STATE OF THE ENERGY MARKET 2012

AUSTRALIAN ENERGY REGULATOR

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PREFACE

The Australian Energy Regulator's sixth *State of the energy market* report comes at a time of community and business concern about rising energy prices. The most significant cause has been the increasing costs of using electricity and gas networks, which make up around 45 per cent of retail energy bills.

Governments, policy makers and regulators have progressed important reforms so that future network price determinations ensure customers pay no more than necessary for an efficient and reliable energy supply. Some reforms were finalised late this year, while others made important advances. The reforms include a major overhaul of the Rules mandating how network charges are set (finalised in November 2012); a major overhaul of the merits review arrangements that added $3.3 billion to network charges since 2008 (expected to be finalised in 2013); a move towards a national approach to setting reliability standards to ensure the community pays only for the reliability it requires (significant work progressed in 2012); and reforms to empower consumers to manage their energy use and save on energy costs by shifting consumption away from peak times (major workstream completed in November 2012, with further work in 2013).

This edition of *State of the energy market* aims to explain, in accessible language, the factors that have driven up energy prices, and the important policy and regulatory responses being implemented. It also covers other important developments in the market. Tasmania and the ACT launched national retail reforms in July 2012, and several jurisdictions announced plans to follow suit during 2013. The AER launched an energy price comparison service (www.energymadeeasy.gov.au) as part of the reforms.

Carbon pricing was introduced on 1 July 2012 and, after a short period of volatility, market prices settled as expected. There was growing evidence that electricity demand may remain flat for several years, pushing out investment horizons for generation and networks. There is a different story in gas, with international demand putting upward pressure on prices and raising the possibility of restricted supply in eastern Australia from 2016.

I hope this 2012 edition of *State of the energy market* will provide a valuable resource for market participants, policy makers and the wider community. As usual, the report focuses on events of the past 12–18 months in those jurisdictions and areas in which the AER has regulatory responsibilities.

Andrew Reeves
Chairman
December 2012

Stephen Cooper (Newspix)

MARKET OVERVIEW

Rising energy prices continued as a major focus for the community, business, policy makers and regulators in 2012. Residential electricity prices over the past five years rose nationally by 91 per cent. Gas prices rose by 62 per cent. Governments, policy bodies and regulators are developing and implementing reforms aimed at limiting future price movements to those necessary to deliver an economically efficient and reliable energy supply.

The main driver of higher retail energy prices has been rising charges for using energy networks—that is, the poles and wires, and gas pipelines that transport energy to customers. A number of factors have driven higher network charges. Some factors—forecast growth in peak energy demand, the need to replace ageing equipment, and higher financing costs due to conditions in global financial markets—were largely unavoidable. But other cost pressures were difficult to justify.

In particular, the energy Rules, drafted in 2006, limited the extent to which the Australian Energy Regulator (AER) could amend the revenue proposals put forward by network businesses. While the Rules reflected policy concerns at the time about the adequacy of network investment, they led to unnecessarily high revenue streams for network businesses. Another source of cost pressure has been the stricter reliability standards that some state and territory governments imposed over the past decade. Meeting these standards has required significantly higher investment by the network businesses.

Much regulatory and policy activity in the past 12–18 months aimed to mitigate network cost pressures. In particular, the AER in 2011 proposed Rule changes to ensure customers pay no more than necessary for an economically efficient and reliable supply of energy. Following detailed public consultation, the Australian Energy Market Commission (AEMC) in November 2012 announced significant reforms that address the areas of concern raised by the AER.

The AEMC in 2012 also reviewed whether network reliability standards are being set at higher levels than the community requires, and whether approaches to meeting the standards are cost effective. Additionally, its *Power of choice* review explored alternatives to network investment in response to rising peak demand. Completed in November 2012, the review recommended empowering consumers to manage their energy use and save on energy costs by shifting consumption away from peak times.

The strategies include: rolling out interval meters on a contestable basis, as part of a package that includes time varying prices; enabling energy customers to sell small scale generation to parties other than their electricity retailer; and offering greater opportunities for customers to engage directly in the wholesale energy market. The Council of Australian Governments (CoAG) in December 2012 approved the adoption in principle of the full set of *Power of choice* recommendations. It proposed the phasing in of time varying network charges, and a new demand side mechanism for the wholesale market, by July 2014.

Also affecting network charges have been the Australian Competition Tribunal's reviews of AER decisions. Network businesses sought review of 22 AER decisions between 2008 and 2012; the Tribunal's decisions on these matters granted the businesses an additional $3.3 billion in revenues, which flowed through to network charges and customer bills.

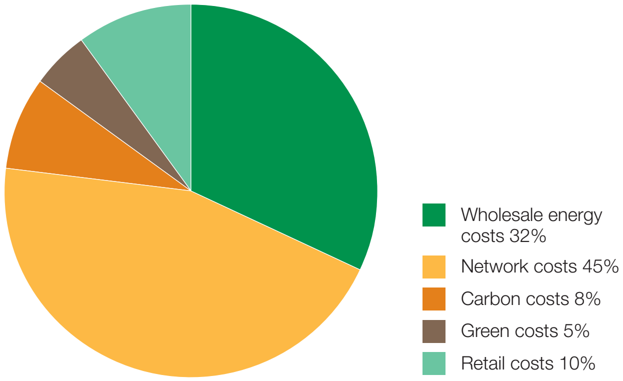
Concerns about the merits review framework led the Standing Council on Energy and Resources (SCER) in 2012 to appoint an expert panel to review the arrangements. The panel recommended the regime should be limited to a single ground for appeal—that a materially preferable decision exists—and should assess review matters in relation to the national energy objectives set out in the legislation. It also recommended allowing the review body to explore any aspect of an AER decision that it considers relevant; and allowing greater input from consumers. CoAG in December 2012 recommended agreement be reached on a policy response to the review by mid–2013, and an amended regime be in place by the end of 2013 in advance of the next round of AER determinations.

Alongside the significant policy response to escalating network costs has been a change in the operating environment for network businesses. AER decisions made in the past 12–18 months reflect flatter energy demand and lower input costs that eased some pressure on network costs. The decisions also reflect a lowering of business financing costs.

While network costs drove higher retail energy prices over the past five years, there was less pressure from wholesale energy costs. Electricity spot prices fell steadily from 2010 until the introduction of carbon pricing on 1 July 2012. Average spot prices in Queensland and South Australia were at record lows in 2011–12, and prices elsewhere in the National Electricity Market (NEM) were near record lows.

An emerging concern has been an increase in disorderly bidding in the wholesale market (that is, generators making bids without reference to their underlying generation costs). While this behaviour had limited direct impact on energy customers in 2011–12, it could adversely affect competition and market efficiency in the longer term.

Figure 1
Indicative composition of residential electricity bills, 2012–13



Note: Based on standing offer prices in Queensland, New South Wales, South Australia, Tasmania and the ACT. Comparable data are not available for Victoria.

Source: AER.

Spot gas prices rose sharply during winter 2012. This trend coincided with a tightening in Queensland's domestic gas contract market, which was associated with liquefied natural gas (LNG) development projects. The eastern gas market is generally expected to remain tight over the next decade, with possible challenges for domestic supply from 2016. Australian governments are considering policy responses, including a new gas trading market at Wallumbilla, which is a major supply hub in Queensland.

Following some initial market volatility, the introduction of carbon pricing on 1 July 2012 caused an uplift in spot electricity prices of around 21 per cent, which was in line with expectations. There was little impact on gas prices. Carbon pricing led to one-off increases in electricity retail bills of 5–13 per cent in 2012–13. Costs associated with other climate change policies (including the renewable energy target (RET) scheme, mandated feed-in tariffs for rooftop solar photovoltaic (PV) installations, and energy efficiency schemes) were relatively stable for 2012–13.

Governments have responded to community concerns about the impacts of climate change policies on retail prices. Many jurisdictions have removed or reduced mandated feed-in tariffs. The Australian Government reviewed the operation of the RET scheme in 2012 and changed carbon pricing arrangements to establish closer links with international carbon markets. It also introduced a financial assistance package for families, to mitigate the effects of carbon pricing on household budgets.

In addition to policy responses to reduce cost pressures on retail energy prices, state and territory governments are progressively implementing reforms that target the retail sector itself. The National Energy Retail Law applies the reforms, which promote competition and empower customers to select energy contracts that suit their needs. Tasmania and the ACT implemented the reforms during 2012. South Australia and New South Wales set target implementation dates of 1 February 2013 and 1 July 2013 respectively.

On 1 July 2012 the AER launched the Energy Made Easy price comparator (www.energymadeeasy.gov.au) to help small customers compare energy offers available to them. The website also provides information on the energy market, energy use, and consumer rights and obligations.

A.1 Retail energy prices

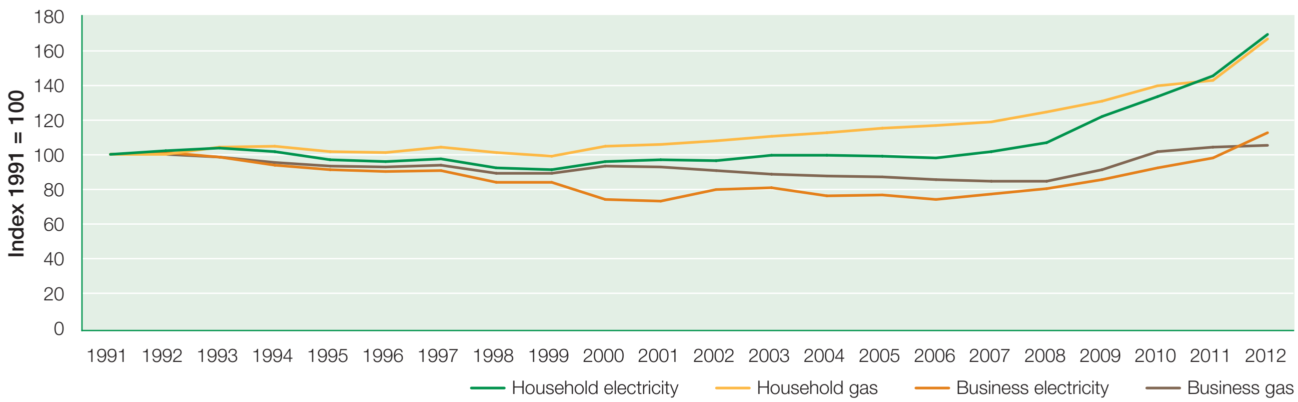
The energy bills paid by retail customers cover the costs of wholesale energy, transport through transmission and distribution networks, retail services and costs associated with climate change policies. Figure 1 estimates the composition of a typical electricity retail bill for a residential customer in eastern Australia.

- *Network charges* for transporting electricity through transmission and distribution networks make up 45 per cent of customer bills; the highest impact is on bills in New South Wales and Queensland. Distribution charges account for the bulk of these costs.
- *Wholesale electricity costs* make up one third of customer bills (net of carbon costs); the highest impact is on bills in Tasmania and South Australia. The costs are incurred by retailers in buying electricity in the spot market and managing price risk through derivatives markets.
- Costs associated with *carbon pricing* make up 8 per cent of customer bills.
- Other *green costs* associated with schemes to develop renewable or low emission generation, or promote energy efficiency, make up 5 per cent of customer bills. The most significant of these costs relates to the RET scheme, the costs of mandated solar feed-in tariffs, and jurisdictional energy efficiency schemes.
- *Retailer operating costs and margins* contribute around 10 per cent to retail bills.

In gas, pipeline charges account for up to two thirds of retail bills. Wholesale energy costs typically account for a lower share of retail bills in gas than electricity, while retailer operating costs (including margins) account for a higher share.

Figure 2

Electricity and gas retail price index (real)—Australian capital cities

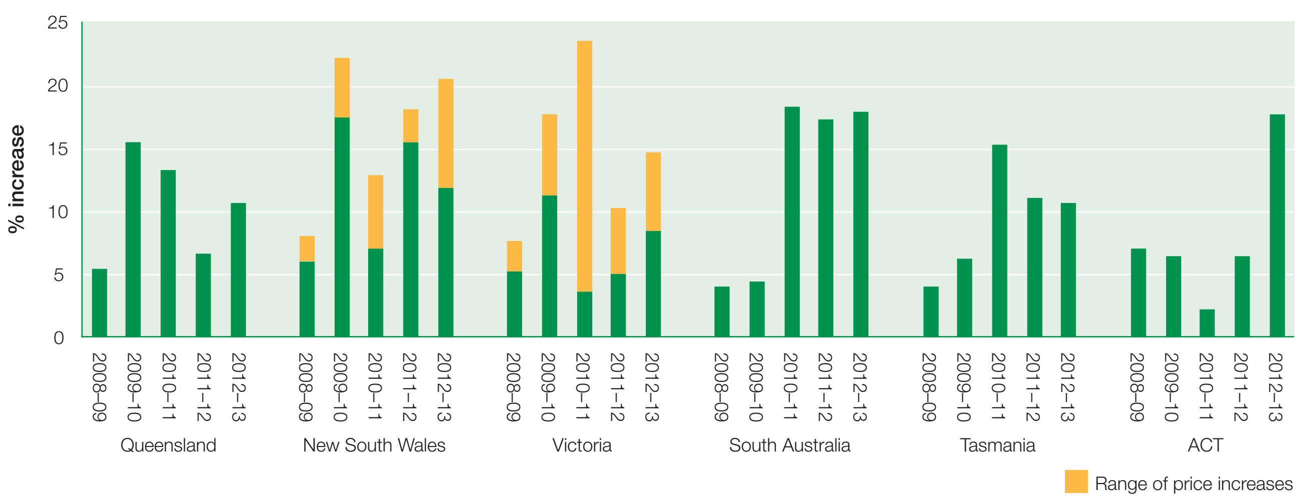


Note: Consumer price index electricity and gas series, deflated by the consumer price index for all groups.

Source: ABS, *Consumer price index*, cat. no. 6401.0, various years.

Figure 3

Movements in regulated and standing offer electricity prices, by jurisdiction



Notes:

Estimated annual cost is based on a customer using 6500 kilowatt hours of electricity per year on a peak only (single rate) tariff at August 2012.

The Victorian price movements (and estimated annual costs) are based on unregulated standing offer prices published in the Victorian Government gazette by the local area retailer in each of Victoria's five distribution networks.

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

Residential electricity customers in jurisdictions other than Tasmania[1] can enter a market contract with a retailer of choice, or a standard retail contract with default terms and conditions. All jurisdictions except Victoria regulate retail prices for small electricity customers supplied under a standing offer contract. The AER does not regulate retail prices in any jurisdiction.

Figure 2 illustrates long term trends in energy retail prices for residential and business customers in capital cities. Figure 3 (and table 5.4 in chapter 5) illustrates recent movements in regulated and standing offer electricity prices. The price spread for New South Wales and Victoria reflects a range of outcomes across distribution networks in those jurisdictions.

From 2000 to 2007, electricity prices rose annually by around 3.6 per cent (0.8 per cent in real terms). Following this period of relative stability, energy prices began to rise significantly from 2008. Residential electricity prices rose nationally by 91 per cent (66 per cent in real terms) in the five years to 2012–13. Gas prices rose by 62 per cent (40 per cent in real terms) over this period.[2]

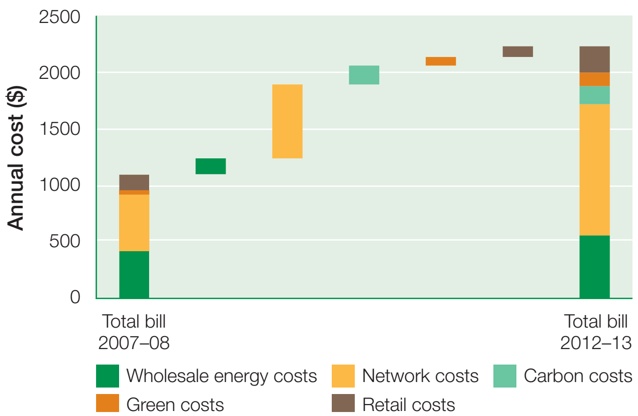
Rising network costs (especially for distribution networks) were the main driver of these outcomes (as explained in section A.2). In the current regulatory period, the annual increase in network charges has been over 20 percent in New South Wales and South Australia; 9–10 per cent in Queensland; and up to 15 per cent in Victoria. The estimates include costs associated with solar feed-in tariffs.

The Independent Pricing and Regulatory Tribunal (IPART) submitted in September 2012 to the Senate Select Committee that network costs in New South Wales rose by 130 per cent over the past five years, adding $654 to annual charges for a typical residential customer (figure 4). Network costs were responsible for almost 60 per cent of retail price rises in New South Wales in this period.

Costs associated with green schemes—including the RET, carbon pricing, solar feed-in tariffs and energy efficiency schemes—also flowed through to retail prices. The introduction of carbon pricing on 1 July 2012 led to one-off retail price rises in 2012–13 of 5–13 per cent. The variation reflects a number of factors, including differences in how state and territory agencies pass through carbon pricing to energy customers.

Figure 4

Change in average New South Wales residential customer bills, 2007–8 to 2012–13



Source: IPART, *Promoting the long term interests of electricity customers: submission to the Senate Select Committee on Electricity Prices*, September 2012.

The carbon impact was lowest in South Australia, reflecting the relatively low emissions intensity of the state's gas powered and wind generation. The proportional impact was higher in the ACT, where retail prices came off a relatively low base after limited movement for a number of years. IPART estimated the combined costs associated with green schemes (the RET, carbon pricing, the NSW Climate Change Fund and the NSW Energy Savings Scheme) added $316 to New South Wales customer bills over the past five years (30 per cent of the total price rise over this period).[3]

Coinciding with the introduction of carbon pricing, the Australian Government introduced a Household Assistance Package in 2012 to offset the rise in energy costs for low and middle income households. The package provides for households to receive compensation through pensions, allowances and other assistance payments, and to benefit from tax adjustments.

While regulated and standing offer prices have risen significantly, customers in most jurisdictions can negotiate discounts against standing offer charges by entering a market contract. In August 2012:

- the average discount in Queensland, New South Wales and South Australia under market contracts was 5.5 per cent (with discounts as high as 15 per cent)

1 The Tasmanian Government expects to extend retail contestability to all Tasmanian electricity customers from 1 January 2014.

2 ABS, *Consumer price index*, cat. no. 6401.0, various years.

3 IPART, *Promoting the long term interests of electricity customers: submission to the Senate Select Committee on Electricity Prices*, September 2012.

- opportunities for discounting were higher in Victoria, where the average market contract discount was 8 per cent (with discounts as high as 25 per cent)
- discounts in gas contracts averaged 6 per cent in Victoria, but less than 2 per cent elsewhere.

The variety of contract offerings and discounts results in significant price spreads. Across all jurisdictions in 2012, the spread in annual retail charges within a particular distribution network was up to $500 in electricity (but $850–1150 in Victoria) and up to $200 in gas. These outcomes suggest considerable scope for informed consumers to negotiate their energy contract—particularly in Victoria, where retail prices are not regulated.

But the variety of retail offers poses challenges for small customers. It takes time and knowledge to make meaningful comparisons. To help small customers compare retail offerings, the AER launched an online price comparison service—www.energymadeeasy.gov.au—for customers in all jurisdictions that implement the Retail Law. Tasmania and the ACT had introduced the Retail Law at 1 December 2012. Some jurisdictional regulators and private entities also operate websites allowing customers to compare their energy contract with available market offers.

Several jurisdictional governments responded to community concerns about energy prices in 2012 by reviewing their approaches to regulating standing offer prices:

- The Queensland Government imposed a price freeze on the regulated electricity peak tariff for residential customers (apart from increases resulting from the introduction of carbon pricing). The decision limited electricity price increases for an average customer on this tariff to 10.6 per cent for 2012–13.
- The Essential Services Commission of South Australian (ESCOSA) proposed a new approach—using market costs, rather than the long run marginal cost of generation—to estimate the wholesale energy costs flowing through to regulated retail prices. Poor liquidity in hedging markets had previously precluded this approach. If applied in 2013, the proposed approach would reduce the wholesale cost allowance by 22 per cent and the regulated retail price by 8.1 per cent.
- In Tasmania, a change in the basis for estimating wholesale energy costs reduced retail prices by 6.1 per cent in 2012, partly offsetting rises in other costs.
- Queensland and New South Wales revised their approaches to estimating wholesale energy costs. Retail price determinations for the period beginning 1 July 2013 will reflect these changes.
- The Victorian Government will allow electricity customers a choice between fixed and time varying retail prices from July 2013 (section A.3.5).

A.2 Energy network charges

Using competing poles and wires to transport electricity to customers would be inefficient; instead, regulated natural monopoly businesses transport electricity. Gas distribution networks and some gas transmission pipelines are regulated for similar reasons.[4] The AER determines allowable network revenues and charges for using electricity networks in eastern Australia, and for using gas pipelines outside Western Australia.

The overarching regulatory frameworks are set out in the National Electricity Law and National Gas Law. The legislation aims to promote efficient investment in, and operation of, energy services for the long term interest of consumers. The National Electricity Rules and National Gas Rules set out requirements that give effect to the legislation, including processes the AER must follow in determining allowable revenue recovery for electricity networks and gas pipelines.

The AER assesses the forecasts that a network business submits of the revenue it needs to cover efficient costs and earn an appropriate return on capital. The main revenue components are:

- the return on capital, which may account for 40–70 per cent of revenue due to the capital intensive nature of network businesses. Three factors determine the return on capital—the size of a network's asset base, new investment added to the base, and the rate of return (the weighted average cost of capital, WACC). Relatively minor changes to the WACC can materially impact on network charges.
- operating and maintenance costs, which account for around 30 per cent of revenues.

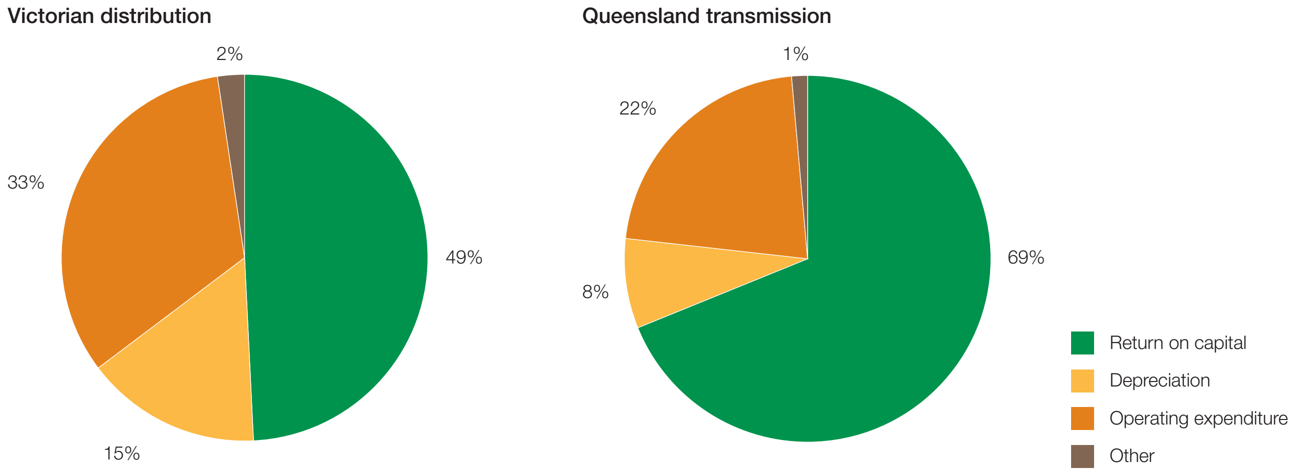
Figure 5 illustrates the revenue components for Queensland transmission (2012–17) and Victorian distribution (2011–15).

Total revenues for networks in the NEM are forecast at $60 billion over the current five year regulatory periods, comprising over $12 billion for transmission and $47 billion for distribution. Figure 6 illustrates trends in network revenues from recent AER decisions.

4 The construction of new gas transmission pipelines has increased competition in that sector and removed the need to regulate some pipelines.

Figure 5

Indicative composition of electricity network revenues



Notes:

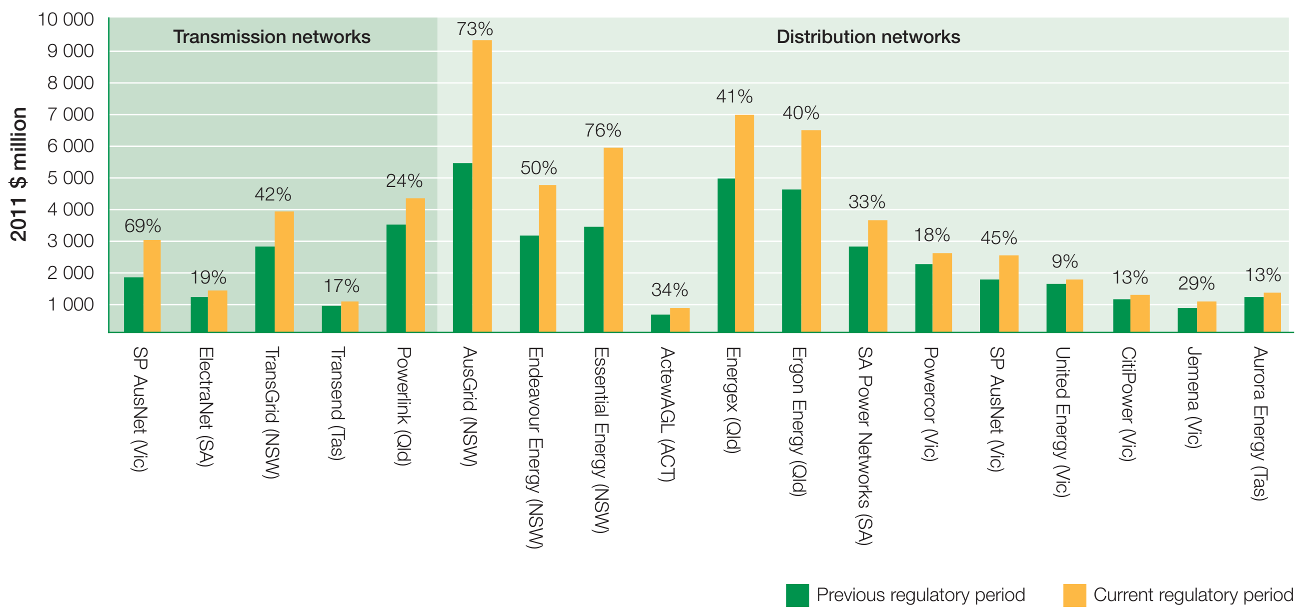
Victorian distribution is an average for five networks.

Determinations made in 2010 (Victoria) and 2012 (Queensland).

Source: AER.

Figure 6

Electricity network revenues



Notes:

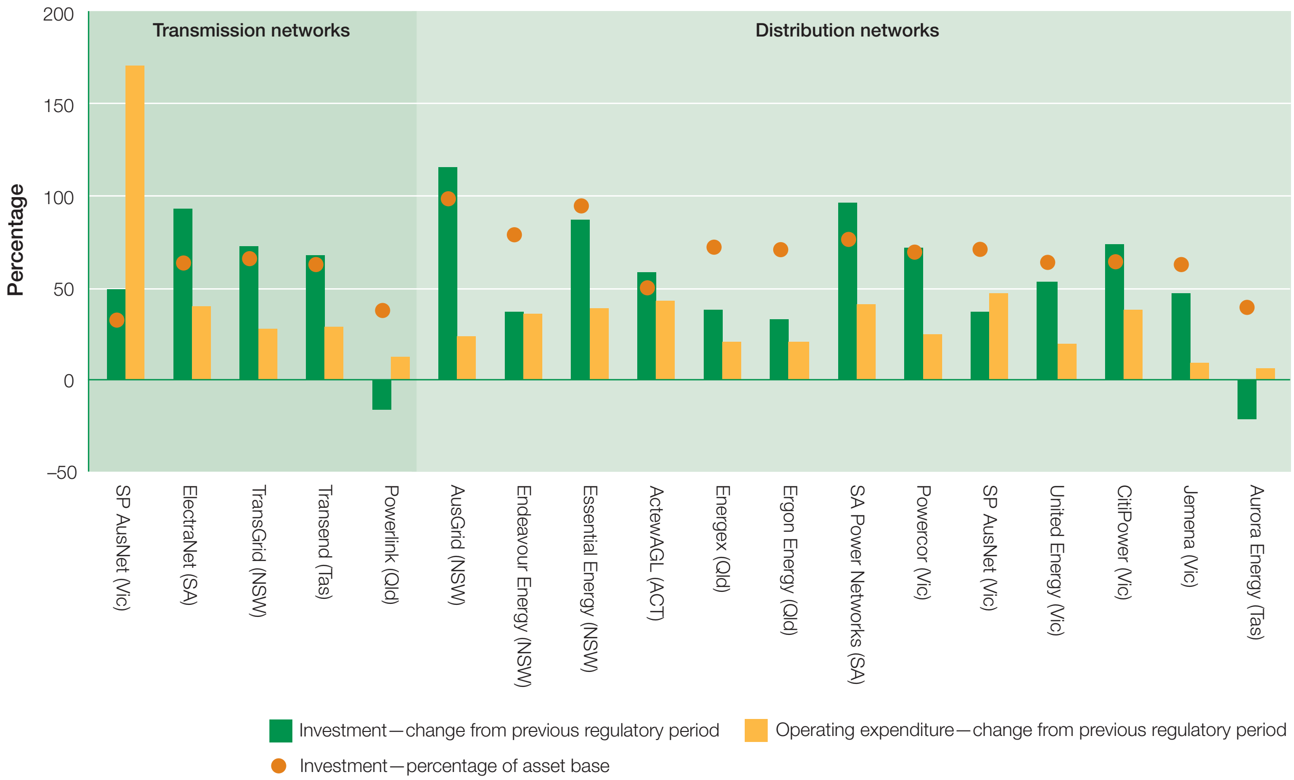
Forecasts in regulatory determinations, amended for decisions by the Australian Competition Tribunal.

The Queensland Government prevented Energex and Ergon Energy from recovering $270 million and $220 million respectively of these allowances.

Source: AER.

Figure 7

Electricity network investment and operating expenditure



Note: Forecasts in regulatory determinations, amended for decisions by the Australian Competition Tribunal.

Source: AER.

Figure 7 illustrates trends in two key revenue drivers—capital investment, and operating and maintenance costs.

Comparing outcomes in the current five year regulatory cycle with the previous cycle:

- networks revenues are forecast to rise (in real terms) by 44 per cent
- investment is forecast to rise (in real terms) by 27 per cent in transmission and 60 per cent in distribution
- operating and maintenance costs are forecast to rise (in real terms) by 48 per cent in transmission and 28 per cent in distribution.

Higher network revenues, investment and operating costs have been driven by a mix of factors, some of which required policy reform (sections A.3). Other drivers relate to legitimate customer considerations and costs. In particular, a number of determinations made several years ago reflected the need to upgrade ageing network assets, meet new bushfire (safety) standards, and respond to forecasts made at the time of rising peak demand.

Additionally, conditions in global financial markets meant the cost of capital factored into revenue allowances for most networks in the current regulatory cycle was significantly higher than that applied in previous periods. The primary factor underpinning the increase was a higher debt risk premium (which reflects borrowing costs for a business based on its risk of default). Issues in global financial markets affected liquidity in debt markets and increased perceptions of risk from late 2008, pushing up the debt risk premium. Additionally, the Rules required the AER to apply a debt risk premium above that faced by the businesses in practice. The instability in financial markets also increased the market risk premium factored into the cost of equity (the return required by shareholders to reward the risks of investing in a network business).

Figure 8

Weighted average cost of capital—electricity and gas distribution

Note: Nominal vanilla WACC.

Source: AER.

The higher cost of capital resulting from these factors led to average revenue approvals being 7 per cent higher in current determinations than if the cost of capital had remained unchanged from the previous round of determinations.

Figure 8 illustrates the WACC in regulatory decisions on electricity and gas distribution networks since 2004. It also illustrates how merits review outcomes affected particular AER decisions; in several reviews, the Tribunal substituted a higher WACC than that determined by the AER (section A.2.1). The cumulative impact was greater, given the AER applied Tribunal decisions in subsequent regulatory reviews of other networks.

Electricity network charges will plateau in 2013 and throughout the remaining years of current regulatory determinations, particularly for customers in New South Wales, Queensland and South Australia. Charges for some New South Wales networks are forecast to fall in real terms in 2013–14. Additionally, new AER decisions and draft decisions made in 2012 reflect a significant shift in cost drivers that will ease pressure on network charges in the future. In particular, forecast industrial and residential energy use, including peak demand, have been revised down (section A.4); forecast input costs are also flatter.

Reflecting these changes in operating environments, the AER in 2012 determined:

- a softening in forecast peak demand growth in Queensland contributed to transmission investment requirements for 2012–17 being 16 per cent less than in the previous period
- subdued economic growth in Tasmania, with lower expected demand and fewer new connections, contributed to distribution investment requirements for 2012–17 being 21 per cent less than in the previous period.

These developments have been accompanied by changes in global financial markets over the past 18 months, which have lowered equity and borrowing costs. In 2011, the AER reduced by 50 basis points the market risk premium, returning it to the level it was at prior to the global financial crisis. This change first affected determinations made in 2011 for Queensland and South Australian gas distribution networks. More recently, a reduction in government bond yields reduced the risk free rate (lowering the cost of equity and debt). Reflecting these financial market developments, WACC allowances made in 2012 for Powerlink (Queensland transmission) and Aurora Energy (Tasmania distribution) were lower than those provided for in the networks' previous determinations made during the global financial crisis.

Following significant changes to the energy Rules in November 2012, the AER is developing new guidelines on its approach to the WACC (section A.3.1).

A.2.1 Reviews by the Australian Competition Tribunal

The energy laws allow a network business to apply to the Australian Competition Tribunal for a limited review of an AER determination, or part of it. Network businesses sought reviews of 22 AER determinations between 2008 and 2012—three in electricity transmission, 14 in electricity distribution and five in gas distribution. The Tribunal's decisions on these reviews increased network revenues by around $3.3 billion. Around 85 per cent of revenue impacts relate to elements of the WACC and the value of tax imputation credits (gamma).

In two decisions made in January 2012, the Tribunal:

- increased Victorian electricity distribution revenues by $255 million in the current regulatory period, increasing a typical electricity residential bill by 0.5–1.5 per cent
- increased Queensland and South Australian gas distribution revenues by $92 million in the current regulatory period, increasing a residential gas bill by 2 per cent in Queensland and 1 per cent in South Australia.

Concerns among policy makers about the impact of Tribunal decisions led to Australian governments bringing forward a review of the merits review provisions from 2015 to 2012 (section A.3.2).

A.3 Reforming network regulation

While legitimate cost pressures—the replacement of ageing assets, network expansion in response to rising peak demand forecasts, and conditions in financial markets—significantly drove higher network charges over the past five years, reform was needed to address other contributing factors. Australian governments, policy bodies and regulators have been working to address these issues and ensure network pricing is no more than necessary to provide an economically efficient and reliable energy supply.

A.3.1 Strengthening of the energy Rules

In September 2011 the AER submitted proposals to the AEMC, seeking changes to the energy Rules governing how network businesses are regulated to better promote efficient investment in, and use of, energy services for the long term interests of consumers. While recognising the fundamental drivers of higher network costs, the AER considered some provisions drafted in 2006—a time of policy concern about the adequacy of network investment—were causing consumers to pay more than necessary for energy services. The AER argued:

- the Rules constrained the extent to which it could make holistic and independent assessments of a network's proposed expenditure needs
- the automatic roll-in of all capital expenditure—including amounts above AER allowances—to a network's asset base created incentives for overinvestment
- inconsistent approaches to setting the cost of capital for electricity and gas network businesses, along with constraints on the AER in setting costs that reflect current commercial practices, led to inflated cost estimates
- the consultation arrangements hindered effective stakeholder engagement.

Following detailed consultation, the AEMC released Rule changes in November 2012 that strengthen the AER's capacity to set network prices so consumers do not pay more than necessary for an economically efficient and reliable energy supply. The changes:

- create a common approach to setting the cost of capital across electricity and gas network businesses, whereby the AER makes a best possible estimate of the cost for a benchmark efficient service provider at the time a regulatory determination is made
- require the AER to undertake a full public review at least every three years on its approach to setting the cost of capital, completing the first review by November 2013
- clarify the AER's power to assess and amend network revenue proposals. Additionally, the AER will publish annual benchmarking reports on the relative efficiency of the businesses
- enhance incentives for efficient investment by enabling the AER to review the actual capital expenditure of network businesses to ensure it was prudent and efficient. Expenditure in excess of regulatory approvals may be removed from the regulated asset base if the AER finds it is not prudent or efficient

- commence the electricity regulatory process four months earlier, to allow more effective consultation with stakeholders. More information will be made available early in the regulatory process to strengthen consumer engagement.

The Senate Select Committee on Electricity Prices in November 2012 endorsed a number of these reforms. In particular, it agreed the AER should be permitted to review the efficiency of historical capital expenditure and develop new guidelines for setting rates of return for network businesses.

In response to the Rule changes, the AER will consult with stakeholders to develop new guidelines, including those for assessing expenditure proposals, setting allowed returns on assets, setting incentives for efficient investment and effectively engaging with consumers.

In relation to the WACC, the new Rules require the AER to estimate a cost of capital that takes account of market circumstances, estimation methods, financial models and other relevant information. The AER published an issues paper in December 2012 as the first stage in developing its approach and in November 2013 will finalise a guideline that may include indicative cost of capital parameters.

Aside from changes related to the new Rules, the AER in 2012 continued to improve its regulatory approach by refining:

- benchmarking techniques and tools and their application in regulatory decisions, which the new Rules will better enable. The AER is developing key benchmarking indicators in consultation with industry, aiming to first apply enhanced metrics in regulatory reviews of the New South Wales and ACT electricity distribution networks
- information requirements on energy business, to improve the quality and consistency of data for regulatory reviews and annual performance reporting. The enhancements also aim to improve the robustness of regulatory decision making, and provide data to develop and apply benchmarking techniques and publish benchmarking reports on network businesses.

The Productivity Commission in October 2012 found benchmarking would complement the tools currently applied in regulation, including for the testing of network business proposals.

A.3.2 Review of limited merits review arrangements

In response to policy concerns, the SCER brought forward a review of the limited merits review regime from 2015 to 2012. Tribunal decisions made under the regime increased network revenues by $3.3 billion between June 2008 and June 2012 (section A.2.1).

In March 2012 the SCER appointed an expert panel to review the regime. In its final report, released in September 2012, the panel found the regime has not operated as intended. In particular, the regime:

- does not sufficiently consider the national electricity and gas objectives, which focus on the long term interests of consumers
- places a narrow focus on the matters raised for review, without sufficiently considering the overall balance of a determination.

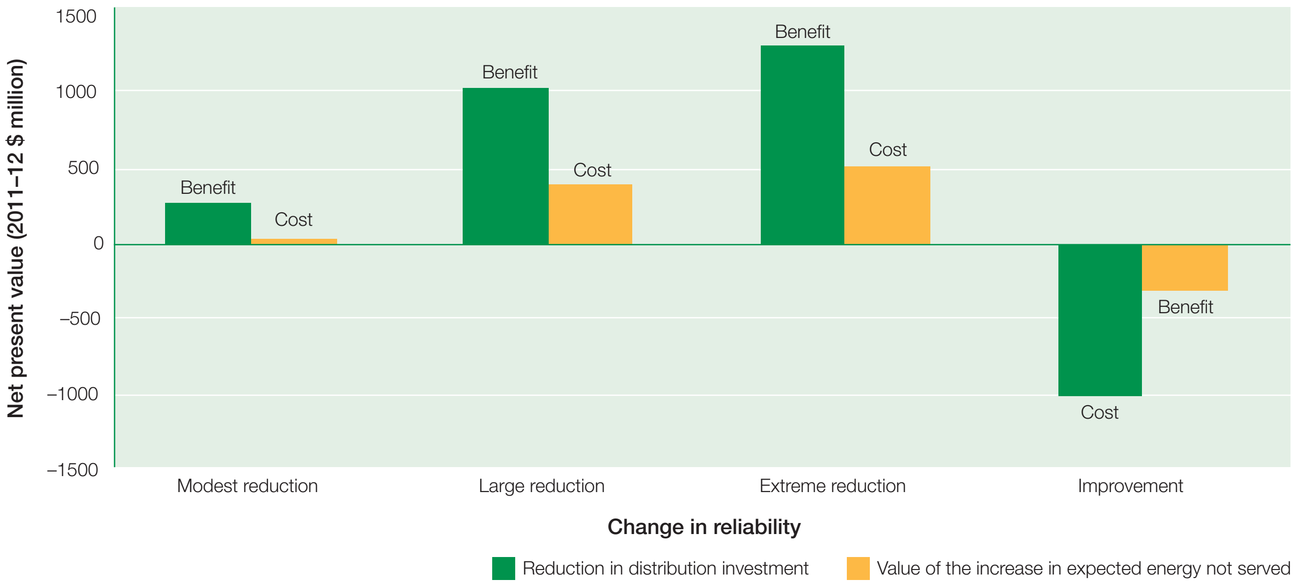
The panel found a limited merits review regime is preferable to the alternatives—such as *de novo* (full) review or reliance on judicial review only—but recommended the following improvements:

- Reviews should be conducted by a new administrative body attached to the AEMC.
- The regime should be limited to a single ground of appeal—that a materially preferable decision exists—and should assess review matters in relation to the national energy objectives set out in the legislation.
- A review should be investigative rather than adversarial, with greater input from consumers. Additionally, the energy legislation should clarify the AER's role in assisting the review body.
- The review body should be free to explore any aspect of a decision that it considers relevant.

CoAG recommended in December 2012 that agreement be reached on a policy response to the review by mid–2013. It proposed that an amended regime be in place by the end of 2013 in advance of the next round of AER determinations.

Figure 9

Costs and benefits of reducing distribution reliability, New South Wales



Source: AEMC.

A.3.3 Testing of the efficiency of new investment

Reforms to the electricity Rules are streamlining the assessment process for large investment projects to ensure they are efficient. The regulatory investment test for transmission (RIT-T), introduced in August 2010, requires a network business to determine whether a proposed investment passes a cost–benefit analysis or provides a least cost solution to meeting an identified need. The network business must publicly consult on its proposal, and affected parties can lodge a formal dispute. The AER monitors and enforces a proposal's compliance with the RIT-T; it conducted a number of compliance reviews in 2012.

The AEMC in October 2012 finalised a Rule change to introduce a RIT-D test for distribution networks.[5] The AER must develop and publish the RIT-D (and related application guidelines) by September 2013. The new test will apply to investment projects over $5 million. The new Rule includes a dispute resolution process, and requires distribution businesses to release annual planning reports and maintain a demand side engagement strategy.

5 AEMC, National Electricity Amendment (Distribution Network Planning and Expansion Framework) Rule 2012.

A.3.4 Network reliability arrangements

The need to meet reliability requirements is a key driver of network investment, operating expenditure and charges. The trade-off between reliability and cost means a government decision to increase reliability standards will raise customer bills. The SCER in August 2011 noted the significant impact of distribution investment on retail electricity prices, and directed the AEMC to review the approaches to setting distribution reliability standards across jurisdictions, with a view to developing a national approach.

In November 2012 the AEMC proposed the introduction of a nationally consistent framework for distribution reliability.[6] It recommended jurisdictions continue to set reliability standards, but follow a consistent national approach based on output performance. It also recommended reporting and incentive scheme arrangements be standardised.

In parallel with this broad review, the AEMC also reviewed the costs and benefits of reliability arrangements in New South Wales. Its August 2012 report found a reduction in reliability standards could save distribution network investment of $275 million to $1.3 billion over 15 years, depending on how much the standards are reduced. It forecast this would save a typical consumer $3–15 per year, at a cost of around 2–15 extra minutes of outages per year.

6 AEMC, *Review of distribution reliability outcomes and standards, draft report—national workstream*, 2012.

The research found the consumer savings of reducing the standards would outweigh the costs of weaker reliability. In contrast, the costs of further improving reliability would outweigh the benefits (figure 9).

The Senate Select Committee in November 2012 recommended the adoption of a national framework to determine reliability standards that reflect customers' valuation of reliability. It recommended tasking the AEMC with this responsibility. CoAG supported this recommendation in December 2012.

A.3.5 Management of rising energy use and peak demand

Forecast growth in energy use and peak demand has been another key driver of network investment and revenues over the past five years. While energy demand has eased from its peaks recorded around 2007–08 (as explained in section A.4), the Australian Energy Market Operator (AEMO) forecast growth will resume in the medium to longer term.

Energy networks are engineered with sufficient capacity to meet peak demand, which typically occurs on days of extreme weather. Around 20–30 per cent of the $60 billion of electricity network capacity in the NEM is idle 99 per cent of the time. While this capacity is drawn on for less than 90 hours a year, the associated network charges are fully passed on to retail energy customers.

Policy and regulatory work in 2012 aimed to develop efficient ways of responding to rising peak demand. The AEMC 's *Power of choice* review (completed in November 2012) focused on empowering consumers to manage their energy use and save on energy costs by shifting their consumption away from peak times. The AEMC recommended:

- new meters installed for residential and small business customers should be interval meters with remote communication capacity. It preferred the supply of metering and related data services to be contestable, with retailers having primary responsibility.
- improving price signals to customers by introducing time varying network tariffs. It noted small and medium sized customers should be given a choice between time varying and flat network charges. The Senate Select Committee considered this reform should be supported by a consumer education campaign.
- providing more flexibility for consumers to access their own consumption data, and a framework for consumers to engage with suppliers of demand management services
- enabling consumers to sell small scale generation (for example, solar or battery storage) to parties other than their electricity retailer
- allowing greater participation by large customers or aggregators in wholesale electricity markets to widen opportunities for demand response at times of high spot prices.

The rollout of interval meters—with time based data on energy use and communication capabilities for remote reading and customer connection to the network—is central to many of the AEMC's recommendations. This type of metering, when coupled with time varying prices, would allow consumers to save on their energy bills by reducing energy use at times of peak demand. In the longer term, it may facilitate dynamic grid operation.

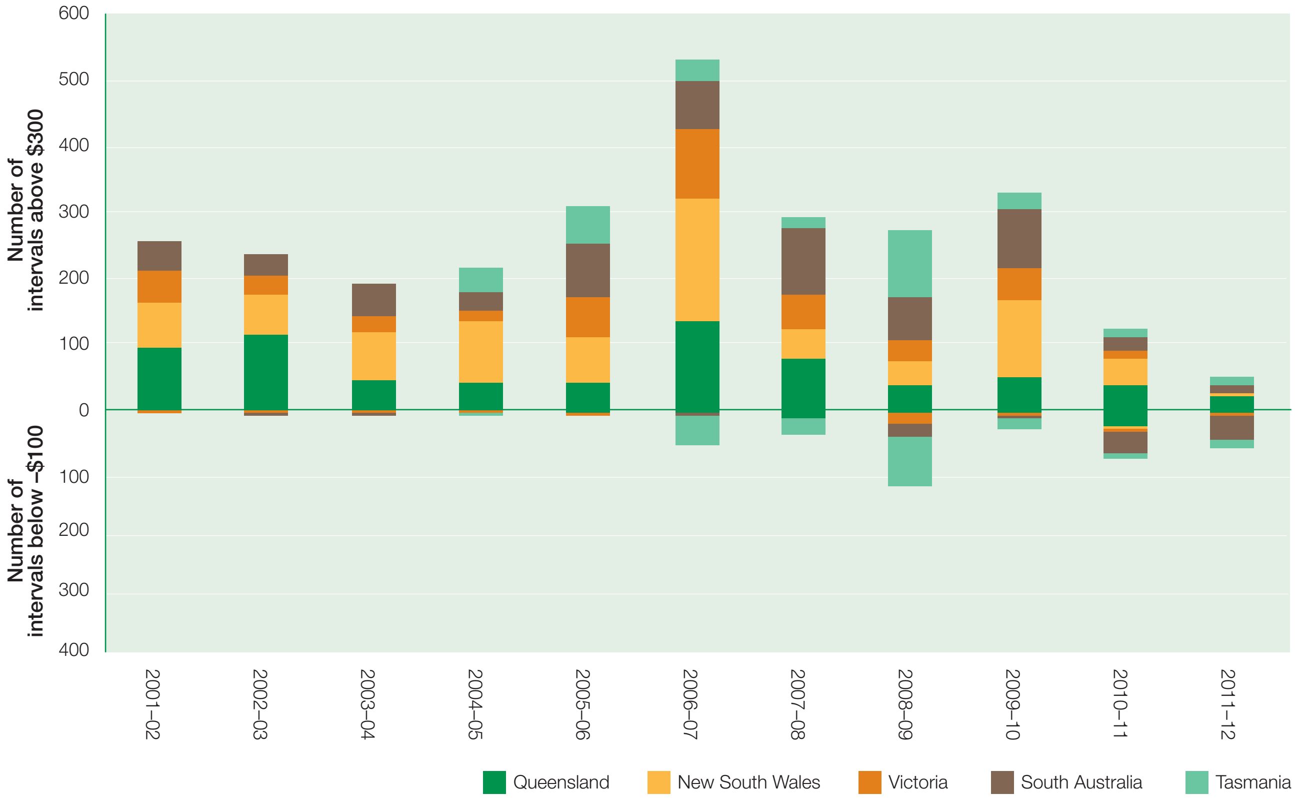
CoAG in December 2012 approved the adoption in principle of the full set of *Power of choice* recommendations. It also proposed the phasing in of time varying network charges, and a new demand side mechanism for the wholesale market, by July 2014.

A Victorian rollout of interval meters with remote communications to all customers is expected to be completed in 2013. All customers will be free to move to time varying prices from July 2013. Some Victorian energy businesses in 2012 launched portals enabling customers with interval meters to monitor and manage their energy use and costs. These customers can compare energy use with similar households, estimate bills based on consumption, and set an electricity budget and then track progress.

In addition to metering developments, the Australian Government is investing $100 million in the Smart Grid, Smart City initiative, which is testing the capacity of smart grid technologies. The initiative explores the use of advanced communication, sensing and metering equipment to provide customers with improved energy use information, automation and savings, and to improve network reliability. It is also considering options to connect more localised generation (such as solar) and hybrid vehicles to the grid. The program, which is operating in Newcastle and parts of Sydney, runs from 2010 to 2013.

The AER provides demand management incentive schemes for network businesses to research and implement non-network approaches to manage demand. The schemes fund innovative projects beyond standard capital expenditure funded through the regulatory process. The AEMC recommended refining the schemes to capture wider market benefits and network deferral benefits beyond the current

Figure 10
Incidence of extremely high and negative electricity prices



Sources: AEMO; AER.

regulatory period. The AER will review the program following CoAG's consideration of the *Power of choice* review and any subsequent amendments to the Rules.

Other work in demand management includes strengthening customer engagement in the regulatory process, including during AER regulatory reviews of network charges (section A.3.1).

A.4 Wholesale electricity market

After easing in 2010–11, spot electricity prices fell to near record lows in 2011–12 before the introduction of carbon pricing (section A.5). Average prices in 2011–12 ranged from $28 per megawatt hour (MWh) in Victoria to $33 per MWh in Tasmania. Low average prices were mirrored in the small number of very high prices. Across the NEM, the spot price exceeded $300 per MWh on 65 occasions, and exceeded $5000 per MWh only once—the lowest incidence since the commencement of the NEM (figure 10).

A number of factors contributed to lower spot prices. In particular, electricity demand fell by 2.5 per cent in 2011–12, continuing a declining trend since 2007–08. The fall reflected the impact of flatter economic conditions on commercial and industrial demand; the increasing use of rooftop solar generation; and customers' adoption of energy efficiency measures such as solar water heating (partly in response to jurisdictional energy efficiency schemes). Additionally, consecutive summers of below average temperatures capped peak demand by reducing the use of air conditioners. This latter factor helps explain the near absence of extremely high prices.

Despite low average prices, there was market volatility in South Australia, Tasmania and Queensland. In particular, 274 negative prices—mostly in Tasmania and South Australia—contributed to low average spot prices (figure 10). The rising incidence of negative prices in South Australia links to the increasing use of wind generation. Wind generators bid low and often at slightly negative prices to ensure dispatch, because they receive the value of renewable energy certificates in addition to spot market returns.

But, all instances of South Australian prices that were *significantly* below zero in 2011–12 (including prices around the –$1000 market floor) were associated with strategic generator bidding or rebidding. On several occasions, AGL Energy's bidding strategy in South Australia effectively shut down other generators (including wind generators).[7]

Hydro Tasmania also engaged periodically in strategic bidding to drive negative prices in Tasmania. At other times from 2009, it was able to withdraw low priced capacity from the market (often when demand was moderate) to drive *up* prices. An expert panel established by the Tasmanian Government concluded in March 2012 that the electricity industry structure allows Hydro Tasmania to control regional spot prices, posing a barrier for new entrant retailers. The report proposed industry reform, including restructuring Hydro Tasmania's trading functions into three new state owned entities.

The Tasmanian Government in May 2012 responded to the report by announcing major reforms affecting every segment of the industry. It decided on a regulatory solution to address Hydro Tasmania's market power, rather than following the panel's recommendation to restructure the entity. From 1 July 2013 the Office of the Tasmanian Economic Regulator will regulate Hydro Tasmania's wholesale market activities. Tasmanian contract prices will be set by reference to Victorian contract prices, to reflect the opportunity cost of Hydro Tasmania selling into an alternative market.[8] The Tasmanian Parliament passed legislation to implement the reforms in November 2012.

Queensland spot electricity prices were volatile during summer 2011–12, with over 70 spot prices exceeding $100 per MWh between 1 December 2011 and 31 March 2012 (including two prices above $2000 per MWh). Typically, the events were of very short duration. Sixteen negative spot prices (including three *below* –$100 per MWh) followed the short duration high prices. Counter-price exports from Queensland into New South Wales occurred during each high price event (that is, electricity was flowing from the higher to the lower price region). Similar incidents of market volatility occurred in August–October 2012.

While this volatility typically stemmed from network congestion around Gladstone in central Queensland, the scenario created incentives and opportunities for generators to try to influence dispatch by engaging in disorderly bidding (issuing bids without reference to generation costs). This behaviour exacerbated network congestion and market volatility.

An AER study found network congestion around Gladstone frequently encouraged disorderly generator bidding between 2009 and 2012. When Queensland prices are at least $100 per MWh higher than those in New South Wales, the study found power typically flows counter-price into New South Wales, causing negative settlement residues. Similar issues periodically occur in trade between New South Wales and Victoria.

Spot price volatility causes market uncertainty and can affect the efficient dispatch of generation. The incidence of counter-price export flows also poses difficulties for retailers and smaller generators seeking to hedge against volatility, especially across regions through inter-regional settlement residue auctions (section 1.4). These conditions create risks for generators and reduce competition among generators in adjoining regions. The additional risks can deter new entry and investment in both generation and retail, leading to higher costs that consumers ultimately bear.

