STATE OF THE ENERGY MARKET MAY 2017

AUSTRALIAN ENERGY REGULATOR

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Cover image by John Grainger (Newspix)

PREFACE

For the past 10 years, the Australian Energy Regulator has reported to policy-makers, industry and the Australian community on the state of the energy market.

We have focused on providing independent and reliable information about what's happening in Australia's wholesale electricity and gas markets, the transmission and distribution networks and the rapidly evolving retail sector. Our report aims to be a bedrock of unbiased information for those within the energy market and those with a keen interest in its future.

At a time when Australia's energy markets are undergoing unprecedented change and becoming more complex, it is more important than ever to understand the drivers and outcomes that have impacted energy markets over the past 12–18 months. Technology change is impacting on the wholesale electricity and gas markets more than at any other time in the history of the NEM, while network costs are falling and new and innovative products and services are emerging for retail customers, enabling them to take more control over their energy usage and bills.

This year's report provides an overall picture of the market and shines a light on complex issues, placing the big drivers of change in context as well as how the sector and stakeholders are responding. If knowledge is power, then we hope this year's *State of the energy market* makes a valuable contribution.

Paula Conboy—Chair
May 2017

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SNAPSHOT

National Electricity Market

- Peak demand is rising, particularly in Queensland (reaching a record level in January 2017) and NSW.
- Coal generators are being retired and not being replaced, removing significant capacity from the market and leaving a tighter supply–demand balance.
- High gas fuel costs are contributing to high electricity prices.
- Growing investment in renewable generation requires a greater understanding of the services needed to support power system security.
- Uncertainty about governments' energy and climate change policies is affecting investor confidence. Outside of renewables, private investment in new plant has stalled while governments have announced plans to invest (or to explore investment) in gas, pumped hydro and energy storage.
- The Australian Energy Regulator (AER) has a new role in monitoring the competitiveness of the National Electricity Market, including deterrents to competition.

Eastern Australian gas markets

- Queensland's liquefied natural gas (LNG) industry is having a significant impact on the eastern gas market.
- Gas prices struck under new contracts and in spot markets are rising and appear often to be above LNG netback prices—something the Australian Competition and Consumer Commission (ACCC) will examine in its three year review.
- Subdued international oil prices and regulatory restrictions are hampering investment in exploration and new gas projects.
- The Australian Energy Market Operator raised concerns of possible supply shortfalls if conditions in the eastern gas markets persist.
- Market responses include Jemena's Northern Gas Pipeline targeting completion in 2018, a new producer of offshore Victorian gas targeting production in 2019, Santos preparing to develop its Narrabri onshore gas project and AGL Energy exploring LNG imports.
- Government and regulatory responses include a new power to limit exports to apply from 1 July 2017, new ACCC wholesale gas markets monitoring, reforms to the gas pipeline sector and new incentives in South Australia for gas exploration.

Regulated energy networks

- Recent AER decisions have lowered total network revenues by 13.5 per cent in electricity and 12 per cent in gas, reflecting more stable financial markets and reduced capital expenditure.
- Lower network charges have helped cushion the effect of rising wholesale prices on customer energy bills, but uncertainty remains due to appeals on AER decisions by the energy businesses to the Australian Competition Tribunal and the recent decisions of the Federal Court on some of these appeals.
- While slower growth in demand for energy has seen lower overall capital expenditure in recent years, replacement expenditure is overtaking augmentation as a cost driver for many networks.
- Network businesses are starting to implement more cost reflective network pricing, which gives consumers clearer signals about the cost of energy that they use.

Retail energy markets

- Electricity retail prices trended higher in 2016, except in Victoria, with the sharpest rises in NSW and South Australia (with average market offer prices rising by 13 per cent and 11 per cent respectively).
- Retail energy markets are evolving, with new selling models and products emerging. But concerns persist about the effectiveness of competition and the level of customer engagement in retail energy markets, with 50 per cent of customers not switching their retailer or energy plan in five years.
- Australian household electricity prices are above the OECD average. Australian prices are higher than in the United States, Canada, and South Korea, but lower than in Japan, New Zealand, the United Kingdom and most of Europe.
- The Australian Government in March 2017 directed the ACCC to hold an inquiry into retail electricity pricing, with a preliminary report by the end of September 2017.

Image courtesy of AGL Energy

MARKET OVERVIEW

A.1 Introduction

The past 12–18 months have been some of the most challenging Australia's energy sector has experienced since the National Electricity Market (NEM) was established in 1998. The primary focus has been on wholesale markets, both for electricity and gas. While the two markets are increasingly interdependent, the challenges in the electricity and gas markets have differing causes.

In electricity, investor uncertainty around the viability of new generation investment, combined with recent coal plant closures, has contributed to a generation mix that is increasingly reliant on intermittent wind and solar energy. Price pressures are also motivating consumers to take greater control of their energy consumption, including by installing rooftop solar photovoltaic (PV) and battery storage systems.

In gas, domestic supply has tightened as Queensland's liquefied natural gas (LNG) projects draw on reserves from southern Australia. At the same time, regulatory restrictions on exploration and subdued international oil prices have delayed the development of new reserves. The result, when coupled with rising production costs, has been significantly higher gas contract and spot prices.

Rising wholesale energy prices are affecting retail prices. But unlike previous periods when prices were the primary concern, South Australia's statewide blackout in September 2016 drew attention to the importance of balancing price concerns with ensuring security of supply.

These concerns have prompted policy initiatives and inquiries into whether energy markets are delivering for consumers. The Australian Competition and Consumer Commission (ACCC) in 2017 was tasked with monitoring outcomes in wholesale gas markets and with inquiring into the supply and pricing of retail electricity. Additionally, the AER was in 2016 given a new role in monitoring and reporting on whether the NEM is effectively competitive. More generally, government and industry are inquiring into how the regulatory framework can best accommodate the complex transitions underway in the energy sector.

In the networks sector, the Federal Court on 24 May 2017 upheld elements of the Australian Competition Tribunal's decision on revenues for NSW and ACT energy network businesses. The Court's decision and other ongoing appeals against AER determinations may have implications for the approach to network regulation and the costs to be borne in future by energy customers.

A.2 National Electricity Market

After limited growth for several years, peak grid demand is again rising, particularly in Queensland (with a new regional demand record in January 2017) and NSW. Tightened supply coincided with this growth in demand. An influx of wind and solar generation (figure 1) affected the viability of existing thermal generation, with several coal generators being retired, including South Australia's Northern power station in 2016 and Victoria's Hazelwood plant in 2017. These closures withdrew over 2000 megawatts (MW) from the market, equivalent to around 50 per cent of South Australia's generation capacity (figure 2).

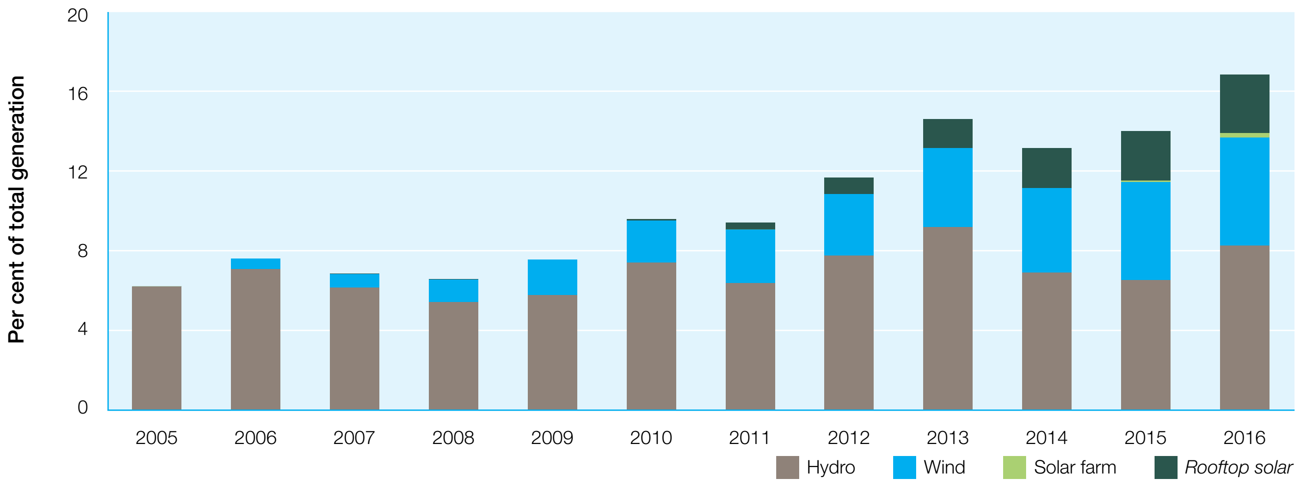
Rising demand and a contraction in supply contributed to tight market conditions, with gas powered generation often setting dispatch prices. And gas generators responded to higher gas fuel costs by bidding into the market at higher price levels, repeatedly spiking wholesale prices in mainland NEM regions during winter 2016 and over summer 2016–17 (figure 3). In 2015–16, 30-minute settlement prices exceeded $200 per megawatt hour (MWh) almost 4000 times—an unprecedented number. Another 2100 instances occurred in the first nine months of 2016–17.

The Australian Energy Market Operator (AEMO) projected the retirement of Hazelwood Power Station may lead to potential breaches of the reliability standard in Victoria and South Australia from 2017–18 under a neutral growth scenario.[1] This closure also led to escalating electricity futures prices, as the market factored in reduced supply on top of already tight market conditions.

Various scenarios could avert this situation, including the return to service of mothballed gas powered generators. In Tasmania, the Tamar Valley plant was returned to service in 2016, and a mothballed unit of South Australia's Pelican Point plant is expected to return to service by July 2017. But AEMO reported in March 2017 that domestic gas supplies could be insufficient to meet demand for gas powered generation by summer 2018–19, with South Australia, NSW and Victoria the regions most affected.[2] These forecasts highlight a growing interdependence between electricity and gas markets in eastern Australia.

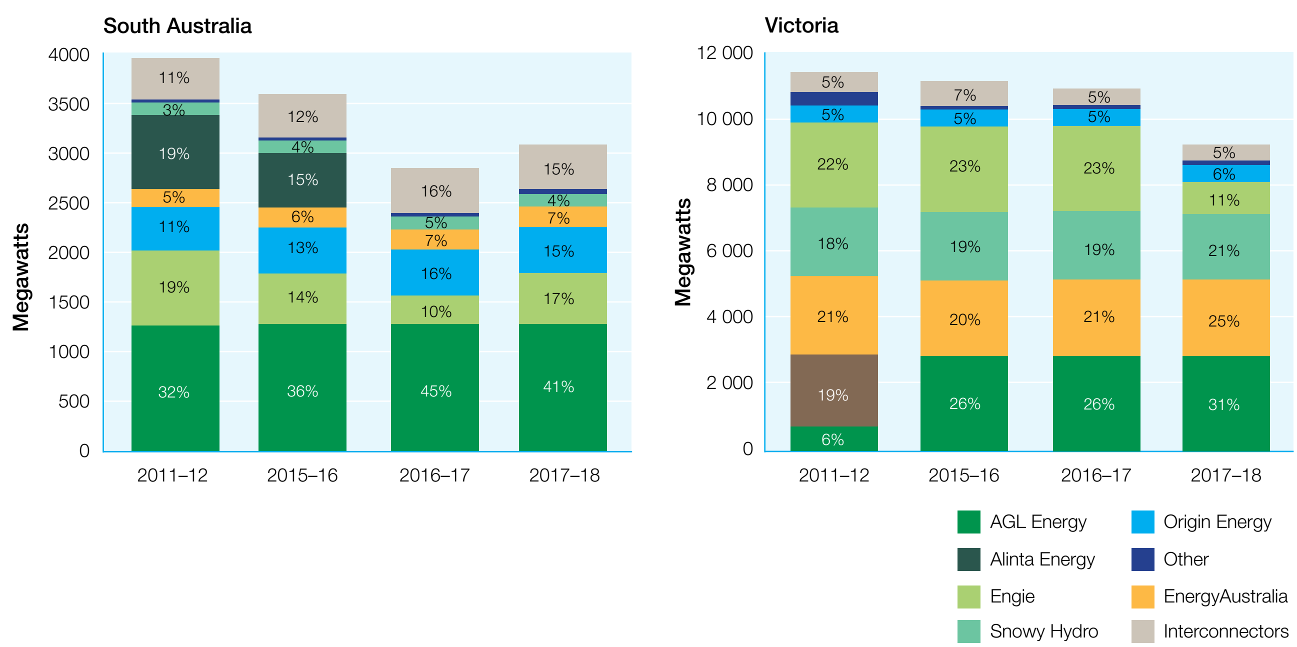
1 AEMO, *Update: Electricity statement of opportunities*, November 2016.
2 AEMO, *Gas statement of opportunities*, March 2017. AEMO expects to release updated forecasts for the eastern gas markets in June 2017.

Figure 1
Renewable generation contribution to NEM electricity supply



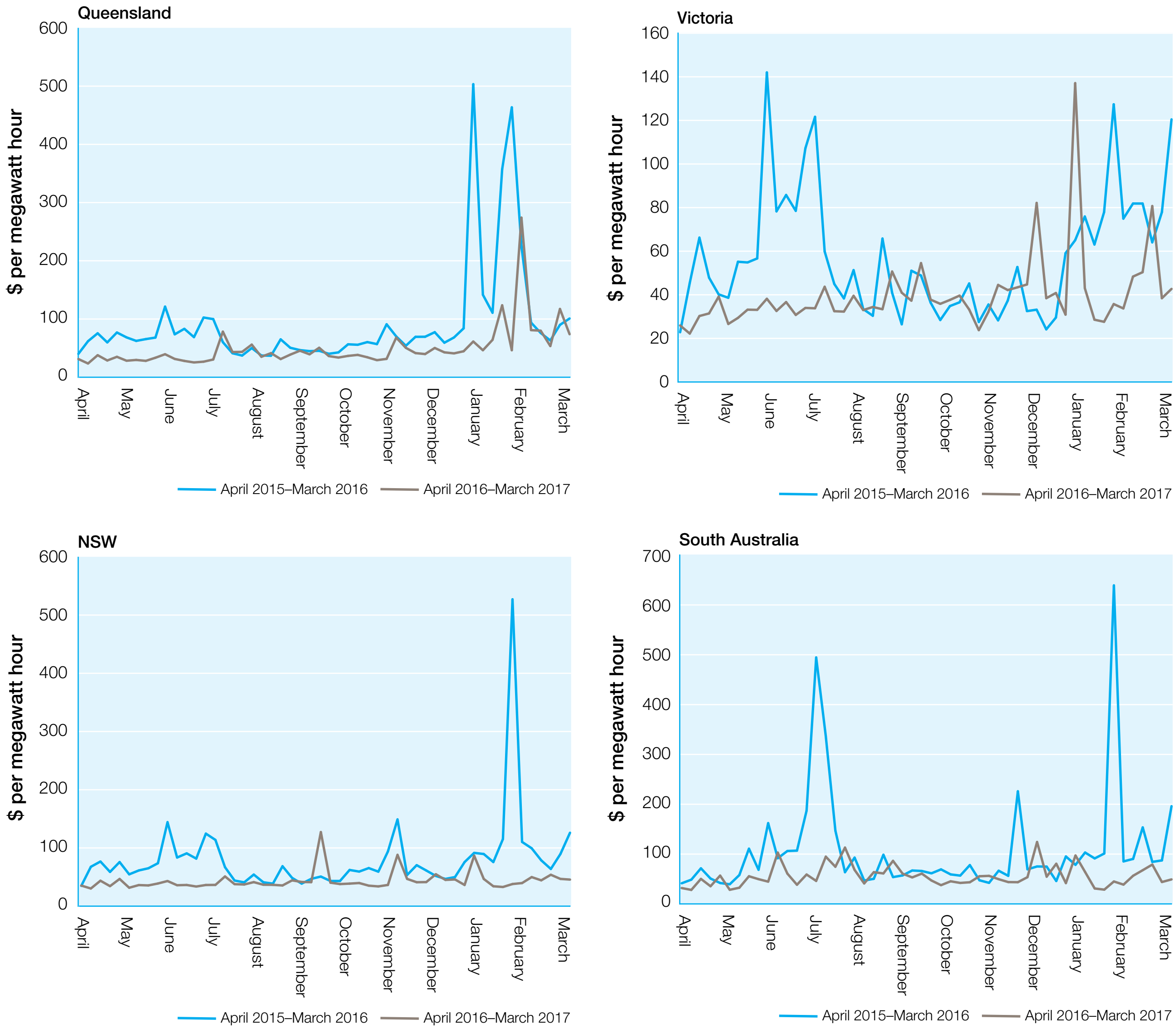
Note: Rooftop solar PV generation is not traded through the NEM. Electricity generated from this source acts to reduce the demand for grid supplied electricity.
Source: AER.

Figure 2
Effect of plant closures on generation capacity



Note: The rise for South Australia in 2017–18 accounts for the planned return to service of the second unit of Engie's Pelican Point plant.
Source: AER.

Figure 3
Weekly wholesale electricity prices



Sources: AER, AEMO.

Alongside this tight market, some regions are more reliant on intermittent renewable generation, with South Australia generating 50 per cent of its electricity from wind and solar in 2016. The weather dependant nature of this generation opens vulnerabilities to supply risk if conditions are unfavourable at times of high demand, or when import capabilities across network interconnectors are constrained. These newer technologies also have different technical characteristics to traditional large thermal generators. The implications of this will need to be understood and harnessed to ensure the ongoing safe and reliable operation of the power system.

We have seen a rise in security issues in the NEM requiring intervention by AEMO. South Australia's statewide blackout on 28 September 2016 was caused by severe storms that brought down three transmission lines, creating voltage instability that shut down the operating systems on 400 MW of wind generation as well as the Heywood interconnector to Victoria. Insecure operating conditions also led the market operator to issue directions to cut supply to some customers in South Australia (on 1 December 2016 and 8 February 2017) and NSW (on 10 February 2017).

Governments and market bodies are undertaking several reviews to identify any necessary changes to the market framework to accommodate the growing contribution of intermittent renewable energy.[3] The Australian Government will finalise its *Independent review into the future security of the National Electricity Market* (Finkel review) in June 2017.

Uncertainty about governments' energy and climate change policies is widely cited as a factor stalling private sector investment in new generation plant. The Australian Energy Market Commission (AEMC) noted in March 2017 that 'without clear, national, coordinated policy objectives and credible mechanisms that reinforce one another both business and consumers find it difficult to invest'.[4] But while the private sector's investment response has been sluggish, governments in 2017 announced plans to explore investment to boost energy security, including in gas powered plant (South Australian Government) and grid scale energy storage through batteries and pumped hydro (Australian, Victorian, South Australian and Tasmanian governments).[5]

A.3 Eastern Australian gas markets

Queensland's LNG industry has brought significant private sector investment and economic activity to the region, but it has also had a significant impact on the eastern Australian gas market.

The first LNG cargo was exported from Curtis Island in January 2015, and by the end of 2016, three LNG projects (Queensland Curtis LNG, Gladstone LNG and Australia Pacific LNG) were operational. Australia is now the world's second largest LNG exporter, and will become the largest by 2018. By 2020, over 70 per cent of eastern and south eastern Australian gas production is likely to be exported.[6]

Australian gas customers now compete with the international market, and Queensland prices are increasingly shaped by LNG netback prices (the LNG export price in Asia, minus shipping and liquefaction costs). Gas prices have also risen in the southern states, with disruptions to the market reducing the availability and diversity of supply.

Originally, the LNG projects were expected to source much of their gas requirements from newly developed reserves in the Surat–Bowen Basin. But gas well development by Santos's Gladstone LNG project has been slower than expected, disrupting the domestic market. Because the project lacks sufficient reserves to meet its LNG requirements, it is sourcing around 50 per cent of its gas from elsewhere—much of it from the Cooper Basin in central Australia but also gas from Victorian production sources.

Other supply issues are also reducing the availability and diversity of supply in the southern gas market:

- Offshore gas production in Victoria is declining, especially in the Otway and Bass basins. Lower international oil prices have reduced incentives for gas exploration and new project development. More generally, production costs are rising as more economical gas reserves are depleted.

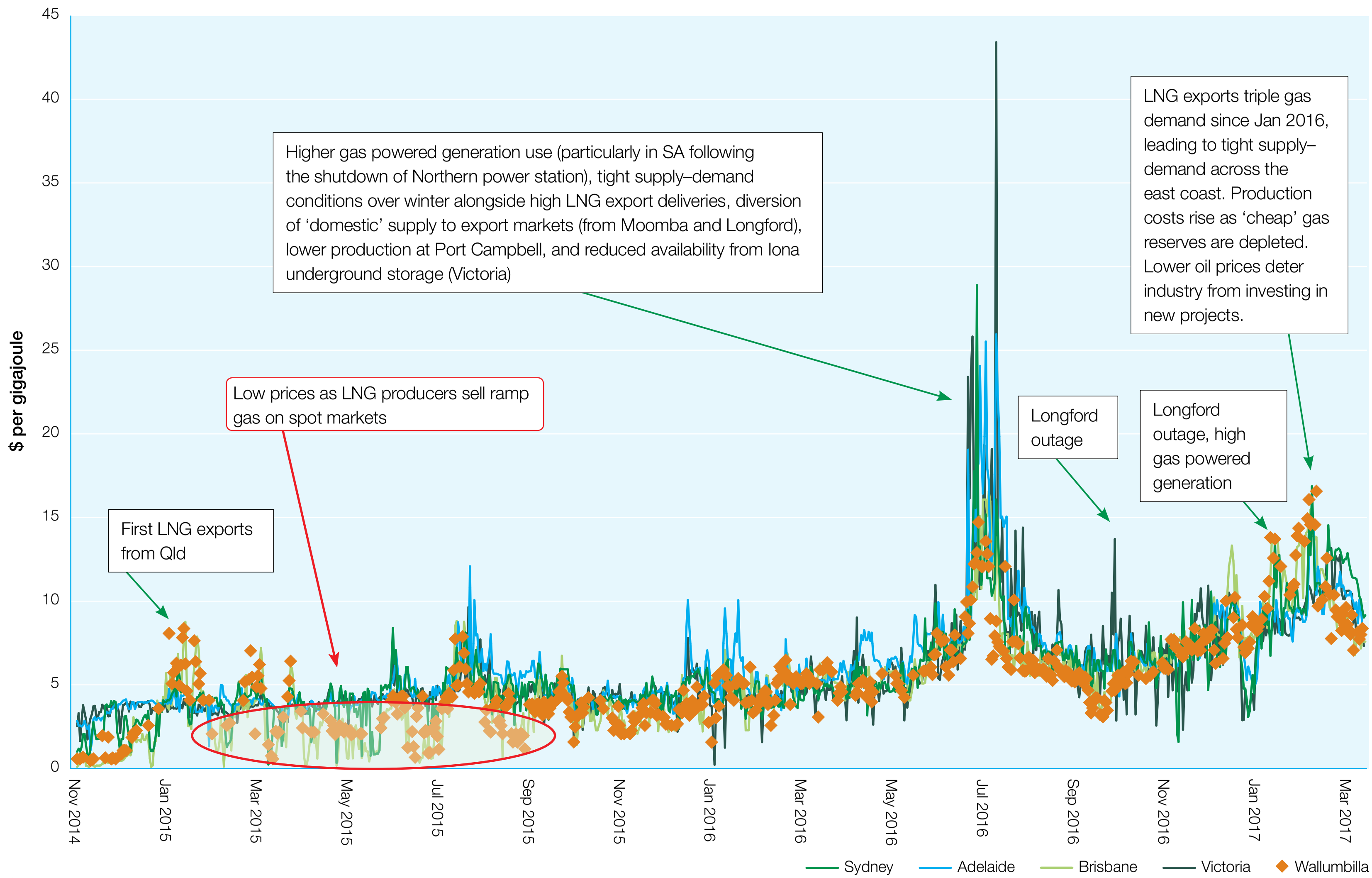
3 See, for example, AEMC, System security market frameworks review, available at www.aemc.gov.au/Markets-Reviews-Advice/System-Security-Market-Frameworks-Review; and AEMO, Future power system security program, available at www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability.

4 AEMC, 'AEMC submission to the Independent review into the future security of the National Electricity Market', Media release, 7 March 2017.

5 Jay Weatherill (Premier of SA), 'South Australia is taking charge of its energy future', Media release, 14 March, 2017; The Hon Malcolm Turnbull MP (Prime Minister of Australia), 'Securing Australia's energy future with Snowy Mountains 2.0', Media release, 16 March 2017; The Hon Malcolm Turnbull MP (Prime Minister of Australia) and Will Hodgman (Premier of Tasmania), 'New Tasmanian pumped hydro', Media release, 20 April 2017; Lily D'Ambrosio (Victorian Minister for Energy, Environment and Climate Change), 'Large Scale Energy Storage: An Investment In Jobs, Reliability And Affordability', Media release, 14 March 2017.

6 AEMO, *Gas statement of opportunities*, March 2017, p. 11.

Figure 4
Daily spot gas prices



Source: AER

- Development of onshore resources has been constrained by moratoria and other regulatory restrictions on gas exploration and development, particularly in NSW and Victoria. Onshore drilling in Australia's petroleum industry for the year to 30 June 2016 declined by almost 70 per cent.[7]

Industrial customers have reported difficulties in securing new long term supply contracts. The offers that they do receive are often at sharply higher prices, for shorter durations, and on strict 'take it or leave it' terms. Public information about gas contract prices is opaque, with the details often private and specific to individual negotiations. It is clear, however, that gas prices struck under new contracts have risen sharply, with offerings of around $20 per GJ being quoted in 2017.[8]

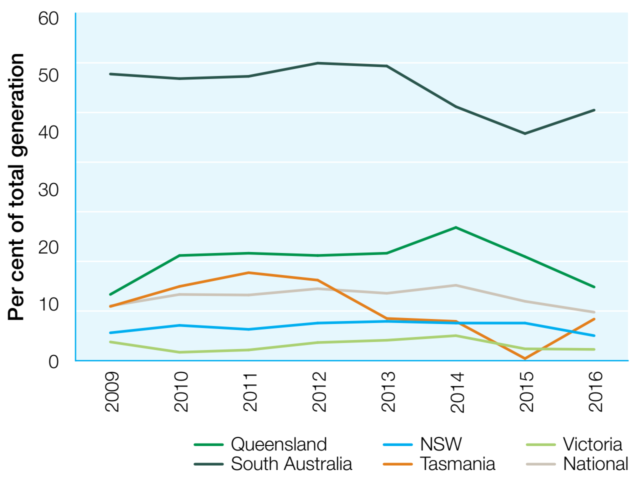
Gas prices in spot markets have also risen, and at times exceeded LNG netback levels. They surged in winter 2016 to be consistently above $10 per GJ and often above $15 per GJ (figure 4), when the start-up of a new LNG train coincided with an already tight southern gas market (reflecting seasonally high demand and a rise in gas powered generation after South Australia's Northern power station was shut down). The gas market continued to tighten in summer 2016–17, with the commissioning of a sixth LNG train, outages at the Longford gas plant in Victoria and high temperatures driving a rise in gas powered generation.

To some extent, weaker domestic gas demand mitigated the effect of these tight supply conditions. Gas powered generation accounts for around 31 per cent of domestic gas demand and, despite still being required to meet periods of high electricity demand, has reduced significantly since 2014 (figure 5).

Conditions in the eastern gas market have raised concerns about the future security of domestic gas supply. AEMO noted in March 2017 that these issues are emerging more quickly than previously expected, and forecast a possible gas supply shortfall by summer 2018–19 in South Australia, NSW and, to a lesser extent, Victoria.[9] In March 2017, EnergyQuest reported a substantial part of the proved plus probable (2P) reserve base underpinning the LNG projects has not demonstrated commercial productivity.

Wholesale supply issues in the gas market have been exacerbated by behaviour in the largely unregulated gas transmission pipeline sector. The ACCC found gas pipeline businesses have responded to the market's needs by offering more flexible services, investing in new pipeline interconnections and re-engineering pipelines to allow bi-directional flows. But it also found evidence of pipeline businesses engaging in monopoly pricing, resulting in higher delivered gas prices for users.

Figure 5
Gas powered generation



Source: AER

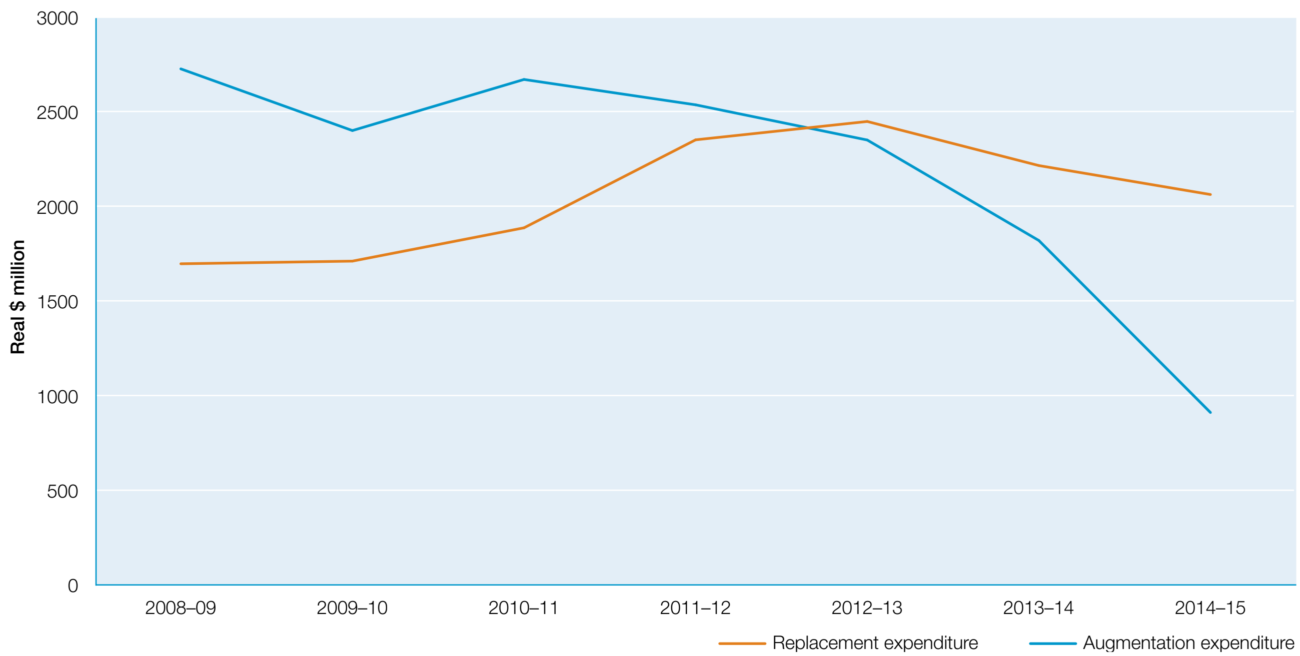
Policy bodies are progressing reforms to encourage more efficient access to gas transmission pipelines. The reforms include binding arbitration to deal with situations where commercial negotiations fail. An expert panel was designing an arbitration framework in early 2017.

In the current market environment, various proposals are on the table to manage the risk of a gas supply shortfall. The initiatives include Jemena's Northern Gas Pipeline that will ship gas from the Northern Territory to Queensland (scheduled for completion in 2018), and AGL Energy exploring options for an LNG import terminal in southern Australia.

While regulatory impediments contributed to restricted development of new gas reserves, some project proponents are pushing ahead. Santos submitted applications to the NSW Government for its Narrabri Gas project in February 2017, while in Queensland, participants are seeking exploration leases in the Surat Basin which the government has designated for domestic supply. In South Australia, the Government has announced new incentives for gas exploration, including royalties for landowners whose property overlies a producing gas field.

7 ABS, *Mineral and petroleum exploration, Australia, June Quarter 2016*, cat. no. 8412.
8 AFR, 'East coast gas shortages to hit this winter', 7 March 2017.
9 AEMO, *Gas statement of opportunities*, March 2017. AEMO expects to release updated forecasts for the eastern gas markets in June 2017.

Figure 6
Replacement and augmentation investment—electricity networks



Source: AER.

In response to escalating concerns about gas prices and the security of east coast gas supplies, the Australian Government announced a series of market interventions in April 2017. These interventions included the power to limit exports, to apply from 1 July 2017 on LNG producers that draw more gas from the domestic market than they supply into it.[10]

The Government also directed the ACCC to monitor wholesale gas markets in eastern Australia over the next three years, to help identify impediments to efficient supply, including the exercising of market power.

A.4 Networks

Recent AER revenue determination and access arrangement decisions resulted in more stable network charges, reflecting lower financing costs and a moderation in energy demand, which in turn lowered investment requirements.

The nature of electricity network investment is also evolving as overall energy demand moderates and new technologies emerge that allow for network expansion projects to be deferred. Replacement expenditure has overtaken augmentation as the main area of investment for many electricity networks, rising as a proportion of total investment from 38 per cent in 2008–09 to 69 per cent in 2014–15 (figure 6).

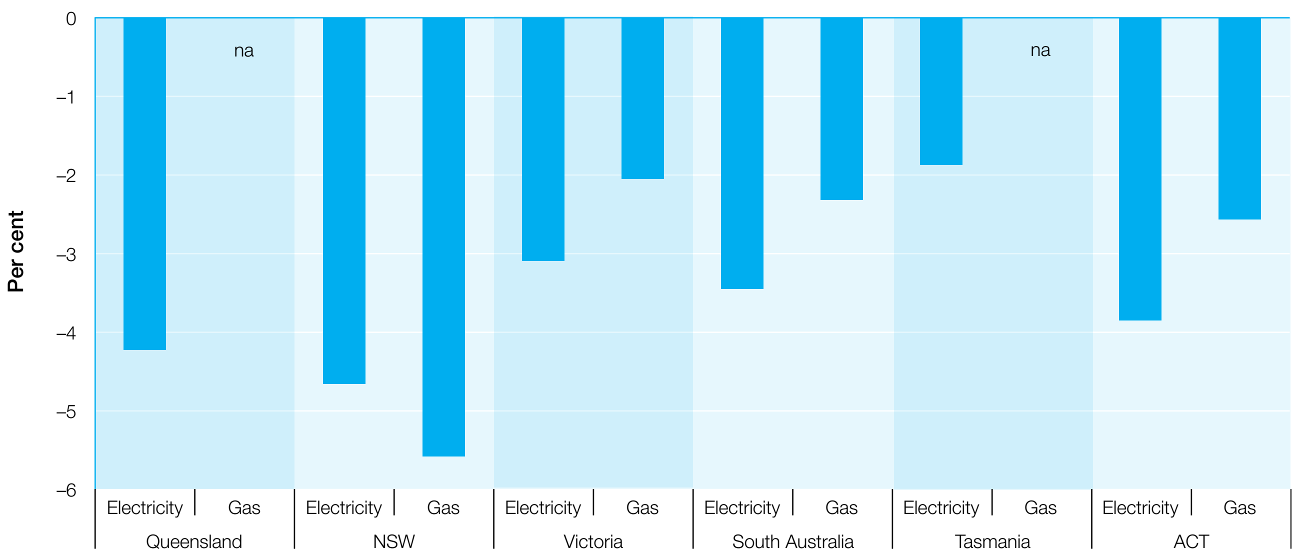
Overall, regulated network revenues under current determinations are 13.5 per cent lower in electricity and 12 per cent lower in gas, compared with revenues in previous decisions.

This moderation in network charges is helping to cushion some of the effect of rises in wholesale prices and other bill components on customer energy costs. Reduced distribution network costs (which account for around 80 per cent of total network costs) translate into an annual reduction of 3.4 per cent in residential energy bills (figure 7).

New electricity network tariff structures taking effect between now and the end of 2018 will require distributors to move closer to prices that reflect the efficient costs of providing network services. Retailers pay the charges initially, then decide whether to pass on those costs to customers and in what form. A retailer might, for example, set higher prices at peak times to reduce demand and their own costs, or offer demand management

10 The Hon Malcom Turnbull MP (Prime Minister of Australia), 'Delivering affordable gas for all Australians', Media release, 27 April 2017.

Figure 7
Effect of AER decisions on residential energy retail bills (annual)



Source: AER.

incentives. The AEMC estimated that under these pricing arrangements, 81 per cent of residential customers would face lower network charges in the medium term, and 69 per cent would have lower charges at peak times.

While the AER's current regulatory decisions have reduced network charges, a number of appeals on decisions to the Australian Competition Tribunal and the Federal Court remain unresolved, creating uncertainty about the ultimate revenue that these networks may recover from their customers. During 2016, 10 electricity distributors in NSW, the ACT, South Australia and Victoria, and two gas distributors in NSW and the ACT were involved in reviews of AER decisions. The businesses sought reviews of fundamental elements of the decisions, including the allowed rate of return, the cost of corporate income tax and the AER's approach to determining efficient operating expenditure (including the use of benchmarking in some matters).

The Tribunal directed the AER to remake some of its decisions relating to the NSW electricity and ACT gas distributors. The AER subsequently applied to the Full Federal Court for judicial review, asking the Court to consider whether the grounds of review were properly established by the network businesses and correctly applied by the Tribunal. In May 2017, the Federal Court found in the AER's favour on the approach to determining income tax costs, but upheld the Tribunal's decision on network operating expenses and the cost of debt. The AER is considering the implications of the Federal Court decision for the current determinations, and for our approach to future regulatory decisions.

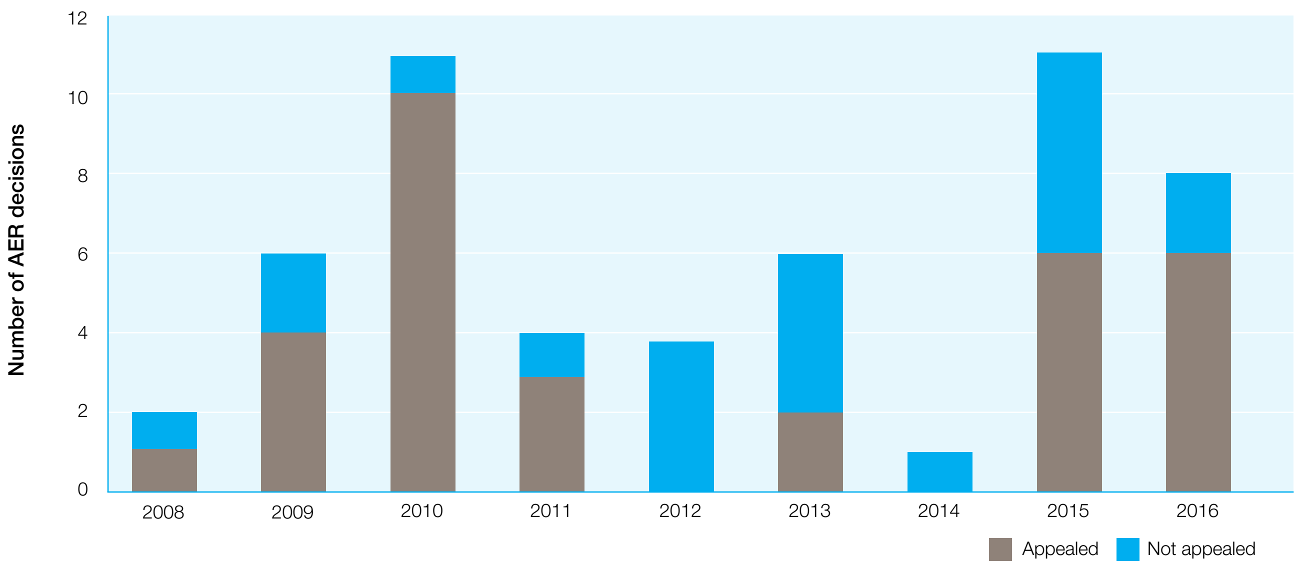
Since 2008, reviews have been sought on 32 out of 51 regulatory decisions (figure 8). Of the matters that were varied or remitted back to the AER, *none* resulted in a decrease in revenues the regulated businesses could collect from their customers compared with the original decision. Service providers face little practical downside from seeking merits review. The legal costs of seeking review are minor compared with the potential upside from successfully reviewing elements of the decision. To date, consumers have not argued successfully for any decrease in network revenues.

A.5 Retail energy markets

Electricity retail prices trended higher in 2016 on the back of rising market costs (wholesale and retail costs), except in Victoria. The rise in average market contract prices was highest for NSW (13 per cent), followed by South Australia (11 per cent), the ACT (5 per cent), Tasmania (3 per cent) and Queensland (2 per cent).

In Victoria, significantly lower network charges offset the effect of rising wholesale costs. As a result, average market

Figure 8
Number of merits reviews sought on AER decisions



Source: AER.

offer prices fell by 3 per cent in 2016 (figure 9). But Victorian retailers in December 2016 announced price rises to account for further pressure on wholesale costs resulting from the closure of Hazelwood in March 2017.

Gas wholesale market conditions also put upward pressure on retail gas prices in recent years, with average market offer increases in 2016 in Victoria and Queensland of 9 per cent and 2 per cent respectively. But AER determinations for gas pipelines in NSW (2015), South Australia (2016) and the ACT (2016) more than offset this wholesale price pressure, with average market prices in these jurisdictions falling to their lowest levels in the past four years.

Questions are being asked about whether competition in retail energy markets is delivering for consumers. Despite many new entrants, AGL Energy, EnergyAustralia and Origin Energy continue to dominate, supplying 70 per cent of small electricity customers and 80 per cent of small gas customers in southern and eastern Australia in 2016. The businesses are also vertically integrated with generation assets, and have raised their market share in electricity generation from 15 per cent in 2009 to 46 per cent in 2016.

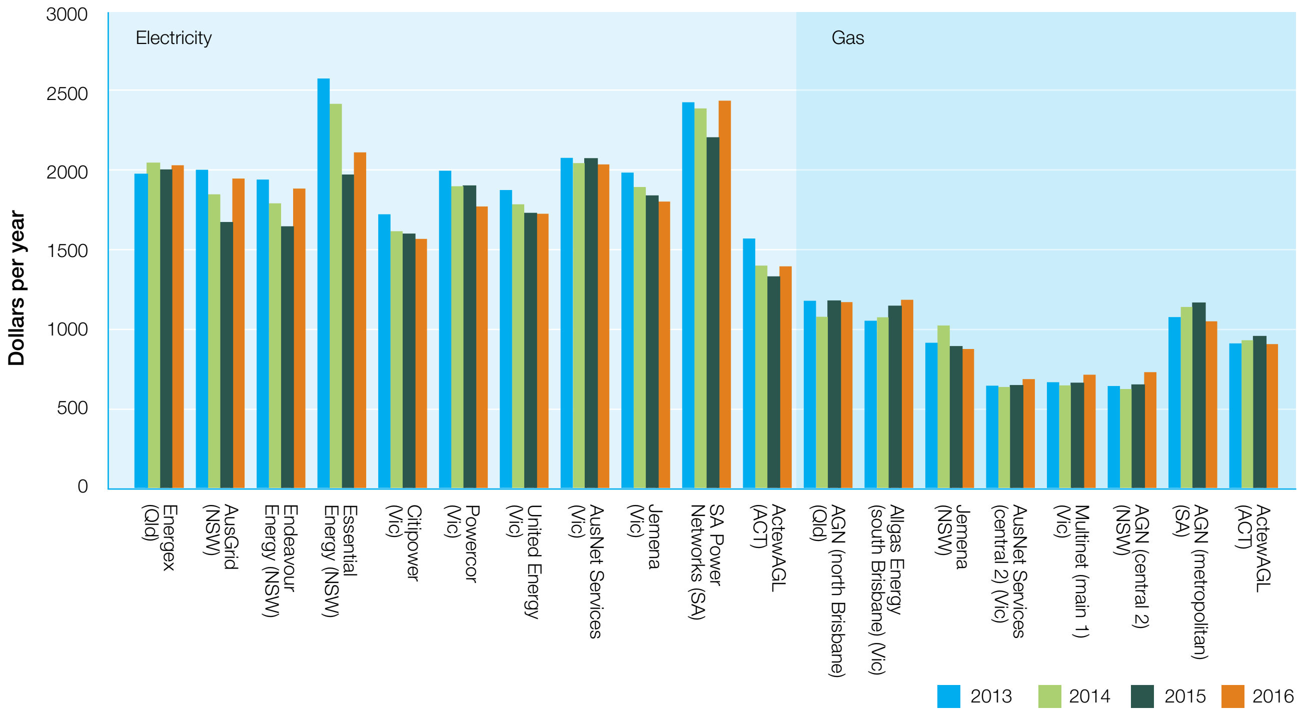
The AEMC reported in 2016 that most consumers are aware they have choice in the market and that competition is effective in most markets. However, around 70 per cent of customers do not actively investigate their energy options, and 50 per cent of customers had not switched their retailer or energy plan in five years. The AEMC identified around 20 per cent of energy customers as highly vulnerable, including middle income households overwhelmed by financial and family commitments, and not aware of how to access support services such as concessions and payment plans.[11]

These findings are significant as discounts in market offers tend to be finite and conditional on customers meeting requirements such as on-time payment. Customers who do not switch regularly may find themselves moving back to prices closer to standing offers. In Victoria, we estimate that electricity retailers' market offers average 17–22 per cent lower than the same retailer's standing offer. In other regions, market offers average 8–13 per cent lower than standing offers. Potential savings are typically lower in gas offers, but are still significant.

The contribution of retailer's margins to energy bills is unclear. Most retailers hedge their wholesale exposure in derivative markets, but data on their hedging activity is not publicly available, making it difficult to assess their actual wholesale market costs and the operating margins. There is also limited information on what energy costs customers actually pay, with most reporting focused on offers available in the market. However, there are ongoing concerns in government and industry that retail margins do appear to be high in some regions. In March 2017, the Grattan Institute, for example, estimated profit margins for electricity retailers

11 AEMC, *2016 Retail Competition Review*.

Figure 9
How retail energy bills have moved



Note: Estimated average annual cost under a market contract for a customer using 6500 kilowatt hours of electricity per year and 24 gigajoules of gas per year.
Sources: energymadeeasy.gov.au; switchon.vic.gov.au; yourchoice.vic.gov.au; comparator.qca.org.au.

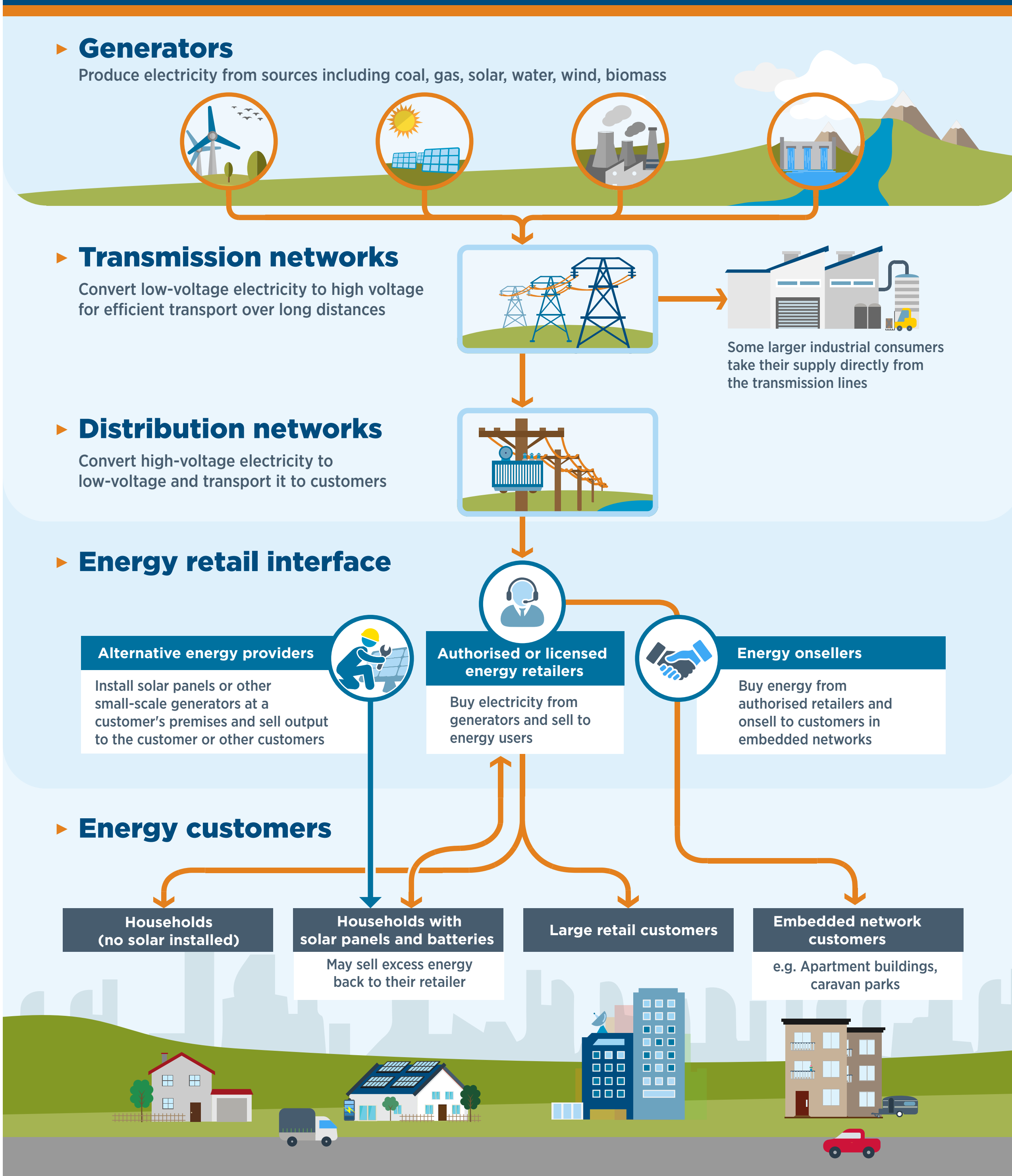
in Victoria at around 13 per cent—more than double the margin that regulators traditionally allowed when they set retail prices in the past.[12]

In response to these concerns about the effectiveness of retail competition, the Australian Government in March 2017 directed the ACCC to inquire into retail electricity pricing, using its powers to gather information and hold hearings. The review will examine the cost components of electricity pricing and whether retailers' margins and profitability are in line with their costs and risks. It will also consider any impediments to consumer choice, such as the transparency and clarity of contracts that energy companies offer to consumers. The ACCC will produce a preliminary report by the end of September 2017.

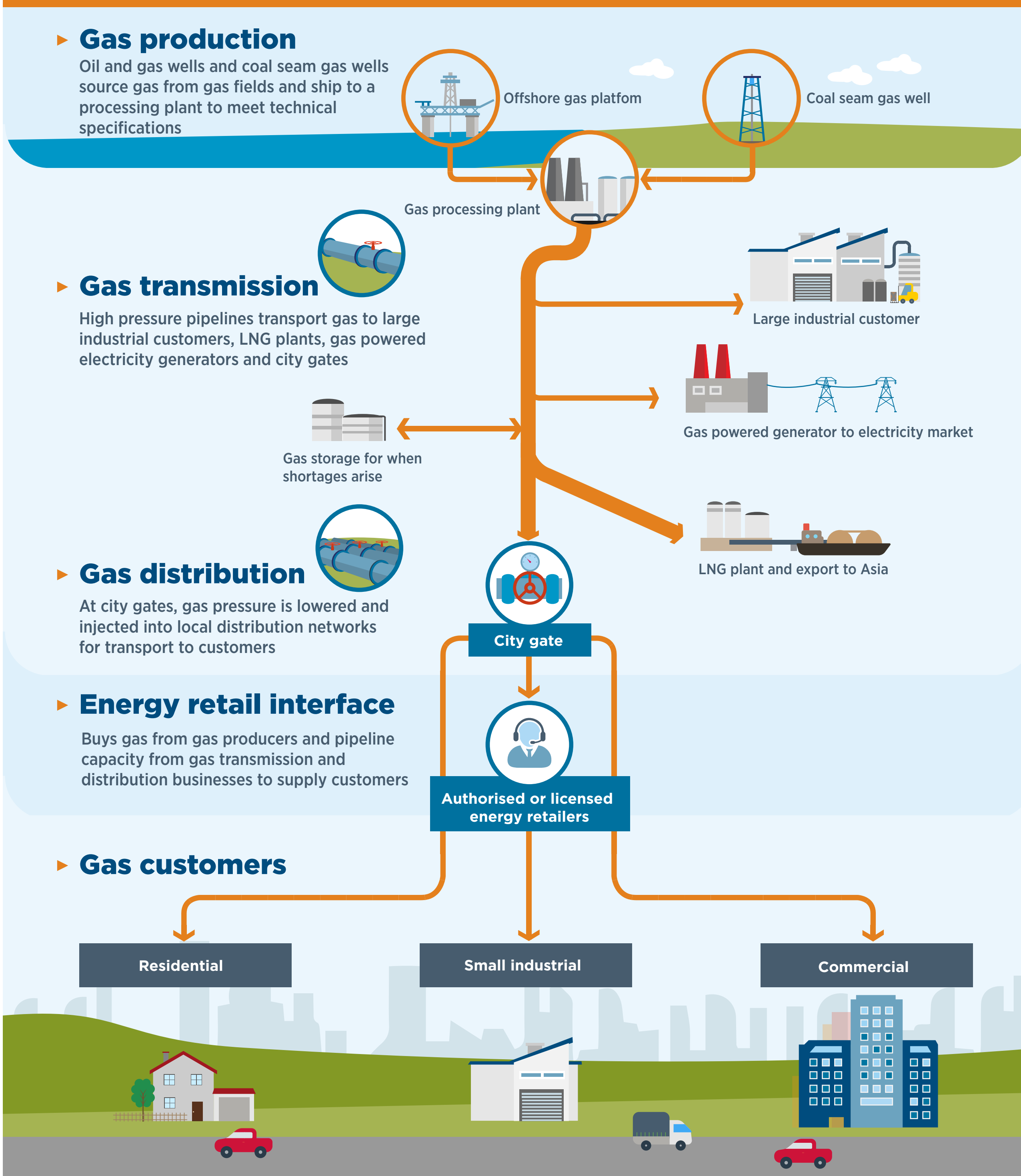
More generally, retail markets are also becoming more complex. Time-of-use tariffs are available to a growing number of customers as smart meters are installed, new selling models and products are emerging regularly, and around 17 per cent of Australian households have installed solar PV to self-generate some of their energy needs. These changes raise questions around whether consumers have appropriate protections and can confidently engage with these new options. The CoAG Energy Council is reviewing regulatory frameworks to ensure they are flexible enough to support an electricity market with increasingly decentralised supply options, and to enable consumers to benefit from innovative products and services.

12 Tony Wood and David Blower, *Price shock: is the retail electricity market failing consumers?*, March 2017

Infographic 1—Electricity supply chain



Infographic 2—Gas supply chain



iStock (Getty Images)

1 NATIONAL ELECTRICITY MARKET

Wholesale electricity in eastern and southern Australia is traded through the National Electricity Market (NEM). 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 1.2). 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.

The supply of electricity to energy customers involves several steps (see infographic 1 in this report). Over 300 registered generators sell electricity into the NEM, a wholesale spot market in which changes in supply and demand determine prices (box 1.1). The NEM's transmission grid, with 40 000 kilometres of transmission lines and cables, carries the power from electricity generators to large industrial energy users and local electricity distribution networks.

Energy retailers act as market intermediaries by buying 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.

This chapter covers the NEM wholesale market and the derivatives (contract) markets that support the wholesale market. Other segments of the supply chain are addressed elsewhere in this report. Chapter 3 covers the electricity transmission and distribution sector, while chapter 4 covers electricity retailing.

1.1 Electricity demand

Almost 10 million residential and business customers consume electricity in the five NEM regions. Most of that electricity is produced by registered generators and sold through the NEM for supply through the transmission grid.

But, in the past few years, many customers began self-generating some or all of their electricity by installing rooftop photovoltaic (PV) systems, and selling any surplus to their local electricity distributor or a retailer. The output of solar PV installations in the NEM was virtually zero until 2010, but 1.6 million households self-generated with solar PV installations in 2015–16, meeting 3 per cent of electricity needs in the NEM (figure 1.1). In the coming years, customers will increasingly be able to meet their energy needs by drawing on electricity that they self-produce and store in batteries.

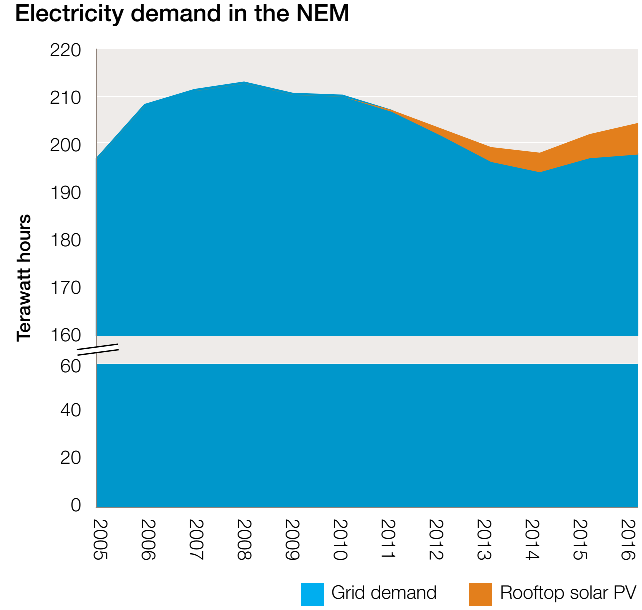
1.1.1 Grid consumption

Around 97 per cent of electricity consumed in the NEM is produced by registered generators and transported through the NEM transmission grid. Grid consumption rose by 2 per cent to 198 terawatt hours (TWh) in 2015–16, after several years of declining consumption (figure 1.1). The rise was apparent in all mainland regions. Queensland recorded the strongest growth, reflecting the escalating energy requirements of its liquefied natural gas (LNG) industry.

The Australian Energy Market Operator (AEMO) in June 2016 forecast demand for electricity supplied through the grid would remain flat over the next 20 years. While population growth, the continuing uptake of energy efficiency measures, and switching from gas to electric appliances will drive some growth, AEMO expects further rises in rooftop solar PV generation to be sufficient to meet it.[1] An exception to this trend is Queensland, where electricity demand may keep rising until 2020 as LNG trains ramp up to full production. Beyond then, AEMO expects Queensland to align more closely with the wider NEM trend of flat demand growth.

South Australia is the only region where grid consumption is forecast to *decrease* over the next 20 years (down 0.5 per cent annually). In part, this fall reflects the region having Australia's highest rate of self-generation from solar PV.

Figure 1.1
Electricity demand in the NEM



Source: AER.

1 AEMO, *National electricity forecasting report*, 2016.

Figure 1.2
National Electricity Market

Source: AER.

Box 1.1 How the NEM works

The NEM is a wholesale spot market into which generators sell electricity (table 1.1). The Australian Energy Market Operator (AEMO) schedules the lowest cost generation to meet demand every five minutes. The generation of electricity must be matched with demand in real time. While battery technologies will change this equation, storage options for most customers are currently uneconomical.

Table 1.1 **National Electricity Market at a glance**

PARTICIPATING JURISDICTIONS	QLD, NSW, VIC, SA, TAS, ACT
NEM regions	Qld, NSW, Vic, SA, Tas
Installed capacity	47 148 MW
Number of registered generators	336
Number of customers	9.6 million
NEM turnover 2015–16	$11.7 billion
Total energy generated 2015–16	198 TWh
National maximum winter demand 2015–16	31 977 MW[a]
National maximum summer demand 2015–16	32 859 MW[b]

MW, megawatts; TWh, terawatt hours.

a The maximum historical winter demand of 34 422 MW occurred in 2008.

b The maximum historical summer demand of 35 551 MW occurred in 2009.

Generators in the NEM

Over 300 registered generators participate in the NEM, by making bids to supply quantities of electricity at different prices for periods of time. They use a mix of technologies, including coal fired plant, gas powered generators, wind turbines, hydroelectric plant and solar PV panels. Electricity generated by small rooftop solar systems is not traded through the NEM (section 1.2.6).

How prices are set

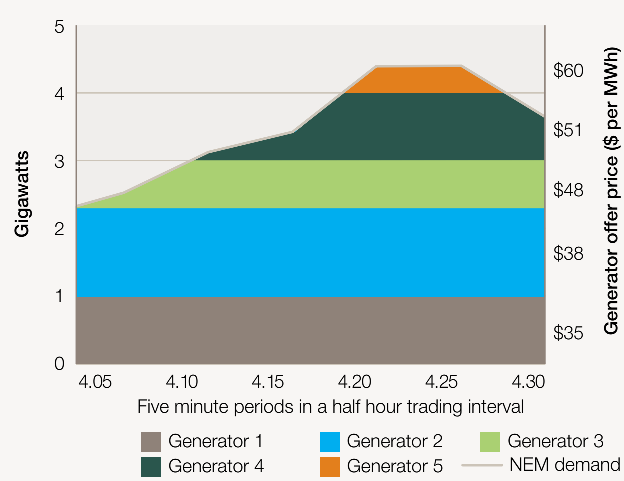
From all the bids offered, AEMO uses sophisticated IT systems to determine which generators will be deployed to produce electricity. The cheapest bids are selected first, then progressively more expensive bids until enough electricity can be dispatched to meet demand every five minutes. The highest priced offer needed to meet demand sets the dispatch price.

The settlement price paid to generators is the average dispatch price over 30 minutes; all successful bidders are paid at this price, regardless of how they bid. A separate spot price is determined for each of the five NEM regions every 30 minutes. Prices are capped at a maximum of $14 000 per megawatt hour (MWh). A price floor of –$1000 per MWh also applies.

Figure 1.3 illustrates how prices are set. In the example, five generators are offering capacity in different price bands between 4.00 pm and 4.30 pm. At 4.15 pm the demand for electricity is 3500 megawatts (MW). 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 at which a fifth generator must be dispatched. This higher cost generator has an offer price of $60 per MWh, which drives up the price to that level. The settlement price paid to all dispatched generators for the half hour trading interval is about $54 per MWh, being the average of the six dispatch prices for the half hour period.

While the market is designed to meet electricity demand in the most 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. At other times, market conditions may allow a generator to bid in a way that causes prices to rise above competitive levels (section 1.5.2).

Figure 1.3
Generator bid stack



Power system management

AEMO is responsible for monitoring the spot market and transmission network to 'keep the lights on'. The power system needs to be both *reliable* (having enough generation and network capacity to supply customers) and *secure* (being technically stable, even in the case of an incident such as the loss of a major transmission line or large 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.

To maintain system security, AEMO procures ancillary services from market participants. Frequency control ancillary services (FCAS), for example, maintain system frequency within a safe range. 'Regulation' services correct for minor deviations in load or generation. 'Contingency' services correct the supply–demand balance following a major event such as the loss of a generator, transmission line or major industrial customer. These services can be offered by generators and industrial loads with the ability to rapidly adjust output. Further, AEMO acquires network support and control services to maintain safe power flows and voltage levels, and to stabilise the power system following a major disturbance.

If consumption in a NEM region exceeds supply, and all other means of meeting that demand have been exhausted, then AEMO can instruct network service providers to temporarily cut the electricity supply to some customers. This action is taken only when protection of the power system is urgent.

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 be blacked out for several hours on 28 September 2016, but this blackout was not at AEMO's direction (section 1.7).

Energy customers

While some large customers buy electricity directly from the wholesale market, most customers purchase it through a retailer, which buys it on their behalf from the NEM. Prudent retailers act to manage the risk of volatile prices that can occur in the wholesale market. One way to manage risk is to take out financial contracts (derivatives) that lock in a firm price for electricity to be supplied in the future (section 1.10). Another way is through vertical integration of generators with energy retailers (section 1.5.1).

The AER's role

The Australian Energy Regulator (AER) monitors the NEM to ensure participants comply with the underpinning legislation and rules, taking enforcement action when necessary. We also monitor for irregularities and wider market inefficiencies. Our quarterly compliance reports provide regular updates on our compliance and enforcement activity.[a] We report weekly on activity in the market,[b] with more detailed reporting on extreme price events.[c]

Additionally, the AER draws on its regulatory and monitoring work to advise the Council of Australian Governments' (CoAG) Energy Council, the Australian Energy Market Commission (AEMC), AEMO and other stakeholders on wholesale market issues. To the extent that resourcing allows, we also engage in policy reviews and rule change processes.

In 2016 the CoAG Energy Council tasked the AER with a new role: to monitor and report on wholesale market performance. This role will include analysing whether the market is effectively competitive, and whether any features detrimentally affect efficient market functioning. In early 2017 the AER was developing frameworks to implement the new role.

a AER, https://www.aer.gov.au/wholesale-markets/compliance-reporting?f[0]=field_accc_aer_report_type%3A318

b AER, https://www.aer.gov.au/wholesale-markets/market-performance?f[0]=field_accc_aer_report_type%3A324&f[1]=field_accc_aer_sector%3A4

c AER, https://www.aer.gov.au/wholesale-markets/market-performance?f[0]=field_accc_aer_report_type%3A310

1.1.2 Maximum grid demand

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

Maximum demand for grid sourced electricity rose steadily until 2009, but then flatlined or declined in most regions for several years (figure 1.4). The trend began to reverse in 2015–16, when maximum demand for NSW, Victoria and South Australia rose significantly over 2014–15 levels (although it remained well below historical peaks) (table 1.2). Maximum demand also rose in Tasmania, and approached a new historical peak. Queensland continued its almost unbroken trend of rising maximum demand, setting a new record peak on 18 January 2017 when the state experienced extreme temperatures.

Maximum demand is forecast to remain relatively flat over the next 10 years, and the ratio of maximum to average grid demand (figure 1.5) will remain fairly stable. South Australia has the 'peakiest' demand profile, partly reflecting its high penetration of solar PV generation. This profile weakens the commercial viability of some large generation plant because, while capacity is needed to meet demand peaks, average plant use is falling. This scenario makes alternative ways of meeting demand peaks—such as small scale local generation, energy storage and demand-side measures—more viable.

1.2 Generation technologies in the NEM

The NEM uses a mix of generation technologies to meet electricity demand, some of which are illustrated in figure 1.6. Figure 1.2 maps the locations of generation plant, and the types of technology in use. Figures 1.7–1.9 illustrate electricity generation by fuel source across each region, including movements over time.

The main source of electrical supply in the NEM is fossil fuel generators. These facilities burn coal or gas to create pressurised steam. The steam is forced through a turbine at high pressure to spin large magnets inside coils of conducting wire. Emissions from the combustion process are released into the atmosphere as a byproduct.

But, as Australia transitions to a lower emissions economy, the focus is shifting to renewable generation. Hydro and wind plant use water and wind respectively (rather than steam) to drive a generator. 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* require up to three days 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 into the NEM at low prices to guarantee dispatch and to keep their plant running.

Plant that has high operating costs, but that can quickly change output levels (for example, open cycle *gas powered generation*), typically operates only when electricity prices are high. *Hydrogeneration* plant has low operating costs, but finite water supplies to draw on, meaning it cannot operate continuously like coal plant. Typically, it operates in peak demand periods to take advantage of high prices. *Intermittent generation*, such as wind and solar, can operate only if weather conditions are favourable.

1.2.1 Plant technology and carbon emissions

The mix of generation plant technologies impacts on carbon emissions. The electricity sector contributes over one third of Australia's carbon emissions, mainly due to our reliance on high emitting coal fired generation.[2] In 2015–16, coal fired plant supplied 76 per cent of electricity generation in the NEM.

Australia has made international commitments to reduce its carbon emissions by 26–28 per cent below 2005 levels by 2030.[3] This effort builds on an earlier target of reducing emissions by 5 per cent below 2000 levels by 2020. Australia's principal climate change policies in recent years have been the Australian Government's Renewable Energy Target (RET) scheme (launched in 1999 and amended several times), carbon pricing (2012–14) and Direct Action (launched 2014). Alongside these schemes, state governments have operated feed-in tariff schemes that subsidised solar PV generation. Boxes 1.2–1.4 outline these policies.

2 See, for example, Commonwealth of Australia, *Uranium mining, processing and nuclear energy—opportunities for Australia?*, Report to the Prime Minister by the Uranium Mining, Processing and Nuclear Energy Review Taskforce, 2006.

3 21st Conference of Parties (Paris 2015) emissions abatement commitments.

Table 1.2 Maximum grid demand, by region, 2015–16

	QUEENSLAND	NEW SOUTH WALES	VICTORIA	SOUTH AUSTRALIA	TASMANIA
Change from 2014–15 (%)	3.2	14.5	10.3	5.4	3.5
Change from historical maximum (%)	3.2	–7.9	–9.2	–13.0	–4.0
Year of historical maximum	2015–16	2010–11	2008–09	2010–11	2008–09

Sources: AEMO; AER.

