

### STATE OF THE ENERGY MARKET 2009







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# CONTENTS

- vi PREFACE
- viii MARKET OVERVIEW
- 22 PART ONE—ESSAY
- 24 AUSTRALIA'S NATURAL GAS MARKETS: CONNECTING WITH THE WORLD A REPORT BY ENERGYQUEST
- 26 E.1 Liquefied natural gas
- 31 E.2 Coal seam gas
- 37 E.3 Climate change policies
- 38 E.4 Global financial crisis
- 41 E.5 Security of gas supply
- 42 E.6 Conclusion

#### 44 PART TWO—ELECTRICITY

- 48 CHAPTER 1: ELECTRICITY GENERATION
- 50 1.1 Electricity generation
- 52 1.2 Generation in the National Electricity Market
- 61 1.3 Investment
- 65 1.4 Reliability of the generation sector
- 70 CHAPTER 2: NATIONAL ELECTRICITY MARKET
- 72 2.1 Features of the National Electricity Market
- 73 2.2 How the National Electricity Market works
- 76 2.3 Demand and capacity
- 76 2.4 Trade across the regions

81	2.5	National Electricity Market prices
85	2.6	Price volatility
88	CHAP	TER 3: ELECTRICITY FINANCIAL MARKETS
91	3.1	Financial market structure
93	3.2	Financial market instruments
96	3.3	Financial market liquidity
96	3.4	Trading volumes in Australia's electricity derivative market
101	3.5	Price transparency and bid-ask spread
101	3.6	Number of market participants
102	3.7	Price outcomes
105	3.8	Price risk management—other mechanisms
106	CHAP	TER 4: BEYOND THE NATIONAL ELECTRICITY MARKET
108	4.1	Western Australia's electricity system
108	4.2	Electricity reform in Western Australia
109	4.3	Western Australia's electricity market structure
112	4.4	Electricity generation in Western Australia
113	4.5	Western Australia's wholesale electricity market
119	4.6	Network access in Western Australia
119	4.7	Retail arrangements in Western Australia
119	4.8	The Northern Territory's electricity industry
122	CHAP	TER 5: ELECTRICITY TRANSMISSION
124	5.1	Role of electricity transmission networks
125	5.2	Australia's electricity transmission networks
130	5.3	Economic regulation of electricity transmission services
133	5.4	Electricity transmission investment
135	5.5	Financial performance
138	5.6	Service reliability of electricity transmission networks
140	5.7	Electricity transmission congestion
147	5.8	Policy developments in electricity transmission
152	CHAP	TER 6: ELECTRICITY DISTRIBUTION
155	6.1	Role of distribution networks
155	6.2	Australia's distribution networks
161	6.3	Economic regulation of distribution services
165	6.4	Distribution investment
168	6.5	Financial performance of distribution networks
172	6.6	Service quality and reliability
185	6.7	Policy developments in electricity distribution
187	6.8	Demand management and metering
190	CHAP	TER 7: ELECTRICITY RETAIL
193	7.1	Retail market structure
198	7.2	Trends in market integration
200	7.3	Retail competition
207	7.4	Retail prices

7.5	Quality of retail service
7.6	Energy efficiency
7.7	Future regulatory arrangements
PART	THREE—NATURAL GAS
CHAP	TER 8: UPSTREAM GAS MARKETS
8.1	Exploration and development
8.2	Australia's natural gas resources
8.3	Domestic and international demand for Australian gas
8.4	Industry structure
8.5	Gas wholesale markets
8.6	Gas prices
8.7	Gas market development
8.8	Reliability of supply
CHAP	TER 9: GAS TRANSMISSION
9.1	Australia's gas transmission pipelines
9.2	Ownership of gas transmission pipelines
9.3	Economic regulation of gas transmission pipelines
9.4	Recent gas pipeline investment
9.5	Pipeline tariffs
9.6	Performance indicators
CHAP	TER 10: GAS DISTRIBUTION
10.1	Role of distribution networks
10.2	Australia's distribution networks
10.3	Ownership of distribution networks
10.4	Regulation of distribution networks
10.5	Investment in distribution networks
10.6	Operating and maintenance costs
10.7	Quality of service
CHAP	TER 11: GAS RETAIL
11.1	Retail market structure
11.2	Trends in market integration
11.3	Retail competition
11.4	Retail prices
11.5	Quality of retail services
11.6	Future regulatory arrangements
APPE	NDIX: ENERGY MARKET REFORM
ABBR	EVIATIONS
	7.5 7.6 7.7 PART CHAP 8.1 8.2 8.3 8.4 8.5 8.6 8.7 8.8 CHAP 9.1 9.2 9.3 9.4 9.5 9.6 CHAP 10.1 10.2 10.3 10.4 10.5 10.6 10.7 CHAP 11.1 11.2 11.3 11.4 11.5 11.6 APPE ABBR

## PREFACE

The Australian Energy Regulator (AER) aims to keep stakeholders informed of policy, regulation and market developments in the energy sector. This is the AER's third *State of the energy market* report, which provides a high level overview of energy market activity in Australia. The report is intended to meet the needs of a wide audience, including government, industry and the broader community. The report supplements the AER's extensive technical reporting on the energy sector.

The *State of the energy market* report consolidates information from various sources into one user friendly publication. The aim is to better inform market participants and assist policy debate on energy market issues. The AER is not a policy body, however. In that context, the report focuses on presenting facts, rather than advocating policy agendas. This 2009 edition consists of a market overview, supported by 11 chapters on the electricity and natural gas sectors. The essay this year is an assessment by EnergyQuest of the state of the natural gas industry, focusing on the growing integration of Australian and global energy markets. There is also an appendix providing background on energy market reform in Australia, including the roles of key policy and regulatory bodies.

The 11 chapters of the report provide more detail on market activity and performance in the electricity and natural gas sectors. The chapters follow the supply chain in each industry—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, it also contains some coverage of Western Australia and the Northern Territory. The *State of the energy market* is an evolving project. This year's edition provides increased coverage of energy policy and regulatory developments, including the AER's recent activity. The chapters also provide a stronger focus on key market developments in each sector over the past 12–18 months. The market overview includes some discussion of the implications of climate change policies and the global financial crisis for the energy industry, with the chapters containing more detailed coverage.

Looking forward, the AER will review its approach to *State of the energy market* reporting and consider ways to better inform our audience. As always, we hope to hear the views of readers in this regard. In the meantime, I hope this 2009 edition will provide a valuable resource for market participants, policymakers and the wider community.

Steve Edwell Chairman



# MARKET OVERVIEW



### MARKET OVERVIEW

Despite difficult economic conditions, there has been considerable momentum in the energy sector over the past 12–18 months. We have seen renewed growth in generation investment, especially in Queensland, New South Wales and South Australia. Network investment is also increasing to meet the challenges of rising peak demand, ageing assets and more rigorous licensing requirements to improve network security.

There has been continued growth and diversification in the natural gas industry, with major projects underway in Western Australia, the continued expansion of Queensland's coal seam gas (CSG) industry and the likelihood of east coast liquefied natural gas (LNG) exports in the next few years. Australia's gas pipeline network continues to expand, with Queensland now interconnected with the south east gas markets, and Bonaparte Basin gas coming onstream in Darwin.

A number of recent policy initiatives will enhance transparency and efficiency in upstream gas markets. The National Gas Market Bulletin Board, which began in July 2008, provides real-time and independent information on the state of the gas market, system constraints and market opportunities. To complement this reform, new spot markets for short term gas trading will begin in the winter of 2010.

On the regulatory front, the transition to national energy regulation has continued. The Australian Energy Regulator (AER) is now the economic regulator of all electricity networks and covered gas pipelines in southern and eastern Australia. It has completed its first determinations for the electricity distribution sector, and is undertaking its first access arrangement reviews in gas distribution.

A new body—the Australian Energy Market Operator (AEMO)—began operation on 1 July 2009 as the single electricity and gas market operator in southern and eastern Australia. It is also coordinating high level national transmission planning and will report on investment opportunities in electricity and natural gas.

Alongside these developments are challenges and concerns. Rising investment and operating costs are significantly increasing network charges and placing upward pressure on retail energy prices. There are also concerns that market power is affecting wholesale electricity prices in some regions.

While generation investment has picked up, there is continued uncertainty over climate change policies. The Australian Energy Market Commission (AEMC) cited concerns that this uncertainty may be delaying generation investment needed for reliability purposes.<sup>1</sup> At the same time, climate change policies are providing momentum for network improvements such as the installation of smart meters to help consumers actively manage their energy consumption.

#### 1 National Electricity Market

The AER closely monitors activity in the National Electricity Market (NEM), which is the wholesale spot market covering Queensland, New South Wales, Victoria, South Australia, Tasmania and the Australian Capital Territory (ACT). It publishes reports on market activity and the compliance of participants with the National Electricity Rules (Electricity Rules).

Wetter conditions in parts of eastern Australia and a mild winter in 2009 led to an easing of wholesale price pressure in most regions of the NEM in the past 18 months or so. Tasmania was the only region in which spot electricity prices rose during 2008–09. Queensland's average spot price in that period was its lowest for several years. While prices fell sharply in South Australia, they remained high relative to those in other mainland regions.

Despite generally benign conditions, concerns remain that some generators have been exercising market power in some regions. The NEM was designed to minimise the risk of market power, through an interconnected transmission grid that allows competition between generators. But there are circumstances in which baseload generators can price capacity at around the market cap and be certain of at least partial dispatch. This behaviour is often more evident at times of peak demand, typically on days of extreme temperatures. The opportunities for market power are enhanced if transmission interconnector limits are reduced. Given the relatively inelastic demand for electricity and the high market price cap, such circumstances can lead to significant opportunities for price manipulation.

The AER referred in previous *State of the energy market* reports to generators exercising market power in New South Wales in 2007 and South Australia in 2008. These occurrences were reflected in significant price spikes (figure 1). While some price events relate to exogenous factors such as extreme weather, bushfires and unplanned infrastructure outages, a number of spikes in the past two years coincided with strategic generator bidding.

There have been continuing concerns in South Australia, where spot prices in the past two years were significantly higher than in other mainland NEM regions. In the early months of 2009 South Australian spot prices exceeded \$5000 per megawatt hour (MWh) on 27 occasions. The bidding strategies of AGL Energy for its Torrens Island power station were a key contributing factor on most occasions. The events typically occurred on days of extreme temperatures and demand, which created a tight supply-demand balance. Under these conditions, Torrens Island can bid a significant proportion of its capacity at around the market cap and be guaranteed at least partial dispatch.

More recently, market bidding strategies emerged as a concern in Tasmania. In June 2009 the spot price in Tasmania exceeded \$5000 per MWh on 13 occasions. The spikes were often driven by Hydro Tasmania making sudden and repeated cuts in the output of its non-scheduled (mini hydro) generators, in conjunction with strategic bidding for the rest of its portfolio. The strategy led to administered pricing being applied for four days in June—the first time for Tasmania.

Tasmania also experienced extreme prices for raise contingency frequency control services in early April. The Office of the Tasmanian Economic Regulator has given notice of its intention to declare the supply

1 AEMC, Review of energy market frameworks in light of climate change policies, final report, Sydney, October 2009, pp. 81-2.

Figure 1 National Electricity Market—average weekly prices



AGL, AGL Energy; CPT, cumulative price threshold; Macquarie, Macquarie Generation; Hydro Tas, Hydro Tasmania. Note: Volume weighted prices.

Sources: AEMO; AER.

of these services, which would enable it to regulate prices. While the AER recognises the need for this proposal, such an outcome cannot be seen as a positive development for the market.

The AER monitors activity in the spot market to screen for issues of noncompliance with the Electricity Rules. While bidding capacity at high prices is not a breach of the Rules, it may raise issues under the anticompetitive conduct provisions of the *Trade Practices Act 1974* (Cwth). The AER assists the Australian Competition and Consumer Commission (ACCC) in relation to enforcing these provisions. The exercise of market power by some generators is a continuing concern. There is evidence that it is leading to increased market volatility and higher spot prices in some regions. The AER will continue to monitor and report on generator bidding behaviour.

The AER reports on all extreme price events in the NEM and conducts more intensive investigations where warranted. It has conducted two recent investigations into the rebidding behaviour of generators. While the Electricity Rules allow generators to amend their original price bids to supply electricity, they require that generators make all bids and rebids in 'good faith.' The rebidding provisions play an important role in promoting accurate dissemination of information for efficient market dispatch.

In 2008 the AER launched separate investigations into whether Stanwell (a Queensland generator) and AGL Energy (in relation to its South Australian generators) acted 'in good faith' (as contemplated under the Rules) when they rebid capacity during periods of high prices in early 2008. In its investigation findings, published on 12 May 2009, the AER found AGL Energy's bidding was not in breach of the Rules.

The AER investigation into the rebidding behaviour of Stanwell led to it instituting proceedings in the Federal Court, Brisbane. It has alleged that several of Stanwell's rebids of offers to generate electricity on 22 and 23 February 2008 were not in 'good faith'. The AER is seeking orders that include declarations, civil penalties, a compliance program and costs. The matter has been set down for trial in June 2010.

The AER also investigated the operation of the market on 29 and 30 January 2009, when extreme temperatures in Victoria and South Australia led to record electricity demand. There were also significant interruptions to transmission lines and interconnectors on those two days. In combination, these events led to extreme spot prices, administered pricing and supply interruptions. The investigation identified issues relating to the performance of, and reporting on, network capabilities by network businesses, but no breaches of the Rules.

#### Generation investment and reliability

The *State of the energy market 2008* report referred to concerns that generation investment had been slow to respond to rising electricity demand. There was little generation investment across the NEM in the middle of the current decade, but then tightening supply conditions led to significant new investment in the past few years (figure 2). New investment has occurred in coal and gas fired capacity in Queensland since 2005–06 and in wind capacity in South Australia over the same period. In part, the shift towards investment in gas fired plant and wind generation reflects market expectations that climate change policies will improve the competitiveness of these technologies in the generation mix.

Table 1a sets out major new generation investment that came on line in the NEM in 2008–09, excluding wind. The bulk of new investment—1100 megawatts (MW) was in privately developed gas fired plant in New South Wales. Origin Energy commissioned the 648 MW Uranquinty plant near Wagga Wagga, and TRUenergy commissioned the 435 MW Tallawarra plant.

Queensland added around 460 MW of private investment with the commissioning in 2009 of the Braemar 2 plant, developed by ERM Power and Arrow Energy. In South Australia, Origin Energy completed a 128 MW expansion of its Quarantine plant. Government businesses in New South Wales and Tasmania also commissioned new plant in 2009. In addition, Victoria, New South Wales and South Australia recorded around 500 MW of new wind generation capacity.

Table 1b sets out *committed* investment projects in the NEM at June 2009. It includes those under construction and those where developers and financiers have formally committed to construction. There is around 2650 MW of committed capacity in the NEM, of which more than 2000 MW is in gas fired generation. Origin Energy has committed to major developments in Queensland (including a 605 MW plant on the Darling Downs) and Victoria (a 518 MW plant at Mortlake). In addition, government owned generators in New South Wales have committed to significant investment. At June 2009 AEMO reported another 15 490 MW of *proposed* investment, including:

- > 8760 MW of non-wind capacity, mostly in gas fired generation for New South Wales, Queensland and Victoria
- > 6730 MW of wind capacity, mainly in Victoria, New South Wales and South Australia.





Note: Net change in registered capacity from 1998-99. A decrease may reflect a reduction of capacity due to decommissioning or a change in the ratings of generation units.

Sources: AEMO; AER.

#### Table 1a Generation investment, 2008–09 (excluding wind)

POWER STATION	DATE COMMISSIONED	TECHNOLOGY	CAPACITY (MW)	ESTIMATED COST (\$ MILLION)	OWNER
Braemar 2	April-June 2009	OCGT	462	546	ERM Power and Arrow Energy
Colongra (unit 1)	June 2009	OCGT	157		Delta Electricity
Tallawarra	February 2009	CCGT	435	350	TRUenergy
Uranquinty	October 2008 – January 2009	OCGT	648	700	Origin Energy
Quarantine	March 2009	OCGT	128	90	Origin Energy
Tamar Valley Peaking	April 2009	OCGT	58		Aurora Energy
	POWER STATION Braemar 2 Colongra (unit 1) Tallawarra Uranquinty Quarantine Tamar Valley Peaking	DATE COMMISSIONEDBraemar 2April-June 2009Colongra (unit 1)June 2009TallawarraFebruary 2009UranquintyOctober 2008 - January 2009QuarantineMarch 2009Tamar Valley PeakingApril 2009	DATE COMMISSIONEDTECHNOLOGYBraemar 2April-June 2009OCGTColongra (unit 1)June 2009OCGTTallawarraFebruary 2009CCGTUranquintyOctober 2008 - January 2009OCGTQuarantineMarch 2009OCGTTamar Valley PeakingApril 2009OCGT	DATE COMMISSIONEDTECHNOLOGYCAPACITY (MW)Braemar 2April-June 2009OCGT462Colongra (unit 1)June 2009OCGT157TallawarraFebruary 2009CCGT435UranquintyOctober 2008 - January 2009OCGT648QuarantineMarch 2009OCGT128Tamar Valley PeakingApril 2009OCGT58	DATE COMMISSIONEDDATE COMMISSIONEDCAPACITY (MW)ESTIMATED COST (\$ MILLION)Braemar 2April-June 2009OCGT462546Colongra (unit 1)June 2009OCGT157TallawarraFebruary 2009CCGT435350UranquintyOctober 2008 - January 2009OCGT648700QuarantineMarch 2009OCGT12890Tamar Valley PeakingApril 2009OCGT5858

#### Table 1b Committed investment in the National Electricity Market, June 2009

			CAPACITY	PLANNED		
DEVELOPER	POWER STATION	TECHNOLOGY	(MW)	COMMISSIONING DATE		
QUEENSLAND						
Queensland Gas Company	Condamine	CCGT	135	2009-10		
Origin Energy	Darling Downs	CCGT	605	2010		
Origin Energy	Mount Stuart (extension)	OCGT	127	2009		
Rio Tinto	Yarwun Cogen	Gas cogeneration	152	2010		
NEW SOUTH WALES						
Eraring Energy	Eraring (extension)	Coal fired	120	2010-11		
Delta Electricity	Colongra (units 2–4)	OCGT	471			
VICTORIA						
AGL Energy	Bogong	Hydro	140	2009-10		
Origin Energy	Mortlake	OCGT	518	2010		
Pacific Hydro	Portland	Wind	164	2009-10		
SOUTH AUSTRALIA						
International Power	Port Lincoln	OCGT	25	2010		
TASMANIA						
Aurora Energy	Tamar Valley	CCGT	196	2009		

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

Note: Capacity is summer capacity for all generators.

Source: AEMO.



Figure 3

Notes: Capacity (excluding wind) is scheduled capacity and encompasses installed and committed capacity. Wind capacity includes scheduled and semi-scheduled wind generation. Proposed capacity includes wind projects. The maximum demand forecasts for each region in the NEM are aggregated based on a 50 per cent probability of exceedance and a 95 per cent coincidence factor. Unscheduled generation is treated as a reduction in demand. 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: AEMO, *Electricity statement of opportunities for the National Electricity Market*, Melbourne, 2009.

Investment in wind generation continues to rise, especially in South Australia, where it now accounts for around 20 per cent of installed generation capacity. The extent of new and proposed investment in wind generation has raised concerns about system security and reliability. These concerns led to a change of the Electricity Rules, requiring from 31 March 2009 that new wind generators greater than 30 MW must be classified as 'semi-scheduled' and participate in the central dispatch process. This allows AEMO to reduce the output of these generators if necessary. The Australian Government's expanded renewable energy target (RET), passed in August 2009, will likely further stimulate investment in wind generation.

Figure 3 charts forecast peak demand in the NEM against installed, committed and proposed capacity over the next six years. It also shows the amount

of capacity that AEMO considers necessary to maintain a reliable power system, given projected demand. It indicates current installed and committed capacity will be sufficient to meet peak demand projections and reliability requirements until at least 2012–13 on a national basis. Individual regions may require generation investment at an earlier date.

While only a small percentage of proposed projects would need to be developed to meet reliability requirements beyond 2012–13, the AEMC has cited uncertainty over the details of climate change policies as one factor that may delay some investment. As the details of climate change policies become more certain, the investment response will likely strengthen.

#### 2 Energy networks

The transition to national regulation of energy networks is continuing. The AER completed its first revenue determinations in electricity distribution in April 2009, for the New South Wales and ACT networks. It also published determinations for the New South Wales and Tasmanian transmission networks at that time.

The AER received its first proposals on access arrangement revisions in gas distribution in June 2009. It is also considering new regulatory proposals for electricity distribution networks in Queensland and South Australia.

Figure 4 sets out indicative timelines for the AER's consideration of regulatory proposals for energy networks. The AER has published guidelines and frameworks to explain its regulatory approach.

A common feature of recent proposals has been substantial increases in capital and operating expenditure requirements. Figure 5 illustrates new investment under current regulatory proposals and AER determinations compared with investment in previous regulatory periods.

7

#### Figure 4

#### Indicative timelines for AER determinations on energy networks Electricity transmission



1 Regulatory proposals submitted by the businesses 2 Draft determination released by the AER 3 Final determination released by the AER



#### **Electricity distribution**

Gas distribution



Note (gas distribution): The timeframes are indicative. The standard review period begins when a gas distributor submits an access arrangement proposal to the AER by a date specified in the previous access arrangement. The timeframes may vary if the AER grants a time extension for the submission of a proposal. An access arrangement period is typically five years, but a provider may apply for a different duration.

8



Figure 5 Network investment—AER determinations and regulatory proposals, 2009

Note: Proposed investment refers to business proposals not yet assessed by the AER.

Investment in electricity distribution will rise by around 80 per cent in New South Wales and 66 per cent in the ACT in the new five year regulatory cycle. In total, the AER signed off in April 2009 on over \$14 billion of distribution investment for New South Wales and the ACT over the next five years. Across the NEM, distribution investment is running at over 40 per cent of the underlying asset base in most networks, over 65 per cent in Queensland and up to 90 per cent in parts of New South Wales.

The story is similar for transmission, for which investment will rise by 72 per cent in New South Wales and 57 per cent in Tasmania over the current regulatory cycle. In total, transmission investment across the NEM was forecast to rise to over \$1.6 billion in 2008–09.

A number of factors are driving rising investment requirements. In particular, the networks need to:

- > meet load growth and rising peak demand
- > replace ageing and obsolete assets
- > satisfy more rigorous licensing conditions for network security and reliability.

More generally, all networks face the issue of needing to build capacity to keep air conditioners running on a few very hot days each year. Several businesses challenged aspects of the recent AER revenue determinations in the Australian Competition Tribunal. In part, the appeals related to inputs in calculating the weighted average cost of capital. The tribunal was considering the appeals in late 2009.

As in New South Wales, the Queensland and South Australian electricity distributors have proposed substantial increases in investment. In South Australia, ETSA Utilities proposed a 126 per cent increase in capital investment over the next five years. In Queensland, ENERGEX and Ergon Energy proposed increases of around 50 per cent. In total, the Queensland and South Australian proposals would involve around \$15 billion of investment in the next regulatory cycle.

There are similar trends in gas. Access arrangement revisions for gas distribution networks in New South Wales and the ACT encompass significant increases in investment. Jemena has proposed a 63 per cent increase in investment for its New South Wales gas networks and ActewAGL proposed a 227 per cent increase for the ACT network.

In addition to step-increases in capital spending, operating and maintenance costs are also rising across the networks (figure 6). While these costs are rising less sharply than capital spending, the increases are nonetheless substantial. The Electricity Rules allow network businesses discretion in how they use their capital and operating expenditure allowances. There are also mechanisms to reward businesses for efficient investment and operating programs, balanced with incentives for reliable service delivery.

With network costs accounting for around 50 per cent of a typical electricity bill, rising capital and operating expenditure are flowing through to energy customers. In May 2009 the New South Wales regulator (the Independent Pricing and Regulatory Tribunal) announced that higher distribution charges will increase the average residential electricity bill in the state by around 10 per cent. The impact on large energy users is even greater. The Energy Users Association of Australia has referred to network tariff increases of up to 55 per cent for some large customers.

ETSA Utilities' regulatory proposal would increase distribution charges in South Australia by around 6-7 per cent per year for a small residential customer and 10 per cent for a small business customer. The Queensland proposals would increase distribution charges by around 10 per cent in the first year, followed by annual increases of around 4 per cent.

Energy customers will expect a return for these price increases. In particular, they will look to reliability outcomes and the types of services offered, and in the longer term, to more efficient networks with more competitive pricing structures.

Rising capital and operating expenditure over the past few years has enabled the networks to deliver reasonably stable reliability. The average duration of outages per customer in the NEM has generally been 200–250 minutes per year, allowing for regional variations (figure 7). Electricity customers will look to network businesses to continue to translate rising investment and operating costs into stable or improving reliability outcomes.

While reliability is one aspect of service delivery, network businesses should also look to improve the range of services offered—for example, demand management has many benefits for consumers, from deferring capital expenditure to offsetting the needle peaks in energy demand. The AER has introduced a demand management innovation allowance to encourage network businesses to consider nonnetwork augmentations. The scheme allows businesses to recover implementation costs and forgone revenues from introducing demand management measures. While the scheme is in its early stages, it will mature and likely become more important over time.

Policy and regulatory responses are underway to enhance network performance. One response is the rollout of smart meters and, potentially, smart grids. Smart meters allow customers to track their energy consumption. When combined with appropriate tariff structures, they can reduce peak and overall demand and delay network augmentations. The Council of Australian Governments has committed to a national rollout of smart meters where the benefits outweigh the costs, with initial deployment in Victoria and New South Wales. The rollout in Victoria began in 2009.

Smart grids take the concept of smart meters further towards direct control of load, the use of communications technology to rapidly detect and switch around faults to minimise supply disruptions, and the integration of embedded generation that can be switched on and off to support the network. The Australian Government recently committed \$100 million for a trial of smart grid technologies.

While innovations such as smart meters and smart grids will pose operational challenges for the distribution sector, their introduction can be accommodated within the regulatory framework. The Electricity Rules allow for stable returns on efficient investment in network innovations to improve grid operation and control. If these innovations are accepted into the regulated asset base, the costs will be ultimately borne by consumers, who will expect to benefit through enhanced network performance. In particular, consumers would expect better information on their energy use, which would enable (in the longer term) wider product choice and greater control over their energy consumption and costs.



Figure 6 Operating and maintenance expenditure—AER determinations and regulatory proposals, 2009

Note: Proposed investment refers to business proposals not yet assessed by the AER.



Notes:

Figure 7

The data reflect total outages experienced by distribution customers. In some instances, the data may include outages resulting from issues in the generation and transmission sectors. In general, the data have not been normalised to exclude distribution network issues beyond the reasonable control of the network operator. The data for Queensland in 2005-06 and New South Wales in 2006-07 have been adjusted to remove the impact of natural disasters (Cyclone Larry in Queensland and extreme storm activity in New South Wales), which would otherwise have severely distorted the data.

The NEM averages are weighted by customer numbers.

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

Sources: Performance reports published by the ESC (Victoria), IPART (New South Wales), the QCA (Queensland), ESCOSA (South Australia), the ERA (Western Australia), OTTER (Tasmania), the ICRC (ACT), EnergyAustralia, Integral Energy and Country Energy. Some data are AER estimates derived from official jurisdictional sources. The AER consulted with PB Associates in developing historical data.

An overarching reform towards more efficient network investment is the establishment of a national transmission planning function within AEMO. The goal is to overlay the traditional jurisdiction based approach to network planning with a more strategic, long term focus on the efficient development of the transmission grid from a national perspective. To this end, AEMO will publish an annual network development plan to complement shorter term regional planning. The first plan is scheduled for release by the end of 2010.

In addition, a new regulatory investment test will help transmission businesses identify effective ways of responding to rising demand for electricity services—for example, in assessing whether the most efficient response is a network augmentation or an alternative such as generation investment. The new test, which takes effect in August 2010, will account for the effects of planned investment on reliability and a range of market impacts. The AER will publish the test and associated guidelines by July 2010.

Similar reforms are underway—but at an earlier stage of development—in distribution. In September 2009 the AEMC recommended a new regulatory test similar to that for transmission.<sup>2</sup> It also recommended more transparent planning requirements, including annual reports that detail projections of load and network capacity and potential projects for the next five years; and arrangements to jointly plan investment affecting both transmission and distribution networks.

Recent reviews have identified impediments to efficient network investment—for example, the AEMC recently recommended changes in interregional transmission charging mechanisms to enhance network planning across regions. The new charging regime is expected to commence on 1 July 2011. The AEMC also recommended reforms in response to climate change policies (see below).

#### Review of capital costs

A key element of the energy regulatory framework is the return on capital to network owners, which may account for up to 60 per cent of allowed revenues. In May 2009 the AER released a decision on the parameters of the weighted average cost of capital model, which determines the return on capital for regulated electricity networks.<sup>3</sup> The weighted average cost of capital represents the cost of debt and equity required by an efficient benchmark electricity network business to supply regulated electricity services.

The review covered the rate of return values and methods to be adopted in electricity network pricing determinations over the next five years. It was the first review of its type under the Electricity Rules, and its release coincided with the onset of the global financial crisis. Based on the parameters established through the review, the weighted average cost of capital in October 2009 was around 10 per cent—reflecting a cost of debt of 9.7 per cent and an equity return of 10.6 per cent.

The decision accounted for the global financial crisis and recognised the potential for a shift in the market's assessment of risk. More generally, however, the AER takes a long term perspective on the cost of capital. In particular, the regulatory regime should allow returns that provide incentives for efficient investment over the long term—in what are long term assets—rather than reacting to shorter term influences. More recent events in financial markets tend to reinforce this view, with equity yields and credit spreads moving back towards levels more in keeping with those before the global financial crisis.

Businesses will continue to be compensated for any rises in debt margins at each reset. This compensation, being based on a benchmark corporate bond of BBB+ rating, is well above that which higher rated network businesses incur. More generally, evidence from a number of sources suggests the regulatory regime helps insulate network businesses from market volatility. Significantly,

2 AEMC, Review of national framework for electricity distribution network planning and expansion, final report, Sydney, September 2009.

3 AER, Electricity transmission and distribution network service providers: review of the weighted average cost of capital (WACC) parameters, final decision, Melbourne, May 2009. the ability of a regulated network business to align its debt issuance to the time of a regulatory determination mitigates a large proportion of the risks associated with rising debt costs.

#### 3 Climate change policies

Australian governments are implementing measures to encourage the use of low greenhouse gas emission technologies. These policies have significant implications for energy markets. The Australian Government's primary emissions reduction policies are an expanded RET and a proposed emissions trading scheme—the Carbon Pollution Reduction Scheme (CPRS).

On 20 August 2009 the Commonwealth Parliament passed legislation to implement the expanded RET scheme. The scheme requires 20 per cent of Australia's electricity generation to come from renewable energy sources by 2020. It increases the pre-existing national target by more than four times to 45 850 gigawatt hours in 2020, before falling to 45 000 gigawatt hours in the following decade. The scheme is set to expire in 2030, when the proposed CPRS is intended to provide sufficient stimulus for renewable energy projects.

The expanded scheme aims to encourage investment in renewable energy technologies by providing for the creation of renewable energy certificates. One certificate is created for each megawatt hour of eligible renewable electricity generated by an accredited power station, or deemed to have been generated by eligible solar hot water or small generation units. Retailers must obtain and surrender certificates to cover a proportion of their wholesale electricity purchases. If a retailer fails to surrender enough certificates to cover its liability, then it must pay a penalty for the shortfall.

The design of the proposed CPRS was set out on 15 December 2008 in the *Carbon Pollution Reduction Scheme: Australia's low pollution future* (white paper). It aims to create a market for the right to emit carbon by placing a cap on Australia's total emissions. It is designed as a broad based trading scheme, covering sectors responsible for around 75 per cent of Australia's carbon emissions. The target for emissions reduction will depend on international mitigation efforts. The Australian Government has committed to a minimum 5 per cent reduction in emissions (from 2000 levels) by 2020, with the potential for a 25 per cent reduction by 2020 in the event of coordinated international action.

On 4 May 2009 the Australian Government announced a one year delay in the introduction of the CPRS, to 1 July 2011. Figure 8 illustrates how this announcement affected prices for electricity base futures on the Sydney Futures Exchange. Taking Victorian contracts as an example, the chart compares base futures prices on 27 April 2009 (one week before the announcement) with prices on 4 May 2009 (after the announcement). The difference between the lines approximates market expectations of the net impact of the CPRS on future spot electricity prices. The impact is predictably stronger during the summer peak period, but is mostly around \$5 per MWh. As expected, the impact was minimal outside the period of the delay.

Climate change policies pose challenges and opportunities for the energy sector. In particular, coal fired electricity generation, which accounts for around 85 per cent of Australia's generation output, is emissions intensive. The introduction of the CPRS may result in some asset write-downs. Mitigating factors such as forward market trading, vertical integration and new investment in gas fired generation are likely to ease the risk of possible supply issues.

There has been debate over the issue of assistance to coal fired generators. The white paper proposed a one-off assistance package for the energy sector, consisting of free carbon permits directed at mainly brown coal generators, valued at around \$3.6 billion. The Australian Government has engaged Morgan Stanley to further review the forecast impacts of climate change policies on high emission plant.

Figure 8 Victorian electricity base futures prices



#### Q, quarter

#### Source: d-cyphaTrade.

The CPRS is likely to improve the competitiveness of gas fired generation in relation to coal fired technology. This is reflected in the extent of gas fired generation in recent and committed investment decisions, including 2400 MW of new capacity in 2008–09 (tables 1a and 1b). There will be substantial opportunities for the natural gas industry, although rising demand for gas—both for electricity generation and for likely LNG exports from eastern Australia—may increase gas prices in the longer term and partly neutralise its cost advantages (section 6).

As the cheapest and most mature renewable energy technology, wind generation is likely to grow significantly under the expanded RET. But wind generation depends on prevailing weather conditions, and its intermittent nature poses challenges for power system reliability and security. In addition, momentary fluctuations in wind output create issues for maintaining power flows within the capacity limits of transmission infrastructure. To maintain reliability and security, standby capacity-in transmission and generation that can respond quickly to changing market conditions-is required. Peaking plant (such as open cycle gas turbines) typically provides standby generation capacity. This may necessitate refinements in the market's design, in terms of inertia services and the procurement of transmission network control services.

In the longer term, there is potential to develop other renewable energy technologies, such as geothermal, solar, wave and tidal generation. Additionally, carbon capture and storage technologies that extract carbon dioxide from fossil fuel power plants and store it in deep geological formations may become viable. None of these technologies is currently capable of large scale entry into the market, given either technical issues or cost.

#### Review of energy market frameworks

In October 2009 the AEMC completed a review of Australia's energy market frameworks in light of climate change policies. It found the frameworks are efficient and robust enough to deal with most issues, but need refinements.

In relation to generation, the report considered concerns that the potential early closure of some coal fired plant could lead to short term capacity shortfalls. The current reliability mechanisms to address this risk include:

- AEMO's power to direct generators to provide additional supply
- > the reliability and emergency reserve trader mechanism, which allows AEMO to enter reserve contracts with generators to ensure sufficient supply.

The proposals to address potential capacity risks include allowing AEMO more flexibility to procure emergency supplies, such as through short notice contracting. The AEMC also proposed more accurate reporting of demand-side capability and the removal of regulatory barriers to using embedded generation to meet supply shortfalls. These changes would better place AEMO to minimise intervention in the market and avoid involuntary load shedding.

The increasing use of gas fired and renewable generation will present challenges for the network sector. Electricity networks have developed around the location of coal fired generation plant. New investment in renewable generation, however, is likely to occur in areas not presently serviced by networks. Specifically, the transmission network may need augmentation to deliver electricity from remote generators to load centres.

The AEMC has proposed an approach whereby transmission businesses can size network extensions to remote generators to accommodate anticipated future needs, with customers underwriting the risk of asset stranding. The AER will have a role in ensuring consumers' interests are protected. Additionally, in August 2009 the AEMC amended the confidentiality provisions for network connection applications, to allow for a more coordinated approach under the existing framework.

The sourcing of large volumes of electricity from new locations on the network may also affect flows and create new points of transmission congestion. Congestion can sometimes impede the dispatch of costefficient generation and create opportunities for the exercise of market power.

The AEMC has proposed a form of generator transmission use-of-system charge to provide better locational signals for new generation investment (and exit) that would avoid significant increases in network congestion. The new charging system would provide price signals to investors on areas of the network that may require new capacity.<sup>4</sup> Given the proposal represents a significant departure from current arrangements, the AEMC will establish a working group to develop an implementation plan by late 2010. Climate change policies have implications for the natural gas sector. Greater reliance on gas fired generation would increase both the level and volatility of gas demand. Generators are likely to need access to large quantities of gas at relatively short notice at times of peak demand and to back up intermittent generation. This will likely require substantial new investment in gas pipeline and storage capacity, as well as greater flexibility in gas contracting arrangements. The convergence of the electricity and gas markets also raises issues of security of supply. Any response to emergency shortfall events in one part of the energy market will need to consider consequences across the energy sector as a whole. Section 6 further discusses gas market activity.

### 4 Global economic and financial conditions

From late 2007 the emergence of the global financial crisis has affected the availability and cost of funding for new investment and refinancing. This impact has been particularly evident in significant increases in risk premiums on all forms of debt.

While Australian financial and economic conditions have remained relatively robust, the crisis has had ramifications for the energy sector. Coal fired generators have raised concerns that tighter liquidity and more risk averse financial markets have made it more difficult to refinance debt. More generally, they argue that financial conditions have aggravated the risks they already face from the introduction of climate change policies. Financial conditions have also raised issues for new entrant generators, and might have delayed some new investment that would have increased competitive pressures on incumbents. Further, less finance has been available to develop renewable technologies such as for solar and geothermal generation.

Tighter credit markets have also posed issues for energy retailers—for example, those seeking access to prudential cover to support wholesale and contract

4 The AEMC is also exploring the need for congestion pricing at points on the network with prolonged and material levels of congestion.



market exposures—as well as for network businesses and gas industry participants.

As noted, the AER accounted for the impact of the global financial crisis in its 2009 review of capital costs for regulated networks (section 2). It increased the market risk premium to 6.5 per cent (from the previous value of 6 per cent), for example, recognising the uncertainty in financial markets. Similarly, it took a cautious approach to interpreting empirical evidence on the equity beta of a benchmark electricity network business, by adopting a value above the range indicated by empirical estimates.

The AER is also accounting for financial conditions in revenue determinations for regulated networks. The recent New South Wales and ACT electricity distribution determinations, for example, took account of the effects of financial conditions on demand forecasts, the cost of capital, materials and labour input cost escalators, and defined benefit superannuation costs in operating expenditure forecasts.

EnergyQuest's essay in this report discusses the effects of the financial crisis on gas markets. It notes that while the recession has weakened global demand for gas, Australian LNG exports have increased against this trend. Domestically, the downturn does not appear to have significantly affected gas consumption. The essay also notes, while financing has become more difficult and expensive since 2007, that Australian gas development projects have not been seriously affected. Companies have managed to raise finance, rationalise exploration and sell non-core assets to fund key projects.

The relatively high gearing of pipeline companies has created difficulties for them in obtaining finance at an acceptable cost for new projects. A proposed expansion of the South West Queensland Pipeline to provide capacity for Origin Energy, for example, was made subject to obtaining the necessary funding on acceptable commercial terms.

Financial market conditions have contributed to some changes in asset ownership across the energy sector. Babcock & Brown Power, for example, sold a number of generation assets and trading contracts. In December 2008 APA Group spun off some of its network assets into a new unlisted investment vehicle, and applied the proceeds to reduce \$647 million of corporate debt. More generally, EnergyQuest notes in its essay that companies are reviewing their portfolios and disposing of non-core assets to fund core projects. It notes that competition has generally been keen for those assets offered for sale.

#### 5 Retail markets

The first exposure draft of legislation to establish a national energy customer framework was released on 30 April 2009. The legislation will transfer several non-price retail functions from state and territory jurisdictions to the AER. Consultation on a second exposure draft was scheduled for late 2009, and the legislation is scheduled for introduction to the South Australian Parliament in spring 2010.

Under the proposed framework, the AER will be responsible for authorising (licensing) energy retailers, approving authorisation exemptions, monitoring retailers' compliance with the legislation and undertaking any enforcement action, and providing guidance on matters such as hardship issues and how retailers represent their products to customers. The states and territories will retain responsibility for any continuing price regulation, unless they choose to transfer those arrangements.

#### Market structure

AGL Energy, Origin Energy and TRUenergy collectively account for most retail market share in Victoria, South Australia and Queensland, but Simply Energy (owned by International Power) has acquired a significant customer base in Victoria and South Australia. There has also been ongoing new entry by niche businesses. Retailers with full or part government ownership supply the bulk of customers in other jurisdictions.

The New South Wales Government in September 2009 released the *Energy Reform Transaction Strategy*, outlining the proposed structure for the sale of its

three state owned energy retailers: EnergyAustralia, Integral Energy and Country Energy. Bidders for EnergyAustralia will have the flexibility to bid for its gas and electricity customers separately, or for both. The government also proposes to contract out the right to sell electricity produced by state owned generators to the private sector, and to sell seven power station development sites. Subject to market conditions, it expects to complete the sale process in the first half of 2010.

The New South Wales Government will simultaneously prepare for a share market listing of an entity that includes the retail business of Integral Energy, the generation trading contract for Eraring Energy and the Bamarang power station development site. The float will proceed if the initial sales process fails to meet the government's strategic, competition and valuation requirements.

#### Retail competition

Energy retail competition has continued to develop over the past year. Customer switching continued strongly in Victoria (and, to a lesser extent, in South Australia and Queensland) in 2008–09. Cumulative switching rates for small customers in Victoria and South Australia are about double those for New South Wales (figure 9). The low rates for Queensland partly reflect that small customer switching has been possible only since July 2007. Across all jurisdictions, switching rates are higher in electricity than in gas, although the rates are comparable in Victoria, where gas is used more widely for household purposes than in other states. South Australia and Victoria have also reported high rates of customer movement from standing offer contracts to market contracts with their host retailer.

While most jurisdictions allow customers to choose their energy retailer, jurisdictions other than Victoria apply some form of electricity retail price regulation, and several apply similar arrangements in gas. The AEMC is assessing the effectiveness of energy retail competition in each jurisdiction to advise on the appropriate time to remove retail price caps, with state and territory governments making final decisions.

#### Figure 9

Cumulative retail switching to 30 June 2009 small customers



Notes:

Cumulative switching as a percentage of the small customer base since the start of full retail contestability: Victoria and New South Wales 2002; South Australia 2003 (electricity) and 2004 (gas); Queensland 2007.

If a customer switches to a number of retailers in succession, each move counts as a separate switch. Cumulative switching rates may, therefore, exceed 100 per cent.

Sources: Electricity customer switches: AEMO. Gas customer switches: AEMO (Queensland, New South Wales, the ACT, Victoria), REMCo (South Australia). Customer numbers: IPART (New South Wales), ICRC (ACT), ESCOSA (South Australia), ESC (Victoria), QCA (Queensland).

Victoria responded to an AEMC review by removing retail price caps on 1 January 2009. To balance this change, the Essential Services Commission of Victoria is monitoring and reporting on retail prices. In addition, retailers must publish a range of offers, to help consumers compare energy prices. Other obligations on retailers, including the obligation to supply and the consumer protection framework, remain in place. The Victorian Government retains a reserve power to reinstate price regulation if competition is found to be no longer effective.

The AEMC review of South Australian retail energy markets, completed in December 2008, found competition was effective for small customers, but more intense in electricity than in gas. It noted, while overall competition was effective, that the state's relatively high wholesale prices, price volatility and increasing vertical integration may limit further new entry. The AEMC proposed that South Australia introduce price monitoring to support the competitive market, and that it retain reserve powers to re-introduce price regulation if competition deteriorates. In April 2009 the South Australia Government stated it did not accept the AEMC's recommendations at that time. It was concerned that more than 30 per cent of small customers remain on standing contracts and that stakeholders have differing views on the effectiveness of competition.

The Ministerial Council on Energy has agreed to proceed with reviews of retail competition for the ACT in 2010, New South Wales in 2011, Queensland in 2012 and Tasmania in 2013 (if it introduces full customer choice by that time). The AEMC recommended in October 2009 that jurisdictions bring forward their consideration of the removal of retail price regulation.<sup>5</sup> For those jurisdictions that retain regulated energy prices beyond the introduction of the proposed CPRS, the AEMC recommended that price setting frameworks allow for regular wholesale energy and carbon cost reviews (as frequently as six monthly). Prices could then be adjusted if costs have changed materially.

The Queensland Competition Authority is reviewing its electricity retail price setting framework. The review aims to ensure the framework captures all relevant costs (including costs from environmental obligations) and provides flexibility to set tariff structures that will encourage customers to use electricity efficiently. Queensland expects to apply the review's recommendations in setting retail prices for 2010–11.

#### Retail prices

As noted, retail price pressure is an emerging concern in energy markets. In 2009 several jurisdictions announced significant increases in regulated electricity prices, in response to rising network and wholesale energy costs:

 In New South Wales, a typical retail electricity bill will rise by around 18–22 per cent in 2009–10. About 50 per cent of the increase is due to higher network costs.

- > The Queensland Competition Authority announced in June 2009 that regulated electricity retail prices for 2009–10 would rise by 11.82 per cent. Following a successful appeal by Origin Energy and AGL Energy, the authority announced a further increase that would raise prices in total by 15.5 per cent.
- > The Independent Competition and Regulatory Commission announced that retail electricity prices in the ACT would increase by up to 6.4 per cent in 2009–10, mainly reflecting higher network costs.
- In Western Australia, the Office of Energy recommended in 2008 that retail electricity prices increase by 52 per cent, following several years of declining real prices. The Western Australian Government rejected this recommendation and announced that residential prices would increase by 10 per cent on 1 April 2009, and by a further 15 per cent on 1 July 2009.
- > In the Northern Territory, electricity tariffs for non-contestable customers rose by 18 per cent from 1 July 2009.

Figure 10 estimates movements in real energy retail prices (under regulated and market arrangements) in major capital cities over time. It illustrates the recent upswing in electricity and gas retail prices, especially for households. The tendency for household customers to experience larger price rises than business customers partly reflects the continued unwinding of historical cross-subsidies in some jurisdictions. More generally, it illustrates that household customers are increasingly exposed to prices in wholesale energy markets.

Climate change policies will likely add further upward pressure on retail prices. McLennan Magasanik Associates' modelling for the Australian Treasury estimated that a carbon emissions price of \$35 per tonne (A\$2005 prices) in 2020 could result in household electricity prices rising by up to 23 per cent.<sup>6</sup> Retail gas prices are also likely to rise as demand for gas fired generation increases.

5 AEMC, Review of energy market frameworks in light of climate change policies, final report, Sydney, October 2009, p. v.

<sup>6</sup> MMA, Impacts of the Carbon Pollution Reduction Scheme on Australia's electricity markets, Report to Federal Treasury, Melbourne, December 2008, p. 7.

Figure 10 Electricity and gas retail price index (real)—Australian capital cities



Sources: ABS, Consumer Price Index and Producer Price Index, cat. no. 6401.0 and 6427.0, Canberra, various years.

#### 6 Upstream gas

In a commissioned essay for this report, EnergyQuest examines the strengthening links between Australia's natural gas industry and global energy markets. The industry continues to expand rapidly, driven by buoyant interest in Australian LNG exports, investment in gas fired electricity generation, and a rapidly expanding resource base of CSG in Queensland and New South Wales.

Australia is now the world's sixth largest LNG exporter. Notwithstanding a recent easing in LNG demand, oil and gas companies are committing to spend billions of dollars on new Australian projects. The \$50 billion Gorgon project in Western Australia is scheduled to begin operation in 2014 and produce around 15 million tonnes of LNG per year—equal to Australia's current total LNG production.

Also on the west coast, the 4.3 million tonne per year Pluto project is under construction and set to become Australia's third operational LNG project. Pluto is due for completion in 2010 and will supply major Japanese buyers.

Long term projections of rising international energy prices, together with rapidly expanding reserves of CSG in Queensland, have improved the economics of developing LNG export facilities in eastern Australia. Four export projects that rely on CSG are at an advanced stage of planning. Most are at the front end engineering and design stage, aiming for final investment decisions by the end of 2010. The proposals range in size from 1.5 to 14 million tonnes of LNG per year. Over 20 million tonnes per year from these projects is already committed to buyers.

On the domestic front, weaker economic growth in 2009 led to a softening in gas demand on both sides of the country. In Western Australia, weaker global energy prices also took some pressure off domestic gas prices. On the east coast, Victoria's spot market provides the most transparent price signals. Spot prices averaged \$2.68 per gigajoule for June quarter 2009, down 19 per cent on June quarter 2008.

Activity is strong in the increasingly deregulated gas transmission sector, which is taking a longer term view. Climate change policies, new investment in gas fired peaking generators and Queensland's burgeoning CSG industry are driving significant investment in gas transmission infrastructure.

The commissioning of the QSN Link and expansion of the South West Queensland Pipeline in 2009 brought Queensland into an interconnected pipeline network spanning Queensland, New South Wales, Victoria, South Australia, Tasmania and the ACT. This is moving us closer to a national gas market. For the first time, CSG from Queensland can compete in southern markets with gas produced in the Cooper and Victorian gas basins.

Further dynamic change is likely in the east coast gas markets with the development of CSG-LNG projects around Gladstone in the next few years. While this development may increase wholesale gas prices in the longer term, EnergyQuest predicts domestic prices may ease during the lengthy ramp-up of LNG export capacity.

While upstream gas is a lightly regulated sector, there have been significant developments to enhance transparency. The National Gas Market Bulletin Board, which began in July 2008, provides real-time and independent information on the state of the gas market, system constraints and market opportunities. And with plans to launch a new annual statement of opportunities for gas (similar to that published for electricity), AEMO aims to improve information for planning and commercial decisions on investment in gas infrastructure. The first gas statement is scheduled for publication in December 2009.

To complement these reforms, new spot markets (in addition to that operating in Victoria) for short term gas trading will begin next winter. The first markets will be based around the Sydney and Adelaide hubs. While the markets relate to gas for balancing purposes, they will provide transparent price guidance for the market as a whole. Any move to greater depth in short term gas markets will better enable Australian energy markets to maximise the benefits of any 'surplus' gas associated with gas export projects.

### 7 The Australian Energy Regulator's role

As the transition to national energy regulation continues, the AER is mindful of its responsibilities as the regulator of energy infrastructure in eastern and southern Australia. In addition to regulating network assets, it monitors the wholesale energy markets for compliance with the underpinning legislation, and reports on market activity.

The AER will continue to work closely with industry and energy customers in undertaking these roles. It will look to apply consistent and transparent approaches to encourage efficient investment and reliable service delivery. Across its work program, the AER will continue to work towards best practice regulatory and enforcement outcomes, including the provision of independent and comprehensive information on market developments.



## **PART ONE** ESSAY



AUSTRALIA'S NATURAL GAS MARKETS: CONNECTING WITH THE WORLD A report by EnergyQuest



### AUSTRALIA'S NATURAL GAS MARKETS: CONNECTING WITH THE WORLD A report by EnergyQuest

EnergyQuest is an advisory firm focused on energy analysis and strategy.

Historically, natural gas markets in eastern Australia were isolated from the rest of the world. While Western Australia's gas market was linked to global markets through liquefied natural gas (LNG) exports, the impact on the domestic market was limited. A number of developments are now leading to closer integration of gas markets in Australia and the rest of the world. This essay explores some of these developments.

Australia's LNG is a pivotal link between domestic and international markets. In the early 1970s Woodside discovered immense gas resources off the Western Australian coast, which could not only meet the state's domestic needs but also supply Asian markets. Export production began in the late 1980s. The North West Shelf now has five trains (processing plants) with a total annual capacity of 16.3 million tonnes. In 2006 Australia's second LNG plant commenced exporting from Darwin. With these developments, Australia's annual LNG capacity has risen to 19.5 million tonnes (nearly 1100 petajoules (PJ) a year—close to Australia's total domestic demand for natural gas). Figure E.1 illustrates Australian LNG export growth relative to domestic demand. As will be discussed, Western Australia's domestic gas market is increasingly integrated with the global market by way of LNG, and similar events look set to occur on the east coast.

Figure E.1 Australian natural gas production



#### Source: ABARE.

A second link between Australian gas markets and the rest of the world is the exponential rise of coal seam gas (CSG) on the east coast. This has become closely linked with major LNG developments and is attracting significant foreign investment.

Interest in CSG began in the United States and has contributed to a reversal in the historic decline in US gas production. With its world class coal resources, Australia has been recognised as having immense CSG potential since the 1980s. A number of major international oil and gas companies tried to commercialise CSG in Queensland and New South Wales but with mixed results. Texan father and son Dr James Butler and James Butler Jr, founders of Tri-Star Petroleum, are credited with Australia's first commercially viable CSG, produced from the Fairview field in 1998. They also discovered the Durham Ranch field, later developed by Origin Energy as the Spring Gully project. Ultimately, after years of trial and error, the industry began to develop early this decade.

The early focus of CSG production was as a supplement to conventional gas for domestic use in Queensland. In particular, the Queensland Government promoted the use of CSG for electricity generation through the Queensland Gas Scheme. The state previously planned to import gas from Papua New Guinea to address supply issues, but the growth of CSG ultimately eroded the commercial viability of that option.

It soon became apparent that while Queensland had more CSG than could be absorbed by the east coast domestic gas market—or commercialised at low Australian gas prices—the burgeoning global LNG market had potential, as with the North West Shelf discoveries three decades earlier.

This created interest among international LNG companies who wanted gas reserves in the Asia Pacific region and were familiar with the growth of unconventional gas in the United States. As a result, several international companies have taken a stake in Queensland CSG for LNG projects. The east coast gas market now appears set to follow Western Australia in becoming more closely integrated with the rest of the world through LNG.

Climate change is a third global influence on Australian gas markets. For many years natural gas played a lead role in power generation in only South Australia and Western Australia, which lacked large supplies of commercial coal. Along the east coast, coal has been king in power generation. But global concerns about climate change, as reflected in Australia's proposed Carbon Pollution Reduction Scheme, now look set

Figure E.2 World imports of liquefied natural gas



Source: BP, Statistical review of world energy 2009, London, 2009.

to change the technology mix in power generation. A range of fuels and technologies will increasingly compete to provide cleaner electricity. Natural gas produces around half the greenhouse emissions of coal when used in combined cycle gas turbines for electricity generation. Wind produces no emissions but has reliability issues. Geothermal has promise but is in the pilot stage. While the outlook for power generation a decade or two out is unclear, gas will likely play an increasing role in providing reliable baseload capacity and filling the growing demand for peaking capacity.

A fourth global influence considered in this essay is the financial and economic crisis. The recession has affected energy demand and prices across the world. The cost of developing gas fields, plants and pipelines can run to billions of dollars. After years of easy credit and low financing costs, interest costs have spiked and credit availability has shrunk, making it more difficult to refinance existing borrowings and fund new projects. Tighter financial markets do not appear so far, however, to have impeded any major gas developments in Australia.

Finally, security of gas supply is an important issue for all markets. This essay provides some perspectives on recent developments in the security of Australia's natural gas supply system.

#### E.1 Liquefied natural gas

Global LNG consumption has risen strongly over the past decade. From 2003 until 2008, when the recession flattened growth, LNG consumption was rising annually by around 7 per cent. The world's largest import customers are Japan and South Korea (figure E.2). Japan is a critical market for Australia: 79 per cent of Australia's LNG goes to Japan (supplying 17 per cent of its LNG demand).

Demand for LNG is linked to various factors. Japan, South Korea and Taiwan lack alternative sources of natural gas, and China has insufficient infrastructure to meet gas demand in coastal cities from domestic sources. In Europe, an increasing number of countries are seeking to diversify their sources of gas supply away from Russia.

While global LNG demand has eased in the recession, it is likely to regain strength over the medium term as existing importers add further re-gasification capacity and new countries become importers. In addition to the 18 countries that import LNG, a further 17 countries have import plants under construction or planned. In the Asia Pacific region, these include Malaysia, Singapore, Thailand, Indonesia, Chile and the Philippines (figure E.3).

#### Figure E.3

#### Countries importing liquefied natural gas, 2009



A Planned or proposed

Source: EnergyQuest, based on International Energy Agency, Natural gas market review, Paris, 2009.

On the supply side, the largest LNG exporters are Qatar, Malaysia and Indonesia. According to BP, Australia was the world's sixth largest exporter in 2008, supplying around 9 per cent of global exports. In the current decade, production has increased from Qatar, Malaysia, Nigeria, Australia, Trinidad and Oman (figure E.4). Qatar is increasing its capacity enormously, from 30 million tonnes per year to 77 million tonnes per year by 2012. In the Asia Pacific region, two projects were scheduled to commence production in 2009—Sakhalin 2 in Russia and Tangguh in Indonesia.

While Indonesia was the world's largest LNG producer until 2006, its annual exports have fallen from over 25 million tonnes early this decade to 19 million tonnes in 2008. This fall reflects reduced gas availability and the prioritisation of gas for domestic use.<sup>1</sup> Output from Tangguh will only partly offset the recent decline in Indonesian production.

1 J Stern, Natural gas in Asia, Oxford Institute for Energy Studies, Oxford, 2008.

There is the risk of a looming surplus of LNG over the next few years, due to the recession and increased capacity, particularly from Qatar. But LNG liquefaction projects take many years to build, and only five new projects have reached final investment decision since mid-2005. As the International Energy Agency noted:

In the LNG sector, notwithstanding the massive increases in capacity that will be seen in the next few years from projects under construction, very few new projects have been sanctioned in recent years. Unless 2009 and 2010 see a number of new project approvals, there will be a dearth of new capacity in the period after 2012. Globally there is nearly twice as much regasification capacity operating or well under construction, compared to liquefaction capacity.<sup>2</sup>

<sup>2</sup> International Energy Agency, Natural gas market review, Paris, 2009, p. 14.
Figure E.4 World exports of liquefied natural gas



#### Source: BP, Statistical review of world energy 2009, London, 2009.

It questioned where the next generation of LNG projects will come from after 2012. Many developers think the answer is Australia. While Australia is only one of a number of countries proposing new liquefaction projects, it has the most ambitious expansion plans of any country.

### E.1.1 Liquefied natural gas prices

Interest in further developing Australian LNG export projects is driven by Australia's abundant gas resources —over 200 000 PJ, one of the largest endowments in the Asia Pacific region—as well as disparities between domestic and international gas prices. While international gas prices have trended significantly higher over the past decade (figure E.5), Australian domestic gas prices have been relatively low. Until recently, upstream prices were around \$2–3 per gigajoule in Western Australia and \$3–4 per gigajoule on the east coast. In contrast, US gas prices (an indicator of gas prices globally) peaked at over US\$12 per gigajoule in mid–2008.

Like domestic gas, most LNG is sold under long term contracts (although the spot market is growing). But unlike domestic gas, global gas prices have increasingly tended to settle around energy equivalent oil prices. An energy equivalent price for gas is 17.2 per cent of the oil price, based on the energy composition of LNG compared with a barrel of oil. At an oil price of US\$70 per barrel, an energy equivalent price for gas would be US\$12.04 per million British thermal units (US\$11.35 per gigajoule).

Australian LNG export prices are linked to Asian oil prices, and are increasingly quoted on a straight percentage basis—typically, a percentage of average Japanese oil import prices (known as the 'Japanese crude cocktail'). Over the past year or two some long term LNG contracts have been written at oil parity and others at close to oil parity.

To compare this with Australian gas prices, it is necessary to account for the costs of liquefaction and freight. After adjusting for these costs, the equivalent Australian gas price received by producers at the gas field would still be significantly higher than historical Western Australian domestic gas prices or current east coast prices.

International gas prices have fallen since the peaks of 2008, with US prices falling below US\$4 per gigajoule in 2009—around one third of oil parity, based on an oil price of US\$70 per barrel. The proponents of Australian LNG projects consider, however, there will be significant commercial benefits over the longer term from exporting Australian gas as LNG.

# E.1.2 Australian liquefied natural gas developments

Notwithstanding the recent easing in LNG demand, oil and gas companies are committing to spend billions of dollars on new Australian projects. The Gorgon project in Western Australia alone could involve a \$50 billion investment.<sup>3</sup> Also on the west coast, the 4.3 million tonne per year Pluto project is under construction and set to become Australia's third operational LNG project. Pluto is due for completion in 2010 and will supply the major Japanese buyers Tokyo Gas and Kansai Electric. Other potential LNG projects in north west Australia are at an advanced stage of planning, including the Ichthys project in the Browse Basin, which is aiming to reach final investment decision (FID) by the end of 2010 (table E.1).

In Queensland, four LNG projects reliant on CSG are at an advanced stage of planning. Most are at the front end engineering and design (FEED) stage and aiming for FID by the end of 2010. Section E.2 considers the Queensland proposals in more detail.

Nationally, these projects have a combined potential annual capacity of 47–72 million tonnes. Over 20 million tonnes per year from these projects is already committed to buyers—a similar magnitude to Australia's total current LNG capacity.

There are further proposed projects: additional trains for the Pluto project; the Browse Basin LNG project operated by Woodside; a floating LNG development on the Prelude field in the Browse Basin (Shell); the project based on the Sunrise field between Australia and Timor Leste (Woodside); a project based on the massive Scarborough field in the Carnarvon Basin (BHP Billiton); and another CSG-LNG project in Queensland (Shell).

At the time of writing, the global financial crisis and recession have not affected the momentum behind these projects—notwithstanding higher financing costs and reduced funding availability. It can take five years to build an LNG project, and companies are looking through the current downturn to the middle of the next decade.

# E.1.3 Domestic implications

Australia produces almost as much gas for LNG as for domestic use. Even if only some of the proposed LNG projects proceed, LNG will increasingly drive domestic markets.



#### Figure E.5

Source: EnergyQuest, based on BP, Statistical review of world energy 2009, London, 2009.

3 Hon M Ferguson, Minister for Resources and Energy (Queensland), Speech to Queensland Resources Council, 20 July 2009, http://minister.ret.gov.au/ TheHonMartinFergusonMP/Pages/QUEENSLANDRESOURCESCOUNCIL.aspx.

PROJECT	OPERATOR	LOCATION	SCALE (MILLION TONNES PER YEAR)	OFFTAKE AGREEMENTS	STATUS AT JULY 2009	PLANNED START			
WESTERN AUSTRALIA	WESTERN AUSTRALIA								
Pluto	Woodside	Carnarvon Basin	4.3	$\checkmark$	Over 70% complete	2010			
Gorgon	Chevron	Carnarvon Basin	15.0	✓	In FEED				
Wheatstone	Chevron	Carnarvon Basin	9.0		In FEED				
WESTERN AUSTRALIA /	WESTERN AUSTRALIA / NORTHERN TERRITORY								
lchthys	INPEX	Browse Basin	8.4		In FEED				
QUEENSLAND									
Fisherman's Landing LNG	LNG Ltd and Arrow Energy	Gladstone	1.5-3.0	$\checkmark$	In FEED	Late 2012			
Queensland Curtis LNG	BG Group	Gladstone	7.4-12.0	$\checkmark$	In FEED	2014			
Gladstone LNG	Petronas and Santos	Gladstone	3.5-10.0	$\checkmark$	In FEED	2014			
Australia Pacific LNG	ConocoPhillips and Origin Energy	Gladstone	3.5-14.0		Pre-FEED	2014 or 2015			

#### Table E.1 Near term potential of Australian liquefied natural gas projects

FEED, front end engineering and design.

Source: EnergyQuest.

Western Australia has substantial gas resources available for LNG (over 100 000 petajoules) but a shortage of gas for domestic use. In 2007 this led to gas prices for new long term domestic contracts increasing from around \$2–3 per gigajoule to over \$7 per gigajoule. Higher prices have been attributed to a range of factors:

- > Strong global demand significantly raised international energy prices, making LNG exports an attractive alternative to domestic sales.
- > Historically low domestic prices created little incentive to explore for new sources of domestic gas supply.
- > Western Australia's resources boom pushed up input prices generally. Development costs for gas fields have also increased for both LNG and domestic gas. In part, this is because new fields tend to be located in deeper water and are more expensive to develop.
- > Western Australia has a limited number of fields producing domestic gas. Most recently discovered offshore fields are large enough to have LNG potential. The relative shortage of gas fields that are unsuitable for LNG makes domestic gas users relatively dependent on LNG projects.

> Much of Western Australia's domestic market relies on a single transmission pipeline—the Dampier to Bunbury Pipeline (see below).

The Western Australian Government is undertaking measures in response to domestic supply issues. One issue is that the gas specification for the Dampier to Bunbury Pipeline is narrower than the Australian standard, which has prevented development of the Macedon field.<sup>4</sup> The government plans to introduce legislation to broaden the specification.<sup>5</sup> Under the proposal, gas producers that supply at the broader specification will compensate pipeline owners and large consumers for increased costs to their operations, as part of their commercial negotiations. Suppliers providing gas at the broader specification will also pay a levy to fund the replacement of some pre-1980 gas appliances that may have safety issues. The broader gas specification and appliance prohibition will apply from 1 January 2012.

<sup>4</sup> Gas from the Macedon field does not meet the pipeline's current specification.

<sup>5</sup> Hon. P Collier, Minister for Energy and Training (Western Australia), 'State Government opens door to greater domestic gas supplies', Media release, Perth, 27 December 2008.

There has also been concern about the quantity of gas held under retention leases for discoveries that are not currently commercial. The leases allow successful explorers to retain rights over a gas field until it becomes commercial. Australia's Department of Resources, Energy and Tourism is reviewing the retention lease system.<sup>6</sup> The Western Australian Government has also released and promoted onshore exploration acreage considered to have gas potential, and has reduced the royalty rate for onshore tight gas from 10 per cent to 5 per cent.<sup>7</sup>

The development of significant volumes of domestic gas depends (at least in part), however, on the early development of LNG projects. In 2006 the Western Australian Government introduced a policy to reserve gas from LNG projects for domestic purposes. Under the policy, the government negotiates with project proponents to include a domestic gas supply commitment as a condition of land access for processing facilities. The state aims to secure domestic gas commitments up to the equivalent of 15 per cent of LNG production from each project. Commitments have been made in relation to the Gorgon, Pluto and Wheatstone projects. The price of gas sold into the domestic market is to be determined through commercial arrangements between gas buyers and sellers. The prices are likely to be comparable to the returns that gas producers can obtain from LNG.

One risk mitigation approach that some major gas buyers are starting to adopt is to move up the supply chain and participate directly in gas field exploration and development. This approach provides a hedge against gas supply and price risk. It increasingly occurs on the east coast, where major gas and electricity utilities have acquired interests in gas exploration and development. In Western Australia, Alcoa has taken interests in onshore exploration.

# E.2 Coal seam gas

The fastest growing source of gas supply in eastern Australia is CSG, with production having grown from around 17 PJ to 135 PJ in the five years to 2008. It now supplies around 21 per cent of the east coast gas market (figure E.6). Around 96 per cent of east coast CSG production is sourced from Queensland, with the remainder from the Sydney Basin.<sup>8</sup>



#### Figure E.6 Australian coal seam gas production

Source: EnergyQuest.

- 6 Hon. M Ferguson, Minister for Resources and Energy (Australian Government), 'Retention lease discussion paper released', Media release, Canberra, 12 June 2009.
- 7 Tight gas is gas with low flow rates due to low reservoir permeability. Such gas is less commercially viable than gas from highly productive reservoirs.
- 8 As well as CSG activity in Queensland and New South Wales, interest in unconventional gas and increased recovery from existing fields is increasing elsewhere in Australia. In 2008 Santos identified 6900 PJ (gross) of contingent resources in the South Australian Moomba and Big Lake fields. This substantial gas resource could be commercialised at somewhat higher than current gas prices. Lakes Oil is having success with tight gas onshore in Victoria. Tight gas reservoirs onshore in Western Australia are also being actively assessed.

#### Box E.1 What is coal seam gas?

Like conventional natural gas, coal seam gas (CSG) is mostly methane but may also contain trace elements of carbon dioxide and/or nitrogen. While CSG is essentially transported, sold and used in the same way as conventional gas, the geology differs (table E.2). In particular, CSG is produced from coal deposits permeated with methane rather than sandstone reservoirs.

Coal seam gas is either biogenic or thermogenic in origin. Biogenic methane is generated from bacteria in organic matter in coal. Biogenic processes occur at depths of up to 1 kilometre. Thermogenic methane forms when heat and pressure transform organic matter in coal into methane. Thermogenic methane is generally found at greater depths than biogenic methane is found. Queensland basins have biogenic gas, thermogenic gas and mixed gases.

The natural fractures in coal create a large internal surface area that can hold larger volumes of gas than conventional sandstone reservoirs hold. A cubic metre of coal can contain six or seven times the volume of natural gas that exists in a cubic metre of a conventional reservoir.

The coal formation process generates methane, carbon dioxide and water. The large quantities of methane produced during the formation of the high rank bituminous and anthracite coals generally flush away most of the carbon dioxide. The bituminous coals of the Sydney and Bowen basins typically contain gas consisting of over 95 per cent methane, with smaller quantities of carbon dioxide, nitrogen and inert gases.

#### Table E.2 Conventional and coal seam gas

CONVENTIONAL NATURAL GAS	COAL SEAM GAS
Gas is generated in coals or shales at depth.	Coal seams are both the source and the reservoir.
Conditions must be right to generate gas and expel it from the source rock.	Methane is generated as coals are buried, heated and compressed.
Gas must migrate to a suitable structural trap in a suitable reservoir where it is stored in the pore spaces between the grains of the rock. Natural pressure drives	Gas is adsorbed as a thin film on the surface of the coal, and is held there by water pressure. No structural trap is required. The gas is liberated by removing water from the seam. The gas
the gas to the surface.	desorbs and flows to the surface.

Source: Origin Energy/EnergyQuest, Australian coal seam gas 2008: CSG meets LNG, Adelaide, 2008

Management of CSG production is more difficult than management of conventional gas production. While production from conventional gas wells can usually be shut in and then recommenced, CSG wells generally cannot be shut in without repeating the entire dewatering process. There are, however, 'free flow' holes in which the gas can flow freely without the need for further pumping of water.

From a commercial point of view, CSG requires considerably more drilled wells than conventional gas does to deliver comparable quantities of gas. While the cost per well is much lower for CSG, conventional fields also may contain high value oil or liquids that increase their potential economic value, which is not the case with CSG. Conversely, CSG has the advantage of being onshore and, in the majority of cases, relatively close to destination markets.

Certified proved and probable CSG reserves are increasing even faster than production rates—from 3176 PJ at the end of 2004 to 17 599 PJ in May 2009. Most reserves are in Queensland, but there is also significant growth in New South Wales (figure E.7). There are also substantial volumes of higher risk possible reserves (24 566 PJ) and contingent resources (32 319 PJ). Table E.3 summarises the details.<sup>9</sup>

9 Proved and probable reserves (2P) are those that geoscience and engineering data indicate are more likely than not to be recoverable. There is at least a 50 per cent probability that the quantities recovered will equal or exceed the sum of estimated proved plus probable reserves. Possible reserves are those that are recoverable to a low degree of certainty (10 per cent confidence). There is relatively high risk associated with these reserves. Proved plus probable plus possible reserves are also known as 3P or P10. Contingent resources are those estimated, at a given date, to be potentially recoverable from known accumulations, but not considered to be commercially recoverable.

	BOOKED RESERVES (PETAJOULES)		RESOURCE		
GAS BASIN	PROVED AND PROBABLE	POSSIBLE	CONTINGENT	SPECULATIVE POTENTIAL	2008 PRODUCTION (PETAJOULES)
Cooper (South Australia)	1 138		6900		140
Otway (Victoria)	1 416		205	2000-4000	110
Bass (Victoria)	306		420	Underexplored	16
Gippsland (Victoria)	5 637		3000	Possible upside	261
East Queensland conventional	144				19
Queensland CSG	16 708	22 141	29 094	Possible significant upside	130
New South Wales CSG	891	2 425	3225	Possible significant upside	5
Total	26 240	24 566	42 844		681

#### Table E.3 Gas reserves and resources—eastern Australia, May 2009

Source: EnergyQuest.



Figure E.7

Source: EnergyQuest.

A key reason for the rapid growth in CSG reserves and resources has been a greater understanding of the nature of Queensland CSG, which has helped stakeholders identify the most suitable resources and understand how best to exploit them. There has been a continuing accumulation of geoscience and engineering data from producing fields and from the large number of wells being drilled. Around 600 new wells were drilled in 2008.

In addition, higher gas price assumptions play a role. Estimates of reserves and resources are sensitive to assumptions about future gas prices. The higher the price, the larger is the resource base that can be commercialised. In particular, the bookings of contingent resources are generally premised on the assumption that significantly higher gas prices can be achieved from LNG developments.

# E.2.1 Australian regions that produce coal seam gas

Coal seam gas is produced from the bituminous coals of the Bowen and Sydney basins and the sub-bituminous coals of the Surat Basin. There is also exploration and early commercialisation in the Clarence-Morton, Gunnedah and Gloucester basins in New South Wales.

The major Queensland fields are shown in figure E.8. In 2008 Spring Gully had the largest production (36 PJ), followed by Berwyndale South (27 PJ) and Fairview (22 PJ). Spring Gully and Fairview are in an area known as the Comet Ridge. Berwyndale South is on the Undulla Nose.

Figure E.8 Coal seam gas fields—Queensland



Source: EnergyQuest.

Spring Gully (operated by Origin Energy) has contracts with Queensland customers and with AGL Energy for gas sales to the southern states. Origin Energy is building a 630 megawatt combined cycle power station to be supplied from Spring Gully and its Walloon acreage. The new station, located on the Darling Downs near Braemar, is expected to commence operating in 2010. Berwyndale South (operated by BG Group) commenced production in 2006 and supplies various Queensland power stations. BG also has gas contracts with AGL, which has completed a pipeline from Berwyndale South to Wallumbilla, to join with the South West Queensland and QSN Link pipelines to supply gas to the southern states.

Fairview (operated by Santos) has contracts with Queensland customers and also with Origin Energy for supply to AGL Energy for transport to the southern states.

#### Figure E.9

Coal seam gas projects—New South Wales



Source: EnergyQuest.

Arrow Energy operates four producing fields:

- > Moranbah (operated by Arrow Energy in joint venture with AGL Energy) commenced production in 2004 and supplies gas to the Townsville Power Station.
- > Kogan North commenced production in 2006. Gas from the field is contracted to CS Energy for the Swanbank E Power Station.
- Daandine and Tipton West commenced production in 2007. Daandine supplies gas to a power station development, and Tipton West is contracted to Braemar Power.

There is also considerable interest in the CSG potential of the vast coal resources in New South Wales (figure E.9). Active CSG exploration and appraisal are continuing in northern New South Wales in the Gunnedah and Clarence-Morton basins. Santos considers the Gunnedah Basin may contain 40 000 PJ of recoverable gas. There has also been success in the Gloucester Basin, near Newcastle. AGL Energy operates the Camden gas project in the Sydney Basin. This project, which is being expanded, produced just over 5 PJ in 2008.

Success with CSG in New South Wales would be significant, given the state's historical reliance on gas imported from interstate. The potential for New South Wales CSG will become clearer over the next few years.

#### E.2.2 Liquefied natural gas proposals

Until 2007 the focus of CSG development was on the Queensland domestic market, particularly on gas for power generation. Many early CSG contracts were for the Swanbank and Braemar power stations. In the past two years it became apparent that eastern Australia has considerably more CSG potential than can be commercialised for the domestic market alone. The supply curve for CSG is quite sensitive to price, and the CSG resource base that could be commercialised at LNG prices is significantly greater than could be developed at historic east coast prices. This has led to a shift in focus to the LNG market.

Four major LNG projects are proposed for Gladstone in Queensland (totalling 39 million tonnes per year). In 2007 Santos and Arrow Energy announced LNG development plans. Queensland Gas Company (later acquired by BG Group) and Origin Energy followed suit in 2008. (Table E.1 summarises details.) There are also smaller proposals.

While these plans were originally greeted with scepticism in Australia, they offered opportunities to major international LNG companies looking for substantial gas resources in the Asia Pacific region (the largest and fastest growing LNG market in the world), with low barriers to entry and low exploration risk. Accordingly, the Australian proponents were joined in 2008 by major international companies Petronas, Shell, BG Group and ConocoPhillips. In total, these entities spent around \$20 billion to acquire CSG interests.

> Origin Energy entered an alliance with ConocoPhillips to develop a four train LNG project with ultimate capacity of 16 million tonnes per year, requiring more than 25 000 PJ of gas over 30 years. As part of the transaction, ConocoPhillips acquired 50 per cent of Origin Energy's CSG interests.

- > BG Group acquired Queensland Gas Company (which had acquired Sunshine Gas and Roma Petroleum). It has since also acquired Pure Energy, and is developing an LNG project with initial production capacity of 7.4 million tonnes of LNG a year. It is seeking approval for capacity of 12 million tonnes per year.
- > Santos entered an alliance with Petronas to develop its proposed Gladstone LNG project, targeting up to 10 million tonnes per year. As part of the arrangement, Petronas acquired 40 per cent of Santos's CSG interests.
- > Shell acquired a 30 per cent interest in Arrow Energy's CSG fields. Arrow Energy has agreed to supply sufficient gas for up to 3 million tonnes per year of LNG for the project proposed for Fisherman's Landing at Gladstone.

New entry has led to extensive industry consolidation over the 18 months to June 2009. As noted, Queensland Gas Company, Pure Energy, Sunshine Gas and Roma Petroleum are now all part of the BG Group. AGL Energy, Origin Energy and Arrow Energy have also acquired various interests. At the same time, total CSG reserves have grown significantly, and the interest in CSG has encouraged a flurry of interest in exploration and in new basins.

The entry of major international companies is a significant development, underlining their confidence in both the future demand for LNG and the quality of Queensland CSG resources. Notwithstanding the softening of immediate LNG demand, the four major LNG projects proposed for Gladstone are all pushing ahead (and with further interest from Shell and other companies). There is an increasing likelihood of LNG exports from Gladstone, with three of the four major projects at the FEED stage and having gas sale contracts in place. All four are aiming for FID by late 2010 (table E.1).

