8 UPSTREAM GAS MARKETS

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The upstream gas industry encompasses several phases, including exploration for gas resources, field development, gas gathering and, finally, the processing of natural gas to meet customer and regulatory requirements. The wholesale gas market involves sales by producers to energy retailers and other major customers. While the gas wholesale market remains characterised by confidential long-term contracts, there have been a number of recent initiatives to increase market transparency and competitive conditions.

8 UPSTREAM GAS MARKETS

This chapter considers:

- Australia's natural gas resources
- exploration and development of gas resources
- gas production and consumption, including coal seam gas and liquefied natural gas
- upstream industry structure, including participants and ownership changes
- gas wholesale markets
- gas prices
- current market developments, including a gas market bulletin board and 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. 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; perceptions of risks and rewards; and the availability of finance.

The costs incurred during this phase relate to surveying and drilling to identify possible resources and the acquisition of exploration permits. In recent years, rising equipment costs have significantly increased the cost of offshore exploration and development.[1] Given the cost and risk characteristics, exploration tends to be undertaken through joint venture arrangements to enable costs to be shared. If exploration is successful, the joint venture parties may proceed to the production phase or sell their interest to other parties.

1 ERA, *Gas issues in Western Australia*, Discussion paper, Perth, 2007.

In 2007–08, petroleum exploration expenditure in Australia was forecast to increase by around 41 per cent to $3.2 billion—the highest on record.[2] The Australian Bureau of Agricultural and Resource Economics (ABARE) has linked the sharp increase to rising global oil prices. The rise is mainly accounted for by growth in offshore exploration in Western Australia. There has also been a significant rise in exploration activity in Queensland, mostly associated with coal seam gas (CSG) (see section 8.2).[3]

The right to conduct exploration activity—including seismic acquisition and exploratory drilling—and develop gas fields is controlled by governments. In Australia, the states and territories control onshore resources and resources in coastal waters while the Australian Government has jurisdiction over resources in offshore waters outside the three 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 ability to carry out the proposed work program, and any other criteria relevant to a tender. While the approach to issuing licences is relatively consistent across states and territories, there are significant differences in licence tenure and conditions.

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. 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 sugar cane residue) were forecast to supply about 4 per cent of Australia's primary energy consumption in 2007–08.[4]

Australia has abundant natural gas reserves (see table 8.1). At June 2008, total *proved and probable reserves*—those with reasonable prospects for commercialisation—stood at around 52 000 petajoules, comprising:

> 40 000 petajoules of conventional natural gas
> 12 000 petajoules of CSG.[5]

2 ABARE, *Minerals and energy: Major development projects–April 2008 listing*.

3 Australian Bureau of Statistics, *Mineral and Petroleum Exploration, ABS Cat. no. 8412.0*, March 2008; ABARE, *Minerals and energy: Major development projects–April 2008 listing*.

4 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 Industry, Tourism and Resources, Canberra, 2007, Table A3, p. 55. 'Primary energy' refers to the use of primary fuel in the conversion and end use sectors. It includes the consumption of fuels to produce electricity.

5 EnergyQuest, *Energy Quarterly*, August 2008.

Table 8.1 Natural gas reserves and production in Australia, 2008

GAS BASIN	PRODUCTION (YEAR TO JUNE 2008)		PROVED AND PROBABLE RESERVES[2] (JUNE 2008)	
	PETAJOULES	PERCENTAGE OF DOMESTIC SALES	PETAJOULES	PERCENTAGE OF AUSTRALIAN RESERVES
CONVENTIONAL NATURAL GAS[1]				
WESTERN AUSTRALIA				
Carnarvon	332	32.6	29 723	56.4
Perth	9	0.9	30	0.1
NORTHERN TERRITORY				
Amadeus	21	2.0	205	0.4
Bonaparte	0	0.0	1663	3.2
EASTERN AUSTRALIA				
Cooper (SA–Qld)	131	12.9	1129	2.1
Gippsland (Vic)	267	26.2	5602	10.6
Otway (Vic)	85	8.3	1429	2.7
Bass (Vic)	18	1.8	306	0.6
Surat–Bowen (Qld)	22	2.2	221	0.4
Total conventional natural gas	885	86.9	40 308	76.5
COAL SEAM GAS				
Surat–Bowen (Qld)	128	12.6	11 632	22.1
Sydney (NSW)	5	0.5	743	1.4
Total coal seam gas	133	13.1	12 375	23.5
DOMESTIC TOTALS	**1018**	**100.0**	**52 683**	**100.0**
LIQUIFIED NATURAL GAS (EXPORTS)				
Carnarvon (WA)	669			
Bonaparte (NT)	13			
Total liquified natural gas	682			
TOTAL PRODUCTION	**1700**			

Notes:

1. Conventional natural gas reserves include liquefied natural gas and ethane.
2. Proved reserves are those for which geological and engineering analysis suggests 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 2008.

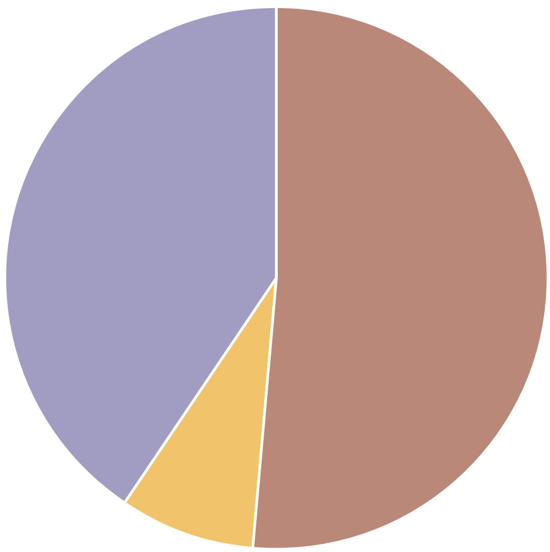
These estimates rise sharply to around 173 000 petajoules if *contingent resources*—known accumulations that are not yet commercially viable—are factored in.[6] The development of CSG has expanded rapidly in the current decade and ongoing exploration will likely add to Australia's natural gas reserves. For example, proved and probable reserves of CSG increased by around 145 per cent in the period from January 2007 to June 2008.[7]

Australia produced over 1700 petajoules of natural gas in the year to June 2008, of which around 60 per cent was for the domestic market (see figure 8.1). CSG accounts for around 8 per cent of total production,

6 Ministerial Council on Mineral and Petroleum Resources / Ministerial Council on Energy, *Final report of the Joint Working Group on Natural Gas Supply*, September 2007, p. 7.

7 EnergyQuest, *Energy Quarterly*, August 2008, p. 27.

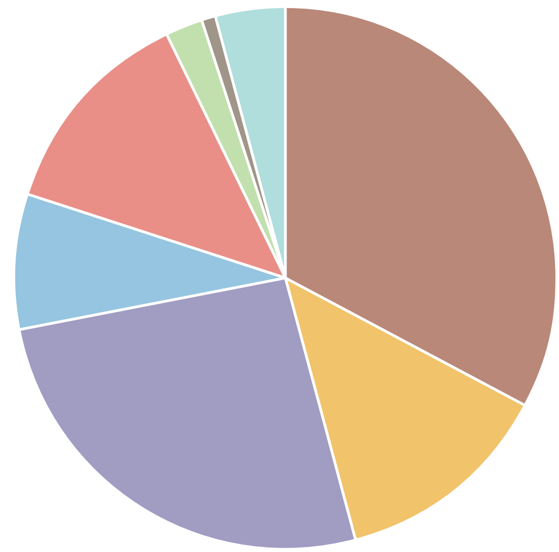
Figure 8.1
Australian natural gas production, 2007–08



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

Source: EnergyQuest, *Energy Quarterly*, August 2008.

Figure 8.2
Natural gas production for domestic use by location, 2007–08



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

Source: EnergyQuest, *Energy Quarterly*, August 2008.

but its share is rising rapidly. Around 40 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). At current projected rates of production, Australia has sufficient proved, probable and contingent reserves to meet domestic and export demand for around 66 years.[8]

8.2.1 Geographical distribution

Figure 8.3 (overleaf) shows the location of Australia's major natural gas basins, including reserves and production levels. Figure 8.2 sets out the contribution of each basin to Australia's natural gas production for the domestic market. The principal sources of natural gas production are Western Australia's offshore Carnarvon Basin and Victoria's offshore Gippsland Basin. 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 are declining. Production in Queensland's Surat–Bowen Basin and Victoria's Otway Basin has risen sharply during the current decade.

