8 UPSTREAM GAS MARKETS

Matthias Kulka (Corbis)

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.[1] 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).[2]

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.[3]

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.[4]

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.

1 ABARE, *Minerals and energy: major development projects*, April 2009 listing, Canberra, 2009.
2 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.
3 A Schultz, *Energy Update 2009*, ABARE, August 2009, p. 2.
4 EnergyQuest, *Energy Quarterly*, August 2009.

Table 8.1 **Natural gas reserves and production in Australia, 2009**

GAS BASIN	PRODUCTION (YEAR TO JUNE 2009)		PROVED AND PROBABLE RESERVES[2] (JUNE 2009)	
	PETAJOULES	PERCENTAGE OF DOMESTIC SALES	PETAJOULES	PERCENTAGE OF AUSTRALIAN RESERVES
CONVENTIONAL NATURAL GAS[1]				
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.[5] The development of CSG has expanded rapidly in the current decade, and ongoing exploration will likely add to Australia's natural gas reserves.

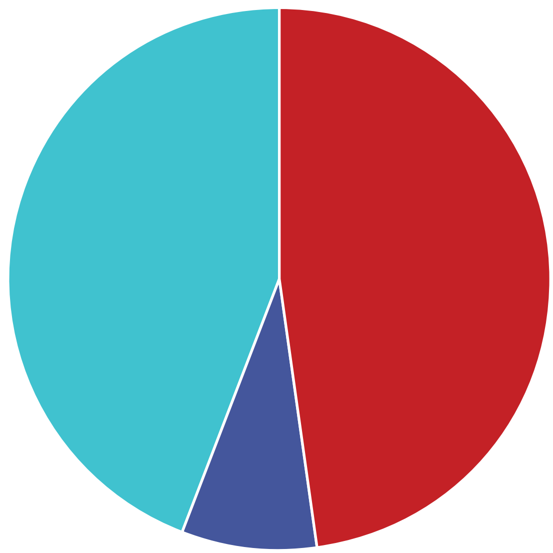
Australia produced 1780 PJ of natural gas in the year to June 2009, of which around 56 per cent was for the domestic market (figure 8.1). The CSG share of total production was only around 8 per cent, but is rising rapidly. Around 44 per cent of Australia's gas production—all currently sourced from offshore 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).

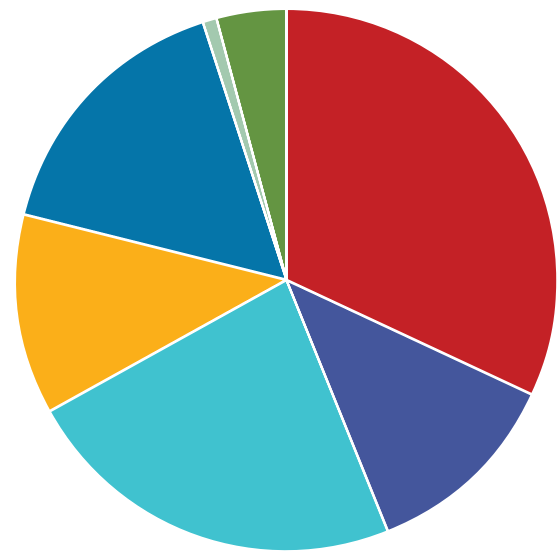
Figure 8.1
Australian natural gas production, 2008–09



CSG, coal seam gas; LNG, liquefied natural gas.

Source: EnergyQuest, *Energy Quarterly*, August 2009.

Figure 8.2
Natural gas production for domestic use, by gas basin, 2008–09



CSG, coal seam gas.

Note: 'Other' consists of the Perth, Amadeus and Bass basins.

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.[6] The small Perth Basin supplies just under 1 per cent of the domestic market.

