3 NATURAL GAS

The two main types of natural gas in Australia are conventional natural gas and coal seam gas (CSG). Conventional natural gas is found in underground reservoirs trapped in rock, often along with oil. In contrast, CSG is produced when coal is created from peat. There are also renewable gas sources, such as biogas (landfill and sewage gas) and biomass (wood, wood waste and sugarcane residue).

Natural gas is produced both for domestic markets and for export as liquefied natural gas (LNG). High pressure transmission pipelines transport natural gas over long distances to domestic markets. 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 reduce the pressure of the gas before it enters the distribution network.

This chapter covers natural gas production, wholesale market arrangements, and the transmission and distribution pipeline sectors. While the chapter focuses on domestic markets in eastern Australia in which the Australian Energy Regulator (AER) has regulatory responsibilities,[1] it also covers gas markets in Western Australia, the Northern Territory and LNG export markets. Chapter 4 considers the retailing of natural gas to end customers.

3.1 Reserves and production

In August 2010 Australia's proved and probable (2P) natural gas reserves—those with reasonable prospects for commercialisation—stood at around 106 000 petajoules (PJ), comprising 78 000 PJ of conventional natural gas and 28 000 PJ of CSG.[2] Total proved and probable reserves increased by around 76 per cent in 2009–10. This increase was mainly due to 40 000 PJ of reserves added in the Gorgon fields in Western Australia's Carnarvon Basin. CSG reserves in Queensland and New South Wales also rose by 34 per cent.

Australia produced 1911 PJ of natural gas in 2009–10, of which around 54 per cent was for the domestic market. The CSG share of total production rose from 8 per cent in 2008–09 to 10 per cent in 2009–10. Around 46 per cent of Australia's gas production—all sourced from offshore basins in Western Australia and the Northern Territory—is exported as LNG.

3.1.1 Geographic distribution

Table 3.1 sets out the geographic distribution of Australia's natural gas reserves in June 2010 and production for the year to 30 June 2010. Figure 3.1 illustrates the locations of major gas basins and the transmission pipelines used to ship gas from the basins to domestic markets.

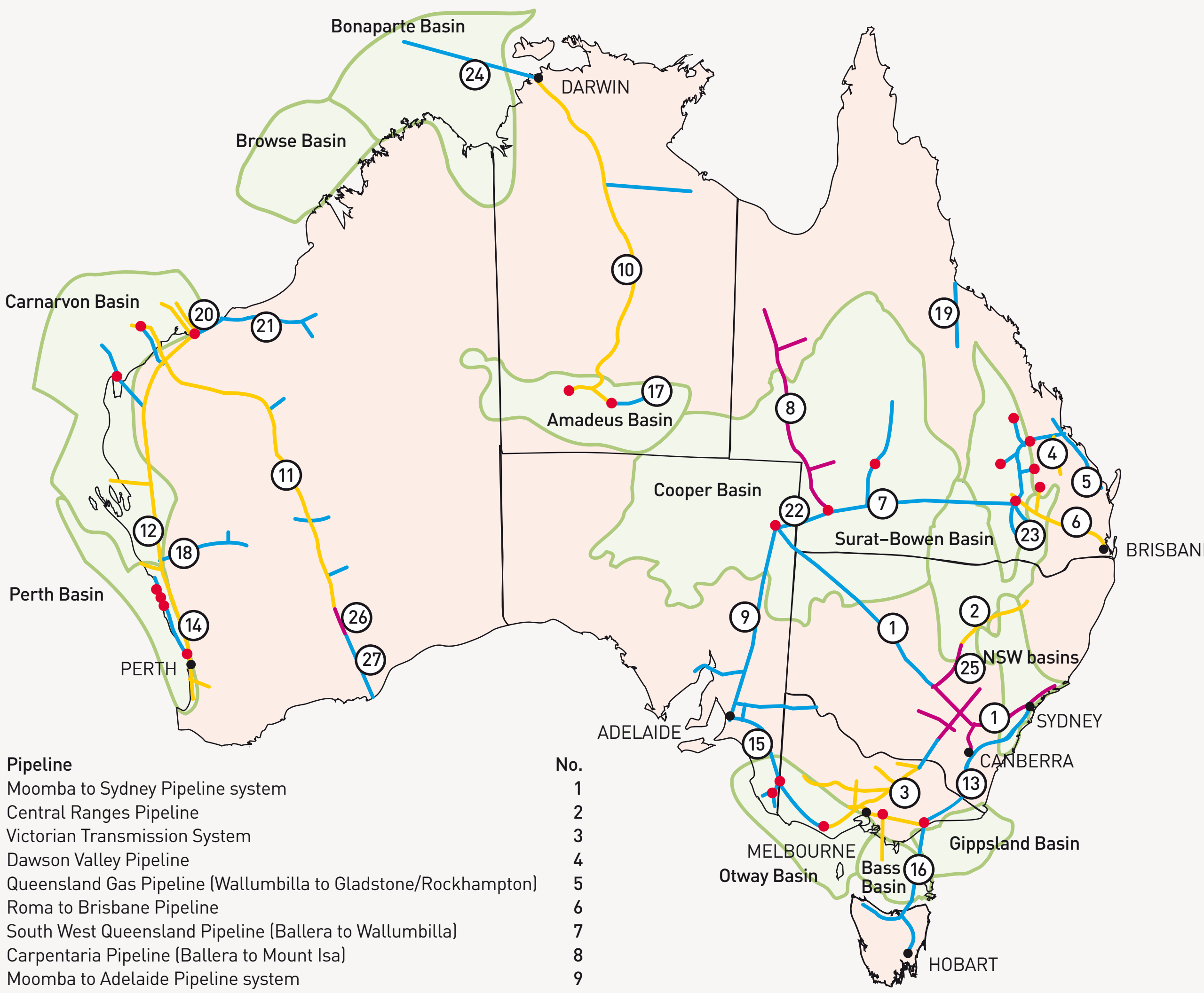
Western Australia's offshore Carnarvon Basin holds the majority of Australia's proved and probable natural gas reserves. It supplies around one third of Australia's domestic market and 99 per cent of Australian gas for LNG export. Newly added reserves in the Gorgon fields increased the share of Australian reserves in this basin from around 48 per cent to 64 per cent in 2009–10.

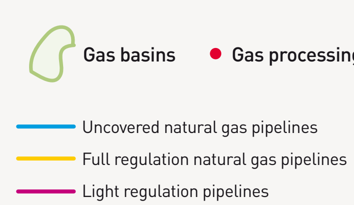
The Bonaparte Basin along the north west coast contains around 1 per cent of Australia's gas reserves. While its development has focused on producing LNG for export (which began in 2006), the Bonaparte Gas Pipeline was commissioned in 2008 to ship gas to Darwin for domestic consumption. This capacity will supplement gas from the Amadeus Basin, which is in decline.

1 The AER has compliance and enforcement responsibilities—under ss. 18–20 of the National Gas Rules—in relation to the Natural Gas Bulletin Board, the Victorian wholesale gas market and the short term trading market that commenced operating in Sydney and Adelaide in 2010.

2 EnergyQuest, *Energy Quarterly*, August 2010.

Figure 3.1
Australian gas basins and transmission pipelines





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

Source: AER.

Table 3.1 Natural gas reserves and production, 2010

GAS BASIN	PRODUCTION (YEAR TO JUNE 2010) PETAJOULES	PRODUCTION (YEAR TO JUNE 2010) PERCENTAGE OF DOMESTIC SALES	PROVED AND PROBABLE RESERVES[2] (30 JUNE 2010) PETAJOULES	PROVED AND PROBABLE RESERVES[2] (30 JUNE 2010) PERCENTAGE OF AUSTRALIAN RESERVES
CONVENTIONAL NATURAL GAS[1]				
WESTERN AUSTRALIA				
Carnarvon	354	34.2	68 353	64.3
Perth	4	0.4	23	0.0
NORTHERN TERRITORY				
Amadeus	10	1.0	156	0.1
Bonaparte	9	0.8	1 198	1.1
EASTERN AUSTRALIA				
Cooper (South Australia – Queensland)	103	10.0	1 157	1.1
Gippsland (Victoria)	228	22.0	5 233	4.9
Otway (Victoria)	105	10.1	1 245	1.2
Bass (Victoria)	12	1.2	275	0.3
Surat–Bowen (Queensland)	16	1.6	196	0.2
Total conventional natural gas	842	81.2	77 836	73.2
COAL SEAM GAS				
Surat–Bowen (Queensland)	189	18.2	26 008	24.5
New South Wales basins	6	0.6	2 466	2.3
Total coal seam gas	195	18.8	28 474	26.8
AUSTRALIAN TOTALS	**1 036**	**100.0**	**106 310**	**100.0**
LIQUEFIED NATURAL GAS (EXPORTS)				
Carnarvon (Western Australia)	862			
Bonaparte (Northern Territory)	12			
Total liquefied natural gas	874			
TOTAL PRODUCTION	**1 911**			

1. Conventional natural gas reserves include LNG 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 2010.

Eastern Australia contains around 35 per cent of Australia's natural gas reserves, of which the majority are CSG. The principal sources of reserves are the Gippsland Basin off coastal Victoria (which meets around 22 per cent of national demand) and the Surat–Bowen Basin in Queensland (20 per cent). The Cooper Basin in central Australia meets about 10 per cent of demand but its reserves are declining. Production in Victoria's offshore Otway Basin (10 per cent) has risen significantly since 2004.