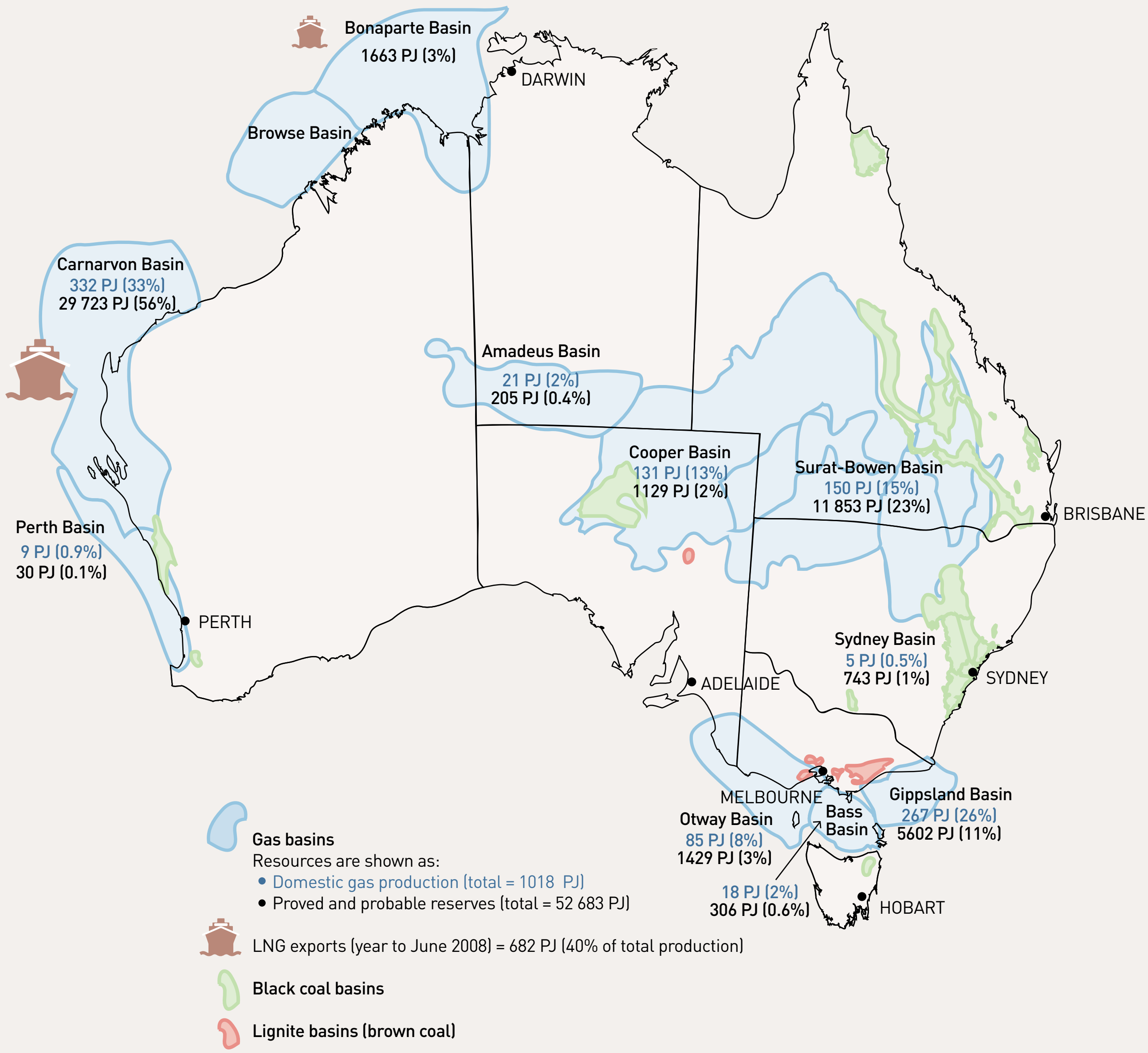
Western Australia's Carnarvon Basin holds about 56 per cent of Australia's natural gas reserves. It supplies around one-third of Australia's domestic market and 98 per cent of Australia's LNG exports. The small Perth Basin supplies about 1 per cent of the domestic market.

The Bonaparte Basin along the north-west coast contains around 3 per cent of Australia's gas reserves. The basin's development has focused on LNG for export. The first LNG exports from the basin were shipped from Darwin in 2006. The Amadeus Basin, which currently supplies gas for use within the Northern Territory, is in decline and will soon be supplemented by gas from the Bonaparte Basin.

8 Ministerial Council on Mineral and Petroleum Resources / Ministerial Council on Energy, *Final report of the Joint Working Group on Natural Gas Supply*, September 2007, p. 7.

Figure 8.3

Australia's gas reserves and production, 2008



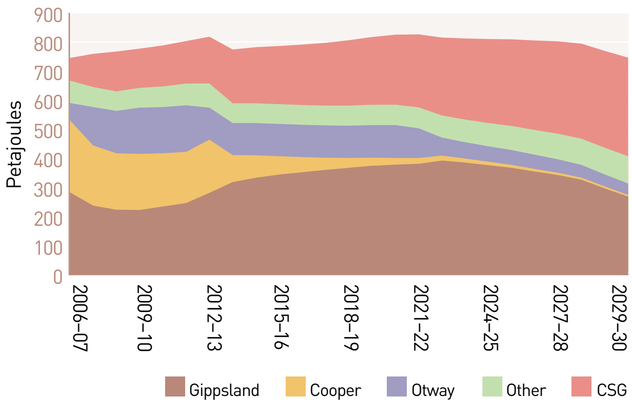
LNG, liquefied natural gas; PJ, petajoules.

Note: Production data for year ended 30 June 2008. Reserves at June 2008.

Sources: EnergyQuest, *Energy Quarterly*, August 2008; K Donaldson, *Energy in Australia 2006*, ABARE report, prepared for the Australian Government Department of Industry, Tourism and Resources, Canberra, 2007.

Figure 8.4

Forecast sources of eastern Australia's natural gas production



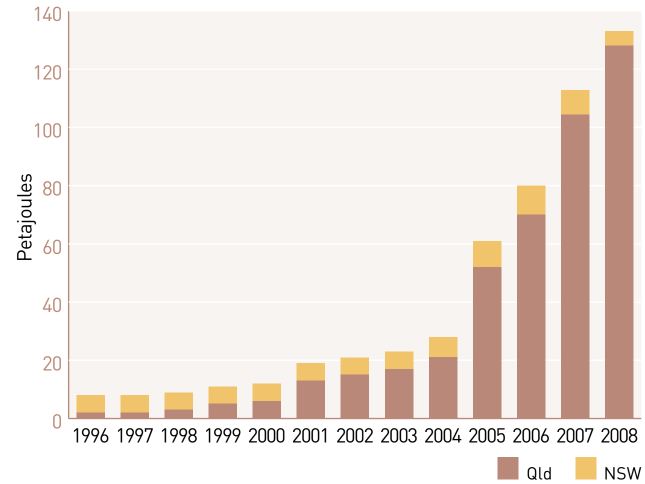
CSG, coal seam gas.

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: 2008 data are for the year ended 30 June. Other data are for calendar years.

Source: EnergyQuest.

Eastern Australia has around 40 per cent of Australia's natural gas reserves, the majority of which are CSG. The principal sources are the Surat–Bowen Basin in Queensland (which meets around 15 per cent of national demand), the Gippsland Basin off coastal Victoria (26 per cent) and the Cooper Basin in central Australia (13 per cent). Production in Victoria's offshore Otway (8 per cent) and Bass (2 per cent) basins has risen significantly since 2004.[9]

A number of changes are forecast in the geography of gas production in eastern and central Australia over the next 25 years (see 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.

Production of CSG has risen exponentially since 2004 (see 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 gas prices have also strengthened the commercial viability of the resource.

Queensland CSG has a variety of commercial advantages, including that it is found closer to the surface and under lower pressure than conventional natural gas. It also tends to have a relatively high concentration of methane, lower levels of impurities and is closer to some markets. These features also allow for a more incremental investment in production and transport than is required when bringing a conventional natural gas development on stream.

9 Data sourced from EnergyQuest, *Energy Quarterly*, August 2008.

While CSG is produced only in Queensland and New South Wales, it is the fastest growing gas production sector: it supplied almost 20 per cent of gas produced in eastern Australia in the year to June 2008,[10] and meets around 70 per cent of the Queensland market.[11] ACIL Tasman forecasts that Queensland production may rise by around 60 per cent during 2008 to about 160 petajoules.[12]

ABARE published forecasts in 2007 that CSG production will supply around 32 per cent of the eastern Australian gas market by 2011–12. It also forecast that production will reach around 529 petajoules by 2029–30, making it the principal source of gas supply in eastern Australia (as shown in figure 8.4).[13]

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 between three regional markets—eastern Australia, Western Australia and the Northern Territory.[14]

An interconnected transmission pipeline network enables gas producers in the Cooper, Gippsland, Otway, Bass and Sydney basins to sell gas to customers across South Australia, Victoria, New South Wales, the ACT and Tasmania. The construction of a new transmission pipeline—the QSN Link—will interconnect Queensland with the south-eastern jurisdictions from 2009. This will allow gas producers in the Surat–Bowen Basin to market gas throughout southern and eastern Australia.[15] At present, there is no LNG export facility in eastern Australia.

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 creates exposure in 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 and commenced LNG exports from the Bonaparte Basin in 2006.

8.3 Domestic and international demand for Australian gas

Australia consumed around 1020 petajoules of natural gas in the year to June 2008, including conventional natural gas and CSG.[16] 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. Natural gas 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.

10 EnergyQuest, *Energy Quarterly*, August 2008.

11 Minister for Mines and Energy (Qld) (Hon. Geoff Wilson), *Coal seam methane for a cleaner energy future*, Press Release, 13 September 2007.

12 ACIL Tasman, *Australia's natural gas markets: The emergence of competition?* (lead essay of this report), 2008, p. 3.

13 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.

14 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*, September 2007, pp. 7–8; ACIL Tasman, *Australia's natural gas markets: The emergence of competition?* (lead essay of this report), 2008, p. 2.

