# STATE OF THE ENERGY MARKET 2007

AER
AUSTRALIAN
ENERGY
REGULATOR

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# PREFACE

The Australian Energy Regulator (AER) is Australia's independent national energy market regulator. It monitors and enforces compliance with the national legislation governing the electricity and natural gas industries and is the economic regulator of the electricity transmission sector in eastern and southern Australia. Its regulatory responsibilities will soon extend to gas transmission, energy distribution and non-price aspects of energy retail markets. The AER also assists the Australian Competition and Consumer Commission on energy competition matters such as merger issues and energy authorisations.

In undertaking its work program and in preparing for the transfer of new functions the AER monitors and collects a range of information on the energy sector. The AER has decided to publish this information periodically to improve market transparency. The *State of the energy market* report is the result of that decision. This report aims to present a big picture perspective on energy market activity in Australia. It has been written for a wide audience, including government, industry and the broader community, and supplements the more technical weekly and quarterly reports the AER already publishes on activity in the National Electricity Market.

With the rapid evolution and growing complexity of energy markets, the AER believes there is a need for reliable and accessible data to assist stakeholders. The *State of the energy market* report consolidates publicly available information from various sources into a single user-friendly publication. At present, energy market data is published by various bodies, including the AER, state regulators, market management bodies (such as the National Electricity Market Management Company), the Energy Supply Association of Australia, d-cyphaTrade, EnergyQuest, the Australian Financial Markets Association, government agencies such as ABARE and the ABS, private monitoring bodies and others. While each publishes high-quality data, the focus is naturally on the specific areas of responsibility or interest of each body. Conversely, there is little public data available on some aspects of market activity. These conditions can make it difficult for an observer to discern a global sense of what is happening in energy markets. This poses challenges for market participants and can affect the quality of the policy debate on energy market issues.

It should be noted, however, that the AER is not a policy body but a regulatory agency. In that context, the *State of the energy market* report focuses on the presentation of facts and is not a vehicle to advocate policy agendas. While some policy areas are noted in the report, they are presented for information purposes only.

This *State of the energy market* report focuses on the AER's current and future areas of responsibility, but for completeness covers most aspects of the energy sector, including comparisons with international energy markets. This is necessary to document the increasingly complex relationships between market segments and the policy environment within which they operate. For example, there are increasing ownership linkages between the electricity generation and retail sectors that make it difficult to analyse market behaviour in either sector in isolation. Similarly, the electricity derivatives market is now an integral adjunct to the spot market.

The AER envisages that each edition of the *State of the energy market* report will consist of a survey of market activity and performance in electricity and gas supported by focal essays that develop particular issues in more depth. Some essays will be developed in-house, while others may be commissioned. This 2007 report includes two essays. The first is an independent analysis developed by Firecone Ventures on the state of play in energy reform, including an assessment of the extent to which energy reforms have delivered on the promises of the 1990s. The second essay, developed in-house by AER staff with assistance from PB Associates, provides a holistic survey of the reliability of the National Electricity Market in delivering electricity to customers.

The 2007 survey of market activity and performance covers each segment of the electricity and gas supply chain in turn—from electricity generation and gas production through to energy retailing. There is also a survey of contract market activity in electricity derivatives. While the report focuses on activity in the southern and eastern jurisdictions in which the AER has regulatory and compliance roles, there is also some coverage of market activity in Western Australia and the Northern Territory.

This is an evolving project. As a first report, this edition sets the scene with background material on the structure and design of energy markets. Future editions will adopt a more succinct approach. There may also be changes in approach over time to particular areas of reporting. For example, while the 2007 edition includes separate chapters on electricity and gas retailing, future editions may consider a more integrated approach to energy retailing in line with the evolution of that sector. In addition, there are areas of market activity where the quality of public data is uneven. For example, there is limited data on gas wholesale prices, energy retail prices and market shares in the energy retail sector. The AER will consider ways to improve the quality of data in some of these areas.

I invite stakeholders to let the AER know what they think of this report. The AER seeks your views on possible improvements, including areas where better market information may be needed and possible matters for coverage in future editions. The AER also seeks feedback on any errors or omissions, which inevitably find their way into a report of this nature. Over time, I hope the *State of the energy market* report will become a valuable resource—both for market participants and policymakers.

**Steve Edwell**
Chairman

# EXECUTIVE OVERVIEW


Mark Wilson

The Australian energy sector has been markedly transformed during the past 15 years. Until the 1990s vertically integrated monopolies dominated the electricity and natural gas industries. Infrastructure deficiencies combined with regulatory barriers to limit trade, leading to separate state markets in which consumers were obliged to purchase energy from a monopoly supplier.

# EXECUTIVE OVERVIEW

The energy sector in 2007 is barely recognisable from that which operated in the 1990s. Regulatory barriers to interstate trade have been removed. There are regimes for third party access to the services of energy infrastructure. The old public monopolies have been split up. Where a single government-owned business used to generate, transport and sell electricity, there are now competing generators and retailers. Specialist businesses run the transmission (long distance) and distribution (local area) networks that transport electricity to customers. Victoria, South Australia and Queensland have privatised some or all of their electricity supply. The gas industry has undergone similar restructuring and is mostly now in private hands.

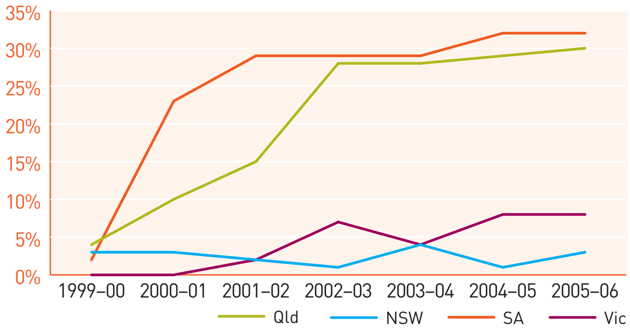
These changes have allowed competitive energy markets with a more national focus to develop. Queensland, New South Wales, Victoria, South Australia, Tasmania and the Australian Capital Territory have established a National Electricity Market (NEM) in which power can flow across state borders to meet customer demand in other jurisdictions. The NEM operates as a competitive spot market in which prices adjust in real time to supply and demand conditions. Investment in new generation and transmission capacity, combined with the national market arrangements, has delivered improved productivity in the sector and stable reliability.

While the market has delivered lower energy costs for business customers since 1999, a combination of record demand and tight supply led to significantly higher prices in 2007. These movements have been mirrored in higher forward prices for electricity derivatives. The forward markets provide a means for participants to manage price risk, and have become an integral part of the energy market framework in recent years. Traded volumes in electricity derivatives on the Sydney Futures Exchange have risen sharply since 2005, with 345 per cent growth in the year to June 2007.

The electricity networks and gas pipelines that transport energy to consumers have been separated from the production and retail sectors into stand-alone businesses. Independent regulators manage the risk of monopoly pricing and poor service quality. Governments are progressively transferring this role to the Australian Energy Regulator (AER) with the aim of achieving a consistent national approach to regulation. The regulation of electricity transmission (long distance) networks was transferred from the

Figure 1

Cumulative growth in net generation capacity since 1999–2000

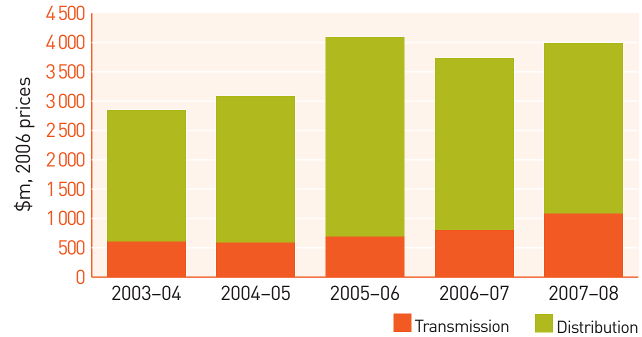



Note: Growth is measured from market start in 1998–99. A decrease may reflect a reduction of capacity due to decommissioning or a change in the ratings of generation units.

Source: NEMMCO, based on registered capacity data.

Figure 2

Real NEM-wide electricity network investment




Note: Actual data where available. Regulator-approved forecast data in other years.

Source: Regulatory determinations of AER, ESC, IPART, ESCOSA, QCA, OTTER and ICRC.

Australian Competition and Consumer Commission (ACCC) to the AER in July 2005, and responsibility for distribution (local networks) is scheduled to transfer from state and territory regulators to the AER from 2008. The transfer of the regulation of gas pipelines is also scheduled from 2008. Western Australia will retain separate state-based regulatory arrangements in gas and electricity.

## Investment and reliability

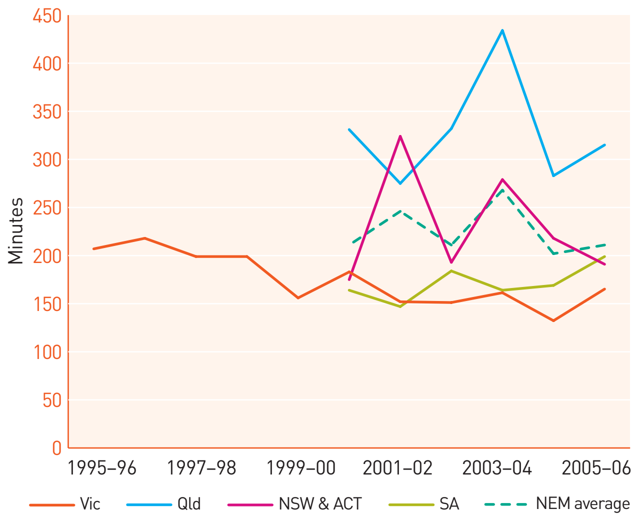
The liberalisation of energy markets has been accompanied by substantial new investment. Five thousand megawatts of electricity generation capacity was installed in the NEM between 1999 and 2006—enough to meet peak electricity demand for the whole of South Australia and Tasmania. Another 1600 megawatts are committed for construction by 2008. Many other projects have been proposed. Figure 1 tracks the cumulative growth in net generator capacity in each region since market start. The strongest growth has been in Queensland and South Australia, in which capacity has expanded by over 30 per cent since 1999.

There is a similar picture for the networks. Annual investment is running at around $700 million in high voltage electricity transmission infrastructure and $3 billion in the local distribution networks that move electricity to customers (figure 2). Across the networks, real investment is forecast to rise by around 40 per cent in the five years to 2007–08, driven largely by transmission network expansions and upgrades. Real transmission investment is forecast to rise by around 80 per cent over this period.

Strong investment is occurring in an environment in which the regulated revenues of network businesses are rising and network reliability is being maintained. The generation and transmission sectors have caused very few power outages since the NEM commenced. While distribution networks are engineered to allow for some outages—the cost of perfect reliability in a distribution network would be prohibitive—they appear to have delivered reasonably stable reliability over the past few years. Figure 3 indicates that the average duration of distribution outages per customer in the NEM has remained in a range of about 200–270 minutes per year since 2000–01, although there are regional differences. The data should be interpreted with caution due to significant differences in network characteristics as well as differences in information, measurement and auditing systems (see chapter 5).

There has also been significant investment in gas. Development expenditure in the petroleum industry increased four fold from 2002 to 2006. Coal seam methane has emerged as a significant new source of gas (figure 4) and is increasing competition in the gas production sector. It already meets over 60 per cent of Queensland's total gas demand and is growing rapidly.

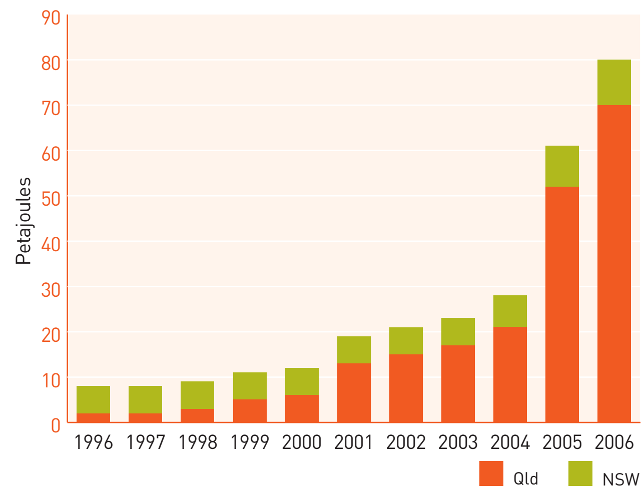
Figure 3
Average outage duration per customer in distribution networks (system average interruption duration index—SAIDI)




Notes: PB Associates developed the data for the AER from the reports of jurisdictional regulators and from reports prepared by distribution businesses for the regulators. Queensland data for 2005–06 is normalised to exclude the effect of a severe cyclone. Victorian data is for the calendar year ending in that period (for example, Victorian 2005–06 data is for calendar year 2005). NEM averages exclude New South Wales and Queensland (2000–01) and Tasmania (all years).

Source: PB Associates (unpublished)

Figure 4
Coal seam methane production




Source: EnergyQuest

New gas basins and fields are being developed, often in conjunction with the construction of new transmission pipelines to ship gas to markets. For example, the development of Victoria's Otway Basin was followed by the construction of the SEA Gas Pipeline in 2004, which ships the gas to South Australian markets. Australia's gas transmission pipeline network has almost trebled in length since the early 1990s. Table 1 indicates that around $2.5 billion has been invested in new gas transmission pipelines and major expansions since 2000.

Much of this investment is in long-haul pipelines that have introduced new supply sources and improved the security of gas supplies into markets in south-eastern Australia. Sydney, Melbourne, Adelaide and Canberra are now each served by at least two transmission pipelines, each of which ships gas from a different basin. For example, while Sydney traditionally sourced most of its gas from the Cooper Basin in South Australia, the construction of the Eastern Gas Pipeline in 2000 significantly increased access to Bass Strait gas from Victoria. The new pipelines have improved the environment for competition between gas basins, prompting governments and the Australian Competition Tribunal to wind back the economic regulation of some of Australia's most important gas pipelines. None of the major transmission pipelines constructed in the past decade is subject to economic regulation. This marks a significant contrast with the gas distribution and electricity network sectors, which mostly remain regulated.

## Energy retailing

The energy retail sector is also being transformed, with millions of customers now free to choose their energy supplier. With the introduction of full retail contestability in Queensland on 1 July 2007, all customers nationally are eligible to choose their natural gas supplier and similar arrangements for electricity apply in New South Wales, Victoria, Queensland, South Australia and the Australian Capital Territory (figure 5). While the maturity of retail competition may vary between jurisdictions there is evidence of consumers taking advantage of competitive offers. By December 2006 in Victoria, the number of small customer switches from one retailer to another exceeded 60 per cent of the

**Table 1 Gas transmission pipelines completed since 2000**

| PIPELINE | STATE | LENGTH (KM) | PROJECT COST | PROJECT COMPLETION | OWNER |
|---|---|---|---|---|---|
| Gladstone–Bundaberg Pipeline | Qld | 300 | na | 2000 | Envestra (Cheung Kong Infrastructure 16.57%; Origin Energy 16.57%) |
| Eastern Gas Pipeline | Vic–NSW | 795 | $490m | 2000 | Alinta |
| Wagga–Tumut Pipeline | NSW | 65 | na | 2001 | NSW Government |
| Hoskinstown–Canberra Pipeline | NSW ACT | 31 | na | 2001 | ActewAGL (Alinta 50%; ACT Government 50%) |
| Wandoan to Roma–Brisbane main | Qld | 111 | na | 2001 | APA Group (35% Alinta) |
| Tasmanian Gas Pipeline | Vic–Tas | 732 | $476m | 2002 | Alinta |
| Roma to Brisbane Pipeline (looping) | Qld | 434 | $70.7m | 2002 | APA Group (35% Alinta) |
| VicHub | Vic | 2 | $100m | 2003 | Alinta |
| Telfer Gas Pipeline | WA | 443 | na | 2004 | APA Group (35% Alinta) |
| SEA Gas Pipeline | Vic–SA | 660 | $526m | 2004 | International Power; Origin Energy; China Light & Power |
| Kambalda to Esperance Gas Pipeline | WA | 350 | $45m | 2004 | WorleyParsons, ANZ Infrastructure |
| North Queensland Gas Pipeline | Qld | 369 | $150m | 2005 | Qld Government |
| Central Ranges Pipeline | NSW | 300 | $130m | 2006 | Central Ranges Pty Ltd |
| Dampier to Bunbury Pipeline (compression & looping) | WA | 217 | $433m | 2006 | DUET 60%; Alinta 20%; Alcoa 20% |

na not available. Notes: 1. As at 1 May 2007, part of Alinta's equity in the APA Group was subject to legal appeal. 2. See also notes to table 3 on p.9.
Sources: ABARE, *Minerals and energy, major development projects*, 2006 and earlier issues; Productivity Commission, *Review of the gas access regime*, 2004.

underlying customer base.[1] South Australian customers were exercising choice at a similar rate. Switching outcomes in New South Wales were considerably lower (figure 6). A 2006 report by the Finnish-based Utility Customer Switching Research Project described Victoria and South Australia as among the 'hottest' (most active) retail markets in the world.[2]

In part, customer switching reflects a shift away from the traditional marketing of electricity and gas as separate products. Increasingly, retailers market the products jointly, and customers are taking advantage of price discounts by entering into contracts for dual supply. The introduction of competition has led to a rebalancing of household and business retail prices to reduce some of the traditional cross-subsidies between these groups. This has meant that, to date, retail prices have fallen in real terms for business customers rather than for households (figure 7). The benefit to households has been the flow-on effects of cheaper energy costs on prices generally. This has also improved Australia's international competitiveness.

## Market developments

The energy sector continues to evolve, posing challenges both for the market and regulators. There are substantial changes in the legislative framework, with governments about to introduce a new National Gas Law and amendments to the National Electricity Law to consolidate regulatory reforms, including the shift to a national framework.

The Council of Australian Governments (COAG) agreed in 2007 to a number of high-level policy initiatives aimed at further strengthening market arrangements. In particular, it agreed to establish a National Energy Market Operator (NEMO) by June 2009. NEMO will become the operator of the wholesale electricity and gas markets and will be responsible for national transmission planning. COAG also agreed to a national implementation strategy for the progressive rollout of 'smart' electricity meters. This reform is aimed at providing better price signals

1 Since the introduction of retail choice in 2002. If a customer switches to a number of retailers in succession, each move counts as a separate switch. Over time, cumulative switching rates may therefore exceed 100 per cent.

2 First Data Utilities and Vaasa EMG, Utility customer switching research project, *World retail energy market rankings,* 2006.

**Figure 5**

**Introduction of full retail contestability**

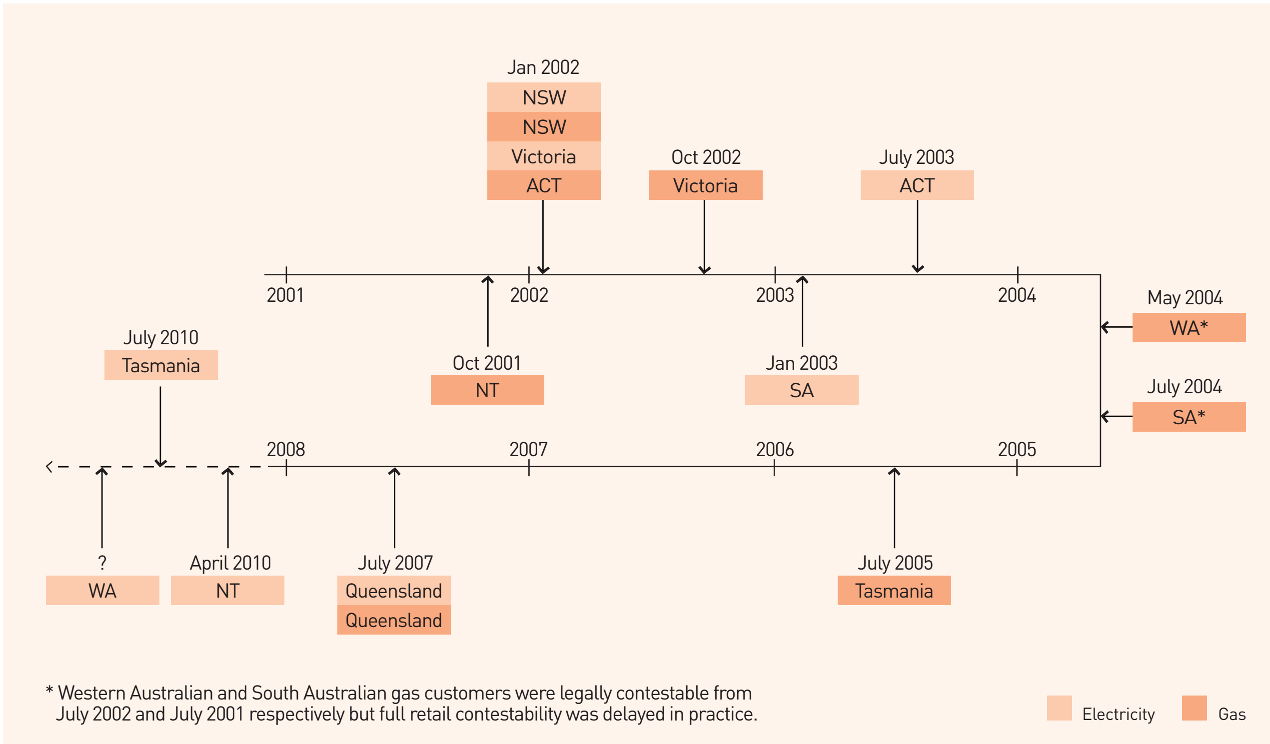
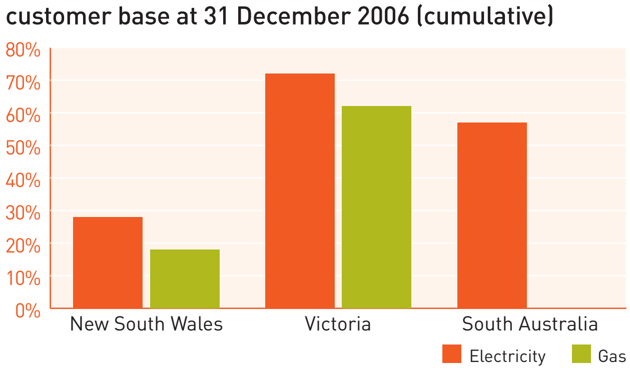



**Figure 6**

**Small customer switches as percentage of small customer base at 31 December 2006 (cumulative)**

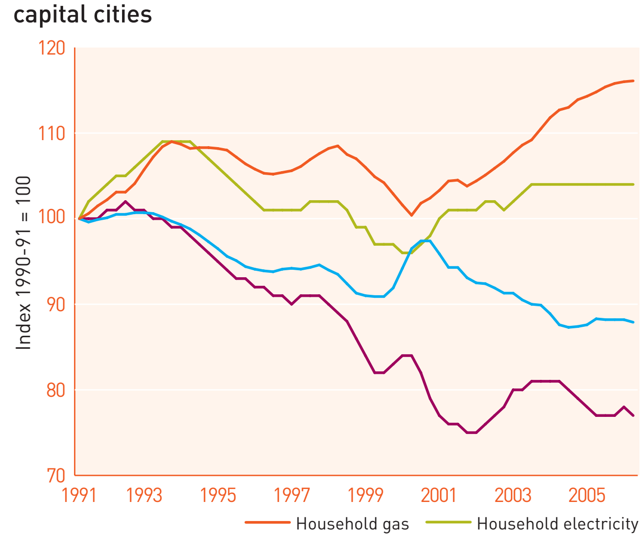



Note: Comparable data for South Australia gas is not available.

Sources: NEMMCO (electricity churn); GasCo (New South Wales gas churn); VenCorp (Victoria gas churn); AER estimates based on ESAA, ESC, ESCOSA and IPART data (customer base).

**Figure 7**

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




Data source: ABS

to consumers to help them self-manage their demand for electricity during peak periods.

The provision of price signals depends partly on having an appropriate tariff structure. The Australian Energy Market Commission (AEMC) will assess the effectiveness of retail competition in each jurisdiction to determine the appropriate time to remove the current retail price caps. The AEMC will conduct sequential assessments starting with Victoria in 2007, followed by South Australia in 2008 and New South Wales in 2009.

One of the most fluid aspects of market activity over the past 12 months has been the extent of privatisation, acquisition and merger activity. Queensland recently privatised most of its energy retail and gas distribution sectors, selling the businesses to Origin Energy, AGL and the APA Group (formerly the Australian Pipeline Trust). In the private sector there has been a merger and demerger of AGL and Alinta assets, Babcock & Brown's acquisition of NRG's electricity generation assets in South Australia, and APA Group's acquisition of GasNet in Victoria. Several proposals were floated in early 2007, including a merger between AGL and Origin Energy (subsequently withdrawn), a generator swap between AGL and TRUenergy in South Australia (which took effect in July 2007), the sale of Origin Energy's gas infrastructure assets to APA Group in July 2007, and a conditional agreement to sell Alinta to Singapore Power and Babcock & Brown. A summary of recent merger activity is set out in table 2.

There are some common threads in the changing ownership landscape, including a tendency towards greater specialisation. Most entities have been shifting their primary focus either towards network infrastructure or the non-network (production, generation and retail) sectors. The trend appears to be driven by capital markets and may reflect an assessment of limited efficiency benefits from integration across the network and non-network sectors. At the same time, there is increasing integration within each sector.

This has seen a rationalisation of the energy networks sector, with Alinta, the APA Group (formerly Australian Pipeline Trust), Cheung Kong Infrastructure/Spark and Singapore Power/SP AusNet emerging as key private sector players (table 3). There have been moves towards further ownership consolidation within that group, some of which are ongoing (table 2). The proposed Babcock & Brown/Singapore Power acquisition of Alinta in 2007 would establish Babcock & Brown as a major new player in the network sector.

A substantially different set of entities operate private generation and retail businesses, with ownership consolidation occurring between the two sectors in Victoria and South Australia. Two major retailers—AGL and TRUenergy—have significant generation interests. In 2007, International Power announced its full acquisition of the retail partnership it had formed with EnergyAustralia, and from August 2007 will retail in its own right. Origin is currently the only major retailer with limited generation capability—but is planning the development of new capacity. There have been proposals for further consolidation, both between the major retailers, and between the retail and generation sectors (table 2).

Vertical integration across the generation and retail sectors is a way for generators and retailers to manage the risk of price volatility in the electricity spot market. While this is often a rational strategy for the relevant entities, it can raise some interesting and complex competition issues. For example, vertical integration can reduce an entity's activity in electricity financial markets by allowing it to internally balance risk. Some stakeholders have argued that this can pose a barrier to entry for new generators and retailers by reducing liquidity in the financial markets.

As this report goes to press in July 2007, an emerging issue has been a sustained increase in electricity prices in the NEM over a period of several months. There have also been historically high prices in the forward market for derivative contracts. The main cause of high prices in April and May was that the drought constrained hydro-generating capacity in the Snowy, Tasmania and Victoria. The drought also limited the availability of water for cooling in some coal-fired generators, especially in Queensland. In combination, these factors led to a tightening of supply and higher offer prices by generators.

**Table 2 Energy market merger activity: 1 January 2006 to 1 July 2007**

| DATE | PROPOSAL | SECTORS AFFECTED | STATUS |
|---|---|---|---|
| March 2006 | APA Group acquires the Murraylink interconnector from Hydro Quebec and SNC Lavalin | Electricity: transmission | Acquired |
| April 2006 | Alinta and AGL merger and demerger—Separation of network (Alinta) and generation/retail (AGL) assets | Electricity: generation, distribution, retail<br>Gas: distribution, retail | Completed—subject to undertakings |
| June 2006 | Babcock & Brown acquires the Flinders power station in South Australia from NRG Energy. | Electricity: generation | Acquired |
| | Arrow Energy acquires gas production business CH4 | Gas: production | Acquired |
| August 2006 | APA Group acquires the GasNet transmission network in Victoria | Gas: transmission | Acquired |
| September 2006 | Beach Petroleum acquires gas production business Delhi Petroleum | Gas: production | Acquired |
| October 2006 | APA Group acquires Allgas distribution network from the Queensland Government | Gas: distribution | Acquired |
| | Santos to acquire Queensland Gas Company | Gas: production | Proposal withdrawn |
| November 2006 | Alinta raises shareholding in Alinta Infrastructure Holdings from 20% to 100% | Electricity: generation<br>Gas: transmission | Acquired |
| | Origin acquires electricity retailer Sun Retail from the Queensland Government | Electricity: retail | Acquired |
| | AGL acquires gas retailer Sun Gas Retail from the Qld Government | Gas: retail | Acquired |
| December 2006 | APA Group acquires the DirectLink interconnector from Country Energy (50%), Hydro Quebec (33%) and Fonds de Solidarites des Travailleurs de Quebec (17%) | Electricity: transmission | Acquired |
| January 2007 | AGL and Origin merger | Electricity: generation, retail<br>Gas: production, transmission, distribution, retail | Proposal withdrawn |
| | AGL to acquire 27.5% stake in Queensland Gas Company | Gas: production | Acquired |
| | SP AusNet to acquire Origin Energy's gas network assets, including a 33% stake in the SEA Gas Pipeline and a 17% share in Envestra | Gas: transmission, distribution | Proposal withdrawn |
| February 2007 | AGL and TRUenergy swap electricity generation assets in South Australia (AGL acquires the Torrens Island power station in return for $300 million and the Hallett power station) | Electricity: generation, retail | Acquisition completed July 2007 |
| April 2007 | APA Group to acquire Origin Energy's gas network assets, including a 33% stake in the SEA Gas Pipeline and a 17% share in Envestra | Gas: transmission, distribution | Acquisition completed July 2007 |
| May 2007 | Babcock & Brown/Singapore Power acquisition of Alinta | Electricity: generation, transmission, distribution, retail<br>Gas: transmission, distribution, retail | Conditional agreement<br>ACCC review in progress |
| | International Power buys remaining 50 per cent of the EnergyAustralia–International Power Retail Partnership, to acquire full ownership | Electricity: generation, retail<br>Gas: retail | Acquisition due for completion August 2007<br>Approved by ACCC |

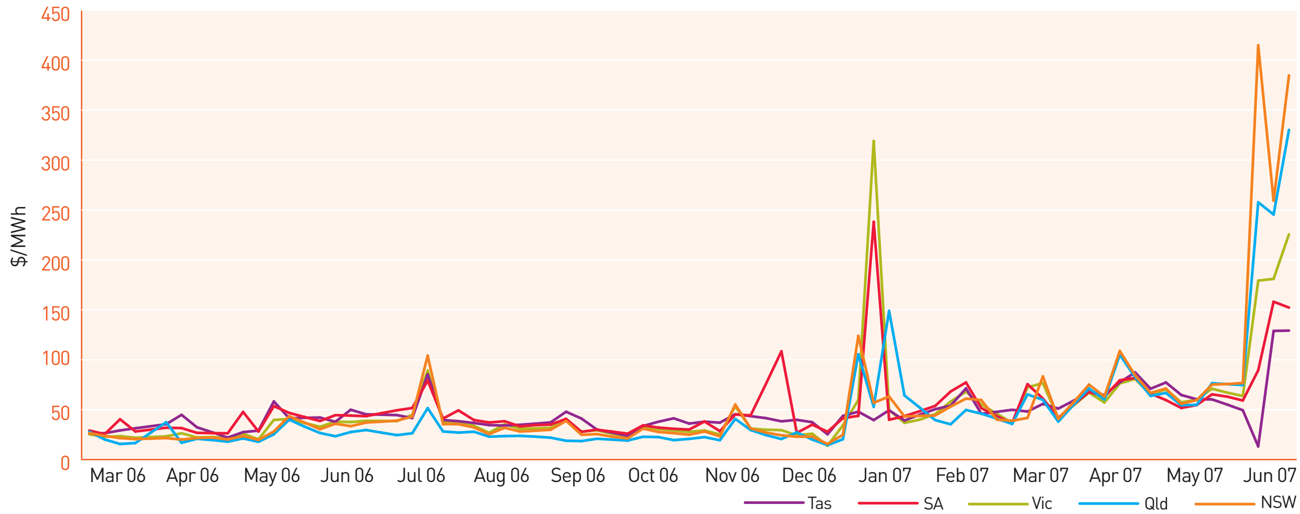
**Table 3 Ownership of private network infrastructure at 1 June 2007**

| | |
|---|---|
| **ELECTRICITY TRANSMISSION** | |
| STATE-BASED NETWORKS | |
| Victoria | SP AusNet (51% Singapore Power) |
| South Australia (Electranet) | Qld Government 41.11%; YTL Power 33.50%; Hastings 19.94% |
| **INTERCONNECTORS** | |
| Murraylink (Vic–SA) | APA Group (Alinta 35%) |
| Directlink (Qld–NSW) | APA Group (Alinta 35%) |
| Basslink (Vic–Tas) | National Grid Transco (UK) |
| **ELECTRICITY DISTRIBUTION** | |
| Eastern Energy (Vic) | SP AusNet (51% Singapore Power) |
| Solaris (Vic) | Alinta |
| United Energy (Vic) | Alinta 34%; DUET 66% |
| CitiPower (Vic) | Cheung Kong Infrastructure/Hongkong Electric 51%; Spark Infrastructure 49% |
| Powercor (Vic) | Cheung Kong Infrastructure/Hongkong Electric 51%; Spark Infrastructure 49% |
| ETSA Utilities (SA) | Cheung Kong Infrastructure/Hongkong Electric 51%; Spark Infrastructure 49% |
| ACT Network (ACT) | Alinta 50%; ACT Government 50% |
| GAS TRANSMISSION | |
| Victorian transmission system | APA Group (Alinta 35%) |
| Moomba to Sydney Pipeline | APA Group (Alinta 35%) |
| Eastern Gas Pipeline | Alinta |
| Tasmanian Gas Pipeline | Alinta |
| SEA Gas Pipeline | Origin Energy 33%; International Power 33%; China Light & Power 33% |
| Moomba to Adelaide Pipeline | Hastings |
| Ballera to Wallumbilla Pipeline | Hastings |
| Roma to Brisbane Pipeline | APA Group (Alinta 35%) |
| Carpenteria Pipeline | APA Group (Alinta 35%) |
| Wallumbilla to Gladstone Pipeline | Alinta |
| Gladstone to Rockhampton Pipeline | Alinta |
| Dampier to Bunbury Pipeline | Alinta 20%; DUET 60%; Alcoa 20% |
| Goldfields Gas Pipeline | APA Group 88.2% (Alinta 35%); Alinta 11.8% |
| Amadeus Basin to Darwin Pipeline | APA Group 96% (Alinta 35%) |
| Palm Valley to Alice Springs Pipeline | Envestra (Cheung Kong Infrastructure 16.57%; Origin Energy 16.57%) |
| GAS DISTRIBUTION | |
| ActewAGL (ACT) | Alinta 50%; ACT Government 50% |
| AllGas (Qld) | APA Group (Alinta 35%) |
| Gas Corporation of Queensland (Qld) | Envestra (Cheung Kong Infrastructure 16.57%; Origin Energy 16.57%) |
| Alice Springs Distribution | Envestra (Cheung Kong Infrastructure 16.57%; Origin Energy 16.57%) |
| South Australian Distribution | Envestra (Cheung Kong Infrastructure 16.57%; Origin Energy 16.57%) |
| Stratus (Vic) | Envestra (Cheung Kong Infrastructure 16.57%; Origin Energy 16.57%) |
| Westar (Vic) | Singapore Power |
| Multinet Gas (Vic) | Alinta 20.1%; DUET 79.9% |
| NSW Gas Networks (NSW) | Alinta |
| Western Australian Distribution | Alinta 74%; DUET 26% |
| Tasmanian Gas Network | Babcock & Brown |

1. A Babcock & Brown/Singapore Power consortium acquired Alinta under a conditional agreement in May 2007. As a consequence, the ownership of APA Group is likely to change.
2. APA Group acquired Origin Energy's 33 per cent stake in the SEA Gas Pipeline and 17 per cent share in Envestra in July 2007.

Figure 8

**NEM prices 1 March 2006–30 June 2007 (weekly volume weighted averages)**




Data source: NEMMCO

These conditions were exacerbated in June 2007 by a number of generator outages, network outages and generator limitations. For example, rain and flooding in the Hunter Valley made some generation capacity unavailable for a period. Tight supply was accompanied by record electricity demand as cold winter days increased heating requirements. In combination these factors led to an extremely tight supply-demand balance during the early evening peak hours, particularly in New South Wales.

These conditions led to some of the highest spot prices since the NEM commenced. In particular, spot prices exceeded $5000 a MWh on 42 occasions during June 2007 in New South Wales, Queensland and Snowy. The AER published a report on these events in July 2007, including the contributing impact of high demand, constrained supply and other factors.

Prices in the physical spot market flowed through to forward prices, which in 2007 reached historically high levels. High forward prices may reflect expectations that tight supply conditions will persist for some time into the future. They may also reflect concerns about the possible effects of carbon trading on energy prices.

There is evidence that high prices are placing pressure on the retail sector. One new entrant, Energy One, suspended its energy retailing business in June 2007 and cited the effects of high forward prices on profitability. Another retailer, Momentum Energy, sold part of its customer base in July 2007 due to rising wholesale costs.

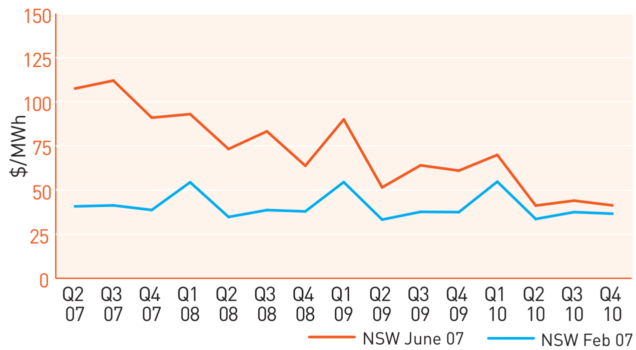
Figure 8 charts average weekly prices in the NEM since March 2006. The price spikes in Victoria and South Australia in January 2007 occurred when bushfires caused an outage of the Victoria–Snowy interconnector. There were also network issues in Queensland in late January. The impact of drought was prominent in April and May, with the compounding effect of demand and supply issues in New South Wales evident in June.

Figure 9 illustrates forward prices for electricity derivative contracts in June 2007 as compared to prices for equivalent contracts in February 2007. By way of illustration, the figure illustrates the New South Wales base futures curve (showing the price of contracts for each quarter out to 2010), but similar trends were evident for other regions and derivative products. The upward shift in forward prices is evident out to at least 2010.

In the short term, high prices are a normal response to tight supply in a competitive market, and provide signals for new investment in generation capacity. A scenario of persistent high prices above new entrant costs—without a sufficient investment response—would raise serious market power concerns. The AER closely monitors the market and reports weekly on wholesale and forward market activity. It also publishes more detailed analysis of extreme price events.

Figure 9

New South Wales base futures prices: February 2007 and June 2007




Data source: d-cypha Trade

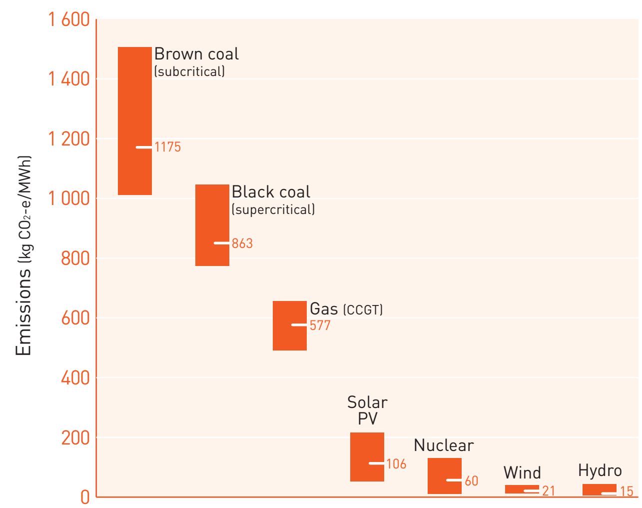
Perhaps the most significant challenge for the energy sector relates to carbon emissions. Growing concerns about the effect of emissions on greenhouse gas levels have resulted in the Australian and state and territory governments developing policies that include mandatory renewable energy targets and increased research funding (see appendix B). The Australian Government also announced in June 2007 that it would introduce an emissions trading scheme, based on a 'cap and trade' approach, by 2012.

The introduction of such measures affect the cost competitiveness of different energy technologies. In the short term, these policies are likely to accelerate the development of natural gas—which has lower carbon emissions than other fossil fuels—and cost-effective, renewable energy sources (figure 10). In the longer term, carbon emission pricing policies, regulation (for example, energy efficiency requirements) and research and development create the potential for a wider range of low carbon emission technologies. These might include clean coal, renewable energy sources that are not currently cost effective and nuclear power. There is also the potential for international emissions trading. Australia's national electricity and gas market frameworks, in conjunction with appropriate environmental policies, provide a flexible basis for the adoption of efficient low-carbon energy sources and technologies.

It is interesting to note that most of the power stations that the electricity industry is considering for future investment are gas-fired generators. With the increasing importance of natural gas in the energy mix there will be a need for better price transparency to enhance competition and to provide appropriate signals for new investment. Gas sales remain largely based on long-term confidential contracts, and price information is not readily available. Victoria alone operates a spot market in which up to 20 per cent of gas transported on the state's transmission network is traded. National initiatives are now under way to improve gas price transparency in all jurisdictions.

Figure 10

Life-cycle greenhouse gas emissions of electricity generation technologies




Note: PV is photovoltaic; CCGT is combined cycle gas turbine; OCGT is open cycle gas turbine. Includes emissions from the extraction of fuel sources.

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

The AER will play a number of roles in the evolving energy market environment. As the national regulator for electricity networks and gas pipelines the AER will look to apply a consistent and transparent approach that is conducive to efficient prices and investment, and reliable service delivery. The AER will also regulate aspects of the retail market, as agreed by the jurisdictions. It will continue to monitor the wholesale electricity market and investigate breaches of the rules and will help the ACCC assess the implications of merger activity for competition.

The energy sector continues to evolve. The AER will monitor and report on ongoing developments in future editions.

# REPORT STRUCTURE

## Part one Essays

### Essay A Stocktake of energy reform

This essay provides an overview of energy reform, and compares achievements so far with the goals of the reform program. It covers gas and electricity and touches on a range of themes including competitive neutrality issues and investment outcomes.

### Essay B Reliability in the National Electricity Market

Reliability refers to the continuity of electricity supply to end users, and is a key performance indicator of customer service. This essay looks at:

- the causes and effects of reliability issues
- reliability standards
- the measurement of reliability
- the reliability of electricity supply in the National Electricity Market (NEM), from generation through to the transmission and distribution networks that deliver power to customers.

The essay shows that most reliability issues are attributable to distribution issues. In part, this reflects differences in the costs and benefits of improving reliability across each segment of the supply chain.

## Part two Electricity

### Chapter 1 Electricity generation

This chapter provides a brief overview of the electricity supply chain and a survey of electricity generation in the NEM. It considers:

- the geographical distribution of generators, types of generation technology, life cycle costs and greenhouse emissions of different generation technologies
- the ownership of generation infrastructure
- investment in generation infrastructure
- the reliability of electricity generation in the NEM.

## Chapter 2 Electricity wholesale market

The NEM is a wholesale market through which generators and electricity retailers trade electricity in eastern and southern Australia. There are six participating jurisdictions—Queensland, New South Wales, the Australian Capital Territory, Victoria, South Australia and Tasmania, which are physically linked by transmission network interconnectors.

This chapter considers:
> features of the NEM, including the dynamics of the market, regional demand and trade
> spot prices, including volatility, and international price comparisons.

## Chapter 3 Electricity financial markets

Wholesale price volatility in the NEM can cause price risk to market participants. One method by which participants manage their exposure to price volatility is to enter into financial contracts that lock in firm prices. This report includes a survey of electricity derivative markets in recognition of their wider significance in the energy market framework. The chapter considers:
> the structure of electricity financial markets in Australia, including over the counter markets and trading on the Sydney Futures Exchange
> financial market instruments traded in Australia
> liquidity indicators for Australia's electricity financial markets, including trading volumes, open interest, changes in the demand for particular instruments, changes in market structure and vertical integration in the underlying electricity wholesale market
> price outcomes in the electricity futures market
> other mechanisms to manage price risk in the wholesale electricity market.

## Chapter 4 Electricity transmission

The electricity supply chain requires transmission networks to transport power from generators to local distribution areas. Transmission networks also enhance the reliability of electricity supply by allowing a diversity of generators to supply electricity to end markets. This chapter considers:
> the structure of the transmission sector, including industry participants and ownership changes
> the economic regulation of the transmission network sector by the AER
> financial outcomes, including revenues and returns on assets
> new investment in transmission networks
> operating and maintenance costs
> quality of service, including reliability and the effects of congestion.

## Chapter 5 Electricity distribution

This chapter focuses on the low voltage distribution networks that move electricity from points along the transmission line to customers in cities, towns and regional communities. The chapter considers:
> the structure of the distribution sector, including industry participants and ownership changes
> the economic regulation of the distribution network sector
> financial outcomes, including revenues and returns on assets
> new investment in distribution networks
> quality of service, including reliability and customer service performance.

## Chapter 6 Electricity retail markets

The retail market is the final link in the electricity supply chain. It provides the main interface between the electricity industry and customers such as households and small business. This chapter considers:
> the structure of the retail market, including industry participants, ownership changes, vertical integration activity with the generation sector and convergence between electricity and gas retail markets
> the development of retail competition
> retail market outcomes, including price, affordability and service quality
> the regulation of the retail market.

### Chapter 7 Beyond the National Electricity Market

This chapter surveys the electricity industry in the jurisdictions that are not interconnected with the NEM—Western Australia and the Northern Territory. Western Australia recently introduced a number of electricity market initiatives, including new wholesale market arrangements. The Northern Territory has introduced electricity reforms but at present there is no competition in generation or retail markets.

## Part three Natural gas

### Chapter 8 Gas exploration, production, wholesaling, and trade

This chapter surveys the gas exploration and production sector, including:

- exploration and development activity in Australia
- gas production and consumption and the future outlook for growth
- gas prices
- industry participants and ownership changes
- gas wholesale operations and trade
- market developments.

### Chapter 9 Gas transmission

High pressure transmission pipelines ship gas from production fields to destinations such as cities and to large customers located along the route of the pipeline. This chapter considers:

- the structure of the transmission sector, including industry participants and ownership changes over time
- the economic regulation of the gas transmission sector
- new investment in transmission pipelines and related infrastructure.

### Chapter 10 Gas distribution

Natural gas distribution networks transport gas from transmission pipelines and reticulate it into residential houses, offices, hospitals and businesses. This chapter considers:

- the structure of the distribution sector, including industry participants and ownership changes over time
- the economic regulation of distribution networks
- new investment in distribution networks
- quality of service.

### Chapter 11 Gas retail markets

The retail market provides the main interface between the gas industry and customers such as households and small business. This chapter considers:

- the structure of the retail market, including industry participants and ownership changes
- convergence between electricity and gas retail markets
- the development of retail competition
- retail market outcomes, including price, affordability and service quality
- the regulation of the retail market.

## Part four Appendices

### Appendix A Institutional arrangements

This appendix outlines the roles and responsibilities of the national, state and territory stakeholders involved in energy policy and economic regulation.

### Appendix B Greenhouse gas emissions policy

This appendix outlines key Australian, state and territory government initiatives for reducing greenhouse gas emissions from the stationary energy sector.

### Appendix C Australian transmission pipelines

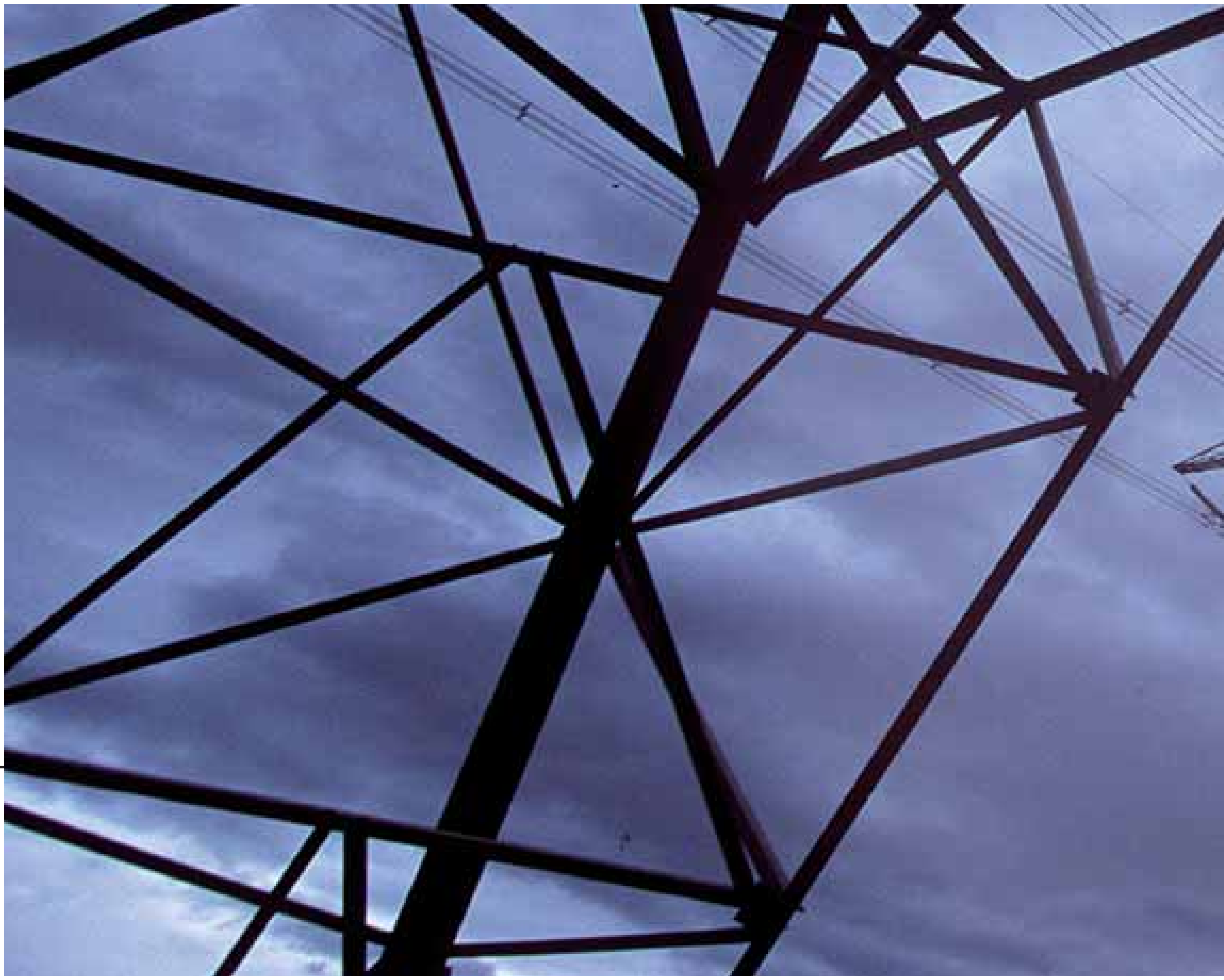
This appendix lists Australia's main onshore natural gas transmission pipelines.

# ABBREVIATIONS

| | |
|---|---|
| 1P | proved reserves |
| 2P | proved plus probable reserves |
| 3P | proved plus probable plus possible reserves |
| AASB | Australian Accounting Standards Board |
| ABARE | Australian Bureau of Agricultural and Resource Economics |
| ABDP | Amadeus Basin to Darwin Pipeline |
| ABS | Australian Bureau of Statistics |
| AC | alternating current |
| ACCC | Australian Competition and Consumer Commission |
| AEMA | Australian Energy Market Agreement |
| AEMC | Australian Energy Market Commission |
| AER | Australian Energy Regulator |
| AFMA | Australian Financial Markets Association |
| AGA | Australian Gas Association |
| AIH | Alinta Infrastructure Holdings |
| ANTS | Annual National Transmission Statement |
| APS | Australian Power Strip |
| APT | Australian Pipeline Trust (part of the APA Group) |
| B&B | Babcock & Brown |
| boe | barrel of oil equivalent |
| CAIDI | customer average interruption duration index |
| CBD | central business district |
| CCGT | combined cycle gas turbine |
| CCS | carbon capture and storage |
| CLP | China Light & Power |
| $CH_4$ | methane |
| COAG | Council of Australian Governments |
| CPI | consumer price index |
| CSG | coal seam gas |
| CSM | coal seam methane |
| DBNGP | Dampier to Bunbury Natural Gas Pipeline |
| DC | direct current |
| DUET | Diversified Utility and Energy Trust |
| EAPL | East Australian Pipeline Limited |
| EBIT | earnings before interest and tax |
| EBITDA | earnings before interest, tax depreciation and amortisation |
| EGP | Eastern Gas Pipeline |
| ERA | Economic Regulation Authority of Western Australia |

| | |
|---|---|
| ERCOT | Electric Reliability Council of Texas |
| ERIG | Energy Reform Implementation Group |
| ESC | Essential Services Commission (Victoria) |
| ESCOSA | Essential Services Commission of South Australia |
| ESAA | Energy Supply Association of Australia |
| EST | Eastern Standard Time |
| ETEF | electricity tariff equalisation fund |
| FEED | front end engineering design |
| FRC | full retail contestability |
| Gas Code | National Third Party Access Code for Natural Gas Pipeline Systems |
| Gas Law | Gas Pipeline Access Act |
| GasCo | Gas Market Company |
| GEAC | Great Energy Alliance Corporation |
| GGP | Goldfields Gas Pipeline |
| GJ | gigajoule |
| GMLG | Gas Market Leaders Group |
| GSL | guaranteed customer service levels |
| GWh | gigawatt hour |
| ICRC | Independent Competition and Regulatory Commission |
| IMO | Independent Market Operator |
| IPART | Independent Pricing and Regulatory Tribunal |
| JV | joint venture |
| Km | kilometre |
| kV | kilovolts |
| KW | kilowatt |
| KWh | kilowatt hour |
| LNG | liquefied natural gas |
| LPG | liquefied petroleum gas |
| MAIFI | momentary average interruption frequency index |
| MAPS | Moomba to Adelaide Pipeline System |
| MCE | Ministerial Council on Energy |
| MCC | marginal cost of constraints |
| MDQ | maximum daily quantity |
| MSP | Moomba to Sydney Pipeline |
| MW | megawatt |
| MWh | megawatt hour |
| NCC | National Competition Council |
| NECA | National Electricity Code Administrator |
| NEL | National Electricity Law |
| NEM | National Electricity Market |
| NEMO | National Energy Market Operator |
| NEMS | National Electricity Market of Singapore |
| NEMMCO | National Electricity Market Management Company |
| NER | National Electricity Rules |
| NGERAC | National Gas Emergency Response Advisory Committee |
| NGL | National Gas Law |
| NGMC | National Grid Management Council |
| NGPAC | National Gas Pipelines Advisory Committee |
| NGR | National Gas Rules |
| NGS | National Greenhouse Strategy |
| NGT | National Grid Transco |
| NWIS | North West Interconnected System |
| OCC | outage cost of constraints |
| OCGT | open cycle gas turbine |
| OTC | over-the-counter |
| OTTER | Office of the Tasmanian Energy Regulator |
| PASA | projected assessment of system adequacy |
| PG&E | Pacific Gas and Electric |
| PJ | petajoule |
| PJM | Pennsylvania–New Jersey–Maryland pool |
| PNG | Papua New Guinea |
| POE | probability of exceedence |
| PPA | power purchase agreement |
| PV | photovoltaic |
| PwC | PricewaterhouseCoopers |
| QCA | Queensland Competition Authority |
| QNI | Queensland to New South Wales interconnector |
| QPTC | Queensland Power Trading Corporation |
| RAB | regulated asset base or regulatory asset base |
| REMCo | Retail Energy Market Company |
| SAIDI | system average interruption duration index |
| SAIFI | system average interruption frequency index |

| | |
|---|---|
| SECWA | State Energy Commission of Western Australia |
| SFE | Sydney Futures Exchange |
| SOO | statement of opportunities (published by NEMMCO) |
| SPCC | supercritical pulverised coal combustion |
| SPI | Singapore Power International |
| STEM | short-term energy market |
| SWIS | South West Interconnected System |
| TCC | total cost of constraints |
| TJ | terajoule |
| TNSP | transmission network service provider |
| TW | terawatt |
| TWh | terawatt hour |
| UC | Utilities Commission (Northern Territory) |
| URF | Utility Regulators Forum |
| VENCorp | Victorian Energy Networks Corporation |
| VRET | Victorian renewable energy target scheme |
| VTS | Victorian transmission system |
| WAPET | West Australian Petroleum |
| WMC | Western Mining Company |



# PART ONE
ESSAY A

Phil Carrick (Fairfax Images)

# STOCKTAKE OF ENERGY REFORM

# ESSAY A

# STOCKTAKE OF ENERGY REFORM

## A Report by Firecone Ventures Pty Ltd April 2007

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### Introduction

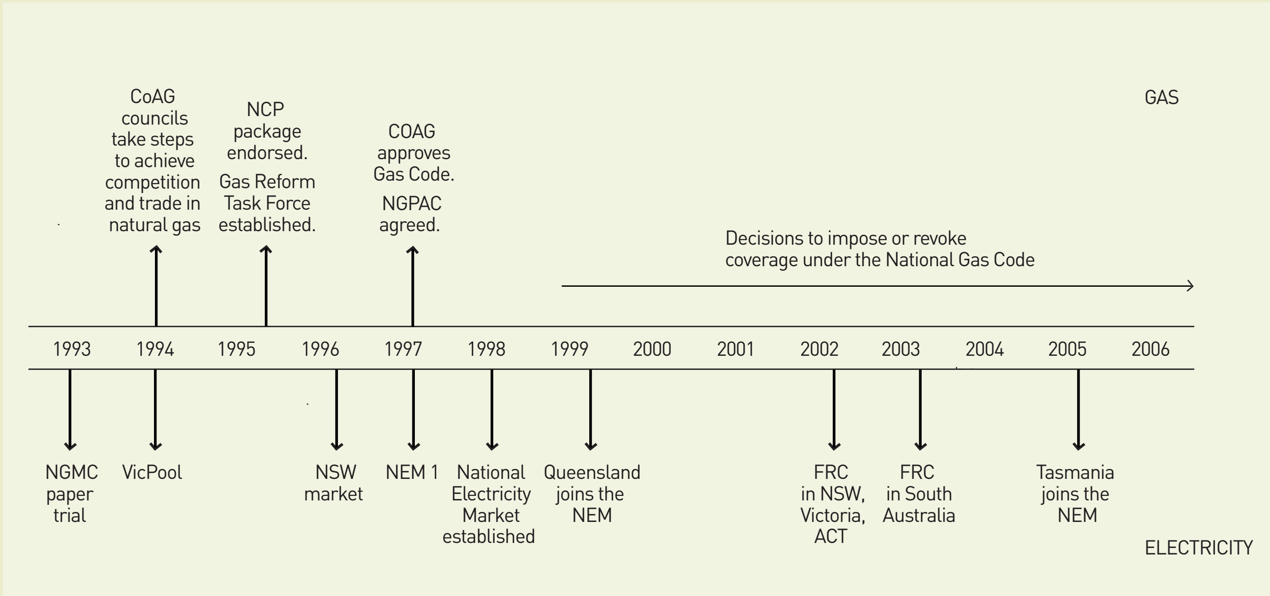
In the early 1990s, Australian governments embarked on reforms to establish a competitive energy sector. These included:

> **structural reform**—separating potentially competitive functions from monopoly infrastructure, and establishing a competitive industry structure for commercial functions
> **competitive neutrality**—establishing corporatised governance structures for significant government businesses
> **access**—enabling access to monopoly infrastructure, with independent authorities to oversee prices
> **market design**—establishing a national electricity market, with associated institutions to oversee the rules and manage the market, and establishing gas market arrangements.

Some of the key steps in energy sector reform are illustrated in figure A.1.

Figure A.1

**Key timelines in reform**




This essay provides an overview of the implementation of these reforms. It considers whether the model has been implemented as originally intended and how it has worked. It looks at both gas and electricity, but concentrates on the National Electricity Market (NEM).

Structural reform and changes to the governance arrangements for government-owned businesses have been implemented across Australia. Subsequent developments have varied. In jurisdictions with continued government ownership, industry structure has changed little. In jurisdictions that have privatised their energy sector, industry structure has changed rapidly, leading to separation between network and merchant businesses, increased concentration of ownership in both, and vertical integration between retail and generation.

Access regimes have been implemented across Australia. There have been different trends in electricity and gas. Electricity has relied almost 100 per cent on regulated access, despite attempts at a deregulated model for electricity transmission. Gas transmission pipelines have increasingly become unregulated, while gas distribution has remained largely regulated. Electricity and gas networks have both seen high levels of investment.

A competitive wholesale electricity market has been established across the eastern seaboard. The market design has been stable, but has faced some difficulty in evolving the regional structure as envisaged. Full retail competition has been introduced, or a commitment made to introduce it, in all jurisdictions in the NEM. However, full deregulation of the retail market has not yet been achieved.

This framework has delivered substantial investment in generation and in networks. Overall electricity prices have reduced, although with rebalancing between business and households. The retail market is increasingly competitive, particularly in Victoria and South Australia.

## Implementing the reforms

The jurisdictions entered into agreements to implement structural reform, competitive neutrality and the introduction of competitive markets. How have the reforms gone?

### Structural reform

*The starting point for most jurisdictions was an integrated electricity utility. Separation was required between the networks and the potentially competitive parts of the industry. Competitive wholesale and retail markets also required sufficient businesses to set prices through competition rather than regulation.*

*There was substantial restructuring in the mid-1990s. In jurisdictions with public ownership, industry structure has been reasonably stable since then. Jurisdictions with a high level of private ownership have seen a continued rapid pace of change. This has led to separation between merchant businesses and networks; integration between generation and retail; and concentration in the ownership of generation, retail and networks.*

*Victoria and South Australia privatised their electricity supply industry. In New South Wales and Queensland, the industry has remained predominantly in public ownership. Across the NEM, around two-thirds of generation, and 70 per cent of transmission, are publicly owned. There has been both private and public investment in new capacity, for both generation and network businesses.*

**Industry structure**

All jurisdictions implemented a similar set of reforms to the structure of their electricity industry in the early to mid-1990s. These entailed breaking up generation into several businesses; establishing one or more transmission businesses; and creating several retail/distribution businesses, with ring-fencing between the distribution and retail functions.

The pace of restructuring was rapid. In New South Wales, Pacific Power was created from the former Electricity Commission in 1992 and restructured into three generation business units, a network business and a trading business. In 1995 Transgrid was separated from the network business, and 25 electricity distributors were amalgamated into six. In 1996 two government-owned generation businesses, Delta and Macquarie Generation were spun out, and the state-based competitive market started.

Similar developments took place in other states. In Queensland the Queensland Electricity Corporation was divided into a generation corporation, and a transmission and supply corporation in 1996. The generation corporation was split into three generation companies, CS Energy, Tarong Energy and Stanwell. In addition, the Queensland Power Trading Corporation (now Enertrade) owned some generation assets, and held a number of power purchase agreements. By 1998 seven distribution and retail businesses were consolidated into two, Ergon and Energex.

Victoria broke the former State Electricity Commission of Victoria into generation, transmission and distribution companies in 1993. In 1994 it consolidated 18 business units and 11 municipal undertakings into five distribution and retail businesses. These businesses were sold in 1995. Generation was broken into five generation companies and mostly sold during 1996 to 1997, with Ecogen being sold in March 1999.

These reforms were all similar, driven in part by agreements under the National Competition Policy. However, they also had distinctive features. Victoria restructured its generation sector into businesses at power station level although, as discussed below, there has been substantial reintegration. New South Wales created 'portfolio' generation companies, with several generating plants in each company.

Subsequent developments have varied. Jurisdictions with a high level of government ownership have had a stable industry structure. New South Wales completed the creation of its generating businesses through spinning off Eraring Energy from Pacific Power in 2000 and selling off Pacific Power's coal and consulting businesses. New South Wales also consolidated three regional distribution and retail businesses into one, Country Energy.

Queensland largely maintained its industry structure until recently. However, in November 2006 and February 2007 its government sold its mass market retail businesses, Powerdirect and Sun Retail. This has led to vertical separation of retail and distribution.

The industry structure in Victoria and South Australia has continued to change rapidly. Privately owned assets have changed ownership two or three times. This has resulted in some significant differences in industry structure between Victoria/South Australia and elsewhere.

One difference is the nature and extent of vertical integration. In Queensland and New South Wales, generation and retail businesses are largely separate. A number of generators have retail licences, but have a low market share. However, in Victoria and South Australia AGL, TRUenergy and Origin combine large retail businesses with ownership or part-ownership of around 55 per cent of generating capacity.

New South Wales has maintained common ownership of its distribution networks and mass retail businesses. In Victoria and South Australia a complete separation between retail and distribution businesses has emerged. This appears to reflect capital market drivers. Queensland has now largely separated the sectors.

Another difference is the approach taken to structural separation initially and subsequent developments. All jurisdictions established several generation businesses. In Victoria each generating plant was a separate business, other than Southern Hydro and Ecogen. In New South Wales, Queensland and South Australia portfolio generators were created.

Again, states that privatised have seen rapid changes to industry structure. Figure A.2 shows the trends in ownership of generation in Victoria and South Australia. In the past few years:

> AGL has acquired a part-interest in Loy Yang A, bought Southern Hydro and in 2007 acquired Torrens Island from TRUenergy

> International Power, which already owned Synergen and Pelican Point in South Australia, bought Hazelwood and then Loy Yang B

> TRUenergy, which already owned generation at Yallourn, acquired the former TXU generation capacity

> several major investors have exited from the industry.

**Figure A.2**

**Generation ownership in South Australia and Victoria by installed capacity to 2006**

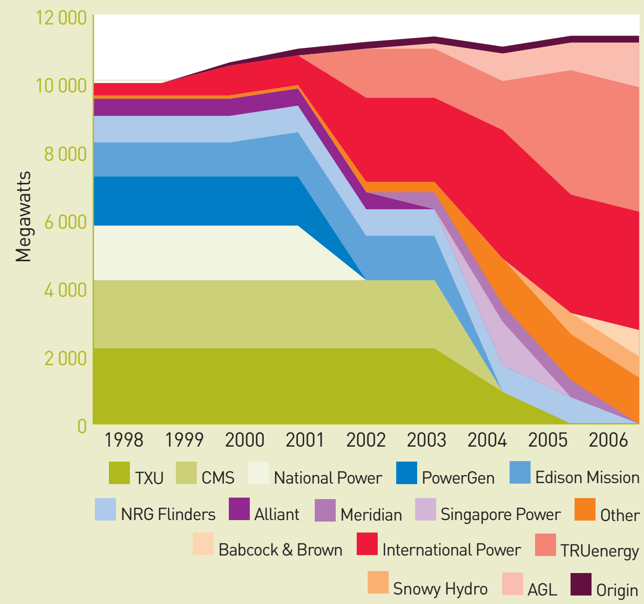



Figure A.2 illustrates the increasing degree of concentration in Victoria and South Australia in recent years. The figure is over-simplified, as ownership arrangements can be quite complex. It also excludes the recent exchange of generation capacity between AGL and TRUenergy. However, it does allow a relatively clear visual depiction of increasing concentration in the sector.

The result is less concentrated than generation ownership in New South Wales and rather more concentrated than in Queensland. Victoria and South Australian generation remains exposed to competition from the north and more recently from the south through Basslink.

There has been a similar concentration of ownership in retail. TRUenergy, Origin and AGL, the three gentailers (retailers that own generation plant), have absorbed all of the mass market electricity and gas retail businesses sold in Victoria, South Australia and Queensland. There has been no comparable change in retail ownership in New South Wales.

There has also been a concentration of network ownership in Victoria and South Australia. Cheung Kong Infrastructure/Hong Kong Electric Holdings control two distribution businesses in Victoria—CitiPower and Powercor—and the distribution business in South Australia. Also in Victoria, SP AusNet owns a distribution business and is the major transmission service provider.

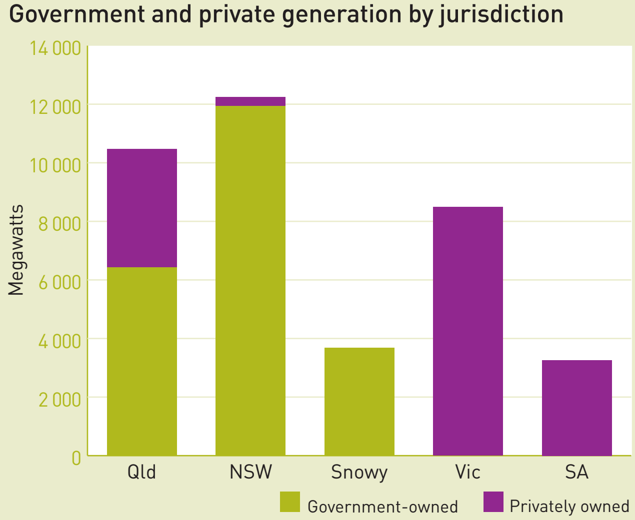
There have been some similar trends elsewhere. The New South Wales Government has consolidated its three regional distribution and retail businesses into one, Country Energy. A recent Boston Consulting report for the Queensland Government also raised the possible cost synergies from a merger of its distribution businesses.[1]

### Competitive neutrality

As the role of the public sector in the electricity industry varies from state to state, so too does the need for competitive neutrality.

Overall, nearly two-thirds of generation is government-owned. The shares of government-owned and privately owned generation by jurisdiction are shown in figure A.3.

Figure A.3
Government and private generation by jurisdiction




New South Wales has kept its generation businesses in public ownership. The New South Wales Government recently announced a 400 megawatt (MW) combined cycle generation plant to be developed by TRUenergy at Tallawarra, and a 600 MW open cycle plant to be developed by Delta, a government-owned generation business, at Lake Munmorah.

Queensland has had a mix of public, private and joint ownership of generation. Callide Power and Tarong North were developed jointly by government and private investors. The most recent power plant, Kogan Creek, was initiated as a 40/60 joint venture between the government-owned CS Energy and privately owned Mirant. It is being undertaken solely by CS Energy since Mirant sold out its 60 per cent interest in May 2002. Victoria and South Australia have sold their generation interests, and rely on private investment for new capacity.

Network businesses in New South Wales, Queensland and Tasmania remain in public ownership. Victoria and South Australia have privatised their network businesses.

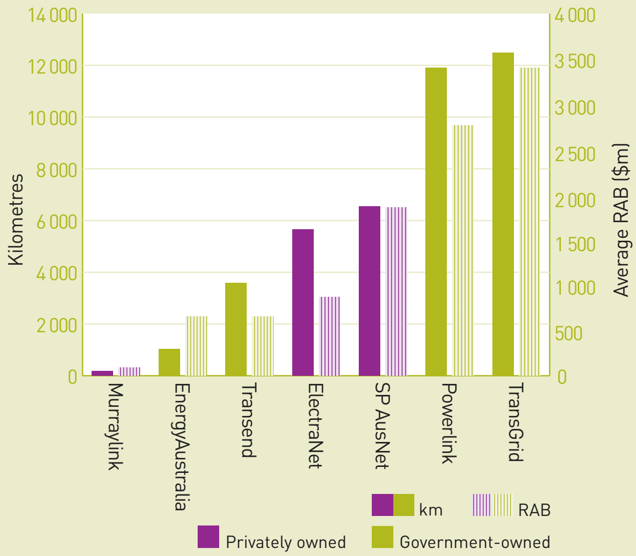
There has been some private investment in unregulated DC transmission links. Two mainland DC links have since converted to regulated status. The transmission link to the mainland, Basslink, remains unregulated. The link is owned and operated by a private company, with financial support being provided by the public sector.

The size of the transmission businesses, in both kilometres of transmission line and size of the regulatory asset base, is shown in figure A.4. The information is drawn from the Australian Energy Regulator (AER) report of April 2006 on transmission network service providers (TNSPs), and excludes Directlink and Basslink.[2] The government-owned transmission businesses in New South Wales, Queensland and Tasmania account for around 70 per cent of the regulatory asset base, and a rather larger share of new transmission investment.

1 The Boston Consulting Group, *Queensland energy structure review*, Final report, March 2006.
2 AER, *Transmission network service providers electricity regulatory report for 2004/05*, April 2006.

Figure A.4

Size of the transmission businesses




Retail businesses in Victoria, South Australia and Queensland are private. In Tasmania and New South Wales the mass market retail businesses remain government-owned.

Competitive neutrality has been implemented. All government businesses in generation, network and retail are corporatised, and all governments have set up competitive neutrality complaints units. No use has been made of this complaints mechanism to address concerns that have sometimes arisen about government-financed investment.

While the policy of competitive neutrality has been implemented, it is not clear that it has worked. Private investors remain unsure about the policy settings—are governments seeking private generation investment, or are they happy to finance this investment themselves? And private investors remain concerned about whether decision-making by government-owned business is fully commercial, and earning returns in line with the risks they are bearing.

An energy-only market moves in rather long waves, with average prices rising to new entrant prices—and enabling existing investors to recover their capital costs—as the supply position tightens. If governments facilitate investment in advance of the likely commercial response, this may provide high reserves but—under the current market design—will undermine reasonable commercial returns to private investment.

As a result, there is a somewhat uneasy coexistence between public and private investment in the electricity sector. This uneasiness may be reduced through changes in ownership, such as Queensland's recent sale of its retail interests. It could also be reduced if any non-commercial objectives were made explicit. These issues were strongly raised in the 2007 report to the Council of Australian Governments (COAG) by the Energy Reform Implementation Group (ERIG).

## Access to monopoly infrastructure

*Separation between the potentially competitive elements of the market and the monopoly networks was combined with the introduction of access regimes, with independent price regulation. The application of these reforms has differed sharply between gas and electricity. The electricity sector tested a deregulation model for transmission, but has reverted to close to complete regulatory coverage in that sector. The gas sector has seen increasing deregulation.*

The National Electricity Code has always allowed for both regulated and unregulated transmission investments and code changes established the basis for unregulated investments. Subsequently three unregulated transmission investments were made: Directlink, Murraylink and Basslink.

Two of the investments have subsequently converted to regulated status, at a loss, while Basslink only started operations on 29 April 2006. The Ministerial Council on Energy (MCE) announced in December 2003 that it would remove a perceived bias in favour of unregulated investment. This change was implemented in mid-2004. In addition, the commercial appetite for unregulated transmission investment may be low, given previous experience.

The main focus has therefore been on developing a regulatory regime for transmission, which so far has been an open access regime. Generators get dispatched on the basis of their offers, within the constraints imposed by secure operation of the network. They have no rights to transmission capacity. The interaction between incumbent rights and access to the network by new investors remains a contentious topic.

The regime itself has developed through principles and practice. Regulatory principles have been developed by the AER and, more recently, rules for transmission revenue regulation and pricing have been developed by the Australian Energy Market Commission (AEMC).

Decisions have been made on revenue caps for all the TNSPs, with a second set of five-year determinations recently for Transgrid and EnergyAustralia and second determinations under way for Powerlink and SP AusNet. As a result there is a considerable body of practice.

All distribution businesses are regulated by jurisdictional regulators, through five-year resets. The resets are based on revenue or price caps that use a building block—that is, an estimation of the efficient costs of providing the distribution services allowing for return on capital, depreciation, new capital expenditure and operating costs. There has been some convergence in regulatory approach. This should be strengthened with the proposed transfer of these functions to the AER under the Australian Energy Market Agreement (AEMA).

The Gas Code has arrangements for certain pipelines to be 'covered' under the code and required to offer benchmark tariffs approved by a regulator. However, while the trend in electricity networks has been towards increased reliance on regulated networks, the trend for gas pipelines has been in the opposite direction.

There has been a high level of deregulation in gas. Recent decisions to remove or not impose coverage include:

> the decision against coverage of the Eastern Gas Pipeline, from Longford to Sydney, in 2000
> the revocation of coverage of the main trunk of the East Australia pipeline from Moomba to Sydney (but not other parts of the pipeline system)
> many smaller pipelines in Queensland, South Australia, Victoria and Western Australia.

This has led to much greater reliance on unregulated investments in the gas pipeline sector. Gas distribution networks have largely remained regulated.

## Market design

*The introduction of competition required the design of a wholesale market. The wholesale market has stayed reasonably close to original design, but has come under pressure from failure to evolve the regional structure.*

In electricity, the wholesale market is settled on the basis of half-hourly consumption. Extending competition to mass-market consumers, who do not have half-hourly meters, required the design of a retail market. The retail market design adopted a relatively low-cost and pragmatic approach. This appears to have been successful so far, but may require change as interval meters are rolled out.

In the gas sector, Victoria has a spot market, with the market operator VENCorp carrying out functions that are managed by the pipeline operator in other states. There is no commitment to a single model for gas markets, but proposals have been put forward on steps to increase the transparency of the market. COAG has also agreed to establish a National Energy Market Operator.

### The National Electricity Market

The market design was developed during the 1990s. The National Grid Management Council conducted a paper trial of a national market in 1993–94. Separate markets were established in Victoria and New South Wales in the mid-1990s, a National Electricity Code agreed to in 1996 and the NEM started operations in 1998. Tasmania joined in 2005.

The wholesale electricity market relies on competition to set half-hourly prices. The NEM is an energy-only gross pool:

- 'Energy-only' means that generators are only paid for producing energy. Some markets have capacity payments in different forms. The NEM has no payment for simply making capacity available, and no obligations on retailers to contract for reserve.
- 'Gross pool' means that all energy has to be sold through the pool. This contrasts with some other markets where the bulk of energy is managed through bilateral arrangements between generators and major consumers/retailers, with the pool only acting as a balancing market.

Changes to market design have been considered with the arguments for a capacity market having been rejected twice, in 1999 and 2002. The issue is currently being raised again by some market participants, in response to tightness in supply in some jurisdictions. The Parer report considered and rejected a shift from a gross pool to a net pool, although some commentators have continued to argue the case.

The design of the NEM is similar to the original England and Wales pool. One important difference is the use of regions. Prices within the wholesale market are established on a regional basis. Prices are reasonably uniform across the regions, but can diverge sharply when transmission lines between regions are constrained.

The NEM was initially structured around regions based on jurisdictions, with the exception of the Snowy region. The code included criteria for the evolution of regional boundaries. These were designed to ensure reasonably strong transmission interconnection within regions. Although the criteria for boundary change were met, the regional structure has not yet changed.

The failure to evolve the regional structure as originally intended has arguably been the greatest divergence from the original design of the wholesale market. This has resulted in major stresses, in particular in and across the Snowy region. It has also encouraged consideration of alternative solutions, and the trialling of approaches to improve price signals to generators. However, the MCE has recently endorsed the continued use of a regional framework for the NEM.

As a result, the market design has been stable since market start, with minor changes rather than large shifts in fundamental design. On balance, this has been a strength of the NEM. Other markets have seen major changes in design, with high direct and indirect costs. For example, the introduction of new market arrangements in England and Wales were estimated to create industry costs of up to £580 million (A$1.4 billion in 2001 prices).[3] There has been no sign in the NEM of market design problems that would justify such high costs.

### Electricity retail markets

The wholesale market is settled on the basis of production and consumption every half-hour. However, mass market consumers only have meters that read consumption cumulatively, rather than half-hourly. Extending the competitive market to smaller consumers required a new market model.

The NEM adopted a model for retail competition based on the 'net system load profile'. Essentially, the time profile for all smaller consumers was assumed to be identical, and was set by the residual after netting off consumption whose time profile was known, such as major consumers with time-of-use metering and street lighting.

3 National Audit Office, *The new electricity trading arrangements in England and Wales*, 2003, p. 5.

This approach is simpler than some models elsewhere. For example, the United Kingdom adopted a profiling approach based on eight deemed profiles for smaller users that are not half-hourly metered. The costs of implementing retail competition in the United Kingdom are understood to be considerably higher than they have been in Australia. This is understood to be attributable in part to the use of a greater number of deemed profiles.

The adoption of retail competition based on net system load profile appears to have gone smoothly in Australia. It is not much discussed—often a good sign. A uniform model has been used across the NEM, although many other aspects of retail regulation continue to be decided at a jurisdictional level.

It seems possible, however, that the approach to retail competition may change in future years. In 2005 COAG committed to the roll-out of interval meters across the NEM. This will remove the need for net system load profiling, since information will be available on the actual half-hourly consumption by consumers. This may lead at some point to a change in the design of the market.

More attention has so far been devoted to how to implement an interval meter roll-out rather than to the effect it would have. However, the combination of well functioning spot and contract markets, the roll-out of interval meters and a very 'spiky' demand in some jurisdictions creates the possibility of substantial innovation over future years.

Considerable effort has gone into the creation of a competitive retail market and an industry structure to support competition. As discussed below, that has achieved high levels of customer movement in some states.

There is an unresolved debate over the continuing need for retail price caps. One argument is that caps, at a high level, simply protect against the risk to customers, without damaging competition. The counter argument is that complying with retail price regulation is an additional and unnecessary regulatory burden, and that the existence of price caps leaves a risk that these will be set at too low a level, undermining competition and the financial viability of retailers.

**Gas markets**

The NEM has created a uniform wholesale market in eastern Australia. This was needed to ensure instantaneous balance over a synchronous electricity grid.

There is no similar uniformity in the gas market. Victoria manages gas balancing on its transmission system through a spot market. Participants do not need to contract for gas, but must inform VENCorp of their daily supply and demand requirements. The supply offers are stacked in order of price and cleared against total demand. In other states, this scheduling is typically managed by the gas pipeline operator.

While there is no uniform market structure, the industry has put forward proposals to deliver increased transparency and ease of price discovery. These proposals led to an agreed action plan, dependent on continued support from industry participants, which was announced by the MCE in October 2006.

## Market institutions

The MCE set out the new governance arrangements for energy markets in its report to COAG in December 2003. These arrangements were reflected in the AEMA in June 2004, and subsequently in the National Electricity Law and related legislation.

The MCE has been established as the single energy market governance body. Two new statutory commissions have been created. The AEMC is responsible for rule-making and market development. The AER is responsible for market regulation. The governance framework for these institutions has removed the previous strong link to state governments. However, this earlier governance framework remains in place for the National Electricity Market Management Company (NEMMCO).

The new institutions have only recently been established, and it is early to form views on their performance. However, the new structures seem to have established greater transparency in government policy, and should avoid policy entrepreneurialism by the market institutions, since the AEMC has no power to initiate amendments. The rather cumbersome duplication with reviews by the National Electricity Code Administrator and Australian Competition and Consumer Commission under previous arrangements has also been avoided, although with a corresponding reduction in checks and balances.

The new institutions seem to have an impressive—and demanding—workload. The ability of market participants to establish the AEMC's agenda is in many ways a strength, but this may require future active management to ensure a coordinated and manageable work program. Separation between the making of regulatory rules and the conduct of regulation was an objective of the institutional design, but putting this into practice has raised issues about the appropriate level of codification, and discretion of the two institutions.

In April 2007 COAG agreed to establish a National Energy Market Operator for both electricity and gas. However, at the time of preparing this essay, the role and functions of the new body and the governance arrangements to ensure effective industry participation were yet to be developed.

## Effect of the reforms

As described above, the introduction of competitive markets in the energy sector has largely followed the reforms agreed to in the early 1990s. How successful has it been in relation to investment, prices and quality of supply?

### Investment

*Since the market start, there has been investment in around 5000 MW of new electricity generation at a cost of around $4.7 billion. Victoria and South Australia have had a reasonably tight supply, against the conservative forecasts established by NEMMCO. Queensland has had higher reserve levels than the rest of the NEM.*

There has been substantial investment—currently around $1 billion a year—in almost entirely regulated electricity transmission networks. This has contributed to an increasing convergence of prices between regions.

Around $3 billion of investment has been made in gas pipelines since 1997, most of it unregulated. This has transformed the nature of gas supply in southern and eastern Australia, meaning that most major cities are now supplied from at least two basins and producers have access to a wider customer base.

#### Generation investment

There has been substantial investment in new generation, estimated at $4.7 billion since market start. Figure A.5 shows the average wholesale price and the level of investment for each region (other than Snowy) in each year since market start. The investment figure is the gross megawatts of new investment and augmentations and does not include deratings or retirements. The price shows the annual average price for the region.

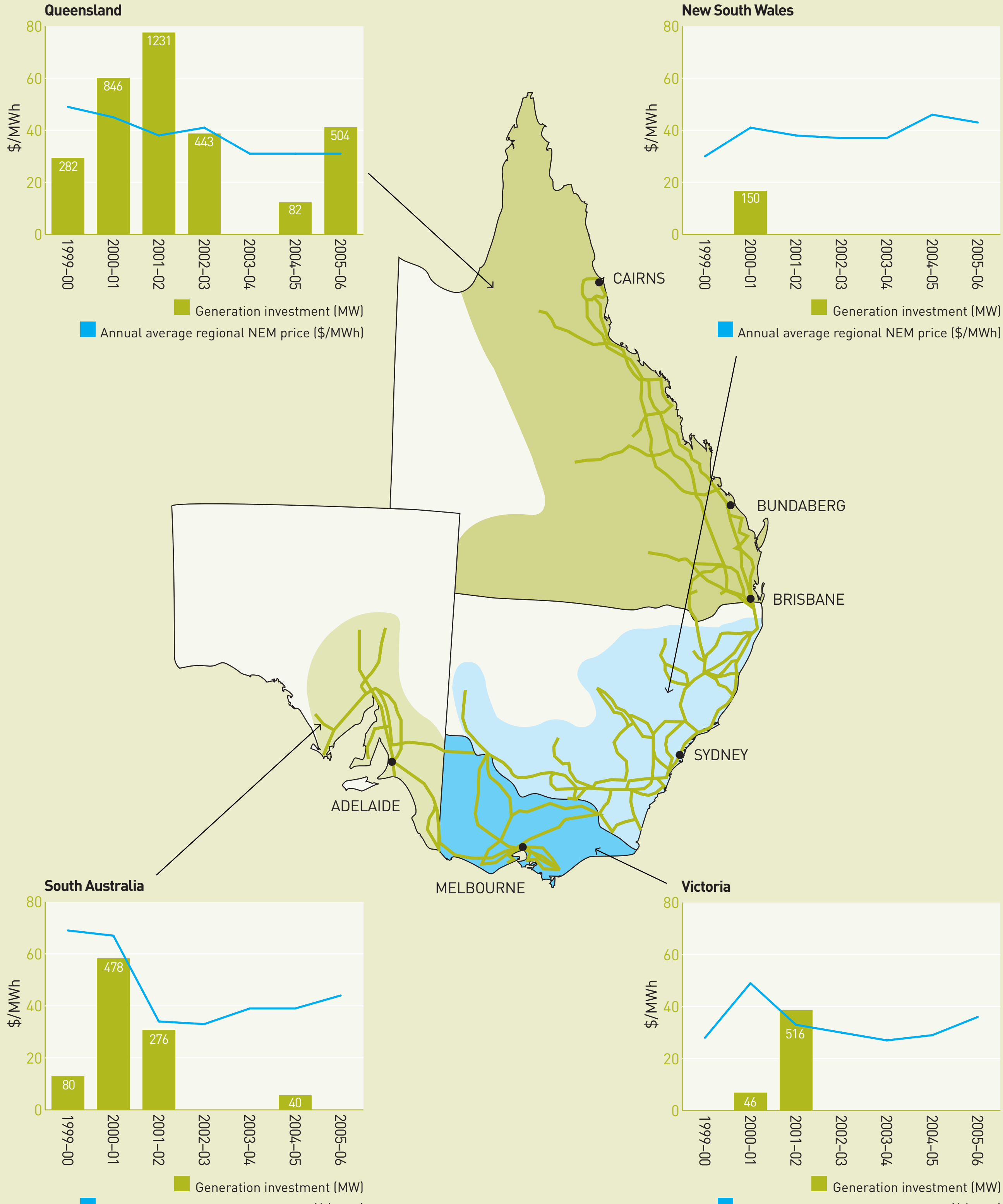
The figure suggests that, initially at least, generation has responded to price signals. South Australia initially experienced high average prices, which fell after significant investment. Queensland also had prices above new entrant levels in early years, with average prices falling after new investment.

The success of the market in ensuring timely investment appears to have varied. Victoria and South Australia have very peaky load shapes, driven by high air conditioning load on a few summer days. NEMMCO forecasts the demand/supply balance and, if necessary, takes action to manage possible shortfalls, to ensure minimum reserve margins on a one-in-ten-year peak demand.

The combination of a conservative approach with a highly peaky demand has meant periodic tight supply. In the past two years, NEMMCO has operated the reserve trader mechanism—essentially a way to seek out additional generation or demand side response in preparation for possible tight supply. Although there has been no shortfall due to generation capacity, the use of reserve trader suggests that supply has been rather tight. Future additional opportunities may emerge to manage short spikes in demand. For example, the roll-out of interval meters will create greater opportunities to develop demand as well as supply-side responses.

Figure A.5

Generation investment and electricity prices by region



There has also been substantial debate as to whether there is the right mix between generation and transmission investment. There are two ends to the spectrum in this debate:

- The NEM is characterised by large, concentrated load centres, with long distances between them. The load centres are supplied by similar generation plant, with similar variable costs. Increasingly, the marginal generation is gas-fired and gas prices have been converging. Interconnection between these regional markets is needed to avoid market power, and ensure prices are cost reflective, but the benefits of major increases in transmission are unlikely to justify the costs.
- The NEM is characterised by relatively small, regional markets, with a limited number of generators in each market. As a result, there is potential for the exercise of market power and for prices which are well above costs. Substantial increases in transmission investment can pay for themselves, by constraining this market power and keeping prices at low levels.

Although the issues are clear enough, the facts have been weaker. The AER is conducting the main quantitative analysis. This has identified that transmission constraints raised wholesale generation costs by about $36 million in 2003–04 and $45 million in 2004–05. Previous studies estimated that the impact on wholesale *prices* (as opposed to costs) may be up to $2.6 billion a year.[4] If true, this would present a somewhat frightening prospect for generation owners, since it would suggest that average wholesale prices—which have not been at high levels in recent years—could fall by a third if more investment was made in transmission. However, these headline figures appear substantially overstated.

## Investment in electricity networks

There has been significant investment in transmission since market start. This is best illustrated by periodic price resets:

- TransGrid's regulatory asset base in 1999 was $2 billion. Capital expenditure for 1999–2004 exceeded $1.2 billion. For 2005–09 TransGrid anticipates capital expenditure of $1.2–1.9 billion.
- Powerlink's regulatory asset base in 2002 was $2.27 billion. Capital expenditure for 2002–06 was around $1.3 billion. For 2007–10 Powerlink anticipates expenditure of around $2.5 billion.
- Transend's regulatory asset base in 2003 was $604 million. Capital expenditure was $341 million for 2003–07.
- Electranet and SP AusNet have rather lower expenditure levels.

Care needs to be taken in interpreting these numbers: figures for the regulated asset base (RAB) and for capital expenditure are calculated differently, and the TNSPs vary a good deal in the networks they have inherited and in the demand growth that they face. However, they do illustrate that there has been significant investment in transmission networks.

In addition to private and public investments in regulated transmission, there have been private investments in unregulated transmission. These are Murraylink, a 180-kilometre DC link between New South Wales and South Australia; Directlink, a 59-kilometre DC link between Queensland and New South Wales; and Basslink, a 290-kilometre sub-sea cable and associated investments linking Tasmania to the grid.

4 Port Jackson Partners Ltd, *Reforming and restoring Australia's infrastructure*, Report prepared for the Business Council of Australia, March 2005, p. 20.

## Investment in the gas sector

The nature of the eastern Australian gas sector and its level of interconnectivity has changed markedly in recent years. Historically, the major markets within south-eastern Australia have been supplied by a single gas production source through a single gas transmission pipeline. New South Wales and South Australia were supplied from Moomba. Victoria and Queensland had their own isolated supply systems and Tasmania had no supply. Up until the late 1990s there were no pipelines interconnecting supply basins.

Figure A.6
Eastern Australian gas transmission network


| Pipeline | No. |
|---|---|
| Longford–Melbourne | 1 |
| South-West Pipeline | 2 |
| Victorian Transmission System | 3 |
| Moomba to Sydney | 4 |
| Eastern Pipeline | 5 |
| Moomba to Adelaide | 6 |
| SEA Gas | 7 |
| Roma to Brisbane | 8 |
| Roma to Gladstone | 9 |
| Ballera to Roma | 10 |
| Ballera to Mt Isa | 11 |
| Longford to Bell Bay | 12 |

Figure A.7

**Average wholesale prices by region**

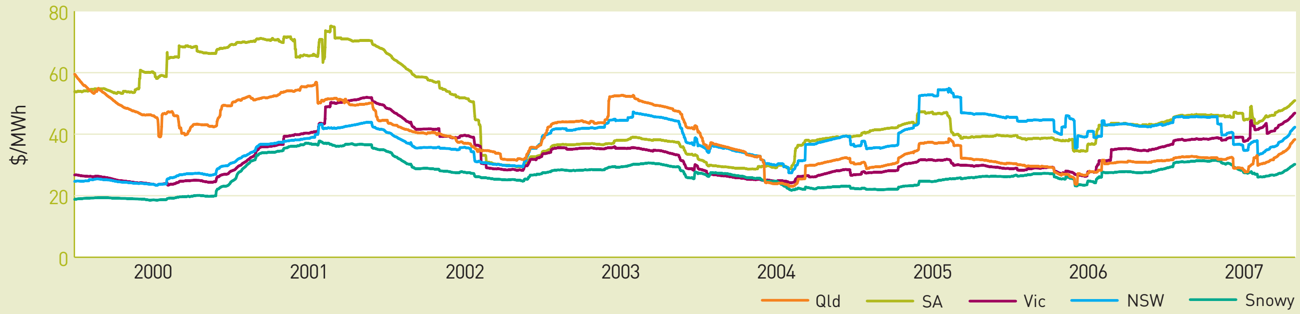
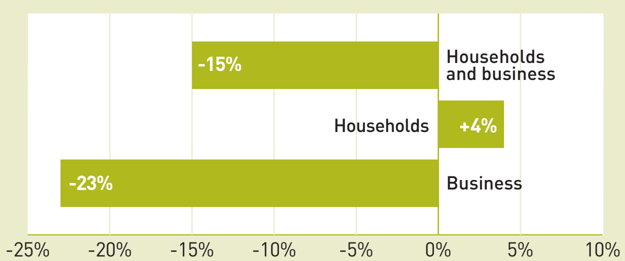



Figure A.8

**Changes in the real price of electricity: 1990–91 to 2005–06**




National transmission capacity has increased rapidly from 9000 kilometres in 1989 to over 17 000 kilometres in 2001 and 21 000 kilometres currently. The interconnection between supply basins has radically changed since 1998. The Culcairn interconnect links Victoria and New South Wales; the Eastern Gas Pipeline Longford to Sydney; the SEA Gas Pipeline Port Campbell to Adelaide; and the South West Pipeline Port Campbell to the main Victorian transmission system. Tasmania is supplied through the Tasmanian gas pipeline.

The gas transmission pipeline system is now much more of a meshed network, with at least two pipelines supplying major loads at Sydney, Melbourne and Adelaide. Users have greater choice of supplier and producers have greater diversity of end market. This is shown in figure A.6.

There are also developments in the upstream sector. These include coal seam gas producers in Queensland and New South Wales and new fields in the Otway Basin.

It is anticipated that this new entry into upstream gas supply will lead to a slow decline in the dominance of the major producers. The Australian Bureau of Agricultural and Resource Economics most recent projections showed the three largest market participants (BHP Billiton, ExxonMobil and Santos) accounting for 95 per cent of contracted supply to eastern Australia. This is projected to decline to 87 per cent by 2010.

## Prices

In the early years of the wholesale electricity market, prices diverged sharply between regions. South Australia had high prices in 1998–99, which gradually fell as new investment came on line. Queensland also experienced high wholesale prices in early years. More recently, prices have converged between the NEM regions. This is shown in figure A.7. Wholesale pool prices can be expected to fluctuate around the entry price. Prices have been below entry level, but tightened significantly in 2007 because of drought effects and emerging requirements for new investment.

The development of the NEM has led to:

- lower electricity prices overall
- more cost reflective prices, so that prices have risen for households and fallen for business
- greater convergence of prices across the market.

Figure A.8 shows trends in the real price of electricity between 1990–91 and 2005–06, for Australia as a whole. Overall, real prices fell by 15 per cent. Households have experienced an average 4 per cent real increase, while businesses have had an average 23 per cent real reduction in price.

James Davies (Fairfax Images)

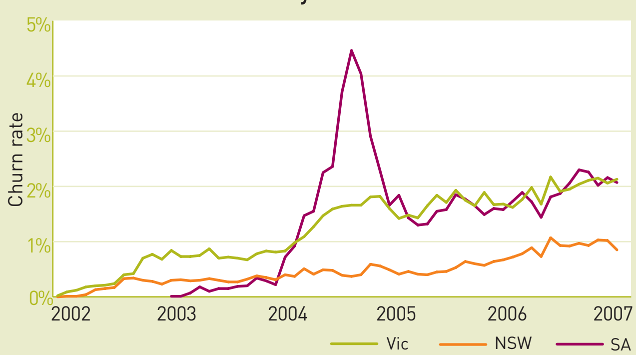
Construction of the SEA Gas Pipeline from Port Campbell to Adelaide, 2003

## Retail competition

Full retail competition was introduced in Victoria and New South Wales from 1 January 2002, and a year later in South Australia. Figure A.9 shows monthly churn rates in all three jurisdictions since then. However, care should be taken in using these figures. The South Australian data includes moves to a market contract with the host retailer. Victoria and New South Wales data excludes this, and only covers movement from a host retailer to a new retailer.

Churn rates in South Australia hit a peak in the winter of 2004. This was probably due to the government's $50 transfer rebate at that time. While monthly churn rates have since reduced, the level of competition in both South Australia and Victoria is high by world standards.

Figure A.9
Churn levels in Victoria, New South Wales and South Australia—electricity




## Conclusions

The establishment of the national electricity market was an ambitious vision in the early 1990s. On balance, the benefits forecast have been delivered, but not without much perseverance and hard work.

The market still faces challenges. Timely investment in new generation will be needed. The interaction between government-owned and private businesses is a continuing source of tension. The appropriate framework for ensuring optimal national transmission investment, when planning is conducted primarily at state level, has continued to receive review and attention. The new regulatory regime will require bedding down—and no doubt many other issues will arise.

However, it is less than 10 years since the first trial of an interstate market and eight years since the start of the NEM. A lot has been achieved, but there is still much to do.

# ESSAY B

Robert Rough (Fairfax Images)

# RELIABILITY IN THE NATIONAL ELECTRICITY MARKET

ESSAY B

# RELIABILITY IN THE NATIONAL ELECTRICITY MARKET

Reliability refers to the continuity of electricity supply to end-users and is a key performance indicator for customer service. As electricity cannot easily be stored, a reliable supply requires the generation and network sectors to produce and transport the needs of households and business users in real time.

From time to time the electricity supply can be interrupted by outages in generation or in the networks that deliver power to customers. To maintain a reliable power system, it is important to pinpoint the causes of interruptions. In particular, clear signals are needed to ensure that generators and network operators address any weak spots in the power system through investment, maintenance or other solutions.

This essay looks at:

- the causes and effects of reliability issues
- reliability standards
- the measurement of reliability
- the reliability of electricity supply in the National Electricity Market (NEM), from generation through to the transmission and distribution networks that deliver power to customers.

There is a common perception that a lack of generation capacity or overloaded transmission systems cause most power system outages. As this essay will show, the Australian data indicates there is no chronic shortage of generation or transmission capability. Rather, when 'the lights go out' for electricity customers, it is generally caused by an issue in the local distribution network.

## B.1 What causes unreliability?

Various factors—planned and unplanned—can interrupt the power supply. These may occur in generation or in the networks that deliver power to customers.

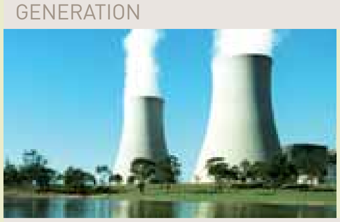
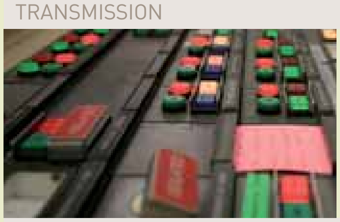
- A planned outage may occur for maintenance or construction works. Such interruptions can be timed for minimal impact.
- Unplanned outages occur when equipment failure causes the supply of electricity to be disconnected unexpectedly. For example, trees, birds, possums, vehicle impacts and vandalism can cause outages in distribution networks. Networks can also be vulnerable to extreme weather, such as bushfires or storms. There may be ongoing reliability issues in any part of the power system that is inadequately maintained or is used near the limits of its capacity.

Table B.1 lists examples of outages stemming from each sector of the electricity chain. In addition, some electricity users might experience outages due to their own faulty equipment or wiring, or due to their failure to pay an electricity bill. Such outages do not relate to the reliability of power supply delivery and are not considered in this essay.

Whether a power supply interruption arises in generation, transmission or distribution, the underlying cause can usually be traced to one or a combination of:

- the quality and capacity of infrastructure—for example, there is a higher risk of outages if generators or networks are aging or are being used near their capacity limits
- inadequate maintenance, monitoring and/or operating procedures—for example, poor vegetation management around power lines or inadequate generator maintenance will increase the risk of outages
- extreme events that are not provided for in contingency planning—for example, a severe storm may cause power line damage.

**Table B.1 Examples of power outages**

| SOURCE OF OUTAGE | EXAMPLES |
|---|---|
| GENERATION | |
|  | In December 2004 the power system operator requested that 200 MW of load be shed in New South Wales after a generator tripped (shut down) during a low reserve period. |
| TRANSMISSION | |
|  | On 20 March 2006 gale force winds associated with Cyclone Larry caused severe damage to the transmission network and the loss of 132 kV supply to Innisfail, Kamerunga, Tully, Cardwell, Kareeya and Barron Gorge bulk supply substations. |
| DISTRIBUTION | |
|  | A bird eating grubs on high voltage equipment in rural Victoria shorts an insulator, causing a fuse on a transformer to blow. This led to an outage for the 100 customers connected to the transformer.<br>Storms in Queensland in January 2004 caused significant outages in local distribution networks. This led to the Queensland Government commissioning a report into the state of the networks. |

An assessment of the underlying causes of power system outages can help to determine whether the appropriate response requires capital investment, improved maintenance or better monitoring and operating procedures.

## B.2 Effects of reliability issues

The effect of a power system outage varies, depending on the sector affected. A major generation or transmission failure could potentially shift generation and consumption out of balance and cause the power system to collapse—affecting hundreds of thousands of customers. The power system operator, the National Electricity Market Management Company (NEMMCO), can manage this in several ways. Some quick start peaking generators can be switched on to supply electricity to the market within half an hour. In the interim, NEMMCO can manage the effect of lost supply and out of balance events through controlled load shedding (disconnections). Jurisdictional security coordinators determine the order in which customers are load shed.[1]

While NEMMCO can manage the effects of a generation or transmission outage, a distribution outage usually has a localised impact. For instance, an outage caused by a collision with a suburban power line will result in nearby residents losing supply. Affected customers may not be reconnected until the physical damage to the network is repaired.

## B.3 Reliability standards—how reliable is reliable?

Governments and regulators set standards for acceptable reliability. There are trade-offs between reliability and cost in each sector of the power system, making it inefficient to try to eliminate every possible source of interruption. Rather, an efficient outcome reflects the level of service that customers are willing to pay for. There has been some research on the willingness of electricity customers to pay higher prices for a reliable electricity supply. A 1999 Victorian study found that more than 50 per cent of customers were willing to pay a higher price to improve or maintain their level of supply reliability.[2] However, a 2003 South Australian survey indicated that customers were willing to pay for improvements in service only to poorly serviced customer areas.[3]

In practice, the trade-offs between improved reliability and cost mean that reliability standards tend to be high for generation and transmission because an outage can have a widespread geographical effect and potentially high socio-economic costs. In comparison, standards tend to be less stringent for distribution networks, where the impact of an outage may be localised. At the same time, the capital intensive nature of distribution networks[4] makes it expensive to build in high levels of redundancy (spare capacity) to improve reliability.

1 NEMMCO manages load shedding in accord with priorities set by the jurisdictional system security coordinators, which make judgments as to which customers are least affected by the loss of supply. Rule 4.1.1(b) of the National Electricity Rules stipulates that the jurisdictional system security coordinators must submit to NEMMCO a schedule of all the sensitive loads in the jurisdiction, and the order in which loads may be shed if NEMMCO deems that load shedding is required.

2 KBA, *Understanding customers' willingness to pay: components of customer value in electricity supply*, 1999.

3 The survey found that 85 per cent of consumers were satisfied with their existing level of service and were generally unwilling to pay for improvements in these levels. It found that there was a willingness to pay for improvements in service only to poorly served consumers. On this basis, the South Australian regulator has focused on providing incentives to improve the reliability performance for the 15 per cent of worst served consumers, while maintaining average reliability levels for all other customers. See ESCOSA, *2005–10 Electricity distribution price determination, Part A*, April 2005; KPMG, *Consumer preferences for electricity service standards*, March 2003.

4 The combined regulated asset base of distribution networks in the NEM is more than double that of transmission networks.

**Table B.2 Agencies that report on power system reliability**

| AGENCY | REPORT | MARKET SECTOR | | |
|---|---|---|---|---|
| | | GENERATION | TRANSMISSION | DISTRIBUTION |
| Australian Energy Market Commission | Reliability Panel's Annual Report | ✓ | ✓[1] | |
| Australian Energy Regulator | Electricity Regulatory Report | | ✓ | |
| National Electricity Market Management Company | Statement of Opportunities | ✓ | ✓ | |
| Jurisdictional regulators | Performance reports for distribution networks businesses | | | ✓ |
| Energy Supply Association of Australia | Electricity Gas Australia | ✓ | ✓ | ✓ |

1. Bulk transmission only.

**Table B.3 Duration below minimum reserve levels (hours)**

| YEAR | NEW SOUTH WALES | VICTORIA | QUEENSLAND | SOUTH AUSTRALIA |
|---|---|---|---|---|
| 2005–06 | 0 | 0 | 0 | 1 |
| 2004–05 | 2 | 0 | 0 | 0 |
| 2003–04 | 1 | 4 | 0 | 6 |
| 2002–03 | 1 | 0 | 0 | 0 |
| 2001–02 | 0 | 0 | 0 | 0 |
| 2000–01 | 0 | 3 | 0 | 24 |
| 1999–00 | 4 | 36 | 5 | 88 |

Tasmania, which was interconnected with the NEM in 2006, had zero minutes below the minimum reserve level in 2005–06.

Source: AEMC Reliability Panel, *Annual electricity market performance review: reliability and security 2006*.

## B.4 Who measures reliability?

Various agencies report on the reliability of Australia's power system (table B.2). Most report on only one or two sectors of the electricity supply chain.

## B.5 Reliability of electricity generation

The Australian Energy Market Commission (AEMC) Reliability Panel, established under the National Electricity Law, reports annually on the reliability of the wholesale market. The panel has set a reliability standard that requires sufficient generation and bulk transmission capacity to ensure that in the long term, no more than 0.002 per cent of energy demand in any region[5] is at risk of not being supplied (or being 'unserved'). NEMMCO determines minimum reserves of generator capacity above the demand for electricity in each region of the NEM, which aim to ensure that this standard is met. The panel also aims to set a wholesale market price cap at a level that will stimulate sufficient investment in generation capacity to meet the reliability standard.

The Reliability Panel reports performance against the reliability standard and the minimum reserve levels set by NEMMCO. Table B.3 shows the number of hours of insufficient generation capacity available to meet the minimum reserve levels. The data indicates that reserve levels are rarely breached and that generator capacity across all regions of the market is generally sufficient to meet peak demand and allow for a reserve margin. The performance of generators in maintaining reserve levels has improved since the NEM began in 1998, notably in South Australia and Victoria. This reflects significant generation investment and improved transmission interconnection capacity between the regions.

5 As at May 2007, the NEM has six regions, four of which are based on state boundaries (Victoria, Queensland, South Australia and Tasmania). The other two regions are New South Wales including the Australian Capital Territory, and the Snowy, which is located in Southern New South Wales.

In practice, generation has proved highly reliable, with only two instances of insufficient capacity to meet consumer demand since the NEM began. One was in Victoria in early 2000 when a coincidence of industrial action, high demand and temporary loss of generating units resulted in load shedding. The other was in New South Wales on 1 December 2005 when a generator failed during a period of record summer demand caused by hot weather. The restoration of load began within ten minutes.

Table B.4 sets out the performance of the generation sector in selected states against the 0.002 per cent reliability standard. While all states now operate within the standard, Victoria and South Australia's long-term averages fall outside because of the events that occurred in early 2000. Both states have met the standard since that year.

**Table B.4** Unserved energy: long-term averages from December 1998 to 30 June 2006

| STATE | UNSERVED ENERGY |
|---|---|
| New South Wales | 0.0001% |
| Victoria | 0.0101% |
| Queensland | 0% |
| South Australia | 0.0025% |

Source: AEMC Reliability Panel, *Annual electricity market performance review: reliability and security 2006*.

The Reliability Panel excludes some supply interruptions from its reliability data and focuses on credible (likely) reliability events. The power system is operated so capacity can cope with credible supply interruptions. These events are foreseeable, and can be avoided through investment in generation capacity.

