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Australia's natural gas: issues and trends

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Executive summary

- Australia has limited crude oil but is relatively well endowed with natural gas resources. The natural gas industry has shown remarkable growth—both the domestic and export sectors—over the last few decades and this is projected to continue.
- The bulk of Australia's gas resources are located long distances from the eastern Australian markets. These are offshore northwest Western Australia (Carnarvon and Browse basins) and in the Timor Sea to the north of Australia (Bonaparte Basin). Because of the uneven distribution of our gas resources it had been thought that gas would need to be piped from these fields when the closer smaller eastern fields run down prior to 2020.
- The above scenario is now less likely with the development of newer gas fields in the Gippsland, Bass and Otway Basins located offshore in southern Victoria. Furthermore, there has been rapid development of coal seam gas reserves in Queensland and New South Wales with the potential to become a major source of gas for eastern Australia.
- The natural gas export sector is presently supplied from the North West Shelf and Bayu-Undan, Darwin. Additional export volumes are expected from the North West Shelf in late 2008 and thereafter from a number of new ventures including Greater Gorgon, Pluto, Pilbara LNG, and Browse Gas all in Western Australia, and coal seam gas field developments in Queensland and New South Wales.
- A recurring question in natural resource use and development is: why export a commodity with an important domestic use, especially with gas exports projected to increase to around 60 per cent of production by 2020. The answer invariably relates to economics and the adequacy of the resource base to provide for domestic use into the foreseeable future.
- Natural gas as an energy source has significant environmental benefits over both coal and oil in terms of lower greenhouse gas and other emissions. This aspect will be of considerable advantage in the further promotion of natural gas use and Australia's energy future.
- Natural gas remains a cheap energy source in Australia when compared to the United States and Europe. However, wholesale gas prices have generally trended upwards in the last few years, especially in Western Australia.
- Implementation of newer gas regulatory processes has been protracted although considerable progress has been made in recent times. The present Gas Code will be replaced with the National Gas Law and National Gas Rules. Regulation will be simplified with a single Australian Energy Regulator.

Contents

Glossary

Combined-cycle gas turbine	incorporating heat capture from the primary turbine and resultant steam production to drive an auxiliary turbine.
Condensate	hydrocarbons which are gaseous in a reservoir, but which condense to form a liquid as they rise to the surface where the pressure is much less.
Covered pipeline	a pipeline subject to third party access arrangements.
CNG	compressed natural gas.
CSG	coal seam gas.
High pressure pipeline system	the pipeline networks carrying natural gas from the gas fields to regional centre nodes.
LNG liquefaction train	a liquefied natural gas processing unit.
Liquefied natural gas (LNG)	liquefied natural gas, gaseous at normal temperatures and pressures, but held in a liquid state at very low temperatures to facilitate storage and transport.
Open-cycle gas turbine	a single gas turbine operation.
Primary energy	forms of energy obtained directly from nature including the use of coal, oil and gas. This is distinct from final energy such as electricity produced from either coal-fired or gas-fired electricity generating plant.
Reserve	comprising oil and gas fields declared commercial (Category 1), in addition to estimates of recoverable reserves still to be declared commercial but are awaiting further appraisal (Category 2).
Reserve to production ratio	the time in years to deplete a measured reserve at current rates of production.
Resource	its economic extraction is presently or potentially (within a 20–25 year timeframe) feasible. A resource estimate is generally far larger than a more clearly defined reserve.
Ring-fencing	the discrete separation of business units resulting from the break up of a larger former corporate or government vertically integrated utility.
Take or pay	a legal undertaking committing to the purchase of a specific quantity of gas whether or not delivery is taken.

Introduction

The aim of this paper is to present an overview of the Australian natural gas sector and outline some recent important developments. It also expands on and updates earlier work by the Parliamentary Library on this topic.[1]

The paper looks at characteristics of natural gas, units of measurement, Australia's gas reserves and resources, the coal seam gas sector, industry gas pipeline developments, natural gas consumption incorporating supply, demand and export projections, natural gas prices, industry gas pipeline developments, and environmental issues and contains a summary of recent regulatory issues.