Production of CSG has risen exponentially since 2004, 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. In New South Wales, commercial production of CSG began in 1996 in the Sydney Basin.

While CSG is produced only in Queensland and New South Wales, it is the fastest growing gas production sector. CSG production rose by around 32 per cent to 195 PJ in 2009–10, and accounted for almost 30 per cent of gas production in eastern Australia over the same period.[3]

3.2 Domestic and international demand

Australia consumed around 1036 PJ of natural gas in 2009–10.[4] Natural gas has a range of industrial, commercial and domestic applications in Australia. It is increasingly used for electricity generation, mainly to fuel intermediate and peaking generators. The residential sector uses natural gas mainly for heating and cooking.

The consumption profile varies across the jurisdictions. Natural gas is widely used in most jurisdictions for industrial manufacturing. Western Australia, South Australia, Queensland and the Northern Territory especially rely on natural gas for electricity generation. In Western Australia, 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.

3.2.1 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.

Australia has LNG export projects in Western Australia's North West Shelf and Darwin. Export volumes rose in 2009–10 by 7.4 per cent to 874 PJ, mostly from the Carnarvon Basin,[5] and the major players are continuing to expand capacity:

- Woodside's 4.3 million tonne per year Pluto project is nearing completion and will become Australia's third operational LNG project. The first exports are expected in early 2011.
- The $50 billion Gorgon project in Western Australia is scheduled to begin operation in 2015 and produce around 15 million tonnes of LNG per year—almost equal to Australia's current total LNG production. The project partners have signed a number of long term sales agreements with international buyers.

Long term projections of rising international energy prices, together with rapidly expanding reserves of CSG, have improved the economics of developing LNG export facilities in eastern Australia. Several export projects that rely on CSG are at an advanced stage of planning in Queensland. Major domestic and international players are developing the proposed projects, which range in size from 1.5 to 14 million tonnes of LNG per year.

3.3 Industry structure

Gas production in Australia is relatively concentrated. EnergyQuest estimated six major producers supplied around 79 per cent of the domestic market in 2009–10: BHP Billiton (19 per cent), Santos (18 per cent), Esso (14 per cent), Woodside (12 per cent), Apache Energy (10 per cent) and Origin Energy (6 per cent).[6]

3.3.1 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.

3 All data on gas production, consumption and reserves are sourced from EnergyQuest, *Energy Quarterly*, August 2010.
4 EnergyQuest, *Energy Quarterly*, August 2010.
5 LNG production and export data are sourced from EnergyQuest, *Energy Quarterly*, August 2010, p. 24.
6 EnergyQuest, *Energy Quarterly*, August 2010.

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, and is expanding its electricity generation portfolio in eastern Australia. It has significant equity in CSG production in Queensland and in conventional gas production in Victoria's Otway and Bass basins, and a minority interest in gas production in the Cooper Basin.

> AGL Energy is a leading energy retailer in Queensland, Victoria, New South Wales and South Australia, and is a major electricity generator in eastern Australia. 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.

3.3.2 Market concentration

Market concentration in particular gas basins depends on multiple factors, including the number of fields developed, the ownership structure of the fields, and acreage management and permit allocation. Figure 3.2 illustrates EnergyQuest estimates of market shares in gas production for the domestic market in the major basins. Table 3.2 sets out market shares in proved and probable gas reserves (including reserves available for export) at August 2010.

Several major companies have equity in Western Australia's Carnarvon Basin, which is Australia's largest producing basin. The businesses participate in joint ventures, typically with overlapping ownership interests. Chevron (33 per cent), Shell (18 per cent) and Esso (15 per cent) have the largest stake in gas reserves in the Carnarvon Basin, given their equity in the Gorgon project.

Woodside (24 per cent) and Apache Energy (23 per cent) are the largest producers for the domestic market, but Santos (14 per cent), BP and Chevron (10 per cent each), and BHP Billiton and Shell (3 per cent each) have significant market shares.

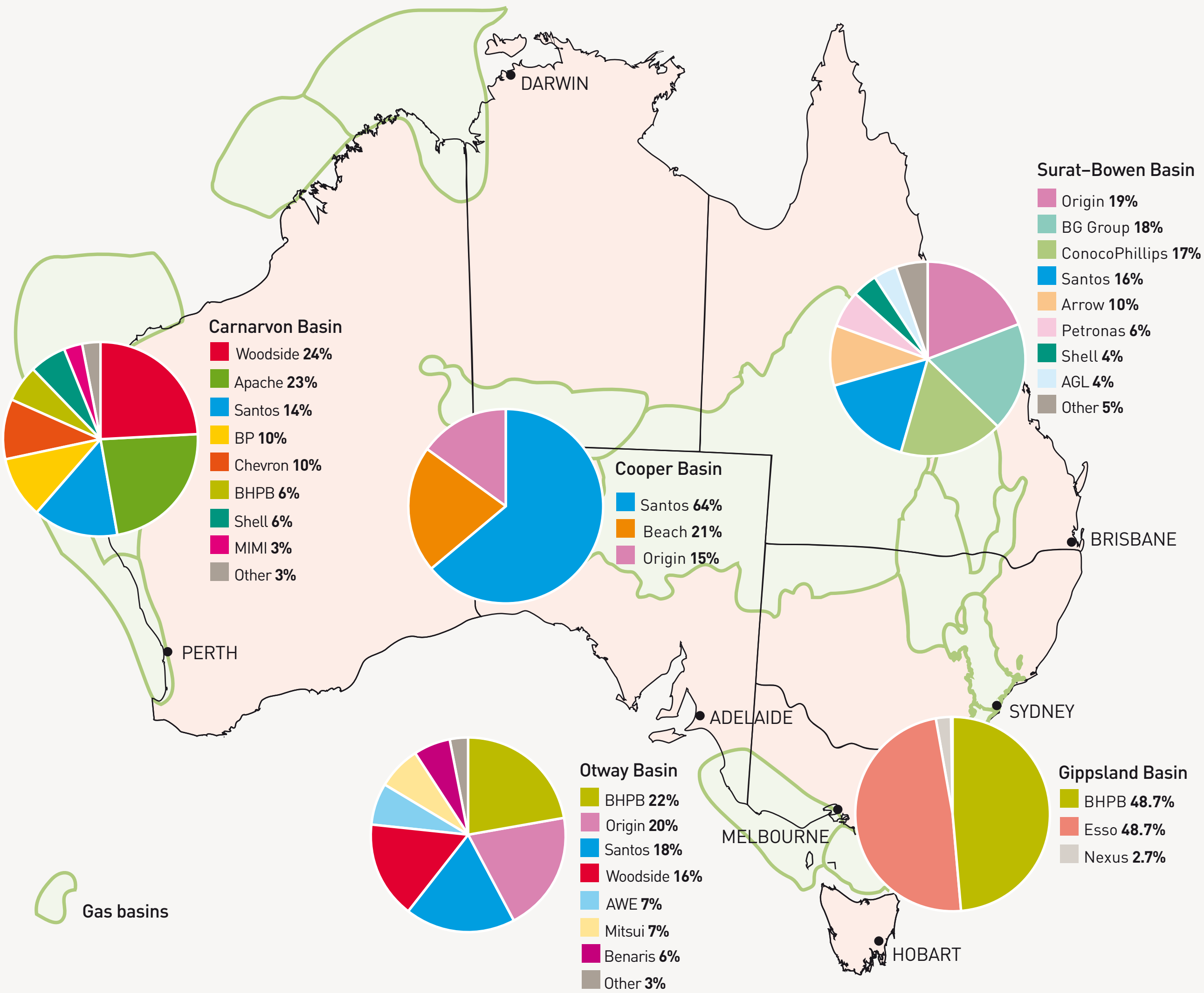
Gas for the Northern Territory was historically sourced from the Amadeus Basin and produced by Santos and Magellan. The principal reserves in the Northern Territory are located in the Bonaparte Basin in the Timor Sea. Eni owns over 80 per cent of Australian reserves in the basin.