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

16 EnergyQuest, *Energy Quarterly*, August 2008.

Figure 8.6
Primary gas consumption (forecasts)

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.

Figure 8.6 sets out ABARE forecast data on primary consumption of natural gas by state and territory in 2007–08 and 2029–30. Western Australia and Victoria have the highest consumption levels, while demand growth is forecast to be strongest over the next 20 years in Queensland, Western Australia and the Northern Territory.

The consumption profile varies between the jurisdictions (see 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.

8.3.1 Liquefied natural gas exports

LNG is produced by converting natural gas into liquid. The development of an LNG export facility requires large up-front capital investment in processing plant and port and shipping facilities. The magnitude of investment means that a commercially viable LNG project requires access to substantial reserves of natural gas. The reserves may be sourced from the LNG owner's interests in a gas field, a joint venture arrangement with a natural gas producer or through long-term gas supply contracts.[17]

Australia has LNG export projects in the North West Shelf (annual capacity of 11.9 million tonnes but scheduled to rise to over 16 million tonnes in 2008) and Darwin (annual capacity of 3.5 million tonnes). ABARE forecasts that expansion of existing projects and greenfield LNG projects will increase export capacity to around 24 million tonnes by 2011–12 and 76 million tonnes by 2029–30. This would support an annual growth in LNG exports of 7.8 per cent over the period to 2029–30.[18]

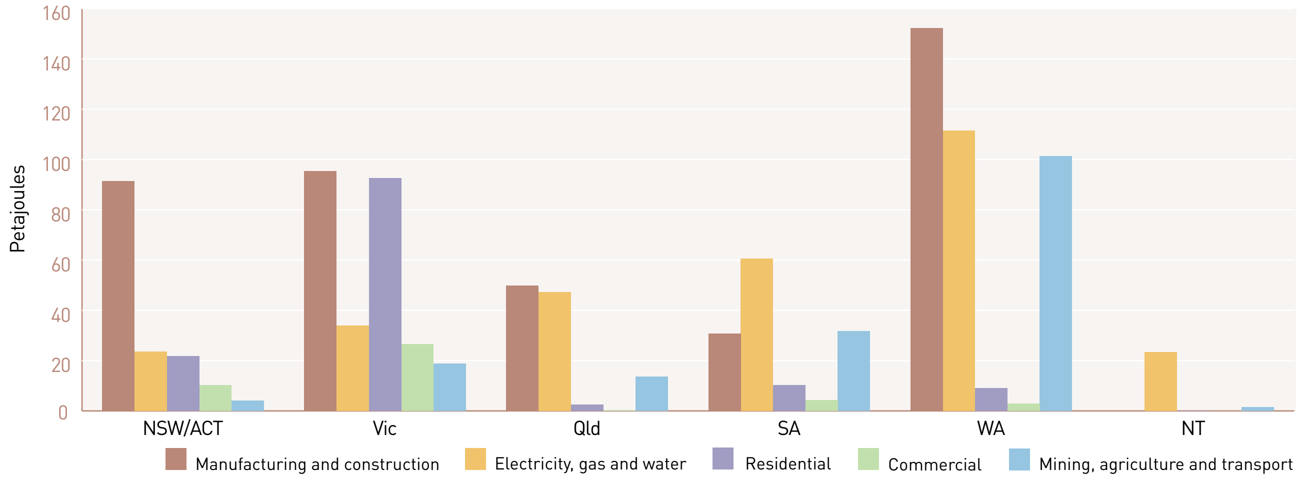
Australia is the world's fifth largest LNG exporter after Qatar, Indonesia, Malaysia and Algeria (see figure 8.8). In the year to June 2008, Australia exported around 682 petajoules of LNG, mostly from the Carnarvon Basin.[19] LNG shipments from Darwin began in February 2006. LNG accounts for around 40 per cent of Australia's natural gas production. ABARE projects that this ratio will rise to around 68 per cent by 2029–30.[20]

Rising international LNG prices together with rapidly expanding reserves of CSG in Queensland have recently 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 proposals range in size from 0.5 to 4 million tonnes of LNG per year. ACIL Tasman assessed in 2008 that the economics of the projects appear to be sound.[21] EnergyQuest

17 NERA, *The gas supply chain in eastern Australia*, A report to the AEMC, March 2008, p. 16.
18 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. 43.
19 EnergyQuest, *Energy Quarterly*, August 2008.
20 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.
21 ACIL Tasman, *Australia's natural gas markets: The emergence of competition?* (lead essay of this report), 2008, p. 26.

Figure 8.7

Primary natural gas consumption by industry

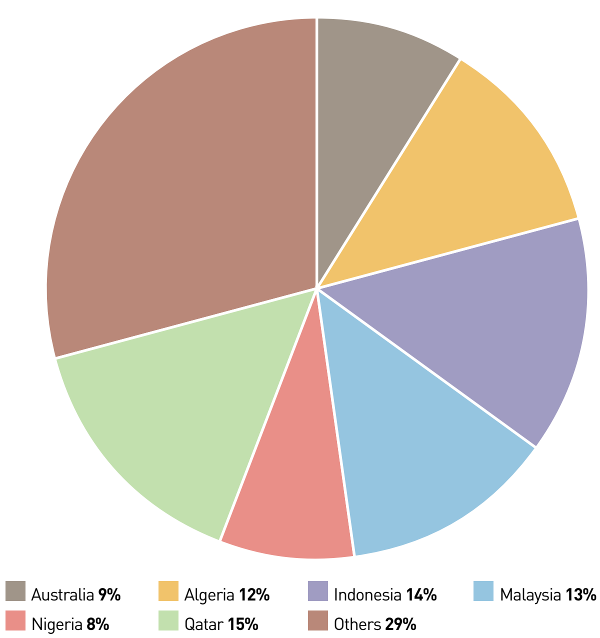


Note: Data for year ended 30 June 2005.

Source: ABARE.

Figure 8.8

World liquefied natural gas exports by country, 2006



Source: IEA statistics, *Natural gas information 2007*, table 19.

argued in August 2008 that the increasing involvement of major international players in east coast LNG projects makes it 'no longer a question of whether east coast LNG will proceed but rather when and how much'.[22]

8.3.2 Adequacy of supply

ACIL Tasman estimates that underlying gas demand in Australia could grow on average by around 2.4 per cent annually over the next 20 years. It also estimates that LNG exports from Western Australia and the Northern Territory could reasonably increase by around 90 per cent over this period.[23] ABARE projects that domestic demand will rise most strongly in Western Australia, Queensland and the Northern Territory (figure 8.6). Key contributors to the growth include greater use of gas in electricity generation, mining and energy-intensive refining.

There has been some debate as to the adequacy of domestic sources to satisfy Australia's natural gas demand over time. Recent assessments have highlighted contrasting conditions between Western Australia, the Northern Territory and eastern Australia.

The Western Australian gas market has experienced considerable tightening since 2006, with rising

22 EnergyQuest, *Energy Quarterly*, August 2008, p. 19.

23 ACIL Tasman, *Australia's natural gas markets: The emergence of competition?* (lead essay of this report), 2008, p. 28.

production costs and strong domestic demand occurring at a time when most producers have fully contracted their developed reserves. In addition, Western Australia's LNG export capacity makes the domestic market relatively sensitive to international energy prices, which have increased significantly since 2005.

In combination, these factors have led to a substantial rise in domestic prices in Western Australia, with some contracts in 2007 being negotiated at around $7 per gigajoule compared to typical prices of around $2.50 earlier in the decade.[24] In June 2008, an explosion at the Varanus Island gas facility reduced domestic gas supplies by 30 per cent for over two months and put further pressure on short-term prices (see section 8.6). There have been projections that Western Australia will face difficulties achieving a supply–demand balance until at least 2010.[25]

There have been some suggestions that the opening of an LNG export facility in the Northern Territory in 2006 could affect the availability of gas supplies there. While supply contracts in the Territory 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.[26]

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 between the eastern gas basins has enhanced the flexibility of the market to respond to customer demand. The construction in 2008 of the QSN Link pipeline from Queensland to southern Australia will result in an interconnected pipeline network linking Queensland, New South Wales, the ACT, Victoria, South Australia and Tasmania (see chapter 9). In addition, the rapid escalation of CSG reserves in Queensland has at least delayed the need to invest in new pipelines to ship gas from sources such as Papua New Guinea.

While new pipeline investment and rising CSG reserves are strengthening the supply base, a number of factors may also put upward pressure on demand. While eastern Australia is currently insulated from global gas markets, this may change if any of several proposed LNG export projects comes to fruition.[27] The introduction of the Carbon Pollution Reduction Scheme will also likely increase reliance on natural gas as a fuel for electricity generation.

Figure 8.9 illustrates ACIL Tasman forecasts of the demand for natural gas over the next 20 years, taking into account the projected effects of the Carbon Pollution Reduction Scheme. ACIL Tasman forecasts that demand growth will be principally driven 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 petajoules (including exports) over the next 20 years.[28]

The net impact of rising demand for natural gas (from electricity generation and LNG exports) coupled with rising reserves (particularly from CSG) is difficult to predict. In a report published in July 2007, McLennan Magasanik Associates found that the eastern market supply outlook was relatively benign in the medium to long term, and that buyers and sellers appear willing to contract ahead to avoid supply shocks.[29]

ABARE reached similar findings in a December 2007 report, which projected that the positive outlook for

24 Department of Industry and Resources (WA), *Western Australian Oil and Gas Review*, 2008; ACIL Tasman, *Australia's natural gas markets: The emergence of competition?* (lead essay of this report), 2008.