Australia's domestic use of natural gas continues to increase as do exports of liquefied natural gas (LNG). Whilst Australia has limited reserves of crude oil it is relatively well endowed with natural gas resources. Worldwide use of natural gas is also on the increase, largely because of an abundant resource base and its excellent environmental credentials. Compared with other hydrocarbons, when gas is burned it produces fewer particulates, and less sulphur dioxide and nitrogen oxides. It is also less carbon intensive, which means it emits less carbon dioxide per joule of energy released than other hydrocarbons.

Characteristics of natural gas

Conventional natural gas occurs in underground porous sedimentary rock reservoirs generally juxtaposed in the pore spaces with oil. Natural gas that occurs in reservoirs with little to no oil is called non-associated gas. More recently natural gas is being produced by the drainage of natural gas from Australia's coalfields, termed coal seam gas. These significant sources are being progressively developed in eastern Australia.

Naturally occurring gas is composed of the less complex hydrocarbons mainly methane (CH_4) with some ethane (C_2H_6). Depending on the source of the gas it may contain minor quantities of propane (C_3H_8), butane (C_4H_{10}) and pentane (C_5H_{12}). Other constituents may or may not be present, such as the more complex hydrocarbons, in addition to nitrogen (N_2), carbon dioxide (CO_2) and hydrogen sulphide (H_2S). Pure methane gas is colourless, odourless and lighter than air. Impurities such as hydrogen sulphide can give natural gas an odour.

Liquid hydrocarbons or natural gas liquids—as distinct from natural gas—comprise ethane, propane, butane and pentane. Liquefied petroleum gas (LPG) comprises both propane and butane, and ethane is widely used as a petrochemical feedstock. Natural gas with a low concentration of liquid hydrocarbons it is known as a 'dry' gas, and that with a high concentration is known as a 'wet' gas. A 'lean' gas falls between the two. A 'sour' gas

1. Paul Kay, 'Natural Gas – An Australian Growth Industry' *Research Paper* no. 2 1994 and Mike Roarty, 'Natural Gas: Energy for the New Millennium', *Research Paper* no. 5 1998–99, Department of the Parliamentary Library, Parliament House, Canberra.

contains more than one part per million hydrogen sulphide and is characterised by a foul or rotten egg smell. Australian natural gas is generally 'sweet' due to its low hydrogen sulphide content.

Units of measurement

To the uninitiated, gas measurement units are complex. A broad outline of the more common units and conversions is provided in Box 1.

Box 1: Common gas measurement units.

The basic unit of energy is the joule. The common energy unit used in the gas sector is the megajoule (MJ) or one million joules.[2] Gas volumes (in either cubic metres or cubic feet) and weights (liquefied natural gas (LNG) in tonnes)—units used to quantify gas reserves or resources or production of LNG—can be readily converted via appropriate factors to joules. For example, Australia's gas reserve and resource estimates, commonly quoted in either billions of cubic metres (bcm) or trillions of cubic feet (tcf) can be converted to gigajoules (10^9) or petajoules (10^{15}). Approximate conversions are: 1 GJ = 948 cubic feet of gas, or 1 000 PJ (petajoules) = 0.948 tcf.

The conversion of cubic metres of gas to megajoules depends on the nature and composition of the gas. The energy content of gas depends on its particular chemical and physical characteristics and this varies from field to field. The following approximate energy content factors apply to Australia's gas reserves and resources:

State/Territory[3]	MJ per cubic metre
Western Australia	38.2
Victoria	38.6
South Australia	39.1
Queensland	39.6
Northern Territory	40.4

Common conversion units used in the gas industry are published by the Australian Gas Association and in the yearly publication, the BP Statistical Review of World Energy. Common unit multiples include:

Unit	Abbreviation	Factor multiple	
kilo	k	10^3	(eg 10x10x10)
mega	M	10^6	
giga	G	10^9	
tera	T	10^{12}	
peta	P	10^{15}	
exa	E	10^{18}	

2. For comparative purposes one kilowatt hour (1kWh), the energy unit used in the electricity sector is equivalent to 3.6 MJ.
3. As New South Wales gas is presently sourced from interstate (apart from newly developing coal seam gas reserves), there are no separate figures available.

