STATE OF THE ENERGY MARKET 2013

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PREFACE

The Australian Energy Regulator's seventh *State of the energy market* report comes at a time of changing dynamics in the energy industry. Declining electricity demand has led to surplus generation capacity in most regions and has delayed the need to invest in electricity networks. Additionally, greater stability in global financial markets has eased finance costs for energy businesses. In 2013, these developments translated into more stable retail electricity prices in most jurisdictions.

Reforms to the energy rules (announced in November 2012) aim to deliver future decisions on network revenues and investment that are in the long term interests of consumers. In 2013 the AER published guidelines under the Better Regulation program on implementing the rules. The guidelines will apply first to regulatory determinations taking effect in 2015.

In retail, the transition to national regulation is continuing, with New South Wales on 1 July 2013 becoming the fourth jurisdiction (following South Australia, Tasmania and the ACT) to implement the National Energy Retail Law. Consumers in those jurisdictions now enjoy access to the AER's price comparator, www.energymadeeasy.gov.au.

Dynamics in the eastern gas market differ from those in electricity. While domestic demand has weakened, international demand for liquefied natural gas (LNG) exports from Queensland (scheduled to commence in 2014–15) is exerting pressure on gas prices. Policy makers are introducing reforms to help manage pressures in the eastern gas market.

This edition of *State of the energy market* 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.

Andrew Reeves
Chairman
December 2013

MARKET OVERVIEW

The energy market landscape has shifted considerably over the past 12–18 months. Rising energy prices were a major focus for the community and policy makers in 2012, but the dynamics of underlying cost drivers are shifting. A trend of rising electricity demand—which exerted upward pressure on wholesale and network costs for several years—has now reversed. The change is causing surplus generation capacity and removing the impetus for a number of network expansions. Further, the instability in global financial markets has eased, bringing down finance costs for energy businesses.

These developments are translating into more stable retail electricity prices in most jurisdictions. Following double digit rises in 2012–13, electricity retail price increases under regulated offers for 2013–14 were contained to below 4 per cent in New South Wales, Tasmania and the ACT (figure 1). In one New South Wales network area (Essential Energy), retail prices fell by 0.6 per cent.

Victoria and South Australia do not regulate retail electricity prices. In Victoria, standing contract prices rose by 5–12 per cent in 2013 across the state's five distribution network areas, following increases of 20–25 per cent in 2012. Because prices are unregulated, limited information is available on the reasons for these outcomes. But the Essential Services Commission reported in May 2013 that retailer margins in Victoria have increased since the removal of retail price regulation in 2009. In South Australia, electricity prices in standing contracts fell by 9.1 per cent following deregulation on 1 February 2013. Subsequent movements resulted in a net price decrease of 1.8 per cent during 2013.

An exception to this move towards more stable electricity prices was Queensland, where the regulated single-rate residential tariff rose by 20.4 per cent for 2013–14. The rise passes through two years of network cost increases following the Queensland Government's price freeze for this tariff in 2012–13.

Retail prices tended to rise more strongly for gas than electricity in 2013–14. In New South Wales, higher network costs contributed 60 per cent to the gas retail price rise. And gas retail prices are unlikely to ease in the near future. While domestic demand recently flattened, international demand for liquefied natural gas (LNG) exports from Queensland (scheduled to commence in 2014–15) is placing upward pressure on wholesale prices.

A.1 Transition to national regulation

The transition to national regulation of retail energy markets is continuing. The National Energy Retail Law commenced in Tasmania (for electricity only) and the ACT on 1 July 2012, in South Australia on 1 February 2013 and in New South Wales on 1 July 2013. Victoria and Queensland are yet to implement the Retail Law.

The Retail Law operates with the Australian Consumer Law to protect small energy customers in their electricity and gas supply arrangements. It also transfers significant functions from state and territory governments to the Australian Energy Regulator (AER). While the AER does not regulate retail energy prices, it maintains the Energy Made Easy website, which provides a tool for energy customers to compare prices of generally available retail market offers. The website also provides a benchmarking tool for households to compare their electricity use with that of similar households, and information on the energy market, energy efficiency and consumer protections. At 1 December 2013 small energy customers in New South Wales, South Australia, Tasmania and the ACT had access to all functions of the website.

The AER also monitors energy affordability and retailers' policies for assisting hardship customers. AER research found average energy costs rose faster than household disposable income in 2012–13. For a benchmark low income household that receives energy bill concessions:

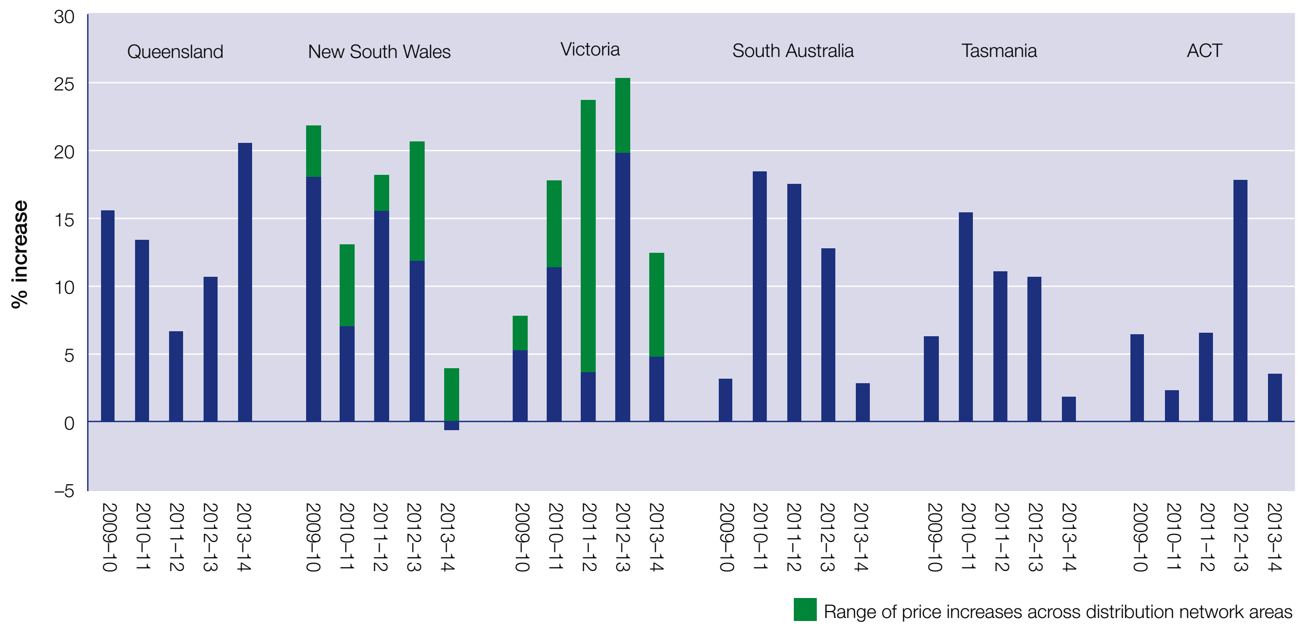
- electricity costs accounted for 2.4–7.1 per cent of their disposable income in 2011–12 (depending on region), rising to 2.9–7.9 per cent in 2012–13
- gas costs accounted for 1.2–3.2 per cent of their disposable income in 2011–12, rising to 1.4–3.4 per cent in 2012–13.

