.6). The decisions covered three NSW electricity distributors (Essential Energy, Endeavour Energy and Ausgrid), the ACT electricity distributor (Evoenergy, formerly ActewAGL), and the NSW gas distribution network (Jemena Gas Networks), for the regulatory period 1 July 2014 to 30 June 2019.

The AER found the five networks were operating less efficiently than comparable networks, and their owners had proposed excessive rates of return and tax allowances. The five businesses sought review of the AER's decisions, seeking to recover around $5 billion in additional revenue from consumers.

The Tribunal in February 2016 found in favour of the businesses in areas relating to operating expenses, taxation costs and debt costs—and directed the AER to remake its revenue decisions. The AER then appealed to the Federal Court for a judicial review of the Tribunal's decisions.

8 AER, *Consumers win as Full Federal Court confirms AER revenue decision for SA Power Networks*, media release, 18 January 2018.

Figure 3.6
Timeline of AER revenue decisions for NSW and ACT



In 2017 the Full Federal Court upheld the Tribunal's findings in relation to the networks' operating expenses and debt costs, and ordered the AER to remake the five revenue decisions. The Productivity Commission reported the Tribunal's decision would allow the businesses to recover about $2.5 billion in additional revenue above what the AER had determined was efficient.[9]

The lengthy legal process posed unique challenges—in particular that the 2014–19 regulatory period to which the decisions applied was far advanced at the time

9 Productivity Commission, *Energy, shifting the dial: 5 year productivity review*, Supporting Paper no. 11, Canberra, August 2017, p. 76. The report quotes an estimate by Winestock, G and McDonald-Smith, A, 'Ausgrid, Endeavour, AGL, Jemena score win in $5b NSW case', *Australian Financial Review*, 26 May 2017.

of the remittal. Additionally, the AER's remaking of the 2014–19 decisions overlapped the early stages of the next regulatory reset for the five networks (which take effect on 1 July 2019).

The prolonged legal process led to significant over-recovery of revenue by the five networks during 2014–19. To manage price uncertainty for energy consumers, the AER accepted enforceable undertakings from the five businesses covering the three years to 30 June 2019, limiting rises in distribution charges to changes in the CPI.

The AER also worked with the Australian Energy Market Commission (AEMC) on a rule change allowing revenue impacts arising from the remittals to be 'smoothed' and recovered from customers over both the current regulatory period and the next period starting 1 July 2019.

In August 2017 the AER convened a stakeholder meeting to discuss resolving the remittal matters in a manner consistent with the long term interests of consumers. It also published consultation papers on its approach to remaking the operating expenses and debt costs in the decisions.

By August 2018 all four electricity businesses submitted new regulatory proposals addressing outstanding issues for the 2014–19 period. The AER made final decisions on the Essential Energy and Endeavour Energy proposals in May and September 2018 respectively. Each business developed its proposal in close consultation with key stakeholders, including Energy Consumers Australia, Energy Users Association of Australia, Public Interest Advocacy Centre, and the AER's *Consumer Challenge Panel*. The AER published a draft decision on the revised Ausgrid proposal in November 2018.

The proposals largely adopted the AER's original 2015 decision, plus up to $110 million in additional revenue. Any revenues recovered above the approved amounts will be returned to customers through lower charges in the next regulatory period (2019–24).

The AER found the proposals were consistent with its forecasts of operating expenditure and debt costs in light of the information before it in 2018. Since the original decisions, each business embarked on reforms to reduce their operating costs to levels consistent with those decisions, without compromising the quality, safety, reliability and security of supply on their networks. Previously contentious legal issues relating to financing costs and determining the cost of debt had also been clarified by recent legal cases.

The 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 allowed a timely resolution of an unusually lengthy process, and so provided certainty and price stability to consumers.

The AER in September 2018 published a draft decision to accept Evoenergy's new proposal for 2014–19 for the ACT distribution network. The AER found Evoenergy had consulted constructively with stakeholders and its proposal was consistent with the AER's cost forecasts. The draft decision would allow Evoenergy to earn revenues up to $26 million above the level approved in the AER's original 2015 decision. These additional revenues mostly cover efficient redundancy costs that Evoenergy has incurred since the 2015 decision to meet operating expenditure targets.

3.6 Refining the regulatory approach

The AER in 2011 proposed reforms to the energy rules to ensure customers pay no more than necessary for a safe, reliable supply of energy. The AEMC in November 2012 implemented several reforms—allowing wider use of benchmarking to assess network costs and introducing new incentives for network efficiency. The reforms also require network businesses to engage more closely with their customers to develop revenue proposals that better meet their needs.

The AER developed guidelines and schemes to apply the reforms. Due to the length of the regulatory cycle and the need for extensive consultation on implementation guidelines, the reforms first applied to decisions taking effect in 2015. They have been progressively applied to each network as it comes up for review, and by 2020 will apply to all networks.

Regulatory reform is ongoing. The AER continues to streamline its approach to benchmarking network businesses. In late 2017 it launched a review of operating environment factors unique to particular networks that may impact their measured efficiency data. Then in 2018, it reviewed the approach to setting rates of return for network businesses, and whether the approach to setting taxation allowances for network businesses needs reform (section 3.12.2 and box 3.2).

A critical focus in 2018 was on the quality of engagement by network operators with their customers and the AER (section 3.6.2). There is also ongoing work to improve incentive schemes and guidelines, such as new demand management incentives launched in late 2017 (section 3.11.5).

More generally, the AER is pursuing opportunities to remove contestable services—such as metering—from economic regulation to support the development of competitive markets. Its work in this area included new ring-fencing guidelines to enforce the separation of regulated service delivery from the supply of contestable services (section 3.7.1).

Box 3.2 Review of regulatory taxation

In 2018 the AER investigated whether some energy network businesses are being overcompensated for their corporate tax liabilities, resulting in consumers paying more than necessary for energy services.

We set revenues so energy networks can recover their expected costs, including their tax costs. In calculating expected tax costs, we have regard to expected taxable revenue, tax expenses (depreciation, interest, operating expenses) and the corporate tax rate. We use an incentive approach—a network that keeps its actual tax costs below expected costs can retain part of the benefit for the remainder of the regulatory period. But if actual tax paid is above the expected amount, the network bears the loss.

We estimated that regulated energy networks would pay around $5 billion in tax across the five year period from 2012–17 (in 2017 dollars). But the Australian Taxation Office (ATO) notified that privately owned energy networks have been paying less tax, and government owned networks paying more tax, than estimated by our modelling.[10] The ATO noted this discrepancy may relate to differences in ownership structure, gearing (debt) and depreciation methods. We are exploring whether changes to the regulatory model or the energy rules themselves are needed to address this issue, as part of our review of regulatory tax.

In our November 2018 discussion paper, we found a material difference between our regulatory forecast of tax costs and actual tax payments made. We found some aspects of our regulatory approach may not reflect current efficient tax management practices and identified possible changes to incorporate these practices.[11]

10 Australian Taxation Office, *Note to Australian Energy Regulator, Indicative comparative analysis of the AER electricity distribution tax allowance and tax payable*, 10 April 2018.

11 AER, *Review of regulatory tax approach, Discussion paper*, November 2018.

3.6.1 Aligning business and consumer interests

The regulatory process is complex and often adversarial. In this environment, consumers find it challenging to have their perspectives heard, and difficult to assess whether a network proposal reflects their interests. To help consumers engage in the regulatory process, the AER publishes documents—including factsheets that simplify technical language—and holds public forums.

To engage more effectively with stakeholders, the AER established a *Consumer Challenge Panel* in 2013 to ensure consumer perspectives are properly voiced and considered. In September 2016 the AER appointed a new panel of experienced and highly qualified individuals with consumer, regulatory and/or energy expertise to continue to bring strong consumer perspectives to its decision making processes.[12]

Reforms launched in 2013 also sharpened focus on how effectively network businesses engage with their customers in shaping their revenue proposals. Powerlink and TasNetworks were among the first networks to start focusing on this issue.

The AER's 2017 revenue decisions for those networks found each business had developed their regulatory proposals in close consultation with their customers. This consultative work laid foundations for the AER to accept major elements of the proposals, including capital and operating expenditure forecasts. In 2018 the AER made similar findings of constructive engagement by ElectraNet with its customers.

Evidence of constructive engagement also enabled the AER to adopt a relatively expedited process for its 2018 draft decisions on the remittal processes for Essential Energy and Endeavour Energy. Stakeholders endorsed the efforts and goodwill shown by each business to develop proposals aligning their interests with those of customers.

SA Power Networks followed a similar path to develop a new regulatory proposal in 2018. It conducted research to understand customer sentiment and priorities, before engaging with its customers on price, reliability and resilience, and the network's evolution. Engagement methods included workshops, focus groups, and online engagement. In 2018 this engagement explored topics through 'deep dive' workshops. SA Power Networks

12 The panel's composition is published on the AER website at www.aer.gov.au/about-us/consumer-challenge-panel.

indicated it would seek further feedback ahead of lodging its regulatory proposal with the AER in January 2019.[13]

3.6.2 Early engagement models

Following the developments noted above, a number of businesses are experimenting with early engagement models to better reflect consumer interests and perspectives in framing their regulatory proposals. Early engagement offers potential to expedite the regulatory process, reducing costs for businesses and consumers. The AER is trialling one such approach—the New Reg—in partnership with Energy Networks Australia and Energy Consumers Australia (box 3.3).[14]

The New Reg involves a network business establishing an independent customer forum to collect consumers' views through research and engagement. The forum can negotiate agreement with the business on elements of its revenue proposal, and must justify positions it negotiates in a public report.

The AER participates from an early stage by approving engagement plans and processes, and ensuring the customer forum is equipped to navigate the complexities of a regulatory proposal. Additionally, the AER may advise on which issues are within scope for agreement. Matters such as the rate of return (which in future will be subject to a binding guideline (section 3.12.2) and reliability standards (which jurisdictions mandate) may fall outside the scope for negotiation, for example.

If early engagement achieves agreement between the business and its customers on key areas, and a regulatory proposal reflects that agreement, the AER would put significant weight on these outcomes in its decision making. The AER may expedite its regulatory assessment by undertaking a less detailed examination of areas upon which agreement was reached.

The AER is exploring innovative approaches to engagement across its work program. Recent examples include engagement on tariff structure reviews in NSW and in the development of new rate of return guidelines for network businesses.

Box 3.3 Trialling the New Reg model

AusNet Services, one of Victoria's five electricity distributors, launched an active trial of the New Reg model in 2018 to develop its upcoming revenue proposal for the regulatory period 2021–25.[15] In consultation with the AER and Energy Consumers Australia, AusNet Services established a customer forum consisting of a former state government minister, a former senior finance executive and board member at Yarra Valley Water, a consumer advocate, and a market and social researcher. Its first step was undertaking comprehensive engagement to understand its customers' concerns and preferences.

AusNet Services planned to release a draft for public consultation in 2018, including on issues agreed with the forum. It will continue to engage with its customer forum and the AER in shaping its revenue proposal until its formal lodgement in July 2019.

The AusNet Services trial and our consultation on it will inform our assessment of the New Reg model's effectiveness in enabling consumers' preferences to drive network decision making. The results will inform discussions about possible future changes to the energy rules. Broader consultation on the New Reg model will also continue throughout the AusNet Services trial. Learnings from the trial will inform the model's development.

3.7 Power of Choice reforms

Innovations in network and communications 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 customers make choices to voluntarily reduce their energy use in peak periods, it potentially delays the need for costly network investment.

Power of Choice reforms are being progressively rolled out to unlock the potential benefits of these changes. The reforms, many of which came into effect in 2017, include a market led rollout of 'smart' meters, supported by more cost reflective network pricing (section 3.7.1), and incentivising

13 AER, *Preliminary framework and approach—SA Power Networks, Regulatory control period commencing 1 July 2020*, March 2018.

14 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 and Approach Papers, March 2018.

15 AusNet Services, www.ausnetservices.com.au/en/Misc-Pages/Links/About-Us/Charges-and-revenues/Electricity-distribution-network/Customer-Forum, accessed 19 June 2018.

demand management as a lower cost alternative to network investment (section 3.11.5).

3.7.1 Tariff structure reforms

Under traditional network tariff (price) structures, households and small businesses pay the same tariffs regardless of how and when they use energy. Some customers—such as those with airconditioners or solar PV systems—do not pay their full network costs under these structures, while other customers pay *more* than they should.

Reforms introduced in December 2017 require distribution businesses to move energy customers onto network tariffs more closely reflecting the efficient costs of providing the services they use. Distributors are phasing in the new structures. For the initial pricing period, most networks adopted a form of demand tariff. The NSW distribution businesses Ausgrid and Endeavour Energy introduced another form of cost reflective tariff (time-of-use tariffs).[16]

Retailers pay the new network charges initially, then decide whether to pass on those costs to customers and in what form. Most networks are offering the new cost reflective structures on an opt-in basis (that is, a customer may choose to adopt the new pricing, but otherwise stays on the old flat price structure). But some networks are making the tariffs mandatory for new customers, or those with smart meters.

Around 12 per cent of small customers in 2018 were on new tariff structures,[17] with most of these on time-of-use tariffs. In those networks with opt-in arrangements, very few small customers have elected to move voluntarily to a new tariff structure.

Distributors are required to progress towards full cost reflective pricing through their tariff structure statements, which the AER examines within the revenue determination process. This progress may include:

- simplifying tariff offerings
- designing tariffs that more closely reflect how customer use affects the network's costs
- applying an opt-out approach requiring customers to move to a new tariff unless they elect not to
- integrating network pricing with broader management policies (such as network planning and demand management).

Limited penetration of smart meters for residential and small business customers is a barrier to implementing cost reflective network tariffs outside Victoria. Smart meters measure electricity use in half hour blocks, allowing energy customers to monitor their energy use.

At June 2018 30 per cent of customers in the NEM had metering capable of supporting cost reflective tariffs. While over 97 per cent of Victorian customers had access to a smart meter, penetration in other regions was around 5 per cent of customers. Another 6 per cent of customers in these regions (mostly in NSW) had access to an interval meter providing half hourly reading of consumption but without remote reading and connection capabilities.[18]

Network businesses traditionally provided electricity meters on residential premises. But this arrangement limits competition and consumer choice. It may also discourage investment in metering technology to support the uptake of new and innovative energy products. Changes promoting competition in the provision of metering services took effect in December 2017 to address this barrier.

Where 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 launched new ring-fencing guidelines requiring 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, and prohibit a regulated business from engaging in a potentially contestable activity.[19]

Distribution networks were required to comply with the ring-fencing rules by January 2018. But during the first six months of operation, the AER raised numerous compliance concerns with network businesses. In most cases, these concerns related to the businesses failing to properly train staff or implement appropriate systems.[20]

16 Demand tariffs charge a customer based on their maximum point-in-time demand during pre-defined periods linked to peak system demand. These charges can be applied in addition to usage and supply charges. Time-of-use tariffs apply different pricing to electricity usage in peak and off-peak times. Both tariffs are designed to encourage customers to minimise their usage at peak times.

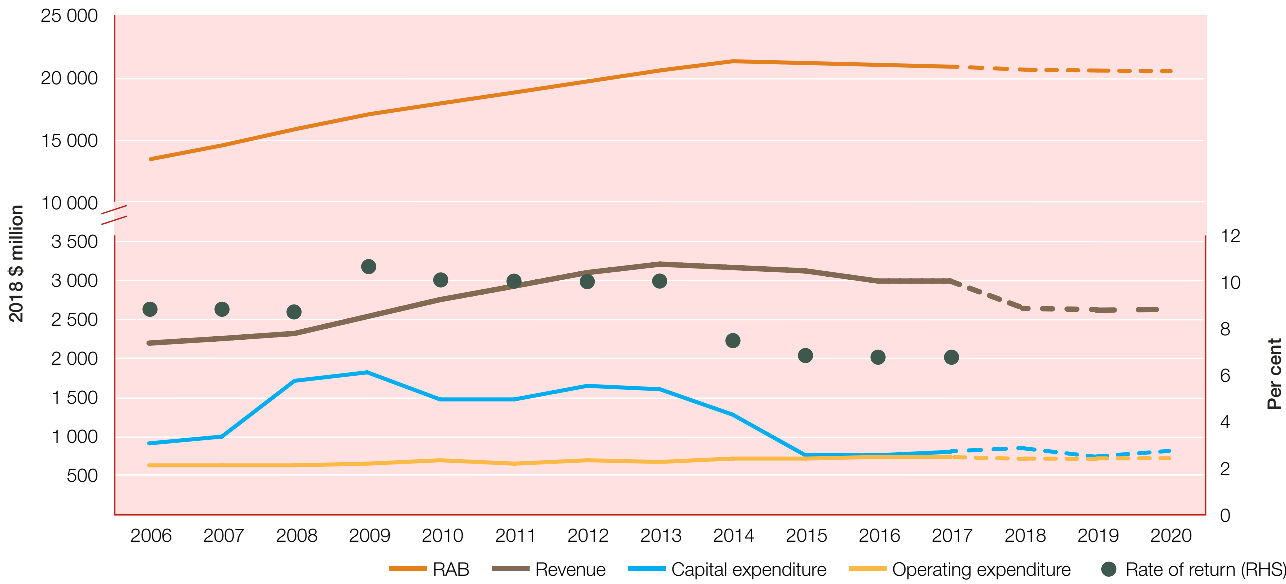
17 ACCC, *Retail Electricity Pricing Inquiry—Final Report*, p. 177.

18 AER estimates based on information gathered through the ACCC Retail Electricity Pricing Inquiry.

19 The ring-fencing reforms also apply to demand management incentives (section 3.11.5).

20 AER, *Quarterly Compliance Report. National Electricity and Gas Laws*, 1 April–30 June 2018.

Figure 3.7
Transmission revenues and key drivers



RAB, regulatory asset base.

Note: Revenue, capital expenditure, operating expenditure and RAB data are actual outcomes to 2017, and forecasts for 2018, 2019 and 2020. RAB is actual closing data at end of relevant year. Data is shown for relevant regulatory years on an end of year basis. Networks report on a 1 July to 30 June basis, except in Victoria, where they report from 1 April–31 March basis. All data is CPI adjusted to June 2018 dollars. Rates of return are WACC forecasts in AER revenue decision and Australian Competition Tribunal decisions for transmission networks.

Source: AER estimates derived from economic benchmarking RIN responses, AER revenue decisions, Australian Competition Tribunal decisions and AER modelling.

3.8 Headline trends in AER decisions

AER revenue decisions over the past 12 years show two distinct trends—rapid revenue and investment growth for several years, following by a significant downturn in both. Similar trends are apparent across transmission and distribution, although transmission revenues peaked earlier (2013) than distribution (2015), and the decline in transmission revenues was more gradual (figures 3.7 and 3.8).

AER forecasts indicate network revenues will plateau over the period 2018–20. An increase in forecast capital expenditure will raise the regulatory asset base (RAB) and generate slightly positive revenue growth in the distribution sector.

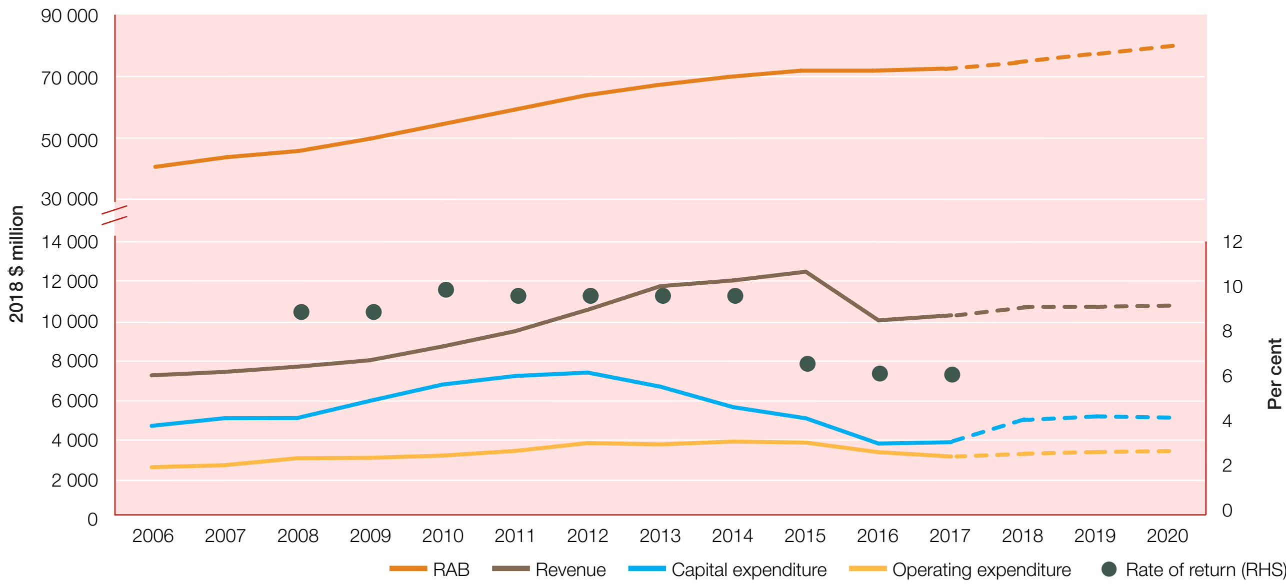
Changes in rates of return have significantly driven these revenue trends. Rates of return set in Tribunal decisions peaked at over 10 per cent in 2011, following a period of financial market instability. By 2017 they were running at just over 5 per cent.

A surge in network investment from 2006–12 also added to the RAB. But weaker electricity demand caused network businesses to delay or postpone capital projects after 2012, stemming further rapid growth in the RAB (especially in transmission, where the asset base shrank after 2014).

Despite a shift to more moderate operating conditions from around 2012, the five year regulatory cycle meant lower investment and rates of return only flowed through to revenue after a significant lag. Returns will also continue to be paid on assets added in those peak years for the duration of their economic life, which may run to decades.

Operating expenditure correlates less closely with market conditions than other drivers, and shows relatively stable trends. Capital expenditure almost trebled operating expenditure in 2009, but the two were almost comparable in scale by 2015. Since then, operating expenditure has also eased, as network businesses (especially distributors) implement efficiency programs. Reforms to the regulatory framework also began to impact outcomes from 2015 (section 3.6).

Figure 3.8
Distribution revenues and key drivers



RAB, regulatory asset base.

Note: Revenue, capital expenditure, operating expenditure and RAB data are actual outcomes to 2017, and forecasts for 2018, 2019 and 2020. RAB is actual closing data at end of relevant year. Data is shown for relevant regulatory years on an end of year basis. Networks report on a 1 July to 30 June basis, except in Victoria, where they report on a calendar year basis. All data is CPI adjusted to June 2018 dollars. Rates of return are WACC forecasts in AER revenue decision and Australian Competition Tribunal decisions, for distribution networks.

Source: AER estimates derived from economic benchmarking RIN responses, AER revenue determinations, Australian Competition Tribunal decisions and AER modelling.

The following sections more closely examine trends in network revenues and the factors driving them.

3.9 Electricity network revenues

Electricity networks in the NEM earned just under $13 billion in 2017, a 2 per cent rise on the previous year.[21] But revenues were significantly lower than the peaks recorded a few years earlier (figure 3.9):

- Transmission businesses earned $2.9 billion in 2017, which was 7 per cent less than when revenues peaked in 2013.
- Distribution businesses earned $9.9 billion in 2017, which was 18 per cent less than when revenues peaked in 2015.

3.9.1 Recent outcomes

All AER decisions in 2017 and 2018 approved lower revenues than in previous regulatory periods (figure 3.10). Network revenues are forecast to be around 16 per cent lower on average in current regulatory periods (at 1 July 2018) than in previous regulatory periods. Lower revenues are forecast for every transmission network in the NEM and for every distribution network outside Victoria.

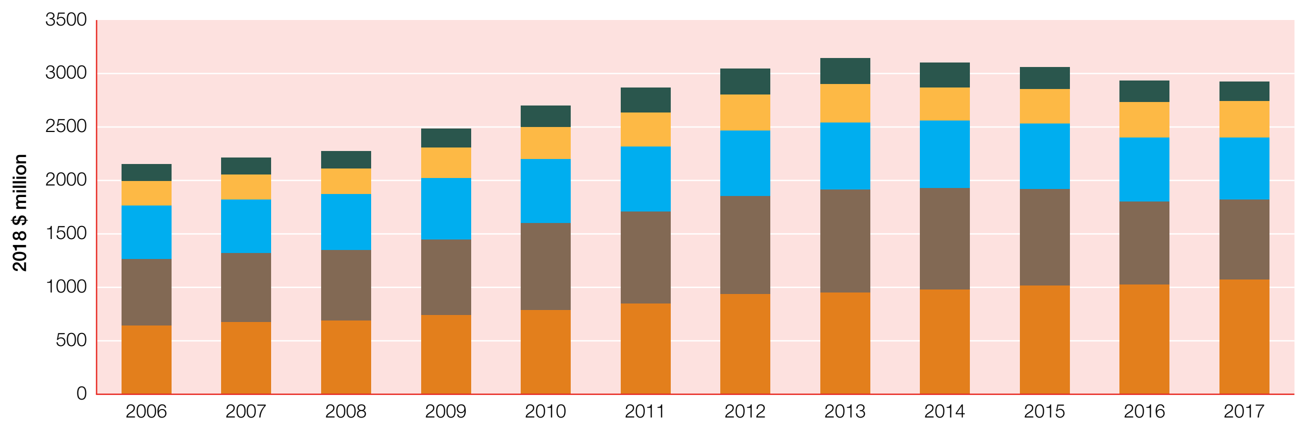
Lower commercial rates of return have been a key driver of lower network revenues. Weaker electricity demand has also eased network investment, stemming the previously rapid growth in network assets and associated capital costs (depreciation and returns on assets). Additionally, networks are implementing efficiencies to better control their operating costs. Lags in the regulatory cycle and lengthy legal appeals for some networks mean the trend towards lower revenues has varied between jurisdictions.

This trend of weakening network revenues, combined with growing customer numbers, is translating into lower network

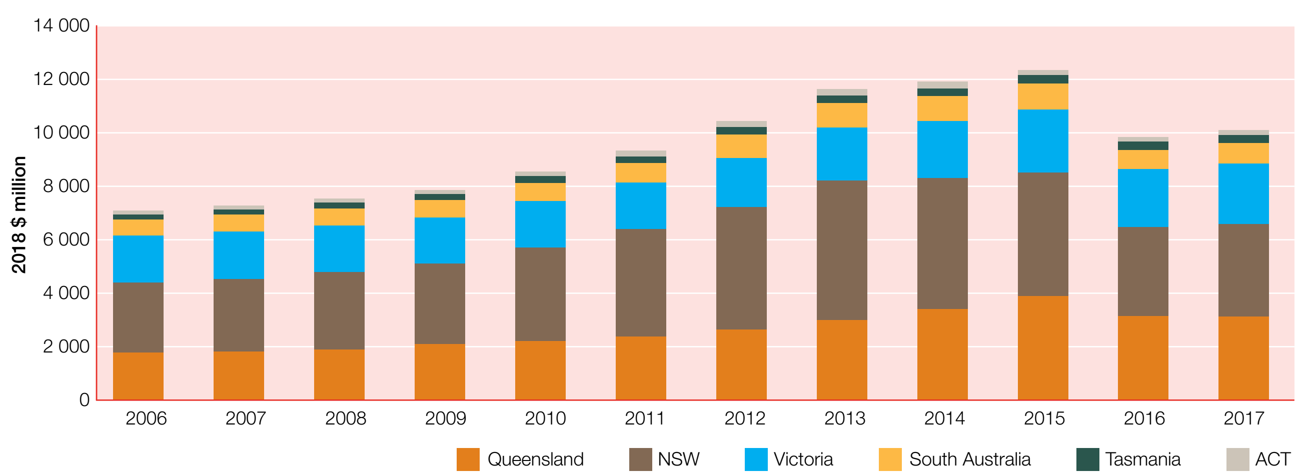
21 Data refers to actual outcomes for the 2017 regulatory year adjusted to 2018 dollars. The assumptions are explained in more detail in the notes to figures 3.7 and 3.8.

Figure 3.9
Electricity network revenues

Transmission



Distribution



Note: Actual outcomes, CPI adjusted to June 2018 dollars. Assumptions set out in notes to figures 3.7 and 3.8.
Source: Economic benchmarking RIN responses, AER regulatory decisions and regulatory proposals from businesses.

charges in retail energy bills for most networks (figure 3.11). This reduction is helping mitigate some of the upward pressure on retail energy bills in recent years from rising wholesale electricity costs.

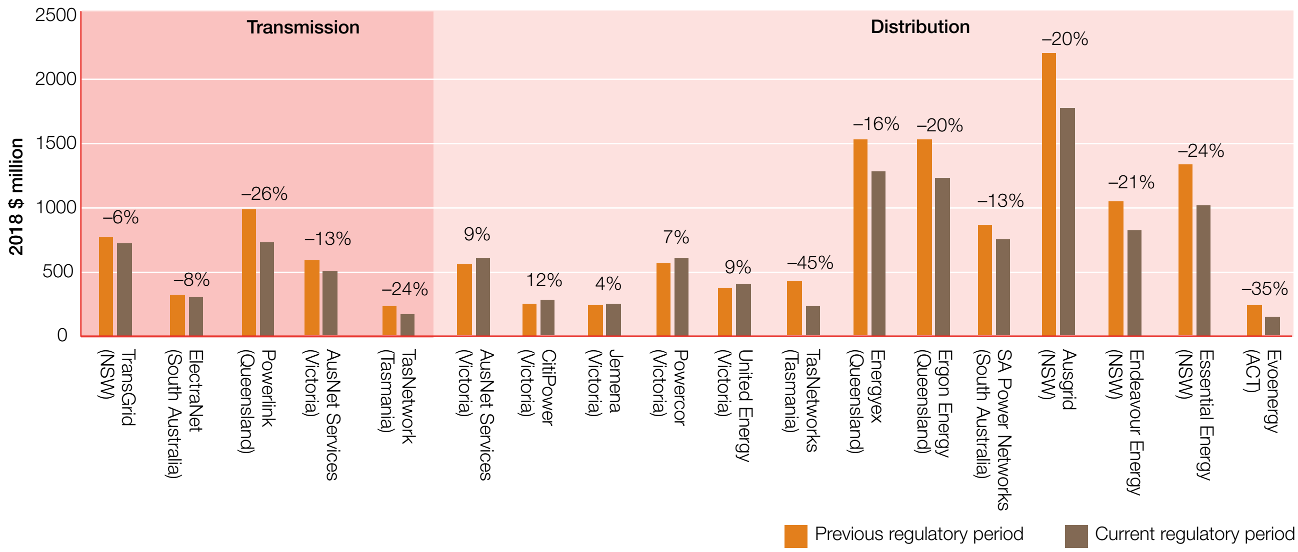
Victoria's distribution networks differ from the industry trend, with revenues in the current period forecast at 4–12 per cent higher than in the previous period. Increases were driven by forecasts of rising operating costs and replacement expenditure (sections 3.11 and 3.13). These outcomes partly reflect that the Victorian networks achieved a number of operating efficiencies earlier than networks elsewhere, as well as pipeline investment in new housing estate projects.

3.9.2 Longer term trends

The longer term saw a steep rise in network revenues from 2006 until around 2015. Changes to the energy rules in 2006 led to rapid growth in network investment at a time of globally high interest rates, compounding the impact on revenues. Operating expenditure also rose, with 45 per cent

Figure 3.10

Network revenues—change from previous period



Note: Revenues are smoothed annual averages. Actual outcomes for previous regulatory period, and forecasts for current period. Percentages represent the revenue change between regulatory periods. Forecast updates may result in some outcomes varying from those previously reported.

Current regulatory periods at 1 July 2018 (see table 3.1 for transmission and table 3.2 for distribution). Determinations in each sector appear in chronological order of the decision dates (listed in tables 3.1 and 3.2).

Source: AER economic benchmarking RINs; AER regulatory determinations and AER modelling.

real growth from 2006–2014, putting further pressure on revenues.[22]

- At the peak of this growth, network revenues rose by over 9 per cent each year in real terms between 2009 and 2013. This growth was the main cause of escalating retail electricity prices over this period, with network charges making up 43 per cent of retail customers' bills.

Many AER decisions also faced legal challenges in this period (section 3.5.1), often resulting in the Tribunal or Full Federal Court further increasing network revenues (of the 38 appeals in this period, none reduced revenues).

Revenues rose higher in Queensland and NSW than elsewhere. In Queensland, revenues more than doubled between 2006 and 2015. In NSW, revenues rose by 90 per cent from 2006–13. Revenue growth was less dramatic in Victoria, at 32 per cent from 2006–15.[23] A key cost driver in Queensland and NSW was stricter reliability standards imposed by state governments, which required new investment and operating expenditure to meet targets.

Some of the cost pressures facing network businesses began to ease when electricity demand from the grid began to decline, causing new investment to be scaled back from 2013. The changing demand outlook coincided with government moves to allow network businesses greater flexibility in meeting reliability requirements.

The financial environment also improved from 2013, easing borrowing and equity costs. In combination, these factors reduced the revenue needs of network businesses, with the impact flowing through to customers on a lagged basis as new regulatory cycles took effect. However, legal appeals on some AER decisions delayed the benefit of this shift to customers.

Reforms to the energy rules phased in from 2015 also began to impact network revenues. The reforms, which more explicitly linked network costs to efficiency factors, encouraged many network businesses to rationalise their operating costs.

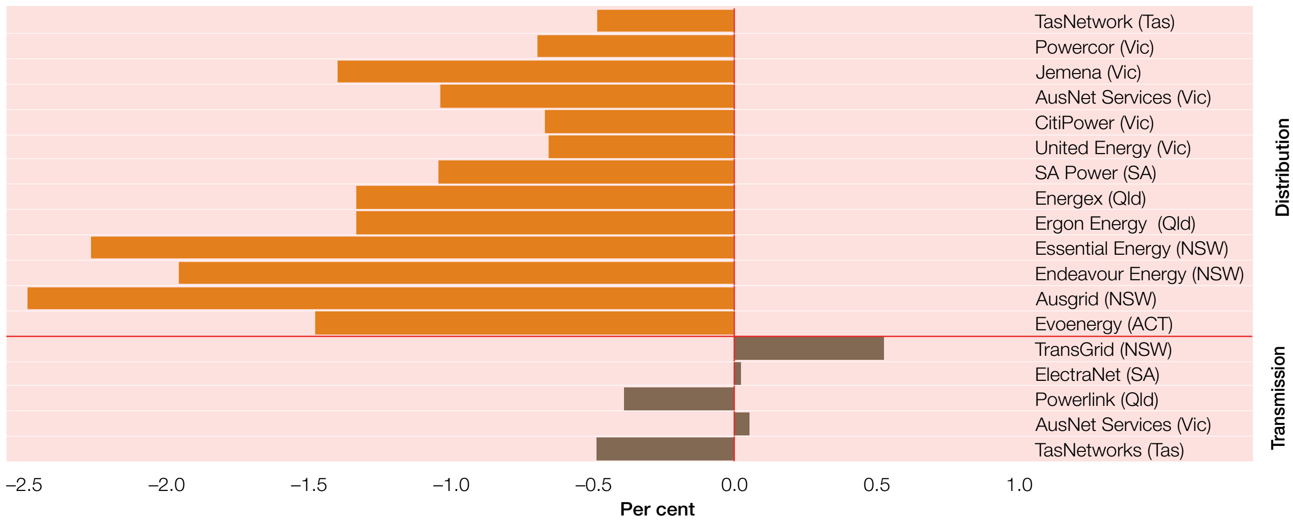
While network revenues are generally moving lower, network costs will continue to reflect over-investment from 2006–13 for the economic lives of those assets—which can be up to 50 years. The Grattan Institute called for the asset bases of some networks to be written down so consumers do not pay for that over-investment.[24] The Australian Competition

22 ACCC, *Retail Electricity Pricing Inquiry—Final Report*, June 2018 p. 64

23 ACCC, *Retail Electricity Pricing Inquiry—Final Report*, June 2018, p. 61 and figure 2.33.

24 Grattan Institute, *Down to the wire—A sustainable electricity network for Australia*, March 2018.

Figure 3.11
How AER decisions affect customer bills



Note: Estimated impact of latest AER decision on 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 only accounts for changes in network charges. Changes in other bill components are not reflected. Outcomes will vary among customers, depending on energy use and network tariff structures. The outcomes for NSW and ACT reflect the AER's original 2015 decisions, which were later varied by the Australian Competition Tribunal and Full Federal Court.

Source: AER revenue decisions and additional AER modelling.

and Consumer Commission (ACCC) supported this position, particularly for government owned networks in Queensland, NSW and Tasmania.[25]

Consumer groups and some industry observers remain concerned the regulatory framework enables network businesses to earn excessive profits, given the low market risks they face. To help evaluate this argument, the AER in 2018 began publishing new profitability data that allows stakeholders to compare the returns earned by each business (section 3.12.1).

3.10 How network charges impact electricity bills

Electricity network charges make up around 43 per cent of a residential customer's energy bill (figure 1.x). Most of these charges are distribution network costs.

3.10.1 Distribution charges

Current AER decisions reduced distribution charges in residential energy bills by around 1–2.5 per cent per year in all states and territories (figure 3.11). The falls mostly accrue in the first or second years of a regulatory period, followed by stable prices or small price movements (occasionally, small increases) in later years.

The reduction in network charges reflects a combination of factors noted previously—lower finance costs, weaker electricity demand requiring less 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.

The significant savings of up to 2.5 per cent per year for NSW and ACT energy customers reflect outcomes in the AER's 2015 decision for those networks. But those savings were partly set aside by the Tribunal. During the lengthy legal and remittal processes that followed, the AER accepted enforceable undertakings on network prices covering the three years to June 2019. The undertakings indexed network charges to the CPI (section 3.5.2).

3.10.2 Transmission charges

Current AER decisions reduced network charges in Queensland and Tasmania, but allowed increases in NSW, Victoria and South Australia. The Queensland and South Australian networks were among the first businesses in the NEM to develop regulatory proposals in close consultation with their customers (section 3.6.1).

25 ACCC, *Retail Electricity Pricing Inquiry—Final Report*, June 2018.

The TransGrid (NSW) decision in 2018 followed a more adversarial process in which the AER required significant changes to the network's proposals. The decision is expected to raise residential energy bills by around 0.5 per cent—the highest for any current revenue decision. This outcome partly reflects over-investment by TransGrid in previous regulatory periods, which raised the network's asset base, upon which depreciation costs and returns to investors continue to be calculated.

3.11 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 between networks and depend on a network's age and technology, load characteristics, the demand for new connections, and reliability and safety requirements. Some investment is needed to replace old equipment as it wears out or becomes technically obsolete. Other investment may be made to augment (expand) a network's capability in response to changes in electricity demand.

As part of the revenue determination process, the AER forecasts a network's efficient investment requirements over the upcoming period. This approved investment gets added to the network's regulated asset base.[26] As the RAB grows, the returns paid to shareholders and lenders who fund those assets also rises—this cost is passed on to customers. As some network assets have an asset life of up to 50 years, network investment will impact on retail energy bills long after the investment is made.

Network operators receive a guaranteed return on their RAB and so may have incentives to over-invest or 'gold plate' the networks to maximise those returns, particularly where their allowed rate of return is higher than their actual financing costs. Previous versions of the energy rules allowed for significant over-investment in network assets, which partly drove the sharp rise in network revenues from 2006–15 (section 3.9.2).

But reforms to the energy rules introduced incentives for efficient investment. Under the reforms, which have progressively applied since 2015, the AER can remove inefficient investment from a network's asset base where a network over-spends its allowance, so consumers do not have to pay for it.

The AER also launched a *capital expenditure sharing scheme* (CESS), which first applied in 2015. If a network business manages its investment program efficiently and under-spends against its forecast, it can 'keep the difference' between its forecast and actual capital costs[27] for the remainder of the regulatory period. However, it must bear the difference as lower profits if it over-invests. In the following regulatory period, a network business must share efficiency savings with its customers by passing on 70 per cent of savings as lower network charges. The business may retain the remaining 30 per cent of savings.

The scheme poses risks that require careful management. It encourages businesses to inflate their original investment forecasts. To manage this, the AER closely scrutinises whether proposed investments are efficient at the time of each reset. Additionally, it may incentivise a network business to earn a bonus by deferring critical investment needed to maintain the network's safe and reliable operation. The scheme is balanced by a separate incentive scheme to maintain service quality in ways that customers value (section 3.15.5).

3.11.1 Investment activity in electricity networks

Electricity networks in the NEM invested $4.5 billion in network assets in 2017, a 2.5 per cent rise on the previous year.[28] Around 83 per cent of that investment was made by distribution networks, with transmission networks investing the remaining 17 per cent.

While investment rose slightly in 2017, it was significantly below the peaks recorded a few years earlier (figures 3.7 and 3.8):

- Transmission businesses invested over $760 million in network assets in 2017—56 per cent lower than in 2009, when transmission investment peaked.
- Distribution businesses invested $3.7 billion in network assets in 2017—48 per cent lower than in 2012, when distribution investment peaked.

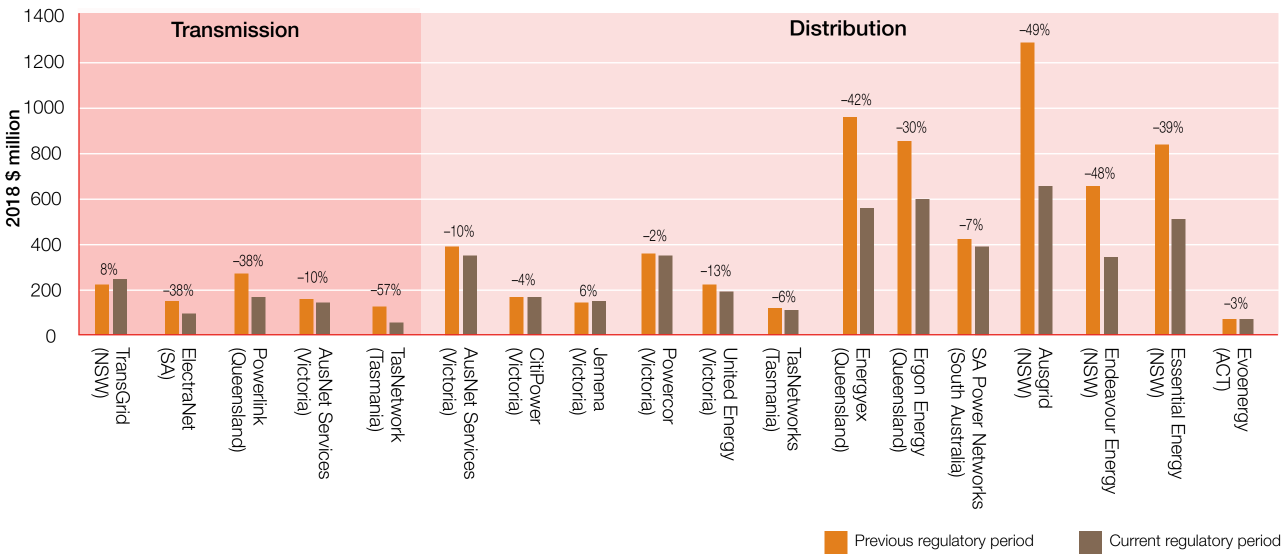
26 For example, if a network has an opening asset of $48 billion, and approved investment during the year of $5 billion, the asset base at the end of the year rises to $53 billion. If depreciation of assets due to old age and technical obsolescence is $3 billion, this is then subtracted to give a closing asset base of $50 billion.

27 The capital costs factored into a network's forecast revenue are: the return on capital needed to fund assets; and asset depreciation costs. If a network invests below forecast, these capital costs are reduced. The incentive scheme allows the business to retain these savings for the remainder of the regulatory period.

28 The assumptions underpinning data in this chapter are explained in the notes to figures 3.7 and 3.8. Unless otherwise stated, data refers to actual outcomes adjusted to 2017 dollars.

Figure 3.12

Network investment—change from previous period



Note: Smoothed annual averages, 2018 dollars. Actual outcomes for previous regulatory period, and forecasts for current period. Percentages represent the change between regulatory periods. Revisions may result in some outcomes varying from those previously reported.

Current regulatory periods at 1 July 2018 (see table 3.1 for transmission and table 3.2 for distribution). Determinations in each sector appear in chronological order of the decision dates (listed in tables 3.1 and 3.2).

Source: AER economic benchmarking RINs; AER regulatory determinations and AER modelling.