Australia's natural gas reserves and resources

Figure 1 shows Australia's sedimentary basins (containing Australia's oil and gas resources) together with the high pressure pipeline networks.

Figure 1: Australia's oil and gas basins and gas pipeline networks

Source: Australian Energy Regulator

Australia has large natural gas resources capable of sustaining our future production and exports well into and probably throughout the 21st Century. As at 1 January 2005, Australia's

Category 1 and 2 reserves[4] totalled just over 4 000 billion cubic metres (bcm) or 144 trillion cubic feet (tcf).[5] Australia's natural gas consumption for 2005–2006 amounted to 1 184PJ[6] (equivalent to around 1.12 tcf). Exports in that same year amounted to 12.495 million tonnes (Mt) of LNG [7] equivalent to 684.73 PJ.[8]

Somewhat inconveniently, Australia's gas reserves and resources are distributed unevenly throughout the continent, with over 90 per cent of the reserves and resources located offshore from northwest Western Australia (Carnarvon and Browse Basins) and in the Timor Sea to the north of Australia (Bonaparte Basin). The largest onshore accumulation of conventional gas reserves and resources occur in the Cooper/Eromanga Basins (some 45.04 bcm) in north-east South Australia and south-west Queensland. It is this source that currently supplies the bulk of the domestic eastern Australian gas market (South Australia, the Australian Capital Territory, New South Wales, and Queensland). Victoria and the emerging Tasmanian market are dominantly supplied from the Gippsland Basin, offshore south east Victoria.

The development of gas reserves in both the Bass and Otway Basins, which are located offshore from southern and south western Victoria is relatively new. The Yolla field located in the Bass Basin which is being developed by a consortium led by Woodside, came on stream towards the end of 2007. A number of fields in the Otway Basin including Minerva, Casino, Geographe and Thylacine are being developed by a consortium including Woodside, BHP Billiton and Santos. These fields were close to production towards the end 2007. Esso Australia, along with joint venture partners BHP Billiton and Santos have also announced the development of a new gas and condensate field, Kipper, in the well-established long-term producing oil and gas fields of the Gippsland Basin. The Kipper project involving capital expenditure of up to $1.3 billion will be the biggest gas development on the eastern seaboard since the Esso and BHP discovery of the Bass Strait oil and gas fields 40 years ago. Construction of the project is expected to start late 2008 with first production expected in 2011.[9]

Although estimates of the resources of the Bass and Otway Basins are small in comparison to those contained in the Carnarvon, Browse, and Bonaparte Basin and to a lesser extent the Gippsland Basin, they are none-the-less sufficient to warrant current project development of

4. Category 1 comprises current reserves of those fields which have been declared commercial. It includes both proved and probable reserves. Category 2 comprises estimates of recoverable reserves which have not yet been declared commercially viable; they may be either geologically proved or are awaiting further appraisal.

5. Geoscience Australia, 'Oil & Gas Resources of Australia 2004', Canberra, 2004, p. 27.

6. esaa, 'Electricity Gas Australia 2007', Melbourne, p. 44.

7. abare, 'Australian commodities', December Quarterly, 67.4, Canberra, p. 63.

8. Note: 1 000 PJ is equivalent to around 1 tcf of gas.

9. Mathew Murphy, 'Greenlight for Kipper gas project', Sydney Morning Herald, 20 December 2007, p. 24.

these fields. This will cost some $400 million (for the Yolla field) and $810 million (Geographe and Thylacine). Sales gas produced from these developments will feed into the Victorian and South Australian high pressure transmission pipeline grids.

