SNAPSHOT

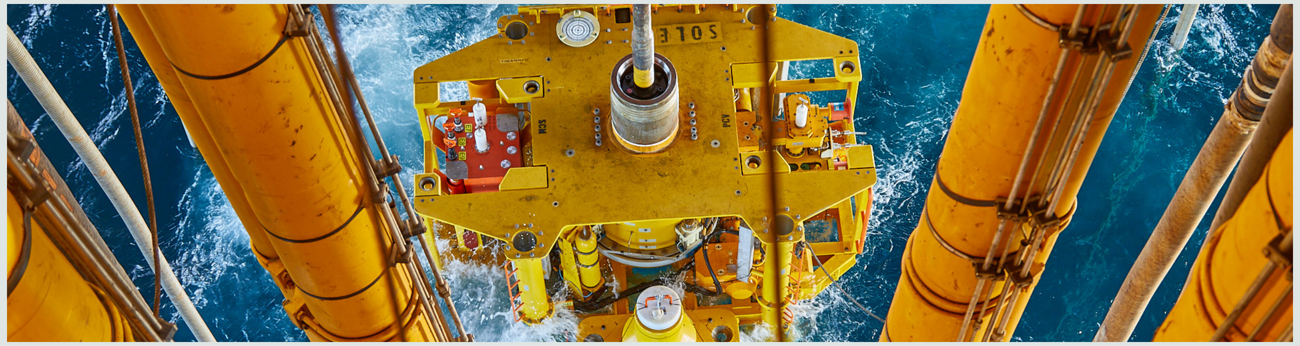
Retail energy markets

- 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

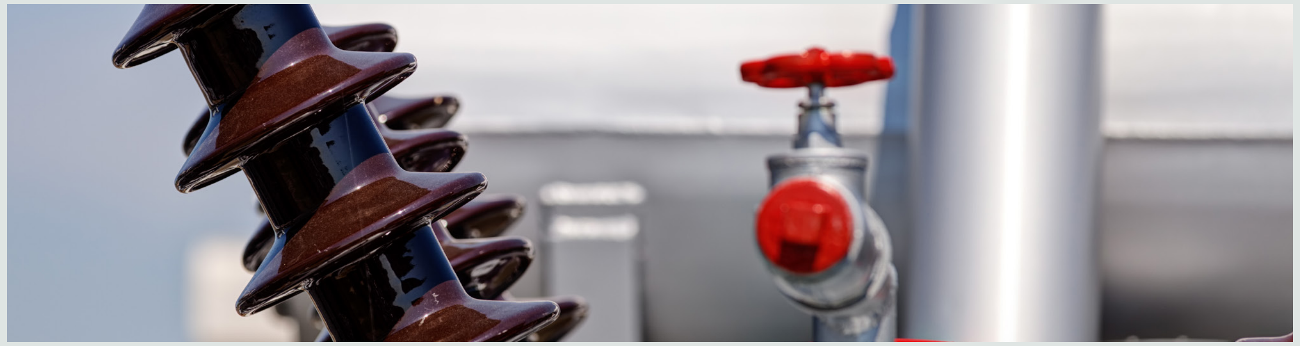
- Coal fired generators are being retired as they reach the end of their economic life, withdrawing 4200 MW of capacity from the market since 2014. But 4300 MW of large scale wind and solar capacity was added over the same period. The pace of this investment is rising, with renewable capacity additions 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