Electricity costs were highest in Tasmania, where average electricity use is significantly higher than elsewhere. Gas costs were highest in Victoria, for a similar reason.

A.2 State of retail competition

The retail sector experienced a slight increase in market depth in 2012–13. While three retailers—AGL Energy, Origin Energy and EnergyAustralia (formerly TRUenergy)—jointly supplied 77 per cent of small electricity customers and 85 per cent of small gas customers in southern and eastern Australia, their combined market share fell by 2 per cent in 2012–13. Small private retailers (mostly new entrants) in the New South Wales and Victorian electricity markets gained market share during the year. In Victoria, which is the region

Figure 1
Movements in regulated and standing offer prices—electricity



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 2013.

The Victorian price movements (and estimated annual costs) are for the calendar year ending in that period—for example, the 2013–14 Victorian data are for calendar year 2013. Victorian price movements (and those for South Australia in 2013–14) are based on unregulated standing offer prices of the local area retailer for each distribution network. The data for South Australia in 2013–14 relates to movements in the standing offer in the six months to December 2013.

The price increase for Tasmania in 2013–14 relates to the period 1 July 2013 to 31 December 2013. A further price adjustment will occur on 1 January 2014.

Sources: Determinations, factsheets and media releases by IPART (New South Wales), the QCA (Queensland), ESCOSA (South Australia), OTTER (Tasmania) and the ICRC (ACT); Victorian Government gazette.

with the most diverse market structure, small private retailers supplied 27 cent of electricity customers. Some of the gains to smaller retailers were reversed in August 2013 when AGL Energy acquired the former independent retailer Australian Power & Gas.

Customer switching activity continued to be strong, with record highs for both electricity and gas in Victoria, New South Wales and South Australia in 2012–13 (figure 2). Particularly strong growth in New South Wales led its switching rate for electricity to reach a level previously seen only in Victoria. But switching rates fell in Queensland, where energy retailers reduced their marketing efforts in response to concerns about how regulated electricity prices are set.[1]

High switching rates were mirrored by evidence of reasonable price diversity, although discounting fell in some jurisdictions. In August 2012 the average discount off base offers[2] was 5–6 per cent in Queensland, New South Wales and South Australia, and 8–9 per cent in Victoria. In August 2013 the average discount was relatively unchanged in Queensland, but lower in New South Wales (below 4 per cent) and South Australia (1.5 per cent). The variation across Victorian network areas was generally higher, from 7–11 per cent.

In August 2013 the average discount off base offers was lower in gas than electricity—less than 4 per cent in jurisdictions other than Victoria. The average discount for Victoria was 6 per cent. In South Australia and in

1 See, for example, AGL, 'AGL 2013 earnings guidance', Media release, 23 October 2012.

2 Base offers are regulated offers in New South Wales (electricity and gas) and Queensland (electricity). In other jurisdictions, base offers are the standing offers of the local area retailer for each distribution network.

Figure 2
Switching of energy retailers by small customers

Sources: Customer switches: AEMO, MSATS transfer data to July 2013 and gas market reports, transfer history to July 2013; customer numbers: estimated from retail performance reports by the AER, IPART (New South Wales), the ESC (Victoria), ESCOSA (South Australia) and the QCA.

Queensland's North Brisbane network, gas contract prices on average exceeded the base offer price of the local area retailer.

Increased competition among retailers for new customers has intensified marketing activity, resulting in a greater volume of customer complaints about inappropriate conduct. The Australian Competition and Consumer Commission (ACCC) has acted on several alleged breaches of the Australian Consumer Law related to door-to-door and other marketing activity. As a result, the Federal Court imposed penalties on a number of businesses. In response, and recognising the widening use of price comparison and switching websites, the three largest energy retailers—AGL Energy, EnergyAustralia and Origin Energy—committed in 2013 to cease door-to-door marketing.

The Australian Energy Market Commission (AEMC) advises jurisdictions on the effectiveness of retail competition and whether to remove price regulation. In February 2013 South Australia became the second jurisdiction to remove retail energy price regulation. As in Victoria (which removed price regulation in 2009), retailers must publish unregulated standing offer prices that small customers can access.

The AEMC in September 2013 found competition was effective in New South Wales energy retail markets, with retailers' offering substantial discounts off the regulated price. It recommended the New South Wales Government remove price regulation and improve consumer information and ongoing market monitoring. The AEMC provided further advice in October 2013 on how to inform and empower consumers to promote effective competition.

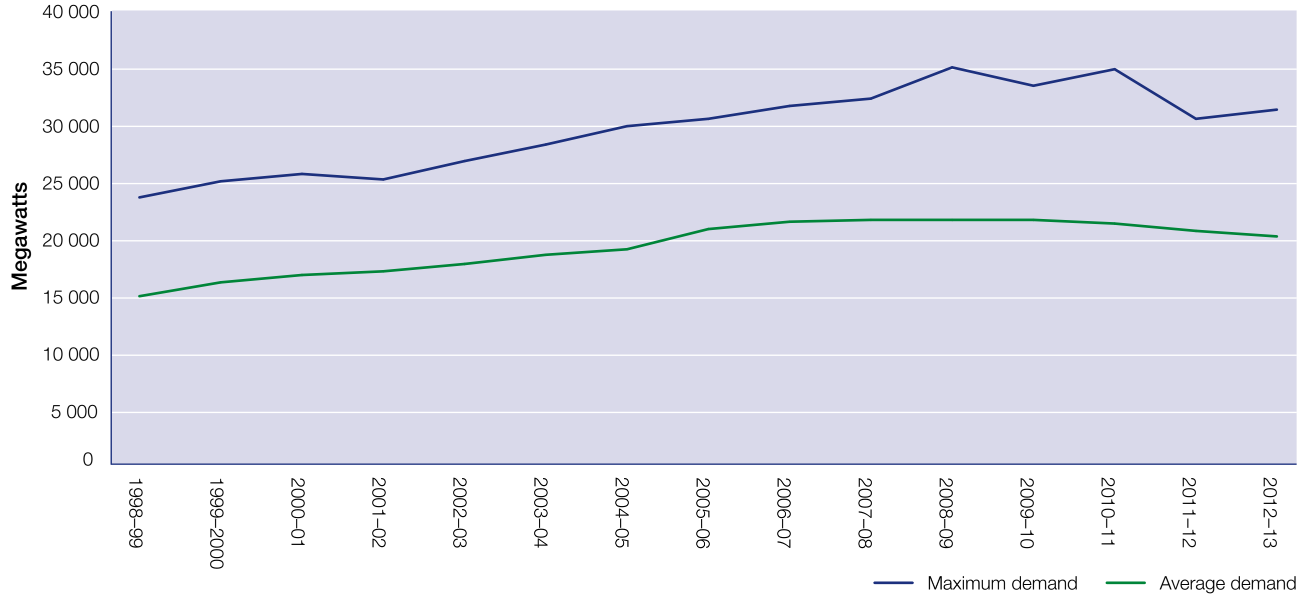
The Queensland Government committed to removing electricity retail price regulation in south east Queensland by 1 July 2015, so long as appropriate consumer protection and engagement policies are in place. Regulated price setting will continue for the Ergon Energy distribution area, pending the development of a strategy to introduce retail competition in regional Queensland.

In Tasmania, the government plans to allow all customers to choose their energy retailer from 1 July 2014. A planned sale of Aurora Energy's retail customer base to private retailers was abandoned in September 2013. But reforms to Tasmania's wholesale market arrangements began in June 2013, to encourage new retail entry.