Some power supply interruptions are caused by events that are non-credible. Typically, they occur simultaneously or in a chain reaction. For example:

- several generating units might fail at the same time
- a transmission fault might cause the tripping of a generator.

It would not be feasible to operate the power system to cope with non-credible events (also called multiple contingency events). The events are uncommon, and the cost of power system infrastructure would be significantly greater if they were accommodated. For similar reasons, non-credible events are excluded from reliability statistics. As the events are not considered foreseeable, they do not reflect a lack of investment in generation capacity. But such events do affect the continuity of electricity supplies. A non-credible event may require NEMMCO to interrupt electricity supplies to customers to avoid a power system collapse.

Multiple contingency events in Queensland and Tasmania caused a significant amount of unserved energy in 2005–06, including outages caused by Cyclone Larry in Queensland in March 2006. The Reliability Panel noted that these events seriously affect continuity of supply, and that from a consumer perspective the effect is not clearly distinguishable from that of reported reliability events. The panel indicated it will reconsider its approach to the reporting of multiple contingency events.[6]

## Investment in generation and long-term reliability

The NEM combines a number of mechanisms to ensure high levels of reliability in the generation sector. In the short term, NEMMCO can manage shortfalls in reserves by directing peak generators. In the longer term, a reliable power supply needs sufficient investment in generation to meet the needs of customers.

### Price signals

A central element in the design of the NEM is that spot prices respond to a tightening in the supply–demand balance. Wholesale prices and projections in the supply–demand balance are also factored into forward prices in the contract market. Regions with potential generation shortages (which could lead to reliability issues) will therefore exhibit rising prices in the spot

6 AEMC Reliability Panel, *Annual electricity market performance review: reliability and security 2006*, p. 9. The panel is undertaking a comprehensive reliability review and released an interim report in March 2007.

and contract markets. High prices may eventually lead to some demand-side management response if suitable metering is available. For example, retailers might offer a customer financial incentives to reduce consumption at times of high demand to ease pressure on prices. There is some demand-side response in the NEM. In the longer term, higher prices create signals to invest in generation capacity, which helps prevent a potential future reliability problem from becoming a reality.

Price differences between regions help to attract investment to the areas where it is needed. For example, supply shortages and high demand growth forced up average wholesale prices in Queensland to around $50 to $60 a megawatt hour (MWh) in the 1990s. This led to significant investment in new generation and the commissioning of new transmission interconnectors. Similarly, high prices in South Australia in 1999 and 2000 led to significant investment in new capacity (see figure 1.10, chapter 1). This, combined with improved interconnection with Victoria, helped to ease spot prices after 2000.

Seasonal factors (for example, summer peaks in air conditioning loads) also create a need for 'top-up' generation to cope with periods of extreme demand. The NEM allows for extreme pricing during peak demand to provide incentives to invest in 'peaking' generation capacity needed to meet that demand. The market allows a price cap of $10 000 a MWh—called the value of lost load—which may be reached when demand approaches generation capability (including imports) in a particular region. While this may appear extreme compared to long-term average prices of around $30 to $40, the price cap is not often reached, and customers are shielded from the impact by retailers hedging their exposure in financial markets. The significance of extreme prices is the incentive they provide to hedge against the associated risks. For example, the risk of high prices encourages investment in peaking generation plants and contracting with customers to provide a demand-side response.

The price cap is necessarily high to encourage investment in peaking plant, which is expensive to run. Peaking plant is only profitable when high demand or tight supply drives prices well above average. It may only be profitable for some generators to run for a few hours a year. This means that peaking generators have few opportunities to recoup fixed costs. But unlike base load plants, they can come online quickly, and are therefore responsive to price movements. Over the longer term, peaking plants play a critical role in ensuring there is adequate generation capacity (and therefore reliability) in the NEM. Victoria and South Australia have invested in significant peaking generation capacity (see figure 1.5, chapter 1).

### Forecasts and planning

NEMMCO publishes short, medium and long-term forecasts of electricity supply and demand (table B.5). The forecasts can enhance reliability by highlighting opportunities for generation investment to fill gaps in the supply–demand balance before a shortfall occurs.

Long-term forecasts provide regional investment signals to fill future supply gaps, helping to avert future stresses on the power system. Medium and short-term forecasts highlight imminent gaps in the supply–demand balance, which can help electricity businesses to plan maintenance outages. NEMMCO also uses a reliability safety net that allows it to take action to address potential reserve shortfalls. For example, a forecast supply gap in the near future might be averted by:

- postponing scheduled generation or network maintenance until peak demand eases
- NEMMCO contracting for reserve capacity (which occurred for Victoria and South Australia in February 2005 and February 2006).


Mark Wilson

Transmission Lines

**Table B.5 NEMMCO planning instruments**

| PLANNING INSTRUMENT | DESCRIPTION |
|---|---|
| Statement of opportunities | Ten year outlook on demand and new generation capacity. Provides information to potential NEM participants to assist investment decisions. |
| Medium-term projected assessment of system adequacy | Aggregate supply and demand balance at the anticipated daily peak demand, based on a 10 per cent probability of exceedence for each day of the next two years. |
| Short-term projected assessment of system adequacy | Aggregate supply and demand balance comparison for each half hour of the coming week. |
| Pre-dispatch | Aggregate supply and demand balance comparison for each half hour of the next trading day (up to 40 hours). |
| Annual national transmission statement | Integrated overview of the current and projected state of national transmission flow paths, with forecasts of constraints and options to relieve them. |

Source: NEMMCO

## B.6 Transmission reliability

Many factors can potentially interrupt the flow of electricity on a transmission network. Interruptions may be planned (for example, scheduled maintenance of equipment) or unplanned (for example, equipment failure caused by bushfires, lightning strikes or hot weather raising air conditioning loads above the capability of a network). A serious network failure might require the power system operator to load-shed some customers.

While there are differences in the reliability standards applied in each jurisdiction, all transmission networks are designed to deliver high rates of reliability. They are engineered with sufficient capacity to act as a buffer against planned and unplanned interruptions in the power system. More generally the networks enhance the reliability of the power supply as a whole by allowing a diversity of generators to supply electricity to end markets. In effect, the networks provide a mix of capacity that can be drawn on to help manage the risk of a power system failure.

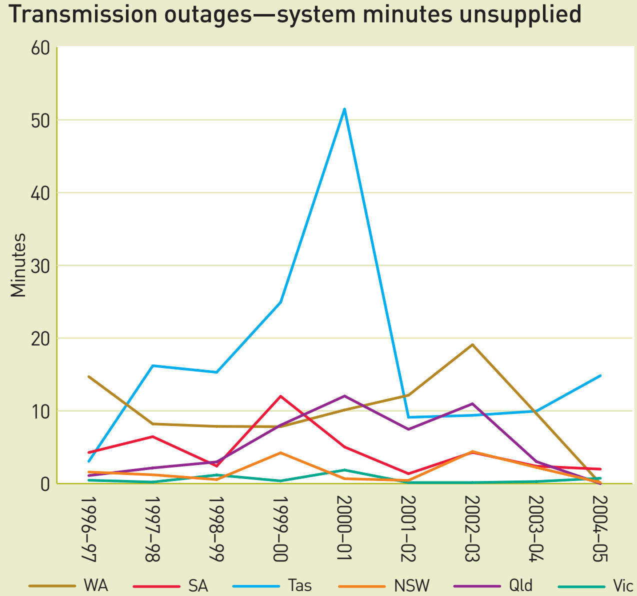
The Energy Supply Association of Australia (ESAA) and the Australian Energy Regulator (AER) report on the reliability of Australia's transmission networks.

### Energy Supply Association of Australia data

The ESAA publishes survey data from transmission network businesses on network reliability, based on system minutes of unsupplied energy to customers (figure B.1). The data is normalised in relation to maximum regional demand to allow comparability.

The data indicates that NEM jurisdictions have generally achieved high rates of transmission reliability. In 2003–04, there were fewer than 10 minutes of unsupplied energy in each jurisdiction due to transmission faults and outages, with New South Wales, Victoria and South Australia each losing less than three minutes. The networks again delivered high rates of reliability in 2004–05. Much of the volatility in Tasmania's data can be traced to a single incident in 2001. This suggests that the reliability of Australia's transmission networks is generally so high that a single incident can significantly alter measured performance.

**Figure B.1**
**Transmission outages—system minutes unsupplied**




Note: System minutes unsupplied is calculated as megawatt hours of unsupplied energy divided by maximum regional demand. ESAA data not available for Queensland and Western Australia in 2004–05.

Source: ESAA, *Electricity gas Australia 2006* and previous years.

## Australian Energy Regulator data

While Australian transmission networks are generally very reliable, the AER applies service incentive schemes to maintain or further enhance their performance. The schemes provide financial bonuses and penalties to network businesses that meet (or fail to meet) performance targets, including for reliability. A business can receive +/–1 per cent of its regulated revenue for over or under performance against a target. The AER sets separate standards for each network that take account of specific circumstances, rather than applying a common benchmark. The targets are based on the network's past performance. For this reason, the raw data collected by the AER does not easily lend itself to comparisons between firms.

The AER standardises the results for each transmission network service provider (TNSP) to derive an 's-factor' indicator that ranges from –1 to +1. This standardised measure determines financial penalties and bonuses. An s-factor of –1 represents the maximum penalty, while +1 represents the maximum bonus. Zero represents a revenue neutral outcome. Table B.6 sets out the s-factors for each network since the scheme began in 2003. While caution must be taken in drawing conclusions from three years of data, it is interesting to note that the major networks in eastern and southern Australia have consistently outperformed their targets.

**Table B.6** AER s-factor values 2003–05

| TNSP | 2003 | 2004 | 2005 |
|---|---|---|---|
| ElectraNet (SA) | 0.74 | 0.63 | 0.71 |
| SP AusNet (Vic) | (0.03) | 0.22 | 0.09 |
| Murraylink (interconnector) | na | (0.80) | 0.15 |
| Transend (Tas) | na | 0.55 | 0.19 |
| TransGrid (NSW) | na | 0.93 | 0.70 |
| Energy Australia (NSW) | na | 1.00 | 1.00 |

na not applicable.

Note: An incentive scheme for Powerlink (Queensland) begins in 2007.

Sources: AER, Annual regulatory reports from 2003–04 to 2005–06, and AER letters to respective network businesses.

There has nonetheless been industry concern that congestion in some transmission lines (often cross-border interconnectors) periodically blocks electricity flows in parts of the NEM, leading to higher cost electricity generation. New work by the AER with help from NEMMCO is developing measures of how transmission network congestion can affect electricity costs. The preliminary outcomes suggest that there is some significant congestion and that the impact has risen since 2003–04. Total costs nonetheless appear to be relatively modest given the scale of the market. Section 4.7 of this report provides a more detailed discussion of AER work in this area.

## Transmission investment and long-term reliability

Several regulatory and planning instruments help to ensure there is appropriate investment in transmission infrastructure to avoid potential reliability issues. The instruments include:

- capital expenditure allowances for network businesses, administered by the AER
- service standard incentive schemes administered by the AER
- planning obligations applied by state governments
- the annual national transmission statement (ANTS), published by NEMMCO.

In regulating transmission networks, the AER uses a mix of capital expenditure allowances and incentive schemes to ensure that investment is both efficient and sufficient for reliability needs. Every five years the AER sets a revenue cap for each network that provides an allowance for investment. A network business can spend this allowance on the projects it deems appropriate without the risk of any future review by the regulator.

To encourage efficient network spending, the AER uses incentive schemes that permit network businesses to retain the returns on any underspending against their investment allowance. This helps avoid 'gold plating' the networks with unnecessary spending, for which customers must ultimately pay. If used in isolation, however, the schemes might also encourage businesses to delay expenditure that would improve reliability.

Recognising this, the AER uses service quality incentive schemes alongside the capital expenditure schemes. As noted, the service quality schemes reward network businesses for maintaining or improving service quality and penalise any deterioration in performance. In combination, the capital expenditure allowances and the twin incentive schemes encourage efficient investment in transmission infrastructure to help avoid potential reliability issues.

Investment decisions are also guided by planning requirements set by state governments in conjunction with standards set by NEMMCO. There is considerable variation in the approaches of state governments to planning. The responsible body ranges from the network business itself (in New South Wales and Queensland), to a not-for-profit entity (in Victoria), a statutory authority (in South Australia) and the jurisdictional regulator (in Tasmania).[7] Reliability standards applied by each jurisdiction also differ.

To address concerns that jurisdiction-by-jurisdiction planning might not adequately reflect a national perspective, NEMMCO began to publish in 2004 the ANTS to provide a wider focus. It aims, at a high level, to identify future transmission requirements to meet reliability needs.

Acting on the recommendations of the Energy Reform Implementation Group, the Council of Australian Governments agreed in 2007 to establish a National Energy Market Operator (NEMO) by June 2009. As well as becoming the operator of the electricity and gas wholesale markets, NEMO will be responsible for national transmission planning. As one of its functions it will release an annual national transmission network development plan, to replace the current ANTS process.

## B.7 Distribution reliability

As in transmission, electricity distribution networks can be affected by planned and unplanned interruptions. The impacts of planned outages can be managed more easily than unplanned outages. Some unplanned outages can be traced to inadequate maintenance or capacity issues.

Jurisdictions track the reliability of distribution networks against performance standards. The standards are set out in monitoring and reporting frameworks, service standard incentive schemes and guaranteed service level payment schemes. All NEM jurisdictions monitor reliability outcomes and provide guaranteed service level payments to customers who receive unsatisfactory service. Victoria, South Australia and Tasmania currently apply a service standards incentive scheme.

In effect, service standards weigh the costs of improved reliability (through investment, maintenance and other solutions) against the benefits, taking account of specific network characteristics. As noted in section B.3, the trade-offs between improved reliability and cost tend to result in reliability standards for distribution being less stringent than for generation and transmission. For similar reasons, standards tend to be higher for a central business district (CBD) network with a large customer base and a concentrated customer and load density than for a highly dispersed rural network with a small customer base and small load density—the costs of redundancy in the rural network would be high in relation to the loads likely to be affected by an outage.

### Utility Regulators Forum framework

All jurisdictions have their own monitoring and reporting framework on reliability. In addition, the Utility Regulators Forum (URF) developed a national framework in 2002 for electricity distribution businesses to report against national criteria.[8] The URF proposed four reliability indicators that are widely used in Australia and overseas. The indicators relate to the average frequency and duration of network interruptions or outages (table B.7).

7 In South Australia and Tasmania, the network businesses have ultimate responsibility for investment.

8 Utility Regulators Forum, *National regulatory reporting for electricity distribution and retailing businesses*, Discussion paper, 2002.


Mark Wilson

Pole top transformer

**Table B.7 Reliability measures—distribution**

| INDEX | | MEASURE/DESCRIPTION |
|---|---|---|
| SAIDI | System average interruption duration index | Average total number of minutes that a distribution network customer is without electricity in a year (excludes interruptions of one minute or less) |
| SAIFI | System average interruption frequency index | Average number of times a customer's supply is interrupted per year |
| CAIDI | Customer average interruption duration index | Average duration of each interruption (minutes) |
| MAIFI | Momentary average interruption frequency index | Average number of momentary interruptions (of one minute or less) per customer per year |

Source: Utility Regulators Forum, *National regulatory reporting for electricity distribution and retailing businesses*, 2002.

Distribution businesses report annually to the jurisdictional regulators on the performance of their networks against these indicators. The regulators and the regulated businesses publish the SAIDI, SAIFI and CAIDI data, typically down to feeder level (CBD, urban and rural) for each network.

Tables B.8 and B.9 set out summary data for the SAIDI and SAIFI indicators for NEM jurisdictions. PB Associates developed the data for the AER from the reports of jurisdictional regulators and from reports prepared by distribution businesses for the regulators.

There are several issues with the published data that limit the validity of any performance comparisons. In particular, the accuracy of the network businesses' information systems may differ. There are also geographical, environmental and other differences between the states and between networks within particular states. Technical differences, such as the age of the networks, can also affect reliability outcomes—but might also raise issues about the adequacy of investment and maintenance.

There are also differences in regulatory approach between the jurisdictions, for example, the treatment of exclusions. The URF agreed that in some circumstances, reliability data should be normalised to exclude interruptions that are beyond the control of a distribution business. The URF excludes outages that:

- exceed a threshold SAIDI impact of three minutes
- are caused by exceptional natural or third party events
- the distribution business cannot reasonably be expected to mitigate the effect through prudent asset management.

In practice, jurisdictions differ in the approval and reporting of exclusions. More generally, there is no consistent approach to auditing performance outcomes.

Noting these caveats, the SAIDI data indicates that since 2000–01, the average duration of outages per customer tended to be lower in Victoria and South Australia than other jurisdictions—despite some community concerns that privatisation might adversely affect service quality (table B.8). While New South Wales tended to record higher SAIDI outcomes, it has recorded a decline in average outage time over each of the past three years. The average duration of outages in Queensland tended to be higher than in other jurisdictions. It should be noted that Queensland is subject to significant variations in performance, in part due to its large and widely dispersed rural networks, and its exposure to extreme weather events. These characteristics make it more vulnerable to outages than some other jurisdictions.

The NEM-wide SAIDI averages rely on the jurisdictional data and are therefore subject to the caveats outlined above. In addition, the NEM averages include several assumptions to allow comparability over time (see notes to tables B.8 and B.9). Noting these cautions, the data indicates that distribution networks in the NEM have delivered reasonably stable reliability outcomes over the past few years. NEM-wide SAIDI remained in a range of about 200–270 minutes between 2000–01 and 2005–06. This estimate excludes the effect of a Queensland cyclone in 2006.

**Table B.8 System average interruption duration index—SAIDI (minutes)**

| | OUTAGE DURATION | | | | | | |
|---|---|---|---|---|---|---|---|
| STATE | 1999–00 | 2000–01 | 2001–02 | 2002–03 | 2003–04 | 2004–05 | 2005–06 |
| Vic | 156 | 183 | 152 | 151 | 161 | 132 | 165 |
| NSW and the ACT | | 175 | 324 | 193 | 279 | 218 | 191 |
| Qld | | 331 | 275 | 332 | 434 | 283 | 315 |
| SA | | 164 | 147 | 184 | 164 | 169 | 199 |
| NEM weighted average | 156 | 211 | 246 | 211 | 268 | 202 | 211 |

**Table B.9 System average interruption frequency index—SAIFI**

| | OUTAGE FREQUENCY INDEX | | | | | | |
|---|---|---|---|---|---|---|---|
| STATE | 1999–00 | 2000–01 | 2001–02 | 2002–03 | 2003–04 | 2004–05 | 2005–06 |
| Vic | 2.1 | 2.1 | 2.0 | 2.0 | 2.2 | 1.9 | 1.8 |
| NSW and the ACT | 1.7 | 2.5 | 2.6 | 1.4 | 1.6 | 1.6 | 1.8 |
| Qld | | 3.0 | 2.8 | 3.3 | 3.4 | 2.7 | 2.7 |
| SA | | 1.7 | 1.6 | 1.8 | 1.7 | 1.7 | 1.9 |
| NEM weighted average | 1.6 | 2.4 | 2.4 | 2.1 | 2.2 | 1.9 | 2.0 |

Notes: PB Associates developed the data for the AER from the reports of jurisdictional regulators and from reports prepared by distribution businesses for the regulators. Queensland data for 2005–06 is normalised to exclude the effect of a severe cyclone. Victorian data is for the calendar year ending in that period (for example, Victorian 2005–06 data is for calendar year 2005). NEM averages exclude New South Wales and Queensland (2000–01 only) and Tasmania (all years).

Sources: PB Associates (unpublished) and performance reports published by ESC (Vic), IPART (NSW), QCA (Qld), ESCOSA (SA), OTTER (Tas), ICRC (ACT), EnergyAustralia, Integral Energy and Country Energy.

There appears to have been an overall improvement in the average frequency of outages (SAIFI) across the NEM since 2000 (table B.9). On average distribution customers in the NEM experience outages around twice a year, but two to three times a year in Queensland.

Given the diversity of network characteristics, it is often more meaningful to compare network reliability on a feeder category basis (CBD, urban and rural) than a statewide basis. Section 5.6 of this report sets out SAIDI outcomes by feeder for distribution networks in the NEM. While care needs to be taken in making performance comparisons, the data indicates that CBD and urban feeders tend to be more reliable than rural feeders.

## B.8 Whole of power system reliability

It is difficult to form an holistic assessment of reliability across the electricity supply chain as each sector uses different reliability indicators. One basis for comparison is the reliability data submitted by distribution businesses to jurisdictional regulators. This data distinguishes supply interruptions that can be traced to generation and transmission from interruptions that originate in the distribution networks.[9] It is therefore possible to estimate the contribution of each sector to reliability outcomes. The estimates should be taken only as broad indicators, given the measurement issues noted in section B.7.

Figure B.2 sets out whole of power system reliability data for 2005–06 at a national level. The charts distinguish between 'normalised' and 'excluded' distribution outages. Across all feeders, over 90 per cent of the duration of electricity outages originated in the distribution networks. This trend is most pronounced in the CBD, where distribution accounts for virtually all outages. About 40 per cent of distribution outage time is excluded from the normalised data. Less then 5 per cent of the total duration of outages was traceable to generation and transmission interruptions. While there is some variation across the feeders, it is clear that distribution networks were the principal source of power system outages.

9 The data does not disaggregate generation and transmission outages. It aggregates all outages that originate in those sectors, including those caused by non-credible events.

Figure B.2
SAIDI: NEM averages, 2005–06


Note: Data for 2005–06 financial year, except for Victoria—2005 calendar year and Tasmania and the Australian Capital Territory—2004–05 financial year.

Sources: Distribution network performance reports published by ESC (Vic), IPART (NSW), QCA (Qld), ESCOSA (SA), OTTER (Tas), ICRC (ACT), EnergyAustralia, Integral Energy and Country Energy.

While the data suggests that distribution networks are the main source of reliability issues, it does not necessarily follow that the networks have underperformed. An assessment of performance adequacy would need to compare outcomes with performance standards.

As noted, reliability standards in generation and transmission tend to be more conservative than in distribution, and require higher levels of built-in redundancy to cope with emergencies. While a generation or transmission outage could affect hundreds of thousands of downstream customers, a distribution outage usually has more confined effects. Distribution networks are designed to a cost and a standard that reflect these considerations and normally allow for some level of interruptions.

Two other considerations should be noted.

> Distribution networks are often longer than transmission networks. For example, South Australia's distribution network is around 14 times longer than the transmission network.[10] The discrepancy between reliability in transmission and distribution would often be reduced on a per kilometre assessment. The size of distribution networks relative to transmission networks also has implications for the relative cost of improving their reliability.

> While NEMMCO can often act to minimise the effect of generation and transmission incidents, the localised nature of distribution outages can make their effects difficult to manage.

The appropriate level of capital investment and operating expenditure to achieve a reliable electricity supply depends on the quality of service that consumers are willing to pay for. When distribution networks are meeting performance targets that reflect community choices, their reliability would be considered satisfactory. As noted, there remain some differences between the jurisdictions in the measurement of distribution reliability. A more consistent approach to auditing and the treatment of exclusions would likely help the community to better assess reliability performance.

From time to time, performance does not meet community standards. The case study in box B.1 considers an investigation into the performance of Queensland's distribution networks in 2004. It highlights the range of factors that can affect reliability, some of which are difficult to manage. It also illustrates how indicators such as SAIDI can gauge the adequacy of reliability performance. Finally, it provides examples of the type of action that can be taken to improve performance.

10 ElectraNet is around 5600 km, while the ETSA distribution network is around 80 000 km.

### Box B.1 Case study—Queensland's Somerville report

The Queensland Government established an independent panel to investigate the performance of the state's distribution networks after a series of storms and hot weather caused significant outages in 2004. It granted the panel wide terms of reference covering assessments of reliability and levels of capital and operating expenditure. The panel's report (the Somerville report)[11] noted the timeliness of the review, given that many network components were approaching replacement age (40–50 years).

The panel compared the reliability of Queensland distributors Ergon Energy and ENERGEX against Victorian and New South Wales distributors. It found that Ergon Energy had the most and longest outages of these distributors. ENERGEX performed relatively well for the Brisbane CBD against the SAIDI and SAIFI performance measures. However, its performance for urban and rural short feeders was below the peer group average.

The panel considered several possible reasons for poor network reliability. It noted that Queensland is prone to extreme weather and that its networks have larger coverage areas and a more dispersed customer base than networks in New South Wales and Victoria. While the panel recognised that these characteristics would place Queensland networks at the upper end of SAIDI performance, it considered their performance to be unacceptably poor.

In particular, the panel considered that investment, maintenance (for example, vegetation management) and operating systems were inadequate. It considered that a lack of regulated service standards in combination with perverse regulatory incentives contributed to poor performance. In particular, these factors allowed distributors to benefit by delaying or avoiding expenditure that would improve reliability.

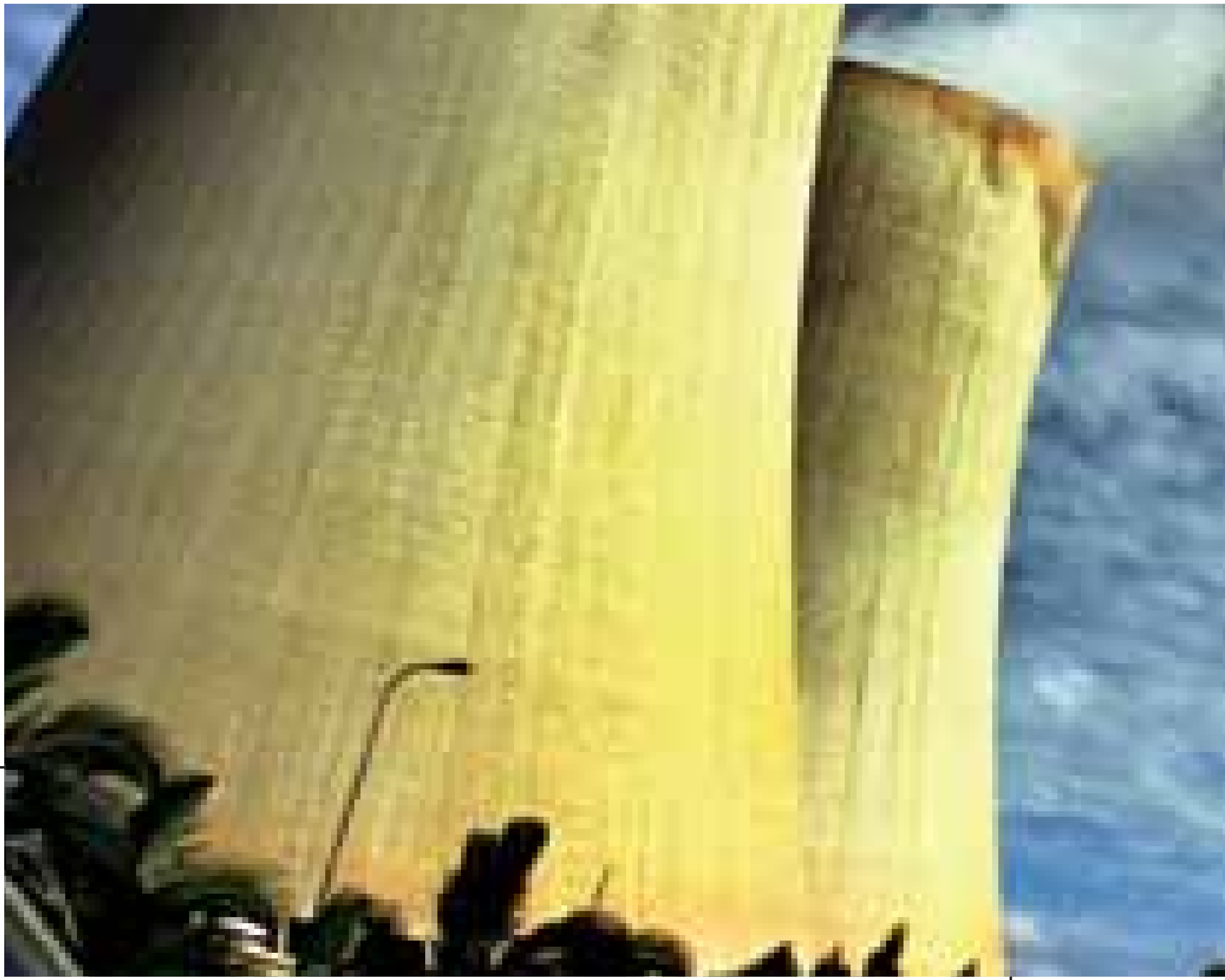
The panel reviewed the adequacy of investment to cater for current and future demand. It considered that it would be inefficient to build out all outages by 'gold plating' the networks, and recognised a trade off between service quality and expenditure. It noted that having a network with spare capacity at peak times is costly, and that Queensland has summer peaks of extended length. Nonetheless the distributors had undertaken insufficient expenditure to maintain the networks to satisfy customer demand.

The report found differences between the issues facing each network. The capacity of the ENERGEX network was constrained by management decisions to reduce spare capacity and increase system utilisation to improve financial results. This led to ENERGEX utilising the network at around 76 per cent in 2002, compared with the Australian average of around 56 per cent. ENERGEX has since undertaken to return network utilisation to 60–65 per cent.

Ergon Energy inherited six networks of 'varying quality' after the industry was restructured. The panel considered that Ergon Energy had been slow to take remedial action in some of the poorly maintained parts of the networks, and that a significant percentage of its substations were operating under capacity or voltage constraints.

The Queensland government launched an action plan in response to the review in August 2004. In 2005, the government introduced a new electricity code, setting guaranteed levels of service and performance requirements for ENERGEX and Ergon Energy. The standards are based on achieving an overall improvement in electricity reliability of about 25 per cent over the five years to June 2010.

11 Independent Panel (Chair: Darryl Somerville), *Electricity distribution and service delivery for the 21st century*, Summary report, Queensland, 2004.



# PART TWO
# ELECTRICITY


Robert Rough (Fairfax Images)

Electricity is a form of energy that is transported along a conductor such as metal wire. While it cannot be stored economically, it is readily converted to other forms of energy, such as heat and light, and can be used to power electrical machines. These characteristics make it a convenient and versatile source of energy that has become essential to modern life.

# ELECTRICITY

The supply of electricity begins with generation in power stations. Electricity generators are usually located near fuel sources, such as coalmines, natural gas pipelines and hydro-electric water reservoirs. Most electricity customers, however, are located a long distance from these generators in cities, towns and regional communities. The supply chain therefore requires networks to transport power from generators to customers. There are two types of network:

- high-voltage transmission lines transport electricity from generators to distribution networks in metropolitan and regional areas
- low-voltage distribution networks transport electricity from points along the transmission lines to customers in cities, towns and regional communities.

The supply chain is completed by retailers, which buy wholesale electricity and package it with transmission and distribution services for sale to residential, commercial and industrial customers.

Part Two of this report provides a chapter-by-chapter survey of each link in the supply chain. Chapter 1 considers electricity generation in the National Electricity Market (NEM), the wholesale market in which most electricity is traded in eastern and southern Australia. Chapter 2 considers activity in the wholesale market, while chapter 3 surveys the electricity derivatives markets that complement the wholesale market.

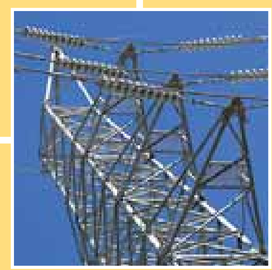
Chapters 4 and 5 provide data on the electricity transmission and distribution sectors, while chapter 6 considers retail. A survey of electricity markets in the non-NEM jurisdictions of Western Australia and the Northern Territory is provided in chapter 7.

## Electricity supply chain

**GENERATION**

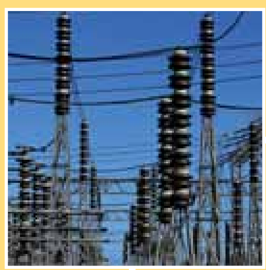
Electricity is generated at a power plant

Transformer converts low voltage electricity to high voltage electricity for transport



**TRANSMISSION**

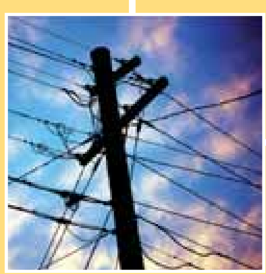
Transmission lines carry high voltage electricity long distances



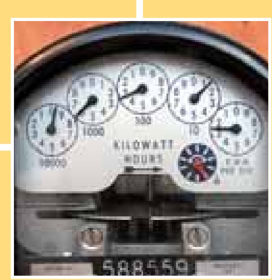
Substation transformers convert high voltage electricity to low voltage for distribution

**DISTRIBUTION**

Distribution lines carry low voltage electricity to customers

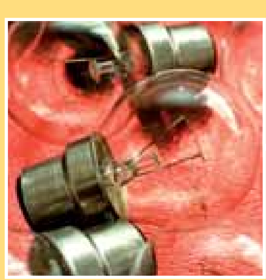


Transformers convert electricity to safe, usable levels




**RETAIL**

Retailers meter electricity usage



**CONSUMPTION**

Customers use electricity for lighting, heating and to power appliances

# 1 ELECTRICITY GENERATION

SPPL Power Station. Rob Homer (Fairfax Images)

The supply of electricity begins with generation in power stations. This chapter provides a survey of electricity generation in the National Electricity Market, a wholesale market in which generators and retailers trade electricity in eastern and southern Australia. There are six participating jurisdictions, physically linked by a transmission network—Queensland, New South Wales, the Australian Capital Territory, Victoria, South Australia and Tasmania.

# 1 ELECTRICITY GENERATION

This chapter considers:

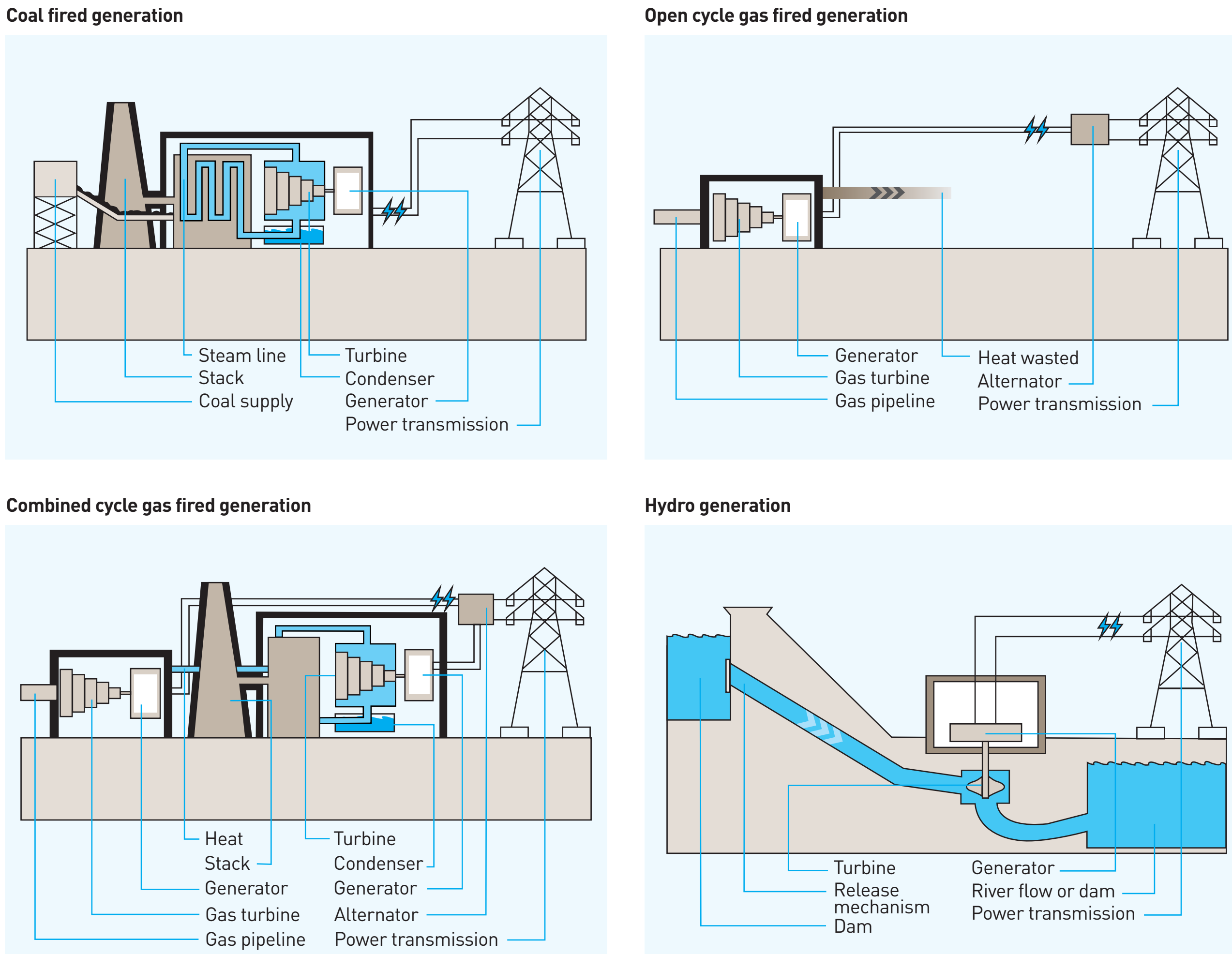
> electricity generation in the National Electricity Market, including geographical distribution, types of generation technology, the life-cycle costs and greenhouse emissions of different generation technologies
> the ownership of generation infrastructure
> investment in generation infrastructure
> the reliability of electricity generation in the National Electricity Market.

## 1.1 Electricity generation

A generator creates electricity by using energy to turn a turbine, which makes 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 generators rely on the heat emitted through a nuclear reaction, or renewable energy sources such as the sun, wind or the flow of water down pipes to generate electricity. Figure 1.1 illustrates four types of electricity generation commonly used in Australia—coal-fired, open cycle gas-fired, combined cycle gas-fired and hydro (water) generation.

The fuels that can be used to generate electricity each have distinct characteristics (table 1.1). Coal-fired generation, for example, has a long start-up time (8–48 hours), while hydro generation can start almost instantly. Life-cycle costs and greenhouse gas emissions also vary markedly with generator type.

**Figure 1.1**
**Electricity generation technologies**




Source: Babcock & Brown

**Table 1.1 Characteristics of generators**

| CHARACTERISTIC | GENERATOR TYPE | | | |
|---|---|---|---|---|
| | GAS AND COAL-FIRED BOILERS | GAS TURBINE | WATER (HYDRO) | RENEWABLE (WIND/SOLAR) |
| Time to fire-up generator from cold | 8–48 hours | 20 minutes | 1 minute | dependent on prevailing weather |
| Degree of operator control over energy source | high | high | medium | low |
| Use of non-renewable resources | high | high | nil | nil |
| Production of greenhouse gas | high | medium-high | nil | nil |
| Other characteristics | medium-low operating costs | medium-high operating costs | low fuel cost with plentiful water supply; production severely affected by drought | suitable for remote stand-alone applications; batteries may be used to store power |

Source: NEMMCO, *Australia's National Electricity Market, Wholesale Market Operation, Executive Briefing*, 2005

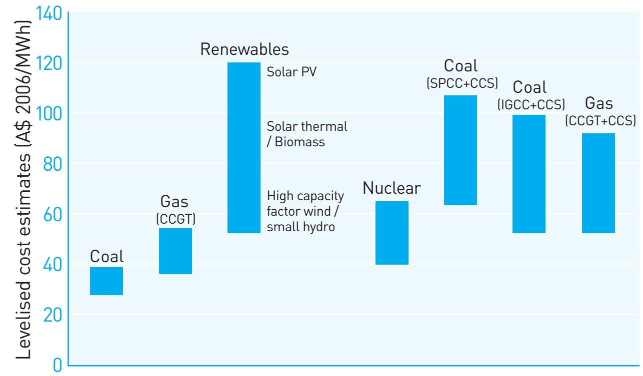
## Life-cycle costs

Estimates of the economic life-cycle costs of different electricity generation technologies in Australia are provided in figure 1.2. To allow comparison, the costs of each generation option have been converted to a standardised cost per unit of electricity.[1] Figure 1.2 includes both current generation technologies in Australia, and alternatives such as nuclear energy and carbon capture and storage (CCS) technology.[2] The cost estimates for CCS, which can be used to reduce carbon emissions from fossil-fired generation (coal, gas and oil) technologies, are indicative only.

Developing a consistent evaluation of electricity generation costs across different technologies can be difficult because of variations in the size and timing of construction costs, fuel costs, operating and maintenance costs, plant utilisation and environmental regulations. Site-specific factors can also affect electricity generation costs. Figure 1.2 therefore expresses the economic costs for each technology in wide bands.

Coal and gas are the lowest cost fuel sources for electricity generation. Of the renewable technologies currently used in Australia, wind and hydroelectric generation are cheaper over their life cycle than biomass and solar. It is estimated that the cost of nuclear generation would fall between that for conventional and renewable generation.

**Figure 1.2**
**Life-cycle economic costs of electricity generation**




AER note: SPCC is supercritical pulverised coal combustion (in which steam is created at very high temperatures and pressures); IGCC is integrated gasification combined cycle (in which coal is converted into a hydrocarbon vapour at high temperature and is then cleaned, stripped of most pollutants and used as fuel in a combined-cycle generation plant, resulting in significantly reduced carbon emissions); CCGT is combined cycle gas turbine; PV is photovoltaic; CCS is carbon capture and storage (costs are indicative only).

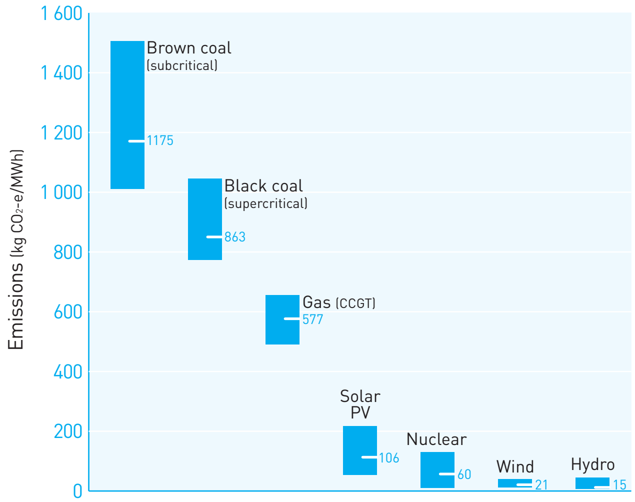
Source: Commonwealth of Australia, *Uranium mining, processing and nuclear energy—opportunities for Australia?*, Report to the Prime Minister by the Uranium Mining, Processing and Nuclear Energy Review Taskforce, December, 2006.

1 The levelised cost of electricity is the real wholesale price of electricity that recoups capital, operating and fuel costs. The present value of expenditures is divided by the electricity generated over the lifetime of the plant to produce a cost per unit of electricity (in $ per MWh).

2 Carbon capture and storage, also known as carbon sequestration, is an approach to mitigating carbon dioxide emissions by storing the carbon dioxide. Potential storage methods include injection into underground geological formations, injection deep into the ocean, or industrial fixation in inorganic carbonates.

Figure 1.3

Life-cycle greenhouse gas emissions of electricity generation




AER note: The figure shows the estimated range of emissions for each technology and highlights the most likely emissions value; PV is photovoltaic; CCGT is combined cycle gas turbine.

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

### Greenhouse emissions

Greenhouse gas emissions for different electricity generation technologies, based on current best practice under Australian conditions, are shown in figure 1.3. The data takes account of full life-cycle emission contributions—including from the extraction of fuels—and estimates the emissions per megawatt hour of electricity generated.

Renewables (hydro-electric, wind and solar electricity) and nuclear electricity generation have the lowest carbon emissions of the generation technologies analysed. Of the fossil fuel technologies, natural gas has the lowest emissions and brown coal, the highest. Figure 1.3 does not account for CCS technologies, which can significantly reduce emissions for gas and coal generators.

## 1.2 Generation in the NEM

Australia has about 230 large electricity generators (figure 1.4), of which around 180 are in National Electricity Market (NEM) jurisdictions in eastern and southern Australia. The electricity produced by major generators in the NEM is sold through a central dispatch managed by the National Electricity Market Management Company (NEMMCO). Chapter 2 of this report outlines the dispatch process.

The demand for electricity is not constant, varying with time of day, day of week and ambient temperature. Demand tends to peak in summer (when hot weather drives up air conditioning loads) and winter (when cold weather increases heating requirements). A reliable power system needs sufficient capacity to meet these demand peaks. In effect, a substantial amount of capacity may be called on for only brief periods and may remain idle for most of the year.

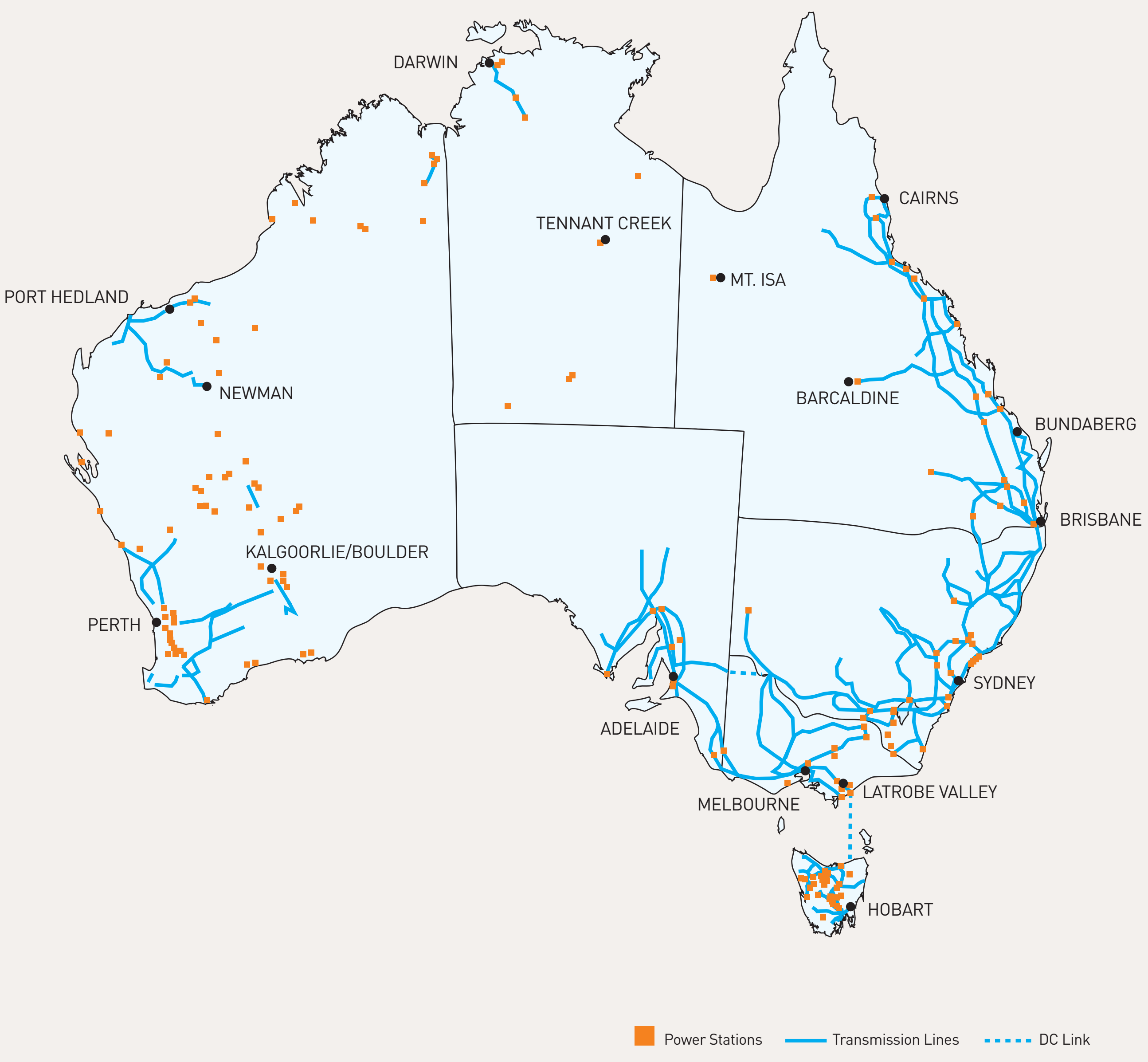
It is necessary to have a mix of generation capacity that reflects these demand patterns. The mix consists of base load, intermediate and peaking power stations.

*Baseload* generators, which meet the bulk of demand, tend to have relatively low operating costs but high start-up costs—making it economical to run them continuously. *Peaking* generators have higher operating costs and so are used to supplement base load at times when prices are high. This normally occurs in periods of peak demand, or when an issue such as a network outage constrains the supply of cheaper generators. While peaking generators are expensive to run, they must be capable of a reasonably quick and economical start-up as they may be called upon to operate at short notice. There are also *intermediate* generators, which operate more frequently than peaking plants, but not continuously.

Figure 1.5 sets out the mix of base load, intermediate and peaking generation capacity across the NEM. Most regions rely principally on base load generation, but Victoria and South Australia have a significant share of peaking and intermediate generation. In Victoria, for example, base load consists mainly of coal-fired generation, while most peaking capacity relies on gas. The Snowy and Tasmanian regions produce hydro-electricity, which is classified as intermediate generation.

Figure 1.4

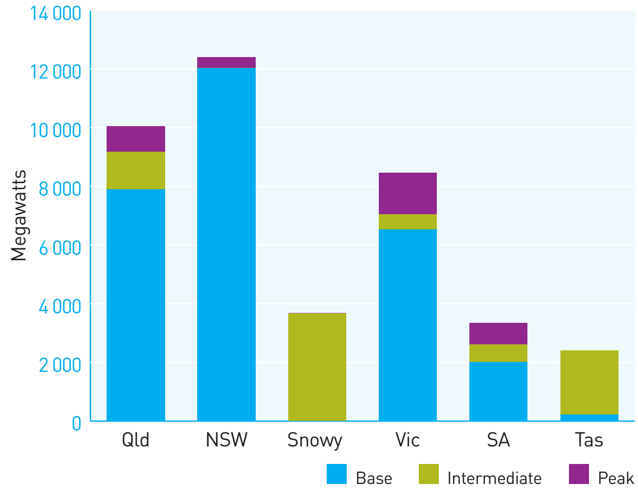
**Electricity generators in Australia**




Locations are indicative only

Source: ABARE 2006

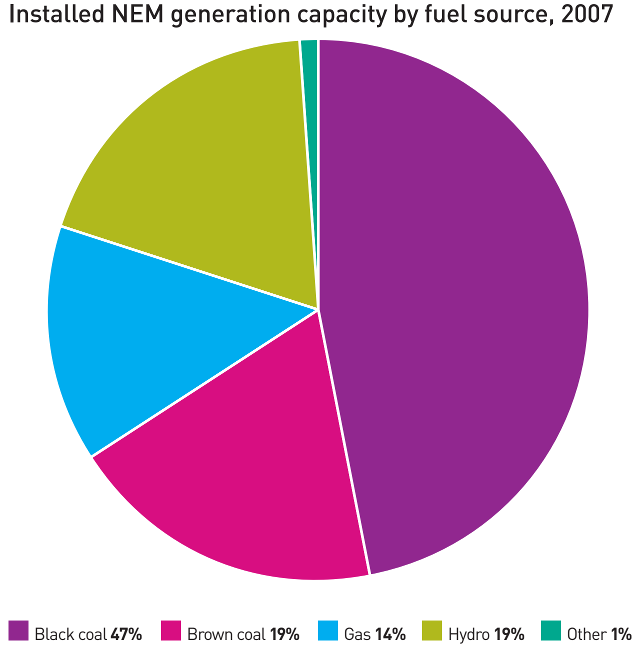
## Figure 1.5
**Installed NEM generation capacity by region, 2007**




Notes: Excludes power stations not managed through central dispatch. The classifications of 'base', 'intermediate' and 'peak' are based on typical hours of running or capacity factors, and mode and cost of operation. Generation classified as base has a long-term capacity factor (proportion of capacity in use) close to one, and low operating costs, but can take many hours to start. Peak generation has a long term capacity factor closer to zero, and higher operating costs, but can start rapidly. Intermediate generation falls in between. Wind generation is not included in conventional calculations of installed capacity because of the intermittent nature of its generation.

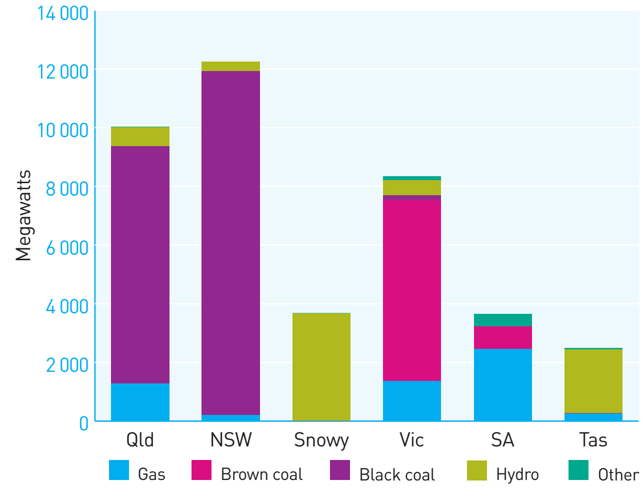
Data source: NEMMCO

## Figure 1.6
**Installed NEM generation capacity by fuel source, 2007**




Data source: NEMMCO

## Figure 1.7
**Regional generation capacity by fuel source, 2007**




Note: Excludes power stations not managed through central dispatch.

Data source: NEMMCO

The NEM generation sector uses a variety of fuel sources to produce electricity (figure 1.6). Black and brown coal account for around 66 per cent of total generation across the NEM, followed by hydro (19 per cent) and gas fired generation (14 per cent). Wind generation accounts for around 1.5 per cent of registered capacity in the NEM. Wind has a significantly higher share at 10 per cent in South Australia.

Figure 1.7 sets out regional data on generation by fuel source. Victoria's base load generation is mainly fuelled by brown coal, supplemented by gas-fired and hydro-electric intermediate and peaking generation. New South Wales and Queensland mainly rely on black coal, but there has been some recent investment in gas-fired generation. Electricity generation in Western Australia, South Australia and the Northern Territory is mainly fuelled by natural gas. Tasmania and Snowy use hydro-electric generation to produce electricity. The Snowy region supports other regions of the NEM with intermediate and peaking requirements.

The future pattern of generation technologies across the NEM may change. As indicated in figure 1.3, coal fired generators produce relatively more greenhouse gas emissions than most other technologies. Australian governments have implemented—and are


Tumut 3 power station, Snowy

developing—initiatives to encourage the development and use of low emission technologies. These include funds for technology development and mandatory targets for greenhouse gas reductions, renewable energy and other low emission generation. Such initiatives result in low carbon emission technologies such as renewables, nuclear and CCS technologies becoming more cost competitive with fossil fuel technologies.

Governments are also considering the introduction of emissions trading or similar policies that would place a price on carbon emissions. In May 2007 the Prime Ministerial Task Group on Emissions Trading recommended that Australia introduce emissions trading, using a 'cap and trade' approach, by 2012.[3] The Government accepted the task force's recommendations in June 2007 and announced that a target or cap for reducing carbon emissions will be set in 2008 following modelling of the economic impact.[4]

## Generation ownership

Table 1.2 and figures 1.8–1.9 provide background on the ownership of generation businesses in Australia. Historically, state-owned utilities ran the entire electricity supply chain in all states and territories. In the 1990s, governments began to carve out the generation and retail segments into stand-alone businesses, and allowed new entrants to compete for the first time. Victoria and South Australia privatised their electricity generation businesses. Other NEM jurisdictions retained government ownership, but also allowed new entry. Across the NEM, around 63 per cent of generation capacity is government-owned or controlled.

Victoria and South Australia disaggregated their generation sectors in the 1990s into multiple stand-alone businesses and privatised each business. Several businesses have since changed hands. Most generation capacity in these regions is now owned by International Power, AGL, TRUenergy, the GEAC group (in which AGL holds a 32.5 per cent stake), and Babcock & Brown. International Power, Alinta, AGL, Origin Energy, Snowy Hydro and others have invested in new generation capacity—mainly gas-fired intermediate and peaking plants—since the NEM commenced.

There has been a significant trend in Victoria and South Australia towards vertical integration of electricity generators with retailers. In Victoria, AGL and TRUenergy are now key players in both generation and retail. In South Australia, AGL is both a major generator and the leading retailer. Across Victoria and South Australia, AGL and TRUenergy own around 40 per cent of registered generation capacity.[5] International Power, which controls around 30 per cent of generation capacity in Victoria and South Australia, fully acquired its retail joint venture with EnergyAustralia in 2007.

New South Wales and Queensland disaggregated their generation sectors but retained significant government ownership. Generation capacity in New South Wales is mainly split between the state-owned Macquarie Generation, Delta Electricity and Eraring Energy. Two private sector entrants, Babcock & Brown and the Marubeni Corporation, each own around 1.5 per cent of the state's generation capacity.

In Queensland, the state-owned Tarong Energy, Stanwell Corporation and CS Energy own around 53 per cent of generation capacity. Queensland privatised the Gladstone Power Station in 1994. There has since been private investment in new capacity, including through joint ventures with government-owned entities (Callide C and Tarong North). RioTinto/NRG, Intergen, Transfield, Origin Energy and Babcock & Brown are among the private sector participants. As indicated in table 1.2 and figure 1.9, much of this privately owned generation capacity has been contracted under power purchase agreements to Enertrade, a Queensland Government-owned wholesale energy provider.[6]

Hydro Tasmania owns virtually all generation capacity in Tasmania, while Snowy Hydro (owned by the Australian, New South Wales and Victorian governments) owns all capacity in the Snowy region.[7]

3 The Prime Ministerial Task Group on Emissions Trading, *Report of the task group on emissions trading*, Department of Prime Minister and Cabinet, 2007.
4 Howard, Hon J. W (MP), Address to the Liberal Party Federal Council, The Westin Hotel, Sydney, 3 June 2007.
5 Includes AGL's 32.5 per cent stake in Loy Yang A and TRUenergy's contractual arrangement for capacity owned by Babcock & Brown. See table 1.2.
6 The Queensland Government announced in May 2007 that it would disband Enertrade and transfer its assets to other government corporations.
7 For the non-NEM jurisdictions of Western Australia and the Northern Territory, see chapter 7 of this report.

Table 1.2 Generation ownership in the NEM: June 2007

| GENERATION BUSINESS | POWER STATIONS | CAPACITY[1] (MW) | OWNER |
|---|---|---|---|
| NEM REGIONS | | | |
| NEW SOUTH WALES AND THE AUSTRALIAN CAPITAL TERRITORY | | | |
| Macquarie Generation | Bayswater; Liddell; Hunter Valley | 4734 | NSW Government |
| Delta Electricity | Vales Point B; Mt Piper; Wallerawang C; Munmorah | 4240 | NSW Government |
| Eraring Energy | Eraring; Shoalhaven; Hume | 2880 | NSW Government |
| Marubeni Australia Power Services | Smithfield | 162 | Marubeni Corporation |
| Redbank Project | Redbank | 148 | Babcock & Brown |
| Snowy Hydro | Blowering | 80 | NSW Govt (58%); Vic Govt (29%); Australian Govt (13%) |
| Various | Embedded and non-grid | 513 | Various |
| VICTORIA | | | |
| Loy Yang Power | Loy Yang A | 2020 | GEAC (AGL Energy (32.5%) |
| Hazelwood Power | Hazelwood | 1580 | International Power (98.1%) |
| TRUenergy | Yallourn | 1420 | TRUenergy (CLP Power Asia) |
| IPM Australia | Loy Yang B | 1000 | International Power (70%), Mitsui (30%) |
| Ecogen Energy | Newport; Jeeralang A & B | 891 | Babcock & Brown (73%); Industry Funds Management (Nominees) Ltd (27%) (all contracted to TRUenergy) |
| AGL Hydro Partnership | McKay Creek; Dartmouth; Somerton; Eildon; West Kiewa | 587 | AGL |
| Snowy Hydro | Laverton North; Valley Power | 570 | NSW Govt (58%); Vic Govt (29%); Australian Govt (13%) |
| Alcoa | Anglesea | 158 | Alcoa |
| Energy Brix Australia | Morwell | 139 | Energy Brix Australia |
| Alinta Energy | Bairnsdale | 70 | Alinta |
| Eraring Energy | Hume VIC | 58 | NSW Government |
| Various | Embedded and non-grid | 474 | Various |
| SOUTH AUSTRALIA | | | |
| AGL | Torrens Island | 1260 | AGL[2] |
| Flinders Power | Northern; Playford B | 760 | Babcock & Brown |
| Pelican Point Power | Pelican Point | 450 | International Power |
| Synergen | Dry Creek; Mintaro; Snuggery; Port Lincoln | 277 | International Power |
| ATCO Power | Osborne | 175 | ATCO (50%); Origin Energy (50%) (all contracted to Babcock & Brown) |
| TRUenergy | Hallett | 155 | TRUenergy (CLP Power Asia)[2] |
| Origin Energy | Quarantine; Ladbroke Grove | 146 | Origin Energy |
| Infratil Energy Australia | Angaston | 40 | Infratil |
| Various | Embedded and non-grid | 398 | Various |

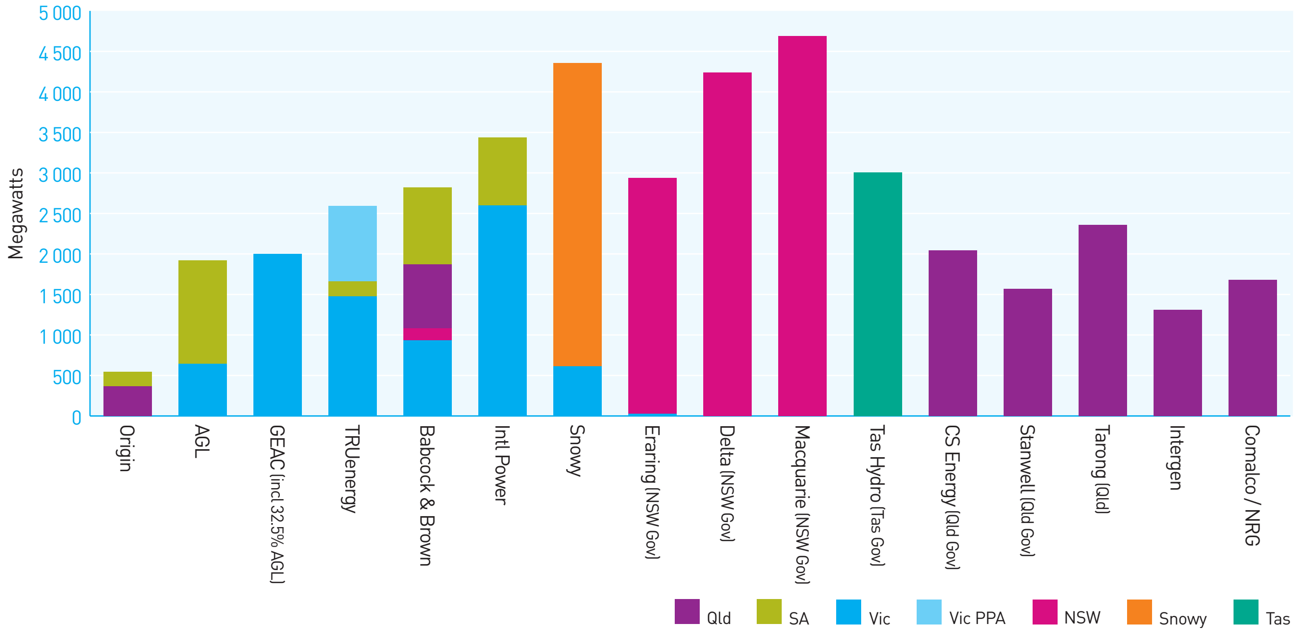
| GENERATION BUSINESS | POWER STATIONS | CAPACITY[1] (MW) | OWNER |
|---|---|---|---|
| **QUEENSLAND** | | | |
| Tarong Energy | Tarong; Wivenhoe | 1900 | Queensland Government |
| Tarong Energy | Tarong North | 443 | Queensland Government (50%); TM Energy (TEPCO & Mitsui Joint Venture) (50%) |
| NRG Gladstone Operating Services | Gladstone | 1680 | Rio Tinto (42%), NRG Energy (37.5%); SLMA GPS (8.5%); Ykk GPS (4.8%); Mitsubishi (7.1%) (all contracted to Enertrade) |
| Stanwell Corporation | Stanwell; Kareeya; Barron Gorge; Mackay | 1608 | Queensland Government |
| CS Energy | Callide B; Swanbank B; Swanbank E | 1535 | Queensland Government |
| Callide Power Management (CS Energy 50%; Intergen Australia 50%) | Callide C | 900 | Queensland Government (50%); Intergen (25%); China Huaneng Group (25%) |
| Millmerran Power Management | Millmerran | 860 | Intergen |
| Braemar Power Projects | Braemer | 453 | Babcock & Brown (85%); ERM Group (15%) |
| Transfield Services (Australia) | Yabulla; Collinsville | 420 | Transfield Services (all contracted to Enertrade) |
| Origin Energy | Mt Stuart; Roma | 342 | Origin Energy (all contracted to Enertrade) |
| Oakey Power Holdings | Oakey Power | 276 | Babcock & Brown (50%); ERM Group (25%); Contact Energy (25%) |
| QPTC (Enertrade) | Barcaldine | 49 | Queensland Government |
| Various | Embedded and non grid | 1002 | Various |
| **TASMANIA** | | | |
| Hydro Tasmania | Gordon; Poatina; Reece; John Butters; Tungatinah, other | 2172 | Tasmanian Government |
| Bell Bay Power (Hydro Tasmania) | Bell Bay | 336 | Tasmanian Government |
| Various | Embedded and non-grid | 29 | Various |
| **SNOWY** | | | |
| Snowy Hydro | Tumut 1, 2 & 3; Murray 1 & 2; Guthega | 3676 | NSW Govt (58%); Vic Govt (29%); Australian Govt (13%) |
| **NON-NEM** | | | |
| **WESTERN AUSTRALIA** | | | |
| Verve | Maju; Kwinana WPC; Pinjar; Collie; Cockburn; other | 3473 | Western Australian Government |
| Various | Independent and remote | 2012 | Various |
| **NORTHERN TERRITORY** | | | |
| Power and Water Corporation | Channel Island; Ron Goodin; Berrimah; Katherine; other | 418 | Northern Territory Government |
| Various | Embedded and non-grid | 230 | Various |

Notes: 1. Capacity is total capacity for embedded, non-grid, Western Australian and Northern Territory generators; and summer capacity for other generators. An embedded generator is one that directly connects to a distribution network and does not have access to a transmission network. 2. AGL entered agreements in January 2007 to acquire the 1260 MW Torrens Island power station in South Australia from TRUenergy, and to sell its 155 MW Hallett power station to TRUenergy. The transaction was completed in July 2007.

Data sources: NEMMCO; ESAA *Electricity gas Australia, 2006;* and other public sources.

## Figure 1.8

### Ownership of major power stations in the NEM—major stakeholders, 2007

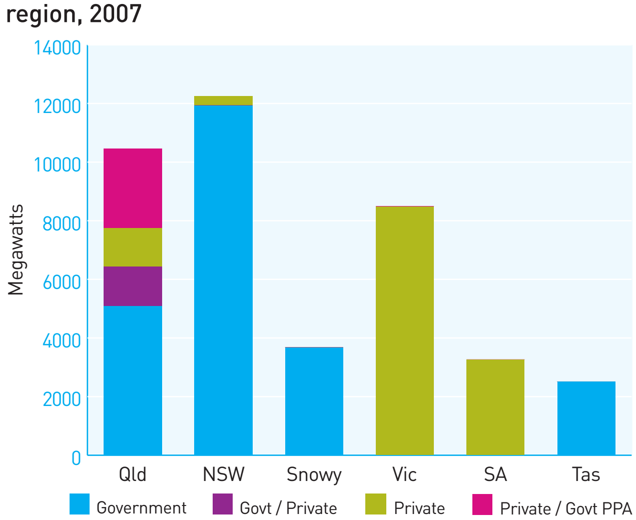



Notes: 1. Excludes power stations that are not managed through central dispatch. 2. AGL ownership excludes its 32.5 per cent stake in GEAC, which owns Loy Yang A. 3. Ecogen Energy capacity is owned by Babcock & Brown but is included for TRUenergy, which has a power purchase agreement for that capacity. 4. Figure 1.8 does not adjust ownership shares for power purchase agreements held by the Queensland government owned Enertrade over the capacity of some stakeholders. 5. Figure 1.8 accounts for AGL's acquisition of the 1260 MW Torrens Island power station in South Australia from TRUenergy, in exchange for the 155 MW Hallett power station. The transaction was completed in July 2007.

Data source: NEMMCO

## Figure 1.9

### Private and public sector generation ownership by region, 2007




Notes: 1. Excludes power stations that are not managed through central dispatch. 2. Private/Govt PPA refers to capacity that is privately owned but contracted under power purchase agreements to government owned corporations. 3. Govt/Private refers to joint venture arrangements between the private and government sectors. Tarong North and Callide C generators in Queensland are Govt/Private joint ventures.

Data source: NEMMCO

## 1.3 Investment in generation infrastructure

Investment in generation capacity is needed to meet the future growth in demand for electricity and to maintain the reliability of the power system. Investment includes the construction of new power stations and upgrades or extensions of existing power stations.

Some electricity markets (including Western Australia and most markets in the United States) use a capacity mechanism to encourage new investment in generation capacity. This may take the form of a tendering process in which capacity targets are determined by market operators and then built by the successful tenderers. Chapter 7 describes the Western Australian capacity market.

By contrast the NEM is an 'energy only' market in which wholesale price outcomes create investment signals. There are several possible indicators of the effectiveness of the NEM in attracting new generation investment. The indicators include:

- investment since NEM start
- generation capacity compared to demand
- the reliability of generation supply
- committed and proposed investment.

### Investment since NEM start

There was investment in almost 5000 megawatts (MW) of generation capacity in power stations managed through central dispatch from the inception of the NEM in 1999 until 2006. This includes investment in new power stations and upgrades. Table 1.3 highlights the net change in generation capacity since the start of the market, taking account of decommissioned plant. The data excludes new investment in plant that was not fully operational in 2006, including Kogan Creek in Queensland. Investment is largely driven by price signals in the wholesale and contract electricity markets (see chapters 2 and 3 of this report).

Table 1.3 Net change in generation capacity, 1999–2006 (megawatts)

| STATE | BASELOAD AND INTERMEDIATE PLANT | PEAKING PLANT (GAS) | TOTAL CHANGE |
|---|---|---|---|
| Queensland | 2091 | 352 | 2443 |
| New South Wales | 650 | –110 | 540 |
| Victoria | 181 | 583 | 764 |
| South Australia | 631 | 373 | 1004 |
| Total | 3553 | 1198 | 4751 |

Notes: Excludes power stations that are not managed through central dispatch. There was a net decommissioning of peaking plant in New South Wales over the period 1999–2006.

Data source: NEMMCO

Figures 1.10 and 1.11 illustrate new investment in generation capacity since market start on an annual (figure 1.10) and cumulative basis (figure 1.11). The investment profile has differed between regions. The strongest growth has been in Queensland and South Australia, where capacity has grown by around 32 per cent since the NEM commenced. In South Australia high spot prices around 1999–2000 fuelled new investment, mainly in peaking and intermediate generation. In turn, capacity additions eased spot prices after 2000 and slowed the rate of capacity expansion. Queensland also responded to high spot prices in the late 1990s with significant investment in base load generation.

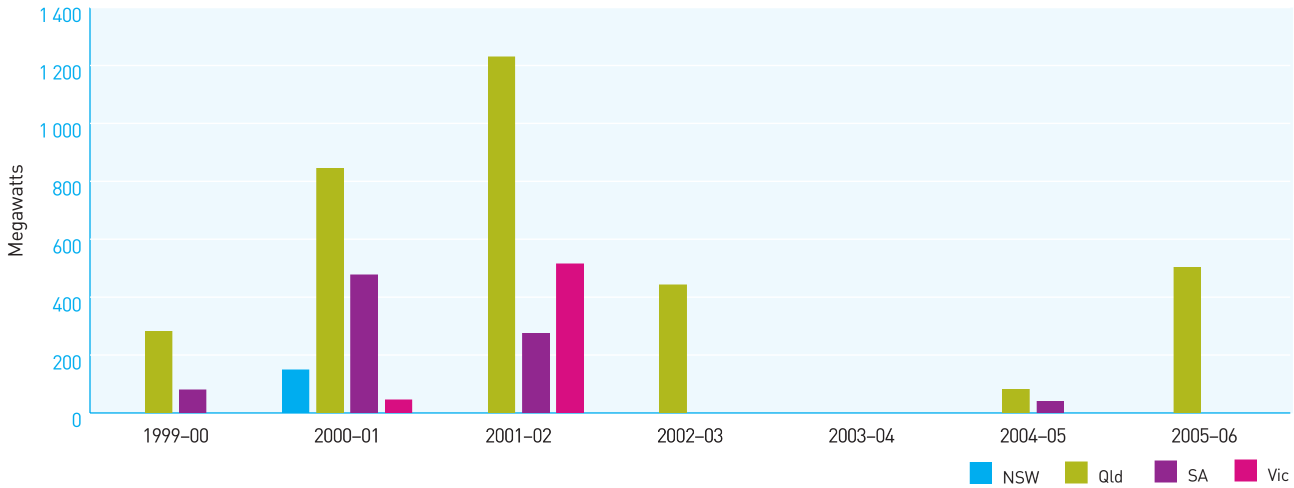
There has been less investment in New South Wales and Victoria. The bulk of new investment in Victoria has been in peaking capacity to meet summer demand peaks. This followed tight conditions in the late 1990s when it experienced short duration or 'needle' peak demand events totalling around three to four hours a year, where prices touched the market price cap.

There has also been investment in generators that bypass the central dispatch process—for example, small generators, wind generators, remote generators not connected to a transmission network, and generators that produce exclusively for self-use (such as for remote mining operations).


Solar power station

**Figure 1.10**

**Annual investment in new generation capacity**

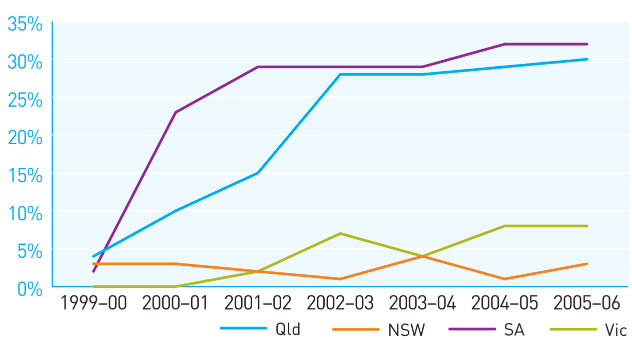



Notes: These are gross investment estimates that do not account for decommissioned plant. Excludes power stations not managed through central dispatch.

Data source: NEMMCO, based on registered capacity data.

**Figure 1.11**

**Cumulative growth in net generation capacity since 1999–2000**




Note: Growth is measured from market start in 1998–99. A decrease may reflect a reduction of capacity due to decommissioning or a change in the ratings of generation units.

Data source: NEMMCO, based on registered capacity data.

## Generation capacity and demand

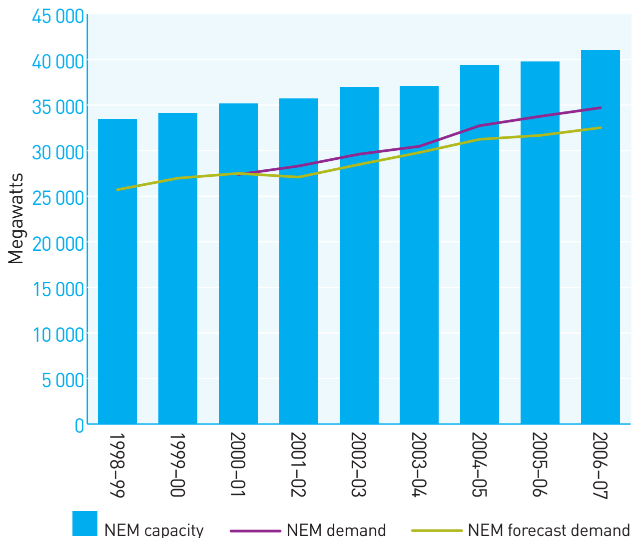
Figure 1.12 compares total generation capacity with national peak demand. The chart includes actual demand and the demand forecasts published by NEMMCO two years in advance. The chart indicates that the NEM has generated sufficient investment in new capacity to keep pace with rising demand (both actual and forecast levels), and to provide a 'safety margin' of capacity to maintain the reliability of the power system.

## Reliability of generation supply

Plant failure or inadequate generation capacity can lead to interruptions to electricity supply. The reliability standard adopted in the NEM is that over the long term at least 99.998 per cent of customer demand must be met. To provide this reliability, NEMMCO determines the necessary spare capacity for each region that must be available (either within the region or via transmission interconnectors). These minimum reserves provide a buffer against unexpected demand spikes and generation failure.

In practice generation has proved highly reliable since the NEM commenced. There have only been two instances of insufficient generation capacity to meet consumer demand. The first occurred in Victoria in early 2000 where a coincidence of industrial action, high demand and temporary loss of generating units resulted in load shedding. The second occurred in New South Wales on 1 December 2005, when a generator failed during a period of record summer demand. The restoration of load began within ten minutes.

Figure 1.12
NEM peak demand and generation capacity




Note: Demand forecasts are taken two years in advance, based on a 50 per cent probability that the forecast will be exceeded (due, for example, to weather conditions) and a coincidence factor of 95 per cent.

Source: NEMMCO, *Statement of opportunities for the National Electricity Market* (various years).

Essay B of this report provides an overview of power system reliability in the NEM and the causes of supply interruptions. In summary the essay finds that generation supply is highly reliable and is a minor contributor to electricity supply interruptions.

## Committed and proposed investment

Investment in generation capacity needs to respond dynamically to future projections in market conditions. Investors have committed to a number of future generation projects, and have proposed several others.

### Committed projects

Committed investment projects include those already being constructed and those where the project developers have formally committed to the project's construction. NEMMCO takes account of committed projects in making future projections of electricity supply and demand.

In 2006, 1600 MW of new capacity had been committed by developers (table 1.4), of which around 75 per cent was in Queensland. The Braemer Stage 1 project became operational in late 2006, and Kogan Creek is expected to be fully operational by late 2007. TRUenergy's Tallawarra project will become the third privately owned major power station in New South Wales.

### Proposed projects

Proposed projects include generation capacity that is either in the early stages of development or at more advanced stages that might include a proposed commissioning date. Such projects are not fully committed, and may be shelved in the event of a change in circumstances such as a change in demand projections or business conditions.

NEMMCO's annual statement of opportunities for the National Electricity Market (SOO) refers to proposed projects that are 'advanced' or publicly announced. NEMMCO does not include these projects in its supply and demand outlooks as it considers them too speculative. In total, the 2006 SOO referred to around 9200 MW of proposed capacity (excluding wind) in the NEM. The bulk is for New South Wales and Queensland. The significant amount of proposed capacity for New South Wales may reflect that the region is currently the highest net importer in the NEM.

**Table 1.4** Major committed generation capacity in the NEM, 2006

| REGION | DEVELOPER | POWER STATION | FUEL | CAPACITY IN MW | YEAR OF COMMISSIONING |
|---|---|---|---|---|---|
| Qld | CS Energy | Kogan Creek | Coal | 750 | 2007 |
| Qld | Braemar Power Project | Braemar Stage 1 | Gas | 450 | 2006 |
| NSW | TRUenergy | Tallawarra | Gas | 400 | 2008 |

Source: NEMMCO, *Statement of opportunities for the National Electricity Market*, 2006.

**Table 1.5** Proposed capacity (excluding wind) in the NEM by region, 2006

| DEVELOPER | STATION NAME | FUEL | CAPACITY IN MW | PLANNED COMMISSIONING |
|---|---|---|---|---|
| NEW SOUTH WALES | | | | |
| Macquarie Generation | Tomago | Gas | 500 | – |
| Delta Electricity | Mt Piper upgrade | Coal | 180 | 2008 |
| Wambo Power Ventures | NewGen Uranquinty | Gas | 640 | 2008–09 |
| Delta Electricity | Bamarang (Nowra) | Gas | 400 | 2010 |
| Wambo Power Ventures | NewGen Bega | Gas | 120 | 2008–09 |
| Wambo Power Ventures | NewGen Cobar | Gas | 114 | 2008–09 |
| Delta Electricity | Munmorah | Gas | 600 | 2009–10 |
| Delta Electricity | Big Hil (Marulan) | Gas | 300 | 2010–11 |
| Delta Electricity | Mt Piper extension | Coal | 1500 | – |
| Eraring Energy | Eraring Black Start Gas Turbine | Gas | 40 | 2007 |
| Eraring Energy | Eraring Upgrade | Coal | 360 | 2009 |
| QUEENSLAND | | | | |
| Stanwell Corporation | Stanwell Peaking Plant | Gas | 300 | 2008 |
| Queensland Gas Company | Chinchilla | Gas | 242 | 2008 |
| Origin | Spring Gully | Gas | 1000 | 2009 |
| Stanwell Corporation | Stanwell Coke Project | Coal | 350 | 2008–09 |
| Wambo Power Ventures | Braemer Stage 2 | Gas | 450 | 2008–09 |
| SOUTH AUSTRALIA | | | | |
| Origin | Quarantine expansion | Gas | 70 | – |
| AGL | Hallett expansion | Gas | 250 | – |
| International Power | Pelican Point Stage 2 | Gas | 225 | 2008 |
| VICTORIA | | | | |
| Loy Yang Power | Unit 2 upgrade | Coal | 25 | 2009 |
| Loy Yang Power | Unit 4 upgrade | Coal | 25 | 2008 |
| Origin | Mortlake | Gas | 1000 | 2009 |
| AGL Hydro Partnership | Bogong | Hydro | 130 | 2010 |
| SNOWY | | | | |
| Snowy Hydro | Murray 2 upgrade | Hydro | – | – |
| Snowy Hydro | Tumut 3 upgrade | Hydro | – | 2006–2009 |

Source: NEMMCO, *Statement of opportunities for the National Electricity Market*, 2006.

Verve Energy

Wind power

Planned wind projects are reported separately in the SOO because their capacity is weather dependent and cannot be relied on to generate when required. Wind projects can, however, play an important role in providing energy for future demand growth. The 2006 SOO listed about 5400 megawatts of proposed wind capacity, predominantly in South Australia, Victoria and New South Wales.

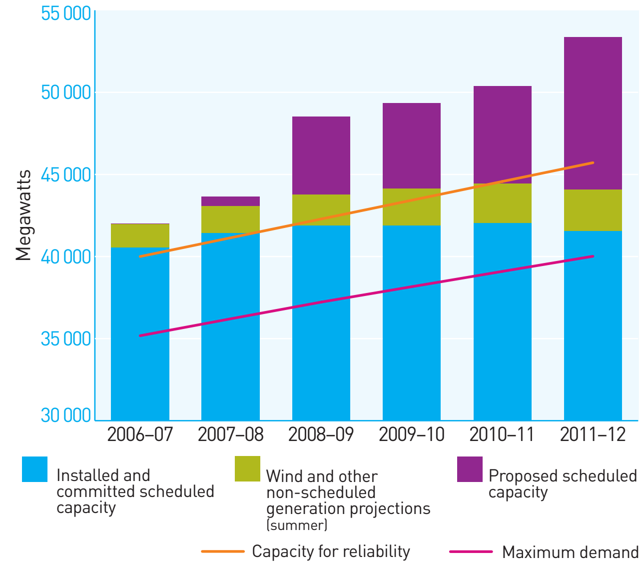
The classification of a particular project may change over time. A project listed as proposed may become committed, and then constructed. Other proposed projects may never come to fruition.

## Reliability outlook

The relationship between future demand and capacity will determine both future prices and the reliability of the power system. Figure 1.13 projects future forecast peak demand in the NEM against installed, committed and proposed capacity. The chart indicates the amount of capacity that NEMMCO considers would be needed to maintain the reliability of the power system, given the projected rise in demand. While wind generation is not classified as installed capacity, it is included as a possible source of energy.

Figure 1.13 indicates that new capacity may be needed as soon as 2008–09 to meet NEMMCO's peak demand projections and reliability requirements. Installed wind generation and committed projects provide a margin of safety, but beyond 2009–10 there will be a need for further capacity. The chart indicates the extent of proposed capacity to meet the shortfall. While many proposed projects may never be constructed, only a relatively small percentage would need to come to fruition to address demand and reliability needs into the next decade.

**Figure 1.13**
**Demand and capacity outlook to 2011–12**




Notes: The maximum demand forecasts for each region in the NEM are aggregated based on a 50 per cent POE and a 95 per cent coincidence factor. Reserve levels required for reliability are based on an aggregation of minimum reserve levels for each region. Accordingly, the data cannot be taken to indicate the required timing of new generation capacity within individual NEM regions.

Data source: NEMMCO, *Statement of opportunities for the National Electricity Market,* 2006.

While the uncertain nature of proposed projects means they cannot be factored into NEMMCO's reliability equations, they do provide an indicator of the market's awareness of future capacity needs. In particular, they can be seen as an indicator of the extent of competition in the market to develop electricity infrastructure.

Government policies aimed at reducing carbon emissions will likely influence the mix of proposed projects that are constructed. Mandatory renewable energy targets, Queensland's 13 per cent gas scheme, the greenhouse gas abatement scheme in New South Wales and the Australian Capital Territory, and the likely introduction of a national emissions trading scheme will affect investment decisions and increase the viability of low emission technologies.[8]

8 For more information on greenhouse gas emissions policies, see appendix B of this report.

# 2 ELECTRICITY WHOLESALE MARKET

Power Station control panel. Mark Wilson

Generators in the National Electricity Market sell electricity to retailers through wholesale market arrangements in which the dynamics of supply and demand determine prices and investment. The Australian Energy Regulator monitors the market to ensure that participants comply with the National Electricity Law and National Electricity Rules.

# 2 ELECTRICITY WHOLESALE MARKET

This chapter considers:

- features of the National Electricity Market
- how the wholesale market operates
- the demand for electricity by region, and electricity trade between regions
- spot prices for electricity in the National Electricity Market, including price volatility, and international price comparisons

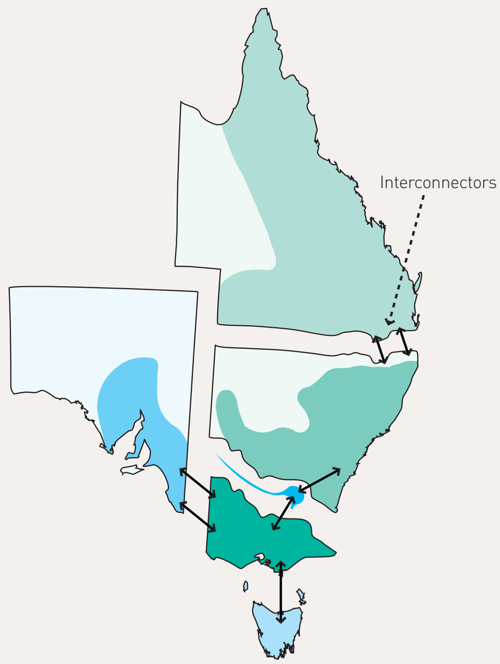
## 2.1 Features of the National Electricity Market

The National Electricity Market (NEM) is a wholesale market through which generators and retailers trade electricity in eastern and southern Australia. There are six participating jurisdictions—Queensland, New South Wales, the Australian Capital Territory, Victoria, South Australia and Tasmania, which are physically linked by transmission network interconnectors.

The NEM has around 260 registered generators, six state-based transmission networks (linked by cross-border interconnectors) and 13 major distribution networks that collectively supply electricity to end-use customers. In geographical span, the NEM is the largest interconnected power system in the world. It covers a distance of 4500 km, from Cairns in North Queensland to Port Lincoln in South Australia and Hobart in Tasmania. The market has six regions (figure 2.1). The Queensland, Victoria, South Australia and Tasmania regions follow state boundaries. The other regions are New South Wales and Snowy, which is located in southern New South Wales. Snowy is a major generation centre that has negligible local demand.[1]

1 The Australian Energy Market Commission released a draft determination in January 2007 proposing to abolish the Snowy region. This would involve an expansion of the New South Wales and Victorian regions.

**Figure 2.1**
**Regions of the National Electricity Market**




The shaded area represents the approximate geographical range of the interconnected network in each NEM region.

Vic NSW Qld SA Tas Snowy

### Box 2.1 Development of the National Electricity Market

Historically, governments owned and operated the electricity supply chain from generation through to retailing. There was no wholesale market because generation and retail were operated by vertically integrated state-based utilities. Typically, each jurisdiction generated its own electricity needs, with limited interstate trade.

Australian governments began to reform the electricity industry in the 1990s. The vertically integrated utilities were separated into generation, transmission, distribution and retail businesses. For the first time, generation and retail activities were exposed to competition. This created an opportunity to develop a wholesale market that extended beyond jurisdictional borders.

The Special Premiers' Conference in 1991 agreed to establish the National Grid Management Council to coordinate the development of the electricity industry in eastern and southern Australia. In early 1994 the Council of Australian Governments (COAG) developed a code of conduct for the operation of a national grid, consisting of the transmission and distribution systems in Queensland, New South Wales, the Australian Capital Territory, Victoria and South Australia. In 1996, these jurisdictions agreed to pass the National Electricity Law, which provided the legal basis to create the National Electricity Market.

During the transition to a national market, Victoria and New South Wales trialled wholesale electricity markets that used supply and demand principles to set prices. The National Electricity Market commenced operation in December 1998, with Queensland, New South Wales, Victoria, South Australia and the Australian Capital Territory as participating jurisdictions. While Queensland was part of the NEM from inception, it was not physically interconnected with the market until 2000–01 when two transmission lines (Directlink and the Queensland to New South Wales interconnector (QNI)) linked the Queensland and New South Wales networks. Tasmania joined the NEM in 2005 and was physically interconnected with the market in April 2006 with the opening of Basslink, a submarine transmission cable from Tasmania to Victoria.


Mark Wilson

Power station control room

The NEM supplies electricity to over 7.7 million residential and business customers. In 2006–07, the market generated around 206 terawatt hours[2] of electricity with a turnover of almost $13 billion (table 2.1).

Table 2.1 NEM at a glance

| | |
|---|---|
| Participating jurisdictions | NSW, Qld, Vic, SA, ACT, Tas |
| NEM regions | NSW, Qld, Vic, SA, Snowy, Tas |
| Registered capacity | 43 130 MW |
| Number of registered generators | 263 |
| Number of customers | 7.7 million |
| NEM turnover 2006–07 | $13 billion |
| Total energy generated 2006–07 | 206 TWh |
| National max winter demand 2006–07 (21 June 2007) | 32 688 MW |
| National max summer demand 2006–07 (5 February 2007) | 31 796 MW |

## 2.2 How the National Electricity Market works

The NEM is a wholesale pool into which generators sell their electricity. The main customers are retailers, which buy electricity for resale to business and household customers. While it is also possible for an end-use customer to buy directly from the pool, few choose this option.

The market has no physical location, but is a virtual pool in which supply bids are aggregated and dispatched to meet demand. The Australian Energy Regulator (AER) monitors the market to ensure that participants comply with the National Electricity Law and the National Electricity Rules.

The design of the NEM reflects the physical characteristics of electricity. This means:

> Supply must meet demand at all times because electricity cannot be economically stored. This requires coordination to avoid imbalances that could seriously damage the power system.

> One unit of electricity cannot be distinguished from another, making it impossible to determine which generator produced which unit of electricity and which market customer consumed that unit. The use of a common trading pool addresses this issue by removing any need to trace particular generation to particular customers.

The NEM is a gross pool in which all physical delivery of electricity is managed through the pool. In contrast, a net pool or voluntary pool would allow generators to contract with market customers directly for the delivery of some electricity. Western Australia's electricity market uses a net pool arrangement (see chapter 7).

Unlike some overseas markets, the NEM does not provide additional payments to generators for capacity or availability. This characterises the NEM as an energy-only market and gives reason for a high price cap of $10 000 a MWh. Generators earn their income in the NEM from market transactions (either in the spot or ancillary services[3] markets or by trading hedge instruments in financial markets[4] outside NEM arrangements). In some jurisdictions, generators might earn income outside the wholesale market through emissions trading[5] or for the use of renewable technologies.

### Market operation

The National Electricity Market Management Company (NEMMCO) coordinates a central dispatch to manage the wholesale spot market. The process instantaneously matches generator supply offers against demand in real time. NEMMCO issues instructions to each generator to produce the required quantity of electricity that will meet demand at all times at the lowest available cost, while maintaining the technical security of the power system. NEMMCO does not own physical network or generation assets.

2 One terawatt hour (TWh) is equivalent to 1000 gigawatt hours (GWh), 1 000 000 megawatt hours (MWh) and 1 000 000 000 kilowatt hours (KWh). One TWh is enough energy to light 10 billion light bulbs with a rating of 100 watts for one hour.

3 NEMMCO operates a market for a number of ancillary services. These include frequency control services that relate to electricity supply adjustments to maintain the power system frequency within the standard. Generators can bid offers to supply these services into spot markets that operate in a similar way to the wholesale energy market.

4 See chapter 3.

5 For example, the Greenhouse Gas Abatement Scheme in New South Wales and the Australian Capital Territory.

There are some generators in NEM regions that bypass the central dispatch process—for example, they might only generate intermittently (such as wind generators), may not be connected to a transmission network, and/or might produce exclusively for self-use (such as for remote mining operations).

## Demand and supply forecasting

NEMMCO continuously monitors demand and capacity across the NEM and issues demand and supply forecasts to help participants respond to the market's requirements. While demand varies, industrial, commercial and household users have relatively predictable patterns, including seasonal demand peaks related to extreme temperatures. NEMMCO uses data such as historical load (demand) patterns and weather forecasts to develop demand forecasts. Similarly, it forecasts the adequacy of supply in its projected assessment of system adequacy (PASA) reports. It publishes a seven-day PASA that is updated every 30 minutes, and a two-year PASA that is updated weekly.

## Central dispatch and spot prices

NEMMCO uses a sophisticated IT system to match electricity supply and demand in the most cost-effective manner that meets power system security requirements. Market supply is based on the offers of generators to produce particular quantities of electricity at various prices for each of the 30-minute trading intervals in a day. Generators must lodge offer bids ahead of each trading day. Coal-fired base load generators need to ensure their plants are kept running at all times to cover their high start-up costs, and may offer to generate some electricity at low or negative prices to ensure they are dispatched.[6] Peaking generators, on the other hand, face high operating costs and normally offer to supply electricity only when the price is high.

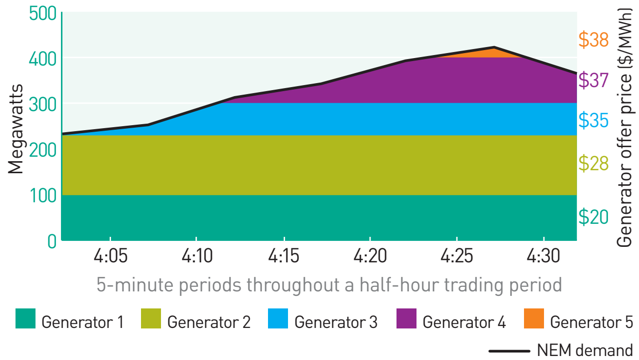
NEMMCO determines which generators are dispatched to satisfy demand by stacking the offer bids of all generators in ascending price order for each five-minute dispatch period. NEMMCO dispatches the cheapest generator bids first, then progressively more expensive offers until enough electricity is dispatched to satisfy demand. This results in demand being met at the lowest possible cost. In practice, the dispatch order may be modified by a number of factors, including generator ramp rates—that is, how quickly generators can adjust their level of output—and congestion in transmission networks.

The dispatch price for a five-minute interval is the offer price of the highest (marginal) priced megawatt (MW) of generation that must be dispatched to meet demand. For example, in figure 2.2, the demand for electricity at 4.15 is about 350 MW. To meet this level of demand, the four generators offering to supply at prices up to $37 must be dispatched. The dispatch price is therefore $37. By 4.25, demand has risen to the point where a fifth generator needs to be dispatched. This higher cost generator has an offer price of $38, which drives the price up to that level. The wholesale spot price is the volume weighted average of the six dispatch prices over half an hour, and is the price that effectively brings demand into balance with supply. In figure 2.2, the spot price is about $37 a MWh. This is the price all generators receive for production during this 30-minute period and the price market customers pay for the electricity they use in that period. A separate spot price is determined for each region, taking account of physical losses in the transport of electricity over distances and transmission congestion that can sometimes isolate particular regions from the national market (section 2.4).

The price mechanism in the NEM allows spot prices to respond to a tightening in the supply-demand balance. This creates signals for demand-side responses. For example, customers may be able to adjust their consumption in response to higher prices, provided suitable metering arrangements are available (section 2.6). In the longer term, price movements also create signals for new investment (see sections 1.3, 2.5 and 2.6).

6 The minimum allowed bid price is $–1000 a MWh.

**Figure 2.2**
**Illustrative generator offers (megawatts) at various prices**

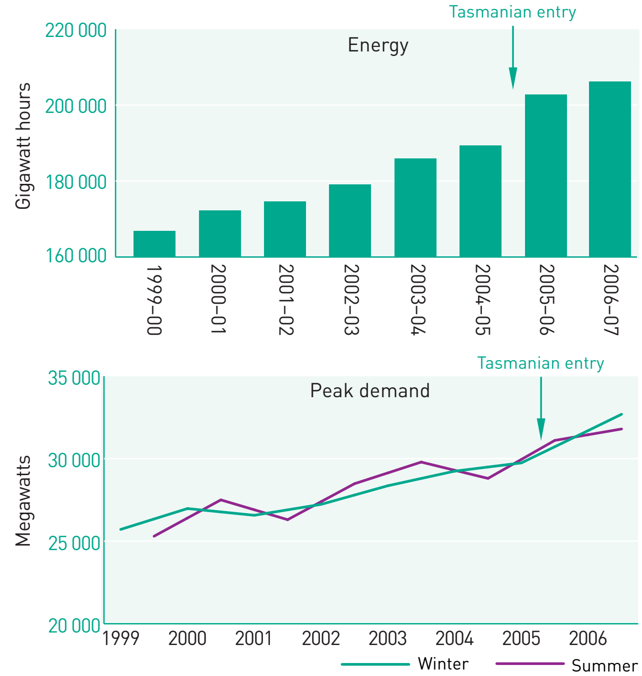



Source: NEMMCO

## 2.3 National Electricity Market demand and capacity

Annual electricity consumption in the NEM rose from under 170 000 GWh in 1999–2000 to over 205 000 GWh in 2006–07 (figure 2.3a). The entry of Tasmania in 2005 accounted for around 10 000 GWh. Demand levels fluctuate throughout the year, with peaks occurring in summer (for air conditioning) and winter (for heating). The peaks are closely related to temperature. Figure 2.3b shows that seasonal peaks have risen nationally from around 26 000 MW in 1999–2000 to over 31 000 MW in 2006–07. The volatility in the summer peaks reflects variations in weather conditions from year to year.

**Figure 2.3a and b**
**NEM energy consumption and peak demand since 1999**




Data source: NEMMCO

Table 2.2 sets out the demand for electricity across the NEM since 1998–99. Reflecting its population base, New South Wales has the highest demand for electricity, followed by Queensland and Victoria. Demand is considerably lower in the less populated regions of South Australia and Tasmania.

**Table 2.2 Annual energy demand (terawatt hours)**

| | QLD | NSW | SNOWY | VIC | SA | TAS | NATIONAL |
|---|---|---|---|---|---|---|---|
| 2006–07 | 51.4 | 78.6 | 1.3 | 51.5 | 13.4 | 10.2 | 206.4 |
| 2005–06 | 51.3 | 77.3 | 0.5 | 50.8 | 12.9 | 10 | 202.8 |
| 2004–05 | 50.3 | 74.8 | 0.6 | 49.8 | 12.9 | na | 189.7 |
| 2003–04 | 48.9 | 74.0 | 0.7 | 49.4 | 13.0 | na | 185.3 |
| 2002–03 | 46.3 | 71.6 | 0.2 | 48.2 | 13.0 | na | 179.3 |
| 2001–02 | 45.2 | 70.2 | 0.3 | 46.8 | 12.5 | na | 175.0 |
| 2000–01 | 43.0 | 69.4 | 0.3 | 46.9 | 13.0 | na | 172.5 |
| 1999–00 | 41.0 | 67.6 | 0.2 | 45.8 | 12.4 | na | 167.1 |

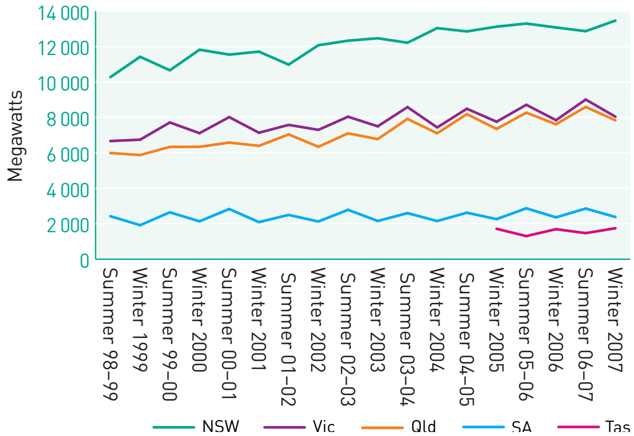
na not applicable.

Note: Tasmania entered the market on 29 May 2005.

Data source: NEMMCO

Figure 2.4

Seasonal peak demand in the NEM




Data source: NEMMCO

Figure 2.4 compares seasonal demand across the regions. Victoria, South Australia and Queensland experience high demand in summer due to air conditioning loads. Tasmania tends to experience its maximum demand in winter due to heating loads. New South Wales was traditionally winter peaking, but since the summer of 2002–03 has been alternately summer and winter peaking.

## 2.4 Trade between the regions

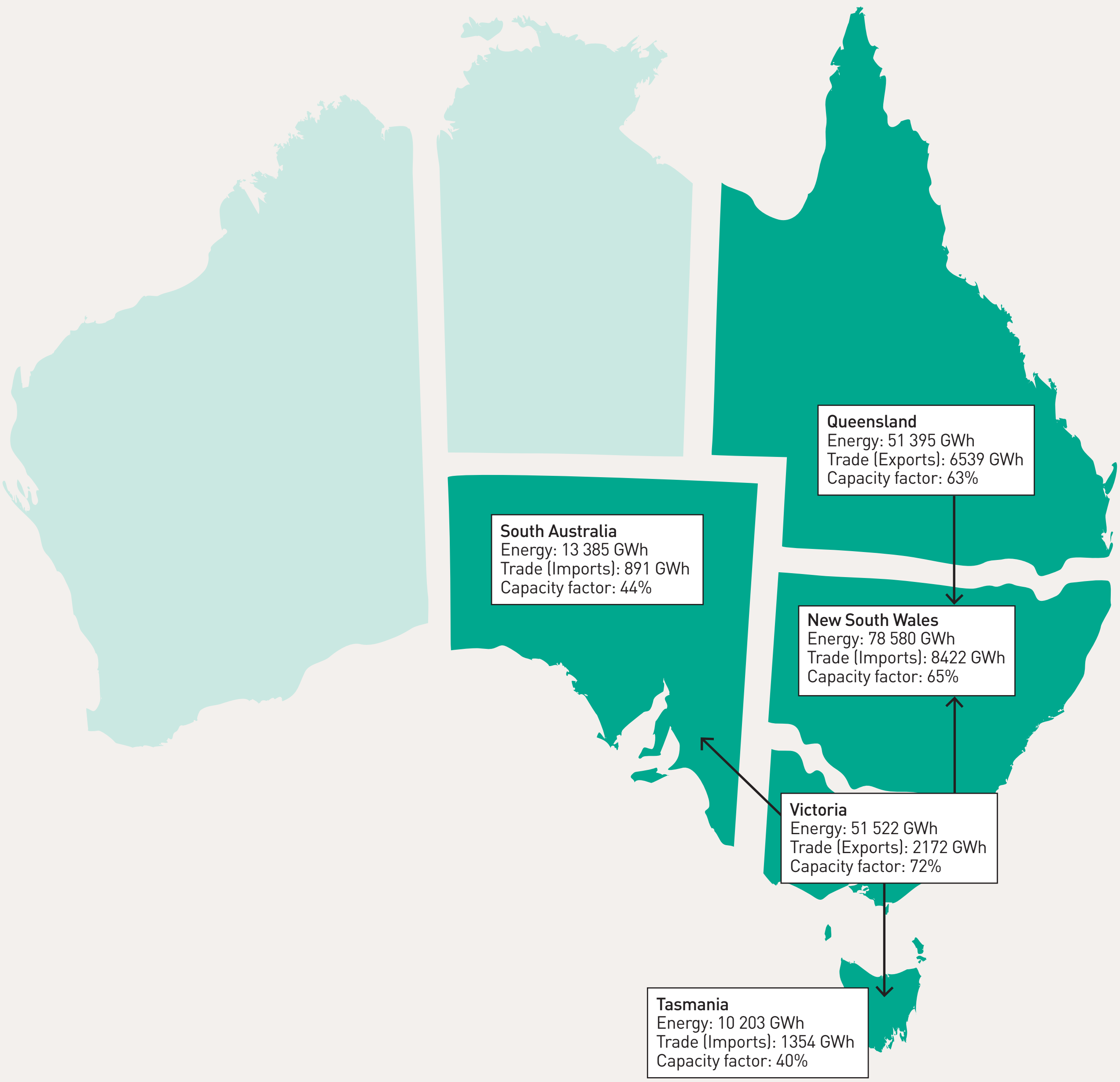
The NEM promotes efficient generator use by allowing trade in electricity between the regions. The six regions of the NEM are linked by transmission interconnectors that make trade possible. This enhances the reliability of the power system by allowing the regions to pool their reserves to manage the risk of a system failure. Trade also provides economic benefits by allowing high-cost generating regions to import from lower cost regions. For example, importing electricity from another region's base load generators may be cheaper than using local peaking generation.

Imports are especially attractive when peak demand forces up local prices. For example, a day of hot weather in South Australia might drive up electricity demand to the point where high-cost local generators are needed to satisfy demand. This can make lower cost interstate generation a competitive alternative. NEMMCO can dispatch electricity from lower cost regions and export it to South Australia (up to the technical capacity of the interconnectors).

Figure 2.5 shows annual energy (consumption) and trade between the regions in 2006–07. The figure also shows each region's generation capacity factor (the rate at which local generation capacity is used):

- New South Wales is a net importer of electricity. It relies on local base load generation due to its low cost, but has limited peaking capacity at times of high demand. This puts upward pressure on prices in peak periods, making imports a cheaper alternative.
- Victoria is a net exporter because it has substantial low-cost base load capacity. This is reflected in the region's 72 per cent capacity factor, the highest for any region. Victoria tends to import only at times of peak demand, when its regional capacity is stretched.
- Queensland's installed capacity exceeds its demand for electricity, making it a significant net exporter.
- South Australia is a net importer. The region has a high proportion of open cycle gas turbine generation, resulting in relatively high-cost generation. South Australia's peak demand exceeds its average demand by a greater margin than for any other region. This is reflected in South Australia's low generation capacity factor. Depending on prevailing market conditions, it is usually cheaper for South Australia to import electricity than to meet demand exclusively from local generation. It also has the highest proportion of wind generation, the energy output of which cannot be accurately forecast as it varies with weather conditions.
- Tasmania is currently a net importer from Victoria, although this relationship may be reversed during periods of peak demand in Victoria. Tasmania's rainfall and dam levels can affect its ability to use hydro capacity.
- The Snowy region (not shown) has little local demand and is almost exclusively an exporter of electricity to other regions. As for Tasmania, rainfall and dam levels can affect the region's ability to generate hydro-electricity.

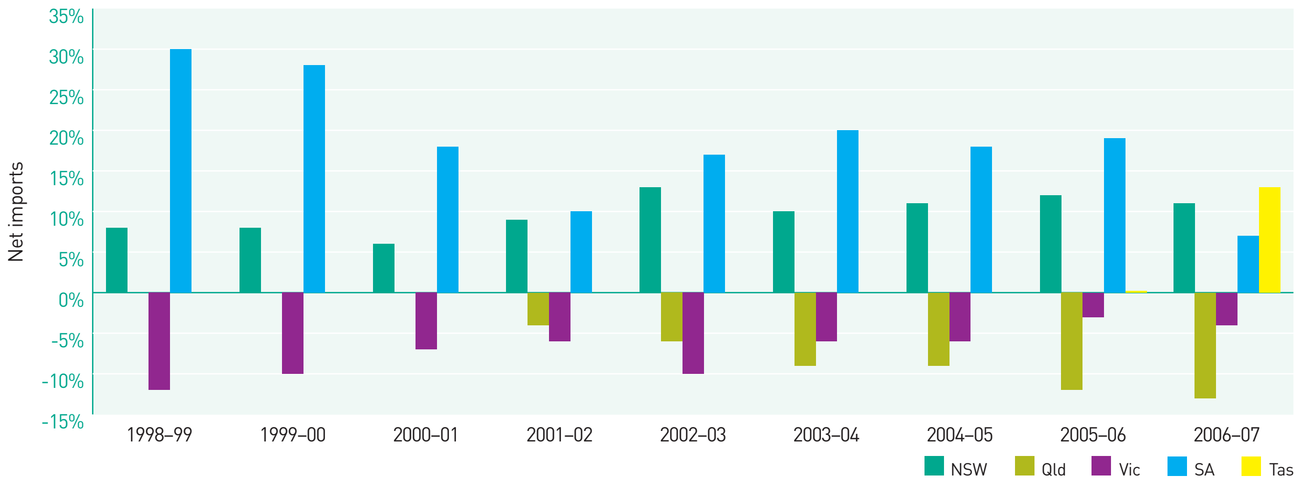
Figure 2.5
Trade flows across the NEM regions in 2006–07




Notes: 1. Energy refers to energy consumption. 2. Capacity factor refers to the proportion of local generation capacity in use. 3. The Snowy region (not shown) is located in south-eastern New South Wales. It generates around 5200 GWh of energy a year. The region's energy consumption, which is mainly for pumping purposes in its hydro generation plants, is equal to around 9 per cent of Snowy generation.

