STATE OF THE ENERGY MARKET 2014

AUSTRALIAN ENERGY REGULATOR

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Editor: Editor's Mark, Melbourne

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PREFACE

The Australian Energy Regulator's *State of the energy market* report explores conditions in energy markets over the past 12–18 months in those jurisdictions in which the AER has regulatory responsibilities. The report consists of a market overview, supported by five chapters on the electricity and gas sectors. As usual, it employs accessible language to reach a wide audience. I hope this year's report is a valuable resource for policy makers, consumers, industry and the media.

This eighth edition of *State of the energy market* comes at a time when declining energy demand is bringing structural shifts across the entire supply chain. In the wholesale electricity market, declining demand is reflected in a widening surplus of generation capacity and subdued prices. The abolition of carbon pricing further lowered wholesale prices in 2014, although carbon emissions from electricity generation rose as coal fired generation increased its market share.

Weakening demand is also removing the impetus for network expansions and flattening revenue requirements. At the same time, there is a greater focus on demand response and small scale local generation as viable alternatives to network investment to help meet energy demand. Pricing and metering reforms are also underway to help consumers make efficient use of their electrical appliances, especially at times of high demand.

In gas, liquid natural gas (LNG) export projects in Queensland are nearing completion. But the ramp up of gas production for LNG, at a time of subdued domestic demand, caused market volatility in 2014, with Brisbane spot prices falling close to zero late in the year.

Developments in the wholesale and network sectors impact on the retail energy sector. The repeal of carbon pricing led retail electricity prices to fall over 2014 in many jurisdictions, although gas prices fell only in Victoria. There was also evidence of more widespread retail price discounting in all regions. But many customers find energy contracts complex and struggle to compare available offers. The AER continues to explore ways of improving the quality of information available to consumers choosing an energy retail contract, and will roll out improvements to the Energy Made Easy price comparison website throughout 2015.

Paula Conboy
Chair
December 2014

MARKET OVERVIEW

A.1 Introduction

Electricity demand continued to decline in 2013–14, resulting in a widening surplus of generation capacity and subdued wholesale prices. The abolition of carbon pricing further lowered wholesale prices, but reversed a trend of declining carbon emissions from electricity generation. Other climate change policies (such as the renewable energy target scheme) were under review in 2014, creating uncertainty in the renewable energy sector.

Weakening demand, lower capital financing costs and more flexible arrangements for electricity network businesses to meet reliability requirements are removing the impetus for network expansions and flattening revenues. Alongside changes in the operating environment, significant regulatory reforms are encouraging network businesses to seek more efficient ways of providing services.

The nature and function of energy networks are also evolving. Escalating cost pressures in recent years gave impetus to alternatives such as 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, potentially, energy storage technologies. Metering and pricing reforms are underway to create a regulatory framework that can respond to this dynamic landscape and allow consumers greater control over how they manage their energy use. Alongside the regulatory changes, alternative retail models are emerging that provide consumers with energy service packages that reflect when and how they use energy.

In gas, the development of liquid natural gas (LNG) export projects in Queensland will fuel exponential growth in international demand for Australian gas. But domestic demand is subdued, with the abolition of carbon pricing reducing the cost competitiveness of gas powered generation. The ramp up of gas production for LNG export caused volatility in domestic spot markets, with prices falling close to zero in late 2014. Policy reforms are being implemented to manage the impacts of LNG developments on domestic markets, including the new Wallumbilla gas supply hub and enhanced pipeline capacity trading arrangements.

Developments in wholesale energy markets and energy network regulation impact on retail energy prices. The repeal of carbon pricing led retail electricity prices to fall over 2014 in jurisdictions other than Queensland and South Australia (where higher solar feed-in tariff costs and higher network charges respectively offset the carbon savings). Retail gas prices fell only in Victoria. In other jurisdictions, rising costs associated with the reduced availability of wholesale gas contracts offset savings from the repeal of carbon pricing. Pipeline charges also rose in most regions, putting additional pressure on retail gas prices.

The average extent of retail price discounting was greater in 2014 than in the previous year in all regions. Following the findings of the Australian Energy Market Commission (AEMC) that competition was effective in its energy markets, New South Wales (NSW) in July 2014 joined Victoria and South Australia in removing retail price regulation for electricity. The Queensland Government committed to removing electricity retail price regulation in south east Queensland from 1 July 2015.

For competition to be effective, consumers must be able to make informed choices on the energy product that best meets their needs. But many customers find energy contracts complex and struggle to compare available offers, creating a risk of exploitation. Given this risk, the behaviour of energy retailers is a compliance and enforcement priority. For example, the Australian Energy Regulator (AER) and Australian Competition and Consumer Commission (ACCC) in 2014 instituted proceedings in the Federal Court against EnergyAustralia for failing to obtain customers' consent before transferring them to new energy plans.

The AER continues to explore ways of improving the quality of information available to consumers choosing an energy retail contract. It intends to roll out improvements to the Energy Made Easy price comparison website in 2015, making it easier for customers to see which offer would best suit their needs.

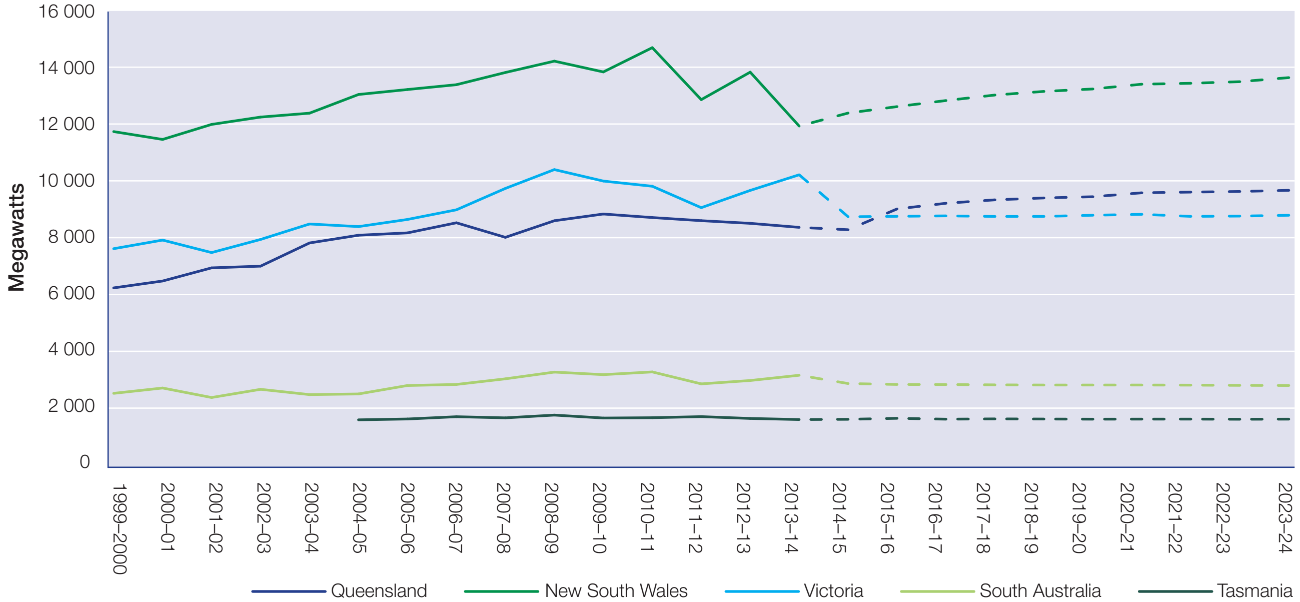
A.2 National Electricity Market

Wholesale electricity in eastern and southern Australia is traded through the National Electricity Market (NEM), covering Queensland, NSW, Victoria, South Australia, Tasmania and the Australian Capital Territory (ACT). A significant structural development in the market in 2014 was the ongoing privatisation of state owned generation businesses in NSW. In particular, AGL Energy acquired the region's largest generation business—Macquarie Generation—in September 2014. The ACCC opposed the sale, but its decision was overturned by the Australian Competition Tribunal, which found the public benefits of the acquisition outweighed any detriment to competition.

The NEM in 2013–14 generated 194 terawatt hours (TWh) of electricity—a 2.5 per cent reduction from the previous year, and 3 per cent below forecast.[1] This outcome

1 AEMO, *National electricity forecasting report 2014*.

Figure 1
Annual maximum demand, and forecast maximum demand, by region



Note: Actual data to 2013–14, then AEMO forecasts published in 2014.
Sources: AEMO; AER.

continued a trend of declining electricity consumption from the NEM grid. Over the past five years, annual grid consumption declined by an average 1.7 per cent, for the following reasons:

- Commercial and residential customers are more actively managing their energy use in response to price signals. The Australian Energy Market Operator (AEMO) estimated total energy savings of around 10 per cent annually over the next three years, with key contributions from more energy efficient air conditioning, refrigeration and electronics.
- Economic growth has been subdued, and energy demand from the manufacturing sector has weakened, reflecting an ongoing decline in energy intensive industries.
- Rooftop solar PV generation continues to increase, which reduces demand for electricity supplied through the grid. In 2013–14 solar PV generation rose to 2 per cent of all electricity produced. This growth has been driven by incentives under the renewable energy target (RET) scheme and lower cost systems. Solar penetration is highest in South Australia, where 22 per cent of households have installed capacity, just ahead of Queensland's 20 per cent penetration rate.[2] AEMO projected around 24 per cent annual growth in installations over the next three years.

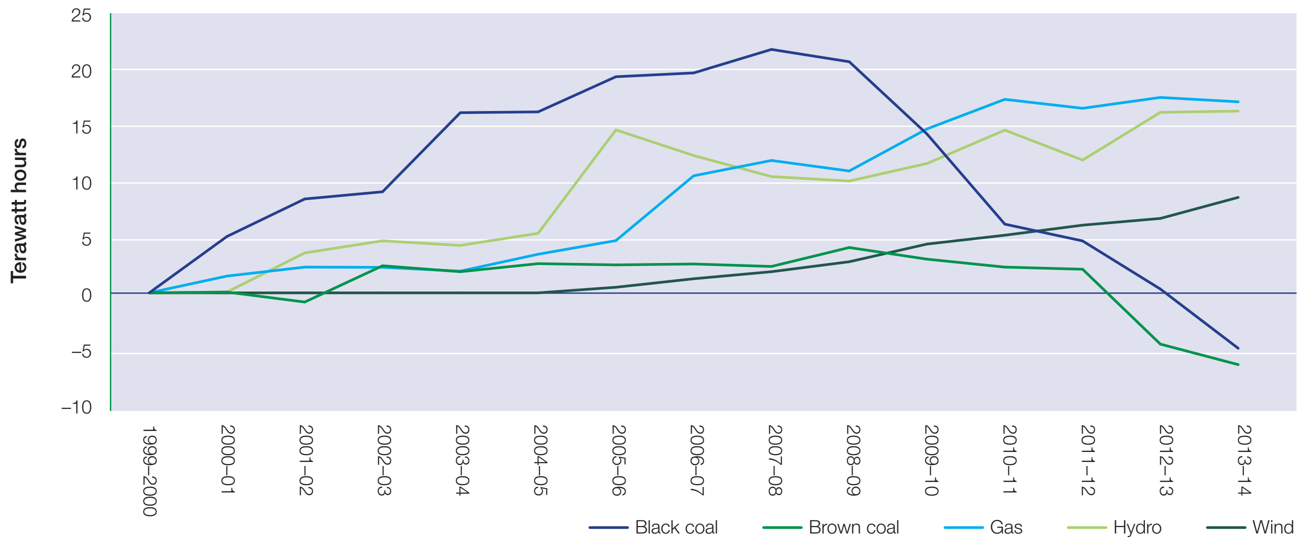
Maximum demand, which typically occurs during heatwaves when air conditioning use is high, has also flattened. It moved significantly below trend in the three years to 30 June 2014 (figure 1). AEMO forecast maximum demand will remain below historical peaks in most regions for at least the next 20 years. Queensland is the exception, due to its LNG projects.

Declining grid consumption and flat growth in maximum demand are reflected in a widening oversupply of generation capacity. AEMO projected in 2014 that no NEM region would require additional capacity to maintain supply–demand adequacy for the next 10 years. Despite this trend, around 650 megawatts (MW) of committed projects remained committed[3] at July 2014, comprising wind and commercial solar farms supported by the RET. The NEM's first commercial solar farm—Royalla—was commissioned in September 2014.

2 ESAA, *Solar PV report*, January 2014.

3 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 2
Annual change in electricity generation, by energy source



Sources: AEMO; AER.

Note: The rise in hydro generation in 2005–06 reflects Tasmania's entry into the NEM in 2005.

Climate change policies and electricity generation

Climate change policies have altered the composition of electricity generation in the NEM (figure 2). An expansion of the RET scheme in 2007 contributed to 2300 MW of wind capacity being added in the following six years, more than tripling existing capacity. Wind capacity in 2013–14 supplied 4.4 per cent of electricity generated across the NEM (35 per cent in South Australia). On 8 September 2014, wind output accounted for 76 per cent of South Australian generation. Spot prices are typically lower when wind generation is high.

The Coalition Government in 2014 appointed an expert panel to review the RET. The panel's report (the Warburton Report)[4] found the RET had led to the abatement of 20 million tonnes of carbon emissions. If left in place, the scheme was expected to abate a further 20 million tonnes of emissions per year from 2015 to 2030—almost 10 per cent of annual electricity sector emissions. The report also found the RET's cumulative effect on household energy bills over 2015–30 was likely to be small. But it considered the RET to be an expensive emissions abatement tool that subsidises renewable generation at the expense of fossil fuel fired electricity generation. In November 2014 the Australian Government was negotiating a policy response to the report.

The introduction of carbon pricing by the Labor Government in July 2012 increased operating costs for coal fired plant. Over the two years of the scheme's operation, coal fired generation declined by 11 per cent; its share of the market reached an historical low of 73.6 per cent in 2013–14. The reduction in coal generation (18 TWh) almost doubled the overall fall (associated with weak demand) in NEM electricity generation during this period (10 TWh). Over 2000 MW of coal plant was shut down or periodically taken offline during the period that carbon pricing was in place.

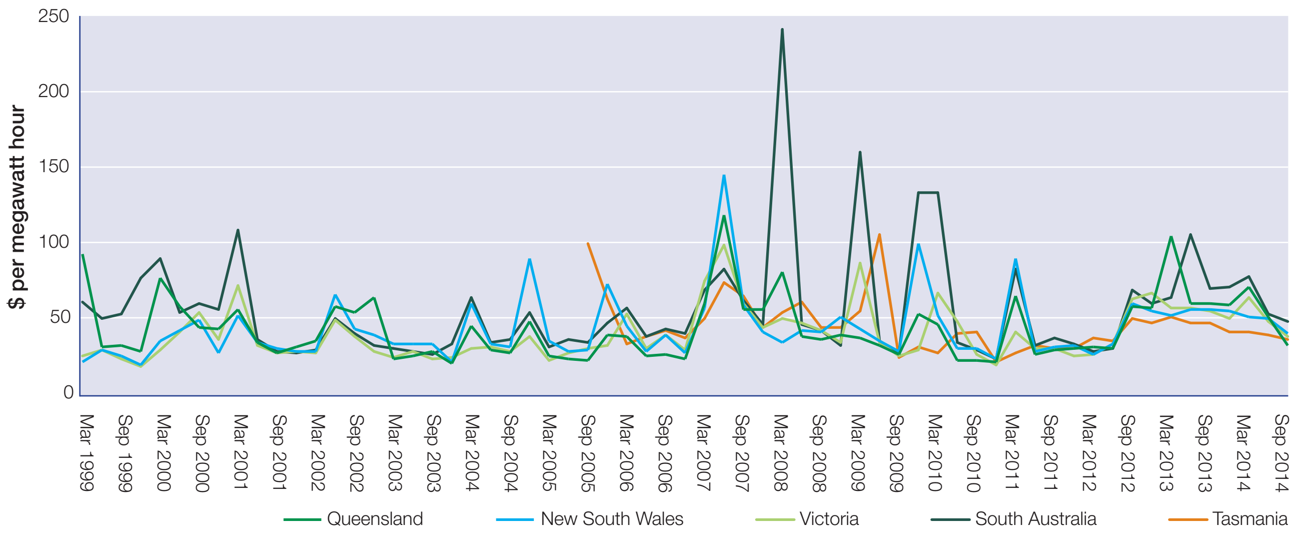
Some generators planned to return coal plant to service following the repeal of carbon pricing on 1 July 2014. Queensland generator Stanwell, for example, announced plans to return 700 MW of coal fired capacity to service at Tarong Power Station in 2014–15; the units had been withdrawn from service in 2012. It planned to operate the plant in place of the Swanbank E gas fired power station.[5]

Meanwhile, carbon pricing increased returns for hydro generation, contributing to record output levels during the two years of the scheme's operation—output in each year

4 Expert Panel, *Renewable energy target scheme: report of the Expert Panel*, August 2014.

5 Stanwell, 'Tarong power station to return generating units to service', Media release, 5 February 2014.

Figure 3
Quarterly spot electricity prices



Note: Volume weighted average prices.

Sources: AEMO; AER.

was 36 per cent higher than in the year before carbon pricing. The share of gas powered generation in the energy mix also rose in the two years.

Reflecting these changes in the generation mix, the overall emissions intensity of NEM generation fell by 4.7 per cent in the past two years. It fell from 0.903 tonnes of carbon dioxide equivalent emissions per megawatt hour (MWh) of electricity produced in 2011–12, to 0.861 tonnes in 2013–14.[6] This fall in emissions intensity, combined with lower NEM demand, led to a 10.3 per cent fall in total emissions from electricity generation over the two years that carbon pricing was in place.

Following the repeal of carbon pricing from 1 July 2014, carbon emissions from electricity generation in the NEM were 3.2 million tonnes higher in the following five months than in the comparable period in 2013. The rise reflected both an increase in electricity demand (up 2.4 per cent) and a rise in emissions intensity (2.4 per cent higher in the year to November 2014 than in the year to June 2014) as coal fired generation increased its market share.[7]

The Coalition Government in 2014 passed legislation for a Direct Action plan to achieve Australia's commitment to a 5 per cent reduction in greenhouse emissions by 2020. The scheme requires the government to pay for emissions abatement activity. Central to the plan is a $2.55 billion Emissions Reduction Fund to provide incentives for abatement activities. The fund allows businesses, local governments, community organisations and individuals to undertake approved emissions reduction projects and to seek funding for those projects. The Clean Energy Regulator will purchase emissions reductions at the lowest available cost, generally through competitive auctions.

A safeguard mechanism that penalises businesses for increasing their emissions above a baseline will commence on 1 July 2015, applying to around 130 large businesses with direct emissions over 100 000 tonnes a year. The government planned to release draft legislation to implement the safeguard mechanism in early 2015.[8]

Spot electricity market dynamics

Spot prices eased across all regions of the NEM in 2013–14, with falls ranging from 5 per cent (NSW) to over 13 per cent (Queensland and Tasmania). On average, volume weighted prices fell across the NEM by 10 per cent compared with the previous year (figure 3). Declining electricity demand and the continued uptake of renewable generation, including large scale wind and domestic solar PV generation, contributed to these price outcomes.

6 AEMO, Carbon dioxide equivalent intensity index, accessed 15 September 2014.

7 Pitt & Sherry, *Cedex*, December 2014.

8 Australian Government (Department of Industry), *The Emissions Reduction Fund: the safeguard mechanism*, 2014.

Following the repeal of carbon pricing on 1 July 2014, spot prices fell during the third quarter (1 July to 30 September 2014) in all NEM regions, most notably in Queensland. Monthly prices for July 2014 were the lowest since May 2012 for Queensland, and the lowest since June 2012 for NSW and Victoria. Monthly averages for August were lower again in all regions except Tasmania. After rebounding towards their July levels in early September, spot prices fell sharply later in the month and into October 2014, when a collapse in spot gas prices flowed through to electricity markets (section A.4).

Price volatility in Queensland

While average spot prices in Queensland eased in 2013–14, they were 14 per cent higher than NSW prices, after previously being lower for several years. Queensland spot prices were volatile during summer, repeating a pattern of the previous year. Over the summer, the five minute dispatch price exceeded $1000 per MWh on 50 occasions.

The rebidding strategies of some Queensland generators caused this volatility. Generators rebid capacity from lower to higher price bands during each affected trading interval. Demand and generation plant availability were within forecasts on each occasion, and pre-dispatch forecasts did not predict the price spikes.[9]

Most rebids occurred late in the 30 minute trading interval and applied for very short periods of time (usually five to 10 minutes), allowing other participants little, if any, time to make a competitive response. CS Energy was by far the most active player rebidding capacity into high price bands (above $10 000 per MWh) close to dispatch. Towards the end of the summer, other participants similarly rebid capacity from low to high prices, causing prices to spike more frequently.

The behaviour compromised the efficiency of dispatch, causing prices to spike independently of underlying supply–demand conditions. The average Queensland price for summer 2013–14 was $68.77 per MWh. Had the short term price spikes not occurred, the average price would have been 18 per cent lower at $56.10 per MWh. The increase represents a wealth transfer of almost $200 million based on energy traded. More generally, spot price volatility puts upward pressure on forward contract prices, which ultimately flows through to consumers' energy bills.

9 AER, *Electricity report 23 February to 1 March 2014*.

Promoting market efficiency

The AER in 2014 drew on its analysis of rebidding activity in Queensland to support a proposal by the South Australian Minister for Mineral Resources and Energy to strengthen and clarify the 'rebidding in good faith' provisions of the National Electricity Rules. The AER argued a recent rise in the incidence of late rebidding was making forecast information in the NEM less dependable, which affects market efficiency. The AEMC expected to publish a draft determination on the proposal in April 2015.

The effects of late rebidding on price and market efficiency would be mitigated if the output of competing generators could adjust more quickly. In 2013 the AER proposed a rule change that generators' ramp rates—the minimum rates at which generators may adjust output—must reflect the technical capabilities that the plant can safely achieve at the time. Currently, the minimum rate is 3 MW per minute, or 3 per cent for generators under 100 MW.

In August 2014 the AEMC found the existing provisions governing ramp rates may distort competitive outcomes and investment signals. It proposed ramp rates be at least 1 per cent of maximum generation capacity per minute (or the plant's technical capability if the generator cannot meet that threshold), regardless of plant size, configuration or technology. The AEMC expected to make a final determination on the ramp rate proposal in March 2015.

More generally, the AER takes enforcement action against market participants in alleged breach of the National Electricity Rules. Failure to comply with the rules can impair market efficiency. In 2014 the AER instituted proceedings in the Federal Court against Snowy Hydro for allegedly failing to follow dispatch instructions issued by AEMO. The AER alleged Snowy Hydro, on each occasion, generated substantially more power than the dispatch instruction required it to generate, and earned a greater trading amount from each transaction than it would have earned if it had complied with the instructions.

A.3 Energy networks

Rising costs of using energy networks (electricity poles and wires, and gas pipelines) were the main driver of rising energy retail prices for several years. Costs rose to replace ageing assets, meet stricter reliability standards, and respond to forecasts made at the time of rising peak demand. Additionally, instability in global financial markets exerted upward pressure on the costs of funding investment.

Figure 4
Weighted average cost of capital—electricity and gas distribution

Note: Nominal vanilla weighted average cost of capital.
Source: AER.

These pressures have eased more recently, lowering revenue and investment requirements for energy networks. Energy demand has declined, and is expected to remain below historical peaks in most regions for at least the next 20 years.[10] This trend has coincided with reductions in capital financing costs and government efforts to provide electricity network businesses with greater flexibility in meeting reliability requirements.

Alongside changes in the operating environment, significant reforms to energy network regulation in 2012 encourage network businesses to operate more efficiently in providing services. New measures support ongoing investment in essential services without requiring consumers to pay for excessive returns to network businesses. In AER determinations made since 2012:

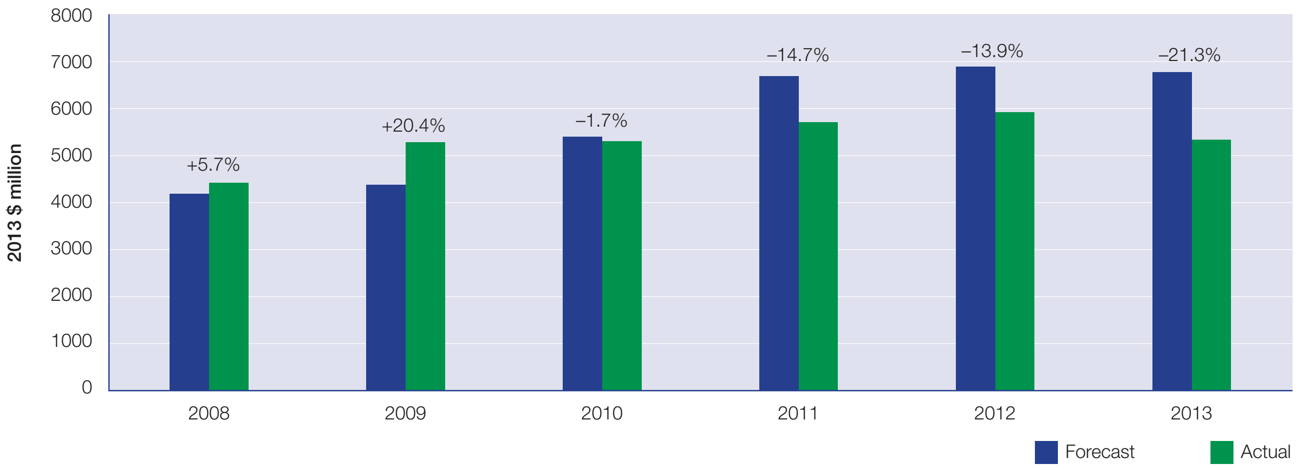
- electricity network revenues are on average 2 per cent *lower* than in previous regulatory periods. A similar trend is apparent in gas, with Victorian pipeline revenues being 11 per cent lower on average than in previous regulatory periods.
- reductions in the risk-free rate and market and debt risk premiums lowered the cost of capital from around 10 per cent in 2010 to 7.2–8.3 per cent in recent electricity and gas determinations (figure 4). The cost of capital set out in draft AER decisions in November 2014 was lower again, at 6.9–7.2 per cent. Under a revised framework applying for the first time in these decisions, the cost of capital will be revised annually to reflect changes in debt costs.
- approved investment forecasts for electricity networks are 24 per cent lower, on average, than levels in previous regulatory periods. The lower forecasts are mainly due to falling energy demand.

Delivering efficient network investment

Weakening energy demand is reducing the number of planned network investments, deferring projects that had already passed a regulatory investment test (a cost–benefit analysis to assess a project's viability). This trend is particularly reflected in declining network augmentations. Draft decisions for the NSW and ACT distribution networks in November 2014 provided for $1.2 billion of augmentation expenditure (16 per cent of total capital expenditure) across the four businesses—one-quarter of the amount approved in the previous regulatory period ($5 billion, or 35 per cent of total capital expenditure).

10 AEMO, *Electricity statement of opportunities*, 2014.

Figure 5
Capital expenditure by distribution networks against forecasts



Source: Annual financial RIN responses by distribution businesses.

Investment trends for the AusGrid distribution network (NSW) illustrate the effects of falling energy demand can be complex. The network's regulatory determination for 2009–14 provided for investment to meet an expected rise in maximum demand from 5500 to 6700 MW over the period. But these forecasts proved optimistic; maximum demand peaked at around 6000 MW, allowing the business to defer significant capital investment. This trend of underspending in capital programs occurred across all networks in recent years; from 2011 to 2013, distribution businesses underspent their approved forecasts by an average 17 per cent (figure 5).

One of the drivers of rising network charges in recent years was capital investment to ensure the networks delivered on reliability requirements. The AEMC in September 2013 proposed a new approach to setting distribution reliability targets—one that weighs the cost of new investment against the value that customers place on reliability and the likelihood of interruptions. In 2014 AEMO consulted with industry stakeholders to measure the value that customers place on a reliable supply of electricity. The valuations will feed into future regulatory determinations to ensure network investment delivers a secure and reliable electricity supply, while maintaining reasonable costs for consumers.

Some jurisdictions are already moving to reform distribution reliability standards. The removal of strict input based reliability standards for Queensland networks from 1 July 2014 is expected to save $2 billion in capital expenditure over the next 15 years. Supply interruptions will likely increase by 13 minutes for urban customers in 2020 (to 83 minutes, compared with 69 minutes under the previous standard).[11]

Similarly, the NSW Government in July 2014 removed deterministic planning obligations on distributors set out in network licence conditions. The remaining conditions focus solely on 'output' standards for reliability, providing more discretion for the businesses to determine the most appropriate ways to plan their network to meet the standard.[12]

The regulatory process includes incentives to improve service quality, particularly at times most valued by customers. As part of the service target performance incentive scheme, for example, transmission businesses can earn additional revenue for projects that improve a network's capability, availability or reliability when users most value reliability, or when wholesale electricity prices are likely to be affected. They face penalties if they fail to achieve improvement targets.

An element of network performance that has attracted recent policy focus is that pockets of network congestion periodically interfere with the efficient dispatch of generation plant. The AEMC in April 2013 began work on an *optional firm access* model to better manage this issue. In 2014 it developed core elements of the model's design and consulted widely with stakeholders.

11 Queensland Department of Energy and Water Supply, *Changes to electricity network reliability standards factsheet*.

12 AER, *Ausgrid distribution determination 2015–16 to 2018–19* (draft decision), Attachment 6: Capital expenditure, November 2014.

Optional firm access is intended to create locational signals that account for congestion costs against network expansion costs, providing efficient locational signals for new and existing generation plant. As a result, generation and transmission investment would likely become more efficient. The model also provides incentives for transmission businesses to maximise network availability when it is most valuable to the market.

Power of choice reforms

The nature and function of energy networks is evolving. Escalating cost pressures in recent years gave impetus to alternatives such as demand response (whereby users adjust their energy use in response to price signals), small scale local generation (such as rooftop solar PV generation) and, potentially, energy storage technologies. Innovations in network and communications technology, including smart meters and interactive household devices, are allowing consumers to access real-time information on their energy use and to have greater control over how they manage it.

These developments are transforming the nature of a network from being a one-way conduit for energy transportation, to a platform for multilateral trade in energy products. Some electricity consumers are becoming producers, able to switch from net consumption to net production in response to market signals. Over one million households have installed rooftop solar PV, for example. Further, customer investment in smart appliances and battery storage could shift the amount of power that customers withdraw from or inject into a network throughout the day. These developments are slowing the growth in peak demand, reducing the need for costly network augmentations.

In 2012 the AEMC launched *Power of choice*, an umbrella of reforms relating to efficient use of energy networks and non-network alternatives. The Council of Australian Governments (CoAG) Energy Council endorsed the reforms and proposed rule changes to apply them. The use of smart meters is central to the reforms, allowing consumers to access a wider range of retail price offers and demand management products.

Most electricity meters on residential premises are exclusively provided by regulated network businesses. But this arrangement can inhibit competition and consumer choice, and discourage investment in metering technology that could support the uptake of innovative energy products and services.

The AEMC consulted in 2014 on a CoAG Energy Council proposal to allow competition in the provision of metering and related services. It also progressed related reforms to allow customers more ready access to their electricity consumption data, and for multiple trading relationships at the customer's connection point. The reforms aim to create a regulatory framework that matches the realities of a dynamic and evolving energy market.

Victoria was the first jurisdiction to progress metering reforms, launching a rollout of smart meters with remote communications to all customers from 2009. The rollout was close to completion in late 2014. NSW in October 2014 announced a competitive framework for its own voluntary rollout of smart meters. The framework aims to encourage competition by allowing metering providers, such as electricity retailers or other energy service providers, to offer smart meters to customers as part of energy deals.[13]

In its current review of the NSW networks, the AER reclassified certain metering services, making them open to competition. It is also looking at other ways to facilitate the competitive framework. One way is to ensure exit fees are not unreasonably high, so customers incur only the efficient costs of moving from legacy (regulated) meters to third party provided meters.

While smart meters allow consumers to monitor their energy use, price signals are needed to create incentives for efficient demand response. Under traditional pricing structures, energy users pay the same network price regardless of how or when they use power. Charges to customers using large amounts of electricity at peak times do not reflect the costs that they impose on the network. For example, a residential consumer using a five kilowatt (kW) air conditioner at peak times causes around $1000 a year in additional network costs, but might pay only $300 under current price structures. The remaining $700 is covered by other customers, who pay more than what it costs to supply their own network services.[14]

Similarly, customers with solar PV installations may not bear the full cost of their network use under current price structures, which reward reductions in total energy consumption regardless of whether they occur at peak times. A customer can save around $200 in network costs per year by installing solar PV and reducing their use of electricity from the grid. But most solar energy is

13 The Hon. Anthony Roberts MP (NSW Minister for Resources and Energy), 'NSW gets smart about meters', Media release, Tuesday 28 October 2014.

14 Commissioner Neville Henderson (AEMC), 'Power of choice and other energy market reforms', Speech delivered to 2014 Energy Users Association of Australia (EUAA) conference, 13 October 2014.

generated at non-peak times, so the customer will reduce network costs by only $80 because they will still use the network at peak times. Other consumers without solar PV cross-subsidise the remaining $120 by paying higher network charges.[15]

To address these inefficiencies, *Power of choice* proposed network prices should vary depending on time of use, thus encouraging retailers to reflect those charges in customer contracts. Time varying prices encourage consumers to make efficient choices on the best times to use their electrical appliances—for example, customers could shift some use from peak times when charges are high, to off-peak times (such as late evening). More generally, cost-reflective pricing structures create incentives for customers to invest in local generation and smart devices.

To progress the matter, energy ministers in 2013 proposed reforms to distribution network pricing. The AEMC in November 2014 set out principles for distribution prices to reflect the efficient costs of providing network services to each consumer. Network businesses will need to consult with stakeholders when developing their charging structures, to account for consumer impacts.

The reforms aim to minimise network costs over time. The AEMC estimated 81 per cent of residential customers will face lower network charges in the medium term under cost-reflective pricing, and up to 69 per cent will see lower charges at peak times.[16] Business users with relatively flat load profiles can also expect lower network charges. The AEMC recommended the new rules be progressively implemented in 2016–17, to give energy customers time to adjust to the changes.

Victoria was the first jurisdiction to implement time varying prices. From September 2013 Victorian small customers could choose to remain on a traditional tariff structure or move to a more flexible structure.

15 Paul Smith (CEO, AMEC), 'Responding to consumer demands, promoting competition and preparing for change', Speech delivered to 2014 Australian Institute of Energy symposium, 22 September 2014.

16 Commissioner Neville Henderson (AEMC), 'Power of choice and other energy market reforms', Speech delivered to 2014 EUAA conference, 13 October 2014.

A.4 Gas markets

Despite a weakness in global demand, Australia's LNG exports rose in 2013–14 by 15 per cent to $16.5 billion, becoming Australia's third largest export after iron ore and coal.[17] Australia's gas industry is about to be transformed, with three major LNG projects in Queensland nearing completion. The three projects—the world's first to convert coal seam gas (CSG) to LNG—include processing facilities at the port of Gladstone and transmission pipelines to ship gas from CSG fields in the Surat–Bowen Basin.

In 2014 the Queensland LNG project developers continued to build and test wells, and began operating new production facilities. Developers also neared the completion of gas processing facilities, liquefaction plants and transmission pipelines, including the interconnection of pipelines to enable gas flows between projects.

The development of Queensland's LNG industry is exerting significant pressure on the domestic gas market. Gas production in eastern Australia is forecast to treble over the next two decades to meet international LNG demand,[18] with the first exports scheduled for 2014–15. With LNG proponents sourcing reserves that might otherwise have been available to the domestic market, domestic customers are having difficulty buying gas under medium to long term contracts.[19] The effect of these market conditions was apparent in 2013 and 2014, with prices in new gas contracts reportedly linked to international oil prices or LNG netback.[20] Further, the Australian Government's energy green paper noted in September 2014 that sellers appear to have access to more market information than buyers, raising policy concerns.[21]

While prices in spot markets reflected similar behaviour to contract prices in 2012–13, the markets diverged from late 2013. Winter prices were lower in all hubs in 2014 than in 2013, averaging just below $4 per gigajoule (GJ) in Sydney, Melbourne and Adelaide, and $2.50 per GJ in Brisbane. The abolition of carbon pricing, which took effect on 1 July 2014, reduced the cost competitiveness of gas powered generation, contributing to weaker gas demand.

17 EnergyQuest, *EnergyQuarterly* August 2014, Media release, 29 August 2014.

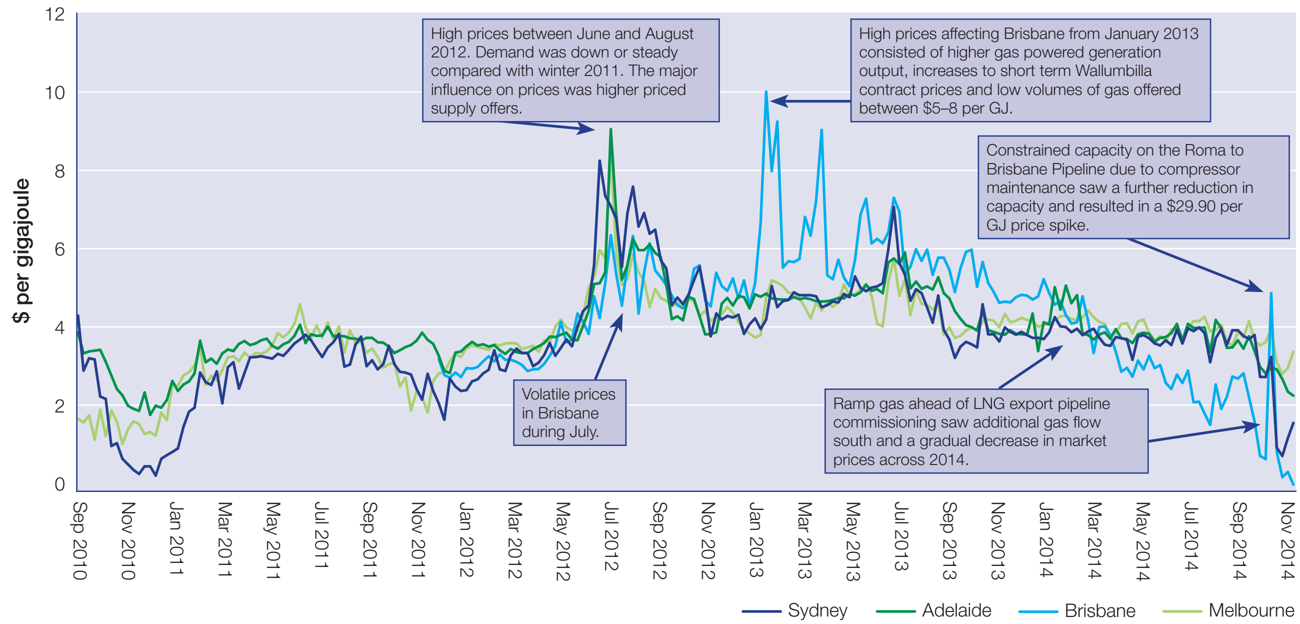
18 AEMO, *Gas statement of opportunities*, May 2014.

19 K Lowe Consulting, *Gas market scoping study: a report for the AEMC*, July 2013.

20 LNG netback prices simulate an export parity price by stripping out shipping, transportation and liquefaction costs.

21 Australian Government (Department of Industry), *Energy green paper*, September 2014.

Figure 6
Spot gas prices—weekly averages



Notes: Volume weighted ex ante prices derived from demand forecasts. Sydney, Adelaide and Brisbane data are short term trading market prices. Melbourne prices are estimates for the metropolitan area, based on Victorian wholesale spot gas prices plus APA Group's transmission withdrawal tariff for the two Melbourne metropolitan zones. The Sydney data exclude the 1 November 2010 price of $150 per GJ, which data errors caused.

Sources: AER estimates (Melbourne); AEMO (other cities).

Queensland prices diverged markedly from prices in southern markets in 2014, coinciding with rising gas production around Roma as production facilities ramped up for LNG export (figure 6). Significant quantities of the ramp-up gas were sold into the Brisbane hub of the short term trading market and the gas supply hub at Wallumbilla.

These increased gas flows caused Brisbane spot prices to collapse during 2014. October and November prices were typically below $1 per GJ and fell close to zero on some days. Prices also trended lower in the gas supply hub at Wallumbilla. Ramp-up gas also flowed into the southern states. In September and October 2014 gas flows from Queensland to South Australia and NSW via the QSN Link more than doubled the flows in the corresponding period in 2013. The rise in gas volumes caused lower than average prices, with Sydney prices falling below $1 per GJ on a number of days from late October into November. Additionally, these flows reduced NSW's usual reliance on Victorian gas, causing a reversal in flows between the two states along the NSW–Victoria Interconnect; that is, gas flowed south along the pipeline, from NSW into Victoria.

The collapse in gas prices flowed through to electricity markets in 2014. Falling gas prices in Brisbane coincided with higher levels of gas powered generation in Queensland and low spot electricity prices, which fell as low as $11 per MWh in October 2014 (figure 7).

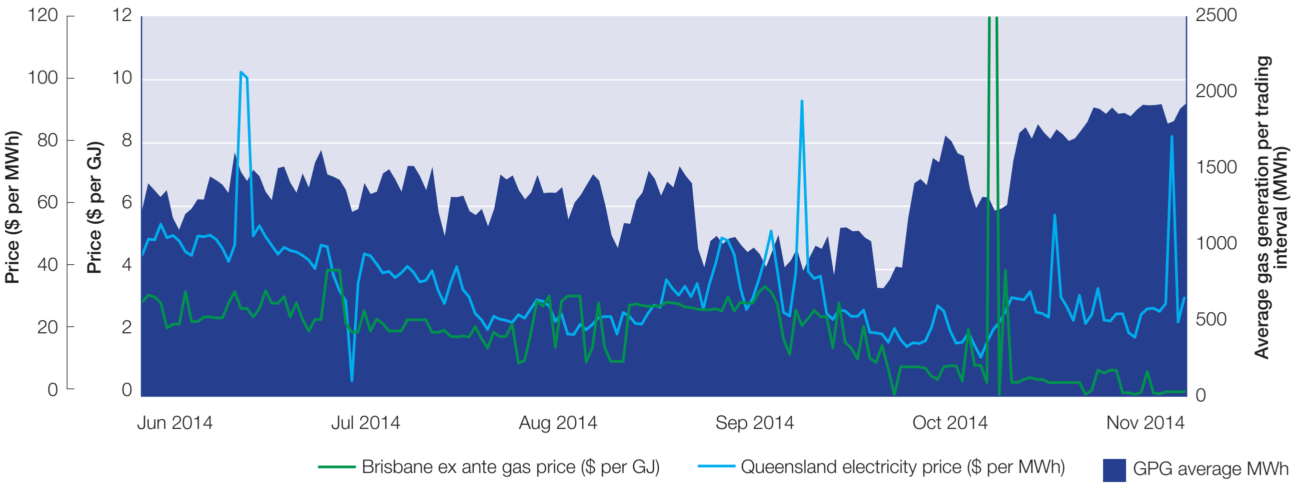
East coast supply–demand balance

Ramp-up gas will continue to be sold into domestic spot markets in the lead-up to commissioning each of Queensland's six committed LNG trains, exerting downward pressure on spot prices. The timing of each train's commissioning is uncertain, although each of the three LNG projects expects to commission at least one train by mid-2015.

While the domestic gas market will tighten once all LNG facilities are exporting at full capacity, a countervailing influence is weaker projections of gas powered electricity generation (which accounts for 31 per cent of domestic

Newcastle Gas Storage Project (AGL Energy)

Figure 7:
Spot gas prices (Brisbane) and spot electricity prices and gas powered generation (Queensland)



Note: Brisbane average ex ante daily gas price per GJ. Volume weighted average daily spot electricity price per MWh. Gas powered generation (MWh) per trading interval.

Sources: AER; AEMO.

gas demand in Australia).[22] Stanwell took its Swanbank E generator offline in December 2014 for up to three years, reducing domestic gas demand over that period.

Accounting for these factors, AEMO in 2014 scaled back earlier projections of gas supply shortfalls in eastern Australia.[23] But various contingencies affect the forecasts, including the timing of each LNG train's commissioning, changing forecasts of electricity demand growth (and the proportion of forecast demand expected to be sourced from gas powered generation), the effects of government climate change policies on gas demand, and the availability of gas storage facilities.

In this volatile environment, industry participants are considering supply alternatives to avoid possible shortfalls. Pipeline owners, for example, have expanded or are expanding capacity on several transmission pipelines. The NSW and Northern Territory governments in November 2014 signed a Memorandum of Understanding to work closely on the development of a pipeline connecting the Northern Territory with eastern gas markets. Additionally, AGL Energy in 2015 will complete a 1.5 petajoule (PJ) LNG storage facility near Newcastle to help manage fluctuations in gas supply, particularly during peak periods.

Proponents are seeking to develop new CSG resources in eastern Australia, although community concerns about health and environmental impacts have delayed their development. The NSW Government in November 2014 launched a new strategic framework to determine appropriate areas to develop and extract gas, accounting for economic benefits and any effects on the environment and communities. The potential to develop unconventional gas in the Cooper Basin is also significant. While two shale wells were producing in 2014,[24] Santos indicated production could take up to a decade to be commercially viable, given the costs of drilling and extraction technologies, and varying geological conditions.[25]

Policy responses

Policy makers are progressing reforms to help alleviate pressures in the eastern gas market. A gas supply hub launched at Wallumbilla, Queensland in March 2014 aims to alleviate bottlenecks by facilitating short term gas trades. As a pipeline interconnection point, Wallumbilla links gas markets in Queensland, South Australia, NSW and Victoria. The market model could be adapted to other hubs in the future.

22 Bureau of Resources and Energy Economics (BREE), *Gas market report*, October 2013, p. 26.
23 AEMO, *Gas statement of opportunities update*, May 2014.
24 Santos, Presentation to 2014 CLSA investors' forum, 15 September 2014.
25 'Shale gas success still a decade away for Australia, says Santos', *The Australian*, 26 September 2014.

The hub promotes transparent and efficient gas trading, allowing participants to manage the risks associated with variable gas prices. It also deepens market liquidity by attracting participants such as LNG plants, industrial customers and gas powered generators. The diversity of contract positions and the number of participants at Wallumbilla create a natural point of trade.

Trading activity in the gas supply hub was intermittent in 2014, which is not unusual in a new market. The existence of long term contracts and physical pipeline constraints also limited the volume of trades. While few traders were active, the number of buyers and sellers rose during the year, with more sellers than buyers in October 2014. On average, around 12 trades per week occurred between four participants. While a majority of trades were for gas delivered along the Roma to Brisbane Pipeline, trading on the South West Queensland Pipeline rose from August 2014.

Industry participants expect liquidity in the hub to improve in 2015, with pipeline augmentations and market conditions around Wallumbilla expected to free up more gas for trade. The ongoing development of hub products should further promote trade. A number of participants indicated the availability of a single trading price would also enhance liquidity, but may require improved interconnection between the three transmission pipelines serving the hub.

In other developments, the CoAG Energy Council is reforming pipeline capacity trading arrangements, to promote trade in idle contracted capacity. Throughout the year, some pipelines have significant idle capacity that is contracted to gas retailers and industrial consumers. In 2014 the Energy Council and AEMO consulted with stakeholders on enhancing pipeline capacity trading information on the National Gas Market Bulletin Board. As a preliminary step, AEMO in 2014 changed the bulletin board's interface to improve accessibility and data discoverability. It also launched an eastern market capacity listing service, with voluntary standard contractual terms and conditions for secondary capacity trade.

Pipeline entities also made progress towards secondary trading in capacity. APA Group launched an operational transfer capacity trading platform in 2014, and Jemena expects to launch a trading platform in December 2014. Customers have not widely used existing platforms, with some suggesting prices of around $1 per GJ are too high.

The AEMC in September 2013 proposed further market reforms, including refining spot market design and streamlining the rule change process for spot markets.[26] AEMO progressed reforms to interregional trade in 2013–14 by improving the interface between the Victorian spot market and interconnecting pipelines and facilities. It similarly progressed reforms of market operator (gas balancing) services in the short term trading market.[27]

The Australian Government's 2014 energy green paper cited a need for greater transparency of gas production potential and trading information (including prices), to improve gas market operation.[28] Additionally, stakeholders in 2014 called for closer harmonisation of the gas spot market models. Three spot market models operate in eastern Australia—the short term trading market in Brisbane, Sydney and Adelaide; the Victorian spot market; and the gas supply hub at Wallumbilla. The existence of multiple market structures imposes a significant regulatory burden on participants.

The Business Council of Australia noted an absence of standardisation across markets hinders the development of a viable forward market in gas.[29] The Victorian Government recently advocated more integrated market arrangements, including a possible move to a single market design to reduce barriers to interregional trading. It also advocated a single set of principles for access to east coast pipelines.[30]

A.5 Retail energy markets

The repeal of carbon pricing led retail electricity prices in 2014 to fall in jurisdictions other than Queensland and South Australia (figure 8). Retailers estimated annual electricity cost savings for residential customers from the carbon repeal were 5.2–12.4 per cent.[31] However, in Queensland, higher wholesale energy costs and feed-in tariff payments for solar PV systems offset the savings; in South Australia, rising network costs drove up prices.

26 AEMC, *Taking stock of Australia's east coast gas market*, Information paper, September 2013; K Lowe Consulting, *Gas market scoping study: a report for the AEMC*, July 2013.

27 AEMO, *2014 Annual report*, 2014.

28 Australian Government (Department of Industry), *Energy green paper*, September 2014.

29 Business Council of Australia, *Australia's energy advantages*, November 2014.

30 Victorian Government (Department of State Development, Business and Innovation), *Victoria's energy statement*, 2014.

31 ACCC, *Monitoring of prices, costs and profits to assess the general effect of the carbon tax scheme in Australia*, October 2014.

Figure 8
Movements in regulated and standing offer prices

Notes:

Estimated annual cost is based on a customer using 6500 kilowatt hours (kWh) of electricity per year and 24 GJ of gas per year on a single-rate tariff at September 2014.

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.

Retail gas prices fell only in Victoria. In other jurisdictions, rising costs associated with a reduced availability of wholesale gas contracts (section A.4) offset savings from the repeal of carbon pricing. Pipeline charges also rose in most regions, putting additional pressure on retail prices.

Retail energy prices remain high by historical standards, reflected in the number of customers experiencing payment difficulties. At 30 June 2014 the rate of energy customers on hardship programs ranged from 0.4 per cent in Tasmania (electricity) and the ACT (electricity and gas), to 1.2 per cent in South Australia (electricity). Almost 12 per cent of electricity customers (and 4 per cent of gas customers) had debts greater than $2500 before joining a hardship program. Of those customers exiting a program in 2013–14, only 20 per cent had successfully completed it. Other customers were removed from hardship programs for failing to meet energy repayments.

Some consumer stakeholders raised concerns that barriers restrict access to hardship assistance and that some retailers set unaffordable payment plans. In response to these and related concerns, the AER in 2014 reviewed hardship policies and practices, focusing on how retailers identify and assist customers experiencing payment difficulties.

Retail competition

All energy customers in eastern and southern Australia are free to choose their retailer, following Tasmania's extension of full retail contestability to electricity customers using less than 50 MWh per year from 1 July 2014.

Despite retail contestability operating for over a decade in most regions, retail markets remain concentrated. Three private retailers—AGL Energy, Origin Energy and EnergyAustralia—jointly supplied over 70 per cent of small electricity customers and over 80 per cent of small gas customers at 30 June 2014. Competition from smaller retailers eroded around 5 per cent of their market share over the past two years.

Vertical integration with the generation sector increased following AGL Energy's acquisition of Macquarie Generation in 2014. Overall, the three major retailers now control 46 per cent of generation capacity, up from 15 per cent in 2009. Another major player, Snowy Hydro, increased its market share to 10 per cent in December 2014, following its acquisition of Colongra power station from Delta Electricity. Snowy Hydro also emerged as the fourth large energy retailer in September 2014, when it acquired Lumo Energy (adding to its existing Red Energy business). The acquisition raised Snowy Hydro's retail market share in electricity and gas to 7 per cent.

But retail competition has deepened with the emergence of alternative retail models, driven by rising energy prices, consumers wishing to manage their energy use, and wider access to renewable energy options. The models include solar power purchase agreements (whereby businesses sell energy generated from solar panels installed at a customer's residence), tailored products for customers with specific energy requirements (such as households with swimming pools), and energy sales as part of a package that provides a customer with greater control over their energy use.

The regulatory approach will need to keep pace with these changes. The AER published a statement of approach in July 2014, focusing on solar power purchase agreements. In November 2014 it published an issues paper on regulating innovative energy selling business models more generally (including energy storage), to help develop an appropriate and flexible approach.

The AEMC in 2014 found that energy retail competition was effective in NSW, Victoria, South Australia and south east Queensland. Competition is generally more effective in electricity than gas, due to differences in market scale and the difficulties in sourcing gas and transport services in some regions.[32]

Following advice from the AEMC, NSW in July 2014 joined Victoria and South Australia in removing retail price regulation for electricity. The Queensland Government committed to removing electricity retail price regulation in south east Queensland from 1 July 2015.

The average extent of retail price discounting was greater in 2014 than in the previous year in all regions. The average discount for electricity bills under market contracts, over standing contracts, ranged from 5 per cent in Queensland to 16–19 per cent in Victoria. Discounts were typically lower for gas, at around 5 per cent in most jurisdictions and 10 per cent in Victoria.

The annual bill spread in September 2014 also varied across jurisdictions. Victoria exhibited the strongest price diversity. The spread for electricity contracts ranged from $200 in Queensland to over $1000 in Victoria. Gas contract spreads were consistent with the previous year, at around $200 for most networks.

32 AEMC, *2014 Retail competition review, final report*, August 2014.

For competition to be effective, consumers must be able to make informed choices on the energy product that best meets their needs. The AEMC found consumers generally have good awareness of their ability to choose a retailer. In markets with effective competition, awareness ranged from 90 per cent of electricity customers (85 per cent for gas) in NSW to 95 per cent of electricity and gas customers in Victoria. However, consumers were less aware of tools available to compare retail offers effectively. Over 60 per cent of respondents in the AEMC review were not aware of, or unable to name, a price comparator website. The review noted many customers find energy contracts complex and struggle to compare available offers.

Consumer protection

Lack of understanding among consumers increases the risk of exploitation. For this reason, the behaviour of energy retailers has become a compliance and enforcement priority:

- The AER in November 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 in South Australia and the ACT before transferring them to new energy plans. The ACCC instituted proceedings against the businesses for similar behaviour in Queensland, NSW and Victoria under provisions in the Australian Consumer Law on misleading conduct or representations.
- The ACCC instituted proceedings in the Federal Court against AGL Energy in December 2013 and Origin Energy in March 2014 relating to how the businesses promote discounts and savings under their energy plans. The action followed concerns that the retailers were misleading consumers about the extent of savings available, and the period over which discounts would be provided.

The Consumer Action Law Centre and the Consumer Utilities Advocacy Centre raised concerns in 2013 about the ability of retailers to raise prices under fixed term energy contracts with termination fees. They considered this arrangement unfairly shifts price risk onto consumers, which may erode confidence in the market and weaken competition.

The AEMC in October 2014 rejected a rule change proposal on this matter. It considered the key issue is that some consumers may enter contracts unaware that prices may change. To address this issue, it introduced a rule requiring a retailer to clearly inform a consumer entering a contract whether prices can change and, if so, when the retailer would notify the customer of the change.

The AER participated in the rule change process and is exploring ways to improve the quality of information available to consumers choosing an energy retail contract. It is also reviewing the *Retail pricing information guideline* that sets out how retailers must present offers, including all information that must be provided. Additionally, the AER intends to roll out improvements to the Energy Made Easy price comparison website in 2015, making it easier for customers to see which offer would best suit their needs.

Mortlake Power Station (Origin Energy)

1 NATIONAL ELECTRICITY MARKET

The National Electricity Market (NEM) is a wholesale market in which generators sell electricity in eastern and southern Australia (table 1.1). The main customers are energy retailers, which bundle electricity with network services for sale to residential, commercial and industrial energy users. The Australian Energy Regulator (AER) plays a number of roles in the market (box 1.1).

The NEM covers six jurisdictions—Queensland, New South Wales (NSW), the Australian Capital Territory (ACT), Victoria, South Australia and Tasmania—that are physically linked by an interconnected transmission network. The NEM has around 200 large generators, five state based transmission networks (linked by cross-border interconnectors) and 13 major distribution networks that supply electricity to end use customers. In geographic span, the NEM is one of the longest continuous alternating current systems in the world, covering a distance of 4500 kms.

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	47 779 MW
Number of registered generators	322
Number of customers	9.5 million
NEM turnover 2013–14	$10.8 billion
Total energy generated 2013–14	194 TWh
National maximum winter demand 2013–14	30 114 MW[1]
National maximum summer demand 2013–14	33 610 MW[2]

MW, megawatts; TWh, terawatt hours.

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

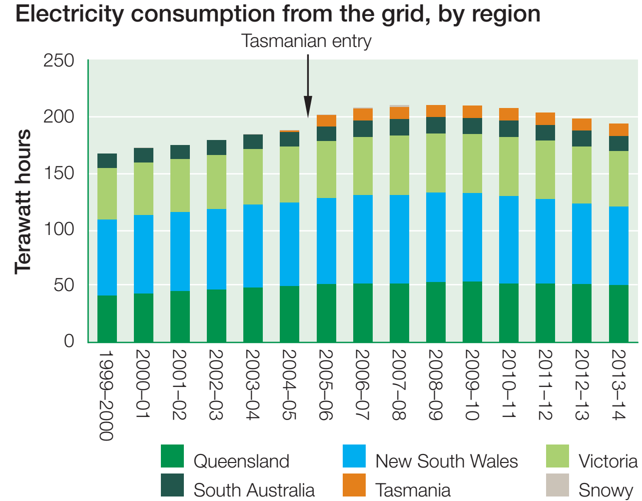
2 The maximum historical summer demand of 35 551 MW occurred in 2009.

Sources: AEMO; AER.

1.1 Electricity demand

The NEM supplies electricity to over nine million residential and business customers. In 2013–14 the market generated 194 terawatt hours (TWh) of electricity—a 2.5 per cent reduction from the previous year, and around 3 per cent below forecast.[1] This outcome continues a trend of declining electricity consumption from the NEM grid (figure 1.1).[2] Over the past five years, grid consumption declined by an average 1.7 per cent annually across the market.

Figure 1.1
Electricity consumption from the grid, by region



Note: The Snowy region was abolished on 1 July 2008. Its energy demand was redistributed between the Victoria and NSW regions from that date.

Sources: AEMO; AER.

The Australian Energy Market Operator (AEMO) in June 2014 projected annual consumption from the NEM grid would rise by an average 0.4 per cent over the three year period to 30 June 2017. Liquefied natural gas (LNG) projects in Queensland would fully account for this marginal growth. Excluding those projects, annual electricity consumption over the period is forecast to *decline* across all regions by 1.1 per cent, with falls ranging from 0.1 per cent in NSW to 2.1 per cent in Victoria. The contraction will be most pronounced for large industrial use, which is forecast to decline by 3 per cent annually. Residential electricity consumption is forecast to decline by 0.5 per cent per year.[3]

1 AEMO, *National electricity forecasting report 2014*.

2 Some electricity consumption is not sourced from the grid—for example, rooftop solar photovoltaic (PV) generation (section 1.2.1).