Figure 1.4
Maximum grid demand, by region

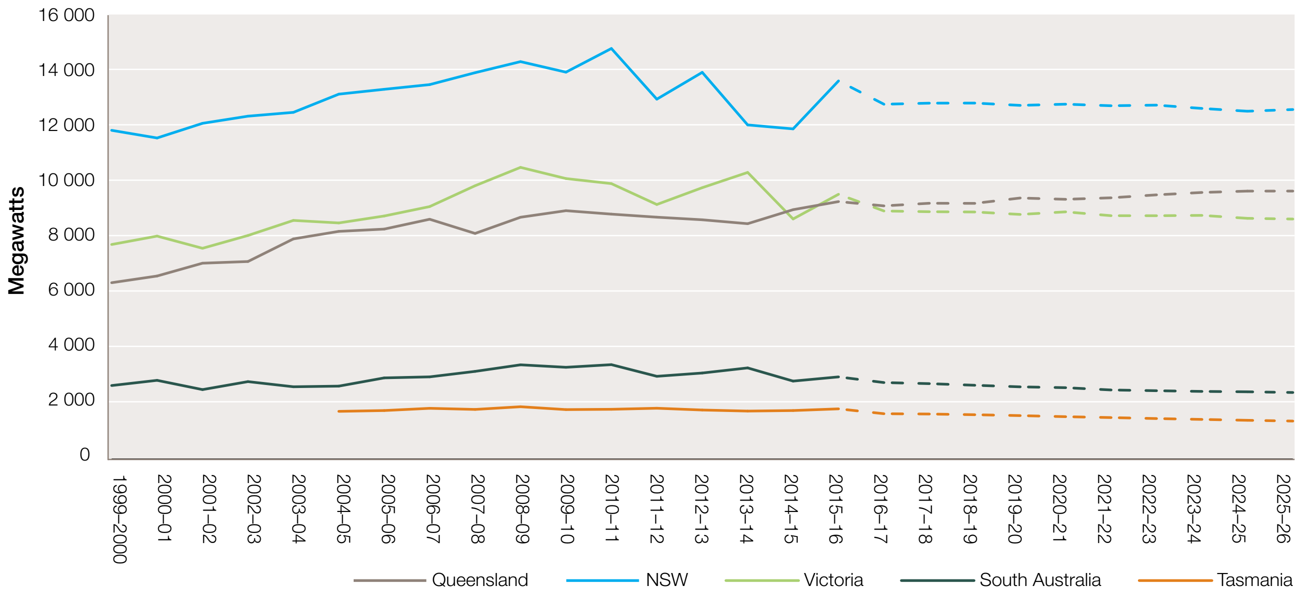
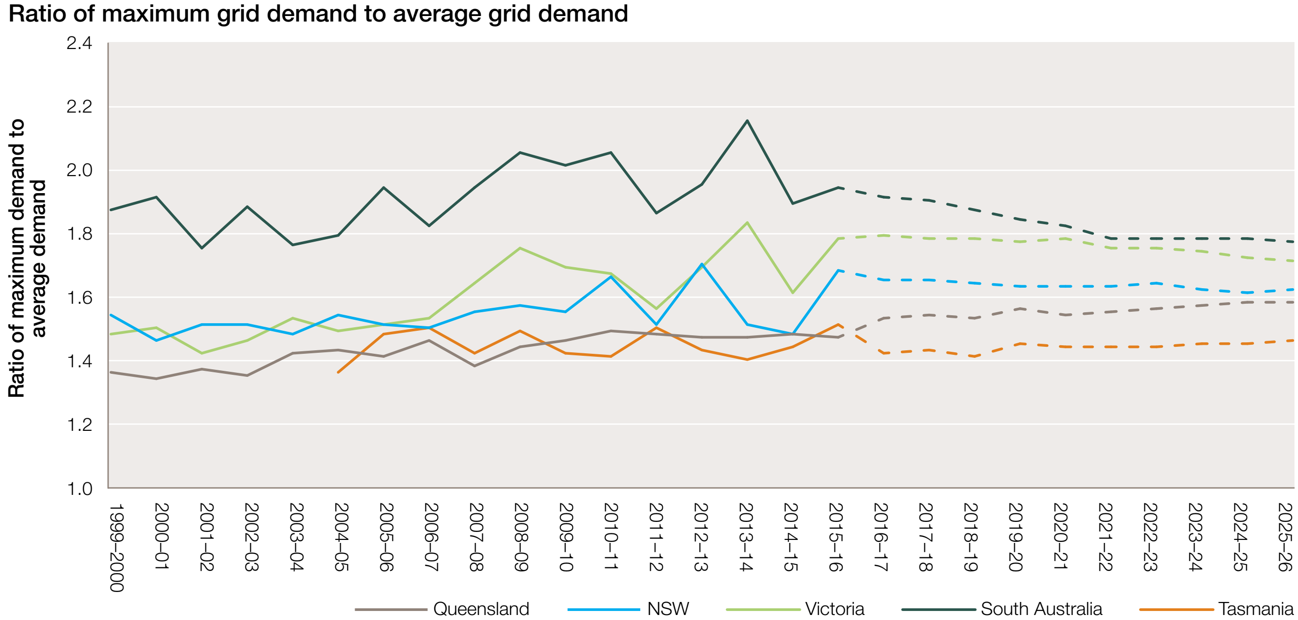


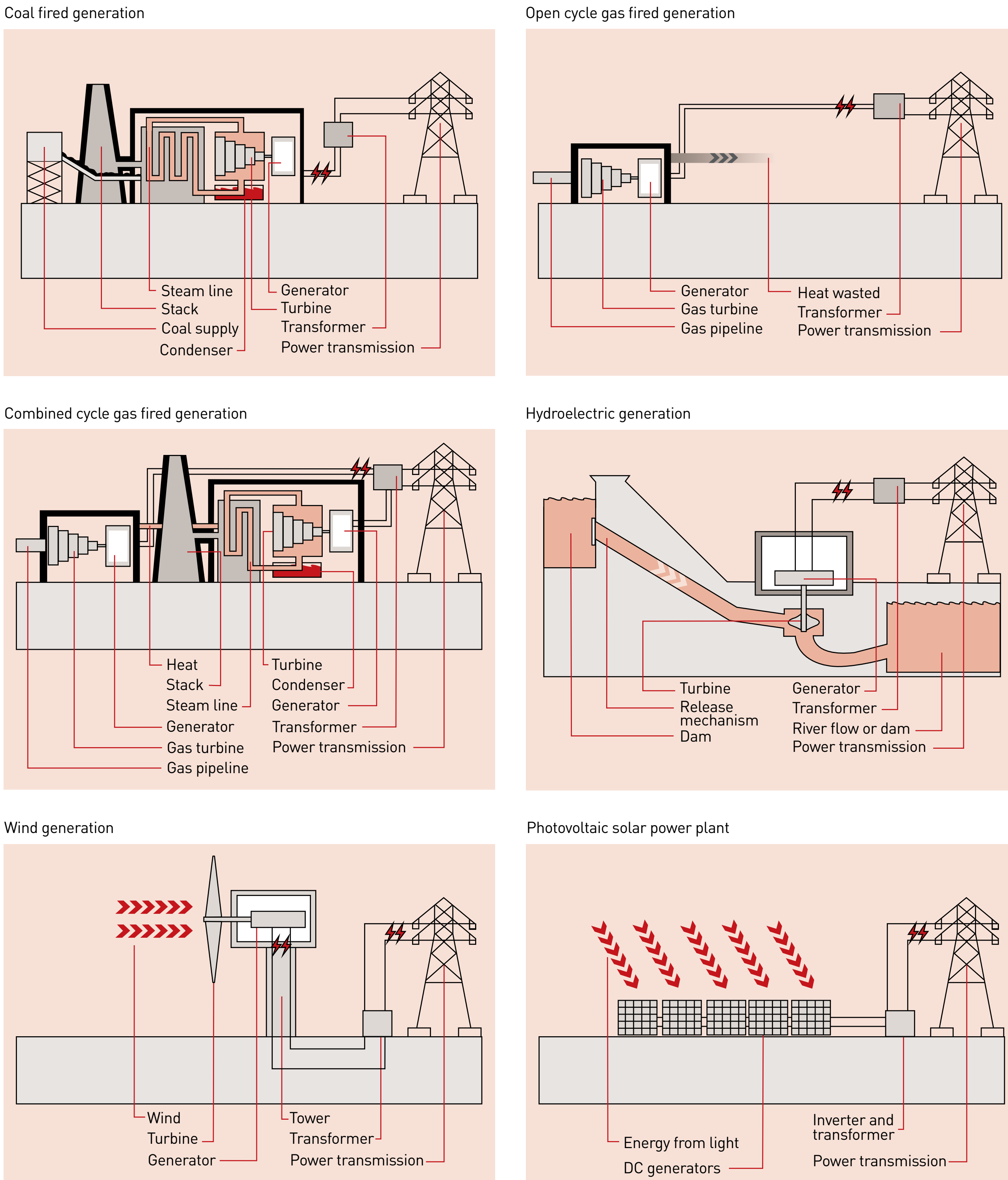
Figure 1.5
Ratio of maximum grid demand to average grid demand



Note (figures 1.4 and 1.5): Actual data to 2015–16, then AEMO forecasts (dotted lines) published in 2016.

Sources (figures 1.4 and 1.5): AEMO; AER.

Figure 1.6
Generation technologies in the NEM



Sources: AER, Babcock and Brown.

1.2.2 Coal fired generation

Coal fired generation remains the dominant supply technology in the NEM, accounting for 52 per cent of registered capacity and supplying 76 per cent of output in 2015–16. Victoria, NSW and Queensland rely on coal more heavily than do other regions (figures 1.7–1.9).

After a decline over the two years that carbon pricing was in place (1 July 2012 to 30 June 2014), coal fired generation rose by 7 per cent in 2015–16. The rise was most apparent for black coal generation in Queensland and NSW. But this rise may be temporary, with significant coal fired capacity being retired from the market in 2016 and 2017:

- The closure of Alinta's Northern Power Station in May 2016 marked the end of coal fired electricity generation in South Australia, removing 546 megawatts (MW) of capacity from the NEM.
- The closure of Engie's Hazelwood power station in Victoria in March 2017 removed another 1600 MW of brown coal generation from the NEM.[4] The facility was over 50 years old, and was Australia's most emissions intensive power station.

Placing further pressure on coal fired generators, the Council of Australian Governments (CoAG) affirmed that the electricity sector's contribution to meeting Australia's abatement commitments on carbon emissions should be consistent with national reduction targets. For this contribution to occur, further withdrawals of coal plant may be necessary.[5]

The retirement of aging coal plant from the market raises issues with traditional approaches to recruiting ancillary services, and with the role that generator rotational inertia plays in contributing to power system security.[6] The CoAG Energy Council in October 2016 commissioned an expert panel led by Dr Alan Finkel to explore how best to manage these issues (section 1.7.1).

1.2.3 Gas powered generation

Gas is often described as a transition fuel towards a lower carbon economy, with the fast response times of open cycle gas fired generators complementing the NEM's rising dependence on intermittent wind and solar sources of generation. Across the NEM, gas powered plant accounted for 19 per cent of registered capacity in 2015–16, but supplied only 7 per cent of output. South Australia is the region that most relies on gas powered generation.

Gas powered generation rose strongly while carbon pricing was in place (July 2012 to June 2014). But the abolition of carbon pricing in 2014, coupled with rising gas fuel costs linked to Queensland's LNG projects and a lack of new gas supplies, has stalled gas powered generation. In Queensland, for example, it slumped from 22 per cent of NEM output in 2014 to just 12 per cent in 2016. A similar squeezing of gas powered generation is apparent in most regions (section 2.3 and figure 1.9).

This trend is reflected in the mothballing of gas plant, some of which was commissioned after 2000. Queensland generator Stanwell, for example, mothballed its 385 MW Swanbank E gas plant in 2014, following the repeal of carbon pricing. Rising gas fuel costs prolonged the mothballing of Swanbank E to December 2018 and also contributed to the mothballing of part of South Australia's gas fired Pelican Point plant in 2015.

1.2.4 Hydro generation

Hydroelectric generators accounted for 17 per cent of registered capacity in the NEM in 2015–16, supplying 10 per cent of electricity generated. The bulk of Tasmanian generation is hydroelectric; NSW, Victoria and Queensland also have hydrogeneration.

Hydrogeneration rose strongly during the two year period of carbon pricing, which also coincided with high dam levels. But the abolition of carbon pricing and low water storages reduced its profitability, resulting in a 29 per cent decline in output in 2014–15. Hydrogeneration recovered in 2015–16, recording a 15 per cent rise in output from a year earlier.

Tasmania, which normally exports hydroelectricity to the mainland, faced unprecedented dry conditions in spring 2015. As a result, it cut production and imported up to 40 per cent of its energy needs.[7] The state's hydrogeneration output rose in early 2016 following an outage on the Basslink interconnector to the mainland. Water storage levels subsequently declined to an all-time low of 13 per cent in April 2016. But, in an abrupt turnaround, drought turned to flooding in autumn 2016, restoring hydro dam storages. Further, volatile electricity prices on the mainland provided opportunities for profitable generation in 2016–17.

4 Engie, 'Hazelwood power station in Australia to close at the end of March 2017', Media release, 3 November 2016.
5 AEMO, *Electricity statement of opportunities*, August 2016.
6 AEMO, *Electricity statement of opportunities*, August 2016.
7 Hydro Tasmania, *Annual report 2016*.

Figure 1.7

Generation in the NEM, by fuel source, 2015–16

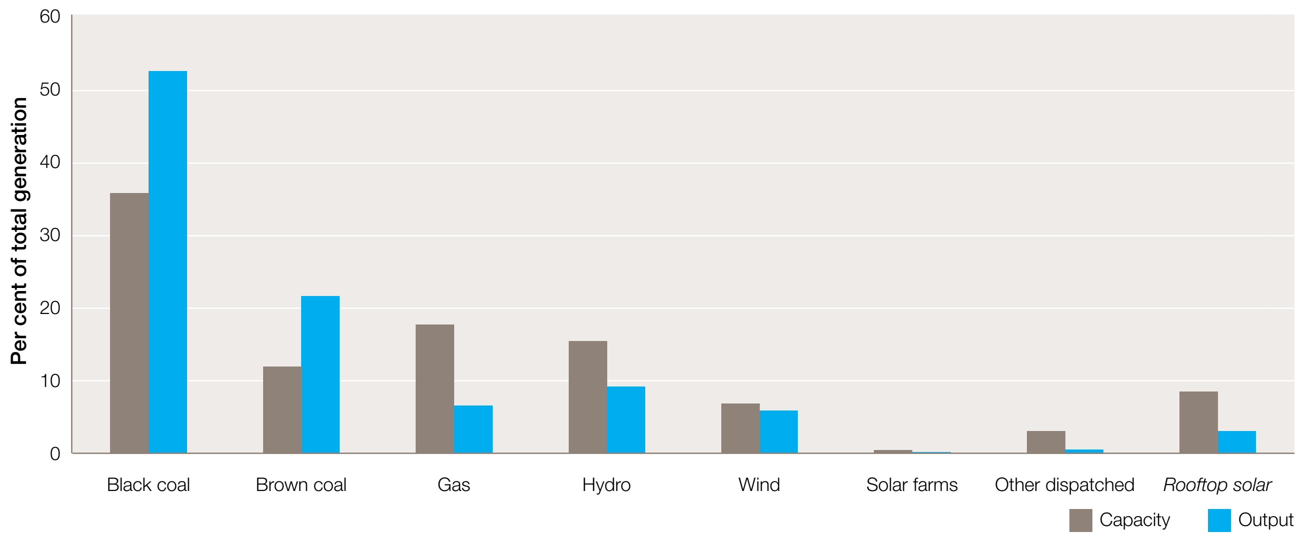
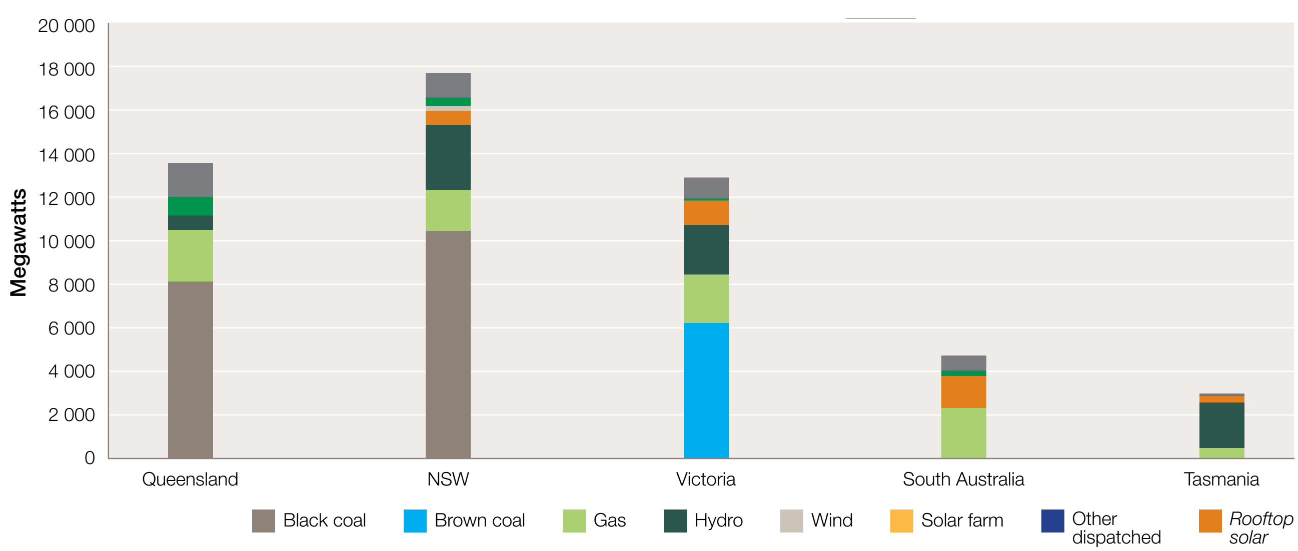


Figure 1.8

Generation capacity in the NEM, by region and fuel source, 1 January 2017

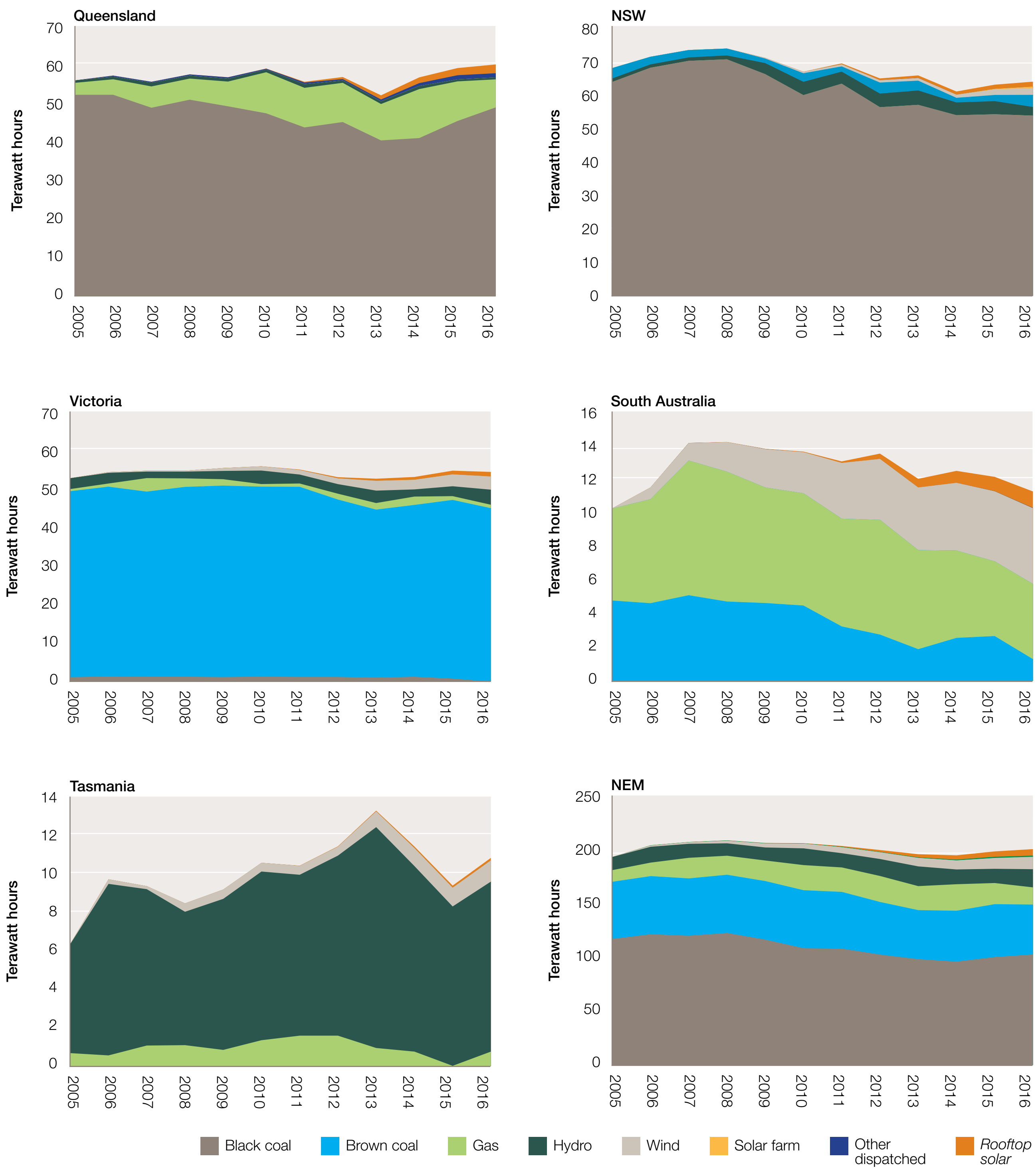


Note (figures 1.7 and 1.8): Rooftop solar generation is not traded through the NEM. Electricity generated from this source acts to reduce the demand for grid supplied electricity.

Sources (figures 1.7 and 1.8): AEMO; AER.

Figure 1.9

Changes in electricity generation, by fuel source



Note: Rooftop solar generation is not traded through the NEM. Electricity generated from this source acts to reduce the demand for grid supplied electricity.

Sources: AEMO; AER.

Box 1.2 Carbon pricing and Direct Action

A carbon pricing scheme operated in Australia between 1 July 2012 and 1 July 2014. The then Labor Government introduced the scheme in 2012 as part of its Clean Energy Future Plan. The central mechanism placed a fixed price on carbon for three years, 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, whereby 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 (figure 1.10). 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 hydrogeneration shares rose significantly.

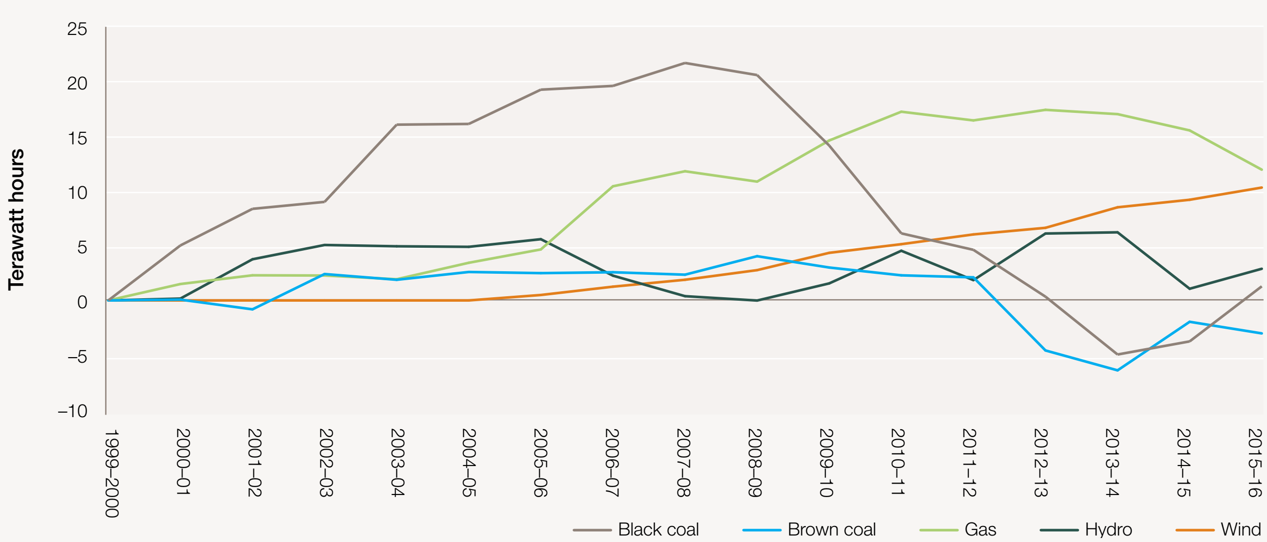
Overall, these changes contributed to the emissions intensity of NEM generation falling by 4.7 per cent over the two years that carbon pricing was in place (from 0.903 tonnes of carbon dioxide equivalent emissions per MWh of electricity produced in 2011–12, to 0.861 tonnes in 2013–14). This drop in emissions intensity, combined with lower NEM demand, led to a 10.3 per cent fall in total emissions from electricity generation over those two years.

The Coalition Government elected in 2014 abolished carbon pricing, effective from 1 July 2014. This decision led to some coal plant being returned to service, and contributed to a significant fall in hydrogeneration output. Plant use rates for coal generators rose to new highs in 2015–16.

The same Coalition Government introduced a Direct Action plan in 2014 to replace carbon pricing. Central to the plan is the Emissions Reduction Fund, under which the government pays for emissions abatement through auctions run by the Clean Energy Regulator. Five auctions were held to April 2017, spending $2.2 billion to abate 189 million tonnes of carbon. To date, only one electricity generation project has successfully participated in the scheme. The project will convert waste gas from a coal mine to electricity.

In December 2015, the CoAG Energy Council sought advice from the AEMC and AEMO on how best to integrate energy and emissions reduction policies. The AEMC recommended in December 2016 that an emissions intensity target (EIT) scheme is technologically neutral and, therefore, a lower cost form of emissions abatement than other mechanisms.[a]

Figure 1.10
Annual change in electricity generation, by energy source



Sources: AEMO; AER.

a AEMC, *Integration of energy and emissions reduction policy*, 9 December 2016.

Figure 1.11
Wind generation share of total generation, by region

Sources: AEMO; AER.

1.2.5 Wind generation

Wind generation has risen rapidly under the RET, which effectively subsidises renewable generation (box 1.3). An expansion of the RET in 2007 contributed to the addition of 2760 MW of wind capacity in the following eight years.

Revisions to the RET scheme in June 2015 set a target for renewable generation of 33 000 gigawatt hours (GWh) per year for 2020–30. The NEM requires an additional 7000 GWh of renewable energy to meet this target. Clarity around the scheme's future improved certainty, and an additional 400 MW of wind capacity was added in the NEM in 2015–16.

Wind generators accounted for 7.5 per cent of capacity and generated 6.1 per cent of output in 2015–16. Overall, wind generation rose by 12 per cent in 2015–16. Its penetration is especially strong in South Australia, where it represented 36 per cent of capacity and met 38 per cent of the state's electricity requirements in 2015–16. In the nine months to 31 March 2017, the contribution of wind generation was even greater, supplying 50 per cent of South Australia's electricity (figure 1.11).

Across the NEM, favourable weather conditions on 8 December 2016 resulted in record levels of wind output, peaking at 3365 MW. On that day, wind generation accounted for more than 12.5 per cent of all electricity generated in the NEM.[8]

8 ARENA, 'Historic day for Australian solar as 12 new plants get support', Media release, 8 September 2016.

1.2.6 Solar PV generation

The newest addition to the NEM's generation profile is commercial solar farms. This technology has been slow to develop in Australia, partly due to its relatively high cost. At March 2017, only 232 MW of solar capacity had been installed in the NEM, all located in NSW.

The Australian Renewable Energy Agency (ARENA) announced in September 2016 that it would contribute $86 million to develop another six large scale solar plants in Queensland (300 MW) and five in NSW (162 MW).[9] The projects will provide sufficient energy to power 150 000 homes. By 2017, AEMO was tracking proposals for over 1700 MW of large scale solar PV capacity across the NEM.

While large scale solar generation remains in its infancy in the NEM, more than 1.6 million households and many commercial businesses have rooftop solar PV installations. The RET creates financial incentives for households and small businesses to invest in these systems. State based feed-in tariff schemes, under which distributors and/or retailers paid households for electricity generated from rooftop installations, provided further incentives (box 1.4). Energy businesses have recovered the costs of these schemes from other energy users by charging higher electricity prices. While state governments are phasing out premium feed-in tariffs, the loss of these incentives is being largely offset by declining installation costs for solar systems.

9 ARENA, 'Historic day for Australian solar as 12 new plants get support', Media release, 8 September 2016.

Box 1.3: Renewable energy target scheme

The Australian Government's RET scheme, introduced in 2001 but since modified on a number of occasions, requires electricity retailers to source a proportion of their energy from renewable sources developed since 1997. An expert panel in 2014 found the RET had led to the abatement of 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). Under the scheme, energy retailers are obliged 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.

Amendments to the RET in June 2015 reduced the 2020 target for energy from large scale renewable projects from 41 000 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.[b] Each year the renewable target rises towards the 2020 target; the annual target for 2017 is just over 26 000 GWh.

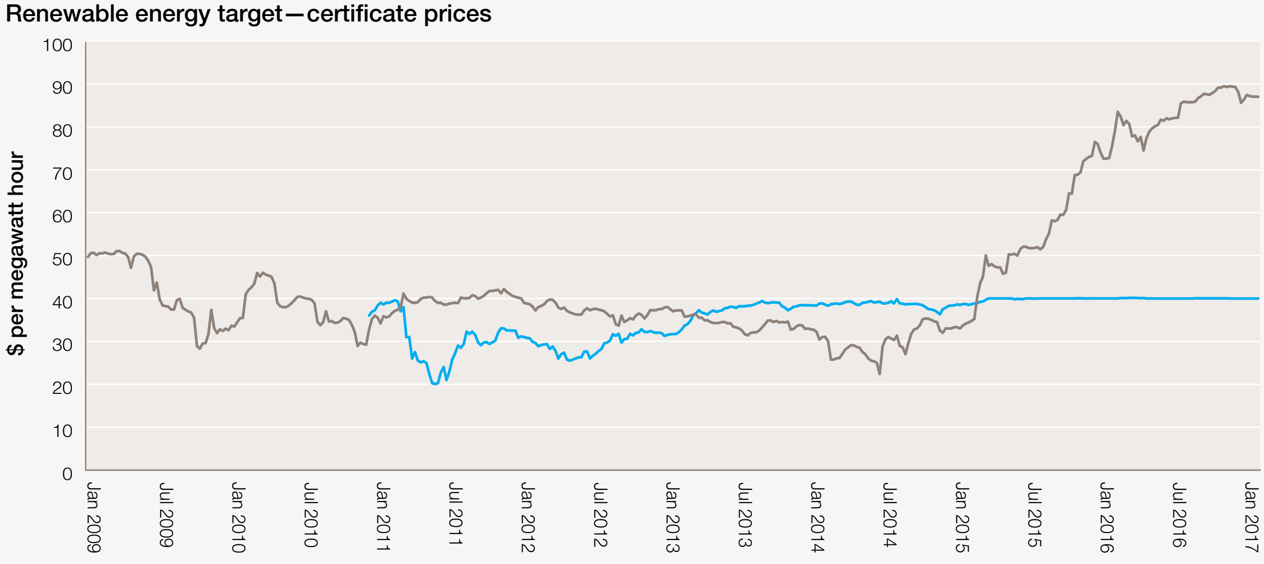
Figure 1.12 illustrates movements in RET certificate prices. A certificate represents 1 MWh of output from qualifying renewable generators (or deemed output from small scale generation). Qualifying generators in the NEM receive both the certificate price and the wholesale spot price for electricity that they generate.

The availability of RET certificates relative to the prevailing target determines the value of the certificates. Certificates from *large scale* projects traded at around $40 in 2011, but gradually eased over the following years, reaching a low of $22 in June 2014. This fall coincided with uncertainty over climate change policies, following a change of government in 2013. Certificate prices recovered sharply from late 2014, and have continued to rise as it became clear that new renewable investment was not keeping pace with the rising target, creating a shortfall in certificates for trading. Prices neared $90 in January 2017, close to the penalty that a business must pay for failing to surrender a RET certificate (allowing for the tax deductibility of certificate purchases).

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.

Figure 1.12

Renewable energy target—certificate prices



Source: Clean Energy Regulator.

a Expert Panel, *Renewable Energy Target scheme: report of the Expert Panel*, 2014.

b The Hon. Greg Hunt MP, Minister for the Environment, 'Paris and beyond: an integrated approach to climate and the environment', Speech delivered to the National Press Club, Canberra, 25 November 2015.

Box 1.4 Feed-in tariff schemes

Most state governments mandated premium feed-in-tariff payments for small scale solar PV generation from around 2008 to 2012. Since 2012, the schemes have been phased out or closed to new entrants, and replaced by 'market offers' from electricity retailers at unregulated prices. These offers tend to be much lower than premium feed-in-tariff rates, and do not provide significant incentives to take up solar PV systems.[a]

a Jacobs Group, *Projections of uptake of small-scale systems*, Report prepared for AEMO, 6 June 2016.

Rooftop solar PV generation is not traded through the NEM. Instead, the installation owner receives a reduction in their energy bills for feeding energy into the grid. AEMO treats the contribution of rooftop PV generation to meeting energy requirements as a reduction in energy demand—in the sense that it reduces electricity demand from the grid—rather than as generation output.

The total installed capacity of rooftop solar systems in the NEM reached 5286 MW in 2016, equivalent to 9 per cent of total installed generation capacity (figure 1.13). The output of solar PV installations was virtually zero until 2010, but by 2016 was meeting over 3 per cent of the NEM's electricity requirements. The penetration rate for rooftop solar PV systems in Australia is now among the world's highest (figure 1.14).

Solar penetration is highest in South Australia and Queensland, where 30 per cent of households have installed capacity. Solar PV installations generated 7.6 per cent of South Australia's annual energy requirements in 2015–16 (up from 7.1 per cent in 2014–15).[10] And AEMO projected that rooftop PV capacity in South Australia will reach over 1500 MW by 2025–26.[11] In Victoria and NSW, 15 per cent of households have solar PV, just ahead of Tasmania's 13 per cent rate.[12]

In a survey of Australian households, Energy Consumers Australia found most consumers install solar PV to reduce energy bills and to reduce their reliance on energy from the grid.[13] Most households reported an overall positive experience with solar PV, noting the performance of their systems exceeded their expectations. The survey found the most significant barriers to further uptake were households that are renting and concerns about installation costs.

While solar PV installations are predominantly in the residential sector, commercial installations have also grown. Commercial systems accounted for 17 per cent of installed solar PV capacity in 2015–16, up from 12 per cent in the previous year.

Total solar PV capacity continues to rise, although annual additions are declining. While monthly new installations slowed from 25 000 in 2011 to 7500 in 2016, their average capacity rose from 2.5 kilowatts (kW) to 5.5 kW over that period (figure 1.15). This trend reflects the offsetting impacts of the rollback in subsidised feed-in tariffs towards market levels, and significantly lower installation costs that make larger PV systems more affordable.[14]

Across the NEM, the contribution of solar PV installations to peak demand is generally lower than the rated system capacity. In mainland regions, summer energy consumption typically peaks in late afternoon, when solar PV generation is declining. AEMO estimated rooftop solar generation in South Australia can contribute 31 per cent of the region's installed capacity at times of maximum summer demand, compared with 24 per cent in NSW and 19 per cent in Queensland.[15] But the increasing use of solar PV generation is reducing grid demand around midday and shifting demand peaks to later in the day (when solar generation is falling).

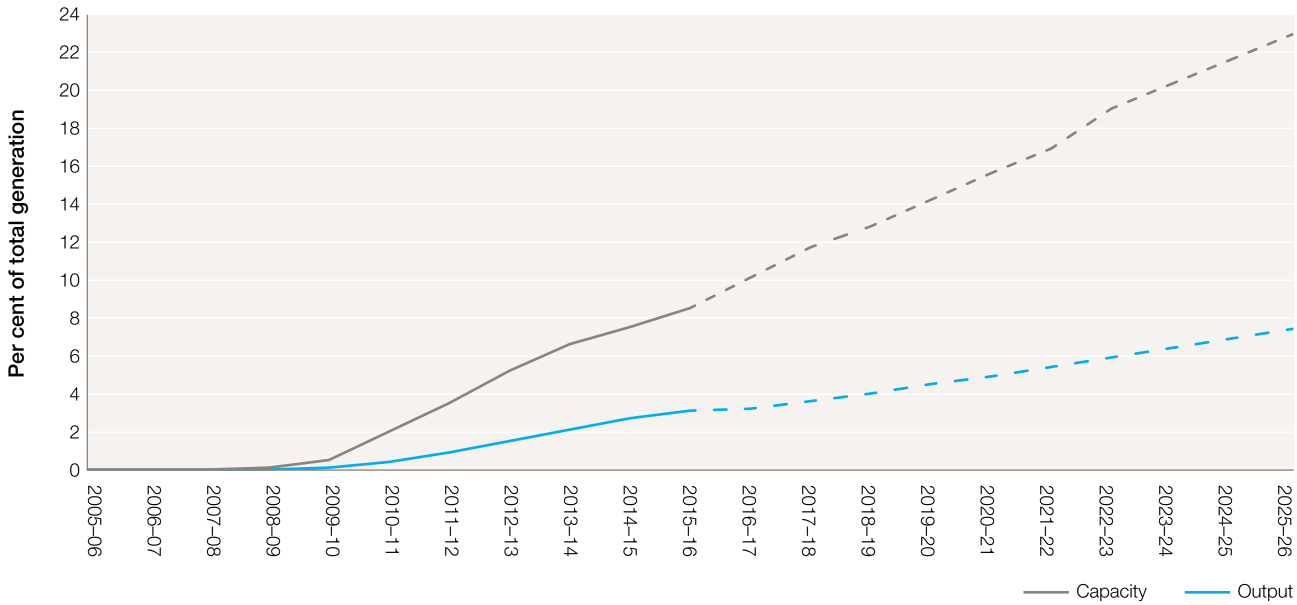
AEMO forecast rooftop installations will increase by 350 per cent over the next two decades and contribute around 11 per cent of the NEM's energy requirements by 2035–36.[16] Queensland has the highest forecast growth, and is expected to produce one third of the NEM's solar energy by 2035–36.[17]

1.2.7 Battery storage

Until recently, storing electricity was generally not commercially viable, but emerging technologies are changing this equation. The uptake of battery storage and electric vehicles continues to gather momentum internationally, with declining battery costs and advances in lithium ion batteries. In Australia, both products are in their infancy, and AEMO predicted adoption rates will likely remain low until the early 2020s, when the technology becomes more economic for the average consumer.[18]

10 AEMO, *South Australian historical market information report*, August 2016.
11 AEMO, *South Australian renewable energy report*, 2016.
12 Climate Council, *State of solar 2016: globally and in Australia*, February 2017.
13 Energy Consumers Australia, *Usage of solar electricity in the NEM*, November 2016.
14 Jacobs, *Projections of uptake of small scale systems*, report prepared for AEMO,2016.
15 AEMO, *South Australian electricity report*, 2015.
16 AEMO, *National electricity forecasting report*, 2016.
17 AEMO, *National electricity forecasting report*, 2016.
18 AEMO, *National electricity forecasting report,* 2016.

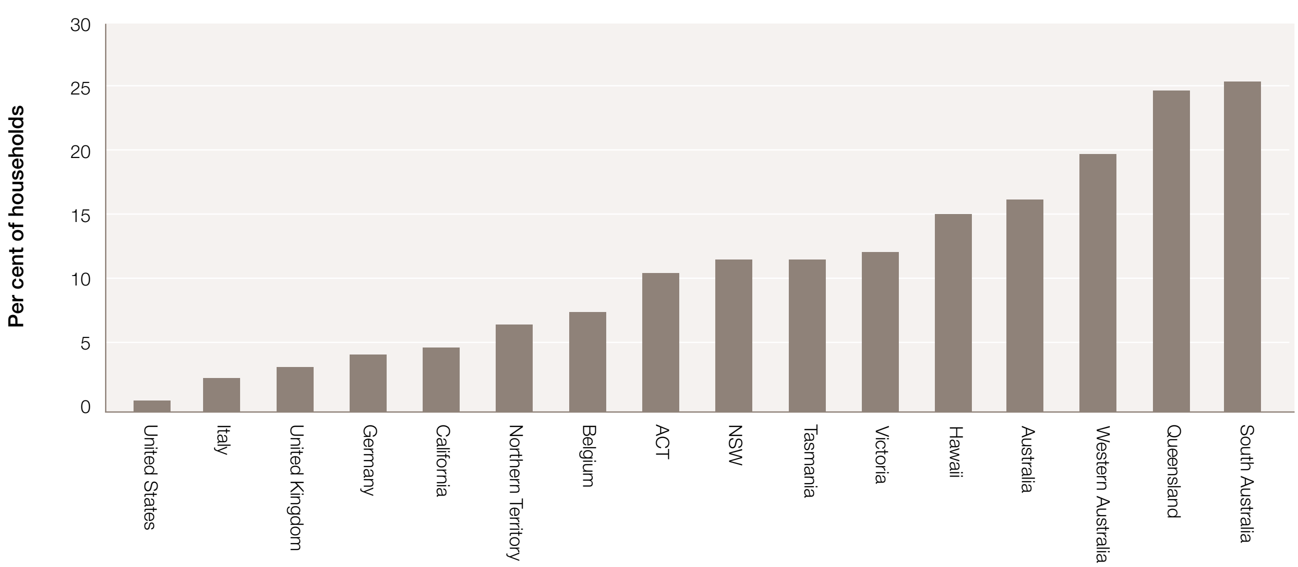
Figure 1.13
Solar PV generation capacity and output



Note: Actual data to 2015–16, then AEMO forecasts (dotted lines) published in 2016.

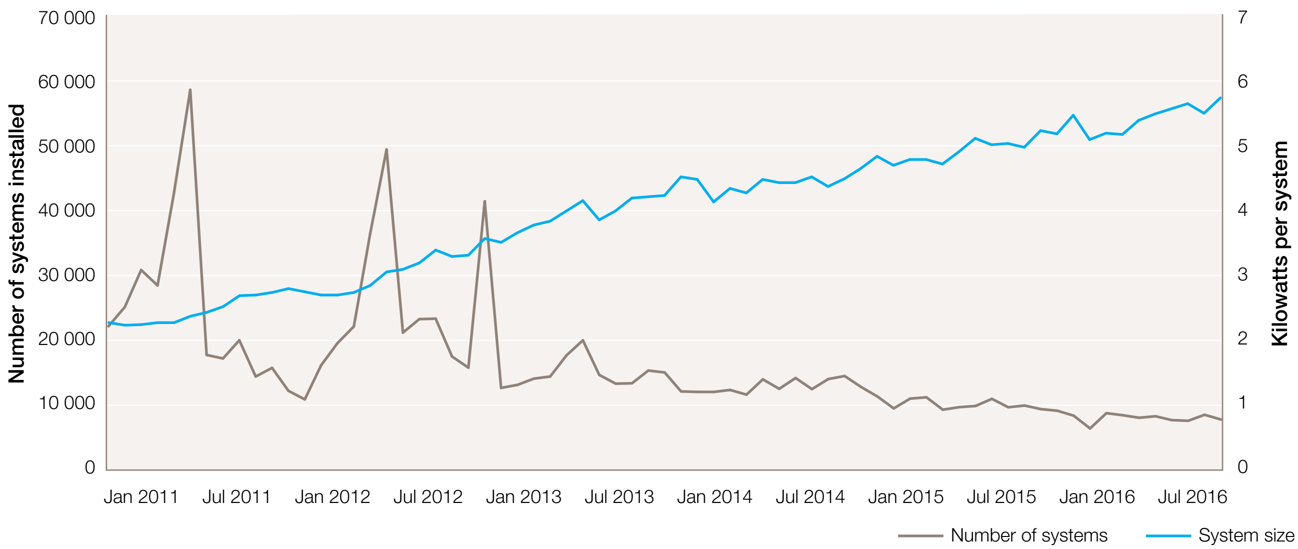
Sources: AEMO, AER.

Figure 1.14
Rooftop solar PV penetration



Source: International Energy Agency, *Renewable energy medium-term market report 2016*, p. 144; and reproduced in Expert Panel (Dr Alan Finkel, Chair), *Independent Review into the Future Security of the National Electricity Market, preliminary report*, December 2016.

Figure 1.15
Monthly solar PV installations



Source: Clean Energy Regulator.

In the short term, however, battery storage is more likely to be economically viable for commercial energy users rather than households. Battery costs will also be a key driver of the future uptake of solar PV systems with storage capacity.

A transition towards time-of-use electricity pricing would encourage more residential customers to adopt battery storage, by creating opportunities 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. In particular, nearly three quarters of customers with solar PV installations are interested in using batteries.[19]

Wider use of battery storage would allow for better matching of output from intermittent generation (such as solar PV) with evening demand peaks. By 2035–36, 3800 MW of rooftop PV generation may have integrated battery storage.[20]

1.3 Generation investment and disinvestment

Between the NEM's start in December 1998 and March 2017, new investment added over 15 200 MW of registered generation capacity (figure 1.16). Over the same period, almost 5500 MW of capacity was withdrawn from the market, either through permanent retirement or mothballing (removal from service for a specified or indefinite period).

Since 2012–13, capacity additions to the NEM have largely been in wind and solar plant. All plant retirements over this period have been in coal fired plant, but some gas powered plant has been mothballed.

1.3.1 New investment

Of the 2000 MW of plant capacity added over the five years to 31 March 2017, 92 per cent was in renewables (80 per cent wind and 12 per cent solar), which the RET scheme subsidises. The balance of investment was in waste coal mine gas and diesel plant. Table 1.3 lists capacity added since 1 July 2015. At March 2017, a further 125 MW of solar capacity and over 600 MW of wind capacity was committed to the market (table 1.4).[21]

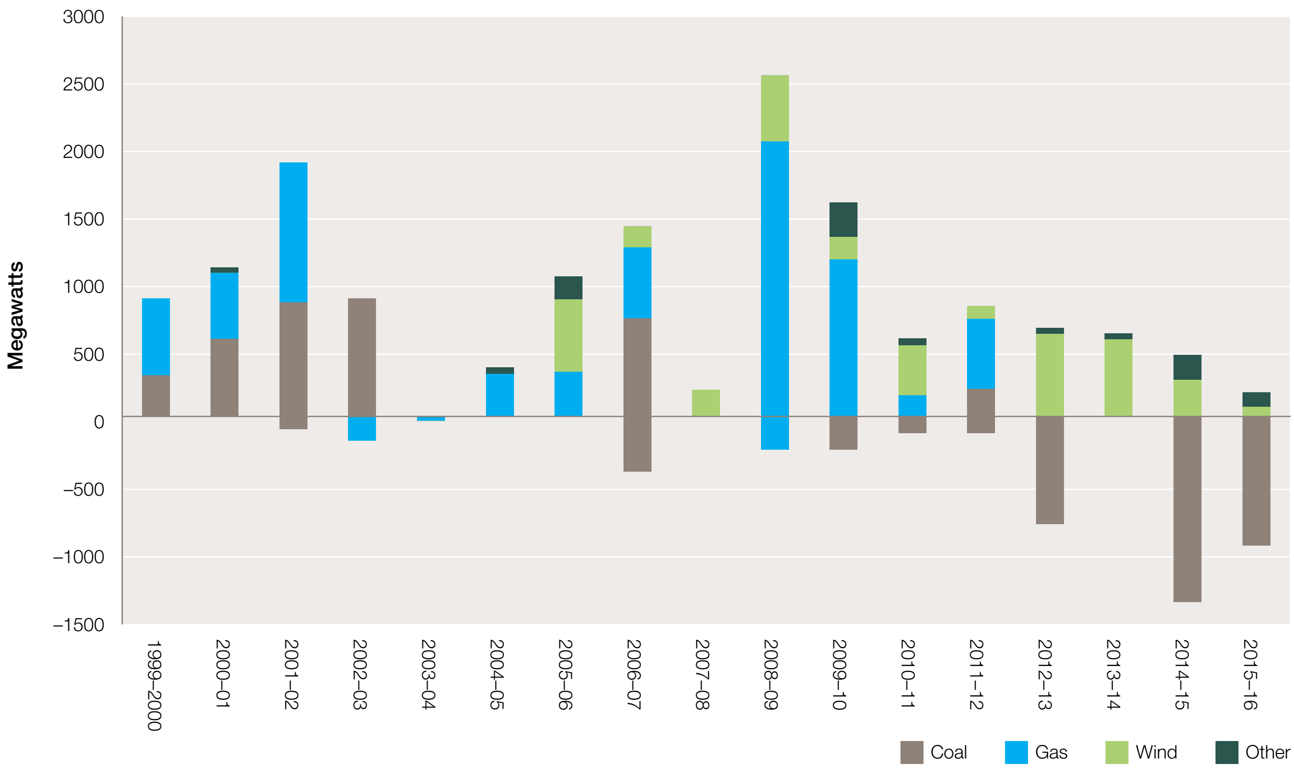
Additionally, AEMO classified another 20 000 MW of generation proposals as 'advanced' although not formally committed for development (figure 1.17). The bulk of these proposals were for wind (62 per cent) and gas powered plant (25 per cent). But grid scale solar proposals are

19 Energy Consumers Australia, *Usage of solar electricity in the NEM,* November 2016.
20 AEMO, *National electricity forecasting report*, 2016.

21 Committed projects include those under construction or for which developers and financiers have formally committed to construction. AEMO accounts for committed projects in projecting electricity supply and demand.

Figure 1.16

Investment in new generation, and plant retirements



Note: Retirements exclude mothballed plant.

Source: AEMO; AER.

on a growth trajectory, accounting for 11 per cent of all proposals, compared with just 2 per cent in 2015.[22]

No new investment in baseload plant (coal or gas) has occurred since a 240 MW upgrade to the Eraring plant in NSW in 2013. Business leaders and other stakeholders have pointed to a lack of coordination in government policy as a significant deterrent to new investment.[23]

1.3.2 Capacity withdrawals

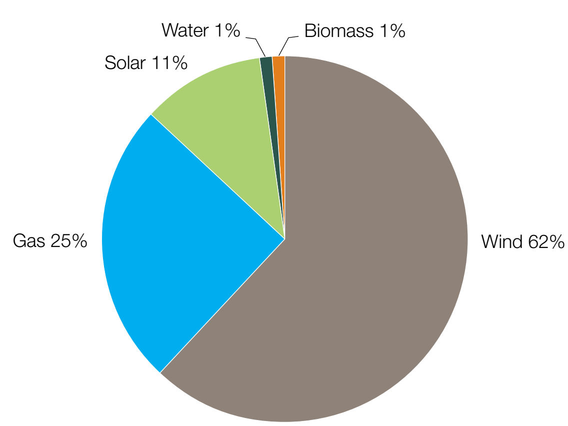
A flattening of electricity demand from 2008, along with incentives to invest in renewable plant, led to an oversupply of generation capacity for several years. In response, significant capacity was permanently or temporarily removed from the market (table 1.5). Indeed, more capacity was withdrawn from the market during 2011–16 than was added through new investment over that period.

22 AEMO, 'Generation information', http://aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.

23 Business Council of Australia, Energy Networks Australia, Australian Industry Group, Australian Energy Council, Energy Consumers Australia, ACOSS and others, 'Energy reform is urgent to avert systemic crisis', Media release, 15 November 2016, available at http://energyconsumersaustralia.com.au/joint-statement-energy-reform-is-urgent-to-avert-systemic-crisis

Figure 1.17

Advanced generation proposals at March 2017



Data source: AEMO, 'Generation information', http://aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.

Table 1.3 **Generation investment in the National Electricity Market**

OWNER	POWER STATION	TECHNOLOGY	SUMMER CAPACITY (MW)	DATE COMMISSIONED
QUEENSLAND				
EDL OCI	Oaky Creek 2	Waste coal mine gas	15	2016
NEW SOUTH WALES				
AGL PV Solar Development	Broken Hill	Solar	53	2015
Moree Solar Farm	Moree	Solar	56	2016
Elementus Energy	Williamsdale	Solar	10	2017
VICTORIA				
Pacific Hydro Portland Wind Farm	Portland Stage 4	Wind	47	2015
Coonooer Bridge Wind Farm	Coonooer Bridge	Wind	20	2016
SOUTH AUSTRALIA				
Hornsdale Wind Farm	Hornsdale (stage 1)	Wind	102	2016
Waterloo Windfarm	Waterloo Expansion	Wind	20	2017

Table 1.4 **Committed investment in the National Electricity Market, March 2017**

DEVELOPER	POWER STATION	TECHNOLOGY	SUMMER CAPACITY (MW)	PLANNED COMMISSIONING
QUEENSLAND				
Lyon Infrastructure Investments	Lakeland Solar and Storage Project	Solar	28	2017
NEW SOUTH WALES				
Goldwind Australia	White Rock	Wind	175	2017
Zhenfa Canberra Solar Farm One	Mugga Lanek	Solar	13	TBA
Griffith Solar Farm	Griffith	Solar	29	TBA
Parkes Solar Farm	Parkes	Solar	55	TBA
VICTORIA				
Partners Group, OPTrust, GE and RES	Ararat	Wind	240	2017
Kiata Wind Farm	Kiata	Wind	31	2017
Acciona Energy	Mount Gellibrand stage 1	Wind	66	TBA
SOUTH AUSTRALIA				
Hornsdale Wind Farm	Hornsdale (stage 2)	Wind	102	2017

MW, megawatts; TBA, to be advised.

Source (tables 1.3 and 1.4): AEMO, 'Generation information', http://aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.

Table 1.5 **Generation withdrawals from 2011–12**

YEAR	POWER STATION	REGION	GENERATION TECHNOLOGY	CAPACITY (MW)	STATUS
WITHDRAWN					
2011–12	Swanbank B	Qld	CCGT	480	Decommissioned progressively between April 2010 and May 2012
2012–13	Munmorah	NSW	Coal	600	Retired
2012–13	Tarong	Qld	Coal	700	Closed 2012 to 2014
2012–13	Collinsville	Qld	Coal	180	Retired
2014–15	Morwell, Brix	Vic	Coal	205	Retired
2014–15	Wallerawang C	NSW	Coal	1000	Retired
2014–15	Redbank	NSW	Coal	144	Retired
2014–15	Pelican Point	SA	CCGT	249	Half capacity withdrawn. Announced return to full capacity in June quarter 2017
2014–15	Swanbank E	Qld	CCGT	385	Placed into cold storage. Expected to return December 2018
2015–16	Northern	SA	Coal	540	Retired
2015–16	Playford B	SA	Coal	200	Retired
2015–16	Anglesea	Vic	Coal	150	Retired
2016–17	Hazelwood	Vic	Coal	1600	Retired
ANNOUNCED WITHDRAWAL					
2017	Smithfield	NSW	Gas	171	Retirement
2017	Tamar Valley	Tas	CCGT	208	Mothballing
2021	Mackay	Qld	OCGT	34	Retirement
2022	Daandine	Qld	CCGT	33	Retirement
2022	Liddell	NSW	Coal	2000	Retirement

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

Sources: company announcements; AEMO, Electricity statement of opportunities (various years).

In particular, owners made commercial decisions to exit the market, permanently retiring a number of coal plants. Most of these plants had operated for three or more decades and outlived their initial expected life. The Wallerawang plant in NSW closed after 38 years of operation, while the Playford plant in South Australia closed after 55 years of operation. Most recently, Engie closed its Hazelwood power station in Victoria in March 2017, removing another 1600 MW of brown coal capacity from the NEM. The Hazelwood power station had been commissioned in the 1960s. The aging plants had become increasingly unprofitable due to rising maintenance costs and competition from renewable generation. Looking ahead, AGL Energy plans to retire its 2000 MW Liddell plant in NSW in 2022.

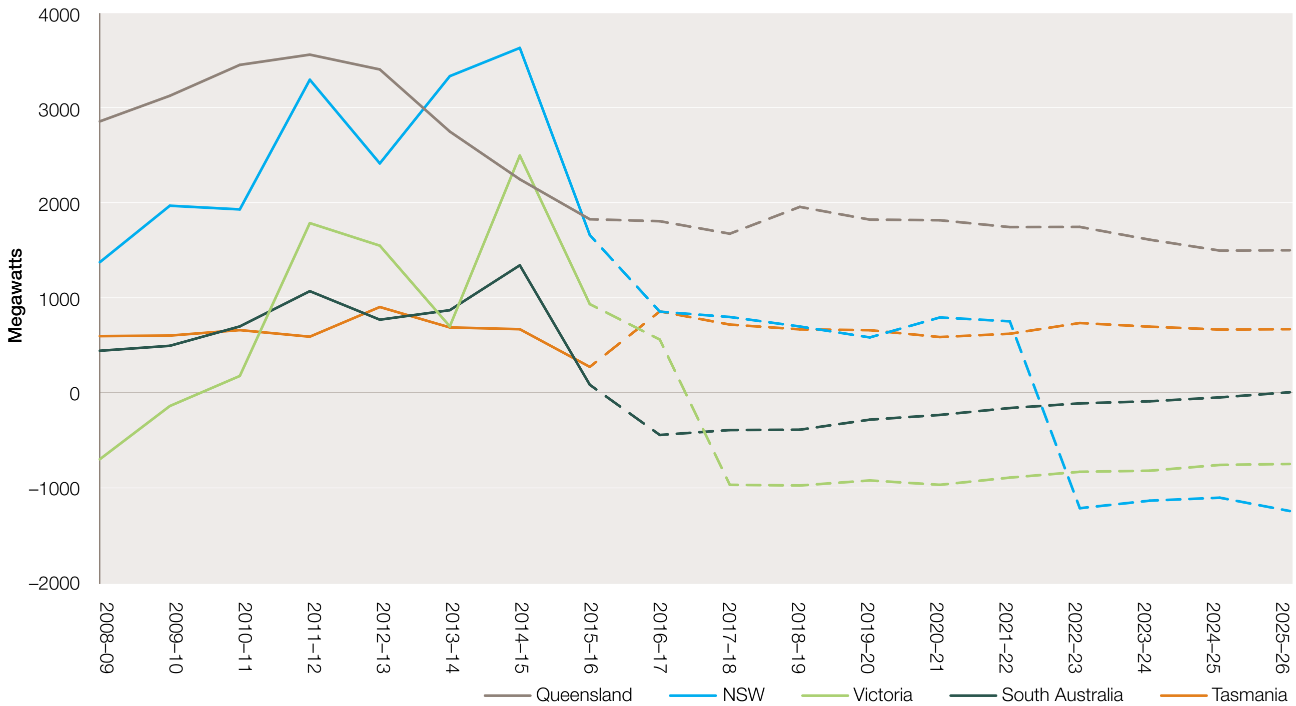
1.3.3 Supply–demand balance

Declining electricity demand and new investment in renewable generation led to surplus generation capacity in the NEM for several years (figure 1.18). That surplus peaked in 2014–15. But the trend then reversed, with all regions recording a declining surplus in 2015–16, and again in 2016–17 (except Tasmania).

The retirement of the Hazelwood power station in March 2017 further tightens the supply–demand balance. AEMO projected the retirement, without any market response, may lead to insufficient capacity to meet maximum demand in Victoria and South Australia by summer 2017–18. It noted limited support will be available to South Australia when supply is tight in Victoria after the retirement of Hazelwood.

Figure 1.18

Surplus generation capacity, by region



Notes:

Historical data to 2015–16 reflects a surplus of generation capacity (based on summer ratings) over maximum demand. Beyond that year, the data reflects surplus existing and committed generation capacity over maximum demand forecasts in AEMO's medium growth scenario at a 50 per cent probability of exceedance.

Wind contribution to capacity is based on summer ratings for semi-scheduled plant and registered capacity for non-scheduled plant. AEMO's forecasts of wind capacity are based on modelled contribution at times of peak demand.

Sources: AEMO, AER.

Support from NSW to Victoria is also limited, given network constraints when Snowy Hydro's Murray power station is operating near maximum capacity.

AEMO outlined market responses that could avert this situation, including increased output by some generators currently in operation. It also noted three mothballed gas powered generators—Tamar Valley in Tasmania, Swanbank E in Queensland, and capacity at Pelican Point in South Australia—could be returned to service with about three months' notice.[24]

But, in March 2017, AEMO reported a shortage of domestic gas supply could result in insufficient gas to meet projected demand for gas powered generation in the NEM by summer 2018–19. It noted South Australia, NSW and Victoria would be the regions most affected.[25] Shortly after AEMO published this report, the Australian and state governments made announcements to intervene in the market through investment in publicly owned generation infrastructure.

On 14 March 2017, the South Australian Government announced it would:

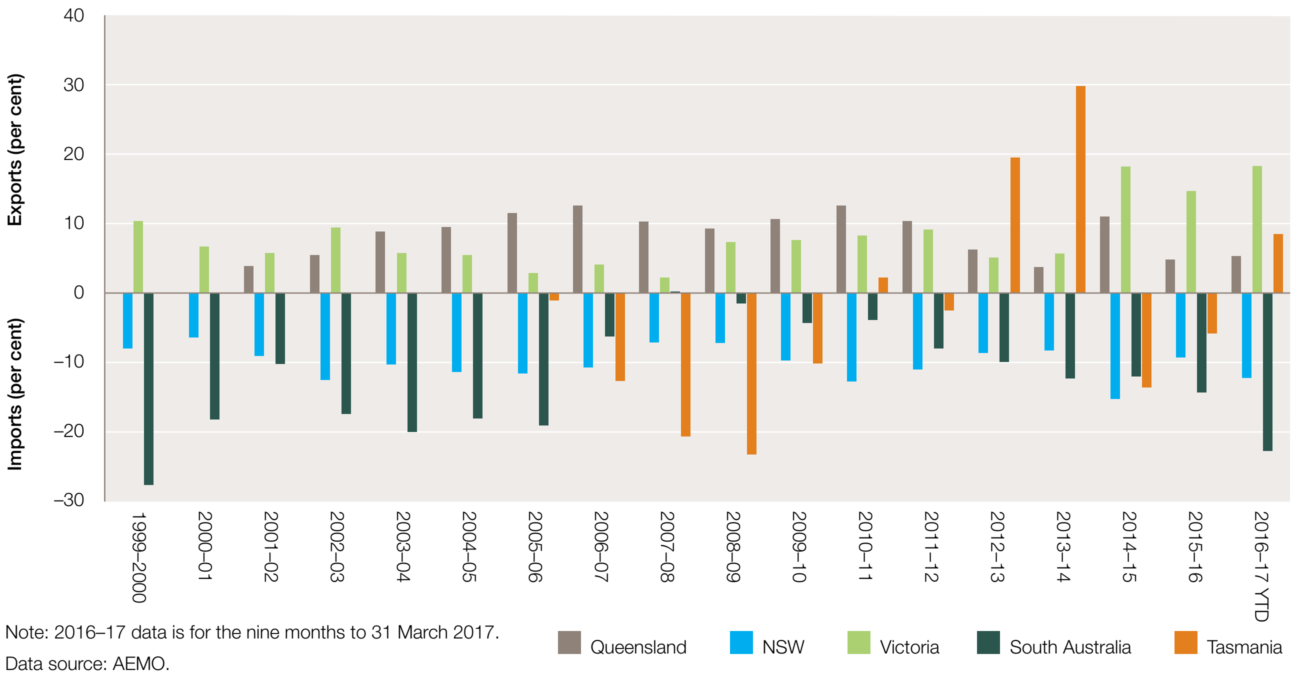
- invest in a 250 MW gas powered generator that could be switched on when power is required, and provide round-the-clock inertia services to stabilise the power system
- create a $150 million fund to support renewable projects that can run continuously, including a grid connected battery that will provide 100 MW of storage
- procure interim back-up generation if necessary.[26]

24 AEMO, *Update: Electricity statement of opportunities for the National Electricity Market*, November 2016.
25 AEMO, *Gas statement of opportunities*, 9 March 2017.

26 Jay Weatherill (Premier of South Australia), 'South Australia is taking charge of its energy future', Media release, 14 March 2017.

Figure 1.19

Interregional trade as a percentage of regional electricity demand



Note: 2016–17 data is for the nine months to 31 March 2017.

Data source: AEMO.

Two days later, the Australian Government announced it would undertake a feasibility study into a future expansion of Snowy Hydro, which it jointly owns with the NSW and Victorian governments. The proposal would increase Snowy Hydro's capacity by around 2000 MW—a rise of 50 per cent. [27]

Then, in April 2017, the Australian and Tasmanian governments announced they would undertake a feasibility study to expand the Tasmanian hydro 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.[28]

These announcements were in addition to ongoing work to assess the viability of expanding network interconnection to better link South Australia and Tasmania with other regions of the NEM.

In contrast to these initiatives, the private sector's investment response to the NEM's tightening supply–demand balance has been muted. Uncertainty about government climate change policies has been widely cited as a reason for this sluggish response. The AEMC, for example, noted 'without clear, national, coordinated policy objectives and credible mechanisms that reinforce one another, both business and consumers find it difficult to invest—which undermines the reliability of supply.'[29]

1.4 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 high cost generating regions to import electricity from lower cost regions.

Queensland and Victoria are the NEM's principal electricity exporters, while South Australia and NSW typically import electricity. Tasmania's trade position fluctuates, depending on market and weather conditions (figure 1.19).

Victoria's abundant supplies of low cost brown coal have made it a net exporter of coal fired electricity. The state's

27 The Hon Malcolm Turnbull MP (Prime Minister of Australia), 'Securing Australia's energy future with Snowy Mountains 2.0', Media release, 16 March 2017.

28 The Hon Malcolm Turnbull MP (Prime Minister of Australia) and Will Hodgman (Premier of Tasmania), 'New Tasmanian pumped hydro', Media release, 20 April 2017.

29 AEMC, 'AEMC releases submission to Finkel review on energy security', Media release, 7 March 2017.

trading position weakened during 2012–14, when carbon pricing made brown coal less competitive. But the abolition of carbon pricing and South Australia's rising dependence on Victorian electricity reversed this trend, making Victoria the NEM's largest exporter in 2014–15 and 2015–16. Looking ahead, the closure of the Hazelwood power station in 2017 may weaken exports from Victoria.

Surplus capacity and low fuel prices have made *Queensland* a net electricity exporter. Low gas spot prices, coinciding with the availability of large quantities of 'ramp-up' gas from LNG projects, boosted Queensland's exports of gas powered generation in 2014–15. But subsequent gas price rises have reduced Queensland's exports.

NSW has relatively high fuel costs, typically making it a net importer of electricity. During the two years of carbon pricing, Snowy Hydro significantly increased output, reducing the region's reliance on imports. But this position has since reversed.

South Australia is a regular electricity importer, given its high fuel costs. While investment in wind generation allows the region to export electricity during low demand periods, baseload withdrawals have increased the region's trade dependency. This dependency, combined with a reliance on trade with Victoria at times of low wind generation, has made South Australia the highest net importing region in the NEM.

Tasmania became the NEM's largest net exporter during 2012–14, when carbon pricing made hydro generation more competitive. But the abolition of carbon pricing and declining dam levels reversed this position. By late 2015, Tasmania was experiencing drought conditions, requiring it to import up to 40 per cent of the state's energy needs across the Basslink interconnector to Victoria.[30]

A major outage on Basslink from December 2015 to May 2016 curtailed all trade between Tasmania and the mainland. The prolonged outage at a time of extreme drought meant Tasmania's imports were lower than otherwise would have been the case (section 1.9). With Basslink back in service and hydro storage returning to normal levels, Tasmania returned to a net exporting position in 2016–17.

1.4.1 Market alignment and network constraints

The market sets a separate spot price for each NEM region. When the market is operating efficiently, interregional trade aligns prices across all regions (allowing for differences caused by physical losses when transporting electricity). Alignment rates in mainland NEM regions have deteriorated significantly in recent years. The market was typically aligned 60–80 per cent of the time after the NEM commenced. But the rate fell to 50 per cent in 2014–15, before recovering slightly to 58 per cent in 2015–16. In the first three quarters of 2016–17, the alignment rate was only 38 per cent.

The recent deterioration in market alignment reflects a rising incidence of network congestion.[31] While the duration of congestion on interconnectors linking NSW with Queensland has been fairly stable, congestion on both Victoria—South Australia interconnectors has risen every year since 2013–14, and has more than doubled overall. Heywood was the NEM's most congested interconnector, partly because an upgrade periodically limited its capacity. Congestion also rose sharply on the NSW–Victoria interconnector in 2016–17.

1.5 Generation ownership

Over 300 registered generators sell electricity into the NEM spot market. Table 1.6 lists the major generators, plant technologies and ownership arrangements (including the entities that control each plant's dispatch). Figure 1.20 illustrates market shares in generation capacity for each region (including inbound interconnector capacity). Market concentration in Victoria and South Australia has risen following recent plant withdrawals.

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

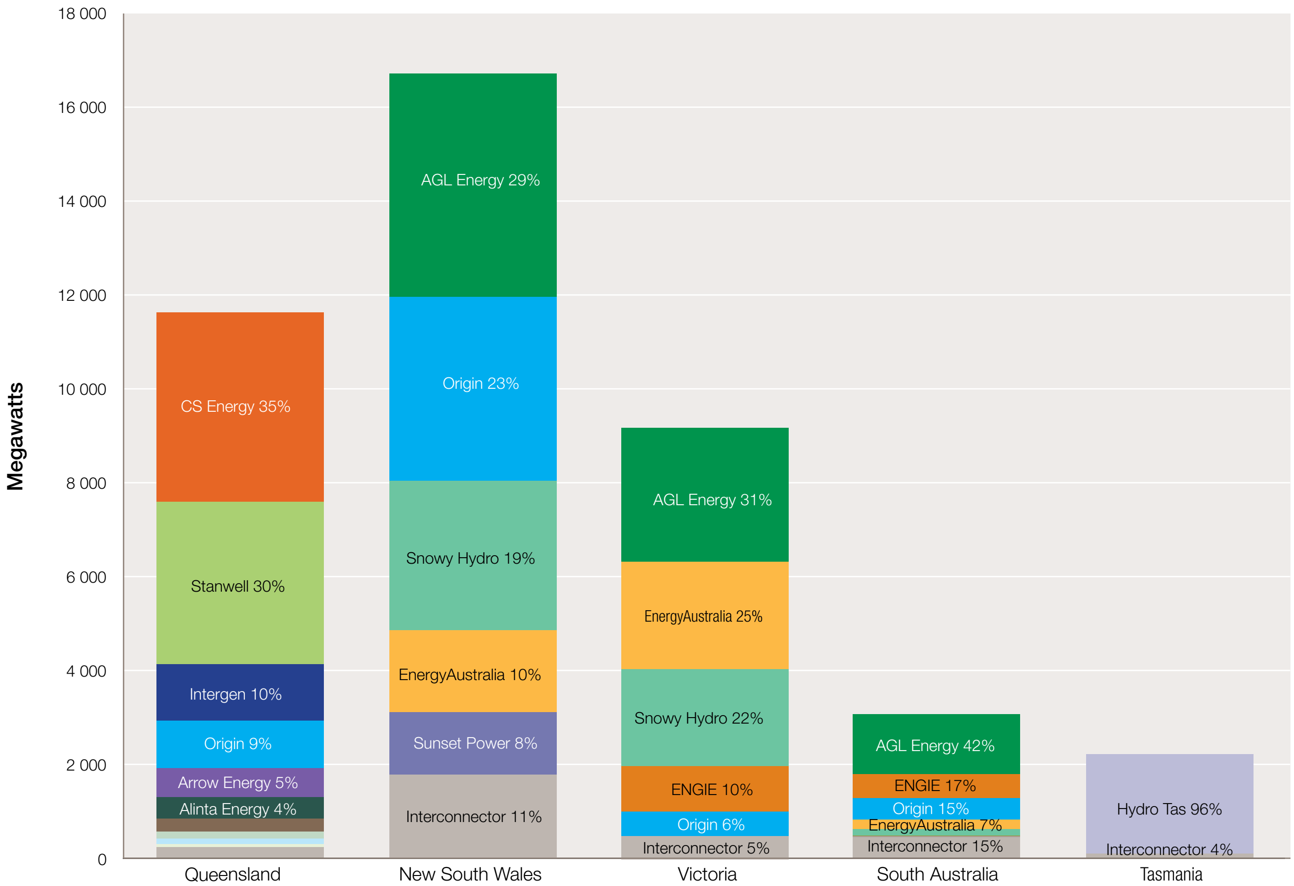
- In *Victoria*, AGL Energy (31 per cent), EnergyAustralia (25 per cent) and Snowy Hydro (22 per cent) control a majority of capacity. Engie controlled 23 per cent of the market until decommissioning its Hazelwood plant in March 2017.
- In *South Australia,* AGL Energy is the dominant generator, with 45 per cent of capacity. Other significant entities are Origin Energy (16 per cent), Engie (10 per cent) and EnergyAustralia (7 per cent). Before retiring its Playford (2012) and Northern (2016) power stations, Alinta had an 18 per cent market share in South Australia.
- In *NSW*, the privatisation of state owned generation businesses was completed in 2015. EnergyAustralia (Delta West), Origin Energy (Eraring Energy), AGL Energy (Macquarie Generation), Snowy Hydro (Delta

30 Hydro Tasmania, *2016 annual report.*

31 Price separation is usually caused by network outages or technical limits on the power flows across the interconnectors. These network limitations can island a region from the rest of the market (in terms of price) if local demand is high, forcing it to rely on local generation to meet demand.