Coal seam gas

The rapidly developing coal seam gas (CSG) industry is adding to Australia's known economic gas resources. Importantly, these gas sources are relatively close to the major centres of population in eastern Australia. The development of these gas sources could delay the need for gas to be piped from Western and Northern Australia for many years and possibly decades to come. Whilst the outlined reserves and resources of coal seam gas are still relatively modest, there has been strong growth in this sector of the gas industry with year on year production increases, beginning with 2 petajoules (PJ)/y in 1994 and growing to 45PJ/y in 2004.[10]

Gas associated with coal mining was long regarded as a major hazard causing explosions in underground coal mining operations. These gas accumulations were often vented where practical and subsequently wasted. Furthermore, this gas is a highly intensive greenhouse gas, with a global warming potential some 21 times higher than carbon dioxide. Modern technology and the realisation that such gas can be a valuable energy resource have led to the development of this industry. CSG—often referred to as coal seam methane (CSM)—is naturally occurring methane gas in coal seams. The associated gas in coal has been absorbed onto the grain faces and micro-pores of the coal during the geological thermal maturation process of coalification. CSG resources contained within the Queensland and New South Wales coal reserves and resources are located fairly close to large potential markets in eastern Australia. The successful development of CSG fields now contributes to the diversification of gas supply sources, particularly in Queensland.

Geoscience Australia indicated Australia's CSG reserves as at the end of December 2006 to be 4 642 PJ or 4.4 tcf.[11] A comprehensive resource evaluation is yet to be undertaken. The assessment to date comprises an aggregation of published reserves of operating CSG companies. Production in 2004 amounted to some 45PJ which contributed about 4.5 per cent of Australia's domestic natural gas consumption.

Whilst these reserves and resource evaluations appear modest, Origin Energy—presently Australia's largest CSG producer—believe it is realistic to talk in the longer term of CSG reserves for the industry as a whole to be between 15 000 and 30 000PJ, or the equivalent of up to thirty times Australia's present annual natural gas consumption.[12]

10. Geoscience Australia, 'Oil & Gas Resources of Australia 2004', Canberra, 2006, p. 58.
11. Geoscience Australia, 'Australia's identified mineral resources 2007', Canberra, 2007, p. 23.
12. Origin Energy, 'Annual General Meeting Report to Shareholders', 31 October 2007, Sydney, p. 12.

A number of newly built gas-fired power plants in Queensland are to be fuelled with CSG. For example, ERM Power is proceeding with plans to double its 450MW open cycle gas-fired plant near Braemer by the fourth quarter of 2009. Additionally, Origin Energy is building a 630MW combined-cycle power station on Queensland's Darling Downs, also near Braemer. The contract for the construction of the power station, worth $780 million, has been awarded to GE and CH2M Hill. The power station will emit about half the greenhouse gas emissions that a coal-fired power station using current technology would create.[13] Origin Energy is also considering the development of a nominal 1 000MW coal seam gas-fired power station at Spring Gully, 80 kilometres north of Roma, Qld, with fuel for the power station to be provided from the adjacent Spring Gully CSG plant.

Another major Australian oil and gas company, Santos, has proposed a LNG processing facility at Gladstone, based on its nearby CSG Fairfield project. An independent consultant, Wood Mackenzie, endorsed the Gladstone plant as a potentially viable development opportunity, indicating the 4 tcf of gas reserves needed for the project could be comfortably covered through the expansion of the company's Fairfield project.[14] A second LNG export proposal sited at Gladstone sourced on CSG feed has emerged from a joint venture comprising Queensland Gas and Britain's BG Group. [15]

Natural gas consumption

Natural gas consumption in Australia has continually increased since the mid–1960s (Figure 2). Australian gas consumption was 1 184.6 PJ in 2005–06. Growth in domestic use of natural gas is projected to remain strong (growing at 4.0 per cent per annum in the medium term to 2010–11 and thereafter at 2.5 per cent per annum) to reach 1740 PJ in 2019–20. Exports of LNG exports are projected to increase almost four fold to around 50 million tonnes or 2700 PJ in 2019–20, to account for around 60 per cent of Australia's total gas production in that year.[16] Historical and projected demand growth for both the domestic and export sectors are shown in Figure 2.