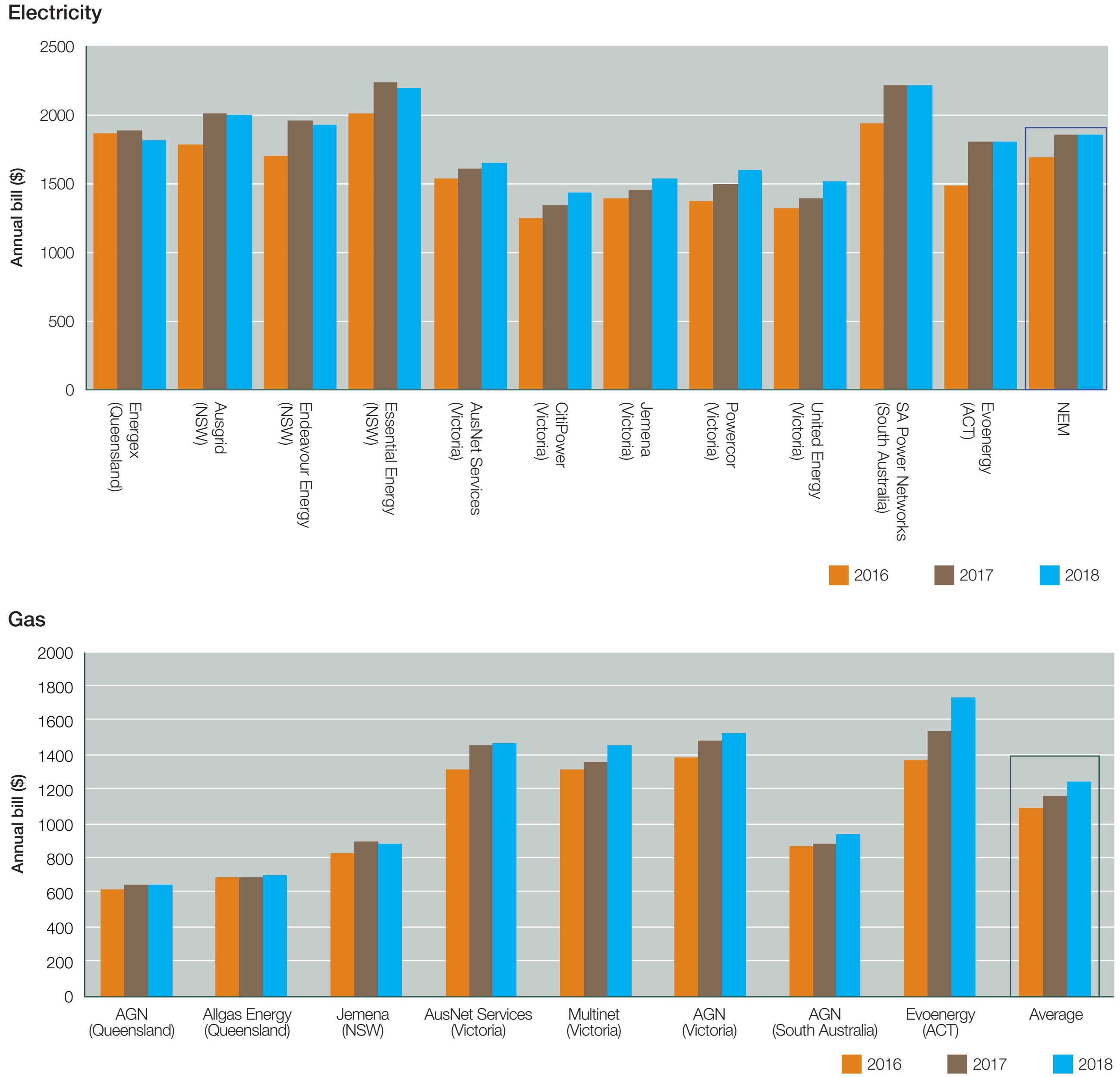
1 ACCC, *Restoring electricity affordability and Australia's competitive advantage, Retail Electricity Pricing Inquiry—Final Report*, June 2018.