Figure 1.20

Market shares in generation capacity, 2017



Notes:

Capacity is based on summer availability for January 2017, except wind, which is adjusted for an average contribution factor.

Interconnector capacity is based on observed flows when the price differential between regions exceeds $10 per MWh in favour of the importing region; the data excludes trading intervals in which counter flows were observed (that is, when electricity was imported from a high priced region into a lower priced region).

Capacity that is subject to power purchase agreements is attributed to the party with control over output.

Data sources: AEMO, AER.

Electricity's Colongra plant) and Sunset Power (Delta's Vales Point plant) were the successful bidders. AGL Energy (29 per cent), Origin Energy (23 per cent) and Snowy Hydro (19 per cent) emerged as the state's leading generators.

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 65 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). The degree of market concentration increased in 2011, when the Queensland Government dissolved one of three state owned generation businesses (Tarong Energy) and re-allocated its capacity to the remaining two state owned entities.
- In *Tasmania*, the state owned Hydro Tasmania owns nearly all generation capacity. To encourage competition in the retail market, the Office of the Tasmanian Economic Regulator regulates the price at which Hydro Tasmania can offer four safety net contract products, and it ensures adequate volumes of these products are available.

Table 1.6 **Registered plant capacity and ownership in the NEM, 2017**

TRADING RIGHTS	POWER STATIONS	CAPACITY (MW)	OWNER
QUEENSLAND (12 041 MW)			
Stanwell Corporation	Stanwell; Tarong; Tarong North; Barron Gorge; Kareeya; Mackay	3489	Stanwell Corporation (Qld Government)
CS Energy	Callide B; Kogan Creek; Wivenhoe	1930	CS Energy (Qld Government)
CS Energy	Gladstone	1680	Rio Tinto 42.1%; NRG Energy 37.5%; others 20.4%
Origin Energy	Darling Downs; Mount Stuart; Roma	1013	Origin Energy
CS Energy / InterGen	Callide C	900	CS Energy (Qld Government) 50%; InterGen (China Huaneng Group / Guangdong Yudean Group 50%; others 50%) 50%
InterGen	Millmerran	760	InterGen (China Huaneng Group / Guangdong Yudean Group 50%; others 50%) 59%; KIAMCO/Daelim 35%; others 6%
Arrow Energy	Braemar 2	504	Arrow Energy (Shell 50%; PetroChina 50%)
Alinta Energy	Braemar 1	471	Alinta Energy (TPG Capital)
ERM Power	Oakey	282	ERM Group
AGL Energy / Arrow Energy	Yabulu	242	RATCH Australia (Ratchaburi Electricity Generation 80%; Ferrovial 20%)
RTA Yarwun	Yarwun	154	Rio Tinto Alcan
Shell	Condamine	144	Shell
Wilmar International	Pioneer Sugar Mill; Invicta Sugar Mill	118	Wilmar International
AGL Energy	Moranbah North; German Creek	108	Energy Developments (DUET Group)
Mackay Sugar	Racecourse Mill	48	Mackay Sugar
Ergon Energy	Barcaldine	34	Ergon Energy (Qld Government)
Origin Energy	Daandine	33	Energy Infrastructure Investments (Marubeni 50%; Osaka Gas 30%; APA Group 20%)
National Power Partners	Rocky Point	30	National Power Partners
	Unscheduled plant < 30 MW	101	
NSW (16 380 MW)			
AGL Energy	Bayswater; Liddell; Hunter Valley	4764	AGL Energy
AGL Energy	Broken Hill; Nyngan	155	Powering Australian Renewables Fund (AGL Energy 20%; QIC 80%)
Origin Energy	Eraring; Shoalhaven; Uranquinty; Eraring	3802	Origin Energy
Origin Energy	Cullerin Range	30	Energy Developments (DUET Group)
Snowy Hydro	Tumut 3; Colongra; Upper Tumut; Blowering; Guthega	3212	Snowy Hydro (NSW Government 58%; Vic Government 29%; Australian Government 13%)
EnergyAustralia	Mount Piper; Tallawarra	1745	EnergyAustralia (CLP Group)
Sunset Power International	Vales Point	1320	Sunset Power International (Waratah Power Pty Ltd 50%; Vales Point Invesments 50%)
Infigen Energy	Capital; Woodlawn	188	Infigen Energy
EnergyAustralia	Gullen Range	166	Beijing Jingneng Clean Energy 75%; Goldwind Capital 25%
Origin Energy	Smithfield Energy Facility	162	Marubeni Corporation
EnergyAustralia	Taralga	106	State Power Investment Corporation (Chinese Government)
Stanwell Corporation	Appin; Tower	96	Energy Developments (DUET Group)

Continued

Table 1.6 **Registered plant capacity and ownership in the NEM, 2017 (continued)**

TRADING RIGHTS	POWER STATIONS	CAPACITY (MW)	OWNER
NSW continued			
Capital Dynamics	Broadwater; Condong	68	Capital Dynamics
EnergyAustralia	Boco Rock	113	Electricity Generating Public Company
Essential Energy	Broken Hill	50	Essential Energy (NSW Government)
Acciona Energy	Gunning	46	Acciona Energy
Trustpower	Hume	29	Trustpower (51% Infratil)
Origin Energy	Moree	56	Fotowatio Renewable Futures
	Unscheduled plant < 30 MW	272	
VICTORIA (10 306 MW)			
AGL Energy	Loy Yang A; Kiewa; Somerton; Eildon; Clover; Dartmouth; McKay	2885	AGL Energy
Snowy Hydro	Murray; Laverton North; Valley Power	2080	Snowy Hydro (NSW Government 58%; Vic Government 29%; Australian Government 13%)
EnergyAustralia	Yallourn	1420	EnergyAustralia (CLP Group)
Origin Energy	Longford	44	BHP Billiton 50%; Exxon Mobil 50%
Engie	Loy Yang B	980	Engie 70%; Mitsui 30%
EnergyAustralia	Jeeralang A and B; Newport	883	IFM Investors
Origin Energy	Mortlake	518	Origin Energy
AGL Energy	Macarthur	336	Morrison & Co. 50%; Malakoff Corporation Berhad 50%
Pacific Hydro	Yambuk; Challicum Hills; Portland	231	Pacific Hydro (State Power Investment Corporation (Chinese Government))
Acciona Energy	Waubra	192	Acciona Energy
Meridian Energy	Mount Mercer	131	Meridian Energy
Alinta Energy	Bald Hills	106	Mitsui
Hydro Tasmania	Bairnsdale	70	Alinta Energy (TPG Capital)
AGL Energy	Oaklands Hill	50	Challenger Life (Challenger)
Trustpower	Hume	29	Trustpower (51% Infratil)
ACT Government 33%; Ararat Wind Farm 67%	Ararat	170	RES; GE; Downer; Partners Group; OPTrust
	Unscheduled plant < 30 MW	181	
SOUTH AUSTRALIA (4055 MW)			
AGL Energy	Torrens Island	1260	AGL Energy
Engie	Pelican Point; Canunda; Dry Creek; Mintaro; Port Lincoln; Snuggery	565	Engie 72%; Mitsui 28%
Origin Energy	Snowtown; Snowtown North; Snowtown South	369	Trustpower (51% Infratil)
Origin Energy	Quarantine; Ladbroke Grove	254	Origin Energy
EnergyAustralia	Hallet	198	EnergyAustralia (CLP Group)
Infigen Energy	Lake Bonney 2 and 3	182	Infigen Energy
Origin Energy	Osborne	172	ATCO 50%; Origin Energy 50%
AGL Energy	Hallett 2; Wattle Point	145	Energy Infrastructure Trust (Infrastructure Capital Group)
EnergyAustralia 50%; Hydro Tasmania 50%	Waterloo	130	Palisade Investment Partners / Northleaf Capital Partners

Table 1.6 **Registered plant capacity and ownership in the NEM, 2017 (continued)**

TRADING RIGHTS	POWER STATIONS	CAPACITY (MW)	OWNER
SOUTH AUSTRALIA continued			
Snowy Hydro	Port Stanvac; Angaston; Lonsdale	128	Snowy Hydro (NSW Government 58%; Vic Government 29%; Australian Government 13%)
AGL Energy	North Brown Hill	92	Energy Infrastructure Trust (Infrastructure Capital Group) 40%; Osaka Gas 40%; APA Group 20%
Essential Energy	Lake Bonney 1	81	Infigen Energy
AGL Energy	Hallett 1	71	Pacific Hydro (State Power Investment Corporation (Chinese Government))
Meridian Energy	Mount Millar	70	Meridian Energy
EnergyAustralia	Cathedral Rocks	66	EnergyAustralia (CLP Group) 50%; Acciona Energy 50%
Pacific Hydro	Clements Gap	57	Pacific Hydro (State Power Investment Corporation (Chinese Government))
AGL Energy	The Bluff	53	Eurus Technical Service Corporation (Toyota Tsusho 60%, Tokyo Electric Power Company 40%)
Hydro Tasmania	Starfish Hill	35	RATCH Australia (Ratchaburi Electricity Generation 80%; Ferrovial 20%)
ACT Government	Hornsdale	100	Neoen 70%, John Laing 30%
	Unscheduled plant < 30 MW	27	
TASMANIA (2665 MW)			
Hydro Tasmania	Gordon; Poatina; Tamar Valley; Bell Bay; others	2136	Hydro Tasmania (Tas Government)
Hydro Tasmania	Woolnorth; Musselroe	308	Shenhua Clean Energy 75%; Hydro Tasmania 25%
	Unscheduled plant < 30 MW	106	

Fuel types: coal; gas; hydro; wind; diesel/fuel oil/multi-fuel; biomass, bagasse; solar; unspecified.

MW, megawatts.

Note: Capacity as published by AEMO for summer 2016–17, except for non-scheduled plant (registered capacity).

Source: AER.

1.5.1 Vertical integration

While governments structurally separated the energy supply industry in the 1990s, many retailers later reintegrated with generators to form ‘gentailers’ that own portfolios in both generation and retail. Three retailers—AGL Energy, Origin Energy and EnergyAustralia—supply 70 per cent of retail electricity customers in the NEM. The same entities expanded their market share in NEM generation capacity from 15 per cent in 2009 to 48 per cent in 2017.

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.

1.5.2 Competition in the NEM

High levels of market concentration and vertical integration between generators and retailers lead to market structures that may provide opportunities for the exercise of market power. The AER has monitored competition metrics in the NEM since 2013, reporting annually on outcomes in the *State of the energy market* report (box 1.5).

In 2016 the CoAG Energy Council tasked the AER with a new role: to monitor and report on whether the NEM is effectively competitive, including factors that detrimentally affect the NEM’s efficient functioning. Following the passage of enabling legislation in December 2016, the AER in early 2017 was developing frameworks to implement the new role.

Box 1.5 Competition metrics in the NEM

The market structure of the generation sector affects the 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.

Structural indicators of competitiveness include:

- market shares in capacity (or output)
- the Herfindahl–Hirschman index
- the residual supply index.

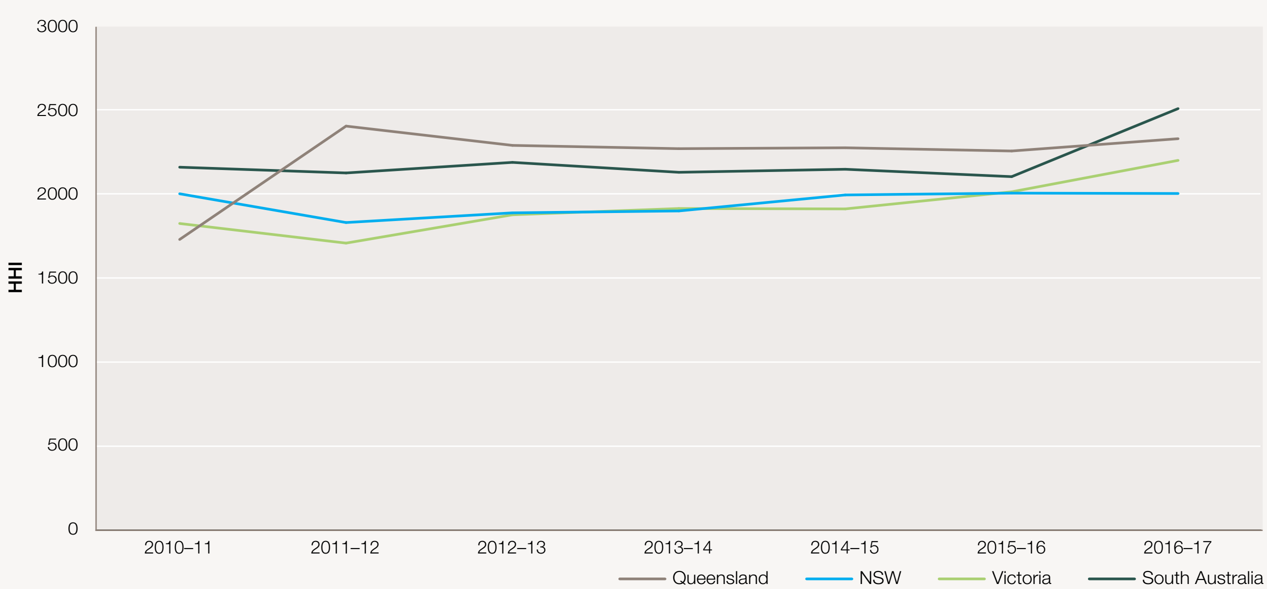
Market shares are a simple illustrator of the degree of concentration in a market. Markets with a high proportion of capacity controlled by one or two generators are more likely to be susceptible to the exercise of market power. Figure 1.20 illustrates generation market shares in 2017, based on capacity under each firm's trading control. It illustrates the relatively strong market positions held by AGL Energy in South Australia, NSW and Victoria; and by state owned generators in Queensland (CS Energy and Stanwell) and Tasmania (Hydro Tasmania).

Transmission interconnectors can provide a competitive constraint on generators by enabling electricity imports from other regions. But network congestion issues sometimes limit the effectiveness of this constraint. Congestion on some interconnectors has risen markedly in recent years (section 1.4.1).

The *Herfindahl–Hirschman index* (HHI) accounts for the relative size of firms when analysing market structure, by tallying the sum of squared market shares for all firms 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 highlights the impact of large firms. The higher the HHI, the more concentrated and less competitive is a market.

Figure 1.21 illustrates recent trends. In Queensland, the index rose in 2011–12 (from being the NEM's lowest to its highest) following a consolidation of state owned generators. The Victorian index rose in 2012–13 when AGL Energy's full acquisition of Loy Yang A increased market concentration. Similarly, South Australia's HHI rose sharply following the retirement of Alinta's coal fired plants in 2015–16. The sharp rise for Victoria in 2016–17 accounted for the closure of Engie's Hazelwood power station, which increased the market share of remaining participants.

Figure 1.21
Herfindahl–Hirschman index



Note: Based on the market share data in figure 1.20.

Source: AER.

Market share and HHI analysis do not account for variations in demand over time. This deficiency is significant because high demand is generally necessary for market power to be profitably exercised. The *residual supply index* (RSI) measures the extent to which one or more generators is 'pivotal' to clearing the market. A generator is pivotal if market demand exceeds the capacity of all other generators. In these circumstances, the generator *must* be dispatched (at least partly) to meet demand.

The RSI–1 measures the ratio of demand that can be met by all but the largest generator in a region. An RSI–1 *greater* than 1 means demand can be fully met without dispatching the largest generator. But an RSI–1 *below* 1 means the largest generator becomes pivotal to meeting demand. Various factors may cause the RSI–1 index to deteriorate over time, including a rise in demand, a decrease in available generation capacity, or an increase in the proportion of available capacity supplied by the largest generator.

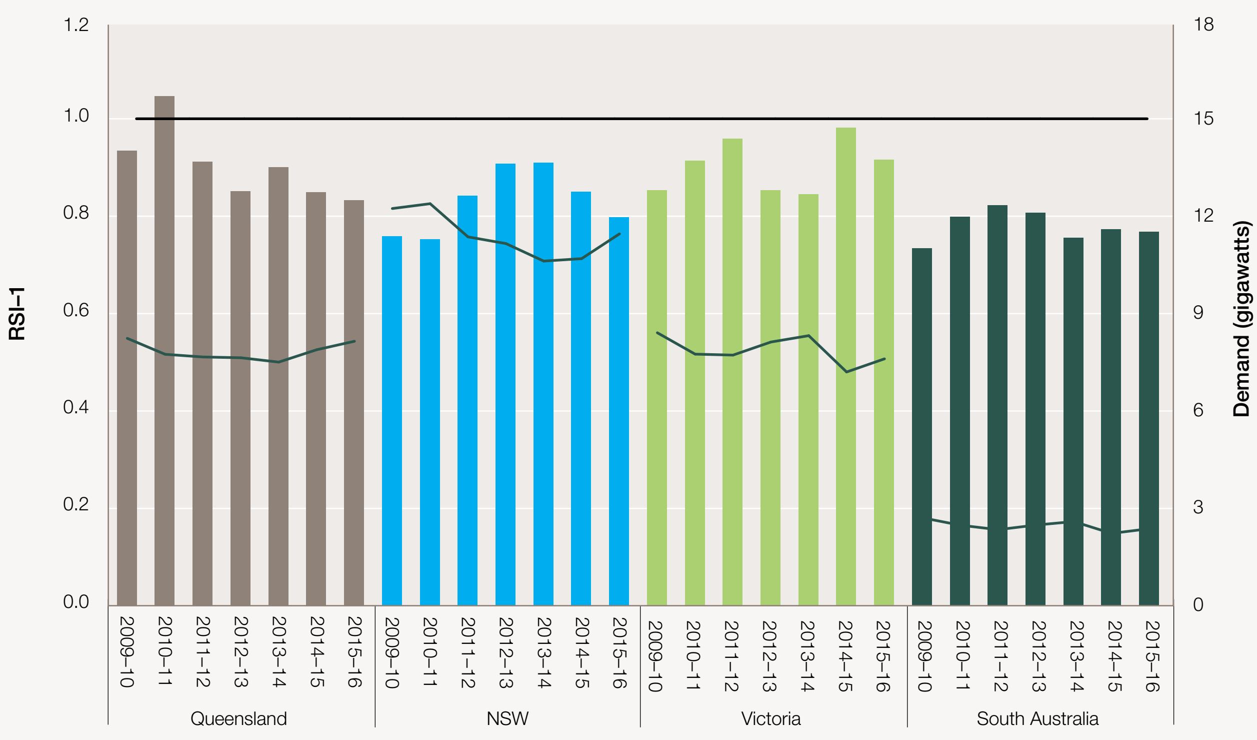
Figure 1.22 tracks the RSI–1 for NEM regions at times of peak demand (the highest 2 per cent of demand trading intervals, which is equivalent to seven days per year). It also tracks average demand at peak times. The data indicates the largest generator must usually be dispatched in *all* NEM regions to meet peak demand, with the most pivotal generator in any region being AGL Energy in South Australia. Further, the largest generator became more pivotal in *every* region in 2015–16, due to a recovery in peak demand, plant closures and changes in plant availability.

In *Victoria*, the HHI and RSI–1 metrics indicate competitive conditions gradually improved until AGL Energy fully acquired Loy Yang A (2210 MW) in 2012, which increased market concentration. This shift was partly offset by Origin Energy's commissioning of the gas powered Mortlake plant (566 MW) in late 2012. A significant fall in peak demand led to AGL Energy becoming less pivotal in 2014–15. But this position reversed in 2015–16 when peak demand rebounded.

For *NSW* and *Queensland*, rising demand across the top 2 per cent of demand periods contributed to deteriorating RSI–1 data over the past three years. The NSW data also reflects an increase in market concentration following the closure of EnergyAustralia's Wallerawang power station in 2014–15.

Figure 1.22

Residual supply index, excluding the largest generator (RSI–1) at times of peak demand



Note: Based on generator availability for the top 5 per cent of trading intervals by demand.

Source: AER.

Behavioural indicators

The structural indicators illustrated in figures 1.20–1.22 point to high levels of market concentration in some NEM regions. But a generator's *ability* to exercise market power is distinct from its *incentives* to exploit that power. A generator's incentives will link to its exposure to spot or contract prices, and to its strategies to deter competition. Behavioural indicators explore the relationship between a generator's bidding behaviour and market outcomes.

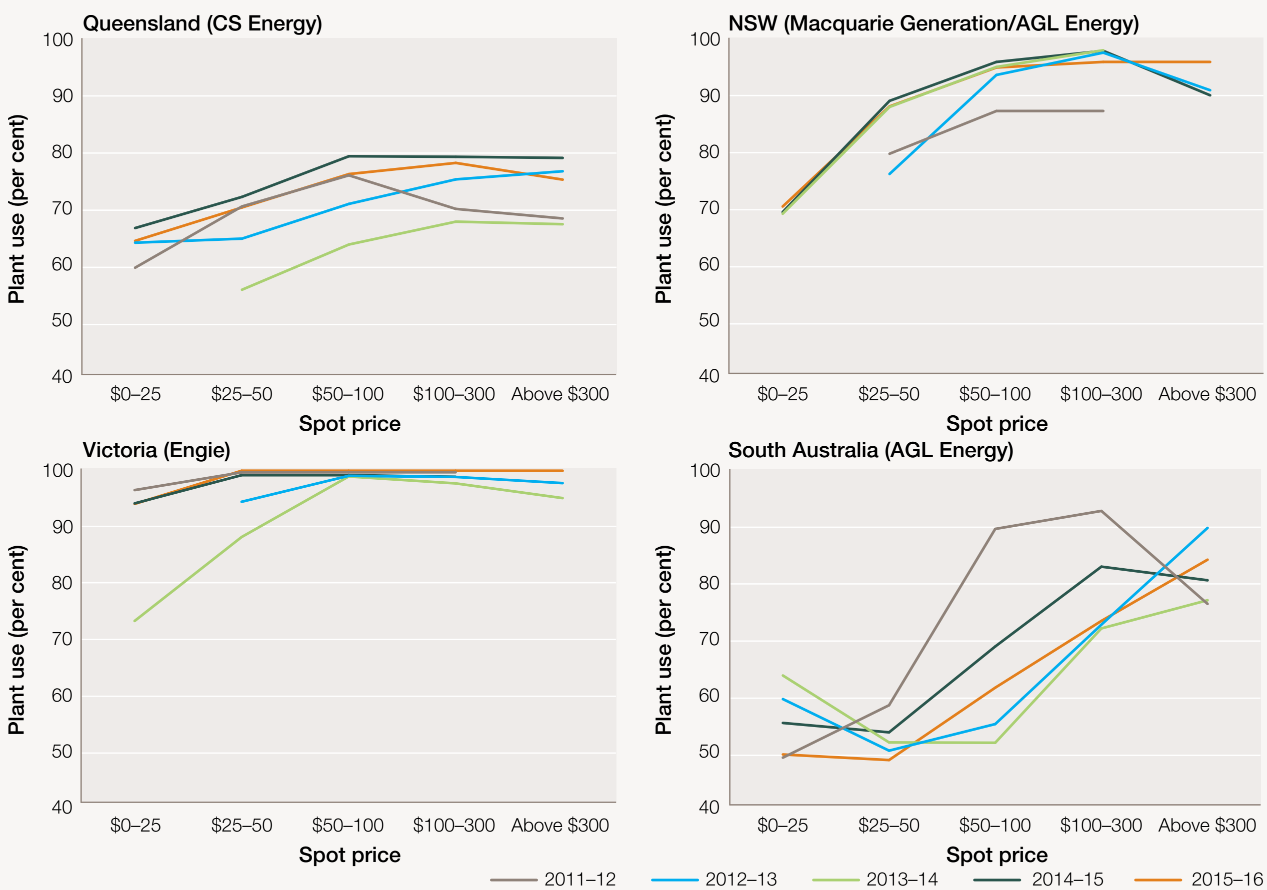
Figure 1.23 illustrates links between wholesale electricity prices and plant capacity use for a sample of large generators: CS Energy in Queensland, AGL Energy in NSW and South Australia, and Engie in Victoria. The data records the share of its available capacity that a generator dispatches in various price bands. In a competitive market, generators typically make greater use of their asset portfolios when prices rise.

As might be expected for a rational business in a competitive market, large generators *do* tend to produce more output as prices rise—at least to around $100 per MWh. But, in each region in the five years to 2015–16, generators sometimes *reduced* their output when prices rose above $100 per MWh.

This behaviour may be explained by deliberate capacity withholding to tighten supply and thus influence prices. Other possible explanations include the inability of some generation plant to respond quickly to sudden price movements, and network congestion that constrains efficient plant dispatch. Additionally, maintenance and outages sometimes reduce a plant's availability to below normal levels.

Figure 1.23

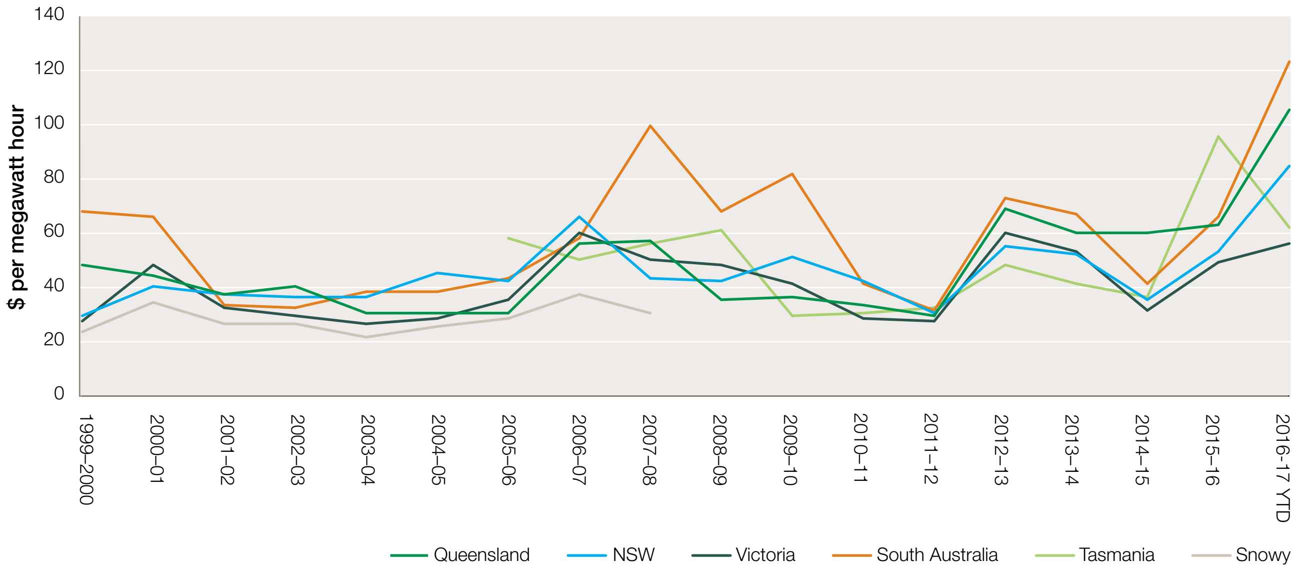
Average annual capacity use by the largest generator in each region



Note: Data is excluded if based on fewer than five observations.

Source: AER.

Figure 1.24
Annual NEM electricity prices



Notes: Volume weighted average prices; 2016–17 data is for the nine months to 31 March 2017.
Sources: AEMO; AER.

1.6 State of the NEM

Wholesale electricity prices rose in every NEM region in 2015–16, with rises around 50–60 per cent in Victoria, NSW and South Australia (figure 1.24 and table 1.7). Tasmanian prices rose by 160 per cent (to a regional record) when a six month outage on the Basslink interconnector to Victoria coincided with depleted dam levels for hydro generation (section 1.9).

Prices continued their upward trajectory on the mainland in the nine months to 31 March 2017, with the steepest rises occurring in South Australia, Queensland and NSW. Against this pattern, Victorian prices held relatively steady over this period, and Tasmanian prices eased off their historical peak of the previous year.

More generally, the market has been extremely volatile since winter 2015, particularly in Queensland, South Australia and Tasmania (figures 1.25 and 1.26). Thirty minute prices exceeded $200 per MWh almost 4000 times in 2015–16, which was an unprecedented number. And another 2100 instances were recorded in the first nine months of 2016–17.

The causes of this volatility are complex and differ between regions (sections 1.7–1.9), although common factors are evident. One common thread is a tightening in the supply–demand balance. In particular, the closure or mothballing of significant coal fired plant has coincided with a resurgence in peak demand, particularly in NSW and Queensland.

These conditions affected the entire market in June 2016, when the closure of Alinta's Northern power station in South Australia, combined with maintenance on other coal plant, caused a 2200 MW reduction in available capacity compared with a year earlier. This reduction in supply meant gas fired generation was setting the dispatch price more often than usual—at a time when gas fuel costs were extremely high.

The market stabilised in most regions in July 2016, but prices remained high in South Australia. In that state, work to upgrade the Heywood interconnector constrained the state's import capacity in a period of low wind generation (section 1.7).

Volatility affected many regions in summer 2016–17, when high temperatures drove up peak demand and contributed to a series of price spikes in Queensland and NSW. Queensland recorded a new record peak demand on 18 January 2017. Infrastructure issues—planned and unplanned generator outages, interconnector outages and network constraints—played a part in several high price events (section 1.8).

The Victorian market has been more stable and has had lower average prices than other NEM regions in the past

Table 1.7 **Annual NEM electricity prices, by region ($ per megawatt hour)**

	QUEENSLAND	NSW	VICTORIA	SOUTH AUSTRALIA	TASMANIA
1999–2000	49	30	28	69	
2000–01	45	41	49	67	
2001–02	38	38	33	34	
2002–03	41	37	30	33	
2003–04	31	37	27	39	
2004–05	31	46	29	39	
2005–06	31	43	36	44	59
2006–07	57	67	61	59	51
2007–08	58	44	51	101	57
2008–09	36	43	49	69	62
2009–10	37	52	42	83	30
2010–11	34	43	29	42	31
2011–12	30	31	28	32	33
2012–13	70	56	61	74	49
2013–14	61	53	54	68	42
2014–15	61	36	32	42	37
2015–16	64	54	50	67	97
2016–17 YTD	108	86	58	128	64

Notes: Volume weighted average prices; 2016–17 data is for the nine months to 31 March 2017.

Sources: AEMO; AER.

three years. But the March 2017 closure of the Hazelwood power station changed the region's supply–demand balance, and futures markets are factoring in significant price rises for 2017–18 (section 1.10).

An emerging theme in 2016–17 was the rising incidence of security issues across the NEM. All of South Australia was blacked out on 28 September 2016 when severe storms brought down transmission lines and caused voltage instability, affecting wind farms and the Heywood interconnector. An insecure operating state also led AEMO to intervene in the market by cutting supply to some South Australian customers on 1 December 2016 and 8 February 2017 (section 1.7).

AEMO intervened in NSW too on one occasion, interrupting some industrial load. In Tasmania, automatic control systems interrupted load on one occasion:

- In NSW, a combination of factors caused load shedding on 10 February 2017. High demand, some plant being unavailable, low renewable output, and import constraints overloaded the interconnectors into NSW, resulting in insufficient generation being available to meet demand. In response, AEMO instructed TransGrid to reduce demand at the Tomago aluminium smelter (290 MW) for one hour, and the NSW Government urged the public to reduce its electricity use.
- In Tasmania, network issues were the main reason for load shedding on 20 December 2016, when outages on two transmission lines resulted in the loss of around 170 MW of load. AEMO found the incorrect operation of protection relays during planned maintenance by TasNetworks caused the power system to be in an insecure operating state for 15 minutes.[32]

These events (particularly the South Australian blackout) triggered urgent policy reviews of the NEM's changing generation mix, including how the shift from coal fired generators to intermittent wind and solar generation is affecting the NEM's security (section 1.7.1).

32 AEMO, *Load shedding in Tasmania on 20 December 2016*, *final report*, 6 April 2017.

Figure 1.25
Weekly spot electricity prices

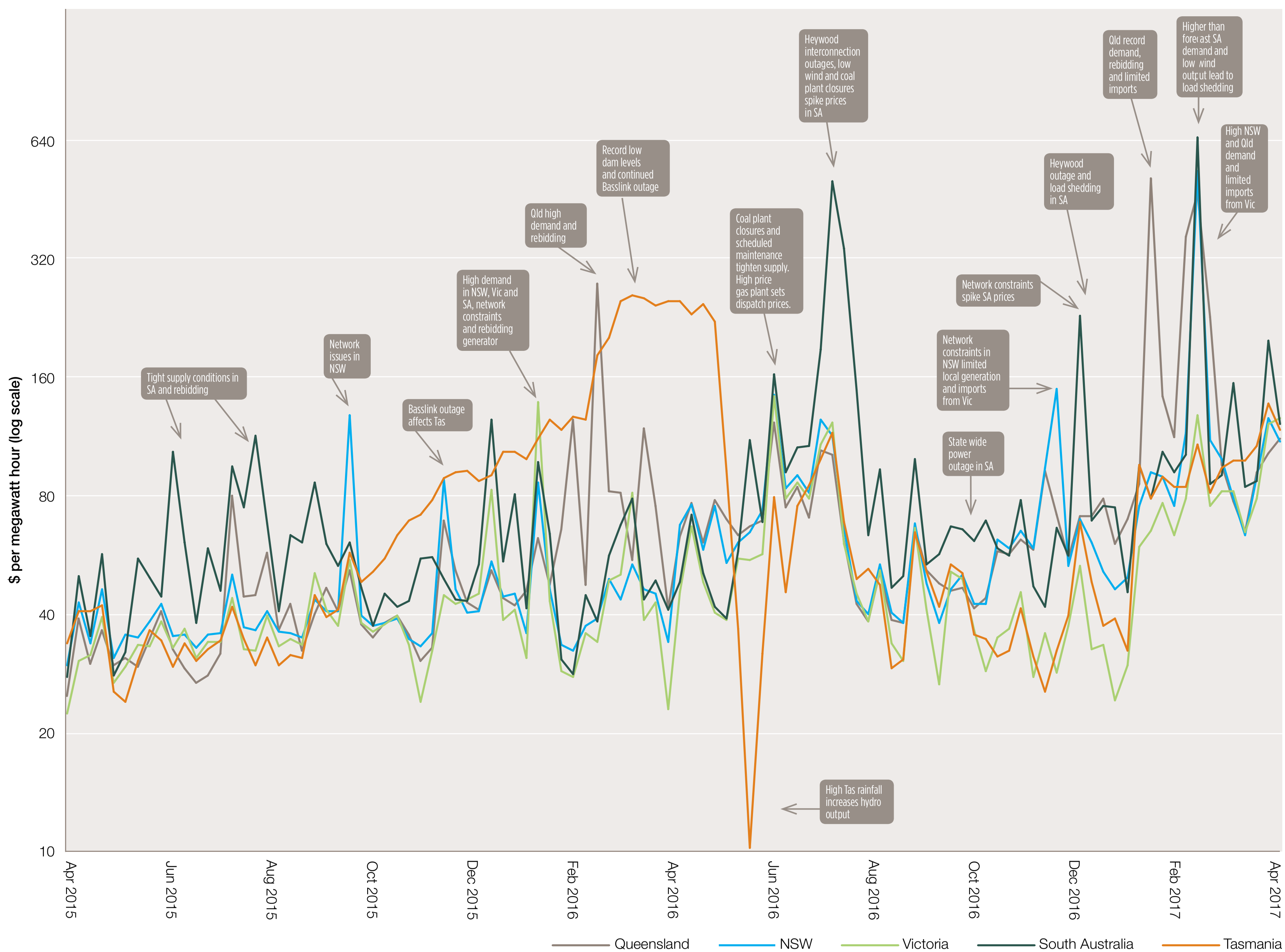
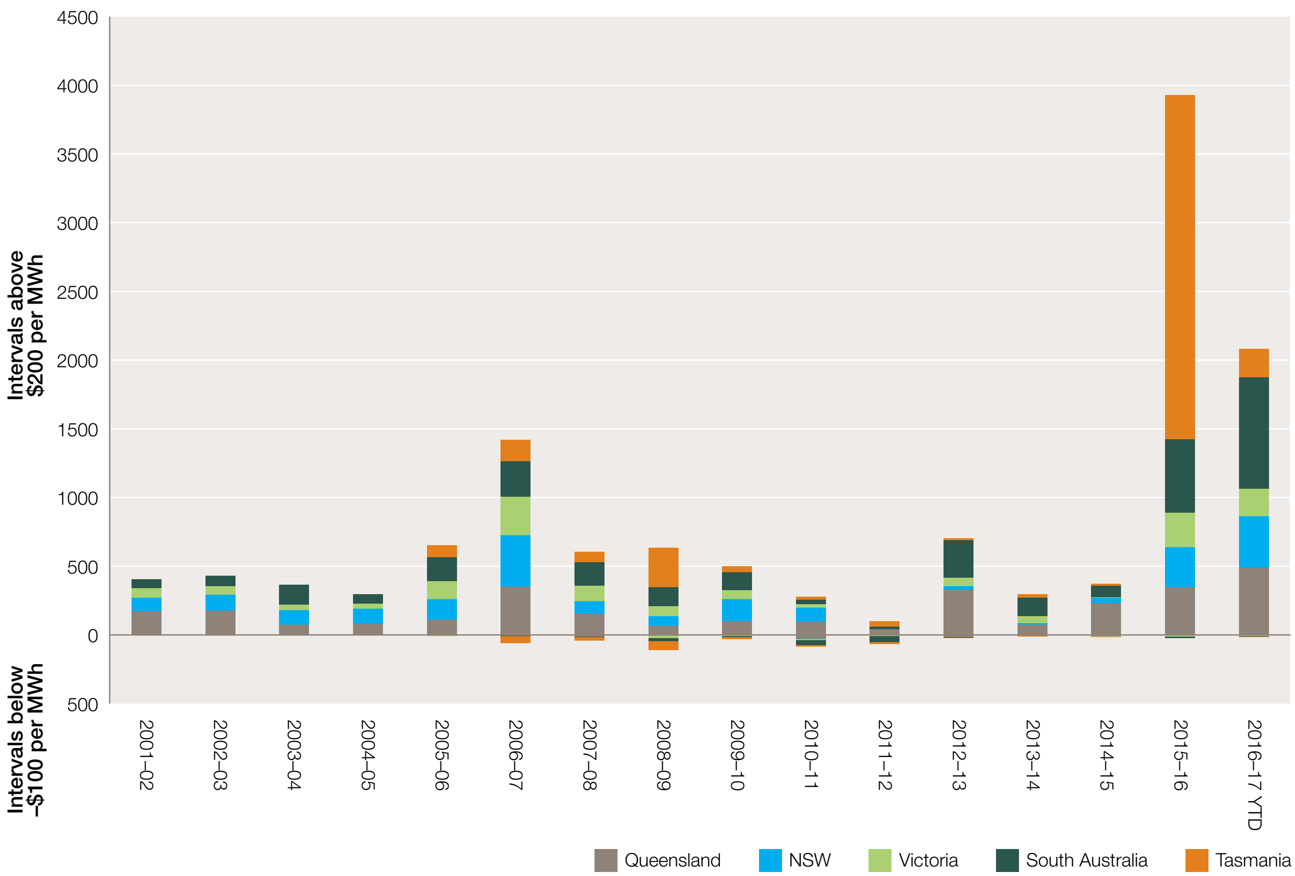


Figure 1.26

Market volatility—prices above $200 per MWh and below –$100 per MWh



Sources: AEMO, AER.

1.7 South Australian market

Wholesale electricity prices tend to be higher and more volatile in South Australia than elsewhere. This price differentiation partly reflects South Australia's historical reliance on gas powered generation, and its higher ratio of peak to average demand (compared with other NEM regions). Other contributing factors are the region's relatively concentrated generator ownership, generator bidding behaviour, thermal plant withdrawals, and limited import capability. South Australia's high levels of wind capacity also contribute to price swings, given wind's intermittent nature.

South Australia's supply–demand balance has progressively tightened since the part mothballing of Engie's Pelican Point plant (249 MW) in April 2015, and Alinta's closure of its Northern power station in May 2016 (546 MW) (figure 2 in Market overview). Transmission outages associated with the Heywood interconnector upgrade contributed, periodcally limiting imports from Victoria.

Volatility spread to South Australia's frequency control ancillary services market in late 2015, following a change in the management of system security issues during the Heywood interconnector upgrade. From October 2015, AEMO required some frequency control ancillary services (FCAS) to be sourced locally whenever a region could credibly be islanded from the rest of the NEM. But the diminished availability of plant in South Australia allows available generators to rebid FCAS capacity into high price bands whenever this risk arises. During the month in which the change was introduced, FCAS prices rose above $5000 per MW several times. This pattern recurred frequently in FCAS markets in 2016 and 2017 (see below).

The South Australian electricity market recorded some volatility in the first six months of 2016, but conditions became acute in winter 2016. A reduced availability of electricity generators caused June prices across all NEM regions to be around 2.5 times long term monthly averages. But, while conditions improved in most regions in July, they deteriorated in South Australia, where monthly prices averaged 4.5 times the long term July average.

The causes were complex and multiple. Import constraints, caused by works on the Heywood interconnector, left the state with a very tight supply–demand balance. Since the closure of the Northern plant, South Australia's generation stock consists primarily of gas and wind plant. But wind generation was low in July 2016, averaging 57 per cent below the historical monthly average. To fill the gap, more gas powered plant than usual was dispatched, and at a time when LNG export demand had driven gas fuel prices to unprecedented levels (chapter 2).

As a result, South Australian prices diverged materially from other regions for around 60 per cent of the time in July 2016, with gas plant typically setting the spot price at these times. Many prices settled above $500 per MWh, and three prices exceeded $5000 per MWh.

South Australia continued to experience several bouts of market volatility and extreme prices in 2016–17. In the nine months to 31 March 2017, its weekly prices averaged $128 per MWh, which was an unprecedented level for the NEM (table 1.7). South Australia also experienced security issues over the period, including load shedding and blackouts.

On 28 September 2016, the entire state was blacked out for several hours when severe storms brought down three transmission lines, creating voltage instability that tripped off (shut down) the operating systems on 400 MW of wind generation and the Heywood interconnector to Victoria. AEMO classified the event as 'non-credible' (meaning it could not have been reasonably anticipated). It suspended the market in South Australia and applied administered pricing arrangements from 28 September to 11 October.

AEMO then acted to ensure system limitations for wind turbines are appropriately managed. But it 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.[33]

On 1 December 2016, the market experienced disruption soon after midnight, when a fault on one of the Heywood interconnector's two lines occurred during maintenance on the other line, leaving South Australia islanded from the NEM. Prices spiked above $5000 per MWh for three trading intervals. Additionally, 230 MW of South Australian customer load was interrupted for 90 minutes, along with 473 MW of load to the Portland aluminium smelter in Victoria. AEMO instructed BHP Billiton to reduce its load by 100 MW for the period of the outage, to protect system security in South Australia.

A fourth extreme price event occurred on the same day when network constraints and a change in output at Origin Energy's Mortlake plant in Victoria forced the Heywood interconnector to operate counter price, compelling South Australia to boost local generation (despite high local prices) and export it to Victoria to protect power system security.

On 8 February 2017, another four hours of prices above $5000 per MWh occurred during a heatwave, when 42 degree temperatures fueled above forecast demand at a time when wind generation was below forecast. And, some thermal plant was unexpectedly offline (due to the hot weather and technical faults), further tightening the supply–demand balance. In response, South Australia imported its local supply shortfall, causing the interconnectors to breach their secure operating limits.

To manage the risk of the interconnectors tripping, AEMO sought advice on additional local generation. Engie advised at 6 pm that its mothballed gas unit at Pelican Point could be fully operational by 7.45 pm. AEMO determined this option was not viable, and ordered 100 MW of customer load to be shed. But SA Power Networks erroneously cut supply to 90 000 homes instead of the required 30 000, shedding a total of 300 MW of load.[34]

On 3 March 2017, three faults in ElectraNet's transmission network (at the Torrens Island switchyard) caused the loss of 610 MW of South Australian generation. While AEMO did not instruct load shedding, a 400 MW drop in rooftop PV generation occurred as systems shut off in response to voltage disturbances. The power system in South Australia operated in an insecure state for 40 minutes.

AEMO noted the 3 March 2017 event was similar to the system blackout on 28 September 2016, in that a large and sudden reduction in local generation caused power flows across the Heywood interconnector to exceed normal operating limits. Voltage levels were not as low as on 28 September 2016; if they had been, another system blackout might have occurred. All wind farms successfully rode through the transmission faults, indicating the protection system changes made after 28 September 2016 were successful.[35]

33 AEMO, *Black system South Australia 28 September 2016*, *final report*, March 2017, p. 7.

34 AEMO, *System event report: South Australia*, 8 February 2017.

35 AEMO, *Fault at Torrens Island switchyard and loss of multiple generating units on 3 March 2017*, Incident report.

South Australia's FCAS market was also volatile in 2016–17, with network outages obliging AEMO to source regulation services locally on several occasions from August 2016 to January 2017. These interventions triggered a change in bidding behaviour by local generators, causing prices to spike. Prices reached the cap on two occasions, causing AEMO to administer prices in the market.

1.7.1 Policy responses

South Australia's ongoing market volatility, and the system blackout in particular, triggered urgent policy reviews of the NEM's changing generation mix. The review areas included the efficient integration of renewable generation.

The CoAG Energy Council in October 2016 commissioned an expert panel led by Dr Alan Finkel to explore options for delivering secure, reliable and affordable energy supplies while meeting Australia's international emissions reduction commitments. The panel's December 2016 report noted the shift from coal fired generators to intermittent wind and solar generation is affecting the NEM's security and reliability. This shift is more advanced in South Australia than other NEM regions.

Unlike thermal plant, wind and solar PV installations do not inherently provide rotational inertia that can support power system security. So, these technologies have generally not contributed to frequency and other ancillary services needed to maintain a secure and reliable power system. Dr Finkel's report noted a number of technologies could help integrate renewables into the grid, such as intelligent wind turbine controllers, batteries and synchronous condensers. But it considered that markets for ancillary services to maintain system security have not kept pace with the transition. New and updated frameworks, technical standards and rules may be required.[36]

The report also noted the importance of open cycle gas fired generators to complement renewables. But it found, for Australia to rely on gas plant, we urgently need access to increased gas supplies for electricity generation. More generally, it noted the need for a coherent national approach to address Australia's emissions reduction commitments in the electricity sector, to support efficient generation investment.

Alongside this process, the AEMC is reviewing the rules governing the NEM to ensure the drive towards non-synchronous technologies (such as wind farms and solar panels) does not threaten system security. The review focuses on the management of frequency and system strength in a power system with diminishing synchronous generation. The AEMC published proposals in March 2017 on mechanisms to procure new frequency management services.[37]

The South Australian Government in March 2017 announced measures to safeguard the state's energy security, including the construction of a 250 MW gas powered generator to provide emergency back-up power and system stability services; incentives for increased gas production; and investment in large scale battery storage.[38] Further, on 29 March 2017, Engie announced its mothballed capacity at Pelican Point would return to service by 1 July 2017. The generator has secured a gas supply agreement with Origin Energy to provide gas to Pelican Point. The return to service will add 240 MW of capacity to the South Australian market.[39]

1.8 Queensland market

Opportunistic bidding by large generators has caused periods of spot market volatility in Queensland for several years, typically during summer.[40] In summer 2014–15, for example, generators periodically rebid large volumes of capacity from low to very high prices late in a trading interval, typically on days of high energy demand and when import capability on transmission interconnectors was constrained. By rebidding late in a trading interval, other generators lacked time to respond by ramping up their output. Given the settlement price is the average of the six dispatch prices forming a trading interval, a price spike in just one dispatch interval can flow through to very high 30 minute settlement prices.

Similar patterns occurred in the Queensland market in summer 2015–16. Generators rebid capacity into high price bands on days when hot weather drove very high demand, typically when import capacity across the interconnectors to NSW was constrained. In some instances, network limitations forced counter price export flows—that is, Queensland exported power to NSW when its own capacity was stretched and its prices were high.

36 Dr Alan Finkel AO (Chair of the Expert Panel), *Independent Review into the Future Security of the National Electricity Market, preliminary report*, December 2016.

37 AEMC, *System Security Market Frameworks Review, directions paper*, 23 March 2017.

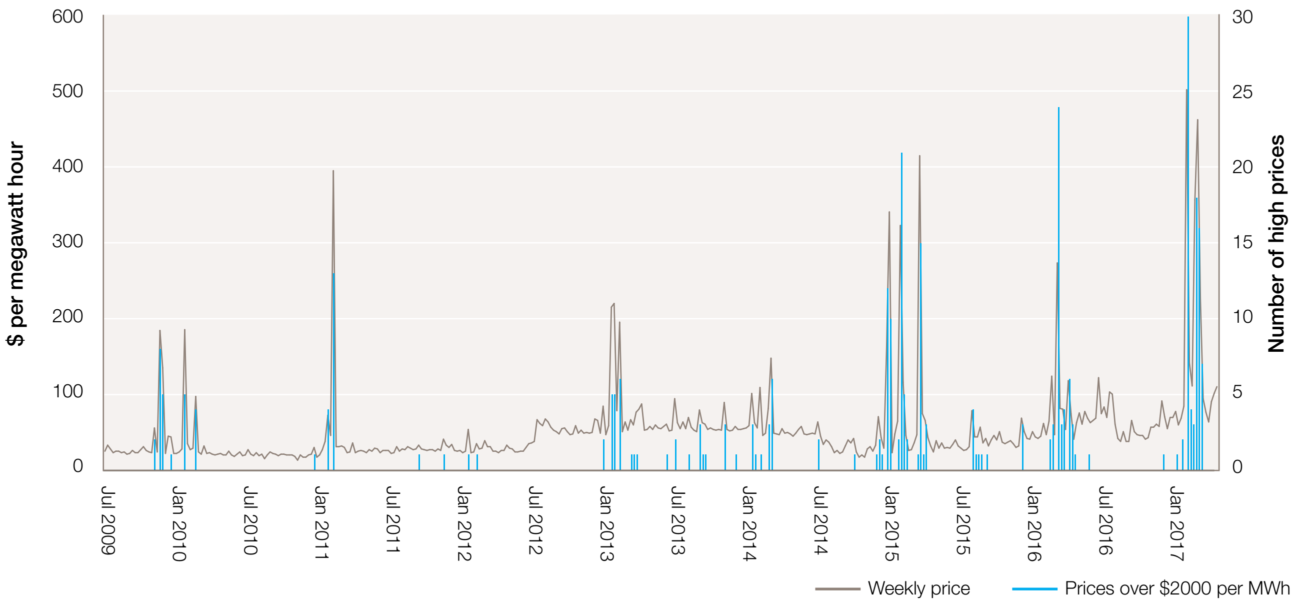
38 Jay Weatherill (Premier of SA), 'South Australia is taking charge of its energy future', Media release, 14 March, 2017.

39 Engie, 'Pelican Point to return to full capacity', Media release, 29 March 2017.

40 See, for example, AER, *State of the energy market 2013*, pp. 39–42; *State of the energy market 2014*, pp. 48–9, *State of the energy market 2015*, pp. 48–50.

Figure 1.27

Weekly prices, and count of prices above $2000 per MWh in Queensland



Note: Volume weighted average prices.

Source: AER.

Queensland recorded persistently high prices over January and February 2017. The events were intensified by peak demand rising to record levels (on 18 January 2017). The region also recorded its highest average weekly price in six years, for the week to 14 January 2017 (when 14 settlement prices exceeded $5000 per MWh). More generally, the frequency of high Queensland prices has increased significantly since summer 2014–15 (figure 1.27). These events are reflected in Queensland's wholesale prices averaging $108 per MWh in the nine months to 31 March 2017, which is an unprecedented average for the region (table 1.7).

1.8.1 Policy responses

Opportunistic bidding by large generators can be profitable because dispatch and settlement prices are determined over different timeframes—that is, the 30 minute settlement price is the *average* of six of the five minute dispatch prices.

The AEMC was considering a rule change proposal in 2017 to align the timeframes for dispatch and settlement prices to five minutes. It considered the change to a more granular price signal would encourage more efficient bidding and operational decisions. Under the existing 30 minute settlement arrangements, the responses of generation and load to a price signal can be delayed by up to 25 minutes after the physical electricity system needs a response.

But a shift to five minute settlement would also pose costs, affecting IT systems, metering infrastructure, and financial contract markets that refer to 30 minute settlement. The AEMC expects to publish a draft determination on the rule change in July 2017, and a final determination in September 2017.[41]

In 2015–16, the AER engaged closely with wider rule change processes focusing on the integrity of bidding behaviour in the NEM. The reforms, relating to bidding in good faith[42] and generator ramp rates,[43] came into effect in July 2016.

The rebidding reforms strengthen the requirement for generators to have genuine intent to honour their bids. To do so, they:

- prohibit offers, bids and rebids that are false, misleading or likely to mislead

41 AEMC, *Five minute settlement*, Information sheet–directions paper, 11 April 2017.

42 AEMC, *Final rule determination, National Electricity Amendment (Bidding in Good Faith) Rule 2015*, 10 December 2015.

43 AEMC, *Generator ramp rates and dispatch inflexibility in bidding,* March 2015.

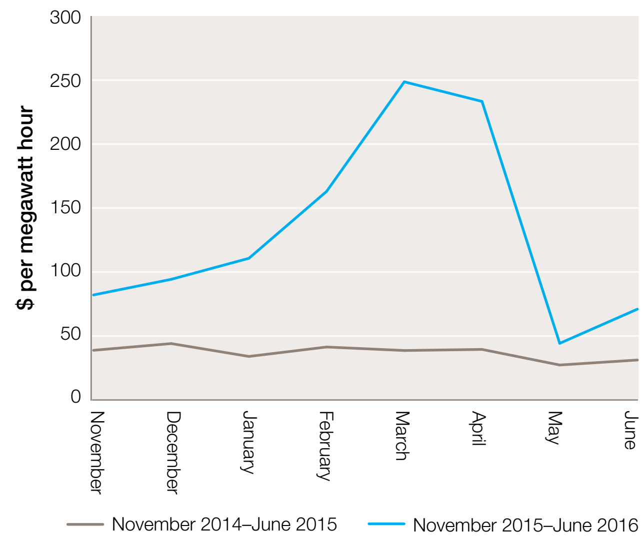
- require rebids to be made as soon as practicable after a generator or market participant becomes aware of the changed material conditions or circumstances that prompted the rebid
- require participants to maintain a contemporaneous record of the circumstances surrounding late rebids.

The ramp rate reforms apply existing ramp rate limits to individual physical units that make up aggregated generation facilities. In doing so, they effectively raise the minimum aggregate ramp rate capability across the NEM by around 30 per cent.

The AER in 2016 revised its *Rebidding and technical parameter guidelines* to reflect the new rules. The guidelines set out the information that must be provided to AEMO to support a rebid of capacity, and bids or rebids of technical parameters. They also explain how the AER requests additional information from generators on their bidding behaviour.

Figure 1.28

Year-on-year price comparison for Tasmania



Sources: AEMO; AER.

1.9 Tasmanian market

Wholesale electricity prices in Tasmania averaged $97 per MWh in 2015–16, which was the highest average recorded for the state, and the second highest average recorded in the NEM to that time. Two key factors accounted for this outcome—extended drought conditions (which limited dam storage needed for hydro generation) and a six month outage on the Basslink interconnector to the mainland.

Tasmania experienced unprecedented drought conditions with record low dam inflows from September 2015 to April 2016. The onset of drought coincided with already low dam levels due to Hydro Tasmania's decision to raise output in 2012–13 and 2013–14 when carbon pricing made hydrogeneration more profitable.

By December 2015, Tasmania was importing up to 40 per cent of its energy needs from Victoria.[44] But, on 20 December 2015, a major fault on the Basslink interconnector curtailed all trade between Tasmania and the mainland. Difficulties in identifying the fault's location and undertaking repair work meant the interconnector remained out of service until 13 June 2016.

With Tasmania islanded from the NEM for the duration of the outage, it was forced to rely on local generation. To supplement hydro generation, Hydro Tasmania returned its Tamar Valley gas combined cycle plant (208 MW) to service on 20 January 2016. This plant had been closed since June 2014. Hydro Tasmania added 200 MW of capacity by installing containerised diesel generators, with the first units operating from March 2016.

Hydro Tasmania also implemented demand-side measures. It entered voluntary agreements with three major industrial customers—Bell Bay Aluminium's and TEMCO's smelters in the Tamar Valley, and Norske Skog's paper mill at Boyer—to reduce their load by a combined 180 MW.

The generation constraints saw most hydro output offered into the market at high prices. The average monthly price of output during the Basslink outage ranged from around $110 per MWh in January 2016, to over $250 per MWh in March 2016. These averages compared to prices of around $40 per MWh in the corresponding period in 2015 (figure 1.28).

Even with hydro plant constrained, Tasmania's dam storages fell to a low of 13 per cent in April 2016. But sustained rainfall in May and June 2016 abruptly returned dam storages to normal levels, causing prices to ease sharply. In the nine months to 31 March 2017, Tasmania's average spot price was the lowest for any NEM region.

1.9.1 Policy responses

The Tasmanian Energy Security Taskforce found the Basslink outage posed the most significant energy security risk to Tasmania in half a century. It recommended

44 Hydro Tasmania, *Annual report 2016*.

Tasmania develop a more rigorous framework to manage water storages, and retain the Tamar Valley gas powered generator as a back-up power station.[45]

AEMO reported in December 2016 that a second Bass Strait interconnector would provide $48 million in market benefits by increasing the transmission network's resilience to potential interconnector failures.[46]

1.10 Electricity contract markets

Volatile wholesale electricity prices can pose significant risks to market participants. While merchant generators risk having low prices reduce their earnings, retailers risk having to pay high prices that they cannot pass on to their customers. Market participants need to manage their exposure to these risks to ensure their financial solvency. Failure to do so can result in market failure. Two energy retailers recently went into administration—GoEnergy in 2016 and Urth Energy in 2017 (section 4.12)—following financial difficulties associated with exposure to high wholesale prices.

Generators and retailers can manage their market exposure by entering hedge contracts (derivatives) that lock in firm prices for the electricity that they intend to sell or buy in the future. Other participants merge generation with energy retailing, to balance out the risks across each market. Vertically integrated 'gentailers' in the NEM include AGL Energy, Origin Energy, EnergyAustralia, Snowy Hydro (with retail brands Red Energy and Lumo Energy), Engie (with the retail brand Simply Energy) and Hydro Tasmania (with the retail brand Momentum).

Typically, gentailers are imperfectly hedged; their position in generation may be 'short' or 'long' relative to their position in retail. For this reason, the businesses also participate in derivatives markets to manage outstanding exposures. Other participants in electricity derivatives markets include financial intermediaries and speculators such as hedge funds. Brokers facilitate many transactions between contracting participants in these markets.

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

- over-the-counter (OTC) markets, in which counterparties 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—including generators, retailers, speculators, banks and other financial intermediaries—buy and sell futures contracts.

Exchange trades are publicly reported, so they have greater market transparency than do OTC contracts, which are confidential between the parties. The Australian Financial Markets Association (AFMA) previously reported data on OTC markets through voluntary surveys of market participants. AFMA discontinued the surveys in 2015–16, citing difficulties with the survey method.[47]

A range of products are traded in electricity derivatives markets. The ASX products are standardised to promote trading, while OTC products can be sculpted to suit the requirements of the counterparties:

- Futures (swaps or contracts for difference in OTC markets) allow a party to lock in a fixed price to buy or sell a given quantity of electricity over a specified time. Each contract relates to a nominated time of day in a particular region. The products include quarterly base contracts (covering all trading intervals) and peak contracts (covering specified times of generally high energy demand) for settlement in the future. Futures are also traded as calendar or financial year strips covering four quarters.
- Options give the holder the right—without obligation—to enter a contract at an agreed price, volume and term in the future. The buyer pays a premium for this added flexibility.

Caps (which set an upper limit on the price that the holder will pay for electricity in the future) and floors (which set a lower price limit) are traded as both futures and options.

Exchange traded derivatives are settled through a centralised clearing house, which is the counterparty to all transactions and requires daily market-to-market 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 via block trading on the ASX.

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

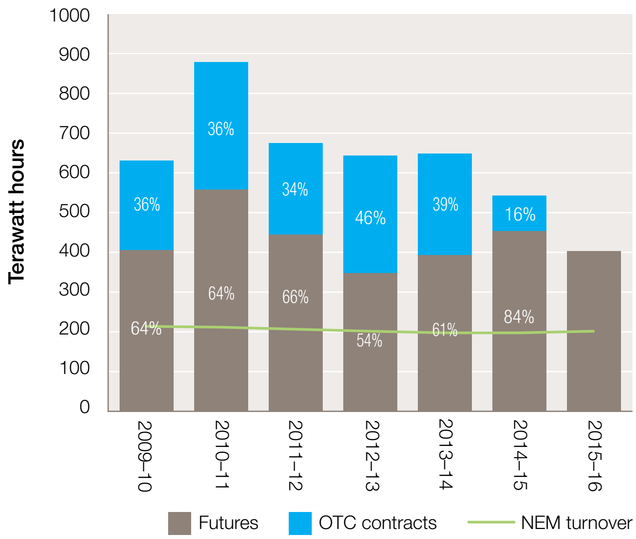
1.10.1 Contract market activity

In 2015–16 contracts covering 396 TWh of electricity were traded on the ASX, equivalent to 200 per cent of

45 Tasmanian Energy Security Taskforce, *Interim report*, 21 December 2016.
46 AEMO, *National transmission network development plan*, December 2016, pp. 31–2.
47 AFMA, *2016 Australian financial markets report.*

Figure 1.29

Traded volumes in electricity futures contracts

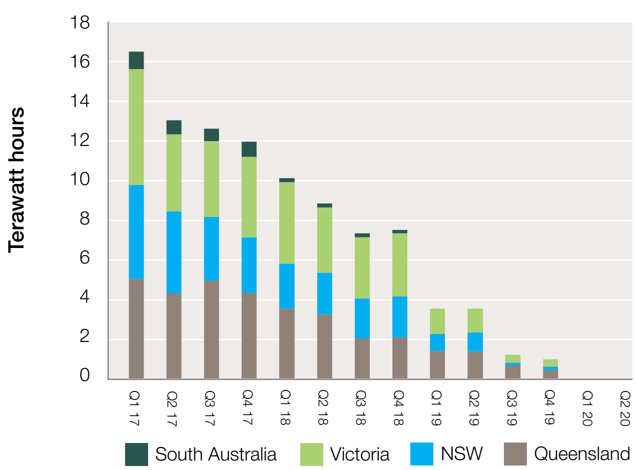


Note: AFMA stopped publishing OTC contract volumes in 2015–16.

Sources: AER, ASX Energy.

Figure 1.30

Open interest in electricity derivatives on the ASX, March 2017



Sources: AER, ASX Energy.

underlying NEM demand. Volumes were down from a peak of 260 per cent of underlying NEM demand in 2010–11 (figure 1.29). Activity switched from ASX to OTC markets during the period of carbon pricing (2012–14), when participants sought greater contract flexibility. But then volumes recovered in ASX trading after carbon pricing was repealed in July 2014.

Electricity futures cover instruments for Victoria, NSW, Queensland and South Australia. Victoria accounted for 36 per cent of ASX traded volumes in 2015–16, followed by Queensland (33 per cent) and NSW (30 per cent). Liquidity in South Australia was low, accounting for only 1 per cent of overall volume.[48]

The most heavily traded ASX products in 2015–16 were baseload quarterly futures (55 per cent of traded volume), followed by options (25 per cent) and cap futures (13 per cent).

Liquidity is mostly in products traded 12–24 months out. Open interest at March 2017 was mostly for contracts out to the March quarter 2018, with liquidity rapidly tailing off beyond December 2018 (figure 1.30).

1.10.2 Contract prices

Figure 1.31 tracks price movements for electricity base futures for calendar years 2017 and 2018. It shows average spot prices for 2016 as a reference point.

Base futures prices rose steadily throughout 2016, indicating a clear expectation that spot prices in the NEM would rise. In January 2017, contracts for the coming year were trading at levels above 2016 spot prices in all regions. The highest premiums were for Victoria (44 per cent) and South Australia (41 per cent), with sizable premiums also for NSW (23 per cent) and Queensland (21 per cent).

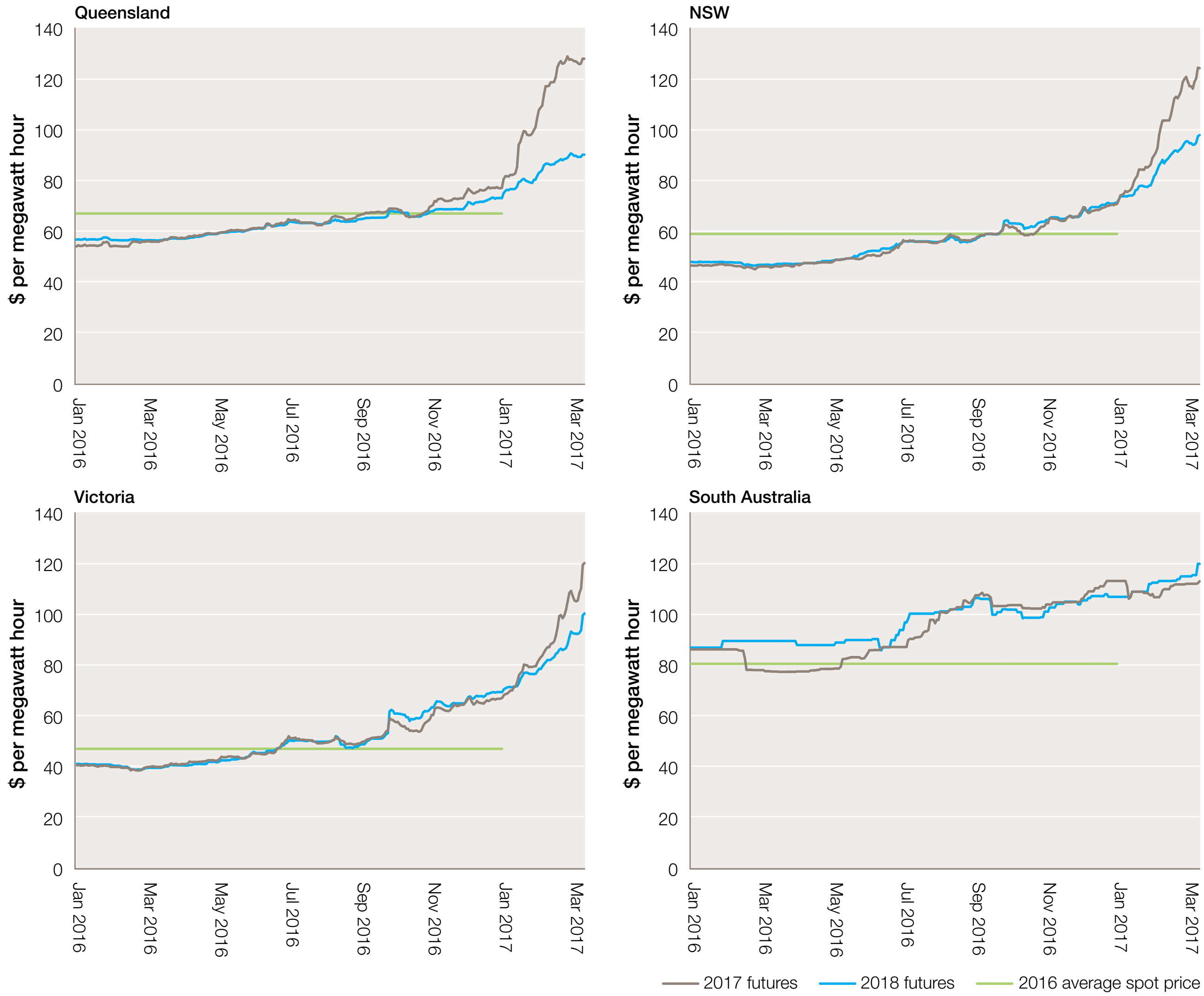
The upward trend accelerated in most regions during summer 2016–17, coinciding with high spot prices in the NEM. In the first 10 weeks of 2017, prices for NSW and Victorian 2017 calendar futures rose by over 70 per cent, almost tripling the prices of those contracts at January 2016. Queensland prices rose by 60 per cent over the same period. By contrast, in South Australia, contract prices trended only slightly higher. This outcome might reflect the very low levels of liquidity for South Australian electricity derivatives, making price trends difficult to interpret.

The escalation in futures prices coincided with high summer spot electricity prices and concerns about the ongoing availability of sufficient gas for the domestic market.

48 AFMA, *2016 Australian financial markets report*.

Figure 1.31

Electricity base futures prices



Sources: AER, ASX Energy.

AEMO in 2017, for example, published forecasts that insufficient gas may be available to meet gas powered generation needs in the summer of 2018–19.[49] The rise in prices may also reflect participants factoring in the imminent closure of the Hazelwood power station in March 2017.

But the upward trend in prices is sharper for 2017 than 2018 futures, perhaps indicating market expectations that solutions to gas supply and generation adequacy issues may be in train by 2018.

Prices for first quarter base futures indicate the market is factoring in a tighter supply–demand balance for the 2017–18 summer in Victoria and South Australia than for 2016–17. In Queensland and NSW, prices are expected to moderate from 2016–17 levels. Beyond 2018, NEM prices are expected to soften to around $80–90 per MWh by the first quarter of 2020—still significantly above historical prices for most regions.

49 AEMO, *Gas statement of opportunities*, March 2017.

Image courtesy of Santos

2 GAS MARKETS IN EASTERN AUSTRALIA


L N G

The main forms of gas produced in Australia are *conventional* gas and *coal seam* gas (CSG). Conventional gas is found trapped in underground reservoirs, often along with oil, while CSG is extracted from coal beds. Advancements in extraction techniques have improved the commercial prospects for a third form of gas: unconventional gas, which includes shale and tight gas.[1]

Gas production in eastern Australia commenced just under 50 years ago in Victoria's offshore basins, the Cooper Basin in South Australia, and the Surat–Bowen Basin in Queensland. Unlike electricity, the consumption of gas can often be substituted with other sources of energy. Relatively low cost supplies from the above basins encouraged the adoption of gas among residential, commercial and industrial customers, who valued its clean burning properties. Gas consumption later expanded into the power generation market, because gas's rapid responsiveness makes it an ideal fuel for peaking electricity generation and combined cycle baseload generation.[2] Gas powered generation thus has accounted for almost half of all generation investment since the start of the National Electricity Market (NEM).

Gas prices in eastern Australia were traditionally low, reflecting the efficiencies of gas production as a byproduct of oil production. And, with gas perceived as a substitute for coal and coal fired electricity generation, Australia's low cost coal sources effectively capped gas prices.

But recently, the development of Queensland's liquefied natural gas (LNG) industry linked the eastern Australian gas market to international markets, and domestic prices have aligned more closely with international oil and gas prices. This trend has affected domestic gas demand, which also competes with alternative fuel technologies. In electricity generation, for example, the growth in intermittent renewables has meant that gas has become more important for providing energy to meet fluctuations in supply, but less important as a fuel for providing baseload power.