Data source: NEMMCO

Figure 2.6
Inter-regional trade as percentage of regional energy consumption




Note: The Snowy region (not shown) has little local demand and is almost exclusively an exporter to other regions.

Data source: NEMMCO

The NEM's inter-regional trade relationships are also reflected in figure 2.6, which shows the net trading position of the regions since the NEM commenced. South Australia, historically the most trade-dependent region, has reduced its reliance on imports from over 25 per cent of its annual energy consumption in the early years of the NEM to 7 per cent since 2006–07. The reduction reflects new investment in generation since 1999. New South Wales, also a net importer, has increased its reliance on imports from around 5 to 10 per cent in the early years of the NEM to over 10 per cent.

Victoria has consistently been a net exporter, although its exports as a share of consumption has fallen since 2004–05. Queensland has been a net exporter since it was interconnected with other regions of the NEM. Queensland exports as a share of its consumption has steadily risen since 2001–02 and has exceeded 10 per cent since 2005–06.

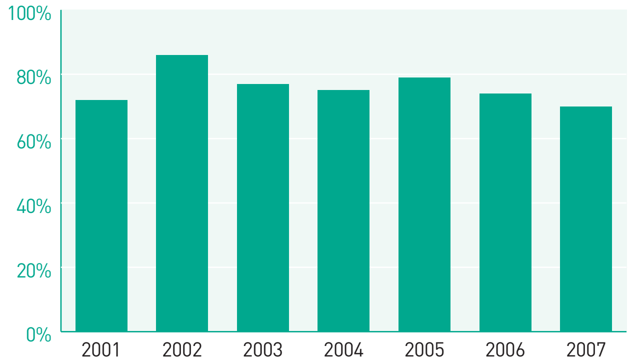
## Market separation

The NEM central dispatch determines a separate spot price for each region of the NEM. In the absence of networks constraints, interstate trade brings prices across the regions towards alignment. Due to transmission losses that occur when transporting electricity over distances, it is normal to have some disparities between regional prices. More significant price separation may occur if an interconnector is congested. For example, imports may be restricted when import requirements exceed an interconnector's design limits. Similar issues may arise if the interconnector is undergoing maintenance or an unplanned outage that reduces its import capability. The availability of generation plant and the bidding behaviour of generators may also contribute to transmission congestion.

When congestion restricts a region's ability to import electricity, prices in the high-demand region may spike above prices elsewhere. For example, if low-cost Victorian electricity is constrained from flowing into South Australia on a day of high demand, more expensive South Australian generation—for example, local peaking plants—would need to be dispatched in place of imports. This would drive South Australian prices above those in Victoria.

Figure 2.7 indicates that the NEM operates as an 'integrated' market with price alignment across all regions for around 70 per cent of the time. The market is considered aligned when every interconnector in the NEM is unconstrained and electricity can flow freely between all regions. There may still be price differences between regions due to loss factors that occur in the transport of electricity.

Figure 2.7
Market alignment as a percentage of trading hours




Data source: NEMMCO

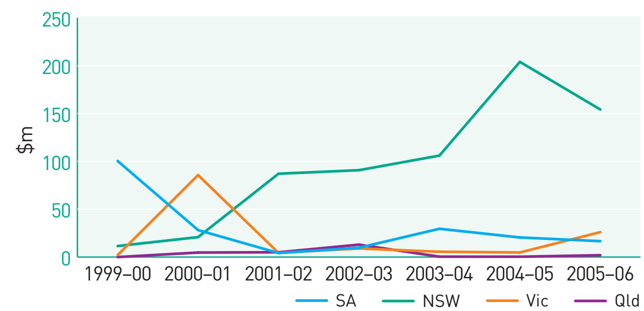
While the extent of alignment is an indicator of how effectively the market is working, it should be noted that full alignment would require significant investment to remove all possible causes of congestion. There is also some conjecture as to the benefits of addressing the issue. Preliminary AER research indicates that the economic costs of transmission congestion may be relatively modest (see section 4.7).

## Settlement residues

When there is price separation between regions, electricity tends to flow from lower priced regions to higher priced regions. The exporting generators are paid at their local regional spot price, while importing customers (usually energy retailers) must pay the higher spot price in the importing region. The difference between the price paid and the price received multiplied by the amount of electricity exported is called a settlement residue. Over time, these residues accrue to the market operator, NEMMCO.

Figure 2.8 charts the annual accumulation of inter-regional settlement residues in each region. There is some volatility in the data, reflecting that a complex range of factors can contribute to price separation—for example, the availability of transmission interconnectors and generation plant, weather conditions and the bidding behaviour of generators.

Figure 2.8
Settlement residues

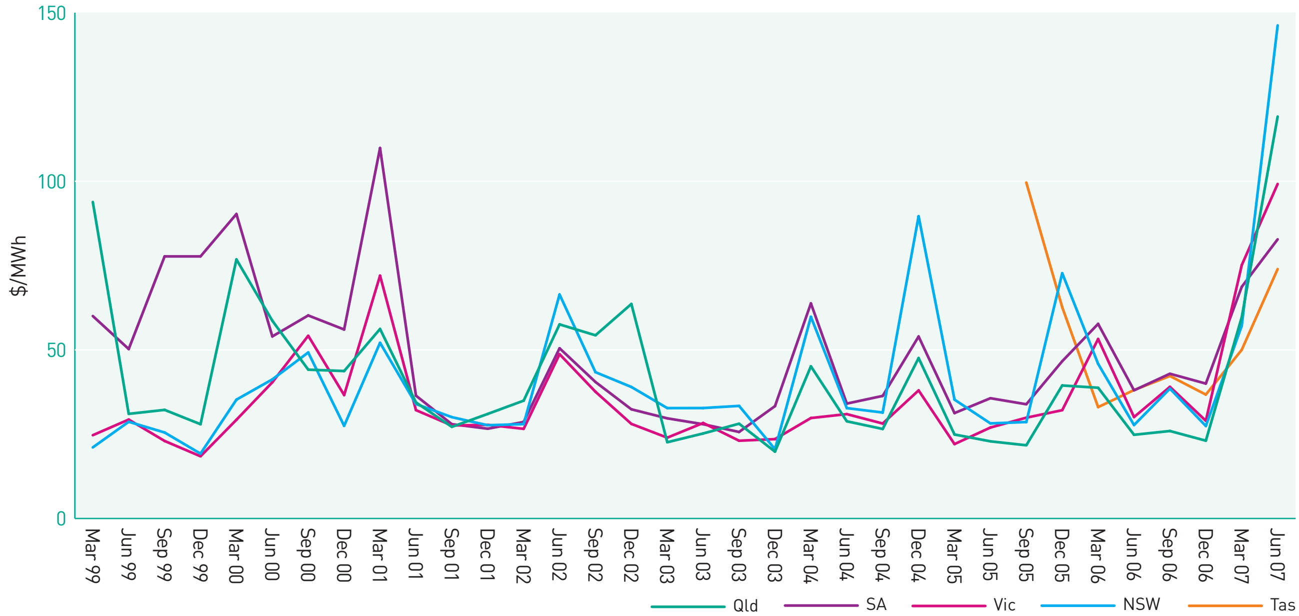



Data source: NEMMCO

New South Wales recorded settlement residues of around $100 million or more each year from 2001–02, reaching $200 million in 2004–05. This may reflect the region's status as the largest importer of electricity (in dollar terms) since the NEM commenced, making it vulnerable to price separation events. South Australia and Victoria also recorded settlement residues. As a net exporter, the Queensland region tends not to accumulate settlement residue balances. The residues resulting from exports from the Snowy region are included in the relevant importing region.

Price separation creates risks for the parties that contract across regions. NEMMCO offers a risk management instrument by holding quarterly auctions to sell the rights to future residues. An explanation of the auction process is provided in section 4.7.

Figure 2.9
**Quarterly volume weighted average spot prices in the National Electricity Market**




Data source: NEMMCO

## 2.5 National Electricity Market prices

NEMMCO's central dispatch process determines a spot price for each NEM region every 30 minutes.[7] As noted, prices can vary between regions because of losses in transportation and transmission congestion, which sometimes restricts inter-regional trade.

Figures 2.9 charts quarterly volume-weighted average prices since the NEM commenced, while table 2.3 sets out annual volume weighted prices. Figure 2.10 provides a more detailed snapshot of weekly prices since July 2005. Overall, prices tended to fall in the early years of the NEM—especially in Queensland and South Australia—following investment in new transmission and generation capacity. In the past three years, warmer summers and record peak demands have seen prices rise relative to earlier in the decade.

A variety of factors led to significantly higher prices in 2006–07. In January 2007, bushfires caused an outage of the Victoria–Snowy interconnector, causing price spikes in Victoria and South Australia. Network issues in Queensland in late January also affected prices. While wholesale prices normally ease in autumn—when demand is relatively subdued—the reverse occurred in 2007, when drought began to impact on prices. The drought constrained hydro-generating capacity in the Snowy, Tasmania and Victoria and also limited the availability of water for cooling in some coal-fired generators. In combination, these factors led to a tightening of supply and higher offer prices by generators.

These conditions were exacerbated in June 2007 by a number of generator outages, network outages and generator limitations. For example, rain and flooding in the Hunter Valley made some generation capacity unavailable for a period. Tight supply was accompanied by record electricity demand as cold winter days increased heating requirements. In combination these factors led to an extremely tight supply-demand balance during the early evening peak hours, particularly in New South Wales.

7 NEMMCO issues dispatch instructions every five minutes. The instructions tell each generator how much it needs to generate during the five-minute dispatch interval. A price is determined for each five-minute period based on generator offers, and is then averaged over 30-minute time periods ('trading intervals'). Generators are paid for each MW generated during a trading interval at the average price over the trading interval.

**Table 2.3 Annual average NEM prices by region ($/MWh)**

| | QLD | NSW | SNOWY | VIC | SA | TAS |
|---|---|---|---|---|---|---|
| 2006–07 | 57 | 67 | 38 | 61 | 59 | 51 |
| 2005–06 | 31 | 43 | 29 | 36 | 44 | 59 |
| 2004–05 | 31 | 46 | 26 | 29 | 39 | |
| 2003–04 | 31 | 37 | 22 | 27 | 39 | |
| 2002–03 | 41 | 37 | 27 | 30 | 33 | |
| 2001–02 | 38 | 38 | 27 | 33 | 34 | |
| 2000–01 | 45 | 41 | 35 | 49 | 67 | |
| 1999–2000 | 49 | 30 | 24 | 28 | 69 | |
| 1998–99[1] | 60 | 25 | 19 | 27 | 54 | |

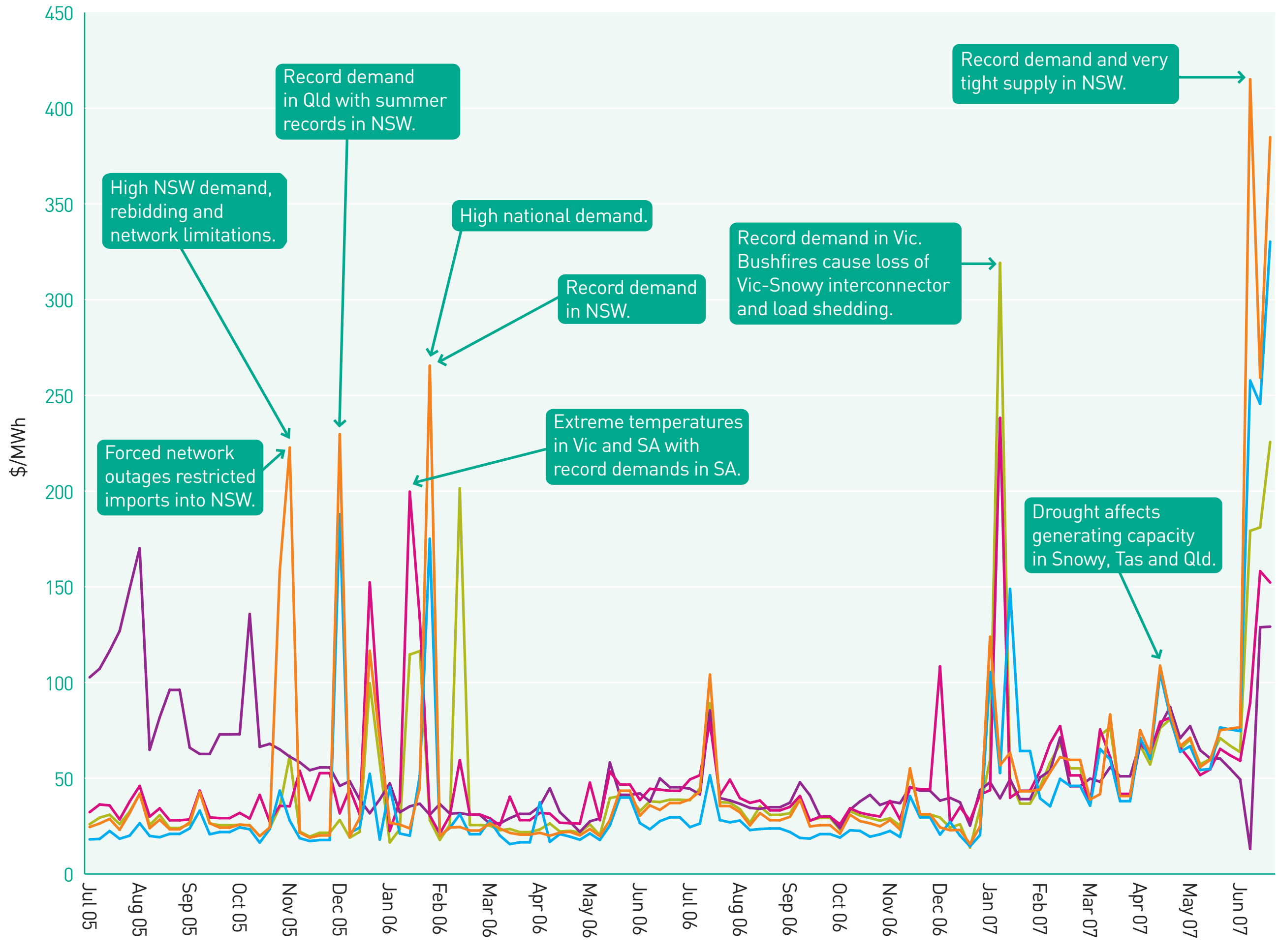
1. 6 months to 30 June 1999.
Data source: NEMMCO

These conditions led to some of the highest spot prices since the NEM commenced. In particular, spot prices exceeded $5000 a MWh on 42 occasions during June 2007 in New South Wales, Queensland and Snowy. The AER published a report on these events in July 2007, including the contributing impact of high demand, constrained supply and other factors.

Prices in the physical spot market flowed through to forward prices, which in June 2007 reached historically high levels (chapter 3). This suggests that the market is factoring in the risk of persistently tight supply for some time into the future.

The AER closely monitors the market and reports weekly on wholesale and forward market activity. It also publishes more detailed analysis of extreme price events.

**Figure 2.10**
**NEM prices July 2005–June 2007 (weekly volume weighted averages)**




Data source: NEMMCO

## 2.6 Price volatility

The spot prices determined every 30 minutes in the NEM reflect fluctuating supply and demand conditions. The market is sensitive to changes in these conditions, which can occur at short notice. For example, electricity demand can rise swiftly on a hot day. Similarly, an outage of a generator or transmission line can quickly increase regional spot prices. The sensitivity of the market to changing supply and demand conditions can result in considerable price volatility.

Figure 2.10 charts volume weighted spot prices on a weekly basis in the NEM from July 2005 to June 2007. As noted, there were a number of price spikes in 2006–07. Prices spiked in Victoria and South Australia in January 2007 due to bushfires that caused an outage of the Victoria-Snowy interconnector and other flow-on effects. There were also price spikes due to network issues in Queensland in late January. Extremely tight demand and supply conditions in New South Wales in June 2007 caused record prices with flow-on effects in other regions.

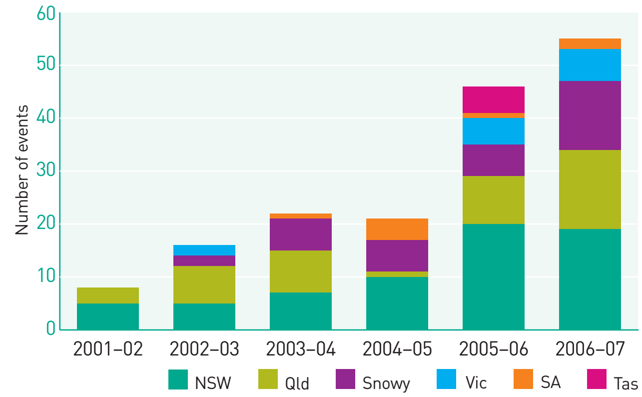
### Extreme price events

As figure 2.10 is based on weekly averages, it masks more extreme spikes that can occur during a half-hour trading interval. On occasion, 30-minute spot prices approach the market cap of $10 000 a MWh. Two indicators of the incidence of extreme price events are:

- the number of 30-minute trading intervals above $5000 a MWh (figure 2.11)
- the number of 30-minute spot prices per week that are more than three times the volume weighted average price (figure 2.12).

The number of 30-minute trading intervals with prices above $5000 a MWh has increased since the NEM commenced (figure 2.11). In particular, the number of events more than doubled in 2005–06 to 46 events, and rose again in 2006–07 to 55 events. Figure 2.12 indicates that weekly spot prices above three times the volume weighted average occur most frequently in summer and winter, when peak demand is highest. The AER publishes a report on every price event above $5000 a MWh.

Figure 2.11
**Number of price intervals above $5000 a MWh**




Data source: NEMMCO

Many factors can cause price spikes. While the cause of a high price event is not always clear, underlying causes might include:

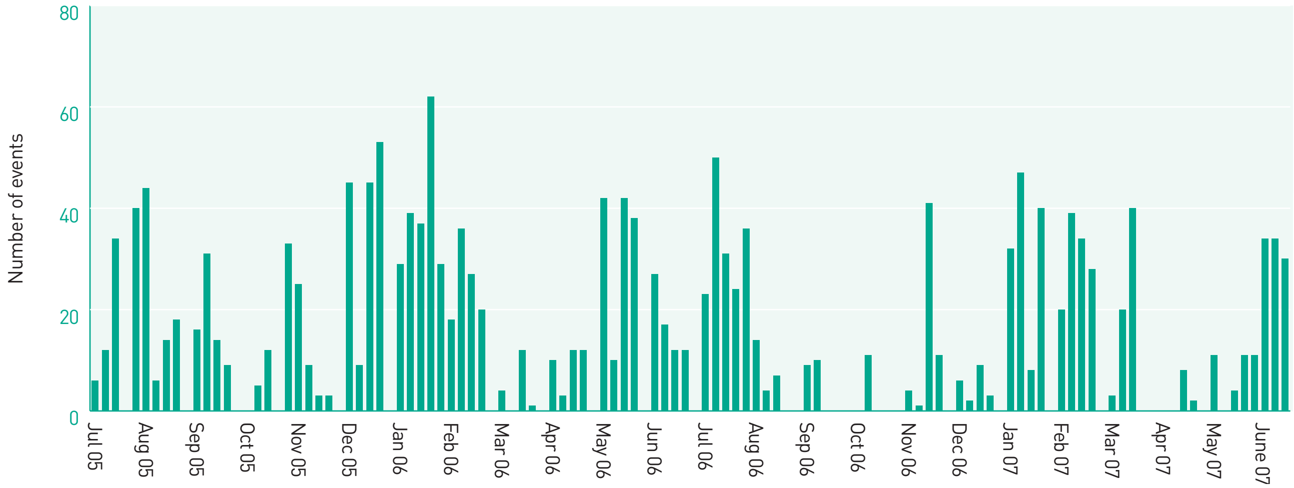
- high demand that requires the dispatch of high-cost peaking generators
- a generator outage that affects regional supply
- transmission network outages or congestion that restricts the flow of cheap imports into a region
- a lack of effective competition in certain market conditions
- a combination of factors.

To increase transparency, the AER publishes weekly reports on market outcomes. The reports highlight factors contributing to spot prices that are more than three times the volume-weighted average price for the week.

Price spikes are not uncommon in the market but can have a material impact on outcomes. If prices approach $10 000 for just two hours a year, the average price in a region may rise by 10 per cent. Generators and retailers typically hedge against this risk by taking out contractual arrangements in financial markets (see chapter 3). This can help to insulate market players from the impact of price spikes.

Figure 2.12

Weekly spot prices above three times volume-weighted average



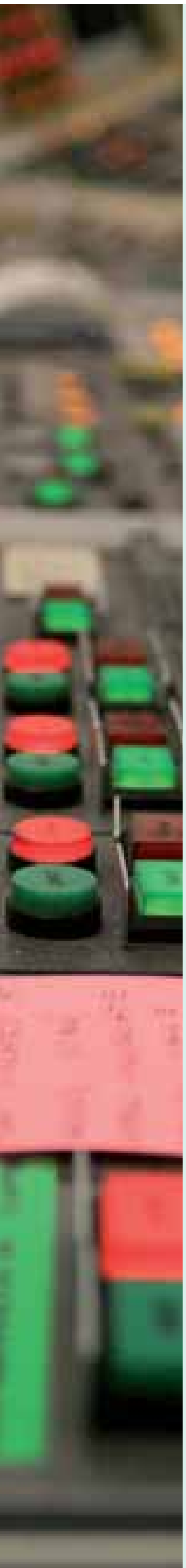

Data source: NEMMCO

Price volatility in the NEM plays an important role in providing solutions to capacity issues. In particular, extreme prices create incentives to hedge against the associated risks. This encourages investment in peaking generation plant and contracting with customers to provide a demand-side response.

For example, summer peaks in air conditioning loads create a need for peaking generation that can come online quickly. High spot prices are needed to encourage investment in peaking plant, which is expensive to operate. Spot price activity in Victoria and South Australia has led to significant investment in peaking capacity (see figure 1.10 in chapter 1).

Demand-side management responses can also help to manage tight supply-demand conditions. This might involve a retailer offering a customer financial incentives to reduce consumption at times of high demand to ease price pressures. Effective demand-side management requires suitable metering arrangements to enable customers to manage their consumption. The Energy Reform Implementation Group noted in 2007 that demand-side management activity in the NEM was mainly confined to the large customer segment. It estimated that the extent of potential demand-side response in the NEM is around 700 MW across a range of energy-consuming industries.[8] At the small customer level, COAG agreed in 2007 to a national implementation strategy for the progressive roll out of 'smart' electricity meters to encourage demand-side response (see section 6.5.4 of this report).

8 Energy Reform Implementation Group, *Energy reform: The way forward for Australia—a report to the Council of Australian Governments*, 2007.



## Box 2.2 International electricity prices

While Australian electricity prices rose in 2007, over the longer term they have been low relative to liberalised markets overseas. The principal reason is access to a low-priced fuel such as brown or black coal. Table 2.4 compares annual load-weighted wholesale prices in the NEM with selected international markets on a calendar year basis.

Comparisons across markets should be made with caution. Various factors can impact on wholesale market outcomes, including:

- market design—for example, the use or absence of a capacity market
- the stage of the investment cycle
- overcapacity that may be a legacy from previous regulatory regimes
- meteorological conditions
- fuel costs and availability
- exchange rates
- requirements under a carbon trading scheme
- regulatory intervention.

Prices in the Nordpool (an electricity market linking Norway, Sweden, Finland and Denmark) increased significantly over the period 1999–2006. Heavily reliant on hydro-electric power, prices in this region have a strong negative correlation with rainfall levels. The sharp price increase in 2006 resulted from a combination of factors, including increased load, rising fuel costs, low reservoir levels, unavailability of nuclear plants in Sweden and the introduction of a carbon-trading scheme in Europe.

The Electric Reliability Council of Texas (ERCOT) operates a wholesale market that supplies electricity to 75 per cent of Texas. Price fluctuations in this market, as well as the Alberta market, largely reflect changes in the cost of natural gas.

**Table 2.4 Average wholesale prices in selected markets ($AUD/MWh)**

| | NEM | | | | INTERNATIONAL | | | | |
|---|---|---|---|---|---|---|---|---|---|
| YEAR | NSW | QLD | SA | VIC | NORDPOOL (SCANDINAVIA) | ALBERTA[1] (CANADA) | ERCOT (TEXAS) | NEMS (SINGAPORE) | PJM[2] (USA) |
| 2006 | 35 | 28 | 45 | 38 | 81 | 95 | – | 111 | 71 |
| 2005 | 41 | 27 | 37 | 28 | 48 | 76 | 95 | 86 | 83 |
| 2004 | 53 | 37 | 47 | 32 | 49 | 57 | 61 | 66 | 60 |
| 2003 | 30 | 24 | 29 | 25 | 64 | 69 | 68 | 82 | 64 |
| 2002 | 45 | 52 | 38 | 35 | 47 | 52 | 47 | – | 57 |
| 2001 | 36 | 37 | 52 | 40 | 40 | 92 | – | – | 71 |
| 2000 | 39 | 56 | 65 | 40 | 20 | – | – | – | 53 |
| 1999 | 24 | 46 | 60 | 24 | 22 | – | – | – | 53 |

1. Prices for Alberta are unweighted.

2. The PJM includes a capacity market.

NordPool: Market between Norway, Sweden, Finland and Denmark; ERCOT: Electric Reliability Council of Texas; NEMS: National Electricity Market of Singapore; PJM: Pennsylvania–New Jersey–Maryland Pool.

Rounded annual volume weighted price comparison based on calendar year data.

Price conversions to Australian dollars based on average annual exchange rates.

Sources: Nordpool, PJM, Electricity Market Company of Singapore, ERCOT, Alberta Electric System Operator.

The Pennsylvania–New Jersey–Maryland pool (the PJM) links generating facilities in 12 states in the USA. Coal is the major fuel source for electricity in the market (accounting for over 50 per cent of generation), with gas (28 per cent) and nuclear (19 per cent) also significant. For 1999 prices in the PJM were comparable to those in Queensland and South Australia. The market then saw a fairly steady increase in prices to 2005. Average prices moved above $80 a MWh in 2005 following a 40 to 50 per cent increase in oil and gas costs.[9]

Unlike the NEM, the PJM operates a capacity market in conjunction with the energy market. Capacity markets provide an additional source of revenue for generators and so reduce revenue requirements in the energy market. Accordingly, spot prices in the PJM would likely be higher in the absence of capacity markets. Adjusting for this difference, table 2.4 may understate the price discount in the NEM compared to the PJM.

The National Electricity Market of Singapore (NEMS) commenced operating in January 2003. With electricity generation fuelled by gas (49 per cent), fuel oils (48 per cent) and diesel (3 per cent), prices have been substantially above those experienced in the NEM.[10]

9 PJM, *2005 State of the market report*, Market Monitoring Unit, 2006.

10 Energy Market Company of Singapore, *2006 Market report of the National Electricity Market of Singapore*, 2007.


# 3 ELECTRICITY FINANCIAL MARKETS


Sydney Futures Exchange. Michelle Mossop (Fairfax Images)

Spot price volatility in the National Electricity Market can cause significant price risk to market participants. While generators face a risk of low prices impacting on earnings, retailers face a complementary risk that prices may rise to levels they cannot pass on to their customers. A common method by which market participants manage their exposure to price volatility is to enter into financial contracts that lock in firm prices for the electricity they intend to produce or buy in the future.

# 3 ELECTRICITY FINANCIAL MARKETS

This chapter considers:

- the structure of electricity financial markets in Australia, including the direct over-the-counter market, the brokered over-the-counter market and the exchange traded market on the Sydney Futures Exchange
- financial market instruments traded in Australia
- liquidity indicators for Australia's electricity financial markets, including trading volumes, open interest, changes in the demand for particular instruments, changes in market structure and vertical integration in the underlying electricity wholesale market
- price outcomes on the Sydney Futures Exchange
- other mechanisms to manage price risk in the wholesale electricity market.

While the Australian Energy Regulator (AER) does not regulate the electricity derivatives markets, it monitors the markets because of their significant linkages with wholesale and retail activity. For example, levels of contracting and forward prices in the financial markets can affect generator bidding in the physical electricity market. Similarly, financial markets can influence retail competition by providing a means for new entrants to manage price risk (box 3.1). More generally, the markets create price signals for energy infrastructure investors and provide a means to secure the future earnings streams needed to underpin investment.

## 3.1 Financial market structure

Financial markets offer contractual instruments—called derivatives—to manage forward price risk in electricity markets. While the derivatives provide a means of locking in future prices, they do not give rise to the physical delivery of electricity.

The participants in electricity derivatives markets include generators, retailers, financial intermediaries and speculators such as hedge funds. Brokers facilitate many transactions, but in other cases the contracting parties negotiate directly with one another.

Financial markets support wholesale electricity markets in various parts of the world, including Germany (European Energy Exchange), France (Powernext), Scandinavia (NordPool) and a number of markets in the USA. In Australia, two distinct electricity financial markets have emerged:

- over-the-counter (OTC) markets, comprising direct transactions between two counterparties, often with the assistance of a broker
- the exchange traded market on the Sydney Futures Exchange (SFE).

### Over-the-counter markets

OTC markets allow market participants to enter into confidential contracts to manage risk. Many OTC contracts are bilateral arrangements between generators and retailers, which face opposing risks in the physical spot market. Other OTC contracts are arranged with the assistance of brokers that post bid (buy) and ask (sell) prices on behalf of their clients. Financial intermediaries and speculators add market depth and liquidity by quoting bid and ask prices, taking trading positions and by taking on market risk to facilitate transactions.

Most OTC transactions are documented under the International Swaps and Derivatives Association master agreement, which provides a template of standard terms and conditions, including terms of credit, default provisions and settlement arrangements. While the template creates considerable standardisation in OTC contracts, the terms can be modified by agreement. In particular, it is open to market participants to negotiate OTC arrangements to suit their particular needs. This means that OTC products can provide flexible solutions through a variety of structures.



#### Box 3.1 Case study—Price spikes in the National Electricity Market—a retailer's exposure

On 31 October 2005, the New South Wales spot price spiked due to an outage on a major transmission line supplying Sydney. The repair of the line caused a second line to be taken out of service. The loss of transmission capacity meant that less electricity could be imported from the Snowy region. In addition, some New South Wales generators were constrained from operating at maximum output levels. Even though it was not a day of extreme demand, the New South Wales spot price rose as high as $7000 a megawatt hour (MWh) for some price intervals. While the spike affected only nine out of 48 price intervals on that day, an unhedged retailer would have faced significant losses that could not be recouped in the retail market.

To manage spot price risk, retailers can hedge their portfolios by purchasing financial derivatives that lock in firm prices for the volume of energy they expect to purchase in the future. This eliminates exposure to future price volatility for the quantity hedged, and provides greater certainty on profits. Similarly, a generator can hedge against low spot prices.

While retailers typically adopt a 'long' position in financial markets to protect against high spot prices, they sometimes take a 'short' portfolio position by deferring hedging. For example, a retailer might predict that forward prices will fall, such that hedge cover will be available at a better price in the future. This poses a risk that the retailer may be exposed to losses if forward prices rise.

The *Financial Services Reform Act 2001* includes disclosure provisions that relate to OTC markets. In general, however, the bilateral nature of OTC markets tends to make volume and price activity less transparent than in the exchange traded market.

## Exchange traded futures

Derivative products such as electricity futures are traded on registered exchanges. In Australia, electricity futures are traded on the SFE, in which participants (licensed brokers) buy and sell contracts on behalf of clients such as generators, retailers, speculators, financial intermediaries and hedge funds.[1]

There are a number of differences between OTC trading and exchange trade on the SFE:

> Exchange traded derivatives are highly standardised in terms of contract size, minimum allowable price fluctuations, maturity dates and load profiles. The product range in OTC markets tends to be more diverse and includes 'sculpted' products.

> Exchange trades are multilateral and publicly reported, giving rise to greater market transparency and price discovery than in the OTC market.

> Unlike OTC transactions, exchange traded derivatives are settled through a centralised clearing house, which becomes the central counterparty to all transactions. Exchange clearing houses, such as the SFE Clearing Corporation, are regulated and are subject to prudential requirements that mitigate credit default risks. This offers an alternative to OTC trading, in which trading parties rely on the credit worthiness of electricity market counterparties. More generally, liquidity issues can arise in OTC markets if trading parties reach or breach their credit risk limits with other OTC counterparties.

## Regulatory framework

Electricity financial markets are subject to a regulatory framework that includes the *Corporations Act 2001* and the *Financial Services Reform Act 2001*. The Australian Securities and Investment Commission is the principal regulatory agency. Amendments to the Corporations Act in 2002 extended insider trading legislation and the disclosure principles expected from securities and equity-related futures to electricity derivative contracts. The Energy Reform Implementation Group (ERIG) noted in 2006 that there remains some uncertainty among market participants as to their disclosure requirements under the legislation.[2]

In 2004, the Australian Accounting Standards Board (AASB) issued new or revised standards to harmonise Australian standards with the International Financial Reporting Standards. The new standards included AASB 139, which requires companies' hedging arrangements to pass an effectiveness test to qualify for hedge accounting. The standards also outline financial reporting obligations such as mark to market valuation of derivative portfolios.[3]

There are a number of further regulatory overlays in electricity derivative markets. For example:

> the Corporations Law requires that OTC market participants have an Australian Financial Services licence or exemption

> exchange based transactions are subject to the operating rules of the SFE.

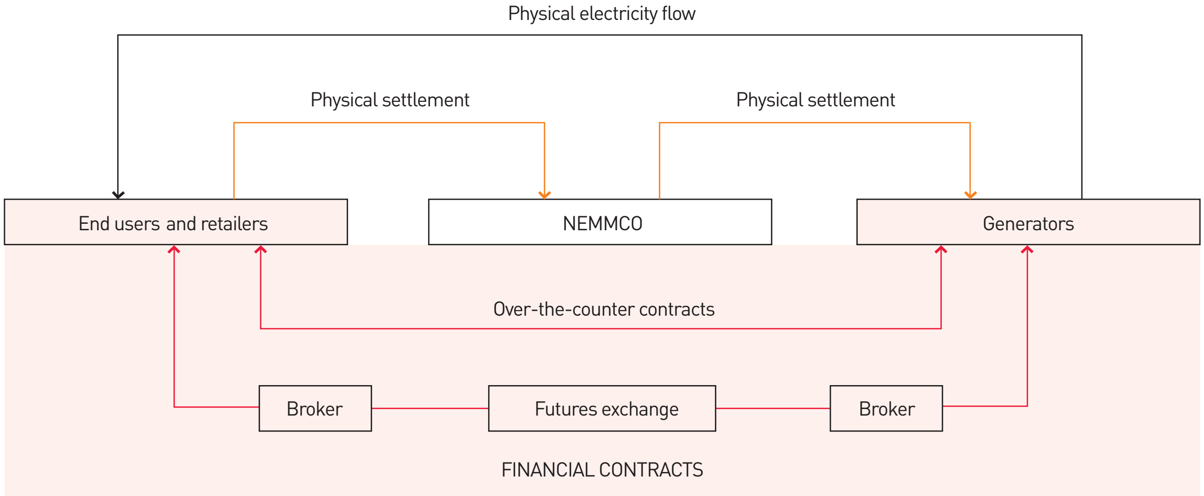
1 In 2006 the Sydney Futures Exchange merged with the Australian Stock Exchange. The merged company operates under the name Australian Securities Exchange.

2 ERIG, *Discussion papers*, November 2006.

3 Mark to market refers to the valuation technique whereby unrealised profit or loss associated with a derivative position is determined (and reported in financial statements) by reference to prevailing market prices.

Figure 3.1

Relationship between the NEM and financial markets




Source: Energy Reform Implementation Group

## Relationship with the National Electricity Market

Figure 3.1 illustrates the relationship between the financial markets and the National Electricity Market (NEM). Trading and settlement in the NEM occur independently of financial market activity—although a generator's exposure in the financial market can affect its bidding behaviour in the NEM. Similarly, a retailer's exposure to the financial market may affect the pricing of supply contracts offered to customers.

## 3.2 Financial market instruments

The financial market instruments traded in the OTC and exchange traded markets are called derivatives because they derive their value from an underlying asset—in this case, electricity traded in the NEM. The derivatives give rise to cash flows from the differences between the contract price of the derivative and the spot price of electricity. The prices of these instruments reflect the expected spot price and premiums to cover credit default risk and market risk.

Table 3.1 lists some of the derivative instruments available in the OTC and exchange traded markets. Common derivatives to hedge exposure to the NEM spot price are forwards (such as swaps and futures), and options (such as caps). Each provides the buyer and seller with a fixed price—and therefore a predictable future cash flow—either upon purchase/sale of the derivative or, in the case of an option, if the option is exercised. The following section describes some of the instruments in more detail.

**Table 3.1 Common electricity derivatives in OTC and SFE markets**

| INSTRUMENT | DESCRIPTION |
|---|---|
| Forward contracts<br>– swaps (OTC market)<br>– futures (SFE) | Agreement to exchange the NEM spot price in the future for an agreed fixed price. Settlement is based on the difference between the future spot price and the agreed fixed price. Forwards are called swaps in the OTC markets and futures on the SFE |
| Options | A right—without obligation—to enter into a transaction at an agreed price in the future |
| – cap | A contract that places a ceiling on the effective price the buyer will pay for electricity in the future |
| – floor | A contract that sets a minimum effective price the buyer will pay for electricity in the future |
| – swaptions/future options | An option to enter into a swap/futures contract at an agreed price and time in the future |
| – Asian options | An option in which the payoff is linked to the average value of an underlying asset (usually the NEM spot price) during a defined period |
| – profiled volume options for sculpted loads | A volumetric option that gives the holder the right to purchase a flexible volume in the future at a fixed price |

## Forward contracts

Forward contracts—called swaps in the OTC market and futures on the SFE—allow a party to buy or sell a given quantity of electricity at a fixed price over a specified time horizon in the future. Each contract relates to a nominated time of day in a particular region. On the SFE, contracts are quoted for quarterly base load and peak load contracts, for up to four years into the future.[4]

For example, a retailer might enter into an OTC contract to buy 10 megawatts of Victorian peak load in the third quarter of 2007 at $59 a MWh. During that quarter, whenever the Victorian spot price for any interval from 7.00 am to 10.00 pm Monday to Friday settles above $59 a MWh, the seller (which might be a generator or financial intermediary) pays the difference to the retailer. Conversely, the retailer pays the difference to the seller when the price settles below $59. In effect, the contract locks in a price of $59 a MWh for both parties.

A typical OTC swap might involve a retailer and generator contracting with one another—directly or through a broker—to exchange the NEM spot price for a fixed price that reduces market risk for both parties. On the exchange-traded market, the parties (generators, retailers, financial intermediaries and speculators) that buy and sell futures contracts through SFE brokers remain anonymous, and the SFE Clearing Corporation is the central counterparty to all transactions. As noted, exchange trading is more transparent in terms and prices and trading volumes, but tends to offer a narrower range of instruments than the OTC market.[5]

## Options

While a swap or futures contract gives price certainty, it locks the parties into defined contract prices with defined volumes—without an opt out provision. An option gives the holder the right—without obligation—to enter into a contract at an agreed price, volume and term in the future. The buyer pays a premium to the option seller for this added flexibility.

A call (put) option effectively gives the holder the right to buy (sell) a specified volume of electricity in the future at a predetermined strike price—either at any time before the option's maturity (an 'American' option) or at maturity (a 'European' option). For example, a retailer that buys a call option to protect against a rise in NEM spot prices can later abandon that option if prices do not rise as predicted. The retailer could then take advantage of the prevailing NEM spot price.

4 A peak contract relates to the hours from 7.00 am to 10.00 pm Monday to Friday, excluding public holidays. Off-peak is outside that period. A flat price contract covers both peak and off-peak periods.

5 There are around 640 listed d-cypha SFE electricity futures and options products. The OTC market can support a virtually unlimited range of bilaterally negotiated product types.

Option products include caps, floors and combinations such as collars (see below). The range and diversity of products is expanding over time to meet the requirements of market participants. More exotic options include swaptions and Asian options (table 3.1).

### Caps, floors and collars

Commonly traded options in the electricity market are caps, floors and collars.[6] A cap allows the buyer—for example, a retailer with a natural 'short' exposure to spot prices—to set an upper limit on the price that they will pay for electricity while still being able to benefit if NEM prices are lower than anticipated. For example, a cap at $300 a MWh—the cap most commonly traded in Australia—ensures that no matter how high the spot price may rise, the buyer will pay no more than $300 a MWh for the agreed volume of electricity. In Australia, a cap is typically sold for a nominated quarter—for example, July–September 2008.

By contrast, a floor contract struck at $30 a MWh will ensure a minimum price of $30 a MWh for a buyer such as a generator with a natural 'long' exposure to spot prices. Retailers typically buy caps to secure firm maximum prices for future electricity purchases, while generators use floors to lock in a minimum price to cover future generation output. A collar combines a cap and floor to set a price band in which the parties agree to trade electricity in the future.

### Flexible volume instruments

Instruments such as swaps and options are used to manage NEM price risk for fixed quantities of electricity. But the profile of electricity loads varies according to the time of day and the weather conditions. This can result in significant volume risk in addition to price risk. In particular, it can leave a retailer over-hedged or under-hedged, depending on actual levels of electricity demand. Conversely, windfall gains can also be earned.

Structured products such as flexible volume contracts are used to manage volume risks. These sculpted products, which are mainly traded in the OTC market, enable the buyer to vary the contracted volume on a pre-arranged basis. The buyer pays a premium for this added flexibility.

## 3.3 Financial market liquidity

The effectiveness of financial markets in providing risk management services depends on the extent to which they offer the products that market participants require. Adequate market liquidity is critical in this regard. In electricity financial markets, liquidity relates to the ability of participants to transact a standard order within a reasonable timeframe to manage their load and price risk, using reliable quoted prices that are resilient to large orders, and with sufficient market participants and trading volumes to ensure low transaction costs.

There are various indicators of liquidity in the electricity derivatives market, including:

- the volume and value of trade (including relating to NEM volumes)
- the open interest of contracts
- transparency of pricing
- the number and diversity of market participants
- the number of market makers and the bid-ask spreads quoted by them
- the number and popularity of products traded
- the degree of vertical integration between generators and retailers
- the presence in the market of financial intermediaries.

This chapter focuses mainly on liquidity indicators relating to trading volumes, but it includes some consideration of open interest data, pricing transparency, changes in the demand for particular derivative products, changes in the financial market's structure and vertical integration.



6 While caps and floors are technically options—they are effectively a series of half-hourly options—they are typically linked to the NEM spot price and are automatically exercised when they deliver a favourable outcome. Other options, such as swaptions, are generally linked to forward prices, and the buyer must nominate whether or not the option is to be exercised.

## 3.4 Trading volumes in Australia's electricity derivative market

There is comprehensive data on derivative trading on the SFE, which is updated on a daily and real time basis. The OTC market is less transparent, but periodic survey data provides some indicators of trading activity.

### Trading volumes — Sydney Futures Exchange

Financial market vendors such as d–cyphaTrade publish data on derivative trading on the SFE. Table 3.2 and figure 3.2 illustrate the growth in trading volumes in electricity futures and options. Trading levels rose sharply from a low base in 2003–04, eased in 2004–05 and rose by 129 per cent in 2005–06. Growth then accelerated, with volumes rising by around 345 per cent in 2006–07. Traded volumes in 2006–07 reached around 125 per cent of underlying NEM physical demand. These outcomes appear to be consistent with the Australian Securities Exchange's view that futures market liquidity takes time to build from a low base to an 'inflection point' where proprietary trading firms, banks, funds and other speculators are attracted en masse.[7]

Trading on the SFE comprises a mix of futures (first listed in September 2002) and caps and other options (first listed in November 2004). Trading in options currently represents up to 40 per cent of monthly turnover.

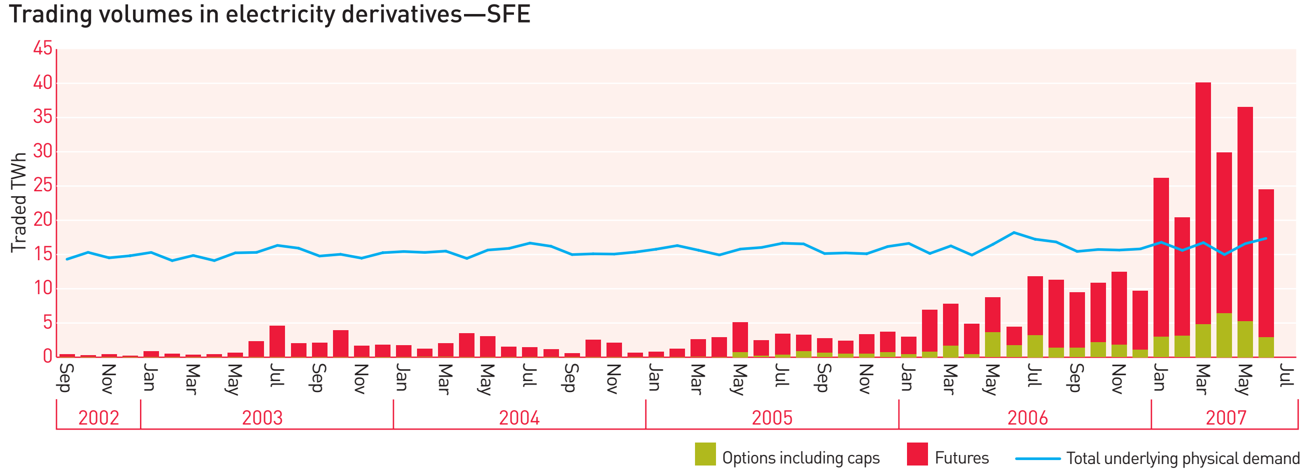
**Table 3.2** Trading volumes in electricity derivatives—SFE

| | 2002–03 | 2003–04 | 2004–05 | 2005–06 | 2006–07 |
|---|---|---|---|---|---|
| Total trade (TWh) | 6.7 | 29.5 | 23.8 | 54.6 | 243.1 |
| Increase (%) | | 340.9 | –19.1 | 129.3 | 345 |

Source: d-cyphaTrade

Figure 3.3 shows the composition of futures and options trade on the SFE by maturity date, based on open interest data—the number of open contracts at a point in time (box 3.2). The SFE trades quarterly futures and options out to four years ahead, compared to three years in many overseas markets.[8] Liquidity tends to be highest one to two years out as electricity retail contracts typically run from one to three years with the majority being negotiated for one year. Some retailers do not lock in forward hedges beyond the term of existing customer contracts.

**Figure 3.2**
Trading volumes in electricity derivatives—SFE




Source: d-cyphaTrade

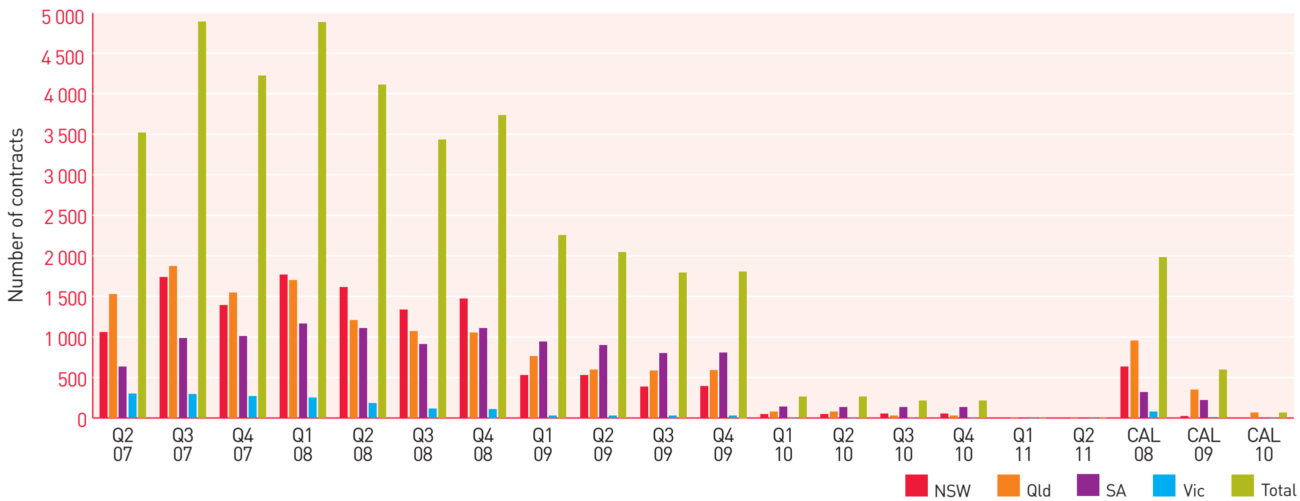
7 Australian Securities Exchange, *Submission to Energy Reform Implementation Group*, 2006.
8 See, for example, www.eex.de (Germany) or www.powernext.fr (France).

Figure 3.4 illustrates regional trading volumes. New South Wales, Queensland and Victoria have recorded significant growth in trading volumes since 2005, with exceptional growth in the early months of 2007. In 2006–07, Victoria accounted for 38 per cent of volumes, followed by New South Wales and Queensland (29 per cent each). Liquidity levels in South Australia have remained low since 2002. South Australia accounts for around 4 per cent of traded volumes (figure 3.5).



## Figure 3.3

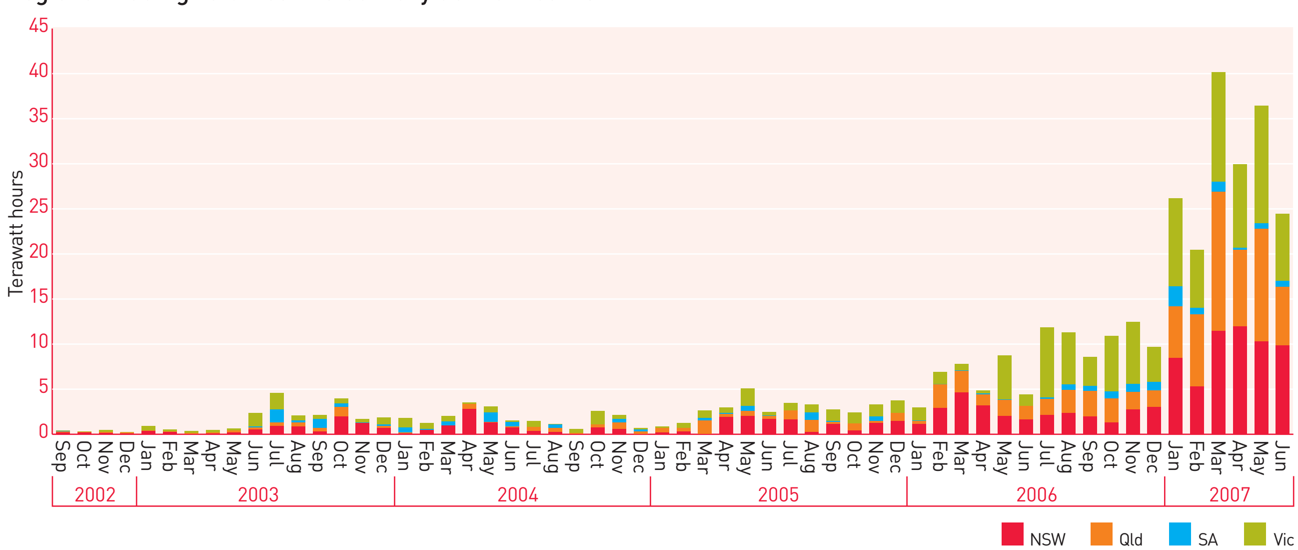
### Open interest in electricity forward contracts by maturity date at June 2007—SFE




Source: d-cyphaTrade

## Figure 3.4

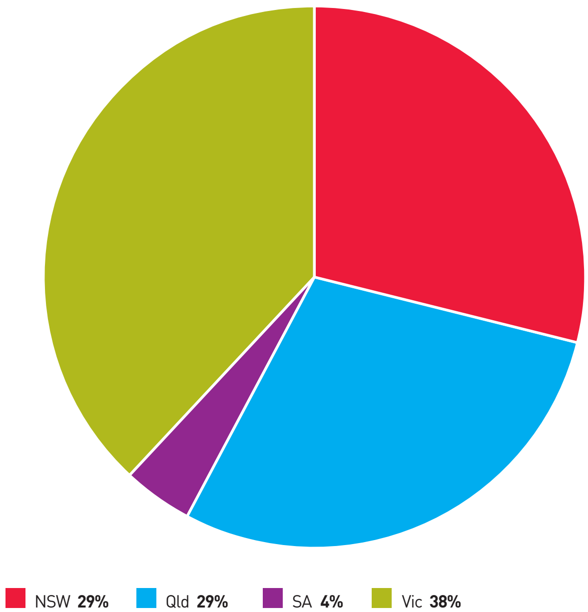
### Regional trading volumes in electricity derivatives—SFE




Source: d-cyphaTrade

Figure 3.5

**Regional shares of SFE electricity derivatives trade (terawatt hours), 2006–07**




Source: d-cyphaTrade

## Trading volumes—OTC markets

There is limited data on liquidity in the OTC markets because transactions are only visible to the parties engaged in trade. The Australian Financial Markets Association (AFMA) conducts an annual survey of OTC market participants on direct bilateral and broker-assisted trade. AFMA reports that most, but not all, participants respond to the survey. A particular OTC transaction will be captured in the AFMA data if at least one party to the trade participates in the survey.

As figure 3.7 indicates, total OTC trades have averaged around 200 terawatt hours (TWh) a year since 2000–01. Volumes peaked at 235 TWh in 2002–03, and fell to 177 TWh in 2005–06. Turnover fell by 9 per cent in 2004–05, and by 11 per cent in 2005–06.


### Box 3.2 Open interest on the Sydney Futures Exchange

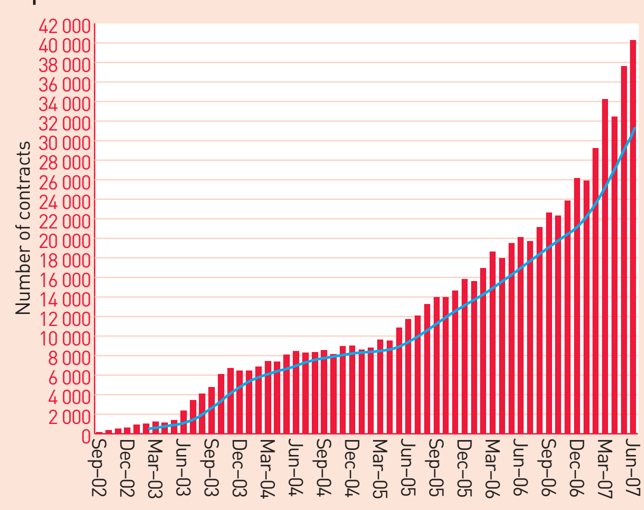
Many financial contracts are entered into, while others are closed out or transferred, every trading day on the SFE. Open interest refers to the total number of futures and option contracts that have been entered into and remain open—that is, have not been exercised, expired or closed out—at a point in time. In other words, it provides a snapshot on a particular day of all contracts that remain open, including contracts entered into on that day and those that have been open for days, months or years.

Trends in open interest provide one indicator of market liquidity, usually in conjunction with trading volumes. An increase in open interest typically accompanies a rise in trading volumes and reflects underlying demand growth. A decline in open interest indicates that market participants are closing their open position, which suggests they have less need to retain the hedges they have entered into.

As figure 3.6 illustrates, the SFE electricity futures market has experienced a steady increase in open interest since 2002. The number of open contracts rose from around zero in 2002 to over 40 000 in June 2007. This provides one indicator of rising overall liquidity in the exchange market.

Figure 3.6

**Open interest on the SFE**




Source: d-cyphaTrade

Figure 3.7

**Regional trading volumes—OTC market**

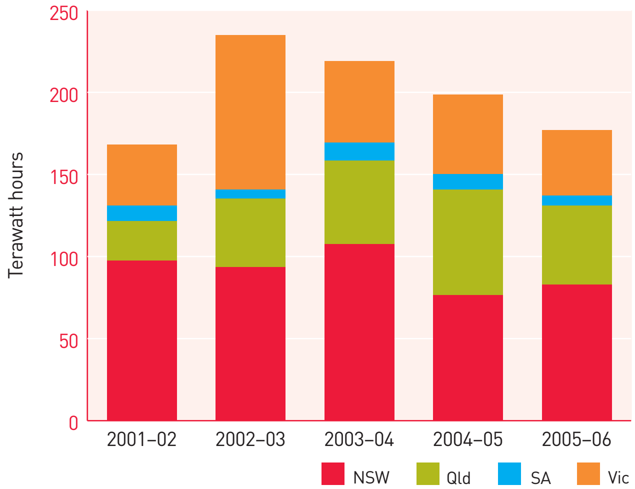
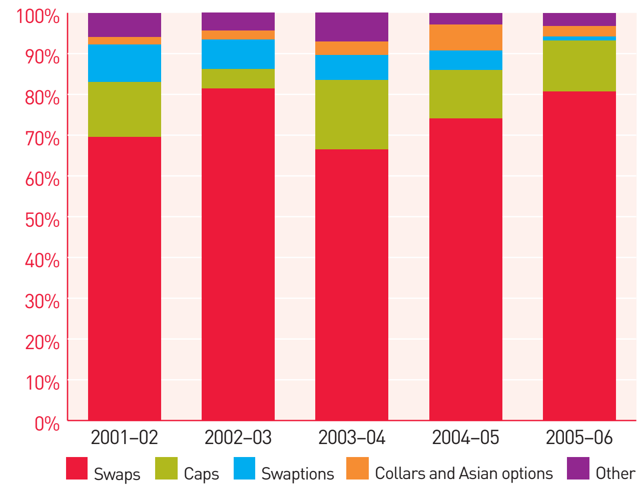



Figure 3.8

**Trading volumes by derivative type—OTC market**




Data source: AFMA, *2006 Australian Financial Markets Report*, 2006.

On a regional basis, volumes fell in 2005–06 in Queensland, Victoria and South Australia, which AFMA attributed to ownership changes in those markets. Turnover rose in New South Wales. The low volumes recorded for South Australia are consistent across the OTC and exchange-traded markets.

Around 80 per cent of OTC trade in 2005–06 was in swaps, with the balance in caps, swaptions, collars and Asian options. The last three years have seen a shift away from exotic derivatives in favour of swaps (figure 3.8).[9]

## Composition of OTC trading

In 2006, PricewaterhouseCoopers (PwC) published a survey of liquidity in electricity derivatives,[10] which indicated that broker assisted trading in OTC markets rose strongly from 2002–03 to 2004–05 before falling by around 14 per cent in 2005–06.[11] PwC also compared its data against the AFMA survey data on total OTC turnover and found a trend away from direct bilateral trading towards broker-assisted trading (figure 3.9). Broker trading doubled from around 30 per cent of AFMA volumes in 2002–03 to around 60 per cent in 2005–06.

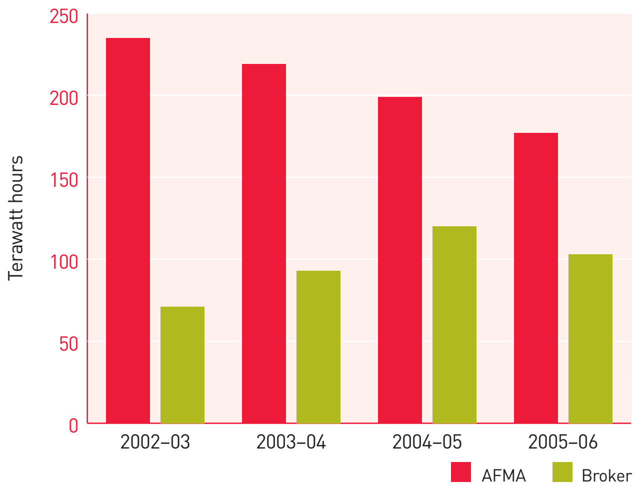


9 AFMA, *2006 Australian financial markets report*, 2006.

10 PwC, *Independent survey of contract market liquidity in the National Electricity Market 9th August*, commissioned by the National Generators Forum and Energy Retailers Association of Australia, 2006.

11 Broker assisted OTC trade fell in the year to 2005–06 but was more than offset by a significant rise in volumes on the SFE.

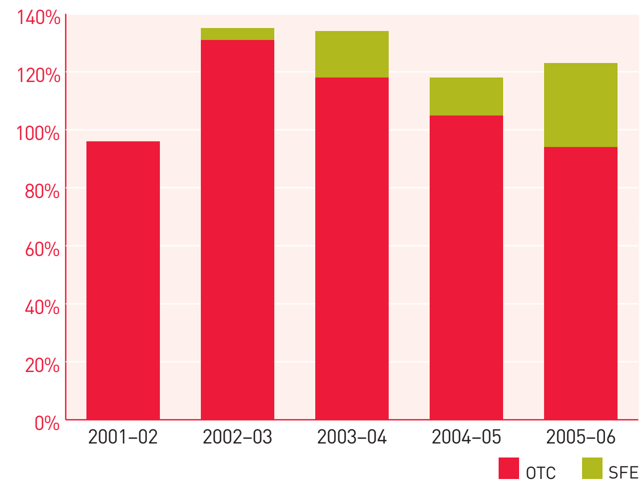
Figure 3.9
AFMA and PwC survey data on OTC trades




Note: The AFMA data includes direct bilateral trade and OTC broker activity. The difference between the two bars therefore represents an estimate of direct bilateral trade.

Source: PwC, *Independent survey of contract market liquidity in the National Electricity Market,* August 2006.

Figure 3.10
Trading volumes—OTC and SFE as a percentage of underlying NEM demand




Note: NEM demand excludes Tasmania, for which derivative products were not available.

Data sources: d-cyphaTrade/AFMA/NEMMCO.

## Aggregate trading volumes in OTC and SFE markets

Table 3.3 estimates aggregate volumes of electricity derivatives traded in OTC markets and on the SFE. The data is a simple aggregation of AFMA data on OTC volumes and d-cyphaTrade data on exchange trades. Figure 3.10 charts the same data in relation to the underlying demand for electricity in the NEM. The results should be interpreted with some caution, given that the AFMA data is based on a voluntary survey. This would result in the omission of transactions between survey non-participants. AFMA considers that the survey captures most OTC activity.

It should be noted that a particular contract may be traded more than once in a financial market if participants—including speculators—adjust their positions. This can result in derivative trading volumes that exceed 100 per cent of NEM demand. As figure 3.10 indicates, trading volumes were the equivalent of around 123 per cent of NEM volumes in 2005–06.

**Table 3.3 Volumes traded in OTC markets, SFE and NEM (terawatt hours)**

| | OTC | SFE | UNDERLYING NEM DEMAND |
|---|---|---|---|
| 2001–02 | 168.1 | 0 | 175.0 |
| 2002–03 | 235.0 | 6.7 | 179.3 |
| 2003–04 | 219.0 | 29.4 | 185.3 |
| 2004–05 | 198.9 | 23.9 | 189.7 |
| 2005–06 | 177.1 | 54.6 | 187.9 |

Note: NEM demand excludes Tasmania, for which derivative products were not available.

Data sources: d-cyphaTrade/AFMA/NEMMCO.

The data illustrates that the majority of financial trade until June 2006 occurred in the OTC markets. But OTC trading is declining both in absolute terms and relative to trading on the SFE. In 2005–06, OTC trade was equivalent to 94 per cent of NEM demand, down from 131 per cent in 2002–03. Volumes on the SFE rose from near zero in 2001–02 to levels equivalent to around 30 per cent of NEM demand in 2005–06. SFE trade grew exponentially in 2006–07, reaching around 125 per cent of underlying NEM demand.

Figure 3.11

Trading volumes by region—OTC and SFE as a percentage of regional NEM demand


Data sources: d-cyphaTrade/AFMA/NEMMCO

There are a number of reasons for the strong growth in exchange traded volumes. Amendments to the Corporations Act and the introduction of international hedge accounting standards to strengthen disclosure obligations for electricity derivatives contracts may have raised confidence in exchange-based trading. The SFE also redesigned the product offerings in 2002 to tailor them more closely to market requirements. These changes have encouraged greater depth in the market, including the entry of active financial intermediaries.

The increase in trading volumes on the SFE has also been driven by credit default risk issues in the OTC markets, where some trading parties may be reaching their credit limits with counterparties. The PwC survey of market participants cited anonymity and credit benefits as being among the reasons for the shift away from OTC markets towards exchange trading. This trend may continue with record forward prices in 2007 (section 3.7) creating large shifts in mark-to-market OTC credit exposures for some participants.[12]

Across the combined OTC and exchange markets, aggregate volumes peaked in 2002–03 and 2003–04 at over 130 per cent of NEM demand. Volumes fell below 120 per cent of NEM demand in 2004–05, but rose slightly in 2005–06.

Figure 3.11 charts regional trading volumes as a percentage of regional NEM demand. The share of total trade relative to regional NEM demand has been fairly steady in New South Wales, but has tended to rise in Queensland (despite a fall in 2005–06). In Victoria, a sharp fall in trade in 2003–04 was followed by a more stable trend. South Australia has experienced a sharp decline in trading volumes, with turnover falling from around 132 per cent of regional NEM demand in 2003–04 to 62 per cent in 2005–06. This compared with significantly higher rates in 2005–06 for Victoria (112 per cent), Queensland (121 per cent) and New South Wales (135 per cent).

12 For example, retailers that purchased OTC base load calendar 2008 contracts prior to the significant price rises in 2007 may be exposed to substantial contract replacement costs if their OTC counterparties default.

The PwC survey of market participants found that a majority of respondents considered that liquidity in South Australia's financial markets was inadequate. Survey respondents raised a number of possible issues, including the relatively small scale of the South Australian electricity market, perceptions of risk associated with interconnection, generation capacity and extreme weather, and perceptions of high levels of vertical integration.[13] ERIG also noted gaps in the liquidity and depth of financial markets in South Australia. It also noted liquidity issues for Tasmania, which was not physically connected to the NEM until 2006. More generally, there are gaps in the market for sculpted and flexible products, which are mainly traded in the direct OTC market.[14]

## 3.5 Price transparency and bid-ask spread

While trading volumes and open interest provide indicators of market depth, part of the cost to market participants of transacting is reflected in the bid-ask spread (the difference between the best buy and best sell prices) quoted by market makers and brokers. A liquid market is characterised by relatively low price spreads that allow parties to transact at a nominal cost.

d-cyphaTrade and other market data providers publish bid-ask spreads for the exchange-traded market. In 2007 most spreads were in a range of $2 to $3. In a 2006 survey of bid-ask spreads in the OTC market, PwC found that spreads of $1 or more are not unusual and that spreads are higher for peak than off-peak periods.

The survey indicated a number of market gaps—for example:

- bids and offers were not evident for short-term products or beyond calendar year 2010
- there was a lack of bids and offers for all products in South Australia.[15]

## 3.6 Number of market participants

Ownership consolidation, such as vertical integration across the generation and retailer sectors, can affect participation in financial markets. In particular, vertical integration can reduce a company's activity in financial markets by increasing its capacity to internally offset risk. Figure 3.12 displays PwC estimates of the match of generation and retail load for Origin Energy, AGL and TRUenergy across the Victorian and South Australian markets in 2005–06.[16] While each generator has significant price and risk positions that need to be managed all have announced proposals to develop new generation projects.

KPMG estimate that vertically-integrated firms account for about 14 per cent of installed capacity across the NEM. The United Kingdom market has significant vertical integration—six vertically-integrated firms dominate the market—and low levels of financial market liquidity. ERIG considered that if the Australian market were to evolve to a handful of balanced participants, little financial trade would be expected.[17]

13 PwC, *Independent survey of contract market liquidity in the National Electricity Market,* August 2006, p. 28.

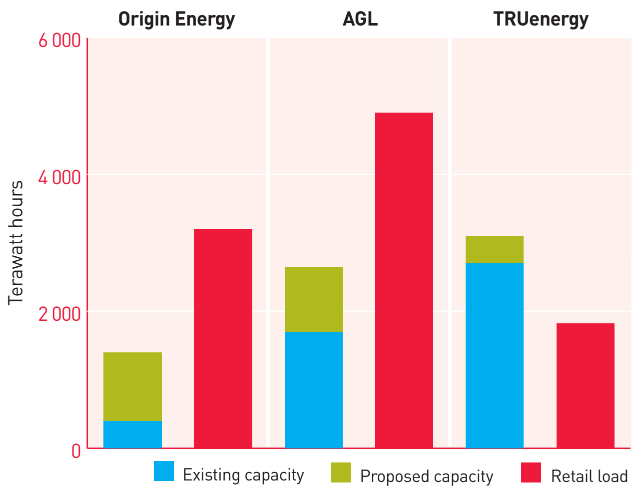
14 ERIG, *Discussion papers*, November 2006, p. 194.

15 PwC, 2006, p. 16. See footnote 13

16 Figure 3.12 excludes TRUenergy's contractual arrangement for Ecogen Energy capacity in Victoria (around 890 MW). In January 2007 AGL entered agreements to acquire the 1260 MW Torrens Island power station in South Australia from TRUenergy, and to sell its 155 MW Hallett power station to TRUenergy. The transaction was completed in July 2007, and is not reflected in figure 3.12.

17 ERIG, 2006, pp. 195–6. See footnote 14

Figure 3.12
Generator capacity and retail load of vertically integrated players in Victoria and South Australia, 2005–06




Note: Average retail load is determined based on the estimated market share of each retailer as a proportion of NEM demand for 2005–06. Market share has been estimated from annual reports. This information is not intended to be an accurate reflection of participants' positions, rather an estimate of the possible degree of vertical integration.

Source: PwC, *Independent survey of contract market liquidity in the National Electricity Market,* August 2006.

While integration has reduced the number of generators and retailers in the financial markets, there has been new entry by financial intermediaries such as BP Singapore, ANZ, Optiver, Attunga Capital, Commonwealth Bank and Arcadia Energy. ERIG considered that the increasing involvement of financial intermediaries is evidence of a dynamic market.

## 3.7 Price outcomes

### Base futures

Average price outcomes for electricity base futures[18] are reflected in the Australian Power Strip (APS). The strip represents a basket of the electricity base load futures listed on the SFE for New South Wales, Victoria, Queensland and South Australia. It is calculated as the average daily settlement price of a common quarter of base futures contracts, one year ahead across the four regions. The APS is published daily by d-cyphaTrade and is tradeable on the exchange.[19]

APS data is available from the commencement of d-cyphaTrade in 2002. Figure 3.13 shows that until 2007, base load futures followed seasonal patterns, with higher prices in summer (Q1) before easing in subsequent quarters. This reflects that NEM spot prices also tend to rise in summer and illustrates the linkages between derivative prices and underlying NEM wholesale prices. Base futures prices rose more sharply than usual in Q1 2007, and continued to rise strongly against historical trends in Q2 2007. This pattern mirrored high prices in the physical electricity market, caused by tight demand-supply conditions (section 2.5).

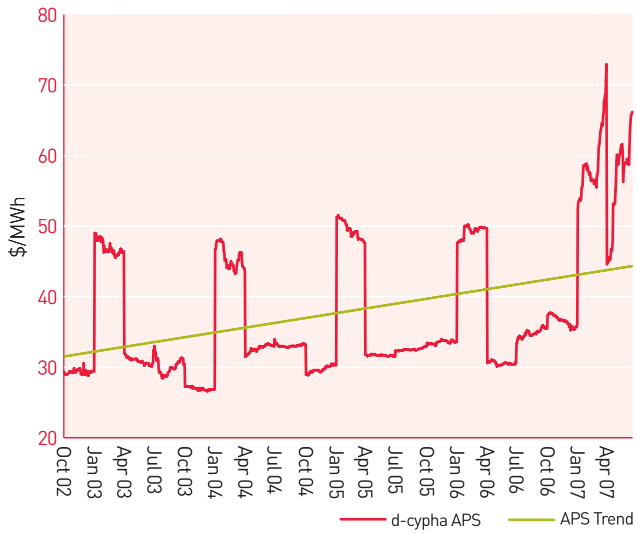
The persistence of high forward prices in 2007 suggests that the market is factoring in expectations of tight supply in the physical electricity market for most of 2007 and into 2008. Higher forward prices may also reflect concerns about the possible effects of carbon trading on energy prices.

The trend line in figure 3.13 averages out seasonal impacts to show the underlying trend in base futures prices. Across New South Wales, Victoria, Queensland and South Australia, average prices rose from around \$34 in 2002 to \$44 in June 2007—a rise of around 29 per cent over five years. Most of this increase derives from price activity in 2007.

18 Base load futures cover the hours from 0.00 to 24.00 hours, seven days a week.

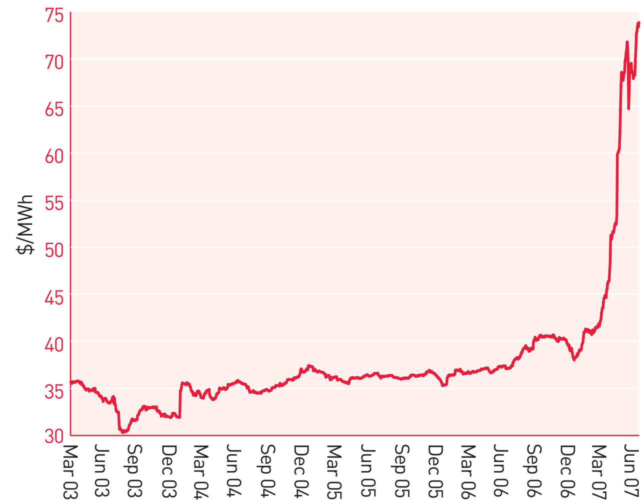
19 The contracts included in the basket are based on a rolling one-year forward continuation strip. The APS therefore includes the prices for quarter base load futures contracts for New South Wales, Victoria, South Australia and Queensland that are one year forward of the current quarter. For example, if the current quarter is Q3 2007, the prices included in the APS will be for Q3 2008 contracts. In Q4 2007, the prices will roll forward to Q4 2008 contracts. The components of the Australian Power Strip are rolled over to the next listed contracts at the commencement of each new quarter (on the first business day in January, April, July and October).

Figure 3.13
Australian Power Strip listed on the SFE




Source: d-cyphaTrade

Figure 3.14
National base futures prices—rolling calendar year




Source: d-cyphaTrade

Figure 3.14 sets out an alternative indicator of base futures prices, based on the average price of a national basket of contracts for the following calendar year. The use of calendar years removes seasonality from the data. The basket consists of New South Wales, Victorian, Queensland and South Australian base futures. The chart illustrates that base futures prices were fairly stable for many years before rising in late 2006 and again—sharply—in 2007. The price of base load calendar contracts rose by around 90 per cent between 1 January 2007 and 22 June 2007.

Figure 3.15 tracks spot prices in the NEM against the APS for base futures. In general, contract markets trade at a premium to the physical spot market for an underlying commodity to cover the cost of managing risk. On average, base futures prices in the NEM have reflected a fairly constant premium over spot prices of around $2 to $3 a megawatt hour.[20] This relationship became blurred in the volatile market conditions that prevailed in 2007, when both NEM prices and the APS rose sharply.

## Peak futures

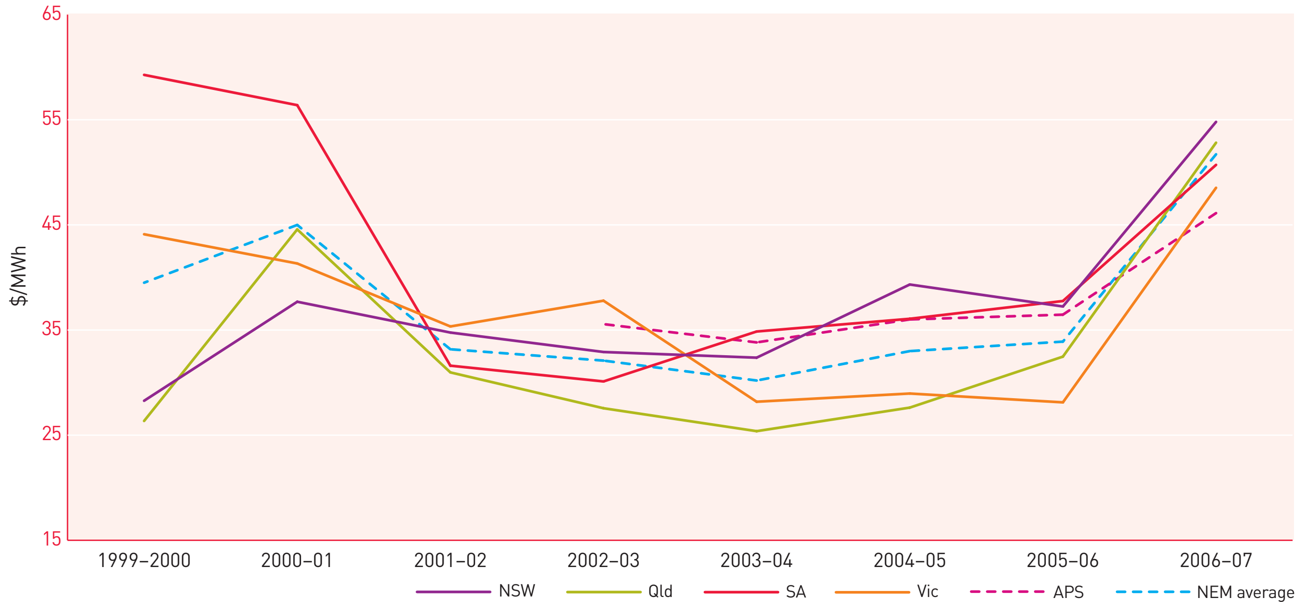
Prices for peak futures[21] have historically been higher than for base futures. Figure 3.16 charts the prices of peak futures that mature in the first quarter (Q1) 2008 in four regions of the NEM against open interest (open contracts) in those instruments. Open interest rose steadily from 2005, mostly in Victorian instruments. The negligible interest in South Australian peak futures is consistent with low levels of liquidity in that region.

Prices for all Q1 2008 peak contracts rose during 2006, and again—more sharply—in 2007, partly in response to rising wholesale prices. As noted, there were indications in 2007 that the market was factoring in expectations of tight supply conditions in the physical electricity market at least into early 2008.

20 KPMG estimate that the premium in the contract market as a whole (base and peak contracts) relative to the NEM spot price is around $4 to $5 a megawatt hour (ERIG, *Discussion papers*, November 2006).

21 Peak futures cover the hours from 07.00 to 22.00 hours Monday to Friday, excluding public holidays.

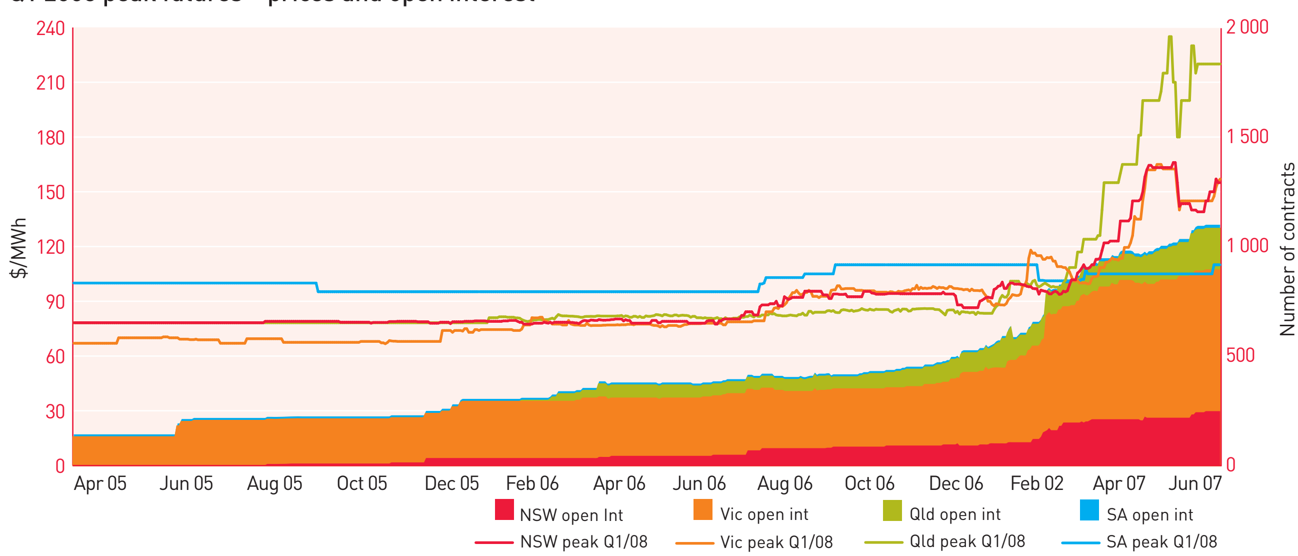
## Figure 3.15
**NEM annual average prices and Australian Power Strip annual average**




Note: NEM prices are time-weighted averages to allow comparability with the Australian Power Strip (APS)

Data source: NEMMCO/d-cyphaTrade

## Figure 3.16
**Q1 2008 peak futures—prices and open interest**




Note: Open Int = open interest; Q1 = quarter 1

Data Source: d-cyphaTrade

## Future forward prices

Figures 3.17 and 3.18 provide a snapshot on 25 June 2007 of the forward prices for base load and peak load futures for New South Wales, Victoria, Queensland and South Australia on the SFE. The charts show the trading prices on that date for futures that mature in the period 2007-2011. These are often described as forward curves. The first four quarters of a forward curve are the prompt quarters. Later quarters are called forward quarters.

The charts reflect that first quarter futures prices (for the summer quarters) tend to be higher than for other quarters for base and peak load contracts. As noted, prices for Q2, Q3 and Q4 2007 futures were unseasonably high.

In June 2007, the market was mostly trading in backwardation—that is, futures prices for the prompt quarters (in 2007 and Q1 2008) were trading above prices for the equivalent quarters in later years. In commodity markets, backwardation usually indicates a perceived shortage of physical supply in the short to medium term that the market anticipates will reduce in the longer term. The charts suggest that the market expects a continuation of tight supply-demand conditions for electricity for the duration of 2007 and at least into the summer of 2008, but a gradual easing in conditions in later years (for example, due to expectations of an investment response to increase capacity). Forward prices are nonetheless persistently high compared to historical levels out to at least 2010.

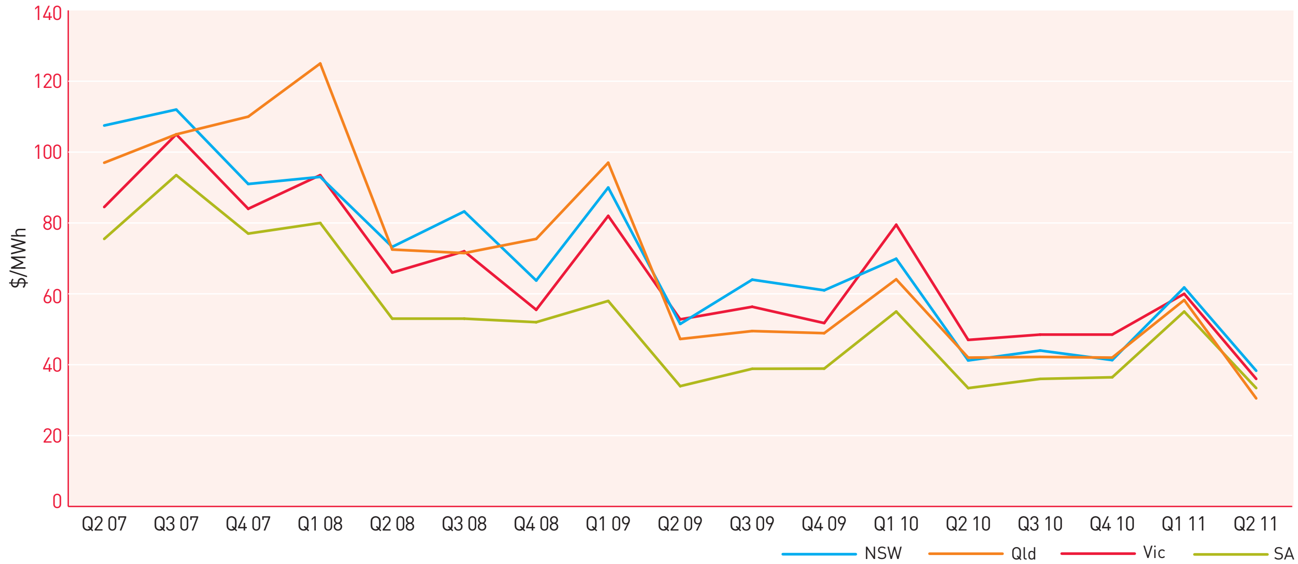
## 3.8 Price risk management — other mechanisms

Aside from financial contracts there are other mechanisms to manage price risk in electricity wholesale markets. As noted, some retailers and generators have reduced their exposure to NEM spot prices through vertical integration. In addition:

- In New South Wales the Electricity Tariff Equalisation Fund (ETEF) provides a buffer against prices spikes in the NEM for government-owned retailers that are required to sell electricity to end users at regulated prices. When spot prices are higher than the energy component of regulated retail prices, ETEF pays retailers from the fund. Conversely, retailers pay into ETEF when spot prices are below the regulated tariff. ETEF was due to expire in 2007, but the New South Wales Government has announced that it will extend its operation until June 2010.
- Auctions of settlement residues allow for some financial risk management in inter-regional trade, although the effectiveness of this instrument has been the subject of some debate (section 4.7).

Figures 3.17

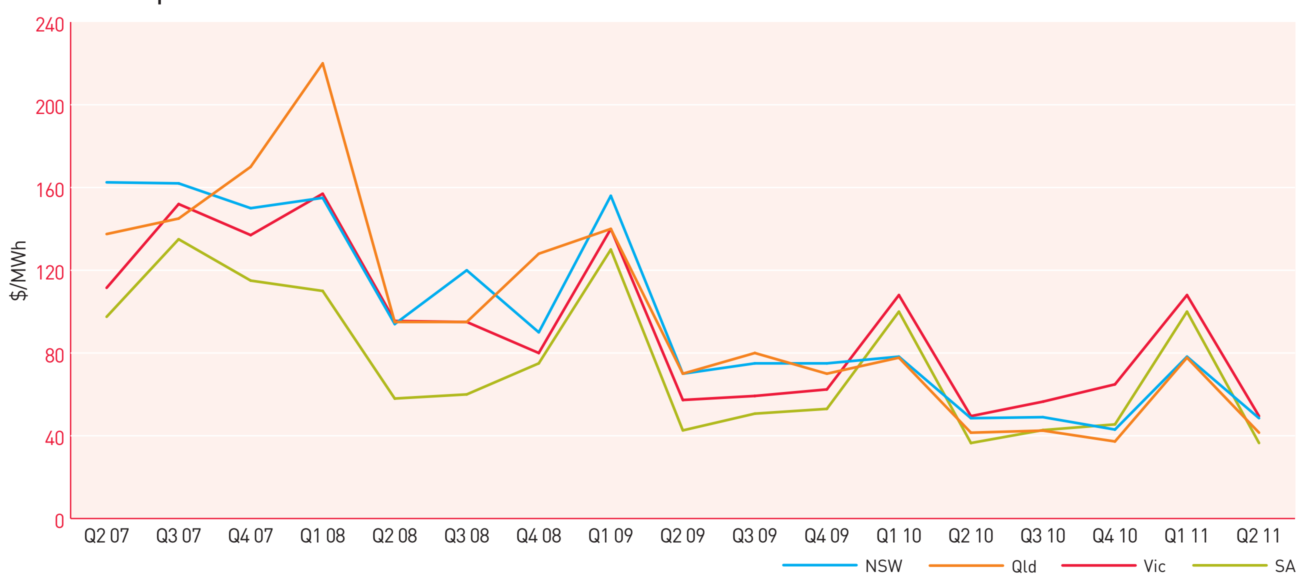
Base futures prices at 25 June 2007




Source: d-cyphaTrade

Figures 3.18

Peak futures prices at 25 June 2007




Source: d-cyphaTrade

# 4 ELECTRICITY TRANSMISSION


Mark Wilson

Electricity generators are usually located close to fuel sources such as natural gas pipelines, coalmines and hydro-electric water reservoirs. Most electricity customers, however, are located a long distance from these generators in cities, towns and regional communities. The electricity supply chain therefore requires networks to transport power from generators to customers. The networks also enhance the reliability of electricity supply by allowing a diversity of generators to supply electricity to end markets. In effect, the networks provide a mix of capacity that can be drawn on to help manage the risk of a power system failure.

# 4 ELECTRICITY TRANSMISSION

This chapter considers:

- the role of the electricity transmission network sector
- the structure of the sector, including industry participants and ownership changes over time
- the economic regulation of the transmission network sector by the Australian Energy Regulator
- revenues and rates of return in the transmission network sector
- new investment in transmission networks
- operating and maintenance costs of running transmission networks
- quality of service, including transmission reliability and the market impacts of congestion.

Some of the matters canvassed in this chapter are addressed in more detail in the Australian Energy Regulator's annual report on the transmission sector.[1]

There are two types of electricity network:

- high-voltage transmission lines that move electricity over long distances from generators to distribution networks in metropolitan and regional areas
- low-voltage distribution networks that move electricity from points along the transmission line to customers in cities, towns and regional communities (see chapter 5).

## 4.1 Role of transmission networks

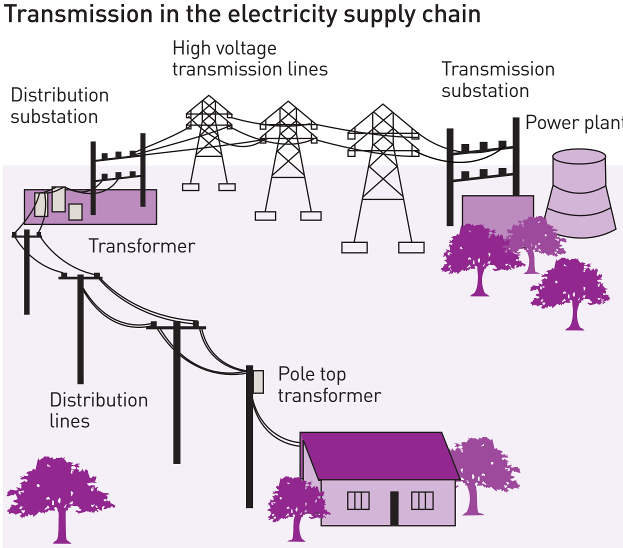
Transmission networks transport electricity from generators to distribution networks, which in turn transport electricity to customers. In a few cases, large businesses such as aluminium smelters are directly connected to the transmission network. A transmission network consists of towers and the wires that run

1 AER, *Transmission network service providers: Electricity regulatory report for 2005–06*, 2007.

between them, underground cables, transformers, switching equipment, reactive power devices, monitoring and telecommunications equipment. In the National Electricity Market (NEM), transmission networks consist of equipment that transmits electricity at or above 220 kilovolts (kV) and assets that operate between 66 kV and 220 kV, which are parallel to, and provide support to, the higher voltage transmission network.

The physics of electricity means that it must be converted to high voltages for efficient transport along a transmission network. This minimises the loss of electrical energy that naturally occurs when transmitting electricity over long distances. However, high voltages also increase the risk of flashover.[2] High towers, better insulation and wide spacing between the conductors help to control this risk.

Figure 4.1
**Transmission in the electricity supply chain**




The high-voltage transmission network strengthens the performance of the electricity industry in three ways:

- First, it gives customers access to large, efficient generators that may be located hundreds of kilometres away. Without transmission, customers would have to rely on generators in their local area, which may be more expensive than remote generators.
- Second, by allowing many generators to compete in the electricity market, it helps reduce the risk of market power.
- Third, by allowing electricity to move over long distances at a moment's notice, it reduces the amount of spare generation capacity that must be carried by each town or city to ensure a reliable electrical supply. This reduces the amount of investment that needs to be tied up in generators.

## 4.2 Australia's transmission network

The NEM in eastern and southern Australia has a combination of state-based transmission networks and cross-border interconnectors that connect the networks together. This arrangement provides a fully interconnected transmission network from Queensland through to New South Wales, the Australian Capital Territory, Victoria, South Australia and Tasmania, as shown in figure 4.2. The transmission networks in Western Australia and the Northern Territory are not interconnected with the NEM (see chapter 7).

Aside from the Snowy Mountains Hydro-Electric Scheme, which has supplied electricity to New South Wales and Victoria since 1959, transmission lines that cross state and territory boundaries are relatively new. More than 30 years after the inception of the Snowy scheme, the Heywood interconnector between Victoria and South Australia was opened in 1990.

The construction of new interconnectors gathered pace with the commencement of the NEM in 1998. Two interconnectors between Queensland and New South Wales (Directlink and the Queensland–New South Wales Interconnector (QNI)) commenced in 2000, followed by a second interconnector between Victoria and South Australia (Murraylink) in 2002. The construction of Basslink between Victoria and Tasmania in 2006 completed the interconnection of all transmission networks in eastern and southern Australia. Figure 4.3 depicts the interconnectors in the NEM.



2 A flashover is a brief (seconds or less) instance of conduction between an energised object and the ground (or other energised object). The conduction consists of a momentary flow of electricity between the objects, which is usually accompanied by a show of light and possibly a cracking or loud exploding noise.

Figure 4.2
**Transmission networks in the National Electricity Market**

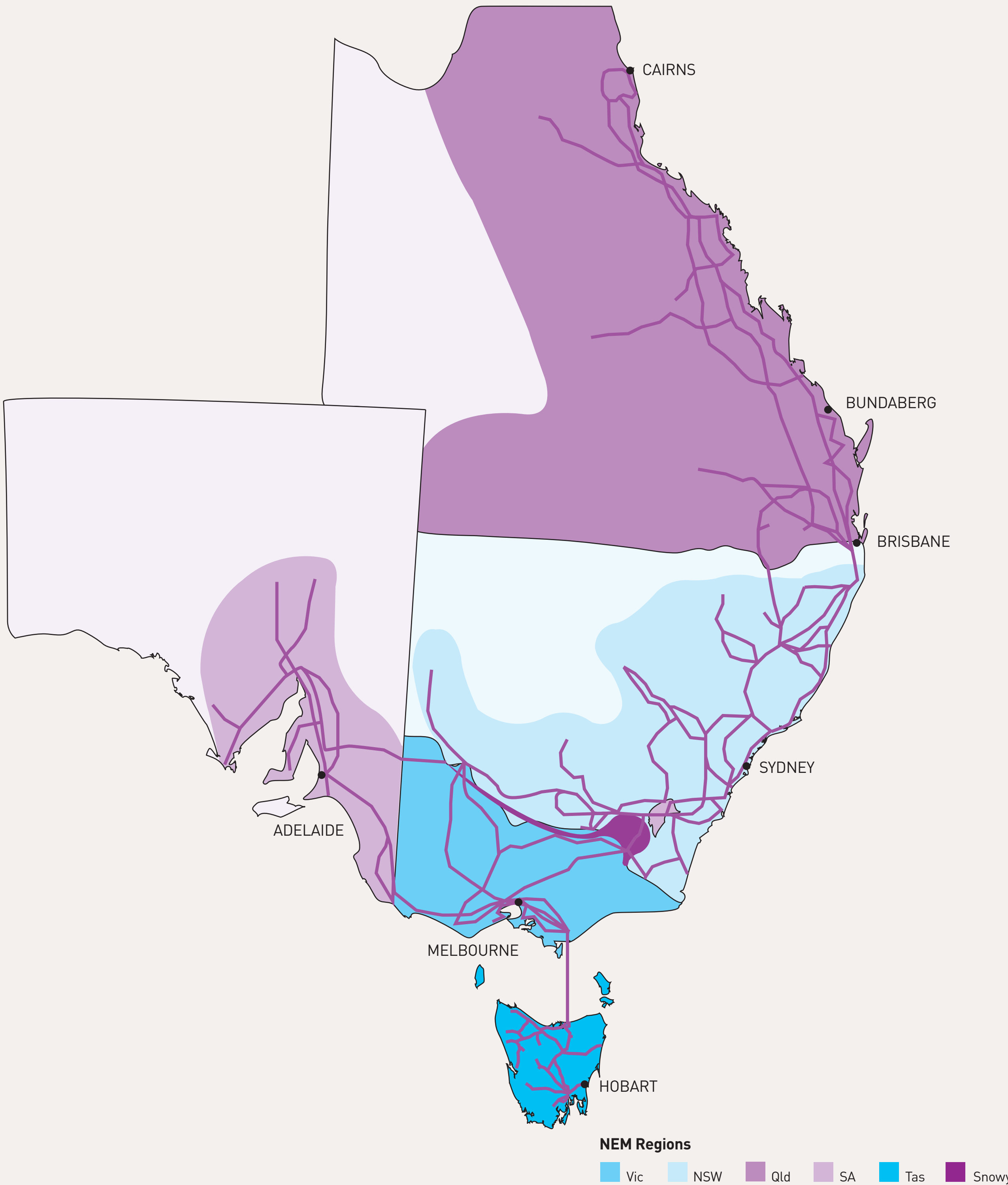
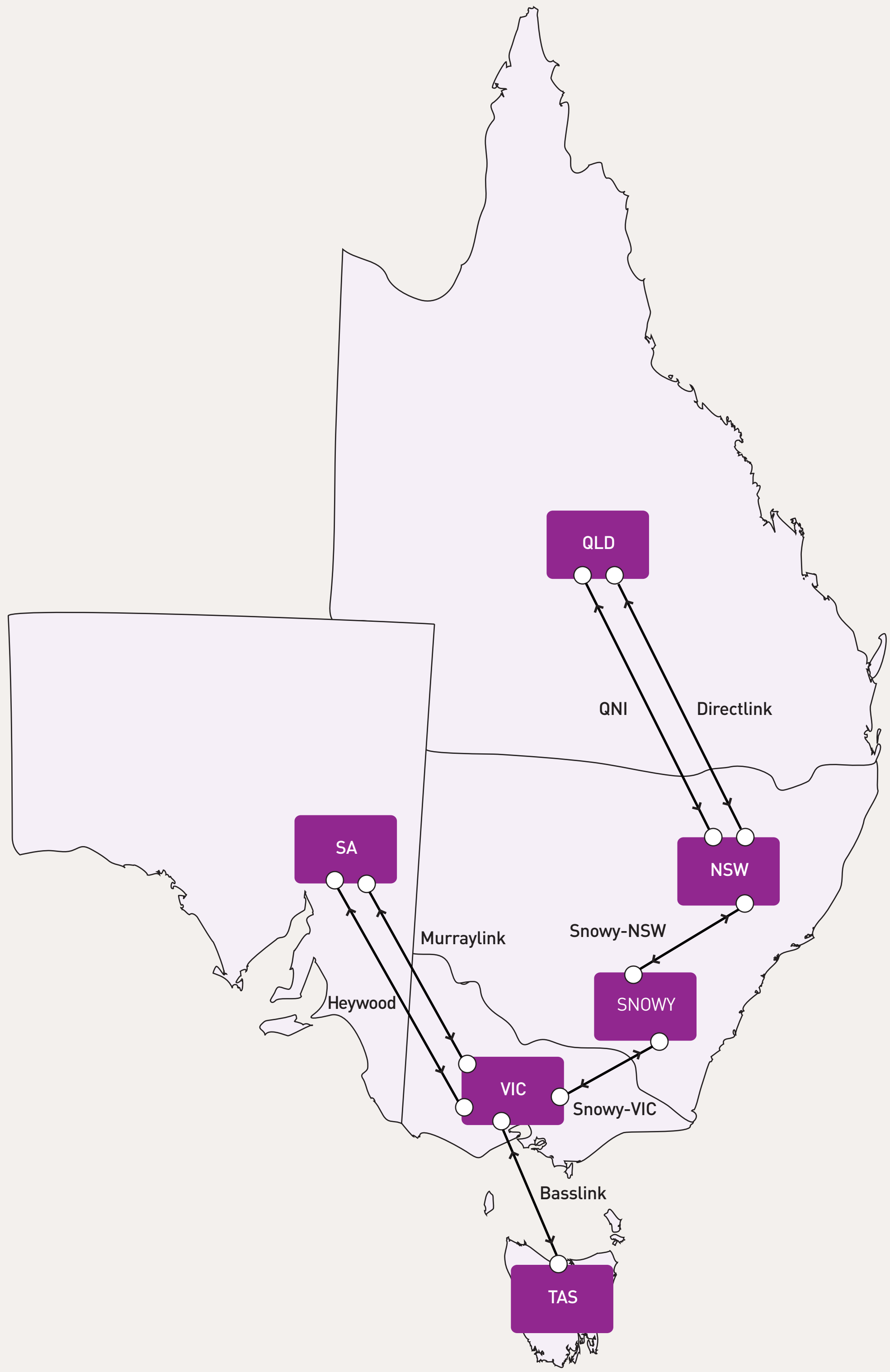


Figure 4.3

Transmission interconnectors in Australia



The NEM transmission network is unique in the developed world in terms of its long distances, low density and long, thin structure. This reflects that there are often long distances between demand centres and fuel sources for generation. For example, the 290 km link between Victoria and Tasmania is the longest submarine power cable in the world. By contrast, transmission networks in the USA and many European countries tend to be higher density and meshed. These differences result in transmission charges being a more significant contributor to end prices in Australia than in many other countries. For example, transmission charges comprise about 10 per cent of retail prices in the NEM,[3] compared to 5 per cent in the United Kingdom.

Electricity can be transported over alternating current (AC) or direct current (DC) networks. Most of Australia's transmission network is AC, in which the power flow over individual elements of the network cannot be directly controlled. Instead, electrical power, which is injected at one point and withdrawn at another, flows over all possible paths between the two points. As a result, decisions on how much electricity is produced or consumed at one point on the network can affect power flows on network elements in other parts of the network. Australia also has three DC networks, all of which are cross-border interconnectors (table 4.1).

## Ownership

Table 4.1 lists Australia's transmission networks and their current ownership arrangements. Historically, government utilities ran the entire electricity supply chain in all states and territories. In the 1990s, governments began to carve out the generation, transmission, distribution and retail segments into stand-alone businesses. Generation and retail were opened up to competition, but this was not feasible for the networks, which became regulated monopolies (section 4.3).

Victoria and South Australia privatised their transmission networks, but other jurisdictions retained government ownership.

> Victoria sold the state transmission network (Powernet Victoria) to GPU Powernet in 1997, which in turn sold the business to Singapore Power in 2000. Singapore Power sold 49 per cent of its Australian electricity assets through its partial float of SP AusNet in November 2005.

> South Australia sold the state transmission network (ElectraNet) in 2000 to a consortium of interests led by Powerlink, which is owned by the Queensland Government. YTL Power Investments, part of a Malaysian conglomerate, is a minority owner. Hastings Fund Management acquired a stake in ElectraNet in 2003.

Victoria has a unique transmission network structure in which network asset ownership is separated from planning and investment decision making. SP AusNet owns the state's transmission assets, but the Victorian Energy Networks Corporation (VENCorp) plans and directs network augmentation. VENCorp also buys bulk network services from SP AusNet for sale to customers.

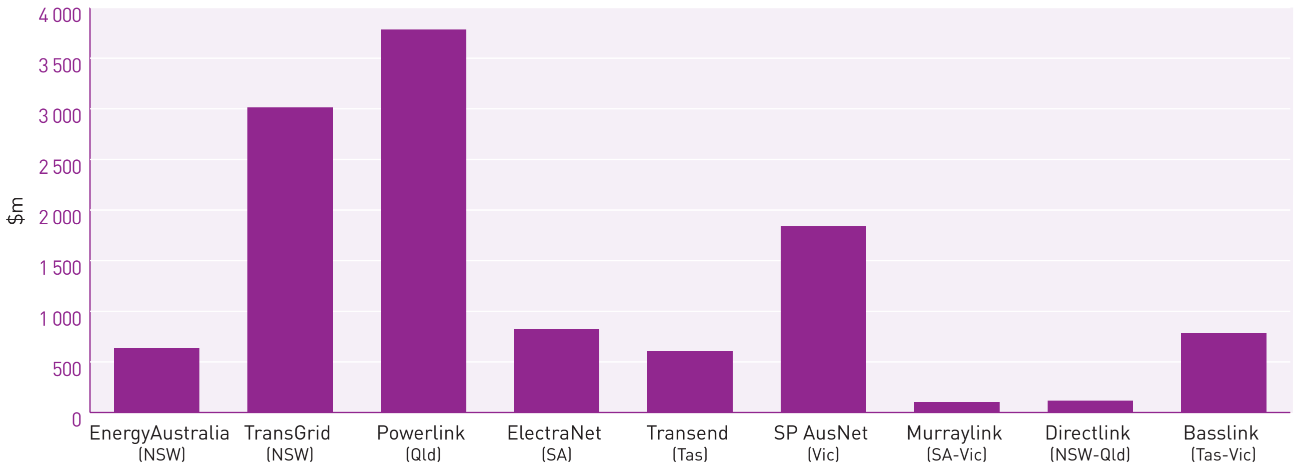
3 The contribution of transmission to final retail prices varies between jurisdictions, customer types and locations.

Table 4.1 Transmission networks in Australia

| NETWORK | LOCATION | LINE LENGTH (KM) IN 2005–06 | MAX DEMAND (MW) IN 2005–06 | CURRENT | REGULATED ASSET[1] BASE ($ MILLION) | OWNER |
|---|---|---|---|---|---|---|
| NEM REGIONS[2] | | | | | | |
| NETWORKS | | | | | | |
| TransGrid | NSW | 12 485 | 13 126 | AC | 3 013 (1 July 2004) | New South Wales Government |
| Energy Australia | NSW | 1 040 | 5 165 | AC | 636 (1 July 2004) | New South Wales Government |
| SP AusNet | Vic | 6 553 | 8 535 | AC | 1 836 (1 January 2003) | Singapore Power International 51% |
| VENCorp[3] | Vic | – | – | – | – | Victorian Government |
| Powerlink | Qld | 11 902 | 8 232 | AC | 3 781 (1 July 2007) | Queensland Government |
| ElectraNet | SA | 5 663 | 2 659 | AC | 824 (1 January 2003) | Powerlink (Queensland Government), YTL Power Investment, Hastings Utilities Trust |
| Transend | Tas | 3 580 | 1 780 | AC | 604 (31 December 2003) | Tasmanian Government |
| INTERCONNECTORS[4] | | | | | | |
| Murraylink | Vic–SA | 180 | | DC | 103 (1 October 2003) | APA Group (35% Alinta) |
| Directlink | Qld–NSW | 63 | | DC | 117 (1 July 2005) | APA Group (35% Alinta) |
| Basslink | Vic–Tas | 375 | | DC | 780 | National Grid Transco (United Kingdom) |
| NON-NEM REGIONS | | | | | | |
| NETWORKS | | | | | | |
| Western Power | WA | 6 623 | | AC | 1 387 (1 July 2006) | Western Australian Government |
| Power and Water | NT | 671 | | AC | – | Northern Territory Government |

1. Regulated asset base is an asset valuation applied by the economic regulator. The RABs are as at the beginning of the current regulatory period for each network, as specified in the National Electricity Rules, schedule 6A.2.1(c)(1). Powerlink's RAB is as determined in the AER's 2006–07—2011–12 revenue cap draft decision, December 2006. Western Power's RAB is current as specified in the Economic Regulation Authority of Western Australia's *Further Final Decision on the Proposed Access Arrangement for the South West Interconnected Network*, 2007.
2. All networks and interconnectors in the NEM except for Basslink are regulated by the Australian Energy Regulator; Western Power is regulated by the Economic Regulation Authority of Western Australia and Power and Water is regulated by the Utilities Commission (Northern Territory).
3. VENCorp acquires bulk transmission services in Victoria from SP AusNet under a network agreement and provides them to customers. It plans and directs augmentation of the network but does not own network assets.
4. Not all interconnectors are listed. The unlisted interconnectors, which form part of the state-based networks, are Heywood (Vic-SA), QNI (Qld-NSW), Snowy-NSW and Snowy-Vic.
5. As Basslink is not regulated there is no RAB. $780 million is the estimated construction cost.
6. A Babcock & Brown/Singapore Power consortium acquired Alinta under a conditional agreement in May 2007. As a consequence, the ownership of APA Group is likely to change.

Figure 4.4
Regulated asset bases of transmission networks




Note: The RABs are as at the beginning of the current regulatory period for each network. See table 4.1.

Sources: National Electricity Rules, schedule 6A.2.1(c)(1); AER, *Powerlink Queensland transmission network revenue cap 2007–08 to 2011–12*, Draft determination, December 2006.

Private investors have constructed three interconnectors since the commencement of the NEM:

- Murraylink, which runs between Victoria and South Australia, is the world's longest underground power cable. It was developed by TransÉnergie Australia, a member of the Hydro-Quebec group, and SNC-Lavalin, and commenced operations in 2002. Murraylink was sold to APA Group (formerly Australian Pipeline Trust)[4] in 2006.
- Directlink is an underground interconnector between Queensland and New South Wales that was developed by TransÉnergie Australia and the New South Wales distributor NorthPower (now Country Energy). It commenced operations in 2000.
- Basslink, which connects Victoria and Tasmania, is the longest submarine power cable in the world and commenced operation in 2006. National Grid Transco, one of the largest private transmission companies in the world, owns Basslink.