3 AEMO, *National electricity forecasting report 2014*.

Box 1.1: The AER's role in the National Electricity Market

The AER monitors the NEM to ensure market participants comply with the underpinning legislation and rules, and to detect irregularities and wider harm issues. We report on these issues to strengthen market transparency and confidence. In 2013–14 we published weekly reports on NEM performance, five reports on high price events (section 1.9.4), and a special report on unusual market outcomes in South Australia.[4]

Additionally, we draw on our monitoring activity to support compliance and enforcement work, and to advise and assist bodies including the Council of Australian Governments (CoAG) Energy Council, the Australian Energy Market Commission (AEMC) and the Australian Competition and Consumer Commission (ACCC). This compliance and enforcement work in 2013–14 included:

- advising the ACCC on energy market mergers
- assisting the ACCC to monitor energy market behaviour following the repeal of carbon pricing in July 2014 (section 1.9.3)
- investigating Snowy Hydro's alleged failure to follow dispatch instructions from the Australian Energy Market Operator (AEMO). In July 2014, the AER instituted proceedings in the Federal Court against Snowy Hydro for alleged contraventions of the National Electricity Rules (section 1.11).[5]

Our wider policy work in 2013–14 included:

- proposing amendments to the rules governing the rate at which generators can be required to alter their output (section 1.11)
- developing new metrics on the impacts of rebidding, to support the South Australian Government's proposal to amend the 'good faith' bidding rule (section 1.9.5)
- publishing indicators of market concentration and competitive conditions in the NEM (section 1.13).

Electricity consumption from the grid has been declining (and will continue to decline) due to:

- commercial and residential customers more actively managing their energy use in response to price signals, including using energy efficiency measures such as solar water heating. New building regulations on energy efficiency reinforce this trend. AEMO estimated total energy savings of around 10 per cent annually over the next three years, with key contributions from more energy efficient air conditioning, refrigeration and electronics.
- subdued economic growth and weaker energy demand from the manufacturing sector. These trends reflect an ongoing decline in energy intensive industries, including the Port Henry aluminium smelter closure in Victoria in August 2014. In South Australia, the desalination plant will reduce electricity consumption once operational testing is completed in December 2014.
- the continued rise in rooftop solar photovoltaic (PV) generation, which reduces consumption of electricity sourced from the grid. In 2013–14 solar PV generation reduced grid consumption by 2.9 per cent. This growth has been driven by small scale renewable energy certificates and lower cost systems (section 1.2.1). AEMO projected continued strong growth in solar PV installations over the next three years (around 24 per cent annually), with the strongest growth in Queensland and Victoria.

1.1.1 Maximum demand

Electricity demand fluctuates throughout the day (usually peaking in early evening) and by season (peaking in winter for heating and summer for air conditioning). Around three quarters of Australian households have air conditioning or evaporative cooling. Over the course of a year, demand typically peaks on a handful of days of extreme temperatures, when air conditioning (or heating) loads are highest.

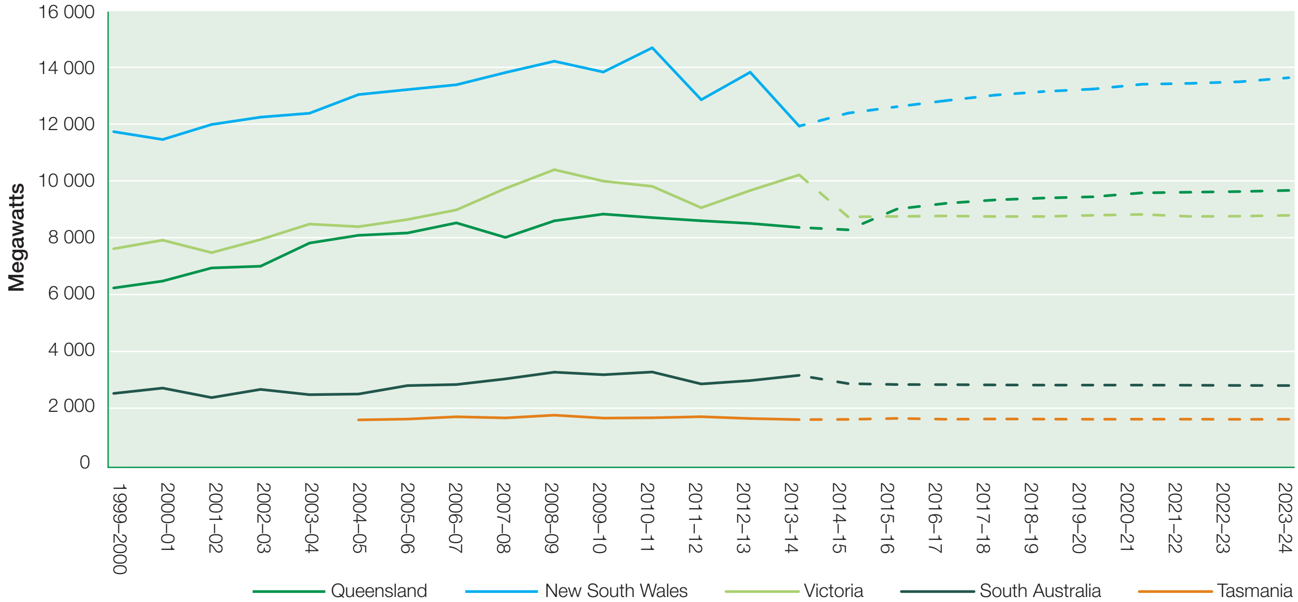
A succession of hot summers caused maximum (or peak) demand to rise steadily until 2008–09, typically at a faster rate than average demand (figure 1.2).[6] The growth in maximum demand drove significant investment in energy networks to meet expectations that demand would continue

4 AER, *Special report: Market outcomes in South Australia during April and May 2013*, July 2013. See also AER, *State of the energy market 2013*, pp. 42–3.

5 'AER takes action against Snowy Hydro Limited for alleged failure to comply with AEMO dispatch instructions', Media release, 2 July 2014.

6 Australian Bureau of Statistics, *Household energy use and conservation 2011*.

Figure 1.2
Annual maximum demand, and forecast maximum demand, by region



Note: Actual data to 2013–14, then AEMO forecasts published in 2014.
Sources: AEMO; AER.

Table 1.2 Maximum demand growth, by region, 2013–14

	QUEENSLAND	NEW SOUTH WALES	VICTORIA	SOUTH AUSTRALIA	TASMANIA
Change from 2012–13 (%)	–1.6	–13.6	5.6	5.9	–2.1
Change from historical maximum (%)	–5.2	–18.6	–1.7	–3.4	–8.2
Year of historical maximum	2009–10	2010–11	2008–09	2010–11	2008–09

Sources: AEMO; AER.

to rise rapidly. But maximum demand has plateaued since 2008–09. The underlying causes are similar to those that have weakened overall grid consumption.

While recent average summer temperatures were above trend (with summer 2012–13 being Australia's warmest summer on record), maximum demand met from the grid was below historical levels. Victoria and South Australia recorded a rise in maximum demand in 2013–14, peaking on 16 January 2014 during one of south east Australia's most significant heatwaves on record (table 1.2). While peak temperatures mostly fell short of those observed in 2009, extreme heat persisted for longer than it did in that earlier heatwave.[7] Maximum demand on 16 January 2014 approached but did not reach historical levels, partly because the heatwave occurred during a holiday period when commercial and industrial loads are lower.

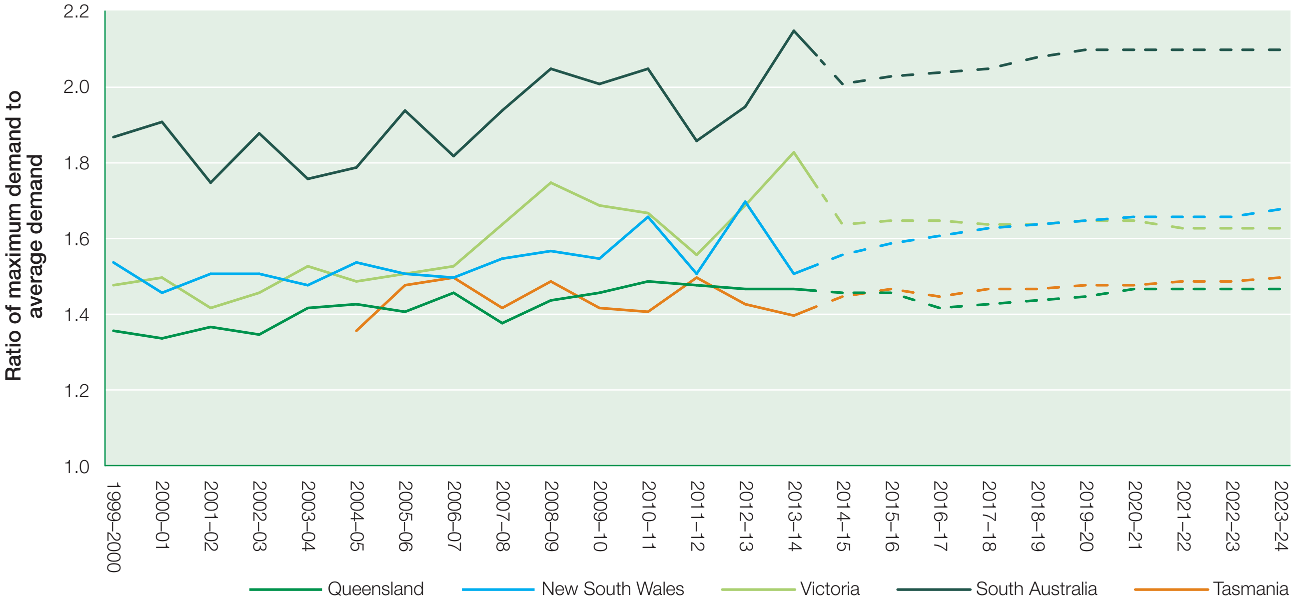
AEMO forecast maximum demand will remain below historical peaks in most regions for at least the next 20 years. Queensland is the exception, with maximum demand expected to surpass its historical record in 2015–16, due to LNG projects. Subdued demand has led to surplus capacity in the NEM, causing several generators to be shut down or periodically offline, and delaying the need for new investment in generation capacity (section 1.5).

While maximum demand remains subdued, it is forecast to grow marginally faster than overall grid consumption in NSW, South Australia and Tasmania (figure 1.3). This peakier

7 Bureau of Meteorology, *Seasonal climate summary for Australia*, summer *2013–14*.

Figure 1.3

Ratio of maximum demand to average demand



Sources: AEMO; AER.

demand profile affects the commercial viability of some large generation plant, because sufficient capacity is needed to meet demand peaks, while average plant use is falling. This trend creates incentives to meet demand peaks through alternative mechanisms, including demand-side measures (box 1.3), small scale local generation and new energy storage technologies.

Additionally, rising solar PV generation is shifting demand peaks to later in the day. In South Australia, AEMO forecasts a delay of 60 minutes in the short term. Given this shift, further solar PV penetration is unlikely to significantly affect peak demand unless new systems are positioned to catch the late afternoon sun.

1.2 Generation technologies in the NEM

Most electricity dispatched in the NEM is generated using coal, gas, hydro or wind technologies. A generator creates electricity by using energy to turn a turbine, making large magnets spin inside coils of conducting wire. Figure 1.4 illustrates the location of major generators in the NEM, and the technologies in use.

In Australia, electricity is mainly produced by burning fossil fuels (such as coal and gas) to create pressurised steam. The steam is forced through a turbine at high pressure to drive the generator. Other types of generator rely on renewable energy sources such as water, the sun and wind. Solar PV generation has recently emerged as a significant technology in NEM regions, although the electricity generated is not traded through the NEM (section 1.2.1).

The demand for electricity is not constant, varying with the time of day, the season and the ambient temperature. A mix of generation technologies is needed to respond to these demand characteristics. Plant with high start-up and shut-down costs but low operating costs tend to operate relatively continuously; for example, coal generators may require up to 48 hours to start up. Generators with higher operating costs, but with the ability to quickly change output levels (for example, open cycle gas powered generation), typically operate when prices are high (especially in peak demand periods). Intermittent generation, such as wind and solar, operate only when weather conditions are favourable.

Black and brown coal generators accounted for 53 per cent of registered capacity in the NEM in 2013–14, but supplied 74 per cent of output (figure 1.5). Victoria, NSW and Queensland rely on coal more heavily than do other regions (figure 1.6). The introduction of carbon pricing contributed to coal fired generation declining by 7 per cent in 2012–13, with a further 5 per cent decrease recorded in 2013–14. The reduction in coal fired generation almost doubled the overall

Figure 1.4

Electricity generation in the National Electricity Market

Sources: AEMO; AER.

fall in NEM generation (associated with weak demand) over the two years (section 1.3.4).

Gas powered generators accounted for 21 per cent of registered capacity across the NEM in 2013–14, but supplied only 12 per cent of output. Among the NEM jurisdictions, South Australia is the most reliant on gas powered generation. More generally, 52 per cent of new generation investment over the past decade was in gas plant.

Hydroelectric generators accounted for 16 per cent of registered capacity in 2013–14 but contributed 9 per cent of output. The bulk of Tasmanian generation is hydroelectric; Queensland, Victoria and NSW also have hydro generation. The introduction of carbon pricing and good rainfall in catchment areas contributed to a 36 per cent increase in hydro generation in 2012–13, with this output maintained in 2013–14.

Wind generation has increased under climate change policies such as the renewable energy target (RET) (section 1.3.1). Despite falling electricity demand removing the need for additional generation capacity, almost 1200 megawatts (MW) of wind capacity have been added in the past two years. Nationally, wind generators accounted for 6.3 per cent of capacity and contributed 4.4 per cent of output in 2013–14. AEMO projected wind generation will drive much of the growth in electricity generation over the next 20 years.

The penetration of wind generation is especially strong in South Australia, where it represented 29 per cent of capacity and met 35 per cent of electricity requirements in 2013–14 (figure 1.7). South Australia has one of the highest penetrations of wind generation of any electricity market in the world. In late June 2014, wind was the dominant fuel source in the region. At its peak on 24 June 2014, wind output accounted for 72 per cent of total generation in South Australia, which was the highest proportion on record.[8] On that day, wind plant operated at 87 per cent of its installed capacity. Another record was set on 8 September 2014, with wind output accounting for 76 per cent of South Australian generation.

Figure 1.5

Registered generation, by fuel source, 2013–14

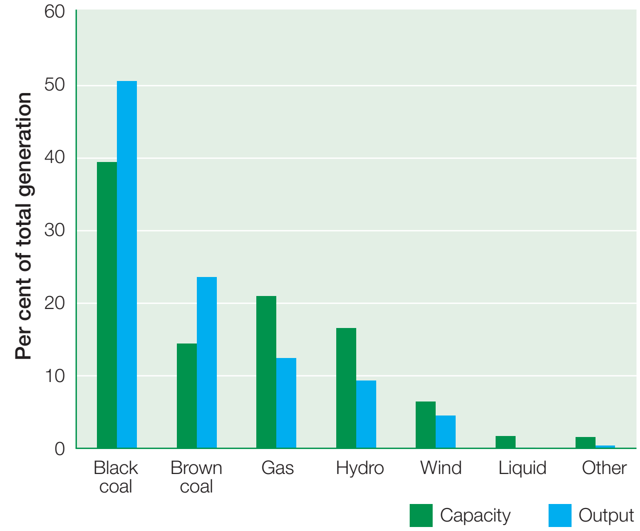
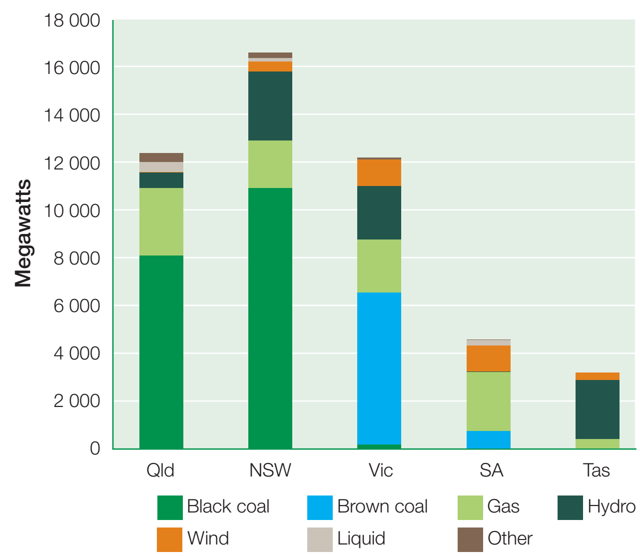


Figure 1.6

Generation capacity, by region and fuel source, 30 June 2014

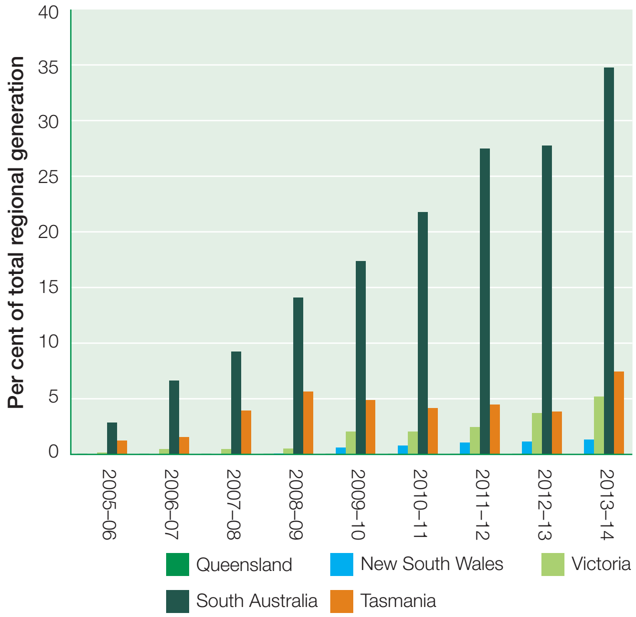


Note (figures 1.5–1.6): Excludes rooftop solar PV generation, which is not traded through the NEM wholesale market.

Sources (figures 1.5–1.6): AEMO; AER.

8 AER, *Electricity report 22 to 28 June 2014*.

Figure 1.7
Wind generation share of total generation, by region



Note: Excludes rooftop solar PV generation, which is not traded through the NEM wholesale market.
Sources: AEMO; AER.

However, wind generation tends to be lower at times of maximum demand—typically, it contributes around 9 per cent of its installed capacity during peak demand periods in summer.[9] It also poses challenges to the market operator in periods when high wind generation coincides with low electricity demand. But, wind generation is having a moderating impact on electricity prices; in particular, spot prices are typically lower when wind generation is high.

1.2.1 Rooftop solar PV generation

Climate change policies, including the RET and subsidies for solar PV installations, led to a rapid increase in solar PV generation over the past five years. The subsidies include feed-in tariff schemes established by state and territory governments, under which distributors or retailers pay households for electricity generated from rooftop installations. The energy businesses recover subsidies from energy users through electricity charges.

Rooftop solar PV generation is not traded through the NEM. Instead, the installation owner receives a reduction in their energy bills. AEMO calculates the contribution of rooftop PV generation as a reduction in energy demand, in the sense that it reduces the community's energy requirements from the national grid.

Around 1.3 million households have installed small scale solar PV systems.[10] Total installed capacity reached 3370 MW in 2013–14, equivalent to 6.4 per cent of total installed generation capacity in the NEM. Most of this capacity has been installed since 2010–11. The output of solar PV installations was virtually zero until 2010, but by 2013–14 had risen to 2 per cent of electricity produced in the NEM. This proportion was equivalent to around half the contribution of wind generation.

Solar penetration is highest in South Australia, where 22 per cent of households have installed capacity, just ahead of Queensland's 20 per cent penetration rate.[11] In South Australia, solar PV installations reached the equivalent of 10 per cent of the state's generation capacity in 2013–14, and generated 6 per cent of its annual energy requirements (up from 3.8 per cent in 2012–13).[12]

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. The AER estimated solar PV capacity in South Australia during a heatwave in January 2014 contributed around 75 per cent of its installed capacity in the early afternoon. But that contribution averaged around 55 per cent at 4 pm, declining to around 30 per cent at 6 pm. More generally, the increasing use of solar PV generation is shifting demand peaks to later in the day (when solar generation is falling), especially in South Australia.

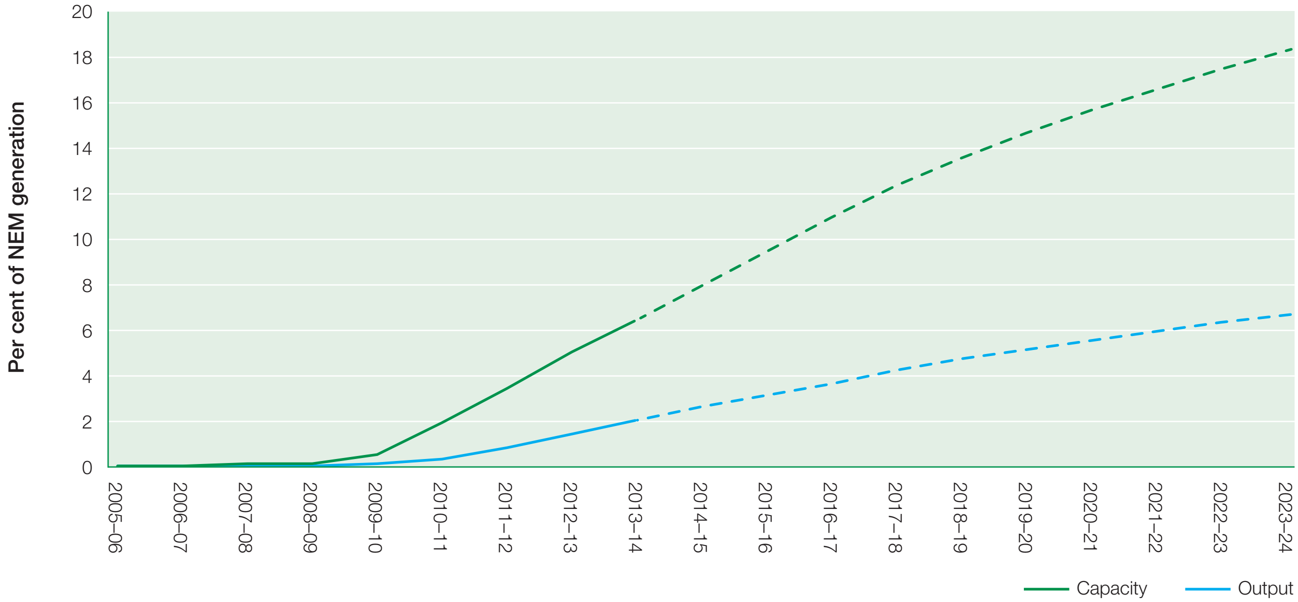
AEMO estimated rooftop solar generation can contribute around 45 per cent of its installed capacity in South Australia, and 48 per cent in Queensland, at times of maximum energy requirements. The rate for NSW is lower, at around 36 per cent.[13] Maximum demand in Tasmania typically occurs on winter evenings, when solar PV generation is negligible.

AEMO in 2014 revised upwards its forecasts of the uptake of solar PV installations over the next decade. In earlier forecasts, a reduction of feed-in tariffs was expected to ease the growth in installations.[14] But continued decreases in solar panel costs and consumers' response to rising

9 AEMO, *South Australian wind study report*, 2013.

10 Expert Panel, *Renewable energy target scheme: Report of the Expert Panel*, August 2014.
11 ESAA, *Solar PV Report*, January 2014.
12 AEMO, *South Australian electricity report 2014*.
13 AEMO, *South Australian electricity report 2014*.
14 AEMO, *Rooftop PV information paper*, 2012, p. iii.

Figure 1.8
Solar PV generation capacity and output



Note: Dotted lines are AEMO forecasts published in 2014.
Sources: AEMO, AER.

electricity prices are offsetting this influence. AEMO forecast solar installations will equal around 17 per cent of total installed generation capacity in the NEM by 2022–23, and will contribute around 6.3 per cent of the NEM's energy requirements at that time (figure 1.8). Queensland and Victoria have the highest forecast growth in solar PV installations over the next decade.

1.3 Carbon emissions and the NEM

The mix of generation technologies across the NEM has evolved in response to technological change and government policies to mitigate climate change. The electricity sector contributes over 30 per cent of national greenhouse gas emissions, mainly due to its high reliance on coal fired generation.[15] Climate change policies aim to change the economic drivers for new investment and shift the reliance on coal fired generation towards less carbon intensive energy sources. The policies have an impact on investment in new generation and the operation of existing plant. In Australia, climate change policies currently or recently implemented by federal governments include:

- the RET scheme (launched 2001, expanded 2007)
- carbon pricing (operating 1 July 2012 to 30 June 2014)
- Direct Action (legislation introduced June 2014).

1.3.1 Renewable energy target scheme

The Australian Government in 2001 introduced a national RET scheme, which it expanded in 2007. The scheme aims to achieve a 20 per cent share for renewable energy in Australia's electricity mix by 2020. It requires electricity retailers to source a proportion of their energy from renewable sources developed after 1997. Retailers comply with the scheme by obtaining renewable energy certificates created for each MWh of eligible renewable electricity that an accredited power station generates, or from the installation of eligible solar hot water or small generation units (box 1.2).

The scheme applies different arrangements for small scale generation (such as solar PV installations) and large scale renewable supply (such as wind farms). It has a 2020 target of 41 000 gigawatt hours (GWh) of energy from large scale renewable energy projects. Small scale renewable projects do not contribute to the national target, but still produce renewable energy certificates that retailers must acquire.

15 Australian Government, *Quarterly update of Australia's national greenhouse gas inventory, March quarter 2014*, 2014.

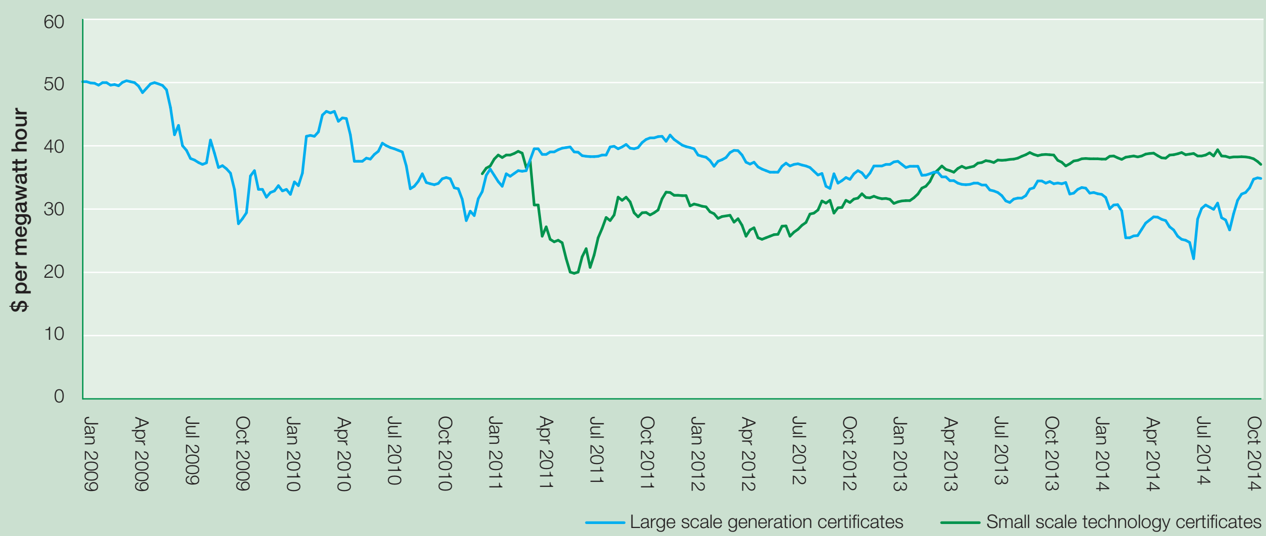
Box 1.2 Renewable energy target—certificate prices

Figure 1.9 illustrates the prices of certificates issued under each component of the RET scheme. A certificate represents one 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.

Since the 2011 revisions to the RET scheme, certificates from large scale projects have traded at around $30–40. The price of certificates from small scale projects has been more volatile, trading between $20–40. Some price movements reflect scheme changes and market uncertainty about possible changes.

Figure 1.9

RET Certificate prices



Source: Clean Energy Regulator.

The Coalition Government in 2014 appointed an expert panel to review the RET. The panel's report (the Warburton Report)[16] found the RET had led to the abatement of around 20 million tonnes of carbon emissions and, if left in place, would abate a further 20 million tonnes of emissions per year from 2015 to 2030—almost 10 per cent of annual electricity sector emissions. The report also found the RET's cumulative effect on household energy bills over 2015–30 was likely to be small.

But the report considered the RET to be an expensive emissions abatement tool that subsidises renewable generation at the expense of fossil fuel fired electricity generation. It recommended either closing the large RET scheme to new entrants or limiting any increase in the current target to 50 per cent of future demand growth. It also recommended closing, or accelerating the phase-out, of the small scale scheme. In November 2014 the Australian Government was negotiating a policy response.

1.3.2 Carbon pricing

A carbon pricing scheme operated in Australia between 1 July 2012 and 1 July 2014. The Coalition Government abolished carbon pricing in Australia, effective from 1 July 2014, under legislation passed by the Senate on 17 July 2014.

The Labor Government had introduced a price on carbon in 2012 as part of its Clean Energy Future Plan. The plan targeted a reduction in carbon and other greenhouse emissions to at least 5 per cent below 2000 levels by 2020 (and a reduction of up to 25 per cent with equivalent international action). The central mechanism placed a fixed price on carbon for three years, starting at $23 per tonne

16 Expert Panel, *Renewable energy target scheme: Report of the Expert Panel*, August 2014.

of carbon dioxide equivalent emitted. An emissions trading scheme was to replace the fixed price in July 2015 (later brought forward to July 2014), whereby the market would determine a carbon price.

1.3.3 Direct Action

The Coalition Government in 2014 passed legislation for a Direct Action plan to achieve Australia's commitment to a 5 per cent reduction in greenhouse emissions by 2020. The scheme requires the government to pay for emissions abatement activity. Central to the plan is a $2.55 billion Emissions Reduction Fund to provide incentives for abatement activities. The fund allows businesses, local governments, community organisations and individuals to seek funding for approved emissions reduction projects. The Clean Energy Regulator will purchase emissions reductions at the lowest available cost, generally through competitive auctions. A safeguard mechanism that penalises businesses for increasing their emissions above a baseline will commence on 1 July 2015, applying to around 130 large businesses with direct emissions over 100 000 tonnes a year. The government planned to release draft legislation to implement the safeguard mechanism in early 2015.[17]

1.3.4 Effects of climate change policies on generation

Climate change policies have altered the composition of electricity generation in the NEM. An expansion of the RET in 2007 contributed to 2300 MW of wind capacity being added in the following six years, more than tripling existing capacity. The RET, in conjunction with attractive feed-in tariffs, also supported a rapid uptake of solar PV installations (section 1.2.1).

The introduction of carbon pricing in July 2012 contributed to further shifts in the mix of generation plant. Over the two years of the scheme's operation, coal fired generation declined by 11 per cent (figure 1.10); its share of the market reached an historical low of 73.6 per cent in 2013–14. The reduction in coal generation (18 terawatt hours, TWh) almost doubled the overall fall (associated with weak demand) in NEM generation during this period (10 TWh). Over 2000 MW of coal plant was shut down or periodically taken offline during the period that carbon pricing was in place.

Some generators planned to return coal plant to service following the repeal of carbon pricing in 2014. Queensland generator Stanwell, for example, announced plans to return 700 MW of coal fired capacity to service at Tarong Power Station in 2014–15; the units had been withdrawn from service in 2012. It planned to operate the plant in place of the Swanbank E gas fired power station.[18]

Meanwhile, carbon pricing increased returns for hydro generation, contributing to record output levels during the two years of the scheme's operation—output in each year was 36 per cent higher than in the year before carbon pricing. The share of gas powered generation in the energy mix also rose in the two years.

Overall, these changes in the generation mix contributed to the emissions intensity of NEM generation falling by 4.7 per cent between 2011–12 and 2013–14 (from 0.903 tonnes of carbon dioxide equivalent emissions per MWh of electricity produced in 2011–12, to 0.861 tonnes in 2013–14).[19] This fall in emissions intensity, combined with lower NEM demand, led to a 10.3 per cent fall in total emissions from electricity generation over the two years that carbon pricing was in place.

Following the repeal of carbon pricing from 1 July 2014, carbon emissions from electricity generation in the NEM rose by 3.2 million tonnes in the following five months compared with the comparable period in 2013. The rise reflected both an increase in electricity demand (up 2.4 per cent) and a rise in emissions intensity (2.4 per cent higher in the year to November 2014 than in the year to June 2014) as coal fired generation increased its market share.[20]

1.4 Generation investment

Price signals in the wholesale and contract markets for electricity largely drive new investment in the NEM, with climate change policies affecting the technology mix. Between the NEM's start in December 1998 and June 2014, new investment added over 14 400 MW of registered generation capacity—an average of around 1000 MW per year (figures 1.11 and 1.12). Additionally, significant investment has been made in generation not connected to the transmission grid, including investment in solar PV installations (section 1.2.1).

Tightening supply conditions led to an upswing in generation investment from 2008–10, with over 4000 MW of new capacity added in those years (predominantly gas fired generation in NSW and Queensland). More recently,

17 Australian Government (Department of the Environment), *The Emissions Reduction Fund: The safeguard mechanism, 2014*.

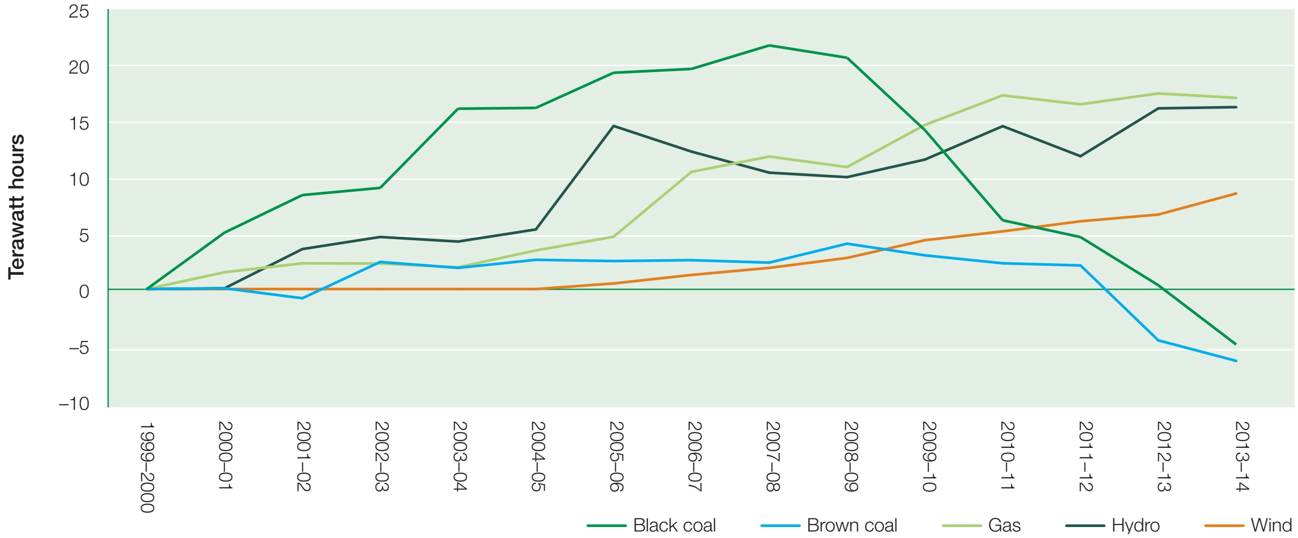
18 Stanwell, 'Tarong power station to return generating units to service,' Media release, 5 February 2014.

19 AEMO, Carbon dioxide equivalent intensity index, accessed 15 September 2014.

20 Pitt & Sherry, *Cedex*, December 2014.

Figure 1.10

Annual change in electricity generation, by energy source



Sources: AEMO; AER.

Note: The rise in hydro generation in 2005–06 reflects Tasmania's entry into the NEM in 2005.

subdued electricity demand and surplus capacity have pushed out the required timing for new investment, with significant amounts of plant being decommissioned or periodically taken offline (section 1.5). Additionally, the Australian Energy Market Commission's (AEMC) *Power of choice* review noted the potential efficiencies of demand-side measures as an alternative to new investment in generation plant (box 1.3).

These expectations are reflected in the limited amount of recent investment. Of the 2600 MW of capacity added over the four years to 30 June 2014, 63 per cent was in wind generation (which the RET scheme subsidises). The balance of investment over the past four years was in gas fired plant in Victoria, South Australia and Queensland. The only investment in coal fired generation related to upgrades of the Eraring power station in NSW.

Table 1.3 details generation investment in the NEM in 2013–14, all in wind capacity. Investment in other types of plant is likely to be limited over the next few years, with only a small number of projects in development. At July 2014 the NEM had around 650 MW of committed projects,[21] comprising wind and commercial solar farms (table 1.4). Around 70 per cent of committed projects are located in NSW.

The NEM's first commercial solar farm—Royalla—was commissioned in September 2014. Other solar farms are being developed:

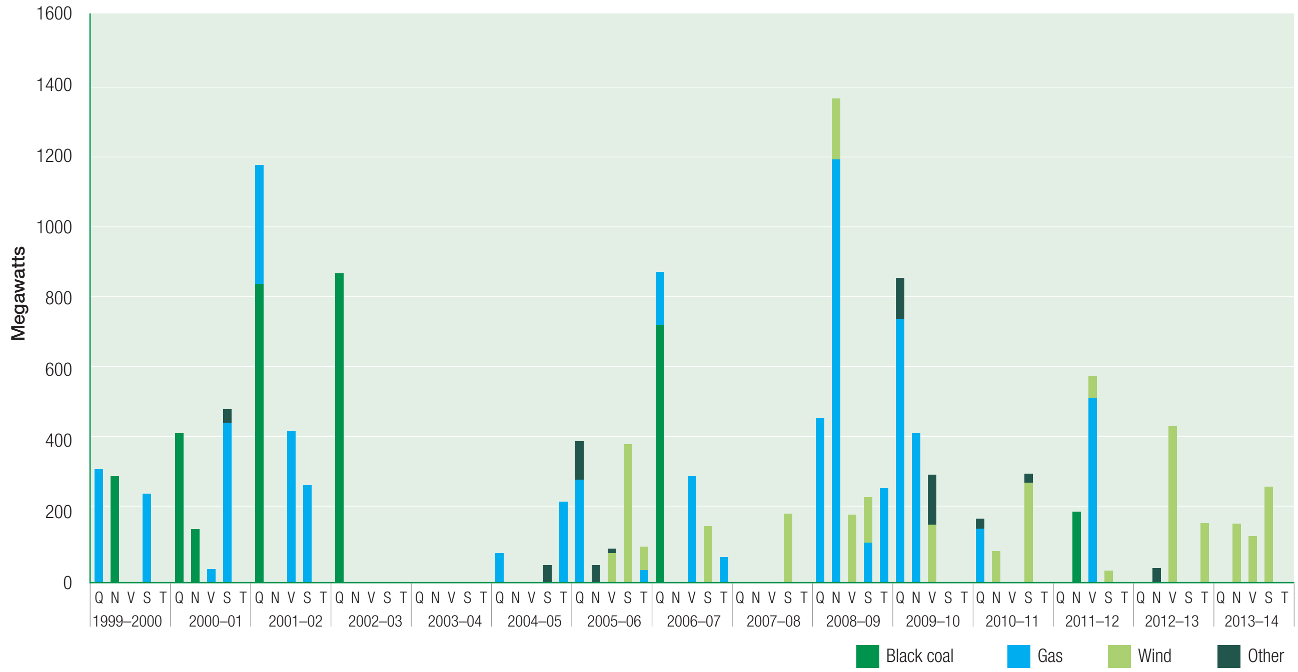
- AGL is developing large scale solar PV power plants at Nyngan (102 MW) and Broken Hill (53 MW) in regional NSW. The Australian Renewable Energy Agency and the NSW Government provided funding to support the projects, which will jointly produce 360 000 MWh of electricity per year, sufficient to meet the needs of over 50 000 homes. Construction on both plants began in 2014, with the Nyngan plant expected to be completed by June 2015, and the Broken Hill plant by November 2015.
- Fotowatio Renewable Ventures in August 2014 announced construction would immediately begin on its 70 MW Moree Solar Farm. The farm will use mechanical trackers to continually orient its solar panels to the sun to optimise power output.

While few generation projects are being developed, a large number are 'proposed', and some of these may be developed in the medium to long term. AEMO lists proposed generation projects that are 'advanced' or publicly announced, but excludes them from supply and demand outlooks because they are speculative. At July 2014 it listed around 20 000 MW of proposed capacity across the NEM (figure 1.13), mostly in wind (60 per cent) and gas fired capacity (25 per cent). Around 2.6 per cent of proposed projects are solar farms.

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 1.11

Annual investment in registered generation capacity

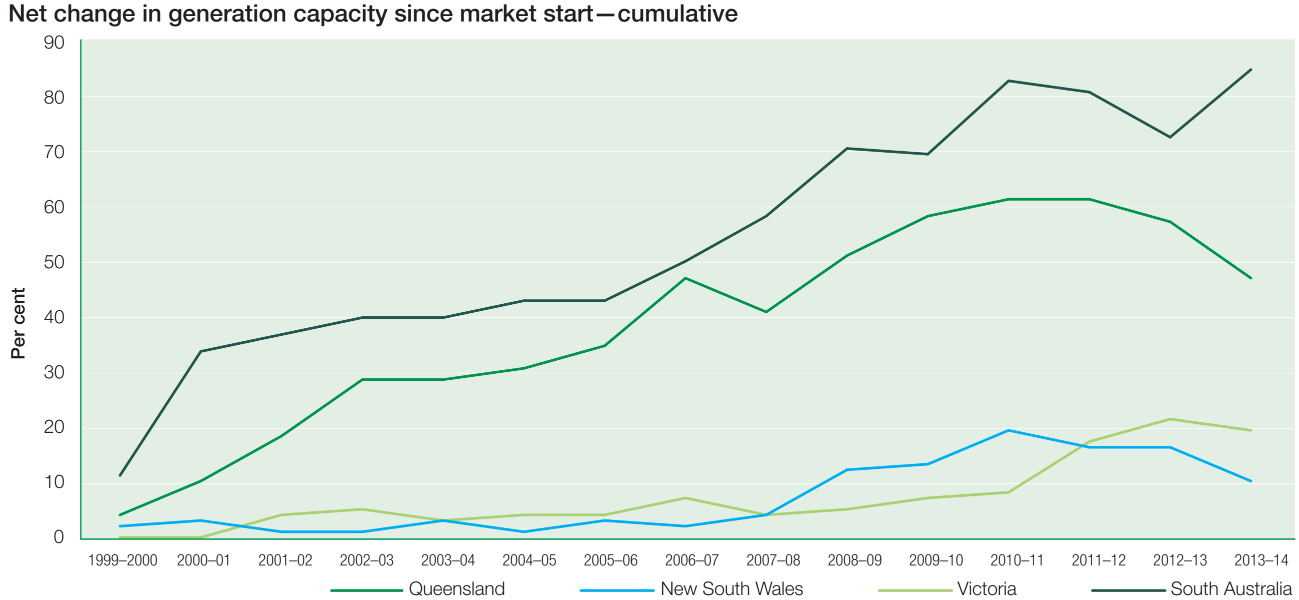


Q, Queensland; N, NSW; V, Victoria; S, South Australia; T, Tasmania.

Note: Data are gross investment estimates that do not account for decommissioned plant.

Figure 1.12

Net change in generation capacity since market start—cumulative



Sources (figures 1.11 and 1.12): AEMO; AER.

Table 1.3 Generation investment in the National Electricity Market, 2013–14

OWNER	POWER STATION	TECHNOLOGY	SUMMER CAPACITY (MW)	DATE COMMISSIONED
NEW SOUTH WALES				
Goldwind	Gullen Range	Wind	166	2014
VICTORIA				
Meridian Energy Australia	Mount Mercer	Wind	131	2014
SOUTH AUSTRALIA				
Trustpower	Snowtown 2 North	Wind	144	2014
Trustpower	Snowtown 2 South	Wind	126	2014

Source: AEMO; AER.

Table 1.4 Committed investment in the National Electricity Market, July 2014

DEVELOPER	POWER STATION	TECHNOLOGY	SUMMER CAPACITY (MW)	PLANNED COMMISSIONING
QUEENSLAND				
CS Energy	Kogan Creek Solar Boost	Solar	44	2015
NEW SOUTH WALES				
CBD Energy and Banco Santanda	Taralga	Wind	107	2014
Royalla Asset	Royalla	Solar	20	2014
Electricity Generating Public Company Limited	Boco Rock	Wind	113	2015
AGL PV Solar Development	Nyngan	Solar	102	2015
AGL PV Solar Development	Broken Hill	Solar	53	2015
Moree Solar Farm	Moree	Solar	56	2016
VICTORIA				
Mitsui and Co. Australia	Bald Hills p1	Wind	107	2015
Pacific Hydro Portland Wind Farm	Portland Stage 4	Wind	47	2015

Source: AEMO; AER.

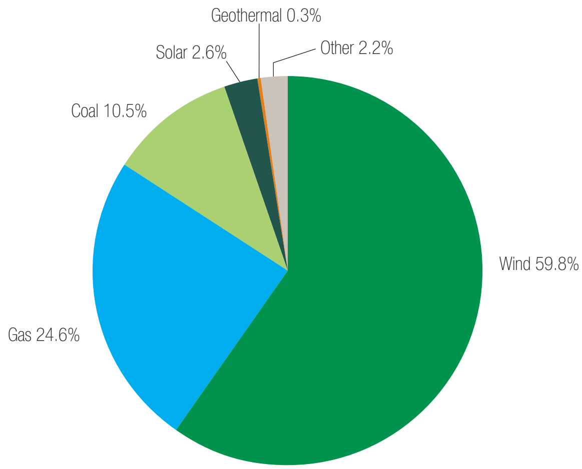
1.5 Supply–demand balance

A flattening out of electricity demand since 2008 (section 1.1) has led to a widening oversupply of generation capacity. Notably, muted demand and climate change policies contributed to over 2000 MW of coal plant being shut down or periodically taken offline in 2012–13.[22] AEMO reported a further 1385 MW of thermal baseload (mainly coal) capacity was placed in storage in 2013–14.

AEMO projected the NEM will have 7600–9000 MW of surplus generation capacity in 2014–15, with around 90 per cent located in NSW, Queensland and Victoria. For the first time in the NEM's history, no new capacity would be required in any NEM region to maintain supply–demand adequacy for the next 10 years. AEMO found, even with 10 consecutive years of demand growth, around 4500 MW of surplus generation capacity would be available in 2023–24 (figure 1.14). In particular, it pushed

22 AER, *State of the energy market 2013*, p. 28, table 1.3.

Figure 1.13
Major proposed generation investment, June 2014



Sources: AEMO; AER.

out its forecast timing of new generation requirements for Queensland by more than seven years compared with its forecasts 12 months earlier.[23]

Despite this trend, investment opportunities may still arise through schemes supporting renewable energy. South Australia, for example, has 16 wind farm proposals for the coming decade.[24]

1.6 Market structure of the generation sector

While the NEM operates as a single market, the pattern of generation ownership varies across regions and includes pockets of high concentration. Additionally, the trend of vertical integration among electricity generators, energy retailers and gas producers continues.

1.6.1 Generation ownership

Table 1.5 provides details of generators in the NEM, including the entities that control dispatch. Figure 1.4 identifies the location of each plant. The ownership arrangements in electricity generation vary markedly across regions. Private businesses own most generation capacity in Victoria, NSW and South Australia, while government owned corporations own or control the majority of capacity in Queensland and Tasmania.

Figure 1.15 illustrates generation market shares based on summer capacity under each firm's trading control in 2014. It includes import capacity from interconnectors, which provide some competitive constraint on regional generators in NSW, Victoria and South Australia (equivalent to 8–10 per cent of regional capacity). The constraint is less effective in Queensland, where import flows average less than 200 MW at times of high Queensland prices—equivalent to less than 2 per cent of regional capacity.

Box 1.3 Demand response mechanism

An alternative to generation investment is demand response, whereby energy users are incentivised to reduce consumption at times of peak demand. Customer participation in the NEM spot market is currently limited and available mainly to large customers. AEMO estimated around 206 MW of capacity would likely be available through demand-side participation across the NEM during summer 2014–15 when the spot price is above $1000 per MWh. Around 880 MW would be available when the spot price hits the cap. Forty per cent of the identified capacity was in Victoria.

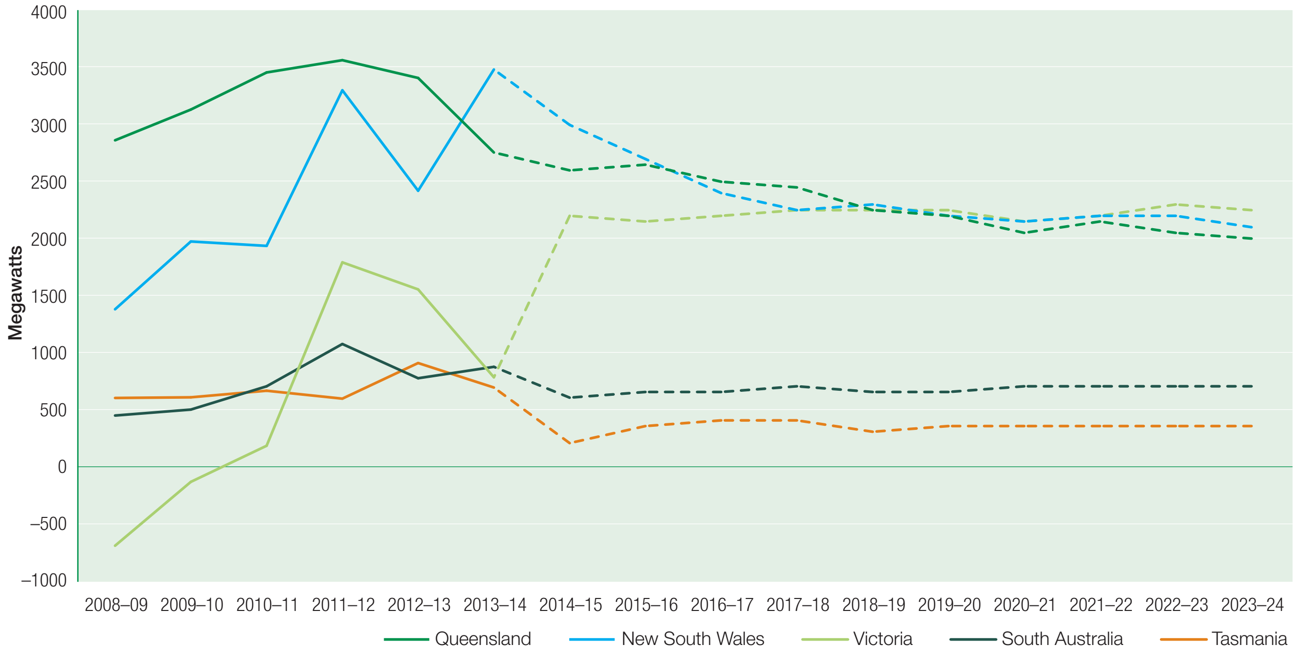
The AEMC's *Power of choice* review recommended allowing consumers to participate directly or via their agents in the spot market, and to receive payment from the market for reducing their electricity use on days of very high demand. Payments would be based on a consumer's reductions in demand against a predetermined baseline for that customer. The reforms are part of a suite of measures aimed at reducing costly investment in energy networks (section 2.6).

The CoAG Energy Council in 2013 directed AEMO to develop the necessary rule change proposals, including a method for determining baseline consumption. The new mechanism would enable energy service companies to compete with retailers in offering financial incentives for customers to reduce demand when spot prices are high. But in December 2013 the CoAG Energy Council noted ongoing weakness in electricity demand had reduced the need for new investment and, therefore, may mitigate some benefits of a demand response mechanism. In 2014 it commenced a cost–benefit study of the mechanism.

23 AEMO, *Electricity statement of opportunities 2014.*
24 AEMO, *Energy update*, August 2014.

Figure 1.14

Surplus generation capacity



Notes:

Historical data to 2013–14 reflect surplus of generation capacity (based on summer ratings) over maximum demand. AEMO forecasts beyond 2013–14 reflect capacity that could be removed while still meeting the reliability standard.

Forecast data based on a medium growth scenario with a 50 per cent probability that the forecast will be exceeded.

Wind contribution to capacity to 2013–14 based on summer ratings for semi-scheduled plant and registered capacity for non-scheduled plant. AEMO forecasts of wind capacity based on modeled contribution at times of peak demand.

Sources: AEMO, AER.

Regional analysis

In **Queensland**, state owned corporations Stanwell and CS Energy control 66 per cent of generation capacity, including power purchase agreements over privately owned capacity (such as the Gladstone power station). The degree of market concentration increased in 2011, when the Queensland Government dissolved the state owned Tarong Energy and reallocated its capacity to the remaining two state owned entities.

The Queensland Government in October 2014 announced policy under its *Strong Choices* plan to lease government owned electricity assets for 50 years, with options to extend for a further 49 years. The assets include state owned generators Stanwell and CS Energy, as well as transmission and distribution networks.

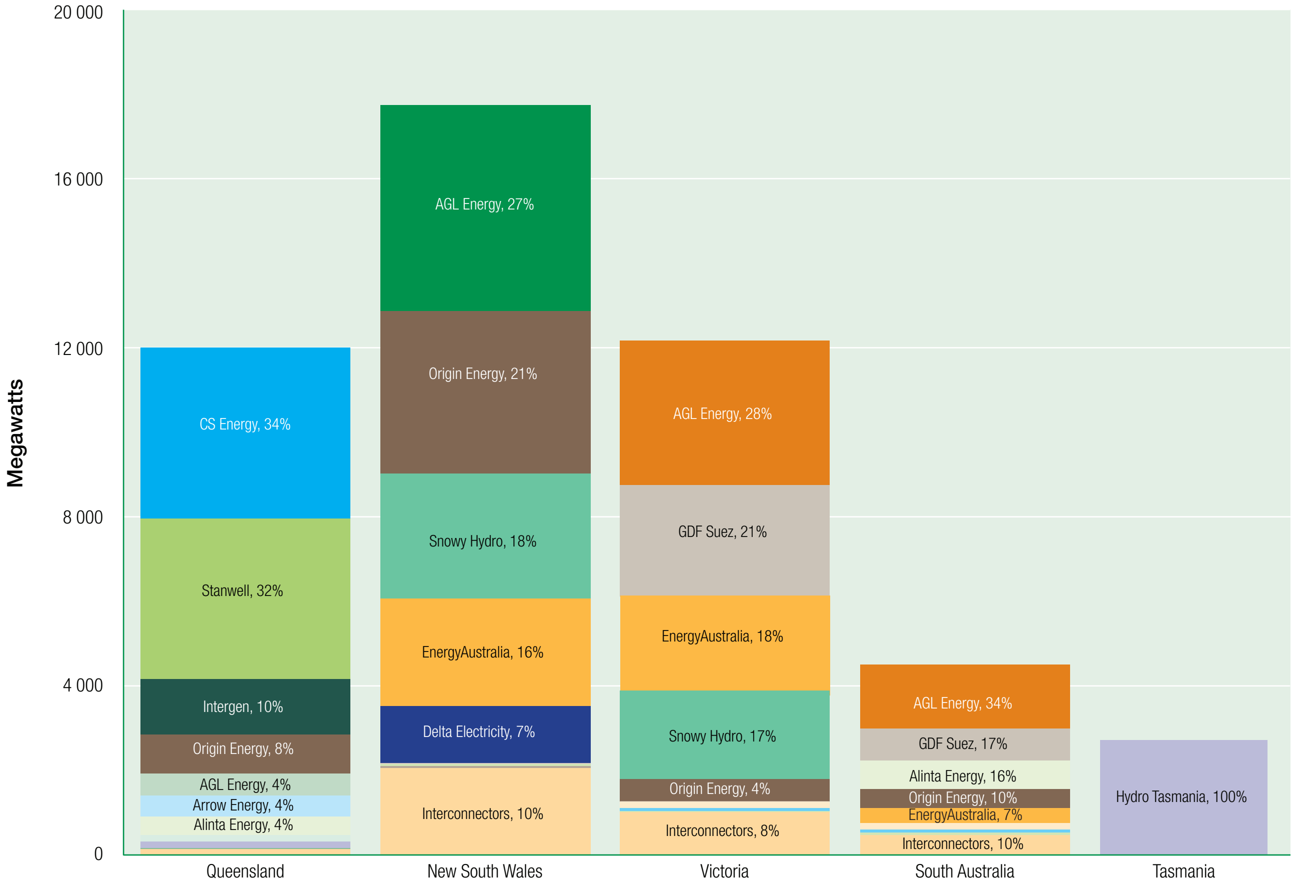
Currently, the largest private generators in Queensland are InterGen (10 per cent of statewide capacity) and Origin Energy (8 per cent).

In **NSW**, the privatisation of state owned generation businesses continued in 2014. The NSW Government in 2011 sold the electricity trading (gentrader) rights to around one-third of state owned capacity to EnergyAustralia (Delta West) and Origin Energy (Eraring Energy). The businesses acquired the plant underlying those contracts in August 2013.

A second round of privatisations began in late 2013, with Macquarie Generation and Delta Coastal portfolios offered for sale. AGL Energy acquired Macquarie Generation in September 2014. The ACCC opposed the sale, but its decision was overturned by the Australian Competition Tribunal, which found the public benefits of the acquisition outweighed any detriment to competition. In December 2014, Snowy Hydro acquired Delta Electricity's Colongra plant.

Following the sales, private entities control over 65 per cent of capacity available to NSW. They include AGL Energy (27 per cent), Origin Energy (21 per cent)

Figure 1.15
Market shares in generation capacity, 2014



Notes:

Capacity based on summer availability for January 2014, 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 exclude 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.

Source: AER.

and EnergyAustralia (16 per cent). Snowy Hydro's market share rose from 14 to 18 per cent.[25] The state owned Delta Electricity retained 7 per cent.

In **Victoria**, three private entities are the major players: AGL Energy (28 per cent of capacity), GDF Suez (21 per cent) and EnergyAustralia (18 per cent). Origin Energy has a 4 per cent share. The government owned Snowy Hydro has a 17 per cent market share.

In **South Australia**, AGL Energy is the dominant generator, with 34 per cent of capacity. Other significant entities are GDF Suez (17 per cent), Alinta (16 per cent), Origin Energy (10 per cent), EnergyAustralia (7 per cent) and Infigen (4 per cent). Snowy Hydro has around 130 MW of non-scheduled generation capacity following its acquisition of Lumo Energy from Infratil Energy in September 2014.

In **Tasmania**, the state owned Hydro Tasmania owns nearly all generation capacity, following a transfer of assets from Aurora Energy in June 2013. To encourage new entry into 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.