The Productivity Commission considered market power issues arise if a generator can artificially create greater price volatility. It noted the potential advantages that this behaviour may give a generator, including in the market for hedging instruments such as price caps.[9]

Workstreams are in place to mitigate issues of congestion, counter-price flows and disorderly bidding in the NEM. The AEMC's *Transmission frameworks review* (second interim report, August 2012) recommended changes to the settlement arrangements for generators through an optional firm access model. The proposal aims to increase the firmness of network availability so generators have greater certainty about their dispatch. This outcome would remove an impediment to liquidity in energy contract markets and enhance competition. The issues are complex, and reform may take considerable time. The AEMC expects to complete its transmission frameworks review by 31 March 2013.

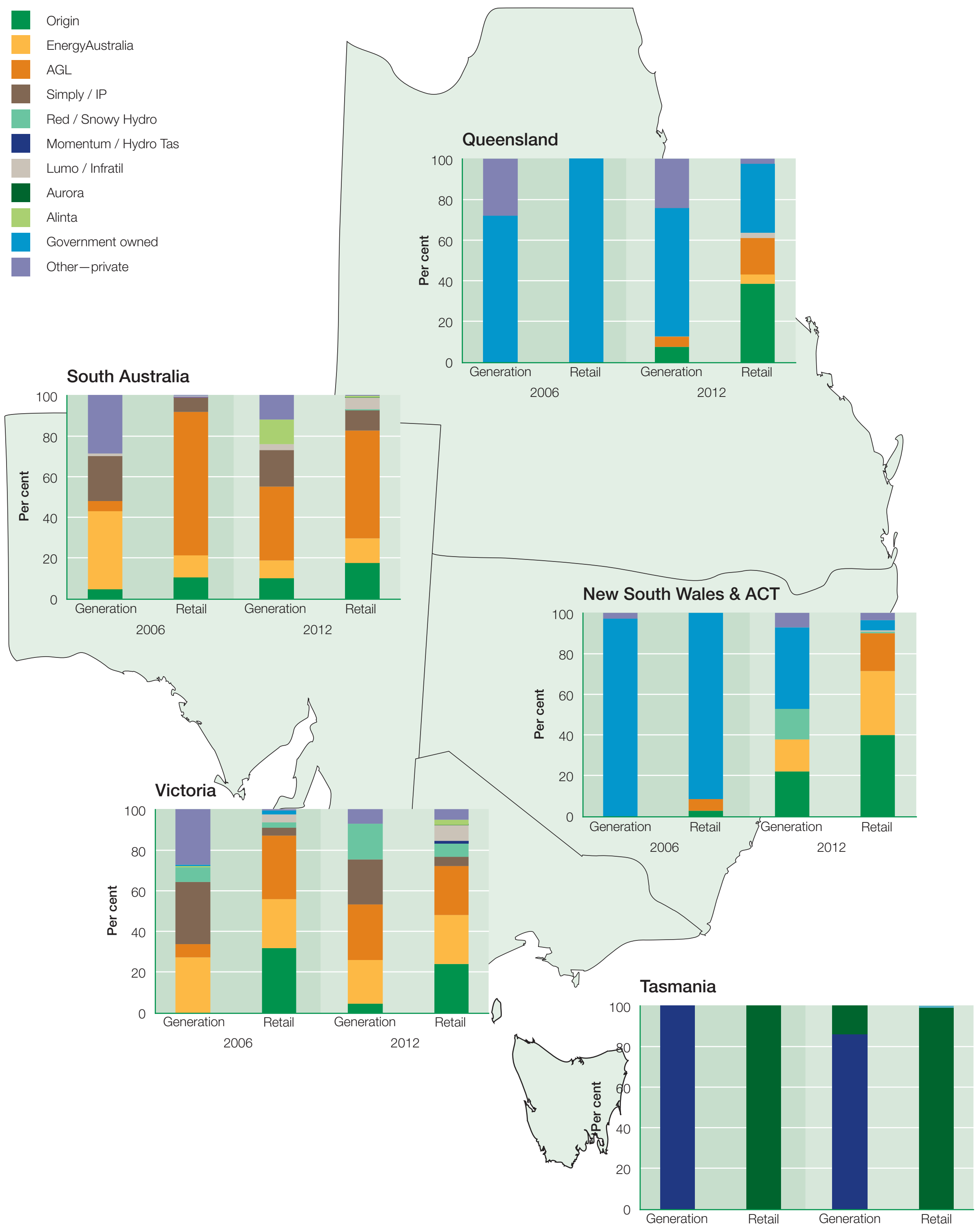
7 The AER analyses spot prices below –$100 per MWh in its weekly market reports. See, for example, weekly reports for 1–7 April 2012 and 22–28 April 2012.

8 Department of Treasury and Finance (Tasmania Government), *Energy for the future: reforming Tasmania's electricity industry*, May 2012.

9 Productivity Commission, *Electricity network regulatory frameworks, draft report*, October 2012, pp. 631–2.

Figure 11

Vertical integration—electricity retail and electricity generation, 2006 and 2012



MW, megawatt.

Note: Generation market share relates to installed capacity; retail market share is for small electricity customers.

Source: AER estimates.

In its submission to the review, the AER argued the issues of disorderly bidding and counter-price flows are serious enough to warrant interim measures until a more comprehensive solution is in place. It suggested implementing a simplified mechanism (such as shared access congestion pricing) in the short term, via relatively straightforward changes to the current market settlement systems.

A.4.1 Market concentration, vertical integration and market power

While governments structurally separated the energy supply industry in the 1990s, the generation sector in some regions remains highly concentrated. Additionally, retailers and generators have tended to vertically integrate to form 'gentailer' structures, as a way of managing the risk of price volatility in wholesale energy markets. While it makes commercial sense for the entities concerned, vertical integration reduces liquidity and contracting options in hedge markets; this affects energy costs for independent retailers and may pose a barrier to entry and expansion for both independent generators and retailers.

Three retailers—AGL Energy, Origin Energy and EnergyAustralia—jointly supply 76 per cent of retail electricity customers and 85 per cent of gas customers in eastern Australia. The entities increased their market share in generation from 11 per cent in 2007 to 35 per cent in 2012 (figure 11). The same entities are also expanding their interests in upstream gas production, both to supply their retail customers and to provide fuel for their gas powered generation interests.

Vertical integration by these businesses since 2007 includes:

- AGL Energy and Origin Energy acquiring retail customers in Queensland through privatisation in 2006–07
- Origin Energy and EnergyAustralia (branded at the time as TRUenergy) acquiring generation contracts and retail customers in New South Wales in 2010
- AGL Energy, Origin Energy and EnergyAustralia controlling 58 per cent of new generation capacity commissioned or committed since 2007, mainly in gas powered and wind generation
- AGL Energy acquiring South Australia's largest generator (Torrens Island) in 2007 and raising its equity in Victoria's Loy Yang A power station from 32.5 per cent to 100 per cent in 2012.

In addition, many new entrant retailers since 2007 are vertically integrated with entities that were previously stand-alone generators—for example, International Power (trading as Simply Energy in retail markets), Infratil (Lumo Energy) and Alinta. Government owned generators are also vertically integrating. The generator Snowy Hydro owns Red Energy, which operates in the New South Wales, Victorian and South Australian retail markets. The Tasmanian Government owned Hydro Tasmania has a retail arm (Momentum Energy).

The AER's weekly market reports, along with previous editions of *State of the energy market*, noted evidence of the periodic exercise of market power in several NEM regions. A vertically integrated business with significant market share in generation may have the ability and incentive to manipulate spot prices to harm its competitors in the retail market. A generator may seek to drive either high or low spot prices, depending on its incentives (including contract positions). The Productivity Commission noted this behaviour is difficult to detect, because hedging positions are commercial-in-confidence. It also noted the distorting impacts of the exercise of market power, including the dispatch of high cost plant ahead of low cost plant; distorted incentives for new investment; and deterring efficient new entry in retail markets.[10]

The AEMC in 2012 considered issues of market power in relation to a Rule change proposal by Major Energy Users to restrict the bidding of 'dominant generators' to $300 per MWh at times of high demand. In its draft determination, the AEMC found insufficient evidence of the exercise of market power. In its August 2012 submission on the draft, the AER encouraged the AEMC to broaden the range of evidence and analytical tools for assessing market power in the NEM. On 30 August 2012 the AEMC extended the timing of its final determination to 11 April 2013.

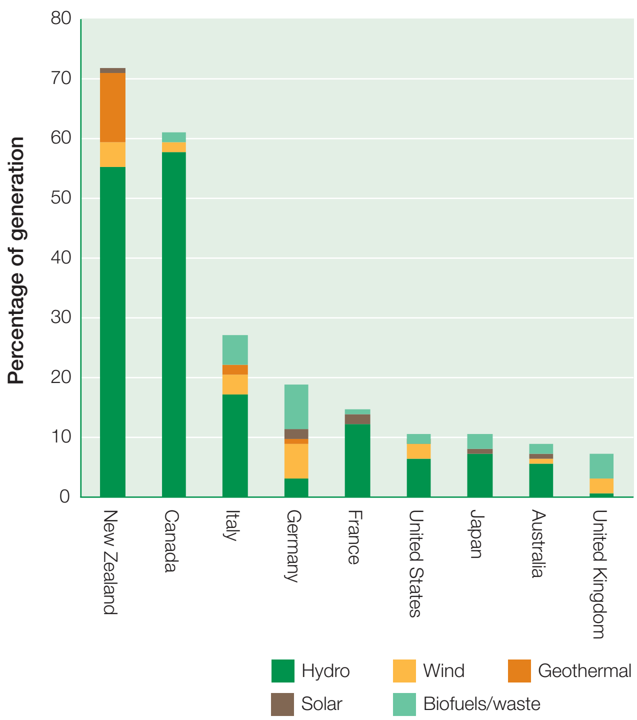
10 Productivity Commission, *Electricity network regulatory frameworks, draft report*, October 2012, pp. 631–2.

A.5 Climate change policies

Australia is one of the highest emitters of greenhouse gases among countries in the Organisation for Economic Cooperation and Development (OECD). The electricity sector contributes around 35 per cent of these emissions, mainly due to an historical reliance on coal fired generation.[11] Additionally, Australia has a low share of renewable electricity generation; it ranks seventh lowest among the 28 member countries of the International Energy Agency (figure 12).[12]

Figure 12

Renewable generation share of total generation, 2010



Source: International Energy Agency, *Energy policies of IEA countries—Australia*, November 2012 .

Australia is one of many countries implementing policies to encourage the adoption of lower carbon emissions technologies. The central plank of Australia's climate change response is the carbon price introduced by the Australian Government on 1 July 2012 as part of its Clean Energy Future Plan. The plan targets a reduction in carbon and other greenhouse emissions to at least 5 per cent below 2000 levels by 2020 (and up to 25 per cent with equivalent international action). The central mechanism places a fixed price on carbon for three years, starting at $23 per tonne of carbon dioxide equivalent emitted. The plan includes financial assistance to offset the rise in energy costs for low and middle income households.

The fixed price scheme will be replaced by an emissions trading scheme on 1 July 2015, with the price determined by the market. The Australian Government in August 2012 announced changes that will, from 1 July 2015, closely link Australia's carbon price to the price of EU carbon allowances, which were trading at around $10 per tonne in September 2012.

Market expectations were that the introduction of carbon pricing would increase average spot electricity prices by around $20 per MWh. But the initial price change was much greater, with average spot prices in the week 1–7 July 2012 ranging from $38 to $84 per MWh above 2011–12 average prices (in New South Wales and South Australia respectively). The average spot price across the NEM rose from $37 per MWh in June 2012 to $67 per MWh in July 2012.

Aside from carbon pricing, various factors contributed to these outcomes—fuel supply and non-carbon related cost issues, plant outages, reasonably strong demand and low wind output. Additionally, network outages contributed to the price peaks in early July. More generally, spot prices in July were coming off very low bases in 2011–12. Nonetheless, the price rises are difficult to reconcile with those factors alone. In particular, a number of generators raised their offer prices above the levels required to adjust for the carbon intensities of their plant.

Spot prices moderated over the following weeks and continued to ease into spring 2012. By mid-October, the average spot price in the NEM (filtered for extreme price events) since the introduction of carbon pricing was broadly in line with market expectations—around $21 per MWh above the average price for June 2012.[13]

The Australian Government also operates a RET scheme to achieve its commitment to a 20 per cent share for renewable energy in Australia's electricity mix by 2020. The scheme provides subsidies for renewable generation—such as wind and solar generation—by requiring electricity retailers to source a proportion of their energy from renewable sources developed after 1997. It has a 2020 target of 41 000 gigawatt hours of energy from large scale renewable energy projects. Wind generation has risen strongly since the government expanded the scheme in 2007. Small scale

11 Garnaut, Professor R, *The Garnaut Review 2011: Australia in the global response to climate change*, Final report of the Garnaut Climate Change Review, 2012.

12 International Energy Agency, *Energy policies of IEA countries—Australia,* November 2012.

13 AEMO, *Carbon price—market review*, 8 November 2012.

Table 1 Generation plant shut down or offline, 2012

BUSINESS	POWER STATION	TECHNOLOGY	SUMMER CAPACITY (MW)	PERIOD AFFECTED
QUEENSLAND				
Stanwell	Tarong (2 units)	Coal fired	700	October 2012 to at least October 2014
RATCH Australia	Collinsville	Coal fired	189	Retired
CS Energy	Gladstone	Coal fired	560	Two units not operating July–December 2012
NEW SOUTH WALES				
Delta Electricity	Munmorah	Coal fired	600	Retired
VICTORIA				
Energy Brix	Morwell Unit 3	Coal fired	70	From July 2012 until viable
Energy Brix	Morwell Unit 2	Coal fired	25	Not run since July 2012
EnergyAustralia	Yallourn (1 unit)	Coal fired	360	Offline July–December 2012
SOUTH AUSTRALIA				
Alinta Energy	Northern	Coal fired	540	April–September 2012
Alinta Energy	Playford	Coal fired	200	From March 2012 until viable

Source: AER.

renewable projects do not contribute to the national target, but still produce renewable energy certificates that retailers must acquire.

The Climate Change Authority was reviewing the RET scheme in 2012, including the overall target, the eligibility framework and the scheme's impact on electricity costs, prices and energy security. In a discussion paper in October 2012, it recommended retaining the form and level of the 2020 target for large scale renewable energy projects, and reviewing in 2016 the arrangements for beyond 2020. It also recommended retaining the scheme in its current form for small scale installations. The Authority will consider whether the size threshold for these installations should be reduced. A final report is expected in December 2012.

There are indications that climate change policies (in conjunction with flat electricity demand) are affecting the generation mix in the NEM. Notably, over 3000 megawatts (MW) of coal plant was shut down or periodically offline during 2012 (table 1). This reduced capacity was spread across every mainland NEM region, and does not include Victoria's 1450 MW Yallourn power station operating below capacity during winter as a result of flooding. Most plant owners cited low energy demand as a key factor in their decisions. The owners of Tarong (Queensland), Munmorah (New South Wales), Morwell (Victoria) and Yallourn (Victoria) cited carbon pricing and the impact of the RET in shifting generation away from coal to renewable sources as contributing factors.

Flatter forecasts of future energy use and peak demand growth, combined with further expected growth in renewable generation are delaying the need for new investment in baseload and peaking generation capacity. Revised forecasts in 2012 deferred new investment requirements by at least four years in all NEM regions, compared with forecasts in 2011. Victoria will be the first region to require new investment (in summer 2018–19), followed by South Australia (summer 2019–20) and Queensland (summer 2020–21). New South Wales and Tasmania are not forecast to require new generation investment over the next decade.

A.6 Gas

Significant links exist between electricity and gas markets, with gas powered generation accounting for 24 per cent of domestic gas demand in eastern Australia.[14] Gas also has a range of industrial, mining and commercial applications. Household demand for gas is relatively small, except in Victoria, where residential demand for cooking and heating accounts for around one-third of total gas consumption.

Australian gas prices have generally been low by international standards (typically $3–4 per gigajoule), but the development of LNG export capacity in Queensland is exposing eastern Australia's domestic market to international energy prices. LNG exports are expected to commence from Gladstone in 2014–15.

14 AEMO, *Gas statement of opportunities for eastern and southern Australia*, Executive briefing, 2011.

While the introduction of carbon pricing in 2012 increased the competitiveness of gas relative to coal, growing uncertainty about gas prices will likely constrain the growth in gas powered generation for several years. More generally, a projected softening in electricity demand is affecting investment horizons. The *Queensland gas market review 2012* projected little growth in gas powered generation in the state until 2020.[15] AEMO modelled in 2012 that the stimulus from the RET to invest in wind generation, combined with weaker projected energy demand, may delay a significant rise in gas powered generation until 2025.[16]

While LNG exports from Queensland are not expected to begin until 2014, the project developers are securing gas reserves to underpin supply contracts. This trend is putting pressure on domestic gas availability and prices. The 2012 Queensland review noted east coast prices are increasingly based on export opportunity value; domestic users are now competing with LNG when contracting for supply. The report also noted liquidity issues in the Queensland market, with gas in short supply for new contracts. More generally, customers seeking new domestic supply contracts for gas post-2015 are facing a lack of basic market information (forward prices, volumes available and potential delivery timeframes) for contracting.[17] The Australian Government's *Energy White Paper 2012* considered the market is not providing efficient platforms for contracting, and that such arrangements may take some time to emerge.[18]

The development of LNG projects in Queensland was widely expected in 2011 to produce 'ramp-up' gas for domestic sale at relatively low prices. Contrary to these expectations, the domestic sale of ramp-up gas has not materialised. Instead, project developers appear to be retaining reserves to preserve options for further LNG train development.[19] Additionally, EnergyQuest considered none of the projects appear to be achieving their drilling targets. The Bureau of Resources and Energy Economics noted landowners' concerns about the impact of coal seam gas (CSG) extraction on water resources have led to restrictions on drilling and tighter regulatory controls on land access.[20]

These tight market conditions may persist. The 2012 Queensland review noted a new trend for LNG proponents to enter contracts with one another, including gas swaps. Its modeling found all four LNG projects would likely experience a shortfall in their required gas reserves at some stage in the period to 2030, and would need to source gas from the broader market.[21]

Aside from developments in Queensland, other factors are affecting east coast gas markets. EnergyQuest noted a lack of recent exploration success in offshore Victoria.[22] In New South Wales, complex regulatory hurdles have hampered the development of CSG resources in the Gunnedah and Gloucester basins.[23] The New South Wales Government released its Strategic Regional Land Use Policy in September 2012, clarifying the regulatory regime for exploration and future development of the state's CSG resources.

Also, long term contract replacement is an ongoing issue; historical low priced domestic gas contracts will progressively expire over the next five years. Contract replacement activity is expected to peak in Queensland in 2015–16, and in New South Wales and Victoria in 2018. The expiration of low priced contracts and their renegotiation in a market exposed to global prices will continue to place pressure on domestic prices.[24]

Together, these factors are causing uncertainty in eastern gas markets and impacting on prices. The Bureau of Resources and Energy Economics predicted eastern gas wholesale prices will converge towards global prices in anticipation of LNG exports from 2014–15.[25] The 2012 Queensland review predicted Queensland domestic gas prices could rise to $6.50–10 per gigajoule by 2015 (depending on international energy market conditions). It predicted domestic prices of $7–12 per gigajoule in 2020. The modeling indicated a widening divergence between Queensland domestic prices and relatively lower prices in the southern states. Transportation costs will likely constrain flows of Victorian gas into Queensland, unless the gas price differential becomes sufficiently wide.

Overall, the review predicted further tightening in the gas market from 2014–15 through to 2021, when greater volumes of unconventional gas—such as shale gas from

15 Department of Energy and Water Supply (Queensland), *2012 Queensland gas market review, 2012*, pp. 25–26.

16 AEMO, Unpublished briefing to the AER, November 2012.

17 Department of Energy and Water Supply (Queensland), *2012 Queensland gas market review*, 2012, pp. 23, 27, 38.

18 Australian Government, *Energy white paper*, 2012, p. 141.

19 Department of Energy and Water Supply (Queensland), *Queensland gas market review 2012*, 2012, pp. ix, x.

20 BREE, *Gas market report*, July 2012, p. 45.

21 Department of Energy and Water Supply (Queensland), *Queensland gas market review 2012*, 2012, pp. ix, x.

22 EnergyQuest, *Energy Quarterly*, August 2012, p. 22.

23 BREE, *Gas market report*, July 2012, p. 56.

24 Department of Energy and Water Supply (Queensland), *Queensland gas market review 2012*, 2012, p. 23; BREE, *Gas market report*, July 2012, pp. 50, 66.

25 BREE, *Gas market report*, July 2012, p. iv.

the Cooper Basin and CSG from New South Wales—may become available.[26] ACIL Tasman also considered the development of shale gas may cap gas prices from around 2021.[27]

AEMO modeled in 2012 that eastern Australia has sufficient gas reserves to meet demand over the period to 2032, but that the speed of developing new reserves is crucial. It noted the relatively small volume of uncommitted proved plus probable (2P) gas reserves, combined with a large proportion of reserves being earmarked for LNG export, create challenges for domestic supply.

AEMO found a 15 per cent reduction in reserve development could cause supply shortfalls to the LNG export and domestic markets from 2016.[28] While a shortfall for LNG contract obligations could be alleviated by diverting Cooper Basin gas from the domestic market, this diversion would likely affect the New South Wales domestic market. This scenario would present opportunities to further develop CSG reserves in New South Wales (in the Gunnedah, Gloucester and Sydney basins) and expand gas pipeline capacity to transport gas to demand centres.

The *Energy White Paper 2012* identified reforms that the Australian Government is considering with state and territory governments to alleviate transitional pressures in the eastern gas market. The reforms include:

- developing a national gas supply hub trading model to enhance market transparency and reliability of supply. Energy ministers scheduled in December 2012 to consider options for implementing a trading hub market at Wallumbilla in Queensland.
- streamlining third party access to underused (but contracted) capacity on gas pipelines to enhance trading opportunities.

Alongside these reforms, the Australian Government is working through SCER to develop a nationally harmonised regulatory framework for the CSG industry; enhance understanding of the impacts of CSG development on groundwater and the environment; and develop a world class multiple use framework to promote coexistence.[29]

A.6.1 Spot gas prices

The Victorian wholesale gas market and the short term trading market in Sydney, Adelaide and Brisbane provide data on spot gas prices. While prices in all hubs tend to be higher in winter than in summer, prices above $4 per gigajoule were uncommon until winter 2012. A step change in prices occurred at this time, with monthly averages in all cities rising to $5–8 per gigajoule. Compared with July 2011, average prices in July 2012 were around 85 per cent higher in Sydney, 69 per cent higher in Adelaide and 62 per cent higher in Victoria (figure 13).

Winter gas prices peaked at $17.30 per gigajoule in Sydney (on 23 June 2012), $14.89 per gigajoule in Adelaide (on 4 July), $15.57 per gigajoule in Victoria (on 7 July) and over $8 per gigajoule in Brisbane (on several days in July). Prices began to ease during August and returned to levels below $5 per gigajoule in September 2012, but remained well above longer term averages.

The significant tightening in the contract market for gas in eastern Australia likely contributed to the price spikes in winter 2012. Also, gas powered generation increased in winter 2012, although overall gas demand was relatively stable. An outage at the BassGas production facility impacted on Victorian supply. AEMO reported gas spot prices were largely unaffected by the introduction of carbon pricing on 1 July 2012.[30]

While factors such as changes in contract positions might have flowed through to spot prices, the AER detected instances of participants rebidding their spot market offers on high price days and driving prices higher than would otherwise be the case. This behaviour was evident in both the short term trading market and the Victorian gas market. In particular, the tighter market might have enhanced opportunities for some participants to influence price outcomes through strategic bidding. This influence is indicated by significant variations between forecast and actual prices. Linked to this variation were poor quality demand forecasts by participants on a number of days.

The AER inquired into participant demand forecasts, offers and bids over the winter period, and will report on compliance issues.

26 Department of Energy and Water Supply (Queensland), *Queensland gas market review 2012*, 2012, pp. vii, 27, 37.

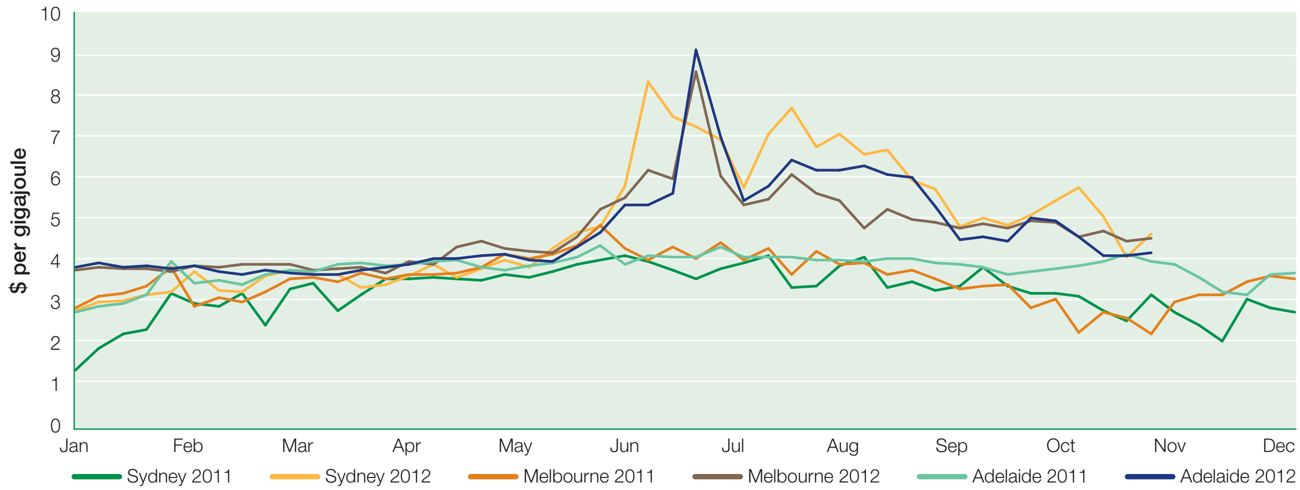
27 ACIL Tasman, 'National gas outlook: domestic gas prices and markets', Presentation by Paul Balfe*,* 30 May 2012.

28 AEMO, Unpublished briefing to the AER, November 2012.

29 Australian Government, *Energy White Paper* 2012, p.xxi.

30 AEMO, *Carbon price—market review*, 8 November 2012.

Figure 13
Spot gas prices—weekly averages



Notes:

Volume weighted ex ante prices. Sydney and Adelaide data are short term trading market prices in each hub. Melbourne prices are estimates for the metropolitan area, based on Victorian wholesale spot gas prices plus APA Group's current transmission withdrawal tariff ($0.3685 per gigajoule) for the two Melbourne metropolitan zones.

Sources: AEMO (Sydney and Adelaide); AER estimates (Melbourne).

A.7 Reforming retail energy markets

State and territory governments are progressively implementing national reforms aimed at making retail markets work more effectively. The National Energy Retail Law applies the reforms, which commenced in Tasmania and the ACT on 1 July 2012. South Australia and New South Wales announced target implementation dates of 1 February 2013 and 1 July 2013 respectively. Victoria committed to implementing the Law as soon as practicable and no later than 1 January 2014 (providing outstanding issues are resolved).

The Retail Law aims to promote retail competition and empower customers to negotiate energy contracts that suit their needs. It strengthens the position of customers in areas such as hardship, retailer failure, access to digestible market information, and disconnections.

On 1 July 2012 the AER launched the Energy Made Easy price comparator (www.energymadeeasy.gov.au) to help small customers compare energy offers available to them. The website also provides information on the energy market, energy use, and consumer rights and obligations. The price comparison function is available to customers in all jurisdictions that apply the Retail Law.

By replacing state-by-state regulation with a national approach, the Retail Law establishes consistency in matters such as compliance and enforcement, performance reporting, authorisations to sell energy (and exemptions from the requirements) and market protections if a retail business fails. Achieving national consistency in these areas will create significant efficiencies for retailers operating in multiple jurisdictions.

The Retail Law operates alongside the Australian Consumer Law to empower retail energy customers. The Australian Consumer Law, introduced on 1 January 2011, strengthened consumer protection in many areas, including in relation to door-to-door selling. While international assessments consistently rate Australian energy markets as being among the most competitive in the world, competition for new customers has intensified retailer marketing activity. Door-to-door marketing is widely used in the energy industry and accounts for more than half of all new contracts—around one million new energy contracts resulted from door-to-door marketing in 2011.[31] The use of energy switching websites has also increased.

31 Frost & Sullivan, *Research into the door-to-door sales industry in Australia*, Report for the ACCC, 2012, p. 11.

Door-to-door sales enable retailers to target regions and customers considered open to switching retailer. Additionally, outsourcing sales to door-to-door agents paid on a commission basis is less expensive than undertaking other forms of marketing. However, some door-to-door marketing practices involve aggressive sales behaviour.

The Australian Competition and Consumer Commission (ACCC) enforces the Australian Consumer Law, including its protections for customers from improper conduct by door-to-door salespeople. The provisions relate to unsolicited sales, misleading and deceptive conduct, and unconscionable conduct.

The ACCC took action in 2012 against energy retailers and energy switching sites for alleged breaches of the Australian Consumer Law. In March 2012 it filed proceedings against AGL Energy and Neighbourhood Energy, and the marketing companies engaged by them, for misleading and deceptive conduct in door-to-door selling. Also, the ACCC alleged each respondent failed to immediately leave the premises at the request of an occupier. In September 2012 the Federal Court found Neighbourhood Energy and its marketing contractor had breached the Australian Consumer Law, and it imposed penalties of $1 million. At November 2012 the AGL Energy matters were before the Federal Court.

In July 2012 the Federal Court ordered Energy Watch—a provider of energy price comparison services—to pay $1.95 million for misleading advertising. It also ordered the former chief executive officer of Energy Watch to pay $65 000 for his role in the advertisements. The advertising related to representations of the nature of the Energy Watch service and the savings that consumers would make by switching energy retailers.

Hydro Tasmania

1 NATIONAL ELECTRICITY MARKET

The National Electricity Market (NEM) is a wholesale market in which generators sell electricity in eastern and southern Australia. The main customers are energy retailers, which bundle electricity with network services for sale to residential, commercial and industrial energy users.

The market covers six jurisdictions—Queensland, New South Wales, the Australian Capital Territory (ACT), Victoria, South Australia and Tasmania—that are physically linked by an interconnected transmission network. It 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 kilometres.

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	48 311 MW
Number of registered generators	308
Number of customers	9.7 million
NEM turnover 2011–12	$6 billion
Total energy generated 2011–12	199 TWh
National maximum winter demand 2011–12	31 084 MW[1]
National maximum summer demand 2011–12	30 322 MW[2]

MW, megawatt; 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.

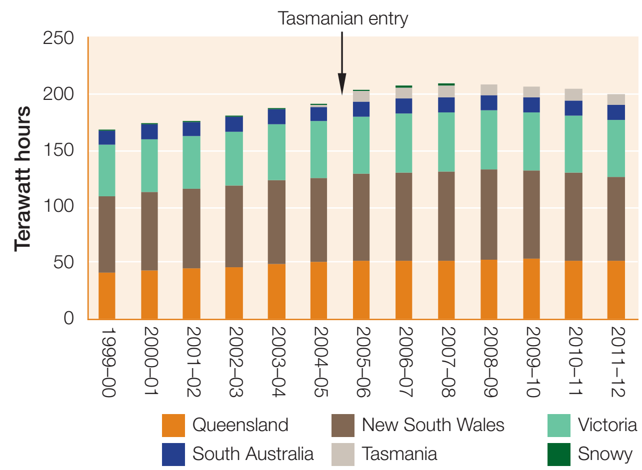
Sources: AEMO; AER.

1.1 Demand and capacity

The NEM supplies electricity to almost 10 million residential and business customers. In 2011–12 the market generated 199 terawatt hours (TWh) of electricity—a 2.5 per cent reduction from the previous year, reflecting a trend of declining energy demand since 2007–08 (figure 1.1). Energy demand has weakened as a result of:

- commercial and residential customers responding to rising electricity costs by reducing energy use and adopting energy efficiency measures such as solar water heating
- moderating rates of economic growth and weaker energy demand from the manufacturing sector
- the increasing use of rooftop solar photovoltaic (PV) generation, which is reducing demand for energy supplied through the grid by the national market.

Figure 1.1
National Electricity Market electricity demand, by region



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

Sources: AEMO; AER.

The Australian Energy Market Operator (AEMO) projected annual energy demand will be flat in 2012–13 and grow annually by around 1.7 per cent over the next decade.[1] Most of the growth is linked to major industrial projects in Queensland. The growth forecasts are significantly lower than those made 12 months ago, and the national demand forecast for 2012–13 was revised down by 8.8 per cent.

Green Energy Markets estimated rooftop PV generation and solar water heating, supported by the renewable energy target (RET) and energy efficiency schemes, accounted for 53 per cent of the reduction in energy demand since 2008.[2]

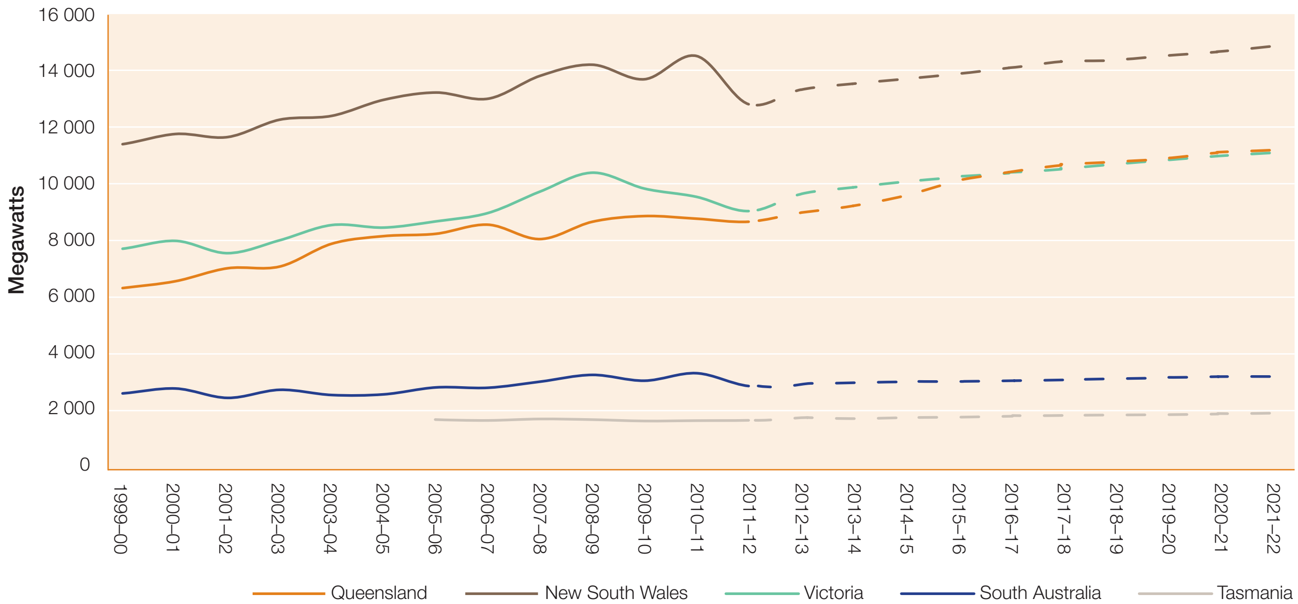
Electricity demand fluctuates throughout the day (usually peaking in early evening) and the season (peaking in winter for heating and summer for air conditioning). Over a year, demand typically reaches its zenith on a handful of days of extreme temperatures, when air conditioning (or heating) loads are highest. Peak demand rose steadily during much of the past decade, reflecting a succession of hot summers and the increasing use of air conditioners (figure 1.2a).

1 AEMO, *National electricity forecasting report 2012*, 2012, p. 3-1.

2 Green Energy Markets, *Impact of market based measures on NEM power consumption: report for the REC Agents Association and the Energy Efficiency Certificate Creators Group*, 2012.

Figure 1.2a

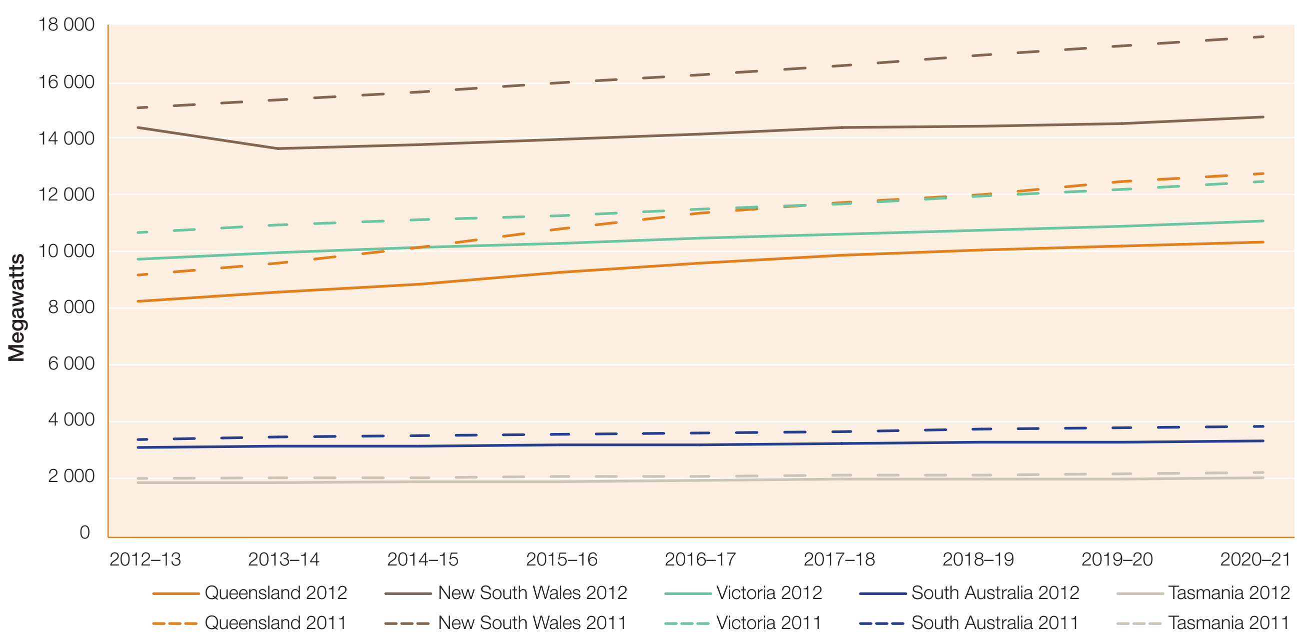
Annual actual and forecast peak demand, by region



Sources: AEMO; AER.

Figure 1.2b

Electricity peak demand, by region—2012 and 2011 forecasts



Sources: AEMO; AER.

Table 1.2 Peak demand growth, by region, 2011–12

	QLD	NSW	VIC	SA	TAS
Change from 2010–11 (%)	–1.2	–11.8	–5.3	–13.5	0.7
Change from historical peak (%)	–2.3	–11.8	–13.1	–13.5	–2.7
Peak year	2009–10	2010–11	2008–09	2010–11	2007–08

Sources: AEMO; AER.

The proportion of Australian households with air conditioning or evaporative cooling rose from 59 per cent in 2005 to 73 per cent in 2011.[3]

A mild summer, combined with the general moderation in energy demand, led to peak demand falling in most regions in 2011–12 (table 1.2). The decrease was most evident in New South Wales (down 11.8 per cent from its 2010–11 record) and South Australia (down 13.5 per cent). Peak demand in Victoria was 13 per cent lower than the state's historical peak set in 2008–09.

AEMO projected that peak demand will return to positive growth from 2012–13 in all regions, but may take several years to return to its historical peaks in New South Wales, Victoria and South Australia (figure 1.2a). More generally, current forecasts of the growth in peak demand are considerably softer than those projected 12 months ago (figure 1.2b).

Subdued electricity demand has flowed through to historically low spot prices (section 1.5). In 2012 it contributed to around 3000 megawatts (MW) of coal plant being shut down or periodically offline (section 1.2.2).

1.2 Generation in the NEM

Most electricity demand in the NEM jurisdictions is met by generators using coal, gas, hydro and wind technologies. The generators sell the energy they produce through a national market that AEMO manages. Figure 1.3 illustrates the location of the major generators in the NEM.

1.2.1 Generation technologies

A generator creates electricity by using energy to turn a turbine, making large magnets spin inside coils of conducting wire. 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 the sun or wind.

Each generation technology has unique characteristics—for example, while coal generators can require up to 48 hours to start up, gas powered and hydroelectric generation can be started relatively quickly. Wind generation relies on weather conditions, so is intermittent. Each type of generator also has significantly different carbon emissions, along with different operating cost structures.

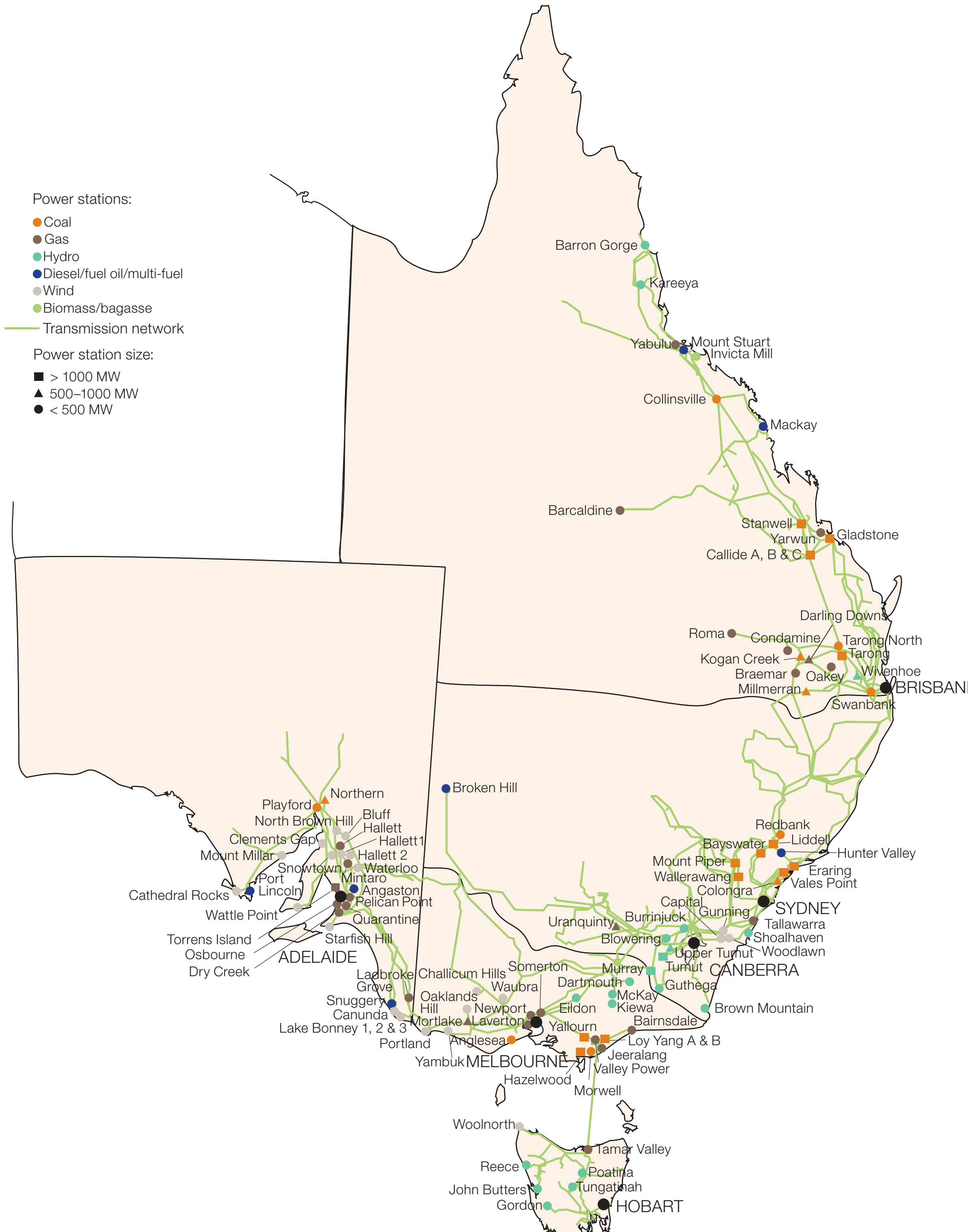
The demand for electricity is not constant, varying with the time of day, the season and the ambient temperature. A mix of generation capacity is thus needed, to respond to these demand characteristics. The mix consists of baseload, peaking, intermediate and intermittent generation.

Baseload plant, which meets the bulk of demand, tends to have relatively low operating costs but high start-up costs, making it economical to run it continuously. *Peaking* generators have higher operating costs and lower start-up costs, and are used to supplement baseload when prices are high (typically, in periods of peak demand). While peaking generators are expensive to run, they must be capable of a reasonably quick start-up because they may be called on to operate at short notice. *Intermediate* generators operate more frequently than peaking plants, but not continuously. *Intermittent* generation, such as wind and solar, can operate only when the weather conditions are favourable.

Across the NEM, black and brown coal account for 57 per cent of registered generation capacity, but this baseload plant supplies 79 per cent of output (figure 1.4). Victoria, New South Wales and Queensland rely on coal more heavily than do other regions (figure 1.5).

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

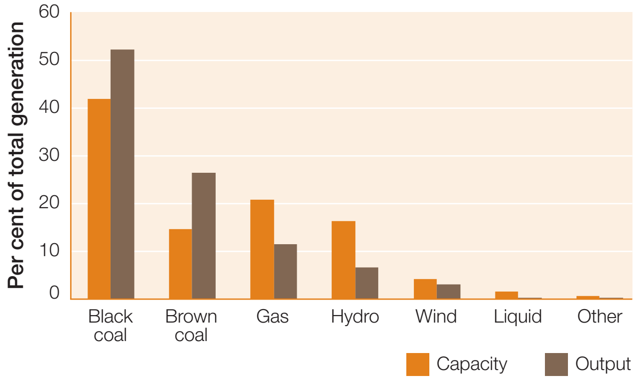
Figure 1.3
Large electricity generators in the National Electricity Market



Sources: AEMO; AER.

Figure 1.4

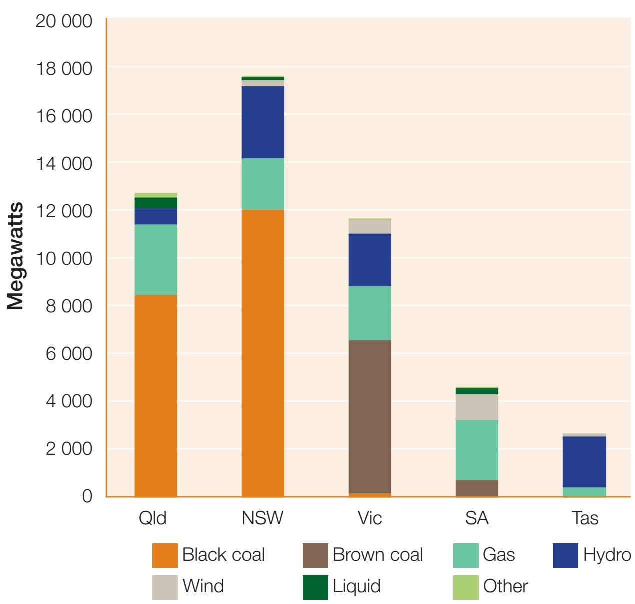
Registered generation, by fuel source, 2011–12



Sources: AEMO; AER.

Figure 1.5

Generation capacity, by region and fuel source, 30 June 2012



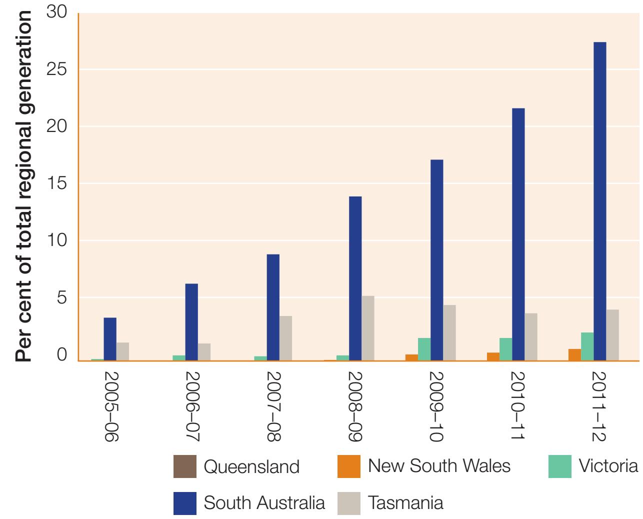
Note: New South Wales and Victoria include Snowy Hydro capacity allocated to those regions.

Sources: AEMO; AER.

Gas powered generation accounts for 21 per cent of registered capacity across the NEM but—as intermediate and peaking plant—supplies only 11 per cent of output. Among the NEM jurisdictions, South Australia is the most reliant on gas powered generation. More generally, 54 per cent of new generation investment over the past decade has been in gas plant.

Figure 1.6

Wind generation share of total generation, by region



Sources: AEMO; AER.

Hydroelectric generation accounts for 16 per cent of registered capacity but less than 7 per cent of output. The bulk of Tasmanian generation is hydroelectric. There is also hydro generation in Victoria and New South Wales (mainly Snowy Hydro).

The role of intermittent wind generation is expanding under climate change policies such as the RET (section 1.2.2). Nationally, wind generation accounts for 4 per cent of capacity and 3 per cent of output. In South Australia, however, it represents 24 per cent of capacity, and it accounted for 27 per cent of output in 2011–12 (figure 1.6).[4] On particular days, wind has accounted for up to 65 per cent of total generation in the state (and up to 86 per cent of generation for a trading interval).

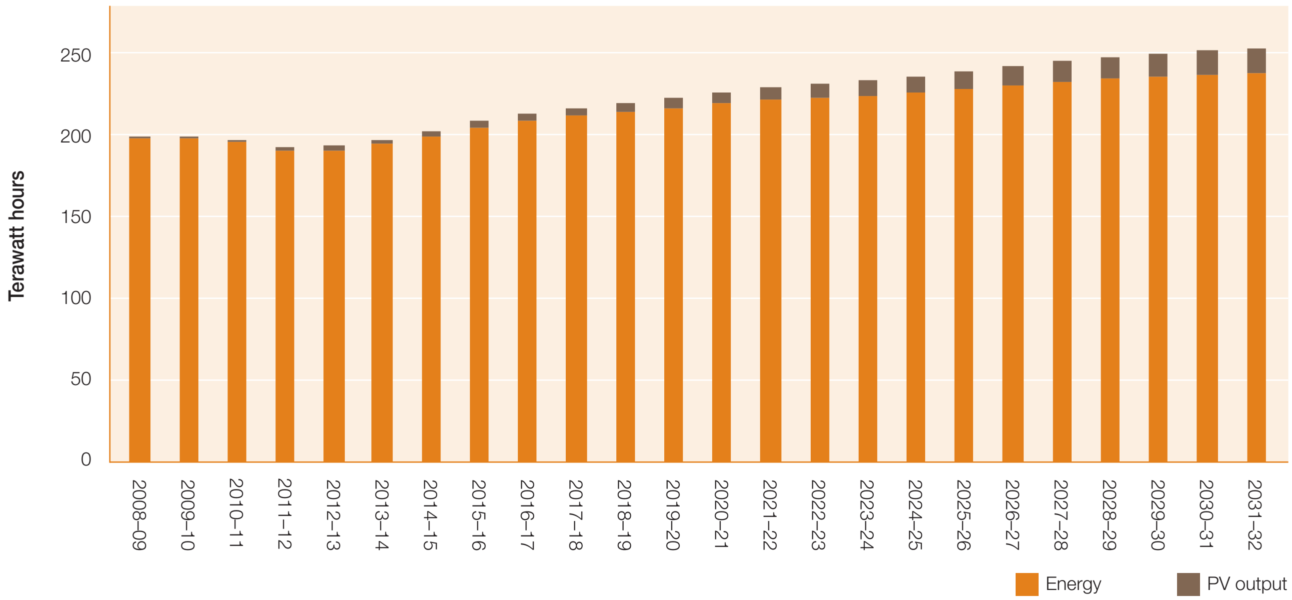
However, wind generation is generally lower at times of peak demand—on average, it contributes to less than 9 per cent of supply at any given time during summer. Yet, there is evidence that wind generation is having a moderating impact on electricity prices in South Australia; spot prices are typically higher at times of low wind.[5]

The extent of new investment in intermittent generation led to changes in how wind generation is integrated into the market. Since 31 March 2009 new wind generators greater than 30 MW have been classified as 'semi-scheduled', and they participate in the central dispatch process.

4 AEMO, *2012 South Australian electricity report*, 2012, p. 16.

5 AEMO, *South Australian wind study report*, 2012, p. 2-1.

Figure 1.7
Forecast contribution of rooftop PV generation to meeting energy demand



Data source: AEMO forecasts.

Rooftop solar generation

Climate change policies, including the RET and other subsidies for rooftop solar PV installations, led to a rapid increase in solar PV generation over the past four 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 subsidies are recovered from energy users through electricity charges.

Rooftop PV generation is not traded through the NEM market. Instead, the installation owner receives a reduction in their energy bills. AEMO measures 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 (figure 1.7).

Installed rooftop PV capacity rose from 23 MW in 2008 to around 1450 MW in February 2012.[6] The contribution of rooftop installations to annual energy requirements is expected to rise from 0.9 per cent in 2011–12 to 1.3 per cent in 2012–13. The uptake of these systems has been especially significant in South Australia, which has a higher average sunlight intensity than other NEM jurisdictions. In 2011–12 solar PV installations in South Australia generated around 306 gigawatt hours (GWh), or 2.4 per cent of the state's annual energy requirements.

The contribution of rooftop PV installations to peak demand is generally lower than rated system capacity. In the mainland regions, summer demand typically peaks in late afternoon, when rooftop PV generation is declining from its midday levels and is operating at 28–38 per cent of capacity. Maximum demand in Tasmania typically occurs on winter evenings, when rooftop PV generation is negligible.

AEMO expects the uptake of rooftop installations to flatten out until 2017, due mainly to a reduction of feed-in tariffs, but then accelerate from 2018.[7] The contribution of rooftop PV generation is forecast to rise to 3.4 per cent of the NEM's energy requirements by 2021–22; in South Australia, it is forecast to reach 6.4 per cent.[8]

1.2.2 Climate change policies

The pattern of generation technologies across the NEM is evolving in response to technological change and government policies to mitigate climate change. The electricity sector contributes around 35 per cent of national

6 AEMO, *Rooftop PV information paper*, 2012, p. iii.

7 AEMO, *Rooftop PV information paper*, 2012, p. iii.

8 AEMO, *National electricity forecasting report 2012*, 2012, pp. 3-1, 6-1.

greenhouse gas emissions, mainly due to an historical reliance on coal fired generation.[9] 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 central plank of Australia's climate change response is the carbon price introduced by the Australian Government on 1 July 2012 as part of its Clean Energy Future Plan. The plan, overseen by the newly created Climate Change Authority, targets a reduction in carbon and other greenhouse emissions to at least 5 per cent below 2000 levels by 2020 (and up to 25 per cent with equivalent international action). The central mechanism places a fixed price on carbon for three years, starting at $23 per tonne of carbon dioxide equivalent emitted. The fixed price will then be replaced by an emissions trading scheme on 1 July 2015, with the price determined by the market. The legislation to establish the scheme included transitional provisions for floor and ceiling prices. Entities would be entitled to acquit up to 50 per cent of their annual carbon liability using international emission reduction units (created through schemes set up under the Kyoto Protocol).