A.3 National Electricity Market

Wholesale electricity in eastern and southern Australia is traded through the National Electricity Market (NEM), covering Queensland, New South Wales, Victoria, South Australia, Tasmania and the ACT. Electricity demand peaked across the NEM in 2008–09 but has since declined (figure 3). The Australian Energy Market Operator (AEMO) has twice revised down the demand forecast for 2013–14. Maximum demand, which typically occurs during heatwaves

Figure 3
Maximum and average electricity demand



Sources: AER, AEMO.

when air conditioning use is high, has also flattened since 2008–09. It moved significantly below trend in the 24 months to 30 June 2013.

This trend of declining demand reflects:

- commercial and residential customers responding to higher electricity costs by reducing energy use and adopting energy efficiency measures such as solar water heating
- subdued economic growth and weaker energy demand from the manufacturing sector
- the continued rise in rooftop solar photovoltaic (PV) generation (which reduces demand for energy supplied through the grid). During 2012–13, PV generation output rose by 58 per cent to 2700 gigawatt hours, equal to around 1.3 per cent of electricity consumption. This growth has been driven by small scale renewable energy certificates and lower cost solar systems.[3]

Subdued electricity demand has led to surplus generation capacity in the NEM, causing around 2300 megawatts (MW) of plant to be retired or periodically offline since 2012. Some plant is running only over summer, when demand is typically high (for example, Alinta's Northern plant in South Australia). Other owners are rotating plant throughout the year. CS Energy, for example, operated only three of its six 280 MW Gladstone units in Queensland during January 2013.

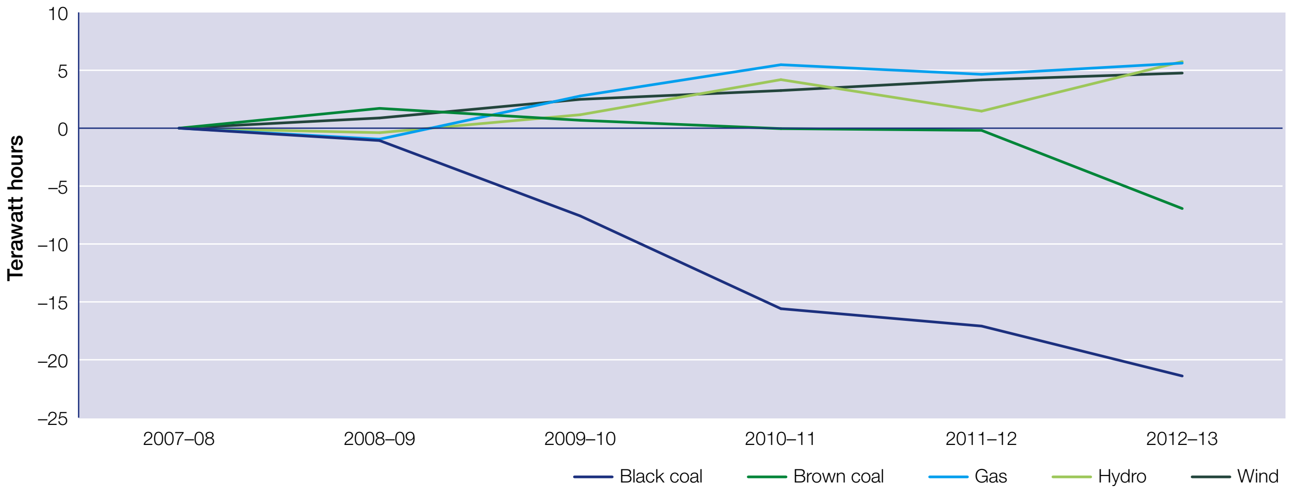
In these market conditions, AEMO forecast in 2013 that New South Wales, Victoria and South Australia were unlikely to need new generation capacity for at least 10 years. Two years ago, the outlook was quite different, with New South Wales and Victoria expected to require new plant capacity as early as 2014–15. In contrast to other regions, industrial development in Queensland (mostly associated with LNG projects) caused AEMO to bring forward the timing of new investment requirements to 2019–20.[4]

Climate change policies also contributed to change in the generation sector by altering the competitiveness of alternative technologies (figure 4). The renewable energy target scheme stimulated investment in wind generation, which supplied 3.4 per cent of electricity in the NEM in 2012–13 (including 28 per cent of output in South Australia). Additionally, the carbon pricing regime introduced in July 2012 made older coal fired plant less competitive, leading to some plant closures. But it enhanced the competitiveness of hydro generation, contributing to a 36 per cent rise in output in 2012–13 to supply 9 per cent of electricity in the NEM. The share of gas powered generation in the energy mix also rose.

3 AEMO, *National electricity forecasting report 2012* and *National electricity forecasting report 2013*.

4 AEMO, *Electricity statement of opportunities 2013*.

Figure 4
Change in generation mix since 2007–08



Sources: AEMO; AER.

Overall, these changes contributed to the emissions intensity of generation in the NEM falling by 4.5 per cent in 2012–13. This fall in emissions intensity, combined with lower NEM demand, led to a 7 per cent fall in total emissions from electricity generation in 2012–13.

A.4 Wholesale electricity prices

Declining electricity demand and the rising uptake of renewable generation, including wind and solar PV, contributed to historically low spot electricity prices in 2011–12 (figure 5). But this trend reversed in 2012–13: average prices more than doubled in Queensland (to $70 per megawatt hour (MWh)), Victoria (to $61 per MWh) and South Australia (to $74 per MWh), and almost doubled in New South Wales (to $56 per MWh). Tasmanian prices rose by around 50 per cent (to $49 per MWh).

In part, the higher prices reflected carbon pricing, introduced on 1 July 2012 at $23 per tonne of emissions. The carbon pass through to spot electricity prices was broadly consistent in mainland regions (averaging $17.70 per MWh), but significantly lower in Tasmania ($10 per MWh) due to its high concentration of hydro generation. But average prices for 2012–13 rose by around $31 per MWh, suggesting other factors contributed. The largest increases occurred in South Australia and Queensland, where carbon adjusted prices rose by over 70 per cent (figure 6). These outcomes were mainly driven by price spikes in summer 2013 (Queensland) and autumn 2013 (South Australia). While prices came off a low base in 2011–12, the rises occurred against a backdrop of weak electricity demand.