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

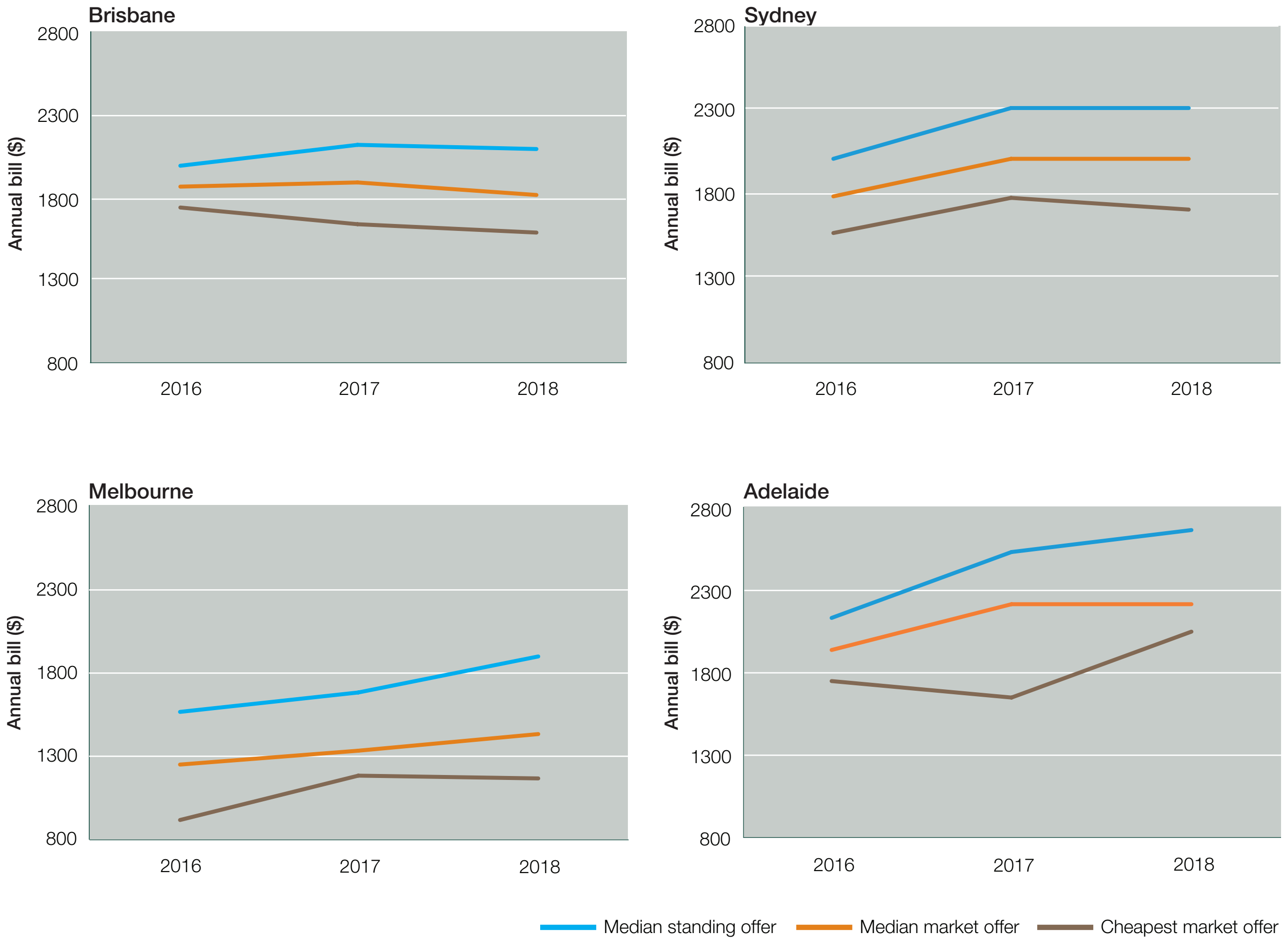


Note: Median market offers in each calendar year. Data includes all generally available offers for residential customers using a 'single rate' tariff structure at December 2016, December 2017 and August 2018. Annual bills based on average consumption in each jurisdiction: NSW 6130 kWh (electricity), 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.

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

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.

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

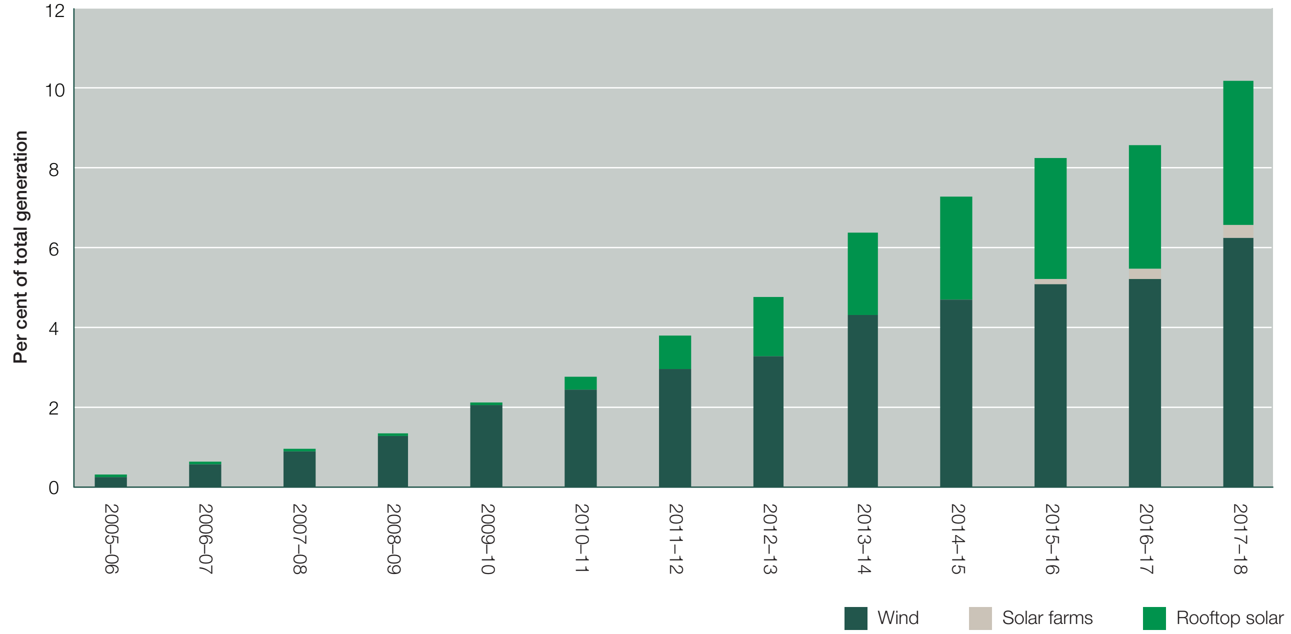
Wholesale electricity in eastern and southern Australia is traded through the national electricity market (NEM), a spot market in which supply and demand conditions determine prices in real time. Over 230 large scale power stations sell electricity into the market, which is transported along 40 000 kilometres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