The Australian Government announced changes to the scheme in August 2012 that link the Australian and European Union (EU) emissions trading markets under the floating price scheme to begin in 2015. The changes will permit an Australian entity to use EU emissions allowances to meet up to 50 per cent of its carbon liability. And they will reduce to 12.5 per cent the extent to which an entity can use other international emission reduction units. The government will also abandon the carbon floor price. In effect, from 1 July 2015, the Australian carbon price will be closely linked to the price of EU allowances, which were trading at around $10 per tonne in September 2012.

The Clean Energy Future Plan includes assistance (cash and free carbon permits) for emission intensive generators, estimated at $5.5 billion. It also established the Clean Energy Finance Corporation, with access to $10 billion over five years for investment in renewable and low emissions energy.

A proposal for the Australian Government to contract for the closure of up to 2000 MW of coal fired generation by 2020 did not proceed. The government negotiated terms with the owners of five high emitting coal generators in Queensland, Victoria and South Australia, but the parties could not agree on a price.

9 Garnaut, Professor R, *The Garnaut Review 2011: Australia in the global response to climate change*, Final report of the Garnaut Climate Change Review, 2012.

The Australian Government also operates a national RET scheme, which it revised in 2011. The scheme is designed to achieve the government's commitment to 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 megawatt hour (MWh) of eligible renewable electricity that an accredited power station generates, or that eligible solar hot water or small generation units generate.

The scheme applies different arrangements for small scale and large scale renewable supply. It has a 2020 target of 41 000 GWh of energy from large scale renewable energy projects. Small scale renewable projects no longer contribute to the national target, but still produce renewable energy certificates that retailers must acquire. Since the 2011 revisions to the RET scheme, certificates from large scale projects have traded at around $35–40 (box 1.1). The price of certificates from small scale projects has been more volatile, trading at $20–33.

The Climate Change Authority was reviewing the RET scheme in 2012, including the overall target, the eligibility framework and the scheme's impact on electricity costs, prices and energy security. In a discussion paper in October 2012, it recommended retaining the form and level of the 2020 target for large scale renewable energy projects, and reviewing in 2016 the arrangements for beyond 2020. It also recommended retaining the scheme for small scale installations in its current form. The authority will consider whether the size threshold for these installations should be reduced. A final report is expected in December 2012.

Impacts of climate change policies on electricity generation

The use of black and brown coal for electricity generation peaked in 2008–09 and has since steadily declined (figure 1.9). While energy demand has also declined since 2008–09, gas powered generation rose over the past decade, reflecting new investment in all regions of the NEM. Wind generation has risen strongly, particularly since a 2007 expansion of the RET scheme increased the target and extended it to 2020.

New investment patterns are also changing. In the 10 years to June 2012, electricity generation businesses in eastern Australia invested in 4700 MW of gas powered generation capacity, compared with 750 MW of coal generation

Box 1.1 Certificate prices—renewable energy target

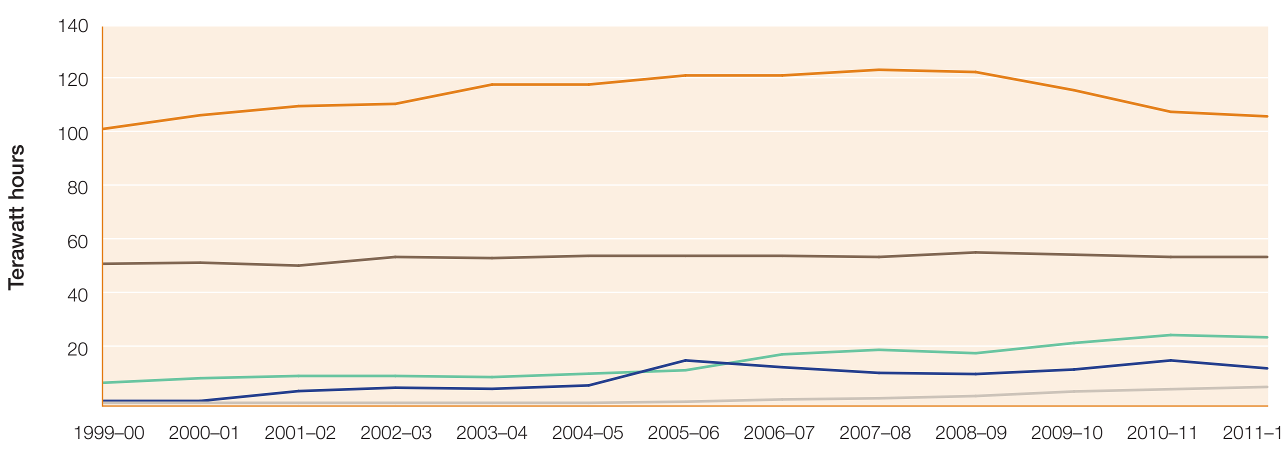
Figure 1.8 illustrates prices of *large generation certificates* (previously renewable energy certificates) issued under the RET scheme, showing prices paid per MWh of generation to wind and other qualifying renewable generators. Wind generators receive both the certificate price *and* the wholesale spot price for electricity.

Some price movements reflect scheme changes and market uncertainty about possible changes. The decline in prices in 2009 reflected a significant supply of certificates from rooftop PV and other small scale installations. It led to a change in the scheme to separate small and large generators.

Figure 1.8
Large generation certificate prices

Source: Deutsche Bank Markets Research, *Utilities meter*, 5 October 2012.

Figure 1.9
Fuel mix in energy generation, by energy source



Sources: AEMO; AER.

Table 1.3 **Generation plant shut down or offline, 2012**

BUSINESS	POWER STATION	TECHNOLOGY	SUMMER CAPACITY (MW)	PERIOD AFFECTED
QUEENSLAND				
Stanwell	Tarong (2 units)	Coal fired	700	October 2012 to at least October 2014
RATCH Australia	Collinsville	Coal fired	189	Retired
CS Energy	Gladstone	Coal fired	560	Two units not operating July–December 2012
NEW SOUTH WALES				
Delta Electricity	Munmorah	Coal fired	600	Retired
VICTORIA				
Energy Brix	Morwell Unit 3	Coal fired	70	From July 2012 until viable
Energy Brix	Morwell Unit 2	Coal fired	25	Not run since July 2012
EnergyAustralia	Yallourn (1 unit)	Coal fired	360	Offline July–December 2012
SOUTH AUSTRALIA				
Alinta Energy	Northern	Coal fired	540	April–September 2012
Alinta Energy	Playford	Coal fired	200	From March 2012 until viable

Source: AER.

capacity.[10] Kogan Creek power station in Queensland was the only major new investment in coal fired generation in that period. New investment in wind generation was also significant.

Bloomberg estimated $18 billion will be invested between 2011 and 2018 in wind energy projects, alongside $16 billion in solar PV and $400 million in solar thermal. The estimates do not account for up to $10 billion of project financing that the Clean Energy Finance Corporation may provide.[11]

There are indications that climate change policies affected the generation mix in the NEM during 2012. Notably, over 3000 MW of coal plant was shut down or periodically offline during the year (table 1.3). This reduced capacity was spread across every mainland NEM region, and did not include Victoria's 1450 MW Yallourn power station operating below capacity during winter as a result of flooding.

A number of interrelated factors—flat electricity demand, the introduction of carbon pricing and the impact of the RET in shifting generation away from coal to renewable sources—appear to have contributed to the reduction in coal capacity. Most plant owners cited low energy demand as a key factor in their decisions. The owners of Tarong (Queensland), Munmorah (New South Wales), Morwell and Yallourn (Victoria) cited climate change policies as a contributing factor.

1.2.3 Generation market structure

Private entities own the bulk of generation capacity in Victoria and South Australia, while public corporations own or control the majority of capacity in New South Wales and Queensland. The Tasmanian generation sector remains mostly in government hands. Table 1.4 lists the ownership of generation businesses. Figure 1.10 illustrates the ownership shares of the major players in each region.

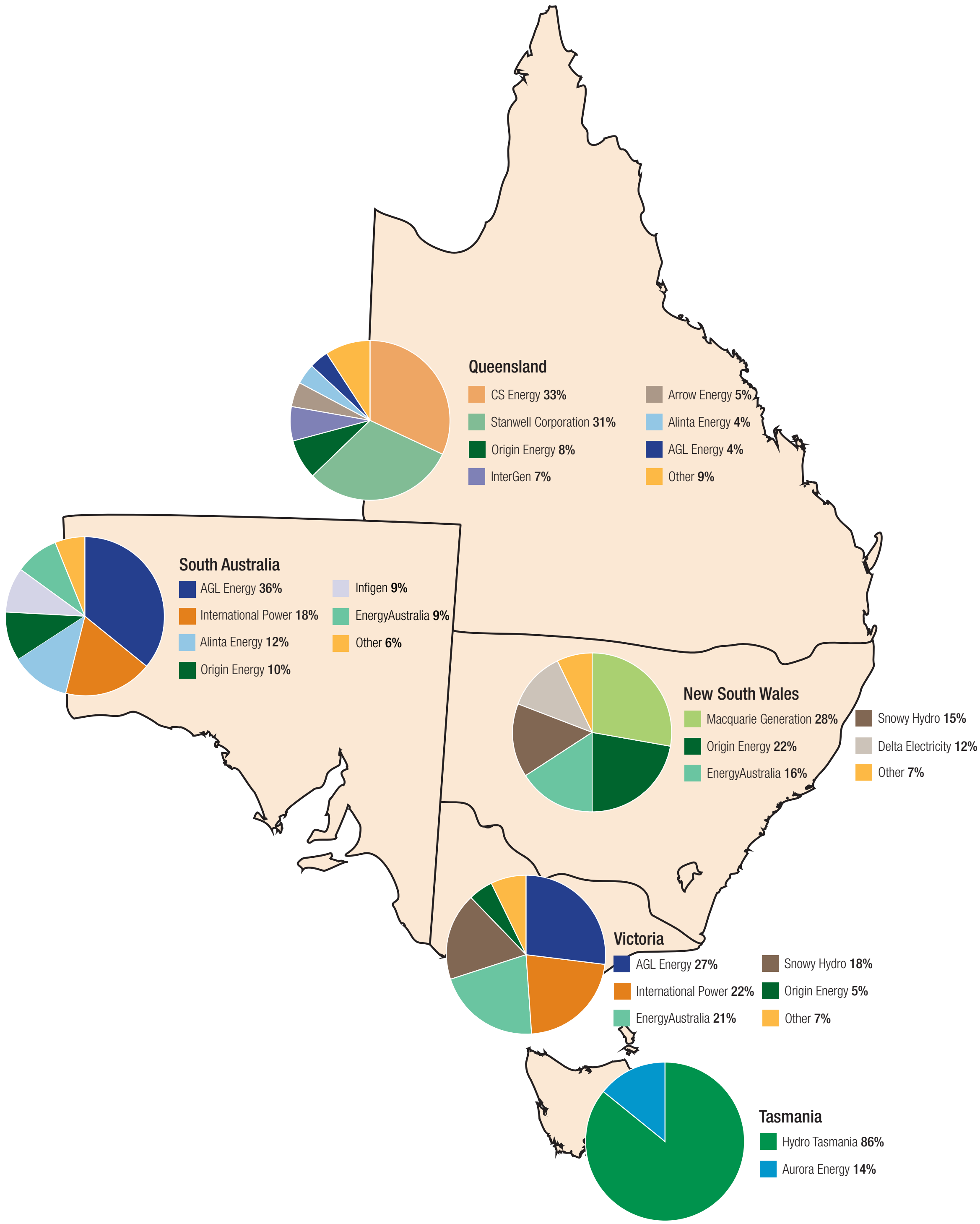
- In Victoria, three private entities are the major players: AGL Energy (27 per cent of capacity), International Power (22 per cent) and EnergyAustralia (formerly TRUenergy, 21 per cent). AGL Energy's acquisition of Loy Yang A power station in June 2012 (after previously owning a one-third minority interest) lifted its market share in Victorian generation from 5 per cent. Origin Energy commissioned new gas peaking plant at Mortlake in 2012—its first plant in Victoria. The government owned Snowy Hydro owns about 18 per cent of generation capacity, mostly comprising historical investment associated with the Snowy Mountains scheme.[12]

10 ACIL Tasman, 'National gas outlook: domestic gas prices and markets', Presentation by Paul Balfe to EUAA conference, 30 May 2012.

11 The Allen Consulting Group, *Client update: renewed energy in renewable energy*, 25 September 2012.

12 The New South Wales, Victorian and Australian governments jointly own Snowy Hydro.

Figure 1.10
Market shares in electricity generation capacity, by region, 2012



Notes:

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

Excludes power stations not managed through central dispatch.

Source: AER.

Table 1.4 Generation capacity and ownership, 2012

GENERATING BUSINESS	POWER STATIONS	CAPACITY (MW)	OWNER
NEM Regions			
QUEENSLAND	TOTAL CAPACITY	12 421	
Stanwell Corporation	Stanwell; Tarong; Tarong North; Swanbank; Barron Gorge; Kareeya; Mackay Gas Turbine; others	3 853	Stanwell Corporation (Qld Government)
CS Energy	Callide; Kogan Creek; Wivenhoe	1 954	CS Energy (Qld Government)
CS Energy	Gladstone	1 680	Rio Tinto 42.1%; NRG Energy 37.5%; others 20.4% Contracted to CS Energy
Origin Energy	Darling Downs; Mt Stuart; Roma	1 038	Origin Energy
Callide Power Trading	Callide C	900	CS Energy (Qld Government) 50%; InterGen 50%
Millmerran Energy Trader	Millmerran	856	InterGen 50% (China Huaneng Group 50%; others 50%); China Huaneng Group 50%
Arrow Energy	Braemar 2	495	Arrow Energy (Shell 50%; PetroChina 50%)
Braemar Power Projects	Braemar 1	435	Alinta Energy
AGL Hydro	Oakey	282	ERM Group 75%; Contact Energy 25% Contracted to AGL Energy
AGL Hydro	Yabulu	235	RATCH Australia Contracted to AGL Energy / Arrow Energy
RTA Yarwun	Yarwun	155	Rio Tinto Alcan
QGC Sales Qld	Condamine	144	BG Group
AGL Energy	German Creek; KRC Cogeneration; others	78	AGL Energy
Pioneer Sugar Mills	Pioneer Sugar Mill	68	CSR
EDL Projects Australia	Moranbah North	46	EDL Projects Australia
CSR	Invicta Sugar Mill	39	CSR
Ergon Energy	Barcaldine	34	Ergon Energy (Qld Government)
NEW SOUTH WALES	TOTAL CAPACITY	17 035	
Macquarie Generation	Bayswater; Liddell; Hunter Valley	4 824	Macquarie Generation (NSW Government)
Origin Energy	Eraring; Shoalhaven	3 162	Eraring Energy (NSW Government) Contracted to Origin Energy
Snowy Hydro	Blowering; Upper Tumut; Tumut; Guthega	2 564	Snowy Hydro (NSW Government 58%; Vic Government 29%; Australian Government 13%)
EnergyAustralia	Mt Piper; Wallerawang;	2 340	Delta Electricity (NSW Government) Contracted to EnergyAustralia
Delta Electricity	Vales Point B; Colongra; others	2 048	Delta Electricity (NSW Government)
Origin Energy	Uranquinty; Cullerin Range	670	Origin Energy
EnergyAustralia	Tallawarra	420	EnergyAustralia (CLP Group)
Infigen Energy	Capital; Woodlawn	188	Infigen Energy
Marubeni Australia Power Services	Smithfield Energy Facility	162	Marubeni Corporation
Redbank Energy	Redbank	145	Redbank Energy
Eraring Energy	Brown Mt; Burrinjuck; Warragamba; others	116	Eraring Energy (NSW Government)
EDL Group	Appin; Tower; Lucas Heights	108	EDL Group
AGL Hydro	Copeton; Burrendong; Wyangala; others	83	AGL Energy
Essential Energy	Broken Hill Gas Turbine	50	Essential Energy (NSW Government)
Acciona Energy	Gunning	47	Acciona Energy
Infratil Energy Australia	Hunter; Awaba	30	Infratil
VICTORIA	TOTAL CAPACITY	11 531	
AGL Energy	Loy Yang A	2 190	AGL Energy
Snowy Hydro	Murray; Laverton North; Valley Power	2 083	Snowy Hydro (NSW Government 58%; Vic Government 29%; Australian Government 13%)
International Power	Hazelwood	1 600	International Power / GDF Suez 91.8%; Commonwealth Bank 8.2%

GENERATING BUSINESS	POWER STATIONS	CAPACITY (MW)	OWNER
NEM Regions			
EnergyAustralia Yallourn	Yallourn; Longford Plant	1 511	EnergyAustralia (CLP Group)
International Power	Loy Yang B	965	International Power / GDF Suez 70%; Mitsui 30%
Ecogen Energy	Jeeralang A and B; Newport	891	Industry Funds Management (Nominees) Contracted to EnergyAustralia
AGL Hydro	Kiewa; Somerton; Eildon; Clover; Dartmouth; McKay; others	810	AGL Energy
Origin Energy	Mortlake	518	Origin Energy
Pacific Hydro	Yambuk; Challicum Hills; Portland; Codrington	265	Pacific Hydro
Acciona Energy	Waubra	192	Acciona Energy
Alcoa	Angelsea	156	Alcoa
Energy Brix Australia	Energy Brix Complex; Hrl Tramway Road	104	HRL Group / Energy Brix Australia
Alinta Energy	Bairnsdale	70	Alinta Energy Contracted to Aurora Energy (Tas Government)
AGL Energy	Oaklands Hill	63	Challenger Life Contracted to AGL Energy
SOUTH AUSTRALIA	TOTAL CAPACITY	4 392	
AGL Energy	Torrens Island	1 280	AGL Energy
Alinta Energy	Northern	546	Alinta Energy
International Power	Pelican Point; Canunda	494	International Power / GDF Suez
Synergen Power	Dry Creek; Mintaro; Port Lincoln; Snuggery	317	International Power / GDF Suez
TRUenergy	Hallet; Waterloo	309	EnergyAustralia (CLP Group)
Origin Energy	Quarantine; Ladbroke Grove	256	Origin Energy
Infigen Energy	Lake Bonney 2 and 3	182	Infigen Energy
Origin Energy	Osborne	175	ATCO 50%; Origin Energy 50%
Infratil Energy Australia	Snowtown; Pt Stanvac	147	Infratil
AGL Energy	Hallett 2; Wattle Point	135	Energy Infrastructure Trust Contracted to AGL Energy
AGL Energy	North Brown Hill	82	Energy Infrastructure Investments (Marubeni 50%; Osaka Gas 30%; APA Group 20%) Contracted to AGL Energy
Infigen	Lake Bonney 1	81	Infigen Energy Contracted to Essential Energy (NSW Government)
Meridian Energy	Mount Millar	70	Meridian Energy
EnergyAustralia	Cathedral Rocks	66	EnergyAustralia (CLP Group) 50%; Acciona Energy 50%
AGL Energy	Hallett 1	59	Palisade Investment Partner Contracted to AGL Energy
Pacific Hydro	Clements Gap	57	Pacific Hydro
Infratil Energy Australia	Angaston	50	Infratil (all contracted to AGL Energy)
Ratch Australia	Starfish Hill	35	RATCH Australia Contracted to Hydro Tasmania (Tas Government)
AGL Energy	The Bluff	33	Eurus Energy Contracted to AGL Energy
TASMANIA	TOTAL CAPACITY	2 743	
Hydro Tasmania	Gordon; Poatina; Reece; John Butters; Tungatinah; Woolnorth; others	2 355	Hydro Tasmania (Tas Government)
Aurora Energy Tamar Valley	Tamar Valley; Bell Bay	386	Aurora Energy (Tas Government)
Woolnorth	Woolnorth	140	Shenhua Clean Energy 75%; Hydro Tasmania 25%

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

Note: Capacity as published by AEMO for summer 2012–13, except for wind farms (registered capacity).

Sources: AEMO; AER.

- In South Australia, AGL Energy is the dominant generator, with 36 per cent of capacity. Other significant entities are International Power (18 per cent), Alinta (12 per cent), Origin Energy (10 per cent), EnergyAustralia and Infigen (9 per cent each).
- In New South Wales, state owned corporations own around 90 per cent of generation capacity. In 2011 the New South Wales Government sold the electricity trading rights to around one-third of state owned capacity to TRUenergy (rebranded in 2012 as EnergyAustralia) and Origin Energy. Following the sale, control over the dispatch of state owned plant is now split between the government entities Macquarie Generation (28 per cent) and Delta Electricity (12 per cent), and the private entities EnergyAustralia (16 per cent) and Origin Energy (22 per cent).

  In September 2012, the New South Wales Government announced a scoping study was underway on the proposed privatisation of its remaining state owned generation assets. As in Victoria, Snowy Hydro also has market share in generation (15 per cent).
- In Queensland, state owned corporations Stanwell and CS Energy control around 63 per cent of generation capacity, including power purchase agreements over privately owned capacity (such as the Gladstone power station).
- In Tasmania, state owned corporations own nearly all generation capacity. The market is highly concentrated, with Hydro Tasmania owning 86 per cent of capacity. The Tasmanian Government in 2012 announced it would establish regulatory control over Hydro Tasmania's wholesale market activity (section 1.5.4).

1.2.4 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. Section 5.2 of the retail chapter details vertical integration in the NEM. In summary, the three leading retailers—AGL Energy, Origin Energy and EnergyAustralia, which jointly supply 76 per cent of retail electricity customers—increased their market share in generation from 11 per cent in 2007 to 35 per cent in 2012. The increase reflects the commissioning of Origin Energy's Mortlake power station and AGL Energy's acquisition of Loy Yang A in Victoria in 2012 (after previously having a one-third minority interest).

The three retailers control around 58 per cent of new generation capacity commissioned or committed in the NEM since 2007. Additionally, many new entrant retailers are vertically integrated with generators—for example, International Power (Simply Energy), Infratil (Lumo Energy), Alinta (Neighbourhood Energy) and Snowy Hydro (Red Energy).

1.3 How the market operates

Generators in the NEM sell electricity through a wholesale spot market in which changes in supply and demand 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 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 bid at 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 bids being in 'good faith'. In rebidding, a generator may alter supply quantities at each price level, but cannot alter prices.

Generator offers are affected by a range of factors, including plant technology. Coal fired generators, for example, need to ensure their plants run constantly to cover their high start-up costs, and they may offer to generate some electricity at low or negative prices to guarantee dispatch.[13] Gas powered generators face higher operating costs and normally offer to supply electricity only when prices are high.

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 market power in particular regions and periodically offer capacity at above competitive prices, knowing that capacity must be dispatched if regional demand exceeds a certain level. This type of behaviour most commonly occurs at times of peak demand, often accompanied by generator outages or network constraints. More recently, some generators have periodically used strategic bidding to drive negative prices. The Australian Energy Regulator (AER) is monitoring this behaviour to ascertain whether it raises market power issues.

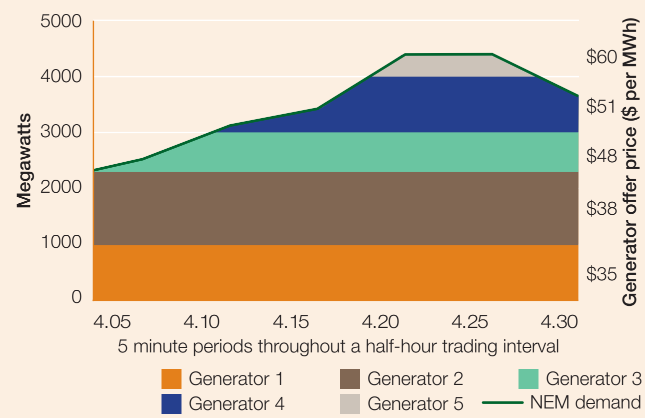
13 The price floor equals –$1000 per MWh.

Box 1.2 Setting the spot price

Figure 1.11 illustrates a simplified bid stack in the NEM between 4.00 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 1.12, 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 1.11
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 they bid (box 1.2).[14]

The market allows spot prices to respond to movements in the supply–demand balance. Rising prices create signals for demand side response and, in the longer term, new generation investment.

Spot prices may range between a floor of –$1000 per MWh and a cap of $12 900 per MWh (raised from $12 500 per MWh on 1 July 2012). The cap is increased annually to reflect changes in the consumer price index. The Australian Energy Market Commission (AEMC) can further change the cap through its reviews of reliability standards and other market settings (section 1.9).

The market sets a separate spot price for each of the five NEM regions. Price separation in 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 all other times, prices align across regions, except for minor price disparities due to physical losses in the transport of electricity over long distances. Allowing for these transmission losses, prices across the mainland regions of the NEM were aligned for about 70 per cent of the time in 2011–12, compared with 61 per cent in 2010–11. But the periods of misalignment pose significant issues (section 1.4).

14 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).

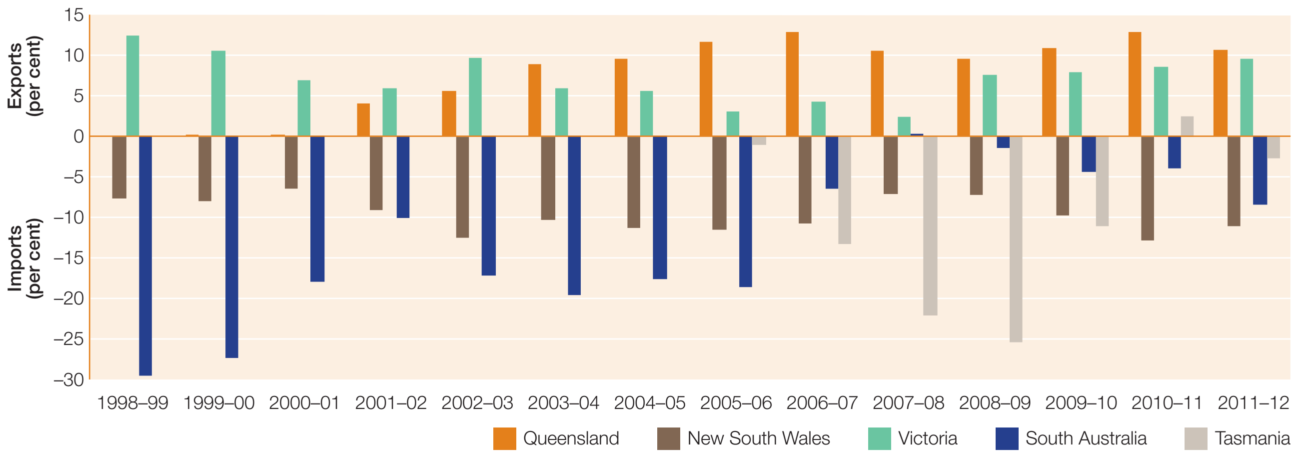
1.4 Interregional trade

The NEM promotes efficient generator use by allowing electricity trade among the five regions, which transmission interconnectors link (figure 1.3). Trade enhances the reliability of the power system by allowing each region to draw on a wider pool of reserves to manage generator outages. It also allows high cost generating regions to import electricity from lower cost regions. The technical capabilities of cross-border interconnectors set an upper limit on interregional trade. At times, network congestion constrains trading levels to below nominal interconnector capabilities.

Figure 1.12 shows the net trading position of the five regions:

- Victoria has substantial low cost baseload capacity, making it a net exporter of electricity. Its net exports have grown steadily since 2008–09.

Figure 1.12
Interregional trade as a percentage of regional energy demand



Sources: AEMO; AER.

- Queensland's installed capacity exceeds the region's peak demand for electricity, making that state a significant net exporter.
- New South Wales 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. While new investment in wind generation has significantly increased exports during low demand periods, the temporary or longer term shut down of some baseload plant in 2012 caused a rise in net imports.
- Tasmania is typically a net importer of electricity. Its trade dependence was particularly high in 2007–09, when drought affected the region's hydrogeneration.

There is evidence that network congestion is affecting interregional trade, constraining the market from exporting electricity from lower to higher price regions (box 1.3). When spot prices between adjacent regions differ by more than $100 per MWh, trade across some interconnectors is significantly below nominal capacity. For example, while the import links into New South Wales have a nameplate capacity of over 3000 MW (equivalent to almost 20 per cent of the state's generation capacity), network congestion constrains import capacity to about 700 MW at times of high prices. On some interconnectors, power is flowing in the reverse direction to what prices would suggest—that is, electricity is flowing from high price to low price regions. These issues are also influencing risk management arrangements for interregional trade (see box 1.3).

1.5 Spot electricity prices

The Australian Energy Regulator (AER) monitors the spot market and reports weekly on activity. It also publishes detailed analyses of extreme price events. Figure 1.14 provides a snapshot of weekly prices since 2009. Figure 1.15 charts quarterly volume weighted average prices in each region, while table 1.6 sets out annual prices.

Prices across most regions peaked during 2006–08, when drought constrained the availability of water for hydrogeneration and cooling in coal generation. This period coincided with escalating peak and average demand for electricity. Additionally, the AER noted evidence of the periodic exercise of market power affecting spot prices, particularly by AGL Energy in South Australia between 2008 and 2010.[15]

1.5.1 The market in 2011–12

After easing in 2010–11, spot electricity prices fell further in most regions in 2011–12. Queensland and South Australia recorded their lowest average spot price since the NEM commenced, and prices elsewhere were near record low levels. All regional averages were record lows in real terms.

15 AER, *Submission on draft determination—potential generator market power in the NEM*, 1 August 2012. The AER also reported on this behaviour in its weekly electricity market reports.

Box 1.3 Network congestion, disorderly bidding and interregional trade

In theory, generators can offer contracts to customers in other regions—for example, a Victorian generator might contract to sell power to a South Australian retailer at a fixed price. Such arrangements offer price certainty and strengthen competition and liquidity in contract markets.

But little interregional contracting is occurring because it poses significant risks. While AEMO pays a generator at the spot price in the region in which it operates, retailers pay the price in the region in which they are based. If spot prices are misaligned across the regions, then one party may be at serious financial risk.

In theory, parties to interregional contracts can reduce their exposure to price misalignment by purchasing a share of *settlement residues* that accrue across regions. The residues are a pool of funds equal to the difference between the price paid in an importing region and the price received in the generating region, multiplied by the amount of electricity flow. Electricity typically flows from lower to higher priced regions, resulting in positive residues that accrue initially to AEMO in the market settlement process. AEMO then holds quarterly auctions to sell the rights to future residues up to three years in advance.[16]

Participants can bid for a share of the residues on any cross-border interconnector. The residues can then be used to manage interregional trading risks when prices diverge across regions. Participants make their own assessments of the likely price divergence between two adjacent regions, which feeds into the value of the auction proceeds.

Network congestion affecting interconnector flows can distort the effectiveness of settlement residues as a hedge instrument. In particular, AEMO may need to manage a congestion issue by 'constraining off' a generator to protect the security of energy supply. In turn, the generator may try to avoid this scenario and ensure it gets dispatched by rebidding its capacity at prices below its underlying costs. In some cases, this 'disorderly bidding' can reduce the import capability of an interconnector or result in electricity flowing counter price, reducing the amount of residues available to participants.

An AER study found, when spot prices diverge between adjacent regions, trade across some interconnectors is counter price—electricity flows from high to lower priced regions (table 1.5). The study found when Queensland prices are at least $100 per MWh higher than those in New South Wales, power typically flows counter price *into* New South Wales, causing *negative* settlement residues. This scenario typically occurs when network congestion around Gladstone in central Queensland encourages disorderly generator bidding.

Similar issues have occurred across the Victoria–New South Wales interconnectors (especially in 2009–10) when disorderly bidding by Snowy Hydro (which owns generation on both sides of the border) has caused counter price flows northwards at times, and southwards at other times.

The incidence of counter price flows is reducing the residues returned to participants that purchase them at auction, and causing lower auction proceeds. This development reflects the reduced market valuation of this hedge mechanism, and is most evident for trade flows from New South Wales to Queensland (figure 1.13).

Table 1.5 Interregional settlement residues when prices diverge by more than $100 per MWh

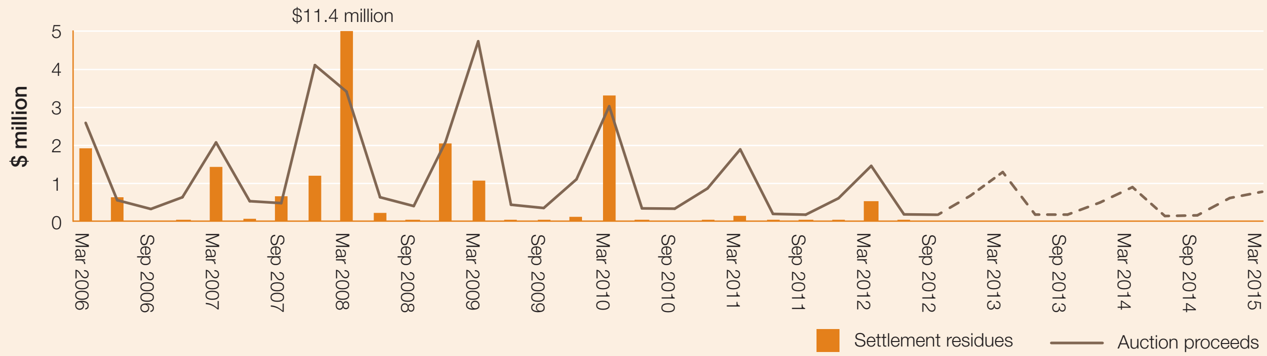
	2009–10		2010–11		2011–12	
RELATIVE REGIONAL SPOT PRICES	POSITIVE RESIDUES ($'000)	NEGATIVE RESIDUES ($'000)	POSITIVE RESIDUES ($'000)	NEGATIVE RESIDUES ($'000)	POSITIVE RESIDUES ($'000)	NEGATIVE RESIDUES ($'000)
Qld > NSW	3 821	857	172	5 775	559	7 318
NSW > Qld	63 218	2 418	60 025	1 190	15 194	2
NSW > Vic	75 977	7 329	50 148	168	14 717	1 765
Vic > NSW	14 371	20 861	873	2 907	742	37
SA > Vic	74 114	608	26 923	147	12 153	517

Source: AER.

16 Negative residues are funded by transmission network businesses and passed on to customers in the importing region.

Figure 1.13

Settlement residues and auction proceeds—trade from New South Wales to Queensland



Source: AER.

A number of workstreams are in place to mitigate issues of congestion, counter price flows and disorderly bidding in the NEM. The AEMC's continuing Transmission Frameworks Review recommended changes to the settlement arrangements for generators located at mispriced connection points, through an optional firm access package.

The model aims to increase the firmness of interconnector availability to improve energy contract liquidity and competition. The issues are complex and reform may take considerable time to implement.

Table 1.6 Volume weighted average spot electricity prices ($ per megawatt hour)

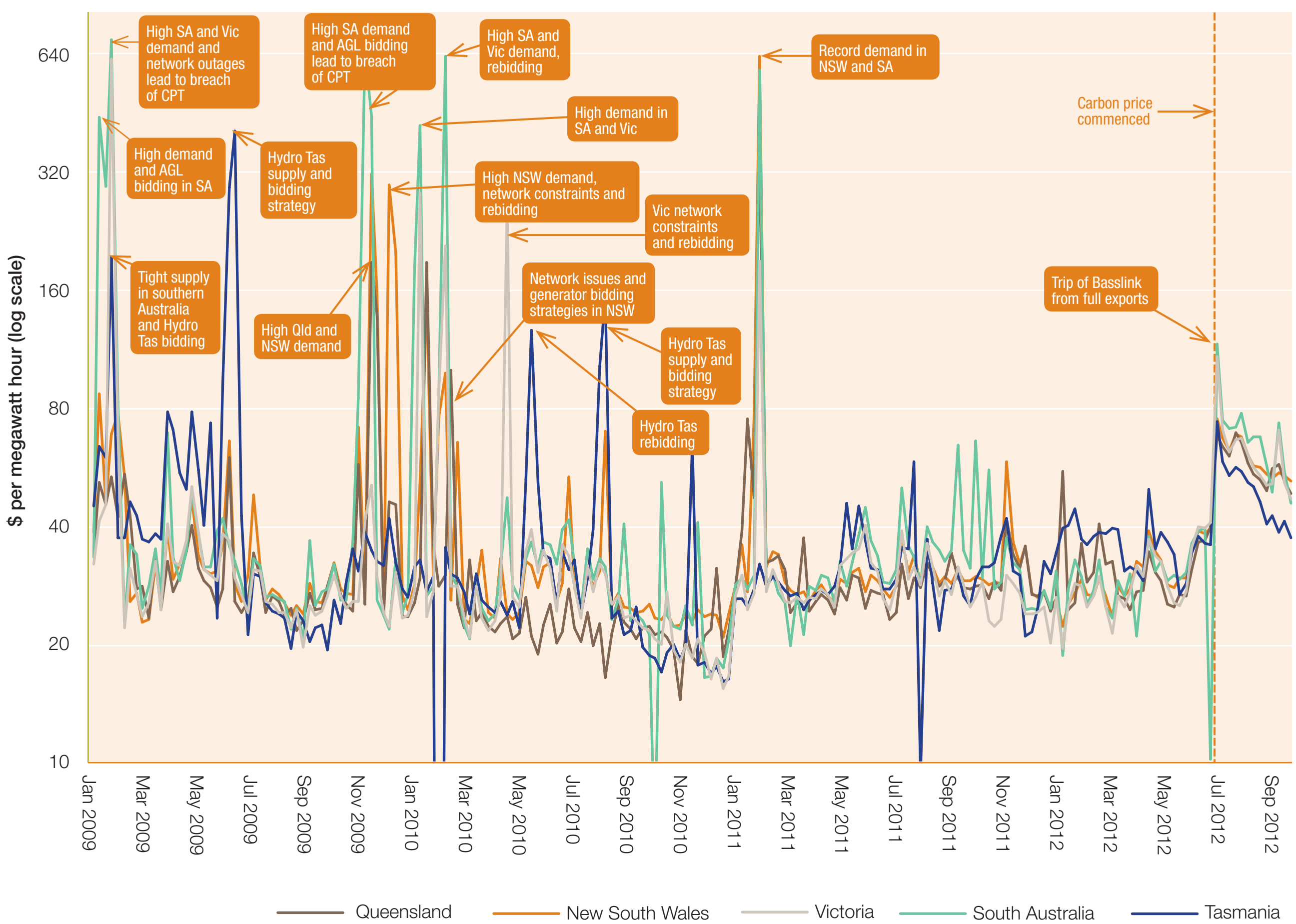
	QLD	NSW	VIC	SA	TAS[2]	SNOWY[3]
2011–12	30	31	28	32	33	
2010–11	34	43	29	42	31	
2009–10	37	52	42	82	30	
2008–09	36	43	49	69	62	
2007–08	58	44	51	101	57	31
2006–07	57	67	61	59	51	38
2005–06	31	43	36	44	59	29
2004–05	31	46	29	39		26
2003–04	31	37	27	39		22
2002–03	41	37	30	33		27
2001–02	38	38	33	34		27
2000–01	45	41	49	67		35
1999–2000	49	30	28	69		24
1999[1]	60	25	27	54		19

1. Six months to 30 June 1999.
2. Tasmania entered the market on 29 May 2005.
3. The Snowy region was abolished on 1 July 2008.

Sources: AEMO; AER.

Figure 1.14

Weekly spot electricity prices



CPT, cumulative p rice threshold.

Note: Volume weighted average prices.

Source: AER.

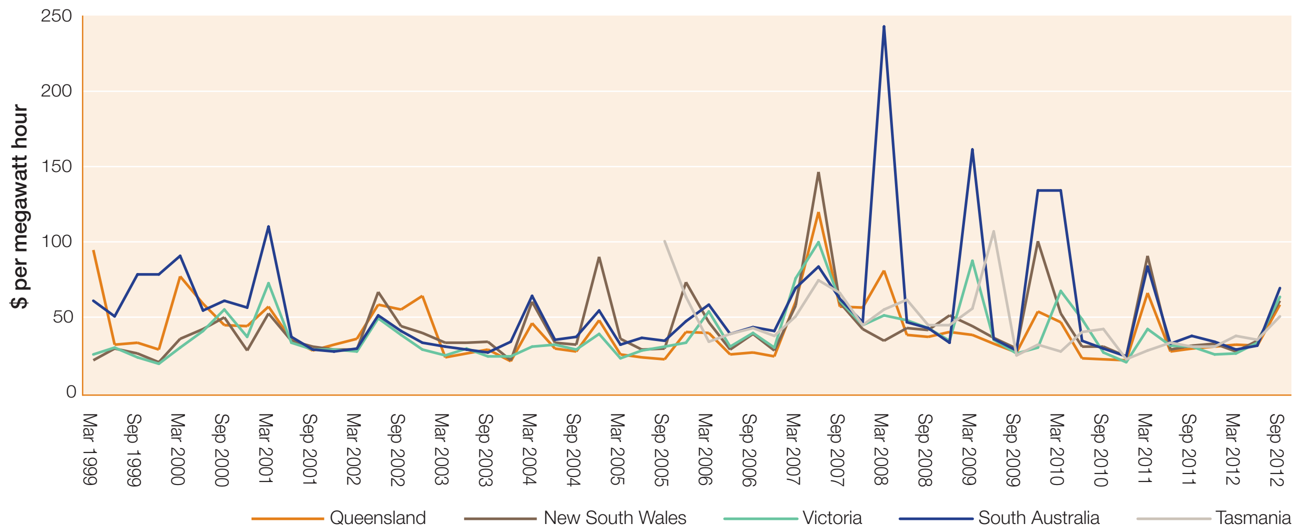
Average prices fell for the second consecutive year in all mainland regions, with the sharpest reductions occurring in New South Wales (down $12 per MWh) and South Australia (down $10 per MWh). Significant market alignment was also (down $10 per MWh). Significant market alignment was also evident, with average prices ranging from $28 per MWh (Victoria) to $33 per MWh (Tasmania). The small spread in average spot prices was reflected in the mainland market being aligned for 70 per cent of the time in 2011–12.

Low average prices in 2011–12 were mirrored in the small number of very high prices (figure 1.16). Across the NEM, the spot price exceeded $2000 per MWh on 16 occasions, and exceeded $5000 per MWh on only one occasion (when a combination of network issues, generator outages and rebidding caused the New South Wales spot price to reach $6498 per MWh on 9 November 2011).[17] The number of spot prices above $5000 per MWh was the lowest since the commencement of the NEM. Similarly, Victoria's maximum spot price ($133 per MWh) was its lowest since the NEM commenced.

17 One price event above $5000 per MW also occurred in an ancillary services market, when a process failure led to a commissioning test of the Mortlake generator during a planned network outage in Victoria. The test thus created a large requirement for local frequency control ancillary service in South Australia. The cost to South Australian customers was $3.9 million, compared with less than $3000 on a typical day.

Figure 1.15

Quarterly spot electricity prices

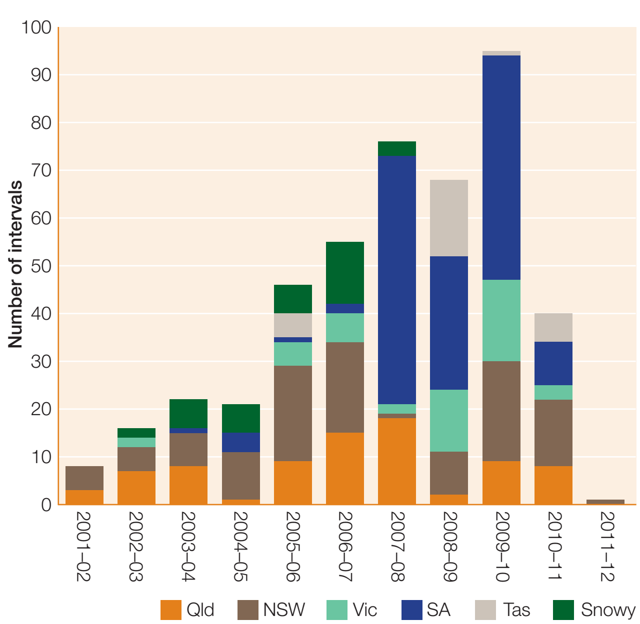


Note: Volume weighted average prices.

Sources: AEMO; AER.

Figure 1.16

Trading intervals above $5000 per megawatt hour



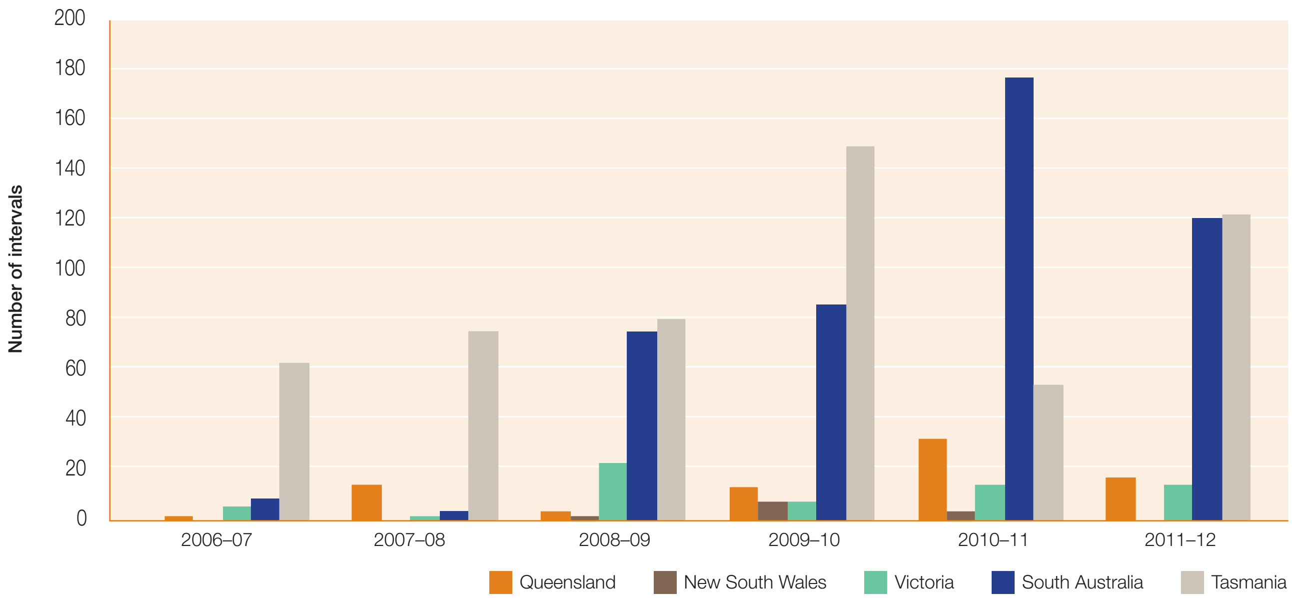
Note: Each trading interval is a half hour.

Sources: AEMO; AER.

A number of demand related factors contributed to lower spot prices. In particular, electricity demand fell by 2.5 per cent in 2011–12, continuing a trend of declining energy use since 2007–08. It reflects weaker demand from the manufacturing sector; the increasing use of rooftop PV generation; and customers responding to rising electricity costs by adopting energy efficiency measures such as solar water heating. Additionally, consecutive summers of below average temperatures capped peak demand by reducing the use of air conditioners (section 1.1). This latter factor helps explain the near absence of extreme prices.

Also contributing to low average spot prices were the 274 negative prices recorded during the year, mostly in Tasmania and South Australia (figure 1.17). The rising incidence of negative spot prices in the past few years can be partly explained by the increasing use of wind generation. Wind generators bid low and often at slightly negative prices to ensure dispatch, because they receive the value of renewable energy certificates in addition to spot market returns. But all instances of South Australian and Tasmanian prices that were *significantly* below zero (including prices at or near the –$1000 market floor) were associated with strategic generator bidding or rebidding. The AER analyses spot prices below –$100 per MWh in its weekly market reports.

Figure 1.17
Negative spot prices



Sources: AEMO; AER.

While average prices were low, price volatility was evident in some regions. Aside from the strategic generator bidding in South Australia and Tasmania, network congestion caused volatility in the Queensland market over summer (section 1.5.5).

1.5.2 Introduction of carbon pricing

The carbon price established under the Australian Government's Clean Energy Future Plan took effect on 1 July 2012 (section 1.2.2). It was introduced at $23 per tonne. Electricity generators are required to purchase and surrender carbon permits to offset their emissions, which increases their operating costs. This cost increase was expected to flow through to generator offers and electricity spot prices.

Market expectations were that the introduction of carbon pricing would increase average spot electricity prices by around $20 per MWh. This expectation was evident from electricity futures prices for the third quarter 2012. But the initial price change was much greater, with average spot prices in the week 1–7 July 2012 ranging from $38 to $84 per MWh above 2011–12 average prices (in New South Wales and South Australia respectively). The average spot price across the NEM rose from $37 per MWh in June 2012 to $67 per MWh in July 2012.

Aside from carbon pricing, various factors contributed to these outcomes—fuel supply and non-carbon related cost issues, plant outages, reasonably strong demand and low wind output. Additionally, network outages contributed to the price peaks in early July. More generally, spot prices in July were coming off very low bases in 2011–12. Nonetheless, the price rises are difficult to reconcile with those factors alone. In particular, a number of generators raised their offer prices above the levels required to adjust for the carbon intensities of their plant.

Spot prices moderated over the following weeks and continued to ease into spring 2012. By mid-October, the volume weighted average spot price in the NEM (filtered for extreme price events) since the introduction of carbon pricing was in line with market expectations—around $21 per MWh above the average price for June 2012.[18]

1.5.3 Market focus—South Australia

AGL Energy's strategic withholding of generation capacity contributed to average spot prices in South Australia being significantly above those in other NEM regions between 2007–08 and 2009–10. Prices in the state fell significantly in 2010–11, then aligned with prices in other regions in 2011–12.

18 AEMO, *Carbon price—market review*, 8 November 2012.

South Australia's annual average spot price ($32 per MWh) in 2011–12 was the state's lowest since the NEM commenced. Consistent with other regions, flat growth in energy consumption and lower peak demand (due to mild weather) contributed to this outcome.

The spot price in South Australia did not exceed $5000 per MWh at any time in 2011–12. It exceeded $2000 per MWh on nine occasions, with the highest price of $3956 per MWh recorded on 21 October 2011. Most of the high price events were associated with AGL Energy rebidding capacity to near the price cap, often near the time of dispatch.

Additionally, South Australia in 2011–12 recorded its second consecutive year of at least 100 negative spot price events: it recorded 177 negative price events in 2010–11 and 120 in 2011–12. The frequency and magnitude of negative spot prices contributed to South Australia's lower average prices in the past two years. During the week of 24–30 June 2012, the state had 24 negative spot prices lower than –$100 per MWh, including 15 events below –$600 per MWh.

Wind generators bid low and sometimes slightly negative prices, given they earn the value of renewable energy certificates (in addition to spot market returns) to cover costs. For this reason, South Australian wind generation is contributing to lower spot prices for the state. But all instances of prices below –$100 per MWh (including those near the –$1000 per MWh market floor) were driven by AGL Energy bidding or rebidding large amounts of capacity to prices near the floor at times of low demand. On several occasions, this effectively shut down other generators (including wind generators).[19] This type of disorderly market activity can have detrimental longer term consequences for market stability and investment.

1.5.4 Market focus—Tasmania

Tasmania recorded the highest average spot price of all regions in 2011–12, and was the only region in which average spot prices were higher than in 2010–11. Hydro Tasmania continued to influence spot prices during 2011–12 by periodically withdrawing low priced capacity from the market, typically at times of low demand. At other times it engaged periodically in strategic behaviour to drive negative prices.

In 2010 the Tasmanian Government established the Electricity Supply Industry Expert Panel to review the state's electricity supply industry. The panel's final report in March 2012 found the current market structure allows Hydro Tasmania to control regional spot prices, posing a barrier for new entrant retailers. The report proposed major industry reforms, including restructuring Hydro Tasmania's trading functions into three new state owned entities.

The Tasmanian Government in May 2012 responded to the report by announcing major reforms affecting every segment of the industry. It decided on a regulatory solution to address Hydro Tasmania's market power, rather than following the panel's recommendation to restructure the entity. From 1 July 2013, the Office of the Tasmanian Economic Regulator will regulate Hydro Tasmania's wholesale market activities. Tasmanian contract prices will be set by reference to Victorian contract prices, which reflect the opportunity cost of Hydro Tasmania selling into an alternative market.[20]

1.5.5 Market focus—Queensland

Queensland spot electricity prices during summer 2011–12 were periodically volatile, with over 70 spot prices exceeding $100 per MWh between 1 December 2011 and 31 March 2012 (including two prices above $2000 per MWh). Typically, the events were of very short duration. Sixteen negative spot prices (including three *below* –$100 per MWh) followed the short duration high prices. Counter price exports from Queensland into New South Wales occurred during each high price event. Similar incidents of market volatility occurred in August–October 2012.

Initially, the price volatility coincided with the onset of summer and higher energy demand. In January, unexpected changes in the rating of transmission lines in central Queensland (connecting the Gladstone, Stanwell and Callide power stations) led to network congestion, which constrained the use of cheap generation both within and outside Queensland. The bidding behaviour of certain generators, aimed at influencing spot prices, exacerbated network congestion and contributed to market volatility.

Spot price volatility causes market uncertainty and the inefficient dispatch of generation. The incidence of counter price export flows also poses difficulties for retailers and smaller generators seeking to hedge against volatility, especially across regions through settlement residue auctions. Disorderly market activity of this nature can deter new entry and investment in both the generation and retail sectors (box 1.3).

19 The AER analyses spot prices below –$100 per MWh in its weekly market reports. See, for example, weekly reports for 1–7 April 2012 and 22–28 April 2012.

20 Department of Treasury and Finance (Tasmania Government), *Energy for the future: reforming Tasmania's electricity industry*, May 2012.

1.5.6 Rule change proposal on market power

In June 2012 the AEMC published a draft determination on an Electricity Rule change request by Major Energy Users in relation to generators' potential exercise of market power in the NEM. The proponent argued some large generators have the ability and incentive to use market power to increase wholesale electricity prices during periods of high demand. The proposed Rule change would require 'dominant' generators, as determined by the AER, to offer their entire capacity at times of high demand at a price of no more than $300 per MWh.