Current decisions

AER decisions in place at 1 July 2018 forecast network investment being 31 per cent lower on average than in the previous regulatory periods (figure 3.12). Across the NEM, only two of 18 current decisions approved higher investment than in the previous period.[29]

In distribution, the largest cuts were for government owned networks in Queensland (where investment is forecast to fall by 30–42 per cent) and NSW (falls of 39–49 per cent). Only one network (Jemena in Victoria) is forecast to increase investment.

The pattern is more varied in transmission, with the government owned Powerlink (Queensland) and TasNetworks recording substantial reductions. The privately owned ElectraNet (South Australia) also recorded a substantial fall, with the AER in 2018 approving some of its investment proposals only on a contingent basis (subject to future trigger events). TransGrid (NSW) is the only transmission network forecast to increase its investment in the current regulatory period (see figure 3.12).

29 Excludes decisions on transmission interconnectors.

Investment decisions in 2018

The AER in 2018 made final revenue decisions on three transmission networks—ElectraNet in South Australia, TransGrid in NSW and the Murraylink interconnector between Victoria and South Australia. The decisions cover the five year regulatory period 1 July 2018 to 30 June 2023. All three networks forecast the need for major new investment projects in the upcoming period.

ElectraNet's proposal was its first since a 'black system' event in South Australia on 28 September 2016 resulted in a state wide loss of electricity. While the AER lowered investment by 38 per cent compared with the previous regulatory period, it did accept a 13 per cent rise in investment in projects to enhance the network's security and resilience to extreme weather events.

The AER's TransGrid decision scaled back the network's proposed investment by around 20 per cent. Despite this, approved investment was still 8.5 per cent higher than in the previous period, partly to finance TransGrid's proposed 'Powering Sydney's Future' project. While the AER's draft decision rejected that proposal, its final decision accepted a revised proposal with lower costs, on condition that independent project oversight ensures it benefits consumers.

The Murraylink decision approved a $25 million upgrade to replace an aging control system to enable a safe and secure electricity supply to South Australia. This represents the first major capital expenditure for the interconnector in some time.

Additionally, the AER approved a number of major projects on a contingent basis, after finding their need, cost and scope was uncertain. The quantum of these projects is substantial—almost $5 billion across the three networks, which almost tripled the $1.7 billion of approved investment.

The networks can ask the AER to reassess whether these projects are prudent and efficient if certain trigger events occur. TransGrid proposed nine contingent projects, totally around $4 billion of investment. The projects include connecting large scale renewable generation such as Snowy 2.0 to the network, and a new transmission interconnector between NSW and South Australia. ElectraNet's contingent projects include a $950 million proposal to address power system security and reliability.

Longer term investment trends

The longer term saw a rapid escalation in network investment from 2006 until around 2012, which often outpaced forecasts (figure 3.13).

Changes to the energy rules in 2006 spurred much of this growth.[30] Governments and the AEMC changed the rules to incentivise investment, to address concerns that network investment was not keeping pace with projected growth in electricity demand at the time. More stringent reliability standards imposed by state governments in NSW and Queensland also contributed to this growth by requiring new investment to meet the stricter targets.

But weakening electricity demand began to reverse this trend from 2013. Many projects were postponed or abandoned when it became clear earlier projections of sustained demand growth would not eventuate. Further, a shift in government policy towards less stringent reliability obligations on network businesses made some projects redundant, leading to several proposals being scaled back or deferred.

Investment levels further eased from 2015 when AER reforms protecting consumers from funding inefficient network projects began to apply. Additionally, the CESS scheme offered financial incentives for network businesses to invest below forecast levels.

30 ACCC, *Retail Electricity Pricing Inquiry—Final Report*, June 2018, p. 111; Reeves, A, Consumer involvement in energy regulation, speech, 23 May 2013; Productivity Commission, *Electricity Network Regulatory Framework*, Inquiry report, 9 April 2013.

These trends are also evident on a per customer basis. Distribution network investment per customer peaked in 2012, then sharply declined. Transmission network investment per customer peaked in 2009—three years earlier than in distribution. Overall investment fell sharply from 2013–16, before recovering slightly in 2017. By 2017 per customer investment was 49 per cent below the peak for distribution businesses, and 56 per cent below the peak for transmission businesses.

Impacts on the asset base

Capital investment increases a business's regulatory asset base, upon which it earns returns. Escalating investment from 2006 inflated RABs in the network sector, with a 70 per cent rise in real terms over the nine years to 30 June 2015 (figure 3.14).

Weaker investment is reflected in reduced RAB growth per customer in distribution (from 2015) and transmission (from 2014), stemming a decade of continuous rapid growth. From 2015 to 2017, RAB per customer in the NEM fell 1–2 per cent per year (figure 3.15).

3.11.2 The changing composition of investment

While annual investment in electricity networks has been declining for several years, the *composition* of that investment has changed markedly.

A network business's capital expenditure program mostly relates to:

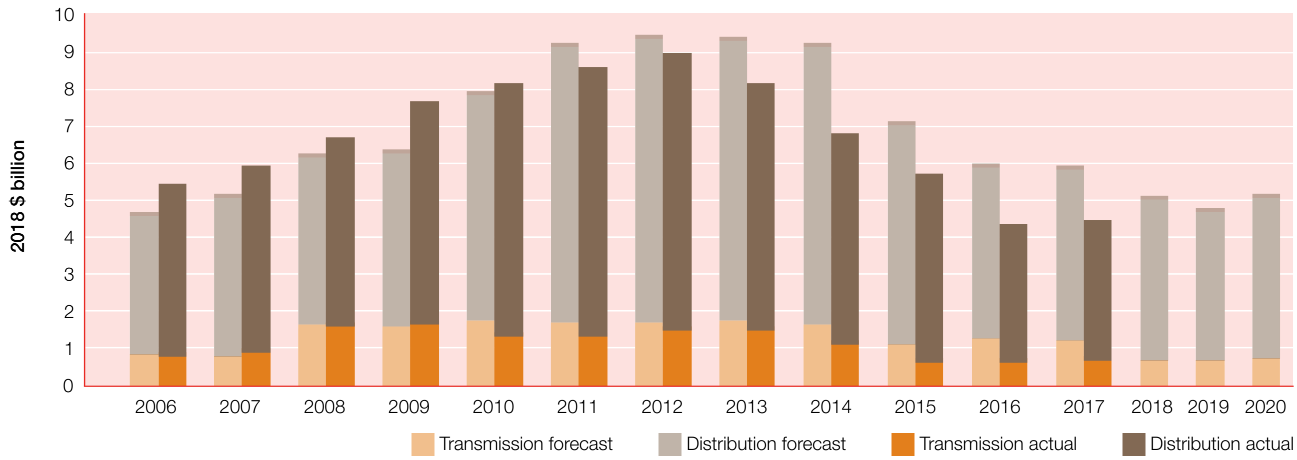
1. 'growth' (augmentation) expenditure to expand capacity to cope with forecast rising demand
2. replacement expenditure for aging or technologically obsolete assets that have reached the end of their economic life.

Other categories of capital expenditure include investment supporting new connections (such as new substations), non-network assets (such as motor vehicles) and capitalised overheads such as IT.

For most network businesses, growth expenditure was traditionally the main component of investment. In 2009, it accounted for 63 per cent of all transmission investment and 42 per cent of distribution investment.

But weakening electricity demand along with less stringent reliability obligations led many network owners to shelve or delay growth plans over the following years. By 2017 growth investment had shrunk to 9 per cent of transmission investment and 26 per cent of distribution investment. In

Figure 3.13
Network investment—forecast and actual



Note: Actual outcomes for relevant year on an end of year basis, 2018 dollars. Assumptions set out in notes to figures 3.7 and 3.8.
Source: AER estimates derived from Economic benchmarking RIN responses, AER revenue determinations, and AER modelling.

dollar terms, growth investment declined from over $3 billion in 2009 to just over $1 billion in 2017 (figure 3.16).[31]

In contrast, replacement expenditure has remained relatively steady at around $1.5 billion. But as a proportion of the shrinking total investment pool, replacement investment has risen strongly. In transmission, replacement investment rose from 27 to 69 per cent of the investment pool from 2009 to 2017. In distribution, it rose from 24 to 38 per cent of investment over the same period.

3.11.3 Regulatory tests for efficient investment

The AER assesses a network's efficient investment requirements as part of the revenue reset process. Additionally, a network business must conduct a cost–benefit analysis (a regulatory investment test) for each project to ensure it is efficient. The analysis must include an evaluation of the investment proposal against viable alternatives, including non-network options such as electricity generation. The business must give due consideration to alternatives, before identifying the best way to address the needs on their network. Public consultation is required as part of the assessment.

The AER monitors businesses' compliance with the tests. It also resolves disputes over whether a network business has properly applied a test. At 1 March 2018 the AER had reviewed or monitored 18 applications of the Regulatory Investment Test for Transmission (RIT–T), 17 applications of the Regulatory Investment Test for Distribution (RIT–D) and resolved one RIT–D dispute, since the tests were introduced.[32]

The Energy Users Association of Australia (EUAA) notified a dispute in July 2018 over Ausgrid's application of a RIT–D test to an investment proposal in the Sydney Central Business District. The dispute concerned Ausgrid's estimated value of customer reliability (VCR), which EUAA claimed was significantly higher than an estimate TransGrid recently applied in a cost–benefit analysis for a similar project. The AER found the choice of VCR estimate would not materially impact the ranking of project options, but was critical of Ausgrid's cost–benefit analysis and the lack of transparency in its consultation process.[33]

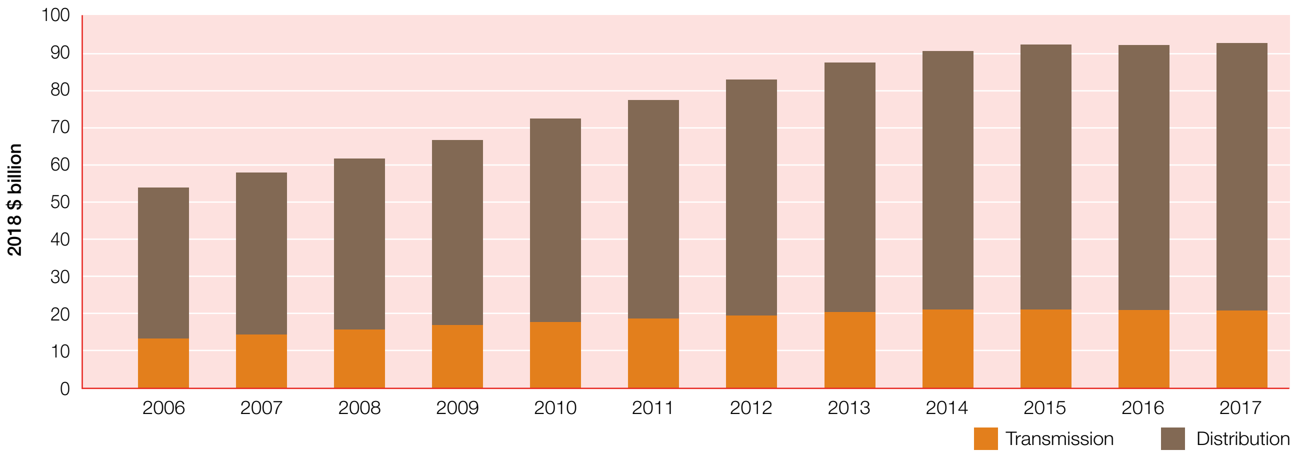
Until 2017 the regulatory investment tests only applied to growth investment, which in recent years accounted for the bulk of network investment. But the composition of network investment is evolving, with replacement expenditure overtaking growth investment in most networks (section 3.11.2). Recognising this shift, the AER in June 2016 proposed widening the scope of regulatory investment tests to also include replacement investment—including asset refurbishment and de-rating decisions.

31 Measured in real (2017) dollars.

32 Some of those processes were ongoing. Details of how RIT–T and RIT–D tests are applied to particular projects can be found in AER, *Review of the application guidelines for the regulatory investment tests*, Issues Paper, February 2018. The RIT–T was introduced in 2010 and the RIT–D in 2014.

33 AER, *AER releases determination on Sydney CBD RIT–D dispute,* media release, 25 October 2018.

Figure 3.14
Value of network assets



Note: Closing RABs for electricity networks in the NEM, June 2018 dollars. Assumptions set out in notes to figures 3.7 and 3.8.
Source: Economic benchmarking RIN responses and AER modelling.

The AEMC widened the regulatory tests in July 2017,[34] and the AER amended its guidelines to implement the change.[35] The amended test imposes new reporting requirements on network businesses to justify asset retirement decisions and allow interested parties to propose alternatives to asset replacement.

Separately, the AER in 2018 completed a review of the RIT–T to ensure it adequately considers system security, emissions reduction goals, and events with a low probability of occurring but high impact. The review also explored how to better align the RIT–T with the RIT–D and how the tests can work jointly with AEMO's integrated system plan (ISP) for optimising transmission investment.[36] In particular, the RIT–T needs to complement the ISP's approach to identifying which transmission upgrades and interconnectors are in the long-term interest of consumers. The AER released draft application guidelines in July 2018, with a view to finalising the review in late 2018.[37]

The COAG Energy Council also asked the AEMC to explore whether the AER should have greater oversight over the RIT–T process, and whether civil penalty provisions should be introduced. The AEMC in December 2017 recommended that breaches of regulatory test processes be subject to civil penalty provisions.[38]

3.11.4 Annual planning reports

The regulatory test framework does not operate in isolation. Other mechanisms complement the framework, and the AER has recently applied measures to improve their effectiveness.

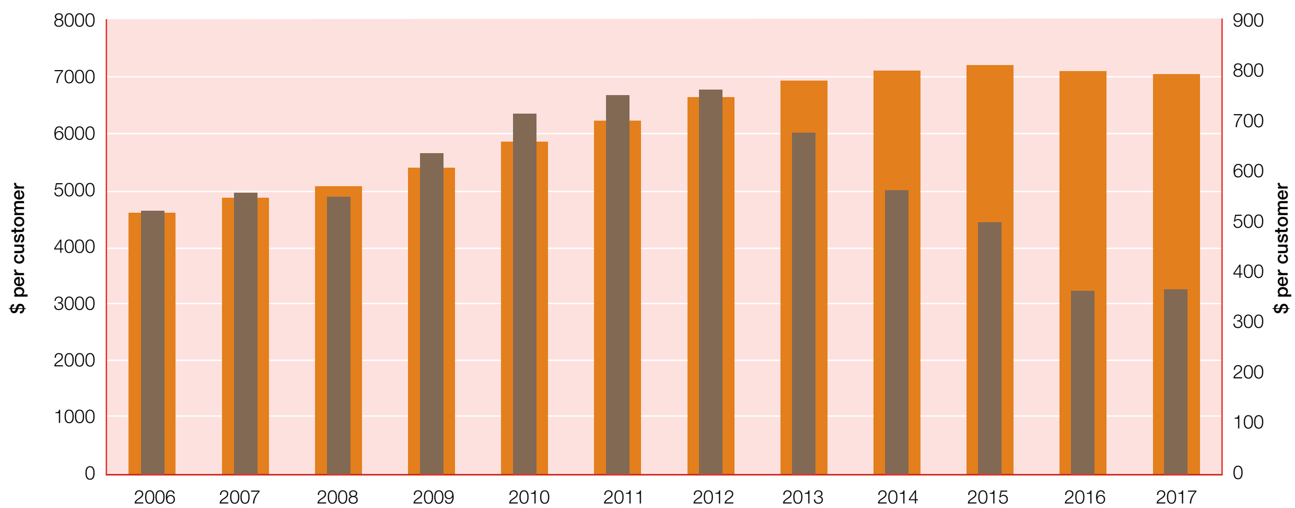
Network businesses must publish *annual planning reports* to identify new investment that may be needed to efficiently deliver network services. The reports provide public information on emerging network constraints, including potential options to alleviate those constraints. In making this information publicly available, the reports help non-network providers identify and propose solutions to address network needs.

In light of the AEMC's July 2017 rule change on the regulatory investment tests, network businesses will be required to expand their planning reports to include network asset retirement and de-rating information. In 2017 the AER also published a template to improve the consistency and useability of distribution planning reports. In 2018 it began consulting on similar guidelines for transmission networks.[39]

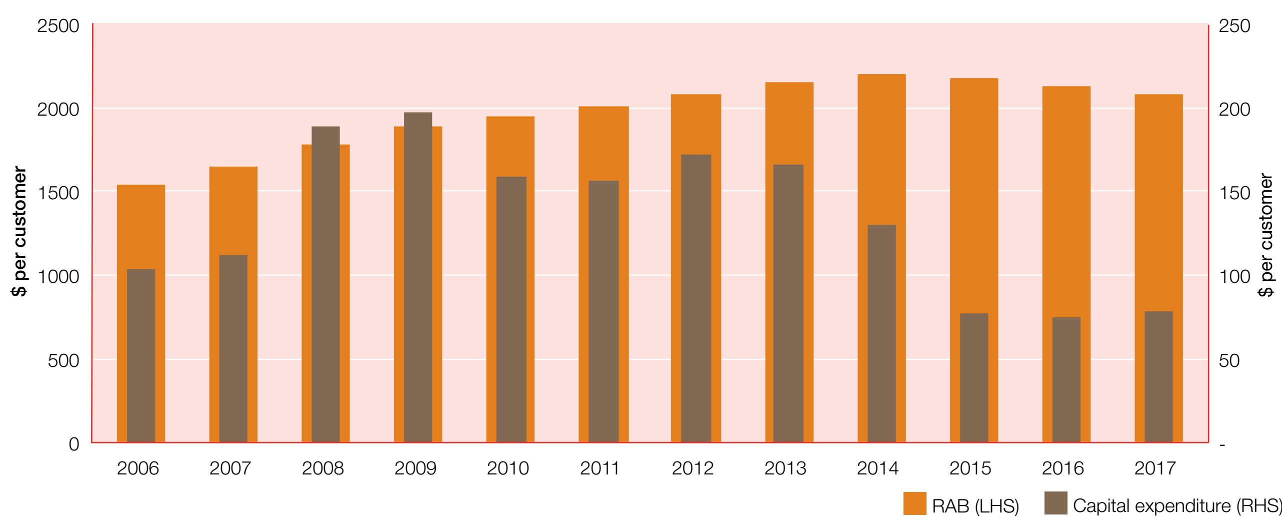
34 AEMC, *Replacement expenditure planning arrangements rule*, factsheet, 18 July 2017.
35 AER, *RIT–T and RIT–D application guidelines (minor amendments) 2017*.
36 AEMO, *Integrated system plan for the National Electricity Market*, July 2018.
37 AER, *Review of the application guidelines for the regulatory investment tests for transmission and distribution*.
38 AEMC, *Rule determination: National Electricity Amendment (Contestability of energy services) Rule 2017*, December 2017, p. 130.
39 AER, *Transmission Annual Planning Report Guideline, Consultation paper*, April 2018.

Figure 3.15
Network investment and asset base per customer

Distribution



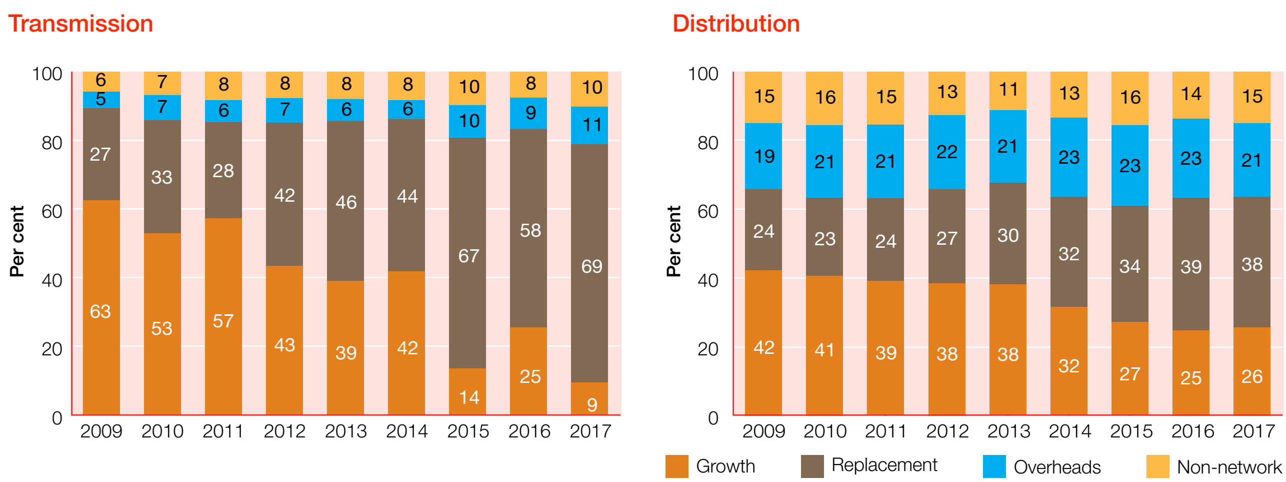
Transmission



Note: Closing RABs, June 2018 dollars. Investment is actual outcomes on an end of year basis, 2018 dollars. Assumptions set out in notes to figures 3.7 and 3.8.

Source: Economic benchmarking RIN responses and AER modelling.

Figure 3.16
Network expenditure by driver



Source: AER economic benchmarking RINs and AER modelling.

3.11.5 Demand management

The AER in December 2017 launched new initiatives encouraging network businesses to find lower cost alternatives to new investment to help cope with changing demands on the network and manage system constraints. An enhanced *demand management incentive scheme* 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 expanded its *demand management innovation allowance*. This is a research and development fund to help distribution businesses develop new ways of using demand management to keep network costs down in the longer term. The new allowance provides funding to expand research and development by around 30 per cent from previous levels. To provide accountability, project eligibility criteria were tightened and reporting requirements clarified to emphasise sharing of project learnings across the industry and with consumers.

The incentive scheme and updated innovation allowance apply in regulatory periods commencing from 1 July 2019. To enable greater uptake, the AEMC in 2018 approved an AER rule change request to allow early application of the new scheme. By October 2018 three distributors—AusNet Services, Energex and Ergon Energy—had applied to bring forward new demand management projects.

Funded projects under earlier versions of the schemes included trials of innovative tariffs and customer payments designed to incentivise customers to reduce (or shift) their use at peak demand times.

Energex, for example, introduced demand based electricity tariffs in 2016 to test whether it incentivised customers to adopt technologies such as battery storage, and whether educational and promotional materials would encourage the adoption of more cost reflective tariffs. United Energy's 'summer saver' program trialled bonus payments ('critical peak rebates') to customers for reducing their demand at peak times.

Other funded projects focused on technology solutions, including load control devices and storage (batteries), and improving network system controls and information. Battery storage trials, either at grid scale or at the residential level, were undertaken in all regions and accounted for over one third of all innovation allowance expenditure (figure 3.17).

In addition to managing network constraints, demand response provided by network businesses can help manage wholesale electricity supply during extreme peaks. The Australian Renewable Energy Agency (ARENA) and AEMO in 2017 announced a three year trial of demand response technologies and services to deliver 200 megawatts of capacity in the NEM by 2020. Among the ten selected projects was a United Energy proposal to install voltage control devices at substations to better manage voltage issues and electricity use during peak demand surges.

Network businesses varied in their appetite to use funding available under the previous demand management innovation allowance. Of the 13 distributors, only AusNet Services, SA Power Networks and TasNetworks had spent (or were on track to spend) their full funding allocation by mid-2017.[40]

3.12 Rates of return for network businesses

The shareholders and lenders who finance the assets operated by a network business must be paid a commercial return on their investment. The dollar returns paid to investors each year is calculated by multiplying the asset base by the *rate of return*.[41] Given electricity networks are capital intensive, this return typically accounts for around 50 per cent of a network' revenue.

The rate of return estimates the cost of funds a network business requires to make investments. It combines the returns needed to attract two sources of investment funding—*equity* (funding provided by the network owner or shareholders) and debt (funding borrowed from banks and other lenders). The *return on equity* is the return required by shareholders of the business for them to continue to invest. The *return on debt* is the interest rate the network business needs to pay when it borrows money to invest. For this reason, the allowed rate of return is sometimes called the weighted average cost of capital.

If the rate is set too low, the networks may not be able to attract sufficient funds to be make required investments to maintain reliability and safety of supply. But if the rate is set too high, the networks are incentivised to over-invest, and consumers pay for a 'gold plated' network they do not need.

Estimation of the rate of return is complex, and a significant driver of network revenue. A small rise in the rate of return will significantly impact revenues (and energy bills for customers). A 1 percentage point increase in the allowed rate of return for TransGrid's NSW transmission network would increase its forecast revenues from 2018–23 by around 10 per cent, for example. For this reason, the rate of return is often the most contentious part of a revenue decision.

Conditions in financial markets are a key determinant of the allowed rate of return. AER decisions from 2009–12 occurred 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 was as high as 10 per cent in decisions in 2008–10 (figure 3.18). Additionally, the Tribunal increased some rates of return following appeals by the network businesses.

The financial environment improved from 2012, and borrowing and equity costs eased accordingly. AER decisions since 2015 also adopted a new approach to determining rates of return, with the cost of capital updated annually to reflect changes in debt costs. Stable financial market conditions resulted in an average allowed rate of return of around 6 per cent in decisions from 2016–18, compared with over 10 per cent in decisions from 2009–11. These lower rates of return have been a key driver of lower network revenues and charges over the past few years (figures 3.7 and 3.8).

3.12.1 Profitability reporting

In response to calls for greater transparency around the actual returns achieved by the businesses, the AER in September 2018 began publishing information about network businesses' profitability. Some observers are concerned networks may be earning excessive profits, given the market risks they face. In the first phase of this initiative return on assets data for each network business was published. More comprehensive reporting will follow in 2019.

Figure 3.19 compares approved rates of return for network businesses in 2016–17 with the returns actually earned by each business in that year (excluding bonuses earned under regulatory incentive schemes). While the data indicates several businesses earned above their regulated rates of return, it represents the first stage of developing profitability reporting and should be interpreted with caution.[42]

3.12.2 Review of the rate of return

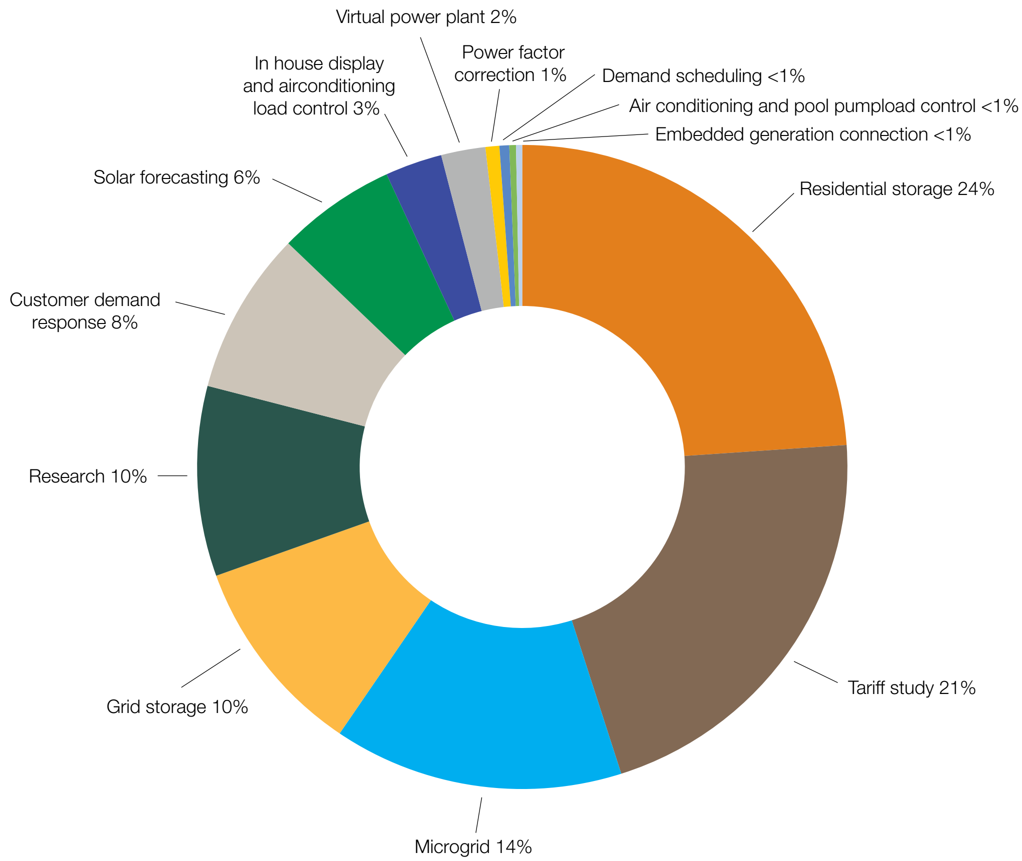
In the past, the AER set a separate rate of return for each network as part of its revenue determination. The AER published non-binding guidelines on its approach in 2013, following extensive consultation with businesses. Despite

40 AER, *Approval of Demand Management Innovation Allowance (DMIA) expenditures by distributors in 2016–17 and 2017*, July 2018.

41 If the rate of return is 5 per cent, and the RAB is $50 billion, for example, 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.

42 Time series data is published on the AER website at www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/profitability-measures-for-electricity-and-gas-network-businesses.

Figure 3.17
Demand management innovations funded in 2016–17



Note: per cent of total funding applied under the scheme. 2016–17 data (2017 for Victoria).

Source: AER, *Approval of Demand Management Innovation Allowance expenditures by distributors*, July 2018.

this, the process of applying the guideline has been adversarial, with businesses frequently making a case to deviate from it in their revenue proposals. Over the past five years, many network businesses argued for a different approach or different parameters. The AER's decisions—which were consistent with the guidelines—were often challenged. Legal battles were long, costly and added to uncertainty for the businesses, consumers and investors. Some decisions originally made in 2015 were still being remade in 2018 (section 3.5.2).

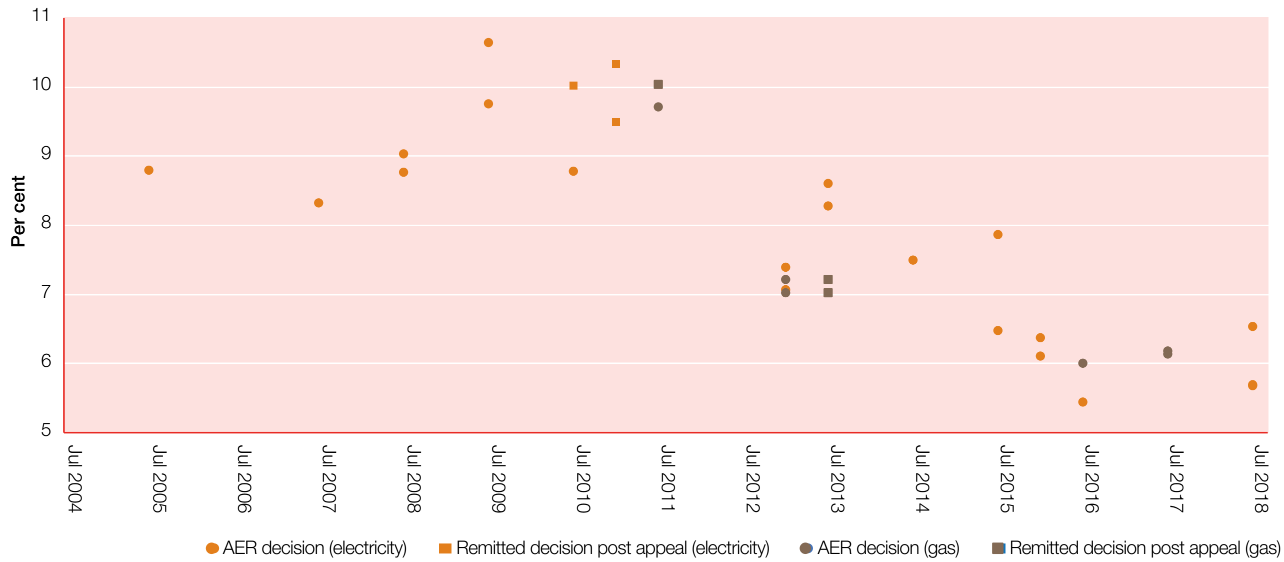
To provide certainty and predictability for stakeholders, the COAG Energy Council in 2017 agreed to make the AER's rate of return guideline binding on both the AER and energy networks. From December 2018 a new binding guideline will apply to revenue decisions made over the next four years.

To ensure an open and transparent review, the AER set up comprehensive consultation and engagement processes, including:

- a consumer reference group comprising academics, energy consumer associations, community and advocacy groups, to provide ongoing feedback throughout the review
- a dedicated consumer challenge sub-panel
- an investor reference group, to provide direct feedback from investors
- expert evidence 'hot-tubbing' sessions, to allow the AER Board to explore areas of agreement/disagreement between finance experts
- an independent panel to review the AER's draft guideline and report back before its final decision.

Figure 3.18

Rates of return for energy networks



Note: Nominal vanilla WACC.

Source: AER decisions on electricity network revenue proposals and gas pipeline access arrangements; AER decisions following remittals by the Tribunal/Full Federal Court.

The AER's draft decision published in July 2018 would, if implemented, reduce a typical residential electricity bill by around $30–40 per year.[43]

3.13 Electricity network operating costs

Electricity network businesses face various operating and maintenance costs in supplying electricity to consumers. These costs absorb around 30 per cent of a network's annual revenues.

Businesses present their cost forecasts to the AER as part of their revenue proposals. The AER then assesses whether those forecasts reasonably reflect the efficient costs of supplying power to customers. In making this assessment it forecasts various cost drivers such as electricity demand, productivity improvements, changes in labour and materials costs, and changes in the regulatory environment. If the AER does not consider a business's cost forecasts to be reasonable, it may replace them with its own cost forecasts.

Additionally, the AER runs an *efficiency benefit sharing scheme* (EBSS), offering incentives for network businesses to keep their operating and maintenance spending to efficient levels. The scheme allows business to retain efficiency gains for up to five years—but they must also bear efficiency losses. In the longer term, network businesses must share efficiency gains with customers, passing on 70 per cent of the gains as lower network charges.

3.13.1 Operating cost expenditure

Electricity networks in the NEM spent $3.7 billion on operating and maintenance costs in 2017, a 2.8 per cent decrease on the previous year (figure 3.20):

- Distribution businesses spent $3 billion in operating costs in 2017—16 per cent lower than in 2012, when those costs peaked in the sector.
- Transmission businesses spent $720 million in operating costs in 2017—less than 1 per cent lower than 2016, when those costs peaked in the sector.[44]

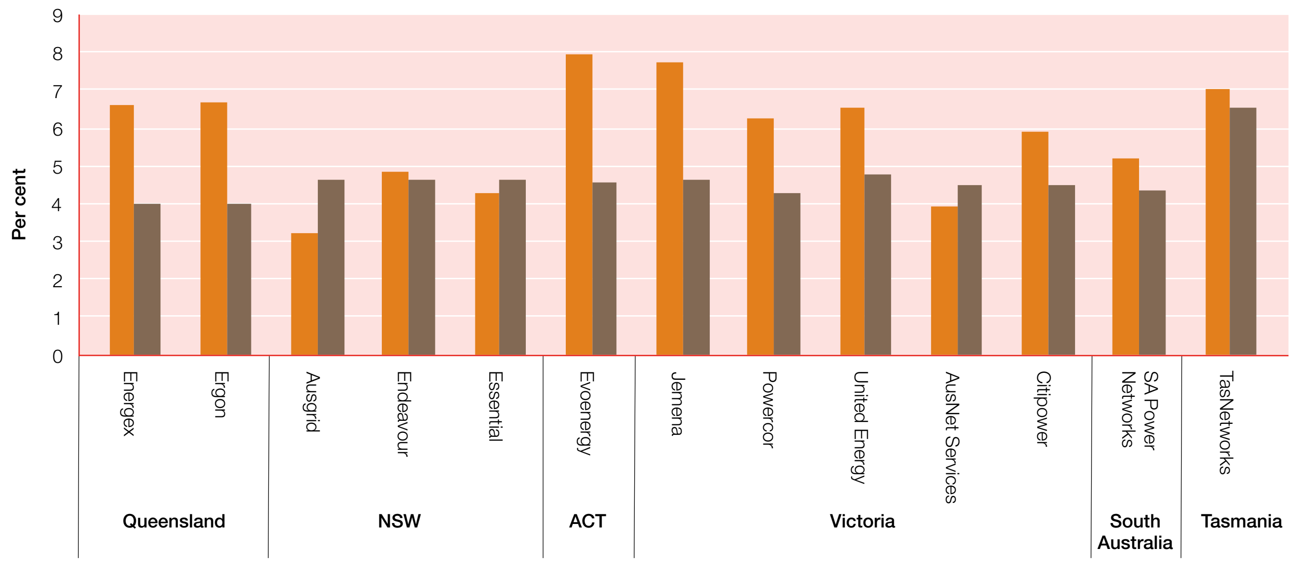
There was a sustained escalation in operating costs from 2006–2012, followed by a four year plateau, with a shift to lower costs in 2016 and 2017. Actual costs tended to

43 AER, *AER releases draft decision on new Rate of Return Guideline*, media release, 10 July 2018.

44 The assumptions underpinning data in this chapter are explained in the notes to figures 3.7 and 3.8. Unless otherwise stated, data refers to actual outcomes adjusted to 2017 dollars.

Figure 3.19
Rates of return for network businesses, 2016–17

Distribution



Transmission

WACC, weighted average cost of capital.

Note: Rates of return for 2016–17. Outcomes for NSW and ACT electricity distributors were affected by transitional arrangements pending the outcome of legal appeals.

Source: AER, *Profitability measures for electricity and gas network businesses*, September 2018.

outpace forecasts in most years, though they were slightly below forecast in 2017.

While operating expenditure has eased since 2012, the reduction is less marked than for capital expenditure. Operating and maintenance costs are largely independent of electricity use. This means operating costs do not decline significantly with falling electricity demand., and long term trends shift gradually. This is especially the case for transmission, where operating costs grew fairly steadily from 2006–16, before easing slightly in 2017. Shifts in costs for distribution networks tend to be more pronounced. The 20 per cent reduction in operating costs for that sector since 2014 reflects significant efficiencies being achieved in some networks.

3.13.2 Recent operating cost outcomes

AER decisions in place at 1 July 2018 forecast network operating costs being 4.9 per cent lower on average than in the previous round of AER assessments (figure 3.21). However, outcomes varied. In distribution, operating costs were forecast to rise for the Victorian and South Australian networks, but to fall significantly in Queensland, NSW, ACT and Tasmania.

A number of networks have implemented efficiencies in managing their operating costs since 2015, when the AER widened its use of benchmarking to identify operating inefficiencies in some networks. The AER's EBSS also incentivises network businesses to spend efficiently.

In current decisions, a combination of AER incentives and network driven efficiencies drove significant cost reductions, especially among government owned (or recently privatised) distribution networks in NSW, Queensland and Tasmania, and the part government owned ACT network. The largest cuts were for distribution networks in Queensland (where operating costs are forecast to fall by 23–34 per cent), NSW (falls of 15–28 per cent) and Tasmania (a fall of 21 per cent).

Operating costs were forecast to rise for the privately owned Victorian and South Australian distribution networks. The AER found some of these businesses had been improving efficiency for some time, so their base levels of expenditure were already leaner than for networks elsewhere. New regulatory obligations—including new regulatory information reporting processes, changes to the connections charging framework, and Power of Choice requirements—were also forecast to raise operating costs in some areas.

Outcomes tended to be steadier in transmission than distribution. Current AER decisions allow for higher transmission operating costs in Victoria, NSW and South Australia, but lower costs in Queensland and Tasmania.

The AER in 2018 made final revenue decisions on three transmission networks—ElectraNet in South Australia, TransGrid in NSW and the Murraylink interconnector. Its decisions for ElectraNet and TransGrid allowed 4–5 per cent increases in operating expenditure over the previous regulatory period. This partly reflects new obligations on the businesses arising from recent market reviews, rule changes, and revised licence conditions. ElectraNet identified additional obligations relating to frequency control and fault management, connection and planning arrangements, and generator licensing arrangements. TransGrid identified revised licence conditions and additional network support costs associated with its Powering Sydney's Future project.

3.14 Electricity network productivity

The AER's benchmarking work tracks the relative efficiency of electricity networks over time. The AER applies a *multilateral total factor productivity* approach to benchmark how effectively a network uses its inputs (assets and operating expenditure) to produce outputs. Indicators include maximum electricity demand, electricity delivered, reliability of supply, customer numbers (only for distribution networks), line length and the voltage of transmission connection points.

The AER considers benchmarking a useful tool for comparing the performance of different networks. But there may be operating environment factors not fully captured in its model that drive apparent differences in estimated productivity and operating efficiency across networks in the NEM. The benchmarking models do not directly account for differences in legislative or regulatory obligations, climate and geography, for example. The AER in October 2018 published research into the impact of operating environment factors on distribution networks, which will be used as part of its continuous refinement of benchmarking techniques.[45]

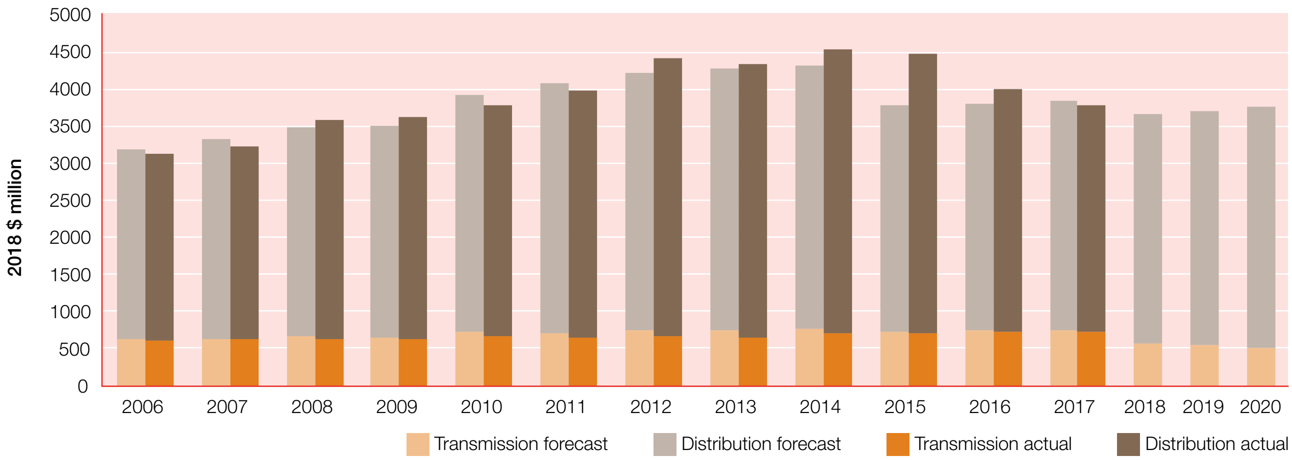
Productivity will rise if the resources used to maintain, replace and augment energy networks rise faster than the demand drivers for network services.[46] Some productivity

45 AER, *Independent review of Operating Environment Factors used to adjust efficient operating expenditure for economic benchmarking*, Simon Orme, Dr. James Swansson, Geoff Glazier, Ben Kearney, Dr Howard Zhang, October 2018.

46 The AER uses a multilateral total factor productivity approach to measures networks' relative productivity performance over time. The approach assesses the volume of inputs needed to produce specified outputs.

Figure 3.20

Annual network operating costs—forecast and actual



Note: Actual outcomes for relevant year on an end of year basis, 2018 dollars. Assumptions set out in notes to figures 3.7 and 3.8.

Source: Economic benchmarking RIN responses; AER revenue determinations; AER modelling.

drivers are beyond the control of network businesses—for example reliability standards set by government bodies.

Productivity in most networks declined from 2006–15, especially in the distribution sector. Over this period, the privately owned networks in Victoria and South Australia tended to operate more efficiently than government owned (or recently privatised) networks in Queensland, NSW, the ACT and Tasmania.[47]

But this trend has reversed since 2015. Productivity in distribution networks rose by 5 per cent over the two years to 31 December 2017, the most positive outcome in over a decade. Transmission networks also improved their productivity in 2017, averaging a 6 per cent rise over in the year.[48]

3.14.1 Transmission network productivity

The electricity transmission sector achieved an overall productivity gain of 5.8 per cent over the two years to 31 December 2017. The gain in each year was higher than for any other year since 2006. Powerlink (Queensland) was the only network not to make productivity gains in 2017.