2.1 Gas supply chain

The supply of gas to energy customers involves several steps (see infographic 2 of this report). It begins with the exploration and appraisal of potential reserves for commercial viability. Gas is then extracted through wells and processed to separate methane from impurities (such as nitrogen, carbon dioxide and sulphur dioxide), and to remove and treat any water. In some fields, gas production is associated with petroleum products such as crude oil, condensate (light oils) and gas liquids (ethane, propane, butane, isobutane and pentane).

A majority of gas produced in eastern Australia is exported as LNG to overseas markets, mainly in Asia (section 2.4.2). The remaining 42 per cent is sold domestically, for use in power generation and industrial processes, and by households. The gas is transported from producing basins through high pressure transmission pipelines to demand centres in cities and regional areas. Many large industrial gas users draw their gas directly from points along the transmission networks.

At demand centres, transmission pipelines connect to lower pressure distribution networks, which then transport gas to residential and business customers. Energy retailers act as market intermediaries by buying gas from producers and packaging it with pipeline services for sale to residential, commercial and small industrial customers.

Storage facilities (often underground depleted gas fields or LNG tanks) are typically located close to demand or production centres, and they help manage variations in gas production. In particular, they can store surplus production and later draw on it to augment supply in times of peak demand.

This chapter covers wholesale gas markets and the gas transmission pipeline sector in eastern Australia. Other segments of the supply chain are addressed elsewhere in this report. Chapter 3 covers regulated gas pipelines and networks (mostly distribution networks), while chapter 4 covers gas retailing.

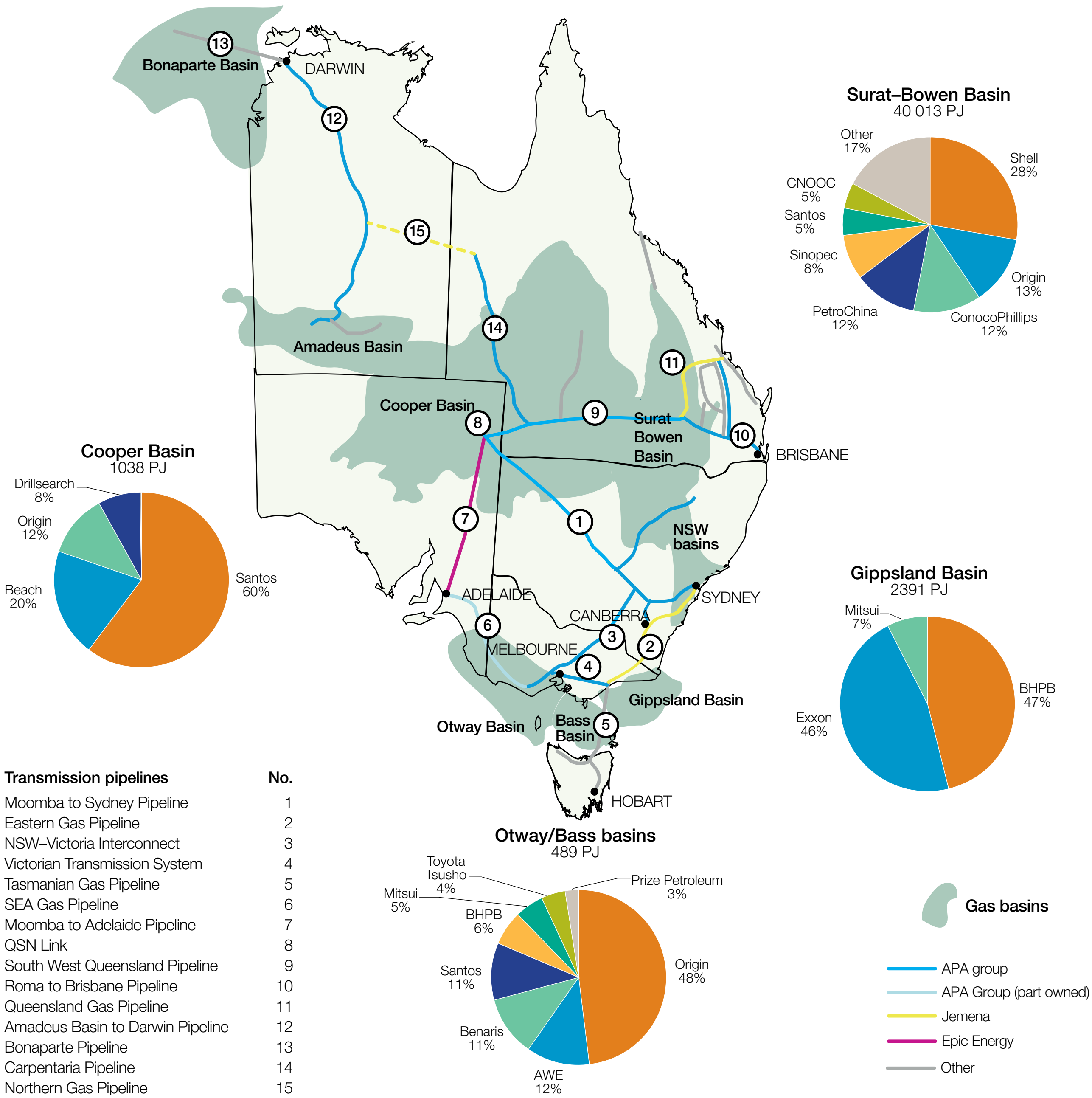
2.2 Australia's gas markets

Australia has three distinct regional gas markets. The *eastern gas market* (the subject of this chapter) encompasses Queensland, NSW, Victoria, South Australia, Tasmania and the ACT. It is interconnected by a network of transmission pipelines, and mostly sources gas from the Surat–Bowen, Cooper, Gippsland and Otway basins. It became linked to global oil and gas markets when LNG exports began in 2015. Figure 2.1 illustrates the market's gas basins and transmission pipelines, along with ownership arrangements. The Australian Energy Regulator (AER) has regulatory responsibilities in the eastern market, in both the wholesale and retail sectors. It is also the gas pipeline regulator (box 2.1).

1 Shale gas is contained within organic-rich rocks such as shale and fine grained carbonates, rather than in underground reservoirs. The application of horizontal drilling techniques in the past five years is enhancing the economic viability of shale gas development. Tight gas is found in low porosity sandstone and carbonate reservoirs.

2 Office of the Chief Economist, Department of Industry, Innovation and Science (Australian Government), *Gas market report 2015*, February 2016, available at www.industry.gov.au/oce, pp. 27–8.

Figure 2.1
Eastern gas market—basins and transmission pipelines



Transmission pipelines	No.
Moomba to Sydney Pipeline	1
Eastern Gas Pipeline	2
NSW–Victoria Interconnect	3
Victorian Transmission System	4
Tasmanian Gas Pipeline	5
SEA Gas Pipeline	6
Moomba to Adelaide Pipeline	7
QSN Link	8
South West Queensland Pipeline	9
Roma to Brisbane Pipeline	10
Queensland Gas Pipeline	11
Amadeus Basin to Darwin Pipeline	12
Bonaparte Pipeline	13
Carpentaria Pipeline	14
Northern Gas Pipeline	15

Note: Pie charts illustrate market shares in 2P (proved plus probable) gas reserves for each basin. Not all major transmission pipelines are shown. Table 2.3 and figure 2.7 provide further detail.

Source: AER.

Box 2.1 The AER's role in gas markets

The AER has regulatory responsibilities across the entire gas supply chain in eastern Australia. At the *wholesale* level, we monitor gas spot markets in Adelaide, Sydney, Brisbane and Victoria; gas supply hubs at Wallumbilla (Queensland) and Moomba (South Australia); and activity on the Gas Bulletin Board. We monitor the markets to ensure participants comply with the legislation and rules, and we take enforcement action when necessary. Our compliance and enforcement work aims to strengthen data quality and promote confidence in gas markets, to encourage market participation and efficient prices. Our quarterly compliance reports provide regular updates on this work.

We report weekly on prices and trade in all gas spot markets, with more detailed reporting on significant price events. We also monitor for irregularities and wider market inefficiencies. Our monitoring role at the Wallumbilla and Moomba hubs includes an explicit focus on detecting price manipulation.

We are the *gas pipeline* regulator for covered pipelines in eastern Australia and the Northern Territory. Only a handful of gas transmission pipelines are under full economic regulation, whereby pipeline charges are independently vetted. Most gas distribution networks remain fully regulated (chapter 3).

In *gas retail*, we are the regulator in jurisdictions that have passed the National Energy Retail Law—namely, NSW, Queensland, South Australia and the ACT. The AER undertakes wide ranging responsibilities in these markets, but we do not set retail prices (chapter 4).

Across the gas supply chain, we draw on our regulatory and monitoring work to advise the Council of Australian Governments' (CoAG) Energy Council, the Australian Energy Market Commission (AEMC), AEMO and other stakeholders on market trends, policy issues and irregularities. When appropriate, we propose or participate in reforms to improve the market's operation.

The *Northern Territory gas market* is supplied by the Amadeus and Bonaparte basins. The Bonaparte Basin in the Timor Sea produces LNG for export, and it has displaced the Amadeus Basin as the territory's main source of gas. The AER is the gas pipeline regulator for the Northern Territory (chapter 3), but has no wholesale market responsibilities there.

The *Western Australian gas market* is supplied by the Carnarvon and Perth basins. The Carnarvon Basin supplies both the local domestic market and LNG exports. Chevron, Shell, ExxonMobil and Woodside are among the major companies with equity in the basin. The AER has no regulatory responsibilities in Western Australia. Rather, the Economic Regulation Authority (ERA) is the economic regulator for gas markets and pipelines in that state, and the Australian Energy Market Operator (AEMO) operates a spot gas market there.[3]

While Australia's three regional markets are not interconnected, Jemena is constructing a transmission pipeline that will link the Bonaparte Basin off northern Australia with the eastern gas market.[4] Called the Northern Gas Pipeline, the pipeline from Tennant Creek to Mount Isa is scheduled for completion in 2018.

2.3 Gas demand in eastern Australia

Domestic customers in eastern Australia consumed around 700 petajoules of gas in 2016, using it for a range of industrial, commercial and domestic purposes. Gas use is highest in South Australia, where it accounts for 32 per cent of primary energy consumption, followed by Queensland and Victoria (20 per cent), and NSW (10 per cent).[5] The high penetration of gas in South Australia reflects the state's reliance on gas powered generation, which has increased since the state's coal fired plants closed.

Of domestic gas sales, around 46 per cent goes to industry, which uses gas 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

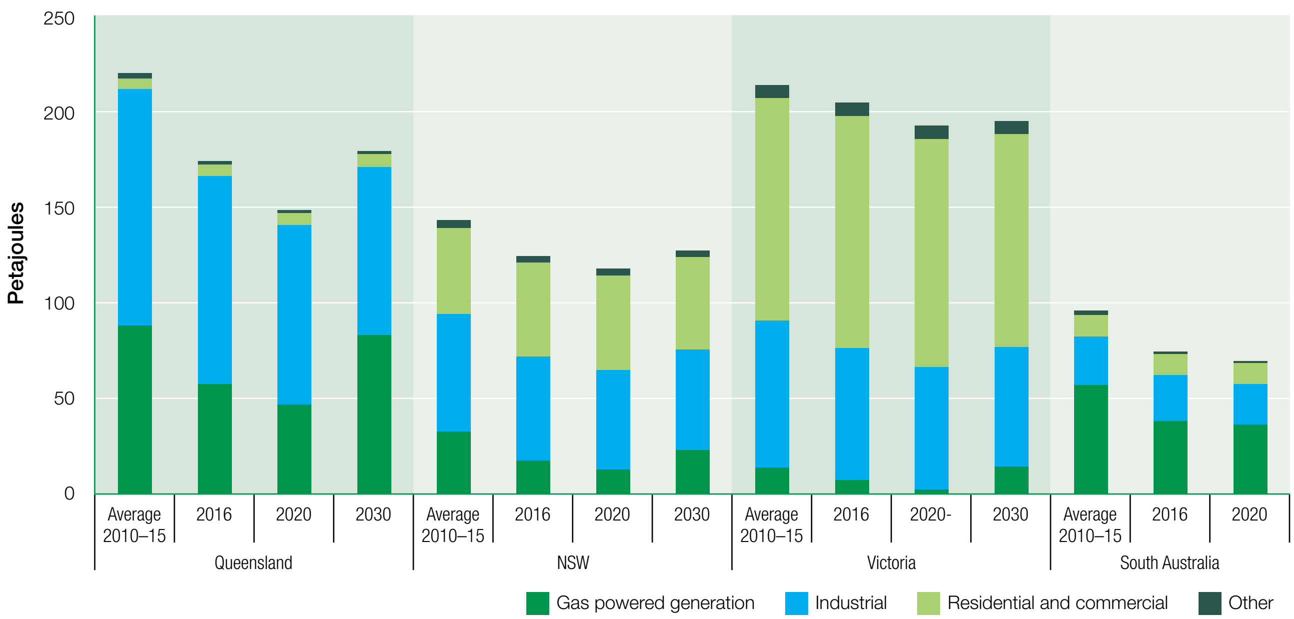
3 For more information on the Western Australian gas market, see www.erawa.com.au/gas. For projections for the Western Australian market, see AEMO, *Gas statement of opportunities for Western Australia*, December 2016, available at www.aemo.com.au/-/media/Files/Gas/National_Planning_and_Forecasting/WA_GSOO/2016/2016-WA-Gas-Statement-of-Opportunities.pdf.

4 Jemena, 'Jemena to build north east gas interconnector', Media release, 17 November 2015.

5 Office of the Chief Economist, Department of Industry, Innovation and Science (Australian Government), *Australian energy statistics 2016*, table C, available at https://industry.gov.au/Office-of-the-Chief-Economist/Publications/Pages/Australian-energy-statistics.aspx.

Figure 2.2

Domestic gas consumption



Source: AEMO, *National gas forecasting report*, 2016.

fertilisers and explosives. Another 21 per cent is used to fuel intermediate and peaking electricity generators. The remaining 33 per cent is sold to residential and commercial customers, mainly for use in heating and cooking.

The composition of consumption differs across jurisdictions (figure 2.2). In South Australia, electricity generation accounted for over 50 per cent of gas demand in 2016. In Queensland, industrial demand and gas powered generation accounted for most gas use, while industrial and residential demand dominated in NSW, roughly in equal measure. But, in Victoria, over 60 per cent of consumption was for small customers, most of whom use gas for cooking and heating.

Domestic gas demand (and its composition) is shifting over time. Overall demand has levelled since 2014, when the repeal of carbon pricing made gas powered generation less competitive relative to coal fired generation. More generally, there is a continuing trend of weak electricity demand. Additionally, competition for gas supplies from Queensland's LNG industry has escalated gas fuel costs, making it less economical to run gas powered plant.

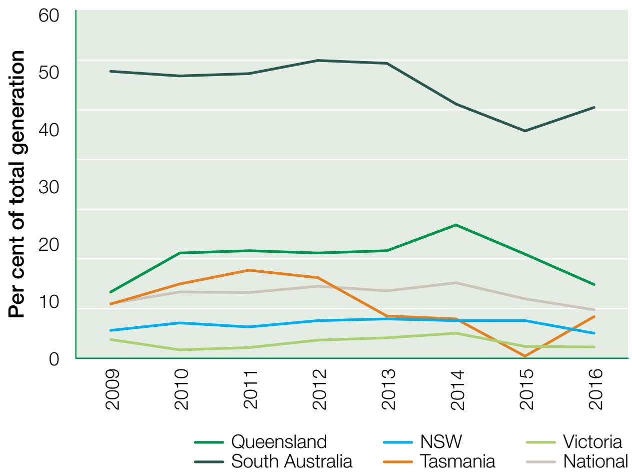
In these difficult market conditions, the share of gas powered generation in the electricity mix fell from 12 per cent in 2012, to 8 per cent in 2016 (figure 2.3). The slump is forecast to continue to at least 2020, reducing overall gas consumption:

- In South Australia, gas powered generation fell from 52 per cent of the generation mix in 2013, to 39 per cent in 2015. It rebounded to 43 per cent in 2016 following the closure of the state's last coal fired generation plant.
- In Queensland, gas powered generation declined from 23 per cent of the generation mix in 2014, to under 13 per cent in 2016, mainly due to rising gas fuel costs associated with demand pressures from the LNG industry.
- The closure of Tasmania's Tamar Valley generator in 2015 eliminated gas powered generation from the state's electricity supply mix. But a prolonged outage on the Basslink electricity interconnector resulted in the power station being returned to service in 2016.

EnergyQuest noted gas demand for industrial use has also weakened. Businesses as diverse as food processors, wool processors, glass manufacturers and other energy intensive industries (such as concrete, fertiliser and aluminium production) are struggling under gas contract prices that doubled in the past 12–24 months. Some manufacturers claimed in 2016–17 that three out of four gas suppliers could not offer gas under any terms.[6]

6 EnergyQuest, *Energy Quarterly*, March 2017, p. 28.

Figure 2.3
Gas powered generation



Sources: AER, AEMO.

2.4 Gas reserves and production in eastern Australia

In calendar year 2016, eastern Australia produced 1660 petajoules of gas, of which a majority (58 per cent) was exported from Queensland as LNG. The remaining 42 per cent was sold into the domestic market (table 2.1).

Queensland's *Surat–Bowen Basin*, the largest basin in eastern Australia, supplied 70 per cent of gas produced in eastern Australia in 2016, including much of the gas earmarked for LNG export. Its gas production has risen exponentially since 2014. Participants in the basin's three LNG projects control a majority of its reserves and supplied 93 per cent of its output in 2016 (figures 2.1 and 2.4). In addition to supplying their LNG facilities, the LNG participants sell some gas into the domestic market.

The *Gippsland Basin* is the most significant of three producing basins off coastal Victoria, meeting 19 per cent of eastern Australia supply but a significantly higher share of domestic demand. A joint venture between Esso (ExxonMobil) and BHP Billiton controls 95 per cent of production in the basin. The principal producers in the smaller *Otway Basin* and *Bass Basin* (jointly supplying 5 per cent of the market) are Origin Energy, BHP Billiton, Santos, Benaris and Australian Worldwide Exploration. Declining reserves are likely to result in lower levels of Otway Basin production in the coming years.

In South Australia, a joint venture led by Santos dominates gas production in the *Cooper Basin*, which meets 6 per cent of eastern Australia supply. Beach Petroleum and Origin Energy are other participants in the venture. After several years of declining production, Santos entered an agreement in 2010 to supply one of the Queensland LNG projects with 750 petajoules of gas over 15 years, which is accelerating the depletion of the basin's conventional reserves. Almost 80 per cent of remaining contingent resources in the Cooper Basin are from unconventional sources, primarily shale gas. Extracting these resources presents significant technological challenges.

NSW has a small amount of CSG production in the *Sydney Basin* and *Gunnedah Basin*. Santos in 2017 submitted an application to develop reserves near Narrabri in the Gunnedah Basin, which then went to an environmental assessment by the NSW Government (section 2.7.3).

No producing gas basins are located in Tasmania or the ACT.

Overall, production rates across the eastern gas basins have shifted markedly over the past 12–18 months in response to changing market dynamics since LNG exports began from Queensland. Production rose by 83 per cent in the Surat–Bowen Basin in 2016, mirrored by a 194 per cent rise in east coast LNG exports. With production from the Surat–Bowen Basin increasingly earmarked for export, supply from the Gippsland Basin rose by 24 per cent over the same period, with sales to both domestic users and LNG producers. Production in the smaller Bass and NSW basins also rose.

2.4.1 Gas reserves in eastern Australia

There is no clear, consistent and accurate reporting on gas reserves in eastern Australia. The data is collected through a range of disconnected mechanisms and bodies. The Australian Securities Exchange (ASX) requires listed companies to report limited data on gas reserves; unlisted companies and those listed overseas may not report at all. State and territory governments each have reporting requirements, and the Australian Government collects some information (particularly on offshore resources), but much is commercial in confidence. There is little consistency in data standards and aggregation across these sources, and the assumptions underlying the data are often not transparent.[7]

Market analysts such as EnergyQuest publish reserves estimates, drawing on available sources. EnergyQuest estimated that eastern Australia's proved and probable (2P) gas reserves stood at 44 000 petajoules in March 2017. Around 90 per cent of these reserves are CSG reserves in Queensland's Surat–Bowen Basin (table 2.1).

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

Table 2.1 Eastern Australia's gas production (2016) and 2P reserves (2017)

GAS BASIN	GAS PRODUCTION[1] (YEAR TO DECEMBER 2016)			2P GAS RESERVES[2] (MARCH 2017)	
	PETAJOULES	SHARE OF EASTERN AUSTRALIAN SUPPLY (%)	CHANGE FROM PREVIOUS YEAR (%)	PETAJOULES	SHARE OF EASTERN AUSTRALIA RESERVES (%)
Surat–Bowen (Queensland)	1 158	70	83	40 013	91
Gippsland (Victoria)	314	19	24	2 391	5
Cooper (South Australia–Queensland)	97	6	–3	1 038	2
Otway (Victoria)	71	4	–15	400	1
Bass (Victoria)	17	1	11	89	<1
NSW basins	5	<1	–2	34	<1
EASTERN AUSTRALIA TOTAL	1 660		53	43 965	
DOMESTIC GAS SALES	690		–9		
LNG EXPORTS	971		194		

2P, proved plus probable.

1. Most production and reserves in the Surat–Bowen and NSW basins are CSG. Production and 2P reserves in other basins are mainly conventional gas.
2. Proved reserves are those for which geological and engineering analysis suggests at least a 90 per cent probability of commercial recovery. Probable reserves are those for which geological and engineering analysis suggests at least a 50 per cent probability of commercial recovery.

Source: EnergyQuest, *Energy Quarterly*, March 2017.

The other reserves are located in Victoria's offshore basins and South Australia's Cooper Basin.

Reserve ownership is highly concentrated in some basins, but more diverse across the market as a whole. Shell (28 per cent) became the largest holder of 2P gas reserves[8] in eastern Australia, following its acquisition of BG Group in 2016 (figure 2.4). Two energy retailers—Origin Energy (11 per cent) and AGL Energy (3 per cent)— hold significant reserves, although AGL Energy announced in February 2016 that exploration and production of natural gas would no longer be a core business for the company.[9] Other major reserve holders include PetroChina and ConocoPhillips (10 per cent each).

EnergyQuest argued that Shell (via its Arrow and QGC holdings) and the Gippsland Basin joint venture have strong market positions because they hold the only material uncontracted reserves that are saleable in the relatively short term. Shell has particular commercial strength, from its position in an LNG export project and its ability to manage a global LNG portfolio to seek leverage from a tight domestic market if and when it chooses.[10]

2.4.2 Liquefied natural gas exports

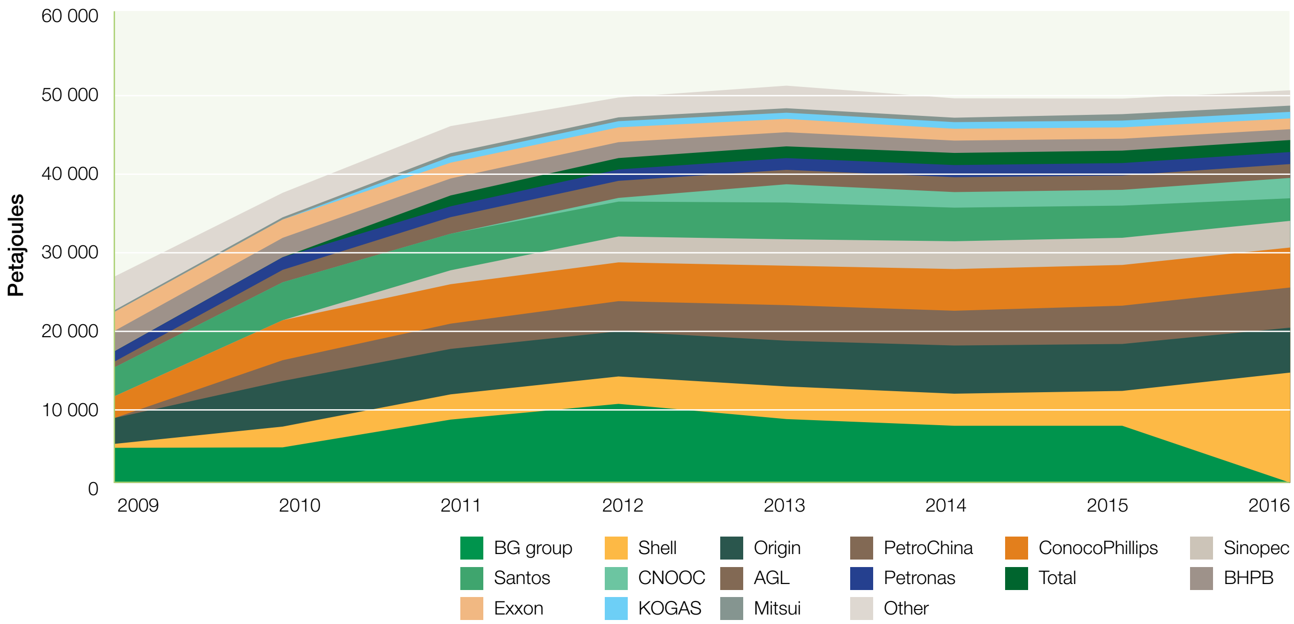
Australia operates LNG export projects at Curtis Island in Queensland, on Western Australia's North West Shelf, and in Darwin. More than $200 billion has been invested in Australia's LNG industry over the past decade,[11] and Australia is expected to become the world's largest LNG producer by 2018.

At LNG facilities, gas is cooled and condensed into a liquid for efficient storage and transport. Most Australian LNG is shipped to Asia, where it is stored, regasified and injected into local pipeline networks. LNG projects thus require large upfront capital investment in processing plant, port and shipping facilities. The magnitude of this investment requires access to substantial reserves of gas, which may be sourced through the owner's interests in gas fields, joint venture arrangements with gas producers, and/or contracts with third party producers.

8 2P reserves are those for which geological and engineering analysis suggests at least a 50 per cent probability of commercial recovery.
9 AGL Energy, 'Review of gas assets and exit of gas exploration and production', Media release, 4 February 2016.
10 EnergyQuest, *Energy Quarterly*, March 2017, p. 28.
11 CoAG Energy Council, *Gas market reform package, bulletin two*, August 2016.

Figure 2.4

Market shares in 2P gas reserves in eastern Australia



Note: Aggregated market shares in 2P (proved 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.

Data source: EnergyQuest, *Energy Quarterly* (various years), supplemented by unpublished EnergyQuest data.

Queensland's LNG industry has transformed the eastern Australian gas industry. The following three projects[12] were made possible by the Surat–Bowen Basin's vast CSG reserves, and spurred by expectations of rising international energy prices:

- The $20 billion Queensland Curtis LNG (QCLNG) project began exporting LNG in January 2015, and launched a second train in July 2015. Shell is the principal owner (73.75 per cent via its ownership in BG), and CNOOC (25 per cent) and Tokyo Gas (1.25 per cent) have minority interests. The project has capacity to produce 8.5 million tonnes of LNG per year (mtpa), which could be raised to 12 mtpa.
- The $18.5 billion 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 has been slower than expected, with the project having to rely on third party gas for about 50 per cent of its plant feedstock. The project has capacity to produce 7.8 mtpa, which could be raised to 10 mtpa.
- The $24.7 billion Australia Pacific LNG project (APLNG) began exporting in January 2016. It commissioned a second LNG train in October 2016. Origin Energy and ConocoPhillips (37.5 per cent each), and Sinopec (25 per cent) own the project.

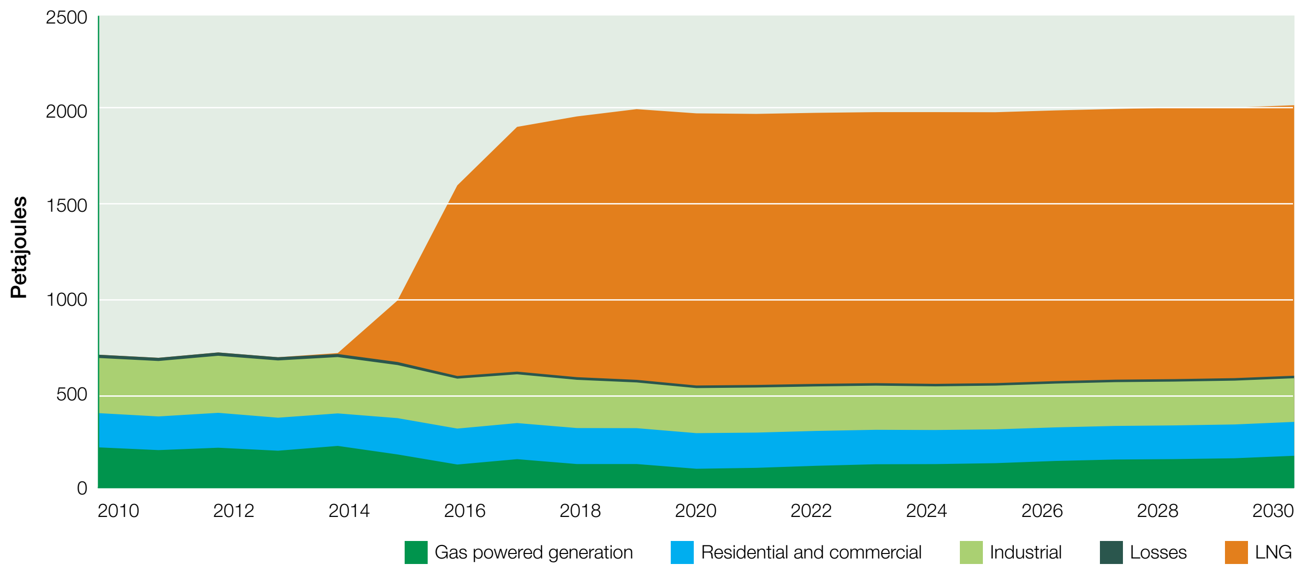
Eastern Australian LNG production will continue to rise in 2017, dwarfing domestic demand in magnitude (figure 2.5). But the LNG sector faces challenges. Weaker Chinese growth, rising shale production in North America, and a significant increase in OPEC production caused oil prices to fall sharply in 2014 and 2015. While gas prices fell only moderately, the decline in oil prices critically affected the profitability of gas producers, many of whom also produce oil.

Share prices for LNG participants fell sharply in response, prompting takeover bids. Santos rejected a takeover bid from private equity fund Sceptre Partners in October 2015, but Shell acquired BG Group in 2016. The Australian Competition and Consumer Commission (ACCC) did not

12 The projects involved the construction of processing facilities at Gladstone and three new transmission pipelines. The world's first to convert CSG to LNG, they each have two trains (liquefaction and purification facilities).

Figure 2.5

Forecast eastern Australia gas demand



Source: AEMO, *National gas forecasting report*, December 2016.

oppose the acquisition, finding it unlikely to substantially lessen competition in the wholesale gas market.[13]

Global oil prices stabilised in 2016 and have since trended higher. Brent oil prices (a major worldwide benchmark price for oil) bottomed at around US$30 per barrel in January 2016, but were trading in the mid US$40s in April 2017, following OPEC's agreement to cut its oil production. A decline in US shale oil production from mid 2015 also helped stabilise oil prices.

2.4.3 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 saves surplus gas for when it is needed.

Eastern Australia has a number of gas storage facilities (table 2.2), which 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 peaking storage services on gas pipelines, which are mostly held by retailers.

13 ACCC, 'ACCC will not oppose Shell's acquisition of BG', Media release, 19 November 2015.

The importance of storage in managing supply and demand has risen since the LNG industry began affecting the domestic gas market, and some large buyers (particularly retailers) have secured capacity. AGL, for example, commissioned an LNG storage facility at Newcastle in 2015, and has contracted to use 50 per cent of Iona's storage capacity from January 2021 to manage seasonal demand. In addition, Lochard Energy in 2017 signalled its intention to expand the Iona storage facility, noting this expansion would help shippers manage their interests.[14]

Transmission pipeline businesses are also promoting their functionality as storage providers. For example, the Tasmanian Gas Pipeline in 2017 offered on its website a facility to store over 150 terajoules of gas in its pipeline, which could later be drawn on for sale into the Victorian market at times of peak demand.

2.5 Gas transmission pipelines

Transmission pipelines transport gas at high pressure from production fields to major demand centres (hubs). The pipelines typically have wide diameters and operate at high pressure to optimise shipping capacity. Gas transmission

14 Lochard Energy, Submission to the AER, 8 March 2017, www.aer.gov.au/system/files/Lochard%20Energy%20%E2%80%93%20APA%20Victorian%20Transmission%20System%20Access%20Arrangement%202018–22%20%E2%80%93%208%20March%202017.pdf.

Table 2.2 Gas storage facilities (excludes storage in gas pipelines)

STORAGE FACILITY	OWNER	WITHDRAWAL CAPACITY (TJ/DAY)	STORAGE CAPACITY (PJ)
Moomba (South Australia)	Santos	80+	85
Ballera (Queensland)	Santos	40	10
Roma (Queensland)	GLNG	75	70
Silver Springs (Queensland)	AGL Energy	30	35
Newstead (Queensland)	Armour Energy	8	2
Iona (Victoria)	QIC[1]	500	26
Dandenong LNG (Victoria)	APA Group	158	0.7
Newcastle LNG (NSW)	AGL Energy	120	1.5

PJ, petajoules; TJ/d, terajoules per day.

1. QIC (a Queensland Government owned fund manager) acquired the Iona facility from EnergyAustralia in October 2015.

Sources: ACCC, *Inquiry into the east coast gas market*, April 2016, p. 74; Gas Bulletin Board, March 2017.

Table 2.3 Major gas transmission pipelines in eastern and northern Australia

PIPELINE	LENGTH (KM)	CAPACITY (TJ/D)	REGULATORY STATUS	OWNER
EASTERN AUSTRALIA				
QUEENSLAND				
Roma (Wallumbilla) to Brisbane	438	233 (125 reverse)	Full regulation	APA Group
South West Queensland Pipeline	756	404 (340 reverse)	Unregulated	APA Group
QSN Link	182	404 (340 reverse)		
Queensland Gas Pipeline (Wallumbilla to Gladstone)	627	149 (40 reverse)	Unregulated	Jemena (State Grid Corporation 60%, Singapore Power International 40%)
Carpentaria Pipeline (Ballera to Mount Isa)	840	119	Light regulation	APA Group
GLNG Pipeline	435	1430	15 year no coverage	Santos 30%, Petronas 27.5%, Total 27.5%, KOGAS 15%
Wallumbilla Gladstone Pipeline	334	1588	15 year no coverage	APA Group
APLNG Pipeline	530	1560	15 year no coverage	Origin Energy 37.5%, ConocoPhillips 37.5%, Sinopec 25%
Berwyndale to Wallumbilla Pipeline	112	164 (276 reverse)	Unregulated	APA Group
Dawson Valley Pipeline	47	30	Unregulated (revoked 2014)	Westside 51%, Mitsui 49%
Wallumbilla to Darling Downs Pipeline	205	270 (530 reverse)	Unregulated	Origin Energy
Comet Ridge to Wallumbilla Pipeline	127	950 (175 reverse)	Unregulated	Santos 30%, PETRONAS 27.5%, Total 27.5%, KOGAS 15%
North Queensland Gas Pipeline	391	108	Unregulated	Victorian Funds Management Corporation
NSW				
Moomba to Sydney Pipeline	2029	439 (381 reverse)	Partial light regulation	APA Group
Central West Pipeline (Marsden to Dubbo)	255	10	Light regulation	APA Group
Central Ranges Pipeline (Dubbo to Tamworth)	294	7	Full regulation	APA Group

PIPELINE	LENGTH (KM)	CAPACITY (TJ/D)	REGULATORY STATUS	OWNER
Eastern Gas Pipeline (Longford to Sydney)	797	351	Unregulated	Jemena (State Grid Corporation 60%, Singapore Power International 40%)
VICTORIA				
Victorian Transmission System (GasNet)	2035	1030	Full regulation	APA Group
South Gippsland Pipeline	250		Unregulated	DUET Group
Vic–NSW Interconnect		153 (196 reverse)	Unregulated	Jemena (State Grid Corporation 60%, Singapore Power International 40%)
SOUTH AUSTRALIA				
Moomba to Adelaide Pipeline	1184	241 (55 reverse)	Unregulated	QIC Global Infrastructure
SEA Gas Pipeline (Port Campbell to Adelaide)	680	314	Unregulated	APA Group 50%, Retail Employees Superannuation Trust 50%
TASMANIA				
Tasmanian Gas Pipeline (Longford to Hobart)	734	129	Unregulated	Palisade Investment Partners
NORTHERN TERRITORY				
Bonaparte Pipeline	286	80	Unregulated	Energy Infrastructure Investments (APA Group 19.9%, Marubeni 49.9%, Osaka Gas 30.2%)
Amadeus Gas Pipeline	1658	120	Full regulation	APA Group
Daly Waters to McArthur River Pipeline	332	16	Unregulated	Power and Water
Palm Valley to Alice Springs Pipeline	146	27	Unregulated	Australian Gas Networks (Cheung Kong Infrastructure)

TJ/d, terajoules per day.

Note: The Moomba to Sydney Pipeline is unregulated from Moomba to Marsden. Light regulation applies to the remainder of the pipeline.

Sources: National Gas Bulletin Board (www.gasbb.com.au); Dr Michael Vertigan AC, *Examination of the current test for the regulation of gas pipelines*, 14 December 2016; Bureau of Resources and Energy Economics; EnergyQuest; corporate websites.

investment typically involves large and lumpy capital projects to build new pipelines, and is normally underwritten by foundation shippers through medium to long term contracts. After their initial construction, the pipelines can be incrementally expanded to meet rising demand, through compression, looping or extensions.

Since 2000, Australia's gas transmission pipeline industry has invested or committed over $10 billion[15] in new pipelines, interconnections and enhancements to existing pipelines, creating a network covering over 20 000 kilometres. The sector is fully privately owned. Of the 30 or so transmission pipelines on the east coast, APA Group has an interest in 13, Jemena has an interest in two, and Epic has an interest in two (table 2.3).

Figure 2.1 illustrates major pipeline routes in eastern Australia, where an interconnected network runs from Queensland to Tasmania. Significant investment has occurred to meet the needs of Queensland's LNG industry, including capacity expansions on existing pipelines and the construction of new pipelines to ship gas to LNG processing facilities. Additionally, Jemena's Northern Gas Pipeline will interconnect eastern Australia with the Northern Territory gas market in 2018.

More generally, the range of services provided by transmission pipelines is expanding as the market evolves, to meet the needs of industry. Pipeline operators no longer simply transport gas from a supply source to a demand centre. Gas customers now seek more flexible

15 Australian Pipelines and Gas Association (APGA), Submission to the *Examination of the current test for the regulation of gas pipelines: consultation paper*, October 2016.

arrangements such as bi-directional and backhaul shipping, park and loan services, capacity expansions, and interconnection with other pipelines.

The AER is the economic regulator for *covered* pipelines in eastern and northern Australia. Only 20 per cent of transmission pipelines are covered, and only four of these are subject to a full regulatory assessment of pricing proposals. Another three pipelines are subject to *light regulation*. But 80 per cent of transmission pipelines are unregulated and can set their own terms and conditions.[16]

2.6 Gas markets in Eastern Australia

Most gas sales in eastern Australia are struck under confidential bilateral contracts, traditionally locking in terms and conditions over a long period. More recently, the industry has shifted towards shorter term contracts with review provisions.

Public information about wholesale gas prices is opaque. A lot of pricing information is 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 customers that less frequently participate in the market. This imbalance favours large incumbents in price negotiations. Currently, no accurate and useful indicative price is readily available to the market.

Nevertheless, it is clear that gas prices struck under new contracts have risen sharply, with offerings around $20 per gigajoule being quoted in 2017. These prices are significantly above LNG netback prices,[17] making it theoretically more profitable for an LNG producer to sell gas domestically than to export it (section 2.7.1).

In eastern Australia, a number of facilitated spot markets (launched for gas balancing and other purposes)[18] allow retailers and other large customers to purchase gas without entering long term contracts:

- A *short term trading market* for gas operates at Sydney, Brisbane and Adelaide (section 2.6.1). It allows participants to manage contractual imbalances, and is supported by a Gas Bulletin Board (section 2.6.4).
- Victoria operates a *declared wholesale gas market* to manage system imbalances and pipeline constraints in that state (section 2.6.2).
- *Gas supply hubs* operate at two major junctions in the transmission pipeline network—Wallumbilla in Queensland and Moomba in South Australia (section 2.6.3).

While trade in the markets is relatively thin, a number of industrial participants use the short term trading market and the Victorian declared market to supplement their gas needs through opportunistic purchases of cheap gas when it is available (typically when surplus gas is sold on the market between LNG shipments). Additionally, the LNG projects sometimes participate in short term trades at the Wallumbilla hub, to manage their portfolios. Prices in the markets are volatile, reflecting short term shifts in the supply–demand balance.

Sections 2.6.1–2.6.3 provide background on the spot markets, including their role in the eastern gas market, relevant trends and market activity. Section 2.7.1 outlines recent prices as part of a wider discussion of gas prices in eastern Australia.

2.6.1 Short term trading market

A short term trading market for gas operates at three hubs in eastern Australia. It was launched in Sydney and Adelaide in September 2010, and in Brisbane in December 2011. AEMO operates the market, which has a floor price of $0 per gigajoule and a cap of $400 per gigajoule. Each hub is scheduled and settled separately, but all three operate under the same rules.

Prices in the short term trading market reflect short term fluctuations in supply and demand, so play an important role in revealing seasonal and other factors impacting gas demand and price. But market participants generally consider these prices are not a useful guide to prices that would be struck in bilateral contract negotiations. Additionally, no ASX derivatives market has developed for the short term trading market, despite a Victorian product being available since 2010.

The market has around 30 active participants, which include energy retailers, power generators and other large gas users. Shippers deliver gas for sale into the market, and users buy the gas for delivery to energy customers; many participants act as both shippers *and* users, but only net positions—that is, the difference between a participant's scheduled gas deliveries into and out of the market—are traded.

16 Chapter 3 explains the regulatory models that apply to gas pipelines (box 3.2).

17 LNG netback prices are calculated by subtracting the costs of shipping and liquefaction from the LNG export price in Asia.

18 AEMO operates the spot markets, and the AER plays a number of regulatory roles. The AER also publishes a user guide to the markets: www.aer.gov.au/wholesale-markets/market-performance.

Gas is traded a day ahead of the relevant gas day, and AEMO sets a day-ahead (ex ante) 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'.

Based on the market schedule, shippers nominate the quantity of gas that they require from a pipeline operator, which develops a schedule for that pipeline to ensure it remains in physical balance. On the gas day, quantities delivered to and withdrawn from a hub may not match the day-ahead nominations, due to demand variations and other factors. As gas requirements become better known during the day, shippers may renominate quantities with pipeline operators (depending on the terms of their contracts).

While there is scope for broader gas trading, participants tend to limit their exposure by targeting a net sell or buy position in the market of around 5–15 per cent, or zero in some cases. In Sydney, around 10–15 per cent of total market demand is met through the market; volumes in Brisbane and Adelaide are usually smaller.

Some participants with flexibility in their day-to-day gas requirements—including a number of smaller retailers—use the spot market to source their gas purchases or to supplement their gas buying, such as on days when demand differs from their contracted supply. But no producer currently uses the short term trading market as a major outlet for their supply. Gas producers gave evidence to the ACCC that they lack confidence in the market's maturity to supply significant volumes of gas.[19]

In addition to allowing general trade, the short term trading market plays an important role in managing system imbalances in gas supplies to distribution networks. AEMO procures balancing gas—called *market operator services* (MOS)—to meet any supply shortfalls. The AER reported instances of abnormally high MOS payments in 2016, triggering a number of reporting obligations (box 2.2).

As part of wider reform proposals to rationalise gas spot markets in eastern Australia, the AEMC in May 2016 recommended simplifying the short term trading market so it transitions into a gas balancing mechanism only. The market's role as a broader trading market would eventually be replaced by the creation of a new southern gas hub (section 2.7.5).

19 ACCC, *Inquiry into the east coast gas market*, April 2016, pp. 77–8.

2.6.2 Victoria's declared gas market

Victoria launched its declared wholesale gas market in 1999 to manage flows on the Victorian Transmission System, and to allow market participants to buy and sell gas at spot prices.

Participants submit daily bids ranging from $0 per gigajoule (the floor price) to $800 per gigajoule (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.[20]

The market has around 17 active suppliers and buyers operating in the longer term. Typically, gas trades account for 5–15 per cent of total gas demand (up to 1200 terajoules per day), after accounting for net positions.

As in the short term trading market, participants primarily use the Victorian gas market to manage imbalances in their forecast supply and demand schedules, and prices typically reflect day-to-day fluctuations in supply and demand. No gas producer currently uses the market as a major outlet for their supply.

While the Victorian gas market shares these similarities with the short term trading market, the two markets are different in design and operation:

- 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 Victorian market is for gas only, while prices in the short term trading market cover gas as well as transmission pipeline delivery to the hub.

In a review of the Victorian market, the AEMC noted the market design makes it difficult to identify a clear price on which to base derivatives trading. It also found Victoria's market carriage model may not provide effective incentives for market led investment.[21] As part of wider reforms to rationalise gas spot markets in eastern Australia, the AEMC in May 2016 recommended transitioning the Victorian declared market to a new southern hub with continuous exchange based trading.

20 See AEMO, *Guide to Victoria's declared wholesale market*, 2012, available at www.aemo.org.au.

21 AEMC, *Review of the Victorian declared wholesale gas market, draft report*, 4 December 2015.

Box 2.2 Market operator services (MOS)

Customer demand for gas is not perfectly predictable. But demand forecasting errors impose costs: any excess supply must be disposed of, and any shortfall in supply must be met by additional gas purchases.

The short term trading market helps to manage imbalances in gas supply to distribution networks when actual gas demand deviates from forecast. AEMO procures extra balancing gas—called *market operator services* (MOS)—to meet any supply shortfall from shippers that can absorb daily fluctuations. Conversely, it procures gas storage on transmission pipelines with spare capacity to manage an oversupply.

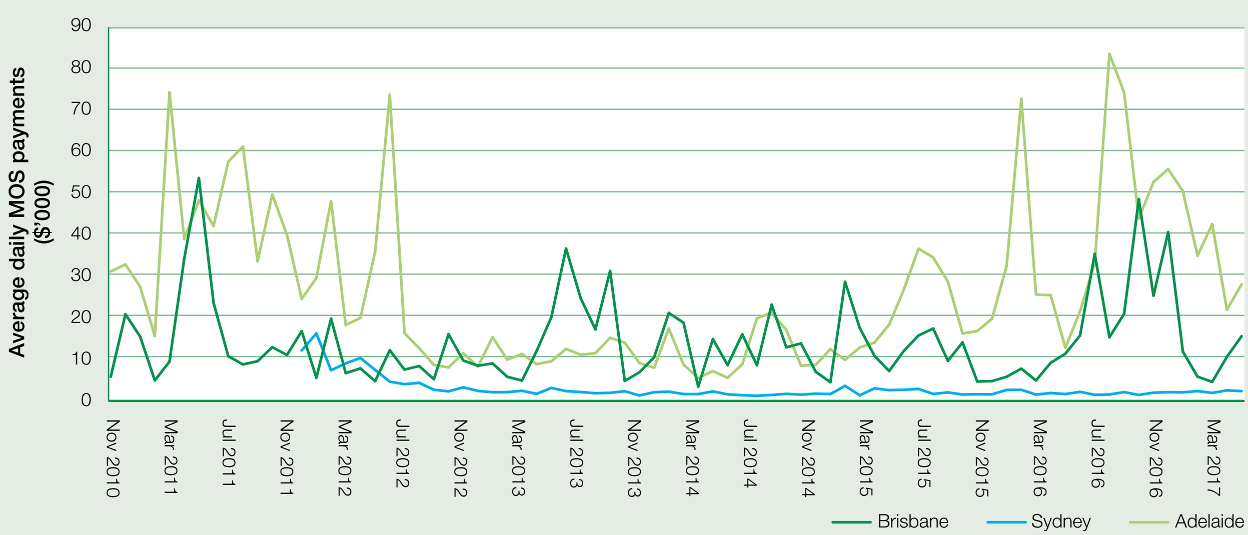
In each case, shippers submit MOS offers, which are pooled and arranged in merit order from lowest to highest price. AEMO uses the offer stack to allocate MOS as required. Gas procured under this mechanism is mainly paid for by the parties causing the imbalances. Inaccurate demand forecasts can result in large MOS payments, imposing significant costs on the market. Market mechanisms are in place to discourage this scenario, but large retailers (being MOS suppliers) are less exposed than small retailers.

Inaccurate demand forecasting led to instances of abnormally high MOS payments in 2016 (figure 2.6), triggering the AER's reporting thresholds for significant pricing variations on several occasions.[a] The AER investigated the causes and engaged with energy retailers on their performance in this area. The AER this year will further analyse inaccurate forecasting, working with participants to understand the causes and possible solutions.[b]

Another issue is counteracting MOS, which occurs when AEMO simultaneously sources MOS gas on one pipeline and storage services on another. The situation can result from pipeline engineering issues. Counteracting MOS was an issue for Adelaide in 2013, and re-emerged in 2016 when a record payment occurred. The AER discussed the matter with transmission pipeline operators servicing Adelaide, and investigated whether participants are contributing to counteracting MOS. It concluded several factors aligned to create the problem, but found no evidence of any market participant being in breach of the Gas Rules on this occasion.[c]

Figure 2.6

Average daily MOS payments



Source: AER.

a Reports on each event are published on the AER website: www.aer.gov.au/wholesale-markets/market-performance?f[0]=field_accc_aer_sector%3A5&f[1]=field_accc_aer_report_type%3A320.

b AER, *Quarterly compliance report: National Electricity and Gas Laws, 1 October – 31 December 2016,* 3 March 2017.

c AER, *Significant price variation report, 21 November 2016 (Adelaide STTM),* 31 March 2017.

The hub would feature an exchange model similar to that at Wallumbilla, providing a low cost, anonymous and transparent way for participants to trade gas (section 2.6.3).

2.6.3 Gas supply hubs at Wallumbilla and Moomba

AEMO launched a new gas supply hub at Wallumbilla, Queensland, in March 2014, and another at Moomba, South Australia, in June 2016. Each location is a major pipeline junction linking gas basins and markets in eastern Australia (figure 2.7). The diversity of contract positions and the number of participants at each hub create a natural point of trade. Participation is voluntary, and trade has been slow to develop. The volume of trade has gradually risen at Wallumbilla, but bid-offer spreads indicate ongoing low liquidity (box 2.3).

The same trading platform and settlement systems apply to each hub, as does a common regulatory framework. The AER monitors the hubs, reporting weekly on activity. It also reports quarterly on participants' compliance with the hub's rules.

Registered participants include producers, large retailers, gas powered generators and large industrial users, who must physically supply gas to and from each hub. A brokerage model applies, allowing buyers and sellers to trade spot (balance-of-day or day ahead) or forward (daily, weekly or monthly) gas products. Participants place anonymous offers or bids on a specified quantity of gas, at a specified price, which can then be automatically matched on the exchange to form transactions. Each price struck is unique to a particular trade. There is no market clearing price that applies to all participants.

As for the short term trading market and the Victorian declared market, the gas supply hubs sit alongside bilateral contracts rather than replacing them. But, unlike the other markets, the hubs allow participants to trade gas up to several months in advance of physical supply, and on a weekly, monthly and three monthly basis, rather than on a daily basis only.

Until recently, separate trades were allowed at three delivery points in the Wallumbilla hub: the South West Queensland, Roma to Brisbane, and Queensland Gas pipelines.[22] But splitting trade across the three locations hampered liquidity and trading. Additionally, participants required access to the transmission pipelines serving the hub, not all of which interconnect. To start to address this issue, compression products were launched in October 2016, allowing gas to be transported from low pressure locations to high pressure locations. The products promote secondary trade by allowing participants that own spare pipeline capacity to sell it. Then, in March 2017, AEMO replaced the hub's three pricing points with a single Wallumbilla location, to pool potential buyers and sellers in a single market.

In May 2016, the AEMC recommended using the gas supply hub's exchange trading model as a template to create two new trading hubs—a northern and a southern hub (section 2.7.4). The northern hub would be located at Wallumbilla and largely retain the market model in place there. The southern hub would be located in Victoria. The two hubs would eventually replace other spot gas markets operating in eastern Australia. The AEMC also proposed that the Moomba hub continue as a transitional measure until the northern and southern hubs mature.[23]

2.6.4 Gas Bulletin Board

The Gas Bulletin Board (www.gasbb.com.au) is an electronic platform that provides current information on gas production fields, storage facilities, demand centres and transmission pipelines in eastern Australia. It covers the zones and facilities noted in figure 2.7, and records:

- gas pipeline capabilities (maximum daily flow quantities, including bi-directional flow information), linepack capacity adequacy outlooks, outlooks for pipeline capacity, nominated gas flow quantities and actual gas quantities
- production capabilities (maximum daily quantities) and capacity outlooks for production facilities
- gas storage (maximum daily withdrawal and holding capacities) and capacity outlooks for storage facilities, and actual injections/withdrawals.

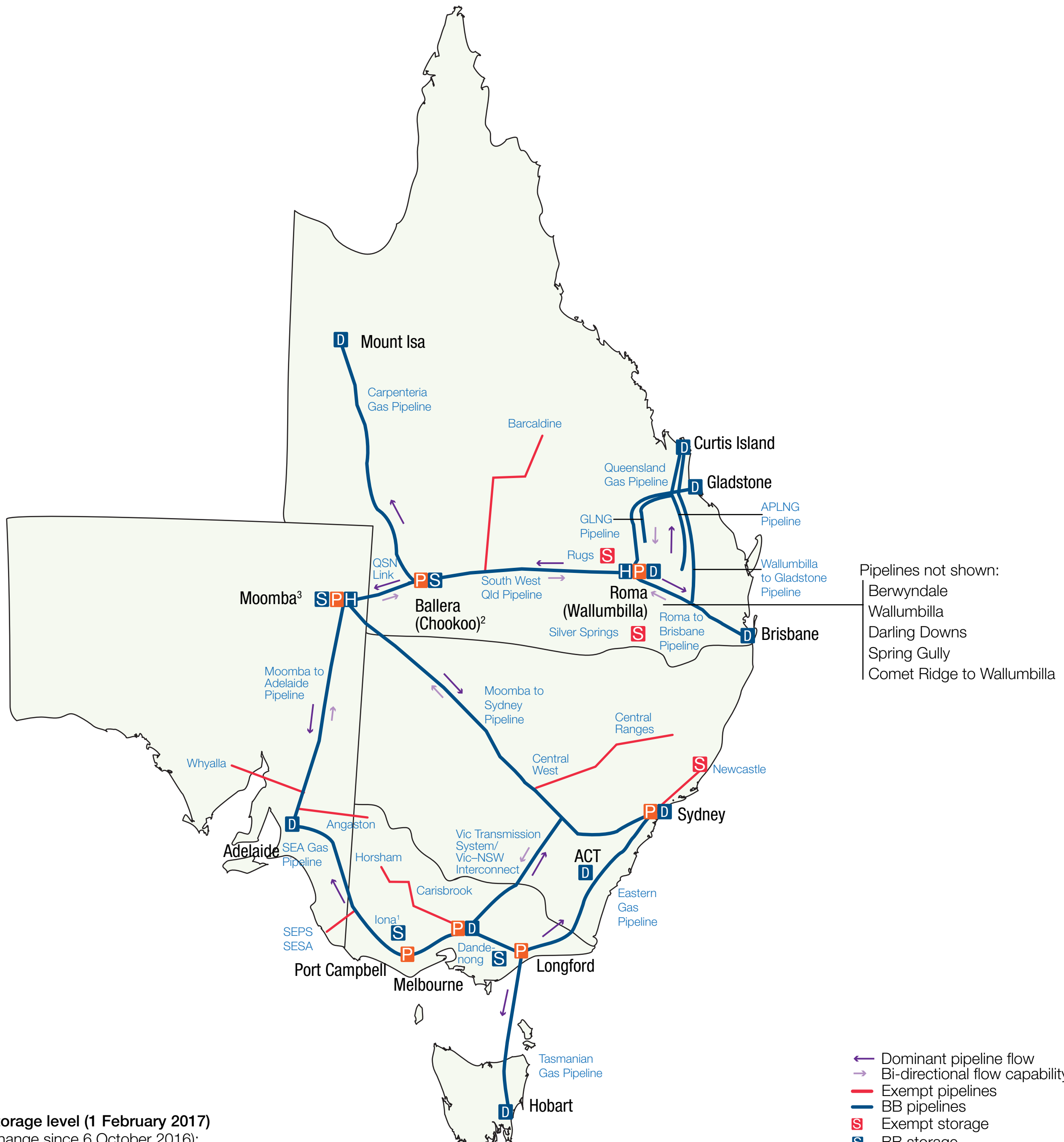
The Gas Bulletin Board includes an interactive map that depicts participant supplied data on plant capacity and production, and pipeline capacity and flow, at any chosen point in the network. Pipeline operators, gas producers and storage facility owners are obliged to submit information to the bulletin board under National Gas Law obligations, and the AER monitors participants' compliance.

22 The Moomba hub also has multiple trading locations.

23 AEMC, *East Coast Wholesale Gas Markets and Pipeline Frameworks Review, stage 2 final report*, May 2016.

Figure 2.7

Eastern gas market and Gas Bulletin Board coverage, 2017



Storage level (1 February 2017)
(change since 6 October 2016):
1. Iona: 15 710 TJ (+81%)
2. Chookoo: 0 TJ (2031 TJ)
3. Moomba: 47 263 TJ (–13%)

Source: AER.

Box 2.3 Gas supply hub activity

Trade at *Wallumbilla* has been intermittent, but volumes generally rose from June 2015, notably during the run-up to commissioning new LNG trains in June to December. Up from around four participants in March 2014, eight to 12 participants were active in the hub in 2016, including the Queensland LNG projects. The projects gave evidence to the ACCC gas inquiry that they engage in short term trades to manage variations in production and LNG plant performance. APLNG, for example, sold surplus gas in the ramp-up to commissioning new LNG trains in 2015 and 2016.[a]

EnergyQuest reported all Queensland LNG producers have periodically diverted gas into the domestic market or sought to do so at times of market tightness. It noted this behaviour became more visible in late 2016, with QCLNG in particular acting as a swing producer into the domestic market when domestic prices were high.[b]

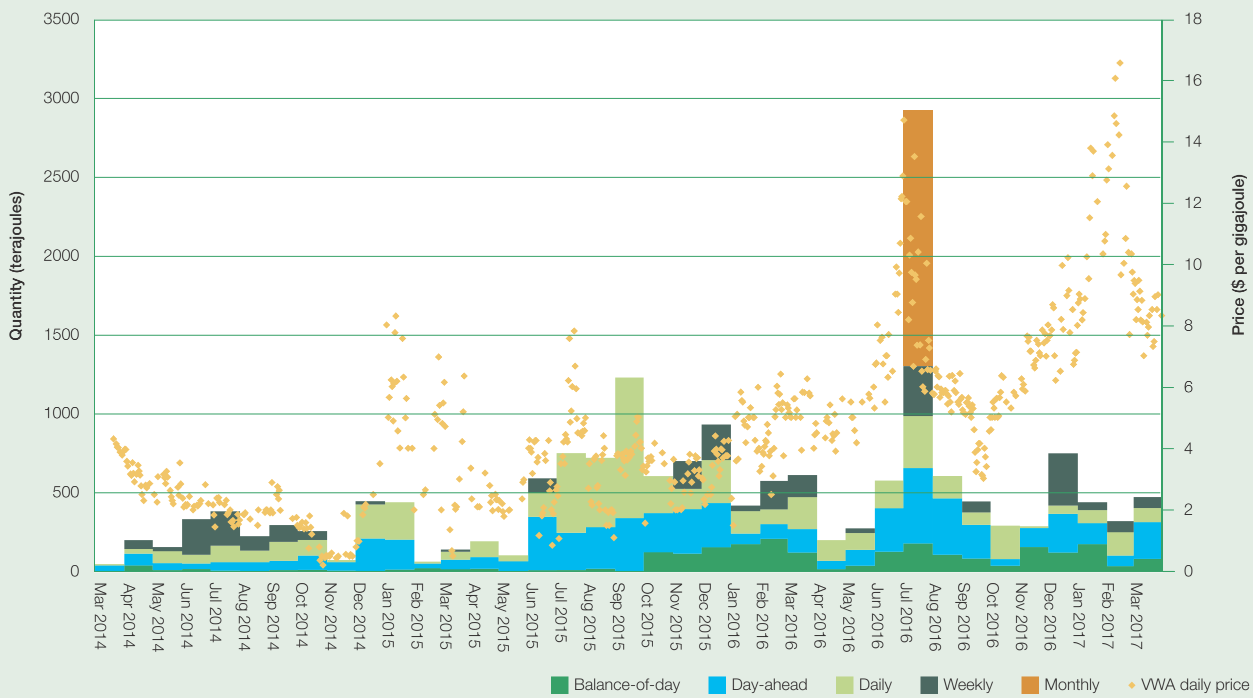
Other participants in the hub include gas powered generators such as Stanwell, Alinta and ERM, as well as industrial users such as Incitec Pivot. A number of gas powered generators sourced gas from the Wallumbilla hub in early 2017, helping push prices into the $10–15 per gigajoule range (figure 2.8 and section 2.7.2). 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 AER is working with the AEMC to improve data on liquidity at Wallumbilla, and it will soon broaden the range of data that it regularly publishes on traded volumes and prices.

Trade at the *Moomba* gas supply hub has been slow to develop. While there have been a number of offers and some bidding for gas at the Moomba hub, no participant transactions had occurred by May 2017.

Figure 2.8

Gas trades and prices at Wallumbilla hub



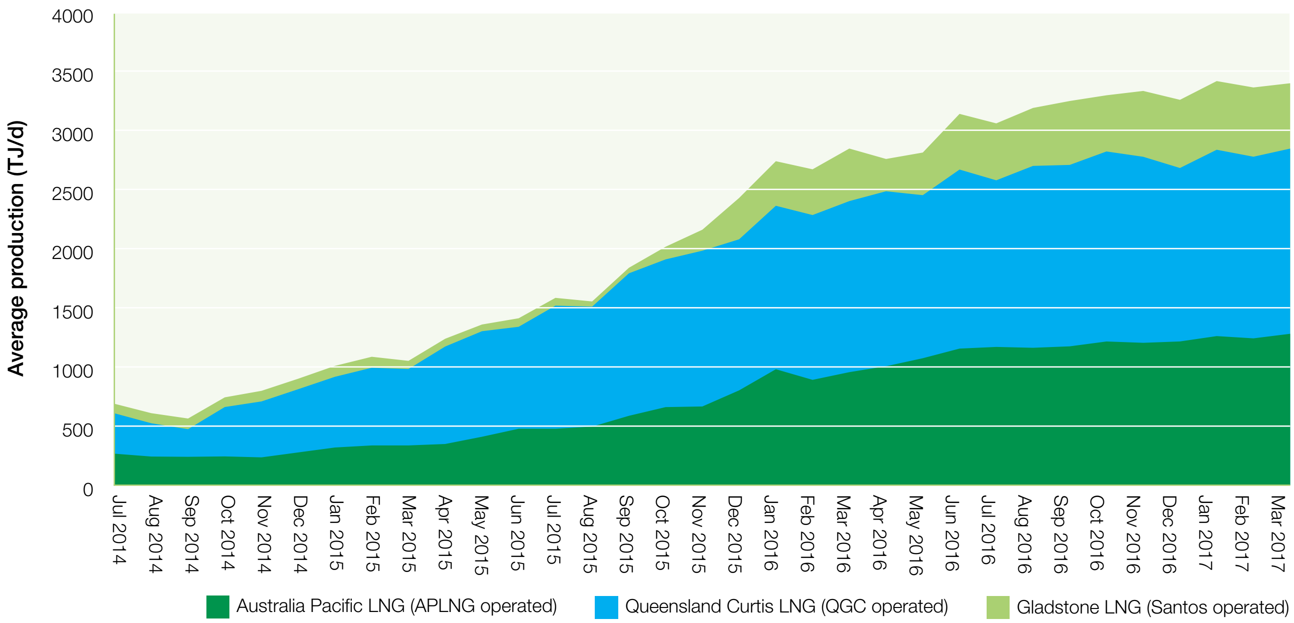
a ACCC, *Inquiry into the east coast gas market*, April 2016, p. 78.

b EnergyQuest, *Energy Quarterly*, March 2017, p. 22.

Sources: AEMO, AER.

Figure 2.9

Gas production around Roma (Surat–Bowen Basin), Queensland



Note: The data show production by LNG participants, which supplied 93 per cent of gas produced in the Surat-Bowen Basin in 2016.

Source: AER.

Recent changes to the Bulletin Board

The coverage of the Gas Bulletin Board recently widened. New Gladstone and Curtis Island demand zones were added in October 2015, and a new demand zone at Wallumbilla was added in June 2016. The introduction of new zones requires more facilities to report to the Bulletin Board, including transmission pipelines that ship gas between Wallumbilla and the LNG export facilities. As a result, the Bulletin Board is a more comprehensive source of information on the gas market.

Further, new rules that took effect in October 2016 require pipeline operators, storage facilities and production facilities to provide more detailed information on gas storage levels, uncontracted capacity outlooks for gas storage and pipelines, and secondary trading in pipeline capacity. The reforms aim to promote trading in uncontracted or underused pipeline and storage capacity.

The new reporting arrangements have made a more comprehensive and consistent body of information available to the market. But reporting exemptions apply to a number of transmission pipelines that do not transport gas between zones, and to storage facilities and production facilities that are not directly connected to those pipelines. Accordingly, some lateral pipelines and storage and production facilities do not appear on the Bulletin Board.

Additionally, some participants received exemptions from the new reporting requirements, allowing them to report under interim arrangements or use alternative calculation methods. Alongside the formal exemptions that apply under the Bulletin Board's zonal model, these specific exemptions contribute to inconsistencies across the reporting landscape.[24]

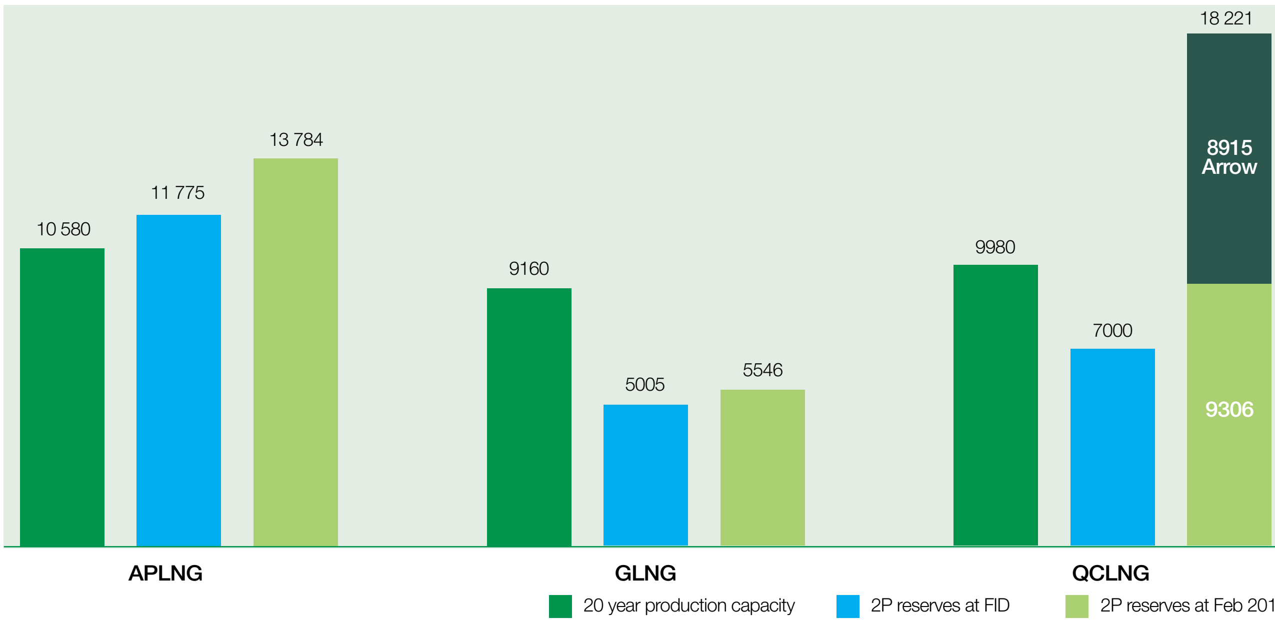
2.7 State of the eastern gas market

Queensland's LNG industry has brought significant private sector investment and economic activity to the region. But it has also caused significant disruption to the eastern gas market. The first LNG cargo was exported from Curtis Island in January 2015, and gas production in Queensland's Surat–Bowen Basin gas production in Queensland's Surat–Bowen Basin rose exponentially over the following year (figure 2.9). By the end of 2016, all three LNG projects were operational, and each had commissioned two LNG trains. By 2020, over

24 AER, *Quarterly compliance report, July–September 2016* and *Quarterly compliance report, 1 October – 31 December 2016*, available at www.aer.gov.au/wholesale-markets/compliance-reporting/.

Figure 2.10

LNG plant capacity and 2P reserves—Queensland LNG projects



APLNG, Australian Pacific LNG; FID, final investment decision; GLNG, Gladstone LNG; QCLNG, Queensland Curtis LNG.

Note: A 50/50 joint venture between Shell and PetroChina owns Arrow Energy, which controls the most significant uncommitted gas reserves on the east coast.

Source: ACCC, *Inquiry into the east coast gas market*, April 2016, p. 28.

70 per cent of eastern and south eastern Australian gas production will be exported.[25]

Queensland's LNG industry's scale is enormous, even by global standards. In 2016 Australia became the world's second largest LNG exporter, and it will be the largest by 2018. Given its scale, the LNG industry is linking the domestic gas sector to volatile global energy markets.

All three LNG projects were originally envisaged to source their gas requirements from their own reserves in the Surat–Bowen Basin. But the development of gas wells by Santos's Gladstone LNG project (GLNG) has been slower than expected, causing much of the recent disruption to the domestic market. Because the project lacks sufficient reserves to meet its LNG feedstock requirements, it is sourcing substantial volumes of gas from outside its own portfolio, absorbing supplies that might otherwise have been available to the domestic market (figure 2.10). EnergyQuest estimated that GLNG relies on third parties for around 50 per cent of its LNG plant feedstock[26], much of it from the Cooper Basin (which has been a key supplier to the southern gas market), and also from Victoria's Gippsland Basin. QCLNG has also purchased gas from third parties.