The AEMC's draft determination found insufficient evidence of the exercise of market power. In its August 2012 submission on the draft, the AER encouraged the AEMC to broaden the range of evidence and analytical tools for assessing market power in the NEM.[21] On 30 August 2012 the AEMC extended the timing of its final determination to 11 April 2013.

1.6 Electricity futures

Volatility in electricity spot prices can pose significant risk for market participants. While generators risk low spot prices affecting earnings, retailers face a complementary 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 that they intend to produce or buy in the future. 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
- the exchange traded market, in which electricity futures products developed by d-cyphaTrade are traded on the ASX. Participants—including generators, retailers, speculators (such as hedge funds), banks and other financial intermediaries—buy and sell futures contracts.

The terms and conditions of OTC contracts are confidential between the parties. Exchange trades are publicly reported, giving rise to greater market transparency than does OTC contracting. 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* (called *contracts for the difference* or *swaps* 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 both as 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.

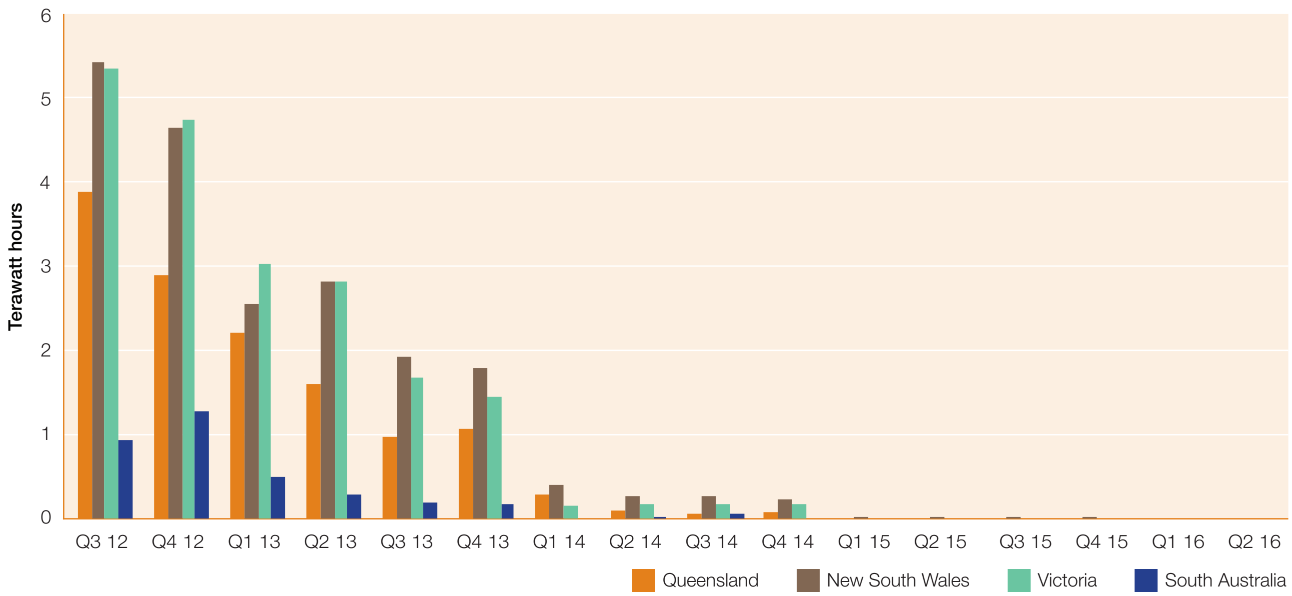
The complex financial relationships between generators, retailers and other businesses create financial interdependency, meaning financial difficulties for one participant can affect others. In November 2012 the AEMC released an options paper on ways to mitigate risk from the financial distress or failure of a large electricity retailer. The paper is the first stage of the AEMC's advice to the Standing Council on Energy and Resources on the resilience of financial markets underpinning the NEM.[22]

21 AER, *Submission on draft determination—potential generator market power in the NEM*, 1 August 2012.

22 AEMC, *NEM financial market resilience*, Options Paper, 9 November 2012.

Figure 1.18

Open interest in electricity derivatives on the ASX, 1 July 2012



Source: d-cyphaTrade.

The Australian Government in 2012 was progressing reforms to implement Australia's G20 commitments in relation to OTC derivatives. The reforms include the reporting of OTC derivatives to trade repositories. They also include obligations on the clearing and execution of standardised derivatives. Some reforms could potentially capture OTC electricity derivatives.

1.6.1 Electricity futures trading on the ASX

Electricity futures trading on the ASX covers instruments for Victoria, New South Wales, Queensland and South Australia. Trading volumes in 2011–12 were equivalent to 231 per cent of underlying energy demand, down from 285 per cent in 2010–11. New South Wales accounted for 38 per cent of traded volumes, followed by Victoria (32 per cent) and Queensland (27 per cent). Liquidity in South Australia is low, accounting for only 3 per cent of volumes.

The most heavily traded products in 2011–12 were base futures (55 per cent of traded volumes), followed by options (32 per cent), $300 cap futures (10 per cent) and peak futures (3 per cent). Liquidity is mostly in products traded 18–24 months out—for example, open interest in forward contracts at 1 July 2012 was mostly for quarters to the end of 2013, with little liquidity into 2014 (figure 1.18).

Forward prices

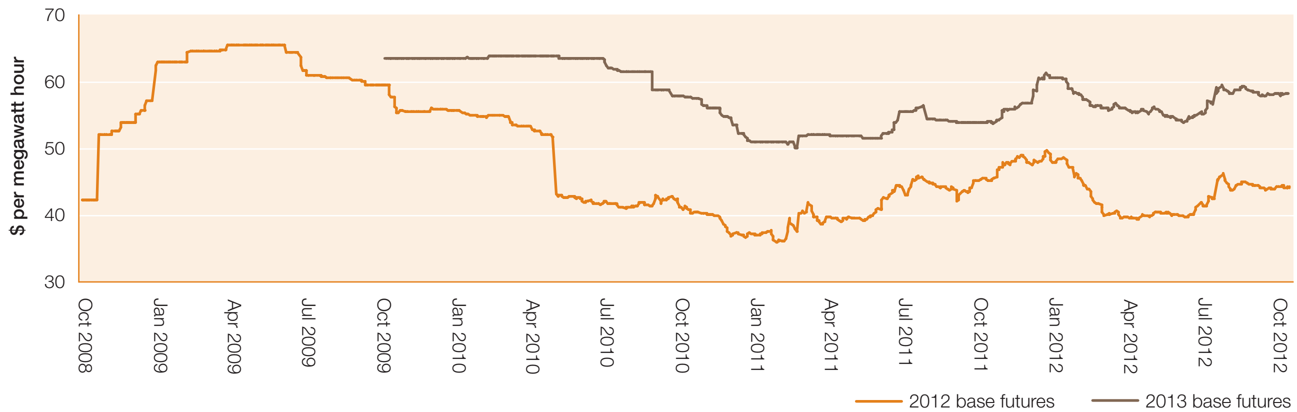
Figure 1.19 shows average price outcomes for electricity base futures, as reflected in the national power index. The index (which d-cyphaTrade publishes for each calendar year) represents a basket of electricity base futures for New South Wales, Victoria, Queensland and South Australia. It is calculated as the average daily settlement price of base futures contracts across the four regions for the four quarters of the relevant calendar year.

Fluctuations in futures prices reflect changing expectations of the cost of underlying wholesale electricity. In recent years, uncertainty around the introduction of a carbon price led to prices fluctuating as the scheme's likelihood was reassessed. Prices peaked towards the end of 2011 when the Senate passed the Clean Energy Future Plan, and rose again in June 2012 when the scheme's introduction was imminent. On 30 June 2012, base load 2013 calendar year prices were $55 in Queensland, $59 in New South Wales, $54 in Victoria and $58 in South Australia. The relatively close alignment across regional prices mirrored the wholesale spot market.

Throughout the measured period, prices for 2013 products were consistently higher than for 2012 products, which cover only six months of carbon pricing.

Figure 1.19

National power index



Source: d-cyphaTrade.

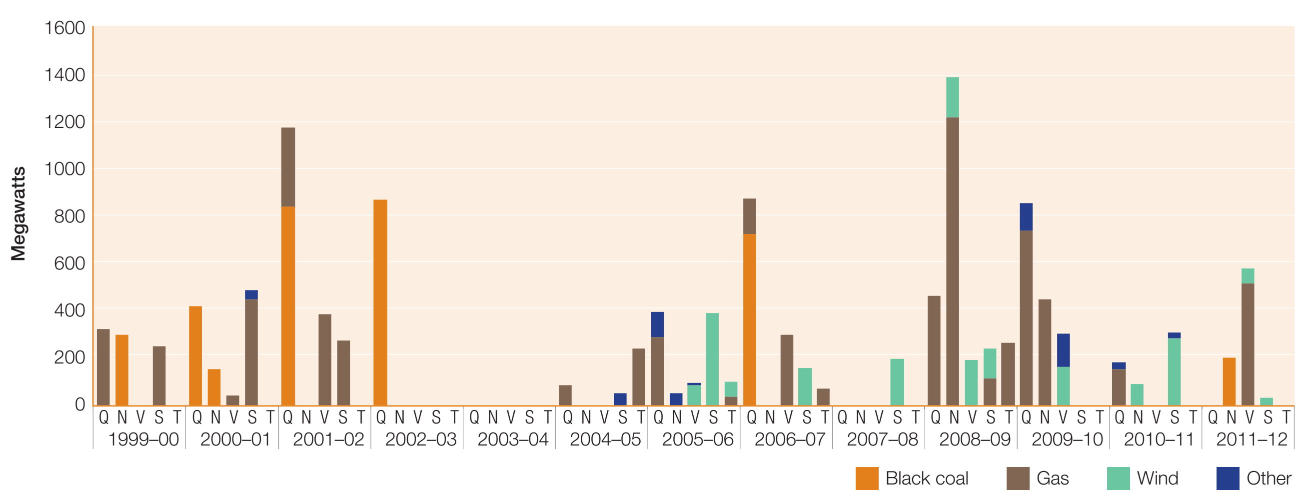
1.7 Generation investment

Price signals in the wholesale and forward contract markets for electricity largely drive new investment in the NEM. From the inception of the NEM in 1999 to June 2012, new investment added 13 200 MW of registered generation capacity—around 1000 MW per year. Figures 1.20 and 1.21 illustrate investment in registered capacity since market start. Additionally, significant investment has been made in generation not connected to the transmission grid, including investment in rooftop PV installations (section 1.1).

Tightening supply conditions led to an upswing in generation investment in 2008–09 and 2009–10, with over 4100 MW of new capacity added in those years—predominantly gas fired generation in New South Wales and Queensland. More recently, subdued electricity demand and surplus capacity have pushed out the required timing for new generation capacity to at least 2018–19 in all jurisdictions (section 1.9.5). This trend is reflected in flat investment: only 1350 MW of capacity was added over the past two years, of which one-third was in wind generation (which the RET

Figure 1.20

Annual investment in registered generation capacity



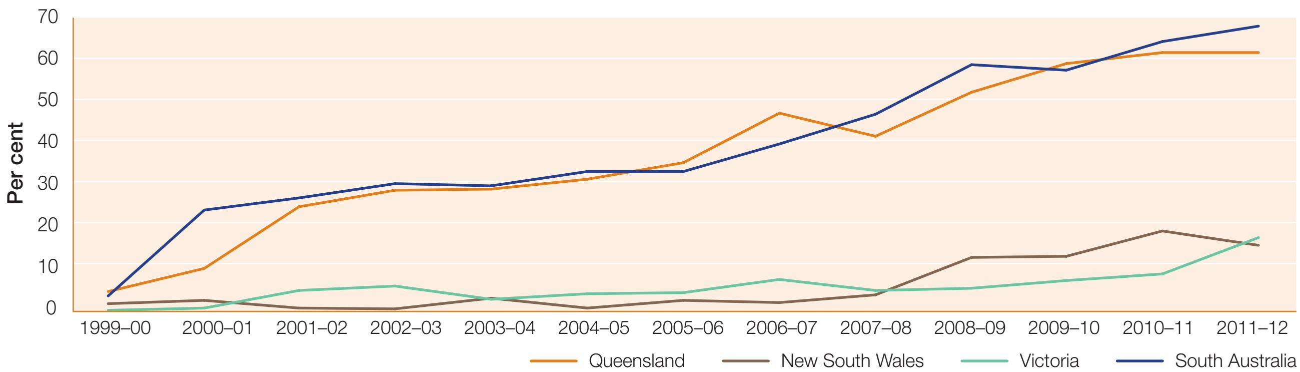
Q, Queensland; N, New South Wales; V, Victoria; S, South Australia; T, Tasmania.

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

Sources: AEMO; AER.

Figure 1.21

Net change in generation capacity since market start—cumulative



Source: AER.

scheme effectively subsidises). Additionally, weak demand and climate change policies contributed to around 3000 MW of coal plant in 2012 being shut down or periodically offline (section 1.2.2).

Table 1.7 details generation investment since 1 July 2011. The most significant event was the commissioning of stage 1 of Origin Energy's 518 MW gas powered plant at Mortlake (Victoria).

Generation investment (other than in wind) is likely to be limited over the next few years, with only a small number of projects in development. At June 2012 the NEM had 700 MW of committed capacity,[23] mostly in wind generation, which (as a result of the RET) may be profitable despite depressed wholesale prices (table 1.8). The most significant committed project is Victoria's 420 MW Macarthur wind farm, which will be the largest wind farm in the southern hemisphere.

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 2012 it listed 32 500 MW of proposed capacity in the NEM (figure 1.22). While 3600 MW of capacity is scheduled to be commissioned before 2017–18, much of this capacity (including 1200 MW of gas powered generation in Queensland) may not be needed by this time, based on current demand forecasts.

The bulk of proposed capacity is in wind and gas powered generation. While most of the gas plants adopt open or combined cycle technologies, the proposals also include more innovative and experimental approaches. The Australian Government's Solar Flagships program has led to several proposals for large scale solar projects. In June 2012 AGL's 159 MW solar PV project at Broken Hill and Nyngan (New South Wales) was selected to receive funding under the program. A further 1070 MW of major solar projects are proposed for Queensland, New South Wales and Victoria, including:

- a 250 MW solar thermal gas hybrid plant in Chinchilla (Queensland), combining solar generation with a low emission gas boiler back-up system
- two PV projects (180 MW and 154 MW) near Mildura and a 180 MW project in the Mallee (Victoria)
- a 44 MW solar thermal addition to the Kogan Creek power station in Queensland. The solar project will augment the power station's steam generation system to increase electricity output and fuel efficiency.

There are also plans for geothermal generation in South Australia. A 525 MW geothermal plant was announced for Innamincka, with another plant planned for Paralana.

The Australian Renewable Energy Agency, created on 1 July 2012 as part of the Australian Government's Clean Energy Future package, will provide support for renewable energy projects.

23 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.

Origin Energy

Table 1.7 Generation investment, 1 July 2011—31 October 2012

OWNER	POWER STATION	TECHNOLOGY	SUMMER CAPACITY (MW)	DATE COMMISSIONED	ESTIMATED COST ($ MILLION)
NEW SOUTH WALES					
Eraring Energy	Eraring (upgrade)	Coal fired	180	January 2012	225
VICTORIA					
AGL Energy	Oaklands Hill	Wind	63	August 2011	200
Origin Energy	Mortlake	OCGT	518	August 2011	650
SOUTH AUSTRALIA					
AGL Energy	The Bluff	Wind	34	July 2011	120

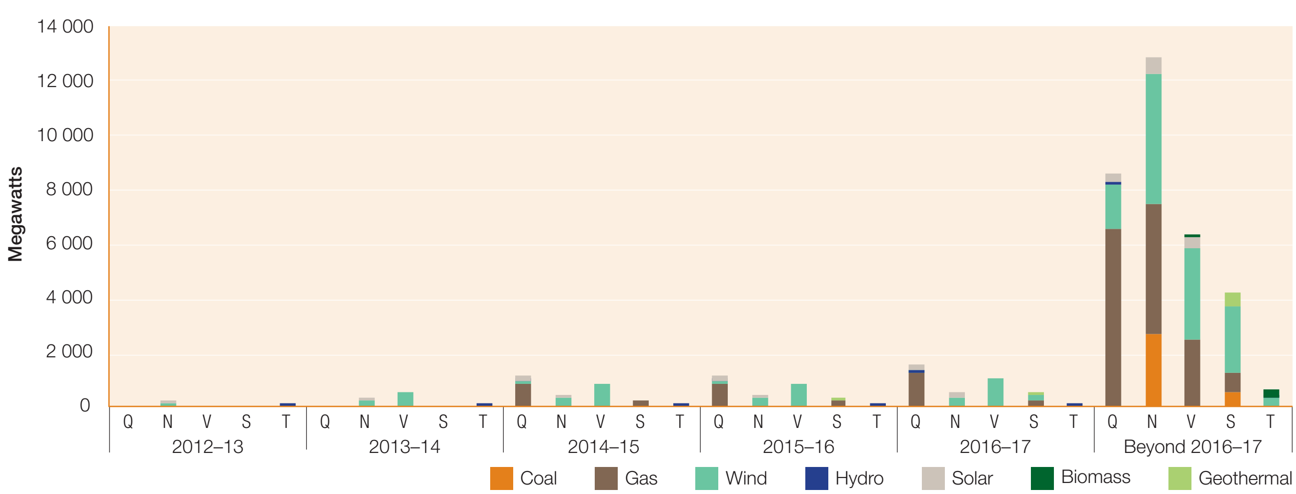
Table 1.8 Committed investment in the National Electricity Market, June 2012

DEVELOPER	POWER STATION	TECHNOLOGY	SUMMER CAPACITY (MW)	PLANNED COMMISSIONING
NEW SOUTH WALES				
Eraring Energy	Eraring (upgrade)	Coal fired	60	2012
VICTORIA				
AGL Energy / Meridian Energy	Macarthur	Wind	420	2013
Goldwind / New En	Morton's Lane	Wind	20	2012
Qenos	Qenos Cogeneration Facility	CCGT	21	2012
TASMANIA				
Hydro Tasmania	Musselroe	Wind	168	2013

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

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

Figure 1.22
Major proposed generation investment—cumulative, June 2012



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

Sources: AEMO; AER.

1.8 Demand side participation

An alternative or supplement to generation investment is demand side participation, whereby energy users are incentivised to reduce consumption at times of peak demand. Customer participation in the NEM spot market for demand management is limited, and available mainly to large customers. AEMO in 2012 identified 218 MW of capacity that was 'very likely' to be available across the NEM through demand side participation over the 2012–13 summer (up from 142 MW in 2011–12). It forecast annual growth in demand side participation of 3.2 per cent (for New South Wales) to 5.4 per cent (for Victoria and South Australia).[24]

In November 2012 the AEMC concluded its *Power of choice* review into efficient responses to rising peak demand. While the report's recommendations mainly relate to the network and retail sectors (section 2.6.1), some recommendations relate to generation and wholesale markets. For example, it recommended allowing consumers to participate directly or via their agents in the market, and to receive spot price compensation for reducing their electricity use. Payments would be based on a consumer's reductions in demand against a predetermined baseline for that customer.

1.9 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 the NEM generation sector. The standard is the expected amount of energy at risk of not being delivered to customers due to a lack of available capacity. To meet this standard, AEMO determines the necessary spare generation capacity needed for each region (including capacity via transmission interconnectors) to provide a buffer against 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.

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, allowing for demand side response and imports from interconnectors. It does not account for supply interruptions in transmission and distribution networks, which are subject to different standards and regulatory arrangements (sections 2.7.1 and 2.8.1). The standard is equivalent to an annual system wide outage of seven minutes at peak demand.

1.9.1 Reliability settings

Procedures are in place to ensure the reliability standard is met—for example, AEMO publishes forecasts of electricity demand and generator availability to allow generators to respond to market conditions and schedule maintenance outages. The reliability panel also recommends settings to ensure the 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 \$12 500 per MWh to \$12 900 per MWh on 1 July 2012.
- 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 \$193 900 per MWh on 1 July 2012; 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.

Safety net mechanisms allow AEMO to manage a short term risk of unserved energy:

- 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 give priority to facilities that would least distort wholesale market prices. The AEMC in 2012 extended the operation of the RERT mechanism until 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.

1.9.2 Reliability performance

The reliability panel annually reports on the generation sector's reliability performance. Reserve levels are rarely breached, with generator capacity across all regions of the market usually sufficient to meet peak demand and allow for acceptable reserve margins.

24 AEMO, *National electricity forecasting report 2012*, 2012, appendix D, p. D-3.

Insufficient generation capacity to meet consumer demand occurred only three times from the NEM start to 30 June 2012. The most recent instance, and the only exceedance of the 0.002 per cent reliability standard, resulted from a heatwave in Victoria and South Australia 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.

For the second consecutive year, AEMO was not required to issue any directions in 2011–12 to manage local power system issues (compared with seven directions in 2009–10 and 18 in 2008–09).

1.9.3 Security issues

The power system is operated to cope with only credible contingencies. On rare occasions, power supply interruptions are caused by non-credible (multiple contingency) events. Such interruptions may involve several credible events occurring simultaneously or in a chain reaction—for example, several generating units may fail or 'trip' at the same time, or a transmission fault may occur at the same time as a generator trips.

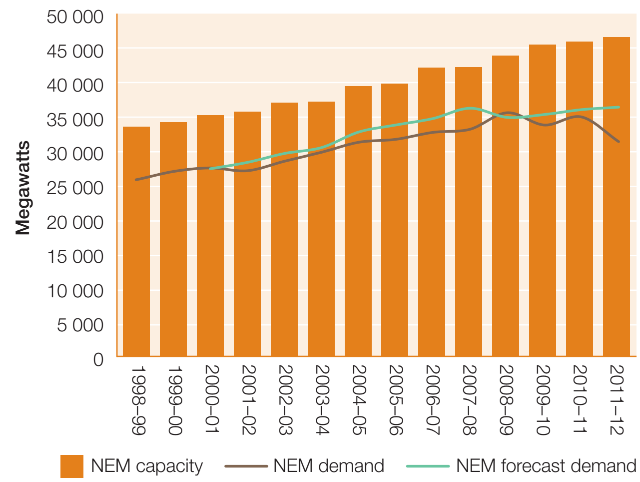
When such events occur, the market operator may need to interrupt customer supply to prevent a power system collapse. That is, while security issues are not reflected in reliability calculations, they can affect the continuity of supply. But operating the power system to cope with non-credible events would be economically inefficient. Likewise, additional investment in generation or networks may not avoid such interruptions.

AEMO reported on 42 security issues in 2011–12 (up from 36 issues in 2010–11); some incidents disrupted customer supply.

1.9.4 Historical adequacy of generation

Figure 1.23 compares total generation capacity with national peak demand since the NEM began. It shows actual demand and AEMO's demand forecasts two years in advance. The data indicate investment in the NEM over the past decade kept pace with rising demand (both actual and forecast levels), allowing reserve margins of capacity to maintain reliability. With peak demand flattening out from 2008–09, reserve margins have risen significantly, indicating a significant amount of surplus capacity.

Figure 1.23
Peak demand and generation capacity



Notes:

Demand forecasts are two years in advance, based on a 50 per cent probability that the forecast will be exceeded and an average diversity factor.

NEM capacity excludes wind generation and power stations not managed through central dispatch.

Source: AEMO, *Electricity statement of opportunities for the National Electricity Market*, various years.

1.9.5 Reliability outlook

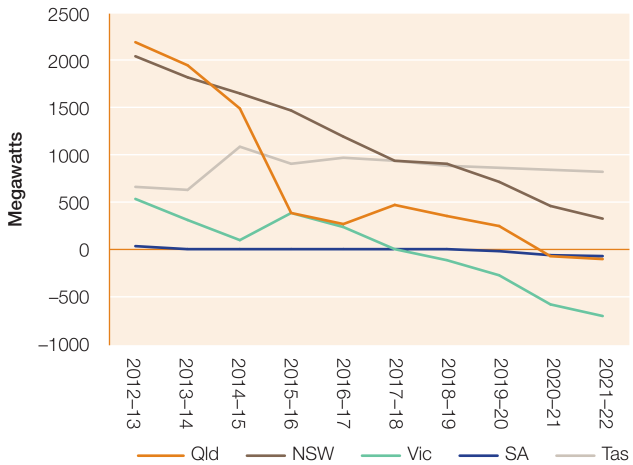
The relationship between demand and generation capacity determines the long term reliability of the power system. Figure 1.24 illustrates the margin of excess generation capacity above peak demand in each NEM region through to 2021–22, based on AEMO forecasts at 30 June 2012. Generation capacity includes wind, but at a factor below its nominal capacity (to reflect its intermittent nature). Forecast generation capacity includes committed capacity but not proposed capacity.

Figure 1.24 indicates the timing of new investment that will be needed to maintain reliability, given projected demand. Victoria will be the first region to require new investment (in summer 2018–19), followed by South Australia (summer 2019–20) and Queensland (summer 2020–21). New South Wales and Tasmania are not forecast to require new generation investment over the next decade.

In 2012, weakening growth in forecast peak demand led to a deferral of new investment requirements by at least four years in all NEM regions, compared with forecasts in 2011 (when AEMO projected Queensland, Victoria and South Australia would all require new investment by 2014–15).

Figure 1.24

Excess reserve capacity, 30 June 2012



Note:

Capacity includes installed and committed regional capacity, demand side participation and import capacity via transmission interconnectors. Wind capacity is included at a reduced factor, based on historical output, to account for its intermittent nature. The data account for rooftop PV generation as a reduction in demand.

Data source: AEMO, *2012 Electricity statement of opportunities*, 2012.

1.10 Compliance monitoring and enforcement

The AER monitors the wholesale electricity market to ensure compliance with the National Electricity Law and Rules governing the NEM, and takes enforcement action if appropriate. It also monitors the market to detect issues such as market manipulation. The AER draws on its monitoring activity to report on the NEM and make submissions and other contributions to the Standing Council on Energy and Resources, the AEMC and other bodies.

The AER's compliance and enforcement activity in the electricity generation sector[25] includes:

- electricity market monitoring to identify compliance issues
- targeted compliance reviews of Electricity Rules provisions—both randomly and in response to electricity market events or inquiries that raise concerns—to identify how participants comply with their obligations
- audits of compliance programs for generators' technical performance standards
- forums and other meetings with electricity industry participants to discuss compliance.
- publication of quarterly compliance reports (outlining the AER's compliance activity) and compliance bulletins (giving additional guidance on the Rules).

When deciding whether and how to act in the case of noncompliance, the AER aims for a proportionate response. It accounts for the impact of the breach, the circumstances and the participant's compliance programs and compliance culture, among other factors. Since 2006 the AER has issued nine infringement notices for electricity matters, and it commenced proceedings in the Federal Court on one occasion (against Stanwell, a Queensland generator, in relation to its compliance with the 'good faith' rebidding provisions of the Rules). Additionally, the AER has issued six compliance bulletins on electricity matters.

The AER's compliance monitoring activity in 2013 will include two new focus areas:

- Recognising the development in customer metering technologies and the importance of transparent market information, the AER will use new metrics to monitor compliance with metering and settlement obligations.
- The introduction of carbon pricing may lead to some coal fired generators being offline more frequently than in the past. The AER will continue to monitor outages and ensure published information about changes in a generator's participation in the market is timely and accurate.

25 The AER's compliance and enforcement activity in gas is considered in section 3.6.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2 ELECTRICTY NETWORKS

Electricity networks transport 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.

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, 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. There are 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, New South Wales and Victoria each have multiple networks that are monopoly providers within 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 750 000 kilometres—18 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 transmission networks in Victoria and South Australia, and three network 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. The ACT distribution network has joint government and private ownership. All networks (transmission and distribution) in Queensland, New South Wales and Tasmania are government owned.

Aside from state and territory governments, the principal network owners at June 2011 were:

- *Cheung Kong Infrastructure* and *Power Assets*, which 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 in 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*, which owns the Jemena distribution network and has minority ownership of the United Energy distribution network, both in Victoria. It has a 50 per cent share in the ACT distribution network (ActewAGL) and a 51 per cent stake in SP AusNet, which owns the Victorian transmission network and SP AusNet distribution network.

These businesses also own or have equity in a number of gas networks (chapter 4).

Victoria has a unique transmission network structure that separates asset ownership from planning and investment decision making. SP AusNet 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 SP AusNet for sale to customers.

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

- In Tasmania and the ACT,[1] common ownership occurs in electricity distribution and retailing, with ring fencing arrangements for operational separation.
- The Tasmanian Government announced industry reforms in 2012 that will separate the ownership of energy networks from energy retailing. It will also merge the transmission (Transend) and distribution (Aurora Energy) networks.
- Queensland privatised much of its energy retail sector in 2006–07, but the state owned Ergon Energy continues to provide both distribution and retail services.

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 $46 billion—almost three times the valuation for transmission infrastructure (around $16 billion).

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 networks in the National Electricity Market

QNI, Queensland–New South Wales Interconnector.

Table 2.1 **Electricity transmission networks**

NETWORK	LOCATION	LINE LENGTH (KM)	ELECTRICITY TRANSMITTED (GWH), 2010–11	MAXIMUM DEMAND (MW), 2010–11	REVENUE—CURRENT PERIOD ($ MILLION)[1]	ASSET BASE ($ MILLION)[2]	INVESTMENT—CURRENT PERIOD ($ MILLION)[1]	CURRENT REGULATORY PERIOD	OWNER
NEM REGION NETWORKS									
Powerlink	Qld	13 986	47 341	8 109	4 720	6 260	2 455	1 July 2012–30 June 2017	Queensland Government
TransGrid	NSW	13 957	70 828	13 760	3 880	4 485	2 620	1 July 2009–30 June 2014	New South Wales Government
SP AusNet	Vic	6553	52 352	9 982	2 940	2 365	830	1 Apr 2008–30 Mar 2014	Publicly listed company (Singapore Power International 51%)
ElectraNet	SA	5 591	13 045	3 570	1 365	1 415	840	1 July 2008–30 June 2013	Powerlink (Queensland Government), YTL Power Investments, Hastings Utilities Trust, UniSuper
Transend	Tas	3 688	11 185	1 377	1 010	1 010	645	1 July 2009–30June 2014	Tasmanian Government
NEM TOTALS		43 775	194 751		13 915	15 535	7 390		
INTERCONNECTORS[3]									
Directlink (Terranora)	Qld–NSW	63		180		140		1 July 2005–30 June 2015	Energy Infrastructure Investments (Marubeni 50%, Osaka Gas 30%, APA Group 20%)
Murraylink	Vic–SA	180		220		130		1 Oct 2003–30 June 2013	Energy Infrastructure Investments (Marubeni 50%, Osaka Gas 30%, APA Group 20%)
Basslink	Vic–Tas	375				910		Unregulated	Publicly listed CitySpring Infrastructure Trust (Temesek Holdings (Singapore) 37%)

GWh, gigawatt hours; MW, megawatts.

1. Revenue and investment data are forecasts over the current regulatory period, converted to June 2011 dollars. The data are adjusted for the impact of merits review decisions by the Australian Competition Tribunal.
2. The regulated asset bases are as set at the beginning of the current regulatory period for each network, converted to June 2011 dollars.
3. Not all interconnectors are listed. The unlisted interconnectors, which form part of the state based networks, are Heywood (Victoria–South Australia), QNI (Queensland–New South Wales) and New South Wales–Victoria.
4. Basslink is not regulated, so has no regulated asset base. The listed asset value is the estimated construction cost.

Sources: AER, *Transmission network service providers: electricity performance report for 2010–11*, 2012 regulatory determinations by the AER.

Table 2.2 **Electricity distribution networks**

NETWORK	CUSTOMER NUMBERS	LINE LENGTH (KM)	MAXIMUM DEMAND (MW), 2010–11	REVENUE—CURRENT PERIOD ($ MILLION)[1]	ASSET BASE ($ MILLION)[2]	INVESTMENT—CURRENT PERIOD ($ MILLION)[1,3]	CURRENT REGULATORY PERIOD	OWNER
QUEENSLAND								
Energex	1 316 295	53 928	4 875	6 900	8 120	5 970	1 Jul 2010–30 Jun 2015	Qld Government
Ergon Energy	689 277	160 998	2 429	6 425	7 380	5 275	1 Jul 2010–30 Jun 2015	Qld Government
NEW SOUTH WALES AND ACT								
AusGrid[4]	1 619 988	49 781	5 812	9 300	8 965	8 855	1 Jul 2009–30 Jun 2014	NSW Government
Endeavour Energy	877 340	34 172	4 069	4 680	3 925	3 150	1 Jul 2009–30 Jun 2014	NSW Government
Essential Energy	1 301 626	190 531	2 292	5 920	4 595	4 415	1 Jul 2009–30 Jun 2014	NSW Government
ActewAGL	168 937	4 922	701	770	635	325	1 Jul 2009–30 Jun 2014	ACTEW Corporation (ACT Government) 50%; Jemena (Singapore Power International) 50%
VICTORIA								
Powercor	723 094	84 791	2 351	2 570	2 260	1 600	1 Jan 2011–31 Dec 2015	Cheung Kong Infrastructure/ Power Assets 51%; Spark Infrastructure 49%
SP AusNet	637 810	48 841	1 798	2 475	2 120	1 510	1 Jan 2011–31 Dec 2015	SP AusNet (listed company; Singapore Power International 51%)
United Energy	641 130	12 875	1 962	1 700	1 410	905	1 Jan 2011–31 Dec 2015	DUET Group 66%; Jemena (Singapore Power International) 34%
CitiPower	311 590	7 406	1 453	1 240	1 315	850	1 Jan 2011–31 Dec 2015	Cheung Kong Infrastructure/ Power Assets 51%; Spark Infrastructure 49%
Jemena	314 734	6 043	1 008	985	770	485	1 Jan 2011–31 Dec 2015	Jemena (Singapore Power International)
SOUTH AUSTRALIA								
SA Power Networks[5]	825 218	87 226	3 128	3 620	2 860	2 225	1 Jul 2010–30 Jun 2015	Cheung Kong Infrastructure/ Power Assets 51%; Spark Infrastructure 49%
TASMANIA								
Aurora Energy	275 536	25 844	1 760	1 290	1 410	555	1 Jul 2012–30 Jun 2017	Tas Government
NEM TOTALS	9 702 575	767 358		47 875	45 765	36 120		

MW, megawatts.

1. Revenue and investment data are forecasts over the current regulatory period, converted to June 2011 dollars. The data are adjusted for the impact of merits review decisions by the Australian Competition Tribunal.
2. Asset valuation is the opening regulated asset base for the current regulatory period, converted to June 2011 dollars.
3. Investment data include capital contributions, which can be significant—for example, 10–20 per cent of investment in Victoria and over 20 per cent in South Australia—but do not form part of the regulated asset base for the network.
4. AusGrid's distribution network includes 962 kilometres of transmission assets that are treated as distribution assets for economic regulation and performance assessment.
5. ETSA Utilities was rebranded as SA Power Networks in 2012.

Sources: Regulatory determinations and performance reports by the AER and OTTER (Tasmania).

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 must assess the forecasts submitted by a network business of the revenue it 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.

The largest component is the return on capital, which may account for up to two-thirds of revenues. 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 must determine a cap on the maximum revenue that a network can earn during a regulatory period. The range of control mechanisms is wider in distribution—the AER may set a ceiling on the revenues *or prices* that can be earned or charged during a period. The available mechanisms in distribution include:

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

Until November 2012, the regulatory process for transmission businesses began 13 months before the end of the current regulatory period and took 11 months to complete. The AER must publish a final decision on a proposal at least two months before the beginning of the next regulatory period. The process for distribution businesses commenced earlier—24 months before the end of the current regulatory period—to allow time for preliminary consultation on the framework and approach for a determination. A Rule change in November 2012 provided for the regulatory process to be extended by four months to allow more effective consultation with stakeholders (section 2.2.2).

2.2.2 Refining the regulatory process and approach

In 2011 the AER submitted Rule change proposals to the Australian Energy Market Commission (AEMC), seeking changes in chapters 6 and 6A of the Rules to better promote efficient investment in, and use of, energy services for the long term interests of consumers. Following detailed consultation, the AEMC released Rule changes in November 2012 that will strengthen the AER's capacity to set network price increases so consumers do not pay more than necessary for a reliable energy supply. The changes:

- create a common approach to setting the *cost of capital* across electricity and gas network businesses, whereby the AER makes a best possible estimate of a rate of return for a benchmark efficient service provider at the time of making a regulatory determination. The AER will undertake public consultation at least every three years to develop its approach to setting the rate of return, completing the first review by November 2013.
- enhance *incentives for efficient investment* by equipping the AER with new regulatory tools, such as a review of the capital expenditure undertaken by a network business to ensure it is prudent and efficient; expenditure in excess

of regulatory approvals may be removed from the RAB if the AER finds it is not prudent or efficient.

- clarify the AER's powers to assess and amend *capital and operating expenditure proposals* by network businesses. Additionally, the AER will publish annual benchmarking reports on the relative efficiency of the businesses.
- commence the electricity regulatory process four months earlier to allow more effective consultation with stakeholders. More information will be made available early in the regulatory process to strengthen consumer engagement. The framework and approach process will extend to transmission businesses and the AER will publish an issues paper after a regulatory proposal is submitted to it.

In addition to the Rule change proposals, the AER is continuing to strengthen its regulatory approach under the current Rules framework by refining:

- benchmarking techniques and tools and their application in regulatory decisions. The AER is developing key benchmarking indicators in consultation with industry, with a view to applying enhanced metrics in regulatory reviews of the New South Wales and ACT electricity distribution networks.
- information requirements on energy business, to improve the quality and consistency of data for regulatory reviews and annual performance reporting. The enhancements also aim to improve the robustness of regulatory decision making, and provide important data for developing and applying benchmarking techniques.

2.2.3 Regulatory timelines and recent AER activity

Figure 2.2 shows the regulatory timelines for electricity networks in each jurisdiction. In 2012 the AER:

- published final determinations for Aurora Energy (Tasmanian electricity distribution) and Powerlink (Queensland electricity transmission)
- began reviews of ElectraNet (South Australian electricity transmission) and Murraylink (transmission interconnector between Victoria and South Australia) for the regulatory periods commencing 1 July 2013, and released draft determinations in November 2012
- began preparatory work for reviews of the New South Wales and ACT electricity distribution businesses for the regulatory periods commencing 1 July 2014. The November 2012 Rule change on regulatory process includes transitional arrangements for these jurisdictions, which will affect the AER's process and timing for the reviews.

In addition to revenue determinations, the AER undertakes other functions associated with economic regulation. It assesses network proposals on matters including cost pass-throughs and contingent projects; develops and applies service incentive regimes and ring fencing policies and other regulatory guidelines; assists in access and connection disputes; and undertakes annual tariff reviews for distribution businesses. The AER monitors the compliance of network businesses with the Electricity Rules, and reports on outcomes, including in quarterly compliance reports.[2]

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 the whole determination.

To have a decision amended, the network business must demonstrate the AER:

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

Between June 2008 and June 2012 network businesses sought review of 17 AER determinations on electricity networks—three reviews in transmission and 14 in distribution.[3] 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—the subject of review applications for eight networks, with a combined revenue impact of over $900 million.

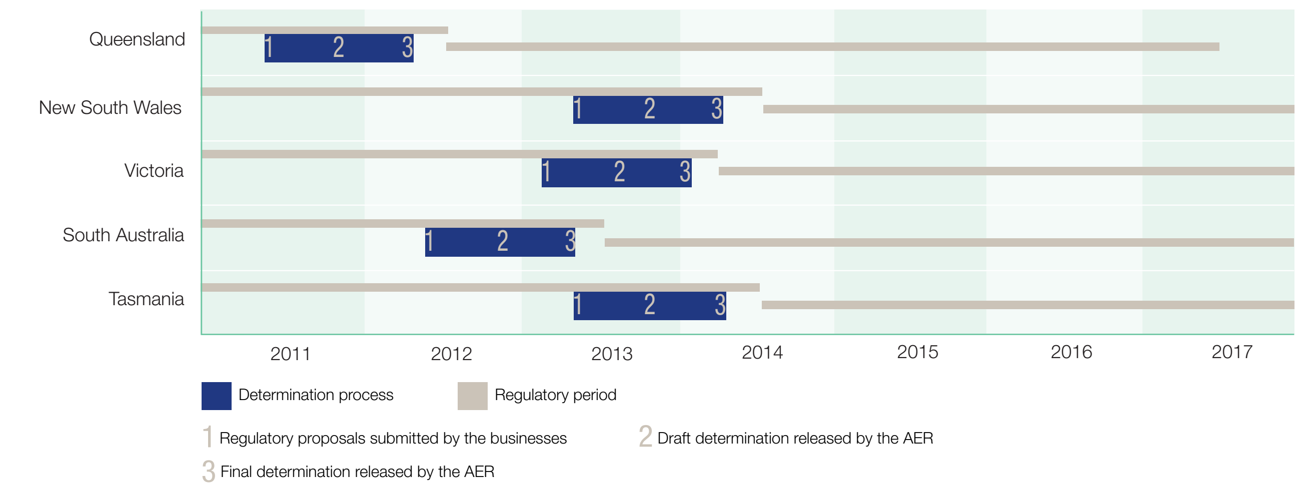
2 AER, *Strategic plan and work program 2012–13*.

3 Three 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* (Cth).

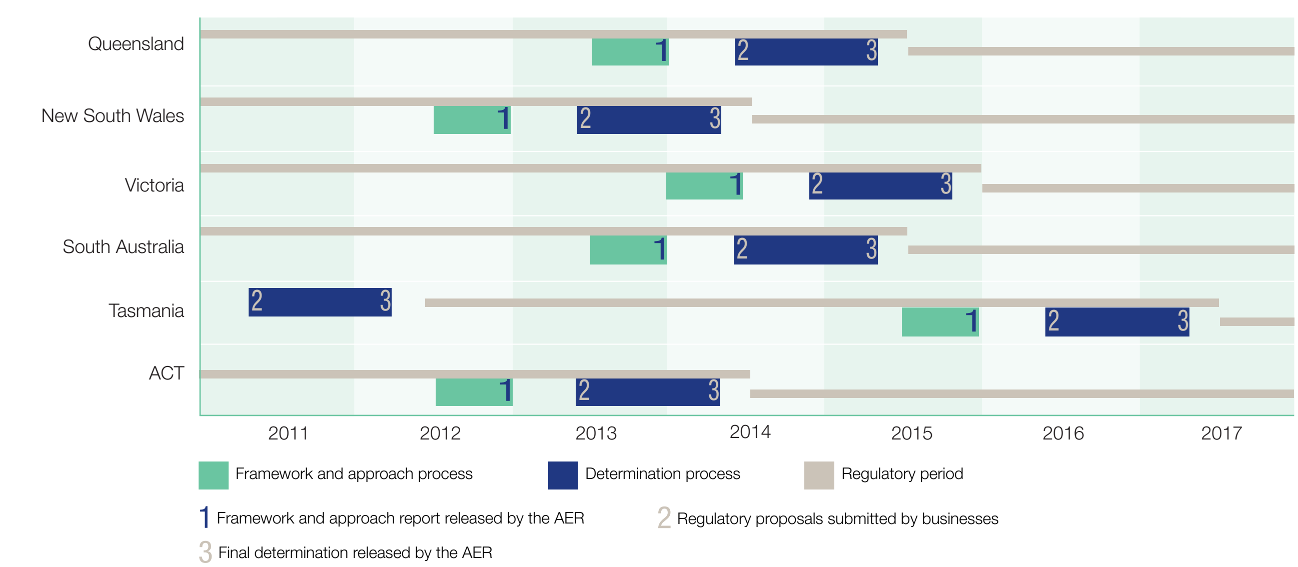
Figure 2.2

Indicative timelines for AER determinations on electricity networks

Electricity transmission



Electricity distribution



Note: For reviews commencing from 2013, Rule changes made by the AEMC in November 2012 will lengthen the regulatory process to commence four months earlier than the dates set out above. Transitional arrangements arising from the Rule changes may affect these timelines.

Source: AER.

In January 2012 the Tribunal made decisions on matters appealed by the Victorian electricity distribution networks (following the AER's determination of October 2010). The matters on which the businesses sought review varied. All sought review of gamma and the debt risk premium that is applied to calculate the cost of capital. Other matters included aspects of approved capital and operating expenditure, the method of escalating the RAB over the regulatory period, and the application of pass through provisions.

The Tribunal upheld aspects of the AER's decisions (relating to the treatment of pass throughs and some operating expenditure), but overturned the AER's approach to certain operating costs and the debt risk premium, indexation of the RAB, and the application of penalties from two incentive schemes under the previous regulatory regime. Some matters were remitted to the AER for a further decision. These Tribunal decisions increased the Victorian networks' allowable revenues by around $255 million (a 3 per cent increase) over five years. This increase represents a 0.5–1.5 per cent rise in a typical residential electricity bill.

In April 2012 the Tribunal completed a review of the AER's determination on smart meter costs for Victoria's SP AusNet network. The AER found SP AusNet should have reconsidered its decision to use WiMAX communications technology (rather than the cheaper mesh radio technology adopted by the other distribution businesses) and removed associated expenditure from its budget. The Tribunal remitted that aspect of the determination back to the AER. Additionally, it required the AER to allow certain costs in respect of foreign exchange contracts and project management labour. The AER expected to release an amended determination in December 2012. SP AusNet also sought judicial review of the AER's determination. The Federal Court adjourned a decision on this application in April 2012.

At October 2012 no electricity matters were before the Tribunal. Aurora Energy (Tasmanian distribution) and Powerlink (Queensland transmission) did not seek review of the AER's decisions made in April 2012 on these networks for the period commencing 1 July 2012.

2.2.5 Independent review of merits review arrangements

In 2012 the Standing Council on Energy and Resources (SCER) commissioned an independent review of the operation of the *limited merits review regime*. In its final report, released in September 2012, the review panel found the regime has not operated as intended. In particular, the regime:

- does not sufficiently consider the national electricity and gas objectives, which focus on the long term interests of consumers
- places a narrow focus on the matters raised for review, without sufficiently considering the overall balance of a determination.

The panel found a limited merits review regime is preferable to the alternatives—such as *de novo* (full) review or reliance on judicial review only—but recommended the following improvements:

- reviews should be conducted by a new administrative body attached to the AEMC
- the regime should be limited to a single ground of appeal—that a materially preferable decision exists—and should assess review matters in relation to the national energy objectives
- a review should be investigative rather than adversarial, with greater input from consumers. Additionally, the AER's role in assisting the review body should be clarified in the Electricity Law.
- the review body should be free to explore any aspect of a decision that it considers relevant.

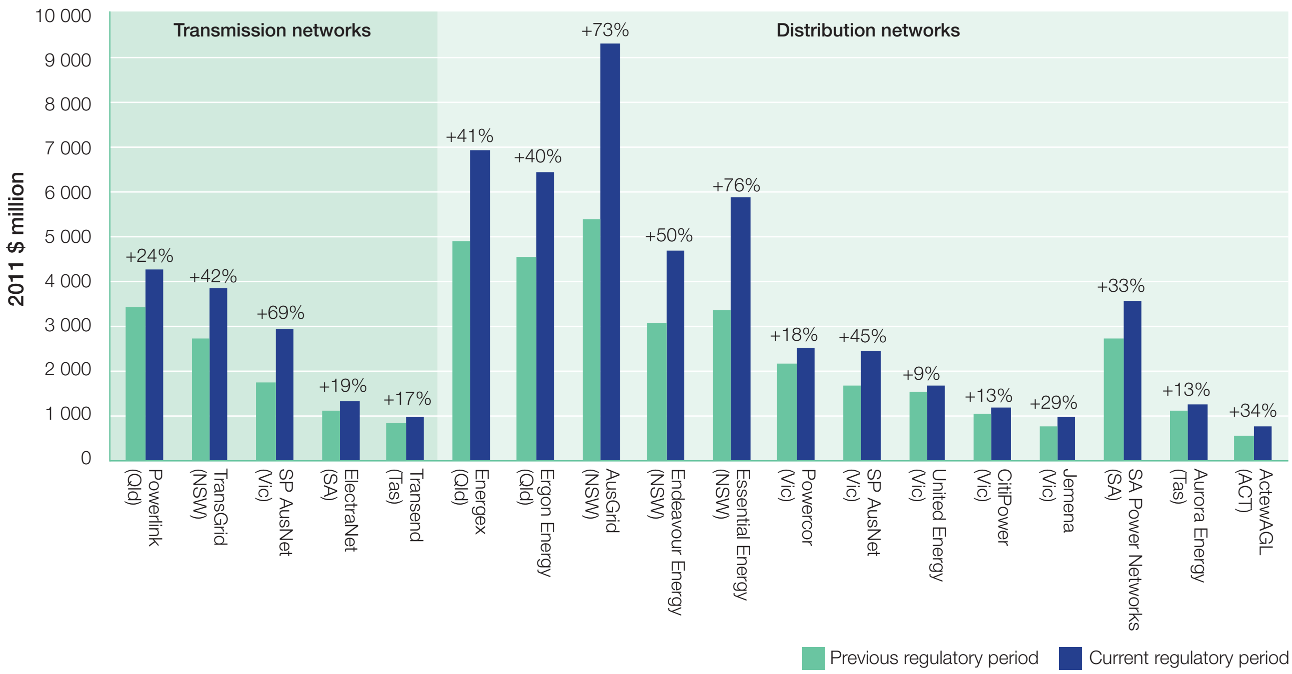
The Council of Australian Governments (CoAG) considered the panel's recommendations in December 2012 (see *Market overview*, section A.3.2).

2.3 Electricity network revenues

Figure 2.3 illustrates AER revenue allowances for electricity networks in the current five year regulatory periods compared with previous periods. Combined network revenues were forecast at $60 billion over the current cycle, comprising over $12 billion for transmission and $47 billion for distribution—a 44 per cent real increase from the previous regulatory periods. The main drivers are higher capital expenditure (investment), and increased capital financing and operating costs (discussed in sections 2.4 and 2.5).

The forecast cost of capital used to determine revenue allowances in the current regulatory periods were higher for most network business than in previous periods. The increases led to average revenue forecasts increasing by 7 per cent more than if the cost of capital were unchanged.

Figure 2.3
Electricity network revenues



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: Regulatory determinations by the AER.

The cost of capital comprises several parameters. The primary factor underpinning the increases is the debt risk premium, which reflects the cost of borrowing for a business based on its risk of default. Issues in global financial markets affected liquidity in debt markets and increased perceptions of risk from late 2008, pushing up the cost of borrowing. AER determinations made in 2012 reflect recent reductions in the risk free rate and market and debt risk premiums that have lowered the overall cost of capital.

The Tribunal's decision to amend the value adopted for tax imputation credits (gamma) for the Queensland and South Australian distribution networks (with consequential impacts on other network determinations) also increased revenue allowances.

2.4 Electricity network investment

New investment in infrastructure is needed to maintain or improve network performance over time. Investment includes network augmentations (expansions) to meet rising 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.

2.4.1 Regulatory test, RIT-T and RIT-D

The regulatory process approves the overall efficiency of a business's capital expenditure program. Additionally, there is a separate assessment process 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. Until 2010 the assessment entailed a common *regulatory test* for both transmission and distribution. The test requires a business to determine whether a proposed augmentation passes a cost–benefit analysis or provides a least cost solution to meet network reliability standards.[4]

The regulatory investment test for transmission (*RIT-T*), introduced in August 2010, requires a more comprehensive assessment and applies to a wider range of projects than the previous test. The RIT-T also prescribes more closely the market benefits and costs that an assessment may consider.

Under the RIT-T, a network business must identify the purpose of an investment as well as all credible options for achieving that purpose. It must publicly consult on its proposal. Affected parties can lodge a formal dispute.

The AER developed the RIT-T and the previous regulatory test. Additionally, it:

- helps resolve disputes over how the tests are applied
- monitors and enforces compliance. The AER conducted a number of compliance reviews in 2012
- periodically reviews project cost thresholds. The AER initiated the first cost thresholds review for the RIT-T in July 2012.

For distribution networks, the regulatory test still applies. But the AEMC in October 2012 finalised a Rule change to introduce a RIT-D similar to the RIT-T.[5] The AER must develop and publish the RIT-D (and related application guidelines) by September 2013. The RIT-D will apply to investment projects over $5 million. It includes a dispute resolution process, and requires distribution businesses to release annual planning reports and maintain a demand side engagement strategy (section 2.9.5).

A number of RIT-T and regulatory test processes were occurring in 2012, including for the following projects:

- ElectraNet and AEMO (as the transmission network planner in Victoria) were assessing the viability of upgrading the Heywood interconnector between Victoria and South Australia. A draft report in September 2012 found the upgrade would provide additional energy supply to South Australia at times of maximum (summer) demand; allow more efficient generation dispatch in Victoria and South Australia; and promote new investment in low fuel cost generation. The project was estimated to have net benefits of up to $190 million.
- Powerlink and TransGrid were evaluating an upgrade to the transfer capacity of the Queensland–New South Wales interconnector (QNI). The businesses consider market benefits arise from allowing generation capacity in one region to meet peak demand in another. A previous test in 2008 found an upgrade would not be required until 2015–16.
- AEMO identified forecast demand growth in Victoria requires greater supply capability in eastern Melbourne, and in regional Victoria around Bendigo and Ballarat. The analysis considered network options, as well as demand management.
- AEMO, Jemena and Powercor identified emerging transmission limitations in western Melbourne from the expansion of residential, industrial and commercial load. They forecast extra capacity would be required by 2016–17, and chose the establishment of a new terminal station at Deer Park as the preferred option.
- ElectraNet was seeking to reinforce the transmission network in the Lower Eyre Peninsula to meet reliability standards and prepare for additional loads in the area from 2014.
- Powerlink and Energex identified forecast demand growth around southern Brisbane from summer 2013–14 would require additional network capacity to meet reliability obligations. They identified five network augmentation options for analysis.

2.4.2 Investment trends

Figure 2.4 illustrates investment allowances for electricity networks in the current five year regulatory periods compared with previous 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 five year cycle is forecast at over $7 billion for transmission networks and $36 billion for distribution networks. These forecasts represent an increase on investment in the previous regulatory periods of around 27 per cent in transmission and 60 per cent in distribution (in real terms). More recent determinations reflect a different trend.