In eastern Australia, control of 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.

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 (22 per cent), Origin Energy (20 per cent), Santos (18 per cent) and Woodside (16 per cent) accounting for the bulk of production. The principal producers in the smaller Bass Basin are Origin Energy and Australian Worldwide Exploration.

The growth of the CSG industry has led to considerable new entry in Queensland's Surat–Bowen Basin over the past decade. The largest producers are Origin Energy (19 per cent), BG Group (18 per cent), ConocoPhillips (17 per cent), Santos (16 per cent), Arrow Energy (now owned by Shell and PetroChina, 10 per cent), Petronas (6 per cent), and Shell and AGL Energy (4 per cent each). These businesses also own the majority of gas reserves in the Surat–Bowen Basin.

Figure 3.2
Market shares in domestic gas production, by basin, 2009–10



Notes:

Excludes liquefied natural gas.

Some corporate names are shortened or abbreviated.

Source: EnergyQuest 2010 (unpublished data).

Table 3.2 Market shares in proved and probable gas reserves, by basin, 2010 (per cent)

COMPANY	CARNARVON (WA)	BONAPARTE (WA/NT)	PERTH (WA)	AMADEUS (NT)	COOPER (SA/QLD)	SURAT–BOWEN (QLD)	GUNNEDAH (NSW)	CLARENCE MORTON (QLD/NSW)	GLOUCESTER (NSW)	SYDNEY (NSW)	GIPPSLAND (VIC)	OTWAY (VIC)	BASS (VIC)	ALL BASINS
Chevron	32.6													21.0
Shell	18.2					10.1								14.2
Esso	15.0										44.5			11.8
Woodside	11.5													7.4
Origin			51.7		13.5	19.4						36.5	42.5	5.4
Santos	1.1	2.3		60.7	65.8	11.8	35.0				4.4	17.7		5.3
BHP Billiton	4.1										44.5	11.5		4.9
ConocoPhillips		11.6				19.4								4.9
QGC/BG						17.1								4.2
BP	5.1													3.3
MIMI	3.9													2.5
PetroChina						10.1								2.5
Apache	3.7													2.4
Petronas						6.1								1.5
AGL						2.9			100.0	100.0				1.5
Eastern Star Gas							65.0							0.9
ENI		81.9												0.9
CNOOC	1.3													0.9
Kufpec	1.2													0.8
Tokyo Gas	1.0													0.6
Osaka Gas	0.7													0.5
Metgasco								100.0						0.4
Nexus											6.7			0.3
Mitsui						0.7						8.3		0.3
AWE			48.3									8.1	57.5	0.3
Other	0.6	4.2		39.3	20.7	2.6						17.9		1.6
TOTAL (PETAJOULES)	**68 353**	**1 198**	**33**	**156**	**1 157**	**26 202**	**1 520**	**397**	**669**	**154**	**5 233**	**1 163**	**275**	**106 511**

Notes:

Based on proved and probable reserves at August 2010.

Some corporate names are shortened or abbreviated. Not all minority owners are listed.

Source: EnergyQuest 2010 (unpublished data).

3.3.3 Mergers and acquisitions

Merger and acquisition activity in upstream gas since 2006 has focused mainly on CSG (and associated LNG proposals) in Queensland and New South Wales. The AER *State of the energy market 2009* report listed proposed and successful acquisitions from June 2006 to September 2009 (section 8.4.3, including table 8.5). Activity from that time until October 2010 included the following:

- Origin Energy acquired Woodside's interest in the Otway Basin in March 2010. The acquisition increased Origin's market share in Otway Basin reserves from 15 per cent to 36 per cent.
- Shell and PetroChina acquired Arrow Energy in August 2010. The acquisition increased Shell's market share in the Surat–Bowen Basin from 3 per cent to 10 per cent.
- Santos proposed in September 2009 to sell a 15 per cent interest in its Gladstone LNG project to Total for $650 million. Petronas proposed to sell a further 5 per cent interest in the same project to Total for around $210 million.
- AGL Energy acquired Mosaic Oil (which owned around 0.3 per cent of reserves in the Surat–Bowen Basin) in October 2010.

3.4 Gas wholesale markets

Gas producers sell natural gas in wholesale markets to major industrial, mining and power generation customers, and to energy retailers which on-sell it to business and residential customers. In Australia, wholesale gas is sold mostly 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 often struck for 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.

Reforms have increased transparency and competition in Australian gas markets. Victoria established a wholesale spot market in 1999 to facilitate gas sales for managing system imbalances and pipeline network constraints. More recently, governments established the National Gas Market Bulletin Board and short term gas trading markets in Sydney and Adelaide.

3.4.1 Victoria's gas wholesale market

Victoria established a spot market for gas in 1999 to manage gas flows on the Victorian Transmission System. 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) operates both the wholesale market and the Victorian Transmission System.

The *State of the energy market 2009* report provides background on the operation of the Victorian market (pp. 246–7). In summary, participants submit daily bids ranging from $0 per gigajoule (the floor price) to $800 per gigajoule (the price cap). Following initial bidding at the beginning of the gas day (6 am), the bids may be revised four times a day at the scheduling intervals of 10 am, 2 pm, 6 pm and 10 pm.

At the beginning of each day, AEMO stacks supply offers and selects the least cost bids to match demand across the market. This establishes a spot market clearing price. Given Victoria has a net market, this price applies only to differences between contracted and actual amounts. Sometimes AEMO needs to schedule additional injections of gas (typically LNG) at above market price to alleviate short term constraints.

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. Section 3.5.2 of this chapter notes recent price activity.

3.4.2 National Gas Market Bulletin Board

The National Gas Market Bulletin Board, which commenced in July 2008, is a website covering major gas production plants, storage facilities, demand centres and transmission pipelines in southern and eastern Australia. Provision has been made for facilities in Western Australia, the Northern Territory and north Queensland to participate in the future.

The bulletin board aims to provide transparent, real-time information to gas customers, small market participants, potential new entrants and market observers on the state of the gas market, system constraints and market opportunities. It covers:

- gas pipeline capacity and daily aggregated data on expected gas volumes
- production capabilities (maximum daily quantities) and three day outlooks for production facilities
- pipeline storage (linepack) and three day outlooks for gas storage facilities
- daily demand forecasts, changes in supply capacity and the management of gas emergencies and system constraints.

Market participants must provide the information, and the AER monitors and enforces participants' compliance with the relevant rules. The bulletin board is operated by AEMO, which also publishes an annual Gas Statement of Opportunities (GSOO) to help industry participants plan and make commercial decisions on infrastructure investment. AEMO published the first GSOO in December 2009.

3.4.3 Short term trading market

Gas pipeline flows must be scheduled to ensure gas produced and injected into a pipeline system remains balanced with gas withdrawn for delivery to customers. A variety of systems assist with physical imbalances between nominated injections and actual withdrawals. AEMO operates a spot market in Victoria to manage gas balancing (section 3.4.1). Market arrangements for balancing are also being introduced in other major gas hubs in eastern Australia.

A short term trading market in gas was launched in September 2010 in the metropolitan hubs of Sydney and Adelaide, following a trial from March 2010. The reform creates a day-ahead wholesale spot market in gas for balancing purposes. It aims to enhance market transparency and competition, to address concerns that the traditional gas balancing arrangements in Sydney and Adelaide hindered retail market entry and gas supply efficiency.[7] AEMO operates the short term trading market, which may be extended to other gas hubs. Victoria will retain its own gas wholesale market.