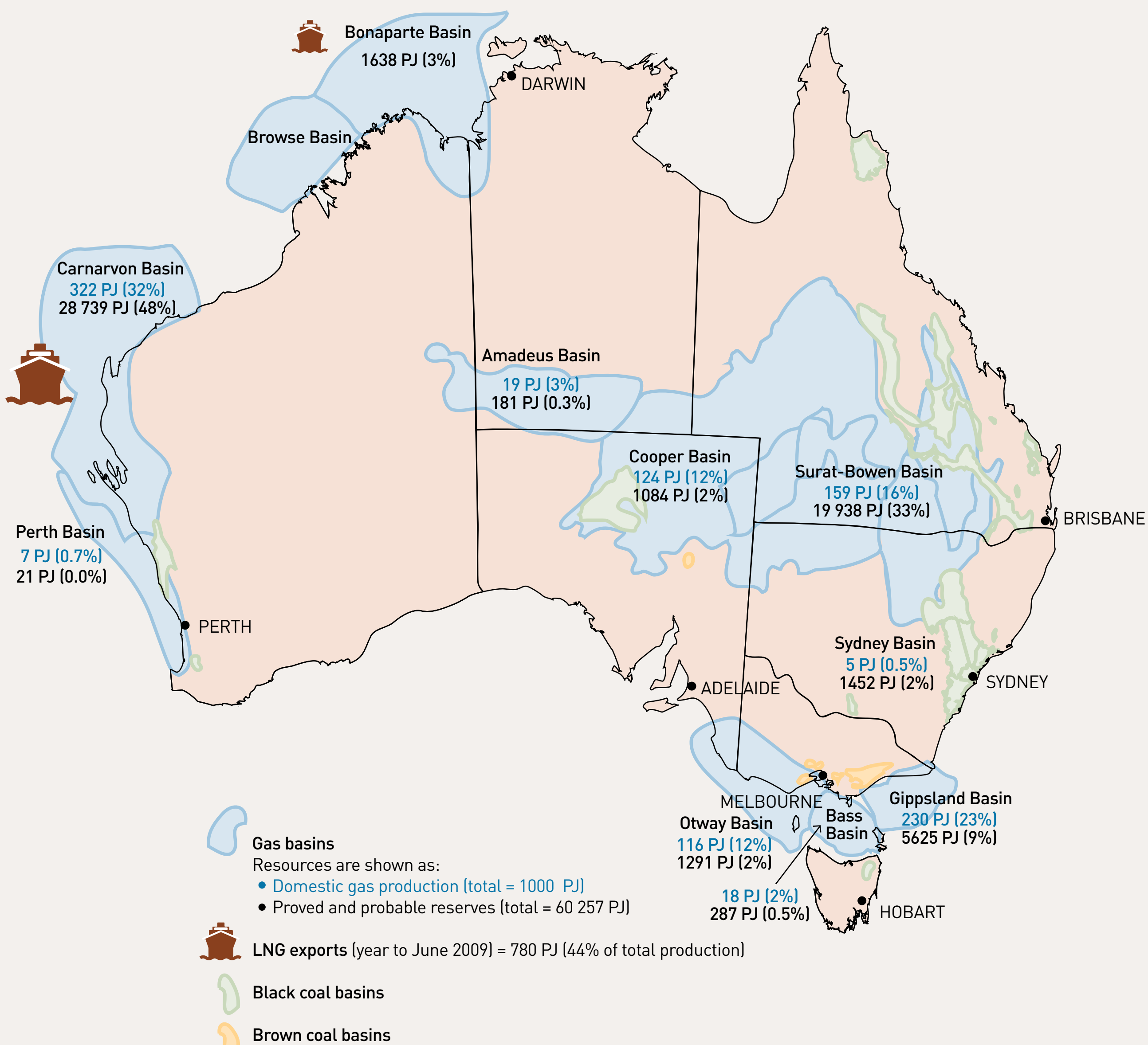
The Bonaparte Basin along the north west coast contains around 3 per cent of Australia's gas reserves. Its development has focused on producing LNG for export, although the Bonaparte Gas Pipeline was recently constructed to ship gas to Darwin for domestic consumption. This capacity will supplement gas 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.[7]

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.

7 EnergyQuest, *Energy Quarterly*, August 2009.

Figure 8.3
Australia's gas reserves and production, 2009

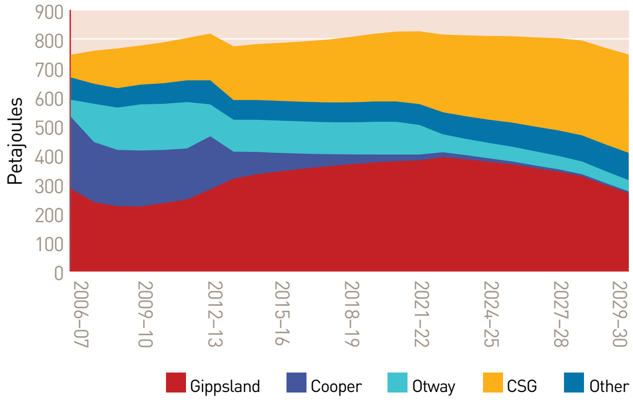


LNG, liquefied natural gas; PJ, petajoules.