The degree of confidence has been highlighted by the decisions of Petronas and the Chinese company CNOOC to buy Australian CSG based LNG for the Malaysian and Chinese markets.

If all successful, these LNG projects could require 2750 PJ of gas per year—more than Australia's total current gas production of 1600 PJ per year—and CSG reserves of at least 55 000 PJ. Queensland's proved, probable and possible reserves in May 2009 stood at 38 849 PJ, with a further 29 094 PJ of contingent resources.

A number of challenges are associated with using CSG for LNG. There is no associated liquids production (which improves the economics of conventional LNG projects); the gas has lower energy content than that of conventional LNG; and the process of managing the CSG production profile to meet LNG production requirements is more complicated.

Water disposal and treatment is a particular issue and is becoming a significant cost. In 2007 Queensland CSG fields produced 12.5 billion litres of water. The quality of the water can vary from drinkable to highly saline. Water production is now around 22 billion litres and could grow to 250–480 billion litres per year if LNG development reaches annual production of 40 million tonnes.<sup>10</sup>

The CSG proposals are competing with conventional LNG projects proposed for Australia and Papua New Guinea, all involving large scale gas resources and experienced international LNG participants. A number of these competing projects are progressing quickly. Conventional LNG projects can also have various challenges, however, depending on the field. Some fields contain significant quantities of carbon dioxide. Others may have a low concentration of liquids, significant water depth, distance from shore or remoteness of location.

# E.2.3 Implications for the domestic gas market

With four major east coast LNG projects aiming for FID by late 2010, there have been concerns that prices for new domestic gas contracts may rise close to international levels, as has occurred in Western Australia. There are some similarities between the Queensland and Western Australian market contexts. In each case:

- > the LNG market is potentially larger than the domestic market
- > the bulk of gas resources is owned by a small number of entities targeting LNG exports.

One important difference relates to the amount of 'ramp-up' gas likely to be produced by the east coast projects. LNG projects require substantial annual gas volumes of around 200 PJ per year for each train. In a conventional LNG project, this requirement may be met by six or eight gas development wells that would be drilled and then shut in until the plant is ready for commissioning. Providing the same gas volumes from CSG may require 500–700 wells, however, given the much lower flow rates per well. Drilling this number of wells may take a couple of years, rather than a few months. Each well then has to 'ramp up', first producing water and then increasing volumes of gas. This may take months for each well.

Once a CSG well is in production, it is generally difficult to shut it in without having to start the process again. The result is that substantial volumes of 'ramp up' gas are likely to be produced in the lead-up to the commissioning of Queensland's CSG-LNG projects. In the short to medium term, this is likely to mean that increased supplies of gas will be available at relatively low prices for domestic purposes such as power generation. There is evidence, however, that domestic buyers are already finding it difficult to secure long term gas supply commitments beyond the likely start-up times for LNG projects.<sup>11</sup>

10 M Helmuth, 'Developing Queensland's CSM and LNG industries: a Queensland Government perspective', Paper presented at the FutureGas Conference, Brisbane, 22 March 2009.

<sup>11</sup> Rio Tinto, Energy white paper submission, 11 June 2009, www.ret.gov.au/energy/Documents/ewp/pdf/EWP%200102%20DP%20Submission%20-%20Rio%20 Tinto.pdf.

While real prices may rise in the medium to longer term, this would likely increase gas supply for both LNG and domestic markets. Experience has been that higher gas prices lead to substantial increases in the volume of commercially viable CSG.

Any significant increase in demand (such as would occur from LNG exports) over the long term, however, is likely to raise production costs. In particular, the resources targeted for LNG projects are among the highest quality, and using these for LNG may force domestic use towards lower quality/higher cost reserves. This would put upward pressure on prices. The use of CSG for LNG will also tighten the gas demand-supply balance generally.

A number of features of east coast markets may cushion price impacts. Unlike Western Australia, the east coast has a number of gas basins, with greater diversity of supply. There is substantial exploration acreage with relatively low barriers to entry, and an extensive gas transmission network linking the producing basins.

# E.3 Climate change policies

Climate change is a third global influence impacting on energy markets. While natural gas is a fossil fuel, it can produce large volumes of reliable baseload electricity with around half the greenhouse emissions of coal. Increased use of gas in electricity generation is likely, therefore, to form part of the suite of responses needed to shift economies to a lower carbon footprint. In particular, gas can play an important role as a transition fuel. Its increased use can avoid the locking in of higher emissions from coal fired generation, thereby buying more development time for other clean energy solutions to grow.

The Garnaut climate change review predicted the introduction of emissions trading would lead to an increased role for gas in power generation in Australia.<sup>12</sup> This would imply substantial increases in demand

for natural gas. In 2007–08 Australia produced 30 terawatt hours of gas fired power, consuming 307 PJ of natural gas.<sup>13</sup> According to Australian Treasury estimates published in December 2008, gas fired power generation could increase to 60–64 terawatt hours by 2020 under the Garnaut scenarios. This would increase gas demand to 530–560 PJ—a doubling of current gas use in power generation.<sup>14</sup>

The Garnaut review also predicted greenhouse mitigation policies overseas would expand opportunities to export gas. It expected, however, that while gas use would continue to grow in absolute terms, its role may be constrained beyond 2020 as rising permit prices make renewable sources and coal with carbon capture and storage more competitive.

The International Energy Agency came to similar conclusions. It projected continued global growth in the longer term use of natural gas under carbon abatement scenarios—but at a slower rate than under business-as-usual conditions. The agency projected that if greenhouse gases are stabilised at 450 parts per million, gas demand would grow at an average rate of 0.9 per cent per year over the period to 2030—half the rate of growth under business-as-usual conditions.<sup>15</sup> A high carbon price would make low carbon generation more attractive than gas. Rising electricity prices in the residential sector would encourage energy efficiency and renewable investment, which reduce the use of fossil fuels.

These projections rely on assumptions about long term energy prices, carbon prices, the outcomes of future research and development, and costs of competing forms of energy—all of which are subject to considerable uncertainty. In particular, the long term economics and operational performance of carbon capture and storage (and of some renewable energy technologies) are not known with certainty. In contrast, gas has a proven record as a reliable supplier of relatively clean baseload power on a large scale.

<sup>12</sup> R Garnaut, The Garnaut climate change review: final report, Canberra, October 2008, p. 498

<sup>13</sup> ESAA, Electricity gas Australia, Melbourne, 2009.

<sup>14</sup> MMA, Impacts of the Carbon Pollution Reduction Scheme on Australia's electricity markets, Report to Federal Treasury, Melbourne, December 2008. The spread of outcomes reflects different emissions target scenarios. See R Garnaut, The Garnaut climate change review: final report, Canberra, October 2008, p. 296.

<sup>15</sup> International Energy Agency, World energy outlook 2008, Paris, 2008.

Governments in Australia and overseas have tended to focus on the development of renewables and low emission coal technologies, rather than gas, as preferred long term options for reducing greenhouse emissions.<sup>16</sup> The 2009 Australian Government budget, for example, allocated \$4.5 billion to support the growth of clean energy generation and new technologies, including \$2.4 billion for clean coal technologies and \$1.3 billion for solar technology.<sup>17</sup>

Consistent with this, the Australian Government has expanded the renewable energy target. The expanded scheme aims to increase renewable energy generation to 20 per cent of all generation by 2020 (an increase from the current level of around 20 terawatt hours to 60 terawatt hours). The Australian Treasury noted that one likely effect of the expanded scheme would be to 'crowd out' gas fired generation.<sup>18</sup>

In its 2008 report to Treasury, McLennan Magasanick Associates estimated that in the absence of mandated renewables, there would be 62 terrawatt hours of gas fired generation by 2020 under the proposed Carbon Pollution Reduction Scheme (assuming a 5 per cent targeted reduction in emissions from 2000 levels). With mandated renewables, gas fired generation would be around 59 terrawatt hours, regardless of whether the targeted reduction in emissions is 5 or 15 per cent from 2000 levels.

The future role of gas depends on the prices of gas, coal and carbon. For existing power stations, coal is still much cheaper than gas, ranging from less than \$0.50 per gigajoule in Victoria to \$1.50–2.00 in New South Wales and Queensland.<sup>19</sup> If ramp-up gas from LNG projects keeps gas prices low on the east coast, then gas could be competitive for power generation. Likely higher gas prices once LNG projects commence, however, would make gas less competitive. Higher carbon prices favour gas over coal but give renewables an advantage. Some major gas users—such as aluminium and cement—are also emissions intensive, and their treatment under the Carbon Pollution Reduction Scheme will affect gas demand.

Gas is likely to play an important role under climate change policies in complementing intermittent renewable electricity generation. Wind generation the likely primary renewable technology to 2020—has intermittent output and must be backed up by other generation. Open cycle gas plants can respond quickly when there is insufficient wind generation, but any new plant is likely to operate at relatively low capacity factors. There will also be an increased need for gas transmission and storage to provide gas at short notice.

In addition to the impacts of climate change policies on gas use for electricity generation, there may be implications for the LNG industry. In Asia, climate policies are likely to increase the demand for LNG (and LNG prices) as a cleaner alternative to coal for power generation. At the same time, LNG production creates greenhouse emissions that may be priced under the Carbon Pollution Reduction Scheme. Some gas reservoirs being proposed for Australian LNG projects contain significant volumes of carbon dioxide, and the process of liquefaction also emits carbon dioxide. The proponents have plans to manage these emissions, but have also sought relief under the proposed Carbon Pollution Reduction Scheme.

# E.4 Global financial crisis

The global financial and economic crisis is a fourth global influence potentially affecting Australian gas markets. Overseas, the recession has led to a significant easing in the demand for gas. Australian LNG exports have increased against this trend, with a fifth train on the North West Shelf recently becoming

<sup>16</sup> J Snyder, 'Natural gas companies challenge coal industry on climate change bill', *The Hill*, 29 July 2009, http://thehill.com/business--lobby/natural-gascompanies-challenge-coal-industry-on-climate-change-bill-2009-07-29.html.

<sup>17</sup> Hon. M Ferguson, Minister for Resources and Energy (Australian Government), Speech to Queensland Resources Council, Rockhampton, 20 July 2009, http:// minister.ret.gov.au/TheHonMartinFergusonMP/Pages/QUEENSLANDRESOURCESCOUNCIL.aspx.

<sup>18</sup> Australian Treasury, Australia's low pollution future: the economics of climate change mitigation, Canberra, October 2008, p. 181.

<sup>19</sup> ACIL Tasman, Fuel resources, new entry and generation costs in the NEM, Report to AEMO, Melbourne, April 2009.

fully operational. Domestically, the downturn does not appear to have significantly affected east coast gas consumption.

Billions of dollars are needed to fund the suite of proposed Australian upstream developments, processing facilities and infrastructure. So far, the signs are that companies have been tightening their belts but not deferring or cancelling gas developments in the context of lower revenues and tighter financial markets.

Companies typically finance development projects from: > cash flow

- > asset sales and/or cuts to exploration
- > debt raising
- > equity raising.

While many Australian upstream oil and gas companies have reasonably strong balance sheets, the recent fall in commodity prices has reduced their capacity to fund new developments. This has led a number of upstream companies to sell non-core assets, look for partners and reduce exploration spending.

Generally, the credit ratings of oil and gas companies operating in Australia have been largely unaffected by the crisis, although Standard and Poor's outlook for Woodside's long term A- rating was revised from stable to negative. The agency said this revision reflected the fall in oil prices and ongoing funding requirements for Woodside's Pluto LNG project.

In relation to debt raising, companies typically seek bank funding, issue bonds or seek project financing. Generally, the global financial crisis has increased the cost of debt and reduced its availability. In particular:

- > banks have become more inward focused as they give priority to resolving their own financial positions. This behaviour has included withdrawal from some offshore markets, including Australia.
- > banks have less capital and are using it cautiously
- > banks are repricing risk across the credit curve, reflecting increases in their own funding costs

- > banks have been giving priority to supporting key existing customers and attractive new clients
- > more banks are needed to fund any one transaction
- > borrowing terms have been reduced, typically to three years, and interest costs have more than doubled.<sup>20</sup>

Companies operating in Australia's gas sector have nonetheless been able to raise debt. In May 2009 Woodside announced it had executed a US\$1.1 billion syndicated loan facility with 26 banks—a large number. This followed a US\$1 billion issue in the US bond market in February 2009. Interest spreads, however, have typically been around 400 basis points over the five year swap rate, giving an overall funding cost of 9–10 per cent.

AGL Energy has successfully refinanced its 2009 and 2010 debt maturity obligations of \$800 million but at a cost of 280 basis points over the relevant base rates, and requiring the participation of Australia's four major banks and 13 offshore banks.

Pipeline companies have generally been more negatively affected than upstream gas companies by higher borrowing costs and reduced financing availability. In particular, the higher gearing of pipeline companies has made it more difficult for them to obtain finance for new projects at an acceptable cost. A proposed expansion of the South West Queensland Pipeline to provide capacity for Origin Energy, for example, was subject to obtaining the necessary funding on acceptable commercial terms. The availability of project finance is also reported to have shrunk. A year ago industry found it relatively easy to source project finance for a gas fired power station project, but this is no longer the case.

The other financing option for companies is to raise equity. Santos raised \$3 billion of new equity from institutional and retail investors to fund its commitments to the Papua New Guinea LNG project and to redeem a previous issue. This was successful but was made at a 27 per cent discount to the previous share closing price.

<sup>20</sup> Based on EnergyQuest discussions with market participants. See also: S3 Advisory, *Financing of future energy sector investments in Australia: the potential effects of the Carbon Pollution Reduction Scheme and Renewable Energy Target*, Report prepared for the AEMC, Sydney, December 2008; and I Little, *Envestra open briefing*, Adelaide, 8 July 2009.



There has also been an increase in the number of assets offered for sale. Companies are reviewing their portfolios and disposing of non-core assets to fund core projects. While there have been some sales by distressed buyers, however, there has not been a flood of properties onto the market, and competition has been keen for those that have come up for sale.

Generally, financing is much more difficult and expensive than it was before 2007, but this has not yet stopped any major gas projects. Financing conditions in the gas sector appear to be mostly more favourable than, for example, conditions for refinancing coal fired power stations.

# E.5 Security of gas supply

Security of gas supply is a critical issue globally and one of the key drivers of LNG demand—particularly in Europe, which depends on Russian gas supplies.

Australia's Department of Resources, Energy and Tourism recently reviewed Australia's natural gas security.<sup>21</sup> It assessed security as being only 'moderate' through to 2023 on three criteria: adequacy, affordability and reliability.<sup>22</sup> It found affordability to be currently 'high', but with the potential to fall to 'low' by 2018. The department assessed the current adequacy of natural gas supplies readily available for domestic consumption as 'moderate' on the east coast but 'low' in Western Australia.

With only two major gas producing facilities and one major pipeline to Perth, Western Australia is vulnerable to gas supply disruptions. The structural shortage of domestic gas in Western Australia was exacerbated by a pipeline rupture and fire at Varanus Island on 3 June 2008, which curtailed 30 per cent of the state's gas supply. Production was shut in from both the Harriett and John Brookes fields. Major gas and electricity customers—such as Alcoa, Newcrest, Iluka, Rio Tinto, BHP Billiton, Oxiana, Newmont, Alinta, Verve Wesfarmers and Burrup Fertiliserswere affected. There was substantial switching to North West Shelf gas (an extra 50 terajoules per day of output, which was limited by transmission pipeline capacity) and diesel, while major gas users brought forward maintenance. The Western Australian Government also recommissioned the coal fired Muja AB power station at Collie, freeing up 75 terajoules per day of gas supply for other users. A total 150 terajoules per day of additional gas was sourced, including gas surplus to requirements or capable of being freed up through use of diesel.

The Western Australian Treasury estimated the crisis cost the state economy \$2 billion. The Reserve Bank of Australia estimated a reduction in state economic output of 3 per cent for the duration of the incident, and a reduction in Australian gross domestic product growth of 0.25 per cent in the June and September quarters of 2008.<sup>23</sup> It has taken 12 months to repair the Varanus Island facilities and return to pre-incident production rates. The Western Australian Government is reviewing the security of the state's gas supplies.

The east coast is now much less vulnerable to supply disruptions than is the west coast. East coast gas markets have continued to evolve rapidly, with a range of new supply sources. Historically, most east coast gas was supplied from two sources: the Gippsland Basin in offshore Victoria and the Cooper Basin in north east South Australia. The basins are still important, with Gippsland supplying 37 per cent of east coast gas in 2008 and the Cooper Basin supplying 20 per cent. East coast supply is now more diversified, however, with almost 20 per cent of east coast gas supplied from the Otway and Bass basins in offshore Victoria and 23 per cent supplied from Queensland CSG fields.

The east coast transmission pipeline system also continues to expand. Sydney, Melbourne, Adelaide and Canberra are now each served by transmission pipelines connecting multiple gas basins. Until early 2009 there was no pipeline between Queensland and the southern states, but this has now been rectified

<sup>21</sup> Department of Resources, Energy and Tourism (Australian Government), National energy security assessment, Canberra, 2009.

<sup>22</sup> The possible assessments are 'high', 'moderate' and 'low'.

<sup>23</sup> Senate Standing Committee on Economics (Australian Senate), Matters relating to the gas explosion at Varanus Island, Western Australia, Canberra, 2008.

with the completion of the QSN Link from Ballera in Queensland to Moomba in South Australia. The QSN Link and the associated South West Queensland Pipeline are also being upgraded. Stage 1 of the South West Queensland Pipeline expansion is fully contracted from 2009 at up to 168 terajoules per day. AGL Energy has exercised an option for a stage 2 expansion, with gas deliveries commencing by 1 January 2013. This will take capacity to 220 terajoules per day. Origin Energy subsequently committed to a transportation agreement that will underpin an increase in capacity to 380 terajoules per day. This will enable Origin Energy to transport its CSG to southern markets. These arrangements will make the South West Queensland Pipeline/QSN Link one of Australia's largest gas transmission pipeline systems.

# E.6 Conclusion

Australia is becoming a gas supplier of international significance on the back of its rapidly expanding resource base. It is now among the top 10 nations in terms of gas reserves and resources—with over 200 000 PJ—and in the next decade will likely become a major international producer. A significant driver has been gas price expectations. The Australian experience shows gas supply is highly price elastic. Rising price expectations are encouraging major investment in exploration and infrastructure.

The development of LNG will potentially benefit Australia's terms of trade, economic growth and employment. A significant benefit may be the buffer that LNG can provide against our declining oil production. Australia is relatively oil intensive by international standards.<sup>24</sup> Crude oil is Australia's largest import, followed by refined petroleum products.<sup>25</sup> Australia's self-sufficiency in oil and liquid fuels is 60 per cent and likely to decline further. This dependence exposes the economy to the risk of rising oil prices—something to which it has been relatively immune since the discovery of oil in the 1950s.

There are options for reducing this exposure, including increasing the efficiency of oil use and the development of liquid fuels from Australia's bountiful resources of shale and coal. That LNG development plans are progressing rapidly and have not been greatly affected by the global financial crisis is a positive development in the context of declining oil production and relatively high oil prices by historical standards. Further gas development may be part of the menu for offsetting and reducing Australia's oil vulnerability. As discussed, LNG export prices are indexed to oil prices. While Australia's current LNG exports of almost \$6 billion are only a fraction of our \$33 billion oil imports, LNG growth can help offset oil imports and volatility in the terms of trade due to fluctuating oil prices.

The growth in Australia's gas resources can also provide environmental benefits. While there is great enthusiasm to develop renewables, gas is a proven lower emissions fuel. Despite relatively low domestic prices, Australian gas use still accounts for only 18 per cent of primary energy consumption—low by international standards, and the same as a decade ago.<sup>26</sup> Of the world's largest holders of gas reserves, only Norway makes less use of gas domestically than Australia. In the United States, gas comprises 26 per cent of primary energy consumption; in the United Kingdom, it is 40 per cent. In Japan, which does not have its own gas and relies on relatively expensive imports, gas has a similar share of the primary energy mix as it does in Australia. Indonesia, the world's largest coal exporter and a major oil producer, uses gas for 27 per cent of its energy mix.

- 25 Department of Foreign Affairs and Trade (Australian Government), Composition of trade Australia 2008, Canberra, 2009.
- 26 BP, Statistical review of world energy, London, 2009.

<sup>24</sup> Geoscience Australia, Submission to the Senate Rural and Regional Affairs and Transport Committee Inquiry into Australia's Future Oil Supply and Alternative Transport Fuels, Canberra, February 2006; Queensland Energy Resources, *Australia's future transport fuel supply options*, Report by ACIL Tasman, EnergyQuest, Rurvin & Gertz and RARE Consulting, Brisbane, 2009.

The increasing use of gas for domestic purposes—not only in power generation, but also in transport, business and retail applications—would reduce greenhouse emissions and deliver environmental and economic benefits. While wholesale Australian gas prices may rise in real terms, they are likely to remain relatively low compared with prices in gas importing countries.

The world wants and understands the value of Australian gas. The timing may be right for Australian gas to assume a more significant role at home as well as contributing to the energy needs of Asia.



# PART TWO ELECTRICITY



Electricity is a form of energy that is transported along a conductor such as metal wire. Although 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 located usually near fuel sources such as coal mines, natural gas pipelines and hydroelectric water reservoirs. Most electricity customers, however, are located a long distance from electricity 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, and chapter 3 surveys the electricity derivatives markets that complement the wholesale market. Chapter 4 provides a survey of electricity markets in the non-NEM jurisdictions of Western Australia and the Northern Territory. Chapters 5 and 6 provide data on the electricity transmission and distribution sectors, and chapter 7 considers electricity retailing.

46

# Electricity supply chain



Image sources: Consumption, Jessica Shapiro (Fairfaxphotos); Other, Mark Wilson.



# 1 ELECTRICITY GENERATION



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. The six participating jurisdictions, physically linked by a transmission network, are 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 geographic distribution and types of generation technology
- > climate change policies and electricity generation
- > the ownership of generation infrastructure
- > new investment in generation infrastructure
- > generation reliability 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 generator rely on the heat emitted through a nuclear reaction, or renewable energy sources such as the sun, wind, geothermal resources (hot rocks) or water flow to generate electricity. Figure 1.1 illustrates five types of electricity generation most commonly used in Australia: coal fired, open cycle gas fired, combined cycle gas fired, hydroelectric and wind.

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

50

#### Figure 1.1 Electricity generation technologies

#### **Coal fired generation**



Combined cycle gas fired generation



Open cycle gas fired generation



Hydroelectric generation



Wind generation



Sources: AER (wind); Babcock & Brown (all others).

# 1.1.1 Lifecycle costs

Figure 1.2 provides estimates of the economic lifecycle costs of different electricity generation technologies in Australia. To allow comparison, the costs of each generation option have been converted to a levelised cost per unit of electricity.<sup>1</sup>

Figure 1.2 includes technologies in use, as well as alternatives such as nuclear energy, and fossil fuel fired generators using carbon capture and storage (CCS) technology.<sup>2</sup> The cost estimates for CCS, which can be used to reduce greenhouse gas emissions from fossil fuel fired generation (coal, gas and oil) technologies, are indicative only.

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

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

### 1.1.2 Greenhouse gas emissions

Figure 1.3 shows greenhouse gas emissions for a range of different electricity generation technologies, based on current best practice under Australian conditions. The data account for full lifecycle emission contributions —including those from construction and the extraction of fuels—and estimate the emissions per megawatt hour (MWh) of electricity generated.

### Figure 1.2

Lifecycle economic costs of electricity generation



CCGT, combined cycle gas turbine; CCS, carbon capture and storage (costs are indicative only); PV, photovoltaic; SPCC, supercritical pulverised coal combustion (in which steam is created at very high temperatures and pressures).

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, Canberra, December 2006.

Renewable sources of electricity (hydroelectric, wind and solar) and nuclear electricity generation have the lowest greenhouse gas emissions of the generation technologies analysed. Of the fossil fuel technologies, natural gas has the lowest emissions and brown coal has the highest. Figure 1.3 does not account for CCS technologies, which could reduce emissions from gas and coal fired generators.

# 1.2 Generation in the National Electricity Market

About 200 large<sup>3</sup> electricity generators (figure 1.4) operate in the National Electricity Market (NEM) jurisdictions.<sup>4</sup> The electricity produced by major generators in the NEM is sold through a central dispatch process managed by the Australian Energy Market Operator (AEMO). Chapter 2 outlines this process.

<sup>1</sup> 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 estimate a cost per unit of electricity (in dollars per megawatt hour).

<sup>2</sup> 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, and industrial fixation in inorganic carbonates. Some industrial processes may use and store small amounts of captured carbon dioxide in manufactured products.

<sup>3 &#</sup>x27;Large' refers to generators with capacity greater than 30 megawatts.

<sup>4</sup> This chapter does not cover Western Australia or the Northern Territory, which do not participate in the NEM. Chapter 4 provides information on the generation sectors in those jurisdictions.

#### Figure 1.3

Lifecycle greenhouse gas emissions from electricity generation



CCGT, combined cycle gas turbine; OCGT, open cycle gas turbine; PV, photovoltaic. Notes:

The figure shows the estimated range of emissions for each technology and highlights the most likely emissions value. It includes emissions from power station construction and the extraction of fuel sources.

kg CO<sub>2</sub>-e/MWh refers to the quantity of greenhouse gas emissions (in kilograms, converted to a carbon dioxide equivalent) that are produced for every megawatt hour of electricity produced.

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, Canberra, December 2006.

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 baseload, 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 lower start-up costs and are used to supplement baseload 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 start-up because they may be called on to operate at short notice. There are also intermediate generators, which operate more frequently than peaking plants, but not continuously.

The NEM generation sector uses a variety of fuel sources to produce electricity (figures 1.5a and 1.5b). Black and brown coal account for around 60 per cent of registered<sup>5</sup> generation capacity across the NEM but as predominantly baseload generators—supply a much larger share of output (85 per cent). Gas fired generation accounts for around 20 per cent of registered capacity but—as intermediate and peaking plant—supplies only around 8 per cent of output.

5 Generators seeking to connect to the network must register with the Australian Energy Market Operator, unless granted an exemption.





Registered generation capacity, by fuel source— National Electricity Market, 2009

#### Figure 1.5b

Registered generation output, by fuel source— National Electricity Market, 2009



Note: Data based on market output published by AEMO. The data exclude output from non-registered generators. Sources: AEMO/AER.

Hydroelectric generation accounts for around 17 per cent of registered capacity, but less than 6 per cent of output. Hydro's contribution to output has fallen in the past few years as a result of drought conditions in eastern Australia. Wind plays a relatively minor role in the market (around 4 per cent of capacity and 1 per cent of output), but its role is expected to expand under climate change policies. Liquid fuels account for around 1 per cent of capacity.<sup>6</sup>

Figure 1.6 sets out regional data on generation capacity by fuel source. Victoria's generation is fuelled by mainly brown coal, supplemented by hydroelectric and gas fired peaking generation. New South Wales and Queensland rely on mainly black coal, but there has been some recent investment in gas fired generation. New South Wales also has some hydroelectric generation, mainly owned by Snowy Hydro.<sup>7</sup> Electricity generation in South Australia is fuelled by mainly natural gas. Tasmania relies on hydroelectric generation primarily, but there has been some recent investment in gas fired generation.

The extent of new and proposed investment in intermittent generation (mainly wind) has raised concerns about system security and reliability. Wind generation grew strongly in the NEM—especially in South Australia—following the introduction of a national mandatory renewable energy target in 2000. That growth led to changes in the way wind generation is integrated into the market.

Since 31 March 2009 new wind generators greater than 30 megawatts (MW) must be classified as 'semischeduled' and participate in the central dispatch process. This allows AEMO to limit the output of these generators if necessary to maintain the integrity of the power system. While wind accounts for only around 4 per cent of registered capacity in the NEM, it has a significantly higher share in South Australia at 20 per cent (figure 1.7).

<sup>6</sup> Liquid fuels include diesel, distillates and jet fuel.

<sup>7</sup> The former Snowy region was abolished on 1 July 2008. It is now split between the Victoria and New South Wales regions of the NEM.

Figure 1.6

Registered generation capacity, by fuel source regional, 2009



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

Sources: AEMO/AER.

The pattern of generation technologies across the NEM is evolving. As indicated in figure 1.3, coal fired generators produce relatively more greenhouse gas emissions than produced by most other technologies. The Australian and state and territory governments have implemented (and are developing) initiatives to encourage the development and use of low emission technologies.

The Australian Government's two primary emissions reduction policies are an emissions trading scheme called the Carbon Pollution Reduction Scheme (CPRS)—and an expanded national renewable energy target (RET).

On 20 August 2009 the Commonwealth Parliament passed legislation to implement the expanded RET scheme. The scheme is designed to achieve the Australian Government's commitment to a 20 per cent share of renewable energy in Australia's electricity mix by 2020. It increases the national target by more than four times to 45 850 gigawatt hours in 2020, then dropping to 45 000 gigawatt hours for the following decade until 2030. The scheme is set to expire in 2030, by which time the proposed CPRS is intended to result

#### Figure 1.7





Sources: AEMO/AER.

in a sufficiently high carbon price to drive renewable energy projects.

The expanded scheme aims to encourage investment in renewable energy technologies by providing for the creation of renewable energy certificates. One certificate is created for each megawatt hour of eligible renewable electricity generated by an accredited power station, or deemed to have been generated by eligible solar hot water or small generation units. Retailers must obtain and surrender certificates to cover a set proportion of their wholesale electricity purchases. If a retailer fails to surrender enough certificates to cover its liability, then it must pay a penalty for the shortfall.

The design of the proposed CPRS was set out on 15 December 2008 in the *Carbon Pollution Reduction Scheme: Australia's low pollution future* (white paper). On 4 May 2009 the Australian Government announced a delay in the scheme's introduction by one year, to 1 July 2011.

If introduced, the scheme will create a market for the right to emit carbon by placing a cap on Australia's total emissions. In doing so, it is likely to alter the mix of generation output away from fossil fuel fired generation technologies (particularly brown coal), which are relatively low cost but high in emissions, in favour of lower emission and renewable energy technologies.

In addition, governments apply a range of other policies that may affect the generation technology mix. These include low emission generation targets (for example, the Queensland Gas Scheme)<sup>8</sup> and funding for low emission technology development.

### 1.2.1 Generation ownership

Table 1.1 and figures 1.8 and 1.9 provide information on the ownership of generation businesses in Australia. Across the NEM, around two thirds of generation capacity is government owned or controlled.

In the 1990s Victoria and South Australia disaggregated their generation sectors into multiple stand-alone businesses and privatised each business. Most generation capacity in these jurisdictions is now owned by International Power, AGL Energy, TRUenergy, Great Energy Alliance Corporation (GEAC, in which AGL Energy holds a 32.5 per cent stake) and Snowy Hydro.<sup>9</sup> Some of these businesses have invested in new generation capacity—mainly gas fired intermediate and peaking plants—since the NEM began.

There has been a significant trend in Victoria and South Australia towards vertical integration of electricity generators with retailers. In Victoria, AGL Energy and TRUenergy are key players in both generation and retail. In South Australia, AGL Energy has the largest generation capacity and the largest retail market share. Across Victoria and South Australia, AGL Energy and TRUenergy own or control around 35 per cent of registered generation capacity.<sup>10</sup>

Generation capacity in New South Wales is mainly split between the state owned Macquarie Generation, Delta Electricity and Eraring Energy. Snowy Hydro also has significant hydroelectric generation capacity in that state. There has recently been some private sector investment in New South Wales. TRUenergy and Origin Energy have entered the generation market with the Tallawarra (417 MW) and Uranquinty (678 MW) power stations. They bring the number of private sector generation businesses in New South Wales to five. (Babcock & Brown Power, Marubeni Corporation and Infigen also have small generation holdings.) In total, the private sector accounts for around 10 per cent of the state's generation capacity.

In March 2009 the New South Wales Government announced it would contract the right to sell electricity produced by state owned generators to the private sector. The government expects to complete the sale process in the first half of 2010. It will offer the contracts in the following five bundles:

- > Liddell power station (2000 MW, owned by Macquarie Generation)
- > Bayswater power station (2640 MW, owned by Macquarie Generation)
- Mount Piper and Wallerawang power stations (2400 MW, owned by Delta Electricity)
- Vales Point, Munmorah and Colongra power stations (2588 MW, owned by Delta Electricity)
- > Eraring power station and Shoalhaven pumped storage hydro-electric system (3120 MW, owned by Eraring Energy).<sup>11</sup>

Queensland has disaggregated its generation sector, but government owned businesses (including Tarong Energy, Stanwell Corporation and CS Energy) control around 75 per cent of the state's generation capacity. This includes some joint ventures with the private sector (such as the Tarong North and Callide C power stations) and power purchase agreements over much of the privately owned capacity (such as the Gladstone and Collinsville power stations).

<sup>8</sup> Under the scheme, Queensland electricity retailers must source a prescribed percentage (currently 13 per cent) of their electricity from gas fired generation. The target will increase to 15 per cent in 2010, with an option to increase to 18 per cent by 2020. The scheme will be transitioned into the CPRS as soon as is practicable.

<sup>9</sup> The New South Wales, Victorian and Australian governments jointly own Snowy Hydro.

<sup>10</sup> Includes AGL Energy's 32.5 per cent stake in Loy Yang A and TRUenergy's contractual arrangement for Ecogen Energy's capacity (table 1.1).

<sup>11</sup> New South Wales Government, New South Wales Energy Reform Strategy, delivering the strategy: approach to transactions and market structure, Sydney, September 2009.

		CAPACITY	,
GENERATING BUSINESS	POWER STATIONS	(MW)	OWNER
NEM REGIONS			
QUEENSLAND			
CS Energy	Callide; Kogan Creek; Swanbank	2254	CS Energy (Qld Government)
Tarong Energy	Tarong; Wivenhoe	1900	Tarong Energy (Qld Government)
Stanwell Corporation	Gladstone	1680	Rio Tinto 42.1%; Transfield Services 37.5%; others 20.4%. All contracted to Stanwell Corporation (Qld Government)
Stanwell Corporation	Barron Gorge; Kareeya; Mackay Gas Turbine; others	1571	Stanwell Corporation (Qld Government)
Callide Power Trading	Callide C	900	CS Energy (Qld Government) 50%; InterGen 50%
Millmerran Energy Trader	Millmerran	852	InterGen 50%; China Huaneng Group 50%
ERM Power and Arrow Energy	Braemar 2	462	ERM Power 50%; Arrow Energy 50%
Braemar Power Project	Braemar 1	450	Babcock & Brown Power
Tarong Energy	Tarong North	443	Tarong Energy (Qld Government) 50%; TEPCO 25%; Mitsui 25%
Origin Energy	Mount Stuart; Roma	314	Origin Energy
AGL Hydro	Oakey	275	Babcock & Brown Power 50%; ERM Group 25%; Contact Energy 25%. All contracted to AGL Energy
AGL Hydro	Yabulu	232	Transfield Services Infrastructure Fund. All contracted to AGL Energy and Arrow Energy
CS Energy	Collinsville	187	Transfield Services Infrastructure Fund. All contracted to CS Energy (Qld Government)
Pioneer Sugar Mills	Pioneer Sugar Mill	68	CSR
Ergon Energy	Barcaldine	49	Ergon Energy (Qld Government)
EDL Projects Australia	Moranbah North	46	EDL Projects Australia
CSR	Invicta Sugar Mill	39	CSR
AGL Energy	German Creek; KRC Cogeneration	32	AGL Energy
Other registered capacity		273	
NEW SOUTH WALES			
Macquarie Generation	Bayswater; Liddell; Hunter Valley	4844	Macquarie Generation (NSW Government)
Delta Electricity	Mount Piper; Vales Point B; Wallerawang; Munmorah; Colongra; others	4547	Delta Electricity (NSW Government)
Eraring Energy	Eraring; Shoalhaven; Brown Mountain; Burrinjuck; others	2972	Eraring Energy (NSW Government)
Snowy Hydro	Blowering; Upper Tumut; Tumut; Guthega	2336	Snowy Hydro (NSW Government 58%; Vic Government 29%; Australian Government 13%)
Origin Energy	Uranquinty; Cullerin Range	678	Origin Energy
TRUenergy	Tallawarra	417	TRUenergy (CLP Group)
Marubeni Australia Power Services	Smithfield Energy Facility	160	Marubeni Corporation
Redbank Project	Redbank	145	Babcock & Brown Power
Infigen	Capital	140	Infigen Energy
Country Energy	Broken Hill Gas Turbine	50	Country Energy (NSW Government)
Other registered capacity		109	

# Table 1.1 Generation ownership in the National Electricity Market, July 2009

GEAC, Great Energy Alliance Corporation; NEM, National Electricity Market.

Fuel types: coal; gas; hydro; wind; liquid; biomass/bagasse; unspecified.

Note: Capacity is as published by AEMO for summer 2009-10.

Source: AEMO.

		CAPACITY	
GENERATING BUSINESS	POWER STATIONS	(MW)	OWNER
VICTORIA			
LYMMCo	Loy Yang A	2080	GEAC (AGL Energy 32.5%; TEPCO 32.5%; Transfield Services 14%; others 21%)
Snowy Hydro	Murray; Laverton North; Valley Power	1933	Snowy Hydro (NSW Government 58%; Vic Government 29%; Australian Government 13%)
Hazelwood Power	Hazelwood	1580	International Power 91.8%; Commonwealth Bank 8.2%
TRUenergy Yallourn	Yallourn; Longford Plant	1451	TRUenergy (CLP Group)
International Power	Loy Yang B	975	International Power 70%; Mitsui 30%
Ecogen Energy	Jeeralang A and B; Newport	891	Industry Funds Management (Nominees) Ltd. All contracted to TRUenergy (CLP Group)
AGL Hydro	Mckay; Somerton; Eildon; Clover; Dartmouth; others	423	AGL Energy
Pacific Hydro	Yambuk; Challicum Hills; Portland	247	Pacific Hydro
Acciona Energy	Waubra	192	Acciona Energy
Energy Brix Australia	Energy Brix Complex; Hrl Tramway Road	160	HRL Group
Alcoa	Angelsea	152	Alcoa
Aurora Energy Tamar Valley	Bairnsdale	70	Babcock & Brown Power
Eraring Energy	Hume	58	Eraring Energy (NSW Government)
Other registered capacity		82	
SOUTH AUSTRALIA			
AGL Hydro	Hallett 1 and 2; Wattle Point	257	AGL Energy
AGL Energy	Torrens Island	1256	AGL Energy
Cathedral Rocks Wind Farm	Cathedral Rocks	66	Roaring 40s (Hydro Tasmania (Tas Government) 50%; CLP Group 50%) 50%; Acciona Energy 50%
Infigen	Lake Bonney 1	81	Infigen Energy. All contracted to Country Energy (NSW Government)
Infigen	Lake Bonney 2	159	Infigen Energy
Flinders Power	Northern; Playford	782	Babcock & Brown Power
Flinders Power	Osborne	175	ATCO 50%; Origin Energy 50%
Infratil Energy Australia	Angaston	49	Infratil. All contracted to AGL Energy
International Power	Pelican Point; Canunda	494	International Power
Transfield Services Infrastructure Fund	Mount Millar	70	Transfield Services Infrastructure Fund
Origin Energy	Quarantine; Ladbroke Grove	267	Origin Energy
Pacific Hydro	Clements Gap	57	Pacific Hydro
Infratil Energy Australia	Snowtown	99	Infratil
Transfield Services Infrastructure Fund	Starfish Hill	35	Transfield Services Infrastructure Fund. All contracted to Hydro Tasmania (Tas Government)
Synergen Power	Dry Creek; Mintaro; Port Lincoln; Snuggery	275	International Power
TRUenergy	Hallet	150	TRUenergy (CLP Group)
Other registered capacity		25	
TASMANIA			
Aurora Energy	Tamar Valley; Bell Bay	374	AETV (Tas Government)
Hydro Tasmania	Gordon; Poatina; Reece; John Butters; Tungatinah; others	2347	Hydro Tasmania (Tas Government)
Hydro Tasmania	Woolnorth	140	Roaring 40s (Hydro Tasmania (Tas Govt) 50%; CLP Group 50%)
Other registered capacity		100	



#### Figure 1.8 Major stakeholders in National Electricity Market power stations, 2009

Notes:

AGL Energy ownership excludes its 32.5 per cent stake in GEAC, which owns Loy Yang A.

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

Excludes power stations that are not managed through central dispatch.

Some corporate names have been shortened or abbreviated.

Sources: AEMO/AER.

#### Figure 1.9

#### Registered generation ownership, by region, 2009



#### Notes:

'Private/government power purchase agreement' refers to capacity that is privately owned but contracted under power purchase agreements to government owned corporations.

'Government/private' refers to joint venture arrangements between the private and government sectors.

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

Sources: AEMO/AER.

Figure 1.10 Annual investment in registered generation capacity



Q, Queensland; N, New South Wales; V, Victoria; S, South Australia; T, Tasmania. Note: These are gross investment estimates that do not account for decommissioned plant. Sources: AEMO/AER.

There has been considerable private investment in new capacity in Queensland, including by Rio Tinto, Intergen, Transfield Services Infrastructure Trust, Origin Energy and Babcock & Brown Power. Most recently, ERM Power and Arrow Energy developed the Braemar 2 power station (462 MW), which began operating in 2009.

State owned enterprises own nearly all of the generation capacity in Tasmania. Hydro Tasmania owns the majority, at 2417 MW. Aurora Energy's Tamar Valley peaking plant (166 MW) has recently been expanded with the addition of a 196 MW combined cycle gas turbine.

# 1.3 Investment

Investment in generation capacity is needed to meet the growing demand for electricity and to maintain the reliability of the power system. It includes the construction of new power stations and upgrades or extensions of existing power stations. The NEM is an 'energy only' market in which investment is largely driven by price signals in the wholesale and forward markets for electricity (see section 1.4). By contrast, most electricity markets across the world (including Western Australia) use a capacity mechanism to encourage new investment in generation capacity. This may involve a tendering process whereby capacity targets are determined by market operators and then built by the successful tenderers. Chapter 4 describes the Western Australian capacity market.

From the inception of the NEM in 1999 to July 2009, new investment added almost 10 300 MW of registered generation capacity, with around 2500 MW occurring in 2008–09.<sup>12</sup> Figures 1.10 and 1.11 illustrate generation investment since market start. There was strong investment in Queensland and South Australia in the early years of the current decade in response to high wholesale electricity prices. Queensland investment was mainly in baseload generation, whereas South Australian investment was mostly in intermediate and peaking generation. There was also some peaking investment in Victoria.

<sup>12</sup> There has also been investment in other generators—for example, small generators, remote generators not connected to a transmission network and generators that produce exclusively for self-use (such as for remote mining operations).

Figure 1.11 Change in net generation capacity since market start



Note: Net change in registered capacity from 1998-99. A decrease may reflect a reduction of capacity due to decommissioning or a reduction in capability of existing generation units.

Sources: AEMO/AER.

There was negligible investment across the NEM in the middle of the current decade. But then tightening supply conditions led to significant new investment in the latter part of the decade. There has been continuing new investment in Queensland and in gas fired plant in New South Wales in 2008–09. South Australia has recorded strong growth in wind capacity over the past few years.

### 1.3.1 Recent investment

Investment in generation capacity needs to respond to projected market requirements for electricity. Table 1.2a sets out major new generation investment that came on line in the NEM in 2008–09, excluding wind. The bulk of new investment (1240 MW) has occurred in New South Wales, of which around 1100 MW was privately developed by Origin Energy and TRUenergy. Queensland has added around 460 MW of private investment, developed by ERM Power and Arrow Energy. There was new investment by government businesses in New South Wales and Tasmania. All new investment in 2008–09 was in gas fired generation.

Table 1.2b shows almost 500 MW of new wind generation investment in the NEM in 2008–09. The investment occurred in Victoria, New South Wales and South Australia. Table 1.2c sets out committed investment projects in the NEM at June 2009. It includes those already under construction and those where developers and financiers have formally committed to construction. AEMO accounts for committed projects in projecting electricity supply and demand. There is around 2650 MW of committed capacity in the NEM, of which more than 2200 MW is gas fired generation. Most projects are expected to be commissioned by the end of 2010. There were no major committed projects added in 2008–09.

# 1.3.2 Proposed projects

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

The AEMO website lists proposed generation projects in the NEM that are 'advanced' or publicly announced. AEMO considers these projects to be speculative and thus excludes them from its supply and demand outlooks. At June 2009 it listed around 8760 MW of proposed capacity (excluding wind) in the NEM (table 1.3).<sup>13</sup> There is significant proposed investment in gas fired generation, mainly for New South Wales (possibly because the region is the highest net importer in the NEM) and Queensland.

13 Sourced from AEMO's generator information page (www.aemo.com.au/data/gendata.shtml), viewed 14 August 2009.

F	REGION	POWER STATION	DATE COMMISSIONED	TECHNOLOGY	CAPACITY (MW)	ESTIMATED COST (\$ MILLION)	OWNER
G	ld	Braemar 2	April-June 2009	OCGT	462	546	ERM Power and Arrow Energy
Ν	ISW	Colongra (unit 1)	June 2009	OCGT	157		Delta Electricity
٨	ISW	Tallawarra	February 2009	CCGT	435	350	TRUenergy
٨	ISW	Uranquinty	October 2008 – January 2009	OCGT	648	700	Origin Energy
S	5A	Quarantine	March 2009	OCGT	128	90	Origin Energy
Т	as	Tamar Valley Peaking	April 2009	OCGT	58		Aurora Energy

#### Table 1.2a Generation investment in the National Electricity Market, 2008–09 (excluding wind)

#### Table 1.2b Wind generation investment in the National Electricity Market, 2008–09

REGION	POWER STATION	CAPACITY (MW)	ESTIMATED COST (\$ MILLION)	OWNER
NSW	Cullerin Range	30	95	Origin Energy
NSW	Capital	140	220	Renewable Power Ventures
Vic	Waubra	192	450	Acciona Energy
SA	Clements Gap	57	135	Pacific Hydro
SA	Hallett 2	71	159	AGL Hydro

Note: Tables 1.2a and 1.2b are based on publicly available information.

#### Table 1.2c Committed investment projects in the National Electricity Market, June 2009

			CAPACITY	PLANNED				
DEVELOPER	POWER STATION	TECHNOLOGY	(MW)	COMMISSIONING DATE				
QUEENSLAND	QUEENSLAND							
Queensland Gas Company	Condamine	CCGT	135	2009–10				
Origin Energy	Darling Downs	CCGT	605	2010				
Origin Energy	Mount Stuart (extension)	OCGT	127	2009				
Rio Tinto	Yarwun Cogen	Gas cogeneration	152	2010				
NEW SOUTH WALES								
Eraring Energy	Eraring (extension)	Coal fired	120	2010-11				
Delta Electricity	Colongra (units 2–4)	OCGT	471					
VICTORIA								
AGL Energy	Bogong	Hydro	140	2009–10				
Origin Energy	Mortlake	OCGT	518	2010				
Pacific Hydro	Portland	Wind	164	2009–10				
SOUTH AUSTRALIA								
International Power	Port Lincoln	OCGT	25	2010				
TASMANIA								
Aurora Energy	Tamar Valley	CCGT	196	2009				

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

Note: Capacity is summer capacity for all generators.

Source: AEMO.
			CAPACITY	PLANNED COMMISSIONING
DEVELOPER	POWER STATION	TECHNOLOGY	(MW)	DATE
QUEENSLAND				
Origin Energy	Spring Gully	CCGT	1000	n/a
ERM Power	Braemar 3	Gas	462	2012
ERM Power	Braemar 4	Gas	434	2013
CS Energy	Swanbank F	CCGT	380	2012
NEW SOUTH WALES				
ERM Power	Wellington (Units 1–4)	OCGT	616	2011
Delta Electricity	Mount Piper expansion	Coal	600	2015-16
Macquarie Generation	Tomago Gas Turbine	OCGT	500	n/a
Delta Electricity	Bamarang	CCGT	450	2012-13
Delta Electricity	Marulan gas turbine	CCGT	420	2013-14
AGL Energy	Leaf's Gully	Gas	360	2012
Delta Electricity	Bamarang	OCGT	330	2012-2013
Delta Electricity	Marulan gas turbine	OCGT	330	2013-14
ERM Power	Wellington (Unit 5)	OCGT	280	2012
International Power	Parkes	OCGT	150	n/a
International Power	Buronga	OCGT	120	n/a
Eraring Energy	Eraring upgrade	Coal	60	2011
Eraring Energy	Eraring upgrade	Coal	60	2012
VICTORIA				
Santos	Shaw River	CCGT	500	2012
AGL Energy	Tarrone	Gas	500	2012
HRL Group and Harbin Power Engineering	IDGCC demonstration plant	IDGCC	500	2013
Origin Energy	Mortlake (Stage 2)	CCGT	470	n/a
Solar System	Solar System Victorian Solar Energy Facility (Units 2–51)	Solar Concentrator	100	2012
Solar System	Solar Systems Victorian Solar Energy Facility (Units 52–77)	Solar Concentrator	54	2013
SOUTH AUSTRALIA				
Altona Resources	Arkaringa	IGCC	560	2014
International power	Pelican Point (Stage 2)	Gas	300	n/a
Strike Oil	Kingston	Coal	40	2015
TASMANIA				
Gunns	Bell Bay pulp mill power plant	Biomass	184	2012

#### Table 1.3 Major proposed generation investment in the National Electricity Market, June 2009

CCGT, combined cycle gas turbine; IDGCC, integrated drying and gasification combined cycle; IGCC, integrated gasification combined cycle; OCGT, open cycle gas turbine; n/a, not available.

Note: Excludes wind generation.

Source: AEMO

64

#### 1.3.3 Wind projects

AEMO reports wind generation investment separately from other proposed investment because wind capacity depends on the weather and cannot be relied on to generate at specified times.<sup>14</sup> At June 2009 it listed around 6730 MW of proposed wind capacity, mainly in Victoria, New South Wales and South Australia (table 1.4).

### Table 1.4 Major proposed wind generation investment in the National Electricity Market, June 2009

COMMISSIONING	CAPACITY (MW)							
DATE	QLD	NSW	VIC	SA	TAS	TOTAL		
2009				39		39		
2010		92	198	129	117	536		
2011		1516	564	724		2804		
2012		350	760			1110		
2013			480			480		
2014	101		234		300	635		
2015	50			71		121		
2016	80	149				229		
2017			120			120		
2018				109		109		
2019		53		80		133		
Unknown		30	144	242		416		
Total	231	2190	2500	1394	417	6732		

Source: AEMO.

#### 1.4 Reliability of the generation sector

Reliability refers to the continuity of electricity supply to customers. The Australian Energy Market Commission (AEMC) Reliability Panel sets the reliability standard for the NEM. The standard requires sufficient generation and bulk transmission capacity to ensure, in the long term, no more than 0.002 per cent of customer demand in each NEM region is at risk of not being supplied. To ensure the standard is met, AEMO 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. The panel also recommends a wholesale market price cap, which is set at a level to stimulate sufficient investment in generation capacity to meet the reliability standard. A review in 2007 of the reliability settings led to a decision to increase the market price cap from \$10 000 per MWh to \$12 500 per MWh, to take effect on 1 July 2010.

The panel reports annually on the performance of the generation sector against the reliability standard and minimum reserve levels set by AEMO. In practice, generation has proved highly reliable. Reserve levels are rarely breached and generator capacity across all regions of the market is generally sufficient to meet peak demand and allow for an acceptable reserve margin.

The performance of generators in maintaining reserve levels has improved since the NEM began in 1998, most notably in South Australia and Victoria. This reflects significant generation investment and improved transmission interconnection capacity across the regions. Table 1.5 sets out the performance of the generation sector in selected regions against the reliability standard. The reliability of all regions falls within the standard.

There have been three instances of insufficient generation capacity to meet consumer demand from the commencement of the NEM to 30 June 2009. The first occurred in Victoria and South Australia in early 2000, when a coincidence of industrial action, high demand and temporary loss of generating units resulted in load shedding. The scope of the reliability standard was amended following the release of the AEMC's *Comprehensive reliability review—final report* in December 2007, to exclude unserved energy associated with power system incidents resulting from industrial action or 'acts of God' at transmission facilities.<sup>15</sup> Accordingly, revised calculations of unserved energy exclude the event in 2000.

15 AEMC Reliability Panel, Reliability standard and settings review, issues paper, Sydney, June 2009.

<sup>14</sup> The Australian Energy Market Commission published a final Rule determination on 1 May 2008 that requires new intermittent generators to register under the new classification of 'semi-scheduled generator'. These generators must participate in the central dispatch process. Additionally, in 2004 the South Australian regulator, the Essential Services Commission of South Australia (ESCOSA), implemented licence conditions preventing wind farms from being classified as non-scheduled. Accordingly, all wind farms commissioned in South Australia since that date are classified as scheduled generation. Some pre-existing South Australian wind farms also have changed classification, from non-scheduled to scheduled.



The second event occurred in New South Wales on 1 December 2004, when a generator failed during a period of record summer demand. The restoration of load began within 10 minutes. The most recent instance of insufficient generation occurred on 29 and 30 January 2009 in Victoria and South Australia. Extremely high temperatures led to record demand in Victoria and near record demand in South Australia. Unplanned outages on Basslink on each day exacerbated the tight supply conditions in Victoria and South Australia. This led to supply interruptions on two days in South Australia (for 90 minutes and 165 minutes respectively) and Victoria (for 160 minutes and 230 minutes respectively).<sup>16</sup>

### Table 1.5Unserved energy—long term averages,December 1998 to June 2009

REGION	UNSERVED ENERGY (%)
Queensland	0.00000
New South Wales	0.00010
Victoria	0.00044
South Australia	0.00051

Note: There has been no breach of the reliability standard in Tasmania since it joined the NEM in 2005.

Source: AEMC Reliability Panel, *Reliability standard and settings review*, *issues paper*, Sydney, June 2009.

#### 1.4.1 Excluded events

The power system is operated to cope with only credible contingencies. Some power supply interruptions are caused by non-credible (multiple contingency) events. This may involve several credible events occurring simultaneously or in a chain reaction—for example, several generating units might fail or 'trip' at the same time, or a transmission fault might occur at the same time as a generator trips. It would be inefficient to operate the power system to cope with non-credible events. Likewise, additional investment in generation or networks may not necessarily avoid such interruptions. For this reason, these events are excluded from reliability calculations.

#### 1.4.2 Reviews of the reliability settings

The AEMC Reliability Panel is required to review the reliability standard and mechanisms every two years. The next review is to be completed by 30 April 2010, with any changes to apply from 1 July 2012. In addition, the AEMC is reviewing the effectiveness of the NEM security and reliability arrangements in the light of extreme weather events. The review, also to be completed by April 2010, will assess:

- > whether the current reliability standard conforms with public expectations of supply reliability
- > the impact of a range of market price caps on reliability and costs to customers
- > whether the process of determining the reliability standard and market price cap requires change.

Further, in June 2009 the panel began a review of the operational arrangements to meet the reliability standard. The review is considering the process for determining minimum reserve levels and obligations on market participants to provide AEMO with accurate information on generation availability.

The NEM combines a number of mechanisms to ensure high levels of reliability in supply. AEMO publishes forecasts of electricity demand and generator availability to allow generators to respond to market conditions and determine the scheduling of maintenance outages. It can intervene in the market when generation capacity forecasts indicate capacity is unlikely to be sufficient to meet minimum reserve levels. The reliability and emergency reserve trader (RERT) mechanism allows AEMO to enter reserve contracts with generators to ensure sufficient reserves to meet the reliability standard. When entering these contracts, AEMO must give priority to facilities that would least distort wholesale market prices. Reserves were contracted through the reserve trading mechanism for the first time in Victoria and South Australia in February 2005 and again in February 2006, but were ultimately not required on either occasion. AEMO can also intervene in the market through its directions power, requiring

16 There were further network outages in Victoria on the evening of 30 January, leading to localised interruptions to customers. The interruptions were not related to a shortfall in generation supply.

generators to provide additional supply at the time of dispatch to ensure sufficient reserves.

In 2008 the AEMC commenced a review of the energy market frameworks to determine their adequacy to accommodate climate change policies, particularly the CPRS and expanded RET. The final report (published 8 October 2009) raised concerns that the current reliability mechanisms—including the RERT mechanism and directions power—do not adequately address the risk of short term generation capacity shortfalls. Addressing this concern, the AEMC Reliability Panel proposed changing the Electricity Rules to allow more flexibility in contracting under the RERT mechanism, including the establishment of a panel of participants and a short notice contracting process.

The AEMC also supported changing the Electricity Rules to require more accurate reporting of demand-side capability. This proposal aims to minimise AEMO's intervention in the market by improving the quality of reserve assessments.

### 1.4.3 Investment in generation and long term reliability

While the NEM combines a number of mechanisms to manage short term generation capacity issues, a reliable power supply in the longer term needs sufficient investment in generation to meet the needs of customers.

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 of the supply-demand balance are also factored into forward prices in the contract market (see chapter 3). Regions with potential generation shortages (which could lead to reliability issues), therefore, will exhibit rising prices in the spot and contract markets. High prices may help attract investment to areas where it is needed, and may lead to some demand-side response if suitable metering and price signals are available to customers —for example, retailers may offer financial incentives for customers to reduce consumption at times of high system demand, to ease pressure on prices.

Seasonal factors (for example, summer peaks in air conditioning loads) create a need for peaking generation to cope with periods of extreme demand. The NEM price cap of \$10 000 per MWh is necessarily high to encourage investment in peaking plant, which is expensive to run and may operate only rarely. Over the longer term, peaking plant plays a critical role in ensuring there is adequate generation capacity (and thus reliability). There has been significant investment in peaking capacity in most regions of the NEM over the past few years.

#### Historical adequacy of generation to meet demand

Figure 1.12 compares total generation capacity with national peak demand since the NEM began. It shows actual demand and AEMO's demand forecasts two years in advance. The data indicate that investment in the NEM over the past decade has kept pace with rising demand (both actual and forecast levels), and has provided a safety margin of capacity to maintain the reliability of the power system. In 2008-09 actual demand was above forecast demand for the first time since 2000-01.

#### **Reliability outlook**

The relationship between future demand and available capacity determines electricity prices and the reliability of the power system looking ahead. Figure 1.13 charts forecast peak demand in the NEM against installed, committed and proposed capacity. It indicates the amount of capacity that AEMO considers would be needed to maintain reliability, given projected demand. Wind generation is treated differently from conventional generation for the purpose of the supply-demand balance. In South Australia, for example, a figure of 3 per cent of installed wind capacity is used to represent the contribution to overall generation supply at times of peak demand; 8 per cent is used in Victoria.

#### Figure 1.12

National Electricity Market peak demand and generation capacity



#### Notes:

Demand forecasts are two years in advance, based on a 50 per cent probability that the forecast will be exceeded and a coincidence factor of 95 per cent.

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

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

Figure 1.13 indicates that current installed and committed capacity will be sufficient to meet peak demand projections and reliability requirements until at least 2012–13.

While the uncertain nature of proposed projects means they cannot be factored into AEMO's reliability equations, they indicate the market's awareness of future capacity needs. In particular, they indicate the extent of competition in the market to develop electricity infrastructure. Figure 1.13 indicates the possible extent of proposed capacity required to be constructed to meet projected shortfalls beyond 2012–13. While many proposed projects may never be constructed, only a relatively small percentage would need to occur to meet demand and reliability requirements into the next decade.

#### Figure 1.13

#### Demand and generation capacity outlook to 2014-15



#### Notes:

Capacity (excluding wind) is scheduled capacity and encompasses installed and committed capacity. Wind capacity includes scheduled and semi-scheduled wind generation. Proposed capacity includes wind projects (see tables 1.3 and 1.4).

The maximum demand forecasts for each region in the NEM are aggregated based on a 50 per cent probability of exceedance and a 95 per cent coincidence factor. Unscheduled generation is treated as a reduction in demand.

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: AEMO, *Electricity statement of opportunities for the National Electricity Market*, Melbourne, 2009.



# 2 NATIONAL ELECTRICITY MARKET



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

# 2 NATIONAL ELECTRICITY MARKET

This chapter considers:

- > features of the National Electricity Market
- > how the wholesale market operates
- > the demand for electricity by region, and electricity trade across regions
- > spot prices for electricity, including international 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 (ACT), Victoria, South Australia and Tasmania—that are physically linked by an interconnected transmission network. The NEM has around 270 registered generators, six state based transmission networks<sup>1</sup> (linked by crossborder interconnectors) and 13 major distribution networks that collectively supply electricity to end use customers. In geographic span, the NEM is the largest interconnected power system in the world. It covers a distance of 4500 kilometres, from Cairns in northern Queensland to Port Lincoln in South Australia and Hobart in Tasmania. The market has five regions: New South Wales, Queensland, Victoria, South Australia and Tasmania.

1 In New South Wales, there are two transmission networks: TransGrid and EnergyAustralia. EnergyAustralia's transmission network assets support the TransGrid network.

The NEM supplies electricity to almost nine million residential and business customers. In 2008–09 the market generated around 208 terawatt hours (TWh)<sup>2</sup> of electricity, with a turnover of \$9.4 billion (table 2.1).

Table 2.1	National	Electricity	v Market at	a glance

Participating jurisdictions	Qld, NSW, Vic, SA, Tas, ACT
NEM regions	Qld, NSW, Vic, SA, Tas
Registered capacity	47 418 MW
Number of registered generators	268
Number of customers	8.8 million
NEM turnover 2008–09	\$9.4 billion
Total energy generated 2008–09	208 TWh
National maximum winter demand 2008–09 (11 June 2009)	32 094 MW <sup>1</sup>
National maximum summer demand 2008–09 (29 January 2009)	35 551 MW

TWh, terrawatt hour; MW, megawatt; NEM, National Electricity Market. 1. The maximum historical winter demand of 34 422 MW occurred in 2008. Sources: AEMO; ESAA, *Electricity gas Australia*, Melbourne, 2009, p. 26.

#### 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 an end use customer can buy directly from the pool, few choose this option.

The market has no physical location, but is a virtual pool in which a central operator aggregates and dispatches supply bids to meet demand. The Australian Energy Market Operator (AEMO) has managed the operation of the NEM since 1 July 2009.<sup>3</sup> The Australian Energy Regulator (AER) monitors the market to ensure participants comply with the National Electricity Law and Rules. The design of the NEM reflects the physical characteristics of electricity:

- Supply must meet demand at all times because electricity cannot be economically stored.
   Coordination is thus required 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, meaning all sales of electricity must occur through a central trading platform. 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 4). Both market designs require the market operator to be informed of all sales so the physical delivery of electricity can be centrally managed.

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 explains the high price cap of \$10 000 per megawatt hour (MWh).<sup>4</sup> Generators earn their income in the NEM from market transactions, either in the spot or ancillary services<sup>5</sup> markets or by trading hedge instruments in financial markets<sup>6</sup> outside NEM arrangements.

4 The market price cap will increase from \$10 000 per MWh to \$12 500 per MWh on 1 July 2010.

<sup>2</sup> One 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.

<sup>3</sup> The National Electricity Market Management Company managed the market until 1 July 2009.

<sup>5</sup> AEMO operates a market for frequency control ancillary 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.

<sup>6</sup> See chapter 3.



#### 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.

In 1996 Queensland, New South Wales, the ACT, Victoria and South Australia agreed to pass the National

Electricity Law, which provided the legal basis to create the NEM. The market commenced in December 1998.

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) 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.

The Snowy region was abolished on 1 July 2008 through a regional boundary change. The area formerly covered by the region is now split between the Victoria and New South Wales regions of the NEM. The other regions—Queensland, South Australia and Tasmania—follow jurisdictional boundaries.

#### 2.2.1 Market operation

As market operator, AEMO coordinates a central dispatch process to manage the wholesale spot market. The process matches generator supply offers to demand in real time: AEMO 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.

Some generators bypass the central dispatch process, including some wind generators,<sup>7</sup> those not connected to a transmission network (for example, embedded generators) and those producing exclusively for their own use (such as in remote mining operations).

#### 2.2.2 Demand and supply forecasting

AEMO 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 customers each have relatively predictable patterns, including seasonal demand peaks related to extreme temperatures. Using data such as historical load (demand) patterns and weather forecasts, AEMO develops demand projections. Similarly, it estimates the adequacy of supply in its projected assessment of system adequacy (PASA) reports. It publishes a seven day PASA report that is updated every two hours, and a two year PASA report that is updated weekly. In response to the growth in wind generation and its impact on the forecasting process, AEMO recently introduced a wind forecasting system in the NEM. It aims to provide better forecasts that will improve dispatch efficiency, pricing, and network and security management.

7 From 31 March 2009 new wind and other intermittent generators must register under the new classification of 'semi-scheduled generator'. The generators must participate in the central dispatch process, including by submitting offers and by limiting their output if requested by AEMO.

#### 2.2.3 Central dispatch and spot prices

Market supply is based on the offers of generators to produce particular quantities of electricity at various prices for each of the 5 minute dispatch periods in a day. Generators must lodge offers ahead of each trading day. They can change their offers (rebid) at any time subject to those bids being in 'good faith'.

Generator offers are affected by a range of factors, including plant technology. Coal fired generators, for example, need to ensure their plants run constantly to cover their high start-up costs, and they may offer to generate some electricity at low or negative prices to guarantee dispatch.<sup>8</sup> Gas fired peaking generators face high operating costs and normally offer to supply electricity only when prices are high.

To determine which generators are dispatched, AEMO stacks the offer bids of all generators in ascending price order for each 5 minute dispatch period. It 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 5 minute interval is the offer price of the highest (marginal) priced megawatt (MW) of generation that must be dispatched to meet demand. In figure 2.1, the demand for electricity at 4.15 is about 350 MW. To meet this level of demand, generators 1, 2 and 3 are fully dispatched and generator 4 is partly dispatched. The dispatch price (or marginal price), therefore, is \$37 per MWh. By 4.20, demand has risen to the point where a fifth generator needs to be dispatched. This higher cost generator has an offer price of \$38 per MWh, which drives up the price to that level.

#### Figure 2.1

Illustrative generator offers (megawatts) at various prices



#### Source: AEMO.

A wholesale spot price is determined for each halfhour period (trading interval) and is the average of the 5 minute dispatch prices during that interval. In figure 2.1, the spot price in the 4.00–4.30 interval is about \$37 per MWh. This is the price that all generators receive for their supply during this 30 minute period, and the price that market customers pay for the electricity they use in that period. A separate spot price is determined for each region, accounting for the physical losses in the transport of electricity over distances and transmission congestion that can sometimes isolate particular regions from the national market (see 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. If, for example, suitable metering arrangements are available, then some customers may be able to reduce their consumption during peak demand periods when prices are high (see section 2.6). In the longer term, price movements also create signals for new investment (see sections 1.3 and 2.6).

8 The minimum allowed bid price is -\$1000 per MWh.

#### 2.3 Demand and capacity

Annual electricity consumption in the NEM rose from under 170 TWh in 1999–2000 to 208 TWh in 2008–09 (figure 2.2a). The entry of Tasmania in 2005 accounted for around 10 TWh. 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 2.2b shows seasonal peaks have risen nationally, from around 26 gigawatts (GW) in 1999 to over 35 GW in 2009. The volatility in the summer peaks reflects variations in weather conditions from year to year.

#### Figure 2.2a





Figure 2.2b

National Electricity Market peak demand



Sources: AEMO; AER.

76

Table 2.2 sets out annual electricity consumption across the NEM since 1999–2000. Reflecting its population base, New South Wales has the highest consumption of electricity, followed by Queensland and Victoria. Demand is considerably lower in the less populated regions of South Australia and Tasmania.

Figure 2.3 compares seasonal peak 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 has alternated between summer and winter peaking for several years.

#### 2.4 Trade across the regions

The NEM promotes efficient generator use by allowing trade in electricity among the five regions, which are linked by transmission interconnectors. Trade enhances the reliability of the power system by allowing the regions to draw on a wider pool of reserves to manage system constraints and outages.

Trade also provides economic benefits by allowing high cost generating regions to import electricity from lower cost regions. On a day of peak electricity demand in South Australia, for example, low cost baseload power from Victoria may provide a competitive alternative to South Australia's high cost peaking generators. The NEM means AEMO can dispatch electricity from lower cost regions and export it to South Australia until the technical capacity of the interconnectors is reached.

Figure 2.4 shows annual electricity consumption and trade across the regions in 2008–09. It also shows each region's generation capacity factor (the use of local generation capacity). The NEM's interregional trade relationships are also reflected in figure 2.5, which shows the net trading position of the regions since the NEM commenced.

	QLD	NSW	VIC	SA	TAS <sup>1</sup>	SN0WY <sup>2</sup>	NATIONAL
2008-09	52.6	79.5	52.0	13.4	10.1		207.9
2007-08	51.5	78.8	52.3	13.3	10.3	1.6	208.0
2006-07	51.4	78.6	51.5	13.4	10.2	1.3	206.4
2005-06	51.3	77.3	50.8	12.9	10.0	0.5	202.8
2004-05	50.3	74.8	49.8	12.9		0.6	189.7
2003-04	48.9	74.0	49.4	13.0		0.7	185.3
2002-03	46.3	71.6	48.2	13.0		0.2	179.3
2001-02	45.2	70.2	46.8	12.5		0.3	175.0
2000-01	43.0	69.4	46.9	13.0		0.3	172.5
1999-2000	41.0	67.6	45.8	12.4		0.2	167.1

Table 2.2 Annual electricity consumption in the National Electricity Market (terawatt hours)

1. Tasmania entered the market on 29 May 2005.

2. The Snowy region was abolished on 1 July 2008. Electricity consumption formerly attributed to Snowy is now reflected in the New South Wales and Victorian data. Source: AEMO.



#### Figure 2.3

Seasonal peak demand in the National Electricity Market

Sources: AEMO; AER.

Figures 2.4 and 2.5 show:

- > New South Wales is a net importer of electricity. It relies on local baseload generation, but has limited peaking capacity at times of high demand.<sup>9</sup> This puts upward pressure on prices in peak periods, making imports a competitive alternative. New South Wales was importing over 10 per cent of its electricity requirements from 2002–03 to 2006–07, but this rate fell to around 7 per cent in 2007–08 and 2008–09.
- > Victoria is a net exporter because it has substantial low cost baseload capacity.<sup>10</sup> This is reflected in the region's 62 per cent capacity factor—the highest for any region. In 2008–09 Victorian net electricity exports were equivalent to around 8 per cent of the state's consumption. Victoria tends to import mainly at times of peak demand when its regional capacity is stretched.

<sup>9</sup> The New South Wales region gained additional hydroelectric peaking capacity following the abolition of the Snowy region on 1 July 2008.

<sup>10</sup> The Victorian region gained additional hydroelectric peaking capacity on 1 July 2008 when the Murray generator was transferred from the Snowy region to Victoria.



'Capacity factor' refers to the proportion of local generation capacity in use. Sources: AEMO; AER.

78



Figure 2.5 Interregional trade as percentage of regional energy consumption

Sources: AEMO; AER.

- > Queensland's installed capacity exceeds its peak demand for electricity by around 3400 MW, making it a significant net exporter. Net exports from Queensland rose steadily from 2001–02, reaching around 13 per cent of the state's electricity consumption in 2006–07. Net exports fell to slightly below 10 per cent of consumption in 2008–09.
- South Australia, historically the most trade dependent region, imported over 25 per cent of its energy requirements in the early years of the NEM. This reflected the region's relatively higher fuel costs, resulting in high cost generation.
   New investment in generation—mostly in wind capacity—has significantly reduced South Australia's net imports since 2005–06. The state was a net exporter for the first time in 2007–08, but recorded net imports of around 2 per cent of electricity consumption in 2008–09.
- > Tasmania has been a net importer since its interconnection with the NEM in 2006. It imported over 25 per cent of its electricity requirements in 2008–09, partly because drought constrained its ability to generate hydroelectricity.

#### 2.4.1 Market separation

The NEM central dispatch process determines a separate spot price for each region of the NEM. In the absence of network constraints, interstate trade brings prices across the regions towards alignment. Due to transmission losses that occur when transporting electricity over distances, minor disparities across regional prices is normal. 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. Import capability may also be reduced when an interconnector is undergoing maintenance or an unplanned outage occurs. The availability of generation plant and the bidding behaviour of generators can also contribute to transmission congestion.

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

N

NATIONAL ELECTRICITY The NEM is considered aligned when electricity can flow freely among all regions. There may still be minor price differences across regions due to loss factors that occur in the transport of electricity. Figure 2.6 indicates the mainland NEM regions operated as an 'integrated' market—with price alignment across the regions—for around 70 per cent of the time in 2008–09. This was the lowest rate of market alignment since the NEM commenced.

While the extent of alignment indicates how effectively the market is working, external factors such as lightning and other extreme weather may restrict interconnector flows. More generally, significant investment would be needed to remove all congestion, even under normal operating conditions. Research by the AER indicates the economic costs of transmission congestion are relatively modest given the scale of the market (see section 5.7).

#### Figure 2.6





Note: Excludes Tasmania. Sources: AEMO; AER.

#### 2.4.2 Settlement residues

When there is price separation across 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. These settlement residues accrue to the market operator (AEMO).

Figure 2.7 charts the annual accumulation of interregional 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.

New South Wales recorded settlement residues ranging from around \$90 million to \$200 million each year from 2001–02 to 2006–07. This range reflects the region's status as the largest importer of electricity (in dollar and volume terms) in the NEM, which can make it vulnerable to price separation events. New South Wales settlement residues fell by around 75 per cent in 2007–08 as a result of more benign market conditions, but rose in 2008–09. High prices on 31 October 2008 contributed around half of the region's settlement residues for the year.

Conversely, South Australian residues increased from a low base to almost \$88 million in 2007–08 as a result of record summer prices in the region. While South Australian summer prices remained high in 2008–09, settlement residues fell closer to historical levels as summer prices also moved higher in Victoria. As net exporters, Queensland and Victoria tend not to accumulate large settlement residue balances.

Price separation creates risks for parties that contract across regions. To offer a risk management instrument, AEMO holds quarterly auctions to sell the rights to future residues. Section 5.7.3 explains the auction process.





Note: AEMO does not auction residues from Basslink, which is a market network service provider that earns income by arbitraging price differences between Tasmania and Victoria.

Sources: AEMO; AER.

#### 2.5 National Electricity Market prices

The central dispatch process determines a spot price for each NEM region every 30 minutes. As noted, prices can vary across regions as a result of losses in transportation and transmission congestion, which sometimes restricts interregional trade.

The AER closely monitors the market and reports weekly on wholesale and forward market activity. It also publishes more detailed analyses of extreme price events. Figure 2.8 charts quarterly volume weighted average prices since the NEM commenced, while table 2.3 sets out annual volume weighted prices. Figure 2.9 provides a more detailed snapshot of weekly prices since January 2007.

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. Drought, record peak demands and other factors led to average prices rising to record levels in 2006–07 and 2007–08.

Average prices in 2008–09 eased in all regions other than Tasmania (table 2.3). This reflected wetter conditions in parts of eastern Australia and, in 2009, the mildest winter on record in New South Wales, Victoria and South Australia. The milder winter temperatures drove lower winter peak demands in most regions. Combined winter peak demand for the NEM in 2009 was 32 094 MW—the lowest since 2006. This led to lower average winter prices in all mainland regions compared with last winter's averages, ranging from 26 per cent lower in New South Wales to 38 per cent lower in Victoria. In Tasmania, the average winter price increased by almost 70 per cent as a result of extreme price events in June 2009.

For the year overall, Queensland recorded its lowest prices since 2005–06. While prices fell sharply in South Australia, they remained high relative to those in other mainland regions.

Despite relatively benign market conditions, several extreme price events occurred in the first six months of 2009. These events occurred mostly in South Australia and Tasmania:

> Spot prices in South Australia exceeded \$5000 per MWh on 27 occasions in the early months of 2009. These events typically occurred on days of extreme temperatures, which led to a tight supply-demand balance. The bidding strategies of AGL Energy on most of these occasions led to South Australian prices rising to near the market cap of \$10 000 per MWh.





Sources: AEMO; AER.

Table 2.3	Weighted	average spot	electricity	prices (\$	per megawatt hou	ır)

	QLD	NSW	VIC	SA	TAS <sup>2</sup>	SN0WY <sup>3</sup>
2008-09	36	43	49	69	62	
2007-08	58	44	51	101	57	31
2006-07	57	67	61	59	51	38
2005-06	31	43	36	44	59	29
2004-05	31	46	29	39		26
2003-04	31	37	27	39		22
2002-03	41	37	30	33		27
2001-02	38	38	33	34		27
2000-01	45	41	49	67		35
1999-2000	49	30	28	69		24
1999 <sup>1</sup>	60	25	27	54		19

1. Six months to 30 June 1999.

2. Tasmania entered the market on 29 May 2005.

3. The Snowy region was abolished on 1 July 2008.

Source: AEMO.

AGL Energy owns the Torrens Island power station, which accounts for 40 per cent of South Australia's generation capacity. Transmission limits on importing electricity from Victoria mean, under certain conditions, that AGL Energy can price a significant proportion of its capacity at around the market cap and be guaranteed some of the high-priced capacity will be dispatched. On 28 January 2009, for example, AGL Energy bid around 800 MW of capacity—around 65 per cent of Torrens Island's summer capacity rating—at close to the price cap of \$10 000 per MWh.  > On 28 and 29 January 2009 extremely hot weather in South Australia and Victoria resulted in record demand. When combined with unplanned reductions in generation capacity and the outage of the Basslink interconnector on 29 January, this led to extreme prices and customer interruptions in both regions. The sustained high spot prices led to the cumulative price threshold being breached and pricing being administered in both regions for several days. The extreme temperatures also contributed to high prices in Tasmania on 29 and 30 January, with three spot prices in excess of \$5000 per MWh. In June 2009 the spot price in Tasmania exceeded \$5000 per MWh on 13 occasions. Reductions in output by Hydro Tasmania of its non-scheduled generation (mini hydro), in conjunction with its bidding strategy for the rest of its portfolio, was the significant driver in the majority of these outcomes. In addition to high energy prices, Tasmania's frequency control ancillary services were very highly priced in April 2009. The prices of some services reached \$5000 per MW for 13 hours over 1 April to 3 April, compared with typical prices of around \$2 per MW. Further sustained high price events occurred through to 17 April.