The short term trading market sets a daily clearing price at each hub, based on bids by gas shippers to deliver additional gas. The market operator then settles, at the clearing price, the difference between each user's daily deliveries and withdrawals of gas. The mechanism aims to provide transparent price signals to market participants, to stimulate trading (including secondary trading) and demand-side response by users.

The short term trading market was designed to work with existing gas market arrangements and operates in conjunction with longer term gas supply and transportation contracts. It provides an option for users to buy or sell gas on a spot basis without entering delivery contracts in advance. It also allows contracted parties to manage short term supply and demand variations to their contracted quantities.

There are differences in design and operation between the short term trading market and the Victorian spot market:

- In the short term trading market, AEMO operates the financial market but does not operate the actual flow of gas (which remains the responsibility of pipeline operators). In the Victorian market, AEMO undertakes both roles.

7 Ministerial Council on Mineral and Petroleum Resources / Ministerial Council on Energy, *Final report of the Joint Working Group on Natural Gas Supply*, 2007, p. 19; McLennan Magasanik Associates, *Report to the Joint Working Group on Natural Gas Supply*, 2007.

- The Victorian market is for gas only, while prices in the short term trading market cover gas and transmission pipeline delivery to the hub.

The AER monitors the short term trading market, enforces the applicable National Gas Rules (Gas Rules), and publishes weekly reports on market activity.

3.5 Gas market activity

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.

3.5.1 Western Australia

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

While international energy prices eased with the onset of the global financial crisis, they again rose strongly from 2009. Anecdotal evidence suggests that some long term contracts in Western Australia were written at prices of \$8–9 per gigajoule in the 18 months to June 2010. Conversely, weaker demand from mining projects led to reports that short term prices eased in 2010 to around \$4.50 per gigajoule.[8]

The Western Australian Department of Mines and Petroleum gave evidence to a parliamentary inquiry into domestic gas prices in September 2010 that Western Australia could face a gas supply shortfall of 300 terajoules per day between 2013 and 2022.[9] To address this shortfall, a number of smaller gas projects focused on the domestic market are expected to come online within the next three years. These include the Halyard–Spar (50–100 terajoules per day) and Reindeer (110–215 terajoules per day) projects. Additionally, the Macedon gas development, sanctioned by BHP Billiton and its partners in 2010, should supply up to 210 terajoules per day to the domestic market from 2013.

3.5.2 Eastern Australia

An interconnected transmission pipeline network in southern and eastern Australia enables gas producers in the Surat–Bowen, Cooper, Gippsland, Otway, Bass and Sydney basins to sell gas to customers across Queensland, New South Wales, Victoria, South Australia, Tasmania and the ACT.

An interaction of several factors affects the gas supply–demand balance and price outcomes in eastern Australia. On the supply side, rising CSG production in Queensland and improved pipeline interconnection among the eastern gas basins have enhanced the flexibility of the market to respond to customer demand. CSG production in Queensland and New South Wales rose by 29 per cent in 2009–10.[10] New infrastructure (such as the QSN transmission link, commissioned in 2009) is providing the physical capacity to enable gas to flow from Queensland into southern markets.

While new pipeline investment and rising CSG reserves are strengthening the supply base, a number of factors may put upward pressure on demand. Rising investment in gas fired power stations is a key driver of natural gas demand in eastern Australia. Output from gas fired electricity generation rose across the NEM by 21 per cent in 2009–10. The introduction of climate change policies may further increase reliance on natural gas as a fuel for electricity generation.

The spot markets in Victoria, Sydney and Adelaide provide transparent data on short term gas prices.

8 EnergyQuest, *Energy Quarterly*, August 2010, p. 89.
9 The findings of the parliamentary inquiry are expected to be released in February 2011.
10 EnergyQuest, *Energy Quarterly*, August 2010, p. 63.

Market volumes in the Victorian spot market 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. Gas prices have generally eased since early 2008 when an expansion to the Victorian Transmission System eased capacity constraints on the network. The market remained relatively stable in 2010, with prices in the first quarter (and the early part of the fourth quarter) typically below $2 per gigajoule (figure 3.3).

Sydney and Adelaide gas prices moved in a wide range in the first six weeks of the short term trading market's operation in 2010, which is not uncommon with the establishment of a new market (figure 3.4).[11]

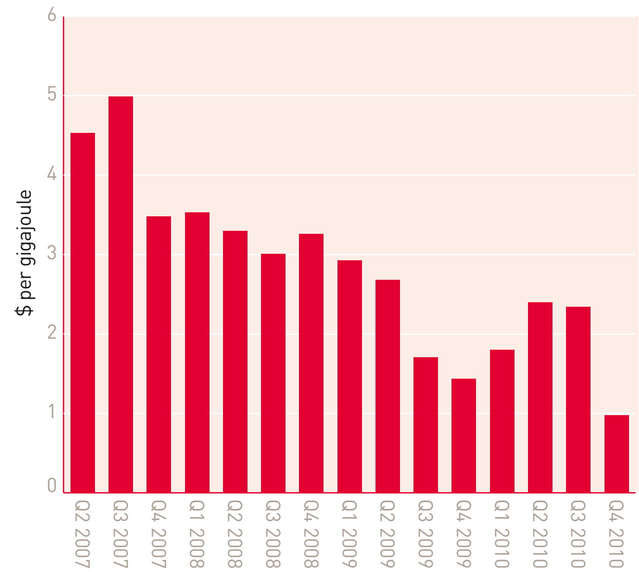
Further dynamic change is likely in east coast gas markets with the development of CSG–LNG projects in Queensland in the next few years. EnergyQuest predicted domestic prices may ease during the lengthy ramp-up of LNG export capacity.[12] In the longer term, prices for new domestic gas contracts may rise closer to international levels, as has occurred in Western Australia.

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

3.6 Gas transmission

Transmission pipelines transport natural gas from production fields to demand centres. The pipelines typically have wide diameters and operate under high pressure to optimise shipping capacity. Table 3.3 sets out summary details of Australia's major transmission pipelines; figure 3.1 illustrates pipeline routes.

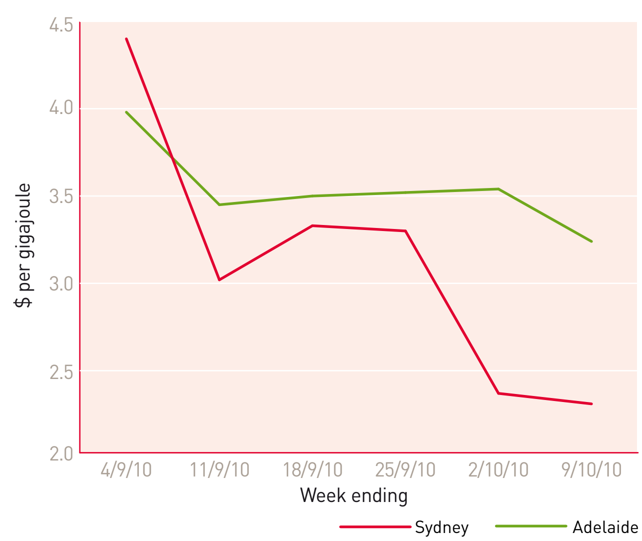
Figure 3.3
Victorian spot gas prices—quarterly averages



Note: Q4 2010 prices cover the period to 9 October 2010.

Sources: AEMO; AER.

Figure 3.4
Sydney and Adelaide spot gas prices—weekly averages



Note: Data are weekly averages of the ex ante daily price in each hub.

Sources: AEMO; AER.

11 Design differences between the short term trading market and the Victorian spot market limit the validity of price comparisons. In particular, the Victorian market is for gas only, while prices in the short term trading market cover gas and transmission pipeline delivery to the hub.

12 EnergyQuest, 'Australia's natural gas markets: connecting with the world', in AER, *State of the energy market 2009*, 2009.