25 AEMO, *Gas statement of opportunities*, March 2017, p. 11.

26 EnergyQuest, *Energy Quarterly*, March 2017.

The impact of these dynamics differs between Queensland and the southern states. In Queensland, the LNG producers can choose to export any uncontracted gas or sell it domestically. Brisbane short term trading market prices, therefore, are particularly sensitive to LNG production, particularly in winter when the east coast market is seasonally tight. EnergyQuest reported an 83 per cent correlation between Brisbane short term trading market prices and LNG output in the 12 months to January 2017.[27] In this environment, Queensland customers now directly compete with the international market, and Queensland prices are increasingly shaped by LNG netback prices.[28]

The southern states are a little more insulated. While Victorian producers also sell gas to the LNG projects for export, transport costs of around $3.50–4 per gigajoule create a buffer in favour of domestic gas users. But this buffer has been weakened by the Cooper Basin producers (particularly Santos) committing significant volumes of gas to the LNG projects. Those producers historically played a critical role in competing with the Gippsland Basin producers for market share in the southern states.[29]

27 EnergyQuest, *Energy Quarterly*, March 2017.

28 LNG netback prices are calculated by subtracting the costs of shipping and liquefaction from the LNG export price in Asia.

29 ACCC, *Inquiry into the east coast gas market*, April 2016, pp. 42, 48.

Weakening this competitive constraint potentially exposes gas buyers in Victoria to prices equivalent to the Queensland price *plus* transportation costs from Queensland.

These dynamics are evident in significant disruption to the established gas flows in southern Australia. The Moomba to Sydney Pipeline, for example, traditionally shipped gas from the Cooper Basin to the NSW market, yet net gas flowed in the opposite direction (back to Moomba and then on to the LNG projects in Queensland) in 2016. To address this shift, NSW is now sourcing most of its gas from Victoria, via the Eastern Gas Pipeline and the NSW–Victoria Interconnect.

Similarly, the Moomba to Adelaide Pipeline traditionally shipped gas from the Cooper Basin for the South Australian market. In 2016 these gas flows declined, and South Australia is increasingly sourcing its gas from Victoria via the SEA Gas Pipeline.

Other supply issues are also weakening competitive dynamics in the southern gas market:

- Gas production in offshore Victoria is declining, especially in the Otway and Bass basins. Based on advice from producers, AEMO projected gas production in offshore Victoria will fall by 38 per cent between 2017 and 2021. Development of new fields will be required to meet forecast demand, although the number of oil and gas wells drilled in Australia has effectively halved since 2014.[30] More generally, production costs are rising as more economical gas reserves are depleted.
- Lower international oil prices have reduced incentives and drained funds for gas exploration and new project development. Onshore drilling in Australia's petroleum industry for the year to 30 June 2016 declined by almost 70 per cent.[31]
- Development of onshore resources has also been constrained by moratoria and other regulatory restrictions on gas exploration and development, particularly in NSW and Victoria.

In combination, these factors are reducing the availability and diversity of supply in the southern states, making customers heavily reliant on Gippsland Basin gas supplied by the Gippsland Basin Joint Venture (ExxonMobil–BHP Billiton). The joint venture contracted to sell in 2017 the highest volumes in the basin's history.[32] The ACCC found the joint venture now holds significant market power as a result of the changed competitive dynamics in the southern states.

More generally, with many long term gas contracts expiring between 2016 and 2018, customers have reported difficulties in securing new arrangements. The offers that they do receive are often at sharply higher prices, for shorter durations, and on strict 'take it or leave it' terms. Additionally, prices in new contracts are increasingly linked to international oil prices or LNG netback pricing.

Supply issues in the gas market have been exacerbated by inefficiencies in the largely unregulated gas transmission pipeline sector. The ACCC found gas pipeline businesses have responded to the market's needs by offering more flexible services, including 'as available', interruptible, backhaul and bi-directional services. These services are particularly sought by gas fired generators and LNG producers. Additionally, pipeline businesses have invested in new interconnections and the re-engineering of pipelines for bi-directional flows.

But the ACCC inquiry also found evidence of pipeline businesses engaging in monopoly pricing. Rates of return factored into access charges for some pipelines are substantially higher than the benchmark returns on equity that the AER applied in recent regulatory decisions (box 2.4). The ACCC found monopoly pricing had led to higher delivered gas prices for users and, in some cases, lower ex-plant prices for producers. It reported examples of excessive pipeline charges discouraging investment in exploration and reserves development, and in industries that rely on gas.[33]

In this complex environment, the efficiency of the east coast gas markets is under scrutiny. The CoAG Energy Council in December 2014 directed the AEMC to review the design and function of spot gas markets and gas pipeline arrangements. In March 2015, the Victorian Government tasked the AEMC with a separate review of the Victorian market. The AEMC found east coast gas markets to be 'fragmented and disjointed'.[34] It recommended a roadmap for gas market development, based on the creation of two trading hubs, a streamlined bulletin board and efficient pipeline capacity trading (section 2.7.4).

30 AEMO, *Gas statement of opportunities*, March 2017, p. 10.

31 ABS, *Mineral and petroleum exploration, Australia, June Quarter 2016*, cat. no. 8412.

32 ACCC, *Inquiry into the east coast gas market*, April 2016, p. 50.

33 ACCC, *Inquiry into the east coast gas market*, April 2016, pp. 1–9.

34 AEMC, *East Coast Wholesale Gas Market and Pipeline Frameworks Review, stage 1 final report*, 23 July 2015, p. 26.

Box 2.4 Monopoly pricing of gas transmission pipeline services

The ACCC gas market inquiry found evidence of gas transmission pipelines charging significantly above competitive tariffs for pipeline use:

- One pipeline had raised its prices by over 90 per cent, despite declining volumes.
- One major arterial pipeline was earning 70 per cent more in revenue than the pipeline operator estimated it would earn if the pipeline was regulated.
- One major pipeline facing some competition earned an annual rate of return above 20 per cent in 2013–15 (before interest and tax).
- Another major pipeline facing some competition expected to generate an internal rate of return of 19 per cent on a recent investment that a shipper had fully underwritten.
- One pipeline operator facing declining volumes was trying to maintain a rate of return that was 1.5 times higher than it estimated it would earn if the pipeline was regulated.

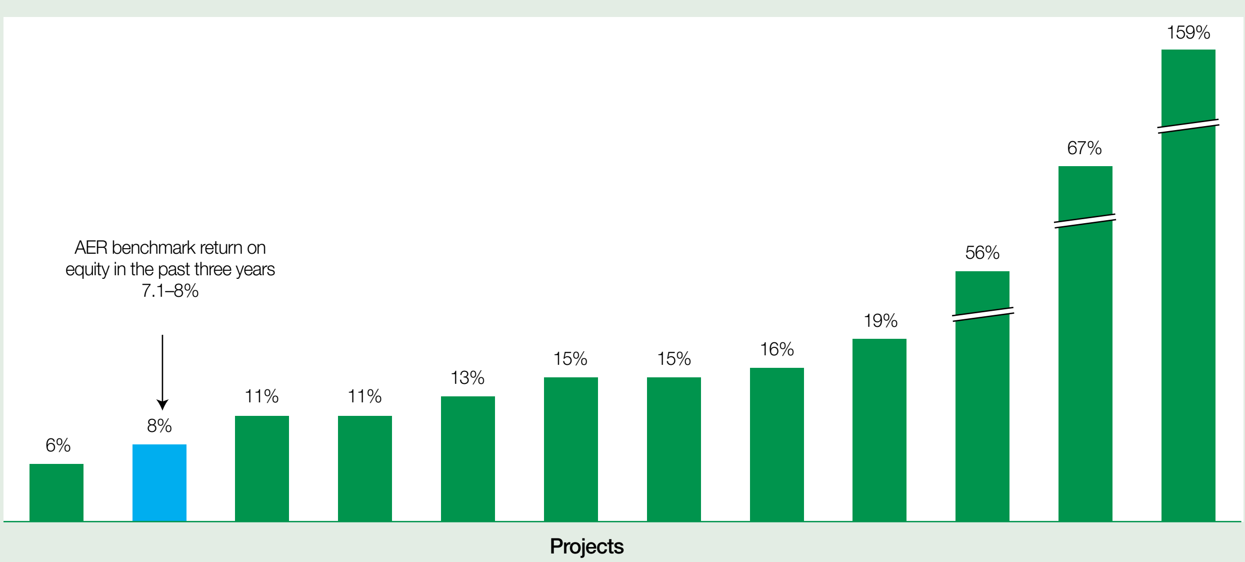
More generally, the inquiry found tariffs did not reflect the cost of providing transportation services. Further, they did not reflect that the costs of establishing some pipeline assets had already been recovered.

The ACCC considered these findings indicated the exercise of market power. Additionally, the inquiry found APA Group, Jemena and Epic Energy expected returns on equity of up to 159 per cent for recent projects to expand or connect transmission pipelines (figure 2.11). Except for one project, the expected returns were above the return on equity benchmark that the AER estimated in regulatory decisions; in many instances, they were more than double the benchmark rate (and 20 times higher in one instance).

Expected returns on investments in bi-directional capability (not shown in figure 2.11) ranged from 55 to 160 per cent. The expected yields on these investments are high because the conversion has a relatively small cost and allows the pipeline to earn revenue on flows in both directions. Further, the relevant pipelines have already been fully underwritten through long term contracts based on forward haul alone.

The ACCC also found the prices charged by some pipeline operators for as-available, interruptible and backhaul services are excessive on key routes between Queensland and southern states, and for hub services at Wallumbilla.

Figure 2.11
Expected returns on equity for incremental gas transmission projects



Source: ACCC, *Inquiry into the east coast gas market*, April 2016, pp. 99–106.

Box 2.4 Monopoly pricing of gas transmission pipeline services (continued)

In work commissioned for the Vertigan Inquiry, JP Morgan's equity research team estimated in 2016 that total shareholder returns over the past 10 years to one Australian pipeline business (APA Group) were around double the returns for a typical regulated electricity network operator. While noting that regulated and unregulated businesses face different risk environments, that difference is not sufficient to explain these returns.[a]

A number of participants reported to the Vertigan Inquiry that significant gas trading around the Wallumbilla hub is occurring bilaterally and off market to avoid the pipeline costs of physically moving gas to Wallumbilla. Participants are sometimes agreeing to delivery points downstream to avoid these costs.

a Reported in Dr Michael Vertigan AC, *Examination of the current test for the regulation of gas pipelines*, 14 December 2016, pp. 45-6. The analysis was not intended to target specific companies, but to demonstrate above-average returns are being generated where market power exists.

Sources: ACCC, *Inquiry into the east coast gas market, April 2016*; Dr Michael Vertigan AC, *Examination of the current test for the regulation of gas pipelines*, 14 December 2016.

Separately, the Australian Government in April 2015 tasked the ACCC with inquiring into the competitiveness and structure of the east Australian gas industry.[35] The ACCC in 2016 recommended measures to address monopoly pricing in the gas transmission sector and to improve gas price disclosure and transparency (box 2.4 and section 2.7.4). It also recommended the development and dissemination of consistent reserve and resource information across the east coast gas market.[36]

2.7.1 Gas contract prices

Gas prices are struck under confidential long term contracts that producers enter with energy customers such as electricity generators, energy retailers and large industrial gas users. These contracts set the underlying price of wholesale gas.

The ACCC observed average contract prices across basins of around $4–5 per gigajoule, based on March 2015 invoices. Some of those legacy contracts have since ended, and prices are now being struck at significantly higher prices for the limited supplies of gas entering the market. AGL Energy in March 2017 was quoting gas prices of $20 per gigajoule to industrial customers, based on expectations of having to source the gas from spot markets (in the absence of uncontracted gas being available from producers).[37] Similarly, the Australian Industry Group reported in February 2017 that Victorian industrial users were receiving limited offers for one or two year contracts at prices of $20 per gigajoule or more.[38]

2.7.2 Spot market prices

While gas contract prices typically reflect expectations of medium to long term trends in market conditions, the facilitated spot markets are more volatile, reflecting short term shifts in the supply–demand balance. These facilitated markets—the short term trading market, the Victorian declared market and the gas supply hubs (sections 2.6.1–2.6.3)—allow participants to trade 'unders' and 'overs' in their contract portfolio.

In 2015, for example, spot prices fell sharply as LNG participants sold surplus 'ramp-up' gas into those markets (figure 2.12). But while spot prices fell, gas contract prices were rising, as LNG participants locked up gas supplies for export that had previously been available to the domestic market.

Gas prices rose across all spot markets during 2016, but continued to be volatile, depending on the timing of LNG shipments, the commissioning of new LNG trains, and activity in the electricity market. They surged in winter, for example, when the start-up of GLNG Train 2 and high LNG export commitments drained supply and diverted gas flows from southern Australia to meet demand. This scenario coincided with an already tight southern gas market (due to seasonally high winter demand and a rise in gas powered generation following the shutdown of South Australia's Northern power station).

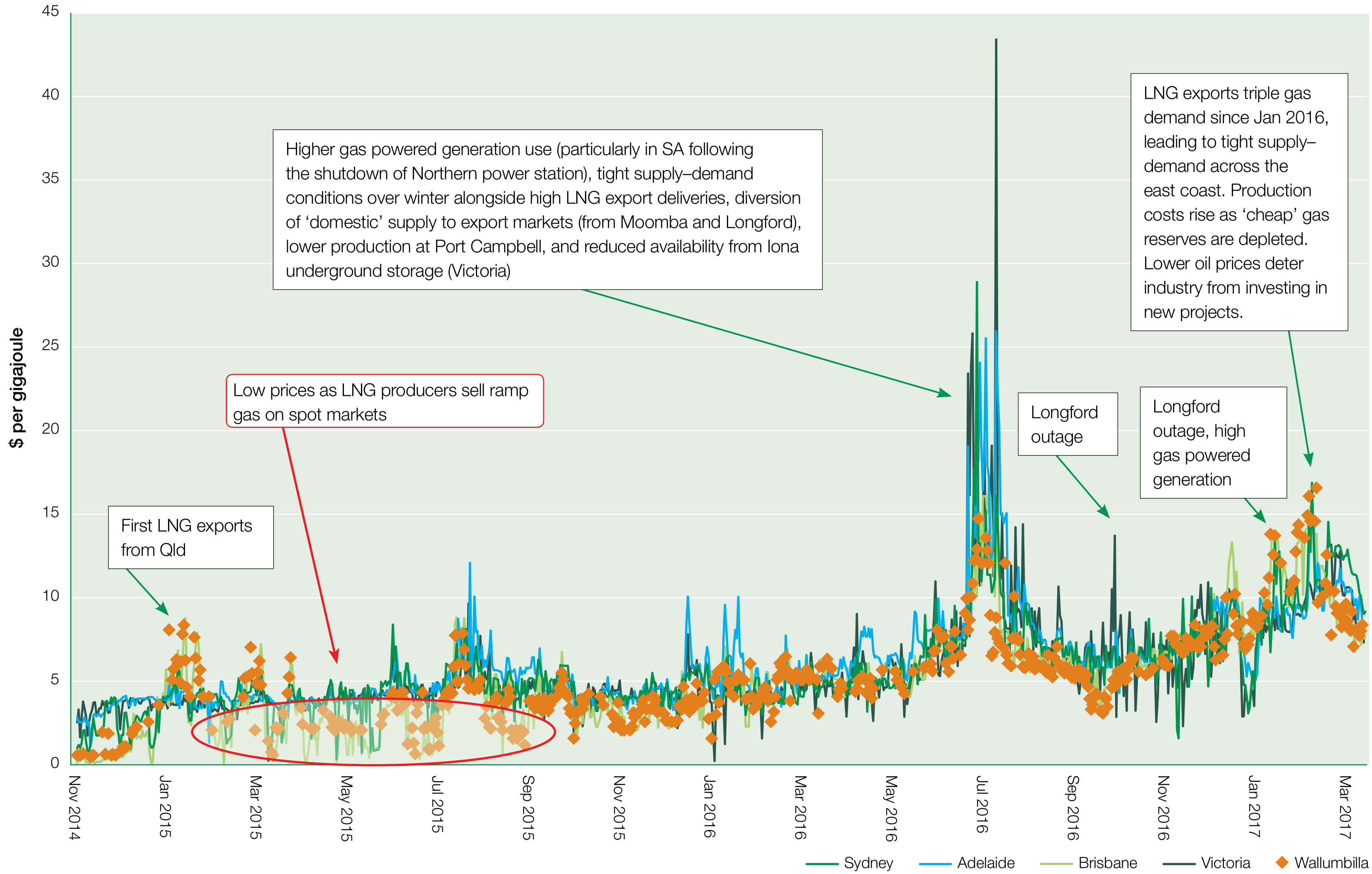
35 ACCC, 'Inquiry into eastern and southern Australian wholesale gas prices', Media release, 13 April 2015.

36 For a full list of recommendations, see ACCC, *Inquiry into the east coast gas market*, April 2016, pp. 20–1.

37 AFR, 'East coast gas shortages to hit this winter', 7 March 2017.

38 Australian Industry Group, *Energy shock: no gas, no power, no future?*, February 2017.

Figure 2.12
Daily spot gas prices



Source: AER.

Box 2.5 Threat to system security in Victoria, 1 October 2016

An onsite power failure affecting all three Esso–BHPB production plants at Longford, Victoria, reduced gas flows from the facilities to zero on the morning of 1 October 2016. Longford supplies most of the gas into Sydney and Melbourne, so this incident was critical.

Following the incident, AEMO declared a threat to system security and brought on out-of-merit order gas from the Iona gas storage facility (via the South West Pipeline) and LNG from the Dandenong storage facility (via the Longford to Melbourne Pipeline). This intervention cost the market around $3 million in ancillary payments. Scheduled prices ranged from around $10 to $34 per gigajoule.

Additionally, the incident resulted in the Eastern Gas Pipeline (Jemena's pipeline to Sydney) advising of a possible gas shortage for Sydney. However, this scenario was averted when Longford production returned to service mid-morning.

The AER examined the timeliness of information provided by Esso–BHPB on this matter, the effectiveness of market communication processes more generally, and whether more timely systemwide alerts are needed. It found more comprehensive information on the Gas Bulletin Board would improve transparency for east coast gas industry participants.[a]

a AER, *Significant price variation report, Victorian gas wholesale market, Longford facility outage, 1 October 2016*, 21 December 2016.

Other contributing price factors included lower Otway Basin production, plant outages and a depletion of stored gas at the Iona facility. In response to these conditions, gas producers shifted their spot market offers into higher price bands.

This 'perfect storm' of market conditions caused winter 2016 gas prices in downstream spot markets in Adelaide, Brisbane, Sydney and Victoria to be consistently above $10 per gigajoule and often $15 per gigajoule for the first time. Notwithstanding the tight Queensland market, Brisbane prices were lower than those in the southern states, reflecting the seasonal impact of winter weather in the south.

Prices then eased until early October 2016, before continuing their upward trend. The market experienced a number of outages and imbalances in this period, including an incident at Longford that raised a threat to system security (box 2.5).

With the startup of APLNG's second train in October 2016, gas prices again moved into an upward trajectory. The progressive commissioning of LNG trains from January 2015 to late 2016 led to eastern Australia's gas demand rising by around 170 per cent. The market tightened further over summer 2016–17, with outages at the Longford facility and high temperatures driving a rise in gas powered generation.

A sustained upswing in gas prices in early 2017 reflected these conditions, with prices often at $9–12 per gigajoule across most spot markets. Wallumbilla prices reached a new high of $16.50 per gigajoule in February 2017, with gas powered generators being the main customers. And, at times during summer 2016–17, domestic spot prices rose *above* LNG netback levels. EnergyQuest reported one LNG producer, in response, was calling back some gas from its export contract so it could supply more gas to the domestic market.[40]

Impacts on gas customers

The impacts of rising gas wholesale prices are significant. The ACCC found a $2 per gigajoule price increase would raise household gas bills by 5 per cent in NSW and 11 per cent in Victoria. It also estimated a $2–4 per gigajoule rise would cut margins for some industrial customers by up to six percentage points.[41] Among industrial users, gas accounts for 15 per cent of input costs for bricks and roof tiles, 25 per cent for cement and alumina, 40 per cent for fertilisers, and 80 per cent for some ammonia.

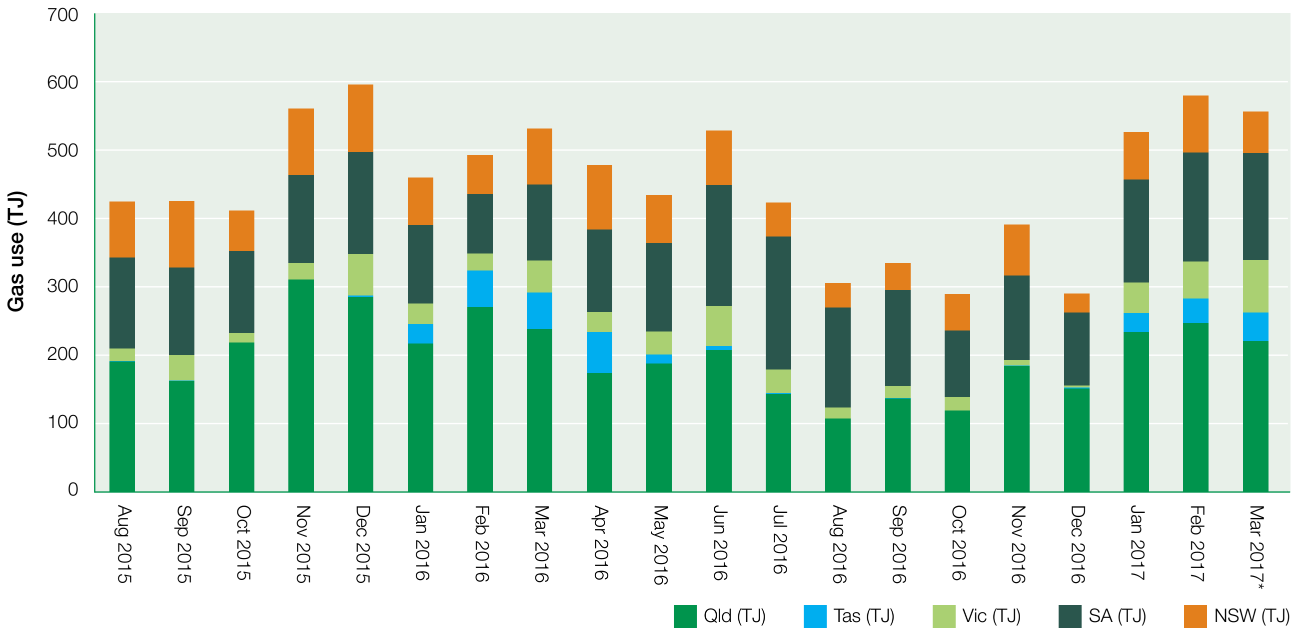
The uncertainty around gas availability and pricing is thus prompting some industrial users to defer investments. AEMO modelled in 2017 that a $2 per gigajoule price rise in wholesale gas for industrial customers could cause the commercial and industrial sectors to reduce their consumption of gas by around 8.6 per cent per year.[42]

39 AER, *Significant price variation report, Victorian gas wholesale market, Longford facility outage, 1 October 2016*, 21 December 2016.

40 EnergyQuest, *Energy Quarterly*, March 2017.
41 ACCC, *Inquiry into the east coast gas market*, April 2016, pp. 1–9.
42 AEMO, *Gas statement of opportunities*, March 2017.

Figure 2.13

Monthly gas demand for gas powered generation



Source: AER.

High gas prices and difficulties in securing gas supplies have also affected gas powered generation, which AEMO considers vital to the security of electricity supply as coal fired generators withdraw from the market. One of two units at the Pelican Point power station in South Australia was offline from 2014 to 2017, with no gas supply contract in place to run it. In Queensland, Stanwell mothballed its efficient Swanbank E plant in 2014 for three years, and then delayed its return to service to 2018.

AEMO noted declining gas supplies, without market responses, could result in electricity supply shortfalls between 2019 and 2021 of 80–363 gigawatt hours in South Australia, NSW and Victoria.[43]

2.7.3 Eastern Australia's supply outlook

Eastern Australia's supply–demand balance has continued to tighten since the commencement of LNG exports in 2015. As noted, the supply available to the domestic market has been limited by the reliance of at least one LNG project on third party gas reserves from southern Australia; declining gas production in Victoria's offshore gas basins; and a lack of exploration and development of new gas reserves (due to weaker industry profits and regulatory restrictions in NSW, Victoria and Tasmania).

In part, these tight supply conditions are offset by weak domestic gas demand. High gas contract prices, weak electricity demand and the abolition of carbon pricing have stifled growth in gas powered generation, which accounts for 31 per cent of domestic gas demand. The exceptions are South Australia (where gas powered generation has risen since the closure of the state's last coal fired plant in 2016) and, to a lesser extent, Tasmania (where the Tamar Valley power station returned to service in 2016 during a prolonged outage on the Basslink electricity interconnector to the mainland). Gas powered generation also rose over the 2016–17 summer to meet seasonal peaks in electricity demand (figures 2.2, 2.3 and 2.13).

Conditions in the eastern gas market have raised concerns about the future security of domestic gas supply. AEMO noted in March 2017 that these issues are emerging more quickly than previously expected, and forecast a possible gas supply shortfall by summer 2018–19 in South Australia, NSW and, to a lesser extent, Victoria. It found a shortfall is unlikely in Queensland over the coming decade.[44]

43 AEMO, *National gas forecasting report*, December 2016. AEMO expects to release updated forecasts for the eastern gas markets in June 2017.

44 AEMO, *Gas statement of opportunities*, March 2017. AEMO expects to release updated forecasts for the eastern gas markets in June 2017.

The ACCC noted uncertainty about the development of gas reserves in the Surat–Bowen Basin (held by the Arrow Joint Venture), which are the most significant uncommitted reserves on the east coast.[45] It considered there is little prospect of a significant increase in supply from existing production basins in the southern states. While some producers in the Cooper Basin and offshore Victoria have ramped up output to meet demand, this decision may accelerate the decline of their reserves over the medium term. The Cooper, Otway and Gippsland basins face increasing costs and challenging decisions about potential new field expansions in the current economic conditions.

EnergyQuest reported in March 2017 that a substantial part of the 2P reserve base underpinning the LNG projects has not demonstrated commercial productivity. This observation applies particularly to GLNG.[46] It also noted the investment underway in new east coast supply is nowhere near sufficient to meet domestic demand. On balance, it found a material risk of increasing market shortfalls within the next two or three years. While the LNG projects may divert some supplies to meet seasonal demand peaks, EnergyQuest considered they would be unlikely to sign significant new domestic gas contracts. Accordingly, without significant gas imports or major cheap discoveries that can be quickly brought to market, new field development is critical (particularly Arrow's acreage in Queensland).

2.7.4 Market responses

In this uncertain market environment, industry is taking or exploring measures to manage the risks of possible gas supply shortfalls. The initiatives include:

- transmission pipeline investment and upgrades, including pipeline re-engineering and new interconnections
- gas field development
- LNG imports.

Transmission pipeline investment and upgrades

The gas transmission pipeline industry is investing in new infrastructure and providing more flexible arrangements to meet customer requirements:

- There was an incremental expansion of the NSW–Victoria Interconnect to accommodate increased northbound gas exports from Victoria. To be completed in 2017, the expansions will collectively treble the pipeline's capacity. Additionally, APA Group is looping (duplicating) parts of the Victorian Transmission System and the Moomba to Sydney Pipeline. Jemena has also expanded capacity on the Eastern Gas Pipeline to boost northbound capacity.
- Major pipelines were re-engineered for bi-directional flow capability to allow greater flow mobility. The upgraded facilities include the South West Queensland Pipeline and the QSN Link (connecting South Australia and Queensland), the Roma to Brisbane Pipeline, the Moomba to Sydney Pipeline, the Moomba to Adelaide Pipeline and the NSW–Victoria Interconnect.

  Recent flows on the QSN Link illustrate how the pipeline industry responds to market conditions (figure 2.14). Heavy southbound flows occurred in 2015 as the LNG projects sold large quantities of cheap ramp-up gas to buyers in southern Australia. The QSN Link's flow direction then reversed in 2016 as southern gas flowed north to meet rising demand from the LNG projects. This pattern reversed again for a period during winter 2016, when a surge in southern gas prices attracted the LNG projects to divert some gas flows southbound.
- The SEA Gas and Moomba to Adelaide pipelines were interconnected in July 2015, allowing Victorian gas to be shipped north via South Australia. Additionally, the Moomba to Sydney Pipeline was interconnected with the Eastern Gas Pipeline.
- Jemena is constructing the Northern Gas Pipeline from the Northern Territory to Queensland, which will link the Bonaparte Basin off northern Australia with the eastern gas market. The pipeline is scheduled for completion in 2018.

In total, around $900 million in recent investment has occurred, of which over 50 per cent is to enable more Victorian gas to flow north to NSW and Queensland. The expansion of northbound capacity on the Victorian gas transmission system has involved the most significant investment, with $260 million reportedly being spent to accommodate various shippers over the past four years.[47]

Gas field development

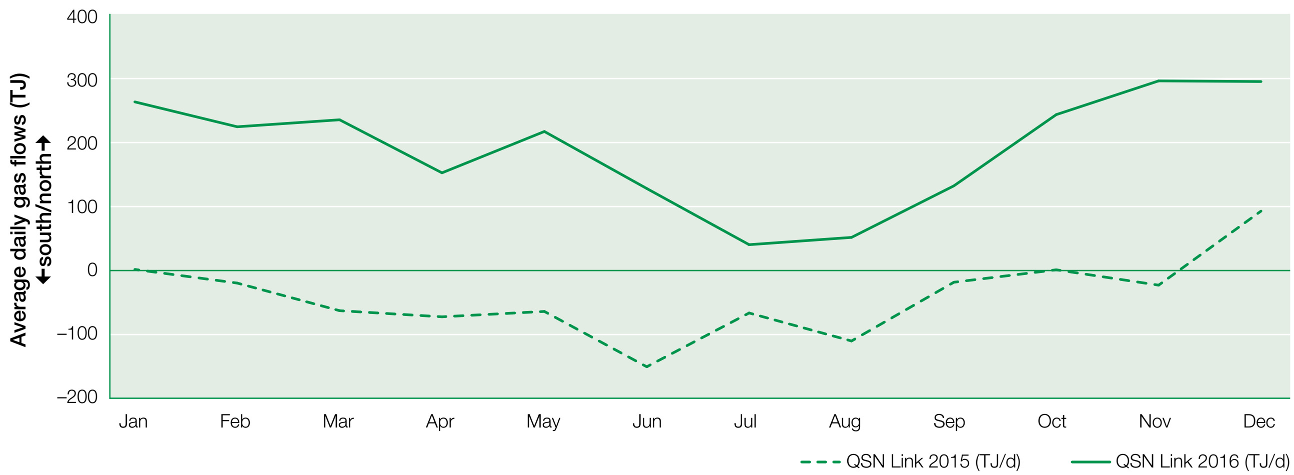
Various gas development proposals were on the table in 2017, although EnergyQuest assessed only two as showing material progress: Cooper Energy's Sole project and Senex's south west Queensland project.[48]

The use of hydraulic fracture stimulation technologies (fracking), and its potential impact on water resources and the environment, has raised community concerns about CSG development. In response to these concerns, moratoria on onshore gas exploration and development,

45 ACCC, *Inquiry into the east coast gas market*, April 2016, p. 5.
46 EnergyQuest, *Energy Quarterly*, March 2017, pp. 2, 28.
47 ACCC, *Inquiry into the east coast gas market*, April 2016, p. 93.
48 EnergyQuest, *Energy Quarterly*, March 2017.

Figure 2.14

Gas flows on the QSN Link



Source: AER.

and other regulatory impediments have restricted the development of onshore conventional and unconventional reserves in some jurisdictions.

In NSW, government regulations in response to community concerns about health and environmental impacts have delayed a number of CSG projects. The NSW Government in July 2015 launched a new strategic framework to determine appropriate areas in which to develop and extract gas, accounting for economic benefits and evidence of exploration and mining effects on the environment and communities. A Bill to ban CSG production in northern NSW, and to place a moratorium on all exploration across the state, was narrowly defeated in the NSW Parliament in August 2015.

Ongoing uncertainty around the issue led AGL Energy to announce in February 2016 that it would not proceed with its Gloucester Gas Project and would cease production at its Camden Gas Project. The announcement raised questions about the future of CSG in NSW. However, Santos submitted applications for its Narrabri Gas project in February 2017, and reached a conditional agreement with APA Group to develop a 450 kilometre pipeline from Narrabri to connect with the Moomba to Sydney Pipeline.[49]

Concerns about environmental impacts also led the Victorian Government to place a moratorium on CSG extraction and fracking, which it later extended to cover all onshore gas exploration. The moratorium affects 10 mineral exploration licences that cover CSG, 11 petroleum exploration permits that cover tight and shale gas, and three retention leases that cover tight and shale gas. The Victorian Parliament in March 2017 permanently banned fracking and extended the moratorium on onshore exploration until 2020.

Across the other states and territories:

- the Tasmanian Government put a moratorium on the use of fracking until 2020
- the Northern Territory Government placed a moratorium on hydraulic fracking after its election win in August 2016, but subsequently launched an inquiry into the technology. The inquiry was continuing in the first quarter 2017
- the South Australian Government, against the national trend, announced in March 2017 new measures to incentivise exploration for gas. The scheme offers a 10 per cent royalty rate to landowners whose property overlies a petroleum field that is brought into production[50]
- the Queensland Government has made available land access to explore and develop gas, conditional on the gas being for domestic sale only. In April 2017, it indicated its intent to expand the amount of land earmarked for domestic gas.[51]

49 APA Group, 'APA's agreement to deliver potential new source of gas for East Coast markets', ASX media release, 31 January 2017.

50 South Australian Government, *Our Energy Plan*, March 2017, available at http://ourenergyplan.sa.gov.au/.

51 Queensland Government, 'Queensland puts foot on the gas with Feds', Media release, 16 April 2017.

Imports of LNG

AGL Energy is exploring options for an LNG import terminal by 2021, to source lower cost gas for its customers. It plans to launch regulatory and community engagement on the project in 2017, and identified potential sites in NSW, South Australia and Victoria. EnergyQuest noted the high cost of pipeline transport (around $2.50 per gigajoule from Queensland to Sydney), compared with the much lower cost of transporting via LNG tanker (around $0.40 per gigajoule from Indonesia to Sydney), is a factor favouring a gas terminal in the southern states.[52] This is still the case after accounting for the costs of reprocessing LNG into gas ($0.75 per gigajoule).[53]

2.7.5 Policy initiatives

Policy makers are progressing reforms to help alleviate pressures in the eastern gas market. Two key inputs to the reform process were the ACCC's inquiry into the east coast gas market[54] and the AEMC's Eastern Australian Wholesale Gas Market and Pipelines Framework Review.[55] Separately, the AEMC is reviewing Victoria's declared gas market (in progress at March 2017).

The ACCC inquiry and AEMC review recommended ways to promote gas market competition and encourage supply. The recommendations included reforms to spot market design, better quality information to market participants, and easier access to gas pipelines. The CoAG Energy Council in August 2016 set up a new Gas Market Reform Group to implement the inquiry's and review's recommendations. It also appointed Dr Michael Vertigan to examine gas pipeline issues that the ACCC raised in its inquiry report.

In response to escalating concerns about gas prices and the security of east coast gas supplies, the Australian Government in April 2017 announced it would impose export limits from 1 July 2017 on LNG producers that draw more gas from the domestic market than they supply into it. Producers will have flexibility in how they meet this obligation—for example, by swapping cargoes out of portfolios, or by sourcing gas on the spot market. The government announcement followed an inability to reach a voluntary agreement with LNG exporters to act as net supply contributors to the domestic market.[56]

Also in April 2017, the government directed the ACCC to monitor wholesale gas markets in eastern Australia, using its inquiry powers to acquire information compulsorily as necessary. The inquiry will run over three years, with six monthly reporting.

In the inquiry, the ACCC will identify impediments to efficient supply, including the exercise of market power. It will also propose measures to address any issues found. As part of this work, the ACCC will scrutinise the pricing, volume and availability of domestic gas compared with gas that is being exported. It will also examine gas storage, transportation and processing, to ensure industry participants do not undermine reliable, secure and affordable domestic gas supplies, including supplies for electricity generation, industrial use and residential demand.[57]

Reform of gas spot markets

The AEMC found the east coast gas market and underpinning regulatory frameworks are fragmented and disjointed.[58] It noted a diversity of arrangements, including:

- three different spot market designs (the short term trading market, the Victorian gas market and the gas supply hub model)
- four sets of pipeline regulatory arrangements (full regulation, light regulation, no regulation and 15 year coverage exemptions)
- two different pipeline carriage arrangements (market carriage in Victoria and contract carriage elsewhere).[59]

The AEMC concluded that the multiple arrangements create unnecessary complexity and inefficiency. Some participants, for example, are registered only at the hubs where they directly consume gas, which limits their ability to trade across the east coast. A fully integrated east coast gas market would mean all gas suppliers and users could easily participate at any of the hubs and thus realise commercial benefits.

The AEMC also proposed immediate actions to improve market and price transparency. Reforms include harmonising the gas day start time for spot markets across the east coast (to take effect in April 2021), and enhancing pipeline capacity trading information on the Gas Bulletin Board (to promote trade in contracted but idle capacity)

52 EnergyQuest, *Energy Quarterly* March 2017, p.29.
53 ACCC, *Inquiry into the east coast gas market*, April 2016, p. 48.
54 ACCC, *Inquiry into the east coast gas market*, April 2016.
55 AEMC, *East Coast Wholesale Gas Market and Pipeline Frameworks Review, stage 2 final report*, 23 May 2016.
56 The Hon Malcolm Turnbull MP (Prime Minister of Australia), 'Delivering affordable gas for all Australians', Media release, 27 April 2017.
57 The Hon Scott Morrison MP, 'ACCC to monitor eastern Australian wholesale gas market', Media release, 19 April 2017.
58 AEMC, *East Coast Wholesale Gas Market and Pipeline Frameworks Review, stage 2 final report*, 23 May 2016.
59 AEMC, *East Coast Wholesale Gas Market and Pipeline Frameworks Review, stage 1 final report*, 23 July 2015.

It also proposed a longer term rationalisation of spot markets in eastern Australia, based on the creation of a northern hub at Wallumbilla, Queensland, and a southern hub in Victoria (to eventually replace the declared gas market in Victoria). The two hubs would share common trading arrangements to improve price discovery and reduce barriers to participation. The proposed model is exchange based trading (consistent with the gas supply hubs' design), with common gas day start times, backend systems, registration, prudentials, settlement and training where possible. But prices would differ between the hubs, reflecting market conditions in each region.

The AEMC argued that further splitting spot markets into other locations would spread liquidity too thinly. It considered the short term trading markets could remain following the development of the northern and southern hubs, but should be simplified and eventually used only for balancing and pipeline capacity trading.

Reform of the gas transmission pipeline sector

Access to transmission pipelines is essential for shippers—especially those without legacy contracts—to transport gas from new gas fields, particularly in south west Queensland and the Northern Territory.

In response to issues raised by the ACCC (box 2.4) and the AEMC, the CoAG Energy Council tasked an expert panel led by Dr Michael Vertigan with examining the regulatory framework for gas pipelines, including the adequacy of the coverage criteria. The expert panel found parties negotiating for pipeline services have unequal levels of bargaining power and information. It noted the regulatory regime for covered pipelines typically regulates only forward haul tariffs and does not adequately deal with other services that market participants increasingly seek.[60]

To address the negotiating imbalance, the expert panel advised pipelines should publish better quality information (including information on pricing methods and costs) so potential shippers can judge the reasonableness of offers. It argued binding arbitration should be introduced to deal with failed commercial negotiations, thus strengthening the negotiating power of shippers. While arbitration is available for regulated pipelines, Dr Vertigan recommended widening the provisions to all pipelines. The CoAG Energy Council subsequently tasked the Gas Market Reform Group with designing an arbitration framework, for the Energy Council to consider in mid-2017. This work has begun, with an issues paper released in March 2017.

60 Dr Michael Vertigan AC, *Examination of the current test for the regulation of gas pipelines*, 14 December 2016.

Pipeline capacity trading reforms

Capacity on many transmission pipelines in eastern Australia is fully contracted, posing a barrier to entry for new participants. Fully contracted facilities include the Sydney to Moomba service on the Moomba to Sydney Pipeline; the Moomba to Wallumbilla service on the South West Queensland Pipeline; and services on the Moomba to Adelaide Pipeline in both directions.[61]

Nonetheless, some pipelines have contracted capacity that is underused. A number of submissions to the AEMC review claimed difficulties in accessing capacity on fully contracted pipeline routes; the claims included concerns about pricing. Despite some stakeholders' suggestions of systemic capacity withholding by incumbent shippers, the ACCC found evidence of capacity trading occurring in 2015 (around 20 individual trades covering durations of three months to 20 years). The transactions included pure capacity trades, as well as delivered gas trades. But the ACCC also heard evidence that some trading opportunities could not be realised because shippers faced difficulties in procuring pipeline access at short notice across multiple pipelines. The AEMC raised similar concerns and proposed measures to promote further secondary trading in pipeline capacity.[62]

In response, the CoAG Energy Council agreed to wide ranging reforms to promote trading in underused pipeline capacity. It agreed to establish a trading platform, day-ahead auctions of contracted but un-nominated capacity, the standardisation of contractual terms, and the publication of secondary capacity trade information. The Gas Market Reform Group was working to implement these reforms in early 2017.

61 Gas Bulletin Board, www.gasbb.com.au, accessed 17 April 2017.
62 AEMC*, East Coast Wholesale Gas Markets and Pipeline Frameworks Review*, *stage 2 final report*, 23 May 2016.

Image courtesy of DUET Group

3 REGULATED ENERGY NETWORKS

Capital intensive networks are used to transport electricity and gas from producers to energy customers. This chapter focuses on energy networks for which the Australian Energy Regulator (AER) has regulatory responsibilities (box 3.1).

3.1 Electricity networks

Electricity transmission networks transport power at high voltages from generators to load centres (see Infographic 1 of this report). They consist of towers and wires, underground cables, transformers, switching equipment, reactive power devices, and monitoring and telecommunications equipment.

Electricity distribution networks transport electricity from points along the transmission network, and criss-cross urban and regional areas to supply electricity to customers. They consist of poles and wires, substations, transformers, switching equipment, and monitoring and signaling equipment. Electricity is stepped down to lower voltages in a distribution network, for safe use by customers. But, while electricity distributors transport electricity to customers, they do not sell it. Instead, retailers bundle electricity generation with transmission and distribution services, and sell them as a package (chapter 4).

While networks traditionally provided a one-way delivery service to customers, their role is changing as technological innovations allow the networks to provide a platform for trading a variety of electricity services.

The AER regulates electricity networks in the National Electricity Market (NEM), which is a fully interconnected grid covering Queensland, New South Wales (NSW), the Australian Capital Territory (ACT), Victoria, South Australia and Tasmania. The transmission grid has a long, thin, low density structure, reflecting the location of, and distance between, major demand centres. It comprises five state based transmission networks, linked by cross-border interconnectors (figure 3.1). Three interconnectors (the Queensland–NSW Interconnector (QNI), Heywood and NSW–Vic) form part of the state based networks, while the other three (Basslink, Directlink and Murraylink) are separately owned. Only Basslink, which connects Victoria with Tasmania, is unregulated.

The NEM has 13 major electricity distribution networks. Queensland, NSW and Victoria each have multiple networks that are monopoly providers in designated areas. The ACT, South Australia and Tasmania each have one major network. Some jurisdictions also have small regional networks. The total length of distribution infrastructure in the NEM is around 735 000 kilometres—17 times longer than the total for transmission.

Box 3.1 The AER's roles for electricity networks and gas pipelines

The AER sets the amount of revenue that a network businesses can recover from customers for the use of its energy networks. In particular, we determine the efficient costs of providing electricity network services, and access prices for covered gas pipeline services. We undertake this role for energy networks in Queensland, NSW, Victoria, South Australia, Tasmania, the ACT and the Northern Territory. At 1 January 2017, we regulated 32 energy network (21 electricity networks and 11 gas pipelines and networks).

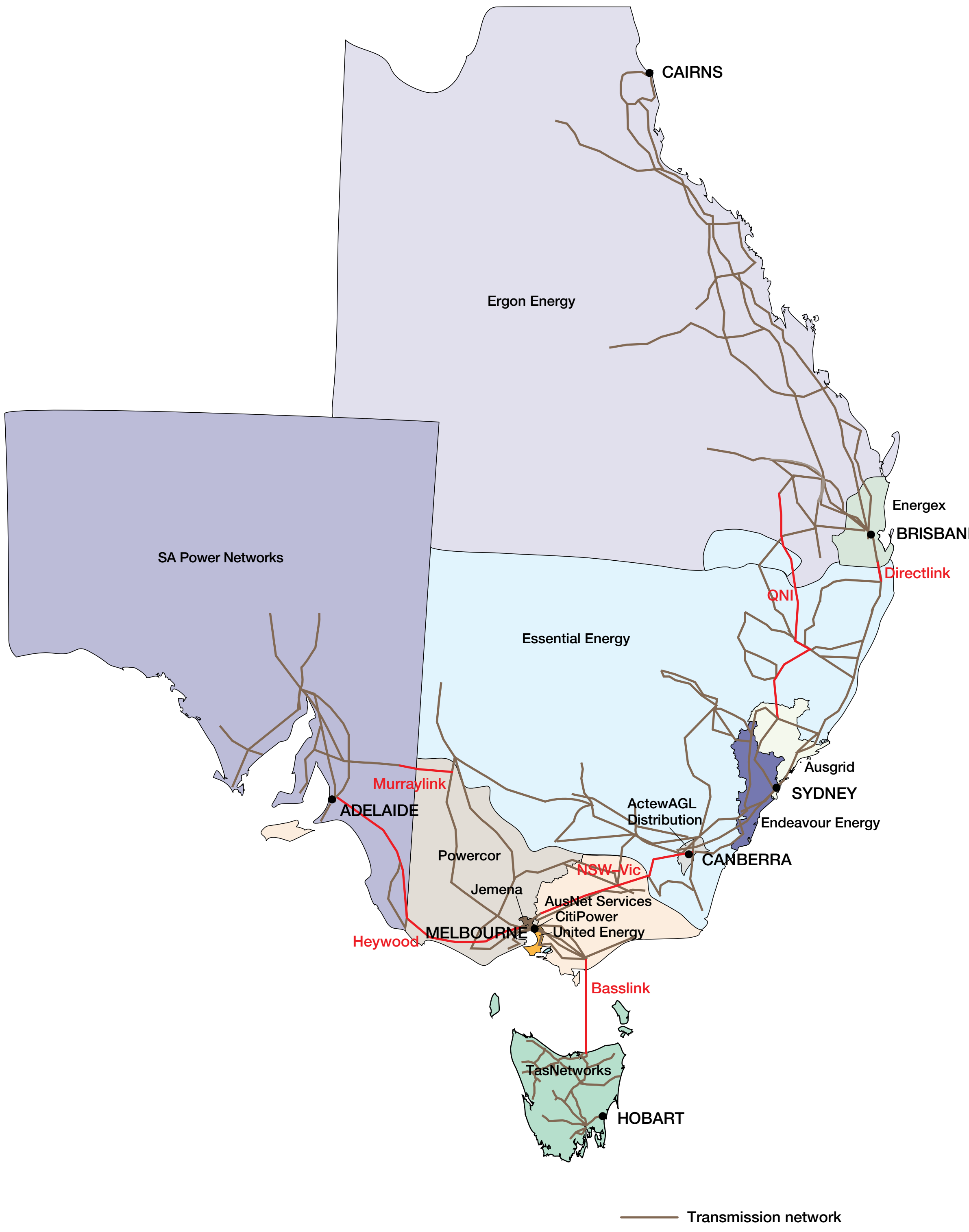
Our approach is to apply regulation that promotes efficient investment in energy services valued by customers. In assessing revenues, we account for the efficient costs of providing network services, but we also offer incentives for network businesses to spend efficiently and share the benefits with consumers.

Typically, we undertake a full regulatory review of each network or pipeline once every five years, engaging closely with consumers and other stakeholders. If our final determination is subject to legal appeals, we also participate in those processes.

Alongside this central role, we undertake broader regulatory functions. Some of these functions recur regularly (such as approving annual tariffs), while the timing of others is unpredictable (such as assessing cost pass throughs and resolving connection disputes).

We are also implementing reforms that empower customers to make informed choices about their energy use, and that optimise the use of energy networks. This work includes network pricing reforms to give consumers clearer signals about the cost of energy that they use. We are also helping to build competitive markets for metering services, and for solar photovoltaic (PV) and battery installations. To do so, we are making costs more transparent and introducing ring fencing rules to create a level playing field for existing network businesses and new entrants.

Figure 3.1
Electricity networks in the NEM



QNI, Queensland–NSW Interconnector.

Source: AER.

Table 3.1 Electricity transmission networks regulated by the AER

NETWORK	LOCATION	LINE LENGTH (CIRCUIT KM)	ELECTRICITY TRANSMITTED (GWH) 2015–16	MAXIMUM DEMAND (MW) 2015–16[1]	ASSET BASE ($ MILLION)[2]	CURRENT REGULATORY PERIOD	OWNER
NEM REGION NETWORKS							
Powerlink	Qld–NSW	14 756	52 872	11 616	6 571	1 July 2012–30 June 2017	Queensland Government
TransGrid	NSW	13 039	72 200	18 000	6 082	1 July 2014–30 June 2018	Hastings 20%; Spark Infastructure 15%; other private equity 65%
AusNet Services	Vic	6 559	na	na	2 880	1 April 2014–31 March 2017	Listed company (Singapore Power 31.1%, State Grid Corporation 19.9 %)
ElectraNet	SA	5 524	14 248	3 198	2 102	1 July 2013–30 June 2018	State Grid Corporation 46.6%; YTL Power Investments Limited 33.5%; Hastings 19.9%
TasNetworks	Tas	3 564	11 655	2 456	1 378	1 July 2014–30 June 2019	Tasmanian Government
NEM TOTALS		43 441	150 975		19 014		
STAND-ALONE INTERCONNECTORS							
Directlink	Qld-NSW	63			135	1 July 2015–30 June 2020	Energy Infrastructure Investments (Marubeni 49.9%, Osaka Gas 30.2%, APA Group 19.9%)
Murraylink	Vic-SA	180			104	1 July 2013–30 June 2018	Energy Infrastructure Investments (Marubeni 49.9%, Osaka Gas 30.2%, APA Group 19.9%)
Basslink	Vic-Tas	375				Unregulated	Keppel Infrastructure Trust

GWh, gigawatt hours; km, kilometres; MW, megawatts; na, not available.

1. Transmission system non-coincident, summated maximum demand in 2015–16.
2. The asset base at June 2016 (March 2016 for AusNet Services).

Sources: AER regulatory determinations and economic benchmarking regulatory information notices (RINs); Australian Securities Exchange (ASX) releases; company websites; company annual reports.

The combined asset value of the NEM's distribution networks is $68 billion—over three times the valuation for transmission infrastructure ($19 billion).[1]

Alongside the NEM jurisdictions, the AER in 2016 became regulator of the Northern Territory's electricity distribution network. In 2017 the AER is developing a framework and approach to regulating the network in consultation with stakeholders. The network owner (Power and Water Corporation) will submit a regulatory proposal in early 2018, covering the period 1 July 2019 to 30 June 2024.

In Western Australia, electricity networks are subject to separate regulatory arrangements administered by the Economic Regulation Authority (ERA).

1 As measured by the regulated asset base (RAB). In general, the RAB reflects the replacement cost of a network when it was first regulated, plus subsequent new investment, less depreciation.

Figure 3.1 illustrates electricity transmission networks and interconnectors, and distribution networks in NEM jurisdictions. Tables 3.1 and 3.2 set out ownership arrangements and other information for each network.

3.2 Gas pipelines and networks

Gas transmission pipelines transport gas from production fields to major demand centres (hubs). The pipelines typically have wide diameters and operate under high pressure to optimise shipping capacity. An interconnected transmission pipeline network runs from Queensland to Tasmania, allowing competition between gas basins and strengthening the security of supply. While Western Australia and the Northern Territory are not interconnected with eastern Australia, Jemena is scheduled to commission the North Gas Pipeline from Tennant Creek in the Northern Territory to Mount Isa, Queensland, by 2018.

Table 3.2 **Electricity distribution networks regulated by the AER**

NETWORK	CUSTOMER NUMBERS	LINE LENGTH (CIRCUIT KM)	ELECTRICITY TRANSMITTED (GWH) 2015–16[1]	MAXIMUM DEMAND (MW) 2015–16[2]	ASSET BASE ($ MILLION)[3]	CURRENT REGULATORY PERIOD	OWNER
QUEENSLAND							
Energex	1 421 522	53 202	21 138	5 181	11 545	1 July 2015–30 June 2020	Qld Government
Ergon Energy	739 354	152 255	13 747	3 230	10 210	1 July 2015–30 June 2020	Qld Government
NEW SOUTH WALES AND ACT							
AusGrid	1 688 282	41 453	25 618	5 475	14 676	1 July 2014–30 June 2019	New South Wales Government 49.6%; IFM Investors 25.2%; AustralianSuper 25.2%
Endeavour Energy	968 355	36 468	16 645	4 272	5 979	1 July 2014–30 June 2019	NSW Government
Essential Energy	879 065	191 945	12 313	2 392	7 380	1 July 2014–30 June 2019	NSW Government
ActewAGL	184 962	5 312	2 876	672	907	1 July 2014–30 June 2019	Icon Water (ACT Government) 50%; Jemena (State Grid Corporation of China 60%, Singapore Power 40%) 50%
VICTORIA							
Powercor Australia	777 161	74 452	10 713	2 299	3 296	1 January 2016–31 December 2020	Cheung Kong Infrastructure/Power Assets Holdings 51%; Spark Infrastructure 49%
AusNet Services	706 424	44 349	7 686	1 815	3 459	1 January 2016–31 December 2020	Listed company (Singapore Power 31.1%, State Grid Corporation 19.9 %)
United Energy	664 549	12 873	7 604	1 894	2 051	1 January 2016–31 December 2020	Cheung Kong Infrastructure 66%; SGSP Australia (State Grid Corporation 60%, Singapore Power International 40%) 34%
CitiPower	327 907	4 505	5 944	1 287	1 755	1 January 2016–31 December 2020	Cheung Kong Infrastructure/Power Assets Holdings 51%; Spark Infrastructure 49%
Jemena	321 417	6 252	4 212	924	1 191	1 January 2016–31 December 2020	SGSP Australia (State Grid Corporation 60%, Singapore Power International 40%)
SOUTH AUSTRALIA							
SA Power Networks	858 647	88 808	10 355	2 894	3 863	1 July 2015–30 June 2020	Cheung Kong Infrastructure/Power Assets Holdings 51%; Spark Infrastructure 49%
TASMANIA							
TasNetworks	285 325	22 681	4 243	232	1 615	1 July 2012–30 June 2017	Tasmanian Government
NEM totals	9 822 967	734 556	143 095		67 929		

GWh, gigawatt hours; km, kilometres; MW, megawatts

1. Calendar year ending December 2015 for Victorian businesses.
2. Non-coincident, summated, raw system, annual maximum demand at the zone substation level in 2015–16 (calendar year ending December 2015 for Victorian businesses).
3. The asset base at June 2016 (December 2015 for Victorian businesses).

Note: The AER in 2017 is developing a framework and approach to regulating the Northern Territory distribution network in consultation with stakeholders, covering the period 1 July 2019 to 30 June 2024.

Sources: AER regulatory determinations and economic benchmarking RINs; ASX releases; company websites; company annual reports.

Table 3.3 Covered gas transmission pipelines regulated by the AER

PIPELINE	STATE	LENGTH (KM)	CAPACITY (TJ/D)[4]	ASSET BASE[3] ($ MILLION)	INVESTMENT CURRENT PERIOD ($ MILLION)[3]	CURRENT REGULATORY PERIOD	OWNER
FULL REGULATION							
Roma to Brisbane Pipeline	Qld	438	233/125	460	20	1 Sep 2012–30 Jun 2017	APA Group
Central Ranges Pipeline	NSW	294	7	na	na	7 Dec 2005–30 Jun 2019	APA Group
Victorian Transmission System (GasNet)	Vic	2035	1030	670	185	1 Jan 2013–31 Dec 2017	APA Group
Amadeus Gas Pipeline	NT	1658	120	116	17	1 Jul 2016–30 Jun 2021	APA Group
LIGHT REGULATION[2]							
Carpentaria Pipeline	Qld	840	119	na	na	na	APA Group
Central West Pipeline (Marsden to Dubbo)	NSW	255	10	na	na	na	APA Group
Moomba to Sydney Pipeline[1]	NSW	2029	439/120	na	na	na	APA Group

km, kilometres; na, not available; TJ/d, terajoules per day.

1. The Moomba to Sydney Pipeline is uncovered from Moomba to the offtake point of the Central West Pipeline at Marsden.
2. The AER does not undertake a full regulatory assessment for light regulation pipelines, for which limited data is available.
3. The asset base is the opening valuation for the current regulatory period in June 2016 dollars. Investment is as forecast for the current regulatory period.
4. Where two values appear, the first value represents pipeline capacity for the primary gas flow direction. The second value represents reverse flow capacity for bidirectional piplelines.

Sources: National Gas Bulletin Board; Australian Energy Market Commission (AEMC) gas scheme register; company websites.

A network of *gas distribution pipelines* delivers gas from demand hubs to commercial and residential customers. A gas distribution network typically consists of high, medium and low pressure pipelines. The high and medium pressure mains provide a 'backbone' that services areas of high demand and transports gas between population concentrations within a distribution area. The low pressure pipes lead off the high pressure mains to end customers. 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, but the proportion of households and businesses connected to the networks varies across regions. Gas penetration in the residential market in 2016 was around over 80 per cent in Victoria, 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.

The AER regulates 'covered' gas pipelines in jurisdictions other than Western Australia. Four *transmission* pipelines are subject to 'full' regulation (involving a full economic assessment of pricing proposals), and another three pipelines are subject to 'light' regulation (box 3.1). No other transmission pipeline is subject to any form of economic regulation.

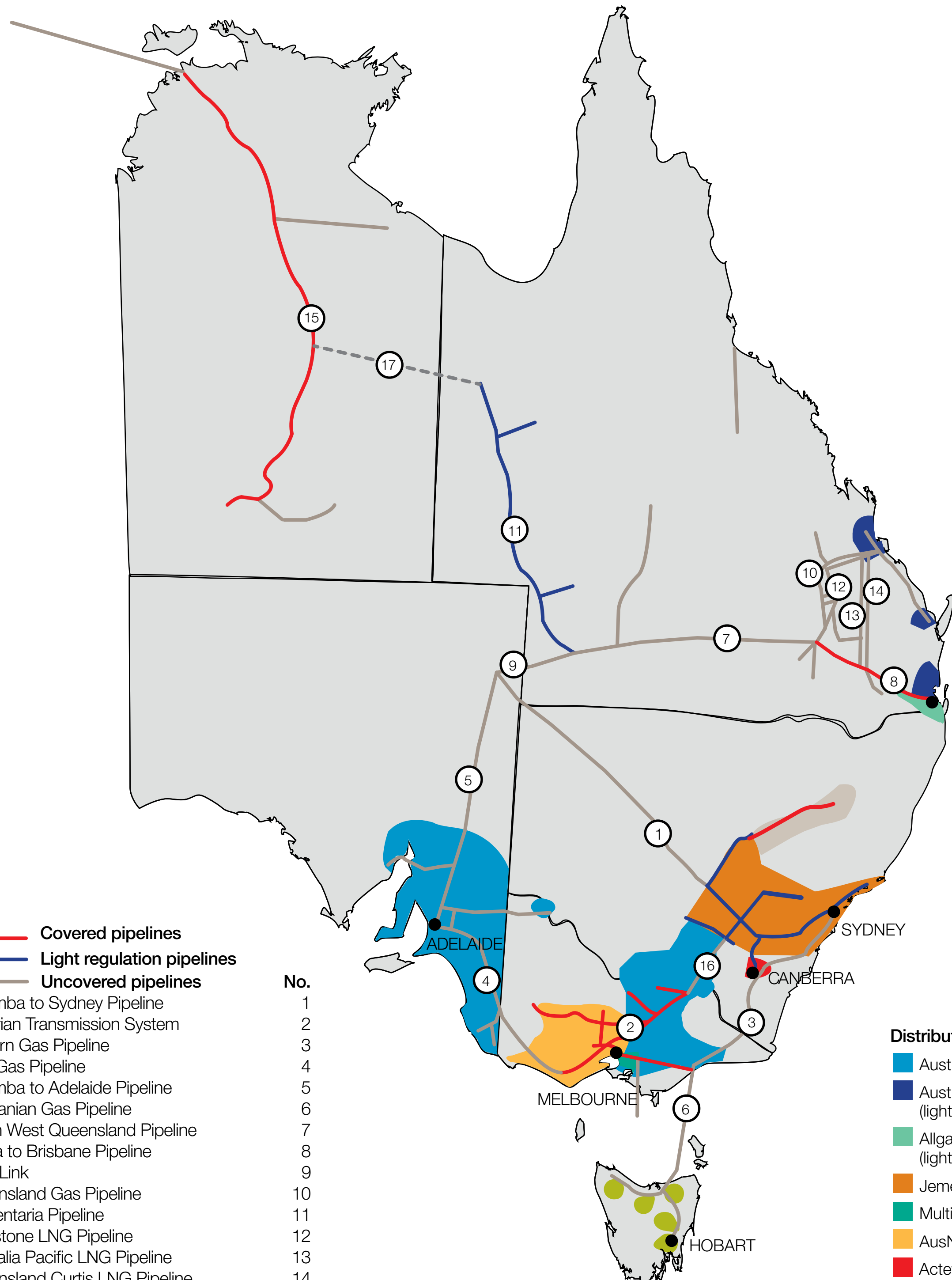
By contrast, full regulation applies to all major *distribution* networks in NSW, Victoria, South Australia and the ACT. 'Light' regulation applies to the Queensland's distribution networks, and the Tasmanian network is unregulated.

Figure 3.2 illustrates gas transmission networks and distribution network areas in jurisdictions for which the AER has regulatory responsibilities. Tables 3.3 and 3.4 set out ownership arrangements and other information for each network.

3.3 Network ownership

There is a mix of public and private ownership of Australia's energy networks. Significant ownership links also exist across the gas and electricity network sector. Jemena, AusNet Services, APA Group and Cheung Kong Infrastructure have ownership interests (some substantial) across both sectors. Cheung Kong Infrastructure raised its equity in the industry in 2017 by acquiring DUET Group's gas and electricity distribution assets in Victoria.

Figure 3.2
Major gas pipelines in eastern Australia



Covered pipelines
Light regulation pipelines
Uncovered pipelines

	No.
Moomba to Sydney Pipeline	1
Victorian Transmission System	2
Eastern Gas Pipeline	3
SEA Gas Pipeline	4
Moomba to Adelaide Pipeline	5
Tasmanian Gas Pipeline	6
South West Queensland Pipeline	7
Roma to Brisbane Pipeline	8
QSN Link	9
Queensland Gas Pipeline	10
Carpentaria Pipeline	11
Gladstone LNG Pipeline	12
Australia Pacific LNG Pipeline	13
Queensland Curtis LNG Pipeline	14
Amadeus Basin to Darwin Pipeline	15
NSW–Victoria Interconnect	16
Northern Gas Pipeline (proposed)	17

Distribution networks
- Australian Gas Networks
- Australian Gas Networks (light regulation)
- Allgas Energy (light regulation)
- Jemena
- Multinet
- AusNet Services
- ActewAGL
- Tas Gas Networks (unregulated)
- Central Ranges System

Source: AER.

3.3.1 Electricity network ownership

Tables 3.1 and 3.2 detail ownership arrangements for electricity networks regulated by the AER. All Victorian networks and the South Australian transmission network are privately owned. South Australia's distribution network is government owned but leased to private interests. The three stand-alone interconnectors (Directlink, Murraylink and Basslink) are also privately owned. In the transmission sector, the leading private owners include Cheung Kong Infrastructure and Power Assets, Singapore Power International and the State Grid Corporation of China.

Victoria's transmission network arrangements separate asset ownership 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. AEMO also buys bulk network services from AusNet Services for sale to customers.

The NSW Government in 2015 launched a partial privatisation of its electricity networks:

- In November 2015, a consortium led by Hastings Funds Management (20 per cent) and Spark Infrastructure (15 per cent) acquired a 99 year lease for the TransGrid (transmission) network.
- In October 2016, a consortium comprising IFM Investors and AustralianSuper entered a 99 year lease of 50.4 per cent of the AusGrid (distribution) network.
- In December 2016, the NSW Government called for expressions of interest for the long term lease of 50.4 per cent of the Endeavour Energy (distribution) network.

The rural Essential Energy distribution network will remain owned by the NSW Government.

The Queensland and Tasmanian networks are government owned. The Queensland Government in 2016 merged its state owned electricity distributors, Energex and Ergon Energy, under a new parent company called Energy Queensland. The ACT distribution network has joint government and private ownership.

In some jurisdictions, ownership of electricity networks overlaps with other industry segments, with ring fencing arrangements for operational separation. In the ACT, common ownership occurs in electricity distribution and retailing,[2] while Queensland's state owned Ergon Energy provides both distribution and retail services.

2 In the ACT, ACTEW Corporation has a 50 per cent share in ActewAGL Retail and ActewAGL Distribution. AGL Energy and Singapore Power International respectively own the remaining shares.

3.3.2 Gas pipeline ownership

Australia's gas pipelines are privately owned. Tables 3.3 and 3.4 detail ownership arrangements for *covered* gas pipelines regulated by the AER. Chapter 2 provides ownership and other information for uncovered pipelines.

APA Group is the principal owner in the gas pipeline sector. Other participants include Australian Gas Networks (owned by Cheung Kong Infrastructure), Jemena (owned by the State Grid Corporation of China) and Singapore Power International.

3.4 Economic regulation of networks and pipelines

Electricity networks and gas pipelines are capital intensive and incur declining average costs as output rises. So, a single supplier is typically the most efficient way to supply network and pipeline services in a geographic area. The result is a natural monopoly industry structure. For this reason, the electricity networks and some gas pipelines are regulated to manage the risk of monopoly pricing.

The AER sets the amount of revenue that electricity networks and covered pipelines can recover from customers (box 3.1) in jurisdictions other than Western Australia, where the ERA is the regulator. In 2016 the Western Australian Government introduced Bills to transfer responsibility for economic regulation of its electricity business, Western Power, and four gas pipelines to the AER. However, the timeframe for the proposed transfer was not achieved, so the ERA continues as the regulator of these networks.

3.4.1 Regulatory approach

The National Electricity Law and the National Gas Law set the regulatory frameworks for the electricity network and gas pipeline sectors.

All electricity networks in the NEM are subject to full economic regulation. For gas, the National Gas Law applies different forms of regulation (box 3.2). At 1 January 2017, 'full regulation' applied to four transmission pipelines and seven distribution networks, while 'light regulation' applied to three transmission pipelines and two distribution networks. Tables 3.3 and 3.4 indicate the regulatory status of those pipelines. Additionally, many pipelines—including most transmission pipelines—are unregulated (chapter 2).

The regulatory objective in both industries is to promote efficient investment in, and operation of, energy services for the long-term interest of consumers. The underlying laws set

Table 3.4 Covered gas distribution networks regulated by the AER

NETWORK	CUSTOMER NUMBERS (APPROX)	LENGTH OF MAINS (KM)	ASSET BASE ($ MILLION)[1]	INVESTMENT—CURRENT PERIOD ($ MILLION)[2]	REVENUE—CURRENT PERIOD ($ MILLION)[2]	CURRENT REGULATORY PERIOD	OWNER
FULL REGULATION							
NEW SOUTH WALES AND ACT							
Jemena Gas Networks (NSW)	1 300 000	25 380	3 022	971	2 101	1 Jul 2015– 30 Jun 2020	Jemena (State Grid Corporation 60%, Singapore Power International 40%)
ActewAGL	137 800	4 900	343	80	291	1 Jul 2016– 30 Jun 2021	ACTEW Corporation (ACT Government) 50%; Jemena (State Grid Corporation 60%, Singapore Power International 40%) 50%
Central Ranges System	7 000	230	na	na	na	1 Jul 2004– 30 Jun 2019	APA Group
VICTORIA							
AusNet Services	647 000	10 480	1 362	498	944	1 Jan 2013– 31 Dec 2017	Listed company (Singapore Power International 31%, State Grid Corporation 20%)
Multinet	687 000	10 030	1 126	259	897	1 Jan 2013– 31 Dec 2017	Cheung Kong Infrastructure
Australian Gas Networks[3]	648 000	11 000	1 193	431	904	1 Jan 2013– 31 Dec 2017	Cheung Kong Infrastructure
SOUTH AUSTRALIA							
Australian Gas Networks	423 500	7 950	1 386	558	845	1 Jul 2016– 30 Jun 2021	Cheung Kong Infrastructure
LIGHT REGULATION[4]							
QUEENSLAND							
Allgas Energy	100 000	3 220	na	na	na	Light regulation from July 2015	APA Group 20%; Marubeni 40%; Deutsche AWM 40%
Australian Gas Networks	92 900	2 700	na	na	na	Light regulation from February 2015	Cheung Kong Infrastructure
TOTALS	4 043 200	75 890					

km, kilometres; na, not available.

1. The asset base is the initial capital base, adjusted for additions and deletions, as reset at the beginning of the current access arrangement period, converted to June 2016 dollars.
2. Investment and revenue are forecasts for the current access arrangement period (typically, five years), converted to June 2016 dollars.
3. Customer numbers and line length for the Australian Gas Networks in Victoria include the gas network in Albury.
4. The AER does not undertake a full regulatory assessment for light regulation pipelines, for which limited data is available.

Sources: access arrangements for covered pipelines; AEMC gas scheme register; company websites.

out revenue and pricing principles, including that network businesses should have a reasonable opportunity to recover at least efficient costs.

Network businesses must periodically submit regulatory proposals (for electricity networks) and access arrangements (for full regulation gas pipelines) to the AER. The proposals include forecast expenditure and revenue requirements (typically covering a five year period); for gas, they also include a reference tariff (box 3.2). In a dispute, an access seeker may ask the regulator to arbitrate on and enforce the access arrangement.

For electricity networks, the AER has 15 months to review a revenue proposal before releasing a final decision. For gas pipelines, it has six months (plus stop-the-clock time

Box 3.2 Types of gas pipeline regulation

The National Gas Law provides for different types of regulation to apply to gas pipelines, based on competition and significance criteria. Only 'covered' pipelines are regulated, and this regulation may be 'full' or 'light'.

A **full regulation** pipeline must periodically submit an access arrangement to the AER, setting out pricing for a 'reference service' sought by a significant portion of the market. Currently, the AER regulates four transmission pipelines and seven gas distribution networks under full regulation.

In some circumstances, a pipeline may convert to **light regulation**, without upfront price regulation. This regulatory model is more a negotiate–arbitrate approach, placing greater emphasis on commercial negotiation and information disclosure. The AER plays a role only if dispute resolution provisions are triggered. A light regulation pipeline may not engage in inefficient price discrimination or other conduct that may adversely affect access or competition in other markets.