25 The NSW, Victorian and Australian governments jointly own Snowy Hydro.

Table 1.5 Generation capacity and ownership, 2014

TRADING RIGHTS	POWER STATIONS	CAPACITY (MW)	OWNER
QUEENSLAND (11 738 MW)			
Stanwell Corporation	Stanwell; Tarong; Tarong North; Barron Gorge; Kareeya; Mackay	3151	Stanwell Corporation (Qld Government)
CS Energy	Callide; Kogan Creek; Wivenhoe	1980	CS Energy (Qld Government)
CS Energy	Gladstone	1680	Rio Tinto 42.1%; NRG Energy 37.5%; others 20.4%
Origin Energy	Darling Downs; Mt Stuart; Roma	1018	Origin Energy
CS Energy / InterGen	Callide C	900	CS Energy (Qld Government) 50%; InterGen 50%
InterGen	Millmerran	760	InterGen (China Huaneng Group 50%; others 50%) 59%; Marubeni 30%; others 11%
Arrow Energy	Braemar 2	495	Arrow Energy (Shell 50%; PetroChina 50%)
Alinta Energy	Braemar 1	465	Alinta Energy
AGL Energy	Oakey	282	ERM Group
AGL Energy / Arrow Energy	Yabulu	235	RATCH Australia
RTA Yarwun	Yarwun	155	Rio Tinto Alcan
BG Group	Condamine	144	BG Group
CSR	Pioneer Sugar Mill; Invicta Sugar Mill	118	CSR
EDL Projects Australia	Moranbah North	63	EDL Projects Australia
Mackay Sugar Coop	Racecourse Mill	48	Racecourse Mill
AGL Energy	German Creek	45	AGL Energy
Ergon Energy	Barcaldine	34	Ergon Energy (Qld Government)
Essential Energy	Daandine	33	Arrow Energy (Shell 50%; PetroChina 50%)
National Power	Rocky Point	30	National Power
	Unscheduled plant < 30 MW	102	
NEW SOUTH WALES (16 254 MW)			
AGL Energy	Bayswater; Liddell; Hunter Valley	4764	AGL Energy
Origin Energy	Eraring; Shoalhaven; Uranquinty; Cullerin Range; Eraring	3832	Origin Energy
Snowy Hydro	Tumut; Upper Tumut; Colongra; Blowering; Guthega	3288	Snowy Hydro (NSW Government 58%; Vic Government 29%; Australian Government 13%)
EnergyAustralia	Mt Piper; Tallawarra	1775	EnergyAustralia (CLP Group)
Delta Electricity	Vales Point	1320	Delta Electricity (NSW Government)
Infigen Energy	Capital; Woodlawn	188	Infigen Energy
EnergyAustralia	Gullen Range	166	Goldwind
Marubeni Corporation	Smithfield Energy Facility	162	Marubeni Corporation
EDL Group	Appin; Tower	96	EDL Group
Capital Dynamics	Broadwater; Condong	68	Capital Dynamics
EnergyAustralia	Boco Rock	53	Electricity Generating Public Company
Essential Energy	Broken Hill	50	Essential Energy (NSW Government)
Acciona Energy	Gunning	47	Acciona Energy
Eraring Energy	Hume	29	Trustpower
	Unscheduled plant < 30 MW	416	
VICTORIA (11 896 MW)			
AGL Energy	Loy Yang A; Kiewa; Somerton; Eildon; Clover; Dartmouth; McKay	2906	AGL Energy
Snowy Hydro	Murray; Laverton North; Valley Power	2153	Snowy Hydro (NSW Government 58%; Vic Government 29%; Australian Government 13%)
GDF Suez	Hazelwood	1600	GDF Suez 72%; Mitsui 28%

TRADING RIGHTS	POWER STATIONS	CAPACITY (MW)	OWNER
EnergyAustralia	Yallourn; Longford	1431	EnergyAustralia (CLP Group)
GDF Suez	Loy Yang B	965	GDF Suez 70%; Mitsui 30%
EnergyAustralia	Jeeralang A and B; Newport	883	Industry Funds Management
Origin Energy	Mortlake	518	Origin Energy
AGL Energy	Macarthur	315	AGL Energy 50%; Malakoff Corporation Berhad 50%
Pacific Hydro	Yambuk; Challicum Hills; Portland	247	Pacific Hydro
Acciona Energy	Waubra	192	Acciona Energy
Alcoa	Angelsea	157	Alcoa
Meridian Energy	Mount Mercer	131	Meridian Energy
Hydro Tasmania	Bairnsdale	70	Alinta Energy
Energy Brix Australia	Energy Brix	65	HRL Group / Energy Brix Australia
AGL Energy	Oaklands Hill	47	Challenger Life
Eraring Energy	Hume	29	Trustpower
	Unscheduled plant < 30 MW	187	
SOUTH AUSTRALIA (4687 MW)			
AGL Energy	Torrens Island	1260	AGL Energy
GDF Suez	Pelican Point; Canunda; Dry Creek; Mintaro; Port Lincoln; Snuggery	790	GDF Suez 72%; Mitsui 28%
Alinta Energy	Northern	546	Alinta Energy
Origin Energy	Snowtown; Snowtown North; Snowtown South	369	Trustpower
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	175	ATCO 50%; Origin Energy 50%
AGL Energy	Hallett 2; Wattle Point	145	Energy Infrastructure Trust
EnergyAustralia	Waterloo	111	Palisade Investment Partners / Northleaf Capital Partners 75%; EnergyAustralia (CLP Group) 25%
Snowy Hydro	Pt Stanvac; Angaston	103	Snowy Hydro
AGL Energy	North Brown Hill	92	Energy Infrastructure Investments (Marubeni 50%; Osaka Gas 30%; APA Group 20%)
Essential Energy	Lake Bonney 1	81	Infigen Energy
AGL Energy	Hallett 1	71	Palisade Investment Partners
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
AGL Energy	The Bluff	39	Eurus Energy
Hydro Tasmania	Starfish Hill	35	RATCH Australia
	Unscheduled plant < 30 MW	43	
TASMANIA (2664 MW)			
Hydro Tasmania	Gordon; Poatina; Reece; John Butters; Tamar Valley; Bell Bay; others	2348	Hydro Tasmania (Tas Government)
Hydro Tasmania	Woolnorth; Musselroe	308	Shenhua Clean Energy 75%; Hydro Tasmania 25%
	Unscheduled plant < 30 MW	8	

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

Note: Capacity as published by AEMO for summer 2014–15, except for wind farms (registered capacity).

Sources: AEMO; AER.

1.6.2 Vertical integration

While governments structurally separated the energy supply industry in the 1990s, the trend has been for vertical re-integration of retailers and generators to form 'gentailer' structures. Vertical integration provides a means for generators and retailers to internally manage price risk in the spot market, reducing their need to participate in hedge (contract) markets (section 1.10). Less participation in contract markets can reduce liquidity in those markets, posing a potential barrier to entry and expansion for generators and retailers that are not vertically integrated.

Section 5.1.2 of the retail chapter details vertical integration in the NEM. In summary, three private businesses, AGL Energy, Origin Energy and EnergyAustralia:

- increased their market share in electricity generation from 15 per cent in 2009 to 46 per cent in 2014, largely through the acquisition of previously state owned generation in NSW. Over this period, Origin Energy also commissioned new power stations in Queensland and Victoria, and AGL Energy acquired full ownership of Loy Yang A in Victoria
- control 57 per cent of new thermal and hydro generation capacity commissioned in the NEM since 2009. Investment by entities that do not also retail energy has been negligible, except in wind generation
- supply over 75 per cent of energy retail customers. Origin Energy and EnergyAustralia acquired significant retail market share in NSW in 2010 following the privatisation of government owned retailers. AGL Energy acquired Australian Power & Gas (one of the largest independent retailers) in August 2013
- are expanding their interests in upstream gas production and storage.

Government owned generators are also vertically integrating. The generator Snowy Hydro owns Red Energy, and in September 2014 acquired Lumo Energy from Infratil Energy. The Tasmanian Government owns Hydro Tasmania, which is a generation business that also has a retail arm (Momentum Energy), and the stand-alone retailer Aurora Energy.

1.6.3 Potential for market power

High levels of market concentration and vertical integration between generators and retailers give rise to a market structure that may, in certain conditions, provide opportunities for the exercise of market power. Section 1.13 sets out metrics for analysing competitive conditions in electricity markets, and tracks recent data for the NEM.

In April 2013 the AEMC found potential for substantial market power to exist or be exercised in future in the NEM, particularly in South Australia. It recommended that Energy Ministers consider conferring on the AER powers to monitor the market for that possibility. In May 2013 the Ministers tasked officials with further work on the need for changes to the National Electricity Law, before concluding a policy position.[26]

1.7 How the NEM operates

Generators in the NEM sell electricity through a wholesale spot market in which changes in the supply–demand balance determine prices. The NEM is a gross pool, meaning all electricity sales must occur through the spot market. As an energy only market, it has no payments to generators for capacity or availability. The main customers are energy retailers, which pay for the electricity used by their business and household customers.

Registered generators make bids (offers) into the market to produce particular quantities of electricity at various prices for each of the five minute dispatch periods in a day. A generation business can offer its capacity across 10 different price levels of its choosing. It must lodge offers ahead of each trading day, but can change its offers (rebid) at any time, subject to those rebids being in 'good faith'. In rebidding, a generator may alter supply quantities at each price level, but cannot alter prices.

A range of factors, including plant technology, affect generator offers. Coal fired generators, for example, must account for the high start-up costs of their plant when submitting bids; they may offer to generate some electricity at low or negative prices to guarantee dispatch and to minimise the number of times they need to start up and shut down their plant.[27] Other generation technologies, such as gas powered generators, face higher fuel costs and typically offer to supply electricity at higher prices.

Bidding may also be affected by supply issues such as plant outages or constraints in the transmission network that limit transport capabilities. Some generators have a degree of market power in particular regions and periodically offer capacity at above competitive prices, knowing capacity must be dispatched if regional demand exceeds a certain level. This behaviour most commonly occurs at times of peak demand, often accompanied by generator outages or network constraints.

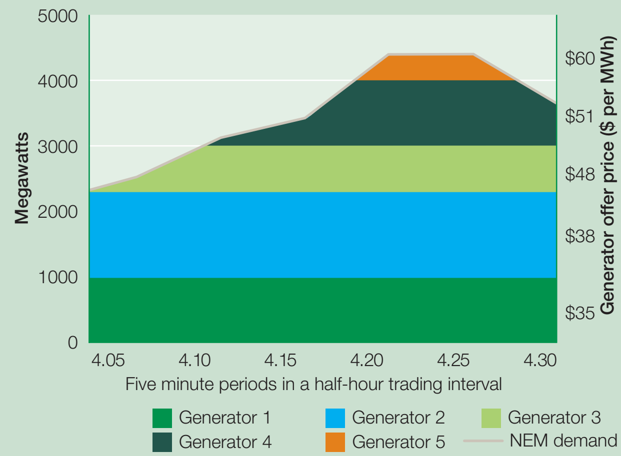
26 SCER, *Meeting communiqué*, Brisbane, 31 May 2013.
27 The price floor equals –$1000 per MWh.

Box 1.4 Setting the spot price in the NEM

Figure 1.16 illustrates a simplified bid stack in the NEM between 4.00 pm and 4.30 pm. Five generators are offering capacity into the market in different price ranges. At 4.15 pm the demand for electricity is about 3500 MW. To meet this demand, generators 1, 2 and 3 must be fully dispatched and generator 4 is partly dispatched. The dispatch price is $51 per MWh. By 4.20 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.

A wholesale spot price is determined for each half hour period (trading interval) and is the average of the five minute dispatch prices during that interval. In figure 1.16, the spot price in the 4.00–4.30 interval is about $54 per MWh. This is the price that all generators receive for their supply during this 30 minute period, and the price that customers pay in that period.

Figure 1.16
Generator bid stack



To determine which generators are dispatched, AEMO stacks the offer bids of all generators from the lowest to highest price offers for each five minute dispatch period. It dispatches the cheapest generator bids first, then progressively more expensive offers until enough electricity is dispatched to meet demand. The highest priced offer (the marginal offer) needed to meet demand sets the dispatch price. The wholesale spot price paid to generators is the average dispatch price over 30 minutes; all generators are paid at this price, regardless of the price that they bid (box 1.4).[28]

Movements in supply and demand set spot prices, which may range between –$1000 per MWh and a cap of $13 500 per MWh (raised from $13 100 per MWh on 1 July 2014). The cap is increased annually to reflect changes in the consumer price index. The AEMC assesses the cap every four years as part of its reviews of reliability standards and other market settings (section 1.12.1).

The market sets a separate spot price for each of the five NEM regions. Price separation of a region occurs when only local generation sources can meet an increase in demand—that is, network constraints prevent a neighbouring region from supplying additional electricity across a transmission interconnector. At other times, prices effectively align across regions, differing only marginally to account for physical losses in the transport of electricity over long distances. Allowing for these transmission losses, prices across the mainland regions of the NEM aligned for 83 per cent of the time in 2013–14, compared with 77 per cent in 2012–13 and 70 per cent in 2011–12.

1.8 Interregional trade

The NEM promotes efficient generator use by allowing electricity trade across the five regions, which transmission interconnectors link (figure 1.4). Trade enhances the reliability of the power system by allowing each region to draw on a wider pool of reserves to manage generator outages. Under the current market conditions of surplus generation capacity, trade also enhances opportunities for efficient dispatch by promoting competition and allowing high cost generating regions to import electricity from lower cost regions. The technical capabilities of cross-border interconnectors set upper limits on interregional trade. At times, network congestion constrains trading levels to below nominal interconnector capabilities.

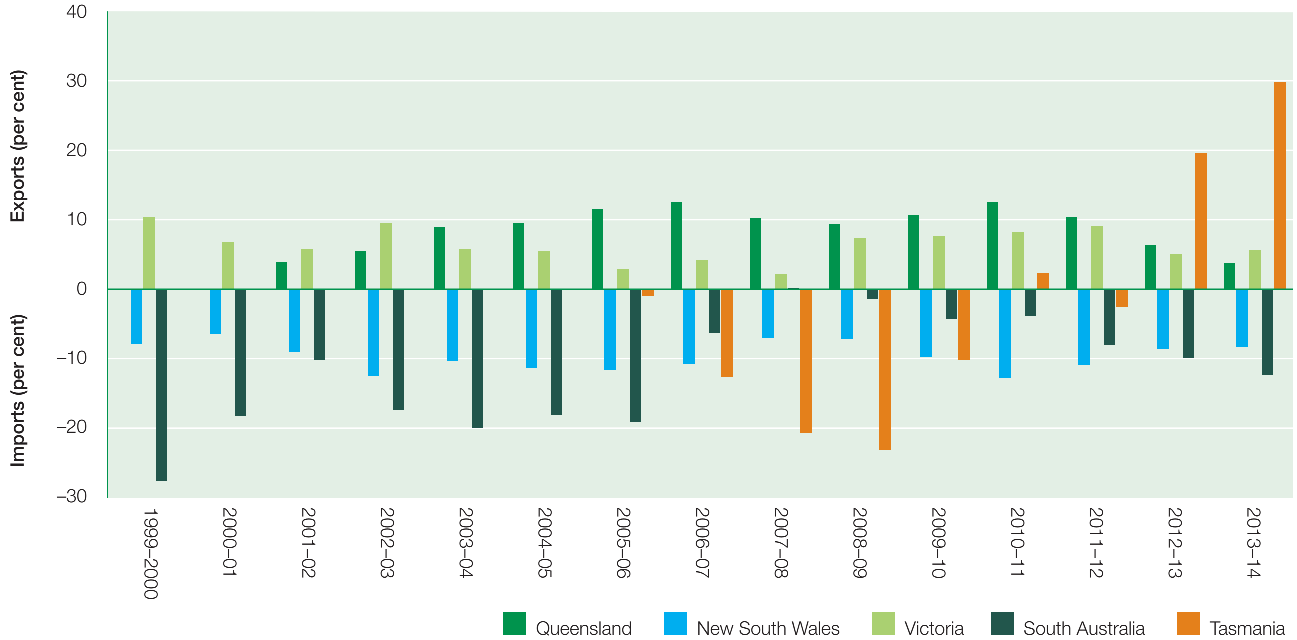
Figure 1.17 shows the net trading position of the five regions:

- Victoria has substantial low cost coal fired generation, making it a net exporter of electricity (particularly to NSW and South Australia). However, its exports to those regions in the past two years were partly offset by hydro generation imports from Tasmania.

28 Some generators bypass this central dispatch process, including some older wind generators, those not connected to a transmission network (for example, solar rooftop installations) and those producing exclusively for their own use (such as remote mining operations).

Figure 1.17

Interregional trade as a percentage of regional electricity demand



Sources: AEMO; AER.

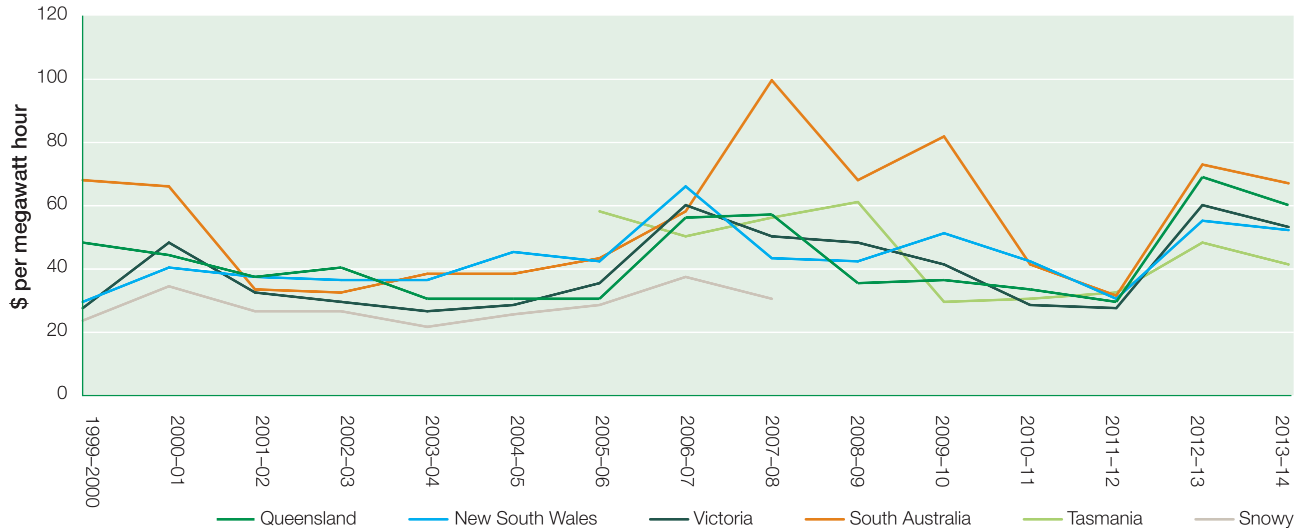
- Queensland's surplus capacity and low fuel prices make it a net exporter. Regional spot market instability over the past two years contributed to lower export volumes than in previous years, as noted below.
- NSW has relatively high fuel costs, making it a net importer of electricity.
- South Australia imported over 25 per cent of its energy requirements in the early years of the NEM, because it mainly relied on gas powered plant with significantly higher fuel costs than coal fired plant in neighbouring Victoria. While new investment in wind generation subsequently increased exports during low demand periods, commercial decisions to reduce plant availability caused imports to rise over the past two years. An expansion of the Heywood transmission interconnector between South Australia and Victoria (scheduled for July 2016) may allow South Australia to import greater volumes of energy at times of high demand, but it may also increase capacity to export wind generation.
- Tasmania has a volatile trade position, depending on market conditions for hydro generation. It has frequently been a net importer, notably when drought affected hydro generation in 2007–09. But the introduction of carbon pricing in July 2012 enhanced the competitiveness of hydro generation, resulting in Tasmania becoming a major net exporter. In 2013–14 it recorded the highest ratio of exports to regional demand for any region since the NEM commenced.

Network congestion periodically inhibits efficient trade by constraining electricity flows from low to high price regions. At times, counter-price flows occur, with electricity being exported from high to low price regions. Counter-price flows create market distortions that damage interregional trade and impose costs on consumers.

All regions of the NEM have been affected by counter-price flows at one time or another. The AER reported network congestion and disorderly generator bidding in Queensland in 2012–13 caused inefficient trade flows, as reflected in a decline in Queensland exports.[29] In December 2013 NSW generators bid in reaction to network congestion in Victoria, again causing electricity to flow from a high to low price region (section 1.9.4).

29 AER, *State of the energy market 2013*, pp. 39–42.

Figure 1.18
Annual spot electricity prices



Notes:
Volume weighted average prices.
Tasmania entered the market on 29 May 2005. The Snowy region was abolished on 1 July 2008.
Sources: AEMO; AER.

1.9 Electricity spot prices

The AER monitors the spot market and reports weekly on activity. Figure 1.18 sets out annual average spot prices, while figure 1.19 charts quarterly average prices, illustrating seasonal movements. Figure 1.20 provides a snapshot of weekly prices.

1.9.1 Historical price trends

Escalating electricity demand combined with drought to cause electricity prices to peak across most regions during 2006–08. The AER also reported evidence of the periodic exercise of market power affecting spot prices in this period. The rising uptake of renewable generation (mostly wind) from 2009–10 coincided with energy demand plateauing and then falling, causing spot prices to fall to historical lows in 2011–12 (figure 1.18).

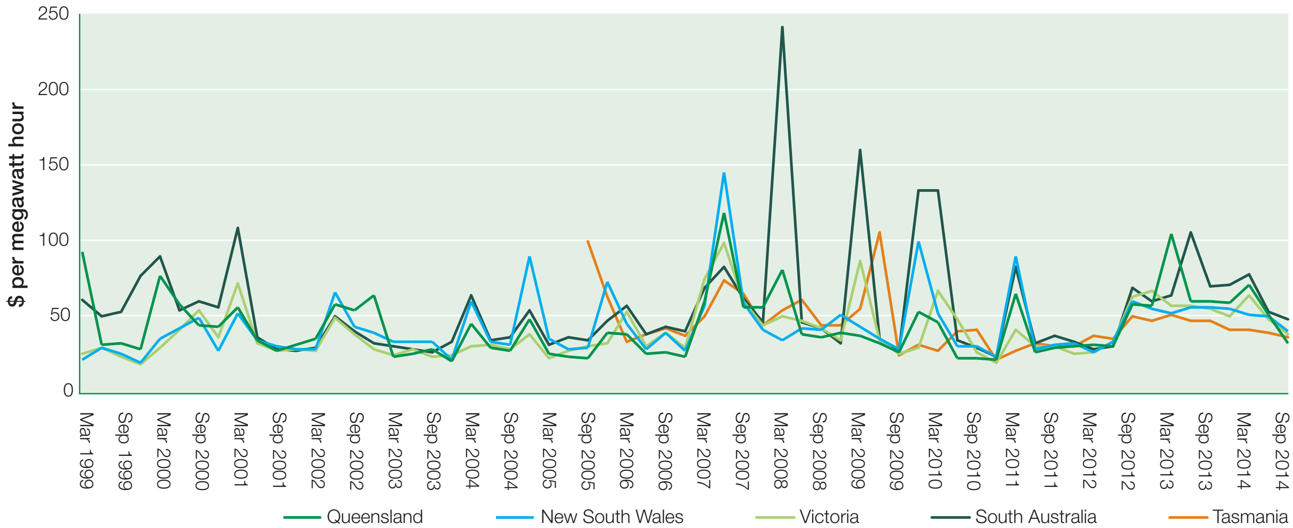
The introduction of carbon pricing on 1 July 2012 at $23 per tonne of emissions caused a reversal in this trend. After some initial volatility, the average NEM spot price (filtered for extreme price events) in the months following the introduction of carbon pricing settled around $21 per MWh above the average price for June 2012.

While a range of factors influence wholesale spot prices—including demand, generation availability, solar production, fuel costs and hedge contract positions—carbon costs clearly contributed to the higher spot prices. The AER estimated for 2012–13 that the average flow through to spot prices required to cover carbon costs of the marginal generator was $17.70 per MWh on the mainland, but $10 per MWh in Tasmania (reflecting that region's high concentration of hydro generation).

But average prices for 2012–13 rose across the NEM by $31 per MWh compared with the previous year, with higher increases in South Australia and Queensland. Factors unrelated to carbon pricing contributed to these outcomes. In Queensland, transmission network congestion precipitated generator bidding patterns that caused high prices in August–October 2012 and January 2013. In South Australia, commercial decisions to reduce plant availability contributed to lower reserves at times, enabling opportunistic bidding by major generators during April–May 2013.[30] The price peaks associated with these events in Queensland and South Australia are evident in figures 1.19 and 1.20.

30 AER, *State of the energy market 2013*, pp. 39–43.

Figure 1.19
Quarterly spot electricity prices



Note: Volume weighted average prices.
Sources: AEMO; AER.

1.9.2 The market in 2013–14

Spot prices eased across all regions in 2013–14, with falls ranging from 5 per cent (NSW) to over 13 per cent (Queensland and Tasmania). On average, volume weighted prices fell across the NEM by 10 per cent compared with the previous year.

Declining electricity demand and the continued uptake of renewable generation, including large scale wind and domestic solar PV generation, contributed to these outcomes. The weakening in Queensland prices partly reflects the resolution of some network congestion (and associated opportunistic bidding) issues affecting the region in 2012–13. But market volatility over summer 2013–14 meant that annual average prices were 14 per cent higher in Queensland than NSW, after previously being lower for several years (section 1.9.5).

The constrained supply conditions and opportunistic generator bidding that affected South Australian prices during autumn 2013 did not widely recur in 2013–14, contributing to spot prices easing by 8 per cent. But, despite having the highest penetration of wind and solar generation of any region, South Australian spot prices continued to be the highest in the NEM, averaging $68 per MWh. In part, this outcome results from the region relying on relatively high cost gas powered generation, and having the highest load factor (ratio of peak to average demand) of any region (section 1.1.1).

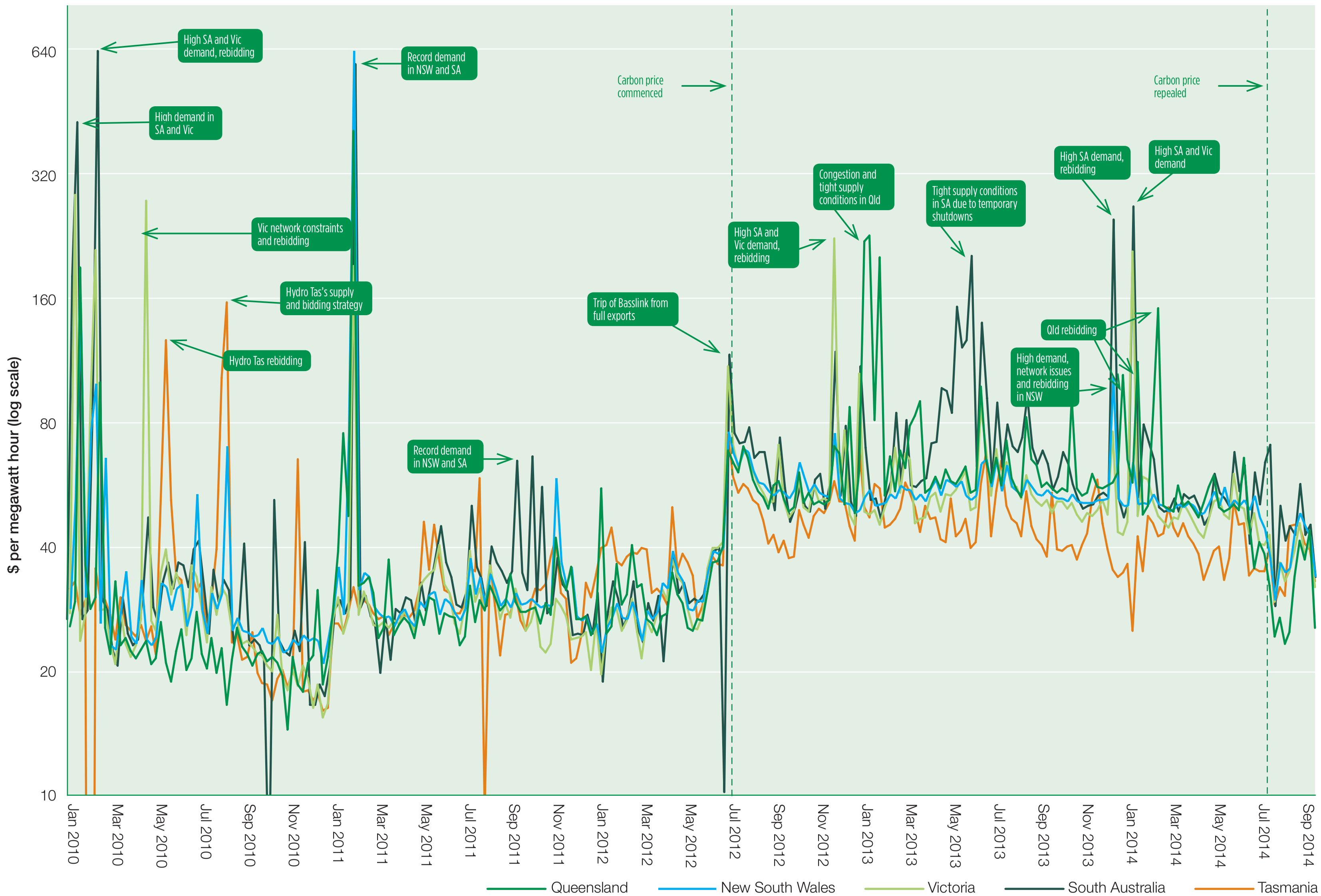
South Australia recorded the year's highest weekly prices ($244 per MWh for the week from 15 December 2013 and $264 per MWh for the week from 12 January 2014). The December price occurred in a week with the hottest December day since 1931, and the January price occurred during one of south east Australia's most intense heatwaves on record.[31] That heatwave also caused Victorian weekly prices to average $204 per MWh in the same week (section 1.9.4).

Generator rebidding contributed to these summer price spikes, although less so than in previous years. It also affected spot prices in the week commencing 15 December 2013 in NSW (section 1.9.4).

For the second year in a row, Tasmania recorded the lowest average spot price in the NEM ($42 per MWh), reflecting high levels of hydro generation output, which incurred no carbon liability. But the region also recorded a number of negative spot prices.

31 Bureau of Meteorology, *Seasonal climate summary for Australia, summer 2013–14*.

Figure 1.20
Weekly spot electricity prices



CPT, cumulative price threshold.

Note: Volume weighted average prices.

Source: AER.

Table 1.6 Monthly spot prices, June–September 2014 ($ per MWh)

	QUEENSLAND	NSW	VICTORIA	SOUTH AUSTRALIA	TASMANIA
June 2014	52	50	50	56	43
July 2014	34	42	40	55	34
August 2014	27	37	36	44	37
September 2014	35	41	38	43	38

Note: Monthly volume weighted averages.

Sources: AEMO; AER.

1.9.3 Repeal of carbon pricing

Under the carbon price regime operating from 1 July 2012 to 1 July 2014, generators incurred a carbon liability based on their output and the carbon intensity of their plant. Generators sought to recover the cost of this liability by factoring it into their bids in the spot market and through provisions in hedge contracts.

Following the repeal of carbon pricing on 1 July 2014, spot prices fell during the third quarter (1 July to 30 September 2014), most notably in Queensland. The monthly averages for July 2014 were the lowest since May 2012 for Queensland, and the lowest since June 2012 for NSW and Victoria. Monthly averages for August were lower again in all regions except Tasmania. Prices in September 2014 rebounded towards their July levels in most regions (table 1.6).

Overall, while prices trended downwards during the third quarter 2014, week-to-week prices were volatile (figure 1.21). Lower prices in Queensland, NSW and Victoria from June–August 2014 reflected baseload power stations bidding greater capacity into the market at lower prices. While various factors might have contributed, the repeal of carbon pricing was likely a significant influence on this bidding behaviour. The higher September prices appear to reflect tighter supply–demand conditions, particularly early in the month. But prices fell sharply from late September 2014, especially in Queensland, when a collapse in spot gas prices triggered a surge in gas powered generation and low electricity spot prices (figure 7 in *Market overview*).

1.9.4 Price volatility in the NEM

Price volatility has been a feature of the NEM since its commencement, although the nature of that volatility is evolving. A relatively tight supply–demand balance contributed to an escalating trend of 30 minute spot prices above $5000 per MWh for several years from 2004–05, peaking at 95 events in 2009–10. Subsequently, declining electricity demand and the rising penetration of renewable generation caused surplus capacity in most regions, resulting in a significant reduction in such extreme prices. Only one such event occurred in 2011–12, then four events in 2012–13.

Five spot prices were above $5000 per MWh in 2013–14:

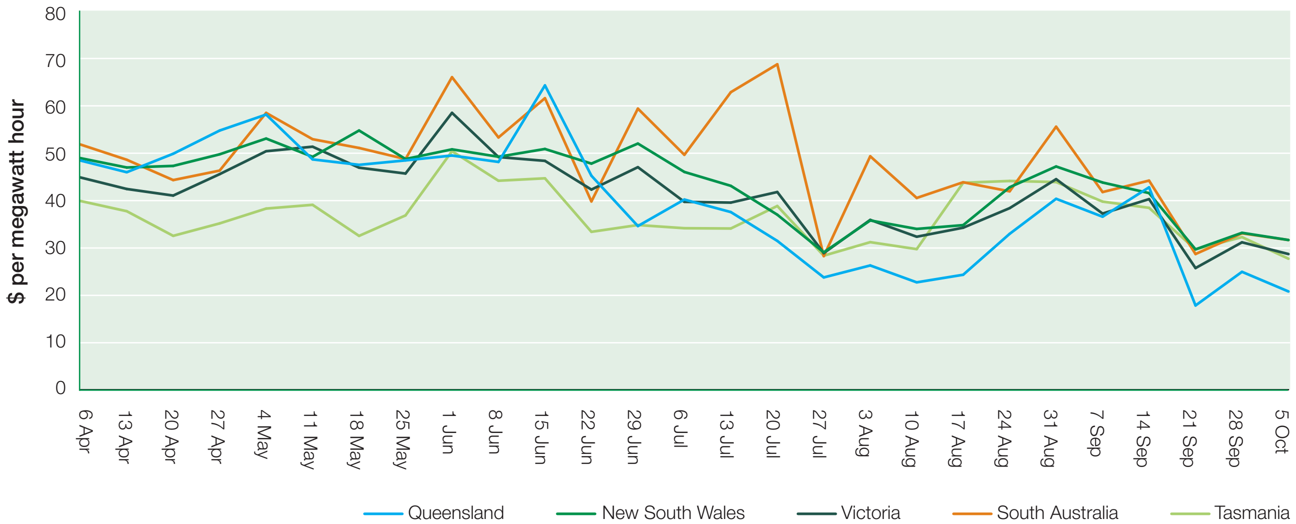
- In NSW, the spot price at 1.30 pm on 20 December 2013 was $7696 per MWh. Overall, the five minute dispatch price exceeded $5000 per MWh eight times between 1.30 pm and 2.30 pm. A key contributing factor was high temperatures (reaching 41 degrees) that drove above-forecast demand at a time when unplanned generator outages had reduced available capacity. At the same time, network congestion in Victoria triggered rebidding by Snowy Hydro to reduce output from its Victorian plant, requiring NSW to export electricity to meet demand in northern Victoria. These counter-price trade flows further tightened the supply–demand balance in NSW, driving local prices even higher.[32]

  This event is one of many instances in recent years of generators causing counter-price electricity flows from high priced to low priced regions.
- South Australia recorded spot prices on 19 December 2013 of $10 627 per MWh at 4 pm and $5640 per MWh at 4.30 pm. The prices were not forecast. Overall, South Australia recorded 17 five minute dispatch prices above $10 000 per MWh that afternoon. High demand due to extreme heat was a key contributor—it was the third hottest December day on record. A plant outage, a lower than forecast contribution from wind and constraints limiting interconnector import flows also contributed to tight supply conditions. Rebidding by generators during the afternoon, particularly by AGL Energy and GDF Suez, was also an important factor. The generators shifted

32 AER, *Electricity spot prices above $5000 per MWh, 20 December 2013: NSW.*

Figure 1.21

Weekly NEM spot prices, April–September 2014



Note: Weekly volume weighted averages.

Sources: AEMO; AER.

significant capacity from under $300 per MWh to prices at or near the cap.[33]

- South Australia and Victoria experienced coincident events at 4 pm on 15 January 2014, with a spot price of $6213 per MWh in South Australia and $5972 per MWh in Victoria. The prices were lower than forecast and occurred during one of south east Australia's most intense heatwaves on record. Spare generation capacity was extremely tight on the day, with AEMO issuing warnings of possible shortages to meet demand in both regions, and the possibility of interrupting supply to maintain system security (section 1.12.2). During the 4 pm interval, an absence of capacity priced from $100–8000 per MWh meant a small change in demand, a small reduction in import capacity from Tasmania, and some generator rebidding combined to cause prices to spike. Solar PV generation helped delay these price impacts until later in the day than otherwise might have occurred, although cloudy conditions inhibited the solar contribution to some extent.[34]

Additionally, South Australia experienced a price event above $5000 per MW in ancillary service markets, on 1 October 2013. During the day, transmission network outages in Victoria caused a rise in exports from South Australia to Victoria, requiring intervention to manage frequency control and voltage stability. In combination, these factors increased the requirement for local frequency control services in South Australia, which could be satisfied only by high priced offers; the price for 'lower 60 second' services and 'lower 6 second' services exceeded $5000 MWh for nine consecutive five minute intervals. The spikes led to a total cost on the day of $1.6 million, compared with less than $3000 for each service on a typical day. South Australian consumers met this cost.[35]

While prices spike above $5000 per MWh less frequently than in the past, greater volatility in lower price bands has a cumulative effect on prices. In 2012–13 the market recorded 704 prices above $200 per MWh (for a 30 minute trading interval)—the highest for seven years (figure 1.22). More stable market conditions led a reduction to 297 events in 2013–14, with around 44 per cent of those events occurring in South Australia. Several events in South Australia and Victoria were associated with heatwave conditions during January 2014. Queensland recorded 73 prices above $200 per MWh, of which some were linked to opportunistic generator bidding behaviour (section 1.9.5).

Market volatility can also result in negative spot prices. The incidence of negative prices greater than –$100 fell

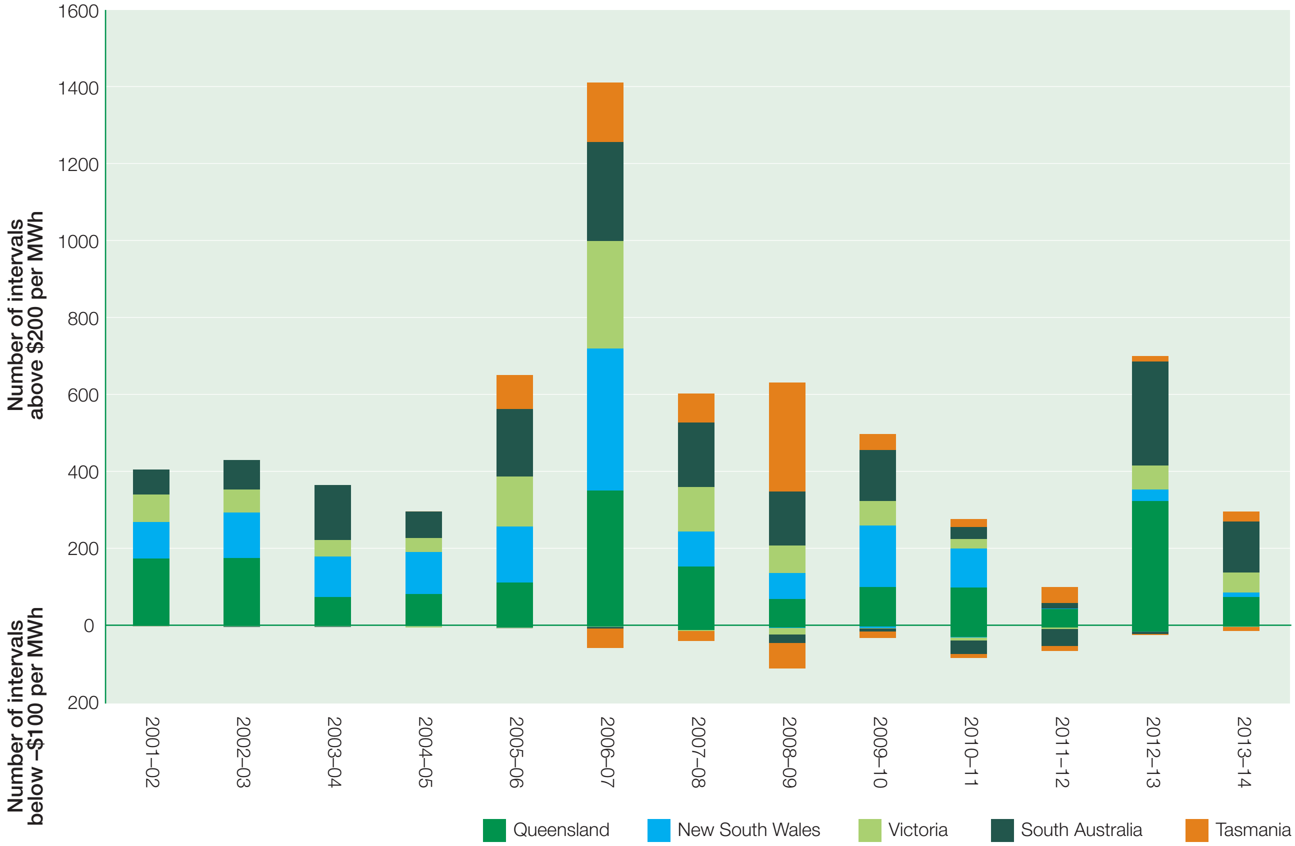
33 AER, *Electricity spot prices above $5000 per MWh, 19 December 2013: South Australia*.

34 AER, *Electricity spot prices above $5000 per MWh, 15 January 2014: South Australia and Victoria*.

35 AER, *Market ancillary service prices above $5000 per MW: 1 October 2013*.

Figure 1.22

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



Sources: AEMO; AER.

in 2013–14 to 13 events. Most of the events occurred in Tasmania. The AER analyses all spot prices below –$100 per MWh in its weekly market reports.

1.9.5 Price volatility in Queensland

An interplay of transmission network congestion and opportunistic generator bidding led to spot market volatility in Queensland in August–October 2012 and again in January 2013. In particular, network congestion around Gladstone enabled opportunistic bidding by CS Energy, causing price spikes in Queensland and forcing counter-price trade flows into NSW.[36]

The construction of a new transmission line between Gladstone and Stanwell (completed late 2013) built out the congestion that made this bidding activity possible. But other types of market inefficiency were evident in Queensland in 2013–14. In August–September 2013 Queensland experienced a series of price spikes driven by relatively small increases in five minute demand that could be met only by the dispatch of plant at around the price cap. Typically, the spikes occurred at times of relatively low demand, but when import capacity from NSW was constrained.

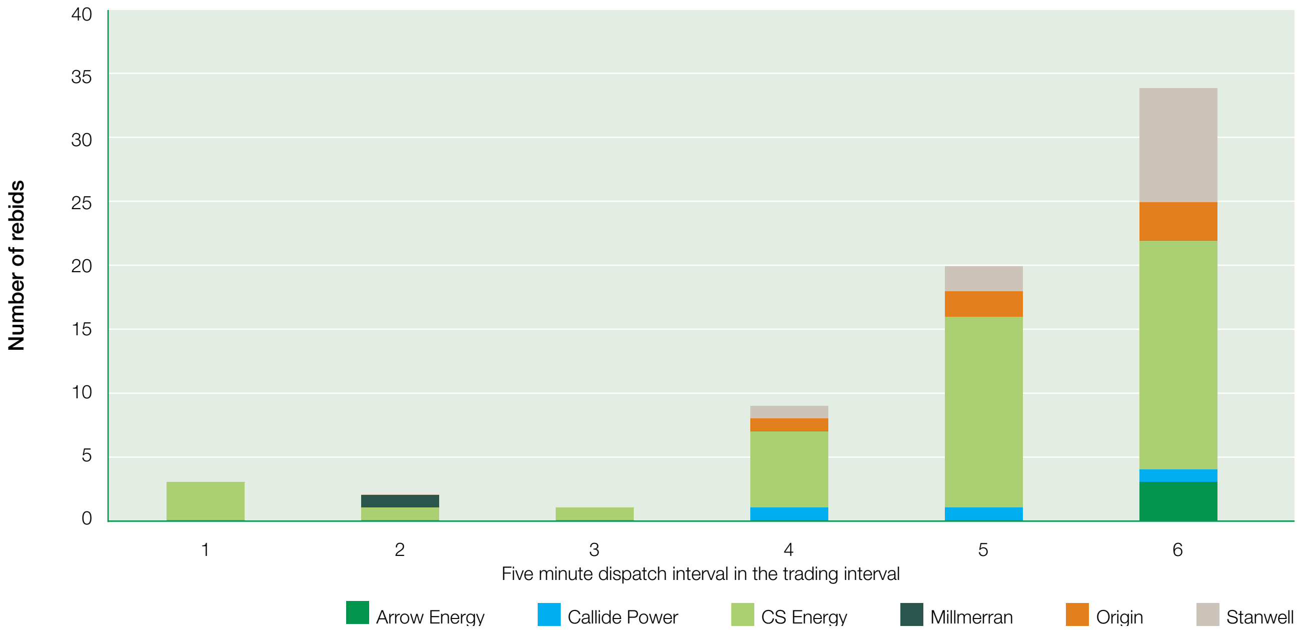
Queensland again experienced significant market volatility during summer 2013–14, when the five minute dispatch price exceeded $1000 per MWh on 50 occasions. The rebidding strategies of some Queensland generators caused this volatility. Generators rebid capacity from lower to higher price bands during each affected trading interval. Demand and generation plant availability were within forecasts on each occasion, and pre-dispatch forecasts did not predict the price spikes.[37]

36 AER, *State of the energy market 2013*, pp. 39–42.

37 AER, *Electricity report 23 February to 1 March 2014*.

Figure 1.23

Timing and maker of significant rebids, Queensland, summer 2013–14



Note: Rebids with volume shifts above 100 MW for trading intervals with dispatch prices above $1000 per MWh.

Source: AER.

Most rebids occurred late in the 30 minute trading interval and applied for very short periods of time (usually five to 10 minutes), allowing other participants little, if any, time to make a competitive response. CS Energy was by far the most active player rebidding capacity into high price bands (above $10 000 per MWh) close to dispatch (figure 1.23). Towards the end of the summer, other participants similarly rebid capacity from low to high prices, causing prices to spike more frequently.

The behaviour compromised the efficiency of dispatch, causing prices to spike independently of underlying supply–demand conditions. The average Queensland price for summer 2013–14 was $68.77 per MWh. Had the short term price spikes not occurred, the average price would have been 18 per cent lower at $56.10 per MWh. The increase represents a wealth transfer of almost $200 million based on energy traded. More generally, spot price volatility puts upward pressure on forward contract prices, which ultimately flows through to consumers' energy bills.

The AER in 2014 drew on its analysis of rebidding activity in Queensland to support a proposal by the South Australian Minister for Mineral Resources and Energy to strengthen and clarify the rebidding in good faith provisions in the National Electricity Rules (box 1.5 and section 1.11).

1.10 Electricity contract markets

Volatility in electricity spot prices can pose significant risks to market participants. While generators face a risk of low spot prices reducing their earnings, retailers face a risk of spot prices rising to levels that they cannot pass on to their customers. Market participants commonly manage their exposure to forward price risk by entering hedge contracts (derivatives) that lock in firm prices for the electricity they intend to produce or buy. The participants in electricity derivatives markets include generators, retailers, financial intermediaries and speculators such as hedge funds. Brokers facilitate many transactions between contracting participants.

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

- over-the-counter (OTC) markets, comprising direct contracting between counterparties, often assisted by a broker

Box 1.5 AER rebid index

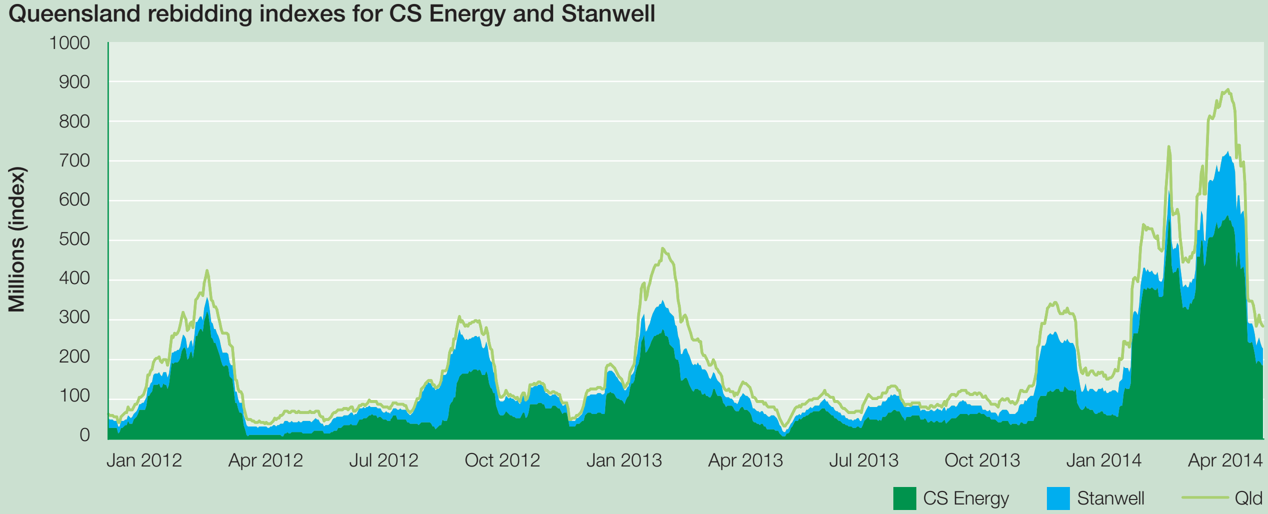
The AER's rebid index assesses the impact of rebidding on efficient market outcomes.[38] It accounts for the frequency of rebidding, relative changes in capacity and offer price, and the time in which a competitive response can occur. The index reflects the change in the value of energy shifted in a rebid, against the number of dispatch intervals to the end of the trading interval. Below are examples:

- A rebid that shifts 500 MW by $10 per MWh is given equal weight with a rebid that shifts 100 MW by $50 per MWh.
- A rebid made two hours before dispatch is given greater weight than an equivalent rebid made four hours before dispatch.
- A rebid made at the start of a trading interval is given less weight than one made later, given the market has more time to react to the information.

Higher index levels reflect more volatile rebidding and less dependable market forecasts. Allowing for load growth, changes in ownership and increases in the number of participants, the index shows rebidding activity in the NEM rose markedly after December 2011. In particular, the Queensland index has accelerated (figure 1.24) and is significantly higher than the index for other regions. The rise for Queensland began soon after the Federal Court's *AER v. Stanwell* decision (August 2011) and a consolidation of the Queensland Government's generation portfolio from three to two businesses (July 2011).[39]

The 28 day rolling rebidding index for the Queensland region and for CS Energy and Stanwell (previously named in AER reports as contributing to high price events) shows a significant spike in the intensity of rebidding activity from January 2014.

Figure 1.24
Queensland rebidding indexes for CS Energy and Stanwell



Note: 28 day rolling averages.

Source: AER.

38 Outlined in AER, *Submission: National Electricity amendment—bidding in good faith*, May 2014, pp. 5–9.

39 AER, *Submission: National Electricity amendment—bidding in good faith*, May 2014, pp. 5–9.

- 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.

The terms and conditions of OTC contracts are confidential between the parties. But exchange trades are publicly reported, so have greater market transparency than do OTC contracts. Unlike OTC transactions, 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 being cleared and registered via block trading on the ASX.

Electricity derivatives markets support a range of products. 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.

Electricity derivatives markets are subject to a regulatory framework that includes the *Corporations Act 2001* (Cwlth) and the *Financial Services Reform Act 2001* (Cwlth). The Australian Securities and Investments Commission is the principal regulatory agency.

The complex financial relationships among generators, retailers and other businesses create financial interdependency, meaning financial difficulties for one participant can affect others. The AEMC investigated ways to mitigate risk from the financial distress or failure of a large electricity business. One consideration was the possible application of Australia's G20 commitments on OTC derivatives to the electricity sector. The reforms aim to reduce the risk of financial system instability arising from counterparty default, and to increase transparency about OTC market activity. They include the reporting of OTC derivatives to trade repositories, and obligations on the clearing and execution of standardised derivatives.

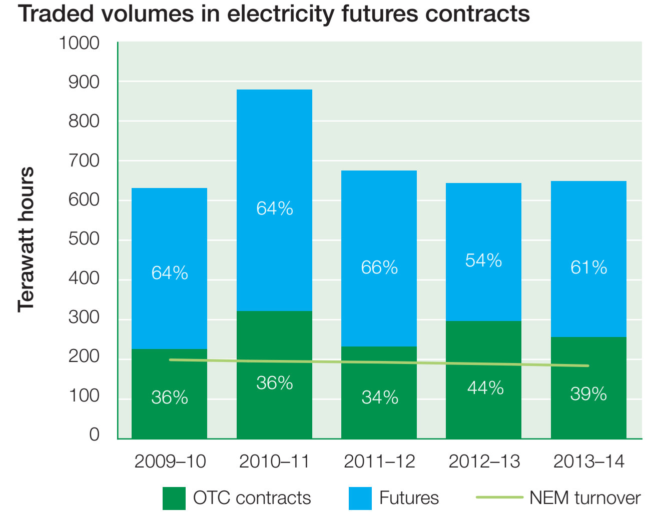
The AEMC published draft advice in August 2014 that the costs of applying the G20 measures to the electricity sector would, at present, outweigh any benefits. It found the reforms would place significant costs and regulatory burdens on participants, and mandatory central clearing could discourage the use of OTCs as a hedging instrument. It argued the development of electronic trading platforms should be driven by participants' demand for such services rather than by mandated use of such platforms.[40]

1.10.1 Contract market activity

In 2013–14 contracts covering 638 TWh of electricity were traded in the NEM, comprising 387 TWh traded on the ASX and 251 TWh in OTC markets (figure 1.25). Trading volumes were 32 per cent below their 2010–11 peak, but up marginally on 2012–13 levels. Overall trading volumes were down from a peak of 450 per cent of underlying NEM demand in 2010–11 to 360 per cent in 2013–14.

Figure 1.25

Traded volumes in electricity futures contracts



Sources: AFMA; ASX Energy.

Shifts between ASX and OTC trading have been significant in recent years. The Australian Financial Markets

40 AEMC, *NEM financial market resilience, second interim report*, 14 August 2014.

Table installation at Nyngan Solar Plant (AGL Energy)

Association's (AFMA) addendum to manage the risks of carbon price movements drew significant turnover from the ASX to OTC markets in 2012–13. But this shift reversed in 2013–14, with a 16 per cent fall in OTC volumes offset by a 13 per cent rise in ASX volumes. AFMA attributed this decline in OTC liquidity to uncertainty about carbon pricing (including the prospect of a retrospective repeal) and the continued decline in electricity demand. It argued the sale of generation assets in NSW and Queensland could negatively impact on liquidity in future years if it leads to further vertical integration between the generation and retail sectors.[41]

Electricity futures trading covers instruments for Victoria, NSW, Queensland and South Australia. NSW accounted for 37 per cent of ASX traded volumes in 2013–14, followed by Victoria (33 per cent) and Queensland (27 per cent). Liquidity in South Australia was low, accounting for only 3 per cent. In the OTC market, Queensland accounted for 40 per cent of traded volumes, followed by NSW (34 per cent), Victoria (24 per cent) and South Australia (2 per cent).

While the most heavily traded ASX products in 2013–14 were base futures (52 per cent of volumes), the strongest growth in that year was in options (37 per cent, up from 27 per cent in 2012–13). Cap futures accounted for 11 per cent of trade volume. By contrast, in the OTC market, swaps accounted for almost 80 per cent of trade.

Liquidity is mostly in products traded 18–24 months out—for example, open interest in forward contracts at September 2014 was mostly for quarters to the end of 2015–16, with little liquidity into 2016–17 (figure 1.26).

1.10.2 Contract prices

Fluctuations in futures prices reflect changing expectations of the cost of underlying wholesale electricity. Figure 1.27 shows prices of electricity base futures contracts for calendar years 2014 and 2015, based on average daily settlement prices for the four quarters of the year.

In recent years, uncertainty about government policy on carbon pricing caused contract prices to fluctuate. Base futures prices peaked before the federal election in September 2013, then steadily declined in line with expectations that the Coalition Government would repeal carbon pricing from 1 July 2014. A continuing trend of declining energy demand and subdued peak demand (despite a heatwave in south east Australia in January 2014) contributed to a further weakening of contract prices during 2014. Overall, base futures prices for calendar year 2015 fell most significantly in NSW and Victoria (22 per cent and 23 per cent respectively), followed by Queensland (11 per cent) and South Australia (7 per cent). Prices then stabilised or rose from July 2014, indicating the contract market had fully factored in the carbon repeal (figure 1.27).[42]

At September 2014, reflecting market expectations that electricity prices will rise from their current low base, forward contracts are trading in contango—that is, quarter 1 (January to March) prices are higher in later years than for the upcoming year. This trend is most apparent for Queensland and South Australia (figure 1.28). Queensland prices likely reflect market concerns about recent spot market volatility (section 1.9.5) and forecasts of rising electricity demand associated with LNG developments in that region. South Australia's relatively high contract prices mirror the spot market, in which the region has recorded the highest prices among NEM regions for the past four years. Liquidity for South Australian contracts is also low, partly reflecting a concentrated generation sector and some recent market instability.

1.11 Improving market efficiency

The AER engages with the AEMC on rule change processes aimed at improving market efficiency in the NEM. It may initiate these matters, or engage in processes initiated by third parties. Two recent processes (both ongoing in October 2014) related to the rules governing bidding in good faith and generator ramp rates.

The AER also takes enforcement action against market participants in alleged breach of the National Electricity Rules. Failure to comply with the rules can impair market efficiency. In 2014 the AER instituted proceedings in the Federal Court against a generator for allegedly failing to follow dispatch instructions issued by AEMO.