Table 3.3 Major gas transmission pipelines

PIPELINE	LOCATION	LENGTH (KM)	CAPACITY (TJ/D)	CONSTRUCTED	COVERED?
NORTH EAST AUSTRALIA					
North Queensland Gas Pipeline	Qld	391	108	2004	No
Queensland Gas Pipeline (Wallumbilla to Gladstone)	Qld	629	142	1989–91	No
Carpentaria Pipeline (Ballera to Mount Isa)	Qld	840	119	1998	Yes (light)
Berwyndale to Wallumbilla Pipeline	Qld	113		2009	No
Dawson Valley Pipeline	Qld	47	30	1996	Yes
Roma (Wallumbilla) to Brisbane Pipeline	Qld	440	219	1969	Yes
Wallumbilla to Darling Downs Pipeline	Qld	205	400	2009	No
South West Queensland Pipeline (Ballera to Wallumbilla)	Qld	756	181	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 Pipeline (Marsden to Dubbo)	NSW	255	10	1998	Yes (light)
Central Ranges Pipeline (Dubbo to Tamworth)	NSW	300	7	2006	Yes
Eastern Gas Pipeline (Longford to Sydney)	Vic–NSW	795	268	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	303	2003	No
Moomba to Adelaide Pipeline	SA	1185	253	1969	No
WESTERN AUSTRALIA					
Dampier to Bunbury Pipeline	WA	1854	892	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 (light)
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:

Covered pipelines are subject to regulatory arrangements under the National Gas Law. The AER regulates covered pipelines outside Western Australia (where the Economic Regulation Authority is the 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
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	APA Group	APA Group
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 Diversified Utilities Fund; APA Group 16.8%)	Epic Energy
165 (2009)	Not required	Epic Energy (Hastings Diversified Utilities Fund; APA Group 16.8%)	Epic Energy
835 (2003)	Not required	APA Group	APA Group
28 (1999)	Not required	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	Prime Infrastructure	Prime Infrastructure
500 (2003)	Not required	International Power, APA Group and REST (equal shares)	APA Group
370 (2001)	Not required	Epic Energy (Hastings Diversified Utilities Fund; APA Group 16.8%)	Epic Energy
1618 (2004)	2005–10	DBP Transmission (DUET Group 60%, Alcoa 20%, Prime Infrastructure 20%)	DBP Transmission
439 (2009)	2010–15	APA Group 88.2%, Alinta Energy 11.8%	APA Group
	Not required	APA Group	APA Group
	Not required	Epic Energy (Hastings Diversified Utilities Fund; APA Group 16.8%)	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
	Not required	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 Gas 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 19%)	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 3.1). 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 are abbreviated or shortened.

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

Australia's gas transmission network covers over 20 000 kilometres. Around $4 billion has been invested or committed to new transmission pipelines and expansions since 2000. In combination, these projects have created an interconnected pipeline network covering Queensland, New South Wales, Victoria, South Australia, Tasmania and the ACT. This investment has enhanced the competitive environment for gas producers, pipeline operators and gas retailers, and improved security of supply. While pipeline investment in Western Australia and the Northern Territory has also been significant, there is no transmission interconnection with other jurisdictions.

3.6.1 Ownership of transmission pipelines

The AER *State of the energy market 2009* report traces the ownership history of Australia's gas transmission pipelines (section 9.2). The principal owners in the sector are:

> *Jemena*, owned by *Singapore Power International*, which acquired a portfolio of gas transmission assets from Alinta in 2007. It owns and operates the Eastern Gas Pipeline, VicHub and the Queensland Gas Pipeline, and operates the Tasmanian Gas Pipeline.

> *APA Group*, which owns three pipelines in New South Wales, including the Moomba to Sydney Pipeline, the Victorian Transmission System, two major Queensland pipelines, three major Western Australian pipelines and a major Northern Territory pipeline. It also part owns the SEA Gas Pipeline. In December 2008 APA Group sold three pipelines to an unlisted investment vehicle, Energy Infrastructure Investments, but continues to operate the assets. In 2010 APA Group increased its interest in Hastings Diversified Utilities Fund (see below) from about 4.5 per cent to 16.8 per cent.

> *Prime Infrastructure*, formerly Babcock and Brown Infrastructure, which acquired a 20 per cent interest in the Dampier to Bunbury Pipeline from Alinta in 2007.[13] 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, which acquired Epic Energy's gas transmission assets in 2000. It owns the Moomba to Adelaide Pipeline, the Pilbara Energy Pipeline, the South West Queensland Pipeline and the QSN Link. APA Group has a 16.8 per cent interest in Hastings.

3.6.2 Regulation of transmission pipelines

The National Gas Law (Gas Law) and Gas Rules set out the regulatory framework for the gas transmission sector. On 1 July 2008 the AER replaced the Australian Competition and Consumer Commission as the regulator of pipelines outside Western Australia (where the Economic Regulation Authority is the regulator).

The Gas Law and Gas Rules apply to covered pipelines. The AER *State of the energy market 2009* report explains the coverage process and the different forms of economic regulation that may apply (section 9.3).

Table 3.3 indicates the coverage status of each major transmission pipeline. In summary, seven transmission pipelines are subject to *full regulation*, which requires the service provider to submit an access arrangement to the regulator for approval. An access arrangement sets out the terms and conditions under which third parties can use a pipeline. It must specify at least one reference service likely to be sought by a significant part of the market, and a reference tariff for that service. The AER has published an *Access arrangement guideline* (available on its website) that details the regulatory process. A separate guideline explains dispute resolution under the Gas Law.[14]

A pipeline may, in some circumstances, convert to *light regulation* without upfront price regulation. Where light regulation applies, the pipeline provider must publish access prices and other terms and conditions on its website. Four transmission pipelines are subject to light regulation: the Carpentaria Gas Pipeline in

13 DUET Group is the majority owner (60 per cent) of the Dampier to Bunbury Pipeline.

14 AER, *Access arrangement guideline*, 2009; AER, *Guideline for the resolution of distribution and transmission pipeline access disputes under the National Gas Law and National Gas Rules*, 2008.

Queensland, the covered portions of the Moomba to Sydney Pipeline, the Central West Pipeline in New South Wales, and the Kalgoorlie to Kambalda Pipeline in Western Australia.

The Gas Law anticipates the potential for market conditions to evolve, and includes a mechanism for reviewing whether a particular pipeline needs regulation. The coverage of several major transmission pipelines has been revoked over the past decade. In addition, only one pipeline constructed in the past decade is covered. In June 2010, the Minister for Resources and Energy granted a 15 year 'no coverage' determination for a proposed Queensland pipeline from the Surat Basin to Curtis Island. The pipeline's construction was scheduled to begin in 2010.

3.6.3 Recent investment in transmission pipelines

Table 3.4 summarises major transmission investment (including expansions of existing pipelines) since 2009. It also lists major projects that, in 2010, were under construction or had been announced for future development.

The development of Queensland's CSG industry continues to spur transmission pipeline investment. Epic Energy commissioned the QSN Link and expanded capacity on the South West Queensland Pipeline in 2009, to enable gas delivery between Queensland and the southern states. It was constructing a $760 million expansion of the QSN Link and South West Queensland Pipeline in 2010, and plans a further expansion by 2013. Also in Queensland, the planned development of LNG projects spurred plans for new transmission infrastructure to transport CSG to Gladstone for processing.

In Western Australia, new investment has centred on 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. A $690 million stage 5B expansion to add 120 terajoules per day of capacity was completed in 2010. The expansion involved 440 kilometres of looping. On completion, around 94 per cent of the pipeline had been duplicated. A stage 5C expansion has been announced for 2011–12.

3.7 Upstream competition

Investment over the past decade has developed an interconnected gas pipeline system linking gas basins in 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.

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 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 3.5–3.7 illustrate recent trends in gas delivery from competing basins into New South Wales, Victoria and South Australia since the bulletin board opened in July 2008:

- While New South Wales historically relied on Cooper Basin gas shipped on the Moomba to Sydney Pipeline, gas shipped on the Eastern Gas Pipeline from Victoria's Gippsland Basin now supplies an equivalent proportion of the state's gas requirements.
- 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.

- While the Moomba to Adelaide Pipeline historically transported most of South Australia's gas, the SEA Gas Pipeline now transports greater volumes of gas for that market. The Moomba to Adelaide Pipeline transports gas from Queensland's Surat–Bowen Basin via the QSN Link, and from South Australia's Cooper Basin. The SEA Gas Pipeline delivers gas from Victoria's Otway Basin.