#### Figure 2.9



#### National Electricity Market—average weekly prices

AGL, AGL Energy; CPT, cumulative price threshold; Macquarie, Macquarie Generation; Hydro Tas, Hydro Tasmania. Note: Volume weighted prices. Sources: AEMO; AER. MARKET



## CHAPTER 2 NATIONAL ELECTRICITY MARKET

#### 2.6 Price volatility

Spot price volatility in the NEM reflects fluctuating supply and demand conditions. The market is sensitive to changes in these conditions, which can occur at short notice. Electricity demand can rise swiftly on a hot day, for example. Similarly, a generator or network outage can quickly increase regional spot prices. The sensitivity of the market to changing supply and demand conditions can result in considerable price volatility.

While figure 2.9 indicates volatility in weekly prices, it masks more extreme spikes that can occur during half hour trading intervals. On occasion, half hour spot prices approach the market cap of \$10 000 per MWh. The main indicator of the incidence of extreme price events is the number of trading intervals during which the price is above \$5000 per MWh (figures 2.10 and 2.11)

The AER draws on its market monitoring to publish weekly reports on market outcomes and more detailed reports when the electricity spot price exceeds \$5000 per MWh.

The incidence of trading intervals with prices above \$5000 per MWh has increased since the NEM commenced (figure 2.10). The number of events rose significantly from 21 in 2004–05 to 76 in 2007–08. There were 68 events in 2008–09, of which 27 occurred in South Australia and 16 occurred in Tasmania in the first six months of 2009. The bidding behaviour of AGL Energy and Hydro Tasmania respectively contributed to many of these price outcomes. Figure 2.11 sets out the data on a quarterly basis.

Many factors can cause price spikes. While the cause of a high price event is not always clear, underlying causes may 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 cheaper imports into a region
- > a lack of effective competition in certain market conditions
- > a combination of factors.

#### Figure 2.10

Trading intervals above \$5000 per megawatt hour— National Electricity Market



Note: Each trading interval is a half hour. Sources: AEMO; AER.

Table 2.4 summarises key features of extreme price events in 2008–09, noting the regions in which they occurred and indicating causes. The most common causes were:

- > extreme weather
- network flow limits placed on particular transmission lines and interconnectors
- > network outages
- > generator bidding behaviour.

On one occasion, an error by AEMO contributed to high spot prices.

Price spikes can have a material impact on market outcomes. If prices approach \$10 000 per MWh for just three hours in a year, the average annual price may rise by almost 10 per cent. Generators and retailers typically hedge against this risk by taking out contractual arrangements in financial markets (see chapter 3).

Extreme price events help to provide solutions to tight supply conditions. In particular, they create incentives to invest in peaking generation plant for operation during periods of peak demand.

Extreme price events may also create incentives for retailers to contract with customers to manage their demand in peak periods. A retailer may, for example, offer a customer financial incentives to reduce



#### Figure 2.11 Trading intervals above \$5000 per megawatt hour (quarterly)—National Electricity Market

Sources: AEMO; AER.

consumption at times of high system demand, to ease price pressures. Effective demand management requires suitable metering arrangements to enable customers to manage their consumption. In 2009 AEMO estimated 195 MW of committed demand-side response in the NEM, with a further 559 MW of less firm capacity available.<sup>11</sup>

In April 2009 the Australian Energy Market Commission released a draft review of demand-side participation in the NEM.<sup>12</sup> It found the current framework allows for efficient participation, but also found a few minor barriers that a change in the Electricity Rules will address.

At the small customer level, the Council of Australian Governments agreed in 2007 to a progressive rollout of 'smart' electricity meters (where the benefits outweigh costs) to encourage demand-side response (see section 6.8.2).

#### 2.7 Market investigations

The AER monitors activity in the spot market to screen for issues of non-compliance with the Electricity Rules. In addition to reporting on all extreme price events in the NEM, it conducts more intensive investigations where this is warranted.

In 2008 the AER launched separate investigations into whether Stanwell (a Queensland generator) and AGL Energy (in relation to its South Australian generators) acted 'in good faith', as contemplated under the Rules, when they rebid capacity during periods of high prices in early 2008. While bidding capacity at high prices is not a breach of the Rules, generators are required to make capacity offers and any rebids in 'good faith.' In its investigation findings published on 12 May 2009, the AER found that AGL Energy's bidding was not in breach of the Rules.

The AER investigation into the rebidding behaviour of Stanwell led to it instituting proceedings in the Federal Court, Brisbane. The AER has alleged that several of Stanwell's rebids of offers to generate electricity on 22 and 23 February 2008 were not made in 'good faith'. The AER is seeking orders including declarations, civil penalties, a compliance program and costs. The matter has been set down for trial in June 2010.

11 AEMO, Electricity statement of opportunities, Melbourne, 2009, p. 67.

12 AEMC, Demand-side participation in the National Electricity Market, draft report, Sydney, April 2009.

DATE OR PERIOD	REGIONS	NO. OF EVE <u>NTS</u>	CAUSES IDENTIFIED BY THE AER
23 July 2008	New South Wales, Queensland, Victoria and South Australia	4	Unplanned outages of two Hazelwood to Loy Yang transmission lines in the LaTrobe Valley (Victoria) left only one line in operation between Loy Yang and Tasmania and the rest of the market. Very high frequency control ancillary services were required to manage this. In addition, generation at Loy Yang was constrained and exports from Tasmania via Basslink were reduced to zero.
31 October 2008	New South Wales	7	High temperatures in Sydney led to above forecast demand. Around 4300 MW of generation was unavailable (mostly unplanned) and import capability into New South Wales was also lower than forecast.
20 November 2008	Queensland	1	Unplanned reductions in Queensland generator availability occurred, in combination with low import capability and higher than forecast demand. Millmerran Energy Trader and Stanwell Corporation then rebid low priced capacity at close to the price cap.
13 January 2009	South Australia	8	AGL's bidding behaviour, high temperatures and high demand at a time of lower than forecast import capability. This required the dispatch of high priced generation.
15 January 2009	New South Wales	1	Temperatures in western Sydney reached 43 degrees, leading to record summer demand. In addition, around 2100 MW of New South Wales generation was unavailable and import capability was reduced as a result of planned network outages. New South Wales generators reacted to the tight supply–demand balance by rebidding capacity into higher price bands.
19 January 2009	South Australia	6	For five trading intervals, high demand caused by extreme temperatures led to the dispatch of high priced capacity. Rebidding by AGL Energy shifted a significant amount of required capacity from prices below \$101 per MWh to the price cap. Dispatch of this capacity set the spot price for two and a half hours.
			In the other interval, an incorrect input into the dispatch process led to the spot price exceeding \$5000 per MWh.
28–29 January 2009	South Australia and Victoria	24	Record demand (due to extreme weather in South Australia and Victoria), combined with unplanned reductions in generation capacity and the unplanned outage of the Basslink interconnector on 29 January, required the dispatch of high priced generation. The extreme conditions led to customer interruptions in both regions on 29 January. The sustained high prices led to the cumulative price threshold being breached and pricing being administered in both regions for several days.
29–30 January 2009	Tasmania	3	On 29 January one spot price exceeded \$5000 per MWh when Hydro Tasmania rebid a significant amount of capacity from below \$1600 per MWh to above \$5000 per MWh. On 30 January two spot prices exceeded \$5000 per MWh as a result of tight supply in southern Australia combined with high priced generation offers in Tasmania.
31 March 2009	South Australia	1	An unplanned outage at South Australia's largest generator—Northern power station—led to the dispatch of high priced generation.
1 June 2009	Tasmania	1	Hydro Tasmania rebid a significant amount of capacity from prices below \$300 per MWh to prices above \$9000 per MWh. It can set the spot price in Tasmania, even at moderate levels of demand.
10–19 June 2009	Tasmania	12	Eleven events occurred when Hydro Tasmania made sudden and repeated reductions in the output of its non-scheduled generators, requiring the dispatch of other generation in its portfolio. At the same time, Hydro Tasmania made a step change in the amount of capacity it was offering at prices above \$5000 per MWh. The other event occurred when Hydro Tasmania bid a significant amount of capacity at above \$5000 per MWh for the trading interval.
			The sustained high prices caused a breach of the cumulative price threshold for the first time ever in Tasmania, and led to administered pricing for several days.

#### Table 2.4 Price events above \$5000 per megawatt hour—National Electricity Market, 2008–09



# 3 ELECTRICITY FINANCIAL MARKETS



Spot price volatility in the National Electricity Market can cause significant risk to physical market participants. While generators face a risk of low prices having an impact on earnings, retailers face a complementary risk that prices may rise to levels they cannot pass on to their customers. Market participants commonly manage their exposure to volatility by entering 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 over-the-counter markets 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 they have significant links with wholesale and retail activity. Levels of contracting and forward prices in the financial markets can, for example, affect generator bidding in the National Electricity Market (NEM). Similarly, financial markets can influence retail competition by providing a means for new entrants to manage price risk. 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 (derivatives) to manage forward price risk in wholesale electricity markets.<sup>1</sup> 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 between contracting participants.

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

- > over-the-counter (OTC) markets, comprising direct transactions between counterparties, often with the assistance of a broker
- > the exchange traded market on the Sydney Futures Exchange (SFE).<sup>2</sup>

#### 3.1.1 Over-the-counter markets

The OTC markets allow wholesale electricity 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 wholesale electricity market. Other OTC contracts are arranged with the assistance of brokers that post bid (buy) and ask (sell) prices on behalf of their clients. In 2008–09 around 62 per cent of OTC contracts were arranged through a broker.<sup>3</sup> Financial intermediaries and speculators add market depth and liquidity by quoting bid and ask prices, taking trading positions and 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, market participants usually modify contract terms to suit their needs. This means OTC products can provide flexible solutions through a variety of structures.

The *Financial Services Reform Act 2001* (Cwlth) 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.

#### 3.1.2 Exchange traded futures

Derivative products such as electricity futures and options are traded on registered exchanges. In Australia, electricity futures products developed by d-cyphaTrade are traded on the SFE. Participants (licensed brokers) buy and sell contracts on behalf of clients that include generators, retailers, speculators such as hedge funds, and banks and other financial intermediaries.

*Normal trades* on the SFE are made by matching buy and sell offers for contracts through the exchange. Prices struck through normal trades are used to determine end-of-day contract settlement prices.

*Block trades* are negotiated bilaterally—either via brokers or directly between counterparties—before being registered as a centrally cleared contract position on the SFE. This trading mechanism provides market participants with the flexibility to negotiate deals bilaterally yet receive the risk mitigation benefits of contracting with the SFE Clearing Corporation. Similarly, *exchange for physical* contracts enable participants to eliminate credit default risk by converting OTC contracts into exchange traded contracts. Participants are limited to combinations of products specified on the SFE. Block trades and exchange for physical contract prices are not used to determine end-of-day contract settlement prices.

<sup>1</sup> Spot prices in the wholesale market can vary between -\$1000 per megawatt hour (MWh) (the price floor) and \$10 000 per MWh (the price cap). To manage risk resulting from volatility in the spot price, 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.

<sup>2</sup> In 2006 the Sydney Futures Exchange merged with the Australian Stock Exchange. The merged business operates as the Australian Securities Exchange.

<sup>3</sup> AFMA, 2008 Australian financial markets report, Sydney, 2008 and supporting 'Full report data' spreadsheet.

Figure 3.1 shows that over half of trades processed through the SFE are block trades. Only a small percentage of trades are exchange for physical contracts.

Exchange trading on the SFE differs from OTC trading in a number of ways:

- > 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 is the central counterparty to transactions and applies daily mark-to-market cash margining to manage credit default risk.<sup>4</sup> Exchange clearing houses, such as the SFE Clearing Corporation, are regulated and are subject to prudential requirements to mitigate credit default risks. This offers an alternative to OTC trading, where 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 (for example, breaches due to revaluations of existing bilateral hedge obligations or credit downgrades of counterparties).

#### 3.1.3 Regulatory framework

Electricity financial markets are subject to a regulatory framework that includes the *Corporations Act 2001* (Cwlth) and the *Financial Services Reform Act 2001* (Cwlth). The Australian Securities and Investments Commission is the principal regulatory agency. Amendments to the Corporations Act in 2002 extended insider trading legislation and the disclosure principles expected of securities and equity related futures to electricity derivative contracts.

#### Figure 3.1

Composition of trading in electricity derivatives —Sydney Futures Exchange



Block **56%** EFP **3%** Normal **41%** EFP, exchange for physical. Source: d-cyphaTrade.

Market participants must also comply with standards issued by the Australian Accounting Standards Board (AASB). In particular, AASB 139 requires companies' hedging arrangements to pass an effectiveness test to qualify for hedge accounting. The standards also outline financial reporting obligations such as markto-market valuation of derivative portfolios, and they require financial derivative revaluations to be benchmarked against observable market prices and adjusted for embedded credit default risk.

Further regulatory overlays in electricity derivative markets include the following:

- > The Corporations Act requires OTC market participants to have an Australian Financial Services licence or exemption.
- > Exchange based transactions are subject to the operating rules of the SFE.

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

#### Figure 3.2 Relationship between the National Electricity Market and financial markets



AEMO, Australian Energy Market Operator. Source: Energy Reform Implementation Group.

#### 3.1.4 Relationship with the National Electricity Market

Figure 3.2 illustrates the relationship between the financial markets and the physical trading of electricity in the 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 and availability of supply contracts that it offers to customers.

The settlement process in the NEM, combined with hedging contracts, gives rise to circular cash flows or contracts for difference payments. The NEM settlement arrangements also allow for re-allocations, whereby an off-market financial commitment (such as a hedge contract between participants) is netted off against settlements in the physical market. This mechanism has not been widely used. The Australian Energy Market Commission (AEMC) is reviewing the potential for further integrating the wholesale and financial electricity markets to minimise circular cash flows and reduce the prudential burden on market participants.<sup>5</sup> Options include:

- > allowing a NEM participant to offset its prudential requirements using its futures contract margin payments
- > using futures prices to determine a participant's prudential obligations, rather than relying on historical wholesale price outcomes.

#### 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, plus premiums to cover credit default risk and market risk.

5 AEMC, Review into the role of hedging contracts in the existing NEM prudential framework, framework and issues paper, Sydney, March 2009.

INSTRUMENT	DESCRIPTION
Forward contracts	An agreement to exchange the NEM spot price in the future for an agreed fixed price. Forwards are called swaps in the OTC markets and futures on the SFE.
<ul> <li>Swaps (OTC market)</li> </ul>	OTC swap settlements are typically paid or received weekly in arrears (after the spot price is known) based on the difference between the spot price and the previously agreed fixed price.
> Futures (SFE)	SFE electricity futures and options settlements are paid or received daily based on mark-to-market valuations. SFE futures are finally cash settled against the average spot price of the relevant quarter.
Options	A right—without obligation—to enter into a transaction at an agreed price in the future (exercisable option) or a right to receive cash flow differences between an agreed price and a floating price (cash settled option).
> Cap	A contract through which the buyer earns payments when the pool price exceeds an agreed price. Caps are typically purchased by retailers to place a ceiling on their effective pool purchase price in the future.
> Floor	A contract through which the buyer earns payments when the pool price is less than an agreed price. Floors are typically purchased by generators to ensure a minimum effective pool sale price in the future.
<ul> <li>Swaptions or futures options</li> </ul>	An option to enter a swap or futures contract at an agreed price and time in the future.
> Asian options	An option through which the payoff is linked to the average value of an underlying benchmark (usually the NEM spot price) during a defined period.
<ul> <li>Profiled volume options for sculpted loads</li> </ul>	A volumetric option that gives the holder the right to purchase a flexible volume in the future at a fixed price.

Table 3.1 Common electricity derivatives in over-the-counter and Sydney Futures Exchange markets

NEM, National Electricity Market; OTC, over-the-counter; SFE, Sydney Futures Exchange

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—on purchase/sale of the derivative or, in the case of an option, if the option is exercised. The following section describes some instruments in more detail.

#### 3.2.1 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. Each contract relates to a nominated time of day in a particular region. On the SFE, contracts are quoted for quarterly base and peak contracts, for up to four years into the future.<sup>6</sup>

A retailer may, for example, enter an OTC contract to buy 10 megawatts (MW) of Victorian peak load in the fourth quarter of 2009 at \$40 per megawatt hour (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 \$40 per 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 \$40 per MWh. In effect, the contract locks in a price of \$40 per MWh for both parties.

A typical OTC swap may involve a retailer and generator contracting with one another—directly or through a broker—to exchange the NEM spot price for a fixed price, thereby reducing 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. The SFE Clearing Corporation is the central counterparty to SFE transactions. As noted, exchange trading is more transparent in terms of prices and trading volumes.

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

While the SFE tends to offer a narrower range of instruments than offered by the OTC market,<sup>7</sup> up to 3000 futures and options products are listed on the SFE at any time.

#### 3.2.2 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 if the underlying market moves adversely to the agreed contract price. An option gives the holder the right—without obligation—to enter a contract at an agreed price, volume and term in the future. The buyer pays a premium to the option seller for this added flexibility.

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

Commonly traded options in the electricity market are caps, floors and collars.<sup>8</sup> 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. A cap at \$300 per MWh (the cap most commonly traded in Australia), for example, ensures a buyer using the cap to hedge a natural 'short' retail spot market position will pay no more than \$300 per MWh for the agreed volume of electricity, no matter how high the spot price may rise. In Australia, a cap is typically sold for a nominated quarter—for example, January–March 2010. Base cap contracts are listed two years ahead on a quarterly basis on the SFE and regularly trade in full year strips (comprising a bundle of the four quarters of the year).

By contrast, a floor contract struck at \$40 per MWh will ensure a minimum price of \$40 per MWh for a floor 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 contract combines a cap and floor to set a price band in which the parties agree to trade electricity in the future.

The range and diversity of products is expanding over time to meet the requirements of market participants.

#### 3.2.3 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 variation 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, a retailer can also earn windfall gains.

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

<sup>7</sup> The OTC market can theoretically support an unlimited range of bilaterally negotiated product types.

<sup>8</sup> 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 the option is to be exercised.

	2002-03	2003-04	2004-05	2005-06	2006-07	2007-08	2008-09
Total trade (TWh)	7	29	24	55	243	241	301
Increase (per cent)		341	-19	129	345	-1	25

#### Table 3.2 Trading volume in electricity derivatives—Sydney Futures Exchange

TWh, terawatt hours.

Source: d-cyphaTrade.

#### 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 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.

Indicators of liquidity in the electricity derivatives market include:

- > the volume and value of trade
- > open interest in contracts
- > the transparency of pricing
- > the number and diversity of market participants
- > the number of market makers and the bid-ask spreads they quote
- > the number and popularity of products traded
- > the degree of vertical integration between generators and retailers
- > the presence of financial intermediaries in the market.

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

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

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

#### 3.4.1 Sydney Futures Exchange

Financial market vendors such as d-cyphaTrade publish data on electricity derivative trading on the d-cypha SFE electricity futures market. Table 3.2 and figure 3.3 illustrate volume trends. Trading levels accelerated from 2005–06, with 345 per cent growth in 2006–07. They flattened in 2007–08, but again rose in 2008–09, when they exceeded 300 terawatt hours (TWh) for the first time (despite relatively flat underlying electricity demand).

In 2008–09 Queensland accounted for 35 per cent of traded volume, followed by Victoria (34 per cent) and New South Wales (30 per cent). Liquidity in South Australia has remained low since 2002, accounting for around only 1 per cent of volume (figure 3.4).

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 increased from around 16 per cent of traded volumes in 2007–08 to around 38 per cent in 2008–09.<sup>9</sup>

Figure 3.5 shows trading volumes for 2010 contracts recorded a step increase from around August 2008, with significant activity in options. The swing towards options applied to all products and continued throughout 2008–09. It might have reflected the need

9 d-cyphaTrade, Energy focus, FY review 2008/2009, Sydney, 2009.



Figure 3.3 Regional trading volume in electricity derivatives—Sydney Futures Exchange

Source: d-cyphaTrade.

for market participants to hedge in an increasingly uncertain market, particularly given the planned introduction of the Carbon Pollution Reduction Scheme (CPRS) in 2010. Trading in options remained strong, however, despite the Australian Government's decision to delay introducing the CPRS to 2011.

During 2008-09 the d-cypha SFE electricity options market grew to become one of the largest electricity options markets in the world, trading 115 TWh—the equivalent of 58 per cent of underlying NEM demand.

Figure 3.6 shows the composition of futures and options trade on the SFE in 2008–09 by maturity date. The SFE trades quarterly futures and options out to four years ahead, compared with three years in many overseas markets.<sup>10</sup> Liquidity was highest for contracts with an end date between six months and two years from the trade date. Only a relatively small number of open contracts have an end date beyond 2.5 years. This timing is consistent with the trading preferences of speculators and the time horizons of electricity retail contracts, of which the majority are negotiated for one year and which rarely run beyond three years. Some retailers do not lock in forward hedges beyond the term of existing customer contracts.

#### Figure 3.4

Regional shares of trading volume in electricity derivatives—Sydney Futures Exchange, 2008–09



CHAPTER 3 ELECTRICITY FINANCIAL MARKETS

Figure 3.5 Traded volume for 2010 contracts—Sydney Futures Exchange



Source: d-cyphaTrade.



#### Figure 3.6



Source: d-cyphaTrade.

Figure 3.7 illustrates open interest in electricity futures on the SFE over time. Open interest refers to the total number of futures and option contracts that have been entered and remain open—that is, have not been exercised, expired or closed out—at a point in time. An increase in open interest typically accompanies a rise in trading volumes and reflects underlying demand growth. As figure 3.7 illustrates, open interest for SFE electricity futures increased from 2002 to late 2008, before levelling out over the remainder of 2008–09. The number of open contracts rose from around zero in 2002 to over 52 000 in June 2009.

54 000 48 000 Number of contracts 42 000 36 000 30 000 24 000 18 000 12 000 6 0 0 0 Dec Sep 2003 Mar 2003 Jun 2003 Sep 2007 /ar 2007 )ec 2003 1ar 200, un 2002 ep 2002 1ar 2006 un 2006 un 2007 ec 2004 lar 2005 ın 2005 p 2006 p 2005 ec 2005 p 2008 r 2008 r 2009 2007 2009 2002 Six month moving average

Figure 3.7 Open interest on the Sydney Futures Exchange

Source: d-cyphaTrade.

#### 3.4.2 Over-the-counter markets

Data on liquidity in the OTC markets are limited because transactions are visible only 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. It reports that most, but not all, participants respond to the survey. The AFMA data will capture a particular OTC transaction if at least one party to the trade participates in the survey.

As figure 3.8 indicates, total OTC trades declined from around 235 TWh in 2002–03 to around 177 TWh in 2005–06. This trend was reversed in 2006–07, with turnover increasing by more than 90 per cent to around 337 TWh. Volumes remained above 300 TWh in 2007–08 but fell significantly to around 208 TWh in 2008–09.

On a regional basis, trading volumes rose by more than 70 per cent in 2008–09 in Queensland, accounting for around 44 per cent of trade across all regions (up from around 17 per cent in 2007–08). Turnover remained steady in South Australia, but fell by 65 per cent in Victoria and 40 per cent in New South Wales.

As in 2007–08 the bulk of OTC trade in 2008–09 was in swaps (around 65 per cent) and caps (around 20 per cent). Swaptions and other forms of options made up the balance (figure 3.9).

Figure 3.8 Regional trading volumes—over-the-counter market



Source: AFMA, 2009 Australian financial markets report, Sydney, 2009.

#### Figure 3.9

Trading volumes, by derivative type over-the-counter market



Source: AFMA, 2009 Australian financial markets report, Sydney, 2009.
#### 3.4.3 Aggregate trading volumes

Table 3.3 aggregates volumes of electricity derivatives traded in OTC markets and on the SFE, and compares these volumes with underlying demand for electricity in the NEM. The data are a simple aggregation of AFMA data on OTC volumes and d-cyphaTrade data on exchange trades. The results must be interpreted with some caution, given the AFMA data are based on a voluntary survey and are not subject to independent verification, and thus could omit transactions between survey non-participants (although AFMA considers the survey captures most OTC activity).

Derivative trading volumes can exceed 100 per cent of NEM demand, because some financial market participants take positions independent of physical market volumes and regularly re-adjust their contracted positions over time.

Based on the available data, the volume of financial trading in the SFE in 2008-09 exceeded volumes in the OTC market for the first time. The share of derivative trading in OTC markets declined from 97 per cent in 2001-02 to just 41 per cent in 2008-09. As table 3.3 indicates, OTC trades in 2008-09 were equivalent to 105 per cent of NEM demand, compared with a record 174 per cent in 2006-07. Volumes on the SFE rose from near zero in 2001-02 to levels equivalent to over 150 per cent of NEM demand in 2008-09. Across the combined OTC and exchange markets, trading volumes in 2008-09 were almost 260 per cent of NEM demand, down from almost 300 per cent in 2006-07 but still well above volumes in the preceding years.

There are a number of reasons for the relatively 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 might have raised confidence in exchange based trading. In addition, d-cyphaTrade, in conjunction with the SFE, redesigned the product offerings in 2002 to tailor them more closely to market

### Table 3.3Volumes traded in over-the-counter marketsand the Sydney Futures Exchange

	OTC (TWH)	OTC (% OF NEM DEMAND)	SFE (TWH)	SFE (% OF NEM DEMAND)	TOTAL (% OF NEM DEMAND)
2001-02	168	96	0	0	96
2002-03	235	131	7	4	135
2003-04	219	118	29	16	134
2004-05	199	106	24	13	118
2005-06	177	92	55	28	120
2006-07	337	174	243	124	298
2007-08	304	156	241	123	279
2008-09	208	105	301	153	258

NEM, National Electricity Market; OTC, over-the-counter; SFE, Sydney Futures Exchange; TWh, terawatt hours.

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

Sources: AEMO; AFMA; d-cyphaTrade.

requirements. These changes have encouraged greater depth in the market, including the entry of financial intermediaries.

The increase in trading volumes on the SFE has also been driven by some trading parties seeking to minimise mark-to-market OTC credit exposures. This issue became more acute in the difficult economic conditions in 2008–09, where a perception of increased financial risk for energy market participants might have accelerated the shift from OTC to SFE trading.

Figure 3.10 charts regional trading volumes in both the OTC and SFE sectors as a percentage of regional NEM demand. Trading volumes were generally equivalent to around 100–150 per cent of regional NEM demand in Queensland, New South Wales and Victoria from 2002–03 to 2005–06. Volumes rose sharply in 2006–07 to 370 per cent of NEM demand in Queensland, 330 per cent in Victoria, 250 per cent in New South Wales and 180 per cent in South Australia. In 2008–09 only Queensland experienced growth in trading volumes relative to regional NEM demand, reaching a record for the region of almost 375 per cent. Volumes in other regions were below levels for the past two years.

100



Figure 3.10 Regional trading volumes as a percentage of regional National Electricity Market demand

OTC, over-the-counter; SFE, Sydney Futures Exchange. Sources: AEMO; AFMA; d-cyphaTrade.

The SFE trading volumes in 2008–09 exceeded OTC volumes in all regions except South Australia—the first time this has occurred in Victoria and New South Wales. Victoria's SFE trades accounted for over two thirds of regional trading volumes. In Queensland and New South Wales, SFE trade accounted for around 54 per cent and 61 per cent of trading volumes respectively. In South Australia, SFE trade fell from a high of 41 per cent in 2006–07 to 23 per cent in 2008–09.

A PricewaterhouseCoopers survey of market participants in 2006 raised possible reasons for poor liquidity in South Australia's financial markets. Reasons cited included the relatively small scale of the South Australian electricity market; perceptions of risk associated with network interconnection, generation capacity and extreme weather; and perceptions of high levels of vertical integration.<sup>11</sup>

#### 3.5 Price transparency and bid-ask spread

While trading volumes and open interest indicate 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 2008–09 most spreads for base futures products were less than \$3. Spreads are generally higher in the market for peak futures, which tends to be less liquid.

#### 3.6 Number of market participants

Ownership consolidation, such as vertical integration across the generation and retailer sectors, can affect participation in financial markets. Vertical integration can reduce a company's activity in financial markets by increasing its internal capacity offset risk.

11 PricewaterhouseCoopers, Independent survey of contract market liquidity in the National Electricity Market, Sydney, 2006, p. 28.

The three largest private energy retailers—Origin Energy, AGL Energy and TRUenergy-are moving towards portfolios more balanced between generation and retail assets. In 2007 AGL Energy acquired the 1260 MW Torrens Island power station in South Australia from TRUenergy, in exchange for the Hallett power station (150 MW) and a cash sum. Origin Energy is quickly expanding its generation portfolio, commissioning the Uranquinty power station (650 MW) and expanding its Quarantine plant (130 MW) in 2008-09. It has also committed to a further 1250 MW of gas fired generation in Queensland and Victoria. All three businesses also have ownership interests in Australian wind farms. In addition, major generator International Power operates a retail business in Victoria and South Australia (trading as Simply Energy) and has achieved significant market penetration.

While integration might have reduced the number of generators and retailers in Australia's financial markets, new entry by financial intermediaries continues to add depth to the market.

#### 3.7 Price outcomes

Base futures account for most SFE trading volumes and open interest positions. Accordingly, the following discussion of price outcomes focuses on base futures. Prices for peak futures tend to be higher than for base futures, but follow broadly similar trends.<sup>12</sup>

Figure 3.11 shows average price outcomes for electricity base futures, as reflected in the National Power Index (NPI). The index is published by d-cyphaTrade for each calendar year and represents a basket of the electricity base futures listed on the SFE for New South Wales, Victoria, Queensland and South Australia. It is calculated as the average daily settlement price of base futures contracts across the four regions for the four quarters of the relevant calendar year. The NPI data are available from June 2006 and are published daily. d-cyphaTrade also publishes a Eastern Power Index that excludes South Australian futures.



#### Figure 3.11

National Power Index, 2008–10

Source: d-cyphaTrade.

12 Base futures cover 0.00 to 24.00 hours, seven days per week. Peak futures cover 7.00 am to 10.00 pm Monday to Friday, excluding public holidays.

Figure 3.11 shows base futures prices were fairly flat throughout 2006, trading between \$35 and \$40 per MWh, before rising sharply in the first half of 2007. Prices for the 2007 calendar year basket peaked in June 2007 at close to \$100 per MWh. This peak mirrored high prices in the physical electricity market, caused by tight supply-demand conditions (see section 2.5). Futures prices also rose sharply for the 2008 calendar year, but less so for later years (reflecting expectations that the tight supply-demand conditions at that time would be relatively short term).

A return to more benign conditions in the physical electricity market led to an easing of 2007 and 2008 base futures prices in the summer of 2007–08. Prices converged at around \$50–55 per MWh over 2008. Prices fell further over the first half of 2009, to less than \$45 per MWh for 2009 calendar year base futures. For the 2010 calendar year, base futures were trading at around a \$5 premium over the 2009 product. But following the announcement in May 2009 of a delay in the introduction of the CPRS from 2010 to 2011, the premium for 2010 contracts fell from a high of around \$6–7 per MWh to \$2–3 per MWh at June 2009.

In general, contract markets often trade at a premium to the physical spot market for an underlying commodity. On average, base futures prices on the SFE traded at a fairly constant premium over NEM spot prices of around \$2 per MWh over the past four years.<sup>13</sup>

#### 3.7.1 Future forward prices

Figure 3.12 provides a snapshot in June 2009 of forward prices for quarterly base futures on the SFE for quarters up to two years from the trading date. These forward prices are often described as forward curves. The first four quarters of a forward curve are the prompt quarters. For comparative purposes, forward prices in June 2008 are also provided.

In June 2009 prices were generally down on the levels of 2008. This might have reflected lower demand projections for the coming year (particularly for summer) and the commissioning in 2008–09 of almost 2500 MW of new generation capacity. South Australia was the exception, with generally higher futures prices in 2009 than in 2008. This may indicate market concerns that high prices in South Australia's physical electricity market over the past two summers—as a result of high temperatures, interconnector constraints and opportunistic bidding by generators—may recur.

Figure 3.12 also illustrates that futures prices tend to be higher for the first quarter (Q1, January–March) than for other quarters. This reflects the tendency for NEM spot prices to peak in summer—when hot days lead to high demand for air conditioning, tightening the electricity supply–demand balance—and illustrates the links between derivative prices and underlying NEM wholesale prices.

The introduction of the CPRS is expected to put upward pressure on wholesale prices, as evident in rising forward prices from the third quarter of 2011 (relative to the same quarters in the previous year). For most regions, an initial price shift of around \$5-6 per MWh was evident for the third and fourth quarters of 2011, rising to \$10-14 in 2012. In Victoria, there is a larger increase in prices for the first quarter of 2012, perhaps reflecting concerns that the supply-demand balance in the electricity market may be tight at that time unless planned new capacity such as Origin Energy's 518 MW plant at Mortlake are operational. Poor liquidity in South Australian futures products makes it difficult to assess market expectations for that region.

While futures contracts typically relate to a specific quarter of a year, contracts are increasingly being traded as calendar year strips, comprising a 'bundle' of the four quarters of the year. This tendency is more pronounced for contracts with a starting date at least one year from the trade date. Figure 3.13 charts prices in June 2009 for calendar year futures strips to 2012. In June 2009 all regions had forward curves in strong contango—that is, prices are higher for contracts in the later years.

13 Based on a comparison of time weighted calendar year wholesale market spot prices to the average NPI value for each calendar year.





Source: d-cyphaTrade.





Source: d-cyphaTrade.

This is indicative of market expectations that price risk may be greater in the medium to longer term, and is consistent with an expectation that the CPRS may increase pool prices from 2011. The market may also be factoring in assessments of supply adequacy in some regions. South Australian prices are considerably above those for other regions, perhaps reflecting ongoing concerns about price risk in the wholesale market.

### 3.8 Price risk management—other mechanisms

Aside from financial contracts, other mechanisms can 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. The New South Wales Government has announced it will phase out ETEF over 2010–11.
- > Auctions of settlement residues allow for some financial risk management in interregional trade, although the effectiveness of this instrument has been debated (see section 5.7).



## 4 BEYOND THE NATIONAL ELECTRICITY MARKET



Western Australia and the Northern Territory have electricity markets that are not interconnected with the National Electricity Market. Western Australia introduced a new wholesale electricity market in 2006. The Northern Territory has no wholesale market competition.

## 4 BEYOND THE NATIONAL ELECTRICITY MARKET

#### 4.1 Western Australia's electricity system

Reflecting Western Australia's geography, industry and demographics, the state has several distinct electricity infrastructure systems (figure 4.1). The South West Interconnected System (SWIS) supplies 840 000 retail customers in the south west, including Perth. It has 5134 megawatts (MW) of installed generation capacity, 6000 kilometres of transmission lines and 85 000 kilometres of distribution lines. Western Australia introduced a wholesale electricity market in the SWIS in September 2006 (see section 4.5).

The North West Interconnected System (NWIS) operates in the north west of the state and centres on the industrial towns of Karratha and Port Hedland, and resource centres. It has a generation capacity of about 400 MW, mainly fuelled by natural gas. Given its small scale, the NWIS has no foreseeable plans to adopt a wholesale market in the manner of the SWIS. In addition, 29 non-interconnected distribution systems operate around towns in rural and remote areas beyond the SWIS and NWIS networks.

## 4.2 Electricity reform in Western Australia

In 1993, when Australian governments decided to create a national electricity market, it was considered impractical for Western Australia to join. Geography dictated that the state's networks could not physically interconnect with the other jurisdictions.

Consistent with the eastern and southern states, Western Australia's electricity industry was historically dominated by a single, vertically integrated utility under government ownership. Western Australia retained this structure for almost a decade longer than other jurisdictions did. The lack of competition, combined with relatively high generation costs (due to relatively expensive coal sources and the remoteness of major gas fields), led to high wholesale electricity prices. From 2003 the Western Australian Government launched a series of reforms. The central reform, undertaken in 2006, was the disaggregation of the state electricity utility into four separate entities:

- > Verve Energy-generation
- > Western Power—transmission and distribution networks
- > Synergy-retail
- > Horizon Power-integrated supply in regional areas.

The government also:

- > established a wholesale electricity market in 2006 (see section 4.5)
- > established an Electricity Networks Access Code in 2004 for access to transmission and distribution networks (see section 4.6)
- extended the retail contestability threshold in 2005 to all customers using more than 50 megawatt hours (MWh) per year (see section 4.7)

#### 4.3 Western Australia's electricity market structure

Western Australia's electricity market retains a relatively concentrated ownership structure, with state owned utilities being prominent across the supply chain. In the SWIS—the principal electricity system—the state owned Western Power owns the bulk of transmission and distribution systems. Another state owned utility—Verve Energy—owns about two thirds of generation capacity. The balance is privately owned and mainly dedicated to resource projects.

The introduction of a wholesale market in 2006 led to new generator entry and greater ownership depth. Verve Energy's share of installed generation capacity will fall from around 77 per cent in 2007–08 to 60 per cent in 2010–11.<sup>1</sup> In particular, three new participants—NewGen Power, Griffin Power and Alcoa—have acquired (or will acquire) significant capacity. Table 4.1 illustrates the extent of new entry since 2006. Table 4.2 summarises recent investment activity.

Despite new entry, all but one of the new generation plants scheduled by 2010–11 has been contracted to the state owned retailer, Synergy.<sup>2</sup> The absence of full retail competition in Western Australia means Synergy supplies all retail customers in the SWIS (including small business and residential consumers) using up to 50 MWh of electricity per year. The Economic Regulation Authority (ERA) considers the absence of a clear timetable for full retail contestability may deter new entry in retail and generation.<sup>3</sup>

The Office of Energy commenced a review in 2008 of the costs and benefits of introducing full retail contestability, but at 1 July 2009 had not made any recommendations. The ERA has described the current arrangements in generation and retail as leading to a 'quasi bilateral monopoly market structure'.<sup>4</sup>

The Western Australian Government expects further new entry and the phasing out of vesting contracts to reduce the market share of state owned corporations over time.<sup>5</sup> In addition, the government:

- > has placed a 3000 MW cap on Verve Energy's ability to invest in new generation plant, to allow independent generators to increase their market share over time
- > restricted Synergy from generating electricity, and Verve Energy from retailing electricity, until at least 2013.

<sup>1</sup> ERA (Western Australia), Annual wholesale electricity market report for the Minister for Energy, Perth, 2008, p. vii.

<sup>2</sup> ERA (Western Australia), Annual wholesale electricity market report for the Minister for Energy, Perth, 2008, p. 45.

<sup>3</sup> ERA (Western Australia), 'Energy market reform in WA—a progress report', Presentation by Lyndon Rowe to the WA Power & Gas 2009 Conference, Perth, 17 and 18 February 2009, p. 4.

<sup>4</sup> ERA (Western Australia), 'Energy market reform in WA—a progress report', Presentation by Lyndon Rowe to the WA Power & Gas 2009 Conference, Perth, 17 and 18 February 2009, p. 4.

<sup>5</sup> The vesting contracts relate to the wholesale supply of electricity by Verve Energy to Synergy in the SWIS. The arrangements were intended as a transitional measure to ensure Synergy could meet the sales obligations it inherited in 2006 from former integrated utility Western Power.



Figure 4.1 Electricity infrastructure map—Western Australia

Source: ERA (Western Australia).

PARTICIPANT	GENE	RATORS	CUST <u>OMERS</u>			
	2006	2009	2006	2009		
Alcoa						
Alinta Sales Pty Ltd						
Barrick (Kanowna) Limited						
Bioenergy Limited						
Clear Energy Pty Ltd						
Coolimba Power Pty Ltd						
EDWF Manager Pty Ltd						
Eneabba Gas Limited						
Enebba Energy Pty Ltd						
Energy Response Pty Ltd						
Goldfields Power Pty Ltd						
Griffin Power Pty Ltd						
Griffin Power 2 Pty Ltd						
Karara Energy Pty Ltd						
Landfill Gas and Power Pty Ltd						
Mount Herron Engineering Pty Ltd						
Namarkkon Pty Ltd						
NewGen Neerabup Pty Ltd						
NewGen Power Kwinana Pty Ltd						
Newmont Power Pty Ltd						
Perth Energy Pty Ltd						
Premier Power Sales Pty Ltd						
SkyFarming Pty Ltd						
South West Cogeneration Joint Venture						
Southern Cross Energy						
Synergy						
Transalta Energy (Australia)						
Transfield Services Kemerton Pty Ltd						
Verve Energy						
Walkaway Wind Power Pty Ltd						
Waste Gas Resources Pty Ltd						
Water Corporation						
Worsley Alumina						

#### Table 4.1 Participants in Western Australia's wholesale electricity market

Source: ERA (Western Australia).

CHAPTER 4 BEYOND THE NATIONAL ELECTRICITY MARKET

111

PARTICIPANT	INVESTMENT
Alinta Sales	280 MW OCGT power station at Pinjarra (acquired by BBP August 2007)
	380 MW OCGT power station at Wagerup (acquired by BBP August 2007)
Stanwell/Griffin	80 MW wind farm at Emu Downs opened October 2006
Griffin Energy	200 MW Bluewaters 1 coal fired plant commissioned in 2009
	200 MW Bluewaters 2 coal fired plant under construction for end 2009
	330 MW North Peak gas fired plant near Neerabup proposed for 2010-11
NewGen Power Kwinana	320 MW Kwinana combined cycle gas plant opened November 2008
Western Australian Biomass	40 MW boiler/steam turbine power station fired by biomass to begin operation in 2009-10
Eneabba Gas	168 MW Centauri 1 gas fired plant near Eneabba scheduled to begin operation in 2009
Western Energy	80 MW Kwinana combined cycle gas fired plant due 2010
Aviva	400 MW Coolimba coal fired plant near Eneabba due 2012
ATCO Power	86 MW Karratha gas fired plant under construction for 2010
Western Power	<ul> <li>\$3.5 billion on network improvements from 2008, including:</li> <li>&gt; 330 kV transmission line from Pinjar to Moonyoonooka</li> <li>&gt; 330 kV transmission line from Collie to Perth's eastern suburbs</li> <li>&gt; new transmission capacity, including new substations at Wangara, Joondalup, Warwick and Thornlie</li> <li>&gt; expansion of distribution network's capacity</li> </ul>

#### Table 4.2 Investment in the South West Interconnected System from 2006

BBP, Babcock & Brown Power; kV, kilovolt; OCGT, open cycle gas turbine.

Principal sources: IMO (Western Australia), Office of Energy (Western Australia).

In 2008 a possible merger between Verve Energy and Synergy was considered. The Western Australian Government decided in August 2009 not to proceed with the merger.<sup>6</sup>

In regional Western Australia, Horizon Power is a vertically integrated utility responsible for the generation (or its procurement), transmission, distribution and retailing of electricity to customers in the NWIS and in 29 smaller non-interconnected systems. Horizon Power buys power from a number of private generators in the Pilbara, including Hamersley Iron's 120 MW generation plant at Dampier, Robe River's 105 MW plant at Cape Lambert and Babcock & Brown Power's 175 MW plant at Port Hedland.

### 4.4 Electricity generation in Western Australia

Statewide, around 60 per cent of installed generation capacity is fuelled by natural gas and 35 per cent by coal (figure 4.2). Gas is used in base load cogeneration plants and peaking units. Generation from renewable sources has grown, with wind accounting for around 63 per cent, and hydro and biomass comprising most of the balance. Renewable sources fuelled about 3.8 per cent of statewide generation in 2007–08. In the SWIS, generation from renewables increased sevenfold between 2003 and 2008, and now supplies around 5 per cent of electricity demand.<sup>7</sup>

The Western Australian Government has set a target of 6 per cent of electricity to be sourced from renewable energy by 2010. The biomass plant scheduled for commissioning in December 2009 is expected to lift the share of renewable energy production above this target.

6 Peter Collier (Minister for Energy, Western Australia), 'State's energy future outlined', Media release, 26 August 2009.

7 Sustainable Energy Development Office (Western Australia), Renewable energy, fact sheet, Perth, 2008.

## CHAPTER 4 BEYOND THE NATIONAL ELECTRICITY

MARKET

Figure 4.2



Installed generation capacity—Western Australia's south west

Note: Data are for the South West Interconnected System, covering Perth and other major centres in the south west of the state. Source: IMO (Western Australia).

#### 4.5 Western Australia's wholesale electricity market

In September 2006 Western Australia launched a wholesale electricity market in the SWIS. A combination of bilateral contracts, a day-ahead short term energy market (STEM) and a balancing market facilitate energy trading. The market was designed to suit Western Australian conditions and differs considerably from the National Electricity Market (NEM) (see chapter 2):

- The Independent Market Operator (IMO),
   a government entity established in 2004, is the rule development body and market operator.<sup>8</sup>
   It has no commercial interest in the market and no connection with any market participant.
- > The physical system operator, System Management, is a ring-fenced entity within Western Power that is tasked with maintaining the safe, secure and reliable operation of the power system. It is responsible for the operation and control of generators, transmission and distribution networks, and large customer retailer supply management.

#### 4.5.1 Market design

Figure 4.3 illustrates the key elements of Western Australia's wholesale market in the SWIS. The following are the three main areas of difference between the market design for the SWIS and the NEM in eastern and southern Australia:

- > 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 occurs in a spot market. NEM participants also enter formal hedge contracts to manage spot market risk. In contrast, energy in the SWIS is traded mainly through bilateral contracts outside the pool. These contracts may be entered into years, weeks or days before supply. Before the trading day, generators must inform the IMO of the quantity of energy to be sold under bilateral contracts, and to whom it will be sold, to enable the IMO to schedule that supply.

In the lead-up to dispatch, System Management issues instructions to ensure supply equals demand in real time. Dispatch, rather than being on a least cost basis, reflects mainly 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. They are obliged to follow these plans, unless dispatch instructions replace the plans. Verve Energy's facilities are scheduled around the resource plans of other generators. If it appears supply will not equal demand, the IMO will schedule Verve Energy generation first, then issue dispatch instructions to other market participants as necessary.

Beyond bilateral contracts, a day-ahead STEM and a balancing market are used to trade wholesale electricity (figure 4.3). The STEM supports bilateral trades by allowing market participants to trade around their contract positions a day before energy is delivered. If, for example, a generator does not have sufficient

8 Information on the market can be found on the IMO website (www.imowa.com.au).

capacity to meet its contracted position, then it can bid to purchase energy in the STEM. Participating generators must offer generation plant at short run marginal cost. Each morning, market participants may submit to the IMO bids to purchase energy and/or offers to supply energy.<sup>9</sup> The IMO then runs an auction, in which it takes a neutral position to determine a single price for each trading interval of the day.

A market participant's actual supply or consumption of electricity during a trading interval may deviate from its net contract position (the sum of its bilateral position and STEM trades), given unexpected deviations in demand and unplanned plant outages. The shortfall or surplus is traded on the balancing market. The IMO calculates balancing prices, which for Verve Energy plant are generally equal to the short run marginal cost of the last unit dispatched. Any independent power producer plant dispatched for balancing or ancillary service provision is 'paid as bid'.

#### **Capacity market**

The SWIS market includes both an energy market (the STEM) and a capacity market (figure 4.3). The capacity market is intended to provide incentives for investment in generation to meet peak demand. In particular, it is intended to provide sufficient revenue for investment without the market experiencing high and volatile energy prices. The IMO administers a reserve capacity mechanism to ensure there is adequate installed capacity to meet demand. It 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).

Generators are assigned capacity credits, which entitle them to payments for offering their capacity to the market at all times. The IMO assigns credits to generators that intend to trade their capacity bilaterally. If insufficient reserves are obtained through this process, the IMO runs an auction to allocate the additional capacity credits.

The market made monthly payments of \$10 625 per MW of capacity from market start to 1 October 2008. For the 12 months from 1 October 2008, generators received a monthly payment of \$8152 per MW of capacity. This amount rose to \$9038 per MW of capacity for the 12 months from 1 October 2009.<sup>10</sup> The payments are intended to cover the fixed costs of an open cycle peaking gas turbine and to partly cover the capital costs of base load units.

The NEM has 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 spot energy prices in Western Australia are unlikely to peak as high as NEM prices to stimulate investment.

There are two energy price limits in the STEM: a maximum price for supply other than that from plant running on liquid fuel; and an alternative maximum STEM price (AMSP) based on supply from all facilities. The maximum price is based on the marginal cost of an open cycle gas turbine using natural gas as fuel. It is adjusted annually. For the year to 1 October 2008, the cap was \$206 per MWh. For the year to 1 October 2009, the cap was \$286 per MWh. In comparison, the NEM operates with a price cap of \$10 000 per MWh. The AMSP is adjusted monthly based on movements in the Singapore Crude Oil price. It peaked in September 2008 at \$779 per MWh.

9 To receive reserve capacity payments, generators must offer all registered capacity to the STEM.

10 Information on capacity credits can be found on the IMO website (www.imowa.com.au).

#### Figure 4.3 Western Australia's wholesale electricity market



Source: IMO (Western Australia).

The IMO determines annual reserve capacity requirements and releases an annual statement of opportunities report covering 10 years. The ERA must approve the IMO's proposed maximum reserve capacity price and energy price caps in the short term market.

Figure 4.4 summarises the demand and capacity outlook for 2010–11 at 2008. The IMO has set a reserve capacity target for 2010–11 of 5146 MW. To meet this target, 226 MW of new generation and demand-side management capacity will be required beyond that already in place or under construction.<sup>11</sup>

#### APACITY MARKE

- Generators are assigned capacity credits entitling them to payments for offering capacity into the market at all times.
- > This market is intended to provide incentives for investment to meet peak demand.
- > It is administered by the IMO.



Western Power

#### Ancillary services

The NEM has eight frequency control ancillary services spot markets in which participants may bid to provide services. Network control ancillary services are procured through long term contracts. In contrast, the SWIS has no spot markets for ancillary services; rather, System Management determines ancillary services requirements and procures them from Verve Energy or other participants under contract arrangements.



#### Figure 4.4





#### 4.5.2 Market outcomes

While it is too early to assess the outcomes of the Western Australian energy market, developments can be observed. The number of market participants is increasing, with new retailers and generators entering the market. Table 4.2 shows there has been strong interest in investment in the energy market, including in renewable energy. There is evidence of more varied plant sizes, technologies and fuel types, as well as costefficient plant upgrades. The ERA stated, however, that resourcing constraints within Western Power are delaying some generation investment.<sup>12</sup>

Another outcome has been the introduction of more cost-reflective prices in the STEM, which reflect the cost of energy during system peaks and short term pressures such as fuel shortages and strong demand. There is less cost reflectivity in the retail market, however, where gazetted tariffs have applied for several years.<sup>13</sup>

Trading activity in the STEM and balancing market typically ranged from about 4 per cent to 6 per cent of total sales in the first year of the market's operation (2006–07). More recently, STEM trades have risen, largely between generators seeking access to lower cost plant. In 2008–09 the volume of energy traded in the STEM and balancing market ranged from about 6 per cent to 14 per cent of total sales (figure 4.5).

On most days, the number of market participants placing STEM bids fluctuates between four and seven. While Verve Energy accounts for a majority of capacity in the market, other participants have also been active. In contrast, the level of competition in the bilateral contract market is difficult to gauge because such contracts are confidential.

The ERA stated it is not aware of outcomes in the STEM that indicate market power is an issue. It has raised concerns, however, about:

- > the appropriateness of the investment signals provided by the market
- > the appropriateness of the timing of the reserve capacity mechanism and whether this can create barriers to investment for facilities with long lead times
- > whether the timing of planned network outages has an impact on the effectiveness of the market
- > whether there are barriers to the participation of consumers in demand-side management programs.<sup>14</sup>

#### **Price outcomes**

Price outcomes in the STEM and balancing markets provide transparent price signals on the cost of electricity. The mean peak STEM price from market start to 31 July 2008 was \$80.20 per MWh, while the mean off-peak price was \$38.10 per MWh.<sup>15</sup> MARKET

<sup>12</sup> ERA (Western Australia), Annual wholesale electricity market report for the Minister for Energy, Perth, 2008, p. viii.

<sup>13</sup> See section 4.7.

<sup>14</sup> ERA (Western Australia), Annual wholesale electricity market report for the Minister for Energy, Perth, 2007, p. viii.

<sup>15</sup> ERA (Western Australia), Annual wholesale electricity market report for the Minister for Energy, Perth, 2008, p. 10.





Source: IMO (Western Australia).





Source: IMO (Western Australia).

Figure 4.6 shows the weighted average weekly STEM prices from market start to June 2009. The early high prices were due to fuel restrictions and low generator availability. Prices then followed a fairly regular seasonal pattern—with summer and winter peaks—until May 2008. In June 2008 gas shortages caused by an explosion at the Varanus Island plant led to soaring gas prices. Given natural gas fuels a majority of Western Australia's generation plant, this flowed through to record wholesale electricity prices. Average daily prices peaked on 26 June 2008 at \$429 per MWh.<sup>16</sup> Prices eased in late 2008 as the gas constraints were addressed, but remained above historical seasonal levels in early 2009.

16 ERA (Western Australia), Annual wholesale electricity market report for the Minister for Energy, Perth, 2008, p. 11.

In 2004 Western Australia implemented the Electricity Networks Access Code for access to transmission and distribution network services. The code covers only 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 certified the code as an effective access regime under the *Trade Practices Act 1974*.

The ERA administers the code, which 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 ERA's acceptance or rejection of an access arrangement that the service provider proposes.

The ERA in 2007 approved Western Power's first access arrangement under the code, covering the three year period from 2006–07. In July 2009 it released a draft decision on Western Power's access arrangement for the three year period from 2009–10.

Chapters 5 and 6 of this report include some data on the Western Power networks, including performance outcomes.

#### 4.7 Retail arrangements in Western Australia

In January 2005 Western Australia extended retail contestability to electricity customers using at least 50 MWh per year. In the SWIS, all customers using less than 50 MWh per year are served by Synergy, the state owned energy retailer. Horizon Power serves most customers outside the SWIS. In 2008 the state's Office of Energy commenced a review of the costs and benefits of introducing full retail contestability, but it had not released its findings as of 1 July 2009. Regulated retail tariffs in the SWIS are set at levels that are well below costs. In January 2009 the Office of Energy recommended residential tariffs increase by 52 per cent in 2009–10 and a further 26 per cent in 2010–11, to reflect substantial increases in the cost of supplying electricity.<sup>17</sup> In February 2009 the Western Australian Government rejected these recommendations and announced domestic electricity charges would rise by 10 per cent on 1 April 2009, followed by a rise of 15 per cent in July 2009.<sup>18</sup> The ERA noted that retailers will not be able to compete with Synergy for those customers that have the option of remaining on below-cost regulated tariffs. It considers this outcome is likely to preserve a concentrated retail sector.<sup>19</sup>

Chapter 7 of this report further details Western Australia's electricity retail market.

#### 4.8 The Northern Territory's electricity industry

The Northern Territory's electricity industry is small, reflecting its population of around 220 000, of whom only around 82 500 are connected to a network. There are three relatively small regulated systems,<sup>20</sup> of which the largest is the Darwin-Katherine system, with a capacity of around 320 MW (figure 4.7). The total capacity of the Territory's regulated systems was 444 MW at 30 June 2008, after the commissioning of the first generator at the Weddell Power Station. In 2007–08 the Territory consumed around 1795 gigawatt hours of electricity.

The Territory uses gas fired plant to generate public electricity, sourcing gas from the Amadeus Basin in Central Australia. The Amadeus fields cannot sustain increasing demand, however, and many contracts for gas supply are due to end in 2009. In some cases, diesel has been used at considerable cost to meet gas supply shortfalls.

17 Office of Energy (Western Australia), Electricity Retail Market Review, Final recommendations report-review of electricity tariff arrangements, Perth, 2009, p. 2.

20 The Darwin-Katherine, Alice Springs and Tennant Creek systems.

<sup>18</sup> Peter Collier (Minister for Energy, Western Australia), 'State Government announces increases in tariff arrangements', Media release, 23 February 2009.

<sup>19</sup> ERA (Western Australia), 'Energy market reform in WA—a progress report', Presentation by Lyndon Rowe to the WA Power & Gas 2009 Conference, Perth, 17 and 18 February 2009, p. 3.







- Power station—power purchase agreement
- Retail agreement only
- Transmission lines
- Distribution lines
   Northern Region
- Katherine Region
- Barkley Region
- Southern Region

Source: Power and Water Corporation.

120

A new source of gas supply from late 2009 will be the Blacktip Field in the Joseph Bonaparte Gulf. The gas will come onshore to a processing plant near Wadeye, then will be transported by the Bonaparte Gas Pipeline (which connects to the existing Amadeus Basin-to-Darwin Pipeline). Delays in the construction of the processing plant postponed the first supply of gas from the Blacktip Field, which was scheduled for 1 January 2009. Once the processing plant is complete, this arrangement is expected to meet the Territory's gas demand for the next 25 years.<sup>21</sup>

#### 4.8.1 Market arrangements

Given the scale of the Northern Territory market, a wholesale electricity spot market was not considered feasible. Rather, the Territory uses a 'bilateral contracting' system whereby generators are responsible for dispatching the power that their customers require.

The industry is dominated by a government owned corporation, Power and Water, which owns the transmission and distribution networks. Power and Water is also the monopoly retail provider and generator. In addition, it is responsible for power system control. Six independent power producers in the resource and processing sector generate their own requirements and also generate electricity under contract with Power and Water.

From around 2000 the Northern Territory Government introduced measures to open the electricity market to competition:

- > It commenced a phased introduction of retail contestability, scheduled for completion by April 2005 but later rescheduled for April 2010 (see below).
- > It corporatised the vertically integrated electricity supplier (Power and Water) and ring-fenced its generation, power system control, network and retail activities.

- > It allowed new suppliers to enter the market.
- > It established an independent regulator, the Utilities Commission, to regulate monopoly services and monitor the market.
- > It 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. In March 2009 the Utilities Commission made its third five year determination on network access arrangements (for 2009-10 to 2013-14).

There has been one new entrant in generation and retail since the reforms: NT Power, which acquired some market share. It withdrew from the market in September 2002, however, citing its inability to source ongoing gas supplies for electricity generation. In light of this withdrawal, the Northern Territory Government suspended the contestability timetable in January 2003, effectively halting 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 the applicant's 'inability to meet reasonably foreseeable obligations for the sale of electricity'.<sup>22</sup> The introduction of full retail contestability is scheduled for April 2010.

When Power and Water reverted to a retail monopoly, the government approved prices oversight by the Utilities Commission of Power and Water's generation business for as long as the business is not subject to a 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.

<sup>21</sup> Power and Water Corporation, Annual report 2008, Darwin, 2008, p. 18.

<sup>22</sup> Department of Business, Economic and Regional Development (Northern Territory Government), *The NT electricity, water and gas supply sector*, fact sheet, Darwin, 2005.



# 5 ELECTRICITY TRANSMISSION



Electricity generators are usually located close to fuel sources such as natural gas pipelines, coal mines and hydroelectric 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 diverse range 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.

## 5 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
- > the 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.<sup>1</sup>

#### 5.1 Role of electricity 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 between them, underground cables, transformers, switching equipment, reactive power devices, and monitoring and telecommunications equipment.

1 AER, Transmission network service providers: electricity performance report for 2007-08, Melbourne, 2009.

and Tasmania, for example, is one of the longest submarine power cable in the world. By contrast, transmission networks in the United States and many European countries tend to be meshed and of a higher density. These differences result in transmission charges being a more significant contributor to end prices in Australia than they are in many other countries —for example, transmission charges comprise about 10 per cent of retail prices in the NEM<sup>3</sup> compared with 4 per cent in the United Kingdom.<sup>4</sup>

The NEM transmission network is unique in the

developed world in terms of its long distances, low

density and long, thin structure. It reflects the often

long distances between demand centres and fuel sources

for generation. The 290 kilometre link between Victoria

Electricity can be transported over alternating current (AC) or direct current (DC) networks. Most of Australia's transmission network is AC, whereby 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 in other parts of the network. Australia also has three DC networks, of which all are cross-border interconnectors.

#### 5.2.1 Ownership

Table 5.1 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 separate the generation, transmission, distribution and retail segments into stand-alone businesses. Generation and retail were opened up to competition, but this approach was not appropriate for the transmission and distribution networks, which became regulated monopolies.

- 3 The contribution of transmission to final retail prices varies across jurisdictions, customer types and locations.
- 4 Ofgem, Factsheet 66, London, January 2008 (available at www.ofgem.gov.uk).

Electricity must be converted to high voltages for efficient transport over long distances. This minimises the loss of electrical energy that naturally occurs.<sup>2</sup> In Australia, transmission networks consist of equipment that transmits electricity at or above 220 kilovolts (kV), along with assets that operate at 66–220 kV that are parallel to, and provide support to, the higher voltage transmission network.

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 infrastructure, customers would have to rely on generators in their local area, which may be more expensive than remote generators.
- > Second, allowing many generators to compete in the electricity market helps reduce the risk of market power.
- > Third, allowing electricity to move instantaneously over long distances reduces the amount of spare generation capacity that must be provided at each town or city to ensure a reliable electrical supply. This reduces inefficient investment in generation.

#### 5.2 Australia's electricity transmission networks

In Australia, there are transmission networks in each state and territory, with cross-border interconnectors that link some networks. The National Electricity Market (NEM) in eastern and southern Australia provides a fully interconnected transmission network from Queensland through to New South Wales, the Australian Capital Territory (ACT), Victoria, South Australia and Tasmania (figure 5.1). The transmission networks in Western Australia and the Northern Territory do not interconnect with the NEM or each other (see chapter 4).

#### 125

<sup>2</sup> While transportation of electricity over long distances is efficient at high voltages, there are risks, such as flashovers. A flashover is a brief (seconds or less) instance of conduction between an energised object and the ground (or another energised object). The conduction consists of a momentary flow of electricity between the objects, and is usually accompanied by a show of light and possibly a cracking or loud exploding noise. High towers, insulation and wide spacing between the conductors help to manage this risk.

Figure 5.1 Transmission networks in the National Electricity Market



Table 5.1 Electrie	ity transmission	networks in	Australia
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NEM REGION NETWORKS           Powerlink         Qld         12 671         48 576         8 082         3 922         2 528         1 July 2007 - 30 June 2012         Queensland Government           TransGrid         NSW         12 486         76 359         12 954         4 064         2 405         1 July 2009 - 30 June 2014         New South Wales Government           EnergyAustralia <sup>3</sup> NSW         885         32 007         5 683         1 013         1 182         1 July 2009 - 30 June 2014         New South Wales Government           SP AusNet         Vic         6 553         51 927         9 850         2 232         990 <sup>4</sup> 1 Apr 2008 - 30 June 2014         New South Wales Government (Singapore Power International 51%)           ElectraNet         SA         5 620         13 734         3 172         1 284         650         1 July 2008 - 30 June 2014         Powerlink (Queensland Government), YTL Power Investment, Hastings Utilities Trust           Transend         Tas         3 650         11 298         2 332         936         606         1 July 2009 - 30 June 2014         Tasmanian Government           NEM total         41 865         233 901         42 073         13 451         8 292         Investments (Marubeni 50%, Osaka Gas 30%, APA Group 20%)         Osaka Gas 30%, APA Group 20%)	NETWORK	LOCATION	LINE LENGTH (KM)	ELECTRICITY TRANSMITTED (GWh), 2007–08	MAXIMUM DEMAND (MWI), 2007–08	ASSET BASE (2008 \$ MILLION) <sup>1</sup>	INVESTMENT— CURRENT PERIOD (2008 \$ MILLION) <sup>2</sup>	CURRENT REGULATORY PERIOD	OWNER
Powerlink         Qld         12 671         48 576         8 082         3 922         2 528         1 July 2007 - 30 June 2012         Queensland Government           TransGrid         NSW         12 486         76 359         12 954         4 064         2 05         1 July 2009 - 30 June 2014         New South Wales Government           EnergyAustralia <sup>3</sup> NSW         885         32 007         5 683         1 013         1 182         1 July 2009 - 30 June 2014         New South Wales Government           SP AusNet         Vic         6 553         51 927         9 850         2 232         990 <sup>4</sup> 1 Apr 2008 - 30 June 2014         Publicly listed company [Singapore Power International 51%]           ElectraNet         SA         5 620         13 734         3 172         1 284         650         1 July 2008 - 30 June 2013         Powerlink (Queensland Government), YTL Power Investment, Hastings Utilities Trust           Transend         Tas         3 650         11 298         2 332         936         606         1 July 2009 - 30 June 2014         Tasmanian Government           NEM total         41 865         233 901         42 073         13 451         8 292         Energy Infrastructure Investments (Marubeni 50%, Osaka Gas 30%, APA Group 20%)           Murraylink         Vic - SA         18	NEM REGION NET	WORKS							
TransGrid         NSW         12 486         76 359         12 954         4 064         2 405         1 July 2009 - 30 June 2014         New South Wales Government 30 June 2014           EnergyAustralia <sup>3</sup> NSW         885         32 007         5 683         1 013         1 182         1 July 2009 - 30 June 2014         New South Wales Government 30 June 2014           SP AusNet         Vic         6 553         51 927         9 850         2 232         990 <sup>4</sup> 1 Apr 2008 - 30 Mar 2014         Publicly listed company (Singapore Power International 51%)           ElectraNet         SA         5 620         13 734         3 172         1 284         650         1 July 2008 - 30 June 2013         Powerlink [Queensland Government], YTL Power Investment, Hastings Utilities Trust           Transend         Tas         3 650         11 298         2 332         936         606         1 July 2009 - 30 June 2014         Tasmanian Government           NEM total         41 865         233 901         42 073         13 451         8 292         Imvestments [Marubeni 50%, Osaka Gas 30%, APA Group 20%]           Murraylink         Vic- SA         180         130         1 July 2005 - 30 June 2013         Energy Infrastructure Investments [Marubeni 50%, Osaka Gas 30%, APA Group 20%]           Basslink         Vic- Tas         375	Powerlink	Qld	12 671	48 576	8 082	3 922	2 528	1 July 2007 – 30 June 2012	Queensland Government
EnergyAustralia³NSW88532 0075 6831 0131 1821 July 2009 - 30 June 2014New South Wales GovernmentSP AusNetVic6 55351 9279 8502 23299041 Apr 2008 - 30 Mar 2014Publicly listed company [Singapore Power International 51%]ElectraNetSA5 62013 7343 1721 2846501 July 2008 - 30 June 2013Powertink [Queensland Government], YTL Power Investment, Hastings Utilities TrustTransendTas3 65011 2982 3329366061 July 2009 - 30 June 2013Tasmanian GovernmentNEM total41 865233 90142 07313 4518 292Energy Infrastructure Investments (Marubeni 50%, Osaka Gas 30%, APA Group 20%)MurraylinkVic- Tas3758456Unregulated UnregulatedEnergy Infrastructure Investments [Marubeni 50%, Osaka Gas 30%, APA Group 20%)BasslinkVic- Tas3758456Unregulated Publicly listed CitySpring Infrastructure Trust (Temesek Holdings [Singapore] 28%)	TransGrid	NSW	12 486	76 359	12 954	4 064	2 405	1 July 2009 – 30 June 2014	New South Wales Government
SP AusNet       Vic       6 553       51 927       9 850       2 232       990 <sup>4</sup> 1 Apr 2008 - 30 Mar 2014       Publicly listed company (Singapore Power International 51%)         ElectraNet       SA       5 620       13 734       3 172       1 284       650       1 July 2008 - 30 wertink (Queensland Government), YTL Power International 51%)         Transend       Tas       3 650       11 298       2 332       936       606       1 July 2009 - 30 June 2014       Tasmanian Government         NEM total       41 865       233 901       42 073       13 451       8 292       Energy Infrastructure Investments (Marubeni 50%, Osaka Gas 30%, APA Group 20%)         Directlink       Qld-NSW       63       180       130       1 July 2005 - 30 June 2015       Energy Infrastructure Investments (Marubeni 50%, Osaka Gas 30%, APA Group 20%)         Murraylink       Vic - SA       180       220       119       1 Oct 2003 - 30 June 2013       Energy Infrastructure Investments (Marubeni 50%, Osaka Gas 30%, APA Group 20%)         Basslink       Vic - Tas       375       845 <sup>6</sup> Unregulated       Publicly listed CitySpring Infrastructure Trust (Temesek Holdings (Singapore) 28%)         NON-NEM REGION NETWORKS       Singapore) 28%       Singapore) 28%       Singapore) 28%       Singapore) 28%	EnergyAustralia <sup>3</sup>	NSW	885	32 007	5 683	1 013	1 182	1 July 2009 – 30 June 2014	New South Wales Government
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INTERCONNECTORS <sup>5</sup> Directlink       Qld- NSW       63       180       130       1 July 2005 - 30 June 2015       Energy Infrastructure Investments (Marubeni 50%, Osaka Gas 30%, APA Group 20%)         Murraylink       Vic- SA       180       220       119       1 Oct 2003 - 30 June 2013       Energy Infrastructure Investments (Marubeni 50%, Osaka Gas 30%, APA Group 20%)         Basslink       Vic- Tas       375       845 <sup>6</sup> Unregulated       Publicly listed CitySpring Infrastructure Trust (Temesek Holdings (Singapore) 28%)         NON-NEM REGION NETWORKS       Data and an an an and an an an and an and an	NEM total		41 865	233 901	42 073	13 451	8 292		
Directlink       Qld- NSW       63       180       130       1 July 2005 - 30 June 2015       Energy Infrastructure Investments (Marubeni 50%, Osaka Gas 30%, APA Group 20%)         Murraylink       Vic- SA       180       220       119       1 Oct 2003 - 30 June 2013       Energy Infrastructure Investments (Marubeni 50%, Osaka Gas 30%, APA Group 20%)         Basslink       Vic- Tas       375       845 <sup>6</sup> Unregulated       Publicly listed CitySpring Infrastructure Trust (Temesek Holdings (Singapore) 28%)         NON-NEM REGION NETWORKS       Marubani Sama Sama Sama Sama Sama Sama Sama Sam	INTERCONNECTO	RS⁵							
Murraylink       Vic- SA       180       220       119       1 Oct 2003 – 30 June 2013       Energy Infrastructure Investments (Marubeni 50%, Osaka Gas 30%, APA Group 20%)         Basslink       Vic- Tas       375       845 <sup>6</sup> Unregulated       Publicly listed CitySpring Infrastructure Trust (Temesek Holdings (Singapore) 28%)         NON-NEM REGION NETWORKS       Sector       Sector       Sector	Directlink	Qld- NSW	63		180	130		1 July 2005 – 30 June 2015	Energy Infrastructure Investments (Marubeni 50%, Osaka Gas 30%, APA Group 20%)
Basslink       Vic-       375       845 <sup>6</sup> Unregulated       Publicly listed CitySpring         Tas       Infrastructure Trust (Temesek         Holdings (Singapore) 28%)	Murraylink	Vic- SA	180		220	119		1 Oct 2003 – 30 June 2013	Energy Infrastructure Investments (Marubeni 50%, Osaka Gas 30%, APA Group 20%)
NON-NEM REGION NETWORKS	Basslink	Vic– Tas	375			8456		Unregulated	Publicly listed CitySpring Infrastructure Trust (Temesek Holdings (Singapore) 28%)
	NON-NEM REGIO		ORKS						
Western Power         WA         6 792         14 500         3 420         2135'         1528'         1 July 2009 –         Western Australian Government           30 June 2012 <sup>8</sup>	Western Power	WA	6 792	14 500	3 420	2135 <sup>7</sup>	1528 <sup>7</sup>	1 July 2009 – 30 June 2012 <sup>8</sup>	Western Australian Government
Power and Water     NT     730     1 July 2009 –     Northern Territory Government       30 June 2014     30 June 2014	Power and Water	NT	730					1 July 2009 – 30 June 2014	Northern Territory Government

1. The regulated asset bases are as set at the beginning of the current regulatory period for each network, converted to June 2008 dollars.

2. Investment data are forecast capital expenditure over the current regulatory period, converted to June 2008 dollars.

3. EnergyAustralia's transmission assets, at 1 July 2009, are treated as distribution assets for the purpose of economic regulation. Future performance of the network will be assessed under the framework applicable to distribution network service providers.

4. SP AusNet's investment data include forecast augmentation investment by AEMO (formerly VENCorp).

5. Not all interconnectors are listed. The unlisted interconnectors, which form part of the state based networks, are Heywood (Victoria - South Australia), QNI (Queensland - New South Wales), Snowy - New South Wales and Snowy-Victoria.

6. Given Basslink is not regulated, there is no regulated asset base. The asset value listed is the estimated construction cost.

7. Data from the ERA's draft decision on proposed revisions to Western Power's access arrangement for the period 2009-10 to 2011-12.

8. At July 2009 Western Power's access arrangement for the period 2009-10 to 2011-12 was not finalised.

Principal sources: AER, *Transmission network service providers: electricity performance report for 2007-08*, Melbourne, 2008, and previous years; AER/ACCC revenue cap decisions; ERA (Western Australia), *Draft decision on proposed revisions to the access arrangement for the South West Interconnected Network*, Perth, July 2009; company websites and media releases.

#### Figure 5.2

Electricity transmission network ownership

		1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
QLD	Powerlink	Queensland Government															
NSW	TransGrid	New S	New South Wales Government														
	Energy Australia	New S	New South Wales Government														
VIC	SP AusNet	Power	Powernet Victoria         GPU Powernet         SPI PowerNet (Singapore Power)         SP AusNet (51% Singapore Power)														
SA	ElectraNet	South Australian Government Powerlink (Qld Power Government), YTL Power								rlink (Q ower, H	ık (Queensland Government), er, Hastings						
TAS	Transend	Tasma	Tasmanian Government														
CTORS	Directlink	Hydro-Quebec Group, NorthPower APA Group APA, Maruben Osaka Ga										beni, a Gas					
SCONNEG	Murraylink									Hydro SNC-I	-Quebe Lavalin	c Group	ο,	APA G	iroup	APA, Marul Osaka	beni, a Gas
INTEF	BassLink													NGT	CitySp Infras	oring tructur	e Trust
WA	Powerlink	Wester	rn Aust	ralian (	Governr	nent											

NGT, National Grid Transco.

Note: Some corporate names have been abbreviated or shortened.

Figure 5.2 illustrates network ownership changes since 1994. Victoria and South Australia privatised their transmission networks, but other jurisdictions retained government ownership:

- > Singapore Power International acquired Victoria's state transmission network in 2000 following the network's original sale to GPU Powernet in 1997. Singapore Power International floated SP AusNet in 2005, but retained a 51 per cent stake.
- > South Australia sold the state transmission network (ElectraNet) in 2000 to a consortium of interests led by Powerlink, which the Queensland Government owns. 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 asset ownership is separated from planning and investment decision making. SP AusNet owns the state's transmission assets, but the Australian Energy Market Operator (AEMO, formerly VENCorp) plans and directs network augmentation. AEMO also buys bulk network services from SP AusNet for sale to customers.

Private investors have constructed three interconnectors —Murraylink, Directlink and Basslink—since the commencement of the NEM. All have since changed ownership. As of December 2008 Energy Infrastructure Investments has owned Murraylink and Directlink. The APA Group has a 20 per cent stake in the business and manages, maintains and operates the assets. A trust with links to Singapore Power International acquired Basslink in 2007.

#### 5.2.2 Interconnection

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. In 1990, more than 30 years after the inception of the Snowy scheme, the Heywood interconnector between Victoria and South Australia commenced operation.

Figure 5.3 Electricity transmission network assets and investment



#### Notes:

Regulated asset bases are as at the beginning of the current regulatory period. The regulated asset base value for Basslink is the estimated construction cost. Investment data are forecast capital expenditure for the current regulatory period (typically, five years). See table 5.1 for the timing of current regulatory periods.

EnergyAustralia's transmission assets, at 1 July 2009, are treated as distribution assets for the purpose of economic regulation.

 $\operatorname{SP}\operatorname{AusNet}$  includes augmentation investment by AEMO (formerly VENCorp).

Data for Western Power are from the ERA's draft decision on proposed revisions to Western Power's access arrangement for the period 2009-10 to 2011-12. All values are converted to June 2008 dollars.

Sources: AER/ACCC revenue cap decisions; ERA (Western Australia), Draft decision on proposed revisions to the access arrangement for the South West Interconnected Network, Perth, July 2009.

The construction of new interconnectors gathered pace with the commencement of the NEM in 1998. Two interconnectors between Queensland and New South Wales (Directlink<sup>5</sup> and the Queensland – New South Wales Interconnector) commenced operation in 2000, followed by a second interconnector between Victoria and South Australia (Murraylink) in 2002. Murraylink is the world's longest underground power cable. The construction of a submarine transmission cable (Basslink) from Victoria to Tasmania in 2006 completed the interconnection of all transmission networks in eastern and southern Australia. Figure 5.1 shows the interconnectors in the NEM.

#### 5.2.3 Scale of the networks

Figure 5.3 compares asset values and capital expenditure in the current regulatory period for the transmission networks. It reflects asset values as measured by the regulated asset base (RAB) for each network. The RAB is the asset valuation that regulators use, 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 indicates relative scale. Powerlink (Queensland) and TransGrid (New South Wales) have significantly higher RABs than those of other networks. Many factors can affect the size of the RAB, including the basis of original valuation, network investment, the age of a network, geographic scale, the distances required to transport electricity from generators to demand centres, population dispersion and forecast demand profiles. The combined RAB of all transmission networks is around \$15.6 billion. This amount will continue to rise over time, with investment in the current regulatory periods forecast at almost \$10 billion (see section 5.4).

### 5.3 Economic regulation of electricity transmission services

Electricity transmission networks are capital intensive and incur declining marginal costs as output increases. This gives rise to a natural monopoly industry structure. In Australia, the networks are regulated to manage the risk of monopoly pricing.<sup>6</sup> The Australian Competition and Consumer Commission (ACCC) was the industry regulator of transmission networks in the NEM until this role transferred to the Australian Energy Regulator (AER) in 2005. The Economic Regulation Authority and Utilities Commission are the regulators for the Western Australian and Northern Territory networks respectively.