Improved network reliability contributed around 70 per cent of productivity improvements in NSW, Victoria and South Australia. Other factors included reductions in overhead line length in Queensland and NSW, and growth in energy throughput in all networks outside Victoria. Gains in Tasmania were largely driven by lower operating costs.[49]

The Victorian and Tasmanian networks ranked highest by productivity score in 2017. The South Australian and NSW networks ranked mid-range, while the Queensland network ranked lowest.

Regulatory incentives may be contributing to improved outcomes. In particular, the AER allows network businesses to retain efficiency gains for up to five years. Additionally, it may remove inefficient investment from the regulatory asset base.

Recent outcomes reversed a trend of poor industry performance (figure 3.22). Transmission network productivity in NSW, Queensland and South Australia declined by 20 per cent over the 11 years to 2017. Over that period, productivity improved only in the Victorian and Tasmanian networks (by around 10 per cent).[50]

Rising capital investment (inputs) at a time when electricity demand (output) had plateaued or was declining drove

47 Queensland Government, *Independent Review Panel on Network Costs, Electricity Network Costs Review, Final Report*, June 2014, p. 102. Quoted in ACCC, *Retail Electricity Pricing Inquiry—Final Report*, June 2018 p. 108

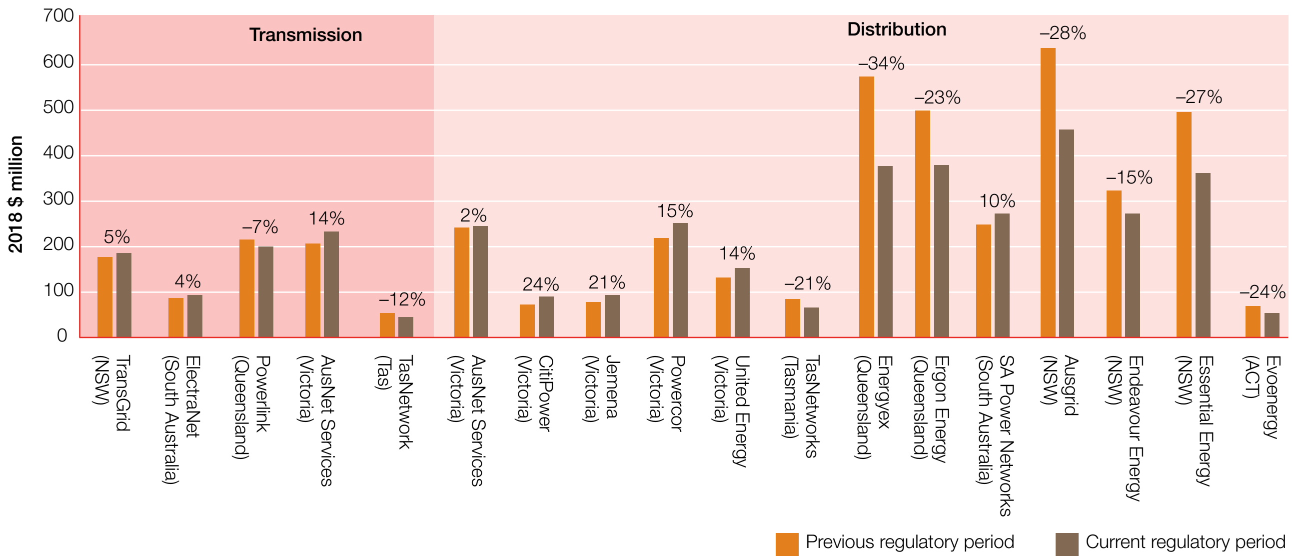
48 AER, *Annual benchmarking report: electricity transmission network service providers*, November 2018; AER, *Annual benchmarking report: electricity distribution network service providers*, November 2018.

49 AER, *Annual Benchmarking Report, Electricity distribution network service providers*, December 2018.

50 In this section, industry wide data are based on Total Factor Productivity measures. Outcomes for particular networks and comparisons across networks are based on Multilateral Total Factor Productivity or Multilateral Partial Factor Productivity. See AER, *Annual Benchmarking Report, Electricity transmission network service providers*, November 2017.

Figure 3.21

Network operating expenditures—change from previous period



Note: Smoothed annual averages, 2018 dollars. Actual outcomes for previous regulatory period, and forecasts for current period. Percentages represent the forecast change from the previous regulatory period. Revisions may result in some outcomes varying from those previously reported.

Current regulatory periods at 1 July 2018 (see table 3.1 for transmission and table 3.2 for distribution). Determinations in each sector appear in chronological order of the decision dates (listed in tables 3.1 and 3.2).

Source: AER economic benchmarking RINs; AER regulatory determinations; AER modelling.

weaker productivity outcomes in many networks. Only Victoria recorded relatively stable productivity relating to capital inputs over the decade. For most networks, operating cost inputs also drove weaker productivity (only Tasmania achieved higher productivity in this area). Deteriorating network reliability also reduced productivity.

3.14.2 Distribution network productivity

The electricity distribution sector achieved an overall productivity gain of 5 per cent over the two years to 31 December 2017, comprising a 2.7 per cent rise in 2016 (the most positive outcome in over a decade) and a further 2.2 per cent in 2017.

Driving these gains were reductions in operating expenditure over both years, and in 2017, growth in customer numbers and a reduction in the number of minutes off supply. Network businesses lowered their operating expenditure through efficiency drives, including through workforce restructuring and redundancies. Savings in operating expenditure were greater than suggested by the benchmarking results, due to one-off costs associated with restructuring programs. Removing the cost of redundancy programs from the 2016 data would see the reported 2.7 per cent increase rise to 5.1 per cent, for example.

Regulatory incentives may be contributing to improved outcomes (section 3.13).

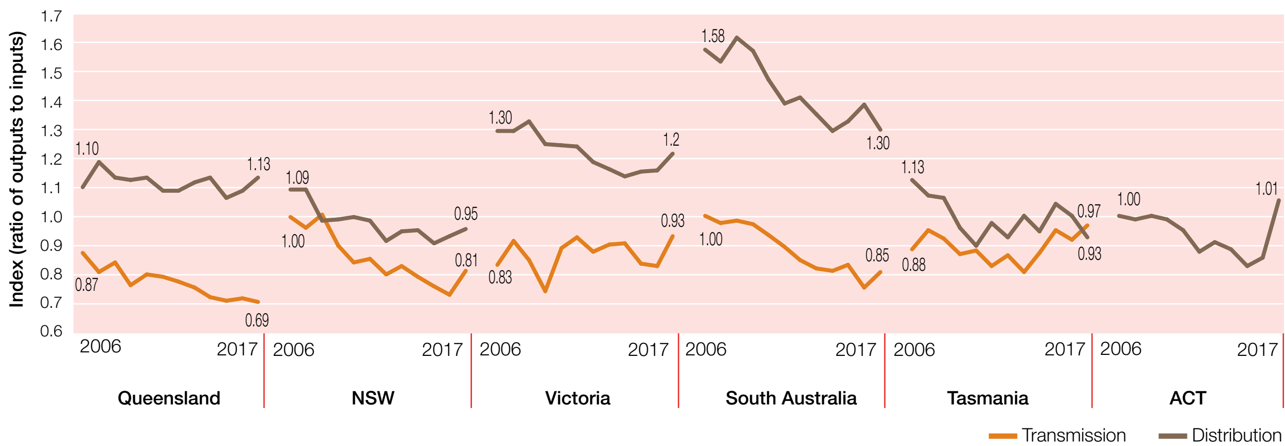
The productivity of 10 of the NEM's 13 distribution networks improved over the two years to December 2017. Powercor (Victoria), Energex and Ergon Energy (Queensland), Essential Energy and Ausgrid (NSW), and Evoenergy (ACT) each improved their productivity by over 5 per cent.

The only networks to record declining productivity were Jemena (Victoria), SA Power Networks (South Australia) and TasNetworks (Tasmania). The outcome for SA Power Networks mainly reflected increased operating expenditure to manage severe weather events. Similarly, TasNetworks faced higher operating costs due to bushfire and asset related risks.

CitiPower (Victoria) was the best performing network in 2017, followed by SA Power Networks (South Australia), United Energy and Powercor (Victoria). These four networks were consistently the best performers over the past 12 years. The AER's 2015 regulatory decision to scale back SA Power Network's operating expenditure contributed to improved outcomes for that network.

Government owned networks have improved their operating expenditure efficiency in recent years through efficiency

Figure 3.22
Electricity network productivity



Note: Index of multilateral total factor productivity relative to the 2006 performance of ElectraNet (South Australia). Distribution outcomes are averaged for jurisdictions with multiple networks (Victoria, NSW and Queensland). Data is not comparable to that published in *State of the energy market 2017* due to methodology changes (see AER, *Annual benchmarking report: electricity transmission network service providers*, November 2017, page 6). The ACT does not have a transmission network.

Source: AER, Annual benchmarking reports for electricity transmission and distribution networks.

reforms and restructuring, including by significantly reducing their workforce. While Ausgrid and Essential Energy (NSW) recorded among the poorest productivity outcomes in 2017, both are implementing reform programs to better manage their operating expenditure, as reflected in the AER's remade 2014–19 revenue decisions, and draft 2019–24 revenue decisions for those networks.

Recent improved outcomes come after a period of poor industry performance (figure 3.22). Distribution network productivity declined on average by 1.3 per cent annually over the nine years to 2015. Rising capital and operating expenditure (inputs) at a time of weakening electricity demand (output) drove these outcomes. Expenditure rose in part to meet stricter reliability standards in NSW and Queensland, and regulatory changes following bushfires in Victoria. The privately operated networks in South Australia and Victoria consistently recorded higher productivity scores over this period than government owned or recently privatised networks.

The decline in productivity plateaued from 2012 as the NSW and Queensland governments relaxed reliability standards, and new energy rules allowed the AER to scale back investment and cost proposals by some networks. In Tasmania, a merger between the transmission and distribution networks created opportunities to adopt new operational efficiencies. Similarly, the Queensland Government in 2016 merged its state owned electricity distributors to form a single parent company.

3.14.3 Investment disconnect

A key contributor to the poor productivity performance among electricity networks over the past decade was sustained investment growth at a time when electricity use was falling (figure 3.23). Investment rose almost continuously from 2006–12 in both transmission and distribution. But electricity transmitted peaked in 2008 in transmission and 2010 in distribution, before sharply declining in both sectors. The decline began earlier in transmission due to the losses of a number of industrial loads.

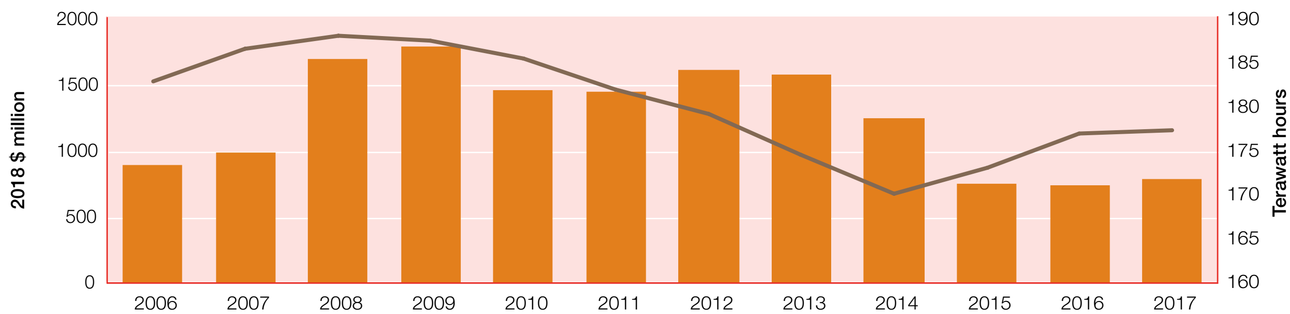
There were two key drivers of this mismatch between electricity use and new investment—a growing divide between maximum network demand and total electricity generated, and inaccurate forecasts of growth in maximum demand.

Network productivity is dependent on overall use of assets to meet a range of outcomes, including reliability. But capital expenditure was, to a large extent, driven by the need to meet the maximum level of demand on the network. As network demand becomes 'peakier', assets installed to meet maximum demand may sit idle (or be underused) for long periods. While total energy delivered fell over the period 2006–17 by 2.5 per cent, maximum demand increased on all networks by an average of 1 per cent each year.

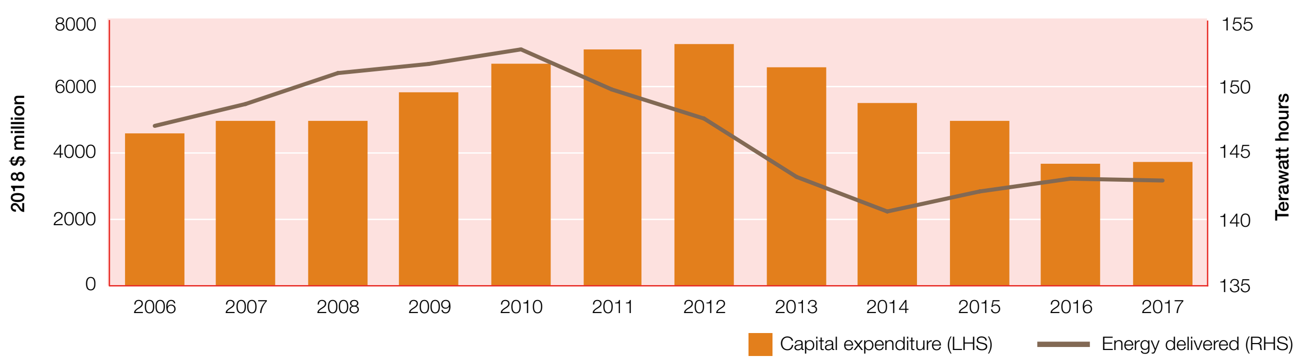
Demand response allows networks to meet short term peaks in demand without the need for investment in long lived assets (section 3.11.5).

Figure 3.23
Investment and energy delivered

Transmission



Distribution



Note: Energy transported through transmission networks includes deliveries to industrial customers that take supply directly off the transmission network. Data excludes energy delivered to other transmission networks via interconnectors. Physical losses account for some differences between transmission and distribution loads

Source: AER, Annual Benchmarking Reports 2018; RINs submitted by network businesses.

Forecasts by planning authorities and market participants consistently failed to capture a step change decline in electricity use and the flatlining of maximum demand that began around 2006. This is when customers began adopting energy efficiency measures and self-generating electricity with rooftop solar PV systems. A contraction in electricity use in the manufacturing sector also proved to be long term rather than cyclical.[51]

These inaccurate forecasts raised concerns the predicted growth in electricity demand could outstrip supply. In response, the energy rules were redrafted in 2006 to encourage new investment to meet demand growth that never eventuated. But that investment inflated the regulatory asset bases of electricity networks, which customers continue to pay for.

This over-investment contributed to poor productivity outcomes. The AER reported a declining trend in capital productivity for all transmission networks from 2006–17, except AusNet Services (Victoria).[52] In distribution, the AER found over-investment also drove weaker productivity, although to a lesser extent than growth in operating expenditure. Only Ergon Energy (Queensland) recorded an improvement in capital productivity over the period. But

51 AEMC, *Electricity Network Economic Regulatory Framework Review*, 18 July 2017, pp. 37–38.

52 AER, *Annual Benchmarking Report, Electricity transmission network service providers*, December 2018.

slower growth in capital inputs has contributed to improved productivity outcomes since 2012.[53]

3.14.4 Adapting to an evolving market

The AEMC found in 2018 that as the market evolves, the regulatory framework may discourage network businesses from making efficient choices between their capital and operating expenditure programs. This particularly impacts non-network (demand response) projects that can be offered by third parties. A traditional network solution to meet increasing consumer demand in an area might be to augment a zone substation, for example. But it may be more efficient to purchase services from a battery provider, or an aggregator of many small scale batteries, to reduce peak demand.

The current framework encourages businesses to favour (expensive) long lived capital expenditure solutions over cheaper operating expenditure alternatives, especially if the business' regulated rate of return is higher than current borrowing costs. AER incentive schemes seek to limit this bias. Another solution may be a more holistic approach to regulatory assessments of capital and operating expenditure programs. The AEMC will further explore these issues in 2019.

3.14.5 Network usage

Usage (or utilisation) rates are a partial productivity measure, indicating the extent to which a network's assets are being used to meet maximum demand. As noted above, network use can be improved by using demand response rather than additional network investment.

Capacity use tends to be higher in the privately owned distribution networks in Victoria and South Australia (58 per cent) than in networks that are fully or partially government owned (38 per cent). But since 2014, the partially privatised networks in NSW have improved outcomes (figure 3.24).

Usage rates declined almost continuously from 2006–15, from around 56 per cent to 45 per cent. A key factor underpinning the decline has been over-investment in new assets at a time of weakening electricity demand. Demand forecasts since 2004 consistently over-estimated the growth in maximum electricity demand. Networks investment in new assets was based on these inflated forecasts.

Usage rates improved after 2015 in NSW, South Australia and Queensland, reflecting lower levels of new investment. They also improved in Victoria in 2016, but eased in 2017. Usage rates for the ACT are more variable.

Underuse of assets raises concerns about asset stranding—where assets form part of the RAB but are no longer useful—if network businesses do not respond to changing conditions. The risk of stranded assets may become more acute as the uptake of decentralised generation transforms the industry. The electricity rules do not allow for regulatory asset bases to be adjusted to reflect asset stranding. This means network businesses have little incentive to avoid over-investment. Electricity consumers—who have to pay for stranded assets—may also have an incentive to seek ways to bypass the grid.[54]

3.15 Network reliability

Reliability refers to the continuity of electricity supply to customers. Many factors can interrupt the flow of electricity on a network. Interruptions may be planned (for example, due to the scheduled maintenance of equipment) or unplanned (for example, due to equipment failure, bushfires, extreme weather events, or the impact of high demand stretching the network's engineering capability). A serious 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 can also overload parts of a distribution network during extreme weather. Transmission network issues rarely cause consumers to lose power, but their effect is widespread. South Australia's catastrophic network failures in September 2016 caused the entire state to be blacked out, for example.

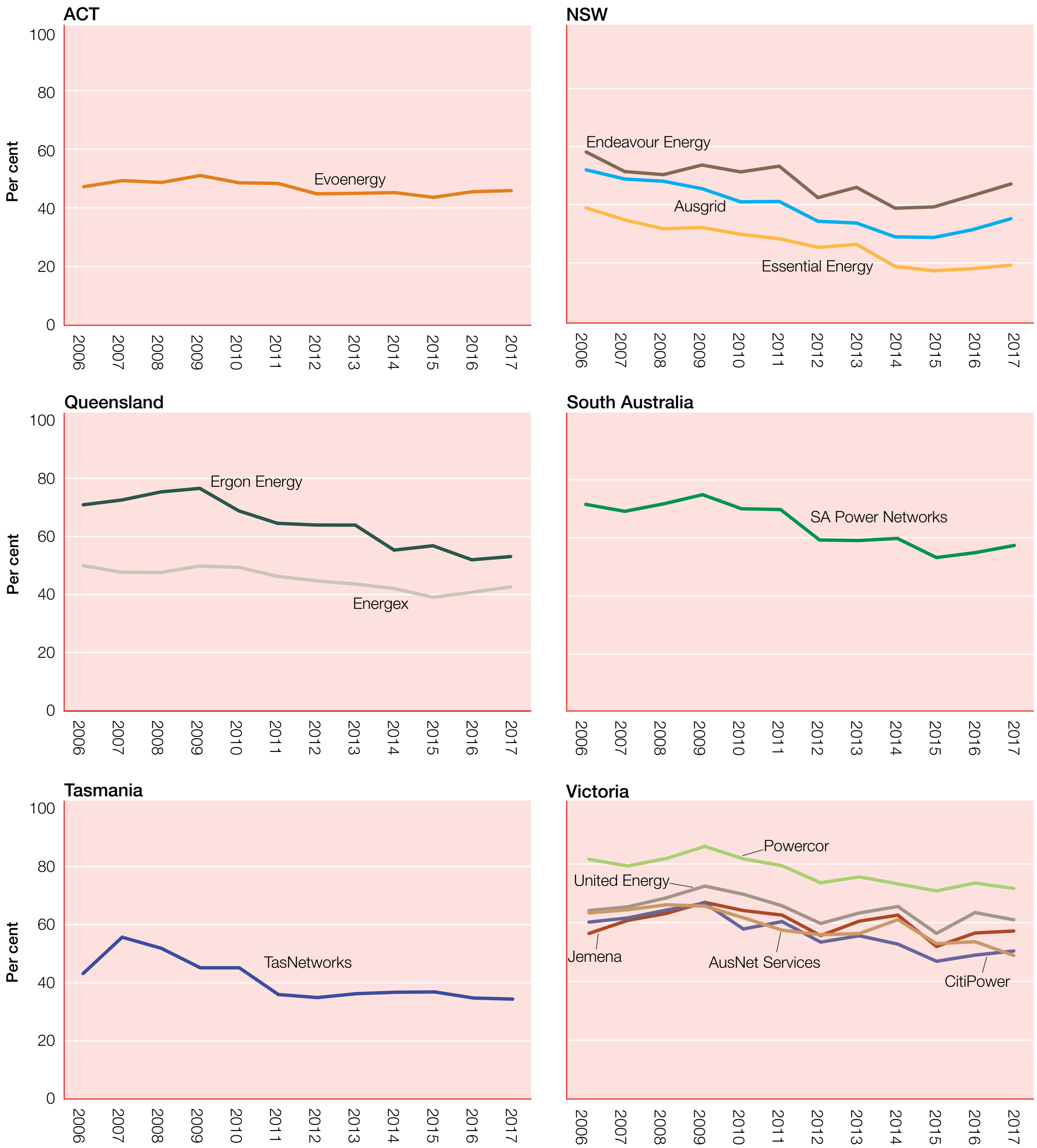
Electricity outages impose costs on consumers. Costs include financial losses resulting from lost productivity and business revenues, and intangible costs such as reduced convenience, comfort, safety and amenity.

Household and business consumers desire a reliable electricity supply that minimises these costs. But a reliable electricity supply requires investment in transmission and distribution in network assets, which is paid for by electricity consumers. These costs form a significant portion of consumer bills. There is, therefore, a trade-off between electricity reliability and affordability. It is important

53 AER, *Annual Benchmarking Report, Electricity distribution network service providers*, December 2018.

54 Grattan Institute, *Down to the wire—A sustainable electricity network for Australia*, March 2018.

Figure 3.24
Distribution network capacity usage



Note: Non-coincident summated raw system annual peak demand *divided by* total zone substation transformer capacity.
Source: AER, Annual Benchmarking Reports 2018; RINs submitted by network businesses.

that reliability standards strike the right balance by considering the value customers place on different levels of network reliability.

3.15.1 Reliability standards

State and territory governments set reliability standards for electricity networks that seek to efficiently balance the costs and benefits of a reliable power supply. Approaches to setting standards vary across jurisdictions. Strict reliability standards operated for several years in NSW and Queensland, for example, requiring substantial network investment that contributed to escalating power bills from around 2006–14.

More recently, governments have moved to a more consistent national approach to reliability standards, including factoring in the value consumers place on having a reliable power supply.

3.15.2 Valuing reliability

The COAG Energy Council agreed in 2014 that reliability standards should reflect the value customers place on reliability—that is, customers' willingness to pay for a reliable electricity supply, measured in dollars per kilowatt hour. Understanding how customers value reliability is an important consideration when balancing delivery of secure and reliable electricity supplies against reasonable costs for electricity customers.

A customer's valuation of reliability depends on many factors. These factors include the customer's access to alternative energy sources, their past experience of supply interruptions, and the duration, frequency, timing and location of an interruption. In particular, many outages occur on hot summer days when the networks are under strain and at capacity.

Understanding the value customers place on reliable supply in different parts of the network can help network businesses and planners deliver the right level of investment to meet customer needs on peak summer days. Expensive overbuilds can be avoided where they are not needed, while ensuring a reliable supply where and when customers want it the most.

AEMO surveyed customer reliability values in 2014, which were later used to set transmission reliability standards in Victoria, South Australia and, from July 2018, NSW.

The AER also uses the values as an input to its regulatory assessments for network businesses.[55]

In July 2018 the AER became responsible for calculating the price customers are prepared to pay for reliable electricity supply. The AER will estimate VCRs every five years based on consumer surveys, and update these annually. The values will have wide application, especially:

- in cost–benefit assessments such as those applied in regulatory investment tests
- in regulatory assessments of a network's investment forecasts in their revenue proposals
- as an input to assessing bonuses and penalties in the STPIS scheme
- in setting transmission and distribution reliability standards and targets
- to inform market settings such as wholesale price caps.

The AER will publish its first VCR estimates by December 2019.

3.15.3 Transmission reliability

Electricity transmission networks are engineered and operated to be extremely reliable, because an interruption may require the power system operator to disconnect a large number of customers (known as load shedding). To avoid this, the networks are engineered with sufficient capacity to provide a buffer against planned and credible unplanned interruptions to the power system.

Transmission reliability can be measured by indicators such as the number of lost supply events (figure 3.25) and the cost to customers of energy not supplied (figure 3.26).

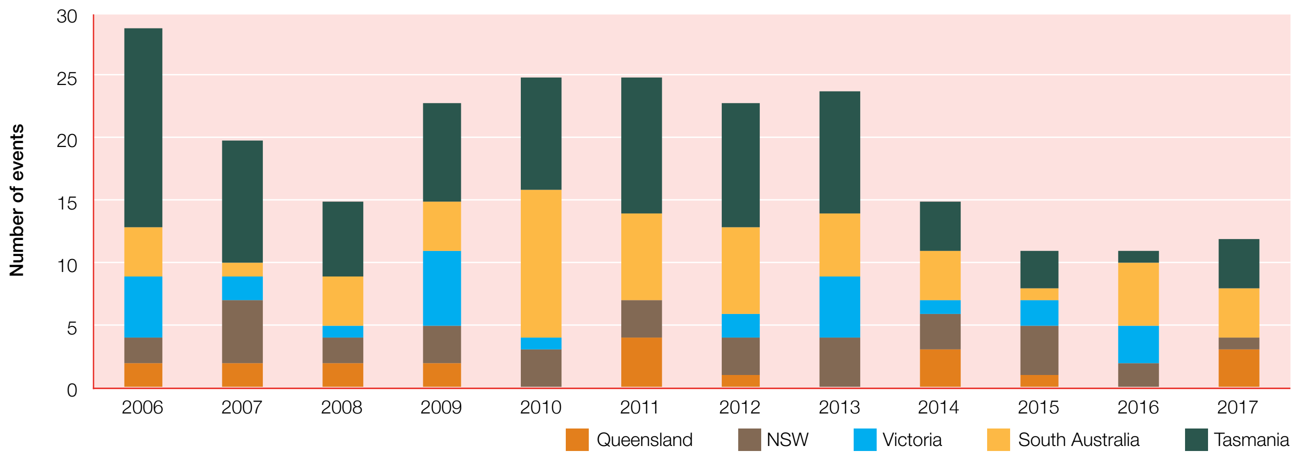
Across the NEM, total loss of supply due to transmission failures has occurred no more than 30 times per year since 2006. Recent outcomes have been lower, with 11–12 events occurring each year from 2015–17. Tasmania accounted for a significant share of outages until 2013, but has since recorded similar outcomes to other jurisdictions. South Australia and Tasmania each recorded four of the NEM's 12 loss of supply events occurring in 2017.[56]

Another measures of transmission reliability is the value to customers of energy not supplied due to network interruptions. While unsupplied energy is a very small proportion of total electricity transported (generally less than

55 The Hon Josh Frydenberg MP, *Non-controversial rule change proposal—Making the AER responsible for values of customer reliability,* 21 December 2017.

56 AER, *Electricity Transmission Network Service Provider Performance data*, April 2018.

Figure 3.25
Transmission reliability—number of lost supply events



Note: Loss of supply events are the number of times energy is not available to transmission network customers above a specific time period. The threshold varies between businesses from 0.05–1.0 system minutes as published in AER decisions on the STPIS. The thresholds may also vary between regulatory periods for each network.

Source: AER, *Electricity transmission network service provider performance report*, 4 September 2018.

0.005 per cent), the cost of a transmission outage can be high (figure 3.26).

Network congestion imposed significant costs on the Queensland market in 2007 and 2009, while network outages in Victoria associated with bushfires imposed extreme costs in 2009. After a number of years of more stable outcomes, the cost of transmission outages moved higher in 2015 and 2016 for networks in Victoria, NSW and South Australia.

Transmission network congestion

Service performance criteria differ between transmission and distribution networks. For transmission networks, service performance criteria include the efficient management of network congestion and system reliability.

All networks have capability limits. Congestion issues arise when electricity flows on a network threaten to overload the system, requiring intervention to maintain power system security. A surge in electricity demand to meet airconditioning loads on a hot day may push a network close to its secure operating limits, for example.

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 dispatched instead, for example. Congestion, therefore, raises electricity prices by displacing low cost generation with more expensive generation. At times, congestion causes perverse trade flows, such as a low priced NEM region importing electricity from a region with much higher prices.

Transmission congestion caused significant market disruption in 2006, when rising electricity demand placed strain on the networks (figure 3.27). But significant investment from 2006–14—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.

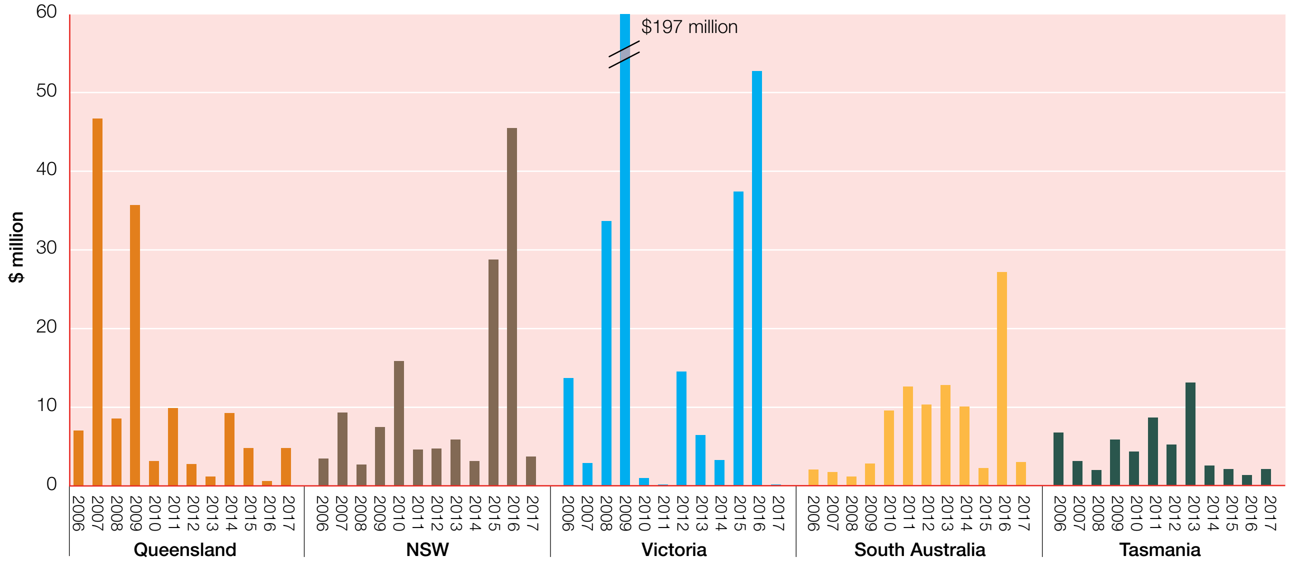
Higher congestion levels re-emerged from 2015, partly associated with outages associated with network upgrades in Queensland and on cross-border interconnectors linking Victoria with South Australia and NSW. Congestion was lower in South Australia in 2017 following completion of an interconnector upgrade.

Not all congestion is inefficient, however. Reducing congestion through investment to augment transmission networks is an expensive solution. Eliminating congestion is only efficient to the extent that the market benefits outweigh the costs of new investment.

Network businesses can help minimise congestion by scheduling planned outages, maintenance, and operating procedures to avoid peak periods. For this reason, the AER offers incentives for network businesses to reduce the market impact of congestion (discussed below).

Figure 3.26

Customer cost of energy not supplied due to supply interruptions



Note: Energy unsupplied includes major event days. Customer costs based on AEMO valuations of customer reliability made in 2014. Data is reported on a calendar year basis.

Source: AER, *2018 transmission network service provider benchmarking report*, *p. 32*; RINs submitted by network businesses.

3.15.4 Distribution reliability

In distribution, reliability—how effectively the network delivers power to its customers—is a central focus of network performance. Other aspects of network performance include complaints handling, timely notice of interruptions, promptness of new connections, call centre performance and the avoidance of wrongful disconnections.

Around 97 per cent of outages that electricity customers experience are due to issues in their local distribution network.[57] But the capital intensive nature of the networks makes it prohibitively expensive to invest in sufficient capacity to avoid all outages.

Reliability standards were historically set at high levels to protect customers from the cost and inconvenience of supply interruptions. Capital investment to ensure networks met those reliability standards drove network costs for several years. NSW and Queensland introduced more stringent reliability standards from around 2005, based on input methodologies that required significant investment. In contrast, Victoria placed more emphasis on reliability outcomes and the value customers place on reliability. A number of reviews found NSW and Queensland customers paid more than they should have due to unnecessarily high reliability standards. While Queensland and NSW began to relax reliability standards from 2014, the assets built to meet those high standards remain and customers continue to pay for them.[58]

Concerns that reliability driven investment was driving up power bills led the COAG Energy Council in 2014 to endorse a new approach to setting distribution reliability targets. The approach accounts for the value customers place on reliability, and the likelihood of interruptions.

Several jurisdictions subsequently reformed their distribution reliability standards. The Queensland Government removed strict input based reliability standards in 2014. Similarly, the NSW Government removed deterministic planning obligations from network licence conditions. It introduced a new approach focusing solely on 'output' standards, to allow network businesses more discretion in determining how to meet reliability standards.

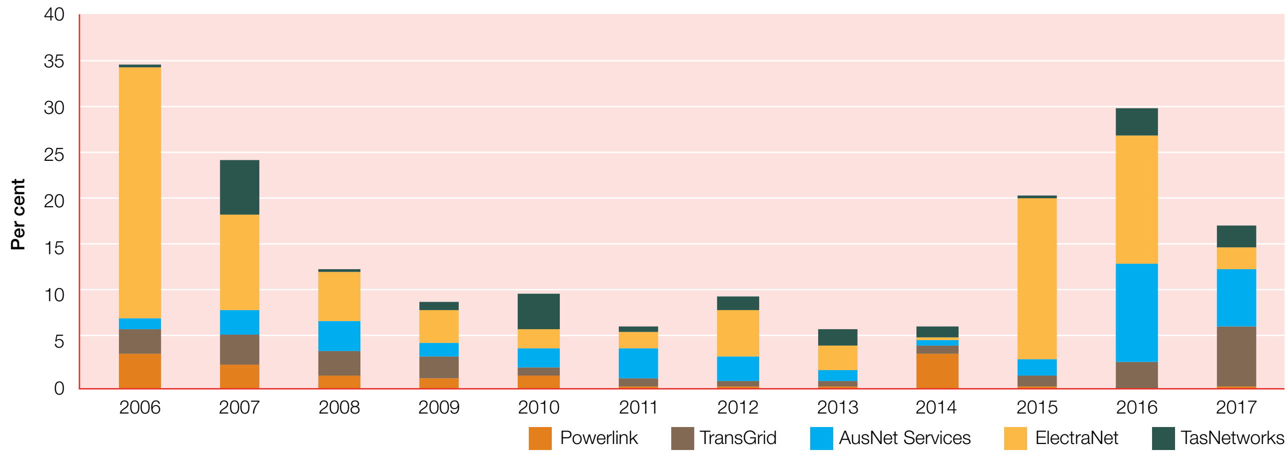
More recently, policy has focused on developing a consistent approach to estimating the value customers place on having a reliable electricity supply as a basis for setting standards (section 3.15.2).

57 Reliability Panel AEMC, *Annual market performance review 2017*, March 2018

58 ACCC, *Retail Electricity Pricing Inquiry—Final Report*, June 2018, p. 109.

Figure 3.27

Market intervals disrupted by transmission congestion



Note: Percentage of trading intervals each year where transmission network congestion impacted the NEM spot price by more than $10 per MWh. The data excludes outages caused by force majeure events and other specific exclusions.

Source: AER, *Electricity Transmission Network Service Provider Performance data*, April 2018.

The AER in 2018 examined setting up uniform distribution reliability measures across all jurisdictions to assess and compare the reliability performance of distributors. As part of this, it considered the extent to which outages beyond the control of a distributor should be excluded from the data—such as outages caused by the transmission network (which are currently usually excluded from reliability measures) and those caused by catastrophic events. It also explored new measures to capture the impact on customers most severely affected by outages.[59] The review will also inform revisions to AER incentives relating to network performance (section 3.15.5).

The AER in July 2018 also began work to estimate values of customer reliability. This work will have a range of applications, including as an input into setting reliability standards.

Distribution reliability indicators

Two widely used indicators of distribution reliability are:

- system average interruption duration index (SAIDI)
- system average interruption frequency index (SAIFI).

The SAIDI and SAIFI indicators measure the average duration and frequency respectively of unplanned outages experienced by distribution network customers. Figure 3.28 sets out data for each indicator. Comparisons across jurisdictions need to be made with care. In particular, the accuracy of businesses' information systems may vary. Environmental conditions and historical investment also differ across networks.

Across the NEM, a typical customer experiences around 250 minutes of outages per year, but outcomes vary between regions and over time. In particular, severe weather activity can affect reliability outcomes—cyclones affected a number of observations for Queensland, for example.

The average outage duration rose sharply in 2017 for South Australia, Queensland and NSW. South Australia's record outages reflect a state-wide blackout in September 2016. While the ACT has the lowest incidence of unplanned outage time in the NEM, outage duration also rose in 2017. Only Victoria and Tasmania recorded an improvement in outage duration, with Victoria recording its best performance in over a decade.

The frequency of unplanned outages generally declined over the past decade, with energy customers across the NEM typically experiencing around 1.5 outages each year. But outage frequency rose in South Australia, NSW and the ACT in 2017. The Victorian and Tasmanian networks reduced both the frequency and duration of power outages in 2017.

59 *AER, Draft distribution reliability measures guidelines, Explanatory statement*, June 2017.

Customer service by distributors

While reliability is the key service concerns for most customers, a distribution network's service performance also comprises:

- the timely notice of planned interruptions
- the quality of supply, including voltage variations
- wrongful disconnection and timeframes for reconnection
- being on time for appointments
- response time for fault calls
- the provision of fault information.

Individual jurisdictions set different service standards for these performance measures. Some jurisdictions apply guaranteed service level (GSL) schemes that require network businesses to compensate customers for inadequate performance. As reporting criteria vary by jurisdiction, performance outcomes are not directly comparable. The AER provides an annual summary for jurisdictions covered by the National Energy Retail Law (NSW, Queensland, South Australia, Tasmania and the ACT).[60] Victoria reports separately on performance.[61]

Between January 2017 and 30 November 2018, the AER issued 24 infringement notices to distribution businesses for failures to provide sufficient notice of outages to life support customers. Eight notices were issued to Energex (Queensland), six notices to Ausgrid (NSW), seven notices to TasNetworks (Tasmania), three notices to Evoenergy (ACT). The AER also accepted administrative undertakings from Energex and TasNetworks and a court enforceable undertaking from Ausgrid committing to improving their procedures and processes relating to life support customers.

3.15.5 Incentivising good performance

The AER runs incentive schemes that encourage good network performance. The schemes pay bonuses for good performance, and in some cases, apply penalties for underperformance.

Transmission incentives

The AER operates a service target performance incentive scheme (STPIS) that encourages transmission businesses to improve network performance in ways that customers value. It is designed as a counterbalance to the EBSS (section 3.13), to ensure businesses do not unreasonably cut operating and maintenance spending at the expense of service quality. The AER sets separate targets reflecting the circumstances of each network based on its past performance:

- A *service* component sets targets for the frequency of supply interruptions, outage duration, and the number of unplanned faults on the network.
- A *market impact* component encourages businesses to improve their operating practices to reduce network congestion—for example, by scheduling outages to minimise network disruption. A network business can earn bonuses/incur penalties of up to 1 per cent of its regulated revenue by eliminating outages with a market impact of over $10 per megawatt hour.
- A *network capability* component funds one-off projects to 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. AEMO helps prioritise projects that deliver best value for money to consumers, and the AER approves a project list. Network businesses can earn bonuses each year, but may face a penalty of up to 2 per cent of revenue in the final year of their regulatory period if they fail to achieve improvement targets.

The results are standardised for each network, to derive an 's factor' that can range from –1 (the maximum possible penalty) to +4.5 (the maximum possible bonus).

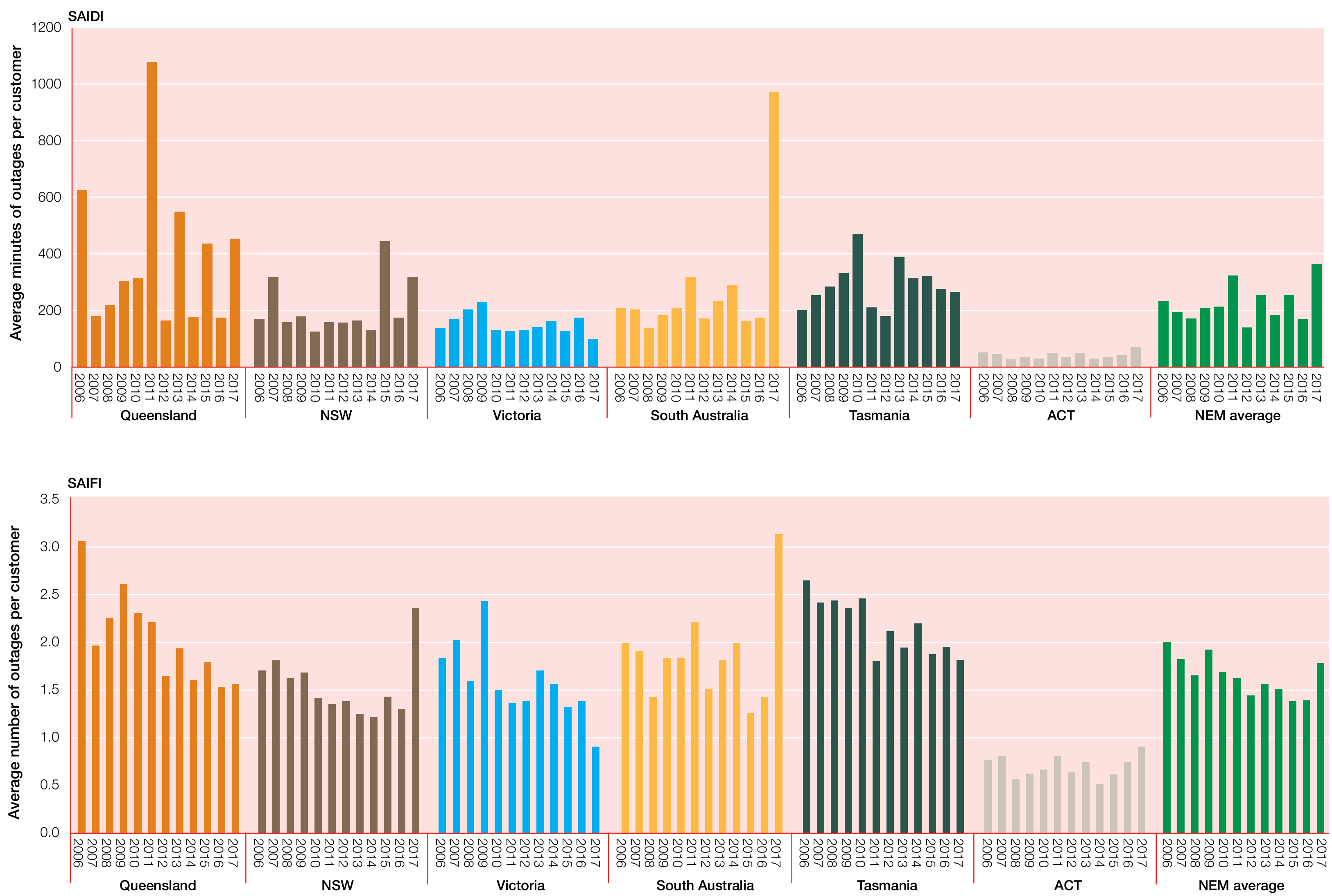
While performance against individual component targets varies, the networks have generally earned bonuses for above target performance.[62] The Murraylink (in 2016) and Directlink (in 2016 and 2017) interconnectors were the only networks to incur penalties for below target service performance in the past two years. Most networks performed above target on congestion management (market impact) and network capability targets. In total, the NEM's transmission networked earned around $57 million in performance bonuses in 2016, and $50 million in 2017.