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. 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 3.4 Major gas transmission pipeline investment since 2009

<table>
<tr><th>PIPELINE</th><th>LOCATION</th><th>OWNER/PROPONENT</th><th>SCALE</th><th>COST ($ MILLION)</th><th>COMPLETION DATE</th></tr>
<tr><td colspan="6">COMPLETED</td></tr>
<tr><td colspan="6">NORTH EAST AUSTRALIA</td></tr>
<tr><td>Wallumbilla to Darling Downs Pipeline</td><td>Qld</td><td>Origin Energy</td><td>205 km</td><td>90</td><td>2009</td></tr>
<tr><td>Berwyndale to Wallumbilla Pipeline</td><td>Qld</td><td>AGL Energy</td><td>113 km</td><td>70</td><td>2009</td></tr>
<tr><td>South West Queensland Pipeline—stage 1</td><td>Qld</td><td>Epic Energy</td><td>Expansion to 170 TJ/d</td><td rowspan="2">165</td><td rowspan="2">2009</td></tr>
<tr><td>QSN Link—stage 1</td><td>Qld–SA and NSW</td><td>Epic Energy</td><td>180 km, 250 TJ/d</td></tr>
<tr><td>Carpentaria Pipeline</td><td>Qld</td><td>APA Group</td><td>15% expansion to 117 TJ/d</td><td></td><td>2009</td></tr>
<tr><td>Queensland Gas Pipeline expansion</td><td>Qld</td><td>Jemena</td><td>Expansion from 79 TJ/d to 140 TJ/d</td><td>112</td><td>2010</td></tr>
<tr><td colspan="6">SOUTH EAST AUSTRALIA</td></tr>
<tr><td>South Gippsland Natural Gas Pipeline</td><td>Vic</td><td>Multinet Gas</td><td>250 km</td><td>50</td><td>2009</td></tr>
<tr><td>Eastern Gas Pipeline</td><td>Vic–NSW</td><td>Jemena</td><td>Expansion from 250 TJ/d to 268 TJ/d</td><td>41</td><td>2010</td></tr>
<tr><td colspan="6">WESTERN AUSTRALIA</td></tr>
<tr><td>Goldfields Gas Pipeline</td><td>WA</td><td>APA Group 88.2%, Alinta Energy 11.8%</td><td>20% expansion to 150 TJ/d</td><td></td><td>2009</td></tr>
<tr><td>Dampier to Bunbury stage 5B expansion</td><td>WA</td><td>DUET Group 60%, Prime Infrastructure 20%, Alcoa 20%</td><td>Expansion—additional 120 TJ/day</td><td>690</td><td>2010</td></tr>
<tr><td colspan="6">NORTHERN TERRITORY</td></tr>
<tr><td>Wickham Point Pipeline</td><td>NT</td><td>Energy Infrastructure Investments</td><td>13 km</td><td>36</td><td>2009</td></tr>
</table>

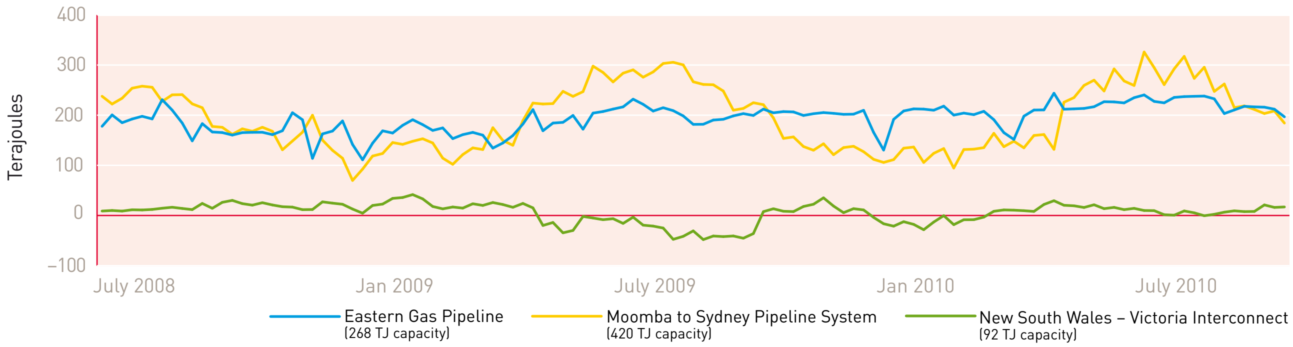
PIPELINE	LOCATION	OWNER/PROPONENT	SCALE	COST ($ MILLION)	COMPLETION DATE
UNDER CONSTRUCTION					
NORTH EAST AUSTRALIA					
South West Queensland Pipeline—stage 3	Qld	Epic Energy	Expansion by additional 212 TJ/d	760	2012
QSN link—stage 3	Qld–SA and NSW	Epic Energy			
SOUTH EAST AUSTRALIA					
Moomba to Sydney Pipeline	NSW	APA Group	Five year 20% capacity expansion	100	From 2008
ANNOUNCED					
NORTH EAST AUSTRALIA					
South West Queensland Pipeline—stage 2	Qld	Epic Energy	Expansion by additional 52 TJ/d	64	2013
QSN link—stage 2	Qld–SA and NSW	Epic Energy			
Queensland Hunter Pipeline (Wallumbilla to Newcastle)	Qld–NSW	Hunter Gas Pipeline	831 km	750–850	Construction commencing in 2012
Lions Way Pipeline (Casino to Ipswich)	NSW–Qld	Metgasco	145 km	120	Construction commencing in 2012
Gladstone LNG Pipeline (Fairview to Gladstone)	Qld	Santos	432 km		2014
Surat Basin to Gladstone	Qld	Arrow	450 km	500	
QCLNG Pipeline (Wandoan to Gladstone)	Qld	BG Group	340 km		Construction commencing in 2010
WESTERN AUSTRALIA					
Dampier to Bunbury stage 5C expansion	WA	DUET Group 60%, Prime Infrastructure 20%, Alcoa 20%	Expansion—additional 100 TJ/day		2011–12

TJ/d, terajoules per day.

Note: Projections of future scale, costs and completion dates are indicative.

Sources: ABARE, *Major development projects*, 2010; EnergyQuest, *Energy Quarterly* (various issues); National Gas Market Bulletin Board (www.gasbb.com.au); corporate websites, reports and media releases.

Figure 3.5
Gas flows into New South Wales



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

Figure 3.6
Gas flows into Victoria

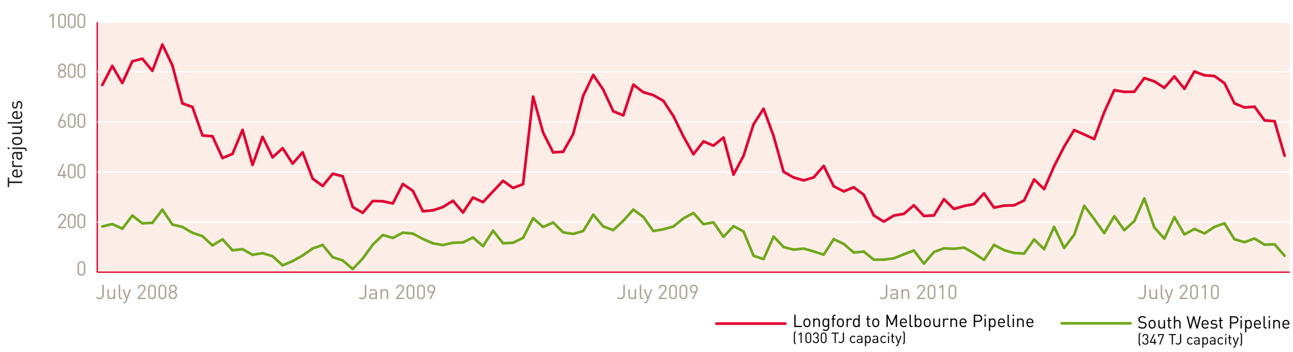
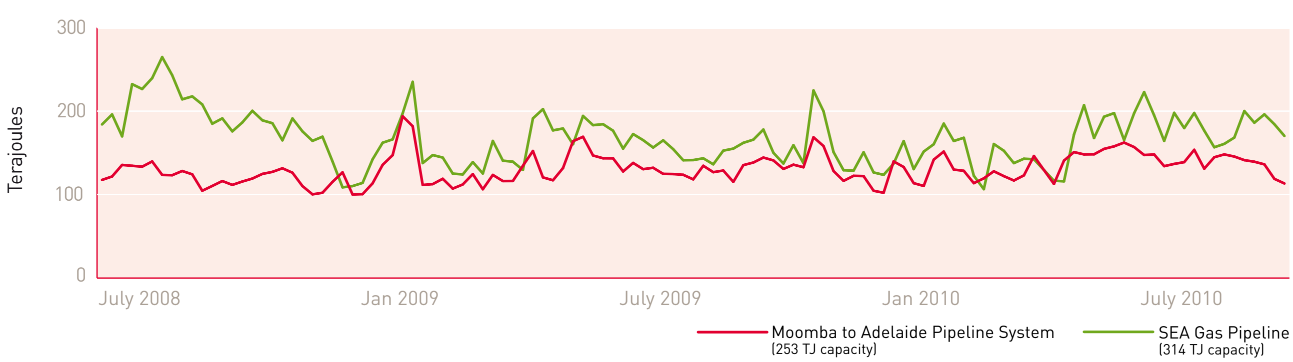


Figure 3.7
Gas flows into South Australia



Sources (figures 3.5–3.7): AER; Natural Gas Market Bulletin Board (www.gasbb.com.au).