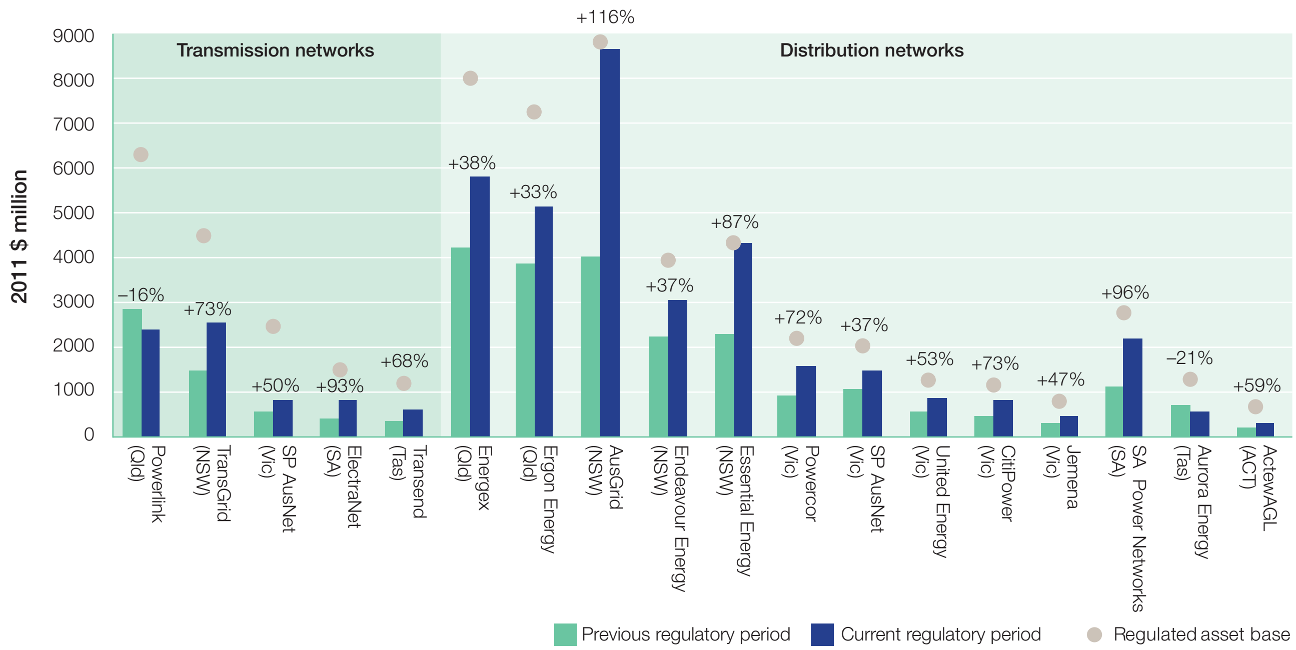
Changes in operating environments, even over a relatively short period, can cause significant variations in investment requirements. A number of active AER determinations that were made several years ago reflected increased capital needs to replace ageing assets, meet higher reliability and

4 AER, *Regulatory test for network augmentation, version 3*, 2007.

5 AEMC, National Electricity Amendment (Distribution Network Planning and Expansion Framework) Rule 2012.

Figure 2.4

Electricity network investment



Notes:

Regulated asset bases are as 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.

AusGrid's distribution network includes 962 kilometres of transmission assets.

Sources: Regulatory determinations by the AER.

new bushfire (safety) standards, and respond to forecasts made at the time of rising peak demand.

More recent determinations, however, reflect a moderation in forecast growth in industrial and residential energy use, including peak demand (section 1.1). This led to a revision in forecast investment requirements for the networks reviewed in 2012. The AER found:

- a softening in forecast peak demand growth in Queensland meant Powerlink's transmission investment requirements were 16 per cent less than in the previous regulatory period
- subdued economic growth in Tasmania, with lower expected demand and fewer new connections, meant Aurora Energy's investment requirements were 21 per cent less than in the previous regulatory period.

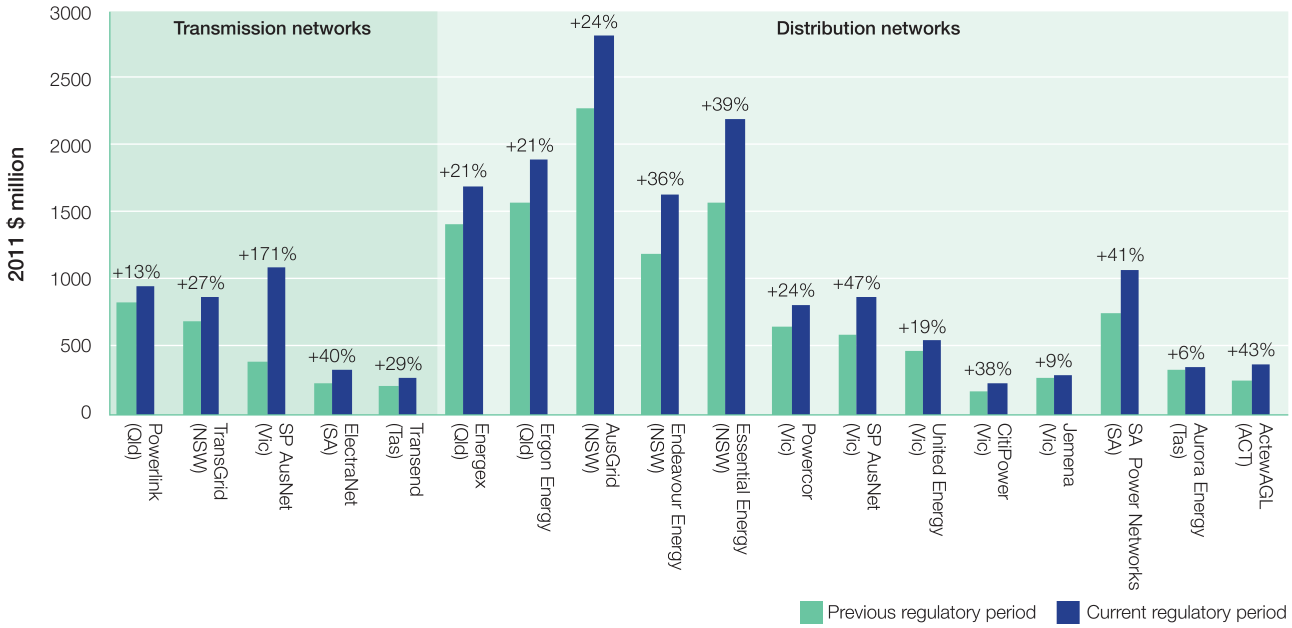
2.5 Operating and maintenance expenditure

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

Figure 2.5 illustrates operating and maintenance expenditure allowances for electricity networks in the current five year regulatory periods compared with previous periods. In the current cycle, transmission businesses in the NEM are forecast to spend $3.5 billion on operating and maintenance costs. Distribution businesses are forecast to spend almost $15 billion.

Figure 2.5

Operating expenditure of electricity networks



Notes:

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

The increase in SP AusNet's transmission operating expenditure in the current period was partly due to the introduction of an easement land tax (around $80 million per year) mid way through the previous period.

Sources: Regulatory determinations by the AER.

Differences in the networks' operating environments result in significant variations in expenditure allowances. On average, costs are forecast to rise by 48 per cent in transmission and 28 per cent in distribution over the current regulatory periods. More recent determinations reflect lower rates of growth in line with flatter forecasts of energy demand and input costs.

In assessing operating expenditure forecasts, the AER considers relevant cost drivers, including load 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 business requirements that were not part of the previous regulatory period. The 2010 Victorian determinations, for example, had to account for an expected increase in regulatory compliance costs for electrical safety, network planning and customer communications, largely stemming from government decisions following the 2009 Victorian bushfires.

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. The 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. 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.

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.

2.6 Demand management and metering

Demand management relates to strategies to manage the growth in overall or peak demand for energy services. It aims to reduce or shift demand, or implement efficient alternatives to network augmentation. Such strategies are typically applied at the distribution or retail level, and require cooperation between energy suppliers and customers.

2.6.1 *Power of choice* review

The AEMC in November 2012 completed its *Power of choice* review into efficient alternatives to network investment as solutions to rising peak demand. It recommended:

- improving price signalling to customers, by introducing time varying network tariffs and continuing the rollout of interval metering (section 2.6.2)
- removing barriers to large consumers offering demand reduction into the wholesale electricity market
- providing more flexibility for consumers to access their own consumption data, and a framework for consumer engagement with demand side providers
- modifying the AER's demand management incentive scheme to capture wider market benefits and network deferral benefits beyond the current regulatory period
- considering, when the AER develops its national ring fencing guidelines, the benefits of allowing network businesses to own and operate generation plant connected to their networks
- enabling consumers to sell small scale generation (for example, solar or battery storage) to parties other than their electricity retailer

CoAG in December 2012 approved the adoption in principle of the full set of *Power of choice* recommendations.

2.6.2 Metering and smart grids

The rollout of interval meters—with time based data on energy use and communication capabilities for remote reading and customer connection to the network—is central to many of the AEMC's *Power of choice* recommendations. This type of metering, when coupled with time varying prices can encourage customers to actively manage their electricity use. In the longer term, it may facilitate dynamic grid operation.

The *Power of choice* review recommended that all new meters installed for residential and small businesses consumers be interval meters with remote communication capacity. It proposed that new metering be installed on an accelerated basis for large residential and small business consumers. The AEMC prefers that the supply of metering and related data services be contestable, with retailers having primary responsibility.

Under the AEMC proposal, a network business would be required to implement time varying pricing in network charges, to encourage retailers to reflect these charges in customer contracts. It would remain open to small and medium sized customers to choose between time varying and flat network charges. CoAG in December 2012 proposed the phasing in of time varying network charges by July 2014.

The Victorian Government expects to complete a rollout of interval meters with remote communications to all customers by the end of 2013. A moratorium on the introduction of time varying prices for small customers with interval meters is in place until July 2013.[6] From that time, customers will be able to choose to move to time varying prices.

Interval meter costs have been progressively passed on to Victorian retail customers since 1 January 2010. Network charges increased by almost $70 for a typical small retail customer in 2010, with a further increase of around $8 in 2011. In October 2011 the AER released a final determination on metering services budgets and charges for 2012–15.[7] Over this period, meter costs will increase network charges for a typical small retail customer by $9–21 per year.[8]

In addition to metering developments, the Australian Government in 2010 implemented a $100 million Smart Grid, Smart City initiative to support the installation of Australia's first commercial scale smart grid. Based in Newcastle and several other locations in New South Wales, the initiative explores the use of advanced communication, sensing and metering equipment to provide customers with improved energy use information, automation and savings, and to improve network reliability. The initiative is also looking at options to connect additional localised generation (such as solar) and hybrid vehicles to the grid.

6 If the customer consumes less than 20 megawatt hours of electricity per year.

7 AER, *Victorian advanced metering infrastructure review—2009–11 AMI budget and charges applications, final determination*, 2009.

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

2.6.3 Other demand management initiatives

In distribution, the AER applies incentives for demand management that enable businesses to investigate and implement non-network approaches to manage demand. The schemes fund innovative projects that are additional to the demand management 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. No business is compelled to take up the scheme. In reviewing the impact of climate change policies on energy market frameworks, the AEMC recommended expanding the allowance to cover innovations in connecting generators to distribution networks. A Rule change on this issue was finalised in December 2011. The AER will review the demand management incentive schemes once CoAG finalises its response to the AEMC's *Power of choice* recommendations.

In April 2012 ClimateWorks Australia, Seed Advisory and the Property Council of Australia submitted a Rule change request to the AEMC on the process for connecting generators to the distribution network. The request sought to enable a more timely, clear and less expensive process for these connections. The proponents considered the current process poses uncertainty for connection applicants. The AEMC published a consultation paper in August 2012 on the proposal.

The Senate Select Committee on electricity prices (section 2.9.1) recommended in November 2012 that SCER examine barriers to embedded generation. Additionally, it recommended that the AEMC amend the Electricity Rules to ensure network charges and payments (for network support) for these generators are appropriate.

2.7 Transmission network performance

Barometers of performance for electricity transmission networks include:

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

2.7.1 Reliability of supply

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 2010–11 caused less than 3 minutes of unsupplied energy in New South Wales, Victoria and South Australia; Tasmania had 8 minutes of unsupplied energy. No data were published for Queensland. Performance improved in 2010–11 compared with the previous year in Victoria, South Australia and Tasmania.[9]

State and territory agencies determine transmission reliability standards. The AEMC in 2008 and 2010 recommended a national framework be introduced for a more consistent approach. The framework would economically derive standards using a customer value of reliability or a similar measure. A body independent of transmission network owners would determine standards by jurisdiction. A national reference template would provide a basis for comparing the standards in each jurisdiction, and jurisdictions would need to justify any divergence from the template.

The SCER in November 2011 agreed with the AEMC's recommendations, noting the reforms would help optimise the balance between investment in transmission and generation assets. The reforms would also assist the AER's revenue determination process and enhance the effectiveness of the RIT-T.[10] The SCER requested the AEMC develop an implementation program for the reforms.

In its *Transmission frameworks review* (section 2.9.2), the AEMC noted national consistency in reliability standards would complement its proposals to coordinate decision making in transmission investment. It identified a role for AEMO, as the national transmission planner, to provide independent advice to the institutions that set reliability standards in each jurisdiction. Submissions to the AEMC review largely supported the proposal for a national framework on reliability standards.

2.7.2 Transmission network congestion

Physical limits (constraints) are imposed on electricity flows along transmission networks to avoid damage and maintain power system stability. These constraints can lead to network congestion, especially at times of high demand. Some congestion results from factors within the control of a

9 ESAA, *Electricity gas Australia 2012*, 2012.

10 MCE, *Transmission reliability standards review*, Response to AEMC final report, 2011.

network business—for example, the scheduling of outages, maintenance and operating procedures, and standards for network capability (such as thermal, voltage and stability limits). Factors beyond the control of the business include extreme weather—for example, hot weather can result in high air conditioning loads that push a network towards its pre-determined limits. Typically, most congestion occurs on just a few days, and is largely attributable to network outages.

If a major transmission outage occurs in combination with other generation or demand events, it can interrupt the supply of energy to some customers. This scenario is, however, rare in the NEM. Rather, the main impact of congestion is on the cost of producing electricity. In particular, transmission congestion increases the total cost of electricity by displacing low cost generation with more expensive generation. Congestion can also lead to disorderly bidding in the wholesale market, and to inefficient electricity trade flows between the regions (section 1.4).

Not all congestion is inefficient. Reducing congestion may require significant investment to augment the transmission network. Eliminating congestion is efficient to the extent that the market benefits outweigh the costs. The AER in 2008 introduced an incentive scheme to encourage network businesses to apply relatively low cost solutions to congestion.

2.7.3 Service target performance incentive scheme—transmission

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

- transmission circuit availability
- the average duration of transmission outages
- the frequency of 'off supply' events.

Rather than impose a common benchmark target on all transmission networks, the AER sets separate standards that reflect the circumstances of each network based on its past performance. Under the scheme, the over- or underperformance of a network against its targets results in a gain (or loss) of up to 1 per cent of its regulated revenue.

The scheme includes a separate component based on the market impact of transmission congestion (box 2.1). Under this component, a business can earn up to a further 2 per cent of its regulated revenue.

The results are standardised for each network to derive an 's factor' that can range between –1 (the maximum penalty) and +3 (the maximum bonus). Table 2.3 sets out the s factors for each network for the past six years. While performance against individual component targets has varied, the networks generally receive financial bonuses for overall performance. The only businesses to receive financial penalties in 2011 were TransGrid and Directlink.

In 2010–11 underperformance was evident in some areas. In New South Wales, transmission circuit availability was below target. Queensland and Tasmania underperformed in terms of critical transmission circuit availability. In Tasmania and Victoria, the average duration of outages increased.

Following a review, the AER in September 2012 released a draft proposal to amend the incentive scheme:

- Under the *service component*, a transmission circuit availability parameter would be replaced. Also, the definitions for other parameters would be standardised across the businesses. A 'near miss' parameter should be introduced (but with no financial incentive or penalty) that measures the number of times that protection and control equipment fail to operate correctly.
- Under the *market impact component*, a network's performance would be assessed as an average over two calendar years, and the target would be based on outcomes over the previous three calendar years, to encourage consistency in network performance.
- A *network capability component* would be introduced to incentivise transmission businesses to undertake expenditure to improve network capability. A business would receive an allowance to undertake a set of approved projects, and would be subject to penalties if it failed to achieve its target. AEMO would play a part in prioritising the projects to deliver best value for money for consumers.

The AER expected to finalise the amendments in December 2012. The changes, if adopted, would first apply to SP AusNet, Transend and TransGrid from 2014, although transitional arrangements associated with proposed changes to chapter 6A of the Electricity Rules will see a staged approach to adopting the new scheme.

Table 2.3 S factor values

	2006	2007	2008		2009		2010	2011
Powerlink		0.82		0.53		0.17	2.62	2.37
TransGrid	0.63	0.17		0.31	0.22	0.06	1.21	1.25
AusGrid	0.39	−0.14		0.72		0.37		
SP AusNet	−0.29	0.06	0.15	0.82		0.51	0.58	0.72
ElectraNet	0.59	0.28	0.29	−0.40		0.60	0.00	0.84
Transend	0.06	0.56		0.85	0.88	0.11	0.35	−0.41
Directlink	−0.54	−0.62		−1.00		−0.98	−1.00	−0.87
Murraylink	0.21	−0.32		0.69		0.87	1.00	0.70

Notes:

SP AusNet reported separately for the first quarter of 2008 and the remainder of the year.

ElectraNet reported separately for the first and second halves of 2008.

TransGrid and Transend reported separately for the first and second halves of 2009. AusGrid data for 2009 are for the six months to June; AusGrid moved to the distribution performance framework on 1 July 2009.

In 2008 SP AusNet transitioned to a new regulatory period, with the financial incentive capped at 1 per cent of its maximum allowable revenue. Its financial incentive in previous regulatory periods was capped at 0.5 per cent.

Source: AER, *Transmission network service providers: electricity performance report for 2010–11*, 2012.

Box 2.1 Incentives to reduce network congestion

The AER in 2008 expanded the *service target performance incentive scheme* to provide incentives for network businesses to apply relatively low cost solutions to congestion. The *market impact parameter* operates as a bonus only scheme and rewards transmission network owners for improving their operating practices to reduce congestion. These practices may include more efficient outage timing and notification, the minimising of outage impact on network flows (for example, by conducting live line work, maximising line ratings and reconfiguring the network) and equipment monitoring.

The mechanism permits a transmission business to earn an annual bonus of up to 2 per cent of its revenue if it can eliminate all outage events with a market impact of over $10 per megawatt hour.

TransGrid, Powerlink, ElectraNet and SP AusNet participate in the scheme, which appears to be driving improved behaviour by the transmission businesses. The AER's qualitative analysis of market outcomes found a reduction in outage related high price events across all regions that participate in the scheme. Payments to date under the scheme total around $46 million (table 2.4).

Table 2.4 Incentive payments under the market impact parameter

	PAYMENTS ($M)			
TRANSMISSION NETWORK	2009	2010	2011	TOTAL
TransGrid	1.3[1]	10.3	10.7	22.3
Powerlink		6.8[1]	15.2	22.0
SP AusNet			0.0[2]	0.0
ElectraNet			1.5	1.5

1. Payments for 1 July to 31 December.
2. Payments for 1 August to 31 December.

2.8 Distribution network performance

Barometers of performance for electricity distribution networks include:

- reliability of supply
- levels of customer service.

2.8.1 Reliability of distribution networks

Reliability is the main barometer of service 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.

Distribution outages account for over 95 per cent of electricity outages in the NEM. The capital intensive nature of distribution networks makes it expensive to build in high levels of redundancy (spare capacity) to improve reliability. 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, network outages should be kept to efficient levels—based on the assessed value of reliability to the community (measuring the impact on services) and the willingness of customers to pay—rather than trying to eliminate every possible interruption.

State and territory governments determine distribution reliability standards. The trade-off between reliability and cost means a government decision to increase reliability standards may require substantial new investment and affect customer bills. The SCER in August 2011 noted the significant impact of distribution investment on retail electricity prices, and directed the AEMC to review the approaches to setting distribution reliability standards across jurisdictions, with a view to developing a national approach. This review follows the AEMC review of transmission reliability standards, completed in 2010 (section 2.7.1).

In November 2012 the AEMC proposed the introduction of a nationally consistent framework for distribution reliability.[11] It recommended jurisdictions continue to set reliability standards, but follow a consistent national approach based on output performance. It also recommended reporting and incentive scheme arrangements be standardised.

In parallel with this broad review of distribution reliability standards, the SCER also directed the AEMC to make a more detailed review of standards in New South Wales. The aim was to identify the costs and benefits of alternative approaches. The AEMC's August 2012 report found a reduction in reliability standards could reduce distribution network investment by $275 million to $1.3 billion over 15 years, depending on how much the standards are reduced. It forecast an increase in outages for an average customer of 2–15 minutes per year, corresponding with average customer savings of $3–15 per year. The cost savings in reducing reliability standards from their current settings were found to provide consumer benefits that would exceed the adverse impact of weaker reliability performance. In contrast, the costs of further improving reliability would outweigh the benefits.[12]

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.

Figure 2.6 estimates historical data on the average duration (SAIDI) and frequency (SAIFI) of outages experienced by distribution customers. The data include outages that originate in the generation and transmission sectors.

A number of issues limit the validity of comparing reliability data 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.

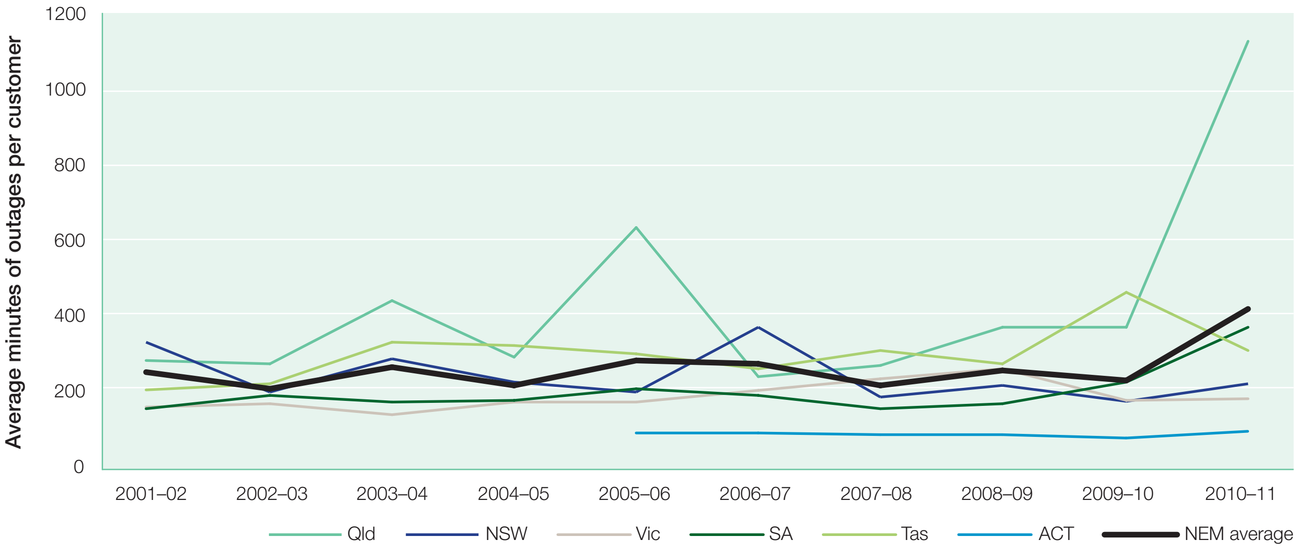
Noting these caveats, the SAIDI data indicate electricity networks in the NEM delivered reasonably stable reliability outcomes over the past few years. Across the NEM, a typical customer experiences around 200–250 minutes of outages per year, but with significant regional variations.

11 AEMC, *Review of distribution reliability outcomes and standards, draft report—national workstream*, 2012.

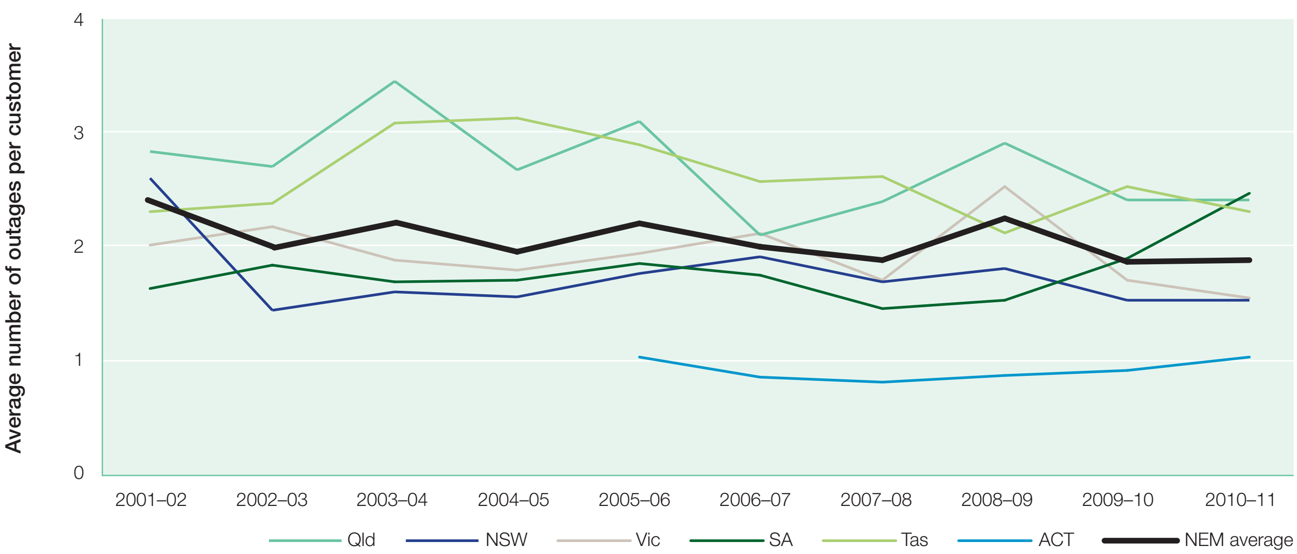
12 AEMC, *Review of distribution reliability outcomes and standards, final report—NSW workstream*, 2012.

Figure 2.6
System reliability

SAIDI



SAIFI



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. Queensland data for 2009–10 are for the year ended 31 March 2010.

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

In 2010–11 the average duration of outages per customer rose in all jurisdictions other than Tasmania. The largest increase occurred in Queensland, where an average customer experienced 1122 minutes of outages in that year—the highest duration in a NEM jurisdiction in the past decade. Performance on both the Energex and Ergon Energy networks was affected by extreme weather, with severe flooding in the south east and Cyclone Yasi in the north. Queensland experiences significant variations in performance, partly because its large and widely dispersed rural networks make it more vulnerable to outages than are other NEM jurisdictions.

South Australian customers also experienced a large increase in outage duration in 2010–11, with a higher than average level of extreme weather events during the period—including three severe storms that accounted for one-third of the outage time. Tasmanian outages in 2010–11 were close to the state's average for the past 10 years. This performance followed a high average outage duration in 2009–10, largely caused by six days when storms, lightning and wind affected network performance.

The SAIFI data show the average frequency of outages was relatively stable between 2002–03 and 2010–11, with energy customers across the NEM experiencing an outage around twice a year. The average frequency of outages in 2010–11 was consistent with that of the previous year in all jurisdictions except South Australia (which had an increase in the number of outages).

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* of outages for each distribution business. The targets are based on historical data. From a customer perspective, the unadjusted reliability data in figure 2.6 are relevant, but in assessing network performance the AER normalises data to exclude interruption sources beyond the network's reasonable control. In 2010–11 most businesses underperformed against their targets—that is, their customers experienced more minutes of outages than targeted.

The AER also sets targets for the average *frequency* of outages for some distribution businesses. In 2010–11 all businesses outperformed their targets—that is, their customers experienced less frequent outages than targeted.

2.8.2 Customer service—distribution

Network businesses report on their responsiveness to customer concerns, including the timely connection of services, call centre performance and customer complaints. Table 2.5 provides a selection of data. Customer service outcomes in 2010–11 broadly aligned with those of previous years, but there was some deterioration in performance. Aurora Energy (Tasmania) and SP AusNet (Victoria) recorded their highest proportion of late connections for the past five years. And call centre responsiveness fell sharply in four of the Victorian networks and Queensland's Ergon Energy network.

2.8.3 Distribution service performance incentives

The AER's service target performance incentive scheme encourages distribution businesses to maintain or improve service performance. It focuses on supply reliability (section 2.8.1) and customer service (section 2.8.2). It includes a guaranteed service level (GSL) component, under which customers are paid directly if performance falls below threshold levels. The GSL component does not apply if the distribution business is subject to jurisdictional GSL obligations.

The incentive scheme generally provides financial bonuses and penalties of up to 5 per cent of revenue to network businesses that meet (or fail to meet) performance targets.[13] 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 currently applies in Queensland, Victoria, South Australia and Tasmania, and as a paper trial in New South Wales 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 in a network. A fire start includes any fire that originates from a network, or is caused by something coming into contact with the network. This 'f factor' scheme will reward or penalise the businesses $25 000 per fire under or over their fire start targets.

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

Table 2.5 **Timely provision of service by electricity distribution networks**

NETWORK	PERCENTAGE OF CONNECTIONS COMPLETED AFTER AGREED DATE					PERCENTAGE OF CALLS ANSWERED BY HUMAN OPERATOR WITHIN 30 SECONDS				
	2006–07	2007–08	2008–09	2009–10	2010–11	2006–07	2007–08	2008–09	2009–10	2010–11
QUEENSLAND[1]										
Energex	0.6	10.8	2.5	0.4	…	79.1	96.3	89.7	90.0	86.6
Ergon Energy	0.5	0.7	0.3	0.4	…	87.0	86.2	87.2	87.0	78.1
NEW SOUTH WALES[2]										
AusGrid	<0.1	<0.1	<0.1	<0.1	<0.1	74.3	81.1	79.7	82.6	83.6
Endeavour Energy	<0.1	<0.1	<0.1	<0.1	<0.1	70.9	96.2	92.0	90.2	90.2
Essential Energy	<0.1	<0.1	<0.1	<0.1	<0.1	…	61.4	51.4	62.5	61.1
ActewAGL	…	…	…	…	…	62.4	70.5	70.2	72.9	75.7
VICTORIA[3]										
Powercor	<0.1	<0.1	<0.1	<0.1	<0.1	89.4	90.0	86.6	85.3	67.4
SP AusNet	2.7	1.7	2.6	1.7	3.9	91.2	92.3	91.6	92.6	94.1
United Energy	0.1	0.1	0.1	0.0	0.2	74.0	73.0	73.1	76.2	60.1
CitiPower	0.1	<0.1	<0.1	<0.1	<0.1	87.2	87.8	82.0	82.3	73.4
Jemena	0.2	0.8	0.9	0.1	<0.1	79.9	73.1	77.4	77.2	60.1
SOUTH AUSTRALIA[1]										
SA Power Networks	0.5	3.3	0.6	0.6	0.6	89.3	88.7	88.5	88.6	87.6
TASMANIA[1]										
Aurora Energy	3.9	4.6	4.6	3.7	14.5	…	…	…	…	…

1. Completed connections data for Queensland, South Australia and Tasmania include new connections only. Queensland data for 2009–10 are for the year ended 31 March 2010.
2. New South Wales completed connections data are state averages.
3. Victorian data are for the calendar year beginning in that period.

Sources: Distribution network performance reports by the AER (Victoria), IPART (New South Wales), the QCA (Queensland), ESCOSA (South Australia), OTTER (Tasmania) and the ICRC (ACT). Some data are AER estimates derived from official jurisdictional sources.

Jurisdictional GSL schemes

Jurisdictional GSL schemes provide for payments to customers experiencing poor service. The schemes are not intended to provide legal compensation to customers, but to enhance the service performance of distribution businesses.

These schemes 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 2011–12 related to the duration and frequency of supply interruptions exceeding specified limits. This outcome is consistent with previous years' results.

In Victoria (in 2011) and New South Wales (in 2010–11), GSL payments rose slightly from the previous year. Payments in Victoria (almost $8 million, compared with $7 million in 2010) were mostly for low reliability in the Powercor and SP AusNet networks. The rise in payments by New South Wales networks was largely due to a slightly diminished performance in providing timely and accurate information on interruptions to supply.

SA Power Networks (South Australia) also increased GSL payments in 2010–11, to almost $7 million—nearly four times higher than its payment in 2009–10. This rise was largely driven by an increase in payments for supply interruptions longer than 18 hours, resulting from severe weather events.

Aurora Energy (Tasmania) made GSL payments of $1.1 million in 2010–11. This total was significantly down on payments in 2009–10 ($4.7 million) resulting from outages associated with a major storm in September 2009.

2.9 Policy developments for electricity networks

The AEMC undertakes reviews on its own initiative or as directed by the SCER, and provides policy advice on electricity market issues. It is also responsible for Rule making under the Electricity Law, including determinations on proposed Rule changes. It progressed or finalised a number of reviews and Rule change proposals in 2012.

2.9.1 Senate Select Committee on electricity prices

In August 2012 a Senate Select Committee was formed to investigate the cause of electricity price rises, review the regulatory framework for electricity networks, and identify options to manage energy use and reduce energy costs.

The committee released its final report in November 2012. Many of its recommendations were proposed in previous reviews, including the AEMC's review of the Rules for network regulation (section 2.2.2), the independent review of the Limited merits review regime (section 2.2.4), the Transmission frameworks review (section 2.9.2) and the *Power of choice* review (section 2.6.1). The committee recommended:

- developing new guidelines for calculating a network business's required rate of return
- having the AEMC set national reliability standards that reflect customers' valuation of reliability
- making AEMO the single network planning agency for the NEM, including responsibility for implementing reliability standards
- decoupling network revenues from energy volumes, and providing more guidance in the Electricity Rules on setting network prices to reflect costs
- enabling the AER to review the efficiency of historical capital expenditure
- providing incentives for generators to consider the network costs of their location decisions, and for more transparent negotiation between generators and network businesses.

2.9.2 Transmission frameworks review

The AEMC in 2012 continued reviewing arrangements for the provision and use of electricity transmission services, and implications for the NEM's market frameworks. The review aims to ensure market frameworks—including incentives for generation and network investment—align with frameworks for network operation to deliver efficient outcomes. It stems from earlier AEMC findings that climate change policies would affect the use of transmission networks and place stress on market frameworks.[14]

In August 2012 the AEMC published its second interim report, which addressed three broad issues:

- Generators' certainty of access to the network—the AEMC presented an option for generators to purchase 'firm' access from network business at charges reflecting the additional cost of providing capacity. Generators with firm access would be compensated by 'non-firm' generators or the network business if they are constrained from supplying electricity.
- Network planning—the AEMC proposed to enhance transmission planning and investment by expanding the role of the national transmission planner. The new functions would include reviewing network planning reports and RIT-T processes, providing demand forecasts for network planning, and assuming the Last Resort Planning Power from the AEMC. Additionally, the AEMC proposed networks be required to consult with each other and the national transmission planner on projects with interregional impacts.
- Network connection arrangements—the AEMC proposed to improve the information available to connection applicants, which would include publishing standard contracts and design standards. Applicants would have increased access to cost information, greater input into the selection of contractors, and the ability to determine how extension assets are provided.

The AEMC expects to release the final report prior to 31 March 2013.

2.9.3 Productivity Commission review of electricity network regulatory frameworks

In January 2012 the Australian Government directed the Productivity Commission (PC) to examine the efficiencies of using benchmarking in network regulation, and to assess whether the regulatory regime is delivering efficient interconnector investment. The PC's draft report (released October 2012) found:

- benchmarking, while not yet capable of replacing the current framework for setting network revenues, could be incorporated into existing processes to test network business proposals. The AER, in consultation with industry, has been developing key benchmark indicators for use in future regulatory reviews.
- interconnection is sufficient at present, but the current framework may not encourage efficient levels of interconnection in the future. It recommended amendments to the RIT-T to remove a bias against interconnection investment.

14 AEMC, *Review of energy market frameworks in light of climate change policies, final report*, 2009.

- changes to the regulatory framework may allow for more efficient use of interconnector capacity. It considered the recommendation in the AEMC's transmission frameworks review regarding optional firm access to transmission capacity should largely address this concern. Over the longer term, nodal pricing (where the price paid to generators varies within a region) should be considered.

Outside its terms of reference, the PC also recommended enhancing consumer participation by establishing an industry funded consumer body and encouraging greater demand side participation.

2.9.4 Interregional transmission charging

In February 2010 the SCER proposed a Rule change on interregional charging arrangements for transmission networks, to promote more efficient operation of, and investment in, the networks. Currently, a transmission business recovers its costs from customers within the region in which its network is located. Customers in an *importing* region, therefore, do not pay the costs incurred in an *exporting* region to serve their load. The proposed Rule change would introduce a load export charge that effectively treats the business in the importing region as a customer of the business in the exporting region.

Consultation on the Rule change identified issues with existing transmission charging methods, including a lack of consistency in how charges are calculated across NEM regions. These issues could reduce the efficiency of the proposed scheme and make interregional charges more volatile. The AEMC is developing a uniform national interregional transmission charging regime to address these issues. It released a discussion paper in August 2011, setting out options. The AEMC completed modeling of the proposed options in October 2012 and presented a recommendation for the charging method. A final Rule determination is expected by February 2013.

2.9.5 Distribution network planning and expansion

The AEMC finalised a Rule change in October 2012 on a national framework for electricity distribution network planning and expansion, to support efficient investment decisions. The new provisions include requirements for distribution businesses to:

- annually review and report on network requirements for the following five years
- observe demand side engagement obligations, including consulting with non-network providers and considering their proposals
- undertake joint planning on common issues across networks.

The provisions also introduce a RIT-D, with dispute resolution through the AER (section 2.4.1).

2.9.6 Electric and natural gas vehicles

In 2011 the SCER requested the AEMC to identify energy market arrangements for the economically efficient uptake of electric and natural gas vehicles. The AEMC's draft report in August 2012 found existing market arrangements could accommodate natural gas vehicles. But, without appropriate price signals in place, electric vehicles could impose significant additional costs on the network that all customers would bear. The AEMC recommended introducing:

- separate metering of large loads (including electric vehicles) to allow for appropriate price signals and enable competition in the supply of energy for these loads
- metering arrangements to enable charging infrastructure to be installed on commercial properties.

The AEMC's final advice was expected towards the end of 2012.

2.9.7 Cost pass through arrangements

In October 2011 Grid Australia submitted a Rule change proposal to the AEMC requesting amendments to the cost pass through regime for electricity networks. It argued the networks are exposed to the risk of significant cost impacts from natural disasters and third party insurance liability claims that are beyond their reasonable control.

In August 2012 the AEMC finalised a Rule change that will enable a transmission network to nominate additional pass through events when it submits a revenue proposal to the AER (matching the current arrangement for distribution networks). The AER must have regard to specified considerations when determining whether to accept the pass through event. The Rule also allows networks to recover their efficient costs if a pass through event occurs in the final year of a regulatory period.

Origin Energy

3 UPSTREAM GAS MARKETS

The two main types of gas in Australia are conventional natural gas and coal seam gas (CSG). Conventional natural gas is found trapped in underground reservoirs, often along with oil. In contrast, CSG is a form of gas extracted from coal beds. There are also renewable gas sources, such as biogas (landfill and sewage gas) and biomass (wood, wood waste and sugarcane residue). The potential for shale gas is being explored in the Cooper Basin.[1]

Gas is produced both for domestic markets and for export as liquefied natural gas (LNG). The 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 that may be present, and to remove any impurities.

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 in wholesale markets 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,[2] it has some coverage of upstream gas markets in Western Australia and the Northern Territory, and LNG export markets.

Chapter 4 considers the transmission and distribution pipeline sectors; chapter 5 covers the retailing of gas to small customers.

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

2 The AER has compliance and enforcement responsibilities (under parts 18–20 of the National Gas Rules) in relation to the Natural Gas Market Bulletin Board, the Victorian wholesale gas market and the short term trading market that commenced operating in Sydney and Adelaide in 2010, and in Brisbane in December 2011.

3.1 Gas reserves and production

In August 2012 Australia's proved and probable (2P) gas reserves stood at around 140 000 petajoules (PJ), comprising 98 000 PJ of conventional natural gas and 42 000 PJ of CSG (table 3.1 and figure 3.2).

Total 2P reserves increased by around 21 per cent in 2011–12, mainly due to the upgrading of Browse Basin reserves in Western Australia to 2P status. Excluding this change, 2P reserves rose nationally by 6 per cent in 2011–12. CSG reserves in Queensland and New South Wales rose by 10 per cent.

Australia produced 1924 PJ of gas in 2011–12, of which around 55 per cent was for the domestic market. Production for domestic use was down 1.4 per cent from levels in 2010–11. The CSG share of production for domestic use rose from 21 per cent in 2010–11 to 23 per cent in 2011–12. Around 45 per cent of Australia's gas production—all currently sourced from offshore basins in Western Australia and the Northern Territory—is exported as LNG. This ratio will increase, with the development of major LNG projects in Queensland and Western Australia (section 3.2.1).

3.1.1 Geographic distribution

Western Australia's offshore Carnarvon Basin holds about half of Australia's 2P gas reserves. It supplies almost one third of Australia's domestic market and 99 per cent of Australian gas for LNG export.[3]

The Bonaparte Basin along the north west coast contains 1 per cent of Australia's gas reserves. While the basin's development has focused on producing LNG for export (which began in 2006), the Bonaparte Pipeline was commissioned in 2008 to ship gas to the Northern Territory for domestic consumption. The basin has now displaced the Amadeus Basin as the main source of gas for the Northern Territory.

Eastern Australia contains around 35 per cent of Australia's gas reserves, of which the majority are CSG reserves in the Surat–Bowen Basin. The basin, which extends from Queensland into northern New South Wales, accounts for 80 per cent of gas reserves in eastern Australia and supplies 35 per cent of that market. In New South Wales, commercial production of CSG began in 1996 in the Sydney Basin and more recently in the Gunnedah Basin. CSG production in eastern Australia rose by 7 per cent to 247 PJ in 2011–12,

3 Data on gas production, consumption and reserves are sourced from EnergyQuest, *Energy Quarterly*, August 2012.

Figure 3.1
Domestic gas supply chain

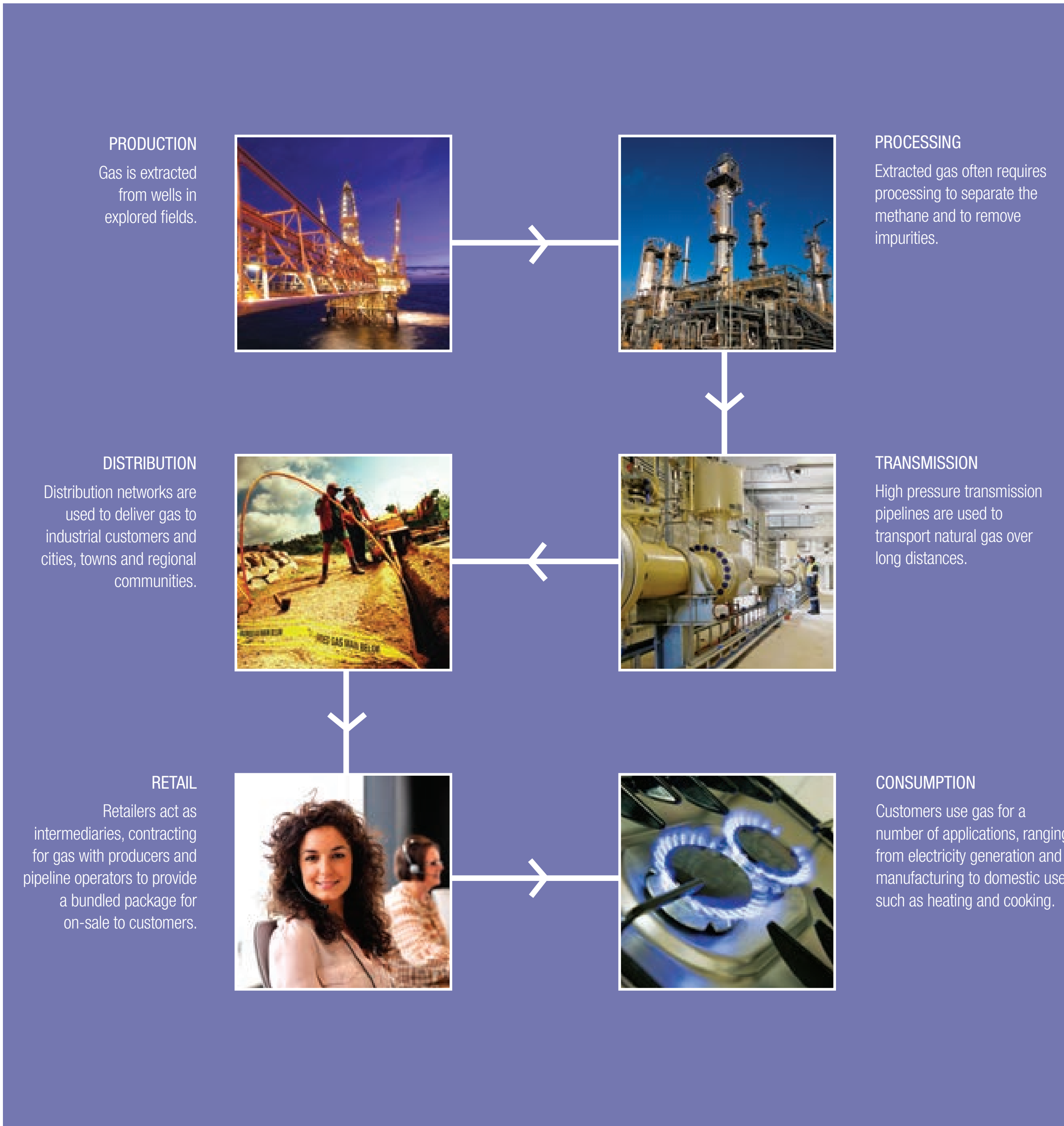
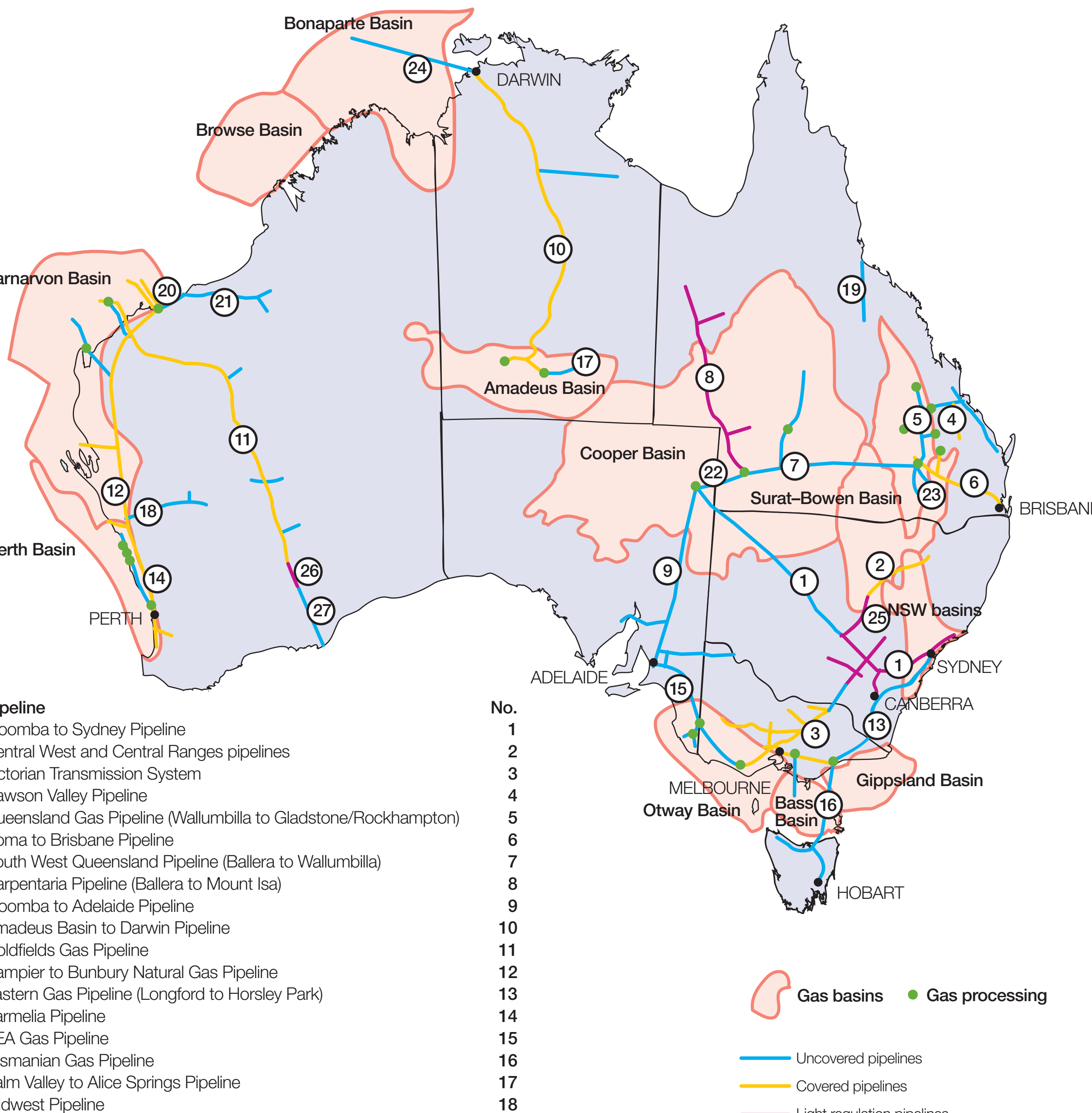


Image Sources: Origin Energy, Woodside, Jemena.

Figure 3.2

Australian gas basins and transmission pipelines



Pipeline	No.
Moomba to Sydney Pipeline	1
Central West and Central Ranges pipelines	2
Victorian Transmission System	3
Dawson Valley Pipeline	4
Queensland Gas Pipeline (Wallumbilla to Gladstone/Rockhampton)	5
Roma to Brisbane Pipeline	6
South West Queensland Pipeline (Ballera to Wallumbilla)	7
Carpentaria Pipeline (Ballera to Mount Isa)	8
Moomba to Adelaide Pipeline	9
Amadeus Basin to Darwin Pipeline	10
Goldfields Gas Pipeline	11
Dampier to Bunbury Natural Gas Pipeline	12
Eastern Gas Pipeline (Longford to Horsley Park)	13
Parmelia Pipeline	14
SEA Gas Pipeline	15
Tasmanian Gas Pipeline	16
Palm Valley to Alice Springs Pipeline	17
Midwest Pipeline	18
North Queensland Gas Pipeline	19
Pilbara Pipeline	20
Telfer Pipeline	21
QSN Link	22
Berwyndale to Wallumbilla Pipeline	23
Bonaparte Pipeline	24
Central West Pipeline	25
Kalgoorlie to Kambalda Pipeline	26
Kambalda to Esperence Pipeline	27

Source: AER.

Table 3.1 Gas reserves and production, 2012

GAS BASIN	PRODUCTION (YEAR TO JUNE 2012) PETAJOULES	PRODUCTION (YEAR TO JUNE 2012) PERCENTAGE OF DOMESTIC SALES	PROVED AND PROBABLE RESERVES[1] (AUGUST 2012) PETAJOULES	PROVED AND PROBABLE RESERVES[1] (AUGUST 2012) PERCENTAGE OF AUSTRALIAN RESERVES
CONVENTIONAL NATURAL GAS				
WESTERN AUSTRALIA				
Browse	0	0.0	17 384	12.4
Carnarvon	342	32.1	72 456	51.8
Perth	5	0.5	41	0.0
NORTHERN TERRITORY				
Amadeus	1	0.1	138	0.1
Bonaparte	20	1.9	1 123	0.8
EASTERN AUSTRALIA				
Cooper (South Australia–Queensland)	95	8.9	1 740	1.2
Gippsland (Victoria)	244	22.8	4 124	2.9
Otway (Victoria)	102	9.6	847	0.6
Bass (Victoria)	8	0.8	249	0.2
Surat–Bowen (Queensland)	4	0.4	147	0.1
Total conventional natural gas	820	76.9	98 249	70.2
COAL SEAM GAS				
Surat–Bowen (Queensland)	241	22.6	38 918	27.8
New South Wales basins	6	0.5	2 827	2.0
Total coal seam gas	247	23.1	41 745	29.8
AUSTRALIAN TOTALS	1 067	100.0	139 994	100.0
LIQUEFIED NATURAL GAS (EXPORTS)				
Carnarvon (Western Australia)	846			
Bonaparte (Northern Territory)	12			
Total liquefied natural gas	857			
TOTAL PRODUCTION	1 924			

1. Proved reserves are those for which geological and engineering analysis suggests at least a 90 per cent probability of commercial recovery. Probable reserves are those for which geological and engineering analysis suggests at least a 50 per cent probability of commercial recovery.

Source: EnergyQuest, *Energy Quarterly*, August 2012.

in contrast to an overall decline of 6 per cent in east coast conventional gas production.

The Gippsland Basin off coastal Victoria supplies 35 per cent of the eastern market. Production in Victoria's offshore Otway Basin (15 per cent of eastern production) has risen significantly since 2004, but declined by 4 per cent in 2011–12.

After several years of decline, Cooper Basin reserves in central Australia rose in the past two years, up 27 per cent in the year to June 2012. Production in the basin may continue to rise in the future, with new activity focused on the development of shale gas.[4]

4 In August 2012 Santos announced Australia's first commercially viable gas drawn from fractured shale rock at Moomba.

3.2 Gas demand

Australia consumed 1067 PJ of gas in 2011–12 (down slightly from 1082 PJ in 2010–11) for industrial, commercial and domestic use. The consumption profile varies across the jurisdictions.

While gas is widely used in most jurisdictions for industrial manufacturing, a key driver of domestic gas demand over the next 20 years is likely to be in gas powered electricity generation (section 3.5.1). Western Australia, South Australia, Queensland and the Northern Territory especially rely on gas for electricity generation. In Western Australia, the mining sector is also a major user of gas. 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.

3.2.1 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, and is developing new projects in Queensland. While exports of Australian produced LNG decreased in 2011–12 by 9 per cent (to 15.6 million tonnes),[5] major players are continuing to expand capacity:

- Woodside's 4.3 million tonne per year Pluto project (Carnarvon Basin) is completed and began exporting LNG in May 2012. It became Australia's third operational LNG project. The estimated development cost was $14.9 billion.
- Chevron's Gorgon project (Carnarvon Basin) is scheduled to begin operation in 2014 and will produce around 15.6 million tonnes of LNG per year. The project partners have signed long term sales agreements with international buyers. EnergyQuest reported the project was over 45 per cent complete in June 2012. In addition, Chevron committed to the $29 billion Wheatstone project (foundation capacity of 8.9 million tonnes per year) in September 2011. 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 Inpex and Total's $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 2017.
- The Browse LNG project—Woodside (operator) 31 per cent, Shell 27 per cent, BP 17 per cent, MIMI 14.7 per cent and BHP Billiton 10 per cent—reached the front end engineering and design (FEED) stage in 2012. The project is expected to produce 12 million tonnes per year.