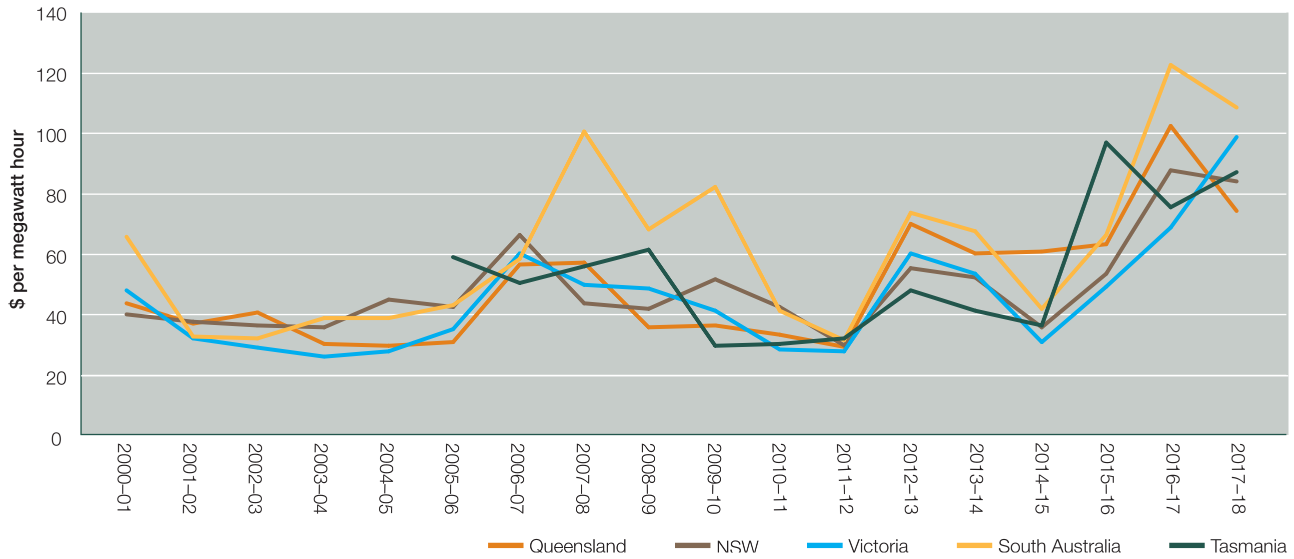
Hazelwood was over 50 years old, and was Australia's most emissions intensive power station. But its closure was significant given it supplied 5 per cent of the NEM's total output. Further coal plant closures are likely in the future. AGL plans to retire its Liddell power station (1680 megawatts (MW)) 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

