STATE OF THE ENERGY MARKET 2012

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Level 35, The Tower, 360 Elizabeth Street, Melbourne Central, Melbourne, Victoria 3000

Email: AERInquiry@aer.gov.au

Website: www.aer.gov.au

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CONTENTS

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.

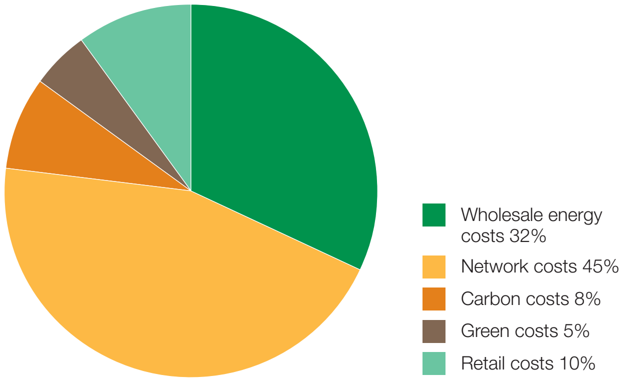
Concerns about the merits review framework led the Standing Council on Energy and Resources (SCER) in 2012 to appoint an expert panel to review the arrangements. The panel recommended the regime should be limited to a single ground for appeal—that a materially preferable decision exists—and should assess 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

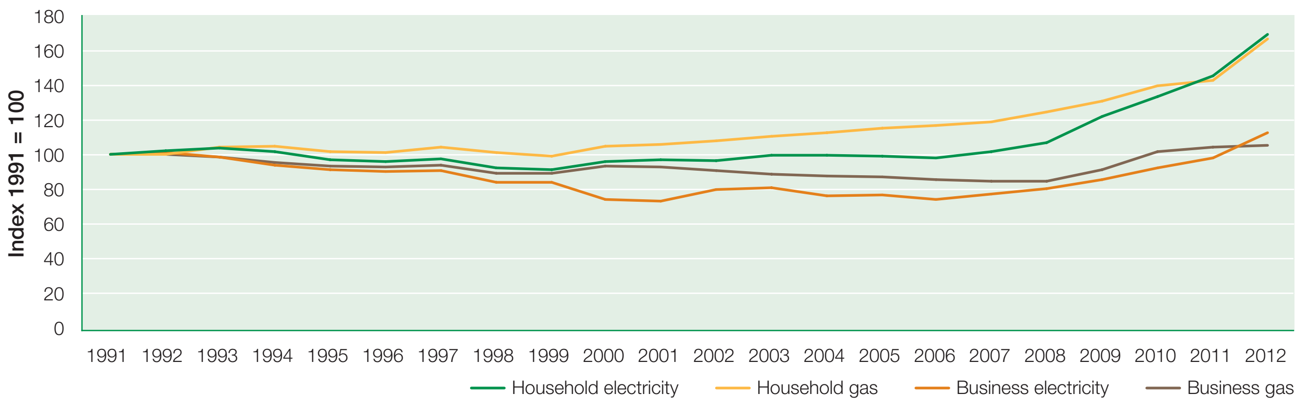
The energy bills paid by retail customers cover the costs of wholesale energy, transport through transmission and distribution networks, retail services and costs associated with climate change policies. Figure 1 estimates the composition of a typical electricity retail bill for a residential customer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