25 Ministerial Council on Mineral and Petroleum Resources / Ministerial Council on Energy, *Final report of the Joint Working Group on Natural Gas Supply*, September 2007, p. 10.

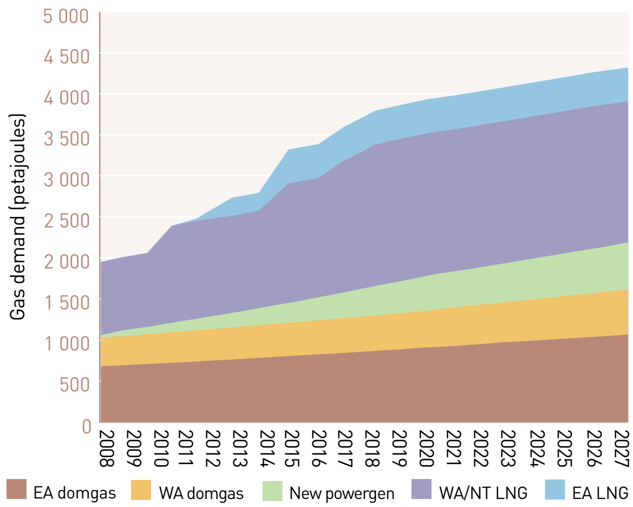
26 Ministerial Council on Mineral and Petroleum Resources / Ministerial Council on Energy, *Final report of the Joint Working Group on Natural Gas Supply*, September 2007, p. 11.

27 See ACIL Tasman, *Australia's natural gas markets: The emergence of competition?* (lead essay of this report), 2008 for a more detailed discussion of these factors.

28 ACIL Tasman, *Australia's natural gas markets: The emergence of competition?* (lead essay of this report), 2008.

29 R Lewis, M Goldman and R Farmer, *Report to the Joint Working Group on Natural Gas Supply: Natural gas in Australia*, McLennan Magasanik Associates, July 2007.

Figure 8.9
Australian gas demand outlook



EA, eastern Australia; WA, Western Australia; NT, Northern Territory; domgas, domestic gas; new powergen, new power generation.

Note: Forecasts take into account the projected effects of the Carbon Pollution Reduction Scheme and LNG expansion.

Source: ACIL Tasman, *Australia's natural gas markets: The emergence of competition?* (lead essay of this report), 2008.

natural gas production from CSG would result in the eastern gas market remaining in balance over the period to 2029–30. The assessment did not account for the effects of the Carbon Pollution Reduction Scheme or LNG exports from eastern Australia.[30]

A recent ACIL Tasman assessment found that a 4 million tonne per year LNG plant (as proposed by Santos in 2007) would potentially divert very significant quantities of gas to exports. ACIL Tasman argues that while this may not leave the domestic market short of supply, it would likely require earlier reliance on higher-cost and less productive sources of CSG than in the absence of the LNG projects. This would have implications for domestic gas prices.[31]

A joint working group established by the Ministerial Council on Energy (MCE) reported in September 2007 on how best to balance the dual objectives of building Australia's LNG export capabilities while ensuring the long-term supply of competitively priced gas for domestic users.[32] The report recommended that attention be centred on:

> improving acreage management processes
> improving gas market efficiency, including through the development of a bulletin board covering major gas production fields, demand centres and transmission pipelines, and the development of a short-term trading market for natural gas (these reforms are being progressed in 2008: see section 8.7 and appendix A)
> developing an annual national gas statement of opportunities, similar to the statement currently prepared for the electricity sector (this reform is also being progressed in 2008: see section 8.7 and appendix A).

8.4 Industry structure

The prevalence of high sunk costs and the relatively small number of Australian gas fields means that the supply of natural gas is concentrated in the hands of a small number of producers.[33] 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), Beach Petroleum and Origin Energy.

There are some differences between the structure of the exploration and development sector and the gas production sector, although many participants—especially the large corporations—are active in both.

There are three main types of entities involved in gas and oil exploration. These are:

30 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, pp. 1, 42, 43.

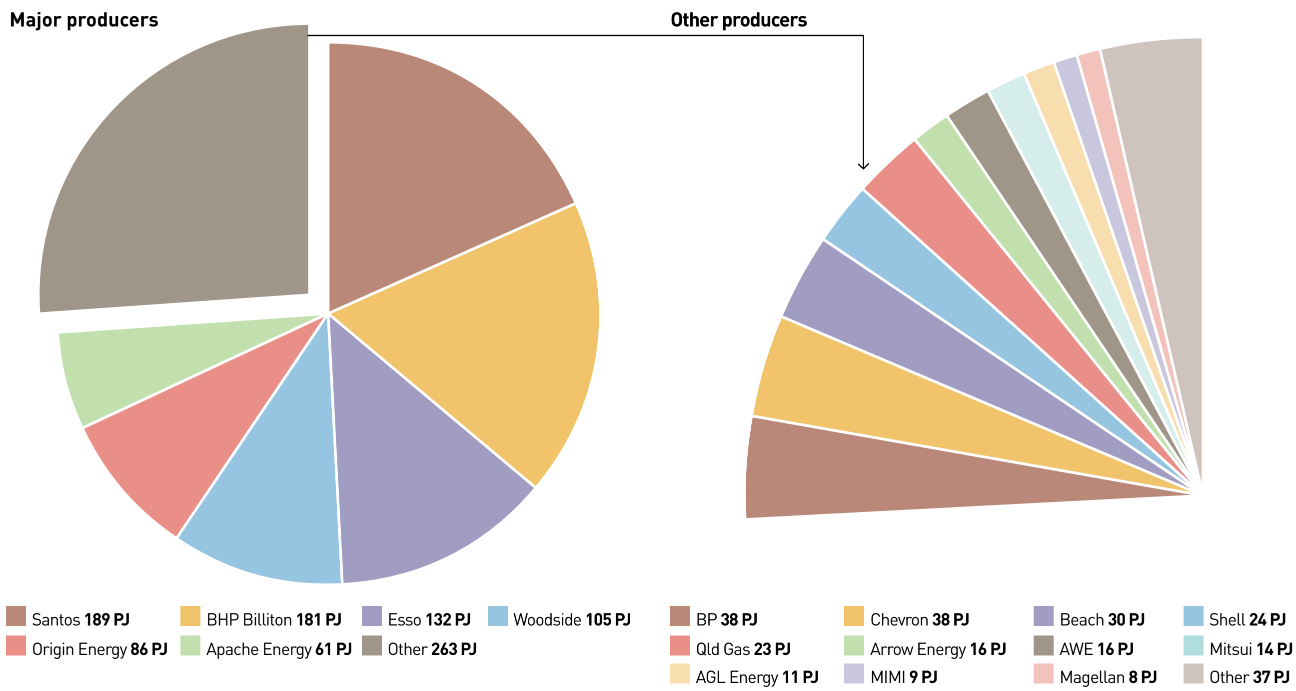
31 ACIL Tasman, *Australia's natural gas markets: The emergence of competition?* (lead essay of this report), 2008, p. 26.

32 Ministerial Council on Mineral and Petroleum Resources / Ministerial Council on Energy, *Final report of the Joint Working Group on Natural Gas Supply*, September 2007. The lead essay of this report considers the Joint Working Group report in more detail.

33 NERA, *The gas supply chain in eastern Australia*, A report to the AEMC, March 2008, p. 14.

Figure 8.10

Natural gas producers supplying the domestic market, 2007–08



PJ, petajoules.

Note: Some corporate names have been shortened or abbreviated.

Source: EnergyQuest, *Energy Quarterly*, August 2008.

- international majors—multinational corporations with large production interests and substantial exploration budgets (eg BP, BHP Billiton, Esso, Chevron and Apache Energy)
- Australian majors—major Australian energy companies with significant production interests and exploration budgets (eg Woodside Petroleum, Santos and Origin Energy)
- juniors—smaller exploration and production companies, that may or may not engage in gas production (eg Australian Worldwide Exploration, Arrow Energy and Queensland Gas Company).

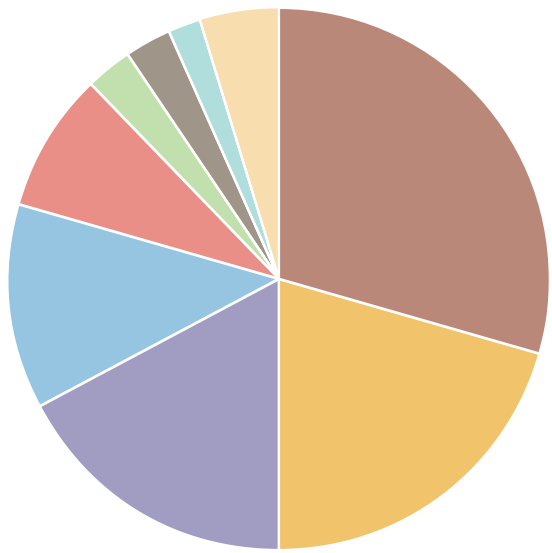
International majors tend to be involved in the larger offshore oil and LNG projects. Australian majors and smaller companies mainly focus on onshore discoveries, typically for natural gas sales to the domestic market.