60 AER, *Annual report on compliance & performance of the retail energy market 2016–17*, November 2017, appendix 3.

61 See, for example, Essential Services Commission 2017, *Victorian Energy Market Report 2016–17*, November 2017.

62 Service standards compliance reports for each network are available at www.aer.gov.au.

Figure 3.28
Electricity supply reliability



Note: The data reflects total *unplanned* outages experienced by distribution customers, including outages originating in generation and transmission networks. The data is *not* normalised for outages beyond the network operator's reasonable control. Data is for the 12 month period ending 30 June for all states except Victoria. Victorian data is for the calendar year ending in that period.

Source: AER economic benchmarking RINs.

3.16 Distribution incentives

The AER launched a STPIS for distribution networks in 2009, aimed at aligning network reliability with customers' valuations of that reliability. The STPIS sets targets for the average duration and frequency of outages based on a business's past performance, which is normalised to exclude interruptions beyond the network's reasonable control. The STPIS also accounts for customer service and faults, and call centre performance. A GSL component requires network businesses to pay customers if their performance falls below threshold levels. Performance outcomes are converted to an 's factor' reflecting deviations from targets.

The incentive scheme provides financial bonuses (and penalties) for network businesses that meet (or fail to meet) performance targets. The default bonus or penalty is 5 per cent of revenue. While the scheme aims to be nationally consistent, it has flexibility to deal with the operating environment of each network, resulting in larger bonuses or penalties in some instances. Outcomes are rewarded or penalised via the AER's annual tariff reviews for each network.

The SPTIS performance targets are adjusted every five years, based on the recent performance of each distribution business. Improvements in service performance will result in the benchmark performance targets being tightened in future years. A distributor must, therefore, maintain reliability improvements to continue benefitting under the scheme.

The STPIS has been applied to Victorian distribution networks since 2011. Among all the Victorian businesses, only Jemena has outperformed its targets every year.

Queensland networks Energex and Ergon Energy have exceeded their performance targets each year since the scheme was applied in 2012. South Australian and Tasmanian networks have also outperformed their targets in most years since the scheme commenced in 2012 and 2013 respectively. For ACT and NSW networks, the STPIS was first applied for the 2015–19 regulatory period.

The AER reviewed the scheme in 2018, examining how financial bonuses and penalties are calculated and how renewable energy and distributed generation affect the scheme's operation.

Victoria's distribution 'f factor' scheme

The AER administers a Victorian Government scheme offering incentives to Victorian distributors to lower the number of fire starts originating from their network. This 'f factor' scheme provides strong incentives to reduce the number of fire starts in high fire danger zones and times. Incentives may be as high as $1.48 million per fire start avoided in high risk areas on a code red day. But if the number of fire starts rises, the networks pay a penalty.

All businesses outperformed their benchmark targets during 2016–17.[63] Incentive payments varied from around $43 000 for the small, predominantly urban CitiPower network, to $4.6 million for the large and predominantly rural Powercor network.

Distributors will only continue to receive payments if they make sustained and continuous improvements in fire start performance. Once improvements are made, the benchmark fire start targets are tightened in future years.

63 AER, *Victoria F-factor scheme results for 2016–17 reporting period*, Media release, 29 June 2018.


Image courtesy of Cooper Energy

4 GAS MARKETS IN EASTERN AUSTRALIA

Gas is a fossil fuel consisting mainly of methane, a naturally occurring hydrocarbon made up of one carbon atom and four hydrogen atoms. Gas 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 of this report). It begins with the exploration and appraisal of potential reserves for commercial viability. Gas discoveries are extracted through wells as 'wet gas', which is 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, over 60 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 drawn on to augment supply at peak times.

Gas sold to domestic customers is transported from production fields to major demand centres or hubs via high pressure *transmission pipelines*. 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. Applying 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 'upstream' gas markets in which the Australian Energy Regulator (AER) has regulatory responsibilities (illustrated in figure 4.1). The upstream sector encompasses gas production, wholesale markets for trading gas and Insert the transport of gas along transmission pipelines to demand hubs.

The chapter's principal focus is on the eastern gas market, encompassing 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 in south east Queensland, north east South Australia, and offshore basins in Victoria.

The AER's regulatory responsibilities in the eastern gas market relate to wholesale market monitoring and enforcement, and gas pipeline regulation. It also has responsibilities in the downstream sector, both in gas distribution (chapter 5) and gas retailing (chapter 1).

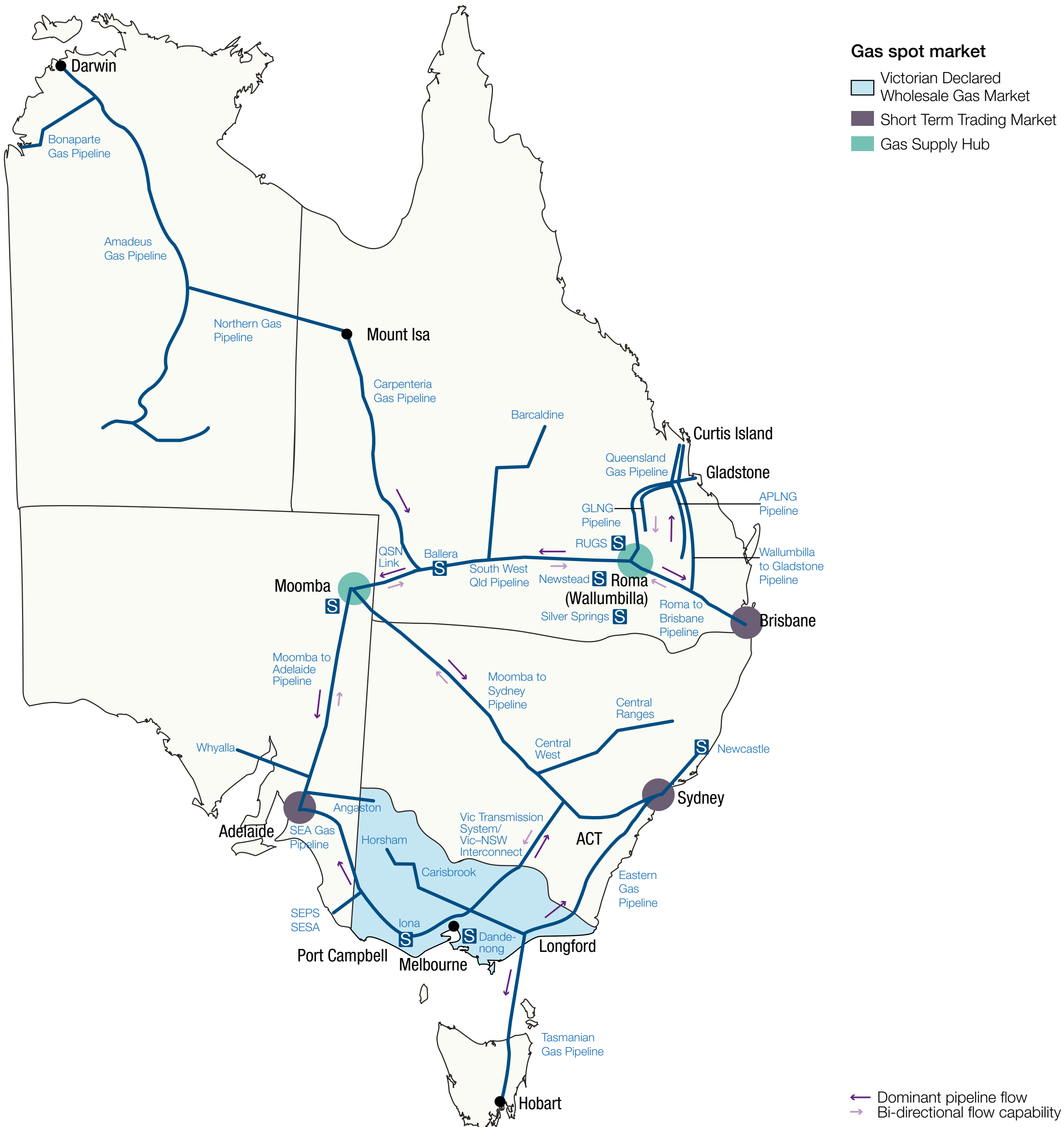
Outside the eastern gas market, the AER is the gas pipeline regulator for the Northern Territory, but plays no role in the territory's wholesale market. The AER has no regulatory function in Western Australia, where a separate regime applies.[2] The AER's role in gas markets is summarised in box 4.1.

Gas production in eastern Australia began around 50 years ago. The main production basins are the Surat–Bowen Basin in Queensland, the Cooper Basin in South Australia and three basins off coastal Victoria, the largest of which is the Gippsland Basin. 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, because the rapid responsiveness of gas powered turbines make them suitable for peak electricity generation capacity and combined cycle intermediate load generation. Gas powered generation also plays an important role in managing fluctuations in intermittent wind and solar generation. More recently, gas has become a major export industry in eastern Australia, with the launch in 2015 of major LNG projects.

2 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 4.1
Eastern gas markets, major pipelines and storage



Source: AER; Gas Bulletin Board.

Box 4.1 The AER's role in gas markets

The Australian Energy Regulator 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, 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. Our focus areas include data quality and market behaviour, and the readiness of market participants to comply with reforms occurring in the market. In 2018 we launched a more stringent compliance framework for the Bulletin Board to ensure the integrity of the information it provides. We also began administering new civil penalty provisions relating to breaches.

We draw on our market monitoring capabilities to regularly report on gas market activity. In 2018 we began publishing data on prices and liquidity in spot gas markets, which we update regularly. We also monitor the markets for particular irregularities and wider inefficiencies. Our monitoring role at the Wallumbilla and Moomba hubs includes an explicit focus on detecting price manipulation.

Alongside our work in gas wholesale markets, we are the economic regulator for two major transmission pipelines in eastern Australia and one in the Northern Territory. We also arbitrate disputes relating to 'light regulation' pipelines and may appoint an arbitrator to settle disputes affecting other pipelines.[a]

From 2019 we will monitor and enforce compliance with reforms to improve access to underused capacity in transmission pipeline, including bilateral trading and mandatory auctioning of contracted capacity that is not in use.

In the downstream gas industry, we set 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, NSW, Queensland, South Australia and the ACT (chapter 1).

Across the gas sector, we draw on our regulatory and monitoring work to advise policy bodies and other stakeholders on market trends, policy issues and irregularities. Where appropriate, we propose or participate in reforms to improve the market's operation. Our current work in this area includes providing resources to the Australian Competition and Consumer Commission's 2017–20 gas inquiry.

a. The different tiers of pipeline regulation are outlined in chapter 5.

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 pipeline investment has interconnected these markets, making it possible to transport gas from Queensland to the southern states, and (since key pipelines became bi-directional) vice versa. This interconnected network further expanded with the opening in December 2018 of the 622 kilometre (km) Northern Gas Pipeline linking Tennant Creek in the Northern Territory with Mount Isa in Queensland. For the first time, the new pipeline allows the eastern gas market to source gas from the Bonaparte Basin in the Timor Sea (located between the Northern Territory and East Timor).

The development of Queensland's LNG industry transformed the eastern Australian gas markets, giving producers choice between exporting their 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 following the closure of several coal fired generators in 2016 and 2017.

4.2 Gas demand in eastern Australia

Domestic customers in eastern Australia used around 630 petajoules (PJ) of gas in 2017. These customers included commercial and industrial (C&I) businesses, electricity generators and households. C&I customers are the biggest users, consuming 41 per cent of gas sold to the

Figure 4.2

Gas consumption in eastern Australia

Note: Data for 2010–15 is average annual consumption over that period.

Source: AEMO, *National gas forecasting report*, 2016; AEMO, *2018 Gas Statement of Opportunities,* June 2018.

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.

The electricity sector is another major customer, using gas to fuel generators. Gas powered generation accounted for 29 per cent of domestic gas sales in 2017. The remaining 30 per cent was sold to residential and commercial customers, for purposes such as heating and cooking.[3]

Reliance on gas is highest in South Australia, where it accounts for 41 per cent of primary energy consumption, followed by Queensland and Victoria (20 per cent in each). Gas reliance is lower in NSW, where it accounts for 10 per cent of energy consumption.[4] South Australia's high degree of reliance on gas reflects its dependence on gas powered generation, which has risen since the closure of major coal fired generators.

The composition of domestic gas consumption differs across jurisdictions (figure 4.2). In South Australia, electricity generation accounted for 66 per cent of gas demand in 2017. Industrial demand dominates in Queensland, while industrial and residential demand are roughly equal as the main components in NSW.[5]

Victoria is the only state where a majority of demand (55 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.[6] Around 35 000 new residential gas connections were made in Victoria each year from 2014–18, in part due to new housing developments as the state's population grows.[7] Residential gas penetration is around 80 per cent in the ACT, 60 per cent in South Australia, 45 per cent in NSW, 10 per cent in Queensland and 6 per cent in Tasmania.[8]

Domestic gas demand (and its composition) is shifting over time. Total consumption has declined since 2014, mainly

3 AEMO, *2018 Gas Statement of Opportunities*, June 2018. Calendar year data for 2017.

4 Department of the Environment and Energy, *Australian Energy Statistics 2016–17*, Table C.

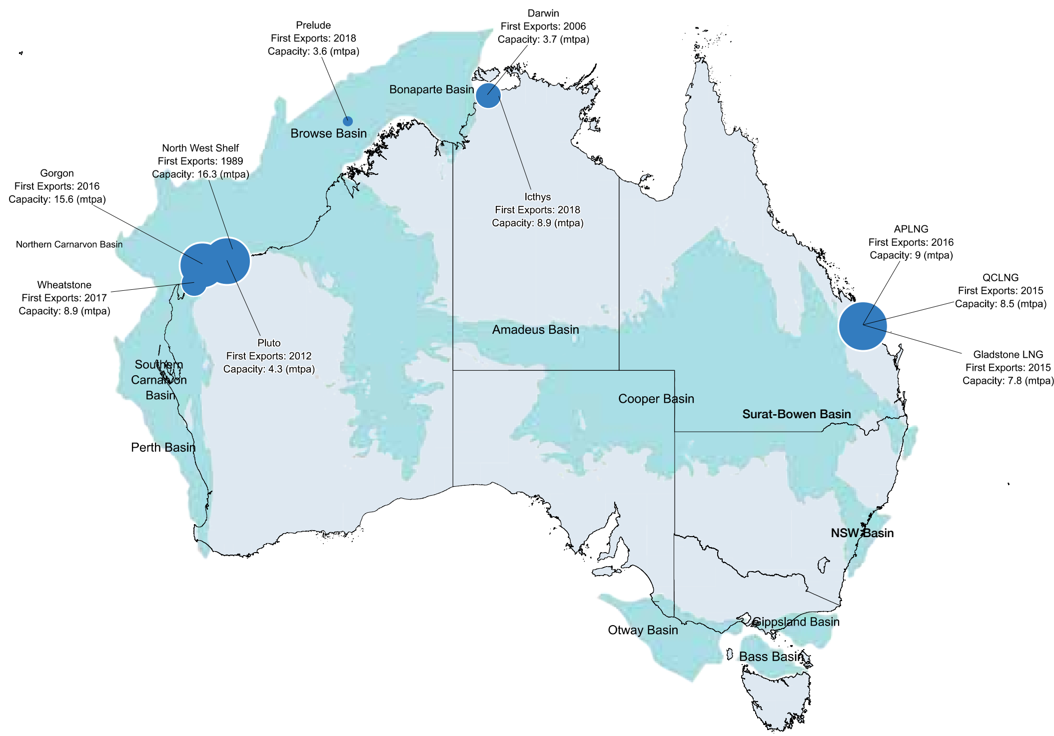
5 AEMO, *2018 Gas Statement of Opportunities*, June 2018, p. 15

6 AEMO, *National Gas Forecasting Report—2016*.

7 AEMO, *Winter 2018—Victorian Gas Operations outlook*, 8 May 2018.

8 AEMO, *National Gas Forecasting Report,* December 2016.

Figure 4.3
Australia's LNG export projects



Note: Capacity in million tonnes per annum (mtpa).
Source: AER.

because competition for gas supplies by the LNG industry drove up fuel prices for gas powered generators, making it less economical to run that plant. Higher gas prices also reduced industrial consumption. The closure of coal fired generators in South Australia and Victoria led to a recovery in consumption by gas powered generators in those regions in 2017 (section 4.9.1).

4.3 Liquefied natural gas exports

Eastern Australian gas producers exported 1145 PJ of gas in 2017–18, compared to 740 PJ of sales to domestic customers (table 4.1).

Gas exports are converted to LNG for efficient shipping. LNG is produced by cooling gas and condensing it to a liquid so it to make it easier to store and transport. The gas is chilled to –162 deg Celsius, which shrinks volume by 600 times and makes it economic to ship gas in large quantities.

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. Most Australian LNG is shipped to Asia, where it is stored, regasified and injected into local gas pipeline networks.

Alongside Queensland's LNG industry, Australia operates five LNG projects in Western Australia, and two in the Northern Territory (figure 4.3). More than $230 billion has been invested in the industry over the past decade[9], and in 2018 Australia was the world's second largest LNG

9 COAG Energy Council, *Gas Market Reform Package—Bulletin Two*, August 2016.

exporter.[10] Prices and revenue in the industry surged during 2018 due to rising oil prices and strong Chinese demand. In 2017–18 LNG exports earned Australia $31 billion, making gas Australia's third largest resource and energy export, behind coal and iron ore.[11]

4.3.1 Queensland LNG industry

As noted above, Queensland's LNG industry has transformed the eastern Australian gas market. The industry is based around three major projects at Gladstone, which liquefy and purify gas shipped along gas transmission pipelines from where it is extracted in the Surat–Bowen Basin. The projects—the world's first to convert CSG to LNG—were made possible by the basin's vast CSG reserves. The industry's scale is enormous, even by global standards.

The *Queensland Curtis LNG (QCLNG) project* began exporting LNG in January 2015, and launched a second train (liquefaction and purification facility) in July 2015. Shell is the principal owner (73.75 per cent through its ownership stake in BG Group). China National Offshore Oil Corporation (CNOOC) owns 25 per cent of the project and Tokyo Gas a 1.25 per cent interest. The project has capacity to produce 8.5 million tonnes of LNG per annum (mtpa). In December 2017 QCLNG contracted with Arrow—a joint venture between PetroChina and Shell—to buy the majority of gas produced from Arrow's substantial reserves.[12] In 2018 it contracted to use APLNG's pipeline network to transports this gas to market.[13]

The *Gladstone LNG (GLNG) project* commissioned its first train in October 2015, and a second in May 2016. Santos (30 per cent), Petronas and Total (27.5 per cent each), and Kogas (15 per cent) own the project. The ramp-up to full production was slower than expected, with the project initially relying on third party gas for 50 per cent of its plant feedstock. By 2018 this ratio had fallen to around 30 per cent.[14] The project has capacity to produce 7.8 mtpa. In May 2018 GLNG committed to invest more than $400 million in the Arcadia gas project in the Bowen Basin to supply additional gas to its LNG plant.[15]

The *Australia Pacific LNG* (*APLNG) project* began exporting gas in January 2016. Origin Energy and ConocoPhillips (37.5 per cent each), and Sinopec (25 per cent) own the APLNG project, which has capacity to produce 9 mtpa.[16] The project's second train began operating in October 2016, although operation testing delayed formal commissioning until 2017. APLNG's financial obligations required it to demonstrate its LNG trains could run at maximum output for an extended time without technical difficulties.

4.3.2 Northern Territory LNG industry

The Northern Territory's LNG industry began in 2006 with the commissioning of Darwin LNG, which relies on gas feedstock from the Bonaparte Basin in the Timor Sea. A second project—Ichthys LNG—launched in 2018. The project transports gas by undersea pipeline from the North West Shelf off Western Australia to onshore processing facilities near Darwin. Ichthys LNG's onshore facilities include two LNG trains. After repeated delays installing its offshore facility (including due to bad weather conditions), gas production from the project's offshore wells began in July 2018.[17]

4.3.3 Western Australia LNG industry

Western Australia has five LNG projects. 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.

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 (2018). Prelude expects to begin exporting in late 2018.

4.4 Gas reserves

Gas reserves are known but unexploited accumulations of gas that are anticipated to be commercially recoverable. Data on gas reserves are an important input to forecasting supplies of gas that may enter the market in the future.

Different measures of gas reserves are quoted, based on geological, engineering and commercial analysis of the likelihood of successful recovery:

10 Department of Industry, Innovation and Science, *Resources and Energy Quarterly*, March 2018
11 Department of Industry, Innovation and Science, *Resources and Energy Quarterly*, September 2018, p. 51.
12 Arrow Energy, *Surat Gas Project*, www.arrowenergy.com.au/Operations/Arrow-in-the-Surat-Basin/surat-gas-project.
13 APLNG, *Australia Pacific LNG to share infrastructure and secure additional gas supply to diversify portfolio*, 5 November 2018.
14 EnergyQuest, *Energy Quarterly, September 2018*, p. 14.
15 Australian Financial Review, *Santos commits to $400m Arcadia gas project to bolster GLNG* supplies, May 2018.
16 APPEA, *Australian LNG* projects.
17 EnergyQuest, *Energy Quarterly,* September 2018, p. 103.

- *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 sure 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*—those considered potentially recoverable from known accumulations, but for other reasons are not yet technically or commercially recoverable.

This probabilistic approach to measuring gas reserves results in frequent, and sometimes substantial, adjustments. Eastern Australia's 2P reserves, for example, were written down by around 2000 PJ between June 2017 and June 2018, mostly attributable to large write downs in Arrow Energy's reserves in Queensland.[18]

Nor is there clear, consistent and accurate *reporting* of gas reserves in Australia, with data collected through various disconnected mechanisms and bodies. There is little consistency in data standards and aggregation across these sources, and the assumptions underlying the data are often not transparent.[19]

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. EnergyQuest estimated eastern Australia's 2P gas reserves stood at 42 907 PJ in August 2018, but noted this estimate is subject to uncertainty.[20]

The Australian Competition and Consumer Commission (ACCC) is undertaking work to improve transparency in this area, and expects to commence publishing reserves and resources information in December 2018. The Gas Bulletin Board (section 4.8.6) will also begin publishing information on gas reserves in 2019.

18 EnergyQuest, *Energy Quarterly,* September 2018, p. 27.
19 ACCC, *Inquiry into the east coast gas market*, April 2016.
20 EnergyQuest, *Energy Quarterly*, September 2018, p. 12.

4.4.1 Ownership of gas reserves in eastern Australia

Reserve ownership is highly concentrated in some basins, but more diverse across the market as a whole (figure 4.4). Shell (26 per cent) became the largest holder of 2P gas reserves in eastern Australia after acquiring BG Group in 2016 (figure 4.5). Other major reserve holders include ConocoPhillips and Origin Energy (which each hold 11 per cent), and PetroChina (9 per cent).

Falling LNG prices and declining share prices for LNG participants from 2015 prompted a number of takeover bids, including Shell acquiring BG Group. Santos rejected a takeover bid by private equity fund Sceptre Partners in October 2015 and another bid by Harbour Energy in May 2018.[21]

In September 2017 Beach Energy purchased Origin Energy's conventional upstream gas business (Lattice Energy), tripling its market share in 2P reserves. In addition, Mitsui completed its takeover of Australian Worldwide Exploration on 2 May 2018, providing Mitsui with an interest in the Bass Basin.

4.4.2 Surat–Bowen Basin

Queensland's Surat–Bowen Basin is the largest basin in eastern Australia, with almost 90 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.

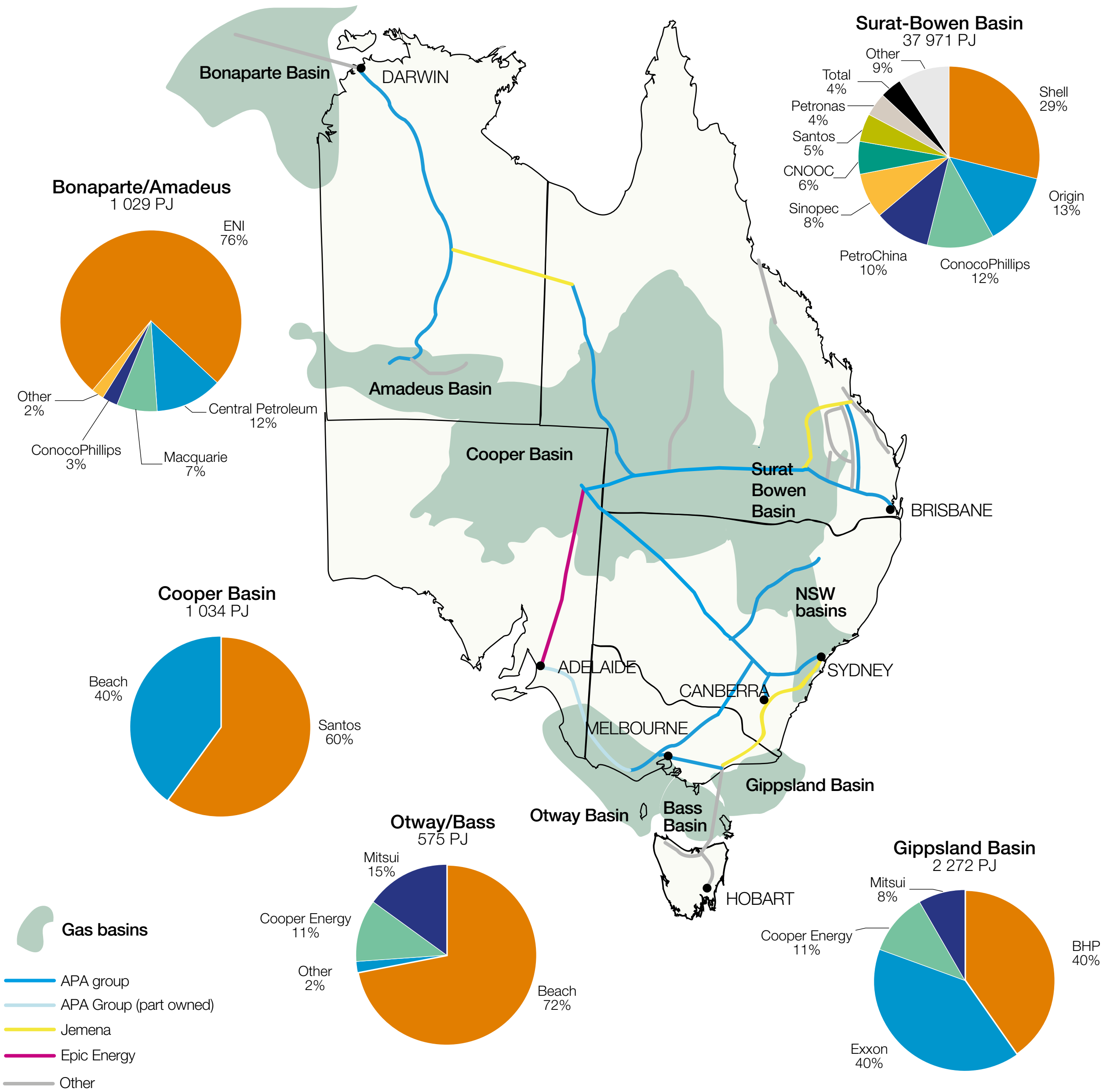
Participants in Queensland's three LNG projects control a majority of reserves in the basin, which are mostly CSG. Shell (29 per cent) is the largest equity holder, followed by Origin (13 per cent), ConocoPhillips (12 per cent), PetroChina (10 per cent), Sinopec (8 per cent), CNOOC (6 per cent), Santos (5 per cent), Petronas (4 per cent) and Total (4 per cent).

4.4.3 The Victorian basins

The Gippsland Basin is the most significant of the three producing basins in Victoria, accounting for 5 per cent of eastern Australian reserves. A joint venture between Esso (ExxonMobil) and BHP controls 80 per cent of reserves in the basin. The principal producers in the smaller Otway Basin and Bass Basin are Beach Energy (72 per cent), Mitsui (15 per cent) and Cooper Energy (11 per cent).

21 Australian Financial Review, *Santos rejects Harbour Energy's $14.4b takeover bid*, 22 May 2018.

Figure 4.4
Eastern gas market—basin and transmission pipeline ownership

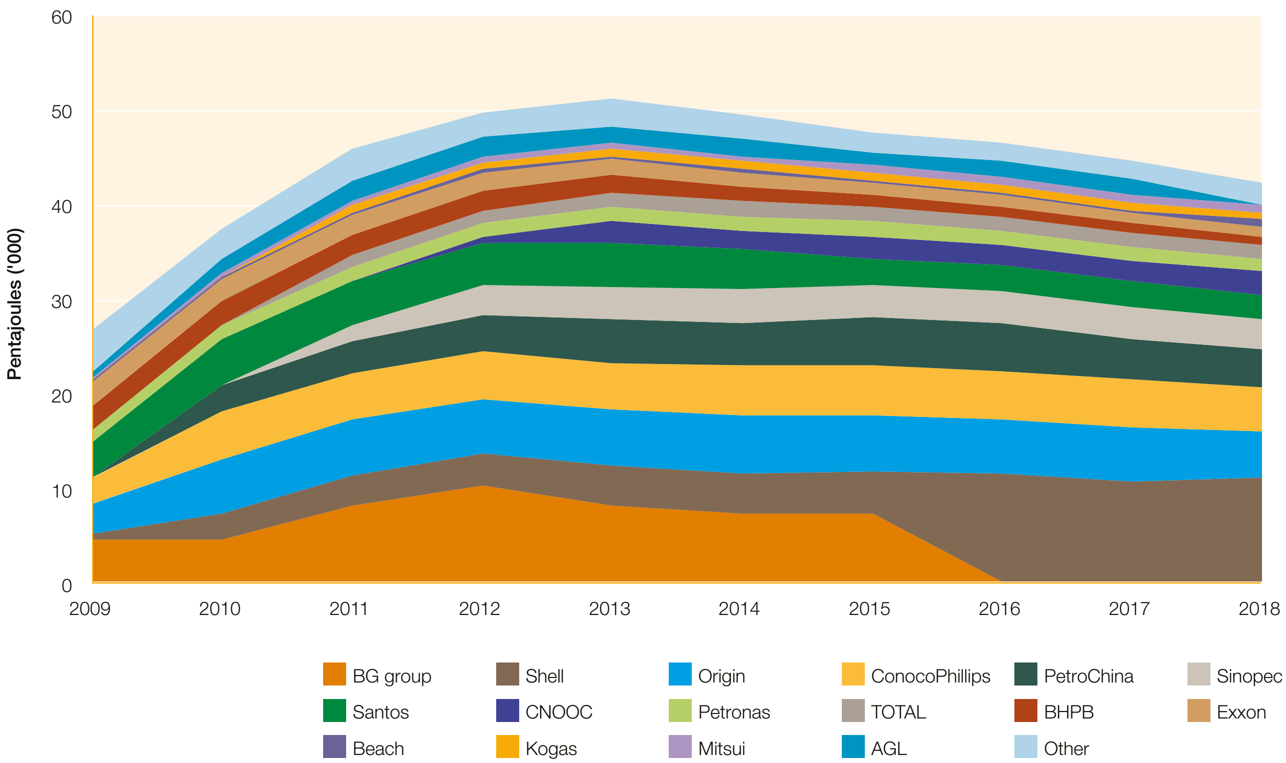


Note: Ownership at 30 June 2018. Pie charts illustrate shares in 2P (proven plus probable) gas reserves by basin.

Source: AER; EnergyQuest (data commissioned by AER).

Figure 4.5

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).

Reserves in the Victorian basins are declining. In the year to June 2018, 2P reserves fell by 14 per cent in the Bass Basin and by 12 per cent in the Gippsland Basin, partly offset by a 43 per cent increase in reserves in the Otway Basin.[22] EnergyQuest noted considerable volatility in reserve assessments for Victoria, describing some recent revisions and updates as 'confusing'.[23]

4.4.4 Cooper Basin

The Cooper Basin in central Australia has around 1000 PJ of 2P reserves and almost 6000 PJ of contingent resources. A joint venture led by Santos (66 per cent) and Beach Petroleum (34 per cent) controls most reserves in the basin, which accounts for 2 per cent of eastern Australia's 2P reserves. Other participants in the basin include Senex, Icon Energy, Strike Energy and Real Energy.

Santos entered an agreement in 2010 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 more recently, and rose in the year to June 2018. Almost 75 per cent of contingent resources in the Cooper Basin are from unconventional sources, primarily shale gas. Extracting these resources presents significant technological challenges.

4.4.5 NSW basins

NSW has significant contingent resources (2254 PJ) but less than 30 PJ of 2P reserves, and negligible current production. Santos in 2017 applied to develop reserves near Narrabri in the Gunnedah Basin. The project prompted widespread opposition, with over 20 000 submissions being made during the environmental impact statement process.

22 EnergyQuest, *Energy Quarterly,* September 2018, Table 23. p. 66.
23 EnergyQuest, *Energy Quarterly,* September 2018, Table 23. p. 25.

Table 4.1 **Gas basins serving eastern Australia**

GAS BASIN	GAS PRODUCTION—12 MONTHS TO JUNE 2018			2P GAS RESERVES (AUGUST 2018)	
	PETAJOULES	SHARE OF EASTERN AUSTRALIAN SUPPLY (%)	CHANGE FROM PREVIOUS YEAR (%)	PETAJOULES	SHARE OF EASTERN AUSTRALIAN RESERVES (%)
Surat–Bowen (Qld)	1 368	73	8	37 971	88
Cooper (SA–Qld)	84	4	3	1 034	2
Gippsland (Vic)	291	15	–4	2 272	5
Otway (Vic)	68	4	–21	502	1
Bass (Vic)	18	1	20	73	0
Sydney and Narrabri (NSW)	6	0	9	26	0
Amadeus (NT)	10	1	68	199	0
Bonaparte (NT)	38	2	–1	830	2
Eastern Australia total	1 883		4	42 907	
Domestic gas sales	738		3		
LNG exports	1 145		5		

2P, Proven plus probable reserves estimated to be at least 50 per cent sure of successful commercial recovery.

Note: Most production and reserves in the Surat–Bowen and NSW basins are CSG. Production and 2P reserves in other basins are mainly conventional gas.

Source: EnergyQuest, *Energy Quarterly*, September 2018.

4.4.6 Northern Australia

Northern Australia was historically insulated from the eastern gas market, but the commissioning of the Northern Gas Pipeline in 2018 changed this situation by linking gas fields in the Bonaparte Basin (offshore of Darwin in the Timor Sea) with Queensland.

The Amadeus Basin historically met all gas demand in the Northern Territory. The basin has around 200 petajoules of 2P reserves but has been in decline. The offshore Bonaparte Basin was developed to support the Northern Territory's LNG industry, which is based in Darwin. The basin is currently estimated to have over 800 PJ of 2P reserves. Most gas produced in the basin is converted to LNG for export. Eni is the major equity holder in the Northern Territory basins, with 76 per cent of 2P reserves, followed by Central Petroleum (12 per cent), Macquarie (7 per cent), ConocoPhillips (3 per cent).

4.5 Gas production

In the year to June 2018, eastern Australia produced almost 1900 PJ of gas, with a majority (61 per cent) exported as LNG. The remainder was sold to the domestic market (table 4.1).

Queensland's Surat–Bowen Basin supplied 73 per cent of gas produced in eastern Australia in the year to June 2018, including much of the gas earmarked for LNG export. Gas production in the basin has risen exponentially since 2014. Participants in Queensland's three LNG projects produced over 95 per cent of the basin's output in the year to June 2018. 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 15 per cent of demand. The smaller Otway and Bass basins jointly supply 5 per cent of the market.

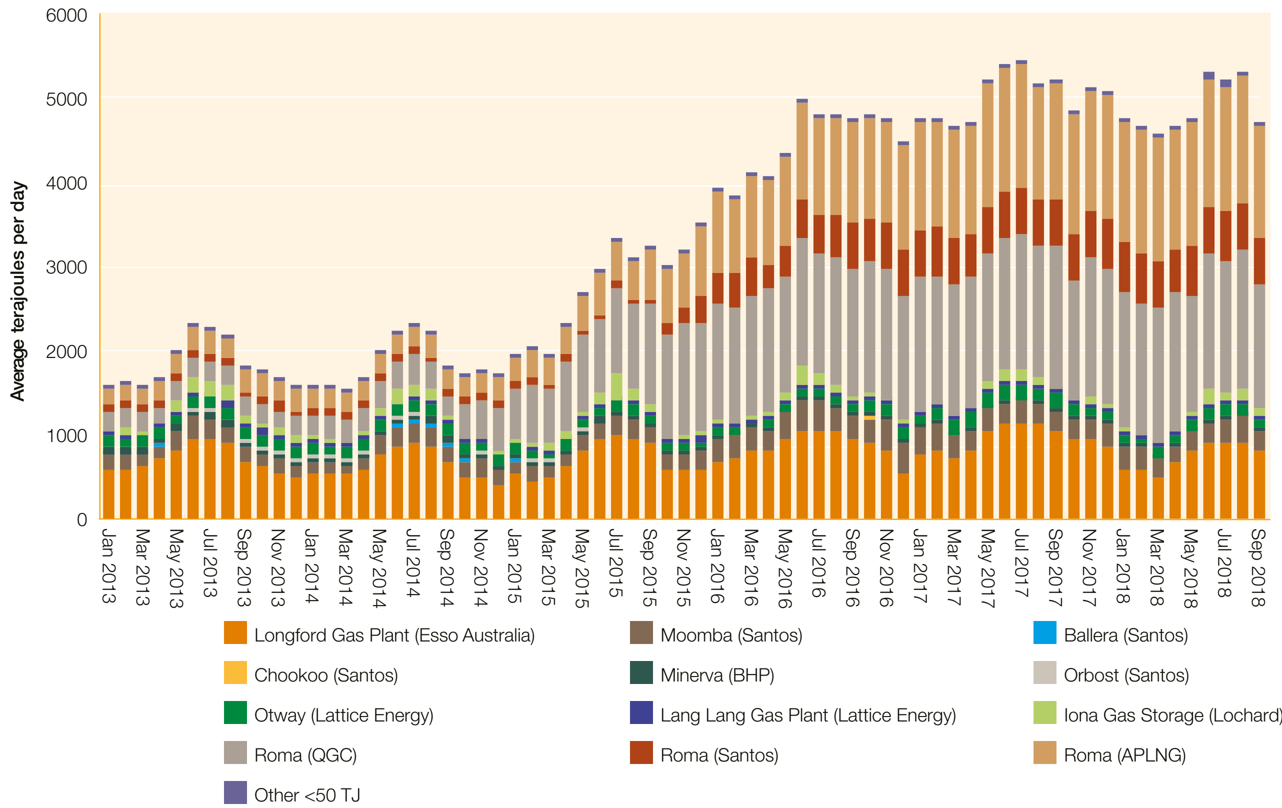
The Longford gas plant, servicing the Gippsland Basin, achieved record production in 2017, some of which was shipped to Queensland for LNG exports (figure 4.6). But production is expected to decline in 2018 and beyond. Despite falling reserves, the Australian Energy Market operator (AEMO) forecast production from the Gippsland Basin to remain stable out to 2022.[24]

The Cooper Basin in central Australia accounts for 4 per cent of eastern Australian gas production. The basin plays an important role as a 'swing' producer in managing seasonal and short term supply imbalances in the domestic gas market.

24 AEMO, *2018 Gas statement of opportunities*, June 2018, p. 11.

Figure 4.6

Eastern Australia gas production



Source: AER; Gas Bulletin Board (data).

With the opening of the Northern Gas Pipeline in December 2018, the Northern Territory's offshore Bonaparte Basin will become a new supplier to the eastern gas market in the near future.

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 meet domestic demand and shortfalls in Queensland production to meet export contracts.

This shift accelerated a depletion of gas reserves in southern basins, leading to concerns in 2017 of an imminent shortfall. 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. Surat–Bowen Basin production in the year to June 2018 rose by 8 per cent, faster than LNG export growth (5.5 per cent). Production also rose in the Cooper Basin. With Queensland production able to meet more of the domestic demand, production in southern basins fell by around 5 per cent over this period.

4.6 Gas storage

Gas can be stored in its natural state in depleted underground reservoirs and pipelines or post liquefaction as LNG in purpose built facilities. Storage provides a means of conserving surplus gas production for quick delivery when needed.

Eastern Australia's gas storage facilities include:

- large facilities using depleted gas fields in Queensland, Victoria and South Australia

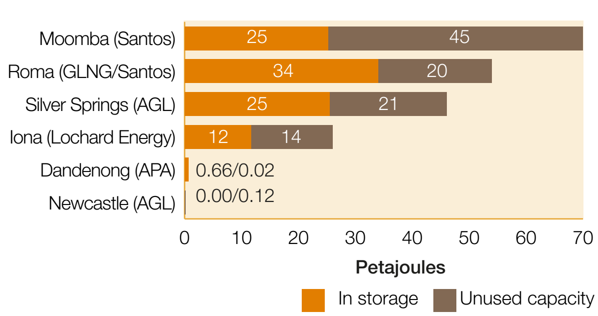
- smaller seasonal or peaking storage facilities located near demand centres—for example, the Newcastle LNG facility in NSW and the Dandenong LNG facility in Victoria
- short term peak storage services on gas pipelines, which are mostly contracted by energy retailers.

The 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 had significantly depleted by 2018, as stocks were run down to meet LNG export demand (figure 4.7).

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 launched an expansion of its Iona capacity, anticipating this storage would help manage future peak demand periods, such as in winter.[25]

Transmission pipelines can also provide gas storage services. The Tasmanian Gas Pipeline in 2017 was offering storage in its pipeline, for example, which could be drawn on for sale into the Victorian market at times of peak demand.

Figure 4.7
Gas storage in eastern Australia



Source: AER; Gas Bulletin Board, 2 December 2018.

4.7 Gas transmission pipelines

Wholesale customers must buy capacity on transmission pipelines to transport their gas purchases from processing plants to destination markets. Around 20 major transmission pipelines transport gas to the eastern gas market (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 transmission 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 before.

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 (duplicating parts of the pipeline) and extensions.

Since 2010 $1.5 billion has been invested or committed in new transmission pipelines, interconnections, and enhancements to existing pipelines in eastern Australia.[26] Significant investment has occurred to meet the needs of Queensland's LNG industry, including capacity expansions on existing pipelines and constructing new pipelines to ship gas to LNG processing facilities. Additionally, Jemena's Northern Gas Pipeline, completed in 2018, provides eastern Australia's first pipeline interconnection with the Northern Territory, making it possible to ship gas produced in the Northern 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.

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 4.9.4).

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

25 Premier of Victoria, *Securing gas for future winter warmth,* media release, June 2018.

26 APGA, *ACCC report highlights importance of continued pipeline investment*, media release, 13 December 2017.

Table 4.2 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
South West Queensland Pipeline (Wallumbilla to Qld–SA border)	Qld	755	404 (340 reverse)	Part 23 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%)
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 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%
Berwyndale to Wallumbilla Pipeline	Qld	112	164 (276 reverse)	Part 23 exemption	APA Group
Wallumbilla to Darling Downs Pipeline	Qld	205	270 (530 reverse)	Part 23 exemption	Beach Energy
Comet Ridge to Wallumbilla Pipeline	Qld	127	950 (175 reverse)	Part 23 exemption	Santos 30%, PETRONAS 27.5%, Total 27.5%, KOGAS 15%
North Queensland Gas Pipeline (Moranbah to Townsville)	Qld	391	108	Part 23 exemption	Palisade Investment Partners
QSN Link	Qld–SA	182	404 (340 reverse)	Part 23 regulation	APA Group
Moomba to Sydney Pipeline	SA–NSW	2029	489 (120 reverse)	Partial light regulation / partial Part 23 regulation[2]	APA Group
Moomba to Adelaide Pipeline	SA	1184	241 (85 reverse)	Part 23 regulation	QIC Global Infrastructure
Central West Pipeline (Marsden to Dubbo)	NSW	255	10	Light regulation	APA Group
Central Ranges Pipeline (Dubbo to Tamworth)	NSW	294	7	Full regulation	APA Group
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 (150 reverse)	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
APA Victorian Transmission System	Vic	2035	1030	Full regulation	APA Group

PIPELINE	LOCATION	LENGTH (KM)	CAPACITY (TJ/DAY)	REGULATORY STATUS[1]	OWNER
South Gippsland Pipeline	Vic	250		Part 23 exemption	DUET Group
Northern 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	1658	120	Full regulation	APA Group

QSN, Queensland to South Australia/New South Wales; TJ/d, 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: Gas Bulletin Board (www.gasbb.com.au); AER; ACCC, Gas Inquiry 2017–2020, interim reports; corporate websites.

routes into Melbourne, Sydney, Brisbane and Darwin. Other major pipeline owners include Jemena and Singapore Power International.