1.11.1 Rebidding in good faith

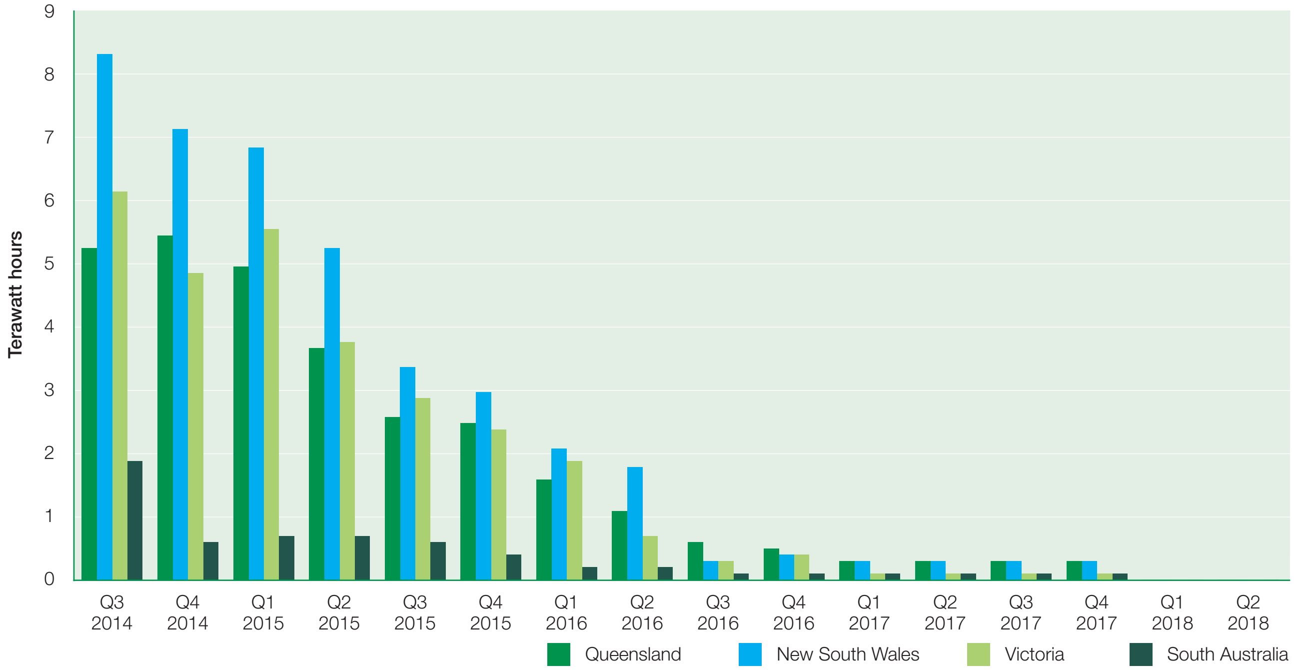
The AER in 2014 supported a proposal by the South Australian Minister for Minister for Mineral Resources and Energy to strengthen and clarify the rebidding in good faith provisions in the National Electricity Rules.[43] The AER argued a recent rise in the incidence of late rebidding was

41 AFMA, *2014 Australian financial markets report*.

42 In the OTC market, carbon costs were incorporated in contracts in a variety of ways, with many including an addendum developed by AFMA. The addendum calculated a carbon uplift by multiplying the carbon reference price by the NEM's average carbon intensity (published by AEMO). In June 2014 AFMA set the carbon reference price to $0 from 1 July 2014.

43 AER, *Submission: National Electricity amendment—bidding in good faith*, May 2014.

Figure 1.26
Open interest in electricity derivatives on the ASX, September 2014



Source: ASX Energy.

making forecast information in the NEM less dependable, impacting on market efficiency.

The rules require a generator, at the time of making a bid, to have a genuine intention to honour the bid if the material conditions and circumstances upon which it was based remain unchanged. The AER is responsible for ensuring compliance with the good faith provisions.

The rule change request does not represent a wholesale change to the 'good faith' provisions, but a refinement designed to ensure the original policy intent is met. The provision was originally introduced to improve the reliability of information, including price forecasts, necessary for the efficient operation of a wholesale electricity market such as the NEM, where commitment and investment decisions are decentralised and left to market participants.

The AEMC expected to publish a draft determination on the proposal in April 2015.

1.11.2 Generator ramp rates

The effects of late rebidding on price and market efficiency would be mitigated if the output of competing generators could adjust more quickly. In 2013 the AER proposed a rule change that generators' ramp rates—the minimum rates at which generators may adjust output—reflect the technical capabilities that the plant can safely achieve at the time. Currently, the minimum rate is 3 MW per minute or 3 per cent for generators under 100 MW.

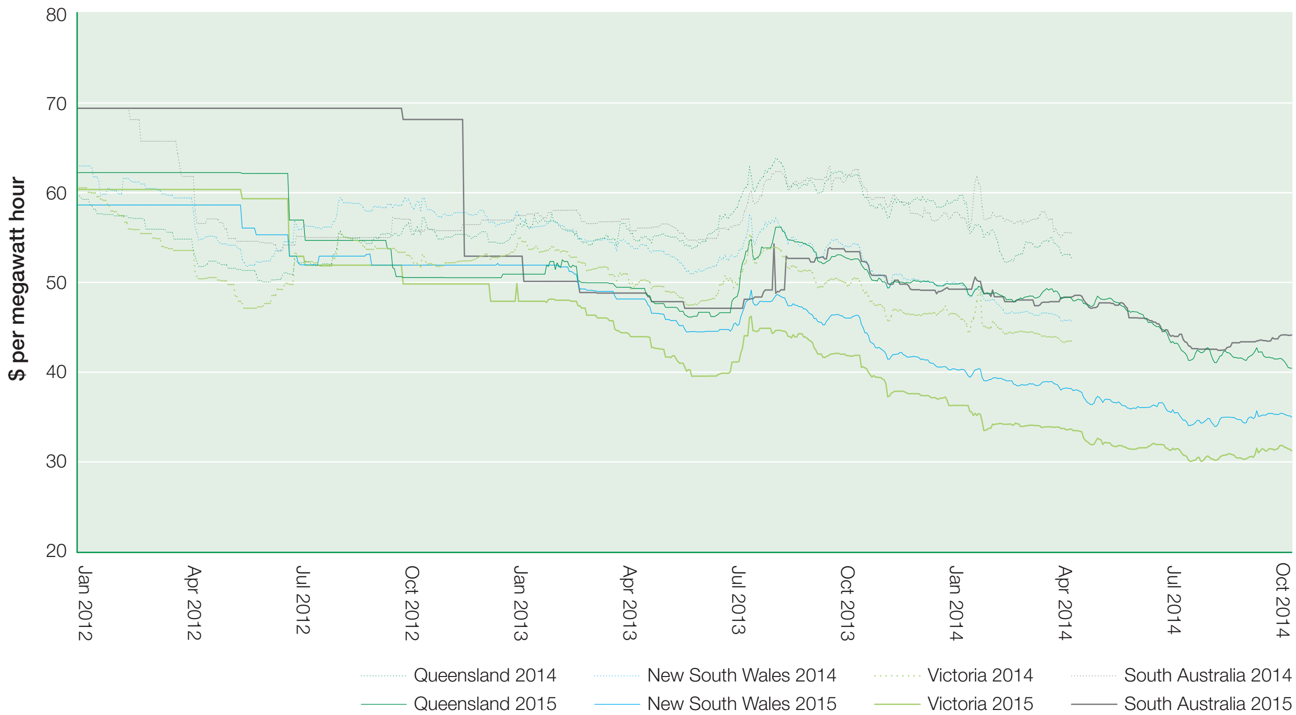
The AER argued the proposal would limit the impacts of late rebidding and other types of disorderly bidding. As part of the same process, it proposed that fast start inflexibility profiles should also reflect a plant's technical capabilities.

In August 2014 the AEMC found the existing provisions governing ramp rates may distort competitive outcomes and investment signals. It proposed an alternative draft rule that ramp rates be at least 1 per cent of maximum generation capacity per minute (or the plant's technical capability if the generator cannot meet that threshold), regardless of plant size, configuration or technology. The AEMC expected to make a final determination on the proposal in March 2015.

1.11.3 Following dispatch instructions

Generators must follow the dispatch instructions issued by AEMO to ensure efficient dispatch and the security of the power system. Any failure to follow dispatch instructions may enable a generator to increase its revenue at the

Figure 1.27
Electricity base futures contracts, calendar year prices



Note: Average daily settlement prices of base futures contracts for the four quarters of the relevant calendar year.
Source: ASX Energy.

expense of power system security and, if widespread, may result in higher energy prices for consumers.

In July 2014 the AER instituted proceedings in the Federal Court against Snowy Hydro, alleging it failed to follow dispatch instructions issued by AEMO on nine occasions in 2012 and 2013. The AER alleged Snowy Hydro, on each occasion, generated substantially more power than the dispatch instruction required it to generate, and earned a greater trading amount from each transaction than it would have earned if it had complied with the instructions.

1.12 Reliability of supply

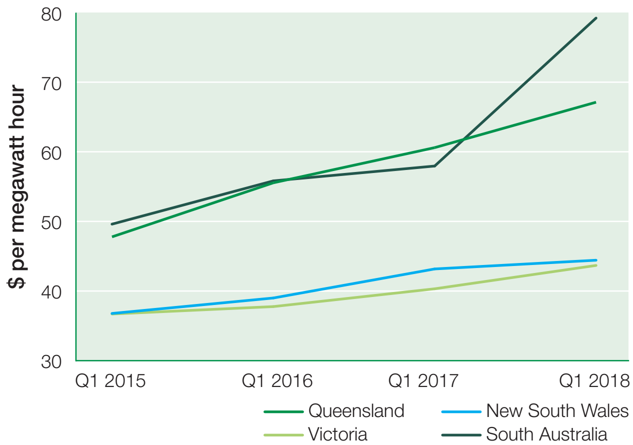
Reliability refers to the continuity of electricity supply to customers. While power outages can originate from the generation, transmission or distribution sectors, about 95 per cent of reliability issues in the NEM originate in the distribution network sector (section 2.8.1).

The AEMC Reliability Panel sets the reliability standard for generation in the NEM. The standard is the expected amount of energy at risk of not being delivered to customers because not enough capacity is available. To meet this standard, AEMO determines the necessary spare generation capacity needed for each region (including capacity via transmission interconnectors) to manage unexpected demand spikes and generation failure. It aims for the reliability standard to be met in each financial year, for each region and for the NEM as a whole. It does not account for supply interruptions in distribution and non-core transmission networks, which are subject to different standards and regulatory arrangements (sections 2.8.1 and 2.7.1).

The current reliability standard is that no more than 0.002 per cent of customer demand in each NEM region should be unserved by generation capacity per financial year, allowing for demand-side response and imports from interconnectors. AEMO sets reserve margins so the reliability standard is met in each financial year, for each region and for the NEM as a whole. The standard is equivalent to an annual systemwide outage of seven minutes at peak demand.

Figure 1.28

First quarter base futures prices, by region, September 2014



Source: ASX Energy.

1.12.1 Reliability settings

The AEMC Reliability Panel recommends price settings that help ensure the reliability standard is met, including:

- a spot market price cap, which is set at a sufficiently high level to stimulate the required investment in generation capacity to meet the standard. The cap was raised from $13 100 per MWh to $13 500 per MWh on 1 July 2014.
- a cumulative price threshold to limit the exposure of participants to extreme prices. If cumulative spot prices exceed this threshold over a rolling seven days, then AEMO imposes an administered price cap. The threshold was raised to $201 900 per MWh on 1 July 2014; the administered cap is $300 per MWh.
- a market floor price, set at –$1000 per MWh.

The market price cap and cumulative price threshold are adjusted each year in line with movements in the consumer price index. Additionally, the reliability panel conducts a full review of the reliability standard and settings every four years. In its July 2014 review, the panel recommended not changing the reliability standard and continuing to adjust the market price cap and cumulative price threshold in line with changes in the consumer price index.[44]

44 AEMC Reliability Panel, *Reliability standard and reliability settings review 2014, final report*, July 2014.

Other reliability measures

AEMO publishes forecasts of electricity demand and generator availability to allow generators to respond to market conditions and schedule maintenance outages. Safety net mechanisms allow AEMO to manage any short term risks of unserved energy identified in forecasts:

- AEMO can enter reserve contracts with generators under a reliability and emergency reserve trader (RERT) mechanism to ensure reserves are available to meet the reliability standard. When entering these contracts, AEMO must prioritise facilities that would least distort wholesale market prices. The RERT mechanism is due to expire in 2016.
- AEMO can use its directions power to require generators to provide additional supply at the time of dispatch to ensure sufficient reserves are available.

1.12.2 Reliability performance

The reliability standard has been breached only twice, in Victoria and South Australia during a heatwave in January 2009. The unserved energy from these events on an annual basis was 0.0032 per cent for South Australia and 0.004 per cent for Victoria.

On 15 January 2014, the third day of a heat wave affecting south east Australia, supply conditions in Victoria and South Australia were extremely tight, with forecasts indicating insufficient capacity was available in both regions to meet demand. AEMO issued Lack of Reserve Level 3 market notices (an infrequent occurrence), noting customers may need to be interrupted to maintain system security.[45] AEMO also engaged the RERT provision. But the mechanism was ultimately not required when capability on the Basslink interconnector increased sufficiently for Tasmanian generation to meet capacity shortfalls on the mainland.

1.13 Barometers of competition in the NEM

There is no universally accepted approach to measuring competitiveness in electricity markets. The AER monitors a number of structural and behavioural indicators for each NEM region. Its analysis:

- is based on the entity with offer control, which may be distinct from the entity that owns/operates a plant, due

45 Lack of Reserve Level 3 indicates AEMO expects load shedding to be required, even if all available generation capacity and interconnectors are in operation.

to power purchasing agreements and joint ownership. Table 1.5 lists the entities with trading rights over generation plant in the NEM.

- is limited to scheduled and semi-scheduled generation units. Wind generation capacity is scaled by contribution factors that AEMO determines.
- excludes Tasmania, given its highly concentrated ownership
- accounts for imports into a region via network interconnectors, by including flows when the price differential between the importing and exporting regions is at least $10 per MWh. Any negative flows are assumed to be zero, because interconnectors do not provide a competitive constraint when a region is exporting. Figure 2.1 illustrates the geography of interconnectors in the NEM.

1.13.1 Structural indicators

The market structure of the generation sector affects the likelihood of, and incentives for, generators to exercise market power. A structure with few generators—particularly in a region with limited in-flow interconnector capacity—is likely to be less competitive than a market with diluted ownership. The AER monitors structural indicators that include:

- market shares
- the Herfindahl–Hirschman index
- the residual supply index.

Market shares provide information on the extent of concentration, as well as the relative size of each generator. Markets with a high proportion of capacity controlled by a small number of generators are usually more susceptible to the exercise of market power. Figure 1.15 illustrates generation market shares in 2014, based on capacity under each firm's trading control. It indicates the relatively strong market positions held by AGL Energy in NSW and South Australia, and by the state owned generators CS Energy and Stanwell in Queensland.

Interconnectors provide a competitive constraint for generators in NSW, Victoria and South Australia. That constraint is less effective in Queensland, which periodically experiences significant counter-price trade flows at times of high prices.

The *Herfindahl–Hirschman index* (HHI) accounts for the relative size of firms. It is defined as the sum of squared market shares (expressed as percentages) of all firms in the market. The HHI can range from zero (for a market with a large number of negligible firms) to 10 000 (that is, 100 squared) for a monopoly. By squaring market shares, the HHI enhances the contribution of large firms. The higher the HHI is, the more concentrated and less competitive is the market.

Figure 1.29 illustrates the HHI across NEM regions from 2008–09 to 2013–14. In Queensland, the index rose in 2011–12 from being the lowest in the NEM to the highest, following a consolidation of the state owned generation sector. The index levels for other regions have recently moved in a comparable band.

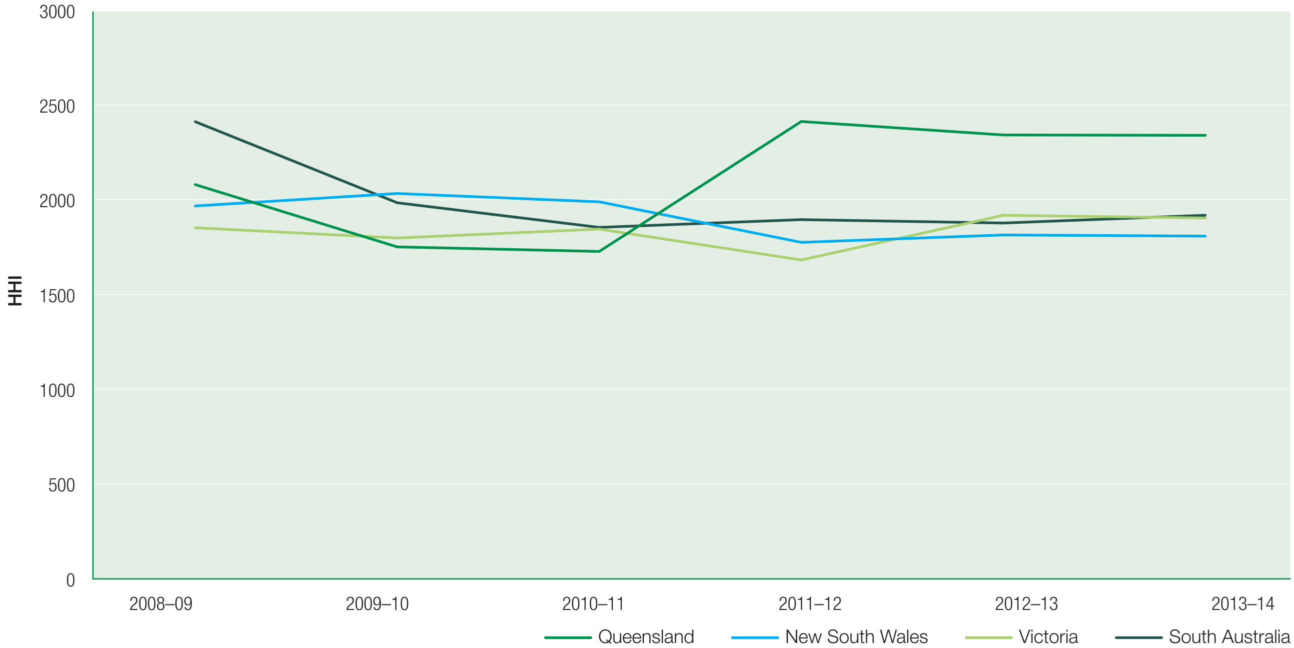
But market share and HHI analysis do not account for variations in demand over time. This deficiency is significant because high demand is generally necessary for market power to be profitably exercised. The *residual supply index* (RSI) measures the extent to which one or more generators are 'pivotal' to the clearing of a market. A generator is pivotal if market demand exceeds the capacity controlled by all other generators; that is, some capacity controlled by the generator is required for the market to clear. Multiple generators may be pivotal simultaneously.

The RSI-1 measures the ratio of demand that can be met by all but the largest generator in a region. If the RSI-1 is greater than one, then demand can be fully met without requiring the dispatch of the largest generator. But if the RSI-1 is below one, then the largest generator becomes pivotal. In general, a lower RSI-1 indicates a less competitive market. It may result, for example, from an increase in demand, a decrease in available generation capacity, or an increase in the proportion of available capacity that is supplied by the largest generator.

Figure 1.30 illustrates the RSI-1 in each NEM region since 2008–09. The data are for times of peak demand (based on the highest 2 per cent of demand trading intervals, equivalent to seven days per year). The largest generator must usually be dispatched during peak periods across all NEM regions. Only in Queensland in 2010–11 was the largest generator not usually required. Among the regions, the largest generator (AGL Energy) was most pivotal in South Australia, and the need for it to meet peak demand increased in 2013–14. This shift may reflect decisions by generators such as Alinta to withdraw capacity from the market.

Figure 1.30 also illustrates average demand during peak periods. If demand increases, then the RSI-1 is likely to deteriorate (that is, the largest firm is more likely to be pivotal). The converse is also true, because weakening demand reduces how pivotal the largest generator is in meeting peak demand. Falling peak demand in NSW

Figure 1.29
Herfindahl–Hirschman index



Source: AER.

contributed to the region's improved RSI-1 over the past five years.

The HHI and RSI-1 metrics indicate a gradual improvement in competition for in Victoria until AGL Energy's full acquisition of Loy Yang A (2210 MW) in June 2012 increased the region's market concentration. This shift was partly offset by Origin Energy's commissioning of the gas powered Mortlake plant (566 MW) in late 2012.

1.13.2 Behavioural indicators

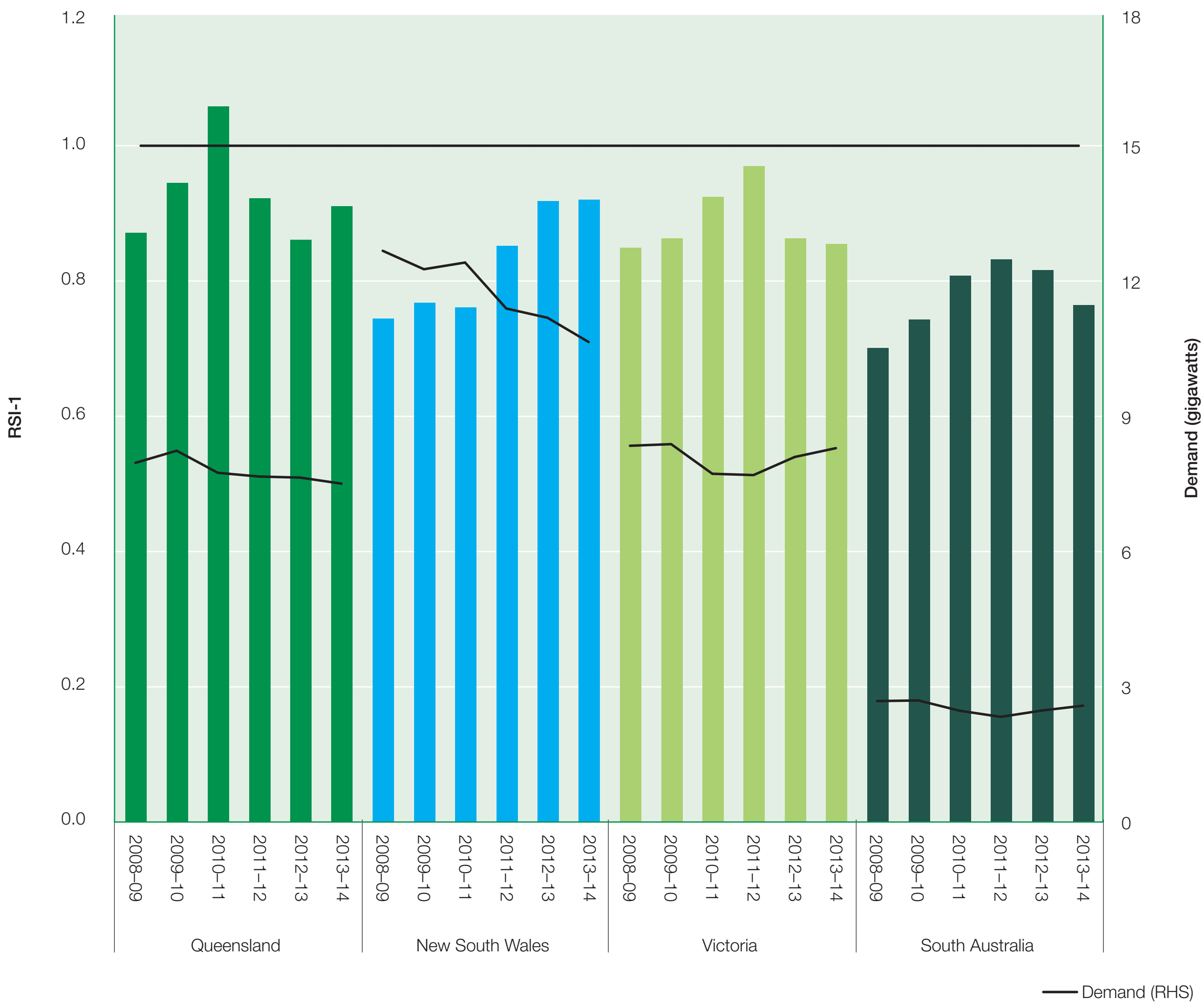
The structural indicators indicate significant levels of market concentration in some NEM regions. But a generator's ability to exercise market power is distinct from its incentive to exercise that power. In part, the incentives link to a generator's exposure to the spot price. The greater its exposure, the greater is its incentive to exercise market power. Behavioural indicators explore the relationship between a generator's bidding and spot price outcomes.

Figures 1.31–1.34 illustrate the relationship between capacity use and spot prices. They record the average percentage of available capacity that is dispatched when prices settle in each price band for a sample of large generators: CS Energy in Queensland, Macquarie Generation in NSW, GDF Suez in Victoria and AGL Energy in South Australia. In a competitive market, generators would typically make greater use of their assets portfolio as prices rise.

As expected, figures 1.31–1.34 show generators tend to increase output as prices rise to around $100 per MWh. However, in some years, output by large generators tends to decline as prices enter higher price bands. In 2013–14 Macquarie Generation in NSW and GDF Suez in Victoria behaved in this way: each generator offered less capacity when prices were above $300 per MWh, compared with when prices were $50–300 per MWh.

One possible explanation for this behaviour is deliberate capacity withholding to influence spot prices. Other possible explanations include the inability of some generation plant to respond quickly to sudden price movements, or transmission congestion at times of high prices that constrains the use of some plant. Given the data relate to maximum plant availability on the relevant day, technical plant issues might have reduced output during some high price periods to below daily maximum availability.

Figure 1.30
One firm residual supply index (RSI-1) at times of peak demand



Source: AER.

Figure 1.31

Average annual capacity use, CS Energy (Queensland)

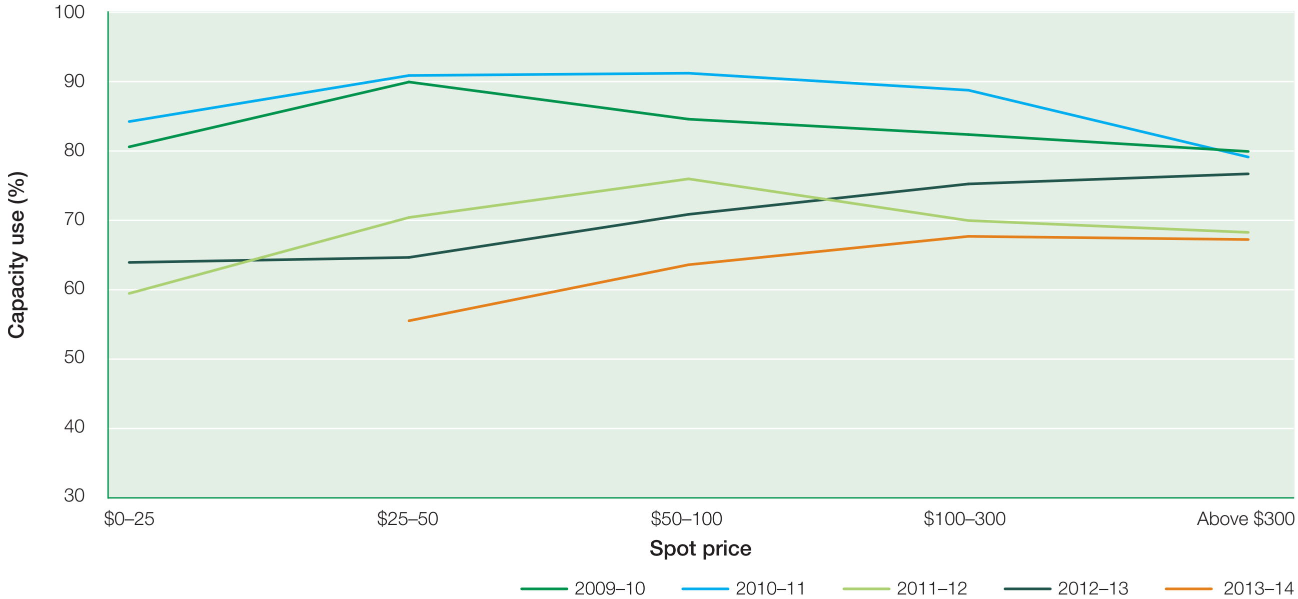


Figure 1.32

Average annual capacity use, Macquarie Generation (NSW)

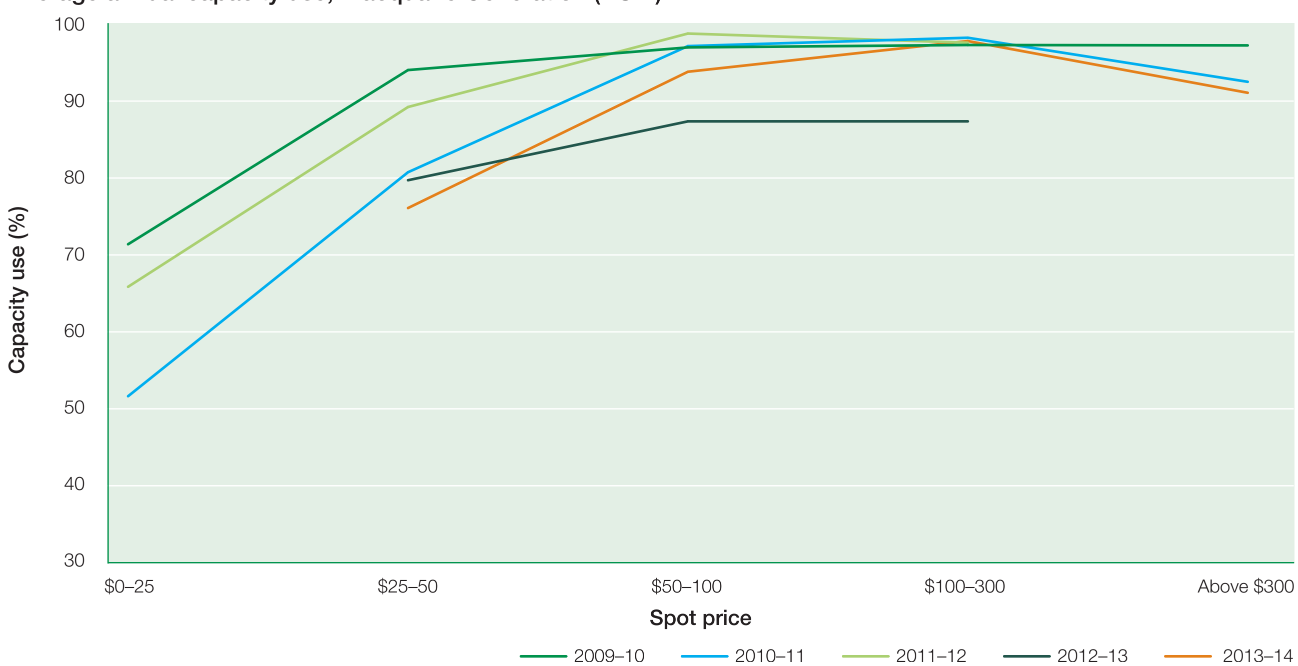


Figure 1.33
Average annual capacity use, GDF Suez (Victoria)

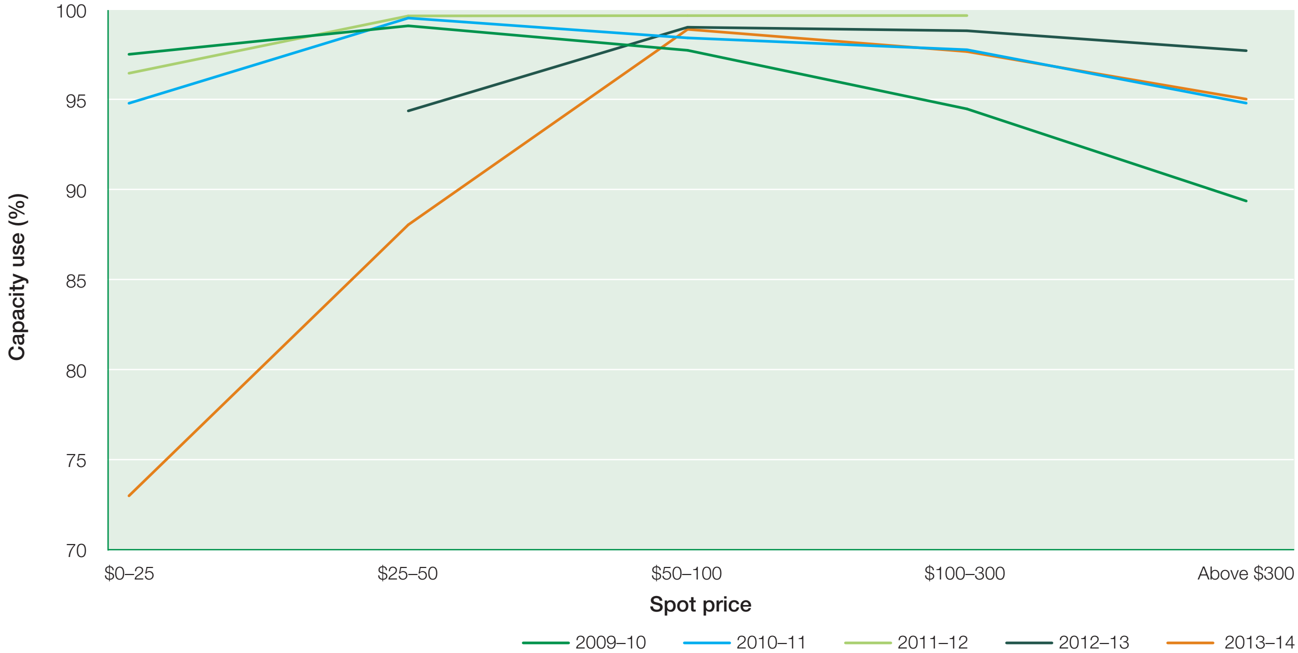
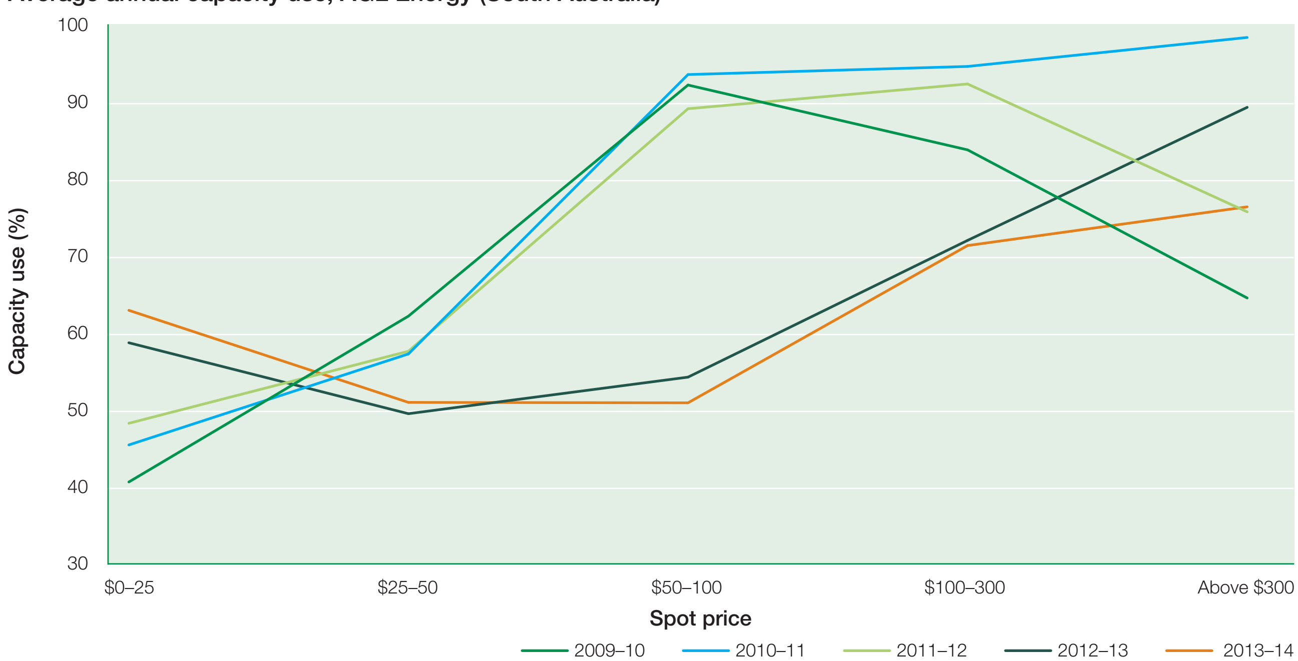


Figure 1.34
Average annual capacity use, AGL Energy (South Australia)



Note (figures 1.31–1.34): Data excluded if based on fewer than five observations.
Source (figures 1.31–1.34): AER.

TransGrid

2 ELECTRICITY NETWORKS


GS-3268 RT

Electricity networks provide a means of transporting power from generators to customers. Transmission networks transport power over long distances, linking generators with load centres. Distribution networks transport electricity from points along the transmission network, and criss-cross urban and regional areas to provide electricity to customers.

While energy networks traditionally provided a one-way delivery service to customers, recent technological innovations mean networks can provide a platform for trading a variety of electricity services.

2.1 Electricity networks in the NEM

The National Electricity Market (NEM) in eastern and southern Australia provides a fully interconnected transmission network from Queensland through to New South Wales (NSW), the Australian Capital Territory (ACT), Victoria, South Australia and Tasmania. The NEM transmission network has a long, thin, low density structure, reflecting the location of, and distance between, major demand centres. It comprises five state based transmission networks, with cross-border interconnectors linking the grid (table 2.1).

The NEM has 13 major electricity distribution networks (table 2.2). 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 with separate ownership. The total length of distribution infrastructure in the NEM is around 735 000 kms—17 times longer than transmission infrastructure. Figure 2.1 illustrates the transmission and distribution networks in the NEM.

2.1.1 Ownership

Tables 2.1 and 2.2 list ownership arrangements for electricity networks in the NEM. The Queensland, NSW and Tasmanian networks are all government owned. The ACT distribution network has joint government and private ownership.

All transmission networks in Victoria and South Australia, and three interconnectors (Directlink, Murraylink and Basslink) are privately owned. Victoria's five distribution networks are also privately owned, while the South Australian distribution network is leased to private interests:

- *Cheung Kong Infrastructure* and *Power Assets* jointly have a 51 per cent stake in two Victorian distribution networks (Powercor and CitiPower) and a 200 year lease of the South Australian distribution network (SA Power Networks, formerly ETSA Utilities). The remaining 49 per cent of the two Victorian networks is held by Spark Infrastructure, a publicly listed infrastructure fund in which Cheung Kong Infrastructure has a direct interest.
- *Singapore Power International* has a minority ownership in Jemena (which owns the Jemena distribution network in Victoria) and part owns the United Energy (Victoria) and ActewAGL (ACT) distribution networks. Singapore Power International also has a 51 per cent stake in AusNet Services, which owns Victoria's transmission network and the AusNet Services distribution network.
- *State Grid Corporation of China* entered the Australian market in 2012, purchasing a 41 per cent stake in the South Australian transmission network. It raised its stake to 46 per cent in 2013. In 2013 it acquired a 60 per cent stake in Jemena, and a 20 per cent share in AusNet Services from Singapore Power International. These businesses also own or have equity in the gas pipeline sector (chapter 4).

Victoria has a unique transmission network structure that separates 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.

In some jurisdictions, ownership links exist between electricity networks and other segments of the electricity sector:

- In the ACT, common ownership occurs in electricity distribution and retailing, with ring fencing arrangements for operational separation.[1]
- Queensland privatised much of its energy retail sector in 2006–07, but the state owned Ergon Energy continues to provide distribution and retail services.
- Tasmania had common ownership in electricity distribution and retailing until 1 July 2014, when the Tasmanian Government created a new business—TasNetworks—that merged the Transend transmission network and the Aurora Energy distribution network.

1 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.

Figure 2.1

Electricity transmission grid and distribution networks in the National Electricity Market

QNI, Queensland–NSW Interconnector.

Table 2.1 Electricity transmission networks

NETWORK	LOCATION	LINE LENGTH (CIRCUIT KM)	ELECTRICITY TRANSMITTED (GWH), 2012–13	MAXIMUM DEMAND (MW), 2012–13[1]	ASSET BASE ($ MILLION)[2]	CURRENT REGULATORY PERIOD	OWNER
NEM REGION NETWORKS							
Powerlink	Qld	14 310	49 334	10 956	6 035	1 July 2012–30 June 2017	Queensland Government
TransGrid	NSW	12 893	65 200	17 100	5 289	1 July 2014–30 June 2015[3]	NSW Government
AusNet Services	Vic	6 573	49 056	9 342	2 414	1 Apr 2014–30 Mar 2017	Listed company (Singapore Power International 31%, State Grid Corporation 20%)
ElectraNet	SA	5 527	14 284	4 136	1 786	1 July 2013–30 June 2018	State Grid Corporation 46.5%, YTL Power Investments 33.5%, Hastings Utilities Trust 20%
TasNetworks	Tas	3 503	12 866	2 483	1 236	1 July 2014–30 June 2015[3]	Tasmanian Government
NEM TOTALS		42 806	190 740		16 760		
INTERCONNECTORS[4]							
Directlink	Qld–NSW	63				1 July 2005–30 June 2015	Energy Infrastructure Investments (Marubeni 50%, Osaka Gas 30%, APA Group 20%)
Murraylink	Vic–SA	180				1 July 2013–30 June 2018	Energy Infrastructure Investments (Marubeni 50%, Osaka Gas 30%, APA Group 20%)
Basslink	Vic–Tas	375				Unregulated	Publicly listed CitySpring Infrastructure Trust

GWh, gigawatt hours; MW, megawatts.

1 Transmission system non-coincident, summated maximum demand.

2 Asset bases are at June 2013 (December 2013 for Victorian businesses).

3 One year transitional arrangements are in place in NSW and Tasmania.

4 Not all interconnectors are listed. The unlisted interconnectors, which form part of state based networks, are Heywood (Victoria–South Australia), QNI (Queensland–NSW) and NSW–Victoria.

Sources: AER regulatory determinations and benchmarking regulatory information notices (RINs).

Table 2.2 Electricity distribution networks

NETWORK	CUSTOMER NUMBERS	LINE LENGTH (CIRCUIT KM)	ELECTRICITY DELIVERED (GWH), 2012–13	MAXIMUM DEMAND (MW), 2012–13[1]	ASSET BASE ($ MILLION)[2]	CURRENT REGULATORY PERIOD	OWNER
QUEENSLAND							
Energex	1 359 712	51 781	21 055	5 029	10 197	1 Jul 2010–30 Jun 2015	Qld Government
Ergon Energy	710 431	160 110	13 496	3 420	8 837	1 Jul 2010–30 Jun 2015	Qld Government
NEW SOUTH WALES AND ACT							
AusGrid	1 635 053	40 964	26 338	5 570	13 613	1 Jul 2014–30 Jun 2015[3]	NSW Government
Endeavour Energy	919 385	35 029	16 001	4 156	5 344	1 Jul 2014–30 Jun 2015[3]	NSW Government
Essential Energy	844 244	191 107	12 291	2 294	6 518	1 Jul 2014–30 Jun 2015[3]	NSW Government
ActewAGL	177 255	5 088	2 903	698	790	1 Jul 2014–30 Jun 2015[3]	ACTEW Corporation (ACT Government) 50%; Jemena (State Grid Corporation 60%, Singapore Power International 40%) 50%
VICTORIA							
Powercor	753 913	73 889	10 556	2 396	2 869	1 Jan 2011–31 Dec 2015	Cheung Kong Infrastructure / Power Assets 51%; Spark Infrastructure 49%
AusNet Services	681 299	43 822	7 501	1 877	2 809	1 Jan 2011–31 Dec 2015	Listed company (Singapore Power International 31%, State Grid Corporation 20%)
United Energy	656 516	12 837	7 856	2 077	1 789	1 Jan 2011–31 Dec 2015	DUET Group 66%; Jemena (State Grid Corporation 60%, Singapore Power International 40%) 34%
CitiPower	322 736	4 318	5 981	1 493	1 601	1 Jan 2011–31 Dec 2015	Cheung Kong Infrastructure / Power Assets 51%; Spark Infrastructure 49%
Jemena	318 830	6 135	4 254	986	1 031	1 Jan 2011–31 Dec 2015	Jemena (State Grid Corporation 60%, Singapore Power International 40%)
SOUTH AUSTRALIA							
SA Power Networks	847 766	87 883	11 008	2 915	3 469	1 Jul 2010–30 Jun 2015	Cheung Kong Infrastructure / Power Assets 51%; Spark Infrastructure 49%
TASMANIA							
TasNetworks	279 868	22 336	4 248	239	1 455	1 Jul 2012–30 Jun 2017	Tas Government
NEM TOTALS	9 507 007	735 298	143 488		60 322		

1 Non-coincident, summated, raw system, annual maximum demand at the zone substation level.

2 Asset bases are at June 2013 (December 2013 for Victorian businesses).

3 One year transitional arrangements are in place in NSW and the ACT.

Sources: AER regulatory determinations and benchmarking RINs.

2.1.2 Scale of the networks

Tables 2.1 and 2.2 show the asset values of NEM electricity networks, 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. The combined opening RAB of distribution networks in the NEM is around $54 billion—over three times the valuation for transmission infrastructure (around $17 billion).

2.2 Economic regulation of electricity networks

Energy networks are capital intensive and incur declining average costs as output increases. So, network services in a particular geographic area can be most efficiently provided by a single supplier, leading to a natural monopoly industry structure. In Australia, the networks are regulated to manage the risk of monopoly pricing and encourage efficient investment in infrastructure. The Australian Energy Regulator (AER) sets the prices for using electricity networks in the NEM. The Economic Regulation Authority regulates networks in Western Australia, and the Utilities Commission regulates networks in the Northern Territory.

2.2.1 Regulatory process and approach

The National Electricity Law lays the foundation for the regulatory framework governing electricity networks. In particular, it sets out the National Electricity Objective: to promote efficient investment in, and operation of, electricity services for the long term interest of consumers. It also sets out revenue and pricing principles, including that network businesses should have a reasonable opportunity to recover at least efficient costs.

Regulated electricity network businesses must periodically apply to the AER to assess their forecast expenditure and revenue requirements (typically, every five years). Chapters 6 and 6A of the National Electricity Rules set out the framework that the AER must apply in undertaking this role for distribution and transmission networks respectively.

The AER assesses a network business's forecasts of the revenue that the business requires to cover its efficient costs and an appropriate return. It uses a building block model that accounts for a network's operating and maintenance expenditure, capital expenditure, asset depreciation costs and taxation liabilities, and for a return on capital. Figure 2.2 illustrates the revenue components of the South Australian transmission network (for the regulatory period 2013–18) and Tasmanian distribution network (for 2012–17).

The largest component is the return on capital, which may account for up to two-thirds of revenue. The size of a network's RAB (and projected investment) and its weighted average cost of capital (the rate of return necessary to cover a commercial return on equity and efficient debt costs) affect the return on capital. An allowance for operating expenditure typically accounts for a further 30 per cent of revenue requirements.

While the regulatory frameworks for transmission and distribution are similar, they do differ. In transmission, the AER determines a cap on the maximum revenue that a network can earn during a regulatory period. In distribution, the range of control mechanisms is wider, and the AER may set a ceiling on the revenue or prices that a distribution business can earn or charge during a period. The available control mechanisms for distribution include:

- weighted average price caps, allowing flexibility in individual tariffs within an overall ceiling—used for the NSW, Victorian and South Australian networks
- average or maximum revenue caps, setting a ceiling on revenue that may be recovered during a regulatory period—used for the Queensland, ACT and Tasmanian networks.

The regulatory process for network businesses begins with preliminary consultation on the framework and approach for the determination, around two years before the current regulatory period expires. The network business then submits a regulatory proposal to the AER, which assesses the proposal in consultation with stakeholders. The AER must publish a final decision on a proposal at least two months before the regulatory period starts.

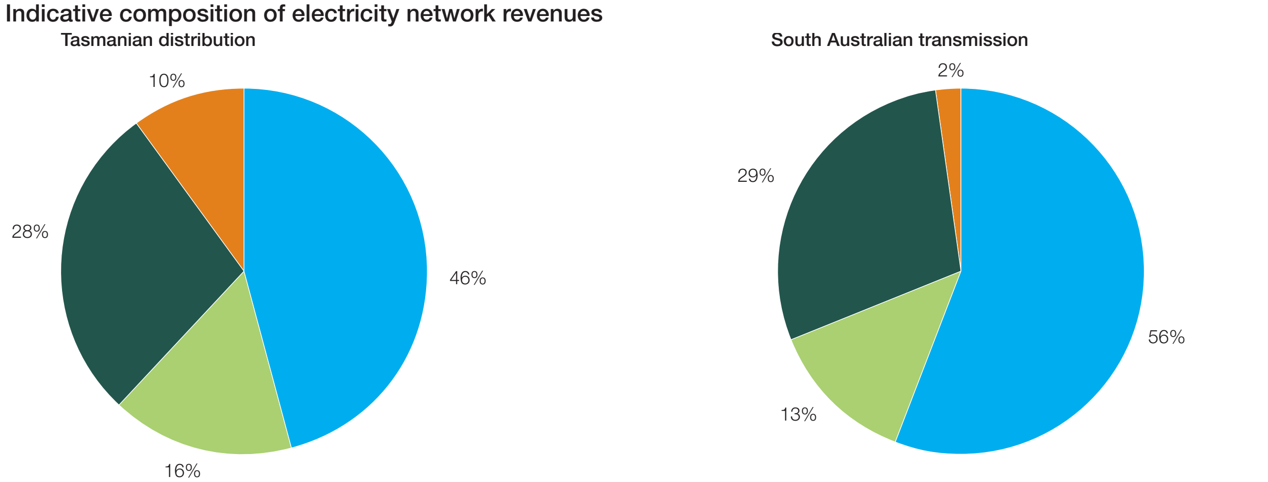
2.2.2 Refining the regulatory process and approach

Energy consumers should pay no more than necessary for the safe and reliable delivery of electricity network services. Significant reforms to energy network regulation in the past few years encourage network businesses to seek more efficient ways of providing services. New measures support ongoing investment in essential services without requiring consumers to pay for excessive returns to network businesses.

The AER published guidelines in 2013 on how it will consider network proposals. The guidelines also cover new schemes to incentivise network businesses to invest and spend efficiently, and to share efficiency benefits with

Figure 2.2

Indicative composition of electricity network revenues



Source: AER.

consumers.[2] The approaches include a greater emphasis on benchmarking in assessing network proposals.

The reforms set out rules that first apply to regulatory determinations taking effect in 2015 for transmission networks in NSW and Tasmania, and for distribution networks in NSW, Queensland, South Australia and the ACT.

2.2.3 Regulatory timelines and recent AER activity

Figure 2.3 shows the regulatory timelines for electricity networks in each jurisdiction. In 2014 the AER:

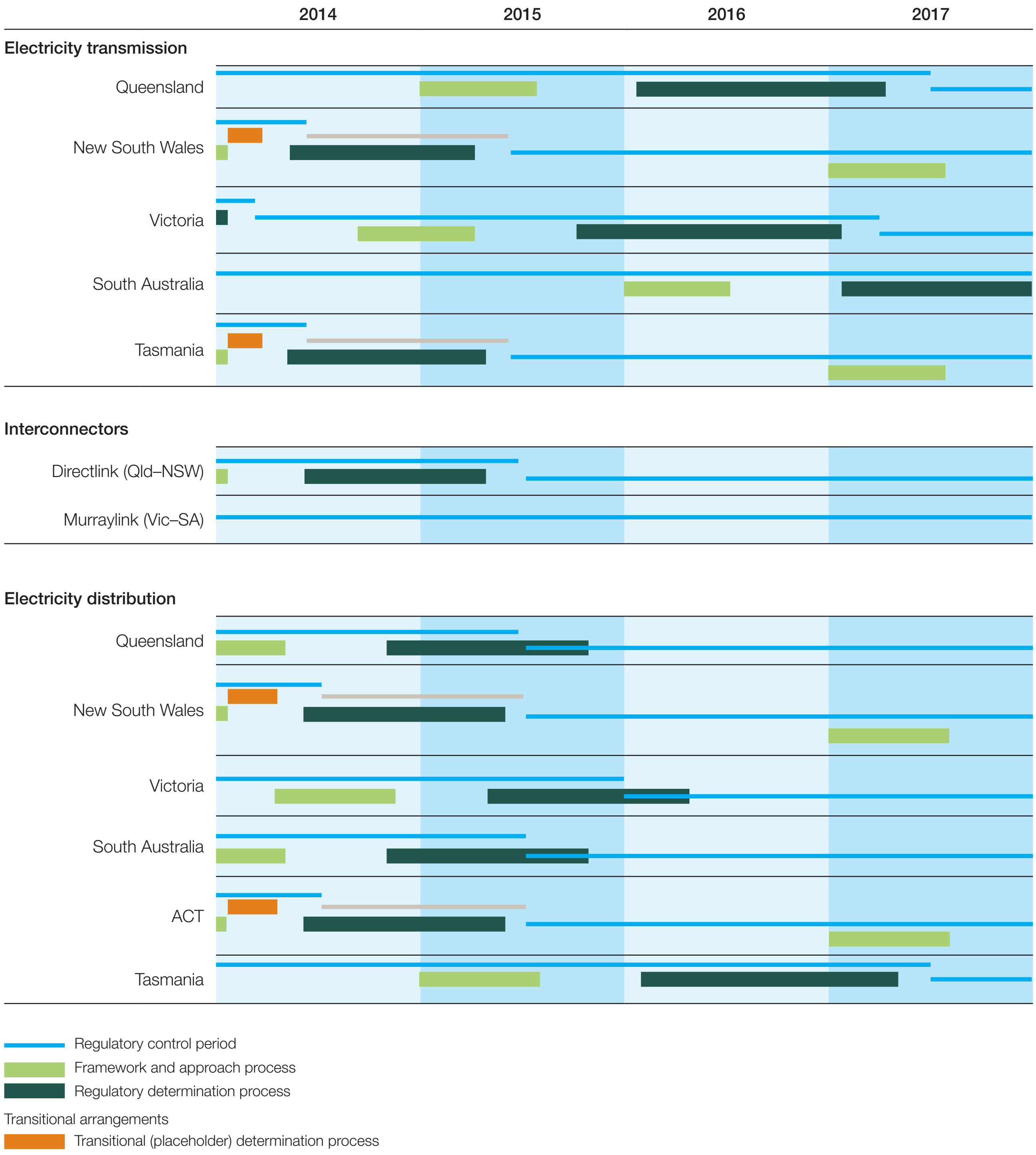
- made a final determination for AusNet Services (Victorian transmission) for the three year regulatory period commencing 1 April 2014. Work also commenced in late 2014 on the framework and approach for this network for the period commencing 1 April 2017.
- made transitional decisions under the new rules for transmission networks in NSW and Tasmania, and distribution networks in NSW and the ACT, to apply in 2014–15. In November 2014 the AER released draft decisions on new arrangements to replace the transitional arrangements from 1 July 2015.
- released a draft determination in November 2014 for Directlink (transmission interconnector between Queensland and NSW), covering the regulatory period commencing 1 July 2015
- began assessing proposals for the Queensland and South Australian distribution businesses, covering regulatory periods commencing 1 July 2015
- established a framework and approach to review the Victorian distribution businesses for regulatory periods commencing 1 January 2016.

In addition to revenue determinations, the AER undertakes other economic regulation functions. It assesses network proposals on matters including cost pass-throughs and contingent projects; develops and applies service incentive regimes, ring fencing policies and other regulatory guidelines; assists in access and connection disputes; and undertakes annual tariff compliance reviews of distribution businesses. The AER also monitors the compliance of network businesses with the Electricity Rules, and reports on outcomes, including in quarterly compliance reports.[3]

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

3 AER, *Strategic priorities and work program 2013–14*, 2013.

Figure 2.3
Indicative timelines for AER determinations on electricity networks



Source: AER.

2.2.4 Merits review by the Australian Competition Tribunal

The National Electricity Law allows network businesses to apply to the Australian Competition Tribunal for a limited review of an AER determination or a part of it. Network businesses have typically sought review of specific matters in a determination, rather than of the whole determination.

The review framework was amended in November 2013 to link it more closely to the national electricity and gas objectives. The Tribunal must consider the overall balance of a determination in making its decision, and can consider any matters linked with the grounds of the appeal. It can consult with relevant users and consumers during a review.

To have a decision amended on review, the network business must demonstrate the AER erred, and that addressing the grounds of appeal would lead to a materially preferable outcome in the long term interests of consumers. The AER will have erred if it:

- makes an error of fact that was material to its decision, or
- incorrectly exercises its discretion, having regard to all the circumstances, or
- makes an unreasonable decision, having regard to all the circumstances.

If the Tribunal finds the AER erred, it can substitute its own decision or remit the matter back to the AER for consideration. At November 2014 no businesses had applied for review of an AER decision under the new framework.

Under the previous merits review framework, network businesses sought review of 18 AER determinations on electricity networks—three reviews in transmission and 15 in distribution.[4] The Tribunal's decisions increased allowable electricity network revenues by around $3.2 billion, with substantial impacts on retail energy charges. The two most significant contributors to this increase were Tribunal decisions on:

- the averaging period for the risk–free rate (an input into the weighted average cost of capital)—reviewed for five networks, with a combined revenue impact of $2 billion
- the value adopted for tax imputation credits (gamma), which affects the estimated cost of corporate income tax—reviewed for eight networks, with a combined revenue impact of over $900 million.

4 Four of the distribution reviews related to charges for advancing metering infrastructure (smart meters) in Victoria. In addition, two determinations were subject to judicial review under the *Administrative Decisions (Judicial Review) Act 1977* (Cwlth).

The Tribunal in August 2013 affirmed the AER's decision to reject significant price increases for Victoria's AusNet Services distribution network, which were intended to recover unanticipated costs of advanced metering infrastructure. In September 2014 the Federal Court dismissed AusNet Services' judicial review application on this matter.

2.3 Electricity network revenue

Figure 2.4 illustrates the AER's revenue allowances for electricity networks in the current five year regulatory periods compared with previous regulatory periods. Combined network revenue was forecast at $12.5 billion per year in the current regulatory cycle, comprising over $2.7 billion for transmission and $9.8 billion for distribution. The main revenue drivers are capital financing (section 2.3.1), capital expenditure (section 2.4) and operating costs (section 2.5).

Rising network costs drove escalating revenues and charges for several years. Costs rose to replace ageing assets, meet stricter reliability and bushfire (safety) standards, and respond to forecasts made at the time of rising peak demand. Additionally, instability in global financial markets exerted upward pressure on the costs of funding investment.

These pressures have eased more recently, lowering revenue and investment requirements for energy networks. Energy demand has declined, and is expected to remain below historical peaks in most regions for at least the next 20 years.[5] This has coincided with reductions in capital financing costs (see below) and governments moving to provide electricity network businesses with greater flexibility in meeting reliability requirements (section 2.8.1).

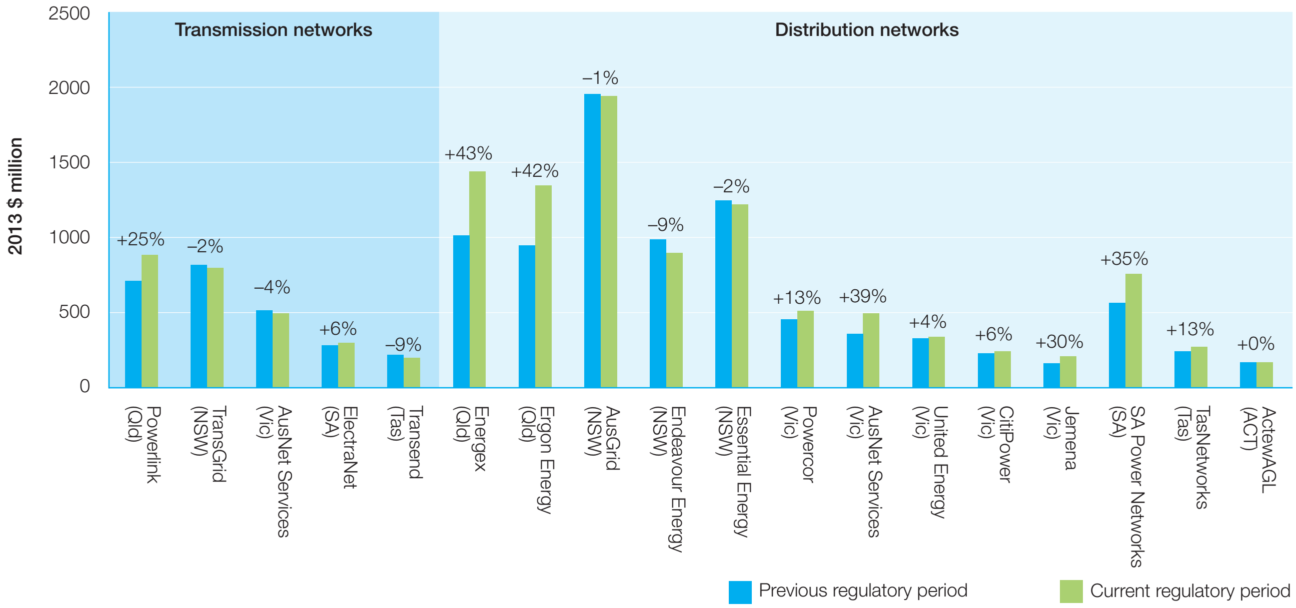
These developments account for a recent flattening out of network revenues. In determinations made since 2012, forecast revenues are an average 2 per cent *lower* than for the previous regulatory period. By comparison, average revenues rose by 30 per cent in determinations made between 2009 and 2011.