The three interconnectors were originally constructed as unregulated infrastructure that aimed to earn revenue by arbitraging the difference between spot prices in adjacent regions of the NEM—that is, the interconnectors profited by purchasing electricity in low-price markets and selling it into high-price markets. However, Murraylink and Directlink applied to convert to regulated networks in 2003 and 2006 respectively. This means that their revenues are now set by regulatory determinations. Basslink is currently the only unregulated transmission network in the NEM.

## Scale of the networks

Figure 4.4 compares the value of transmission networks in the NEM as reflected in their regulated asset bases (RABs). This is the asset valuation that regulators apply in conjunction with rates of return to set returns on capital to infrastructure owners. In general, it is set by estimating the replacement cost of an asset at the time it was first regulated, plus subsequent new investment, less depreciation. More generally, it provides an indication of relative scale.

4 As at November 2006 the Australian Pipeline Trust began trading as part of the APA Group, which comprises the Australian Pipeline Ltd, Australian Pipeline Trust and APT Investment Trust.

Powerlink (Queensland) and TransGrid (New South Wales) have significantly higher RABs than other networks. Many factors can affect the size of the RAB, including the basis of original valuation, network investment, the age of a network, geographical scale, the distances required to transport electricity from generators to demand centres, population dispersion and forecast demand profiles. The combined RABs of all transmission networks in the NEM is around $11.7 billion. This will continue to rise over time with ongoing investment (section 4.4).

## 4.3 Regulation of transmission services

While wholesale electricity is traded in a competitive market, this is not the case for transmission services. Electricity transmission networks are highly capital intensive and incur relatively low operating costs. These conditions give rise to economies of scale that make it cheaper to meet rising demand by expanding an existing network than building additional networks. As a result, the efficient market structure is to have one firm operate a transmission network without competition. This situation is described as a natural monopoly.

Given the dependence of generators and retailers on the networks to transport electricity to customers, there are incentives for a network service provider to exercise market power. The structural separation of the networks from generators and retailers means that network owners have no incentive to protect affiliated businesses by denying third-party access to the networks. However, a monopolist typically has incentives to charge a price that exceeds the cost of supply. This is in contrast to a competitive market, where rivalry between firms drives prices towards cost. For this reason, independent price regulation has been introduced.

There was a shift from state-based determination of transmission prices to national regulation with the commencement of the NEM in 1998. The Australian Competition and Consumer Commission (ACCC) commenced regulation of the networks on a progressive basis, depending on the timing of the expiry of state-based regulatory arrangements. The first networks to move to national regulation were TransGrid and EnergyAustralia (New South Wales) in 1999, followed by Powerlink (Queensland) in 2002, SP AusNet and VENCorp (Victoria) in 2003, Electranet (South Australia) in 2003 and Transend (Tasmania) in 2004. The regulation of transmission networks in Western Australia and the Northern Territory remains under state and territory jurisdiction. The National Electricity Law transferred national transmission regulation from the ACCC to the Australian Energy Regulator (AER) on 1 July 2005.[5]

The AER regulates transmission networks under a framework set out in the National Electricity Rules. The rules require the AER to determine a revenue cap for each network, which sets the maximum allowable revenue a network can earn during a regulatory period—typically five years. In setting the cap, the AER applies a building block model to determine the amount of revenue needed by a transmission company to cover its efficient costs while providing for a commercial return to the owner. Specifically, the component building blocks cover:

> operating costs
> asset depreciation costs
> taxation liabilities
> a commercial return on capital.

5 Section 15 of the *National Electricity (South Australia) (New National Electricity Law) Amendment Act 2005.*

To illustrate, figure 4.5 shows the components of the revenue caps for TransGrid for the period 2004–05 to 2008–09 and Transend for the period 2004 to 2008–09. For each network:

> over 50 per cent of the revenue cap consisted of the return on capital invested in the network
> around 70 per cent of the cap consisted of the return on capital plus the return of capital (depreciation).

The regulatory process includes incentives for efficient transmission investment and operating expenditure. There is also a service standards incentive scheme to ensure that efficiencies are not achieved at the expense of service quality (sections 4.4 to 4.6).

## Revenues

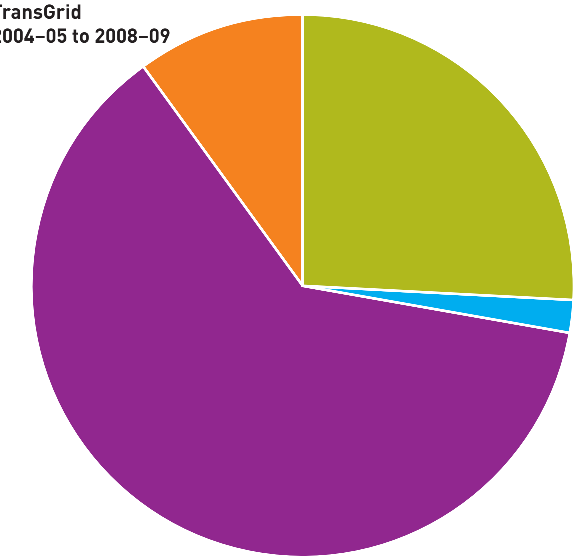
Figure 4.6 charts the capped revenues allowed under national regulation for major transmission networks in the NEM. The year in which the data commences varies between networks, reflecting that the transfer to national regulation occurred in progressive stages. The step movements in the data—for example, TransGrid in 2004–05—usually reflect a transition from one five-year regulatory period to another. The first plot points for Electranet (2001–02) and Transend (2002–03) represent the final revenue determination under state regulation.

Different outcomes between the networks reflect differences in scale and market conditions. However, the revenues of all networks are increasing to meet rising demand over time. The combined revenue of the networks is forecast to reach around $1660 million in 2006–07, representing a real increase of about 6 per cent over two years.

Some networks experienced a significant rise in revenues in their first revenue determination under national regulation. For example, the ACCC allowed Transend (Tasmania) a 28 per cent increase in revenue in 2003–04 above its earnings under previous regulatory arrangements.

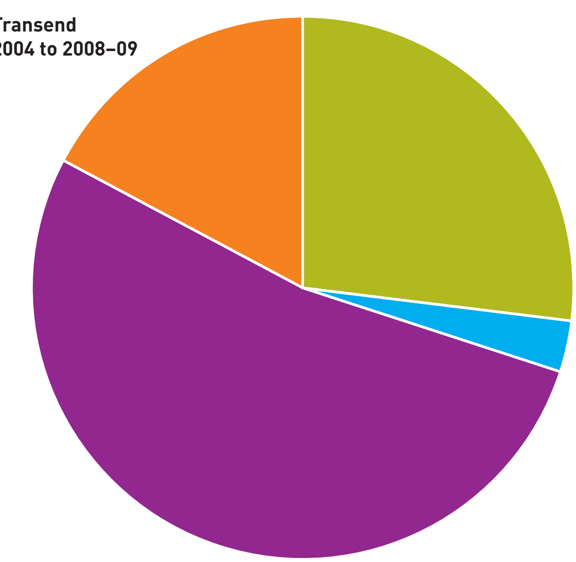
Figure 4.5
Composition of the TransGrid and Transend revenue caps

**TransGrid**
**2004–05 to 2008–09**



Operating expenditure **26%** Taxation liabilities **2%** Return on capital **62%**
Depreciation **10%**

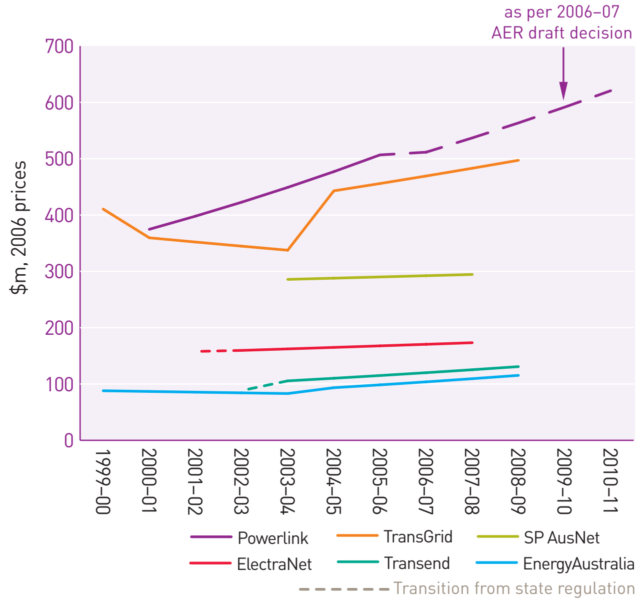
**Transend**
**2004 to 2008–09**



Operating expenditure **27%** Taxation liabilities **3%** Return on capital **53%**
Depreciation **17%**

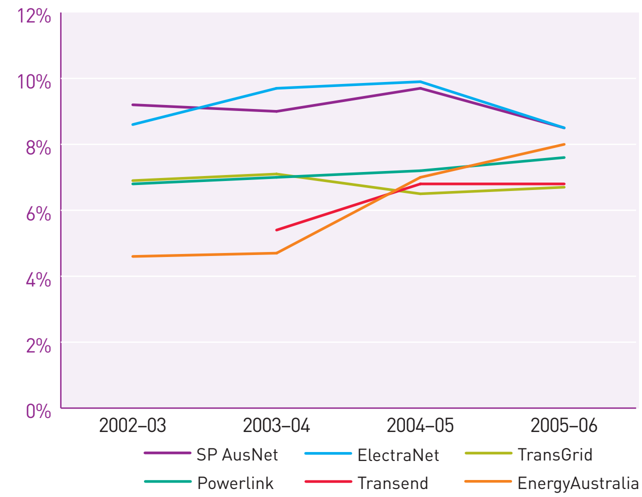
Source: ACCC revenue cap decisions

Figure 4.6
Real maximum revenues 2002–03 to 2008–09




Source: AER final and draft revenue cap decisions.

Figure 4.7
Return on assets




Source: AER, *Transmission network service providers: Electricity regulatory report for 2005–06*, 2007.

## Return on assets

The AER's annual regulatory reports publish a range of profitability and efficiency indicators for transmission network businesses in the NEM.[6] Of these, the return on assets is a widely used indicator of performance.

The return on assets is calculated as operating profits (net profit before interest and taxation) as a percentage of the RAB. Figure 4.7 sets out the return on assets for transmission networks over the four years to 2005–06. In this period, government-owned network businesses achieved annual returns on assets ranging from 5 to 8 per cent. The privately owned networks in Victoria and South Australia (SP AusNet and ElectraNet) yielded higher returns in the range of 8 to 10 per cent, although there was some convergence in 2005–06 outcomes.

A variety of factors can affect performance in this area, including differences in the demand and cost environments faced by each business and variances in demand and costs outcomes compared to those forecasted in the regulatory process. In order to draw firm conclusions, a longer time series of data would be necessary.

## 4.4 Transmission investment

New investment in transmission infrastructure is needed to maintain or improve network performance over time. Investment covers network augmentations (expansions) to meet rising demand and the replacement of depreciated and ageing assets. Some investment is driven by technological innovations that can improve network performance.

The regulatory process aims to create incentives for efficient transmission investment. At the start of a regulatory period an investment (capital expenditure) allowance is set for each network. The process also allows for a contingent allowance for large investment projects that are foreseen at the time of the revenue determination, but where there is significant uncertainty about timing or costs of the project.

6 AER, *Transmission network service providers: Electricity regulatory report for 2005-06*, 2007. See also reports from previous years.

Table 4.2 Real transmission investment in the NEM ($m, 2006 prices)

| NETWORK | LOCATION | 2002–03 | 2003–04 | 2004–05 | 2005–06 | 2006–07 | 2007–08 | SIX YEAR TOTAL |
|---|---|---|---|---|---|---|---|---|
| | | ACTUAL INVESTMENT | | | | FORECAST INVESTMENT | | |
| NETWORKS | | | | | | | | |
| TransGrid | NSW | 234 | 235 | 138 | 156 | 230 | 364 | 1357 |
| EnergyAustralia | NSW | 34 | 37 | 40 | 43 | 65 | 61 | 280 |
| SP AusNet | Vic | 40 | 57 | 74 | 102 | 82 | 83 | 438 |
| Powerlink | Qld | 224 | 179 | 226 | 271 | 258 | 490[1] | 1648 |
| ElectraNet | SA | 37 | 36 | 57 | 55 | 74 | 45 | 304 |
| Transend | Tas | … | 61 | 55 | 68 | 92 | 43 | 319 |
| Total | | 569 | 605 | 590 | 695 | 801 | 1086 | 4346 |
| INTERCONNECTORS[2] | | | | | | | | |
| Murraylink (2000) | Vic–SA | | | | | | | 102 |
| Directlink (2002) | NSW–Qld | | | | | | | 117 |
| Basslink (2006) | Vic–Tas | | | | | | | 780 |
| NEM total | | | | | | | | 5345 |

1. Powerlink estimate for 2007–08 is current as of the AER's 2007–12 revenue cap draft decision, December 2006. 2. Annual data for interconnectors is not available. Data refers to RAB (Murraylink and Directlink) and estimated construction cost (Basslink).

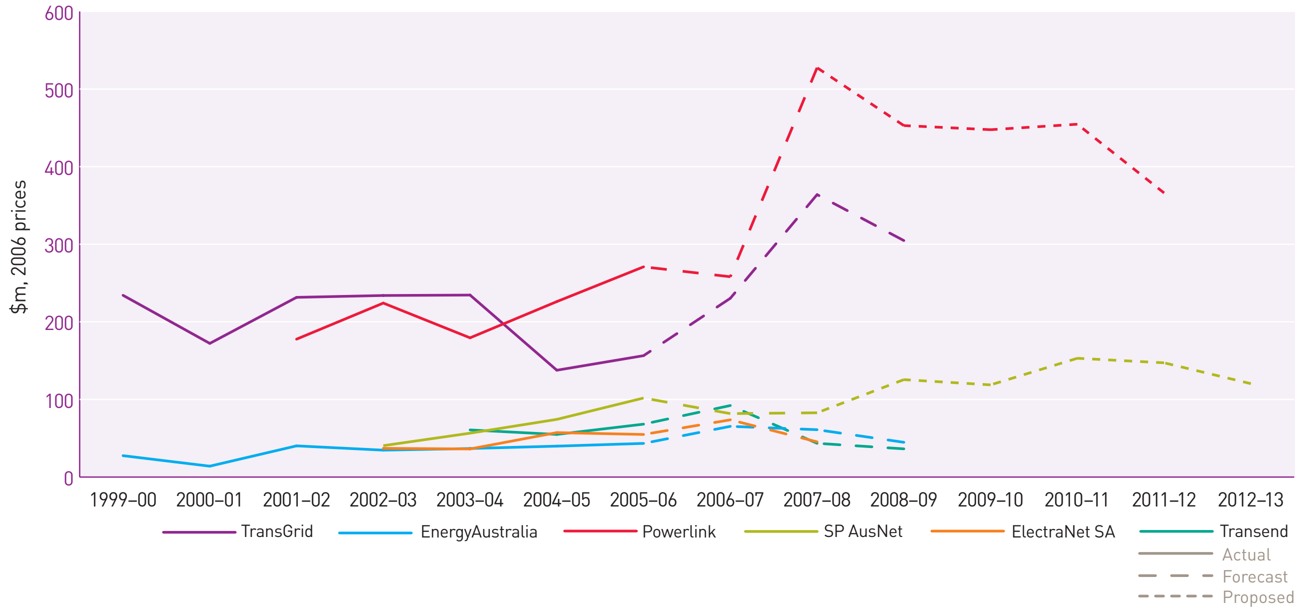
In determinations made since 2005, the AER has allowed network businesses discretion over how and when to spend its investment allowance, without the risk of future review. To encourage efficient network spending, network businesses retain a share of the savings (including the depreciation that would have accrued) against their investment allowance. There is a service standards incentive scheme to ensure that cost savings are not achieved at the expense of network performance (section 4.6).

There has been significant investment in transmission infrastructure in the NEM since the shift to national regulation (table 4.2 and figures 4.8 and 4.9). Transmission investment in the major networks reached almost $700 million in 2005–06, equal to around 6 per cent of the combined RAB, and is forecast to rise to around $1080 million by 2007–08. Investment over the six years to 2007–08 is forecast at around $4.3 billion. There has also been over $700 million in private investment in interconnectors since 2002–03, giving a NEM-wide investment total of around $5 billion. This is equal to around 40 per cent of the combined network RAB.

Investment levels have been highest in New South Wales and Queensland. Differences in investment levels between the states reflect the relative scale of the networks and investment drivers such as the age of the networks and demand projections.

> In New South Wales, TransGrid invested almost $1 billion in the 1999–2004 regulatory period, and anticipates investment of around $1.2 billion during the 2005–09 regulatory period.
> In Queensland, Powerlink's capital expenditure in the 2002–06 regulatory period was around $1.1 billion. The AER's final determination for 2007–12 supports investment of over $2.6 billion.
> SP AusNet (Victoria), ElectraNet (South Australia), Transend (Victoria) and EnergyAustralia (New South Wales) have relatively lower investment levels, reflecting the scale of the networks (table 4.1). It may also reflect differences in investment drivers.

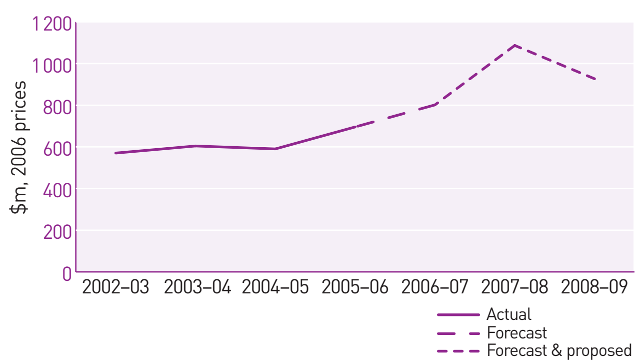
## Figure 4.8
### Transmission investment by network




Note: Forecast capital investment is as approved by the regulator through revenue cap determinations. Proposed capital investment is subject to regulatory approval.

Sources: ACCC and AER final and draft revenue cap decisions.

## Figure 4.9
### NEM-wide transmission investment




Note: Excludes private interconnectors. Powerlink's investment estimates for 2007–08 and 2008–09 are current as of the AER's 2007–12 revenue cap draft decision, released December 2006.

Sources: ACCC and AER final and draft revenue cap decisions.

There has been a trend of rising investment in most networks (figures 4.8 and 4.9), although timing differences between the commissioning of some projects and their completion creates some volatility in the data. Transmission infrastructure investment can be 'lumpy' because of the one-off nature of large capital programs. More generally, care should be taken in interpreting year-to-year changes in capital expenditure. As regulated revenues are set for five-year periods, the network businesses have flexibility to manage and reprioritise their capital expenditure over this period. The analysis of investment data should therefore focus on longer term trends rather than short-term fluctuations.

In recent and current revenue cap applications, TransGrid, Powerlink and SP AusNet have projected a significant rise in investment into the next decade (figure 4.8).[7]

7 AER, *Transmission network service providers: Electricity regulatory report for 2004–05*, 2006, ch. 5.


Robert Rough (Fairfax Images)

Power cables in rural Victoria

## 4.5 Operating and maintenance expenditure

In setting a revenue cap for a transmission network, the AER factors in the amount of revenue needed to cover efficient operating and maintenance costs. A target level of expenditure is set and an incentive scheme encourages the transmission business to reduce its spending through efficient operating practices. The scheme allows the business to retain any underspend against target in the current regulatory period, and also retain some of those savings into the next period. The AER also applies a service standards incentive scheme to ensure that cost savings are not achieved at the expense of network performance (section 4.6).

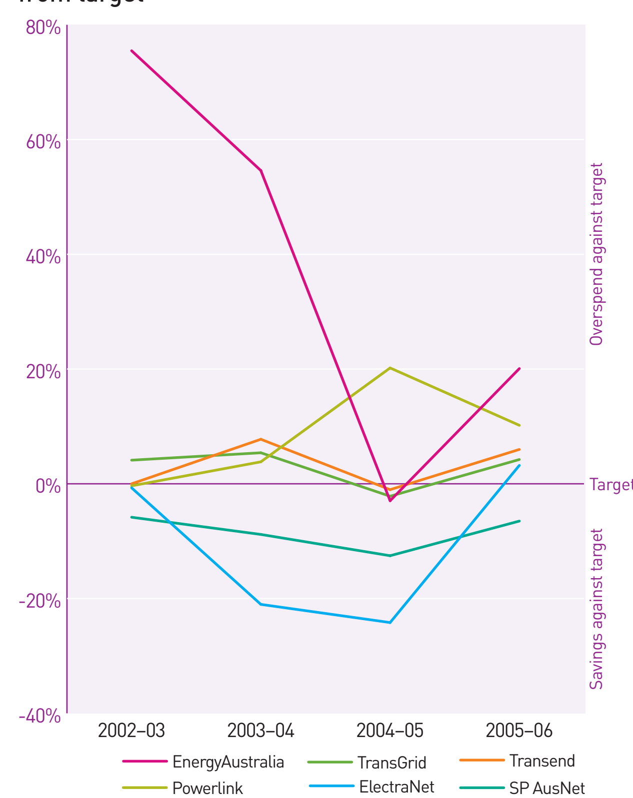
The AER's annual regulatory report[8] compiles data on target and actual levels of operating and maintenance expenditure. A trend of negative variances between these data sets may suggest a positive response to efficiency incentives. Conversely, it would be possible that the original targets were too generous. More generally, care should be taken in interpreting year-to-year changes in operating expenditure. As the network businesses have some flexibility to manage their expenditure over the regulatory period, timing considerations may affect the data. This suggests that analysis should focus on longer term trends.

In 2004–05 network businesses spent about $354 million on operating and maintenance costs, about $8 million below forecast. In comparison, 2005–06 expenditure ($387 million) was about $17.5 million above forecast. Network spending was highest for TransGrid (New South Wales) and Powerlink (Queensland), which at least in part reflects the scale of those networks. It should be noted that several factors affect the cost structures of transmission companies. These include varying load profiles, load densities, asset age, network designs, local regulatory requirements, topography and climate.

SP AusNet (Victoria) has spent below its target level every year since the incentive scheme began in 2002–03 (figure 4.10). ElectraNet (South Australia) has generally spent below target, except in 2005–06 when it slightly overspent. SP AusNet and ElectraNet have reported that they actively pursue cost efficiencies in response to the incentive scheme.[9] The other networks have tended to spend above target.

As noted, it is important that cost savings are not achieved at the expense of service quality. AER data indicates that all major networks in eastern and southern Australia have performed well against target levels of service quality (section 4.6).

**Figure 4.10**
**Operating and maintenance expenditure—variances from target**




Source: AER, *Transmission network service providers: Electricity regulatory report for 2005–06, 2007.*

8 AER, *Transmission network service providers: Electricity regulatory report 2005-06*, 2007. See also reports from previous years.
9 AER, *Transmission network service providers: Electricity regulatory report 2004-05*, 2006, pp. 59 and 63.

## 4.6 Reliability of transmission networks

Reliability refers to the continuity of electricity supply to customers. The reliability of a transmission network depends on the extent to which it can deliver the electricity required by users. There are many factors that can interrupt the flow of electricity on a transmission network. Interruptions may be planned (for example, due to the scheduled maintenance of equipment) or unplanned (for example, due to equipment failure, bushfires, lightning strikes or the impact of hot weather raising air-conditioning loads above the capability of a network). A serious network failure might require the power system operator to disconnect some customers, otherwise known as load-shedding.

As in other segments of the power system, there is a trade-off between the price and reliability of transmission services. While there are differences in the reliability standards applied by each jurisdiction, all transmission networks are designed to deliver high rates of reliability. They are engineered with sufficient capacity to act as a buffer against planned and unplanned interruptions in the power system. More generally, the networks enhance the reliability of the power supply as a whole by allowing a diversity of generators to supply electricity to end markets. In effect, the networks provide a mix of capacity that can be drawn on to help manage the risk of a power system failure.

Regulatory and planning frameworks aim to ensure that, in the longer term, there is efficient investment in transmission infrastructure to avoid potential reliability issues. In regulating the networks, the AER provides investment allowances that network business can spend at their discretion. To encourage efficient investment, the AER uses incentive schemes that permit network businesses to retain the returns on any 'underspend' against their allowance. To balance the scheme, service quality incentive schemes reward network businesses for maintaining or improving service quality. In combination, the capital expenditure allowances and incentive schemes encourage efficient investment in transmission infrastructure to maintain reliability over time.

Investment decisions are also guided by planning requirements set by state governments in conjunction with standards set by the National Electricity Market Management Company (NEMMCO). There is considerable variation in the approaches of state governments to planning and in the standards applied by each jurisdiction (essay B).

To address concerns that jurisdiction-by-jurisdiction planning might not adequately reflect a national perspective, NEMMCO commenced publication in 2004 of an annual national transmission statement (ANTS) to provide a wider focus. It aims, at a high level, to identify future transmission requirements to meet reliability needs.

Acting on the recommendations of the Energy Reform Implementation Group (ERIG), the Council of Australian Governments agreed in 2007 to establish the National Energy Market Operator (NEMO) by June 2009. NEMO will become the operator of the power system and wholesale market, and will be responsible for national transmission planning. As one of its functions it will release an annual national transmission network development plan to replace the current ANTS process.

## Transmission reliability data

The Energy Supply Association of Australia (ESAA) and the AER report on the reliability of Australia's transmission networks.

### Energy Supply Association of Australia data

The ESAA collects survey data from transmission network businesses on reliability, based on system minutes of unsupplied energy to customers. The data is normalised in relation to maximum regional demand to allow comparability.

The data indicates that NEM jurisdictions have generally achieved high rates of transmission reliability. In 2003–04, there were fewer than 10 minutes of unsupplied energy in each jurisdiction due to transmission faults and outages with New South Wales, Victoria and South Australia each losing fewer than three minutes. The networks again delivered high rates of reliability in 2004–05. Essay B of this report charts the ESAA data (figure B.1).

### Australian Energy Regulator data

As noted, the AER has developed incentive schemes to encourage high transmission service quality. The schemes provide financial bonuses and penalties to network businesses that meet (or fail to meet) performance targets, which include reliability targets. Specifically, the targets relate to:

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

Rather than impose a common benchmark target for all transmission networks, the AER sets separate standards that reflect the individual circumstances of each network based on its past performance. Under the scheme, the over- or under-performance of a network against its targets results in a gain (or loss) of up to 1 per cent of its regulated revenue. The amount of revenue-at-risk may be increased to a maximum of 5 per cent in future regulatory decisions.

Table 4.4 sets out the performance data for each network business against its individual target. The data reveals trends in the performance of particular networks over time. While caution must be taken in drawing conclusions from two or three years of data, it can be noted that the major networks have generally performed well against their targets.

The results are standardised for each network to derive an 's-factor' that can range between –1 and +1. This measure determines financial penalties and bonuses. An s factor of –1 represents the maximum penalty, while +1 represents the maximum bonus. Zero represents a revenue neutral outcome. Table 4.3 sets out the s-factors for each network since the scheme began in 2003. All major networks in eastern and southern Australia have outperformed their s-factor targets. As the targets are based on past performance, these outcomes indicate that service quality is improving over time.

**Table 4.3** AER s-factor values 2003–05

| TNSP | 2003 | 2004 | 2005 |
|---|---|---|---|
| ElectraNet (SA) | 0.74 | 0.63 | 0.71 |
| SP AusNet (Vic) | (0.03) | 0.22 | 0.09 |
| Murraylink (interconnector) (Vic–SA) | na | (0.80) | 0.15 |
| Transend (Tas) | na | 0.55 | 0.19 |
| TransGrid (NSW) | na | 0.93 | 0.70 |
| EnergyAustralia (NSW) | na | 1.00 | 1.00 |

na not applicable

Note: An incentive scheme for Powerlink (Queensland) commenced in July 2007.

Source: AER, *Transmission network service providers: Electricity regulatory report for 2005–06*, 2007.

Table 4.4 **Performance of Transmission Networks against AER targets**

| TRANSGRID (NSW) | TARGET | 2003 | 2004 | 2005 |
|---|---|---|---|---|
| Transmission circuit availability (%) | 99.5 | | 99.72 | 99.57 |
| Transformer availability (%) | 99.0 | | 99.30 | 98.90 |
| Reactive plant availability (%) | 98.5 | | 99.47 | 99.64 |
| Frequency of lost supply events greater than 0.05 mins | 6 | | 0 | 1 |
| Frequency of lost supply events greater than 0.40 mins | 1 | | 0 | 0 |
| Average outage duration (minutes) | 1500 | | 936.84 | 716.73 |
| **ENERGY AUSTRALIA (NSW)** | | | | |
| Transmission feeder availability (%) | 96.96 | | 98.57 | 98.30 |
| **SP AUSNET (VIC)** | | | | |
| Total circuit availability (%) | 99.2 | 99.323 | 99.27 | 99.34 |
| Peak critical circuit availability (%) | 99.6 | 99.787 | 99.97 | 99.94 |
| Peak non-critical circuit availability (%) | 99.85 | 99.841 | 99.57 | 99.86 |
| Intermediate critical circuit availability (%) | 99.85 | 99.479 | 99.8 | 99.75 |
| Intermediate non-critical circuit availability (%) | 99.75 | 99.338 | 99.39 | 98.21 |
| Frequency of lost supply events greater than 0.05 mins | 2 | 3 | 2 | 5 |
| Frequency of lost supply events greater than 0.30 mins | 1 | 0 | 0 | 2 |
| Average outage duration–lines (hours) | 10 | 9.978 | 2.73 | 7.54 |
| Average outage duration–transformers (hours) | 10 | 7.659 | 4.86 | 6.64 |
| **ELECTRANET (SA)** | | | | |
| Transmission line availability (%) | 99.25 | | 99.38 | 99.57 |
| Frequency of lost supply events greater than 0.2 mins (number) | 5–6 | | 7 | 0 |
| Frequency of lost supply events greater than 1 min | 2 | | 0 | 0 |
| Average outage duration (minutes) | 100–110 | | 48.92 | 114.11 |
| **TRANSEND (TAS)** | | | | |
| Transmission line availability (%) | 99.10–99.20 | | 99.34 | 98.67 |
| Transformer circuit availability (%) | 99–99.10 | | 99.31 | 99.2 |
| Frequency of lost supply events greater than 0.1 mins | 13–16 | | 18 | 13 |
| Frequency of lost supply events greater than 2 mins | 2–3 | | 0 | 0 |
| **MURRAYLINK** | | | | |
| Planned circuit energy availability (%) | 99.45 | 99.27 | 99.27 | 98.18 |
| Forced outage circuit availability in peak period (%) | 99.38 | 99.68 | 98.88 | 99.63 |
| Forced outage circuit availability in off-peak period (%) | 99.4 | 99.55 | 99.38 | 99.72 |

Met target    Failed to meet target

Note: An incentive scheme for Powerlink (Queensland) commences in July 2007

Source: AER, *Transmission network service providers: Electricity regulatory report for 2005–06*, 2007; and reports for previous years.

## 4.7 Transmission congestion

Transmission networks do not have unlimited ability to carry electricity from one location to another. Rather, there are physical limits on the amount of power that can flow over any one part or region of the network. These physical limits arise from the need to prevent damage to the network and ensure stability in the face of small disturbances.

A transmission line can become congested, or 'blocked', due to events and conditions on a particular day. Some congestion is caused by factors within the control of a service provider—for example, through the way they schedule outages, their maintenance and operating procedures, their standards for network capability (such as thermal, voltage or stability limits), changes in network monitoring procedures and decisions on equipment upgrades. Conversely, service providers are not responsible for all transmission congestion. Other contributing factors include extreme weather and constraints imposed by NEMMCO to manage issues in the power system.

For example, hot weather can cause high air conditioning loads that may push a network towards its pre-determined limits set by NEMMCO. Similarly, line maintenance may limit available capacity. The potential for network congestion would be magnified if these events occur simultaneously.

If a major transmission outage occurs in combination with other generation or demand events, it can sometimes cause users to be blacked out. However, this is rare in the NEM. Instead the main impact of congestion is on the cost of electricity. If a particular transmission line is congested, it can prevent a low-cost generator that uses the line from being dispatched to satisfy demand. Instead, generators that do not require the constrained line will be used. If this requires the use of higher cost generators, it ultimately raises the cost of producing electricity. The market impact of transmission congestion is therefore the cost of using expensive generators when low-cost generation could have been used instead.

Congestion can also create opportunities for the exercise of market power. If a network constraint prevents low-cost generators from moving electricity to customers, there is less competition in the market. This can allow the remaining generators to adjust their bidding to capitalise on their position. Ultimately this is likely to raise electricity prices.

Not all constraints have the same market impact. Most do not cause blackouts or force more expensive generation to be dispatched. For example, congestion which 'constrains off' a coal-fired plant and requires the dispatch of another coal-fired plant may have little impact. But the costs may be substantial if cheap coal fired generation needs to be replaced by a high-cost peaking plant such as a gas-fired generator.

With the assistance of NEMMCO, the AER completed a two-year project in 2006 to measure the impact of transmission congestion in the NEM. The following is a non-technical discussion of the results of this research. A more detailed discussion appears in the AER June 2006 decision on the market impact of transmission congestion and in the AER annual reports on congestion.[10]

The AER has developed three measures of the impact of congestion on the cost of electricity (table 4.5). The measures relate to the cost of using more expensive plant than would be used in the absence of congestion. Two measures (the total cost of constraints, TCC, and the outage cost of constraints, OCC) focus on the overall impact of constraints on electricity costs, while the third measure (the marginal cost of constraints, MCC) identifies which particular constraints have the greatest impact.



10 AER, *Indicators of the market impact of transmission congestion—decision*, 9 June 2006; AER, annual congestion reports for 2003–04, 2004–05 and 2005–06.

Table 4.5 **Market impact of transmission constraints—the AER measures**

| MEASURE | DEFINITION | EXAMPLE |
|---|---|---|
| Total cost of constraints (TCC) | The total increase in the cost of producing electricity due to transmission congestion (includes outages and network design limits).<br>> Measures the total savings if all constraints were eliminated. | Hot weather in New South Wales causes a surge in demand for electricity, raising the price. The line between Victoria and the Snowy reaches capacity, preventing the flow of lower cost electricity into New South Wales to meet the demand. Higher cost generators in New South Wales must be used instead.<br>> TCC measures the increase in the cost of electricity caused by the blocked transmission line. |
| Outage cost of constraints (OCC) | The total increase in the cost of producing electricity due to outages on transmission networks.<br>> Only looks at congestion caused by network outages.<br>> Excludes other causes, such as network design limits.<br>> Outages may be planned (e.g. scheduled maintenance) or unplanned (eg equipment failure). | Maintenance on a transmission line prevents the dispatch of a coal-fired generator that requires the use of the line. A higher cost gas-fired peaking generator (that uses a different transmission line) has to be dispatched instead.<br>> OCC measures the increase in the cost of electricity caused by line maintenance. |
| Marginal cost of constraints (MCC) | The saving in the cost of producing electricity if the capacity on a congested transmission line is increased by 1 MW, added over a year.<br>> Identifies which constraints have a significant impact on prices.<br>> Does not measure the actual impact. | > See TCC example (above).<br>> MCC measures the saving in the cost of producing electricity in New South Wales if one additional MW of capacity was available on the congested line. At any time several lines may be congested. The MCC identifies each network element while the TCC and OCC aggregate the impact of all congestion—and do not discriminate between individual elements. |
| Qualitative impact statements | A description of major congestion events identified by the TCC, OCC and MCC data.<br>> Analyses the causes of particular constraints, for example, network design limits, outages, weather, demand spikes. | Lightning in the vicinity of the Heywood interconnector between Victoria and South Australia led to reduced electricity flows for 33 hours in 2003–04. |

The measures estimate the impact of congestion on generation costs rather than spot prices. In particular, the measures reflect how congestion raises the cost of producing electricity, taking account of the costs of individual generators. If the bidding of generators reflects their true cost position, the measures will be an accurate measure of the economic cost of congestion. They therefore reflect the negative efficiency effects of congestion and make an appropriate basis to develop incentives to mitigate this cost. However, if market power allows a generator to bid above its true cost structure, the measures will reflect a mix of economic costs and monopoly rents.

The AER has published three years data on the costs of transmission congestion (figure 4.11). This data indicates that the annual cost of congestion has risen from around $36 million in 2003–04 to $66 million in 2005–06. Typically, most congestion costs accumulate on just a handful of days. Around 66 per cent of the total cost for 2005–06 accrued on just 10 days. Around 40 per cent of total costs are attributable to network outages. Breaking down the data by month, the bulk of congestion costs in 2005–06 occurred in late spring and summer (figure 4.12).

Figure 4.11
Costs of transmission congestion

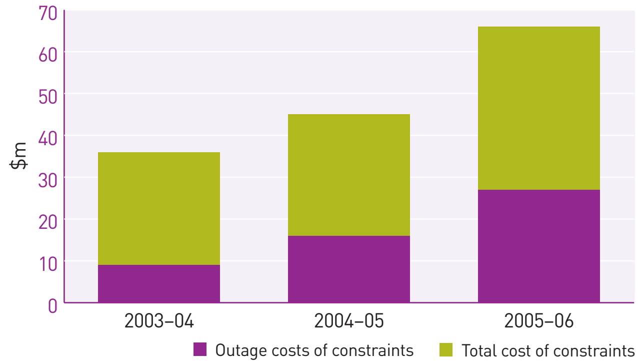
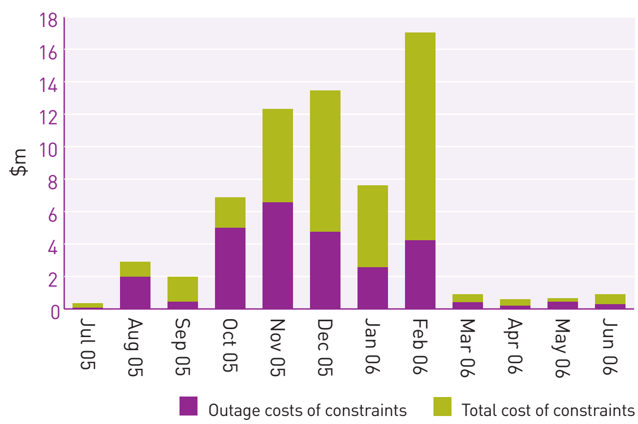



Figure 4.12
Monthly congestion costs, 2005–06




Source: AER

The MCC data, which identifies particular constraints with a significant impact, showed that in 2005–06 around 800 network constraints affected the market at least once. At any one time between 150 and 250 constraints were typically in place. Of these:

> 32 network constraints significantly affected interconnectors, compared to 15 in 2004–05 and five in 2003–04. Congestion on Basslink, which connects Victoria and Tasmania, is not included in this data.

> Nine network constraints within particular regions of the NEM caused congestion for 10 hours or more, compared to nine constraints in 2004–05 and seven in 2003–04. There were also 13 constraints in Tasmania in this category.

The AER plans to assess the impact of major constraints in its weekly market reports. The data will provide information to industry and policy makers on the costs of congestion and will help identify measures to reduce those costs.

In June 2007, the AER released an issues paper on the development of a new incentive scheme to reward transmission companies for reducing the number and duration of outages with a market impact, and for providing more advanced notice of outages.

To date, network service providers have had little incentive to minimise congestion costs as they must bear the costs of network improvements, while retailers, generators and customers gain the benefits. A well-designed incentive scheme would reward network owners for improving operating practices in areas such as outage timing, outage notification, live line work and equipment monitoring. These may be more cost-efficient measures to reduce congestion than solutions that require investment in infrastructure.

More generally, the congestion data should be treated with caution as it outlines results for only three years. Longer term trends may become apparent with the publication of more data over time. The preliminary outcomes suggest that there are some significant constraints and that their impact has risen since 2003–04. Total costs are nonetheless relatively modest given the scale of the electricity market, suggesting that the transmission sector as a whole is responding well to the market's needs.

Transmission tower

## Settlement residue auctions

Congestion in transmission interconnectors can cause prices to differ across regions of the NEM (section 2.4). In particular, prices may spike in a region that is constrained in its ability to import electricity. To the extent that trade remains possible, electricity should flow from lower price to higher price regions. Consistent with the regional design of the NEM, the exporting generators are paid at their local regional spot price, while importing retailers must pay the higher spot price in their region. The difference between the price paid in the importing region and the price received in the generating region, multiplied by the amount of flow, is called a settlement residue. Figure 2.8 (chapter 2) charts the annual accumulation of settlement residues in each region of the NEM.

Price separation creates risks for the parties that contract across regions. NEMMCO offers a risk management instrument by holding quarterly auctions to sell the rights to future residues up to one year in advance. Retailers, generators and other market participants may bid for a share of the residues. For example, a Queensland generator, trading in New South Wales, may bid for residues between those regions if it expects New South Wales prices to settle above Queensland prices. As New South Wales is a significant importer of electricity, it can be vulnerable to price separation and often accrues high settlement residue balances.

Table 4.6 shows the amount of settlement residues that accrued each year against the proceeds of residue auctions. The total value of residues represents the net difference between the prices paid by retailers and the prices received by generators across the NEM. It therefore gives an approximation of the risk faced by market participants from inter-regional trade. The table illustrates that the residues are frequently auctioned for less than their ultimate value. On average, the actual residues have been around 75 per cent higher than the auction proceeds.

**Table 4.6 Inter-regional hedging: auction proceeds and settlement residues**

| YEAR | PREMIUM (AUCTION PROCEEDS) | ACTUAL SETTLEMENT RESIDUE DISTRIBUTED | EXCESS OF ACTUAL OVER PREMIUM | |
|---|---|---|---|---|
| | $ MILLION | $ MILLION | $ MILLION | % |
| 1999–00 | 41 | 60 | 19 | 46% |
| 2000–01 | 64 | 99 | 35 | 55% |
| 2001–02 | 87 | 98 | 11 | 13% |
| 2002–03 | 62 | 120 | 58 | 94% |
| 2003–04 | 81 | 141 | 60 | 74% |
| 2004–05 | 98 | 230 | 132 | 135% |
| 2005–06 | 118 | 220 | 102 | 86% |
| Total | 558 | 974 | 416 | 75% |

Source: ERIG, *Discussion papers*, November 2006.

ERIG considered that market participants discount the value of settlement residues because they are not a firm hedging instrument.[11] In particular, a reduction in the capability of an interconnector—for example, due to an outage—reduces the cover that the hedge provides. This makes it difficult for parties to assess the amount of hedging they are bidding for at the residue auctions. The auction units are therefore a less reliable risk management tool than some other financial risk instruments, such as those traded in over-the-counter and futures markets (chapter 3).

11 ERIG, *Discussion papers*, November 2006, p. 177.

# 5 ELECTRICITY DISTRIBUTION

Quentin Jones (Fairfax Images)

Most electricity customers are located a long distance from generators. The electricity supply chain therefore requires networks to transport power from generators to customers. Chapter 4 provides a survey of high-voltage *transmission* networks that move electricity over long distances from generators to distribution networks in metropolitan and regional areas. This chapter focuses on the lower voltage *distribution* networks that move electricity from points along the transmission line to customers in cities, towns and regional communities.

# 5 ELECTRICITY DISTRIBUTION

The chapter considers:

> the role of the electricity distribution network sector
> the structure of the sector, including industry participants and ownership changes over time
> the economic regulation of the distribution network sector
> financial outcomes, including revenues and returns on assets
> new investment in distribution networks
> quality of service, including reliability and customer service performance.

There are a number of possible ways to present and analyse data on Australia's distribution networks. This chapter mostly adopts a convenient classification of the networks based on jurisdiction and ownership criteria. Other possible ways to analyse the data include by feeder—for example, a rural/urban classification. Section 5.6 includes some analysis based on a feeder classification.

While this chapter includes data that might enable performance comparisons to be made between networks, such analysis should note that geographical, environmental and other differences can affect relative performance. These factors are noted, where appropriate, in the chapter.

## 5.1 Role of distribution networks

Distribution networks move electricity from the transmission network to residential and business electricity customers.[1] A distribution network consists of low-voltage substations, transformers, switching equipment, monitoring and signalling equipment and the poles, underground channels and wires that carry electricity.

Transmission networks minimise the energy losses that occur in transporting electricity by moving it at high voltages along widely spaced lines between high towers. This configuration would not be cost effective in distribution, and it would raise aesthetic and environmental issues. Nor can high-voltage electricity be safely consumed in homes and businesses. It is therefore necessary to step electricity down to lower voltages when it enters a distribution network. Voltage levels vary in different parts of a distribution network, but most customers in the National Electricity Market (NEM) require delivery at around 230–240 volts.

While transmission networks run for long distances on high towers between substations, distribution networks consist of smaller poles and wires that crisscross customer areas and connect to every customer. This tends to make distribution networks longer in length than transmission networks. The total length of distribution infrastructure in the NEM (700 000 km) is around 16 times greater than the total length of transmission infrastructure (42 000 km).

In Australia, electricity distributors provide the infrastructure to transport electricity to household and business customers, but do not sell electricity. Instead, retailers bundle electricity generation with transmission and distribution services and sell them as a package. In some jurisdictions, there is common ownership of distributors and retailers, which are 'ring-fenced' or operationally separated from one another.

The contribution of distribution costs to final retail prices varies between jurisdictions, customer types and locations. Data on the underlying composition of retail prices is not widely available. A 2002 report for the Victorian Government estimated that transmission and distribution jointly account for about 44 per cent of a typical residential electricity bill.[2] The Essential Services Commission of South Australia (ESCOSA) reported a similar estimate in 2004.[3] The Essential Services Commission of Victoria (ESC) reported in 2004 that distribution can account for 30 to 50 per cent of retail prices, depending on customer type, energy consumption, location and other factors.[4]

## 5.2 Australia's distribution networks

In Australia, there are distribution networks in all states and territories, serving population centres and industry in cities, towns and regional areas. This section provides an overview of network ownership, geography and size. Table 5.1 provides a full listing of the networks.



1 There are exceptions. For example, some large businesses such as aluminium smelters can bypass the distribution network and source electricity directly from the transmission network. Conversely, embedded generators have no physical connection with the transmission network and dispatch electricity directly into a distribution network.

2 Charles Rivers Associates, *Electricity and gas standing offers and deemed contracts (2003)*, December 2002.

3 ESCOSA, *Inquiry into retail electricity price path: Discussion paper*, September 2004, p. 27.

4 ESC, *Electricity distribution price review 2006–10*, Issues paper, December 2004, p. 5.

John Donegan (Fairfax Images)

## Ownership

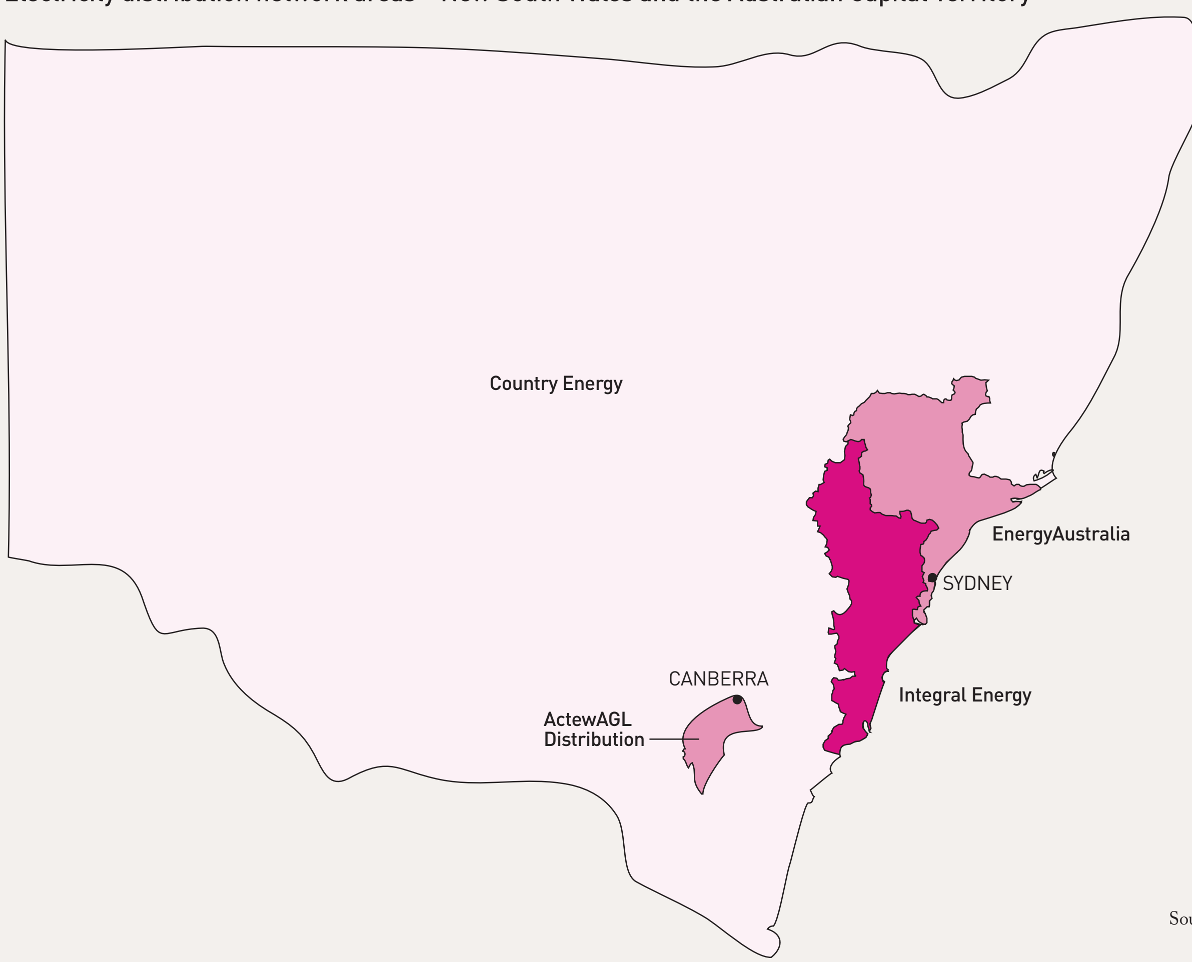
There are 13 major electricity distribution networks in the NEM (table 5.1). Of these, six (in Victoria and South Australia) are privately owned or leased, one has combined government and private ownership (the Australian Capital Territory) and six (in other jurisdictions) are government owned.

Historically, government utilities ran the entire electricity supply chain in all states and territories. In the 1990s, governments began to carve out the generation, transmission, distribution and retail segments into stand-alone businesses. Generation and retail were opened up to competition. This was not feasible in transmission and distribution, where economies of scale make it more efficient to have a regulated monopoly provider of services rather than competing networks.

New South Wales, Victoria and Queensland have multiple major networks, each of which is a monopoly provider in a designated area of the state. Figures 5.1a–c provide illustrative maps for New South Wales, Victoria and Queensland. In the other jurisdictions there is one major provider of network services. There are also small regional networks with separate ownership in some jurisdictions.

Figure 5.1a

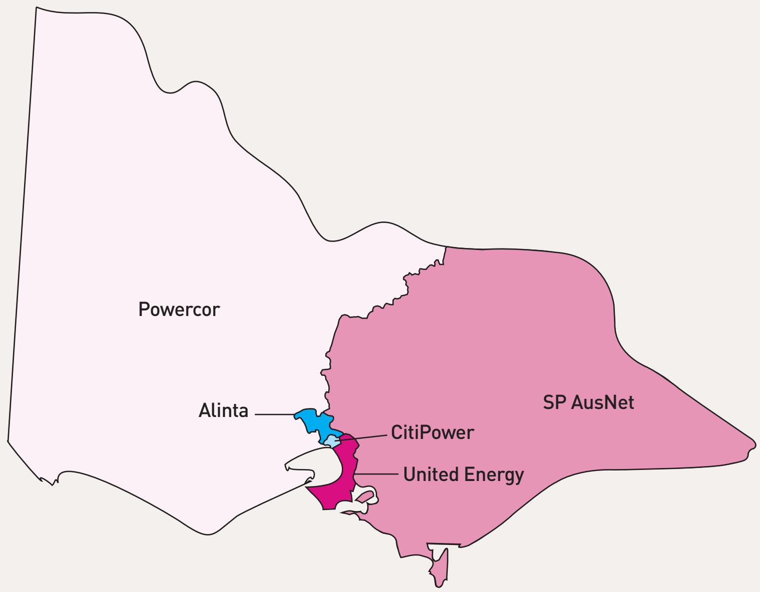
Electricity distribution network areas—New South Wales and the Australian Capital Territory




Source: IPART

Figure 5.1b

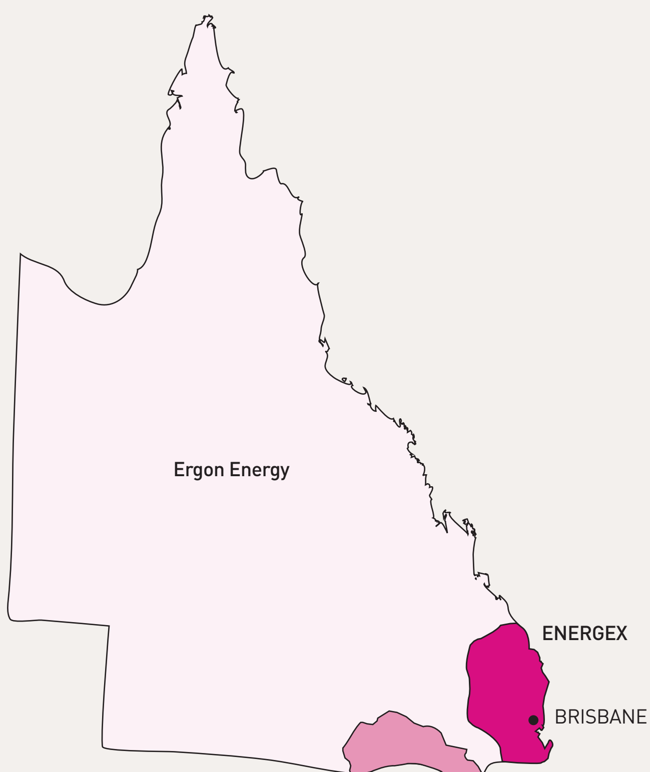
Electricity distribution network areas—Victoria




Source: ESC

Figure 5.1c

Electricity distribution network areas—Queensland




Source: QCA

Table 5.1 sets out current ownership arrangements for the networks. Privatisation in Victoria and South Australia in the 1990s led to considerable ownership diversity, but merger and acquisition activity has since reduced the number of private sector players to three—Cheung Kong Infrastructure/Spark, SP AusNet/Singapore Power and Alinta/Diversified Utility and Energy Trust (DUET).

**Table 5.1 Distribution networks**

| NETWORK | LOCATION | LINE LENGTH (KM) | CUSTOMER NUMBERS | RAB ($ MILLION) | REGULATOR | OWNER |
|---|---|---|---|---|---|---|
| NEM REGIONS | | | | | | |
| Alinta (Solaris) | Vic | 5579 | 286 085 | 589 | ESC | Alinta |
| CitiPower | Vic | 6488 | 286 107 | 1 022 | ESC | Cheung Kong Infrastructure Holdings Limited and Hongkong Electric Holdings 51%; Spark Infrastructure 49% |
| Powercor | Vic | 80 577 | 644 113 | 1 671 | ESC | Cheung Kong Infrastructure Holdings Limited and Hongkong Electric Holdings 51%; Spark Infrastructure 49% |
| SP AusNet | Vic | 29 397 | 573 766 | 1 363 | ESC | Singapore Power International 51% |
| United Energy | Vic | 12 308 | 609 585 | 1 229 | ESC | Alinta 34%; DUET 66% |
| ETSA Utilities | SA | 80 644 | 781 881 | 2 468 | ESCOSA | Cheung Kong Infrastructure Holdings Limited and Hongkong Electric Holdings 51%; Spark Infrastructure 49% |
| EnergyAustralia | NSW | 47 144 | 1 539 030 | 4 116 | IPART | NSW Government |
| Integral Energy | NSW | 33 863 | 822 446 | 2 283 | IPART | NSW Government |
| Country Energy | NSW | 182 023 | 734 071 | 2 375 | IPART | NSW Government |
| ActewAGL | ACT | 4623 | 146 556 | 528 | ICRC | ACTEW Distribution Limited 50% (ACT Government); Alinta 50% |
| ENERGEX | Qld | 48 115 | 1 217 193 | 5 023 | QCA | Qld Government |
| Ergon Energy | Qld | 142 793 | 736 710 | 4 690 | QCA | Qld Government |
| Aurora Energy | Tas | 24 400 | 259 600 | 687 | OTTER | Tas Government |
| NON-NEM REGIONS | | | | | | |
| Western Power | WA | 69 083 | | 1 595 | ERA | WA Government |
| Power and Water | NT | 7869 | | 440 | UC | NT Government |

Notes:

1. ESC (Essential Services Commission of Victoria); ESCOSA (Essential Services Commission of South Australia); IPART (Independent Pricing and Regulatory Tribunal); ICRC (Independent Competition and Regulatory Commission); QCA (Queensland Competition Authority); OTTER (Office of the Tasmanian Energy Regulator); ERA (Economic Regulation Authority of Western Australia); UC (Northern Territory Utilities Commission).
2. RAB (regulated asset base) measurement: ESC ($2004 as of 2006–07); ESCOSA (Dec $2004 as of 2006–07); IPART (nominal as of 1 July 2004); ICRC (nominal as of 2005–06); QCA (nominal as of 2005-06); OTTER (nominal as of 30 June 2003); ERA (nominal as of 30 June 2006); UC (includes both transmission and distribution as of February 2004).
3. A Babcock & Brown/Singapore Power consortium acquired Alinta under a conditional agreement in May 2007.

The Victorian Government initially split its distribution sector into five separate businesses: CitiPower, Solaris and United Energy which mainly serve metropolitan Melbourne; and Eastern Energy and Powercor which serve the rest of Victoria (figure 5.1b). In 1995, the networks were sold to various private interests, but there has since been considerable consolidation:

- Cheung Kong Infrastructure/Hong Kong Electric Holdings, members of the Cheung Kong group, acquired Powercor in 2000 and CitiPower in 2002. Cheung Kong floated 49 per cent of its Victoria/South Australia distribution assets as Spark Infrastructure in 2005.
- Singapore Power acquired the Eastern Energy network from TXU in 2004, following its acquisition of the Victorian transmission network in 2000. Singapore Power sold 49 per cent of its Australian electricity assets through a partial float of SP AusNet in November 2005.
- Alinta and DUET, which is managed by AMP Henderson and Macquarie Bank, acquired the United Energy network in 2003. United Energy is 34 per cent owned by Alinta, which operates and manages the network. DUET holds a 66 per cent equity interest. Alinta also acquired the Solaris network from AGL in 2006.
- A Babcock & Brown/Singapore Power consortium acquired Alinta under a conditional agreement in May 2007.

There has also been a separation between the ownership and operation of some networks. For example, while DUET has a majority equity interest in United Energy, the minority owner—Alinta—operates and manages the network.

In South Australia, the government leased the single distribution network business (ETSA Utilities) to the Cheung Kong group in January 2000 under a 200-year lease. In 2005, Cheung Kong floated 49 per cent of its equity as Spark Infrastructure.

The other NEM jurisdictions restructured their distribution networks but retained government ownership:

- New South Wales restructured 25 electricity distribution businesses into six government owned corporations in the 1990s. Further consolidation of regional networks reduced this number to three —EnergyAustralia, Integral Energy and Country Energy (figure 5.1a). The most recent change involved Australian Inland, which merged with Country Energy in 2005.
- Queensland consolidated seven government-owned electricity distributors into two in the late 1990s —ENERGEX and Ergon Energy (figure 5.1c).
- The government owned Aurora Energy is the sole electricity distributor in Tasmania.
- The Australian Capital Territory electricity distribution network is jointly owned by the Australian Capital Territory Government and Alinta.[5]

In some jurisdictions there are ownership linkages between electricity distribution and other parts of the energy sector (table 5.2). New South Wales and Tasmania have common ownership in electricity distribution and retailing, with ring-fencing arrangements for operational separation. Victoria completed its separation of the sectors in 2006 when Alinta acquired AGL's networks assets. Queensland privatised most of its energy retail sector in 2006–07, which largely separated it from distribution.[6]

A number of electricity distributors also provide gas transportation services. The most significant is Alinta/DUET, which owns electricity and gas distribution infrastructure in Victoria, gas distribution in Western Australia and several gas transmission pipelines. Cheung Kong Infrastructure owns electricity distribution assets in Victoria and South Australia, and is a minority owner of Envestra—which distributes gas in a number of jurisdictions, including Victoria, South Australia and Queensland. SP AusNet has interests in electricity transmission and distribution and gas distribution. The Queensland Government traditionally owned electricity and gas distribution networks, but privatised its gas assets in 2006.

5 For information on Western Australia and the Northern Territory see chapter 7.
6 The Queensland Government owned distributor Ergon Energy is also an energy retailer to 600 000 unprofitable customers.

## Scale of the networks

Table 5.1 notes the size of Australia's distribution networks as reflected by their line length and regulated asset base (RAB). The RAB is an asset valuation that regulators apply in conjunction with rates of return to set the returns on capital for infrastructure owners.

Figure 5.2 compares the RABs of distribution networks in the NEM. ENERGEX and Ergon Energy (Queensland) and EnergyAustralia (New South Wales) have the largest RABs, each exceeding $4 billion. The Queensland networks make up the largest combined statewide RAB (around $9.7 billion), followed by New South Wales ($8.8 billion), Victoria ($5.8 billion) and South Australia ($2.5 billion). The RABs of the Tasmanian and the Australian Capital Territory networks are relatively small. NEM-wide, the combined RABs of distribution networks is around $27 billion, more than double the valuation for transmission infrastructure.

Many factors can affect RAB value, including the basis of original valuation, network investment, the age of a network, geographical scale, the distances required to transport electricity from transmission connection points to demand centres, population dispersion and forecast demand profiles.

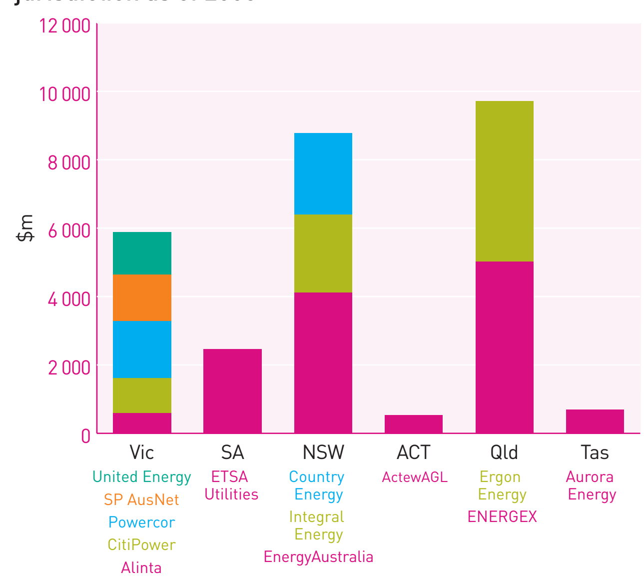
## 5.3 Economic regulation of distribution services

Electricity networks are highly capital intensive and incur relatively low operating costs. This gives rise to economies of scale that make it more efficient to have one provider of network services in a geographical area than to have competing providers. Economists describe this situation as a natural monopoly. As noted in section 4.3, independent regulation of natural monopolies can manage the risk of the exercise of market power.

**Table 5.2 Ownership linkages between electricity distribution and other energy market segments**

| OWNERSHIP LINKAGE | DISTRIBUTION BUSINESS |
|---|---|
| Electricity distribution and transmission | SP AusNet (Vic); EnergyAustralia (NSW) |
| Electricity distribution and retail | EnergyAustralia, Integral Energy and Country Energy (NSW); Aurora Energy (Tas); Ergon Energy (Qld) |
| Electricity distribution and gas transportation | Alinta/DUET; Cheung Kong Infrastructure; SP AusNet |

**Figure 5.2**
**Regulated asset bases of distribution networks by jurisdiction as of 2006**




Note: See note 2, table 5.1

Sources: Regulatory determinations of ESC (Vic); IPART (NSW); QCA (Qld); ESCOSA (SA); OTTER (Tas); and ICRC (ACT).

State-based regulatory agencies are currently responsible for the economic regulation of distribution networks. However, governments in the NEM have agreed to transfer these responsibilities to the Australian Energy Regulator (AER) from 2008. The regulation of distribution networks in Western Australia and the Northern Territory will remain under state and territory jurisdiction.

The National Electricity Rules (NER) set out the framework for regulating distribution networks. The NER require the use of an incentive-based regulatory scheme but allow each jurisdictional regulator to choose the form of regulation. The options allowed under the NER include a revenue cap, a weighted average price cap or a combination of the two. In addition, some jurisdictional regulators impose local regulatory frameworks as a condition of licensing arrangements for distribution businesses. Regulatory frameworks that some jurisdictional regulators impose include revenue yield models that control the average revenue per unit sold, based on volumes or revenue drivers. In South Australia, an electricity pricing order sets some elements of the regulatory framework.

In essence, each approach involves the setting of a ceiling on the revenues or prices that a distribution business is allowed to earn or charge. As table 5.3 illustrates, the NEM jurisdictions use a range of approaches.

Most jurisdictions apply a building-block approach to determine the revenue or price ceiling. The building blocks factor in a network's operating costs, asset depreciation costs, taxation liabilities and a commercial return on capital. The setting of these elements has regard to various factors, including projected demand growth, price stability, the potential for efficiency gains in cost and capital expenditure management, service standards and the provision of a fair and reasonable risk-adjusted rate of return on efficient investment.

Table 5.3 Forms of incentive regulation in the NEM

| FORM OF REGULATION | HOW IT WORKS | REGULATOR | NETWORK(S) |
|---|---|---|---|
| Weighted average price cap | Sets a ceiling on a weighted average of distribution tariffs (prices). The distribution business is free to adjust its individual tariffs as long as the weighted average remains within the ceiling.<br><br>There is no cap on the total revenue a distribution business may earn. Revenues can vary depending on tariff structures and the volume of electricity sales. | Essential Services Commission (Vic)<br><br>Independent Pricing and Regulatory Tribunal (NSW) | Alinta<br>CitiPower<br>Powercor<br>SP AusNet<br><br>United Energy<br>EnergyAustralia<br>Integral Energy<br>Country Energy |
| Revenue cap | Sets the maximum revenue a distribution network may earn during a regulatory period. It effectively caps total earnings. This mirrors the approach used to regulate transmission networks.<br><br>The distribution business is free to determine individual tariffs such that total revenues do not exceed the cap. | Queensland Competition Authority (Qld)<br><br>Independent Competition and Regulatory Commission (ACT)<br><br>Office of the Tasmanian Energy Regulator (Tas) | ENERGEX<br>Ergon Energy<br><br>ActewAGL<br><br>Aurora Energy |
| Revenue yield (average revenue control) | Links the amount of revenue a distribution business may earn to the volume of electricity sold. Total revenues are not capped and may vary in proportion to the volume of electricity sales.<br><br>The distribution business is free to determine individual tariffs—subject to tariff principles and side constraints—such that total revenues do not exceed the average. | Essential Services Commission of South Australia (SA) | ETSA Utilities |

There are also variations in the treatment of specific components of the building block and the incentive schemes attached to some elements of the blocks. For example:

> most jurisdictions 'lock in and roll forward' although in 2005 the Queensland regulator revalued the regulated asset bases of ENERGEX and Ergon Energy, using a depreciated optimised replacement cost method[7]
> in determining a return on capital, there are differences in the treatment of taxation between jurisdictions
> jurisdictions apply different types of incentive mechanisms that encourage distribution businesses to manage their operating and capital expenditure efficiently
> some jurisdictions conduct an ex post check of the prudency of past investment when determining the amount of capital expenditure to be rolled into the RAB
> Victoria, South Australia and Tasmania apply financial incentive schemes for distribution businesses to maintain—and improve—efficient service standards over time. New South Wales has a paper trial in progress. Queensland does not currently operate such a scheme.

In applying any of the forms of regulation in table 5.3, a regulator must forecast the revenue requirement of a distribution business over the regulatory period. In turn, this must factor in investment forecasts and the operating expenditure allowances that a benchmark distribution business would require if operating efficiently. The aim is not to encourage a distribution network to fully spend its forecast allowances, but to provide incentives for it to reduce costs through efficient management—that is, to beat the allowance. However, as discussed in section 5.6, these incentives must be balanced against a service standards regime to ensure underspending does not occur at the expense of a reliable and safe distribution network.

## Revenues

Figures 5.3a and 5.3b chart the forecast revenue allowances for distribution networks in the NEM, as determined by the jurisdictional regulators. The data is deflated to remove the effects of inflation. Various factors affect the forecasts, including differences in scale and market conditions and differences in regulatory approach.

Allowed revenues are tending to rise over time as the underlying asset base expands to meet rising demand. The combined revenue of the NEM's 13 major distribution networks was forecast at around $5150 million in 2005–06 (in $2006), with projected real growth of around 12.5 per cent in the two years to 2007–08. Revenue growth has been strong for the New South Wales and Queensland networks, but has generally been flatter in Victoria and South Australia.

## Return on assets

Jurisdictional regulators publish annual regulatory and performance reports that include indicators of the profitability and efficiency of distribution businesses. A commonly used financial indicator to assess the performance of a business is the return on assets.

The return on assets is calculated as operating profits (net profit before interest and taxation) as a percentage of the average RAB. Figure 5.4 sets out the return on assets for distribution networks where data is available. Over the last five years, the government owned distribution businesses in New South Wales, Queensland and Tasmania have achieved returns ranging between 4 and 10 per cent. The privately owned distribution businesses in Victoria and South Australia tended to yield returns of about 8 to 12 per cent.

A variety of factors can affect performance in this area. These might include differences in the demand and cost environments faced by each business and variances in demand and costs outcomes compared to those forecasted in the regulatory process.

7 Queensland Competition Authority, *Final determination: Regulation of electricity distribution*, April 2005, p. 57.

Figure 5.3a

**Allowed revenues — Victoria, South Australia and Tasmania**

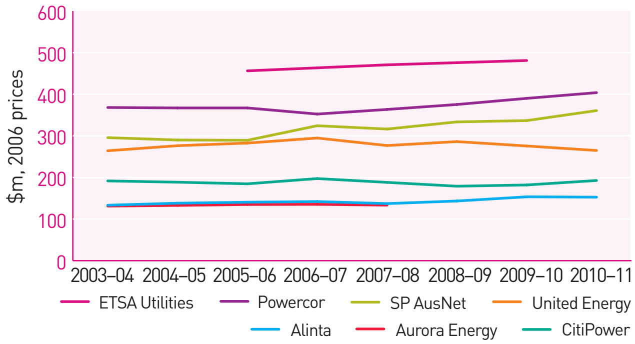
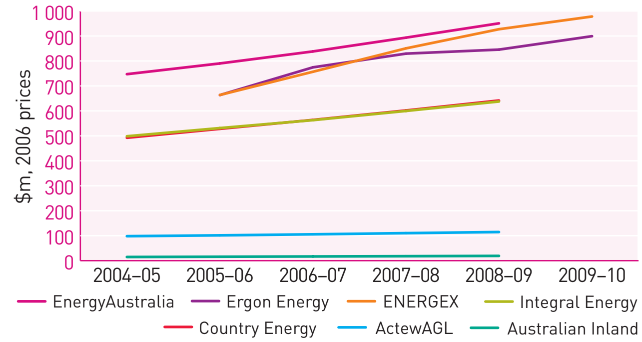



Figure 5.3b

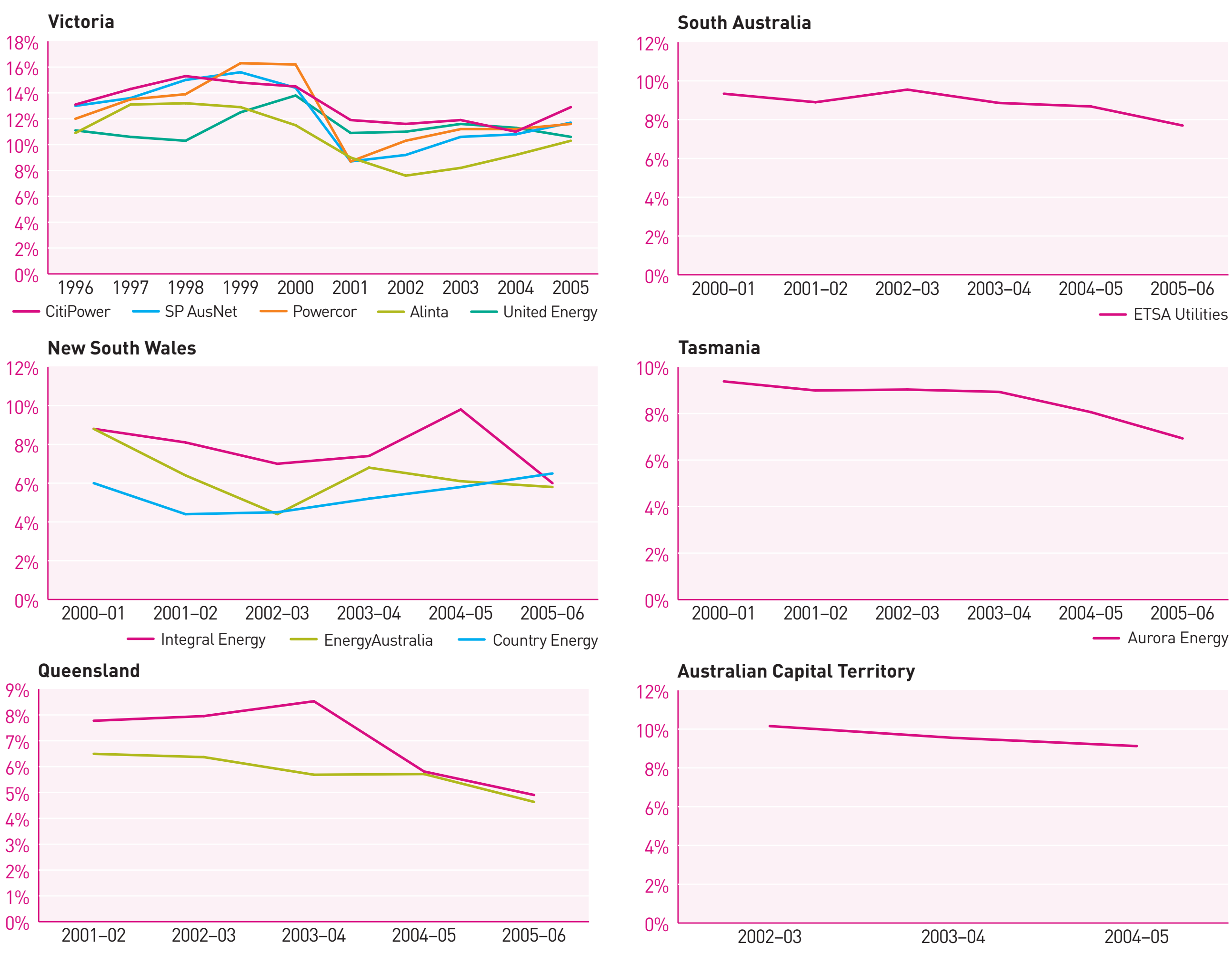
**Allowed revenues — New South Wales, the Australian Capital Territory and Queensland**




Source: Regulatory determinations of ESC (Vic); IPART (NSW); QCA (Qld); ESCOSA (SA); OTTER (Tas); and ICRC (ACT).

Figure 5.4

**Return on assets for distribution networks in the NEM**




Sources: Regulatory determinations and distribution network performance reports published by ESC (Vic); IPART (NSW); QCA (Qld); ESCOSA (SA); OTTER (Tas); and ICRC (ACT).

## 5.4 Distribution investment

New investment in distribution infrastructure is needed to maintain or improve network performance over time. Investment covers network augmentations (expansions) to meet rising demand and the replacement of depreciated and ageing assets. Some investment is driven by regulatory requirements on matters such as network reliability.

Figures 5.5 and 5.6 chart real investment in distribution infrastructure in the NEM, based on actual data where available, and forecast data for other years. Figure 5.5 charts investment by network business, while figure 5.6 charts aggregate outcomes for each jurisdiction.

The forecast data relates to investment proposed by a distribution business that the regulator has approved as efficient at the beginning of the regulatory period. At the end of the regulatory period, the RAB is adjusted to reflect actual investment that has occurred over the period. In some jurisdictions, actual expenditure will be subject to a prudency test before qualifying for inclusion in the RAB.

There is some volatility in the data, which reflects timing differences between the commissioning and completion of some projects. More generally, the network businesses have some flexibility to manage and reprioritise their capital expenditure over the five-year regulatory period. Further, there is some lumpiness in distribution investment because of the one-off nature of some capital programs—although investment tends to exhibit smoother trends in distribution than in transmission. The transition from actual to forecast data may also cause some volatility in the data points. These factors suggest that the analysis of investment data should focus on longer term trends rather than short-term fluctuations.

The charts indicate that there has been significant investment in distribution infrastructure since the commencement of the NEM. In total, real investment has risen from around \$2080 million in 2001–02 to around \$3400 million in 2005–06. This represents average annual real growth of around 13 per cent. Real investment growth is forecast to ease in the latter part of the decade.

At the jurisdiction level:

- investment in New South Wales rose by around 62 per cent between 2001–02 and 2005–06 to around \$1190 million—equal to around 13.6 per cent of the statewide RAB
- investment in Queensland rose by around 110 per cent between 2001–02 and 2005–06 to over \$1300 million—equal to around 13.4 per cent of the statewide RAB
- investment in Victoria rose by around 13.7 per cent between 2001–02 and 2005–06 to around \$600 million—equal to around 10.2 per cent of the statewide RAB
- investment in South Australia rose by around 28.5 per cent between 2001–02 and 2005–06 to around \$180 million—equal to around 7.2 per cent of the statewide RAB
- investment in Tasmania rose by around 160 per cent between 2001–02 and 2005–06 to around \$100 million—equal to around 14.6 per cent of the statewide RAB.

The different outcomes between jurisdictions reflect a range of variables, including differences in scale and investment drivers, such as the age of the networks and demand projections. Differences in regulatory requirements on matters such as network reliability also affect investment outcomes.

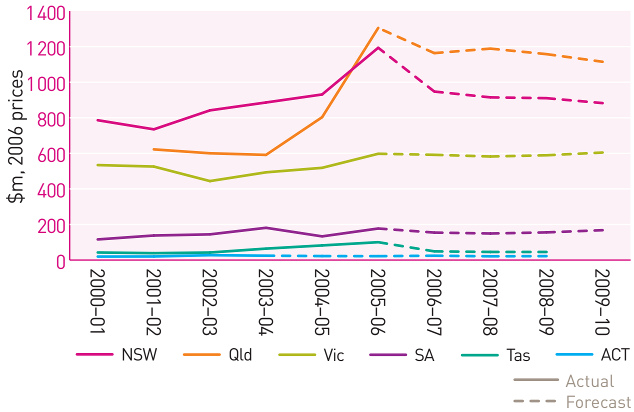
**Figure 5.5**

**Actual and forecast capital expenditures**


Source: Regulatory determinations and distribution network performance reports published by ESC (Vic); IPART (NSW); QCA (Qld); ESCOSA (SA); OTTER (Tas); and ICRC (ACT).

Figure 5.6

**Aggregate distribution capital expenditure by jurisdiction**




Source: Regulatory determinations and distribution network performance reports published by ESC (Vic); IPART (NSW); QCA (Qld); ESCOSA (SA); OTTER (Tas); and ICRC (ACT).

## 5.5 Operating and maintenance expenditure

As in the regulation of transmission businesses, regulators provide an allowance for distribution businesses to cover an efficient level of operating and maintenance expenditure over the regulatory period. A target (forecast) level of expenditure is set and an incentive scheme encourages the distribution business to reduce its spending through efficient operating practices. The schemes vary between jurisdictions, but generally allow the business to retain some or all of its underspending against target in the current regulatory period. Some jurisdictions also apply a service standards incentive scheme to ensure that cost savings are not achieved at the expense of network performance (section 5.6).

The jurisdictional regulators publish comparisons of target and actual levels of expenditure. Figure 5.7 charts the percentage variances for each jurisdiction. A positive variance indicates that actual expenditure exceeded target in that year—that is, the distribution business overspent. Similarly, a negative variance indicates that a distribution business underspent against target. A trend of negative variances over time may suggest a positive response to efficiency incentives. Conversely, it would be possible that the original targets were too generous. More generally, care should be taken in interpreting year-to-year changes in operating expenditure. As the network businesses have some flexibility to manage their expenditure over the regulatory period, timing considerations may affect the data. This suggests that analysis should focus on longer term trends.

Figure 5.7 indicates that most of the Victorian networks and ENERGEX (Queensland) underspent against their forecast allowances for most or all of the charted period. The New South Wales networks and Ergon Energy (Queensland) have tended to overspend against target, but each recorded sharply improved performance in 2005–06. ETSA Utilities has had varied performance against target, but with sharp improvement since 2003–04.

## 5.6 Service quality and reliability

Electricity distribution networks are monopolies that face little risk of losing customers if they provide poor quality service. In addition, regulatory incentive schemes for efficient cost management might encourage a business to sacrifice service quality to reduce costs. In recognition of these risks, governments and regulators monitor the performance of distribution businesses to ensure they provide acceptable levels of service. Some jurisdictions also provide financial incentives to encourage distribution businesses to meet target levels of service.

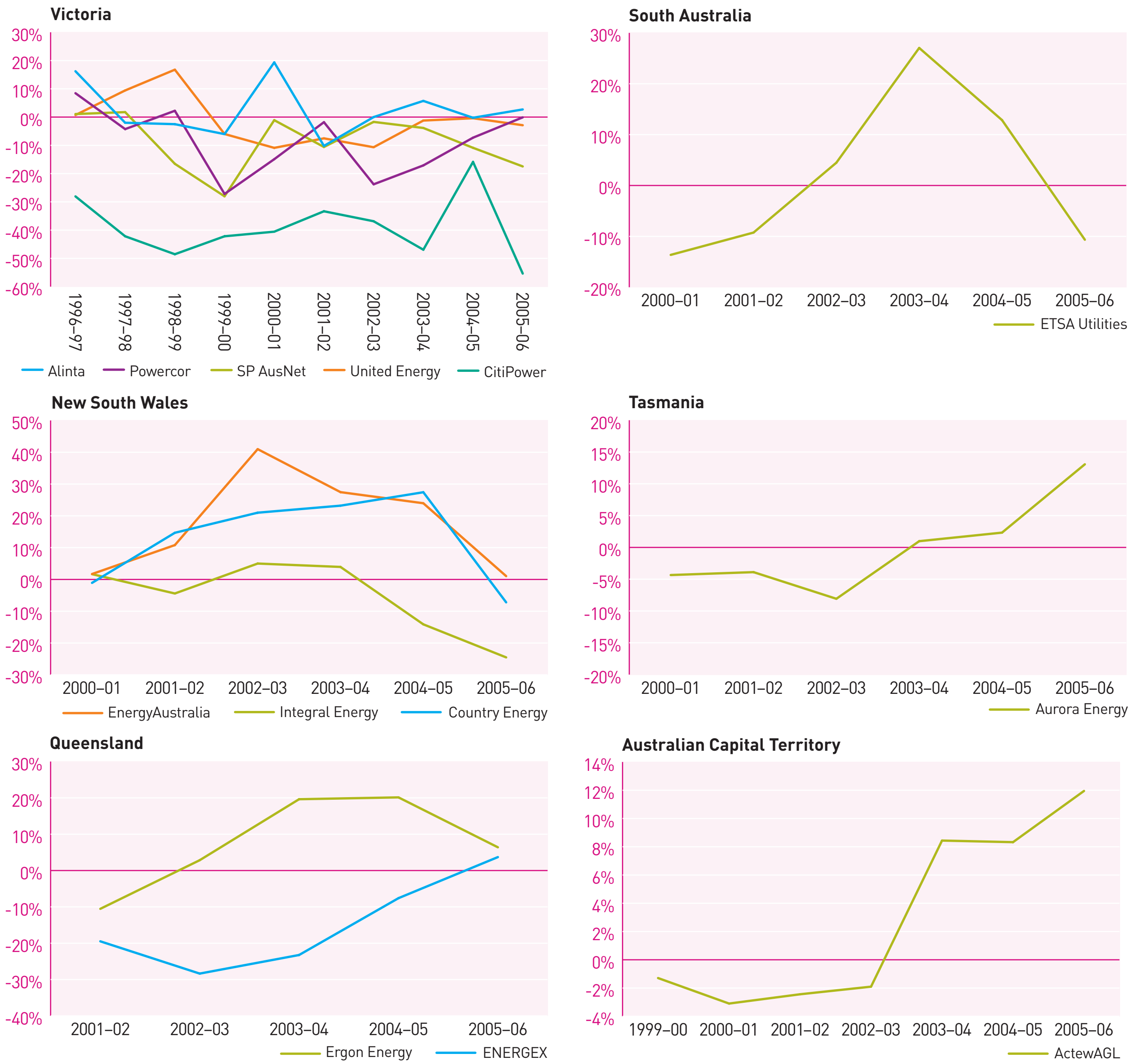
All jurisdictions have their own monitoring and reporting framework on service quality. In addition, the Utility Regulators Forum (URF) developed a national framework in 2002 for distribution businesses to report against common performance criteria.[8] All NEM jurisdictions report against the criteria, which address:

- reliability (the continuity of electricity supply through the network)
- technical quality (for example, voltage stability)
- customer service (for example, on-time provision of services and the adequacy of call centre performance).

8 Utility Regulators Forum, *National regulatory reporting for electricity distribution and retailing businesses*, Discussion paper, March 2002.

Figure 5.7

**Operating and maintenance expenditure—variances from target**




Source: Regulatory determinations and distribution network performance reports published by ESC (Vic); IPART (NSW); QCA (Qld); ESCOSA (SA); OTTER (Tas); and ICRC (ACT).

Jurisdictions regulate the service performance of distribution networks through schemes that include:

- the monitoring and reporting of reliability, technical quality and customer service outcomes against standards set out in legislation, regulations, licences and codes. There may be sanctions for non-compliance.
- financial incentive schemes for distribution businesses to maintain—and improve—service standards over time. The Victorian, South Australian and Tasmanian regulators administer the schemes as part of the economic regulation of the networks. Victoria and Tasmania currently use service incentive schemes that apply an 's-factor' approach.[9] The South Australian scheme, which does not apply an s-factor, focuses on customers with poor reliability outcomes.
- guaranteed customer service levels (GSLs) that, if not met, require a network business to make payments to affected customers. Typically, the schemes are made available only to small customers. The service level guarantees relate to network reliability, technical quality of service and customer service. Each of the NEM jurisdictions implements a GSL scheme.

There is considerable variation in the detail of these schemes from jurisdiction to jurisdiction. Box 5.1 provides a case study of the Victorian framework.

## Reliability

Reliability refers to the continuity of electricity supply to customers, and is a key performance indicator that impacts on customers. The following discussion on distribution reliability should be read in conjunction with essay B of this report, which examines reliability across the broader power supply chain.

A reliable distribution network keeps interruptions or outages in the transport of electricity down to acceptable levels. Various factors, both planned and unplanned, 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 supply of electricity to be disconnected unexpectedly. There are often routine external causes, such as damage caused by trees, birds, possums, vehicle impacts or vandalism. Networks can also be vulnerable to extreme weather, such as bushfires or storms. There may be ongoing reliability issues if a network has inadequate maintenance or is utilised near its capacity limits at times of peak demand. Sometimes these factors occur in combination.

The impact of an outage depends on customer load, the design of the network, maintenance practices and the time taken by a distributor to restore supply after an interruption. Unlike generation and transmission, the impact of a distribution outage tends to be localised to a part of the network.

Jurisdictions track the reliability of distribution networks against performance standards to assess whether they are operating at a satisfactory level. The standards take account of the trade-off between improved reliability and cost. Ultimately, customers must pay the cost of investment, maintenance and other solutions needed to deliver a reliable power system. It would therefore be inefficient to try to eliminate every possible interruption. Rather, an efficient outcome would reflect the level of service that customers are willing to pay for. There has been some research on the willingness of electricity customers to pay higher prices for a reliable electricity supply. A 1999 Victorian study found that more than 50 per cent of customers were willing to pay a higher price to improve or maintain their level of supply reliability.[10] However, a 2003 South Australian survey indicated that customers were willing to pay for improvements in service only to poorly serviced customer areas.[11]

9 The use of s-factor schemes is discussed in the context of electricity transmission in section 4.6 of this report.

10 KBA, *Understanding customers' willingness to pay: Components of customer value in electricity supply*, 1999.

11 The survey found that 85 per cent of consumers were satisfied with their existing level of service and were generally unwilling to pay for improvements in these levels. It found that there was a willingness to pay for improvements in service only to poorly served consumers. On this basis, ESCOSA has focused on providing incentives to improve the reliability performance for the 15 per cent of worst served consumers, while maintaining average reliability levels for all other customers. See ESCOSA, *2005–2010 Electricity distribution price determination, part A*, April 2005; and KPMG, *Consumer preferences for electricity service standards*, March 2003.

**Box 5.1 Case Study—service standard regimes in Victoria**

The Victorian regulatory regime, administered through the ESC, implements a suite of service standard regimes for electricity distribution businesses. The regimes include a service-standards reporting framework, a service-standards incentive mechanism and a GSL payment scheme. All are benchmarked annually against predetermined targets.

For monitoring and reporting purposes, the ESC tracks:

- reliability outcomes, based on the URF indicators
- reliability experienced by the worst supplied 15 per cent of customers
- technical quality of supply measures, such as voltage stability
- customer service measures, such as call centre performance.

There is some overlap between these measures and those used in the financial incentive scheme that is part of the regulation of network price caps. For the 2006–10 regulatory period, the ESC is tracking network performance against specific reliability standards and call centre performance. The ESC converts outcomes to a standardised 's-factor' measure that provides the basis for financial bonuses and penalties.

Under the GSL scheme, Victoria requires distributors to pay compensation to customers when they have failed to meet minimum thresholds for acceptable levels of reliability and customer service. The GSLs for reliability relate to low supply reliability and delays in restoring lost supply. The GSLs for customer service relate to failures to meet on-time appointments, customer connections and repair of streetlights.

Further information: Essential Services Commission, *Electricity distribution businesses — comparative performance report 2005*, 2006.

In practice, the trade-offs between improved reliability and cost result in standards for distribution networks being less stringent than for generation and transmission. This reflects the localised effects of distribution outages, compared with the potentially widespread geographical impact of a generation or transmission outage. At the same time, the capital intensive nature of distribution networks makes it very expensive to build in high levels of redundancy (spare capacity) to improve reliability.

For similar reasons, there tend to be different reliability standards for different feeders (parts) of a distribution network. For example, a higher reliability standard is usually required of a central business district (CBD) network with a large customer base and a concentrated load density than for a highly dispersed rural network with a small customer base and low load density. While the costs of redundancy in a dispersed rural network are relatively high, few customers are likely to be affected by an outage.

### Reliability data—Utility Regulators Forum indicators

All jurisdictions have their own monitoring and reporting framework on reliability. In addition, the URF has adopted four indicators of distribution network reliability which are widely used in Australia and overseas. The indicators relate to the average frequency and duration of network interruptions or outages (table 5.4). The indicators do not distinguish between the nature and size of loads that are affected by supply interruptions.

In most jurisdictions, distribution businesses are required to report performance against the SAIDI, SAIFI and CAIDI indicators (table 5.4). Jurisdictional regulators audit, analyse and publish the results[12], typically down to feeder level (CBD, urban and rural) for each network.

12 The distribution businesses publish this data in the first instance in New South Wales. IPART publishes periodic summaries of the data.

Table 5.4 **Reliability measures—distribution**

| INDEX | MEASURE | DESCRIPTION |
|---|---|---|
| SAIDI | system average interruption duration index | average total number of minutes that a distribution network customer is without electricity in a year (excludes interruptions of one minute or less) |
| SAIFI | system average interruption frequency index | average number of times a customer's supply is interrupted per year |
| CAIDI | customer average interruption duration index | average duration of each interruption (minutes) |
| MAIFI | momentary average interruption frequency index | average number of momentary interruptions (of one minute or less) per customer per year |

Source: URF, *National regulatory reporting for electricity distribution and retailing businesses*, 2002.

Tables 5.5 and 5.6 and figure 5.8 set out summary data for the SAIDI and SAIFI indicators for NEM jurisdictions, including NEM-wide averages. PB Associates developed the data for the AER from the reports of jurisdictional regulators and from reports prepared by distribution businesses for the regulators.

There are a number of issues with the reliability data that limit the validity of any performance comparisons. In particular, the data relies on the accuracy of the network businesses' information systems, which may vary considerably. There are also geographical, environmental and other differences between the states and between networks within particular states.

In addition, there are differences in the approach of each jurisdiction to excluded events. The URF agreed that in some circumstances, reliability data should be normalised to exclude interruptions that are beyond the control of a network business.[13] In practice, there are differences between jurisdictions in the approval and reporting of exclusions. More generally, there is no consistent approach to auditing performance outcomes. Finally, these are relatively new data series in some jurisdictions, and the quality of reporting is likely to improve over time.

Noting these caveats, the SAIDI data indicates that since 2000–01 the average duration of outages per customer tended to be lower in Victoria and South Australia than other jurisdictions—despite some community concerns that privatisation might adversely affect service quality. New South Wales recorded a significant decline in outage time in the three years to 2005–06, and was the only jurisdiction to improve its performance in that year. Average reliability in Queensland tended to be lower than in other jurisdictions. It should be noted that Queensland is subject to significant variations in performance, in part because of its large and widely dispersed rural networks, and extreme weather events. These characteristics make it more vulnerable to outages than some other jurisdictions.

The NEM-wide SAIDI averages rely on the jurisdictional data, and are therefore subject to the caveats outlined above. In addition, the NEM averages include a number of assumptions to allow comparability over time (see notes to tables 5.5 and 5.6). Noting these cautions, the data indicates that distribution networks in the NEM have delivered reasonably stable reliability outcomes over the last few years. NEM-wide SAIDI remained in a range of about 200–270 minutes between 2000–01 and 2005–06. This estimate excludes the impact of a cyclone that affected large parts of Queensland in 2006.

There appears to have been an overall improvement in the average frequency of outages (SAIFI) across the NEM since 2000. On average distribution customers in the NEM experience outages around twice a year, but two to three times a year in Queensland.



13 The URF definitions exclude outages that (i) exceed a threshold SAIDI impact of three minutes, (ii) are caused by exceptional natural or third party events and (iii) the distribution business cannot reasonably be expected to mitigate the effect of by prudent asset management.

**Table 5.5** System average interruption duration index—SAIDI (minutes)

| | OUTAGE DURATION | | | | | | |
|---|---|---|---|---|---|---|---|
| JURISDICTION | 1999–00 | 2000–01 | 2001–02 | 2002–03 | 2003–04 | 2004–05 | 2005–06 |
| Vic | 156 | 183 | 152 | 151 | 161 | 132 | 165 |
| NSW & the ACT | | 175 | 324 | 193 | 279 | 218 | 191 |
| Qld | | 331 | 275 | 332 | 434 | 283 | 315 |
| SA | | 164 | 147 | 184 | 164 | 169 | 199 |
| NEM weighted average | 156 | 211 | 246 | 211 | 268 | 202 | 211 |

**Table 5.6** System average interruption frequency index—SAIFI

| | OUTAGE FREQUENCY INDEX | | | | | | |
|---|---|---|---|---|---|---|---|
| JURISDICTION | 1999–00 | 2000–01 | 2001–02 | 2002–03 | 2003–04 | 2004–05 | 2005–06 |
| Vic | 2.1 | 2.1 | 2.0 | 2.0 | 2.2 | 1.9 | 1.8 |
| NSW & the ACT | 1.7 | 2.5 | 2.6 | 1.4 | 1.6 | 1.6 | 1.8 |
| Qld | | 3.0 | 2.8 | 3.3 | 3.4 | 2.7 | 2.7 |
| SA | | 1.7 | 1.6 | 1.8 | 1.7 | 1.7 | 1.9 |
| NEM weighted average | 1.6 | 2.4 | 2.4 | 2.1 | 2.2 | 1.9 | 2.0 |

Notes: PB Associates developed the data estimates for the AER from the reports of jurisdictional regulators and from reports prepared by distribution businesses for the regulators. Queensland data for 2005–06 is normalised to exclude the impact of a severe cyclone. Victorian data is for the calendar year ending in that period (for example, Victorian 2005–06 data is for calendar year 2005). NEM averages exclude New South Wales and Queensland (2000–01) and Tasmania (all years).

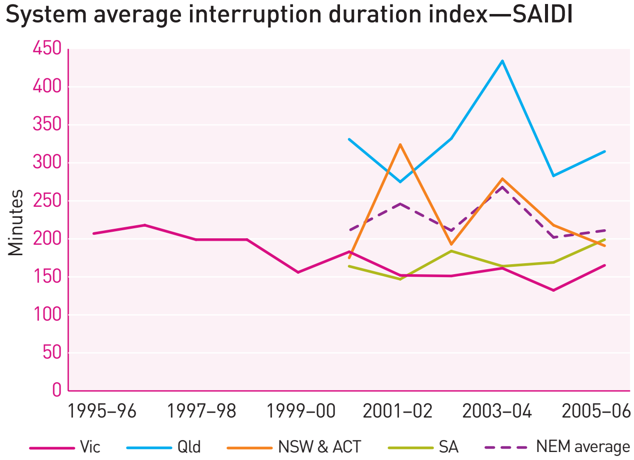
Source: PB Associates (unpublished) and performance reports published by ESC (Victoria); IPART (New South Wales); QCA (Queensland); ESOCSA (South Australia); OTTER (Tasmania); ICRC (the Australian Capital Territory); EnergyAustralia; Integral Energy and Country Energy.

**Table 5.7** Feeder categories

| FEEDER CATEGORY | DESCRIPTION |
|---|---|
| central business district | predominately supplies commercial, high-rise buildings, through an underground distribution network containing significant interconnection and redundancy when compared to urban areas |
| urban | a feeder, which is not a CBD feeder, with actual maximum demand over the reporting period per total feeder route length greater than 0.3 MVA/km |
| rural short | a feeder which is not a CBD or urban feeder with a total feeder route length less than 200 km |
| rural long | a feeder which is not a CBD or urban feeder with a total feeder route length greater than 200 km |

Source: Utilities Regulators Forum, *National regulatory reporting for electricity distribution and retailing businesses*, 2002.

**Figure 5.8**
System average interruption duration index—SAIDI




Source: PB Associates (unpublished). See notes to tables 5.5 and 5.6.

### Reliability of distribution networks by feeder

Given the diversity of network characteristics, it may be more meaningful to compare network reliability on a feeder category basis than on a statewide basis. Feeders are used to carry electricity from bulk distribution hubs to the low-voltage networks that move electricity to customers. The URF defines four categories of feeder based on geographical location (table 5.7).

Figures 5.9a–5.9d set out the average duration of supply interruptions per customer (SAIDI) for the networks from 2002–03 to 2005–06, for each feeder type, subject to data availability. The charts set out normalised data that excludes outages deemed to be beyond the control of the networks—for example, outages caused by cyclones or bushfires. As a general principle, it would be unreasonable to assess performance unless the impact of such events is excluded. For the sake of completeness, the excluded outages are shown separately as dotted lines. Total outages in a period are the sum of the normalised and excluded data.

As noted, it is difficult to make reliable comparisons between jurisdictions—even based on the normalised data—because of differences in approach to exclusions and auditing practices. Any attempt to compare performance should also take account of geographical, environmental and other differences between the networks. In addition, care should also be taken in drawing conclusions from a short time series of data. That said, it is apparent that CBD and urban customers tend to experience better reliability than rural customers. This reflects that reliability standards have regard to the differing cost-benefit reliability equations of each part of a network. To illustrate, there are likely to be more severe economic consequences from a network outage on a CBD feeder compared to a similar outage on a remote rural feeder where customer bases and loads are more dispersed. CBD networks are therefore designed for high reliability, and include the use of underground feeders, which are less vulnerable to outages.

In summary, in the period from 2002–03 to 2005–06:

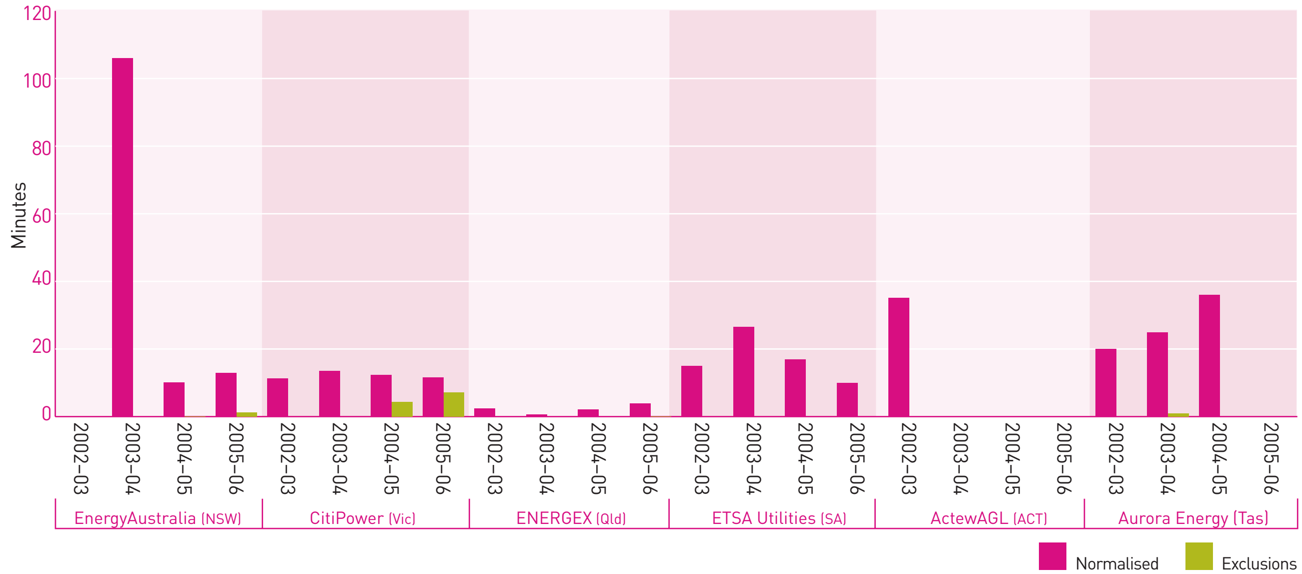
> CBD feeders were more reliable than other feeders. Most CBD customers experienced outages totalling less than 30 minutes per year.

> Urban customers typically experienced normalised outages totalling around 30 to 150 minutes per year, but higher for Ergon Energy (Queensland) customers. Queensland, New South Wales and the Australian Capital Territory customers also faced significant interruptions that were excluded from the normalised data. There were significant improvements over the four-year period for the Victorian networks and ENERGEX (Queensland).

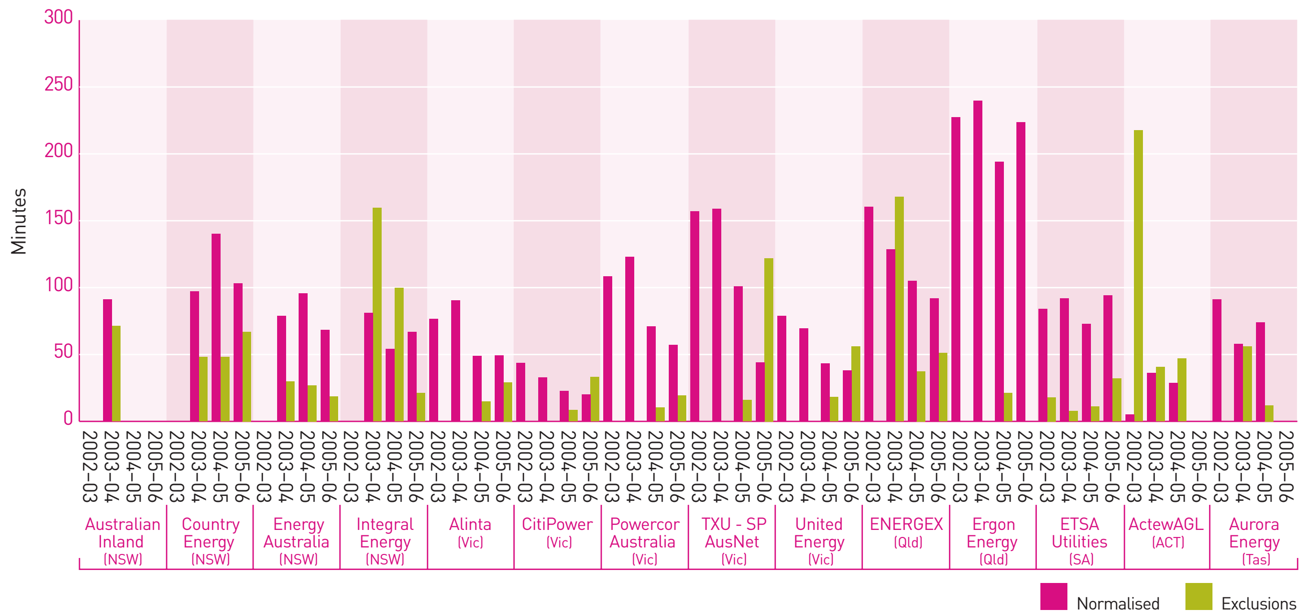
> Rural short customers typically experienced normalised outages of around 100 to 300 minutes per year. Some New South Wales and Queensland customers faced a higher duration of outages, with Ergon Energy recording up to 600 minutes. There were significant exclusions for some networks.

> With a feeder route length of more than 200 km, rural long customers experience the least reliable electricity supply. Rural long feeders are prevalent in discussions of worst serving feeders. Rural long customers in Victoria and South Australia experienced outages of around 200 to 400 minutes per year on average, but were generally around 200 minutes in 2005–06. In some years outages times exceeded 600 minutes for some New South Wales customers, and 1000 minutes for Queensland customers. The Victorian networks, EnergyAustralia (New South Wales) and Aurora Energy (Tasmania) recorded significant improvements over the period. The high level of exclusions for Ergon Energy in 2005–06 relates to extreme weather events.

## Figure 5.9a
**CBD feeders—Average duration of supply interruptions per customer (SAIDI) 2002–03 to 2005–06**




## Figure 5.9b
**Urban feeders—Average duration of supply interruptions per customer (SAIDI) 2002–03 to 2005–06**




Notes: Figures 5.9a–d: Victorian data is for the calendar year ending in that period (for example, Victorian 2005–06 data is for calendar year 2005). Exclusions for ActewAGL in 2002–03 are not shown. Exclusions for Ergon Energy (urban and rural short) in 2005–06 are not shown.