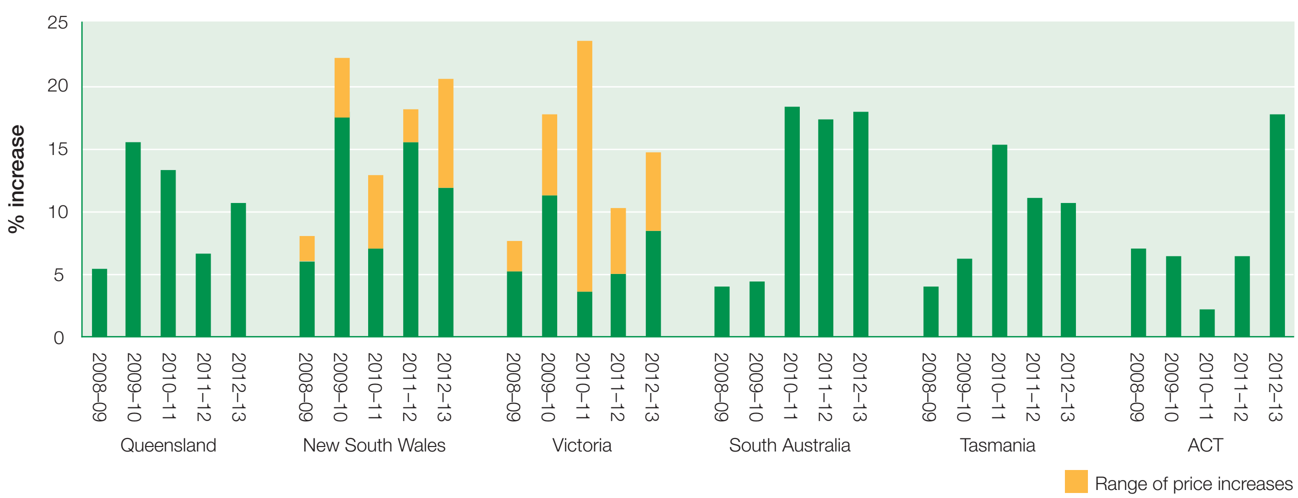


Note: Consumer price index electricity and gas series, deflated by the consumer price index for all groups.

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]

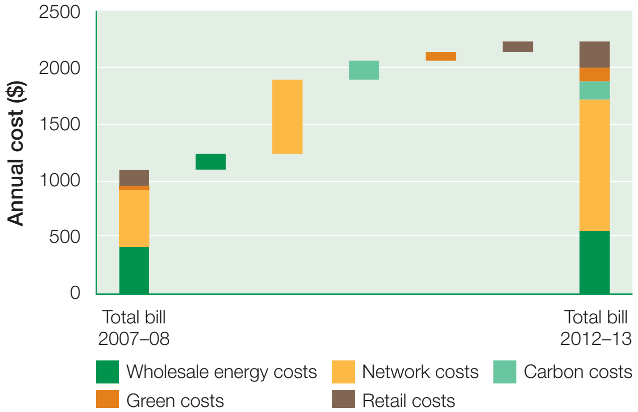
Rising network costs (especially for distribution networks) were the main driver of these outcomes (as explained in section A.2). In the current regulatory period, the annual increase in network charges has been over 20 percent in New South Wales and South Australia; 9–10 per cent in Queensland; and 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.

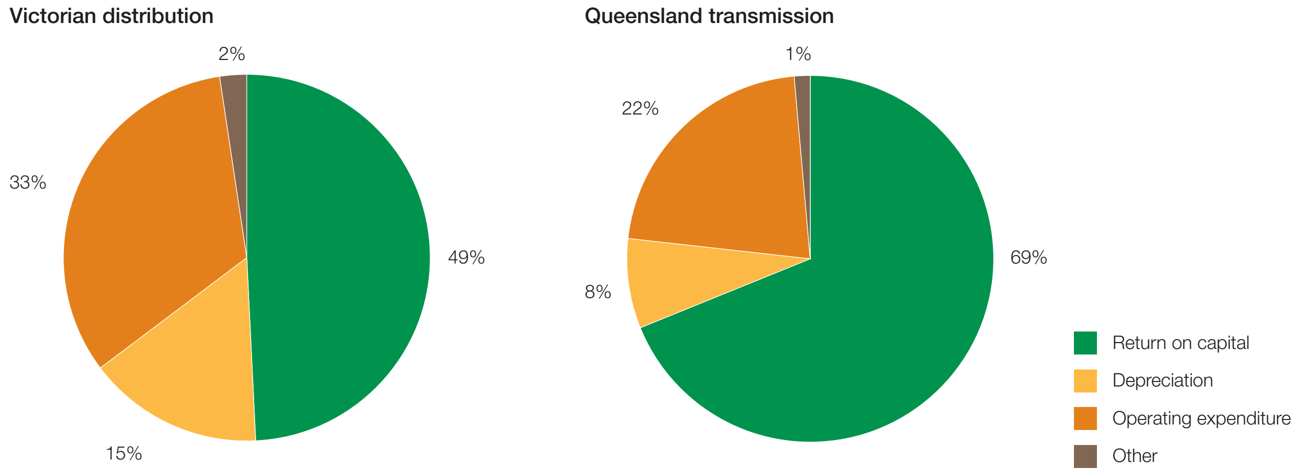
Figure 5 illustrates the revenue components for Queensland transmission (2012–17) and Victorian distribution (2011–15).