Where light regulation applies, the pipeline provider must publish access prices and other terms and conditions on its website. In eastern Australia, the Carpentaria Gas Pipeline in Queensland, the covered portions of the Moomba to Sydney Pipeline, and the Central West Pipeline in NSW are subject to light regulation. Queensland's two distribution networks—Australian Gas Networks and Allgas Energy—in 2015 became the first major distribution networks to convert to light regulation. The National Competition Council found light regulation of the networks would be similarly effective compared with full regulation, but would provide significant cost savings that may benefit customers.

The Gas Law enables the Commonwealth Minister for Resources and Energy to grant a 15 year 'no coverage' determination for new pipelines in certain circumstances. Since 2010, the Minister has granted 'no coverage' determinations for four transmission pipelines supplying gas from the Surat–Bowen Basin to LNG projects in Queensland.

The Australian Competition and Consumer Commission (ACCC) recommended in April 2016 that the Council of Australia Governments (CoAG) Energy Council replace the test for determining whether a pipelines is subject to regulation. It recommended a new test based on whether a pipeline has substantial market power. The Energy Council tasked Dr Michael Vertigan AC in August 2016 with reviewing whether a new test is needed. Dr Vertigan did not recommend changes to the coverage test; instead, he recommended increased disclosure and transparency around pipeline service pricing and contract terms, supported by binding commercial arbitration. The recommendations are scheduled to take effect from 1 May 2017, pending legislative approval and other regulatory processes.

at certain stages of the process) to decide whether to approve an access arrangement proposal. This time can be extended by two months, with a maximum of 13 months to render a decision.

The AER assesses regulatory proposals and access arrangements against legislative criteria, accounting for issues raised in consultation. In particular, it assesses the business's forecast revenue requirements to cover its efficient costs. The AER uses a building block model that accounts for operating and maintenance expenditure, capital expenditure, asset depreciation costs and taxation liabilities, and an appropriate return on capital to network owners.

Figure 3.3 illustrates revenue components for a sample of recent AER determinations. The largest component is the return on capital, which may account for up to two thirds of revenue. The size of a network's asset base (and projected investment) and weighted average cost of capital (the rate of return necessary to cover a commercial return on equity and efficient debt costs) determine the return on capital. Operating costs typically account for 30 per cent of revenue requirements for electricity networks and 30–40 per cent of revenue requirements for covered gas pipelines.

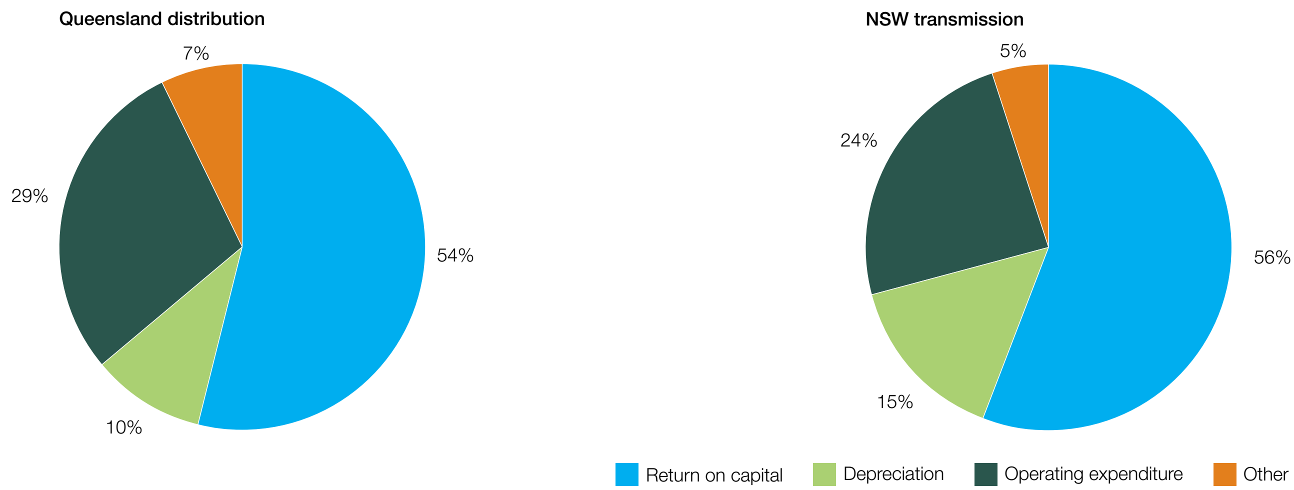
While the approach to assessing revenue is similar across electricity and gas, there are differences:

- In electricity transmission, the AER determines a cap on the maximum revenue that a network can earn during a regulatory period.
- In electricity distribution, revenue caps apply in all states except the ACT. In the ACT, an average revenue cap (revenue yield) links revenue to volumes of electricity sold.
- In gas transmission and distribution, weighted average price caps allow flexibility in individual tariffs within an overall ceiling. In 2016 the Victorian gas distributor Multinet Gas proposed moving to a revenue cap from 2018. The AER will consider this proposal in 2017.

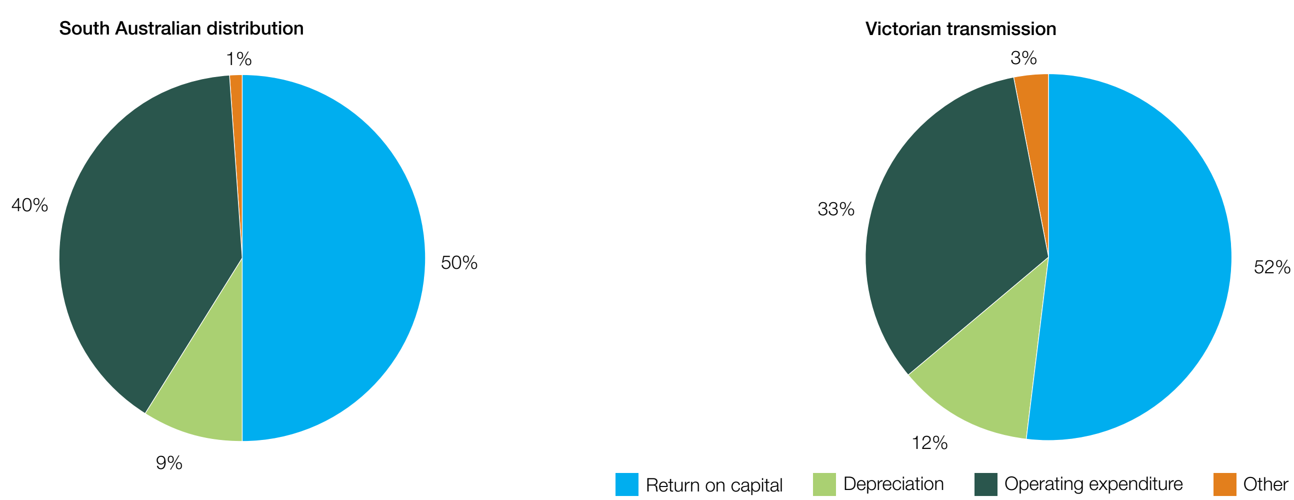
The regulatory framework provides incentives for network businesses to spend efficiently and share the benefits

Figure 3.3
Indicative composition of revenue

Electricity networks



Gas networks



Note: Estimates for the NSW electricity transmission network (for the regulatory period 2014–18), the Queensland electricity distribution network (2015–20), the Victorian gas transmission system (2013–17) and the South Australian gas distribution network (2011–16).

Sources: AER regulatory determinations and final decisions on access arrangements.

with consumers. Consumer engagement, therefore, is a pivotal part of the process. When the AER assesses a regulatory proposal, it considers how effectively a network business has consulted with the community. It also seeks stakeholder input through public forums and by consulting with network businesses, consumer representatives, governments and investment groups. As an example, the Consumer Challenge Panel advises the AER on issues that are important to consumers. To inform such stakeholders and encourage their participation, the AER publishes framework and approach documents, issues papers and draft decisions for electricity reviews, and draft decisions for gas reviews.[3]

Reforms progressively introduced in AER determinations made since 2015 include new incentive schemes (with benefit sharing with consumers), a more flexible approach

3 The AER website sets out the administrative steps in the regulatory processes for each network and pipeline. See www.aer.gov.au/networks-pipelines/determinations-access-arrangements.

to estimating rates of return, strengthened consultation requirements, and greater emphasis on benchmarking to assess electricity network proposals.[4] By 2020 the reforms will apply to all networks. At 1 January 2017, they applied to:

- electricity transmission networks in NSW and Tasmania
- electricity distribution networks in Queensland, NSW, Victoria, South Australia and the ACT
- gas distribution networks in NSW and the ACT
- the Amadeus Gas Pipeline (transmission) in the Northern Territory.

An affected party may apply to the Australian Competition Tribunal for a limited review of an AER decision. A party may also apply to the Federal Court for judicial review of the decision (section 3.4.4).

3.4.2 Regulatory timelines and recent AER activity

Figure 3.4 sets out regulatory timelines for energy networks in each jurisdiction. In 2016 the AER issued:

- final determinations for electricity distribution networks in Victoria
- final decisions on access arrangements for the Amadeus Gas Pipeline in the Northern Territory and for gas distribution networks in South Australia and the ACT
- preliminary decisions for the Victorian and Queensland electricity transmission networks and the Tasmanian electricity distribution network.

The final determinations approved total recoverable revenue of $12.6 billion, compared with the network businesses' proposed $15.3 billion—a reduction of 18 per cent.

In 2017 the AER will make final determinations for the Queensland and Victorian electricity transmission networks and the Tasmanian distribution network. In gas, it will make final determinations for Victoria's transmission and distribution networks and the Roma to Brisbane Pipeline (transmission).

3.4.3 Ongoing management of network revenue decisions

The regulatory process extends beyond completing revenue determinations for each network. Revenue decisions require ongoing management. In particular, the AER:

- conducts annual reviews of tariffs for electricity distribution and gas pipeline services, to ensure the tariffs do not breach revenue or pricing limits and reflect underlying costs. The scope of these reviews widened from 2016, when the AER assessed whether the Victorian electricity distribution businesses' tariff structures were cost reflective. The AER is making similar assessments in 2017 for the Queensland, NSW, South Australian, Tasmanian and ACT networks.
- assesses applications by network businesses to pass through to customers any costs arising from events that are outside the business's control and that were not anticipated when the regulatory decisions were made. Before approving a pass through, the AER must consider the efficiency of the expenditure, along with the business's actions to mitigate costs.
- publishes information submitted by network businesses on operational and financial performance, reliability and customer service. It also publishes benchmarking reports and category analysis information.
- operates incentive schemes for network businesses to maintain or improve service reliability in ways that customers value.[5]

3.4.4 Merits and judicial review of AER decisions

The National Electricity and Gas Laws allow an affected party to:

- apply to the Australian Competition Tribunal for a limited merits review of an AER determination
- apply to the Federal Court for judicial review of an AER decision.

Limited merits review

An affected party may apply to the Australian Competition Tribunal for a limited merits review of an AER decision. A review is limited to information that was before the AER and can be made only on the grounds that the AER's decision involved material error(s) of fact, was an incorrect exercise of discretion, or was unreasonable.

An applicant must also demonstrate how the Tribunal's determination would be, or would likely be, materially preferable to the AER's decision for the long term interests of consumers.

In making its decision, the Tribunal must consider the AER's determination as a whole, and how the parts of

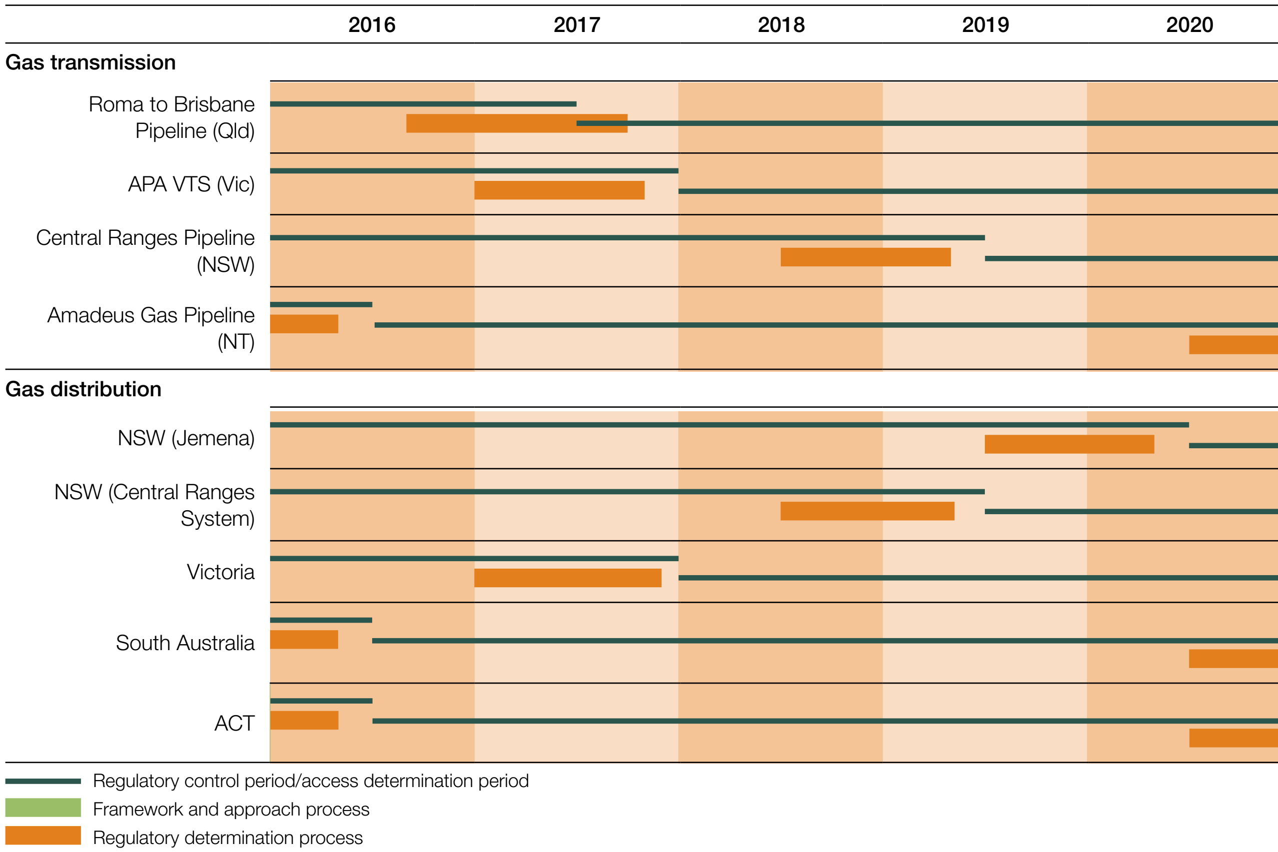
4 For a summary of the reforms, see AER, *State of the energy market 2013*, table 2.3, pp. 66–7.

5 The AER's annual reports provide more detail on these areas—for example, AER, *Annual report 2015–16*, pp. 30–1.

Figure 3.4
Timelines for AER determinations on electricity networks

Figure 3.4 (continued)

Timelines for AER determinations on gas pipelines and networks



VTS, Victorian Transmission System.

Note: These times are subject to variation. For the latest information, please check www.aer.gov.au/networks-pipelines/determinations-access-arrangements.

Source: AER.

the determination interrelate with each other. It must also consult with relevant users and consumers.

The Council of Australian Governments (CoAG) Energy Council in 2016 initiated a review of the effectiveness of the merits review regime, including the role of the Australian Competition Tribunal. The AER argued that the limited merits review regime has compromised the regulatory determination process by making the Tribunal, rather than the regulator, the primary audience for material presented by service providers. In doing so, the regime incentivises service providers to be strategic in the timing and scope of information submitted. For example, some providers routinely submit a significant volume of new material to the AER very late in the process, leaving little opportunity for the regulator to appropriately consider or consult on the material.[6]

At its December 2016 meeting, the CoAG Energy Council agreed in principle to reform the regime, including:

- tightening and clarifying the grounds for review
- introducing strict timeframes
- raising the onus on a network business making an appeal by requiring it to demonstrate that overturning the AER's decision would not be of serious detriment to the long-term interests of consumers
- providing more flexible arrangements for consumers to participate in reviews.

6 AER, *Review of the limited merits review framework*, submission, October 2016.

It also agreed in principle to introduce a binding rate-of-return guideline to reduce the elements of the AER's decisions that are open to merits review.

The Council tasked a working group with developing amendments to implement these changes, to take effect later in 2017.

Recent Tribunal and judicial review activity

In 2016, 10 electricity distributors in NSW, the ACT, South Australia and Victoria, and two gas distributors in NSW and the ACT were involved in reviews of AER decisions.

The businesses sought reviews of several key parts of the decisions, including the allowed rate of return, the cost of corporate income tax, and the AER's approach to determining efficient operating expenditure (including the use of benchmarking in some matters).

Various other parties also participated in Tribunal reviews:

- The Public Interest Advocacy Centre and the Commonwealth Minister for Industry and Science intervened in the proceedings for the NSW and ACT businesses, raising issues about the operation of the limited merits review regime and other matters determined in the AER's decisions. The Victorian electricity networks, the South Australian electricity and gas distribution networks, and the Queensland electricity distributor Ergon Energy also intervened in the proceedings in support of the network businesses.
- The South Australian Minister for Minerals, Resources and Energy intervened in the review of the AER's decision on the South Australian electricity distribution network. The Minister raised issues relating to the proper construction of the electricity legislation and to forecasts of capital and operating expenditure. The South Australian Council of Social Service also sought leave to appeal the AER decision, but was denied.
- The Victorian Minister for Energy, Environment and Climate Change intervened in merits review processes for the Victorian electricity distribution networks, focusing on issues related to smart meters and operating costs.

All businesses also filed applications with the Federal Court for *judicial review* of the AER's decisions. Those processes were placed on hold pending the outcome of the limited merits review processes.

In 2016 the Tribunal ruled on the appeals relating to the NSW, ACT and South Australian electricity distribution networks, and the NSW gas distribution network.

In ruling on the NSW and ACT matters, the Tribunal found the AER was correct in some matters, including how the cost of equity was to be calculated. However, the businesses were successful in other areas, and the Tribunal directed the AER to remake its decision.

For the South Australian network, the Tribunal upheld the AER's decision in full. The network owner subsequently sought judicial review of the Tribunal's decisions, with hearings scheduled for May 2017. The Tribunal's decisions on the Victorian electricity and ACT gas distribution businesses are expected later in 2017.

In March 2016, the AER applied to the Full Federal Court for judicial review of the Tribunal's decisions on the NSW and ACT networks in relation to their operating expenses, the cost of corporate income tax, and the cost of debt.

In May 2017, the Federal Court found in the AER's favour on the approach to determining income tax costs, but upheld the Tribunal's decision on network operating expenses and the cost of debt.The AER is considering the implications of the Federal Court decision for the current determinations, and for our approach to future regulatory decisions.

3.5 Network revenues

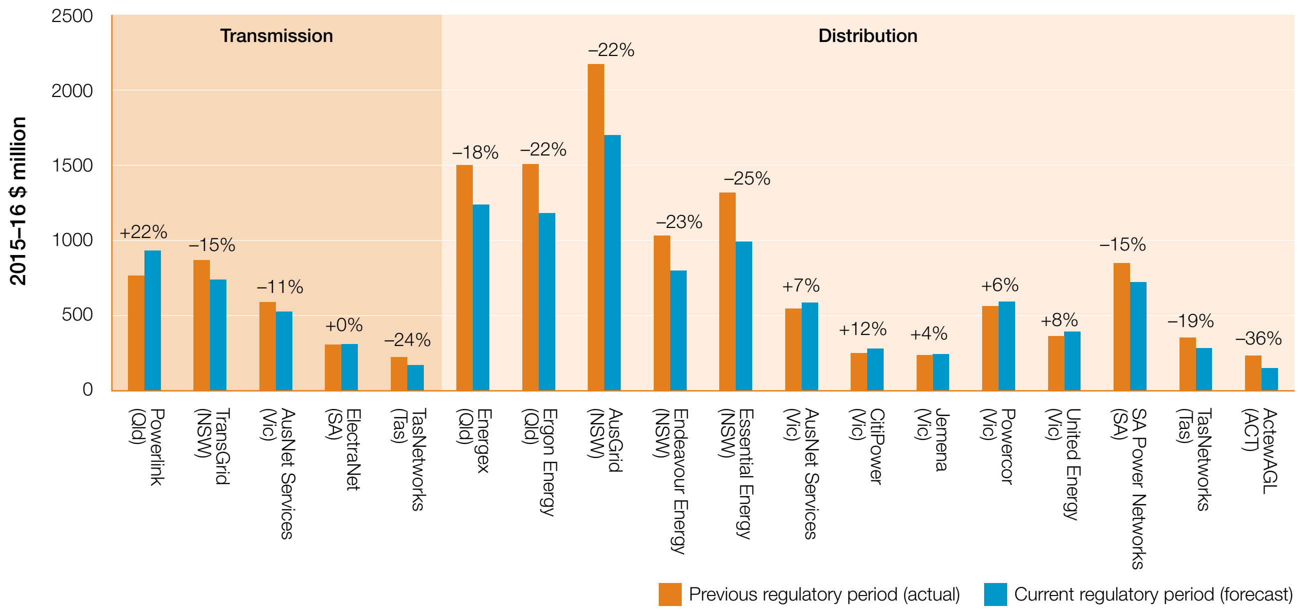
The AER's regulatory decisions reflect developments and projections in energy and financial markets. The previous round of regulatory determinations was made at a time when network costs were on the rise to replace ageing assets, meet stricter reliability and bushfire safety standards, and respond to forecasts made at the time of rising peak demand. Further, network businesses had higher financing costs, because instability in global financial markets exerted upward pressure on the costs of funding investment. These rising costs drove escalating revenues for several years from around 2009.

These cost pressures have now eased. The financial environment has improved, and borrowing and equity costs have eased accordingly. Lower financing costs coincided with declining energy demand in recent years, and with government moves to provide electricity network businesses with greater flexibility in meeting reliability requirements. In combination, these factors have reduced the forecast revenue requirements for most network businesses.

In the current round of AER decisions, regulated network revenues are forecast to *fall* by an average 13.5 per cent in electricity and 12 per cent in gas, compared with the previous round of decisions. In contrast, forecast electricity network revenues in determinations made from 2009 to 2011 *rose* by 30 per cent.

Figure 3.5

Electricity network revenues (annual)

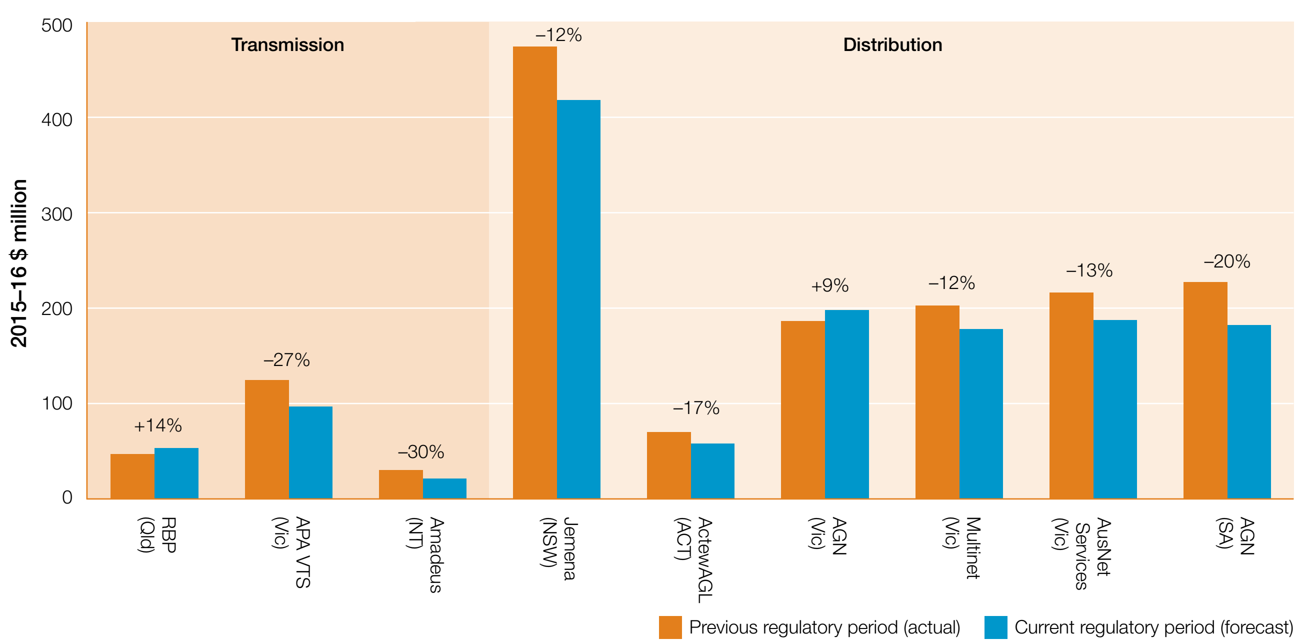


Notes: Smoothed revenues. Percentages are the revenue change across the regulatory periods.

Sources: AER economic benchmarking RINs, at March 2017; AER regulatory determinations.

Figure 3.6

Gas pipeline revenues (annual)

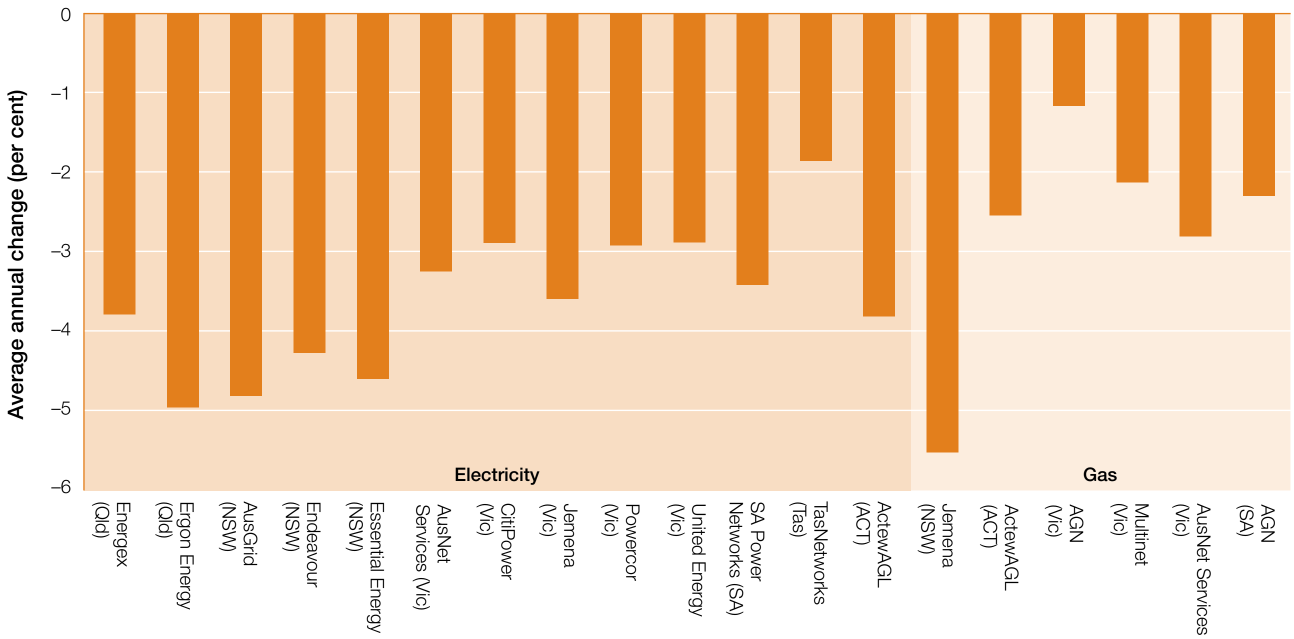


VTS, Victorian Transmission System.

Notes: Full regulation pipelines only. Previous regulatory period data for the Amadeus gas pipeline (NT) is forecast, rather than actual data. Percentages are the revenue change across the regulatory periods.

Sources: AER final decisions on access arrangements; Independent Competition and Regulatory Commission (ICRC), *Final approval on access arrangement 2004*.

Figure 3.7
Impact of AER decisions on residential energy charges (annual)



Notes: Real average annual impact on electricity and gas charges for a typical residential customer in that jurisdiction in the current regulatory period. The data accounts for the impact of decisions by the Australian Competition Tribunal. The estimates are based on information available at the time of the decisions, and may change due to factors such as annual updates to capital costs. They also do not account for changes in other components of a retailer bill, such as wholesale costs and a retailer's profit margins. Outcomes will vary among customers, depending on energy use and network tariff structures.

Sources: AER regulatory determinations and final decisions on access arrangements.

In total, electricity network revenues are forecast to total $12 billion annually in the current regulatory cycle, of which distribution networks account for almost 80 per cent. Revenues for regulated gas pipelines are forecast at $1.4 billion per year in the current cycle (figures 3.5 and 3.6).

3.5.1 Recent revenue decisions

The AER's 2016 decisions for the South Australian and ACT gas distribution networks, and the Northern Territory's Amadeus gas pipeline forecast that revenues in current regulatory periods would be 17–30 per cent lower than in previous periods.

But the AER's decisions on Victorian electricity distribution networks (which took effect in 2016) show a different trend, with revenues in the current regulatory period forecast to be 4–12 per cent higher than in previous periods. The increases were driven by forecasts of rising operating costs (section 3.7.4) and replacement expenditure (section 3.7.2).

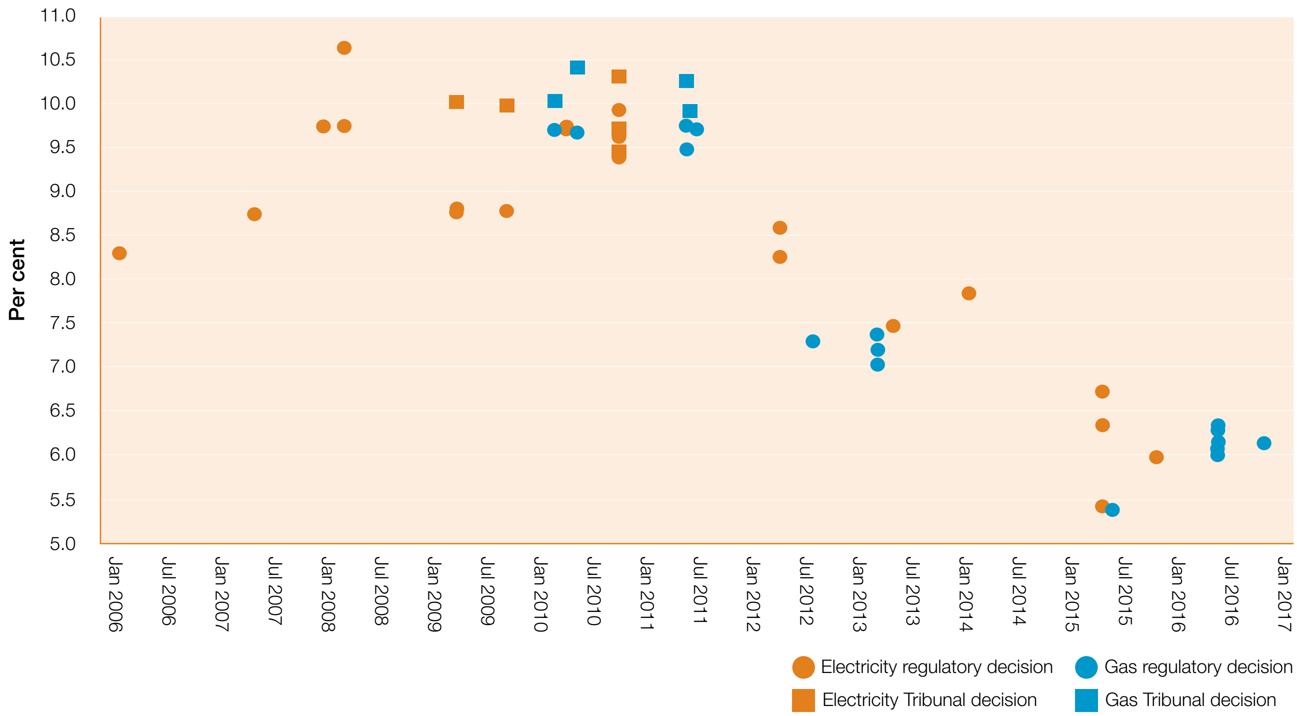
3.5.2 Impacts on customer bills

Electricity network charges typically make up 40–55 per cent of a customer's retail energy bill. In gas, pipeline charges can make up to 30–70 per cent of a bill. The bulk of these charges relate to distribution network costs (figures 4.2 and 4.3 in chapter 4).

Recent AER decisions are forecast to result in distribution charges in residential energy bills *falling* by up to 5.6 per cent per year (figure 3.7). The falls mostly accumulate in the first or second years of a regulatory determination, with smaller reductions or slight increases forecast for subsequent years. The largest overall fall is expected for the NSW gas distributor Jemena, for which the forecast reduction in network costs will lead a typical residential customer's bill to fall by almost 25 per cent between 2015 and 2020.

Figure 3.8

Weighted average cost of capital—electricity networks and gas pipelines



Note: Nominal vanilla weighted average cost of capital.

Sources: AER regulatory determinations and final decisions on access arrangements.

3.6 Capital financing costs

The largest component of a network's revenue is typically the return allowed on the network owner's investment. Electricity networks and gas pipelines are capital intensive, so even a small change in the return on assets will significantly alter revenue. For example, a 1 per cent increase in the cost of capital for electricity distributor Endeavour Energy in the AER determination for 1 July 2014 to 30 June 2019 would have increased its revenue by over 8 per cent.

The AER's regulatory decisions reflect conditions in financial markets. The previous round of determinations was made during an uncertain period associated with the global financial crisis, which reduced liquidity in debt markets and raised risk perceptions. But the financial environment has since improved, and borrowing and equity costs have eased accordingly. The determinations made since 2015 also incorporate a new approach to determining rates of return. Under a revised framework applied for the first time in those decisions, the cost of capital will be updated annually to reflect changes in debt costs.

In combination, these factors reduced the average allowed rate of return in decisions made in 2016 to 6.18 per cent, compared with over 10 per cent in decisions made from 2008 to 2010 (figure 3.8). This reduction translates to significantly lower network revenue.

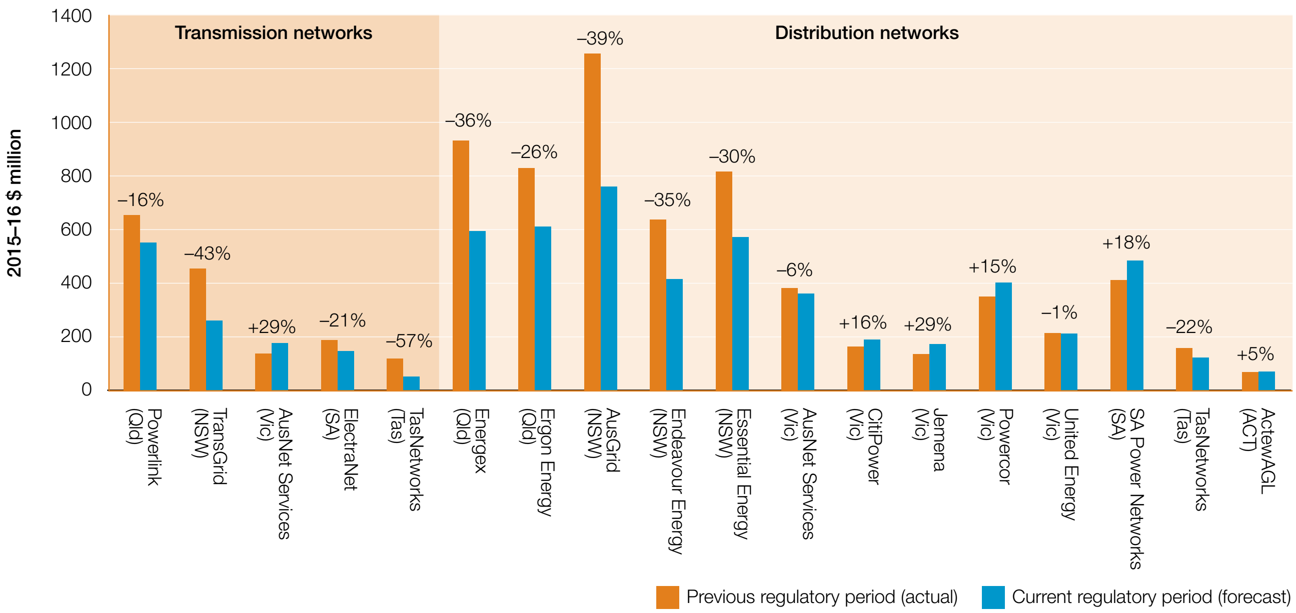
3.7 Investment and operating costs—electricity

An electricity network periodically requires new investment to replace ageing equipment and other assets. If energy demand is rising, then *augmentation* (expansion) of parts of a network may also be considered. While network businesses make investment decisions, AEMO provides high level coordination of the transmission network, and publishes an annual development plan.

As part of the regulatory process, the AER forecasts a network's efficient investment needs, which is added to its regulated assest base (RAB) over the current determination period. The network owner earns a return on this investment. At the end of the period, the RAB is adjusted

Figure 3.9

Electricity network investment (annual averages)



Note: Percentages are the revenue change across the regulatory periods.

Source: AER regulatory determinations.

to reflect actual levels of investment. The AER may deem above-forecast investment to be inefficient, and remove it from the RAB so it cannot earn future returns. This removal protects consumers from paying for the cost of inefficient investment. Additionally, the AER operates an incentive scheme that allows a network owner to retain a share of any capital 'underspending' against investment forecasts (section 3.7.5).

3.7.1 Investment activity in electricity networks

In the current regulatory cycle, electricity networks are forecast on average to invest $1.2 billion in transmission networks and $5 billion in distribution networks each year. In currently active determinations, the AER assessed efficient investment levels are, on average, 22 per cent *below* those in previous periods (figure 3.9).

Investment drivers vary across networks and depend on a network's age and technology, load characteristics, the demand for new connections, and licensing, reliability and safety requirements. Flat industrial and residential energy demand, along with less stringent reliability obligations on the network businesses, have led network owners to scale back or defer many investment projects. Electricity demand is expected to remain below historical peaks in most regions for at least the next decade.[7] Apart from pockets of high growth, most networks will require less augmentation to deliver reliable energy supply.

AER determinations commencing in 2016 forecast an increase in investment for three Victorian electricity distribution networks. While a reduction in Victorian customers' valuation of supply reliability will ease investment requirements in 2016–21, this outcome will be more than offset by a rise in replacement expenditure (partly to meet regulatory obligations arising from the 2009 Victorian Bushfire Royal Commission).

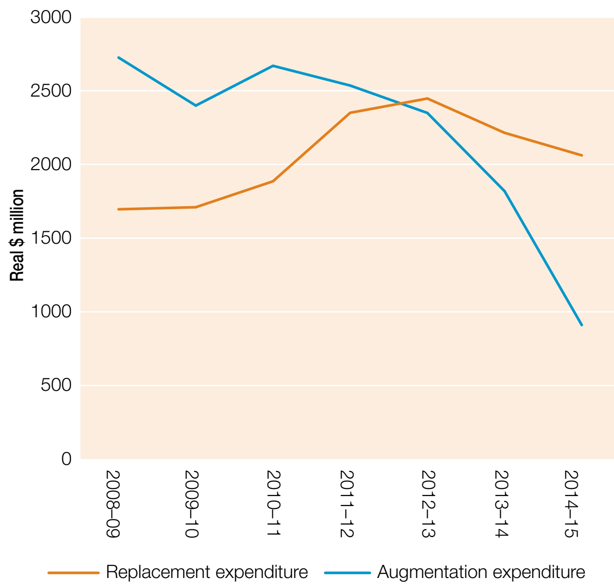
3.7.2 Replacement versus augmentation investment

The composition of network investment has been evolving, with a long term decline in augmentation spending to expand network capacity (figure 3.10). In 2014–15 networks spent less than $1 billion in real terms on augmentation expenditure, compared with $2.7 billion in 2008–09. While replacement expenditure has also declined in absolute terms, it rose as a proportion of total investment from 38 per cent in 2008–09 to 69 per cent in 2014–15.

7 AEMO, *National electricity forecasting report*, 2016.

Figure 3.10

Replacement and augmentation investment—electricity networks



Source: AER category analysis RINs, at March 2017.

3.7.3 Regulatory tests for efficient investment

The AER plays a number of roles in promoting efficient investment in energy networks. Part of the revenue determination process involves forecasting a network's total efficient investment requirements. Additionally, network businesses must apply a *regulatory investment test* to individual projects to ensure they are efficient. The test requires a network business to evaluate a proposed investment against credible alternatives (including non-network options) on a level playing field.

Separate regulatory investment tests apply for transmission (RIT-T) and distribution (RIT-D) networks. In each, a proposed investment must pass a cost–benefit analysis or provide the least cost solution to meet network reliability standards. As part of this, the business must identify the purpose of a proposed investment and show that it publicly consulted on its evaluation of alternatives.

The AER monitors businesses' compliance with the tests and, on request from a business, may determine whether an assessment satisfies the test. It also resolves disputes over how network businesses apply the tests.

The tests currently apply to only *augmentation* expenditure, which in recent years accounted for the bulk of network investment. But forecasts of continued flat energy demand have scaled back new investment proposals. The composition of network investment is evolving, with *replacement* expenditure overtaking augmentation of distribution networks (section 3.7.2). Recognising this shift, the AER in June 2016 proposed a rule change to widen the scope of regulatory investment tests to cover replacement expenditure. The change would impose new reporting requirements on network businesses to justify asset retirement decisions and to allow interested parties to propose alternatives to asset replacement. The AEMC is continuing in 2017 to consult on the AER proposal.

Following energy security issues in South Australia and Tasmania, the CoAG Energy Council in August 2016 tasked officials with reviewing whether the RIT-T is still an appropriate test of network investment, especially for transmission interconnectors. In December 2016, the Council found a cost–benefit test remains appropriate. But it agreed to change the RIT-T so the test adequately considers energy system security, emissions reduction goals, and events that have a low probability of occurring but a high impact.

3.7.4 Operating and maintenance costs—electricity networks

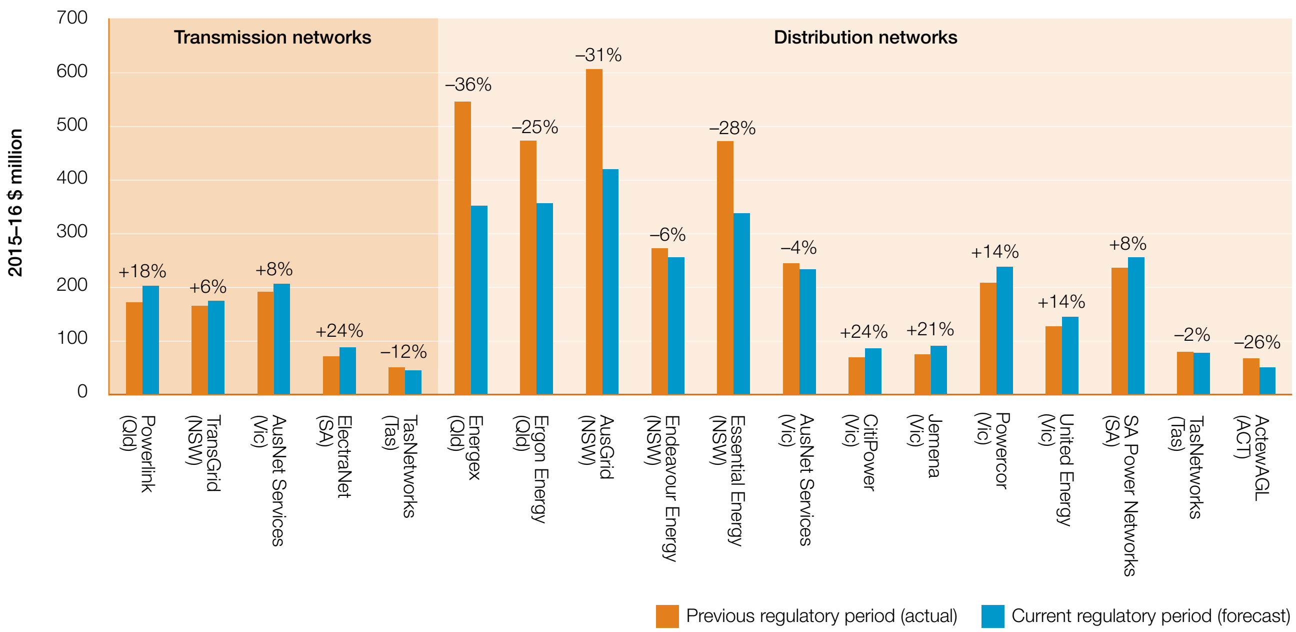
The AER assesses a network's efficient operating and maintenance cost requirements as part of the revenue determination process. The assessment accounts for cost drivers such as forecast customer growth, expected productivity improvements, changes in labour and materials costs, and changes in the regulatory environment. The regulatory framework provides incentives for network businesses to manage their costs efficiently.

In the current regulatory cycle, electricity transmission and distribution networks are forecast to spend over $700 million and $2.9 billion respectively on operating and maintenance costs per year (figure 3.11). On average, these costs are forecast to be 10 per cent *higher* for transmission networks, and 17 per cent *lower* for distribution networks in the current regulatory cycle than in previous periods.

Operating and maintenance costs are largely independent of energy use, so falling electricity demand does not significantly reduce them. Rather, the forecast cost reductions for distribution networks reflect the use of AER benchmarking in regulatory assessments, which identified operating inefficiencies in some networks. In the current regulatory cycle, the largest reductions in operating and maintenance costs were forecast for the Queensland, NSW and ACT networks, with an average fall of 27 per cent.

Figure 3.11

Operating costs—electricity networks (annual averages)



Note: Percentages are the revenue change across the regulatory periods.

Sources: AER economic benchmarking RINs, at March 2017; AER regulatory determinations.

AER determinations commencing in 2016 forecast rises in operating expenditure of 14–24 per cent for Victoria's distribution networks. The AER found the businesses operated relatively efficiently in the past, so base levels of expenditure would likely remain stable. But new regulatory obligations on the businesses—including new regulatory information reporting processes, changes to the connections charging framework, and *Power of choice* requirements—may raise operating costs in some areas.

3.7.5 Electricity network productivity

The AER's benchmarking work tracks the relative efficiency of electricity networks over time. It uses a multilateral total factor productivity approach that assesses the volume of inputs (assets and operating expenditure) needed to produce outputs (line length, maximum energy demand, energy delivered, reliability of supply, customer numbers for distribution networks, and the voltage of connection points for transmission networks).

Productivity in transmission and distribution networks has been declining for several years (figure 3.12). That is, the resources used to maintain, replace and augment the networks are rising at a faster rate than are the drivers of demand for network services. Declining network productivity may reflect (1) reduced efficiency in resource use, (2) rising input costs when outputs are flat or declining, and/or (3) regulations that require networks to spend more for no corresponding rise in output (for example, more stringent reliability or bushfire mitigation obligations).

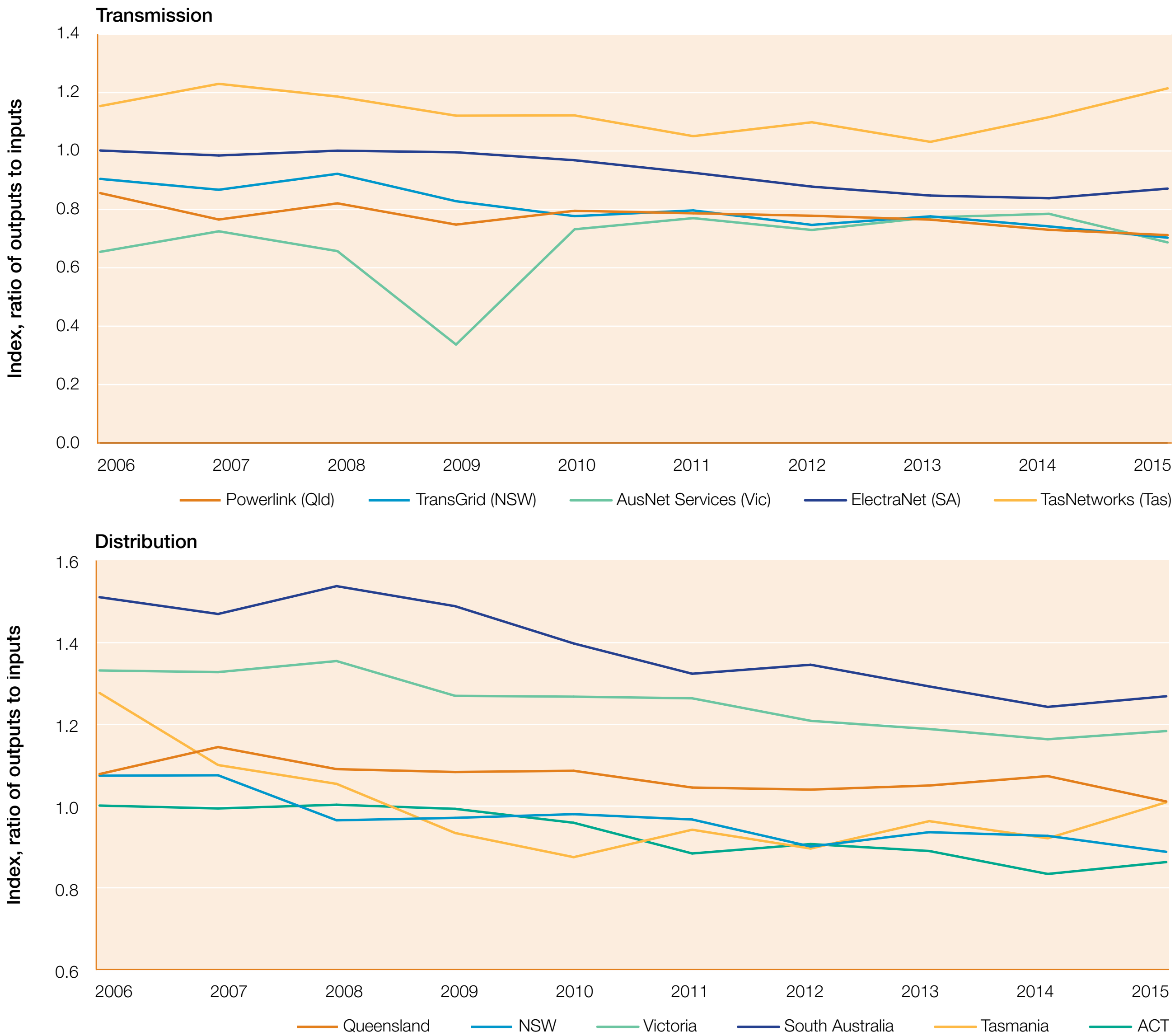
The AER's benchmarking indicates electricity distribution businesses in NSW and the ACT tend to operate less efficiently than do those businesses in other jurisdictions. It also indicates productivity improved for most networks in 2015, despite a longer term underlying trend of declining productivity. In particular, TasNetworks, ActewAGL, CitiPower, United Energy, Powercor and SA Power Networks (distribution), and ElectraNet and TasNetworks (transmission) recorded improved outcomes in 2015.

Productivity incentives

The AER operates incentive schemes for electricity network businesses to invest in and operate their networks efficiently. The schemes complement incentives for network businesses to provide efficient levels of service (sections 3.10.1 and 3.10.2).

The *efficiency benefit sharing scheme* (EBSS) provides incentives for network businesses to undertake efficient operating and maintenance expenditure by allowing them to

Figure 3.12
Electricity network productivity



Note: Index of multilateral total factor productivity relative to the 2006 performance of ElectraNet (South Australia) for transmission networks, and ActewAGL (ACT) for distribution networks.

Source: AER, *Annual benchmarking report: electricity distribution network service providers,* November 2016.

retain any efficiency gains for five years after a gain is made.[8] But the business must also bear the cost of any efficiency losses for the same period.

In the longer term, network businesses share efficiency gains or losses with customers through tariff adjustments, passing on 70 per cent of those gains or losses.

8 The AER's approved expenditure forecasts set the base for calculating efficiency gains or losses, after certain adjustments.

The *capital expenditure sharing scheme* (CESS) provides network businesses with similar rewards and penalties for investment expenditure. The scheme first applied in 2015. Its incentives are similar to those in the EBSS, with the businesses retaining (paying) 30 per cent of any capital underspends (overspends).

3.8 Investment and operating costs—gas networks

The gas transmission and distribution sectors have differing investment requirements. Gas *transmission* investment typically involves large and lumpy capital projects to expand existing pipelines (through compression, looping or extension) or construct new infrastructure. Significant investment in eastern Australia's transmission sector has occurred since 2010 to expand pipeline capacity, and to link gas supplies with LNG processing facilities in Queensland. Additionally, some transmission pipelines have been re-engineered for bi-directional flows. Chapter 2 considers recent investment in gas transmission, of which much is in pipelines that are not regulated or are subject to only light regulation.

For those pipelines under full economic regulation (tables 3.3 and 3.4), the AER approves prudent and justifiable investment forecasts, based on criteria in the National Gas Rules. The underlying investment drivers include rising connection numbers, the replacement of ageing networks, and the maintenance of capacity to meet customer demand.

Similarly, in assessing operating expenditure forecasts, the AER considers cost drivers that include customer growth, expected productivity improvements, and changes in real input costs for labour and materials. Operating cost increases may also reflect step change factors arising from external drivers, such as changes in government regulation.

3.8.1 Investment activity in gas networks

Full regulation *gas transmission pipelines* are forecast to invest a total of $220 million over the current regulatory periods (typically five years) (figure 3.13):

- Investment in the Roma to Brisbane Pipeline is forecast to fall by 80 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 61 per cent over 2016–21) following the completion of an integrity works program.
- Investment growth is steady for Victoria's GasNet transmission system.

Investment in full regulation *gas distribution networks* in eastern Australia is forecast at around $2.8 billion in the current access arrangement periods—15 per cent higher than in the previous periods:

- Forecast investment growth is highest in Victoria's AGN and AusNet Services distribution networks (up 23 per cent and 24 per cent respectively).
- The AER's 2016 determinations for the AGN South Australia network forecast that investment would rise by 19 per cent over 2016–21 to fund a major mains replacement project.
- Less investment is forecast for the ACT's ActewAGL 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 11 per cent in 2016–21 compared with the previous period.

3.8.2 Operating and maintenance costs—gas networks

The AER's assessment of a gas network's efficient operating and maintenance cost requirements accounts for cost drivers such as forecast customer growth, expected productivity 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 $59 million per year on operating expenses.

Operating expenditure will also rise for gas distribution networks, which are jointly forecast to spend over $460 million annually on these costs. This forecast is a rise of 6 per cent on actual expenditure in previous periods. The largest rise (20 per cent) is forecast for Victoria's AGN network.

The AER's 2016 decision on the forecast operating expenditure of South Australia's AGN distribution network involves a 6 per cent rise in 2016–21 from actual 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 ActewAGL network are forecast to rise by 16 per cent over the same period. The expected cost increase is mainly associated with compliance issues and business-to-business harmonisation.

Figure 3.13

Gas pipeline investment (annual averages)

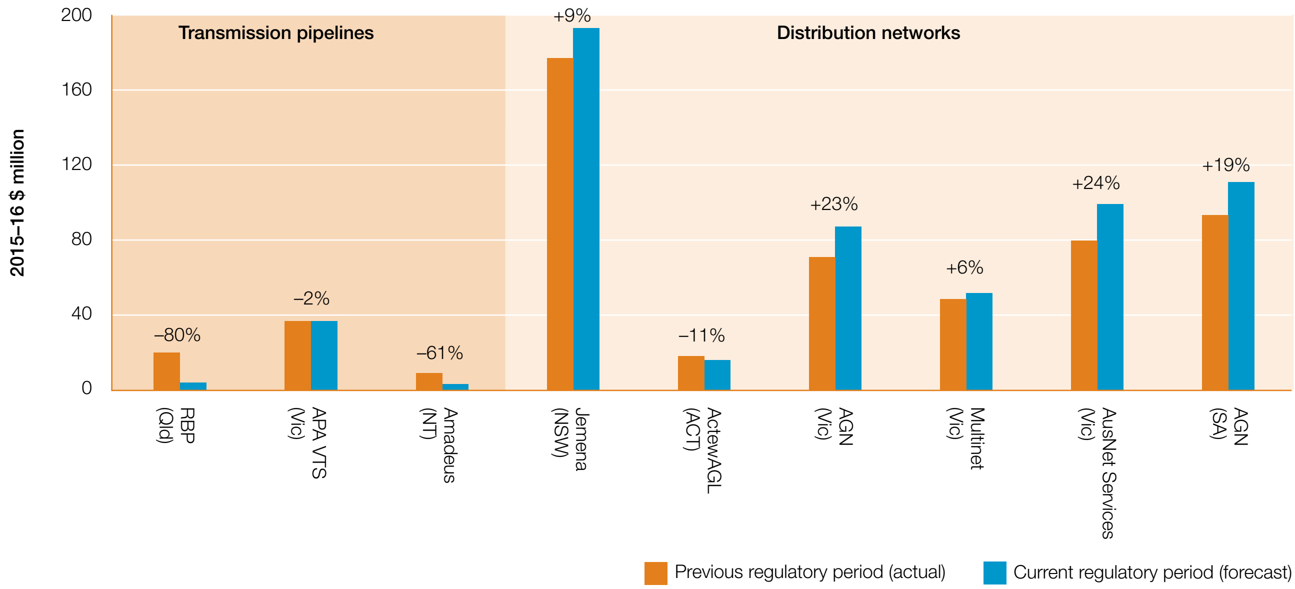
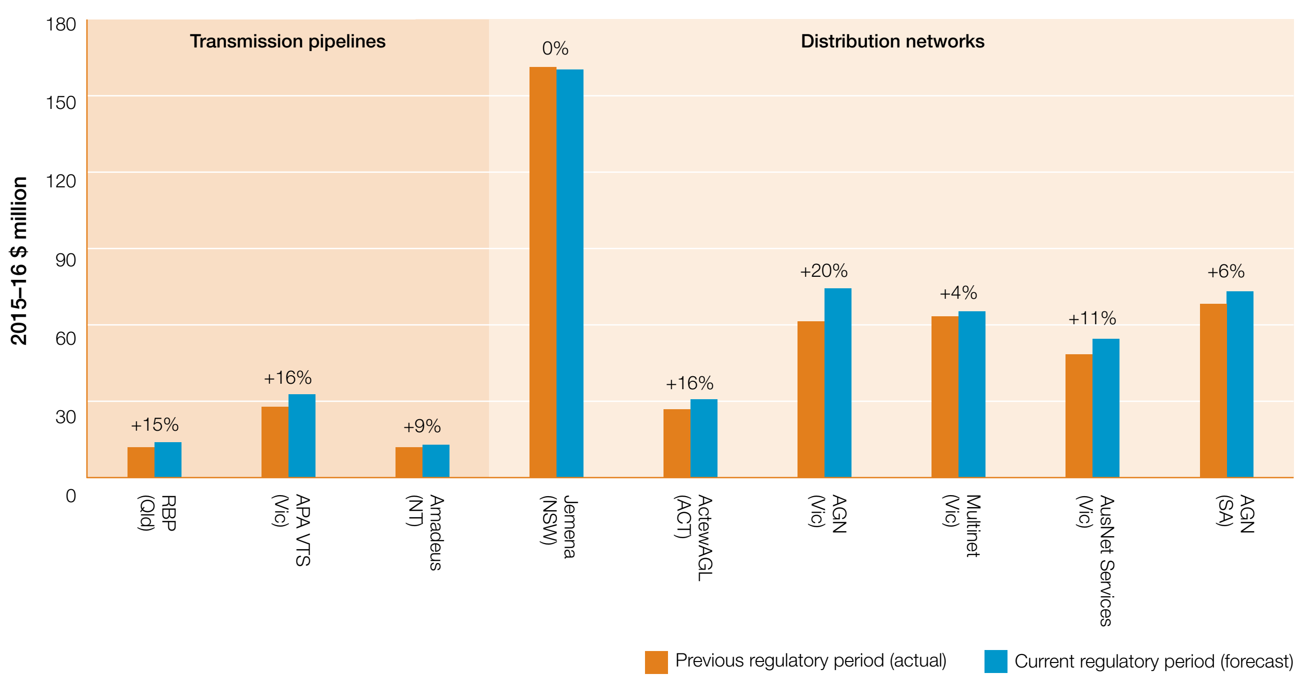


Figure 3.14

Operating costs—gas networks (annual averages)



VTS, Victorian Transmission System.

Note (figures 3.13 and 3.14): Percentages are the revenue change across the regulatory periods. ActewAGL excludes the transition year (2015–16) between the previous and current regulatory periods.

Source (figures 3.13 and 3.14): AER final decisions on access arrangements.

3.9 Power of choice reforms

The nature and function of energy networks are evolving. Escalating cost pressures have given impetus to demand response (whereby users adjust their energy use in response to price signals), small scale local generation (such as rooftop solar photovoltaic (PV) generation) and, more recently, energy storage technologies. Innovations in network and communications technology—including smart meters, interactive household devices, and energy management and trading platforms—are allowing consumers to access real-time information on their energy use, and to better control how they manage that use. These developments are transforming the nature of a network from being a one-way conduit for energy transportation, to being a platform for multilateral trade in energy products.

Over 1.6 million households have installed rooftop solar PV systems. While most of these systems produce energy for use as it is generated, the uptake of battery storage[9] and smart appliances could shift the amount of power that customers withdraw from or inject into a network throughout the day in response to market signals. These developments can potentially stem growth in peak demand, delaying the need for costly network augmentations.

The AEMC implemented rule changes under the *Power of choice* umbrella to promote efficient use of energy networks and to empower customers to make efficient energy decisions. The reforms, which largely come into effect in 2017, relate to matters that include metering, ring fencing, network pricing and embedded generation.

The AEMC also introduced new rules making it easier for customers in embedded networks to participate in retail markets. Many of those customers currently cannot arrange for energy supply by a provider other than their network operator, or can do so only at significant cost. But the new rules, effective from December 2017, will require an embedded network manager to link customers to AEMO's electricity market systems—a necessary first step for customers to access retail market offers.

3.9.1 Metering

The *Power of choice* reforms recommended all new meters installed for residential and small businesses consumers be *smart meters*. These meters can record energy consumption on a near real-time basis, and they have capabilities for remote reading and customer connection to the network. Smart meters thus provide consumers with information about their energy use, and with greater control over how they manage it. Consumers can also access a wider range of retail offers, or take up offers of demand management or energy trading products.

Victoria was the first jurisdiction to progress metering reforms, with its distribution businesses rolling out smart meters with remote communications across 2009–14. The rollout costs were progressively passed on to retail customers. Metering charges will fall in 2016–18, following the recovery period for rollout costs, and then stabilise for most networks.[10]

Several electricity retailers in other jurisdictions have started rolling out smart meters to their existing customers, usually at no upfront cost. An initial focus of this rollout has been those customers with solar PV installations, particularly in NSW.

Metering arrangements are also being reformed to boost competition. Network businesses were the traditional providers of electricity meters on residential premises. But this arrangement inhibits competition and consumer choice. It also discourages investment in metering technology that could support the uptake of new and innovative energy products. To address these issues, rule changes supporting competition in the provision of metering and related services will take effect from 1 December 2017.

Complementary reforms will allow customers more ready access to their electricity consumption data, and introduce consistent meter communications standards. These changes aim to facilitate a market led rollout of smart meters, and to promote energy management products and services that rely on advanced metering functionality.

Where a network business offers services in a contestable market, robust ring fencing should be in place to ensure the business does not unfairly deter new entrants. The AER in December 2016 introduced new ring fencing guidelines to create a level playing field for network businesses and new entrants. The guidelines require distribution networks to separate their regulated network services (and the costs and revenues of those services) from unregulated services such as metering and solar PV and battery installations. Those unregulated services must be provided through a separate entity.

The new ring fencing rules aim to ensure network businesses do not use revenue earned from regulated

9 Industry market analysts estimate that around 6750 home battery systems were installed in 2016. See, for example, SunWiz, 'Australia's battery market: believe the hype!', Media release, 20 February 2017.

10 AER distribution determinations for the Victorian distributors for 2016–20, and the AER's Transition Charge 2017 determination for the Victorian distributors.

services to cross-subsidise their unregulated products. They also deter discrimination in favour of an affiliate businesses. And they may prohibit a network business from engaging in a potentially contestable activity.

Distribution networks are required to comply with the ring fencing guidelines as soon as reasonably practicable, but no later than 1 January 2018.

3.9.2 Cost-reflective network tariffs

While smart meters *allow* consumers to monitor their energy use, cost-reflective prices incentivise consumers to use energy (and energy networks) efficiently. In particular, network costs are highest when the network is under peak demand pressure and becomes congested. A household consuming energy at peak times may impose significant network costs, even if its average energy consumption is low.

Most large customers pay cost-reflective network charges that reflect the impact of the energy use on the network. But, under traditional pricing structures, households and small businesses have paid the same network charges, regardless of how and when they use energy. Customers with airconditioners or solar PV systems, for example, are not exposed to their full network costs under current tariff structures. The AEMC found that a household using a 5 kilowatt airconditioner at peak times imposes around $1000 a year in additional network costs, but might pay only $300 under current tariff structures.[11] Other customers subsidise that household's network costs, paying more than the cost of supplying their own network services.

New arrangements require distribution businesses to move customers onto tariffs that better reflect the efficient costs of providing their network services. Retailers pay the charges initially, then decide whether to pass on those costs to customers and in what form.

Exposing retailers to the true costs of using energy network incentivises them to encourage their customers to shift discretionary appliances use to off-peak times. A retailer might, for example, set higher prices at peak times to reduce demand, or offer demand management incentives.

While some customers would pay higher bills under cost-reflective pricing, the AEMC estimated 81 per cent of residential customers would face lower network charges in the medium term, and 69 per cent would have lower charges at peak times.[12]

The new tariff structures take effect over 2017 and 2018. But the move to cost-reflective pricing is being phased in, with distributors required to move closer to full cost reflectivity with each annual tariff proposal over upcoming regulatory periods. Most distributors have already developed a 'demand tariff' for small customers, which typically includes:

- a fixed daily supply charge
- a use charge based on the total volume of electricity consumed
- a demand charge based on the customer's maximum point-in-time electricity use.

The specific elements of each tariff vary across distributors, and between households and small business customers. Some tariffs include, for example, a separate demand charge for peak and off-peak times, or a demand charge that varies by season. And use charges can be flat or vary by time of use. The proposed demand tariff for Tasmania does not include any use charge.

The new tariff arrangements will largely apply on an opt-in basis. But, in some networks, they will be mandatory for new customers, existing small businesses, and households with smart meters. The NSW distributors AusGrid and Endeavour Energy are the only network providers choosing *not* to introduce a demand tariff for small customers. Instead, they will introduce more basic time-of-use tariffs.

A key barrier to implementing cost-reflective network tariffs is the limited penetration of smart meters for residential and small business customers outside Victoria.

3.9.3 Demand management and embedded generation

The *Power of choice* reforms include a focus on demand management to ease pressure on electricity networks at times of peak demand. The AER runs a scheme for distribution businesses to fund innovative projects for non-network approaches to manage demand. The approaches include measures to reduce demand or provide alternative ways to meet supply (such as connecting small scale local generation).

11 Commissioner Neville Henderson (AEMC), 'Power of choice and other energy market reforms', Speech at 2014 EUAA conference, 13 October 2014.

12 Commissioner Neville Henderson (AEMC), 'Power of choice and other energy market reforms', Speech at 2014 EUAA conference, 13 October 2014.

New rules introduced in August 2015 strengthen incentives for distribution businesses to undertake demand management projects that deliver a net benefit. The AER in 2017 is finalising a new demand management incentives scheme and innovation allowance mechanism to implement the rules:

- The incentive scheme aims to incentivise electricity distributors to invest in efficient non-network projects that help to manage demand on the networks.
- The innovation allowance funds distributors' research and development in demand management projects that could reduce long term network costs.

This work follows earlier reforms to remove impediments to investment in smaller scale embedded generation that connects directly to the distribution network. The reforms improve information sharing with proponents, and provide clearer enquiry, application and connection processes.

3.10 Reliability and service performance

Reliability—that is, having sufficient capacity to meet customer demand—is a key barometer of an energy network's performance. The reliability that customers experience is a combination of the service provided by generators, transmission networks and distribution networks. However, most of the outages that customers experience are due to issues on the distribution networks.

3.10.1 Transmission network performance

Electricity transmission networks are engineered and operated with sufficient capacity to provide a buffer against planned and unplanned interruptions to the power system. While a serious network failure may require the power system operator to disconnect some customers (known as load shedding), transmission networks in the NEM generally deliver high rates of reliability. Transmission outages in 2014–15 caused less than three minutes of unsupplied energy in jurisdictions other than Victoria, which experienced over six minutes of unsupplied energy.[13]

State and territory agencies determine transmission reliability standards. The CoAG Energy Council in December 2014 endorsed principles requiring the standards to reflect the value that customers place on reliability. It required the standards to be set independently of the transmission business.

13 Australian Energy Council, *Electricity gas Australia 2016*.

Transmission network congestion

A key aspect of network performance is the efficient management of network congestion, which can have widespread impacts on electricity prices and system reliability.

Limits (constraints) are imposed on electricity flows along all transmission networks to avoid system damage and maintain power system stability. At times, these constraints result in network congestion. Some congestion arises from factors within the control of a network business—for example, the scheduling of outages, maintenance and operating procedures, and network capability limits (such as thermal, voltage and stability limits). But some arises from uncontrollable factors—for example, hot weather can cause congestion by raising airconditioning loads. Typically, congestion with high market impacts occurs on just a few days each year, and is often associated with network outages.

A major transmission outage combined with other generation or demand events can interrupt the supply of energy. But this scenario is rare in the NEM. More commonly, congestion raises electricity prices by displacing low cost generation with more expensive generation. Congestion can also force inefficient electricity trade flows between the regions. For these reasons, the AER offers incentives for network businesses to reduce the impact of congestion on the wholesale electricity market (see below).

Not all congestion is inefficient. Reducing congestion through investment to augment the transmission network is an expensive solution. Eliminating congestion is efficient only to the extent that the market benefits outweigh the costs.

Performance incentives—transmission

The AER operates a service target performance incentive scheme (STPIS) that offers incentives for transmission businesses to maintain or improve network performance in ways that customers value. It is designed as a counterbalance to the efficiency benefit sharing scheme (section 3.7.5) to ensure businesses do not unreasonably cut operating and maintenance spending at the expense of service quality. In 2015, the AER amended the scheme, adding new financial incentives and penalties, and strengthening ex-post assessments.

The STPIS has three components.