3.8 Gas storage

Natural gas can be stored in its natural state in depleted underground reservoirs and pipelines or post liquefaction in purpose built facilities as LNG. Given Australia's increasing reliance on gas fired electricity generation, gas storage enhances security of supply by allowing for injections into the system at short notice to better manage peak demand and emergencies. It also allows producers to meet contract requirements if production is unexpectedly curtailed, and provides retailers with a hedging mechanism if gas demand is significantly above forecast.

The Dandenong LNG storage facility in Victoria (0.7 petajoules) is Australia's only LNG storage facility. It provides the Victorian Transmission System with peak shaving and security of supply services and truck loading services for LNG tankers. In 2010, AGL Energy announced it would develop a $300 million LNG storage facility in New South Wales by 2014 to ensure security of supply during peak periods and supply disruptions. There are also conventional gas storage facilities in Victoria, Western Australia and the Cooper Basin. Following its purchase of Mosaic Oil in 2010, AGL Energy is developing a CSG storage facility in Queensland, to be operational in 2011.

3.9 Gas distribution

A gas distribution network typically consists of high, medium and low pressure pipelines. The high and medium pressure mains provide a 'backbone' that services areas of high demand and transports gas between population concentrations within a distribution area. The low pressure pipes lead off the high pressure mains to end customers.

Natural gas is now reticulated to most Australian capital cities, major regional areas and towns. This chapter focuses on distribution networks in southern and eastern Australia, over which the AER has regulatory responsibilities. Table 3.5 summarises the major networks; figure 3.8 illustrates their locations.

The total length of gas distribution networks in the southern and eastern jurisdictions was nearly 73 000 kilometres in 2010. The networks have a combined value of almost $7 billion. Investment to augment and expand the networks is forecast at around $2.5 billion in the current access arrangement periods (typically five years).

3.9.1 Ownership of distribution networks

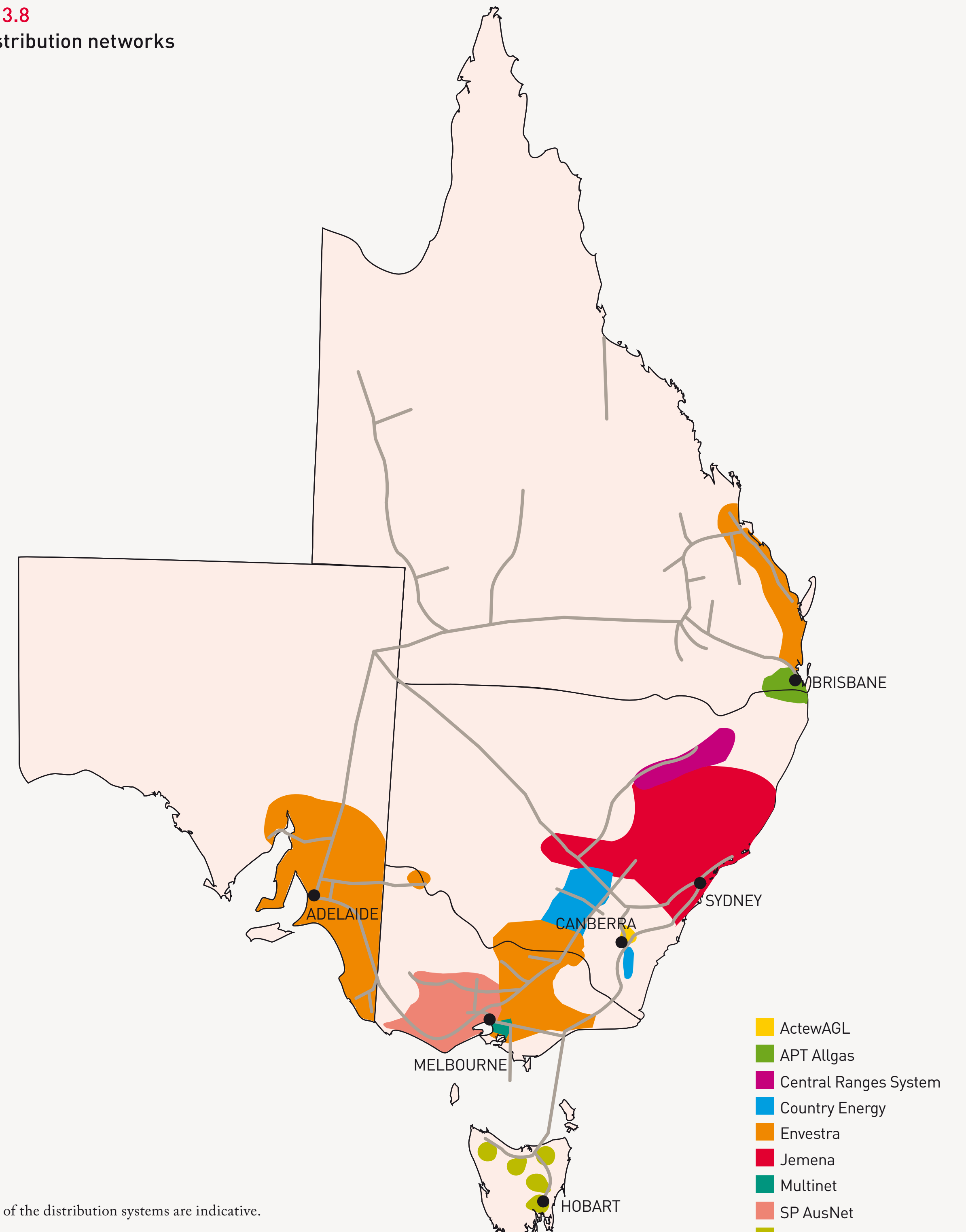
The major gas distribution networks in southern and eastern Australia are privately owned, with four principal players:

- *Jemena*, owned by *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).
- *Envestra*, a public company in which APA Group (32 per cent) and Cheung Kong Infrastructure (19 per cent) have shareholdings, owns networks in Victoria, South Australia, Queensland and the Northern Territory.
- *Prime Infrastructure* (formerly Babcock & Brown Infrastructure) owns the Tasmanian distribution network and has an interest in the Multinet network (Victoria).
- *APA Group* owns the APT Allgas networks in Queensland and has a 31 per cent stake in Envestra.

There are significant ownership links between gas distribution and other energy networks. In particular, Jemena and APA Group own and/or operate gas transmission pipelines (section 3.6.1). In addition, Jemena, APA Group, Cheung Kong Infrastructure and DUET Group all have ownership interests—in some cases, substantial interests—in the electricity network sector (chapter 2).

15 The unregulated 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.

Figure 3.8
Gas distribution networks



Notes:

Locations of the distribution systems are indicative.

Some corporate names are abbreviated.

Source: AER.