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

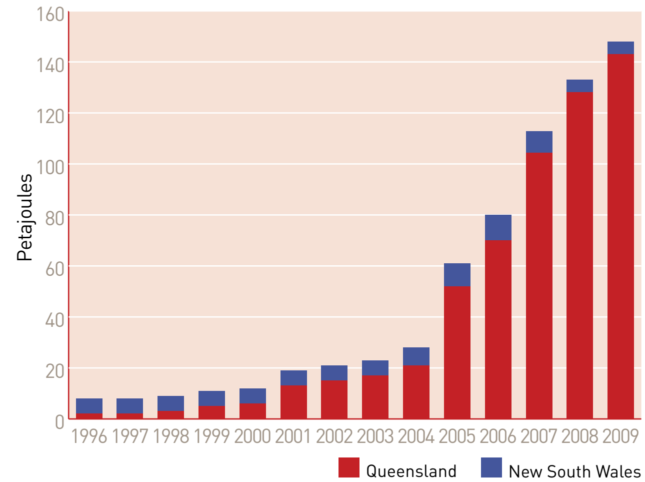


CSG, coal seam gas.

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.

Figure 8.5
Coal seam gas production



Note: 2009 data are for the year ended 30 June. Other data are for calendar years.

Source: EnergyQuest.

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.[8]

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 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,[9] and it meets over 70 per cent of the Queensland market.[10] In 2008–09 Queensland CSG production rose by around 18 per cent to about 143 PJ.[11]

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.

10 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.

11 EnergyQuest, *Energy Quarterly*, August 2009.

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).[12]

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.[13]

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.[14]

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.[15] 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.[16]

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

12 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.

13 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;

14 For further information on the gas transmission network, see chapter 9 of this report.

15 The AER's weekly gas reports are available at www.aer.gov.au/content/index.phtml/itemId/729309.

16 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:

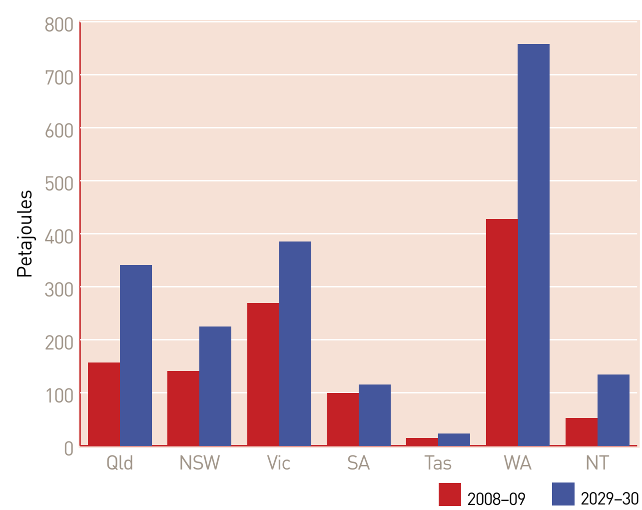
1. Surat–Bowen Basin (Queensland)—Berwyndale South, Fairview, Kenya, Kincora, Kogan North, Peat, Rolleston, Scotia, Spring Gully, Strathblane, Taloona, Wallumbilla and Yellowbank gas plants
2. Cooper Basin (South Australia / Queensland)—Moomba and Ballera gas plants
3. Otway Basin (Victoria)—Iona Underground 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.[17] 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.