Cheung Kong Infrastructure (CKI) and its associates in 2018 launched 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.[27] On 20 November 2018, following consultation with the Foreign Investment Review Board, the Australian Government blocked the bid on grounds the acquisition 'would be contrary to the national interest' as 'it would result in a single foreign company group having sole ownership and control over Australia's most significant gas transmission business.'[28]

4.8 Contract and spot gas markets

Wholesale gas is traded in two distinct types of markets. Around 90 per cent of gas sales in eastern Australia are struck under confidential *bilateral contracts*, with the remaining 10 per cent traded in *spot markets*.[29]

27 ACCC, *ACCC will not oppose acquisition of APA,* media release, 12 September 2018.
28 The Hon. Josh Frydenberg MP (Treasurer), *Final Decision on the proposed acquisition of APA,* media release, 20 November 2018.
29 AER estimate derived from public sources and discussions with market participants.

4.8.1 Contract markets

Bilateral gas contracts (also known as gas supply agreements) are wholesale supply deals negotiated between sellers and buyers. There are two main levels of contracting: 1. supply offers by gas producers, which are typically available to very large customers such as major energy retailers and gas powered generators and, 2. supply offers by retailers and other aggregators that buy gas from producers and on-sell it to C&I customers. Prices quoted to C&I customers tend to be higher than to very large customers, in part because they must cover the aggregator's margins. But the ACCC found prices to C&I customers have been unreasonably high at times (section 4.10.1).

Gas contracts traditionally locked in prices and other terms and conditions for several years at a time. More recently, the industry has shifted towards shorter term contracts with review provisions. The ACCC reported in 2018 that recent contract offers for gas 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 durations of two years or less.[30]

Public information about contract prices is opaque. Much of it 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.

30 ACCC, *Gas inquiry 2017–2020—Interim report,* July 2018, pp. 24, 49.

4.8.2 Spot markets

While most gas is traded under confidential contracts, spot markets allow wholesale customers to trade gas without entering long term contracts. Spot market trading can be a useful mechanism for participants to manage imbalances in their contract positions.

Three separate spot markets for gas operate in eastern Australia. The oldest of the three is *Victoria's declared 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 at Wallumbilla, Queensland in 2014 and at Moomba, South Australia in 2016.

The three spot markets operate under different rules, do not interact with each other, and have different purposes. The Australian Energy Market Commission (AEMC) in June 2017 found the disjointed nature of having multiple market designs inhibits trading between regions, increases complexity and imposes transaction costs. It recommended in the longer term eastern Australia's spot markets transition to a single market design, based on the gas supply hub model currently operating at Wallumbilla and Moomba.[31]

An information platform—the Gas Bulletin Board—was launched in 2008 to provide transparency about gas market conditions and so encourage participation in the spot markets. The AER monitors the bulletin board, as well as the spot markets, and reports regularly on activity. It also monitors participants' compliance with the underpinning rules, and takes enforcement action where necessary.[32]

The following sections explain the workings of each spot market, as well as the bulletin board. Price trends in the spot markets are outlined in section 4.10.2.

4.8.3 Gas supply hubs at Wallumbilla and Moomba

AEMO launched the gas supply hub model at Wallumbilla, Queensland, in March 2014. Wallumbilla is a major pipeline junction linking gas basins and markets in eastern Australia (figure 4.8). Three critical pipelines—the South West Queensland, Roma to Brisbane, and Queensland Gas pipelines—along with several smaller transmission pipelines, connect 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 and gas powered generators were among the most active participant categories in 2017, with increased activity by traders also evident.[33]

Around 11 participants were active each month in the first half of 2018, with 100 trades or more executed in a typical month. The trades are split across a range of product types (such as intra-day, day-ahead, weekly and monthly) and include both on-market and off-market trades.[34]

LNG producers are the largest suppliers of gas into the hub, and some competitive tension appears to have developed between two of them. But operational issues tend to limit their participation at the hub. One factor is the existing physical interconnection between LNG facilities allows them to trade easily among themselves. Some participants have suggested sudden changes in their operations typically involve volumes greater than what the hub can currently absorb.[35]

A brokerage model allows buyers and sellers to place anonymous offers or bids for quantities of gas at nominated prices, which can then be a matched on the exchange to make trades. Each price struck is unique to a particular trade. There is no market clearing price applicable to all participants.

As in the other spot markets, the gas supply hub complements bilateral contracts rather than replacing them. But the hub model allow 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 each of the hub's 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. To address this problem, in October 2016 AEMO introduced a compression product that enables transporting gas from low to high pressure locations within the hub. Participants

31 AEMC, *Review of the Victorian declared wholesale gas market—final report*, factsheet, June 2017.

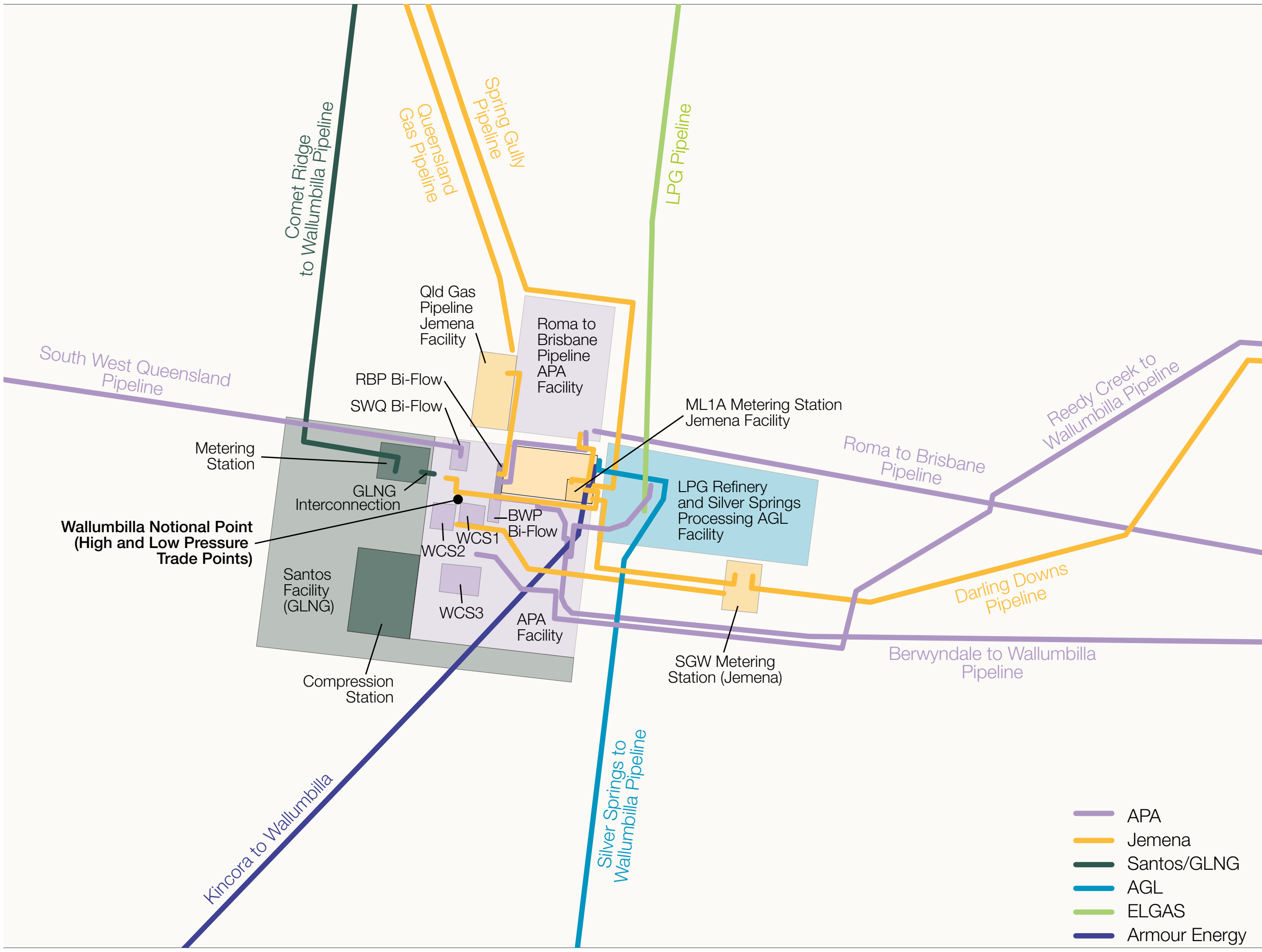
32 AER, *Compliance reporting,* available at: www.aer.gov.au/wholesale-markets/compliance-reporting.

33 AEMC, *Final report: biennial review into liquidity in wholesale gas a pipeline trading markets*, August 2018 p. 30.

34 AER, *Wholesale statistics*, at: www.aer.gov.au/wholesale-markets/wholesale-statistics.

35 AER market intelligence.

Figure 4.8
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.

can also enter location swaps that allow gas to be received at one location in the hub and delivered to another without physically moving gas between those points.

In March 2017 AEMO replaced the hub's three trading locations with a single Wallumbilla product that groups together all delivery points (box 4.2). 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 (SEQ) product 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 paying pipeline costs to transport gas to Wallumbilla. Participants also sometimes arrange downstream delivery points to avoid these costs.

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, few transactions have occurred. The first trade was executed in September 2017, and by mid-2018, around 10 trades had been executed. The AEMC reported stakeholder views that transportation and operational issues are barriers to trade at the Moomba hub, including uncertainty about injection and delivery points.[36]

36 AEMC, *Final report: biennial review into liquidity in wholesale gas a pipeline trading markets*, August 2018.

Box 4.2 Wallumbilla hub activity

Trade at Wallumbilla has progressively increased since its launch in 2014 (figure 4.9). Initially, some LNG projects used the hub to sell surplus 'ramp' gas during the run-up to commissioning new LNG trains. Once operational, they continued to use the hub from time to time to manage variations in production and LNG plant performance. This use involved alternate periods of selling surplus supply and buying gas when LNG plant performance was not keeping up with export obligations. EnergyQuest reported Queensland Curtis LNG in particular has acted as a 'swing' producer into the domestic market when domestic prices are high.

Other participants in the hub include gas powered generators such as Stanwell, Alinta, Origin, Arrow Energy and ERM, as well as industrial users such as Incitec Pivot. Gas powered generators sourced significant volumes of gas from the Wallumbilla hub in 2017, helping push prices up to $10–15 per gigajoule. But, with all six LNG trains then in operation and absorbing gas supplies, traded volumes at the hub did not rise in response to these high prices.

The Australian Energy Market Commission (AEMC) reported in June 2018 that quantitative indicators of liquidity at the Wallumbilla hub have improved over the past two years. Traded volumes were 47 per cent higher in 2017 than a year earlier.[a] Participation was also higher, with gas powered generators and energy retailers among the most active participants. There was also a shift in product preferences with growth of more than 300 per cent in daily, weekly and monthly products, compared with 30 per cent growth in balance of day and day-ahead trades.

Volumes continued to grow in 2017–18, with prices mostly struck at $7–10 per gigajoule. The upturn was partly attributable to Australian Government intervention in 2017 requiring LNG producers to sell more gas into the domestic market (section 4.12.1). Queensland's gas powered generators were also active buyers at Wallumbilla when electricity demand was high.

Despite this growth, transmission pipeline capacity has been raised as an impediment to hub trading, because all gas traded needs to be physically shipped to a hub location. Reforms in 2019 to introduce a day-ahead capacity auction may help to overcome this issue by enabling trade in pipeline capacity (section 4.13.2).

A number of participants suggested more flexibility to negotiate delivery points and storage options would make the hub more useful for trading, given these options are possible in bilateral trading. In general, stakeholders consider that the hub design should cater better for bespoke needs.[b]

We are working with the AEMC to improve data on liquidity at Wallumbilla, and in 2018 we began publishing a range of liquidity indicators.[c]

a AEMC, *Final report: biennial review into liquidity in wholesale gas a pipeline trading markets*, August 2018, pp. 10, 30, 41.
b AEMC, *Final report: biennial review into liquidity in wholesale gas a pipeline trading markets*, August 2018.
c AER, *Industry statistics,* available at: www.aer.gov.au/industry-information/industry-statistics.

In 2016 the AEMC recommended using the gas supply hub model as a template for new market arrangements in eastern Australia. A northern hub would be located at Wallumbilla and largely retain the market model already in place there. The southern hub located in Victoria would use the same market arrangements.[37] The reforms require significant legislative changes in several jurisdictions. Progress to date has been slow.

4.8.4 Short term trading market

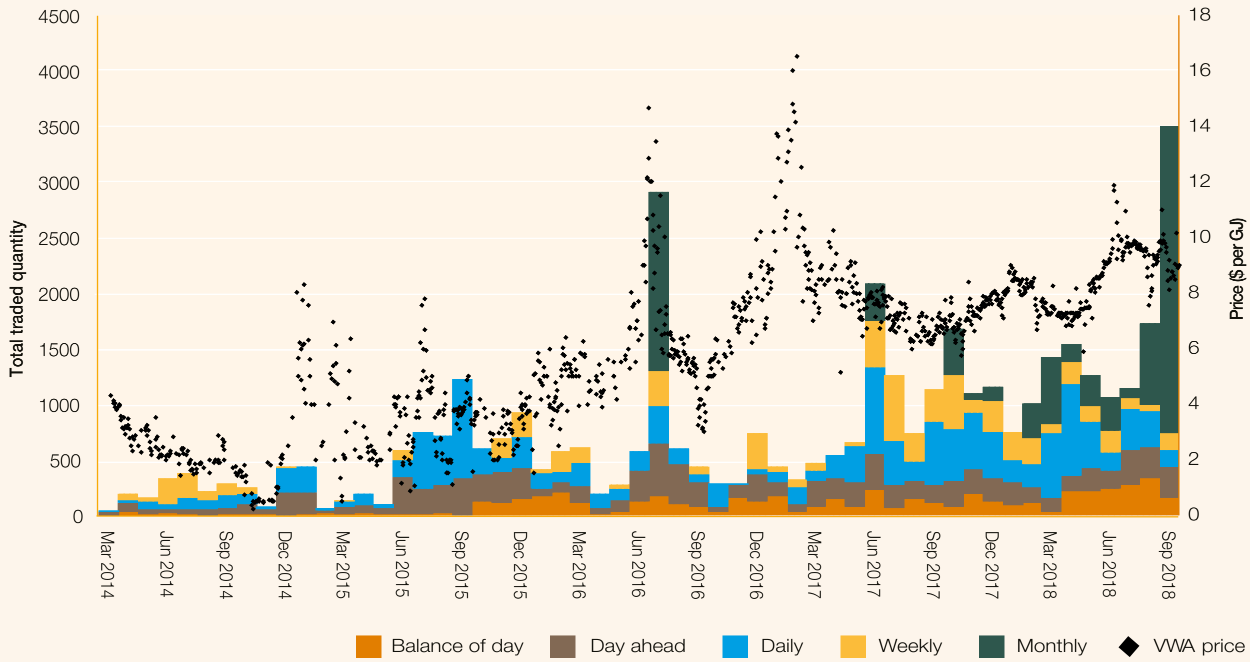
A short term trading market for gas operates at three locations in eastern Australia—Sydney, Adelaide and Brisbane. AEMO operates the market, which launched in 2010. The market has a floor price of $0 per gigajoule (GJ) and a cap of $400 per GJ. Each hub is scheduled and settled separately, but all three operate under the same rules.

Prices are volatile, reflecting short term shifts in supply and demand, including conditions in LNG export markets. Given its responsiveness to short term conditions, participants consider the market is less useful as an indicator of

37 AEMC, *East Coast Wholesale Gas Markets and Pipeline Frameworks Review, stage 2 final report*, May 2016.

Figure 4.9

Gas trades and prices at Wallumbilla hub



TJ, terajoule; GJ gigajoule.

Source: AER, AEMO (data).

prices that would be struck in bilateral contracts. No ASX derivatives market has developed for the short term trading market.

On average, around 22 participants were active at the Sydney hub in 2017. The Adelaide and Brisbane hubs each had around seven active participants.[38] The participants included energy retailers, power generators, large industrial gas users, and traders. The market benefits gas powered generators because it can supply volumes of gas at short notice when electricity demand is high and/or electricity supply is constrained.

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 only trade their net positions—the difference between their scheduled gas deliveries into and out of the market. In Sydney, around 10–15 per cent of total gas demand is met through the market. Volumes in Brisbane and Adelaide tend to be smaller.[39]

Gas producers gave evidence to the ACCC in 2016 that they lack confidence in the market's ability to supply significant volumes of gas.[40] But while no gas producer currently uses the short term trading market as a major outlet for supply, some participants with flexibility in their day-to-day gas requirements—including a number of smaller retailers—use the market to manage imbalances in their contract positions. LNG projects also sometimes trade in the market to manage their portfolios.

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

38 AEMC, *Final report: biennial review into liquidity in wholesale gas a pipeline trading markets*, August 2018, pp. 29–33. An active participant is one that has been engaged in trading on the market at least once in any given month by submitting a valid bid or an offer.

39 AEMC, *Stage 1 Final Report: East Coast Wholesale Gas Market and Pipeline Frameworks Review*, p. 90.

40 ACCC, *Inquiry into the east coast gas market*, April 2016.

where they would have been with contracts they had been offered in 2017 for 2018 supply. More generally, customers 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. One customer said participating in the market had 'taken away the highly speculative offers from retailers in the order of $15 per GJ'.[41]

The AEMC found traded volumes at the Sydney hub were 84 per cent higher in 2017 than a year earlier, but volumes declined by 22 per cent at the Adelaide hub and 5 per cent at the Brisbane hub. Trading profiles varied across the hubs. Energy retailers tended to be more active in Adelaide than at the other hubs.[42]

How the market works

The short term trading market allows gas trading on a day-ahead basis. 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, 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 required. Gas procured under this mechanism is mainly paid for by parties causing the imbalances. The AER has periodically reported instances of abnormally high MOS payments in parts of the market, resulting in a number of investigations.[43]

4.8.5 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.

41 ACCC, *Gas inquiry 2017–2020—Interim report,* July 2018, p. 66.
42 AEMC, *Final report: biennial review into liquidity in wholesale gas a pipeline trading markets*, August 2018, pp. 12, 32.
43 AER, *State of the Energy Market 2017*, p. 76.

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.[44]

On average, around 26 participants were active in the Victorian market in 2017.[45] The participants included 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, due to its flexibility and relatively low transaction costs.[46] Industrial users and traders showed the greatest increase in activity in 2017.

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.

The AER estimated volumes traded in the Victorian market were 60 per cent higher in 2017 than a year earlier.[47] This trend was consistent with higher volumes of local gas being available in the Victorian market in 2017, following a return to full service of the Iona underground gas storage facility, and unusually high volumes of production at the Longford processing facility. The AER will update trading data on its website throughout 2019.

A small futures market has developed for the Victorian market, although trading is sporadic and liquidity remains low. In April 2018 80 gas futures contracts were traded (60 quarterly contracts and 20 yearly contracts), amounting to about 1.3 PJ of gas.[48] Trade has grown over 2018, with just over 5 PJ of 2019 futures traded at November 2018.[49]

The Victorian market differs from the short term trading market in a number of respects, including:

44 See AEMO*, Guide to Victoria's declared wholesale market*, 2012, available at: www.aemo.org.au.
45 AEMC, *Final report: biennial review into liquidity in wholesale gas a pipeline trading markets*, August 2018, p. 35–36. Note: An active participant is one that has been engaged in trading on the market at least once in any given month by submitting a valid bid or an offer.
46 AEMC, *Final report: biennial review into liquidity in wholesale gas a pipeline trading markets*, August 2018, p. 14.
47 AEMC, *Final report: biennial review into liquidity in wholesale gas a pipeline trading markets*, August 2018, p. 14.
48 ACCC, *Gas inquiry 2017–2020—Interim report,* July 2018, p. 47.
49 AER estimate, based on market intelligence.

- 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.

The AEMC reviewed the Victorian gas market in 2017 at the request of the Victorian Government.[50] The AEMC found the market has structural limitations, and recommended a number of reforms. It also recommended the market eventually transition to a new 'southern hub' that would also incorporate the short term trading market hubs in Sydney and Adelaide. The southern hub would feature a brokerage model similar to that operating at Wallumbilla (section 4.8.3). AEMO reported in 2018 that the Victorian Government was considering reforms to the Victorian market that do not involve a transition to a southern hub.[51]

4.8.6 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 is responsible for publishing it. The AER monitors participants' compliance with their obligations to submit accurate data, taking action where necessary to enforce compliance.

The bulletin board plays an important role in making the gas market more transparent, especially for smaller players, such as small gas producers and retailers, who may not otherwise be able to access day-to-day information on demand and supply conditions.

The information supplied on the bulletin board includes:

- pipeline capabilities (maximum daily flow quantities, including bi-directional flows), pipeline and storage capacity outlooks, 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.

50 AEMC, *Final Report: Review of the Victorian declared wholesale gas market*, 30 June 2017, p. i.

51 AEMC, *Final report: biennial review into liquidity in wholesale gas a pipeline trading markets*, August 2018, p. 1.

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.

Recent changes to the bulletin board

The bulletin board's coverage has widened incrementally since 2015. Significant reforms taking effect in September 2018 removed most reporting exemptions and mandated more comprehensive detail for covered facilities. To encourage compliance, the reforms also made reporting obligations subject to civil penalty provisions.

Reporting obligations were also extended to gas facility operators in the Northern Territory, in recognition that the Northern Gas Pipeline now connects the Territory with the eastern gas grid.

The reforms are detailed in section 4.13.1.

4.9 State of the eastern gas market

While Queensland's LNG export industry has brought significant investment and growth to the state, it has also caused disruptive price increases in the eastern Australian gas market. The industry, launched in January 2015, increased demand for Australian produced gas and placed pressure on gas reserves in southern Australia.

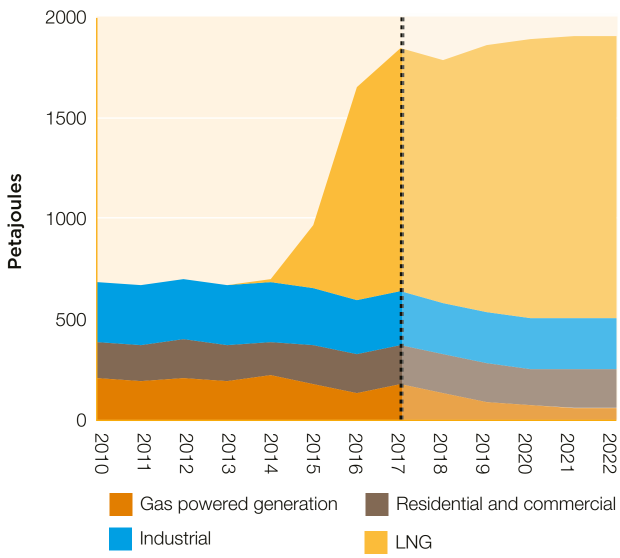
High gas demand for electricity generation following the closure of coal fired generators, regulatory restrictions on developing new gas supplies, and impediments to pipeline access for transporting gas, all further intensified market pressures. These pressures peaked in 2017 before Australian Government intervention led to more gas supplies being diverted to the domestic market. Despite this intervention, the market remained tight in 2018, and wholesale prices continue to be set at levels two to three times above historical levels.

4.9.1 Demand conditions

Domestic demand for gas derives from three sources—C&I gas users (around 41 per cent of domestic demand), gas powered generators (29 per cent), and residential customers (29 per cent). With the launch of LNG exports in 2015, international customers became a new source of demand competing to buy Australian gas. LNG supply rose exponentially from 2015–17 and now outweighs supply to the domestic market (figure 4.10).

Figure 4.10

Eastern Australian gas demand



Note: Data are actual demand to 2017 and forecasts from 2018.

Source: AEMO, *2018 Gas Statement of Opportunities*, June 2018.

Among domestic sources of demand, gas powered generation is the most volatile source of demand. Gas demand by C&I users and residential customers is more stable, although high gas prices have impacted C&I customers. Several gas intensive producers consider high prices a significant risk to commercial viability.[52] Coogee Chemical's decision to mothball a methanol plant, Qenos laying off 15 per cent of its workforce, and EnergyQuest describing Incitec Pivot's fertiliser plant's position as 'precarious'[53] were each reportedly linked to high gas prices.

LNG producers

Queensland's three LNG projects were originally anticipated to source their gas requirements from their own reserves in the Surat–Bowen Basin. But the development of gas wells by Santos's GLNG project was slower than expected, requiring it to source substantial volumes of gas from other producers to meet its LNG supply contracts. EnergyQuest estimated GLNG relied on third parties for around 30 per cent of its LNG plant feedstock in the June quarter of 2018[54] sourcing much of it from other Queensland fields and the Cooper basin. QCLNG also purchases gas from outside its portfolio, having signed a 27 year gas supply agreement with Arrow Energy in December 2017.[55]

LNG exports from Queensland peaked during summer 2017–18, when exporters took advantage of high Asian demand due to a particularly cold winter, which coincided with the need for high capacity use associated with operational testing.

Strong demand caused a surge in LNG spot prices from mid-2017, which, coupled with rising oil prices, translated into surging revenues for the Queensland industry. Monthly Asian spot prices reached around $14 per GJ delivered in December 2017. LNG prices were 25 per cent higher in the June quarter 2018 than in the same quarter in 2017, and 44 per cent higher than in 2016.[56]

Despite this strong demand, the Queensland projects only operated at around 77 per cent of capacity in mid-2018, compared with rates for the two largest projects on the west coast of 89–95 per cent.[57] In part, this outcome reflects the LNG producers diverting more gas to the domestic market following the Australian Government's gas market intervention in 2017 (section 4.12.1). In the June quarter 2018 almost 16 per cent of Queensland gas production flowed to the domestic market[58]—similar to the rate supplied to the domestic market in Western Australia under the state's gas reservation policy.

Future demand for Australian LNG is uncertain. Several LNG projects in the United States are scheduled to come online in 2019, creating a significant new global competitor in the Asian LNG market.[59] But LNG demand is strengthening in China and South Korea as those countries shift from coal towards gas and renewables in electricity generation and domestic use. This behaviour shift is driven in part to reduce carbon emissions, and reduce the localised health impacts of fine particulate pollution caused by burning coal.

In the first six months of 2018 China's LNG imports increased 53 per cent on an annualised basis.[60] The Chinese government aims to raise the share of energy provided by gas from 5.3 per cent in 2015 to 8.3–10 per cent in 2020. Japan's LNG imports, however, are expected to fall by around 5 per cent between 2017 and 2020, as the

52 ACCC, *Gas inquiry 2017–2020—Interim report,* July 2018, pp. 13, 62–63.
53 EnergyQuest, *Energy Quarterly*, June 2018, p. 22.
54 EnergyQuest, *Energy Quarterly,* September 2018, p. 14.
55 Arrow Energy, *Arrow Energy agrees deal for Surat Basin reserves*, media release, 1 December 2017.
56 EnergyQuest, *Energy Quarterly,* September 2018, p. 94.
57 EnergyQuest, *Energy Quarterly,* September 2018, p. 82.
58 EnergyQuest, *Energy Quarterly,* September 2018, p. 11.
59 Department of Industry, Innovation and Science, *Resources and Energy Quarterly*, March 2018; Institute for Energy Research, *U.S. to become a major LNG exporter*, October 2017.
60 Department of Industry, Innovation and Science, *Resources and Energy Quarterly*, September 2018, p. 49.

country's nuclear plant is brought back online, with seven of its 24 plants having resumed operation by March 2018.[61]

Gas powered generation

Around 29 per cent of domestic demand for Australian gas is for power generation. 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).[62]

Rising gas fuel costs linked to Queensland's LNG industry and a shortage of gas supplies stalled demand for gas powered generation from 2015. The share of gas powered generation in the national electricity market (NEM) generation mix fell from 12 per cent in 2013–14 to 9.5 per cent in 2017–18 (figure 2.8). The decline was most pronounced in Queensland, coming off a high associated with sales into the domestic market by LNG exporters during the commissioning phases of their projects. Gas powered generation slumped from 21 per cent of Queensland's electricity output in 2014–15 to 9 per cent in 2017–18. A similar squeezing of gas powered generation occurred in NSW.

Different conditions prevailed in Victoria and South Australia, where the retirement of coal generators made gas generation critical to meeting electricity demand, particularly when weather conditions for wind and solar generation were unfavourable. Outages at coal generators also contributed to gas generation in 2017–18 being 270 per cent higher in Victoria and 160 per cent higher in South Australia than two years earlier (figure 4.11).

AEMO in 2018 forecast lower levels of gas powered generation in 2019 as new wind and solar plants come online to reduce the gap left by coal plant closures (section 4.9.5).

61 Department of Industry, Innovation and Science, *Resources and Energy Quarterly*, September 2018, p. 49; World Nuclear Association, *Nuclear Power in Japan*, July 2018.

62 EnergyQuest found a minus 89 per cent correlation between gas and hydroelectric generation; and a minus 48 per cent correlation between gas and wind generation over 42 months to June 2018. See EnergyQuest, *Energy Quarterly,* September 2018, p. 35

4.9.2 Supply conditions

While a majority of eastern Australia's gas reserves are located in the Surat–Bowen Basin, those reserves are largely committed to the LNG export industry. The Victorian gas basins and the Cooper Basin in central Australia are, therefore, pivotal to meeting domestic gas demand in southern Australia. But reserves in those basins are declining and scope to increase production in the short to medium term is limited. The decline in recoverable reserves has been accelerated by the Victorian and Cooper basins supplying gas to LNG projects to meet production shortfalls in Queensland. With a few exceptions, declining reserves in legacy fields have not been offset by new gas field developments (section 4.11).

Both onshore and offshore exploration expenditure has declined, mirroring a significant fall in oil prices that dampened investors' appetite for risk (figure 4.12). Exploration expenditure in the first quarter of 2018 was at its lowest quarterly level in four years.[63] While oil prices began to recover in 2016, exploration investment has been slow to respond and legacy reserves continue to dwindle. While some development proposals show promising signs, others face significant regulatory hurdles linked to environmental concerns.

In response to this weakness in exploration activity, the Australian Government and some state governments have launched initiatives to encourage new projects to supply the domestic market (section 4.12).

Supply conditions in the Surat–Bowen Basin

Gas production in the Surat–Bowen Basin rose exponentially from 2014–17 to meet the demands of Queensland's LNG export industry. While production continues to rise, this growth levelled out somewhat in 2017–18 as the three LNG projects reached full operation.

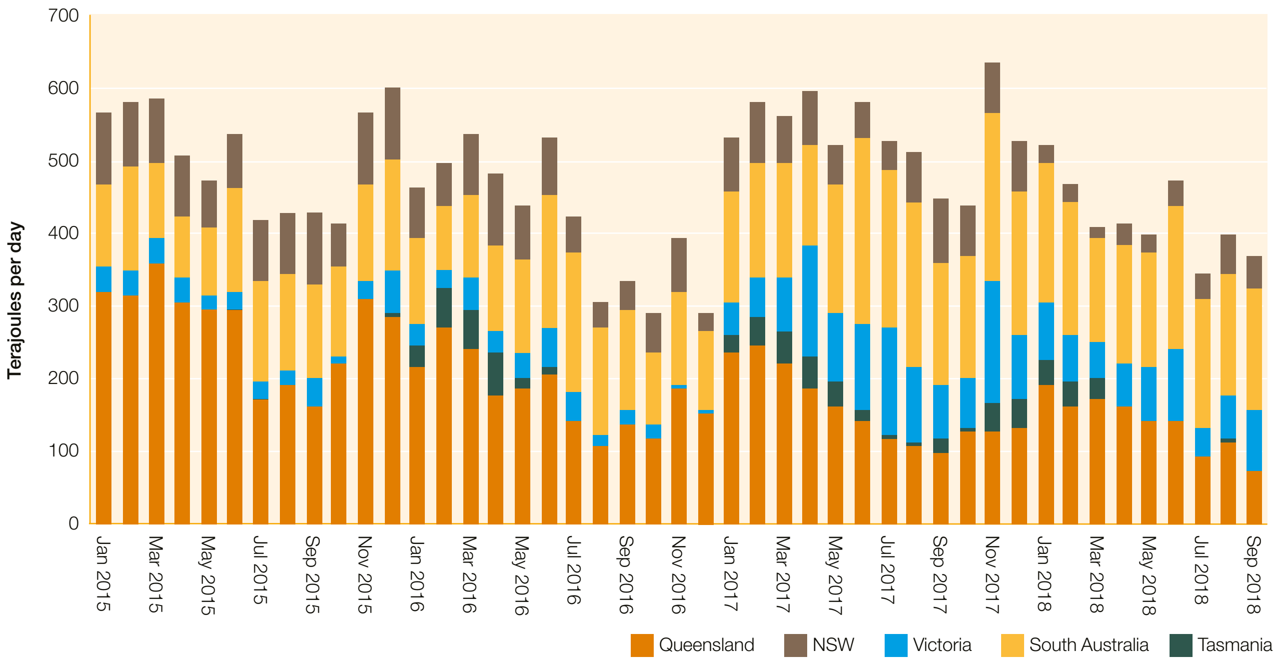
In response to concerns around the adequacy of gas supplies to meet domestic demand, the Australian Government in 2017 threatened to instruct LNG producers to supply more gas to the domestic market. The Australian Domestic Gas Security Mechanism empowers the Energy Minister to require LNG projects to limit exports or find offsetting sources of new gas if a supply shortfall is likely (section 4.12.1).[64]

63 Australian Bureau of Statistics, *8412.0 Mineral and Petroleum Exploration,* March 2018.

64 Department of Industry, Innovation and Science, *Australian Domestic Gas Security Mechanism*, July 2018.

Figure 4.11

Monthly gas demand for gas powered generation



Source: AER, AEMO (data).

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), in which they committed to offer uncontracted gas on reasonable terms to meet expected future domestic supply shortfalls.

The LNG projects have since used various methods to sell more gas domestically. These methods include selling products on the Wallumbilla Gas Supply Hub, launching expression of interest (EOI) processes for customers and entering bilateral negotiations.[65] Santos' GLNG project, which sources gas from southern Australia to meet its export commitments, has been especially active in entering new supply agreements with gas powered electricity generators and other large domestic customers.[66] With the LNG projects offering more gas to the domestic market, daily production set new records at Roma in 2018.

Completing operational testing of the APLNG project in 2017 also increased Queensland gas supplies to the domestic market. Additionally, launching the Reedy Creek to Wallumbilla Pipeline in May 2018 allowed APLNG to transport gas directly to the Wallumbilla hub.

More generally, the rise in oil prices improved cash flows for all three LNG projects, allowing further development of gas resources. EnergyQuest reported an upswing in drilling for development wells in the Surat–Bowen Basin in 2018.[67]

The ACCC also noted the number of suppliers in the market has risen, with new entrant retailers and aggregators such as Shell Energy Australia expanding their presence. As a result, supply options to C&I gas users appear to be improving.

Supply conditions in Victorian basins

According to Esso, one of the Gippsland Basin's large legacy fields has depleted earlier than expected, with another two fields expected to be depleted in the early 2020s.[68] Production in Gippsland is currently transitioning from old to new fields, but it is not yet clear how much the new gas fields can produce.

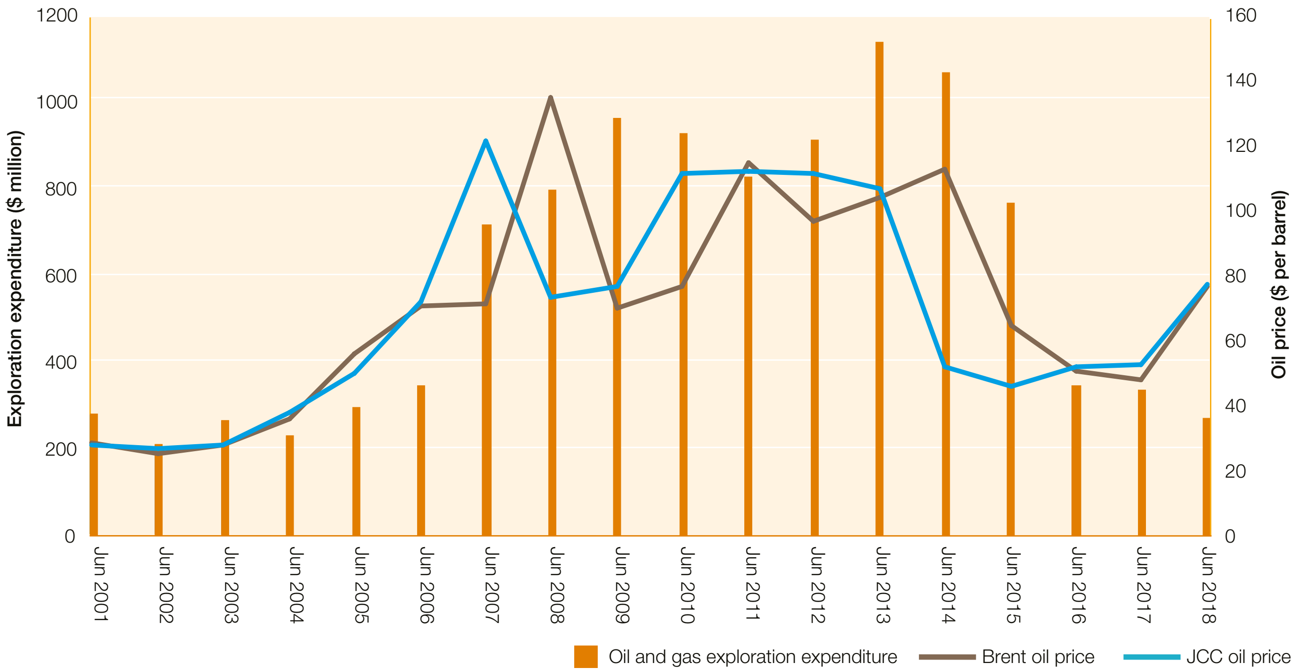
The Longford gas plant servicing the Gippsland Basin achieved record production in 2017, taking advantage of high gas prices and periods of high demand for gas powered generation. But Longford flagged lower production in 2018. The plant is becoming less reliable as it is run

65 ACCC, *Gas inquiry 2017–2020—Interim report,* July 2018, p. 27
66 Santos media centre 14 August 2017, 8 September 2017, 22 November 2017, 15 February 2018 and 27 February 2018.

67 EnergyQuest, *Energy Quarterly,* September 2018, pp. 85–87.
68 ACCC, *Gas inquiry 2017–2020—Interim report,* July 2018

Figure 4.12

Brent oil price and exploration expenditure



Note: Annual data to 30 June.

Source: Exploration: Australian Bureau of Statistics, *8412.0 Mineral and Petroleum Exploration,* March 2018; Oil price: Business Insider (markets.businessinsider.com/commodities/oil-price).

harder for longer, and plant constraints and outages increasingly disrupt production (box 4.3 and figure 4.13).

The ACCC reported a recovery in production forecasts for Victoria in 2019, including higher forecasts by legacy producers Esso Australia and BHP. But forecasts remain significantly lower than 2017 production levels. In the longer term, EnergyQuest predicts gas production from Victoria's offshore fields will fall by 57 per cent in 2022 from the peak achieved in 2017.[69]

Cooper Energy's Sole project in the Gippsland Basin is expected to come online in mid-2019. The project marks the first new production well to be drilled in offshore Victoria since 2012 and is expected to produce around 25 PJ per annum. Esso Australia also expects to bring forward a final investment decision for its West Barracouta project.[70] The ACCC identified limited other prospects of new gas supply from the southern states in the immediate future.

Most potential developments are subject to risk and uncertainty, as illustrated by Esso's recent drilling in the Dory prospect, initially thought to be one of the largest untapped gas resources in Victoria. After several months and $120 million in drilling expenditure, no new resources had been discovered by November 2018.[71] More generally, production costs in new offshore projects coming online in the southern basins tend to be relatively high, posing challenges for commercial viability.

69 EnergyQuest, *Energy Quarterly*, June 2018.
70 ACCC, *Gas inquiry 2017–2020—Interim report,* July 2018, p. 29.
71 Matt Chambers, *Exxon's $120m Bass Strait bet fails to deliver gas,* The Australian, 15 November 2018.

Box 4.3 Gas security issues in Victoria

The Australian Energy Market Operator (AEMO) declared threats to gas system security in Victoria on three occasions in 2017–18.

The most significant event occurred on 30 November 2017, when high temperatures and an outage at Victoria's Loy Yang A coal power station caused a spike in demand for gas powered electricity generation during the day. The high temperatures also caused compressors supplying one of Longford's three gas processing plants to trip (figure 4.13). The outage coincided with high gas demand in surrounding areas of Victoria, resulting in forecasts that local gas pressure would fall below acceptable operating limits. AEMO declared a threat to system security and intervened in the market by directing back-up gas supplies from the Iona storage facility into the system.

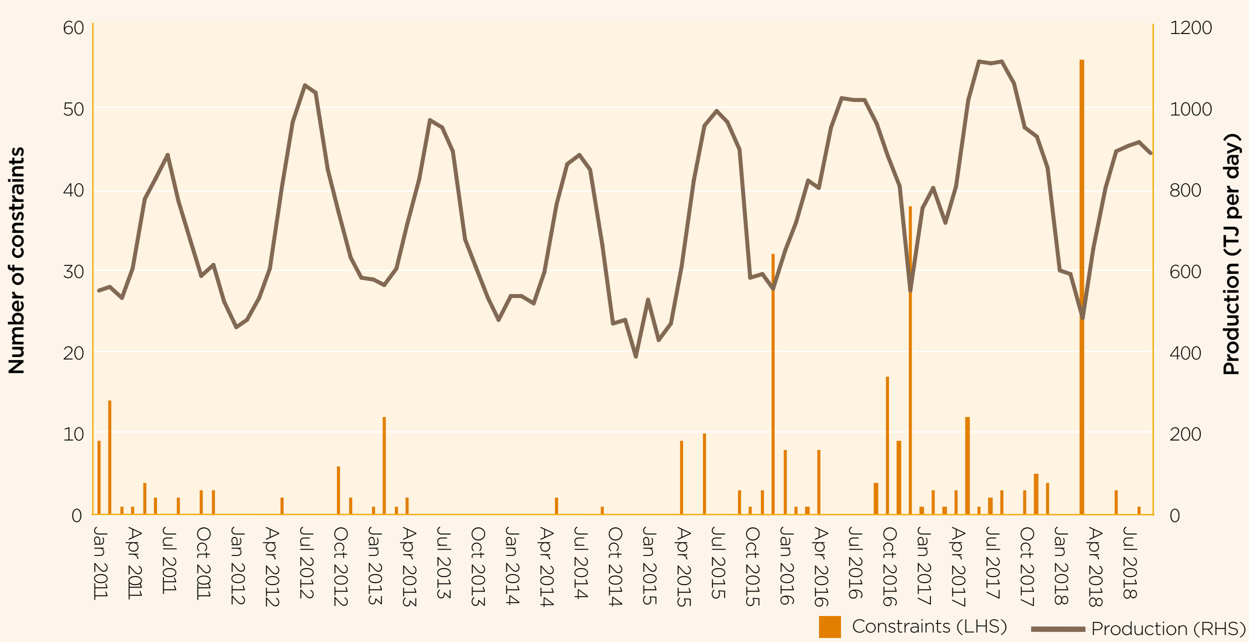
The intervention cost the market over $260 000 as gas was scheduled out of merit order, most of it coming from storage. The incident triggered an Australian Energy Regulator investigation, with the findings published in January 2018.[a]

AEMO also declared threats to gas system security in Victoria on 3 August 2017 and 22 February 2018:

- On 3 August 2017 higher than expected gas powered generation coincided with an unplanned maintenance outage at the Dandenong LNG storage facility, which supplies emergency gas to Victoria. Gas demand on the day reached 1300 terajoules, the highest level since August 2008.
- On 22 February 2018 overheating caused an unplanned outage at a compressor station, limiting gas supply from Longford to the Victorian Transmission System. The outage meant gas pressure into the south west pipeline supplying western Victoria was at risk of falling below minimum thresholds. Similar to the November 2017 event, AEMO scheduled out of merit gas supply from the Iona storage facility, which injected enough gas to maintain pipeline pressures.

Figure 4.13

Longford monthly production and outages



Note: Daily production (supply). Daily constraints used as proxy for outages.