#### 5.3.1 Regulatory process

Chapter 6A of the National Electricity Rules (Electricity Rules) sets out the timelines and processes for the regulation of transmission businesses in the NEM. Regulated transmission businesses must periodically apply for the AER to assess their revenue (typically, every five years). These applications, or revenue proposals, must be consistent with the submission guidelines that the AER developed under the Electricity Rules. The regulatory process usually commences with a transmission business submitting a revenue proposal to the AER. Once a proposal is submitted, the determination process takes 13 months, including time to consult with stakeholders. The transmission business must also submit a proposed pricing methodology and negotiating framework for approval by the AER. The pricing methodology is a formula or process for a business to allocate its revenue allowance and determine the structure of prices it may charge for its prescribed services. The negotiating framework details guidelines for the provision of services to third parties.

Within six months of a revenue proposal being lodged, the AER must release a draft determination. As part of the determination, the AER must decide whether a service target performance incentive scheme (service standards scheme) and/or efficiency benefit sharing scheme will apply to the transmission business. It must also approve or reject the pricing methodology and negotiating criteria.<sup>7</sup>

Once a draft determination is published, the transmission business may submit a revised revenue proposal within 30 business days. The AER must also hold a conference to allow stakeholders to comment on the draft determination. After the conference, stakeholders have a further 45 business days to make written submissions. The AER's final decision, which accounts for any revised proposal and stakeholder comments, is released at least two months before the new regulatory period begins.

Figure 5.4 shows the regulatory timelines for each transmission network. The most recent determinations were for the New South Wales and Tasmanian networks (box 5.1)

<sup>6</sup> The Murraylink, Directlink and Basslink interconnectors were constructed as unregulated infrastructure that aimed to earn revenue through arbitrage. That is, they profited by purchasing electricity in low price NEM regions and selling it into higher price regions. Murraylink and Directlink converted to regulated networks in 2003 and 2006 respectively. Basslink is the only unregulated transmission network in the NEM.

<sup>7</sup> If the AER does not accept the pricing method and negotiating framework proposed by the transmission business, it must detail how those documents can be changed to make them compliant with the Electricity Rules.

Figure 5.4





#### Box 5.1 New South Wales and Tasmanian transmission determinations

In April 2009 the AER released its revenue determination for TransGrid and EnergyAustralia<sup>8</sup> (the transmission service providers in New South Wales) and Transend (the provider in Tasmania). These determinations provide for \$3.6 billion of capital expenditure for the New South Wales networks and \$0.6 billion for the Tasmanian network between 2009–10 and 2013–14.

The determinations provide for a significant increase in investment—140 per cent higher than for the previous five years (in real terms)—and will allow the networks to comply with more stringent network performance, reliability and security requirements, replace aging assets and meet growing peak demand. Projects include constructing a 500 kV network around the Newcastle–Sydney–Wollongong area to meet future load growth, reinforcing the inner Sydney transmission system and constructing a Waddamana– Lindisfarne transmission line in Tasmania.

The AER also approved significant increases in operating and maintenance expenditure allowances.

The overall revenue allowance for the regulatory period is \$3.6 billion for TransGrid and around \$0.9 billion for EnergyAustralia and Transend. The decisions reflect revised economic forecasts (factoring in the effect of the global financial crisis) of weaker demand growth.

These revenue allowances will increase annual nominal transmission charges by about 4.8 per cent for TransGrid and 6 per cent for Transend.

Sources: AER, TransGrid transmission determination 2009–10 to 2013–14, final decision, Melbourne, April 2009; AER, Transend transmission determination 2009–10 to 2013–14, final decision, Melbourne, April 2009; AER, New South Wales distribution determination 2009–10 to 2013–14, final decision, Melbourne, April 2009; AER, New South Wales distribution determination 2009–10 to 2013–14, final decision, Melbourne, April 2009; AER, New South Wales distribution determination 2009–10 to 2013–14, final decision, Melbourne, April 2009; AER, New South Wales distribution determination 2009–10 to 2013–14, final decision, Melbourne, April 2009; AER, New South Wales distribution determination 2009–10 to 2013–14, final decision, Melbourne, April 2009; AER, New South Wales distribution determination 2009–10 to 2013–14, final decision, Melbourne, April 2009; AER, New South Wales distribution determination 2009–10 to 2013–14, final decision, Melbourne, April 2009; AER, New South Wales distribution determination 2009–10 to 2013–14, final decision, Melbourne, April 2009; AER, New South Wales distribution determination 2009–10 to 2013–14, final decision, Melbourne, April 2009; AER, New South Wales distribution determination 2009–10 to 2013–14, final decision, Melbourne, April 2009; AER, New South Wales distribution determination 2009–10 to 2013–14, final decision, Melbourne, April 2009; AER, New South Wales distribution determination 2009–10 to 2013–14, final decision, Melbourne, April 2009; AER, New South Wales distribution determination 2009–10 to 2013–14, final decision, Melbourne, April 2009; AER, New South Wales distribution determination 2009–10 to 2013–14, final decision, Melbourne, April 2009; AER, New South Wales distribution determination 2009–10 to 2013–14, final decision, Melbourne, April 2009; AER, New South Wales distribution determination 2009–10 to 2013–14, final decision, Melbourne, April 2009; AER, New South Wales distribution determination 2009–10 to 2013–14, final decision, Melbourne, April 2009; AER, New South Wa

131

#### 5.3.2 Regulatory approach

The AER's regulatory approach, as set out in the Electricity Rules, is to determine a revenue cap for each transmission business, setting the maximum revenue that a network can earn during a regulatory period (typically, five years). Unlike the distribution sector, all transmission businesses must be subject to a revenue cap (as opposed to other control mechanisms—for example, a price cap). In setting the revenue cap, the AER applies a building block model to determine the revenue that a transmission business needs to cover its efficient costs while providing for a commercial return to the business. The component building blocks cover:

- > operating and maintenance expenditure
- > capital expenditure
- > asset depreciation costs
- > taxation liabilities
- > a commercial return on capital.

To illustrate, figure 5.5 shows the components of the revenue cap for TransGrid (New South Wales) for the period 2009–10 to 2013–14. For most networks, over 60 per cent of the revenue cap consists of returns on capital.

The AER has developed incentive schemes as part of the regulatory process:

- > An *efficiency benefit sharing scheme* provides incentives for transmission businesses to achieve efficient operating and maintenance expenditure in running their networks. The scheme shares efficiency gains between a business and its customers (through lower prices). The scheme applies to all transmission businesses except EnergyAustralia, which is subject to an equivalent distribution business scheme.<sup>9</sup>
- > A service target performance incentive scheme encourages businesses to maintain or improve network service performance. It acts as a counterbalance to the efficiency benefit sharing scheme so businesses do not reduce costs at the expense of service quality.

#### Figure 5.5

Composition of TransGrid revenue cap, 2009–10 to 2013–14



Source: AER, TransGrid transmission determination 2009-10 to 2013-14, final decision, Melbourne, April 2009.

The scheme focuses on network availability and reliability (the frequency and duration of network outages). It also includes a component based on the market impact of transmission congestion (see section 5.7.2). If service performance is above target, the business earns rewards; if performance falls below target, a business may be penalised. The service standards scheme applies to all transmission businesses (although only TransGrid is subject to the congestion component).<sup>10</sup>

As part of its role as economic regulator of transmission networks, the AER has developed guidelines to assist stakeholders and to provide regulatory certainty to transmission businesses developing revenue proposals.

<sup>9</sup> From 1 July 2009 EnergyAustralia has been subject to the incentive schemes applicable to distribution businesses. For more details on these schemes, see chapter 6.

<sup>10</sup> The market impact of transmission congestion component of the scheme will apply to other transmission businesses from the beginning of their next regulatory period. On 30 April 2009, however, Grid Australia submitted a Rule change proposal that would allow a transmission business to elect to be covered by the scheme from an earlier date.

These guidelines include:

- > transmission guidelines, which set out the process that businesses must follow in structuring and submitting their revenue proposals for assessment by the AER
- > a decision on the parameters of the weighted average cost of capital (WACC) model, which determines the return on capital that a regulated network may recover.<sup>11</sup> The WACC model sets an efficient benchmark for elements including equity raising and debt costs faced by a business when seeking finance. The WACC model applies to all network businesses that submit regulatory proposals after 1 May 2009.
- > cost allocation and pricing methodology guidelines, which set out the general principles for allocating costs to, and charges for, services provided by the business
- > a post-tax revenue model, which determines the annual revenue requirement needed in each year of the regulatory period to cover a network's cost estimates (or building blocks)
- > a roll-forward model, which determines a network's opening RAB, accounting for capital expenditure, asset disposal and depreciation over the previous regulatory period. The model also establishes annual RAB forecasts for the coming regulatory period.

The AER has also provided guidance on other aspects of the regulatory framework, including:

- > guidelines on the operation of the regulatory test, which is an analysis tool used by network businesses to assess the efficiency of planned investment (see section 5.8.2)
- > a statement of approach detailing the priorities and objectives of annual performance reports on transmission businesses
- > ring-fencing guidelines, which set out how transmission businesses that own or operate other network businesses (for example, distribution businesses) are to maintain and separate their accounts.

#### 5.4 Electricity 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 ageing assets. Some investment is driven by technological innovations that can improve network performance.

The regulatory process aims to create incentives for efficient investment. At the start of a regulatory period, the AER approves an investment (capital expenditure) forecast for each network. It can also approve contingent projects—large investment projects that are foreseen at the time of the revenue determination, but that involve significant uncertainty about timing and/or costs.

While the regulatory process approves a pool of funds for capital expenditure, individual projects must undergo a regulatory test of economic efficiency. Under the test, a network business must determine that a proposed augmentation passes a cost-benefit analysis, or provides a least cost solution for meeting network reliability standards.<sup>12</sup> The AER is developing a regulatory investment test for transmission (RIT-T) to replace the current regulatory test. The new test will be published by 1 July 2010 (see section 5.8.2).

In determinations since 2005 the AER has allowed network businesses discretion over how and when to spend their investment allowances, without the risk of future review. To encourage efficient spending, network businesses retain a share of any savings (including the depreciation that would have accrued) against their investment allowance. A service standards incentive scheme ensures cost savings are not achieved at the expense of network performance (see section 5.3.2).

11 AER, Electricity transmission and distribution network service providers, Review of the weighted average cost of capital (WACC) parameters, final decision, Melbourne, May 2009.

<sup>12</sup> The test comprises a reliability limb (a least cost test for reliability projects) and a market benefits limb (a cost-benefit test for all other projects). See AER, *Regulatory test for network augmentation, version 3,* Melbourne, November 2007.

Figure 5.6 Electricity transmission investment by network



#### Notes:

Actual data (unbroken lines) are used where available; forecast data (broken lines) are used for other years.

Forecast capital investment is as approved by the regulator through revenue cap determinations (averaged over the regulatory period), except for Western Power where data are from the ERA's draft decision on proposed revisions to Western Power's access arrangement for the period 2009-10 to 2011-12.

For SP AusNet, actual expenditure is replacement expenditure only; forecast expenditure includes network augmentation by AEMO (formerly VENCorp). All values are converted to June 2008 dollars.

Sources: AER/ACCC annual regulatory reports and revenue cap decisions; ERA performance reports and access arrangement decisions.

#### Figure 5.7



#### Notes:

134

Actual data (unbroken lines) are used where available; forecast data (broken lines) are used for other years.

Excludes private interconnectors.

All values are converted to June 2008 dollars.

Sources: AER/ACCC annual regulatory reports and revenue cap decisions; ERA performance reports and access arrangement decisions.

There has been significant investment in transmission infrastructure in the NEM since the shift to national regulation (figures 5.6 and 5.7).<sup>13</sup> Investment levels have been highest for TransGrid and Powerlink. The other networks typically have relatively lower investment levels, reflecting the scale of the networks and differences in investment drivers such as infrastructure age and demand projections.

Care must be taken in interpreting year-to-year changes in investment data. Timing differences between the commissioning of some projects and their completion creates volatility. In addition, transmission investment can be 'lumpy' given the one-off nature of very large capital programs. More generally, because regulated revenues are typically set for five year periods, the network businesses have flexibility to manage and reprioritise their capital expenditure during this time.

13 Figure 5.6 includes Western Power for comparative purposes.

Transmission investment in the major NEM networks totalled around \$1.4 billion in 2007-08, equal to around 10 per cent of the combined RABs. Investment was forecast to rise to over \$1.6 billion in 2008-9. Investment over the 10 years to 2011-12 (including the Basslink interconnector) is forecast at around \$12.4 billion. In Western Australia, investment in 2007-08 reached around \$260 million. The Economic Regulation Authority's draft decision for Western Power provides an investment allowance of around \$1.5 billion for the three year period starting 1 July 2009.

Recent AER revenue cap decisions project significantly higher investment into the next decade. Forecasts indicate that a step-change rise in investment levels is taking place across the NEM. This reflects substantial real investment in new infrastructure as well as rising resource costs in the energy construction sector.

The Transend, TransGrid and EnergyAustralia revenue determinations in 2009 took account of the changing economic environment. Various input costs (including labour and materials) have recorded slowing growth trends, given the economic downturn. While labour and material costs are still forecast to rise over the regulatory period, the rate of increase is expected to be lower than previously forecast. This expectation contrasts with the revenue determinations for SP AusNet and ElectraNet in 2008, for which input costs were forecast to grow rapidly over the regulatory period.

#### 5.5 Financial performance

The AER publishes an annual performance report on the electricity transmission network sector.<sup>14</sup> In addition, new regulatory determinations include both historical performance data for the preceding regulatory period and forecasts of future outcomes.

#### 5.5.1 Revenues

Figure 5.8 charts revenue outcomes for the major transmission businesses, as well as forecast revenues provided through the regulatory process. The year



#### Figure 5.8

Electricity transmission revenue

#### Notes:

Actual data (unbroken lines) are used where available; forecast data (broken lines) are used for other years.

All values are converted to June 2008 dollars.

Sources: AER/ACCC annual regulatory reports and revenue cap decisions; ERA performance reports and access arrangement decisions.

14 AER, Transmission network service providers: electricity performance report for 2007-08, Melbourne, 2009.
in which the data commence varies across networks, reflecting the staged transfer to national regulation. Different outcomes across the networks reflect differences in scale and market conditions. The revenues of all networks, however, are increasing to meet rising demand. The combined revenue of the NEM's transmission businesses was forecast to exceed \$2 billion in 2008–09, representing a real increase of about 30 per cent over five years. Revenue for Western Power was forecast at over \$200 million in 2008–09.

Some networks experienced a significant rise in revenues in their first revenue determination under national regulation—for example, in 2003–04 the ACCC allowed revenues for Transend (Tasmania) that were 28 per cent higher than those provided in its previous regulatory period. In addition, the start of a new regulatory period sometimes provides a sharp increase in revenues, reflecting a step-change in capital expenditure—for example, SP AusNet's forecast revenue for 2008–09 (the first year of the current regulatory period) represented a 40 per cent real increase over the previous year's.

#### 5.5.2 Return on assets

The AER's annual regulatory report contains a range of profitability and efficiency indicators for transmission businesses in the NEM.<sup>15</sup> Of these, the return on assets is a widely used indicator of performance. The return on assets is based on operating profits (net profit before interest and taxation) as a percentage of the RAB.<sup>16</sup> Figure 5.9 shows the return on assets for transmission businesses over the six years to 2007–08. In this period, government owned network businesses typically achieved annual returns on assets of 5–8 per cent. The privately owned networks in Victoria and South Australia (SP AusNet and ElectraNet respectively) yielded returns of 7–10 per cent. Outcomes diverged in 2007–08, following convergence over the previous two years.

#### Figure 5.9

Return on assets for electricity transmission businesses



Sources: AER/ACCC annual performance reports for transmission network service providers.

A variety of factors can affect performance in this area, including differences in the demand and cost environments faced by each business, the rate of return allowed by the regulator, and demand and cost outcomes that differ from those forecast in the regulatory process.

# 5.5.3 Operating and maintenance expenditure

In setting a revenue cap, the AER allows for efficient operating and maintenance costs. In 2007-08 transmission businesses spent about \$420 million on operating and maintenance costs, which was about \$50 million below regulatory forecasts. Overall, real expenditure allowances are rising over time in line with rising demand and costs. Three of the six NEM networks, however, incurred lower costs in 2007-08 than in the previous year (figure 5.10). Spending is highest for TransGrid (New South Wales) and Powerlink (Queensland), partly reflecting the scale of those networks. Several factors affect the cost structures

15 AER, Transmission network service providers: electricity performance report for 2007-08, Melbourne, 2009, and previous years.

16 The RAB is recalculated annually (with new investment rolled in) for the purposes of this measure.

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ELECTRICITY TRANSMISSION

of transmission companies, including the varying load profiles, load densities, asset age, network designs, local regulatory requirements, topography and climate.

The regulatory framework provides incentives for network businesses to reduce their spending through efficient operating practices. The AER sets expenditure targets and allows a business to retain any underspend in the current regulatory period (and to retain some savings into the next period). The AER also applies a service standards incentive scheme to ensure cost savings are not achieved at the expense of network performance (see section 5.6).

The AER's 2007–08 regulatory report<sup>17</sup> compares 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. It may be, however, that delays in undertaking some projects deferred the need to operate and maintain those assets. More generally, care must be taken in interpreting year-to-year changes in operating expenditure. The network businesses have some flexibility in managing their expenditure over the regulatory period, so timing considerations may affect the data.

SP AusNet (Victoria) and ElectraNet (South Australia) have spent below their forecast targets since the incentive schemes began in 2002–03 (figure 5.11). TransGrid has underspent every year since 2004–05.

The other networks have tended to spend above target, with large overspends by Transend and EnergyAustralia in 2007–08.

Cost savings should not be achieved at the expense of service quality. AER data indicate that all major networks in eastern and southern Australia have performed satisfactorily against target levels of service quality (see section 5.6).

#### Figure 5.10

Operating and maintenance expenditure for electricity transmission businesses



Note: All values are converted to June 2008 dollars.

Sources: AER/ACCC annual performance reports for transmission network service providers.

#### Figure 5.11

# Operating and maintenance expenditure—variances from target



Sources: AER/ACCC annual performance reports for transmission network service providers.

# 5.6 Service reliability of electricity transmission networks

Reliability refers to the continuity of electricity supply to customers. Many factors 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 (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 the jurisdictions apply different reliability standards, all transmission networks are designed to deliver high rates of reliability. The networks are engineered and operated with sufficient capacity to act as a buffer against planned and unplanned interruptions in the power system. More generally, they 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, in the longer term, efficient investment in transmission infrastructure to avoid potential reliability issues. In regulating the networks, the AER approves capital and operating expenditure allowances that network businesses 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 allowances. As a counterbalance, a service quality incentive scheme rewards network businesses for maintaining or improving service quality. In combination, capital and operating expenditure allowances and incentive schemes encourage transmission businesses to maintain network reliability over time. Investment decisions are also guided by planning requirements set by state governments, in conjunction with standards set by AEMO. The state governments vary considerably in their approaches to planning, and in the standards they apply. The Australian Energy Market Commission (AEMC) completed a review of national reliability standards in 2008, to develop a nationally consistent framework (see section 5.8.2).

# 5.6.1 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 businesses on reliability, based on system minutes of unsupplied energy to customers. The data are normalised in relation to maximum regional demand to allow comparability.<sup>18</sup>

The data indicate the NEM jurisdictions have generally achieved high rates of transmission reliability (figure 5.12). In 2007–08 total unsupplied energy in all jurisdictions was lower than in the previous year. Unsupplied energy across New South Wales, Victoria and South Australia totalled only 2.1 minutes. New South Wales and Victoria generally experience the least minutes off supply, while Western Australia and Tasmania historically experience the most minutes off supply.

#### Australian Energy Regulator data

The AER has developed incentive schemes to encourage efficient 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
- > the average duration of transmission outages
- > the frequency of 'off supply' events.

18 System minutes unsupplied are calculated as megawatt hours of unsupplied energy divided by maximum regional demand.

Figure 5.12 Electricity transmission outages—system minutes unsupplied



Note: Data not available for Queensland in 2006-07 and 2007-08. Source: ESAA, *Electricity gas Australia 2009*, Melbourne, August 2009.

#### Table 5.2 S-factor values

TRANSMISSION BUSINESSES	2004	2005	2006	2007	2	008
Powerlink (Qld)				0.82		0.53
TransGrid (NSW)	0.93	0.70	0.63	-0.12		0.31
EnergyAustralia (NSW)	1.00	0.67	0.39	-0.14		0.72
SP AusNet (Vic)	0.22	0.09	-0.17	0.06	0.15	0.82
ElectraNet (SA)	0.63	0.71	0.59	0.28	0.29	-0.40
Transend (Tas)	0.55	0.19	0.06	0.56		0.85
Directlink (Qld—NSW)			-0.54	-0.62		-1.00
Murraylink (Vic—SA)			0.21	-0.32		0.69

Notes:

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

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

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

Source: AER, Transmission network service providers: electricity performance report for 2007-08, Melbourne, August 2009.

Rather than impose a common benchmark target for all transmission networks, the AER sets separate standards that reflect the circumstances of each network based on its past performance. Under the scheme, the over- or underperformance of a network against its targets results in a gain (or loss) of up to 1 per cent of its regulated revenue. A further bonus of up to 2 per cent is available through the transmission congestion component of the scheme (see section 5.7.2). The revenue at risk may be increased to a maximum of 5 per cent in future regulatory decisions.

The results are standardised for each network to derive an 's-factor' that can range between -1 and +1. An s-factor of -1 represents the maximum penalty, while +1 represents the maximum bonus. Zero represents a revenue neutral outcome. Table 5.2 sets out the s-factors for each network for the past five years. The major networks in eastern and southern Australia have generally outperformed their s-factor targets. The only businesses to receive a financial penalty in 2008 were ElectraNet (South Australia), for the second half of the year, and Directlink. Transend received the highest financial reward for 2008 service (0.85 per cent of revenue).

Table 5.3 shows the transmission businesses' performance against their individual targets. While caution must be taken in drawing conclusions from short data series, the major networks appear to have generally performed well against their targets.

Figure 5.13 illustrates the net financial reward or penalty from the scheme for each major network. While the scheme encourages network businesses to improve their performance over time, the financial outcomes relate to individual targets for each network and are not a comprehensive indicator of service quality.

#### Figure 5.13

140





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

Sources: AER, Transmission network service providers: electricity performance report for 2007-08, Melbourne, August 2009, and previous years.

## 5.7 Electricity transmission congestion

Transmission networks do not have unlimited capacity 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 constrained due to events and conditions on a particular day. Some congestion is caused by factors within the control of a service provider-for example, its scheduling of outages, its maintenance and operating procedures, its standards for network capability (such as thermal, voltage and stability limits), changes in its network monitoring procedures and its decisions on equipment upgrades. Factors beyond the control of the service provider include extreme weather-for example, hot weather can result in high air-conditioning loads that push a network towards its pre-determined limits. To protect system security, AEMO may invoke network constraints. Similarly, line maintenance may limit available capacity. The potential for network congestion is magnified if these events occur simultaneously.

If a major transmission outage occurs in combination with other generation or demand events, it can cause the load shedding of some customers. This is rare in the NEM, however. Rather, the main impact of congestion is on the cost of electricity. In particular, transmission congestion increases the total cost of electricity by displacing low cost generation with more expensive generation. If, for example, 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 higher cost generators are used, then the cost of producing electricity ultimately increases.

POWERLINK (QLD)	TARGET	2004	2005	2006	2007	20	08
Transmission line availability—critical elements (%)	99.07				99.44		98.99
Transmission circuit availability—non-critical elements (%)	98.40				98.70		98.51
Transmission circuit availability—peak hours (%)	98.16				98.60		98.48
Frequency of lost supply events greater than 0.2 system minutes	5				1		2
Frequency of lost supply events greater than 1 system minute	1				0		0
Average outage duration (minutes)	1033				612		1046
TRANSGRID (NSW)	TARGET	2004	2005	2006	2007	20	08
Transmission line availability (%)	99.50	99.72	99.57	99.57	99.38		98.54
Transformer availability (%)	99.00	99.30	98.90	98.84	97.46		98.53
Reactive plant availability (%)	98.50	99.47	99.64	98.92	99.23		99.01
Frequency of lost supply events greater than 0.05 system minutes	5	0	1	2	4		2
Frequency of lost supply events greater than 0.40 system minutes	1	0	0	0	1		0
Average outage duration (minutes)	1500	937	717	812	788		869
ENERGYAUSTRALIA (NSW)	TARGET	2004	2005	2006	2007	20	08
Transmission feeder availability (%)	96.96	98.57	98.30	97.74	96.62		98.41
SP AUSNET (VIC)	TARGET	2004	2005	2006	2007	20	08
Total circuit availability (%)	98.73	99.27	99.34	99.25	99.11	99.44	99.12
Peak critical circuit availability (%)	99.39	99.97	99.94	99.88	99.75	99.49	99.80
Peak non-critical circuit availability (%)	99.40	99.57	99.86	99.79	99.86	99.94	99.93
Intermediate critical circuit availability (%)	98.67	99.80	99.75	99.54	99.32		99.42
Intermediate non-critical circuit availability (%)	98.73	99.39	98.21	98.97	95.78		99.53
Frequency of lost supply events greater than 0.05 system minutes	5	2	5				1
Frequency of lost supply events greater than 0.3 system minutes	1	0	2				1
Average outage duration—lines (minutes)	382	164	452	1856	96	172	226
Average outage duration-transformers (minutes)	412	292	398	431	326	656	263
ELECTRANET (SA)	TARGET	2004	2005	2006	2007	20	08
Transmission line availability (%)	99.25	99.38	99.57	99.42	99.38	99.39	
Total transmission circuit availability (%)	99.47						99.05
Peak critical circuit availability (%)	99.24						97.26
Frequency of lost supply events greater than 0.05 system minutes	4						3
Frequency of lost supply events greater than 0.2 system minutes	2	7	0	4	1	0	1
Frequency of lost supply events greater than 1 system minute	2	0	0	0	0	0	
Average outage duration (minutes)	78	49	114	88	270	203	195
TRANSEND (TAS)	TARGET	2004	2005	2006	2007	20	08
Transmission line availability (%)	99.10- 99.20	99.34	98.67	99.21	98.99		99.40
Transformer circuit availability (%)	99-99.10	99.31	99.20	98.80	99.55		99.06
Frequency of lost supply events greater than 0.1 system minutes	13–16	18	13	16	10		6
Frequency of lost supply events greater than 2 system minutes	2–3	0	0	1	0		0

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Notes:

Performance targets vary across years. The listed target is for 2008. Performance in previous years is measured against the targets for the relevant year.

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

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

Sources: AER, Transmission network service providers: electricity performance report for 2007-08, Melbourne, August 2009, and previous years.

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) > Measures the total savings if all constraints were eliminated.	<ul> <li>Hot weather in New South Wales causes a surge in demand for electricity, raising the price. The line between Victoria and the Snowy region 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.</li> <li>&gt; TCC measures the increase in the cost of electricity caused by the blocked transmission line.</li> </ul>
Outage cost of constraints (OCC)	<ul> <li>The total increase in the cost of producing electricity due to outages on transmission networks</li> <li>&gt; Looks at only congestion caused by network outages.</li> <li>&gt; Outages may be planned (e.g. scheduled maintenance) or unplanned (e.g. equipment failure).</li> <li>&gt; Excludes other causes, such as network design limits.</li> </ul>	<ul> <li>Maintenance on a transmission line prevents the dispatch of a coal fired generator that requires the use of the line.</li> <li>A higher cost gas fired peaking generator (that uses a different transmission line) has to be dispatched instead.</li> <li>OCC measures the increase in the cost of electricity caused by line maintenance.</li> </ul>
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 megawatt, added over a year > Identifies which constraints have a significant impact on prices. > Does not measure the actual impact.	<ul> <li>See above TCC example.</li> <li>MCC measures the saving in the cost of producing electricity in New South Wales if one additional megawatt 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 measure the impact of all congestion (and do not discriminate between individual elements).</li> </ul>

#### Table 5.4 Market impact of electricity transmission constraints—Australian Energy Regulator measures

Congestion can also create opportunities for the exercise of market power. If a network constraint prevents low cost generators from moving electricity to customers, then there is less competition in the market. Subsequently, the remaining generators can adjust their bidding to capitalise on their position, which is likely to result in increased electricity prices.

Not all constraints have the same market impact. Most do not force more expensive generation to be dispatched —for example, congestion that 'constrains off<sup>719</sup> a coal fired plant and requires the dispatch of another coal fired plant may have little net 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 the National Electricity Market Management Company (NEMMCO, now AEMO), the AER completed a project in 2006 to measure the impact of transmission congestion in the NEM. The AER measures the cost of transmission congestion by comparing dispatch costs with and without congestion. It has developed three measures of the impact of congestion on the cost of electricity (table 5.4). 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 constraints have the greatest impact.<sup>20</sup>

<sup>19</sup> Under the Electricity Rules, 'constrained off' means 'in respect of a generating unit, the state where, due to a constraint on a network, the output of that generating unit is limited below the level to which it would otherwise have been dispatched by AEMO on the basis of its dispatch offer'.

<sup>20</sup> A more detailed discussion appears in: AER, *Indicators of the market impact of transmission congestion-decision*, Melbourne, 9 June 2006; AER, annual congestion reports for 2003-04, 2004-05, 2005-06 and 2006-07, Melbourne.

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, accounting for the costs of individual generators. If generators' bidding reflects their true cost position, then the measures will be an accurate measure of the economic cost of congestion. The measures reflect, therefore, the negative efficiency effects of congestion and make an appropriate basis for developing incentives to mitigate this cost. If, however, market power allows a generator to bid above its true cost structure, then the measures will reflect a mix of economic costs and monopoly rents. An example of the impact of congestion on the wholesale market is provided in box 5.2.

The AER assesses the impact of major constraints in its weekly market reports. It published four annual congestion reports for the 2003-04 to 2006-07 financial years. These reports assisted in the development of the market impact parameter in the service target performance incentive scheme. This new parameter applied for the first time to TransGrid from July 2009 (see section 5.3.2).

The annual cost of congestion rose from \$36 million in 2003-04 to \$189 million in 2007-08 but fell to \$83 million in 2008-09 (figure 5.14). Typically, most congestion costs accumulate on just a handful of days. Around two thirds of the total cost for 2007-08 accrued on 26 days, with 57 per cent of the costs attributable to network outages. In 2008-09 around two thirds of the total cost accrued on 13 days, with 42 per cent of the costs attributable to network outages.

The data indicate that the cost of network congestion has generally risen over the past six years. In 2008–09 the impact of congestion and particularly network outages was, however, considerably less than for the previous two years. The costs are relatively modest given the scale of the market. Recent regulatory decisions have provided for increased transmission investment that may help to address capacity issues and reduce congestion costs over time.

#### Figure 5.14 Costs of transmission congestion



#### Source: AER.

Figure 5.15 shows congestion on a monthly basis from July 2007 to June 2009. The bulk of congestion costs occurred during the months of August and September 2007 (a result of maintenance outages in Queensland) and over the two summer periods (mainly due to extreme demand in Victoria and South Australia).

There were significant congestion costs in January and February 2009. Costs totalled \$45 million—more than half the total for the financial year—on the last four days of January. In part this was due to a number of unplanned outages on days of high demand—for example, on 29 January the Basslink interconnector and some transmission infrastructure in the Latrobe Valley were out of service.

There were outage costs of \$6 million on 7 and 8 February when Victorian bushfires caused significant network outages including on the Victorian to New South Wales interconnector.



Figure 5.15 Monthly costs of transmission congestion for 2007–08 and 2008–09

Source: AER

#### Box 5.2 Case study-transmission outages in Victoria

An example of the effects of transmission constraints on energy market outcomes occurred on Wednesday 23 July 2008, when outages of network equipment between Hazelwood Terminal Station and Loy Yang Power Station in Victoria coincided with high winter demand.

For several hours from around 6 pm that evening, two of the three Hazelwood to Loy Yang 500 kV lines were out of service: the first to investigate an equipment alarm triggered early that morning, and the other following an unplanned outage due to the incorrect action of protection equipment. Only one line was left connecting Loy Yang A and B power stations and Tasmania to the rest of the market. This reduced electricity production from Loy Yang by around 1000 megawatts and prevented any flows into Victoria across BassLink.

Due to the risk of losing the remaining Hazelwood to Loy Yang line, the requirement for frequency control

ancillary services to cover this contingency increased significantly—the 6 second requirement increased from 212 MW to 1076 MW, the 60 second requirement from 212 MW to 1538 MW and the 5 minute requirement from 406 MW to 1731 MW. The prices for those services rose to the price cap. The cost of ancillary services that evening totalled around \$118 million—compared with less than \$60 million for the rest of 2008–09. At the same time, generators reduced energy output to provide these services. This reduced the dispatch of low priced energy generation by more than 1 gigawatt.

As a result of the reduced availability of low priced generation, combined with record winter demand, the spot price for each of the mainland regions exceeded \$8000 per megawatt hour for the 6.30 pm trading interval. The total cost of congestion for this event was \$1.6 million, with outage cost accounting for \$1.2 million.



Around 1200 network constraints affected the market at least once in 2007–08 and 2008–09. At any one time, between 550 and 650 constraints were typically in place. Congestion may be significant in a particular area for only a few days a year, but this is sometimes sufficient to have a significant impact on congestion costs.

Figure 5.16 shows the locations of significant congestion over the past six years. Locations of congestion may change from year to year due to conditions such as drought, weather events and unscheduled line outages. In 2007–08 and 2008–09, there was congestion in northern Tasmania; in Victoria's Latrobe Valley around Hazelwood; in South Australia (mainly in the south east and around Mintaro); and Queensland. Congestion between central Queensland and the load centre in Brisbane has affected the market every year. There was also congestion in northern and central Queensland and on the Middle Ridge to Tangkam transmission line.

There was also congestion on interconnectors between regions, including on the Heywood interconnector (Victoria to South Australia), across QNI (Queensland to New South Wales) and across the Snowy interconnector (Victoria to New South Wales).

# 5.7.2 Measures to reduce congestion costs

The AER recognises the significance of congestion costs and has responded to the issue by:

- > developing measures of the market impact of transmission constraints and publishing data against these measures (as outlined)
- > implementing an incentive scheme to reduce transmission constraints
- providing for rising transmission investment in regulatory decisions.

Other responses include the AEMC congestion management review, which aimed to enhance mechanisms to manage congestion in the NEM. The review considered options such as congestion pricing, changes to regional pricing structures and deeper connection charges (see section 5.8.4). In addition, the Ministerial Council on Energy (MCE) has implemented national transmission planning arrangements which are expected to reduce congestion through enhanced whole-of-NEM network planning (see section 5.8.1).

Further, the AEMC congestion management review recommended that AEMO develop a Congestion Information Resource to provide cost-effective information to participants, to enable them to understand patterns of network congestion and project market outcomes. The review recommended that the resource provide the most recent information on network outages and other planned network events. This would provide participants with a better understanding of how potential changes in system conditions are likely to affect their market risks, allowing for more informed decision making. The AEMC published its decision on changes to the Electricity Rules in August 2009. AEMO is required to publish an interim by March 2010, guidelines by September 2010 and its first final resource by September 2011.

## Congestion management incentive scheme

The AER introduced a new incentive mechanism in 2008 to reduce the effects of transmission congestion. The mechanism forms part of the service performance incentive scheme and is designed to encourage network owners to account for the impact of their behaviour on the market.<sup>21</sup> The mechanism operates as a bonus-only scheme. It aims to reward network owners for improving operating practices in areas such as outage timing, outage notification, live line work and equipment monitoring. In some cases, these improvements may be more cost-efficient measures to reduce congestion than solutions that require investment in infrastructure.

The mechanism permits a transmission business to earn an annual bonus of up to 2 per cent of its revenue if it can eliminate all outage events with a market impact of over \$10 per megawatt hour.<sup>22</sup>

22 The level of performance improvement required to receive the full 2 per cent bonus is probably an unrealistic aim. It may be difficult to determine a realistic level of performance, however, until the scheme has been in place for a period of time.

<sup>21</sup> AER, Electricity transmission network service providers: service target performance incentive scheme, Melbourne, March 2008.

Figure 5.16 Congestion within regions of the National Electricity Market 2003–04 2004–05





2007-08







2008-09



Source: AER.

## 5.7.3 Settlement residue auctions

Congestion in transmission interconnectors can cause wholesale electricity prices to differ across the regions of the NEM (see 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 will flow from lower 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. AEMO offers a risk management instrument by holding quarterly auctions to sell the rights to future residues up to one year in advance.<sup>23</sup> 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. New South Wales is a significant importer of electricity, so it can be vulnerable to price separation and often accrues high settlement residue balances.

Figure 5.17 charts the amount of settlement residues that accrued each year against the proceeds of residue auctions from 2000 to 2008. 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 approximates, therefore, the risk faced by market participants from interregional trade. The figure illustrates that the residues are frequently auctioned for less than their ultimate value. On average, the actual residues have been around 55 per cent higher than the auction proceeds.

#### Figure 5.17

Interregional hedging—auction proceeds and settlement residues



Source: AEMO.

Market participants tend to discount the value of settlement residues because they are not a firm hedging instrument. 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 for which they are bidding 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 (see chapter 3).

# 5.8 Policy developments in electricity transmission

Recent policy activity in the transmission sector has focused on network planning and operation and the approach to economic regulation. This section summarises policy developments in these areas. Appendix A describes the institutional bodies and organisations with responsibility for developing and implementing energy policy.

23 In September 2009 AEMO began consultation on a proposal to extend auctions from one to three years.



# 5.8.1 Australian Energy Market Operator and the National Transmission Planner

In July 2009 AEMO began operating as a single, industry funded national energy market operator for both electricity and gas. It merges the roles of the national electricity market operator (previously undertaken by NEMMCO) with the gas market operators in New South Wales, the ACT, Queensland, Victoria and South Australia. It also assumes the state based electricity planning functions of VENcorp (in Victoria) and the Electricity Industry Supply Planning Council (in South Australia).

AEMO also undertakes new functions, including:

- > the planning and coordination of development of the national transmission network
- > the preparation of a gas statement of opportunities (see chapter 8).

The National Transmission Planner (NTP) role aims to strengthen transmission planning arrangements in the NEM. In particular, it will attempt to move the planning focus away from priorities within individual jurisdictions, onto the national grid as a whole.

An annual national transmission network development plan will outline the efficient development of the power system. It will provide a long term strategic outlook (minimum 20 years), focusing on national transmission flow paths. It will not replace local planning and will not be binding on transmission businesses or the AER. Rather, the plan will complement shorter term investment planning by transmission businesses.

## 5.8.2 Regulatory test for investment

The regulatory test is an analysis tool that network businesses use to assess the efficiency of planned investment. It identifies the most effective network augmentation or non-network option for meeting an identified investment need. In July 2009 the AEMC completed a rule change to replace the regulatory test with the Regulatory Investment Test for Transmission (RIT-T).<sup>24</sup> The new test removes the distinction between reliability driven projects and those driven by the delivery of market benefits. All projects will now be assessed through a single consultation and assessment framework, which aims to identify investments that promote efficiency and, where applicable, meet reliability standards.

The revised assessment process is more comprehensive than the previous process set out in the Electricity Rules, and applies to a wider range of investment projects. It involves greater prescription in the Electricity Rules of the market benefits and costs that the analysis can consider, and a new market benefit category covering an asset's option value. The AER will develop and publish the RIT-T and associated guidelines by July 2010.

# 5.8.3 Climate change (review of energy market frameworks)

The AEMC has reviewed the likely impacts of climate change policies—particularly the carbon pollution reduction scheme and expanded renewable energy target —on energy market frameworks. It released the final report in October 2009.

The AEMC identified the connection process for new generators as a weakness in the Electricity Rules.<sup>25</sup> The current process is unlikely to cope with a large increase in connection applications that may result from the introduction of climate change policies—particularly for new investment in renewable generation that may be clustered in certain geographic locations and remote from customers and the transmission network. In particular:

> the current bilateral negotiation framework is unlikely to lead to the development of appropriately by sized connection assets to cater for expected future demand for network access

<sup>24</sup> AEMC, National Electricity Amendment (Regulatory Investment Test for Transmission) Rule 2009 No. 15, Sydney

<sup>25</sup> AEMC, Review of energy market frameworks in light of climate change policies, final report, Sydney, October 2009.

> confidentiality provisions limit the opportunity to coordinate multiple connection applications, leading to delays and additional costs in the connection process.

To take advantage of economies of scale in network assets, the AEMC has recommended a new framework for developing network extensions for remote generation. The framework will coordinate connection applications, with the extension assets sized to allow for expected growth in demand for network access. Customers will bear the risk of oversized connection assets.

In May 2009 the AEMC published a draft rule determination to amend the confidentiality provisions for network connection applications. The change is designed to allow for greater coordination of connection applications.

The AEMC also considered that climate change policies may result in higher levels of network congestion within and across regions. It suggested stronger signals for generator entry location and generator exit could help resolve this issue. The signals could be provided through a combination of generator transmission charges (revenue neutral within each region) and constraint pricing at points in the network experiencing ongoing congestion.

The AEMC also proposed a model for interregional transmission charging. Under current arrangements, customers in an importing region of the NEM do not pay transmission businesses in the exporting region the costs incurred to serve their load. The AEMC supports the introduction of a load export charge that would treat the transmission business of the importing region as a customer of the transmission business of the exporting region. All charges to the network would ultimately be recovered from the network's customers.

### 5.8.4 Congestion management

While the reliability of transmission networks in the NEM is consistently high, network congestion sometimes impedes the dispatch of the most cost-efficient generation to satisfy demand. The AEMC finalised a congestion management review in 2008 that considered the scope for enhanced market based solutions to manage trading risks.<sup>26</sup>

Following the review, the MCE initiated a rule change to implement the main recommendations. These included:

- > formalising in the Electricity Rules AEMO's current process for determining which generators to dispatch in the market
- > amending the Electricity Rules to reduce financial uncertainty for holders of settlement residue units, including new arrangements to manage and fund negative settlement residues
- > publishing a congestion information resource by AEMO to consolidate and enhance information on network congestion.

In 2008 the AER launched a scheme that provides incentives for network businesses to better manage factors within their control that can lead to transmission congestion—for example, the scheduling of outages (see section 5.7.2).<sup>27</sup>

# 5.8.5 Jurisdictional reliability standards

The Energy Reform Implementation Group reported in 2007 that the current transmission reliability standards set by the jurisdictions need greater clarity and transparency. In particular, it formed a view that clause 5.1 of the Electricity Rules and the majority of jurisdictional reliability obligations require significant interpretation.<sup>28</sup>

150

<sup>26</sup> AEMC, Congestion management review, final report, Sydney, June 2008

<sup>27</sup> AER, Service target performance incentive scheme version 2, Melbourne, March 2008.

<sup>28</sup> ERIG, Energy reform-the way forward for Australia, Report to the Council of Australian Governments, Canberra, January 2007.

In response, the AEMC Reliability Panel undertook a review of jurisdictional transmission reliability standards. In August 2008 the AEMC released a final report endorsing the findings of the panel and setting out its preferred option for a nationally consistent framework.<sup>29</sup> Key features of the framework include:

- > economically derived and deterministically expressed standards set on a jurisdictional basis by independent jurisdictional authorities
- > the introduction of a national reference standard to compare reliability standards across jurisdictions
- > a clear and transparent standard setting process.

#### 5.8.6 Jurisdictional technical standards

In April 2009 the AEMC Reliability Panel completed an initial review of jurisdictional transmission technical standards.<sup>30</sup> The final report set out guiding principles on which to base a detailed review of the technical standards in the NEM, and it suggested minor changes to allow more efficient compliance.

The panel recommended deferring a detailed review until sufficient new connections have taken place under the current technical standards to better assess their effectiveness.

29 AEMC, Towards a nationally consistent framework for transmission reliability standards, final report, Sydney, September 2008.

30 AEMC Reliability Panel, Technical standards review, final report, Sydney, April 2009.





Most electricity customers are located a long distance from generators. The electricity supply chain thus requires networks to transport power from generators to customers. Chapter 5 provides a survey of high voltage transmission networks that move electricity over long distances. 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.

# 6 ELECTRICITY DISTRIBUTION

This 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 ways to present and analyse data on Australia's electricity 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 6.6 includes analysis based on a feeder classification. While this chapter includes data that might enable performance comparisons across networks, such comparative analysis should note that geographic, environmental and other differences can affect relative performance.

154

# 6.1 Role of distribution networks

Distribution networks move electricity from transmission networks to residential and business customers.<sup>1</sup> A distribution network consists of the poles, underground channels and wires that carry electricity, as well as substations, transformers, switching equipment, and monitoring and signalling equipment. While electricity moves along transmission networks at high voltages to minimise energy losses, it must be stepped down to lower voltages in a distribution network for safe use by customers. Most customers in Australia require delivery at around 230–240 volts.

Distribution networks criss-cross urban and regional areas to provide electricity to every customer. This requires substantial investment in infrastructure. The total length of distribution infrastructure is around 750 000 kilometres in the National Electricity Market (NEM) and around 100 000 kilometres in Western Australia and the Northern Territory—17 times longer than transmission infrastructure.

In Australia, electricity distributors provide the infrastructure to transport electricity to household and business customers, but they do not sell electricity. Instead, retailers bundle electricity generation with transmission and distribution services, and sell them as a package (see chapter 7). In some jurisdictions, there is common ownership of distributors and retailers, which are ring-fenced (operationally separated) from one another.

The contribution of distribution costs to final retail prices varies across jurisdictions, customer types and locations. The Queensland Competition Authority (QCA) reported in 2009 that distribution services account for about 36.5 per cent of a typical residential electricity bill.<sup>2</sup> The Essential Services Commission (ESC) of Victoria reported in 2004 that distribution can account for 30–50 per cent of retail prices, depending on customer type, energy consumption, location and other factors.<sup>3</sup>

# 6.2 Australia's distribution networks

Australia has 16 major electricity distribution networks, of which 13 are located in the NEM. Table 6.1 provides summary details. Queensland, New South Wales, Victoria and Western Australia have multiple networks, of which each is a monopoly provider in a designated area. In the other jurisdictions, there is one major network. There are also small regional networks with separate ownership in some jurisdictions. Figure 6.1 illustrates the distribution network areas for Queensland, New South Wales, the Australian Capital Territory (ACT) and Victoria. Figure 4.1 in chapter 4 illustrates the network areas for Western Australia.

## 6.2.1 Ownership

Table 6.1 sets out ownership arrangements forAustralian distribution networks. At June 2009:

- > Victoria and South Australia's networks are privately owned or leased, and the ACT network has joint government and private ownership
- > New South Wales, Queensland, Tasmania and the non-NEM jurisdictions of Western Australia and the Northern Territory have retained government ownership of the electricity distribution sector.

<sup>1</sup> There are exceptions. Some large businesses (such as aluminium smelters), for example, 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.

<sup>2</sup> QCA (Queensland), Final decision-benchmark retail cost index for electricity: 2009-10, Brisbane, June 2009, p. 54.

<sup>3</sup> ESC (Victoria), *Electricity distribution price review 2006-10, issues paper*, Melbourne, December 2004, p. 5.

## Table 6.1 Electricity distribution networks

		CUSTOMER	LINE LENGTH	ENERGY DELIVERED	MAXIMUM DEMAND	DISTRIBUTION LOSSES (%),
NETWORK	LOCATION	NUMBERS	(KM)	(GWH), 2007–08	(MW), 2007–08	2007–08
NEM REGIONS						
QUEENSLAND						
ENERGEX	Brisbane, Gold Coast, Sunshine Coast and surrounds	1 270 734	51 349	20 879	4 142	5.7
Ergon Energy	Country and regional Queensland	766 453	146 339	13 813	2 313	6.5
NEW SOUTH WAL	ES AND THE ACT					
EnergyAustralia	Inner, northern and eastern metropolitan Sydney and surrounds	1 580 933	49 556	30 624	5 683	4.3
Integral Energy	Southern and western metropolitan Sydney and surrounds	853 322	33 299	17 586	3 317	4.1
Country Energy	Country and regional NSW; southern regional Queensland	780 222	205 133	11 973	2 329	7.0
ActewAGL	All of the ACT	158 455	4 696	2 799	599	4.5
VICTORIA						
Powercor	Western Victoria	668 680	82 459	10 299	2 066	6.6
SP AusNet	Eastern Victoria	592 263	46 039	7 500	1 596	6.0
United Energy	South eastern metropolitan Melbourne	619 666	12 858	7 891	1 735	3.9
CitiPower	Inner metropolitan Melbourne	297 568	6 485	6 079	1 338	4.1
Jemena	Western metropolitan Melbourne	299 662	5 775	4 378	867	5.5
SOUTH AUSTRAL	IA					
ETSA Utilities	All of South Australia	786 800	85 833	11 380	2 847	5.5
TASMANIA						
Aurora Energy	All of Tasmania	265 524	24 641	4 487	1 073	1.1
NEM TOTALS						
NON-NEM REGIO	NS					
WESTERN AUSTR	ALIA					
Western Power	South western Western Australia	973 516	85 182	14 500	3 420	
Horizon Power	North western Western Australia	37 508	7 747			
NORTHERN TERF	RITORY					
Power and Water	All of the Northern Territory	74 097	7 311			7.0 <sup>5</sup>

ASSET BASE (2008 \$ MILLION) <sup>1</sup>	INVESTMENT— CURRENT PERIOD (2008 \$ MILLION) <sup>2</sup>	CURRENT REGULATORY PERIOD	OWNER
(	0.075		
4 778	3 077	1 July 2005 – 30 June 2010	Qld Government
4 656	3 147	1 July 2005 –	Qld Government
		30 June 2010	
7 184	6 535	1 July 2009 – 30 June 2014	NSW Government
3 633	2 679	1 July 2009 – 30 June 2014	NSW Government
4 252	3 767	1 July 2009 – 30 June 2014	NSW Government
589	271	1 July 2009 – 30 June 2014	ACTEW Corporation (ACT Government) 50%; Jemena (Singapore Power International (Australia)) 50%
1 849	905	1 Jan 2006 – 31 Dec 2010	Cheung Kong Infrastructure/ Hongkong Electric Holdings 51%; Spark Infrastructure 49%
1 486	714	1 Jan 2006 – 31 Dec 2010	SP AusNet (listed company; Singapore Power International 51%)
1 387	550	1 Jan 2006 – 31 Dec 2010	Jemena (Singapore Power International (Australia)) 34%; DUET Group 66%
1 126	520	1 Jan 2006 – 31 Dec 2010	Cheung Kong Infrastructure/ Hongkong Electric Holdings 51%; Spark Infrastructure 49%
657	239	1 Jan 2006 – 31 Dec 2010	Jemena (Singapore Power International (Australia))
2 771	846	1 July 2005 – 30 June 2010	Cheung Kong Infrastructure/ Hongkong Electric Holdings 51%; Spark Infrastructure 49%
1.075			<b>T A</b>
1 072	566	1 Jan 2008 – 20 June 2013	Tas Government
2 574 <sup>3</sup>	1 392 <sup>3</sup>	1 July 2009 – 30 June 2012 <sup>4</sup>	WA Government
 		UI	WA Government
500 <sup>5</sup>		1 July 2009 – 30 June 2014	NT Government

- Asset valuation is the opening regulated asset base for the current regulatory period, converted to June 2008 dollars.
- 2. Investment data are forecast capital expenditure over the current regulatory period, converted to June 2008 dollars.
- Data from the ERA's draft decision on proposed revisions to Western Power's access arrangement for the period 2009-10 to 2011-12.
- 4. At July 2009 Western Power's access arrangement for the period 2009-10 to 2011-12 was not finalised. Network prices for 2009-10, therefore, have been established under the previous access arrangement.
- 5. Includes transmission network assets.

Principal sources: Regulatory determinations and performance reports published by the AER (NSW and the ACT), the QCA (Qld), IPART (NSW), the ESC (Vic), ESCOSA (SA), the ERA (WA), OTTER (Tas), the ICRC (ACT) and the Utilities Commission (NT).

Ergon Energy ENERGEX BRISBANE • Country Energy Country Energy EnergyAustralia SYDNEY CANBERRA Powercor ActewAGL Distribution Integral Energy SP AusNet CitiPower Jemena -United Energy Ś

Figure 6.1 Electricity distribution network areas—Queensland, New South Wales, the ACT and Victoria

Figure 6.2 Electricity distribution networks—private ownership

	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Powercor		PacifiCorp				Cheung Kong					Che	Cheung Kong (51%), Spark (49%)				
SP AusNet			Texas Utilities (TXU) Sing Power								SP AusNet (Singapore Power (51%))				b))	
United Energy				Utilicorp, AMP, NSW State Super							Al D	Alinta (34%), Sing Po DUET (66%) DUE			) Power )UET (60	(34%), 6%)
CitiPower			Entergy		Ame	American Electric Power Cheung Kong						Cheung Kong (51%), Spark (49				(49%)
Jemena		AGL, (	General Utilities	Public		AGL							Alinta	Sing	gapore l	Power
ETSA Utilities		Go	overnme	ernment				Cheung Kong				Cheung Kong (51%), Spark (49%)				(49%)
ActewAGL							ACTEW Corporation (50%), AGL (50%			0%)	%) ACTEW (50%), (50%) Alinta (50%) Singapore Power (5			0%), ver (50%)		

Note: Some corporate names have been abbreviated or shortened.

Victoria's five distribution networks—Powercor, SP AusNet, United Energy, CitiPower and Jemena—are privately owned. The South Australian network (ETSA Utilities) is leased to private interests. Figure 6.2 tracks ownership changes since privatisation. At June 2009 there are two principal network owners:

- > Cheung Kong Infrastructure and Hongkong Electric Holdings have a 51 per cent stake in two Victorian networks (Powercor and CitiPower) and a 200-year lease of the South Australian distribution network (ETSA Utilities). The remaining 49 per cent in each network is held by Spark Infrastructure, a publicly listed infrastructure fund in which Cheung Kong Infrastructure has a direct interest.
- > Singapore Power International owns a 51 per cent stake in SP AusNet, which owns Victoria's SP AusNet network. Singapore Power International acquired a second Victorian network (Jemena) and part ownership of a third network (United Energy) from Alinta in 2007. It also owns a 50 per cent share in the ACT distribution network (ActewAGL).

DUET Group has a majority interest in Victoria's United Energy network.<sup>4</sup> The minority owner, Singapore Power International, operates the network.

### 6.2.2 Cross-ownership

In some jurisdictions, there are ownership links between electricity distribution and other segments of the energy sector. In New South Wales, Tasmania and the ACT, common ownership occurs in electricity distribution and retailing, with ring-fencing arrangements for operational separation.<sup>5</sup> Queensland privatised much of its energy retail sector in 2006–07, but Ergon Energy continues to jointly provide distribution and retail services. In Western Australia, Western Power owns both electricity transmission and distribution assets. Horizon Power in Western Australia and Power and Water in the Northern Territory are vertically integrated electricity businesses.

The private electricity distributors also provide other energy network services. The most significant is Singapore Power International, which owns electricity transmission and distribution networks, and gas transmission and distribution pipelines. Cheung Kong Infrastructure has an interest in gas distribution pipelines through its 19 per cent stake in Envestra.

<sup>4</sup> DUET Group comprises a number of trusts, for which Macquarie Bank and AMP Capital Holdings jointly own the responsible entities.

<sup>5</sup> In the ACT, ACTEW Corporation has a 50 per cent share in ActewAGL Retail and ActewAGL Distribution. AGL Energy and Singapore Power International respectively own the remaining shares.





# 6.3 Economic regulation of distribution services

Electricity distribution networks are capital intensive and incur declining marginal costs as output increases, thus realising economies of scale. This gives rise to a natural monopoly structure. In the NEM, the networks are regulated under the National Electricity Law (Electricity Law) and the National Electricity Rules (Electricity Rules) to manage the risk of monopoly pricing and ensure the reliability, safety and security of the power system.

On 1 January 2008 the Australian Energy Regulator (AER) acquired responsibility for the economic regulation of electricity distribution—previously the responsibility of state and territory regulators. The regulation of distribution networks in Western Australia and the Northern Territory remains under state and territory jurisdiction. Jurisdictional regulators continue to administer determinations made before 1 January 2008, except in Victoria, where the AER undertakes this role.<sup>6</sup> The AER is working with jurisdictional regulators and network businesses to maintain regulatory certainty in the transition period.

# 6.3.1 Regulatory process

Chapter 6 of the Electricity Rules sets out the timelines and processes for the economic regulation of distribution businesses. Distribution network businesses must periodically apply to the AER to determine their total revenue requirements for periods of at least five years. The regulatory process is lengthy to allow time for stakeholder consultation and the engagement of specialist consultants.

The process begins when the AER publishes a draft framework and approach paper for a network 24 months before the start of the next regulatory period. The paper is finalised in consultation with stakeholders six months after the draft paper is published. The AER first applied this process to the South Australian and Queensland networks in 2008.<sup>7</sup>

The framework and approach process acknowledges differences in the regulation of each network. This partly reflects historical differences in regulatory approach across the jurisdictions. In the transition to national regulation, it is important to clarify these differences upfront and indicate how the AER will approach each determination. The process also enhances transparency and certainty by giving stakeholders an opportunity to understand and comment on the regulatory approach.

The framework and approach process clarifies high level regulatory mechanisms and aims to assist network businesses to prepare their proposals. While the process sets out the AER's thinking at the time, there is scope for the AER to modify its position on some mechanisms. In summary, of the positions developed through the framework and approach process:

- > the control mechanism for setting a network's revenues or prices remains binding
- > the classification of services remains binding unless the AER considers there are good reasons to change it
- > all other positions are not binding.

Once the framework and approach process is completed, the network business must submit a regulatory proposal and a negotiation framework. This must occur at least 13 months before the end of the current regulatory period. The AER then assesses the proposal, typically with help from specialist consultants, and releases a draft determination for further consultation. It must release a final determination two months before the beginning of the upcoming regulatory period.

<sup>6</sup> This administration of determinations after they have been made involves assessing pass-through applications, approving prices, and assessing and reporting performance. State and territory regulators can elect to transfer the administration of current determinations to the AER. In Victoria, several of these functions have been transferred, and the AER will administer the Electricity Distribution Price Determination applicable until 31 December 2010. In other states and territories, jurisdictional regulators will continue to administer current determinations.

<sup>7</sup> The New South Wales and ACT distribution determinations were developed under transitional Electricity Rules, which did not provide for a framework and approach process.

#### Box 6.1 New South Wales and ACT distribution determinations

In April 2009 the AER released its first determinations for the distribution sector—for the New South Wales and ACT networks. The determinations provide for, in real terms, \$13 billion of capital expenditure across the three New South Wales networks and \$270 million for the ACT network over the period 2009–10 to 2013–14. The allowances are around 70 per cent higher than capital expenditure for the preceding five years.

The justification for higher investment varied across the networks but included:

- → network augmentations to meet rising peak demand across the networks and significant load growth in regions including the north coast, the Sydney central business district and western Sydney
- $\rightarrow$  the need to meet enhanced licensing conditions for network security and reliability
- $\rightarrow$  the replacement of ageing and obsolete assets.

The AER also approved significantly higher allowances for operating and maintenance expenditure—over \$6.5 billion for the regulatory period across the four businesses. This reflects assessments of prudent expenditure requirements for the networks. The overall revenue allowance across the four businesses is almost \$19 billion, around 60 per cent higher than for the previous regulatory period (in real terms). While this is a considerable increase, the allowances are lower than those sought by the businesses and those foreshadowed in the AER's draft report. This decision reflects revised economic forecasts (factoring in the effect of the global financial crisis) of easing demand growth.

The determinations will result in an increase in average residential electricity bills of up to \$1.50 per week in 2009–10.

The New South Wales distribution businesses lodged appeals with the Australian Competition Tribunal over aspects of the decisions. The appeals may result in amendments to the determinations.



162



#### Determination processes for electricity distribution networks

Figure 6.3 shows the regulatory timelines for each network. The AER completed its first electricity distribution reviews, for businesses in New South Wales and the ACT, in April 2009 (box 6.1). It has started work on determinations for the Queensland and South Australian networks, following the submission of regulatory proposals to the AER in June 2009. This process will determine each business's annual revenue requirements for the five year period from 1 July 2010.

For the Victorian networks, the next determinations are due to take effect on 1 January 2011. The AER has completed the framework and approach process and will complete the formal review process in late 2010.

## 6.3.2 Regulatory approach

The AER's regulatory approach involves setting a ceiling on the revenues or prices that a distribution business can earn or charge during a period, typically five years. The Electricity Rules require the use of incentives to optimise performance, but allow the regulator to choose the form of incentive. Regulatory frameworks currently used in Australia include revenue yield models (which control the average revenue per unit sold, based on volumes or revenue drivers) and weighted average price caps (which allow flexibility in individual tariffs within an overall ceiling).<sup>8</sup> Table 6.2 illustrates the range of available approaches.

FORM OF		REGULATORY POSITION AT 1 JULY 2009					
REGULATION	HOW IT WORKS	REGULATOR	DISTRIBUTION BUSINESSES				
Price cap or tariff basket	Sets a ceiling on distribution tariffs/prices. For a weighted average price cap, the business is free to adjust its individual tariffs as long as the weighted average remains within the ceiling.	Essential Services Commission (Vic), administered by the AER	Powercor SP AusNet United Energy CitiPower Jemena				
	a distribution business may earn. Revenues can vary depending on tariff structures and the volume of electricity sales.	AER	EnergyAustralia Integral Energy Country Energy				
Revenue cap	Sets the maximum revenue that a business may earn during a regulatory period. It effectively caps	Queensland Competition Authority	ENERGEX Ergon Energy				
	total earnings. This mirrors the approach used to regulate transmission networks. The distribution business may set individual tariffs such that total	Office of the Tasmanian Economic Regulator	Aurora Energy				
	revenues do not exceed the cap.	Economic Regulation Authority (WA)	Western Power				
Maximum average revenue cap	Sets a ceiling on average revenues during a regulatory period. Total prescribed distribution service revenues are capped each year at the average revenue allowance for a year multiplied by actual energy sales. Tariffs must be set to comply with this constraint.	AER	ActewAGL				
Revenue yield control	Links the amount of revenue that a 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.	Essential Services Commission of South Australia	ETSA Utilities				
	The business is free to determine individual tariffs —subject to tariff principles and side constraints— such that total revenues do not exceed the average.						
Schedule of fixed prices	Sets a list or schedule of prices for each individual service provided by the distribution business.						

#### Table 6.2 Control mechanisms available to electricity distribution businesses

8 Some mechanisms are reflected only in past determinations by jurisdictional regulators.

As noted in table 6.2, the regulatory approach varies across networks. The AER's April 2009 determinations applied a weighted average price cap (which places a ceiling on the prices of distribution services during a regulatory period) to the New South Wales networks, and an average revenue cap (which sets a ceiling on revenue yields that may be recovered during a regulatory period) to the ACT network.

Recent AER framework and approach papers determined that the South Australian and Victorian networks will be subject to a weighted average price cap. The Queensland networks will be subject to a revenue cap. The AER has consulted with the relevant business to settle on these approaches.

In applying any of the forms of regulation in table 6.2, the AER must forecast the revenue requirement of a business over the regulatory period. To do this, it uses a building block model that factors in:

- > investment forecasts (capital expenditure)
- > the operating expenditure allowances that a benchmark distribution business would require if operating efficiently
- > asset depreciation costs
- > a commercial return on capital
- > taxation liabilities.

In setting these elements, the AER has regard to demand projections, price stability, the potential for efficiency gains in cost and capital expenditure management, service standards and other factors. While jurisdictional regulators have taken varying approaches to specific building block components, the AER has developed a consistent method for all future revenue determinations.

Since assuming responsibility for the economic regulation of distribution networks, the AER has published models and guidelines to assist stakeholders.

These include:

- > a post-tax revenue model, which takes the cost estimates (or building blocks) for a network and determines the annual revenue requirement needed in each year of the regulatory period
- > a roll-forward model, which determines a network's opening regulated asset base (RAB), taking account of capital expenditure, asset disposal and depreciation over the previous regulatory period. The model also establishes annual RAB forecasts for the coming regulatory period.
- > a decision on the parameters of the weighted average cost of capital (WACC) model, which determines the return on capital that a regulated network may recover.<sup>9</sup> The WACC model sets an efficient benchmark for elements including equity raising and debt costs faced by a business when raising finance. The WACC model applies to all distribution businesses that submit regulatory proposals after 1 May 2009.
- > cost allocation guidelines, which outline the cost allocation method for a network and the basis on which the AER will assess that method
- > an issues paper on annual regulatory reporting requirements, with a view to publishing a regulatory information order in 2009. The order will set out guidance and protocols for the annual collection and submission of information to the AER for comparative analysis.

The AER has also developed incentive schemes to apply to distribution businesses:

> A national efficiency benefit sharing scheme provides incentives for distribution businesses to achieve efficient operating and maintenance expenditure in running their networks. The scheme shares efficiency gains between the business and customers (through lower prices). The AER indicated in its framework and approach papers that it will apply the scheme to businesses in Queensland, South Australia and Victoria from the next regulatory control period (see also section 6.5.3).

9 AER, Electricity transmission and distribution network service providers, Review of the weighted average cost of capital (WACC) parameters, final decision, Melbourne, May 2009.

- > A national incentive scheme on service target performance provides incentives for businesses to maintain or improve service performance across the network. It acts as a counterbalance to the efficiency benefit sharing scheme so businesses do not reduce costs at the expense of service quality. The scheme focuses on supply reliability (the frequency and duration of network outages) and customer service. If service performance falls below target, a business is penalised; if performance is above target, the business earns rewards. The scheme also includes a guaranteed service level (GSL) component, under which payments are made directly to customers when service performance falls below threshold levels. The service standards scheme applies as a paper trial in New South Wales and the ACT in the current regulatory period (that is, targets will be set but no financial penalties or rewards will apply). The AER indicated in its framework and approach papers that it will apply the service performance scheme to the Queensland, South Australian and Victorian networks in the next regulatory period (see also section 6.6.2).
- Jurisdictional demand management incentive schemes provide incentives for network businesses to implement efficient non-network approaches to manage demand. The schemes offer allowances for projects or initiatives that reduce network demand. In some jurisdictions, the schemes allow businesses to recover revenue that has been forgone due to successful demand reduction initiatives. No business is compelled to take up the scheme, with the allowance provided on a 'use it or lose it' basis. The AER has developed individual demand management schemes for New South Wales and the ACT, South Australia and Queensland, and Victoria (see also section 6.8.1).

# 6.4 Distribution investment

New investment in distribution infrastructure is needed to maintain and, where appropriate, improve network performance over time. Investment covers network augmentations to meet rising demand and expand into new regional centres and towns. It also covers upgrades to improve the quality of existing networks by replacing ageing assets. Some investment is driven by regulatory requirements on matters such as network reliability.

Figure 6.4 shows the opening RABs and forecast regulated investment over the current regulatory period for the major networks.<sup>10</sup> The combined opening RABs of distribution networks are around \$39 billion, more than double the valuation for transmission infrastructure. Investment over the current regulatory cycle for the networks is forecast at around \$25 billion.<sup>11</sup>

Many factors can affect the value of RABs and investment, including the basis of original valuation, historical network investment, the age of a network, geographic scale, the distances required to transport electricity from transmission connection points to demand centres, population dispersion and forecast demand profiles.

Figure 6.5 charts annual investment in regulated assets in each network, using actual data where available and forecast data for other years. The forecast data relate to proposed investment that the regulator has approved as efficient at the beginning of the regulatory period. The forecast data are smoothed over the regulatory period to remove the significant volatility often evident in the annual forecast data. The charts depict real data in June 2008 dollars.

CHAPTER 6 ELECTRICITY DISTRIBUTION

<sup>10</sup> Regulated investment in most networks does not include capital contributions. Although this expenditure forms part of the overall investment in a network, the distribution business does not incur the development costs and, accordingly, does not receive a return on those assets. At the end of the regulatory period, the RAB is adjusted to reflect new regulated investment that has occurred.

<sup>11</sup> Investment estimates are for the current (typically five year) regulatory periods. The RAB and investment values are in June 2008 dollars.



Figure 6.4 Electricity distribution network assets and investment—current regulatory period

Notes:

The regulated asset base is the opening asset valuation for the current regulatory period. Forecast capital expenditure is for the current regulatory period. The regulatory period is 4.5 years for Aurora Energy (Tas), three years for Western Power (WA) and five years for other networks. Data for Western Power are from the ERA's draft decision on proposed revisions to Western Power's access arrangement for the period 2009–10 to 2011–12. All values are converted to June 2008 dollars.

Sources: Regulatory determinations published by the AER (NSW and ACT), the ESC (Vic), the QCA (Qld), ESCOSA (SA), OTTER (Tas) and the ERA (WA).

In summary, investment in the NEM jurisdictions was forecast at over \$4.1 billion in 2008–09, increasing to almost \$4.8 billion in 2009–10. In Western Australia, \$380 million of investment was forecast in 2008–09, with the Economic Regulation Authority proposing investment by Western Power of \$450 million in 2009–10. Investment has risen steadily during the current decade in most networks. This has generally been accompanied by stable reliability outcomes.<sup>12</sup>

On average, investment during the current regulatory cycle is running at over 40 per cent of the underlying asset base in most networks, over 65 per cent in Queensland and up to 90 per cent in parts of New South Wales. Different outcomes across jurisdictions reflect a range of variables, including forecast demand, the scale and age of the networks, and investment allowances in historical regulatory determinations. Box 6.1 includes a summary of the New South Wales and ACT distribution determinations released by the AER for the period 2009–10 to 2013–14.

There is some volatility in the investment data, reflecting a number of factors. In particular, investment is somewhat lumpy as a result of the one-off nature of some capital programs. More generally, the network businesses have some flexibility in managing and reprioritising their capital expenditure over the regulatory period. Transitions between regulatory periods, and from actual to forecast data, also result in some data volatility—for example, network businesses tend to schedule a significant portion of investment in the early stages of a regulatory period, although some projects may be subsequently delayed.

12 See section 6.6 and figure 6.10.

Figure 6.5



Notes:

Actual data (unbroken lines) used where available and forecasts (broken lines) for other years as set out in regulatory determinations (except for Western Australia, for which forecasts for 2009-10 to 2011-12 are based on the ERA's draft decision for Western Power). Forecasts are of average capital expenditure over the regulatory period.

Western Power

All data have been converted to June 2008 dollars.

Sources: Regulatory determinations published by the AER (NSW and the ACT), the ESC (Vic), the QCA (Qld), ESCOSA (SA), the ERA (WA) and OTTER (Tas).

Aurora Energy

In addition to regulated investment undertaken by the distribution businesses, market participants can also fund new investment in the networks. These capital contributions can form a significant proportion of new network investment—for example, they have typically accounted for over 15 per cent of total distribution network investment in Victoria and over 25 per cent of investment in South Australia.

For most distribution businesses, investment funded through capital contributions sits outside the RAB and the businesses do not earn a return on the assets. In Queensland and Western Australia, however, distribution businesses have capital contributions included in the RAB. The revenue allowance of these businesses is adjusted to ensure overall returns reflect the actual business activity of the network.<sup>13</sup>

# 6.5 Financial performance of distribution networks

Financial data on distribution networks are available from two main sources—performance reports and regulatory determinations. Until recently, all jurisdictional regulators published annual reports on electricity distribution networks, covering financial and service performance.

With the move to national regulation in 2008, the AER will play a role in public reporting on the financial performance of the networks. Initial reports will be prepared for the Victorian networks for the 2009 reporting year, and for the New South Wales and ACT networks for 2009–10. The AER will consult with stakeholders to develop an appropriate reporting framework.

Regulatory determinations include historical financial data for the preceding regulatory period and forecast outcomes.

# 6.5.1 Revenues

Figure 6.6 charts revenues for distribution networks, based on actual results where available and otherwise using regulatory forecasts. Allowed revenues are tending to rise over time as underlying asset bases expand to meet rising demand. The combined revenue of the NEM's 13 major distribution networks was forecast at around \$6.1 billion in 2008–09, a rise of about 4 per cent in real terms over the previous year. A further rise of about 12 per cent in real terms (\$6.8 billion) is forecast for 2009–10.

In Western Australia, Western Power's allowed revenues in 2008–09 were around \$400 million. It has proposed an increase to over \$600 million in 2009–10.

# 6.5.2 Return on assets

A common financial indicator for a business is its return on assets. The ratio is calculated as operating profits (net profit before interest and taxation) as a percentage of the average RAB. Figure 6.7 sets out the returns on assets for distribution businesses in the NEM, where data are available. Over the past seven years, the privately owned businesses in Victoria and South Australia tended to yield returns of about 8–12 per cent. Returns for these businesses were consistently higher than regulatory forecasts of 7–9 per cent. The government owned distribution businesses in New South Wales, Queensland and Tasmania achieved returns ranging from 4 per cent to 10 per cent.

A variety of factors can affect performance in this area. These include differences in the demand and cost environments faced by each business, and variances in demand and costs outcomes compared with those forecast in the regulatory process.

13 Western Power has proposed, for the regulatory period 2009-10 to 2011-12, that capital contributions be excluded from the RAB.

#### Figure 6.6





#### Notes:

Actual data (unbroken lines) used where available and forecasts (broken lines) for other years as provided in regulatory determinations (except for Western Australia, for which forecasts for 2009-10 to 2011-12 are based on the ERA's draft decision).

Data are for year ended 30 June. Victorian data are for the calendar year ending in that period.

All data have been converted to June 2008 dollars.

Sources: Regulatory determinations published by the AER (NSW and the ACT), the QCA (Qld), IPART (NSW), the ESC (Vic), ESCOSA (SA), the ERA (WA), OTTER (Tas) and the ICRC (ACT).

#### Figure 6.7

#### Electricity distribution network return on assets



RAB, regulated asset base.

Note: Data are for year ended 30 June. Victorian data are for the calendar year ending in that period.

Sources: Performance reports published by the ESC (Vic), IPART (NSW), the QCA (Qld), ESCOSA (SA), OTTER (Tas) and the ICRC (ACT).



Figure 6.8 Forecast operating and maintenance expenditure—electricity distribution networks, 2008–09

Note: Forecast data for 2008-09 are converted to June 2008 dollars. Victorian data are for the calendar year 2008. Sources: Regulatory determinations published by the ESC (Vic), IPART (NSW), the QCA (Qld), ESCOSA (SA), the ERA (WA), OTTER (Tas) and the ICRC (ACT).

# 6.5.3 Operating and maintenance expenditure

Figure 6.8 charts forecast operating and maintenance expenditure for each network on per kilometre and per customer bases in 2008-09. The forecasts reflect regulatory allowances for each network to cover efficient operating and maintenance expenditure. There is a range of outcomes in this area, reflecting differences in customer and load densities, the scale and condition of the networks, geographic factors and reliability requirements. Normalising on a per kilometre basis tends to bias against high density urban networks with relatively short line lengths-reflected in the high outcomes for the three Victorian urban networks and the ACT network-while normalising on a per customer basis tends to bias against low density rural networks such as the Ergon Energy and Country Energy networks.

The AER published details in June 2008 of an efficiency benefit sharing scheme as part of the national framework for distribution regulation.<sup>14</sup> The scheme provides incentives for businesses to reduce their spending against benchmarks through efficient operating practices. It applies uniformly to all distribution businesses. The AER will first apply the scheme to the Queensland and South Australian networks from July 2010.

The scheme provides incentives for a distribution business to make efficient expenditure, by allowing it to retain efficiency gains for five years after a gain is made. A benchmark level of expenditure is used to determine revenue adjustments. Under the national scheme, the distribution business retains 30 per cent of efficiency gains against the benchmark, with the remaining 70 per cent being returned to customers through lower prices.

14 AER, Electricity distribution network service providers: efficiency benefit sharing scheme, final decision, Melbourne, June 2008.





Operating and maintenance expenses of electricity distribution networks—variances from target

Sources: Performance reports published by the ESC (Vic), IPART (NSW), the QCA (Qld), ESCOSA (SA), OTTER (Tas) and the ICRC (ACT).
Over time, the national scheme will replace the current state based incentive schemes that jurisdictional regulators administer in the NEM. Figure 6.9 compares actual expenditure against target expenditure for each network under the state based schemes. A positive variance indicates that actual expenditure exceeded the benchmark in that year-that is, the distribution business overspent. A negative variance indicates underspending against the benchmark. A trend of negative variances over time may suggest a positive response to efficiency incentives. More generally, care should be taken in interpreting year-to-year changes in operating expenditure. The network businesses have some flexibility in managing their expenditure over the regulatory period, so timing considerations may affect the data. Delays in completing a project may also affect expenditure.

Figure 6.9 indicates that the South Australian network and most Victorian networks underspent against their forecast allowances for most or all of the charted period. The Queensland networks recorded small but consistent overspends of up to 10 per cent from 2005–06. The Tasmanian network consistently overspent from 2003–04.

# 6.6 Service quality and reliability

Electricity distribution networks are monopolies that face little risk of losing customers if they provide poor service. In addition, regulatory incentive schemes for efficient cost management might encourage a business to sacrifice service performance to reduce costs. Recognising these risks, governments and regulators monitor the performance of distribution businesses to ensure they provide acceptable levels of service. Quality of service monitoring for electricity distribution typically relates to:

- 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).

All jurisdictions regulate the service performance of distribution networks through:

- > the monitoring and reporting of reliability, technical quality and customer service outcomes against standards set in legislation, regulations, licences and codes (possibly with sanctions for non-compliance)
- > GSLs (relating to network reliability, technical quality of service and customer service) that require, if not met, a network business to pay affected customers.

The legislated service standards are designed to ensure distribution businesses maintain appropriate levels of performance. GSL schemes ensure distribution businesses do not have an incentive to neglect regions or individual customers within their network. In addition to these measures, some jurisdictions have applied financial incentive schemes for distribution businesses to maintain and improve service performance over time. With the shift to national distribution regulation, the AER published in 2009 details of a national service target performance incentive scheme that will apply, over time, to all distribution networks.

In the future, the AER will publicly report on the service performance of distribution businesses. It will consult with stakeholders on the reporting measures and future reporting arrangements.