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 30 produce gas. Six majors supplied around 77 per cent of the domestic market in 2007–08. Santos supplied around 21 per cent, followed by BHP Billiton (19 per cent), Esso (13 per cent), Woodside (10 per cent), Origin Energy (7 per cent) and Apache Energy (7 per cent). The next tier of players in terms of market share include BP, Chevron, Beach Petroleum, Shell and Queensland Gas Company (see figure 8.10).

The rise of CSG has seen the entry of several new players in both the exploration and production sectors over the past decade. New entrants include Queensland

Figure 8.11
Coal seam gas producers in Australia, 2007–08



PJ, petajoules.

Note: Some corporate names have been shortened or abbreviated.

Source: EnergyQuest, *Energy Quarterly*, August 2008.

Gas Company, Sydney Gas, Sunshine Gas and coal producers Anglo Coal and Xstrata. Smaller producers and new entrants to the production sector—including Queensland Gas Company, Sydney Gas, AGL Energy and Arrow Energy—accounted for around 50 per cent of CSG production in 2007–08 (see figure 8.11), which is considerably higher than their market share in conventional gas production.

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 has held a minority interest in gas production in the Cooper Basin for some time, but since 2000 has expanded its equity in CSG production in Queensland and in conventional gas production in Victoria's Otway and Bass basins.[34] Origin Energy is currently developing new gas-fired electricity generation capacity in Queensland, Victoria, South Australia and New South Wales. Origin Energy is a leading energy retailer in Queensland, Victoria and South Australia.

> AGL Energy, a relative newcomer to gas production, 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). AGL Energy is a major electricity generator in eastern Australia (especially in Victoria and South Australia) and is a leading energy retailer in Victoria, New South Wales, South Australia and Queensland.

8.4.2 Market concentration by basin

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 8.2 and figure 8.12 set out EnergyQuest estimates of market shares in the major basins, based on production for the domestic market. Table 8.3 sets out market share data based on proved and probable gas reserves (including reserves available for export).

Several major companies have equity in Western Australia's Carnarvon Basin—Australia's largest producing basin. Woodside is the largest producer for the domestic market (around 30 per cent), but Apache Energy (19 per cent), Chevron (11 per cent), BP (11 per cent), Santos (9 per cent), BHP Billiton (7 per cent) and Shell (6 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 CNOOC (China National Offshore Oil Company). The businesses

34 NERA, *The gas supply chain in eastern Australia*, A report to the AEMC, March 2008, p. 24.

Table 8.2 Market shares in domestic gas production by basin, 2007

COMPANY	CARNARVON (WA)	PERTH (WA)	AMADEUS (NT)	COOPER (SA/QLD)	SURAT–BOWEN (QLD)	SYDNEY (NSW)	GIPPSLAND (VIC)	OTWAY (VIC)	BASS (VIC)	ALL BASINS
AGL					6.5%	29.3%				1.1%
Anglo Coal					3.0%					0.4%
Apache	19.3%									6.3%
ARC		57.1%							6.8%	0.7%
Arrow					10.3%					1.3%
AWE								14.2%	30.2%	1.7%
Beach				20.8%	1.1%					3.0%
Benaris								0.1%		0.0%
BHP Billiton	6.7%					41.5%	49.1%	37.9%		19.0%
BP	11.2%									3.7%
CalEnergy									15.0%	0.3%
Chevron	11.2%									3.7%
CS Energy					0.9%					0.1%
Esso	0.2%						49.1%			13.5%
Inpex	0.1%								0.8%	0.1%
Kufpec	2.3%									0.7%
Magellan			37.9%							0.8%
MIMI	1.7%									0.6%
Mitsui					2.9%			14.0%	4.8%	1.5%
Molopo					0.3%					0.0%
Mosaic					1.5%					0.2%
Origin		42.9%		15.1%	31.3%			1.3%	42.4%	7.3%
Qld Gas					14.3%					1.8%
Santos	9.2%		62.1%	64.1%	27.1%		1.7%	32.3%		19.5%
Shell	6.4%									2.1%
Sydney Gas						29.3%				0.2%
Tap	1.4%									0.5%
Woodside	30.2%							0.2%		9.9%
Other					0.7%					0.1%
Total	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
TOTAL (PJ)	**331**	**9**	**21**	**137**	**129**	**9**	**277**	**79**	**19**	**1011**

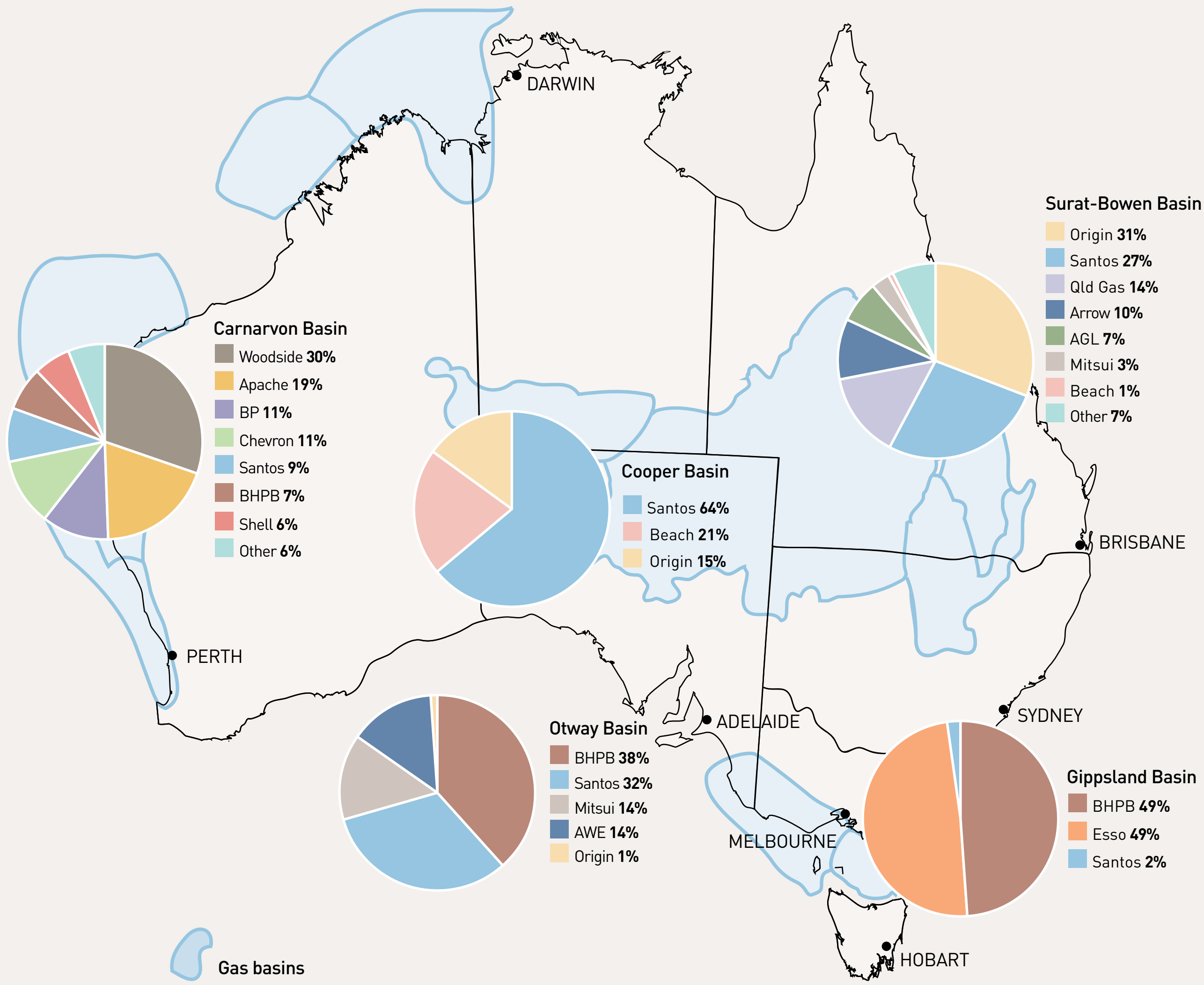
Notes:

1. Excludes liquefied natural gas.
2. Some corporate names have been shortened or abbreviated.

Source: EnergyQuest 2008 (unpublished).

Figure 8.12

Market shares in domestic gas production by basin, 2007



Notes:

1. Excludes liquefied natural gas.
2. Some corporate names have been shortened or abbreviated.

Source: EnergyQuest 2008 (unpublished).

participate in a number of joint ventures, typically with overlapping ownership interests.

Gas for the Northern Territory is currently sourced from the Amadeus Basin and produced by Santos and Magellan. The principal reserves are located in the Bonaparte Basin in the Timor Sea. The Italian energy firm ENI owns the majority of 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 the established producers Santos, Origin Energy, BHP Billiton and Esso. In 2007, these four entities accounted for around 82 per cent of production and owned around 69 per cent of proved and probable reserves in eastern Australia.[35]

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. There has been some new entry by smaller explorers in the Cooper Basin in recent years.

A joint venture between Esso and BHP Billiton accounts for around 98 per cent of production in Victoria's offshore Gippsland Basin—the largest producing basin in eastern Australia. There has been some new entry in the basin, for example, the Manta and Gummy gas project is being developed by Beach Petroleum, Anzon and Itochu.