Figure 8.6
Forecast primary gas consumption

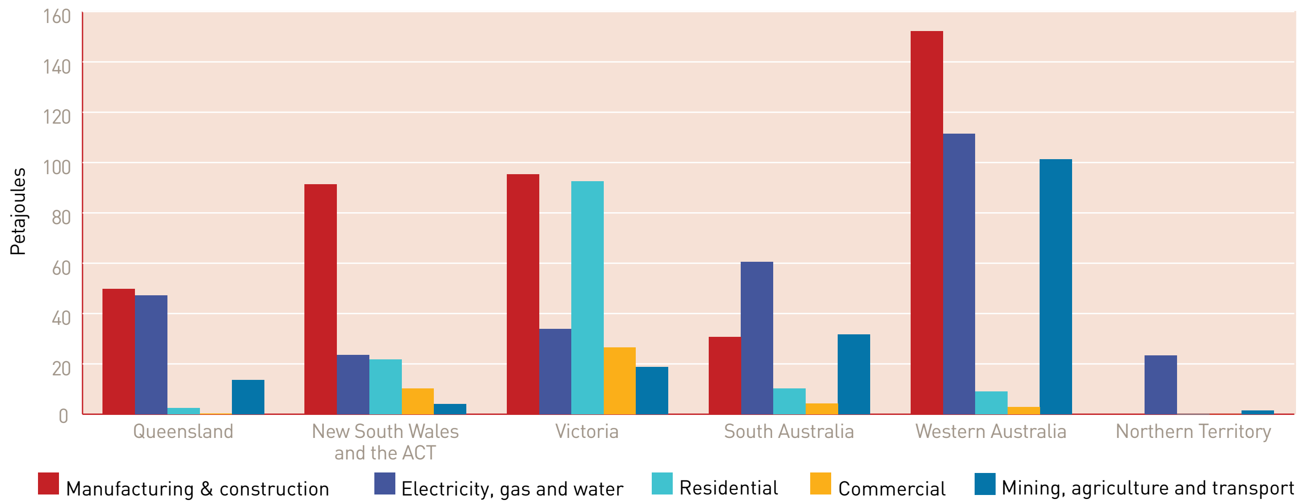


Source: A Syed, R Wilson, S Sandu, C Cuevas-Cubria and A Clarke, *Australian energy: national and state projections to 2029–30*, ABARE research report 07.24, prepared for the Australian Government Department of Resources, Energy and Tourism, Canberra, 2007.

The 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, 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.

17 EnergyQuest, *Energy Quarterly*, August 2009.

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.[18]

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).[19] 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.[20]

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.[21] 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.[22]

18 NERA, *The gas supply chain in eastern Australia*, Report to the AEMC, Sydney, March 2008, p. 16.

19 EnergyQuest, *Energy Quarterly*, August 2009.

20 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.

21 EnergyQuest, *Energy Quarterly*, August 2009.

22 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.

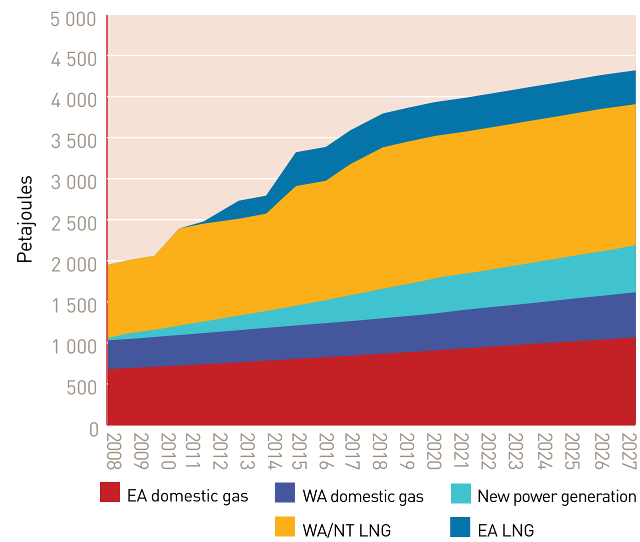
8.3.2 Links between international and domestic gas markets

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.[23]

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, 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.

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.

Source: ACIL Tasman, 'Australia's natural gas markets: the emergence of competition?', essay in AER, *State of the energy market 2008*, Melbourne, 2008.

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.[24] 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

23 ACIL Tasman, 'Australia's natural gas markets: the emergence of competition?', essay in AER, *State of the energy market 2008*, Melbourne, 2008.
24 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.[25] 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.[26]

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.