A.4.1 South Australia

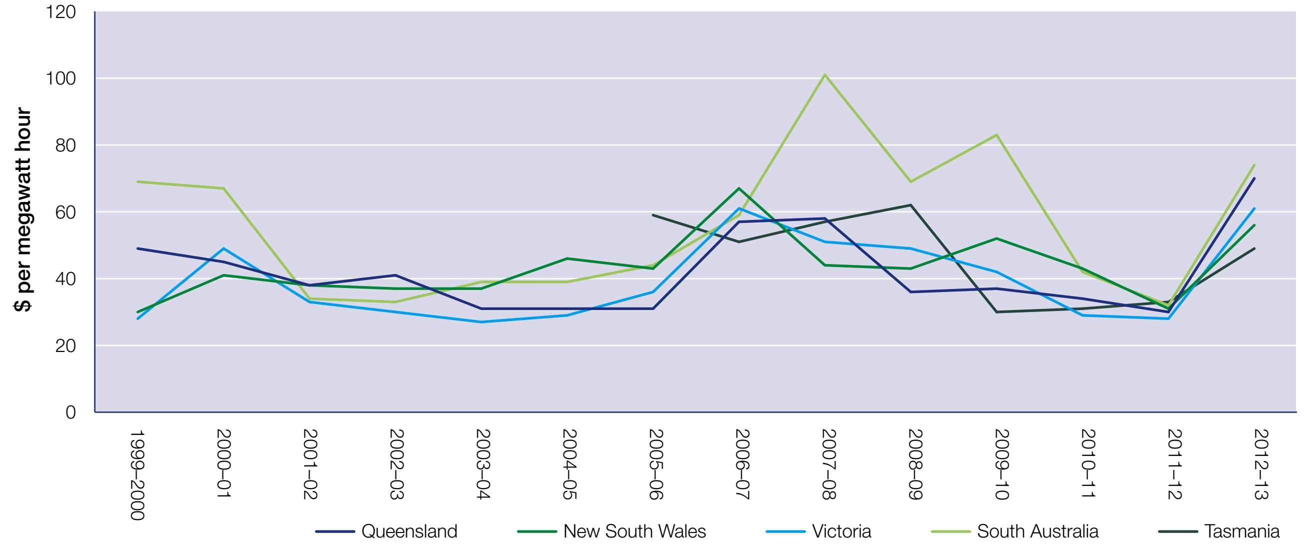
A tight supply–demand balance caused South Australian spot prices to average $106 per MWh in April–June 2013, almost double the average in other mainland regions of the NEM. This outcome occurred at a time of year when energy use is normally subdued.

The tight supply conditions were caused by Alinta, International Power and AGL Energy making commercial decisions to take some of their generation capacity offline and to increase the offer prices of remaining capacity. Overall, the maximum available capacity offered into the market by South Australian generators was around 700 MW lower in April–June (Q2) 2013 than in the corresponding period in 2012 (figure 7). This reduction in available capacity significantly raised the market clearing price.

Challenging market conditions contributed to the decisions to reduce available capacity. In addition to the weak energy demand affecting all regions, South Australia's high reliance on wind generation drove down spot prices, eroding generator returns. Meanwhile, input costs (including carbon and gas costs) had risen.

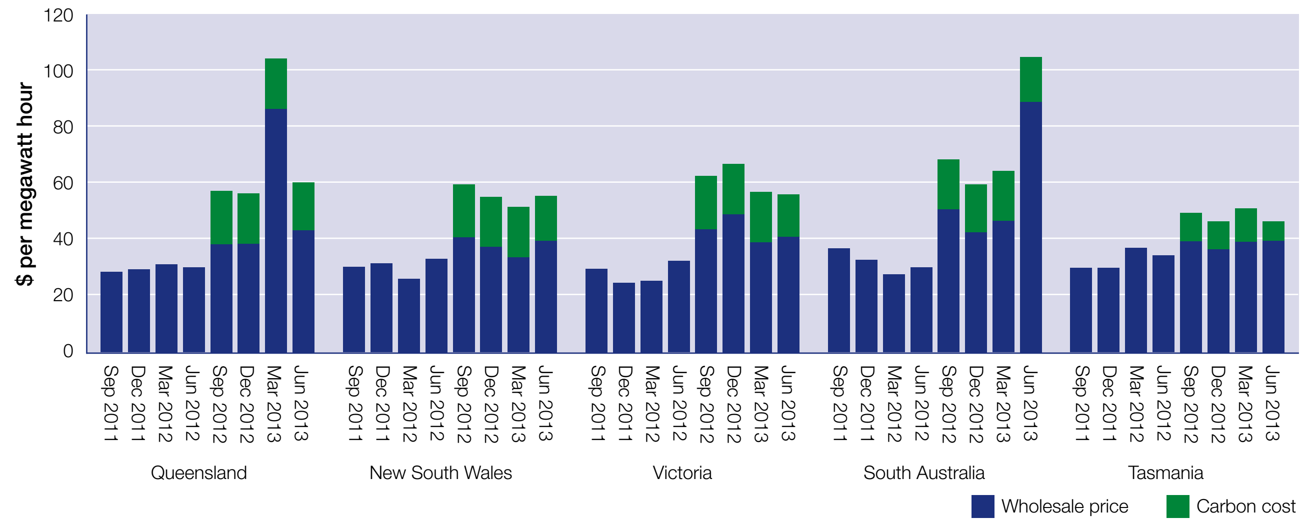
Higher spot prices led to a rise in South Australian energy imports from Victoria during April–June 2013. But technical limits on the interconnectors, and AEMO's management of

Figure 5
Annual spot electricity prices



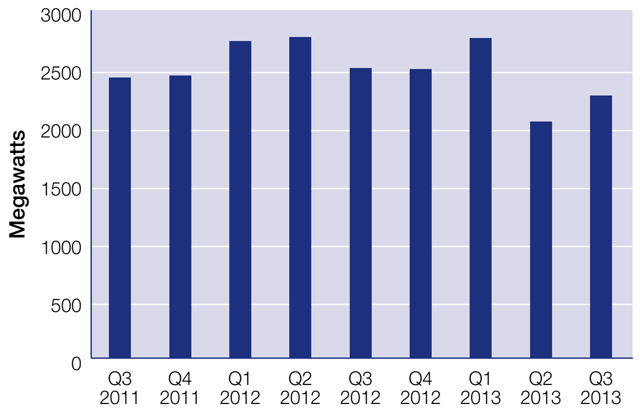
Note: Volume weighted annual average prices.
Sources: AER; AEMO.

Figure 6
Spot electricity prices, isolating carbon costs



Note: Average implied carbon cost represents the amount required to meet carbon price financial obligations, based on the emissions and carbon permit costs for the marginal generator in each dispatch interval.
Source: AER.

Figure 7
Average half hourly maximum generation availability, South Australia



Source: AER.

those limits, restricted import capacity. The AER has worked closely with AEMO to improve market systems and lessen the impact of these issues.

In such a tight market, issues that usually have a negligible impact can significantly affect prices. In April and May 2013 step changes in overnight demand associated with hot water loads contributed to a number of high prices. The AER held discussions with SA Power Networks to find better ways of managing this issue. More generally, even small forecasting errors can cause market volatility when the supply–demand balance is so finely tuned.

A.4.2 Queensland

An interplay of factors caused volatility in the Queensland market in January 2013, resulting in 116 prices above $300 per MWh, including 16 prices above $1000 per MWh (figure 8). While the events occurred in summer, a number occurred between midnight and 7 am, when demand was low.

Queensland's supply–demand balance was relatively tight in the first quarter of 2013, with generators offering 12 per cent less capacity (around 1320 MW) into the market than during the same quarter in 2012. These conditions were aggravated during much of January by transmission network congestion around central Queensland.

Following an ownership restructure in July 2011, CS Energy acquired control over generation plant at both ends of a strategic transmission line in central Queensland. Subsequently, its bidding behaviour periodically resulted in power flows that contributed to network congestion. AEMO was obliged to manage the issue by 'constraining off' low cost generation in southern Queensland and 'constraining on' higher cost generation around Gladstone. It also forced power flows out of Queensland into New South Wales, often contrary to price signals—that is, electricity flowed from the higher priced Queensland region to the lower priced New South Wales region.