Figure 5.9c

Rural short feeders—Average duration of supply interruptions per customer (SAIDI) 2002–03 to 2005–06

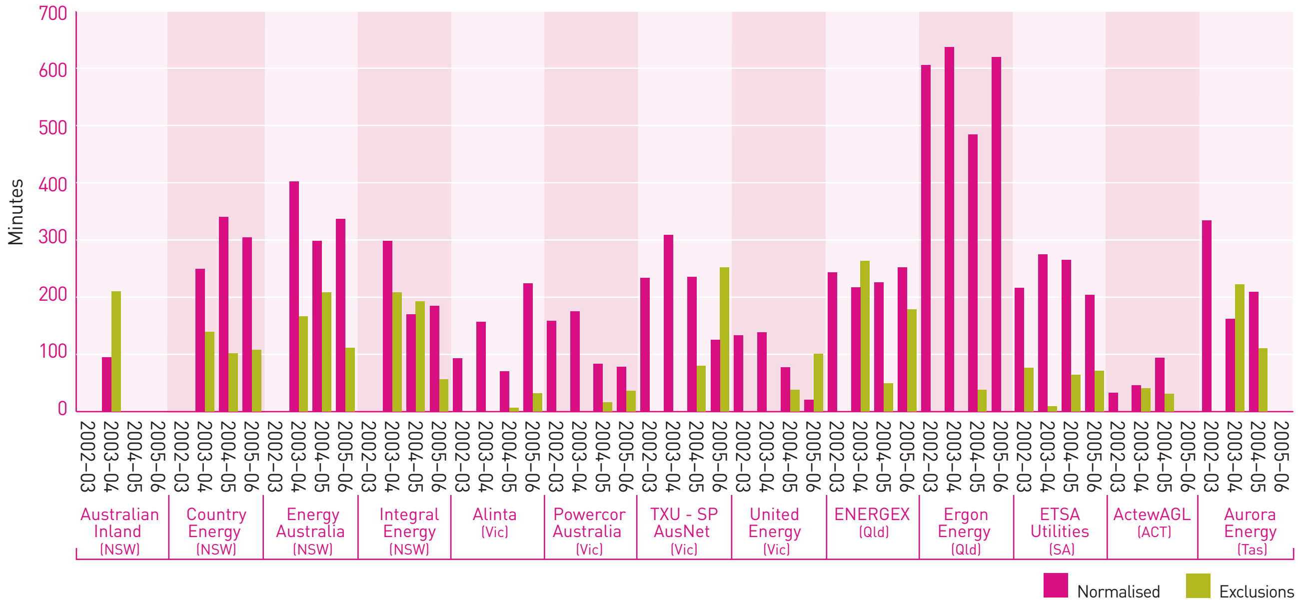
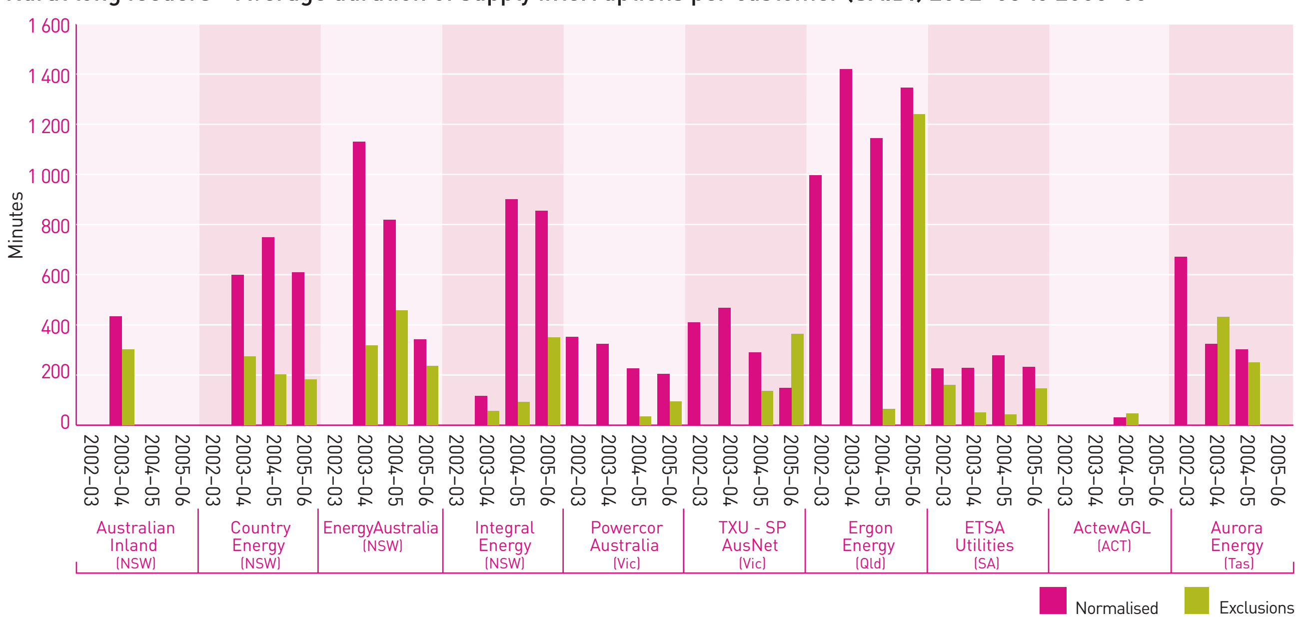



Figure 5.9d

Rural long feeders—Average duration of supply interruptions per customer (SAIDI) 2002–03 to 2005–06




Sources for figures 5.9a–d: Distribution network performance reports published by ESC (Vic); IPART (NSW); QCA (Qld); ESCOSA (SA); OTTER (Tas); ICRC (ACT); EnergyAustralia; Integral Energy; and Country Energy.

## Box 5.2 Case Study—Performance of the Victorian and South Australia networks against service targets

### Victoria

In the 2001–05 regulatory period, Victoria's ESC set service targets (standards) for three performance measures—average minutes-off-supply per customer, the average number of interruptions per customer and the average interruption duration. Different targets were set for each network, taking account of specific characteristics.

Figure 5.10 sets out the percentage variances between target and actual minutes-off-supply (SAIDI) for the five Victorian distribution networks from 2001 to 2005. Over this period the regulator set sliding targets for improved reliability over time. There is a service standards incentive mechanism, with financial incentives for meeting targets, and penalties for underperformance. The chart indicates that most Victorian networks consistently bettered their SAIDI targets. The SP AusNet (previously TXU) network was below target in most years, but improved its performance in 2005.

### South Australia

In South Australia, the Essential Services Commission (ESCOSA) sets reliability targets as part of a service incentive scheme. The scheme examines the reliability of components of the distribution network that have experienced poor past performance.[14] In the year to December 2005, ETSA Utilities performed favourably against its incentive scheme targets, resulting in an increase in allowable revenues.

ESCOSA also reports the performance of ETSA Utilities against best endeavours SAIDI and SAIFI standards set out in the Electricity Distribution Code. ETSA Utilities failed to achieve many of these targets in 2005–06 (table 5.8).

**Table 5.8 Reliability outcomes against target—ETSA Utilities 2005–06**

| REGION | SAIFI (FREQUENCY) | | | CAIDI (MINUTES) | | | SAIDI (MINUTES) | | |
|---|---|---|---|---|---|---|---|---|---|
| | Target | Performance | | Target | Performance | | Target | Performance | |
| Adelaide Business Area | 0.30 | 0.20 | ✓ | 80 | 55 | ✓ | 25 | 11 | ✓ |
| Major Metropolitan Areas | 1.40 | 1.61 | ✗ | 82 | 88 | ✗ | 115 | 142 | ✗ |
| Central | 2.10 | 1.64 | ✓ | 115 | 146 | ✗ | 240 | 239 | ✓ |
| Eastern Hills/ Fleurieu Peninsula | 3.30 | 3.72 | ✗ | 105 | 111 | ✗ | 350 | 414 | ✗ |
| Upper North & Eyre Peninsula | 2.50 | 3.31 | ✗ | 150 | 184 | ✗ | 370 | 610 | ✗ |
| South East | 2.70 | 2.36 | ✓ | 120 | 108 | ✓ | 330 | 256 | ✓ |
| Kangaroo Island | na | 9.34 | na | na | 145 | na | 450 | 1354 | na |
| Total (state wide) | 1.70 | 1.88 | | 97 | 107 | | 165 | 201 | |

na not applicable.

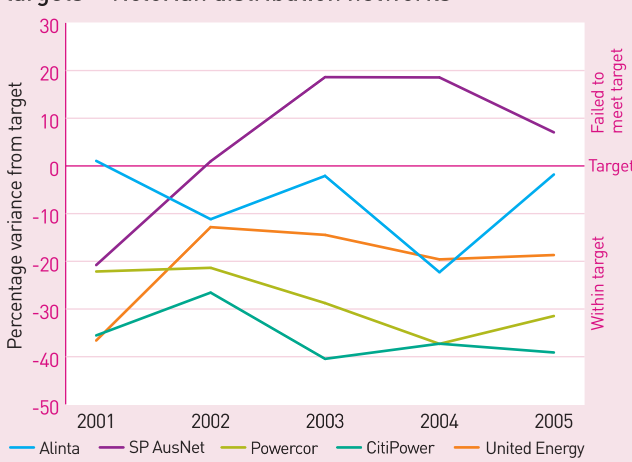
Source: ESCOSA, *2005–06 Distribution network performance report,* November 2006.

14 Reliability targets under the scheme are set for feeders that have experienced two consecutive years of at least three interruptions, or two consecutive years of more than 180 minutes off supply.

Care should be taken in comparing the performance of networks against locally set targets. For example, while ETSA Utilities did not meet some of its best endeavours SAIDI targets in 2005–06, it met its incentive scheme target and has generally recorded outage durations below the national average. More generally, some jurisdictions may set more stringent standards than others.

Figure 5.10

**Minutes off supply against service incentive targets—Victorian distribution networks**




Source: ESC, *Electricity distribution businesses—comparative performance report 2005*, October 2006.

## Performance against reliability standards

Jurisdictions track the reliability of distribution networks against performance standards that are set out in monitoring and reporting frameworks, service standard incentive schemes and guaranteed service level payment schemes. Standards provide a benchmark to assess whether a network is performing to a satisfactory standard. As noted, the standards effectively weigh the costs of improving network reliability through investment, maintenance and other solutions against the benefits. Such assessments take account of the specific characteristics of each network.

To illustrate the use of reliability standards, box 5.2 provides a case study of the performance of the Victorian and South Australian networks against standards developed for incentive schemes that form part of the regulatory framework. Tasmania (not covered in this case study) has recently commenced a similar scheme.

## Technical quality of supply

The technical quality of electricity supply through a distribution network can be affected by issues such as voltage dips, swells and spikes, and television or radio interference. Some problems are network-related (for example, the result of a network limit or fault) but in other cases may trace to an environmental problem or the customer.

Network businesses report on technical quality of supply by disaggregating complaints into categories and their underlying causes. There are a number of issues in making performance comparisons between jurisdictions—in particular, the definition of 'complaint' adopted by each business may vary widely.

The complaint rate for technical quality of supply issues in 2004–05 and 2005–06 was less than 0.1 per cent of customers for most distribution networks in the NEM.

## Customer service

Network businesses report on their responsiveness to a range of customer service issues, including:

> timely connection of services
> timely repair of faulty street lights
> call centre performance
> customer complaints.

Tables 5.9 and 5.10 provide a selection of customer service data, where available, from state and territory regulators.[15] As noted, it is difficult to make reliable performance comparisons between jurisdictions due to the significant differences between networks, as well as differences in definitions and information, measurement and auditing systems. Noting these contexts, the following observations should be interpreted with caution:

> The New South Wales and Victorian networks completed over 99.5 per cent of supply connections on time in 2003–04, 2004–05 and 2005–06. South Australia achieved a slightly lower rate. The Queensland networks recorded a significant improvement in this area in 2005–06 (table 5.9).
> Country Energy and EnergyAustralia (New South Wales) took longer to repair faulty streetlights than other networks in 2004–05 and 2005–06, but their rates of completing repairs by the agreed date was generally comparable with other networks. Ergon Energy (Queensland) and CitiPower (Victoria) achieved lower rates of on-time repair work than the other networks in 2005–06 (table 5.9).
> Tasmanian customers were more likely to have a complaint call answered than mainland customers, while call abandonment levels for ENERGEX (Queensland) and Integral Energy (New South Wales) customers significantly reduced between 2003–04 and 2005–06. Customers of Country Energy (New South Wales) and United Energy (Victoria) faced a higher risk than customers elsewhere of having their call unanswered in 2005–06 (table 5.10).
> The Queensland and South Australian networks generally provided the quickest response to customer phone calls. Most networks improved their call centre response time between 2003–04 and 2005–06, with EnergyAustralia and Integral Energy (New South Wales), CitiPower and Powercor (Victoria) and ENERGEX and Ergon Energy (Queensland) all registering sharp improvements in this area (table 5.10).

15 More comprehensive data is available on the websites of the jurisdictional regulators.

## Table 5.9 Timely provision of service indicators

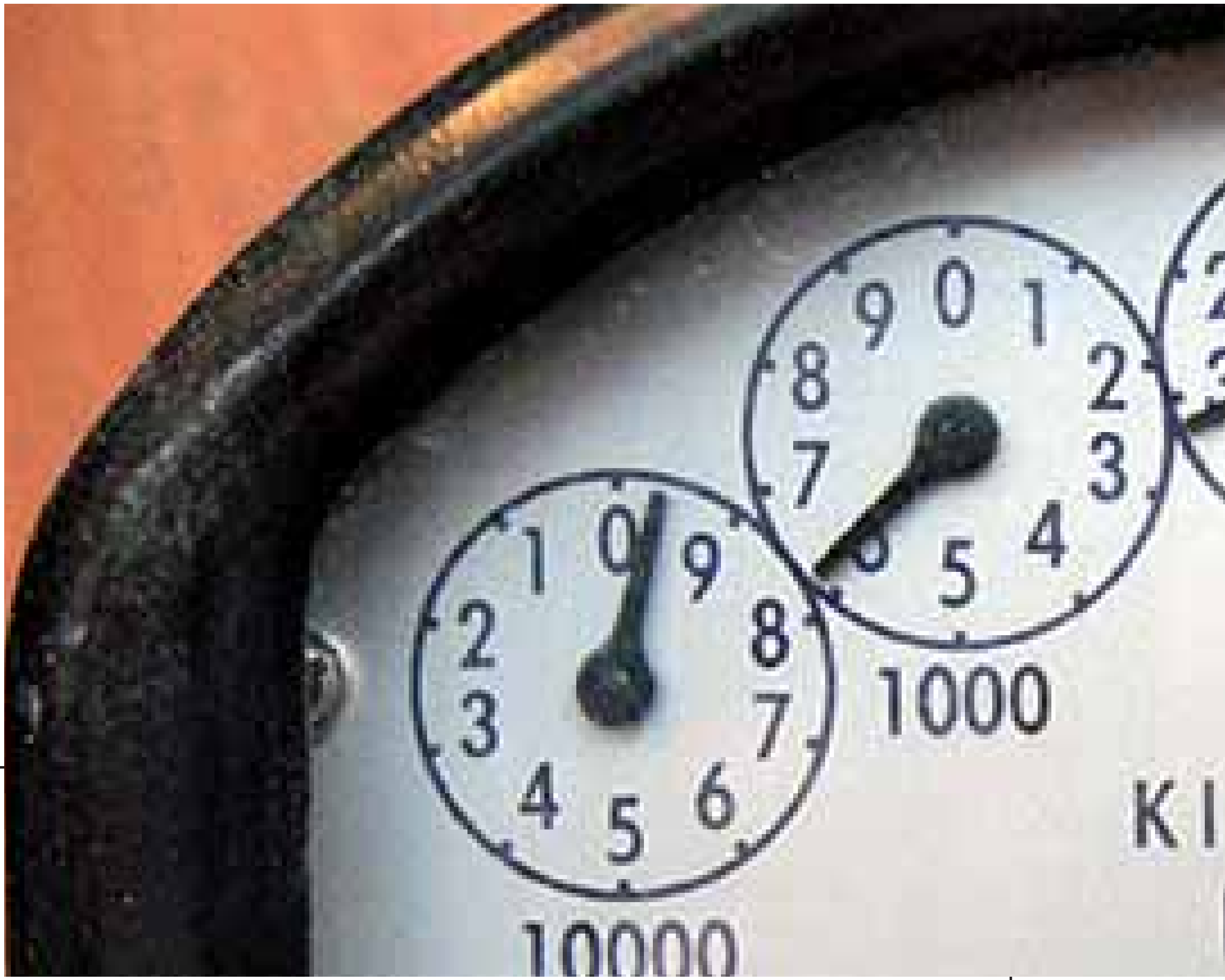
| NETWORK | JURISDICTION | PERCENTAGE OF SUPPLY CONNECTIONS NOT PROVIDED BEFORE THE AGREED DATE | | | PERCENTAGE OF STREETLIGHT REPAIRS NOT COMPLETED BY AGREED DATE | | AVERAGE NUMBER OF DAYS TO REPAIR FAULTY STREETLIGHT | |
|---|---|---|---|---|---|---|---|---|
| | | 2003–04 | 2004–05 | 2005–06 | 2004–05 | 2005–06 | 2004–05 | 2005–06 |
| Country Energy | NSW | 0.03 | 0.02 | 0.02[1] | 1.3 | 1.0 | 9.0 | 8.0 |
| EnergyAustralia | NSW | 0.01 | 0.01 | 0.02[1] | 6.6 | 6.0 | 8.0 | 9.0 |
| Integral Energy | NSW | 0.01 | 0.01 | 0.02[1] | 5.5 | 0.9 | 2.0 | 2.0 |
| Alinta (AGL) | Vic | 0.04 | 0.14 | 0.12 | 6.1 | 6.9 | 2.0 | 3.0 |
| CitiPower | Vic | 0.00 | 0.00 | 0.02 | 7.8 | 11.3 | 2.3 | 3.0 |
| Powercor | Vic | 0.04 | 0.13 | 0.12 | 0.3 | 0.9 | 2.0 | 2.0 |
| SP AusNet | Vic | 0.21 | 0.03 | 0.21 | 0.0 | 0.2 | 2.0 | 2.0 |
| United Energy | Vic | 0.22 | 0.12 | 0.05 | 0.8 | 2.8 | 1.4 | 1.0 |
| ENERGEX | Qld | 4.40[2] | 3.98[2] | 0.62[2] | 5.4 | 4.8 | 3.5 | 4.5 |
| Ergon Energy | Qld | 4.90[2] | 6.62[2] | 0.84[2] | 9.7 | 21.5 | 2.8 | 3.9 |
| ETSA | SA | 1.23 | 0.91 | 1.33 | 4.5 | 5.5 | 3.8 | 3.6 |
| Aurora Energy | Tas | – | – | – | 10.5 | – | – | – |
| ACT Utilities | ACT | – | – | – | – | – | – | – |

## Table 5.10 Call centre performance

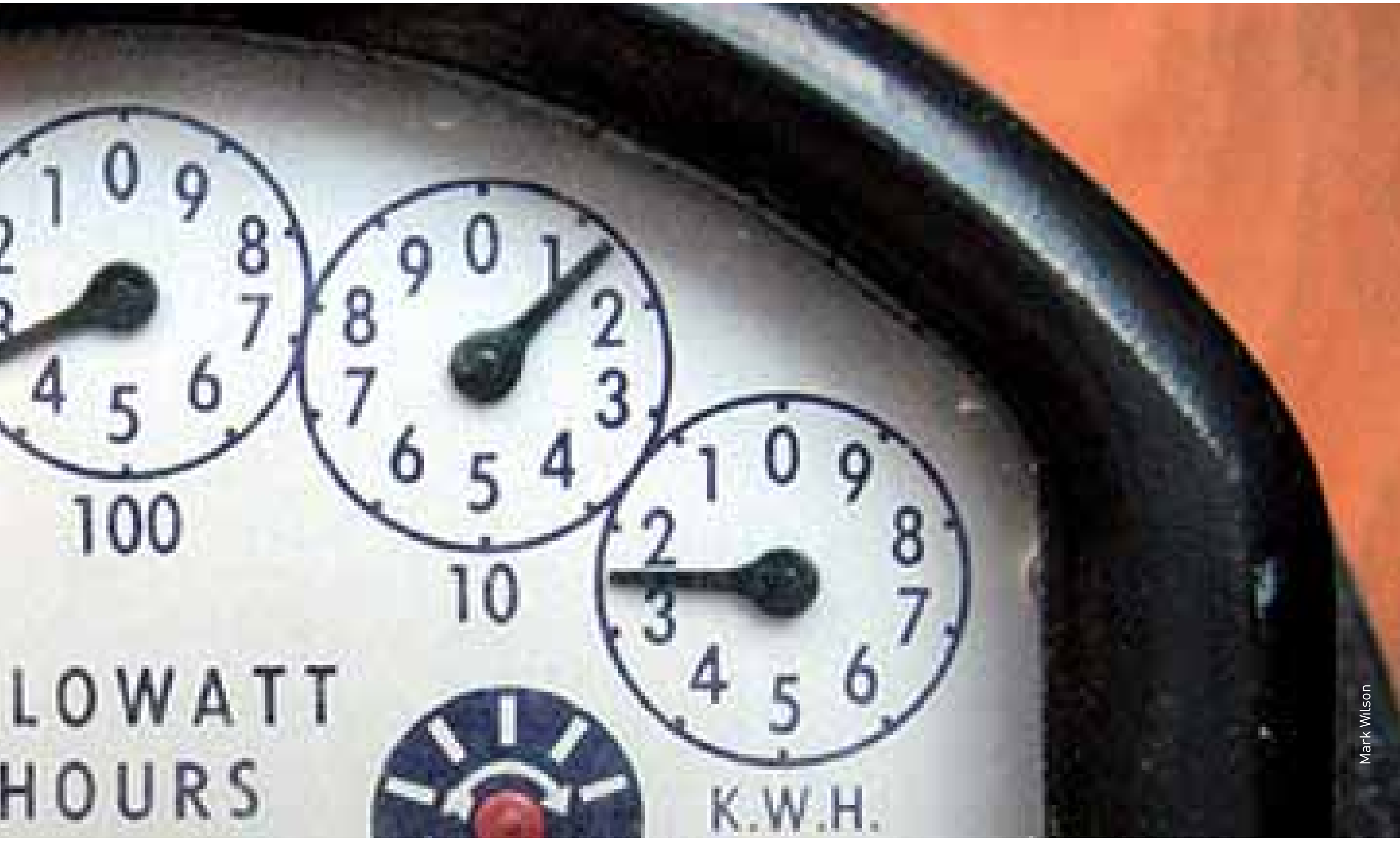
| NETWORK | JURISDICTION | PERCENTAGE OF ABANDONED CALLS BEFORE REACHING A HUMAN OPERATOR | | | PERCENTAGE OF CALLS ANSWERED BY A HUMAN OPERATOR WITHIN 30 SECONDS | | |
|---|---|---|---|---|---|---|---|
| | | 2003–04 | 2004–05 | 2005–06 | 2003–04 | 2004–05 | 2005–06 |
| Country Energy | NSW | 24.5 | 41.2 | 42.6 | 66.7 | 48.4 | 47.2 |
| EnergyAustralia | NSW | 12.3 | 10.5 | 10.5 | 46.4 | 44.6 | 81.3 |
| Integral Energy | NSW | 16.0 | 6.0 | 3.2 | 58.0 | 81.0 | 89.0 |
| Alinta (AGL) | Vic | – | 0.9 | 5.0 | 70.8 | 73.8 | 75.2 |
| CitiPower | Vic | – | 10.8 | 10.0 | 46.4 | 88.2 | 89.2 |
| Powercor | Vic | – | 5.9 | 7.0 | 40.5 | 90.9 | 88.7 |
| SP AusNet | Vic | – | 8.8 | 6.0 | 81.1 | 79.8 | 82.7 |
| United Energy | Vic | – | 7.7 | 24.0 | 61.0 | 75.6 | 73.8 |
| ENERGEX | Qld | 9.6 | 4.1 | 3.9 | 64.0 | 80.6 | 89.4 |
| Ergon Energy | Qld | 5.2 | 2.7 | 3.5 | 69.4 | 77.3 | 85.1 |
| ETSA Utilities | SA | 5.0 | 4.4 | 4.0 | 85.8 | 86.9 | 85.2 |
| Aurora Energy | Tas | 1.0 | 1.0 | – | – | – | – |
| ActewAGL | ACT | 12.7 | 16.9 | – | 76.1 | 65.6 | – |

Notes: Tables 5.9 and 5.10: Victorian data is for the calendar year ending in that period (for example, Victorian 2005–06 data is for calendar year 2005).
1. Average performance of all New South Wales distribution networks.
2. Includes new connections only.

Source: Distribution network performance reports published by ESC (Vic); IPART (NSW); QCA (Qld); ESCOSA (SA); OTTER (Tas); ICRC (ACT); EnergyAustralia; Integral Energy; and Country Energy.




# 6 ELECTRICITY RETAIL MARKETS




The retail market is the final link in the electricity supply chain. It provides the main interface between the electricity industry and customers, such as households and small business. Because retailers deal directly with consumers, the services they provide can significantly affect perceptions of the performance of the electricity industry.

Retailers buy electricity in the wholesale market and package it with transportation for sale to customers. Many retailers also sell 'dual fuel' products that bundle electricity and gas services. While retailers provide a convenient aggregation service for electricity consumers, they are not direct providers of network services.

# 6 ELECTRICITY RETAIL MARKETS

This chapter provides a survey of electricity retail markets. It covers:

- the structure of the retail market, including:
  - industry participants
  - ownership changes
  - convergence between electricity and gas retail markets
  - trends towards integration of the electricity generation and retail sectors
- the development of retail competition
- retail market outcomes, including price, affordability and service quality
- the regulation of the retail market.

State and territory governments are responsible for the regulation of retail energy markets. Governments agreed in 2004 to transfer several non-price regulatory functions to a national framework to be administered by the Australian Energy Market Commission (AEMC) and the Australian Energy Regulator (AER). The Ministerial Council on Energy (MCE) has scheduled the transfer of responsibilities to occur from July 2008.

This chapter focuses on the retailing of electricity to 'small customers' using less than 160 megawatt hours (MWh) a year.[1] This encompasses most customers and includes households and small business users. Large customers are typically major industrial users. Although relatively few, large customers buy the bulk of electricity sold by volume.

While this chapter includes data that might enable performance comparisons to be made between retailers, such analysis should note that a variety of factors can affect relative performance. These factors are noted, where appropriate, in the chapter.

1 Queensland reviewed its definition of 'small customer' in 2006 as part of its introduction of retail customer choice and set a breakpoint of 100 MWh a year.

## 6.1 The retail sector

Historically, state-owned utilities ran the entire electricity supply chain in all states and territories. In the 1990s, governments began to disaggregate the utilities. Victoria and South Australia privatised their distribution and retail sectors as stapled entities. The retail businesses were then spun off separately. Queensland privatised most of its energy retail entities in 2006–07, which largely separated that sector from distribution. New South Wales and Tasmania retain common ownership in distribution and retailing, with ring fencing for operational separation. The Australian Capital Territory Government formed a joint venture with the private sector to provide distribution and retail services, which was later separated into separate entities. These changes were accompanied by regulatory reforms to allow new retailers to enter the market.

These events have led to significant ownership changes in the retail sector. Table 6.1 lists licensed retailers that were active in the market for residential and small business customers in July 2007. High prices in the wholesale energy market put some pressure on the retail sector in 2007. One new entrant, Energy One, suspended its energy retailing business in June 2007 and cited the effects of high forward prices on profitability. Another retailer, Momentum Energy, sold part of its customer base in July 2007 due to rising wholesale costs.

**Table 6.1 Active electricity retailers: small customer market (July 2007)**

| RETAILER | OWNERSHIP | VIC | NSW | QLD | SA | TAS | ACT | WA | NT |
|---|---|---|---|---|---|---|---|---|---|
| ActewAGL Retail | ACT Government & AGL Energy | | New entrant | | | | Host | | |
| AGL Energy | AGL Energy | Host | New entrant | | Host | | | | |
| Aurora Energy | Tasmanian Government | | | | New entrant | Host | | | |
| Australian Power & Gas | Australian Power & Gas | New entrant | New entrant | | | | | | |
| Country Energy | NSW Government | New entrant | Host | | New entrant | | New entrant | | |
| EnergyAustralia | NSW Government | | Host | | | | New entrant | | |
| EnergyAustralia – International Power Retail Partnership | EnergyAustralia & International Power | New entrant | | | New entrant | | | | |
| Ergon Energy | Queensland Government | | | Host | | | | | |
| Horizon | WA Government | | | | | | | Host | |
| Integral Energy | NSW Government | | Host | | | | | | |
| Jackgreen (International) | Jackgreen | New entrant | New entrant | | | | | | |
| Origin Energy | Origin Energy | Host | New entrant | | New entrant | | | | |
| Power and Water Corporation | NT Government | | | | | | | | Host |
| Powerdirect | AGL Energy | New entrant | New entrant | Host | New entrant | | | | |
| Red Energy | Snowy Hydro | New entrant | | | New entrant | | | | |
| South Australia Electricity/ Victoria Electricity | Infratil | New entrant | | | New entrant | | | | |
| Sun Retail | Origin Energy | | | Host | | | | | |
| Synergy | WA Government | | | | | | | Host | |
| TRUenergy | China Light and Power | Host | New entrant | | New entrant | | | | |

Host (local or incumbent) retailer   New entrant

1. Not all licensed retailers are listed. Some generators are licensed retailers but are active only in the market for larger industrial users. The following generators have retail licenses: CS Energy, Delta Energy, Eraring Energy, International Power, NRG Flinders, Stanwell and Tarong Energy. The following distributors also have retail licenses: CitiPower, PowerCor, SP AusNet.
2. The Queensland Government privatised Sun Retail (formerly the retail business of ENERGEX) and Powerdirect (formerly owned by Ergon Energy) in 2006–07. It sold Sun Retail to Origin Energy and Powerdirect to AGL.
3. In 2007, International Power announced its full acquisition of the EnergyAustralia—International Power Retail Partnership, and from August 2007 will retail energy in its own right.

Source: Jurisdictional regulator websites, updated by information on retailer websites and other public sources.

Louie Douvis (Fairfax Images)

Not all licensed retailers are active in the small customer market. Some retailers target only large customers. Others may have been active in the past, or may have acquired a licence with a view to future marketing.

The retail players in each jurisdiction include:

- one or more 'host' retailers (also referred to as incumbent, local, standard or tier-1 retailers)[2] that are subject to various regulatory obligations. In some jurisdictions host retailers must offer to supply customers in a designated geographical area at standard terms and conditions, and often at capped prices. Some jurisdictions have several host retailers, each of which has obligations in specific geographical areas. The host retailer is typically the entity that sold electricity to all customers when competitive market arrangements began. Some have changed hands through privatisation or acquisitions.
- new entrants, including established interstate players, gas retailers branching into electricity retailing, and new players in the energy retail sector.

State government-owned host retailers in New South Wales, Tasmania, Western Australia and the Northern Territory are the major players in those jurisdictions, and some have acquired market share in Victoria and South Australia. Following privatisation and ownership consolidation there are now three major private retailers—AGL Energy, Origin Energy and TRUenergy. Each has significant market share in Victoria and South Australia and is building market share in New South Wales. AGL Energy and Origin Energy entered the Queensland small customer market in 2006–07 via the privatisation of two government owned retailers. In 2007, International Power fully acquired its retail partnership with EnergyAustralia, and from August 2007 will retail energy in its own right in Victoria and South Australia. The partnership had already garnered some market share in those states. Aside from the leading private retailers, a number of niche players are active in Victoria, South Australia and New South Wales.

The following survey provides background on developments in each jurisdiction.

2 The terminology varies between jurisdictions.

### Victoria

In the 1990s Victoria split its retail sector into five separate businesses, each stapled to a local distribution network area, and sold them to different private interests. Some of the businesses have since changed hands, reducing the number of host retailers to three. The opening of the sector to competition has also led to new entry by established interstate retailers and new players. At March 2007, Victoria had 26 licensed retailers, 12 of which were active in the residential and small business market. These were:

- AGL Energy, Origin Energy and TRUenergy—each of which is the host retailer in designated areas of Victoria
- nine new entrants, including established interstate retailers EnergyAustralia (in partnership with International Power) and Country Energy; and seven new players (Jackgreen, Momentum Energy, Powerdirect, Red Energy, Victoria Electricity, Energy One and Australian Power and Gas).

At March 2007, Click Energy and Our Neighbourhood Energy had applied for retail licences but were not actively marketing retail services to small customers.

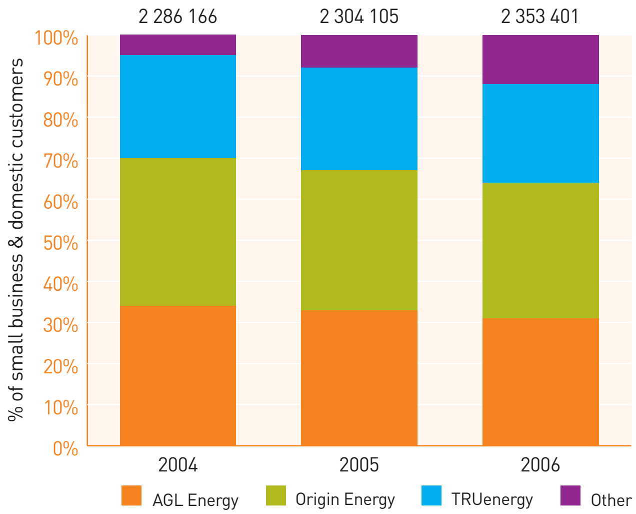
Table 6.2 sets out the market share of Victorian retailers (by customer numbers). The three host retailers account for about 87 per cent of the market, and each has acquired market share beyond its local area. Significantly, new entrants without any local customer base have increased their market share from 5 per cent of small customers in 2004 to over 13 per cent in 2006 (figure 6.1).

Table 6.2 Electricity retail market shares—Victoria, 30 June 2006

| RETAILER | DOMESTIC CUSTOMERS | BUSINESS CUSTOMERS | TOTAL RETAIL CUSTOMERS |
|---|---|---|---|
| AGL Energy | 31% | 24% | 31% |
| Origin Energy | 32% | 38% | 33% |
| TRUenergy | 24% | 23% | 24% |
| Other | 13% | 15% | 13% |
| Total customers | 2077135 | 276266 | 2353401 |

Source: ESC, *Energy retail businesses comparative performance report for the 2005–06 financial year*, November 2006, p. 2.

Figure 6.1
Electricity retail market shares (small customers)—Victoria




Source: ESC, *Energy retail businesses comparative performance report*, (various years).

## South Australia

South Australia sold its integrated distribution and retail business to Cheung Kong Infrastructure Holdings and Hong Kong Electric International Limited in 1999. The retail business was on-sold to AGL Energy in 2000.

The introduction of retail competition has led to new entry by established interstate retailers and new players. In March 2007, South Australia had 16 licensed electricity retailers, of which nine were active in the small customer market. These were:

> AGL Energy—South Australia's host retailer
> eight new entrants, including South Australia's host retailer in gas (Origin Energy); established interstate retailers (TRUenergy, EnergyAustralia—in partnership with International Power, Country Energy and Aurora Energy); and three new players (Momentum Energy, Powerdirect and South Australia Electricity).

At March 2007, Jackgreen and Red Energy held retail licences but were not actively marketing to small customers.

Table 6.3 sets out the small customer market share of South Australian retailers (by customer numbers). Four retailers account for 98 per cent of the market. The host retailer—AGL Energy—supplies 68 per cent of small customers. Origin Energy and TRUenergy have been actively seeking market share, and each has acquired more than 10 per cent of the small customer base. South Australia has registered three new active retailers since November 2005, but apart from the EnergyAustralia—International Power Retail Partnership the newer players have a negligible market share.

Table 6.3 Electricity retail market shares (small customers)—South Australia, 30 June 2006

| RETAILER | SMALL CUSTOMERS |
|---|---|
| AGL Energy | 68.7% |
| Origin Energy | 10.4% |
| TRUenergy | 10.9% |
| EnergyAustralia | 7.9% |
| Powerdirect | 1.8% |
| Country Energy | 0.2% |
| Momentum Energy | <0.1% |
| Aurora | <0.1% |
| SA Electricity | <0.1% |
| Total customers | 760 600 |

Source: ESCOSA, *SA energy retail market 05/06*, November 2006, p. 72

## New South Wales and the Australian Capital Territory

In March 2007 New South Wales had 24 licensed retailers, of which 13 supply (or intend to supply) residential and/or small business customers. The active retailers include:

> EnergyAustralia, Country Energy and Integral Energy—the government-owned host retailers
> seven new entrants including the state's host retailer in gas (AGL Energy), established interstate players (Origin Energy, TRUenergy and ActewAGL Retail) and new players (Powerdirect, Jackgreen and Energy One).

At March 2007, Momentum Energy, Australian Power & Gas and New South Wales Electricity held retail licences but were not actively marketing to small customers.

Available information for 2006–07 indicated that new entrants had acquired at least 9 per cent of the small customer market from the government-owned incumbents. AGL Energy had acquired about 6 per cent of the market[3] and Origin Energy had acquired around 3 per cent.[4] The Independent Pricing and Regulatory Tribunal (IPART) published data in 2007 on the market share of host retailers in their local supply areas. In July 2006, EnergyAustralia and Integral Energy retained about 80 per cent of small customers in their local supply areas. IPART considered that this was reflective of a market in transition from the previous monopoly arrangements towards a competitive market. Country Energy has retained a market share of about 97 per cent in its local supply areas. IPART considered that this most likely indicates there are barriers to entry in that market.[5]

The Australian Capital Territory has 14 licensed retailers, of which three were active in the residential market at April 2006—ActewAGL Retail (the host retailer), EnergyAustralia and Country Energy.[6]

### Queensland

In Queensland, there has been some new entry by retailers to supply large customers, but regulatory restrictions prevented new entry in the small customer market prior to July 2007.

Until 2006, Queensland's small customer market was divided between two government-owned businesses—ENERGEX and Ergon Energy. Queensland restructured the electricity retail sector in 2006 by creating two new businesses—Sun Retail (800 000 ENERGEX customers) and Powerdirect (400 000 ENERGEX customers, 17 000 Ergon Energy customers and 55 000 interstate customers).[7] Origin Energy acquired Sun Retail in November 2006 and AGL Energy acquired Powerdirect in February 2007. The government has retained ownership of Ergon Energy's retail business, now consisting of 600 000 'unprofitable' customers in rural and regional areas.

### Other jurisdictions

Government-owned incumbents control the small customer markets in Western Australia, Tasmania and the Northern Territory. Regulatory restrictions prevent new entry to supply small customers.

Western Australia restructured Western Power in March 2006 and divided the small customer retail market between two new government-owned energy retailers, Synergy and Horizon. Each retailer is stapled to a designated geographical area. The *Electricity Corporations Act 2005* requires the Minister for Energy to undertake a review in 2009 with the aim of further extending contestability.

Small customers in Tasmania and the Northern Territory are serviced by government owned retailers Aurora Energy and Power and Water Corporation respectively.

## 6.1.1 Trends in market integration

A variety of ownership consolidation activity has occurred in the energy retail sector in recent years, including:

- retail market convergence between electricity and gas
- vertical integration between electricity retailers and generators.

3 AGL, *The Australian Gas Light Company scheme booklet – part 1*, 10 August 2006.

4 Power Industry News, Edition 531, 5 March 2007.

5 IPART, *Promoting retail competition and investment in the NSW electricity industry, regulated electricity retail tariffs and charges for small customers 2007-2010, Electricity draft report and draft determination*, April 2007.

6 ICRC, *Final report: retail prices for non-contestable electricity customers*, April 2006.

7 The Queensland government established a third new retailer, Sun Gas Retail with about 71 000 gas customers. AGL Energy acquired Sun Gas Retail in November 2006.

### Energy retail market convergence

Electricity and gas were traditionally marketed as separate services by separate retailers. This reflected regulatory arrangements that required separate provision. In the past few years, regulatory reform and the economics of energy retailing have changed this position. Many energy retailers are now active in both electricity and gas markets, and offer 'dual fuel' retail products.

Several factors are driving retail convergence. The sharing of billing, call centre, marketing and administrative overheads offers cost savings. The provision of dual fuel offers can also help to attract and retain customers. At the same time, convergence can create hurdles for new entrants—especially small players—which may need to offer a broader range of services to win customer share. New entrants also need to deal with different market arrangements and different risks in the provision of electricity and gas services, particularly in the wholesale energy sector.

There has been significant retail convergence in Victoria, where AGL Energy, Origin Energy and TRUenergy jointly account for around 87 per cent of small electricity retail customers and 94 per cent of small gas retail customers. The market share of AGL Energy and Origin Energy is similar in each sector. TRUenergy has a higher market share in gas than electricity. The principal difference between the two sectors is the lack of penetration by niche players in gas (figure 6.2).

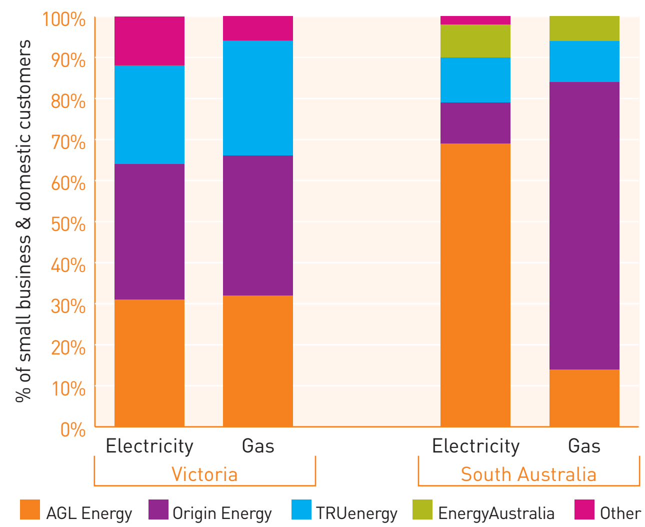
AGL Energy, Origin Energy and TRUenergy are active in both electricity and gas retailing in South Australia (figure 6.2) and New South Wales. Similar trends are emerging in other jurisdictions, where the incumbent retailers in electricity and gas are active in the energy retail market as a whole.

### Vertical integration in the electricity sector

The energy market reforms introduced by governments in the 1990s included the structural separation of the power supply industry into generation, transmission, distribution and retail businesses. Where linkages remain between contestable and non-contestable sectors (for example, distribution and retail), regulators apply ring-fencing arrangements to ensure operational separation of the businesses.

Figure 6.2

**Electricity and gas retail market shares (small customers)—Victoria and South Australia, 30 June 2006**




Note: In Victoria and South Australia, EnergyAustralia operated a retail partnership with International Power (the EnergyAustralia–International Power Retail Partnership). International Power acquired the partnership outright in 2007.

Sources: ESC, *Energy retail businesses comparative performance report for the 2005–06 financial year*, November 2006; ESCOSA, *SA energy retail market 05/06*, November 2006.

A recent phenomenon is a shift towards vertical integration of privately owned electricity retailers and generators in Victoria and South Australia. Vertical integration provides a means for retailers and generators to manage the risk of price volatility in the electricity spot market. If wholesale prices rise, the retailer can balance the increased cost against higher generator earnings. Ownership consolidation therefore provides a 'natural hedge' against price volatility in the wholesale market by offsetting the complementary price risks faced by generators and retailers.[8]

8 There has been debate as to whether this form of ownership consolidation might in some contexts pose a barrier to entry for new entrant retailers. See, for example, Energy Reform Implementation Group, *Energy reform: the way forward*, A Report to COAG, January 2007, p. 125-6.

Figure 6.3 illustrates the changes in generation and retail (electricity and gas) ownership since 1995 in these jurisdictions. Figure 6.4 compares generation and retail market shares in 2006.[9] Two of the three major retailers, AGL and TRUenergy, have significant generation interests. The third, Origin Energy, has limited generation capability at present, but has proposed the development of new capacity. In addition, the major generator International Power formed a retail partnership with EnergyAustralia in Victoria and South Australia, and announced in 2007 that it would become a retailer in its own right. There have been proposals for further consolidation, both between the major retailers and between the retail and generation sectors (see table 2, Executive overview).

### Figure 6.3
**Changes in generation and retail (electricity and gas) ownership 1995–2006 in Victoria and South Australia**

<table>
<tr><th></th><th></th><th>1995</th><th>1996</th><th>1997</th><th>1998</th><th>1999</th><th>2000</th><th>2001</th><th>2002</th><th>2003</th><th>2004</th><th>2005</th><th>2006</th></tr>
<tr><td rowspan="4">Gas Retail</td><td>Ikon</td><td colspan="4">Government</td><td>United Energy</td><td colspan="2">Pulse</td><td colspan="5">AGL Energy</td></tr>
<tr><td>Kinetic</td><td colspan="4">Government</td><td colspan="4">TXU</td><td colspan="2">Singapore Power</td><td colspan="2">TRUenergy</td></tr>
<tr><td>Energy 21</td><td colspan="4">Government</td><td colspan="8">Origin</td></tr>
<tr><td>SAGASCO</td><td colspan="12">Origin</td></tr>
<tr><td rowspan="6">Electricity Retail</td><td>Solaris Power</td><td colspan="12">AGL Energy</td></tr>
<tr><td>United Energy</td><td>Govt.</td><td colspan="4">United Energy</td><td colspan="2">Pulse</td><td colspan="5">AGL Energy</td></tr>
<tr><td>Eastern Energy</td><td colspan="2">Government</td><td colspan="6">TXU</td><td colspan="2">Singapore Power</td><td colspan="2">TRUenergy</td></tr>
<tr><td>Powercor</td><td colspan="2">Government</td><td colspan="3">Pacificorp/Scottish Power</td><td>CKI</td><td colspan="6">Origin</td></tr>
<tr><td>CitiPower</td><td colspan="2">Government</td><td colspan="2">Entergy</td><td colspan="4">AEP</td><td colspan="4">Origin</td></tr>
<tr><td>ETSA</td><td colspan="4">Government</td><td colspan="8">AGL Energy</td></tr>
<tr><td rowspan="18">Generation</td><td>Torrens Island</td><td colspan="4">Government</td><td colspan="4">TXU</td><td colspan="2">Singapore Power</td><td colspan="2">TRUenergy</td></tr>
<tr><td>Yallourn Energy</td><td colspan="2">Government</td><td colspan="6">PowerGen</td><td colspan="4">TRUenergy</td></tr>
<tr><td>Southern Hydro</td><td colspan="2">Government</td><td colspan="2">Infratil</td><td colspan="4">Alliant</td><td colspan="2">Meridian</td><td colspan="2">AGL Energy</td></tr>
<tr><td>Loy Yang A</td><td colspan="2">Government</td><td colspan="6">CMS</td><td colspan="4">GEAC (32.5% AGL Energy)</td></tr>
<tr><td>Loy Yang B</td><td colspan="2">Government</td><td colspan="7">Edison Mission</td><td colspan="3">International Power (70%)</td></tr>
<tr><td>Ecogen Energy</td><td colspan="4">Government</td><td colspan="4">AES/TXU</td><td>B&B/TXU</td><td colspan="3">B&B (73%)—contracted to TRUenergy</td></tr>
<tr><td>Synergen</td><td colspan="4">Government</td><td colspan="8">Internation Power</td></tr>
<tr><td>Hazelwood Power</td><td colspan="2">Government</td><td colspan="10">Internation Power</td></tr>
<tr><td>Flinders Power</td><td colspan="4">Government</td><td colspan="7">NRG</td><td>B&B</td></tr>
<tr><td>Valley Power</td><td colspan="5"></td><td colspan="4">Edison Mission/Contact</td><td>IP/ Contact</td><td colspan="2">Snowy Hydro</td></tr>
<tr><td>Snowy Hydro</td><td colspan="12">Snowy Hydro</td></tr>
<tr><td>Pelican Point</td><td colspan="4"></td><td colspan="8">Internation Power</td></tr>
<tr><td>Laverton</td><td colspan="10"></td><td colspan="2">Snowy Hydro</td></tr>
<tr><td>AGL Hydro</td><td colspan="7"></td><td colspan="5">AGL Energy</td></tr>
<tr><td>Hallet</td><td colspan="7"></td><td colspan="5">AGL Energy</td></tr>
<tr><td>Quarantine</td><td colspan="7"></td><td colspan="5">Origin</td></tr>
<tr><td>Ladbroke</td><td colspan="4"></td><td colspan="8">Origin</td></tr>
</table>

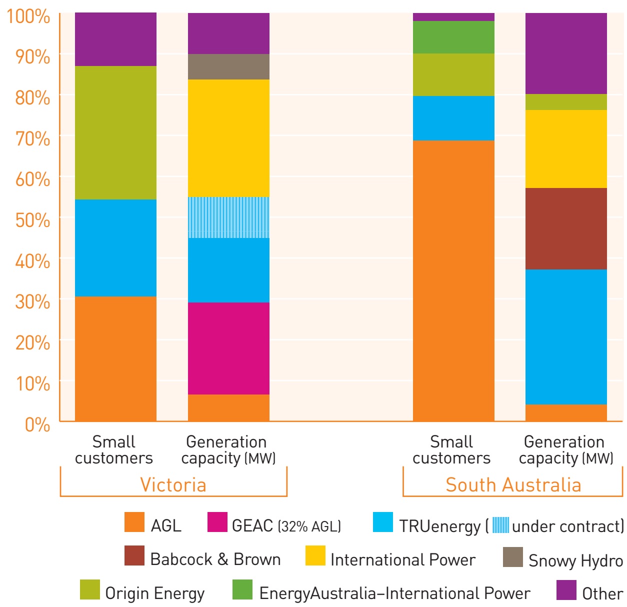
Notes: 1. B&B: Babcock & Brown. 2. AGL and TRUenergy exchanged ownership of Torrens Island and Hallett in 2007.

Source and chart design: Origin Energy (with minor revisions)

9 Figure 6.4 should be interpreted with caution as market shares in each sector are based on different variables. Retail shares relate to small customer numbers, while generation shares relate to capacity.

Figure 6.4

**Market shares in the Victorian and South Australian retail and generation sectors, 2006**




Notes:

1. In Victoria, TRUenergy holds a long-term hedge contract with Ecogen (owned by Babcock & Brown).
2. AGL entered agreements in January 2007 to acquire the 1260 MW Torrens Island power station in South Australia from TRUenergy, and to sell its 155 MW Hallett power station to TRUenergy. The transaction was completed in July 2007.
3. In 2007, International Power fully acquired its retail partnership with EnergyAustralia, and from August 2007 will retail in its own right in Victoria and South Australia.

Sources: ESC, *Energy retail businesses comparative performance report for the 2005–06 financial year*, November 2006; ESCOSA, *SA Energy Retail Market 05/06*, November 2006 (customer numbers); NEMMCO (generation capacity and ownership); company websites.

## 6.2 Retail competition

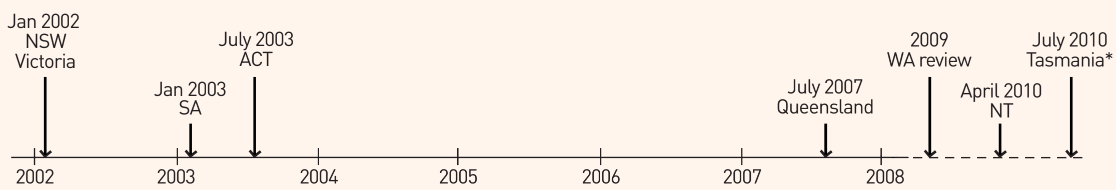
Australian governments began to phase in retail contestability (customer choice) in the late 1990s to extend the benefits of competition reforms in the electricity industry to consumers. Before the reforms, customers were obliged to buy their energy from a monopoly provider. Most governments adopted a staged timetable to introduce customer choice, beginning with large industrial customers followed by small industrial customers and finally small retail customers. Full retail contestability (FRC) is achieved when all customers are permitted to enter a supply contract with a retailer of choice.

Governments adopted different timeframes for the introduction of FRC (figure 6.5). New South Wales and Victoria introduced FRC in 2002, and were followed by South Australia and the Australian Capital Territory in 2003. Queensland introduced FRC in July 2007. Tasmania began phasing in customer choice, beginning with large customers, in July 2006. It intends to introduce choice for households and small businesses from July 2010, subject to a public benefit test. Western Australia allows contestability for customers using at least 50 MWh annually. It will review a further extension of contestability in 2009. The Northern Territory plans to introduce FRC in April 2010.[10]

While most jurisdictions have introduced or are introducing full retail contestability, it can take time for a competitive market to develop. As a transitional measure, most jurisdictions require host retailers to offer to supply electricity services under a regulated standing offer (or default contract) to allow consumers time to understand and adjust to the workings of the new market (see section 6.5). Default contracts cover minimum service conditions, information requirements and some form of regulated price cap or oversight. As of March 2007, all jurisdictions apply some form of retail price regulation.

10 For details on Western Australia and the Northern Territory see chapter 7 of this report.

Figure 6.5
Introduction of full retail contestability




* Introduction of FRC in Tasmania is subject to a public benefit test

Australian governments have agreed to review the continued use of retail price caps and to remove them where effective competition can be demonstrated.[11] The AEMC will assess the effectiveness of retail competition in each jurisdiction to determine the appropriate time to remove retail price caps. The AEMC will conduct sequential assessments, starting with Victoria in 2007, followed by South Australia in 2008, New South Wales in 2009 and the Australian Capital Territory (if required) in 2010. The assessments for other jurisdictions will occur following their introduction of full retail competition.

In October 2006 governments agreed on the following AEMC assessment criteria for effective competition:

- independent rivalry within the market
- ability of suppliers to enter the market
- the exercise of market choice by customers
- differentiated products and services
- prices and profit margins
- customer switching behaviour.

The following section provides a sample—rather than an exhaustive survey—of public data that may be relevant to an assessment of some of the criteria. In particular, it sets out data on the diversity of price and product offerings of retailers, the exercise of market choice by customers, including switching behaviour, and customer perceptions of competition. There is also some consideration of retail profit margins. Other sections of this chapter touch on other indicators—for example, section 6.2 considers new entry.

The report provides this material for information purposes, but does not seek to draw conclusions. More generally, the AER does not purport to assess the effectiveness of retail competition in any jurisdiction.

### 6.2.1 Price and non-price offerings

A competitive retail market is likely to exhibit some diversity in price and product offerings as sellers try to win market share. There is evidence of retail price diversity in electricity markets that have introduced full retail contestability (boxes 6.1 and 6.2). In particular, both host and new entrant retailers tend to offer market contracts at discounts against the 'default' regulated terms and conditions.

There is some price diversity associated with product differentiation. For example, retailers might offer a choice of standard products, dual fuel contracts (for gas and electricity) and green products, each with different price structures. Environmentally friendly offerings sometimes attract a premium. The Essential Services Commission (ESC) has linked the state's high switching rates (section 6.2.2) to an expansion in dual fuel offers.[12]

11 Australian Energy Market Agreement 2004 (amended 2006).
12 ESC, *Energy retail businesses comparative performance report for the 2004 calendar year*, 2005, p. 22.

## Box 6.1 Case study—Price and non-price offerings in South Australia

The Essential Services Commission of South Australia (ESCOSA) provides an estimator that allows consumers to make rough but quick comparisons of retail offers in South Australia (www.escosa.sa.gov.au). Table 6.4 sets out the estimated price offerings in March 2007 for a customer using 6500 kWh a year, based on peak usage, and not using electricity for hot water. The estimator provides an indicative guide only, but takes account of discounts and other rebates. It does not account for elements of retail offers that are not price related. For example, some retailers were offering free DVDs on sign up, and discounts for prompt payment. Others were offering a percentage of supplied electricity from accredited renewable energy sources.

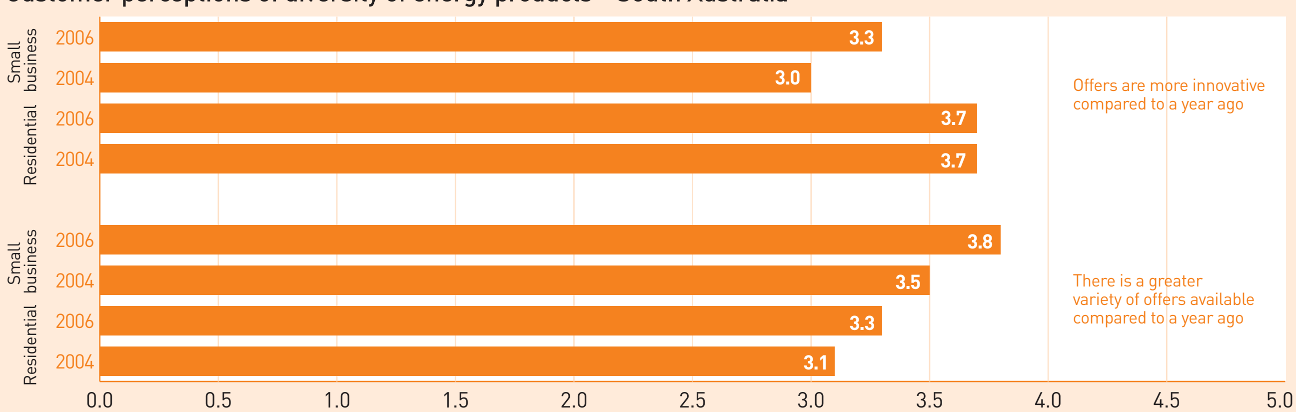
Table 6.4 indicates some price diversity in South Australia's retail market, especially when discounts and rebates are taken into account. The host retailer, AGL, is discounting against its own default tariffs under its Freedom 5% service. There is a price spread of around $150 across all retail offers, and discounts of up to 10 per cent against the standing contract.

South Australia conducted surveys in 2004 and 2006 on customer perceptions of variety and innovation in retailer product offerings in energy (electricity and gas) markets. Figure 6.6 provides summary data, based on customer responses to propositions on a scale of 1 to 5 (1 = strongly disagree; 5 = strongly agree). The results suggest that South Australian customers have a reasonably strong perception that product variety and innovation in the retail market is increasing.

It should be noted that the Victorian and South Australian retail price offers in figure 6.7 and table 6.4 relate to different periods and different product structures and rely on different measurement techniques. The price sets are therefore not directly comparable. Section 6.4 of this report considers comparable public data on retail price outcomes.

**Figure 6.6**

**Customer perceptions of diversity of energy products—South Australia**




Source: ESCOSA, *Monitoring the development of energy retail competition in South Australia*, Statistical report, 2006, pp. 28, 38.

Table 6.4 **Electricity retail price offers in South Australia—March 2007**

| RETAILER AND TARIFF OFFER | COST BEFORE INCENTIVES | DIRECT DEBIT REBATE | OTHER REBATES | ESTIMATED ANNUAL COST | ESTIMATED ANNUAL SAVINGS | ONE-OFF JOINING BONUS |
|---|---|---|---|---|---|---|
| AGL Standing Contract | $1 361 | – | – | $1 361 | – | – |
| AGL Freedom 5% | $1 299 | – | – | $1 299 | $62 | – |
| AGL Freedom 5% + AGL Green Spirit | $1 351 | – | – | $1 351 | $10 | – |
| Country Energy Premium | $1 251 | – | – | $1 251 | $110 | – |
| EnergyAustralia Easy Saver | $1 293 | – | – | $1 293 | $68 | – |
| EnergyAustralia Green | $1 361 | – | – | $1 361 | – | – |
| EnergyAustralia Green Saver 2 | $1 333 | – | – | $1 333 | $28 | – |
| EnergyAustralia Green Saver Premium | $1 361 | – | $25 | $1 336 | $25 | – |
| EnergyAustralia Maxi Saver | $1 279 | – | – | $1 279 | $82 | – |
| EnergyAustralia Qantas Frequent Flyer | $1 361 | – | – | $1 361 | – | – |
| EnergyAustralia Qantas Frequent Flyer Green Saver | $1 361 | – | – | $1 361 | – | – |
| EnergyAustralia RAA Green Saver | $1 333 | – | $25 | $1 308 | $53 | – |
| EnergyAustralia RAA Saver | $1 279 | $11 | – | $1 268 | $93 | – |
| Momentum Energy Residential Anytime | $1 212 | – | – | $1 212 | $149 | – |
| Origin Energy GreenEarth | $1 412 | – | – | $1 412 | – | – |
| Origin Energy GreenEarth Extra | $1 516 | – | – | $1 516 | – | – |
| Origin HomeChoice | $1 293 | – | – | $1 293 | $68 | – |
| Red Energy Red Easy Saver | $1 260 | – | – | $1 260 | $101 | – |
| Red Energy Red Fixed Term Saver | $1 234 | – | – | $1 234 | $127 | – |
| South Australia Electricity | $1 266 | – | – | $1 266 | $95 | – |
| TRUenergy At Home | $1 284 | $12 | $25 | $1 247 | $114 | – |
| TRUenergy Go Easy | $1 320 | – | – | $1 320 | $41 | – |
| TRUenergy Go For More | $1 267 | – | – | $1 267 | $94 | – |
| TRUenergy Go Green | $1 320 | – | – | $1 320 | $41 | – |

Source: ESCOSA estimator, viewed 20 March 2007, <http://www.escosa.sa.gov.au/site/page.cfm?u=18>.

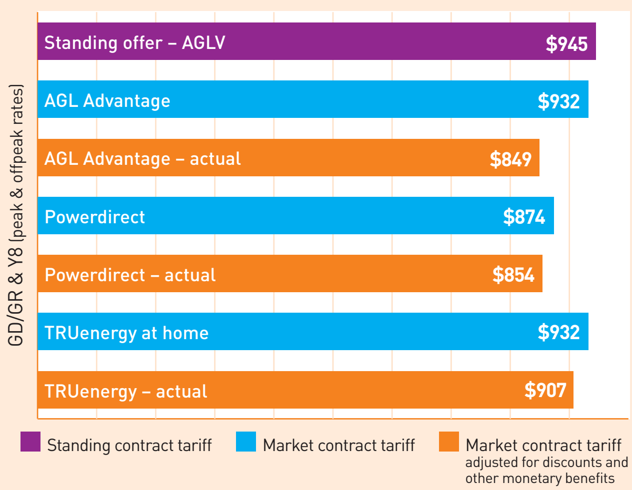

## Box 6.2 Price and non-price offerings in Victoria

In May 2006, the ESC undertook mystery shopper research that compared electricity market contract prices against the standing offers of host retailers. Figure 6.7 compares the annual electricity bill for a consumer using 6500 kilowatt hours (kWh) a year—consisting of 4000 kWh peak and 2500 kWh off-peak consumption—under three scenarios: the host retailer's standing (default) contract offer, the market contract offers of all retailers (based solely on tariffs), and the market contract offers adjusted for other monetary benefits and discounts.

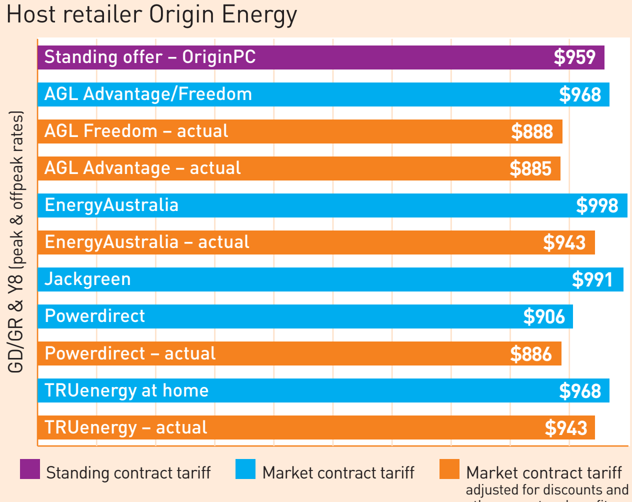
### Figure 6.7

**Comparison of market offers—Victoria, May 2006**

Host retailer AGL




Host retailer Origin Energy

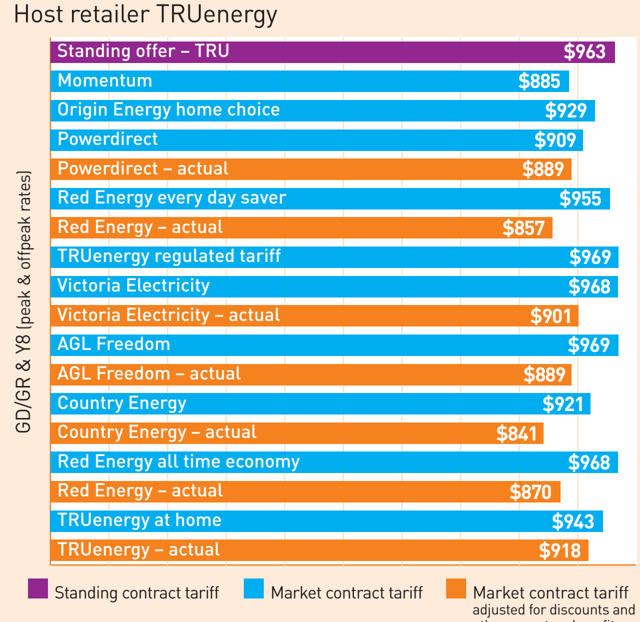



The research found that retailers tend to make market offers at a discount from the standing contract price, as well as additional monetary benefits or inducements to consumers. For example:

- domestic customers, with an annual consumption of 6500 (4000 kWh peak and 2500 kWh off-peak) would pay less than the AGL standing contract price, based solely on tariff offers. The market contract prices offered in comparison to the Origin Energy and TRUenergy standing contract price were more diverse.
- the benefits of market contracts increased when other factors were taken into account—for example, discounts for on-time payment, up-front incentives and loyalty payments. These benefits ranged from $50 to $100 a year.
- small business or commercial customers could receive much higher savings in the AGL area, ranging from $600 and $800 a year. Savings in the TRUenergy area were less substantial.

The research did not account for dual fuel contracts where further savings would have been available.

Host retailer TRUenergy




Notes: For customers with annual consumption of 4000 kWh peak and 2500 kWh off peak. The ESC study included a separate analysis for customers using 4000 kWh a year based only on peak rates, and for business customers.

Source: ESC, *Energy retail businesses, comparative performance report for the 2005–06 financial year*, November 2006.

Some product offerings cover energy services bundled with inducements such as customer loyalty bonuses, awards programs, free subscriptions and prizes. Discounts and other offers tend to vary depending on the length of a contract. Some retail products offer additional discounts for prompt payment of bills or direct debit bill payments. Many contracts carry a severance fee for early withdrawal. More generally, retail price offerings may vary with the location of the customer.

The variety of discounts and non-price inducements makes direct price comparisons difficult. There is also variation in the transparency of price offerings. Some retailers publish details of their products and prices, while others require a customer to fill out online forms or arrange a consultation. Boxes 6.1 and 6.2 provide case study material on the diversity of price and product offerings to small customers in Victoria and South Australia.

### 6.2.2 Customer switching

The rate at which customers switch their supply arrangements is an indicator of customer participation in the market. While switching (or churn) rates can also indicate competitive activity, they should be interpreted with care. Switching rates are sometimes high at a relatively early stage of market development, when customers are first able to exercise choice, and can stabilise even as a market acquires more depth. Similarly, it is possible to have low switching rates in a very competitive market if retailers are delivering good quality service that gives customers no reason to switch.

Time series data on small customer switching is available for New South Wales, Victoria and South Australia. Until 2006, South Australia applied a different indicator from that used in Victoria and New South Wales (box 6.3).

The National Electricity Market Management Company (NEMMCO) publishes churn data measuring the number of customer switches from one retailer to another. NEMMCO has published this data for New South Wales and Victoria since the introduction of FRC in 2002 and for South Australia since 1 October 2006. The data covers 'gross' and 'net' switching.

- Gross switching measures the total number of customer switches in a period, including switches from a host retailer to a new entrant, switches from new entrants back to a host retailer, plus switches from one new entrant to another. If a customer switches to a number of retailers in succession, each move counts as a separate switch. Over time, cumulative switching rates may therefore exceed 100 per cent.
- Net switching measures the total number of customers at a specified time who are no longer with the host retailer and have switched to a new entrant. This indicator counts each customer once only.

Both indicators exclude customers who have switched from a default arrangement to a market contract with their existing retailer. This exclusion may understate the true extent of competitive activity in that it does not account for the efforts of host retailers to retain market share.

A churn rate measures customer switches as a percentage of the underlying customer base. The local energy regulator in each state publishes retail customer numbers on an irregular basis.

Table 6.5 and figures 6.8–6.9 illustrate small customer churn activity in Victoria, New South Wales and South Australia. As noted, the South Australian data is only available from October 2006. Switching activity in Victoria and New South Wales steadily gathered pace after the introduction of FRC in 2002. At December 2006, gross switching rates in Victoria (72 per cent) and South Australia (57 per cent) were more than double the New South Wales rate (28 per cent). Similarly, around 40 per cent of small customers were not with their host retailer in Victoria and South Australia—compared to less than 20 per cent in New South Wales (figure 6.9).

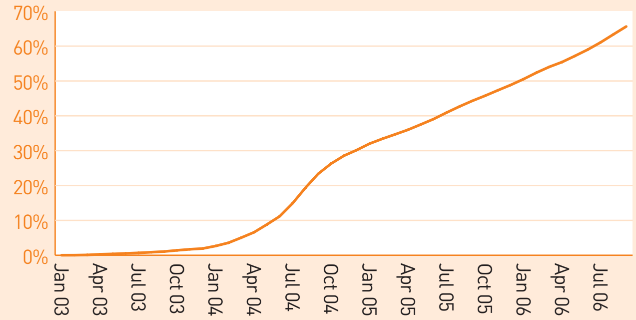
## Box 6.3 Customer switches to market contracts

While NEMMCO reports on customer switching between retailers, an alternative approach is to measure customer switching from regulated 'default' contracts to market contracts. Until October 2006 South Australia published monthly data on customer switching to market contracts. The data did not distinguish between switches to market contracts with new entrants and the host retailer.

Figure 6.10 shows cumulative gross switching in South Australia from 2003 to October 2006, based on this measure. The data shows a sharp acceleration in customer transfers in 2004, followed by steady monthly churn of about 1.5–2 per cent in 2005 and 2006. The high transfer rates in 2004 were likely influenced by the South Australian Government's $50 electricity transfer rebate offer, which ended in August 2004. At September 2006, there had been around 499 000 small customer transfers to market contracts since FRC began (equal to about 66 per cent of small customers). Successive switches by a customer counted as separate switches. Net switching data indicated that by June 2006, around 50 per cent of small customers were on market contracts, with the remaining 50 per cent on default arrangements.

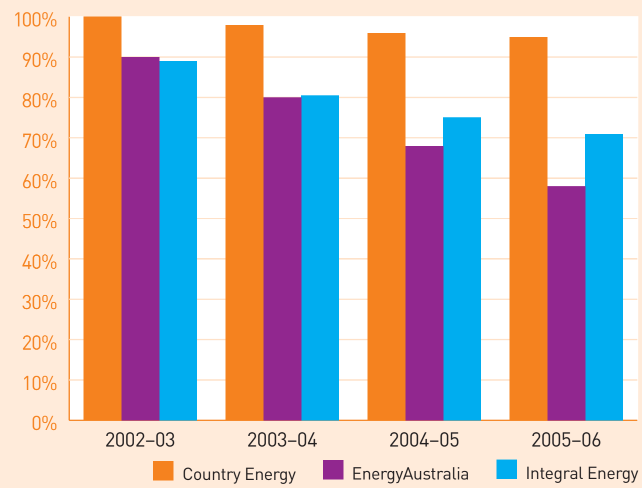
IPART published data in 2007 on the number of New South Wales customers remaining on regulated tariffs in the local supply areas of each host retailer. In 2005–06, around 58 per cent of customers in the EnergyAustralia supply area remained on regulated tariffs, compared with 71 per cent for Integral Energy, and 95 per cent for Country Energy (figure 6.11). IPART noted that these outcomes were indicative of significant differences in competitive activity between metropolitan and non-metropolitan areas.

### Figure 6.10
**Cumulative monthly switches as percentage of small customer base—South Australia**




Source: ESCOSA, *Completed small customer electricity & gas transfers to market contracts*, Schedule, October 2006.

### Figure 6.11
**Percentage of small customers on regulated tariffs in standard supply areas—New South Wales**




Source: IPART, *Promoting retail competition and investment in the NSW electricity industry, Regulated electricity retail tariffs and charges for small customers 2007–2010, Electricity draft report and draft determination*, April 2007.

**Table 6.5** Small customer churn—New South Wales, Victoria and South Australia

| INDICATOR | NEW SOUTH WALES | VICTORIA | SOUTH AUSTRALIA |
|---|---|---|---|
| Percentage of small customers that changed retailer during 2006 | 11% | 23% | na |
| Customer switches as a percentage of the small customer base from the start of FRC until December 2006 | 28% | 72% | 57% |

na: not available.

Note: If a customer switches to a number of retailers in succession, each move counts as a separate switch. Customer base is estimated as at 30 June 2006.

**Figure 6.8**
**Cumulative monthly switches as percentage of small customers—New South Wales, Victoria and South Australia**

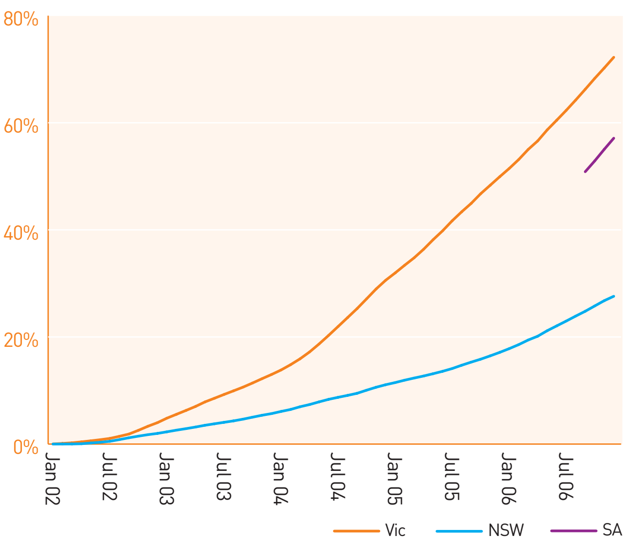
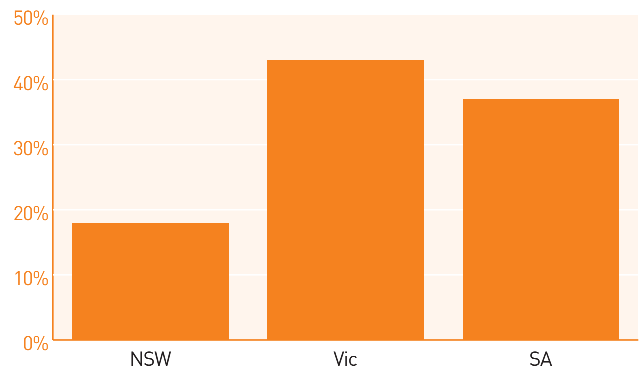



**Figure 6.9**
**Customers not with their host retailer at 31 December 2006—New South Wales, Victoria and South Australia**




Sources for table 6.5 and figures 6.8–9:

Customer switches: NEMMCO; Customer numbers: IPART, *NSW electricity information paper no. 4—Retail businesses' performance against customer service indicators, 1 July 2001 to 30 June 2006*; ESCOSA, *2005–06 Annual performance report: performance of South Australian energy retail market*, 2006, p. 72. ESC, *Energy retail businesses comparative performance report for the 2005–06 financial year*, 2006, p. 2.

## The Australian Capital Territory

The Australian Capital Territory regulator, the Independent Competition and Regulatory Commission (ICRC), refers to customer churn rates from time to time but does not provide monthly switching data. As at February 2006:

> over 20 000 customers (about 17 per cent of the customer base) had elected to enter into market contracts with the host retailer, ActewAGL Retail
> about 5000 customers (about 4 per cent of the customer base) had elected to enter into market contracts with new entrant retailers.[13]

## International comparisons

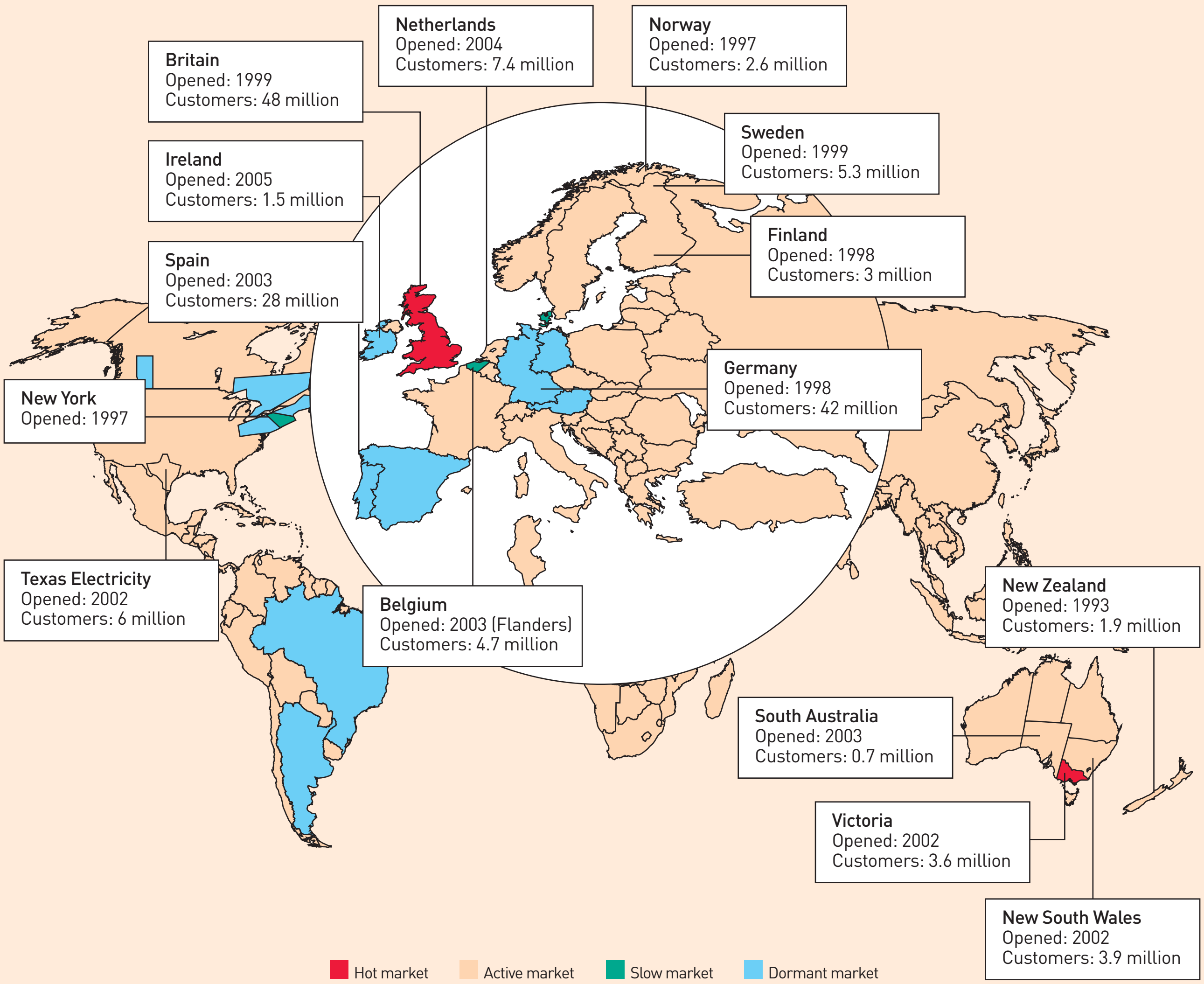
The Utility Customer Switching Research Project founded by First Data Utilities and VaasaEMG published its second report on customer switching in world energy markets in 2006. The report classified competition on a scale ranging from 'hot' to 'dormant'. It found that Victoria and Great Britain had the 'hottest' (most active) retail markets in the world (box 6.4 and figure 6.12). South Australia and New South Wales were found to have 'active' markets.

13 ICRC, *Final report: retail prices for non-contestable electricity customers*, Canberra 2006.

## Box 6.4 The Utility Customer Switching Research Project assessment of Victorian, South Australian and New South Wales retail markets (extract)

Figure 6.12

**Status of energy retail markets—June 2006**



'...in Australia, the state of Victoria has fast become a hotspot of energy retail competition. Following several years of competitive supply to commercial and industrial customers, Victoria introduced full retail competition for electricity and gas in 2002 and it has exhibited increased customer switching year-on-year, reaching 21 per cent in 2005. Strong competition from out-of-state incumbents and new start-up energy retailers have contributed to this dramatic level of switch activity, along with the introduction of lifestyle products and affinity programs cleverly targeted at niche customer segments, and the availability of effective websites where customers can compare suppliers' prices.

South Australia opened its doors to full retail electricity competition in 2003 and customer switch rates quickly soared. Principal reasons behind this rapid acceleration include the divestment of the retail customer base by the state government that removed the incumbent brand advantage, the granting of switching credits to a portion of the customer base, the selling experience of retailers established in neighbouring Victoria, and rising retail prices that motivated customers to shop around. Customer switching in South Australia eased in 2005 to an estimated 11 per cent.

New South Wales in Australia has exhibited a steady increase in customer switching levels since full market opening in 2002. Customer switch rates in 2005 hovered around six per cent, much lower than its neighbouring states Victoria and South Australia, but clearly active. This lesser activity relative to its neighbours has been attributed in varying degrees to the continuing state ownership of New South Wales incumbent utilities, and lower retail margins that can discourage incumbents from aggressively competing for customers and discourage new entrants from entering the market.'

Source: First Data Utilities and VaasaEMG, Utility Customer Switching Research Project, *World retail energy market rankings*, June 2006.

### 6.2.3 Customer perceptions of competition

New South Wales and Victoria conducted survey work on customer perceptions of retail competition in the early stages of FRC. In New South Wales, IPART conducted a survey of residential energy use in 2003 that considered customer approaches by retailers. It conducted another survey in 2006, with the results to be published in 2007. Victoria conducted surveys of customer awareness as part of its 2002 and 2004 reviews of FRC.

South Australia published surveys of customer perceptions and experiences of retail energy market conditions in 2002, 2003 and 2006. The surveys cover:

> customer awareness of their ability to choose a retailer
> customer approaches to retailers about taking out a market contract
> retailer offers received by customers
> ease of understanding of retail offers
> drivers in customer decisions to switch.

Table 6.6 provides summary data from the South Australian surveys. The surveys suggest that customer awareness of retail choice has risen since 2003, but has plateaued at around 80 per cent since 2004. This compares with customer awareness levels in Victoria of 90 per cent (2004 survey) and in New South Wales of 91 per cent (2006 survey).[14] While it remains unusual for customers to approach retailers, there has been a steady rise in retailer approaches to customers. About two-thirds of residential customers find retailer offers easy to understand.

**Table 6.6 Residential customer perceptions of competition—South Australia**

| INDICATOR | 2003 | 2004 | 2006 |
|---|---|---|---|
| Customers aware of choice | 62% | 79% | 79% |
| Customers approaching retailers about taking out market contract | 3% | 10% | 8% |
| Customers receiving at least one retail offer | 5% | 44% | 52% |
| Customers perceiving that retailer offers are easy to understand | | 65% | 65% |

Sources: McGregor Tan Research, *Monitoring the development of energy retail competition—residents*, prepared for ESCOSA, February 2006, September 2004 and November 2003.

14 Data for New South Wales is reported in IPART, *Promoting retail competition and investment in the NSW electricity industry, Regulated electricity retail tariffs and charges for small customers 2007–2010*, Electricity draft report and draft determination, April 2007.


## Box 6.5 Retail margins

Retailers need to earn sufficient profits to compensate for the risks associated with providing an energy retail service. The margins available to energy retailers are sometimes analysed as an indicator of retail competition.

The relationship between retail margins and competition is not always clear. Depending on the circumstances, either high or low margins may be consistent with competition. In a competitive market high margins should attract new entry and drive margins down to normal levels. Sustained high margins might therefore indicate a lack of competitive pressure. Alternatively, very low margins that might result from regulated price caps could deter entry and impede the development of active competition.

Table 6.7 compares published estimates of retail margins available to host retailers from regulated tariffs in selected jurisdictions. There is little public information on the actual margins earned by retailers. It should be noted that the risk profile for a 'host' retailer with a regulated tariff may differ from the risk profile for a new entrant retailer.

The margins in table 6.7 are not directly comparable because there are different approaches to measurement (as indicated). Further, the estimation of retail margins relies on accurate estimates of underlying costs. Cost data is difficult to obtain and may vary across retailers. For example, the wholesale electricity costs incurred by a retailer depend in part on the cost of managing risk

### Table 6.7 Regulatory decisions on retail margins

| JURISDICTION | DATE OF REGULATORY DECISION | RELEVANT RETAILER | RETAIL MARGIN |
|---|---|---|---|
| New South Wales | IPART June 2004 | NSW retailers | 2% of EBIT |
| | IPART April 2007 draft determination | NSW retailers | 5% of EBITDA |
| Victoria | CRA recommendation to Victorian Government December 2003 | Vic retailers | 5–8% of total revenue |
| South Australia | ESCOSA 2005 | AGL SA | 10% of controllable costs (combined wholesale energy costs plus retailer operating costs); equivalent to about 5% of sales revenue |
| Tasmania | OTTER September 2003 | Aurora | 3% of sales revenue |
| ACT | ICRC May 2003 | ACTEW | 3% of sales revenue |

Note: EBIT: earnings before interest and tax. EBITDA: earnings before interest, tax, depreciation and amortisation. Frontier Economics estimates that a 5 per cent EBITDA is equivalent to around 4 per cent on an EBIT basis.

Sources: ESCOSA, *Electricity standing contract price path,* Final inquiry report and final determination, June 2005; OTTER, *Investigation of prices for electricity distribution services and retail tariffs on mainland Tasmania, Final report and proposed maximum prices*, September 2003; CRA Asia Pacific, *Electricity and gas standing offers and deemed contracts (2004–2007)*, Report submitted to the Department of Infrastructure, December 2003; IPART, *NSW electricity regulated retail tariffs 2004/05 to 2006/07,* Final report and determination, June 2004; IPART, *Promoting retail competition and investment in the NSW electricity industry, Regulated electricity retail tariffs and charges for small customers 2007–2010,* Electricity draft report and draft determination, April 2007; Frontier Economics, *Mass market new entrant retail costs and retail margins,* Final report, March 2007, p. 68; ICRC, *Final determination—investigation into retail prices for non-contestable electricity customers in the ACT*, May 2003.

exposure to electricity spot prices. A retailer with vertically integrated generation interests may have different risk management requirements from a retailer that does not own a generator. There may also be differences across retailers in the risks associated with regulatory arrangements, customer default and bad debt, working capital requirements, and competition from electricity substitutes.

Comparisons across jurisdictions should take account of different regulatory approaches to determining costs and margins. Until 2007 the New South Wales regulator, IPART, set relatively low retail margins because the Electricity Tariff Equalisation Fund (ETEF) managed energy purchasing risks for host retailers, eliminating the need for a risk premium. It reviewed this position in its 2007–10 determination in light of the proposed phasing out of ETEF. IPART's 2007 draft determination proposed an increase in the retail margin to 5 per cent on an earnings before interest, tax, depreciation and amortisation basis.

The Victorian Government engaged consultants CRA Asia Pacific in 2003 to review the costs that Victorian electricity retailers faced in supplying standard domestic and small business customers. CRA recommended a retail margin of 5–8 per cent under a benchmarking approach. The report informed the government in responding to retailer pricing proposals for 2004.

ESCOSA used a benchmarking process to set the retail margin for AGL Energy in South Australia. ESCOSA also conducted a return on investment analysis to quantify an appropriate retail margin. The results of the return on investment analysis were used to 'sense check' the benchmark retail margin.

## 6.3 Retail price outcomes

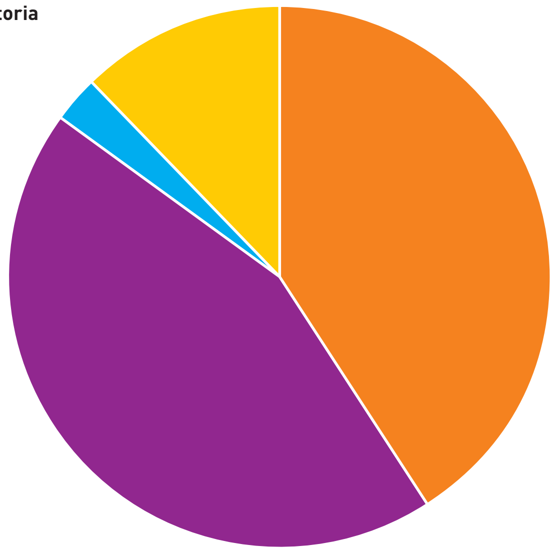
Retail customers pay a single price for a bundled electricity product made up of electricity, transport through the transmission and distribution networks, and retail services. Data on the underlying composition of retail prices is not widely available. Figure 6.13 provides indicative data for residential customers in Victoria and South Australia, based on historical information. The charts indicate that wholesale and network costs account for the bulk of retail prices. Retail operating costs (including margins) account for around 12 per cent of retail prices.

While retail price outcomes are of critical interest to consumers, the interpretation of retail price movements is not straightforward. First, trends in retail prices may reflect movements in the cost of any one, or a combination of, underlying components—wholesale electricity prices, transmission and distribution charges or retail operating costs and margins. The cost of each component may change for a variety of reasons. Similarly, differences in retail price outcomes between jurisdictions may reflect a range of factors, such as differences in underlying cost structures (for example, differences in fuel costs and the proximity of generators to retail markets), industry scale, the existence of historical cross-subsidies, differences in regulatory arrangements and different stages of electricity reform implementation.

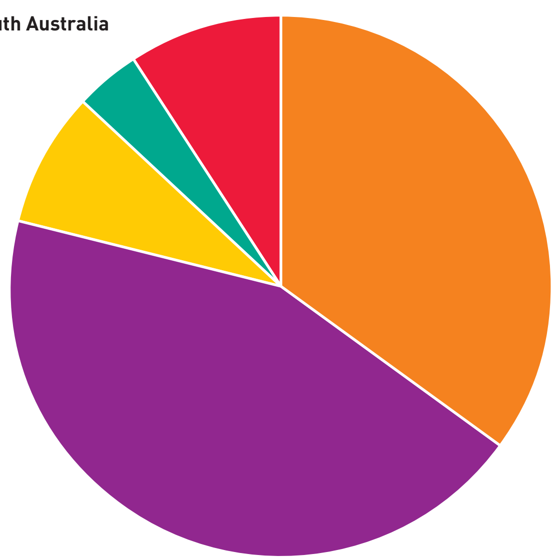
Second, there are differences in jurisdictional regulatory arrangements that affect price outcomes. In New South Wales, Victoria, South Australia and the Australian Capital Territory, the electricity prices paid by residential customers are a mix of prices set (or oversighted) by governments and regulators and prices offered under market contracts. In other jurisdictions, all residential prices are regulated. Regulated prices can reflect a mix of social, economic and political considerations that are not always transparent. To better facilitate efficient signals for investment and consumption, governments are considering removing price caps, and more immediately, aligning them more closely with underlying supply costs.

Figure 6.13
**Composition of a residential electricity bill**

**Victoria**




**South Australia**




Source: Victoria—Charles River and Associates 2003, *Electricity and gas standing offers and deemed contracts 2004–2007*, 2003; South Australia—ESCOSA, *Inquiry into retail electricity price path,* Discussion paper, September 2004.

Particular care should be taken in interpreting retail price trends in deregulated markets. While competition tends to deliver efficient outcomes, it may sometimes give a counter-intuitive outcome of *higher* prices as in the following examples.

- Energy retail prices for some residential customers were traditionally subsidised by governments and other customers (usually business customers). A competitive market will unwind cross-subsidies, which may lead to price rises for some customer groups.
- Some regulated energy prices were traditionally at levels that would be too low to attract competitive new entry. It may sometimes be necessary for retail prices to rise to create sufficient 'headroom' for new entry.

### 6.3.1 Sources of price data

There is little systematic publication of the actual prices paid by electricity retail customers. The ESAA previously published annual data on retail electricity prices by customer category and region but discontinued the series in 2004.

At the state level:

- All jurisdictions publish schedules of regulated prices. The schedules are a useful guide to retail prices, but their relevance as a price barometer is reduced as more customers transfer to market contracts.
- Retailers are not required to publish the prices struck through market contracts with customers, although some states require the publication of market offers.
- The Victorian and South Australian regulators (ESC and ESCOSA) publish annual data on regulated and market prices. The ESC and ESCOSA websites also provide an estimator service by which consumers can compare the price offerings of different retailers (section 6.2.1).

## Consumer Price Index and Producer Price Index data

The Australian Bureau of Statistics (ABS) Consumer Price Index and Producer Price Index track movements in household and business[15] electricity prices. The indexes are based on surveys of the prices paid by households and businesses and therefore reflect a mix of regulated and market prices.

Figure 6.14 tracks real electricity price movements for households and business customers since 1990. The introduction of competition reforms saw real household electricity prices rise between 2000 and 2003, and then stabilise. In the same period, real business prices trended downwards. Since 1990, real household prices have risen by 4 per cent, but business prices have fallen by 23 per cent (figure 6.15). In part, this reflects the unwinding of cross-subsidies from business to household customers that began in the 1990s. There has also been more intensive competition in the business sector due to the earlier phase-in of retail competition for this customer class.

While business prices have fallen substantially, there has been some volatility since 1999. This reflects that business prices are exposed to volatility in the wholesale and contract markets for electricity (see chapters 2 and 3). In most jurisdictions, residential prices have been shielded from volatility by price cap regulation and retailers' hedging arrangements.

Figure 6.16 tracks real electricity price movements for households in Sydney, Melbourne, Adelaide, Brisbane and Perth since 1990. Price variations between the cities may reflect a variety of factors, including differences in generation and network costs, industry scale, historical cross-subsidies, differences in regulatory arrangements and different stages of electricity reform implementation. Price rebalancing to phase out cross-subsidies caused some price volatility in Melbourne and Adelaide after 2000. Most notably affected was Adelaide where prices rose by about 25 per cent in 2003.

**Figure 6.14**
**Retail electricity price index (CPI adjusted)—Australian capital cities**

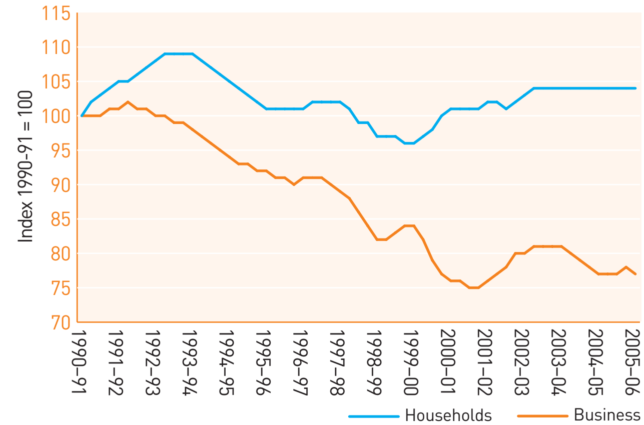
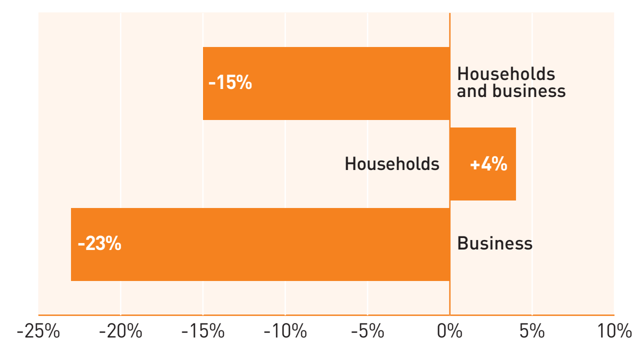



**Figure 6.15**
**Change in the real price of electricity—Australia, 1990–91 to 2005–06**



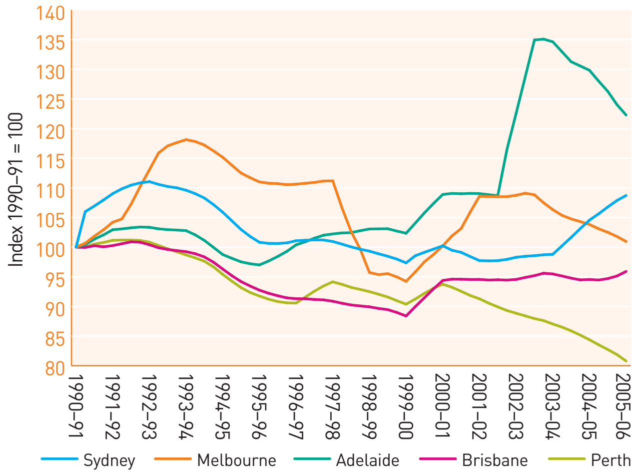

Data source for figure 6.14 and figure 6.15: ABS Cat no.s 6401.0 and 6427.0; AER. The household index is based on the consumer price index for household electricity, deflated by the CPI series for all groups. The business index is based on the producer price index for electricity supply in 'Materials used in Manufacturing Industries,' deflated by the CPI series for all groups.

In Melbourne and Adelaide, prices have trended downwards since 2003. Conversely, Sydney prices remained relatively stable for a decade, before trending up from 2004. In Brisbane where the retail market was heavily regulated until 2007, real prices remained constant from 2001. While retail prices have declined in Perth, they nonetheless remain high compared with some eastern capital cities (see chapter 7).

15 The producer price index series tracks input costs for manufacturers.

Figure 6.16

**Real electricity price movements for households — capital cities**




Data source: ABS

## 6.3.2 International price comparisons

Australian households pay similar prices for electricity to their USA counterparts, but lower prices than households in Japan and Western Europe (figure 6.17). Of the major industrialised economies, only in Canada are average prices for households significantly lower than in Australia. In several European countries, industry pays substantially lower prices for electricity prices than do households. The differential is less pronounced for Australia, with industrial prices more closely aligned with international prices (figure 6.18). The average prices paid by Australian industry are significantly lower than prices in Italy, Japan and Germany, and similar to those in South Korea and the USA.

# 6.4 Quality of retail service

The jurisdictional regulators monitor and report on quality of service in the retail sector to enhance transparency and accountability, and to facilitate 'competition by comparison'.[16] All jurisdictions have their own monitoring and reporting framework. In addition, the Utility Regulators Forum (URF) developed a national framework in 2002 for electricity retailers to report against common criteria on service performance.[17] The criteria address:

> access and affordability of services
> quality of customer service.

The URF measures apply to the small retail market, comprising customers using less than 160 MWh a year.[18] All NEM jurisdictions have adopted the URF reporting template, within which each applies its own implementation framework. This results in some differences in approach.

## 6.4.1 Affordability and access indicators

With the introduction of retail contestability, governments have strengthened consumer protection arrangements, with a particular focus on access and affordability issues. These protections are often given effect through regulated minimum standards regimes and codes.

Access to electricity supplies depends on the capacity of customers to meet bill payments and so avoid disconnection. Customer access is therefore linked to the affordability of retail service but also depends on the options made available by retailers to help customers manage their bill payments. The URF has developed three categories of indicators on affordability and access, covering:

> customer access to payment plans
> customer access to security deposits or refundable advances
> rates of customer disconnections and reconnections.

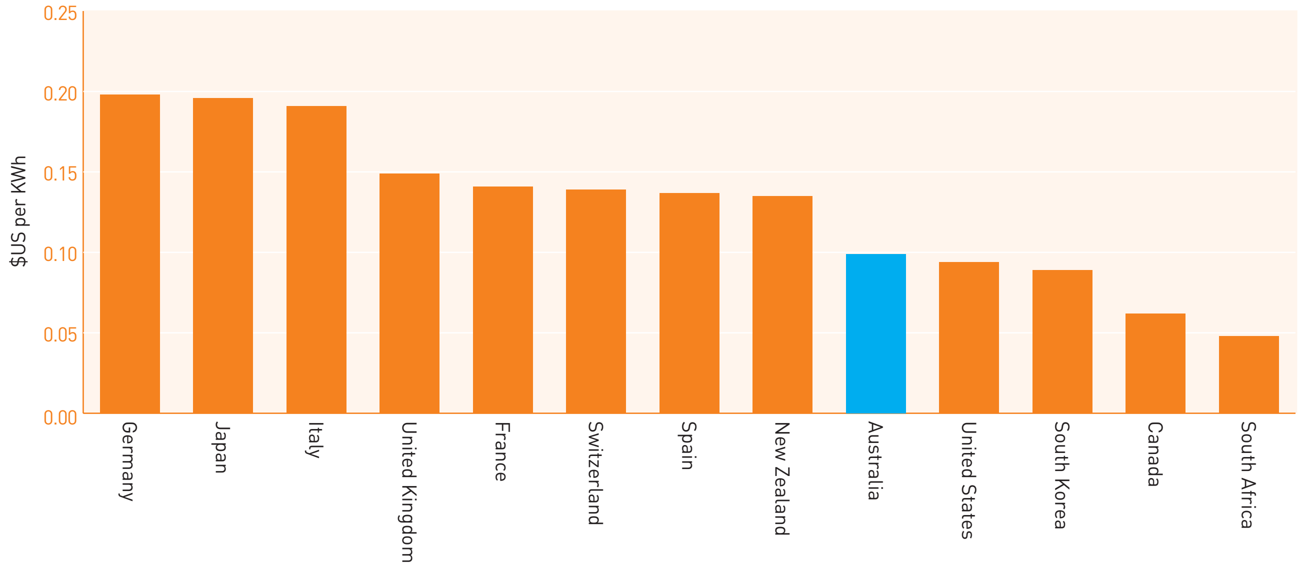
16 See, for example, ESC, *Energy retail businesses, comparative performance report for the 2005-06 financial year*, November 2006, p. 1.

17 Utility Regulators Forum, *National regulatory reporting for electricity distribution and retailing businesses*, Discussion paper, March 2002.

18 Queensland reviewed its definition of 'small customer' in 2006 as part of its introduction of retail customer choice and adopted a breakpoint of 100 MWh a year.

Figure 6.17

International electricity prices for households—2005

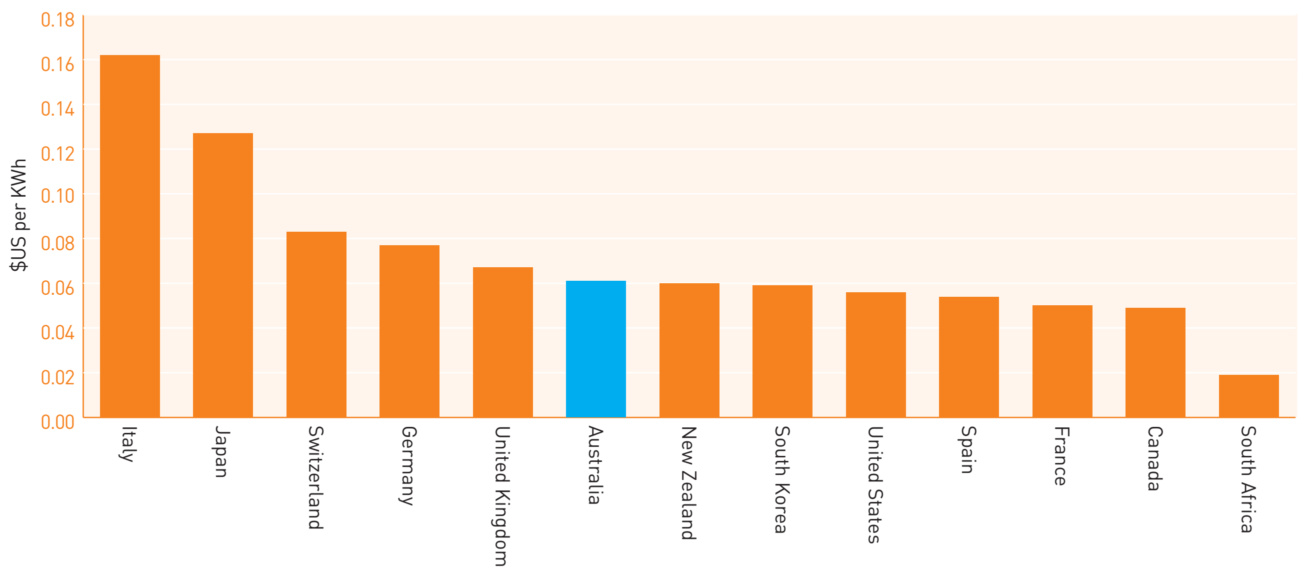



Note: Latest data available at May 2006: Canada, South Africa, Spain (2003); Australia, Germany, Italy, Japan (2004); others 2005.

Source: Energy Information Administration (USA), based on International Energy Agency data.

Figure 6.18

International electricity prices for industry—2005

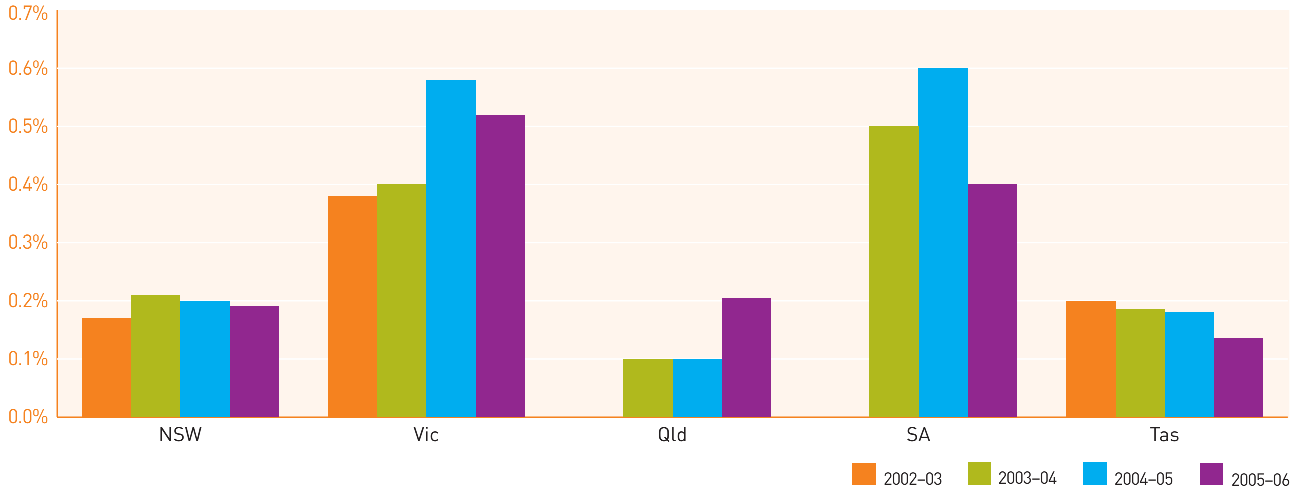



Note: Latest data available at May 2006: Canada, South Africa, Spain (2003); Australia, Germany, Italy, Japan (2004); others 2005.

Source: Energy Information Administration (USA), based on International Energy Agency data.

Figure 6.22

Ombudsman—electricity customer contacts as a percentage of residential customers




Sources: State ombudsmen websites: www.ecpo.qld.gov.au; www.eiosa.com.au; www.ewov.com.au; www.ewon.com.au; www.energyombudsman.tas.gov.au.

### 6.4.2 Customer service indicators

Retail competition allows customers to transfer away from a business with poor standards. In the first instance, customers can raise complaints directly with their retailer through the retailers' dispute resolution procedure. If further action is needed they can refer complaints to their state energy ombudsman or an alternative dispute resolution body. Noting that consumers have a range of options to address service issues, the URF considered that monitoring of this area need not be comprehensive. It proposed the monitoring of:

- customer complaints—the degree to which a retailer's services meet customers' expectations
- telephone call management—the efficiency of a retailer's call centre service.

### 6.4.3 Performance outcomes

Tables 6.8 and 6.9 set out a sample of retailer performance outcomes for residential customers against the URF indicators. The data is derived from the reporting of individual retailers to jurisdictional regulators. The regulators consolidate and publish the data annually.[19]

It should be noted that the validity of any performance comparisons may be limited because of differences in approach between jurisdictions. In particular, measurement systems, audit procedures and classifications may differ between jurisdictions and within the same jurisdiction over time. Similarly, regulatory procedures and practices differ—for example, the procedures a retailer must follow before a customer can be disconnected. More generally, the publication of data against the URF indicators began in most jurisdictions from around 2002–03. It is normal for the quality of a data series to gradually improve as measurement techniques are refined. It should also be noted that data trends from year to year may be influenced by a range of factors, including general economic conditions.

### 6.4.4 Ombudsman contacts

The reporting framework proposed by the URF is based on reporting by retailers in each jurisdiction to regulators. An alternative indicator of retail service is the number of customer contacts (including enquiries and complaints) made to an ombudsman (figure 6.22). Victorian and South Australian customers have shown a greater tendency to contact an ombudsman than

19 Tables 6.11 and 6.12 relate to outcomes for residential customers on a statewide basis. State regulators also publish outcomes for particular retailers and for business customers in their jurisdiction.

customers elsewhere. This may reflect higher rates of customer concern—or a stronger awareness of the presence of an ombudsman than in other jurisdictions.

**Table 6.8 Affordability and access indicators**

| JURISDICTION | 2002–03 | 2003–04 | 2004–05 | 2005–06 |
| --- | --- | --- | --- | --- |
| SHARE OF RESIDENTIAL CUSTOMERS ON PAYMENT INSTALMENT PLANS | | | | |
| New South Wales | 1.40% | 1.90% | 2.80% | 3.20% |
| Victoria | 4.90% | 5.10% | 4.80% | 4.66% |
| Queensland | 10.12% | 12.62% | 0.85% | – |
| South Australia | – | – | 1.50% | 1.96% |
| Tasmania | 1.30%[1] | 1.10%[1] | 1.14% | 1.06% |
| ACT | 1.50% | 1.10% | – | – |
| SHARE OF RESIDENTIAL DIRECT DEBIT CUSTOMERS DEFAULTING | | | | |
| New South Wales | – | – | – | – |
| Victoria | – | – | – | – |
| Queensland | 2.03% | 1.61% | 0.18% | – |
| South Australia | – | – | 4.52% | 4.18% |
| Tasmania | 0.09%[1] | 0.18%[1] | 0.22% | – |
| ACT | 10.10%[1] | 14.00%[1] | – | – |
| SHARE OF RESIDENTIAL CUSTOMERS DISCONNECTED FOR FAILURE TO PAY AMOUNT DUE | | | | |
| New South Wales | 0.68% | 0.80% | 1.00% | 0.90% |
| Victoria | 0.60% | 0.80% | 0.50% | 0.22% |
| Queensland | 1.31% | 1.30% | 1.57% | – |
| South Australia | 0.80% | 2.10% | 1.20% | 1.14% |
| Tasmania | 0.80% | 0.65% | 0.44% | 0.72% |
| ACT | 0.40% | 0.30% | – | – |
| SHARE OF RESIDENTIAL RECONNECTIONS WITHIN SEVEN DAYS OF DISCONNECTION | | | | |
| New South Wales[2] | 63.40% | 58.40% | 61.80% | 59.60% |
| Victoria | 51.30% | 48.80% | 47.80% | 36.40% |
| Queensland | 69.93% | 65.99% | 63.63% | – |
| South Australia | 60.00% | 47.00% | 46.00% | 36.00% |
| Tasmania | 55.45% | 28.70% | 37.98% | 36.31% |
| ACT | 78.00% | 56.90% | – | – |
| SHARE OF RESIDENTIAL CUSTOMERS WHO HAVE LODGED SECURITY DEPOSITS | | | | |
| New South Wales | 10.40% | 10.30% | 9.20% | 7.40% |
| Victoria | 0.02% | 0.01% | 0.01% | – |
| Queensland | 20.07% | 18.50% | 22.25% | – |
| South Australia | 0.00% | 0.00% | 0.00% | 0.00% |
| Tasmania | 0.01% | 0.01% | 0.01% | 0.02% |
| ACT | 0.00% | 0.00% | – | – |

1. Includes residential and business customers.
2. Includes all reconnections (not just within seven days of disconnection).