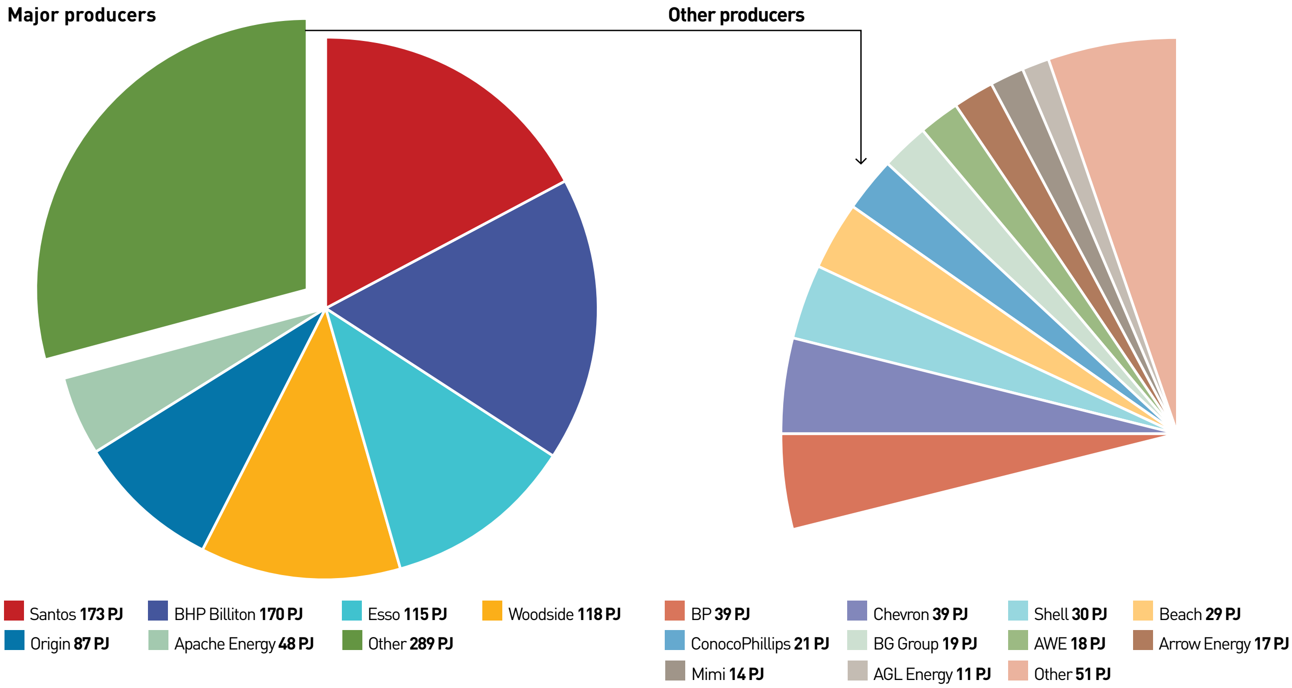
The structures of the exploration and development sector and the gas production sector differ somewhat, although many participants—especially the large corporations—are active in both. The three main types of entity involved in gas and oil exploration are:

- 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.

26 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.

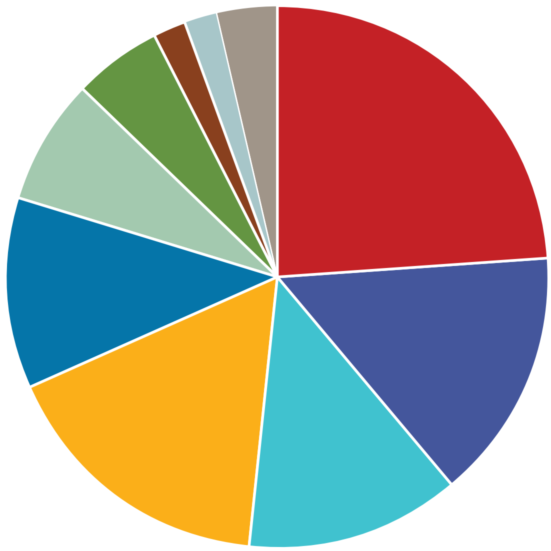
Source: EnergyQuest, *Energy Quarterly*, August 2009.

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.

Table 8.3 Market shares in domestic gas production, by basin, calendar year 2008 (per cent)

COMPANY	CARNARVON (WA)	PERTH (WA)	AMADEUS (NT)	COOPER (SA/QLD)	SURAT–BOWEN (QLD)	SYDNEY (NSW)	GIPPSLAND (VIC)	OTWAY (VIC)	BASS (VIC)	ALL BASINS (%)
AGL Energy					5.1	50.0				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
Tap	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**