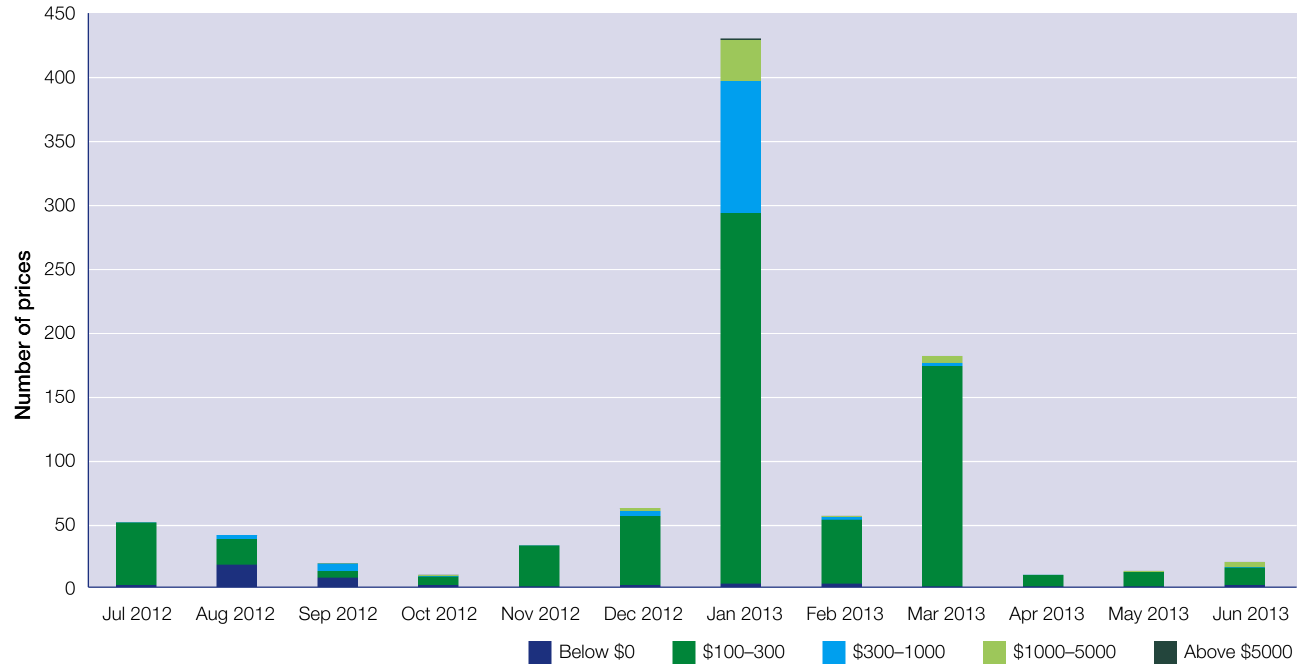
In combination, the reduction in low cost generation in southern Queensland, the dispatch of higher priced capacity around Gladstone, and the counter-price export of electricity into New South Wales caused the Queensland price to spike. The problem was exacerbated by generators engaging in disorderly bidding—that is, bidding contrary to the underlying cost structures and/or technical limitations of generation plant. In particular, generators tried to maintain output levels and receive high spot prices by rebidding capacity to low (or negative) prices. They also rebid down the ramp rates of their plant so they could be constrained off only slowly.

Disorderly bidding causes random and very short fluctuations in prices that are impossible to predict (figure 9), making it difficult for competing generation to respond. Additionally, the effects on interregional trade flows are significant. When electricity flows counter price across state borders, the market operator pays out more to generators in the exporting region than it receives from importing customers. The cost of this negative settlement residue falls on the transmission network provider in the importing region (in this instance, New South Wales). Ultimately, consumers in the importing region bear the cost through increased transmission network charges.

Network augmentation is a costly solution to network congestion and disorderly bidding, which periodically affect all regions of the NEM. The AEMC proposed an 'optional firm access' model, under which generators pay transmission businesses for firm network access, based on the costs of increasing network capacity. If congestion prevents a generator with firm access from being dispatched, then non-firm generators contributing to the problem would be required to pay compensation to the affected generator.

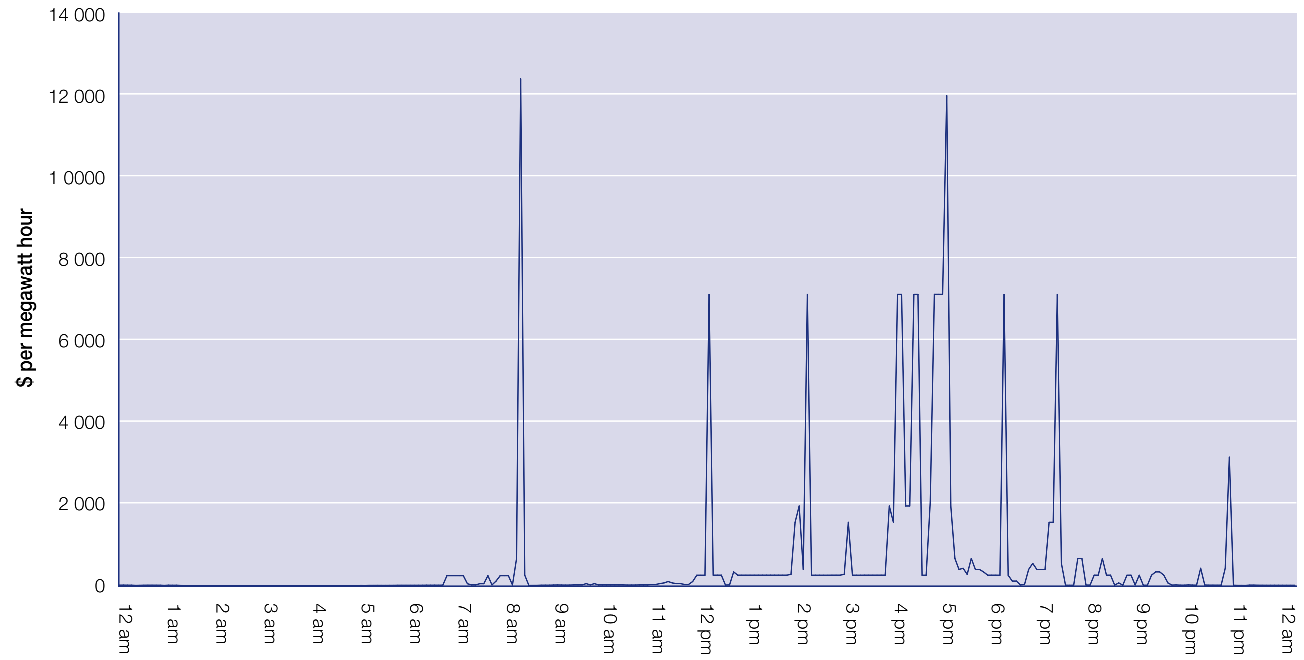
Full implementation of this approach could take several years. So, in August 2013 the AER proposed an interim measure requiring generators to submit ramp rates that reflect the maximum technical rate that their plant can safely achieve. It considers this requirement would limit the frequency and scope of disorderly bidding because AEMO could quickly alter generators' output to resolve constraints.

Figure 8
Frequency of extreme prices, Queensland



Source: AER.

Figure 9
Queensland dispatch prices, 29 January 2013



Note: Five minute dispatch prices.
Source: AER.