In Queensland, long term projections of rising international energy prices, together with rapidly expanding reserves of CSG, have spurred the development of several LNG projects near the port of Gladstone. Construction of three projects, including three gas transmission pipelines to transport gas to Gladstone, is underway:

- The $20 billion Curtis LNG project (BG Group) will initially produce 8.5 million tonnes per year, with potential capacity of 12 million tonnes. The first exports are expected in 2014.
- 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.
- The proponents of the Australia Pacific LNG project (Origin Energy, ConocoPhillips and Sinopec) announced the approval of a second 4.5 million tonne per year production train, increasing total capability to 9.0 million tonnes annually. Construction on the first train commenced in May 2011, and first LNG exports are expected in 2015. Exports from the second train are expected to commence in 2016. The cost of the two trains is estimated at $23 billion.

A fourth project—Arrow LNG project (Shell and PetroChina)—is at the planning stage. It will produce up to 18 million tonnes per year, with first exports expected in 2017. With Queensland LNG projects coming onstream from around 2014–15, Australia would likely become the world's second largest exporter of LNG.[6]

3.3 Industry structure

Six major producers met 65 per cent of domestic gas demand in 2011–12: Santos, BHP Billiton, ExxonMobil, Origin Energy, Woodside and Apache Energy.[7] The mix of players varies across the basins.

3.3.1 Market concentration

Market concentration in particular gas basins depends on multiple factors, including the number of fields developed, the ownership structure of the fields, and acreage management and permit allocation. Figure 3.4 illustrates

5 LNG production and export data are sourced from EnergyQuest, *Energy Quarterly*, August 2011, p. 24.

6 Bureau of Resources and Energy Economics (BREE), *Gas market report*, July 2012, p. 1.

7 EnergyQuest, *Energy Quarterly*, August 2012.

estimated market shares in gas production for the domestic market in the major basins. Table 3.2 sets out market shares in 2P gas reserves (including reserves available for export) at August 2012.

Several major companies have equity in Western Australia's Carnarvon Basin, which is Australia's largest producing basin. The businesses participate in joint ventures, typically with overlapping ownership interests. Chevron (37 per cent), Shell (17 per cent) and ExxonMobil (14 per cent) have the largest reserves in the basin, given their equity in the Gorgon project.

Browse Basin reserves are included in table 3.2 for the first time, following their upgrading to 2P status. Inpex (55 per cent), Total (23 per cent) and Shell (15 per cent) are the major players in that basin.

Woodside (25 per cent) and Apache Energy (24 per cent) are the largest producers for Western Australia's domestic market. Santos (17 per cent), BP and Chevron (10 per cent each), and BHP Billiton and Shell (6 per cent each) also have significant market shares.

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.

In central Australia, a joint venture led by Santos (63 per cent) dominates production in the Cooper Basin. The other participants are Beach Petroleum (22 per cent) and Origin Energy (14 per cent).

The Gippsland, Otway and Bass basins off coastal Victoria serve the Victorian market and provide gas to New South Wales, South Australia and Tasmania. A joint venture between ExxonMobil and BHP Billiton accounts for around 93 per cent of production in the Gippsland Basin. Nexus, which began production from the Longtom gas project in October 2009, acquired a 7 per cent market share.

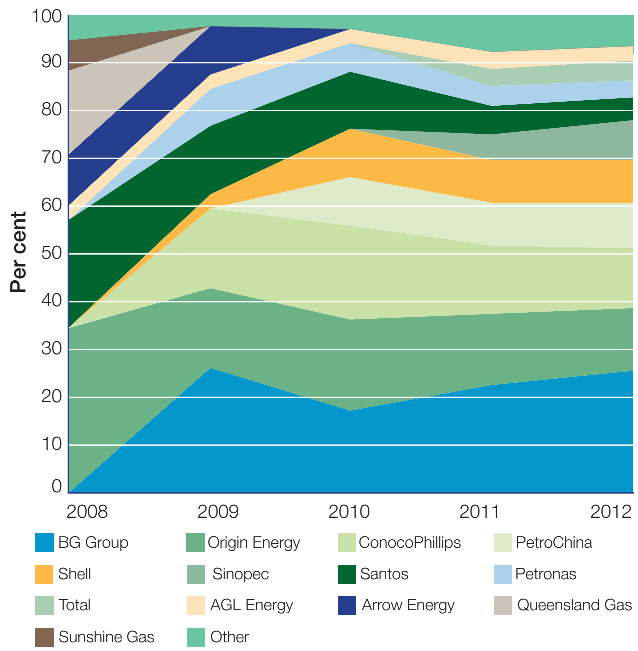
The Otway Basin has a more diverse ownership base, with Origin Energy (32 per cent), BHP Billiton (19 per cent) and Santos (18 per cent) accounting for the bulk of production. The principal producers in the smaller Bass Basin are Origin Energy and Australian Worldwide Exploration (AWE).

The growth of the CSG–LNG industry has led to considerable new entry in Queensland's Surat–Bowen Basin over the past decade. The largest producers are BG Group (21 per cent), Origin Energy (20 per cent), ConocoPhillips (19 per cent), Santos (9 per cent), Sinopec, Shell and PetroChina (6 per cent each). Petronas, Total and AGL Energy have smaller shares. The same businesses also own the majority of reserves in the basin.

Figure 3.3 shows changes in market shares of gas reserves in the Surat–Bowen Basin between 2008 and 2012. The changes reflect mergers and acquisitions, and the development of new projects. In 2008 three entities owned 75 per cent of reserves (Origin Energy 35 per cent, Santos 22 per cent and Queensland Gas 18 per cent). In contrast, the three largest players in 2012 jointly own 52 per cent of reserves (BG Group 26 per cent and Origin Energy and ConocoPhillips each 13 per cent).

Figure 3.3

Market shares in proved and probable reserves, Surat–Bowen Basin, 2008–12



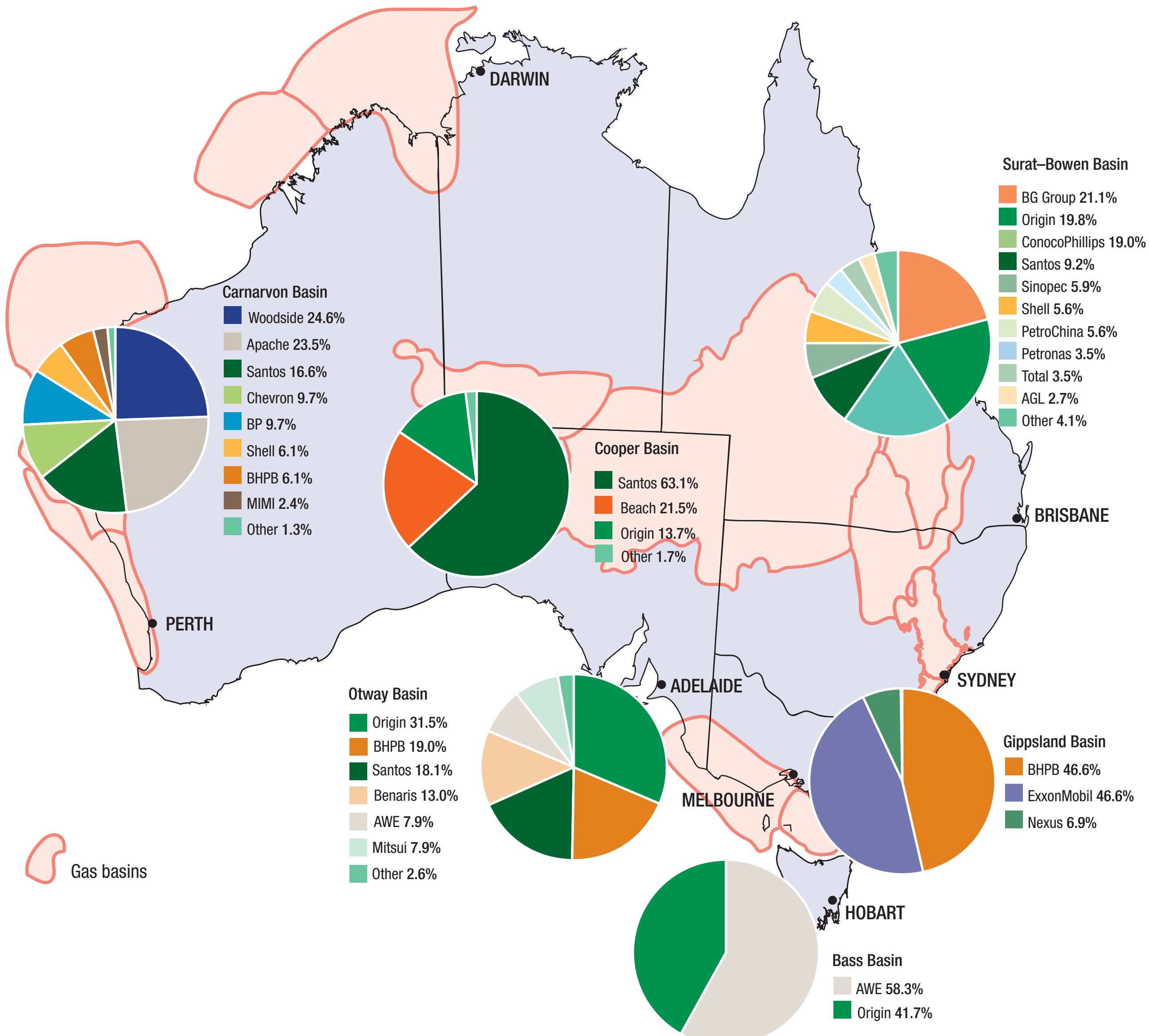
Data source: EnergyQuest 2008–12 (unpublished data).

3.3.2 Mergers and acquisitions

Merger and acquisition activity in upstream gas since 2006 has focused mainly on CSG (and associated LNG proposals) in Queensland and New South Wales. Previous editions of the AER's *State of the energy market* report listed proposed and successful acquisitions from June 2006 to October 2011. Subsequent activity until October 2012 included the following:

- In January 2012 Arrow Energy (Shell and PetroChina) completed its acquisition of Bow Energy, to source additional CSG resources for its Queensland LNG project.

Figure 3.4
Market shares in domestic gas production, by basin, 2011–12



Note: Excludes LNG.

Data source: EnergyQuest 2012 (unpublished data).

Table 3.2 Market shares in proved and probable gas reserves, by basin, 2012 (per cent)

COMPANY	CARNARVON (WA)	BROWSE (WA)	PERTH (WA)	BONAPARTE (WA/NT)	AMADEUS (NT)	SURAT–BOWEN (QLD)	COOPER (SA/QLD)	CLARENCE MORTON (QLD/NSW)	GUNNEDAH (NSW)	GLOUCESTER (NSW)	SYDNEY (NSW)	HUNTER (NSW)	GIPPSLAND (VIC)	OTWAY (VIC)	BASS (VIC)	ALL BASINS
Chevron	36.9															19.1
Shell	17.2	14.8				8.9										13.2
ExxonMobil	14.1												45.7			8.6
BG						25.6										7.1
Inpex		55.4		2.1												6.9
Woodside	11.4															5.9
Origin			63.7			13.0	12.9							37.1	42.5	4.1
Total		23.4				3.7										3.9
Santos	1.1			2.1	89.2	4.6	64.3		80.0				5.3	16.6		3.8
ConocoPhillips				10.4		12.6										3.6
BHPB	3.8												45.7	15.2		3.4
PetroChina						9.8										2.7
Sinopec						8.4										2.3
BP	4.2															2.2
Apache	3.6															1.9
MIMI	3.1															1.6
AGL						3.1				100.0	100.0	100.0				1.5
Petronas						3.7										1.0
CNOOC	1.1					1.2										0.9
Kogas		2.2				2.0										0.8
Eni				83.8												0.7
Kufpec	1.1															0.6
Osaka Gas	0.7	0.9														0.5
Mitsui						1.1								6.5		0.3
Metgasco								96.2								0.3
Beach							20.3							0.1		0.3
EnergyAustralia									20.0							0.2
Kansai Electric	0.4															0.2
Toyota Tsusho						0.5								2.8	11.3	0.2
Nexus													3.3			0.1
Benaris														15.3		0.1
AWE			36.3											6.5	46.3	0.1
Other	1.3	3.3		1.6	10.8	1.8	2.5	3.8								1.7
TOTAL (PETAJOULES)	72 456	17 384	41	1123	138	39 055	1758	445	1426	669	142	142	4124	847	249	139 998

Notes:

Based on 2P reserves at August 2012.

Not all minority owners are listed.

Source: EnergyQuest 2012 (unpublished data).

- In March 2012 AWE sold a share of its interest in the Bass Basin to Toyota Tsusho for $80 million. The transaction gives Toyota Tsusho an 11 per cent share in the reserves of that basin.
- In July 2012 Sinopec increased its stake in the Australia Pacific LNG project from 15 per cent to 25 per cent. Origin Energy and ConocoPhillips each hold a 37.5 per cent stake in the project.

3.3.3 Vertical integration

Vertical integration between gas production, gas powered generation and energy retailing is a means by which energy entities manage risk and achieve efficiencies. For example:

- Origin Energy is a leading energy retailer and is expanding its gas powered generation portfolio in eastern Australia. It has significant equity in CSG production in Queensland and in conventional natural gas production in Victoria's Otway and Bass basins, and a minority interest in gas production in the Cooper Basin. It accounted for 14 per cent of gas production in eastern Australia in 2011–12.
- AGL Energy is a leading energy retailer and a major electricity generator in eastern Australia. It began acquiring CSG interests in Queensland and New South Wales in 2005.

EnergyAustralia (formerly TRUenergy), a third major retailer and generator in eastern Australia, has gas storage facilities in Victoria and acquired gas reserves in the Gunnedah Basin (New South Wales) in 2011.

3.4 Gas wholesale markets

Gas producers sell gas in wholesale markets to major industrial, mining and power generation customers, and to energy retailers that onsell it to business and residential customers. While gas prices were historically struck under confidential, long term contracts, there has been a recent shift towards shorter term contracts and the emergence of spot markets. Victoria established a wholesale spot market in 1999 for gas sales, to manage system imbalances and pipeline network constraints. More recently, governments and industry established the National Gas Market Bulletin Board and a short term trading market in major hubs in eastern Australia.

3.4.1 Short term trading market

A short term trading market—a wholesale spot market for gas—has been progressively 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.[8] The AER monitors and enforces compliance with the market Rules (section 3.6).

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 3.4.2).

The short term trading market provides a spot mechanism for parties to manage contractual imbalances. It also provides a platform for secondary trading and demand side response by users. *Shippers* deliver gas to be sold in the market, and *users* buy gas for delivery to customers. Market participants include energy retailers, power generators and other large scale gas users. The same entity might sell gas into the market (if it has more gas than it requires) and also buy from the market (if it requires additional gas to meet demand).

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 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 Rules require the participants bid in 'good faith'.

Based on the market schedule, shippers nominate the quantity of gas 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, due to variations in demand and other factors. As gas requirements become better known during the day, shippers may renominate quantities (intraday nominations) with pipeline operators (depending on the terms of their contracts).

Pipeline operators use balancing gas to keep the pipeline in physical balance. AEMO procures this balancing gas—market operator service (MOS)—from shippers that have the capacity to absorb daily fluctuations, and the short term

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

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 (section 3.6.1).

Section 3.5.2 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.

3.4.2 Victoria's gas wholesale market

Victoria's spot market for gas was introduced 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 the scheduling intervals of 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. Given Victoria has a net market, the price applies to only net positions—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 constraints.[9]

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 3.5.2 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.

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

3.4.3 National Gas Market Bulletin Board

The National Gas Market Bulletin Board, which commenced in July 2008, is a website (www.gasbb.com.au) covering major gas production plants, storage facilities, demand centres and transmission pipelines in eastern Australia. There is provision for facilities in Western Australia and the Northern Territory to participate in the future.

The bulletin board aims to provide transparent, real-time information on the state of 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.

Bulletin board participants must provide the information, and the AER monitors and enforces compliance with the relevant Rules (section 3.6). AEMO operates the bulletin board; it also publishes an annual gas statement of opportunities to help industry participants plan and make commercial decisions on infrastructure investment.

3.4.4 Gas trading hub market—Queensland

In light of escalating gas development in south east Queensland, the Standing Council on Energy and Resources (SCER, formerly the Ministerial Council on Energy) in 2012 commissioned work on the possible design of a gas trading market at Wallumbilla in Queensland. The hub is a major pipeline interconnection point for the Surat–Bowen Basin.

The proposed model is for a 'brokerage' hub, or exchange, to match and clear trades using existing physical infrastructure. Given physical limitations within the Wallumbilla hub, separate trading nodes would be created for each of the major pipelines connected to the hub. The introduction of services to assist gas trading between nodes may follow. The market model is intended to be capable of replication in other locations.

SCER expected to consider the matter further in December 2012, with a view to launching the market from early 2014. Participation in the market would be voluntary.

3.5 Eastern Australia gas prices and market outlook

Australian gas prices have generally been low by international standards, typically $3–4 per gigajoule. They have also been relatively stable, defined by provisions in long term supply contracts. With gas in Australia historically perceived as a substitute for coal and coal fired electricity generation, Australia's low cost coal sources have effectively capped gas prices.

The growth of LNG export capacity in Western Australia from the late 1980s led to that state's domestic market being increasingly exposed to international energy prices. A similar scenario may be unfolding in eastern Australia, with LNG exports expected to commence from Queensland in 2014–15.

3.5.1 Market conditions

While EnergyQuest reported east coast gas prices under existing contracts remained steady in 2011–12 at around $4 per gigajoule, prices struck under new contracts rose to over $5 per gigajoule.[10] In spot markets, prices rose sharply in winter 2012 to over $6 per gigajoule (and exceeded $7 per gigajoule in all hubs on some days).

An interaction of several factors affects gas markets and price outcomes in eastern Australia. On the supply side, rising CSG production and improved pipeline interconnection among gas basins have made markets more responsive to customer demand. An interconnected transmission pipeline network in eastern Australia now enables gas producers in the Surat–Bowen, Cooper, Gippsland, Otway, Bass and New South Wales basins to sell gas to customers across Queensland, New South Wales, Victoria, South Australia, Tasmania and the Australian Capital Territory (ACT).

While gas demand in eastern Australia fell by 1.7 per cent in 2011–12,[11] two factors are expected to stimulate growth in the next 20 years: gas powered electricity generation and LNG exports from Queensland.

Gas powered electricity generation currently represents around 24 per cent of domestic gas demand in eastern Australia.[12] The Bureau of Resource and Energy Economics and ACIL Tasman noted in 2012 that carbon pricing would increase the competitiveness of gas powered generation relative to coal, making electricity generation a key growth source for domestic gas demand over the next two decades in eastern Australia.[13] But the recent weakening in electricity demand and gas price uncertainty may slow the growth in gas powered generation.

The *Queensland gas market review 2012* projected relatively modest growth in gas powered generation in the state to 2020, but significant growth beyond that time. It considered emerging difficulties in securing domestic gas contracts (due to competing LNG demand) may dampen new investment in gas powered generation.[14]

AEMO modelled in late 2012 that the stimulus from the RET to wind generation, combined with weaker projected energy demand, may delay the need for generation investment for several years; it forecast gas powered generation may not rise significantly until 2025.[15]

While LNG exports from Queensland are not expected to begin until 2014, the project developers are continuing to secure reserves to underpin supply contracts with overseas customers. This trend is starting to put pressure on domestic gas availability and prices. The 2012 Queensland review noted east coast prices are increasingly based on export opportunity value; domestic users are now competing with LNG when contracting for supply. The report also noted liquidity issues in the Queensland market, with gas in short supply for new contracts both pre- and post-2015. More generally, customers seeking new domestic supply contracts for gas post-2015 are facing a lack of basic market information (forward prices, volumes available and potential delivery timeframes) for contracting.[16] The Australian Government's *Energy White Paper 2012* considered the market is currently not providing efficient platforms for contracting, and that such arrangements may take some time to emerge.[17]

The development of LNG projects in Queensland was widely expected in 2011 to produce large quantities of 'ramp-up' gas that would be available to domestic markets at relatively low prices until the projects were commissioned. Contrary to these expectations, the 2012 Queensland review noted the domestic sale of ramp-up gas prior to the commencement of LNG exports may not materialise. It noted in the

10 EnergyQuest, *Energy Quarterly*, August 2011, pp. 94–5.

11 EnergyQuest, *Energy Quarterly*, August 2011, p. 9.

12 AEMO, *Gas statement of opportunities for eastern and southern Australia*, Executive briefing, 2011.

13 BREE, *Gas market report*, July 2012; ACIL Tasman, *National gas outlook: domestic gas prices and markets,* Presentation by Paul Balfe, 30 May 2012.

14 Department of Energy and Water Supply (Queensland), *Queensland gas market review 2012*, pp. 25–26.

15 AEMO, *2012 Electricity statement of opportunities,* p. iii; AEMO (unpublished briefing to AER, November 2012).

16 Department of Energy and Water Supply (Queensland), *Queensland gas market review 2012*, p. 23, 27, 38.

17 Australian Government, *Energy White Paper* 2012, p. 141.

current market environment, some proponents may be stockpiling reserves to preserve options for further LNG train development. The report also noted evidence of a new trend for LNG proponents to enter contracts with one another, including gas swaps. Its modelling found all four LNG projects would likely experience a shortfall in their required gas reserves at some stage in the period to 2030 and would need to source gas from the broader market.[18]

EnergyQuest agreed ramp-up gas would be less than previously expected, noting none of the projects appears to be achieving their drilling targets. The Bureau of Resources and Energy Economics noted landowners' concerns about the impact of CSG extraction on water resources have led to restrictions on drilling and tighter regulatory controls on land access.[19] EnergyQuest estimated in August 2012 that the Queensland LNG projects currently have 20–25 per cent deliverability necessary for their first LNG and other commitments.[20]

Aside from developments in Queensland, other factors are affecting east coast gas markets. EnergyQuest noted a lack of recent exploration success in offshore Victoria.[21] In New South Wales, complex regulatory hurdles have hampered the development of CSG resources in the Gunnedah and Gloucester basins.[22] Goldman Sachs noted policy uncertainty had effectively stalled gas development in that state for almost two years.[23] The New South Wales Government released its Strategic Regional Land Use Policy in September 2012, clarifying the regulatory regime for exploration and future development of the state's CSG resources.

Also, long term contract replacement is an ongoing issue; historical low priced domestic gas contracts will progressively expire over the next five years. Contract replacement activity is expected to peak in Queensland in 2015–16, and in New South Wales and Victoria in 2018. The expiration of low priced contracts and their renegotiation in a market exposed to global prices will continue to place pressure on domestic prices.[24]

Together, these factors are causing uncertainty in eastern gas markets and impacting on prices. The Bureau of Resources and Energy Economics predicts eastern gas wholesale prices will rise sharply in the short to medium term, converging towards global prices in anticipation of LNG exports from 2014–15.[25] ACIL Tasman projects gas prices for southern Queensland will remain higher than elsewhere in eastern Australia through to at least 2020, reaching around $9.40 per gigajoule by that time. It projected Victorian prices would be the lowest in eastern Australia, at around $7.70 per gigajoule in 2020.[26] Goldman Sachs expected New South Wales prices to link closely with those in Queensland.[27]

The 2012 Queensland review predicted Queensland domestic gas prices could rise to $6.50–10 per gigajoule by 2015 (depending on international energy market conditions). It predicted domestic prices of $7–$12 per gigajoule in 2020. The review's modelling indicated a widening divergence between Queensland domestic prices and relatively lower prices in the southern states. Goldman Sachs predicted the current scenario of Queensland gas exports to the southern states will reverse by 2014–15.

The 2012 Queensland review noted transportation costs would likely constrain flows of Victorian gas into Queensland, unless the gas price differential becomes sufficiently wide. Overall, it expected the gas market to further tighten from 2014–15 through to 2021, when greater volumes of unconventional gas—such as shale gas from the Cooper Basin and CSG from New South Wales—may become available. [28] ACIL Tasman also considered the development of shale gas may cap the upside in gas prices from around 2021.[29]

AEMO modelled in 2012 that eastern Australia has sufficient gas reserves to meet demand over the period to 2032, but that the speed of developing new reserves is crucial. It noted the relatively small volume of uncommitted 2P gas reserves, combined with a large proportion of reserves being earmarked for LNG export, create challenges for domestic supply.

18 Department of Energy and Water Supply (Queensland), *Queensland gas market review 2012*, pp. ix, x.

19 BREE, *Gas market report*, July 2012, p. 45.

20 EnergyQuest, *Energy Quarterly*, August 2012, p. 9.

21 EnergyQuest, *Energy Quarterly*, August 2012, p. 22.

22 BREE, *Gas market report*, July 2012, p. 56.

23 Goldman Sachs, *NSW gas briefing*, 2 October 2012, p. 2.

24 Department of Energy and Water Supply (Queensland), *Queensland gas market review 2012*, p. 23; BREE, *Gas market report*, July 2012, pp. 50, 66.

25 BREE, *Gas market report*, July 2012, p. iv.

26 BREE, *Australian energy technology assessment 2012*, p. 18.

27 Goldman Sachs, *NSW gas briefing*, 2 October 2012.

28 Department of Energy and Water Supply (Queensland), *Queensland gas market review 2012*, pp. vii, 27,37.

29 ACIL Tasman, *National gas outlook: domestic gas prices and markets*, Presentation by Paul Balfe, 30 May 2012.

AEMO found that a 15 per cent reduction in reserve development could cause supply shortfalls to the LNG export and domestic markets from 2016.[30] While a shortfall for LNG contract obligations could be alleviated by diverting Cooper Basin gas from the domestic market, this diversion would likely have a flow-on impact in the New South Wales domestic market. This scenario would present opportunities to further develop CSG reserves in New South Wales (in the Gunnedah, Gloucester and Sydney basins) and expand gas pipeline capacity to transport gas to demand centres.

The *Energy White Paper 2012* identifies a number of potential reforms the Australian Government is examining with state and territory governments to help alleviate transitional pressures in the eastern gas market. The reforms include:

- developing a national gas supply hub trading model to enhance market transparency and reliability of supply. In December 2012, SCER will consider options for implementing a trading hub market at Wallumbilla in Queensland (section 3.4.4)
- streamlined third party access to underutilised (but contracted) capacity on gas pipelines to enhance trading opportunities

Alongside these reforms, the Australian Government is working through SCER to develop a nationally harmonised regulatory framework for the CSG industry; enhance understanding of the impacts of CSG development on groundwater and the environment; and develop a world-class multiple use framework to promote coexistence.[31]

3.5.2 Spot market prices

The Victorian wholesale gas market (from 1999), and the short term trading market for Sydney and Adelaide (from September 2010) and Brisbane (from December 2011) provide data on spot gas prices. Section 3.4 provides background on these markets.

Table 3.3 sets out average annual spot prices, while figure 3.5 illustrates weekly averages. Figure 3.6 illustrates recent winter prices. The data are ex ante prices derived from demand forecasts; these prices form the main basis for settlement in the Victorian and short term trading markets. But design differences between the two markets limit the validity of price comparisons. In particular, the Victorian market is for gas only, while prices in the short term trading market cover gas *and* transmission pipeline delivery to the hub. For comparative purposes, the data include estimates for Melbourne gas prices, based on the Victorian wholesale price *plus* an estimate of transmission pipeline delivery costs to the metropolitan hub.[32]

Average daily spot prices for gas in Melbourne, Sydney and Adelaide were significantly higher in 2011–12 than in the previous year (table 3.3). Average prices rose by 45 per cent in Sydney, 33 per cent in Melbourne and 20 per cent in Adelaide. Average spot prices in 2011–12 ranged from $3.45 (Sydney) to $3.79 (Adelaide).

Table 3.3 Average daily spot gas prices ($ per gigajoule)

	BRISBANE	SYDNEY	MELBOURNE	ADELAIDE
2011–12	3.51	3.45	3.65	3.79
2010–11		2.37	2.74	3.17

Notes:

Volume weighted ex ante prices. Sydney, Adelaide and Brisbane data are short term trading market prices in each hub. Melbourne prices are estimates for the metropolitan area, based on Victorian wholesale spot gas prices plus APA Group's current transmission withdrawal tariff ($0.3685 per gigajoule) for the two Melbourne metropolitan zones.

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

Weekly prices (figure 3.5) show significant alignment across the four capital cities. While prices in all hubs tend to be higher in winter than in summer, prices above $4 per gigajoule were uncommon until winter 2012. A step change in prices occurred at this time, with monthly averages in all cities rising to $5–8 per gigajoule. Compared with July 2011, average prices in July 2012 were around 85 per cent higher in Sydney, 69 per cent higher in Adelaide and 62 per cent higher in Victoria (figure 3.6).

Winter prices peaked at $17.30 per gigajoule in Sydney (on 23 June 2012), $14.89 per gigajoule in Adelaide (on 4 July), $15.57 per gigajoule in Victoria (on 7 July) and over $8 per gigajoule in Brisbane (on several days in July). Prices began to ease during August and returned to levels below $5 per gigajoule in September 2012, but remained well above longer term averages (figure 3.5).

A range of factors might have contributed to the price spikes in winter 2012. This period coincided with a significant tightening in the contract market for gas in eastern Australia (section 3.5.1). Also, gas powered generation increased in winter 2012, although overall gas demand was relatively stable. AEMO reported gas spot prices were largely unaffected by the introduction of carbon pricing on 1 July.[33]

30 AEMO 2012 (unpublished briefing to AER, November 2012).

31 Australian Government, *Energy White Paper* 2012, p. xxi.

32 The Sydney data in table 3.3 and figures 3.5–3.6 exclude the 1 November 2010 price of $150 per gigajoule, which data errors caused.

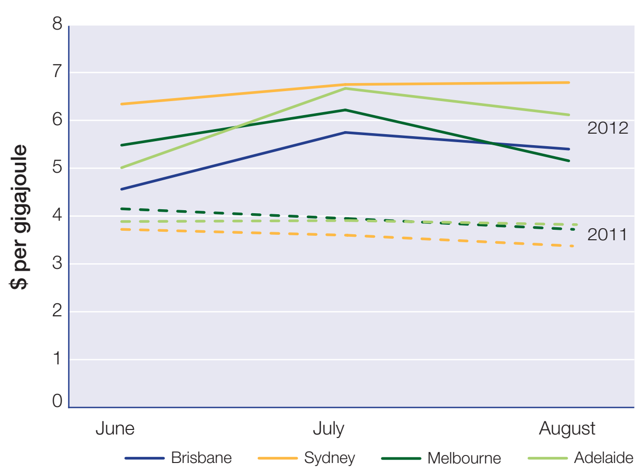
33 AEMO, *Carbon price—Market review*, 8 November 2012.

Figure 3.5

Spot gas prices—weekly averages

Figure 3.6

Spot gas prices—winter 2011 and 2012



Notes (figures 3.5 and 3.6):

Volume weighted ex ante prices. Sydney, Adelaide and Brisbane data are short term trading market prices in each hub. Melbourne prices are estimates for the metropolitan area, based on Victorian wholesale spot gas prices plus APA Group's current transmission withdrawal tariff ($0.3685 per gigajoule) for the two Melbourne metropolitan zones.

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

While factors such as changes in contract positions might have flowed through to spot prices, the AER detected several instances of participants rebidding their offers on high price days and driving prices higher than would otherwise be the case. This behaviour was evident in both the short term trading market and the Victorian gas market. In particular, the tighter market appears to have enhanced opportunities for some market participants to influence price outcomes through strategic bidding. This influence is indicated by significant variations between forecast prices, ex ante prices and ex post prices (which account for the impact of deviations from the day-ahead market schedule on the gas day). Linked to this variation were poor quality demand forecasts by participants on a number of days. The demand forecasting issues and price variations most commonly occurred in Sydney, and were typically accompanied by significant rebidding.

The AER inquired into participant demand forecasts, offers and bids over the winter period, and will report on compliance issues in quarterly compliance reports (published on the AER website).

3.6 Compliance monitoring and enforcement

The AER monitors and enforces compliance with the National Gas Law and Rules in relation to the short term trading market, the Victorian gas market and the bulletin board. Its compliance activity relates to relevant participants, including upstream gas producers, gas pipeline entities and gas retailers.[37]

The AER takes a transparent approach to monitoring, compliance and enforcement, publishing quarterly reports on activity. It also draws on spot market and bulletin board data to publish weekly reports on gas market activity in eastern Australia.

Timely and accurate data and efficient pricing maintain confidence in gas markets and encourage efficient investment in energy infrastructure. The AER monitors the

34 EnergyQuest, *Energy Quarterly*, August 2012, pp. 2, 22, 94–5.

35 ACIL Tasman, *National gas outlook: domestic gas prices and markets*, Presentation by Paul Balfe, 30 May 2012.

36 Economics and Industry Standing Committee (Parliament of Western Australia), *Inquiry into Domestic Gas Prices*, Report no. 6 in the 38th Parliament, 24 March 2011.

37 Chapter 4 of this report covers gas transmission while chapter 5 covers gas retailing. For convenience, section 3.6 includes compliance issues for pipeline and retail entities in relation to the short term trading market, the Victorian gas market and the bulletin board.

Box 3.1 Western Australia's domestic gas market

Because Western Australia is a major LNG exporter, the domestic market is exposed to price volatility in international energy markets. Domestic gas prices in Western Australia remained relatively low until 2006, when rising production costs and strong gas demand—driven partly by the mining boom—put upward pressure on prices. Rising international LNG and oil prices added to this pressure.

EnergyQuest reported in 2012 that domestic demand in Western Australia was subdued, with only 0.9 per cent annual growth in the past five years. It noted average prices rose to around $4.20 per gigajoule in June 2012, but may have been higher in the absence of low priced historical contracts. Gas prices under new contracts (such as the Reindeer project in the Carnarvon Basin) were being struck at prices as high as $10 per gigajoule.[34]

ACIL Tasman considered recent movements in Western Australian gas prices reflect emerging shortages in gas supply relative to demand, rising costs for incremental supply, and competition from LNG. It considered prices for new contracts are likely to remain around $8–10 per gigajoule.[35]

In 2011 a West Australian parliamentary inquiry recommended initiatives to improve the efficiency of the wholesale market by enhancing transparency, competition and liquidity. Several proposed initiatives mirrored recent reforms in eastern Australia, including the introduction of a short term trading market, a gas market bulletin board and a gas statement of opportunities. The inquiry also recommended eliminating joint marketing arrangements when authorisations granted by the Australian Competition and Consumer Commission come up for review in 2015.[36]

The West Australian Government passed legislation in March 2012 to establish a gas bulletin board and publish an annual gas statement of opportunities. It expected the bulletin board to commence operating in July 2013 and to publish the first gas statement of opportunities in mid-2013. It did not plan to establish a short term trading market with market settlement and trading services.

spot markets and bulletin board to improve data provision and has committed to the SCER to monitor gas markets to detect any evidence of the exercise of market power.

The AER's compliance monitoring and enforcement activity in gas over the past 12–18 months focused on:

- identifying possible compliance issues related to record spot price outcomes for gas in winter 2012 (see section 3.5.2)
- high MOS payments in the short term trading market (section 3.6.1)
- the quality of data provision to the short term trading market and bulletin board (section 3.6.2).

3.6.1 Market Operator Service payments

MOS services are required when scheduled pipeline deliveries do not match actual gas demand in the short term trading market. While some balancing is required every day due to variations in forecast and actual demand, some payments for these services have been unusually high. Figure 3.7 shows daily MOS payments for each hub and highlights some extreme outcomes.

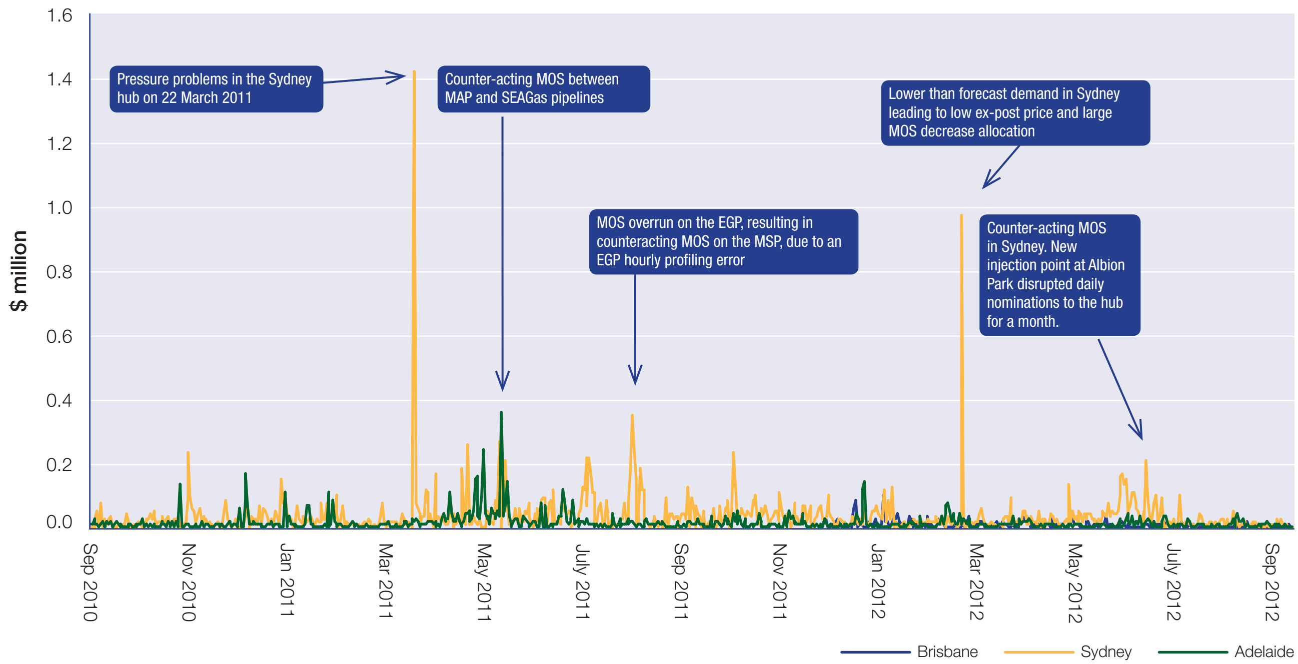
The highest MOS payment in 2011–12 occurred in Sydney on 27 February (around $1 million), following a manual input error on the Eastern Gas Pipeline. The AER held discussions with operating staff and received written undertakings from the pipeline's operator on this matter. It is continuing to closely monitor MOS payments at all hubs.

3.6.2 Data provision by pipeline entities

Errors in data provision by pipeline entities to the short term trading market and bulletin board have been ongoing. The AER served an infringement notice on one pipeline entity in June 2012 for an alleged breach of the Gas Rules. It is also auditing facility operators' processes for achieving compliance in this area, beginning with APA Group, AGL Energy and Epic Energy in 2012–13. It will report the audit outcomes in its quarterly compliance reports.

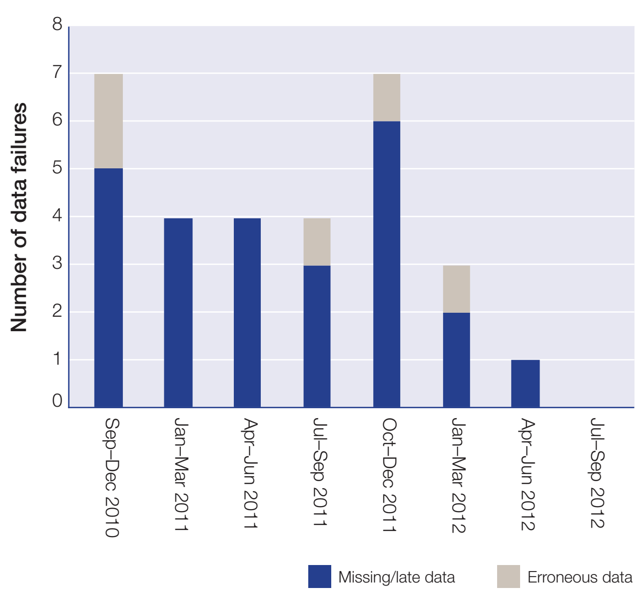
Since the AER increased its focus on this area, the quality of data provision to the short term trading market has improved (figure 3.8). In the six months to 30 September 2012, the AER identified only one error in the submission of pipeline data.

Figure 3.7
MOS payments in Sydney, Adelaide and Brisbane



Source: AER.

Figure 3.8
Data failures in the short term trading market—quarterly



Note: September–December 2010 covers four months.

Source: AER.

3.7 Upstream competition

Investment over the past decade developed an interconnected transmission pipeline system linking gas basins in southern and eastern Australia (chapter 4). While gas tends to be purchased from the closest possible source to minimise transport costs, interconnection of the major pipelines 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 now served by multiple transmission pipelines from multiple gas basins. In particular, the construction of new pipelines and the expansion of existing ones opened the Surat–Bowen, Cooper, Sydney, Gippsland, Otway and Bass basins to increased interbasin competition. By contrast, Brisbane is served by only one transmission pipeline (Roma to Brisbane).

The bulletin board (section 3.4.3) provides real-time information on the gas market to enhance competition. The AER draws on the bulletin board to report weekly on gas market activity in eastern Australia. Its reporting covers gas flows on particular pipelines and gas flows from competing basins to end markets.

Figure 3.9 illustrates recent trends in gas delivery from competing basins into New South Wales, Victoria and South Australia since the bulletin board opened in July 2008:

- While New South Wales historically relied on Cooper Basin gas shipped on the Moomba to Sydney Pipeline, gas shipped on the Eastern Gas Pipeline from Victoria's Gippsland Basin now supplies an equivalent proportion of the state's gas requirements. Gas flows on the Moomba to Sydney Pipeline show significant seasonal fluctuations, while flows on the Eastern Gas Pipeline are relatively steady. There are relatively smaller flows (both northwards and southwards) across the New South Wales–Victoria Interconnect.
- 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 3.9 also illustrates the seasonal nature of Victorian gas demand, with significant winter peaks.
- While the Moomba to Adelaide Pipeline historically transported most of South Australia's gas from the Cooper Basin and more recently from the Surat–Bowen Basin, the SEA Gas Pipeline now transports greater volumes of gas to South Australia from Victoria's Otway Basin.

The extent to which new investment delivers competition benefits to customers depends on a range of factors, including pipeline access and the availability of gas from alternative sources. In particular, capacity constraints limit access on some pipelines. Access seekers must decide whether to try to negotiate a capacity expansion. For a covered pipeline, the regulator (or, in Western Australia, a separate arbitrator) may be asked to arbitrate a dispute over capacity expansions.

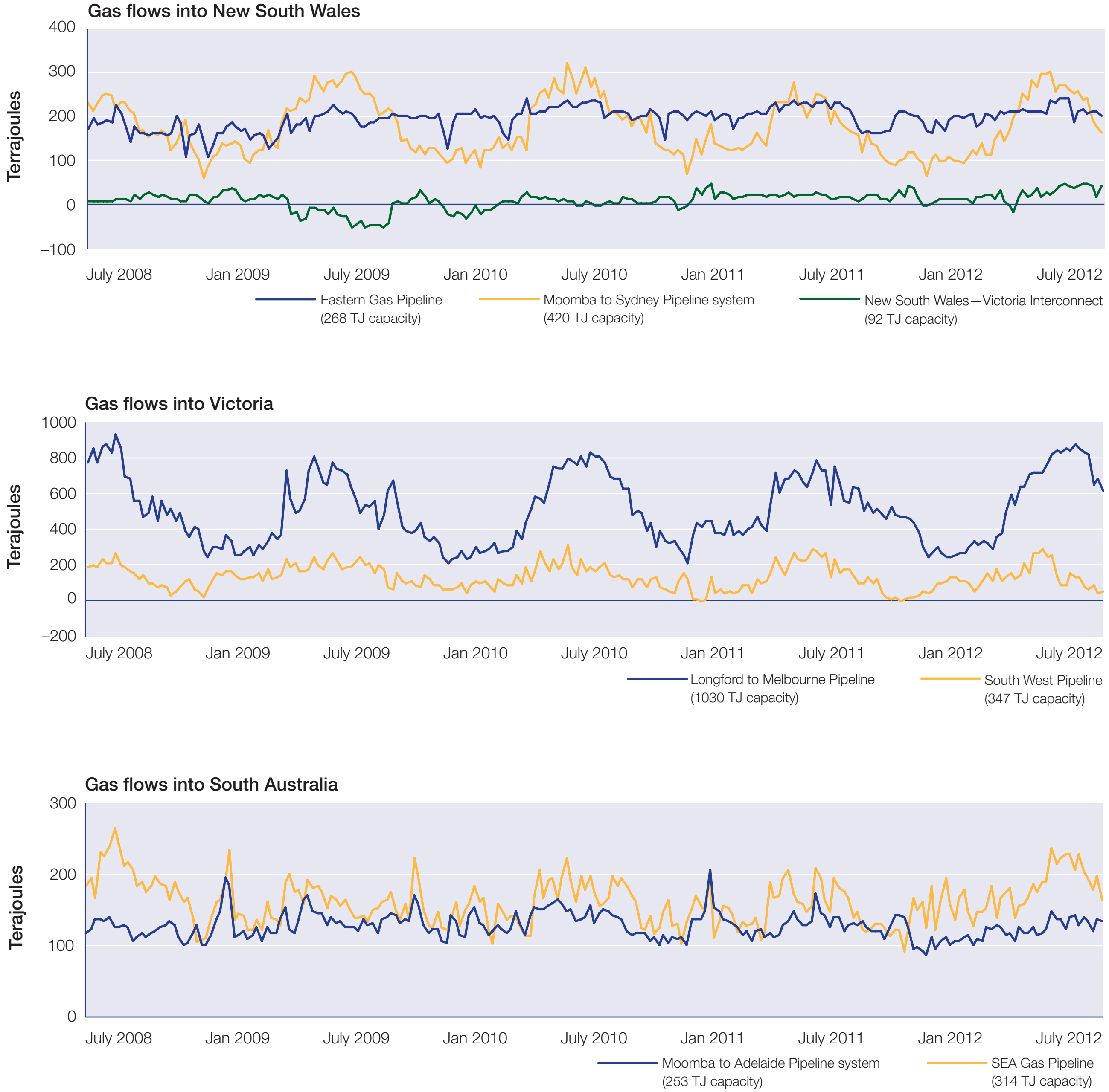
3.8 Gas storage

Gas can be stored in its natural state in depleted underground reservoirs and pipelines, or post liquefaction as LNG in purpose built facilities. Given Australia's increasing reliance on gas powered electricity generation, 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 requirements if production is unexpectedly curtailed, and provides retailers with a hedging mechanism if gas demand is significantly above forecast.

Conventional gas storage facilities are located in Victoria, Queensland, Western Australia 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 of gas per day. In Queensland, AGL Energy in August 2011 began injecting and storing gas underground at the depleted Silver Springs reservoir in central Queensland. The facility will support the development of the Curtis LNG project; it will also allow AGL to manage its gas supply during seasonal variations in summer and winter. In Western Australia, an expansion of the Mondarra storage facility will increase its storage capacity to 15 PJ, and will allow injections and withdrawals on both the Dampier to Bunbury and Parmelia pipelines.

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 New South Wales, AGL Energy is constructing a $300 million LNG storage facility to secure supply during peak periods and supply disruptions. Due to be completed by 2014, the facility will have a peak supply rate of 120 terajoules per day.

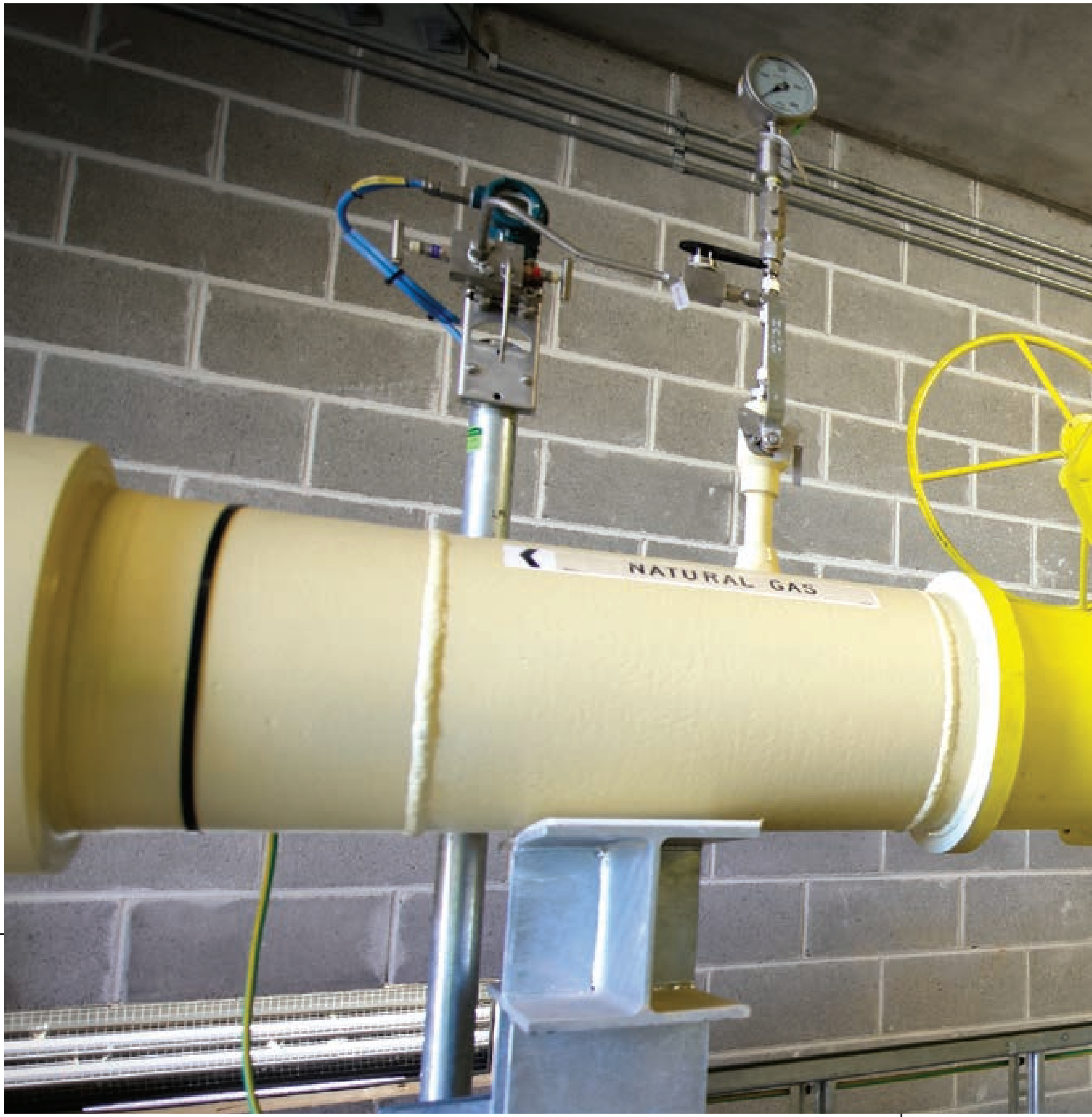
Figure 3.9
Gas flows in eastern Australia



Note: Negative flows on the New South Wales – Victoria Interconnect represent flows out of New South Wales into Victoria.

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

Jemena



4 GAS PIPELINES

Gas pipelines provide a transportation link between upstream gas producers and downstream energy customers. This chapter focuses on gas pipelines in jurisdictions for which the AER has regulatory responsibilities—those located 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 kilometres. The construction of new pipelines and the expansion of existing facilities in the past decade have created an interconnected pipeline network running from Queensland to Tasmania. This investment has enhanced the competitive environment for gas producers, pipeline operators and gas retailers, and improved security of supply. While Western Australia and the Northern Territory have also had significant pipeline investment, they have no transmission interconnection with other jurisdictions.

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. Gas is reticulated to most Australian capital cities, major regional areas and towns.

The total length of gas distribution networks in eastern Australia is around 74 000 kilometres. The networks have a combined asset value of almost $8 billion.

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 3.1 includes a more extensive mapping of transmission pipelines, including those in Western Australia. Tables 4.1 and 4.2 summarise the major pipelines and networks.

4.1 Ownership

Australia's gas pipelines are privately owned. APA Group and Singapore Power International (through its subsidiary Jemena) are the principal owners in the gas transmission sector. Envestra and Singapore Power International (through its subsidiaries SP AusNet and Jemena) are the principal owners in gas distribution (tables 4.1 and 4.2).

4.1.1 Transmission pipeline ownership

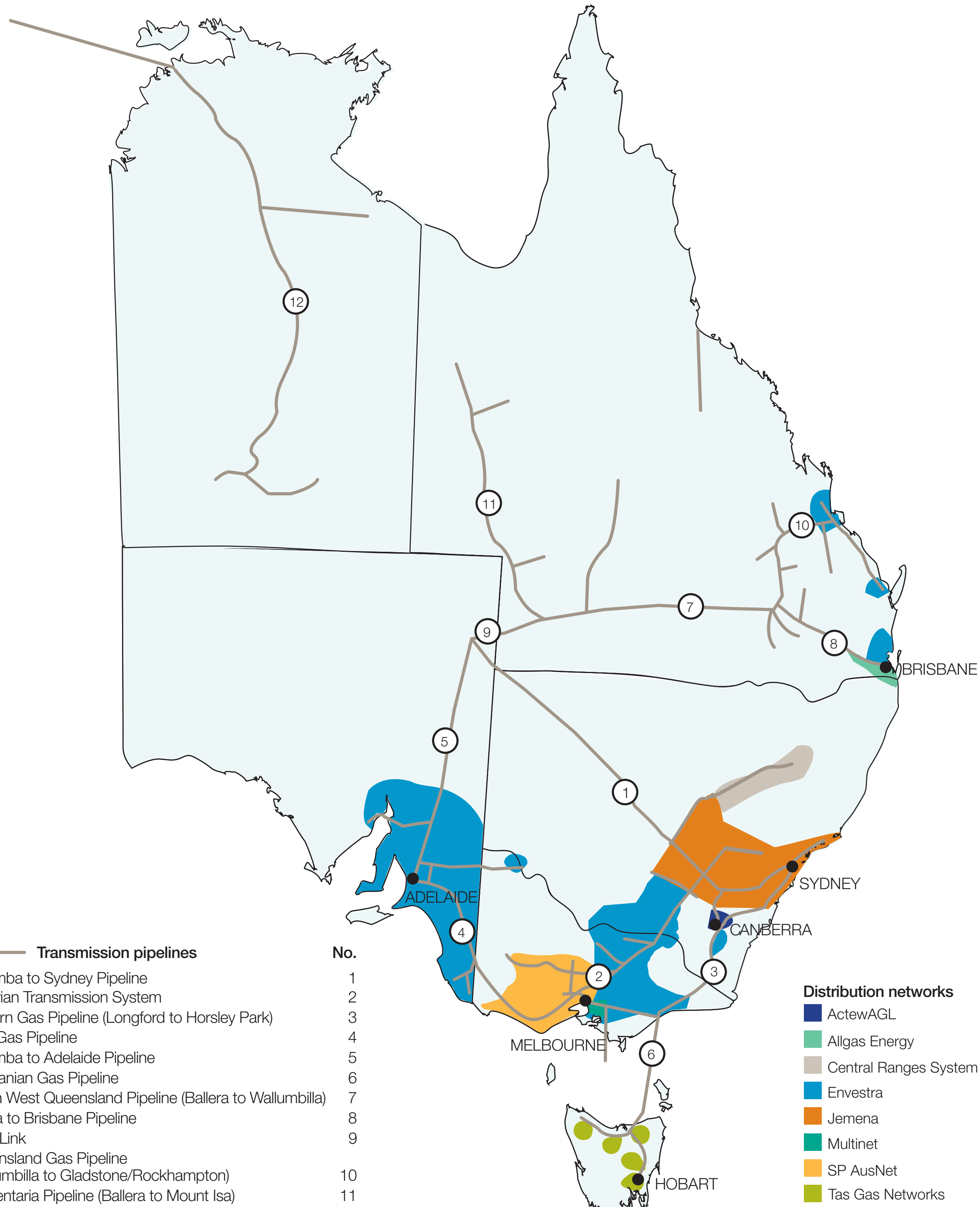
APA Group, a publicly listed company, has the most extensive portfolio of gas transmission assets in Australia. At 1 October 2012, its three largest institutional shareholders held around 34 per cent of share capital. The major foundation shareholder, Petronas, divested its 17.3 per cent stake in the company earlier in 2012.