The Otway Basin off south-western Victoria has a more diverse ownership base, with BHP Billiton (38 per cent), Santos (32 per cent), Australian Worldwide Exploration (14 per cent) and Mitsui (14 per cent) accounting for the bulk of production. Origin Energy is currently a relatively small producer but holds significant reserves.

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 and a diverse ownership profile. A number of smaller businesses such as Queensland Gas Company 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 (31 per cent), Santos (27 per cent), Queensland Gas Company (14 per cent), Arrow Energy (10 per cent) and AGL Energy (7 per cent). These businesses also own the bulk of reserves. There has been significant ownership consolidation in the basin since 2005.

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. Table 8.4 lists a number of proposed and successful acquisitions from June 2006 to September 2008.

Queensland Gas Company, the third largest producer in the Surat–Bowen Basin, has been a focus of acquisition interest. Following an unsuccessful takeover attempt by Santos in 2006, the company formed a strategic partnership with AGL Energy in 2007, which allowed AGL Energy to acquire a 27.5 per cent stake in the business. Queensland Gas Company sold a further 20 per cent stake in its assets to BG Group (formerly British Gas) in 2008. The agreement was based around the development of CSG resources for LNG exports.

BG Group sought to further expand its market profile in 2008 by attempting to acquire Origin Energy.

35 NERA, *The gas supply chain in eastern Australia*, A report to the AEMC, March 2008, p. 22.

Table 8.3 Market shares in proved and probable gas reserves by basin, 2008

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
AGL Energy						3.3%				50.0%				0.6%
AJ Lucas									69.9%					0.3%
Apache Energy	3.3%													2.0%
ARC Energy			58.1%										12.4%	0.1%
Arrow Energy						10.6%								1.6%
AWE												6.0%	29.9%	0.4%
Beach					20.8%	1.6%								0.8%
Benaris												7.9%		0.2%
BHP Billiton	12.6%										44.7%	12.9%		13.2%
BP	12.8%													7.9%
Calenergy												3.1%	15.1%	0.2%
Chevron	12.8%													7.9%
CNOOC	3.4%													2.1%
Conoco–Phillips		9.8%												0.3%
CS Energy						0.6%		13.8%						0.2%
Eastern Star Gas							64.9%							0.2%
ENI		84.7%												2.9%
Esso											44.7%			5.0%
Gastar							35.1%							0.1%
Inpex		1.9%												0.1%
Kansai Electric	0.7%													0.4%
Magellan				47.6%										0.2%
Metgasco								86.2%						0.4%
MIMI	12.4%													7.7%
Mitsui						0.8%						6.0%		0.3%
Molopo						0.6%			30.1%					0.2%
Mosaic						0.7%								0.1%
Nexus											6.5%			0.7%
Origin Energy			41.9%		13.0%	34.6%						19.1%	42.6%	6.6%
Queensland Gas						17.6%								2.7%

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
Santos	2.4%	2.0%		52.4%	66.2%	22.3%					4.0%	13.1%		7.7%
Shell	12.6%													7.8%
Sunshine Gas						6.4%								1.0%
Sydney Gas										50.0%				0.1%
Tokyo Gas	0.7%													0.4%
Woodside	26.1%											31.9%		17.1%
Total	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
TOTAL (PETAJOULES)	**29 723**	**1663**	**31**	**216**	**1183**	**7484**	**185**	**247**	**176**	**84**	**5353**	**1494**	**298**	**48 136**

Notes:
1. Based on 2P (proved and probable) reserves at 31 March 2008.
2. Some corporate names have been shortened or abbreviated. Not all minority owners are listed.

Source: EnergyQuest 2008 (unpublished).

Origin Energy rejected the offer in June 2008, and in September 2008 announced a LNG joint venture with Conoco-Phillips. BG Group subsequently announced that it would not pursue the acquisition of Origin Energy.

Further acquisitions in 2008 based around the development of CSG and LNG export facilities in Queensland included the following:

- In May 2008, Santos agreed to sell a 40 per cent stake in its proposed LNG project at Gladstone to Malaysian energy business Petronas.
- In June 2008, Arrow Energy agreed to sell 30 per cent of its CSG resources in Queensland to Shell.
- In August 2008, Queensland Gas Company reached an initial agreement to acquire Sunshine Gas.
- In August 2008, ARC Energy merged with Australian Worldwide Exploration.

8.5 Gas wholesale markets

Wholesale gas markets involve the sale of gas by producers, mainly to energy retailers that 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 *take or pay* contracts. There has been a trend in recent years 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. It is commonly argued that such long-term contracts are 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 8.4 **Upstream gas merger and acquisition activity, June 2006–September 2008**

DATE	PROPOSED MERGER/ACQUISITION	GAS BASINS	STATUS AT SEPTEMBER 2008
Jun-06	Arrow Energy acquisition of CH4	Surat–Bowen (Qld)	Completed
Sep-06	Beach Petroleum acquisition of Delhi Petroleum	Cooper (Qld/SA)	Completed
Oct-06	Santos acquisition of Queensland Gas Company	Surat–Bowen (Qld)	Proposal withdrawn
Jan-07	AGL Energy and Origin Energy merger	Various	Proposal withdrawn
Jan-07	AGL Energy acquisition of a 27.5 per cent stake in Queensland Gas Company	Surat–Bowen (Qld)	Completed
Nov-07	AGL Energy–Arrow Energy joint venture acquisition of Enertrade's Moranbah gas assets	Surat–Bowen (Qld)	Completed December 2007
Apr-08	BG Group acquisition of about 20 per cent of Queensland Gas Company	Surat–Bowen (Qld)	Completed April 2008
May-08	BG Group acquisition of Origin Energy	Various	Proposal withdrawn September 2008
May-08	Petronas acquisition of 40 per cent of Santos' LNG project at Gladstone (joint venture)	Surat–Bowen (Qld)	FIRB approval July 2008
Jun-08	Shell acquisition of 30 per cent of Arrow Energy's CSG resources	Surat–Bowen (Qld)	Preliminary agreement June 2008
Aug-08	Queensland Gas Company acquisition of Sunshine Gas	Surat–Bowen (Qld)	Preliminary agreement September 2008
Aug-08	ARC Energy and Australian Worldwide Exploration merger	Perth (WA) and Bass (Vic)	Completed September 2008

FIRB, Foreign Investment Review Board.

For example, a 540 petajoule gas supply agreement between AGL Energy and Queensland Gas Company in 2006 was for supply over a period of 20 years.[36]

In Western Australia, strong domestic demand and rising LNG export prices have led to tight market conditions since 2006. The Economic Regulation Authority of Western Australia reported in 2007 that gas producers were only offering contracts with a maximum term of five years with volumes restricted to about 10 terajoules a day.[37]

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. However, the many variations in provisions such as term, volume, volume flexibility and penalties associated with failure to supply mean that there can be significant price differences between contracts.[38]

While contracts form the basis of most gas sales arrangements, Victoria also operates a spot market to facilitate gas sales to manage system imbalances and pipeline network constraints (see box 8.1).

8.5.2 Joint marketing

Joint venture parties in gas production have to date mainly sold their gas through joint marketing arrangements under authorisation from the Australian Competition and Consumer Commission. More recently, there have been some instances of joint venture parties in new gas fields undertaking separate marketing. For example, Santos has separately marketed gas from its interest in the Casino field (Otway Basin), as has Woodside with its interest in the Geographe/Thylacine field (also in the Otway Basin).[39]

36 AGL Energy, *AGL secures cornerstone investment in QGC*, press release, 5 December 2006.
37 ERA, *Gas issues in Western Australia*, Discussion paper, Perth, 2007.
38 ACIL Tasman, *Australia's natural gas markets: The emergence of competition?* (lead essay of this report), 2008.
39 NERA, *The gas supply chain in eastern Australia*, report to the AEMC, March 2008, p. 26.

8.5.3 Scheduling and balancing

Wholesale market arrangements must take account of 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. But gas delivered from the Cooper Basin into Sydney, or from the Carnarvon Basin into Perth, can take 2–3 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 that 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 inject the nominated quantities of gas into the transmission pipeline 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, physical balancing is managed by pipeline operators, while financial settlements for system imbalances are managed by independent system operators: VENCorp (Victoria and Queensland), REMCo (South Australia and Western Australia) and the Gas Market Company (New South Wales and the ACT). In Victoria, VENCorp operates a gas spot market to manage system imbalances and constraints (see box 8.1). Similar market arrangements are currently being developed for a number of major gas hubs in eastern Australia (see section 8.7).

8.5.4 Secondary trading

There is some secondary trading in gas, in which contracted bulk supplies are traded to alter delivery points and other supply arrangements. Types of secondary trades include backhaul and gas swaps.