A.5 Energy networks

Rising costs of energy networks (electricity poles and wires, and gas pipelines) were the main driver of rising energy retail prices over the past five years in many jurisdictions. Regulatory allowances to network businesses rose to fund investment 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.

More recently, weaker energy demand forecasts have lowered investment requirements for network businesses. With demand projections driving around 25 per cent of capital investment for electricity distribution networks and 60 per cent for transmission, this weakening in demand caused the deferral of several projects. Recent regulatory reviews reflect this shift, with forecast investment for the Powerlink, ElectraNet and Aurora Energy networks *below* the levels approved in reviews made five years earlier (figure 10).

Weaker energy demand caused the deferral of a number of planned investments that had already passed a regulatory investment test (a cost–benefit analysis to assess a project's viability). The deferrals include TransGrid projects for new transmission infrastructure between Dumaresq and Lismore, and a network expansion on the mid north coast of New South Wales. Ergon Energy's planned line from Warwick to Stanthorpe was also deferred.

In other cases, assessment processes have been terminated or deferred:

- ElectraNet deferred its assessment of options to address rising demand in the Lower Eyre Peninsula until it is clear whether mining developments in the area will proceed. It also deferred its assessment of options to address voltage limitations in the mid-north of South Australia. The project was initially forecast to be required for summer 2015–16, but that timeframe was extended to 2024.
- AEMO terminated its assessment of options to address emerging voltage stability limitations in regional Victoria. Weaker demand forecasts mean these limitations are now unlikely to arise.

Recent developments in capital markets also lowered capital costs. Regulatory determinations made since 2012 reflect recent reductions in the risk free rate and market and debt risk premiums, which lowered the cost of capital (figure 11). The overall cost of capital in determinations made in 2013 was 7–7.5 per cent, compared with up to 10.4 per cent in 2010.

Reforms to the energy rules (announced in November 2012) will help prevent unjustified increases in network costs. The new rules aim to deliver future decisions on network revenues and investment that are in the long term interests of consumers. The reforms:

- create a common approach to setting the cost of capital across electricity and gas network businesses, based on the rate of return for a benchmark efficient service provider
- provide new tools to (a) incentivise electricity network businesses to invest efficiently, (b) safeguard consumers from paying for inefficient expenditure, and (c) ensure efficiency benefits are shared between consumers and service providers
- strengthen stakeholder involvement in the regulatory review of electricity networks.

In 2013 the AER published guidelines under the Better Regulation program on implementing the new rules. The guidelines will apply first to regulatory determinations taking effect in 2015—that is, for electricity transmission networks in New South Wales and Tasmania, and for electricity distribution networks in New South Wales, Queensland, South Australia and the ACT.

Recent reforms to the appeals provisions in the energy rules will also benefit consumers. Between June 2008 and June 2013 network businesses sought Australian Competition Tribunal review of 25 AER determinations on energy networks—18 reviews for electricity networks and seven for gas pipelines. The Tribunal's decisions increased allowable revenues by around $3.3 billion, with substantial impacts on retail energy charges.

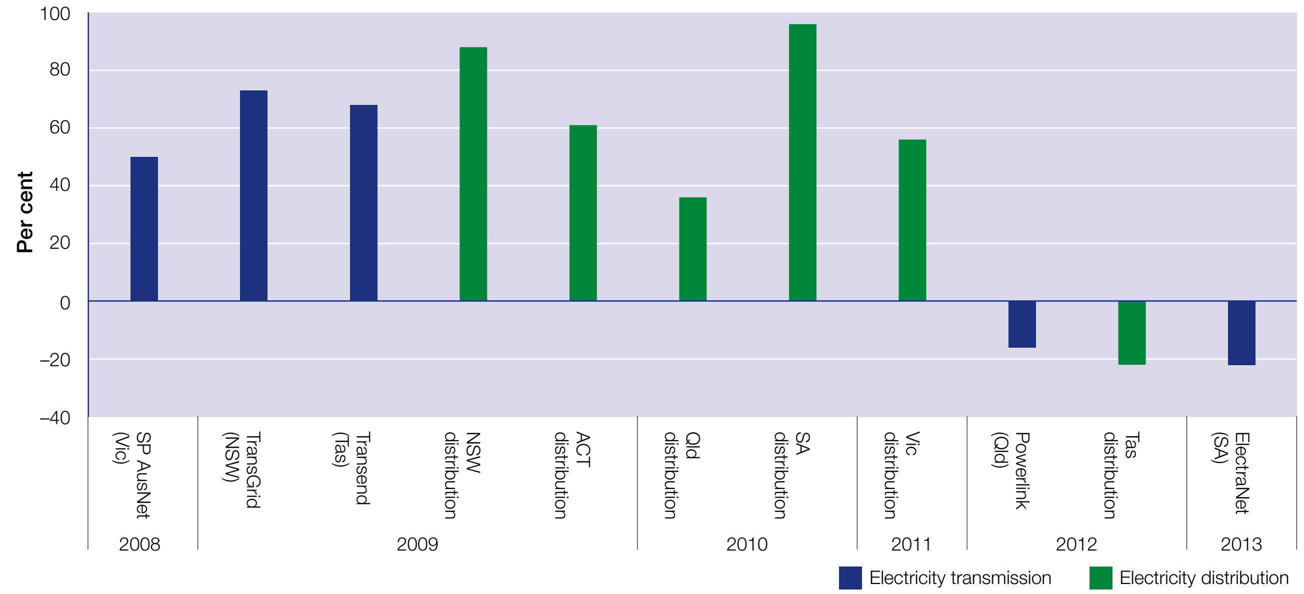
An independent review in 2012 of the limited merits review regime found the regime did not operate as intended. In response, the Standing Council on Energy and Resources (SCER) agreed to amendments requiring:

- a network business to demonstrate that 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 Tribunal to consider any matters interlinked with the grounds of the appeal, and to consult with relevant users and consumers.

The South Australian Parliament in November 2013 passed legislation to implement the reforms.

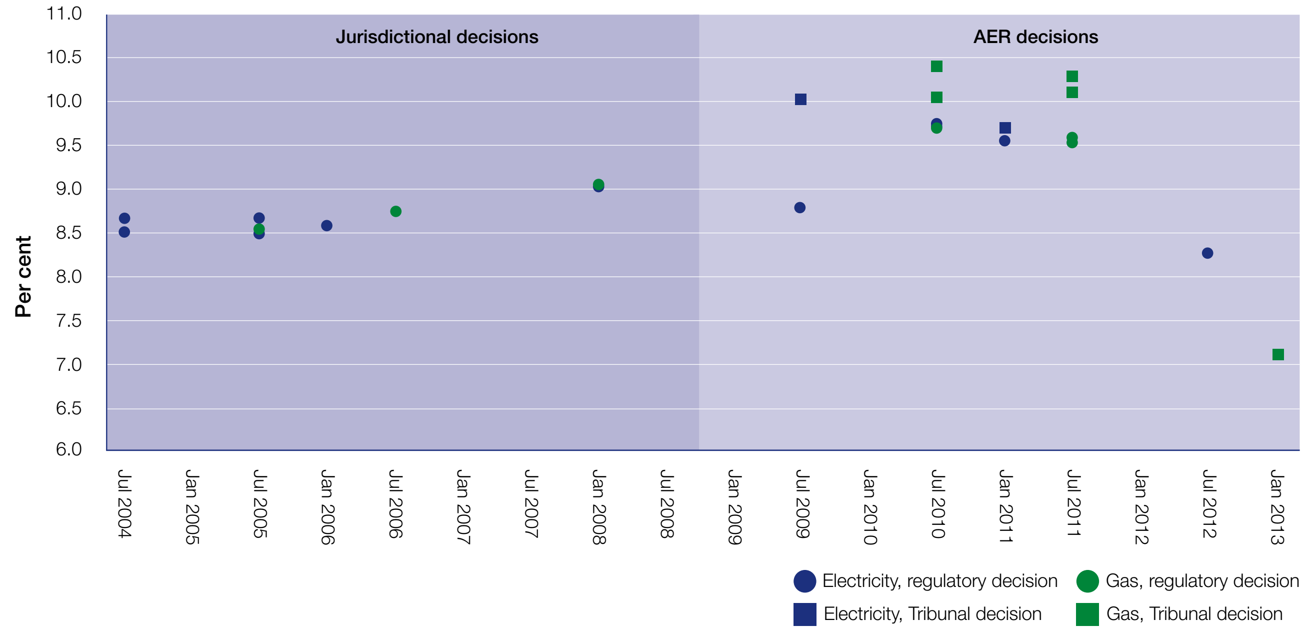
Wider reforms to the policy landscape are in train to better manage network costs in the long term interests of consumers. The AEMC's *Power of choice* review identified a range of efficient alternatives to network investment to