APA Group owns three pipelines in New South Wales (including the Moomba to Sydney Pipeline), the Victorian Transmission System, five major Queensland pipelines and a major Northern Territory pipeline. It has a 50 per cent interest in the SEA Gas Pipeline. APA Group also owns gas transmission pipelines in Western Australia and has a 20 per cent interest in Energy Infrastructure Investments (EII), which owns pipelines in Western Australia and the Northern Territory.

During 2012 APA Group expanded its gas transmission portfolio via a $1.4 billion acquisition of Hastings Diversified Utilities Fund, which owned Epic Energy. The Epic portfolio included the Moomba to Adelaide Pipeline, the South West Queensland Pipeline and QSN Link, and the Pilbara Energy Pipeline (in Western Australia). The Australian Competition and Consumer Commission (ACCC) did not oppose the acquisition, after accepting a court enforceable undertaking from the APA Group to divest the Moomba to Adelaide Pipeline.

Singapore Power International, through its subsidiary *Jemena*, acquired a portfolio of gas transmission assets from Alinta in 2007. It owns and operates the Eastern Gas Pipeline, VicHub and the Queensland Gas Pipeline.

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
Amadeus Basin to Darwin Pipeline	12

Distribution networks
- ActewAGL
- Allgas Energy
- Central Ranges System
- Envestra
- Jemena
- Multinet
- SP AusNet
- Tas Gas Networks

Source: AER.

Table 4.1 **Major gas transmission pipelines**

PIPELINE	LENGTH (KM)	CAPACITY (TJ/D)	CONSTRUCTED	COVERED?
EASTERN AUSTRALIA				
Queensland				
North Queensland Gas Pipeline	391	108	2004	No
Queensland Gas Pipeline (Wallumbilla to Gladstone)	629	142	1989–91	No
Carpentaria Pipeline (Ballera to Mount Isa)	840	119	1998	Yes (light)
Berwyndale to Wallumbilla Pipeline	113		2009	No
Dawson Valley Pipeline	47	30	1996	Yes
Roma (Wallumbilla) to Brisbane	440	219	1969	Yes
Wallumbilla to Darling Downs Pipeline	205	400	2009	No
South West Queensland Pipeline (Ballera to Wallumbilla)	756	181	1996	No
QSN Link (Ballera to Moomba)	180	212	2009	No
New South Wales				
Moomba to Sydney Pipeline	2029	420	1974–93	Partial (light)
Central West Pipeline (Marsden to Dubbo)	255	10	1998	Yes (light)
Central Ranges Pipeline (Dubbo to Tamworth)	300	7	2006	Yes
Eastern Gas Pipeline (Longford to Sydney)	795	268	2000	No
Victoria				
Victorian Transmission System (GasNet)	2035	1030	1969–2008	Yes
South Gippsland Natural Gas Pipeline	250		2006–10	No
VicHub		150 (into Vic)	2003	No
South Australia				
Moomba to Adelaide Pipeline	1185	253	1969	No
SEA Gas Pipeline (Port Campbell to Adelaide)	680	303	2003	No
Tasmania				
Tasmanian Gas Pipeline (Longford to Hobart)	734	129	2002	No
NORTHERN TERRITORY				
Bonaparte Pipeline	287	80	2008	No
Amadeus Gas Pipeline	1512	104	1987	Yes
Wickham Point Pipeline	13		2009	No
Daly Waters to McArthur River Pipeline	330	16	1994	No
Palm Valley to Alice Springs Pipeline	140	27	1983	No

TJ/d, terajoules per day; CKI, Cheung Kong Infrastructure; REST, Retail Employees Superannuation Trust.

Notes:

Covered pipelines are subject to regulatory arrangements under the National Gas Law.

For covered pipelines subject to full regulation, valuation refers to the opening capital base for the current regulatory period. For non-covered pipelines, listed valuations are estimated construction costs, subject to availability of data.

Coverage of the Moomba to Sydney Pipeline was partly revoked in 2003. The revoked portion runs from Moomba to the offtake point of the Central West Pipeline at Marsden. The covered portion became a light regulation pipeline in 2008. The listed valuation of the pipeline is that determined by the Australian Competition Tribunal for the regulatory period before the pipeline converted from full to light regulation.

'Current access arrangement' refers to access terms and conditions approved by the Australian Energy Regulator.

Some corporate names are abbreviated or shortened.

	VALUATION ($ MILLION)	CURRENT ACCESS ARRANGEMENT	OWNER	OPERATOR
	160 (2005)	Not required	Victorian Funds Management Corporation	AGL Energy, Arrow Energy
		Not required	Jemena (Singapore Power International)	Jemena Asset Management
		Not required	APA Group	APA Group
	70 (2009)	Not required	APA Group	APA Group
	8 (2007)	2007–16	Westside 51%, Mitsui 49%	Westside
	418 (2012)	2007–12	APA Group	APA Group
	90 (2009)	Not required	Origin Energy	Origin Energy
		Not required	APA Group	APA Group
	165 (2009)	Not required	APA Group	APA Group
	835 (2003)	Not required	APA Group	APA Group
	28 (1999)	Not required	APA Group	APA Group
	53 (2003)	2005–19	APA Group	Jemena Asset Management
	450 (2000)	Not required	Jemena (Singapore Power International)	Jemena Asset Management
	524 (2007)	2008–12	APA Group	APA Group/AEMO
	50 (2007)	Not required	DUET Group	Jemena Asset Management
		Not required	Jemena (Singapore Power International)	Jemena Asset Management
	370 (2001)	Not required	APA Group (to be divested)	APA Group
	500 (2003)	Not required	APA Group 50%, REST 50%	APA Group
	440 (2005)	Not required	Palisade Investment Partners	Tas Gas Networks
	170 (2008)	Not required	Energy Infrastructure Investments (APA Group 20%, Marubeni 50%, Osaka Gas 30%)	APA Group
	92 (2011)	2011–16	APA Group	APA Group
	36 (2009)	Not required	Energy Infrastructure Investments (APA Group 20%, Marubeni 50%, Osaka Gas 30%)	APA Group
		Not required	Power and Water	APA Group
		Not required	Envestra (APA Group 33.4%, CKI 18.9%)	APA Group

Sources: Capacity: National Gas Market Bulletin Board (www.gasbb.com.au); corporate websites. Other data: access arrangements for covered pipelines; EnergyQuest, *Energy Quarterly* (various issues); corporate websites, annual reports and media releases.

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	427	134	339	1 Jul 2011–30 Jun 2016	APA Group 20%, Marubeni 40%, RREEF 40%
Envestra	89 100	2 560	319	140	312	1 Jul 2011–30 Jun 2016	Envestra (APA Group 33.4%, Cheung Kong Infrastructure 18.9%)
NEW SOUTH WALES AND ACT							
Jemena Gas Networks (NSW)	1 050 000	24 430	2 396	750	2 289	1 Jul 2010–30 Jun 2015	Jemena (Singapore Power International)
ActewAGL	124 000	4 720	288	91	292	1 Jul 2010–30 Jun 2015	ACTEW Corporation (ACT Government) 50%, Jemena (Singapore Power International) 50%
Wagga Wagga	23 800	680	62	21	50	1 Jul 2010–30 Jun 2015	Envestra (APA Group 33.4%, Cheung Kong Infrastructure 18.9%)
Central Ranges System	7 000	180	na	na	na	2006–19	APA Group
VICTORIA							
SP AusNet	602 000	9 860	1 140	367	963	1 Jan 2008–31 Dec 2012	SP AusNet (Singapore Power International 51%)
Multinet	668 000	9 960	1 070	196	906	1 Jan 2008–31 Dec 2012	DUET Group
Envestra	587 400	10 220	973	324	838	1 Jan 2008–31 Dec 2012	Envestra (APA Group 33.4%, Cheung Kong Infrastructure 18.9%)
SOUTH AUSTRALIA							
Envestra	410 700	7 890	1 024	494	1 033	1 Jul 2011–30 Jun 2016	Envestra (APA Group 33.4%, Cheung Kong Infrastructure 18.9%)
TASMANIA							
Tas Gas Networks	9 800	730	121	Not regulated	Not regulated	Not regulated	Tas Gas (Brookfield Infrastructure)
TOTALS	3 656 200	74 130	7 815	2 516	7 021		

na: not available.

1. For Tasmania, the opening capital base value is an estimated construction cost. For other networks, it 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.

Note: Asset base, investment and revenue data are converted to June 2011 dollars.

Sources: Access arrangements for covered pipelines; company websites.

4.1.2 Distribution network ownership

The major gas distribution networks in southern and eastern Australia are privately owned, with four principal players:

- *Envestra*, a public company in which APA Group (33.4 per cent) and Cheung Kong Infrastructure (18.9 per cent) have shareholdings, owns networks in Victoria, South Australia, Queensland and the Northern Territory.
- *Singapore Power International,* through its subsidiary *Jemena*, owns the principal New South Wales gas distribution network (Jemena Gas Networks) and has a 50 per cent share of the ACT network (ActewAGL). Singapore Power International also has 51 per cent direct equity in a Victorian network (SP AusNet).
- *APA Group* has minority interests in Envestra and the Allgas Energy network in Queensland (rebranded from APT Allgas in March 2012), and owns the Central Ranges system in New South Wales.
- *DUET Group* owns Multinet in Victoria.

A series of recent ownership changes related to former Babcock & Brown assets. In December 2010 *Brookfield Infrastructure* acquired a portfolio of these assets via a merger with Prime Infrastructure. Brookfield retained ownership of Tas Gas Networks, but in July 2011 sold a minority share in Victoria's Multinet distribution network to *DUET Group* (raising DUET's equity in the network from 80 to 100 per cent).

In December 2011 the APA Group sold 80 per cent of the Allgas Energy distribution network in Queensland to *Marubeni Corporation* and *RREEF*, each of which holds a 40 per cent interest.

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

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; the Economic Regulation Authority is the regulator in Western Australia.

The Law and Rules apply economic regulation provisions to covered pipelines. Different forms of economic 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 likely to be sought by a significant part of the market, and a reference tariff for that service.

The AER regulates five transmission pipelines and 10 distribution networks under full regulation, including:

- transmission pipelines supplying Brisbane, Melbourne and Darwin (table 4.1)
- all major distribution networks in New South Wales, Victoria, Queensland, South Australia and the ACT. The Tasmanian and Northern Territory distribution networks and a number of small regional networks are unregulated.

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

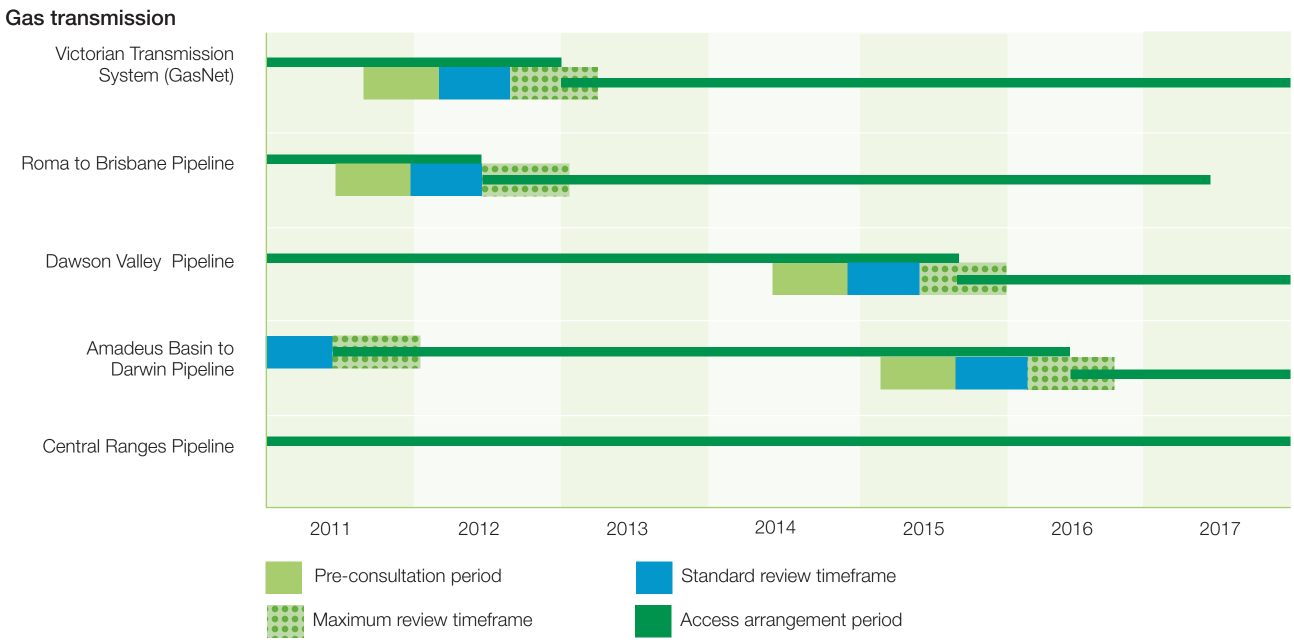
In summary, the regulator assesses the revenues needed to cover efficient costs (including a benchmark return on capital), then derives reference tariffs for the pipeline. The Rules allow for income adjustments via incentive mechanisms that reward efficient operating practices. In a dispute, an access seeker may request the regulator to arbitrate on and enforce the terms and conditions of the access arrangement. The AER's decisions on full regulation pipelines are subject to merits review by the Australian Competition Tribunal (section 4.5).

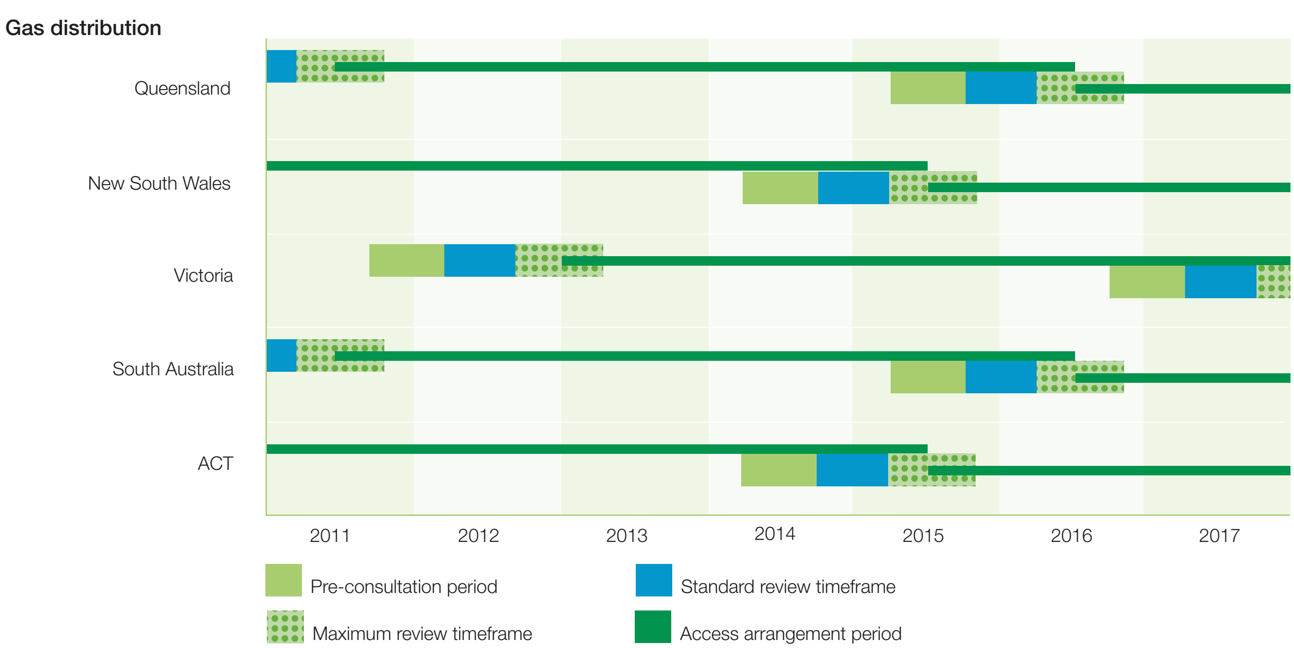
A pipeline may, in some circumstances, convert to *light regulation* without upfront price regulation. When light regulation applies, the pipeline provider must publish access prices and other terms and conditions on its website. The AER is responsible for three transmission pipelines subject to light regulation: the Carpentaria Gas Pipeline in Queensland, the covered portions of the Moomba to Sydney Pipeline and the Central West Pipeline in New South Wales. No Australian distribution network is currently subject to light regulation.

The Gas Law anticipates the potential for market conditions to evolve, and 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.

The Gas Law also enables the federal Minister for Resources and Energy to grant a 15 year 'no coverage' determination

Figure 4.2
Indicative timelines for AER 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 by a date specified in the previous access arrangement. The 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.

for new pipelines in certain circumstances. Following recommendations from the National Competition Council, the Minister granted 'no coverage' determination for two pipelines supplying LNG projects in Queensland:

- BG Group's Queensland Curtis LNG Pipeline (in July 2010)
- the Australia Pacific LNG Gladstone Pipeline, running from the Surat–Bowen Basin to Curtis Island (in August 2012).

4.3 AER Rule change proposal on pipeline regulation

Following a Rule change proposal from the AER in 2011, the Australian Energy Market Commission (AEMC) in November 2012 implemented a common approach to setting the rate of return for the electricity and gas sectors. The new Rule requires a holistic assessment of the overall rate of return required to meet the efficient costs of a benchmark entity. It also introduced a requirement for the AER to develop a guideline on its approach to estimating the rate of return. The guideline must be reviewed at least every three years in consultation with industry, consumers and other interested parties.

4.4 Recent AER decisions on gas pipelines

The AER completed an access arrangement review for Queensland's Roma to Brisbane transmission pipeline in August 2012. It released draft decisions for Victoria's gas transmission and distribution networks in September 2012.

4.4.1 Roma to Brisbane Pipeline

In August 2012 the AER released its final decision on APA Group's access arrangement proposal for the Roma to Brisbane Pipeline in Queensland. While it accepted elements of the proposal, it identified issues relating to the rate of return and operating expenditure. The AER approved a rate of return of 7.3 per cent, compared with APA Group's proposed 8.8 per cent. It approved operating expenditure over the access arrangement period of $64 million (compared with the proposed $80 million) and revenues of $263 million (compared with the proposed $325 million). APA Group did not seek a Tribunal review of the AER's decision.

The AER estimated the effect on residential gas prices will be a 1.5 per cent increase over the life of the access arrangement. The corresponding expected increase in prices for large industrial users is 10 per cent; transmission costs account for a larger proportion of energy bills for industrial users than for residential customers.

4.4.2 Victorian gas transmission system—draft decision

In September 2012 the AER released a draft decision on APA GasNet's access arrangement proposal for the Victorian gas transmission system for 2013–17. The draft decision revised many elements of the proposal. In summary, it approved:

- revenues that are 39 per cent below proposed revenues for the period
- reference tariffs that are 34 per cent below the proposed tariffs
- capital expenditure levels that are 58 per cent below proposed levels.

The differences between the draft decision and the network's proposal related mainly to the AER:

- using a lower rate of return on equity than that proposed
- having lower expectations of capital and operating expenditure requirements than those proposed. In particular, the AER found some proposed capital expenditure was neither prudent not efficient.

The AER's draft decision would significantly alter the impact on customers, compared with the impact of the network's proposal. It would result in a typical residential gas bill *falling* by $4 per year (compared with the proposed average price increase of $6 per year). The AER will make a final decision on the access arrangement (including revisions that APA GasNet may propose) in March 2013.

4.4.3 Victorian gas distribution networks—draft decisions

In 2012 the AER reviewed access arrangement proposals for Victoria's three gas distribution networks—Multinet, Envestra and SP AusNet—for the 2013–17 period. In September 2012 it released draft decisions revising many elements proposed by the distribution network service providers. The nature and degree of revision varied, depending on the circumstances and characteristics of each network. In summary, the draft decisions approved:

- revenues that are 21–32 per cent below proposed revenues for the period
- reference tariffs that are 23–34 per cent below the proposed tariffs. As a result, tariffs would fall over 2013–17 from their 2012 levels in two networks, and would rise by less than consumer price index increases in the third network
- capital expenditure levels that are 22–59 per cent below proposed levels
- operating expenditure levels that are 13–26 per cent below proposed levels.

The differences between the draft decisions and the network proposals related mainly to the AER:

- using a lower rate of return on equity than that proposed
- having lower expectations of capital expenditure requirements than that proposed, especially in relation to distribution mains replacement
- revising operating expenditure requirements to be more in line with historical levels.

The AER draft decisions would significantly alter the impact on customers, compared with the impact of the networks' proposals. They would result in a typical residential gas bill *falling* by $9 per year for customers in the Multinet and SP AusNet networks (compared with the proposed average price increases of $13–19 per year). For Envestra customers, a typical bill would rise by $7 per year on average (compared with an average $56 increase in the proposal). The AER will make final decisions for the three Victorian networks (including revisions that the network providers may propose) in March 2013.

4.5 Tribunal reviews of AER decisions

AER decisions on access arrangement proposals are subject to merits review by the Australian Competition Tribunal. Between September 2008 and October 2012, network businesses sought reviews of five decisions on gas distribution networks. Three reviews were completed in January 2012—for the Queensland and South Australian networks. The Tribunal upheld the AER's decision on returns on equity and cost of gas losses, but overturned the AER's decisions on the cost of debt and operating expenditure. Specifically, the Tribunal rejected:

- the AER's approach to calculating the allowance for the cost of debt
- the AER's decision to prevent Envestra from recovering the costs of a 'network management fee' paid to a related party.

Overall, the Tribunal increased allowable network revenues by $92 million. The decisions increased a typical residential gas bill in Queensland by around 2 per cent and in South Australia by 1 per cent. Two reviews completed before 2012—for the New South Wales and ACT networks—increased allowable network revenues by $190 million.

4.6 Pipeline investment

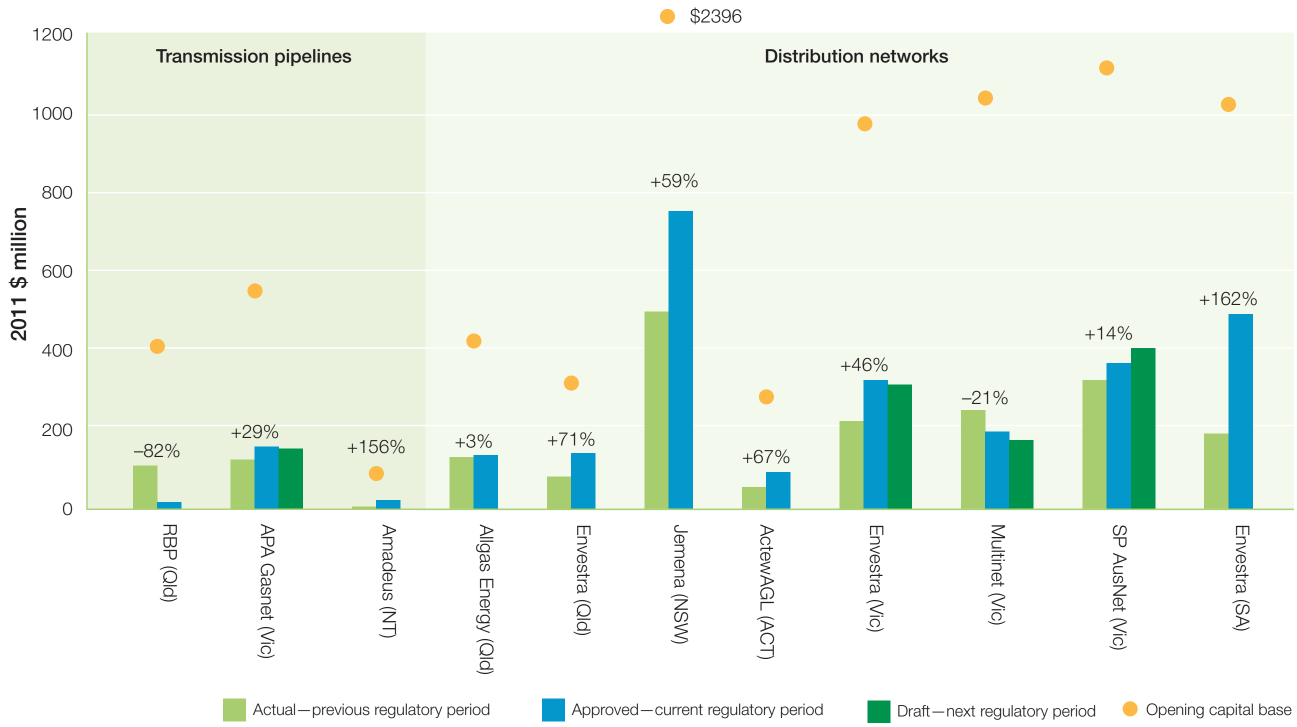
Gas *transmission* investment typically involves large and lumpy capital projects to expand existing pipelines (through compression, looping or extension) or construct new infrastructure. Significant investment in the regulated and unregulated transmission sector has occurred since 2010. Additionally, a number of major projects are under construction or have been announced for development. In eastern Australia:

- Epic Energy (acquired by APA Group in 2012) commissioned the QSN Link and expanded capacity on the South West Queensland Pipeline in 2009, to enable gas delivery between Queensland and the southern states. A $760 million stage 3 expansion of the South West Queensland Pipeline was completed in 2012. The expansion loops the existing 937 kilometre pipeline by building an adjacent pipeline that effectively doubles capacity
- a 10 per cent capacity expansion of the Roma to Brisbane Pipeline is scheduled for completion late in 2012
- a five year capacity expansion of the Moomba to Sydney Pipeline is scheduled for completion in 2013
- construction is underway on three major transmission pipelines in Queensland (each around 400 kilometres in length) to transport gas from the Surat–Bowen Basin to Gladstone for processing and export as LNG. A fourth pipeline has been announced (section 3.2.1).

Investment to augment and expand *distribution* networks in eastern Australia is forecast at around $2.6 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. For example, a significant driver of capital expenditure for Envestra's South Australian distribution network is the replacement of cast iron and unprotected steel mains, to address leaks from older sections of the pipeline.

Figure 4.3

Investment—full regulation pipelines



Notes:

Forecast capital expenditure in the current access arrangement period (typically five years), compared with actual levels in previous periods. See tables 4.1 and 4.2 for the timing of regulatory periods. The data account for the impact of decisions by the Australian Competition Tribunal. The Victorian data include draft approvals released in September 2012 for 2013–17.

Opening capital bases are at the beginning of the current access arrangement period.

Source: AER final and draft decisions on access arrangements.

Figure 4.3 illustrates recent investment data for gas transmission pipelines and distribution networks that are subject to full regulation. The chart compares approved forecasts in current access arrangements with actual expenditure in previous periods; the Victorian data also include draft approved investment for 2013–17 (released in September 2012).

Sections 4.4.1 and 4.4.2 comment on investment outcomes for the major *transmission* pipelines under full regulation—the Roma to Brisbane Pipeline and the Victorian gas transmission system. For *distribution* networks, investment is forecast to increase in the current access arrangement periods, compared with previous periods, by an average of 45 per cent. Investment is equal, on average, to 33 per cent of the networks' opening capital bases.

Investment forecasts vary across the networks. Forecast growth in the current access arrangement periods, compared with actual expenditure in previous periods, is highest in Envestra's Queensland and South Australian networks (up 71 per cent and 162 per cent respectively). Draft decisions for Victoria's distribution networks allow for investment to rise, on average, by 1 per cent in 2013–17, compared with that in 2008–12.

4.7 Pipeline revenues and retail impacts

Figure 4.4 illustrates approved revenue forecasts for gas transmission pipelines and distribution networks that are subject to full regulation. The chart compares approved forecasts in current access arrangements with those approved in previous periods; the Victorian data also include draft approved revenues released in September 2012 for 2013–17.

Sections 4.4.1 and 4.4.2 comment on revenues for the major *transmission* pipelines under full regulation. For *distribution* networks, revenues are forecast to increase in

Figure 4.4

Revenues—full regulation pipelines

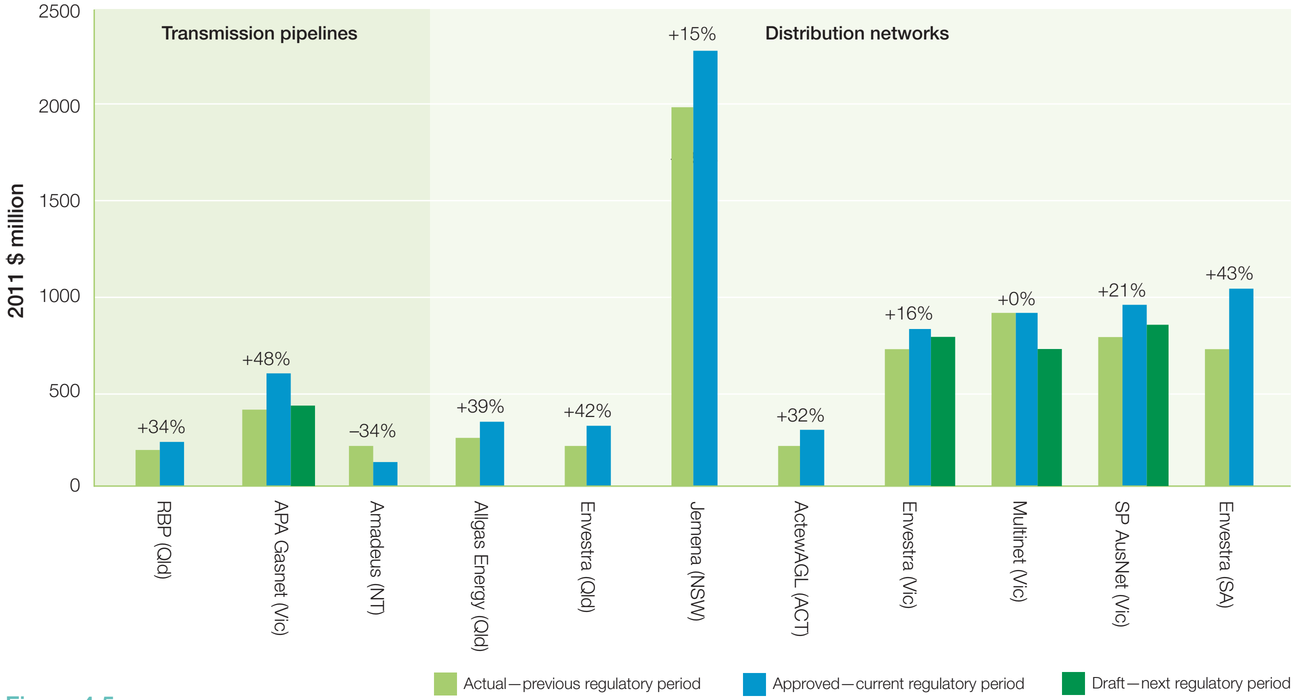
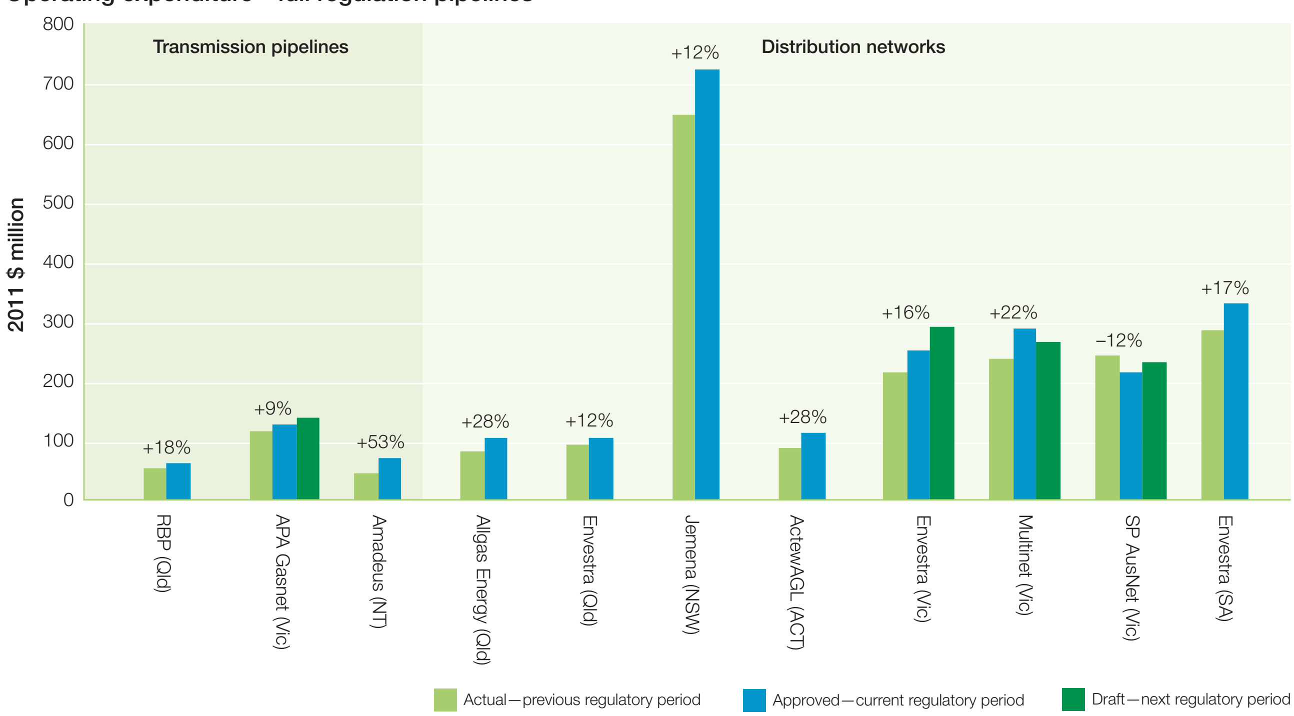


Figure 4.5

Operating expenditure—full regulation pipelines

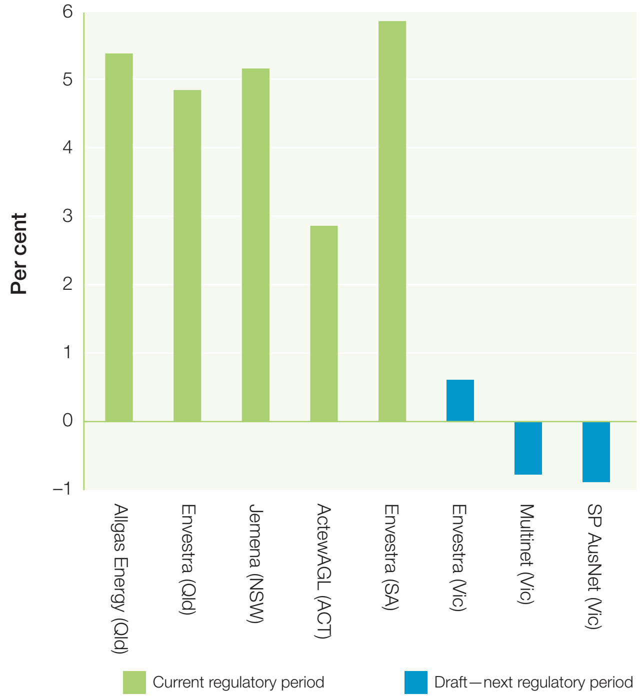


Notes (figures 4.4 and 4.5): Forecast revenues in the current access arrangement period (typically five years), compared with forecasts in previous periods; forecast operating expenditure in the current period, compared with actual levels in previous periods. See tables 4.1 and 4.2 for the timing of regulatory periods. The data account for the impact of decisions by the Australian Competition Tribunal. The Victorian data include draft approvals released in September 2012 for 2013–17.

Source: AER final and draft decisions on access arrangements.

Figure 4.6

Impact of AER decisions on residential gas charges



Note: Impact on annual gas charges for a typical residential customer in that jurisdiction in current access arrangement period. See table 4.2 for the timing of regulatory periods. The Victorian data are based on draft approvals released in September 2012 for 2013–17. The data account for the impact of decisions by the Australian Competition Tribunal.

Source: AER final and draft decisions on access arrangements.

the current access arrangement periods, compared with previous periods, by an average of 18 per cent. The largest increases are for Envestra's networks in South Australia and Queensland (43 per cent and 42 per cent respectively). The drivers include rising asset bases associated with higher levels of investment (resulting in higher returns on capital). Some decisions reflect a rise in underlying costs, including operating and maintenance expenditure and capital financing costs (section 2.3).

AER determinations made in 2012 reflect recent reductions in the risk free rate that have lowered the overall cost of capital. Draft decisions for Victoria's distribution networks would result in revenues falling, on average, by 13 per cent in 2013–17, compared with revenues in 2008–12 (section 4.4.3).

4.7.1 Operating expenditure

Operating and maintenance costs are a key driver of pipeline revenue requirements. Figure 4.5 illustrates recent data for gas transmission pipelines and distribution networks that are subject to full regulation. The chart compares approved forecasts in current access arrangements with actual expenditure in previous periods; the Victorian data also include draft approved operating expenditure for 2013–17 (released in September 2012).

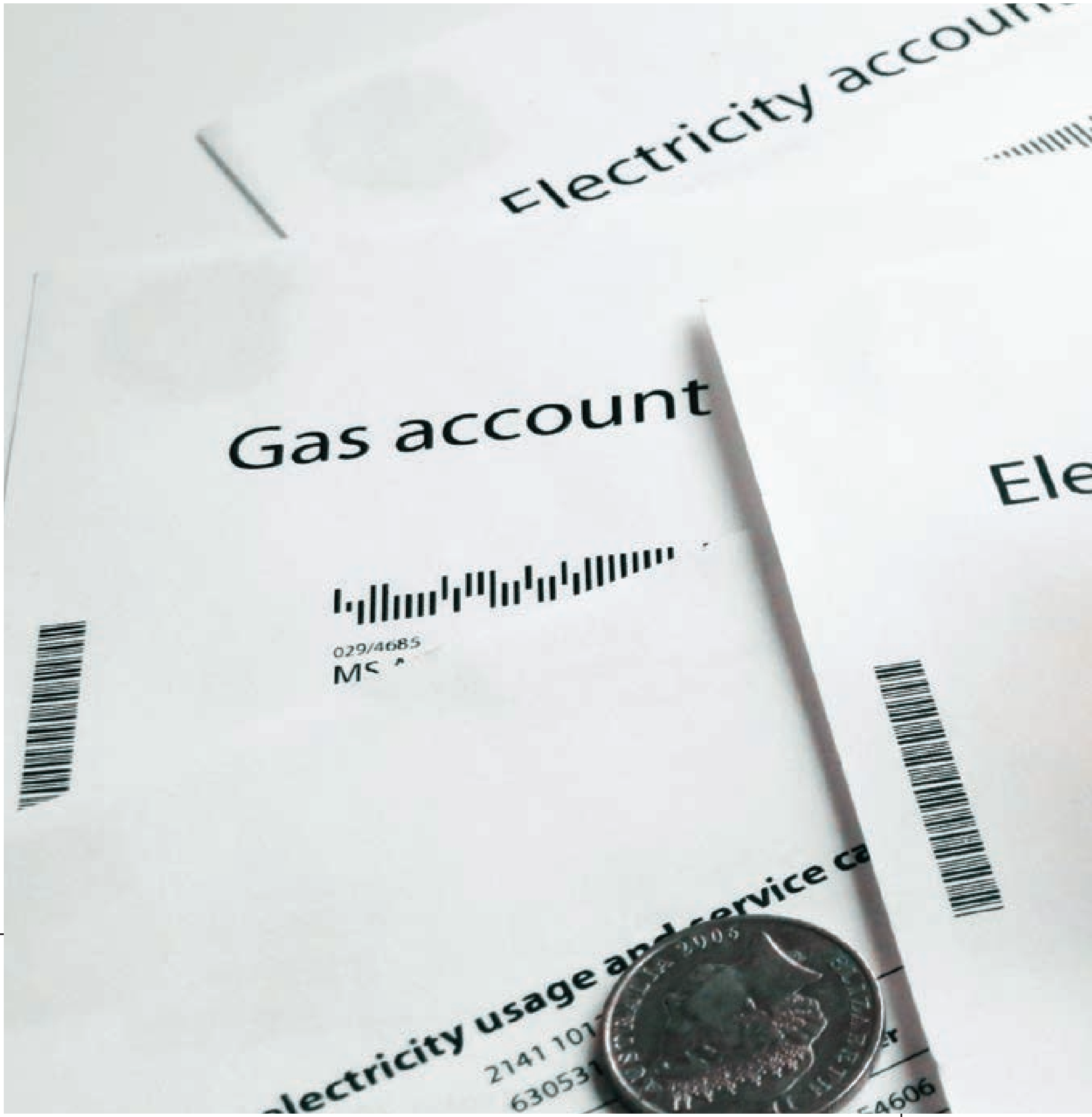
Sections 4.4.1 and 4.4.2 comment on outcomes for the major *transmission* pipelines under full regulation. For *distribution* networks, real operating expenditure is forecast to increase in the current access arrangement periods by an average of 18 per cent, compared with actual expenditure in previous periods. Outcomes vary significantly across the networks, with the largest increases forecast for the Allgas Energy (Queensland) and ActewAGL (ACT) networks (28 per cent).

Draft decisions for Victoria's distribution networks allow for operating expenditure to rise, on average, by 5 per cent in 2013–17, compared with that in 2008–12.

4.7.2 Retail impacts of regulatory decisions

Gas *transmission* charges typically make up 3–8 per cent of a typical gas bill for a residential customer; the ratio is significantly higher for industrial users. In Queensland, the AER's 2012 decision on the Roma to Brisbane Pipeline is expected to cause almost no change in a typical residential customer's bill over the next five years. In Victoria, the AER's 2012 draft decision on APA GasNet's Victorian transmission pipeline would result in a typical residential bill falling by around 0.4 per cent.

Gas *distribution* charges typically make up 40–60 per cent of a typical gas bill for a residential customer. In recent years, rising capital and operating expenditure, as well as other cost drivers (including higher financing costs and the rising cost of unaccounted for gas) raised gas distribution costs, leading to retail charges for residential customers rising by 5–6 per cent (figure 4.6). The AER's 2012 draft decisions for the Victorian distribution networks would have little impact on customer charges over 2013–17.



5 ENERGY RETAIL MARKETS


Account number
Service address
Tax Invoice
Go Easy
Internet
Email

Energy retailers buy electricity and gas in wholesale markets and package it with network (transportation) services for sale to customers. While state and territory governments have been responsible for regulating retail energy markets, the Australian Energy Regulator (AER) is taking on significant functions under national reforms (box 5.1). The transition date for the the National Energy Retail Law (Retail Law) varies among participating jurisdictions—Queensland, New South Wales, Victoria, South Australia, Tasmania and the Australian Capital Territory (ACT). The law commenced in Tasmania (for electricity only) and the ACT on 1 July 2012.

The Retail Law aims to ensure effective protection for small energy customers—residential energy users and small businesses annually consuming less than 100 megawatt hours (MWh) of electricity or one terajoule (TJ) of gas.[1] This chapter covers the retailing of energy to small customers in those jurisdictions participating (or expected to participate) in the national reforms.

5.1 Retail market structure

Table 5.1 lists licensed energy retailers that were active in the market for residential and small business customers in August 2012. Active retailers are those supplying energy services to customers (whether or not the retailer is seeking new customers). The number of active retailers has steadily increased over the past 10 years following the introduction of full retail contestability in most jurisdictions.

Not all retailers are active in every jurisdiction. However, all retailers active at August 2012 held authorisations to sell in every jurisdiction once the Retail Law is adopted.[2] In considering whether to enter a particular market, 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 to supply both electricity and gas in at least some of the jurisdictions in which they are active. Other retailers offer only electricity, and one retailer specialises in gas (Tas Gas Retail, which operates in Tasmania). Reasons for the lower level of competition in gas may include the smaller market (not all households have a gas connection) and the difficulties that new entrant retailers face in contracting for wholesale gas supplies.

Victoria has the largest number of active retailers selling to small customers—both for electricity (16) and gas (seven). Queensland, New South Wales and South Australia each have 11–12 electricity retailers and three to six gas retailers.

Figure 5.1 illustrates retail market shares in electricity and gas by jurisdiction. Three major privately owned retailers—AGL Energy, Origin Energy and EnergyAustralia (formerly TRUenergy)—supply 76 per cent of small electricity customers and 84 per cent of small gas customers in eastern Australia in 2012.

Smaller private retailers (such as Simply Energy, Lumo Energy and Australian Power & Gas) have been successful in building market share in Victoria and South Australia.

- In Victoria, smaller retailers account for 28 per cent of electricity customers in 2012 (up from 8 per cent in 2005) and 22 per cent of gas customers (up from 1 per cent).
- In South Australia, smaller retailers account for 17 per cent of electricity customers (up from 5 per cent in 2005) and 7 per cent of gas customers (up from 3 per cent).

Government retailers are prominent 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 host retailer—Aurora Energy—supplies most small electricity customers. Legislation prevents new entrants from supplying small customers that use less than 50 MWh per year. The Tasmanian Government announced significant reforms to the state's energy market structure in 2012 (section 5.3).
- In the ACT, ActewAGL (a joint venture between the ACT Government and AGL Energy) remains the dominant retailer, with over 95 per cent of small customers.[3]
- Red Energy (owned by the New South Wales, Victorian and Australian governments) and Momentum Energy (owned by the Tasmanian Government) operate in a number of jurisdictions.

Some regional markets are heavily concentrated. Three or fewer retailers account for more than 90 per cent of electricity market share in four of the six jurisdictions. Similar

1 For electricity, some jurisdictions have a consumption threshold different from that specified in the Retail Law. In New South Wales and South Australia, for example, small electricity customers are those consuming less than 160 megawatt hours (MWh) per year; in Tasmania, the threshold is 150 MWh per year.

2 Some limitations apply, including a restriction on selling electricity to customers in Tasmania consuming less than 50 MWh of electricity per year.

3 AEMC, *Review of the effectiveness of competition in the electricity retail market in the ACT*, 2010, p. 23.

Box 5.1 National retail regulation

National reforms to retail energy markets are being progressively implemented from 1 July 2012. The Retail Law, which transfers significant functions to the AER, will work with the Australian Consumer Law to provide small energy customers with effective protections around their electricity and gas supply arrangements.

The transition date for the the Retail Law varies among participating jurisdictions—Queensland, New South Wales, Victoria, South Australia, Tasmania and the ACT. The law commenced in Tasmania and the ACT on 1 July 2012. South Australia and New South Wales announced target implementation dates of 1 February 2013 and 1 July 2013 respectively. Victoria committed to implementing the Law as soon as practicable and no later than 1 January 2014 (providing outstanding issues are resolved).

On 7 August 2012, Prime Minister Julia Gillard urged the remaining jurisdictions to commence the Retail Law as soon as possible to give consumers the benefit of the law's strong protections and use of the AER's *Energy Made Easy* price comparator website.

The Retail Law transfers a range of functions to the AER, including:

- providing an energy price comparator website (www.energymadeeasy.gov.au) for small customers
- enforcing compliance with the Law and its supporting Rules and Regulations
- authorising energy retailers to sell energy, and granting exemptions from the requirement (for example, to retirement villages and caravan parks that onsell energy)
- approving retailers' policies for dealing with customers facing hardship
- administering a 'retailer of last resort' scheme, to protect customers and the market if a retail business fails
- reporting on retailer performance and market activity, including energy affordability, disconnections and competition indicators.

The states and territories remain responsible for regulating retail energy prices.

The AER published procedures and guidelines on how it will undertake its roles under the Retail Law. In Tasmania and the ACT, the AER has commenced these roles, including on retail performance reporting, retail pricing information, compliance and enforcement activity and the connection charging regime. The *Energy Made Easy* price comparator website was launched for customers in those jurisdictions on 1 July 2012. The AER expected to release in late 2012 its retail performance reports on businesses operating in Tasmania and the ACT.

In addition to transitioning retailers that held jurisdictional licences before April 2011, the AER has granted 'national retailer authorisations' to a number of entities. An authorisation enables an entity to sell electricity or gas in those jurisdictions that adopt the Retail Law.

ratios apply in gas. In addition, substantial vertical integration exists between retailers and energy producers (section 5.2).

Some new entry occurred in retail markets in 2011–12, notably Powershop and Blue NRG in Victoria. Existing retailers Alinta Energy, Sanctuary Energy and Momentum Energy widened the geographic range of their activity, moving into Victoria, South Australia and New South Wales respectively, while QEnergy was granted a retail licence in South Australia.

5.2 Vertical integration

While governments structurally separated the energy supply industry in the 1990s, there has since been significant vertical integration of retailers and generators to form 'gentailers.' 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 reduce liquidity in contract markets, posing a potential barrier to entry and expansion for generators and retailers that are not vertically integrated.

Across the National Electricity Market (NEM), three retailers—AGL Energy, Origin Energy and EnergyAustralia—jointly supply 76 per cent of customers. The entities:

- acquired significant market share in Queensland (in 2007) and New South Wales (in 2010) following the privatisation of government owned retailers in those states
- increased their market share in electricity generation from 11 per cent in 2007 to 35 per cent in 2012, following the commissioning of Origin Energy's Mortlake power station and AGL Energy's full acquisition of Loy Yang A in Victoria

Table 5.1 Active energy retailers—small customer market, October 2012

RETAILER	OWNERSHIP	QLD	NSW	VIC	SA	TAS	ACT
ActewAGL Retail	ACT Government and AGL Energy		E, G*				E*, G*
AGL Energy	AGL Energy	E, G*	E, G*	E*, G*	E*, G		
Alinta Energy	Alinta Energy			E	E		
Aurora Energy	Tasmanian Government					E*, G	
Australian Power & Gas	Australian Power & Gas	E, G	E, G	E, G			
BlueNRG	BlueNRG			E			
Click Energy	Click Energy	E		E			
Diamond Energy	Diamond Energy			E	E		
Dodo Power & Gas	Dodo Power & Gas	E	E	E			
EnergyAustralia[1]	CLP Group	E	E*, G	E*, G*	E, G		E, G
Ergon Energy	Queensland Government	E*					
Lumo Energy	Infratil	E	E, G	E, G	E		
Momentum Energy	Hydro Tasmania (Tasmanian Government)		E	E	E		
Neighbourhood Energy	Alinta Energy			E			
Origin Energy[2]	Origin Energy	E*, G*	E*, G*	E*, G*	E, G*		
Powerdirect	AGL Energy	E	E	E	E		
Powershop	Meridian Energy			E			
Qenergy	Qenergy	E			E		
Red Energy	Snowy Hydro[3]		E	E, G	E		
Sanctuary Energy	Living Choice Australia / Sanctuary Life	E	E		E		
Simply Energy	International Power			E, G	E, G		
Tas Gas Retail (formerly Option One)	Brookfield Infrastructure					G	

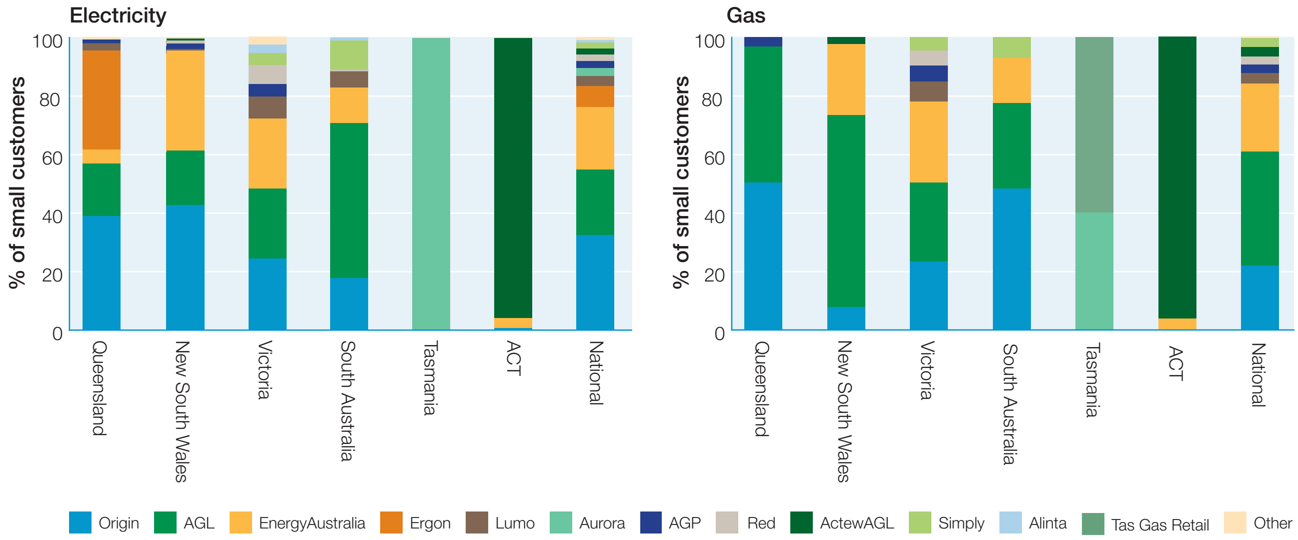
Electricity retailer (E)
Gas retailer (G)
Host retailer *

1. TRUenergy rebranded as EnergyAustralia in 2012.
2. Origin Energy also operates under the brands Country Energy and Integral Energy in New South Wales after acquiring these businesses from the New South Wales Government in 2011.
3. Snowy Hydro is owned by the New South Wales Government (58 per cent), the Victorian Government (29 per cent) and the Australian Government (13 per cent).

Note: The host retailers listed for New South Wales, South Australia, Tasmania and the ACT are those responsible for offering ‘standing offer’ contracts to customers in defined regions of each state. The ‘host’ retailers listed for Victoria and Queensland are those responsible for offering ‘standing offer’ contracts to customers that establish a new connection in defined regions of each state.