- A *service* component sets performance targets for supply interruption frequency, outage duration, and the number of unplanned faults on the network. It also covers protection and control equipment failures. A network's over- or underperformance against its targets can

Table 3.5 S factor values for the STPIS components

		2011		2012		2013		2014		2015
Powerlink (Qld)	Service component	0.42	0.44	0.45		0.54		0.46		0.28
	Market impact component	1.95	1.98	2.00		1.86		0.00		1.91
TransGrid (NSW)	Service component	−0.13		−0.49		−0.61		−0.43	−0.18	0.29
	Market impact component	1.39		1.48		1.58	1.87	0.20		0.00
	Network capability component							1.50		1.50
AusNet Services (Vic)	Service component	0.72		0.82		0.67	0.95	0.24		0.11
	Market impact component	0.00		0.80		1.31	1.70	1.06		0.33
	Network capability component							1.50		1.50
ElectraNet (SA)	Service component	0.32		−0.30	−0.17	0.31		0.63		0.23
	Market impact component	0.52		0.00	1.90	0.00		1.88		0.00
	Network capability component									1.50
TasNetworks (Tas)	Service component	−0.41		0.33		0.57		0.77	0.74	0.45
	Market impact component							0.00		1.01
	Network capability component							1.50		1.50
Directlink (Qld–NSW)	Service component	−0.87		−1.00		−0.47		−1.00	−0.76	−0.60
	Market impact component									0.29
Murraylink (Vic–SA)	Service component	0.70		0.92	−0.41	0.59		−0.33		0.15
	Market impact component					1.19		1.54		0.61

Notes: Powerlink reported separately for the first and second halves of 2012. ElectraNet and Murraylink reported separately for the first and second halves of 2013. TransGrid and TasNetworks reported separately for the first and second halves of 2014. AusNet Services reported first quarter results separately from the rest of 2014. TransGrid, Tas Networks and Directlink reported separately for the first and second halves of 2015. Directlink reported from 5 November to 31 December for 2015.

Source: AER, service standards compliance report for various businesses.

result in gains (or penalties) of up to 1 per cent of its regulated revenue.

- A *market impact* component encourages networks to improve their operating practices to reduce congestion. The practices may include efficiently planning outage timing and duration, and minimising the impact on network flows (for example, by conducting live line work, maximising line ratings and reconfiguring the network). A business can earn up to 2 per cent of its regulated revenue by eliminating outage events 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. Each eligible project is capped at $5 million. AEMO helps prioritise projects that deliver best value for money to consumers, and the AER approves a project list. Network businesses 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 service and market impact components apply to all transmission businesses. The network capability component first applied to transmission networks in NSW, Victoria and Tasmania in 2014, and in South Australia from 2015.

Rather than impose a common benchmark target, the AER sets separate targets reflecting the circumstances of each network based on its past performance. The results under each component are standardised for each network, to derive an 's factor' that can range between −1 (the maximum total penalty) and +4.5 (the maximum total bonus).

Table 3.5 sets out s factors for each network for the past five years. While performance against individual component targets varied, most networks earned financial bonuses for overall performance:

- Under the *service* component, networks received bonuses totalling $5.3 million in 2015. Only Directlink failed to meet its service targets: it paid a penalty of $90 000.
- Network performance in managing the *market impacts* of congestion deteriorated for many networks in 2015.

Directlink reported for the first time on this measure. Total payments under this component totalled around $22 million in 2014 and 2015, with an improved performance by Powerlink and TasNetworks offsetting declining performances by for other networks.

- Those networks applying the *network capability* requirement—TransGrid, AusNet Services, ElectraNet and TasNetworks—received the maximum payment of 1.5 per cent of regulated revenue (totalling $24.8 million) in 2015.

3.10.2 Distribution network performance

Most electricity outages in the NEM originate in distribution networks. But the capital intensive nature of the networks makes it prohibitively expensive to invest in sufficient capacity to avoid all outages. As a result, it is not cost efficient to try to eliminate all distribution network outages.

Capital investment aimed at ensuring the networks meet reliability standards drove rising network costs for several years. Concerns about the impact of this investment on retail electricity bills led the CoAG Energy Council in 2014 to endorse a new approach to setting distribution reliability targets. The approach accounts for (1) the value that customers place on reliability and (2) the likelihood of interruptions.

Accounting for this approach, several jurisdictions 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.

Distribution reliability indicators

Three widely used indicators of distribution reliability are:

- the system average interruption duration index (SAIDI)
- the system average interruption frequency index (SAIFI)
- total energy unsupplied.

The SAIDI and SAIFI indicators measure the average duration and frequency respectively of unplanned outages experienced by distribution network customers. Figures 3.15 and 3.16 set out data for each indicator. Comparisons across jurisdictions need to be made with care. In particular, the data relies on the accuracy of businesses' information systems, which may vary considerably. Geographic conditions and historical investment also differ across the networks.

Across the NEM, a typical customer experiences around 200 minutes of outages per year, but with significant regional variations. In particular, severe weather activity can affect reliability outcomes. Reliability outcomes for Queensland in 2010–11 and 2012–13, for example, were affected by cyclones Yasi and Oswald.

The average outage duration in 2015–16 fell in Queensland and NSW to near their lowest levels of the past decade, with NSW recording the largest fall. It also fell in Tasmania and Victoria, but rose in South Australia and the ACT (up 8 per cent and 22 per cent respectively). Nevertheless, the ACT continues to have the lowest incidence of unplanned outage time in the NEM.

The average frequency of unplanned outages generally declined over the past decade. Now, energy customers across the NEM typically experience around 1.5 outages each year. The average frequency of outages fell in 2015–16 in Queensland and NSW.

Another reliability measure—total energy unsupplied—estimates the volume of energy not supplied as a result of interruptions. Total energy unsupplied was relatively stable over the past decade in all jurisdictions except Queensland (figure 3.17). The ACT experienced an average of less than 1 gigawatt hour (GWh) of unsupplied energy per year, followed by Tasmania (just over 2 GWh), South Australia (5 GWh), Victoria (11 GWh) and NSW (19 GWh). Queensland experienced an average of 58 GWh of unsupplied energy per year, partly because its large and widely dispersed rural networks make it especially vulnerable to outages.

Performance incentives—distribution

The AER runs a service target performance incentive scheme (STPIS) for distribution networks to maintain or improve performance. The scheme focuses on supply reliability, customer service and faults, and call centre performance. A guaranteed service level (GSL) component requires network businesses to pay customers if their performance falls below threshold levels.[14]

The incentive scheme provides financial bonuses and penalties of up to 5 per cent of revenue for network businesses that meet (or fail to meet) performance targets.[15] The results are standardised for each network, to derive an 's factor' that reflects deviations from performance targets.

14 The GSL component does not apply if the distribution business is subject to jurisdictional GSL obligations.

15 Queensland network businesses face financial bonuses and penalties of up to 2 per cent of revenue.

Figure 3.15

System reliability—unplanned SAIDI

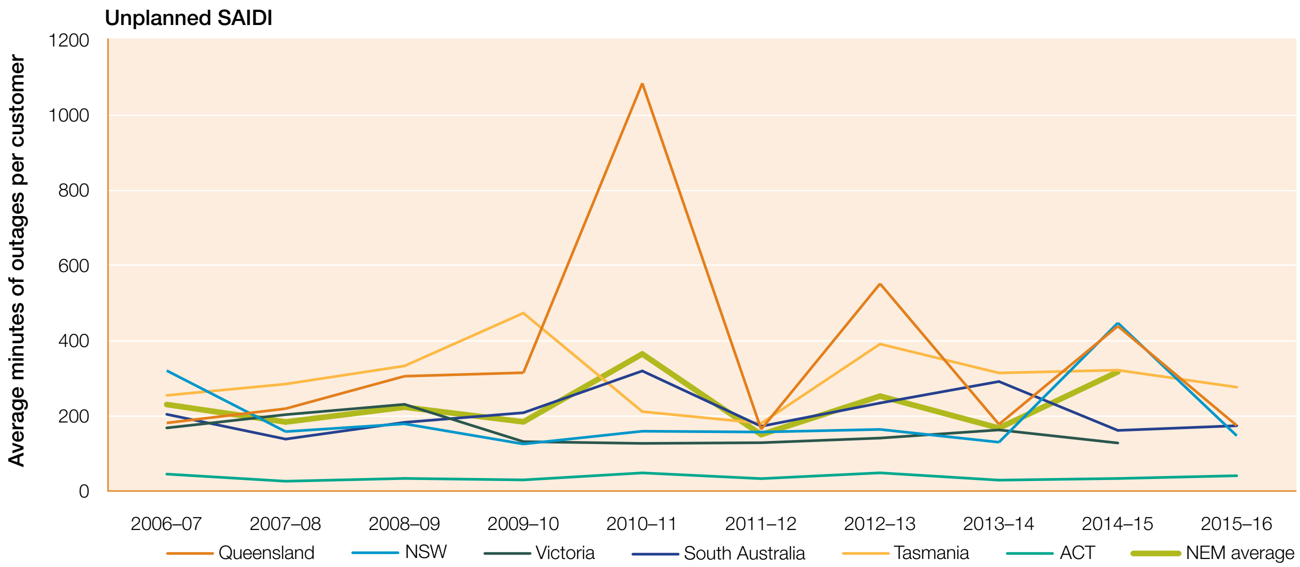
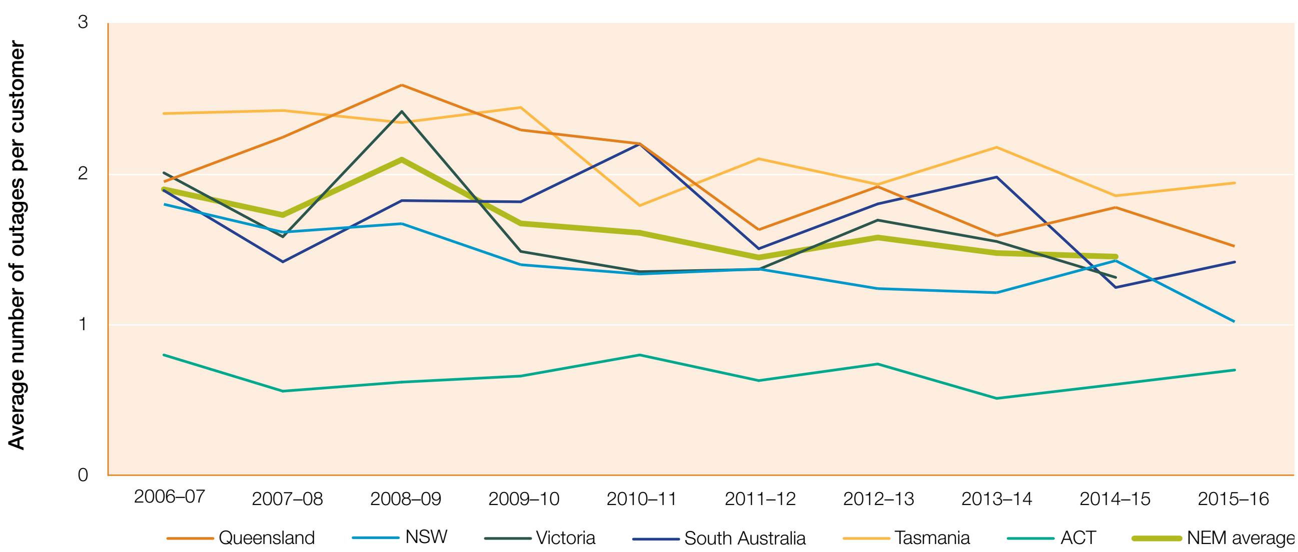


Figure 3.16

System reliability—unplanned SAIFI



Notes (figures 3.15 and 3.16):

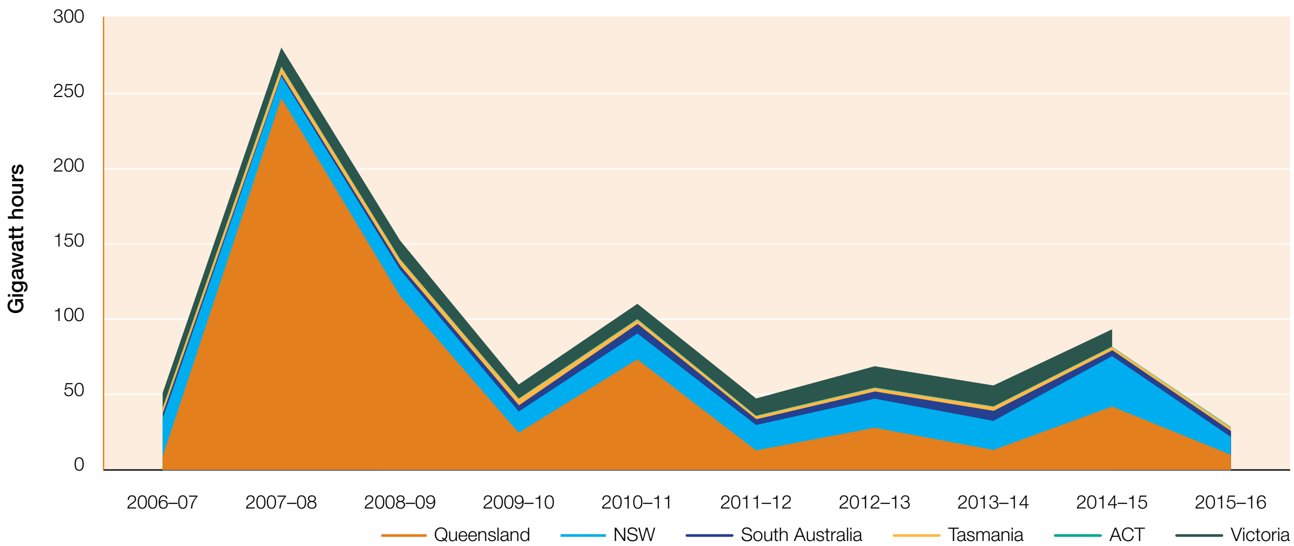
The data reflects total outages experienced by distribution customers, including outages originating in generation and transmission networks. The data is not normalised to exclude outages beyond the network operator's reasonable control.

The NEM averages are weighted by customer numbers.

Data is for the 12 month period ending 30 June for all states except Victoria. Victorian data is for the calendar year beginning in that period.

Source (figures 3.15 and 3.16): AER economic benchmarking RINs.

Figure 3.17
Total energy unsupplied



Notes: Data is for total energy unsupplied and includes major event days. Victorian data is for the calendar year beginning in that period.
Source: AER economic benchmarking RINs.

Outcomes are rewarded or penalised via the AER's annual tariff reviews of each network. While the scheme aims to be nationally consistent, it has flexibility to deal with the circumstances and operating environment of each network.

The reliability component of the scheme sets targets for the average duration and frequency of outages for each distribution business. The targets are based on the business's outcomes over the previous five years, normalised to exclude interruptions beyond the network's reasonable control. In 2014–15 all distribution businesses except United Energy and CitiPower exceeded their overall benchmark. The scheme did not apply to NSW or ACT network businesses.

The AER is reviewing the STPIS scheme in 2017. It is examining how financial bonuses and penalties are calculated, the use of standardised reliability definitions, and the impact of renewable energy and distributed generation on the scheme's operation.

Victoria's distribution 'f factor' scheme

The Victorian distribution businesses are subject to an incentive scheme aiming to reduce the risk of fire starts originating from a network or caused by something coming into contact with the network. This 'f factor' scheme rewards or penalises the businesses $25 000 per fire that occurs under or over their targets. All Victorian distributors outperformed their respective targets in 2015.

AusNet Services and CitiPower both reported significant reductions in fire starts (36 per cent and 11 per cent below their respective targets) since the scheme commenced. Powercor and United Energy reported slightly more fire starts than their respective targets over the same period, while Jemena reported 19 per cent more fire starts than its target.

iStock (Getty Images)

4 ENERGY RETAIL MARKETS

4.1 Retail products and services

Energy retailers typically buy electricity and gas in wholesale markets and package it with network (transportation) services for sale to customers. Charges may be flat or vary according to the time of day or season, but they usually insulate the customer from movements in wholesale energy prices. Retailers use hedging arrangements to manage their own risk of price volatility in the wholesale market.

Until recently, most energy retail contracts for small customers were for the supply of energy only, and customers were charged a flat rate for all energy that they consumed. But the market is becoming more complex, and the range of offers is expanding, particularly in electricity. Time-of-use tariffs are one alternative, made possible by interval (smart) meters that measure a customer's energy use in real time. Other options range from pool pass through arrangements (whereby the customer takes on the risk of wholesale market volatility) to fixed price contracts (whereby the customer pays a fixed amount regardless of how much energy they use). And some retail offers are tailored to customers with specific requirements (such as households with swimming pools).

Retailers and third party energy sellers are also beginning to offer products and services that reward customers for reducing energy use at times of high demand. They may even offer direct load control, whereby the energy seller can remotely adjust a customer's energy use. Or they may provide a platform for customers to onsell energy that they self-generate from solar photovoltaic (PV) systems or battery storage.

Alongside these changes, a growing number of customers are receiving their energy supply through non-traditional channels (figure 4.1) such as:

- *onselling,* whereby an energy provider buys bulk energy from a retailer and onsells it to a cluster of customers located in an embedded network behind a single connection point to the main distribution network. Onselling is increasingly used in new multi-dwelling developments such as apartment buildings and shopping centres
- *isolated networks or microgrids,* where a community is primarily supplied by locally sourced generation and does not rely on a connection to the main grid
- *power purchase agreements,* whereby an energy provider installs generation capacity on a customer's premises, and sells the generated energy to that customer. Under a solar power purchase agreement, for example, the provider installs, owns, operates and maintains a solar PV system at a customer's home. 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. The customer remains connected to the electricity grid for when solar generation does not meet their energy needs. Any surplus solar power is sold back into the grid. Some SPPAs transfer ownership of the solar PV system to the householder or business at the end of a contract.

While new entrant businesses are driving alternative selling models, established energy retailers are also moving into this area. Some established retailers offer, for example, power purchase agreements alongside their traditional products.

Increasing rates of rooftop solar PV generation—from both power purchase agreements and energy users' own solar panels—pose significant challenges for the traditional retail model. Around 17 per cent of residential households in Australia have installed solar PV, which is the highest penetration rate in the world.[1] These households (and others that are installing panels) do not usually produce enough energy to meet all their requirements, and they buy the balance from a retailer. But the lower volumes that they require make these customers less profitable for the retailer. Advances in battery storage may further reduce energy purchases by these users.

4.2 Energy market regulation

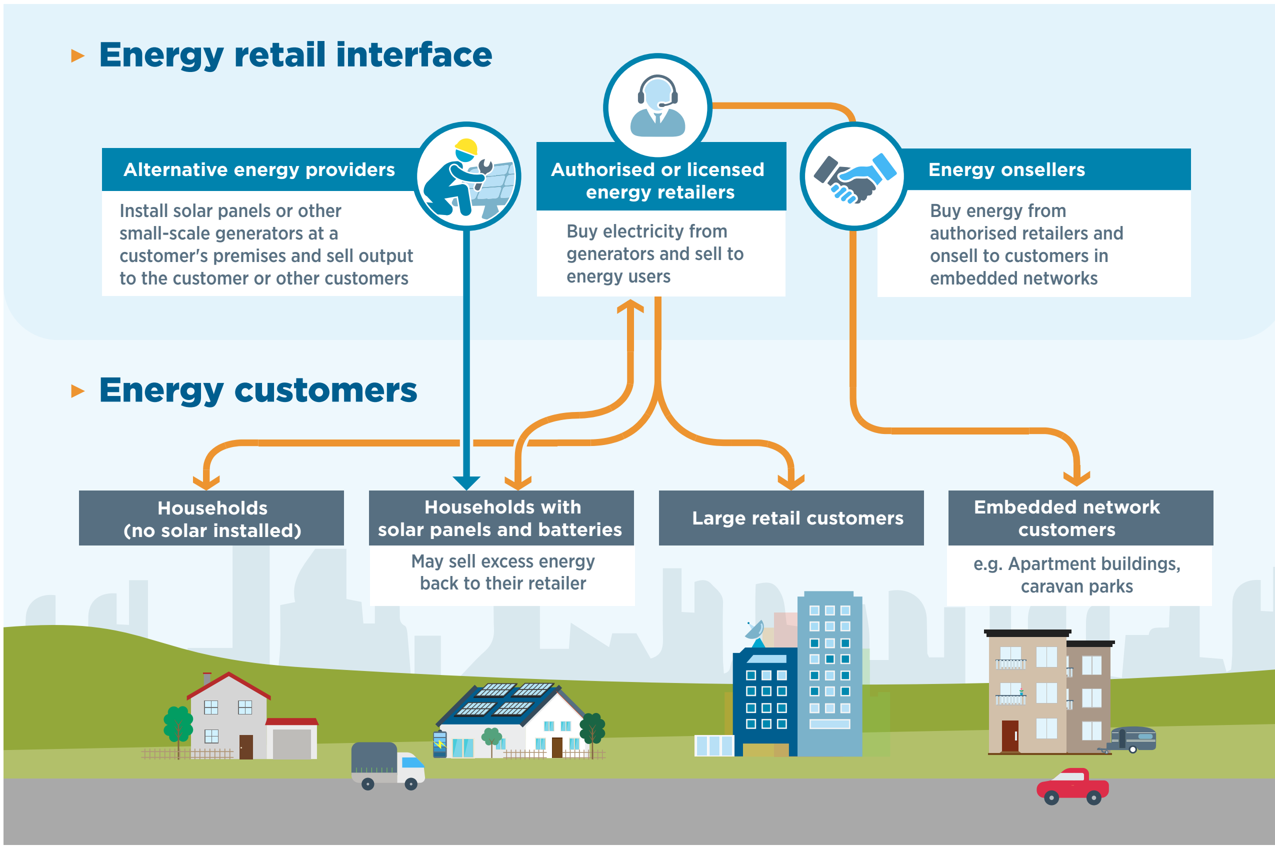
The National Energy Retail Law (Retail Law) operates alongside the Australian Consumer Law to protect small energy customers in their electricity and gas supply arrangements. Small customers include all residential energy users and small businesses consuming fewer than 100 megawatt hours (MWh) of electricity or 1 terajoule (TJ) of gas per year.[2] While small customers make up 98 per cent of electricity connections and over 99 per cent of gas connections, they account for less than 50 per cent of energy sales by volume.

The Retail Law applies to electricity and gas sales in Queensland, NSW, South Australia, and the ACT, and to electricity sales in Tasmania. Victoria has not implemented the Retail Law but partly harmonised its regulatory

1 The Office of the Chief Economist at the Department of Industry, Innovation and Science reported a penetration rate of 17 per cent at October 2015, and determined this rate was the largest rooftop solar PV penetration rate globally.

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

Figure 4.1
An evolving retail energy market



Source: AER.

arrangements with the national framework. Western Australia and the Northern Territory retain separate regulatory arrangements, and they are not covered in this report.

The Retail Law established the Australian Energy Regulator (AER) as the national regulator of retail energy markets (box 4.1). While the AER has wide ranging roles, it does not regulate retail energy prices. State and territory governments retain a price regulatory role in NSW (for gas only), the ACT and Tasmania (for electricity), and Queensland (for rural electricity customers).

4.3 What an energy bill pays for

The energy bills paid by retail customers cover the costs of producing and transporting energy, as well as retailer costs and regulatory obligations.

A typical *electricity* retail bill (figure 4.2) covers:

- network costs for transporting electricity, making up 40–55 per cent of a bill. The AER regulates network charges, which are set to cover the efficient costs of building and operating electricity networks, and to provide a commercial return to the network owner on their invested capital
- the wholesale costs of buying electricity in spot and hedge markets, and retailers' costs and margins, which collectively make up 40–50 per cent of a bill. There is limited data on the separate impact of wholesale and retail costs on energy bills (see below)
- the costs of green schemes for renewable generation and energy efficiency (such as the renewable energy target and feed-in tariffs for solar PV installations), which collectively make up 5–15 per cent of a bill.[3]

3 AEMC, *2016 residential electricity price trends, fact sheet.*

Box 4.1 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 empower customers to make informed decisions on their energy use, and we 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
- 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)
- approve customer hardship policies that energy retailers offer to customers facing financial hardship and seeking help to manage their bills.

While we do not set retail energy prices, our Energy Made Easy website 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. The website includes a price comparator that shows all generally available offers to consumers, an electricity use benchmarking tool that allows households to compare their electricity use with that of similar sized households in their area, and consumer information.

In 2016–17, wholesale and retail costs weighed more heavily on retail bills in all regions, averaging 45 per cent of a bill (up from 42 per cent in 2015–16). This shift coincided with rising wholesale and hedging costs (that is, insurance against spot market volatility) in some regions. But the impact of network charges on retail bills fell in Victoria and Tasmania in 2016–17, following AER decisions that reduced those charges. The cost of green schemes remained highest in Queensland, given legacy impacts of the Solar Bonus Scheme.

The Australian Energy Market Commission (AEMC) reports the joint contribution of wholesale and retailers costs ('market costs') to retail bills, rather than disaggregating the two components. While spot electricity prices are transparent, many retailers hedge their wholesale exposure in derivative markets (chapter 1). Limited transparency in derivative markets makes it difficult to estimate the market costs faced by each electricity retailer.

The composition of gas bills is even more opaque, given wholesale *gas* is mostly sold at prices set in confidential contracts. Figure 4.3 shows Oakley Greenwood estimates of the composition of gas retail prices for 2015.[4] Wholesale costs were estimated to account for less than 20 per cent of retail gas prices, except in Victoria and the ACT, where smaller scale networks lower the relative impact of network charges. Overall, recent increases in wholesale gas prices were likely to have raised the contribution of wholesale costs to retail gas bills in 2016.

Distribution pipeline charges account for 30–70 per cent of retail prices, and transmission charges account for another 3–15 per cent. The impact of these costs on energy bills largely depends on customer density and gas volumes. That is, unit costs for distribution services are lower in regions where more customers are connected to a network and where average customer use is high (as in Victoria).

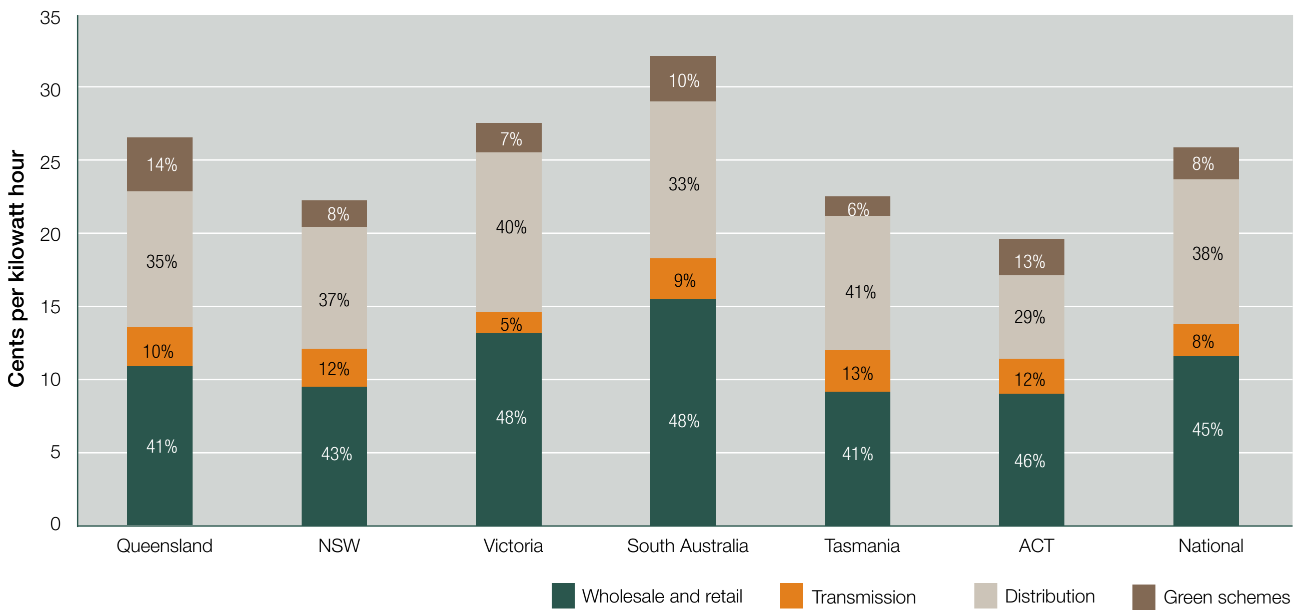
The data indicates relatively high retail margins in some regions, and retailer costs are the largest single contributor to gas retail prices in Victoria. A number of stakeholders have raised concerns that Victorian retail margins are above competitive levels in both electricity and gas. The Grattan Institute estimated in March 2017 that profit margins for electricity retailers are about 13 per cent—more than double the margin that regulators traditionally allowed when they set retail prices.[5] But the AEMC found in 2016 no evidence that margins in Victoria (or any other jurisdiction with deregulated prices) are inconsistent with effective competition.[6] It will

4 Oakley Greenwood, *Gas price trends review report,* 2015.

5 Tony Wood and David Blower, *Price shock: is the retail electricity market failing consumers?*, March 2017.

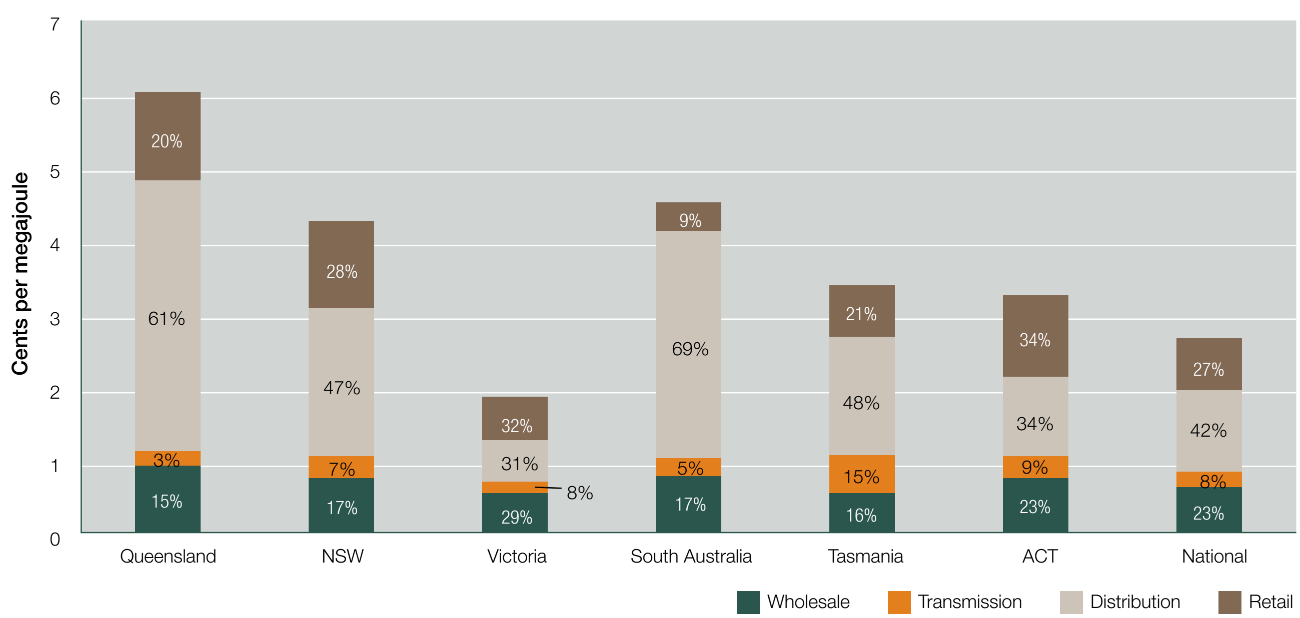
6 AEMC, *2016 residential electricity price trends, final report*, p. 132.

Figure 4.2
Composition of a residential electricity bill



Source: AEMC, 2016 residential electricity price trends, final report.

Figure 4.3
Composition of a residential gas bill



Source: Oakley Greenwood, *Gas price trends review,* 2015.

again focus on margins as part of its 2017 competition review. The Victorian Government is also examining retailer margins as part of a 2017 review of electricity and gas retail markets.[7]

In response to concern about the causes of recent electricity price increases in the NEM, the Australian Government in March 2017 directed the Australian Competition and Consumer Commission (ACCC) to hold an inquiry into retail electricity pricing. The review will examine the cost components of electricity pricing and whether retailers' margins and profitability are in line with their costs and risks. It will also consider any impediments to consumer choice, such as the transparency and clarity of contracts that energy companies offer to consumers.[8]

The ACCC expects to produce a preliminary report by the end of September 2017, with a final report due in 30 June 2018. By holding an inquiry under part VIIA of the *Competition and Consumer Act 2010*, the ACCC can compulsorily gather information and hold hearings to assess the level of competition in a market. The ACCC will work with other relevant agencies, such as the AER and the AEMC, in undertaking the inquiry.

4.4 How retail prices are set

Energy retailers in southern and eastern Australia offer energy contracts at whatever prices they choose. Alongside this deregulated pricing, government agencies in some jurisdictions regulate retail prices for *standing offers.* The AER does not regulate retail prices in any jurisdiction.

For electricity, Victoria (2009), South Australia (2013) and NSW (2014) removed retail price regulation for electricity after the AEMC found energy markets in those states were effectively competitive. Retail prices were deregulated in south east Queensland from 1 July 2016, following similar AEMC findings for that market.[9] But governments in those four jurisdictions do require retailers to publish standing offer prices that small customers can access. Retailers may adjust these prices once every six months.

At 1 January 2017, only Tasmania, the ACT and rural Queensland regulate retail electricity prices for small customers.

7 Department of Environment, Land, Water and Planning (Victoria), *Review of electricity and gas retail markets in Victoria, Discussion paper*, 2017, available at www.delwp.vic.gov.au/__data/assets/pdf_file/0008/369206/Discussion-Paper-Review-of-Electricity-and-Gas-Retail-Markets-in-Victoria-30012017.pdf.

8 Prime Minister of Australia, The Hon Malcolm Turnbull MP, 'ACCC to review electricity prices', Media release, 27 March 2017.

9 AEMC, *2015 Retail Competition Review, final report.*

In gas, only NSW regulates retail prices for small customers. Following an AEMC finding in 2016 that gas market customers would benefit from the removal of retail price regulation, the NSW Government announced it would deregulate retail gas prices from 1 July 2017. Over 80 per cent of the state's 1.3 million residential gas customers have already switched from regulated pricing to a market contract. The state's Independent Pricing and Regulatory Tribunal (IPART) will continue to play a market monitoring role, as it does in the retail electricity market.[10]

4.5 Retail prices

Table 4.1 and figures 4.4 and 4.5 summarise recent movements in regulated and standing offer energy prices, and estimated annual customer bills under those arrangements. Customers who shop around in NSW, Victoria, South Australia and south east Queensland (and, to a lesser extent, the ACT) can usually find a market contract that is cheaper than the standing offers set out in the table (section 4.8.5). Prices are typically higher for customers in regional and remote areas—where infrastructure costs tend to be higher and can be recovered from fewer customers—than for urban customers.

The data assumes identical rates of energy use nationally. In practice, typical energy use varies across jurisdictions because they have varying climates, penetration of gas supply, and other factors.

4.5.1 Analysis of price trends

Retail *electricity* prices rose significantly between 2008 and 2013, mainly due to escalating network costs. During this period, network businesses invested heavily in assets to accommodate expected demand growth, and financial market instability raised debt costs. The carbon price also contributed—raising retail prices by 5–13 per cent in 2012—although an assistance package offset the impact on low and middle income residential customers.

Then, in 2014 the repeal of carbon pricing reduced retail electricity prices in most regions. Declining network costs, accompanied by an oversupply of generation capacity, further eased pressures on retail electricity prices in most jurisdictions in 2015.

This trend reversed in 2016, when the retirement in May of the large Northern coal fired generator in South Australia tightened wholesale market conditions and drove up costs

10 Minister for Industry, Resources and Energy (NSW), 'Boosting competition in the retail gas market', Media release, 23 September 2016.

Table 4.1 Movements in energy bills for customers on regulated or standing offers

JURISDICTION	WHO SETS THESE PRICES?	DISTRIBUTION NETWORK AREA	AVERAGE PRICE INCREASE (PER CENT) 2012	2013	2014	2015	2016	2017	ESTIMATED ANNUAL CUSTOMER BILL, 2016 ($)
ELECTRICITY									
Queensland	Retailers	Energex	10.6	20.4	1.7	–6.1	5.6		2131
	QCA	Ergon Energy	10.6	20.4	1.7	–6.1	5.6		2119
New South Wales	Retailers	AusGrid	20.6	3.9	–5.5	–6.6	9.1		2028
		Endeavor Energy	11.8	1.6	–6.7	–3.5	7.2		1974
		Essential Energy	19.7	–0.6	–6.9	–17.0	7.7		2266
Victoria	Retailers	Citipower	19.9	6.4	–9.0	7.5	0.4	6.5	2097
		Powercor	23.1	5.8	–6.8	7.1	–5.2	6.1	2397
		AusNet Services	19.7	12.4	–3.9	10.6	–3.4	9.7	2687
		Jemena	23.2	6.1	–5.8	4.0	–3.4	9.9	2429
		United Energy	25.2	4.8	–6.2	4.2	–4.4	10.5	2235
South Australia	Retailers	ETSA Utilities	12.7	–1.8	2.2	–9.0	12.8		2632
Tasmania	OTTER	Aurora Energy	10.6	1.8	–12.6	2.0	3.4		2032
ACT	ICRC	ActewAGL	17.7	3.5	–7.0	–4.6	5.9		1482
GAS									
Queensland	Retailers	AGN	13.4	8.4	2.1	6.2	0.0		1149
		Allgas Energy	13.4	5.1	3.4	6.9	2.9		1234
New South Wales	IPART	Jemena	14.8	9.6	12.0	–11.4	0.7		921
Victoria	Retailers	AusNet Services	16.3	3.0	–1.2	8.3	8.3	8.6	842
		Multinet	20.0	2.0	–1.6	6.4	6.3	5.0	837
		AGN	18.4	9.1	–3.2	6.2	31.3	7.5	1023
South Australia	Retailers	AGN	17.7	11.6	9.3	3.7	–10.2		1090
ACT	Retailers	ActewAGL	10.3	5.7	8.7	4.6	–4.4		957

Notes:

Retail prices in standing offers can be changed no more than once every six months. Price adjustments typically link to the timing of network tariff changes, which is 1 July for Queensland, NSW, South Australia, Tasmania and the ACT, and 1 January for Victoria.

Estimated annual cost is based on a customer using 6500 kilowatt hours of electricity per year and 24 gigajoules of gas per year on a single rate tariff at 1 December 2016.

Prices are based on regulated prices of the local area retailer in each distribution network area, or on standing offer prices where prices are not regulated.

Sources: energymadeeasy.gov.au; switchon.vic.gov.au (Victorian Energy Compare website); yourchoice.vic.gov.au; comparator.qca.org.au; determinations, factsheets and media releases by IPART (NSW), the QCA (Queensland), ESCOSA (South Australia), OTTER (Tasmania) and the ICRC (ACT); Victorian Government gazette.

Figure 4.4

How retail energy bills have moved—electricity

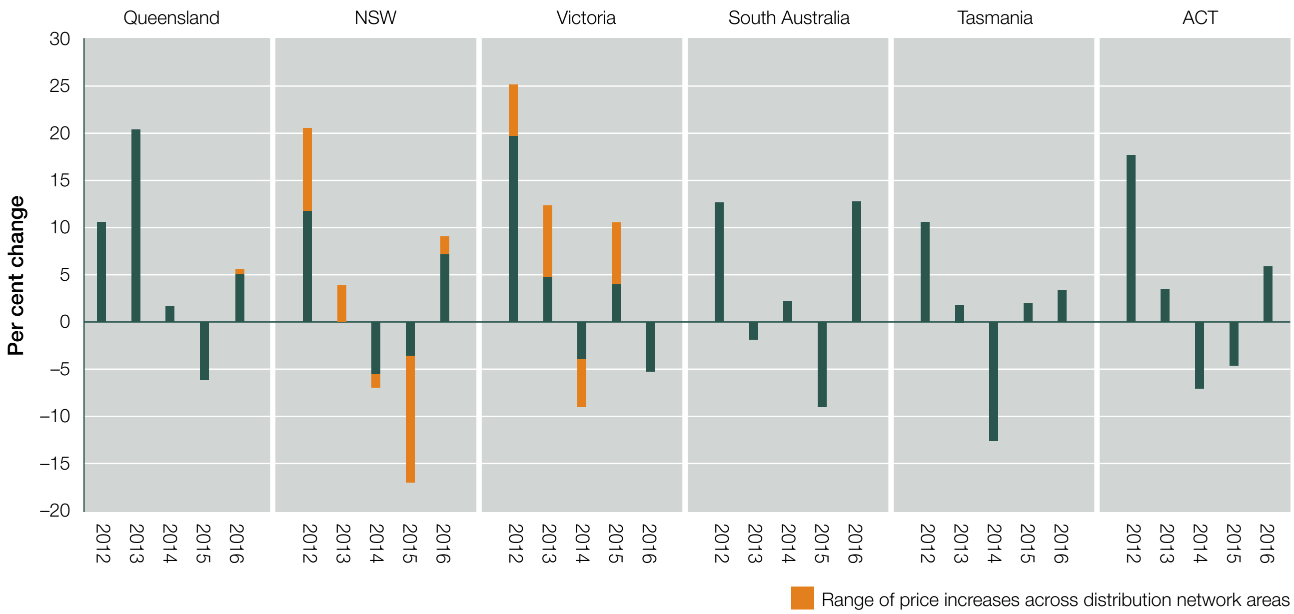
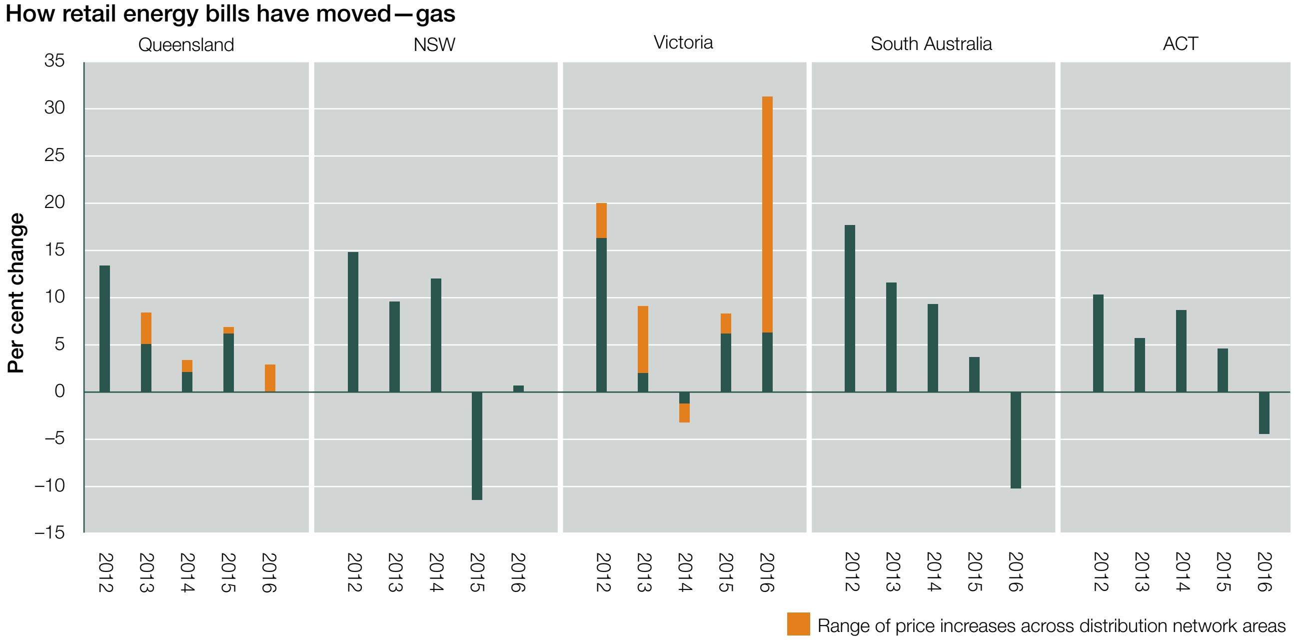


Figure 4.5

How retail energy bills have moved—gas



Notes (figures 4.4 and 4.5):

Estimated annual cost is based on a customer using 6500 kilowatt hours of electricity per year and 24 gigajoules of gas per year on a single rate tariff at August 2015.

Prices are based on regulated prices of the local area retailer for each distribution network, or on standing offer prices where prices are not regulated.

A range of outcomes is shown for jurisdictions with multiple distribution networks, as distribution costs may vary between network areas.

Sources (figures 4.4 and 4.5): energymadeeasy.gov.au; switchon.vic.gov.au; yourchoice.vic.gov.au; comparator.qca.org.au; determinations, factsheets and media releases by IPART (NSW), the QCA (Queensland), ESCOSA (South Australia), OTTER (Tasmania) and the ICRC (ACT); Victorian Government gazette.

in spot and derivative markets. These higher costs began to flow through to residential electricity prices during the year.

Overall, electricity retail prices trended higher in 2016 in all jurisdictions other than Victoria. The rise was highest for South Australia (13 per cent), followed by NSW (7–9 per cent), the ACT (6 per cent), Queensland (5 per cent) and Tasmania (3 per cent). In Victoria, significantly lower network charges following an AER determination offset the impact of rising wholesale costs. As a result, retail bills fell by 3–5 per cent in most of the state.

The AEMC found market costs (wholesale and retail costs) were the main driver of higher retail bills in 2016, with most jurisdictions recording double-digit rises in this cost component.[11] NSW recorded the largest rise in market costs (19 per cent), followed by South Australia (16 per cent), the ACT (11 per cent), Queensland and Tasmania (10 per cent each), and Victoria (9 per cent).[12] The AEMC cited generation plant closures as a significant contributor to these cost increases.

The retirement of Victoria's Hazelwood power station in March 2017 will likely put further pressure on wholesale market costs in the short to medium term. This development was already reflected in significant price rises notified by Victoria retailers in January 2017. As traditional generators leave the market, liquidity in electricity financial markets may further tighten, putting additional upward pressure on wholesale costs.

Rising wholesale gas prices have also affected electricity prices, particularly where gas generation sets the wholesale price, as it often does in South Australia. The Queensland Competition Authority (QCA) noted in 2016 that rising gas fuel costs had affected wholesale electricity costs in Queensland, as had higher Renewable Energy Target costs. But it explained the net impact on electricity retail bills was partly offset by lower electricity network costs following recent AER decisions on the revenues of the state's distribution networks.[13] Over the next few years, gas supply constraints and rising gas prices (arising from closer links of the domestic market to international prices via Queensland's LNG industry) may continue to exert upward pressure on retail energy prices.

The impact of network charges varies across the jurisdictions, largely depending on (a) the timing of AER revenue reviews and (b) each network's stage in the regulatory cycle. A network's revenues are typically open to a full review once every five years, and more recent AER determinations account for forecasts of weaker electricity demand that have eased operating costs and delayed some network expansions. Improved financial market conditions have further moderated cost pressures on the networks. In these conditions, networks are requiring less revenue to operate efficiently. Recent AER network determinations for Victoria, South Australia and Queensland reflect these conditions, and the impacts on retail bills have moderated accordingly (often resulting in lower customer bills).

The AEMC forecast a slightly upward trend in network costs over the next three years. But it noted continuing legal proceedings against a number of AER network determinations make it difficult to predict those costs with accuracy.

Green schemes also continue to affect retail bills in most jurisdictions, especially in Queensland, where they contributed 14 per cent to retail bills. Despite this effect, costs associated with the state's Solar Bonus Scheme eased by 13 per cent from their peak levels in 2015. Green schemes also accounted for 13 per cent of ACT electricity retail prices in 2016–17. A forecast increase in the costs of the ACT's feed-in tariff schemes (schemes that encourage the uptake of small, medium and large scale renewable generation) from 0.83 cents per kilowatt hour in 2015–16 to over 2.9 cents per kilowatt hour in 2018–19 will mean green costs may account for 20 per cent of retail bills by that time.

In *gas*, rising wholesale costs associated with Queensland's liquid natural gas (LNG) projects have put upward pressure on retail bills. Australia's east coast gas market was quarantined from international markets, but domestic prices have more closely linked to international oil prices since LNG exports began. The diversion of some gas supplies from the domestic market to LNG projects also tightened the domestic supply–demand balance, as reflected in rising gas contract and spot prices.

The impact of rising wholesale gas prices on retail bills was partly offset by lower gas pipeline charges under recent AER determinations for NSW (2015), South Australia (2016) and the ACT (2016). The determinations reflect improved financial market conditions that have lowered forecast rates of return for gas pipeline businesses. The determinations resulted in lower gas retail bills in all three jurisdictions for the year in which the relevant determination took effect.

In NSW, IPART determined regulated gas retail prices will remain stable in 2016–17, noting that recent falls in international oil and gas prices had eased domestic gas costs. But it explained prudent retailers would likely enter gas purchase contracts a year in advance, meaning the

11 AEMC, *2016 residential electricity price trends, final report* .

12 Frontier Economics, *2016 residential electricity price trends,* Report prepared for the AEMC. The Frontier data relate to financial year 2016–17.

13 QCA, *Regulated retail electricity prices for 2016–17*, May 2016.

pass through of lower costs to retail customers may not be immediate.[14]

In Victoria, gas retail charges rose strongly in 2016, with further significant rises occurring in 2017. Gas pipeline charges in Victoria have been relatively stable since 2013, indicating rising wholesale costs and/or retail margins were responsible.

4.5.2 CPI data on retail energy prices

Figures 4.6 and 4.7 track movements in real energy prices for metropolitan households since 1991, based on the electricity and gas components of the consumer price index. Adjusting for inflation, national *electricity* prices rose by around 10 per cent each year (13 per cent in nominal terms) over the five years to 2012–13. Real prices peaked nationally in March 2014 before easing significantly as a result of falling network costs 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 pass through of network cost increases, rising gas fuel costs, and costs associated with the Solar Bonus Scheme. And the national trend of declining real prices reversed in 2016, when prices began to rise in most cities for the above reasons.

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 in Sydney, Adelaide and Canberra until new access arrangements lowered gas pipeline charges (which took effect in 2014–15 in Sydney and in 2015–16 in the other cities). Gas prices in Melbourne dipped following the removal of carbon pricing in 2014, but overall have trended higher (although at a lower rate than in Sydney, Adelaide and Canberra). Retail prices in the small residential markets of Brisbane and Hobart have been relatively stable.

4.5.3 International electricity prices

Figure 4.8 compares average Australian household electricity prices with those in other OECD countries, based on purchasing power parity. This measure adjusts for differences in the cost of living across different countries.

While Australian electricity prices were traditionally low by global standards, rising energy network costs drove prices to rise significantly from around 2008 to 2013. In this period, price increases were about 10 per cent each year. Australian electricity costs for a typical household have levelled out more recently, but in 2015 remained slightly above the OECD average. In particular, prices were higher than for households in the United States, Canada, and South Korea, but were lower than for households in Japan, New Zealand, the United Kingdom and most of Europe.

14 IPART, *Review of regulated retail prices and charges for gas from 1 July 2016.*

4.6 Energy retailers

Energy sellers include energy retailers authorised under the Retail Law,[15] and those exempt from the law's provisions. 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.

4.6.1 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 set out in the Retail Law. In February 2017, 60 businesses held authorisations to retail electricity and 28 held authorisations to retail gas.[16]

While many retailers offer energy services to all customers, some target market segments. In making this choice, a retailer considers factors such as price regulation (if it applies), market scale, competition, the ability to source hedging contracts to manage risk and, for gas retailing, whether wholesale gas contracts and pipeline access are available.

Table 4.2 lists authorised or licensed retailers that sell energy to residential and/or small business customers in southern and eastern Australia. In total, around 30 retail brands offer energy contracts to small customers in these markets. Around 50 per cent of them offer both electricity and gas in at least one jurisdiction. Some offer only electricity, while one specialises in just gas.

In 2016, there were four retail electricity market entrants in NSW and South Australia, two in Victoria, and one in the ACT and south east Queensland.

15 In Victoria, in which the Retail Law does not apply, retailers must hold a licence issued by the Essential Services Commission.

16 Some company groups hold multiple authorisations. At July 2016, 33 retailers held an electricity and/or gas licence allowing them to sell energy in Victoria.

Figure 4.6
Electricity retail price index (inflation adjusted)

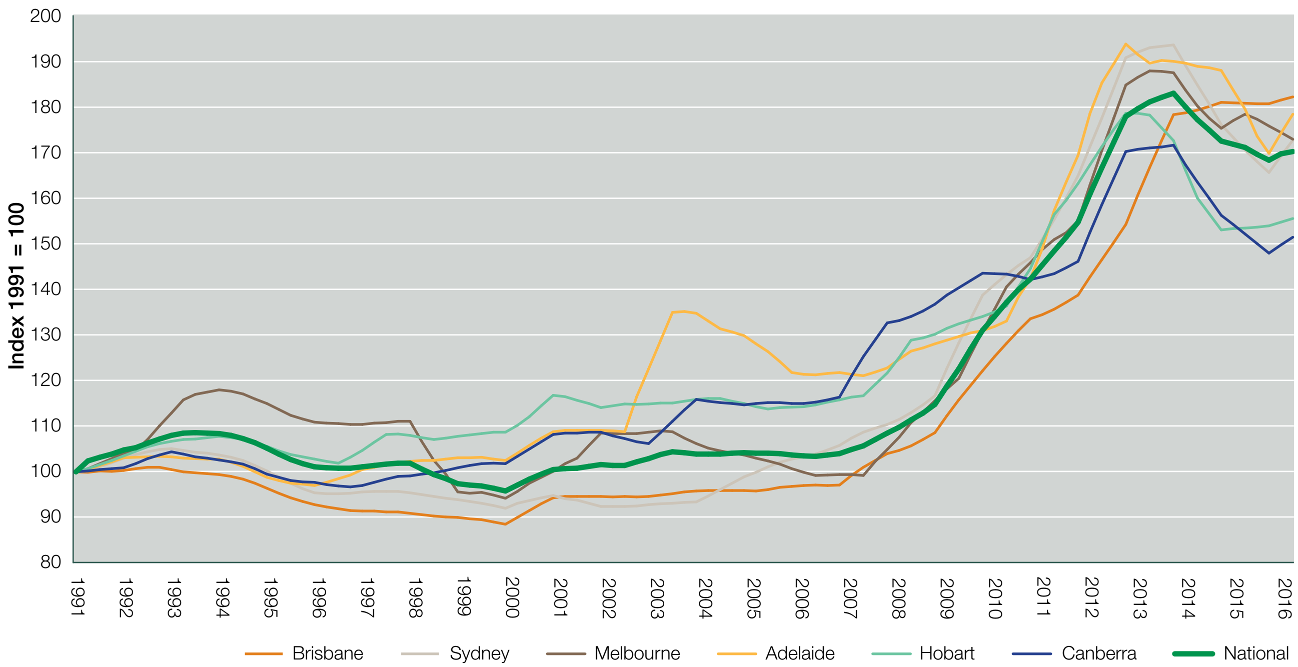
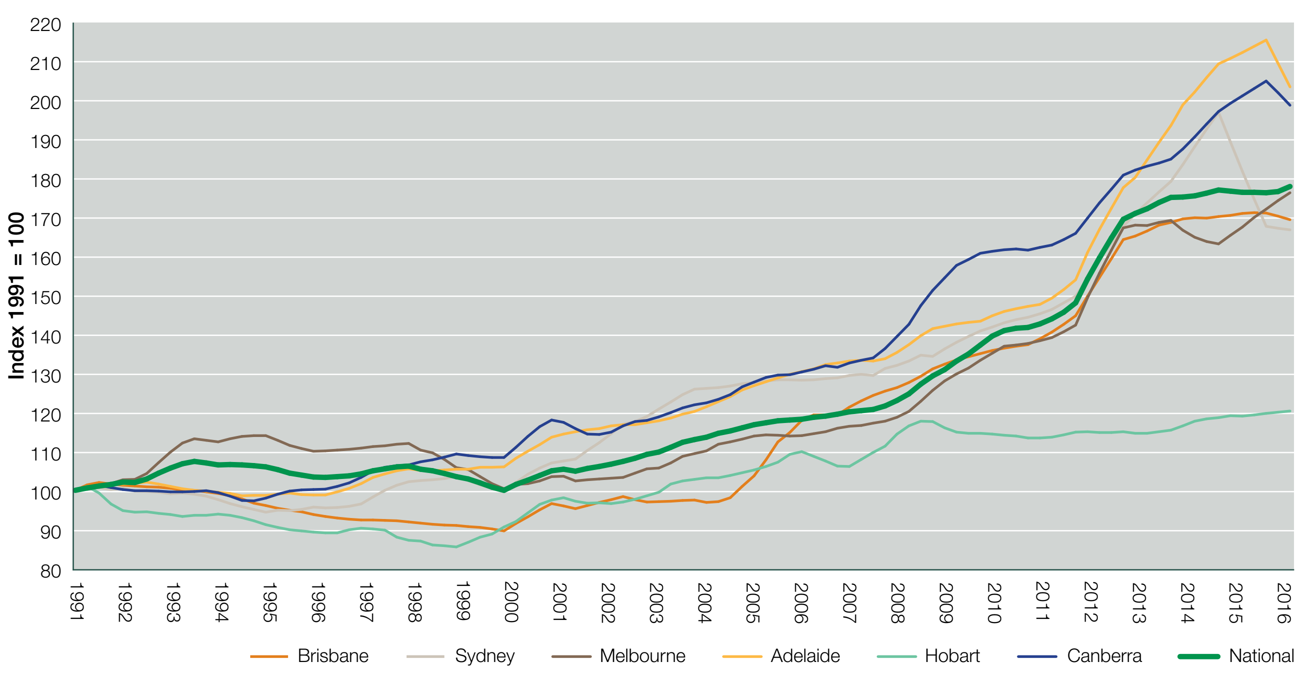


Figure 4.7
Gas retail price index (inflation adjusted)

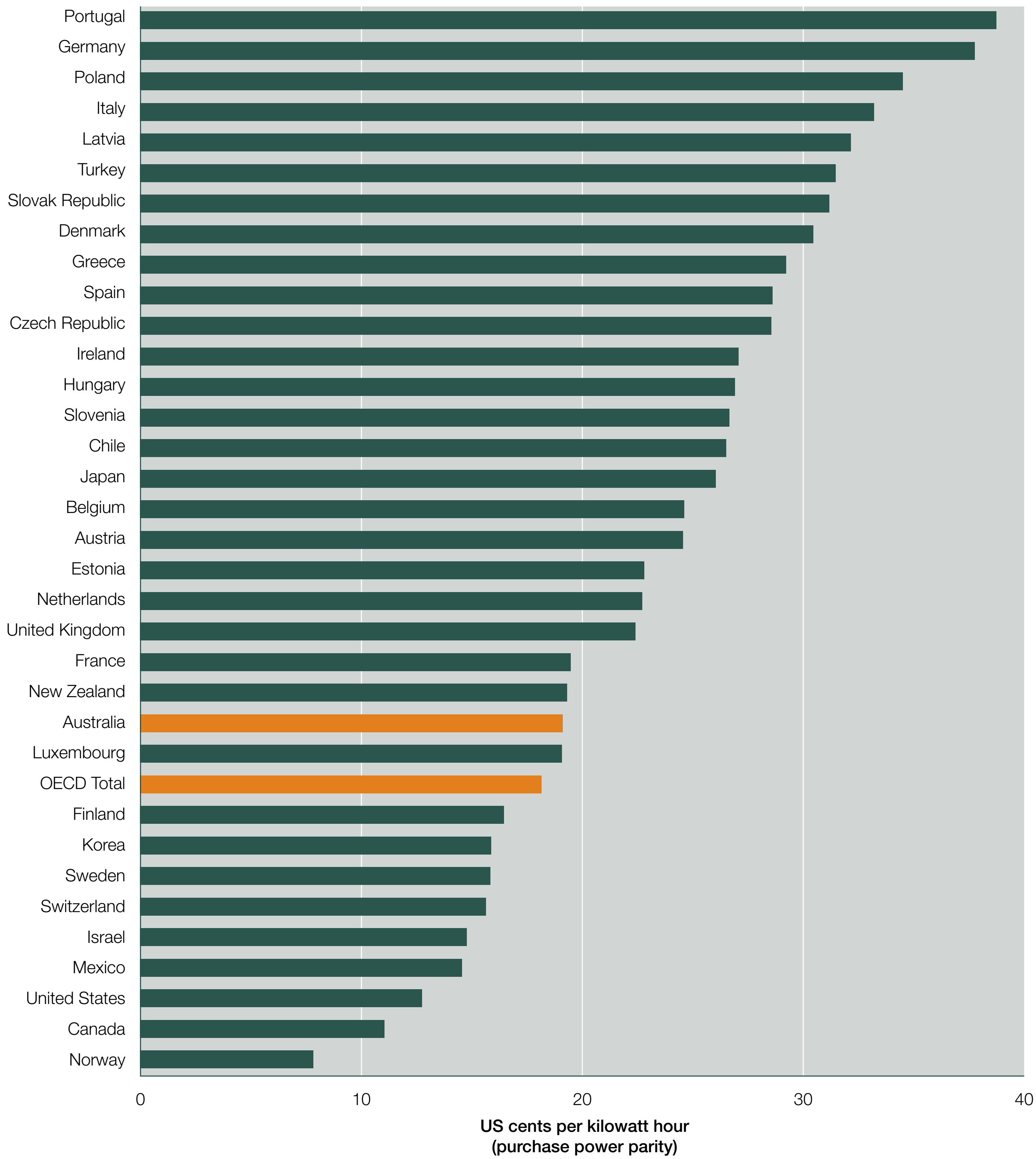


Note (figures 4.6 and 4.7): Consumer price index electricity and gas series, deflated by the consumer price index for all groups.

Source (figures 4.6 and 4.7): ABS, *Consumer price index*, cat. no. 6401.0, various years.

Figure 4.8

International household electricity price comparison, 2015



Data sources: Estimates published by the International Energy Agency, *Energy prices and taxes, 2016*, adjusted for revisions to Australian data published by the AEMC in 2017.

4.6.2 Exempt energy sellers

An energy seller may apply to the AER for an *exemption* from the need to be authorised if (1) the entity intends to supply energy services to a limited customer group (for example, at a specific site or when energy is supplied incidentally through an existing relationship, such as by a body corporate), or (2) the entity supplies only energy that is additional to the customer's primary energy connection. The exemptions framework tailors an energy seller's obligations to the products that the seller offers. The AER determines the conditions of an exemption. Applicants are typically those seeking to supply energy through onselling or power purchase agreements.

The Retail Law provides for a number of exemption types. At February 2017:

- 125 businesses selling electricity held individual exemptions, which are tailored to the applicant's requirements. These exemptions cover mainly legacy solar power purchase agreements, of which the sale is now regulated as a class of registered exemption
- over 2400 businesses held registered 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. New energy rules take effect in December 2017 to give embedded network customers better access to retail market offers from electricity retailers.

The Retail Law also establishes deemed exemption classes for small onselling arrangements. A person operating under a deemed exemption does not need to register with the AER.

4.6.3 Other providers of energy services

Alongside energy markets governed by the Retail Law, wider markets beyond the scope of that law are evolving for:

- energy management services such as brokerage services, energy aggregators and load management services
- energy generation (such as solar PV) and storage products (such as batteries)
- off-grid energy systems (including stand-alone systems and microgrids with some link to the grid) and the management of these systems.

The Council of Australian Governments' (CoAG) Energy Council is reviewing regulatory frameworks to ensure they are flexible enough to support an electricity market with increasingly decentralised supply options, and to enable consumers to benefit from innovative products and services. It has progressed workstreams on stand-alone systems such as microgrids, and on consumer protections for new energy products and services (namely, 'behind the meter' services such as rooftop solar PV and battery storage).[17]

4.7 Industry structure

Australia's retail energy markets tend to be concentrated, with significant vertical integration among retailers and energy producers. Despite the significant number of authorised retailers operating in southern and eastern Australia, the retail brands of three private businesses—AGL Energy, Origin Energy and EnergyAustralia—supply over 70 per cent of small electricity customers and 80 per cent of small gas customers (figures 4.9 and 4.10).[18] For example, while 25 retailers offer electricity contracts to small customers in NSW, 90 per cent of customers are still supplied by the 'big three'.

The smaller markets are even more concentrated. ActewAGL supplies over 92 per cent of ACT households, while Tasmanian households are still waiting for a new entrant to compete with monopolist Aurora Energy to provide choice.

But smaller retailers acquired 8 per cent of customers from the three market leaders between 2012 and 2016. In 2015–16, smaller retailers increased their market share by 25 per cent in NSW, and by 20 per cent in Queensland. Snowy Hydro—owned by the NSW, Victorian and Australian governments—has grown sufficiently in size to be considered a fourth significant retailer, with 7–8 per cent market share in electricity and gas.

Victoria has the highest penetration of smaller retailers, with 20 supplying electricity to around 37 per cent of the state's electricity customers in 2016, and eight supplying gas to 30 per cent of gas customers. In South Australia, smaller retailers supplied 22 per cent of electricity customers and 12 per cent of gas customers. Smaller retailers increased their market share by 4–6 per cent in 2015–16 in those states.

17 CoAG Energy Council, 'Energy market transformation', www.coagenergycouncil.gov.au/current-projects/energy-market-transformation.

18 Includes brands owned by these businesses, such as Powerdirect (owned by AGL Energy).

Table 4.2 **Retailers offering energy contracts to small customers—January 2017**

RETAILER	OWNERSHIP	QLD	NSW	VIC	SA	TAS	ACT
1st Energy	1st Energy		E				
ActewAGL Retail	ACT Government/AGL Energy		E, G*				E*, G*
AGL Energy	AGL Energy	E, G*	E, G*	E*, G*	E*, G		
Alinta Energy	TPG Capital		E	E, G	E, G		
Aurora Energy	Tasmanian Government					E*, G	
BlueNRG	BlueNRG		E	E	E		
Click Energy	Click Energy	E	E	E, G	E		
Commander	M2 Energy		E	E	E		
CovaU	TeLPacific		E, G	E, G			
Diamond Energy	Diamond Energy	E	E	E	E		
Dodo Power and Gas	M2 Energy	E	E, G	E, G	E		
EnergyAustralia	CLP Group	E	E*, G	E*, G*	E, G		E, G
Enova Energy	Enova Community Energy		E				
Ergon Energy	Queensland Government	E*					
ERM Power	ERM Power	E	E		E	E	E
Globird Energy	Globird Energy			E			
Locality Planning Energy	Go Energy	E					
Lumo	Snowy Hydro	E	E, G	E, G	E		
Metered Energy	Metered Energy	E, G					
Mojo Power	Mojo Power		E				
Momentum Energy	Hydro Tasmania (Tasmanian Government)	E	E	E, G	E		
Next Business Energy	Next Business Energy	E	E	E	E		
Online Power and Gas	Online Power and Gas			E			
Origin Energy	Origin Energy	E*, G*	E*, G*	E*, G*	E, G*		E, G
Pacific Hydro	State Power Investment Corporation			E	E		
People Energy	People Energy			E			
Pooled Energy	Pooled Energy		E				
Powerdirect	AGL Energy	E	E	E	E		E
Powershop	Meridian Energy		E	E			
Qenergy	Qenergy	E	E	E	E		
Red Energy	Snowy Hydro	E	E, G	E, G	E		E
Sanctuary Energy	Living Choice Australia/Sanctuary Energy	E	E		E		
Savant Energy Power Network	Savant Energy Power Network				G		
Simply Energy	Engie/Mitsui	E	E	E, G	E, G		E
Sumo Power	Sumo Power			E			
Tas Gas Retail	Brookfield Infrastructure					G	
Urth Energy	Urth Energy	E	E		E		

Electricty retailer | Gas retailer | Host retailer *

Sources: www.energymadeeasy.com.au; switchon.vic.gov.au

Figure 4.9
Retail market share (small customers), June 2016—electricity

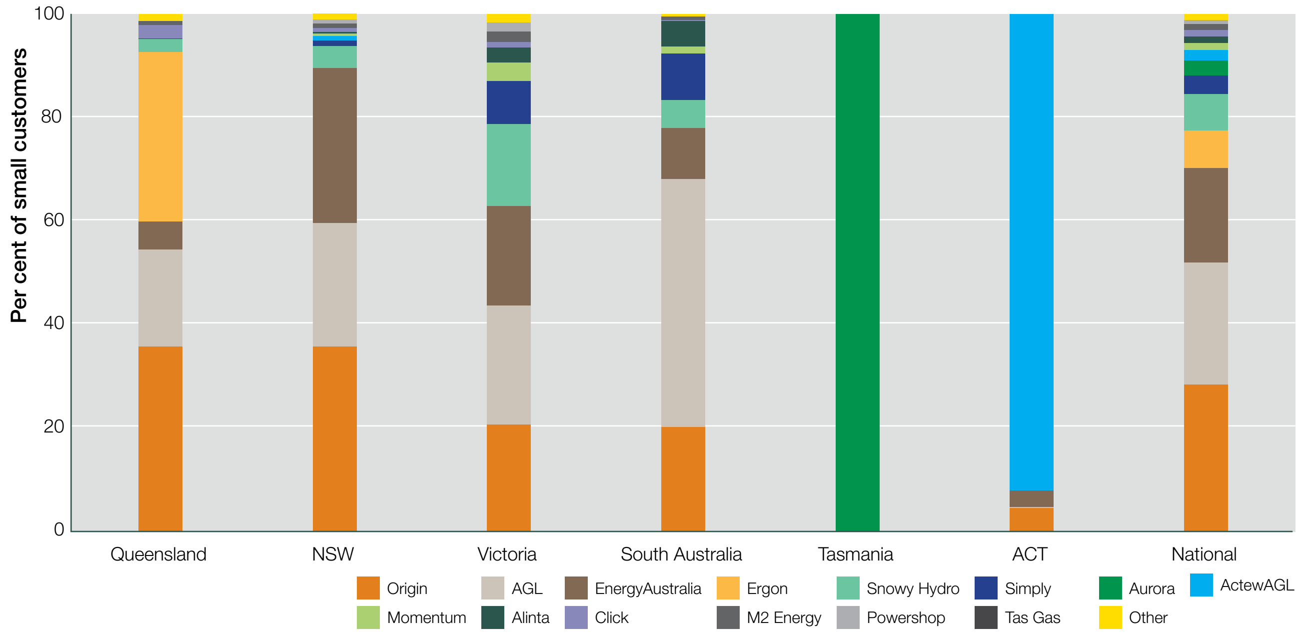
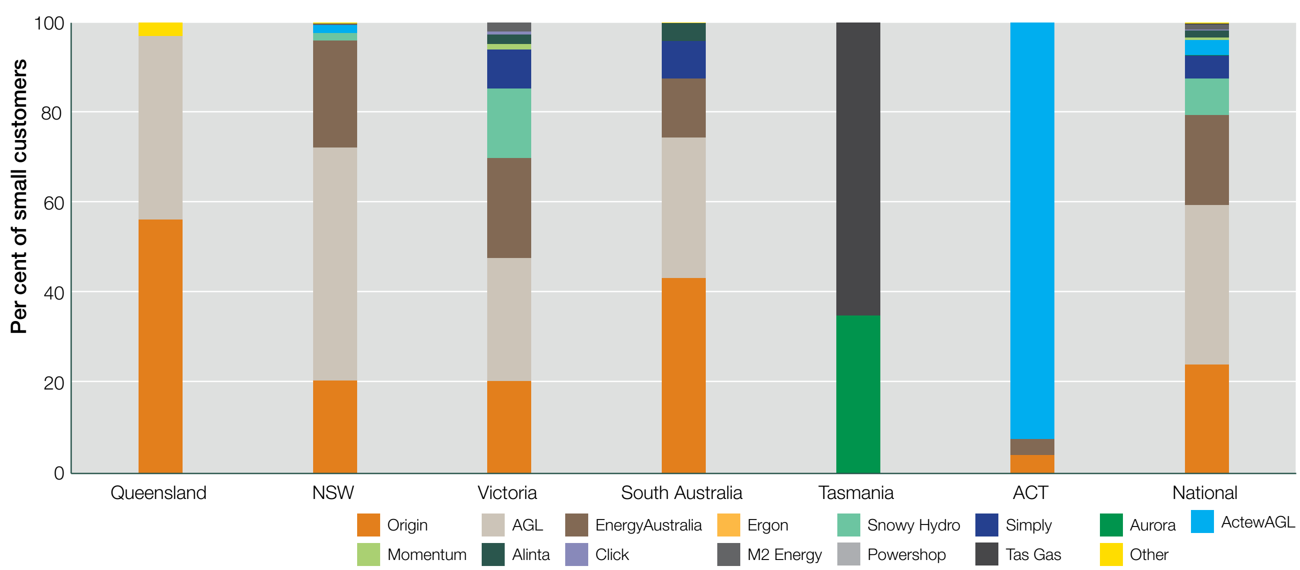


Figure 4.10
Retail market share (small customers), June 2016—gas



Sources (figures 4.9 and 4.10): Queensland, NSW, South Australia, Tasmania and ACT—unpublished data reported by energy retailers to the AER; Victoria—ESC, *Victorian energy market report 2015–16*.