Table 3.5 Natural gas distribution networks in southern and eastern Australia

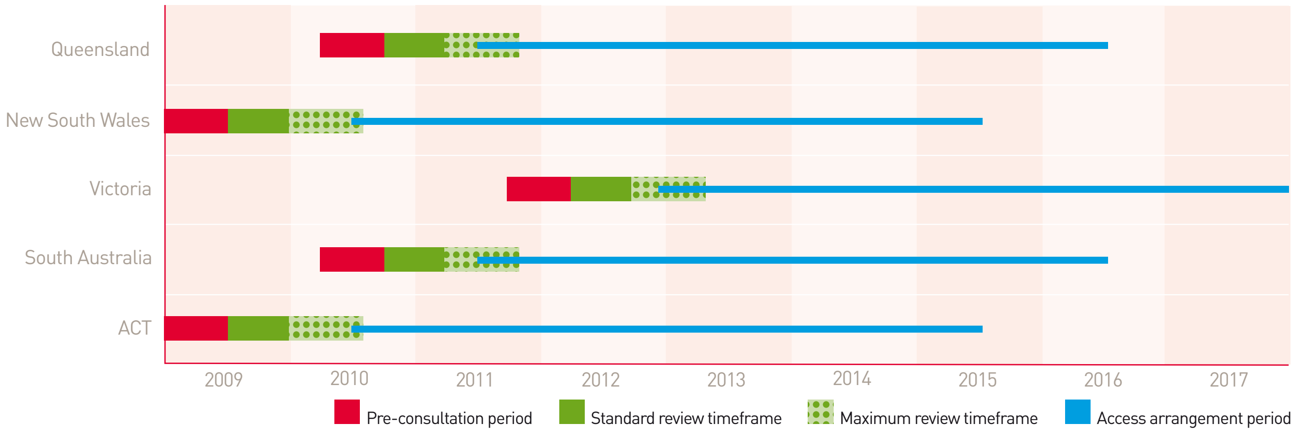
NETWORK	CUSTOMER NUMBERS	LENGTH OF MAINS (KM)	OPENING CAPITAL BASE (2009 $ MILLION)[1]	INVESTMENT—CURRENT ACCESS ARRANGEMENT (2009 $ MILLION)[2]	CURRENT ACCESS ARRANGEMENT PERIOD	OWNER
QUEENSLAND						
APT Allgas	75 000	2 800	367	143	1 Jul 2006 – 30 Jun 2011	APA Group
Envestra	82 500	2 510	265	106	1 Jul 2006 – 30 Jun 2011	Envestra (APA Group 31.7%, Cheung Kong Infrastructure 19%)
NEW SOUTH WALES AND ACT						
Jemena Gas Networks (NSW)	1 050 000	24 430	2 239	749	1 Jul 2010 – 30 Jun 2015	Jemena (Singapore Power International)
ActewAGL	112 000	4 200	272	85	1 Jul 2010 – 30 Jun 2015	ACTEW Corporation (ACT Government) 50%, Jemena (Singapore Power International) 50%
Wagga Wagga	18 700	680	20	59	1 Jul 2010 – 30 Jun 2015	Country Energy (NSW Govt)[3]
Central Ranges System	7 000	180	n/a	n/a	2006 – 19	APA Group
VICTORIA						
SP AusNet	570 000	9 400	969	347	1 Jan 2008 – 31 Dec 2012	SP AusNet (listed company; Singapore Power International 51%)
Multinet	646 600	10 010	901	235	1 Jan 2008 – 31 Dec 2012	DUET Group 79.9%, Prime Infrastructure 20.1%
Envestra	559 600	10 080	872	417	1 Jan 2008 – 31 Dec 2012	Envestra (APA Group 31.7%, Cheung Kong Infrastructure 19%)
SOUTH AUSTRALIA						
Envestra	393 800	7 800	956	216	1 Jul 2006 – 30 Jun 2011	Envestra (APA Group 31.7%, Cheung Kong Infrastructure 19%)
TASMANIA						
Tas Gas Networks	6 500	730	114[1]	Not regulated	Not regulated	Tas Gas (Prime Infrastructure)
NEM TOTALS	**3 521 700**	**72 820**	**6 975**	**2 357**		

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 2009 dollars.
2. Investment data are forecasts for the current access arrangement period, adjusted to June 2009 dollars.
3. In October 2010 Envestra entered an agreement to acquire Country Energy's Wagga Wagga network.

Sources: Access arrangements for covered pipelines; company websites.

Figure 3.9
Indicative timelines for AER determinations on gas networks



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

3.9.2 Regulation of distribution networks

The AER regulates all major distribution networks in New South Wales, Victoria, Queensland, Western Australia, South Australia and the ACT, following a transfer of this role from state and territory agencies in July 2008. The Economic Regulation Authority undertakes this role in Western Australia. The recently constructed Tasmanian network is the only major unregulated network. In addition, a number of small regional networks are unregulated.[15]

The Gas Law and Gas Rules set out the regulatory framework. Different forms of economic regulation apply to covered pipelines, based on criteria in the Gas Law. Most Australian distribution networks are subject to full regulation, which requires the service provider to submit an initial access arrangement to the regulator for approval, and revise it periodically (typically every five years).[16]

An access arrangement sets out the terms and conditions under which third parties can use a pipeline. It must specify at least one reference service likely to be sought by a significant part of the market, and a reference tariff for that service. The AER has published an *Access arrangement guideline* (available on its website) that details the regulatory process. A separate guideline explains dispute resolution under the Gas Law.[17] The AER *State of the energy market 2009* report (section 10.4) also outlines the regulatory process.

In summary, the regulatory process employs a building block approach to determine total network revenues and derive reference tariffs. The Gas Rules also allow for income adjustments from incentive mechanisms that reward efficient operating practices. In a dispute, an access seeker may request the regulator to arbitrate and enforce the terms and conditions of the access arrangement.

Figure 3.9 shows indicative regulatory timeframes for the networks. The AER approved access arrangements for the ACT and New South Wales gas distribution networks in 2010 (in April and June respectively). It also commenced in 2010 reviews of access arrangements for the South Australian and Queensland gas distribution networks.

16 A distribution pipeline may be subject to light regulation, in some circumstances, which means the service provider must publish the terms and conditions of access on its website. No distribution networks in Australia are covered by light regulation.

17 AER, *Access arrangement guideline*, 2009; AER, *Guideline for the resolution of distribution and transmission pipeline access disputes under the National Gas Law and National Gas Rules*, 2008.

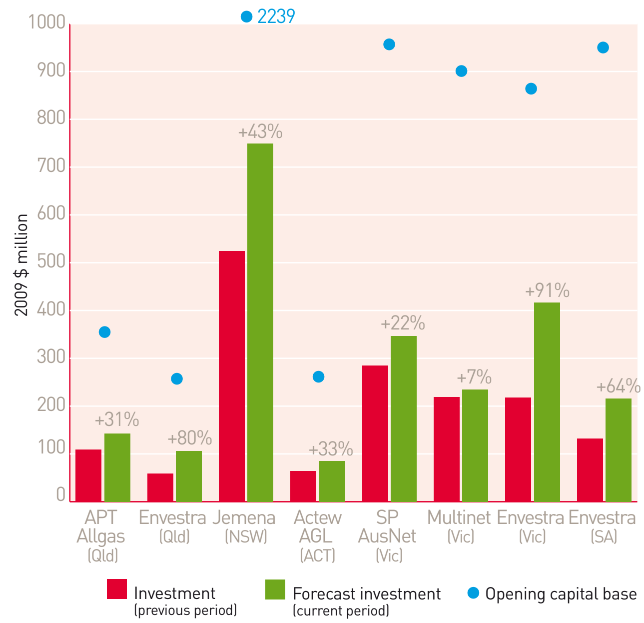
3.9.3 Investment in distribution networks

The capital drivers for gas distribution networks are broadly similar to those for electricity distribution—for example, the AER's 2010 determination for the New South Wales gas networks approved higher capital expenditure to meet demand growth and maintain network capacity. The underlying investment drivers included rising connection numbers, the development of renewal and replacement infrastructure to maintain the capacity of ageing networks, and infrastructure to support changes in market operations.

Figure 3.10 compares forecast investment over the current access arrangement periods (typically five years) for major distribution networks with outcomes in previous access arrangements. It also shows the opening capital bases for each network as a scale reference:

- Investment in the major networks is forecast at around $2.4 billion (in real terms) during the current access arrangement periods—a real increase of 43 per cent over investment in the previous periods.
- 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.
- Investment in the New South Wales and ACT distribution networks is forecast to rise by around 43 per cent and 33 per cent respectively over the current access arrangement period, compared with investment in previous periods. The AER approved these forecasts in its first decisions on the gas distribution sector, which it released in 2010.

Figure 3.10
Gas distribution network investment



Notes:

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

Investment data are forecast capital expenditure over the current access arrangement period (typically five years). See table 3.5 for the timing of current regulatory periods.

All values are converted to June 2009 dollars.

Sources: Access arrangements approved by the AER (New South Wales and the ACT), the ESC (Victoria), the QCA (Queensland) and ESCOSA (South Australia).