Sources: Jurisdictional regulator websites, retailer websites and other public sources.

Figure 5.1
Retail market share (small customers), by jurisdiction, 2012



Source: AER estimates.

- supply around 85 per cent of gas retail customers and are expanding their interests in upstream gas production and storage.

The expanding profile of AGL Energy, Origin Energy and EnergyAustralia is apparent across all mainland regions of the NEM (section 5.2.1). The three entities control 58 per cent of new generation capacity commissioned or committed since 2007. Generation investment since 2007 by entities that do not also retail energy has been negligible. In addition, many new entrant retailers in that period are vertically integrated with entities that were previously stand-alone generators—for example, International Power (trading as Simply Energy in retail markets), Infratil (Lumo Energy) and Alinta (table 5.2).

Government owned generators are also vertically integrating. The generator Snowy Hydro owns Red Energy, which operates in the New South Wales, Victorian and South Australian retail markets. The Tasmanian Government owns Hydro Tasmania, a generation business that also has a retail arm (Momentum Energy), and the stand-alone retailer Aurora Energy; Momentum Energy is restricted from operating in Tasmania.

Australian Power and Gas is the only retailer with a significant market share that does not have related generation interests. However, a number of smaller retailers, including recent market entrants, operate only in the retail market.

There is also vertical integration 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. AGL Energy is a producer of coal seam gas in Queensland and New South Wales. EnergyAustralia has gas storage facilities in Victoria and acquired gas reserves in the Gunnedah Basin (New South Wales) in 2011.

In addition, the Queensland and Tasmanian governments own joint distribution–retail businesses. The ACT Government has ownership interests in both the host energy retailer and distributor. Ring fencing arrangements aim to ensure operational separation of the retail and network arms of these entities. The AER applies jurisdictional ring fencing guidelines to distribution businesses. In September 2012 it released a position paper stating a preference to adopt a nationally consistent approach to ring fencing.

5.2.1 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 but exhibits less vertical integration than most regions do. Electricity generation remains largely in public hands:

Table 5.2 Vertical integration activity in NEM jurisdictions, 2006–12

DATE	EVENT
2012	AGL acquired full ownership of 2080 MW Loy Yang A power station in Victoria
	Origin Energy commissioned 518 MW Mortlake power station in Victoria
	AGL Energy commissioned 63 MW Oaklands Hill wind farm in Victoria and 33 MW The Bluff wind farm in South Australia
2011	TRUenergy announced two 500 MW power plants in Queensland
	Alinta Energy entered retail market in South Australia (and Victoria in 2012)
	AGL Energy commissioned 82 MW North Brown Hill wind farm in South Australia
	TRUenergy acquired 111 MW Waterloo wind farm in South Australia
	AGL Energy (with Meridian Energy) committed to 420 MW Macarthur wind farm in Victoria
2010	Origin Energy acquired Integral Energy and Country Energy (retail) and trading rights for Eraring and Shoalhaven power stations from New South Wales Government
	TRUenergy acquired EnergyAustralia (retail) and trading rights for Mount Piper and Wallerawang power stations from New South Wales Government
2009	Origin Energy commissioned 605 MW Darling Downs power station in Queensland
	Origin Energy commissioned 648 MW Uranquinty power station in New South Wales
	Origin Energy completed a 131 MW expansion of Mount Stuart power station in Queensland
	Origin Energy completed a 128 MW expansion of the Quarantine power station in South Australia
	AGL Energy commissioned 71 MW Hallett 2 wind farm in South Australia
	AGL Energy commissioned 140 MW Bogong Hydro power station in Victoria
2008	TRUenergy commissioned 435 MW Tallawarra power station in New South Wales
	Hydro Tasmania acquires controlling interest in Momentum Energy (full acquisition occurred in 2010)
2007	AGL Energy acquired Torrrens Island power station (40 per cent of South Australian capacity) from TRUenergy in exchange for the 150 MW Hallett power station and a cash sum
	Origin Energy commissioned 30 MW Cullerin Range wind farm in New South Wales
	AGL Energy commissioned 95 MW Hallett 1 wind farm in South Australia
	Origin Energy acquired Sun Retail from Queensland Government
	AGL Energy acquired Powerdirect from Queensland Government
2006	Infratil entered retail market (now trading as Lumo Energy)
	International Power entered retail market (now trading as Simply Energy)

state owned corporations control 60 per cent of capacity, including a power purchase agreement over the privately owned Gladstone power station. The degree of market concentration increased in 2011 with the Queensland Government dissolving the state owned Tarong Energy and reallocating its capacity into the remaining two state owned entities.

While generation is largely state owned, the retail sector was privatised in 2007, with Origin Energy and (to a lesser extent) AGL Energy emerging as the key players. These entities also account for 12 per cent of statewide generation capacity (mainly new investments in gas fired capacity).

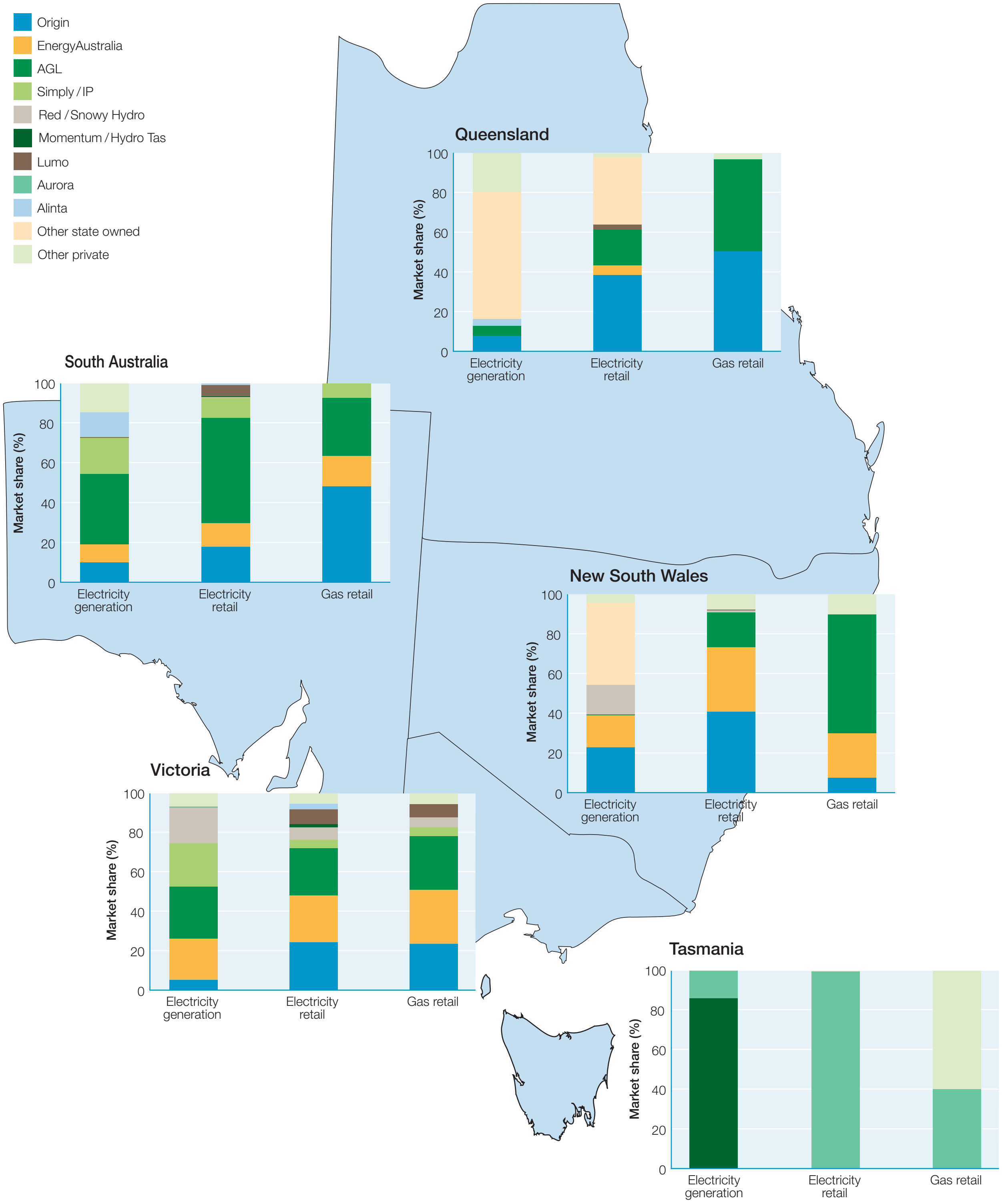
Origin Energy is also one of the leading producers in Queensland's Surat–Bowen Basin, accounting for 20 per cent of the basin's gas production. AGL has a small interest, accounting for less than 3 per cent of the basin's gas production. The basin will soon supply LNG projects as well as the domestic market.

EnergyAustralia supplies around 5 per cent of Queensland's retail electricity customers, but has no local generation assets. It announced plans in 2011 to construct two 500 megawatt power plants in the region.

The *New South Wales* electricity sector was dominated by government entities until 2011, when Origin Energy and EnergyAustralia acquired assets through the privatisation of retailers and generation contracts. State owned corporations (including Snowy Hydro) still control around 55 per cent of generation capacity.

Origin Energy and EnergyAustralia now supply over 75 per cent of retail electricity customers, and control 39 per cent of statewide generation capacity (through either direct ownership or contracted trading rights). EnergyAustralia has also acquired significant market share in gas retail (around 25 per cent of customers).

Figure 5.2
Vertical integration in NEM jurisdictions, 2012



AGL Energy was the historical incumbent in gas retail supply, and retains 65 per cent of customers. It fully owns the state's only operating gas producing entity. AGL Energy's position in the gas market has helped it acquire market share in electricity retail (around 20 per cent of customers).

Victoria's generation sector is disaggregated across a number of 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.

While there is reasonable market depth, Victoria has significant vertical integration. The three major retailers control about 52 per cent of generation capacity—up from 28 per cent in 2007—following the commissioning of Origin Energy's Mortlake power station and AGL Energy's full acquisition of Loy Yang A in 2012. Victoria's other major generators—International Power and Snowy Hydro—jointly supply around 10 per cent of electricity customers via their ownership of Simply Energy and Red Energy respectively.

Origin Energy has also 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 also the Bass Basin.

South Australia's electricity sector is concentrated, with AGL Energy supplying over 50 per cent of retail customers. AGL Energy's acquisition of the Torrens Island power station in 2007, combined with recent investment in wind capacity, raised its share of generation capacity from 5 per cent in 2007 to 36 per cent in 2012.

Origin Energy, EnergyAustralia and International Power are significant but minority players in both generation and retail. Alinta too has generation assets and entered the electricity retail market in 2011. Gas for electricity generation has been 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 nearly all small retail customers and owns 14 per cent of generation capacity; Hydro Tasmania controls the remaining 86 per cent of generation capacity. The Tasmanian Government in 2012 announced reforms aimed at reducing the extent of market concentration (section 5.3).

5.3 Retail competition

NEM jurisdictions other than Tasmania have introduced full retail contestability (FRC) in electricity, allowing all customers to enter a contract with their retailer of choice. Box 5.2 discusses the types of energy contract available. All jurisdictions have introduced FRC in gas retail markets.

At 1 July 2011 Tasmania extended contestability to customers using at least 50 MWh per year. Contestability will likely soon extend to all customers, with the Tasmanian Government announcing it will introduce FRC from 1 January 2014. To coincide with this introduction, the Tasmanian Government will sell Aurora's retail customer base in blocks to private retailers. Hydro Tasmania will retain ownership of its retail business (Momentum Energy). Reforms will also apply to Tasmania's wholesale market arrangements to encourage new retail entry (section 1.5.4). The Tasmanian Government will retain retail price regulation until satisfied competition is fully effective.

5.3.1 Consumer protection in competitive retail markets

The introduction of FRC has increased competition among retailers for new customers and intensified retailer marketing activity. Door-to-door marketing is widely used in the energy industry and accounts for more than half of all new contracts—around one million new energy contracts resulted from door-to-door marketing in 2011.[4] The use of energy switching websites has also increased.

Door-to-door sales enable retailers to target regions and customers considered open to switching retailer. Additionally, outsourcing sales to door-to-door agents paid on a commission basis is less expensive than undertaking other forms of marketing. However, criticisms of door-to-door marketing practices include aggressive sales behaviour.

The Australian Consumer Law, enforced by the Australian Competition and Consumer Commission (ACCC), contains provisions that protect customers from improper conduct by door-to-door salespeople. The provisions relate to unsolicited sales, misleading and deceptive conduct and unconscionable conduct. The Retail Law also contains marketing provisions that protect customers.

The ACCC has taken action against energy retailers and energy switching sites for alleged breaches of the Australian Consumer Law:

4 Frost and Sullivan, *Research into the door-to-door sales industry in Australia*, Report for the ACCC, 2012, p. 11.

Box 5.2 Types of energy retail contract

Small customers have access to two types of energy contract—standard retail contracts and market retail contracts. 'Host' retailers are required to offer a standard retail contract to customers that have not entered a market contract with a retailer of choice. For standard retail contracts, the Retail Law includes model terms and conditions that the retailer cannot amend.

Market retail contracts have a minimum set of terms and conditions, but otherwise vary from contract to contract. A contract may be widely available, or offered only to specific customers. It may offer discounts on the retailer's standard rates or other inducements (section 5.5.3). Market contracts typically have fixed term durations, with exit fees for early withdrawal. Under the Retail Law, retailers must obtain explicit informed consent from a customer entering a market retail contract.

The number of customers on standing contracts varies significantly across jurisdictions—22 per cent of electricity customers are on standing contracts in South Australia, compared with 30 per cent in Victoria, 50 per cent in New South Wales, 55 per cent in Queensland and 80 per cent in the ACT.

- On 27 March 2012 the ACCC filed proceedings against AGL Energy and Neighbourhood Energy, and the marketing companies engaged by them, for misleading and deceptive conduct in door-to-door selling. Also, the ACCC alleged each respondent failed to immediately leave the premises at the request of an occupier. It contended customers requested that salespeople leave by placing a 'do not knock' sign on their door. In September 2012, the Federal Court found Neighbourhood Energy and its marketing contractor had breached the Australian Consumer Law and imposed penalties of $1 million. At November 2012 the AGL Energy matters were before the Federal Court.
- On 13 July 2012 the Federal Court ordered Energy Watch—a provider of energy price comparison services—to pay $1.95 million for misleading advertising. It also ordered the former chief executive officer of Energy Watch to pay $65 000 for his role in the advertisements. The advertising related to representations about the nature of the Energy Watch service and the savings that consumers would make by switching energy retailers.

5.3.2 Customer switching

The rate at which customers switch their supply arrangements is one indicator of customer participation in the market. While switching (or churn) rates can 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 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 (it does not include customer switches between contracts with the same retailer). If a customer switches to a number of retailers in succession, then each move counts as a separate switch. Cumulative switching rates may thus exceed 100 per cent. Figure 5.3 sets out annual and cumulative switching data.

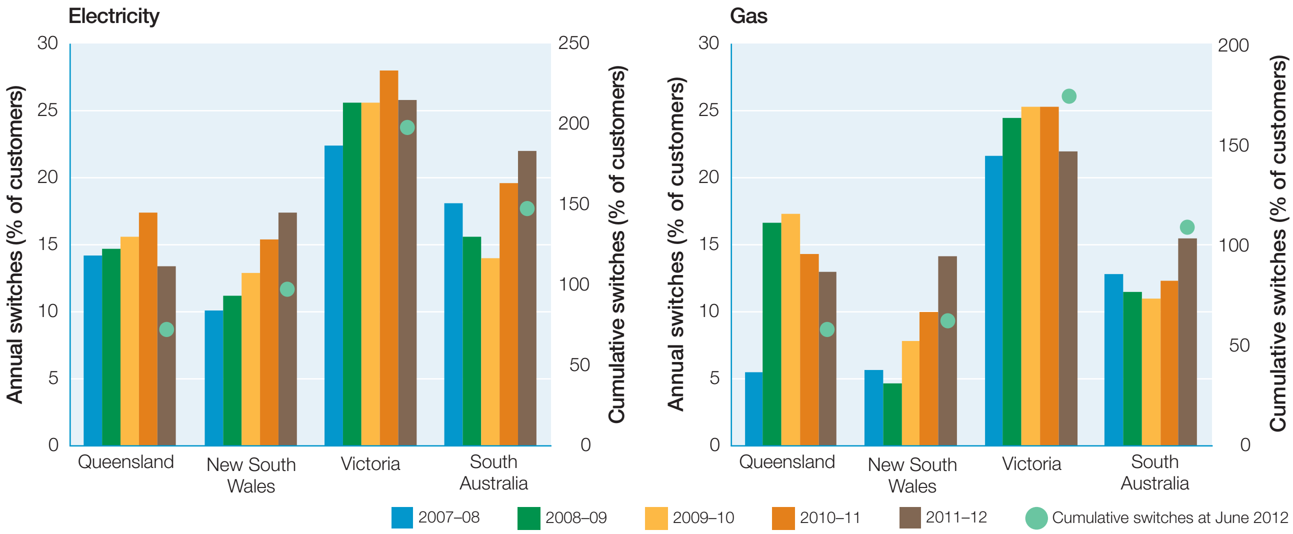
Victoria continues to have a higher switching rate than that of other jurisdictions, although the rate in 2011–12 was below the high of the previous year. Switching activity in New South Wales and South Australia rose in each of the past few years, with rates in 2011–12 the highest recorded in each state for both electricity and gas. Queensland introduced FRC later than other jurisdictions did. Its annual switching rates have generally been comparable with those in New South Wales and South Australia, but fell in 2011–12 below those jurisdictions' rates (recording its lowest level of switching in electricity since the introduction of FRC).

Switching levels remain lower in gas than electricity in all jurisdictions, reflecting the lower number of active participants in the gas market.

5.4 Retail prices

The energy bills paid by retail customers cover the costs of wholesale energy, transport through transmission and distribution networks, and retail services. Table 5.3 estimates the composition of a typical electricity retail bill for a residential customer in each NEM jurisdiction that regulates prices. While data for gas are limited, the table includes estimates for New South Wales and South Australia.

Figure 5.3
Customer switching of energy retailers, as a percentage of small customers



Sources: Customer switches: AEMO, MSATS transfer data to July 2012 and gas market reports, transfer history to July 2012; customer numbers: estimated from retail performance reports by IPART (New South Wales), the ESC (Victoria), ESCOSA (South Australia) and the QCA.

In electricity, the cost of using transmission and distribution networks to transport electricity is the largest component (43–52 per cent) of retail bills, followed by wholesale energy costs (25–36 per cent). Retailer operating costs (including margins) contribute around 10 per cent of retail bills.

The carbon price, introduced in July 2012, contributes 4–11 per cent of the final electricity bill. Other green costs—that is, costs associated with schemes to develop renewable or low emission generation, or promote energy efficiency—have been stable over the past two years and make up 4–7 per cent of retail bills. The most significant of these costs relates to the renewable energy target scheme (section 1.2.2).

In gas, pipeline charges are the most significant component of retail prices. Transmission and distribution charges account for around 47 per cent of gas retail prices in New South Wales and 63 per cent in South Australia. Distribution charges account for the bulk of pipeline costs. Wholesale energy costs typically account for a lower share of retail prices in gas than electricity, while retailer operating costs (including margins) account for a higher share. Given the uneven geographic spread of gas producing basins from major markets, the composition of retail prices can vary significantly across jurisdictions and regions.

5.4.1 Retail price regulation

Many jurisdictions continue to regulate retail prices for energy supplied under a standard retail contract. All jurisdictions except Victoria apply some form of retail price regulation for electricity services. In gas, only New South Wales and South Australia regulate prices for small customers. The prices are set by state or territory government agencies; the AER does not regulate retail prices in any jurisdiction.

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 that have been 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, but some cost components are adjusted annually. Separate pass through provisions cover unexpected costs. New South Wales, Tasmania and Queensland (for 2012–13 onwards) use this 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; it was also previously used in Queensland.

Table 5.3 Indicative composition of residential electricity and gas bills, 2012

JURISDICTION	WHOLESALE ENERGY COSTS	NETWORK COSTS	CARBON COSTS	GREEN COSTS	RETAIL COSTS
	PER CENT OF TYPICAL SMALL CUSTOMER BILL				
ELECTRICITY					
Queensland	34	44	10	4	8
New South Wales	26	52	8	5	10
South Australia	36	44	4	4	12
Tasmania	35	48	5	4	8
ACT	29	43	11	7	10
GAS					
New South Wales	32	45	5		18
South Australia	15	60	5		20

Note: Solar PV feed-in tariff costs are included within the network component.

Sources: Determinations, fact sheets and newsletters by IPART (New South Wales), the QCA (Queensland), ESCOSA (South Australia), OTTER (Tasmania) and the ICRC (ACT).

In 2011 the Essential Services Commission of South Australia introduced a new approach to determining regulated prices—a building block assessment at the start of the regulatory period, with annual adjustments based on movements in the price of unregulated market offers. A tolerance band (determined at the start of the regulatory period) limits the annual adjustments.

While Victoria does not regulate retail prices, its retailers must publish unregulated standing offer prices that small customers can access. The prices are also published in the Victorian Government gazette and cannot be changed for six months following publication.

Australian governments agreed to review the continued use of retail price regulation and to remove it if effective competition can be demonstrated.[5] The Australian Energy Market Commission (AEMC) is assessing the effectiveness of retail competition in each jurisdiction, to advise on whether to remove price regulation and provide a strategy for this to occur. State and territory governments make the final decisions on this matter.

The AEMC in 2008 reviewed the effectiveness of competition in the Victorian and South Australian energy retail markets. It found competition was effective in both markets, but competition in South Australia was more intense in electricity than in gas.[6] In response to the review, the Victorian Government removed retail price regulation on 1 January 2009. The South Australian Government did not accept the AEMC's recommendations to remove retail price regulation; it was concerned that more than 30 per cent of small customers remained on standing contracts (with a regulated price), and that stakeholders had differing views on the effectiveness of competition.

In March 2011 the AEMC reported competition in the ACT small customer market was not effective, partly because customers were unaware of their ability to switch retailers. It recommended removing retail price controls from 1 July 2012, in conjunction with running a consumer education campaign to increase awareness of the benefits of competition.[7] However, the ACT Government decided to retain price controls for another two years. It noted the AEMC's finding that removing price controls would increase the average cost of electricity, which would not benefit customers.[8]

The AEMC in 2012 commenced its review of the effectiveness of competition in the New South Wales energy retail markets. The review is scheduled to be completed in September 2013. The Standing Council on Energy and Resources (SCER, formerly the Ministerial Council on Energy) and the Council of Australian Governments agreed to further energy retail market reviews for Queensland (2013), South Australia (2015), the ACT (2016) and Tasmania (within 18 months of FRC being introduced in the electricity retail market).[9]

5 Australian Energy Market Agreement 2004 (as amended).

6 AEMC, *Review of the effectiveness of competition in the electricity and gas retail markets in Victoria, first final report*, 2007; AEMC, *Review of the effectiveness of competition in electricity and gas retail markets in South Australia, first final report*, 2008.

7 AEMC, *Review of the effectiveness of competition in the electricity retail market in the ACT, stage 2, final report,* 2011, p. 11.

8 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.

9 MCE, *Standing Council on Energy and Resources Meeting Communiqué*, 2011.

5.4.2 Regulated prices—recent trends

Table 5.4 summarises movements in regulated and standing offer electricity and gas prices for the past four years, and estimates the annual bills for customers under these arrangements. Box 5.3 provides additional background on recent changes in retail energy prices for each jurisdiction.

The data assume fixed electricity and gas use across all jurisdictions. In practice, average use varies significantly between (and within) jurisdictions for a range of reasons including climate and the penetration of gas supply. The data on annual cost should not be taken to represent a typical household in the jurisdiction.

The data illustrate significant increases in retail electricity prices over the four years (although customers in some jurisdictions can negotiate significant discounts against these prices by entering a market contract). Rising prices have led to a greater focus on the issue of energy affordability (section 5.4.5).

Network costs were the largest contributor to energy price increases over the four years. Chapter 2 discusses the factors driving network costs. Although network cost increases continued to flow through to retail prices for 2012–13, the introduction of carbon pricing on 1 July 2012 had an impact. The carbon price resulted in retail electricity price increases of 5–13 per cent for 2012–13. Coinciding with the introduction of the carbon price, the Australian Government introduced a Household Assistance Package in 2012 to offset the rise in energy costs for low and middle-income households. The package provides for households to receive compensation through pensions, allowances and other assistance payments, and to benefit from tax adjustments.

Cost pressures from other climate change policies have remained fairly stable since changes to the renewable energy target scheme from 1 January 2011 affected retail prices in 2011–12. The impact of these policies on energy price increases in 2012–13 was minimal.

5.4.3 Retail prices—long term trends

Figure 5.4 tracks movements in real energy prices for metropolitan households since 1991, using the electricity and gas components of the consumer price index. Figure 2 in the *Market overview* compares price outcomes for household and business customers.

Electricity prices began to rise in 2007–08, when drought affected wholesale prices by constraining hydro generation and low cost thermal generators that rely on water for cooling. More recently, rising network costs (especially for distribution networks and pipelines) and the costs of introducing and expanding green schemes have driven retail price rises. Electricity prices rose nationally over the past five years by an average of 66 per cent in real terms (91 per cent in nominal terms). Gas prices rose by 40 per cent in real terms (62 per cent in nominal terms). The discussion of regulated price movements in box 5.3 outlines the drivers of recent price rises in each jurisdiction.

5.4.4 Price diversity

Retailers offer contracts for a range of products with different price 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. On 1 July 2012 the AER launched an online price comparison service—*Energy Made Easy*—to help small customers compare retail product offerings. The website is available for customers in those jurisdictions that have commenced the Retail Law (at 1 October 2012, Tasmania and the ACT). Additionally, the Queensland, South Australian, New South Wales and Victorian regulators and a number of private entities operate websites allowing customers to compare their energy contract with available market offers.

Table 5.5 draws on state regulators' price comparison websites to estimate price offerings in 2012 for residential customers in those jurisdictions with relatively established markets—Queensland, New South Wales Victoria and South Australia. The table provides estimates for February 2012 and August 2012.

The data indicate varying degrees of price diversity, with opportunities for customers to negotiate discounts being greatest in Victoria. In relation to discounting, the average annual electricity bill under *market contracts* in February 2012 was around 5.5 per cent below the equivalent *standing offer* cost (in all jurisdictions). The average discount against the standing offer in August 2012 remained relatively unchanged in Queensland, New South Wales and South

Table 5.4 Movements in regulated and standing offer prices—electricity and gas

JURISDICTION	REGULATOR	DISTRIBUTION NETWORK	AVERAGE PRICE INCREASE (PER CENT) 2009–10	2010–11	2011–12	2012–13	ESTIMATED ANNUAL COST ($)
ELECTRICITY							
Queensland	QCA	Energex and Ergon Energy	15.5	13.3	6.6	10.6	1755
New South Wales	IPART	AusGrid	21.7	10.0	17.9	20.6	2027
		Endeavour Energy	21.1	7.0	15.5	11.8	2011
		Essential Energy	17.9	13.0	18.1	19.7	2741
Victoria	Unregulated	Citipower	5.7	14.6	3.7	19.9	1886
		Powercor	5.2	15.4	7.7	23.1	2257
		SP AusNet	6.0	11.3	23.6	19.7	2122
		Jemena	7.7	17.7	10.5	23.2	2205
		United Energy	7.0	11.4	9.7	25.2	2068
South Australia	ESCOSA	SA Power Networks	3.1	18.3	17.4	18.0	2557
Tasmania	OTTER	Aurora Energy	6.2	15.3	11.0	10.6	2166
ACT	ICRC	ActewAGL	6.4	2.3	6.5	17.7	1523
GAS							
New South Wales	IPART	Jemena	4.4	5.2	4.0	14.8	841
South Australia	ESCOSA	Envestra	5.3	3.1	13.8	17.7	961

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 'peak only' tariff at August 2012. The South Australian gas cost is estimated for a metropolitan customer.

The Victorian price movements (and estimated annual costs) are for the calendar year ending in that period—for example, the 2012–13 Victorian data are for calendar year 2012. They are based on unregulated standing offer prices published in the Victorian Government gazette by the local area retailer in each of Victoria's five distribution networks.

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

Australia, but rose to 8 per cent in Victoria. These outcomes are reflected in a change in energy bill spreads (in dollars).

In August 2012 the average discount from the standing offer cost was lower in gas than electricity—less than 2 per cent in all jurisdictions other than Victoria, where it was around 6 per cent.

Across all jurisdictions, the annual bill spread in August 2012 (measured within a particular distribution network) was:

- up to $500 in electricity, except in Victoria where the spread was $850–1150. This was a larger spread than in February 2012 for Victoria and South Australia, but smaller for Queensland and New South Wales
- up to $200 in gas. This was a larger spread than in February 2012 for all jurisdictions except Queensland.

5.4.5 Retail prices and energy affordability

Energy affordability relates to customers' ability to pay their energy bills. While rising energy prices contribute to the number of customers with payment difficulties, affordability also depends on energy consumption levels, household income and financial assistance or concessions.

The New South Wales regulator, the Independent Pricing and Regulatory Tribunal, reports annually on energy affordability. It found energy costs would increase by $170–410 for residential customers in 2012–13. The impact would be less if energy use continues to fall (average consumption fell by 6 per cent in the four years to 2010–11). But price rises are outstripping changes in disposable income. Around 50 per cent of metropolitan New South Wales households will spend more than 4 per cent of their disposable income on energy bills in 2012–13, compared with 20 per cent of households in 2006–07.

Box 5.3 Retail energy prices, by jurisdiction—recent developments

The *Queensland* Government in 2012 imposed a price freeze on the regulated electricity peak tariff for residential customers, apart from increases resulting from the introduction of the carbon price. The government's decision limited electricity price increases for an average customer on this tariff to 10.6 per cent for 2012–13.

New South Wales regulated electricity prices rose by an average of 18.1 per cent for 2012–13, following an average rise of 17.3 per cent in 2011–12. The carbon price was responsible for around half of the increase for 2012–13 (pushing up prices by 8.9 per cent). Network costs accounted for an 8.4 per cent rise in prices for 2012–13 and contributed to almost 60 per cent of retail price rises over the past five years. Retail costs had a small impact on 2012–13 prices, pushing them up by 1.2 per cent, while wholesale energy costs fell slightly.

Victorian standing electricity price rose by about 20–25 per cent across the state's five distribution networks in 2012, following a wide spread of outcomes in 2011. Because prices are unregulated, limited information is available on underlying cost drivers, including reasons for these outcomes. The carbon price would have been a cost driver, but is likely to account for less than half the overall price increase. Distribution network costs accounted for retail price changes of between 2.4 per cent and 5.9 per cent, and metering charges accounted for a further 1 per cent. A doubling of the target under the Victorian Energy Efficiency Target Scheme on 1 January 2012, along with less 'low hanging fruit' to meet it, would have affected retail prices. Little information is available on the impact of wholesale energy costs (including hedging costs), retailer costs and retail margins in the Victorian market.

South Australian retail electricity prices rose by 18 per cent for 2012–13. Network costs caused around 60 per cent of the increase, of which solar feed-in tariff costs were a major contributor. Carbon pricing caused around 25 per cent of the price increase. The impact of the carbon price was lower in South Australia than in the other mainland jurisdictions, given the state's high reliance on renewable energy (wind) generation. Retail costs and margins accounted for the balance of the retail price increase.

The South Australian regulator, ESCOSA, in 2012 reviewed the method for setting the wholesale energy cost component in its retail price determinations. In its draft report (October 2012) ESCOSA proposed using market costs, rather than the long run marginal cost of generation, to estimate wholesale energy costs. Poor liquidity in hedging markets had previously precluded this approach.

The decision, to take effect on 1 January 2013, would reduce the wholesale cost allowance by 22 per cent and the regulated retail price by 8.1 per cent.

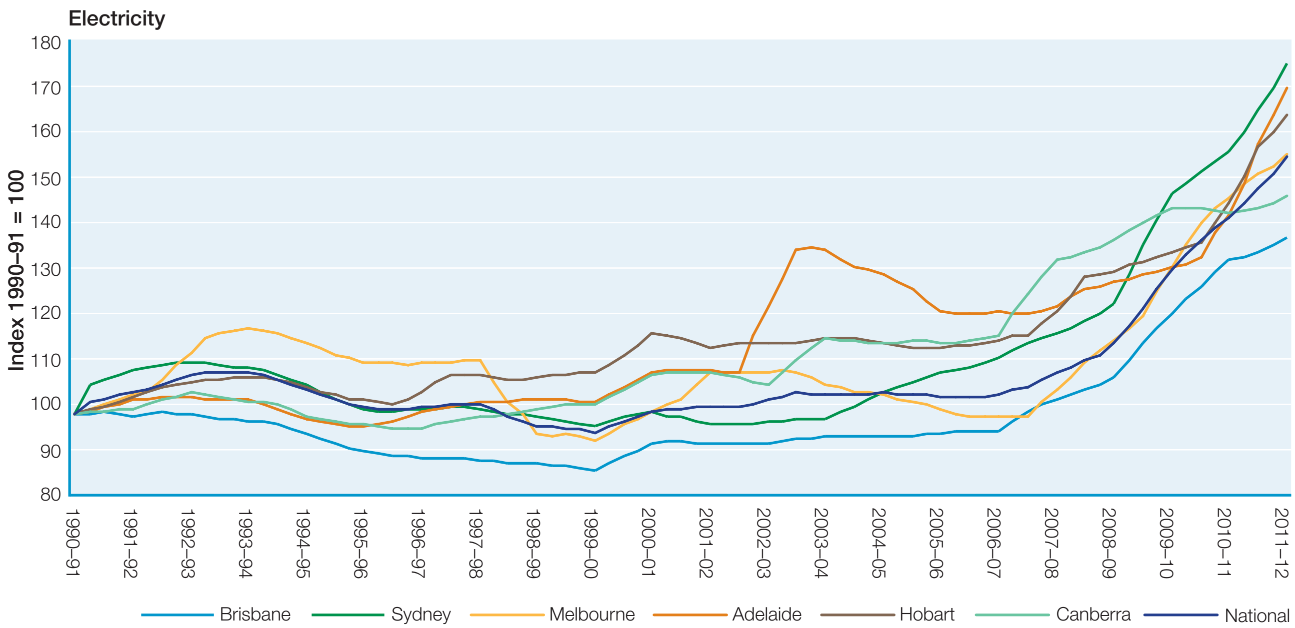
The regulated electricity price in *Tasmania* rose by 10.6 per cent for 2012–13. The carbon price led to prices rising by 5.6 per cent. Network costs were the other significant cost driver, with green schemes also contributing. A change in the basis for estimating wholesale energy costs reduced the retail price by 6.1 per cent, partly offsetting the rises in other cost elements.

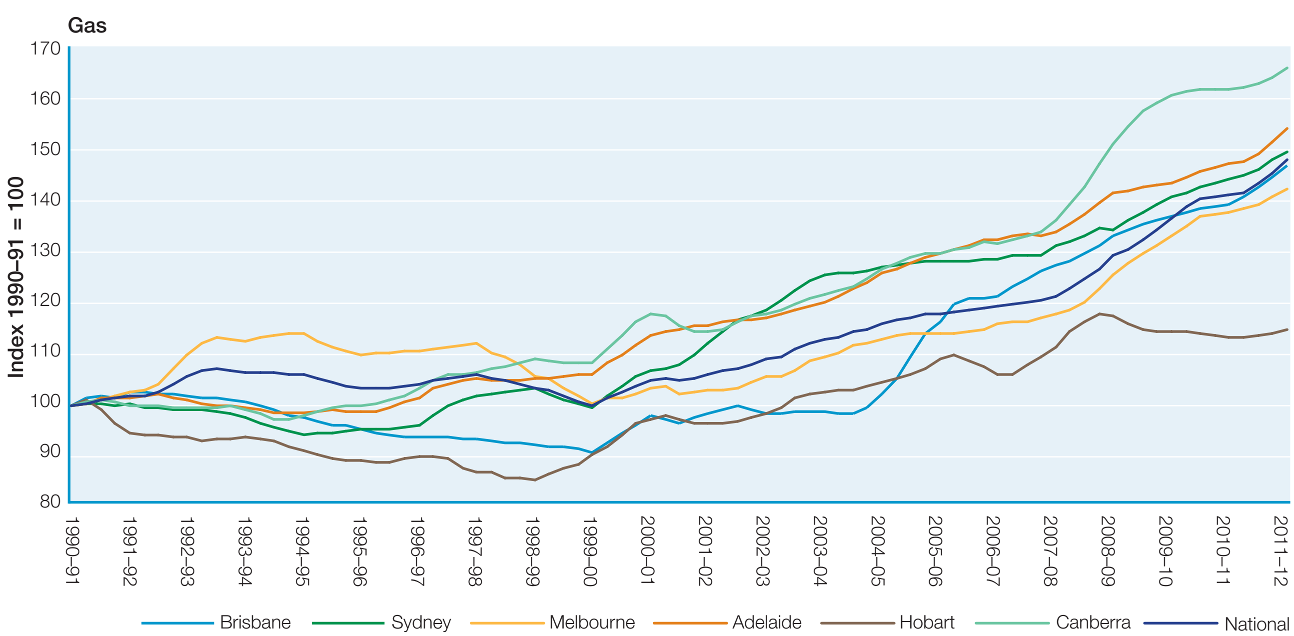
ACT electricity prices increased on average by 17.7 per cent for 2012–13. This followed relatively modest price rises in the previous two years of 2.3 and 6.5 per cent. The carbon price accounted for almost 80 per cent of the 2012–13 price increase (increasing prises by around 14 per cent). The impact of the carbon price was similar to that in New South Wales in dollar terms, but accounted for a larger percentage change in the ACT, where retail prices were lower. Network and retail costs increased retail prices for 2012–13 by around 4 per cent and 1.5 per cent respectively. For the second year in a row wholesale costs fell slightly. Green scheme costs also decreased in 2012–13.

Retail price increases have generally been lower in *gas* than electricity for a number of years. While this was still the case for South Australia and New South Wales in 2012–13, the rises were substantially higher than the gas price increases in previous years. Retail gas prices rose by 14.8 per cent in New South Wales and by 17.7 per cent in South Australia. Higher network charges were the main contributor in both jurisdictions, increasing retail prices by 6.7 per cent in New South Wales and 12.3 per cent in South Australia. The carbon price caused prices to rise by 6 per cent and 4.5 per cent respectively in the two jurisdictions.

Figure 5.4

Retail price index (inflation adjusted)—Australian capital cities



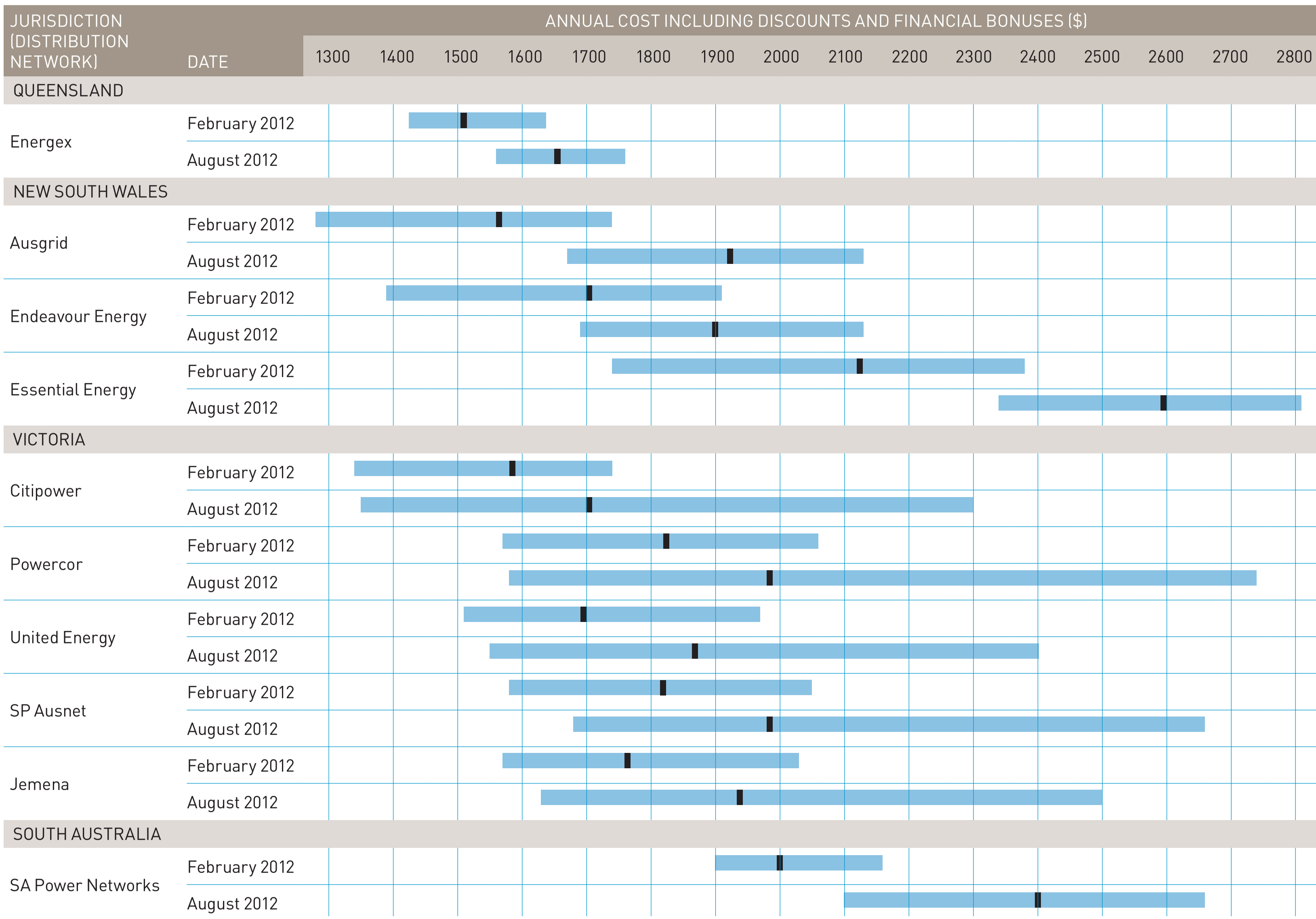


Note: Consumer price index electricity and gas series, deflated by the consumer price index for all groups.

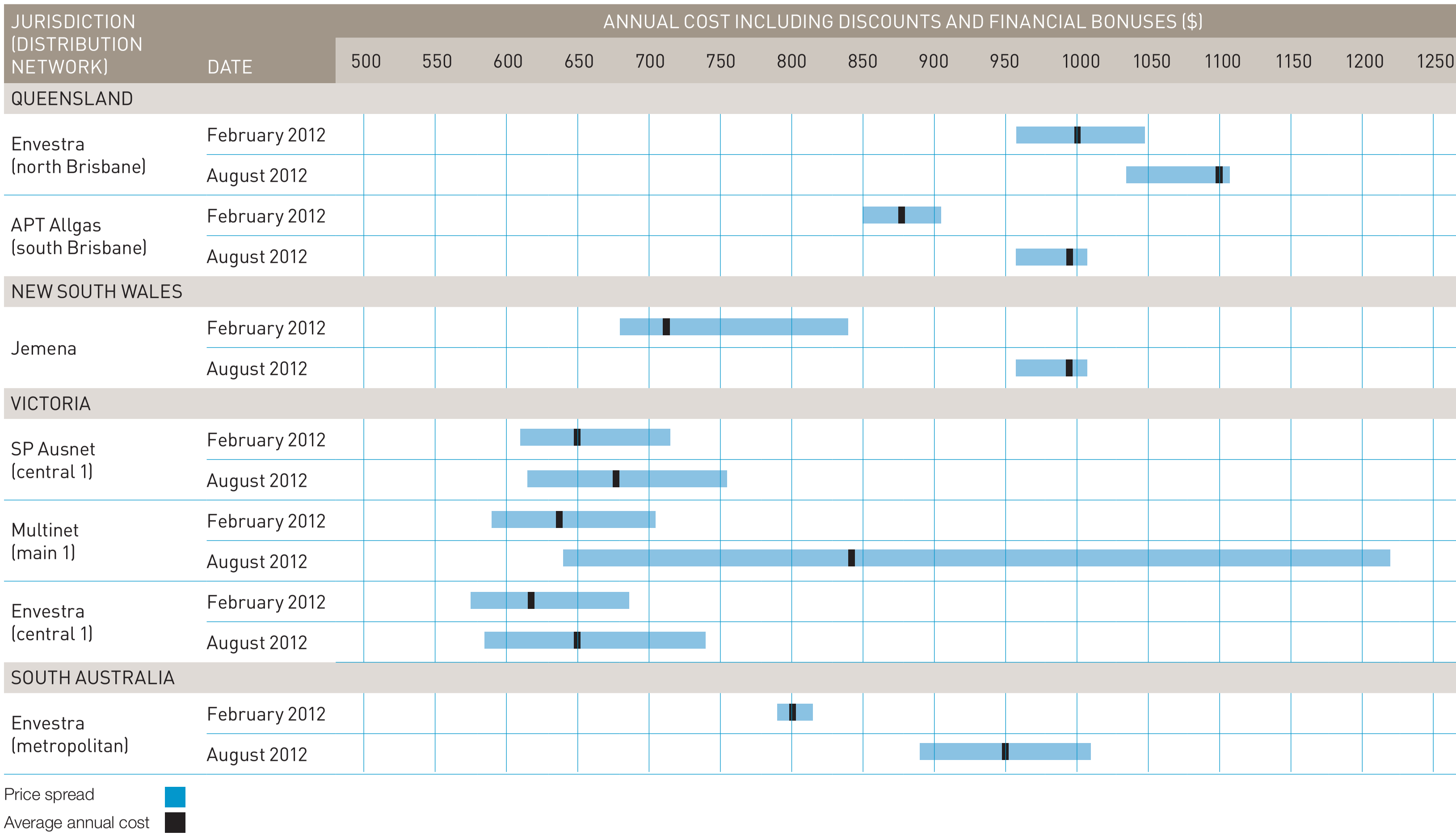
Source: ABS, *Consumer price index*, cat. no. 6401.0, various years.

Table 5.5 Price diversity in retail product offers—February and August 2012

Electricity



Gas



Note: Data are based on market offers (adjusted for discounts) for a customer consuming 6500 kilowatt hours of electricity and 24 gigajoules of gas per year on a peak only (single rate) tariff. Data do not account for Greenpower offers.

Sources: Data from jurisdictional online price comparison services in New South Wales (IPART), South Australia (ESCOSA), Victoria (ESC) and Queensland (QCA).

Low income households are likely to spend about 8 per cent of their disposable income on energy. Around 11 per cent of households will spend over 8 per cent of their disposable income on energy bills in 2012–13, up from 4 per cent of households in 2006–07. Additionally, households in inland areas tend to spend more of their disposable income on energy than do those in coastal areas.[10]

The Retail Law requires retailers to assist customers experiencing payment difficulties or financial hardship. Retailers must:

- protect customers from disconnection in certain circumstances, including if a customer's premises are registered as requiring life support equipment
- take steps to assist customers before considering disconnection for non-payment of a bill, including offering access to a hardship program.

Hardship programs aim to provide early assistance to customers. Retailers may offer:

- specialised staff and teams as a dedicated contact for customers
- extensions of time to pay, as well as flexible payment options
- assistance in identifying government concession and rebate programs that may be available
- referrals to financial counselling services
- review of a customer's energy contract to make sure it is appropriate to their needs
- energy efficiency advice to help reduce a customer's bills, which may include conducting an energy audit and helping replace appliances
- waiver of late payment fees that might have applied.

5.5 Quality of retail service

Reporting on retail service quality tends to focus on affordability, access and customer service indicators. A key indicator of affordability and access is the rate of residential customer disconnections for failure to meet bill payments (figure 5.5).

In 2010–11 the rate of electricity disconnections decreased in Tasmania and the ACT. In Victoria and South Australia, the disconnection rate increased for electricity customers and decreased for gas customers. The regulators noted many electricity customers were reconnected within a week, indicating retailers might have been resorting to disconnection too quickly and the provision of more targeted assistance might have prevented some disconnections.[11] The disconnection rate in New South Wales was consistent with that of the previous year for electricity and increased for gas.

Figure 5.6 illustrates rates of retail customer complaints in electricity and gas. In 2010–11 the rate of electricity complaints rose in several jurisdictions. Billing issues were a significant source of complaint.

10 IPART, *Changes in regulated electricity retail prices from 1 July 2012, final report*, 2012.

11 ESC, *2010–11 Energy retailers comparative performance report*, 2011; ESCOSA, *2010–11 Annual performance report: South Australian energy supply industry*, 2011.

Figure 5.5

Residential disconnections for failure to pay amount due, as a percentage of small customers

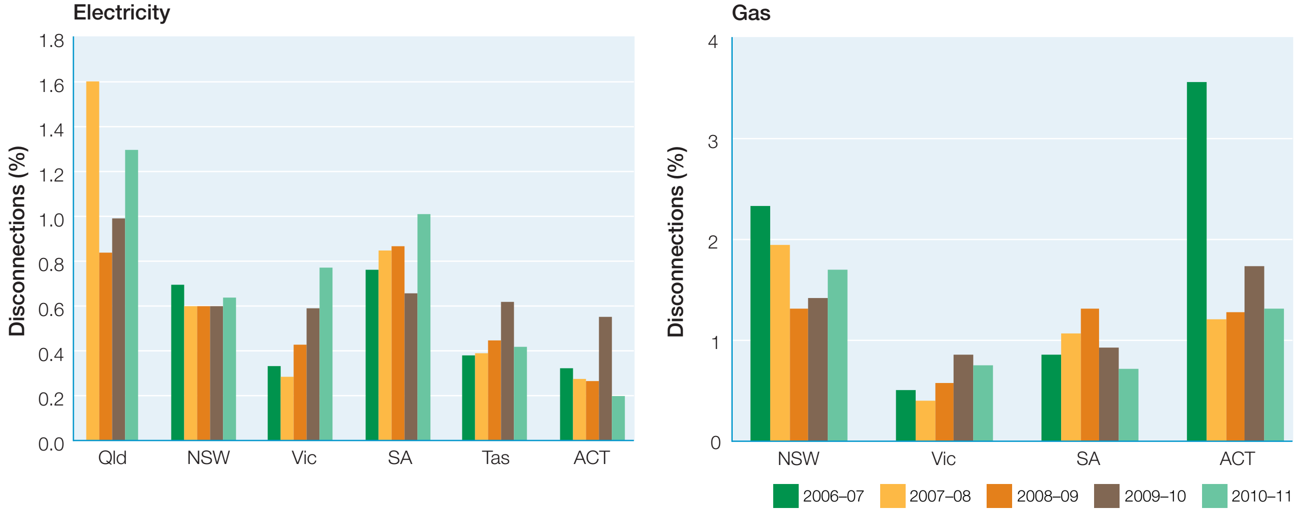
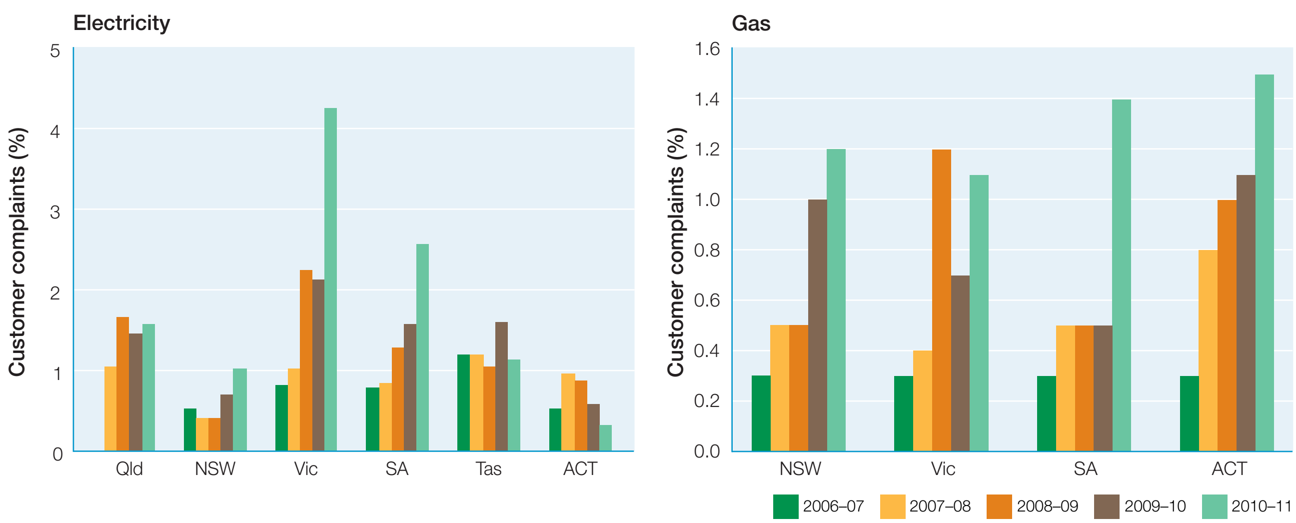


Figure 5.6

Retail customer complaints, as a percentage of total customers



Sources for figures 5.5 and 5.6: Reporting against Utility Regulators Forum templates; retail performance reports by IPART (New South Wales), the ESC (Victoria), ESCOSA (South Australia), OTTER (Tasmania), the QCA and the Department of Employment, Economic Development and Innovation (Queensland) and the ICRC (ACT).

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
ASX	Australian Securities Exchange
BREE	Bureau of Resources and Energy Economics
CCGT	combined cycle gas turbine
CoAG	Council of Australian Governments
CSG	coal seam gas
Electricity Law	National Electricity Law
Electricity Rules	National Electricity Rules
ESC	Essential Services Commission (Victoria)
ESCOSA	Essential Services Commission of South Australia
EU	European Union
FEED	front end engineering and design
FRC	full retail contestability
Gas Law	National Gas Law
Gas Rules	National Gas Rules
GSL	guaranteed service level
GW	gigawatt
GWh	gigagwatt hour
ICRC	Independent Competition and Regulatory Commission
IPART	Independent Pricing and Regulatory Tribunal
kW	kilowatt
kWh	kilowatt hour
LNG	liquefied natural gas
MOS	market operator service
MW	megawatt
MWh	megawatt hour
NEM	National Electricity Market
OCGT	open cycle gas turbine
OTC	over-the-counter
OTTER	Office of the Tasmanian Economic Regulator
PC	Productivity Commission
PJ	petajoule
PV	photovoltaic
QCA	Queensland Competition Authority
RAB	regulated asset base
RERT	reliability and emergency reserve trader
RET	renewable energy target
RIT-D	regulatory investment test for distribution
RIT-T	regulatory investment test for transmission
SAIDI	system average interruption duration index
SAIFI	system average interruption frequency index
SCER	Standing Council on Energy and Resources
TJ	terajoule
TW	terawatt
TWh	terawatt hour
WACC	weighted average cost of capital