# 6.6.1 Reliability

Reliability refers to the continuity of electricity supply to customers, and it is a key service performance indicator. Distribution outages account for over 90 per cent of the duration of all electricity outages in the NEM. Relatively few outages originate in the generation and transmission sectors.<sup>15</sup>

A reliable distribution network keeps interruptions or outages in the transport of electricity down to efficient levels. It would be inefficient to try to eliminate every possible interruption. Rather, an efficient outcome requires assessing the value of reliability to the community (measuring the impact on services) and the willingness of customers to pay. 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 more than 50 per cent of customers were willing to pay a higher price to improve or maintain their level of supply reliability.<sup>16</sup> However, South Australian surveys in 2003 and 2007 indicated few customers were willing to pay for improvements in service. The 2007 survey found only 13 per cent of customers were willing to pay more for service improvement, with no significant difference in response between those experiencing high and low reliability.17

Surveys of consumer preferences do not necessarily capture all benefits from improved supply reliability, particularly those benefits from avoiding disruption to essential services. In a review of minimum service standards and GSLs in Queensland, Evans & Peck concluded, considering all impacts, that customers as a community value improved reliability.<sup>18</sup> 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 unexpectedly disconnected. They may result from operational error, asset overload or deterioration, or 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 part of a network has inadequate maintenance or is used near its capacity limits at times of peak demand. These factors sometimes occur in combination.

The impact of a distribution outage tends to be localised to a part of the network and depends on customer load, the design of the network and the time taken by a distributor to restore supply after an interruption. Maintenance practices are an important factor in reducing the number of outages and the time it takes to reconnect supply. Distribution businesses undertake large maintenance programs that include asset inspections and repairs, vegetation clearing and emergency response.

Jurisdictions track the reliability of distribution networks against performance standards to assess whether it is satisfactory. The standards account for the trade-off between improved reliability and cost. Ultimately, customers must pay for the cost of investment, maintenance and other solutions needed to deliver a reliable power system.

The trade-offs between improved reliability and cost have resulted in standards for distribution networks being less stringent than for generation and transmission.

<sup>15</sup> See AER, State of the energy market 2007, essay B, Melbourne, 2007, pp. 38-53.

<sup>16</sup> KBA and Powercor, Understanding customers' willingness to pay: components of customer value in electricity supply, Melbourne, 1999.

<sup>17</sup> The 2003 survey found 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, Adelaide, April 2005; KPMG, Consumer preferences for electricity service standards, Adelaide, March 2003; and McGregor Tan Research, Consumer preferences for electricity service standards, Adelaide, November 2007.

<sup>18</sup> Evans & Peck, Queensland Competition Authority, Review of minimum service standards and guaranteed service levels, Brisbane, December 2008, p. 49.

These less stringent standards also reflect the localised effects of distribution outages, compared with the potentially widespread geographic impact of a generation or transmission outage. The capital intensive nature of distribution networks makes it very expensive to build in high levels of redundancy (spare capacity) to improve reliability. These factors help to explain why distribution outages account for such a high proportion of electricity outages in the NEM.

For similar reasons, there tend to be different reliability standards for different feeders (parts) of a distribution network. A higher reliability standard is usually required, for example, for 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 a low load density. While the unit costs of improving reliability in a dispersed rural network are relatively high, an outage is likely to affect few customers. Conversely, the unit costs of improving reliability in a high density urban network are relatively low, and an outage is likely to affect many customers.

### **Reliability data**

All jurisdictions have their own monitoring and reporting frameworks for reliability. In addition, the Steering Committee on National Regulatory Reporting Requirements (SCONRRR)<sup>19</sup> has adopted four indicators of distribution network reliability that are widely used in Australia and overseas. The indicators relate to the average frequency and duration of network interruptions or outages (table 6.3). The indicators do not distinguish between the nature and size of loads affected by supply interruptions.

In most jurisdictions, distribution businesses report performance against the system average interruption duration index (SAIDI), the system average interruption frequency index (SAIFI) and the customer average interruption duration index (CAIDI) indicators. The national service performance incentive scheme, published in June 2008, includes the SAIDI and SAIFI indicators.<sup>20</sup>

Table 6.3 Reliability measures—electricity distribution

INDEX	NAME	DESCRIPTION
SAIDI	System average interruption duration index	Average total number of minutes that a 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, Canberra, 2002.

Regulators audit, analyse and publish reliability outcomes, typically down to feeder level (CBD, urban and rural) for each network.<sup>21</sup> Tables 6.4 and 6.5 and figure 6.10 estimate historical SAIDI and SAIFI data for NEM jurisdictions. Some data from Western Australia are also provided. In the future, the AER will report on reliability outcomes as part of its performance reporting on the distribution sector.

The data in tables 6.4 and 6.5 and figure 6.10 reflect total outages experienced by distribution customers. In general, the data have not been normalised to exclude distribution outages that are beyond the reasonable control of the network operator—for example, outages that originate in the generation and transmission sectors, and outages caused by external factors such as extreme weather. The data for Queensland in 2005–06 and New South Wales in 2006–07, however, have been adjusted to remove the impact of natural disasters (Cyclone Larry in Queensland and extreme storm activity in New South Wales), which would otherwise severely distort the data.

<sup>19</sup> SCONRRR is a working group established by the Utility Regulators Forum.

<sup>20</sup> AER, Electricity distribution network service providers: service target performance incentive scheme, final decision, Melbourne, June 2008. See section 6.6.4.

<sup>21</sup> In New South Wales, the distribution businesses publish these data in the first instance. The regulator (IPART) periodically publishes summary data.

Table 6.4	System	average	interruption	n duration	index	(SAIDI)	(minutes)
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	2000-01	2001-02	2002-03	2003-04	2004–05	2005-06	2006-07	2007–08
Queensland	331	275	265	434	283	353	231	264
New South Wales	175	324	193	279	218	191	211	180
Victoria	183	152	151	161	132	165	165	197
South Australia	164	147	184	164	169	199	184	150
Tasmania	265	198	214	324	314	292	256	304
NEM weighted average	211	246	196	268	202	221	202	207
Western Australia							325	317

### Table 6.5 System average interruption frequency index (SAIFI)

	2000-01	2001-02	2002-03	2003-04	2004–05	2005-06	2006-07	2007–08
Queensland	3.0	2.8	2.7	3.4	2.7	3.1	2.1	2.4
New South Wales	2.5	2.6	1.4	1.6	1.6	1.8	1.9	1.7
Victoria	2.1	2.0	2.0	2.2	1.9	1.8	1.9	2.1
South Australia	1.7	1.6	1.8	1.7	1.7	1.9	1.8	1.5
Tasmania	2.8	2.3	2.4	3.1	3.1	2.9	2.6	2.6
NEM weighted average	2.4	2.4	1.9	2.2	1.9	2.1	2.0	1.9
Western Australia							3.3	3.3

### Figure 6.10

### System average interruption duration index (SAIDI)



Notes for tables 6.4 and 6.5 and figure 6.10:

The data reflect total outages experienced by distribution customers. In some instances, the data may include outages resulting from issues in the generation and transmission sectors. In general, the data have not been normalised to exclude distribution network issues beyond the reasonable control of the network operator. The data for Queensland in 2005–06 and New South Wales in 2006–07 have been adjusted to remove the impact of natural disasters (Cyclone Larry in Queensland and extreme storm activity in New South Wales), which would otherwise have severely distorted the data.

The NEM averages are weighted by customer numbers.

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

Sources for tables 6.4 and 6.5 and figure 6.10: Performance reports published by the ESC (Vic), IPART (NSW), the QCA (Qld), ESCOSA (SA), the ERA (WA), OTTER (Tas), the ICRC (ACT), EnergyAustralia, Integral Energy and Country Energy. Some data are AER estimates derived from official jurisdictional sources. The AER consulted with PB Associates in the development of historical data.

From a customer perspective, the unadjusted data presented here are relevant, but an assessment of distribution network performance should normalise data to exclude external sources of interruption. The SCONRRR agreed that reliability data should, in some circumstances, be normalised to exclude interruptions beyond the control of a network business.

Until recently, there was no consistent approach to determining exclusions.<sup>22</sup> Now, the AER national service target performance incentive scheme (published in May 2009) adopts a consistent approach to exclusions, based on a standard set by the Institute of Electrical and Electronics Engineers. The standard is used in a number of Australian jurisdictions. In addition, the scheme identifies events that should be excluded.<sup>23</sup> The impact of excluded events is considered later in this chapter.

A number of issues limit the validity of comparing performance across the networks. In particular, the data rely on the accuracy of the network businesses' information systems, which may vary considerably. There are also differences in design, geographic conditions and historical investment across the networks. As noted, differences in customer density and load density can affect the costs and benefits of achieving high reliability. More generally, each jurisdiction historically took a different approach to approving and reporting excluded events and, until recently, there has been no consistent approach to auditing performance outcomes.

Noting these caveats, the SAIDI data indicate that distribution networks in the NEM have delivered reasonably stable reliability outcomes over the past few years, with recent improvements in some jurisdictions. The NEM-wide SAIDI was generally 200–250 minutes from 2000–01 to 2007–08, but with significant regional variations. The average duration of outages per customer has tended to be lower in Victoria and South Australia than elsewhere, despite some community concerns in the 1990s that privatisation might adversely affect service quality. Outage duration has tended to fall in New South Wales since 2003-04, and in 2007-08 that state recorded the second lowest outage rate behind South Australia. Average reliability (as measured by SAIDI) is weaker in Queensland and Tasmania than in other NEM jurisdictions. Queensland is subject to significant variations in performance, partly as a result of its large and widely dispersed rural networks, and extreme weather events. These characteristics make Queensland more vulnerable to outages than are some other jurisdictions, although it has recorded improvements in reliability since 2003-04. Data for Western Australia indicate that outage duration has recently been higher in that state than in the NEM jurisdictions.

The SAIFI data appear to show an improvement in the average frequency of outages across the NEM since 2000. The average frequency of outages is higher in Queensland than in other mainland jurisdictions, although that state's performance improved over 2006-07 and 2007-08. On average, distribution customers in the mainland NEM regions experience outages around twice a year. The rate has been a little higher in Tasmania. Western Australian customers experience outages around three times a year.

The recent improvements in reliability in New South Wales and Queensland are consistent with the rising investment trends noted in section 6.4. In Queensland, the government acted to improve reliability when a 2004 review (the Somerville review) found distribution service performance was unsatisfactory.<sup>24</sup> The government introduced performance requirements aimed at improving reliability by 25 per cent by 2010.

<sup>22</sup> The SCONRRR definitions of SAIDI and SAIFI exclude outages that exceed a threshold SAIDI impact of 3 minutes; outages that are caused by exceptional natural or third party events; and outages for which the distribution business cannot reasonably be expected to mitigate the effect by prudent asset management.

<sup>23</sup> AER, Electricity distribution network service providers: service target performance incentive scheme, final decision, Melbourne, May 2009, section 6.7.

<sup>24</sup> For background on the Somerville review and Queensland's reliability issues, see AER, State of the energy market 2007, Melbourne, 2007, p. 53.

In New South Wales, licensing requirements relating to network design, reliability and performance have been gradually enhanced, requiring greater expenditure by the network businesses to ensure compliance.

### Reliability of distribution networks by feeder

Given the diversity of network characteristics, it is often more meaningful to compare reliability by feeder category rather than across networks as a whole. There are four categories of feeder, based on geographic location (table 6.6).

#### Table 6.6 Feeder categories

FEEDER CATEGORY	DESCRIPTION
CBD	A feeder that predominately supplies commercial, high rise buildings through an underground distribution network containing significant interconnection and redundancy compared with urban areas
Urban	A feeder that is not a CBD feeder, with actual maximum demand over the reporting period per total feeder route length greater than 0.3 megavolt amperes per kilometre
Rural short	A feeder that is not a CBD or urban feeder, with a total feeder route length less than 200 kilometres
Rural long	A feeder that is not a CBD or urban feeder, with a total feeder route length greater than 200 kilometres

Source: URF, National regulatory reporting for electricity distribution and retailing businesses, Canberra, 2002.

Figures 6.11a-d set out the average duration of supply interruptions per customer (SAIDI) for each feeder type, subject to data availability. The charts distinguish between outages that are deemed within the reasonable control of the networks (normalised outages) and outages deemed beyond their control. The latter exclusions cover outages that originate in the generation and transmission sectors, and outages caused by external events such as extreme weather. Generally, it would be unreasonable to assess network performance unless excluding the impact of these external factors. Total network outages in a period are the sum of the normalised and excluded data.

Meaningful comparisons across jurisdictions—even based on the normalised data—are difficult given the differences in approach to exclusions and in auditing practices. Any attempt to compare performance should also account for geographic, environmental and other differences across the networks. That said, CBD and urban customers tend to experience better network reliability than rural customers.

The variations in performance across feeder types reflect that reliability standards account for the differing costbenefit reliability trade-offs in each part of a network. To illustrate, a network outage on a CBD feeder is likely to have more severe economic consequences than from a similar outage on a remote rural feeder where customer bases and loads are more dispersed. Similarly, the unit costs of improving reliability in a high density urban network will be lower than in a dispersed rural network that is exposed to more variable weather and where it is more difficult to access lines to identify and repair faults. For these reasons, CBD networks are designed for higher reliability than other feeders are, and they use underground feeders, which are less vulnerable to outages.









Rural short feeders—average duration of supply interruptions per customer (SAIDI)

Figure 6.11c

# Figure 6.11d



Unallocated

-exclusions

Distribution

Distribution-normalised

Generation/transmission



Sources: Distribution network performance reports published by the ESC (Vic), IPART (NSW), the QCA (Qld), ESCOSA (SA), OTTER (Tas), EnergyAustralia, Integral Energy and Country Energy. Unallocated data do not provide a breakdown across categories.

In summary, in the period from 2003–04 to 2007–08:

- > CBD feeders were more reliable than other feeders. Most CBD customers experienced outages totalling less than 20 minutes per year. In 2007 CitiPower (Victoria) recorded unadjusted outages totalling 67 minutes—more than three times the level experienced in the previous five years. Most of these outages were the result of three excluded events, including load shedding during the 16 January 2007 bushfires. Unadjusted outages in Aurora Energy's (Tasmania) network averaged more than 100 minutes per customer. The increase in outages relative to the previous year was due to issues in the generation and transmission sectors.
- > Urban customers typically experienced outages totalling around 50–150 minutes per year.
   Normalised outage time tended to be lowest for those networks with less dispersed customer bases.
   Networks in several jurisdictions experienced significant interruptions that were excluded from the normalised data. Extreme weather caused significant exclusions for Queensland in 2005–06 and New South Wales in 2006–07. SP AusNet (Victoria) had significant excluded events affecting its urban feeders for each of the last three years in the data period. The normalised data indicate that reliability was reasonably stable or improving over time in most networks.
- > Rural short customers typically experienced normalised outages of around 100–300 minutes per year, with outages tending to be highest in New South Wales and Queensland. Ergon Energy (Queensland) customers typically experienced over 500 minutes of normalised outages. Weather related factors led to major exclusions in Queensland in 2005–06 and New South Wales in 2006–07.

> With a feeder route length of more than 200 kilometres, rural long customers experienced the least reliable electricity supply. Rural long customers in Victoria, South Australia and Tasmania experienced outages of around 200–400 minutes per year on average. The performance of the New South Wales and Ergon Energy (Queensland) networks was more variable, ranging from 600 minutes of outages to over 2000 minutes. In 2007–08 rural long customers serviced by Integral Energy (New South Wales) experienced normalised outages of over 1600 minutes (and total outages of over 2300 minutes) for the second year running.

### 6.6.2 Technical quality of supply

The technical quality of supply in 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 others may be traced to an environmental issue or to a network customer.

Network businesses report on the technical quality of supply by disaggregating complaints into their underlying causes and categorising them. The complaint rate for technical quality of supply issues since 2004-05 has been less than 0.1 per cent of customers for most mainland distribution networks in the NEM. ENERGEX and Ergon Energy (Queensland) recorded complaint rates of 0.1 per cent and 0.3 per cent of customers respectively in 2007-08, with the performance of these networks having improved steadily since 2004-05. Western Power and Horizon Power (Western Australia) had complaint rates of 0.2 per cent and 0.3 per cent of customers respectively in 2007-08. Aurora Energy (Tasmania) recorded a complaint rate of 0.2 per cent of customers in 2007–08, lower than in the previous five years. Issues arise, however, when making performance comparisons across jurisdictions. In particular, the definition of 'complaint' adopted by each business may vary.

# 6.6.3 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 6.7 and 6.8 provide a selection of customer service data for the networks. As noted, performance comparisons are difficult, given the significant differences across networks, as well as possible differences in definitions and in information, measurement and auditing systems.

Network performance in the timely provision of services in 2007–08 was broadly in line with that of previous years. ENERGEX recorded a significant increase in the number of late connections, and the New South Wales networks recorded longer average times for street light repairs. Call centre performance was similar to that of previous years, with the New South Wales and most Victorian networks recording slight improvements in 2007–08.

# 6.6.4 Service performance incentive schemes

Victoria and South Australia have applied financial incentive schemes for their distribution businesses to maintain and improve service performance over time. The model is an 's-factor' incentive scheme, similar to that applied to transmission networks.<sup>25</sup> The South Australian scheme focuses on customers with poor reliability outcomes.

The AER published details in May 2009 of an incentive scheme for service target performance as part of the national framework for distribution regulation.<sup>26</sup>

The scheme provides financial bonuses and penalties of up to 5 per cent of revenue to network businesses that meet (or fail to meet) performance targets. The targets relate to reliability of supply (duration and frequency of outages) and customer service. The results are standardised for each network to derive an 's-factor' that reflects deviations from target performance levels.

The national scheme includes a GSL component, which provides payments to customers that receive service below predetermined thresholds (for example, failure to attend service appointments). The GSL component does not apply where the distribution business is subject to jurisdictional GSL obligations (see section 6.6.5).

The national scheme is based on existing state based incentive schemes in Victoria and South Australia, so has regard to industry and community expectations. Over time, the national scheme will replace the state based schemes. The AER will first apply the national scheme in its current price reviews of the Queensland and South Australian distribution networks, scheduled to take effect in July 2010. While the AER considers the scheme should apply on a consistent basis nationally where practical, there is some flexibility to allow for transitional issues and the differing circumstances and operating environments of each network. The scheme will likely evolve over time to allow for factors such as changes in energy industry technology, climate change policies and other issues affecting customer expectations of service performance and the wider operating environment for the distribution sector. Table 6.9 shows how the scheme will apply in each jurisdiction.

The AER will publicly report on the service performance of distribution businesses in the future. It will consult with stakeholders on the reporting measures and future reporting arrangements.

25 The use of s-factor schemes is discussed in the context of electricity transmission in section 5.6 of this report.

26 AER, Electricity distribution network service providers: service target performance incentive scheme, final decision, Melbourne, June 2008.

NETWORK	PERCEN COMPLE	ITAGE OF	CONNECT ER AGREE	IONS D DATE	PERCEN STREET COMPLE	ITAGE OF LIGHT REI TED AFTE	PAIRS ER AGREE	D DATE	AVERAG REPAIR	E NUMBE FAULTY S	R OF DAYS TREETLIG	5 TO HT
	2004-05	2005–06	2006-07	2007-08	2004–05	2005–06	2006-07	2007-08	2004–05	2005-06	2006-07	2007-08
QUEENSLAND <sup>1</sup>												
ENERGEX	3.98	0.62	0.54	10.79	5.4	4.8	7.6	4.8	3.5	4.5	4.0	3.0
Ergon Energy	6.62	0.84	0.49	0.72	9.7	21.5	17.9		2.8	3.9	3.5	
NEW SOUTH WALES	5 <sup>2</sup>											
EnergyAustralia	0.01	0.02	0.02	0.01	6.6	6.0	1.0	2.4	8.0	9.0	6.0	12.0
Integral Energy	0.01	0.02	0.02	0.01	5.5	0.9	1.0	2.4	2.0	2.0	2.0	3.0
Country Energy	0.02	0.02	0.02	0.01	1.3	1.0	1.0	2.4	9.0	8.0	8.0	10.0
VICTORIA												
Powercor	0.13	0.12	0.06	0.04	0.3	0.1	3.4	1.8	2.0	2.0	2.2	2.0
SP AusNet	0.03	0.21	2.40	2.66	1.0	0.8	0.1	0.0	2.0	2.0	1.4	1.0
United Energy	0.12	0.05	0.29	0.05	0.8	0.2	0.4	0.2	1.4	1.0	1.0	1.0
CitiPower	0.00	0.02	0.03	0.05	7.8	11.4	5.8	8.4	2.3	3.0	2.2	2.2
Jemena	0.14	0.12	0.09	0.19	6.1	6.9	1.1	0.9	2.0	3.0	2.4	1.9
SOUTH AUSTRALIA												
ETSA Utilities	0.91	1.33	0.51	1.30	4.5	5.5	2.6	1.8	3.8	3.6	2.6	3.0
WESTERN AUSTRA	LIA											
Western Power		20.90	20.40	18.80		8.4	35.0	34.7			6.5	
Horizon Power		0.00	0.00	15.60		0.0	23.0	15.1		2.0	6.8	
TASMANIA												
Aurora Energy		0.15	0.14	2.00	10.5	12.3	14.0					

### Table 6.7 Timely provision of service by electricity distribution networks

1. Completed connections data for Queensland and South Australia include new connections only.

2. New South Wales completed connections data from 2005-06 and street light repair percentage data from 2006-07 are state averages.

Note: Victorian data are for the calendar year ending in that period.

Sources: Distribution network performance reports published by the ESC (Vic), IPART (NSW), the QCA (Qld), ESCOSA (SA), the ERA (WA), OTTER (Tas) and the ICRC (ACT). Some data are AER estimates derived from official jurisdictional sources.

NETWORK	PERCENTAG BEFORE RE	E OF CALLS A	ABANDONED AN OPERATOF	2	PERCENTAG HUMAN OPE	E OF CALLS A	ANSWERED B IN 30 SECONE	Y )S
	2004–05	2005–06	2006-07	2007–08	2004–05	2005–06	2006-07	2007–08
QUEENSLAND								
ENERGEX	2.2	3.9	3.0	3.8	89.4	89.4	79.1	96.3
Ergon Energy	2.8	3.5	2.3	2.5	85.0	85.1	87.0	86.2
NEW SOUTH WALES AND	THE ACT							
EnergyAustralia	10.5	10.5	15.7	10.8	44.6	81.3	74.3	81.1
Integral Energy	6.0	3.2	8.7	3.8	81.0	89.0	70.9	96.2
Country Energy	41.2	42.6	31.1	27.4	48.4	47.2		61.4
ActewAGL	16.9	22.5	21.1	14.0	65.6	39.7	62.4	70.5
VICTORIA								
Powercor	5.9	7.0	7.0	4.0	90.9	88.7	86.7	89.4
SP AusNet	8.8	6.0	9.0	7.0	79.8	82.7	92.3	91.2
United Energy	7.7	24.0	18.0	17.0	75.6	73.8	72.9	74.0
CitiPower	10.8	10.0	5.0	4.0	88.2	89.2	85.7	87.2
Jemena	0.9	5.0	7.0	13.0	73.8	75.2	77.4	79.9
SOUTH AUSTRALIA								
ETSA Utilities	4.4	4.0	3.0	3.0	86.9	85.2	89.3	88.7
WESTERN AUSTRALIA								
Western Power			0.1	4.3				79.0
Horizon Power			9.4	4.5			70.0	83.0
TASMANIA								
Aurora Energy	1.0	9.3	5.6	4.0				

### Table 6.8 Call centre performance by electricity distribution networks

Note: Victorian data are for the calendar year ending in that period.

Sources: Distribution network performance reports published by the ESC (Vic), IPART (NSW), the QCA (Qld), the ERA (WA), ESCOSA (SA), OTTER (Tas) and the ICRC (ACT). Some data are AER estimates derived from official jurisdictional sources.

Table 6.9	Service target	norformanco ir	contivo schomo	for distribution	husinesses to	he applied by	the AFR
Table 0.7	Service larger	. per for mance n	icentive scheme		businesses to	ne applied by	y uie AER

NEW SOUTH WALES AND THE ACT	SOUTH AUSTRALIA	QUEENSLAND	VICTORIA
The national scheme will apply as a reporting requirement, but without financial incentives attached to targets.	The national scheme will likely apply, with ±5 per cent of businesses' revenue at risk under the scheme.	The national scheme will likely apply, with ±2 per cent of revenue at risk under the scheme.	The national scheme will likely apply, with ±5 per cent of revenue at risk under the scheme.
The AER will apply reliability of supply and customer service components.	Targets will be attached to reliability of supply and customer service components.	to reliability of supply and customer service components.	to reliability of supply and customer service components.
No GSL components will apply.	No GSL components will apply, because a jurisdictional GSL scheme applies.	because a jurisdictional GSL scheme applies.	replacing the jurisdictional GSL, which ceases on 1 January 2011.

Sources: New South Wales and the ACT distribution determinations, April 2009; Framework and approach papers for the Queensland, South Australian and Victorian networks.

### Table 6.10 Guaranteed service levels of electricity distribution networks

	NATIONAL (AER)	QLD <sup>1</sup>	NSW	VIC	SA	WA	TAS	ACT
RELIABILITY MEASURES								
Duration of supply interruptions exceeds specified limit	\$80 per interruption	\$80 per interruption	\$80 per interruption (maximum \$320 per year)	\$100–300 per year	\$80–320 per interruption	\$80 per interruption	\$80–160 per interruption	\$20 per interruption
Frequency of supply interruptions exceeds specified limit	\$80 per interruption	\$80 per year	\$80 per year	\$100-300 per year	\$80–160 per year		\$80 per year	
Frequency of momentary supply interruptions (less than 1 minute) exceeds specified limit				\$25–35 per year				
CUSTOMER SERVICE MEAS	SURES							
Wrongful disconnection		\$100						
Late connection	\$50 per day (maximum \$300)	\$40 per day	\$60 per day (maximum \$300)	\$50 per day (maximum \$250)	\$50 per day		\$30 per day (maximum \$150)	\$60 per day (maximum \$300) <sup>2</sup>
Late reconnection		\$40 per day						
Failure to attend a scheduled appointment on time		\$40	\$25	\$20	\$20		\$30	
Failure to respond to a complaint in designated timeframe						\$20		\$20
Failure to give sufficient notice of a planned interruption	\$50	\$20 (residential) \$50 (business)	\$20			\$20	\$30	\$50
Planned interruptions not completed in specified time			\$20					\$50
Late repair of street lights	\$25		\$15	\$10	\$20 per five or 10 day period		\$30 per day (maximum \$150)	
Late response to an inquiry regarding loss of hot water		\$40 per day						
Altered condition of property due to vegetation clearing							\$30	

1. Queensland has a cap on payments of \$320 per customer per year (excludes wrongful disconnection payments). The QCA has approved increases in compensation payments of about 30 per cent, to apply from 1 July 2010.

2. Includes the response time for a reported fault or damage.

# 6.6.5 Guaranteed service levels

The GSL schemes provide for payments to customers that experience poor service. They are not intended to provide legal compensation to customers, but to enhance service performance by distribution businesses.

A range of GSL schemes apply across the jurisdictions. With the shift to national distribution regulation, the AER published details in 2009 of a national GSL scheme as part of the service target performance incentive scheme (see section 6.6.4). But the jurisdictional schemes will continue in some instances: both the Essential Services Commission of South Australia (ESCOSA) and the QCA have indicated they will retain their jurisdictional schemes. However, the national scheme will likely apply to the Victorian networks in the next regulatory period.

The GSL schemes provide payments for poor service quality in areas such as streetlight repair, frequency and duration of supply interruptions, new connections and notice of planned interruptions. Table 6.10 details the performance criteria and associated compensation payments. Payments under the national scheme are made automatically to consumers if service is below target. This arrangement differs from most jurisdictional schemes under which payments are made only if affected customers apply.

Given each jurisdiction reports against different criteria, it is not possible to compare the performance of distribution businesses against GSL targets across jurisdictions. Further, given payments are generally made only if a customer applies, outcomes over time may reflect both changes in customer awareness and business performance.

The majority of GSL payments in 2007–08 in most jurisdictions related to the duration and frequency of supply interruptions exceeding specified limits. Payments in Queensland resulted mainly from wrongful disconnections and late connections.

> In Queensland, GSL payments in 2007-08 were the equivalent of \$0.07 per customer for Ergon Energy and \$0.09 per customer for ENERGEX.

- In New South Wales, GSL payments in 2007–08 were equivalent to \$0.02 per customer. Eighty per cent of the payments were made by Country Energy, with EnergyAustralia and Integral Energy accounting for around 10 per cent each. There was a slight rise in total payments over the previous five years.
- > In Victoria, GSL payments in 2007–08 were equivalent to \$2.21 per customer—around one third higher than the previous year's. However, the performance of individual businesses varied. The majority of payments were made by the predominantly rural networks SP AusNet (81 per cent of total payments by Victorian businesses) and Powercor (18 per cent).
- In South Australia, GSL payments by ETSA Utilities fell by 74 per cent between 2005–06 and 2007–08. Payments in 2007–08 were the equivalent of \$0.64 per customer.
- In Western Australia, Western Power's 2007–08 payments were equivalent to \$0.26 per customer. This was an improvement on 2006–07 but above 2005–06 levels. Horizon Power's payments in 2007–08, equivalent to \$0.06 per customer, were lower than those in the previous two years.
- > In Tasmania, GSL payments in 2007-08 (equivalent to \$2.00 per customer) were three times greater than the previous year's, but consistent with 2005-06 outcomes.

# 6.7 Policy developments in electricity distribution

Recent policy activity in the distribution sector has focused on network planning and operation and the approach to economic regulation. The following section summarises policy developments in these areas. Appendix A describes the institutional bodies responsible for developing and implementing energy policy.

# 6.7.1 Network planning and expansion

On 17 December 2008 the Ministerial Council on Energy (MCE) agreed to establish a national framework for distribution network planning. As part of this process, the MCE directed the Australian Energy Market Commission (AEMC) to review the distribution network planning and expansion arrangements in the NEM. The AEMC submitted its final report to the MCE in September 2009.<sup>27</sup>

The planning framework, once finalised, is intended to ensure clear and efficient planning and investment processes. Recommendations include:

- requiring distribution businesses to publish annual planning reports looking forward a minimum of five years
- > replacing the current regulatory test with a regulatory investment test for distribution—similar to the new test for transmission investment (see section 5.8.2)
- > establishment of a demand-side engagement strategy to ensure that non-network solutions to address system limitations are fully considered.

# 6.7.2 Network connection

In March 2009 the MCE's network policy working group made its final recommendations on a national framework for the connection of customers to distribution networks.<sup>28</sup> The working group found the process for network connection should be simplified and streamlined. Its report recommended distribution businesses be required to have at least one standard connection service for a customer load category (for example, small customers) and at least one standard connection service for micro embedded generators.<sup>29</sup>

The working group suggested two possible methods for connection to a distribution network:

- > standard connections, with a short period (five days) for a connection offer to be made following an application
- > negotiated connections, to be provided on an individual basis and allow more time for offers to be prepared.

A national framework for electricity distribution connection will incorporate these recommendations. The framework is being drafted in 2009, with legislative proposals expected in 2010. Once implemented, it will provide a single customer framework for the provision of electricity and gas connections.

# 6.7.3 Total factor productivity approach

In 2008 the AEMC commenced a review of the total factor productivity (TFP) approach in energy regulation. TFP is a method that measures how businesses use resources to produce output. It exposes regulated businesses to competitive pressures by linking revenues to industry performance rather than the cost structures of specific businesses.

The AEMC will advise the MCE on the potential use of TFP assessments, in conjunction with the building block approach, to determine network revenues and price. The TFP assessment would be used to judge the reasonableness of network expenditure forecasts under the building block method. The AEMC has identified potential benefits from applying a TFP method, including:

- > lower regulatory administrative costs
- > reduced information asymmetry between regulated businesses and regulators
- > stronger performance incentives to the regulated business.<sup>30</sup>

The AEMC expects to finish its review in April 2010, with any recommended rule changes to be considered by the MCE in June 2010. The review will consider:

- > the strength of incentives for networks to pursue efficient costs and share efficiencies with customers
- > whether the TFP framework leads to efficient investment with innovation and technical progress
- > clarity, certainty and transparency in the regulatory framework and processes to reduce avoidable risks for service providers and customers.

<sup>27</sup> AEMC, Review of national framework for electricity distribution network planning and expansion, final report, Sydney, September 2009.

<sup>28</sup> MCE Network Policy Working Group, National connections framework for electricity distribution businesses, final report, Canberra, March 2009.

<sup>29</sup> A micro embedded generator is a generator with a rating below 10 kilovolt amperes (kVa) (for single phase power) or 30 kVa (for three phase power) that is connected to the distribution network.

<sup>30</sup> AEMC, Review into the use of total factor productivity for the determination of prices and revenues: framework and issues paper, Sydney, December 2008.

# 6.7.4 Climate change policy

The AEMC has conducted a review of the likely impacts of climate change policies—particularly the carbon pollution reduction scheme and expanded renewable energy target—on energy market frameworks. It released the final report in October 2009.<sup>31</sup>

The AEMC found the main challenges for distribution networks are the potential growth in embedded generation and the increased variability of network flows, leading to the need for more active management of demand. These changes would make network management more complex and require new investment in network infrastructure. Despite these challenges, the AEMC considered the current regulatory framework is sufficiently flexible to accommodate the evolving demands on network businesses.

The AEMC noted initiatives to facilitate innovation in the management of network reliability, including the demand management innovation allowance (see section 6.8.1). It recommended expanding the allowance to cover innovations in the connection of embedded generators to distribution networks.

# 6.8 Demand management and metering

# 6.8.1 Demand management

Demand management (or demand-side participation) relates to strategies to manage the growth in overall or peak demand for energy services. The objective is to reduce or shift demand, or implement efficient alternatives to network augmentation. Demand management in the NEM is constantly evolving, with a number of initiatives being implemented. The initiatives are primarily undertaken at the retail or distribution level and require cooperation between energy customers and suppliers. The demand management programs trialled in Australia include:

- > controlling the load for residential appliances such as air conditioners and pool pumps. Under these schemes, appliances are remotely switched off (or cycled on and off) at times of peak demand.
- > providing price signals to consumers to encourage them to shift some energy consumption away from times of peak demand. Trialled methods for residential customers include time-of-use and critical peak pricing.<sup>32</sup> The strategies require advanced metering equipment and flexible tariff arrangements. Some distributors have entered into contracts with large energy customers to reduce consumption at peak times.
- > supporting embedded generation, where back-up generation is enabled in large business facilities, as a substitute for network augmentation.

The regulatory process allows for funding to encourage these initiatives. The AER has launched demand management schemes for New South Wales and the ACT, Queensland, South Australia and Victoria. The schemes provide funding to trial and implement demand management solutions. Some of the schemes allow for the recovery of forgone revenue arising from lower demand for network services. Table 6.11 sets out how the schemes will apply in each jurisdiction.

In 2009 the AEMC completed a review of whether there are regulatory impediments to demand-side participation in the NEM.<sup>33</sup> The review investigated whether the current regulatory arrangements are biased towards expanding generation and network capacity to meet demand for electricity, rather than taking more cost-effective approaches to reduce demand.

The AEMC published a draft report in April 2009 that identified material barriers to demand-side participation that are attributable to regulated network businesses.

<sup>31</sup> AEMC, Review of energy market frameworks in light of climate change policies, final report, Sydney, October 2009.

<sup>32</sup> Critical peak pricing involves retailers charging a higher tariff at times of extreme demand. Retailers have some flexibility in when they can institute the higher price; however, there is usually a limit on the number of times the tariff can be used, along with requirements for customers to receive sufficient notice.

<sup>33</sup> AEMC, Demand side participation in the national electricity market, draft report, Sydney, April 2009.

NEW SOUTH WALES	THE ACT	SOUTH AUSTRALIA	QUEENSLAND	VICTORIA
In addition to a demand management innovation allowance, the New South Wales businesses are subject to a d-factor mechanism that allows businesses to recover: > approved non-tariff based demand management implementation costs > tariff based demand management implementation costs > revenue forgone as a result of non- tariff based demand management initiatives.	The ACT distribution network business, ActewAGL, will receive a demand management innovation allowance.	In addition to a demand management innovation allowance, the South Australian network business, ETSA Utilities, is also subject to a forgone revenue mechanism that allows it to recover revenue forgone where demand is successfully reduced by expenditure of the innovation allowance.	The Queensland distribution network businesses, ENERGEX and Ergon Energy, will receive a demand management innovation allowance.	In addition to a demand management innovation allowance, Victorian network businesses are subject to a forgone revenue mechanism that allows it to recover: > revenue forgone where demand is successfully reduced by expenditure of the innovation allowance > an annual allowance to spend on demand management > a forgone revenue component.

Table 6.11	Demand managemen	t incentive schemes to b	e applied b	y the AER for electricit	y distribution businesses

The following are noteworthy:

- > The current method for setting network prices penalises businesses that use demand management initiatives to defer capital expenditure.
- > Businesses have limited financial incentives to innovate under current regulatory approaches. The AEMC considers that 'use it or lose it' funding for innovation may be a proportionate way of addressing such a barrier, by allowing network businesses to recover costs associated with approved innovation projects outside their normal operating or capital expenditure requirements.
- Variability in network connection, planning and consultation processes across network businesses is a barrier to effective demand-side participation.
- > Price cap regulation provides networks with incentives to undertake socially efficient demandside participation.<sup>34</sup>

The AEMC has also considered demand management issues for transmission networks. In response to a proposal from the Total Environment Centre, it implemented amendments to the Electricity Rules. These rule changes support the provision of information about projected network constraints to market participants. This information assists demand management service providers to participate actively in the market and consider efficient alternatives to network augmentation. The amendments relate to:

- > network businesses' provision of specific information about forecast constraints in their annual planning reports
- > the AER's treatment of non-network expenditure (including demand management activities) incurred by network businesses in future revenue determinations
- > obligations on the AER when assessing revenue proposals, to account for whether the network businesses have demonstrated, and provided for, appropriate efficient non-network alternatives
- > obligations on network businesses to provide information on appropriate non-network alternatives in their revenue proposals.<sup>35</sup>

### 6.8.2 Metering

Meters record the energy consumption of customers at the point of connection to the distribution network. Effective metering, when coupled with appropriate price signals, can encourage more active demand management by customers.

34 AEMC, Demand side participation in the national electricity market, draft report, Sydney, April 2009.

35 AEMC, Rule Determination, National Electricity Amendment (Demand Management) Rule 2009, Sydney, April 2009.

There are two main types of meter:

- > The older style accumulation meters record the total consumption of electricity at a connection point, but not the time of consumption. Consumers are billed on solely the volume of electricity consumed.
- > Interval meters are more sophisticated and record consumption in defined time intervals (for example, half hour periods). This allows time-of-use billing so the charge for electricity can be varied with the time of consumption. Industry generally uses interval meters.

Plans are being implemented at the national and state levels to introduce *smart meters*, which are an advanced type of interval meter. These meters have remote communication capabilities between retailers and customer that allow for remote meter reading and connection/disconnection of customers. Add-ons such as an in-house display may provide prices and other aspects of electricity consumption, as well as real time information on power outages. The meters are also compatible with technology that allows retailers and distribution businesses to manage loads to particular customers and appliances.

The take-up of smart meters has varied among jurisdictions:

- > In New South Wales, distribution businesses are rolling out interval meters for customers using more than 15 megawatt hours of electricity a year. For smaller customers, interval meters are provided on a new and replacement basis. The New South Wales Government has committed to a full rollout of smart meters by 2017.
- > The Victorian Government has initiated a program to provide smart meters to all customers over a four year period from 2009. In January 2009 the AER released a framework and approach paper that sets out the process for determining the prices that

distribution businesses can charge for metering services.<sup>36</sup> The Victorian distributors have submitted to the AER budget applications for metering expenditure to 2011. The AER is scheduled to release a final determination on initial budgets and charges on 31 October 2009. Distribution businesses, after installing an interval meter for a customer, are entitled to reassign the customer to a time-of-use tariff.<sup>37</sup> In May 2009 the AER released notification requirements that a distribution business must provide to customers before this change can occur.<sup>38</sup>

> A number of other jurisdictions are rolling out smart meters on a new and replacement basis.

In 2007 the Council of Australian Governments (COAG) agreed to a national implementation strategy for the progressive rollout of smart meters where the benefits outweigh costs. A cost-benefit assessment published in March 2008 found a national rollout would achieve a net benefit.<sup>39</sup> However, in June 2008 the MCE noted uncertainties in the levels of costs and benefits, and supported the implementation of trials and further analysis to help verify jurisdictional costs and benefits.<sup>40</sup>

The MCE is developing a framework to support a rollout of smart electricity meters in the NEM, noting that consistency between NEM and non-NEM jurisdictions will be sought as appropriate. The MCE is focusing on regulatory arrangements (including cost recovery arrangements), consumer protection measures and safety standards. A national stakeholder steering committee was established to lead the development of technical and operational aspects of the framework. The steering committee is also responsible for reviewing progress of jurisdictional pilots and trials.

The MCE has estimated the current process should result in more than 50 per cent of all Australian meters being replaced by 2017. It will consider a timetable for a further rollout of smart meters by June 2012.<sup>41</sup>

189

CHAPTER

6 ELECTRICITY DISTRIBUTION

<sup>36</sup> AER, Framework and approach paper, Advanced metering infrastructure review 2009-11, final decision, Melbourne, January 2009.

<sup>37</sup> Where the customer consumes less than 20 megawatt hours of electricity per year.

<sup>38</sup> AER, Interval meter reassignment requirements, final decision, Melbourne, May 2009.

<sup>39</sup> NERA, Cost benefit analysis of smart metering and direct load control overview report for consultation, Prepared for the Smart Meter Working Group, Sydney, February 2008.

<sup>40</sup> MCE, Communiqué, Canberra, 13 June 2008.

<sup>41</sup> MCE, Communiqué, Canberra, 13 June 2008.



# 7 ELECTRICITY RETAIL



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 businesses. Retailers deal directly with consumers, so 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 sell 'dual fuel' products that bundle electricity and gas services. While retailers provide a convenient aggregation service for electricity consumers, they do not directly provide network services.

7 ELECTRICITY RETAIL

This chapter provides a survey of electricity retail markets. It covers:

- > the structure of the retail market, including industry participants and trends towards horizontal and vertical integration
- > the development of retail competition
- > retail market outcomes, including price and service quality
- > the regulation of the retail market
- > energy efficiency.

State and territory governments are currently responsible for the regulation of retail energy markets. Governments agreed in 2004, however, to transfer several non-price regulatory functions to a national framework that the Australian Energy Market Commission (AEMC) and the Australian Energy Regulator (AER) would administer. The Ministerial Council on Energy (MCE) has scheduled the regulatory package to be introduced to the South Australian parliament in 2010.<sup>1</sup> This chapter focuses on the retailing of electricity to small customers, including households and small business users.<sup>2</sup> Large customers such as major industrial users buy the greatest volume of electricity, but they are relatively few in number. While the chapter reports some data that may enable performance comparisons across retailers, such analysis should note that a variety of factors can affect relative performance.

<sup>1</sup> Section 7.7 provides an update on the transition to a national regulatory framework.

<sup>2</sup> In New South Wales, Victoria, South Australia and Western Australia, small customers are those consuming less than 160 MWh per year. In Queensland and the Australian Capital Territory, small customers are those consuming less than 100 MWh per year. Small customers in Tasmania are those consuming less than 150 MWh per year.

Figure 7.1 Introduction of full retail contestability



# 7.1 Retail market structure

The privatisation of energy retail assets is continuing. Victoria and South Australia privatised their energy retail businesses in the 1990s, and Queensland privatised most of its energy retail entities in 2006–07. The Australian Capital Territory (ACT) Government operates a joint venture with the private sector to provide retail services. At 1 July 2009 New South Wales, Western Australia, Tasmania and the Northern Territory retained government ownership in the retail sector. The New South Wales Government in March 2009, however, affirmed its intention to privatise its energy retail businesses.<sup>3</sup> Subject to market conditions, it expects to complete the sale process in the first half of 2010.<sup>4</sup>

Australian governments have also introduced retail contestability (customer choice) since the mid 1990s. Most governments have adopted a staged timetable to introduce customer choice, beginning with large industrial customers followed by small industrial customers and finally small business and domestic customers. Full retail contestability (FRC) is achieved when all customers are permitted to enter a supply contract with a retailer of their choice. The introduction of contestability arrangements has varied across jurisdictions (figure 7.1):

- > New South Wales, Victoria, Queensland, South Australia and the ACT have introduced FRC.
- > From 1 July 2009 Tasmania extended contestability to customers using at least 150 megawatt hours (MWh) per year. Contestability will not be extended to smaller customers until at least July 2010.<sup>5</sup>
- > Western Australia allows contestability for customers using at least 50 MWh annually. The Office of Energy in 2008 and 2009 reviewed the electricity retail market and considered a possible introduction of FRC.<sup>6</sup>
- > The Northern Territory plans to introduce FRC in April 2010, subject to a public benefit test. In August 2009 the Utilities Commission released an issues paper that considers options for the implementation of FRC for small businesses and households in the Northern Territory.<sup>7</sup>

The retail players in each jurisdiction include:

- > one or more 'host' retailers that are subject to additional regulatory obligations
- > new entrants, including established interstate players, gas retailers branching into electricity retailing and new players in the energy retail sector.

3 Nathan Rees (Premier of New South Wales), 'Strengthening the New South Wales economy: energy reforms begin new phase', Media release, 5 March 2009.

<sup>4</sup> Joe Tripodi (Minister for Infrastructure, New South Wales), 'NSW Government releases energy reform transaction strategy', Media release, 10 September 2009.

<sup>5</sup> Office of the Tasmanian Economic Regulator, 'The power to choose', viewed 11 May 2009, www.power.tas.gov.au. The Tasmanian Government has yet to decide whether to extend FRC to all customers.

<sup>6</sup> Office of Energy (Western Australia), Electricity retail market review-issues paper, Perth, December 2007.

<sup>7</sup> Regulation 6(4), Electricity Reform (Administration) Regulations 2008 (NT); Utilities Commission, *Review of full retail contestability for Northern Territory* electricity customers—issues paper, Darwin, August 2009.

RETAILER <sup>1</sup>	OWNERSHIP	QLD	NSW	VIC	SA	WA	TAS	ACT	NT
ActewAGL Retail	ACT Government & AGL Energy								
AGL Energy	AGL Energy								
Alinta Sales	Babcock & Brown Power								
Aurora Energy	Tasmanian Government								
Australian Power & Gas	Australian Power & Gas								
Click Energy	Click Energy								
Country Energy	NSW Government								
Energy Australia	NSW Government								
Ergon Energy	Queensland Government								
Horizon Power	Western Australian Government								
Integral Energy	NSW Government								
Jackgreen	Jackgreen Ltd <sup>2</sup>								
Momentum Energy	Momentum Energy <sup>3</sup>								
Neighbourhood Energy	Neighbourhood Energy <sup>4</sup>								
Origin Energy	Origin Energy								
Perth Energy	Infratil								
Power and Water Corporation	Northern Territory Government								
Powerdirect	AGL Energy								
Queensland Electricity	Infratil								
Red Energy	Snowy Hydro⁵								
Sanctuary Energy	Sanctuary Energy Pty Ltd <sup>6</sup>								
Simply Energy	International Power								
South Australian Energy	Infratil								
Synergy	Western Australian Government								
TRUenergy	CLP Group								
Victoria Energy	Infratil								
Active retailers		11	9	14	11	4	1	2	1
Approx. market size ('000 000 c	ustomers)	1.9	3.1	2.4	0.8	1.0	0.2	0.2	0.1

### Table 7.1 Active electricity retailers—small customer market, April 2009

Host (incumbent) retailer New entrant retailer

1. Not all licensed retailers are listed. Some generators are licensed retailers but are active only in the market for larger industrial users. Not all retailers listed supply electricity to all customers—for example, some retailers market to only small business users.

2. Babcock & Brown Infrastructure's stake in Jackgreen was bought by institutional investors in August 2009.

3. In September 2008 Hydro Tasmania acquired a controlling interest (51 per cent) in Momentum Energy, and it will purchase the remaining 49 per cent in 2010.

4. The major shareholder of Neighbourhood Energy at 30 June 2008 was Babcock & Brown Power (65 per cent).

5. Snowy Hydro is owned by the New South Wales Government (58 per cent), the Victorian Government (29 per cent) and the Australian Government (13 per cent).

6. Sanctuary Energy Pty Ltd is owned by Living Choice Australia Ltd (50 per cent) and Sanctuary Life Pty Ltd (50 per cent).

Sources: Jurisdictional regulator websites, retailer websites and other public sources.

State government owned host retailers in New South Wales, Tasmania, Western Australia and the Northern Territory are the major players in those jurisdictions. The ACT Government operates a joint venture with a privately owned business to provide electricity retail services.

Privately owned retailers are the major players in Victoria, South Australia and Queensland. The largest private retailers are 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 following the privatisation of government owned retailers. International Power, trading as Simply Energy, continues to emerge as a significant retail business in Victoria and South Australia.

Niche players are active in most jurisdictions. Table 7.1 lists licensed retailers that were active in the market for residential and small business customers in April 2009.<sup>8</sup> Active retailers are those that currently offer supply contracts to new small customers.

The following survey (sections 7.1.1–7.1.8) provides background on developments in each jurisdiction.<sup>9</sup>

# 7.1.1 Queensland

At April 2009 Queensland had 24 licensed retailers,<sup>10</sup> of which 11 were active in the small customer market. Origin Energy and AGL Energy are the biggest private retailers in Queensland, with Integral Energy emerging as the third major player. Sanctuary Energy was granted a retail licence in 2008 and commenced retailing to small customers. The Queensland Government has retained ownership of Ergon Energy's retail business, which supplies the majority of customers in rural and regional areas. Table 7.2 sets out the estimated small customer market share of Queensland retailers (by customer numbers) at 30 June 2008.

# Table 7.2Electricity retail market share (smallcustomers)—Queensland, 30 June 2008

RETAILER	SMALL CUSTOMERS (%)
Origin Energy	36
Ergon Energy	33
AGL Energy	19
Other	12
Total small customers (no.)	1 930 000

Source: QCA estimates.

# 7.1.2 New South Wales

At April 2009 New South Wales had 26 licensed retailers, of which nine supplied (or intended to supply) residential and/or small business customers. The active retailers were:

- > the government owned host retailers—EnergyAustralia, Country Energy and Integral Energy
- > six new entrants—the state's host retailer in gas (AGL Energy), three established interstate players (Origin Energy, TRUenergy and ActewAGL Retail) and two new players in the energy retail market (Powerdirect and Jackgreen).

Momentum Energy, New South Wales Electricity, Dodo Power & Gas and Red Energy held retail licences but were not actively marketing to small customers. At April 2009 Australian Power & Gas continued to provide retail services to existing customers in New South Wales but was not accepting new customers.

At June 2008 new entrant retailers had acquired about 17 per cent of the small customer market (based on customer numbers) from the government owned incumbents. This share was up from about 14 per cent in the previous year.<sup>11</sup>

<sup>8</sup> See footnote 2 for jurisdictional classifications of 'small customers'.

<sup>9</sup> The number of licensed retailers may not correspond with the actual number of retail licences issued, because several licence holders may operate under a single trading name.

<sup>10</sup> The number of licences issued may not correspond with the number of licensed retailers because a retailer may hold more than one licence.

<sup>11</sup> IPART (New South Wales), NSW Electricity Information Paper, *Electricity retail businesses' performance against customer service indicators in NSW: for the period* 1 July 2003 to 30 June 2008, Sydney, March 2009, p. 2.

Figure 7.2 Electricity retail market share (small customers)—Victoria



Note: Figures at top of columns are total small customer numbers.

Source: ESC (Victoria), Energy retailers: comparative performance report-customer service, Melbourne, various years.

### 7.1.3 Victoria

At April 2009 Victoria had 29 licensed retailers, of which 14 were active in the residential and small business market. The active retailers were:

- > the host retailers in designated areas of Victoria— AGL Energy, Origin Energy and TRUenergy
- > eleven new entrants—two established interstate retailers (Country Energy and EnergyAustralia) and nine new players in the energy retail market (Simply Energy, Click Energy, Jackgreen, Neighbourhood Energy, Powerdirect, Red Energy, Victoria Electricity, Momentum Energy and Australian Power & Gas).

Dodo Power & Gas held a retail licence but was not actively marketing to small customers in April 2009.

Table 7.3 sets out the market share of Victorian retailers (by customer numbers) at 30 June 2008. The three host retailers account for about 77 per cent of the market, and each has acquired market share beyond its local area. New entrant penetration in the market increased from 13 per cent of small customers in June 2006 to about 23 per cent in June 2008 (figure 7.2).

# Table 7.3 Electricity retail market share (small customers)—Victoria, 30 June 2008

RETAILER		CUSTOMERS						
	DOMESTIC (%)	BUSINESS (%)	TOTAL (%)					
AGL Energy	25.8	21.6	25.3					
Origin Energy	27.9	33.9	28.6					
TRUenergy	22.9	23.1	22.9					
Other	23.4	21.5	23.2					
Total customers (no.)	2 155 995	288 940	2 444 935					

Source: ESC (Victoria), Energy retailers: comparative performance reportcustomer service 2007-08, Melbourne, December 2008, p. 5.

# 7.1.4 South Australia

At April 2009 South Australia had 16 licensed electricity retailers, of which 11 were active in the small customer market. The active retailers were:

- > the host retailer—AGL Energy
- > ten new entrants—South Australia's host retailer in gas (Origin Energy), three established interstate retailers (TRUenergy, Country Energy and Aurora Energy) and six new players in the energy retail market (Simply Energy, Momentum Energy, Powerdirect, South Australia Electricity, Red Energy and Jackgreen).



Figure 7.3 Electricity retail market share (small customers)—South Australia

Note: Figures at top of columns are total small customer numbers.

Source: ESCOSA (South Australia), Annual performance report: performance of South Australian energy retail market, various years.

EnergyAustralia, Dodo Power & Gas and Australian Power & Gas held retail licences but were not actively marketing to small customers in April 2009.

Table 7.4 sets out the small customer market share of South Australian retailers (by customer numbers) at 30 June 2008. The host retailer—AGL Energy supplied 55 per cent of small customers, down from 59 per cent in June 2007. Other retailers have built market share, with Origin Energy and TRUenergy each supplying more than 10 per cent of the small customer base. Simply Energy's market share slipped to just below 10 per cent at June 2008 (figure 7.3). There has been only marginal penetration by niche retailers, with the four largest retailers accounting for over 90 per cent of the market.

Market penetration by new entrants has been more effective for large customers, with AGL Energy's market share eroding to about 36 per cent (based on sales volume).<sup>12</sup>

# Table 7.4 Electricity retail market share (small customers)—South Australia, 30 June 2008

RETAILER		CUSTOMERS	
	DOMESTIC (%)	BUSINESS (%)	TOTAL (%)
AGL Energy	53.4	63.0	54.5
Origin Energy	14.3	16.0	14.5
TRUenergy	13.1	8.4	12.6
Simply Energy	10.1	4.2	9.5
Other	9.0	8.4	8.9
Total customers (no.)	687 072	84 838	771 910

Note: Rounding means market share data may not add to 100 per cent.

Source: ESCOSA (South Australia), 2007-08 Annual performance report: performance of South Australian energy retail market, Adelaide, November 2008, p. 70.

# 7.1.5 Western Australia

In Western Australia, only customers consuming at least 50 MWh annually are contestable. They represent around 60 per cent of the retail market (by volume) in the South West Interconnected System (SWIS).<sup>13</sup> The government owned host retailer— Synergy—has a market share of 96 per cent of small

12 ESCOSA (South Australia), 2007-08 Annual performance report: performance of South Australian energy retail market, Adelaide, November 2008, p. 27.

13 The SWIS is the main electricity grid in Western Australia and connects Perth, Geraldton, Kalgoorlie and the south west. See chapter 4 for further information on the SWIS.

residential customers and 92 per cent of small non-residential customers in the SWIS. Horizon Power services the regional areas of Western Australia outside of the SWIS, and is the second largest retailer, with 3.6 per cent of small residential customers and 5 per cent of small non-residential customers.<sup>14</sup> The remaining customers are divided among Alinta Sales (owned by Babcock & Brown Power), Perth Energy and the Rottnest Island Authority.

For further information on Western Australia, see chapter 4 of this report.

### 7.1.6 Tasmania

Aurora Energy, the government owned host retailer, controls the small customer market in Tasmania. Legislative restrictions prevent new entrants from supplying small customers.

# 7.1.7 Australian Capital Territory

At April 2009 the ACT had 15 licensed retailers, of which two were active in the residential market: ActewAGL Retail (the host retailer) and TRUenergy. At April 2009 Country Energy and Energy Australia continued to provide retail services to existing customers in the ACT, but were not accepting new customers. Aurora Energy, Dodo Power & Gas, ERM Power, Integral Energy, Jackgreen, Powerdirect, Red Energy, Australian Power & Gas, Sun Retail and Origin Energy held retail licences but were not actively marketing to small customers.

# 7.1.8 Northern Territory

The Northern Territory's electricity market is small, with around 82 500 customers connected to the network. The government owned host retailer, Power and Water Corporation, provides electricity services to these customers.

# 7.2 Trends in market integration

Various ownership consolidation activity has occurred in the energy retail sector in recent years, including: > retail market convergence of electricity and gas

vertical integration of electricity retailers

# 7.2.1 Energy retail market convergence

Many energy retailers offer both electricity and gas services, including 'dual fuel' retail products.<sup>15</sup> The largest retailers in Victoria and South Australia (AGL Energy, Origin Energy and TRUenergy), for example, jointly account for around 77 per cent of small electricity retail customers and 86 per cent of small gas retail customers (figure 7.4). The principal difference between the two sectors is that niche players have greater penetration in electricity markets compared with gas.

### Figure 7.4

and generators.

Electricity and gas retail market share (small customers)—Victoria and South Australia, 30 June 2008



Sources: ESC (Victoria), Energy retailers: comparative performance reportcustomer service 2007-08, Melbourne, December 2008; ESCOSA (South Australia), Annual performance report: performance of South Australian energy retail market 2007-08, Adelaide, November 2008.

14 ERA (Western Australia), 2007-08 Annual performance report-electricity retailers, Perth, January 2008, p. 2.

15 In the ACT, the host retailer in electricity and gas—ActewAGL Retail—also offers contracts that 'bundle' electricity and gas retail services with telecommunications services.

Several factors have driven retail convergence, including business cost savings and convenience for customers. At the same time, convergence can create hurdles for new entrants—especially small players—that may need to deal with different market arrangements and different risks in the provision of electricity and gas services.

# 7.2.2 Vertical integration in the electricity sector

In the 1990s governments introduced reforms to structurally separate the power supply industry into generation, transmission, distribution and retail businesses. However, some links among different sectors of the power supply industry remain. In particular, the New South Wales, Queensland, Tasmanian, Western Australian and Northern Territory governments own joint distribution-retail businesses (although Ergon Energy in Queensland is restricted from competing in the retail market). The Western Australian Government owns Horizon Power, which is an integrated service provider. The ACT Government has ownership interests in both the host retailer of electricity and gas, and the electricity and gas distributor. Where links exist between retail and network sectors, regulators apply ring-fencing arrangements to ensure operational separation of the businesses.

There is also a continuing trend towards vertical integration of privately owned electricity retailers and generators. 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, then the retailer can balance the increased cost against higher generator earnings.<sup>16</sup>

Figure 7.5 compares generation and retail market shares in Victoria and South Australia in 2008. Two of the three major retailers—AGL Energy and TRUenergy —have significant generation interests. In July 2007 AGL Energy and TRUenergy completed a generator swap in South Australia that moved the capacity of each business into closer alignment with their retail loads. Origin Energy has limited generation capability but is developing new capacity. In addition, major generator International Power operates a retail business (trading as Simply Energy) that has achieved significant penetration in the South Australian market.

There has also been vertical integration in the public electricity sector. Snowy Hydro owns Red Energy, which has acquired some market share in Victoria and South Australia. In September 2008 Hydro Tasmania acquired a controlling interest in the small private retailer Momentum Energy, with a move to full ownership intended in 2010.

### Figure 7.5





Notes:

The figures must be interpreted with caution because market shares in each sector are based on different variables: retail shares relate to small customer numbers, while generation shares relate to capacity.

In Victoria, TRUenergy holds a long term hedge contract with Ecogen Energy (owned by Industry Funds Management).

In South Australia, Origin Energy bids in the facility at Osborne power station (owned by ATCO Power and Origin Energy).

The chart represents the generation capacity of majority shareholders only. Sources: ESC (Victoria), *Energy retailers: comparative performance reportcustomer service 2007-08*, Melbourne, December 2008; ESCOSA (South Australia), *Annual performance report: performance of South Australian energy retail market 2007-08*, Adelaide, November 2008 (customer numbers); AEMO (generation capacity and ownership).

16 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 for Australia*, Report to COAG, Canberra, January 2007, pp. 125-6.

# 7.3 Retail competition

While most jurisdictions have introduced or are introducing FRC, a competitive market can take time 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 (see section 7.4.1). Standing offer contracts cover minimum service conditions and information requirements, and may include regulated price caps or prices oversight. At July 2009 all jurisdictions except Victoria applied some form of price cap regulation.<sup>17</sup> Australian governments have agreed to review the continued use of retail price caps and to remove them where effective competition can be demonstrated.<sup>18</sup> The AEMC is assessing the effectiveness of retail competition in each jurisdiction to advise on the appropriate time to remove retail price caps.<sup>19</sup> The relevant state or territory government makes the final decision on this matter. Box 7.1 summarises progress with the outcomes of reviews.

### Box 7.1 Retail competition reviews

The Australian Energy Market Commission (AEMC) in February 2008 completed a review of the effectiveness of competition in Victoria's electricity and gas retail markets. It completed a similar review for South Australia in December 2008. Reviews are planned for the ACT in 2010, New South Wales in 2011, Queensland in 2012 and Tasmania in 2013 if full retail contestability has been introduced in that jurisdiction by that time.

The AEMC applies the following criteria to assess the effectiveness of retail competition:

- independent rivalry within the market
- the ability of suppliers to enter the market
- → exercise of market choice by customers
- → differentiated products and services
- prices and profit margins
- customer switching behaviour.

### Victoria

The AEMC review of the Victorian electricity and gas retail markets found competition is effective in both markets.<sup>20</sup> In response to the review, the Victorian Government removed retail price caps on 1 January 2009. The legislation included provisions for the Essential Services Commission of Victoria (ESC) to monitor and report on retail prices. Retailers are also required to publish a range of their offers, to help consumers compare energy prices. The removal of retail price regulation does not affect other obligations on retailers, including the obligation to supply and the consumer protection framework.<sup>21</sup> The Victorian Government retains a reserve power to re-instate retail price regulation if competition is found to no longer be effective.

### **South Australia**

The AEMC found competition was effective for small electricity and gas customers in South Australia, but more intense in electricity than in gas.<sup>22</sup> It outlined options to phase out retail price regulation in South Australia. These options include a price monitoring and reporting regime to support the competitive market, and the retention of statutory reserve powers to re-introduce price regulation if the level of competition declines.<sup>23</sup>

In April 2009 the South Australia Government stated it did not accept the AEMC's recommendations to remove retail price regulation in electricity and gas at this time. It was concerned that more than 30 per cent of small customers remain on standing contracts and that stakeholders had differing views on the effectiveness of competition.

- 18 Australian Energy Market Agreement 2004 (as amended).
- 19 In Western Australia, the Economic Regulation Authority (ERA) is responsible for this task.
- 20 AEMC, Review of the effectiveness of competition in electricity and gas retail markets in Victoria-first final report, Sydney, December 2007.
- 21 ESC (Victoria), 'Energy customers shop around for retail offers', Media release, 18 December 2008.
- 22 AEMC, Review of the effectiveness of competition in electricity and gas retail markets in South Australia-first final report, Sydney, September 2008, p. 19.
- 23 AEMC, Review of the effectiveness of competition in electricity and gas retail markets in South Australia-second final report, Sydney, December 2008.

<sup>17</sup> See section 7.4.1 for details.

The remainder of this section provides a sample of public data that may be relevant for assessing the effectiveness of retail competition in Australia. 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. This section also considers regulated prices and retail profit margins. Elsewhere, this chapter touches on other barometers of competition—for example, section 7.1 considers new entry.

The information provided here does not seek to draw conclusions. The AER is not assessing or commenting on the effectiveness of retail competition in any jurisdiction.

# 7.3.1 Price and non-price diversity of retail offers

There is evidence of retail price diversity in electricity markets that have introduced FRC (box 7.2). In particular, both host and new entrant retailers tend to offer market contracts at discounts against the 'default' regulated terms and conditions.

Some price diversity is associated with product differentiation—for example, retailers might offer a choice of standard products, green products, 'dual fuel' contracts (for gas and electricity) and retail packages that bundle electricity and gas services with other services such as telecommunications, each with different price structures.<sup>24</sup>

Some product offerings bundle energy services 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, however, for early withdrawal. The variety of discounts and non-price inducements makes direct price comparisons difficult. Further, the transparency of price offerings varies. Some retailers publish details of their products and prices, while others require a customer to fill out online forms or arrange a consultation. Victorian and South Australian retailers are required to publish product information statements on their websites. Additionally, the Queensland, South Australian and Victorian regulators and a number of other entities operate websites that allow customers to compare their current electricity and gas retail contracts with available market offers.

The Australian Consumer Association has launched a website—CHOICEswitch—that allows customers to compare energy retail offers. Box 7.2 draws on the website to comment on the diversity of price and product offerings to small customers in Brisbane, Sydney, Melbourne, Adelaide and Canberra. The price offers noted in box 7.2 are not directly comparable across jurisdictions, because the underlying product structures may not be identical.

For further information on retail prices, see section 7.4.

# 7.3.2 Customer switching

The rate at which customers switch their supply arrangements indicates customer participation in the market. While switching (or churn) rates can also indicate competitive activity, they must be interpreted with care. Switching is sometimes high during the early stages of market development, when customers are first able to exercise choice. Switching rates sometimes stabilise even as a market acquires more depth. Similarly, they may be low in a very competitive market if retailers are delivering good quality service that gives customers no reason to switch.

24 In the ACT, the host retailer in electricity and gas—ActewAGL Retail—offers discounts on electricity services if the customer elects to 'bundle' electricity retail services with gas and telecommunications services.

### Box 7.2 Price and product diversity in the small customer market

The CHOICEswitch website (www.choiceswitch.com.au) provides an online estimator service that allows consumers to make quick comparisons of electricity and gas retail offers available in their area. The website also provides information on the terms, conditions and other benefits of each offer.

Table 7.5 draws on data available on the CHOICEswitch website to set out the estimated price offerings in May 2009 for customers in selected suburban postcodes in Brisbane, Sydney, Melbourne, Adelaide and Canberra using 6500 kilowatt hours (kWh) a year, based on peak use. The offers were only for the postcodes selected and might not have been available to all customers. The data include all financial discounts and bonuses available under each offer but exclude non-financial gifts such as magazine subscriptions, gift cards and movie tickets.

The data indicate some price and product diversity in all of the retail markets, with a price spread of \$582 (Melbourne) to \$864 (Canberra).<sup>25</sup> Most plans included additional financial discounts and bonuses, with prompt payment being the most common condition to attract a discount. Other financial incentives offered by some retailers included joining and loyalty bonuses.

Some of the offers with larger discounts were provided under a fixed term contract that attracts exit fees for early termination. Retail offers in the upper price range generally provided higher levels of accredited renewable energy (GreenPower). For offers with 100 per cent GreenPower, some retailers allowed customers to choose solar or wind power as the source of their energy.

In the capital cities where retail prices are regulated (Brisbane, Sydney, Adelaide and Canberra) most retailers offered products that provided a discount off the regulated price. Retailers in Adelaide offered the largest discount off the regulated price (up to \$220), compared with a discount of up to \$95 in Brisbane, \$87 in Sydney and \$19 in Canberra.

25 Very large price spreads may reflect product differentiation. Some premium priced products have high proportions of accredited green power. Some ActewAGL products, for example, allow customers to purchase more GreenPower than their household would use.



### 202 STATE OF THE ENERGY MARKET 2009

RETAILER	NO. OF PRODUCTS	DISCOUNTS AND BONUSES INCLUDED CONTRA ANNUAL COST (INCLUDING DISCOUNTS AND FINANCIAL BONUSES) IN ANNUAL COST TERM									RACT RM	GREEN POWER?								
		1000	1100	1 1	200	1300	1/00	1500	1600	1700	1800	190	0 200	10 21	Pay- on-time	Loyalty	Sign-up	Fixed	Exit	
BRISBANE (POSTCODE 40	321	1000	1100	, ,	200	1500	1400	1500	1000	1700	1000	170	0 200	50 21	oo bonas	bonus	Donus	term	1663	
Regulated price (AGL Eper	avl																			
AGL Energy	7																	•	•	•
EnergyAustralia	4																	•	•	
Eraon Eneray	1																			
Integral Energy	6		_															•	•	•
Jackgreen	4														•				•	•
Origin Energy	12																	•	•	•
Queensland Electricity	1																			
TRUenergy	13														•			•	•	•
SYDNEY (POSTCODE 2148)																				
Regulated price (Integral E	inergy)																			
AGL Energy	6																	•	•	•
EnergyAustralia	3																			•
Integral Energy	11																	•	•	•
Jackgreen	4														•				•	•
Origin Energy	12																	•	•	•
TRUenergy	13														•			•	•	•
MELBOURNE (POSTCODE	3079)																			
AGL Energy	6																	•	•	•
Australian Power & Gas	7														•		•			•
Click Energy	4														•		•	•	•	
Country Energy	4																•	•	•	•
EnergyAustralia	9																•			•
Jackgreen	7														•			•	•	•
Neighbourhood Energy	5														•					•
Origin Energy	12																	•	•	•
Red Energy	5														•	•		•	•	•
Simply Energy	3														•	•				•
TRUenergy	13														•			•	•	•
Victoria Electricity	4														•			•	•	•
ADELAIDE (POSTCODE 50	0 <b>7)</b>																			
Regulated price (AGL Ener	gy)																			
AGL Energy	6																	•	•	•
Jackgreen	4														•				•	•
Origin Energy	12																	•	•	•
Red Energy	2														•	•		•	•	•
Simply Energy	3														•	•				•
South Australia Electricity	1																			
TRUenergy	13														•			•	•	•
CANBERRA (POSTCODE 2)	616)																			
Regulated price (ActewAG	_)																			
ActewAGI	20																			

# Table 7.5 Electricity retail price offers for a customer using 6500 kWh per year in each capital city, May 2009

Note: The offers were only for standalone electricity products in the postcodes selected and might not have been available to all customers. The data include all financial discounts and bonuses available under each offer. Green power refers to renewable energy accredited under the Australian Government's GreenPower scheme.

Source: CHOICEswitch energy comparison website, viewed 22 May 2009, www.choiceswitch.com.au.

#### Figure 7.6



Cumulative monthly customer switching of retailers as a percentage of small customers, January 2002 to June 2009

### Table 7.6 Small customers switching retailers, 2009

		NEW SOUTH		SOUTH
INDICATOR	QUEENSLAND	WALES	VICTORIA	AUSTRALIA
Percentage of small customers that changed retailer during 2008-09 (%)	14.6	11.5	25.7	16.0
Customer switches as a percentage of the small customer base from start of FRC to June 2009 (cumulative) [%]	28.5	56.1	130.7	104.4

FRC, full retail contestability.

Sources: see table 7.6.

Notes:

If a customer switches to a number of retailers in succession, then each move counts as a separate switch. Cumulative switching rates may thus exceed 100 per cent.

The customer base is estimated at 30 June 2009.

Sources: Customer switches: AEMO, MSATS transfer data to June 2009; customer numbers: IPART (New South Wales), NSW electricity information paperelectricity retail businesses' performance against customer service indicators, Sydney, March 2009; ESCOSA (South Australia), 2007-08 Annual performance report: performance of South Australian energy retail market, Adelaide, November 2008; ESC (Victoria), Energy retailers: comparative performance report-customer service 2007-08, Melbourne, December 2008; ESCOSA (South Australia), Annual performance report: performance of South Australian energy retail market 2007-08, Adelaide, November 2008; QCA (Queensland), Market and non-market customers, December quarter 2008, Brisbane, April 2009.

The Australian Energy Market Operator (AEMO) publishes churn data measuring the number of customer switches from one retailer to another.<sup>26</sup> The data are available for New South Wales and Victoria from the introduction of FRC in 2002, for South Australia from October 2006 and for Queensland from July 2007.

Table 7.6 and figure 7.6 set out gross switching data that is, 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, and 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. Cumulative switching rates may thus exceed 100 per cent.

26 The National Electricity Market Management Company (NEMMCO) published the data until 30 June 2009.

JURISDICTION	DATE	CUSTOMERS ON MARKET CONTRACTS (% OF CUSTOMER BASE)
Queensland	31 March 2009	44.3% of small customers <sup>1</sup>
Victoria	30 June 2008	54% of electricity and gas customers
South Australia	30 June 2008	69% of residential customers (24% with the host retailer and 49% with new entrants)
		52% of small business customers (21% with the host retailer and 31% with new entrants)
		68% of residential and small business customers (averaged)
ACT	30 June 2008	21% of all customers

#### Table 7.7 Customer transfers to market contracts

1. Small customers in Queensland include residential and small business customers.

Sources: ESC (Victoria), Energy retailers: comparative performance report-customer service 2007-08, Melbourne, December 2008; QCA (Queensland), Market and non-market customers as at 30 September 2008, Brisbane, September 2008; ESCOSA (South Australia), 2007-08 Annual performance report: performance of South Australian energy retail market 2007-08, Adelaide, November 2008, pp. 22-3; ICRC (ACT) Draft decision: retail prices for non-contestable electricity customers, 2009-2010, Canberra, April 2009.

The data do not include customers that switch from a default arrangement to a market contract with their existing retailer. The data may thus understate the true extent of competitive activity by not accounting for the efforts of host retailers to retain market share.

Table 7.6 illustrates that switching activity continued strongly in Victoria (and to a lesser extent South Australia and Queensland) throughout 2008–09. A recent survey by *Choice* magazine found Victorian customers are more likely than interstate customers to be approached by door-to-door sales people and telemarketers offering a range of energy services.<sup>27</sup> New South Wales continues to have a switching rate below the other states.

### Switches to market contracts

While AEMO reports on customer switching between retailers, an alternative churn indicator is customer switching from regulated 'default' contracts to market contracts. South Australia and Queensland publish these data periodically, while New South Wales, the ACT and Victoria do so irregularly.

Table 7.7 summarises the available data on switches to market contracts. The data are not directly comparable across jurisdictions because the data collection methods and periods covered differ. Table 7.7 indicates that a significant number of customers are moving from standing offer contracts to market contracts with their host retailer. South Australia has reported relatively high rates of customer switching to market contracts, compared with rates in the other states. Victoria has also reported relatively high rates of customer transfers to market contracts, but the data include transfers in both the electricity and gas retail markets.

### 7.3.3 Customer perceptions of competition

A number of jurisdictions undertake occasional surveys on customer perceptions of retail competition. Issues covered include:

- > customers' awareness of their ability to choose a retailer
- > customer approaches to retailers about taking out a market contract
- > retail offers received by customers
- > customer understanding of retail offers.

Table 7.8 summarises survey data on customer perceptions of retail competition. The data are not directly comparable across jurisdictions because the data collection methods, periods covered and regions surveyed differ. The surveys suggest customer awareness of retail choice is high and rising over time. While it remains unusual for customers to approach retailers, retailer approaches to customers have steadily risen.

27 Choice magazine, 'Power play', March 2009, p. 14. [Reprinted from 'Power play', March 2009 Choice magazine, with the permission of the Australian Consumer Association.]

#### Table 7.8 Residential customer perceptions of competition

NEW SOUTH WALES <sup>1</sup>										
INDICATOR	Sydney	Hunter region	VICT	ORIA	SOUTH AUSTRALIA					
	2003	2008	2002	2007	2003	2008				
Customers aware of choice (%)	74	90	n/a	94	62	82				
Customers receiving at least one retail offer <sup>2</sup> (%)	27	53	17	73	5	68				
Customers approaching retailers about taking out market contracts (%)	n/a	n/a	3	10	3	10				

n/a, not available.

1. New South Wales data in 2003 are based on a household survey conducted in Sydney, while the 2008 data are based on a similar household survey conducted in the Hunter region.

2. In New South Wales, the figures exclude customers approached by their current retailer to switch to a market contract.

Sources: South Australia: McGregor Tan Research, Monitoring the development of energy retail competition—residents, Report prepared for ESCOSA, Adelaide, February 2006, November 2003; McGregor Tan Research, Review of effectiveness of competition in electricity and gas retail markets, Report prepared for the AEMC, Adelaide, June 2008; Victoria: The Wallis Group, Review of competition in the gas and electricity retail markets—consumer survey, Report prepared for the AEMC, Melbourne, August 2007; New South Wales: IPART, Electricity, gas and water research paper—residential energy and water use in the Hunter, Gosford and Wyong, Sydney, December 2008; IPART, Residential energy and water use in Sydney, the Blue Mountains and Illawarra—results from the 2006 household survey, Sydney, November 2007.



#### Composition of a residential and small business electricity bill



Note: Figures represent the composition of estimated costs for an electricity retailer.

Sources: IPART (New South Wales), Regulated electricity tariffs and charges for customers 2007 to 2010-electricity final report and final determination, Sydney, June 2007, p. 2; QCA (Queensland), 2009-10 Benchmark retail cost index, final decision, Brisbane, June 2009, p. 54.

# 7.4 Retail prices

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 are not widely available. Figure 7.7 provides indicative data for residential customers in New South Wales and residential and small business customers in Queensland based on historical information. The charts indicate that wholesale and network costs account for the bulk of retail prices. Retail operating costs (including retail margins) account for around 13 per cent of retail prices in New South Wales and 9 per cent in Queensland.

# 7.4.1 Regulation of retail prices

At July 2009 all jurisdictions except Victoria applied retail price regulation to small customers. Typically, host retailers must offer to sell electricity at default prices based on some form of regulated price cap or oversight. Small customers may request a standing offer contract —with default prices—from the host retailer or choose an unregulated market contract from a licensed retailer.

Price cap regulation was intended as a transitional measure during the development of retail markets. To allow efficient signals for investment and consumption, governments are moving towards removing retail price caps. As noted, the AEMC (and the Economic Regulation Authority in Western Australia) is responsible for reviewing the effectiveness of competition in electricity and gas retail markets to determine an appropriate time to remove retail price caps in each jurisdiction (box 7.1).