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:

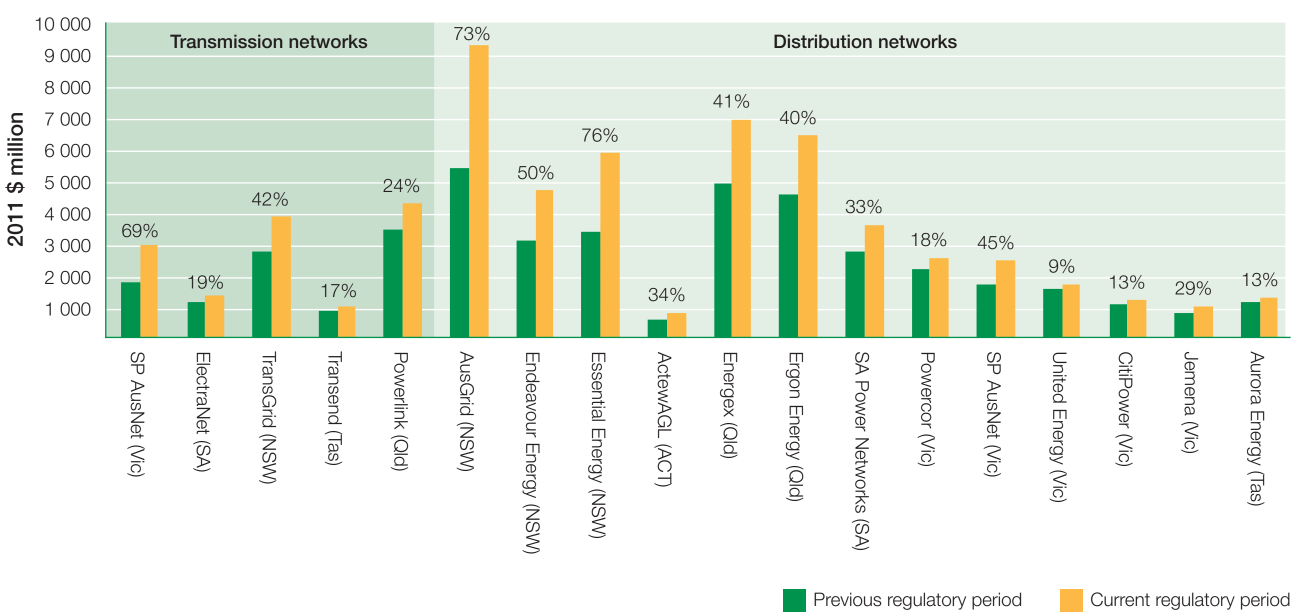
Victorian distribution is an average for five networks.

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

Source: AER.

Figure 6

Electricity network revenues



Notes:

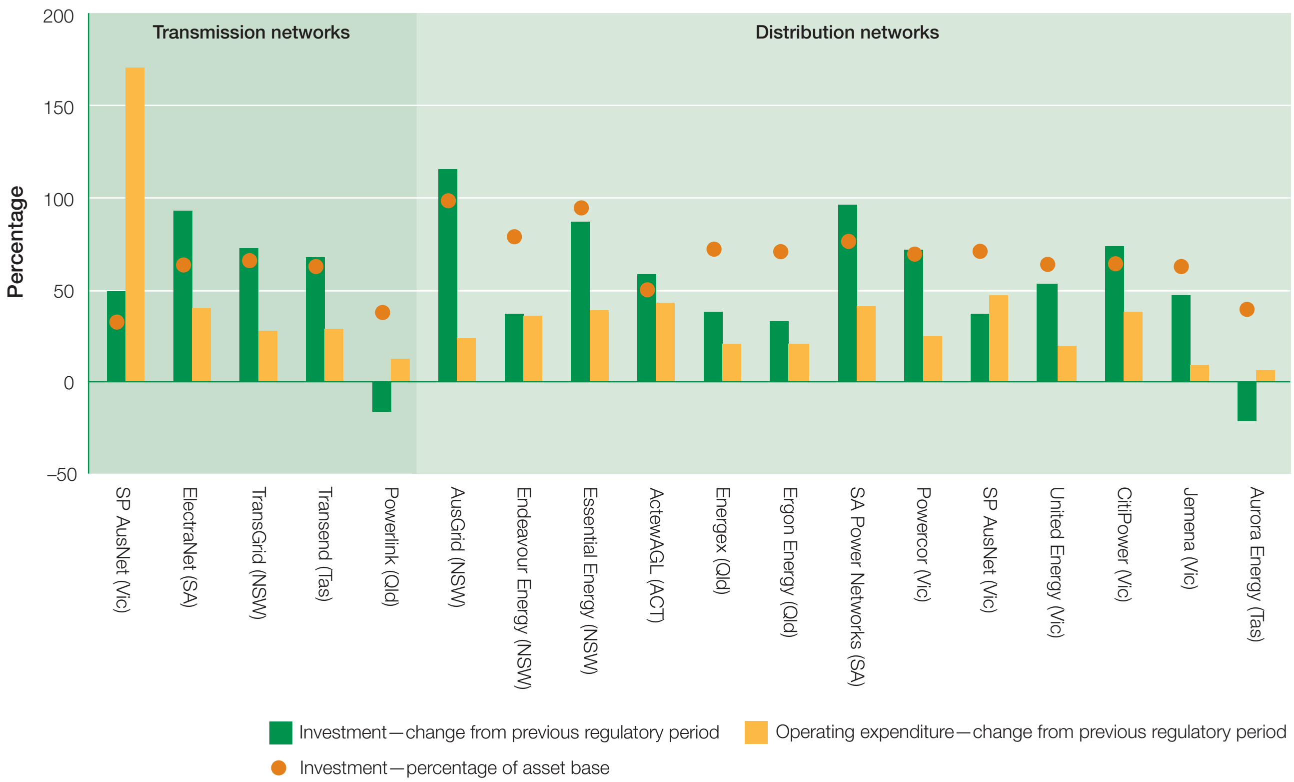
Forecasts in regulatory determinations, amended for decisions by the Australian Competition Tribunal.

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.

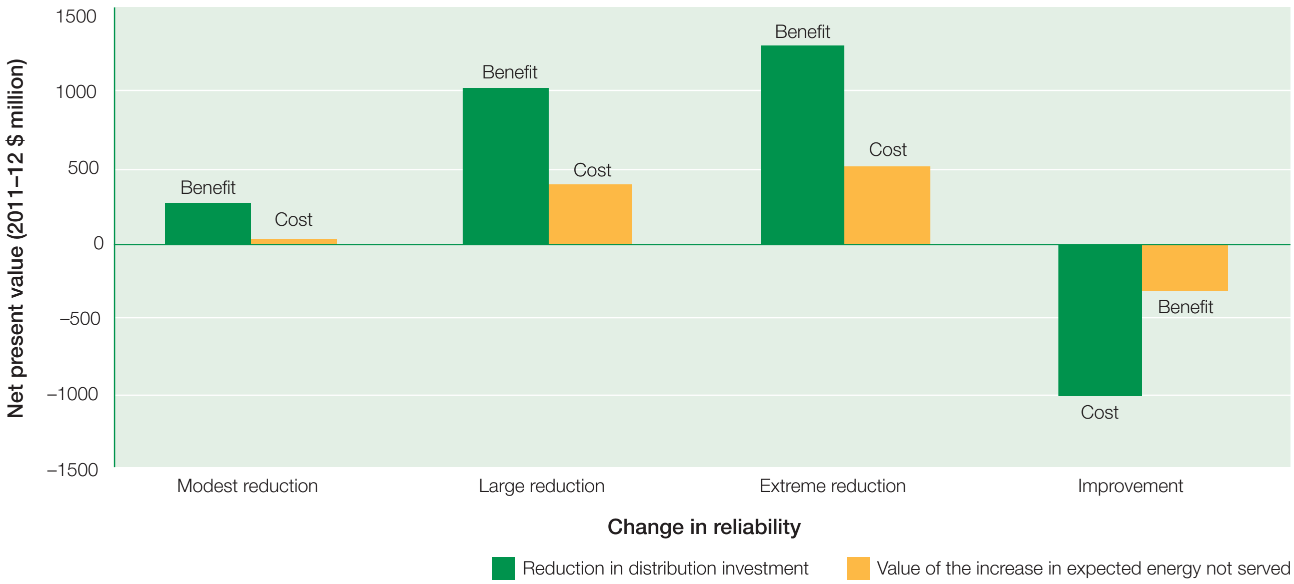
The panel found a limited merits review regime is preferable to the alternatives—such as *de novo* (full) review or reliance on judicial review only—but recommended the following improvements:

- 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.

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.

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

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.

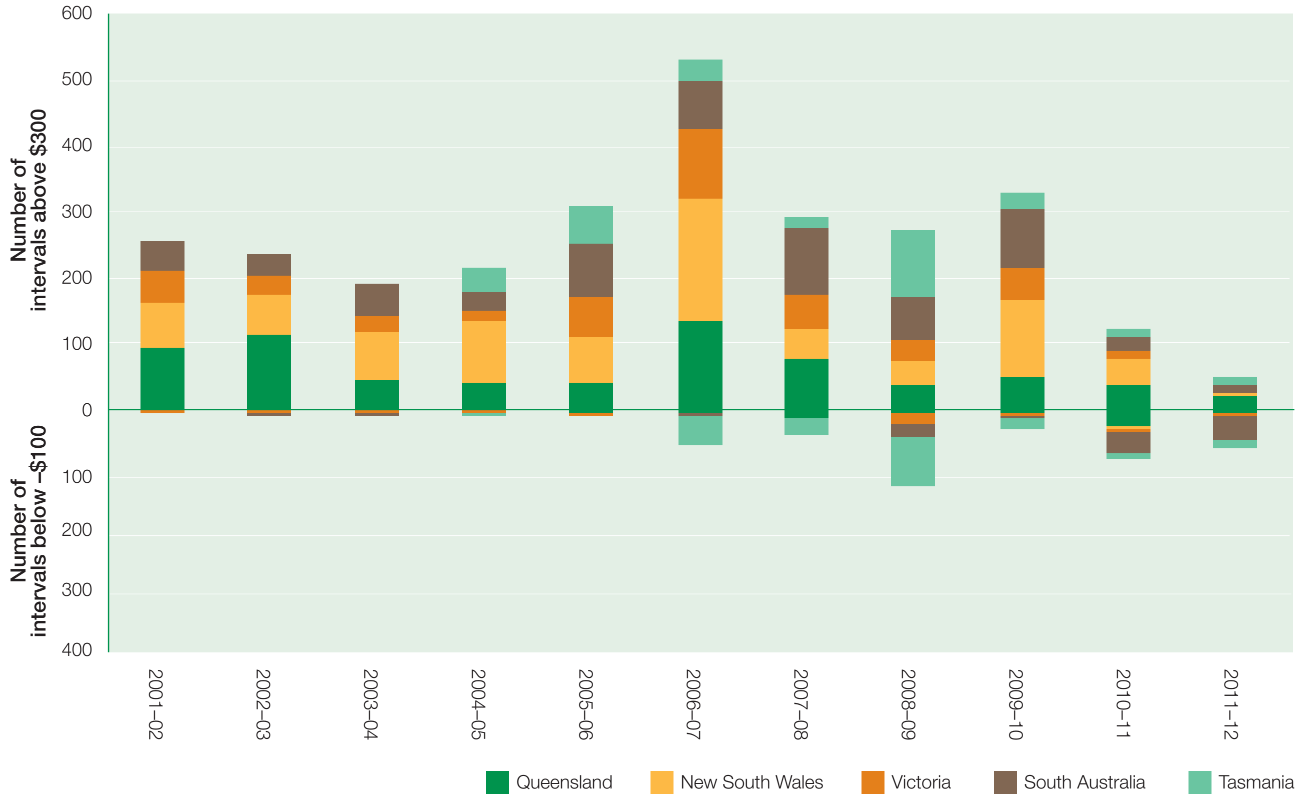
CoAG in December 2012 approved the adoption in principle of the full set of *Power of choice* recommendations. It also proposed the phasing in of time varying network charges, and a new demand side mechanism for the wholesale market, by July 2014.