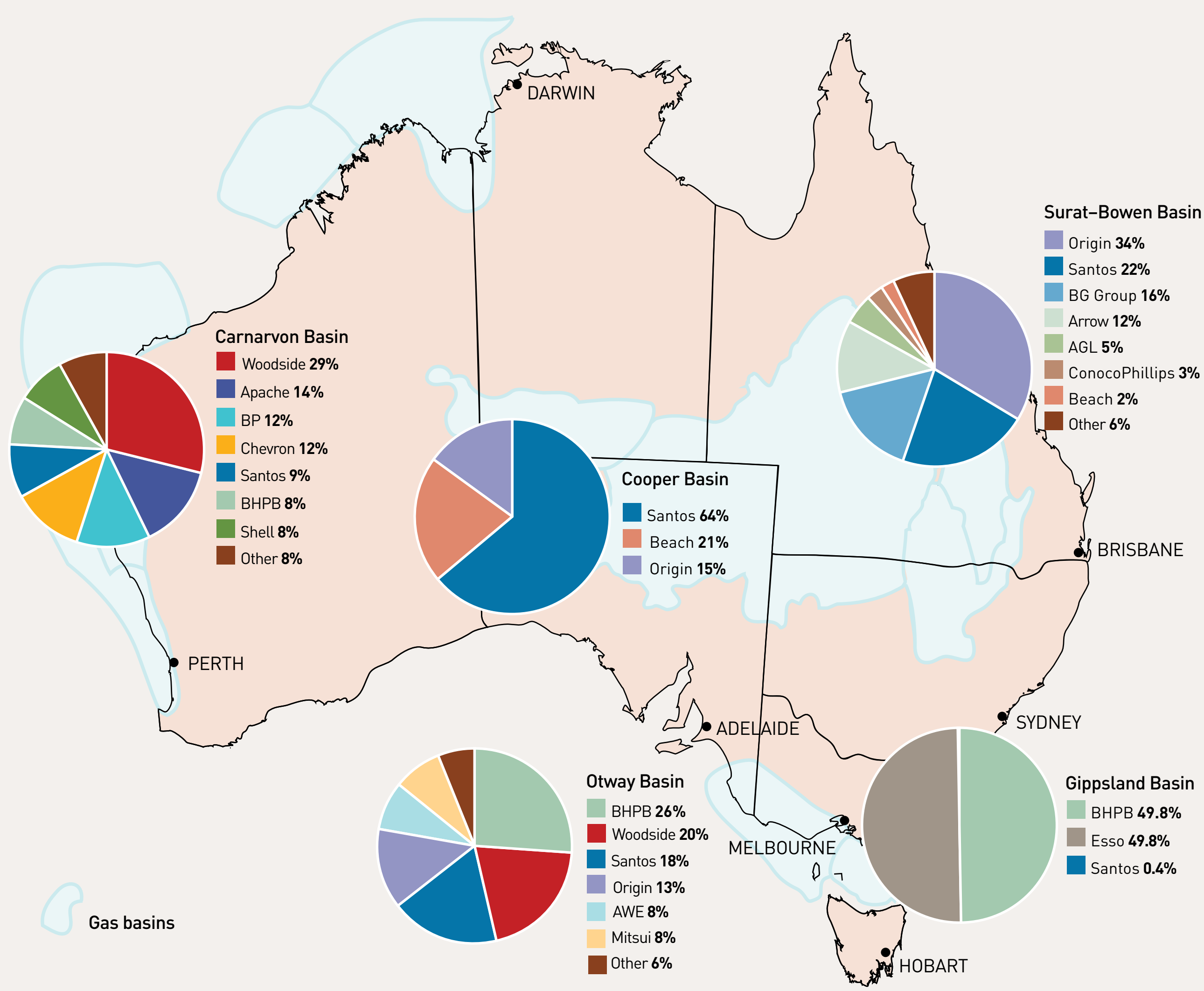
Notes:

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.

Table 8.4 Market shares in proved and probable gas reserves, by basin, May 2009 (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 (%)
Adelaide Energy												3.2		0.1
AGL Energy						2.9			100.0	100.0				1.3
AJ Lucas						0.3								0.1
Anglo						0.6								0.2
Apache Energy	4.6													2.3
Arrow Energy						10.0								2.9
AWE			53.8									8.2	42.5	0.5
Beach					20.7						1.3			0.5
Benaris												6.3		0.2
BG Group						26.4								7.8
BHP Billiton	11.9										42.7	13.1		10.6
BP	12.1													6.1
CalEnergy												2.5	15.0	0.1
Chevron	12.1													6.1
CNOOC	3.3													1.7
ConocoPhillips		9.4				16.5								5.1
CS Energy								11.4						0.1
Drillsearch					0.4									0.0
Eastern Star Gas							64.9							0.4
Eni		85.4												2.5
Esso											42.7			4.2
Gastar							35.1							0.2
Inpex		1.8												0.1
ITOCHU											0.9			0.1
Kansai Electric	0.8													0.4
Kufpec	0.1													0.1
Magellan				44.7										0.1
Metgasco								88.6						0.5
MIMI	11.8													6.0
Mitsui						0.6						8.2		0.4
Molopo						0.3								0.1
Mosaic						0.3								0.1
Nexus											6.2			0.6
Origin Energy			46.2		12.9	16.7						15.2	42.5	5.8
Petronas						7.7								2.3