Figure 10
Investment growth for electricity networks



Notes:
Percentage change in forecast investment in current five year regulatory period compared with levels in previous regulatory periods.
Data appears in chronological order of AER determinations for transmission and distribution sectors.
Data are state averages for electricity distribution networks in Queensland, New South Wales and Victoria.
Source: AER.

Figure 11
Weighted average cost of capital—electricity and gas distribution



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

deal with rising peak demand. Interval meters—with time based data on energy use—are central to many of the recommendations. This type of metering, when coupled with time varying prices, can encourage customers to actively manage their electricity use.

The SCER in September 2013 submitted a rule change proposal to the AEMC on changes to the distribution network pricing principles. The changes would encourage distribution businesses to set cost reflective network prices that provide efficient pricing signals to consumers. The Victorian Government expects to complete a rollout of interval meters with remote communications to all customers in 2014. From September 2013 small customers have been offered the choice of moving to more flexible tariff structures.

The AEMC also reviewed network reliability standards, which have been a significant driver of network investment. Its assessment for New South Wales found less stringent reliability standards would save an average consumer $3–15 per year. Following advice from the Council of Australian Governments, the AEMC in September 2013 proposed a new approach to setting distribution reliability targets. The proposal would weigh the cost of new investment against the value that customers place on reliability and the likelihood of interruptions. The AER's service target performance incentive scheme would provide incentives for network businesses to meet their reliability targets.

The AEMC also recommended a national approach to reporting on reliability, under which the AER would develop values of customer reliability for each jurisdiction every five years. In August 2013 AEMO finalised a method for estimating the value of customer reliability. It will develop the associated values by March 2014.

A.6 Gas markets

An interaction of several factors is shifting the dynamics of gas markets in eastern Australia. Rising coal seam gas (CSG) production, the emergence of spot markets, and improved pipeline interconnection of gas basins have made domestic markets more responsive to customer demand. But the development of at least three LNG export projects in Queensland is exerting significant supply and price pressure.

Gas production in eastern Australia is forecast to treble over the next three to five years to satisfy a rapid expansion in LNG export demand.[5] While Queensland's LNG proponents each have dedicated gas reserves and pipeline infrastructure, difficulties in developing some gas fields are requiring them to source additional supplies from elsewhere. By doing so, they have reduced reserves that would otherwise have been available to the domestic market, leaving few producers in a position to sell gas under medium to longer term contracts.[6]

The effect of these tight conditions was apparent in 2013, with prices in new contracts reportedly linked to international oil prices or LNG netback prices[7] (currently around $10 per gigajoule for export to Japan). Average daily spot prices for gas also rose in 2012–13, mainly due to high winter prices in 2012 and a short term rise in demand associated with the introduction of carbon pricing.

More generally, spot market volatility was evident, with an above average frequency of price spikes (figure 12). Notably, Brisbane prices diverged markedly from prices in other markets. Overall, average prices for 2012–13 rose by 69 per cent in Brisbane, 51 per cent in Sydney, 33 per cent in Melbourne and 34 per cent in Adelaide.[8]

Spot prices tended to ease after June 2013, although they remained at higher levels than those before 2012–13. Winter demand was mostly fairly subdued, however. In Victoria, a mostly mild winter and a reduction in gas powered generation contributed to an overall 8.8 per cent decrease in gas demand during winter 2013.

Gas market conditions will tighten further when LNG facilities come on line and ramp up to full capacity from 2015–18. While delays affected some projects in 2012, Energy Quest reported favourable weather conditions in 2013 put back on schedule the development of each project's first train.[9]

AEMO in November 2013 forecast potential gas supply shortfalls may occur in Queensland if facilities currently dedicated to domestic demand are prioritised to supply LNG export contracts. Without further investment, this shortfall could reach 250 terajoules per day once all LNG trains reach full output, which is scheduled to occur in 2019. If production in Queensland and South Australia is prioritised

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

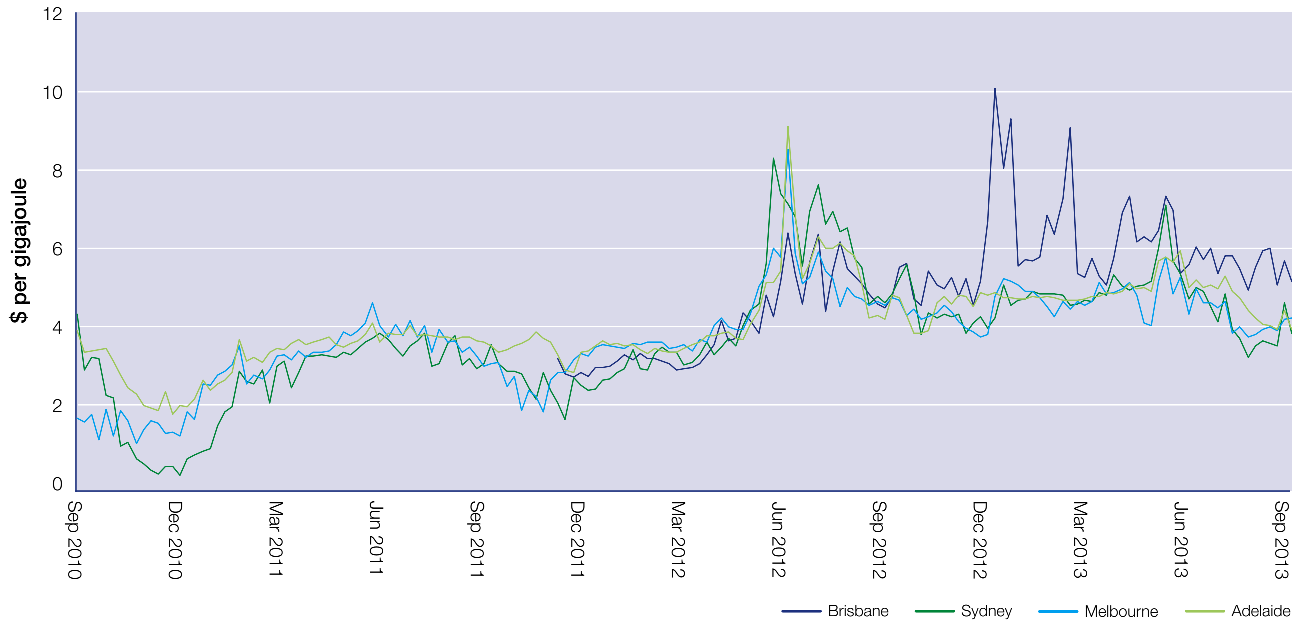
6 K Lowe Consulting, *Gas market scoping study: a report for the AEMC*, July 2013.