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.

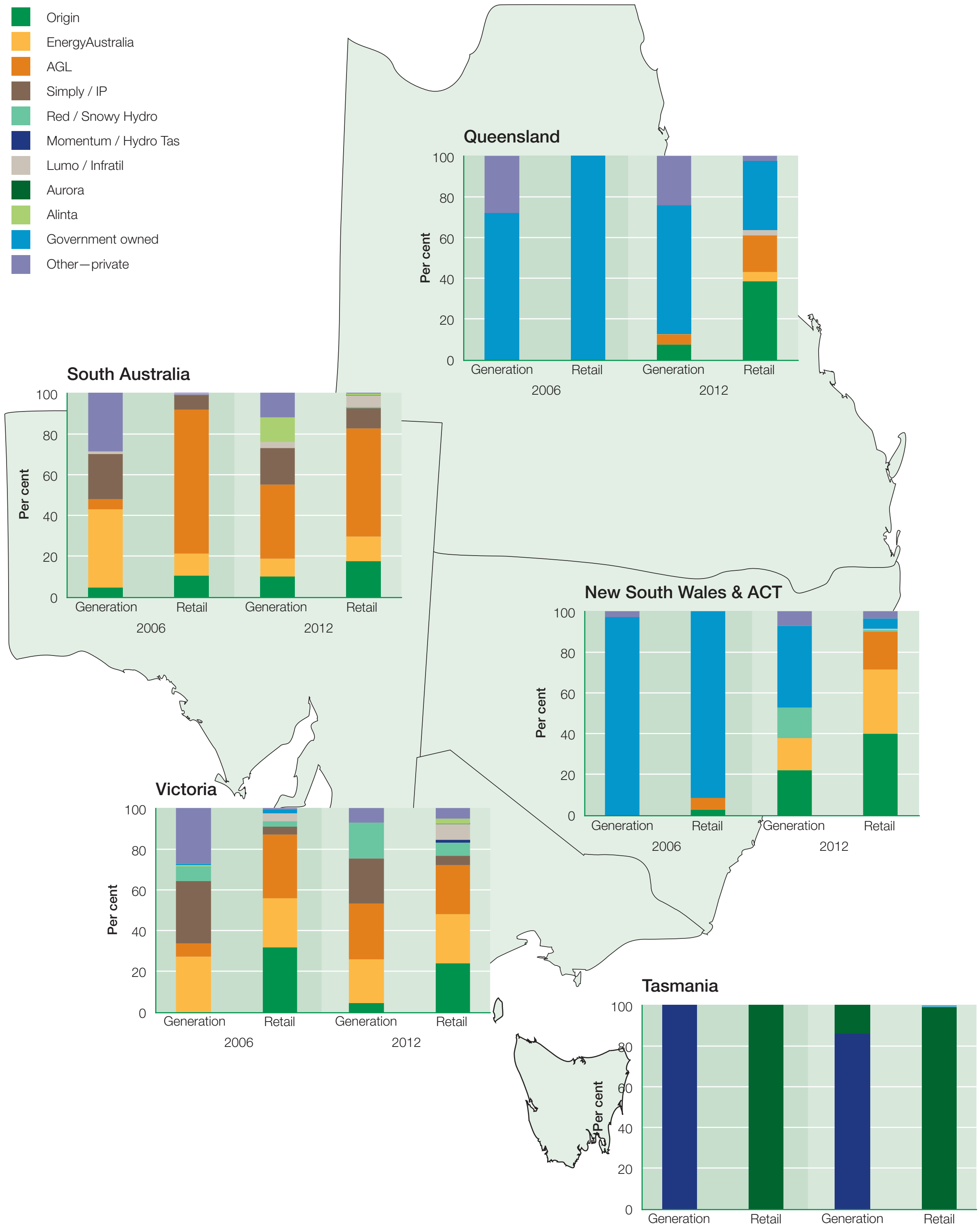
7 The AER analyses spot prices below –$100 per MWh in its weekly market reports. See, for example, weekly reports for 1–7 April 2012 and 22–28 April 2012.