In setting default tariffs, jurisdictions consider energy purchase costs, network charges, retailer operating costs and a retail margin. The approach varies across jurisdictions:

- > The Queensland regulator, the Queensland Competition Authority (QCA), uses a benchmark retail cost index method to calculate annual adjustments in regulated prices for small customers that do not enter a market contract on changes in benchmark costs. In June 2009 the Queensland Government directed the QCA to review the method and prices to determine whether current price levels promote competition, allow real electricity costs to be fully recovered from south east Queensland consumers, and account for government environmental obligations.<sup>28</sup> The QCA will review alternative methods for setting prices and price structures that may assist in managing peak electricity demand and encourage more efficient electricity use.
- > The New South Wales regulator, the Independent Pricing and Regulatory Tribunal (IPART), sets a retail price cap for small customers that do not enter a market contract. IPART noted in its review of retail prices for 2007-10 that the New South Wales Government aimed to reduce customer reliance on regulated prices and had directed IPART to ensure regulated tariffs are cost-reflective by June 2010.<sup>29</sup>
- > The Victorian Government removed retail price caps for small businesses users on 1 January 2008<sup>30</sup> and for residential customers on 1 January 2009.<sup>31</sup>
- > The South Australian regulator, the Essential Services Commission of South Australia (ESCOSA), regulates default prices for small customers. In 2007 ESCOSA made a determination on default prices for three years commencing on 1 January 2008.
- In Western Australia, electricity retail prices for non-contestable customers are regulated under statutory requirements and set out in bylaws. All non-contestable customers are entitled to a uniform price regardless of their geographic location. Customers in major population centres in the state's south west subsidise regional customers through the Tariff Equalisation Fund.<sup>32</sup>
- 28 QCA, Letter from Minister for Natural Resources, Mines and Energy and Minister for Trade, and the Ministers' Direction Notice for the review, Brisbane, 24 June 2009.

<sup>29</sup> IPART (New South Wales), Regulated electricity tariffs and charges for customers 2007 to 2010—electricity final report and final determination, Sydney, June 2007, p. 2.

<sup>30</sup> Peter Batchelor (Minister for Energy and Resources, Victoria), 'Better energy prices available to small businesses', Media release, 8 November 2007.

<sup>31</sup> Department of Primary Industries (Victoria), 'Energy efficiency', viewed 1 May 2009, www.dpi.vic.gov.au/energy.

<sup>32</sup> Office of Energy, *Electricity retail market review-issues paper*, Perth, December 2007, p. 7.
JURISDICTION	PERIOD	RETAILERS	INCREASE IN REGULATED RETAIL PRICE	MECHANISM FOR CHANGES IN REGULATED PRICE	RETAIL MARGIN	
Queensland	1 July 2009 to 30 June 2010	All licensed retailers	Net additional increase of 3.68% for 2008–09 (applying from 1 July 2009) and 11.82% for 2009–10	Prices are adjusted annually in accordance with a benchmark retail cost index.	5% of total revenue	
New Courte Walso	1 July 2007 to	EnergyAustralia	CPI + 4.1%	Electricity purchase costs are annually	5% of	
South wates	30 June 2010	Integral Energy	CPI + 4.9%	be adjusted if the review finds forecast	EBIIDA	
		Country Energy	CPI + 3.7%	electricity purchase costs differ		
			(annual adjustments)	used to set the price path. Retailers are also required to pass on network price increases. In 2009 IPART made a determination to increase a typical bill of EnergyAustralia (by 21.7%), Integral Energy (by 21.1%) and Country Energy (by 17.9%), due to rising wholesale and network costs.		
South Australia	1 January 2008 to 31 December 2010	AGL Energy	6.8% in 1 Jan 08 to 30 June 2008; CPI-only increase to July 2011	There is no provision to adjust the price path due to changes in electricity purchase costs. However, the price determination can be re-opened if a fundamental basis of the determination has been undermined.	10% of controllable costs (equivalent to about 5% of sales revenue)	
Western	1 April 2009	Synergy and	10.0%	Government decision is to be	n/a	
Australia	1 July 2009	Horizon Power	15.0%	price rises will be phased in over six to eight years (after 30 June 2010).		
Tasmania	1 January 2008 to 30 June 2010	Aurora Energy	Average 16.0% in 1 Jan 2008 to 30 June 2008, and estimated average increases of 4.0% in 2008–09 and 3.8% in 2009–10 respectively	There is no provision to adjust the price path due to changes in electricity purchase costs. Regulations set out the average price the regulator is to assume for each period. The regulator has limited discretion to re-open a determination in the event of an unforeseen material change.	3% of sales revenue	
				Provision was made to adjust for certain pass-through costs, including transmission and distribution costs.		
ACT	1 July 2009 to 30 June 2010	ActewAGL Retail	6.42%	Annual price determination. There are no automatic cost adjustments, but the ICRC Act allows for variations to the price direction to occur, if the circumstances change from those that existed when the decision was finalised.	5% of sales revenue	

#### Table 7.9 Recent regulatory decisions—electricity retail prices

n/a, not available; EBITDA, earnings before interest, tax, depreciation and amortisation.

Sources: QCA (Queensland), 2009-10 Benchmark retail cost index, final decision, June 2009, Brisbane, p. i; IPART (New South Wales), Regulated electricity retail tariffs and charges for customers 2007 to 2010: electricity final report and final determination, Sydney, June 2007; ESCOSA (South Australia), 2007 Review of retail electricity price path: final inquiry report and price determination, Adelaide, November 2007; OTTER (Tasmania), Investigation of prices for electricity distribution services and retail tariffs on mainland Tasmania: final report and proposed maximum prices, Hobart, September 2007; ICRC (ACT), Final decision—retail prices for non-contestable electricity customers 2009-2010, Canberra, June 2009; Peter Collier (Minister for Energy, Western Australia), 'State Government announces increases in tariff arrangements', Media release, 23 February 2009.

> When requested by the ACT Government, the ACT regulator, the Independent Competition and Regulatory Commission (ICRC), determines the maximum prices for small customers on a standing offer contract. The regulator annually adjusts the regulated tariff to reflect changes in benchmark costs.

Table 7.9 compares recent movements in regulated default prices and retail margins under regulatory or government decisions. The decisions relate to the supply of electricity by host retailers to customers on standing offer contracts. The chart omits Victoria, which no longer regulates retail prices.

Different price outcomes across the jurisdictions reflect a range of factors, so must be interpreted with care. In particular, the operating environments of retail businesses differ. The degree of retailer exposure to wholesale costs depends on a variety of factors, including the nature and shape of a retailer's load, the extent of hedging in financial markets to protect against price volatility, and the strike price of financial contracts. Some retailers have vertical relationships with generators to cushion the impact of volatile wholesale costs.

Regulated default prices tended to be relatively stable in 2008–09. This followed significant price rises in 2007–08, largely due to the impact of the drought on wholesale electricity prices (see chapter 2). However, prices are set to rise again in some jurisdictions:

- In May 2009 IPART announced that a typical retail bill in New South Wales would rise by 17.9–21.9 per cent in 2009–10 due to network price increases and higher wholesale costs.<sup>33</sup>
- In June 2009 the QCA announced that regulated retail prices for 2009–10 would increase by 11.82 per cent. Following an appeal by Origin Energy and AGL Energy, the QCA announced an additional increase in regulated prices for 2008–09

of 3.68 per cent. This additional increase applied from 1 July 2009, resulting in a total increase in regulated retail prices for 2009–10 of 15.5 per cent.<sup>34</sup>

- > The ICRC announced that retail prices in the ACT will increase by up to 6.42 per cent in 2009–10 due to higher distribution costs.<sup>35</sup>
- In Western Australia, the Office of Energy recommended in 2008 that retail prices increase by 52 per cent. The Western Australian Government rejected this recommendation and announced that residential prices will increase by 10 per cent on 1 April 2009 and a further 15 per cent on 1 July 2009.<sup>36</sup>

# 7.4.2 Retail price outcomes

While retail price outcomes are critical to consumers, the interpretation of retail price movements is not straightforward. 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, and/or retail operating costs and margins.

Care must be taken when interpreting retail price trends in deregulated markets. While competition tends to deliver efficient outcomes, it may give a counter-intuitive outcome of higher prices—especially in the early stages of competition. In particular:

- > governments and other customers (usually business customers) historically subsidised energy retail prices for some residential 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 have been too low to attract competitive new entrants. It may be necessary for retail prices to rise to create sufficient 'head room' for new entry.

35 ICRC (ACT), Final decision-retail prices for non-contestable electricity customers 2009-2010, Canberra, June 2009, p. 5.

<sup>33</sup> IPART (New South Wales), Market-based electricity purchase cost allowance-2009 review, regulated electricity retail tariffs and changes for small customers 2007-2010, Sydney, May 2009, p. 2.

<sup>34</sup> QCA (Queensland), 2009-10 Benchmark retail cost index, final decision, Brisbane, June 2009, p. i.

<sup>36</sup> Peter Collier (Minister for Energy), 'State Government announces increases in tariff arrangements', Media release, 23 February 2009.

#### Figure 7.8

Retail electricity price index (inflation adjusted)— Australian capital cities, June 1991 to March 2009



#### Figure 7.9

Change in the real price of electricity—Australia, June 1991 to March 2009



Note: The household index is based on the CPI 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.

Sources: ABS, Consumer price index and Producer price index, March quarter 2009, cat. nos 6401.0 and 6427.0, Canberra, 2009.

#### Sources of price data

There is little systematic publication of the actual prices paid by electricity retail customers. At the state level:

- > jurisdictions that retain price caps 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 (the ESC and ESCOSA) publish annual data on retail prices
- > the ESC, ESCOSA and the Queensland regulator (QCA) provide estimator services on their websites, allowing consumers to compare the price offerings of retailers
- > the CHOICEswitch website provides a comparison and switching service, to help consumers compare electricity and gas offers (box 7.2). Other price comparison websites also exist.

#### Consumer price index and producer price index

The consumer price index (CPI) and producer price index, published by the Australian Bureau of Statistics, track movements in household and business electricity prices.<sup>37</sup> The indexes are based on surveys of the prices paid by households and businesses, so reflect a mix of regulated and market prices.

Figure 7.8 tracks real electricity price movements for households and business customers. There is some volatility in the data for business customers, given that large energy users are exposed to price volatility in the wholesale and contract markets for electricity (see chapters 2 and 3). In most jurisdictions, residential prices are at least partly shielded from volatility by price cap regulation and retailers' hedging arrangements.

Since 1991 real household prices have risen by 14.3 per cent, while business prices have fallen by 16.5 per cent (figure 7.9). In part, these changes reflect the unwinding of cross-subsidies from business to household customers that began in the 1990s. While business prices have fallen substantially since 1991, they have risen since 2007, mainly as a result of rising wholesale electricity costs.

37 The producer price index series tracks input costs for manufacturers.

210







KWh, kilowatt hour.

Notes:

The prices are estimates based on extrapolating ESAA data published in 2004 using the CPI series for electricity and other household fuels for each capital city. The 2008-09 data cover the three quarters to March 2009.

Sources: ABS, Consumer price index, March quarter 2009, cat no. 6401, Canberra, 2009; ESAA, Electricity prices in Australia 2003-04, Melbourne, 2003.

It is possible to estimate average retail prices for households by using the CPI to extrapolate from historical data published by the Energy Supply Association of Australia (ESAA).<sup>38</sup> Figure 7.10 estimates real electricity prices for households in Brisbane, Sydney, Melbourne, Adelaide, Perth, Hobart, Canberra and Darwin since 1 July 1999. Price variations across the cities reflect multiple factors, including differences in generation and network costs, industry scale, historical cross-subsidies, differences in regulatory arrangements and different stages of electricity reform implementation.

From 2001 to 2009, real electricity prices in Perth trended downwards while Melbourne, Sydney and Canberra prices trended upwards. In Brisbane (where small customer prices remained fully regulated until 2007) and Hobart (where small customer prices are still fully regulated), real prices have remained relatively stable since 2001, but have trended higher since 2007. Price rebalancing to phase out cross-subsidies caused significant price rises in Melbourne and Adelaide early in the decade.

# 7.5 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'.<sup>39</sup> In November 2000 the Utility Regulators Forum (URF) established the Steering Committee on National Regulatory Reporting Requirements. The committee developed a national framework in 2002 for electricity retailers to report against common criteria on service performance.<sup>40</sup> The steering committee amended the national framework and reporting template in 2007.<sup>41</sup> The criteria in the national framework address:

- > access and affordability of services
- > quality of customer service.

The measures apply to the small customer retail market.<sup>42</sup> All National Electricity Market (NEM) jurisdictions have adopted the national template but each jurisdiction applies its own implementation framework. In addition, jurisdictions have their own

- 40 URF, National regulatory reporting for electricity distribution and retailing businesses, discussion paper, Canberra, March 2002.
- 41 URF, National energy retail performance indicators, final paper, May 2007.
- 42 See footnote 2 for jurisdictional classifications of 'small customers'.

<sup>38</sup> The ESAA published annual data on retail electricity prices by customer category and region until 2004.

<sup>39</sup> See, for example, ESC (Victoria), Energy retailers: comparative performance report-customer service 2007-08, Melbourne, December 2008.

monitoring and reporting requirements. There are thus some differences in approach.

The service quality data published by jurisdictional regulators are derived from the reporting of individual retailers. The regulators annually consolidate and publish the data. The validity of any performance comparisons may be limited, however, given the differences in jurisdictions' approach. In particular, measurement systems, audit procedures and classifications may differ across jurisdictions and within the same jurisdiction over time. Similarly, regulatory procedures and practices differ—for example, the procedures that a retailer must follow before a customer can be disconnected.

# 7.5.1 Affordability and access indicators

With the introduction of retail contestability, governments have strengthened consumer protection arrangements, focusing on access and affordability issues. These protections are often given effect through regulated minimum standards regimes and codes.

Retailers provide options to help customers manage their bill payments. The URF's reporting template covers a number of affordability indicators, including rates of customer disconnections and reconnections. The rate of residential customer disconnections for failure to meet bill payments (figure 7.11) and the rate of disconnected residential customers who are reconnected within seven days (figure 7.12) are key affordability and access indicators.

In 2007–08 the rate of disconnections fell in New South Wales, Victoria, the ACT and Western Australia, but increased slightly in South Australia and Tasmania. The rates in that year were below 2003–04 rates in all jurisdictions with available data except Tasmania. A range of factors might have contributed to these outcomes. Difficulties with the implementation of a new billing system, for example, led to AGL Energy suspending customer disconnections in Victoria. As a result, AGL Energy's disconnection rate in 2007–08 was below its historical average, which might have affected Victoria's average disconnection rate.<sup>43</sup>

The rate at which disconnected residential customers are reconnected within seven days (figure 7.12) increased in Victoria in 2007–08, but fell in New South Wales, Western Australia, Tasmania and the ACT. South Australia recorded a slight decrease in its seven day reconnection rate. Rates in 2007–08 were below 2003–04 rates in all jurisdictions with available data.

# 7.5.2 Customer service indicators

Customers can seek to resolve service issues with energy retailers via a range of methods. First, they can raise complaints through the retailer's dispute resolution procedure. If further action is needed, they can refer complaints to the state energy ombudsman or an alternative dispute resolution body. Additionally, retail competition allows customers to transfer away from a business providing poor service.

Monitoring in this area includes:

- > 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.

In 2007–08 the rate of customer complaints fell in New South Wales, but increased slightly in Victoria, South Australia, Western Australia and Tasmania. A significant increase occurred in the ACT (figure 7.13). The rate of customer complaints in Victoria has increased every year since 2003–04. The number of complaints that required a full investigation by the Electricity and Water Ombudsman of Victoria also increased (by 6 per cent) in 2007–08. AGL Energy experienced significant difficulties with a new billing system in December 2007, which might have resulted in a one-off increase in the complaints referred to the Ombudsman.<sup>44</sup>

43 ESC (Victoria), Energy retailers: comparative performance report-customer service 2007-08, Melbourne, December 2008, p. 26.

<sup>44</sup> ESC (Victoria), Energy retailers: comparative performance report—customer service 2007-08, Melbourne, December 2008, p. 42.

The response times of retailer call centres improved in every jurisdiction for which data were available in 2007–08 (figure 7.14). Retailers in Western Australia recorded a significant improvement in prompt call answering times, up from 63 per cent in 2006–07 to 80 per cent in 2007–08.<sup>45</sup>

## 7.5.3 Consumer protection

Governments regulate aspects of the electricity retail market to protect consumers and ensure they have access to sufficient information to make informed decisions. Most jurisdictions require designated host retailers to provide electricity services under a standing offer or default contract to particular customers. Most impose this obligation on retailers on a geographic basis. Queensland, however, requires the financially responsible market participant—generally the current retailer—to offer default contracts for each property; obligations for new connections are imposed on a geographic basis.<sup>46</sup>

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 may also include some form of regulated price cap or prices oversight (see section 7.4.1).

Some jurisdictions have also established industry codes that govern the provision of electricity retail services to small customers, including those under market contracts. Industry codes cover 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 were unable to resolve directly with the retailer. In addition to general consumer protection measures, jurisdictions have introduced 'retailer of last resort' arrangements to ensure customers can transfer from a failed retailer to another retailer.

Community service obligations to particular customer groups (often, low income earners) are another form of consumer protection. Traditionally, the payments were often 'hidden' in subsidies and cross-subsidies between different customer groups, which distorted pricing and investment signals. As part of the energy reform process, the Ministerial Council on Energy developed the Energy Community Service Obligations National Framework to make community service obligations more transparent and fund them directly out of budgets rather than via cross-subsidies.

In April 2008 the Productivity Commission recommended establishing a national consumer protection regime for energy services and a single set of consumer protection requirements in all NEM jurisdictions confirming processes already in place to develop a National Energy Customer Framework.<sup>47</sup> The commission also recommended a more consistent approach to complaint handling and reporting processes by jurisdictional energy ombudsmen and, ultimately, the establishment of a national energy ombudsman.<sup>48</sup>

<sup>45</sup> ERA (Western Australia), 2007-08 Annual performance report-electricity retailers, Perth, March 2009, p. 18.

<sup>46</sup> The AEMC, in its review of the effectiveness of the Victorian energy retail market, recommended Victoria move to a financially responsible market participant model. In response to this recommendation, Victoria made its local area model more consistent with the financially responsible market participant model.

<sup>47</sup> Productivity Commission, Inquiry report: review of Australia's consumer policy framework, Canberra, April 2008, pp. 66-7.

<sup>48</sup> Productivity Commission, Inquiry report: review of Australia's consumer policy framework, Canberra, April 2008, p. 71.



Electricity residential disconnections for failure to pay amount due, as a percentage of the small customer base

#### Notes:

Figure 7.11

Data 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.

Queensland data are not available for all years. Western Australia commenced publication of these data in 2006–07. Source: see figure 7.14.

#### Figure 7.12

#### Electricity residential reconnections within seven days, as a percentage of disconnected customers



#### Notes:

New South Wales data include all reconnections (not just within seven days of disconnection).

Queensland data are not available for all years. Western Australia commenced publication of these data in 2006-07.

Source: see figure 7.14.



Figure 7.13 Electricity retail customer complaints, as a percentage of total customers

Note: Queensland data are not available for all years. Western Australia commenced publication of these data in 2006–07. Source: see figure 7.14.



#### Figure 7.14

Notes:

South Australian and Victorian data from 2005–06 include both electricity and gas customers. From 2007–08, call response rates in Tasmania are for calls answered within 30 seconds. For previous years, the data were based on a 20 second target.

Queensland data are not available for all years. Western Australia commenced publication of these data in 2006-07.

Sources for figures 7.11-7.14: Reporting against URF templates and performance reports on the retail sector by IPART (New South Wales), the ESC (Victoria), ESCOSA (South Australia), OTTER (Tasmania), the QCA and the Department of Mines and Energy (Queensland), the ICRC (ACT) and the ERA (Western Australia). The 2006-07 and 2007-08 data for the ACT are preliminary data provided by the ICRC.

# 7.6 Energy efficiency

Energy efficiency measures are products or strategies that use less energy for the same or higher performance, compared with an existing system or product. While such measures can improve the efficiency of energy use, there are wider benefits. They can, for example, 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. Such measures to improve energy efficiency are being implemented throughout the retail sector (see section 7.6.1).

Demand management measures that address growth in demand (especially peak demand) for electricity are another way to improve efficiency in energy use. These measures often operate via the distribution network sector (see section 6.8).

# 7.6.1 Jurisdictional energy efficiency initiatives

Many state governments are implementing programs to promote energy efficiency:

> In June 2007 the Queensland Government released its climate change strategy, ClimateSmart 2050. The strategy encourages investment in energy saving technologies to reduce greenhouse gas emissions in Queensland businesses and homes, and increase energy conservation.<sup>49</sup>

Queensland's Smart Energy Savings Program commenced on 1 July 2009. The program requires medium to large energy customers to complete energy conservation audits and develop action plans to reduce their energy use.<sup>50</sup>

- > The New South Wales Energy Savings Scheme provides \$150 million over four and a half years on projects to save energy, reduce peak electricity demand, and delay the need for additional energy generation and distribution infrastructure.<sup>51</sup> It also aims to stimulate investment and increase public awareness of the benefits of energy savings.
- > The Victorian Energy Efficiency Target Scheme, which commenced on 1 January 2009, sets an overall target for energy savings. The scheme operates in phases, with new scheme targets and prescribed activities set for each three year phase. The first phase (2009–11) sets a target annual reduction of 2.7 million tonnes of greenhouse gas emissions.<sup>52</sup> The scheme requires energy retailers to meet individual targets through energy efficiency activities, such as providing householders with energy saving products and services.
- > South Australian retailers have been subject to the Residential Energy Efficiency Scheme from 1 January 2009. Initial targets are set for a three year period ending 2011.<sup>53</sup> The scheme requires retailers to meet targets for improving household energy efficiency (for example, through the use of ceiling insulation, draught proofing and more efficient appliances) and to provide energy audits to low income households.
- > The ACT Government released its climate change strategy: Weathering the change, ACT climate change strategy 2007-2025 in July 2007. This strategy includes the set up of the Home Energy Advice Team funded by the ACT Government to provide free, independent, expert advice on how to improve the energy efficiency of ACT residences.<sup>54</sup> The ACT Government has also committed \$40 million to improve the energy efficiency of schools and public housing.

<sup>49</sup> Department of Mines and Energy (Queensland), 'Smart Energy Policy', 23 April 2009, viewed May 2009, www.dme.qld.gov.au.

<sup>50</sup> Office of Clean Energy (Queensland), 'Smart Energy Savings Fund', 14 May 2009, viewed May 2009, www.cleanenergy.qld.gov.au.

<sup>51</sup> Department of Environment and Climate Change (New South Wales), 'NSW Energy Efficiency Strategy', 27 March 2009, viewed May 2009, www.environment.nsw.gov.au.

<sup>52</sup> ESC (Victoria), 'Victorian Energy Efficiency Target Scheme', 2 February 2009, viewed May 2009, www.esc.vic.gov.au.

<sup>53</sup> ESCOSA (South Australia), 'Residential Energy Efficiency Scheme', 21 April 2009, viewed May 2009, http://dtei.sa.gov.au.

<sup>54</sup> Department of the Environment, Climate Change, Energy and Water (ACT), Weathering the change-climate change strategy action plan one 2007-2011, Canberra, 2007.

# 7.7 Future regulatory arrangements

Governments agreed in the Australian Energy Market Agreement 2004 (as amended) that NEM jurisdictions would transfer non-price regulatory functions to a national framework for the AEMC and the AER to administer. These functions include:

- > the obligation on retailers to supply small customers
- > small customer market contracts and marketing
- > retailer business authorisations, ring-fencing and retailer failure
- > balancing, settlement, customer transfer and metering arrangements
- > enforcement mechanisms and statutory objectives.<sup>55</sup>

Non-price regulatory functions for gas retail in the Northern Territory will also be transferred to the national framework.

As part of the reform plan, work is proceeding on the development of a National Energy Customer Framework to regulate the retail supply of electricity and gas to customers. In April 2009 the MCE Standing Committee of Officials released the first exposure draft of the framework.<sup>56</sup> The proposed framework is comprised of a National Energy Retail Law, National Energy Retail Rules and National Energy Retail Regulations.

The AER's functions under the exposure draft include:

- > monitoring the compliance of regulated entities and other persons with the requirements of the national framework, and conducting compliance audits
- > overseeing contractual arrangements among retailers, distributors and customers
- > preparing and publishing annual compliance reports for the national framework, and making guidelines and procedures to support this role
- > preparing and publishing retail performance reports covering matters such as customer service and affordability, as well as retail market activity
- > taking enforcement action for breaches of retail laws
- > publishing retailer standing offer prices

- > granting retailer authorisations and exemptions from the requirement to obtain an authorisation, and establishing a public register with this information
- establishing and maintaining a customer consultative group
- conducting performance audits on hardship, and developing hardship indicators for performance reporting.

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.

A second exposure draft of the legislative package is scheduled for release in late 2009. The MCE anticipates the legislation changes required to implement the national framework will be introduced in the South Australian parliament in 2010.

55 Australian Energy Market Agreement 2004, as amended.

<sup>56</sup> MCE Standing Committee of Officials, Explanatory material—first exposure draft, National Energy Retail Law, National Energy Retail Regulations, National Energy Retail Rules, Canberra, April 2009, pp. 1–2, 4–19, 20–1.



# PART THREE NATURAL GAS



Natural gas is predominately made up of methane, a colourless and odourless gas. There are two main sources of natural gas in Australia. 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 gas is produced during the creation of coal from peat. The methane is adsorbed onto the surface of micropores in the coal. There are also renewable sources of methane, including biogas (landfill and sewage gas) and biomass, which includes wood, wood waste and sugarcane residue (bagasse). Renewable sources supply around 16 per cent of Australia's primary gas use.

# NATURAL GAS

The natural gas supply chain begins with exploration and development activity, which may involve geological surveys and the drilling of wells. Exploration typically occurs in conjunction with the search for other hydrocarbon deposits, such as oil. At the commercialisation phase, the extracted gas is processed to separate the methane from the liquids and other gases that may be present, and to remove any impurities, such as water and hydrogen sulphide.

The gas extracted from a well may be used on site as a fuel for electricity generation or for 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 the source over long distances. A network of distribution pipelines then delivers gas from points along the transmission pipelines to industrial customers, and from gate stations (or city gates) to consumers in cities, towns and regional communities. 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. Retailers act as intermediaries in the supply chain. They enter contracts for wholesale gas, transmission and distribution services, and 'package' the services for 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 is transported by ship to export markets. It is also possible to transport liquefied natural gas by road or pipeline.

Part three of this report provides a chapter-by-chapter survey of each link in the supply chain. Chapter 8 considers upstream gas markets, including exploration, production and wholesale trade. It discusses the supply of gas for domestic use and the export of liquefied natural gas. Chapters 9 and 10 provide data on the gas transmission and distribution sectors, and chapter 11 considers gas retailing.

# Domestic gas supply chain

PRODUCTION Gas is extracted from wells in

explored fields.





#### PROCESSING

Extracted gas often requires processing to separate the methane and to remove impurities.

#### DISTRIBUTION

Distribution networks are used to deliver gas to industrial customers and cities, towns and regional communities.





#### TRANSMISSION

High pressure transmission pipelines are used to transport natural gas over long distances.

## RETAIL

Retailers act as intermediaries, contracting for gas with producers and pipeline operators to provide a bundled package for on-sale to customers.





#### CONSUMPTION

Customers use gas for a number of applications, ranging from electricity generation and manufacturing to domestic use such as heating and cooking.

Image sources: Production, Woodside; Processing, Matthias Kulka (Corbis); Transmission, Jemena; Retail, Sadie Dayton (Corbis); Consumption, Vito Elefante (iStockphoto.com).



# 8 UPSTREAM GAS MARKETS



The upstream gas industry encompasses several phases, including exploration for gas resources, field development, gas gathering and, finally, the processing of natural gas. The wholesale gas market involves sales by producers and storage providers to energy retailers and other major customers. While the market largely remains characterised by confidential long term contracts, recent initiatives have enhanced transparency and competitive conditions.

# 8 UPSTREAM GAS MARKETS

#### This chapter considers:

- > Australia's natural gas resources
- > the exploration and development of gas resources
- > gas production and consumption
- > upstream industry structure, including participants and ownership changes
- > gas wholesale markets
- > gas prices
- > current market developments, including the Gas Market Bulletin Board and a short term trading market
- > reliability of supply.

## 8.1 Exploration and development

Exploration for natural gas typically occurs in conjunction with the search for other hydrocarbon deposits such as oil and coal. The exploration process is characterised by large sunk costs and a relatively low probability of success. Activity levels are driven by a range of factors, including projected energy prices, the availability of acreage, equipment costs, perceived risks and rewards, and the availability of finance. The costs incurred during this phase relate to surveying and drilling to identify possible resources, and acquiring exploration permits. In recent years, rising equipment costs have significantly increased the cost of offshore exploration and development. Given the cost and risk characteristics, exploration tends to be undertaken through joint venture arrangements so project partners share costs. If exploration is successful, the parties may proceed to the production phase or sell their interest to other parties. In the two years to June 2009, petroleum exploration expenditure in Australia was estimated at over \$3 billion—the highest on record.<sup>1</sup> The Australian Bureau of Agricultural and Resource Economics (ABARE) linked this growth to projections that global energy prices will continue to rise over the longer term. The rise is accounted for mainly by growth in offshore exploration in Western Australia and exploration activity in Queensland associated with the discovery of coal seam gas (CSG).<sup>2</sup>

Government control the rights to conduct exploration activity—including seismic acquisition and exploratory drilling—and develop gas fields. In Australia, the states and territories control onshore resources and those in coastal waters, while the Australian Government has jurisdiction over resources in offshore waters outside the 3 nautical mile boundary. 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'). Licences allocated in Australia include exploration, assessment (retention) and production licences:

- > An *exploration* licence provides a right to explore for petroleum, and to carry on such operations as are necessary for that purpose, in the permit area.
- > An assessment or retention licence provides a right to conduct geological, geophysical and geochemical programs to evaluate the development potential of the petroleum believed to be present in the permit area.
- > A *production* licence provides a right to explore for and recover petroleum, and carry on such operations as are necessary for those purposes, in the permit area.

Governments usually allocate petroleum tenements through a work program bidding process, which operates 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 relevant minister chooses the successful applicant by assessing the merits of the work program, the applicant's financial and technical capacity, the applicant's environmental impact statement, and any other criteria relevant to a tender. While the approach to issuing licences is relatively consistent across states and territories, licence tenure and conditions differ significantly.

# 8.2 Australia's natural gas resources

Natural gas consists mainly of methane. The two main types of natural gas in Australia are conventional natural gas and CSG. Conventional natural gas is found in underground reservoirs trapped in rock, often in association with oil. But CSG is produced during the creation of coal from peat. In addition, renewable gas sources such as biogas (landfill and sewage gas) and biomass (including wood, wood waste and sugarcane residue) supplied around 3 per cent of Australia's primary energy consumption in 2008–09.<sup>3</sup>

Australia has abundant natural gas reserves (table 8.1). At June 2009 total *proved and probable reserves*—those with reasonable prospects for commercialisation—stood at around 60 000 petajoules (PJ), comprising: > 39 000 PJ of conventional natural gas

> 21 000 PJ of CSG.<sup>4</sup>

Total proved and probable reserves increased by around 15 per cent in 2008–09. This increase was mainly due to the discovery of further CSG reserves in Queensland and New South Wales. Total proved and probable CSG reserves rose from 12 000 PJ in June 2008 to 21 000 PJ in June 2009.

<sup>1</sup> ABARE, Minerals and energy: major development projects, April 2009 listing, Canberra, 2009.

<sup>2</sup> Australian Bureau of Statistics, Mineral and petroleum exploration, ABS cat. no. 8412.0, Canberra, March 2008; ABARE, Minerals and energy: major development projects, April 2009 listing, Canberra, 2009.

<sup>3</sup> A Schultz, Energy Update 2009, ABARE, August 2009, p. 2.

<sup>4</sup> EnergyQuest, Energy Quarterly, August 2009.

#### Table 8.1 Natural gas reserves and production in Australia, 2009

	PROD (YEAR TO	DUCTION JUNE 2009)	PROVED AND P (JL	ROBABLE RESERVES <sup>2</sup> INE 2009)
GAS BASIN	PETAJOULES	PERCENTAGE OF DOMESTIC SALES	PETAJOULES	PERCENTAGE OF AUSTRALIAN RESERVES
CONVENTIONAL NATURAL GAS <sup>1</sup>				
WESTERN AUSTRALIA				
Carnarvon	322	32.2	28 739	47.7
Perth	7	0.7	21	0.0
NORTHERN TERRITORY				
Amadeus	19	1.9	181	0.3
Bonaparte	0	0.0	1 638	2.7
EASTERN AUSTRALIA				
Cooper (South Australia – Queensland)	124	12.4	1 084	1.8
Gippsland (Victoria)	230	23.0	5 625	9.3
Otway (Victoria)	116	11.6	1 291	2.1
Bass (Victoria)	18	1.8	287	0.5
Surat–Bowen (Queensland)	16	1.6	212	0.4
Total conventional natural gas	852	85.0	39 079	64.9
COAL SEAM GAS				
Surat–Bowen (Queensland)	143	14.3	19 726	32.7
Sydney (New South Wales)	5	0.5	1 452	2.4
Total coal seam gas	148	14.8	21 178	35.1
AUSTRALIAN TOTALS	1 000	100.0	60 257	100.0
LIQUEFIED NATURAL GAS (EXPORTS)				
Carnarvon (Western Australia)	766			
Bonaparte (Northern Territory)	14			
Total liquefied natural gas	780			
TOTAL PRODUCTION	1 780			

1. Conventional natural gas reserves include liquefied natural gas and ethane.

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

Source: EnergyQuest, Energy Quarterly, August 2009.

These estimates of total gas reserves rise sharply if factoring in *contingent resources*, which are known accumulations that are not yet commercially viable.<sup>5</sup> The development of CSG has expanded rapidly in the current decade, and ongoing exploration will likely add to Australia's natural gas reserves.

Australia produced 1780 PJ of natural gas in the year to June 2009, of which around 56 per cent was for the domestic market (figure 8.1). The CSG share of total production was only around 8 per cent, but

is rising rapidly. Around 44 per cent of Australia's gas production—all currently sourced from offshore basins in Western Australia and the Northern Territory—is exported as liquefied natural gas (LNG).

#### 8.2.1 Geographic distribution

The principal sources of natural gas production are Western Australia's offshore Carnarvon Basin and Victoria's offshore Gippsland Basin (figure 8.2).

5 Official sources in 2007 estimated total reserves, including contingent reserves, at 173 000 PJ (Ministerial Council on Mineral and Petroleum Resources / Ministerial Council on Energy, *Final report of the Joint Working Group on Natural Gas Supply*, Canberra, September 2007, p. 7).

Figure 8.1

Australian natural gas production, 2008–09



CSG, coal seam gas; LNG, liquefied natural gas. Source: EnergyQuest, *Energy Quarterly*, August 2009.

The Cooper Basin (in South Australia and Queensland) has been the principal historical source of gas for New South Wales and South Australia, but its reserves have been steadily declining. In contrast, production in Queensland's Surat-Bowen Basin has risen sharply during the current decade.

Figure 8.3 shows the location of Australia's major natural gas basins, including reserves and production levels, and sets out the contribution of each basin to production for the domestic market. Western Australia's Carnarvon Basin holds about 48 per cent of Australia's natural gas reserves. It supplies around one third of Australia's domestic market and 98 per cent of Australia's LNG exports.<sup>6</sup> The small Perth Basin supplies just under 1 per cent of the domestic market.

The Bonaparte Basin along the north west coast contains around 3 per cent of Australia's gas reserves. Its development has focused on producing LNG for

#### Figure 8.2

Natural gas production for domestic use, by gas basin, 2008–09



Note: 'Other' consists of the Perth, Amadeus and Bass basins. Source: EnergyQuest, *Energy Quarterly*, August 2009.

export, although the Bonaparte Gas Pipeline was recently constructed to ship gas to Darwin for domestic consumption. This capacity will supplement gas from the Amadeus Basin, which is in decline.

Eastern Australia contains around 49 per cent of Australia's natural gas reserves, of which the majority are CSG. This share represents an increase from 40 per cent in 2008, driven by continuing discoveries of CSG in New South Wales and Queensland. The principal sources of natural gas reserves are the Surat-Bowen Basin in Queensland (which meets around 16 per cent of national demand), the Gippsland Basin off coastal Victoria (23 per cent) and the Cooper Basin in central Australia (12 per cent). Production in Victoria's offshore Otway Basin (12 per cent) and Bass Basin (2 per cent) has risen significantly since 2004.<sup>7</sup>

6 The balance of Australia's LNG exports are produced at the Darwin LNG plant and sourced from the Bonaparte Basin. The Darwin plant produces LNG from gas produced in Australia and East Timor.

<sup>7</sup> EnergyQuest, Energy Quarterly, August 2009.

Figure 8.3 Australia's gas reserves and production, 2009



LNG, liquefied natural gas; PJ, petajoules. Note: Production data for year ended 30 June 2009. Reserves at June 2009. Data source: EnergyQuest, *Energy Quarterly*, August 2009.

#### Figure 8.4

Forecast sources of eastern Australia's natural gas production



CSG, coal seam gas

Note: 'Other' consists of conventional natural gas from the Surat-Bowen and Bass basins.

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.

Changes are forecast in the geography of gas production in eastern and central Australia over the next 25 years (figure 8.4). In particular, the Cooper Basin is a mature gas producing region with diminishing reserves. ABARE has predicted a rapid decline in production rates in the Cooper Basin after about 2011, to be replaced by increased supplies from the Victorian basins and CSG from Queensland.<sup>8</sup>

Production of CSG has risen exponentially since 2004 (figure 8.5), with the bulk of activity occurring in the Surat-Bowen Basin, which extends from Queensland into northern New South Wales. While the basin is an established supplier of conventional natural gas, it also contains most of Australia's proved and probable CSG reserves. There are also significant reserves of CSG in the Sydney Basin, where commercial production began in 1996.

The development of CSG stemmed initially from the Queensland Government's energy and greenhouse gas reduction policies, but recent improvements

# Figure 8.5





Note: 2009 data are for the year ended 30 June. Other data are for calendar years.

Source: EnergyQuest.

in extraction technology have spurred sustained rapid growth. Rising domestic and international energy prices have also strengthened the commercial viability of CSG exploration and production.

Queensland CSG has some commercial advantages, including that it is found closer to the surface than is conventional gas. It also tends to have a relatively high concentration of methane and lower levels of impurities, and is closer to some markets. These features also allow for a more incremental investment in production and transport than required to bring a conventional natural gas development on stream.

While CSG is produced only in Queensland and New South Wales, it is the fastest growing gas production sector. It accounted for almost 23 per cent of gas produced in eastern Australia in the year to June 2009,<sup>9</sup> and it meets over 70 per cent of the Queensland market.<sup>10</sup> In 2008–09 Queensland CSG production rose by around 18 per cent to about 143 PJ.<sup>11</sup>

8 A Syed, R Wilson, S Sandu, C Cuevas-Cubria and A Clarke, *Australian energy: national and state projections to 2029-30*, ABARE research report 07.24, prepared for the Australian Government Department of Resources, Energy and Tourism, Canberra, 2007.

9 EnergyQuest, Energy Quarterly, August 2009.

11 EnergyQuest, Energy Quarterly, August 2009.

<sup>10</sup> AER estimate derived from Hon. Geoff Wilson (Minister for Mines and Energy, Queensland), 'Coal seam methane for a cleaner energy future', Media release, 13 September 2007.

Forecasts by ABARE in 2007 suggested CSG production will supply around 32 per cent of the eastern Australian gas market by 2011–12. They also suggested that production will reach around 529 PJ by 2029–30, making it the principal source of gas supply in eastern Australia (figure 8.4).<sup>12</sup>

# 8.2.2 Regional markets

The geography of Australia's gas basins and transmission networks gives rise to distinct regional markets. Market analysis often distinguishes three regional markets: eastern Australia, Western Australia and the Northern Territory.<sup>13</sup>

An interconnected transmission pipeline network in south east Australia has enabled gas producers in the Cooper, Gippsland, Otway, Bass and Sydney basins to sell gas to customers across South Australia, Victoria, New South Wales, the Australian Capital Territory (ACT) and Tasmania for a number of years. The completion of the new transmission pipeline extension to the South West Queensland Pipeline—the QSN Link—connected Queensland with these southern markets in January 2009. The QSN Link potentially creates an important source of new interbasin competition, because Queensland sourced CSG from the Surat-Bowen Basin can now compete with gas from Moomba and the southern basins.<sup>14</sup>

Western Australia has no pipeline interconnection with other jurisdictions. It is the largest gas producer nationally, and supplies both the domestic market and most of Australia's LNG exports. The state's LNG export capacity exposes the domestic market to international energy market conditions.

Similarly, the Northern Territory has no pipeline interconnection with other jurisdictions. It has a small domestic market that was historically supplied by gas from the Amadeus Basin. Domestic gas demand will, however, be increasingly sourced from the Bonaparte Basin, which has been exporting LNG since 2006. The Bonaparte Pipeline, completed in December 2008, transports natural gas from the Bonaparte Basin to Darwin. The high pressure transmission pipeline was developed to provide certainty of gas supply to the Northern Territory, as reserves in the Amadeus Basin decline.

# 8.2.3 Gas production in southern and eastern Australia

The Australian Energy Regulator (AER) draws on data and information provided to the National Gas Market Bulletin Board to publish weekly reports on gas market activity in southern and eastern Australia.<sup>15</sup> The reports covers gas flows on registered pipelines, as well as production volumes from gas plants into end markets. Table 8.2 compares average daily gas production in major basins in the third quarter of 2009, compared with the same period in 2008.

While total production for third quarter 2009 was down 6 per cent from the same period last year, volumes for gas plants in the Surat-Bowen Basin increased by 28 per cent, reflecting strong growth in Queensland's CSG sector. In contrast, production from Victorian basins was lower than at the same time last year, including a 16 per cent fall in production at Longford. In part, this decrease correlates with increased gas flows from the northern basins that enter Victoria via the New South Wales – Victoria interconnect.<sup>16</sup>

# 8.3 Domestic and international demand for Australian gas

Australia consumed around 1000 PJ of natural gas, including conventional natural gas and CSG, in 2008–09. This total was slightly down from 1016 PJ

15 The AER's weekly gas reports are available at www.aer.gov.au/content/index.phtml/itemId/729309.

<sup>12</sup> A Syed, R Wilson, S Sandu, C Cuevas-Cubria and A Clarke, *Australian energy: national and state projections to 2029–30*, ABARE research report 07.24, prepared for the Australian Government Department of Resources, Energy and Tourism, Canberra, 2007.

<sup>13</sup> See, for example, Ministerial Council on Mineral and Petroleum Resources / Ministerial Council on Energy, *Final report of the Joint Working Group on Natural Gas Supply*, Canberra, September 2007, pp. 7-8;

<sup>14</sup> For further information on the gas transmission network, see chapter 9 of this report.

<sup>16</sup> National Gas Market Bulletin Board website (www.gasbb.com.au).

#### Table 8.2 Average daily production volumes, by basin

PERIOD	SURAT-BOWEN (QLD)	COOPER (SA/QLD)	OTWAY (VIC)	BASS (VIC)	GIPPSLAND (VIC)	TOTAL
Q3 2009 (TJ)	426	377	343	57	767	1 945
Q3 2008 (TJ)	332	353	387	62	910	2 069
Percentage change	28	-6	-11	-8	-16	-6

Q3, third quarter (1 July to 30 September); TJ, terajoules.

Notes: Data for each basin relate to the following production facilities:

- 1. Surat-Bowen Basin (Queensland)—Berwyndale South, Fairview, Kenya, Kincora, Kogan North, Peat, Rolleston, Scotia, Spring Gully, Strathblane, Taloona, Wallumbilla and Yellowbank gas plants
- 2. Cooper Basin (South Australia / Queensland)-Moomba and Ballera gas plants
- 3. Otway Basin (Victoria)–Iona Underground Gas Storage, and Minerva and Otway gas plants
- 4. Bass Basin (Victoria)—Lang Lang gas plant

5. Gippsland Basin (Victoria)—Longford gas plant.

Source: Gas Market Bulletin Board website (www.gasbb.com.au).

consumed in 2007–08.<sup>17</sup> Natural gas has a range of industrial, commercial and domestic applications within Australia. It is an input to manufacturing pulp and paper, metals, chemicals, stone, clay, glass and certain processed foods. In particular, natural gas is a major feedstock in ammonia production for use in fertilisers and explosives. It is increasingly used for electricity generation, mainly to fuel intermediate and peaking generators. It is also used in the mining industry, to treat waste materials and for incineration, drying, dehumidification, heating and cooling. In the transport sector, natural gas in a compressed or liquefied form is used to power vehicles. The residential sector uses natural gas mainly for heating and cooking.

Figure 8.6 sets out ABARE forecast data on primary consumption of natural gas by state and territory in 2008–09 and 2029–30. Western Australia and Victoria have the highest consumption levels, while demand growth is forecast to be strongest over the next 20 years in Queensland, Western Australia and the Northern Territory.

The consumption profile varies across the jurisdictions (figure 8.7). Natural gas is widely used in most jurisdictions for industrial manufacturing. Western Australia, South Australia, Queensland and the Northern Territory are especially reliant on natural gas for electricity generation. In Western Australia,

Figure 8.6 Forecast primary gas consumption



Source: A Syed, R Wilson, S Sandu, C Cuevas-Cubria and A Clarke, *Australian energy: national and state projections to 2029-30*, ABARE research report 07.24, prepared for the Australian Government Department of Resources, Energy and Tourism, Canberra, 2007.

the mining sector is also a major user of gas, mainly for power generation. Household demand is relatively small, except in Victoria where residential demand accounts for around one third of total consumption. This reflects the widespread use of natural gas for cooking and heating in that state.



Figure 8.7 Primary natural gas consumption, by industry

Note: Data for year ended 30 June 2005. Source: ABARE

## 8.3.1 Liquefied natural gas exports

The production of LNG converts natural gas into liquid. The development of an LNG export facility requires large upfront capital investment in processing plant and port and shipping facilities. The magnitude of investment means a commercially viable LNG project requires access to substantial reserves of natural gas. The reserves may be sourced through the LNG owner's interests in a gas field, a joint venture arrangement with a natural gas producer, or long term gas supply contracts.<sup>18</sup>

Australia has LNG export projects in the North West Shelf (annual capacity of around 16.3 million tonnes) and Darwin (annual capacity of 3.5 million tonnes).<sup>19</sup> Recent LNG developments include the \$50 billion Gorgon project in Western Australia (operated by Chevron with a 50 per cent share, with Shell and ExxonMobil (Esso) each holding 25 per cent). The project is scheduled to begin operation in 2014 and is expected to produce around 15 million tonnes of LNG per year—equal to Australia's current total LNG production.

The Pluto LNG project, also in Western Australia, is set to become Australia's fastest developed LNG project—from discovery of the gas field in 2005, to commencement of gas production in late 2010. The Pluto project is set to become Australia's third LNG project and has a forecast capacity of 4.3 million tonnes of LNG per year.<sup>20</sup>

Australia is the world's sixth largest LNG exporter after Qatar, Malaysia, Indonesia, Algeria and Nigeria. In 2008–09 Australia exported around 780 PJ of LNG, mostly from the Carnarvon Basin.<sup>21</sup> LNG shipments from Darwin began in February 2006. At present, LNG accounts for around 44 per cent of Australia's natural gas production. ABARE projects this ratio will rise to around 68 per cent by 2029–30.<sup>22</sup>

18 NERA, The gas supply chain in eastern Australia, Report to the AEMC, Sydney, March 2008, p. 16.

<sup>19</sup> EnergyQuest, Energy Quarterly, August 2009.

<sup>20</sup> For more information on current LNG developments, see EnergyQuest, 'Australia's natural gas markets: connecting with the world', essay in AER, *State of the energy market 2009*, Melbourne, 2009.

<sup>21</sup> EnergyQuest, Energy Quarterly, August 2009.

<sup>22</sup> A Syed, R Wilson, A Sandu, C Cuevas-Cubria and A Clarke, *Australian energy: national and state projections to 2029–30*, ABARE research report 07.24, prepared for the Australian Government Department of Resources, Energy and Tourism, Canberra, 2007, p. 44.

Rising international LNG prices, together with rapidly expanding reserves of CSG, have improved the economics of developing LNG export facilities in eastern Australia. Several LNG proposals reliant on CSG have been announced for construction in Queensland since early 2007. The proposed projects, which range in size from 1.5 to 14 million tonnes of LNG per year, are being developed by major domestic and international players. All are scheduled to commence production between 2012 and 2015. Table E.1 in the essay in this report sets out details.

# 8.3.2 Links between international and domestic gas markets

Figure 8.8 illustrates ACIL Tasman forecasts (published in 2008) of demand for Australia's natural gas over the next 20 years. The forecasts account for the projected effects of the Carbon Pollution Reduction Scheme. ACIL Tasman forecast that demand growth would be driven principally by rising LNG production—in western, northern and eastern Australia—and the increasing use of gas for electricity generation. According to this view, total gas demand would more than double to around 4300 PJ (including exports) over the next 20 years.<sup>23</sup>

Given projected growth in LNG exports from Western Australia, the Northern Territory and potentially eastern Australia, the adequacy of domestic sources to satisfy Australia's natural gas demand over time has been debated. Assessments of the relationship between international and domestic gas markets typically distinguish among Western Australia, the Northern Territory and eastern Australia.

The Western Australian gas market experienced considerable tightening after 2006, with rising production costs and strong domestic demand occurring at a time when most producers had fully contracted their developed reserves. In addition, rising international energy prices, combined with Western Australia's substantial LNG export capacity,

## Figure 8.8

Australian gas demand outlook, 2008-27



EA, eastern Australia; LNG, liquefied natural gas.

Note: Forecasts account for the projected effects of the Carbon Pollution Reduction Scheme and LNG expansion.

put pressure on domestic prices and supply. In June 2008 an explosion at the Varanus Island gas facility put further pressure on the domestic market, reducing domestic gas supplies by 30 per cent for over two months.

International energy prices eased in 2008-09 due to the effects of the global financial crisis on the manufacturing and industrial sectors. This easing was mirrored by softening price pressure in the domestic market (section 8.6.1). Western Australia has been projected, however, to continue to face difficulties in achieving a supply-demand balance until at least 2010.<sup>24</sup> EnergyQuest's essay further analyses the Western Australian market (section E.1.3).

There have been some suggestions that the opening of an LNG export facility in Darwin in 2006 could affect the availability of gas supplies in the Northern Territory. While supply contracts in the Territory

Source: ACIL Tasman, 'Australia's natural gas markets: the emergence of competition?', essay in AER, *State of the energy market 2008*, Melbourne, 2008.

<sup>23</sup> ACIL Tasman, 'Australia's natural gas markets: the emergence of competition?', essay in AER, State of the energy market 2008, Melbourne, 2008.

<sup>24</sup> Ministerial Council on Mineral and Petroleum Resources / Ministerial Council on Energy, Final report of the Joint Working Group on Natural Gas Supply, Canberra, September 2007, p. 10.

appear to cover the needs of existing customers for up to 15 years, competition to supply LNG exports could pose risks to the market in sourcing additional gas supplies to support major new industrial projects.<sup>25</sup> EnergyQuest estimates that the Blacktip field, which supplies the Darwin LNG plant, could meet current Northern Territory needs for about 70 years. The Bonaparte Pipeline, commissioned in 2008, supplies gas from Blacktip to the domestic market.

In eastern Australia, an interaction of several factors will affect the supply-demand balance over the next few years. Since the 1990s improved pipeline interconnection among the eastern gas basins has enhanced the flexibility of the market to respond to customer demand. Importantly, the completion in 2008 of the QSN Link pipeline from Queensland to southern Australia resulted in an interconnected pipeline network linking Queensland, New South Wales, the ACT, Victoria, South Australia and Tasmania (see chapter 9).

While new pipeline investment and rising CSG reserves are strengthening the supply base, a number of factors may also put upward pressure on demand. Eastern Australia is insulated from global gas markets, but this will change with the likely development of LNG export projects in Queensland. The proposed introduction of the Carbon Pollution Reduction Scheme will also likely increase reliance on natural gas as a fuel for electricity generation.

ACIL Tasman projected that a 4 million tonne per year LNG plant (as proposed by Santos) could divert significant quantities of gas to exports. It argued that such diversion, while maybe not leaving the domestic market short of supply, would likely require earlier reliance on higher cost and less productive sources of CSG than if the LNG projects did not proceed. This would have implications for domestic gas prices.<sup>26</sup>

The EnergyQuest essay in this report argues that domestic gas supplies may increase (and price pressure may ease) in the medium term during the ramp-up phase of Queensland's CSG-LNG projects. In the longer term, prices for new domestic gas contracts may rise closer to international levels, as has occurred in Western Australia.

Features of east coast markets may cushion price impacts. Unlike Western Australia, the east coast has a number of gas basins, with greater diversity of supply. There is substantial exploration acreage with relatively low barriers to entry, and an extensive gas transmission network linking the producing basins.

# 8.4 Industry structure

The prevalence of high sunk costs and the relatively small number of Australian gas fields mean the supply of natural gas is concentrated in the hands of a small number of producers. It is common for oil and gas companies to establish joint ventures to help manage risk. Typically, the operator holds a substantial interest in the project—for example, the Cooper Basin partnership comprises Santos (the operator and majority owner), along with Beach Petroleum and Origin Energy.

The structures of the exploration and development sector and the gas production sector differ somewhat, although many participants—especially the large corporations—are active in both. The three main types of entity involved in gas and oil exploration are:

- international majors—multinational corporations with large production interests and substantial exploration budgets (for example, BP, BHP Billiton, Esso, Chevron and Apache Energy)
- Australian majors—major Australian energy companies with significant production interests and exploration budgets (for example, Woodside Petroleum, Santos and Origin Energy)
- > juniors—smaller exploration and production companies, which may or may not engage in gas production (for example, Australian Worldwide Exploration and Arrow Energy).

25 Ministerial Council on Mineral and Petroleum Resources / Ministerial Council on Energy, Final report of the Joint Working Group on Natural Gas Supply, Canberra, September 2007, p. 11.

<sup>26</sup> ACIL Tasman, 'Australia's natural gas markets: the emergence of competition?', essay in AER, State of the energy market 2008, Melbourne, 2008.

#### Figure 8.9

Natural gas producers supplying the domestic market, 2008-09



PJ, petajoules.

Note: Some corporate names have been shortened or abbreviated. Source: EnergyQuest, *Energy Quarterly*, August 2009.

International majors tend to be involved in the larger offshore oil and LNG projects. Australian majors and smaller companies focus on mainly onshore discoveries, typically for natural gas sales to the domestic market. A number of Australian majors—for example, Woodside Petroleum, Origin Energy, Santos and Arrow Energy—are LNG exporters or are developing LNG projects. Junior explorers often play a significant role in higher risk greenfields exploration, such as the early phase of CSG developments.

Gas production in Australia is relatively concentrated. While over 100 companies are involved in gas and oil exploration, only around 35 produce gas. The six majors supplied around 71 per cent of the domestic market in 2008–09, down from 77 per cent in 2007–08. Santos and BHP Billiton each supplied around 17 per cent, followed by Esso (12 per cent), Woodside (12 per cent), Origin Energy (9 per cent) and Apache Energy (5 per cent). The next tier of players in terms of market share include BP, Chevron, Beach Petroleum, Shell and BG Group (figure 8.9).

The rise of CSG has involved the entry of several new players in both the exploration and production sectors over the past decade. New entrants have included Queensland Gas Company, Sydney Gas, Sunshine Gas and coal and oil producers Anglo Coal and Mosaic Oil (figure 8.10). Since 2007 several international majors, including BG Group, ConocoPhillips and Petronas, have entered the market as project partners with domestic players, with a view to developing CSG resources for LNG export (see section 8.4.3 and section E.2.2 in the essay in this report).

Figure 8.10

Coal seam gas producers in Australia, 2008–09



PJ, petajoules.

Note: Some corporate names have been shortened or abbreviated. Source: EnergyQuest, *Energy Quarterly*, August 2009.

## 8.4.1 Vertical integration

The increasing use of natural gas as a fuel for electricity generation creates synergies for energy retailers to manage price and supply risk through equity in gas production and gas fired electricity generation. The energy retailers Origin Energy and AGL Energy each have substantial interests in gas production and electricity generation:

> Origin Energy is a leading energy retailer in Queensland, Victoria and South Australia; is a significant gas producer; and is expanding its electricity generation portfolio. It has held a minority interest in gas production in the Cooper Basin for some time, and since 2000 has expanded its equity in CSG production in Queensland and in conventional gas production in Victoria's Otway and Bass basins.

It has also been developing new gas fired electricity generation capacity in Queensland, Victoria, South Australia and New South Wales. This includes the Uranquinty power station in New South Wales (commissioned in January 2009), the Darling Downs power station in Queensland (planned for commissioning in late 2009) and the Mortlake power station in Victoria (set for completion in 2010). Origin Energy also completed an expansion of the Quarantine power station in South Australia in March 2009.

> AGL Energy is a leading energy retailer in Queensland, Victoria, New South Wales and South Australia; is a major electricity generator in eastern Australia; and is increasing its interests in gas production. A relative newcomer to gas production, AGL Energy began acquiring CSG interests in Queensland and New South Wales in 2005. It has continued to expand its portfolio through mergers and acquisitions (see section 8.4.3).

#### 8.4.2 Market concentration

Market concentration within particular gas basins depends on a variety of factors, including the number of fields developed, the ownership structure of the fields, and acreage management and permit allocation. Table 8.3 and figure 8.11 set out EnergyQuest estimates of market shares in gas production for the domestic market in each major basin. Table 8.4 sets out market shares in proved and probable gas reserves (including reserves available for export) at May 2009.

Several major companies have equity in Western Australia's Carnarvon Basin, which is Australia's largest producing basin. Woodside is the largest producer for the domestic market (around 29 per cent), but Apache Energy (14 per cent), Chevron (12 per cent), BP (12 per cent), Santos (9 per cent), BHP Billiton (9 per cent) and Shell (8 per cent) each have significant market share. Ownership of gas reserves is split between these and other entities such as MIMI (owned by Mitsubishi and Mitsui) and the China National Offshore Oil Company (CNOOC). The businesses participate in joint ventures, typically with overlapping ownership interests.

COMPANY		PERTH	AMADEUS		SURAT- BOWEN (0, 0)	SYDNEY	GIPPSLAND	OTWAY	BASS	ALL BASINS (%)
AGL Energy			(141)		5.1	50.0	(110)	(10)	(110)	1.0
Anglo Coal					0.6					0.1
Apache Energy	14.4									4.5
ARC Energy		33.8				-			8.5	0.4
Arrow Energy					12.0					1.8
AWE		17.5						7.8	33.9	1.5
Beach				21.2	2.2					3.1
Benaris								5.0		0.5
BG Group					15.7					2.3
BHP Billiton	8.5						49.8	26.3		17.9
BP	12.4									3.9
CalEnergy								1.5	15.2	0.4
Chevron	12.4									3.9
ConocoPhillips					3.0					0.4
CS Energy					1.1					0.2
Esso	0.2						49.8			12.5
Inpex	0.1									0.0
Kufpec	1.1									0.3
Magellan			37.8							0.7
MIMI	4.1									1.3
Mitsui					0.5			7.7		0.9
Molopo					0.1					0.0
Mosaic					1.3					0.2
Origin Energy		48.8		14.6	34.2			13.1	42.4	9.5
Petronas					1.8					0.3
Santos	8.6		62.2	64.1	22.0		0.4	18.3		17.6
Shell	8.2									2.6
Sydney Gas						50.0				0.3
Тар	0.7									0.2
Woodside	29.3							20.5		11.5
Other					0.3					0.0
TOTAL (PETAJOULES)	318	8	20	130	149	5	251	110	17	1008

# Table 8.3 Market shares in domestic gas production, by basin, calendar year 2008 (per cent)

Notes:

Excludes liquefied natural gas.

Some corporate names have been shortened or abbreviated.

Source: EnergyQuest 2009 (unpublished data).

#### Figure 8.11

Market shares in domestic gas production, by basin, 2008



AWE, Australian Worldwide Exploration; BHPB, BHP Billiton Notes: Excludes liquefied natural gas. Some corporate names have been shortened or abbreviated. Source: EnergyQuest 2009 (unpublished data). Gas for the Northern Territory was historically sourced from the Amadeus Basin and produced by Santos and Magellan. The principal reserves in the Northern Territory are located in the Bonaparte Basin in the Timor Sea. The Italian energy firm Eni owns the majority of Australian reserves in the basin.

While around 22 entities have equity in natural gas fields in eastern Australia, control of the more substantial fields in the Gippsland and Cooper basins is concentrated among a handful of established producers. A joint venture led by Santos (64 per cent) dominates production in South Australia's Cooper Basin. The other participants are Beach Petroleum (21 per cent) and Origin Energy (15 per cent). The same companies participate with slightly different shares on the Queensland side of the basin. New entry by smaller explorers has also occurred in the Cooper Basin in recent years.

The Gippsland, Otway and Bass basins off coastal Victoria serve the Victorian market and export gas to New South Wales, South Australia and Tasmania. A joint venture between Esso and BHP Billiton accounts for around 98 per cent of production in the Gippsland Basin, which is the largest producing basin in eastern Australia. The Otway Basin off south west Victoria has a more diverse ownership base, with BHP Billiton (26 per cent), Woodside (20 per cent), Santos (18 per cent) and Origin Energy (13 per cent) accounting for the bulk of production. The principal producers in the smaller Bass Basin are Origin Energy and Australian Worldwide Exploration, with a combined share of 76 per cent of production. The businesses market gas from the Bass Basin through a joint venture.

The growth of the CSG industry has led to considerable new entry in Queensland's Surat-Bowen Basin over the past decade, and a diverse ownership profile. A number of smaller businesses such as Queensland Gas Company (now owned by BG Group) and Arrow Energy have developed considerable market share, alongside more established entities such as Origin Energy and Santos. Overall, the largest producers in the basin are Origin Energy (34 per cent), Santos (22 per cent), BG Group (16 per cent), Arrow Energy (12 per cent) and AGL Energy (5 per cent). These businesses also own the majority of gas reserves in the Surat-Bowen Basin. Recently, international majors ConocoPhillips, Petronas and Shell acquired 17 per cent, 8 per cent and 3 per cent of gas reserves in the basin respectively.

## 8.4.3 Mergers and acquisitions

There has been significant merger and acquisition activity in the gas production sector in recent years, with interest since 2006 focused mainly on CSG (and associated LNG proposals) in Queensland and New South Wales. Table 8.5 lists a number of proposed and successful acquisitions from June 2006 to September 2009.

Queensland Gas Company, a significant producer in the Surat-Bowen Basin, has been a focus of acquisition interest. Following an unsuccessful takeover attempt by Santos in 2006, the company sold a 27.5 per cent stake in its assets to AGL Energy in 2007. In 2008 Queensland Gas Company sold a further 20 per cent stake to BG Group. The agreement was based around the development of CSG resources for LNG exports. BG Group acquired full ownership of Queensland Gas Company in March 2009.

BG Group sought to expand its market profile in 2008 by attempting to acquire Origin Energy. The offer was rejected in June 2008, and in September 2008, Origin Energy announced a LNG joint venture with ConocoPhillips.

SNISV8 [%] 774	0.1	1.3	0.1	0.2	2.3	2.9	0.5	0.5	0.2	7.8	10.6	6.1	0.1	6.1	1.7	5.1	0.1	0.0	0.4	2.5	4.2	0.2	0.1	0.1	0.4	0.1	0.1	0.5	6.0	0.4	0.1	0.1	0.6	5.8	2.3
(JIN) SSVA							42.5						15.0																					42.5	
OTWAY UVICI	3.2						8.2		6.3		13.1		2.5																	8.2				15.2	
(JIN) GIDD <sup>STVND</sup>								1.3			42.7										42.7			0.9									6.2		
IMSNJ AJNAAS		100.0																																	
INSNI BERONCEZLEY MSN/R2		100.0																																	
LOLDON WORTON CLARENCE																	11.4											88.6							
(MSN) HVQEDVH MSN) MSN)																			64.9			35.1													
(UTU) BOMEN 201642-		2.9	0.3	0.6		10.0				26.4						16.5														0.6	0.3	0.3		16.7	7.7
(27/0/D) COOPER								20.7										0.4																12.9	
SUJ <sup>AMA</sup> DEUS																											44.7								
PERTH (WA)							53.8																											46.2	
BONAPARTE (TV/AW) (TV/AW)																9.4				85.4			1.8												
(WA) CARNARVON					4.6						11.9	12.1		12.1	3.3										0.8	0.1			11.8						
COMPANY	Adelaide Energy	AGL Energy	AJ Lucas	Anglo	Apache Energy	Arrow Energy	AWE	Beach	Benaris	BG Group	<b>BHP</b> Billiton	BP	CalEnergy	Chevron	CNOOC	ConocoPhillips	CS Energy	Drillsearch	Eastern Star Gas	Eni	Esso	Gastar	Inpex	ITOCHU	Kansai Electric	Kufpec	Magellan	Metgasco	MIMI	Mitsui	Molopo	Mosaic	Nexus	Origin Energy	Petronas

Table 8.4 Market shares in proved and probable gas reserves, by basin, May 2009 (per cent)

СОМРАNY	NONARNON (AN)	JTAAANOB (TN/AN) (TN/AN)	(MA) PERTH	SUJAMA (TV)	(270/05) 2006EB	(OTD) NANOB SNGAT_	(MSN) HYDAANNOO	נסרם/NRM עסגנסא כרשגבאכב	INSN)	(MSN) AANGAS	(NIC) GIDD <sup>STAND</sup>	UNC) (VIC)	(JIN) SSVA	SNISVB [%] 774
Roc											1.8			0.2
Santos	2.7	1.9		55.3	65.9	14.5					4.0	17.9		8.1
Shell	11.9					3.0								6.9
Sojitz											0.5			0.0
Tap	0.1													0.0
Tokyo Gas	0.8													0.4
Tokyo Electric		1.5												0.0
Woodside	27.7											25.4		14.6
Other CSG						0.3								0.1
TOTAL (PETAJOULES)	28 749	1647	26	190	1138	16 773	336	298	175	82	5637	1416	306	56 773
Notes:														
Based on 2P (proved a1	nd probable) res	erves at May 20	.60											

Further acquisitions in 2008 and 2009 based around the development of CSG and CSG-LNG export projects included the following:

- > In June 2008 Arrow Energy agreed to sell 30 per cent of its CSG resources in Queensland to Shell.
- > In August 2008 ARC Energy merged with Australian Worldwide Exploration.
- > In October 2008 Queensland Gas Company acquired all issued shares in Sunshine Gas.
- > In December 2008 AGL Energy acquired Sydney Gas Limited and CSG assets from AJ Lucas Group and Molopo Australia in the Gloucester basin in New South Wales.
- > In April 2009 Origin Energy acquired an exploration permit in the Surat-Bowen Basin from Pangaea.
- In July 2009 Santos acquired Gastar Exploration's 35 per cent interest in CSG exploration permits and production areas in the Gunnedah Basin in New South Wales. Santos also acquired a 19.99 per cent interest in Eastern Star Gas, a gas explorer in the Gunnedah Basin.

# 8.5 Gas wholesale markets

Wholesale gas markets involve the sale of gas by producers, mainly to energy retailers, which on-sell it to business and residential customers. In addition, some major industrial, mining and power generation customers buy gas directly from producers in the wholesale market.

# 8.5.1 Wholesale market contracts

Some corporate names have been shortened or abbreviated. Not all minority owners are listed

Source: EnergyQuest 2009 (unpublished data).

In Australia, wholesale gas is mostly sold under confidential, long term contracts. The trend in recent years has been towards shorter term supply, but most contracts still run for at least five years. Foundation contracts underpinning new production projects are still often struck for terms of up to 20 years. Such long term contracts are commonly argued as being essential to the financing of new projects because they provide reasonable security of gas supply, as well as a degree of cost and revenue stability.

DATE	PROPOSED MERGER/ACQUISITION	GAS BASINS	STATUS AT SEPTEMBER 2009
June 2006	Arrow Energy acquisition of CH4	Surat–Bowen (Qld)	Completed July 2006
Sept 2006	Beach Petroleum acquisition of Delhi Petroleum	Cooper (Qld/SA)	Completed September 2006
Oct 2006	Santos acquisition of Queensland Gas Company	Surat–Bowen (Qld)	Proposal withdrawn
Jan 2007	AGL Energy and Origin Energy merger	Various	Proposal withdrawn
Jan 2007	AGL Energy acquisition of a 27.5 per cent stake in Queensland Gas Company	Surat–Bowen (Qld)	Completed December 2006
Nov 2007	AGL Energy – Arrow Energy joint venture acquisition of Enertrade's Moranbah gas assets	Surat–Bowen (Qld)	Completed December 2007
April 2008	BG Group acquisition of about 20 per cent of Queensland Gas Company	Surat–Bowen (Qld)	Completed April 2008
May 2008	BG Group acquisition of Origin Energy	Various	Proposal withdrawn September 2008
May 2008	Petronas acquisition of 40 per cent of Santos's LNG project	Surat–Bowen (Qld)	Sales agreement signed June 2009
	at Gladstone ljoint ventureJ		Final investment decision due first half of 2010
June 2008	Shell acquisition of 30 per cent of Arrow Energy's CSG resources	Surat–Bowen (Qld)	Completed February 2009
Aug 2008	Queensland Gas Company acquisition of Sunshine Gas	Surat–Bowen (Qld)	Completed October 2008
Aug 2008	ARC Energy and Australian Worldwide Exploration merger	Perth (WA) and Bass (Vic)	Completed September 2008
Sept 2008	ConocoPhillips acquisition of 50 per cent of the issued share capital of Origin Energy CSG Ltd	Surat–Bowen (Qld)	Completed October 2008
Oct 2008	BG Group acquisition of remaining shares in Queensland Gas Company	Surat–Bowen (Qld)	Completed March 2009
Dec 2008	AGL Energy acquisition of Sydney Gas Limited	Sydney (NSW)	Completed April 2009
Dec 2008	AGL Energy acquisition of certain CSG assets from AJ Lucas Group Ltd and Molopo Australia Ltd	Gloucester (NSW)	Completed December 2008
April 2009	Origin Energy acquisition of exploration permit ATP 788P from Pangaea Group	Surat–Bowen (Qld)	Completed August 2009
July 2009	Santos acquisition of Gastar Exploration's 35 per cent interest in CSG exploration permits and production areas	Gunnedah CSG (NSW)	Completed July 2009
July 2009	Santos acquisition of Hillgrove Resources's 19.99 per cent interest in Eastern Star Gas	Gunnedah CSG (NSW)	Completed July 2009

#### Table 8.5 Upstream gas merger and acquisition activity, June 2006 – September 2009

Wholesale gas contracts typically include *take or pay* clauses that require the purchaser to pay for a minimum quantity of gas each year regardless of the actual quantity used. Prices may be reviewed periodically during the life of the contract. Between reviews, prices are typically indexed (often to the consumer price index). Contract prices, therefore, do not tend to fluctuate on a daily or seasonal basis. But the many variations in provisions—such as term, volume, volume flexibility and penalties associated with failure to supply—mean there can be significant price differences between contracts.<sup>27</sup>

While contracts form the basis of most gas sales arrangements, a wholesale gas market operates in Victoria to facilitate gas sales to manage system imbalances and pipeline network constraints (box 8.1).

# 8.5.2 Joint marketing

Joint venture parties in gas production typically sell their gas through joint marketing arrangements under authorisation from the Australian Competition and Consumer Commission. More recently, some joint venture parties in new gas fields have undertaken

27 ACIL Tasman, 'Australia's natural gas markets: the emergence of competition?', essay in AER, State of the energy market 2008, Melbourne, 2008.

separate marketing. Santos has separately marketed gas from its interest in the Casino field (Otway Basin), for example, as has Woodside with its interest in the Geographe/Thylacine field (also in the Otway Basin).<sup>28</sup>

# 8.5.3 Scheduling and balancing

Wholesale market arrangements must account for the physical properties of natural gas and transmission pipelines:

- > Unlike electricity, gas takes time to move from point to point. In Victoria, gas is typically produced and delivered within 6-8 hours because most demand centres are within 300 kilometres of gas fields.
   Gas delivered from the Cooper Basin into Sydney, or from the Carnarvon Basin into Perth, can take two to three days because the gas must be transported over much longer distances.
- > Natural gas is automatically stored in pipelines (known as *linepack*). It can also be stored in depleted reservoirs or in liquefied form, which is economic only to meet peak demand or for use in emergencies.
- > Natural gas pipelines are subject to pressure constraints for safety reasons. The quantity of gas that can be transported in a given period depends on the diameter and length of the pipeline, the maximum allowable operating pressure and the difference in pressure between the two ends.

These features make it essential that daily gas flows are managed. In particular, deliveries must be scheduled to ensure gas produced and injected into a pipeline system remains in approximate balance with gas withdrawn for delivery to customers. To achieve this, gas retailers and major users must estimate requirements ahead of time and nominate these to producers and pipeline operators, subject to any pre-agreed constraints on flow rates and pipeline capacity.

Each day, producers and storage providers inject the nominated quantities of gas into the transmission network for delivery to customers. There are typically short term variations between a retailer's nominated injections and their actual withdrawals from the system, creating imbalances. A variety of systems operate in Australia for dealing with physical imbalances, as well as financial settlements to address imbalances between the injections and withdrawals of particular shippers.

In most jurisdictions, pipeline operators manage physical balancing, while independent system operators manage financial settlements for imbalances. The Australian Energy Market Operator (AEMO) is the system operator in Victoria, New South Wales, the ACT and South Australia, while REMCo operates the Western Australian market. AEMO also operates a spot market in Victoria to manage gas balancing (box 8.1). Similar market arrangements are being developed for major gas hubs in eastern Australia (see section 8.7.3).

# 8.5.4 Secondary trading

There is some secondary trading in gas, whereby contracted bulk supplies are traded to alter delivery points and other supply arrangements. Types of secondary trade include backhaul and gas swaps.

*Backhaul* can be used for the notional transport of gas in the opposite direction to the physical flow in a pipeline. It is achieved by redelivering gas at a point upstream from the contracted point of receipt. Backhaul arrangements are used most commonly by gas fired electricity generators and industrial users that can cope with intermittent supplies.

A gas swap is an exchange of gas at one location for an equivalent amount of gas delivered to another location. Shippers may use swaps to deal with regional mismatches in supply and demand. Swaps can also help deal with physical limitations imposed by the direction or capacity of gas pipelines, and may delay the need to invest in new pipeline capacity.

Anecdotal evidence suggests swaps are reasonably common in Australia, but mostly conducted on a minor scale.<sup>29</sup> Origin Energy and the South West Queensland

<sup>28</sup> NERA, The gas supply chain in eastern Australia, Report to the AEMC, Sydney, March 2008, p. 26.

<sup>29</sup> Firecone Ventures, Gas swaps, Report prepared for the National Competition Council, Melbourne, 2006.
Gas Producers (SWQP) entered a major swap arrangement in 2004 to enable Origin Energy to meet supply obligations in south east Australia using gas produced by the SWQP in the Cooper Basin. In return, Origin Energy delivered gas from its central Queensland field to meet supply obligations of the SWQP, including to customers in Gladstone and Brisbane.<sup>30</sup>

#### 8.5.5 Trading hubs

A gas hub is an interconnection point between gas pipelines, at which trading in gas and pipeline capacity may occur. In Australia, gas hubs include Moomba (South Australia), Wallumbilla (Queensland) and Longford (Victoria).

VicHub at Longford was established in 2003 and connects the Eastern Gas Pipeline, Tasmania Gas Pipeline and Victorian Transmission System. This connection allows for the trading of gas between New South Wales, Victoria and Tasmania. VicHub allows for the posting of public buy and sell offers, but is not a formal trading centre that provides brokering services.

The establishment of the National Gas Market Bulletin Board in July 2008 and the development of a short term trading market at defined gas hubs (scheduled to commence by winter 2010) are likely to enhance market transparency and opportunities for gas trading at the major hubs of Sydney and Adelaide.

#### 8.6 Gas prices

Australian gas prices have historically been low by international standards. They have also been relatively stable, defined by provisions in long term supply contracts. In the United States and Europe, gas prices closely follow oil prices. Conversely, natural gas in Australia has generally been perceived as a substitute for coal and coal fired electricity. Australia's abundant low cost coal sources have effectively capped gas prices.

Because gas contracts are not transparent outside Victoria, comprehensive price information is not widely available. Figure 8.12 sets out indicative data for domestic

#### Figure 8.12

Indicative wholesale natural gas prices



LNG, liquefied natural gas.

Notes:

Prices for the second quarter of the year (April-June).

Data for producers A, B, C and D are average company realisations for specific Australian gas producers.

Sources: Energy Quest, *Energy Quarterly* (various editions); LNG data are sourced from the ABS.

gas and LNG exports. The data relating to particular producers are based on average prices and, in some cases, may understate prices struck under new contracts.

Between 2005 and 2008 the following interacting factors put upward pressure on gas prices:

- > A substantial rise in exploration, development and production costs flowed through to wholesale prices.
- Rising international energy prices, including for Australian LNG exports, increased domestic gas prices in Western Australia.
- > Drought led to greater demand for gas fired generation in eastern Australia in 2007, with flow-on effects for gas prices.
- > Market participants began factoring the projected effects of the Carbon Pollution Reduction Scheme into demand projections and pricing on long term gas contracts.<sup>31</sup>

Weaker economic growth—domestically and internationally—softened demand for natural gas in 2008 and 2009, and eased price pressure.

<sup>30</sup> Details of the swap arrangement are provided in AER, State of the energy market 2007, box 8.4, Melbourne, 2007, p. 248.

<sup>31</sup> ACIL Tasman, 'Australia's natural gas markets: the emergence of competition?', essay in AER, State of the energy market 2008, Melbourne, 2008, p. 30.