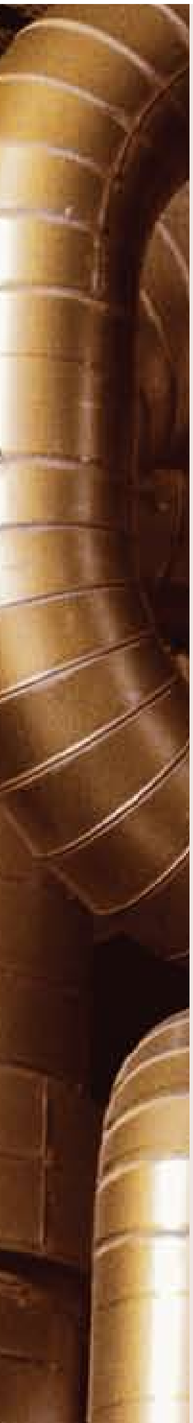
Backhaul can be used for the notional transport of gas in the opposite direction to the physical flow in a pipeline. It is achieved by redelivering gas at a point upstream from the contracted point of receipt. Backhaul arrangements are most commonly used by gas-fired electricity generators and industrial 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 that swaps are reasonably common in Australia, but are mostly conducted on a minor scale.[40] Origin Energy and the South West Queensland Gas Producers (SWQP) entered into a major swap arrangement in 2004 to enable Origin Energy to meet supply obligations in south-eastern Australia using gas produced by the SWQP. In return, Origin Energy delivered gas from its central Queensland field to meet supply obligations of the SWQP in that state.[41]

40 Firecone Ventures, *Gas swaps*, Report prepared for the National Competition Council, 2006.

41 Details of the swap arrangement are provided in AER, *State of the Energy Market 2007*, box 8.4, p. 248.



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. VENCorp operates both the wholesale market and the VTS.

Participants bid into the spot market on a daily basis via a bulletin board. Bids may range from $0 per gigajoule (the floor price) to $800 per gigajoule (the price cap).

Market participants (mostly retailers) inform VENCorp 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 VENCorp, including demand forecasts, bids, conditions or constraints affecting bids, hedge nominations and VENCorp's modelling of system constraints.

At the beginning of each day, VENCorp stacks supply offers and selects the least cost bids to match demand across the market. This establishes a spot market clearing price. As 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 the likely spot market price with underlying contract prices allows a retailer to choose to take a position to modify its own injections of gas and then trade gas at the spot price.

Until 2007, a single price applied in each 24-hour period without reference to system constraints or unforeseen events. Reforms to the gas market in February 2007 introduced rescheduling and rebidding at five defined time intervals over the day. The reforms aim to enhance flexibility, create incentives to respond to the spot price and provide clearer and more certain pricing signals. They also bring the gas market into closer alignment with the National Electricity Market.

Sometimes VENCorp 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 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 uplift charges, which provides price signals to gas users to adjust their usage patterns.

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 as sufficient gas (including LNG) has been available to support all users on the system. Nevertheless, in the event of severe congestion, those users without AMIQ must reduce their usage ahead of authorised users. 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, there had been sufficient available gas and capacity on the VTS to meet customer requirements. Congestion occurred on only a few days a year, usually in winter. However, during winter 2007 there was a greater incidence of VENCorp 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.

However, with the easing of drought effects and the commissioning of new pipeline capacity in 2008, the need for high-cost injections of LNG was less evident in winter 2008.

While prices on the spot market are relatively stable, there are occasional troughs and spikes. For example, while in 2007 the average daily spot price was about $3.50 per gigajoule, it fell to close to zero on 1 May 2007, but achieved a record high on 17 July 2007 of $336 per gigajoule in the day's final trading interval. To date, VENCorp has found that 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 section 8.6 and figure 8.14.

In 2007, VENCorp engaged CRA International to undertake a strategic review of the 'top end' arrangements in the market, with particular emphasis on risk issues. The review was ongoing at August 2008.

Further information: http://www.vencorp.com.au

8.5.5 Trading hubs

A gas hub is an interconnection point between gas pipelines in 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 a 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.

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 seen as a substitute for coal and coal-based 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 readily available. A number of price estimates for Cooper Basin gas in 2004–05 were published during a public process on the regulation of the Moomba to Adelaide Pipeline. The estimates ranged from around $2.90 to $3.15 per gigajoule. Core Collaborative's *Australian Gas Sector Outlook* estimated that in 2005, gas prices in the Cooper and Gippsland basins were around $3.15 per gigajoule.[42]

42 Estimates published in NERA, *The gas supply chain in eastern Australia*, A report to the AEMC, March 2008, pp. 35–36.

ACIL Tasman published forecasts that in 2007–08, electricity generators in southeastern Australia would pay around $2.95 to $3.20 per gigajoule for natural gas.[43]

Since 2005, a number of interacting factors have put upward pressure on gas prices, including the following:

- A substantial rise in resource costs affecting exploration, development and production activities.
- High oil prices have flowed on to international gas prices, including for Australian LNG exports. This has put upward pressure on domestic gas prices in Western Australia, which has substantial LNG export capacity. In eastern Australia, a range of proposed LNG developments are also influencing price expectations.
- Drought led to greater demand for gas-fired generation in eastern Australia in 2007, with flow-on effects for gas prices.
- Market participants may be factoring in the effects of the Carbon Pollution Reduction Scheme into demand projections and pricing on long-term gas contracts.[44]

Figure 8.13 sets out indicative price data from 2005 to 2008 for domestic gas and LNG exports. The data relating to particular producers is based on average prices and in some cases may understate prices struck under new contracts.

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. More recently, significant imbalances have arisen, with high demand for gas contracts—driven in part by the mining boom—at a time when most producers have fully contracted their developed reserves. This has been accompanied by substantial increases in gas field development costs.

At the same time, Western Australia's LNG export capacity creates exposure in the domestic market to international energy prices. Average LNG prices received by Australian producers rose by 48 per cent between the June quarters of 2007 and 2008.[45]

In combination, these factors have led to substantial price escalations in Western Australia's domestic gas market. 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 with mining entities,[46] which is almost three times higher than the wholesale prices of around $2.50 per gigajoule that prevailed until 2006. Short-term wholesale prices averaged almost $17 per gigajoule in July 2008 following the Varanus Island incident, which cut domestic supply by around 30 per cent.[47]

8.6.2 Eastern Australia

There is also some evidence of rising prices on the east coast. While for several years CSG prices in Queensland were typically lower than for conventional natural gas, the development of LNG proposals has raised price expectations.

Core Collaborative's *Australian Gas Sector Outlook* estimated that Queensland prices in 2006 were around $2.50 to $2.90 per gigajoule.[48] ACIL Tasman has reported that Queensland customers are now facing significantly higher prices, in excess of $4 per gigajoule.[49] EnergyQuest has reported that one CSG provider earned an average price for Queensland gas in the first quarter of 2008 of $7.79 per gigajoule ($5.77 in the second quarter), compared with $2.22 per gigajoule in the first quarter of 2006.[50] While these were significantly higher than the average prices received by other Queensland producers, they are nonetheless indicative that CSG prices may be trending higher.

43 ACIL Tasman, *Fuel resource, new entry and generation costs in the NEM*, 6 June 2007.

44 ACIL Tasman, *Australia's natural gas markets: The emergence of competition?* (lead essay of this report), 2008, p. 30.

45 EnergyQuest, *Energy Quarterly*, August 2008.

46 Department of Industry and Resources (WA), *Western Australian Oil and Gas Review*, 2008.

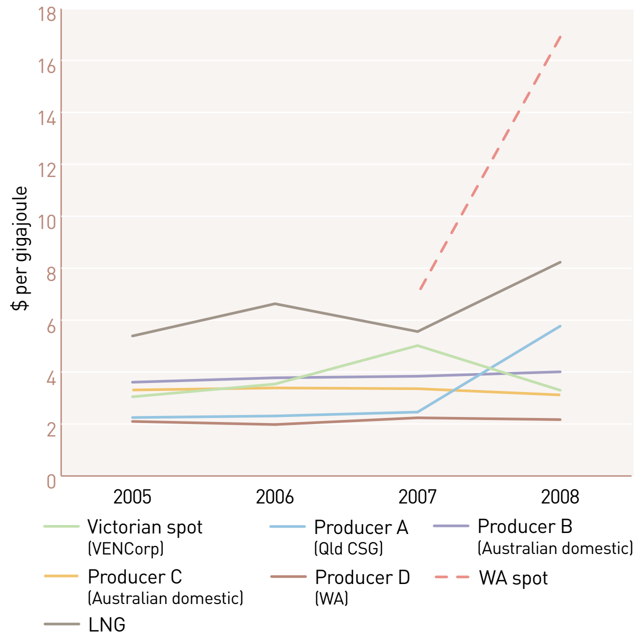
47 EnergyQuest, *Energy Quarterly*, August 2008. See note to figure 8.13.

48 Estimates published in NERA, *The gas supply chain in eastern Australia*, A report to the AEMC, March 2008, p. 36.

49 ACIL Tasman, *Australia's natural gas markets: The emergence of competition?* (lead essay of this report), 2008.

50 EnergyQuest, *Energy Quarterly*, May 2008.

Figure 8.13
Indicative wholesale natural gas prices



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

Notes:

1. Western Australian spot prices are indicative only: 2007 prices are estimates for new Santos contracts signed in July; 2008 prices are based on the weighted average price of gas trades notified to Western Australia's Independent Market Operator in July 2008. Western Australian prices in July 2008 were unusually high due to a major plant outage at Varanus Island.
2. All series (except Western Australian spot) are data from the second quarter of the year.
3. Data for Producers A, B, C and D are average company realisations for specific Australian gas producers.

Sources: WA spot 2007: Department of Industry and Resources (WA), *Western Australian Oil and Gas Review*, 2008; other data: EnergyQuest, *Energy Quarterly,* August 2005, August 2006, August 2007 and August 2008; LNG data is sourced from the ABS.