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.

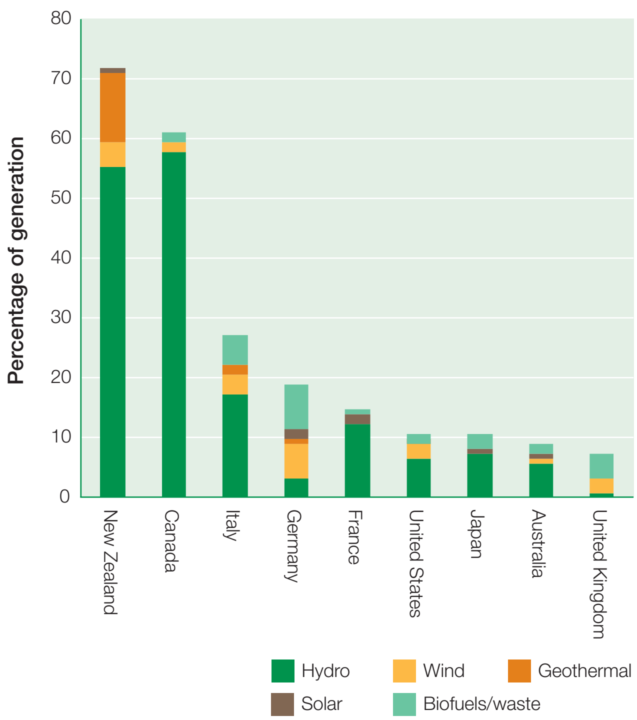
10 Productivity Commission, *Electricity network regulatory frameworks, draft report*, October 2012, pp. 631–2.

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]

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.

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

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.

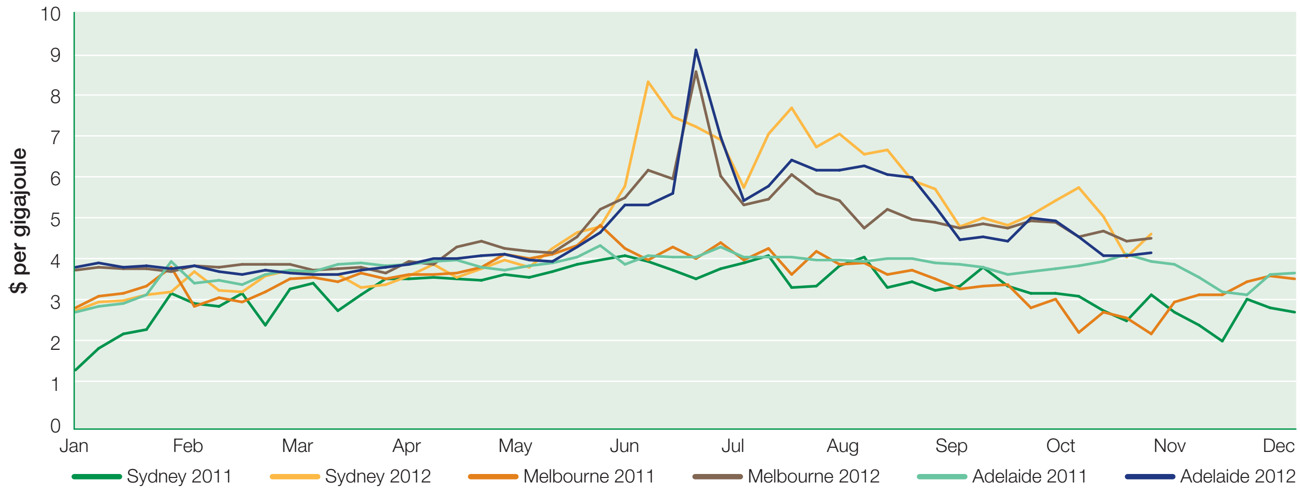
27 ACIL Tasman, 'National gas outlook: domestic gas prices and markets', Presentation by Paul Balfe*,* 30 May 2012.

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.