2.3.1 Capital financing

Electricity network businesses are capital intensive, so even small changes to the return earned on those assets can have a significant impact on overall revenue. As an example, a 1 per cent increase in the cost of capital allowed for ElectraNet in the AER determination for 1 July 2013 to 30 June 2018 would have increased revenues by 8 per cent.

5 AEMO, *Electricity statement of opportunities*, 2014.

Figure 2.4
Annual electricity network revenue



Notes:

Current regulatory period revenues are forecasts in regulatory determinations, amended for merits review decisions by the Australian Competition Tribunal.

The current period revenue allowances for Energex and Ergon Energy are as determined by the Australian Competition Tribunal in May 2011. The Queensland Government prevented Energex and Ergon Energy from recovering $270 million and $220 million respectively of these allowances.

Sources: AER regulatory determinations.

For AER determinations made from 2009 to 2011, the forecast cost of capital used to set revenue allowances was generally higher than in previous regulatory periods (figure 2.5). The primary factor underpinning the increases was a higher debt risk premium, which reflects the cost of borrowing for a business based on its risk of default. Issues in global financial markets reduced liquidity in debt markets and increased perceptions of risk from late 2008, pushing up the cost of borrowing.

AER determinations made since 2012 reflect that reductions in the risk-free rate and market and debt risk premiums have lowered the cost of capital. The overall cost of capital in electricity determinations made since 2012 was 7.5–8.3 per cent, compared with up to 10 per cent in 2010. The cost of capital set out in draft AER decisions in November 2014 was lower again, at 6.9–7.2 per cent. Under a revised framework that applied for the first time in these decisions, the cost of capital will be revised annually to reflect changes in debt costs.

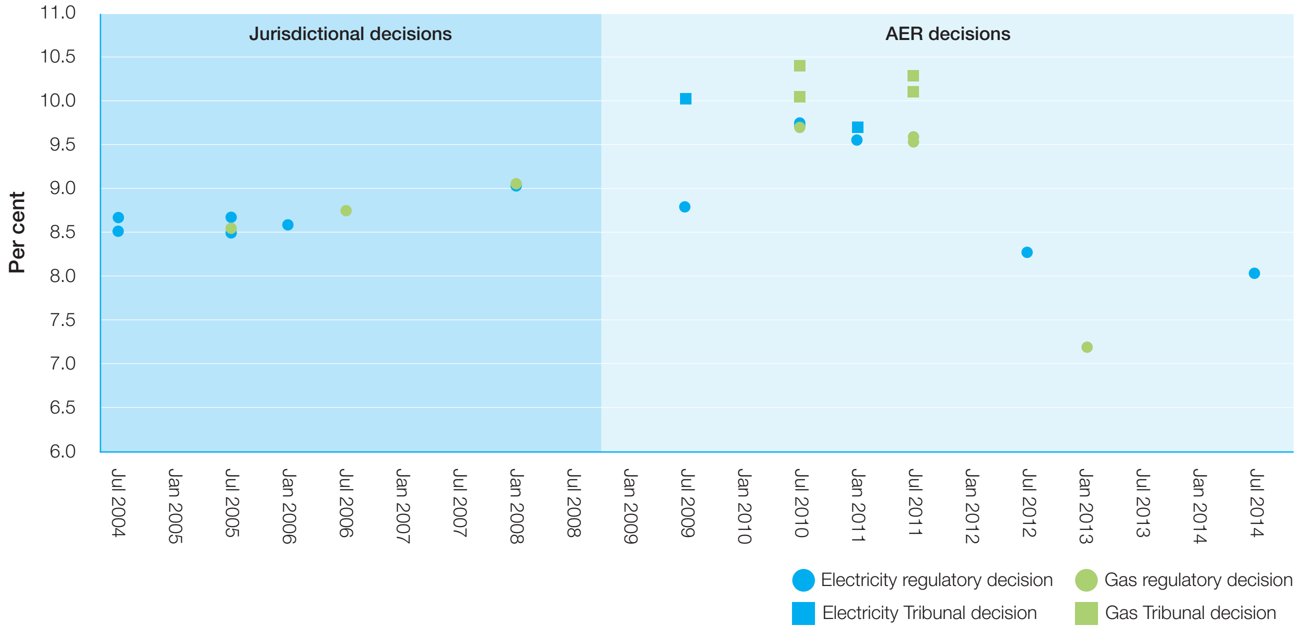
2.4 Electricity network investment

New investment in electricity networks includes augmentations (expansions) to meet demand and the replacement of ageing assets. The regulatory process aims to create incentives for efficient investment. At the start of a regulatory period, the AER approves an investment (capital expenditure) forecast for each network. It can approve contingent projects too—large projects that are foreseen at the time of a determination, but that involve significant uncertainty.

While individual network businesses make investment decisions, AEMO (in its role as national transmission planner) provides high level planning and coordination of the transmission network. It publishes a national transmission network development plan that provides a long term strategic outlook.

Figure 2.5

Weighted average cost of capital—electricity and gas distribution



Note: Nominal vanilla weighted average cost of capital.
Source: AER.

2.4.1 Regulatory investment tests

The regulatory process approves the overall efficiency of a business's capital expenditure program. Additionally, separate consultation and assessment occur for large individual projects to determine whether they are the most efficient way of meeting an identified need, or whether an alternative (such as investment in generation capacity) would be more efficient. Under regulatory investment tests, network businesses must assess investment proposals against a market based cost–benefit analysis. A network business must identify the purpose of a proposed investment and assess that investment against all other credible options for achieving that purpose. The business must publicly consult on a proposal.

The current tests were introduced in August 2010 for transmission (RIT-T) and January 2014 for distribution (RIT-D). The AER:

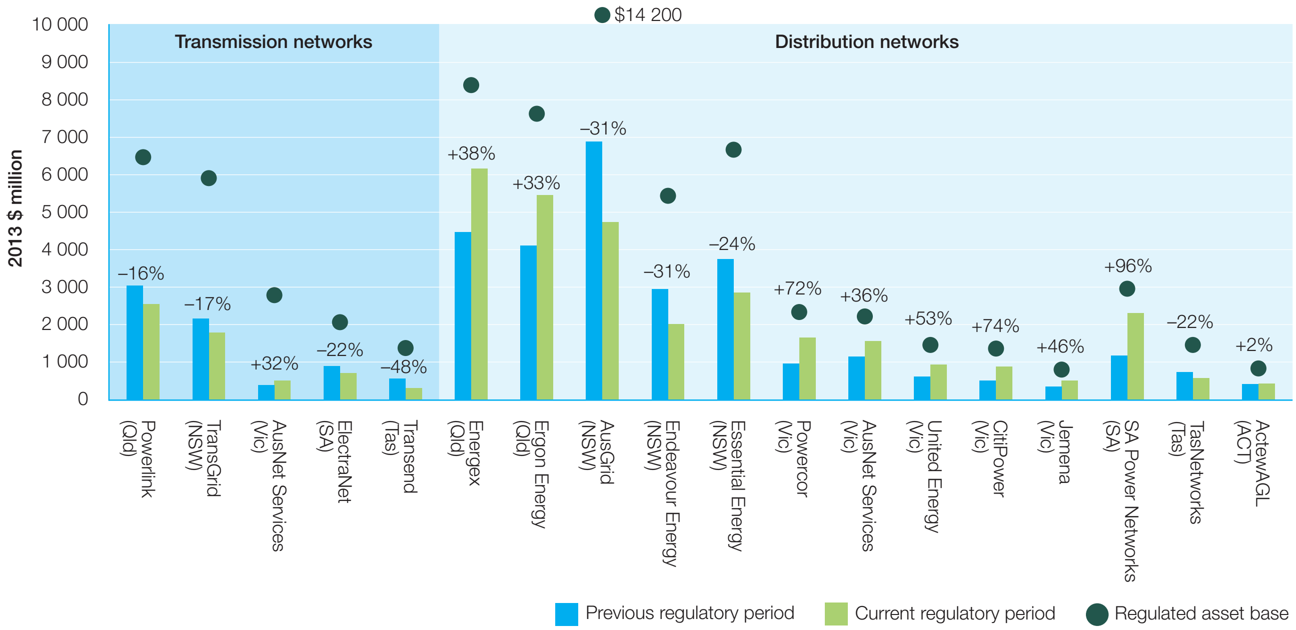
- publishes the tests and associated guidelines
- helps resolve disputes over how the tests are applied
- monitors and enforces compliance
- periodically reviews projects' cost thresholds
- determines whether a preferred investment option meets the RIT-T's cost–benefit analysis, on request from a business conducting the test. This role does not apply to reliability driven projects.

Forecasts of flat maximum demand growth in most regions over the next 10 years have reduced the number of planned network investment projects. Two RIT–D assessments were undertaken in 2014 in NSW and Victoria, along with four distribution projects assessed under the previous regulatory test. No new RIT–T assessments were commenced.

A number of previously initiated assessments progressed in 2014:

- TransGrid and Powerlink recommended no upgrade of the Queensland–NSW interconnector (QNI), citing uncertainty around the project's market benefits.
- Powerlink finalised an assessment of options to meet rising demand from new coal mine developments in the Bowen Basin. Consistent with its draft findings, it concluded a combined network and non-network option is the most efficient way to address emerging network limitations, with estimated net market benefits of up to $40 million.

Figure 2.6
Electricity network investment



Notes:

Regulated asset bases are at the beginning of the current regulatory periods.

Investment data reflect forecast capital expenditure for the current regulatory period (typically, five years), amended for merits review decisions by the Australian Competition Tribunal. See tables 2.1 and 2.2 for the timing of current regulatory periods. The data include capital contributions and exclude adjustments for disposals.

Sources: AER regulatory determinations.

- AEMO released its preferred option for addressing thermal capacity limitations in regional Victoria. The project will consist of three stages, with the final stage on hold pending further assessment.
- AEMO deferred its assessment of projects to meet demand in eastern metropolitan Melbourne, following downward revisions to demand forecasts.
- Ergon Energy reassessed its planned $32 million transmission line from Warwick to Stanthorpe, finding changes in demand and network reliability requirements meant the project was no longer required.

2.4.2 Investment trends

Figure 2.6 illustrates investment allowances for electricity networks in the current five year regulatory periods compared with previous regulatory periods. It shows the RAB for each network as a scale reference. 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.

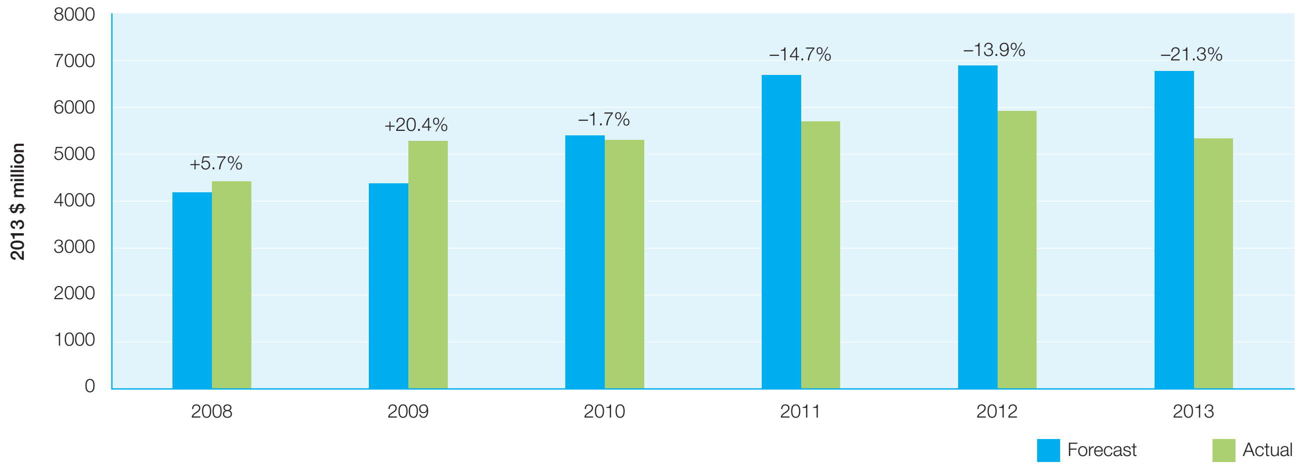
Network investment over the current regulatory cycle is forecast at $6 billion for transmission networks and $30 billion for distribution networks. AER determinations made from 2009 to 2011 reflected increased capital needs to replace ageing assets, meet higher reliability standards, and respond to forecasts made at the time of rising peak demand. The determinations provided for real investment to increase on average by 46 per cent, compared with the previous regulatory period.

Determinations made since 2012 reflect a different trend, with approved investment forecasts being 24 per cent *lower*, on average, than levels in previous periods. Weakening industrial and residential energy use, along with less stringent reliability obligations on the network businesses, are reducing the number of planned network investments and deferring projects that had already passed a regulatory investment test (section 2.4.1).

Investment trends for the AusGrid distribution network (NSW) illustrate that the effects of falling energy demand can be complex. The network's regulatory determination for 2009–14 provided for investment to meet an

Figure 2.7

Forecast and actual capital expenditure by distribution networks



Source: Annual financial RIN responses by distribution businesses.

expected increase in maximum demand from 5500 to 6700 megawatts over the period.[6] But these forecasts proved optimistic; maximum demand peaked at around 6000 megawatts. This outcome allowed the business to defer significant investment, leading it to underspend its allowance by $1.5 billion (around 20 per cent). While customers will benefit from the deferral of investment, they still bear costs during the current period, which are based on the higher expenditure forecasts. This trend of underspending occurred across all networks in recent years. Distribution businesses, for example, underspent their approved forecasts from 2011 to 2013 by an average 17 per cent (figure 2.7).

This trend of weakening investment forecasts is particularly reflected in a decline in network augmentation expenditure. Draft AER decisions for the NSW and ACT distribution networks in November 2014, for example, provided for $1.2 billion of augmentation expenditure (16 per cent of total capital expenditure), which is a quarter of the amount approved in the previous regulatory period ($5 billion, or 35 per cent of total capital expenditure).

New tools available to the AER through the Better Regulation program promote efficient capital expenditure. A capital efficiency benefit sharing scheme creates incentives for businesses to undertake efficient expenditure, by allowing them to retain a share of the gains (section 2.5.1). The AER will also review capital overspends; inefficient expenditure will be excluded from the business's asset base (meaning consumers will not pay for it).

6 AER, *NSW distribution determination 2009–10 to 2013–14, final decision*, 2009.

2.5 Operating and maintenance expenditure

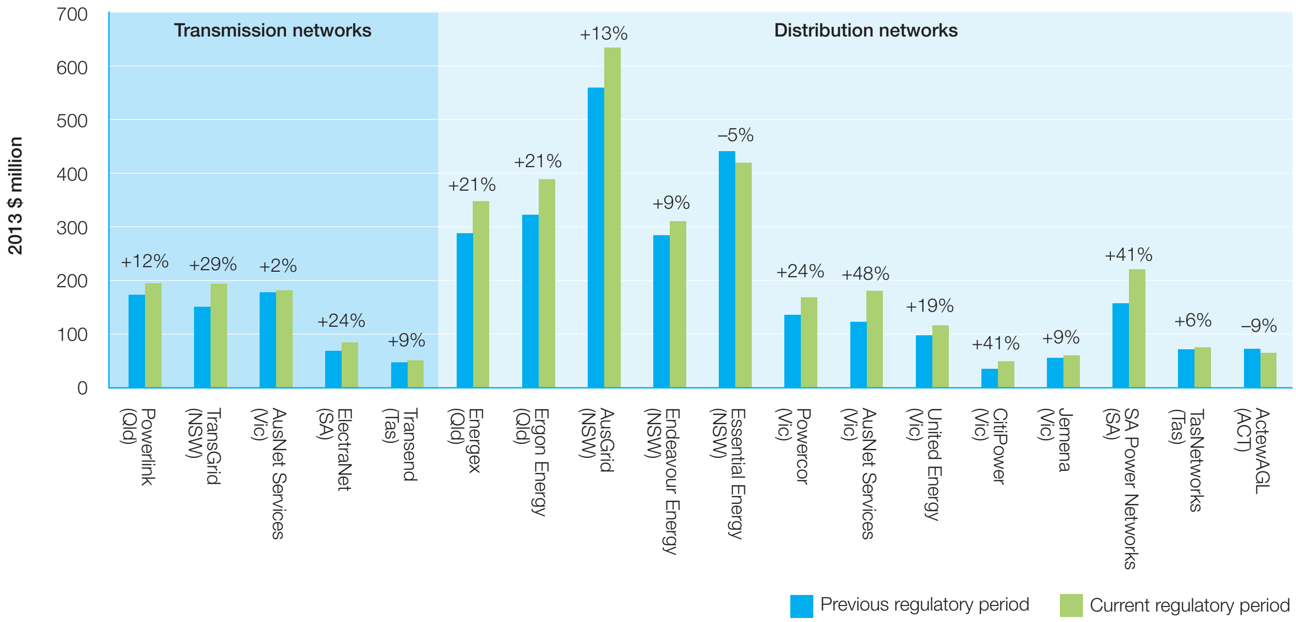
The AER determines allowances for each network to cover efficient operating and maintenance expenditure. A network's requirements depend on load densities, the scale and condition of the network, geographic factors and reliability requirements.

Figure 2.8 illustrates operating and maintenance expenditure allowances for electricity networks in the current five year regulatory periods compared with previous regulatory periods. In the current cycle, transmission businesses in the NEM are forecast to spend $720 million on operating and maintenance costs each year. Distribution businesses are forecast to spend $3 billion each year.

Differences in the networks' operating environments result in significant variations in expenditure allowances. On average, costs are forecast to rise by around 15 per cent across transmission and distribution networks in current regulatory periods compared with previous periods. Operating and maintenance costs are largely independent of energy use, so falling electricity demand does not significantly reduce this expenditure. From 2011 to 2013, total distribution network expenditure was within 1 per cent of AER approved forecasts.

In assessing operating expenditure forecasts, the AER considers relevant cost drivers, including customer growth, expected productivity improvements, and changes in real input costs for labour and materials. Operating cost increases may also reflect step change factors—that is, new

Figure 2.8
Annual operating expenditure of electricity networks



Note: Current regulatory period expenditure reflects forecasts in regulatory determinations, amended for merits review decisions by the Australian Competition Tribunal.

Sources: Regulatory determinations by the AER.

business requirements that were not part of the previous regulatory period. The 2013 ElectraNet (South Australian transmission) determination, for example, accounted for costs incurred under a new asset management policy that aims to detect faults before they become major problems. It also allowed for the costs of remediating high risk, low hanging transmission lines.

2.5.1 Efficiency benefit sharing scheme

The AER operates a national incentive scheme for businesses to improve the efficiency of operating and maintenance expenditure in running their networks. And, as part of the Better Regulation program, it is expanding the scheme to cover capital expenditure. Capital and operating expenditure incentives are aligned with those provided through the AER's service target performance incentive scheme, to encourage business decisions that balance cost and service quality.

The efficiency benefit sharing scheme, which applies to all transmission and distribution networks, allows a business to retain efficiency gains (and to bear the cost of any efficiency losses) for five years after the gain (loss) is made.[7] In the longer term, the businesses share efficiency gains or losses with customers through price adjustments, passing on 70 per cent of the gain or loss. AER determinations for transmission networks since 2012 have provided penalties under the scheme for Powerlink ($4 million) and ElectraNet ($2 million), and a benefit under the scheme for AusNet Services ($37 million).

2.6 *Power of choice* reforms

The nature and function of energy networks is evolving. Escalating cost pressures have given impetus to alternatives such as demand response (where users adjust their energy use in response to price signals), small scale local generation (such as rooftop solar photovoltaic generation) and, potentially, energy storage technologies. Innovations in network and communications technology—including smart meters and interactive household devices—are allowing

7 The AER's approved expenditure forecasts set the base for calculating efficiency gains or losses, after certain adjustments. To encourage wider use of demand management, the incentive scheme does not cover this type of expenditure.

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 a platform for multilateral trade in energy products. Some electricity consumers are becoming producers, able to switch from net consumption to net production in response to market signals. For example, over a million households have installed rooftop solar photovoltaic systems in the past few years. Further, customer investment in smart appliances and battery storage could shift the amount of power customers withdraw from or inject into a network throughout the day. These developments are slowing the growth in peak demand, reducing the need for costly network augmentations.

In 2012 the Australian Energy Market Commission (AEMC) launched *Power of choice*, an umbrella of reforms for the efficient use of energy networks and non-network alternatives. The Council of Australian Governments (CoAG) approved the adoption in principle of the reforms and proposed a series of rule changes to apply them. Progress has since occurred with network reforms (as outlined below), with other work streams relating to the wholesale market (box 1.3).

2.6.1 Metering

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

Victoria was the first jurisdiction to progress these reforms, launching a rollout of smart meters with remote communications to all customers from 2009. The network costs of the rollout were progressively passed on to retail customers, with network charges rising by around $80 for a typical small customer from 2010–12, with further annual increases of $9–21 from 2012–15.[8] The rollout was close to completion in late 2014.

Regulated network businesses currently provide electricity meters on residential premises. But this arrangement can inhibit competition and consumer choice. It also discourages investment in metering technology that could support the uptake of new and innovative energy products and services.

The AEMC was consulting in 2014 on a CoAG Energy Council proposal to allow competition in the provision of metering and related services. It also progressed related reforms to allow customers more ready access to their electricity consumption data and for multiple trading relationships at the customer's connection point. The reforms aim to create a regulatory framework matching the realities of a dynamic and evolving energy market. The AEMC expects to publish a draft determination on the reforms in December 2014.

Linked to these reforms, the NSW Government in October 2014 announced a competitive framework for the voluntary rollout of smart meters. The framework aims to encourage competition by allowing metering providers, such as electricity retailers or other energy service providers, to offer smart meters to customers as part of energy deals.[9] In its current review of the NSW networks, the AER reclassified certain metering services, making them open to competition. It is also looking at other ways to facilitate the competitive framework. These ways include ensuring exit fees are not unreasonably high, so customers incur only the efficient costs of moving from legacy (regulated) meters to third party provided meters.

If network businesses offer services in a contestable market, then the costs should be clearly separated from the RAB. The AER sets ring fencing guidelines to ensure network businesses do not shift costs between regulated and unregulated activities. Ring fencing may also set out rules for non-discrimination or prohibit a network business engaging in a potentially contestable activity.

8 AER, *Victorian advanced metering infrastructure review—2012–15 AMI budget and charges applications, final determination*, 2011.

9 Hon. Anthony Roberts MP, Minister for Resources and Energy, 'NSW gets smart about meters', Media release, Tuesday 28 October 2014.

2.6.2 Cost-reflective network prices

While smart meters allow consumers to monitor their energy use, price signals are needed to provide incentives for efficient demand response. Under traditional pricing structures, energy users pay the same network price regardless of how or when they use power. Charges to customers that consume large amounts of electricity at peak times do not reflect the costs imposed by those customers on the network. As an example, a residential consumer using a 5 kilowatt air conditioner at peak times causes around $1000 a year in additional network costs, but might pay only $300 under current price structures. Other customers cover the remaining $700, paying more than what it costs to supply their own network services.[10]

Similarly, customers with solar photovoltaic systems do not bear the full cost of their network usage under current price structures, which reward reductions in total energy consumption, regardless of whether this occurs at peak times. For example, a customer can save around $200 in network costs per year by installing a solar photovoltaic system and reducing their use of electricity from the grid. But because most solar energy is generated at non-peak times, the customer will reduce network costs by around $80 only, since they will still use the network at peak times. Other consumers without a solar photovoltaic system cross-subsidise the remaining $120 by paying higher network charges.[11]

To address these inefficiencies, *Power of choice* proposed network prices should vary depending on time of use, thus encouraging retailers to reflect those charges in customer contracts. Time varying prices encourage consumers to choose efficient times to use their electrical appliances (perhaps by shifting some use from peak times when charges are high, to off-peak times such as late evening). More generally, cost-reflective pricing structures may create incentives for customers to invest in local generation and smart devices.

To progress the matter, the CoAG Energy Council in 2013 proposed a rule change to reform distribution network pricing. The AEMC's November 2014 determination set out a new pricing objective and pricing principles for distribution businesses, so prices reflect the efficient costs of providing network services to each consumer. Network businesses will also need to consult with stakeholders when developing their charging structures, so those charges account for consumer impacts.

The reforms remove cross-subsidisation and provide for consumer responses that minimise network costs over time. Those responses include better timing of energy use and using technologies that help to manage efficient energy use and costs. The AEMC estimated 81 per cent of residential customers would face lower network charges in the medium term under cost-reflective pricing, and up to 69 per cent would have lower charges at peak times.[12] Business users with relatively flat load profiles could also expect lower network charges.

The AEMC's November 2014 determination requires the new charging structures to be implemented by 2017, giving energy customers time to adjust to the changes. Victoria was the first jurisdiction to implement time varying prices. From September 2013, Victorian small customers could choose to remain on a traditional tariff structure or move to a more flexible structure.

2.6.3 Demand management and embedded generation

The *Power of choice* reforms include a focus on demand management as an efficient response to rising peak demand. The AER runs incentive schemes for distribution businesses to investigate and implement 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). The incentive schemes fund innovative projects that go beyond initiatives funded through capital and operating expenditure forecasts. In some jurisdictions, the schemes allow businesses to recover revenue forgone as a result of successful demand reduction initiatives.

The CoAG Energy Council in 2013 proposed strengthening incentives for distribution businesses to undertake demand management projects that deliver a net benefit. It proposed:

- separating the current arrangement into two parts—an incentive scheme for demand management and an innovation allowance for demand management and the connection of embedded generation
- allowing the AER to compensate network businesses for lost profit arising from eligible demand management projects, and to offer incentives based on a proportion of the net market benefits of eligible projects.

10 Commissioner Neville Henderson (AEMC), Power of choice and other energy market reforms, Speech delivered to 2014 EUAA conference, 13 October 2014.

11 Paul Smith (CEO, AMEC), Responding to consumer demands, promoting competition and preparing for change, speech delivered to 2014 Australian Institute of Energy symposium, 22 September 2014.

12 Commissioner Neville Henderson (AEMC), Power of choice and other energy market reforms, speech delivered to 2014 EUAA conference, 13 October 2014.

Power of choice also focused on removing impediments to investment in embedded generation that connects directly to the distribution network. A range of stakeholders and market reviews suggested a lack of consistent technical standards for mid-scale embedded generator connections creates a barrier to deployments.

In April 2014 the AEMC finalised a rule change for a clearer enquiry and application process, and set out new information requirements. In May 2014, it commenced a further rule change process to give smaller embedded generator proponents greater flexibility and scope to negotiate a connection. Under the draft rule, released in August 2014, smaller generators can use the newly created connection process for larger embedded generators, or a more flexible negotiated process.

2.7 Transmission network performance

Measures of performance for electricity transmission networks include:

- the reliability of supply (the continuity of energy supply to customers) (section 2.7.1)
- the management of network congestion (section 2.7.2).

2.7.1 Transmission network reliability

Transmission networks are engineered and operated with sufficient capacity to act as a buffer against planned and unplanned interruptions in the power system. While a serious transmission network failure may require the power system operator to disconnect some customers (known as load shedding), most reliability issues originate in distribution networks (section 2.8.1).

Transmission networks in the NEM deliver high rates of reliability. According to Energy Supply Association of Australia data, transmission outages in 2012–13 caused less than two minutes of unsupplied energy across NSW and Victoria. However, Tasmania and South Australia experienced their highest levels of unsupplied energy in over 10 years, at 20.5 minutes and 10.7 minutes respectively. No data were published for Queensland.[13]

Transmission reliability standards

State and territory agencies determine transmission reliability standards. The CoAG Energy Council in February 2013 directed the AEMC to develop a national framework for expressing, setting and reporting on transmission reliability. The process was aligned with work previously commenced on a national framework for distribution network reliability (section 2.8.1).

The AEMC finalised work on the transmission framework in November 2013.[14] Jurisdictions would remain responsible for setting reliability standards (with the option of delegating to the AER), drawing on a transparent economic assessment and community consultation. The process would assess the capital and operating costs of different reliability outcomes and compare these costs with the value customers place on each level of reliability.

Reliability standards would be defined on an input basis, but with the potential for jurisdictions to supplement these standards with output measures. The AEMC recommended the standards be reviewed every five years (to align with the regulatory determination process), but with flexibility for adjustments to reflect new information.

The AEMC also recommended a national approach to reporting on reliability performance.

Value of customer reliability

During 2014, AEMO consulted with industry stakeholders on valuations of customers' willingness to pay for a reliable supply of electricity. The valuations are intended to assist electricity planners, asset owners and regulators to deliver secure and reliable electricity supplies while maintaining reasonable costs for customers. They will also form a key component of the proposed transmission reliability framework.

AEMO's September 2014 report found residential customer reliability values are similar across all NEM states.[15] Residential customers value avoiding outages that are lengthy or occur at times of peak demand. Overall though, business customers tend to value reliability more highly, than residential customers.

2.7.2 Transmission network congestion

Limits (constraints) are imposed on electricity flows along transmission networks to avoid damage and maintain power system stability. These constraints can result in network congestion, especially at times of high demand. Some congestion results from factors within the control of a network business—for example, the scheduling of outages,

13 ESAA, *Electricity gas Australia 2014*.

14 AEMC, *Review of the national framework for distribution reliability, final report*, September 2013; AEMC, *Review of the national framework for transmission reliability, final report*, November 2013.

15 AEMO, *Value of customer reliability review, final report*, September 2014.

maintenance and operating procedures, and network capability limits (such as thermal, voltage and stability limits). Factors such as hot weather can cause congestion by sharply raising air conditioning 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. Rather, the main impact of congestion is a change in the cost of producing electricity. In particular, transmission congestion increases the total price of electricity by displacing low price generation with more expensive generation. Congestion can also lead to inefficient electricity trade flows between the regions (section 1.8).

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. The AER in 2008 introduced incentives encouraging network businesses to reduce the impact of outages on the wholesale market.

The AEMC's transmission frameworks review (completed April 2013) looked at options to manage network congestion. Its preferred approach is an 'optional firm access' regime, whereby generators pay for priority access to the network (section 2.7.4).

2.7.3 Service target performance incentive scheme—transmission

The AER's service target performance incentive scheme provides incentives for transmission businesses to improve or maintain network performance. It acts as a counterbalance to the efficiency benefit sharing scheme (section 2.5.1) so businesses do not reduce expenditure at the expense of service quality.

The scheme in place has three components:

- A *service component* sets performance targets for the frequency of supply interruptions, the duration of outages, and the number of unplanned faults on the network. It also covers protection and control equipment failures. The over- or underperformance of a network against its targets results in a gain (or loss) of up to 1 per cent of the network's regulated revenue.
- A *market impact component* encourages a network to improve its operating practices to reduce congestion. These practices may include more efficiently planning outage timing and duration, and minimising the outage 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 if it eliminates all relevant outage events with a market impact of over $10 per megawatt hour.
- A *network capability component* offers incentive of up to 1.5 per cent of regulated revenue. Payments are available to fund one-off projects that improve a network's capability, availability or reliability at times when users most value reliability, or when wholesale electricity prices are likely to be affected. An eligible project may not exceed $5 million, and the total cost of funding through the component may not exceed 1 per cent of network revenue. 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 market impact component has been progressively applied to network businesses since 2009. The network capability incentive will apply first to transmission networks in NSW, Victoria and Tasmania from 2014.

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 penalty) and +4.5 (the maximum bonus).

Table 2.3 sets out s factors for each network for the past five years. While performance against individual component targets varied, the networks generally received financial bonuses for overall performance. Underperformance was most common in relation to transmission circuit availability targets.

TransGrid in 2013 recorded its worst performance under the service component since the scheme commenced, failing to meet its network availability and average outage duration targets. But improved outcomes under the market impact component meant the business's overall s factor was consistent with the previous year's. Directlink also received a financial penalty in 2013 under the service component of the scheme.

Most transmission networks applied the congestion component of the scheme in 2013, including Murraylink for the first time. Network performance in this area improved in 2013 in all regions other than Queensland. Total payments under the congestion component in 2013 were $33 million.

Table 2.3 S factor values

		2009		2010	2011	2012		2013	
Powerlink (Qld)	Service component		0.17	0.65	0.42	0.44	0.45		0.54
	Market impact component			1.97	1.95	1.98	2.00		1.86
TransGrid (NSW)	Service component	0.22	−0.28	−0.24	−0.13		−0.49		−0.61
	Market impact component		0.39	1.45	1.39		1.48		1.58
AusNet Services (Vic)	Service component		0.51	0.58	0.72		0.82		0.67
	Market impact component				0.00		0.80		1.31
ElectraNet (SA)	Service component		0.60	0.00	0.32		−0.30	−0.17	0.31
	Market impact component				0.52		0.00	1.90	0.00
Transend (Tas)	Service component	0.88	0.11	0.35	−0.41		0.33		0.57
Directlink (Qld–NSW)	Service component		−0.98	−1.00	−0.87		−1.00		−0.47
Murraylink (Vic–SA)	Service component		0.87	1.00	0.70		0.92	−0.41	0.59
	Market impact component								1.19

Notes: TransGrid and Transend reported separately for the first and second halves of 2009. Powerlink reported separately for the first and second halves of 2012. ElectraNet and Murraylink reported separately for the first and second halves of 2013.

Source: AER, *Service standards compliance report* for various businesses.

2.7.4 Optional firm access

The AEMC in April 2013 completed a review of how electricity transmission services are provided and used. From the review, it recommended progressing the design of an 'optional firm access' model to manage the risk of network congestion constraining the dispatch of generation plant. In March 2014 the CoAG Energy Council directed the AEMC to design and test the optional firm access model. During the year, the AEMC undertook development work on core elements of the model's design, and consulted widely with stakeholders.

An element of network performance that has attracted recent policy focus is that pockets of network congestion periodically interfere with the efficient dispatch of generation plant. On the direction of the CoAG Energy Council, the AEMC in April 2013 began work on an *optional firm access* model to better manage this issue. During 2014, it developed core elements of the model's design, and consulted widely with stakeholders.

Under the model, generators would pay transmission businesses to secure firm network access. Transmission businesses would plan and operate their networks to provide the agreed capacity, with charges to generators reflecting the cost of providing that capacity. If congestion prevented a generator with firm access from being dispatched, then non-firm generators contributing to the congestion would compensate firm generators for any loss.

The model also allows generators and retailers to buy firm interregional access, entitling them to the price difference between the relevant regions. Payments for interregional access would guide and fund the expansion of interconnectors.

Optional firm access is intended to create locational signals that account for congestion costs against network expansion costs, providing efficient locational signals for new and existing generation plant. As a result, generation and transmission investment would likely become more efficient. The model also provides incentives for transmission businesses to maximise network availability when it is most valuable to the market.

The AEMC also proposed changing the connections framework to strengthen competition and transparency in the market for constructing network assets required for generator connection. Construction, ownership and operation of connection assets that do not form part of the shared network would be contestable; construction of shared network assets used to connect a generator would also be contestable, but the network business would retain responsibility for their operation. Transmission network businesses would have to provide cost information to connection applicants, and publish standard contracts and design standards.

2.8 Distribution network performance

Measures of performance for electricity distribution networks include reliability of supply and levels of customer service.

2.8.1 Reliability of distribution networks

Reliability is a key service measure for a distribution network. Both planned and unplanned factors can impede network reliability:

- A planned interruption occurs when a distributor needs to disconnect supply to undertake maintenance or construction works. Such interruptions can be timed for minimal impact.
- Unplanned outages occur when equipment failure causes the electricity supply to be unexpectedly disconnected. They may result from operational error, asset overload or deterioration, or routine external causes such as damage caused by extreme weather, trees, animals, vehicle impacts or vandalism.

Most electricity outages in the NEM originate in distribution networks. The capital intensive nature of distribution networks makes it expensive to build sufficient capacity to avoid all outages. In addition, the impact of a distribution outage tends to be localised to part of the network, compared with the potentially widespread impact of a generation or transmission outage. For these reasons, distributors should try to keep outages to efficient levels—based on the value of reliability to the community, and the willingness of customers to pay for reliability—rather than trying to eliminate every possible interruption.

Capital investment to ensure the networks delivered on reliability requirements was a significant driver of rising network charges in recent years. The AEMC in September 2013 proposed a new approach to setting distribution reliability targets that weighs the cost of new investment against the value customers place on reliability and the likelihood of interruptions (section 2.7.1). The valuations customers place on reliability will feed into future regulatory determinations to ensure network investment delivers a secure and reliable electricity supply, while maintaining reasonable costs for consumers.

Some jurisdictions are already moving to reform distribution reliability standards. The removal of strict input based reliability standards for Queensland networks from 1 July 2014 is expected to save $2 billion in capital expenditure over the next 15 years. Supply interruptions will likely increase by 13 minutes for urban customers in 2020 (to 83 minutes compared with 69 minutes under the previous standard).[16]

Similarly, the NSW Government in July 2014 removed deterministic planning obligations placed on distributors in network licence conditions. The remaining conditions focus solely on 'output' standards for reliability, providing more discretion for the businesses to determine the most appropriate ways to plan their network to meet the standard.[17]

Concerns about the impact of network investment on retail electricity prices led the CoAG Energy Council in 2012 to call for a national framework on distribution reliability standards. In response, the AEMC in September 2013 proposed a new approach to setting distribution reliability targets. The approach, undertaken independently of the network provider, would weigh the cost of new investment against the value that customers place on reliability and the likelihood of interruptions, to help set efficient output based reliability targets. The assessment would account for specific areas of the distribution network with high economic or social importance. The AER's service target performance incentive scheme would provide incentives for network businesses to meet their reliability targets.

To progress this reform, the CoAG Energy Council in December 2013 requested the AEMC develop common definitions for distribution reliability measures as an interim measure. In September 2014 the AEMC published harmonised definitions of those measures. It proposed the AER develop guidelines to apply the definitions.

The CoAG Energy Council also conferred responsibility on the AER to establish values of reliability to customers, for setting reliability requirements in the round of regulatory determinations commencing in mid-2019. AEMO in 2014 finalised a review of the value of customer reliability that could be used for this purpose (section 2.7.1).

Distribution reliability indicators

The key indicators of distribution reliability in Australia are the system average interruption duration index (SAIDI) and the system average interruption frequency index (SAIFI). The indicators relate to the average duration and frequency of network interruptions and outages. They do not distinguish between the nature and size of loads affected by supply interruptions.

16 Queensland Department of Energy and Water Supply, *Changes to electricity network reliability standards factsheet*.

17 AER, *Ausgrid distribution determination 2015–16 to 2018–19, draft decision, Attachment 6: Capital expenditure*, November 2014.

Figure 2.9 estimates historical data on the average duration (SAIDI) and frequency (SAIFI) of outages experienced by distribution customers. The data include outages that originated in the generation and transmission sectors. Issues with reliability data limit the validity of comparisons across jurisdictions. In particular, the data rely on the accuracy of the businesses' information systems, which may vary considerably. Geographic conditions and historical investment also differ across the networks.

Noting these caveats, the SAIDI data indicate electricity networks in the NEM delivered reasonably stable reliability outcomes over the past few years. Across the NEM, a typical customer experienced around 200–250 minutes of outages per year, but with significant regional variations.

The average outage duration across the NEM in 2011–12 was the lowest in a decade, partly because weather conditions were benign. But the average outage duration rose in all jurisdictions in 2012–13. The largest rise occurred for Queensland (590 minutes, up from 210 minutes in 2011–12) and Tasmania (450 minutes, up from 230 minutes).

Queensland experiences significant variations in performance, partly because its large and widely dispersed rural networks make it more vulnerable to outages than are other jurisdictions. It faced an increase in severe weather activity in 2012–13, including ex-tropical cyclone Oswald that disrupted network services over multiple days in January. Tasmanian performance was also affected by weather conditions, with bushfires on the Tasman Peninsula in January 2013 resulting in a large number of supply interruptions.

The SAIFI data show the average frequency of outages was relatively stable between 2003–04 and 2012–13, with energy customers across the NEM experiencing an outage around twice a year. The average frequency of outages in 2012–13 was higher than that of the previous year in all jurisdictions except NSW and Tasmania. However, the average frequency of outages across the NEM jurisdictions remained lower than the average over the past 10 years. Victoria recorded the largest increase in outage frequency, with 2.1 outages per customer (up from 1.7 outages in 2011–12).

Service target performance incentive scheme—distribution

Through its service target performance incentive scheme (section 2.8.3), the AER sets targets for the average duration and frequency of outages for each distribution business. The targets are based on outcomes for the business over the previous five years. From a customer perspective, the unadjusted reliability data in figure 2.9 are relevant. But, in assessing network performance, the AER normalises data to exclude interruption sources beyond the network's reasonable control.

In 2012–13 businesses other than Energex failed to meet at least one reliability target, with outage duration being the most common missed target. United Energy underperformed against all its reliability targets. AusNet Services missed all its targets relating to the frequency of momentary outages. The scheme did not apply to NSW and ACT network businesses.

2.8.2 Distribution service performance incentives

The AER's service target performance incentive scheme encourages distribution businesses to maintain or improve network performance. It focuses on supply reliability and customer service, including the timely connection of services and call centre performance. A guaranteed service level (GSL) component provides for a business to pay customers if its performance falls below threshold levels.[18]

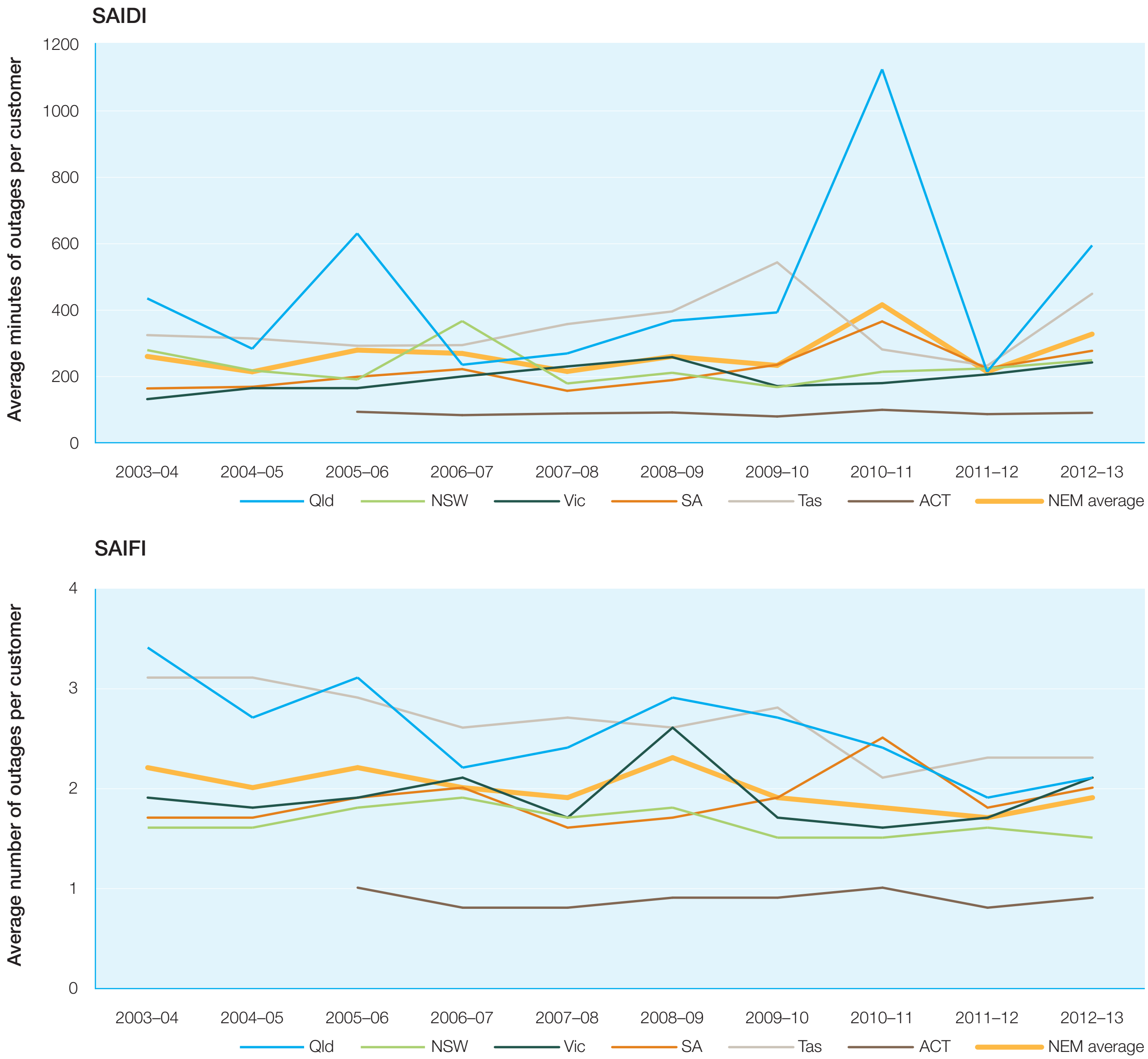
The incentive scheme provides financial bonuses and penalties of up to 5 per cent of revenue to network businesses that meet (or fail to meet) performance targets.[19] The results are standardised for each network, to derive an 's factor' that reflects deviations from target performance levels. While the scheme aims to be nationally consistent, it has flexibility to deal with the differing circumstances and operating environments of each network. The scheme applies in Queensland, Victoria, South Australia and Tasmania, and as a paper trial in NSW and the ACT (where targets are set but no financial penalties or rewards apply).

Since 1 January 2012, the Victorian distribution businesses have been subject to an additional scheme with incentives to reduce the risk of fire starts that originate from a network, or are caused by something coming into contact with the network. This 'f factor' scheme rewards or penalises the businesses $25 000 per fire under or over their targets. AusNet Services was the only business to outperform its target for 2013, receiving an incentive payment of $2 million. Penalties for the other businesses ranged from $65 000 for CitiPower to $2.4 million for Powercor.

18 The GSL component does not apply if the distribution business is subject to jurisdictional GSL obligations.

19 Queensland network businesses face financial bonuses and penalties of up to 2 per cent of revenue.

Figure 2.9
System reliability



Notes:

The data reflect total outages experienced by distribution customers, including outages originating in generation and transmission. The data are not normalised to exclude outages beyond the network operator's reasonable control.

The NEM averages are weighted by customer numbers.

Victorian data are for the calendar year beginning in that period.

Sources: Performance reports by the AER, the QCA (Queensland), the ESC (Victoria), ESCOSA (South Australia), OTTER (Tasmania), the ICRC (ACT), AusGrid, Endeavour Energy and Essential Energy. Some data are AER estimates derived from official jurisdictional sources.

Jurisdictional GSL schemes

Jurisdictional GSL schemes provide for payments to customers experiencing poor service. They mandate payments for poor service quality in matters such as streetlight repair, the frequency and duration of supply interruptions, new connections and notice of planned interruptions. The majority of payments in 2012–13 and 2013–14 related to the duration and frequency of supply interruptions exceeding specified limits. The outcomes are consistent with previous years' results:

- In Victoria in 2013, GSL payments rose in the United Energy, Powercor and CitiPower networks. However, overall payments fell to \$6.2 million (from \$7.5 million in the previous year) following a large reduction in reliability payments in the AusNet Services network (from \$6.6 million in 2012 to \$4.9 million in 2013).
- GSL payments rose by 57 per cent in Queensland's Energex network in 2012–13 (to \$450 000), largely due to weaker reliability performance. Ergon Energy also had a large increase in payments for failing to meet outage duration targets, but these payments were offset by improved performance in notifying customers of supply interruptions. Both networks improved their performance against reliability targets in 2013–14, resulting in a 30–40 per cent fall in GSL payments.
- SA Power Networks (South Australia) and Aurora Energy (Tasmania) increased their GSL payments over the two years, following a rise in the number of severe weather events. SA Power Networks payments rose from \$2.6 million in 2011–12, to almost \$9 million in 2013–14. Aurora Energy's payments rose from \$790 000 to \$3 million.
- NSW networks do not have customer service payments related to reliability of supply. Payments in 2012–13 on other customer service measures—including timely provision of services and notice of interruptions—were at similar levels to those in the previous year.

Woodside

3 UPSTREAM GAS MARKETS

Australia produced 1400 petajoules (PJ) of gas in 2013–14 for domestic use.[1] While gas is widely used for industrial manufacturing, around 31 per cent of Australian gas consumption is for electricity generation.[2] Household demand is relatively small, except in Victoria, where residential demand accounts for around one-third of total consumption. This proportion reflects the widespread use of gas for cooking and heating in that state.

Australia also produces liquefied natural gas (LNG) for export, accounting for 43 per cent of Australia's gas production. This proportion is about to rise significantly, with the commencement of LNG exports from Queensland in 2014–15.

Australia's domestic gas supply chain begins with exploration and development activity, which may involve geological surveys and the drilling of wells (figure 3.1). In the commercialisation phase, extracted gas is processed to separate methane from liquids and other gases, and to remove impurities. The two main types 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. In contrast, CSG is a form of gas extracted from coal beds. Rising gas prices and improved extraction techniques have raised commercial interest in developing other types of unconventional gas such as shale and tight gas;[3] Santos began producing shale gas in the Cooper Basin in 2012.

In the domestic market, high pressure transmission pipelines transport gas from gas fields to demand hubs. A network of distribution pipelines then delivers gas from points along transmission pipelines to industrial customers, and from gate stations (or city gates) to consumers in cities, towns and regional communities. Gate stations measure the gas leaving a transmission system for billing and gas balancing purposes, and reduce the pressure of the gas before it enters a distribution network. Energy retailers complete the supply chain; they buy gas and package it with pipeline transportation services for sale to customers.

This chapter covers gas production and wholesale market arrangements. While it focuses on domestic markets in eastern Australia in which the Australian Energy Regulator (AER) has regulatory responsibilities,[4] it also refers to domestic markets in Western Australia and the Northern Territory, and to LNG export markets. Other segments of the gas supply chain are considered in chapters 4 (transmission and distribution pipelines) and 5 (retail markets).

3.1 Gas reserves and production

In February 2014 Australia's proved and probable (2P) gas reserves stood at around 139 000 PJ, comprising 96 000 PJ of conventional gas and 43 000 PJ of CSG (table 3.1). Australia produced 2450 PJ of gas in 2013–14, of which 57 per cent was for the domestic market. The balance—all sourced from offshore basins in Western Australia and the Timor Sea—was exported as LNG. This ratio will increase, with the development of new LNG projects in Queensland and Western Australia (section 3.1.2).

3.1.1 Geographic distribution and major players

Eastern Australia contains around 36 per cent of Australia's gas reserves, of which 87 per cent are CSG reserves, mostly located in Queensland's Surat–Bowen Basin (figures 3.2 and 3.8). In New South Wales (NSW), limited commercial production of CSG occurs in the Sydney and Gunnedah basins.

The Surat-Bowen Basin supplies 36 per cent of the eastern gas market. Over 98 per cent of gas produced in the basin is CSG. Ownership is relatively diverse, with BG Group, Origin Energy and ConocoPhillips being the largest producers. Other players include Sinopec, Santos, Shell, PetroChina, Petronas, Total and AGL Energy. The same businesses also own the majority of reserves in the basin. Many of these entities entered the Queensland market to develop major LNG projects (section 3.1.2).

The Gippsland, Otway and Bass basins off coastal Victoria serve the Victorian market and provide gas to NSW, South Australia and Tasmania. The Gippsland Basin is the most significant of the three, supplying 34 per cent of the eastern market. A joint venture between ExxonMobil and BHP Billiton accounts for 96 per cent of the basin's production. Production in the Otway Basin (15 per cent of eastern production) has risen significantly since 2004. Origin Energy, BHP Billiton and Santos are the main players. The principal

1 Bureau of Resources and Energy Economics (BREE), unpublished, 2014. Due to accounting differences, BREE production data is typically higher than the EnergyQuest data published in previous editions of this report.

2 BREE, *Gas market report*, October 2013, p. 26.

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

4 The AER has compliance and enforcement responsibilities under the National Gas Rules in relation to the National Gas Bulletin Board, the Victorian wholesale gas market and the short term trading market in Sydney, Adelaide and Brisbane.

Figure 3.1
Domestic gas supply chain

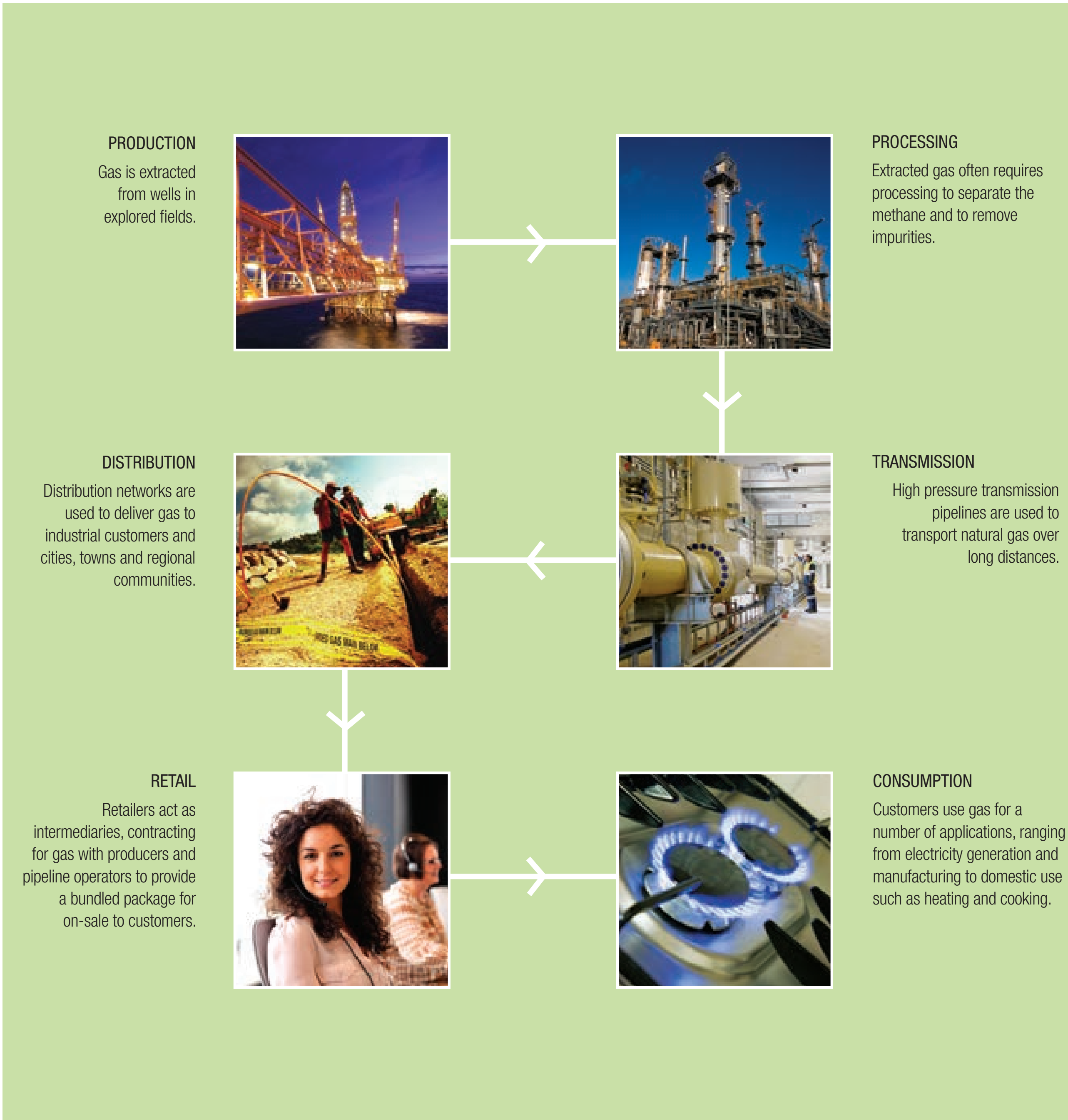


Image sources: Origin Energy, Woodside, Jemena.

Table 3.1 **Gas reserves and production, 2014**

GAS BASIN	GAS PRODUCTION[1,2] (YEAR TO JUNE 2014)			PROVED AND PROBABLE RESERVES[3] (FEBRUARY 2014)	
	PETAJOULES	SHARE OF AUSTRALIAN PRODUCTION (%)	CHANGE FROM PREVIOUS YEAR (%)	PETAJOULES	SHARE OF AUSTRALIAN RESERVES (%)
EASTERN AUSTRALIA					
Cooper (South Australia – Queensland)	104	4.3	–2.9	1 802	1.3
Gippsland (Victoria)	279	11.4	–9.4	3 568	2.6
Otway (Victoria)	119	4.9	–1.6	750	0.5
Bass (Victoria)	17	0.7	47.8	250	0.2
Surat–Bowen (Queensland)					
conventional gas	5	0.2	9.8	131	0.1
coal seam gas	290	11.8	5.3	41 156	29.6
New South Wales basins					
conventional gas	0	0.0	0.0	17	0.0
coal seam gas	5	0.2	–14.4	2 266	1.6
EASTERN AUSTRALIA TOTALS	**820**	**33.5**		**49 940**	**36.0**
WESTERN AUSTRALIA					
Browse	0	0.0	0.0	17 384	12.5
Carnarvon	1 599	65.2	3.1	70 386	50.7
Perth	6	0.2	–22.4	54	0.0
NORTHERN TERRITORY					
Amadeus	<1	0.0	–4.6	178	0.1
Bonaparte (Blacktip)	26	1.1	0.2	870	0.6
AUSTRALIAN TOTALS	**2 451**			**138 812**	
DOMESTIC CONSUMPTION	1 395				
LIQUEFIED NATURAL GAS (EXPORTS)	1 055				
TIMOR SEA					
Joint Petroleum Development Area[4]	260			114	

1 Production is conventional gas, other than in Surat–Bowen and NSW basins.

2 Includes gas consumed on site in the production process.

3 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.

4 Gas reserves in the Joint Petroleum Development Area are jointly managed by Australia and Timor-Leste. Revenue from production is split between Timor-Leste and Australia on a 90:10 basis. Production data for 2013–14 is preliminary, based on ABS trade statistics.

Note: Due to accounting differences, BREE production data is typically higher than the EnergyQuest data published in previous editions of this report.