Source: AER; Gas Bulletin Board.

a AER, *Significant price variation report: Victorian gas wholesale market, ancillary payments, 30 November 2017*, 29 January 2018.

4.9.3 Regulatory barriers to exploration and development

In some states and territories, community concerns about environmental risks associated with fracking[72] have led to legislative moratoria and regulatory restrictions on onshore gas exploration and development. Victoria, South Australia, Tasmania and Western Australia all have onshore fracking bans in place, covering all or part of those states. NSW has no outright ban in place, but significant regulatory hurdles have stalled development proposals. In 2018 the Northern Territory's ban on fracking was partially lifted. Queensland does not restrict fracking.

- The Victorian Government banned onshore hydraulic fracking, exploration for and mining of CSG or any onshore petroleum until 30 June 2020.[73] 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. The release relates to the Australian Government's 2018 Offshore Petroleum Exploration Acreage Release aimed at promoting petroleum exploration in offshore waters.[74]
- South Australia's newly elected government 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 purposes of extracting hydrocarbon resources including shale gas and petroleum until March 2020.
- NSW does not ban onshore exploration, but applies significant regulatory restrictions including 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.[75] 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' Narrabri gas project.[76]
- Following an independent inquiry[77], the Northern Territory Government in April 2018 lifted its moratorium on fracking by announcing it would make 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. It also led to Jemena announcing it would extend and expand its new pipeline linking the Northern Territory to the eastern gas market. The ACCC forecast the pipeline would provide an additional 28 PJ of gas to the eastern market in 2019.[78] Following the upgrade, it will have potential to transport over 250 PJ per year.
- Western Australia has implemented a ban on fracking for existing and future petroleum titles in the South West, Peel and Perth metropolitan regions.

4.9.4 Pipeline access

Wholesale gas customers must buy capacity on transmission pipelines to transport their gas purchases from gas basins. Gas pipelines are separately owned from gas production companies—so a gas customer must negotiate separately with producers to buy gas, and pipeline businesses to get the gas delivered. Gas may need to flow across multiple pipelines with different owners to reach its destination.

Since LNG exports began in 2015, gas flows from the southern states to Queensland, and more recently the reverse, have become an efficient response to managing interregional supply–demand imbalances. So, access to transmission pipelines on key north–south transport routes is critical for gas customers.

But gaining access to pipeline capacity has proved difficult for many customers. The ACCC found many pipelines face little competition and charge monopolistic prices.[79] It cited extensive evidence, including a pipeline that had raised its prices by over 90 per cent despite declining volumes.

72 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 and then horizontally through the rock. The fracturing fluid is the injected into the well at extremely high pressure, forcing open existing cracks in the rocks, causing them to fracture and breaking open small pockets containing 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.

73 Department of Economic Development, Jobs, Transport and Resources (Vic), *Onshore Gas Community Information*, August 2017.

74 Department of Industry Innovation and Science, *The 2018 Offshore Petroleum Exploration Acreage Release*, at: www.petroleum-acreage.gov.au/.

75 Department of Planning and Environment (NSW), *Initiatives Overview,* July 2018.

76 Department of Planning and Environment (NSW), *Community views on Narrabri Gas Project to be addressed*, media release, 7 June 2017.

77 *Independent Scientific Inquiry into Hydraulic Fracturing of Onshore Unconventional Reservoirs in the Northern Territory, Final Report to the Northern Territory Government*, 27 March 2018.

78 ACCC, *Gas inquiry 2017–2020—Interim report,* July 2018, p. 24.

79 ACCC, *Inquiry into the east coast gas market,* April 2016, p. 18.

Other major pipelines were earning internal rates of return of around 20 per cent.

At present, only a handful of pipelines have their prices assessed by the AER. Additionally, several key pipelines have little or no spare capacity, making it difficult to negotiate access. The AEMC in 2018 reported some primary and secondary pipeline capacity is being offered for sale on pipeline operators' websites and on the gas supply hub. It noted seven major transmission pipelines published capacity offers in 2016 and 2017, but actual trades occurred on only two of those pipelines. Publicly reported trade volumes constituted only a fraction of the nameplate capacity of those pipelines.[80]

The ACCC reported congestion issues on many key pipelines. It found APA Group's reported capacity availability for the South West Queensland Pipeline did not provide an accurate picture of actual capacity. The pipeline is a key element in the north–south pipeline grid, and also connects the Northern Territory with the eastern gas market. The Moomba to Adelaide Pipeline (a key route into Adelaide) reportedly has no firm capacity available until 2020. The ACCC also reported compression services at Wallumbilla appear to be contractually congested.[81]

Reforms making it easier for gas customers to negotiate access to underused capacity on transmission pipelines will be implemented in 2019 (section 4.13.2.).

4.9.5 Supply–demand balance

A sharp rise in demand for eastern Australian gas since 2014 (mainly for LNG exports), combined with uncertainties about future gas supply, heightened concerns in 2017 that gas production may not be sufficient to meet domestic demand. In that year, the ACCC and AEMO raised imminent threats a gas supply shortfall could emerge as early as 2018. The ACCC described the market as 'dysfunctional', noting various factors had disrupted the market at a time when it was already undergoing significant change.[82]

Key factors impacting the market in early 2017 included:

- higher gas demand for power generation in Victoria and South Australia following the closure of coal fired generators
- a lack of domestic supply from Queensland's LNG producers due to low oil prices scaling back their drilling activity. In addition, operational testing at the APLNG plant in 2017 restricted its capacity to sell gas into the domestic market.
- forecasts of declining gas production in Victoria in 2018.

But the supply outlook was more optimistic in 2018. In June AEMO forecast a supply gap for the east coast market was unlikely to materialise until at least 2030. The ACCC in July 2018 also noted a significantly improved gas supply outlook, reporting the risk of a gas supply shortfall for 2019 was substantially lower than predicted in 2017.

A key contributor to the improved supply outlook was the Australian Government's threat of market intervention in 2017, which prompted the LNG producers to sell more gas to the domestic market (section 4.9.2). Other key factors included:

- significantly lower forecast gas demand for power generation—AEMO in 2018 forecast demand of 88 PJ, compared with its 2017 year-ahead forecast of 176 PJ. It attributed the shift to higher levels of renewable generation.
- higher production forecasts by Victorian producers for 2019 (including from the new Sole project)
- new gas flows entering the market from the Northern Territory (section 4.11).

The ACCC noted uncertainty remains despite improved conditions. First, gas demand for power generation can be volatile and difficult to forecast. Second, some production (around 9 per cent) is forecast to come from undeveloped (and less certain) gas fields. Third, the nature of CSG development and the need for continuous drilling of wells means there is inherent uncertainty around the quantity of gas that will be extracted.[83]

Some commentators question AEMO's forecast of no east coast gas supply gaps before 2030. EnergyQuest describes the conclusion as 'surprising,' arguing it relies on all current 2P resources being successfully developed, and early development of contingent resources from around 2021, despite limited recent investment that might enable this development.[84]

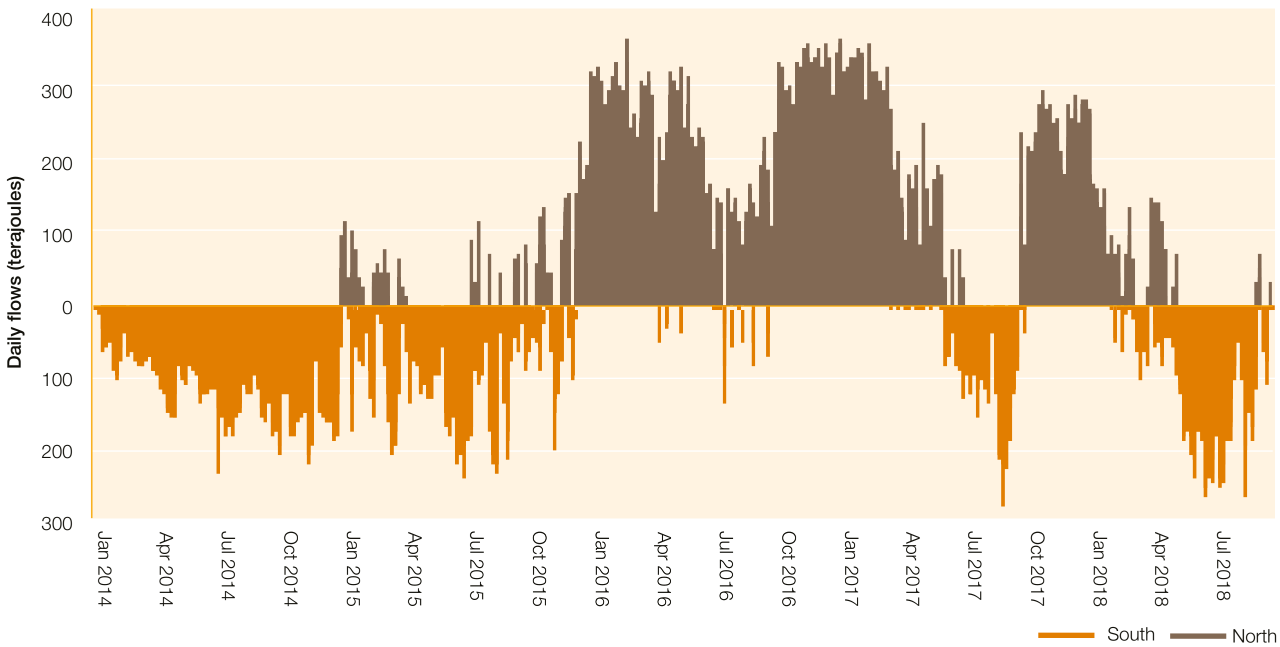
4.9.6 Interregional gas trade

A signature feature of the domestic gas market since 2014 is the role of interregional gas trades to manage the supply–

80 AEMC, *Final report: biennial review into liquidity in wholesale gas a pipeline trading markets*, August 2018, pp. 15–16.
81 ACCC, *Gas inquiry 2017–2020—Interim report,* July 2018, pp. 37, 74. Compression capacity at Wallumbilla is necessary to transport gas on the South West Queensland Pipeline to the southern states if a shipper does not have access to high pressure receipt points at Wallumbilla.
82 ACCC, *Gas inquiry 2017–2020—Interim report,* July 2018, p. 18.
83 ACCC, *Gas inquiry 2017–2020—Interim report,* July 2018, p. 15.
84 EnergyQuest, *Energy Quarterly*, September 2018, p. 12.

Figure 4.14

North–south gas flows in eastern Australia



Note: Flows on the QSN Link section of 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; Gas Bulletin Board (data).

demand balance. Key pipelines have been re-engineered as bi-directional, enabling them to respond more flexibly to regional supply and demand conditions.

Queensland's LNG producers shipped substantial volumes of surplus gas to the southern states in 2014 during the production ramp-up to commissioning LNG trains. But once LNG exports began in 2015, the direction of trade reversed, as LNG projects drew gas from Victoria and South Australia to cover shortfalls in their own reserve portfolios. This trend has continued, most noticeably during the northern hemisphere winter (Australian summer) when Asia's LNG demand peaks (figure 4.14).

Conditions in the domestic electricity market also affect trade flows. Increased demand for gas powered generation in the southern states following the closure of coal fired generators draws gas south, especially during the Australian winter when heating demand peaks. In 2018 gas flows turned southbound even before the onset of winter. The shift was accentuated by weak local demand for gas in Queensland, following state government intervention in the electricity market that weakened demand for gas powered generation (section 2.12.1).

The threat of government intervention in the gas market (section 4.9.2) 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. Despite high LNG prices in early 2018 (the northern hemisphere winter), less gas flowed north in the domestic market during this period than in 2016 or 2017.

Santos' GLNG project, which sources gas from southern and central Australia to meet its export commitments, has been especially active in facilitating more gas supplies to the domestic market since 2017. It entered new supply agreements with southern gas generators Qenos (to supply ethane gas) and Wesfarmers, and made a $900 million investment in new gas field developments.[85]

The data on trade flows may understate the impact of government intervention in the gas market. Some gas producers entered swap agreements to increase deliveries to southern gas customers *without* physically shipping it along pipelines. An example is Shell's agreement

85 Santos media centre 14 August 2017, 8 September 2017, 22 November 2017, 15 February 2018 and 27 February 2018.

with Santos to swap at least 18 PJ of gas.[86] Under the agreement, Shell draws on its CSG reserves to meet part of Santos' LNG supply obligations in Queensland, while Santos diverts gas from the Cooper Basin to meet demand in southern Australia.[87] The swap allows the producers to increase supply to the domestic market, but allows Shell to avoid accessing the South West Queensland Pipeline.

Gas flows into NSW

NSW produces little of its own gas and is, therefore, highly trade dependent. EnergyQuest in 2018 reported Queensland was supplying more gas to NSW following the Australian Government's market intervention, displacing some supplies from Victoria. This shift reflected in a significant rise in gas volumes being shipped along the Moomba to Sydney pipeline. EnergyQuest considers the pipeline now plays a critical role in providing gas to NSW on peak days.[88]

The ACCC in April 2018 reported signs of constraints in available pipeline capacity to NSW. In particular, the South West Queensland Pipeline has very limited uncontracted capacity between Wallumbilla (Queensland) and Moomba (the origin point of the Moomba to Sydney Pipeline). If south bound gas requirements continue to grow, these pressures may intensify.[89]

4.10 Gas prices

LNG export demand, combined with supply issues in southern and central Australia, contributed to a sharp escalation in wholesale gas prices, especially in 2016 and the first half of 2017. Prices stabilised to some degree from late 2017 into 2018, but remained at historically high levels.

More generally, the factors driving domestic gas prices have changed. Domestic prices are now linked to international oil and LNG prices, which are volatile and significantly higher than historical domestic gas prices.

4.10.1 Gas contract prices

A majority of gas prices are agreed in confidential bilateral contracts, with two main types of contracting—supply offers by gas producers to large customers, and supply offers by retailers and other aggregators to C&I customers.

Retailer and aggregator offers tend to be higher than producer prices, partly because they include retailers' costs and margins.

Gas contracts traditionally locked in prices and other terms and conditions for several years. More recently, the industry has shifted towards shorter term contracts with review provisions. The ACCC reported in 2018 that recent contract offers favoured durations of 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 durations of two years or less.[90]

Public information about contract prices is limited. Price information is often private and particular to specific contracts and negotiations. There is also disparity between the type of information available to large participants such as gas producers and retailers, 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. The ACCC in 2018 began publishing gas price data as part of its 2017–20 gas inquiry (section 4.13.1).

Contract price levels

Domestic gas contract prices historically averaged around \$3–4 per GJ. But when Queensland's LNG projects began sourcing gas for their projects from Victoria and South Australia, contract prices rose. The ACCC in March 2015 observed prices of around \$4–5 per GJ. By early 2017 prices of \$22 per GJ were being quoted for a one or two year contract—almost \$10 per GJ above export prices.[91] Contract prices executed by gas producers tended to be higher in the southern states than those executed in Queensland.

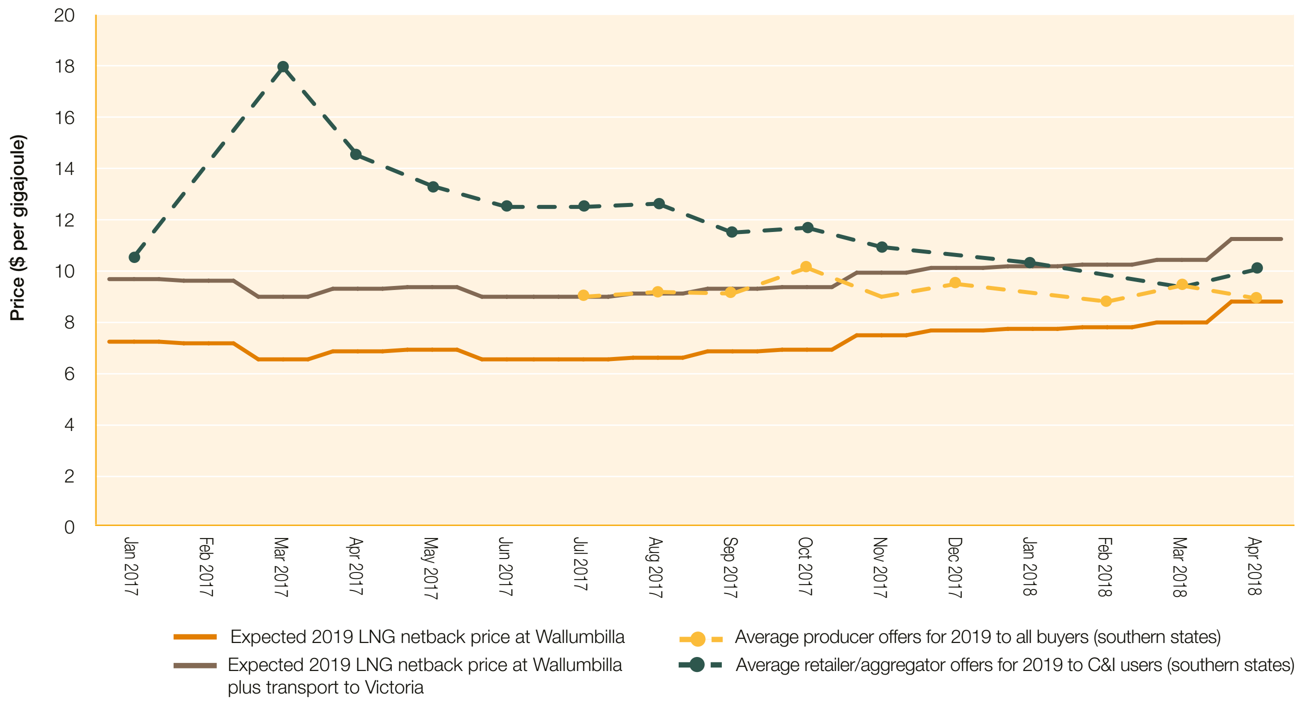
Following the Australian Government's market intervention in 2017 (section 4.9.2), Queensland producers began offering more gas to the domestic market at less onerous prices. By 2018 contract offers for supply in 2019 had eased back into the high \$8–11 per GJ range, aligning them more closely with LNG netback prices (box 4.4 and figure 4.15).

Rising international LNG prices meant by late 2018, domestic gas prices were around \$3 per GJ *lower* than export prices. Despite this outcome, domestic offers remained two to three times above historical prices and were often on less flexible terms. C&I users also reported

86 Santos, *Santos facilitates delivery of gas into southern domestic market*, media release, August 2017.
87 ACCC, *Gas inquiry 2017–2020—Interim report,* September 2017, p. 35.
88 EnergyQuest, *Energy Quarterly*, September 2018, p. 23.
89 ACCC, *Gas inquiry 2017–2020—Interim report,* April 2018, p. 55.
90 ACCC, *Gas inquiry 2017–2020—Interim report,* April 2018, p. 49.
91 ACCC, *Gas inquiry 2017–2020—Interim report* , July 2018

Figure 4.15

Gas price offers for 2019 supply and expected 2019 LNG netback prices



Note: Average monthly gas prices offered for 2019 supply against contemporaneous expectations of 2019 LNG netback prices. Prices are for gas commodity only. Actual prices paid may include transport and retail costs. Includes offers for gas supply of at least 12 months duration.

Source: ACCC, *Gas inquiry 2017–2020—Interim report*, July 2018 report (chart 2.6); Intercontinental Exchange, Argus (data).

the use of EOI processes by gas suppliers was making it more difficult to compare offers.[92]

Figure 4.15 illustrates movements in gas contract prices in the southern states relative to LNG netback prices. In 2017 offers for 2019 gas supply to C&I gas users were well above export parity prices. At their peak in March 2017, domestic prices offered by retailers and aggregators nearly doubled LNG netback prices. In an efficient market, a Victorian gas customer should have been able to buy gas for around $10 per GJ—the export parity price plus the cost of transporting gas from Queensland to Victoria.

While prices being quoted by gas producers were much closer to export parity prices, smaller C&I customers generally do not have options to buy gas directly from producers. Nor can easily they acquire the pipeline capacity to ship the gas. These users were affected more than other gas buyers by the record gas price offers being quoted in early 2017.

Prices offered by retailers and aggregators decreased over the course of 2017 as market dynamics improved. By early 2018 price offers had aligned with expected 2019 LNG netback prices at Wallumbilla, which have increased since mid-2017. By mid-2018 domestic price offers were tracking *below* export parity prices.[93]

4.10.2 Spot market prices

As discussed in section 4.8, three separate spot markets for gas operate in eastern Australia—*gas supply hubs* at Wallumbilla, Queensland and Moomba; the *short term trading market* for gas, with hubs in Sydney, Brisbane and Adelaide; and Victoria's *declared 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, though they often move in similar directions. But while contract prices reflect expectations of future market conditions, the spot markets reflect short term shifts

92 ACCC, *Gas inquiry 2017–2020—Interim report* , July 2018.

93 ACCC, *Gas inquiry 2017–2020—Interim report,* July 2018, pp. 52–56.

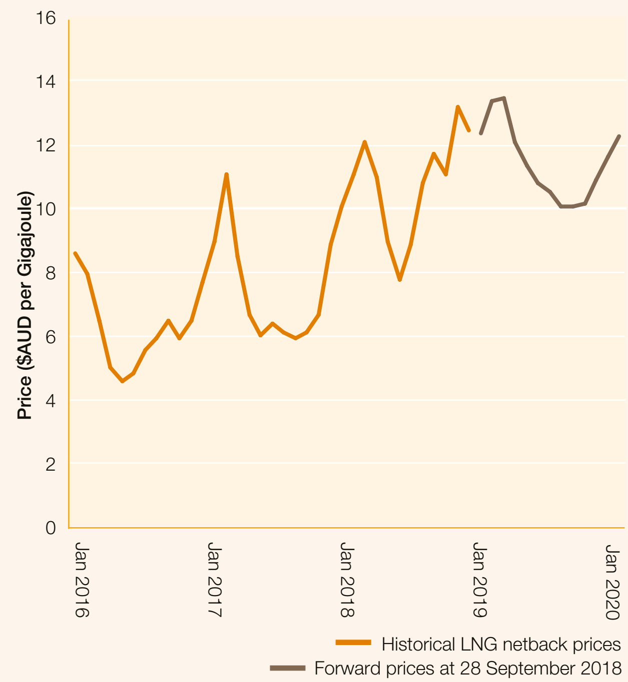
Box 4.4 Liquefied natural gas netback prices

LNG netback prices estimate the export parity price 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 cost include liquefaction at Gladstone, waterborne shipping to Asia and regasification in Asia.

If LNG netback prices exceed domestic prices, it becomes more profitable to export gas than to sell it locally. At times during 2017 the reverse situation prevailed in eastern Australia—domestic gas prices exceeded LNG netback prices. 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 publishes LNG netback prices to improve transparency in the eastern gas market. LNG netback prices tend to peak during the northern hemisphere winter, when LNG demand is highest. Expected netback prices for 2019 supply reached $12 per GJ in February 2018, before easing during the year. A global shift in oil and LNG prices during 2018 saw LNG netback prices move higher during the year, with expectations they will keep rising until the northern hemisphere's 2018–19 winter, when they could reach levels around $15 per GJ (figure 4.16).

Figure 4.16
LNG netback prices



Note: Prices at 28 September 2018.

Source: ACCC, www.accc.gov.au/regulated-infrastructure/energy/gas-inquiry-2017-2020/lng-netback-price-series; historical prices: S&P Global Platts; LNG futures prices: Intercontinental Exchange; forward LNG freight prices: Argus Media Ltd.

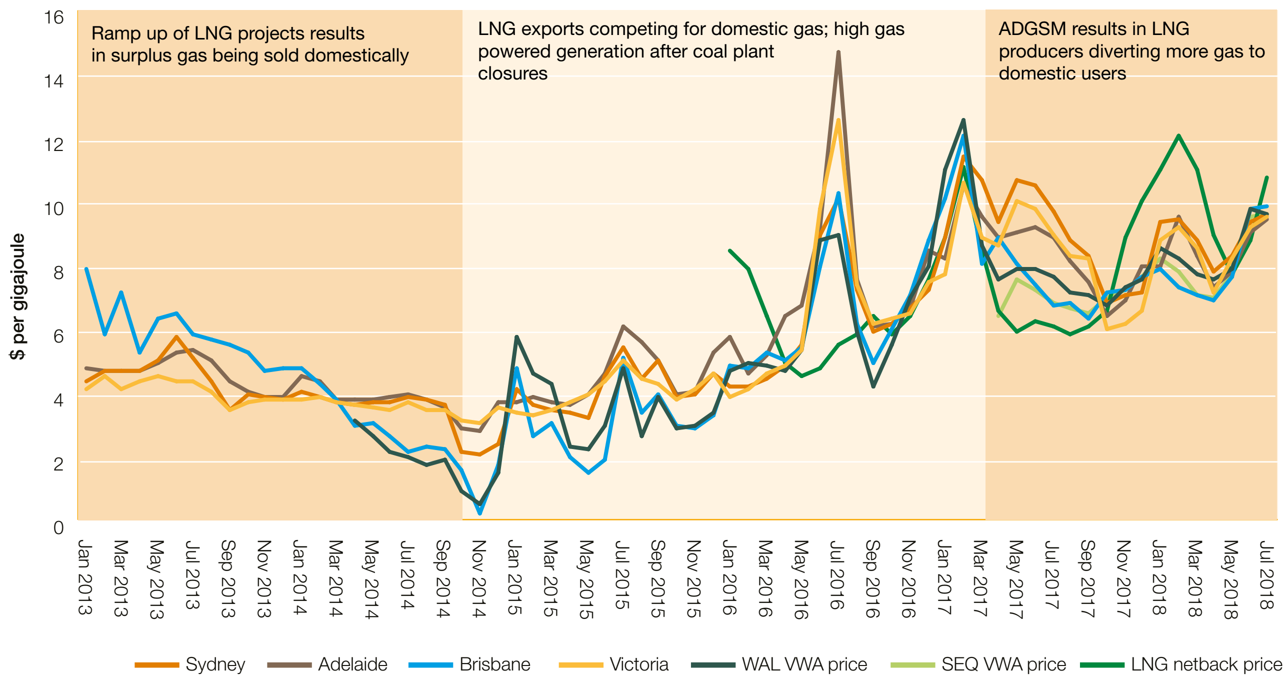
Table 4.3 Gas spot prices

	GAS PRICE ($ PER GJ)					
	2012–13	2013–14	2014–15	2015–16	2016–17	2017–18
Sydney	5.20	4.03	3.44	5.05	8.81	8.50
Adelaide	5.09	4.31	3.77	5.74	8.83	8.06
Brisbane	5.92	4.55	2.28	4.66	8.21	7.46
Victoria	4.49	3.87	3.63	4.99	8.58	8.03
Wallumbilla		2.74	2.74	4.37	8.27	7.80
South east Qld					7.32	7.49

Note: Prices are annual weighted averages. Sydney, Adelaide and Brisbane prices on short term trading market; Victorian prices on Victorian declared market; Wallumbilla and south east Queensland prices at Wallumbilla hub.

Source: AER, AEMO.

Figure 4.17
Spot gas and LNG netback prices



ADGSM, Australian Domestic Gas Security Mechanism; SEQ, south east Queensland; VWA, volume weighted average; WAL, Wallumbilla.

Note: Spot prices are monthly weighted averages. 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; AEMO; ACCC (LNG netback prices).

in market conditions relating to factors such as the timing of LNG shipments and conditions in the electricity market.

The launch of LNG exports in January 2015 caused spot prices to increase as LNG producers competed with domestic customers for gas supplies (table 4.3 and figures 4.17 and 4.18). Prices spiked in winter 2016, when LNG demand coincided with high domestic demand for heating and a rise in gas demand for power generation following the shutdown of South Australia's Northern power station. The retirement of Victoria's Hazelwood generator in March 2017 again put pressure on the market, with gas powered generation being called on to fill some of the gap in the electricity market.

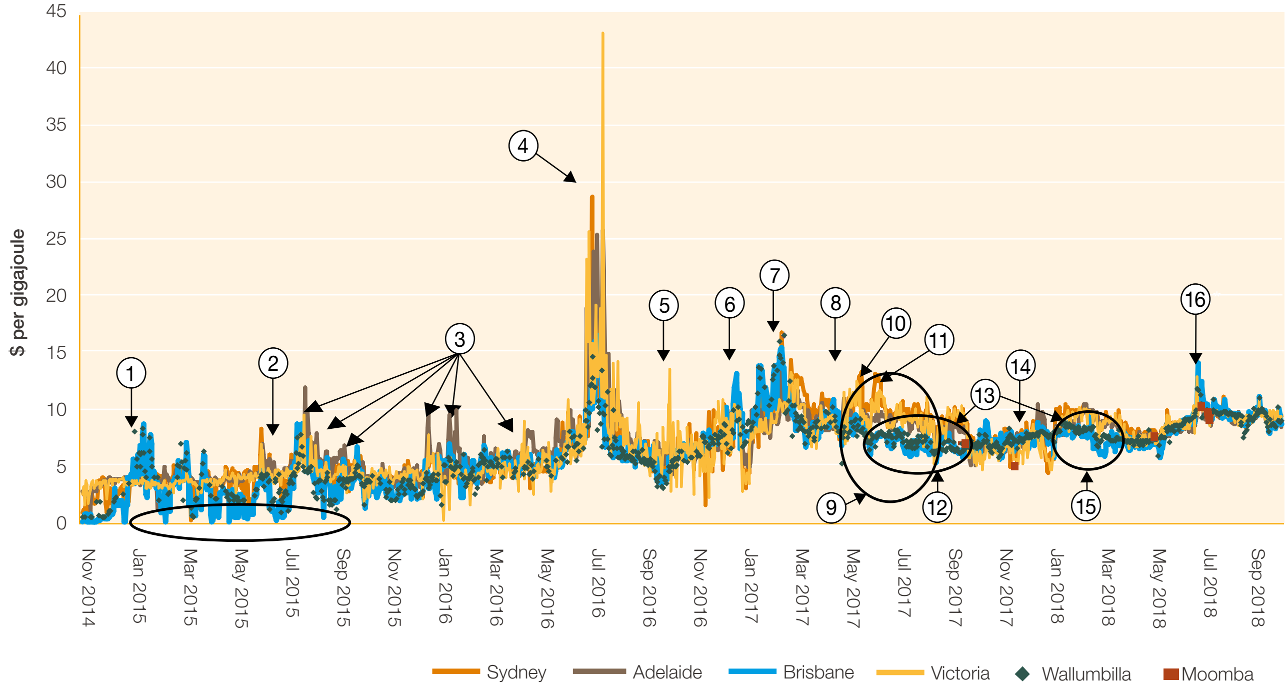
Spot prices vary seasonally, both within and across the markets. Prices tend to peak in summer and winter. In summer, gas demand for electricity generation tends to push up domestic spot prices. Australia's summer also coincides with the northern hemisphere winter, when Asian demand for LNG peaks. In 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 (box 4.5).

Monthly spot prices averaged $10–12 per GJ in all spot markets in February 2017. As noted, market intervention by the Australian Government in 2017 increased gas supplies to the domestic market and eased price pressures in the later months of 2017. Prices again tracked higher from November, when plant outages at Longford affected southern supplies. A particularly cold winter in the northern hemisphere fuelled high LNG demand in the early months of 2018, at times coinciding with high domestic demand for gas powered generation. Spot prices eased during autumn 2018, before again moving higher as winter approached.

Despite some price stability returning to the market in 2017–18, monthly prices continued to average $6–$10 per GJ—well above prices before LNG exports began. Average prices for the year in Sydney, Victoria and Adelaide remained above $8 per GJ for a second year.

Figure 4.18

Daily gas spot prices



1	Jan 2015	First LNG exports from Queensland.
2	Jan to Sep 2015	Low prices when LNG producers sold ramp gas on spot markets.
3	Jul 2015 to Apr 2016	Low wind generation coincided with high electricity demand, spiking gas powered generation demand when gas supplies were limited (multiple instances).
4	Winter 2016	Southern gas diverted to Queensland to supply LNG producers, high gas powered generation following closure of Northern power station, and high winter demand.
5	1 Oct 2016	Longford plant outage reduced gas flows to zero for several hours.
6	19 Dec 2016	Longford outage (planned) coincided with high gas powered generation.
7	Jan 2017	LNG exports increased, drawing gas supplies from the south, coinciding with high gas powered generation demand over summer.
8	27 Apr 2017	Australian Government announced Ministerial discretion to limit LNG exports to address domestic gas shortfall (ADGSM).
9	May to mid-Aug 2017	APLNG (Santos) project in testing mode, limiting ability to supply domestic gas.
10	Mid-May 2017	Closure of Hazelwood generator coincided with Longford maintenance and higher winter demand.
11	Winter 2017	High gas powered generation as coal plant out for maintenance during cold weather period.
12	Mid-May to Oct 2017	Outages on Queensland export pipelines motivated increases in gas flows south.
13	Mid-May to Oct 2017, and Jan to Apr 2018	Threat of ADGSM motivated LNG producers to divert more gas to domestic market, easing price pressure.
14	30 Nov 2017	Longford outage coincided with high gas powered generation, and LNG prices rose off high Asian demand.
15	Jan to Apr 2018	Lower Queensland demand for gas powered generation following Queensland Government direction to increase coal generation led to more Qld production diverted south.
16	17 to 22 Jun 2018	Longford outages constrained Victorian supply, coinciding with high gas powered generation demand in South Australia, Victoria and Queensland, and a Queensland pipeline outage.

Box 4.5 North–south price divide

A significant differential between spot gas prices in Queensland (Wallumbilla and Brisbane) and the southern states emerged for much of 2017 (figure 4.19). Southern gas was more expensive by over $2 per GJ for much of this period—roughly the cost of transporting Queensland gas to the southern states.

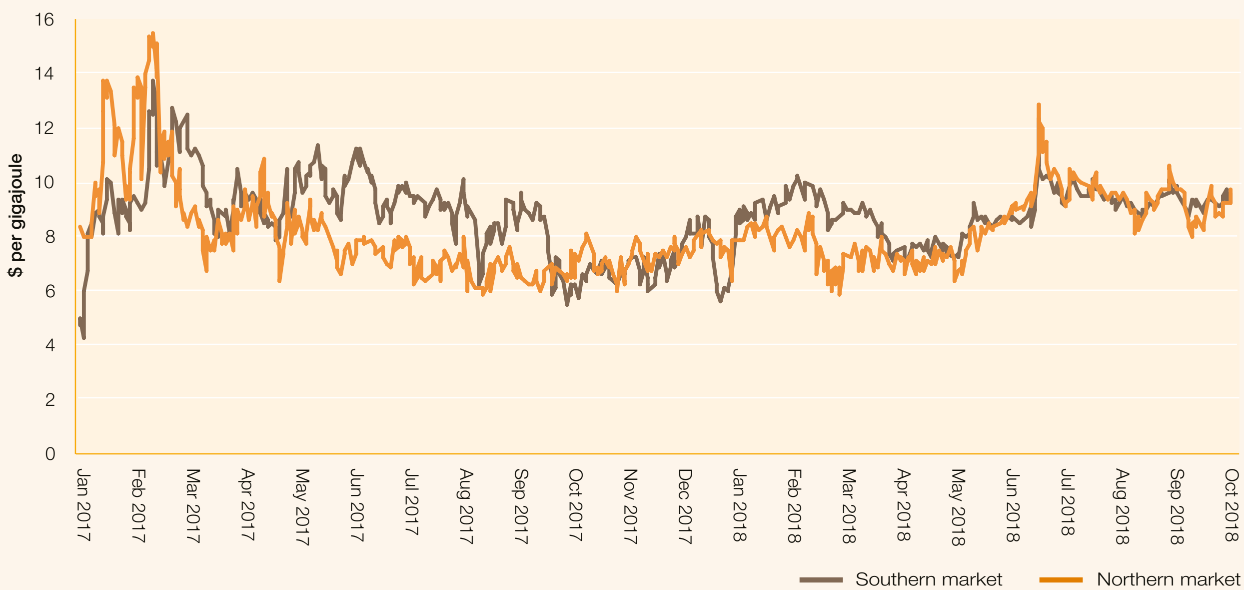
The price difference reflected contrasting demand and supply conditions in the two regions. In Queensland, a significant rise in gas production at Roma (Queensland) in 2017 increased supply, while outages at LNG plants suppressed gas demand. But high demand for gas powered generation in southern Australia coincided with tight supply in the region.

The price differential eased in late 2017 following the Australian Government's market intervention. But it returned in early 2018 when gas plant outages in Victoria (section 4.9.2) meant the southern states relied more on Queensland gas, thus incurring pipeline costs.

Prices largely converged from March 2018, partly because swap agreements between Queensland producers and southern buyers allowed more gas to enter the southern markets without using pipeline transport, resulting in significant transport savings. Storage may also have played a role, as participants used the Iona facility to store gas during off-peak months for reinjection during the winter peak.

Figure 4.19

North–south gas price divide



Note: Southern market is average of NSW, Adelaide and Victorian spot prices. Northern market is average of Brisbane and Wallumbilla spot prices.
Source: AER.

4.11 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, importing LNG, transmission pipeline solutions, and demand response.

4.11.1 Gas field development

Exploration and development in a number of gas fields has increased since international oil and gas prices began to rise in 2017. Additionally, higher domestic gas prices and government funding have improved the economics of some resources and projects. Governments are offering financial or regulatory incentives for projects targeting gas supplies to the domestic market (section 4.12). 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 moratoria on onshore exploration and fracking have impeded the development of gas projects in Victoria, South Australia and Tasmania (section 4.9.3). Elsewhere, stringent regulatory processes apply, as highlighted by the stalled process for Santos' 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 moratoria and constraints in place, a number of development projects look positive and could result in additional supply being brought to the domestic market.

In Victoria, Cooper Energy's Sole gas field in the Gippsland Basin is scheduled to begin commercial production in July 2019.[94] The project, which can produce up to 68 terajoules (TJ) per day, will link to the Orbost Gas Plant, which is being upgraded to treat the gas. Cooper Energy plans to develop its Manta gas field, after developing Sole.

Beach Energy in January 2018 announced a new gas discovery in the Otway Basin.[95] The proposed Katnook Gas Processing Facility (to be partly funded by the GAP scheme) will purify resources from the project.[96]

The Victorian Government in May 2018 released five new oil and gas exploration blocks in the offshore Otway Basin. The release forms part of the Australian Government's Offshore Petroleum Exploration Acreage Release program, aimed at promoting petroleum exploration in Australia's offshore waters.[97]

In NSW, Santos aims to develop 850 wells across its 95 000 hectare Narrabri Gas Project, which has potential to supply up to 200 TJ per day.[98] Environmental and community groups have widely opposed the project's environmental impact. Over 23 000 submissions were made in response to the environmental impact statement, mostly in opposition.[99] The project's status will be determined by the Independent Planning Commission. At July 2018 the project was awaiting an independent review.

In Queensland, the Kincora project (Armour Energy) began processing gas from surrounding wells in December 2017.[100] Armour is expanding its activity in the region after receiving a $6 million grant under the GAP scheme in March 2018. The project is expected to deliver 6.9 PJ by June 2020.[101] 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 4.12.3).[102]

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 LNG partners announced they would invest $900 million in upstream developments in 2018,[103] including the Roma East project, which is expected to produce 50 PJ of gas annually

94 Cooper Energy, *Sole-3 flow-back completed successfully*, ASX Announcement, 6 July 2018.
95 Beach Energy, *New Gas Field Discovery in the Otway Basin, South Australia*, 11 January 2018.
96 Beach Energy, *Quarterly report for the period ended 31 March 2018*, 24 April 2018, p. 13.
97 Department of Industry, Innovation and Science, *Offshore Petroleum Exploration Acreage Release*, accessed 4 July 2018, www.petroleum-acreage.gov.au/.
98 Santos, *Narrabri Gas Project*, available at: www.narrabrigasproject.com.au/ask-us-categories/the-project/.
99 Department of Planning and Environment, *NSW Government assessment of the Narrabri Gas Project proposal update*, media release, 23 April 2018.
100 Armour Energy, *Kincora Gas Project,* available at: www.armourenergy.com.au/kincora-gas-project.
101 Minister for Resources and Northern Australia, *New East Coast Supply from Gas Acceleration Program*, media release, 28 March 2018.
102 Armour Energy, *Kincora Gas Project,* available at: www.armourenergy.com.au/kincora-gas-project.
103 Santos, *Santos GLNG to invest $900m in Queensland gas fields in 2018*, media release, 27 February 2018.

from 2020. The partners also announced a further $400 million investment in the Arcadia gas project, which at its peak would deliver about 27 PJ per annum to the GLNG project.[104]

In June 2018 Senex and Jemena announced a partnership to fast track bringing gas from Senex's Project Atlas in the Surat Basin to the domestic market by late 2019.[105] Jemena will build a 40 TJ per day gas processing facility and pipeline to deliver gas from the project to the Wallumbilla Hub.

In South Australia, Strike Energy is continuing work on its Southern Cooper Gas Project which, if successful, would be the deepest coal seam gas well drilled in Australia.[106] Production testing to confirm commercial quality was scheduled for 2018.[107]

4.11.2 LNG import terminals

While conditions eased in the east coast gas market in 2018, considerable uncertainty remains. To address these concerns, industry was considering at least four projects to develop LNG import facilities on the east coast. Each project would involve importing LNG through floating storage and regasification units. EnergyQuest reported the facilities are relatively inexpensive ($250–300 million each) compared to building new pipeline infrastructure or paying long haul transmission charges from Queensland.[108]

AGL expects to reach a final investment decision in 2018–19 on its $250 million LNG import terminal near Melbourne. A proposal by Australian Industrial Energy for a LNG import terminal near Wollongong (NSW) is also progressing, aiming to receive its first gas by 2020. The NSW Government has tagged the plan with 'critical state significant infrastructure' status to help streamline regulatory processes.[109] Mitsubishi is considering an import terminal in South Australia to supply gas to the domestic market and for gas powered generation in the state.[110] A fourth proposal, by ExxonMobil, would use existing infrastructure at its Longford gas plant in Victoria.[111]

104 Santos, *Santos GLNG announces final investment decision on A$400 million Arcadia project*, media release, 31 May 2018.
105 Senex Energy, *Senex and Jemena fast-track Project Atlas gas to domestic market*, media release, 18 June 2018.
106 EnergyQuest, *Energy Quarterly*, March 2018.
107 Strike Energy, *JAWS-1 Project Update*, ASX Announcement, 26 June 2018.
108 EnergyQuest, *Energy Quarterly*, September 2018, p. 32–33.
109 Australian Financial Review, *Forrest plan earns 'strategic' status,* June 2018.
110 EnergyQuest, *Energy Quarterly*, September 2018, p. 33.
111 The Australian, *ExxonMobil considering Victorian LNG import plan*, 18 June 2018.

4.11.3 Northern Territory gas

Jemena's Northern Gas Pipeline began delivering gas from the Northern Territory to Queensland in 2018. Jemena is evaluating a 1000 km 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.[112] The pipeline has begun signing customers, including Incitec Pivot to deliver gas to its fertiliser plant until the end of 2019.[113] The government aims for gas exploration to resume during the 2019 dry season.[114]

4.11.4 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. 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 arrangements allows the group to access wholesale markets at better prices than would be possible if they acted individually.[115]

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 new LNG import facilities.[116] Some users have lowered their gas use by changing fuels or increasing efficiencies. MSM Milling's canola processing facility in NSW, for example, will replace LPG gas with a 4.88 megawatt biomass fired boiler using waste timber.[117]

Joint ventures between gas customers and producers are also occurring.[118] Incitec Pivot, in partnership with Central Petroleum, won a tender for a coal seam gas tenement release by the Queensland Government, and aims to be producing by 2022.[119]

112 AEMO, *2018 Gas Statement of Opportunities*, June 2018.
113 The Australian, *Incitec secures gas supply deals*, June 2018.
114 Hon. Matt Canavan, *Harnessing the potential of Northern Territory's gas industry,* 15 November 2018.
115 ACCC, *The Eastern Energy Buyers Group—Authorisations—A91594 & A91595*, August 2017.
116 ACCC, *Gas inquiry 2017–2020—interim report,* July 2018, p. 62–66.
117 ARENA, *MSM Milling Biomass Fuel Switch Project,* available at: www.arena.gov.au/projects/msm-milling-biomass-fuel-switch/.
118 AEMO, *2018 Gas Statement of Opportunities*, June 2018.
119 Australian Financial Review, *Incitec lures Richard Cottee back to Queensland's coal seams,* 1 March 2018.

4.12 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 referred to throughout this chapter, but are collated and summarised here.

4.12.1 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.[120] 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), in which they committed to offer uncontracted gas on reasonable terms to meet expected future 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 4.9.2).