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

8 The Brisbane price for 2011–12 covers the period 1 December 2011 (market start) to 30 June 2012 in which the Brisbane market operated. Brisbane prices rose by 82 per cent when comparing average prices for December 2012 to June 2013 with those of the corresponding period in the previous year.

9 EnergyQuest, *Energy Quarterly*, August 2013, p. 64.

Figure 12
Spot gas prices—weekly averages



Notes: Volume weighted ex ante prices. 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.

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

for export, New South Wales could experience flow-on effects, with potential shortfalls of 50–100 terajoules per day on winter peak demand days from 2018.[10]

The ramp up to full LNG export capacity will coincide with the expiry of a large number of domestic gas supply contracts. The review and negotiation of contracts in a market exposed to global prices will place further pressure on domestic prices. Overall, contracts covering the supply of around 260 PJ of gas are due to expire by 2018. The problem is acute for New South Wales: by 2018, existing contracts will meet less than 15 per cent of that state's demand.[11]

Some domestic producers are increasing supply to meet demand. AEMO reported Victorian gas exports to New South Wales were 46 per cent higher in winter 2013 than a year earlier, and significantly higher than in each of the past four years.[12] APA Group in 2013 committed to an expansion of the Victorian Transmission System (for completion by winter 2015) to support higher export volumes from Victoria to New South Wales. Jemena is also considering an expansion of the Eastern Gas Pipeline to boost capacity into New South Wales, which could be completed by the end of 2015. Elsewhere, Cooper Basin production is also likely to rise, but with the bulk of the increase going into LNG exports.[13]

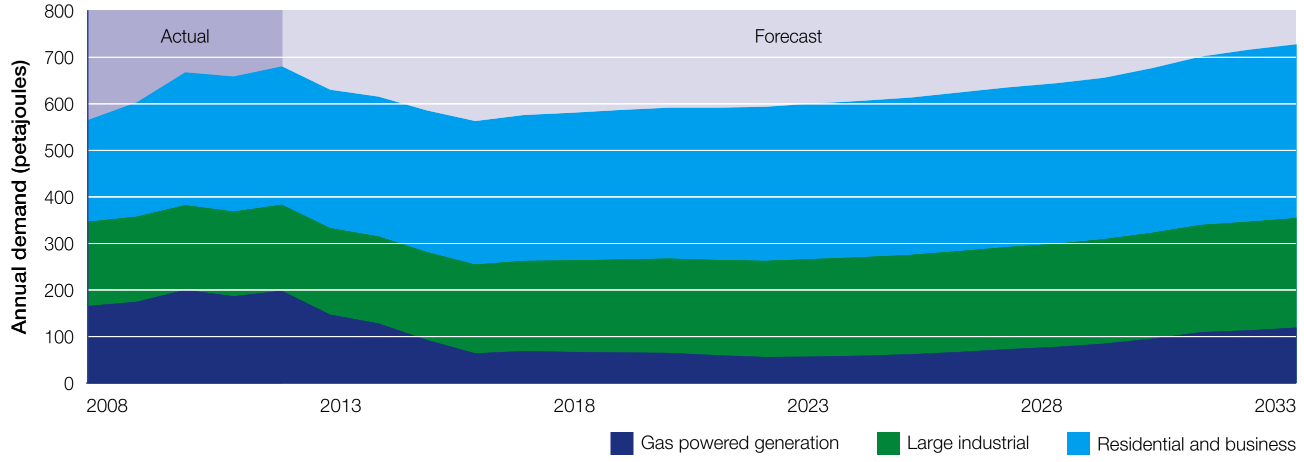
Interest exists in developing new sources of supply to meet the likely gap in the domestic market. Production from the Kipper Tuna Turrum project in the Gippsland Basin began in 2013. Other proposals relate to the Gunnedah and Gloucester basins in New South Wales, the Ironbark field in the Surat Basin, unconventional sources in the Cooper Basin, and the South Nicholson and Isa Super basins in the Northern Territory and north west Queensland.[14]

The development of coal seam and shale gas resources has raised community concerns about potential impacts on agricultural land use, waterways and native vegetation.[15] These concerns have delayed the development of some

10 AEMO, *Gas statement of opportunities 2013*, p. iv.
11 BREE, *Gas market report*, October 2013, pp. 17, 41.
12 AEMO, *Energy update*, October 2013.

13 EnergyQuest, *Energy Quarterly*, August 2013, p. 19.
14 K Lowe Consulting, *Gas market scoping study: a report for the AEMC*, July 2013.
15 See, for example, ACIL Allen Consulting, *NSW coal seam gas*, Report to the Australian Petroleum Production and Exploration Association (APPEA), 2013, p. 2.

Figure 13
East coast domestic gas demand



Source: AEMO, *Gas statement of opportunities 2013*, figure 5.

projects, notably in New South Wales, which restricted development around communities and water catchments critical to agriculture.

While LNG export demand is set for exponential growth, a countervailing market influence is flatter domestic demand for gas, especially for electricity generation. Subdued electricity demand, the continued rise in renewable generation, the coalition government's intention to abolish carbon pricing, rising gas prices and the cessation of the Queensland Gas Scheme (which mandated a minimum rate of gas powered generation) have significantly weakened projections of gas powered generation.

AEMO forecast gas demand will decline until 2016, followed by a gradual recovery (figure 13). The sharpest contraction will be for gas powered generation, with a forecast annual average decline of 9.8 per cent between 2014 and 2022. In contrast, LNG demand is expected to rise from zero to around 1450 petajoules, accounting for around 70 per cent of total gas demand in eastern Australia.[16]

Policy makers are implementing reforms to help alleviate pressures in the eastern gas market. The most advanced reform is a gas trading exchange at the Wallumbilla gas hub in Queensland, set for launch in March 2014. The exchange aims to alleviate unnecessary bottlenecks in the tight Queensland gas market by facilitating short term gas trades.

The market design avoids the need to change infrastructure, operations or contracts. But participants using the exchange will require access to the transmission pipelines serving the hub, not all of which interconnect. To manage this issue, the model includes a web based platform for participants to advertise their interest in buying or selling gas pipeline capacity in the eastern gas market.

In other developments, the SCER consulted in 2013 on possible reforms to pipeline capacity trading to promote trade in idle contracted capacity. The reform could help small participants that lack the scale to invest in transmission capacity.[17] An AEMC scoping study published in September 2013 proposed consideration of further measures. These measures included strategically planning gas market development, refining spot market design, and streamlining the processes for making rule changes that affect gas spot markets.[18]

16 AEMO, *Gas statement of opportunities 2013*, p. 8.

17 Standing Council on Energy and Resources officials, *Regulation impact statement: gas transmission pipeline capacity trading*, Consultation paper, 15 May 2013.
18 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.