Sources: Gas production: Bureau of Resources and Energy Economics (BREE), unpublished; gas reserves: EnergyQuest, *EnergyQuarterly,* February 2014.

producers in the smaller Bass Basin are Origin Energy and Australian Worldwide Exploration.

In central Australia, a joint venture led by Santos dominates production in the Cooper Basin, which supplies 13 per cent of the eastern market. The other participants are Beach Petroleum and Origin Energy. After several years of decline, Cooper Basin reserves in central Australia rose over the past three years, with new activity focused on the development of shale gas. Santos commenced shale gas production in 2012.

Western Australia's offshore Carnarvon Basin holds half of Australia's 2P gas reserves. It is Australia's largest producing basin, supplying both the domestic market and LNG exports. Several major companies have equity in the basin. The businesses participate in joint ventures, typically with overlapping ownership interests. Chevron, Shell and ExxonMobil have the largest reserves, given their equity

Figure 3.2

Australian gas basins and major transmission pipelines

Pipeline	No.
Moomba to Sydney Pipeline	1
Eastern Gas Pipeline (Longford to Horsley Park)	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 (Ballera to Wallumbilla)	9
Roma to Brisbane Pipeline	10
Queensland Gas Pipeline (Wallumbilla to Gladstone/Rockhampton)	11
Amadeus Basin to Darwin Pipeline	12
Bonaparte Pipeline	13
Dampier to Bunbury Natural Gas Pipeline	14
Goldfields Gas Pipeline	15

Source: AER.

Pluto LNG Plant (Woodside)

in the Gorgon project. Apache Energy, Woodside and Santos are the largest producers for Western Australia's domestic market.

The principal reserves in the Northern Territory are located in the Bonaparte Basin in the Timor Sea. Eni Australia owns over 80 per cent of Australian reserves in the basin, which produces LNG for export and gas for consumption in the Northern Territory (via the Bonaparte Pipeline). The basin displaced the Amadeus Basin as the main source of gas for the Northern Territory.

3.1.2 Liquefied natural gas exports

The production of LNG converts gas into liquid. The development of an LNG export facility requires large upfront capital investment in processing plant, port and shipping facilities. The magnitude of investment requires access to substantial reserves of gas, which may be sourced through the owner's interests in gas fields, a joint venture arrangement with a gas producer, or long term gas supply contracts. Australia operates LNG export projects in Western Australia's North West Shelf and Darwin.

Global gas demand slowed during 2013–14, translating into softer prices. International LNG spot prices in September 2014 reached their lowest level since April 2011.[5] Despite this softening, the value of Australia's LNG exports rose in 2013–14 by 15 per cent to $16.5 billion, becoming Australia's third largest export after iron ore and coal.[6]

Australia's LNG export sector is about to be transformed, with three major LNG projects in Queensland nearing completion. Projections of rising international energy prices, together with rapidly expanding reserves of CSG in the Surat–Bowen Basin, spurred the development of the projects. The three projects, the world's first to convert CSG to LNG, include processing facilities at the port of Gladstone and transmission pipelines to ship gas from the Surat–Bowen Basin:

- The $20 billion Queensland Curtis LNG (QCLNG) project, owned by BG Group is scheduled to begin LNG exports in late 2014. The project will initially produce 8.5 million tonnes of LNG per year, with potential capacity of 12 million tonnes.
- The $24.7 billion Australia Pacific LNG project (Origin Energy, ConocoPhillips and Sinopec) is expected to begin LNG exports in 2015.
- The $18.5 billion Gladstone LNG project (Santos, Petronas, Total and Kogas) will initially produce 7.8 million tonnes per year, with potential capacity of 10 million tonnes. The first exports are expected in 2015.

In 2014 the LNG project developers continued to build and test wells, processing facilities, liquefaction plants and transmission pipelines from CSG fields to the Gladstone shipping terminal. The developers also interconnected their pipelines to enable physical gas flows between projects.

Some new production facilities became fully operational in 2014, including Australia Pacific LNG's Condabri Central production facility and QCLNG's Ruby Jo facility. Other facilities at Bellevue (QCLNG), Condabri, Reedy Creek and Orana (Australia Pacific LNG) were scheduled to commence production late in 2014.

Major LNG players are also expanding capacity in Western Australia and northern Australia:

- Chevron's Gorgon project (Carnarvon Basin) is nearing completion. It is scheduled to deliver its first shipment of LNG by the middle of 2015 and expected to produce around 15.6 million tonnes of LNG per year. The project partners signed long term sales agreements with international buyers. In addition, Chevron committed in September 2011 to the $29 billion Wheatstone project (foundation capacity of 8.9 million tonnes per year). The project is expected to produce its first LNG in 2016.
- Shell's $10–13 billion Prelude floating LNG project (Browse Basin) is under construction and expected to commence production in 2017. The project will produce 3.6 million tonnes per year.
- Construction of the $34 billion Ichthys LNG project (Browse Basin) commenced in May 2012. The project is expected to produce 8.4 million tonnes of LNG and 1.6 million tonnes of liquefied petroleum gas annually, with production expected to begin in 2016.
- Woodside announced in 2013 that development of the Browse LNG project would involve an offshore project using floating LNG technology. It expects to commence front end engineering and design work in 2014, with a final investment decision targeted for 2015.

3.1.3 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. Gas storage enhances the security of energy supply by allowing for system injections at short notice to better manage peak demand and emergencies. It also allows producers to meet contract

5 EnergyQuest, *EnergyQuarterly August 2014*, Media release, 29 August 2014.

6 EnergyQuest, *EnergyQuarterly August 2014*, Media release, 29 August 2014.

requirements if production is unexpectedly curtailed. And it provides retailers with a hedging mechanism if gas demand varies significantly from forecast.

The importance of gas storage in managing supply and demand fluctuations will rise as east coast dynamics evolve to integrate an LNG export market.[7] Conventional gas storage facilities are located in Victoria, Queensland and the Cooper Basin. In Victoria, the largest facility is the Iona gas plant (owned by EnergyAustralia), which has 22 PJ of storage capacity and can deliver 570 terajoules (TJ) of gas per day. In Queensland, AGL Energy stores gas underground at the depleted Silver Springs reservoir in central Queensland (35 PJ). This facility supports the development of the Curtis LNG project and allows AGL Energy to manage its gas supply during seasonal variations in summer and winter. The Cooper Basin Joint Venture owns 85 PJ of underground storage at Moomba and another 14 PJ at Ballera.[8]

The Dandenong LNG storage facility in Victoria (0.7 PJ) is Australia's only LNG storage facility. It provides the Victorian Transmission System with additional capacity to meet peak demand and provide security of supply. In NSW, AGL Energy is constructing a $300 million LNG storage facility (1.5 PJ) near Newcastle to secure supply during peak periods and supply disruptions. Due to be completed by 2015, the facility will have a peak supply rate of 120 TJ per day.

3.2 Domestic gas market

In the domestic market, producers sell gas to major industrial, mining and power generation customers, and to energy retailers that onsell the gas to business and residential customers. Australian gas prices have generally been low by international standards, typically $3–4 per gigajoule. With gas in Australia historically perceived as a substitute for coal and coal fired electricity generation, Australia's low cost coal sources effectively capped gas prices.

While gas prices were historically struck under confidential, long term contracts, the industry has shifted towards shorter term contracts, the inclusion of review provisions, and the use of spot markets:

- A short term trading market for gas was launched in Sydney and Adelaide in 2010, with Brisbane following in 2011 (section 3.2.1). The market provides a means for participants to manage contractual imbalances, and is supported by a National Gas Bulletin Board (section 3.2.3).
- Victoria established a wholesale spot market in 1999 for gas sales, to manage system imbalances and pipeline constraints (section 3.2.2).
- As part of the Australian Government's energy market reforms, a gas supply hub was launched at Wallumbilla, Queensland in March 2014. The hub, which links gas markets across eastern Australia, aims to relieve bottlenecks by facilitating short term gas trades (section 3.2.4).

The AER monitors and enforces compliance with the National Gas Law and Rules in relation to spot markets and the bulletin board. Timely and accurate data and efficient pricing maintain confidence in gas markets and encourage efficient investment in energy infrastructure. The AER monitors the markets and bulletin board to improve data provision and to detect any evidence of the exercise of market power. It draws on this information to publish weekly reports on gas market activity in eastern Australia.

3.2.1 Short term trading market

A short term trading market—a wholesale spot market for gas—has been implemented at selected hubs (junctions) linking transmission pipelines and distribution systems in eastern Australia. The Australian Energy Market Operator (AEMO) operates the market, which was designed to enhance gas market transparency and competition by setting prices based on supply and demand conditions.[9]

The market was launched in September 2010 in Sydney and Adelaide, and was extended to Brisbane in December 2011. Each hub is scheduled and settled separately, but all hubs operate under the same rules. Victoria retains a separate spot market for gas (section 3.2.2).

The short term trading market provides a spot mechanism for parties to manage contractual imbalances between their gas injections (deliveries) into and withdrawals from the market. Market participants include energy retailers, power generators and other large gas users. Shippers deliver gas to be sold in the market, and users buy gas for delivery to customers; many participants act both as shippers and users, but only their net position is traded.

Gas is traded a day ahead of the actual 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

7 Australian Government (Department of Industry), *Energy green paper*, September 2014.

8 BREE, *Eastern Australian domestic gas market study*, January 2014.

9 AEMO publishes an explanatory guide on its website: AEMO, *Overview of the short term trading market for natural gas*, 2011.

Box 3.1 Reducing excessive MOS payments

The AER in 2013 investigated the high costs of MOS services in the Sydney and Adelaide hubs of the short term trading market, responding to concerns that these costs may deter new entry. It found a tendency for excessive MOS payments on high demand days. In some instances, the volume of MOS gas significantly exceeded the magnitude of the underlying physical imbalance in gas volumes. The issue peaked on 25 June 2013, when MOS payments in Adelaide exceeded $250 000.

The AER found nomination issues in Sydney and design issues in Australian Gas Networks' Adelaide distribution network periodically raised MOS volumes above necessary levels. It met with industry participants in both markets to resolve the issues. The nomination issue in Sydney was subsequently resolved.

In Adelaide, Australian Gas Networks investigated solutions to the network design issue, which had caused parts of its network to be better served by gas from the Moomba to Adelaide Pipeline than from the SEA Gas pipeline. In July 2014 it opened the Elizabeth valve that had previously isolated part of the network from gas sourced from SEA Gas. Following this action, MOS payments were significantly lower than in the corresponding period in 2013.

Some excessive MOS payments still occur, likely reflecting the timing of nominations and renominations by participants on the SEA Gas pipeline. As an example, a MOS payment of almost $200 000 on 20 August 2014 occurred when renominations to increase flows on SEA Gas were made late in the day to apply overnight. The AER is closely monitoring such activity to ensure participants do not do anything for the purpose of creating a pipeline deviation for which MOS may be required (rule 399(6)) of the National Gas Rules). Further, the eligibility requirements for providing MOS services were broadened from June 2014 to promote competition. One change allows participants to submit MOS offers on a monthly rather than quarterly basis.

On 19 October 2014 MOS payments on the Moomba to Adelaide Pipeline were $67 800, despite only 4.4 TJ of MOS being required. In part, the high payment reflected some participants' decision to offer less MOS in October than in other months. MOS offers and payments returned to normal levels in the following weeks.

gas. All gas supplied according to the market schedule is settled at this price. The market provides incentives for participants to keep to their schedules, and the market rules require the participants 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 separate schedule for that pipeline to ensure it is kept in physical balance. On the gas day, quantities delivered to and withdrawn from a hub may not match the day-ahead nominations, as a result of 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).

Pipeline operators use balancing gas to prevent imbalances in gas supply to distribution networks if demand forecasts are inaccurate. AEMO procures this balancing gas—market operator services (MOS)—from shippers that have the capacity to absorb daily fluctuations, and the short term trading market sets a price for it. Gas procured under this balancing mechanism is settled primarily through deviation payments and charges on the parties responsible for the imbalances. The AER acted this year to reduce excessive MOS payments in the market (box 3.1).

Section 3.4 notes recent price activity in the short term trading market. The market has a floor price of $0 per gigajoule and a cap of $400 per gigajoule.

3.2.2 Victoria's gas wholesale market

Victoria introduced a spot market for gas in 1999 to manage gas flows on the Victorian Transmission System and allow market participants to buy and sell gas at a spot price. Market participants submit daily bids ranging from $0 per gigajoule (the floor price) to $800 per gigajoule (the price cap). Following initial bidding at the beginning of the gas day (6 am), the bids may be revised at 10 am, 2 pm, 6 pm and 10 pm.

At the beginning of each day, AEMO stacks supply offers and selects the least cost bids to match demand across the market. This process establishes a spot market clearing price. In common with the short term trading market, only net positions are traded—that is, the difference between a participant's scheduled gas deliveries into and out of the market. AEMO can schedule additional gas injections (typically LNG from storage facilities) at above market price to alleviate short term transmission constraints.[10]

Typically, gas traded at the spot price accounts for 10–20 per cent of wholesale volumes in Victoria, after accounting for net positions. The balance of gas is sourced via bilateral contracts or vertical ownership arrangements between producers and retailers. Section 3.4 notes recent price activity.

The Victorian gas market and short term trading market have differences 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.

3.2.3 National Gas Bulletin Board

The National Gas Bulletin Board, launched in 2008, is a web based platform (www.gasbb.com.au) that promotes trade in gas. It covers major gas production plants, storage facilities, demand centres and transmission pipelines in eastern Australia. The bulletin board provides transparent, real-time information on the gas market, system constraints and market opportunities. It covers:

- gas pipeline capabilities (maximum daily volumes) and three day outlooks for capacity and volume, and actual gas volumes
- production capabilities (maximum daily quantities) and three day outlooks for production facilities
- pipeline storage (linepack) and three day outlooks for gas storage facilities
- daily demand forecasts, changes in supply capacity, and the management of gas emergencies and system constraints.

In March 2014 the Council of Australian Governments (CoAG) Energy Council asked AEMO to overhaul the bulletin board's functionality to better serve the needs of Australia's fast evolving gas markets. AEMO is developing refinements in consultation with stakeholders, including gas pipeline owners and operators, facility operators, major shippers, retailers and gas users. In November 2014 AEMO was progressing the site's redevelopment and testing.

In 2014 a number of new production facilities associated with LNG projects became operational and began reporting on the bulletin board. The AER engaged with industry, including LNG producers, to ensure they provide accurate capacity outlooks and production data to AEMO for the bulletin board.

3.2.4 Gas supply hub at Wallumbilla, Queensland

In consultation with industry, AEMO launched a new gas supply hub at Wallumbilla, Queensland in March 2014. Energy ministers commissioned the project to support south east Queensland's rapidly expanding gas industry. As a pipeline interconnection point, Wallumbilla links gas markets in Queensland, South Australia, NSW and Victoria.

The hub uses a brokerage model to match and clear trades between gas buyers and sellers at Wallumbilla's three pipeline delivery points. While the market initially operates only at Wallumbilla, it may later be introduced at other locations. The flexible design can be adapted to the circumstances of any location. The CoAG Energy Council will review the hub model in 2015 and consider refinements based on operational experience.

As with other spot markets, the AER monitors and enforces compliance with the market conduct rules, and reports on market activity. Section 3.5 further discusses the hub, including an overview of activity in 2014.

3.3 Upstream competition

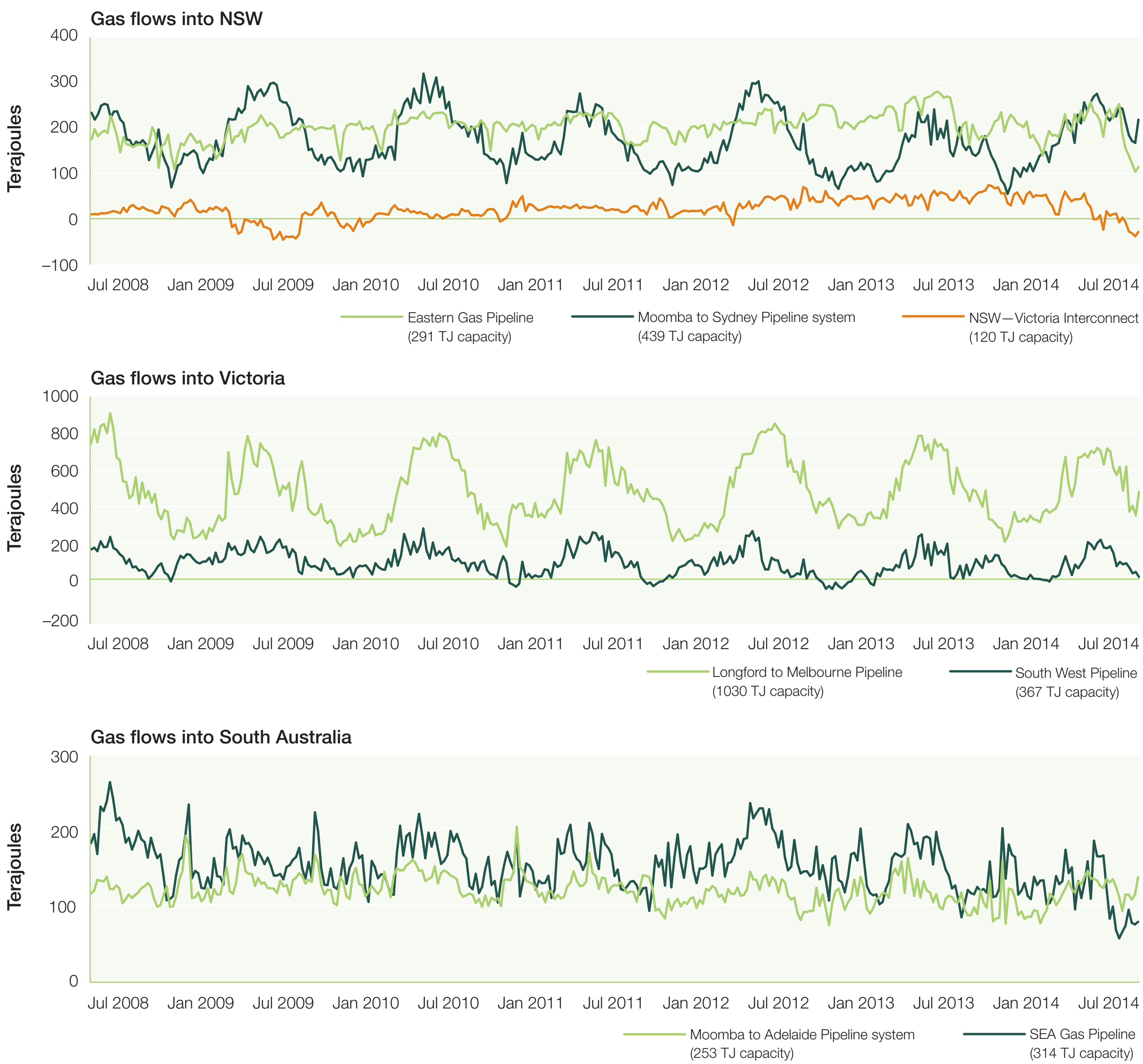
An interconnected transmission pipeline system links the major gas basins in southern and eastern Australia (chapter 4). While gas tends to be purchased from the closest possible source to minimise transport costs, pipeline interconnection provides energy customers with greater choice and enhances the competitive environment for gas supply. Gas customers in Sydney, Melbourne, Canberra, Adelaide, Perth and Darwin are served by multiple transmission pipelines from multiple gas basins; by contrast, Brisbane is served by only one pipeline (Roma to Brisbane).

The AER draws on the bulletin board to report on gas flows in eastern Australia. Figure 3.3 illustrates trends in gas delivery from competing basins into NSW, Victoria and South Australia since the bulletin board opened in July 2008:

10 AEMO publishes an explanatory guide on its website: AEMO, *Guide to Victoria's declared wholesale market*, 2012.

Figure 3.3

Gas flows in eastern Australia



Note: Negative flows on the NSW–Victoria Interconnect represent flows out of NSW into Victoria.

Sources: AER; National Gas Bulletin Board (www.gasbb.com.au).

- NSW sources gas from basins in Queensland and central Australia (via the Moomba to Sydney Pipeline), and from Victoria (via the Eastern Gas Pipeline and the NSW–Victoria Interconnect). Gas flows on the Moomba to Sydney Pipeline fluctuate seasonally, while flows on the Eastern Gas Pipeline are steadier. A downturn in gas flows from Victoria in 2014 reflects a weakening in gas demand in NSW. Overall, gas flows into NSW were 30 per cent lower in September–October 2014 than in the corresponding period in 2013. But gas flows on the Moomba to Sydney Pipeline were steadier, due to very low spot gas prices in Queensland.
- While the Gippsland Basin remains the principal source of gas supply for Victoria, the state also sources some of its requirements from the Otway Basin via the South West Pipeline (an artery of the Victorian Transmission System). Figure 3.3 illustrates the seasonal nature of Victorian gas demand, with significant winter peaks.
- South Australia sources gas from central Australia and Queensland via the Moomba to Adelaide Pipeline, and from Victoria via the SEA Gas Pipeline.

The extent to which interconnection benefits customers depends on a range of factors, including the availability of gas and pipeline capacity from alternative sources. In particular, capacity constraints limit access to some pipelines. Access seekers must decide whether to try to negotiate a capacity expansion. For a covered pipeline, the regulator may be asked to arbitrate a dispute over capacity expansions.

3.4 East coast gas market activity

The development of LNG export projects in Queensland is exerting significant pressure on the domestic gas market. Gas production in eastern Australia is forecast to treble over the next two decades to 2033 to meet international LNG demand,[11] with the first exports scheduled for 2014–15.

While Queensland's LNG proponents each have dedicated gas reserves, they are also sourcing reserves that might otherwise have been available to the domestic market. This development has made it difficult for domestic customers to buy gas under medium to long term contracts.[12] Adding to this difficulty, a large number of domestic gas supply contracts will soon expire. In NSW, existing contracts will meet less than 15 per cent of that state's gas demand by 2018.[13]

11 AEMO, *Gas statement of opportunities*, May 2014.

12 K Lowe Consulting, *Gas market scoping study: a report for the AEMC*, July 2013.

13 BREE, *Gas market report*, October 2013, pp. 17, 41.

The effect of these tight market conditions was apparent in 2013, with prices in new gas contracts reportedly linked to international oil prices or LNG netback.[14] Modelling by Sinclair Knight Merz (SKM) in 2013 forecast wholesale gas prices would rise from around $4 per gigajoule to $9 per gigajoule by 2016, with reasonable price alignment across cities.[15] The Grattan Institute and Deloitte Access Economics confirmed this order of price increases were being factored into new contracts in 2014.[16] SKM projected prices would stabilise at around $7.50–$8 per gigajoule by 2019. The Australian Government's energy green paper noted in September 2014 that sellers appear to have access to more market information than buyers, raising policy concerns.[17]

Consistent with developments in the contract market, spot gas prices rose strongly in 2012–13, averaging over $5 per gigajoule in Sydney, Adelaide and Brisbane (figure 3.4 and table 3.2). In particular, Brisbane prices diverged from other hubs, with weekly averages as high as $10 per gigajoule in January 2013. In part, the rises reflected a significant tightening of supply as producers reserved gas for Queensland's LNG projects. The rises also reflected the introduction of carbon pricing on 1 July 2012, which improved the cost competitiveness of gas powered electricity generation and triggered a withdrawal of coal fired generation capacity from the electricity market.

Average daily spot prices for gas in all markets were significantly lower in 2013–14 than in the previous year. Average prices fell by 23 per cent in Brisbane and Sydney, 15 per cent in Adelaide and 13 per cent in Melbourne. They ranged from $4.03 per gigajoule (Sydney) to $4.55 per gigajoule (Brisbane).

Spot prices settled around $4 per gigajoule for most of 2013–14 in all hubs except Brisbane, where prices fell from $5–6 per gigajoule towards $2 per gigajoule over the year. Winter prices were lower in all hubs in 2014 than in 2013, averaging just below $4 per gigajoule in Sydney, Melbourne and Adelaide (figure 3.5). The abolition of carbon pricing, which took effect on 1 July 2014, reduced the cost competitiveness of gas powered generation, contributing to weaker gas demand.

The divergence of Queensland prices from those in southern markets during 2014 coincided with rising gas production in south east Queensland (figure 3.6). New production

14 LNG netback prices simulate an export parity price by stripping out shipping, transportation and liquefaction costs.

15 SKM, *Gas market modelling*, Gas Market Study Task Force, 2013.

16 Grattan Institute, *Gas at the crossroads*, Tony Wood, October 2014.

17 Australian Government (Department of Industry), *Energy green paper*, September 2014.

Figure 3.4
Spot gas prices—weekly averages

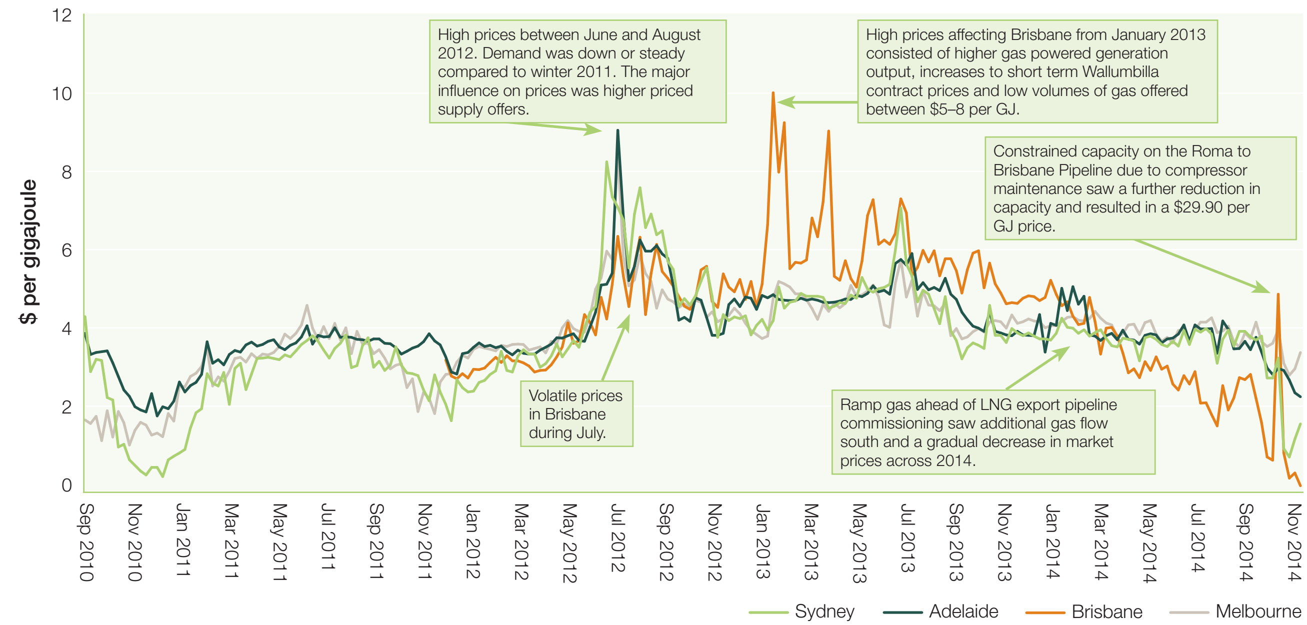
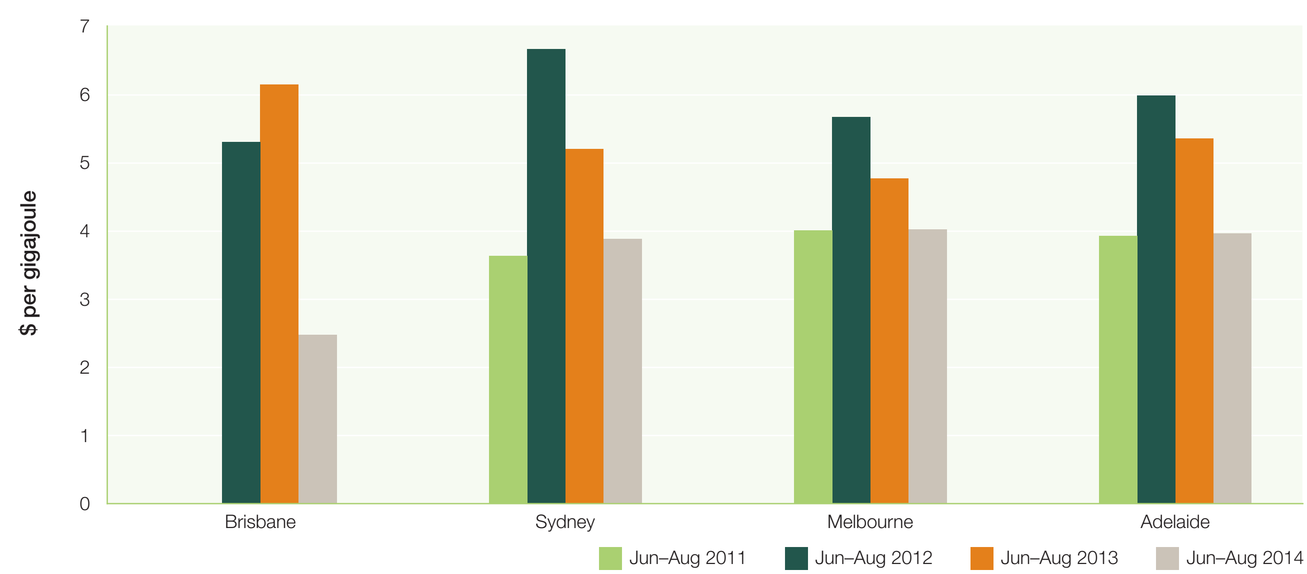


Figure 3.5
Spot gas prices—winter



Notes (table 3.2 and figures 3.4 and 3.5): Volume weighted ex ante prices derived from demand forecasts. Sydney, Adelaide and Brisbane data are short term trading market prices. Melbourne prices are estimates for the metropolitan area, based on Victorian wholesale spot gas prices plus APA Group's transmission withdrawal tariff for the two Melbourne metropolitan zones. The Brisbane price for 2011–12 covers the period 1 December 2011 (market start) to 30 June 2012. The Sydney data exclude the 1 November 2010 price of $150 per gigajoule, which data errors caused.

Sources (table 3.2 and figures 3.4 and 3.5): AER estimates (Melbourne); AEMO (other cities).

Table 3.2 **Average daily spot gas prices ($ per gigajoule)**

	BRISBANE	SYDNEY	MELBOURNE	ADELAIDE
2013–14	4.55	4.03	4.24	4.31
2012–13	5.92	5.20	4.86	5.09
2011–12	3.51	3.45	3.65	3.79
2010–11		2.37	2.75	3.17

facilities at Condabri and Ruby Jo became fully operational in preparation for LNG export, and other facilities were expected to commence production late in the year. LNG proponents sold significant quantities of ramp-up gas from these facilities into the Brisbane hub of the short term trading market and into the gas supply hub at Wallumbilla.

These increased gas flows caused Brisbane spot prices to collapse during 2014. October prices were mostly below $1 per gigajoule and fell close to zero on some days. Prices also trended lower in the gas supply hub at Wallumbilla (section 3.5). Despite the large volumes of ramp-up gas, pipeline constraints occasionally affected the market. Brisbane prices spiked briefly in early October 2014, for example, when planned outages and capacity constraints on the Roma to Brisbane Pipeline temporarily restricted capacity to transport gas.

Ramp-up gas also flowed into the southern states, reflected in rising flows on the QSN link (Ballera to Moomba) connecting Queensland with NSW and South Australia (figure 3.7). In September and October 2014 gas flows from Queensland along the QSN Link to South Australia and NSW more than doubled flows in the corresponding period in 2013. The rise in volumes caused Sydney prices to fall below $1 per gigajoule in October 2014 (figure 3.4). Additionally, these flows reduced NSW's usual reliance on Victorian gas, causing a reversal in gas flows between the two states along the NSW–Victoria Interconnect; that is, gas flowed south from NSW into Victoria (figure 3.7).

The collapse in gas prices flowed through to electricity markets in 2014. Cheaper gas stimulated a rise in gas powered generation and reduced daily spot electricity prices in Queensland to as low as $11 per megawatt hour in October 2014 (figure 7 in 'Market overview').

3.4.1 East coast supply–demand balance

Ramp-up gas will continue to be sold into domestic spot markets in the lead-up to commissioning each of Queensland's six committed LNG trains. The timing of commissioning each train is uncertain, although each of the three LNG projects expects to commission at least one train by mid-2015.

Market conditions will tighten once all LNG facilities are exporting at full capacity, with AEMO forecasting possible domestic supply shortfalls in the absence of new infrastructure developments.[18] But while international demand for east coast gas will rise exponentially, a countervailing influence is weaker projections on gas powered electricity generation, which accounts for 31 per cent of domestic gas demand.[19] Subdued electricity demand, the continued rise in renewable generation, the abolition of carbon pricing, and the cessation of the Queensland Gas Scheme (which mandated a minimum rate of gas powered generation) have stalled growth in gas powered generation. As an example, Stanwell took its Swanbank E generator offline in December 2014 for up to three years, reducing domestic gas demand over that period.

Accounting for these factors, AEMO in 2014 scaled back earlier projections on gas supply shortfalls in eastern Australia.[20] But various contingencies affect the forecasts, including the timing of commissioning each LNG train, changing forecasts of electricity demand growth (and the proportion of forecast demand expected to be sourced from gas powered generation), the effects of government climate change policies on gas demand, and the availability of gas storage facilities. In this volatile environment, industry participants are considering supply alternatives to avoid possible shortfalls:

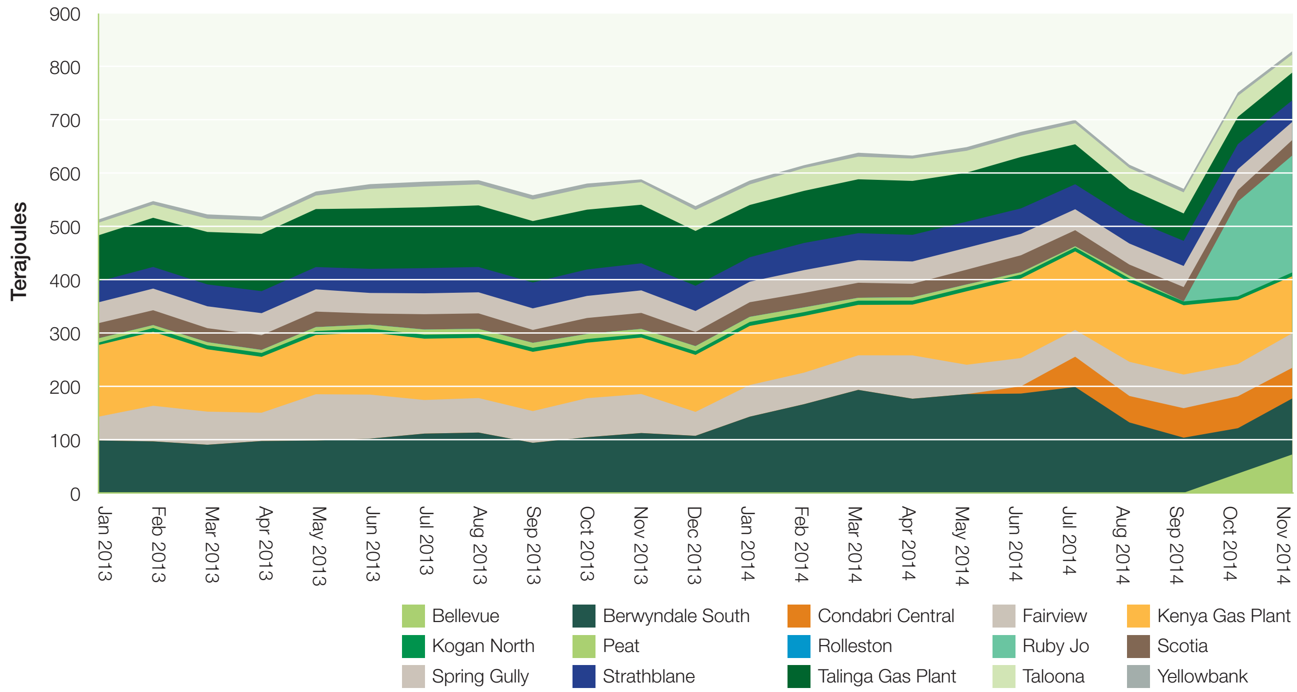
18 AEMO, *Gas statement of opportunities update,* May 2014.

19 BREE, *Gas market report*, October 2013, p. 26.

20 AEMO, *Gas statement of opportunities update,* May 2014.

Figure 3.6

Gas production around Roma, Queensland

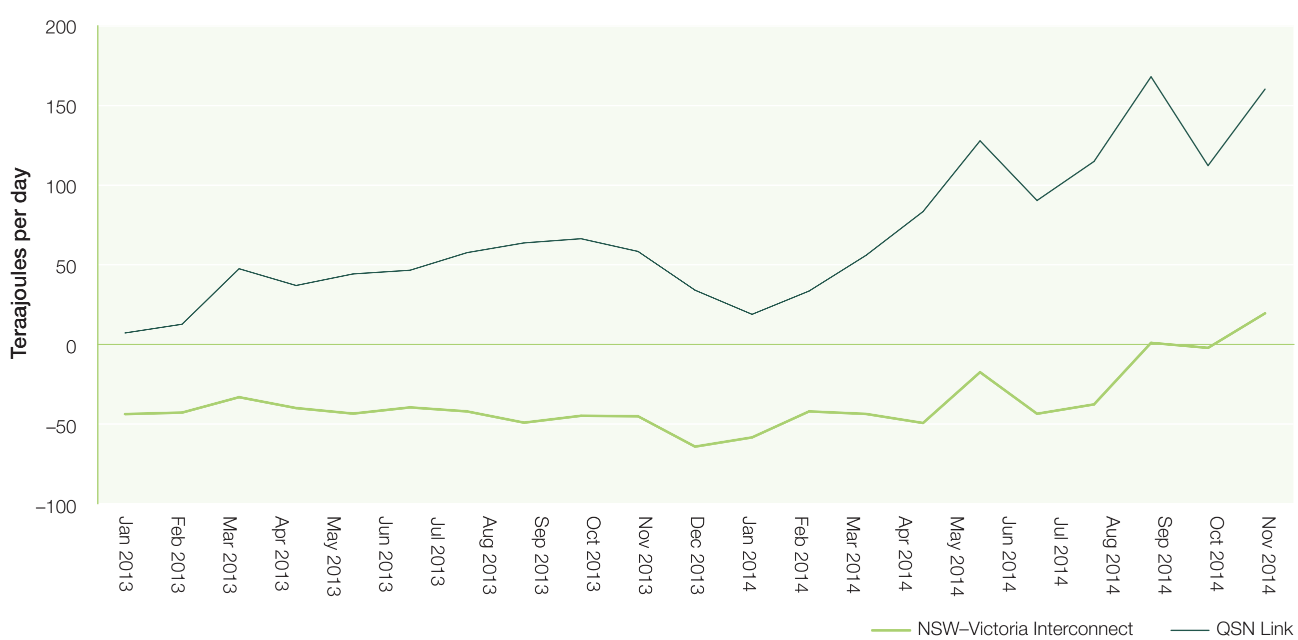


Note: The Roma region covers the Surat–Bowen Basin from which gas is sourced, processed and supplied to the Queensland Gas Pipeline, Roma to Brisbane Pipeline and South West Queensland Pipeline.

Sources: AER; National Gas Bulletin Board (www.gasbb.com.au).

Figure 3.7

Gas flows on the QSN Link and NSW–Victoria Interconnect



Sources: AER; National Gas Bulletin Board (www.gasbb.com.au).

- Pipeline owners have expanded or are expanding capacity on several transmission pipelines, including the NSW—Victoria Interconnect (due for completion in 2015); APA Group's 2013–14 expansion of the Victorian Transmission System to facilitate increased northbound gas exports from Victoria; augmentations of the South West Queensland and Queensland Gas pipelines (scheduled for completion in 2014); and storage capacity on the Tasmanian Gas Pipeline (progressively available from winter 2014). Jemena was considering a capacity expansion of the Eastern Gas Pipeline to boost capacity into NSW, which could be completed by the end of 2015. Additionally, the NSW and Northern Territory governments in November 2014 signed a Memorandum of Understanding to develop a pipeline connecting the Northern Territory with eastern gas markets.
- AGL Energy and Santos are seeking to develop CSG resources in the Gloucester and Narrabri basins in NSW. But community concerns about health and environmental impacts have delayed the development of projects in the state. The NSW Government in March 2014 applied a ban on CSG exploration licenses, which it later extended for 12 months. Concerns about environmental impacts also led the Victorian Government to place a moratorium on CSG extraction and fracking, which it later lengthened to July 2015 and extended to cover all onshore gas exploration.[21]

  The NSW Government in November 2014 launched a new strategic framework to determine appropriate areas to develop and extract gas, accounting for economic benefits and evidence of effects on the environment and communities. Pending licence applications under previous arrangements were to be extinguished. Once the new framework is in place in July 2015, the NSW Environment Protection Authority will be the lead regulator for gas exploration and production. It will be responsible for compliance and enforcement of conditions under gas licences.
- The potential to develop unconventional gas in the Cooper Basin is significant. While two shale wells were online and producing in 2014,[22] Santos indicated it could take up to a decade for production to be commercially viable, due to the costs of drilling and extraction technologies, and varying geological conditions.[23]

21 Grattan Institute, *Gas at the crossroads*, October 2014, p. 9.

22 Santos, *2014 CLSA investors' forum presentation*, 15 September 2014.

23 'Shale gas success still a decade away for Australia, says Santos,' *The Australian*, 26 September 2014.

Policy responses

Policy makers are progressing reforms to help alleviate pressures in the eastern gas market. The gas trading hub at Wallumbilla, Queensland, launched in March 2014 aims to alleviate bottlenecks by facilitating short term gas trades (section 3.5).

In other developments, the COAG Energy Council is reforming pipeline capacity trading arrangements, to promote trade in idle contracted capacity. Throughout the year, some pipelines have significant idle capacity that is contracted to gas retailers and industrial consumers. So, in 2014 the Energy Council and AEMO consulted with stakeholders on enhancing pipeline capacity trading information on the bulletin board. As a preliminary step, AEMO in 2014 improved the bulletin board's interface to improve accessibility and data discoverability. It also launched an eastern market capacity listing service, with voluntary standard contractual terms and conditions for secondary capacity trade.

Pipeline entities also made progress towards secondary trading in capacity. APA Group launched an operational transfer capacity trading platform in 2014, and Jemena expects to launch a trading platform in December 2014. Customers have not widely used existing platforms, with some participants suggesting prices of around $1 per gigajoule are too high.

The AEMC in September 2013 proposed further market reforms, including refining spot market design and streamlining the processes for making rule changes affecting spot markets.[24] AEMO progressed reforms to interregional trade in 2013–14 by improving the interface between the Victorian spot market and interconnecting pipelines and facilities. It similarly progressed reforms to the provision of market operator (gas balancing) services in the short term trading market.[25]

The Australian Government's 2014 energy green paper cited a need for gas production potential and trading information (including prices) to be more transparent, to improve gas market operation.[26] Additionally, stakeholders in 2014 called for closer harmonisation of the gas spot market models. Three spot market models operate in eastern Australia—the short term trading market in Brisbane, Sydney and

24 AEMC, *Taking stock of Australia's east coast gas market*, Information paper, September 2013; K Lowe Consulting, *Gas market scoping study: a report for the AEMC*, July 2013.

25 AEMO, *2014 Annual report*, 2014.

26 Australian Government (Department of Industry), *Energy green paper*, September 2014.

Adelaide; the Victorian spot market; and the gas supply hub at Wallumbilla.

The existence of these multiple market structures imposes a significant regulatory burden on participants. The Business Council of Australia noted an absence of standardisation across markets works against the development of a viable forward market in gas.[27] The Victorian Government recently advocated more integrated market arrangements, including a possible move to a single market design to reduce barriers to interregional trading. It also advocated a single set of principles for access to east coast pipelines.[28]

3.5 Spotlight—Wallumbilla gas supply hub

As part of the Australian Government's energy market reform program, a gas supply hub at Wallumbilla, Queensland commenced in March 2014. The hub is a pipeline interconnection point for the Surat–Bowen Basin, linking gas markets in Queensland, South Australia, NSW and Victoria (figure 3.8).

The hub promotes transparent and efficient gas trading, allowing participants to manage the risks associated with variable gas prices. It also deepens market liquidity by attracting participants such as LNG plants, industrial customers and gas powered generators. The diversity of contract positions and the number of participants at Wallumbilla create a natural point of trade.

The hub uses a brokerage model allowing buyers and sellers to trade spot or forward gas products (table 3.3) through a voluntary gas trading exchange. The mechanism sits alongside bilateral contracts for balancing gas requirements. The hub facilitates separate trades for the delivery of gas at Wallumbilla's three delivery points—the South West Queensland, Roma to Brisbane and Queensland Gas pipelines. In-pipe trades (whereby gas can be delivered and receipted at separate points) are available for the Roma to Brisbane Pipeline.

The market design avoids the need to change infrastructure, operations or contracts. But participants require access to the transmission pipelines serving the hub, not all of which interconnect. To manage this issue, the hub is supported by a web based platform for participants to advertise their interest in buying or selling pipeline capacity. AEMO has developed standardised trading terms.

27 Business Council of Australia, *Australia's energy advantages*, November 2014.

28 Victorian Government (Department of State Development, Business and Innovation), *Victoria's energy statement*, 2014.

Figure 3.8

Gas pipelines and production facilities near Wallumbilla, Queensland

Sources: AER; AEMO.

Membership and trading on the gas supply hub are voluntary. As for other spot markets, the AER monitors and enforces compliance with the market conduct rules, which include a prohibition of non-delivery and price manipulation. This role is the AER's first assigned role in monitoring price manipulation in Australia's energy market.

3.5.1 Gas supply hub activity in 2014

Trading activity in the gas supply hub was intermittent during 2014, which is not unusual in a new market. While the market has several participants (table 3.4), many did not trade in 2014. It had few active sellers, with a single seller accounting for the bulk of sales at times. But the number of buyers and sellers rose during the year, with more sellers than buyers in October 2014 (figure 3.9).

Of the four products traded (table 3.3), liquidity in terms of participant numbers was usually higher for day-ahead and daily products than for balance-of-day and weekly products (figure 3.10).

Volumes have varied from no trades on some days to 105 TJ for a single product on 4 September (figures 3.11

Table 3.3 Products traded at Wallumbilla gas supply hub

PRODUCT	DELIVERY TIMEFRAME
Balance-of-day (spot)	For trading on the gas day for delivery in remaining hours of that day
Day-ahead (spot)	For trading on the day before the delivery gas day
Daily (future)	For trading two to seven days before the delivery gas day
Weekly (future)	For trading that starts on a Saturday four weeks before the commencement of the weekly delivery period and closes on the Friday before the commencement of the week

Source: AEMO.

Table 3.4 Trading and viewing participants at Wallumbilla gas supply hub

TRADING PARTICIPANTS	VIEWING PARTICIPANTS
AGL Wholesale Gas	Australia Pacific LNG Marketing
BP Australia	APT Petroleum Pipelines
Braemar Power Project	Arrow Energy Trading
Incitec Pivot	BHP Billiton Petroleum (Bass Strait)
Origin Energy Retail	EnergyAustralia
Santos QNT	Esso Australia Resources
Stanwell Corporation	Intelligent Energy Systems
Walloons Coal Seam Gas Company	Oakey Power Holdings
	Macquarie Bank
	Santos Toga
	Australian Competition & Consumer Commission
	Department of Industry

Source: AEMO.

and 3.12). On average, around 12 trades per week occurred between four participants. The intermittent activity is attributable to a number of factors, including the immaturity of the market, the existence of long term contracts, and physical pipeline constraints.

Many businesses initially registered as viewing participants, intending to register later as trading participants. This approach allowed them to access information on trading activity, including traded products, quantities and prices. More generally, some businesses did not identify a need to use the gas supply hub to balance their gas requirements, given their long term contracts.

In terms of delivery points, a majority of trades have been for gas delivered along the Roma to Brisbane Pipeline (figure 3.11). Participants indicated the in-pipe trade facility, along with the greater rights to deliver and receive gas, favours trades on this pipeline compared with others. But damage to the Roma to Brisbane Pipeline in June 2014 reduced its capacity, appearing to impact the frequency and size of trades. Trading on the South West Queensland Pipeline rose from August 2014: its highest recorded volume of 105 TJ was traded for a weekly product on 4 September.

Consistent with spot prices in the Brisbane hub of the short term trading market, prices in the Wallumbilla hub fell during 2014, reflecting sales of large amounts of ramp-up gas from LNG projects (figures 3.11 and 3.12).

Industry participants expect liquidity in the hub to improve in 2015, with pipeline augmentations and market conditions around Wallumbilla expected to free up greater volumes of gas for trade. The ongoing development of hub products should further promote trade.

Capacity expansions on the pipelines serving the hub were expected to be completed in 2014. Jemena's project to increase capacity on the Queensland Gas Pipeline by 10 TJ is expected to create opportunities for trade on this heavily contracted pipeline (which has had no trades to date). APA Group's project to enhance the bi-directional flow capability of the South West Queensland Pipeline will also facilitate gas trade between south east Australia and Queensland. Further, gas flows on the pipeline will be reversible almost instantaneously in response to market changes.

Increased volumes of gas produced for LNG projects will likely be made available for trade through the gas supply hub during the ramp-up phase. As the six LNG trains approach completion over the next two years, fluctuating volumes of ramp-up gas will likely be offered into the hub. This outcome was observed in 2014, with QCLNG offering gas for trade into the gas supply hub alongside its first train nearing completion.

Once LNG exports commence from Gladstone, a domestic oversupply scenario may eventuate if an LNG train trips. In this scenario, gas would be diverted from Gladstone, to be flared, stored or sold in the domestic market. As a result, large volumes might be traded through the hub. One of the gas supply hub's market benefits is its ability to help manage an oversupply event.

Forecast changes in the domestic market may also impact on activity in the hub. AEMO projects a fall in domestic gas demand in Queensland in 2015, including lower demand for Roma to Brisbane Pipeline services. Stanwell took its Swanbank E generator offline in December 2014 and BP intends to shut its Bulwer Island refinery from mid-2015. Each sourced its gas requirements under long term

Figure 3.9

Number of buyers and sellers, Wallumbilla gas supply hub

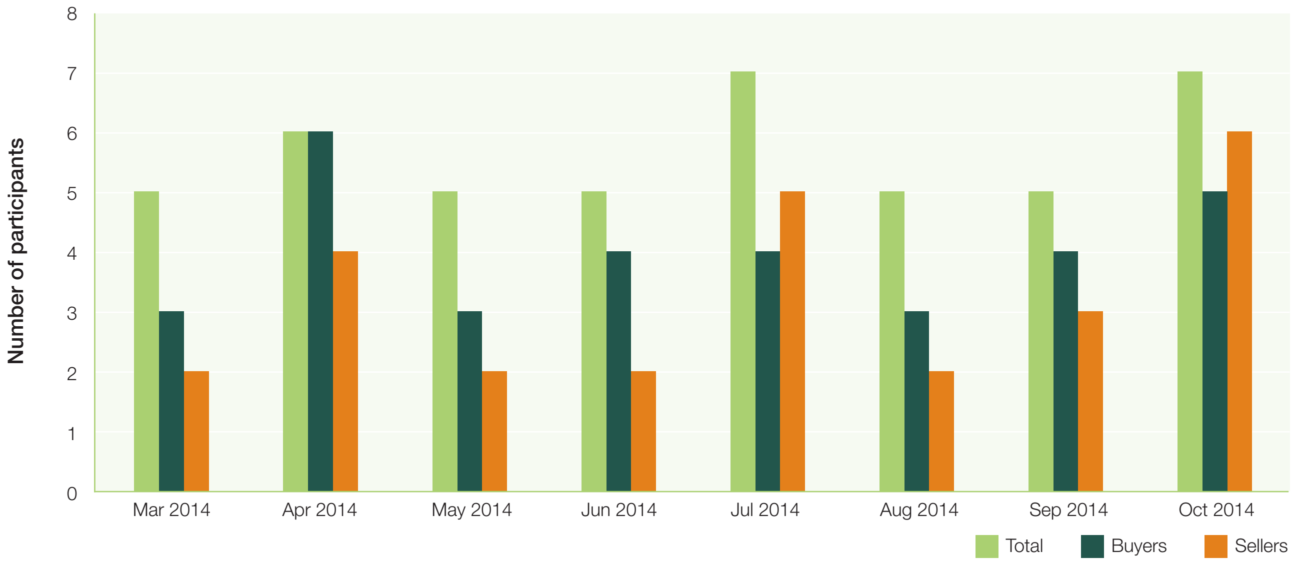
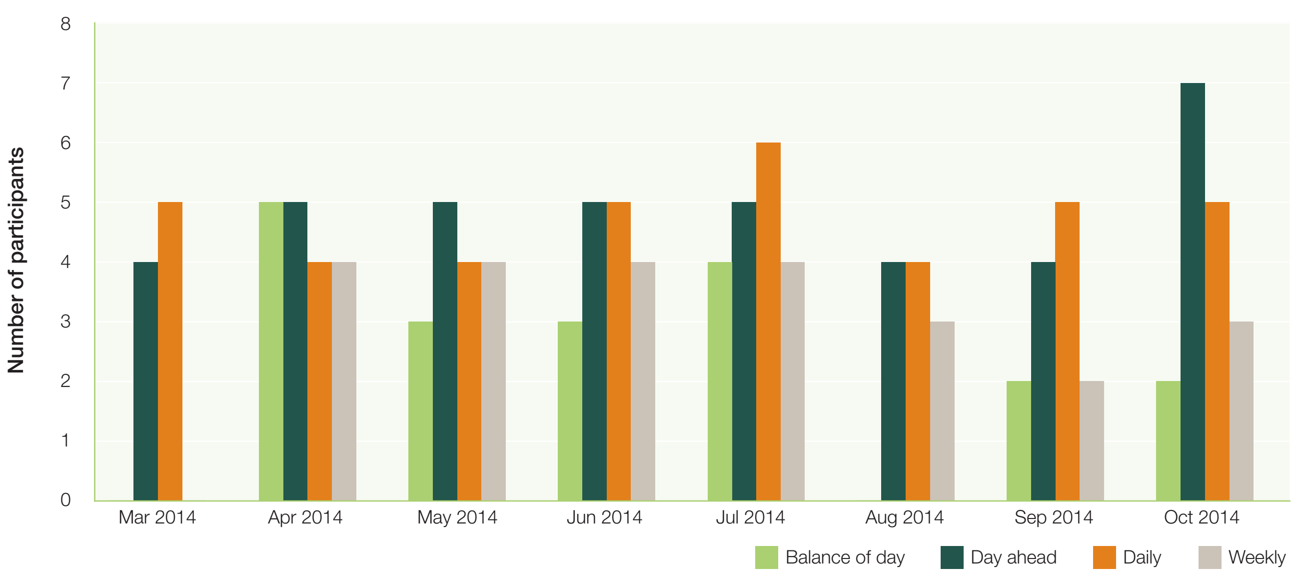


Figure 3.10

Number of participants per product traded, Wallumbilla gas supply hub



Sources (figures 3.9 and 3.10): AER; AEMO.

Figure 3.11
Gas volumes and prices, Wallumbilla gas supply hub

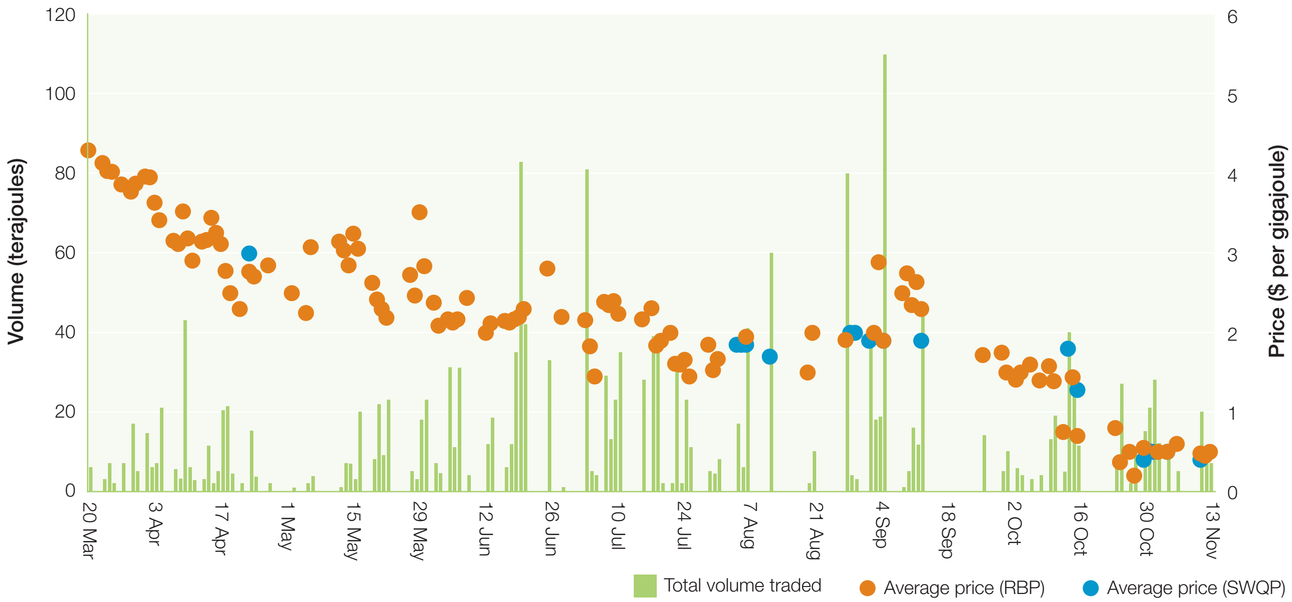
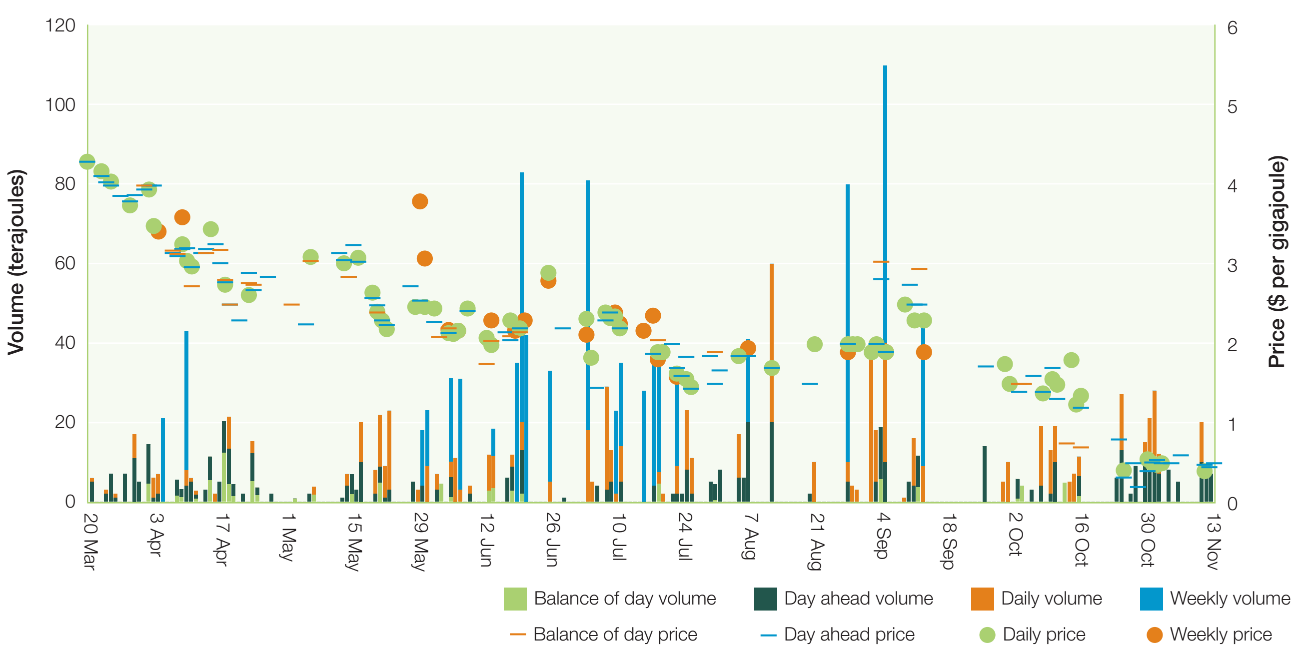


Figure 3.12
Gas volumes and prices per product, Wallumbilla gas supply hub



Sources (figures 3.11 and 3.12): AER; AEMO.

contracts, so these changes will reduce gas demand in Brisbane and on the pipeline by around 80 TJ. With weaker gas demand in Queensland, more gas may be sold through the hub to southern markets via the South West Queensland Pipeline.