#### 8.6.1 Western Australia

Western Australia experienced low domestic gas prices for several years as a result of competition between the North West Shelf Venture and smaller producers dedicated to the domestic market. Price pressure emerged around 2006 as rising demand for gas contracts—driven partly by the mining boom—occurred at a time when most producers had fully contracted their developed reserves. This was accompanied by substantial increases in gas field development costs.

At the same time, Western Australia's LNG export capacity has increased the domestic market's exposure to international energy prices. Average LNG prices received by Australian producers rose by 48 per cent between the June quarters of 2007 and 2008, and led to further escalation in domestic gas prices. The Western Australian Department of Industry and Resources reported that Santos secured domestic gas prices in July 2007 of more than \$7 per gigajoule in two separate contracts.<sup>32</sup> Short term wholesale prices reached almost \$17 per gigajoule in July 2008 following the Varanus Island incident, which cut domestic supply by around 30 per cent.<sup>33</sup>

International energy prices eased in 2008–09, given the effects of the global financial crisis on the manufacturing and industrial sectors. The average price received by Australian LNG producers in June quarter 2009 was \$6.24 per gigajoule—down 24 per cent from the June quarter 2008 price of \$8.17 per gigajoule. This was mirrored in a softening of price pressure in Western Australia's domestic market. EnergyQuest reported that some producers averaged prices in June quarter 2009 of between \$2.26 and \$4.84 per gigajoule (reflecting contracts of varying age and duration). One major producer, however, negotiated a four year contract with a mining customer at a price believed to be above \$5.50 per gigajoule.<sup>34</sup> These price outcomes are generally lower than those recorded in 2007, but remain significantly higher than the typical prices of around \$2.50 per gigajoule that prevailed in Western Australia earlier in the decade.

#### 8.6.2 Eastern Australia

According to some published estimates, wholesale gas prices in Queensland rose from around \$2.50– 2.90 per gigajoule in 2006<sup>35</sup> to around \$4 per gigajoule in 2008.<sup>36</sup> EnergyQuest reported mixed outcomes in 2008–09. One Queensland joint venture recorded average price realisations of \$3.15 per gigajoule in June quarter 2009. On the east coast generally, one major producer recorded average prices of around \$3.46 per gigajoule in June quarter 2009, compared with \$3.12 in the equivalent period of 2008.<sup>37</sup>

While the development of CSG-LNG projects around Gladstone in the next few years may increase wholesale gas prices in the longer term, EnergyQuest projects that domestic prices may ease during the lengthy ramp-up of LNG export capacity.<sup>38</sup>

#### 8.6.3 Victorian spot prices

The Victorian spot market (box 8.1) is Australia's only gas wholesale market that provides transparent price and volume data. The market is for sales of natural gas to balance daily requirements between retailers and suppliers. Market volumes can range from around 300 to 1200 terajoules per day. While the market accounts for only about 10–20 per cent of wholesale volumes in Victoria, its price outcomes are widely used as a guide to underlying contract prices.

<sup>32</sup> Department of Industry and Resources (Western Australia), Western Australian oil and gas review 2008, Perth, 2008.

<sup>33</sup> EnergyQuest, Energy Quarterly, August 2008.

<sup>34</sup> EnergyQuest, Energy Quarterly, August 2009, p. 73.

<sup>35</sup> Core Collaborative's Australian gas sector outlook estimate published in NERA, The gas supply chain in eastern Australia, Report to the AEMC, Sydney, March 2008, p. 36.

<sup>36</sup> ACIL Tasman, 'Australia's natural gas markets: the emergence of competition?', essay in AER, State of the energy market 2008, Melbourne, 2008, p. 47.

<sup>37</sup> EnergyQuest, Energy Quarterly, August 2009, p. 72.

<sup>38</sup> EnergyQuest, 'Australia's natural gas markets: connecting with the world', essay in AER, State of the energy market 2009, Melbourne, 2009.

#### Box 8.1 The Victorian gas wholesale market

Victoria established a spot market for gas in 1999 to manage gas flows on the Victorian Transmission System (VTS). The market allows participants to trade gas supply imbalances (the difference between contracted gas supply quantities and actual requirements) on a daily basis. The Australian Energy Market Operator (AEMO), formerly VENCorp, operates both the wholesale market and the VTS.

Participants submit bids into the spot market on a daily basis via a market information bulletin board. Bids may range from \$0 per gigajoule (the floor price) to \$800 per gigajoule (the price cap). Following initial bidding at the beginning of the gas day (6 am), the bids may be revised four times a day at the scheduling intervals of 10 am, 2 pm, 6 pm and 10 pm.

Market participants (mostly retailers) inform AEMO of their nominations for gas one and two days ahead of requirements. At the beginning of each day, schedules are drawn up that set out the hourly gas injections into and withdrawals from the system. The schedules rely on information from market participants and AEMO, including demand forecasts, bids, weather conditions or supply constraints affecting bids, hedge nominations and AEMO's modelling of system constraints.

At the beginning of each day, AEMO stacks supply offers and selects the least cost bids to match demand across the market. This establishes a spot market clearing price. Given the Victorian market is a net market, this price applies only to net injections or withdrawals (the difference between contracted and actual amounts).

Overall, gas traded at the spot price accounts for around 10–20 per cent of wholesale volumes in Victoria, with the balance sourced via bilateral contracts or vertical ownership arrangements between producers and retailers. In effect, the spot market provides a clearing house in which prices reflect short term supply-demand conditions, while underlying long term contracts insulate parties from price volatility. Nevertheless, a comparison of projected spot market prices with underlying contract prices allows a retailer to take a position to modify its own injections of gas and then trade gas at the spot price.

Sometimes, AEMO needs to schedule additional injections of gas (typically LNG) that have been offered at above market price to alleviate short term constraints. Market participants that inject the higher priced gas receive ancillary payments. These payments are recovered from uplift charges paid, as far as practicable, by the market participants whose actions resulted in a need for injections. A user's authorised maximum interval quantity (AMIQ) is a key allocation factor in determining who must contribute uplift payments to pay for this gas.

In particular, market participants that exceed their AMIQ on a day when congestion occurs may face an uplift charge, which provides a price signal to participants to adjust their gas use.

Market participants with AMIQ credits also have higher priority access to the pipeline system if congestion requires the curtailment of some users to maintain system pressure. This has not been necessary in recent years because sufficient gas (including LNG) has been available to support all users on the system. A party can acquire AMIQ certificates by injecting gas into the Victorian system at Longford or by entering a contract with the VTS owner, GasNet.

Until winter 2007 available gas and capacity on the VTS had been sufficient to meet customer requirements. Congestion occurred on only a few days a year, usually in winter. During winter 2007, however, there was



a greater incidence of the market operator having to inject higher priced LNG to manage constraints and maintain minimum pressures. A key factor was that drought constrained the availability of coal fired and hydroelectric generation, resulting in greater reliance on gas fired generation and increased demand for natural gas.

With the easing of drought, a recent downturn in interstate gas demand, the commissioning of new pipeline capacity in 2008–09, and relatively mild weather, high cost injections of LNG were less necessary in the winter of 2009.

While Victorian spot prices are generally relatively stable, there are occasional troughs and spikes. On 22 November 2008, for example, the spot price rose from \$3.50 per gigajoule at the beginning of the day to the price cap of \$800 per gigajoule in the final trading interval, before falling to \$5.75 per gigajoule at the start of the following gas day. According to AEMO, price spikes in the market have been mostly due to operational and market issues, often related to severe or unpredictable weather.

Further information on Victorian gas prices is set out in sections 8.6.3 and 8.7.4.

Figure 8.13 charts price and volume activity since the market started in 1999. Aside from a winter peaking demand profile, prices remained relatively stable until 2005. Volatility has since been greater, with significantly higher winter prices in 2006, 2007 and 2008. The market recorded its highest monthly price of almost \$9 per gigajoule in July 2007, when drought caused an increase in demand for gas fired electricity generation. Spot prices peaked at \$336 per gigajoule on 17 July 2007.

Prices later eased back towards trend levels, although the price cap of \$800 per gigajoule was reached in the final scheduling interval on 22 November 2008. This outcome was due to a combination of planned and unplanned plant outages and higher than expected gas demand.

Gas prices have generally eased in 2009, reflecting a combination of factors:

- > An expansion of the Victorian Transmission System (completed in 2008) has eased capacity constraints on the network.
- > An easing of the drought in 2008 led to a downturn in interstate demand for gas for electricity generation.
- > A weaker economy and a relatively mild winter led to some easing of demand in 2009.

Victorian spot prices averaged \$2.68 per gigajoule for June quarter 2009—down 19 per cent on the previous year's June quarter average. EnergyQuest reported that spot prices in June 2009 were below current contract prices.<sup>39</sup>

39 EnergyQuest, Energy Quarterly, August 2009, p. 73.

Figure 8.13 Victorian gas market—monthly prices and volumes



Note: Average monthly prices (right axis). Withdrawals are monthly totals (left axis). Source: AEMO.

#### 8.7 Gas market development

The Ministerial Council on Energy (MCE) in 2005 appointed a Gas Market Leaders Group to consider the need for further reform of the Australian gas market. In 2006 the group recommended establishing:

- > a gas market bulletin board
- > a short term trading market in gas
- > a national gas market operator to administer the bulletin board and short term trading market, and to produce an annual national statement of opportunities on the gas market covering supply-demand conditions.

The National Gas Market Bulletin Board was launched on 1 July 2008, and there has been significant progress towards implementing the other initiatives. The reforms aim to improve transparency and efficiency in Australian gas markets. They also aim to provide information to help manage gas emergencies and system constraints.

#### 8.7.1 Australian Energy Market Operator

As the single national energy market operator, AEMO commenced operation on 1 July 2009, replacing gas and electricity market operators such as VENCorp and the National Electricity Market Management Company. It operates the bulletin board and will operate the short term trading market from July 2010. It will also publish an annual Gas Statement of Opportunities (GSOO)— a national gas supply and demand statement similar to the annual Statement of Opportunities published for electricity.

The GSOO is intended to provide information to assist gas industry participants in their planning and commercial decisions on infrastructure investment. AEMO expects to publish the first GSOO in December 2009.

248

#### 8.7.2 National Gas Market Bulletin Board

The bulletin board, which commenced on 1 July 2008, is a website covering major gas production plants, storage facilities, demand centres and transmission pipelines in southern and eastern Australia.<sup>40</sup> Provision has been made for Western Australia, the Northern Territory and facilities in north Queensland to participate in the future.<sup>41</sup>

The bulletin board aims to provide transparent, realtime and independent information to gas customers, small market participants, potential new entrants and market observers (including governments) on the state of the gas market, system constraints and market opportunities. Information provision by relevant market participants is mandatory and covers:

- > gas pipeline capacity and daily aggregated data on expected gas volumes
- > production capabilities (maximum daily quantities) and three day outlooks for production facilities
- > storage capabilities and three day outlooks for storage facilities.

Participants may also advise of spare capacity and make offers through the bulletin board.

The bulletin board facilitates trade in gas and pipeline capacity by providing readily available system and market information. It provides, for example, information on outages and maintenance at production points, and on pipeline linepack.<sup>42</sup> It also provides daily demand forecasts, actual or expected changes in supply capacity to demand centres and, in the event of significant outages or system incidents, a flag indicating likely interruptions to customer supplies.

The bulletin board has been operated by AEMO since 1 July 2009. Under the National Gas Law, the AER monitors and enforces the compliance of market participants with the rules of the bulletin board.

#### 8.7.3 Short term trading market

The Gas Market Leaders Group is developing a short term trading market in gas to commence in June 2010, following a trial from March 2010. The reform will create a day-ahead wholesale spot market in gas for balancing purposes. AEMO will operate the market, which will apply at nominated hubs or city gates. Initially, the market will operate only in Sydney and Adelaide. The MCE has flagged the potential for trading hubs to be established in Queensland and the ACT. The reform will not apply in Victoria, which has operated its own gas wholesale market since 1999 (box 8.1).

The rationale for the market stems from concerns that the gas balancing mechanisms in Sydney and Adelaide have caused barriers to retail market entry and impeded gas supply efficiency. In particular, the mechanisms have created substantial financial exposures that are disproportionate to underlying costs. New entrants have faced difficulties acquiring appropriate hedging to manage these risks. The issues have been especially pertinent for Sydney and Adelaide, which are sourced by multiple transmission pipelines.<sup>43</sup>

The new spot market will set a daily clearing price at each hub, based on bids by gas shippers to deliver additional gas. The market operator will then settle, at the clearing price, the difference between each user's daily deliveries and withdrawals of gas. The mechanism is aimed at providing transparent price signals to market participants to stimulate trading—including secondary trading—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 a spot basis without needing to enter delivery contracts in advance. It will also allow contracted parties to manage short term supply and demand variations to their contracted quantities.

<sup>40</sup> National Gas Market Bulletin Board website (www.gasbb.com.au).

<sup>41</sup> Western Australia created its own limited bulletin board, run by the Independent Market Operator, to assist with the Varanus Island gas emergency in 2008. Although low volumes of trade were reported, the bulletin board provided some indication of prices during this period of restricted supply.

<sup>42 &#</sup>x27;Linepack' refers to the amount of gas stored in a pipeline.

<sup>43</sup> Ministerial Council on Mineral and Petroleum Resources / Ministerial Council on Energy, Final report of the Joint Working Group on Natural Gas Supply, Canberra, September 2007, p. 19; McLennan Magasanik Associates, Report to the Joint Working Group on Natural Gas Supply, Melbourne, July 2007.

#### 8.7.4 Futures markets

Participants in a commodity market can usually hedge their risk using physical or financial instruments. Internationally, gas futures markets tend to develop only after the underlying physical markets reach a certain level of maturity, with significant trading between buyers and sellers under transparent short term contracts.

The Sydney Futures Exchange introduced trading in Victorian wholesale gas futures and options on 21 July 2009. The market enables participants to plan and implement trading strategies, and provides hedge cover for new entrants. It also introduces a new asset class for financial market participants seeking diversity in their commodity portfolios, and allows arbitrage across the energy sectors.

Figure 8.14 illustrates Victorian gas futures prices at 30 September 2009 for December quarter 2009 through to June quarter 2012. The data indicate a general expectation of lower gas prices in the December and March quarters, when warmer weather eases demand for gas. In contrast, futures prices in the June and September quarters are well above \$4 per gigajoule, with colder weather driving up gas demand for heating. Overall, there is a slight upward trend in prices over the next two to three years, with prices reaching \$4.90 per gigajoule for June quarter 2012.

Rising demand for natural gas as a fuel for electricity generation, together with the proposed Carbon Pollution Reduction Scheme, bode well for the growth of gas futures markets in Australia. The short term trading market to commence from 2010 may encourage further development of hedge market instruments for gas.

#### Figure 8.14

Victorian gas futures market-quarterly prices



Source: SFE.

#### 8.8 Reliability of supply

Reliability relates to the continuity of gas supply to customers. Various factors—planned and unplanned can lead to outages that interrupt supply. These interruptions may occur in gas production facilities or in the pipelines that deliver gas to customers.<sup>44</sup> A planned outage may occur for maintenance or construction works, and can be timed for minimal impact. Unplanned outages occur when equipment failure causes the supply of gas to be interrupted.

A distinguishing feature of reliability issues in the gas sector compared with the electricity sector is the management of safety issues. While incidents such as gas explosions and fires at upstream facilities are rare, the risk of widespread damage and injury is serious. In extreme cases, an upstream gas incident may also lead to the load shedding of customers.

44 Section 10.7 of this report discusses reliability issues in the gas distribution sector.

Major upstream incidents occurred at Longford (Victoria) in 1998, Moomba (South Australia) in 2004 and Varanus Island (Western Australia) in 2008. Victoria experienced a major supply outage in 1998 following gas fires at the Longford gas plant, which killed two people and shut down the state's entire gas supply for three weeks. The incident created significant economic costs. There was limited pipeline interconnection in 1998, which restricted Victoria's ability to import gas from other states to alleviate the shortage.

An explosion at South Australia's Moomba gas plant in January 2004 caused a significant loss of production capacity from the Cooper Basin, which restricted gas supplies into New South Wales. The issue was managed partly by importing gas from Victoria along the Eastern Gas Pipeline (constructed in 2000).

The incidents at Longford and Moomba led Australian governments to agree in 2005 on protocols to manage major gas supply interruptions on the interconnected networks.<sup>45</sup> The agreement established a government-industry National Gas Emergency Response Advisory Committee to report on the risk of gas supply shortages, and on options for managing potential shortages. A working group developed a communications protocol and procedures manual that details instructions for officials and industry members in the event of an incident.

In the event of a major gas supply shortage, the protocol requires that commercial arrangements operate, as far as possible, to balance gas supply and demand and maintain system integrity. Emergency powers are available as a last resort. The Gas Market Bulletin Board includes a facility to support the emergency protocol. It can gather emergency information from relevant market participants and jurisdictions. There were significant reliability issues in New South Wales and the ACT in June 2007 when capacity on the Eastern Gas Pipeline and gas flows on the Moomba to Sydney Pipeline were insufficient to meet higher than expected demand. While there was no infrastructure failure by gas producers or transmission pipeline operators, the New South Wales Government established a Gas Continuity Scheme in 2008 to mitigate the risk of a recurrence. The scheme provides commercial incentives for producers to increase supplies and for customers to reduce gas use in the event of a shortfall.

Western Australia's domestic gas supply was severely disrupted by an explosion at Varanus Island on 3 June 2008. The incident shut down Apache Energy's gas processing plant and reduced Western Australia's gas supply by around 30 per cent for over two months.

Spot prices for gas rose sharply as a result of the explosion. Limited gas supplies forced several mining and industrial companies to scale back production, and some electricity generators switched to emergency diesel stocks. Some coal fired power plants that had been closed were also brought back online. Western Australia's Independent Market Operator (which operates the state's wholesale electricity market) established a gas bulletin board to facilitate trading during the disruption.

The Western Australian Treasury estimated that the crisis cost the state economy \$2 billion. It took 12 months to repair the Varanus Island facilities and return to pre-incident production rates.<sup>46</sup>

<sup>45</sup> Memorandum of Understanding in Relation to National Gas Emergency Response Protocol (Including Use of Emergency Powers), June 2005 (available at www.mce.gov.au).

<sup>46</sup> For further information on the Varanus Island incident, see EnergyQuest's essay in this report, section E.5.



# 9 GAS TRANSMISSION



Transmission pipelines transport natural gas from production fields to major demand centres. The pipelines typically have wide diameters and operate under high pressure to optimise shipping capacity. They are placed mainly underground, which helps to minimise damage that could pose safety issues and interrupt gas supplies. In total, Australia's gas transmission network covers over 20 000 kilometres.

## 9 GAS TRANSMISSION

#### This chapter considers:

- > Australia's 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
- > emerging competition in the gas transmission sector
- > pipeline tariffs.

### 9.1 Australia's gas transmission pipelines

Australia's gas transmission pipeline network has almost trebled in length since the early 1990s. Around \$4 billion has been invested or committed to new transmission pipelines and expansions since 2000.<sup>1</sup> Much of this investment has been in long haul interstate pipelines to introduce new supply sources and improve security of supply. The construction of Epic Energy's QSN Link (stage 1 completed in 2009) has interconnected the Queensland transmission network with major pipelines in South Australia and New South Wales.<sup>2</sup>

Earlier projects included the Eastern Gas Pipeline (Longford to Sydney, completed in 2000), the Tasmanian Gas Pipeline (Longford to Hobart, 2002) and the South East Australia Gas (SEA Gas) Pipeline (Port Campbell to Adelaide, 2003). The VicHub in eastern Victoria was constructed in 2002 to physically interconnect the Victorian Transmission System with the Tasmanian Gas Pipeline and the Eastern Gas Pipeline.

1 AER estimate comprising investment in new pipelines and major expansions (table 9.3) and regulatory approved investment in covered pipelines.

<sup>2</sup> Previously, only a raw gas pipeline from Ballera to Moomba connected the Queensland and South Australian pipeline systems.

In combination, these projects have created an interconnected pipeline network covering Queensland, New South Wales, Victoria, South Australia, Tasmania and the Australian Capital Territory (ACT).

The interconnection of the eastern jurisdictions has improved options to source gas from alternative gas basins. A retailer in Sydney, for example, can source natural gas from Queensland's Surat–Bowen Basin (using the QSN Link and Moomba to Sydney Pipeline), South Australia's Cooper Basin (using the Moomba to Sydney Pipeline) or Bass Strait (using the Eastern Gas Pipeline). These developments are enhancing the competitive environment for gas producers, pipeline operators and gas retailers and improve supply options in times of constrained production.

Transmission pipelines in Western Australia and the Northern Territory are not interconnected with other jurisdictions. The populated south west of Western Australia is serviced by the Dampier to Bunbury Pipeline, which delivers gas from the Carnarvon Basin. The smaller Parmelia Pipeline transports gas from both the Carnarvon and Perth basins. There has been substantial investment in Western Australian pipelines in the past decade, including major expansions of the Dampier to Bunbury Pipeline and new pipelines to supply gas to the mining and resources sector.

In the Northern Territory, the completion of the Bonaparte Pipeline in December 2008 introduced a second source of natural gas—from the Blacktip field—to compete with gas from the declining Mereenie and Palm Valley gas fields (which ship gas via the Amadeus Basin to Darwin Pipeline).

Table 9.1 sets out summary details of Australia's major transmission pipelines. Figure 9.1 illustrates pipeline routes.

## 9.2 Ownership of gas transmission pipelines

Government reforms to the gas sector in the 1990s led to structural reform and significant ownership changes. In particular, vertically integrated gas utilities were disaggregated and most government owned transmission pipelines were privatised. Figure 9.2 summarises changes in the ownership of major transmission pipelines since 1994.

Privatisation led to the entry of United States based utilities such as Epic Energy and Duke Energy. The principal domestic player was the New South Wales energy utility AGL, which owned or acquired major transmission assets in New South Wales and Queensland. In 2000 AGL's gas transmission assets were transferred to the Australian Pipeline Trust, which is now part of APA Group.<sup>3</sup>

Over time, the United States based utilities exited the Australian market, and new players such as Alinta took their place. Investment trusts such as Hastings and DUET Group also acquired transmission assets. The ownership landscape experienced a major shift in 2007 with the sale of Alinta to Singapore Power International and Babcock & Brown.<sup>4</sup>

Further consolidation has reduced the number of principal players in the gas transmission sector to four: > *Singapore Power International* acquired a portfolio of gas transmission assets from Alinta in 2007, and rebranded them as *Jemena* in August 2008. It owns and operates the Eastern Gas Pipeline, VicHub and the Queensland Gas Pipeline, and operates the Tasmanian Gas Pipeline.

<sup>3</sup> In 2006 the Australian Pipeline Trust began trading as part of APA Group, which comprises Australian Pipeline Ltd, the Australian Pipeline Trust and the APT Investment Trust.

<sup>4</sup> The 2007 and 2008 editions of the AER's *State of the energy market* report detail the historical changes in the ownership of gas transmission infrastructure. The reports are available on the AER website: www.aer.gov.au.

#### Table 9.1 Major gas transmission pipelines

DIDELINE		LENGTH (KM)		CONSTRUCTED	
	LUCATION	(131-1)	(13/6)	CONSTRUCTED	
North Queensland Gas Pineline	QId	391	108	2004	No
Queensland Gas Pipeline (Wallumbilla to Gladstone)	Qld	629	79	1989-91	No
Carpentaria Pipeline (Ballera to Mount Isa)	Qld	840	117	1998	Yes (light)
Berwyndale to Wallumbilla Pipeline	Qld	113		2009	No
Dawson Valley Pipeline	Qld	47	30	1996	Yes
Roma (Wallumbilla) to Brisbane	Qld	440	208	1969	Yes
Wallumbilla to Darling Downs Pipeline	Qld	205	400	2009	No
South West Queensland Pipeline (Ballera to Wallumbilla)	Qld	756	168	1996	No
QSN Link (Ballera to Moomba)	Qld-SA and NSW	180	212	2009	No
SOUTH EAST AUSTRALIA					
Moomba to Sydney Pipeline	SA-NSW	2029	420	1974–93	Partial (light)
Central West (Marsden to Dubbo) Pipeline	NSW	255	10	1998	Yes
Central Ranges (Dubbo to Tamworth) Pipeline	NSW	300	7	2006	Yes
Eastern Gas Pipeline (Longford to Sydney)	Vic-NSW	795	250	2000	No
Victorian Transmission System (GasNet)	Vic	2035	1030	1969-2008	Yes
South Gippsland Natural Gas Pipeline	Vic	250		2006-10	No
VicHub	Vic		150 (into Vic)	2003	No
Tasmanian Gas Pipeline (Longford to Hobart)	Vic-Tas	734	129	2002	No
SEA Gas Pipeline (Port Campbell to Adelaide)	Vic-SA	680	314	2003	No
Moomba to Adelaide Pipeline	SA	1185	253	1969	No
WESTERN AUSTRALIA					
Dampier to Bunbury Pipeline	WA	1854	785	1984	Yes
Goldfields Gas Pipeline	WA	1427	150	1996	Yes
Parmelia Pipeline	WA	445	70	1971	No
Pilbara Energy Pipeline	WA	219	188	1995	No
Midwest Pipeline	WA	353	20	1999	No
Telfer Pipeline (Port Hedland to Telfer)	WA	443	25	2004	No
Kambalda to Esperance Pipeline	WA	350	6	2004	No
Kalgoorlie to Kambalda Pipeline	WA	44	20		Yes
NORTHERN TERRITORY					
Bonaparte Pipeline	NT	287	80	2008	No
Amadeus Basin to Darwin Pipeline	NT	1512	44	1987	Yes
Wickham Point Pipeline	NT	13		2009	No
Daly Waters to McArthur River Pipeline	NT	330	16	1994	No
Palm Valley to Alice Springs Pipeline	NT	140	27	1983	No

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

Notes:

256

Covered pipelines are subject to regulatory arrangements under the National Gas Law. The Australian Energy Regulator (AER) regulates covered pipelines outside Western Australia, where the Economic Regulation Authority is the transmission regulator.

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

VALUATION (\$ MILLION)	CURRENT ACCESS ARRANGEMENT	OWNER	OPERATOR
4 (0 (0005)	NI		
160 (2005)	Not required	Victorian Funds Management Corporation	AGL Energy, Arrow Energy
	Not required	Jemena (Singapore Power International (Australia))	Jemena Asset Management
	Not required	APA Group	APA Group
70 (2009)	Not required	AGL Energy	AGL Energy
8 (2007)	2007-16	Anglo Coal (51%), Mitsui (49%)	Anglo Coal
296 (2006)	2007-11	APA Group	APA Group
90 (2009)	Not required	Origin Energy	Origin Energy
	Not required	Epic Energy (Hastings)	Epic Energy
165 (2009)	Not required	Epic Energy (Hastings)	Epic Energy
835 (2003)	2004-09	APA Group	APA Group
28 (1999)	2000-10	APA Group	APA Group
53 (2003)	2005-19	APA Group	Country Energy (NSW Govt)
450 (2000)	Not required	Jemena (Singapore Power International (Australia))	Jemena Asset Management
524 (2007)	2008-12	APA Group	APA Group/AEMO
50 (2007)	Not required	Multinet Gas	Jemena Asset Management
	Not required	Jemena (Singapore Power International (Australia))	Jemena Asset Management
440 (2005)	Not required	Babcock & Brown Infrastructure	Jemena Asset Management
500 (2003)	Not required	International Power, APA Group and REST (equal shares)	APA Group
370 (2001)	Not required	Epic Energy (Hastings)	Epic Energy
1618 (2004)	2005-10	DUET Group (60%), Alcoa (20%), Babcock & Brown Infrastructure (20%)	WestNet Energy (Babcock & Brown Infrastructure)
514 (1999)	2000-09	APA Group (88.2%), Babcock & Brown Power (11.8%)	APA Group
	Not required	APA Group	APA Group
	Not required	Epic Energy (Hastings)	Epic Energy
	Not required	APA Group (50%), Horizon Power (WA Govt) (50%)	APA Group
114 (2004)	Not required	Energy Infrastructure Investments (APA Group 20%, Marubeni 50%, Osaka Gas 30% )	APA Group
45 (2004)	Not required	ANZ Infrastructure Services	WorleyParsons Asset Management
	None approved	APA Group	APA Group
170 (2008)	Not required	Energy Infrastructure Investments (APA Group 20%, Marubeni 50%, Osaka Gas 30% )	APA Group
229 (2001)	2001-11	Amadeus Pipeline Trust (APA Group 96%)	NT Gas (APA Group)
36 (2009)	Not required	Energy Infrastructure Investments (APA Group 20%, Marubeni 50%, Osaka Gas 30% )	APA Group
	Not required	APA Group, Power and Water	NT Gas (APA Group)
	Not required	Envestra (APA Group 31%, CKI 17%)	APA Group

Coverage of the Moomba to Sydney Pipeline was partly revoked in 2003. The revoked portion runs from Moomba to the offtake point of the Central West Pipeline at Marsden (figure 9.1). The covered portion became a light regulation pipeline in 2008.

'Current access arrangement' refers to access terms and conditions approved by the regulator.

Some corporate names have been abbreviated or shortened.

Sources: Capacity: Office of Energy (Western Australia); National Gas Market Bulletin Board (www.gasbb.com.au); Energy Quest, Energy Quarterly, August 2009; corporate websites. Other data: access arrangements for covered pipelines; EnergyQuest, Energy Quarterly, August 2009; ABARE, Major development projects, April 2009; corporate websites, annual reports and media releases.

#### Figure 9.1

Major gas transmission pipelines



24

Source: AER.

**Bonaparte Pipeline** 

258

#### Figure 9.2

#### Transmission pipeline ownership

		1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
4	Moomba-Sydney	Govt AGL 51%, Gasinvest 49%										APA	Group				
ALI	Eastern Gas Pipeline								Duke	Energy		Alinta			Jemena (Singapore Power)		e Power)
USTR	Victorian Transmission System			Govt						GasNet					APA Group		
TH EAST A	SEA Gas Pipeline		Origin, IP, CLP 33.3% each										LP h	APA, IP, CLP RE 33.3% each 33. ea			
- <u>_</u>	Moomba-Adelaide	Govt Tenneco Epic Energy									Epic Energ			yy (Hastings)			
S	Tasmanian Gas Pipeline									Duke	Energy		Alinta			BBI	
Δ	QSN Link		Epic (Ha:									Epic E (Hast	inergy tings)				
LAN	Queensland Gas Pipeline	Go	ovt	PG&E			D	uke Ener	ау			Alinta			Jemena (Singapore Power)		
NS	Roma-Brisbane			A	GL		APT							APA Group		р	
Ë	Carpentaria Pipeline					A	GL				APT				APA Group		р
g	South West Qld Pipeline / QSN Link						Epic E	inergy				Epic Energ			y (Hasting	js)	
RN ALIA	Dampier-Bunbury		G	ovt				Epic E	inergy			Alinta 20%, DUET 60%, Alcoa 20%		BBI 20%, DUET 60%, Alcoa 20%		I%, Alcoa	
NT WESTERN QUEENSLAND AUSTRALIA	Goldfields Gas Pipeline		GGT JV V	VMC 63%		S	outhern (	Cross Pipe	elines Au	stralia 88'	%	APA Group 88.2%, Alinta 11.8%			APA Group 88%, BBP 12%		
	Parmelia Pipeline	WAPI	ET joint ve	enture			CMS Gas Transmission				APA Group						
E	Amadeus Basin – Darwin		Amadeus	Gas Trus	t	AGL	96%					APA Gr	oup 96%				
z	Bonaparte Gas Pipeline															EII (AP	A 20%)

APT, Australian Pipeline Trust (assets now part of APA Group); BBI, Babcock & Brown Infrastructure; BBP, Babcock & Brown Power; CKI, Cheung Kong Infrastructure; EII, Energy Infrastructure Investments; GGT JV, Goldfields Gas Pipeline Joint Venture; IP, International Power; WMC, Western Mining Company; PG&E, Pacific Gas and Electric; REST, Retail Employees Superannuation Trust; WAPET, West Australian Petroleum Pty Limited joint venture. Notes:

Some corporate names have been abbreviated or shortened.

From 1996-2003 Epic Energy was owned by El Paso Energy (30%), CNG International (30%), Allgas Energy (10%), AMP Investments (10%), Axiom Funds Management (10%) and Hastings (10%).

In 2008 Singapore Power International rebranded its gas transmission assets as Jemena.

Sources: AER; Australian Gas Association, Gas statistics Australia, Melbourne (various years); corporate reports and websites.

 APA Group owns the Moomba to Sydney, Central West and Central Ranges pipelines in New South Wales; the Victorian Transmission System; two major Queensland pipelines (Carpentaria and Roma to Brisbane); three major Western Australian pipelines (Goldfields, Parmelia and Midwest); and a major Northern Territory pipeline (Amadeus Basin to Darwin). It also part owns the SEA Gas Pipeline and other Northern Territory pipelines. In December 2008 APA Group sold the Bonaparte and Wickham Point pipelines (Northern Territory) and Telfer Gas Pipeline (Western Australia) into an unlisted investment vehicle, Energy Infrastructure Investments Pty Limited (EII). Marubeni Corporation (50 per cent stake) and Osaka Gas (30 per cent) have majority equity. APA Group retains a 20 per cent equity interest and continues to operate the assets.

 Babcock & Brown Infrastructure acquired a 20 per cent interest in the Dampier to Bunbury Pipeline from Alinta in 2007. It now operates the pipeline through its management services business WestNet Energy. It also owns the Tasmanian Gas Pipeline and has a minority interest in Western Australia's Goldfields Gas Pipeline. > Hastings Diversified Utilities Fund, managed by a fund acquired by Westpac in 2005, acquired *Epic Energy*'s gas transmission assets in 2000. It owns the Moomba to Adelaide Pipeline (South Australia), the Pilbara Energy Pipeline (Western Australia) and the South West Queensland Pipeline. In 2009 Epic Energy completed stage 1 of the QSN Link from Queensland to South Australia and New South Wales. In 2009 Hastings called for expressions of interest for the sale of part or all of Epic Energy. Hastings reported on 26 June 2009 that the sale process was continuing.

Other players include:

- > DUET Group, the majority owner (60 per cent) of the Dampier to Bunbury Pipeline<sup>5</sup>
- > International Power and the Retail Employees Superannuation Trust, each of which have ownership interests in the SEA Gas Pipeline
- > AGL Energy, which owns the Berwyndale to Wallumbilla Pipeline (commissioned in 2009) but has announced plans for its sale
- > Origin Energy, which owns the Wallumbilla to Darling Downs Pipeline (commissioned in 2009).

Earlier this decade, the ownership and operation (management control) of gas transmission pipelines tended to be separate, but more recently this pattern has reversed. In particular, APA Group and Jemena have moved to an integrated model, whereby a group entity operates and manages all pipeline assets owned or partially owned in the group. The Epic Energy (Hastings) pipelines continue to be operated by group management companies. Babcock & Brown Infrastructure uses a mix of in-house and outsourced asset management approaches.

## 9.3 Economic regulation of gas transmission pipelines

Gas transmission pipelines are capital intensive and incur declining marginal costs as output increases. This gives rise to a natural monopoly industry structure. Rising demand can usually be accommodated more cheaply by adding compressors or looping (duplicating part or all of) an existing pipeline than by constructing additional pipelines.

The National Gas Law (Gas Law) and National Gas Rules (Gas Rules) provide the overarching regulatory framework for the gas transmission sector. The Gas Law and Gas Rules commenced on 1 July 2008 in all jurisdictions except Western Australia, which expects to implement the pipeline access provisions in the second half of 2009. These instruments replace the Gas Pipelines Access Law and the National Gas Code (Gas Code), which had provided the national regulatory framework from 1997.

On 1 July 2008 the Australian Energy Regulator (AER) replaced the Australian Competition and Consumer Commission (ACCC) as the regulator for pipelines outside Western Australia. The Economic Regulation Authority of Western Australia is the regulator of covered pipelines in that state.

The Gas Law and Gas Rules apply to covered pipelines (see section 9.3.1). There are different forms of economic regulation for covered pipelines, based on criteria set out in the law (see section 9.3.2).

#### 9.3.1 Which pipelines are regulated?

The Gas Pipelines Access Law applied to most Australian transmission pipelines initially, but this coverage changed over the past decade. Significant new investment in gas pipelines has led to improved interconnection between gas basins and retail markets in the southern and eastern states. This interconnection has increased supply options and, in some instances, may limit the ability of pipeline operators to exercise market power.

The Gas Law anticipates the potential for market conditions to evolve, and includes a coverage mechanism to allow for an independent review of whether there is a need to regulate a particular pipeline. The National Competition Council is the coverage review body, but designated government ministers make final decisions.

5 DUET Group comprises a number of trusts, for which Macquarie Bank (50%) and AMP Capital Holdings (50%) jointly own the responsible entities.

The decisions are open to review by the Australian Competition Tribunal, and in 2001 the tribunal reversed a ministerial decision to cover the Eastern Gas Pipeline.<sup>6</sup>

The coverage process has led to the lifting of economic regulation—in whole or part—from several major pipelines, including the Eastern Gas Pipeline, Western Australia's Parmelia Pipeline, the Moomba to Adelaide Pipeline and a significant portion of the Moomba to Sydney Pipeline. The Queensland Government passed legislation in 2008 that revoked the coverage of two major pipelines: the South West Queensland and Queensland Gas pipelines.<sup>7</sup>

The Gas Law includes a process to allow newly constructed pipelines to be covered. Only one pipeline constructed in the past decade (the Central Ranges Pipeline in New South Wales) is currently covered. Other new pipelines—including the SEA Gas and Tasmanian Gas pipelines and several new pipelines in Western Australia—are not covered. At July 2008 no transmission pipeline into Adelaide or Hobart was subject to economic regulation.

The service provider<sup>8</sup> of a covered pipeline must comply with the provisions of the Gas Law and Gas Rules. Pipelines that are not covered are subject only to the general anti-competitive provisions of the *Trade Practices Act 1974* (Cwlth). Access to non-covered pipelines is a matter for the access provider and an access seeker to negotiate, without regulatory assistance.

Table 9.1 indicates the coverage status of each major pipeline. At 1 July 2009 11 gas transmission pipelines were covered under the Gas Law (table 9.2). Of these, nine were subject to full regulation and two were subject to light regulation (see section 9.3.2).

In 2008 the Gas Law introduced incentives for investment in greenfields pipelines and international pipelines to Australia. Pipeline owners can apply for a determination that provides a 15 year exemption from coverage for greenfields pipelines and a 15 year exemption from price regulation for international pipelines.

### Table 9.2 Covered transmission pipelines,September 2009

JURISDICTION AND PIPELINE	COMMENTS
NEW SOUTH WALES	
Moomba to Sydney Pipeline	Partially covered; light regulation of covered portion since 2008 <sup>1,2</sup>
Central West Pipeline (Marsden to Dubbo)	Covered since 1998 <sup>3</sup>
Central Ranges Pipeline	Covered since May 2004 <sup>4</sup>
VICTORIA	
Victorian Transmission System	Covered since 1997
QUEENSLAND	
Roma (Wallumbilla) to Brisbane Pipeline	Covered since 1997; derogations expired in 2006, enabling the regulator to set tariffs for the first time
Dawson Valley Pipeline	Coverage revoked in 2000 but re-instated in 2006
Carpentaria Pipeline (Ballera to Mount Isa)	Covered since 1997; light regulation since 2008 <sup>2</sup>
WESTERN AUSTRALIA <sup>5</sup>	
Dampier to Bunbury Pipeline	Covered since 1999
Goldfields Gas Pipeline	Covered since 1999
Kalgoorlie to Kambalda Pipeline <sup>6</sup>	Covered since 1999
NORTHERN TERRITORY	
Amadeus Basin to Darwin Pineline	Covered since 1997

 Coverage of the Moomba to Sydney Pipeline was partly revoked in 2003. The revoked portion runs from Moomba to the offtake point of the Central West Pipeline at Marsden (figure 9.1). The covered portion (Marsden to Wilton) became a light regulation pipeline in 2008.

- The service provider of a light regulation pipeline must publish the terms and conditions of access, including tariffs, on its website. It is not required to submit an access arrangement to the regulator for approval.
- The service provider of the Central West Pipeline lodged an application in October 2009 to convert to light regulation.
- 4. Under the National Gas Law, the Central Ranges Pipeline will cease to be covered once the current access arrangement expires.
- 5. The Gas Code commenced in Western Australia in 1999.
- 6. The regulator has not approved an access arrangement for this pipeline.

<sup>6</sup> The Eastern Gas Pipeline was covered by a ministerial decision on 16 October 2000. The Australian Competition Tribunal reversed this decision on 4 May 2001.

<sup>7</sup> Any party may apply to the National Competition Council to consider whether a previously covered pipeline should be covered again. The Dawson Valley Pipeline was revoked from coverage in 2000, but a later application reversed this decision in 2006 (table 9.2). The National Gas (Queensland) Regulation 2008 provided that no person may apply to reactivate coverage of the South West Queensland Pipeline for a period of one year, or the Queensland Gas Pipeline for a period of two years.

<sup>8</sup> The service provider may be the controller, owner or operator of the whole pipeline or any part of the pipeline.

#### 9.3.2 Regulatory framework

In Australia, the providers of most gas transmission pipelines negotiate contracts to sell transportation services to customers such as energy retailers. The contracts, which set the terms and conditions of third party access, are negotiated on commercial terms that may differ from those set through regulatory processes. A contract typically features a maximum daily quantity allocation and sets a capacity charge, which must be paid regardless of the amount of gas that a customer transports on the pipeline.

In Victoria, an independent operator—the Australian Energy Market Operator (AEMO)—manages the Victorian Transmission System, and users are not required to enter contracts. Instead, a party's daily gas flow is determined by its bids into the wholesale gas market. The bids enter a market clearing engine, which dispatches the lowest priced supply offers to meet demand. Pipeline charges are based on actual gas flows following this dispatch process.

Different forms of economic regulation apply to covered pipelines, based on criteria under the Gas Law.<sup>9</sup> Nine transmission pipelines are subject to *full regulation*, which requires the service provider to submit an access arrangement to the regulator for approval. The AER is the transmission pipeline regulator, except in Western Australia.<sup>10</sup> An access arrangement sets out the terms and conditions under which third parties can use a pipeline. It must specify at least one reference service that most customers seek, and a reference tariff for that service.

The reference tariff is intended as a basis for negotiation between the pipeline owner and customers. Typically, reference tariffs apply to firm forward haulage services, which are commonly sought on most pipelines.<sup>11</sup> A pipeline may also provide non-reference services, for which the AER does not approve the terms and conditions of access. Gas users seeking access to non-reference services, such as short term or interruptible supply, can try to directly negotiate those services with the pipeline operator or other gas shippers.

An access arrangement must also set out non-price terms and conditions, such as a capacity expansion policy, queuing requirements and gas quality specifications.<sup>12</sup> More generally, an access arrangement must comply with the provisions of the Gas Law, including pricing principles, ring-fencing requirements and provisions for associate contracts. In the event of a dispute, an access seeker may ask the regulator to arbitrate and enforce the provisions of an access arrangement.<sup>13</sup> The AER has published a guideline on dispute resolution under the Gas Law.<sup>14</sup>

The Gas Law establishes a process that may allow a pipeline to convert to *light regulation* without upfront price regulation. The National Competition Council determines whether a pipeline is subject to light regulation. The policy intent is that this form of regulation suits some transmission pipelines.<sup>15</sup> Where light regulation applies, the pipeline provider must publish access prices and other terms and conditions on its website. In the event of a dispute, an access seeker may ask the regulator to arbitrate.

The current light regulation pipelines are the Carpentaria Gas Pipeline in Queensland and the covered portions of the Moomba to Sydney Pipeline (table 9.2).<sup>16</sup>

12 For further information on non-price matters, see AER, Access arrangement guideline, final, Melbourne, March 2009, at s. 5.4.1.

<sup>9</sup> The AER published an *Access arrangement guideline* in March 2009, which sets out the forms of regulation (see part 2 of the guideline). The guideline is available on the AER website at www.aer.gov.au.

<sup>10</sup> The Economic Regulation Authority is the transmission regulator in Western Australia.

<sup>11</sup> Firm forward haulage services enable the customer to reserve capacity on a pipeline and receive a high priority service. Interruptible services are sold on an 'as available' basis and may be interrupted or delayed, especially if a pipeline has capacity constraints.

<sup>13</sup> In Western Australia, a separate arbitrator hears access disputes.

<sup>14</sup> AER, Guideline for the resolution of distribution and transmission pipeline access disputes under the National Gas Law and National Gas Rules, final, Melbourne, November 2008.

<sup>15</sup> The Second Reading Speech for the National Gas (South Australian) Bill 2008 (p. 15) indicates that light regulation may be relevant for point-to-point transmission pipelines with a small number of users, of whom each has countervailing market power.

<sup>16</sup> The service provider of the Central West Pipeline lodged an application in October 2009 to convert to light regulation.

#### 9.3.3 Regulatory process

For a pipeline subject to full regulation, the Gas Law requires the provider to submit an initial access arrangement to the regulator and periodically revise it. The revisions generally occur once every five years as scheduled reviews, but can occur more frequently—for example, if a trigger event compels an earlier review, or if the service provider seeks a variation to the access arrangement.

The Gas Rules prescribe the process and timeframe for an access arrangement review. The arrangements are identical to those for gas distribution pipelines. Section 10.4.3 of this report outlines the key elements; the AER published an *Access arrangement guideline* in March 2009, which details these processes.

#### 9.3.4 Regulatory approach

The Gas Rules require the use of a building block approach to determine total revenue and derive tariffs. Total revenue must be sufficient to allow a business to recover efficient costs, including operating costs, taxation, asset depreciation and a return on capital (using a benchmark cost of capital). The Gas Rules also allow for income adjustments from incentive mechanisms that reward efficient operating practices. Tariffs are typically adjusted annually for inflation, and in some cases other factors.<sup>17</sup>

In approving a reference tariff, the AER must consider the costs of a prudent and efficient service provider of a pipeline service. In doing so, it will look at the circumstances in which a pipeline operates and draw on expert assessments, submissions from interested parties, benchmarking, the operation of efficiency mechanisms, and key performance indicator information.

Figures 9.3 and 9.4 show the revenue components under access arrangements for the Victorian Transmission System and the Roma to Brisbane Pipeline. They provide a guide to the typical composition of the revenue components in a determination. In these decisions, depreciation and returns on capital account for almost three quarters of revenue. Operating and maintenance costs account for most of the balance.

For pipelines subject to full economic regulation, the Gas Law sets a test to assess whether new investment may be rolled into the capital base.<sup>18</sup>

#### 9.4 Recent gas pipeline investment

Investment in the gas transmission sector typically involves large and lumpy capital projects to expand existing pipelines (through compression, looping and extensions) or construct new pipelines.<sup>19</sup> Around \$4 billion has been invested or committed to new transmission pipelines and expansions since 2000.<sup>20</sup> This amount reflects both real investment in new infrastructure and rising resource costs in the construction sector.

Table 9.3 provides summary information on major transmission pipeline investment since 2000. It also lists a selection of pipelines (or expansions) under construction and major pipelines that have been announced for future development.

According to the Second Reading Speech, National Gas (South Australian) Bill 2008, the test is 'designed to capture net increases in producer and consumer surpluses in upstream and downstream gas markets, while also capturing the system security and reliability benefits that were considered by regulators to constitute system wide benefits. The test ... unambiguously includes benefits that accrue to users and end users of gas when they are able to purchase additional quantities of gas, or to gas producers when they are able to sell additional quantities of gas' (p. 18).

<sup>17</sup> For further information on reference tariffs, see AER, Access arrangement guideline, final, Melbourne, March 2009, at s. 5.4.2.

<sup>18</sup> The test allows for capital expenditure to be rolled into the regulated capital base if (1) the overall economic value is positive, (2) the present value of incremental revenue is greater than the present value of the capital expenditure or (3) the expenditure is necessary to maintain and improve service safety, or maintain service integrity, or maintain a service provider's capacity to meet levels of demand for existing services.

In determining the overall economic value, only the economic value directly accruing to the service provider, gas producers, users and end users is to be considered. There are additional criteria for capital expenditure for Western Australian transmission pipelines, which reflect the value that may directly accrue to electricity market participants from additional gas fired generation capacity.

<sup>19</sup> Pipeline capacity can be increased by adding compressor stations to raise the pressure under which gas flows and by looping (duplicating) sections of the pipeline. Extending the length of the pipeline can increase line pack (storage) capacity.

<sup>20</sup> AER estimate comprising investment in new pipelines and major expansions (table 9.3) and regulator approved investment in covered pipelines.

#### Figure 9.3

Revenue composition for the Victorian Transmission System, 2008–12



Substantial investment in transmission pipelines in south east Australia occurred between 2000 and 2005. The new pipelines helped develop an interconnected system linking New South Wales, Victoria, South Australia, Tasmania and the ACT. More recently, the focus for new investment has shifted to north east Australia, the Northern Territory and Western Australia.

#### 9.4.1 North east Australia

The development of Queensland's coal seam gas (CSG) industry has spurred significant new pipeline investment. Epic Energy commissioned the QSN Link (Ballera to Moomba) in January 2009, and has expanded capacity on the South West Queensland Pipeline to 170 terajoules per day. The QSN Link creates the ability, for the first time, to deliver dry gas between Queensland and the southern states. The expansion of the South West Queensland Pipeline allows increased flows of CSG from Queensland's Surat-Bowen basin to south east Australia via the QSN Link.

#### Figure 9.4

Revenue composition for the Roma to Brisbane Pipeline, 2007–11



Source: ACCC, Revised access arrangement by APT Petroleum Pipelines Ltd for the Roma to Brisbane Pipeline, final decision, Canberra, 20 December 2006.

In December 2007 Epic Energy announced plans for a \$64 million expansion of the QSN Link and a further (stage 2) expansion of the South West Queensland Pipeline (to 220 terajoules a day) by 2013, to deliver gas for AGL Energy. In June 2009 it announced a conditional agreement with Origin Energy for a further \$760 million expansion of the South West Queensland Pipeline to 380 terajoules per day. The stage 3 expansion would effectively duplicate the existing pipeline.

Other Queensland pipelines are also being expanded. In 2009 APA Group completed a 15 per cent capacity expansion of the Carpentaria Pipeline. Jemena has announced a \$112 million expansion of the Queensland Gas Pipeline (Wallumbilla to Gladstone) by 2010. The expansion will increase the pipeline's capacity from 79 to 133 terajoules per day. In addition to the QSN Link, two other major pipelines were commissioned in Queensland in 2009:

- > AGL Energy commissioned the \$70 million Berwyndale to Wallumbilla Pipeline. The pipeline allows delivery of CSG from Queensland's Surat-Bowen Basin to the Wallumbilla hub, from which it can be shipped west along the South West Queensland Pipeline to southern markets, or east along the Roma to Brisbane Pipeline to meet gas demand around Brisbane.
- > Origin Energy completed a \$90 million pipeline to ship gas from Wallumbilla to the gas fired Darling Downs power station it is constructing.

Planned development of liquefied natural gas (LNG) projects in Queensland has also spurred plans to develop new transmission infrastructure to transport CSG to Gladstone for LNG processing. Among the proposals are:

- > Santos's 432 kilometre Gladstone LNG Pipeline (Fairview to Gladstone), scheduled for commissioning by 2014
- > Arrow Energy's \$500 million Surat Basin to Gladstone Pipeline (450 kilometres).

#### 9.4.2 South east Australia

Several major transmission pipelines were developed in south east Australia between 2000 and 2005. These included the Eastern, Tasmanian and SEA Gas pipelines (table 9.3). More recently:

- Multinet began a four year project to develop the South Gippsland Natural Gas Pipeline in 2006. The \$50 million project comprises transmission and distribution infrastructure to provide reticulated natural gas to 10 000 properties in south east Victoria.
- > APA Group completed a \$70 million extension of the Victorian Transmission System in 2008 with the Lara to Brooklyn Pipeline (the Corio loop). The loop facilitates gas flow from the Otway Basin to Melbourne.

The owners of the two transmission pipelines serving Sydney have each announced capacity expansions:

> APA Group in 2008 began a \$100 million five year expansion program for the Moomba to Sydney Pipeline, which will increase capacity by around 20 per cent. The expansion will increase gas flows for new gas fired electricity generation projects such as Uranquinty near Wagga Wagga.

> Jemena has announced a \$41 million capacity expansion of the Eastern Gas Pipeline (Longford to Sydney), to be completed by 2010.

#### 9.4.3 Western Australia

In Western Australia, new investment activity has centred on major capacity expansions of the Dampier to Bunbury Pipeline, which is the major link between the state's North West Shelf and gas markets around Perth:

- > The \$430 million stage 4 expansion (completed in December 2006) involved eight new compressors and over 200 kilometres of looping.
- > The \$660 million stage 5A expansion (completed in March 2008) comprised 570 kilometres of looping and added capacity of around 100 terajoules per day. At the completion of stage 5A, around 50 per cent of the pipeline had been duplicated.
- > In 2008 the pipeline owners announced a \$690 million stage 5B expansion to add a further 113 terajoules per day of capacity. The latest expansion, set for completion in 2010, will involve a further 440 kilometres of looping. At the completion of stage 5B, around 94 per cent of the pipeline will have been duplicated.

Also in Western Australia, APA Group completed a 20 per cent expansion of the Goldfields Gas Pipeline in 2009.

#### 9.4.4 Northern Territory

In the Northern Territory, APA Group completed the \$170 million Bonaparte Gas Pipeline in 2008. The 287 kilometre pipeline transports natural gas for domestic supply from the Blacktip field in the Bonaparte Basin. It provides an alternative to gas supply from the declining Palm Valley and Mereenie fields. APA Group sold the pipeline into an unlisted investment vehicle, Energy Infrastructure Investments, in 2008.

PIPELINE	LOCATION	OWNER/PROPONENT	SCALE	COST (\$ MILLION)	COMPLETION DATE
COMPLETED					
NORTH EAST AUSTRALIA					
Wallumbilla to Darling Downs Pipeline	Qld	Origin Energy	205 km	90	2009
Berwyndale to Wallumbilla Pipeline	Qld	AGL Energy	113 km	70	2009
South West Queensland Pipeline—stage 1	Qld	Epic Energy	Expansion to 170 TJ/d	145	2000
QSN Link—stage 1	Qld–SA and NSW	Epic Energy	180 km, 250 TJ/d	165	2007
Carpentaria Pipeline	Qld	APA Group	15% expansion to 117 TJ/d		2009
North Queensland Gas Pipeline (Moranbah to Townsville)	Qld	Victorian Funds Management Corporation	391 km	160	2005
SOUTH EAST AUSTRALIA					
Corio Loop (expansion of Victorian Transmission System)	Vic	APA Group	57 km	70	2008
South Gippsland Natural Gas Pipeline	Vic	Multinet Gas	250 km	50	2009
Tasmanian Gas Pipeline (Longford to Hobart)	Vic-Tas	Babcock & Brown Infrastructure	734 km	440	2002-05
VicHub	Vic	Singapore Power International			2003
SEA Gas Pipeline (Port Campbell to Adelaide)	Vic-SA	International Power, APA Group, Retail Employees Superannuation Trust (equal shares)	680 km	500	2003
Eastern Gas Pipeline (Longford to Sydney)	Vic-NSW	Singapore Power International	795 km	450	2000
WESTERN AUSTRALIA					
Goldfields Gas Pipeline	WA	APA Group (88.2%), BBP (11.8%)	20% expansion to 150 TJ/d		2009
Dampier to Bunbury stage 5A expansion	WA	DUET (60%), BBI (20%), Alcoa (20%)	Capacity increased by 100 TJ/d	660	2008
Dampier to Bunbury stage 4 expansion	WA	DUET (60%), BBI (20%), Alcoa (20%)	200 km	430	2006
Telfer Pipeline (Port Hedland to Telfer Goldmine)	WA	APA Group	443 km	114	2004
Kambalda to Esperance Pipeline	WA	ANZ Infrastructure Services	350 km	45	2004
NORTHERN TERRITORY					
Bonaparte Gas Pipeline	NT	Energy Infrastructure Investments	287 km	170	2008
Wickham Point Pipeline	NT	Energy Infrastructure Investments	13 km	36	2009

#### Table 9.3 Major gas transmission pipeline investment since 2000

PIPELINE	LOCATION	OWNER/PROPONENT	SCALE	COST (\$ MILLION)	COMPLETION DATE
UNDER CONSTRUCTION					
SOUTH EAST AUSTRALIA					
Moomba to Sydney Pipeline	NSW	APA Group	Five year 20% capacity expansion	100	From 2008
Eastern Gas Pipeline	Vic-NSW	Jemena	Expansion from 250 TJ/d to 268 TJ/d	41	2010
NORTH EAST AUSTRALIA					
Queensland Gas Pipeline expansion	Qld	Jemena	Expansion from 79 TJ/d to 133 TJ/d	112	2010
WESTERN AUSTRALIA					
Dampier to Bunbury stage 5B expansion	WA	DUET (60%), BBI (20%), Alcoa (20%)	113 TJ/day	690	2010
ANNOUNCED					
NORTH EAST AUSTRALIA					
South West Queensland Pipeline—stage 2	Qld	Epic Energy	Expansion to 220 TJ/d	44	2012
QSN Link—stage 2	Qld–SA and NSW	Epic Energy		04	2013
South West Queensland Pipeline—stage 3	Qld	Epic Energy	Expansion to 380 TJ/d	7/0	Conditional
QSN Link—stage 3	Qld–SA and NSW	Epic Energy		760	agreement
Queensland Hunter Pipeline (Wallumbilla–Newcastle)	Qld-NSW	Hunter Gas Pipeline	831 km	750-850	2012
Lions Way Pipeline (Casino to Ipswich)	NSW-Qld	Metgasco	145 km	120	2010-11
Gladstone LNG Pipeline (Fairview–Gladstone)	Qld	Santos	432 km		2014
Surat Basin to Gladstone	Qld	Arrow	450 km	500	n/a
WESTERN AUSTRALIA					
Dampier to Bunbury stage 5C expansion	WA	DUET (60%), BBI (20%), Alcoa (20%)	100 TJ/d		2011-12

TJ/d, terajoules per day; BBI, Babcock & Brown Investment.

Note: Projections of future scale, costs and completion dates are indicative.

Sources: Energy Quest, Energy Quarterly, August 2009; ABARE, Major development projects, Canberra, April 2009; National Gas Market Bulletin Board (www.gasbb.com.au); corporate websites, reports and media releases.

#### 9.4.5 Effects on competition

Investment over the past decade has led to the development of an interconnected gas pipeline system covering southern and eastern Australia. While gas tends to be purchased from the closest possible source to minimise transport costs, interconnection of the major pipelines provides energy customers with greater choice and enhances the competitive environment for gas supply.

Table 9.4 lists the pipelines and gas basins serving each major Australian market. Gas customers in Sydney, Melbourne, Canberra, Adelaide, Perth and Darwin are now served by multiple transmission pipelines from multiple gas basins. In particular, the construction of new pipelines and the expansion of existing ones have opened the Surat-Bowen, Cooper, Sydney, Gippsland, Otway and Bass basins to increased interbasin competition.

The National Gas Market Bulletin Board, which commenced in July 2008, provides real-time information on the gas market to enhance competition. The AER draws on the bulletin board to report weekly on gas market activity in southern and eastern Australia. The reporting covers gas flows on particular pipelines and gas flows from competing basins to end markets. Figures 9.5–9.8 illustrate recent activity.

Figure 9.5 illustrates the effects of the opening of the QSN Link on gas flows in south west Queensland. Since the commissioning of the QSN Link in January 2009, westerly flows have significantly increased along the South West Queensland Pipeline, feeding into the QSN Link and the Carpentaria Pipeline to Mount Isa. Figure 9.5 shows average gas flows (including flows to southern markets via South Australia) have roughly trebled since the opening of the QSN Link. Average daily flows for the week ending 12 September 2009, for example, were about 111 terajoules higher than average flows in the same period in 2008. Gas flows to the southern states via the QSN Link accounted for about half of this increase.

Figures 9.6–9.8 illustrate recent trends in the delivery of gas from competing basins into New South Wales, Victoria and South Australia since the opening of the bulletin board in July 2008:

- > While New South Wales historically relied on Cooper Basin gas shipped on the Moomba to Sydney Pipeline, gas shipped on the Eastern Gas Pipeline from Victoria's Gippsland Basin now supplies a substantial proportion of the state's gas requirements.
- > While the Gippsland Basin remains the principal source of gas supply for Victoria, the state also sources some of its requirements from the Otway Basin via the South West Pipeline (an artery of the Victorian Transmission System). Victoria also sources some gas from the northern basins via the New South Wales – Victoria Interconnect Pipeline.
- > The Moomba to Adelaide Pipeline and the SEA Gas Pipeline each transport substantial volumes of gas for the South Australian gas market. The Moomba to Adelaide Pipeline transports gas from Queensland's Surat-Bowen Basin via the QSN Link, and South Australia's Cooper Basin. The SEA Gas Pipeline delivers gas from Victoria's Otway Basin.

While Santos, Origin Energy and BHP Billiton have production interests in several gas basins, transmission pipeline interconnection has also provided new markets for smaller producers. Interconnection may benefit the wider energy sector too. In particular, it may enhance competition in electricity markets by creating opportunities for further investment in gas fired generators.

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

#### Table 9.4 Pipeline links between major gas basins and markets

MARKET / PIPELINES	GAS BASIN	PRODUCERS
SYDNEY AND CANBERRA		
Moomba to Sydney Pipeline (APA Group)	Cooper, Sydney	Santos, Beach Petroleum, Origin Energy, AGL Energy, Sydney Gas
Eastern Gas Pipeline (Singapore Power International), NSW—Vic Interconnect (APA Group)	Gippsland, Otway, Bass	BHP Billiton, ExxonMobil, Origin Energy, Santos AWE, Beach Petroleum
South West Queensland Pipeline/ QSN Link (Epic Energy)	Surat-Bowen	Origin Energy, Santos, Arrow Energy, BG Group, AGL Energy, ConocoPhillips, Petronas
MELBOURNE		
NSW-Vic Interconnect (APA Group)	Cooper (via MSP), Sydney	Santos, Beach Petroleum, Origin Energy, AGL Energy, Sydney Gas
Victorian Transmission System (APA Group)	Gippsland, Bass, Otway	BHP Billiton, ExxonMobil, Origin Energy, Santos AWE, Beach Petroleum
TASMANIA		
Tasmanian Gas Pipeline (Babcock & Brown Infrastructure)	Cooper (via MSP and NSW—Vic Interconnect), Gippsland, Otway, Bass	Santos, Beach Petroleum, Origin Energy
BRISBANE		
Roma to Brisbane Pipeline (APA Group)	Surat-Bowen	Mosaic, Origin Energy, Santos, BG Group, Arrow Energy, Mitsui, Molopo
ADELAIDE		
Moomba to Adelaide Pipeline (Epic Energy)	Cooper	Santos, Beach Petroleum, Origin Energy
SEA Gas Pipeline (APA Group, International Power, Retail Employees Superannuation Trust)	Otway and Gippsland	BHP Billiton, ExxonMobil, Origin Energy, Santos AWE, Beach Petroleum
South West Queensland Pipeline/ QSN Link (Epic Energy)	Surat-Bowen	Origin Energy, Santos, Arrow Energy, BG Group, AGL Energy, ConocoPhillips, Petronas
DARWIN		
Amadeus Basin to Darwin (96% APA Group)	Amadeus	Magellan, Santos
Bonaparte Pipeline (Energy Infrastructure Investments)	Bonaparte	ENI
PERTH		
Dampier to Bunbury Natural Gas Pipeline (DUET, Alcoa, Babcock & Brown Infrastructure)	Carnarvon, Perth	Apache Energy, BHP Billiton, BP, Chevron, ExxonMobil, Inpex, Kufpec, Santos, Shell, Tap Oil, Woodside Petroleum, ARC Energy, Origin Energy
Parmelia Pipeline (APA Group)	Perth	ARC Energy, Origin Energy

CHAPTER 9 GAS TRANSMISSION

MSP, Moomba to Sydney Pipeline.

Figure 9.5 Gas flows on the South West Queensland Pipeline



Note: While the QSN Link was commissioned in January 2009, reporting of gas flows began on 31 March 2009. Source: National Gas Market Bulletin Board, www.gasbb.com.au/AER.

#### Figure 9.6 Gas flows into New South Wales



Notes: Negative flows on the New South Wales -- Victoria Interconnect represent flows out of New South Wales into Victoria.

Figure 9.7 Gas flows into Victoria







Source (figures 9.6-9.8): Natural Gas Market Bulletin Board (www.gasbb.com.au )/AER.

CHAPTER 9 GAS TRANSMISSION

#### 9.5 Pipeline tariffs

The Gas Law requires providers of covered pipelines to publish reference tariffs (prices) and other conditions of access. Service providers must maintain this information on their website, either within their approved access arrangement or separately. They are not required to disclose tariffs for non-covered pipelines, or negotiated tariffs (for covered pipelines) agreed outside the reference tariffs. Some operators publish these tariffs on a website or make them available on request to access seekers.

Figure 9.9 sets out EnergyQuest estimates of indicative pipeline tariffs on selected routes between gas basins and Australian capital cities. The tariffs reflect factors such as differences in transportation distances; underlying capital costs; the age and extent of depreciation on the pipeline; technological and geographic differences; and the availability of spare pipeline capacity. In general, it is cheaper to transport gas into Sydney, Canberra and Adelaide from the Cooper Basin than from the Victorian coastal basins. In practice, pipeline tariffs may vary considerably from the indicative tariffs in figure 9.9. An access seeker can try to negotiate discounts against published rates. Some tariffs may be higher than those in figure 9.9, especially if a pipeline is capacity constrained and requires an expansion to make access possible. Tariffs for interruptible services<sup>21</sup> are typically 30 per cent higher than those for firm transportation charges, but are paid on the actual quantities shipped rather on reserved capacity.<sup>22</sup>

The key consideration for customers is the cost of delivered gas—the bundled cost of gas and transportation services—from alternative sources. The lead essay of the *State of the energy market 2008* report provided ACIL Tasman estimates of the composition of delivered gas prices in mainland state capital cities.<sup>23</sup> Retail prices ranged from around \$15.50 per gigajoule in Melbourne to almost \$28 per gigajoule in Brisbane. Transportation through the high pressure transmission system is the smallest contributor to delivered costs for residential consumers. Transmission charges range from around 2 per cent



#### Figure 9.9

#### Indicative pipeline tariffs to major centres

Note: Distances are indicative.

272

Source: EnergyQuest, Energy Quarterly, August 2009.

21 Interruptible services are provided intermittently, depending on available pipeline capacity.

22 NERA, The gas supply chain in eastern Australia, Sydney, June 2007, pp. 42 and 52. Chapter 8 of this report discusses backhaul arrangements.

23 The report is available on the AER website, www.aer.gov.au.

of delivered gas prices in Adelaide and Melbourne to 7 per cent in Perth. For larger industrial customers, this proportion rises steadily with scale because the fixed costs associated with downstream services are spread across larger gas supply volumes.

#### 9.6 Performance indicators

Performance data for the gas transmission sector are limited. Historically, performance reports have not been published for covered pipelines, although the Gas Law enables the AER to publish such reports in the future. Regulatory decisions on access arrangements include some historical data, as well as forward projections.

The financial data available on transmission pipelines comprise mainly financial forecasts in regulatory determinations for a small number of covered pipelines. The *State of the energy market 2008* report reproduces some of the limited available data.<sup>24</sup> There has been little historical reporting of service quality outcomes.

As noted, the owners of non-covered pipelines are not required to report publicly on historical performance or projected outcomes. The Gas Market Bulletin Board is increasing public information about transmission pipelines, including capacity and supply information. It covers most transmission pipelines in southern and eastern Australia, including non-covered pipelines.<sup>25</sup>

24 AER, State of the energy market 2008, Melbourne, 2008, section 9.6.

25 Section 8.7.2 of this report provides further information on the bulletin board.



# 10 GAS DISTRIBUTION



Natural gas distribution networks take gas from transmission pipelines and reticulate it into residential homes, offices, hospitals and businesses. Their main customers are energy retailers, which aggregate loads for sale to customers. For small gas customers, distribution charges for metering and transport often represent the most significant component—up to 60 per cent—of retail gas prices.

## 10 GAS DISTRIBUTION

This chapter considers:

- > Australia's gas distribution sector
- > the structure of the sector, including industry participants and ownership changes over time
- > the economic regulation of distribution networks
- > new investment in distribution networks
- > financial indicators and the service performance of the distribution sector.

#### 10.1 Role of distribution networks

A distribution network typically consists of high, medium and low pressure pipelines. The high and medium pressure mains provide a 'backbone' that services areas of high demand and transports gas between population concentrations within a distribution area. The low pressure pipes lead off the high pressure mains to end customers.

Gate stations (city gates) link transmission pipelines with distribution networks. The stations measure the natural gas entering a distribution system, for billing and gas balancing purposes. They also adjust the pressure of the gas before it enters the distribution network. Distributors can further adjust gas pressure at regulating stations in the network to ensure gas is delivered at a suitable pressure to operate customer equipment and appliances.

#### 10.2 Australia's distribution networks

The total length of Australia's gas distribution networks expanded from around 67 000 kilometres in 1997 to over 82 000 kilometres in 2009. The networks deliver over 370 petajoules of gas a year and have a combined valuation of almost \$8 billion. Investment to augment and expand the networks is forecast at around \$2 billion in the current access arrangement periods (typically five years). Table 10.1 provides summary details of the major networks.

#### Table 10.1 Australian natural gas distribution networks

DISTRIBUTION NETWORK	LOCATION	LENGTH OF MAINS (KM)	OPENING CAPITAL BASE (2008 \$ MILLION) <sup>1</sup>	INVESTMENT— CURRENT ACCESS ARRANGEMENT (2008 \$ MILLION) <sup>2</sup>	CURRENT REGULATORY PERIOD	OWNER
QUEENSLAND						
APT Allgas	South of the Brisbane River	2 605	362	141	1 July 2006 – 30 June 2011	APA Group
Envestra	Brisbane, Gladstone and Rockhampton	2 489	261	104	1 July 2006 – 30 June 2011	Envestra (APA Group 30.6%, Cheung Kong Infrastructure 18.5%)
NEW SOUTH WA	ALES AND THE ACT					
Jemena Gas Networks (NSW)	Sydney, Newcastle/ Central Coast, Wollongong and parts of country NSW	23 800	2 300	542	1 July 2005 – 30 June 2010	Jemena (Singapore Power International)
ActewAGL	ACT, Palerang (Bungendore) and Queanbeyan	3 604	266	66	1 July 2004 – 30 June 2010	ACTEW Corporation (ACT Govt) 50%; Jemena (Singapore Power International) 50%
Wagga Wagga	Wagga Wagga and surrounding areas	622	49	8	1 July 2005 – 30 June 2010	Country Energy (NSW Govt)
Central Ranges System	Tamworth	180	n/a	n/a	2006–19	APA Group
VICTORIA						
SP AusNet	Western Victoria	9 284	955	342	1 Jan 2008 – 31 Dec 2012	SP AusNet (listed company: Singapore Power International 51%)
Multinet	Melbourne's eastern and south eastern suburbs	9 585	888	232	1 Jan 2008 – 31 Dec 2012	DUET Group 79.9%, BBI 20.1%
Envestra	Melbourne, north eastern and central Victoria, and Albury– Wodonga region	9 603	859	411	1 Jan 2008 – 31 Dec 2012	Envestra (APA Group 30.6%, Cheung Kong Infrastructure 18.5%)
SOUTH AUSTRA	LIA					
Envestra	Adelaide and surrounds	7 477	942	213	1 July 2006 – 30 June 2011	Envestra (APA Group 30.6%, Cheung Kong Infrastructure 18.5%)
TASMANIA						
Tas Gas Networks	Hobart, Launceston and other towns	730	112 <sup>1</sup>	Not regulated	Not regulated	Tas Gas (BBI)
WESTERN AUST	RALIA					
WA Gas Networks	Mid-west and south western regions	12 176	749	163	1 Jan 2005 – 31 Dec 2009	BBI 74.1%, DUET Group 25.9% Operated by WestNet Energy (owned by BBI)
National totals <sup>3</sup>		82 155	7 743	2 222		

BBI, Babcock & Brown Infrastructure. n/a, not available.

1. For Tasmania, the opening capital base value is an estimated construction cost. For other networks, the opening capital base is the initial capital base, adjusted for additions and deletions, as reset at the beginning of the current access arrangement period. All data are converted to June 2008 dollars.

2. Investment data are forecasts for the current access arrangement period, adjusted to June 2008 dollars.

3. National totals exclude the Northern Territory.

Sources: Access arrangements for covered pipelines; company websites.







Notes:

Locations of the distribution systems are indicative only. Some corporate names have been abbreviated.

278 STATE OF THE ENERGY MARKET 2009

#### Figure 10.2

Gas distribution network ownership

	NETWORK	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	
P	APT Allgas					(	ld Gov	ernmen	ernment						APA Group			
a	Envestra		Boral					Envestra										
ᄝᆫ	Jemena						A	AGL AI							Alinta Singapore Power			
V an ACT	Wagga Wagga						Co	Country Energy (NSW Government)										
NSV the	ActewAGL		AGL					ActewAGL (ACT Government, AGL)							) ACT Govt, SIngap Power			
	SP AusNet	GasC	or (Vict	orian	We	star	ar TXU				SP AusNe				et (SPI 51%)			
Vic	Multinet Government)	nt)	Mul	tinet	t AMP and Utilicorp				DUET (79.9%), Alinta (20.1%)				DUET (80%), BBI (20%)					
	Envestra				Stra	atus		Envestra										
SA	Envestra		Boral					Envestra										
Tas	Tas Gas Networks								Powerco Babo					cock & Brown Infrastructure				
L L	NT Gas		An	nadeus	Gas Tru	ust		Amadeus Gas Trust (96% APA Group)										
WA	WA Gas Networks	SECWA AlintaGas (WA Govt)					WAGH (45%) Alinta (74%), DUET					(26%)	9%) BBI (74%), DUET (26%)					

BBI, Babcock & Brown Infrastructure; SECWA, State Energy Commission of Western Australia; WAGH, WA Gas Holdings.

Note: Some corporate names have been abbreviated or shortened. Some minor networks are not shown.

Figure 10.1 shows the locations of the major networks. New networks have been rolled out in north western New South Wales (Central Ranges) and Tasmania following construction of transmission pipelines in these regions. Natural gas is now reticulated to most Australian capital cities, major regional areas and towns.

#### 10.3 Ownership of distribution networks

The major gas distribution networks in Australia are privately owned. South Australia, Victoria, Western Australia and Queensland privatised their state owned networks in 1993, 1997, 2000 and 2006 respectively. The principal New South Wales network and the new Tasmanian network have always been in private hands.<sup>1</sup> AGL developed the Australian Capital Territory (ACT) network, but in 2000 formed a joint venture with the government owned Actew Corporation.

Structural reform and capital market drivers have led to specialist network businesses acquiring most gas distribution assets. Figure 10.2 shows key ownership changes since 1994. By 2008 ownership consolidation had reduced the number of principal players to four:

- Singapore Power International owns the principal New South Wales gas distribution network (Jemena Gas Networks). It has a 51 per cent share in the Victorian network (SP AusNet) and a 50 per cent share of the ACT network (ActewAGL). In August 2008 Singapore Power International rebranded its directly owned distribution entities as Jemena.
- *Envestra*, a public company in which APA Group (31 per cent) and Cheung Kong Infrastructure (19 per cent) have shareholdings, owns networks in Victoria, South Australia, Queensland and the Northern Territory.
- > Babcock & Brown Infrastructure owns the Tasmanian distribution network and is the majority owner of the WA Gas Networks.
- > APA Group owns the APT Allgas networks in Queensland and has a 31 per cent stake in Envestra.

1 There are remnants of state owned networks in rural New South Wales (the Wagga Wagga network owned by Country Energy) and Queensland (the Roma network owned by the Roma Regional Council and the Dalby network owned by the Dalby Regional Council).
In addition, DUET Group is the majority owner of Victoria's Multinet network and a minority owner of WA Gas Networks.<sup>2</sup> It contracts out the operation of these networks.

There are significant ownership links between gas distribution and other energy networks. In particular, Singapore Power International, Babcock & Brown Infrastructure and APA Group own and/or operate gas transmission pipelines. In addition, Singapore Power International, APA Group, Cheung Kong Infrastructure and DUET Group all have ownership interests—in some cases, substantial interests—in the electricity network sector (see chapters 5, 6 and 9).

# 10.4 Regulation of distribution networks

Gas distribution networks are capital intensive and incur declining marginal costs as output increases. This gives rise to a natural monopoly industry structure. In Australia, most networks are regulated to ensure energy retailers and other parties can transport gas on reasonable terms and conditions.

The National Gas Law (Gas Law) and National Gas Rules (Gas Rules) provide the overarching regulatory framework for the gas distribution sector. The Gas Law and Gas Rules commenced on 1 July 2008 in all states and territories except Western Australia, which expects to implement the pipeline access provisions in the second half of 2009. These instruments replace the Gas Pipelines Access Law and the National Gas Code, which had provided the regulatory framework from 1997.

The regulation of distribution networks in southern and eastern Australia transferred from state and territory agencies to the Australian Energy Regulator (AER) on 1 July 2008. The AER is working closely with jurisdictional regulators and network businesses to maintain regulatory certainty in the transition from state based to national regulation. In Western Australia, the Economic Regulation Authority continues to regulate gas distribution services.

# 10.4.1 Which networks are regulated?

The Gas Law includes a coverage mechanism to determine which pipelines are subject to economic regulation. At July 2009 the Gas Law covered 12 distribution networks, including all major networks in New South Wales, Victoria, Queensland, Western Australia, South Australia and the ACT. The recently constructed Tasmanian distribution network is the only major unregulated network. In addition, a number of small regional networks are not covered.<sup>3</sup>

# 10.4.2 Regulatory framework

In Australia, the providers of gas distribution services negotiate contracts to sell pipeline services to customers such as energy retailers. The contracts, which set the terms and conditions of network access, are negotiated on commercial terms that may differ from those that may be set through regulatory processes.