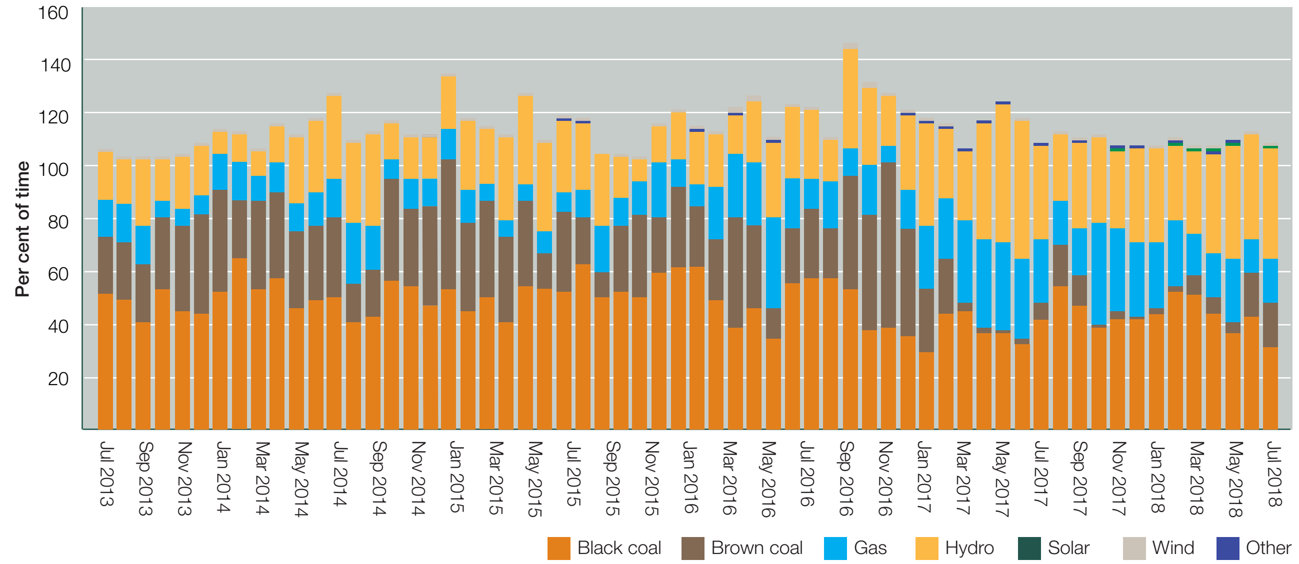
Price pressure intensified following the closure of coal fired plant in South Australia (in May 2016) and Victoria (in March 2017) (figure 4). These retirements followed years of stagnant investment in dispatchable generation, leaving the market without an efficient mix of generation. The removal of 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 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.

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.

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.

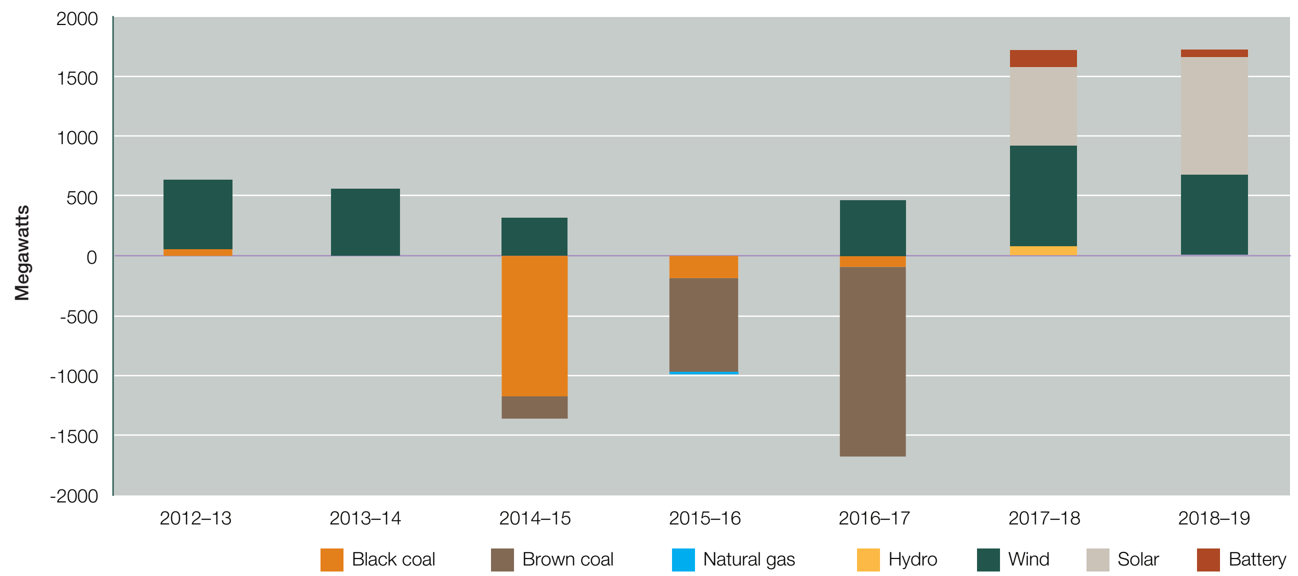
While power system *reliability* incidents rarely result in load shedding, power system *security* issues have become more common, closely linked to higher levels of variable wind and solar generation. The older fossil fuel power plants that are retiring helped maintain power system security by providing 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 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.