**Table 6.9 Customer service indicators**

| JURISDICTION | 2002–03 | 2003–04 | 2004–05 | 2005–06 |
| --- | --- | --- | --- | --- |
| CUSTOMER COMPLAINTS AS SHARE OF TOTAL CUSTOMERS | | | | |
| New South Wales[1] | 0.52% | 0.44% | 0.44% | 0.59% |
| Victoria | 0.41% | 0.50% | 0.64% | 0.71% |
| Queensland | 0.28% | 0.50% | 0.35% | 0.35% |
| South Australia | 0.47% | 0.63% | 0.66% | 0.81% |
| Tasmania | 0.87% | 0.82% | 0.72% | 0.47% |
| ACT | 0.06% | 0.08% | – | – |
| SHARE OF CALLS RESPONDED WITHIN 30 SECONDS (ONCE CONNECTED TO A COMPLAINT/INQUIRY LINE) | | | | |
| New South Wales | 53.78% | 48.23% | 65.70% | 71.70% |
| Victoria | 52.74% | 51.19% | 65.12% | – |
| Queensland | 66.05% | 66.70% | 78.75% | 81.30% |
| South Australia | 73.93% | 81.50% | 85.48% | 80.20%[2] |
| Tasmania[3] | 78.00% | 78.00% | 78.66% | 79.60% |
| ACT | – | – | – | – |
| AVERAGE WAIT BEFORE CALL ANSWERED (SECONDS) | | | | |
| New South Wales | – | – | – | – |
| Victoria | – | – | – | – |
| Queensland | 83 | 53 | 28 | 29 |
| South Australia | 60 | 23 | 27 | 34[2] |
| Tasmania | 33 | 30 | 39 | 38 |
| ACT | – | – | – | – |
| SHARE OF CALLS ABANDONED | | | | |
| New South Wales | 8.33% | 11.14% | 6.70% | 3.90% |
| Victoria | – | – | – | – |
| Queensland | 6.57% | 5.34% | 3.88% | – |
| South Australia | 4.60% | 2.50% | 2.20% | 2.70%[2] |
| Tasmania | 6.00% | 5.00% | 5.02% | 4.2% |
| ACT | – | – | – | – |

1. Small retail customers only.
2. Includes electricity and gas customers.
3. Call response rates in Tasmania are for calls answered within 20 seconds.

Sources for tables 6.8–9: Reporting against URF templates and performance reports on the retail sector by IPART (NSW), ESC (Vic), ESCOSA (SA), OTTER (Tas), QCA and the Department of Mines and Energy (Qld) and ICRC (ACT).

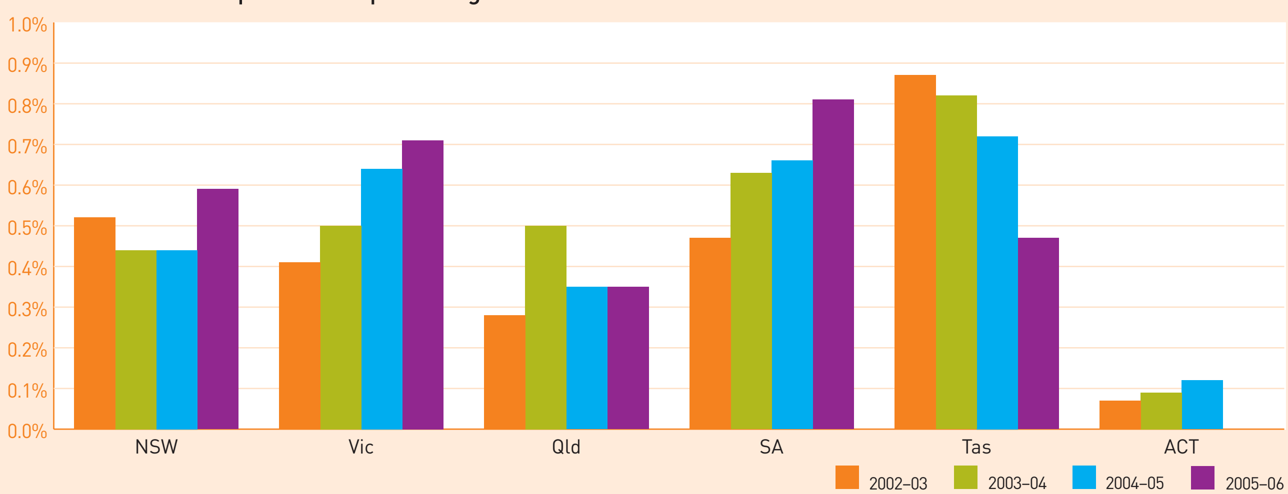

### Box 6.6 Trends in retail service standards—a snapshot

Figures 6.19–21 chart a selection of the data set out in tables 6.8 and 6.9. The rate of customer complaints (figure 6.12) rose between 2002–03 and 2005–06 in New South Wales, Victoria and South Australia, but remained below 1 per cent. The rate of complaints in Queensland and Tasmania fell over this period, and was below 0.5 per cent in 2005–06.

The rate of disconnection of residential customers for failure to meet bill payments (figure 6.20) is a key affordability and access indicator. The rate of disconnections has fallen since 2002–03 in Victoria, Tasmania and the Australian Capital Territory. Despite spikes in 2003–04 for South Australia and Victoria, these regions recorded lower disconnection rates in 2004–05 and 2005–06. A range of factors, that may vary between jurisdictions, may have contributed to these outcomes. For example, Victoria introduced legislation in 2004 providing for compensation to households that are wrongfully disconnected. More generally, the data should be considered in conjunction with reconnection data (figure 6.21).

The rate at which disconnected residential customers are reconnected within seven days[20] has fallen since 2002–03 in all jurisdictions. When considered in conjunction with falling disconnection rates, there are indications that retailers may have improved their customer management services by reducing the rate of avoidable disconnections—perhaps through better use of payments plans and other account management options.

**Figure 6.19**
**Retail customer complaints as a percentage of total customers**




20 Note that the New South Wales figures represent all reconnections, not just those within seven days of disconnection.

**Figure 6.20**

**Residential disconnections as a percentage of customer base**

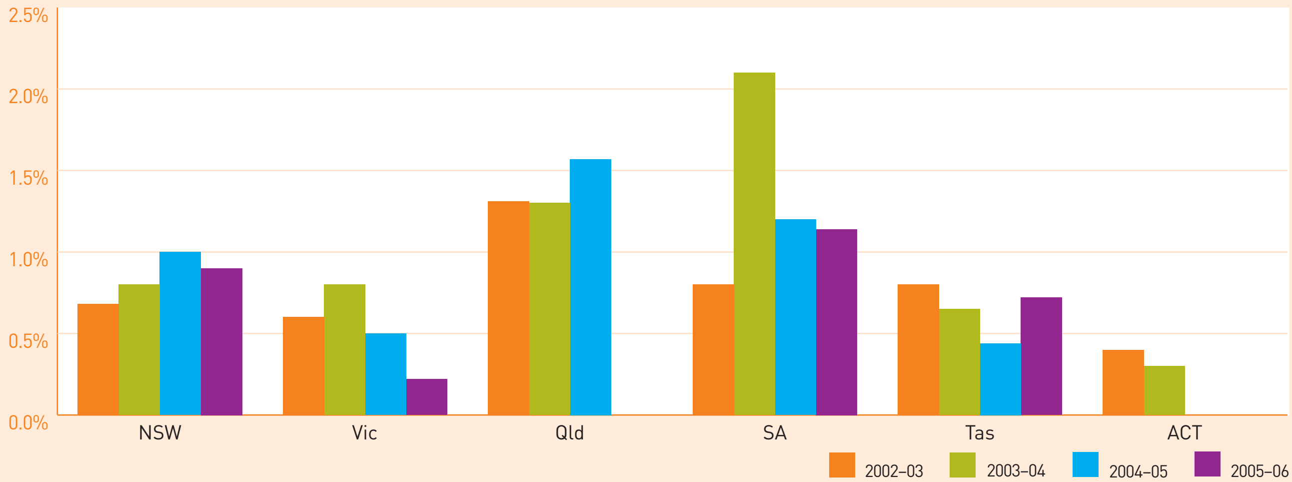
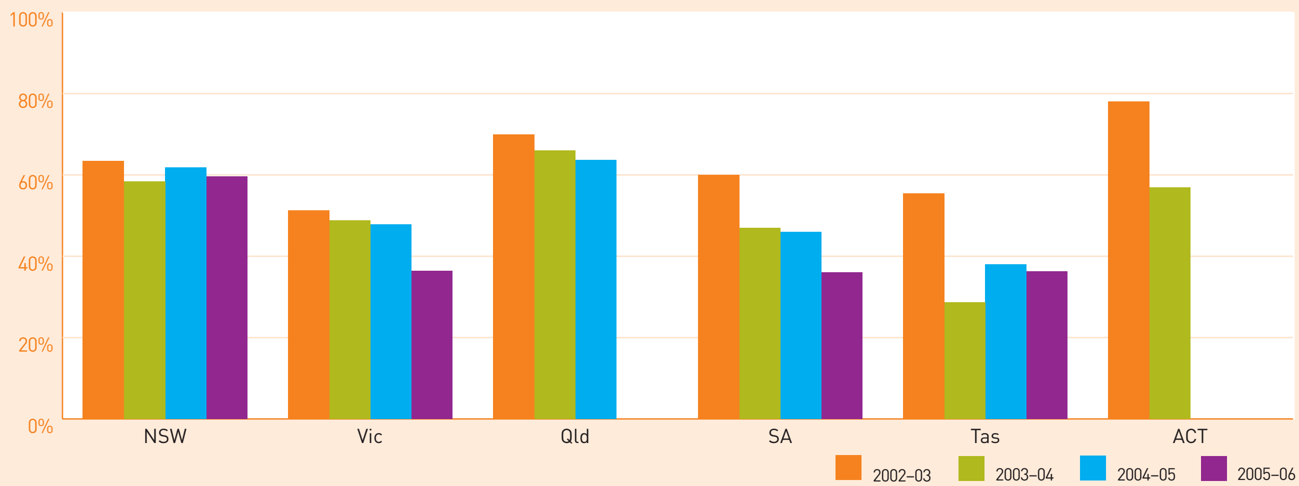



**Figure 6.21**

**Residential reconnections within seven days (as a percentage of disconnected customers)**




CHAPTER 6 ELECTRICITY RETAIL MARKETS

## 6.5 Regulatory arrangements

The development of competitive retail markets is occurring at different rates across the jurisdictions. While New South Wales, Victoria, South Australia and the Australian Capital Territory have introduced FRC, each continues to regulate various aspects of the market. Regulatory measures include:

> price caps for small customers
> the setting of minimum terms and conditions in 'default' service offers
> information disclosure and complaints handling requirements
> community service obligations on retailers.

### 6.5.1 Price caps

All jurisdictions appoint host retailers that must offer to supply small customers in nominated geographical areas at capped tariffs (see section 6.2). This provides a default option for customers who do not have a market contract. Governments that have introduced FRC continue to set default prices as a transitional measure to:

> allow consumers time to understand and adjust to the workings of the new market structure
> protect consumers entering the competitive market from the possible exercise of market power by retailers
> limit the impact of price shocks, both for consumers generally, and for particular classes of consumers.

The approach to regulating default tariffs varies between jurisdictions. For example:

> The New South Wales regulator, IPART, sets a retail price cap for small customers that do not enter a market contract. The cap is for average tariffs and changes to individual tariffs. The Government of New South Wales has extended the use of the cap until 2010. IPART noted in its review of retail prices for 2007–10 that the government aimed to reduce customer reliance on regulated prices and had directed IPART to ensure that regulated tariffs are cost reflective by June 2010.
> The Victorian government has reserve powers to regulate default tariffs charged by host retailers. In December 2003 the government entered into voluntary agreements with host retailers on default retail prices for households and small businesses until the end of 2007. The agreements, which provided for a real decrease in electricity prices over four years, were renegotiated in 2005.
> The South Australian regulator, ESCOSA, regulates standing contract prices for small customers. Small customers may request a standing contract—with regulated prices—from the host retailer, or choose an unregulated market contract from a licensed retailer. ESCOSA's current retail price determination covers January 2005 to December 2007.
> In Queensland the government has set regulated prices with reference to movements in the consumer price index. With the introduction of FRC in July 2007, the government will base annual adjustments in regulated price caps on benchmark costs. In March 2007, the government delegated the calculation of benchmark costs to the Queensland Competition Authority.

To allow efficient signals for investment and consumption, governments are moving towards removing retail price caps. Australian governments reaffirmed their commitment in 2006 to remove retail price caps where effective competition can be demonstrated. The Australian Energy Market Commission (AEMC) will assess the effectiveness of retail competition in each jurisdiction to determine the appropriate time to remove price caps. The AEMC is conducting the first of these reviews on Victoria in 2007.

### 6.5.2 Management of wholesale price fluctuations

In addition to regulating retail prices, Queensland and New South Wales implement schemes to minimise the risk of price volatility faced by government-owned host retailers in the wholesale market. The New South Wales scheme, the electricity tariff equalisation fund (ETEF), provides host retailers with a hedge against price volatility in the wholesale market. Retailers pay into the fund when pool prices are lower than the energy cost component they recover from regulated customers. They can then draw on the fund if pool prices are higher than the energy cost component in the regulated tariff. The New South Wales Government-owned generators make payments to cover any shortfalls in the fund.

The New South Wales Government views ETEF as a transitional measure that provides a 'safety net' to protect small customers. Under legislation, ETEF is due to expire in June 2007. The New South Wales Government has announced that it will extend ETEF's operation, and now intends to phase it out between September 2008 and June 2010.[21]

### 6.5.3 Consumer protection

Governments regulate aspects of the electricity retail market to protect consumers' rights and ensure they have access to sufficient information to make informed decisions. Most jurisdictions require designated retailers to provide electricity services under a standing offer or default contract to customers in nominated geographical areas. Default contracts cover minimum service conditions, billing and payment obligations, procedures for connections and disconnections, information disclosure and complaints handling. During the transition to effective competition, default contracts also include some form of regulated price cap or prices oversight.

Some jurisdictions have established industry codes that govern the provision of electricity retail services to small customers, including under market contracts. Industry codes establish consumer protection measures including:

> minimum terms and conditions under which a retailer can provide electricity retail services.
> standards for the marketing of energy services
> processes for the transfer of customers from one retailer to another.

Most jurisdictions have an energy ombudsman or an alternative dispute resolution body to whom consumers can refer a complaint they have been unable to resolve directly with the retailer. In addition to general consumer protection measures, jurisdictions establish a supplier of last resort to ensure customers can be transferred from a failed retailer to another.

In addition, states and territories provide for a range of community service obligation payments to particular customer groups—often low incomes earners. Traditionally, the payments were often 'hidden' in subsidies and cross-subsidies between different customer groups, which caused distortions to pricing and investment signals. As part of the energy reform process, governments are making community service obligations more transparent and are directly funding them out of budgets rather than by using cross-subsidises.

### 6.5.4 Metering

The energy consumption of end-use customers is recorded on meters at the point of connection to the distribution network. There have been developments, both nationally and in some jurisdictions, to improve the quality of electricity meters to provide better signals to consumers and investors on consumption, price and other aspects of energy use.

Electricity meters vary in the amount of information that is made available to the electricity provider and customers.

> **Accumulation meters** record the total consumption of electricity at a connection point, but not the time of consumption. Consumers are billed solely on the volume of electricity consumed.
> **Interval meters** are more sophisticated and record consumption in defined time intervals (for example, half-hour periods). This information allows time-of-use billing so the charge for electricity can be varied with the time of consumption.

21 IPART *Review of regulated retail tariffs and charges for electricity 2007 to 2010*, Issues paper, July 2006, p. 5.

- **Smart meters** are interval meters with remote communication capabilities between retailers and end users. This allows for remote meter reading, connection and disconnection of customers. It also allows retailers and distributors to manage loads to particular customers and appliances. Add-ons such as an in-house display may provide information on prices, greenhouse gas emissions and other aspects of electricity consumption.

The primary benefit of interval or smart meters is that they, together with an appropriate tariff structure, help energy users self-manage their demand in response to price signals. For example, consumers would be encouraged to reduce their use of electricity at peak times when prices are high. This may help to ease congestion in network infrastructure, allow the deferral of some capital expenditure, reduce the incidence of wholesale electricity price spikes (and retailers' hedging costs) and improve security of supply.

Other potential benefits of interval/smart meters include:

- improved network planning capabilities, using consumption data provided by the meters
- lower costs of remote meter reading, connection and disconnection of customers (for smart meters).

The costs of a meter rollout include the capital costs of the meter, infrastructure to communicate with customers, and the costs of processing and storing the information generated.

Interval meters have so far been used mainly to record the electricity consumption of large (industrial and large business) consumers. In 2007 the Council of Australian Governments agreed to a national implementation strategy for the progressive rollout of 'smart' electricity meters wherever a net benefit is expected. The MCE indicated in 2007 that the rollout is likely to take five years or more.

Mark Wilson

Electricity smart meter

Progress towards a national rollout of interval meters has varied among jurisdictions.

- Victoria—initiated a program to deploy smart meters to all small customers over four to five years from 2008. Technical and consumer response trials are to be undertaken as part of the deployment program.
- New South Wales—EnergyAustralia has committed to a rollout of interval meters for all customers that consume more than 15 MWh of electricity a year. For customers using less than that, interval meters will be provided on a new and replacement basis. Country Energy is installing interval meters on a new and replacement basis for all customers.
- Queensland and the Australian Capital Territory—the Queensland Energy Competition Committee and the ICRC have recommended the rollout of interval meters on a new and replacement basis for small customers.

- Western Australia—all new meters are to support time-of-use pricing.
- South Australia and Tasmania—concluded that the rollout of interval meters to small customers is not currently justified.

### 6.5.5 Future regulatory arrangements

State and territory governments and local regulators have traditionally been responsible for the regulation of retail energy markets. Governments agreed in the Australian Energy Market Agreement (2004, amended 2006) to transfer some regulatory functions to a national framework to be administered by the AEMC and the AER. The agreement scheduled for transfer the regulation of:

- the obligation on retailers to supply small customers at a default tariff with minimum terms and conditions
- arrangements to ensure customer supply continuity and wholesale market financial integrity in the event of a retailer failure
- minimum terms and conditions in retailer market contracts with small customers
- obligations imposed on retailers when marketing to small customers
- retailer general business authorisations (where used for matters other than technical capability and safety).

The MCE has scheduled the transfer of responsibilities to occur from July 2008. Under the current proposals, the states and territories will retain responsibility for price control of default tariffs unless they choose to transfer those arrangements to the AER and the AEMC.

# 7 BEYOND THE NATIONAL ELECTRICITY MARKET


Two jurisdictions have electricity markets that are not interconnected with the National Electricity Market—Western Australia and the Northern Territory. Western Australia has recently introduced a number of electricity market initiatives, including new wholesale market arrangements. The Northern Territory has introduced electricity reforms but at present there is no competition in generation or retail markets. The Northern Territory has introduced an access regime for electricity networks, which has been certified as effective under the *Trade Practices Act 1974*.

# 7 BEYOND THE NATIONAL ELECTRICITY MARKET

## 7.1 Western Australia's electricity market

Western Australia's electricity market is thousands of kilometres from the NEM in eastern and southern Australia. There is neither physical interconnection nor governance linkages between the two markets. With a customer base spread over a third of the national landmass, Western Australia's electricity industry faces some unique challenges.

### 7.1.1 The networks

Reflecting Western Australia's geography, industry and demographics, the state's electricity infrastructure consists of several distinct systems (figure 7.1):

- the South West Interconnected System (SWIS)
- the North West Interconnected System (NWIS)
- 29 regional, non-interconnected power systems.

The largest network, the SWIS, serves Perth and other major population centres in the south-west, while the NWIS serves towns and resource industry loads in the north-west of the state.

#### The South West Interconnected System

The SWIS is the major interconnected electricity network in Western Australia, supplying the bulk of the south-west region. It extends to Kalbarri in the north, Albany in the south, and Kalgoorlie in the east. The network supplies 840 000 retail customers with 6000 km of transmission lines and 64 000 km of distribution lines. It comprises 4200 megawatts (MW) of installed generation capacity, of which about 75 per cent is owned by the state utility Verve. The remaining 25 per cent is privately owned but principally dedicated to resource projects.

Statewide, around 60 per cent of installed capacity is fuelled by natural gas, 35 per cent from coal and 2 per cent from oil. There is growth in generation from renewable sources (3.2 per cent in 2005–06), mainly comprising wind, hydro and biomass.[1]

The government has set a target of 6 per cent of electricity to be sourced from renewable energy by 2010.

The principal base load generators are located near Collie, about 200 km south of Perth, near the state's only coal mining facilities. The majority of principal peak load (open cycle gas turbine) generators are located near the Dampier to Bunbury natural gas pipeline north of Perth. There are also plants at Kemerton and Kalgoorlie, and a large mixed fuel generation station at Kwinana, south of Perth.

The largest renewable energy facilities are the 90 MW Alinta wind farm, near Geraldton, the 80 MW Emu Downs wind farm and the 22 MW Albany wind farm owned by Verve.

Most independent power producers with plants connected to the SWIS use gas as their primary fuel.[2] The North West Shelf Gas project supplies most of the gas, which is transported through the Dampier to Bunbury, Parmelia and Goldfields gas pipelines.

The SWIS has high-voltage transmission capacity between Bunbury, Collie and Perth, with several 330 kilovolts (kV) lines serving the region's generators, industrial loads and population centres. Transmission links to rural towns and outlying cities like Geraldton and Albany have less capacity. The mining city of Kalgoorlie is connected to Collie via 220 kV lines and has local gas-fired generators served by the Goldfields gas pipeline.

Western Australia introduced a wholesale electricity market in the SWIS in September 2006 (section 7.1.4).

### The North West Interconnected System

A second, separate interconnected network—the NWIS operates in the north-west of the state and centres around the industrial towns of Karratha and Port Hedland and resource centres. The network is significantly smaller than the SWIS and its purpose is to supply the resource industry's operations and associated townships in the area.

The NWIS has a generation capacity of 400 MW. The plants are mainly fuelled by natural gas, some of which is shipped on the Pilbara Energy Pipeline, which runs from Karratha to Port Hedland.

Horizon Power is responsible for the transmission, distribution, and retailing of electricity to customers through the NWIS. Horizon purchases power from private generators in the region and sells it to residential and commercial customers. Private generators serve the major resource companies in the Pilbara. These include Hamersley Iron's 120 MW generation plant at Dampier, Robe River's 105 MW plant at Cape Lambert and Alinta's 105 MW plant at Port Hedland.

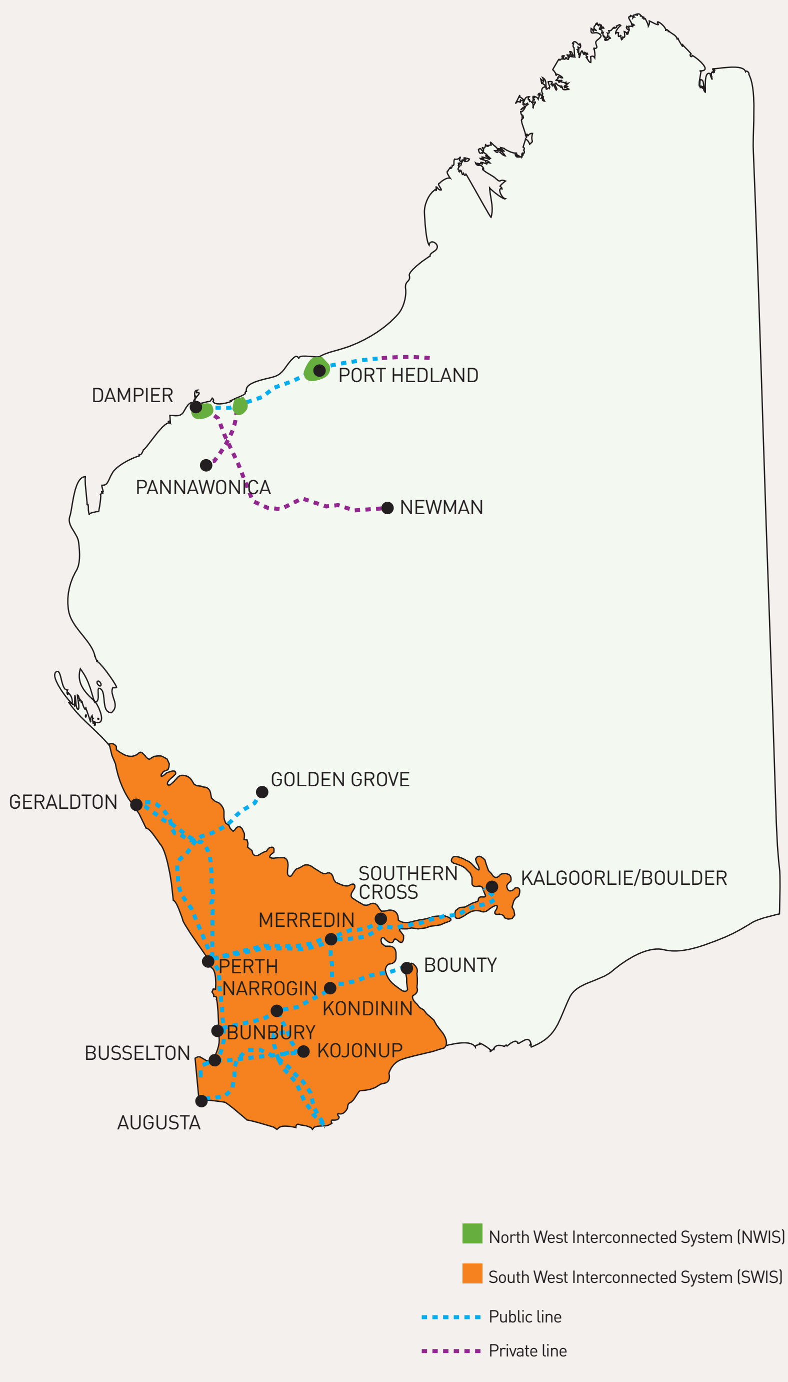
Due to the small scale of this system, the NWIS will not see a wholesale market introduced in the manner of the SWIS in the foreseeable future.

### Regional non-interconnected systems

Further small, non-interconnected distribution systems operate around towns in rural and remote areas beyond the SWIS and NWIS networks.[3] Horizon Power operates the 29 distribution systems located in these regions, but independent generators supply much of the electricity.

1 Office of Energy (WA) 2006, *Electricity generation from renewable energy*, fact sheet.
2 Griffin Power is currently seeking to construct a coal base load plant near Collie in the south-west.
3 The networks are located in such areas as Broome, Gascoyne Junction, Menzies, Camballin, Halls Creek, Mount Magnet, Carnarvon, Hopetoun, Norseman, Cue, Kununurra, Nullagine, Denham, Lake Argyle Village, Sandstone, Derby, Laverton, Wiluna, Esperance, Leonora, Wittenoom, Exmouth, Marble Bar, Wyndham, Fitzroy Crossing, Meekatharra and Yalgoo.

Figure 7.1
Electricity infrastructure map—Western Australia




Source: ERA

## 7.1.2 Electricity market reform

Consistent with the eastern and southern states, Western Australia's electricity industry was historically dominated by a single, vertically integrated utility under government ownership. There was no effective third-party access to electricity networks, no independent entry and no electricity market competition.

When in 1993 Australian governments decided to reform the electricity industry and create a national market, it was thought impractical for Western Australia to join. Geography dictated that its networks could not be physically interconnected with the other states. Western Australia retained a vertically integrated monopoly industry structure for almost a decade longer than the other states; however, it did introduce some reforms in the electricity sector. The government:

- disaggregated the State Energy Commission into separate electricity and gas corporations—Western Power and AlintaGas—in 1995
- introduced transmission access in 1996 and phased distribution access from 1997
- progressively introduced retail contestability for large consumers connected to the distribution system during the period 1997–2005. Customers using more than 50 megawatt hours (MWh) per year are now contestable.

Despite these reforms, competition in electricity wholesale and retail supply remained limited and was dominated by the government-owned incumbent. The lack of competition, in combination with relatively high generation costs (due to relatively expensive coal sources and the remoteness of major gas fields) led to businesses paying high prices for electricity. In 2003–04 real electricity prices for large businesses were 15 to 60 per cent higher in Western Australia than in south and south-eastern Australia.[4] Similarly, residential electricity prices were higher only in Darwin and Adelaide (table 7.1). The Office of Energy has attributed these high prices to a lack of competition and a lack of independent regulation of access to network infrastructure.[5]

**Table 7.1 Electricity prices—2003-04**

| JURISDICTION | MEDIUM SIZED BUSINESS (500 KW) CENTS PER KWH | RESIDENTIAL (REGULATED TARIFFS) CENTS PER KWH |
|---|---|---|
| New South Wales | 7.49 | 9.56 |
| Victoria | 7.56 | 12.56 |
| Queensland | 7.96 | 10.46 |
| South Australia | 10.57 | 15.82 |
| Tasmania | 9.43 | 12.21 |
| Australian Capital Territory | 9.83 | 11.59 |
| Western Australia | 11.52 | 13.32 |
| Northern Territory | 14.83 | 16.04 |

Source: Office of Energy (WA), *Electricity pricing in Australia 2003–04*, derived from ESAA data. The ESAA series was discontinued after 2003–04.

In 2001, the government established the Electricity Reform Task Force to review the structure of the electricity market. The task force recommended 79 reforms. Cabinet endorsed the reforms the following month and implemented them during 2003–06. The key reforms included:

- the disaggregation of Western Power into four separate state-owned entities, which took effect on 1 April 2006
- establishing a wholesale electricity market, which commenced in September 2006
- establishing an electricity networks access code to facilitate access to transmission and distribution networks, which commenced in 2004
- reducing the access threshold for contestability to all customers using more than 50 MWh per annum from January 2005
- implementing regulatory market arrangements and consumer protection measures, including an electricity licensing regime, customer service code, customer transfer code, metering code, network reliability and quality of supply code, Energy Ombudsman scheme, standard form contract regime and obligations to connect and supply
- facilitating the renewable energy sector, distributed generation and demand management.

4 Office of Energy (WA), *Electricity Pricing in Australia 2003-04*.
5 Office of Energy (WA), Electricity Reform Implementation Unit fact sheet, 2006, <http://www.eriu.energy.wa.gov.au/2/3164/3073/what_is_the_sol.pm>.


Transmission lines in Western Australia

## 7.1.3 Disaggregation of Western Power

On 1 April 2006, Western Power was disaggregated into four government-owned corporations:

- Verve—generation
- Western Power—transmission and distribution networks
- Synergy—retail
- Horizon Power—regional supply.

The government has announced that it will not privatise the corporations.

## 7.1.4 Wholesale electricity market

Central to Western Australia's electricity reform is the creation of a wholesale electricity market in the SWIS. Energy trading is facilitated through a combination of bilateral contracts (off market), a day-ahead short-term energy market (STEM) and balancing. The market was originally planned to come into operation in July 2006 but was rescheduled for September 2006 to enable the testing of IT systems. It has been designed to meet the objectives and needs of the Western Australian environment and differs considerably from the NEM.

The rule development body and market operator is the Independent Market Operator (IMO), a government entity established in 2004.[6] The IMO has no commercial interest in the market and no connection with any market participant, including Western Power.

Reflecting Western Australia's industry structure, state-owned energy corporations will continue to dominate the market:

- Verve owns about 75 per cent of installed generation capacity in the SWIS.
- Western Power will continue to own the bulk of the transmission and distribution systems.
- Until full retail contestability is introduced, Synergy will serve all customers using less than 50 MWh per year, including small business and residential consumers. At this stage, Western Australia has not determined a date to introduce full retail contestability.

However, the dominance of state-owned energy corporations may reduce over time with new market entry and greater interaction between state-owned corporations and independent power producers. For example:

- Synergy has entered into supply arrangements with the NewGen power station at Kwinana.
- The government has placed a 3000 MW cap on Verve's ability to invest in the new generation plant to allow for independent power producers to increase their market share over time.
- Synergy is not permitted to own or control the generation plant for a transitional period until the government is satisfied that new market entry has occurred.

### Differences between the SWIS wholesale market and the National Energy Market

There are three main differences between the market design for the SWIS and the NEM:

- gross pool versus net pool
- capacity market arrangements
- ancillary services.

#### *Gross pool versus net pool*

The NEM is a gross pool in which the sale of all wholesale electricity must occur in a spot market. In contrast, energy trading in the SWIS market primarily occurs through bilateral contracts negotiated entirely outside the pool. These may be entered into years, weeks or days prior to supply. Before the trading day, generators must inform the IMO of the quantity of energy to be sold under bilateral contracts and to whom so the IMO can schedule that supply.

The STEM supports bilateral trades by allowing market participants to trade around their net contract positions a day before energy is delivered. If, for example, a generator does not have sufficient capacity to meet its contracted position, it can purchase energy in the

6 Information on the market can be found on the IMO website at www.imowa.com.au.

STEM. Participation in the STEM is optional. Each morning, market participants may submit bids to the IMO to purchase energy and/or offers to supply. The IMO will then run an auction, in which it takes a neutral position, and will determine a single price for each trading interval of the day.

In the lead-up to dispatch, the system operator (System Management, a ring-fenced entity within Western Power), will issue instructions to ensure that supply equals demand in real-time. Rather than being dispatched on a least-cost basis, dispatch will mainly reflect the contract positions of participants. Generators submit daily resource plans that inform the IMO of how their facilities will be used to meet their contract positions. Generators are obliged to follow these plans, unless superseded by dispatch instructions. Verve's facilities are scheduled around the resource plans of other generators. If it appears that supply will not equal demand, the operator will schedule Verve generation first, and then issue dispatch instructions to other market participants as necessary.

### *Capacity market arrangements*

The SWIS market includes both an energy market (the STEM) and a capacity market. The capacity market is intended to provide incentives for investment in generation to meet peak demand. In particular, it is intended that the capacity market will provide sufficient revenue for investment without the market experiencing high and volatile energy prices.

The IMO determines how much capacity is required to meet peak demand each year and allocates the costs of obtaining the necessary capacity to buyers—mostly retailers. Payments through the capacity market are expected to return about $10 to $15 a MW to generators every hour of the year, regardless of whether their energy is used in the market. This is expected to fund the capital costs of peaking facilities and partially cover the costs of base load units.

In the NEM there is no capacity market. Instead, generators are paid only for energy sent out, and a high price cap provides incentives to invest in generation and establish demand side responses. The provision of capacity payments means that wholesale energy prices in Western Australia will not need to rise as high as NEM prices to stimulate investment. Accordingly, the price cap in the energy market is $150 a MWh compared to the $10 000 a MWh cap in the NEM.[7]

The IMO determines annual reserve capacity requirements and will release an annual statement of opportunities report that covers a period of ten years. Western Australia's Economic Regulation Authority (ERA) approves the maximum capacity price and the price cap in the short-term market proposed by the IMO.

### *Ancillary services*

There are eight frequency control ancillary services spot markets in the NEM in which participants may bid to provide ancillary services. Network control ancillary services are procured through long-term contracts. In the SWIS, there are no spot markets for ancillary services. System Management determines ancillary services requirements and procures them from Western Power or participants that have an ancillary services contract with System Management.

## 7.1.5 Network access

In 2004, Western Australia implemented an Electricity Networks Access Code for access to transmission and distribution network services. At present, the code only covers Western Power's networks within the SWIS, but other networks may be covered in the future if they meet the access regime's coverage tests.

In July 2006 the Australian Government Parliamentary Secretary to the Treasurer, on the advice of the National Competition Council, decided that the Western Australian access code was an effective access regime under Part IIIA of the Trade Practices Act and certified it for a period of 15 years.

7 There is an alternative maximum energy price for a facility run on liquid fuel. This was set at $385 in June 2004 and is varied in accord with an adjustment formula related to the Singapore crude oil price.

The code is independently administered by the ERA and prescribes commercial arrangements including access charges that electricity generators and retailers must pay to use Western Power's networks. The regulatory framework sets out criteria for the regulator's acceptance or rejection of an access arrangement proposed by the service provider. An access arrangement must include:

- specification of one or more reference services
- a standard access contract
- service standard benchmarks
- price control and pricing methods
- a current price list
- an applications and queuing policy.[8]

The regulator released a decision in May 2007 on Western Power's access arrangement under the code. Western Power's access tariffs under the decision are available on the ERA website.

### 7.1.6 Retail arrangements

In January 2005, Western Australia extended retail contestability to customers using at least 50 MWh per annum. Customers below this threshold who are connected to the SWIS are serviced by Synergy, the state-owned energy retailer. Customers outside the SWIS are predominantly serviced by Horizon Power.

The Western Australian Government has indicated its intent to consider full retail contestability in electricity, but has not set an implementation date. The *Electricity Corporations Act 2005* requires the Minister for Energy to undertake a review in 2009 with the objective of further extending contestability.

Companies that currently offer retail electricity products in the SWIS, other than Synergy, include Alinta, Griffin Energy, Landfill Gas & Power, Perth Energy, Premier Power Sales, TransAlta Energy (Australia) and Worsley Alumina. The ERA website publishes a list of licensed retailers.

It is government policy that all Synergy and Horizon Power customers are entitled to a uniform tariff, irrespective of their geographic location. The government approves the tariff and implements the scheme through a combination of statutory requirements. Regional electricity tariffs are subsidised by the Tariff Equalisation Fund, which is administered by the Office of Energy and funded by SWIS network users.

In addition to the uniform tariff, Western Australia has other consumer protection measures, including:

- an independent Energy Ombudsman to provide a means for residential and small business customers to resolve disputes with network operators and electricity retailers
- a code of conduct for the supply of electricity to small-use customers that regulates the behaviour of network operators and retailers and specifies levels of service in marketing, disconnection, payment difficulties and financial hardship, information provision and the supply of prepayment meters
- regulations to ensure that residential and small business customers can be connected to a distribution network at the least cost to the customer if the customer is located within a specified distance to the network
- standard form contracts for small customers that specify price and other terms of supply by licensed retailers
- supplier of last resort arrangements
- an electricity licensing regime, which provides for the monitoring and enforcement of the various consumer initiatives
- retention of existing government energy concessions.

8 Section 5.1 of the Electricity Networks Access Code 2004.


Verve Energy

## 7.2 The Northern Territory

The Northern Territory's electricity industry is small, reflecting its population of around 200 000. There are three relatively small regulated systems, of which the largest is the Darwin–Katherine system with a capacity of around 340 MW. In 2005–06 the Territory consumed around 1660 GWh of electricity.

The Territory uses gas-fired plants to generate public electricity, using gas sourced from the Amadeus Basin in Central Australia. Given the scale of the market, it was not considered feasible to establish a wholesale electricity spot market. Rather, the Territory uses a 'bilateral contracting' system in which generators are responsible for dispatching into the system the power their customers require.

The industry is dominated by a government-owned corporation, Power and Water, which owns the transmission and distribution networks. Currently, it is the monopoly retail provider and generates all electricity sold in the retail market. Power and Water is also responsible for power system control. There are six independent power producers in the resource and processing sector that generate their own requirements. Some also generate electricity for the market under contract with Power and Water.

From around 2000, the government introduced measures to open the electricity market to competition. It:

- commenced a phased introduction of retail contestability, originally scheduled for completion by April 2005
- corporatised the vertically integrated electricity supplier (Power and Water) and ring-fenced its generation, power system control, network and retail activities
- allowed new suppliers to enter the market
- established an independent regulator, the Utilities Commission, to regulate monopoly services and monitor the market
- introduced a regulated access regime for transmission and distribution services. In 2002, the Australian Government certified the regime as effective under the Trade Practices Act. The Northern Territory Government amended the regime in 2003 to clarify pricing issues, but it has not responded to a review of non-price issues. The Utilities Commission made its second five-year determination on network access arrangements (for 2004–05 to 2008–09) in 2004.

There has been one new entrant in generation and retail since the reforms—NT Power, which acquired some market share. However, NT Power withdrew from the market in September 2002 citing its inability to source ongoing gas supplies for electricity generation. In light of this, the government suspended the contestability timetable in January 2003. This effectively halted contestability at the 750 MW per year threshold until prospects for competition re-emerge. A single subsequent applicant was not granted an electricity retail licence due to their 'inability to meet reasonably foreseeable obligations for the sale of electricity'.[9] The introduction of full retail contestability is currently scheduled for April 2010.

With Power and Water reverting to a retail monopoly, the government approved in principle a process of prices oversight of Power and Water's generation business by the Utilities Commission for as long as that business is not subject to competition or the tangible threat of competition. The government regulates tariffs for non-contestable customers via electricity pricing orders. The Utilities Commission regulates service standards, including standards for reliability and customer service.

9 Department of Business, Economic and Regional Development (NT Government), *The NT electricity, water and gas supply sector*, fact sheet, 2005, http://www.nt.gov.au/business/documents/general/ELECTRICITY_SNAPSHOT.pdf.

# PART THREE
# NATURAL GAS


Natural gas is predominately made up of methane, a colourless and odourless gas. There are two main types of natural gas used in Australia—conventional natural gas and coal seam methane, alternatively termed coal seam gas. Conventional natural gas is found in underground reservoirs trapped in rock, often in association with oil. It may occur in onshore or offshore reservoirs. Coal seam methane is produced during the creation of coal from peat. The methane is adsorbed onto the surface of micropores in the coal. There are also a range of alternative renewable sources of methane, including biogas (landfill and sewage gas) and biomass, which includes wood, wood waste and sugarcane residue (bagasse). These renewable sources of gas comprise about 16 per cent of Australia's primary gas use.

# NATURAL GAS

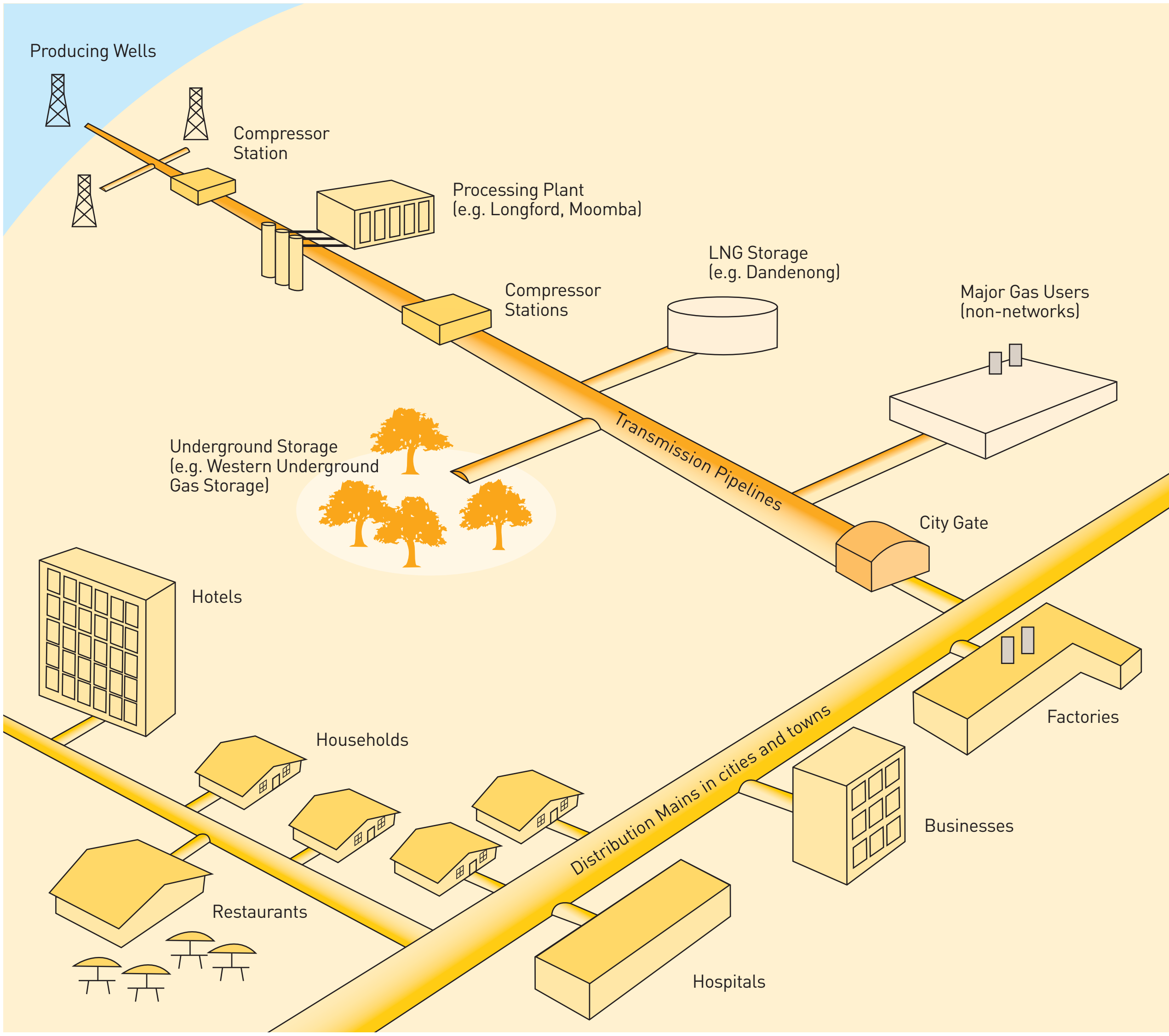
The supply chain for natural gas begins with exploration and development activity, which often involves geological surveying and the drilling of wells to find and verify the recoverable resource. At the commercialisation phase the extracted gas often requires processing to separate the methane from liquids and gases that may be present, and to remove any impurities, such as water and hydrogen sulphide.

The gas extracted from a well can be used on site as a fuel for electricity generation or other purposes. More commonly, however, gas fields and processing facilities are located some distance from the cities, towns and regional centres where the gas is consumed. High pressure *transmission* pipelines are used to transport natural gas from source over long distances. A network of *distribution* pipelines are then used to deliver gas from points along the transmission pipelines to industrial customers and from gate stations (or city gates) for the reticulation of gas in cities, towns and regional communities. The gate stations measure the natural gas leaving a transmission system for billing and gas balancing purposes and are used to reduce the pressure of the gas before it enters the distribution network.

Often retailers act as intermediaries in the supply chain. They enter into contracts for wholesale gas, transmission and distribution services and 'package' the services together for on-sale to industrial, commercial and residential consumers.

Unlike electricity, natural gas can be stored, usually in depleted gas reservoirs, or it can be converted to a liquefied form for storage in purpose-built facilities. Liquefied natural gas (LNG) is transported by ship to export markets. It is also possible to transport LNG by road or pipeline.

Part 3 of this report provides a chapter-by-chapter survey of each link in the supply chain. Chapter 8 considers gas exploration, production, wholesaling and trade. The focus is on natural gas sold for the domestic market. Chapters 9 and 10 provide data on the gas transmission and distribution sectors, while chapter 11 considers gas retailing.




Source: based on Australian Gas Association 2003 (as appearing in Productivity Commission, *Review of the gas access regime*, inquiry report no. 31, June 2004, p. 6).

# 8 GAS EXPLORATION, PRODUCTION, WHOLESALING AND TRADE

Moomba petroleum and natural gas plant, Cooper Basin. Brendan Esposito (Fairfax Images)

Natural gas producers search for, develop, extract and process gas to a standard suitable for industrial and residential purposes.

# 8 GAS EXPLORATION, PRODUCTION, WHOLESALING AND TRADE

This chapter considers:

- the role and significance of the gas exploration and production sector
- exploration and development in Australia
- gas production and consumption and the future outlook for growth
- gas prices
- the structure of the sector, including industry participants and ownership changes
- gas wholesale operations and trade
- market developments.

## 8.1 The role and significance of the gas exploration and production sector

Natural gas is predominately made up of methane, a colourless and odourless gas denoted by the chemical symbol $CH_4$. It usually occurs in combination with other hydrocarbons, in liquid or gaseous form. It is found in underground reservoirs trapped in rock, often in association with oil—conventional natural gas. Methane extracted from coal seams—coal seam gas (CSG) or coal seam methane (CSM)—is also found in Australia in sufficiently large quantities to be a viable alternative to conventional gas supplies. There are also alternative renewable gas sources including biogas (landfill and sewage gas) and biomass, which includes wood, wood waste and sugar cane residue (bagasse). The Australian Bureau of Agricultural Resource Economics (ABARE) projection data suggests that renewable energy comprises only about 5 per cent of the primary energy mix in Australia and is predominantly biomass (68 per cent). Biomass and biogas make up about 16 per cent of primary gas consumption in Australia.[1]

**Exploration** for conventional gas and CSM occurs in conjunction with the search for other hydrocarbon deposits beneath the earth's surface. Explorers use sophisticated survey techniques—such as aeromagnetic, airborne gravity and seismic—and drilling to detect and determine the extent of hydrocarbon deposits.

Conventional natural gas can occur in isolation or contain natural gas liquids (ethane, propane, butane or condensate) or be associated with oil. 'Associated gas' can be separate from oil (free gas) or dissolved in the crude oil (dissolved gas). In addition, raw natural gas may contain impurities such as water, hydrogen sulphide, carbon dioxide, helium, nitrogen and other compounds.

During gas **production** (extraction and processing) discovered gas and other oils and liquids are extracted and separated and impurities removed; and then the raw gas is processed to a standard suitable for sale. Gas production includes underground gas storage (which is the injection and recovery of gas usually in a depleted gas field), construction of pipelines for the transport of raw gas to a processing plant and the processing facilities.

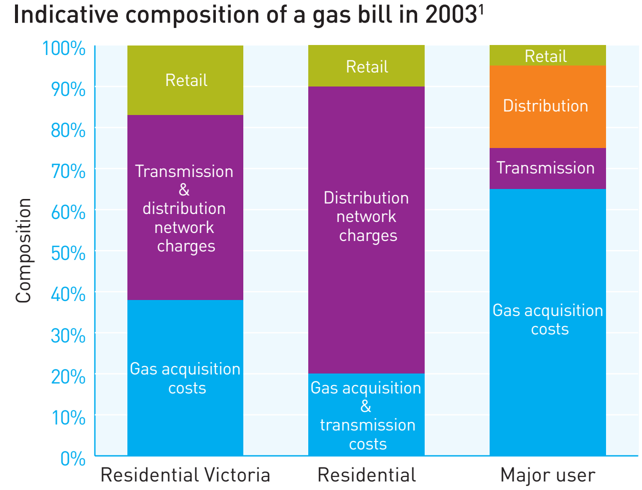
Permits are required to explore for and produce gas and other petroleum products in Australia.

Natural gas exploration and production is the first link in the natural gas supply chain and a significant contributor to the Australian economy. Production of natural gas for the domestic market was worth around $2500 million in 2004–05. Exports of liquefied natural gas (LNG) were valued at around $3700 million in the same year.[2]

The cost of gas typically accounts for the bulk of the cost of a gas supply service for major users, such as electricity generators and metals manufacturers. In contrast, the cost of gas usually accounts for a relatively small share of a residential gas bill, while transport charges typically make up the bulk of the cost of a gas supply service (figure 8.1). Location affects the cost of gas supply with consumers located close to the source of supply, such as Victorians, facing a lower transport cost component.

**Figure 8.1**

**Indicative composition of a gas bill in 2003[1]**

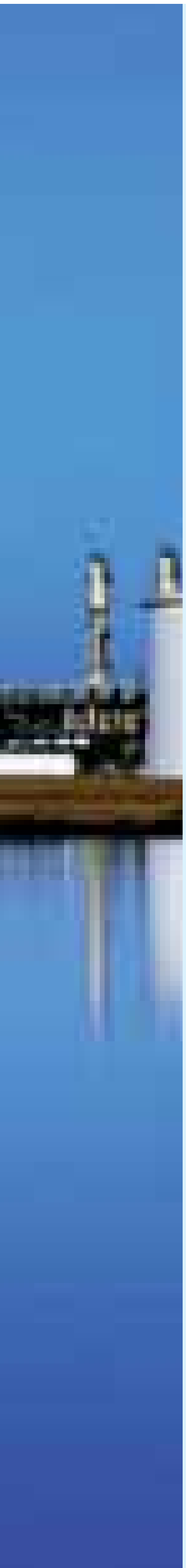



1. 'Residential' is based on Envestra data supplied to the Productivity Commission.

Source: KPMG, *The effectiveness of competition and retail energy price regulation*, 2003; Charles River and Associates, *Electricity and gas standing offers and deemed contracts 2004–2007*, December 2003; Australian Gas Association and Envestra, as published in Productivity Commission, *Review of the gas access regime*, Inquiry report no. 31, 2004, pp. 37 and 46.

1 Based on projections for 2005-06 from C Cuevas-Cubria and D Riwoe, *Australian energy: national and state projections to 2029-30*, ABARE Research Report 06.26, Prepared for the Australian Government Department of Industry, Tourism and Resources, Canberra, 2006, table A2, p. 53.

2 ABS, *Mining operations, Australia*, companion data, cat. no. 8415.0, Canberra, October 2006.



## Box 8.1 Reserves and resources definitions

Reserves: the quantities of gas anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves are categorised by the level of certainty associated with the estimates.

**Proved (1P):** The volumes of gas reserves that analysis of geological and engineering data suggests are recoverable to a high degree of certainty (90 per cent confidence). Reserves may be developed or undeveloped.

**Probable:** The volumes of gas reserves that analysis of geological and engineering data suggests are more likely than not to be recoverable under current economic and operating conditions. There is at least a 50 per cent probability that the quantities actually recovered will exceed the sum of estimated proved plus probable reserves (2P). In the Australian context booking of gas reserves as 2P usually requires gas contracts and development approval to be in place.

**Possible:** The volumes of gas reserves recoverable to a low degree of certainty. There is at least a 10 per cent probability that the quantities actually recovered will exceed the sum of estimated proved plus probable plus possible reserves (3P).

**Resources:** refers to the remaining quantities of gas estimated to be in-place.

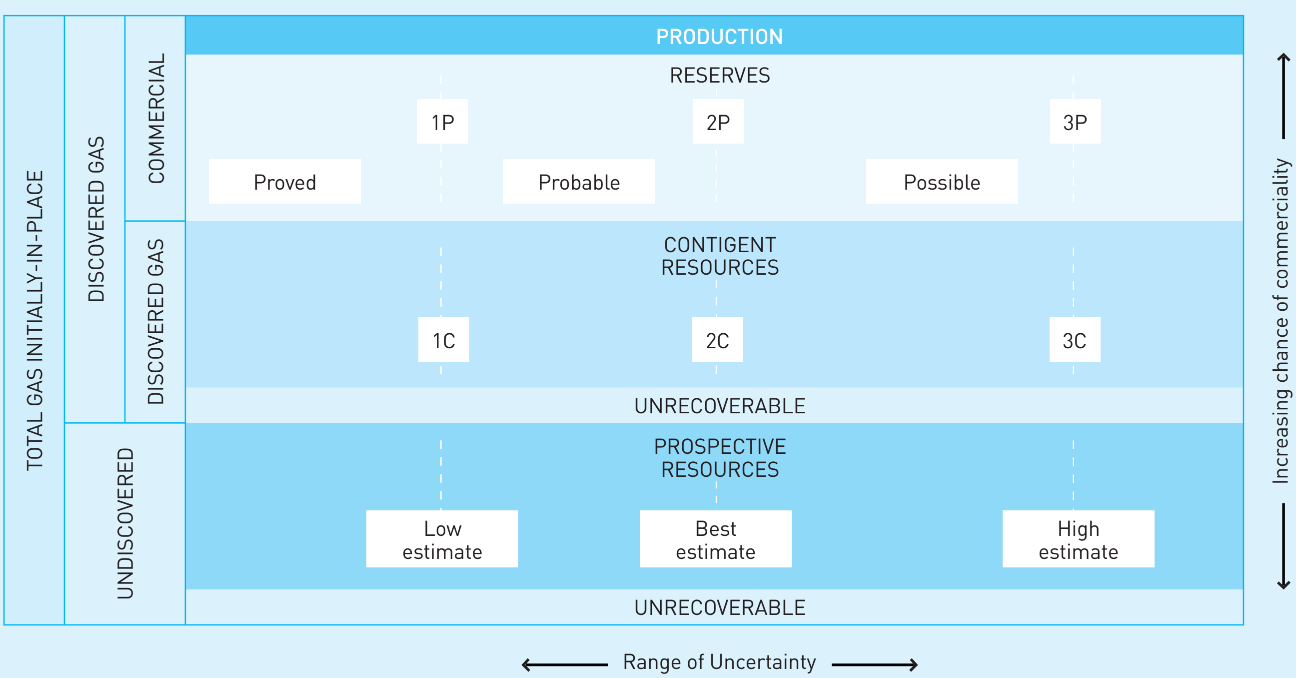
**Contingent resources:** are estimated to be potentially recoverable from accumulations that are known but not currently considered to be technically mature or commercially viable.

**Prospective resources:** The quantity of gas estimated at a given date to be potentially recoverable from undiscovered accumulations by application of future development projects.

**Unrecoverable:** is that portion of discovered or undiscovered gas potentially in-place that is estimated at a given date not to be recoverable.

**Figure 8.2**

**Gas reserves and resources classification framework**




Source: EnergyQuest, *Energy quarterly production report*, February and May 2007; Society of Petroleum Engineers 2007, Petroleum resources management system 2007, viewed 24 May 2007<http://www.spe.org>.

Table 8.1 Natural gas reserves and production in Australia

| GAS BASIN | CONTINGENT RESOURCE[1] | | PROVED & PROBABLE RESERVES (2P)[1] | | PRODUCTION IN 2006[2] | |
|---|---|---|---|---|---|---|
| | PJ | % | PJ | % | PJ | % |
| Amadeus | 0 | – | 218 | 0.5 | 20.6 | 2.3 |
| Bonaparte | 19 500 | 19.9 | 1 687 | 4.2 | – | – |
| Browse | 30 000 | 30.7 | – | – | – | – |
| Carnarvon | 44 030 | 45.0 | 24 313 | 60.0 | 305.2 | 33.6 |
| Perth | 0 | – | 37 | 0.1 | 10.6 | 1.2 |
| Total West/North | 93 530 | 95.6 | 26 255 | 64.8 | 336.4 | 37.0 |
| Cooper–Eromanga | 0 | – | 1 225 | 3.0 | 170.7 | 18.8 |
| Gippsland | 3 670 | 3.8 | 5 377 | 13.3 | 243.5 | 26.8 |
| Otway | 250 | 0.3 | 1 568 | 3.9 | 70.1 | 7.7 |
| Bass | 350 | 0.4 | 315 | 0.8 | 7.6 | 0.8 |
| Bowen–Surat | na | na | 312 | 0.8 | 22.4 | 2.5 |
| Gunnedah | na | na | na | na | 1.0 | 0.1 |
| Total East/South | 4 270 | 4.4 | 8 797 | 21.7 | 514.3 | 54.1 |
| Conventional supplies | 97 800 | 100.0 | 35 052 | 86.6 | 828.1 | 91.2 |
| Bowen–Surat | 4 500 | na | 5 337 | 13.2 | 70.3 | 7.7 |
| Sydney | na | na | 102 | 0.3 | 9.9 | 1.1 |
| Coal seam methane | na | na | 5 439 | 13.4 | 80.2 | 8.8 |
| Domestic production | | | | | 908.3 | 100.0 |
| Exports (LNG) | | | | | 657.8 | |
| Total | 102 300 | | 40 491 | 100 | 1566.1 | |

na not available. 1. As at 31 December 2005. See box 8.1 for details on the classification of reserves. 2. Production in the 2006 calendar year.

Source: EnergyQuest, *Energy quarterly production report*, February and May 2007.

## 8.2 Australia's natural gas reserves

Australia has abundant natural gas reserves. Current estimates indicate that there are around 35 000 petajoules[3] of conventional supplies of proved and probable (2P) reserves (box 8.1), with contingent resources estimated to be around 97 800 (table 8.1). Total proved and probable natural gas reserves, those reserves with reasonable prospects for commercialisation, stand at around 40 500 petajoules (table 8.1). This includes around 5500 petajoules of CSM. Given the relatively early stage of development of the sector and the size of Australia's coal resources, CSM resources are potentially large, well above conventional resources in south and eastern Australia—the area in which CSM is currently produced. For example, from December 2005 to December 2006 estimated proved and probable reserves of CSM have increased from around 3300 petajoules to 5500 petajoules—an increase of 62 per cent.[4]

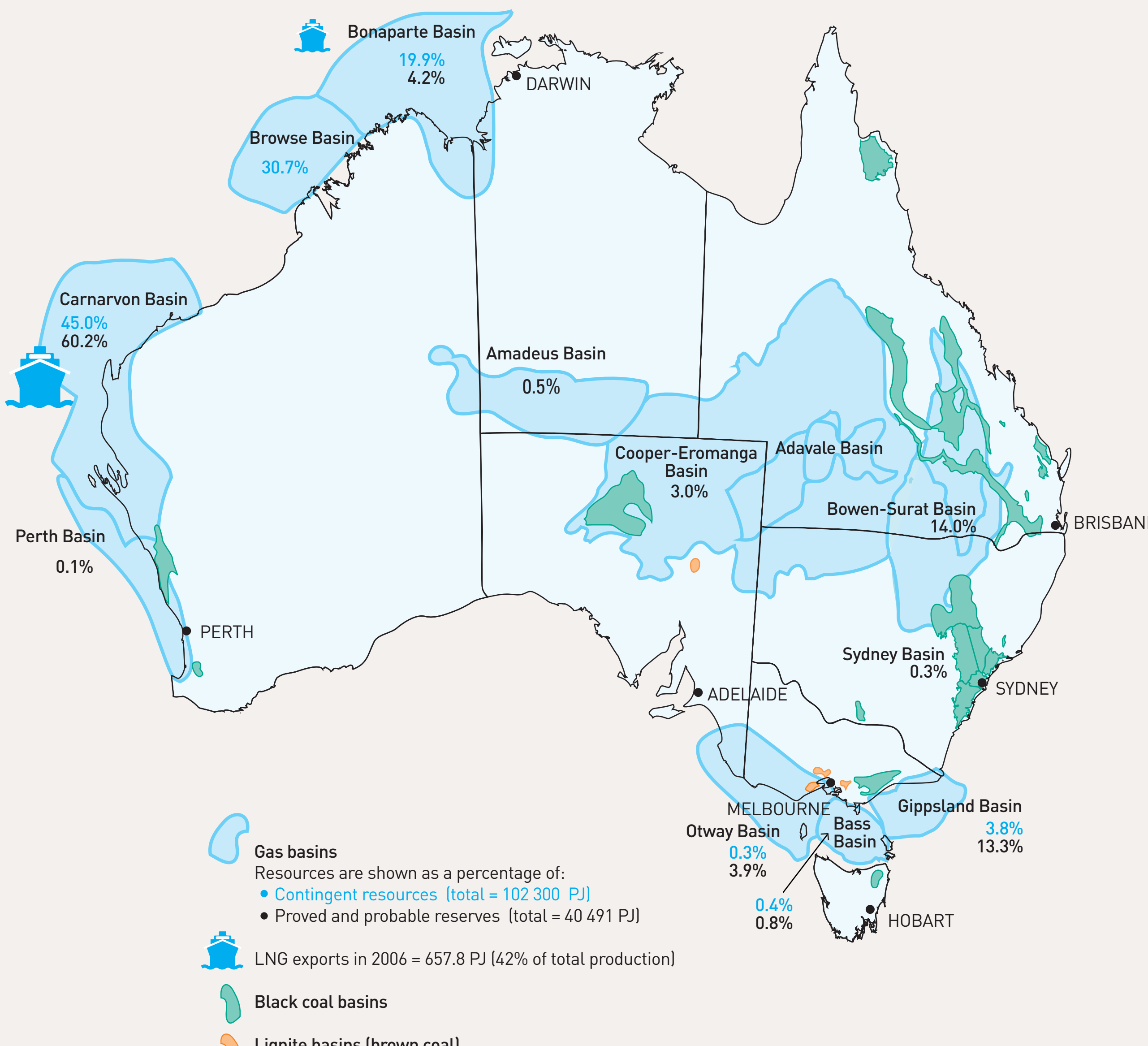
At current rates of consumption and production Australia has sufficient proved and probable reserves to meet domestic and export demand for about 26 years.[5] Exploration for natural gas is a comparatively recent development, which largely began in the 1960s. The development of CSM is even more recent, occurring only within the past decade. It is likely that further exploration will lead to additional discoveries and verification of reserves.

3 A petajoule is $10^{15}$ joules. A joule is a unit of energy, which is sufficient to produce one watt of power continuously for one second. One joule is approximately the energy required to heat one gram of dry, cool air by 1°C. To raise the temperature by 1°C of an average room (3m × 3m, 2.5m high) would take 23 700 joules.

4 EnergyQuest, *Energy quarterly production report*, February and May 2007.

5 The Ministerial Council on Energy and Ministerial Council on Mineral and Petroleum Resources have established a joint working group on natural gas supply. The group is to report in 2007 and, among other things, must consider domestic gas supply and demand, prices, long-term energy security and the need for a national gas plan.

Figure 8.3
Australia's natural gas reserves




1 Locations are indicative only.

Source: K Donaldson, *Energy in Australia 2006*, ABARE report, Prepared for the Australian Government Department of Industry, Tourism and Resources, Canberra, 2007; EnergyQuest, *Energy quarterly production report*, February and May 2007.

Figure 8.3 shows the location of Australia's major natural gas reserves. The most significant reserves of proved and probable gas supplies are in Western Australia. The Carnarvon Basin off the north-west of Australia holds about 60 per cent of Australia's known conventional natural gas reserves and currently accounts for about 34 per cent of gas produced for the domestic market (table 8.1). Gas produced from the basin meets over 95 per cent of Western Australia's gas demand. The state's remaining gas needs are supplied from the smaller and more mature gas-producing region of the Perth Basin, located to the south of the Carnarvon Basin. Gas from the Perth Basin is mainly transported on the Parmelia Pipeline.

The North West Shelf joint venture converts some gas produced from the Carnarvon Basin to LNG gas for export. In 2005–06 around 646 petajoules of gas produced from the basin were exported as LNG. Australia is the world's fifth largest LNG exporter, after Indonesia, Malaysia, Qatar and Algeria. According to EnergyQuest, Woodside expects LNG demand to double over the next ten years while forecast supply has been lowered.

The Bonaparte–Timor Sea Basin along the north-west coast of Australia is estimated to contain a contingent resource of about 19 500 petajoules. The basin is estimated to contain about 4 464 petajoules of 2P gas reserves. Australia's share of this reserve is 1 687 petajoules with the rest belonging to Timor Leste. Bayu-Undan (located in the Australia-Timor Leste Joint Development Area) is the only area in the basin producing gas at this time. Development of the basin centres on LNG production for export. The first shipment of LNG was in February 2006 and overall production for the year to December 2006 was around 123 petajoules (including Australia's share of about 12.3 petajoules, with the rest attributable to Timor Leste). The Blacktip field is being developed to supply domestic gas to the Northern Territory with the first gas expected to flow from January 2009.

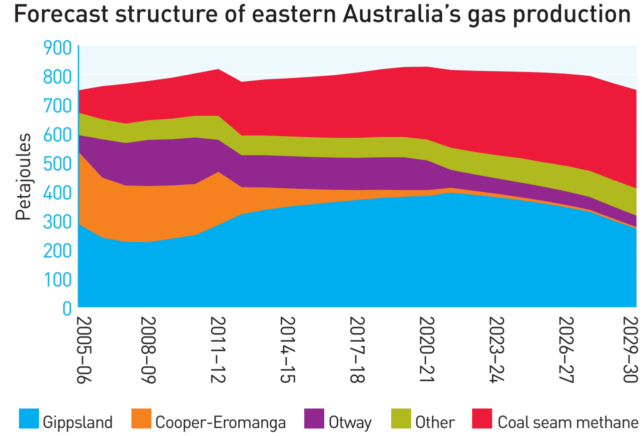
To the south-west of the Bonaparte Basin lies the Browse Basin. It contains significant natural gas resources. These are currently subject to development studies for LNG.

A small reserve of 218 petajoules of gas remains in the Amadeus Basin in central Australia. The basin is currently producing around 20 petajoules of gas a year, which is sufficient to meet all current demand for gas in the Northern Territory. The basin is in decline, however, so that gas for electricity production will soon be supplemented by supplies from the Blacktip field.

The most significant reserves of gas in the south-east of Australia are found in the Gippsland Basin off the Victorian south coast. The basin accounts for around 13.3 per cent of Australian reserves. In 2006 around 243 petajoules of gas (about 27 per cent of total domestic production) were produced from the Gippsland Basin. Some of this gas was exported to New South Wales. The remaining gas is enough to meet more than 90 per cent of Victoria's gas needs. There are also significant reserves of gas in the Bass and Otway basins to the east of the Gippsland Basin.

The Cooper–Eromanga Basin in the north-east of South Australia and south-west Queensland is a mature gas producing region. It has an estimated 1225 petajoules of commercial reserves remaining. At current rates of production of around 158 petajoules of gas a year this is enough to last about nine years. About 14.4 per cent less gas was produced in 2006 than in 2005, and production is expected to decline more rapidly after about 2011–12 (figure 8.4). However, the basin is still being actively explored so new discoveries of gas may extend the life of the basin.

**Figure 8.4**
**Forecast structure of eastern Australia's gas production**




Source: C Cuevas-Cubria and D Riwoe, *Australian energy: national and state projections to 2029-30*, ABARE research report 06.26, Prepared for the Australian Government Department of Industry, Tourism and Resources, Canberra, 2006.

The Bowen–Surat Basin, which extends from northern New South Wales to northern Queensland, is also a relatively mature gas-producing area. It has conventional reserves of about 312 petajoules suitable for commercial production. This is enough for about 14 years at current rates of production. The basin also contains significant quantities of CSM. Reported figures suggest that there are about 152 000 petajoules of gas-in-place, although only about 5500 petajoules are booked as proved and probable (2P) reserves.[6] This provides enough gas to supply all of Queensland's gas requirements for at least 20 years. Current production of CSM from the basin is about 70 petajoules a year, more than three times the level of conventional gas supplies from the basin. CSM from the basin provides over 50 per cent of Queensland's current gas requirements. Wood Mackenzie predicts that in 2007, CSM production will increase by more than one-third to 98 petajoules or 79 per cent of final gas demand in Queensland.[7]

CSM is also found in the Sydney Basin. The gas-in-place in New South Wales is estimated at around 97 000 petajoules, although there is considerable uncertainty about how much of this can be developed.[8] Commercial production within the Sydney Basin began in 1996 at Appin and since 2001 there has been a small quantity of CSM produced close to the Sydney market. CSM currently supplies only around 8 per cent of gas demand in New South Wales. A number of companies are actively engaged in attempts to increase production.

Conventional gas and CSM are found in the Gunnedah Basin in northern New South Wales. Eastern Star is developing this area. The company also has conventional gas and CSM exploration rights in the Clarence Moreton Basin of New South Wales.

There is potential for further development of CSM in other regions where black coal is present, including Tasmania.

Currently CSM production occurs in Queensland and New South Wales only. Nevertheless, CSM is currently the fastest growing sector of gas production. Production has grown nearly three-fold since 2004, mainly as a result of increased production in the Bowen–Surat Basin in Queensland (figure 8.5). ABARE expects CSM production to continue to grow at a rapid rate. It forecasts that annual production will reach to over 300 petajoules by 2029–30 and become the main source of gas supply in eastern Australia (figure 8.4).

CSM provides a highly competitive alternative for conventional natural gas. It also provides opportunities for significant cost savings by delaying the need for investment in infrastructure to ship gas from more distant sources such as PNG or the Timor Sea.

Nevertheless, ABARE currently forecasts that strong demand, in part driven by greenhouse initiatives[9], and dwindling supplies from the Cooper–Eromanga Basin mean that from as early as about 2012–13 there may be an opportunity for supplies from outside the region to enter the eastern Australian market.[10]

ABARE forecasts are, however, likely to be conservative. While ABARE figures suggest that by 2020 CSM will account for about 40 per cent of eastern Australia's gas demand, Wood Mackenzie expects the fuel to account for about half of that demand.[11] There is likely to be substantial growth in gas production from offshore Victoria and stronger growth in CSM production than currently predicted could delay the need to import gas from outside the region.

6 Based on RM Davidson, LL Sloss, and LB Clarke, *Coalbed methane extraction*, IEA coal research, London, 1995, as reported in A Dickson and K Noble, 'Eastern Australia's gas supply and demand balance', *APPEA Journal* 2003, 143.

7 S Wisenthal, 'Coal seam to supply 80pc of Qld's gas', *The Australian Financial Review*, 5 March 2007, p. 16.

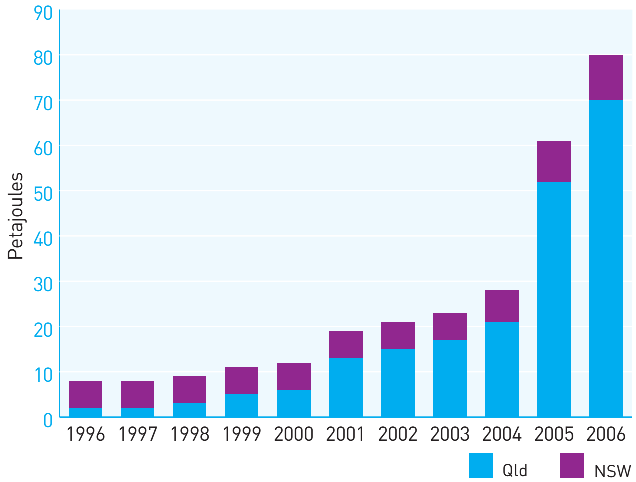
8 Based on K Brown, DA Casey, RA Enever, and K Wright, *New South Wales coal seam methane potential*, Geological survey of New South Wales coal and petroleum geology, New South Wales Department of Mineral Resources, Sydney, 1996, as reported in A Dickson, and K Noble, 'Eastern Australia's gas supply and demand balance', *APPEA Journal* 2003, 143.

9 See appendix B for detail on initiatives targeted at reducing greenhouse gas emissions.

10 C Cuevas-Cubria, and D Riwoe, *Australian energy: national and state projections to 2029-30*, ABARE Research Report 06.26, prepared for the Australian Government Department of Industry, Tourism and Resources, Canberra, December 2006.

11 see footnote 7.

Figure 8.5
Coal seam methane production 1996–2006




Source: Data supplied by EnergyQuest.

## 8.3 Exploration and development in Australia

In Australia, the Crown owns petroleum resources. The states and territories have the statutory rights to onshore resources and resources in coastal waters while the Australian Government controls the resources in offshore waters. The governments coordinate activities through the Ministerial Council on Mineral and Petroleum Resources.

### Exploration rights

Governments release acreage each year for exploration and development. The rights to explore, develop and produce gas and other petroleum products in a specified area or 'tenement' are documented in a lease or licence (also referred to as a 'title' or 'permit'). Australian governments have a suite of exploration titles, each designed for a particular purpose and each with a standard range of qualifying criteria and operating conditions. The three most common licences are:

- an **exploration licence**, which provides a right to explore for petroleum and to carry on such operations and execute such works as are necessary for that purpose, in the permit area
- an assessment or **retention licence**, which provides a right to conduct geological, geophysical and geochemical programs and other operations and works, including appraisal drilling, as are reasonably necessary to evaluate the development potential of the petroleum believed to be present in the permit area
- a **production licence**, which provides a right to recover petroleum, to explore for petroleum and to carry on such operations and execute such works as are necessary for those purposes, in the permit area.

Petroleum tenements are usually allocated through a work program bidding process, which operates somewhat like a competitive tendering process. Under this approach anyone may apply for a right to explore, develop or produce in a tenement based on offers to perform specified work programs. The minister chooses the successful applicant by assessing the merits of the work program, the applicant's financial and technical ability to carry out the proposed work program and any other criteria relevant to a tender.

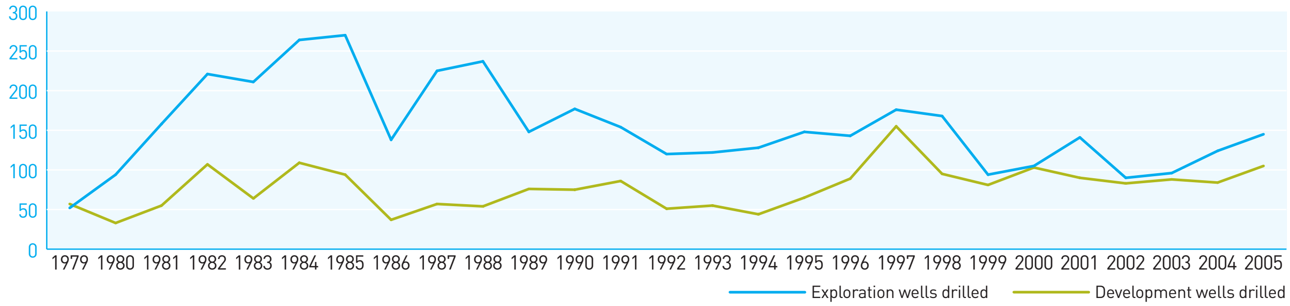
While the approach to issuing licences is relatively consistent across states and territories there are significant differences across jurisdictions in licence tenure and conditions.

Offshore projects are located outside the three nautical mile boundary and fall within the Australian Government's jurisdiction. The Australian Government applies the petroleum resource rent tax to petroleum projects in its jurisdiction.[12] Onshore projects fall within state and territory jurisdiction and are subject to the excise and royalty regime. Tasmania applies a royalty of 11–12½ per cent of the value of the petroleum at the well-head. Western Australia applies a royalty of 5–12½ per cent. The other states and the Northern Territory apply a royalty of 10 per cent.

12 The North West Shelf exploration permits WA-P-1 and WA-P-28 are excluded from the tax. These projects are subject to the excise and royalty regime. The Australian Government shares the royalty with Western Australia.

Figure 8.6

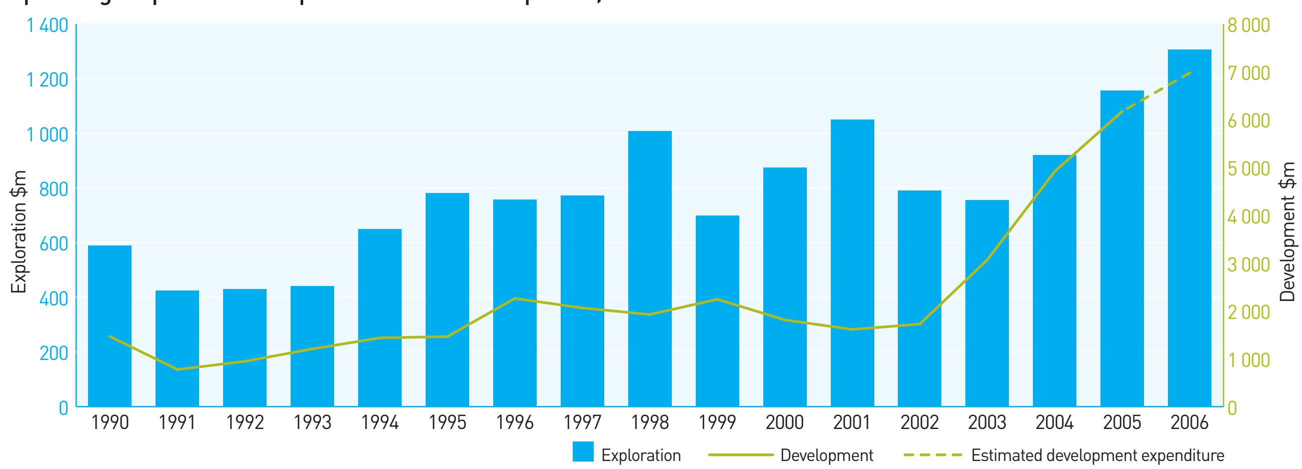
Petroleum exploration and development wells drilled, 1979–2005




Source: Geoscience Australia, *Oil and gas resources of Australia 2004*, Canberra, 2006.

Figure 8.7

Spending on petroleum exploration and development, 1990–2006[1,2]




1. Exploration, development and production expenditure (nominal prices) incurred in the Joint Petroleum Development Area is included in the above figures.
2. Development expenditure in 2005 and 2006 is assumed to increase at the same rate as exploration expenditure.

Sources: Geoscience Australia, *Oil and gas resources of Australia 2004*, Canberra, 2006; ABS, *Mineral and petroleum exploration, Australia*, September 2006, Cat. no. 8412.0; AER estimates.

In addition to royalties the Western Australian Government seeks to impose a domestic gas reservation requirement on export gas (LNG) projects. The domestic reserve is determined through negotiation between the Western Australian Government and LNG project proponents. The government's policy aim is to ensure that sufficient supplies of gas are available to underpin Western Australia's long term energy security and economic development. Based on gas reserves and forecast LNG production the government currently estimates that the equivalent of 15 per cent of LNG production is required to meet the state's future domestic gas needs.

## Exploration and development activity

Petroleum exploration activity tends to vary considerably. Exploration activity is primarily driven by prices, but is also affected by a range of other factors, including access to acreage, equipment costs, perceptions of risks and rewards and availability of finance.

Figure 8.6 shows Australian petroleum drilling activity from 1979 to 2005. Exploration drilling activity grew rapidly from 1979 through to the mid-1980s with an average of almost 600 wells drilled a year. From the mid-1980s exploration activity started to decline. There has been some recovery from the early 1990s,

Table 8.2 Development of Australian gas basins

| GAS BASIN | GAS EXPLORATION BEGAN | GAS FIRST DISCOVERED | GAS PRODUCTION BEGAN |
|---|---|---|---|
| Amadeus | 1964 | 1964 | 1983 |
| Bonaparte Gulf | 1969 | 1999 | Scheduled from 2009 |
| Timor Sea | 1969 | 1981–82 | 2006 |
| Carnarvon | 1953 | 1971 | 1984 |
| Perth | 1964 | 1966 | 1971 |
| Cooper–Eromanga | 1959 | 1963 | 1969 |
| Gippsland | 1964 | 1965 | 1970 |
| Bass | 1965 | 1966–73 | 2006 |
| Otway | 1892 | 1980 | 1987 |
| Bowen–Surat | 1900 | 1900 | 1961 |
| Sydney, Gunnedah, Clarence–Moreton | 1910 | 1980s | 1996 |

Source: Department of Primary Industries (Vic), *History of petroleum exploration in Victoria*, <http://www.dpi.vic.gov.au>; viewed: 19 October 2006; GPInfo, *Petroleum permits of Australasia*, Encom Petroleum Information Pty, Ltd, North Sydney 2006; Industry Commission, *Study into the Australian gas industry*, Report, Canberra, 1995.

in part in response to reduced regulation and reform in the east coast gas market, and again more recently in response to higher world oil and gas prices. The overall decline in the number of exploration wells drilled in part reflects technological improvements, such as 3D seismic technology, which reduces the need for drilling. The number of development wells drilled has shown a slight upward trend over the same period.

There is currently high demand for petroleum acreage and significant exploration and activity throughout Australia due to the high world price of oil, continuing demand for gas and higher LNG prices.

Figure 8.7 shows spending on petroleum exploration and development activity from 1990 to 2006. Spending on exploration activities more than doubled from $589 million in 1990 to $1307 million in 2006. Over the same time development expenditure grew from $1467 million to an estimated $6979 million with much of the growth occurring after 2002. Over the period 1990 to 2001 development expenditure grew by an average of about 1 per cent a year. Between 2002 and 2006 expenditure increased four-fold growing at an average annual rate of about 42 per cent a year. The recent increase in spending reflects the start of several major projects and the rapid growth in the cost of offshore development projects. High demand for equipment has significantly increased the cost of offshore exploration and development. For example, in the past couple of years drilling rig costs have doubled (from about $200 000 to $400 000 a day) as activity has increased in response to the surge in world oil prices.[13]

The increase in costs appears to be having an impact on Western Australia with gas producers no longer offering long term contracts because of uncertainty about future gas field development costs, future prices and the impact of the government's domestic gas reserve policy.[14]

Table 8.2 sets out the chronology of the development of gas basins in Australia. Demand for gas, prices, and infrastructure costs can affect the rate at which a gas basin or field is developed. Offshore the Northern Territory and in the Carnarvon Basin in Western Australia there has been a considerable lag between gas discovery and production. Establishment of a domestic market for the Carnarvon gas has required substantial investment in pipeline infrastructure. The two major pipelines in Western Australia—the Dampier to Bunbury and Goldfields Gas pipelines represent investment of around $3.5 billion in historic terms.

13 Geoscience Australia, *Oil and gas resources of Australia 2004*, Canberra, 2006.
14 ERA, *Gas issues in Western Australia,* Discussion paper, Perth, 2007.

### Coal seam methane

In production, CSM is a close substitute for conventional natural gas. Exploration, development and production of CSM is occurring in New South Wales and Queensland black coal deposits and may become prospective in other black coal regions in Australia. The recent commercial development of CSM stems from Queensland Government energy and greenhouse policies but also reflects improved extraction technology and increased demand for gas with associated higher gas prices.

The profitability of a CSM project is affected by several factors including well flow rates and spacing, drilling and development costs, water disposal costs and access to land and markets. In particular, wells need to be able to produce gas at a rate that is able to supply gas contracts. This means that the coal seams need to have either high gas content with reasonable permeability or low gas content with high permeability. Many wells are usually required for a CSM project, which adds to drilling costs. Water produced during extraction of CSM is often very saline so that the disposal of water is becoming a significant issue. Another disadvantage of CSM is that production rates cannot be varied.

Queensland and New South Wales CSM projects have some commercial advantages over conventional natural gas. The gas is found closer to the surface and under lower pressure than conventional natural gas. It usually has a relatively high concentration of methane, lower levels of impurities and is closer to markets than conventional natural gas. These features reduce exploration and production costs and other risks. It also allows for a more incremental investment in production and transport than bringing a major new conventional natural gas development on stream.

In New South Wales most of the current exploration and production activity relates to CSM. In Queensland around 70 per cent of the production permits issued since 2004 relate to CSM. In addition, in 2005–06, a total of 216 wells were drilled in Queensland to explore for, develop and appraise CSM. By comparison 33 wells were drilled in search of conventional natural gas.

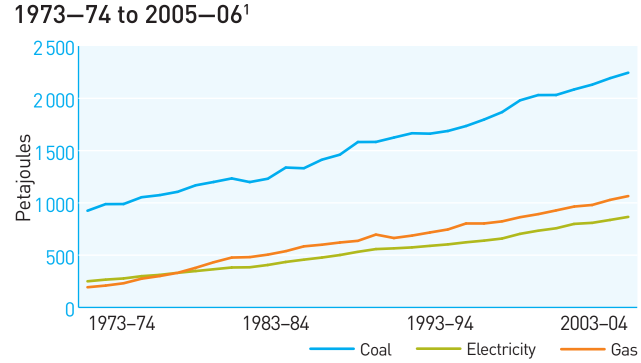
## 8.4 Gas production and consumption

Natural gas is a versatile source of energy, which has a range of industrial, commercial and domestic applications, including electricity generation (mainly for fuelling intermediate and peaking generators) and as an input for manufacturing pulp and paper, metals, chemicals, stone, clay, glass, and certain processed foods. In particular, natural gas is a major feedstock in ammonia production. It is also used to treat waste materials, for incineration, drying, dehumidification, heating and cooling, and cogeneration. In the transport sector, natural gas in a compressed or liquefied form is used to power vehicles. In a commercial and residential setting natural gas is used for space conditioning and refrigeration, heating and cooking.

Natural gas also has the advantage that it burns cleaner than other fossil fuels, such as oil and coal, and produces fewer greenhouse gas emissions per unit of energy released. For an equivalent amount of heat, burning natural gas produces about 45 per cent less carbon dioxide than burning black coal.

**Figure 8.8**

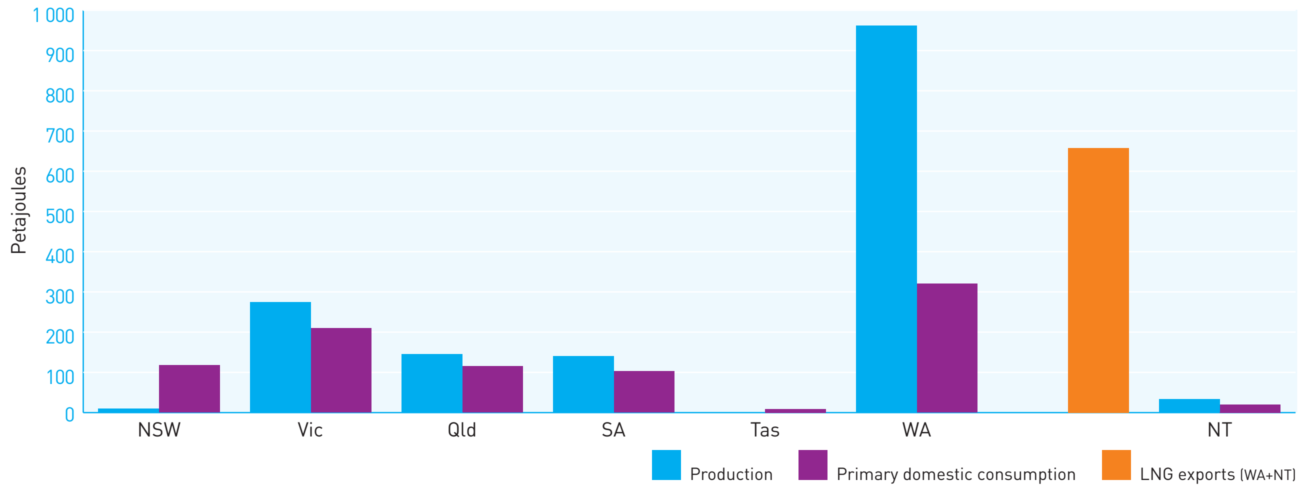
**Australian gas, coal and electricity consumption, 1973—74 to 2005—06[1]**




1. Data for 2005–06 based on ABARE projections.

Sources: ABARE, 'Energy Statistics – Australia', Table F, <www.abareconomics.com>; C Cuevas-Cubria and D Riwoe, *Australian energy: national and state projections to 2029-30*, ABARE Research Report 06.26, Prepared for the Australian Government Department of Industry, Tourism and Resources, Canberra, December 2006.

Figure 8.9
**Gas production and consumption by state and territory, 2006[1, 2]**




1. Production data allocated to the states and territories on the basis of EnergyQuest production data by basin. It is assumed that the production in the Otway Basin is divided equally between South Australia and Victoria. 2. Domestic consumption data is based on ABARE forecasts scaled to match production.

Source: C Cuevas-Cubria and D Riwoe, *Australian energy: national and state projections to 2029-30*, ABARE Research Report 06.26, prepared for the Australian Government Department of Industry, Tourism and Resources, Canberra, 2006; EnergyQuest, Energy quarterly production report, August 2006.

The advantages of gas are reflected in relatively strong growth in domestic gas consumption compared with other energy sources, such as coal and electricity (figure 8.8). While starting from a low base, since 1973–74 gas consumption has risen from around 200 petajoules to 1200 petajoules in 2005–06, a six-fold increase. By comparison over the same period use of black and brown coal has grown from 900 petajoules to 2300 petajoules and electricity from 250 petajoules to 900 petajoules, which on average is about a three-fold increase.

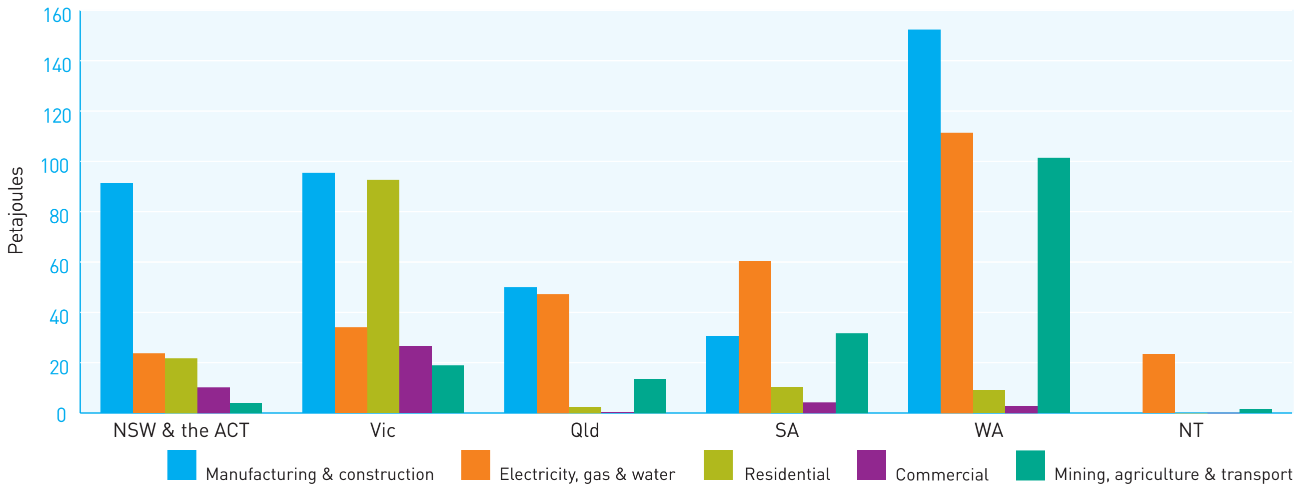
Historical restrictions on interstate trade have limited trade in gas. The 1994 agreement among Australian governments to introduce free and fair trade in gas between and within the states and territories, the introduction of regulated third party access rights to natural gas pipelines and other National Competition Policy and related reforms have created trading opportunities and incentives for expansion of the gas transmission network. Construction of the Eastern Gas Pipeline and the SEA Gas Pipeline has contributed to the opening of the Patricia-Baleen field in the Gippsland Basin and the Minerva and Casino fields in the Otway Basin. Producers from these fields compete with the Cooper–Eromanga Basin producers to supply gas to New South Wales and South Australia, for example. Trade in gas now occurs across south and eastern Australia, with Tasmania and New South Wales mainly relying of gas imported from other states. However, relatively high transport costs limit opportunities to trade in gas such that gas collected from each basin is principally sold into the nearest market. Gas from the Bowen–Surat Basin, for example, is principally marketed into Queensland. Figure 8.9 indicates current production and consumption patterns.

CSM development in Queensland and New South Wales is significantly increasing competition in the sector and is the main driver behind planned infrastructure development over the next 5–10 years (section 8.5). This is likely to see the rapid expansion of the Queensland pipeline system in the next few years and its interconnection with the rest of south-east Australia to allow for the export of Queensland gas to New South Wales, South Australia and Victoria.


Offshore gas rig

Figure 8.10

**Sectoral primary natural gas consumption by state and territory, 2004–05[1]**




1. Mining accounts for at least 69 per cent of the mining, agriculture & transport sector in each state and territory.

Source: ABARE, *'Energy statistics – Australia'*, Table F, http://www.abareconomics.com/interactive/energy/excel/table_f.xls, viewed: 24 November 2006.

Western Australia and the Northern Territory are geographically isolated from the major eastern and southern markets and gas is not traded across state borders. However, LNG exports are growing rapidly and now account for much of Western Australia's production. Similarly, all current production from the Bonaparte Basin is for export. Increased international trade in gas has meant greater integration of Western Australia's domestic market and the global gas market, with subsequent increases in domestic gas prices (section 8.5).

In Australia natural gas is predominantly used for industrial manufacturing purposes and for electricity generation. The mining sector is also a major user of gas in Western Australia (figure 8.10). The residential sector accounts for only a small share of consumption in all states and territories, except in Victoria where the sector accounts for around a third of total consumption.

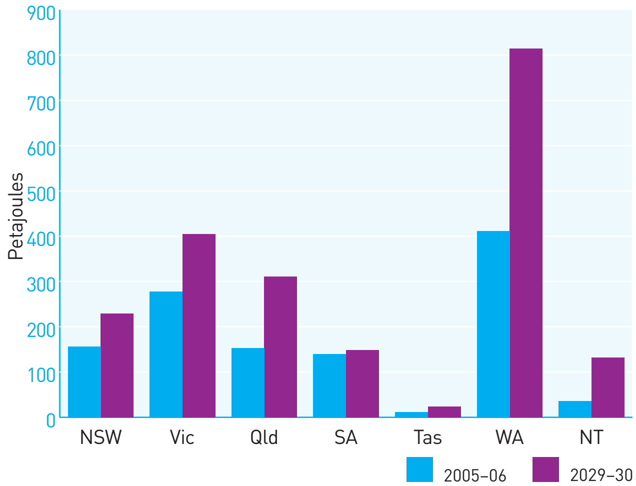
## Future outlook

ABARE has projected that over the period 2005–06 to 2029–30 primary energy consumption in Australia will increase by about 43 per cent from 5715 to 8162 petajoules, growing at an average annual rate of 1.4 per cent. It expects consumption of natural gas to be an important contributor to this growth, projecting gas consumption (including in the LNG export sector) to increase by 2.2 per cent a year, accounting for 37 per cent of the total increase in primary energy consumption. It expects much of this growth to occur in the Northern Territory, Western Australia and Queensland (figure 8.11).

ABARE expects primary natural gas consumption for the Northern Territory to increase about four-fold from about 36 petajoules in 2005–06 to 132 petajoules in 2029–30. Key contributors to this growth are energy intensive refining and the LNG export sector. ABARE also expects that a significant increase in Australia's alumina refining capacity and the new Burrup Peninsula ammonia fertiliser plant will contribute to projected strong growth in natural gas consumption in Western Australia. ABARE forecasts that overall natural gas consumption in Western Australia will almost double from 423 petajoules in 2005–06 to 797 petajoules in 2029–30.

**Figure 8.11**

**Primary gas consumption by state and territory[1]**




1. Based on ABARE forecast data. Actual production data for the 2006 calendar year is provided in table 8.1.

Source: C Cuevas-Cubria and D Riwoe, *Australian Energy: National and state projections to 2029-30*, ABARE Research Report 06.26, prepared for the Australian Government Department of Industry, Tourism and Resources, Canberra, 2006.

In Queensland, mining and minerals processing industries and increased use of gas for electricity generation are expected to contribute to strong growth in natural gas consumption in that state. ABARE projects that gas consumption will rise from about 153 petajoules in 2005–06 to 311 petajoules by 2029–30. In particular the effect of the Queensland Government's greenhouse and energy policies is expected to lead to an increase in demand for gas-fired electricity generation in preference to other fuels such as coal.

ABARE expects gas use in Tasmania to double, growing from a low base of about 11 petajoules in 2005–06 to 23 petajoules by 2029–30. ABARE forecasts relatively modest growth in natural gas consumption in New South Wales, Victoria and South Australia. In South Australia, for example, natural gas consumption is projected to grow by only 0.2 per cent between 2005–06 and 2029–30. The decline in manufacturing in South Australia and Victoria has been reducing demand, although this is offset to some degree by greater use of gas for electricity generation.

## 8.5 Gas prices

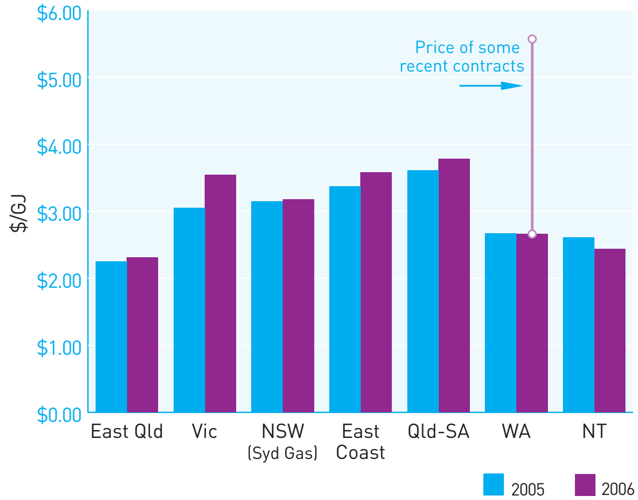
Gas is sold mostly under confidential long-term take or pay contracts. Historically contracts have lasted for up to 30 years, but more recently contracts have typically been shortened to 10–15 years. The contracted price of gas is usually increased each year by 80–90 per cent of the consumer price index. Unlike LNG, prices under domestic gas contracts are generally not related to oil prices.

Because gas contracts are confidential, comprehensive price information is not readily available. However, initiatives to improve price transparency are in train (section 8.8). Available information suggests that gas prices tend to vary within and across states. Figure 8.12 provides illustrative gas prices for different regions in Australia in 2005 and 2006. Available data suggest that current prices are within a band of about \$2.25–\$3.80 a gigajoule with the lowest prices occurring for CSM in eastern Queensland and New South Wales and for conventional supplies under existing long-term contracts in the Northern Territory and Western Australia.[15] Prices for conventional natural gas are relatively similar across most of the east coast of Australia, ranging from around \$3.50–\$3.80 a gigajoule in 2006. Prices on the spot market in Victoria have typically been around \$3 a gigajoule. This is below long-term contracted prices for conventional gas. CSM contract prices have typically been lower, around \$2.00–\$2.50 a gigajoule, but more recently prices have increased to \$2.50–\$3.00 a gigajoule.

15 Price estimates reflect field gate prices, except for Queensland, which reflects the price for delivered gas.

**Figure 8.12**

**Selected natural gas prices by region[1]**




1. Data for the second quarter of 2005 and 2006. Field gate prices, except for Queensland where the price includes delivery costs. Prices for the Vic and WA are based on data provided by the Department of Industry and Resources (WA). Prices for East Qld reflect prices received by CH4. Prices for the East Coast are based on weighted average prices received by Santos and Origin Energy and mainly reflect prices for Cooper Basin gas, but also includes other east coast conventional gas and CSM, Western Australian (conventional and LNG), US and Indonesian gas.

Source: EnergyQuest, *Energy quarterly production report*, August 2006, p. 52; Data supplied by the Department of Industry and Resources (WA).

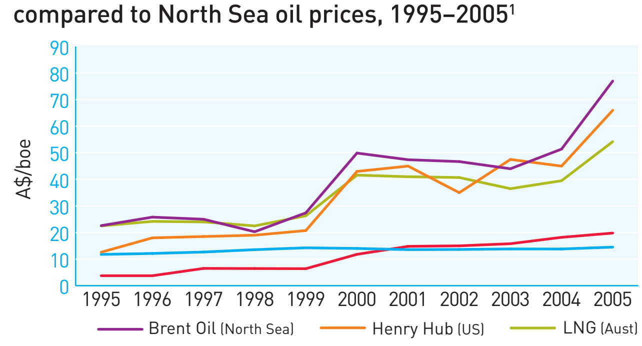
Contract prices for gas in Western Australia vary but are generally considered to be within the range of $2.00 to $2.90 a gigajoule with an average of about $2.45 a gigajoule ($14.25 a boe (barrel of oil equivalent)). However, according to EnergyQuest, in late 2006, some Western Australian domestic gas prices rose to over $5 a gigajoule in response to higher LNG prices. EnergyQuest provided an example of one new contract in which the gas price was $5.48 a gigajoule.[16] The Economic Regulation Authority of Western Australia also reports that wholesale gas prices in the Western Australia market range between $5.50 to $6.00. This represents a doubling of gas contract prices compared with early 2006.[17] During 2006 there was a considerable tightening in the supply of gas in Western Australia. The Economic Regulation Authority of Western Australia reports that gas producers are only offering contracts with a maximum term of five years with volumes restricted to about ten terajoules a day.[18]

The main cause appears to be uncertainty about future gas field development costs in light of the significant cost increases. Other contributing factors may include uncertainty about future gas prices and the government's domestic gas reservation policy.

Australia has had relatively low gas prices by international standards. Figure 8.13 compares gas prices in Australia and the United States with the price of Brent crude oil (sourced from the North Sea). Despite some significant increases in some Australian gas prices over the past decade, the ex-plant price of gas in Victoria and Western Australia has averaged around a third of the price in the United States (which was equivalent to an average of about $9.72 a gigajoule in 2005). Australian prices are also well below those achieved in the United Kingdom and Europe. In 2006, for example, the average wellhead price of gas in the United Kingdom was about $16.44 a gigajoule, while in Europe it was around $10 a gigajoule. This compares with prices generally less than $4 (less than $20 a boe) throughout much of Australia, although under some recent contracts Australian LNG prices have approached parity with oil prices.

**Figure 8.13**

**Australian and United States average gas prices compared to North Sea oil prices, 1995–2005[1]**




1. Brent oil is the average Brent oil price. Victoria Bass Strait gas is a Wood Mackenzie estimate of average Victorian gas prices ex-plant. Henry Hub gas is an annual average of the US Henry Hub spot price. LNG is measured free on board (net) based on an estimate of the average ex-plant LNG price from the North West Shelf adjusted to take account of gas used in liquefaction. All prices are measured in Australian dollars in terms of barrel of oil equivalents (boe).

Source: Department of Industry and Resources (WA), *Western Australian mineral and petroleum statistics digest 2005–06*, 2006, Perth.

16 EnergyQuest, *Energy quarterly production report*, February 2007.

17 Economic Regulation Authority, *Gas issues in Western Australia,* Discussion paper, Perth, 2007.

18 Economic Regulation Authority, See footnote 17.

In the United States and Europe gas prices follow oil prices closely. This has generally not been the case in Australia, primarily because of Australia's geographic isolation and high transport costs. The domestic price of gas reflects local supply and demand, which is characterised by relatively low consumption and high reserves. Increased demand for LNG is, however, leading to increases in the domestic price of gas, particularly in Western Australia.

## 8.6 Industry structure

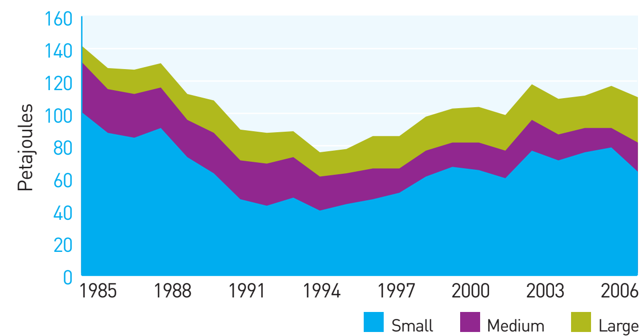
Long-term declining profitability of the global petroleum industry resulted in significant rationalisation of the industry during the second half of the 1980s and early 1990s. There was also considerable merger activity among companies of all sizes. In particular, major oil companies merged to create even larger companies, such as ChevronTexaco and ExxonMobil. These mergers allow control of very large petroleum fields that can be profitable even at relatively low crude oil prices.

Reflecting higher oil prices and continuing gas demand in Australia, the number of companies involved in gas and oil exploration, particularly junior explorers, has expanded since the mid-1990s. Companies floated in the last 10 years and their market capitalisation include AWE ($1219 million), Tap ($235 million), Arc ($306 million), Roc ($886 million), Queensland Gas Company ($1116 million), Arrow Energy ($825 million) and Sydney Gas ($130 million). Over the same period Beach Petroleum has grown to a market capitalisation of $919 million, Australian energy major AGL ($5.7 billion) has entered the gas production sector and both Apache and Mitsui have become important domestic gas producers.

The changing structure of the industry is illustrated by figure 8.14, which shows the change in industry structure from 1985 to 2006 for exploration in offshore waters that are under Australian Government jurisdiction.

**Figure 8.14**

**Companies holding equity in gas and oil exploration permits in offshore waters, classified by size, 1985 to 2006[1]**




1. Data reflects companies with permits issued by the Australian Government for offshore waters only (excludes onshore permits and permits in the JPDA and waters under state and territory jurisdiction). 2. Large refers to multinational and super-major companies and subsidiaries. 3. Medium refers to non-multinational companies with a significant market capitalisation. 4. Small companies have a moderate market capitalisation and are not major producers.

Source: Data provided by Geoscience Australia, 2006.

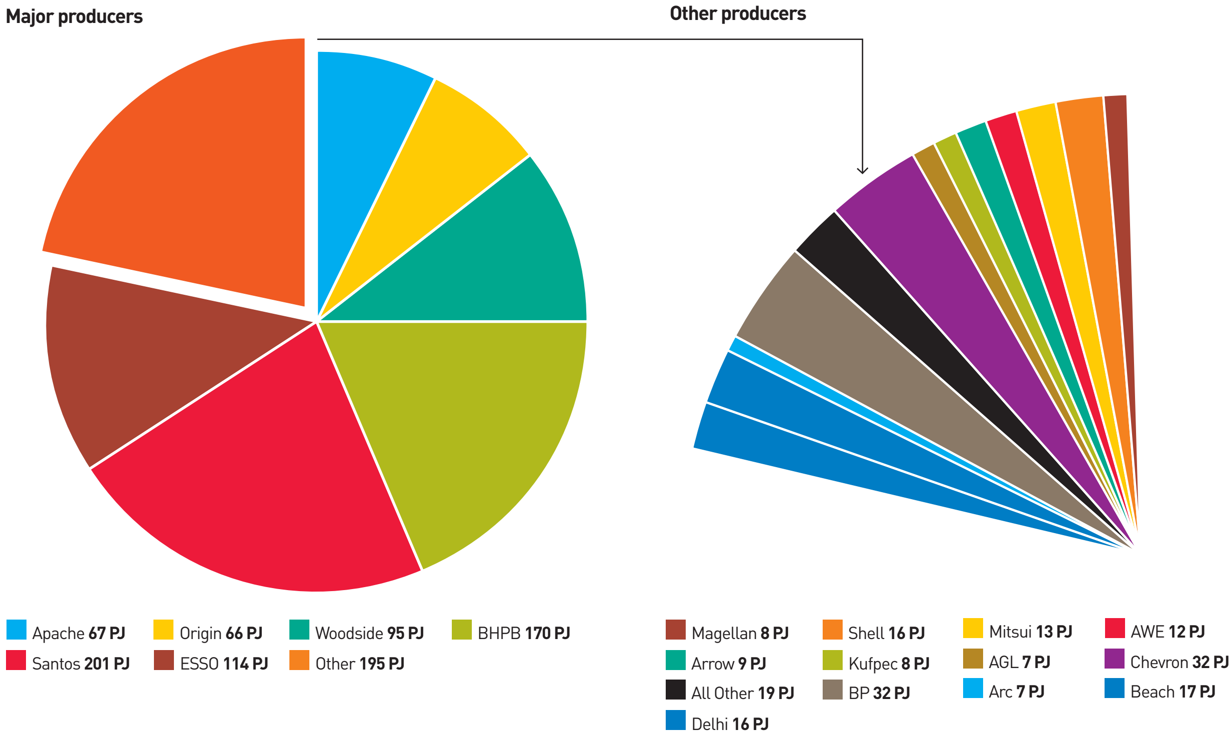
In general, the entities that now comprise the Australian petroleum resources industry fall into three categories. These are:

> International majors—multinational corporations with large production interests and substantial exploration budgets (e.g. BP, BHP Billiton, ExxonMobil, ChevronTexaco and Apache)

> Australian majors—major Australian energy companies with significant production interests and exploration budgets (e.g. Woodside Petroleum, Santos and Origin Energy)

> Juniors—smaller exploration and production companies, which may or may not operate production (e.g. Beach Petroleum, AWE, Tap, Arrow, Queensland Gas Company and Arc). These companies may have a market capitalisation of over $1 billion.