8.6.3 Victorian spot prices

The Victorian spot market (see box 8.1) provides transparent price and volume data on sales of natural gas to balance daily requirements between retailers and suppliers. Market volumes range from around 400 to 1200 terajoules per day. While the market only accounts for about 10–20 per cent of wholesale volumes in Victoria, its price outcomes are widely used as a guide to underlying contract prices.

Figure 8.14 charts price and volume activity since the market started in 1999. Despite a winter peaking demand profile, prices remained relatively stable until 2005. There has since been greater volatility, with significantly higher winter prices in 2006 and 2007. The average price for July 2007 reached a monthly record of almost $9 per gigajoule. Spot prices peaked at $336 per gigajoule on 17 July 2007, a market record. The price spikes were partly due to drought causing a shift to gas-fired electricity generation, which significantly increased demand for gas. Prices have since eased back towards trend levels. The spot price averaged $3.55 per gigajoule in the first quarter of 2008, slightly below the current contract price of about $3.59 per gigajoule.[51] An expansion of the Victorian Transmission System—the Corio Loop—eased capacity constraints on the network in winter 2008. Weighted average prices in June and July 2008 were below contract prices.

8.7 Gas market development

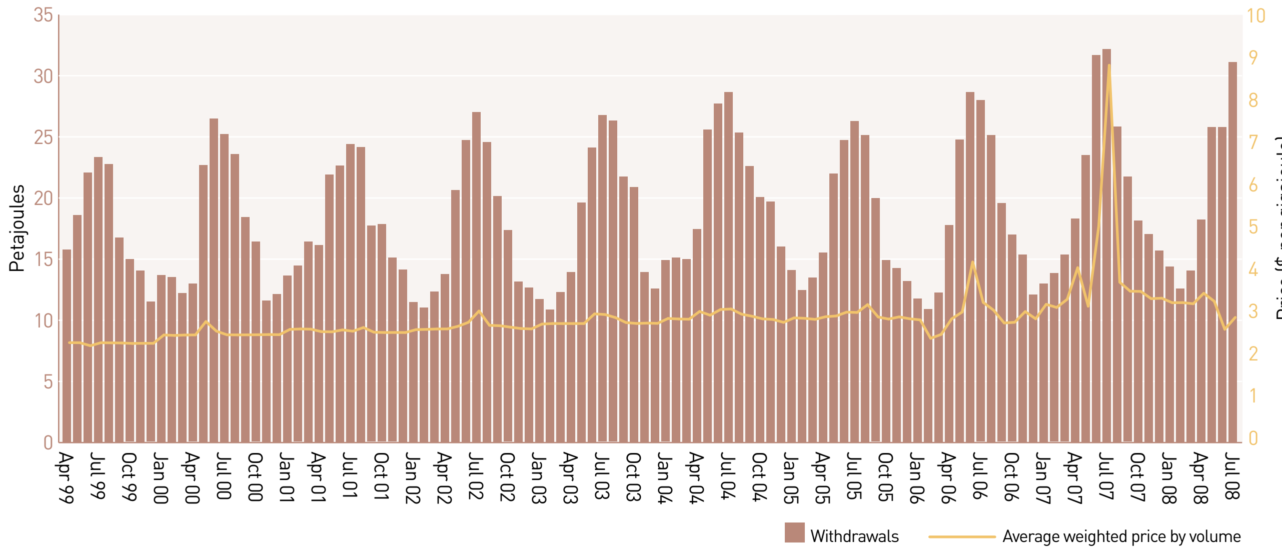
The Ministerial Council on Energy in 2005 appointed a Gas Market Leaders Group[52] to consider the need for further reform of the Australian gas market. In 2006, the Group recommended the establishment of:

> 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 bulletin board was implemented 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.

51 EnergyQuest, *Energy Quarterly*, May 2008, p. 65.
52 The group comprises 12 gas industry representatives and an independent chairperson.

Figure 8.14
Victorian gas market—monthly prices and volumes



Note: Average monthly prices (right-hand axis). Withdrawals are monthly totals (left-hand axis).

Source: VENCorp.

8.7.1 Gas market bulletin board

The gas market bulletin board, which commenced on 1 July 2008, is a website covering major gas production fields, storage facilities, demand centres and transmission pipelines, in southern and eastern Australia.[53] Provision has been made for Western Australia and the Northern Territory to participate in the future.

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 nomination data
> production capabilities (maximum daily quantities) and three-day outlooks for production facilitates
> 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 through the provision of readily available system and market information. For example, the bulletin board will provide information on outages or maintenance at production points and pipelines, including updated daily demand, actual or expected changes in supply capacity to demand centres and potentially, in the event of significant outages or system incidents, a flag indicating likely interruptions to customer supplies.

VENCorp is the interim bulletin board operator, pending the establishment of the Australian Energy Market Operator (AEMO). Under the National Gas Law, the Australian Energy Regulator monitors and enforces the compliance of market participants with the rules of the bulletin board.

Western Australia created its own limited bulletin board, run by the Independent Market Operator, to assist with the gas emergency during 2008. Though

53 http://www.gasbb.com.au

low volumes of trade were reported, the bulletin board provided some indication of prices during this period of restricted supply.

8.7.2 Short-term trading market

The MCE has approved the development, by the Gas Market Leaders Group, of a short-term trading market in gas, to commence by winter 2010. The proposed market is intended to facilitate daily trading by establishing a mandatory price-based balancing mechanism at defined gas hubs. The market would initially cover network hubs in New South Wales and South Australia, and replace existing gas balancing arrangements. Victoria has had a transparent balancing market in place since 1999 (see box 8.1).

The rationale for the market stems from concerns that the current gas balancing mechanisms in New South Wales and South Australia present barriers to retail market entry and impede gas supply efficiency. In particular, the current mechanisms create substantial financial exposures that are disproportionate to underlying costs. New entrants have faced difficulties acquiring appropriate hedging to manage these risks. The issues are especially pertinent for Sydney and Adelaide, which are sourced by multiple transmission pipelines.[54]

A daily market clearing price will be determined at each hub based on bids by gas shippers to deliver additional gas. The difference between each user's daily deliveries and withdrawals of gas will then be settled by the market operator at the clearing price. The mechanism is aimed at providing price signals to shippers and users 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.

Structural and operational details of the market are undergoing further development during 2008.

8.7.3 Australian Energy Market Operator

The Council of Australian Governments agreed in 2007 to establish AEMO by 1 July 2009 to ultimately replace gas and electricity market operators such as VENCorp and the National Electricity Market Management Company. It is envisaged that the AEMO will operate both the gas market bulletin board and the short-term trading market. It is also envisaged that the AEMO will publish an annual Gas Statement of Opportunities (GSOO)—a national gas supply and demand statement—of a similar nature to the annual Statement of Opportunities currently published for electricity.

The GSOO is intended to provide information to assist gas industry participants in their planning and commercial decisions on infrastructure investment. The Gas Market Leaders Group commenced work on the design of the GSOO in 2008.[55]

8.7.4 Futures markets

The risk of participating in a commodity market can usually be hedged using physical or financial instruments. However, a futures gas market tends to develop only after the physical gas market reaches a certain level of maturity—with significant trading under transparent short-term contracts—as in the United States and the United Kingdom.

At present there is no futures market for gas in Australia and current opinion suggests that there is little prospect that a market will develop soon. The new gas market bulletin board and the proposed short-term trading market may facilitate future development of a formalised market for financial risk-hedging instruments (such as forward, futures, swap and option contracts).

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

55 MCE, *Communiqué*, 13 June 2008.

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 may occur in gas production facilities or in the pipelines that deliver gas to customers.[56] 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.

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 in part 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.[57] The agreement established a government–industry National Gas Emergency Response Advisory Committee to report on the risk of gas supply shortages and options for managing potential shortages. A working group developed a communications protocol and a procedures manual which sets outs detailed instructions for officials and industry members in the event of an incident.

In the event of a major gas supply shortage, the protocol requires as far as possible that commercial arrangements operate 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. The bulletin board will gather emergency information, as required, 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 will provide commercial incentives for producers to increase supplies and customers to reduce gas usage 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. Woodside Petroleum, which operates the North West Shelf joint venture, became the state's only major domestic gas supplier during this period. While it increased domestic supplies by around 150 terajoules per day, this was short of the 300 terajoules per day that Apache Energy supplied prior to the explosion.[58]

56 A discussion of reliability issues in the gas distribution sector appears in section 10.7 of this report.

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

58 Office of Energy (WA), *Gas supply disruption recovery update*, 8 July 2008.

Spot prices for gas rose sharply as a result of the explosion, with some reports of a tripling of prices.[59] The Australian and Western Australian governments cautioned that the events would cause significant economic disruption, including to mining exports.[60] 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.[61] 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.

Apache Energy began to resume gas supply incrementally in August 2008. A resumption of full production was not expected until the end of 2008.[62]

59 J Freed, 'Spot price for gas soars after supply cut', *The Sydney Morning Herald*, 10 June 2008.
60 D Shanahan, 'Growth fears as lights start to go out', *The Australian*, 17 June 2008.
61 D Shanahan 'Growth fears as lights start to go out', *The Australian*, 17 June 2008.
62 Office of Energy (WA), *Energy Update,* 5 August 2008.