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.

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

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

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.
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.

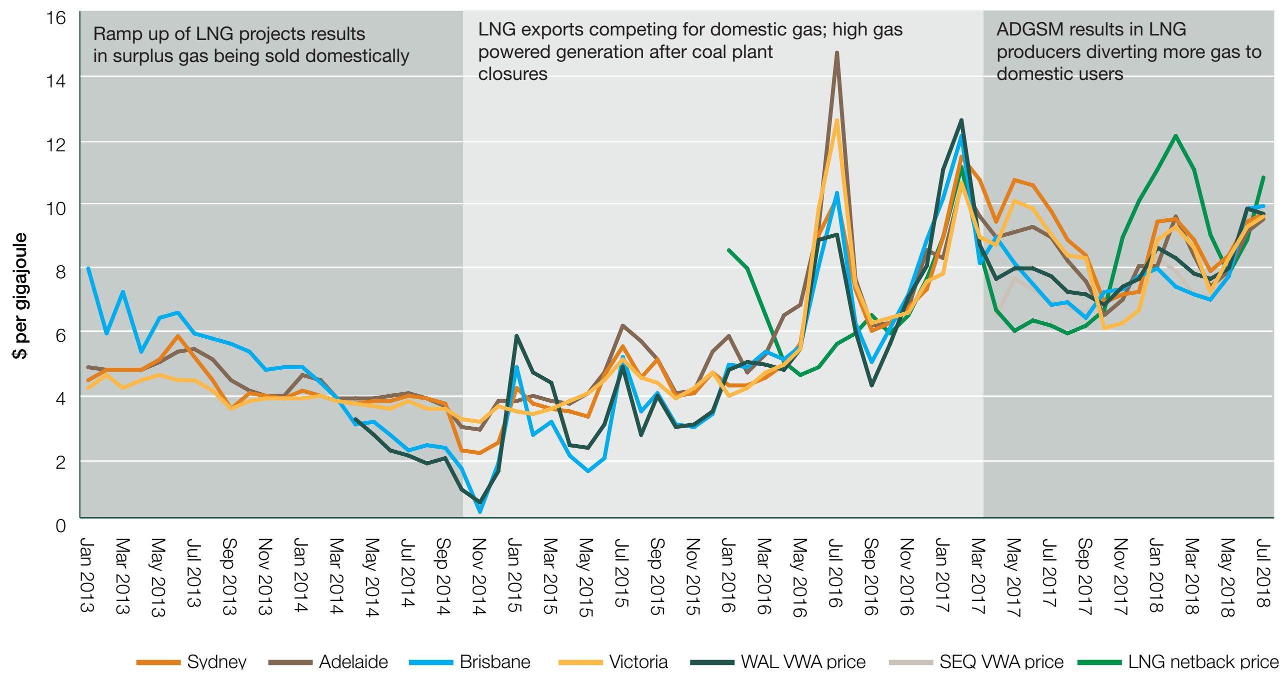
The differential eased in late 2017 following the Australian Government's market intervention (discussed above), but gas plant outages in Victoria in 2018 periodically caused it to return. Price largely converged from March 2018, in part because swap agreements between Queensland producers and southern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

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).

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.