Figure 8.15
Natural gas producers supplying the domestic market, 2006[1]




1. Other includes companies accounting for 4 per cent or less of domestic gas production. The group 'all other' comprises Anglo Coal, CalEnergy, Eastern Star, Enterprise Energy, Great Artesian, Helm Energy, Inpex, Molopo, Mosaic, Queensland Gas Company, Sentient Gas, Sunshine and Tap Oil.

Source: EnergyQuest, *Energy quarterly production report*, February 2007.

International majors tend to be involved in the larger offshore oil and LNG projects with Australian majors and smaller companies mainly focusing on onshore discoveries, often with a greater focus on natural gas sales for the domestic market. Santos, Origin Energy and Woodside Petroleum, for example, accounted for about 40 per cent of the domestic market and around a third of all gas produced in Australia in 2006. Junior explorers often play a significant role in higher risk greenfields exploration, such as the early phase of CSM developments in Australia. However, as illustrated by figure 8.14, smaller companies have been active offshore as well as onshore.

## Gas producers

Gas production in Australia is relatively concentrated. While there are over 100 companies involved in gas and oil exploration only around 25 companies produce gas in Australia. Six major companies account for about 60 per cent of total gas production and almost 80 per cent of production for the domestic market. In 2006 Santos was the largest producer of gas for the domestic market accounting for 22 per cent of the market (figure 8.15). Other major producers were BHP Billiton (19 per cent), Esso (ExxonMobil) (13 per cent), Woodside (10 per cent), Apache (7 per cent) and Origin Energy (7 per cent). Other major players include BP, ChevronTexaco and Beach Petroleum[19] (which each make up 3–4 per cent of the domestic market) followed by other players such as Shell, Mitsui, and AWE (which each supply less than 2 per cent of the domestic market).

19 Beach Petroleum acquired Dehli in September 2006.

Brendan Esposito (Fairfax Images)

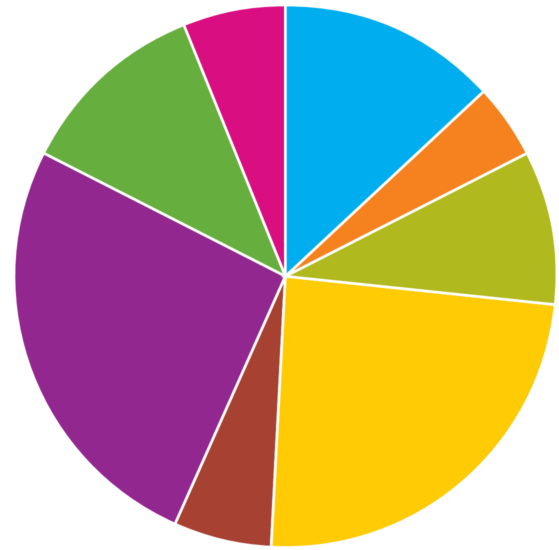
Gas plant at Moomba in South Australia

The development of CSM has seen the entry of a number of new players in exploration and production over the past 5–10 years. New entrants included a number of US companies (although most have now left Australia after little success with CSM development) as well as local companies including the Queensland Gas Company, Metgasco, Pure Energy, Sydney Gas, Hillgrove Resources, Bow Energy, Eastern Star, Sunshine Gas, and coal producers Anglo Coal and Xstrata. Santos, Origin Energy, AGL and Molopo also have involvement in CSM exploration and production.

There has been significant merger and acquisition activity in the CSM sector. Smaller companies are a common takeover target. For example, in 2005 Santos acquired Tipperary Oil and Gas (Australia) Pty Ltd and Sydney Gas Ltd sold 50 per cent of its assets to AGL and entered into a joint venture with AGL for the development of its tenements. In August 2006 Arrow completed a merger with CH4 Gas Limited. Following an unsuccessful takeover attempt by Santos the Queensland Gas Company formed a strategic partnership with AGL in which AGL obtained an initial 27.5 per cent stake in the company. The arrangement also provides for the two companies to enter into an agreement for AGL to purchase 540 petajoules of gas over 20 years, with an additional option of 200 petajoules. Prior to shareholder approval of AGL's cornerstone investment on 2 March 2007, US funds manager TCW, one of the world's biggest investors in CSM, made a takeover bid for the company.

The development of CSM and its impact on competition in the upstream gas industry is illustrated by figure 8.16. While significant gas producers such as Santos, BHP Billiton and Origin Energy accounted for most of the CSM produced in the year to December 2006, smaller players, including Sydney Gas (along with AGL), the Queensland Gas Company, and Arrow accounted for the balance (around 37 per cent).

Figure 8.16
**Coal seam methane producers in Australia, 2006**[1]




1. The other category is comprised of Mitsui, CS Energy, Molopo, Sentient Gas and Helm Energy.

Source: EnergyQuest, *Energy quarterly production report*, February 2007.

In terms of reserves Origin Energy and Santos are reported to have about 67 per cent of 2P reserves (proved and probable) with the balance mainly accounted for by the Queensland Gas Company and Arrow Energy. The smaller companies dominate the 3P reserves (proved, probable and possible) with Santos and Origin Energy having only 38 per cent of reported 3P reserves.[20]

20 Westside, 'Gas markets', <http://www.westsidecorporation.com/gas+markets.aspx>, viewed: 3 March 2007.

## Joint venture arrangements

It is common for oil and gas companies to establish multi-company joint ventures, often at the exploration tenement application or bidding stage. Their purpose in establishing a joint venture is to help to manage risks and other costs. In these partnerships it is common for a significant producer (the operator of the joint venture) to hold a substantial or majority interest in the project with the remaining equity held by other companies including junior explorers. The joint ventures typically involve unincorporated contractual associations between the parties to undertake a specific business project in which the venturers contribute costs and receive output from the venture. They do not invest in a separate entity or receive a share of profits.

An example is the Cooper Basin partnership exploring petroleum tenements in South Australia. This comprises Santos (as operator) holding a 66 per cent interest, Beach Petroleum holding a 21 per cent interest and Origin Energy holding a 13 per cent interest.

The extent of competition within a particular basin depends in a large part on the number of fields developed and the ownership structure of the fields. Other factors include acreage management and permit allocation. Table 8.3 lists the main companies and joint venture arrangements in each major gas producing basin in Australia. There are currently about 16 ventures marketing gas in the south and eastern Australia. However, only about four producer groups are independent of the major producers (ExxonMobil, Santos, Origin Energy and BHP Billiton). In addition a single joint venture dominates production in the Cooper–Eromanga, Bass, and Gippsland basins. Competition is more diverse in the Carnavon, Bowen–Surat and Otway basins.

In Western Australia there are about six key competing producer interests. In the Carnarvon there are around four key joint venture interests, although there are a number of common ownership interests across the ventures. Despite being focused on LNG production, the Woodside joint venture on the North West Shelf supplies about 60 per cent of the domestic Western Australian market. The John Brookes, Harriet and Griffin fields are not involved in LNG production. These fields produce around a third of Western Australia's domestic gas.

There are two producing groups operating in the Perth Basin, although production is dominated by Arc Energy, which wholly controls 64 per cent of the area under licence.

Gas for use in the Northern Territory is supplied from the Palm Valley and Mereenie fields in the Amadeus Basin. These fields are controlled by joint ventures involving Magellan and Santos. There is a joint venture with licences to produce in the Bonaparte and Timor Sea, but the venture is not currently supplying the local market. Supplies from the Bonaparte Basin for electricity generation are likely to commence in 2009 from the Blacktip project, which includes construction of a pipeline from the field to the Amadeus Basin to Darwin Pipeline.

In addition to existing production projects there are several gas projects that may begin in the next few years and could further add to competitive pressures. These projects are listed in table 8.4.

Table 8.3 Gas producers serving the domestic market in Australia, 2006[1]

| NO.[2] | GAS FIELD | PRODUCERS BY MARKET AND GAS BASIN |
|---|---|---|
| 16 | | SOUTH AND EASTERN AUSTRALIA |
| 1 | | GUNNEDAH |
| | | Eastern Star Gas Ltd |
| 1 | | SYDNEY |
| | Cambden | Sydney Gas, AGL |
| 1 | | BASS |
| | Yolla | Origin Energy, Aust Worldwide, MidAmerican Energy, Mitsui |
| 2 | | GIPPSLAND |
| | Kipper | ExxonMobil (Esso), BHP Billiton[3] |
| | Patricia Baleen | Santos |
| 3 | | OTWAY |
| | McIntee | Origin Energy, Beach Petroleum |
| | Minerva | BHP Billiton, Santos |
| | Casino | Santos, Mittwell Energy, AWE |
| 1 | | COOPER-EROMANGA |
| | | Cooper JV: Santos, Origin Energy, Beach Petroleum<br>also others (Beach, Energy World, Drillsearch, Inland Oil, Magellan, CPC Energy)[3] |
| 7 | | BOWEN-SURAT |
| | | Arrow, AGL and others<br>also Arrow and others (Beach, Qld Government)[3] |
| | | Xstrata Coal |
| | | Anglo Coal, Mitsui, Molopo, Helm |
| | | Mosaic Oil and Santos |
| | | Origin Energy and others (Mosaic, Santos, Ausam, Delta, Craig, Tri-Star)[3] |
| | | Queensland Gas and others (Origin Energy, Sentient)[3] |
| | | Santos and others (mainly Sunshine Gas and Origin Energy)[3] |
| 6 | | WESTERN AUSTRALIA |
| 4 | | CARNARVON |
| | Harriet | Apache, Kufpec, Tap Oil<br>also Apache, Pan Pacific, Santos, Tap Oil[3] |
| | John Brookes | Apache, Santos |
| | North West Shelf | North West Shelf JV: Woodside, Royal Dutch Shell, Chevron, BHPB, BP[3] |
| | Griffin | BHPB, ExxonMobil, Inpex |
| 2 | | PERTH |
| | Dongara/Yardarino; Woodada | Arc Energy |
| | Beharra Springs | Origin Energy, Arc Energy |
| 1 | | NORTHERN TERRITORY |
| | | AMADEUS |
| | Meerenie and Palm Valley | Magellan, Santos |

1. Not all fields may have produced gas in 2006. 2. Represents the number of key producer groups operating in each basin and region. 3. Represents the aggregation of a number of production licences with similar joint venture arrangements.

Source: GPInfo, *Petroleum Permits of Australasia*, Encom Petroleum Information Pty, Ltd, North Sydney 2006; Websites of the Department of Industry and Resources (WA); Department of Infrastructure Energy and Resources (Tas); Department of Natural Resources and Water (Qld); Department of Primary Industries (NSW); Department of Primary Industries, Fisheries and Mines (NT); Department of Primary Industries and Minerals (Vic); Primary Industries and Resources South Australia (SA).

Table 8.4 Gas projects with potential to supply the domestic market

| PROJECT | BASIN | OPERATOR (OTHER COMPANIES) | INITIAL PRODUCTION | STATUS AT FEBRUARY 2007 |
|---|---|---|---|---|
| DOMESTIC GAS PROJECTS | | | | |
| Thylacine | Otway | Woodside (Origin, Benaris, CalEnergy) | 60 PJ a year | Production is due to start in late 2007. |
| Henry | Otway | Santos (AWE, Mitsui) | na | Front End Engineering Design (FEED) underway. Possible gas production by early 2009. |
| Trefoil/White Ibis | Bass | Origin (AWE, CalEnergy, Wandoo) | na | Development scoping studies being planned. |
| Kipper | Gippsland/Kipper | Exxon (BHP, Santos) | 30–40 PJ a year | Participants have agreed to enter FEED. Gas production expected to start by 2010. |
| Basker-Manta | Gippsland | Anzon (Beach) | 20 | In FEED stage. Production planned for first half of 2009. |
| Turrum | Gippsland | Exxon (BHP) | na | Under consideration. |
| Longtom | Gippsland | Nexus | 30 PJ a year | Possible production by the second half of 2008. |
| Tipton West | Surat | Arrow (Beach) | 10 PJ a year | Commenced February 2007. |
| Argyle | Surat | QGC (Origin) | 7 PJ a year | First gas likely March 2007. |
| Blacktip | Bonaparte | ENI | 24 PJ a year | Production planned from 2009. |
| Reindeer | Carnarvon | Apache (Santos) | na | Feasibility study underway. Possible production from 2010. |
| LNG PROJECTS WITH DOMESTIC GAS POTENTIAL | | | | |
| NWS JV Fifth Train | Carnarvon | Woodside plus partners | 240 PJ a year | Increased capacity from the end 2008. Already a major gas producer for the domestic market. |
| Gorgon | Carnarvon | Chevron (Shell, Exxon) | 550 PJ a year | In FEED stage. |
| Pluto | Carnarvon | Woodside | 270–330 PJ a year | Possible production, including for the domestic market, by the end of 2010. |
| Darwin LNG | Bonaparte | ConocoPhillips | 190–330 PJ a year | LNG expansion targeted for 2013. Under the right commercial conditions the project could supply the domestic market. |
| STALLED DOMESTIC GAS PROJECTS | | | | |
| PNG | PNG | Exxon (Oil Search, AGL, Merlin) | na | Currently deferred in favour of LNG. |
| Petrel Tern | Bonaparte | Santos | na | At development proposal stage. |

na not available.

Source: Information provided by EnergyQuest.

## 8.7 Gas wholesale operations and trade

Gas processing facilities are connected to end-use markets by gas transmission pipelines and distribution systems. Consequently, trade in gas comprises two distinct but inter-related wholesale components:

- gas sales—producers selling gas directly to major industrial and power generation customers and to energy retailers, who aggregate customer loads for on-sale to smaller customers
- gas transport—transmission and distribution pipeline service operators selling capacity and transport services to energy retailers and major gas users.

Unlike electricity, gas production and delivery is not instantaneous and gas can be stored in gathering and transmission pipelines (known as linepack) and in depleted reservoirs or in liquefied form. It is economic to store gas only to meet peak demand requirements or for use in emergencies.

Natural gas pipelines are subject to minimum and maximum pressure constraints. The quantity of gas that can be transported in a given period varies with diameter and length of the pipeline and the difference in pressure between the two ends. The greater the pressure differential, the faster gas will flow. These features mean that gas deliveries must be scheduled. In Victoria gas is generally produced and delivered in 6–8 hours because most demand centres are less than 300 kilometres from gas fields. Gas delivered from the Cooper Basin into New South Wales can take 2–3 days because the gas must be transported more than 1000 kilometres. Deliveries on the Eastern Gas Pipeline are faster. Time lags between production and delivery of gas are also substantial for some customers in Western Australia and the Northern Territory.

Given the time taken for deliveries, commercial operations mainly focus on managing daily flows of gas, with additional longer or shorter elements as appropriate. Gas retailers and major users estimate requirements for the day ahead and nominate that quantity to their producers and pipeline operators, subject to any pre-agreed constraints on flow rates and pipeline capacity.

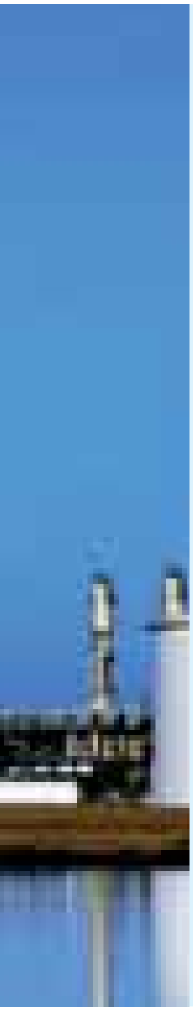
Each day producers inject the nominated quantities of gas into the transmission pipeline on behalf of their customers. Transmission pipeline operators deliver the gas to customers or distribution networks, which in turn deliver the gas to retailers' customers.

There is typically a difference between retailer nominations for injections and actual withdrawals from the system, creating imbalances. A variety of systems operate in Australia for dealing with imbalances. In some systems imbalances are corrected over time through adjustments to future gas scheduling and in others imbalances are rectified through cash transfers, usually determined on a daily basis and reconciled monthly. The independent market operator in Victoria—VENCorp—operates a spot market for managing system imbalances and constraints on the Victorian Transmission System (VTS). The spot market also provides a transparent mechanism for short-term trading in gas (see p. 245 for details).

### Gas supply arrangements

The fact that all stages of the production chain require large sunk investments means that commercial arrangements in the sector tend to be dominated by confidential long-term contracts for gas supply and transport both in Australia and overseas (see box 8.2 for an overview of gas contracting and trading arrangements in the United States and United Kingdom). Typically in Australia contracts extend for 10–15 years, but may extend for 20–30 years for riskier and high cost ventures. During 2006 there has been a considerable tightening in the supply of gas in Western Australia. The Economic Regulation Authority in Western Australia reports that gas producers are only offering contracts with a maximum term of five years with volumes restricted to about 10 terajoules a day.[21]

21 ERA, *Gas issues in Western Australia,* Discussion paper, Perth, 2007.



### Box 8.2 Gas contracting and trade in the United States and United Kingdom

**United States**

The United States is the largest market for natural gas in the world. Gas and pipeline capacity are typically provided under long-term bilateral contracts for services. Gas is sold in an unregulated market while transmission services are subject to regulated price caps. Under federal regulation, pipeline operators must establish electronic bulletin boards to facilitate the trading of capacity, known as 'capacity release'. Shippers holding capacity rights can resell their capacity either bilaterally or through the bulletin boards. Pipeline operators also post available capacity offers on their bulletin boards. Trade terms and conditions are set by the parties, but regulation requires that terms and conditions not be unduly discriminatory or preferential or exceed the regulated price cap. Any agreement reached where capacity is sold at a discount must be posted on the bulletin boards.

Gas trading in the United States largely occurs at hubs, where spot markets have emerged for managing short-term fluctuations in supply. The Henry Hub in Louisiana, which serves the New York area, is the largest trading centre. It provides a spot market for both gas and pipeline capacity. In addition, the New York Mercantile Exchange operates a natural gas futures market at Henry Hub. Prices are quoted for standard gas contracts, delivered to Henry Hub on specific dates.

**United Kingdom**

The United Kingdom is the largest natural gas market in Europe. Gas is sold under long-term bilateral contracts. The United Kingdom operates a regulated National Transmission System with services provided by a single independent operator—National Grid Transco. Transmission service prices are determined by the regulator using a 'building block' approach similar to that adopted in Australia. Services are subject to a network code, which establishes a common set of non-discriminatory rules for all industry players and forms the basis of arrangements for shipping gas.

Pipeline capacity is allocated annually through auctions at each of the main onshore gas receiving terminals. The auctioned rights provide monthly capacity entitlements. Shippers trade in capacity. In addition, National Grid Transco conducts daily auctions in which it acts as the counterparty to all transactions based on the posting of buy and sell offers. Natural gas spot markets have emerged at several of the onshore terminals. Spot market trading is bilateral or on a brokerage basis.

Source: The Allen Consulting Group, *Options for the development of the Australian wholesale gas market*, Report to the Ministerial Council on Energy Standing Committee of Officials—Gas Market Development Working Group, Final report, 2005.

### Box 8.3 Determining the market clearing price in the Victorian spot market

In this example, a 550 TJ demand sets the price for gas on the day. In the absence of any constraints, this demand can be met by scheduling all of the gas offered into the wholesale market by retailers A and B, and 150 TJ of the gas offered by producer X.

Bids stacked in ascending price order

| | | |
|---|---|---|
| Retailer C | 30 TJ @ $5.00/GJ | Price setting demand 550 TJ |
| Producer X | 200 TJ @ $2.72/GJ | ← Market price $2.72/GJ |
| Retailer A | 100 TJ @ $2.63/GJ | |
| Retailer B | 200 TJ @ $2.56/GJ | |
| Retailer A | 100 TJ @ $2.55/GJ | |

Source: Vencorp, *Guide to the Victorian gas wholesale market*, 2006.

Contracts with gas producers include 'take-or-pay' clauses with the purchaser paying for a minimum quantity of natural gas each year irrespective of whether the purchaser actually takes delivery of it.

Two systems operate for bulk transmission of gas in Australia—'contract carriage' and 'market carriage'. Under the contract carriage system a gas shipper contracts for pipeline capacity on a 'take-or-pay' basis. The shipper pays for minimum use of a pipeline (expressed as $/maximum daily quantity (MDQ)) each year regardless of whether the capacity is used. Essentially, shippers purchase a transmission right. Capacity charges generally account for most of the cost of shipping gas, although volume charges for the actual amount of gas transported and other ancillary charges apply.

Under a market carriage system shippers do not contract for pipeline capacity. Rather capacity is assigned to users with shippers paying for capacity on a pro-rata basis. This is the system operated for carriage on GasNet's VTS. The market carriage system was introduced in the late 1990s to provide a more flexible arrangement for operating in a deregulated market. This was considered necessary because of the complexity of the interconnected network, which has five injection points and multi-directional gas flow and limited linepack. It also accommodates the fact that retailers operating in a competitive environment do not have a guaranteed customer base over the long term, potentially making it difficult to enter into contracts for supply.

## Victorian spot market

The spot market operated by VENCorp for gas transported on the VTS operates under a net pool arrangement (that is, for increases and decreases in daily supply). Market participants (mostly retailers) inform VENCorp of their nominations for gas one and two days ahead of requirements. The spot market is then used to respond to changes in customer demands across a gas day and by VENCorp for gas balancing.

VENCorp stacks the bids and selects the least cost bids from participants to match demand across the whole market and establish the market clearing price (box 8.3). Market participants may submit offers for increments or decrements (increases or decreases) to the quantity injected or withdrawn at connection points. Each offer may specify several prices and corresponding quantities of injections or withdrawals that the market participant is prepared to implement if the market price reaches the specified value.

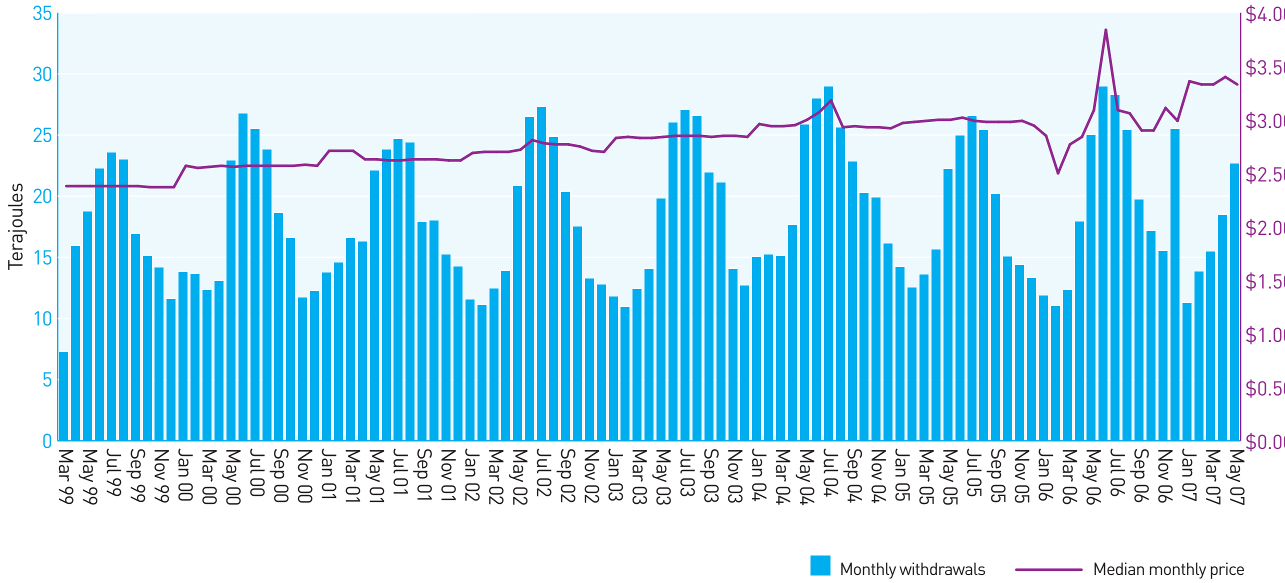
If the spot market price falls below a retailer's contract price, the retailer may take the position that it is better to reduce its own injections of gas and to buy from the spot market. If the spot price for gas rises, then the retailer may wish to inject more gas than it needs for its own customers and sell it through the spot market. As an alternative, a retailer may establish an 'interruptible' contract with a large customer and submit a withdrawal increment or decrement offer structured in such a way that if the spot price for gas rises above a certain price then that customer's use of gas is interrupted or reduced. Any excess gas obtained through such an arrangement can be sold on the spot market.

The spot market for gas in Victoria allows market participants to enter into financial contracts to manage their physical spot price exposure. However, available information suggests that such trading is very limited with all financial contracts conducted on a bilateral basis. There is no formalised market mechanism or brokering service for facilitating trades.

Around 10–20 per cent of gas transported on the VTS is traded through the spot market with the rest sold under commercially negotiated contracts. The price of the gas traded is established by VENCorp at the daily ex-post market clearing spot price based on completed trades.

Figure 8.17

Prices and withdrawals on the Victorian spot market




Source: VENCorp, 'Market reports', http://www.vencorp.com.au/html/index.htm, viewed: 2 November 2006.

Figure 8.17 plots monthly gas withdrawals and the median monthly spot price for gas from March 1999 (market start) to May 2007. It shows that the spot market has been characterised by low variability in prices and typically trading activity is highest during the winter peak period.

While prices on the spot market are relatively stable there are occasional troughs and spikes in the spot market price. For example, while in 2006 the average daily spot price was about $3, it fell to $2.21 on 15 March and achieved a high of $6.04 on 10 June. For the last trading interval on 16 April 2007 the spot price rose to $35.49. Under the Victorian Gas Industry Market and System Operations Rules VENCorp is required to monitor daily trading activity within the market to ensure that trading occurs within the rules. It assesses and reports on significant pricing or settlement events to determine whether the activities of market participants may have significantly affected market outcomes. To date VENCorp has found that price spikes in the market have been due to operational and market requirements, often relating to severe weather conditions.[22] It has not found evidence of anti-competitive conduct.

Prices on the spot market were more volatile during 2006 than in previous years. A range of factors may have contributed to this including:

- the start of new supplies (e.g. Casino and Bass gas)
- changes to contractual positions
- unusual weather events (for example, in 2006 April and May were warmer than usual, while June was unseasonably cold).

Stemming from VENCorp's 2004 *Victorian gas market pricing and balancing review*, reforms to the gas market began in February 2007 with ex ante pricing, within day rescheduling and rebidding being introduced. The spot price is declared ex ante and revised every four hours up until 10 pm EST. This change adds flexibility, promotes incentives to respond to the spot price and provides clearer and more certain pricing signals. It also brings the gas and electricity markets into closer alignment.

The VENCorp review proposed additional reforms that may be implemented at a later stage. Initial reforms could involve the introduction of 'transmission rights', integrated with a change to structure of GasNet tariffs.

22 For details see VENCorp significant pricing events reports at http://www.vencorp.com.au/html/index.htm.

This proposal is intended to give GasNet greater investment and revenue certainty and address 'free-rider' problems by providing incentives for shippers to obtain transmission rights and invest in expansions. The key elements of the proposed changes are:

- a move from predominantly usage-based tariffs to predominantly capacity and contract-based charges
- differentiated usage charges tied to transmission rights involving higher charges for 'unauthorised' or spot usage relative to usage charges for rights holders.

Further enhancement of the market-based system to promote investment incentives, transparency and efficiency could involve:

- introducing locational (hub-based) within-day pricing to provide clearer pricing signals for pipeline constraints, which should enhance investment incentives and promote transparency and efficiency
- replacing transmission rights with biddable capacity rights to provide a market system for day-to-day sale of spare capacity.

## Secondary trading

Secondary trading in gas refers to trading of existing contracted supplies and transport capacity. Most secondary trading is conducted through confidential bilateral contracts tailored to the issues specific to each transaction. For example, Firecone notes that shippers using the Moomba to Adelaide Pipeline System negotiate between themselves to secure additional capacity as required.[23]

## Backhaul

Backhaul is used in uni-directional pipelines to provide for the 'notional' transport of gas in the opposite direction of the physical flow of gas in a pipeline. It is achieved by redelivering gas at a point upstream from the contracted point of receipt.

Backhaul provides an opportunity for trading in pipeline capacity with pipeline operators competing for the sale of their spare capacity (interruptible supply) with sales of (firm) capacity that existing shippers release for trade. Backhaul arrangements are most commonly used by gas-fired electricity generators and industrial users that can cope with intermittent supplies. For example, in November 2006, Epic Energy signed a six-year backhaul contract on the South West Queensland Pipeline valued at $67 million. While Epic Energy did not reveal further details due to confidentiality agreements, Citigroup analysis suggests that the contract is for about 30–35 petajoules a year with the gas supplied from Santos's Fairview and/or Origin Energy's Spring Gully CSM fields for sale to customers on the Carpentaria Pipeline in Mt Isa.[24] This deal follows the decision not to proceed with the PNG pipeline.

## Gas swaps

A gas-for-gas swap is the exchange of gas at one location for the equivalent amount of gas delivered at another location. Swaps are a form of secondary trading with payment being made through the transfer of rights to the physical gas commodity.

The available anecdotal evidence suggests that swaps are reasonably common in Australia, but are conducted only on a minor scale. Most transactions are for a small volume of gas and account for only a small share of total sales.[25] Typically swaps are short-term, lasting for a few months, although there are some examples of multi-year agreements, such as the swap between Origin and South West Queensland Gas Producers (box 8.4).

Firecone reports that shippers use swaps to provide flexibility for dealing with both expected and unexpected mismatches between supply and demand for gas and transport capacity. Swaps also can help shippers to overcome physical limitations imposed by the direction or capacity of gas pipelines and provide significant cost savings by reducing or delaying the need to invest in pipeline capacity.[26]

23 Firecone Ventures, *Gas swaps*, Report prepared for the National Competition Council as part of the NCC occasional series, Melbourne, 2006.
24 Citigroup Global Markets, 'Hastings Diversified Utilities Fund', Company in-depth, 23 February 2007.
25 Firecone Ventures, 2006. See footnote 23
26 Firecone Ventures, 2006. See footnote 23

## Box 8.4 Gas swap between Origin and South West Queensland Gas Producers

In 2004 the South West Queensland Gas Producers entered into an agreement with Origin Energy to swap gas between Queensland and the Moomba Gas Hub. Under the arrangement Origin Energy delivers gas produced at its central Queensland fields to the South West Queensland Gas Producers at Roma in Queensland for use in meeting part of their customer requirements in south-east Queensland. In return the producers redirect (swap) an equal quantity of their Cooper Basin produced gas to the Moomba Gas Hub, which Origin Energy can use to meet its supply commitments in south-eastern Australia (see map).

The agreement extends to 2011. It involves up to 200 petajoules of gas a year, with a mechanism to increase these quantities. Contracting parties benefit from the deal because:

- Origin Energy is able to delay or eliminate the need to construct major additional pipeline infrastructure.
- The South West Queensland Gas Producers earn extra revenue from the swap fee (and incremental processing at the Moomba Gas Hub, which recovers higher levels of liquids than its Ballera facilities).


Source: Santos, 'Cooper Basin and Origin in major gas swap agreement', Media release, 6 May 2004, http://www.originenergy.com.au/files/gasswapagreement_2.pdf; Firecone Ventures, *Gas swaps*, Report prepared for the National Competition Council as part of the NCC occasional series, Melbourne, 2006.

### VicHub

A gas hub is a convergence or interconnection point for alternative gas supplies (often with associated storage capacity) and where gas trades often occur. Hubs exist at Moomba, Wallumbilla and Longford.

VicHub was established in February 2003 at Longford and is currently owned by Alinta. It connects the Eastern Gas Pipeline, Tasmania Gas Pipeline and VTS. This connection allows for trading of gas between New South Wales, Victoria and Tasmania.

VicHub is not a formal trading centre in the sense that it does not currently provide brokering services. Rather it buys and sells gas between the various regions to profit from price differentials, posting public buy and sell offers.

### Emergency management

Following the disruptions at the Longford gas processing plant in 1998 and the Moomba plant in 2004 Australian governments agreed to a non-legally binding protocol for managing major gas supply interruptions occurring on the interconnected networks. Such emergencies are to be managed in accord with the Memorandum of Understanding in Relation to National Gas Emergency Response Protocol (Including Use of Emergency Powers) October 2005, which seeks to provide for:

> …more efficient and effective management of major natural gas supply shortages to minimise their impact on the economy and the community, and thereby contribute to the long term community objective of a safe, secure and reliable supply of natural gas. [p. 5]

The memorandum of understanding established a government–industry National Gas Emergency Response Advisory Committee (NGERAC) to implement the protocol. Its primary role is to report periodically to ministers on the risk of gas supply shortages and options for reducing or averting potential shortages. It must also report on general requirements for communications, information provision and the roles of government and industry in the event of a major shortage of natural gas. The committee has established a Gas Emergency Protocol Working Group to develop an emergency response mechanism. The working group has published an options paper that examines options for managing an emergency including institutional arrangements, required legislative changes and communication protocols.

In the event of a major gas supply shortage the protocol requires:

- NGERAC to be convened to advise the Ministerial Council on Energy (MCE) and jurisdictions on the most efficient and effective way to manage the shortage
- as far as possible, that commercial arrangements be allowed to operate to balance gas supply and demand and maintain system integrity
- government intervention in the market and the use of emergency powers to occur as a last resort, and preferably, only after considering advice from the NGERAC and after reasonable efforts to consult with other interconnected or affected jurisdictions.

## 8.8 Gas market development

Despite the significant development of gas infrastructure and retail markets in the past decade, gas sales in Australia remain largely based on long-term bilateral contracts. Lack of price transparency (except in Victoria) and consistent and simple short-term trading mechanisms increase the difficulties of managing financial risk and security of supply and may raise barriers to entry.

To address this issue the MCE established the Gas Market Leaders Group (GMLG)[27] in November 2005 to develop a plan to deliver on the MCE's objective for a 'competitive, reliable and secure natural gas market delivering increased transparency, promoting further efficient investment in gas infrastructure and providing efficient management of supply and demand interruptions'.

The GMLG submitted its plan to the MCE on 29 June 2006, in which it recommended that the MCE:

> establish a bulletin board covering all major gas production fields, major demand centres and transmission pipeline systems
> direct the GMLG to proceed with detailed design of a short-term trading market for all states (except Victoria, which already has a gas spot market)
> establish a national gas market operator to manage both the wholesale and retail gas markets throughout Australia. The operator should replace the gas retail market functions of GMC and REMCo and the gas functions of VENCorp and be responsible for:
  > administering the bulletin board and, if established, the short-term trading market
  > providing advice to NGERAC in the collection, maintenance, publication and analysis of gas system information and to provide technical advice on managing supply constraints
  > producing an annual national gas supply/demand statement.[28]

The GMLG also proposed that the initiative be jointly funded by industry and government. It estimates that design and implementation of a bulletin board and a trading market would cost around $3.2 million. Industry would face initial set-up costs of about $9 million with ongoing annual costs of around $1.7 million. As an interim measure the GMLG would continue until the Gas Market Operator is established, to ensure the recommendations are implemented.

The GMLC's recommendations are supported by the Energy Reform Implementation Group (see appendix A). At its 27 October 2006 meeting, the MCE accepted the recommendations of the GMLG. The MCE requires the GMLG to develop the bulletin board in conjunction with the NGERAC so that it serves the purposes of both the gas market and the National Gas Emergency Response Protocol that NGERAC manages.

The GMLG has established a steering committee to manage the development of a bulletin board and further consider the design of a short-term trading market. Details of the group's proposal for the bulletin board and the short-term trading market are provided in the following sections.

## Bulletin board

The GMLG proposes that a national bulletin board (website) be established to facilitate improved decision-making and gas trading and provide information to help manage emergencies and system constraints. The bulletin board would cover all major gas production fields, major demand centres and transmission pipeline systems. Its primary purpose would be to provide readily accessible and updated information to end-users, smaller or potential new entrants, and market observers (including governments), on the state of the market, system constraints and market opportunities. It proposes that the bulletin board:

> publish information on physical and available pipeline capacity, pipeline tariffs, production and storage capacities and three-day demand forecasts
> support voluntary posting of buy/sell offers
> provide key contact details for pipeline operators, producers, storage providers, shippers and retailers.

The GMLG is working towards making the bulletin board operational by the first half of 2008.

27 The group comprises 12 gas industry representatives and an independent chairperson.

28 Gas Market Leaders Group, *National gas market development plan*, report to the Ministerial Council on Energy, 2006, http://www.mce.gov.au/assets/documents/mceinternet/FinalGMLGReport20060707135526.pdf

## Short-term trading market

The GMLG proposes that a short-term trading market be designed for all state and territory pipeline systems. It proposes that initially the short-term trading market be established in New South Wales and South Australia to replace existing gas balancing arrangements.

The short-term trading market is intended to facilitate daily trading by establishing a mandatory price-based balancing mechanism at defined gas hubs. A daily market-driven clearing price will be determined at each hub, based on bids by gas shippers to deliver additional gas at the hub.

The difference between each user's daily deliveries and withdrawals of gas at the hub will then be settled by the market operator at the clearing price. The GMLG believes that its recommended market mechanisms will provide price signals to shippers and users and stimulate trading over interconnected pipelines and demand-side response by users.

The short-term trading market is intended to operate in conjunction with longer-term gas supply and transportation contracts. It will provide an additional option for users to buy or sell gas on the short-term market without contracting for delivery and also allow contracted parties to manage short-term supply and demand variations to their daily contracted quantities.

The GMLG intends to make a decision on whether to proceed with development of a short-term trading market by October 2007. Should the short-term trading market proceed it would likely be operated by the National Energy Market Operator that COAG has agreed to establish to replace NEMMCO and the current gas market operators.

## Futures markets

The risk of participating in a commodity market can usually be hedged using physical or financial means. However, a futures gas market tends to develop only after the physical gas market reaches a certain level of maturity and a significant amount of natural gas is traded under transparent short-term contracts, such as has occurred in the United States and United Kingdom.

There is no futures market for gas in Australia at the moment and current opinion suggests that there is little prospect that a market will develop soon. The decision to implement a bulletin board and consider extending short-term trading in other states and territories may facilitate future development of a market for financial risk-hedging instruments (forward, futures, swap and option contracts).

# 9 GAS TRANSMISSION

Vichub. James Davies (Fairfax Images)

In Australia high-pressure transmission pipelines provide long haul bulk gas transport services from production fields to cities and towns and to large customers located along the route of the pipeline.

# 9 GAS TRANSMISSION

This chapter considers:

- the role of the gas transmission sector
- the structure of the sector, including industry participants and ownership changes over time
- the economic regulation of the gas transmission sector
- new investment in transmission pipelines and related infrastructure.

## 9.1 The role of the gas transmission pipeline sector

A gas transmission pipeline system typically consists of large diameter high-pressure pipelines and metering, compression, regulating and monitoring equipment. The pipelines are operated under high pressure to maximise transport volumes and efficiency of operation. They are mainly placed underground, which promotes visual amenity and helps to prevent damage that could interrupt gas services.

Expansion and interconnection of transmission pipeline systems can strengthen the performance of the gas industry by:

- giving customers a choice of gas sources
- encouraging competition among gas producers, pipeline operators and gas retailers.

## 9.2 Australia's gas transmission pipelines

Prior to the early 1990s natural gas services were operated under separate state-based systems. Legislative and regulatory barriers restricted interconnection of pipeline systems across state borders and thereby restricted interstate trade in natural gas. Government reforms in the gas industry began in 1991 and were rolled into the National Competition Policy program agreed in 1995.

The gas reforms have been accompanied by increased activity in the development of new gas fields and existing and new gas transmission infrastructure. Australia's natural gas consumption has almost doubled from 655 petajoules in 1991 to over 1172 petajoules in 2006. Over the same period Australia's natural gas transmission pipeline networks have expanded significantly. In 2006 the pipeline system extended to just over 21 000 kilometres. A significant element of this expansion has been associated with construction of interstate pipelines—the Eastern Gas pipeline (Longford to Sydney), the NSW–Vic Interconnect (Wagga Wagga to Wodonga), the SEA Gas Pipeline (Port Campbell to Adelaide) and the Tasmanian Gas Pipeline (Longford to Bell Bay).

Transmission pipelines deliver gas in all states and territories and to most major cities and regional centres. Table 9.1 sets out summary details of a selection of major transmission pipelines. Figure 9.1 shows pipeline routes.[1] There is now an interconnected transmission pipeline network in New South Wales, the Australian Capital Territory, Victoria, South Australia and Tasmania. This network provides access to gas from the Cooper–Eromanga, Gippsland, Otway and Bass natural gas basins and, potentially, coal seam methane from the Sydney Basin. However, relatively high transport costs mean that gas from a particular basin is most likely to be sold into the markets in closest proximity. Gas from the Gippsland Basin, for example, is mainly marketed in Victoria.

In Queensland, gas is sourced from the Cooper–Eromanga and Bowen–Surat basins through pipelines connected at Ballera and the Wallumbilla hub. A raw gas pipeline from Ballera to Moomba also connects the Queensland and South Australian pipeline systems.

Western Australia is serviced by three main pipelines—Dampier to Bunbury, Parmelia and Goldfields. The Dampier to Bunbury and Goldfields pipelines deliver gas from the Carnarvon Basin. Gas from the Perth Basin is transported on the Parmelia Pipeline. The Parmelia pipeline also transports gas from the Carnarvon Basin via an off-take from the Dampier to Bunbury Natural Gas Pipeline (DBNGP).

The Amadeus Basin to Darwin Pipeline provides transmission services from the Mereenie and Palm Valley gas fields for the Darwin corridor, including McArthur River Mine and Mount Todd.

1 See appendix C for a more comprehensive listing of onshore transmission pipelines in Australia.

**Figure 9.1**

**Major gas transmission pipelines and proposed pipelines in Australia**


| Pipeline | No. |
|---|---|
| Moomba to Sydney pipeline system (except for Moomba to Marsden) | 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 Mt Isa) | 8 |
| Moomba to Adelaide pipeline system | 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 |
| Dongara to Perth/Pinjarra (Parmelia) | 14 |
| SEA Gas pipeline | 15 |
| Tasmanian Gas pipeline | 16 |
| Palm Valley to Alice Springs | 17 |
| Midwest pipeline | 18 |

Source: The map is based on K Donaldson, *Energy in Australia 2006*, ABARE report, Prepared for the Australian Government Department of Industry, Tourism and Resources, Canberra, 2007; supplemented with additional information.

Table 9.1 **Major transmission pipelines (as at May 2007)**

| ROUTE AND/OR PIPELINE | LOCATION | LENGTH KM | APPROXIMATE THROUGHPUT TJ A YEAR | OWNER[1] |
|---|---|---|---|---|
| Moomba–Sydney | SA–NSW | 2013 | 80000 | APA Group |
| Longford–Sydney (Eastern Gas Pipeline) | Vic–NSW | 795 | 36000 | Alinta |
| Victorian transmission system | Vic | 1935 | 213900 | APA Group |
| Wallumbilla to Gladstone | Qld | 532 | 21000 | Alinta |
| Gladstone to Rockhampton | Qld | 97 | 6000 | Alinta |
| Roma to Brisbane | Qld | 440 | 28000 | APA Group |
| Ballera to Wallumbilla (South West Queensland Pipeline) | Qld | 756 | 49200 | Hastings Diversified Utilities Fund |
| Ballera to Mount Isa (Carpentaria) | Qld | 840 | 30000 | APA Group |
| Moomba to Adelaide | SA | 1185 | 52000 | Hastings Diversified Utilities Fund |
| Port Campbell to Adelaide (SEA Gas Pipeline) | Vic–SA | 680 | na | Origin Energy, International Power, China Light & Power |
| Longford to Bell Bay (Hobart) (Tasmanian Gas Pipeline) | Vic–Tas | 576 | na | Alinta |
| Dampier to Bunbury | WA | 1845 | 260000 | Diversified Utility and Energy Trusts (60%), Alcoa (20%) & Alinta (20%) |
| Goldfields Gas Pipeline | WA | 1427 | 39000 | APA Group (88.2 %) & Alinta (11.8 %) |
| Parmelia Pipeline | WA | 445 | 26000 | APA Group |
| Amadeus Basin to Darwin | NT | 1656 | 21000 | Amadeus Pipeline Trust[2] (96% APA Group) |
| Palm Valley to Alice Springs | NT | 147 | 3000 | Envestra |

na not available. 1. Most of the pipelines listed are licensed to a subsidiary or associated entity. For example, GasNet Australia, which is the licensed entity responsible for the VTS is a wholly owned subsidiary of the Australian Pipeline Trust, which is part of the APA Group. 2. The Amadeus Pipeline Trust leases the Amadeus Basin to Darwin Pipeline from a consortium of financial institutions.

Source: Access arrangements for covered pipelines; EnergyQuest, *Energy quarterly production report*, February and May 2007; Productivity Commission, *Review of the gas access regime*, Inquiry report, no. 31, 2004, Canberra.

## 9.3 Ownership of transmission pipelines

During the 1990s governments restructured their vertically integrated gas transport utilities into separate transmission and distribution businesses. Except for the North Queensland Gas Pipeline, gas transmission assets are now privately owned. Figure 9.2 shows the significant changes in the ownership of major transmission pipelines since 1994.

The Moomba to Sydney Pipeline (MSP), which supplies Cooper Basin gas into New South Wales, was the first pipeline to be privatised in Australia. In 1994 the Australian Government sold the pipeline to the East Australian Pipeline Limited (EAPL) consortium, which was formed by AGL (51 per cent) and a Malaysian- and Canadian-owned venture called Gasinvest (49 per cent). In 2000 AGL increased its interest in EAPL to 76.48 per cent and the consortium's interest in the pipeline was transferred to the Australian Pipeline Trust, which is now part of the APA Group.[2] AGL retained a 30 per cent cornerstone investment in the trust. AGL also transferred its other pipeline interests into the trust.[3] This included the Roma to Brisbane (Queensland) and Carpentaria (northern Queensland) pipelines and interests in the Amadeus Gas Trust (which leases the Amadeus Basin to Darwin Pipeline (Northern Territory) and Goldfields Gas Pipeline (Western Australia).[4] The trust has further expanded by increasing its interest in the Goldfields Gas Pipeline.

2 As at November 2006 the Australian Pipeline Trust began trading as part of the APA Group, which comprises the Australian Pipeline Ltd, Australian Pipeline Trust and APT Investment Trust.

3 On 25 October 2006 AGL's interest in the Australian Pipeline Trust transferred to Alinta.

4 AGL had an interest in the Goldfields Gas Pipeline via its 45 per cent interest in the Southern Cross Pipelines Australia consortium.

Victoria, Queensland and Western Australia privatised their government-owned transmission pipeline infrastructure in the mid to late 1990s. Key new entrants into the transmission sector resulting from these sales included US-based energy utilities, PG&E (Pacific Gas and Electric Company), GPU GasNet (a subsidiary of GPU Inc)[5], Duke Energy and Epic Energy (formed from the sale of Tenneco). Queensland is the only government to retain an ownership interest in gas transmission assets. Through its wholly-owned company Enertrade, the Queensland Government operates the North Queensland Gas Pipeline, which transports coal seam gas from Moranbah to Townsville to supply the Mt Stuart industrial hub.[6]

In South Australia, Tenneco Gas Australia acquired the Moomba to Adelaide Pipeline System (MAPS) on 30 June 1995 through its purchase of the operations and assets of the Pipeline Authority of South Australia. The pipeline transferred to Epic Energy under an ownership restructuring of Tenneco.[7] In June 2004 Hastings Funds Management acquired full ownership of Epic Energy's assets other than the DBNGP. The assets owned by Epic Energy (including the MAPS), were rolled into the Hastings Diversified Utilities Fund.[8]

There has been considerable consolidation of ownership in the transmission sector. For example:

- In 2000 Envestra (a major Australian gas distributor that is part-owned by Origin Energy and Cheung Kong Infrastructure) acquired the Palm Valley to Alice Springs, Riverland and Berri to Mildura pipelines.
- In 2004 Alinta, along with DUET[9] and Alcoa, acquired the DBNGP after its owner Epic Energy went into receivership in 2004. Alinta also purchased Duke Energy's other pipeline and electricity interests, which included the Eastern Gas Pipeline (EGP), the Tasmanian Gas Pipeline and a minority interest in the Goldfields Gas Pipeline.
- In 2005 Alinta restructured its Duke Energy gas pipeline and electricity generation assets to form Alinta Infrastructure Holdings. Alinta retained a 20 per cent interest in the holding company and during 2006 steadily increased its shareholdings in the company. In January 2007 the holding company became a wholly-owned subsidiary of Alinta.
- In 2006 Alinta and AGL agreed to merge and restructure the assets of the two companies. On 25 October 2006, as part of the agreement, Alinta gained AGL's pipeline interests, including its stake in the APA Group. Alinta now owns 35.3 per cent of APA Group. On 27 November 2006 Alinta made an undertaking to divest its APA Group and related management contracts for the MSP and the Parmelia Pipeline. Should APA Group divest its interests in the Moomba to Sydney Pipeline, Parmelia Pipeline and GasNet, Alinta is not required to divest its interest in APA Group. The divestment obligation on Alinta is subject to legal appeal. The divestment obligation on Alinta is subject to legal appeal. Should the sale of Alinta to the Babcock & Brown/Singapore Power consortium proceed the divestment obligations may change.
- In 2006 APA Group acquired GasNet Australia, which operates the Victorian transmission system.[10] APA Group has interests in other transmission pipelines, including the Goldfields Gas and Parmelia pipelines, and owns gas storage and processing facilities and electricity infrastructure. APA Group expects to increase its share of the natural gas market from 20 per cent to 28 per cent over the next 15 years.[11]
- In 2007 Origin Energy sold its network assets, including its interest in Envestra and its asset management business, to the APA Group.

5 Following a merger with GPU Inc, First Energy Corporation sold GPU GasNet (renamed GasNet) through a public float.

6 Enertrade's gas assets will transfer to Stanwell Corporation in September 2007.

7 Epic Energy initially consisted of El Paso Energy (30 per cent); CNG International (30 per cent); Allgas Energy (10 per cent); AMP Investments (10 per cent); Axiom Funds Management (10 per cent) and Hastings Funds Management Limited (10 per cent).

8 Hastings Diversified Utilities Fund invests in utility infrastructure. The fund is managed by Hastings Funds Management Ltd, which the Westpac Institutional Bank acquired in September 2005. The funds manager now operates as a division of the bank. Under a service agreement, Epic Energy Corporate Shared Services Pty Ltd operates the MAPS.

9 Diversified Utilities and Energy Trusts (DUET) was formed from the restructure of an AMP consortium and WA Gas Holdings Pty Ltd (WAGH).

10 The Victorian transmission system is often referred to the as the principal transmission system or the GasNet transmission system.

11 Australian Pipeline Trust, 'What's new', http://www.pipelinetrust.com.au/, viewed 11 October 2006.

Figure 9.2

Transmission pipeline ownership changes[1]

<table>
<tr><th></th><th></th><th>1994</th><th>1995</th><th>1996</th><th>1997</th><th>1998</th><th>1999</th><th>2000</th><th>2001</th><th>2002</th><th>2003</th><th>2004</th><th>2005</th><th>2006</th><th>2007</th></tr>
<tr><td rowspan="6">South-east Australia</td><td>Moomba–Sydney</td><td colspan="6">AGL 51%, Gasinvest 49%</td><td colspan="8">APA Group</td></tr>
<tr><td>Eastern Gas Pipeline</td><td colspan="6"></td><td colspan="4">Duke Energy</td><td>Alinta</td><td colspan="2">AIH</td><td>Alinta</td></tr>
<tr><td>Victorian transmission system</td><td colspan="5">Govt</td><td colspan="2">GPU GasNet</td><td colspan="5">GasNet</td><td colspan="2">APA Group</td></tr>
<tr><td>SEA Gas Pipeline</td><td colspan="10"></td><td colspan="3">Origin, IP, CLP — 33.3%</td><td>APA, IP, CLP</td></tr>
<tr><td>Moomba–Adelaide</td><td>Govt</td><td colspan="2">Tenneco</td><td colspan="7">Epic Energy</td><td colspan="4">Hastings</td></tr>
<tr><td>Tasmanian Gas Pipeline</td><td colspan="8"></td><td colspan="2">Duke Energy</td><td>Alinta</td><td colspan="2">AIH</td><td>Alinta</td></tr>
<tr><td rowspan="6">Queensland</td><td>Wallumbilla–Gladstone</td><td colspan="6">Govt</td><td colspan="4">Duke Energy</td><td>Alinta</td><td colspan="2">AIH</td><td>Alinta</td></tr>
<tr><td>Gladstone–Rockhampton</td><td colspan="2">Govt</td><td>PG&E</td><td colspan="7">Duke Energy</td><td>Alinta</td><td colspan="2">AIH</td><td>Alinta</td></tr>
<tr><td>Roma–Brisbane</td><td colspan="6">AGL</td><td colspan="8">APA Group</td></tr>
<tr><td>Carpentaria Gas Pipeline</td><td colspan="4"></td><td colspan="2">AGL</td><td colspan="8">APA Group</td></tr>
<tr><td>Ballera–Wallumbilla</td><td colspan="2"></td><td colspan="8">Epic Energy</td><td colspan="4">Hastings</td></tr>
<tr><td>Dampier–Bunbury</td><td colspan="4">Govt</td><td colspan="6">Epic Energy</td><td colspan="4">DUET 60%, Alinta 20%, Alcoa 20%</td></tr>
<tr><td rowspan="2">West. Aust.</td><td>Goldfields Gas Pipeline[2]</td><td colspan="4">GGT JV: 63% WMC</td><td colspan="6">88% Southern Cross Pipelines Australia</td><td colspan="4">APA Group 88%, Alinta 12%</td></tr>
<tr><td>Parmelia Pipeline</td><td colspan="3">WAPET joint venture</td><td colspan="7">CMS</td><td colspan="4">APA Group</td></tr>
<tr><td rowspan="2">NT</td><td>Amadeus Basin–Darwin[3]</td><td colspan="4">Amadeus Gas Trust</td><td colspan="2">AGL (96%)</td><td colspan="8">APA Group (96%)</td></tr>
<tr><td>Palm Valley–Alice Springs</td><td colspan="6">NT Gas & Holyman</td><td colspan="8">Envestra</td></tr>
</table>

AIH: Alinta Infrastructure Holdings. CLP: China Light & Power. DUET: Diversified Utilities and Energy Trusts. GGT JV: Goldfields Gas Pipeline Joint Venture. PG&E: Pacific Gas and Electric. WAPET: West Australian Petroleum Pty. Limited joint venture (Chevron, Texaco and Shell with a two-seventh interest each, and Ampolex with a one-seventh interest). WMC: Western Mining Company. 1. Changes in ownership in the year it occurred. 2. Duke Energy (now Alinta) acquired an 11.8 per cent stake in the GGT JV in 1999. In 2007 AIH became a wholly-owned subsidiary of Alinta. 3. The Amadeus Pipeline Trust leases the Amadeus Basin to Darwin Pipeline from a consortium of financial institutions.

Source: Australian Gas Association, *Gas statistics Australia*; company websites.

## 9.4 Economic regulation of gas transmission services

Given the capital intensive nature of pipeline infrastructure, it is generally cheaper to transport gas using a single transmission pipeline between a gas producing area and a major load centre. Where major load centres are served by only one gas producing area, the transmission pipeline is likely to have significant market power. Where a load centre can be served by multiple gas producing areas, each connected by a transmission pipeline, there may be a constraint on the ability of pipeline operators to exercise market power. Regional transmission systems and distribution systems are generally natural monopolies. To address risks associated with the market power of pipeline operators, governments introduced a regulatory regime for third-party access to natural gas pipelines to complement structural reform in the industry.

Pipeline access is regulated under the National Third Party Access Code for Natural Gas Pipeline Systems (the Gas Code), which operates under the gas pipeline access Acts (Gas Law) in each state and territory.[12] The Gas Code applies only to pipelines assessed as meeting the following coverage criteria set out in s. 1.9:

(a) That access (or increased access) to Services provided by means of the Pipeline would promote competition in at least one market (whether or not in Australia), other than the market for the Services provided by means of the Pipeline

12 All state and territory gas access regimes, other than Queensland's, have been certified as effective under the *Trade Practices Act 1974*, which precludes the relevant pipelines from declaration of third-party access under the generic access provisions of Part IIIA of the Trade Practices Act.


Natural gas pipe

(b) That it would be uneconomic for anyone to develop another Pipeline to provide the Services provided by means of the Pipeline

(c) That access (or increased access) to the Services provided by means of the Pipeline can be provided without undue risk to human health or safety and

(d) That access (or increased access) to the Services provided by means of the Pipeline would not be contrary to the public interest.

Most pipelines were 'covered' under schedule A when the Gas Code was implemented in 1997. Subsequent coverage of pipelines occurred through extensions to existing covered systems, through a competitive tendering process or application to the National Competition Council (NCC).[13] It is also open to a pipeline operator to apply to the NCC for a recommendation to have coverage revoked.

In assessing applications for coverage and revocation of coverage the NCC assesses the merits of the application against the coverage criteria and makes a recommendation to the minister,[14] who makes the coverage/revocation decision. Parties may seek review of a ministerial decision by the Australian Competition Tribunal or state review body.

To date ministers have adopted all but one of the NCC's recommendations on coverage. In 2002 the NCC recommended retaining coverage of the MSP system, but the minister decided to revoke coverage for that part of the pipeline system running from Moomba to Marsden. In addition, on 4 May 2001, the Australian Competition Tribunal overturned the minister's decision to cover the EGP.

Under reforms agreed to in the Australian Energy Market Agreement 2004 (amended 2006) the current Gas Law and Gas Code are to be replaced with the National Gas Law and National Gas Rules. The proposed reforms do not affect the coverage assessment process, but will amend criterion (a) to limit coverage to pipelines where regulated access is likely to generate a material increase in competition in a related market, provide for light-handed regulation and for binding up-front no coverage rulings for greenfield pipelines and price regulation exemptions for international pipelines. The gas pipeline access Acts were also amended in 2006 to give affect to the decision to alter coverage rulings for greenfield and proposed international gas pipelines that deliver gas to Australia.

The providers of covered pipeline services must submit access arrangements to the nominated regulator for approval and comply with other Gas Code provisions, such as ring-fencing. Pipelines that are not covered are subject only to the general anti-competitive provisions of the *Trade Practices Act 1974*. Access to non-covered pipelines is a matter for commercial negotiation between the access provider and access seeker, without regulation.

## Covered transmission pipelines

The trend in the gas transport sector has been towards deregulation, particularly for transmission pipelines. Some recently constructed pipelines, such as South East Australia (SEA) Gas (Victoria–South Australia), the Tasmanian Gas Pipeline (Victoria–Tasmania), EGP (Victoria–New South Wales) and the Australian Pipeline Trust's (APA Group) section of the New South Wales–Victoria Interconnect have never been covered. In addition, coverage (in whole or in part) has been revoked for 14 transmission systems (table 9.2).[15]

As at 1 April 2007 there were 14 covered transmission pipelines. Figure 9.1 depicts major covered pipelines in green. Uncovered gas pipelines are shown in purple.



13 A service provider can also seek coverage through a voluntary access arrangement.

14 The minister with responsibility for energy makes the coverage decision in Western Australia, South Australia and the Northern Territory. In other states and territories the decision maker is the Australian Government Minister for Industry, Tourism and Resources.

15 As at 1 April 2007, the South Australian Minister for Energy had not made a decision on the NCC's recommendation to revoke coverage of the MAPS.

**Table 9.2 Coverage status of transmission pipelines that have been or are covered**

| PIPELINE | STATUS AT 1 APRIL 2007 |
|---|---|
| COVERED UNDER SCHEDULE A AT GAS CODE INCEPTION | |
| NEW SOUTH WALES AND THE AUSTRALIAN CAPITAL TERRITORY | |
| Moomba to Sydney Pipeline System | Covered (except for Moomba to Marsden) |
| Central West (Marsden to Dubbo) | Covered |
| VICTORIA | |
| Victorian transmission system (incl. Western Transmission System) | Covered |
| QUEENSLAND | |
| Wallumbilla (Roma) to Brisbane | Covered |
| Kincora to Wallumbilla | Coverage revoked November 2000 |
| Ballera to Wallumbilla | Covered |
| Dawson Valley Pipeline[1] | Covered |
| Wallumbilla to Gladstone/Rockhampton (Queensland Gas Pipeline) | Covered |
| Moura Mine to Queensland Gas Pipeline | Coverage revoked November 2000 |
| Ballera to Mt Isa (Carpentaria) | Covered |
| SOUTH AUSTRALIA | |
| Moomba to Adelaide Pipeline System | Covered[2] |
| Riverland Pipeline System | Coverage revoked September 2001 |
| South East Pipeline System | Coverage revoked April 2000 |
| WESTERN AUSTRALIA | |
| Dongara to Perth/Pinjarra (Parmelia) | Coverage revoked March 2002 |
| Karratha to Cape Lambert | Coverage revoked September 1999 |
| Beharra Springs to CMSG | Coverage revoked August 1999 |
| Dampier to Bunbury Natural Gas Pipeline | Covered |
| Tubridgi System | Coverage revoked April 2006 |
| Goldfields Gas Pipeline | Covered |
| WMC laterals | Coverage revoked July 1999 (except Kalgoorlie to Kambalda) |
| Goldfields Gas Pipeline to Kalgoorlie PS | Coverage revoked July 1999 |
| NORTHERN TERRITORY | |
| Palm Valley to Alice Springs | Coverage revoked July 2000 |
| Amadeus Basin to Darwin | Covered |
| City Gate to Berrimah | Coverage revoked May 2003 |
| COVERAGE SINCE IMPLEMENTATION OF THE GAS CODE | |
| Eastern Gas Pipeline (Vic and NSW) | Not covered: the Minister's decision to cover (October 2000) was overturned by the Australian Competition Tribunal (May 2001) |
| Berri Mildura Pipeline (SA and Vic) | Covered by competitive tender in 1997<br>Coverage revoked August 2001 |
| Central Ranges Pipeline (NSW) | Covered by competitive tender May 2004 |

1. Coverage of the Dawson Valley pipeline was revoked in November 2000. Following an application to the NCC the pipeline was covered April 2006.
2. A recommendation to revoke coverage of the Moomba to Adelaide Pipeline System is currently before the Minister for Energy in South Australia.

Source: Information provided by the National Competition Council.

## Regulation of covered pipelines

Regulated access arrangements for covered pipelines specify the reference services that a pipeline operator must offer and reference tariffs, which set benchmark prices that form the basis for negotiation of pipeline services. Typically reference tariffs apply to firm forward haulage services. Transmission services are mostly sold under long-term contract on a forward haul basis. Gas users seeking short-term or interruptible supplies can seek to negotiate for those services directly from the pipeline operator or other gas shippers.

Section 8 of the Gas Code requires that reference tariffs:

- be based on the efficient cost (or anticipated efficient cost) of providing the reference services
- where appropriate, provide the service provider with the ability to earn greater profits (or less profits) than anticipated between reviews if it outperforms (or underperforms against) the benchmarks that were adopted in setting the reference tariffs. This provides a market-based incentive to improve efficiency and to promote efficient growth of the gas market.

For new pipelines the reference tariffs for the first access arrangement period may be determined through a competitive tender process approved by the regulator. For other pipelines reference tariffs are determined on the basis of forecast revenue and demand for the services of a covered pipeline. The Gas Code specifies three methods for determining total revenue:

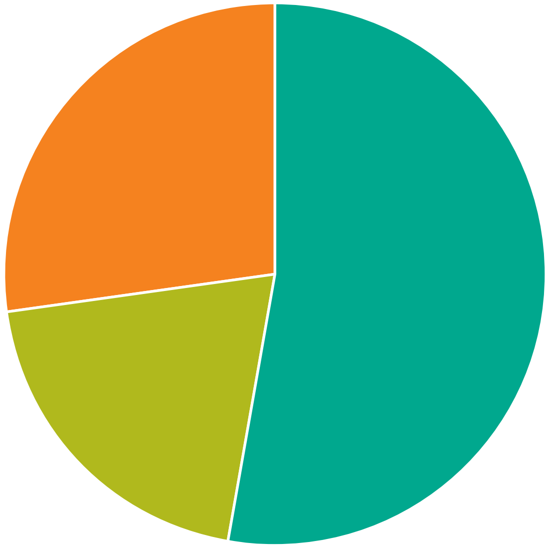
- cost of service—where revenue is set to recover costs using a building block approach that comprises:
  - a rate of return on capital
  - asset depreciation
  - operating and maintenance expenses.
- internal rate of return—where revenue is set to provide an acceptable internal rate of return for the covered pipeline on the basis of forecast costs and sales
- net present value—where revenue is set to deliver a net present value for the covered pipeline (on the basis of forecast costs and sales) equal to zero, using an acceptable discount rate.[16]

In determining price paths, a CPI-X formula is usually applied to provide incentives to improve efficiency.

Most access arrangements apply for a fixed term, usually five years, and are then subject to review and update. Where an access arrangement extends for more than five years there is generally a trigger to allow for early review in the event of a major change occurring. In addition, a service provider may submit unscheduled revisions to the regulator at any time.

Figure 9.3 shows the revenue components under the access arrangement for the DBNGP (Western Australia) for the period 2005 to 2010. This provides a guide to the composition of the building block components in a revenue determination used to determine reference tariffs. Capital and depreciation make up about three-quarters of the revenue determination. Operating and maintenance costs account for around a quarter of the determination.

**Figure 9.3**
**Revenue components for the Dampier to Bunbury Natural Gas Pipeline**



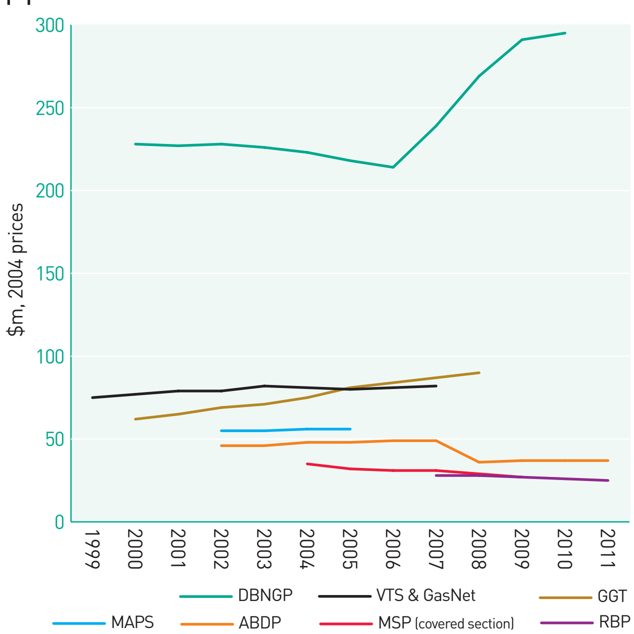

Source: ERA, *Access arrangement information for the Dampier to Bunbury Natural Gas Pipeline*, Perth 2005.

16 Other methods that can be translated into one of these forms are also acceptable.

Figure 9.4 charts forecast revenue over the period 1999–2010 for selected major covered transmission pipelines. The variation in revenue across pipelines reflects differences in demand, age, capacity and length of the pipelines. With the exception of the DBNGP, forecast revenues are relatively stable with changes largely reflecting adjustments to capital expenditure. The significant increase in forecast revenues for the DBNGP reflects an increase in capital-related costs associated with the planned looping and extension of the pipeline, which provides for a substantial increase in gas throughput.

**Figure 9.4**

**Total benchmark revenue for selected transmission pipelines 1999–2010[1]**




ABDP: Amadeus Basin to Darwin Pipeline. MAPS: Moomba to Adelaide Pipeline System. DBNGP: Dampier to Bunbury Natural Gas Pipeline. GGP: Goldfields Gas Pipeline. MSP: Moomba to Sydney Gas Pipeline. RBP: Roma to Brisbane Pipeline. 1. Data for the Western Australian pipelines are based on calendar years. For the other pipelines the data relates to fiscal years.

Source: Approved access arrangement information for each pipeline.

## Ongoing reforms

The Australian Energy Market Agreement 2004 (amended 2006) adopts a national approach to the regulation of gas pipelines. It designates the Australian Energy Regulator as the national regulator of transmission and distribution pipelines. Responsibility for the regulation of transmission and distribution pipelines, except in Western Australia, is scheduled to transfer to the Australian Energy Regulator from 2008 following the implementation of the National Gas Law and the National Gas Rules, which will replace the current Gas Law and Gas Code.

The functions to be transferred to the Australian Energy Regulator are expected to include:

- regulating access arrangements submitted by pipeline service providers under the National Gas Rules
- monitoring compliance with the National Gas Law and National Gas Rules
- arbitrating disputes relating to the terms and conditions of access
- overseeing competitive tendering processes for new transmission pipelines.

The Economic Regulation Authority regulates covered gas transmission and distribution pipelines in Western Australia. It will retain this function under the new framework in recognition that there is no interconnection of pipelines between Western Australia and other states and territories. In support of the new arrangement, Western Australia will implement legislation equivalent to the National Gas Law and the National Gas Rules. In signing the Australian Energy Market Agreement, Western Australia also agreed to conduct an independent review of its institutional arrangements for gas within five years, or earlier, if its pipeline network is to become interconnected with another state or territory.

Details of institutional arrangements for the gas industry are provided in appendix A.

## 9.5 Investment

Typically investment in the transmission sector involves large and lumpy investments associated with the expansion of existing pipelines (through compression and looping) and the construction of new pipelines.[17]

Table 9.3 provides details of completed, planned and proposed major pipeline infrastructure investment projects since 2000. Information in the table indicates that investment spending on major projects over the period 2000–06 was around $2 billion in nominal terms. Current and proposed development activity suggests that the pipeline network will continue to expand at a relatively rapid rate. Several pipelines are being developed, including the Dampier to Bunbury expansion in Western Australia ($1.9 billion, including the $433 million stage 4 project completed in December 2006); the Corio Loop on the Victorian transmission system and a pipeline to connect the Blacktip gas field with the Amadeus Basin to Darwin Pipeline.

New gas developments in Queensland and New South Wales have been accompanied by changes to pipeline proposals. The AGL Petronis consortium have decided not to proceed with the PNG gas pipeline at this time. Instead there are a number of new proposals to expand the Queensland network and connect it with New South Wales and South Australia. Epic Energy and APA Group have entered a heads of agreement on the North Gas Link, (recently renamed the Queensland to South Australia/New South Wales Link or QSN Link), which is a proposal to join the South West Queensland Pipeline at Ballera to the MSP and the MAPS and would make Queensland a part of the interconnected gas pipeline system. Hunter Energy has proposed constructing a gas pipeline to ship gas from Wallumbilla (Queensland) to Hexham (New South Wales). These projects in combination with highly speculative ventures, such as the transcontinental pipeline from Western Australia to Moomba, or the alternative trans-Territory pipeline connecting Moomba with Timor Sea Gas, could potentially result in further investment spending in excess of $3 billion (in nominal terms) into the future.



17 Capacity of a pipeline can be increased by adding compressor stations to raise the pressure under which gas flows and by looping or duplicating sections of the pipeline system. Extending the length of the pipeline can increase line-pack storage capacity.


Erin Jonasson (Fairfax Images)

Laying of new gas pipeline

Table 9.3 **Completed, planned and proposed major pipeline infrastructure investment projects since 2000**

| PIPELINE | STATE | LENGTH (KM) | PROJECT COST | THROUGHPUT (PJ/YR) | PROJECT COMPLETION |
|---|---|---|---|---|---|
| Central Ranges Pipeline | NSW | 300 | $130m | na | 2006 |
| Wagga–Tumut pipeline | NSW | 65 | na | na | 2001 |
| Hunter Gas Pipeline | NSW | 37 | na | na | 2007 |
| Hoskintown–Canberra | NSW–ACT | 31 | na | na | 2001 |
| Eastern Gas Pipeline | Vic–NSW | 795 | $490m | 110 | 2000 |
| SEA Gas Pipeline | Vic–SA | 660 | $526m | 125 | 2004 |
| VicHub | Vic | 2 | $100m | na | 2003 |
| Corio Loop–Vic Transmission System | Vic | 48 | $62m | na | 2008 |
| Tasmanian Gas Pipeline | Vic–Tas | 732 | $476m | na | 2002 |
| Queensland-Hunter Gas Pipeline | Qld–NSW | 850 | $700m | 100 | 2008 |
| North Gas Link (now QSN Link) | Qld–NSW | 180 | $140m | | 2008 |
| Wandoan to Roma–Brisbane main | Qld | 111 | na | na | 2001 |
| Roma–Brisbane pipeline looping project | Qld | 434 | $70.7m | na | 2002 |
| Gladstone–Bundaberg Pipeline | Qld | 300 | na | 1.4 | 2000 |
| North Queensland Gas Pipeline | Qld | 369 | $150m | 20 | 2005 |
| Central Queensland Pipeline | Qld | 440 | $220m | 20–50 | 2008 |
| Ballera to Moomba Interconnect | Qld | 180 | $90m | 20–90 | 2008 |
| Townsville to Ballera Pipeline (Ballera lateral) | Qld | 1200 | $1b | na | 2010[1] |
| Weipa to Gove Pipeline | Qld | na | na | na | 2009[1] |
| Wallumbilla Pipeline | Qld | 152 | na | na | 2008 |
| Ballera to Omicron valve station Pipeline | Qld | 180 | na | na | na |
| Kambalda to Esperance | WA | 350 | $45m | 9 | 2004 |
| Telfer Gas pipeline | WA | 443 | na | na | 2004 |
| Dampier–Bunbury pipeline | WA | | | | |
| > Additional compression | | na | na | na | 2000 |
| > Stage 4 expansion[2] | | na | $433m | 46 | 2006 |
| > Stage 5 expansion[2] | | 570 | $1.5b | 137 | 2009 |
| > *Stage 5A* | | *na* | *$700m* | *na* | *2008* |
| Trans-continental pipeline | WA–SA | 3000 | na | na | na |
| Bonaparte gas pipeline | NT | na | $130m | 30 | 2009 |
| Trans-Territory pipeline | NT–Qld–SA | na | $650m[3] | na | 2009[1] |

na not available. 1. Proposed project commencement. 2. Looping and compression project. 3. Northern Territory component only.

Source: ABARE, Minerals and Energy, *Major development projects*, 2006 and earlier issues.


Mark Wilson

All major capital cities now have access to natural gas supplies. Sydney, Melbourne, Canberra and Adelaide are served by more than one transmission pipeline. Pipeline investment has therefore provided gas users with access to alternative gas basins and pipeline infrastructure.

Table 9.4 lists the pipelines serving each major market in Australia by gas source and producer. The construction of new pipelines has opened the Cooper–Eromanga, Sydney, Gippsland, Otway and Bass basins to increased interbasin competition in south-eastern Australia. In some cases, however, it may only be possible to source gas from a particular basin using backhaul and swap arrangements (for example, supplying Sydney Basin gas into Victoria). More generally, gas tends to be purchased from the closest source possible to reduce the cost of transporting gas.

While Santos, Origin Energy and BHP Billiton have production interests in several of the main gas basins, expansion of the pipeline network has provided new markets for a number of smaller producers, such as Beach, Queensland Gas Company and Sydney Gas. In addition, expansion of the transmission system can enhance competition in the electricity sector by providing opportunities for investment in new gas-fired electricity generators.



**Table 9.4 Pipeline links between major gas sources and markets**

| PIPELINE (OWNER) | GAS BASIN[1] | PRODUCERS |
|---|---|---|
| SYDNEY AND CANBERRA | | |
| Moomba–Sydney Pipeline (APA Group) | > Cooper–Eromanga<br>> Sydney | > Santos, Beach Petroleum, Origin Energy<br>> AGL, Sydney Gas |
| Eastern Gas Pipeline (Alinta)<br>NSW-Vic Interconnect (APA Group) | Gippsland, Otway, Bass | BHPB, ExxonMobil, Origin Energy, Santos<br>AWE, Beach Petroleum, Mitwell |
| MELBOURNE | | |
| NSW-Vic Interconnect (APA Group) | Cooper–Eromanga (via MSP); Sydney | See above |
| Eastern Gas Pipeline (Alinta)<br>Victorian transmission system (APA Group) | Gippsland, Bass, Otway | See above |
| TASMANIA | | |
| Tasmanian Gas Pipeline (Alinta) | Cooper–Eromanga (via MSP and NSW–Vic Interconnect), Gippsland, Otway, Bass | See above |
| BRISBANE | | |
| South West Queensland Pipeline (Hastings Diversified Utilities Fund) | > Cooper–Eromanga<br>> Bowen–Surat | > See above<br>> Mosaic, Origin Energy, Santos, Sunshine Gas, Arrow, Mitsui, Molopo, Qld Gas Corp |
| ADELAIDE | | |
| Moomba–Adelaide Pipeline (Hastings Fund Management) | Cooper–Eromanga | See above |
| SEA Gas Pipeline (APA Group, IP, CLP) | Otway and Gippsland | See above |
| ALICE SPRINGS AND DARWIN | | |
| Amadeus Basin–Darwin (leasehold, 96% APA Group) | Amadeus | Magellan, Santos |
| PERTH | | |
| Dampier–Bunbury Natural Gas Pipeline (DUET (60%), Alcoa (20%), Alinta (20%)) | > Carnarvon<br>> Perth | > Apache, BHPB, BP, Chevron, ExxonMobil, Inpex, Kufpec, Santos, Royal Dutch Shell, Tap Oil, Woodside Petroleum<br>> Arc, Origin Energy |
| Parmelia Pipeline[2] (APA Group) | Perth | Arc, Origin Energy |

1. In some cases it may only be possible to source gas from a particular basin using backhaul and swap arrangements. 2. Industrial supplies only.

Source: EnergyQuest, *Energy quarterly production report*, December 2006.

# 10 GAS DISTRIBUTION NETWORKS

SPAusNet

Natural gas distribution networks transport gas from gas transmission pipelines and reticulate it into residential houses, offices, hospitals and businesses. Their main customers are energy retailers, who aggregate loads for on-sale to end users. For small gas users, distribution charges for metering and transport often represent the most significant component, up to 70 per cent, of delivered gas costs.

# 10 GAS DISTRIBUTION NETWORKS

This chapter considers:

- the role of the gas distribution networks
- the structure of the sector, including industry participants and ownership changes over time
- the economic regulation of distribution networks
- new investment in distribution networks
- quality of service.

## 10.1 Role of distribution networks

A distribution network typically consists of high, medium and low pressure pipelines. The high and medium pressure pipelines are used to service areas of high demand and to provide the 'backbone' of the network (for example, transporting gas between population concentrations within a distribution area). The low pressure pipes lead off the higher pressure mains to the end customer.

Gate stations (or city gates) link transmission pipelines with distribution networks. The stations measure the natural gas leaving a transmission system for billing and gas balancing purposes. They also reduce the pressure of the gas before it enters the distribution network.

Distributors can further reduce the pressure of the gas at regulating stations in the network to ensure that the delivered gas is at a suitable pressure for the operation of customer equipment and appliances.

Australian laws require odorant to be added to gas that enters a distribution system. This promotes safety by making leaks easier to detect. The odorant is usually added to the gas at the gate station.

## 10.2 Australia's distribution networks

Australia's distribution networks expanded from a total length of around 67 000 kilometres in 1997 to over 76 000 kilometres in 2006. The networks represent an investment of more than $7 billion (measured in 2004 prices) and deliver over 300 petajoules of gas a year. Table 10.1 sets out summary details of the distribution networks operating in Australia.

Figure 10.1 shows the location of gas distribution networks in Australia. It illustrates the importance of population density in determining the location of gas reticulation services. In the past few years new distribution networks have been established in northern New South Wales and Tasmania following construction of transmission pipelines in these regions. This means that gas is now reticulated to most of Australia's capital cities, major regional areas and towns, although the Tasmanian and Central Ranges (northern New South Wales) distribution networks are still being rolled out.

**Table 10.1 Major Australian natural gas distribution networks, 2006**

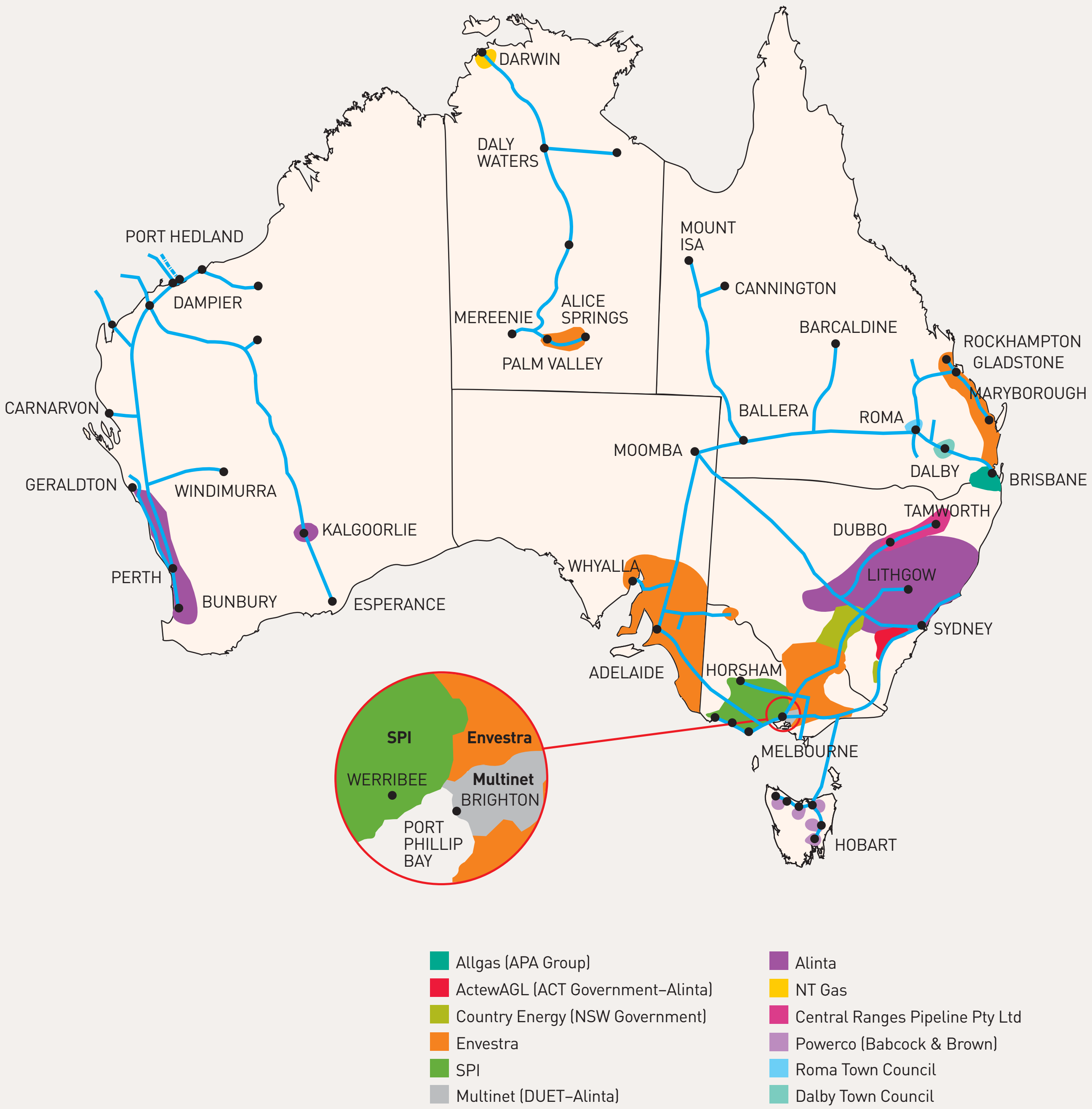
| DISTRIBUTION NETWORK | LOCATION | LENGTH OF MAINS (KM) | THROUGHPUT (PJ A YEAR) | ASSET VALUE[1] ($M, 2004) | CURRENT OWNER[2] |
|---|---|---|---|---|---|
| NEW SOUTH WALES AND THE AUSTRALIAN CAPITAL TERRITORY | | | | | |
| NSW Gas Networks | Sydney, Newcastle/Central Coast, Wollongong | 23 108 | 131.9 | 2116.4 | Alinta |
| Central Ranges System | Dubbo to Tamworth region | na | na | na | Central Ranges Pipeline Pty Ltd[3] |
| Wagga Wagga distribution | Wagga Wagga & surrounding areas | 622 | 1.4 | 51.3 | Country Energy (NSW Govt) |
| Albury Distribution Network | Albury–Wodonga region | 556 | 1.1 | 26.2 | Envestra |
| ActewAGL Distribution (Canberra Gas Network) | ACT, Yarrowlumla and Queanbeyan | 3769 | 7.2 | 264.6 | ActewAGL Distribution (ACT Govt–Alinta) |
| VICTORIA | | | | | |
| Multinet Gas | Melbourne's eastern & south-eastern suburbs | 9420 | 61.4 | 872.7 | DUET (79.9%), Alinta (20.1%) |
| Envestra | Melbourne, north-east & central Victoria | 9040 | 57.5 | 738.9 | Envestra |
| SPI | Western Victoria | 8960 | 71.3 | 862.5 | Singapore Power |
| QUEENSLAND | | | | | |
| AllGas | south of the Brisbane River | 2398 | 13.9 | 309.3 | Australian Pipeline Trust |
| Envestra | Brisbane Region, Rockhampton & Gladstone | 2408 | 5.3 | 232.5 | Envestra |
| Roma Distribution Network | Roma | 70 | 0.02 | na | Roma Town Council |
| Dalby Distribution Network | Dalby | 86 | 0.16 | na | Dalby Town Council |
| SOUTH AUSTRALIA | | | | | |
| Envestra | Adelaide and surrounds | 7492 | 29.1 | 783.0 | Envestra |
| WESTERN AUSTRALIA | | | | | |
| Alinta Gas networks | Mid-west and south west regions | 11 752 | 31 | 658.5 | Alinta |
| TASMANIA | | | | | |
| Tasmanian Gas Network | Hobart, Launceston and other towns | 120 | na | 100.0 | Powerco (B&B) |
| NORTHERN TERRITORY | | | | | |
| Centre Gas Systems[4] | Alice Springs | 35 | na | na | Envestra |
| NT Gas Distribution | Darwin Trade Development Zone | 19 | na | na | NT Gas[5] |

B&B: Babcock & Brown Infrastructure. DUET: Diversified Utilities and Energy Trusts. na not available. 1. Approximate value at the end of 2006 measured in 2004 prices. Based on the rolled forward regulatory asset base for covered pipelines. For Tasmania, the asset value is based on estimated construction costs. 2. As at 1 February 2007. 3. The shareholders of the company are Sun Super and three funds managed by Colonial Funds Management (a wholly-owned subsidiary of the Commonwealth Bank). 4. Also referred to as the Alice Springs Distribution System. 5 The Amadeus Pipeline Trust (96 per cent owned by APA Group) is the major shareholder of NT Gas.

Source: Access arrangements for covered pipelines; Productivity Commission, *Review of the gas access regime*, Report no. 31, 2004, Canberra; company websites.

Figure 10.1

**Gas distribution networks in Australia**




* Locations of the distribution systems are indicative only.

Source: The map is based on AGA submission to the Productivity Commission, *Review of the gas access regime*, August 2003, sub. 13, p. 102; supplemented with additional information.

## 10.3 Ownership of distribution networks

Ownership of distribution assets has tended to remain relatively stable. The changes that have occurred among private players largely reflect a restructuring of existing businesses rather than significant new entry. Major private sector providers of distribution services include Envestra, Diversified Utilities and Energy Trusts (DUET) and Alinta. Under a merger and demerger restructuring completed in late 2006, AGL's interests in distribution services were transferred to Alinta. The swap included AGL's New South Wales distribution network and its 50 per cent share in the Canberra energy networks.

In New South Wales, AGL (now Alinta), through the New South Wales distribution systems, has long been the principal supplier of natural gas distribution services. The system provides more than 90 per cent of the distribution services in the state. Gas services for the Wagga Wagga region were provided by the local council until April 1997. Since then services have been provided by the New South Wales Government corporation Great Southern Energy (now Country Energy).

AGL has provided gas distribution and retail services in the Canberra region since 1991. In 2000 AGL formed a joint venture partnership with the government-owned Actew Corporation to create a combined electricity and gas utility—ActewAGL. Alinta now owns half of the gas and electricity distribution networks. AGL has retained its 50 per cent share of the retail arm.

Victoria privatised its state-owned gas distribution businesses as part of industry reforms between 1997 and 1999. This saw the entry of:

- Envestra (part-owned by Origin Energy[1] and Cheung Kong Infrastructure), which acquired the Stratus network.
- TXU, which acquired the Westar network. Since the end of April 2004 Singapore Power (SPI) has owned and operated the network.
- Utilicorp and an AMP consortium, which acquired the Multinet network. The consortium restructured in 2003 to form DUET. As part of the restructuring deal Alinta also acquired a 20 per cent stake in the network.

In 1995 the Government of Western Australia formed AlintaGas (now Alinta)[2] from the restructuring of the State Energy Commission of Western Australia (SECWA). The government privatised AlintaGas in 2000. WA Gas Holdings Pty Ltd was the cornerstone investor in the process with a 45 per cent holding. The government floated the remaining equity in the business on the stock exchange. As part of a restructuring deal between the AMP consortium and WA Gas Holdings Pty Ltd in 2003, Alinta gained an increased share of the mid-west and south-west distribution systems in Western Australia and a share of the Multinet system in Victoria with the remaining holdings transferred to DUET.

In South Australia Boral acquired the bundled distribution utilities the South Australian Gas Company and the Gas Corporation of Queensland in 1993. It combined the bundled distribution utilities with the assets of Centre Gas Systems (in the Northern Territory) to form Envestra in August 1997. In 1999 Envestra expanded its operations through the acquisition of the Albury Gas Company and the Victorian Stratus network.

1 Origin Energy completed the sale of its network businesses, including its interest in Envestra, to APA Group in July 2007.

2 On 8 May 2003 AlintaGas changed its name to Alinta to reflect its move into electricity.

Figure 10.2

Distribution network ownership changes[1]

<table>
<tr><th></th><th></th><th>1994</th><th>1995</th><th>1996</th><th>1997</th><th>1998</th><th>1999</th><th>2000</th><th>2001</th><th>2002</th><th>2003</th><th>2004</th><th>2005</th><th>2006</th></tr>
<tr><td rowspan="4">NSW and the ACT</td><td>NSW Gas Networks</td><td colspan="12">AGL</td><td>Alinta</td></tr>
<tr><td>Wagga Wagga</td><td colspan="13">Government (now trading as Country Energy)</td></tr>
<tr><td>Albury Gas</td><td colspan="5">Government</td><td colspan="8">Envestra</td></tr>
<tr><td>Canberra Gas Network</td><td colspan="6">AGL</td><td colspan="6">ActewAGL</td><td>Actew-Alinta</td></tr>
<tr><td rowspan="3">Vic</td><td rowspan="3">Gas and Fuel Corporation</td><td colspan="3" rowspan="3">Government</td><td colspan="2">Stratus</td><td colspan="8">Envestra</td></tr>
<tr><td colspan="2">Multinet</td><td colspan="4">AMP Soc & Utilicorp</td><td colspan="4">DUET(79.9%), Alinta (20.1%)</td></tr>
<tr><td colspan="2">Westar</td><td colspan="5">TXU</td><td colspan="3">SPI</td></tr>
<tr><td>Tas</td><td>Tasmanian Gas Network</td><td colspan="9"></td><td colspan="4">Babcock & Brown Infrastructure</td></tr>
<tr><td rowspan="3">Qld</td><td>Allgas</td><td colspan="12">Government</td><td>APA Group</td></tr>
<tr><td>Dalby & Roma distribution</td><td colspan="13">Dalby and Roma local councils</td></tr>
<tr><td>Gas Corp of Qld</td><td colspan="3" rowspan="2">Boral</td><td colspan="10" rowspan="3">Envestra</td></tr>
<tr><td>SA</td><td>SAGASCO</td></tr>
<tr><td rowspan="2">NT</td><td>Centre Gas Systems</td><td colspan="3">Boral</td></tr>
<tr><td>NT Gas</td><td colspan="6">Amadeus Gas Trust</td><td colspan="7">Amadeus Gas Trust (96% APT)</td></tr>
<tr><td>WA</td><td>SECWA</td><td>Govt</td><td colspan="5">AlintaGas created</td><td colspan="3">WA Gas Holdings (45%)</td><td colspan="4">Alinta (75%), DUET (25%)</td></tr>
</table>

APT: Australian Pipeline Trust (which is part of the APA Group). DUET: Diversified Utilities and Energy Trusts. SECWA: State Energy Commission of Western Australia. SPI: Singapore Power. 1. The figure represents changes in ownership in the year it occurred.

In 2006 the Queensland Government sold its state-owned distributor Allgas to the Australian Pipeline Trust (which is part of the APA Group). Allgas operates in south-east Queensland and parts of northern New South Wales. The small distribution networks in Dalby and Roma are owned and operated by the local town councils.

In Tasmania, Powerco provides distribution services. Powerco is owned by Babcock & Brown Infrastructure, a specialist infrastructure entity operating across the energy transmission and distribution, transport infrastructure and power generation sectors in Australia and overseas.

Figure 10.2 summarises ownership changes in the gas distribution sector since 1994.

## 10.4 Regulated distribution networks

When it began in 1997 the National Third Party Access Code for Natural Gas Pipeline Systems (Gas Code) covered 14 distribution networks. Subsequent coverage of pipelines occurred through extensions to existing covered networks, application to the National Competition Council (NCC) or through a competitive tendering process. Conversely, through application to the NCC coverage has been revoked (in whole or in part) for five relatively small distribution networks.

Twelve distribution networks are currently covered (table 10.2). The covered networks operate in the states (except Tasmania) and the Australian Capital Territory.

Table 10.2 **Coverage status of distribution networks that have been or are covered**

| PIPELINE | STATUS AT 1 NOVEMBER 2006 |
|---|---|
| COVERED AT GAS CODE INCEPTION | |
| NEW SOUTH WALES AND THE AUSTRALIAN CAPITAL TERRITORY | |
| NSW Gas Networks (incl Central West)[1] | Covered (except the South West Slopes and Temora extensions)[1] |
| Great Southern (Wagga Wagga) (Country Energy) | Covered |
| Albury Gas Company | Covered |
| Canberra System | Covered |
| VICTORIA | |
| Multinet Gas Systems | Covered |
| Envestra Networks Systems | Covered |
| SPI | Covered |
| QUEENSLAND | |
| Allgas Energy System | Covered |
| Dalby System | Coverage revoked November 2000 |
| Gas Corporation of Queensland (Envestra System) | Covered |
| Roma System | Coverage revoked May 2002 |
| SOUTH AUSTRALIA | |
| Envestra South Australia Distribution Systems | Covered |
| WESTERN AUSTRALIA[2] | |
| Alinta Gas Distribution Systems | Covered |
| NORTHERN TERRITORY | |
| Alice Springs Distribution System (also known as Centre Gas Systems) | Coverage revoked July 2000 |
| COVERAGE SINCE IMPLEMENTATION OF THE GAS CODE | |
| South West Slopes (NSW)[1] | Coverage revoked October 2003 |
| Temora (NSW)[1] | Coverage revoked October 2003 |
| Central Ranges System (NSW) (under construction) | Covered by competitive tender May 2004 |
| Mildura Distribution System (Vic) | Coverage revoked December 2002 |

1. The South West Slopes and Temora distribution networks were constructed as extensions of the NSW network and became automatically covered. 2. The Gas Pipelines Access (Western Australia) Law and Regulations apply to pipelines for the reticulation of natural gas and certain other pipelines transporting liquefied propane, propene, butanes and/or butenes. Only natural gas pipelines are currently covered.

Source: Information provided by the National Competition Council.

## Regulation of covered pipelines

The regulation of distribution networks is the responsibility of state and territory regulators, except in the Northern Territory where the Australian Competition and Consumer Commission (ACCC) fulfils this role. Responsibility for regulating transmission and distribution pipelines, except in Western Australia, is scheduled to transfer to the Australian Energy Regulator from 2008.

The providers of covered pipeline services must submit access arrangements to the nominated regulator for approval, and comply with other Gas Code provisions, such as ring fencing.

Access arrangements specify reference services that the pipeline operator must offer and reference tariffs, which form a benchmark as the basis for negotiating services.[3] Reference tariffs may apply to one or more of the pipeline services offered. For distribution services, reference tariffs often apply to a broad range of services such as capacity reservation, volume, peak, off-peak and metering services.

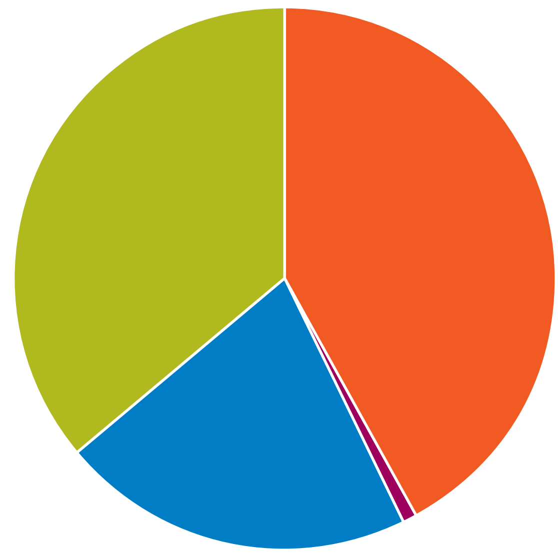
As with transmission most service providers have adopted a building block approach to determining reference tariffs with a CPI-X price path. Pipeline operators can retain any cost savings achieved, but also bear the cost of under-performance. This provides an incentive to improve the efficiency of pipeline operations.

Figure 10.3 shows the components of the revenue cap for the Alinta gas networks in New South Wales (formerly owned by AGL). This illustrates the relative importance of the building block components in a revenue determination used for setting reference tariffs. Capital and depreciation account for over 60 per cent of the revenue determination, while operating and maintenance costs account for most of the rest.

Figure 10.4 shows forecast revenue for selected covered distribution pipelines for 1998–2009. Differences in revenue across pipelines largely reflect the relative size of the networks. Reflecting the incremental nature of investment in the sector, revenue allocations are largely expected to mirror changes in demand.

**Figure 10.3**

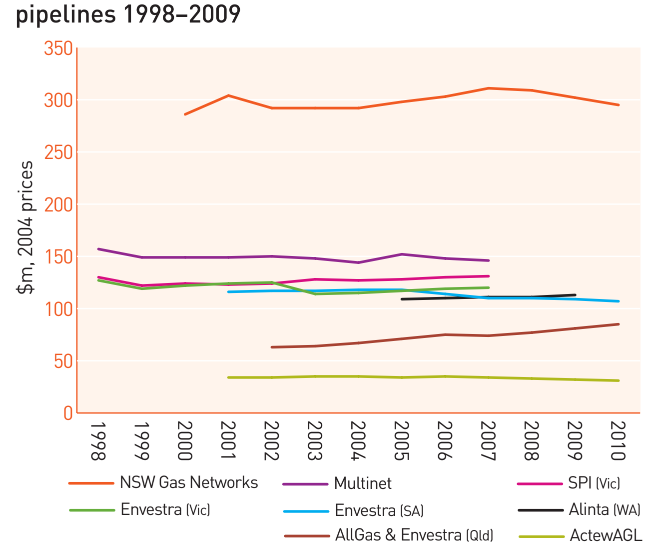
**Revenue building block components for the NSW gas networks, 2005–06 to 2009–10**




Source: IPART, *Revised access arrangement for AGL gas networks*, Final decision, Sydney, 2005.

**Figure 10.4**

**Total revenue allowance for selected distribution pipelines 1998–2009**

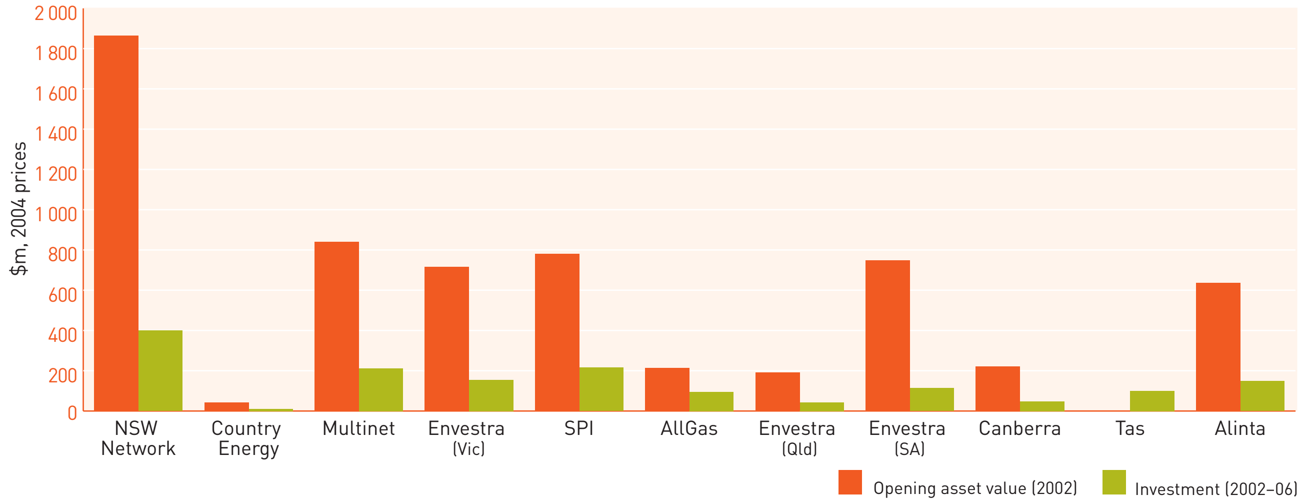



Source: Approved access arrangement information for each pipeline.

3 For the Central Ranges distribution network in New South Wales reference tariffs for the first access period were determined using a regulator-approved competitive tender process.

Figure 10.5

Distribution network assets (2002)[1] and investment (2002–06)[2, 3]




1. The asset values are determined on a depreciated optimised replacement cost basis and derived from the regulatory asset base for 2002, as published in access arrangements. 2. Investment data represents forecast capital expenditure for covered pipelines for 2002–06 (or closest approximation) supplemented with published data on the construction and extension costs for other pipelines. 3. Represents actual investment data for Allgas and Envestra (Qld) as published in the revised access arrangements for the covered networks.

Source: Access arrangement information for each covered pipeline, ABARE, *Minerals and energy, major development projects*, 2006 and earlier issues.



## 10.5 Investment

Investment in the distribution sector includes upgrading and extending existing networks, expanding into new regional centres and towns and constructing new networks. The cost of gas distribution infrastructure varies largely with:

- the distance between access points on a gas transmission line or gas distribution main
- the density of housing and the presence of other industrial and commercial users in the area.

Figure 10.5 shows the value of assets and investment for selected distribution networks. It depicts forecast asset values at the start of the 2002 fiscal year along with forecast capital expenditure for 2002–06. For covered networks the investment data are based on the estimated regulatory asset base (opening value)[4] and forecast capital expenditure published in access arrangements.[5] The value of investment in the Tasmanian Gas Distribution Network is based on projected construction costs as published by Australian Bureau of Agricultural and Resource Economics (ABARE).

Typically investment in the distribution sector is around $250 million a year. Much of this relates to incremental expansion of the existing networks. For example:

- the Victorian Government began a $70 million natural gas extension project in 2003. The project extends the Victorian distribution network to country and regional areas including Bairnsdale, Paynesville, Mornington Peninsula, Macedon Ranges, Creswick, Barwon Heads, Maiden Gully, Port Fairy, Camperdown and the Yarra Ranges.[6]
- ENERGEX began a $3.7 million project in 2005 to upgrade and extend its distribution network in Queensland.

4 The regulatory asset base represents the estimated depreciated optimised replacement cost value of the asset.

5 Investment spending can vary significantly from that determined in access arrangements. For example, the 2001 Allgas access arrangement determined capital expenditure of $59 million for 2002-06. Actual expenditure over that period was $95 million, a variance from the forecast of 60.5 per cent.

6 Business Victoria, Natural Gas Extension Program (NGEP), viewed: 31 August 2006, http://www.business.vic.gov.au/BUSVIC/STANDARD/1001/PC_60302.html.

Construction of new transmission pipelines also provides opportunities to develop new distribution networks. For example:

- The Central Ranges Gas Network (owned by the Central Ranges Pipeline Pty Ltd) is being constructed in New South Wales. It currently provides distribution services in Tamworth and will be incrementally expanded to offer services in Coolah, Coonabarabran, Dunedoo, Gilgandra, Gulgong, Gunnedah, Mudgee, Quirindi and Werris Creek.
- The Tasmanian Natural Gas Distribution Network (owned by Babcock & Brown Infrastructure trading as Powerco) is being rolled out in major cities and towns throughout Tasmania following the construction of the Tasmanian Gas Pipeline.

## 10.6 Quality of service

Quality of service monitoring for gas distribution services is generally in relation to:

- reliability of gas supply (the ability of the service provider to maintain continuous gas supply to customers)
- customer service/customer relations (efficiency and responsiveness of service providers in handling issues such as complaints and reported gas leaks)
- network integrity (gas leaks; operational and maintenance activities).

Some state and territory governments impose quality of service standards and reporting requirements on gas distributors. However, monitoring and reporting of service quality is less comprehensive for the gas industry than for electricity. Gas distribution services are typically more reliable than electricity because gas is transported underground. Even when mains are damaged gas will usually continue to flow so that most customers are unaffected. In addition, gas outages frequently go undetected or have little effect, particularly in the residential sector. By contrast even transient faults in an electrical system can disrupt household, commercial and industrial activities because electricity is used to power continuous equipment operations. For instance lights and fridges stop working and clocks and other equipment may need to be reset once electricity supplies are restored.

Gas distributors also face strong incentives to minimise interruptions. Even when carrying out maintenance work distributors maintain supply to avoid the time and cost associated with lowering pressure and purging air from the pipelines.

### Reliability of supply

The reliability of gas supply refers to the ability of the service provider to maintain a continuous gas supply for customers. Most states and territories impose reliability requirements on gas distributors and monitor their performance. Typically gas distributors are required to:

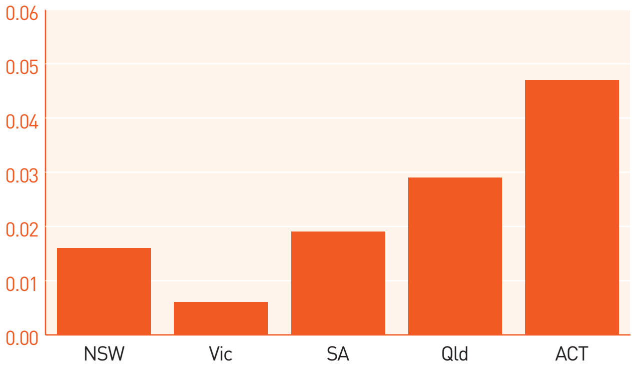
- use their best endeavours to minimise unplanned disruptions to the gas supply
- provide a 24-hour service so customers and retailers can obtain information on unplanned interruptions to supply and for notification of emergencies and faults
- provide minimum notification of planned interruptions to the gas supply.

Figure 10.6 shows unplanned interruption events per 1000 customers in the eastern states and territories. The figure indicates that gas distribution services are reliable. For example, the Australian Capital Territory experienced 88 unplanned interruptions in 2003–04. Only four (0.047 per 1000 customers) of those events affected more that five customers at a time.

In 2004 there were about 19 300 service interruptions in Victoria. In almost all cases fewer than five customers were affected by the outage. In 2005 there were 10 significant events that affected more than 20 people. This equates to 0.006 events per 1000 customers. The Essential Services Commission (ESC) reports that the average customer may expect to lose supply approximately once every 44 years.

Figure 10.6

Unplanned interruption events per 1000 customers




1. NSW data for 2001–02. Vic data for 2005. SA data for 2004-05. Qld and ACT data for 2003-04. 2. For Victoria data reflects the incidence of significant interruptions affecting 20 or more customers. 3. For the ACT data reflects the incidence of interruptions affecting five or more customers.