The AEMC reported some stakeholders were concerned that, while government intervention may increase liquidity in the short term, it does not correct the underlying issue of participants lacking confidence 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.[121]

4.12.2 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 applicants announced in 2018 are based in Queensland. The fifth project was in South Australia's Otway Basin (section 4.11).[122]

4.12.3 Queensland and South Australian schemes

The Queensland and South Australian governments each have run programs to encourage gas exploration in the form of grants for 'domestic only' exploration tenements.

Queensland has released exploration tenements available exclusively for domestic gas supply. Senex won the first tender under the scheme in 2017, and in 2018 as gained a licence to produce. It expected to supply the eastern gas market within two years. In 2018 Central Petroleum and Armour Energy won a tender to explore 400 hectares in south west Queensland for gas exclusively for the Australian market.[123]

The South Australian Government's Plan for Accelerating Exploration scheme offered grants to increase gas supplies in the state and increase competition between suppliers. In 2017 nine grants were awarded to Santos, Senex, Strike, Beach and Vintage.[124] The scheme has now wound up.

4.12.4 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. The inquiry will run until 30 April 2020 and has released several interim reports.[125]

4.13 Gas market reform

The COAG Energy Council is directing gas market reforms, which are being implemented by regulatory and market bodies including the AER, AEMC, AEMO and ACCC.

120 Department of Industry, Innovation and Science, *Australian Domestic Gas Security Mechanism*, July 2018.

121 AEMC, *Final report: biennial review into liquidity in wholesale gas a pipeline trading markets*, August 2018, p. 46.

122 Department of Industry, Innovation and Science, *Gas Acceleration Program*, www.business.gov.au/Assistance/Gas-Acceleration-Program/Gas-Acceleration-Program-successful-applicants, accessed 19 October 2018.

123 Queensland Government, *Gas supply fast tracks to east coast market*, media statement, 29 March 2018.

124 Government of South Australia, PACE gas, available at www.energymining.sa.gov.au/petroleum/latest_updates/pace_gas, accessed 19 October 2018.

125 ACCC, *Gas inquiry 2017–2020*, available at www.accc.gov.au/regulated-infrastructure/energy/gas-inquiry-2017-2020.

4.13.1 Improving transparency

A number of reforms aim to improve transparency in the gas market, including reforms to the Gas Bulletin Board and improving the availability of information about market liquidity, prices and gas reserves.

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 took effect in September 2018 to bring the bulletin board closer to being a 'one stop shop' for the east coast gas system. The reforms remove most avenues for reporting exemptions and mandate provision of more comprehensive detail for covered facilities. Reporting obligations were also extended to facilities in the Northern Territory, recognising the Northern Gas Pipeline now connects the territory with the eastern gas market.

Many gas facilities were covered for the first time in 2018, including gas storage facilities, which play an important role in assessing the future supply–demand balance. The Roma underground storage facility near LNG gas fields in south east Queensland was among the facilities covered for the first time. Significantly, 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. For the first time, market participants can access detailed information from production and compression facilities on their daily nominations, forecast nominations, intra-day changes to nominations, and capacity outlooks. This reporting brings added transparency to production outages, which informs market responses and helps maintain security of supply.

In the pipeline sector, operators must now submit daily disaggregated receipt/delivery point data. 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 for the first time. The AER will assess the quality and accuracy of the data submitted by market participants against a new 'information standard' to ensure the information presented on the bulletin board has integrity. The AER published a compliance note outlining its approach to enforcement.

In 2019 the AEMC will progress further bulletin board reforms that extend reporting to large gas users and LNG processing facilities, and to the reporting of gas reserves.

Liquidity information

The AEMC in August 2018 published its first review into liquidity in wholesale gas spot markets and pipeline capacity trading markets. The review publishes quantitative and qualitative indicators based on a survey of market participants. The AEMC found most indicators reflect improved liquidity at the Wallumbilla gas supply over the past two years. Complementing the review, the AER in August 2018 began publishing a range of quantitative metrics for gas markets on the industry statistics page of its website. It will regularly update this data.

Price and reserves transparency

With gas markets shifting towards shorter term contracts and suppliers using EOI processes, transparency on price and other market information is critical. 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.[126] It will also publish a volume weighted wholesale gas price series. Publishing this data aims to help gas users negotiate more effectively with gas producers and retailers when entering into new gas supply contracts.

Public information on gas reserves and resources tends to lack clarity, consistency and accuracy, which limits the ability of market participants to identify future supply issues and plan accordingly. In late 2018 the ACCC began publishing data on gas reserves and resources, drawing on information provided by reserve owners.

4.13.2 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 it unavailable to third parties. Contractual congestion may occur even if a pipeline has spare physical capacity.

Three major pipelines—the South West Queensland Pipeline, Moomba to Adelaide Pipeline System and the

126 ACCC, *Gas inquiry 2017–2020—LNG netback price series*, available at: www.accc.gov.au/regulated-infrastructure/energy/gas-inquiry-2017-2020/lng-netback-price-series.

Moomba to Sydney Pipeline—were close to fully contracted in 2018, limiting shippers' ability to transport gas between northern and southern markets.[127]

To manage pipeline congestion issues, some gas producers engage in swap agreements—bypassing 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, therefore, unlikely to be an effective long term solution to gas pipeline issues.[128]

Secondary trading in underused capacity

Congestion issues have focused policy attention on ensuring any spare physical pipeline capacity is made available to the market. Reforms to launch a voluntary trading platform for underused capacity take effect in March 2019. The platform will enable secondary trading of contracted pipeline capacity that is not being used. It will also apply to compression facilities. Any underused capacity that is not traded will be put to a compulsory day-ahead auction with a reserve price of zero.[129]

To promote transparency, prices and other key terms in all voluntary trades, as well as the day-ahead auction results, will be published on the Gas Bulletin Board. Standardised provisions in capacity trading contracts will make capacity easier to trade.

The AER will monitor compliance, including with capacity trading regulations and the proper reporting of trades. We will also oversee the resolution of any disputes over cost recovery.

Information disclosure and arbitration

Negotiating a fair price to use a gas pipeline is an ongoing issue, with concerns about monopolistic pricing practices raised by the ACCC,[130] as well as by Dr Michael Vertigan's review for COAG in 2016.[131] The reviews highlighted a lack of transparency and unequal bargaining power between shippers and pipeline operators.

These concerns led to introducing 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 can apply for arbitration. Chapter 5 describes the Part 23 regime in more detail.

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.[132] The review recommended removing a number of inconsistencies between these tiers by:

- requiring 'light regulation' pipelines to publish prices for each pipeline service, as well as reporting similar financial information to that required for 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 similar capacity and use information to that which other distribution pipelines are required to report
- including all pipeline expansions within the regulatory framework of the existing pipeline, rather than being subject to separate arrangements
- widening the scope of pricing information to cover services, including bi-directional flow, and park and hold services.[133]

The COAG Energy Council in late 2018 proposed rule changes to implement the reforms, which the AEMC aims to finalise in March 2019.[134]

127 ACCC, *Gas inquiry 2017–2020—Interim report*, December 2017, p.59.
128 ACCC, *Gas inquiry 2017–2020—Interim report*, December 2017.
129 Gas Market Reform Group, *Capacity Trading Reform—Implementation.*
130 ACCC, *Inquiry into the east coast gas market*, April 2016, pp.99–106.
131 COAG Energy Council, *Examination of the current test for the regulation of gas pipelines*, December 2016.
132 Chapter 5 outlines the tiers of gas pipeline regulation.
133 AEMC, *Review into the scope of economic regulation applied to covered pipelines*, July 2018.
134 AEMC, *AEMC fast tracks draft rules to improve regulation of covered gas pipelines*, media release, 6 December 2018.

Australian Associated Press

5 REGULATED GAS NETWORKS

Gas pipeline networks transport gas from upstream producers to energy customers. Australia's gas pipeline networks consist of long haul *transmission* pipelines that carry gas from producing basins to urban and regional *distribution* networks, which serve 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 only face limited regulation. This chapter explains the various tiers of regulation that apply, but mainly focuses on 'full regulation' pipelines—those for which the AER sets access prices.[2]

Currently, the AER only fully regulates 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 fully regulates major networks in New South Wales (NSW), Victoria, South Australia and the Australian Capital Territory (ACT).

5.1 Gas pipeline services

Gas pipeline companies earn revenue by selling capacity to third parties needing to transport gas—termed providing access. Pipeline customers include energy retailers needing to transport gas to energy consumers, large commercial and industrial users, and liquefied natural gas (LNG) exporters that contract for gas directly with producers.

Gas transmission pipelines transport gas from production fields to major demand centres or hubs. The pipelines typically have wide diameters and operate under high pressure to optimise shipping capacity.

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—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.

1 The Economic Regulation Authority (ERA) administers separate regulatory arrangements in Western Australia.

2 Chapter 4 discusses the wider gas transmission sector, including pipelines not under full regulation.

Backhaul (reverse direction transport) is also sought by some customers. Gas can also be stored (parked) in a pipeline on a firm or interruptible basis.

As the gas market evolves, increasingly sophisticated types of services are being offered, such as compression (adjusting pressure for delivery), loans (loaning gas to a third party), redirection and in-pipe trades.

Some transmission pipelines only interconnect with other transmission pipelines. Others deliver gas to power stations, large industrial and commercial plant, and retailers who then sell the gas to their customers. A number of pipelines deliver into an urban or regional *gas distribution network*, a spaghetti-like cluster of smaller pipes that transports gas to customers in local communities.

Distribution networks consists of high, medium and low pressure pipelines and run underground. The high and medium pressure mains provide a 'backbone' servicing 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—allowing gas injections into a pipeline, conveying it to supply points, and allowing the gas to be withdrawn.

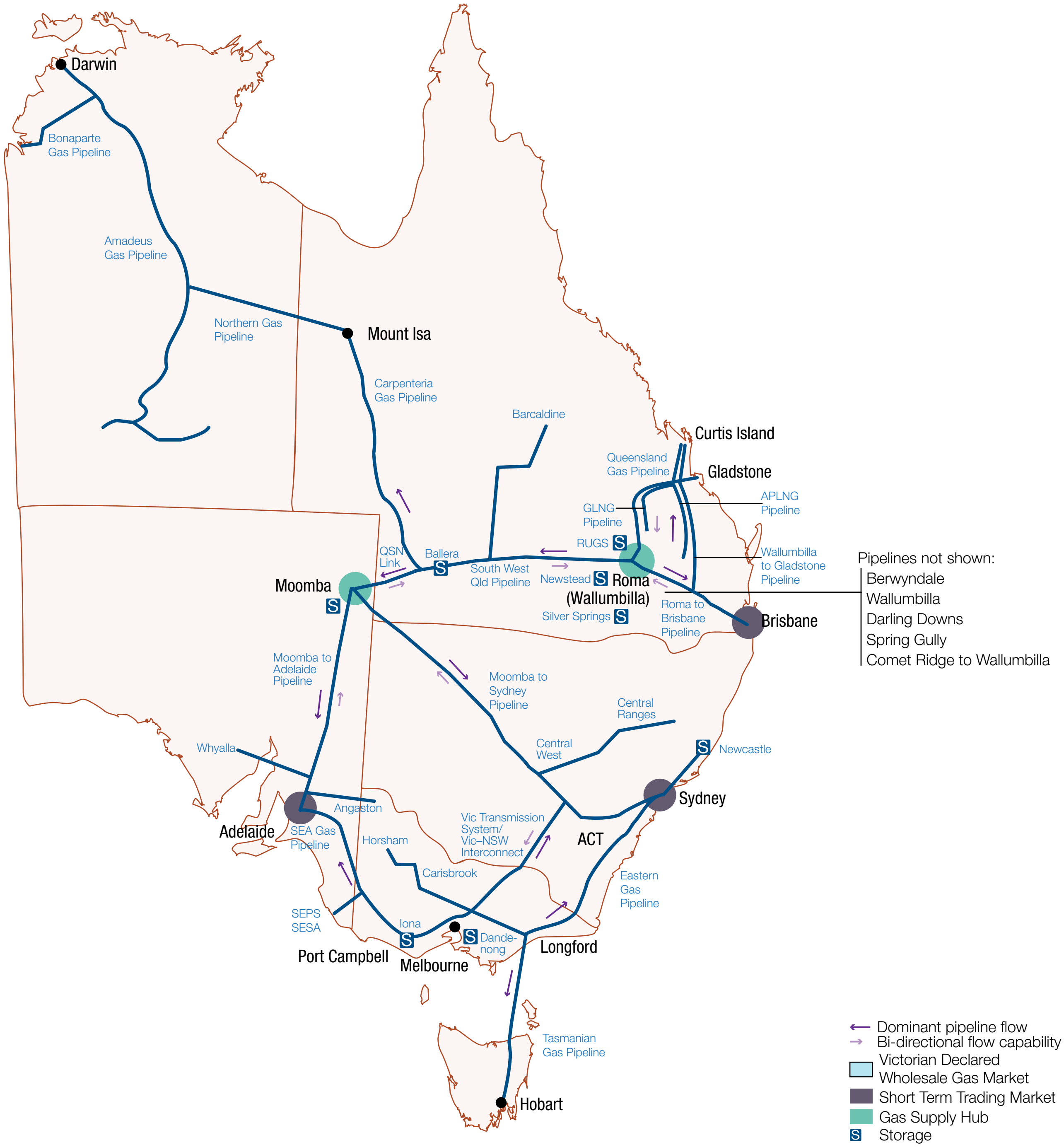
The total length of gas distribution networks in eastern Australia is around 77 000 kilometres. Gas is distributed to most Australian capital cities, major regional areas, and towns. Victoria and Queensland each have multiple distribution networks serving particular areas of the state. NSW, South Australia, Tasmania and the ACT each have a single network.[3]

While gas distributors transport gas to energy customers, they do not sell it. 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 retail products.

3 Some jurisdictions also have smaller unregulated regional networks, such as the Wagga Wagga network in NSW.

Figure 5.1

Gas pipeline networks regulated by the AER



Source: AER.

5.2 Gas pipeline ownership

Australia's gas pipelines are privately owned. Tables 5.1 and 5.2 detail ownership arrangements for pipelines regulated by the AER. Chapter 4 includes information for other pipelines.

The publicly listed APA Group (APA) is the principal owner in the gas pipeline sector. Its portfolio is mainly in the gas transmission sector. Other participants include Jemena (owned by the State Grid Corporation of China and Singapore Power International) and Cheung Kong Infrastructure and its associates (which operates Australian Gas Networks). The State Grid Corporation of China and Singapore Power International also have interests in the publicly listed AusNet Services.

The State Grid Corporation of China, Singapore Power International and Cheung Kong Infrastructure and its associates also have ownership interests (some substantial) in the electricity network sector.

Cheung Kong Infrastructure and its associates recently acquired a number of assets in the energy network sector. In 2017 they acquired DUET Group's gas and electricity assets—Victoria's Multinet gas distribution network, Western Australia's Dampier to Bunbury Gas Pipeline, and equity in Victoria's United Energy electricity distribution network. In 2014 they acquired gas pipeline business Envestra (now operating as Australian Gas Networks).

In 2018 the entities launched a takeover bid for APA, Australia's largest gas pipeline business. 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 it 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 and their average costs decline as output rises. This can give rise to a *natural monopoly* structure, where it is more efficient to have a single provider than multiple providers offering the same pipeline services.

But monopolies face no competitive pressure, so have opportunities and incentives to charge unfair prices. This poses serious risks, because pipeline charges make up a significant portion of a residential gas bill (chapter 1). 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 applicable to each pipeline, considering whether:

- the pipeline is a natural monopoly
- regulation would promote competition
- regulation would be cost effective (that is, the benefits of regulation outweigh the costs).

The AER's role in gas pipeline regulation is summarised in box 5.1.

Box 5.1 The AER's role in gas pipeline regulation

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 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.

4 The Hon. Josh Frydenberg MP, Treasurer, *Proposed Acquisition of APA*, 7 November 2018.

From 2019 we will monitor and enforce compliance with reforms to improve access to underused capacity in transmission pipelines, including bilateral trading and the mandatory auction of any contracted capacity that is not in use.

More generally, we advise policy bodies and other stakeholders on issues in the gas pipeline sector. We may propose or participate in rule change processes and engage in policy reviews with a view to improving the 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 close to $90 billion.

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*, which replaces upfront price regulation with a commercial negotiation approach supported by mandatory information disclosure. Other pipelines are free from any form of regulation.

Full regulation is discussed further in section 5.4.

5.3.2 Light regulation

Light regulation pipeline businesses must publish access prices and other terms and conditions on their website. If unable to negotiate access to the pipeline, a party may request the AER arbitrate a dispute. A light regulation pipeline owner may not engage in inefficient price discrimination or other conduct adversely affecting access or competition in other markets.

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. Queensland's two gas distribution networks—the Australian Gas Networks and Allgas Energy networks—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' and 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 in August 2017. 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 financial, service and access information, following guidelines published by the AER. The obligations on pipeline operators were phased in during 2018. The ACCC will review the quality of information published and report in 2019 on whether further disclosure is needed.

Customers can use the disclosed information 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 establishes 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 may correct errors in arbitrated access determinations. It also maintains a register of arbitrated access determinations.[7]

A pipeline owner can apply to the AER for an exemption from the disclosure provisions—for example, if a pipeline does not provide third party access, only has 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

The first access determination under the Part 23 rules was made on 12 April 2018 by Justin Gleeson SC. The dispute between Hydro Tasmania and Tasmanian Gas Pipeline (TGP)

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 AER, *Part 23 (Access to non-scheme pipelines) exemptions)*, available at www.aer.gov.au/networks-pipelines/non-scheme-pipelines/part-23-access-to-non-scheme-pipelines-exemptions.

Table 5.1
Full regulation pipelines

PIPELINE	LOCATION	CUSTOMER NUMBERS	LENGTH (KM)	CAPACITY (TJ/D)[1]	ASSET BASE ($ MILLION)[2]	ANNUAL INVESTMENT ($ MILLION)[3]	ANNUAL REVENUE ($ MILLION)[3]	CURRENT REGULATORY PERIOD[4]	OWNER
TRANSMISSION									
APA Victorian Transmission System	Vic	na	2 035	1 030	976	240	525	1 Jan 2018–31 Dec 2022	APA Group
Roma to Brisbane Pipeline	Qld	na	867	211/125	461	67	223	1 July 2017–30 June 2022	APA Group
Amandeus Gas Pipeline	NT	na	1 658	104	124	17	109	1 July 2016–30 June 2021	APA Group
DISTRIBUTION									
Jemena Gas Networks	NSW	1 300 000	25 000	na	3 248	1 002	2 169	1 July 2015–30 June 2020	Jemena (State Grid Corporation, Singapore Power)
AusNet Services	Vic	647 000	10 478	na	1 555	480	958	1 Jan 2018–31 Dec 2022	Listed Company (Singapore Power 31%, State Grid Corporation 20%)
Multinet	Vic	687 000	9 866	na	1 199	398	956	1 Jan 2018–31 Dec 2022	Cheung Kong Group
Australian Gas Networks	Vic	613 454	10 447	na	1 580	554	1 113	1 Jan 2018–31 Dec 2022	Cheung Kong Group
Australian Gas Networks	SA	423 462	7 950	na	1 506	577	947	1 July 2016–30 June 2021	Cheung Kong Group
Evoenergy	ACT	137 806	4 911	na	381	114	309	1 July 2015–30 June 2021	ACTEW Corporation (ACT Government) 50%, Jemena (State Grid Corporation, Singapore Power) 50%

km, kilometres; na, not available; TJ/d, terajoules per day.

1. 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.
2. The asset base is the estimated value of network assets based on the closing regulated asset base (RAB) at 30 June 2017, except for Victorian transmission (31 March 2017) and Victorian distribution (31 December 2017). Data is in June 2018 dollars. The RAB rises each year due to new investment, and is lowered by depreciation, and assets disposals.
3. Investment and revenue as forecast for the current regulatory period in June 2018 dollars.
4. The current regulatory period at 1 July 2018.

over access to the TGP transmission pipeline was referred for arbitration in November 2017.

The dispute related to the valuation of assets used to provide the services required by the access seeker. The arbitrator determined an appropriate method reflecting the value of assets used in providing the required services (firm forward haul services, as available forward haulage) but excluding the value of assets used to provide separate services such as high priority storage services and interconnect services with the Victorian gas transmission system.[8]

8 AER, *Final access determination—Tasmanian Gas Pipeline*, April 2018.

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

Table 5.2
Light regulation pipelines

PIPELINE	LOCATION	CUSTOMER NUMBERS	LENGTH (KM)	CAPACITY (TJ/D)[2]	OWNER
TRANSMISSION					
Carpentaria Pipeline (Ballera to Mt Isa)	Qld	na	944	119	APA Group
Central West Pipeline (Marsden to Dubbo)	NSW	na	255	3	APA Group
Moomba to Sydney Pipeline[1]	NSW	na	2 001	489/120	APA Group
DISTRIBUTION					
Allgas Energy[3]	Qld	100 000	3 218	na	Marubeni 40%, Deutsche AWM 40%, APA Group 20%
Australian Gas Networks[3]	Qld	92 852	2 703	na	Cheung Kong Group

km, kilometres; TJ/d, terajoules per day.

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.

Note (tables 5.1 and 5.2): Excludes gas pipelines in Western Australia, which the ERA regulates. The AER does not conduct access arrangement reviews for light regulation pipelines, so limited data is available. Unlisted pipelines are unregulated, except under the Part 23 information disclosure and arbitration provisions introduced in July 2017. Chapter 4 lists unregulated transmission pipelines. Gas distribution networks in Tasmania and the Northern Territory are unregulated.

Source (tables 5.1 and 5.2): AER access arrangement decisions; Gas Bulletin Board; AEMO website; Australian Securities Exchange (ASX) releases; company websites; company annual reports.

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, which the AER applies in states and territories other than Western Australia. The 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 concerning price, quality, safety, reliability and security of supply of gas. The Rules set out revenue and pricing principles, including that pipeline businesses should have a reasonable opportunity to recover efficient costs.

For full regulation gas pipelines, the AER pursues this regulatory objective by setting an access price (reference tariff) for a commonly sought gas pipeline service (reference service)—such as firm haulage—at a level which allows the pipeline to earn enough revenue to cover its efficient costs.

Owners of full regulation gas pipelines must periodically submit a regulatory proposal—called an *access arrangement*—to the AER. The proposal includes the pipeline's forecast revenue and expenditure needs over the upcoming regulatory period (typically five years), and an access price derived from demand forecasts.

The AER then assesses the proposal—focusing on the business's forecast revenue requirements to cover its efficient costs. As in electricity, the AER uses a building block approach to assess the business's efficient costs (section 5.5). Ensuring only *efficient* costs are included helps protect customers from being charged unreasonable prices. The AER's final decision sets an access price for the regulatory period, which the business may increase only to cover inflation.

The AER draws on a range of inputs to assess efficient costs, including cost and demand forecasts and revealed costs from experience, but the approach is not formalised through published guidelines. An exception is the rate of return assessment, where a common guideline applies in both electricity and gas. The AER in 2018 reviewed its approach to setting the rate of return, which will be made binding in future (section 3.12.2).

If the AER's analysis finds a business's access arrangement proposals are unnecessarily costly, it may go back and ask for information that is more detailed or a clearer business case. If these steps fail to reach a satisfactory conclusion, it may amend the access arrangement to align it with efficient costs.

While the approach to assessing revenue is similar for gas and electricity networks, there are differences. In electricity, the AER determines a cap on the maximum revenue a network can earn during a regulatory period. But in gas, it goes a step further by allocating forecast revenue over the demand for pipeline services to set a reference tariff (access price) for using the pipeline. The reference tariff must apply to a widely sought pipeline service, and provides a basis for access seekers to negotiate prices to other services. A frustrated access seeker can apply to the AER to determine a tariff and other conditions of access if a dispute arises.

Concerns have arisen among policy makers that 'too narrow a set of services are subject to the determination of a tariff by the regulator'.[9] The AEMC in July 2018 recommended widening the scope of price regulation to a wider range of services, such as bi-directional flow, park and hold services.[10] The COAG Energy Council in late 2018 proposed rule changes to implement the reforms, which the AEMC intended to fast track.[11]

5.4.2 Incentive schemes

The 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 efficiency savings in managing operating costs for up to six years. In the longer term, pipeline businesses must share efficiency gains with their customers, by passing on about 70 per cent of the gains through lower access prices. The mechanism is similar to the efficiency benefit sharing scheme in electricity (section 3.13), but is written into each business's access arrangement rather than being articulated in a general guideline.

A number of gas distribution businesses proposed a *capital expenditure sharing* scheme (CESS) in their latest access arrangement proposals. The gas rules do not mandate such schemes, but allow flexibility for the AER to approve their use. The AER first approved their use in 2017 to strengthen incentives for pipeline businesses to find efficient ways of maintaining and operating their networks.

The scheme operates in a similar way to the CESS for electricity networks (section 3.11), but is written into each business's access arrangement. It allows a pipeline business to earn a bonus by keeping new investment spending below forecast levels (penalties apply if it invests above target). In later regulatory periods, 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 closely scrutinises whether proposed investments are efficient. The CESS design ensures deferred expenditure does not attract rewards, which removes incentives for businesses to defer critical investment needed for safe and reliable network operation. A network health index ensures rewards are contingent on the pipeline business maintaining current service standards.

The Victorian gas distributors were the first pipeline businesses to implement the CESS scheme as part of their access arrangements, for the period 2018–22. To date, no gas transmission business has sought to participate in the scheme.

Other incentive schemes applying in electricity—for maintaining or improving service performance and demand management innovations—are not currently available to gas pipeline businesses. The Victorian gas distributors sought the introduction of a Network Innovation Scheme in 2018–2022. The AER rejected the scheme, arguing the current framework provides sufficient incentives for innovation, particularly with the addition of the new CESS scheme.[12]

9 AEMC, *Review into the scope of economic regulation applied to covered pipelines*, July 2018, p. ii.

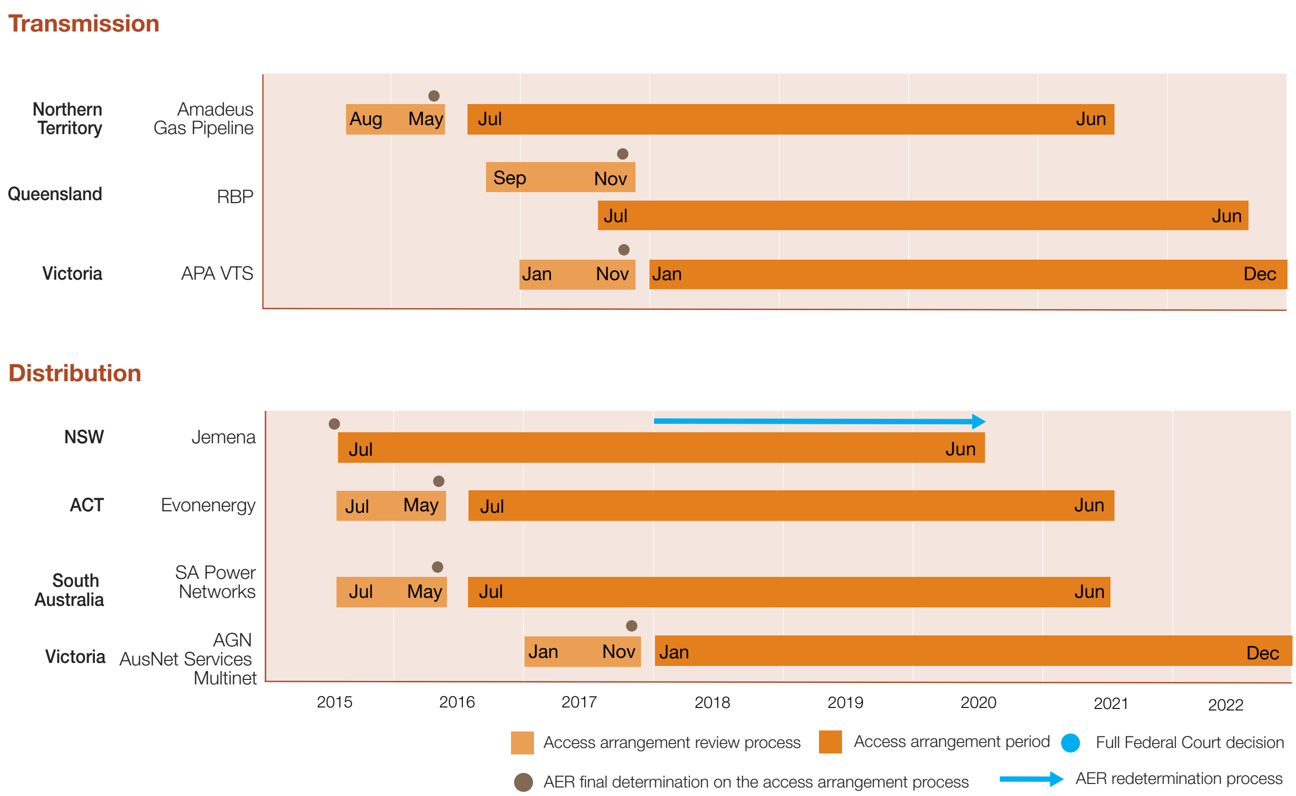
10 AEMC, *Review into the scope of economic regulation applied to covered pipelines*, July 2018.

11 AEMC, *AEMC fast tracks rule change request to improve regulation of covered gas pipelines*, Media release, November 2018.

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.

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 specific stages of the process) to decide whether to approve it. This period can be extended by up to two months, with a maximum of 13 months to render a decision.

The AER consults with gas pipeline customers and other stakeholders during the process, including by publishing a draft decision seeking stakeholder input to inform its final decision.

At the completion of a review, the AER publishes an access arrangement decision setting the reference tariff 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 upcoming access arrangement reviews. The AER assesses access arrangements on a rolling cycle, with the timing of reviews staggered to avoid bunching. The long review cycle helps create a stable investment environment but also risks locking in inaccurate forecasts.

The rules include ways of dealing with some uncertainties, such as cost pass-throughs in the event of a significant event such as a regulatory changes or natural disaster. A gas network may also approach the AER to pre-approve a contingent investment project where the need is uncertain at the time of the reset. A pre-approval allows the project to be rolled into the pipeline's asset base in the next regulatory period (but not the current period).

5.4.4 Customer engagement

As in electricity, an important focus of gas pipeline regulation is how constructively a business engages with its customers in developing an access arrangement proposal. While not mandated in the gas rules, evidence of constructive engagement can give the AER confidence the business is genuinely committed to meeting customer needs and preferences. This can lay the foundation for the AER to accept elements of an access arrangement proposal, including capital and operating expenditure forecasts.

The Victorian gas distributors—Multinet, AusNet Services and Australian Gas Networks (Victoria and Albury)—engaged closely with their customers in developing access arrangements for the 2018–2022 period. The AER's *Consumer Challenge Panel* particularly commended Australian Gas Networks' genuine commitment to giving small and large consumers a say—clearly identifying feedback from stakeholders and how they had addressed it. The panel found this transparency enhanced confidence the business was open to ongoing collaboration on issues of concern.[13]

To date, customer engagement is more advanced in the gas distribution sector than in transmission. APA Group chose not to undertake stakeholder engagement in developing its 2017–2022 access arrangement proposal for the Roma to Brisbane Pipeline. Similarly, the AER's *Consumer Challenge Panel* was critical of APA's commitment to customer engagement on its 2018–2022 access arrangement for the Victorian Transmission System.[14] APA described the AER's and panel's consultation expectations to be 'unrealistic' and 'ultimately…a waste of time and resources.'[15]

5.4.5 Recent AER access arrangement decisions

The AER in November 2017 published final decisions on access arrangements for five gas pipeline systems—Victoria's three gas distribution networks (AusNet Services, Multinet and Australian Gas Networks), and the two major transmission pipelines (APA's Victorian Transmission System and the Roma to Brisbane Pipeline in Queensland). These access arrangements all took effect on 1 January 2018 and will remain in place until 31 December 2022.

In 2018 the AER engaged with Jemena Gas Networks (NSW gas distribution) on remaking its access arrangement for the regulatory period 2014–19, following orders from the Full Federal Court (section 3.5.2). The AER in 2019 will launch a new access arrangement review for Jemena for the period 2020–25.

5.4.6 Price impacts of recent AER decisions

The AER's access arrangement decisions for Victoria's gas distribution networks reduced pipeline charges by up to 9.4 per cent in 2018 (table 5.3).[16] It found the networks needed less revenue than in the past because their financing costs had fallen. The decisions approved rates of return below 6 per cent for each network, compared with over 7 per cent in the previous period. However, transmission charges rose in Victoria, mainly because costs associated with new investment projects offset the impact of lower rates of return.

For a typical residential customer in Victoria, distribution and transmission charges make up about a quarter of their total gas bill. The AER's access arrangement decisions reduced pipeline charges in a typical residential gas bill in 2018 by up to $28 from their 2017 levels. For a small business customer, the AER estimated an average annual bill would fall by around $46 in 2018.[17]

Investment in Victorian gas networks is rising to meet demand for new gas connections and maintain network safety, reliability and security. The AER found Victoria's three gas distributors—Multinet, AusNet Services and Australian Gas Networks—had engaged constructively with their customers on priorities, including that the networks provide a safe and reliable gas supply. The networks will continue with substantial mains replacement programs over the next five years.

The AER took advice from the Consumer Challenge Panel, Australian Energy Market Operator (AEMO) and network users in approving additional capital expenditure for APA to improve capacity and security across the Victorian Transmission System, including construction of a new Western Outer Ring Main Pipeline. This investment will help

13 Sub-Panel CCP11, *Response to the AER's Draft Decisions and the Revised Proposals from AGN, AusNet and Multinet for a revenue reset/access arrangement for the period 2018 to 2022*, 12 September 2017, p. 10

14 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

15 APA, *Victorian Transmission System Access Arrangement Revised Proposal, Submission Response to Draft Decision*, 14 August 2017, p. 8.

16 AER, *Final decisions, Victorian gas access arrangements for 2018–22*, factsheet, November 2017.

17 AER, *Final decisions, Victorian gas access arrangements for 2018–22*, factsheet, November 2017.

Table 5.3 Impact of recent AER decisions on gas pipeline charges

FULL REGULATION PIPELINE	STATE	REGULATION CONTROL PERIOD	ANNUAL REVENUE ($ million)	ANNUAL OPEX ($ MILLION)	ANNUAL CAPEX ($ MILLION)	RATE OF RETURN (%)	CHANGE IN NETWORK PRICES IN 2018 (%)	EFFECT ON RESIDENTIAL GAS BILL IN 2018 (%)
TRANSMISSION								
APA Victorian Transmission System	Vic	1 July 2018–31 Dec 2022	525	27	240	5.75	4.8	0
Roma to Brisbane Pipeline	Qld	1 July 2017–30 June 2022	223	15	67	5.58	−0.4	−0.4
DISTRIBUTION								
Australian Gas Networks	Vic	1 Jan 2018–31 Dec 2022	1113	70	554	5.75	−4.9	0
AusNet Services	Vic	1 Jan 2018–31 Dec 2022	958	55	480	5.67	−9.4	−0.2
Multinet	Vic	1 Jan 2018–31 Dec 2022	956	77	398	5.94	−1.0	−2.2

OPEX, operating and maintenance expenditure; CAPEX, capital expenditure.

Note: per cent changes in forecast revenue, OPEX and CAPEX in current access arrangement period compared with previous period. AER estimates of impact on residential gas bills assuming a standard household consumes 24 gigajoules of gas per year on a single rate tariff. All data is in real 2018 dollars except where otherwise specified.

Source: AER final decisions on gas access arrangements for 2018–22.

address concerns about gas pipeline constraints raised by AEMO (the Victorian gas market operator) and gas users.

In Queensland, the AER's November 2017 decision found the Roma to Brisbane Pipeline (the only transmission pipeline carrying gas to Brisbane) would need 17.2 per cent less revenue in 2018–22 than in the previous period, mainly because improved financial market conditions had reduced financing costs. The approved rate of return fell from 7.22 per cent (nominal) in 2012–17 to 5.58 per cent under the decision.

Despite this, the price savings for small customers are modest, as gas transmission costs only comprise 3 per cent of final bills and expected demand is lower than the current period. The AER estimates reductions in annual gas bills of around $3 for residential customers and $31 for small business customers in 2018. Large customers directly connected to the pipeline will see larger bill reductions of around 5 per cent each year.

The AER explored the pipeline's pricing arrangements in the context of the gas market's evolving dynamics. The pipeline's key service—long term gas transportation (with a minimum three year contract) will be made bi-directional to reflect changing market dynamics.

The AER decided not to regulate a short term service because APA is already negotiating prices for those services with pipeline customers. However, it redefined a number of supporting services (park and loan, in-pipe trading and capacity trading) as rebateable to ensure pipeline customers share the benefits of innovation.[18] In future, APA will pass on 70 per cent of the revenue earned from rebateable services through lower reference tariffs.[19]

5.4.7 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 (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.

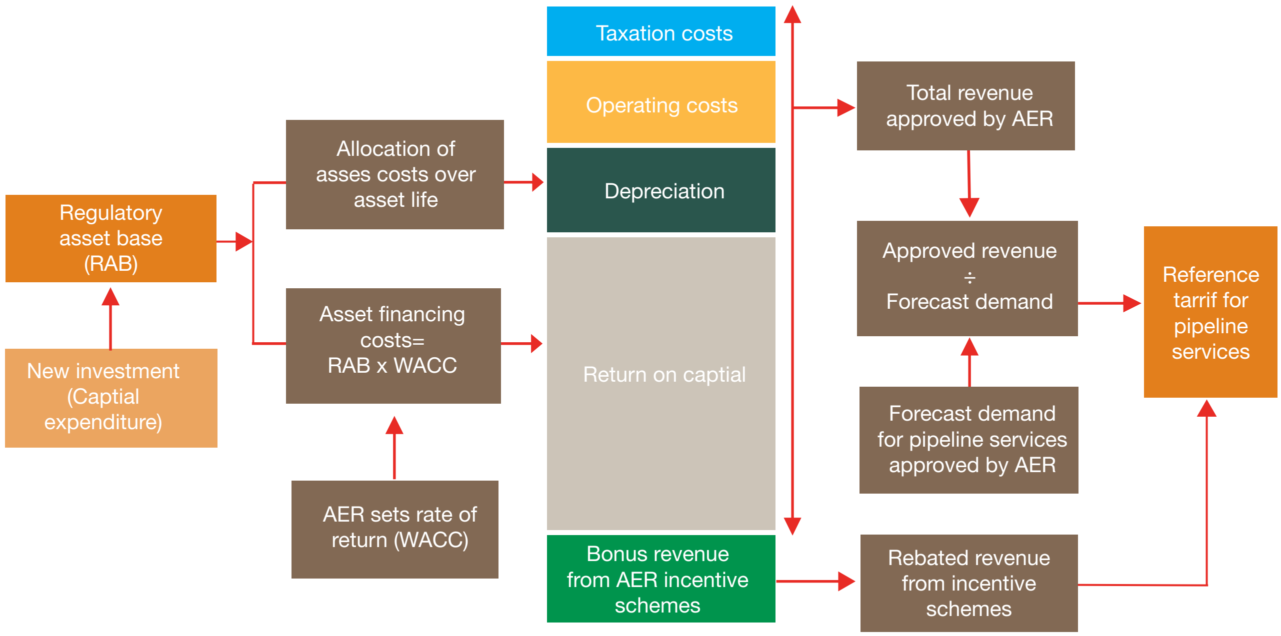
Legal proceedings on two long-running appeals concluded during 2017. The disputed matters included the allowed rate of return, the cost of corporate income tax and the AER's approach to determining efficient operating expenditure.

In July 2017 the Full Federal Court ordered the AER to remake elements of its access arrangement decision for

18 Where there is uncertainty around the amount of revenue a non-reference pipeline service is likely to generate it may be classified as a rebateable service. A portion of the costs of providing this service may be added to the reference tariff. But revenue from sales of this service may later be returned to users of the reference service as a discount.

19 AER, *Final decisions, Roma to Brisbane Pipeline gas access arrangements for 2017–22*, factsheet, November 2017.

Figure 5.3
How gas pipeline revenue and charges are set



Note: Bonus revenue may be earned under incentive schemes encouraging pipeline businesses to efficiently manage their operating and capital expenditure and encourage innovation.

Source: AER.

Jemena Gas Networks (NSW) covering the period 2015–20. In particular, the AER was ordered to revisit its decisions on Jemena's return on debt (an element of the rate of return), and aspects of the business's capital expenditure.

The AER hosted a roundtable meeting with Jemena and the *Consumer Challenge Panel* in January 2018 to resolve outstanding issues. Its discussions with Jemena and key customer groups continued in 2018, aimed at developing a new access arrangement proposal with the long term interests of consumers in mind.

The Tribunal's final limited merits review matter in gas related to the AER's 2016–21 access arrangement for the ACT gas distribution network (owned by Evoenergy, formerly ActewAGL). On 17 October 2017 the Tribunal affirmed the AER's final decision in relation to all grounds of review sought by the business. This meant the AER's original decision to reduce the amount of revenue the business could recover from customers stands.

5.5 The building blocks of gas pipeline revenue

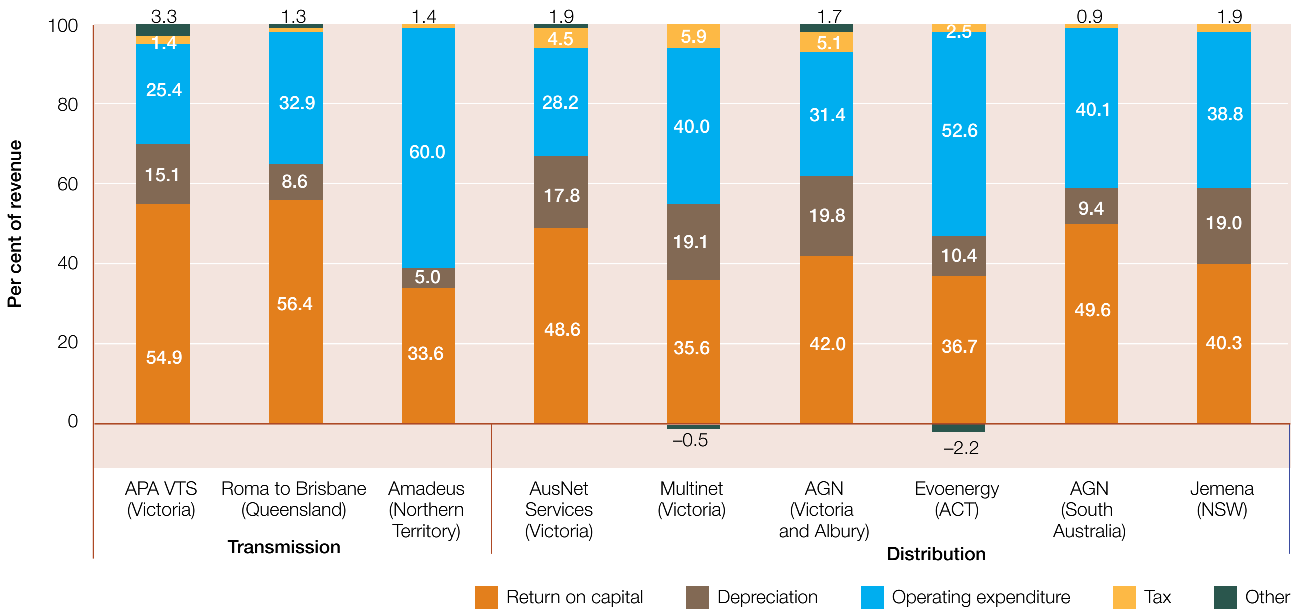
In assessing a gas pipeline business's revenue needs, the AER breaks up its costs into 'building blocks'. Specifically, the AER forecasts how much revenue the business is likely to need to cover:

- efficient operating and maintenance costs
- commercial returns to shareholders and investors who fund its operations
- asset depreciation costs
- forecast taxation costs.

It also makes adjustments for past over or under recovery of revenue, and for incentive payments (figure 5.3).

While gas pipelines are entitled to earn revenue to cover their efficient costs each year, they are *not* entitled to recover all the cost of investment in new assets during any given year. Gas pipelines have a long life, so the cost of new investment is recovered over the economic life of the asset—which may run to several decades. The amount recovered each year is called *depreciation* and covers the lost value of assets through wear and tear, and technical

Figure 5.4
Composition of gas pipeline revenues



AGN, Australian Gas Networks; VTS, Victorian Transmission System.

Note: Other includes incentive scheme payments.