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 (%)
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 and probable) reserves at May 2009.

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

Source: EnergyQuest 2009 (unpublished data).

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

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.

Table 8.5 Upstream gas merger and acquisition activity, June 2006 – September 2009

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 at Gladstone (joint venture)	Surat–Bowen (Qld)	Sales agreement signed June 2009 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

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.[27]

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).[28]

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.[29] Origin Energy and the South West Queensland

28 NERA, *The gas supply chain in eastern Australia*, Report to the AEMC, Sydney, March 2008, p. 26.
29 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.[30]

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.

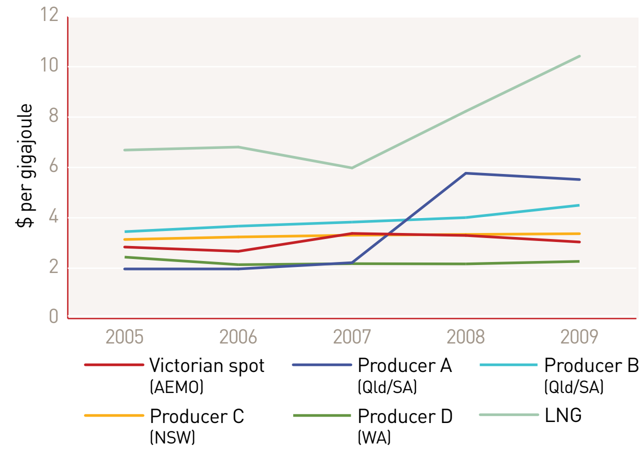
The establishment of the National Gas Market Bulletin Board in July 2008 and the development of a short term trading market at defined gas hubs (scheduled to commence by winter 2010) are likely to enhance market transparency and opportunities for gas trading at the major hubs of Sydney and Adelaide.

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 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.

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: EnergyQuest, *Energy Quarterly* (various editions); LNG data are sourced from the ABS.

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.[31]

Weaker economic growth—domestically and internationally—softened demand for natural gas in 2008 and 2009, and eased price pressure.

30 Details of the swap arrangement are provided in AER, *State of the energy market 2007*, box 8.4, Melbourne, 2007, p. 248.
31 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.[32] 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.[33]

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.[34] 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[35] to around $4 per gigajoule in 2008.[36] 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.[37]

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.[38]

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.

32 Department of Industry and Resources (Western Australia), *Western Australian oil and gas review 2008*, Perth, 2008.

33 EnergyQuest, *Energy Quarterly*, August 2008.

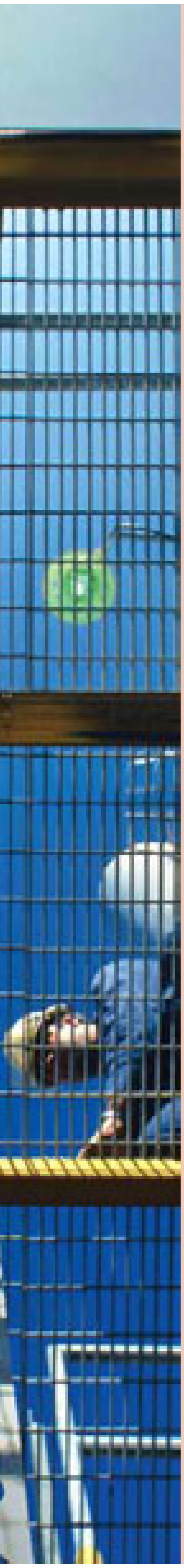
34 EnergyQuest, *Energy Quarterly*, August 2009, p. 73.

35 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.

36 ACIL Tasman, 'Australia's natural gas markets: the emergence of competition?', essay in AER, *State of the energy market 2008*, Melbourne, 2008, p. 47.