Source: ESC, *Gas Distribution Businesses—Comparative performance report 2005*, 2006, Melbourne; ESCOSA, *2004/05 Annual performance report, performance of South Australian Energy Distributors*, 2005, Adelaide; ICRC, *Licensed electricity, gas and water and sewerage utilities, performance report for 2003–04*, 2005.

By contrast, Powerco in Tasmania reported that its customers could expect to lose gas services for an average of about 32.8 minutes a year. Nevertheless, Powerco met its target of the gas being off for less than 0.5 per cent of the time in each network it operates. Powerco is still in the process of rolling out the network and has only a few customers. The Office of the Tasmanian Energy Regulator reports that some volatility in reliability could be expected for the next few years.[7]

## Customer service

The level of customer service achieved by a distributor can be measured in terms of responses to customer calls, promptness of connections, meeting appointments with customers on time and the number and nature of complaints made about service providers.

Victoria and South Australia report on customer complaints. In 2005 there were about 1.7 complaints per 1000 customers in Victoria, an improvement in performance of about 2 per cent over the previous year.[8]

In South Australia Envestra received 26 complaints in 2004–05 and 21 complaints in 2005–06.[9] The South Australian Energy Industry Ombudsman received 19 complaints about Envestra in 2004–05 and 15 complaints in 2005–06. These figures represent fewer than one complaint per 1000 customers.

Victoria also reports on a range of customer service indicators. It sets customer call response targets for distributors. The targets require distributors to respond to:

> 95 per cent of customer calls in metropolitan areas (during 7 am to 7 pm weekday) within 60 minutes
> 90 per cent of customer calls in metropolitan areas (after hours) and country areas (all hours) within 60 minutes.

All Victorian distributors met these targets in 2004 and 2005.

Victoria applies guaranteed service levels to distributors. Payment penalties apply for not meeting guaranteed service levels (table 10.3).

Figure 10.7 shows the number of payments made by each distributor for failure to meet target service levels in 2004 and 2005. The ESC reports that in 2004, distributors made a total of 382 payments worth more than $27 000.[10] Around 208 payments made to residential customers were for lengthy interruptions to the gas supply where interruptions were not restored within 12 hours. Envestra made 95 payments for lengthy interruptions, while the other distributors each made around 60 payments. A total of 143 payments were made for repeat interruptions resulting from a residential customer experiencing more than six unplanned interruptions in a 12-month period. Multinet made 63 of these payments, while Envestra made 49 payments and SPI made 31 payments. Distributors were required to make a total of 31 payments for failure to connect a residential customer within two days of the agreed date. Envestra accounted for 22 payments, SPI 8 payments and Mulitnet one payment for delayed connection times.

7 Office of the Tasmanian Energy Regulator, *Tasmanian energy supply industry performance report 2004-05*, 2005, Hobart.
8 Essential Services Commission, Victoria, *Gas distribution businesses-comparative performance report 2005*, August 2006, Melbourne, p. 27.
9 ESCOSA, *SA energy network businesses 05/06*, 2005/06 Annual performance report, November 2006, p. 95.
10 Essential Services Commission, Victoria, *Gas distribution businesses-comparative performance report 2004*, 2005, Melbourne, p. 19.

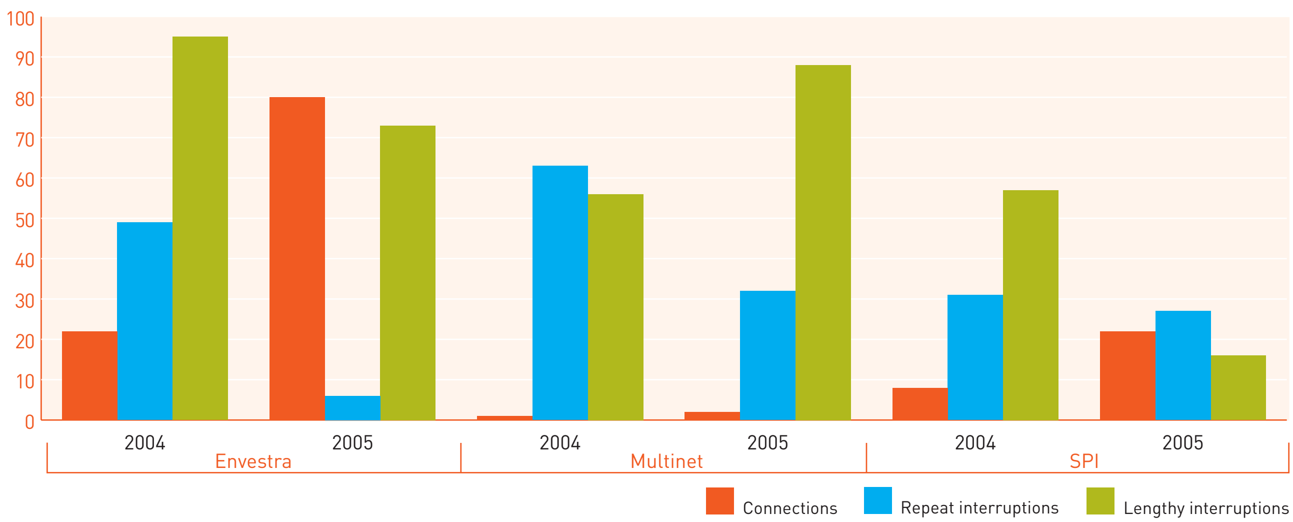
**Table 10.3** Guaranteed service levels (GSL) payment threshold items—Victoria

| AREA OF SERVICE | LEVEL OF SERVICE TO INCUR GSL PAYMENT | LEVEL OF GSL PAYMENT |
|---|---|---|
| Appointments | More than 15 minutes late for appointment with a residential customer[1] | $50 per event |
| Connections | Failure to connect a residential customer within two days of agreed date | $80 per day (subject to a maximum of $240) |
| Repeat interruptions | More than six unplanned interruptions to a residential customer in a 12-month period resulting from faults in the distribution system[2] | $50 for each subsequent event in that calendar year |
| Lengthy interruptions | Gas supply interruption to a residential customer not restored within 12 hours[2] | $80 per event |

1. Appointments rescheduled by the gas businesses are counted as missed appointments. Appointments rescheduled by the customer are excluded from payments.
2. Excluding force majeure, faults in gas installations, transmission faults, third party events and upstream events.

Source: Essential Services Commission, Victoria, *Gas distribution businesses—comparative performance report 2004*, 2005, Melbourne, p. 18.

**Figure 10.7**
**Number of guaranteed service level payments made in 2004 and 2005 by Victorian distributors**




Source: Essential Services Commission (ESC), Victoria, *Gas distribution businesses—comparative performance report 2004*, 2005, Melbourne, p. 18; ESC, Victoria, *Gas distribution businesses—comparative performance report 2005*, August 2006, Melbourne, p. 27.

In 2005, distributors made a total of 347 payments worth about $32 000. Around 177 payments made to residential customers were for lengthy interruptions. Envestra made 73 payments for this, while Multinet made 88 payments and SPI made 16 payments. There were 65 events in 2005 requiring payments for repeat interruptions. Envestra made six payments for this, while the other distributors made about 30 payments each. Distributors were required to make a total of 104 payments for delayed connection times. Envestra accounted for 80 payments, Mulitnet 2 payments and SPI 22 payments.

In 2006 Alinta began a GSL scheme similar to that operated in Victoria. Compensation payments range between $25 for late appointments up to $100 for repeat interruption events.

## Network integrity

Some state regulators report on network integrity issues, including gas leaks, condition of the pipelines and operational and maintenance activities. However, there is little consistency in reporting on gas leaks and unaccounted-for gas. (Unaccounted-for gas is the difference between the quantity of gas delivered into the network and that withdrawn from a network in a given period. This can result from gas leaks, meter error and theft.)

### Victoria (reports on gas leaks per kilometre of pipe)

In 2005 Multinet recorded the highest gas leaks per kilometre at 1.22, followed by SPI (1.15) and Envestra (0.99). The ESC reports that the difference between distributors is not significant and shows fewer leaks than in 2004, but over the three-year period from 2003–05 leaks increased by about 4 per cent. Between 2003–05 Victorian distributors replaced 534 km of low pressure gas mains. This represents about half of the mains targeted for replacement over the five-year period 2003–07.[12]

### Queensland (unaccounted-for gas)

The level of unaccounted-for gas for the Allgas network during 2003–04 was 383 terajoules or about 4 per cent of total throughput. By comparison the level of unaccounted-for gas for the Envestra network during the reporting period was 329 terajoules or about 2 per cent of total throughput.[13]

### South Australian (unaccounted-for gas)

In 2005–06 the proportion of unaccounted-for gas was about 4.2 per cent of delivered gas (1630 terajoules), an increase of almost 60 per cent from 2002–03. ESCOSA reports that the amount of unaccounted gas is linked closely to the amount of cast iron pipelines within the system because such pipelines are susceptible to ground movement and to joint failures. Over 20 per cent of Envestra's network was made up of cast iron pipelines in 2004. This is somewhat higher than Multinet and Envestra (Queensland). By comparison around 13 per cent of the Allgas network was made up of cast iron pipes in 2004. Envestra has a program in place to replace cast iron mains. In 2005–06 it replaced 86 kilometres of mains. Its current access arrangement allows for capital expenditure to replace 100 kilometres of pipe a year.[14]

### The Australian Capital Territory (unaccounted-for gas)

In 2004–05 there were 61 terajoules of gas unaccounted for from ActewAGL's distribution network (including the Queanbeyan portion).

### Western Australian (unaccounted-for gas)

Western Australia collects data from distributors on unaccounted-for gas and reliability, but does not make the information public. In its most recent access arrangement Alinta reports that between 2000 and 2002 unaccounted-for gas fluctuated between 2.6 per cent and 2.7 per cent. Alinta notes that roughly half of its unaccounted-for gas results from measurement error. It forecasts that unaccounted-for gas would be 2.5 per cent a year for the 2005–09 access arrangement period.[15]



12 ESC, *Gas distribution businesses comparative performance report for the calendar year 2005*, August 2006.

13 QCA, *Gas distribution service quality performance: 1 July 2003 to 30 June 2004*, http://www.qca.org.au/files/ServiceQualityReport200304_QCASummary.pdf.

14 ESCOSA, *SA energy network businesses 05/06*, 2005/06 Annual performance report, November 2006.

15 Alinta, *AlintaGas networks access arrangement information for the mid-west and south-west gas distribution systems*, Amended AAI dated 29 July 2005.

# 11 GAS RETAIL MARKETS

Craig Abraham (Fairfax Images)

Retailers contract for gas with producers and pipeline operators to provide a bundled package for on-sale to customers.

# 11 GAS RETAIL MARKETS

The retail market provides the main interface between the gas industry and customers such as households and businesses. This chapter considers:

- the role of the gas retail sector
- the structure of the retail market, including
- industry participants
- ownership changes over time
- convergence between electricity and gas retail markets
- the development of retail competition
- retail market outcomes, including price, affordability and service quality
- the regulation of the retail market.

## 11.1 Role of the retail sector

While retailers bundle gas with transport, they are usually not providers of pipeline services. Rather, they provide a convenient aggregation service for gas consumers, who pay a single price for a 'bundled' product made up of the constituent gas, transmission and distribution services.

Retail customers are residential, business and industrial gas users. This chapter focuses on the regulated segment of the market. Regulation applies to the supply of services to 'small customers', those using less than 1 terajoule of gas a year. This includes all residential and small business gas users.

Gas and electricity were traditionally marketed as separate products by separate retailers. In the last few years, regulatory reform and the economics of energy retailing have caused a change in this approach, with a number of energy retailers being active in both gas and electricity markets and offering 'dual fuel' products. A number of factors are driving convergence. By combining billing systems, call centre, marketing and administrative functions, retailers can achieve cost savings. Convergence also enables retailers to bundle gas and electricity offers, which can help attract and retain consumers. Convergence can, however, create hurdles for new entrants, which may also need to offer a broader range of services to win customer share.

Given this trend, this chapter should be read in conjunction with chapter 6, 'Electricity retail markets'. To avoid repetition, some matters canvassed in chapter 6 are discussed only briefly here.

## 11.2 Gas retailers

Historically, gas retailers in Australia were integrated with gas distributors and operated essentially as monopoly providers in their state or region. Retail service providers represented a mix of both public and private ownership. In Victoria, for example, retail services were fully government-owned and vertically integrated with transmission and distribution services. In South Australia the government owned a 51 per cent shareholding in the distributor/retailer SAGASCO. In New South Wales the privately owned company AGL provided the bulk of distribution and retail services, with the Wagga Wagga City Council providing natural gas services for the Wagga Wagga region.

In the 1990s governments began to implement changes to improve the efficiency of the energy sector through restructuring, privatising and introducing competition. The South Australian Government sold its share in SAGASCO in 1993. Since 1996 New South Wales has applied ring-fencing obligations to integrated gas utilities to operationally separate gas transportation and retailing services and provide a level playing field for all competing retailers. Similar arrangements operate in other states and territories where there are vertically integrated gas businesses.

Victoria restructured, corporatised and privatised its gas retailers between 1997 and 1999. Western Australia followed suit, privatising its state-owned gas retailer in 2000. In 2006–07 Queensland restructured its energy businesses and privatised the gas retail and distribution functions. The combined distributor/retailers in Dalby and Roma remain owned and operated by local government. Tasmania, the Australian Capital Territory and the Northern Territory have opened gas retailing to full competition. The governments of Tasmania and the Australian Capital Territory also maintain some public ownership of gas retail businesses.[1]

There have been significant ownership changes in the gas retail sector. Table 11.1 lists licensed retailers that are currently active in the market for residential and small business customers. Not all licensed retailers are active in the small customer market. Some retailers target only large customers; others may not be active currently but may have been active in the past or may have acquired a licence with a view to future marketing.

The retail players in most jurisdictions include:

- one or more 'local' or 'host' retailers—these retailers are often subject to a range of consumer protection measures that oblige them to offer to supply customers in a designated geographical area according to standard terms and conditions, often at capped prices
- new entrants, including established interstate players, electricity retailers branching into gas retailing and new players in the energy retail sector.

1 The Northern Territory Government has a small ownership interest in gas retailing. The government-owned Power and Water Corporation, through its subsidiary Darnor, has a 2.5 per cent interest in NT Gas.

**Table 11.1** Natural gas retailers active in the small customer market[1]

| RETAILER[2] | NSW | ACT | VIC | SA | TAS | QLD | WA | NT | OWNERSHIP |
|---|---|---|---|---|---|---|---|---|---|
| ActewAGL Retail | Host | Host | | | | | | | ACT Government and AGL Energy |
| AGL Energy Retail | Host | | Host | New entrant | | | | | AGL Energy |
| Sun Gas Retail | Host | New entrant | | | | Host | | | AGL Energy |
| Alinta | | | | | | | Host | | Alinta (67%); AGL Energy (33%) |
| Aurora Energy | | | | | Host | | | | Tasmanian Government |
| Australian Power & Gas[3] | New entrant | | New entrant | | | New entrant | | | Australian Power & Gas |
| Country Energy | Host | New entrant | | | | | | | NSW Government |
| EnergyAustralia | New entrant | New entrant | | | | | | | NSW Government |
| EnergyAustralia[4] | | | New entrant | New entrant | | | | | NSW Government and International Power |
| NT Gas Distribution | | | | | | | | New entrant | NT Gas[5] |
| Centre Gas Systems | | | | | | | | New entrant | Envestra |
| Option One | | | | | New entrant | | | | Babcock & Brown |
| Origin Energy | Host | | Host | Host | | Host | | | Origin Energy |
| TRUenergy | New entrant | | Host | New entrant | | | | | China Light and Power |
| Victoria Electricity | | | New entrant | | | | | | Infratil |
| Active retailers | 8 | 4 | 6 | 4 | 2 | 3 | 1 | 2 | 30 |
| Approx. market size ('000 customers) | 953.6 | 94.0 | 1 587.2 | 368.0 | na | 137.8 | 515.4 | 0.1 | 3 656.1 |

Host (local or incumbent) retailer    New entrant

1. As at 1 April 2007. The list excludes licensed retailers (mainly gas producers and distributors) that are not actively selling to small gas consumers such as BHP Billiton Petroleum, Esso Australia, Santos, CitiPower, Integral Energy, Synergy, Jackgreen, Red Energy and South Australia Electricity. It also excludes licensed LPG retailers and three small retailers (BRW Power Generation (Esperance), Dalby Town Council, Roma Town Council). 2. Some retailers, such as AGL Energy and Infratil, operate under a variety of different trading names. 3. Able to actively trade in Queensland from 1 July 2007. 4. The EnergyAustralia-IPower Pty Ltd Retail Partnership trades under the name of EnergyAustralia. 5. The major shareholder of NT Gas is the Amadeus Pipeline Trust, in which APA Group has a 96 per cent interest.

As at 1 April 2007 there were about 14 gas retailers (operating a total of 30 licences) active in small customer markets in Australia. In the electricity sector there are around 21 retailers (operating a total of 46 licences) active (see also table 6.1). Differences in the level of activity may reflect a range of factors, including market size, profitability, government policy, experience and risk factors. The small customer electricity market is much larger than gas creating more opportunity to compete in this segment of the energy market. Electricity retailers do, however, face risks, such as liquidity problems, that can arise from exposure to a volatile spot market, which can act as a barrier to entry. Similarly, difficulties in contracting for gas and pipeline capacity can affect opportunities to compete in the retail gas and gas-fired electricity generation sectors. In South Australia, for example, pipeline capacity has been an issue with both the Moomba to Adelaide and SEA Gas pipelines being fully contracted. In the Northern Territory all available gas is fully contracted until 2009. This largely precludes entry into the gas and wholesale electricity market until new supplies of gas become available. The Blacktip field is expected to commence supplying gas for the domestic market from early 2009, which may free up supplies and allow new players to enter the Northern Territory retail market.

## 11.2.1 New entry in retail

Information published by state and territory regulators indicates that there has been some development of the active retailer base in a number of states.

### New South Wales and the Australian Capital Territory

New South Wales opened the residential market to competition in 2002. It now has 15 licensed retailers, of which about eight are active in the residential and small business market. Between 2002 and 2006, the total number of licensed retailers has ranged between 13 and 16.

AGL is the main local gas retailer for much of New South Wales. Other retailers with additional regulatory obligations include Country Energy, Sun Gas Retail (now owned by AGL) and ActewAGL, which provide energy retail services in some regional areas. New players include New South Wales electricity retailer EnergyAustralia and an established interstate retailer TRUenergy. Australian Power & Gas entered the New South Wales retail energy market on 1 April 2007.

Four retailers are active in the Australian Capital Territory small customer market—the local retailer ActewAGL Retail (owned by the Australian Capital Territory Government and AGL) plus EnergyAustralia, Country Energy and TRUenergy.

### Victoria

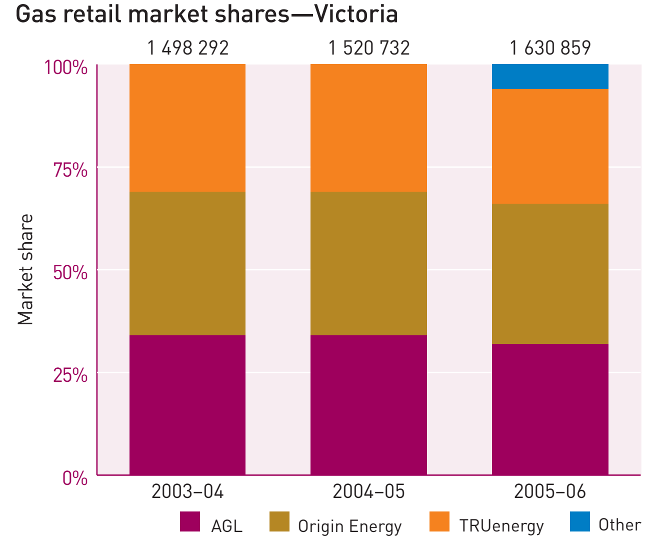
In the late 1990s Victoria split the Gas and Fuel Corporation into three separate retail businesses, each linked to a distribution network area, and sold each to different interests—Utilicorp and AMP Society (operating as United Energy and Pulse Energy), TXU and Origin Energy. Two of the businesses have since changed hands:

> AGL acquired the former United Energy business in 2002.

> TXU sold its retail interests to Singapore Power in 2004, which in turn sold the business to China Light and Power in 2005. The new owners rebadged TXU as TRUenergy.

Victoria opened the residential market to competition in 2002. The state now has 10 licensed retailers, of which about six are active in the residential and small business market. The local retailers—TRUenergy, AGL and Origin Energy—each account for around a third of the market, and each retails beyond its 'local' area (figure 11.1). Other retailers active in the Victorian market include interstate retailers EnergyAustralia and relative newcomers Victoria Electricity (owned by Infratil) and Australian Power & Gas. At present, the market share of new entrants is small (table 11.2). The Victorian market continues to attract new entry. In November 2006, for example, Red Energy obtained a licence to retail gas in Victoria, but at 1 April 2007 it was not actively retailing gas.

**Figure 11.1**
**Gas retail market shares—Victoria**




Source: ESC, *Energy retail businesses comparative performance report for the 2005–06 financial year*, 2006, p. 2.

Table 11.2 Gas retailer customer numbers and market share in Victoria 2005–06

| | RESIDENTIAL | | BUSINESS | | TOTAL | |
|---|---|---|---|---|---|---|
| GAS RETAILER | CUSTOMERS | MARKET SHARE | CUSTOMERS | MARKET SHARE | CUSTOMERS | MARKET SHARE |
| AGL | 505 435 | 32% | 11 361 | 26% | 516 796 | 32% |
| Origin Energy | 547 988 | 35% | 13 656 | 31% | 561 644 | 34% |
| TRUenergy | 431 364 | 27% | 17 264 | 40% | 448 628 | 28% |
| Other | 102 386 | 6% | 1 405 | 3% | 103 791 | 6% |
| Total | 1 587 173 | 100% | 43 686 | 100% | 1 630 859 | 100% |

Source: ESC, *Energy retail businesses comparative performance report for the 2005–06 financial year*, 2006, p. 2.

### South Australia

In 1993, Origin Energy (formerly Boral) acquired the South Australian Government's share of SAGASCO to become the gas retailer for South Australia. There has been some new entry into the gas retail market since the introduction of full retail contestability (FRC) in the state in 2004. As at April 2007 four retailers were active in the residential and small business market.

In addition to Origin Energy, the players are AGL, TRUenergy and EA–IPR Retail Partnership (trading as EnergyAustralia). In the case of the EA–IPR Retail Partnership, International Power announced on 25 May 2007 that it has exercised its option to acquire the remaining 50 per cent of the partnership. The transaction is expected to be completed in August 2007.

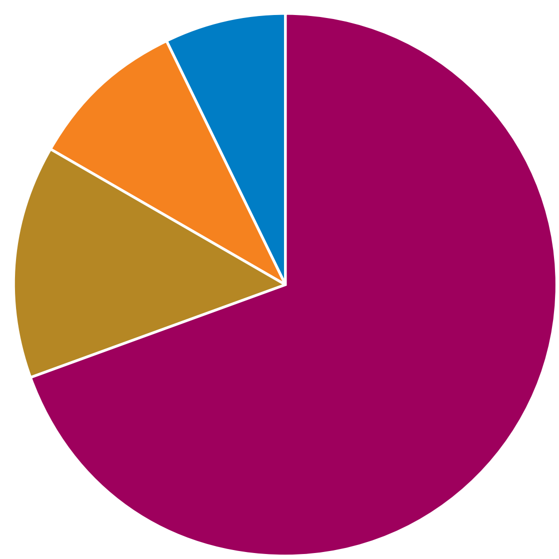
New entrants account for around 30 per cent of the South Australian retail gas market (figure 11.2). South Australia Electricity and Jackgreen also obtained gas retail licences in September 2006, but were not actively retailing gas by April 2007. In April 2007 Momentum Energy lodged an application for a gas retail licence. Momentum Energy holds an electricity retail licence in South Australia.

### Tasmania

In Tasmania Powerco (owned by Babcock & Brown) is constructing distribution networks in parts of the state. Tasmania has two gas retailers—the state-owned Aurora and Option One (also owned by Babcock & Brown).

Tasmania does not consider the supply of natural gas to be an essential service and does not regulate the retail price of natural gas or impose an obligation to supply. Tasmania has a gas retail code in place, which establishes minimum terms and conditions for the supply of gas services to small retail customers.

Figure 11.2
Gas retailers' market shares 2005–06 in South Australia




Source: ESCOSA, *SA energy retail market 05/06*, November 2006.

### Queensland

The small customer market in gas in Queensland is relatively small. The bulk of the small customer market is divided between Sun Gas Retail and Origin Energy. Each company operates within an exclusive designated geographical area. In Dalby and Roma the local councils provide gas distribution and retail services.

In 2006 the Queensland Government commenced a process to restructure and privatise the retail energy sector in preparation for the introduction of FRC in July 2007. In February 2007 the Queensland Government completed the sale of Sun Gas Retail Pty Ltd (a new company created from the energy retailing arm of ENERGEX) to AGL.

Relative newcomer Australian Power & Gas Company Limited (formerly Microview Limited) obtained gas and electricity retailing licences for Queensland in January 2007.

**Western Australia**

Western Australia has had systems in place since the end of May 2004 to allow new entry in the small customer market; however, as at April 2007, Alinta remains the only supplier. Under a recent agreement between AGL and Alinta, AGL has entered the Western Australian retail market through acquisition of a 33 per cent interest in Alinta's retail business. AGL has an option to increase its interest in the business to 100 per cent over five years. In May 2007 Babcock & Brown, in a consortium with Singapore Power and three of its managed infrastructure funds—Babcock & Brown Infrastructure, Babcock & Brown Power and Babcock & Brown Wind Partners—agreed to acquire Alinta's two-third share of the Western Australian gas retail business.

In 2007 Synergy (Western Australia's largest energy retailer) applied for a gas trading licence to allow it to sell gas to some small-use customers. Government-imposed restrictions have prevented Synergy and Verve supplying gas to customers who consume less than 1 terajoule a year. On 1 July 2007 the government lowered the threshold to 0.18 terajoules a year. This change provides the opportunity for Synergy and Verve to compete for gas sales to about 2000 additional energy consumers, mostly small businesses including some restaurants, bakeries and metal fabrication plants with annual gas bills of more than $4000.[2]

**The Northern Territory**

In the Northern Territory gas is predominately used for electricity generation. Envestra retails gas in Alice Springs and NT Gas supplies a small quantity of gas for commercial and industrial customers in Darwin's industrial area. The Northern Territory has never regulated retail gas services.

### 11.2.2 Energy retail market convergence and integration

Efficiencies in the joint provision of electricity and gas services have led to retailers being active in both electricity and gas markets, and offering dual fuel retail products (sections 6.1.1 and 11.1). In Victoria, for example, AGL, Origin Energy and TRUenergy jointly account for about 90 per cent of retail customers in both electricity and gas.

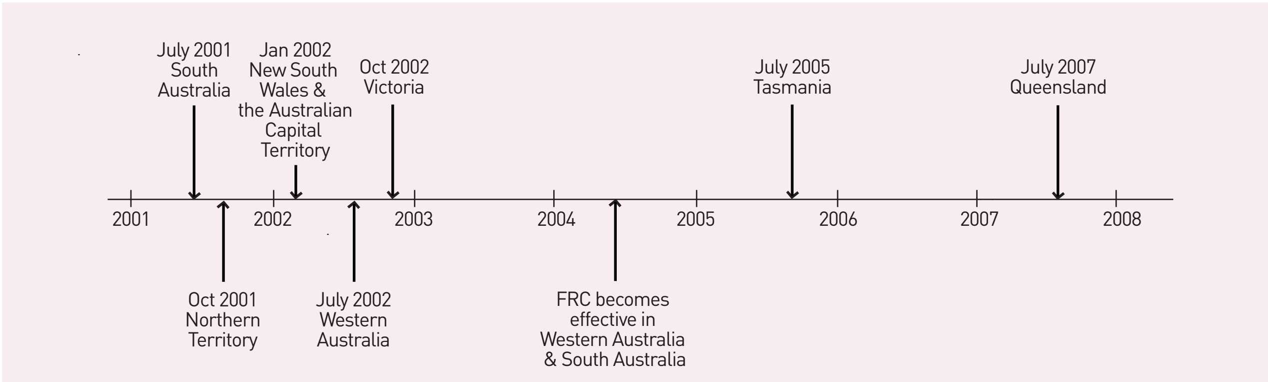
Several new players in the gas retail market reflect the convergence of gas and electricity retailing. TRUenergy, EnergyAustralia, Integral Energy, ENERGEX, Momentum Energy and Aurora Energy are among new entrants in gas retailing that have an established profile in electricity. Similarly, Jackgreen—a recent entrant in the New South Wales and Victorian electricity markets—has obtained licences to retail gas in New South Wales (October 2005) and South Australia (September 2006). Option One, a new entrant trading in Tasmania, was formed by Powerco, one of New Zealand's largest gas and electricity distributors.

Traditional gas retailers, such as AGL and Origin Energy, are also diversifying into electricity retailing and generation (section 6.2). AGL, for instance, has acquired electricity retail interests in the Australian Capital Territory, Victoria and South Australia.



2 Minister for Energy (WA) (Hon. Francis Logan), *Gas market changes to improve consumer choices*, media statement, 23 August 2006.

Figure 11.3
Introduction of full retail contestability




AGL, Origin Energy and TRUenergy have vertical linkages within the gas industry. Origin Energy has an interest in gas resources in Western Australia, South Australia, Queensland and Victoria. AGL has expanded into production of coal seam methane in Queensland and New South Wales. Investment in gas production provides gas retailers with a natural hedge against gas price rises and provides security of supply.

In 2006 AGL distributed gas in New South Wales and the Australian Capital Territory, but has divested its gas infrastructure assets via a swap with Alinta. TRUenergy has gas storage facilities in Victoria.

For a wider discussion of energy market convergence and integration, see section 6.2 of this report.

## 11.3 Retail competition

Historically, gas customers in each state were tied to a single retailer and paid prices set by the government. From 1999 governments began to implement retail contestability (consumer choice) by issuing licences to new retailers to enter the gas market (figure 11.3).

Most governments chose to introduce retail contestability gradually by introducing competition for large industrial customers, followed by small industrial customers and, finally, small business and household customers. With the introduction of FRC in Queensland on 1 July 2007, all states and territories now permit all customers (large and small) to enter a supply contract with a retailer of their choice.

Retail contestability requires management of customer transfers between retailers. In Tasmania, Powerco, the local distributor, undertakes this role. In the other states and territories where there are competing retailers, an independent market operator is responsible for managing customer transfers between retailers and for ensuring compliance with the rules governing the operation of the retail gas market. The independent market operator for New South Wales and the Australian Capital Territory is the Gas Market Company (GasCo). In South Australia and Western Australia it is the Retail Energy Market Company (RemCo). VENCorp is responsible for the Victoria and, since 1 July 2007, Queensland.

The introduction of FRC allows consumers to enter into a contract with any licensed retailer of their choice. As a transitional measure, some jurisdictions require local retailers to supply small customers in nominated geographical areas on a contract that is subject to regulated terms and conditions, often at capped tariffs. As in electricity, this provides a 'default' option for customers who do not have a market contract (section 6.3). However, the goal of FRC is to use competition to deliver lower prices and better service performance. While the flexibility to do this may be constrained by the use of fixed-term contracts, exit notification terms and conditions, exit fees and other costs associated with changing contractors, competition provides an opportunity for consumers to shop around for the best offer. This provides ongoing incentives for retailers to look for cost savings and ways to improve their service offerings.

### 11.3.1 Price and non-price diversity

A competitive retail market is likely to exhibit some diversity in price and product offerings as sellers try to win market share. There is some evidence of price and product diversity in retail gas markets in Australia.

Under market contracts, retailers generally offer a rebate and/or discount from the 'standard' price. Often discounts are tied to the term of the contract with contracts running for a year or more typically attracting larger discounts than more flexible arrangements. Further discounts may be available for prompt payment of bills and direct debit bill payments and so forth. Some retailers offer plans allowing payment options, such as bill smoothing. Such options may attract higher gas tariffs, but may be convenient for some consumers and can help to reduce the likelihood of payment defaults.

Some price diversity is associated with product differentiation. Environmentally friendly services are generally priced at a premium. On the other hand, consumers can obtain a discount for contracting with a single retailer for dual fuel—both gas and electricity—services. The Essential Services Commission (ESC) of Victoria has linked the state's high switching rates (see sections 6.3.2 and 11.3.2) with an expansion in dual fuel offers.

Some product offerings reflect gas services bundled with other inducements such as loyalty bonuses, competitions, membership discounts, shopper cards, discounts and free products. Origin Energy, for example, offers free magazine subscriptions with some of its services. In some states AGL has a rewards program that provides a $50 voucher redeemable at AGL shops, priority installation on appliances and a two-year labour warranty on appliances that AGL installs.

In assessing non-price product innovation in 2004, the ESC reported:

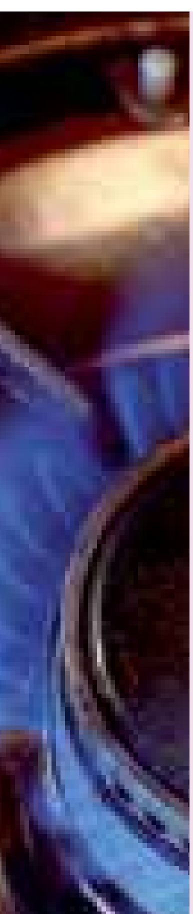
> Retailers appear to have different strategies depending on their 'place' in the market—local or non-local retailer—and whether developing a customer base or maintaining a customer base. A number of non-price offerings are geared towards building brand awareness through alliances with recognisable non-energy products such as credit card companies and the AFL (termed 'referral agents'… These campaigns may also provide a more cost effective channel for retailers to acquire customers as well as building a longer-term relationship with them.[3]

The ESC noted that retailers are actively seeking customer input in developing improved offers that cater to customer requirements. Features of market offers resulting from customer input included evergreen contracts for renters, extended contracts with fixed prices and energy audits and efficiency advice. The ESC added that the margins available for some customer segments may limit the extent of price discounts and retailers may therefore seek other ways to win customers, such as non-price offers that appeal to 'emotional' customer drivers.

3 ESC, *Special investigation: Review of effectiveness of retail competition and consumer safety net in gas and electricity*, final report to minister, June 2004, p. 93.

South Australia conducted surveys in 2004 and 2006 on customer perceptions of variety and innovation in retailer product offerings in energy markets (see figure 6.4). The results suggest that South Australian customers have a reasonably strong perception that product variety and innovation in the retail market is increasing.

The variety of discounts and non-price inducements makes direct price comparisons difficult. There is also variation in the transparency of price offerings. Some retailers publish details of their products and prices, while others require a customer to fill out online forms or arrange a consultation. The ESC and the Essential Services Commission of South Australia (ESCOSA) provide estimator services that allow price comparisons within those states. An example using the estimator provided by ESCOSA appears in box 11.1.



### Box 11.1 Gas contract offers for metropolitan areas in South Australia

Table 11.3 sets out the estimated price offerings in March 2007 for a customer using 24 gigajoules of gas a year in metropolitan South Australia. The estimator provides an indicative guide only, but takes account of discounts and other rebates. It does not account for elements of retail offers that are not price-related and for variations relevant to the circumstances of particular customers. Table 11.3 indicates some price diversity in South Australia's gas retail market, although there appears to be less depth than in electricity (see table 6.6). There is a price spread of around $92 across all retail offers with consumers on a market contract able to save up to $40 compared to a standing offer.

Section 11.4 of this report provides further information on gas retail prices, including trends in average prices over time.

**Table 11.3 Estimated cost of gas contract offers in South Australia[1]**

| RETAIL OFFER | COST BEFORE INCENTIVES | AVAILABLE REBATES | ESTIMATED ANNUAL COST | ESTIMATED ANNUAL SAVINGS | AVERAGE PRICE ($/GJ) |
|---|---|---|---|---|---|
| ORIGIN ENERGY | | | | | |
| Standing Contract | $586 | $0 | $586 | – | $24.38 |
| GreenEarth | $638 | $0 | $638 | –$52 | $26.55 |
| HomeChoice | $574 | $0 | $574 | $12 | $23.88 |
| TRUENERGY | | | | | |
| Go Easy | $568 | $0 | $568 | $18 | $23.63 |
| Go For More | $546 | $0 | $546 | $40 | $22.72 |
| At Home | $563 | $12 | $551 | $35 | $22.93 |

1. Based on roughly average levels of household gas consumption of 24 gigajoules of gas a year (with more consumption in winter than summer) for residents in a metropolitan area.

Source: ESCOSA estimator, viewed 20 March 2007, <www.escosa.sa.gov.au>.

## 11.3.2 Customer switching

The rate at which customers switch their supply arrangements, or 'churn', is often used as an indicator of competitive activity, market power and customer participation in the market. High churn rates can reflect such things as:

- the availability of cheaper and/or better offers from competing retailers
- successful marketing by retailers
- customer dissatisfaction with their service provider.

However, low levels of churn do not necessarily reflect a lack of competition. Retailers can seek to minimise churn by:

- creating barriers to discourage customers from changing their suppliers, such as binding fixed term contracts and exit or early termination fees
- bundling goods and services together (for example, dual fuel offers)
- using retention activities such as loyalty programs
- providing a good quality service.

Churn is also likely to be affected by other factors, such as the number of competitors in the market, customer experience with competition, demographics, demand and the cost of the service. For example, consumers are more likely to be responsive to energy offers and/or actively seek out cheaper services where the cost of gas services represents a relatively high proportion of their budget.

New South Wales and the Australian Capital Territory, Victoria and South Australia publish data on retail churn rates of gas customers. This section compares the available data, but does not attempt to draw any conclusions because, as noted above, churn can be influenced by so many variables.

Gas churn data for New South Wales and the Australian Capital Territory, Victoria and South Australia are published by the independent market operators GasCo (NSW and the ACT), Vencorp (Vic) and REMCO (SA). For each, churn is measured as the number of switches by gas customers from one retailer to another. The churn indicator does not include customers who have switched from type of contract to another with their existing retailer. The New South Wales and the Australian Capital Territory and Victorian data are based on transfers of delivery points. As most residential customers receive gas from only one delivery point, the data approximate the number of customers transferring to another retailer. The REMCO series for South Australia starts only in August 2005, but allows some consistent comparison between jurisdictions.

ESCOSA has published churn data for South Australia since retail competition commenced in 2004. However, ESCOSA uses a different measure of churn than the independent market operators. It measures the number of switches by customers to market contracts. As in New South Wales and Victoria, if a customer makes several switches in succession, each counts as a separate switch. But, unlike New South Wales and Victoria, the ESCOSA measure includes customer switches from a standing contract to a market contract with their existing retailer. The ESCOSA estimates may therefore capture a wider range of customer decisions than other estimates of churn.

Table 11.4 sets out annual customer transfer numbers in New South Wales and the Australian Capital Territory, Victoria and South Australia. Comparisons need to take account of the differences in approach noted above.

While New South Wales and the Australian Capital Territory introduced customer choice ahead of Victoria, switching has been low—averaging around 4 per cent a year. Victorians reacted strongly to the introduction of choice, with average annual switching rates around 14 per cent a year. By the end of 2006, cumulative switching in Victoria was around triple the rate for New South Wales and Australian Capital Territory (figure 11.4). The ESC considers that the opening of the Victorian gas market to FRC and the incidence of dual fuel offers has increased energy switching and driven gas transfers to higher levels than for electricity.[4] Active marketing by energy retailers may also have encouraged increased switching activity.[5]

4 ESC, *Energy retail businesses comparative performance report for the 2004 calendar year*, 2005, p. 22.

5 Peace Vaasa EMG, *World retail energy market rankings 2005*, utility customer switching research project, 2005.

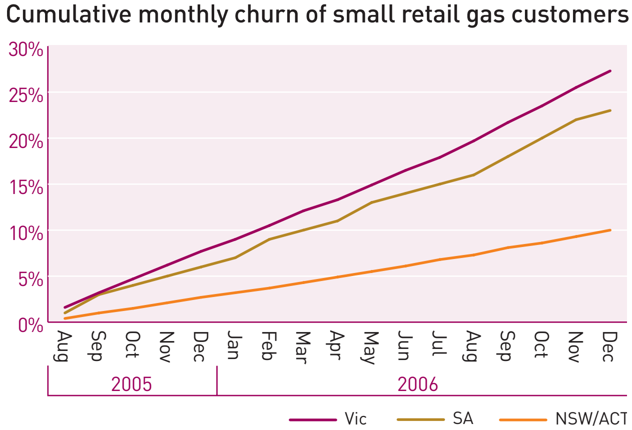
**Table 11.4 Annual small customer transfers[1,2]**

| | NEW SOUTH WALES AND THE ACT | | VICTORIA | | SOUTH AUSTRALIA | |
|---|---|---|---|---|---|---|
| | RETAILER TRANSFERS NO. | TRANSFER RATE % | RETAILER TRANSFERS NO. | TRANSFER RATE % | CONTRACT TRANSFERS NO. | TRANSFER RATE % |
| Jan–Jun 03 | 6583 | 1 | … | … | … | … |
| 2002–03 | 32333 | 3 | 91062[3] | 6[3] | … | … |
| 2003–04 | 39225 | 4 | 202776 | 13 | … | … |
| 2004–05 | 54214 | 5 | 269208 | 16 | 102041 | 28[4] |
| 2005–06 | 40830 | 4 | 305410 | 18 | 102715 *(51638)*[5] | 28 *(14)* |
| Jul–Dec 06 | 29575 | 3 | 184184 | 11 | 49138[6] *(34252)*[5] | 13[6] *(9)* |
| Total | 207792 | 18 | 1052640 | 62 | 229325 *(85890)*[5] | 69 *(23)* |
| Delivery points | 1154109 | | 1685913 | | 369842 | |
| Customers | na | | 1587173[7] | | 370000 | |

1. NSW and the Australian Capital Territory, and Victoria measures customer switches to retailers, while South Australia measures customer switches to market contracts. 2. NSW/ACT and Victorian churn rates are based on delivery points while South Australian rates are based on customer numbers. 3. Value from market start (October 2002) to June 2003. 4. Transfer rates based on customer numbers being 365000 from July 2004 to October 2005 and 370000 thereafter. 5. Excludes transfers to a market contract with the local retailer. 6. Estimate based on transfers for the period July to September. 7. Domestic customers at July 2006.

Source: ESC, *Energy retail businesses comparative performance report for the 2005–06 financial year*, 2006; ESCOSA, *Completed small customer electricity & gas transfers to market contracts, schedule*, October 2006; GasCo, *Gas market activity data*, <www.gasmarketco.com.au>, 2006; REMCO, *Market activity report—South Australia*, March 2007; data supplied by Vencorp.

**Figure 11.4**
**Cumulative monthly churn of small retail gas customers**




Sources: ESC, *Energy retail businesses comparative performance report for the 2005–06 financial year*, 2006; ESCOSA, *Completed small customer electricity & gas transfers to market contracts, schedule*, 2006; GasCo, *Gas market activity data*, <www.gasmarketco.com.au>, 2006; REMCO, *Market activity report—South Australia*, March 2007; data supplied by Vencorp.

South Australia also appears to have responded rapidly to the introduction of choice. In the year to June 2006, for example, around 28 per cent of South Australian customers switched to a market contract, around half of which constituted customer switches to a market contract with their existing retailer. Since August 2005 switches from one retailer to another have averaged around 12 per cent a year.

South Australia implemented FRC in gas about 18 months later than in electricity. ESCOSA considers switching activity in gas to be higher than in the early stages of retail competition in electricity.[6] ESCOSA considers that this may partly reflect greater customer awareness of switching by the time gas FRC commenced, but also notes energy retailer promotions for 'dual fuel' products.[7] ESCOSA survey results indicate that customer awareness of retail choice is relatively high in South Australia and that retailers are actively marketing their services (section 6.3). International observers consider South Australia and Victoria to have two of the most active retail energy markets in the world (box 6.2).

6 ESCOSA, *SA energy retail market 04/05*, 2005, p. 64
7 ESCOSA, *Monitoring the development of energy retail competition in South Australia: Statistical report*, 2006.

## 11.3.3 Retail margins

The profit or retail margins retailers can earn provides a measure of market performance. The margins are calculated as net earnings (before interest and tax). Expressed as a percentage of total sales or revenue, retail margins represent the return on capital employed in a business including compensation for risk.

Retail margins should be interpreted with care. Depending on the circumstances, either high or low retail margins could indicate a problem with market structure or conduct. In a dynamic competitive market the presence of high margins should attract new entry and drive margins down to normal levels. Sustained high margins might indicate a lack of competitive pressure. Alternatively low margins, resulting from regulated revenue caps, could deter entry and impede competition.

In practice, estimating retail margins is difficult. Without detailed information on each retailer's activities and costs, estimation relies on accurate assumptions about the breakdown of costs and exposure to risk, including risks associated with wholesale gas purchasing, customer default and bad debt.

Table 11.5 lists the gas retail margin allowances set in determining retail price caps and price paths in New South Wales, Victoria, South Australia and the Australian Capital Territory. The table indicates a reasonable consistency in setting retail margins with a spread from 2 to 4 per cent.

Since 1997 the Independent Pricing and Regulatory Tribunal (IPART) has set retail gas margins between 2 and 3 per cent. The low margin reflects an assessment that retail supply is a relatively low-risk, high-turnover activity. Costs, such as meter reading, billing and customer service activities are relatively static and predictable. The main risk relates to the purchase of gas, but this risk can be reduced through hedging activity.

The ESC also set Victorian gas retail margins at 2 to 3 per cent, but allows a margin of up to 5 per cent for electricity. The ESC considers that the 'trading risks faced by Victorian gas retailers are less than those faced by electricity retailers by virtue of the long-term contracts that relate to gas purchasing'.[8]

South Australia set Origin Energy's retail margin at 10 per cent of controllable costs, which equates to around 4 per cent of Origin Energy's sales revenue. This appears to be a higher level than in New South Wales and Victoria. The South Australian regulator considers this appropriate to take account of additional risks faced by South Australian retailers, such as the peaky nature of demand.

**Table 11.5 Regulatory decisions on retail margins**

| GAS RETAILER | RETAIL PROFIT MARGIN (% OF SALES) | JURISDICTION | DATE OF REGULATORY DECISION |
|---|---|---|---|
| Origin Energy | 4[1] | SA | ESCOSA 2005 |
| Vic retailers | 2–3 | Vic | ESC 2003 |
| NSW retailers | 2–3 | NSW | IPART 2001; 2004 |
| ActewAGL | 3 | ACT | ICRC 2001 |

1. The determination provides a margin of 10 per cent of controllable costs, which approximately equals 4 per cent of Origin Energy's sales revenue.

Sources: ESCOSA, *Gas standing contract price path inquiry*, discussion paper, 2005; ESCOSA, *Gas standing contract price path*, final inquiry report and final determination, 2005; ESC, *Special investigation—gas retail cost benchmarks*, consultation paper, November 2003; IPART, *Review of the delivery price of natural gas to tariff customers served from the AGL gas network in NSW*, final report, 2001; IPART, *IPART review of the delivered price of natural gas to low-usage customers served by country energy*, final report, 2001; ICRC, *Review of natural gas prices*, final report, 2001.

In its 2001 determination, the Independent Competition and Regulatory Commission (ICRC) set retail margins for ActewAGL in the Australian Capital Territory at 3 per cent. The ICRC took into account the relatively small customer base and aimed to provide sufficient 'head-room' to encourage potential competitors to enter the gas market.[9] Victoria also allows some headroom. Headroom allows retailers to earn excess returns on standard contracts, but encourages competing providers to offer market contracts at a lower price than existing standard offers. Thus margins should be driven to normal levels through competition for market contracts. New South Wales does not add headroom to retail margin

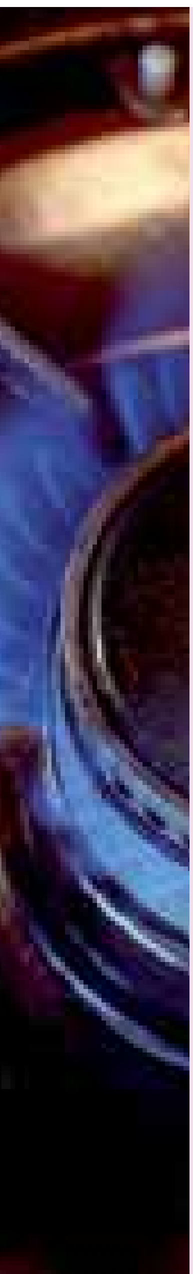
8 ESC, *Special investigation-gas retail cost benchmarks*, consultation paper, 2003, p. 17.

9 ICRC, *Review of natural gas prices*, final report, 2001.

allowances because it does not consider it desirable from an economic efficiency or equity perspective. In setting retail margins South Australia seeks:

> …to strike a balance between the need to attract investment into … the retail market, while ensuring that gas standing contract customers are not funding an excessive return to the retail business.[10]

The ESC has undertaken a detailed study of retail competition, including a more detailed margin analysis (box 11.2). The ESC found competition in the Victorian energy market to be generally effective in constraining prices and delivering non-price benefits in those sub-markets where sufficient margins exist to make market contracts attractive to customers and profitable to serve for retailers. This is the class of customers using more than 50 gigajoules of gas a year.



### Box 11.2 Victorian retail margin analysis for gas

In 2004 the ESC estimated the retail margins available for customer classes in metropolitan Melbourne and Victorian regional areas. From this analysis it aimed to assess the potential 'headroom' in the identified submarkets.

The ESC noted that the results should be interpreted with care giving regard to the assumptions made and to the limitations of the data and the analysis. The estimates are based on broad benchmarks of efficient costs and assumptions, including with respect to the allocation of joint and common costs (eg wholesale energy purchases and hedging contracts) to customer classes and tariff categories.

**Table 11.6 Estimated residential average net retail margins by tariff zone[1,2]**

| CONSUMPTION | METROPOLITAN MELBOURNE | REGIONAL VICTORIA |
|---|---|---|
| 55–65 GJ a year (average consumption) | \$20–\$40 | \$20–\$40 |
| 30–50 GJ a year | \$0–\$20 | \$10–\$30 |
| 100–150 GJ a year | \$100–\$200 | \$100–\$200 |

1. Broad estimates of net margins based on assuming that the retail cost of each customer is \$85. In practice each retailer will allocate fixed costs differently.
2. Based on residential Tariff–03.

The results presented in table 11.6 suggest that:

- all gas market segments are likely to be profitable at average consumption levels.
- retail margins are low for average low-use gas consumers.

The ESC noted that some retail tariffs are being gradually rebalanced under the 2004–2007 price path so that tariffs may progressively approach efficient levels. However, some regional areas that appear to have low margins have long-term gas retail price agreements in place, which may prevent price rebalancing to the extent allowed by the government's price path.

The ESC further reported that the cost to acquire customers varies depending on the sales channel used—door-to-door, telephone, mail advertising, internet and referral agents. Door-to-door sales are most successful, but are also the most expensive means of acquiring customers. Using this channel, the ESC estimated that a customer would need to provide a margin of \$40 to \$50 a year over three years for a retailer to have an incentive to offer a market contract. Its analysis suggested that a household consuming 60–70 gigajoules of gas a year would provide sufficient 'headroom' for competition. Use of other sales channels results in more headroom for retailers to compete, reducing the consumption levels at which retailers can offer market contracts. Similarly, dual fuel contracting permits a retailer to amortise acquisition costs over both electricity and gas reducing the threshold consumption required to provide a return to the retailer. At the time of the report all local retailers and one non-local retailer offered dual fuel options.

Source: ESC, *Special investigation: Review of effectiveness of retail competition and consumer safety net in gas and electricity*, final report to minister, 2004, Appendix E and attachments 4–5.

10 ESCOSA, *Gas standing contract price path*, final inquiry report and final determination, 2005, p. A-85.

## 11.4 Retail price outcomes

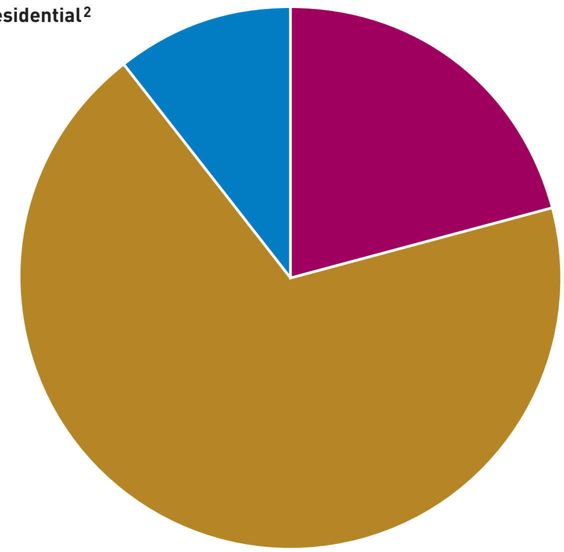
Gas retail prices paid by customers cover the costs of a bundled product made up of gas, transmission and distribution services, and retail services. Data on the underlying composition of retail prices are not widely available. Figure 11.5 provides an indication of the typical make-up of a residential gas bill in 2003. It shows that wholesale gas costs and network charges account for the bulk of retail prices. Retail operating costs account for around 10–15 per cent of retail prices.

Trends in retail prices may reflect movements in the cost of any one or a combination of the bundled components in a retail product—for example, movements in wholesale gas prices, transmission and distribution charges or retail margins. Cost changes may occur in these components for a variety of reasons. Similarly, differences in retail prices between the states reflect in part differences in underlying cost structures (for example, differences in fuel costs and in the proximity of gas fields to retail markets) that may not be associated with competition.

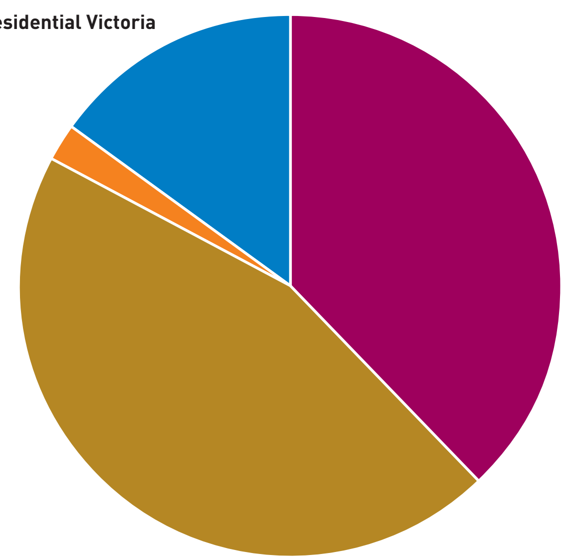
In addition to costs, retail price movements are affected by regulatory arrangements. In Tasmania, the Australian Capital Territory and the Northern Territory retail gas prices are not regulated. In New South Wales, Victoria, Queensland, South Australia and Western Australia prices under standard contracts are capped by regulation or through voluntary arrangements.[11] Price caps are in place largely to smooth the structural adjustment process, to avoid 'price shocks' and to prevent misuse of market power in the transition towards a more competitive retail market environment, but they may also reflect other social and political objectives. Where price caps are in place jurisdictions are moving to align retail prices more closely with underlying supply costs so that prices provide efficient signals for investment and consumption.

Figure 11.5
**Indicative composition of a residential gas bill[1]**

**Residential[2]**




**Residential Victoria**




1. Data relates to 2003. 2. Based on Envestra data supplied to the Productivity Commission.

Sources: Charles River and Associates, *Electricity and gas standing offers and deemed contracts 2004–2007*, 2003; Australian Gas Association, as published in Productivity Commission, *Review of the gas access regime*, inquiry report no. 31, 2004, pp. 37, 46.

11 In Western Australia retail tariff caps apply to Alinta systems including Albany (LPG) and Kalgoorlie, but do not apply for LPG supplied to the Leinster, Margaret River and Esperance regions.

There is little systematic publication of average gas retail prices in Australia. It is possible to track price movements for households via the consumer price index and for business via the producer price index. The Australian Gas Association previously published data on retail gas prices but discontinued the series after 1998. At the state level jurisdictions that regulate prices publish schedules of regulated prices. The schedules are a useful guide to retail prices, but their relevance as a price barometer is reduced as more customers transfer to negotiated contracts. Retailers are not required to publish the prices struck through negotiated contracts with customers. ESCOSA publishes some annual price data covering regulated and negotiated prices. The South Australian and Victorian regulator websites provide an estimator service that can be used to compare the price offerings of different retailers.

Care should be taken interpreting retail price trends in deregulated markets. While competition tends to deliver efficient outcomes, there may be instances where efficient outcomes involve the counterintuitive outcome of *higher* prices. In particular, efficient outcomes might require the unwinding of historical cross-subsidies, which may lead to price adjustments for some customer groups for a period of time.

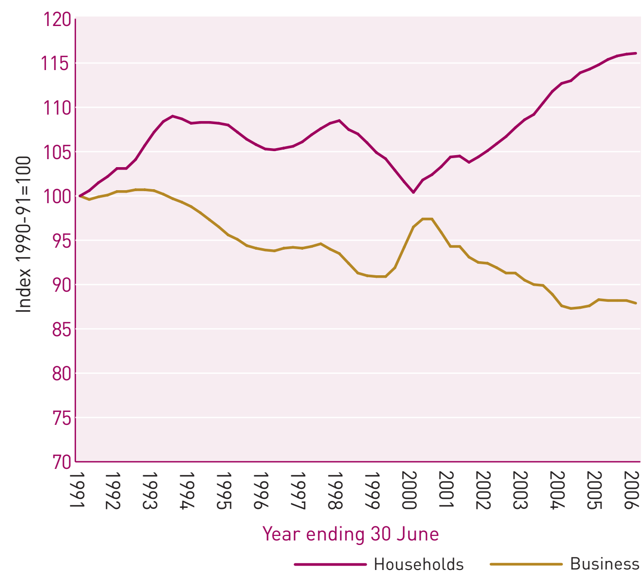
### 11.4.1 Price movements

The Australian Bureau of Statistics (ABS) consumer price index and producer price index track movements in household and business gas prices. The indexes are based on surveys of the prices paid by households and businesses and therefore consider both negotiated and regulated prices.

The introduction of reforms in the gas supply industry has been accompanied by a fall in the real price of gas of about 5 per cent from 1990 to 2006. There has, however, been a significant realignment of gas prices for household and business customers. Figure 11.6 tracks real gas price movements for households and business customers since 1990. While real prices rose for household consumers by 16 per cent, the real price for business users fell by 12 per cent. The disparity reflects in part the rebalancing of retail gas prices to remove cross-subsidies from business to household consumers. Differences in business and household responsiveness to changes in price may play a part. In addition, the disparity also likely reflects higher levels of competition in the business sector because of the earlier introduction of retail competition for this class of gas users in most states. While real household gas prices have risen in all major capital cities, the pattern and rate of adjustment has varied, with Sydney and Adelaide registering the sharpest price impacts (figure 11.7).

**Figure 11.6**

**Movement in real retail household and business gas prices[1, 2]**

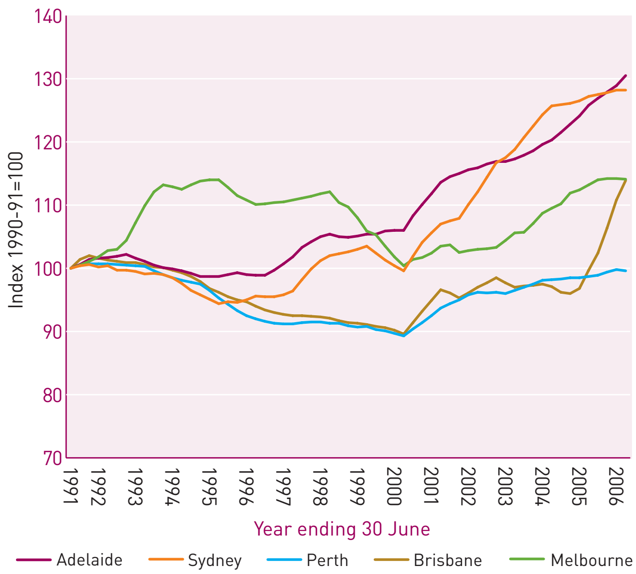



1. The households index is based on consumer price index for household gas (unpublished). The business index is based on the producer price index for gas supply in 'Materials used in Manufacturing Industries'. Both series are deflated by the consumer price index series for all groups. 2. Introduction of the GST on 1 July 2000, which increased prices paid by households for gas services, affects the households index.

Source: ABS, *Consumer price index, Australia*, September quarter 2006, Cat no. 6401.0; ABS, *Producer price indexes, Australia*, September Quarter 2006, category no. 6427.0, Canberra.

Figure 11.7

Movement in real household gas prices in selected capital cities[1]

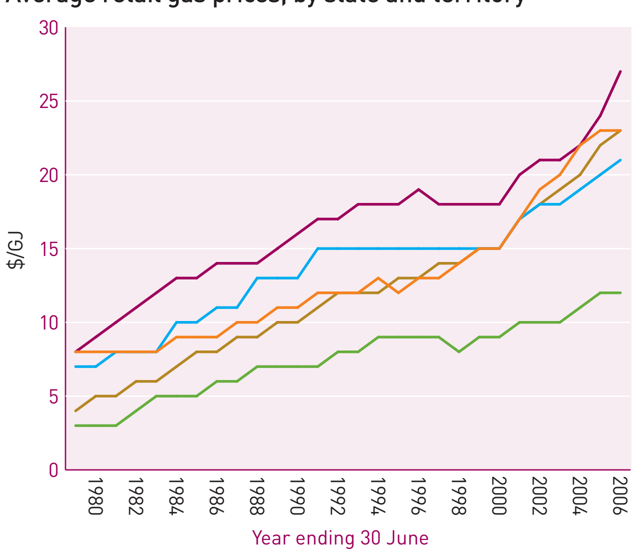



1. The households index is based on capital city consumer price indexes for 'gas and other household fuels' deflated by the capital city CPI series.

Source: ABS, *Consumer price index, Australia*, September quarter 2006, Canberra, cat. no. 6401.0.

Figure 11.8

Average retail gas prices, by state and territory[1]




1. The dashed lines are estimates based on inflating AGA data by the CPI series for gas and other household fuels for the capital city in that State.

Sources: AGA, Gas statistics Australia, Canberra, 2000; ABS, *Consumer price index, Australia*, September quarter 2006, Canberra, cat. no. 6401.0.

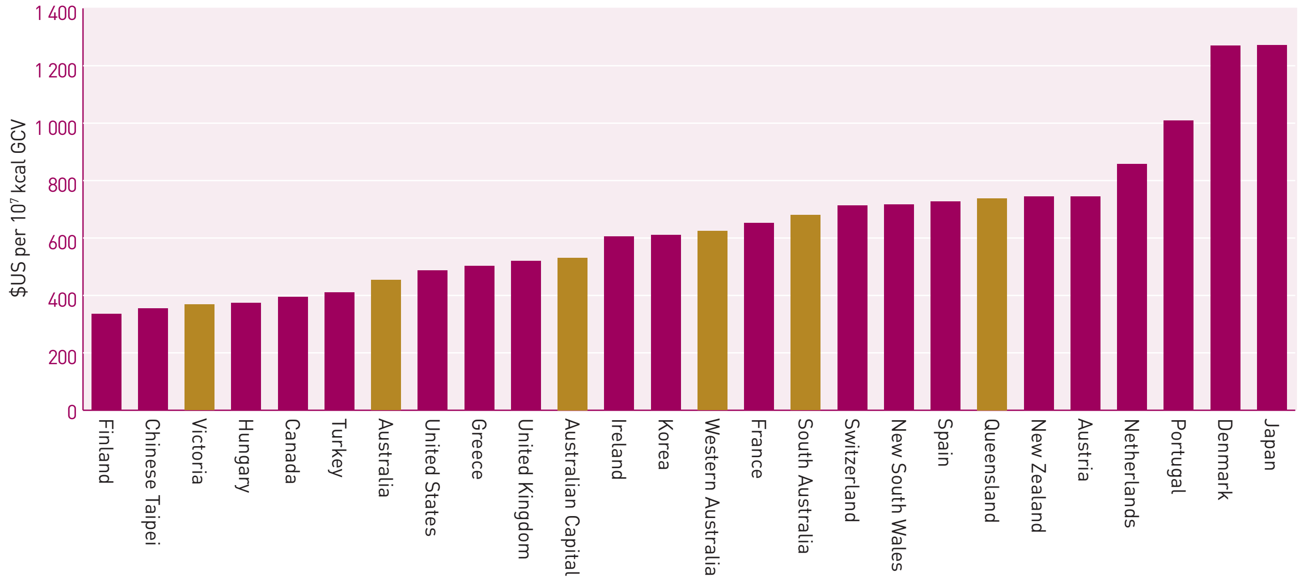
## 11.4.2 Price outcomes

It is possible to estimate residential gas price outcomes by extrapolating from Australian Gas Association data (which concluded in 1998), using consumer price index data for 'gas and other household fuels'. The extrapolated series is set out in figure 11.8. This data series is not available for business users.

The chart shows considerable variation in retail gas prices between the states. The differences reflect many factors, including variations in the wholesale price of gas and the distances over which gas must be hauled. The contribution of transport charges to Australian retail prices ranges from 10 to 80 per cent. Consumption patterns and industry scale also play a role. For example:

- Victoria has a relatively large residential consumer base with consumers located close to the gas fields.
- Western Australia had relatively low wholesale gas prices, but high transport costs as most residential consumers are located a long distance from gas basins.
- Queensland prices reflect a small residential customer base and low rates of consumption because of the state's warm climate.

Figure 11.9
International comparison of residential gas prices for 2006[1, 2]




1. Prices for the first quarter of 2006 or latest available data. 2. Price data for Australia is based on Australian Energy Regulator estimates benchmarked against the US average. The data for each jurisdiction relates to 2005 and is estimated by inflating AGA data by the capital city consumer price index series for gas and other household fuels.

Sources: AGA, *Gas statistics Australia 2000*, 2000; ABS, *Consumer price index, Australia*, September quarter 2006, Canberra, cat. no. 6401.0; Energy Information Administration, <http://tonto.eia.doe.gov>, viewed: 10 August 2006; Australian Tax Office, *Foreign exchange rates*, <www.ato.gov.au>, viewed: 10 August 2006, International Energy Agency, *Key world energy statistics 2006*, 2006.

## 11.4.3 International price comparisons

Figure 11.9 compares residential gas prices in Australia with prices in selected Organisation for Economic Cooperation and Development (OECD) countries. The data indicate that average Australian prices are relatively low by international standards at about seven per cent below the average price in the United States. The Australian Capital Territory has residential gas prices that are about 10 per cent higher than the US average. Gas prices in Queensland, Western Australia, South Australia and New South Wales are around 30 per cent and 50 per cent higher than the US average. These states have similar prices to Korea, France, Switzerland, Spain and New Zealand. In contrast, Victorian residential gas prices are among the lowest in the world.

## 11.5 Quality of service

Competition provides incentives for retailers to improve performance and quality of service as a means of maintaining or increasing market share and profits. In addition, governments have established regulations and codes on minimum terms and conditions, information disclosure and complaints handling requirements that retailers must meet in supplying gas to small retail customers. Most jurisdictions also have an ombudsman where complaints can be referred in the event that a customer is unable to resolve issues directly with the retailer. There is, however, no consistent reporting across jurisdictions. Box 11.3 provides details on aspects of service performance in New South Wales and Victoria.

## 11.6 Regulatory arrangements

While jurisdictions have introduced FRC in gas, each continues to regulate various aspects of the market. Regulatory measures include:

- transitional price caps for small customers using less than 1 terajoule of gas a year
- the setting of minimum terms and conditions in 'default' service offers
- information disclosure and complaints-handling requirements
- payments for delivery of community service obligations.

### 11.6.1 Price caps

Most state governments appoint local retailers that must offer to supply small gas customers in nominated geographical areas at regulated tariffs. This provides a 'default' option for customers who have not entered a market contract. The default tariff takes account of wholesale gas costs, network charges, retailer costs and retailer margins. As noted in section 6.6 of this report, price caps are intended as a transitional measure to:

- allow consumers time to understand and adjust to the competitive market structure
- protect consumers from the possible exercise of market power
- prevent price shocks.

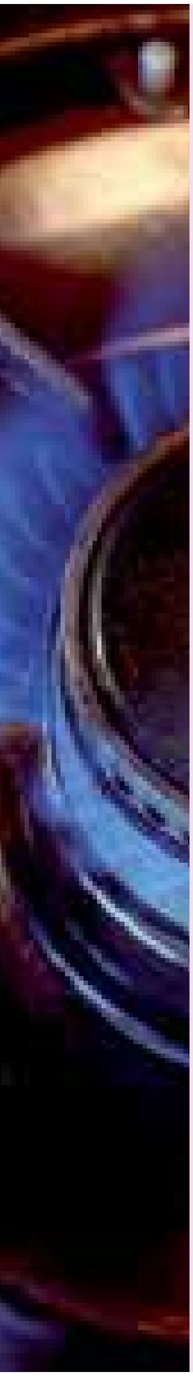
The approach to regulating default tariffs varies among jurisdictions, and in some cases is more light handed than in electricity. This may reflect that gas is sometimes regarded as a fuel of choice rather than necessity. Table 11.7 outlines the current regulatory arrangements in each jurisdiction. These are:

- In Victoria and New South Wales, governments control average default tariffs through agreements with local retailers. New South Wales has agreements with AGL Retail Energy, Country Energy, Origin Energy and ActewAGL, capping prices until June 2007. The retailers have agreed to tie average price increases to the consumer price index and apply a $15 ceiling on annual bill increases. Similar agreements apply for 2007–08 to 2009–10, but without the ceiling on annual bill increases.[12] Victoria has entered into agreements with TRUenergy, AGL and Origin Energy that allow for an annual real increase in retail household and small business tariffs of 2.1–3.6 per cent between 2004 to 2007.
- In Queensland, prior to 1 July 2007 the Minister for Mines and Energy could fix a price cap or determine a method to set maximum prices. Under FRC the Queensland Competition Authority publishes standard retail contract terms (including prices) received from gas retailers.
- South Australia regulates retail gas prices by responding to submissions from the local retailer—Origin Energy. In its most recent determination ESCOSA derived prices from the costs that a prudent retailer with Origin Energy's responsibilities would incur. The approach is consistent with its approach to setting electricity prices.
- Tasmania, the Australian Capital Territory and the Northern Territory do not regulate the retail price of gas.

In 2006 Australian governments reaffirmed their commitment to remove retail price caps where effective competition can be demonstrated. Governments also agreed that transitional price caps should not hinder the development of competitive markets.[13]

12 For details see IPART, *Promoting retail competition and investment in the NSW gas industry, Regulated gas retail tariffs and charges for small customers 2007 to 2010*, Sydney, 2007.

13 Australian Energy Market Agreement 2004, as amended in 2006.



### Box 11.3 New South Wales and Victorian reporting on the quality of gas services

**New South Wales**

IPART in New South Wales monitors and assesses the extent to which licensed energy suppliers and distributors operating in the state comply with the conditions of their licences or authorisations. IPART reports that gas retail suppliers breached 30 licence obligations in 2005–06, compared with 28 breaches in 2004–05. The breaches related to marketing; billing and charging; and a range of other obligations, including customer notifications, information requirements and consumer safety awareness plans.

The tribunal found that most of the non-compliances reported were minor in nature, with minimal or no impact on customers. In most cases licensees were quick to identify and address the incidents. Of the breaches that occurred in 2005–06 two-thirds had been resolved by the time of reporting. Figure 11.10 shows the breakdown of licence breaches by category and retailer in 2004–05 and 2005–06.

**Victoria**

Victoria's Essential Services Commission reports on several retail quality matters, including customer access to gas retail services, call centre performance and complaints handling. Table 11.7 compares outcomes in customer access to electricity and gas retail services. The data indicates that retail disconnections occur more frequently for gas than electricity, but the disconnection rate has trended downwards since 2000 to 0.27 per cent in 2005–06. Victoria introduced legislation in 2004 that provides for compensation to households that are wrongfully disconnected. Around five per cent of gas customers have access to budget instalment plans, which is slightly higher than for electricity.

The ESC reported an improvement in gas retailer call centre performance in 2005–06, with 81 per cent of calls to gas retail account lines being answered within 30 seconds, compared to 68 per cent in 2003–04 and 74 per cent in 2004–05. However, it noted an independent finding that the average time to respond to customer calls had declined to 102 seconds from 90 to 95 seconds and 101 seconds on average in 2003–04 and 2004–05 respectively. This response time is slower than the Australian energy sector average, but better than a range of selected industries also surveyed.

Total complaints to Victorian gas retailers increased from 2506 in 2003–04 and 3479 in 2004–05 to 4630 complaints in 2005–06, equivalent to 0.28 complaints per 100 customers. Complaints relating to gas affordability were low at 0.15 complaints per 100 customers, or 2381 complaints. The ESC noted that some of the newer entrants to the Victorian market recorded higher rates of complaints than the three local retailers.

Figure 11.10
Breaches of gas retailer licence obligations, by category


Source: IPART, *Energy distribution and retail licences, compliance report for 2005/06*, report to the Minister for Energy, 2006.

Table 11.7 Small customer access to gas retail services, Victoria

| INDICATOR | 2000–01 | 2001–02 | 2002–03 | 2003–04 | 2004–05 | 2005–06 |
|---|---|---|---|---|---|---|
| PER 100 CUSTOMERS | | | | | | |
| DISCONNECTIONS | | | | | | |
| Electricity | 0.44 | 0.7 | 0.61 | 0.84 | 0.54 | 0.22 |
| Gas | 1.16 | 1.1 | 0.41 | 0.74 | 0.7 | 0.27 |
| BUDGET INSTALMENT PLANS | | | | | | |
| Electricity | 4.58 | 5.07 | 4.9 | 5.11 | 4.77 | 4.66 |
| Gas | 5.3 | 5.66 | 5.54 | 5.47 | 4.99 | 4.87 |
| REFUNDABLE ADVANCES | | | | | | |
| Electricity | 0.03 | 0.03 | 0.02 | 0.01 | 0.01 | 0.01 |
| Gas | 0.02 | 0.02 | 0.01 | 0.01 | 0.01 | 0.00 |

Source: ESC, *Energy retail businesses comparative performance report for the 2004-05 financial year*, 2005, p. 5.

### 11.6.2 Consumer protection measures

Governments regulate aspects of the energy retail market to protect consumers' rights and ensure they have access to sufficient information to make informed decisions. Most jurisdictions require designated local retailers to provide gas services under a standard or default contract to nominated customers. Default contracts cover minimum service conditions relating to billing, procedures for connections and disconnections, information disclosure and complaints handling. During the transition to effective competition, default contracts also include regulated price caps.

Some jurisdictions have put in place codes that apply to all retail gas services, including those sold under negotiated contracts. The codes govern market conduct and establish minimum terms and conditions under which a retailer can sell gas to small retail customers. The codes often:

- constrain how retailers may contact potential customers
- require pre-contract disclosure of information, including disclosure of commissions for market contracts
- provide for cooling-off periods
- provide rules for the conduct of door-to-door sales, telemarketing and direct marketing.

Most jurisdictions also have an ombudsman to whom consumers can refer a complaint they have been unable to resolve directly with the retailer. In addition to general consumer protection measures, jurisdictions establish a gas supplier of last resort to ensure customers can be transferred from a failed or failing retailer to another.

### 11.6.3 Community service obligation delivery

States and territories provide a range of assistance measures to meet community service obligations payments to particular groups of gas users—mostly low-income earners. Traditionally, community service obligations were funded by cross-subsidies from large industrial and commercial users to small consumers. Under the National Competition Policy and related reforms, governments have been replacing cross-subsidies with transparent concessions and grants funded directly from budgets. This makes it possible to provide community service obligations without distorting competitive outcomes.

### 11.6.4 Future regulatory arrangements

State and territory governments are currently responsible for the regulation of retail energy markets. Governments agreed under the Australian Energy Market Agreement 2004 (amended 2006) to transfer rule-making, and review and regulatory functions to the national governance framework administered by the Australian Energy Market Commission and Australian Energy Regulator. The regulatory responsibilities scheduled for transfer include:

- the obligation on retailers to supply customers at a default tariff with minimum terms and conditions
- arrangements to ensure customer supply continuity and wholesale market financial integrity in the event of a retailer failure
- minimum contract terms and conditions applying to small customer market contracts
- small customer marketing conduct obligations
- retailer general business authorisations (where necessary for matters other than technical capability and safety).

The Ministerial Council on Energy has scheduled the transfer of responsibilities to commence from 2008. Under the current proposals, the states and territories will retain responsibility for price control of default tariffs unless they choose to transfer those arrangements to the Australian Energy Regulator and the Australian Energy Market Commission.

# PART FOUR
# APPENDIXES

# A INSTITUTIONAL ARRANGEMENTS

Since the early 1990s energy policy in Australia has been set at the national level through a series of intergovernmental agreements. In 2004 Australian governments signed a new intergovernmental agreement the Australian Energy Market Agreement 2004 (amended 2006) committing to a new energy reform program. The package includes streamlined regulatory, planning, governance and institutional arrangements for the national energy market.

This appendix outlines the roles and responsibilities of the new and existing national, state and territory stakeholders involved in energy policy and economic regulation.

## A.1 Energy policy institutions

Two key bodies determine the direction of Australia's energy policy. The Council of Australian Governments (COAG) is responsible for making broad in-principle decisions on national energy policy. The Ministerial Council on Energy (MCE), which is the governance body responsible for Australian energy market policy, provides advice to COAG on energy market policy.

### The Council of Australian Governments

COAG is the peak intergovernmental forum in Australia. The council comprises the Prime Minister, state premiers, territory chief ministers and the president of the Australian Local Government Association. The role of COAG is to initiate, develop and monitor the implementation of policy reforms that are of national significance and that require cooperative action by Australian governments, including national competition policy and related energy market reforms.

Since endorsing the Australian Energy Market Agreement, COAG has endorsed a new national competition policy agenda, which includes reforms for the energy sector. At its meeting of 10 February 2006 COAG agreed to three broad actions to further reform in the energy sector.[1]

First, it agreed to improve price signals for energy consumers and investors through a progressive national rollout from 2007 of 'smart' electricity meters. This will allow retailers to introduce time-of-day pricing, giving users the opportunity to better manage their demand

1 COAG communiquè, meeting of 10 February 2006 (www.coag.gov.au).

for peak power. The rollout is to be implemented in accord with a plan that has regard to costs and benefits and differences in market circumstances in each state and territory.

Second, it agreed to ensure the electricity transmission system supports a national electricity market that provides energy users with the most efficient, secure and sustainable supply of electricity from all available fuels and generation sources, including, where appropriate, an increased share of renewable energy. COAG committed to adopting policy settings, governance and institutional arrangements and other actions to improve the framework for planning and network investment and to streamline regulation.

Third, COAG agreed to establish the Energy Reform Implementation Group (ERIG), which comprises industry experts and senior officials, to report on proposals for:

> measures that may be necessary to address structural issues affecting the ongoing efficiency and competitiveness of the electricity sector
> achieving a fully national electricity transmission grid
> measures needed to foster transparent and effective financial markets to support energy markets.

ERIG released reports on these matters in January 2007.

At its meeting of 13 April 2007 COAG considered the recommendations of the MCE in response to the ERIG reports. COAG has agreed to establish an industry-funded National Energy Market Operator (NEMO) for both electricity and gas by June 2009. The new body will replace the functions of the National Energy Market Management Company (NEMMCO) and the gas market operators and undertake a national transmission planning role.

COAG also agreed that the COAG Reform Council should monitor progress with implementing energy market reform and assess the costs and benefits of reforms referred to it unanimously by COAG. COAG has referred the monitoring and assessment of electricity smart meters, NEMO and the new transmission planning function and related reforms to the COAG Reform Council.

## The Ministerial Council on Energy

The MCE comprises Australian, state and territory energy ministers. Ministers from New Zealand and Papua New Guinea have observer status.
As part of implementing the Australian Energy Market Agreement, the MCE subsumed the National Electricity Market Ministers Forum in 2004 to become the sole governance body for Australian energy market policy. Its role is to initiate and develop energy policy reforms for consideration by COAG. It also monitors and oversees implementation of energy policy reforms agreed by COAG.

The MCE's current work program centres on developing and implementing the reforms agreed under the Australian Energy Market Agreement, which aim to:

> strengthen the quality, timeliness and national character of **governance** of the energy markets, to improve the climate for investment
> streamline and improve the quality of **economic regulation** across energy markets to lower the costs and complexity of regulation facing investors, enhance regulatory certainty and lower barriers to competition
> improve the planning and development of **electricity transmission** networks to create a stable framework for efficient investment in new (including distributed) generation and transmission capacity
> enhance the participation of **energy users** in the markets, including through demand-side management and the further introduction of retail competition, to increase the value of energy services to households and business
> further increase the penetration of **natural gas** to lower energy costs and improve energy services, particularly in regional Australia, and reduce greenhouse emissions
> address **greenhouse emissions** from the energy sector in the light of concerns about climate change and the need for a stable long-term framework for investment in energy supplies.

To date the council has:

- Established the Australian Energy Market Commission (AEMC) and Australian Energy Regulator (AER) putting in place the new governance arrangements for the energy sector.
- Developed new national electricity law and rules (the NEL and NER), which provide the new legal framework for economic regulation of electricity.
- Enhanced the national transmission planning process through the development of two key initiatives —the Annual National Transmission Statement and the Last Resort Planning Power.
- Progressed work to encourage greater user participation, including through the rollout of smart meters.
- Determined a model for a common approach to transmission and distribution revenue and network pricing across electricity and gas. The detailed arrangements for transfer of energy distribution and retail functions to the national framework were incorporated into the Australian Energy Market Agreement through amendments implemented in June 2006.
- Released draft legislation to strengthen consumer advocacy arrangements, which is to be passed in the South Australian Parliament with other elements of the 2006 legislative package
- Developed draft national gas law and rules (the NGL and NGR) for consultation on the new legal framework for economic regulation of gas. The draft legislative package incorporates a new and light-handed regulatory approach[2] for gas pipelines and changes to merits review.
- Released a draft national electricity law amendment bill for consultation on conferring functions on the AER in relation to the economic regulation of electricity distribution networks.

## A.2 Economic regulation institutions

Regulatory arrangements across the states and territories are fragmented. Each jurisdiction has a separate regulatory agency, which use differing regulatory approaches. While there is greater consistency in approaches adopted for regulation of the gas sector there are a number of state and territory bodies involved in the regulation of gas pipelines and retail gas markets. The development of a national framework for the energy sector aims to address the costs and uncertainties associated with the current approach.

A key aspect of the new energy reform program is an agreement to streamline and improve the quality of economic regulation across energy markets, to lower the costs and complexity of regulation for investors, enhance regulatory certainty and lower barriers to competition. To achieve this goal, two bodies were created—the AEMC, with responsibility for rule making and market development, and the AER, with responsibility for market regulation. The Australian Energy Market Agreement provides for the transfer of the functions, powers and duties of the National Electricity Code Administrator (NECA), National Gas Pipelines Advisory Committee (NGPAC) and the Code Registrar and certain functions of the ACCC to the AEMC and the AER. The AEMC and the AER will take on additional functions currently performed by state and territory regulators—except in Western Australia—over time.

2 The gas pipeline access Acts were amended in 2006 to give effect to the decision to provide for binding up-front no coverage rulings for greenfield pipelines and price regulation exemptions for international pipelines.

## The Australian Energy Market Commission

The AEMC commenced operation on 1 July 2005 and has responsibility for national rule-making and market development in the NEM and, over time, the gas market. More specifically, the AEMC is currently responsible for:

> administrating and publishing the NER, which have replaced the National Electricity Code
> the rule-making process under the new NEL[3]
> making determinations on proposed rules
> undertaking reviews on its own initiative or as directed by the MCE
> providing policy advice to the MCE in relation to the NEM.

Governments have also agreed to transfer responsibility for rule making in the gas sector to the AEMC from July 2007. At that time it will take over the functions presently performed by the NGPAC and the Code Registrar. The NGPAC manages the process for any amendments to the National Third Party Access Code for Natural Gas Pipeline Systems (the Gas Code). The Code Registrar maintains a public register of information relevant to the code, including amendments to the code.

The AEMC is currently undertaking a number of major reviews of the NER stemming from the package of reforms outlined in the MCE's 2003 *Reform of energy markets* report agreed by COAG.

## The Australian Energy Regulator

The AER was established on 1 July 2005. It is a constituent part of the ACCC but operates as a separate legal entity. Decisions of the AER are subject to judicial review by the Federal Court of Australia and will be subject to merit review by the Australian Competition Tribunal.

The AER enforces the NEL and the NER and is the regulator of the wholesale electricity market and electricity transmission networks in the NEM. These electricity sector-specific regulatory functions were transferred from the ACCC and NECA.

The ACCC currently regulates gas transmission pipelines in all states and territories (except Western Australia) and distribution pipelines in the Northern Territory. The AER is designated to take on this responsibility. Transfer is currently scheduled to occur from 31 December 2007.

The Australian Energy Market Agreement also establishes that the AER will be the economic regulator of NEM and gas distribution networks (except in Western Australia) and retail markets (other than for retail pricing) following the development of a national framework. Retail energy price control will be retained under the existing arrangements, but each jurisdiction has the discretion to transfer this function to the AER and the AEMC.

The additional electricity and gas functions are scheduled to be transferred to the AER from 31 December 2007. The ACCC retains its role as the competition (mergers and anti-competitive conduct) regulator for the energy industry, as part of its role as Australia's general competition regulator.

The functions to be transferred to the AER will include:

> Considering and approving of access arrangements submitted by service providers under the Gas Code. This involves approving the terms and conditions of access, including reference tariffs.
> Monitoring and enforcing access arrangement provisions, including ring-fencing and service standards.
> Arbitrating disputes relating to the terms and conditions of access.
> Overseeing competitive tendering processes for new transmission pipelines.

3 Rule-making was previously the responsibility of NECA, which administered the National Electricity Code.

## The state and territory regulators

Jurisdictional regulators are responsible for a range of matters, including licensing, regulating third-party access for electricity and distribution networks and retail pricing, monitoring service standards and retail pricing. In Western Australia and the Northern Territory, economic regulation of the electricity sector also extends to generation and transmission services because these jurisdictions do not currently participate in the NEM. The role of the jurisdictional regulators may extend beyond the energy sector to cover other infrastructure industries and non-economic regulatory functions. Table A.1 lists the energy regulators and key economic regulation functions and indicates those functions to be transferred to the AER.

**Table A.1** **Responsibility of energy regulators in Australia**

| REGULATOR | | ELECTRICITY TRANS. | DISTR. | RETAIL | GAS TRANS. | DISTR. | RETAIL |
|---|---|---|---|---|---|---|---|
| AER | NSW | ✓ | From 31/12/2007 | Non-price regulation from 1/7/2008 | From 31/12/2007 (incl NT) | | Non-price regulation from 31/12/2007[1] |
| | Vic | ✓ | | | | | |
| | Qld | ✓ | | | | | |
| | SA | ✓ | | | | | |
| | Tas | ✓ | | | | | |
| | ACT | ✓ | | | | | |
| FUNCTIONS THAT WILL BE TRANSFERRED TO THE AER | | | | | | | |
| ACCC | NSW | | | | ✓ | | |
| | Vic | | | | ✓ | | |
| | Qld | | | | ✓ | | |
| | SA | | | | ✓ | | |
| | Tas | | | | ✓[2] | | |
| | ACT | | | | ✓ | | |
| | NT | | | | ✓ | | |
| IPART | NSW | | ✓ | ✓ | | ✓ | ✓ |
| ESC | Vic | | ✓ | ✓ | | ✓ | ✓ |
| QCA | Qld | | ✓ | ✓ | | ✓ | ✓ |
| ESCOSA | SA | | ✓ | ✓ | | ✓ | ✓ |
| OTTER | Tas | | ✓ | ✓ | | ✓[2] | ✓[3] |
| ICRC | ACT | | ✓ | ✓ | | ✓ | ✓ |
| FUNCTIONS THAT WILL NOT TRANSFER TO THE AER | | | | | | | |
| ERA | WA | ✓ | ✓ | ✓ | | ✓ | ✓ |
| UC | NT | ✓ | ✓ | ✓ | | | ✓[3] |

ACCC: Australian Competition and Consumer Commission. AER: Australian Energy Regulator. ERA: Economic Regulation Authority. ESC: Essential Services Commission. ESCOSA: Essential Services Commission of South Australia. ICRC: Independent Competition and Regulatory Commission. IPART: Independent Pricing and Regulatory Tribunal. OTTER: Office of the Tasmanian Energy Regulator. QCA: Queensland Competition Authority. UC: Utilities Commission.

1. Each jurisdiction has the discretion to transfer retail energy price control to the AER and the AEMC.
2. The Tasmanian transmission and distribution pipelines are not covered and therefore are not subject to third party access regulation.
3. Gas retail services in Tasmania and the Northern Territory are not regulated.

# B GREENHOUSE GAS EMISSIONS POLICY

## Greenhouse gas emissions policy and measures affecting the energy sector

Greenhouse gases include carbon dioxide, methane, nitrous oxide and chlorofluorocarbons. Australia contributed 1.6 per cent of world greenhouse emissions in 2003, with over two-thirds of the emissions resulting from the production and use of energy. The stationary energy sector — comprising electricity generation and non-transport fuel combustion in the industrial, commercial and residential sectors—alone contributed 49 per cent of all emissions in 2003. Electricity is the single largest contributor, accounting for 33 per cent of total emissions.[1]

Australian governments have agreed to address greenhouse emissions from the energy sector on a national basis and to ensure that energy reform initiatives consider innovations for combating climate change and strategies for adapting to it. Such objectives form part of the Australian Energy Market Agreement.

Clauses 2.1(v)–(vi) of the agreement set out the following greenhouse-related aims:

(v) further increase the penetration of natural gas, to lower energy costs and improve energy services, particularly to regional Australia, and reduce greenhouse emissions;[2] and

(vi) address greenhouse emissions from the energy sector, in light of the concerns about climate change and the need for a stable long-term framework for investment in energy supplies.

At its 10 February 2006 meeting, the Council of Australian Governments (COAG) agreed to an agenda for a national action plan to reduce greenhouse emissions and respond to the environmental, social and economic impacts that may result from climate change. The proposed actions are to be progressed by the interjurisdictional Climate Change Group and the ministerial councils. The framework envisages that all jurisdictions will work collaboratively and individually to accelerate the development and take-up of renewable and other low-emission technologies. Governments have

1 Australian Greenhouse Office, *Tracking to the Kyoto target 2005, Australia's greenhouse emissions trends 1990 to 2008–2012 and 2020*, Canberra, 2005.

2 Life-cycle emissions from natural gas are approximately half those of Victorian brown coal, and on average approximately 38 per cent less than those of Australian black coal (Australian Gas Association, *Assessment of greenhouse gas emissions from natural gas*, 2000).

agreed on the need to accelerate significantly Australia's conversion to low-emissions practices and technologies to reduce the risk of dangerous climate change and provide greater investment certainty in the light of greenhouse risk.

Key initiatives in the plan include:

> a national framework for the take-up of renewable and low emission technologies
> a national climate change adaptation framework to assist effective risk management by business and community decision makers
> a study to identify the gaps in technology development
> a study to examine options for ensuring that Australia's scientific research resources are organised to effectively support climate change decision-making at the national and regional levels
> the acceleration of work by the ministerial councils on emissions reporting and the development of options for strengthened reporting approaches.

In July 2006, based on advice from the Environment Protection and Heritage Council and Ministerial Council on Energy, COAG decided that a single, streamlined emissions reporting system that imposes the least cost and red-tape burden should be adopted. The COAG Greenhouse and Energy Reporting Group has completed a regulatory impact statement on the matter, which it will present to COAG for consideration at their next meeting.

All relevant ministerial councils are to consider any climate change implications of their decisions and activities.

The plan will complement existing Australian, state and territory government measures to reduce greenhouse gas emissions. The broad suite of measures to address stationary energy greenhouse gas emissions represent a mix of mandatory/regulatory measures, quasi-market measures, voluntary measures and the provision of subsidies for emissions abatement. Key measures are listed in box B.1.

In addition to existing measures and those measures being pursued through COAG processes, the states and territories are investigating options for a national emissions trading scheme for Australia. The governments have established the National Emissions Trading Taskforce, a multi-jurisdictional body, to develop a proposal for consideration by state and territory governments. The taskforce released a discussion paper entitled *Possible design for a national greenhouse gas emissions trading scheme* in August 2006. The taskforce puts forward a cap and trade scheme initially covering the stationary energy sector, which could commence around 2010 and be structured to achieve emission reductions of around 60 per cent by the 2050 compared with 2000 levels. On 9 February 2007 the state and territory governments agreed that this proposal will be implemented unless the Australian Government agrees to a national or international carbon trading system after receiving a report on the issue at the end of May.

On 10 December 2006 the Prime Minister established a government–industry task group to advise on the nature and design of a workable global emissions trading system in which Australia would participate and to report on additional steps that might be taken in Australia, consistent with the goal of establishing such a system.

The Prime Ministerial Task Group on Emissions Trading provided its final report to the Prime Minister on 31 May 2007. The task group concluded that Australia should not wait until a genuinely global agreement on climate change has been negotiated, finding that the benefits of early adoption of an appropriate emissions constraint outweigh the costs.[3]

3 The Prime Ministerial Task Group on Emissions Trading, *Report of the task group on emissions trading*, Department of Prime Minister and Cabinet, 2007.

The task group recommends that Australia introduce a 'cap and trade' model by 2012 that incorporates the following key features:

> a long-term aspirational emissions abatement goal and associated pathways to provide an explicit guide for business investment and community engagement
> an overall emissions reduction trajectory that commences moderately, progressively stabilises and then results in deeper emissions reductions over time with flexibility for change after five-year reviews and that provides markets with the ability to develop a forward carbon price path
> national and comprehensive coverage, where practicable, of emissions sources and sinks
> initially placing permit liability on direct emissions from large facilities and on upstream fuel suppliers for other energy emissions
> subject those sectors initially excluded from the emissions trading scheme, such as agriculture and land use, to other policies designed to deliver abatement
> use of free allocation of emissions permits to ameliorate the impact of the scheme on new investments in trade-exposed, emissions-intensive industries, with the remaining permits to be auctioned
> use of a 'safety valve' to limit unanticipated costs while ensuring an ongoing incentive to abate
> recognition of a wide range of credible carbon offset regimes, domestically and internationally
> capacity, over time, to link to other comparable national and regional schemes in order to provide the building blocks of a truly global emissions trading scheme
> incentives for firms to undertake abatement in the lead-up to the commencement of the scheme
> revenue from permits and fees to be used, in the first instance, to support emergence of low-emissions technologies and energy efficiency initiatives.

On 3 June 2007 the Prime Minister accepted the recommendations of the report and announced that a target for reducing carbon emissions will be determined in 2008 following detailed economic modelling of the impact any target will have on Australia's economy.[4]

On 17 July 2007 the Prime Minister announced that:

> the Department of the Prime Minister and Cabinet will be responsible for implementing the emissions trading system
> a team is to be established in the Treasury to oversee modelling of the impact of various emissions targets and to advise the government on the implications of reducing greenhouse gas emissions
> the long-term emissions target will include built-in flexibility so it can be reset in light of new information, technologies and changes to the international framework
> legislation will be introduced in 2007 for a comprehensive and streamlined national emissions and energy reporting system
> from 2009, an independent regulator for emissions trading will be established in the Treasury. Its responsibilities will include allocating and auctioning permits, certifying offsets and ensuring compliance
> additional funding will be provided to support initiatives such as research, development and demonstration of low emissions technologies and the installation of solar hot water systems in schools and homes.[5]

4 Howard, Hon J. W (MP), 'Address to the Liberal Party Federal Council', The Westin Hotel, Sydney, 3 June 2007.
5 Howard, Hon J. W (MP), 'Address to the Melbourne Press Club', Hyatt Hotel, Melbourne, 17 July 2007.

### Box B.1 Key greenhouse gas reduction measures in the energy sector

**Australian Government measures**

National Greenhouse Strategy (NGS)—energy use and supply measures, including:

- the acceleration of energy market reform
- the Mandatory Renewable Energy Target, which requires the generation of 9500 GWh of extra renewable electricity a year by 2010
- support for renewable energy, including solar and geothermal energy projects
- strategies for energy retailers—for example, Green power.

**Greenhouse Challenge Plus**

A largely voluntary program to support and encourage businesses to manage greenhouse emissions through emissions inventory reporting and action plans for cost-effective abatement. The program includes generator efficiency standards to encourage generators using fossil fuels to achieve best practice performance in their power plants to lower greenhouse emissions.

**Greenhouse Gas Abatement Program**

A program that provides funding to leverage private sector investment in greenhouse abatement activities or technologies. Funding is provided for projects such as co-generation (the use of waste heat or steam from power production or industrial processes for power generation), energy efficiency, coal mine gas technologies and fuel conversion.

Projects supporting renewable energy industry development including:

- Advanced Electricity Storage Technologies
  - identifies and promotes strategically important advanced storage technologies
- Renewable Energy Equity Fund
  - provides venture capital for small innovative renewable energy companies
- Renewable Remote Power Generation Program
  - support for the installation of renewable energy in remote areas
- Renewable Energy Development Initiative
  - grants for renewable energy innovation and commercialisation
- Photovoltaic Rebate Program
  - rebates towards the cost of installing solar energy cells for householders and owners of community use buildings.

Energy Efficiency and Performance Standards including:

- improving energy efficiency in government operations
- the energy efficiency best practice benchmarking program for electricity generators
- Energy Efficiency Opportunities, where businesses identify, evaluate and report publicly on cost-effective energy saving opportunities.

**State and territory government measures**

- *Greenhouse Gas Reduction Scheme (GGAS)*

  A greenhouse trading scheme operated jointly by New South Wales and the Australian Capital Territory that requires electricity retailers and certain other parties that buy or sell electricity in New South Wales to meet mandatory statewide greenhouse gas reduction benchmarks. The benchmarks may be achieved using project-based activities to offset the production of greenhouse gas emissions. Participants are required to reduce greenhouse gas emissions to a benchmark of 7.27 tonnes of carbon dioxide equivalent per head of state population by the end of 2007, which remains as a benchmark until the end of 2020 or until an effective national emissions trading scheme is developed.

- *New South Wales renewable energy target scheme (NRET)*

  The New South Wales Government has announced plans for a mandatory renewable energy target scheme to commence in 2008. The scheme will require electricity retailers to meet renewable energy targets of 10 per cent (1317 GWh) of the state's end use consumption by 2010 and 15 per cent (7250 GWh hours) by 2020.

- *New South Wales Energy Savings Action Plans*

  High energy users, state agencies and local councils, are required to prepare energy savings action plans in which they determine current energy use, undertake a management and technical review, and identify energy savings. The action plans are designed to encourage cost-effective investment in energy efficiency and to fulfil the requirements of the Energy Efficiency Opportunities program.

- *Victorian renewable energy target scheme (VRET)*
  This scheme imposes requirements on electricity retailers to purchase electricity generated from renewable sources. The scheme sets annual targets with the aim that Victoria's consumption of electricity generated from renewable sources will be 10 per cent (3274 GWh hours) by 2016.
  VRET is complemented by a range of other measures including promotion of voluntary renewable energy programs, solar power on houses, technology support and smart energy zones with the aim of meeting the 10 per cent target by 2010.
- *Industry Greenhouse Program*
  This program requires Environment Protection Authority (Vic) licensees that are medium to large energy users to: report their energy use and associated greenhouse gas emissions; conduct an energy audit; identify best practice options and determine payback periods; invest in option with a payback of three years or less; and report annually on implementation and emissions.
  Solar hot water rebates of up to $1500 are available when replacing an existing gas or solid fuel hot water system, or converting an existing hot water system to solar. Only householders, community groups, farmers and local governments are eligible for the rebate.
- *Queensland 13 per cent gas scheme*
  A scheme requiring electricity retailers to source at least 13 per cent of the electricity they sell in Queensland from gas-fired generation. The scheme aims to encourage greater penetration of gas and the development of new gas sources (including coal seam methane) and infrastructure in Queensland and to reduce greenhouse gas emissions from the Queensland electricity sector.
- *South Australia—Climate Change and Greenhouse Emissions Reduction Bill*
  - The Bill sets targets: to reduce greenhouse gas emissions in the state by at least 60 per cent of 1990 levels by the end of 2050 and to increase the share of renewable electricity generated and used in the state to at least 20 per cent by the end of 2014. The Bill was introduced to parliament on 6 December 2006 following a consultation period in mid 2006.
  - Solar hot water rebates of up to $700 are available to residents who purchase a new solar hot water system or retrofit kit for domestic purposes and install it at their principal place of residence. The rebate is subject to a range of other eligibility conditions.
- The Western Australian Government has set a renewable energy target of 6 per cent on the South-West Interconnected System electricity transmission grid by 2010. In February 2007 the Premier announced that the state government will be also required to purchase 20 per cent of its electricity requirements from renewable energy sources by 2010.
  - Solar hot water rebates of up to $700 are available to householders who install certain gas-boosted solar water heaters. The rebate is subject to a range of other eligibility conditions.

**Cooperative measures**

The National Framework for Energy Efficiency Minimum incorporates energy efficiency performance standards for appliances, equipment and buildings:

- Mandatory energy efficiency design standards (MEPS), which requires that certain products sold in Australia (for example, fridges, freezers, electric water heaters and air conditioners) meet minimum energy efficiency standards
- All jurisdictions, except New South Wales, have adopted the national energy efficiency standards for commercial and residential buildings in the Building Code of Australia, which sets energy efficiency design standards for new buildings and major refurbishments. New South Wales operates the building sustainability index (BASIX), which mandates energy and water saving targets house and home unit developers must reach before a building application can be approved.

# C AUSTRALIAN TRANSMISSION PIPELINES

Table C.1 lists Australia's main onshore natural gas transmission pipelines. Not all licensed pipelines are listed.

Table C.1: Main Australian onshore transmission pipelines, 2006

| LICENCE NUMBER | NAME | LICENSEE | LENGTH (KM) | DIAMETER (MM) | YEAR CONSTRUCTED |
|---|---|---|---|---|---|
| NEW SOUTH WALES AND THE AUSTRALIAN CAPITAL TERRITORY | | | | | |
| 16, 17–23 | Moomba to Sydney (and associated laterals) | EAPL | 2 013[1] | 864 | 1974–1993 |
| 24 | Vic–NSW border to Culcairn | GasNet | 57 | 457 | 1999 |
| 25 | Marsden to Dubbo | APT | 255 | 168, 219 | 1999 |
| 26 | Vic–NSW to Wilton | Alinta | 467 | 450 | 2000 |
| 27 | Dubbo to Tamworth | Central Ranges Pipeline | 254 | 219, 168 | 2006 |
| 28 | Llabo to Tumut | Country Energy | 64 | 219 | 2001 |
| 29 | Hoskintown to ACT | ACTewAGL | 22 | 273 | 2001 |
| VICTORIA | | | | | |
| various | Victorian transmission system | GasNet | 1935 | 80–750 | 1969–2006 |
| 75 | Longford to Dandenong | GasNet | 174.20 | 750 | 1971 |
| 179 | Carisbrook to Horsham | Coastal Gas Pipelines | 182.00 | 200, 100 | 1998 |
| 226 | SA–Vic border to Mildura | Envestra | 105.20 | 100 | 1999 |
| 227 | Iona to North Paaratte | TXU | 7.10 | 150 | 1999 |
| 240 | Otway Basin to Heytesbury Gas plant | Origin Energy | 8.50 | 219 | 2002 |
| 243 | Kilcunda to gas processing Lang Lang | Origin Energy | 32.00 | 350 | 2003 |
| 247 | EGP and TGP to GasNet Longford to Dandenong | Alinta DVH | 2.10 | 350 | 2002 |

| LICENCE NUMBER | NAME | LICENSEE | LENGTH (KM) | DIAMETER (MM) | YEAR CONSTRUCTED |
|---|---|---|---|---|---|
| QUEENSLAND | | | | | |
| 2 | Roma to Brisbane | APT | 434 | 273–400 | 1967 |
| 3 | Kincora to Wallumbilla | Origin Energy | 53 | 219 | 1977 |
| 13 | Ballera to SA Border | Santos Ltd | 90 | 400 | 1993 |
| 15 | Cheepie Barcaldine Gas Pipeline | Enertrade | 420 | 168 | 1994 |
| 21 | Moomba to Sydney (Qld section) | EAPL | 56.2 | 864 | 1974 |
| 24 | Ballera to Wallumbilla | Epic Energy | 756 | 406 | 1996 |
| 26 | Dawson River to Wallumbilla–Gladstone | Anglo Coal | na | 168 | 1996 |
| 30 | Wallumbilla to Gladstone, Gladstone to Rockhampton | Alinta | 629 | 219–324 | 1989–91 |
| 41 | Carpentaria Gas Pipeline | Roverton | 841 | 324 | 1997 |
| 42 | Cannington Lateral from Carpentaria Gas Pipeline | APT | 100 | 150 | 1998 |
| 45 | Bunya/Vernon/Cocos to Central Treatment Plant | Australian Gasfields Ltd | 130 | 89 | 1998 |
| 52 | Maryborough to Gladstone via Bundaberg | PG&E | 309 | 100 | 1999–2000 |
| 60 | Wallumbilla–Gladstone to Bundaberg/Maryborough | Envestra | 274 | 114.3 | 2000 |
| 89 | Moranbah to Townsville Pipeline | Enertrade | 393 | 273.1 | 2004 |
| SOUTH AUSTRALIA | | | | | |
| 1 | Moomba to Adelaide (incl. Whyalla Lateral) | Epic Energy | 781 | 89–610 | 1969 |
| 3–4 | Katnook Pipeline and laterals | Epic Energy | 4.5 | 60–160 | 1991, 2000 |
| 5 | Ballera to Moomba (SA portion) | Santos Ltd | 92 | 1993 | 1993 |
| 6 | Angaston to Berri | Envestra | 234 | 1994 | 1994 |
| 7 | Moomba to Qld border (MSP) | EAPL | 101 | 864 | 1974–1976 |
| 11 | Berri to Mildura | Envestra | 42.3 | 114 | 1999 |
| 13, 14 | SEA Gas Pipeline | SEA Gas P/L | 680[2] | 60–457 | 2003 |
| 16 | SESA Pipeline | Origin Energy | 23.3 | 219 | 1976–89 |
| TASMANIA | | | | | |
| na | Tasmanian Gas Pipeline system | Alinta | 576 | 168–350 | 2002–05 |
| WESTERN AUSTRALIA | | | | | |
| 1–3 R1, 5 R1 | Dongara to Pinjarra (including laterals) | APT | 444 | 114–356 | 1972 |
| 8 R1 | Robe River Pipeline | Robe River Mining Co | 58 | 273 | 1984 |
| 18 | Beharra Springs to Parmelia | Origin Energy | 1.6 | 168 | 1992 |
| 16, 19–20 | Tubridgi and Griffin pipelines | BHP Billiton | 180 | 168, 273 | 1992–93 |
| 22 | Karratha to Port Hedland | Epic Energy | 215 | 450 | 1994 |
| 23, 52–53 | Parmelia Pipeline | APT | 0.45 | 168 | 1994 |
| 24–28 | Goldfields Gas Pipeline and laterals | Southern Cross Pipelines | 1426 | 350–400 | 1996 |
| 40 | Dampier to Bunbury (DBNGP) (including a number of laterals under this licence) | DBNGP (WA) Nominees P/L (and Epic Energy) | 1845 | 660 | 1984 |
| 43 | Midwest Pipeline | APT | 352 | 219–168 | 2000 |
| 44–46 | Parmelia Pipeline laterals | APT | – | 200 | 2000 |
| 59 | Kambalda to Esperance Gas Pipeline | Esperance Pipeline Co. | 340 | 150 | 2004 |
| 60, 63, 68 | Telfer Pipeline | Gas Transmission Services WA (Operations) | 464.00 | 250 | 2004 |

| LICENCE NUMBER | NAME | LICENSEE | LENGTH (KM) | DIAMETER (MM) | YEAR CONSTRUCTED |
|---|---|---|---|---|---|
| NORTHERN TERRITORY | | | | | |
| 1 | Palm Valley to Alice Springs | NT Gas Pty Ltd | 140 | 200 | 1983 |
| 4 | Mereenie to Tylers Pass, Katherine and Tennant Creek laterals | NT Gas Pty Ltd | 147 | 114, 273 | 1986 |
| 4 | Palm Valley to Darwin | NT Gas Pty Ltd | 1512 | 356, 324 | 1986 |
| 7 | Brewer Estate | Energy Equity | 10 | 114 | 1989 |
| 8 | Cosmo Howley Lateral | International Oil/ NT Gas | 25 | 90 | 1988 |
| 17 | Daly Waters to McArthur River Mine | PAWA/NT Gas Pty Ltd | 333 | 168 | 1995 |
| 18 | Darwin City Gate to Berrimah | NT Gas Pty Ltd | 19 | 168 | 1996 |
| 19 | Mt Todd Mine Lateral | NT Gas Pty Ltd | 10 | 219 | 1996 |
| 20 | Bayu Undan to Darwin | ConocoPhillips | 92 (NT portion) | 660 | 2004–05 |

EAPL: East Australian Pipeline Limited; APT: Australian Pipeline Trust.

1. Includes Queensland component. 2. Includes Victorian component.

Source: Australian Pipeline Industry Association, *2007 Directory yearbook*, no. 16, 2007; ESAA, *Electricity gas Australia 2006*, 2006.

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