Government retailers retain a strong presence in some jurisdictions. Aside from Snowy Hydro:

- the Queensland Government owns Ergon Energy, which supplies electricity at regulated prices to customers in rural and regional Queensland.
- the Tasmanian Government owns Aurora Energy, which supplies all residential and most small business electricity customers in Tasmania
- ActewAGL (a joint venture between the ACT Government and AGL Energy) is the dominant retailer in the ACT, with 92 per cent of small customers
- the Tasmanian Government owns Momentum Energy, which operates in a number of jurisdictions.

4.7.1 Vertical integration

Governments structurally separated the energy supply industry in the 1990s, but many retailers and generators have since integrated to become 'gentailers'. Vertical integration (box 4.2) allows retailers and energy producers to manage the risk of price volatility in wholesale markets, so they have less need to hedge their positions in futures (derivatives) markets. This approach can drain liquidity from derivatives markets, posing a barrier to entry for retailers that are not vertically integrated.

In the National Electricity Market (NEM), AGL Energy, Origin Energy and EnergyAustralia each have significant market share in both generation and retail markets (figure 4.11). The three businesses:

- increased their market share in electricity generation from 15 per cent in 2009 to 46 per cent in 2016
- supplied 70 per cent of small electricity customers and 80 per cent of small gas customers in southern and eastern Australia in 2016.

While the businesses also have interests in upstream gas production and gas storage that complement their interests in gas fired electricity generation and energy retailing, some have recently scaled back these interests.

AGL Energy in February 2016 announced it planned to exit gas exploration and production, and would sell most of its gas production assets. It entered contracts with other suppliers to secure gas for its residential and small business customers.[19] This announcement followed a decision by EnergyAustralia in October 2015 to sell its Iona gas storage plant in Victoria.[20]

Similarly, Origin Energy in December 2016 announced it would divest its conventional upstream gas interests in the Otway Gas Project, the BassGas Project, the Kupe Gas Project, and the Perth, Cooper, Bonaparte and Canterbury basins.

Outside the 'big three' retailers, a number of former stand-alone generators having 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 owns the retailers Red Energy and Lumo Energy, while Hydro Tasmania owns Momentum Energy.

4.8 State of retail competition

According to survey data published by Energy Consumers Australia in December 2016, around 50 per cent of energy customers in Victoria, NSW and South Australia were satisfied with levels of competition in energy retail markets. This satisfaction rate was around 30 per cent in Queensland and the ACT, and 15 per cent in Tasmania. Further, less than one third of households considered the energy market is working in their long term interests.[21]

The AEMC assessed in 2016 that competition was effective for *electricity* markets in NSW, Victoria, south east Queensland and South Australia.[22] Those markets had evidence of new retailer entry and second tier retailers attracting customers from more established firms, resulting in lower rates of market concentration. The AEMC thus found market concentration fell by around 20 per cent in each of those jurisdictions between 2010 and 2016.[23] Victoria recorded the lowest concentration rate, reflecting the maturity of competition in its market.[24]

19 AGL Energy, 'Review of gas assets and exit of gas exploration and production', Media release, 4 February 2016.

20 *Australian Financial Review,* 'QIC to buy EnergyAustralia's Iona gas plant for 178b', available at www.afr.com/street-talk/qic-to-buy-energyaustralias-iona-gas-plant-for-178b-20151008-gk3zw2, 8 October 2015.

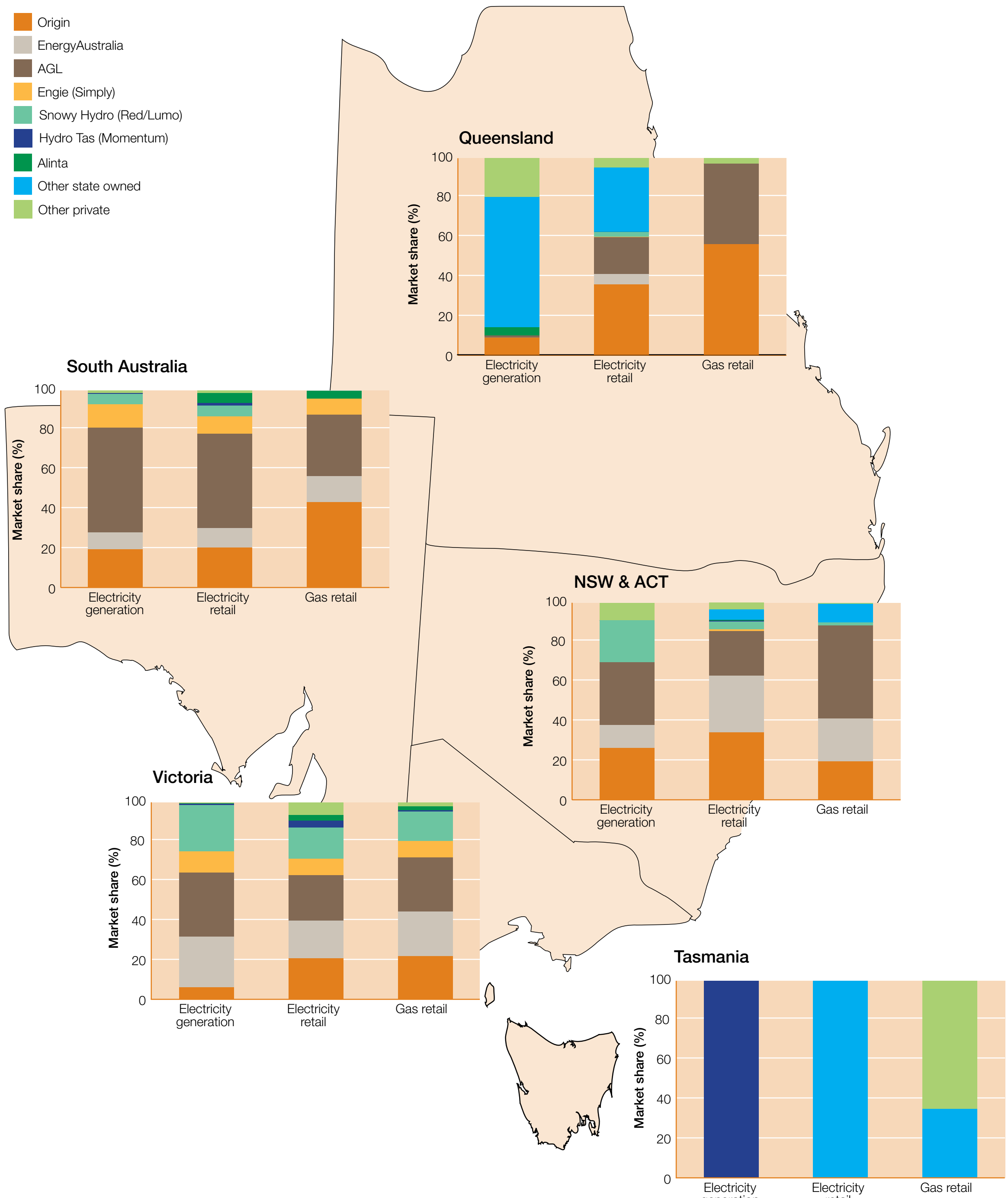
21 Energy Consumers Australia, *Energy Consumer Sentiment Survey findings, December 2016.*

22 AEMC, *2016 Retail Competition Review.*

23 As measured by the Herfindahl–Hirschman Index (HHI), which measures the size of firms in relation to the industry. Section 1.5.2 of this report examines HHI data for the wholesale electricity market.

24 AEMC, *2016 Retail Competition Review,* pp. 117–19.

Figure 4.11
Vertical integration in National Electricity Market jurisdictions, 2016



Notes:

Electricity generation market shares are based on summer availability for January 2017, except wind, which is adjusted by an average contribution factor. The Victorian generation data has been adjusted to account for the retirement of Engie's Hazelwood power station.

Electricity and gas retail market shares are based on small customer numbers at June 2016.

Sources: AER estimates (generation); Queensland, NSW, South Australia, Tasmania and ACT (retail)—unpublished data reported by energy retailers to the AER; Victoria (retail)—ESC, *Victorian energy market report 2015–16*.

Box 4.2 Vertical integration by region

The **NSW** electricity sector is dominated by the big three retailers. Origin Energy, EnergyAustralia and AGL Energy supply 90 per cent of retail customers and control 69 per cent of generation capacity. They also supply 96 per cent of gas retail customers. They acquired their generation and retail assets through privatisation processes that began in 2011. Most recently, AGL Energy acquired Macquarie Generation from the NSW Government in September 2014.

Outside the 'big three,' Snowy Hydro's acquisition of Colongra in December 2014 raised its market share in NSW generation to 21 per cent. Snowy Hydro also expanded its retail portfolio by acquiring Lumo Energy in September 2014, and now supplies 4 per cent of retail electricity customers (and 2 per cent of gas customers).

Victoria has no single dominant retailer, with AGL Energy, Origin Energy and EnergyAustralia each supplying 19–27 per cent of retail electricity and gas customers. But, while having reasonable market depth, Victoria has significant vertical integration. Following the retirement of Engie's Hazelwood power station in March 2017, the 'big three' retailers control 64 per cent of generation capacity.

Victoria's other major generators—Snowy Hydro (23 per cent of capacity) and Engie (11 per cent)—also operate retail brands, supplying 16 per cent and 8 per cent respectively of electricity customers. The businesses supply a similar proportion of gas customers.

South Australia's electricity sector is highly concentrated, with AGL Energy supplying 48 per cent of retail customers and controlling 53 per cent of generation capacity. Origin Energy, EnergyAustralia and Engie (Simply Energy) are significant but minority players in both generation and retail.

Vertical integration is less evident in **Queensland** and **Tasmania**, with a majority of generation capacity in each state controlled by state owned corporations. Origin Energy and (to a lesser extent) AGL Energy are the leading retailers in Queensland. The entities also control 10 per cent of statewide generation capacity. In Tasmania, the state owned Aurora Energy supplies most small retail customers, while the state owned Hydro Tasmania controls nearly all generation capacity.

The AEMC estimated in 2016 that electricity customers in NSW, Victoria, south east Queensland and South Australia could save $140–383 annually by regularly shopping around.[25]

Competition is less effective in the ACT and yet to emerge in Tasmania and regional Queensland. Retailers commonly cite ongoing price regulation and the dominance of incumbent retailers as barriers to entry in those regions. In Tasmania, no energy retailer has entered the residential electricity customer market to compete with Aurora Energy.

Despite the AEMC's findings of effective competition in several markets, retailers in 2016 rated the ease of market entry in Victoria and South Australia as slightly more difficult than a year earlier (section 4.8.3).[26]

More generally, competition is less effective in *gas* than electricity, given the smaller market scale, as well as difficulties in sourcing gas and pipeline services in some regions. The AEMC found retail gas competition is effective in NSW, Victoria and South Australia, but limited in south east Queensland. Retailers have frequently identified access to gas, the small size of the demand base, and the price of gas as barriers to entry and expansion (section 4.8.3).

Assessments of the maturity of retail competition should account for a range of indicators, including:

- customer adoption of market contracts
- customer engagement and activity in the market
- retailer behaviour
- product and price differentiation
- competitive pricing.

4.8.1 Customers on market contracts

Full retail contestability (FRC) in electricity and gas applies in all NEM jurisdictions, allowing all energy customers to enter a market contract with their retailer of choice. Tasmania was the most recent jurisdiction to introduce FRC, extending choice from 1 July 2014 to electricity customers using fewer than 50 MWh per year.

Market contracts permit retailers to tailor their energy offers, if they meet minimum regulated requirements. A contract may be widely available or offered to only specific

25 AEMC, *2016 Retail Competition Review,* p. iii.

26 Farrier Swier Consulting, *2016 Energy Retailer Survey report,* Report to the AEMC.

customers. Retailers can shape their contracts by offering customers different tariff structures, discounted prices, non-price incentives, billing options, fixed or variable terms, and other features. The 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 them into a market contract.

Customers without a market contract are placed on a *standing offer* with the retailer that most recently supplied energy at their premises (or, for new connections, with 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. In some jurisdictions, these contracts have regulated prices set by state or territory governments.

The share of customers on market contracts varies across jurisdictions (figure 4.12). In Victoria and South Australia, over 80 per cent of electricity and gas customers have a market contract. In NSW, the shift towards market contracts has accelerated since electricity prices were deregulated on 1 July 2014.

Figure 4.12
Small energy customers on market contracts, 30 June 2016

Sources: AER, *Retail performance report 2016;* unpublished AER estimates for Queensland.

The share of NSW electricity customers on market contracts rose by five percentage points to 74 per cent in 2016. The share of gas customers is even higher, at 80 per cent.

In Queensland, market contracts are more common in the south east, where about 70 per cent of customers have switched from standing offers. But, in regional Queensland, as well as the ACT and Tasmania, only a minority of customers are on a market contract. While Origin Energy's entry into the ACT retail market in 2014–15 caused an initial increase in market contracts, the share of customers on these contracts grew little in 2015–16. And, in Tasmania, small customers still lack choice, despite the introduction of FRC on 1 July 2014. In June 2016, 88 per cent of small customers remained on standing offers from Aurora Energy, at prices approved by the Tasmanian regulator.[27]

4.8.2 Customer awareness and engagement

The AEMC reported in 2016 that around 90 per cent of customers in NSW, Victoria, south east Queensland and South Australia were aware they can choose their energy retailer.[28] The proportion was lower in the ACT. In Tasmania, most small customers know they lack an effective choice of retailer, with Aurora Energy still being the only active retailer in that market segment.

Despite awareness of choices being generally high, around 70 per cent of customers in NSW, Victoria, south east Queensland and South Australia had not actively investigated their energy options in the 12 months to June 2016. Residential customers' most commonly stated reason for not investigating options was satisfaction with their current retailer or energy plan. The most common reason of small business customers was that they were too busy or lacked the time. Around 22 per cent of residential customers also gave this reason.[29] Research commissioned by the AEMC in 2016 found residential customers who are less willing to take risks and who tend to be late adopters of new technologies are less likely to investigate their energy options.[30]

Of those customers that investigated their energy options in 2016, around 50 per cent went on to switch retailer. Residential customers who had been directly approached by a retailer were more likely to have switched, as were those who had experienced a reduction in household income or unforeseen circumstances that severely affected their financial situation.[31]

27 AER, *Retail performance report 2016.*

28 AEMC, *2016 Retail Competition Review,* p. 56.

29 AEMC, *2016 Retail Competition Review,* pp. 58–61.

30 Newgate Research, *Consumer research for 2016 nationwide review of competition in energy retail markets,* Research report to the AEMC.

31 AEMC, *2016 Retail Competition Review.*

The AEMC found awareness and engagement vary across customer segments, with around 20 per cent of customers being highly vulnerable. The most vulnerable group (8 per cent of all customers) 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. By contrast, low income customers (12 per cent of customers) tend to be more familiar with support services.[32]

High levels of customer vulnerability create a barrier to participation and impede the development of effective competition. Vulnerable consumers are less likely to shop around because they lack confidence in finding the best deal for them, and they fear they may end up worse off. They are often embarrassed by their financial situation and concerned that switching retailers will mean a loss of benefits, increased debt, and exit or reconnection fees. Vulnerable customers also tend to have extremely low awareness of government price comparator websites such as Energy Made Easy, but they show strong interest once they are made aware.[33]

Switching rates

Small customer switching rates have been relatively flat or declining in most jurisdictions for the past two or three years (figures 4.13 and 4.14). Victoria has higher switching rates than elsewhere, with 26 per cent of electricity customers and 22 per cent of gas customers switching retailer in 2015–16. Victoria's higher switching rates reflect its more developed market, with a large number of established retailers giving customers more product choice and more awareness of choice. Further, price spread in energy bills tend to be higher in Victoria than elsewhere, meaning the potential savings from switching are often greater (section 4.8.5).

Switching rates in 2015–16 in NSW, Queensland and South Australia ranged from 12 to 19 per cent for electricity, and from 10 to 13 per cent for gas. Switching rates are lower in gas than for electricity in all jurisdictions, reflecting fewer active participants. Recent price volatility in wholesale gas markets may account for some reticence among new entrants to enter the gas retail market. In Queensland, competition remains limited due to the market's small scale and difficulties in sourcing wholesale gas.

Switching rates in the ACT continue to be low (around 5 per cent), reflecting the market's small scale and the dominance of the incumbent retailer, ActewAGL.

32 Newgate Research, *Consumer research for 2016 nationwide review of competition in energy retail markets,* Research report to the AEMC.

33 AEMC, *2016 Retail Competition Review.*

While overall switching activity remains fairly strong, activity is uneven across the customer base. The AEMC in 2016 reported around 50 per cent of customers in NSW, Victoria, south east Queensland and South Australia had not switched their retailer or energy plan in the past five years, indicating that switching activity is concentrated among particular customers that change retailer frequently.[34]

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. With most market offers including benefits that expire after one or two years, customers who do not switch regularly may not access the benefits of competition and may find themselves paying higher prices than necessary.

Customer awareness of switching benefits

Flat or declining switching activity may indicate many customers remain unaware of the potential savings from switching their retailer or energy plan. Switching activity is usually motivated by a customer wanting a lower price or better deal. The AEMC in 2016 reported residential electricity customers, on average, said they would switch their energy arrangements if they could save $217 a year.[35] But many customers could receive greater savings than this amount by switching their retailer or plan (section 4.8.5).

Conversely, those customers who do engage in the market appear to be gaining confidence. Sixty-three per cent of residential energy customers in 2016 said they were highly confident of finding the right information to choose a suitable energy plan, up from 54 per cent in 2015. The rate for small business customers was 68 per cent in 2016, up from 46 per cent in 2015.

Customers who had used price comparator websites were far more likely to believe they could find the right information to get a better energy deal. But awareness of those websites remains low. Only 30 per cent of residential customers in 2016 could name a comparator website, and only 10 per cent recalled the government run comparator website in their jurisdiction when prompted. The AEMC recommended jurisdictions coordinate communication strategies to improve customer awareness of these tools, to strengthen confidence in the energy market.[36]

34 AEMC, *2016 Retail Competition Review*.

35 AEMC, *2016 Retail Competition Review*, p. 70.

36 AEMC*, 2016 Retail Competition Review,* p. 62.

Figure 4.13
Small energy customer switching—electricity

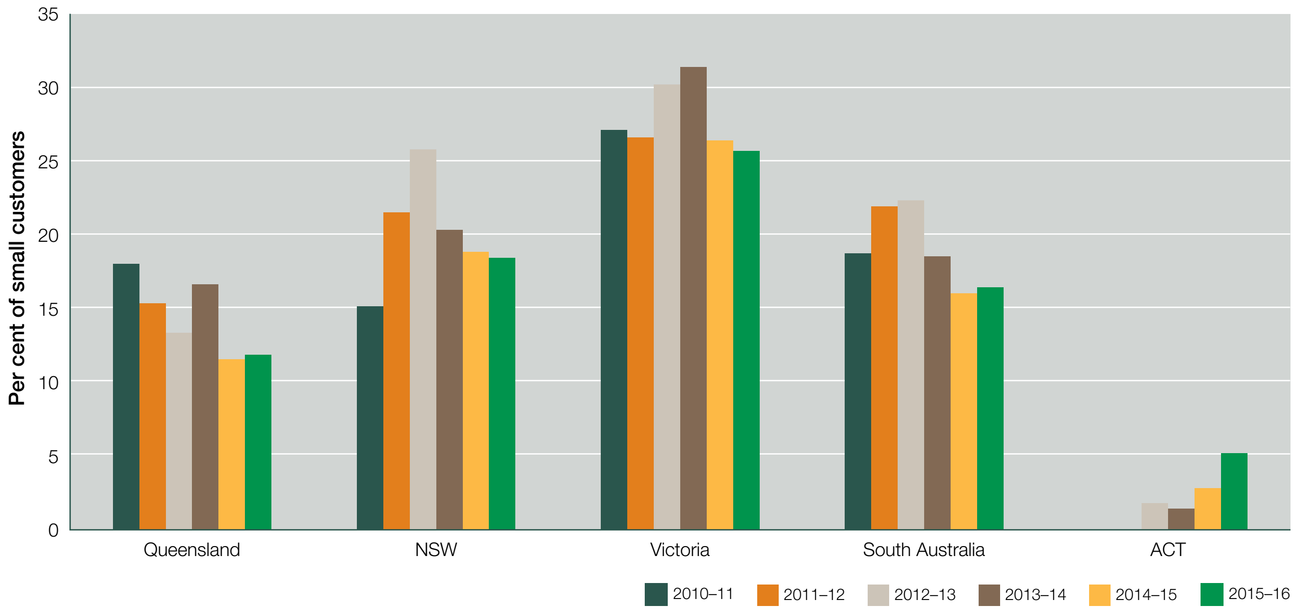
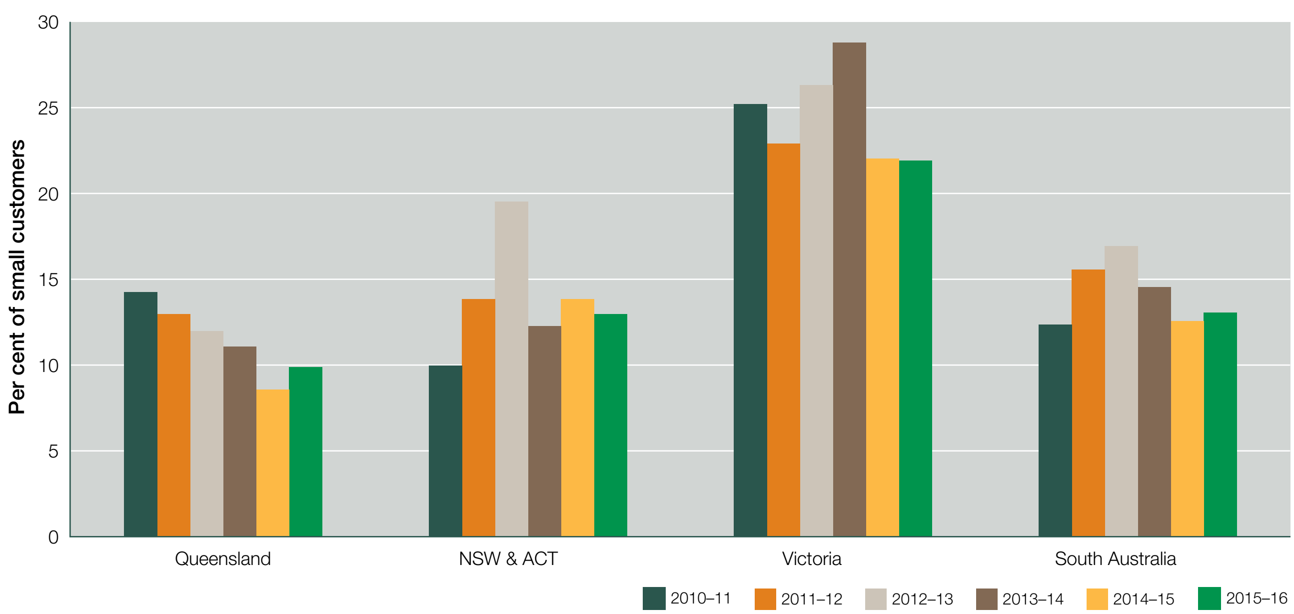


Figure 4.14
Small energy customer switching—gas



Sources (figures 4.13 and 4.14): Customer switches: AEMO, MSATS transfer data to July 2016 and gas market reports, transfer history to June 2016; customer numbers: estimated from retail performance reports by the AER, the ESC (Victoria) and the QCA (Queensland).

4.8.3 Retailer activity

Changes in retailer marketing activity may explain some of the recent downturn in customer switching activity. The AEMC in 2016 reported fewer customers had been approached by a retailer than in previous years—38 per cent of residential customers were approached in 2016, down from 53 per cent in 2014. This trend may reflect a move away from door knocking by the larger retailers, and a shift in retailer focus away from customer acquisition towards customer retention.[37]

It may also reflect perceptions among retailers that barriers to entry and/or expansion persist in some markets. Retailers commonly cite ongoing price regulation and the dominance of incumbent retailers as barriers to entry in some jurisdictions. In a 2016 survey by Farrier Swier Consulting, retailers:

- rated entry and expansion in regional Queensland as the most difficult in the NEM, because the incumbent retailer, Ergon Energy, receives exclusive subsidies
- cited retail price regulation, policy and regulatory risk, and the dominance of the incumbent retailers as impediments to entry in the ACT and Tasmanian markets. [38]

Despite the AEMC findings of effective competition in Victoria and South Australia, retailers in 2016 also rated market entry in those regions as being slightly more difficult than a year ago.[39] They cited difficult wholesale energy market conditions in South Australia and regulatory risk in Victoria (which retains regulatory arrangements outside the national framework) as factors. Tight wholesale market conditions—reflected in rising price volatility and difficulties in sourcing derivative (hedge) products—were also identified as issues for NSW, Queensland, Tasmania and the ACT.

In retail gas markets, retailers frequently identified access to gas, the small size of the demand base, and the price of gas as barriers to entry and expansion. Other commonly mentioned barriers included access to transmission pipeline capacity and state based regulatory issues such as licensing requirements. Policy reforms were underway in 2016 to address some of these issues (chapter 2).

37 AEMC*, 2016 Retail Competition Review,* p. 66.

38 Farrier Swier Consulting, *2016 Energy Retailer Survey report,* Report to the AEMC.

39 Farrier Swier Consulting, *2016 Energy Retailer Survey report,* Report to the AEMC.

4.8.4 Product differentiation

In a competitive market, retailers offer a range of products and services to attract and retain customers. The AEMC found product differentiation tends to be greatest in jurisdictions with deregulated retail prices. Customers in Victoria, South Australia and NSW have a much wider choice of retailers and plans than have those elsewhere.[40]

Retailers compete by discounting (section 4.8.5), bundling offers (such as for electricity, gas and telecommunications), varying contract terms (length and fixed price periods) and offering other incentives (such as sign-up discounts and subscriptions). Despite the range of offers in the market, most maintain a similar basic two-part price structure: a daily supply charge plus a use charge based on overall consumption.

The rollout of advanced (smart) meters has encouraged growth in flexible pricing offers such as time-of-use pricing. Victoria is most active in this area, with 363 time-of-use offers, followed by NSW with 269. But the uptake of flexible pricing offers has been slow, with only 0.27 per cent of Victoria customers adopting them in 2014 (when they were first introduced).[41] In NSW, most customers do not have advanced meters and cannot access these offers.

New energy service providers are also applying competitive pressure to traditional retailers, through product differentiation. At March 2017, 134 energy businesses were offering solar power purchase agreements in jurisdictions applying the Retail Law.[42] Further waves of new products and offers will likely emerge once battery storage systems become more affordable as technology costs fall.

'Traditional' retailers have entered the power purchase agreement market to compete with new energy service providers. The AEMC also noted evidence of some retailers charging higher prices to solar customers.[43]

The variety of product structures, discounts and non-price inducements makes direct price comparisons between retail offers difficult. Further, the transparency of price offerings varies. The AER operates an online price comparison website—Energy Made Easy—to help small customers compare retail offerings. The website's full functionality is available to customers in jurisdictions that have implemented the Retail Law (Queensland, NSW, South Australia,

40 AEMC*, 2016 Retail Competition Review,* p. 127.

41 Victorian Auditor General, *Realising the benefits of smart meters,* September 2015, available at www.audit.vic.gov.au/publications/20150916-Smart-Meters/20150916-Smart-Meters.pdf.

42 AER, 'Public register of retail exemptions', www.aer.gov.au/retail-markets/retail-exemptions/public-register-of-retail-exemptions.

43 AEMC*, 2016 Retail Competition Review,* p. 129.

Tasmania and the ACT). The Victorian regulator (the Essential Services Commission) and a number of private entities also operate websites that allow customers to compare market offers.

4.8.5 Price differentiation

AER research, drawing on the Energy Made Easy website and state regulators' price comparison websites, indicates significant price diversity in the offers of individual retailers, and across retailers. Tables 4.3 and 4.4 set out price offerings for residential customers at December 2016, with September 2015 data included for comparison.

The extent of discounting in market offers appears to be growing over time, widening the gap between standing and market offers. Many discounts are conditional on customer behaviours such as paying on time or via direct debit. In Victoria, a retailer's market offers averaged 17–22 per cent lower than the same retailer's standing offer. In other regions, market offers averaged 8–13 per cent lower than standing offers.

A typical customer switching from an electricity standing offer to the best market offer with the same retailer could save up to $676 in Victoria, $381 in NSW, $332 in South Australia, $256 in Queensland and $204 in the ACT.

The proportion of customers on standing offers is low and declining. But discounts in market offers tend to be finite, and customers who do not switch regularly may find themselves moving back to prices closer to standing offer levels.

Across retailers, the most expensive offer was typically around double the cost of the lowest market offer in Victoria and South Australia, as well as for customers in the NSW AusGrid and Endeavour Energy network areas. For other customers, the lowest offer was 35–40 per cent cheaper than the highest offer. The gap between lowest and most expensive offers in December 2016 widened significantly in each network area observed since 2015 (table 4.4).

Market offer discounts over standing offers in December 2016 were lower in gas than electricity, except in NSW. The discount in gas ranged from 2–3 per cent in Queensland to 11 per cent in NSW. Annual bill spreads (comparing the highest and lowest offer in each jurisdiction) ranged from $140–180 in Victoria, Queensland and the ACT, to $250–280 in South Australia and NSW. Unlike electricity prices, gas price spreads in December 2016 were similar to those observed in 2015.

4.9 Energy affordability

Energy affordability relates to customers' ability to pay their energy bills. Affordability varies, and depends on the amount of energy that a customer uses, the energy prices that they pay, their income and their other living costs.

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

The AER publishes an annual affordability report on how energy bills are trending, with a focus on low income households.[44] Figures 4.15 and 4.16 provide an energy affordability snapshot for a typical low income household. The data accounts for available concessions and rebates.

The AER's research found *electricity* became more affordable for a typical low income household in NSW, Victoria and South Australia in 2016, but remained unchanged elsewhere. This movement continued a trend of improving affordability in most jurisdictions over the past three or four years. But *gas* affordability fluctuated markedly, with improvements in NSW, no change in Queensland and the ACT, and deteriorations in Victoria and South Australia.

For a typical low income household receiving energy bill concessions, at June 2016:

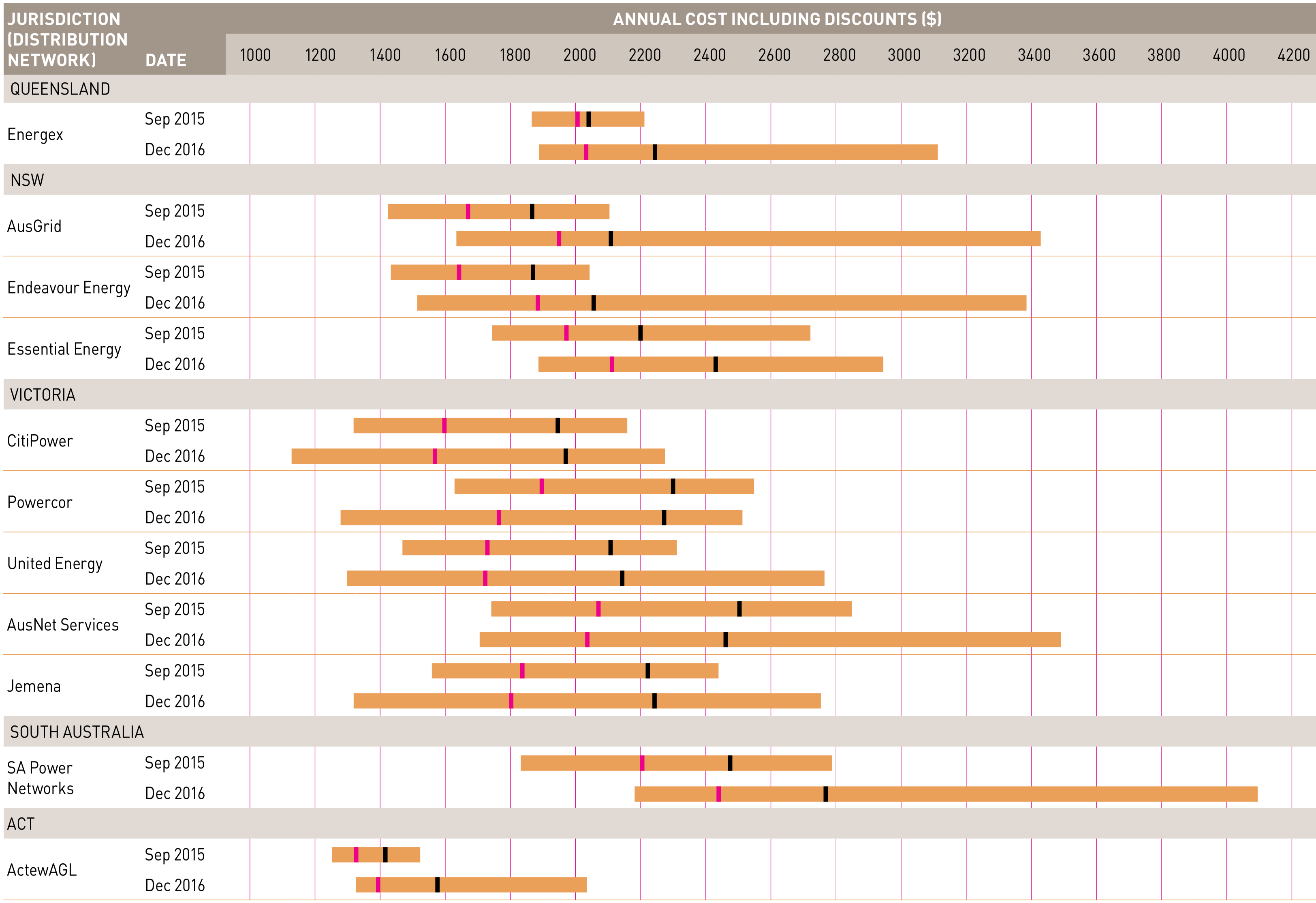
- electricity costs accounted for around 3–5 per cent of disposable income for households on the mainland, and 6.4 per cent for Tasmanian households. Compared with 2013, electricity was more affordable in every jurisdiction except Queensland
- gas costs accounted for around 2.5–5 per cent of disposable income for low income households. Compared with 2013, gas was more affordable in NSW, less affordable in Victoria, Queensland and South Australia, and unchanged in the ACT.

Those jurisdictions in 2016 with the highest electricity use (Tasmania) and gas use (Victoria) spent the highest proportion of income on those fuels. The analysis does not account for the bill impact of changes in energy use. Given average electricity use has declined in recent years, bills may have fallen further than the analysis suggests.

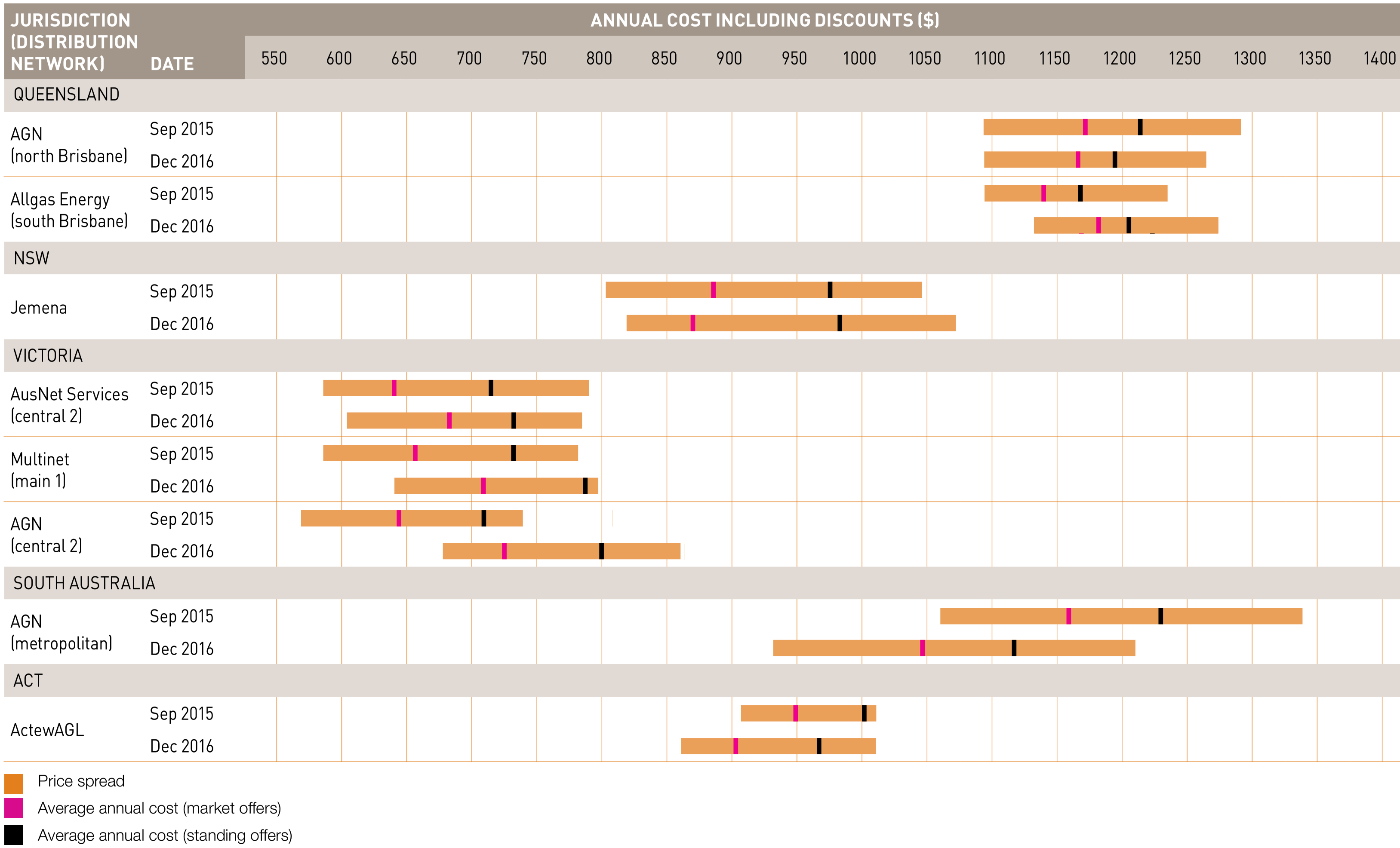
44 AER, *Annual report on the performance of the retail energy market 2016*, pp. 50–72.

Table 4.3 Price diversity in energy retail offers

Electricity



Gas



Notes: Data based on market and standing offers (adjusted for discounts) for a customer using 6500 kilowatt hours of electricity per year and 24 gigajoules of gas per year on a single rate tariff at December 2016.

Sources: energymadeeasy.gov.au; switchon.vic.gov.au; yourchoice.vic.gov.au; comparator.qca.org.au; determinations, factsheets and media releases by IPART (NSW), the QCA (Queensland), ESCOSA (South Australia), OTTER (Tasmania) and the ICRC (ACT); Victorian Government gazette.

Table 4.4 **Comparison of standing and market offers—December 2016**

JURISDICTION (DISTRIBUTION NETWORK)	NUMBER OF OFFERS	LOWEST OFFER	HIGHEST OFFER	PRICE SPREAD	% DIFFERENCE BETWEEN HIGHEST AND LOWEST OFFER	AVERAGE STANDING OFFER	AVERAGE MARKET OFFER	AVERAGE % DISCOUNT STANDING OFFER TO MARKET OFFER	AVERAGE DISCOUNT ($) FROM RETAILER'S STANDING OFFER TO LOWEST MARKET OFFER
ELECTRICITY									
Queensland									
Energex	60	1888	3114	1226	39	2248	2032	10	256
New South Wales									
Ausgrid	79	1634	3430	1796	52	2110	1948	8	244
Endeavour Energy	80	1515	3386	1872	55	2055	1885	8	265
Essential Energy	78	1887	2947	1060	36	2431	2114	13	381
Victoria									
Citipower	71	1125	2277	1152	51	1969	1568	20	566
Powercor	61	1280	2513	1234	49	2273	1772	22	647
United Energy	62	1302	2766	1465	53	2144	1726	19	625
AusNet Services	80	1705	3493	1788	51	2464	2038	17	650
Jemena	62	1321	2755	1434	52	2244	1803	20	676
South Australia									
SA Power Networks	70	2180	4096	1916	47	2771	2440	12	332
ACT									
ActewAGL	23	1325	2036	711	35	1576	1394	12	204
GAS									
Queensland									
AGN (north Brisbane)	9	1096	1268	172	14	1199	1168	3	60
APT Aligas (south Brisbane)	9	1136	1275	139	11	1207	1183	2	51
New South Wales									
Jemena	25	819	1073	254	24	984	873	11	142
Victoria									
AusNet Services (central 2)	28	604	784	181	23	733	683	7	85
Multinet (main 1)	17	640	797	157	20	787	710	10	111
AGN (central 2))	30	678	861	183	21	802	726	9	117
South Australia									
AGN (metropolitan)	15	934	1211	277	23	119	1047	6	129
ACT									
ActewAGL	8	863	1011	148	15	968	904	7	100

Notes:

Estimated annual cost is based on a customer using 6500 kilowatt hours of electricity per year and 24 gigajoules of gas per year on a single rate tariff at December 2016.

Prices are based on regulated or standing offer prices of the local area retailer for each distribution network.

Sources: energymadeeasy.gov.au; switchon.vic.gov.au; yourchoice.vic.gov.au; comparator.qca.org.au; determinations, factsheets and media releases by IPART (NSW), the QCA (Queensland), ESCOSA (South Australia), OTTER (Tasmania) and the ICRC (ACT); Victorian Government gazette.

Electricity bills for low income households tend to be highest in Tasmania, where electricity is the predominant source of fuel and where a cool climate generates significant heating needs. Tasmanian households use more electricity—an average 6500 kilowatt hours (kWh) per year—than used by those on the mainland—3700–5600 kW. While 6.4 per cent represents a significant share of disposable income, electricity is the only energy bill most Tasmanian households pay, because few households are connected to a gas service. In the ACT, which also has high electricity consumption, electricity bills are among the lowest in Australia because the market's regulated use charges are substantially lower than elsewhere.

In gas, low income households spend the most on bills in the ACT and Victoria, where gas is widely used for winter heating. Gas affordability has deteriorated in Victoria, with low income households spending 9.2 per cent more in 2016 than a year earlier. For a low income Victorian household, gas bills represent 5.2 per cent of income—higher than for any other jurisdiction. By contrast, low income households in NSW enjoyed the largest fall in their annual gas bills (down 8.5 per cent) in 2016. Their average 2016 bill of $845 was second lowest nationally, beaten only by $733 in Queensland, where heating demand is much lower. Gas bills in the ACT in 2016 remained comparable with those of recent years.

State and territory governments offer energy concession to eligible households, which can significantly improve energy affordability. The potential savings vary in each jurisdiction and depend on how the concession is applied, but can be around several hundred dollars a year for each fuel. For example, a $484 concession is available to electricity customers in Tasmania, a new $100 concession for gas was introduced in NSW to supplement the existing $250 electricity concession, and $215 is available across both fuels in South Australia. Most jurisdictions also offer emergency bill support.

While concessions represent an important saving for eligible households, the AER's analysis found many households can achieve significant savings just by switching to a cheaper offer. Customers in Queensland, NSW, South Australia, Tasmania and the ACT can check offers on the AER's price comparator website, Energy Made Easy (www.energymadeeasy.gov.au). Victorian households can check available offers on the state government comparator, www.switchon.vic.gov.au.

Figure 4.15

Energy bill burden for low income households—electricity

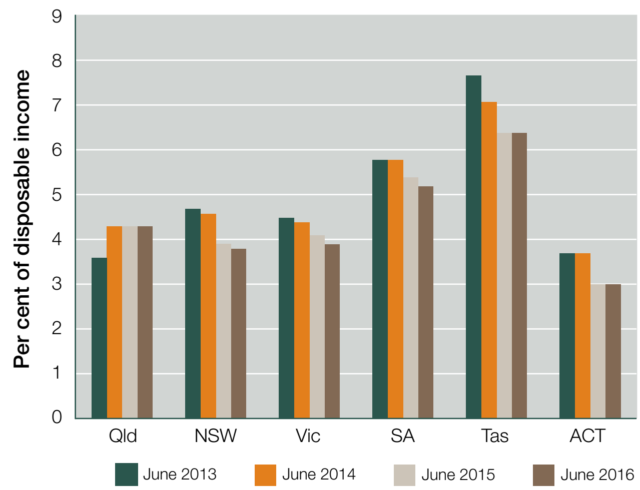
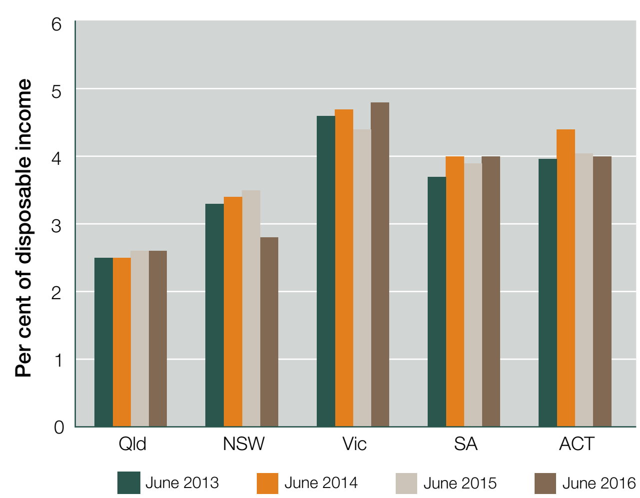


Figure 4.16

Energy bill burden for low income households—gas



Notes (figures 4.15 and 4.16):

Energy bills are adjusted for concessions available to low income households. Energy charges are based on the median market offer.

Disposable income for a low income household is that of the lowest two deciles, excluding the first and second percentiles.

Electricity consumption is the average for low income households in each jurisdiction. *Gas* consumption is the average for all households.

Sources (figures 4.15 and 4.16): AER, *Annual report on the performance of the retail energy market,* various years.

4.9.1 Assisting customers in debt

Energy affordability issues can give rise to customer debt. Energy bill debt is the amount owing to a retailer that has been outstanding for 90 days or more. Among jurisdictions in which the Retail Law applies,[45] South Australia has the highest proportion of electricity customers in debt (5.5 per 100 residential customers) and the ACT has the highest proportion of gas customers in debt (7.9 per 100).[46]

The AER worked with stakeholders in 2015–16 to develop a framework for retailers to negotiate affordable and sustainable payment plans with customers who need assistance.[47] *Payment plans* allow payment of overdue amounts in periodic instalments. They are typically the first assistance offered to customers showing signs of payment difficulties.

Referral to a *hardship program* may be appropriate if a customer's payment difficulties are chronic or more severe. The Retail Law requires energy retailers to develop and maintain a customer hardship policy that underpins how they identify and assist customers who have difficulty paying their energy bills. Victoria operates a separate hardship program, and the regulator will release a new framework in 2017.

Help under a retailer's hardship program can include:

- extensions of time to pay a bill, as well as tailored payment options
- advice on government concessions and rebate programs
- referrals to financial counselling services
- a review of a customer's energy contract to make sure 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 had the highest proportion of customers on a hardship program in 2015–16—that is, 1.8 per cent of electricity customers and 1.4 per cent of gas customers. In other jurisdictions, the proportion of hardship customers was less than 1 per cent for both electricity and gas.[48]

Of customers *exiting* hardship programs in 2015–16, around one third successfully repaid their debt. Almost half of those exiting were excluded from the programs for failing to meet their payment obligations. But, while the programs' success rates are low, some retailers have become more proactive in managing customers with severe financial difficulties. Among individual retailers, low debt levels on entry to hardship programs correlate with higher success rates.

45 Queensland, NSW, South Australia, Tasmania and the ACT.

46 AER, *Annual report on the performance of the retail energy market 2016*.

47 The AER and Energy Made Easy websites list retailers that have adopted the framework.

48 AER, *Annual report on the performance of the retail energy market 2016*.

4.9.2 Disconnecting customers for non-payment

Energy retailers are required under the Retail Law to help customers in financial hardship before considering disconnection 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, or when a customer on a hardship program is meeting their obligations.

The AER reports on disconnection rates (figures 4.17 and 4.18).[49] In 2015–16, the ACT had the lowest rate of customer disconnections for failing to pay an *electricity* bill (0.2 disconnections per 100 customers). The rate was highest for South Australia (1.4 per cent of customers), followed by Victoria (1.3 per cent), Queensland (1.1 per cent), NSW (1 per cent) and Tasmania (0.5 per cent).

Disconnection rates eased in NSW, Queensland and Victoria in 2015–16, but rose in South Australia, Tasmania and the ACT. The rates for NSW and Victoria were the lowest for three years. Despite increases for Tasmania and the ACT, their disconnection rates remained well below those of other regions.

In 2015–16, NSW had the lowest rate (for the fourth consecutive year) of customer disconnections for failing to pay a *gas* bill, with 0.5 disconnections per 100 customers. Gas disconnections were highest in Victoria (1.3 per cent of customers), followed by South Australia and the ACT (1.2 per cent), and the ACT and Queensland (0.8 per cent).

Gas disconnection rates eased in NSW and the ACT in 2015–16 but rose in Victoria and South Australia. The disconnection rate for South Australia reached its highest level in seven years. Victoria was only marginally below its highest disconnection rate in over a decade.[50]

Disconnections of customers on hardship programs were below 1 per cent in both electricity and gas in 2015–16. This outcome highlights the benefit of customers proactively 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

49 AER, *Annual report on the performance of the retail energy market 2016.*

50 Historical data for Queensland is not available.

Figure 4.17

Disconnections for failure to pay amount due—electricity

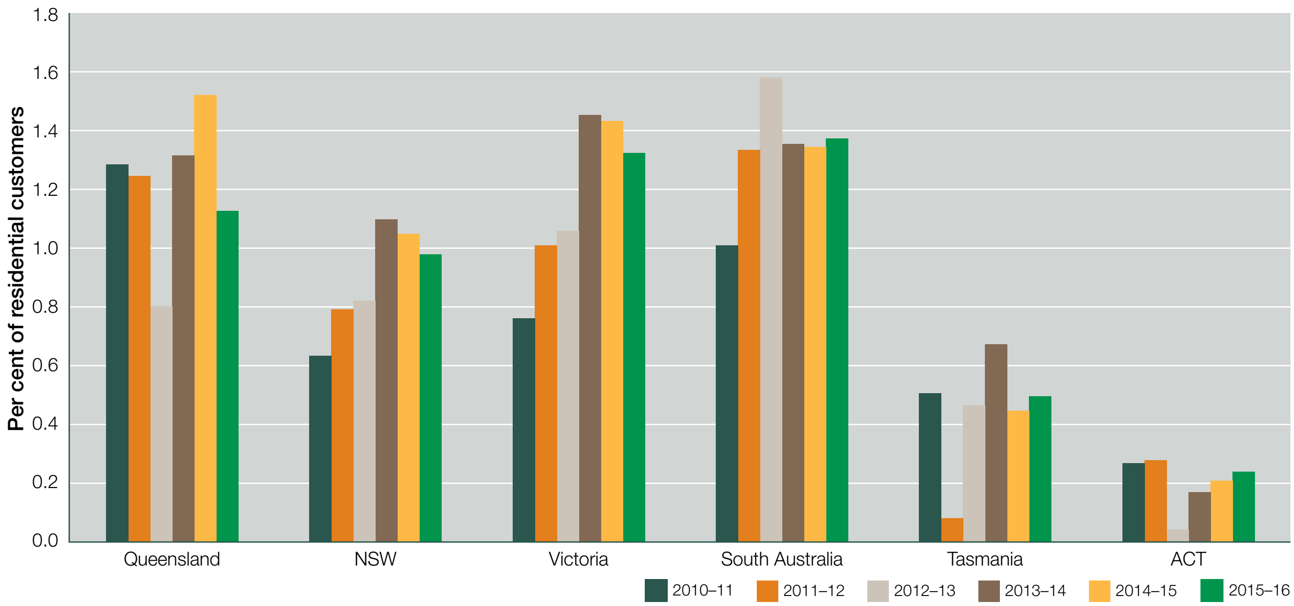
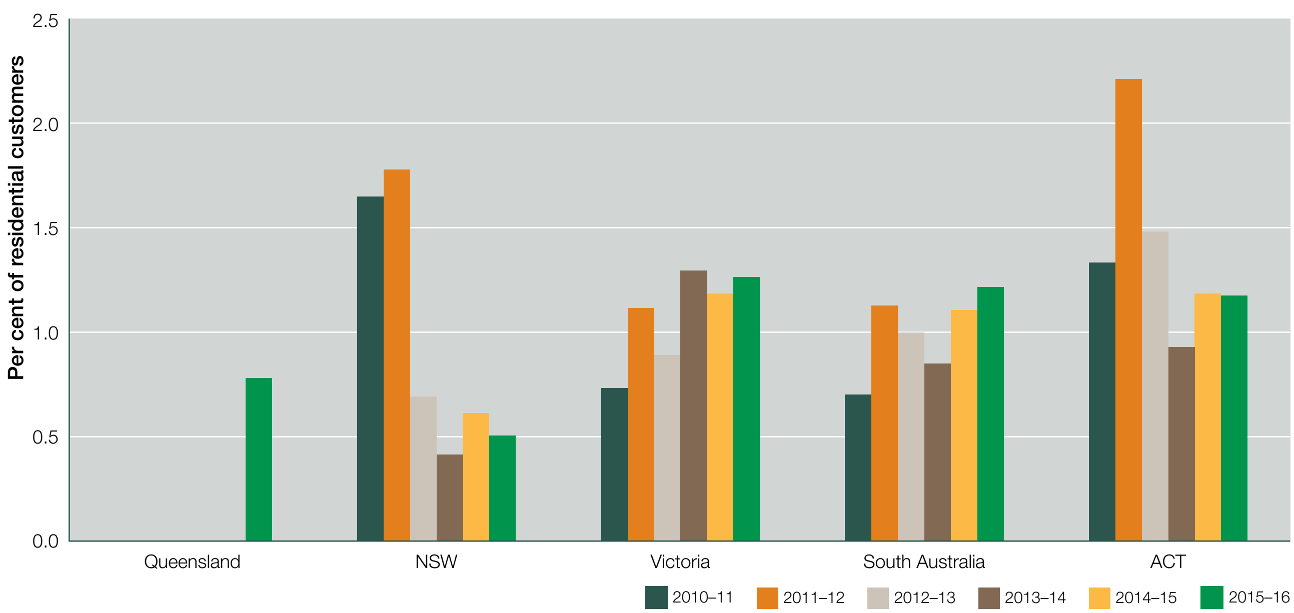


Figure 4.18

Disconnections for failure to pay amount due—gas



Note (figures 4.17 and 4.18): Data for residential (household) disconnections. Data on gas disconnections is not available for Queensland before it adopted the Retail Law.

Sources (figures 4.17 and 4.18): AER, *Annual report on the performance of the retail energy market 2015–16;* ESC, *Victorian energy market report 2015–16*; historical performance reporting on retail energy retail markets by the AER, IPART (NSW), the ESC (Victoria), ESCOSA (South Australia), OTTER (Tasmania), the QCA (Queensland) and the ICRC (ACT).

difficulties. In response to this issue, the AER's Sustainable Payment Plans Framework commenced in November 2016. It sets out good practice principles for retailers to enhance their engagement with customers by encouraging open, clear and ongoing engagement based on trust, respect and empathy. These principles increase the likelihood of constructive and long term customer relationships.

Disconnections of customers who had previously been disconnected rose for both electricity and gas in 2015–16. For electricity, 18 per cent of disconnected customers had been previously disconnected (up from 10 per cent in 2014–15). For gas, disconnections of customers in this category more than doubled, from 6 to 13 per cent of disconnections. These increases suggest more customers may be experiencing long term and/or severe financial difficulties, and hardship programs may not be adequately supporting customers to avoid disconnection.

4.10 Customer complaints

For jurisdictions with effective competition, the AEMC reported around 70 per cent of customers in 2016 were happy with the quality of service provided by their retailers. Around 7 per cent of electricity customers and 6 per cent of gas customers were dissatisfied with their retailer—a slight improvement from 2015 survey data.[51]

Some customers have issues with their retailer about billing discrepancies, wrongful disconnections, the timeliness of customer transfers, supply disruptions, credit arrangements and marketing practices. In the first instance, they can lodge a complaint directly with the retailer. If this contact does not resolve the issue, they can take the complaint to their jurisdictional energy ombudsman scheme. The ombudsman offers free and independent dispute resolution for customers unable to resolve an issue with their retailer.

The AER reports data on customer complaints to energy retailers.[52] The complaints rate rose on average in 2015–16, with billing (including pricing) being the leading concern. The rise largely reflected a significant increase in complaints to Origin Energy, which introduced new complaint processes that captured higher numbers. Excluding Origin Energy, complaint rates were flatter across most jurisdictions, and other top tier retailers (AGL and EnergyAustralia) reported significant rate decreases.

The nature of some complaints is outside the control of the energy retailer. For example, complaints about price rises due to wholesale and network costs may reflect unfairly on energy retailers. For this reason, the manner in which complaints are handled is a more effective measure of retailer performance.

Retailers with effective customer service can generally resolve customer complaints when they receive them, without the need for escalation to energy ombudsman schemes. Given the schemes received fewer complaints in 2015–16 than in 2014–15 in all jurisdictions, retailers appear to have improved their complaint management practices.[53]

Figures 4.19 and 4.20 illustrate rates of customer complaints to ombudsman schemes for electricity and gas. Complaint rates tend to be higher in electricity than gas. In electricity, Queensland recorded the lowest rate of complaints, with less than 0.3 per cent of customers contacting the ombudsman. Victoria and South Australia had the highest rates (0.8 per cent of customers). While the results may reflect retailers' performance and the effectiveness of their internal dispute resolution procedures, they need to be interpreted with caution. They may also reflect the maturity of competition, market depth and customers' awareness of the schemes.

The total *number* of electricity and gas complaints to ombudsman schemes fell by 26 per cent in 2015–16, to around half the levels of the two previous years. The fall in complaint numbers occurred in all jurisdictions.

Billing issues remain the leading driver of complaints, accounting for 41 per cent of all complaints in 2015–16. Credit issues—including disconnection in the case of non-payment, and the collection of outstanding charges—accounted for a further 25 per cent of complaints. Other prominent issues included retailers' customer service (11 per cent of complaints) and the unauthorised transfer of customers to a new retailer (8 per cent).

51 AEMC*, 2016 Retail Competition Review,* p. 79.

52 AER, *Annual report on the performance of the retail energy market 2016*.

53 AER, *Annual report on the performance of the retail energy market 2016.*

Figure 4.19
Complaints to ombudsman schemes—electricity

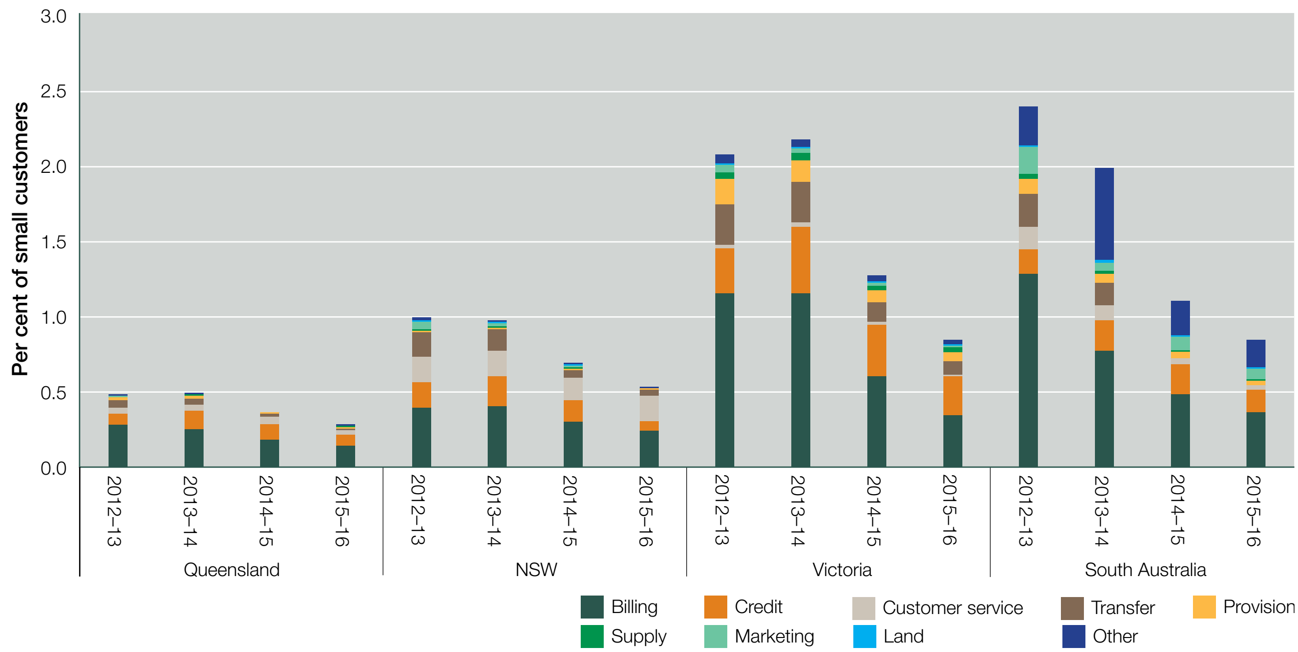
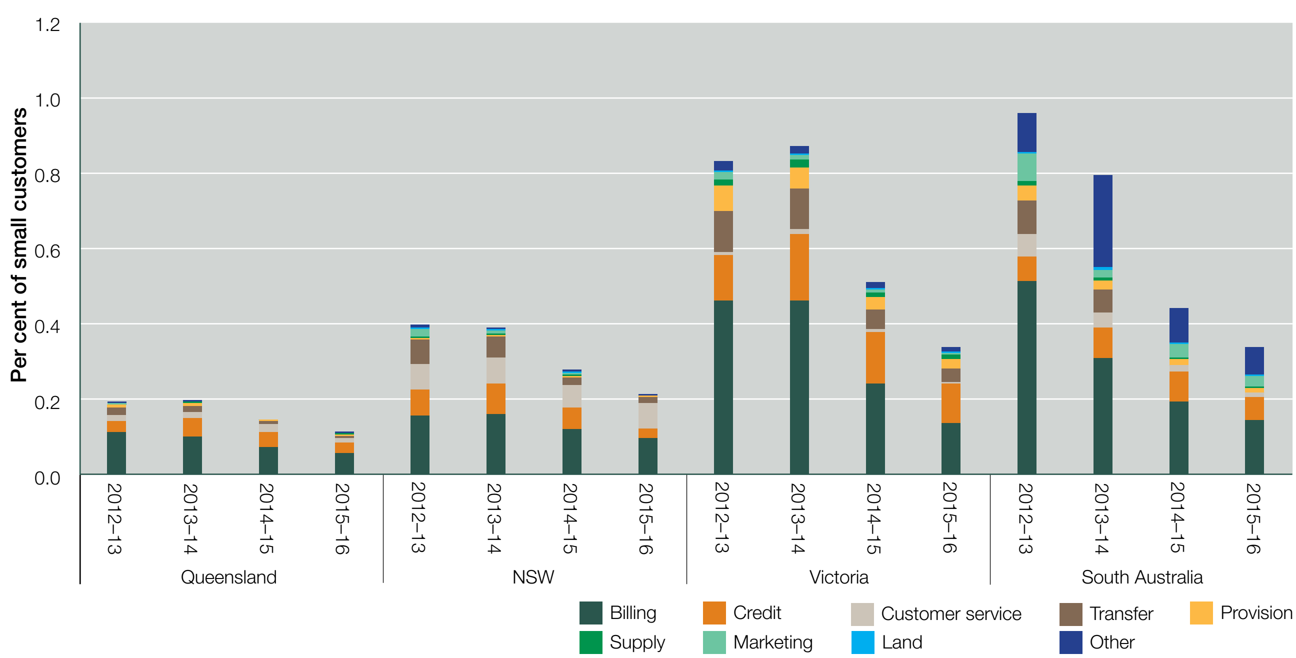


Figure 4.20
Complaints to ombudsman schemes—gas



Sources (figures 4.19 and 4.20): Annual reports by ombudsman schemes in Queensland, NSW, Victoria and South Australia.

4.11 Enforcement action in retail markets

The opening of energy retail markets to competition has been accompanied by significant customer complaints about the conduct of energy sellers. The Australian Consumer Law (enforced by the ACCC) protects customers from improper sales or marketing conduct relating to unsolicited sales, misleading and deceptive conduct, and unconscionable conduct. The Retail Law's marketing provisions also protect customers.

Most major retailers stopped door-to-door marketing in 2013, around the time of enforcement activity by the ACCC. But a number of smaller retailers still use this channel. Most retailers continue to engage in telemarketing (outward sales calls) but this activity too has been problematic. Both the ACCC and the AER have taken action against retailers for misrepresentations and for failing to obtain a customer's explicit informed consent before transferring them after a telemarketing call.

The AER and ACCC in 2014 instituted proceedings in the Federal Court against EnergyAustralia and a telemarking company acting on its behalf, for failing to obtain the explicit informed consent of customers before transferring them to new energy plans. In 2015 the Federal Court imposed penalties of $1.6 million on EnergyAustralia and the telemarketing company.

The AER has also issued infringement notices to retailers for failing to obtain a customer's explicit informed consent before entering them into an energy contract. It issued:

- four infringement notices to Simply Energy in October 2015
- two notices to Red Energy in February 2016
- three notices to Simply Energy in December 2016.

To help businesses, the AER released a Compliance Check in 2015 that guides them through the Retail Law's explicit informed consent requirements.

Since 2013 the ACCC has closely monitored how businesses promote discounts and savings under their energy offers, following concerns that consumers were being misled about the extent of savings available. On this issue, the ACCC took action in the Federal Court against AGL Energy and Origin Energy in 2013. In 2015 the Federal Court imposed penalties totaling over $3 million on the retailers, with orders to compensate affected consumers.

In other enforcement activity, the ACCC in April 2016 issued five infringement notices to Momentum Energy, for misleading advertising that represented that the retailer generated and supplied renewable electricity. The ACCC also issued an infringement notice in February 2017 to Lumo Energy, for misleading representations about the cause of rising retail gas prices.

4.12 Managing retailer failure

The AER manages a Retailer of Last Resort (RoLR) scheme. If a retailer fails, the scheme ensures customers continue to receive their energy supply from another retailer. The transition of customers was necessary following the recent failure of two energy retailers:

- In April 2016, the AER oversaw electricity and gas RoLR events following the failure of GoEnergy. The transfer followed the Australian Energy Market Operator's (AEMO) suspension of GoEnergy from participating in wholesale markets for failing to meet its financial obligations.
- In February 2017, the AER oversaw an electricity RoLR event following the appointment of external administrators to Urth Energy, and that business's subsequent suspension from the wholesale market.

At the time of the RoLR events, GoEnergy had around 2200 electricity customers in the ACT, South Australia, Queensland and NSW, as well as some large commercial gas customers in NSW and Queensland. And Urth Energy had around 800 electricity customers in South Australia, Queensland and NSW. These former customers of GoEnergy and Urth Energy were transferred to ActewAGL Retail, AGL, Origin Energy and EnergyAustralia, without interruption to their energy supply.

ABBREVIATIONS

2P	proved plus probable (natural gas reserves)
ABS	Australian Bureau of Statistics
ACCC	Australian Competition and Consumer Commission
ACT	Australian Capital Territory
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AFMA	Australian Financial Markets Association
APGA	Australian Pipelines and Gas Association
APLNG	Australian Pacific LNG
ARENA	Australian Renewable Energy Agency
ASX	Australian Securities Exchange
CCGT	combined cycle gas turbine
CESS	capital expenditure sharing scheme
CoAG	Council of Australian Governments
CSG	coal seam gas
EBSS	efficiency benefit sharing scheme
EII	Energy Infrastructure Investments
EIT	emissions intensity target
ERA	Economic Regulation Authority (Western Australia)
ESC	Essential Services Commission
ESCOSA	Essential Services Commission of South Australia
FCAS	frequency control ancillary services
FRC	full retail contestability
GJ	gigajoule
GLNG	Gladstone LNG
GSL	guaranteed service level
GW	gigawatt
GWh	gigawatt hour
HHI	Herfindahl–Hirschman index
ICRC	Independent Competition and Regulatory Commission
IPART	Independent Pricing and Regulatory Tribunal
km	kilometre
kW	kilowatt
kWh	kilowatt hour
LNG	liquefied natural gas
MOS	market operator services
MSATS	market settlement and transfer solutions
mtpa	million tonnes per annum
MW	megawatt
MWh	megawatt hour
NCC	National Competition Council
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
OTC	over-the-counter
OTTER	Office of the Tasmanian Economic Regulator
PJ	petajoule
PV	photovoltaic
QCA	Queensland Competition Authority
QCLNG	Queensland Curtis LNG
QNI	Queensland—NSW Interconnector
RAB	regulated asset base
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
SPPA	solar power purchase agreement
STPIS	service target performance incentive scheme
TJ	terajoule
TJ/d	terajoules per day
TW	terawatt
TWh	terawatt hour