There are different forms of economic regulation for covered pipelines, based on criteria set out in the Gas Law.<sup>4</sup> Currently, most Australia distribution networks are subject to full regulation, which requires the service provider to submit an access arrangement to the regulator for approval.<sup>5</sup> An access arrangement sets out terms and conditions for third parties to use a pipeline. It must specify at least one reference service that most customers commonly seek, and a reference tariff for that service.

<sup>2</sup> DUET Group comprises a number of trusts, for which Macquarie Bank and AMP Capital Holdings own the responsible entities.

<sup>3</sup> A party may seek a change in the coverage status of a pipeline by applying to the coverage body, which is the National Competition Council. At present, the non-covered networks include the South West Slopes and Temora extensions of the NSW Gas Network; the Dalby and Roma town systems in Queensland; the Alice Springs network in the Northern Territory; and the Mildura system in Victoria.

<sup>4</sup> The AER published an *Access arrangement guideline* in March 2009, which sets out the forms of regulation (see part 2). The guideline is available on the AER website at www.aer.gov.au.

<sup>5</sup> The service provider may be the controller, owner or operator of the whole pipeline or any part of the pipeline.

A reference tariff may apply to one or more of the reference services offered to different groups of customers, and might cover capacity reservation (managed capacity services), volume (throughput services), peak, off-peak and metering (data) services. A network may also provide non-reference services, for which the AER does not approve the terms and conditions of access.

An access arrangement must also set out non-price terms and conditions, such as capacity expansion policies, queuing requirements and gas quality specifications.<sup>6</sup> More generally, an access arrangement must comply with the provisions of the Gas Law, including pricing principles, ring-fencing requirements and provisions for associate contracts. In the event of a dispute, an access seeker may request the regulator to arbitrate and enforce the terms and conditions of the access arrangement.<sup>7</sup> The AER has published a guideline on dispute resolution under the Gas Law.<sup>8</sup>

In some instances, a distribution pipeline may be subject to light regulation, in which the service provider is obliged to publish the terms and conditions of access on its website. While there are currently no light regulation distribution networks, the Gas Law establishes a process that may allow a distribution pipeline to convert to this form of regulation. However, light regulation may not apply to the Victorian and South Australian distribution pipelines listed in table 10.1.

# 10.4.3 Regulatory process

For a pipeline subject to full regulation, the Gas Law requires the network provider to submit an initial access arrangement to the regulator and revise it periodically. The revisions generally occur once every five years as scheduled reviews, but can occur more frequently—for example, if a trigger event compels an earlier review or the service provider seeks a variation to the access arrangement.

The Gas Rules prescribe the process and timeframe for an access arrangement review.9 A provider may consult with the AER to help develop a complete and well framed proposal. The AER recommends that this consultation process would ideally commence about six months before the scheduled submission date. Once a provider has submitted its access arrangement, the AER has six months to decide whether to approve the proposal. The review process allows time for stakeholder consultation and the engagement of specialist consultants. The consultation and information gathering processes 'stop the clock' and do not count towards the six month decision making time. This means the review process generally takes about nine to 12 months to complete. The decision making timeframe can be extended a further two months, with an absolute time limit of 13 months for a decision to be made.<sup>10</sup>

An AER decision on an access arrangements is subject to merits review by the Australian Competition Tribunal and judicial review by the Federal Court of Australia.

- 7 In Western Australia, a separate arbitrator hears access disputes.
- 8 AER, Guideline for the resolution of distribution and transmission pipeline access disputes under the National Gas Law and National Gas Rules, final, Melbourne, November 2008.
- 9 The AER published an Access arrangement guideline in March 2009, which sets out these processes. The guideline is available on the AER website at www.aer.gov.au.
- 10 The regulatory process in Western Australia is undertaken by the Economic Regulation Authority.

<sup>6</sup> For further information on non-price matters, see AER, Access arrangement guideline, final, Melbourne, March 2009, at s.5.4.1.



Figure 10.3 Indicative decision making timelines

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

Figure 10.3 shows indicative timeframes for the networks. The AER's first access arrangement review in gas distribution will set prices and other access terms and conditions from July 2010 for covered networks in New South Wales and the ACT. ActewAGL and Country Energy submitted their access arrangement revisions on 30 June 2009 and 1 July 2009 respectively. Jemena submitted its access arrangement revisions on 25 August 2009.

The AER will begin its next scheduled reviews—for the South Australian and Queensland networks—in the fourth quarter of 2010.<sup>11</sup>

# 10.4.4 Regulatory approach

The Gas Rules require the use of a building block approach to determine total revenues and derive tariffs. A number of alternatives are permitted for applying this approach (see section 9.3.4 of this report). Total revenue must be sufficient to allow a business to recover efficient costs, including depreciation and an appropriate return on capital. The Gas Rules also allow for income adjustments from incentive mechanisms that reward efficient operating practices. Once total revenue is determined, revenue is allocated to services provided by the distribution pipeline to establish reference tariffs. The tariffs are typically adjusted annually for inflation and other approved factors.<sup>12</sup>

In approving a reference tariff, the AER must have regard to the costs of a prudent and efficient service provider of a pipeline service. In doing so, it will consider the circumstances in which a pipeline operates and draw on expert assessments, submissions from interested parties, benchmarking, the operation of efficiency mechanisms and key performance indicator information.

Figure 10.4 shows the revenue components of SP AusNet's current access arrangement in Victoria. It illustrates the relative importance of the building block components in a typical reference tariff determination. Depreciation and return on capital account for around two thirds of the revenue. Operating and maintenance costs, tax and incentive mechanism payments account for the balance.

<sup>11</sup> APT Allgas is due to lodge access arrangement revisions for its Queensland distribution network on 30 September 2010. Envestra is due to lodge revisions for its Queensland and South Australian networks on 1 October 2010.

<sup>12</sup> For further information on reference tariffs, see AER, Access arrangement guideline, final, Melbourne, March 2009, at s.5.4.2.

### Figure 10.4

Revenue components for Victoria's SP AusNet gas network, 2008–12



Source: ESC, Gas access arrangement review 2008-2012: further final decision, Melbourne, 2008, p. 37.

# 10.5 Investment in distribution networks

Investment in gas distribution typically involves capital works to upgrade and expand the capacity of existing networks and extend the networks into new residential and commercial developments, regional centres and towns. While most major centres already have a distribution network in place, new networks have recently been constructed—for example, the Central Ranges (New South Wales) and Tasmanian networks.

Stay-in-business investment tends to be a relatively stable proportion of the capital base for most networks. However, investment that is program specific—such as meter replacement and major network refurbishment may have 'lumpy' investment profiles. In addition, a network's configuration may include high pressure or trunk pipelines that require significant upfront capital investment and additions over time, giving rise to 'lumpy' investment characteristics similar to those of transmission pipelines. The cost of distribution investment depends on a range of factors, including:

- > the distance of new infrastructure from access points on gas transmission lines or gas distribution mains
- > the density of housing and the presence of other industrial and commercial customers in the area.

Figure 10.5 shows the opening capital bases and forecast investment over the current access arrangement period (typically five years) for the major networks. Figure 10.6 shows annual investment (in June 2008 dollars) in each network, based on actual data where available and forecast data for other years. The forecast data relate to proposed investment that the regulator has approved as efficient. The data are smoothed over the forecast period to remove the significant volatility often evident in annual forecast data. Figure 10.6 excludes Tasmanian's unregulated network, for which data are not available.

Investment in gas distribution networks has grown steadily in recent years:

- > Investment was forecast at around \$440 million in 2008–09, and grew on average by around 8 per cent annually over the preceding five years.
- > Over the longer term, real investment of around \$2 billion is forecast during the current access arrangement periods for the major networks. This represents both substantial real investment in new infrastructure as well as rising resource costs in the construction sector.
- > Investment in current access arrangements is running at around 25 per cent of the underlying capital base for most networks, but around 35 per cent for SP AusNet (Victoria) and 40–50 per cent for Envestra (Victoria) and the Queensland networks.
- > The combined Victorian networks attract significantly higher investment than does New South Wales, partly reflecting the penetration of natural gas as a major heating source in Victoria. More generally, different outcomes across jurisdictions reflect a range of variables, including development activity, incentives or policies that encourage gas supply, market conditions, and investment drivers such as the scale and age of the networks.



Figure 10.5 Gas distribution capital and investment—current regulatory period

The valuation for each pipeline is the capital base published in a regulator approved access arrangement.

Investment data represent forecast capital expenditure over the current access arrangement regulatory period (see table 10.1).

All estimates are converted to June 2008 dollars.

Sources: Access arrangements approved by the ESC (Victoria), IPART (New South Wales), the QCA (Queensland), ESCOSA (South Australia), the ERA (Western Australia) and the ICRC (ACT).

- > Investment is forecast to rise strongly in the next few years in Queensland, South Australia and Victoria. Current access arrangement decisions for these jurisdictions reflect a significant step-increase in forecast investment.
- > Looking forward, the introduction of carbon emission reduction policies may further accelerate the development of natural gas as an energy source, and influence investment.
- > The investment data mostly reflect the incremental expansion of existing networks—for example, Envestra began a \$3.7 million project in 2005 to upgrade and extend its Queensland network.
   The construction of new transmission pipelines also provides opportunities to develop new distribution networks—for example, the Tasmanian distribution network has been rolled out in major cities and towns following the construction of a transmission pipeline from Victoria to Tasmania.

# 10.6 Operating and maintenance costs

Financial performance reporting for gas networks has generally been less comprehensive than for electricity networks. Only Victoria and South Australia have tended to publish regular financial performance reports on the networks. The reporting arrangements may undergo changes with the shift to national regulation.

Regulatory decisions on access arrangements consider forecasts of a range of financial indicators, including revenues, operating and maintenance costs and returns on capital. Figure 10.7 compares forecast operating and maintenance expenditure for the networks on a per kilometre basis and on a per customer basis for 2008–09. The chart indicates that most networks have expenses ranging from about \$4000 to \$8000 per kilometre of network line length, or \$70–170 per customer. Differences may arise for a number of reasons, including the age and condition of the networks and geographic factors.

Figure 10.6 Gas distribution network investment



Actual investment outcomes (unbroken lines) used where available. Broken lines are forecast data from approved access arrangements, averaged over the forecast period.

All data converted to June 2008 dollars.

Sources: Access arrangements and network performance reports published by the ESC (Victoria), IPART (New South Wales), the QCA (Queensland), ESCOSA (South Australia), the ERA (Western Australia) and the ICRC (ACT).

285

CHAPTER 10

DISTRIBUTION

### Figure 10.7



Operating and maintenance expenditure per kilometre of pipeline and per customer—gas distribution networks, 2008–09

Notes:

Forecast data, converted to 2008 dollars.

Victorian data are for the 2008 calendar year

Sources: Access arrangements approved by the ESC (Victoria), IPART (New South Wales), the QCA (Queensland), ESCOSA (South Australia), the ERA (Western Australia) and the ICRC (ACT).

Network-specific characteristics mean benchmarking or comparison across different networks has limitations. Comparisons on a per kilometre basis, for example, will be affected by the density of customers and the length of a pipeline network. Conversely, metrics based on customer numbers will vary between networks with large and small customer bases. There are generally very different metrics between networks in rural and city locations.

# 10.7 Quality of service

Quality of service monitoring for gas distribution services typically relates to:

- > the reliability of the gas supply (the provision of a continuous gas supply to customers)
- > network integrity (gas leaks, the effectiveness of operational and maintenance activities)
- > customer service (responsiveness to issues such as complaints and reported gas leaks).

While the Steering Committee on National Regulatory Reporting Requirements<sup>13</sup> established national reporting indicators on service quality for electricity distribution and energy retailing, no equivalent indicators were developed for gas distribution. Instead, jurisdictions have applied locally determined service standards and reporting arrangements. Some technical and service standards are connected with jurisdictional licensing and safety requirements.

In general, the monitoring and reporting of service quality have been less comprehensive in the natural gas sector than for electricity. The disparity reflects:

- > different approaches to reporting across jurisdictions
- > a lesser reliance on gas than electricity as an energy source for most customers
- > technical characteristics inherent to gas distribution.

13 The Steering Committee on National Regulatory Reporting Requirements is a working group established by the Utility Regulators Forum.

Most jurisdictions publish (or have published) annual service performance reports on gas distribution networks. The reports reflect the dual roles of some jurisdictional agencies as technical and (until 2008) economic regulators. In New South Wales, the Department of Water and Energy publishes the data; in South Australia, Western Australia, Tasmania and the ACT, jurisdictional regulators report on this area. Jurisdictional reporting arrangements may evolve over time with the shift to national regulation. The Queensland Competition Authority ceased performance reporting on gas distribution in 2007. Victoria's Essential Services Commission ceased performance reporting in this area in 2008.

The data in this section are provided for information purposes, and not for making performance comparisons across the networks. As noted, performance monitoring in gas distribution is less evolved than for electricity, and the absence of a uniform national reporting framework can lead to fundamental differences in definitions, measurement and auditing systems. Differences in network age, size, design and historical investment can also have significant effects on measured performance.

# 10.7.1 Reliability of supply

The reliability of gas supply refers to the continuity of supply to customers. Most jurisdictions impose reliability requirements on gas distributors as part of their licence conditions, and publish (or have published) performance data in this area. In some cases, jurisdictions impose statutory obligations on network operators and owners that relate to the continuity of gas supply.

From a reliability perspective, the inherent storage capacity of gas distribution networks can help maintain continuous gas flow to most customers despite a disruption to part of the network. In addition, gas pipes are predominantly buried underground and—unlike electricity networks—are generally not affected by bad weather. In the case of planned renewals—or unplanned incidents such as gas explosions, third party damage, water entering the mains, or directions from the technical regulator—customers in the vicinity of the incident (or those affected by a direction of the regulator) may experience a loss of gas flow.

The generally high rates of network reliability mean a single incident can significantly affect data for a particular year. In particular, there may be significant short term variations in measured performance that result from factors beyond the control of the network providers. When considering network reliability, therefore, it is appropriate to focus on trends over time.

Jurisdictions publish a range of reliability indicators on gas distribution. Some jurisdictions publish reliability indicators similar to those applied in electricity distribution—for example, the average minutes without supply per customer per year (system average interruption duration index, SAIDI). Figure 10.8 sets out time series SAIDI data (unplanned interruptions) for Queensland, New South Wales, Victoria and the ACT. Differences in the jurisdictions' approaches limit the validity of comparisons. Queensland, New South Wales and the ACT account for only unplanned interruptions affecting five or more customers; the Victorian data cover all unplanned interruptions.

The data indicate that an average customer in Victoria and New South Wales is likely to experience gas supply interruptions of less than 3 minutes per year. There is a general trend of improvement in both jurisdictions. Customers in the ACT have experienced negligible supply losses. The Queensland networks generally recorded interruptions of less than 1 minute per customer, in the years for which data are available. Western Australia began publishing SAIDI data in 2009 and reported an average supply loss per customer of 26.8 minutes for WA Gas Networks in 2007-08. Tasmania also reports SAIDI data for its new distribution network, but has cautioned against performance comparisons with mainland jurisdictions until the state's natural gas market becomes more established.



Figure 10.8 Average unplanned gas supply loss per customer per year

NSW and ACT data include only unplanned interruptions affecting five or more customers. Victorian data include all unplanned interruptions. Victoria data are for the calendar year ending in that period. Queensland did not publish 2007-08 data. NSW and ACT data are AER estimates derived from official jurisdictional sources. NSW data are statewide across all networks.

Sources: Network performance reports published by the QCA (Queensland), the Department of Water and Energy (New South Wales), the ESC (Victoria) and the ICRC (ACT).

Another widely used reliability indicator is the number of significant unplanned supply interruptions (affecting five or more customers). Figure 10.9 sets out time series data for Queensland, New South Wales, Victoria and South Australia. Possible variations in underlying definitions limit the validity of comparisons across jurisdictions and networks. In addition, the data have not been normalised to account for differences in network scale or load. The chart does, however, indicate trends in the reliability of particular networks:

- > In Victoria, the number of significant unplanned interruptions has ranged from 45 to 83 events per year since 2001 across the three distribution networks. The Essential Services Commission reported in 2008 a deteriorating statewide trend since 2000, but no apparent major issues with distributors' asset management practices. On average, Victorian customers would expect an unplanned gas outage once every 83 years.<sup>14</sup>
- South Australia's Envestra network recorded
  13 significant unplanned interruptions in 2007-08 (compared with seven events in the previous year). The Essential Services Commission of South Australia (ESCOSA) reported in 2008 that the number of unplanned interruptions had increased in recent years, citing more intensive measurement practices, and an increase in third party damage resulting from civil and construction activity.<sup>15</sup>
- > New South Wales recorded around 54 significant unplanned interruptions across all networks in 2007-08 (compared with 88 the previous year). The number of significant supply interruptions has declined sharply since 2004-05. The New South Wales Department of Water and Energy considered that reduced third party contact with network infrastructure might have contributed to this improvement.<sup>16</sup>
- > Queensland recorded relatively few supply interruptions in the years for which data are available.

<sup>14</sup> ESC, Gas distribution businesses: comparative performance report 2007, Melbourne, 2008, pp. 14, 19, 20.

<sup>15</sup> ESCOSA, 2007-08 Annual performance report: South Australian energy networks, Adelaide, 2008, p. 86.

<sup>16</sup> DEUS, NSW gas networks: performance report 2007-08, Sydney, 2008, pp. 13-15. Data are AER estimates derived from the DEUS report.



Figure 10.9 Significant unplanned interruptions in gas supply

### Data cover unplanned interruptions affecting five or more customers.

Victorian data are for the calendar year ending in that period. Queensland did not publish 2007-08 data.

NSW and ACT data are AER estimates derived from official jurisdictional sources. NSW data are statewide across all networks.

Sources: Network performance reports published by the QCA (Queensland), the Department of Water and Energy (New South Wales), the ESC (Victoria) and ESCOSA (South Australia).

# 10.7.2 Network integrity

Network integrity issues relate to the quality of network infrastructure and associated maintenance practices. Indicators of network integrity include the frequency of gas leaks and repairs, and the amount of unaccounted-for gas. Australian laws require odorant to be added to gas that enters a distribution system. The odorant makes leaks easier to detect. It is usually added at the gate station.

New South Wales, Victoria, Western Australia and the ACT publish data on gas leaks, but the indicators differ across jurisdictions. Some indicators focus on gas leaks reported by the public, while others focus on leaks detected via network surveys. Some indicators focus on total leaks, while others focus on repaired or unrepaired leaks. The range of approaches makes it difficult to compare outcomes between networks in different jurisdictions. Unaccounted-for gas refers to the difference between the amount of gas injected into a distribution network and the amount of gas delivered to customers. Losses can occur for a number of reasons, including gas leaks, meter reading errors and theft. New South Wales, South Australia, Western Australia and Tasmania report annually on loss data; Queensland ceased publishing the data in 2007. Figure 10.10 sets out the available data from 2003–04. It indicates that up to 7 per cent of gas injected into a distribution network cannot be accounted for. ESCOSA has reported that about 80 per cent of unaccounted-for gas relates to leaks.<sup>17</sup>

The New South Wales Department of Water and Energy considered the performance of the state's distribution networks in 2007–08 to be sound in this area.<sup>18</sup> ESCOSA's 2007–08 performance report noted the proportion of unaccounted-for gas in Envestra's South Australian network is around 6.4 per cent

17 ESCOSA, 2007-08 Annual performance report: South Australian energy networks, Adelaide, 2008, p. e.

18 Department of Water and Energy (NSW), NSW gas networks: performance report 2007-08, Sydney, 2008, p. 8

Figure 10.10 Unaccounted-for gas



ACT data are AER estimates derived from official jurisdictional sources.

Queensland did not publish 2007-08 data.

NSW data are statewide across all networks.

Sources: Network performance reports published by the QCA (Queensland), the Department of Water and Energy (New South Wales), ESCOSA (South Australia), the ERA (Western Australia), OTTER (Tasmania) and the ICRC (ACT).

(adjusting for gas delivered through high pressure farm taps that do not leak). ESCOSA considered that a deterioration in the network's unprotected steel and cast iron mains may be contributing to the state's high rate of unaccounted-for gas.<sup>19</sup>

Conversely, the low rate of unaccounted-for gas in Tasmania may reflect the distribution network being relatively new and embodying more recent technology than that of some other networks.

# 10.7.3 Customer service

The level of customer service achieved by a distributor can be measured in terms of timeliness and responsiveness across a range of customer interactions, including customer calls, the arrangement of new connections, the keeping of appointments, and the number and nature of complaints about service providers. New South Wales, Victoria, South Australia, Western Australia, Tasmania and the ACT report annually on at least one customer service indicator. Queensland ceased publication of these data in 2007. The use of different indicators across jurisdictions, combined with differences in measurement and auditing systems, makes it difficult to compare outcomes across jurisdictions.

In addition to performance reporting, distributors in Victoria and Western Australia must meet guaranteed service levels or pay penalties for breaches. Figure 10.11 shows trends in the number of payments for the Victorian networks. The data distinguish between the reasons that distributors were obliged to make the payments. Distributors made 444 payments in 2007 worth almost \$43 000—an increase of 45 per cent over the previous year's payments. The most significant increase related to lengthy supply interruptions not restored within 12 hours.<sup>20</sup>

19 ESCOSA, 2007-08 Annual performance report: South Australian energy networks, Adelaide, 2008, p. 82.

<sup>20</sup> ESC, Gas distribution businesses: comparative performance report 2007, Melbourne, 2008, p. 26.



Figure 10.11 Guaranteed service level payments by gas distributors, Victoria

Source: ESC, Gas distribution businesses: comparative performance report 2007, Melbourne, 2008.

CHAPTER 10 GAS DISTRIBUTION





The retail market is the final link in the natural gas supply chain. It provides the main interface between the gas industry and customers such as households and small business. Retailers enter into contracts with gas producers and pipeline operators, and package an aggregated service for sale to customers. Because retailers deal directly with customers, the services they provide significantly affect perceptions of the performance of the gas industry.

# 11 GAS RETAIL

This chapter provides a survey of natural gas retail markets. It covers:

- > the structure of the retail market, including industry participants and trends towards vertical integration
- > the development of retail competition
- > retail market outcomes, including price, affordability and service quality.

State and territory governments are currently responsible for the regulation of retail energy markets. Governments agreed in 2004, however, to transfer non-price regulatory functions to a national framework for the Australian Energy Market Commission (AEMC) and the Australian Energy Regulator (AER) to administer.<sup>1</sup> The Ministerial Council on Energy (MCE) has scheduled the regulatory package to be introduced to the South Australian parliament in 2010.<sup>2</sup> Retail customers include residential, business and industrial gas customers. This chapter focuses on the retailing of natural gas to small customers,<sup>3</sup> including households and small business customers. Many energy retailers are active in both gas and electricity markets, and offer dual fuel products. This chapter should thus be read in conjunction with chapter 7, 'Electricity retail'.

While this chapter reports data that may enable performance comparisons across retailers and jurisdictions, such analysis should note that a variety of factors can affect relative performance.

1 This commitment does not cover regulatory arrangements for gas and electricity retail in Western Australia or electricity retail in the Northern Territory.

294

<sup>2</sup> Sections 11.6 and 7.7 (in chapter 7) provide an update on future regulatory arrangements.

<sup>3</sup> Small customers are those using less than 1 terajoule of gas a year.

### Figure 11.1 Introduction of full retail contestability



FRC, full retail contestability.

# 11.1 Retail market structure

Historically, natural gas retailers in Australia were integrated with gas distributors and operated as monopoly providers in their state or region. In the 1990s governments began to reform the industry through restructuring, privatisation and the introduction of competition.

South Australia (in 1993), Victoria (in the late 1990s), Western Australia (in 2000) and Queensland (in 2007) have privatised their state owned gas retailers.<sup>4</sup> While New South Wales has some government ownership, its gas retail sector has always been mainly in private hands.<sup>5</sup> The Australian Capital Territory (ACT) Government operates a joint venture with the private sector to provide gas retail services. Before the formation of the joint venture in 2000, the ACT gas retailer was privately owned. In Tasmania, one of the two active retailers in the state's relatively new gas retail sector is state owned.

All state and territory governments have introduced full retail contestability (FRC) for gas customers, meaning all customers can enter a supply contract with a retailer of choice (figure 11.1). Most governments chose to phase in retail contestability by introducing competition for large industrial customers, followed by small industrial customers and, finally, small business and household customers.

The retail players in most jurisdictions include:

- > one or more 'host' retailers, that are subject to additional regulatory obligations
- > new entrants, including new players in the gas retail sector, established interstate gas retailers, and electricity retailers branching into gas retailing.

Table 11.1 lists licensed gas retailers that are active in the market for residential and small business customers. Active retailers are those that offer supply contracts to new small customers. Privately owned retailers are the major players in most jurisdictions:

In the eastern states, the largest retailers are AGL Energy, Origin Energy and TRUenergy. Each has significant market share in Victoria and South Australia. AGL Energy is the largest gas retailer in New South Wales and jointly owns (with the ACT Government) the largest ACT retailer. AGL Energy acquired significant market share in Queensland via the 2006–07 privatisation process, while Origin Energy was already an established retailer in that state.

4 Local councils in Dalby and Roma (Queensland) operate distribution and retail services in their local areas.

<sup>5</sup> The New South Wales Government owns EnergyAustralia and Country Energy.

RETAILER <sup>1</sup>	OWNERSHIP	QLD	NSW	VIC	SA	WA	TAS <sup>2</sup>	ACT
ActewAGL Retail	ACT Government and AGL Energy							
AGL Energy	AGL Energy							
Alinta	Babcock & Brown Power							
Aurora Energy	Tasmanian Government							
Australian Power & Gas	Australian Power & Gas							
Country Energy	NSW Government							
EnergyAustralia	NSW Government							
Origin Energy	Origin Energy							
Red Energy	Snowy Hydro <sup>3</sup>							
Simply Energy	International Power							
Tas Gas Retail (formerly Option One)	Babcock & Brown Infrastructure							
TRUenergy	CLP Group							
Victoria Electricity	Infratil							
Active retailers		2	6	7	4	1	2	2
Approx. market size ('000 000 customers) <sup>4</sup>		0.15	1.19	1.68	0.37	0.58	0.005	0.09

Table 11.1 Active gas retailers—small customer market, June 2009

Host (incumbent) retailer New entrant retailer

1. Not all licensed retailers are listed. Some of the retailers listed offer gas services only as part of a gas and electricity contract. The list excludes three small retailers (BRW Power Generation (Esperance), Dalby Town Council and Roma Town Council).

2. There is no host retailer in Tasmania because gas distribution and retail services have been available only for a short time and FRC existed from market start.

3. Snowy Hydro is owned by the New South Wales Government (58 per cent), the Victorian Government (29 per cent) and the Australian Government (13 per cent).

4. Customer numbers in Queensland, New South Wales and the ACT are estimates based on the number of distribution connection points.

Sources: Jurisdictional regulator websites; ESAA, *Electricity gas Australia 2008*, Melbourne, 2008; updated by information on retailer websites and other public sources.

- > In Western Australia, Alinta (owned by Babcock & Brown Power) is the largest retailer and the only retailer licensed to retail to customers consuming less than 0.18 terajoules a year on the main distribution systems.
- > Various niche players are active in most jurisdictions.

The following survey (sections 11.1.1–11.1.8) provides background on developments in each jurisdiction.

# 11.1.1 Queensland

At June 2009 Queensland had seven licensed retailers, of which two were active in the residential and small business market—namely, the host retailers, AGL Energy (previously Sun Gas Retail)<sup>6</sup> and Origin Energy. In addition, the local councils in Dalby and Roma provide gas services in their local government areas. In June 2008 Australian Power & Gas withdrew from actively retailing in the gas retail market because it could no longer viably compete for gas customers.<sup>7</sup> EnergyAustralia obtained a retail licence in July 2007, as did Dodo Power & Gas in January 2008, but neither were actively retailing to small customers in 2009.

6 AGL Energy acquired the government owned Sun Gas Retail in 2006.

7 QCA (Queensland), Final report-review of small customer gas pricing and competition in Queensland, Brisbane, November 2008, p. 22.

In a review of small customer gas pricing and competition, the Queensland Competition Authority (QCA) found prices in the small customer gas retail market are not cost-reflective, and the lack of a sufficient retail margin reduces the incentive for new retailers to enter the market.8 The QCA noted in its final determination that the residential gas retail market in Queensland at June 2008 was almost evenly split between the two host retailers.9

# 11.1.2 New South Wales

At June 2009 New South Wales had 13 licensed retailers, of which six were active in the residential and small business market:

- > the host retailers—AGL Energy, Country Energy, Origin Energy and ActewAGL Retail
- > two new entrants-electricity retailer EnergyAustralia and established interstate retailer TRUenergy.

Integral Energy and Jackgreen held retail licences in June 2009 but were not actively marketing to small customers.

# 11.1.3 Victoria

At June 2009 Victoria had 12 retailers licensed to sell gas to residential and small business customers, of which seven retailers were active:

- > the host retailers in designated areas of Victoria-TRUenergy, AGL Energy and Origin Energy
- > four new players in the gas retail market—Australian Power & Gas, Red Energy, Simply Energy and Victoria Electricity.

Momentum Energy and Dodo Power & Gas held retail licences in June 2009 but were not actively marketing to small customers.

Table 11.2 and figure 11.2 set out the market share of Victorian retailers (by customer numbers) at 30 June 2008. The three host retailers (TRUenergy, AGL Energy and Origin Energy) accounted for about 86 per cent of the market, and each retailed beyond its 'local' area. While the market share of new entrants is small, new entrant penetration increased from 11 per cent of small customers in June 2007 to over 14 per cent in 2008.

### Table 11.2 Gas retail market share (small customers)— Victoria, 30 June 2008

RETAILER	CUSTOMERS							
	DOMESTIC (%)	BUSINESS (%)	TOTAL (%)					
Origin Energy	32.0	25.7	31.8					
AGL Energy	28.0	31.3	28.1					
TRUenergy	25.4	36.5	25.7					
Other	14.7	6.5	14.4					
Total customers (no.)	1 667 371	50 389	1 717 760					

CHAPTER 11

Source: ESC (Victoria), Energy retailers: comparative performance reportcustomer service 2007-08, Melbourne, December 2008, p. 5.

### Figure 11.2

### Gas retail market share (small customers)—Victoria



Note: Figures at top of columns are total small customer numbers.

Source: ESC (Victoria), Energy retailers: comparative performance reportcustomer service, Melbourne, various years.

QCA (Queensland), Final report-review of small customer gas pricing and competition in Queensland, Brisbane, November 2008, p. 46.

QCA (Queensland), Final report-review of small customer gas pricing and competition in Queensland, Brisbane, November 2008, p. 24.

# 11.1.4 South Australia

At May 2009 South Australia had 10 retailers licensed to sell gas to residential and small business customers, of which four retailers were active:

- > the host retailer—Origin Energy
- > three new entrants—South Australia's host retailer in electricity (AGL Energy), an established interstate retailer (TRUenergy) and Simply Energy (owned by International Power).

Country Energy, EnergyAustralia, Australian Power & Gas, Dodo Power & Gas, Momentum Energy and South Australian Electricity held retail licences but were not actively marketing to small customers in June 2009. Several of these businesses are active in the South Australian electricity retail market. Jackgreen no longer holds a gas retail licence.

Table 11.3 sets out the market share of South Australian retailers (by customer numbers) at June 2008. New entrants accounted for about 42 per cent of the small customer market, up from 40 per cent in 2007 and 30 per cent in 2006 (figure 11.3).

# 11.1.5 Western Australia

Although the Western Australian retail market is open to retail competition, Alinta is the only active retailer for customers using less than 0.18 terajoules of gas a year. In May 2007 Babcock & Brown Power acquired Alinta's Western Australian gas retail business.

The state's host retailer in electricity, Synergy, applied for a gas trading licence in April 2007 to sell gas to small customers. Restrictions imposed by the Western Australian Government, however, prevent Synergy from supplying gas to customers using less than 0.18 terajoules a year.<sup>10</sup>

### Table 11.3 Gas retail market share (small customers)— South Australia, 30 June 2008

RETAILER	CUSTOMERS							
	DOMESTIC (%)	BUSINESS (%)	TOTAL (%)					
Origin Energy	56.9	86.4	57.5					
AGL Energy	19.3	2.8	19.0					
TRUenergy	14.4	8.2	14.2					
Simply Energy	9.4	2.6	9.2					
Total customers (no.)	360 642	7 344	367 986					

Source: ESCOSA (South Australia), 2007-08 Annual performance report: performance of the South Australian energy retail market, Adelaide, November 2008, p. 70.

### Figure 11.3

### Gas retail market share (small customers)— South Australia



Note: Figures at top of columns are total small customer numbers.

Source: ESCOSA (South Australia), Annual performance report: performance of the South Australian energy retail market, Adelaide, various years.

10 ERA (Western Australia), Decision on gas trading licence application for Synergy (Electricity Retail Corporation), Perth, 26 June 2007.

# 11.1.6 Tasmania

At June 2009 Tasmania had two gas retailers active in the small customer market: the state owned Aurora Energy and Tas Gas Retail (formerly Option One, owned by Babcock & Brown Infrastructure). TRUenergy and Country Energy obtained retail licences in 2008 but were not actively marketing to small customers in June 2009.

# 11.1.7 Australian Capital Territory

At June 2009 the ACT had eight licensed retailers, of which two were active in the residential and small business market—namely, the host retailer (ActewAGL Retail) and one new entrant (interstate retailer TRUenergy). EnergyAustralia, Country Energy, Dodo Power & Gas, Australian Power & Gas, Sun Retail and Jackgreen held retail licences in June 2009 but were not actively marketing to small customers.

## 11.1.8 The Northern Territory

In the Northern Territory, gas is used mainly for electricity generation. NT Gas (owned by the APA Group) supplies a small quantity of gas to commercial and industrial customers in Darwin.

# 11.2 Trends in market integration

The energy retail sector has undergone considerable ownership consolidation, including:

- > retail market convergence between electricity and gas
- > vertical integration between gas production and gas retail.

Efficiencies in the joint provision of electricity and gas services have encouraged retailers to be active in both markets, and offer dual fuel retail products. Section 7.2.1 considers the convergence between the gas and electricity retail markets. There is a continuing trend towards vertical integration between privately owned gas retailers and gas producers. Investment in gas production provides gas retailers with a natural hedge against volatile wholesale gas prices and enhances security of supply. The retailers AGL Energy, Origin Energy and TRUenergy each have interests in gas production and/or gas storage. Origin Energy is a gas producer in Queensland, Western Australia, South Australia and Victoria. AGL Energy has become a producer of coal seam gas in Queensland and New South Wales. TRUenergy has gas storage facilities in Victoria. AGL Energy, Origin Energy and TRUenergy are also major electricity generators.

In addition, some ownership links exist between the gas pipeline and gas retail sectors. The retailers TRUenergy and Simply Energy (owned by International Power), for example, have ownership shares in the SEA Gas Pipeline from Victoria to South Australia.

# 11.3 Retail competition

While most jurisdictions have introduced FRC in gas, it can take time for a competitive market to develop. As a transitional measure, some jurisdictions require host retailers to supply under a regulated standing offer (or default) contract to all small customers without a market contract (see section 11.4.1). Standing offer contracts often cover minimum terms and conditions, and may include a regulated price that is subject to some form of cap or oversight. At July 2009 three jurisdictions—New South Wales, South Australia and Western Australia—applied some form of retail price regulation.

Australian governments have agreed to review the continued use of retail price caps and remove them where effective competition can be demonstrated.<sup>11</sup> The AEMC is assessing the effectiveness of retail competition in each jurisdiction to advise on the appropriate time to remove retail price caps.

### Box 11.1 Price and product diversity in the small customer market

The CHOICEswitch website (www.choiceswitch.com.au) provides an online estimator service that allows consumers to make quick comparisons of electricity and gas retail offers available in their area. The website also provides information on the terms, conditions and benefits of each offer.

Table 11.4 draws on data available on the CHOICEswitch website to set out the estimated price offerings in June 2009 for customers in selected suburban postcodes in Brisbane, Sydney, Melbourne and Adelaide using 60 gigajoules (GJ) of natural gas a year. The offers were only for the postcodes selected and might not have been available to all customers. The data include all financial discounts and bonuses available under each offer.

The data indicate some price diversity in the gas retail markets, although less than for electricity (see box 7.2 in chapter 7 of this report). Brisbane had the highest price spread of \$73 (compared with \$666 in electricity), while Melbourne and Sydney had the greatest number of retailers offering contracts to new small customers. Compared with electricity, there were limited bonuses available under each offer. Only products offered by TRUenergy attracted a discount for prompt payment. No offer included non-financial bonuses such as magazine subscriptions or movie tickets.

In Sydney and Adelaide, where retail gas prices are regulated, only TRUenergy offered products with a discount off the regulated price (of up to 6.9 per cent). Some offers with larger discounts were provided under fixed term contracts with exit fees for early termination.

The range of retailers and products increases if a customer accepts gas retail services as part of a 'dual fuel' retail product (covering both gas and electricity services). In Melbourne, for example, an additional four retailers offered gas retail services as part of a dual fuel product. Some dual fuel products also attracted larger discounts than those for standalone gas retail products.

RETAILER	NO. PRODU	OF JCTS			ANN	UAL COST (	INCLUDI	NG D	SCOUNT	'S AND FIN	IANCIAL	BONUSES	;]		DI: AND INC ANN	SCOUNTS D BONUSES CLUDED IN NUAL COST	CON <sup>-</sup> TE	TRACT RM
		800		90	0 10	000 11	00	1200	13	300 -	400	1500	1600	170	l O tir	Pay-on- ne bonus	Fixed term	Exit fee
BRISBANE (POSTCODE 4032)																		
AGL Energy	2											\$159	6	\$1	669	•	•	•
Origin Energy	2													\$1	669			
SYDNEY (POSTCODE 2148)																		
Regulated price (AGL Energy)									\$1206									
Energy Australia	1								\$1224									
Origin Energy	1								\$1206									
TRUenergy	2					\$113	5	<b>\$</b> 11	70							•	•	•
MELBOURNE (POSTCODE 307																		
AGL Energy	1			\$8	83													
Energy Australia	1		9	\$83 <mark>8</mark>														
Origin Energy	1				\$906													
TRUenergy	3	\$83 <mark></mark> 9			\$892											•	•	•
ADELAIDE (POSTCODE 5007)																		
Regulated price (Origin Energy	] 2							\$	51181									
TRUenergy	2					\$1100	\$	11 <mark>4</mark> 6								•	•	•

### Table 11.4 Gas retail price offers for a customer using 60 GJ per year in each capital city, June 2009

Note: The offers were only for standalone gas products in the postcodes selected and might not have been available to all customers. The data include all financial discounts and bonuses available under each offer.

Source: CHOICEswitch energy comparison website, viewed 9 June 2009, www.choiceswitch.com.au.



The relevant state or territory government makes the final decision on this matter. The AEMC reviewed the Victorian market in 2007. In response to the review, the Victorian Government removed retail price caps on 1 January 2009.

The AEMC also reviewed the South Australian market in 2008 and outlined options to phase out retail price regulation in that state. The South Australian Government decided in April 2009 not to accept the AEMC's recommendation to remove retail price controls.<sup>12</sup> Box 7.1 in chapter 7 provides further information on the AEMC reviews.

The following is a sample of public data that may be relevant for assessing the effectiveness of retail competition in Australia. The data show the diversity of price and product offerings of retailers; the exercise of market choice by customers, including switching behaviour; and customer perceptions of competition. Elsewhere, this chapter touches on other barometers of competition—for example, section 11.1 considers new entry in the gas retail market. The AER does not seek to draw conclusions from the information provided and does not attempt to assess the effectiveness of retail competition in any jurisdiction.

# 11.3.1 Price and non-price diversity of retail offers

There is some evidence of price and product diversity in gas retail markets in Australia. Under market contracts, retailers generally offer a rebate and/ or discount from the terms of a standing offer contract. Often, discounts are tied to the term of the contract—for example, longer term contracts typically attract larger discounts than do more flexible arrangements. Discounts may also be available for prompt payment of bills and for payments by direct debit. Some product offerings bundle gas services with inducements such as loyalty bonuses, competitions, membership discounts, shopper cards and free products. Some retailers also offer discounts for contracting jointly for gas and electricity services.

In assessing the effectiveness of competition in gas retail markets in South Australia, the AEMC noted:<sup>13</sup>

To provide customers with an additional incentive to take up a market offer, retailers also offer other price and non-price incentives such as rebates, one month free supply or bill credits for customers staying longer than one year, or free gifts such as magazine subscriptions, sporting club memberships and appliances. While most retailers offer accredited Greenpower or renewable energy products, some retailers are also offering other innovative products and product features which appeal to customers. Gas customers are offered discounts of between 0.5 and 7.5 per cent in comparison to the gas standing contract prices.

The variety of discounts and non-price inducements makes direct price comparisons between retail offers difficult. Further, the transparency of price offerings also varies. Some retailers publish details of their products and prices, while others require a customer to fill out online forms or arrange a consultation.

The Australian Consumers Association has launched a website—CHOICEswitch—that allows customers to compare energy retail offers. Box 11.1 draws on the website to comment on the diversity of product offerings to small customers in Brisbane, Sydney, Melbourne and Adelaide.

The price offers set out in box 11.1 are not directly comparable across jurisdictions because the underlying product structures may not be identical. For further information on retail prices, see section 11.4.

12 Patrick Conlon (Minister for Energy, South Australia), Letter to the AEMC, 6 April 2009.

13 AEMC, Review of the effectiveness of competition in electricity and gas retail markets in South Australia-first final report, Sydney, 19 September 2008, p. 28.

### Table 11.5 Small customers switching retailers, June 2009

INDICATOR (%)	QUEENSLAND	NEW SOUTH WALES AND THE ACT	VICTORIA	SOUTH AUSTRALIA
Percentage of small customers that changed gas retailer during 2008–09 (%)	16	4	23	11
Customer switches as a percentage of the small customer base from start of FRC to June 2009 (cumulative)—gas (%)	23	30	115	81
Customer switches as a percentage of the small customer base from FRC start to June 2009 (cumulative)—electricity (%)	28.5	56.1	130.7	104.4

Notes:

If a customer switches to a number of retailers in succession, each move counts as a separate switch. Cumulative switching rates may thus exceed 100 per cent. The customer base is estimated at 30 June 2009. The New South Wales and ACT, Queensland and Victorian data are based on transfers at delivery points. Sources: New South Wales, ACT: AEMO, Market activity data January 2002 – June 2009; South Australia: REMCo, Market activity reports August 2004 – June 2009; Victoria and Queensland: AEMO, Gas market reports, transfer history January 2002 – June 2009.

# 11.3.2 Customer switching

The rate at which customers switch their supply arrangements (or churn) is an indicator of customer participation in the market. Switching rates can also indicate competitive activity. High rates of switching can reflect the availability of cheaper or better offers from competing retailers, successful marketing by retailers, and customer dissatisfaction with some service providers.

Switching rates should be interpreted with care, however. Switching is sometimes high during the early stages of market development when customers are first able to exercise choice. And switching rates sometimes stabilise even as the market acquires more depth. Similarly, low switching rates are possible in a competitive market if retailers deliver good quality service that gives customers no reason to switch.

Switching rates may also reflect factors such as the number of competitors in the market, customer experience with competition, demographics, demand and the cost of the service in relation to household budgets. Consumers are more likely to be responsive to energy offers and actively seek out cheaper services if, for example, the cost of gas services represents a relatively high proportion of their budget. Since 1 July 2009 the Australian Energy Market Operator (AEMO) has published gas churn data. Previously, a number of independent market operators—the Gas Market Company (New South Wales and the ACT), VENCorp (Victoria and Queensland) and REMCo (South Australia)—published the data.

### Figure 11.4

Cumulative monthly customer switching of retailers as a percentage of small gas customers, to June 2009



Note: The customer base is estimated at 30 June 2009. The New South Wales and ACT, Queensland and Victorian data are based on transfers at delivery points.

Sources: New South Wales and ACT: AEMO, Market activity data January 2002 – June 2009; South Australia: REMCo, Market activity reports August 2004 – June 2009; Victoria and Queensland: AEMO, Gas market reports, transfer history January 2002 – June 2009.

### Table 11.6 Customer transfers to market contracts

JURISDICTION	DATE	CUSTOMERS ON MARKET CONTRACTS (% OF CUSTOMER BASE)
Victoria	30 June 2008	54% of gas and electricity customers
South Australia	30 June 2008	62% of residential customers (20% with the host retailer and 42% with new entrants)
		17% of small business customers (3% with the host retailer and 14% with new entrants)
		61% of residential and small business customers (averaged)

Note: South Australian data are for gas customers only.

Sources: ESC (Victoria), Energy retailers: comparative performance reportcustomer service 2007-08, Melbourne, December 2008; ESCOSA (South Australia), 2007-08 Annual performance report: performance of South Australian energy retail market, November 2008, p. 24.

Churn is measured as the number of switches by gas customers from one retailer to another in a period, including switches from a host retailer to a new entrant, switches from new entrants back to a host retailer, and switches from one new entrant to another (table 11.5 and figure 11.4). The data do not include customers who have switched from a standing offer contract to a market contract with their existing retailer. This exclusion may understate the true extent of competitive activity because it does not account for the efforts of host retailers to maintain market share.

Table 11.5 illustrates switching activity continued strongly in Victoria (and to a lesser extent Queensland and South Australia) in 2008–09. New South Wales and the ACT had a switching rate significantly lower than those recorded in the other states. Only 4 per cent of small customers in New South Wales and the ACT changed gas retailer in 2007–08, compared with 23 per cent in Victoria. Switching activity in South Australia reduced slightly from 13 per cent in 2006–07 to 11 per cent in 2007–08. At June 2009 cumulative switching rates in Victoria (115 per cent) and South Australia (81 per cent) were more than double the New South Wales and ACT rate (30 per cent). More generally, switching rates for gas have been lower than for electricity in all jurisdictions (see table 7.6 in chapter 7).

### Switches to market contract

An alternative approach to measuring customer churn is to measure switching from standing offer contracts to market contracts. In June 2008 South Australia was the only jurisdiction that periodically published these data. In Victoria, the Essential Services Commission published data on customer switching to market contracts, but the data combined gas and electricity.

Table 11.6 summarises available data on switches to market contracts in South Australia and Victoria. The data are not directly comparable because collection methods differ.

The data indicate that in addition to customer movement between retailers, a significant number of residential customers are choosing to move away from standing offer contracts. In South Australia, more customers are choosing market contracts with new entrants in preference to the host retailer. Again, switching rates are lower than for electricity (see table 7.7 in chapter 7).

### 11.3.3 Customer perceptions of competition

A number of jurisdictions undertake occasional surveys on customer perceptions of retail competition. Issues covered include:

- > customer awareness of their ability to choose a retailer
- > customer approaches to retailers about taking out a market contract
- > retailer offers received by customers
- > customer understanding of retail offers.

Table 11.7 provides summary data. The surveys suggest customer awareness of retail choice has risen over time to high levels. It remains unusual for customers to approach retailers about taking out a market contract, but retailers are approaching an increasing number of customers.

### Table 11.7 Residential customer perceptions of competition

NEW SOUTH WALES <sup>1</sup>								
INDICATOR	Sydney	ORIA	SOUTH A	TH AUSTRALIA				
	2006	2008	2004	2007	2003	2008		
Customers aware of choice (%)	92	91	83	91	78	84		
Customers receiving at least one retail offer (%)	29 <sup>2</sup>	35 <sup>2</sup>	22	45	20	20		
Customers approaching retailers about taking out market contracts (%)	n/a	7	6	6	8	5		

n/a not available.

1. New South Wales data in 2006 are based on a household survey conducted in Sydney, and the 2008 data are based on a similar household survey conducted in the Hunter region.

2. Only includes customers approached by their current retailer about switching to a market contract.

Sources: South Australia: McGregor Tan Research, Monitoring the development of energy retail competition—residents, Report prepared for ESCOSA, Adelaide, November 2003; McGregor Tan Research, Review of effectiveness of competition in electricity and gas retail markets, Report prepared for the AEMC, Adelaide, June 2008; Victoria: The Wallis Group, Review of competition in the gas and electricity retail markets—consumer survey, Report prepared for the AEMC, Melbourne, August 2007; New South Wales: IPART, Electricity, gas and water research paper—residential energy and water use in the Hunter, Gosford and Wyong, Sydney, December 2008; IPART, Residential energy and water use in Sydney, the Blue Mountains and Illawarra—results from the 2006 household survey, Sydney, November 2007.

# 11.4 Retail prices

Natural gas retail prices cover the costs of a bundled product made up of gas, transport through transmission and distribution pipelines, and retail services. Data on the composition of residential gas prices are published from time to time in regulatory determinations. Figure 11.5 draws on determinations in Queensland and South Australia to illustrate the typical make-up of a residential gas bill. Wholesale gas costs and pipeline (transmission and distribution) charges account for the bulk of retail gas prices. Retail operating costs and retail margins account for around 36 per cent of retail prices in Queensland and 22 per cent in South Australia.

# 11.4.1 Regulation of retail prices

While most jurisdictions have introduced FRC, at July 2009 New South Wales, South Australia and Western Australia continued to regulate gas retail prices for small customers. The host retailers in those states must offer standing offer contracts to sell gas at default prices based on some form of regulated price cap or oversight. The contracts apply to customers who have not switched to a market contract. Retail gas prices are not regulated in Queensland, Victoria, Tasmania, the ACT or the Northern Territory.

Price cap regulation was intended as a transitional measure during the development of retail markets. To allow efficient signals for investment and consumption, governments are moving towards removing retail price caps. As noted, the AEMC is reviewing the effectiveness of competition in electricity and gas retail markets to determine an appropriate time to remove retail price caps in each jurisdiction (see section 11.3 and box 7.1 in chapter 7).

In setting default prices, jurisdictions consider gas purchase costs, pipeline charges, retailer operating costs and a retail margin. The approach varies across jurisdictions:

- > In New South Wales, voluntary agreements with host retailers limit annual price increases and thus control prices under standing offer contracts.
- > The South Australian regulator (the Essential Services Commission of South Australia, ESCOSA) sets default prices for the host retailer by considering the costs that a prudent retailer would incur in delivering the services.
- > In Western Australia, regulations cap gas retail prices for the major distribution systems.

### Figure 11.5

Indicative composition of a residential gas bill in Queensland and South Australia, 2008



Note: Based on McLennan Magasanik and Associates analysis of the composition of costs for a typical residential customer with an annual consumption of 10 gigajoules.

Source: McLennan Magasanik and Associates, Final report to the Queensland Competition Authority-costs of gas supply for a second tier retailer supplying small customers in Queensland, Brisbane, November 2008 (report prepared for the QCA review of small customer gas pricing and competition in Queensland).

Table 11.8 compares recent movements in regulated tariffs in New South Wales, South Australia and Western Australia and the mechanisms to allow further tariff revision. The changes relate to the supply of gas by host retailers to customers on default arrangements. Different approaches across jurisdictions reflect a range of factors and must be interpreted with care. In particular, the operating environments of retail businesses differ.

In 2008 the Western Australian Office of Energy reviewed the level and structure of gas tariffs, and made an interim recommendation in June 2009 to increase regulated tariffs by between 7.5 per cent



### Notes:

South Australian data are based on 2008–09 prices and an average annual residential consumption of 24 gigajoules.

South Australia's retailer tariffs are Origin Energy's 2008–09 standing contract tariffs (Adelaide) and distribution tariffs are Envestra's 2008–09 tariffs.

Source: ESCOSA (South Australia), 2008 Gas standing contract price path inquiry: draft inquiry report and draft price determination, Adelaide, April 2008.

and 23.6 per cent (depending on the customers' geographic location and level of gas consumption).<sup>14</sup> The Western Australian Government accepted this interim recommendation.<sup>15</sup>

The South Australian regulator (ESCOSA) indicated that a typical residential gas bill would increase by 6.15 per cent in 2008–09. This increase largely reflects a rise in network costs, wholesale gas supply costs and an increase in the retail margin.<sup>16</sup>

Queensland does not regulate retail prices but has experienced significant retail price increases since 2005-06 (figure 11.8). In December 2008 the Queensland regulator (the QCA) released a final report

<sup>14</sup> Office of Energy, Gas tariffs review-interim report, Perth, June 2009.

<sup>15</sup> Peter Collier (Minister for Energy, Western Australia), 'Alinta proposal accepted', Media release, 26 June 2009.

<sup>16</sup> ESCOSA (South Australia), 2008 Gas standing contract price path inquiry: final inquiry report and final price determination, Adelaide, June 2008; ESCOSA, 2008-09 Regulated gas price adjustment impact on residential and small business customers, Adelaide, June 2008.

### Table 11.8 Recent changes in regulated gas retail prices

JURISDICTION	PERIOD	RETAILERS	INCREASE IN REGULATED RETAIL PRICE	MECHANISM FOR FURTHER INCREASES IN REGULATED PRICE		
New South Wales	1 July 2007 to	AGL Energy	Increase by CPI annually	Retailers can apply to IPART in special		
	30 June 2010	Origin Energy	in all areas except the Murray Valley district	circumstances to vary prices outside the limit.		
		ActewAGL Retail	(Origin), which increases			
		Country Energy	by CPT + 2 % annually			
South Australia	1 July 2008 to	Origin Energy	2008–09: 8.25% increase	Increased costs incurred from		
	30 June 2011		2009–10 to 2010–11: CPI + 1% increase annually	prescribed events can be recovered through tariff increases, and the determination may be reopened.		
Western Australia	From 1 July 2009	Alinta	Increase in typical bill of 7.5–23.6%	Government decision will be implemented through regulations.		

CPI, consumer price index; IPART, Independent Pricing and Regulatory Tribunal.

Sources: New South Wales: IPART, Regulated gas retail tariffs and charges for small customers 2007-10: gas final report and voluntary transitional pricing arrangements, Sydney, June 2007, p. 2; South Australia: ESCOSA, 2008-09 Regulated gas price adjustment impact on residential and small business customers, Adelaide, June 2008; Western Australia: Energy Coordination (Gas Tariffs) Regulations 2000 and Office of Energy, Gas tariffs review—interim report, Perth, June 2008.

on its review of small customer prices and competition in the gas retail market. The QCA noted that retail prices, before the introduction of FRC in 2007, were below the level necessary for a retailer to recover its costs. To bring prices closer to cost-reflective levels, two regulated price increases of 10 per cent were approved in 2005. The QCA found, despite these increases, that prices in the residential gas retail market are still not cost-reflective and the lack of a sufficient retail margin reduces the incentive for new retailers to enter the market.<sup>17</sup>

# 11.4.2 Retail price outcomes

Retail price outcomes must be interpreted with care. Trends in retail prices may reflect movements in the cost of any one of, or a combination of, the bundled components in a retail product—for example, movements in wholesale gas prices, transmission and distribution pipeline charges or retail operating costs. In addition, regulatory arrangements affect retail price movements. As section 7.4.2 notes, while competition tends to deliver efficient outcomes, it may sometimes give a counter-intuitive outcome of higher prices, especially in the early stages of competition as historical cross-subsidies are phased out.

# Sources of price data

There is little systematic publication of actual gas retail prices in Australia. The Australian Gas Association (AGA) previously published data on retail gas prices but discontinued the series after 1998. Some jurisdictions publish price information:

- > Jurisdictions that regulate prices publish schedules of default 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.
- > The South Australian regulator (ESCOSA) publishes annual data on default and market prices.
- > The Queensland and Victorian regulators (the QCA and the ESC) and ESCOSA provide an estimator service on their websites that can be used to compare the price offerings of retailers.
- > In some jurisdictions, retailers are required to publish the prices struck through market contracts with customers.
- > The CHOICEswitch website provides a comparison and switching service, to help consumers compare electricity and gas offers (see box 11.1). Other price comparison websites also exist.

17 QCA (Queensland), Final report-review of small customer gas pricing and competition in Queensland, Brisbane, November 2008, pp. 31 and 64.

### Consumer price index and producer price index

The consumer price index (CPI) and producer price index, published by the Australian Bureau of Statistics, track movements in gas retail prices paid by households and businesses.<sup>18</sup> The indexes are based on customer surveys and, therefore, reflect both market and regulated prices.

Figure 11.6 tracks real gas price movements for households and business customers since 1991. There is considerable disparity between outcomes for each customer type. For business, the real price of gas has fallen by 10.6 per cent since 1991; for households, it has increased by 28.6 per cent (figure 11.7). In part, the disparity reflects the rebalancing of retail prices to remove cross-subsidies from business to household consumers.

It is possible to estimate retail price outcomes for households by using CPI data to extrapolate from the historic AGA price data. Figure 11.8 applies this method to estimate real gas prices for households in several states and territories since July 1996. Real household gas prices have risen since 1996 in all states except Victoria, but the pattern and rate of adjustment have varied. Customers in all states except Queensland experienced real price increases from 2000–01 to 2008–09 of between 19.9 per cent and 25.6 per cent. Prices in Queensland were relatively stable from 2000–01 to 2004–05 but have since risen sharply.

Caution must be exercised when making price comparisons. Price variation across the cities (and across individual customers) reflects a variety of factors, including variations in wholesale gas prices and the distances over which gas must be transported, and differences in regulatory arrangements. Consumption patterns and industry scale also play a role—for example:

- > Victoria has a relatively large residential consumer base with consumers located close to major gas fields.
- > Queensland prices reflect a small residential customer base and low rates of residential consumption, given that state's warm climate.

### Figure 11.6

Retail gas price index (inflation adjusted)—Australian capital cities, June 1991–March 2009



### Figure 11.7

Change in the real price of gas—Australia, June 1991– March 2009



Note to figures 11.6 and 11.7: The households index is based on capital city consumer price indexes for 'gas and other household fuels' deflated by the capital city CPI series for all groups. The business index is based on the producer price index for gas supply in 'Materials used in manufacturing industries' deflated by the CPI series for all groups. The household index was affected by the introduction of the Goods and Services Tax (GST) on 1 July 2000, which increased prices paid by households for gas services.

Sources for figures 11.6 and 11.7: ABS, *Consumer price index* and *Producer price index*, *March quarter 2009*, cat. nos. 6401.0 and 6427.0, Canberra, various years.



Figure 11.8 Real retail gas prices, by state and territory, July 1996–March 2009

Note: The dashed lines are estimates based on inflating 1998-99 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, August 2000, p.73; ABS, *Consumer price index, Australia, March quarter 2009*, cat. no. 6401.0, Canberra.

> Western Australia traditionally has relatively low wholesale gas prices but high transport costs because most residential consumers are located a long distance from gas basins. Volumes are also relatively low.

# 11.5 Quality of retail services

Competition provides incentives for retailers to improve performance and quality of service as a means of maintaining or increasing market share. In addition, governments have established regulations and codes on minimum terms and conditions, information disclosure and complaints handling requirements, which retailers must meet when supplying gas to small customers. As discussed in section 7.5, jurisdictional regulators monitor and report on retail service quality to enhance transparency and accountability. Most jurisdictions also have an ombudsman to investigate and report on complaints.

In November 2000 the Utility Regulators Forum (URF) established the Steering Committee on National Regulatory Reporting Requirements. The steering committee developed a national framework in 2002 for electricity retailers to report against common criteria on service performance. In May 2007 the steering committee recommended extending national reporting arrangements for electricity retail businesses to include the gas retail sector from 2007–08.<sup>19</sup> It developed reporting criteria that address:

- > customer affordability and access to services
- > quality of customer services.

19 URF, National energy retail performance indicators-final paper, Canberra, May 2007, p. ii.

CHAPTER 11 GAS RETAIL

New South Wales, Victoria, South Australia, Western Australia and the ACT have reported performance against the URF indicators, but each jurisdiction applies different methods and assumptions. These differences may limit the validity of any national performance comparisons across jurisdictions.

# 11.5.1 Affordability and access indicators

The rate of residential customer disconnections for failure to meet bill payments (figure 11.9) and the rate of disconnected customers reconnected within seven days (figure 11.10) are key affordability and access indicators.

In 2007-08 the rate of residential customer disconnections rose against the previous year's rate in South Australia and Western Australia, remained below 1 per cent in Victoria, and fell in New South Wales and the ACT. The rate at which disconnected customers were reconnected in 2007-08 improved in all states.

# 11.5.2 Customer service indicators

Customer service measures indicate customer satisfaction with the quality of retailer service. Indicators include:

- > the percentage of customer calls answered within 30 seconds (figure 11.11)
- > retail customer complaints as a percentage of total customers (figure 11.12).

Call centre performance varied across the jurisdictions in 2007–08. In Victoria, the number of calls answered within 30 seconds fell from 80 per cent in 2006–07 to 78 per cent in 2007–08, while the rate in South Australia improved from 81.9 per cent to 84.6 per cent over the same period. New South Wales improved from 60 per cent in 2006–07 to 75 per cent in 2007–08. The rate of gas complaints by residential customers was around 0.5 per cent of the customer base in New South Wales, Victoria and South Australia in 2007-08. The rate increased significantly in the ACT, from 0.14 per cent in 2005-06 to 0.76 per cent in 2007-08. In Western Australia, the rate of gas complaints by residential customers remained unchanged at 0.15 per cent. In South Australia, ESCOSA noted that the increase in 2007-08 was principally due to a large increase in complaints reported by AGL Energy following the first phase of conversion of South Australian gas customers to a new billing system in late 2007.<sup>20</sup>

As noted in section 7.4.2, customers have a range of options to redress customer service issues: customers can raise complaints directly with their retailer, refer complaints to their state energy ombudsman or transfer away from a business providing poor service.

# 11.5.3 Consumer protection

Governments regulate aspects of the energy retail market to protect consumers' rights and ensure customers have access to sufficient information to make informed decisions. New South Wales, South Australia and Western Australia require designated host retailers to provide gas services under a standard contract to nominated customers. Standard 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 retail tariffs (see section 11.4.1).

While prices in Queensland are not regulated, host retailers are required to offer small customers a standard contract. This contract must be published on the retailers' website and notified to the Queensland regulator (the QCA).

### Figure 11.9

Gas residential disconnections, as a percentage of the customer base



### Notes:

ACT figures include residential and non-residential customers but exclude disconnections by Energy Australia.

New South Wales data are available only from 2005-06. Western Australia data are available only from 2006-07. Tasmania data are available, but the rates for disconnection and customer complaints are negligible and have not been included in the chart.

Source: see figure 11.12.

### Figure 11.10

Residential gas customers reconnected within seven days, as a percentage of disconnected customers



### Notes:

Victorian data for 2005–06 include only six months of data from January-June 2006.

New South Wales and Victorian data are available only from 2005–06. South Australian data are available only from 2003–04. Western Australia data are available only from 2006–07.

Source: see figure 11.12.

### Figure 11.11

Percentage of gas retail customer calls answered within 30 seconds



### Notes:

South Australia and Victorian data in 2007–08 are for both gas and electricity. New South Wales data are available only from 2005–06. South Australian data are available only from 2004–05. Western Australia data are only available from 2006–07.

Source: see figure 11.12.

### Figure 11.12

# Retail gas customer complaints, as a percentage of total customers



Note: New South Wales data are available only from 2005–06. South Australian data are available only from 2004–05. Western Australia data are available only from 2006–07.

Sources for figures 11.9, 11.10, 11.11 and 11.12: Reporting against URF templates and performance reports on the retail sector by IPART (New South Wales), the ESC (Victoria), ESCOSA (South Australia), the ERA (Western Australia) and the ICRC (ACT). Some jurisdictions have established industry codes that apply to all retail gas services, including those sold under market contracts. The codes govern market conduct and establish minimum terms and conditions under which a retailer can sell gas to small retail customers. They may:

- > constrain how retailers may contact potential customers
- require pre-contract disclosure of information, including 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 energy ombudsman or alternative dispute resolution body to whom consumers can refer a complaint they were unable to resolve directly with the retailer. In addition to general consumer protection measures, some jurisdictions have introduced 'retailer of last resort' arrangements to ensure customers can transfer from a failed or failing retailer to another retailer. Section 7.5.3 provides further background on consumer protection arrangements for energy retail customers.

# 11.6 Future regulatory arrangements

Governments agreed in the Australian Energy Market Agreement 2004 (as amended) that jurisdictions other than Western Australia would transfer non-price regulatory functions to a national framework for the AEMC and the AER to administer. These functions include:

- > the obligation on retailers to supply small customers
- > small customer market contracts and marketing
- > retailer business authorisations, ring-fencing and retailer failure
- > balancing, settlement, customer transfer and metering arrangements
- > enforcement mechanisms and statutory objectives.<sup>21</sup>

The Northern Territory will be transferring only non-price regulatory functions for gas retail.

The MCE has scheduled the regulatory package for the transfer of functions to be introduced to the South Australian parliament in 2010. The arrangements are occurring in tandem with equivalent arrangements in electricity. Section 7.7 in chapter 7 outlines progress.



# APPENDIX: ENERGY MARKET REFORM



In 2004 the Australian, state and territory governments set the agenda for a transition to national energy regulation, with the Australian Energy Market Agreement. The 2006 revisions to that agreement underpin the most recent wave of reform. They include streamlined regulatory, planning, governance and institutional arrangements for the national electricity and gas markets.

# ENERGY MARKET REFORM

# A.1 Institutional framework

At the national level, two intergovernmental bodies determine the direction of Australia's energy policy: the Council of Australian Governments (COAG) and the Ministerial Council on Energy (MCE). The peak intergovernmental forum in Australia, COAG comprises the prime minister, state premiers, territory chief ministers and the president of the Australian Local Government Association. Its role is to initiate, develop and monitor the implementation of policy reforms that are nationally significant and that require cooperative action by Australian governments. These reforms include energy market reform.

The MCE comprises Australian, state and territory energy ministers. Ministers from New Zealand and Papua New Guinea have observer status. The MCE's role is to initiate and develop energy policy reforms for consideration by COAG. It also monitors and oversees the implementation of energy policy reforms agreed by COAG. The Standing Committee of Officials is a group of senior officials from the Australian, state and territory governments who assist the MCE.

In addition, special-purpose bodies have been created to develop and implement reform packages for the energy sector:

- In 2006 COAG established an Energy Reform Implementation Group (ERIG) to report on measures that may be necessary to achieve a fully national electricity transmission grid. ERIG also addressed industry structure and financial market issues that may affect the ongoing efficiency and competitiveness of the energy sector.
- > The MCE established:
  - the Retail Policy Working Group to oversee the transfer of energy distribution (non-economic) and retail regulation functions to the national legislative framework
  - an industry led Gas Market Leaders Group to produce a market development plan for the gas wholesale sector.

Other key agencies in the national energy framework are:

- > the Australian Energy Regulator (AER), which is the independent national energy market regulator
- > the Australian Energy Market Commission (AEMC), which is responsible for rule making and market development in the national electricity and gas markets. It also reviews the energy market framework and provides policy advice to the MCE.
- > the Australian Energy Market Operator (AEMO), which is responsible for the day-to-day operation and administration of the power system and the electricity and gas wholesale and retail markets in all jurisdictions except Western Australia and the Northern Territory.

Although the AER, the AEMC and AEMO are not policy bodies, each participates in energy market reform processes. Figure A.1 outlines the roles and responsibilities of key bodies involved in national energy policy, regulation and market operation.

# A.2 Transition to a national energy framework

The AER and the AEMC were established under the Australian Energy Market Agreement and began on 1 July 2005. The transfer of functions from state and territory regulators, however, is still in progress. Table A.1 sets out the institutional arrangements that will apply once the transfer of functions is complete.

## Market monitoring, compliance and enforcement

The AER monitors and enforces compliance with national energy market legislation, including the National Electricity Law and Rules and the National Gas Law and Rules. This role encompasses compliance with the law and rules governing network regulation, the wholesale electricity market, the Victorian wholesale gas market, the National Gas Market Bulletin Board and jurisdictional retail gas market procedures. These functions have transferred gradually since the AER's inception, with the most recent functions (relating to the Victorian wholesale gas market and retail gas market procedures) incorporated in the National Gas Law from 1 July 2009.

# **Electricity networks**

The AER has been responsible for the regulation of electricity transmission networks since 1 July 2005—a role previously undertaken by the Australian Competition and Consumer Commission (ACCC). On 1 January 2008 revisions to the Electricity Law and Rules refined the regulatory process for electricity networks. The new framework also established the AER as the economic regulator of electricity distribution networks in the National Electricity Market (NEM) jurisdictions.<sup>1</sup>

In 2008 the AER released guidelines to assist electricity distribution businesses and their customers to understand the AER's approach to distribution network regulation. It also released details of the incentive schemes to apply to electricity distribution businesses. The AER's first revenue determinations for electricity distribution were completed in April 2009 for the New South Wales and Australian Capital Territory (ACT) network businesses.

# Gas networks

The Gas Law and Rules, which took effect on 1 July 2008, provide the regulatory framework for the gas transmission and distribution sectors. These instruments replace the Gas Pipelines Access Law and the National Gas Code, which had provided the regulatory framework since 1997.

The new legislation transferred the regulation of covered distribution pipelines outside Western Australia from state and territory regulators to the AER. It also transferred the regulation of covered transmission pipelines outside Western Australia from the ACCC to the AER. As of July 2009 the AER regulated eight transmission pipelines<sup>2</sup> and 11 distribution networks.<sup>3</sup>

2 Two transmission pipelines are subject to light regulation.

<sup>1</sup> The regulation of transmission and distribution networks in Western Australia and the Northern Territory remains under state and territory jurisdiction.

<sup>3</sup> Western Australia has three covered transmission pipelines and one covered distribution network. The Economic Regulation Authority regulates these assets.
## Figure A.1 National energy market—institutional framework

POLICY

### 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. COAG develops and monitors policy reforms that are of national significance and that require cooperative action by Australian governments, including National Competition Policy and related energy market reforms.

### Ministerial Council on Energy

The MCE comprises Australian, state and territory energy ministers. It is 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.



AEMC, Australian Energy Market Commission; AEMO, Australian Energy Market Operator; AER, Australian Energy Regulator; ACCC, Australian Competition and Consumer Commission; COAG, Council of Australia Governments; MCE, Ministerial Council on Energy; NEM, National Electricity Market.

## Table A.1 Energy regulation after implementation of national framework

	QLD	NSW	ACT	VIC	SA	TAS	NT	WA
Gas transmission								
Gas distribution								
Electricity wholesale			Australian En	aray Bagulator				
Electricity transmission	Australian Energy Regulator Economic Regulation Utilities Authority							
Electricity distribution							Utilities	Authority
Retail (non-price)	Cor					Commission		
Retail (pricing)	QCA	IPART	ICRC	ESC	ESCOSA	OTTER and GPOC		
Rule changes	Australian Energy Market Commission							
Competition regulation	Australian Competition and Consumer Commission							

ESC, Essential Services Commission (Victoria); ESCOSA, Essential Services Commission of South Australia; GPOC, Government Prices Oversight Commission (Tasmania); ICRC, Independent Competition and Regulatory Commission (ACT); IPART, Independent Pricing and Regulatory Tribunal (New South Wales); OTTER, Office of the Tasmanian Economic Regulator; QCA, Queensland Competition Authority.

In September 2008 the AER released guidelines to assist gas network businesses and their customers to understand the AER's approach to the regulation of gas distribution businesses.

# Retail

The Retail Policy Working Group recommended retail functions for transfer to national regulation. It reviewed:

- > retailer obligations for supply to small customers
- > customer market contracts
- > marketing
- > business authorisations
- > ring-fencing
- > retailer failure arrangements (retailer of last resort).<sup>4</sup>

The MCE released a first exposure draft of the National Energy Customer Framework for consultation in April 2009. Under the draft legislation, the AER will:

- > be a gatekeeper for authorisation and exemptions
- > publish standing tariffs
- > monitor and enforce:
  - customer financial hardship policies
- compliance with the terms of regulated contracts and rules
- marketing conduct
- 4 MCE, Communiqué, 19 May 2006.
- 5 COAG, *Communiqué*, 13 April 2007.

> issue guidance to market participants on how to apply the new framework and on the AER's enforcement strategy.

The MCE is expected to release a second exposure draft in late 2009, with the final legislative package to be introduced to the South Australian Parliament in the 2010 spring session. States and territories will transition to the national framework as it is adopted through legislation in each relevant jurisdiction.

# A.2.1 The Australian Energy Market Operator

In April 2007 COAG agreed to establish AEMO as a single, industry funded national energy market operator for both electricity and gas.<sup>5</sup> Established as a corporate entity that operates on a cost recovery basis, AEMO began operating on 1 July 2009. Its membership is split between government (60 per cent) and industry (40 per cent). Government members include the Australian Government and the state and territory governments of all jurisdictions in which AEMO operates. The organisation merges the roles of the national electricity market operator (previously undertaken by the National Electricity Market Management Company) with the wholesale and retail gas market operators in New South Wales, the ACT, Queensland, Victoria and South Australia. It also assumes the state based electricity planning functions of VENCorp (in Victoria) and the Electricity Industry Supply Planning Council (in South Australia).

As the electricity market operator, AEMO manages the wholesale NEM and is responsible for scheduling and dispatching generating plant, managing transmission constraints and settling the market. In its gas market role, AEMO operates the Victorian wholesale spot market, wholesale arrangements in other states and territories (and, from 1 July 2010, the short term trading market), the Gas Market Bulletin Board and retail functions, including customer transfers and management of the daily allocation of gas use to retailers. It also oversees the system security of the NEM electricity grid and the Victorian gas transmission network.

The new functions of AEMO include:

- > planning and coordinating the development of the national electricity transmission network
- > preparing an annual Gas Statement of Opportunities (GSOO).

The National Transmission Planner (NTP) role aims to strengthen transmission planning arrangements in the NEM. In particular, it will move the planning focus away from priorities of individual jurisdictions, onto the national grid as a whole.

The NTP will publish an annual national transmission network development plan outlining the efficient development of the power system. The plan will provide a long term strategic outlook (minimum 20 years), focusing on national transmission flow paths. It will not replace local planning and will not be binding on transmission businesses or the AER. Rather, the plan will complement shorter term investment planning by transmission businesses. A national transmission statement is to be published by the end of 2009 as a first step. The first full national transmission network development plan will be completed by the end of 2010.

The GSOO will be an annual publication similar to the current Electricity Statement of Opportunities. These two publications will provide 10 year outlooks for electricity and gas requirements across eastern and southern Australia. AEMO's first GSOO is scheduled for publication in December 2009.



# ABBREVIATIONS

1P	proved reserves	Electricity Law	National Electricity Law		
2P 3P	proved plus probable reserves proved plus probable plus probable plus possible reserves	Electricity Rules	National Electricity Rules		
AASB	Australian Accounting Standards Board	ERA	Economic Regulation Authority (Western Australia)		
ABARE	Australian Bureau of Agricultural and	ERIG	Energy Reform Implementation Group		
	Resource Economics	ESAA	Energy Supply Association of Australia		
ABS	Australian Bureau of Statistics	ESC	Essential Services Commission (Victoria)		
AC	alternating current	ESCOSA	Essential Services Commission of South Australia		
ACCC	Australian Competition and Consumer Commission	ES00	Electricity Statement of Opportunities		
ACT	Australian Capital Territory		(published by AEMO)		
AEMA	Australian Energy Market Agreement	ETEF	Electricity Tariff Equalisation Fund		
AEMC	Australian Energy Market Commission	FEED	front end engineering design		
AEMO	Australian Energy Market Operator	FID	final investment decision		
AER	Australian Energy Regulator	FRC	full retail contestability		
AFMA	Australian Financial Markets Association	Gas Law	National Gas Law		
AGA	Australian Gas Association	Gas Rules	National Gas Rules		
AMIQ	authorised maximum interval quantity	GEAC	Great Energy Alliance Corporation		
AMSP	alternative maximum STEM price	GJ	gigajoules		
BBI	Babcock & Brown Infrastructure	GSL	guaranteed service level		
BBP	Babcock & Brown Power	GS00	Gas Statement of Opportunities		
CAIDI	customer average interruption duration index	GWh	gigawatt hour		
CBD	central business district	ICRC	Independent Competition and Regulatory Commission		
CCGT	combined cycle gas turbine				
CCS	carbon capture and storage	IEA	International Energy Agency		
CNOOC	China National Offshore Oil Company	IMO	Independent Market Uperator		
CO <sub>2</sub>	carbon dioxide	IPART	Independent Pricing and Regulatory Tribunal		
COAG	Council of Australian Governments	JV	joint venture		
CPI	consumer price index	kV	kilovolt		
CPRS	Carbon Pollution Reduction Scheme	kVa	kilovolt amperes		
CPT	cumulative price threshold	kW	kilowatt		
CSG	coal seam gas	kWh	kilowatt hour		
DC	direct current	LNG	liquefied natural gas		
EBIT	earnings before interest and tax	MAIFI	momentary average interruption frequency index		
EBITDA	earnings before interest, tax, depreciation	MCC	marginal cost of constraints		
	and amortisation	MCE	Ministerial Council on Energy		

ABBREVIATIONS

MWh	megawatt hour	TFP	total factor productivity
MVa	megavolt amperes	TJ	terajoule
NCC	National Competition Council	b/LT	terajoules per day
NEM	National Electricity Market	TW	terawatt
NEMMCO	National Electricity Market Management Company	TWh	terawatt hour
NPI	National Power Index	URF	Utility Regulators Forum
NTP	National Transmission Planner	VENCorp	Victorian Energy Networks Corporation
NWIS	North West Interconnected System	VTS	Victorian Transmission System
000	outage cost of constraints	WACC	weighted average cost of capital
OCGT	open cycle gas turbine		
OECD	Organisation for Economic Cooperation and Development		
OTC	over-the-counter		
OTTER	Office of the Tasmanian Economic Regulator		
PASA	projected assessment of system adequacy		
PJ	petajoule		
PV	photovoltaic		
Q	quarter		
QCA	Queensland Competition Authority		
QNI	Queensland to New South Wales interconnector		
RAB	regulated asset base		
RERT	reliable and emergency reserve trader		
RET	renewable energy target		
RIT-T	Regulatory Investment Test for Transmission		
SAIDI	system average interruption duration index		
SAIFI	system average interruption frequency index		
SCONRRR	Steering Committee on National Regulatory Reporting Requirements		
SEA Gas	South East Australia Gas		
SFE	Sydney Futures Exchange		
STEM	short term energy market		
STPIS	service target performance incentive scheme		
STTM	short term trading market		
SWIS	South West Interconnected System		

тсс

total cost of constraints

MW

megawatt