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

obsolescence. Depreciation may absorb 5–20 per cent of a gas pipeline's revenue.

The shareholders and lenders who fund those assets must be paid a commercial *rate of return* on their investment each year. The AER sets this rate of return (also called the weighted average cost of capital, or WACC). This return may account for 30–60 per cent of a gas pipeline's revenue, and depends on:

- the value of the network's assets, measured by the regulated asset base plus forecast new capital expenditure
- the rate of return the AER considers appropriate for the equity and debt used to fund those assets.

Operating costs—such as maintenance and overhead costs—absorb around 20–60 per cent of a pipeline's revenue. *Taxation* and other costs account for the remainder. The AER in May 2018 launched a review into the taxation costs for regulated networks. This review responded to concerns about anomalies in the amount of tax paid by some businesses, relative to their forecast taxation costs (box 3.2).

Businesses also have opportunities to earn additional revenue through regulatory incentives encouraging efficient management of operating and capital expenditure programs (section 5.4.2).

Figure 5.4 illustrates the composition of pipeline revenues in recent gas transmission and distribution decisions. Sections 5.6–5.8 examine the major components in more detail.

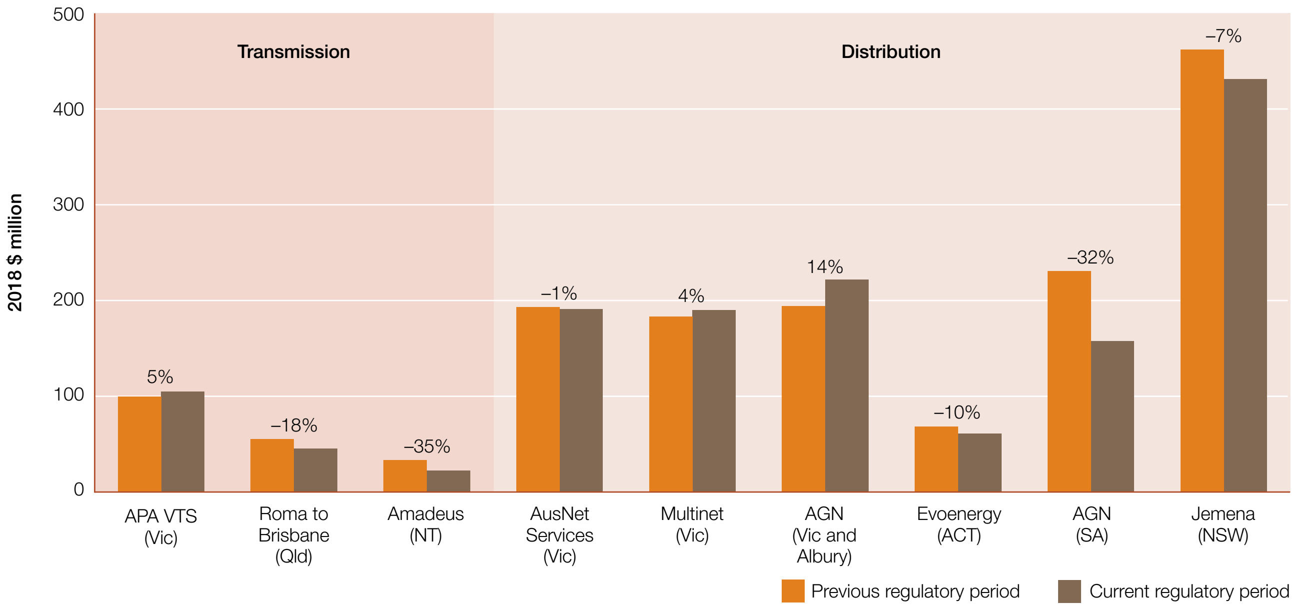
5.6 Gas pipeline revenues

Full regulation gas pipelines (listed in table 5.1) are forecast to earn around $7.36 billion in their current access arrangement periods—3.44 per cent less than forecast in previous periods:

- Full regulation *transmission* pipelines are forecast to earn around $857 million in current access arrangement periods—8.86 per cent less than forecast in previous periods.
- Full regulation *distribution* networks are forecast to earn around $6.5 billion in current access arrangement periods—2.67 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.

Figure 5.5
Gas pipeline revenues



VTS, Victorian Transmission System; AGN, Australian Gas Networks.

Note: Smoothed annual averages. All data are forecasts. Current regulatory period is at 1 July 2018 (tables 5.1 and 5.2). Percentages represent the change between periods. Forecasting updates may result in some outcomes varying from those previously reported.

Source: AER.

Network businesses also had higher financing costs due to instability in global financial markets.

These cost pressures have since eased. Lower financing costs and weaker domestic gas demand in recent years—caused by a significantly higher gas prices—have reduced forecast revenue needs for most pipeline businesses.

Access arrangement decisions made since 2015 also incorporate a new approach to determining rates of return. The cost of capital is now updated annually to reflect changes in debt costs.

These factors reduced the average of return in the AER's five access arrangement decisions made in 2017 to under 6 per cent—compared with over 10 per cent in decisions made from 2008 to 2010. This reduction translates to significantly lower network revenue.

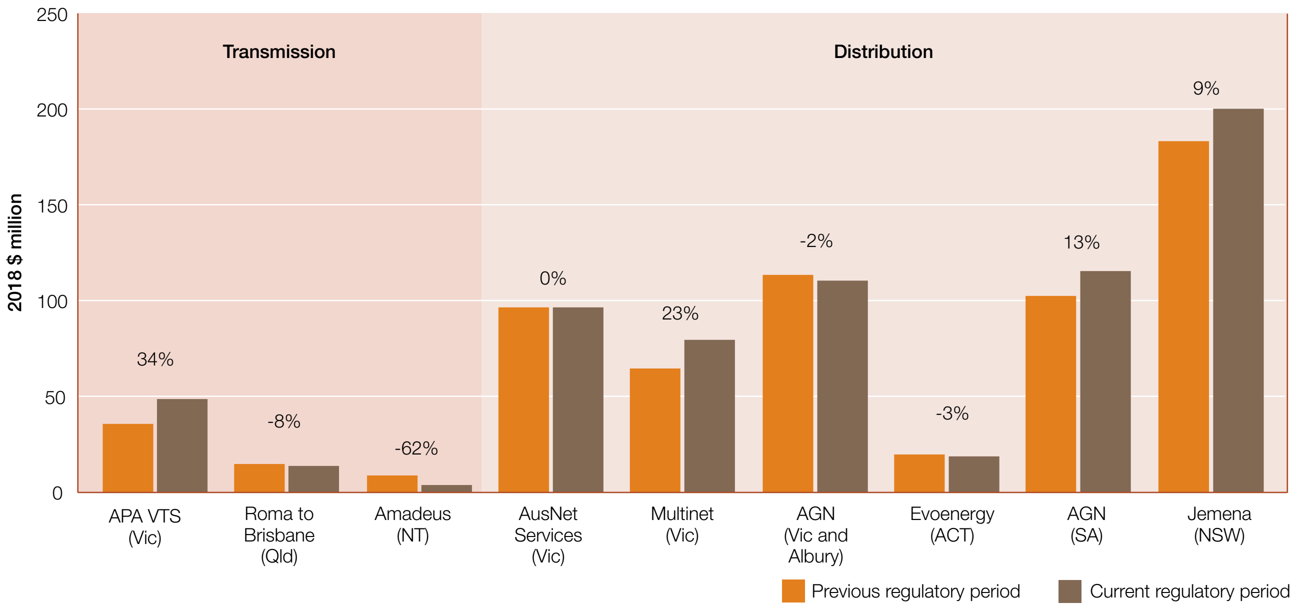
In gas transmission, current AER decisions forecast revenue will fall—by 18 per cent for the Roma to Brisbane Pipeline (Queensland) and 35 per cent for the Amadeus Pipeline (Northern Territory)—compared with the previous period. The reductions mainly reflect significantly lower allowed rates of return. The Victorian Transmission System, however, is forecast to increase revenue by 5 per cent, reflecting the increased capital base from investments APA made in the 2013–17 regulatory period.

In gas distribution, four of the six full regulation networks are forecast to record lower revenue. Revenue for networks in NSW, South Australia and the ACT are forecast to fall by 7–32 per cent, with rises of 4–14 per cent in two Victorian networks. Across transmission and distribution, revenue is more stable or rising for the Victorian networks compared with networks elsewhere. This is mainly due to higher operating and capital expenditure costs associated with new customer connections, such in new housing estates (figure 5.5).

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. Chapter 4 considers recent investment in gas transmission pipelines that are not fully regulated.

Figure 5.6
Gas pipeline investment



VTS, Victorian Transmission System; AGN, Australian Gas Networks.

Note: Smoothed annual averages. All data are forecasts. Current regulatory period is at 1 July 2018 (tables 5.1 and 5.2). Percentages represent the average annual investment (CAPEX) change between the previous and current regulatory period. Forecasting updates may result in some outcomes varying from those previously reported.

Source: AER.

Gas distribution investment mainly comprises augmentation (expansion) of existing systems to cope with new customer connections, such 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 $324 million over the current regulatory periods (typically five years) (figure 5.6):

- Investment in the Roma to Brisbane Pipeline is forecast to fall by 8 per cent in the current period following the completion of a major augmentation program.
- Investment requirements are also forecast to fall in the Northern Territory (by 62 per cent over 2016–21) following the completion of an integrity works program.
- Investment in Victoria's AGN and AusNet Services distribution networks is steady (0 per cent and 2 per cent fall respectively).

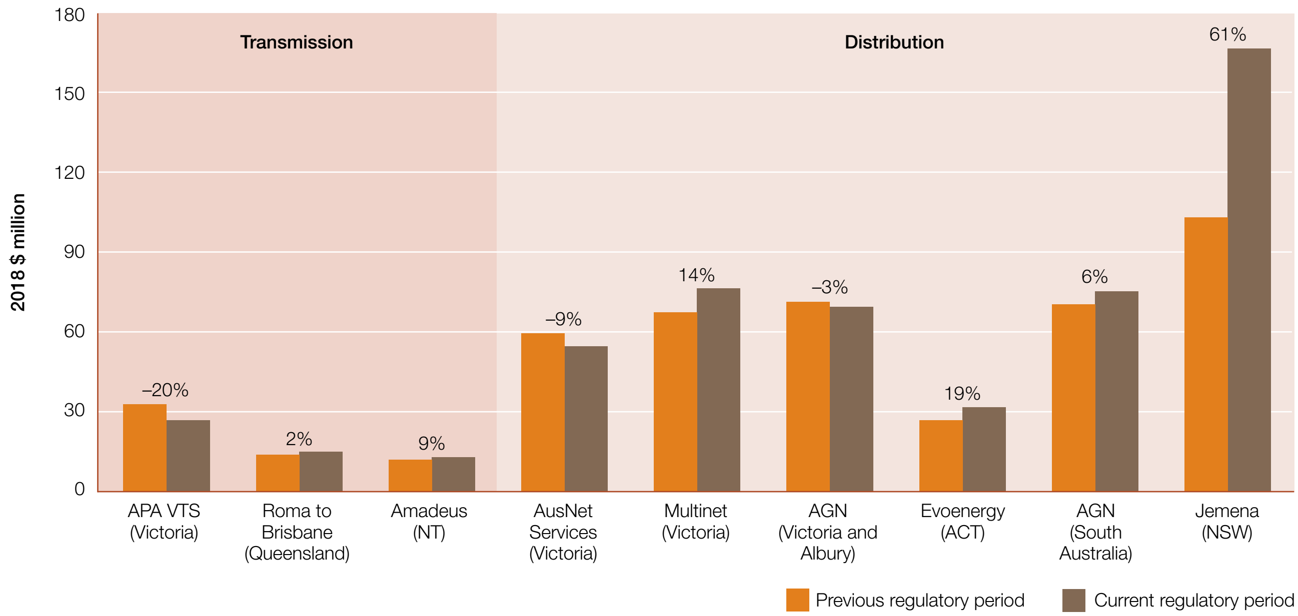
Investment in full regulation distribution networks in eastern Australia is forecast at around $3.13 billion in the current access arrangement periods—7.95 per cent higher than in the previous periods:

- Forecast investment growth is highest in the Victorian Transmission System at 34 per cent.
- The AER's 2016 determinations for the AGN South Australia network forecast investment would rise by 13 per cent over 2016–21 to fund a major mains replacement project.
- Less investment is forecast for the ACT's Evoenergy distribution network, after the AER found a prudent operator would not undertake significant elements of its augmentation proposals. Overall, investment in the ACT network is forecast to fall by 3 per cent in 2016–21 compared with the previous period.

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

Figure 5.7
Gas pipeline operating costs



VTS, Victorian Transmission System; AGN, Australian Gas Networks.

Note: Smoothed annual averages. All data are forecasts. Current regulatory period is at 1 July 2018 (tables 5.1 and 5.2). Percentages represent the average annual change in operating costs (OPEX) between the previous and current regulatory period. Forecasting updates may result in some outcomes varying from those previously reported.

Source: AER.

improvements, changes in labour and materials costs, and changes in the regulatory environment.

In the current regulatory cycle, full regulation transmission networks are forecast to spend around $271 million on operating expenses.

Operating expenditure will also rise for gas distribution networks, which are jointly forecast to spend over $2.42 billion on these costs—a rise of 20 per cent on forecast expenditure in previous periods. The largest rise (61 per cent) is forecast for NSW's Jemena network.

The AER's 2016 decision forecast a 6 per cent rise in operating expenditure of South Australia's AGN distribution network in 2016–21 compared with forecast spending in the previous period. The AER found the network had operated efficiently in the past, so its decision maintained base levels of expenditure, with increases to cover higher costs in some areas. Operating costs for the ACT's Evoenergy network are forecast to rise by 19 per cent over the same period (figure 5.7). The expected cost increase is mainly associated with compliance issues and business-to-business harmonisation.

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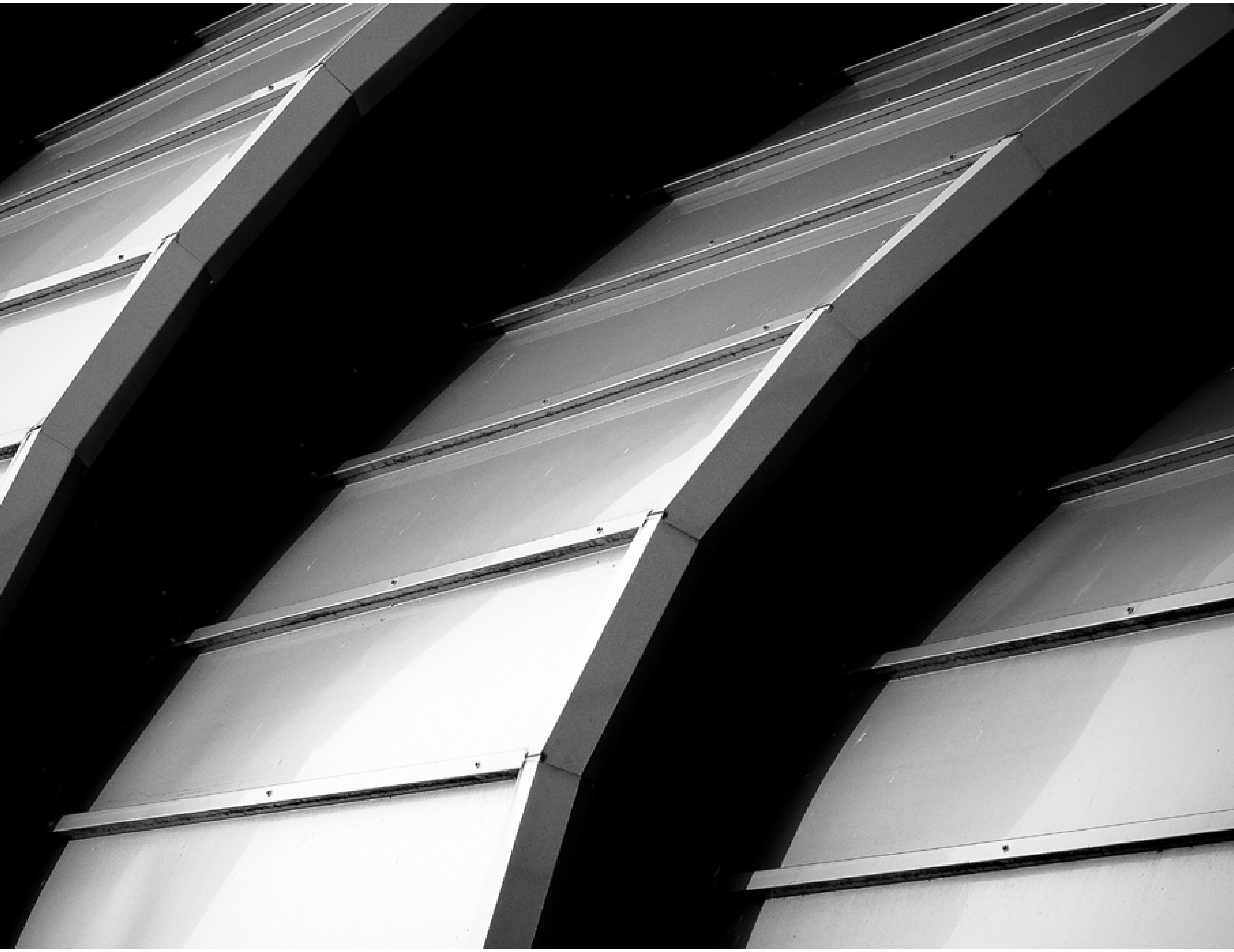
APPENDIX 1 GOVERNMENT ENERGY MARKET INTERVENTIONS



JURISDICTION	NAME	CAPACITY	DETAILS	ESTIMATED COST
PUBLIC INVESTMENT IN GENERATION AND STORAGE				
Federal	Snowy Hydro 2.0	2000 MW/ 35 0000 MWh	Snowy Hydro 2.0 is a proposal to expand the existing Snowy Hydro dam system to allow for additional pumped hydro storage.	$3.8–4.5 b
Queensland	CleanCo	1000 MW	CleanCo is a new generation company established by the Queensland Government with a commercial mandate to increase competition in the generation market. It will focus on low and no emissions technology. Initially, renewable and low emission generators will be transferred to CleanCo from other state-owned generators. Once established, CleanCo will invest in an additional 1000 MW of renewable capacity by 2025.	$250 m
Queensland	Swanbank E Recommissioning	385 MW	Swanbank E is a 385 MW combined cycle gas turbine. It was mothballed in 2014 and its gas entitlements sold off. The Queensland Government announced in June 2017 that the plant would return to service. The generator is part of the government-owned Stanwell Corporation.	
Queensland	Burdekin Hydro	50 MW	The Queensland Government intends to reinvest $100 m in dividends from Stanwell Corporation to develop a 50 MW hydro-electric generator at the Burdekin Falls Dam, subject to the outcomes of a feasibility study.	$100 m
South Australia	South Australia Temporary Generation Initiative	276 MW	The South Australian Government leased nine transportable generator units to provide 'stabilisation services' and to prevent load-shedding in periods of scarcity. The units run on diesel, with the option to convert to gas.	$339 m
South Australia	Hornsdale Power Reserve	100 MW/ 129 MWh	The Hornsdale Power Reserve or 'Tesla Big Battery' comprises 129 MWh of lithium-ion batteries located at the 315 MW Hornsdale wind farm in South Australia. The battery is contracted by the South Australian Government to provide 70 MW for up to 10 minutes (11.7 MWh) of grid services and to prevent load shedding under a $50 m contract. The remaining 90 MWh of storage capacity (30 MW for up three hours) is used by Neoen for load management.	$80 m ($US50 m)
Tasmania	Battery of the Nation	2500 MW	Proposal to construct 2500 MW of pumped hydro storage through additions to existing Tasmanian hydroelectric infrastructure.	$7.4 b for all 4800 MW
NON-PRICE REGULATION				
Federal	National Energy Guarantee (NEG)		The NEG aims to integrate reliability and emissions reduction objectives into a single national electricity policy. Large users purchasing on the wholesale market would be required to ensure that the average emissions intensity of their load was below a specified target. Where a reliability gap is identified by AEMO, large electricity users and retailers would be required to contract for the purchase of a minimum quantity of electricity from 'reliable' dispatchable generators to cover the shortfall.	

ANNOUNCEMENT DATE	IMPLEMENTATION DATE	STATUS	
March 2017	2024	Proposed	A feasibility study was released 20 December 2017 by Snowy Hydro. In July 2018 Snowy Hydro released a project update and said that it had begun geotechnical drilling and work on project design and approvals. A Final Investment Decision to proceed was made by Snowy Hydro's board of directors on 12 December 2018.
June 2017	2019	Committed	CleanCo is expected to begin trading in the NEM by mid-2019 and has been allocated initial funding of $250 m from the Queensland Government.
June 2018	December 2017	Completed	The plant returned to service in December 2017.
June 2017	2020	Proposed	In October 2017 Stanwell Corporation completed a pre-feasibility study. A detailed business case is being developed.
March 2017	November 2017	Completed	Generation units were connected 13 November 2017. The previous South Australian Government subsequently purchased the turbines outright, and announced plans to convert them from diesel to gas fuelled and relocate them at a single site to provide permanent government-owned gas peaking capacity. The current South Australian Government is running a tender process for a private company to operate the generation units for 25 years.
July 2017	December 2017	Completed	Hornsdale Power Reserve was connected on 1 December 2017. Estimates suggest that it reduced Frequency Control Ancillary Service (FCAS) costs by around 90 per cent and achieved a 55 per cent share of the South Australian FCAS market.
April 2017	2023–24	Proposed	A concept study conducted by Hydro Tasmania, in partnership with ARENA, identified 14 suitable sites with a total potential capacity of 4800 MW. Hydro Tasmania is conducting pre-feasibility studies to narrow down sites to around 2500 MW of capacity, due to be complete in 2019.
October 2017	July 2019	Announced	The Australian Government in October 2017 announced it would implement the NEG with an emissions reduction target of 26–28 per cent by 2030. In August 2018, it abandoned the emissions component. The Government retained only the reliability requirement as part of a new energy policy. The Federal opposition announced it would adopt a version of the NEG if elected, with an emissions reduction target of 45 per cent by 2030.

JURISDICTION	NAME	CAPACITY	DETAILS	ESTIMATED COST
Federal	Divestiture and directions powers		In late 2018 the Australian Government drafted legislation to insert a power into the *Competition and Consumer Act 2010* enabling the Courts, on the advice of the Treasurer and ACCC, to order divestiture of an asset by energy companies, or order electricity companies to enter into contracts to supply at specified prices and for specified volumes. The draft legislation listed grounds to force asset divestment, including a retailer's failure to pass on lower wholesale prices to energy customers, or attempts by energy companies to manipulate spot or contract markets	
Queensland	Stanwell Direction		On 6 June 2017 the Queensland Government directed state owned generator Stanwell to alter its bidding behaviour in the NEM during peak periods to put downward pressure on prices.	
FINANCIAL INCENTIVES FOR PRIVATE INVESTMENT				
Federal	Clean Energy Finance Corporation	2400 MW (large scale only, this number includes projects financed under other programs)	The Clean Energy Finance Corporation was established in 2012 as a government-owned green bank. The fund provides debt and equity financing on terms designed to deliver on public policy objectives. Its governance framework requires it to deliver a positive return to taxpayers and evaluate investments in a commercial way. The CEFC has access to $10 b of funding, allocated in $2 b tranches each year from 2013 to 2017.	$10 b
Federal	Emissions Reduction Fund		The Emissions Reduction Fund was established by the Australian Government in 2014 to help Australia achieve emissions reductions on 2005 levels of 5 per cent by 2020 and 26–28 per cent by 2030. $2.55 billion has been budgeted to fund projects that would reduce carbon emissions, which is allocated through reverse auctions. The fund is coupled with the ERF Safeguard Mechanism, which caps emissions for facilities with annual direct emission of more than 100 000 tonnes of CO_2 equivalent/year (about 50 per cent of Australia's emissions).	$2.55 b
Federal	Australian Renewable Energy Agency	263 MW (many of these projects are small-scale or demonstration only and overlap with other programs)	The Australian Renewable Energy Agency was established in 2012 as an independent statutory agency charged with funding research, development and commercialisation of clean energy technologies. Much of its funding is provided in the form of grants and its mandate is not to generate a profit but to advance clean energy technology. It has a total allocation of $3.2 b between 2013 and 2022.	$2 b
Federal	Underwriting Investment		The Australian Government proposes to underwrite new investment in dispatchable generation capacity. This may take the form of a floor price, contracts for difference, collar contracts, government loans, or some alternative mechanism. The program would be open to new applicants for four years and provide support between years six and 15 of plant operation.	
Queensland	Renewables 400	400 MW	The Queensland Government is conducting a reverse auction, using contracts for difference, for 400 MW of renewable capacity (including a 100 MW storage component) to be delivered before 2020.	$1.16 b (total Powering Queensland Plan cost)

ANNOUNCEMENT DATE	IMPLEMENTATION DATE	STATUS	
October 2018		Announced	The government aims to introduce the legislation to the Australian Parliament in 2019.
June 2017		Implemented	Stanwell Corporation stated that it adjusted its bidding behaviour in line with the Direction. Queensland prices in 2017–18 were the lowest for any NEM region. Prices were 27 per cent lower than a year earlier, the largest reduction for any region. Generators shifted capacity previously bid at over \$5000 per MWh to lower prices, typically below \$300 per MWh.
July 2011		Implemented	At 30 June 2018, CEFC investments since inception totalled \$6.6 b and it held a portfolio valued at \$5.3 b. The total value of projects in which it has invested since inception is around \$19 b. These investments include 5500 small scale clean energy projects, 20 large scale solar projects, and 10 wind farms. In 2017–18 the CEFC committed \$2.3 b to 39 projects.
April 2014	2030	Implemented	By the sixth auction in 2018, 12 projects had received funding under the ERF that involved new electricity production or upgrades to existing plant. Total abatement committed under contract for these projects is 3.56 million tonnes CO_2-e. Most of the projects capture and combust waste methane gas from coalmines or landfill for use in electricity generation. Electricity projects represented less than 2 per cent of carbon abatements funded under the scheme.
July 2011	2012	Implemented	At 30 June 2018, ARENA had allocated \$1 b in grant funding to 320 projects, totalling 263 MW of capacity. This includes 12 large-scale solar plants, many with CEFC involvement. It has \$2.5 b worth of projects in development.
October 2018		Announced	The Federal Department of Environment and Energy released a consultation paper on underwriting new generation investments in October 2018. Expressions of interest are expected to open in December 2018 or January 2019 and proposals will be due by March 2019. Financial support is expected to commence from 1 July 2019.
August 2017	2018	Implemented	Expressions of interest for the reverse auction process closed 25 September 2017 with 115 proposals totalling 15 000 MW. Binding bids were due in early 2018 but results had not been announced by December 2018.

JURISDICTION	NAME	CAPACITY	DETAILS	ESTIMATED COST
Queensland	Solar 150	300 MW	The Queensland Government intends to support 150 MW of large-scale solar projects, successful through the ARENA large-scale solar PV - competitive round in Queensland using contracts for difference.	$1.16 b (Total Qld Power Plan cost)
Queensland	Solar Rebate Queensland		The Queensland Government allocated $23 m to provide no interest loans and rebates for the installation of residential PV and battery storage. Loans are worth up to $4500, repayable over seven years and are available until 30 June 2019 or until funding is exhausted. 500 $3000 grants and $6000 loans repayable over 10 years are available for battery storage. 100 $3000 grants and $10 000 loans will be available for combined solar and battery systems.	$21 m
NSW	Emerging Energy Program		The program aims to support large scale projects using emerging and renewable technologies that can provide dispatchable or on-demand energy to boost energy security. Projects must have the ability to manipulate output in response to wholesale energy or ancillary service price signals. The program will provide funding to commercialise projects, as well as support pre-investment studies.	$55 m
Victoria	Victorian Renewable Energy Auction Scheme	650 MW/ 928 MW	The scheme offers long term contracts for difference designed to support investment in renewable energy generation. It was initially to deliver 650 MW of capacity, including 100 MW of large scale solar. The government will make a determination on the need for further auctions to meet the VRET as required.	$1.16 b (total project capital investment, with further $711 m in operating expenditure over 15 years, government spend unclear)
Victoria	Solar Homes Package	2600 MW generation (based on 650 000 homes with 4 kW systems) and 110 MWh storage (based on 10 000 1 kWh systems)	The scheme covers upfront costs of up to $4450 for the installation of new solar PV systems (50 per cent of the cost, up to $2225 as a grant and a further $2225 as a four year interest free loan). The government estimates the policy will support installation of 650 000 systems. The scheme will also provide a 50 per cent rebate on battery installations (capped at $4838 in the first year and tapering to $3714 by 2026) to around 10 000 homeowners with existing solar panel installations, and up to $1000 towards the installation of a solar hot water system for 60 000 homes that are not suitable for solar panels. The program is restricted to households with an income less than $180 000 and homes valued at less than $3 m.	$1.28 b
Victoria	Renewable Certificate Purchasing Initiative	280 MW	The Victorian Government committed to purchase 280 MW of renewable energy certificates directly from new Victorian projects.	$48.1 m

ANNOUNCEMENT DATE	IMPLEMENTATION DATE	STATUS	
July-15	2018	Completed	The program closed to new applicants on 15 June 2016. There were six successful projects in Queensland with a total capacity of 300 MW. Construction began in 2017 and all projects are due for completion by the end of 2018.
May 2018	June 2018	Committed	Loan applications for solar PV systems opened 1 June 2018. Applications related to battery and combined solar/battery systems opened 19 November 2018. On 30 November the government announced a further 1000 solar and battery packages. The government estimated funding would be exhausted by 15 December 2018.
October 2018	2019	Committed	Expression of interest will open in the first quarter of 2019.
June 2016	September 2018	Completed	In September 2018 the Victorian Government announced support for six projects with a total capacity of 928 MW, including 673 MW of wind and 254 MW of solar. The projects were backed with 15 year contracts for difference that include price floors and annual caps on payments.
August 2018	August 2018	Implemented	The rebates for solar panels and hot water systems are available for systems installed from 19 August 2018 to 30 June 2019. The batteries component of the scheme will run over 10 years or until funding is exhausted.
January 2017	August 2017	Implemented	In July 2016 the Victorian Government contracted with the 31 MW Kiata windfarm and the 132 MW Mt Gellibrand windfarm. In August 2017 it contracted with the 110 MW Bannerton Solar Park (which also received $98 m in CEFC financing) and the 38 MW Numurkah Solar Farm. No further tenders have been issued.

JURISDICTION	NAME	CAPACITY	DETAILS	ESTIMATED COST
Victoria	Grid Scale Battery Project	55 MW/ 80 MWh	The Victorian Government committed $25 m in funding for grid scale battery storage projects. The projects are designed to ease constraints on transmission lines in Western Victoria.	$25 m
South Australia	South Australia Virtual Power Plant	250 MW/ 650 MWh	The South Australian Government proposed to install 50 000 home energy systems, each comprising a 5 kW solar photovoltaic system, a 5 kW/13.5 kWh battery and a smart meter. The systems will be rolled out over 4.5 years. The systems will be privately owned and operated by a 3rd party provider, with electricity provided to the consumer metered and billed to the household by a program retailer.	$800 m
South Australia	Aurora Solar Energy Project	150 MW/ 110 MWh	The South Australian Government contracted to source 100 per cent of the government's electricity requirements from the Aurora solar project, a 150 MW solar thermal plant at Port Augusta, due for completion in 2020. The project includes 1100 MWh storage (equivalent to around eight hours of supply) and would meet 100 per cent of the government's power needs for 20 years.	$650 m
South Australia	Home Battery Scheme	333–400 MWh +	The South Australian Government's Home Battery Scheme will provide 40 000 South Australian households with access to around $100 m in grants over four years and $100 m in loans from the Clean Energy Finance Corporation to help pay for the installation of home battery systems. The subsidy will be $500 per kWh ($600 per kWh for concession customers), capped at $6000. Battery systems installed under the scheme must be capable of being remotely controlled as part of a coordinated fleet of storage systems.	$200 m
South Australia	SA Renewable Technology Fund		The fund has $150 m to allocate, including $75 m in grants and $75 m in loans.	$150 m
South Australia	Grid Scale Storage Fund		The South Australian government established the fund to support development of new energy storage projects. It will target distributed storage (behind-the-meter projects in commercial and industrial facilities or in the distribution network), which will be operational within two years, and centralised storage (projects located upstream in the electricity network) that will be operational within four years. It intends to coordinate with ARENA on project assessment and funding.	$50 m
ACT	NextGen Renewable Storage Scheme	36 MW	The project follows on from a pilot scheme begun in 2016. The ACT government will provide grants for 5000 home battery systems be installed by 2020, with 400 by the end of 2018.	$25 m

ANNOUNCEMENT DATE	IMPLEMENTATION DATE	STATUS	
March 2017	March 2018	Committed	In March 2018 the Victorian Government announced $25 m in grant funding matched by $25 m from ARENA for two projects to be built by private consortia. A 25 MW/50 MWh battery connected to the Gannawarra Solar Farm commenced operation 16 October 2018. A 30 MW/30 MWh battery connected to the Ballarat Area Terminal Substation was completed 23 October 2018. Both plant will be privately owned and will be operated by Energy Australia. Both projects will be fully commissioned finish by summer 2018–19.
February 2018	2022	Trial phase	In 2018–19, 1100 systems will be rolled out across South Australian Housing Trust properties, with a $2 m grant and $30 m loaned from the Renewable Technology Fund. Subject to the success of the trial phase a further 24 000 systems will be rolled out to public housing properties and 25 000 to private properties from 2019. Financing for the remainder of the program is yet to be determined but is expected to be raised from private investors.
August 2017	2020	Proposed	The South Australian Government signed a contract for the project in August 2017. At May 2018 the project was yet to complete financing. Construction was scheduled to commence in 2018.
September 2018	October 2018	Committed	Grants will be available from October 2018. $12.5 m in funding has been allocated for around 5000 households in the first year of the scheme.
March 2017	July 2017	Committed	The Hornsdale Power Reserve was the first project to receive money from the Fund in July 2017. In August 2017, second round proposals were called for resulting in 80 submissions. On 16 March 2018, the Fund announced a $10 m loan to SIMEC Zen Energy for a 120 MW/120 MWh battery to be built in Port Augusta On 15 August 2018 the Fund announced a $5 m investment, along with $5 m from ARENA in a $38 m, 25 MW/52 MWh battery project adjacent to the Lake Bonney Wind Farm.
November 2018	November 2018	Implemented	Applications for funding close 7 February 2019, with successful applications to be announced by mid-2019. The government states that it prefers projects that will reach financial close by the end of 2019.
December 2015	2020	Implemented	Round 1 (pilot) and 2 of the program awarded $2.2 m for the installation of 800 systems. Round 3 closed in January 2018 with an allocation of $3 m.

JURISDICTION	NAME	CAPACITY	DETAILS	ESTIMATED COST
RENEWABLE ENERGY TARGETS				
Federal	Renewable Energy Target (RET)	33 000 GWh	The current large scale target of 33 000 GWh of renewable electricity generation per year (expected to be equivalent to around 23.5 per cent of Australia's generation) by 2020 was introduced in 2015. Certificates under the scheme are created based on the output of accredited generators. A small scale scheme sits in addition to the target, with certificates created through the installation of approved systems by households or businesses. Retailers and large commercial users must surrender a specified number of certificates to the Clean Energy Regulator each year, based on their total electricity purchases in the NEM.	
Queensland	Queensland Renewable Energy Target		The Queensland Renewable Energy Target of 50 per cent renewable generation by 2030 is not a legislated. It is supported through government programs to encourage private investment, and through the state owned CleanCo (see above).	$1.16 b (Total Qld Power Plan cost)
Victoria	Victorian Renewable Energy Target	5400 MW (2016 estimate of 2025 capacity)	The Victorian Government announced a renewable energy target of 25 per cent by 2020 and 40 per cent by 2025. These targets were legislated in the Renewable Energy (Jobs and Investment) Bill 2017 (Vic). The legislation requires the minister to make a minimum capacity determination to meet the 2020 target by 31 December 2017 and the 2025 target by 31 December 2019. The minister is required to report to parliament annually on progress.	$2.5 b (estimated total investment)
ACT	ACT Renewable Energy Target/ Large Scale Feed in Tariff	650 MW	The ACT target is for 100 per cent of Canberra's electricity needs to be met by renewable generation by 2020. The Electricity Feed-in (Large-scale Renewable Energy Generation) Act 2011 provides that the ACT Government may award Feed in Tariff entitlements to up to 650 MW of renewable energy generation. The projects may be constructed anywhere in the NEM. Contracts for difference for 20 year terms are awarded through reverse auctions. Generators must have LGCs for all eligible generation and surrender them to receive payment.	$14.6 m (for 240 MW in 2016–17)
PUBLIC INVETSMENT IN TRANSMISSION				
Queensland	North and North-West Queensland Strategic Transmission Infrastructure Investment		The Queensland Government intends to reinvest $150 m in dividends from transmission network operator Powerlink into transmission infrastructure linking the North Queensland Clean Energy Hub to the NEM. The government has indicated that the infrastructure would run from Townsville to Cairns via Hughenden and Kidston in North Queensland.	$150 m
NSW	NSW Transmission Infrastructure Strategy	1610 MW	The NSW Government intends to provide financial guarantees to the NSW transmission grid operator TransGrid to conduct early-stage planning and feasibility work on upgrades to the VIC-NSW Interconnector (170 MW), Qld-NSW Interconnector (190 MW), the SA-NSW Interconnector (750 MW), and new transmission from Snowy Hydro (500 MW). The plan includes an additional 2100 MW of transmission upgrades contingent on Snowy Hydro 2.0 being completed. The plan will also explore ways to improve interconnection to three Renewable Energy Zones in NSW and to streamline the Regulatory Investment Test for Transmission.	$2.6 b (total capital cost, government funding unknown)

ANNOUNCEMENT DATE	IMPLEMENTATION DATE	STATUS	
November 1997	2020		The scheme was first introduced in 2001 with a target of 9500 GWh per year by 2010. The target and elements of the scheme were revised in 2009, 2011 and 2015. The target increases each year to 2020, and then remains stable until the scheme ends in 2030. The Federal opposition Labor party has suggested it will lift the 2030 target to 50 per cent if elected.
2015	2030	Implemented	See details on specific programs above. The Queensland Government forecasts that by mid 2019 21 per cent of Queensland's electricity will be produced from renewable resources.
June 2016	2025	Implemented	On 28 December 2017, the Minister gazetted the capacity requirement, determining a total of 6341 MW of renewable energy would be required to meet the 25 per cent target in 2020. In November 2018, the government announced that, if relected it would raise the target to 50 per cent by 2030.
September 2011	2020	Completed	In August 2016, the ACT government granted its last entitlements under the scheme. A total of 640 MW have now been awarded and the ACT government states that this will be sufficient to achieve the Territory's 100 per cent target by 2020.
June 2017		Proposed	Powerlink was due to provide a feasibility study of the North Queensland Clean Energy Hub to the Queensland government in December 2017.
November 2018	2024	Proposed	The plan aims to accelerate the development of transmission network upgrades by 6–9 months. In line with AEMO's Integrated System Plan, the first two projects are due to be completed by 2022 and the other two by 2023 and 2024 respectively.

JURISDICTION	NAME	CAPACITY	DETAILS	ESTIMATED COST
South Australia	SA-NSW Interconnector Duplication	800 MW	Proposal to construct a new 800 MW interconnector between SA and NSW. The South Australian Government provided $0.5 m to ElectraNet, the operators of the South Australian transmission network, to run a feasibility study into the project. The government has since committed $14 m towards early works and has suggested it would contribute a further $200 m towards construction costs. The remainder of the costs would be financed by ElectraNet.	$214 m (total project costs estimated at $1.5 b)
Tasmania	Marinus Link	600 MW/ 1200 MW	Proposal to duplicate the existing BassLink Interconnector between Victoria and Tasmania. Options exist for a 600 MW connection, which would rely on existing onshore transmission infrastructure, or a 1200 MW link that would require additional onshore investment. Modelling for the 600 MW link suggests a cost up to $1.1 b with a 2026 completion date.	$1.1 b

ANNOUNCEMENT DATE	IMPLEMENTATION DATE	STATUS	
June 2016	2021–2022	Proposed	In June 2018, Electranet released a Project Assessment Draft report, typically the 2nd step in a 3-stage RIT-T assessment. It assessed an option for a 920 km 330 kV connection between mid-north SA and Wagga Wagga in NSW, via Buronga would deliver the greatest net benefit to the NEM. This option would have a notional capacity of 800 MW and cost $1.5 b.
April 2016	2026–2033	Proposed	TasNetworks, in partnership with ARENA, is currently undertaking an initial feasibility report for the Tasmanian Government and ARENA. TasNetworks has also released a Project Specification Consultation Report, the first stage in the RIT-T process.

ABBREVIATIONS

ABS	Australian Bureau of Statistics
ACCC	Australian Competition and Consumer Commission
ACT	Australian Capital Territory
ADGSM	Australian Domestic Gas Security Mechanism
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AFMA	Australian Financial Markets Association
AGN	Australian Gas Networks
APA	APA Group
APGA	Australian Pipelines and Gas Association
APLNG	Australian Pacific LNG
APPEA	Australian Petroleum Production & Exploration Association
ARENA	Australian Renewable Energy Agency
ASX	Australian Securities Exchange
ATO	Australian Taxation Office
CAPEX	capital expenditure
CCGT	combined cycle gas turbine
c/kWh	cents per kilowatt hour
CEFC	Clean Energy Finance Corporation
CER	Clean Energy Regulator
CESS	capital expenditure sharing scheme
C&I	commercial and industrial

CKI	Cheung Kong Infrastructure
CNOOC	China National Offshore Oil Corporation
CoAG	Council of Australian Governments
CPI	consumer price index
CSG	coal seam gas
CST	Concentrated solar thermal
EA	Energy Australia
EBITDA	earnings before interest, taxes, depreciation and amortisation
EBSS	efficiency benefit sharing scheme
ECA	Energy Consumers Australia
EII	Energy Infrastructure Investments
EIT	emissions intensity target
ENA	Energy Networks Australia
EOI	expression of interest
ERA	Economic Regulation Authority (Western Australia)
ERF	Emissions Reduction Fund
ESB	Energy Security Board
ESC	Essential Services Commission
ESCOSA	Essential Services Commission of South Australia
EUAA	Energy Users Association of Australia
FCAS	frequency control ancillary services
FIRB	Foreign Investment Review Board
FRC	full retail contestability
GAP	Gas Acceleration Program
GJ	gigajoule
GLNG	Gladstone LNG
GPG	gas powered generation
GSL	guaranteed service level
GST	goods and services tax
GW	gigawatt
GWh	gigawatt hour
HHI	Herfindahl–Hirschman index
ICE	Intercontinental Exchange
ICRC	Independent Competition and Regulatory Commission
IPART	Independent Pricing and Regulatory Tribunal
ISP	integrated system plan
km	kilometre
kW	kilowatt
kWh	kilowatt hour
LGC	Large-scale Generation Certificate
LNG	liquefied natural gas
MJ	megajoule
MOS	market operator services

MSATS	market settlement and transfer solutions
MtCO2-e	million metric tonnes of carbon dioxide-equivalent
mtpa	million tonnes per annum
MW	megawatt
MWh	megawatt hour
na	not available
NCC	National Competition Council
NEG	National Energy Guarantee
NEM	National Electricity Market
NSW	New South Wales
OCGT	open cycle gas turbine
OECD	Organisation for Economic Co-operation and Development
OPEC	Organization of the Petroleum Exporting Countries
OPEX	operating expenditure
OTC	over the counter
OTTER	Office of the Tasmanian Economic Regulator
PACE	Plan for Accelerating Exploration
PJ	petajoule
PV	photovoltaic
QCA	Queensland Competition Authority
QCLNG	Queensland Curtis LNG
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-D	regulatory investment test—distribution
RIT-T	regulatory investment test—transmission
RoLR	retailer of last resort
RSI	residual supply index
SAIDI	system average interruption duration index
SAIFI	system average interruption frequency index
SEQ	south east Queensland
SPPA	solar power purchase agreement
STPIS	service target performance incentive scheme
STTM	short term trading market
TGP	Tasmanian Gas Pipeline
TJ	terajoule
TJ/d	terajoules per day
Tribunal	Australian Competition Tribunal
TW	terawatt
TWh	terawatt hour

VCR	value of customer reliability
VTS	Victorian Transmission System
VWA	volume weighted average
WACC	weighted average cost of capital
WAL	Wallumbilla