37 EnergyQuest, *Energy Quarterly*, August 2009, p. 72.

38 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.

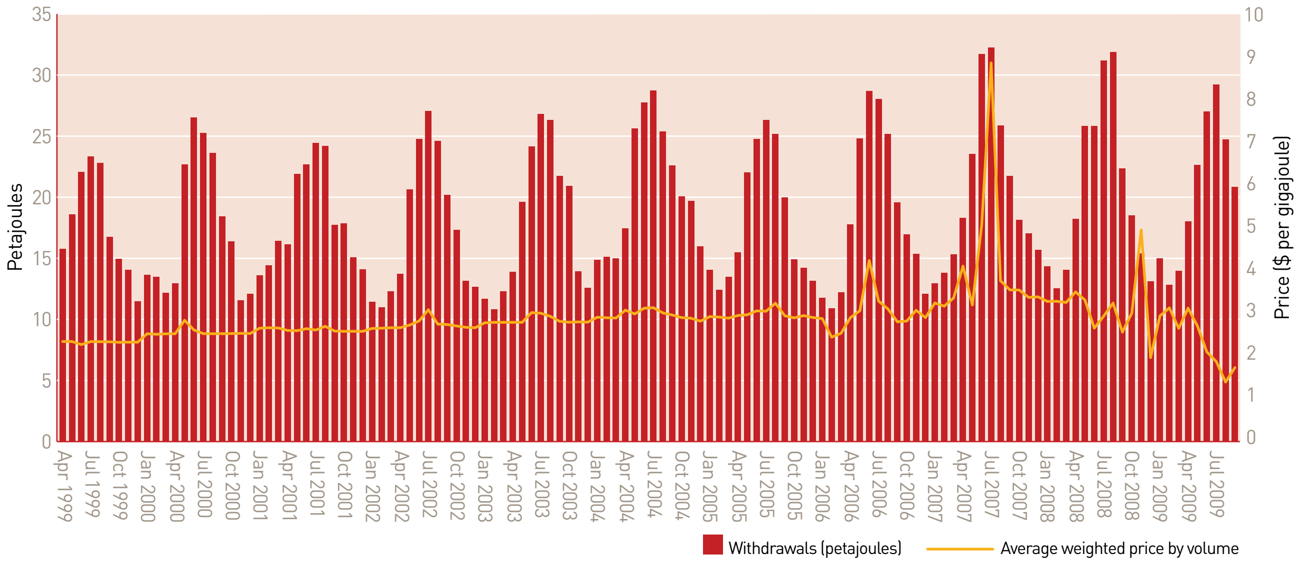
Gas prices have generally eased in 2009, reflecting a combination of factors:

- 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.[39]

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.

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.[40] Provision has been made for Western Australia, the Northern Territory and facilities in north Queensland to participate in the future.[41]

The bulletin board aims to provide transparent, real-time 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.[42] 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.[43]

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.

40 National Gas Market Bulletin Board website (www.gasbb.com.au).

41 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.

42 'Linepack' refers to the amount of gas stored in a pipeline.

43 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

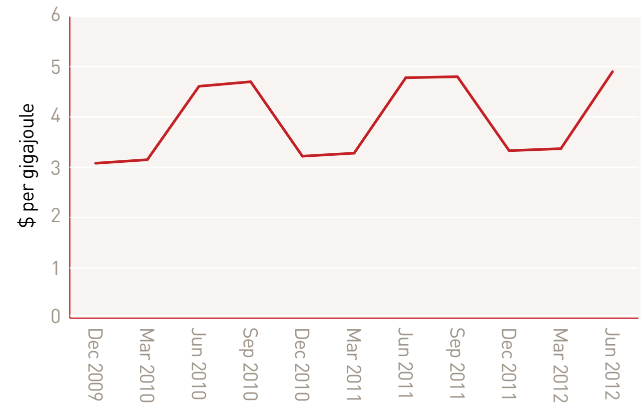
Participants in a commodity market can usually hedge their risk using physical or financial instruments. Internationally, gas futures markets tend to develop only after the underlying physical markets reach a certain level of maturity, with significant trading between buyers and sellers under transparent 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.[44] 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.[45] 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.[46]

45 Memorandum of Understanding in Relation to National Gas Emergency Response Protocol (Including Use of Emergency Powers), June 2005 (available at www.mce.gov.au).

46 For further information on the Varanus Island incident, see EnergyQuest's essay in this report, section E.5.