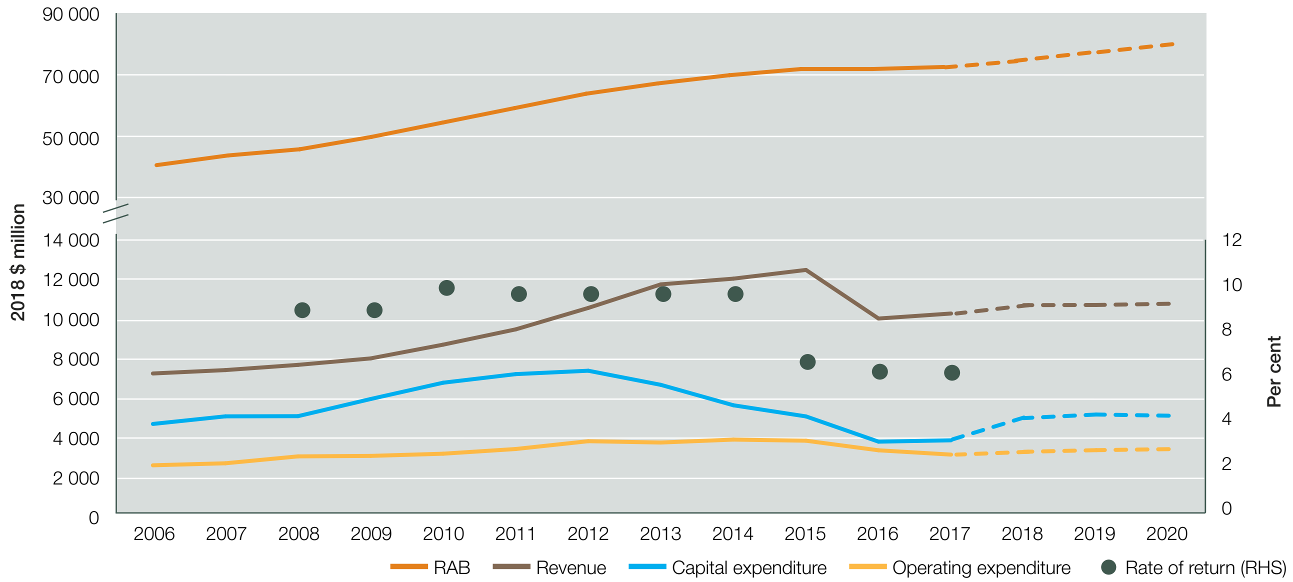
The AER is also helping implement other reforms aimed at making the market more transparent for customers. In 2018 the AER began publishing new data on prices and liquidity in gas markets. And in September 2018 reforms to the Gas Bulletin Board widened and improved reporting coverage, including on gas 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.

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.

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.

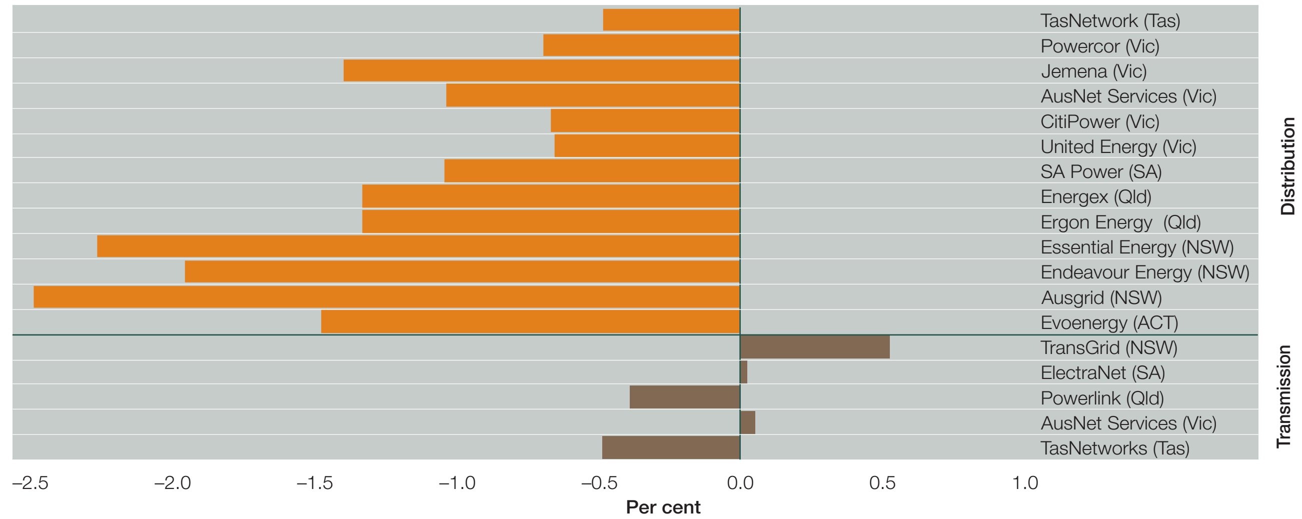
49 AER estimate derived from regulatory information notices submitted by electricity network business.