In June 2014 Argus Media began reporting a month-ahead price index for gas delivered to Wallumbilla, based on information from buyers and sellers actively trading in the hub. Traders can use the index to predict forward gas prices. Additionally, a hub reference group is finalising an end-of-day reference price that may later be used for exchange based futures products.

Price indexes, end-of-day reference pricing, and futures products are signs of growing maturity in the hub, with opportunities emerging for participants to hedge exposure to prices. While these developments will likely increase liquidity in the hub, a number of participants indicated the availability of a single trading price would further enhance liquidity. Participants indicated improved interconnection between transmission pipelines would also promote gas flows within the hub.

Participants also reported the availability of long term contracts has been diminishing in the market. This claim is consistent with the findings of a 2013 Australian Industry Group survey, in which some industrial users claimed to be unable to enter contracts for five years or more 'at any price'. With less gas locked up in domestic contracts, more is being contracted on a shorter term basis. This new contractual environment will likely free up more gas for trade through the hub.

Despite intermittent volumes to date, gas powered generators, LNG producers and industrial customers remain supportive of the gas supply hub. While a number of businesses are still not trading, they consider the hub provides a flexible and fit-for-purpose platform for trading in gas products. In particular, they suggest its voluntary nature and competitive registration fee delivers favourable low market entry costs, particularly compared with the short term trading market.

Construction of the QCLNG Pipeline (BG Group)

4 GAS PIPELINES

Gas pipelines transport gas from upstream producers to downstream energy customers (figure 3.1). This chapter focuses on gas pipelines in jurisdictions for which the Australian Energy Regulator (AER) has regulatory responsibilities—namely, those pipelines in jurisdictions other than Western Australia.

High pressure *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. Australia's gas transmission network covers over 20 000 kms.

An interconnected transmission pipeline network runs from Queensland to Tasmania, providing a competitive environment for gas producers, pipeline operators and gas retailers, and strengthening security of supply. While Western Australia and the Northern Territory have no pipeline interconnection with eastern Australia, the New South Wales (NSW) and Northern Territory governments in November 2014 agreed to work closely on the development of a pipeline connecting the Northern Territory with eastern gas markets.

A network of *distribution* pipelines delivers gas from demand hubs to industrial 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 74 000 kms, with a combined asset value of $8 billion.

Gas is reticulated to most Australian capital cities, major regional areas and towns, but the proportion of households and businesses connected to the networks varies across regions. Australian Gas Networks estimated in 2014 that gas penetration in the residential market was around 90 per cent in Victoria, for example, compared with 75 per cent in South Australia and 15 per cent in Queensland.[1]

Figure 4.1 illustrates the routes of major transmission pipelines and the locations of major distribution networks in jurisdictions for which the AER has regulatory responsibilities. Figure 3.2 includes a more extensive mapping of gas transmission pipelines, including those in Western Australia. Tables 4.1 and 4.2 summarise the major gas pipelines and networks.

1 Envestra, *Application for light regulation of Envestra's Queensland gas distribution network*, August 2014.

4.1 Ownership

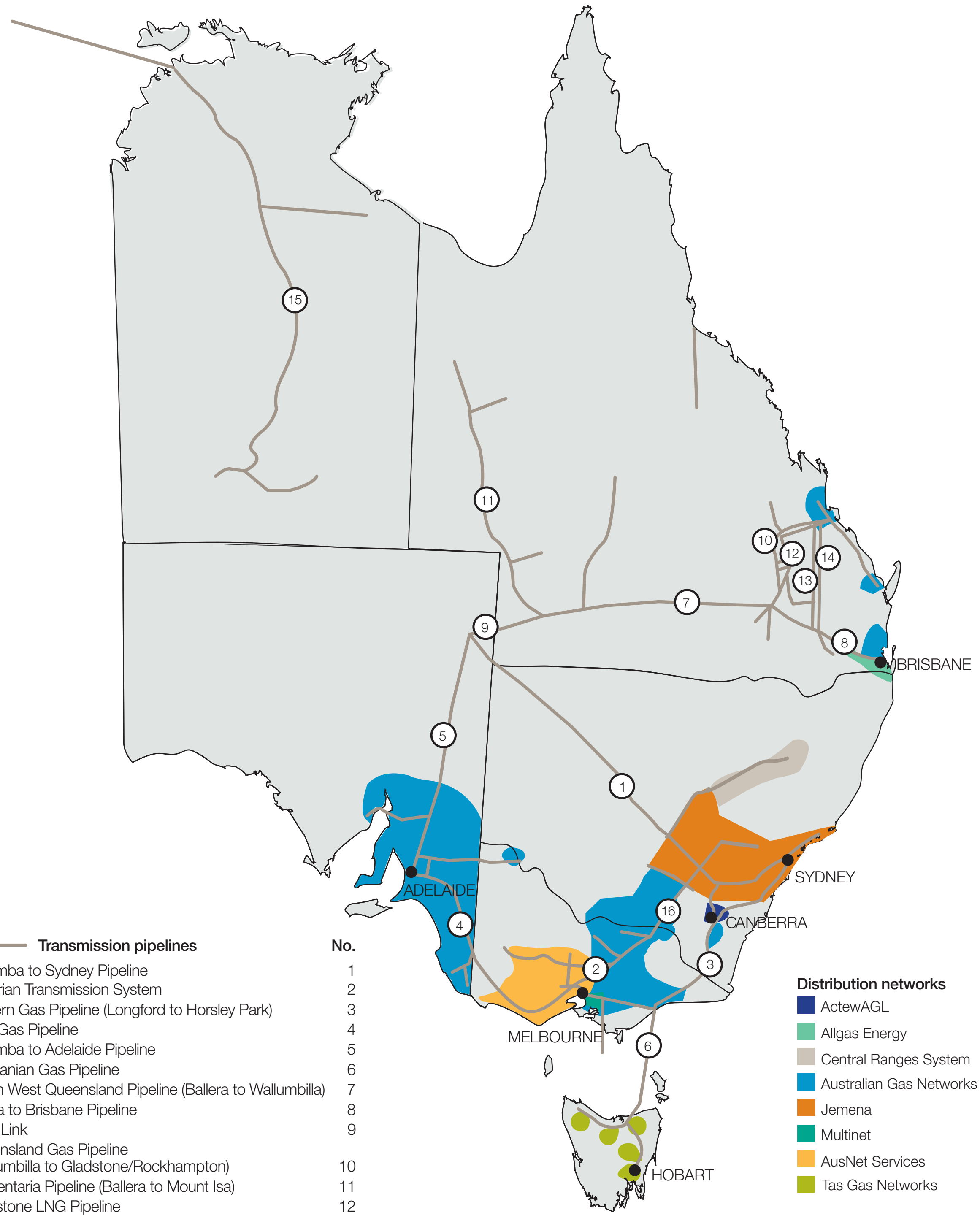
Australia's gas pipelines are privately owned. APA Group is the principal owner in gas transmission. State Grid Corporation of China and Singapore Power International own a number of transmission and distribution pipelines through Jemena and AusNet Services (tables 4.1 and 4.2). Cheung Kong Infrastructure in 2014 acquired full ownership of Australian Gas Networks (formerly Envestra), with interests principally in gas distribution.

- *APA Group* owns three pipelines in NSW (including the Moomba to Sydney Pipeline), the Victorian Transmission System, five major Queensland pipelines (including three pipelines connecting the Cooper Basin in central Australia with Brisbane) and a Northern Territory pipeline. It has a 50 per cent interest in the SEA Gas Pipeline running from Victoria to South Australia, and a 20 per cent interest in Energy Infrastructure Investments (EII), which owns pipelines in the Northern Territory.

  APA Group also has a minority interest in the Allgas Energy distribution network in Queensland, and owns the Central Ranges system in NSW. It manages and operates these assets.
- *Australian Gas Networks* owns distribution networks in Victoria, South Australia, Queensland and the Northern Territory, along with a transmission pipeline in the Northern Territory.
- *Jemena* owns the Eastern Gas, VicHub and Queensland Gas pipelines, along with the principal distribution network in NSW and 50 per cent of the Australian Capital Territory (ACT) network. Jemena's owners, State Grid Corporation of China and Singapore Power International, also have equity interest in Victoria's AusNet Services gas distribution network.

The ownership links between gas and electricity networks are significant. Jemena, AusNet Services, APA Group, Cheung Kong Infrastructure and DUET Group all have ownership interests (some substantial) in both sectors (section 2.1.1).

Figure 4.1
Major gas pipelines—eastern Australia



Transmission pipelines	No.
Moomba to Sydney Pipeline	1
Victorian Transmission System	2
Eastern Gas Pipeline (Longford to Horsley Park)	3
SEA Gas Pipeline	4
Moomba to Adelaide Pipeline	5
Tasmanian Gas Pipeline	6
South West Queensland Pipeline (Ballera to Wallumbilla)	7
Roma to Brisbane Pipeline	8
QSN Link	9
Queensland Gas Pipeline (Wallumbilla to Gladstone/Rockhampton)	10
Carpentaria Pipeline (Ballera to Mount Isa)	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

Distribution networks
- ActewAGL
- Allgas Energy
- Central Ranges System
- Australian Gas Networks
- Jemena
- Multinet
- AusNet Services
- Tas Gas Networks

Source: AER.

Table 4.1 Major gas transmission pipelines

PIPELINE	LENGTH (KM)	CAPACITY (TJ/D)	COVERED?	OWNER
EASTERN AUSTRALIA				
QUEENSLAND				
North Queensland Gas Pipeline	391	108	No	Victorian Funds Management Corporation
Queensland Gas Pipeline (Wallumbilla to Gladstone)	629	142	No	Jemena (State Grid Corporation 60%, Singapore Power International 40%)
Carpentaria Pipeline (Ballera to Mount Isa)	840	119	Yes (light)	APA Group
Berwyndale to Wallumbilla Pipeline	113		No	APA Group
Dawson Valley Pipeline	47	30	No (revoked 2014)	Westside 51%, Mitsui 49%
Roma (Wallumbilla) to Brisbane	440	219	Yes (2012–17)	APA Group
Wallumbilla to Darling Downs Pipeline	205	400	No	Origin Energy
South West Queensland Pipeline (Ballera to Wallumbilla)	756	181	No	APA Group
QSN Link (Ballera to Moomba)	180	212	No	APA Group
Gladstone LNG Pipeline	435	1420	No	Santos; PETRONAS, Total, KOGAS
Queensland Curtis LNG Pipeline	334	1410	No	BG Group
Australia Pacific LNG Pipeline	362	1560	No	Origin Energy, ConocoPhillips, Sinopec
NEW SOUTH WALES				
Moomba to Sydney Pipeline	2029	420	Partial (light)	APA Group
Central West Pipeline (Marsden to Dubbo)	255	10	Yes (light)	APA Group
Central Ranges Pipeline (Dubbo to Tamworth)	300	7	Yes (2005–19)	APA Group
Eastern Gas Pipeline (Longford to Sydney)	795	268	No	Jemena (State Grid Corporation 60%, Singapore Power International 40%)
VICTORIA				
Victorian Transmission System (GasNet)	2035	1030	Yes (2013–17)	APA Group
South Gippsland Natural Gas Pipeline	250		No	DUET Group
VicHub		150 (into Vic)	No	Jemena (State Grid Corporation 60%, Singapore Power International 40%)
SOUTH AUSTRALIA				
Moomba to Adelaide Pipeline	1185	253	No	QIC Global Infrastructure
SEA Gas Pipeline (Port Campbell to Adelaide)	680	303	No	APA Group 50%, Retail Employees Superannuation Trust 50%
TASMANIA				
Tasmanian Gas Pipeline (Longford to Hobart)	734	129	No	Palisade Investment Partners
NORTHERN TERRITORY				
Bonaparte Pipeline	287	80	No	Energy Infrastructure Investments (APA Group 20%, Marubeni 50%, Osaka Gas 30%)
Amadeus Gas Pipeline	1512	104	Yes (2011–16)	APA Group
Daly Waters to McArthur River Pipeline	330	16	No	Power and Water
Palm Valley to Alice Springs Pipeline	140	27	No	Australian Gas Networks (Cheung Kong Infrastructure)

TJ/d, terajoules per day.

Note: The Moomba to Sydney Pipeline is uncovered from Moomba to the offtake point of the Central West Pipeline at Marsden.

Sources: National Gas Market Bulletin Board (www.gasbb.com.au); Bureau of Resources and Energy Economics; EnergyQuest, *EnergyQuarterly* (various issues); corporate websites.

Table 4.2 Gas distribution networks in eastern Australia

NETWORK	CUSTOMER NUMBERS	LENGTH OF MAINS (KM)	ASSET BASE ($ MILLION)[1]	INVESTMENT—CURRENT PERIOD ($ MILLION)[2]	REVENUE—CURRENT PERIOD ($ MILLION)	CURRENT REGULATORY PERIOD	OWNER
QUEENSLAND							
Allgas Energy	84 400	2 900	442	138	351	1 Jul 2011–30 Jun 2016	APA Group 20%, Marubeni 40%, RREEF 40%
Australian Gas Networks[3]	89 100	2 640	330	145	323	Light regulation from February 2015	Cheung Kong Infrastructure
NEW SOUTH WALES AND ACT							
Jemena Gas Networks (NSW)	1 050 000	24 430	2 483	777	2 372	1 Jul 2010–30 Jun 2015	Jemena (State Grid Corporation 60%, Singapore Power International 40%)
ActewAGL	124 000	4 720	299	94	302	1 Jul 2010–30 Jun 2015	ACTEW Corporation (ACT Government) 50%; Jemena (State Grid Corporation 60%, Singapore Power International 40%) 50%
Wagga Wagga[4]	23 800	680	64	22	52	Not regulated (coverage revoked 2014)	Australian Gas Networks (Cheung Kong Infrastructure)
Central Ranges System	7 000	180	na	na	na	2006–19	APA Group
VICTORIA							
AusNet Services	602 000	9 860	1 285	470	891	1 Jan 2013–31 Dec 2017	Listed company (Singapore Power International 31%, State Grid Corporation 20%)
Multinet	668 000	9 960	1 063	244	847	1 Jan 2013–31 Dec 2017	DUET Group
Australian Gas Networks	587 400	10 220	1 126	405	853	1 Jan 2013–31 Dec 2017	Cheung Kong Infrastructure
SOUTH AUSTRALIA							
Australian Gas Networks	410 700	7 790	1 061	512	1 071	1 Jul 2011–30 Jun 2016	Cheung Kong Infrastructure
TASMANIA							
Tas Gas Networks	9 800	730	na	na	na	Not regulated	Brookfield Infrastructure
TOTALS	3 656 200	74 110	8 275	2 807	7 062		

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.

2 Investment data are forecasts for the current access arrangement period, typically of five years duration.

3 Australian Gas Networks' Queensland distribution network converts to light regulation in February 2015. The listed financial indicators reflect the access arrangement applicable until that time.

4 Coverage of the Wagga Wagga distribution network was revoked in April 2014. The listed financial indicators reflect the access arrangement applicable until that time.

Note: Asset base, investment and revenue data are converted to June 2013 dollars.

Sources: Access arrangements for covered pipelines; company websites.

4.2 Regulation of gas pipelines

The National Gas Law and Rules set out the regulatory framework for the gas pipeline sector. The AER regulates pipelines in jurisdictions other than Western Australia, in which the Economic Regulation Authority is the regulator.

4.2.1 Full regulation

The National Gas Law and Rules apply economic regulation to covered pipelines. Different forms of regulation apply, based on competition and significance criteria. Under *full regulation*, a pipeline provider must periodically submit an access arrangement to the regulator for approval. An access arrangement sets out the terms and conditions under which third parties can use a pipeline. It must specify at least one reference service that a significant part of the market is likely to seek, and a reference tariff for that service.

The AER regulates four transmission pipelines and eight distribution networks under full regulation, including:

- transmission pipelines supplying Brisbane, Melbourne and Darwin (table 4.1)
- all major distribution networks in NSW, Victoria, South Australia and the ACT, and one of Queensland's two networks.

The AER's regulatory decisions on access arrangement proposals are subject to merits review by the Australian Competition Tribunal.

An *Access arrangement guideline* (available on the AER website) details the regulatory process. Separate guidelines address dispute resolution and compliance with obligations under the National Gas Law. Figure 4.2 sets out the timelines for regulatory reviews of transmission pipelines and distribution networks.

In summary, the regulator assesses the revenue that a pipeline business needs to cover efficient costs (including a benchmark return on capital), then derives reference tariffs for the pipeline. It uses a building block model that accounts for a pipeline's operating and maintenance expenditure, capital expenditure, asset depreciation costs and taxation liabilities, and a return on capital. Figure 4.3 illustrates the revenue components of Queensland's Roma to Brisbane Pipeline (2012–17) and the Victorian distribution networks (2013–17).

The largest component is the return on capital, which accounts for up to two-thirds of revenue. The scale of a pipeline's asset base (and projected investment) and its weighted average cost of capital (the rate of return covering a commercial return on equity and efficient debt costs) affect the return on capital. An allowance for operating expenditure typically accounts for a further 30 per cent of revenue requirements. The rules allow for income adjustments via incentive mechanisms that reward efficient operating practices.

In a dispute, an access seeker may request the regulator arbitrate on and enforce the terms and conditions of the access arrangement. Regulatory decisions on full regulation pipelines are subject to merits review by the Australian Competition Tribunal (section 4.4).

4.2.2 Light regulation

A pipeline may, in some circumstances, convert to *light regulation* without upfront price regulation. When 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. Australian Gas Networks' Queensland network will in February 2015 become the first major distribution network to convert to light regulation.

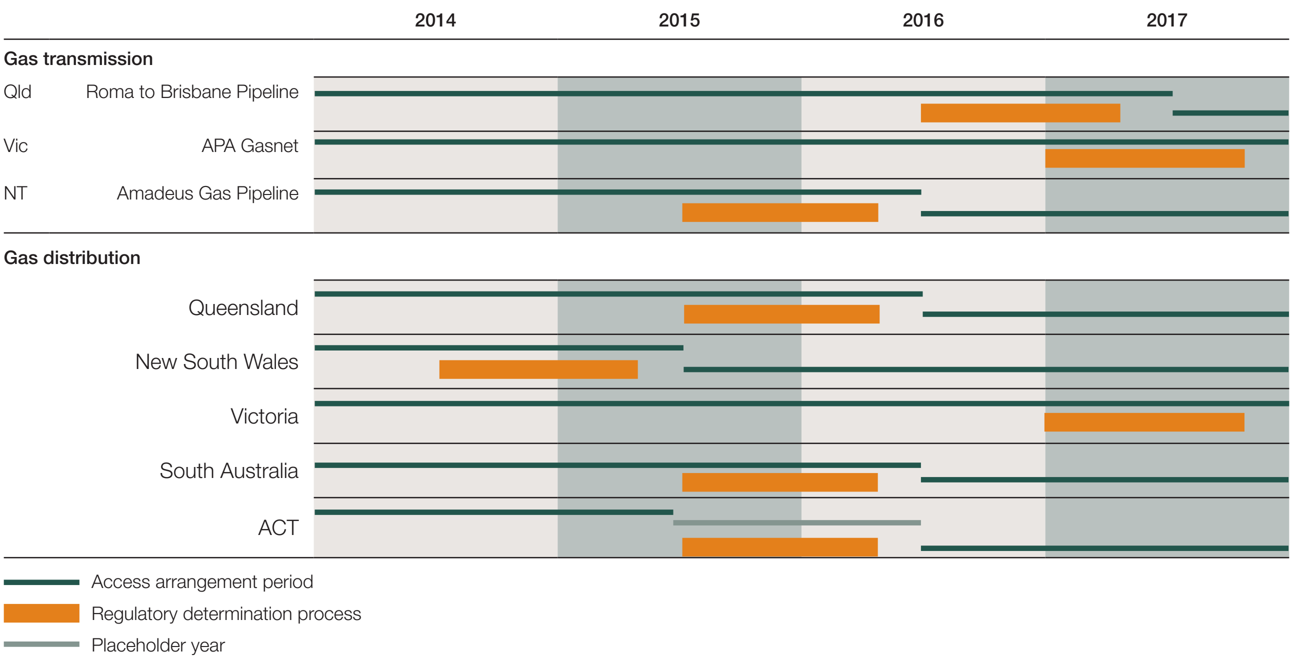
4.2.3 Changes in coverage status

The National Gas Law includes a mechanism for reviewing whether a particular pipeline needs economic regulation. The coverage of several major transmission pipelines has been revoked over the past decade. Additionally, only one transmission pipeline constructed in the past decade is covered.

Coverage decisions on three pipelines were made in 2014:

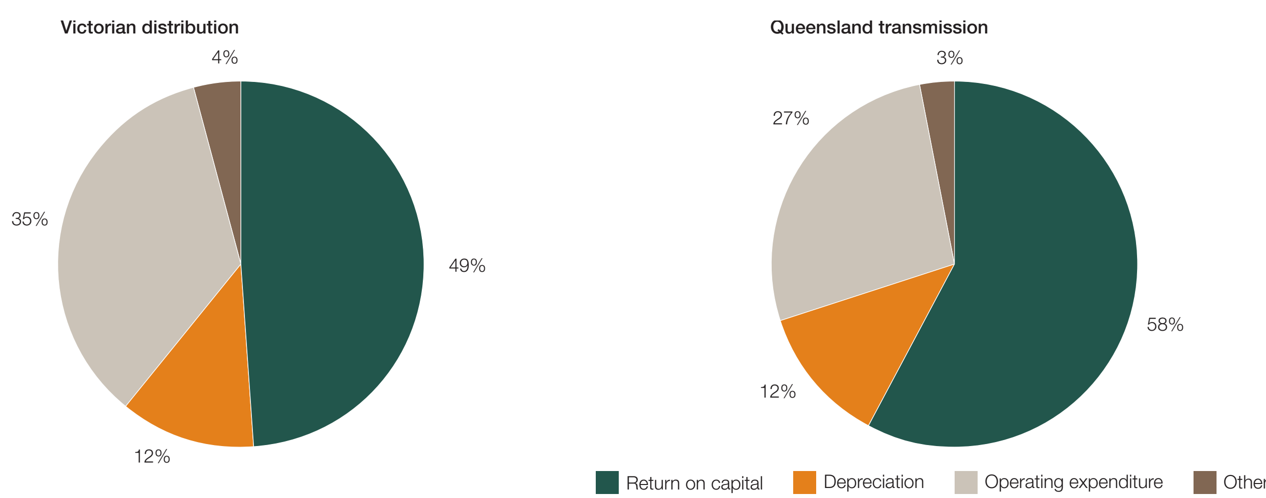
- In April 2014 the NSW Minister for Resources and Energy revoked coverage of Australian Gas Networks' Wagga Wagga distribution network (NSW). The National Competition Council (NCC) had recommended in August 2013 that coverage be revoked if retail gas price regulation continues in the medium term.
- In September 2014 the Federal Minister for Industry revoked coverage of the Dawson Valley Pipeline in Queensland. The minister was not satisfied that access to the pipeline would promote a material increase in competition in upstream or downstream gas markets, or that a competing pipeline would be uneconomic to develop.
- In November 2014 the NCC determined Australian Gas Networks' Queensland distribution network will convert from full to light regulation in February 2015. It found light

Figure 4.2
Indicative timelines for regulatory reviews of gas pipelines



Note: The timeframes are indicative. The standard review period begins when a network business submits an access arrangement proposal to the AER. Timeframes may vary if the AER grants a time extension for the proposal submission. An access arrangement period is typically five years, but a provider may apply for a different duration.

Figure 4.3
Indicative composition of gas pipeline revenues



Source: AER.

regulation of the network will be similarly effective to full regulation, but provide significant cost savings that may benefit customers.

The Gas Law also enables the federal Minister for Resources and Energy to grant a 15 year ‘no coverage’ determination for new pipelines in certain circumstances. Following recommendations from the NCC, the minister granted ‘no coverage’ determinations for three transmission pipelines supplying gas from the Surat–Bowen Basin to LNG projects on Curtis Island in Queensland.

4.3 Pipeline investment

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 regulated and unregulated transmission sector has occurred since 2010. Additionally, a number of major projects are under construction or have been announced for development:

- APA Group completed capacity expansions of pipelines linking Moomba to Sydney and Brisbane in 2012. Work included looping the South West Queensland Pipeline, which effectively doubled capacity. In 2014 APA Group re-configured the South West Queensland Pipeline for bi-directional operation, and plans bi-directional operation of the Roma to Brisbane and Moomba to Sydney pipelines.
- APA Group commenced work in 2014 on expanding capacity on the northern zone of the Victorian Transmission System by 145 per cent to support an increase in gas sales from Victoria to NSW. The expansion is due for completion by winter 2015.
- Three major transmission pipelines in Queensland were completed in 2014 to transport gas from the Surat–Bowen Basin to Gladstone for processing and export as LNG.
- Jemena began work to expand capacity on the Queensland Gas Pipeline in 2014. It was also considering a capacity expansion of the Eastern Gas Pipeline to boost capacity into NSW, which could be completed by the end of 2015.

The NSW and Northern Territory governments in November 2014 signed a Memorandum of Understanding to work closely on the development of a pipeline connecting the Northern Territory with eastern gas markets. The pipeline could run from Alice Springs to Moomba (1100 kms), or from Tenant Creek to Mount Isa (620 kms).

Investment in *distribution* networks in eastern Australia—including investment to augment capacity—is forecast at around $2.8 billion in the current access arrangement periods (typically five years). The underlying drivers include rising connection numbers, the replacement of ageing networks, and the maintenance of capacity to meet customer demand.

Figure 4.4 illustrates recent investment data for gas transmission pipelines and distribution networks that are subject to full regulation. It compares approved forecasts in current access arrangements with actual expenditure in previous periods.

For *distribution* networks, investment is forecast to increase by an average 47 per cent in the current access arrangement periods, compared with previous periods. Investment is equal, on average, to 34 per cent of the networks’ opening capital bases. Forecast growth is highest in Australian Gas Networks’ Queensland and South Australian networks (up 71 per cent and 162 per cent respectively). More recent regulatory reviews reflect a moderation in growth. The decisions for Victoria’s distribution networks, for example, allow for investment to rise by an average 23 per cent in 2013–17, compared with previous periods.

For *transmission* pipelines, investment forecasts vary significantly. An expansion of the Roma to Brisbane Pipeline in the previous regulatory period contributed to a large capital expenditure allowance. But, with no major augmentations planned for the current period, forecast expenditure fell by over 80 per cent. Capital expenditure across the two periods is consistent for Victoria’s GasNet system, while the Northern Territory’s Amadeus Pipeline had a large increase in forecast capital expenditure for an enhanced integrity program.

4.4 Pipeline revenues and retail impacts

Figure 4.5 illustrates approved revenue forecasts for gas transmission pipelines and distribution networks that are subject to full regulation. It compares approved forecasts in current access arrangements with those approved in previous periods.

For *distribution* networks, revenues are forecast to increase by an average 11 per cent in the current access arrangement periods, compared with previous periods. The largest increases will be for Australian Gas Networks' South Australian and Queensland networks (43 per cent and 42 per cent respectively). The drivers include rising asset bases associated with greater investment (resulting in higher returns on capital). Some forecasts reflect a rise in underlying costs, including operating and maintenance expenditure and capital financing costs. For *transmission* networks, revenues are forecast to fall on the Roma to Brisbane Pipeline, but rise for the GasNet system and the Amadeus Pipeline.

Regulatory reviews since 2012 reflect reductions in the risk free rate that have lowered the overall cost of capital. The decisions for Victoria's distribution networks in 2013 will result in revenues falling by an average 8 per cent in 2013–17, compared with revenues in 2008–12.

4.4.1 Operating expenditure

Operating and maintenance costs are a key driver of pipeline revenue requirements. Figure 4.6 illustrates recent operating expenditure data for gas transmission pipelines and distribution networks that are subject to full regulation. It compares approved forecasts in current access arrangements with actual expenditure in previous regulatory periods.

For *distribution* networks, real operating expenditure is forecast to increase by an average 15 per cent in the current access arrangement periods, compared with actual expenditure in previous periods. Forecasts vary across the networks, with the largest increases forecast for the Allgas Energy (Queensland) and ActewAGL (ACT) networks (each by 28 per cent). For *transmission* networks, operating expenditure is forecast to increase by an average 22 per cent.

Regulatory decisions in 2013 for Victoria's distribution networks allow for operating expenditure to rise on average by 13 per cent in 2013–17 from that in 2008–12.

4.4.2 Retail impacts of regulatory decisions

Gas *transmission* charges typically make up 3–8 per cent of a residential gas bill. The percentage is significantly higher for industrial users. The 2012 regulatory decision on Queensland's Roma to Brisbane Pipeline was expected to cause almost no change in a typical residential customer's bill over the five years of the determination. In Victoria, the 2013 decision on the Victorian Transmission System resulted in a typical residential bill falling by around 0.4 per cent per year.

Gas *distribution* charges typically make up 40–60 per cent of a residential gas bill. In recent years, rising capital and operating expenditure and other cost drivers (including higher financing costs and the rising cost of unaccounted for gas) pushed up gas distribution costs, leading retail charges for residential customers to rise by 5–6 per cent per year (figure 4.7).

However, the 2013 regulatory decisions for the Victorian distribution networks show a different trend, leaving little impact on customer charges in 2013–17. Charges are rising annually by around 1.3 per cent for Australian Gas Networks and 0.3 per cent for Multinet. Customer charges for AusNet Services customers are expected to fall by around 0.4 per cent annually. A key reason for this shift was reductions in the risk-free rate that lowered the overall cost of capital for gas networks.

Figure 4.4
Pipeline investment—five year period

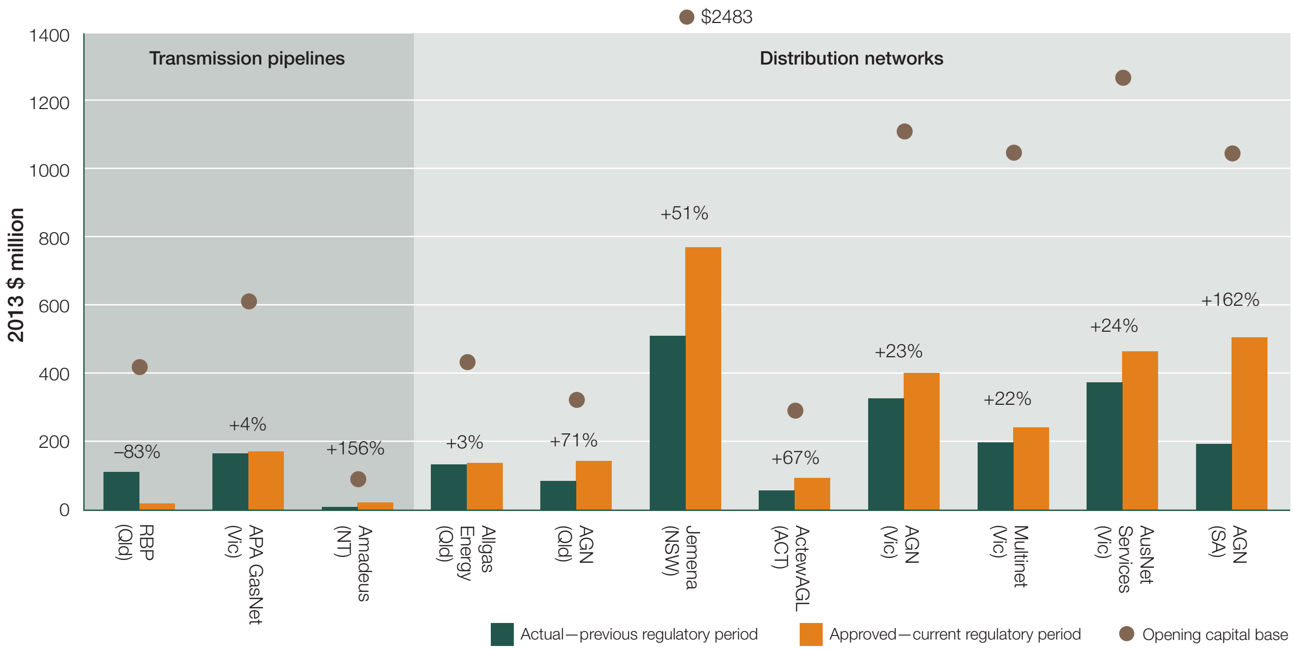
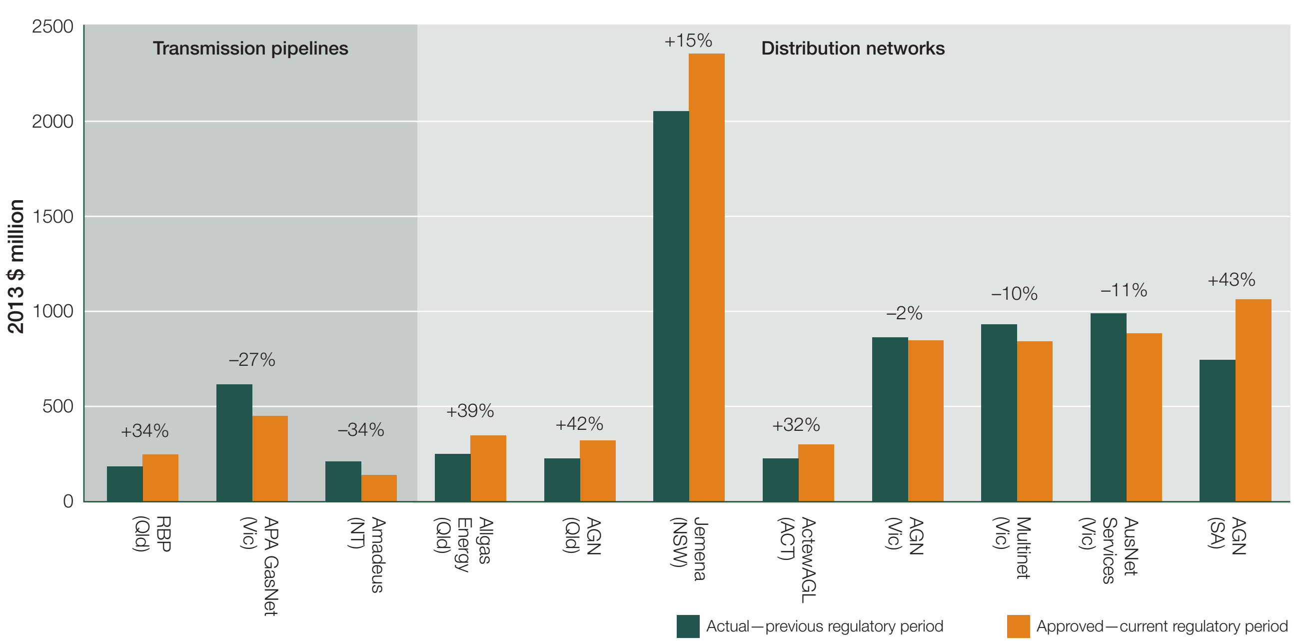


Figure 4.5
Pipeline revenues—five year period



RBP, Roma to Brisbane Pipeline; AGN, Australian Gas Networks.

Note (figures 4.4–4.6): Forecasts in the current access arrangement period (typically five years), compared with actual levels (revenue and operating expenditure) and forecasts (capital expenditure) in previous periods. The data account for the impact of decisions by the Australian Competition Tribunal. Opening capital bases are at the beginning of the current access arrangement period.

Source (figures 4.4–4.6): AER final decisions on access arrangements.

Figure 4.6
Pipeline operating expenditure—five year period

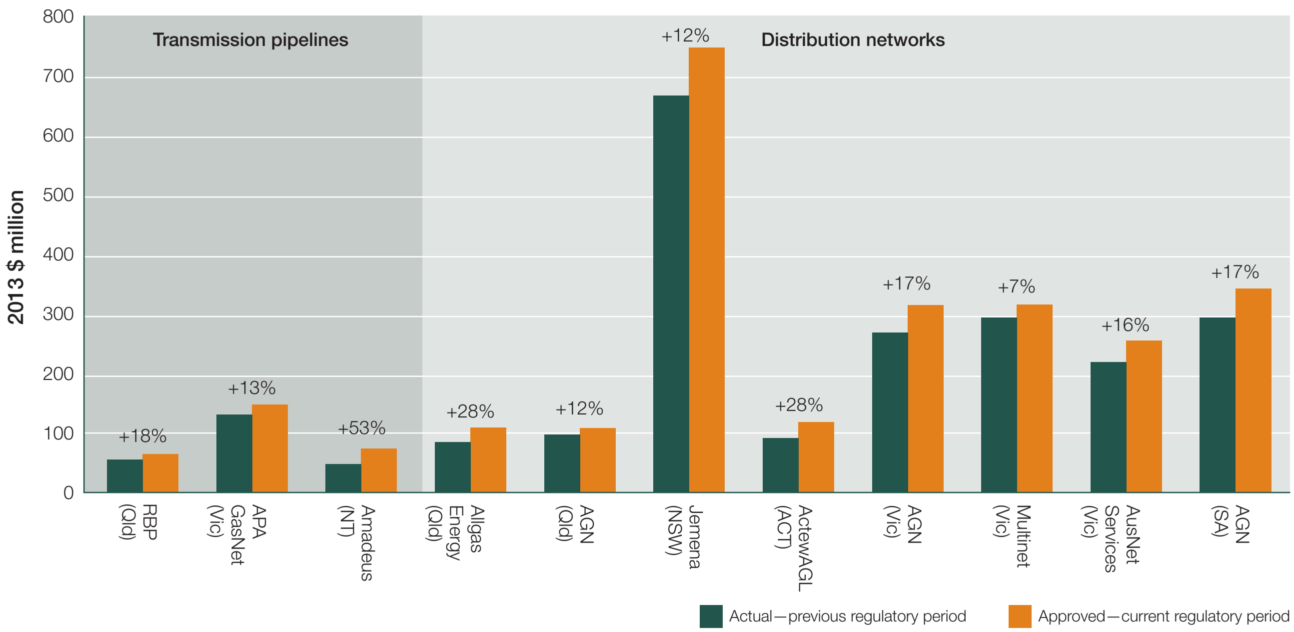
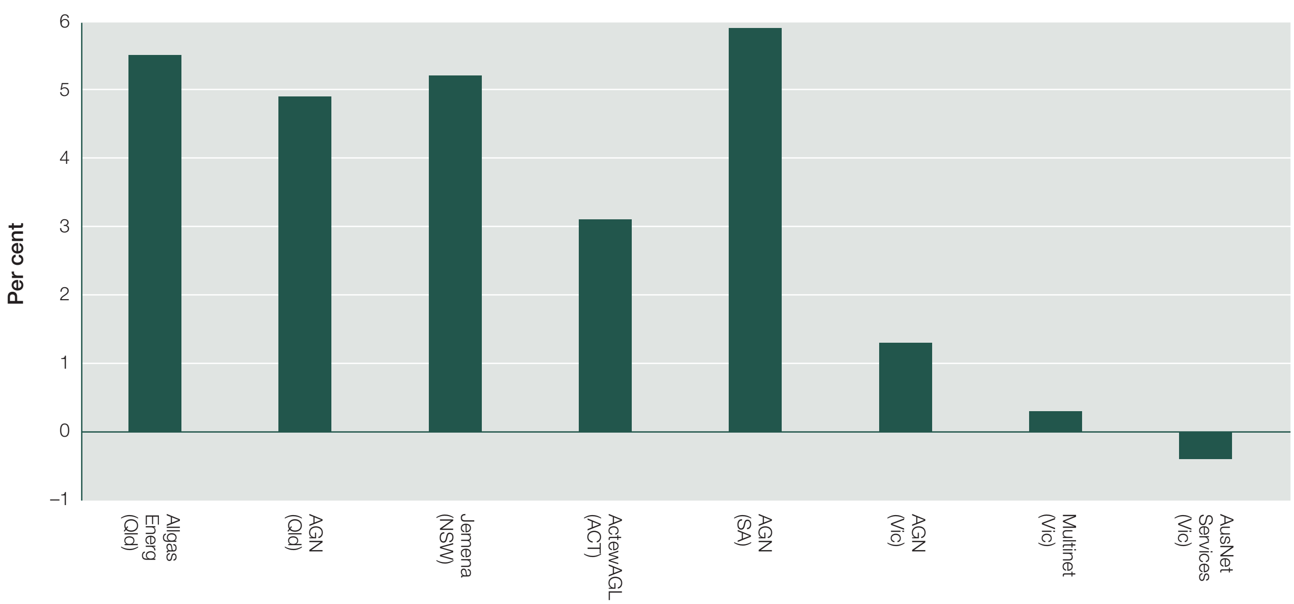


Figure 4.7
Annual impact of AER decisions on residential gas charges



AGN, Australian Gas Networks.

Note: Impact on annual gas charges for a typical residential customer in that jurisdiction in the current access arrangement period. See table 4.2 for the timing of regulatory periods. The data account for the impact of decisions by the Australian Competition Tribunal.

Source: AER final decisions on access arrangements.

5 ENERGY RETAIL MARKETS

Energy retailers typically buy electricity and gas in wholesale markets and package it with network (transportation) services for sale to customers under a retail contract. The customer pays charges based on rates set out in the contract and is not exposed to short term movements in wholesale market prices. Retailers use hedging arrangements to manage the risks of price volatility in the wholesale market.

However, alternative retail models have emerged or grown in recent years, driven by rising energy prices, consumers wishing to manage their energy use, and wider access to renewable energy options. These models include:

- *onselling*, when a business buys bulk energy from a retailer and onsells it to customers within an embedded distribution network[1]
- *solar power purchase agreements*, when businesses sell energy generated from solar panels installed at a customer's home or business
- *pool pass-through arrangements*, when the retailer sources energy from the wholesale market (similarly to the typical retailing model), but the customer takes on the risk of wholesale market volatility
- *customised or packaged energy sales*, when retailers target customers with specific energy requirements (such as households with swimming pools) or sell energy as part of a service package that provides customers with greater control over their energy use.

While state and territory governments traditionally regulated retail energy markets, the Australian Energy Regulator (AER) has taken on significant functions under national energy reforms. The National Energy Retail Law (Retail Law) protects small energy customers—that is, residential energy users and small businesses annually consuming less than 100 megawatt hours (MWh) of electricity or 1 terajoule (TJ) of gas.[2] Small customers make up 98 per cent of electricity connections and over 99 per cent of gas connections, but account for less than 50 per cent of energy sales by volume.

1 Embedded distribution networks have a single connection point with the main distribution network.

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 less than 160 MWh per year; in Tasmania, the threshold is 150 MWh per year.

5.1 Retail market structure

A retailer must be authorised or licensed to sell energy. Under the national scheme, an authorised retailer can provide energy services to contestable customers in all jurisdictions that have implemented the Retail Law. A business may apply to the AER for an exemption from the need to be authorised if it wishes to supply energy services to a limited customer group.

Not all retailers are active in every jurisdiction. And, while many retailers offer energy services to all customers, others focus on particular areas of the market. In considering whether to enter a market or customer segment, a retailer considers a range of factors, including whether prices are regulated (and the level of those prices), the size of the market, the extent of competition, the ability to acquire hedging contracts to manage risk and, for gas retailing, whether wholesale gas contracts and pipeline access can be negotiated.

Around half of all active retailers offer both electricity and gas in at least one jurisdiction in which they are active. Other retailers offer only electricity, while one specialises in gas (Tas Gas Retail, in Tasmania). Reasons for the lower competition in gas may include the smaller market (that is, not all households have a gas connection) and the difficulties that new entrants face in contracting for wholesale gas supplies.

Table 5.1 lists authorised or licensed energy retailers that were active (currently have customers) in the residential and small business market in June 2014. The number of active retailers rose over the past 10 years. Victoria has the largest number of active retailers selling to small customers, in both electricity (20) and gas (eight). New South Wales (NSW) and South Australia also have a significant number of participants in electricity (19 and 16 retailers respectively) and gas (five retailers each). Queensland has 15 active electricity retailers, but only two active gas retailers.

New entrants in 2013–14 included CovaU and GoEnergy, which retail electricity in NSW. M2 Energy, which owns Dodo Power & Gas, also began retailing electricity under a new brand—Commander—aimed at the small business market.

Some existing electricity retailers widened the range of their activity in 2013–14. ERM Power and Pacific Hydro, which previously focused on the large business market, acquired some small customers. Other retailers expanded into new geographic markets, including BlueNRG, Diamond Energy and Simply Energy (NSW), Red Energy and Momentum Energy (Queensland) and Dodo Power & Gas (South Australia).

Table 5.1 Active energy retailers—small customer market, June 2014

RETAILER	OWNERSHIP	QLD	NSW	VIC	SA	TAS	ACT
ActewAGL Retail	ACT Government/AGL Energy		Electricity; Gas *				Electricity *; Gas *
AGL Energy	AGL Energy	Electricity; Gas *	Electricity; Gas *	Electricity *; Gas *	Electricity *; Gas		
Alinta Energy	Alinta Energy			Electricity; Gas	Electricity; Gas		
Aurora Energy	Tasmanian Government					Electricity *; Gas	
BlueNRG	BlueNRG		Electricity	Electricity			
Click Energy	Click Energy	Electricity	Electricity	Electricity			
Commander	M2 Energy		Electricity	Electricity	Electricity		
CovaU	Tel.Pacific		Electricity				
Diamond Energy	Diamond Energy	Electricity	Electricity	Electricity	Electricity		
Dodo Power & Gas	M2 Energy	Electricity	Electricity	Electricity; Gas	Electricity		
EnergyAustralia	CLP Group	Electricity	Electricity *; Gas	Electricity *; Gas *	Electricity; Gas		Electricity; Gas
Ergon Energy	Queensland Government	Electricity *					
ERM Power	ERM Power	Electricity	Electricity	Electricity	Electricity		Electricity
GoEnergy	GoEnergy		Electricity				
Lumo Energy	Snowy Hydro[1]	Electricity	Electricity; Gas	Electricity; Gas	Electricity		
Momentum Energy	Hydro Tasmania (Tasmanian Government)	Electricity	Electricity	Electricity	Electricity		
Neighbourhood Energy	Alinta Energy			Electricity			
Origin Energy	Origin Energy	Electricity *; Gas *	Electricity *; Gas *	Electricity *; Gas *	Electricity; Gas *		Electricity; Gas
Pacific Hydro	Pacific Hydro			Electricity	Electricity		
People Energy	People Energy			Electricity			
Powerdirect	AGL Energy	Electricity	Electricity	Electricity	Electricity		Electricity
Powershop	Meridian Energy			Electricity			
Qenergy	Qenergy	Electricity	Electricity	Electricity	Electricity		
Red Energy	Snowy Hydro[1]	Electricity	Electricity	Electricity; Gas	Electricity		Electricity
Sanctuary Energy	Living Choice Australia/Sanctuary Life	Electricity	Electricity		Electricity		
Simply Energy	GDF Suez/Mitsui	Electricity	Electricity	Electricity; Gas	Electricity; Gas		
Tas Gas Retail	Brookfield Infrastructure					Gas	

Electricity retailer
Gas retailer
Host retailer *

1 Snowy Hydro is owned by the NSW Government (58 per cent), the Victorian Government (29 per cent) and the Australian Government (13 per cent).

Note: The host retailers listed for Tasmania and the ACT are those responsible for offering 'regulated offer' contracts to customers in each region. The host retailers listed for NSW, Victoria, South Australia and Queensland are those responsible for offering 'standing offer' contracts to customers that establish a new connection in defined regions of each state.

Sources: AER; jurisdictional regulator websites; retailer websites; other public sources.

5.1.1 Market concentration

Australia's retail energy markets tend to be highly concentrated. Three or fewer retailers supply more than 90 per cent of small electricity customers in four jurisdictions. Similar ratios apply in gas. In addition, substantial vertical integration exists between retailers and energy producers.

Three private businesses—AGL Energy, Origin Energy and EnergyAustralia—are the leading energy retailers in southern and eastern Australia (figure 5.1). The three jointly supplied over 70 per cent of small electricity customers and over 80 per cent of small gas customers at 30 June 2014.[3] However, competition from smaller retailers eroded their market share by around 5 per cent over the past two years. The market share of smaller retailers grew more strongly in Victoria and NSW than elsewhere over this period. This growth was partly offset by AGL's acquisition of Australian Power & Gas in 2013.

Snowy Hydro, owned by the NSW, Victorian and Australian governments, has emerged as a clear fourth large energy retailer, with around 7 per cent market share in electricity and gas. In September 2014 it acquired Lumo Energy from Infratil Energy, adding to its existing Red Energy business.

Victoria has the highest penetration of small private retailers, which supplied 33 per cent of electricity customers and 24 per cent of gas customers at 30 June 2014. In South Australia, small retailers supplied 19 per cent of electricity customers and 10 per cent of gas customers.

Other than Snowy Hydro, government retailers retain a strong presence in some jurisdictions:

- The Queensland Government owns Ergon Energy, which supplies electricity at regulated prices to customers in rural and regional Queensland. Ergon Energy is not permitted to compete for new customers.
- In Tasmania, the government owned Aurora Energy supplies all small electricity customers. Before 1 July 2014 legislation prevented new entrants from supplying small customers using less than 50 MWh per year.
- In the Australian Capital Territory (ACT), ActewAGL (a joint venture between the ACT Government and AGL Energy) remains the dominant retailer, with 96 per cent of small customers.
- Momentum Energy (Tasmanian Government) operates in a number of jurisdictions.

3 Includes brands owned by these businesses, including Powerdirect (AGL Energy).

5.1.2 Vertical integration

While governments structurally separated the energy supply industry in the 1990s, the subsequent vertical integration of retailers and generators to form 'gentailers' has been significant. Vertical integration provides a means for retailers and generators to internally manage the risk of price volatility in the electricity spot market, reducing their need to participate in hedge (contract) markets. This reduced need for hedge contracts can drain liquidity from contract markets, posing a barrier to entry and expansion by generators and retailers that are not vertically integrated.

Across the National Electricity Market (NEM), three private businesses—AGL Energy, Origin Energy and EnergyAustralia—have significant market share in both generation and retail markets. The three businesses:

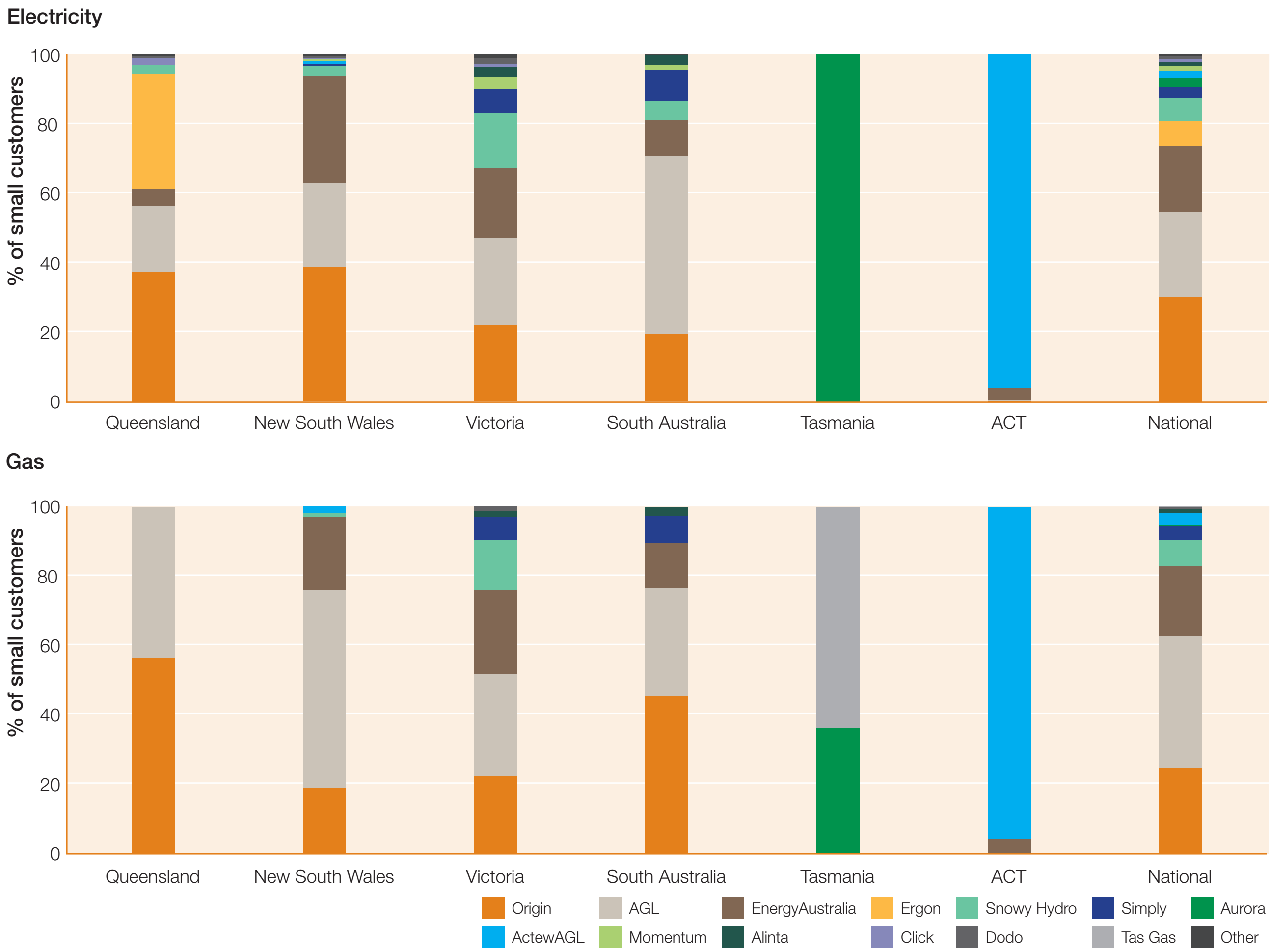
- control 46 per cent of generation capacity, up from 15 per cent in 2009. Over this period Origin Energy commissioned new power stations in Queensland and Victoria and, along with EnergyAustralia, it acquired former state owned generators in NSW. AGL Energy acquired full ownership of Loy Yang A in Victoria and, in September 2014, acquired Macquarie Generation from the NSW Government.
- control 57 per cent of new thermal and hydro generation capacity commissioned since 2009. Generation investment over this period by entities that do not also retail energy was negligible, except for wind generation.
- jointly supply over 75 per cent of energy retail customers. Origin Energy and EnergyAustralia acquired significant retail market share in NSW in 2010 following the privatisation of government owned retailers. AGL Energy acquired Australian Power & Gas (one of the largest independent retailers) in October 2013.

Vertical integration is common among other market participants too, with a number of former stand-alone generators having established retail arms. These businesses include GDF Suez (Simply Energy), Alinta, ERM Power, Pacific Hydro and Meridian Energy (Powershop). Government owned generators—Snowy Hydro (which owns the retailers Red Energy and Lumo Energy), and Hydro Tasmania (which owns Momentum Energy)—have engaged in similar behaviour.

Vertical integration also occurs between the retail sector and other segments of the supply chain. AGL Energy, Origin Energy and EnergyAustralia have interests in gas production and/or gas storage that complement their interests in gas fired electricity generation and energy retailing:

- Origin Energy is a gas producer in Queensland, South Australia and Victoria.

Figure 5.1
Retail market share (small customers), by jurisdiction, June 2014



Source: AER estimates.

- AGL Energy is a producer of coal seam gas in Queensland and NSW.
- EnergyAustralia has gas storage facilities in Victoria and holds gas reserves in the Gunnedah Basin (NSW).

In addition, the Queensland Government owns a joint distribution–retail businesses, and the ACT Government has ownership interests in both the dominant energy retailer and sole distributor. Ring fencing arrangements are in place for operational separation of the retail and network arms of these entities. The AER applies jurisdictional ring fencing guidelines to distribution businesses.

5.1.3 Market concentration and vertical integration, by jurisdiction

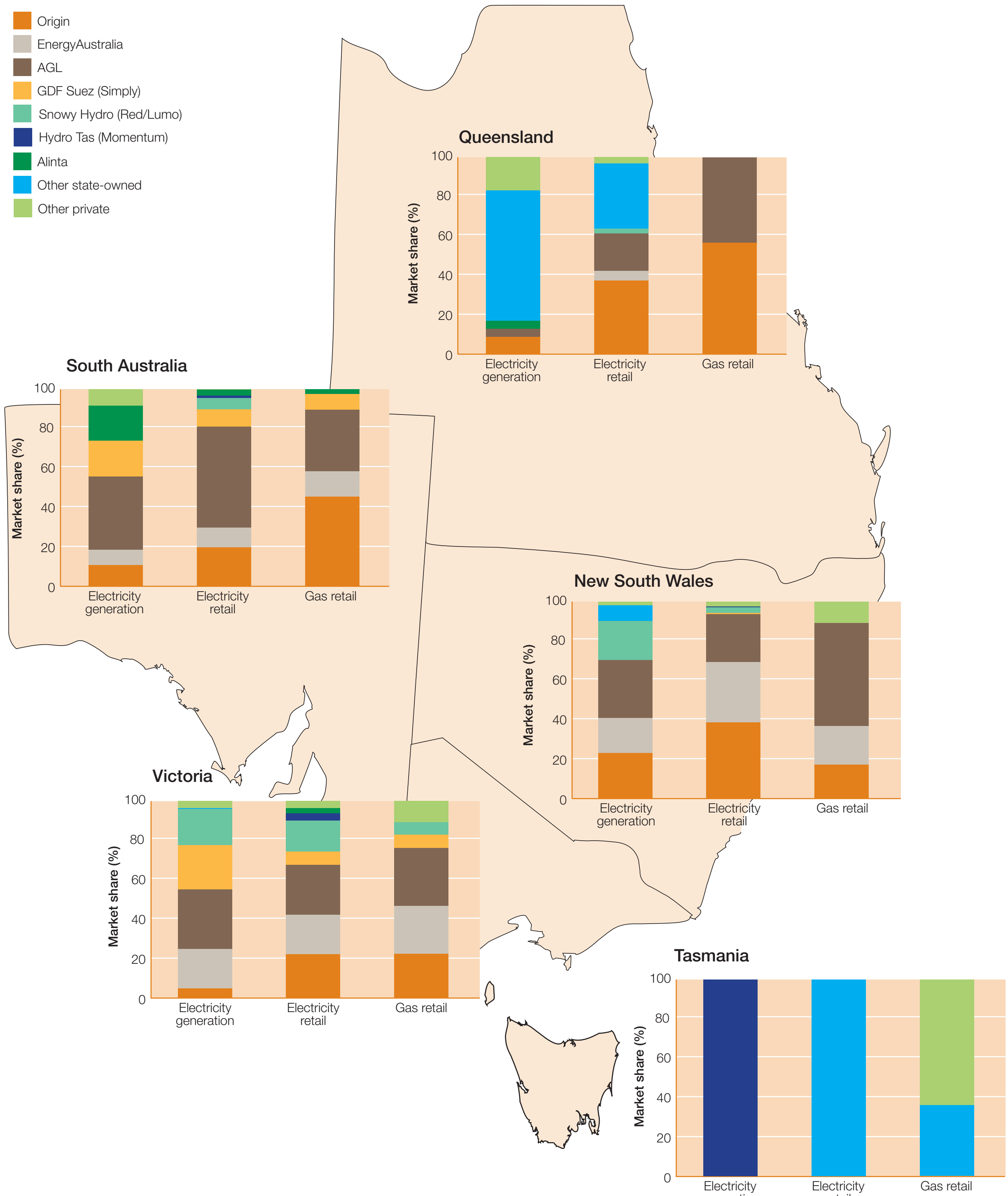
The extent of market concentration and vertical integration in energy markets varies across jurisdictions (figure 5.2).