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

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.

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.

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.

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.

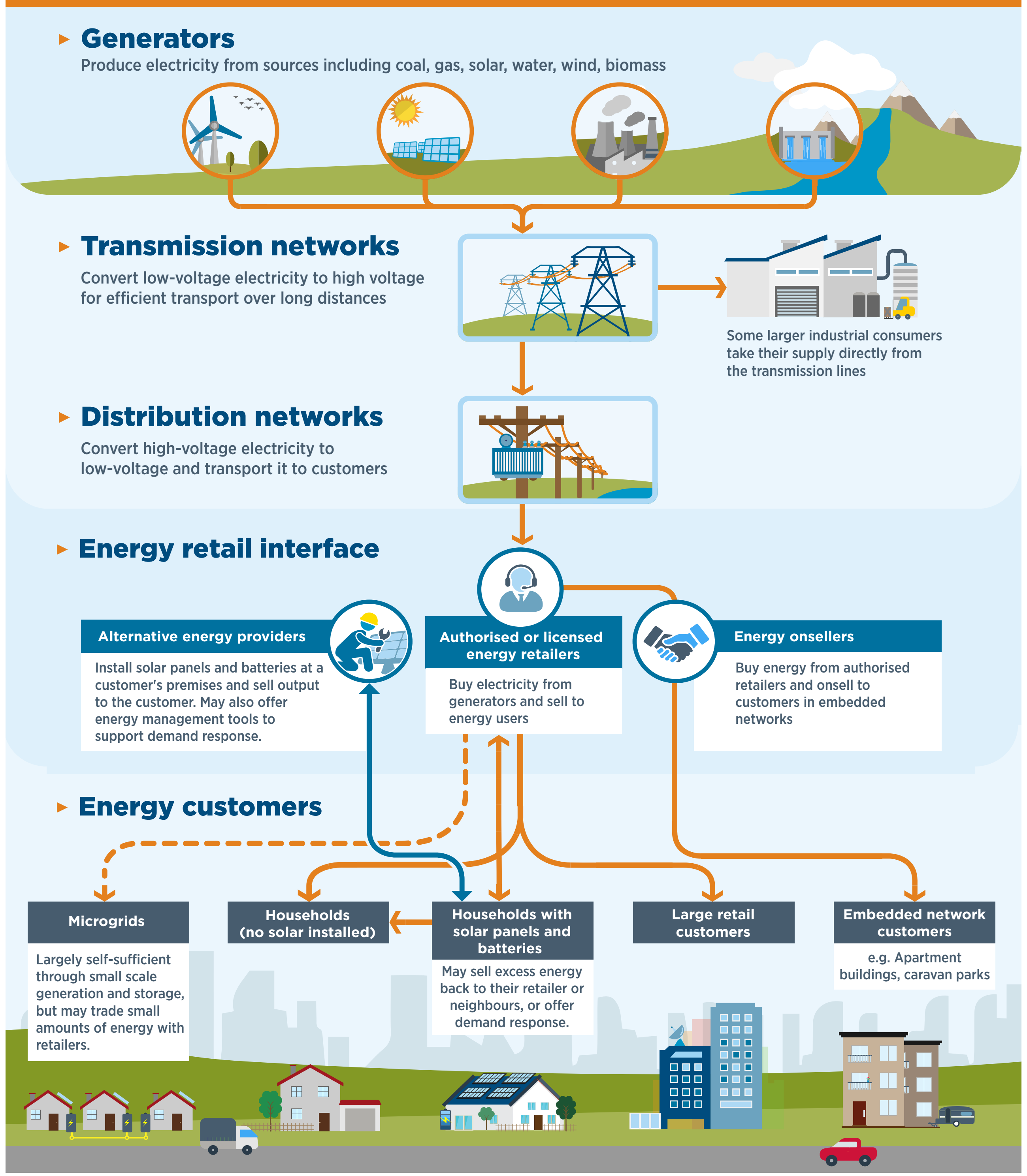
The AER is also examining whether the regulatory test for assessing electricity network investment proposals remains fit for purpose in the current environment. In particular, it is assessing whether the test adequately accounts for system security, emissions reduction goals, and events with a low probability 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.

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

Infographic 1—Electricity supply chain



Infographic 2—Gas supply chain