Queensland has a highly concentrated generation sector, with state owned corporations controlling 67 per cent of capacity either through direct ownership or power purchase agreements over privately owned plant. The degree of market concentration increased in 2011, when the Queensland Government dissolved the state owned Tarong Energy and reallocated its capacity to the remaining two state owned entities.

Despite a highly concentrated generation sector, vertical integration is less common with the retail sector than

Figure 5.2

Vertical integration in NEM jurisdictions, 2014



Note: Electricity generation market shares are based on summer availability for January 2014, except wind, which is adjusted by an average contribution factor. Import capacity from other regions via interconnectors is not accounted for. Electricity and gas retail market shares are based on small customer numbers at June 2014.

Source: AER estimates.

elsewhere. Origin Energy and (to a lesser extent) AGL Energy are the leading retailers, following privatisation in 2007. These entities also account for 13 per cent of statewide generation capacity (mainly in gas fired capacity). EnergyAustralia supplies around 5 per cent of Queensland's retail electricity customers, but has no local generation assets.

Origin Energy is also a leading gas producer in Queensland's Surat–Bowen Basin. AGL Energy too has a small interest in the basin, which will soon supply liquefied natural gas (LNG) projects as well as the domestic market.

The **NSW** electricity sector was dominated by government entities until 2011, when Origin Energy and EnergyAustralia acquired assets through a privatisation process. Those businesses now supply 69 per cent of retail electricity customers, and control 41 per cent of generation capacity. They also supply 40 per cent of gas retail customers.

AGL Energy acquired Macquarie Generation from the NSW Government in September 2014, giving it 30 per cent of statewide capacity. AGL Energy was the incumbent gas retailer, and it retains 57 per cent of customers. Its position in gas helped it develop market share in electricity (around 25 per cent of customers). AGL Energy also owns the state's only operating gas producer.

Following its acquisition of Colongra from Delta Electricity in December 2014, Snowy Hydro's market share in NSW generation rose from 15 to 20 per cent. Snowy Hydro also expanded its retail portfolio by acquiring Lumo Energy in September 2014, and now supplies 3 per cent of retail electricity customers.

Victoria's generation sector is disaggregated across private entities. It has no single dominant retailer, with AGL Energy, Origin Energy and EnergyAustralia each supplying around one-quarter of retail electricity and gas customers. But, while having reasonable market depth, Victoria has significant vertical integration. The three major retailers control 55 per cent of generation capacity.

In addition, Victoria's other major generators—GDF Suez (23 per cent of capacity) and Snowy Hydro (18 per cent)—have strong positions in the electricity retail market (supplying 7 per cent and 16 per cent of customers respectively). These businesses also each supply 6–7 per cent of retail gas customers. Origin Energy too has been active in Victoria's gas supply market. It is a leading player in the Otway Basin (which supplies the Victorian and South Australian markets) and the Bass Basin.

South Australia's electricity sector is concentrated, with AGL Energy supplying over 50 per cent of retail customers. AGL Energy also controls 37 per cent of generation capacity. Origin Energy, EnergyAustralia, GDF Suez (Simply Energy) and Alinta are significant but minority players in both generation and retail. Gas for electricity generation is sourced mainly from the Cooper and Otway basins; Origin Energy is a producer in both basins.

Tasmania's electricity industry is dominated by government entities. Aurora Energy supplies most small retail customers, while Hydro Tasmania controls nearly all generation capacity. The Tasmanian Government in 2013–14 implemented reforms to encourage new retail entry.

5.2 Energy market regulation

The Retail Law establishes national regulation of retail energy markets and transfers significant functions from state and territory governments to the AER. The law operates with the Australian Consumer Law to protect small energy customers in their electricity and gas supply arrangements. It commenced in Tasmania (for electricity only) and the ACT on 1 July 2012, in South Australia on 1 February 2013, and in NSW on 1 July 2013. Queensland is expected to implement the Retail Law from 1 July 2015, while Victoria announced it will transition to the national framework by 31 December 2015.

The AER's role in national retail regulation is to:

- provide an energy price comparator website (www.energymadeeasy.gov.au) for small customers
- authorise energy retailers to sell energy, and grant exemptions from the authorisation requirement (for example, to retirement villages and caravan parks that onsell energy)
- approve retailers' policies for dealing with customers facing hardship
- administer a 'retailer of last resort' scheme, to protect customers and the market if a retail business fails
- report on retailer performance and market activity, including energy affordability, disconnections and competition indicators
- enforce compliance with the Retail Law and its supporting rules and regulations.

Consumers in NSW, South Australia, the ACT and Tasmania have access to all of the functions on the Energy Made Easy website. These functions include a price comparator tool that provides information on generally available retail market offers, a benchmarking tool for households to compare

Box 5.1 Types of energy retail contract

'Host' retailers are required to offer a standard retail contract to customers without a market contract. A standard retail contract includes model terms and conditions that a retailer may not amend.

Market retail contracts vary, but must reflect minimum terms and conditions. A contract may be widely available or offered to only specific customers. It may offer discounts on the retailer's standard rates, or other inducements. And it may have a fixed term duration, with exit fees for early withdrawal. Retailers must obtain explicit informed consent from a customer entering a market retail contract.

The share of customers on market contracts varies significantly across jurisdictions—83 per cent of electricity customers in South Australia, compared with 75 per cent in Victoria, 63 per cent in NSW, 46 per cent in Queensland (but 70 per cent in south east Queensland) and 18 per cent in the ACT. Proportions are similar for gas customers in each jurisdiction.

their electricity use with that of similar households, and information on the energy market, energy efficiency and consumer protections.

The AER does not regulate retail energy prices, over which state and territory governments have jurisdiction.

5.3 Retail competition

All NEM jurisdictions have full retail contestability (FRC) in electricity and gas, allowing customers to enter a contract with their retailer of choice. Box 5.1 outlines the types of energy contract that a consumer may enter.

Tasmania was the most recent jurisdiction to introduce full retail contestability, with choice being extended to electricity customers using less than 50 MWh per year from 1 July 2014. At September 2014 no energy retailers had entered the residential electricity customer market to compete with the incumbent, Aurora Energy.

The Australian Energy Market Commission (AEMC) conducts annual reviews of the effectiveness of retail competition for small customers. Its August 2014 review found the level of competition in energy markets varies across the NEM, reflecting the different pace of reform across jurisdictions. Electricity markets in the ACT, Tasmania and regional Queensland did not yet demonstrate effective competition.[4]

The AEMC review also found competition was generally more effective in electricity than gas, due to differences in market scale and difficulties in sourcing gas and transport services in some regions. It found gas is a secondary consideration for most customers and a less attractive value proposition for some retailers.

Despite finding competition was effective in most regions, the review identified many customers found energy contracts complex and struggle to compare available offers. Customer awareness of government price comparator websites was also very low. The AEMC recommended governments and regulators increase efforts to raise awareness of existing information and tools (such as independent comparator websites) and to make these tools user friendly.

The Consumer Action Law Centre and the Consumer Utilities Advocacy Centre raised concerns in 2013 about the ability of retailers to raise prices under fixed term energy contracts with termination fees. They considered this arrangement unfairly shifts price risk onto consumers, which may erode confidence in the market and weaken competition. The parties submitted a rule change proposal to the AEMC on this matter.

The AEMC rejected the proposal in October 2014. It considered the key issue is that some consumers may enter contracts unaware that their prices may change. To address this issue, it introduced a rule requiring a retailer to clearly inform a consumer entering a contract whether prices can change and, if so, when it would notify the customer of the change.

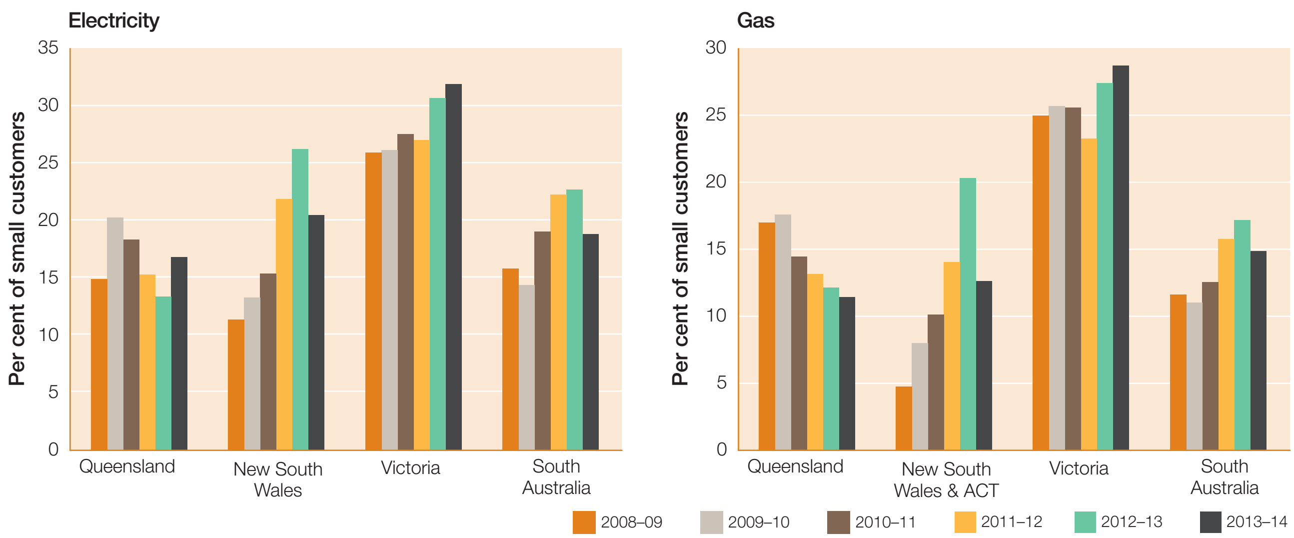
The AER participated in the rule change process and is exploring ways to improve the quality of information available to consumers when choosing an energy retail contract. In 2014 it began revising the *Retail pricing information guideline* that sets out how retailers must present offers, including all information that must be provided. The AER also intends to roll out improvements to the Energy Made Easy price comparison website in 2015, making it easier for customers to see which offer would best suit their needs.

Lack of understanding among consumers increases the risk of their exploitation. Given this risk, the behaviour of energy retailers has become a compliance and enforcement priority for the AER and Australian Competition and Consumer Commission (ACCC) in recent years (section 5.3.2)

4 AEMC, *2014 retail competition review, final report*, August 2014.

Figure 5.3

Customer switching of energy retailers, as a percentage of small customers



Sources: Customer switches: AEMO, MSATS transfer data to July 2014 and gas market reports, transfer history to July 2014; customer numbers: estimated from retail performance reports by the AER, the ESC (Victoria) and the QCA (Queensland).

5.3.1 Customer switching and awareness

The rate at which customers switch their supply arrangements is an indicator of market participation. While switching (or churn) rates may indicate competitive activity, they must be interpreted with care. Switching is sometimes high during the early stages of market development, when customers can first exercise choice, but may then stabilise as a market acquires depth. Similarly, switching may be low in a competitive market if retailers deliver good quality and low priced service that gives customers no reason to change.

The Australian Energy Market Operator (AEMO) publishes churn data measuring the number of customer switches from one retailer to another (but not customer switches between contracts with the same retailer). Figure 5.3 sets out the data, which show switching rates remain lower in gas than electricity in all jurisdictions, reflecting a lower number of active participants in the gas market.

Victoria continues to have higher switching rates than those of other jurisdictions. While it recorded its highest ever rates in 2013–14 (31 per cent of electricity customers and 28 per cent for gas), the transfer of Australian Power & Gas customers to AGL Energy in April and May 2014 inflated electricity and gas switching rates by 3–5 per cent. This transfer also inflated switching numbers in Queensland and NSW, but to a lesser extent.

Switching in NSW and South Australia rose over a number of years, reaching record rates in both electricity and gas in 2012–13. But switching rates eased in both states in 2013–14. This fall coincided with a number of retailers—including AGL Energy, EnergyAustralia and Origin Energy—ceasing door-to-door marketing.

Queensland's switching rates were once comparable with those in NSW and South Australia, but fell in recent years. Energy retailers reduced their marketing effort in Queensland over this period, reflecting concerns about how regulated electricity prices are set. Queensland's electricity switching rate in 2012–13 was its lowest since the introduction of FRC. The rate picked up in 2013–14—aided by a 'One big switch' campaign—but remained below the levels seen in other regions.

The AEMC's review of the effectiveness of competition found consumers had generally good awareness of their ability to choose a retailer. In those markets demonstrating effective competition, awareness ranged from 90 per cent of electricity customers (85 per cent for gas) in NSW to 95 per cent of electricity and gas customers in Victoria. However, consumers showed less awareness of tools available to effectively compare retail offers: over 60 per cent of respondents were not aware of, or unable to name, a price comparator website.

5.3.2 Consumer protection in competitive retail markets

Increased competition among retailers for new customers has intensified retailer marketing activity. This activity has been matched by a growth in customer complaints about the inappropriate conduct of energy salespersons. The Australian Consumer Law, enforced by the ACCC, contains provisions that protect customers from improper sales or marketing conduct. The provisions relate to unsolicited sales, misleading and deceptive conduct, and unconscionable conduct. The Retail Law also contains marketing provisions that protect customers.

Door-to-door marketing

Until recently, door-to-door marketing was the principal method of signing up new customers in the energy industry. However, it is sometimes criticised for the use of aggressive sales behaviour. In September 2011, the ACCC launched the *Knock! Knock! Who's there?* awareness campaign, which informed consumers about their rights and ability to refuse door-to-door sales. Further, it acted on several alleged breaches of the Australian Consumer Law relating to retailers' door-to-door marketing activities in 2012 and 2013. These breaches included:

- misleading and deceptive conduct, including false or misleading representations when calling on consumers to negotiate energy retail contracts
- unconscionable conduct, including dealings with a consumer from a non-English speaking background with very limited English skills
- sales agents' failure to immediately leave a premises at the request of the occupier, as indicated by a 'do not knock' sign on their door
- sales agents' failure to provide consumers with all required information
- breaches of the Unsolicited Consumer Agreement provisions, including sales agents' failure to clearly advise the consumer of the purpose of their visit.

The ACCC's focus on these issues, along with increased customer use of energy price comparison and switching websites to compare energy contracts, influenced the decision of the three largest retailers—AGL Energy, EnergyAustralia and Origin Energy—to cease door-to-door marketing in 2013.

Discounts off what?

In 2013 the ACCC shifted its focus to reviewing how businesses promote discounts and savings under their energy plans. This shift stemmed from concerns that consumers were being misled about the extent of savings available, and the period over which discounts would be provided.

In December 2013 the ACCC instituted proceedings in the Federal Court against AGL Energy. It alleged the business had made false or misleading representations, and engaged in misleading and deceptive conduct, relating to statements to consumers on the level of discount under their energy plans. Changes to the rates charged over time under these contracts eroded the discounts, despite representations from AGL Energy that the discounts would continue.

The ACCC took similar action against Origin Energy in March 2014, for representations made to residential energy consumers in South Australia. It alleged Origin Energy misled consumers about the level of discount (on energy usage charges) that they could obtain under its Daily Saver energy plans. The discounted charges under the plans were higher than those under Origin Energy's standard retail contracts.

Other enforcement action

The AER in November 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 in South Australia and the ACT before transferring them to new energy plans. The ACCC instituted proceedings against the businesses for similar behaviour in Queensland, NSW and Victoria under provisions in the Australian Consumer Law on misleading conduct or representations.

The ACCC has also taken action against energy retailers and energy switching sites for other activity, including misleading advertising by a price comparison service, and misleading and deceptive conduct by a telemarketer.

5.4 Retail prices

The energy bills paid by retail customers cover the costs of wholesale energy, transport through energy networks, and retail services. Table 5.2 estimates the composition of a typical electricity retail bill for a residential customer in each jurisdiction. While data for gas are limited, the table includes gas estimates for NSW.

The composition of energy bills varies across jurisdictions. In electricity, the cost of using networks to transport electricity is the largest component (36–57 per cent) of retail bills, followed by wholesale energy costs (21–27 per cent). Retailer operating costs (including margins) contribute 10–15 per cent of retail bills. Costs

Table 5.2 Indicative composition of residential electricity and gas bills, 2014

<table>
<tr><th></th><th colspan="5">PER CENT OF TYPICAL SMALL CUSTOMER BILL</th></tr>
<tr><th></th><th>WHOLESALE</th><th>RETAIL</th><th>TRANSMISSION</th><th>DISTRIBUTION</th><th>GREEN SCHEMES</th></tr>
<tr><td colspan="6">ELECTRICITY</td></tr>
<tr><td>Queensland</td><td colspan="2">28</td><td>9</td><td>51</td><td>12</td></tr>
<tr><td>New South Wales</td><td colspan="2">28</td><td>15</td><td>51</td><td>6</td></tr>
<tr><td>Victoria</td><td colspan="2">45</td><td>6</td><td>43</td><td>7</td></tr>
<tr><td>South Australia</td><td colspan="2">31</td><td>10</td><td>49</td><td>10</td></tr>
<tr><td>Tasmania</td><td>29</td><td>11</td><td colspan="2">56</td><td>3</td></tr>
<tr><td>ACT</td><td>24</td><td>18</td><td>8</td><td>39</td><td>11</td></tr>
<tr><td>NEM</td><td>20</td><td>15</td><td>10</td><td>47</td><td>7</td></tr>
<tr><td colspan="6">GAS</td></tr>
<tr><td>New South Wales</td><td colspan="2">49</td><td colspan="2">51</td><td>0</td></tr>
</table>

Sources: AEMC, *2013 Residential electricity price trends, final report*, 2013 (electricity); IPART determinations and factsheets (gas).

associated with schemes to develop renewable or low emission generation, or promote energy efficiency, make up the remaining 3–8 per cent of retail bills. The most significant of these costs relate to the renewable energy target (RET) (section 1.3.1) and feed-in tariffs for solar photovoltaic installations.

In gas, pipeline charges are the most significant component of retail gas prices, accounting for 49 per cent of those prices in NSW. Distribution charges account for the bulk of pipeline costs. Wholesale costs typically account for a similar share of retail gas prices as for electricity. Retailer operating costs (including margins) are similar for gas and electricity customers, but lower overall gas charges mean these costs account for a higher share of gas bills.

5.4.1 Retail price regulation

Retail price regulation of energy services is being phased out as effective competition develops in energy markets. The AEMC assesses the effectiveness of retail competition in each jurisdiction, but state and territory governments make the final decisions on whether to remove price regulation. Victoria (2009), South Australia (2013) and NSW (July 2014) removed retail price regulation for electricity, following AEMC reviews. While those jurisdictions no longer regulate retail prices, retailers must publish unregulated standing offer prices that small customers can access. The prices can be changed no more than once every six months.

The ACT Government decided to retain price controls. It noted the AEMC's finding that removing price controls would increase the average cost of electricity, which would not benefit customers.[5] Of the jurisdictions yet to remove retail price regulation, the AEMC's 2014 competition review found only south east Queensland exhibited effective competition.[6] Following the review, the Queensland Government committed to removing electricity retail price regulation in south east Queensland from 1 July 2015. Regulated price setting will continue for the Ergon Energy distribution area, pending the development of a strategy to introduce retail competition in regional Queensland.

In gas, only NSW regulates prices for small customers. The regulated prices are set by state or territory government agencies; the AER does not regulate retail prices in any jurisdiction. Retailers are free in all NEM jurisdictions to offer market contracts with price terms different from the regulated rates.

Jurisdictions generally apply one of two methods to regulate energy retail prices:

- a building block approach, whereby the regulator determines efficient cost components (for example, wholesale costs, retail operating costs and costs associated with regulatory obligations) and passes through costs determined elsewhere (for example, network costs). The regulator uses these costs to determine a maximum revenue requirement to be reflected in the prices that the retailer charges. Determinations typically cover a number of years,

5 ACT Government, 'ACT to keep price regulation for Canberra households', Media release, www.chiefminister.act.gov.au/media.php?v=10936&m=53 2011, September 2011.

6 AEMC, *2014 Retail competition review, final report,* August 2014.

Table 5.3 **Movements in regulated and standing offer prices—electricity and gas**

JURISDICTION	REGULATOR	DISTRIBUTION NETWORK	AVERAGE PRICE INCREASE (PER CENT) 2010	2011	2012	2013	2014	ESTIMATED ANNUAL COST ($)
ELECTRICITY								
Queensland	QCA	Energex and Ergon Energy	13.3	6.6	10.6	20.4	1.7	2149
New South Wales	Unregulated	AusGrid	10.0	17.9	20.6	3.9	–5.5	1991
		Endeavour Energy	7.0	15.5	11.8	1.6	–6.7	1908
		Essential Energy	13.0	18.1	19.7	–0.6	–6.9	2536
Victoria	Unregulated	Citipower	14.6	3.7	19.9	6.4	–9.0	1825
		Powercor	15.4	7.7	23.1	5.8	–6.8	2226
		AusNet Services	11.3	23.6	19.7	12.4	–3.9	2292
		Jemena	17.7	10.5	23.2	6.1	–5.8	2202
		United Energy	11.4	9.7	25.2	4.8	–6.2	2032
South Australia	Unregulated	ETSA Utilities	18.3	17.4	12.7	–1.8	2.2	2564
Tasmania	OTTER	Aurora Energy	15.3	11.0	10.6	1.8	–12.6	1927
ACT	ICRC	ActewAGL	2.3	6.5	17.7	3.5	–7.0	1466
GAS								
Queensland	Unregulated	Australian Gas Networks	6.8	1.4	13.4	8.4	2.1	1081
		Allgas Energy	6.4	7.4	13.4	5.1	3.4	1122
New South Wales	IPART	Jemena	5.2	4.0	14.8	9.6	12.0	1033
Victoria	Unregulated	AusNet Services	5.4	9.0	16.3	3.0	–1.2	661
		Multinet	7.5	3.5	20.0	2.0	–1.6	705
		Australian Gas Networks	11.3	7.3	18.4	9.1	–3.2	683
South Australia	Unregulated	Australian Gas Networks	3.1	13.8	17.7	11.6	9.3	1172
ACT	Unregulated	ActewAGL	3.2	7.0	10.3	5.7	8.7	957

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 August 2014.

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.

but some cost components are adjusted annually. Separate pass through provisions cover unexpected costs. Tasmania and Queensland use a building block approach.

- a benchmark retail cost index, whereby the regulator determines movements in benchmark costs to calculate annual adjustments in retail prices. The ACT uses this approach, which was also previously used in Queensland.

In September 2013 the AEMC completed a review of best practice retail electricity price regulation. Its report for the for energy ministers sets out its preferred methods for estimating each cost component, based on wanting regulated prices to reflect the efficient costs of providing retail services and facilitating competition.

5.4.2 Retail price trends

Table 5.3 (and figure 8 in the Market Overview) summarises recent movements in regulated and standing offer energy prices, and estimates annual customer bills under those arrangements. The data assume fixed electricity and gas use nationally and so, may not reflect a typical household in a particular jurisdiction. In practice, average use varies between (and within) jurisdictions for a range of reasons, including climate and the penetration of gas supply.

Box 5.2 Regulated retail energy prices, by jurisdiction—recent developments

Queensland's single-rate electricity tariff for residential customers rose by 5.1 per cent for 2014–15. Savings from the carbon pricing repeal reduced an average annual bill by 8.5 per cent. But, this reduction was offset by:

- a forecast rise in wholesale prices, driven by industrial demand associated with LNG exports and higher gas prices (increasing bills by 5.1 per cent)
- higher Solar Bonus Scheme costs, reflecting under-recovery of feed-in tariffs in earlier years (increasing bills by 3.8 per cent).
- a rise in network and retailer costs, adding 2.7 per cent and 1.6 per cent respectively to annual bills.

Retail price regulation ended in *NSW* on 1 July 2014, but retailers previously subject to regulation agreed to a transitional price for 2014–15, set at 1.5 per cent below the previous regulated rate. This price does not account for lower costs from the carbon pricing repeal; retailers passed on that cost saving separately, as they did for customers on market contracts.

The regulated electricity price in *Tasmania* fell by 7.8 per cent for 2014–15. The removal of carbon pricing was the main contributor, reducing charges by 9.4 per cent. Reduced energy losses also contributed to lower prices. These saving were partly offset by higher network charges (increasing bills by 2.7 per cent) and retail costs (increasing bills by 2.1 per cent).

ACT electricity prices fell on average by 7.3 per cent for 2014–15. The carbon pricing repeal reduced prices by 11.6 per cent. But, this reduction was partly offset by higher network charges that resulted from a rise in transmission costs, and from the introduction of a feed-in tariff scheme to support a commercial solar facility. Retail costs also rose, while costs associated with the RET and energy losses fell.

In gas, retail prices in NSW rose by an average of 11.2 per cent for 2014–15. Higher expected wholesale costs were the main contributor, driven by a redirection of gas reserves for export.

Standing offer prices vary across distribution networks in NSW, Victoria and Queensland (for gas only). Prices are highest in those networks servicing regional and remote areas, where the costs of providing and servicing infrastructure are higher and recovered from fewer customers.

Retail electricity prices have risen significantly since 2008. Network costs were the key driver, although cost pressures in this area have lessened over the past two years in most regions. The carbon price also contributed, leading to price increases of 5–13 per cent in 2012–13, although the Australian Government's Household Assistance Package offset the impact on low and middle income residential customers.

The repeal of carbon pricing from 1 July 2014 led retail electricity prices to fall in regions other than Queensland and South Australia. In Queensland, carbon price reductions were offset by higher wholesale energy costs and feed-in-tariff payments for solar photovoltaic systems; in South Australia, they were offset by rising network costs (box 5.2).

Gas prices have also risen significantly, mainly driven by rising pipeline charges. More recently, rising wholesale costs associated with the diversion of gas supplies to LNG export have put further pressure on retail prices.

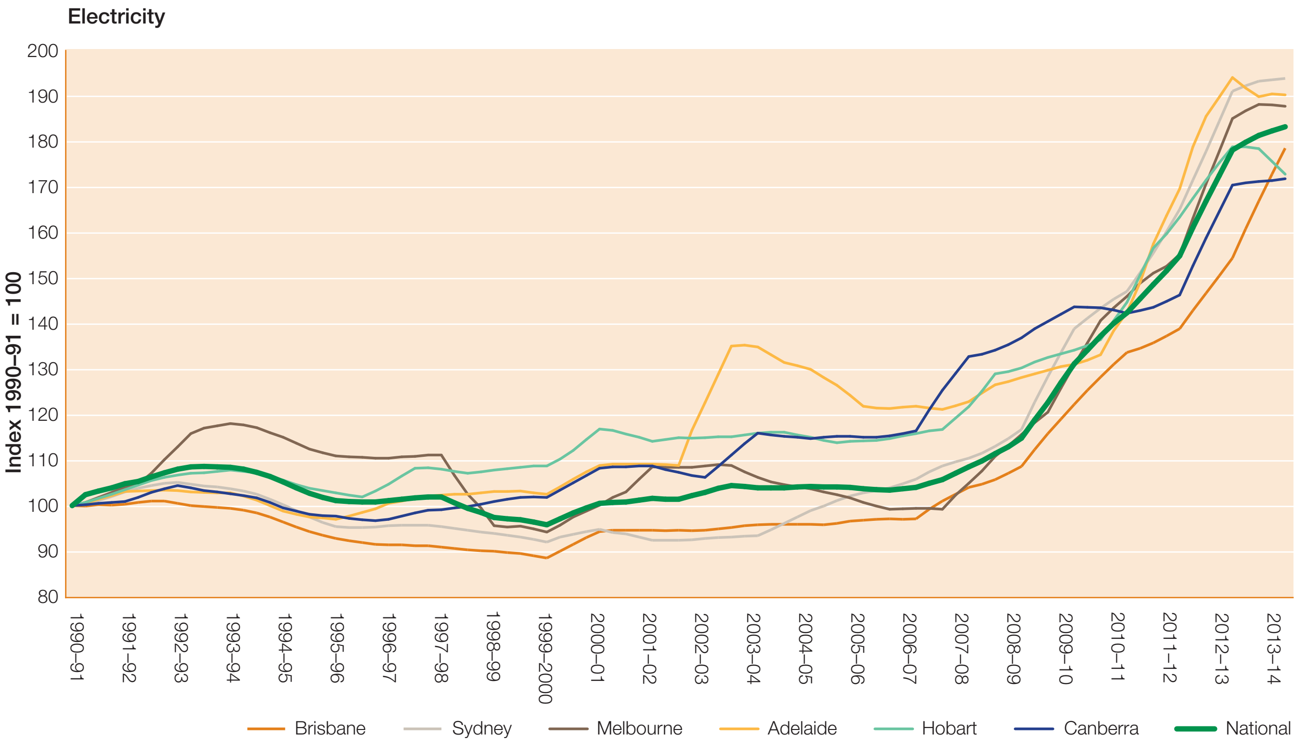
ABS data on energy prices

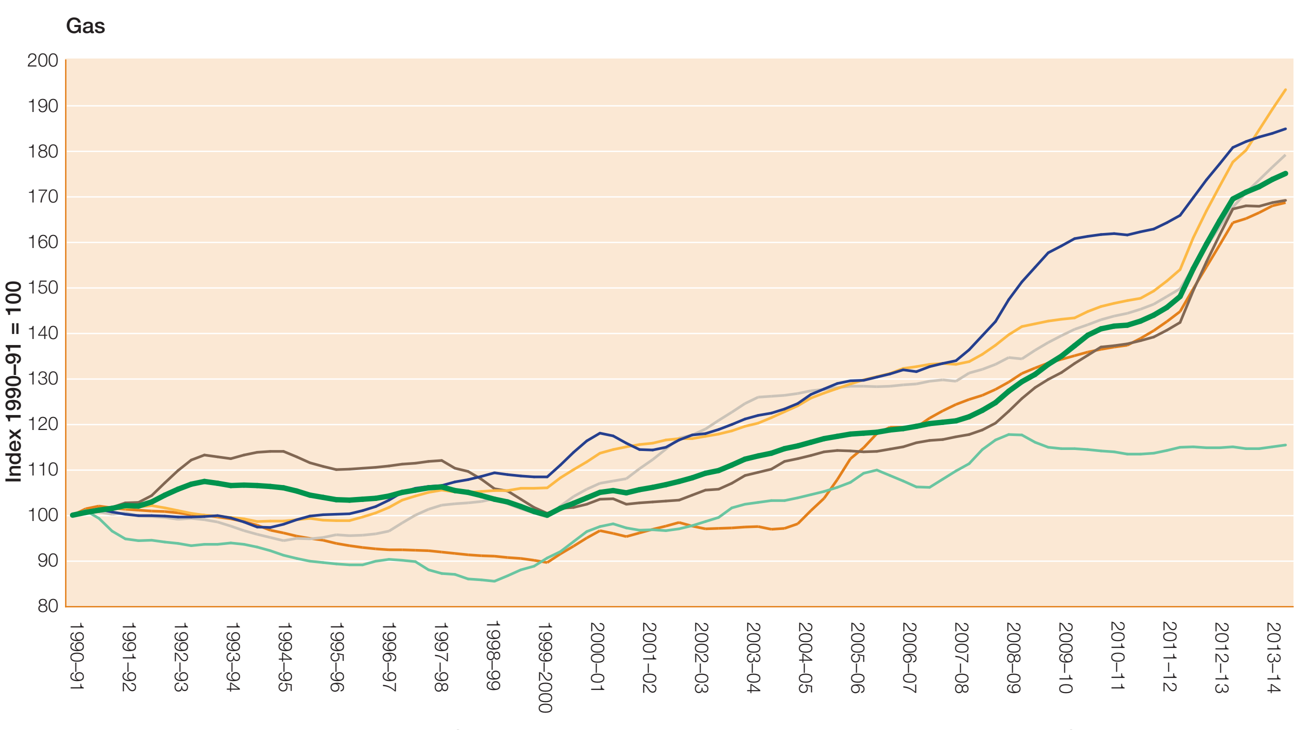
Figure 5.4 tracks movements in real energy prices for metropolitan households since 1991, using the electricity and gas components of the Australian Bureau of Statistics (ABS) consumer price index. After adjusting for inflation, national electricity prices rose by around 10 per cent annually (13 per cent in nominal terms) over the five years to 2012–13. Real prices moderated in 2013–14, with falls recorded in Hobart and Adelaide—the first reductions in those regions since 2005–06. Brisbane was the only city to experience substantial rises, with real prices up by 15 per cent, following a delayed pass-through of network cost increases.

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 all regions in 2013–14, but at a slower rate. The largest price rises were in Adelaide (9 per cent in real terms) and Sydney (7 per cent).

Figure 5.4

Retail price index (inflation adjusted)—Australian capital cities





Note: Consumer price index electricity and gas series, deflated by the consumer price index for all groups.

Source: ABS, *Consumer price index*, cat. no. 6401.0, various years.

5.4.3 Price diversity

Retailers offer a range of contracts with different price and product structures. The offers may include standard products, green products, 'dual fuel' contracts (for gas and electricity) and packages that bundle energy with services such as telecommunications. Some contracts bundle energy services with inducements such as customer loyalty bonuses, awards programs, free subscriptions and prizes. Additional discounts may be offered for prompt payment of bills, or for direct debit bill payments. These offers may vary depending on the length of a contract. Many contracts carry a termination fee for early withdrawal.

The variety of discounts and non-price inducements makes direct price comparisons difficult. Further, the transparency of price offerings varies. The AER operates an online price comparison service—Energy Made Easy—to help small customers compare retail product offerings. The website is available to customers in those jurisdictions that have implemented the Retail Law (at December 2014: NSW, South Australia, Tasmania and the ACT). Additionally, the Queensland and Victorian regulators, and a number of private entities operate websites that allow customers to compare available market offers.

Figure 5.5 draws on Energy Made Easy and state regulators' price comparison websites to list price offerings for residential customers in mainland NEM jurisdictions at September 2013 and September 2014.

Victoria exhibited the strongest price diversity for electricity, with annual charges under the cheapest contract being 40–45 per cent lower than those under the most expensive contract. In September 2014 the average discount in annual electricity bills under market contracts over standing contracts ranged from 5 per cent in Queensland to 16–19 per cent in Victoria. The average level of discounting was higher than for the previous year in all regions.

In September 2014 discounts in market offers over standing offers were typically higher in electricity than gas; the discount for gas was around 5 per cent in most jurisdictions, but 10 per cent in Victoria.

The annual bill spread in September 2014 (within a particular distribution network) varied among jurisdictions:

- In electricity, it ranged from $200 in Queensland to over $1000 in Victoria. The spread for most networks was greater in September 2014 than in September 2013, with the biggest increases recorded for the Endeavour and Essential (NSW) and ActewAGL (ACT) network areas.
- In gas, it was around $200 for most networks. The spread was generally consistent with the previous year's spread. The Queensland network areas had a contraction in the range of offers, following AGL Energy's acquisition of Australian Power & Gas in 2013.

5.4.4 Retail prices and energy affordability

Energy affordability relates to customers' ability to pay their energy bills. While rising energy prices tend to increase the number of customers with payment difficulties, affordability also depends on energy consumption levels, household income and financial assistance or concessions.

AER research found average energy costs as a proportion of household disposable income in 2013–14 were higher than the levels recorded two years earlier, but were lower in Tasmania and Victoria than in 2012–13 (figure 5.6). For a benchmark low income household receiving energy bill concessions:

- electricity costs accounted for 2.4–7.1 per cent of their disposable income in 2011–12 (depending on region), rising to 3.0–7.3 per cent in 2013–14
- gas costs accounted for 1.2–3.2 per cent of their disposable income in 2011–12, rising to 1.9–3.4 per cent in 2013–14.[7]

This analysis does not account for the impact on bills of changes to average domestic energy consumption. A fall in electricity consumption over the past few years, for example, would have offset some of the bill increases identified by the analysis.

Electricity bills in 2013–14 were highest in Tasmania. While its unit charges were lower than in some jurisdictions, low income households used on average 8100 kilowatt hours (kWh) per year (compared with 4700 to 7000 kWh elsewhere). Annual electricity bills were lowest in the ACT. Despite high electricity consumption, that region's use charges are substantially lower than elsewhere.

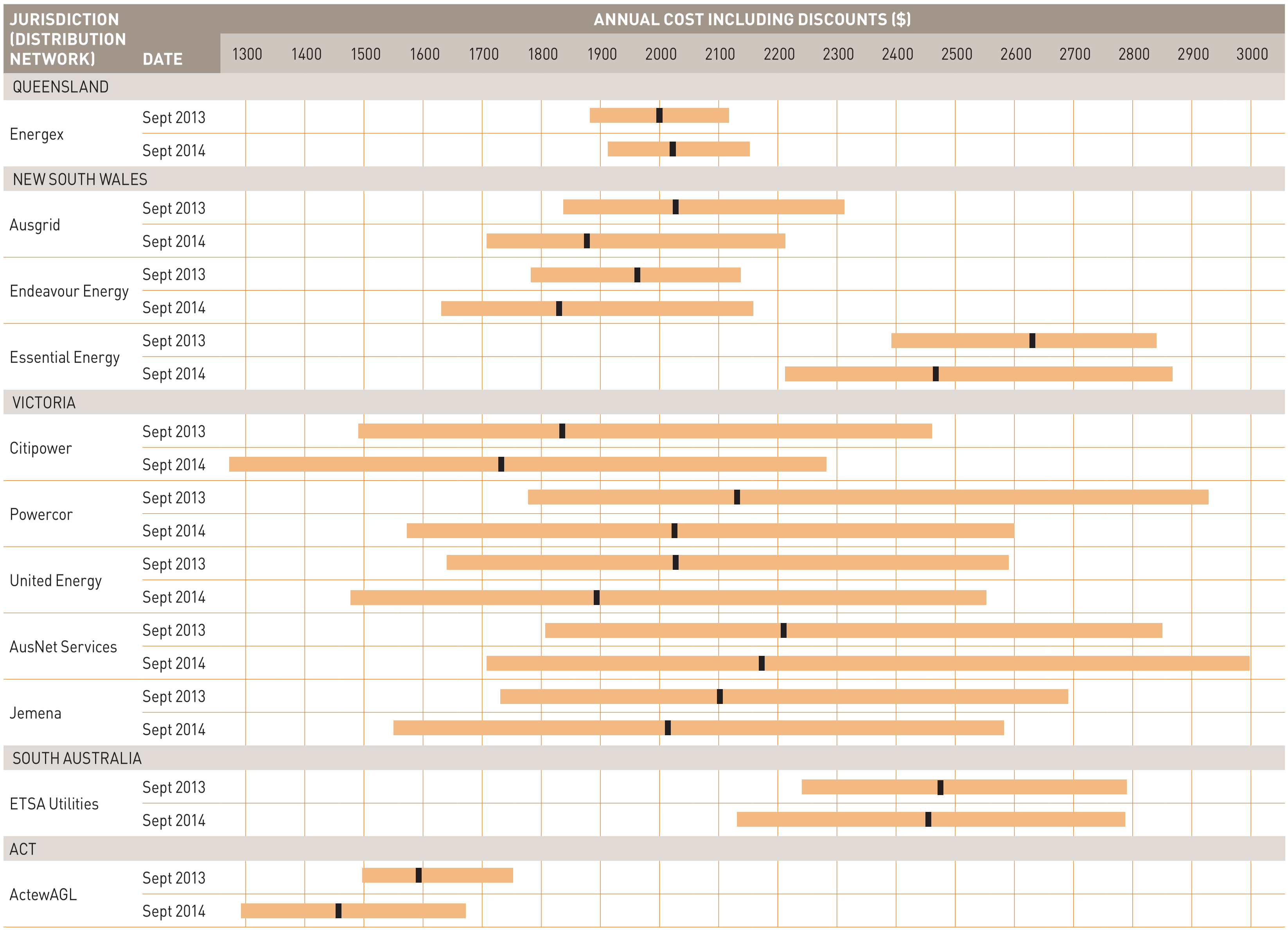
Gas bills in 2013–14 were highest in the ACT and Victoria, where average use was 48 gigajoules and 63 gigajoules respectively (compared with 10–24 gigajoules elsewhere). Queensland had the lowest gas bills, with a relatively low average gas use of 10 gigajoules per year.

A key indicator of affordability and access is the rate of residential customer disconnections for failure to meet bill payments (figure 5.7). In 2013–14 the rate of electricity disconnections for non-payment reached their highest

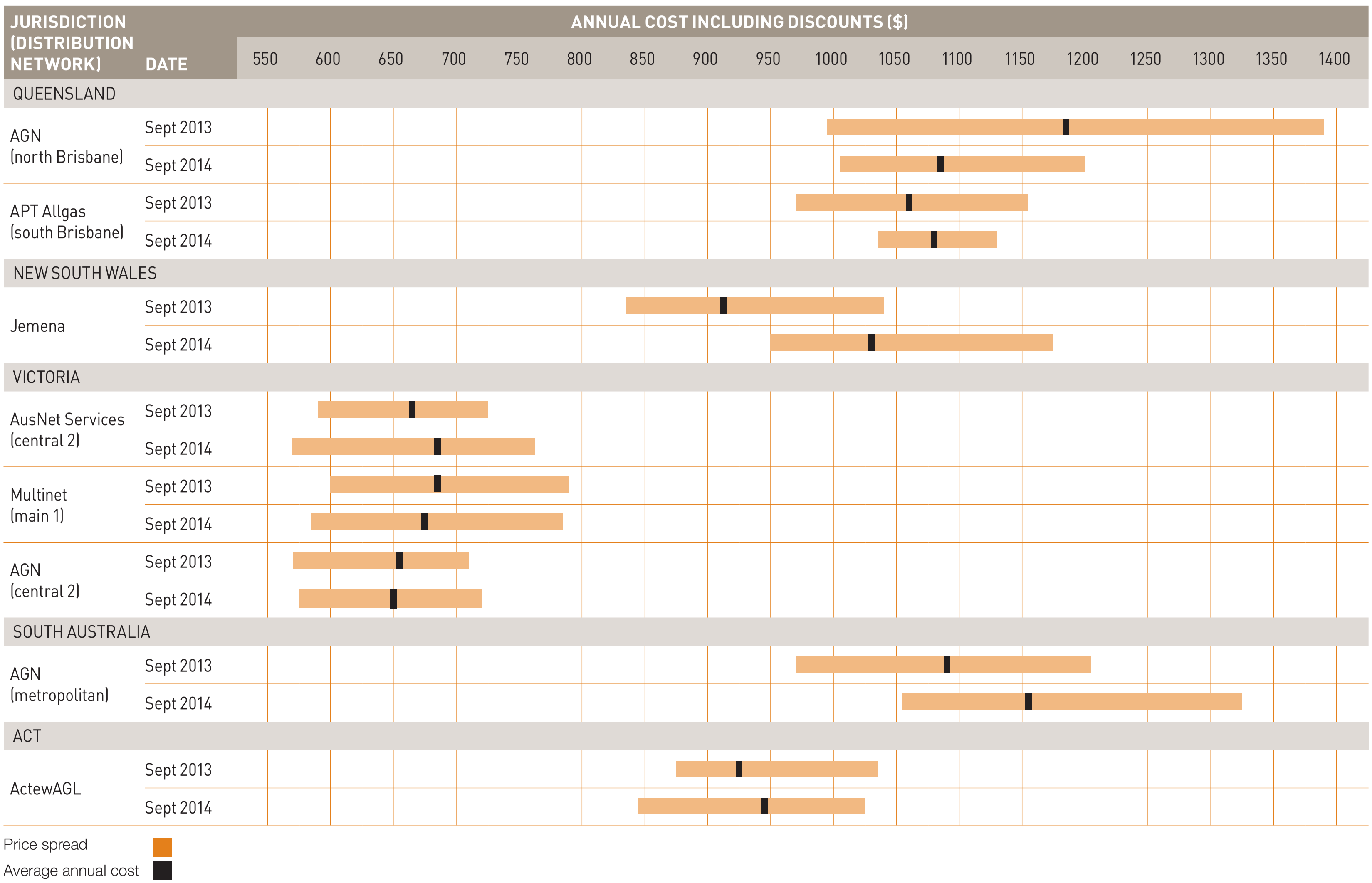
7 AER, *Annual retail energy market performance report, 2013–14*, 2014.

Figure 5.5
Price diversity in retail product offers—September 2013 and September 2014

Electricity



Gas



Sources: Price comparison websites operated by the AER (NSW, South Australia and the ACT), QCA (Queensland) and ESC (Victoria).

levels for the past six years in Queensland, NSW and Tasmania. Disconnection rates were also high in South Australia, although down from record levels in 2012–13. Over 40 per cent of disconnected electricity customers, and 24 per cent of disconnected gas customers, were reconnected within a week.

Hardship issues

The Retail Law requires retailers to assist customers experiencing payment difficulties or financial hardship. Retailers must:

- protect customers from disconnection in certain circumstances, including when a customer's premises are registered as requiring life support equipment
- assist customers (through hardship programs, for example) before considering disconnection for non-payment of a bill.

Hardship programs aim to provide early assistance to customers. Retailers may offer:

- extensions of time to pay, as well as flexible payment options
- help to identify government concession and rebate programs
- referrals to financial counselling services
- review of a customer's energy contract to make sure it suits their needs
- energy efficiency advice to help reduce a customer's bills, which may include conducting an energy audit and helping replace appliances
- a waiver of late payment fees that might have applied.

At 30 June 2014 the number of customers on hardship programs ranged from 0.4 per cent in Tasmania (electricity) and the ACT (electricity and gas), to 1.2 per cent in South Australia (electricity). Customers commonly enter a hardship program with less than $500 of debt to the energy retailer (41 per cent of electricity customers and 57 per cent of gas customers entering a program), and most customers have an average debt of less than $1500. However, almost 12 per cent of electricity customers and 4 per cent of gas customers had debts greater than $2500 before joining a hardship program.

Of those customers exiting a hardship program in 2013–14, only 20 per cent successfully completed the program; a further 26 per cent changed retailers. The remaining customers were removed from hardship programs for failing to meet energy repayments.

5.5 Customer complaints

Energy retailers are required to have complaints handling and dispute resolution processes. Additionally, each jurisdiction has an energy ombudsman scheme offering a free and independent dispute resolution service for energy customers who have been unable to resolve a complaint with their retailer.

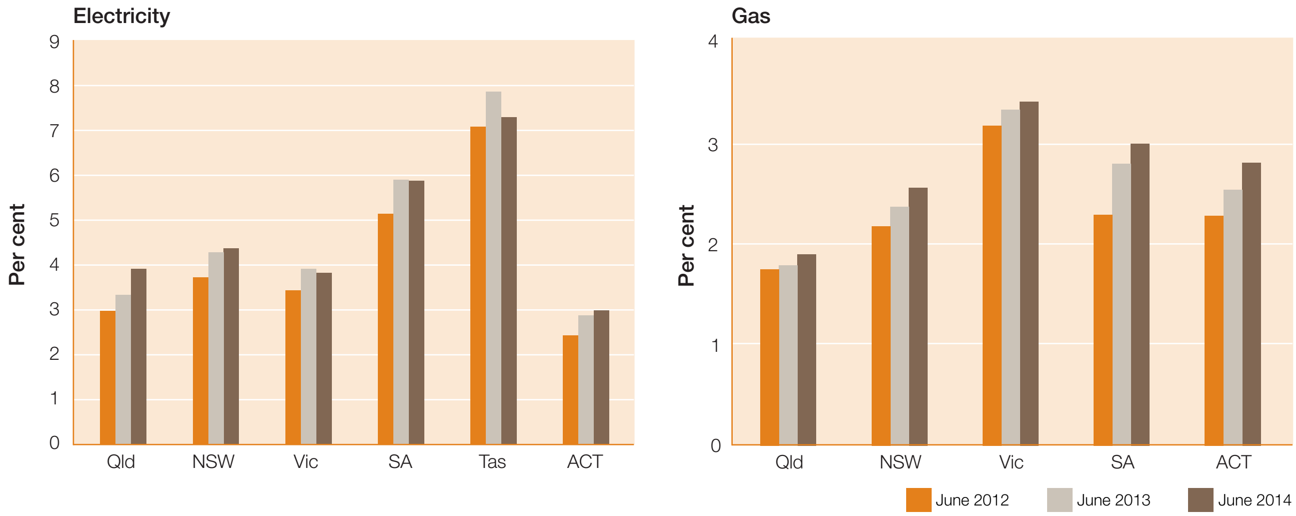
Figure 5.8 illustrates rates of customer complaints in electricity and gas to ombudsman schemes. The complaint rate varies across jurisdictions, from less than 0.5 per cent of customers in Queensland and Tasmania, to 2–2.5 per cent of customers in Victoria and South Australia. While the results may reflect retailers' performance and the effectiveness of their internal dispute resolution procedures, they should be interpreted with caution; the maturity of competition, market depth and customers' awareness of the schemes may also affect outcomes.

The total number of complaints across electricity and gas rose in 2013–14 in Queensland (up 4 per cent on the previous year's total), NSW (up 6 per cent) and Victoria (up 10 per cent). South Australia recorded a 14 per cent reduction in complaints.

Billing issues accounted for almost half of all complaints in 2013–14. Credit issues—including processes for disconnection in the case of non-payment, and for the collection of outstanding charges—accounted for a further 20 per cent of complaints. Other prominent issues included unauthorised transfers of customers to a new retailer, disputes over network connections, and retailers' marketing behaviour.

Figure 5.6

Annual energy costs as a percentage of disposable income for a low income household



Notes:

Energy consumption levels vary for each jurisdiction. Electricity consumption is the average for low income households. Gas consumption is the average for all households.

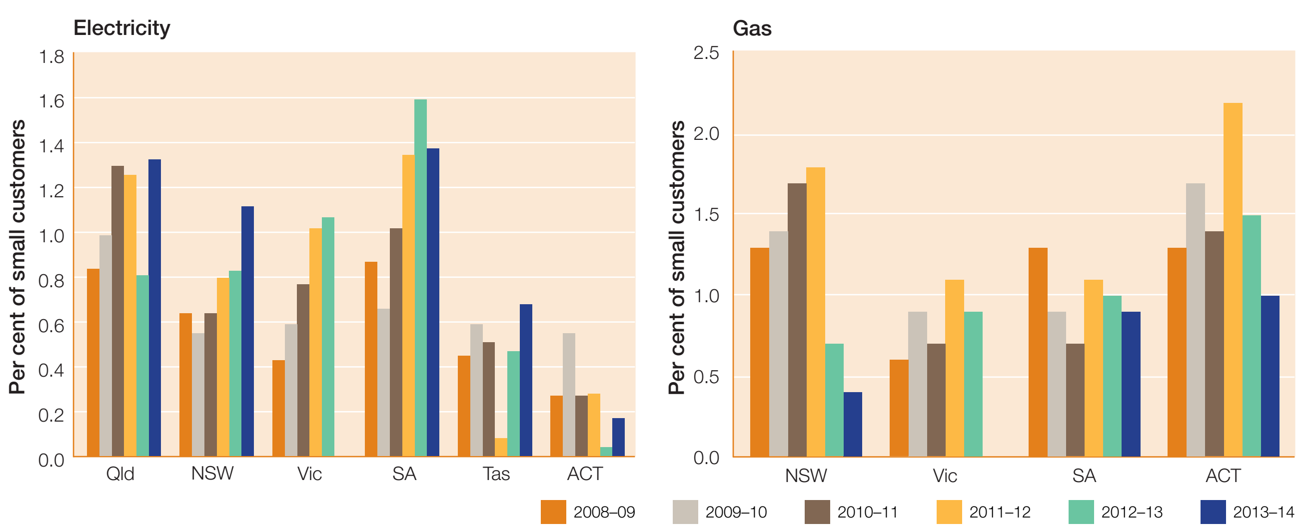
Energy charges are based on the median market offer. Charges are adjusted for concessions available to low income households.

Disposable income for a low income household is the average of the second and third income deciles.

Sources: ABS; AER; Price comparator websites operated by jurisdictional regulators.

Figure 5.7

Residential disconnections for failure to pay amount due, as a percentage of customers

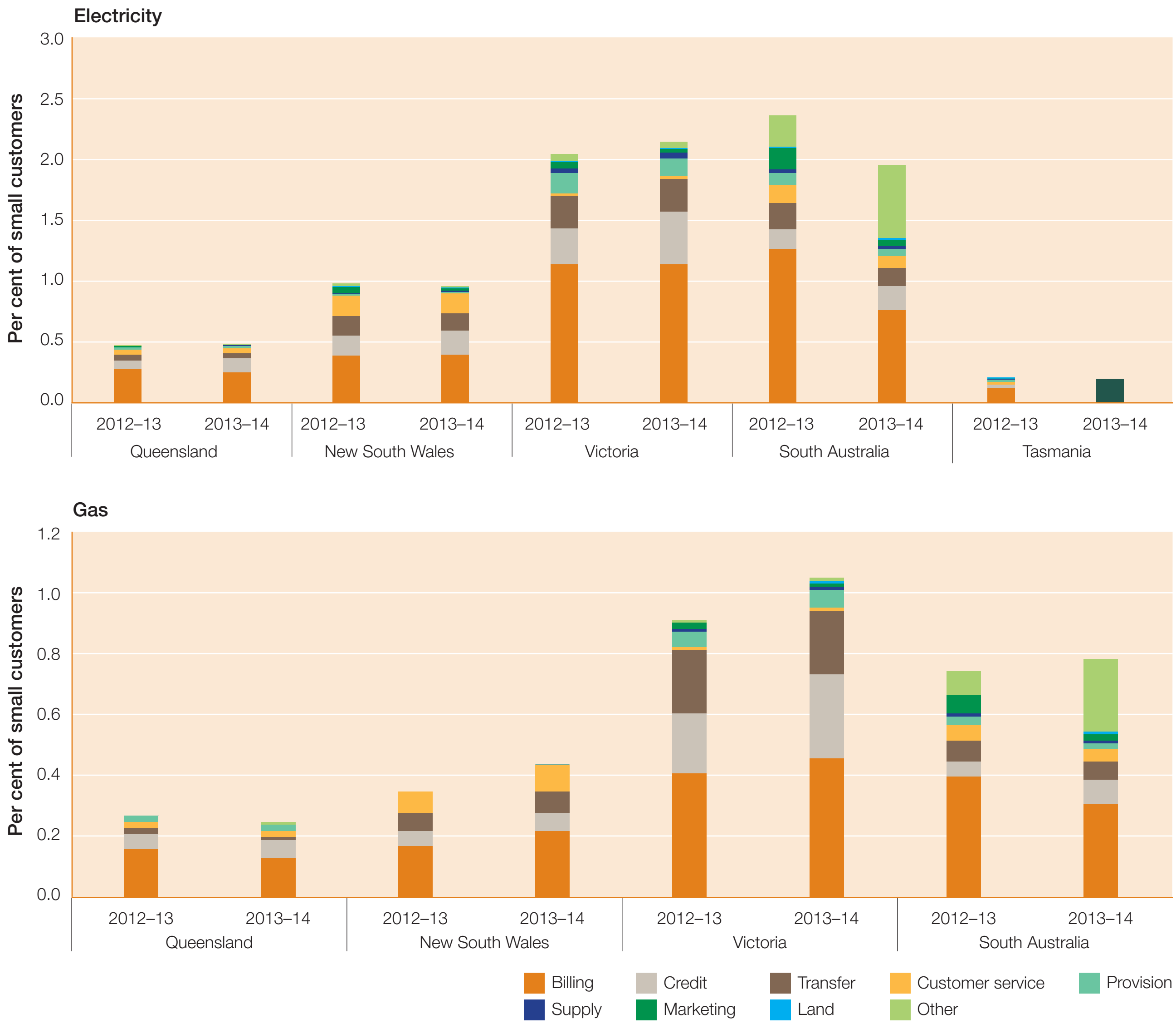


Note: 2013–14 disconnection data were not available for Victoria.

Sources: Retail performance reports by the AER, IPART (NSW), the ESC (Victoria), ESCOSA (South Australia), OTTER (Tasmania), the QCA (Queensland) and the ICRC (ACT).

Figure 5.8

Complaints to ombudsman schemes, as a percentage of total customers



Note: Categorised data were not available for Tasmanian electricity complaints for 2013–14.

Sources: Annual reports by the Energy and Water Ombudsman schemes in Queensland, NSW, Victoria and South Australia, and by the Energy Ombudsman of Tasmania.

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
ASX	Australian Securities Exchange
BREE	Bureau of Resources and Energy Economics
Co2-e	carbon dioxide equivalent
CoAG	Council of Australian Governments
CSG	coal seam gas
EII	Energy Infrastructure Investments
Electricity Rules	National Electricity Rules
ESC	Essential Services Commission
ESCOSA	Essential Services Commission of South Australia
FRC	full retail contestability
GJ	gigajoule
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	liquid natural gas
MOS	market operator services
MSATS	market settlement and transfer solutions
MW	megawatt
MWh	megawatt hour
NCC	National Competition Council
NEM	National Electricity Market
NSW	New South Wales
OTC	over-the-counter
OTTER	Office of the Tasmanian Economic Regulator
PJ	petajoule
PV	photovoltaic
QCA	Queensland Competition Authority
QCLNG	Queensland Curtis liquid natural gas project
QNI	Queensland—NSW Interconnector
RAB	regulated asset base
RERT	reliability and emergency reserve trader
RET	renewable energy target
Retail Law	National Energy Retail Law
RIN	regulatory information notice
RIT-D	regulatory investment test—distribution
RIT-T	regulatory investment test—transmission
RSI	residual supply index
SAIDI	system average interruption duration index
SAIFI	system average interruption frequency index
SCER	Standing Council on Energy and Resources
TJ	terajoule
TJ/d	terajoules per day
TW	terawatt
TWh	terawatt hour
WACC	weighted average cost of capital