In 2004–05 the share of natural gas in Australia's primary energy consumption was 19.7 per cent but is forecast to increase to 24.1 per cent by 2019–20 and further to 25.2 per cent by 2029–30.[17]

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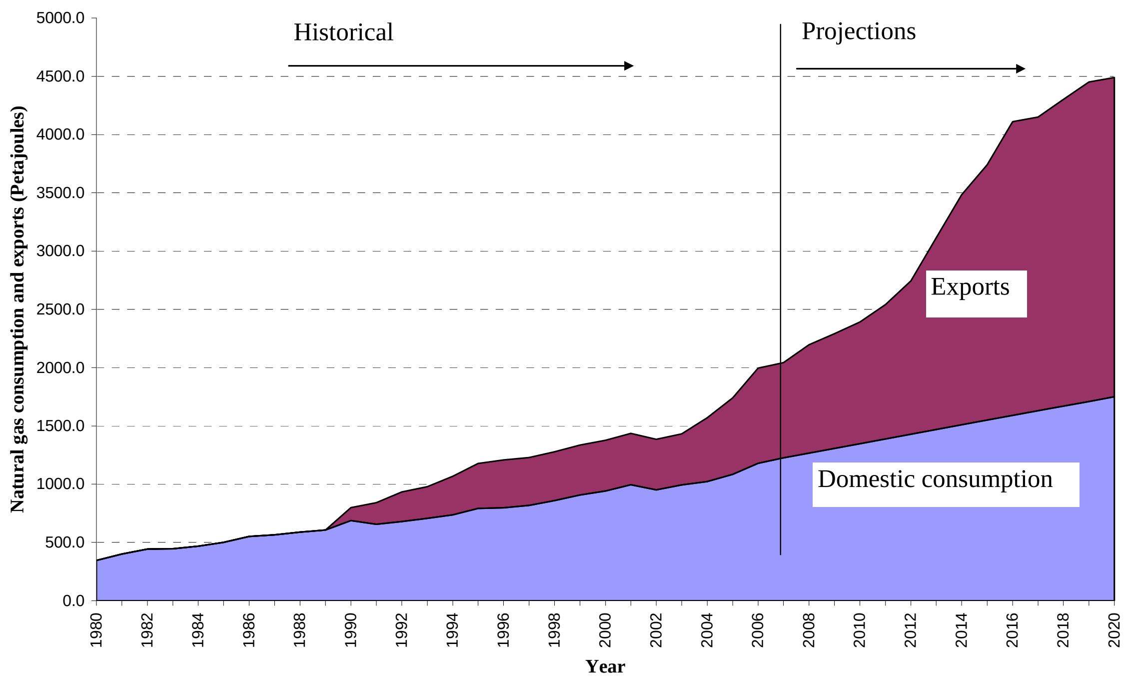
13. Gas Today, '18 per cent gas in Qld by 2020', November 2007, Great Southern Press Pty Ltd, Melbourne, p. 11.
14. ibid., p. 26.
15. Stephen Wisenthal, 'Future bright for Qld gas industry', Australian Financial Review, 6 February 2008, p. 57.
16. Clara Cuevas-Cubria and Damien Riwow, 'Australian energy, national and state projections to 2029–30', Abare Research Report 06.26, December 2006, Canberra, pp. 21 and 43.
17. ibid., p. 21.

A potential issue of concern raised by a number of commentators is the projected vast increase in the level of exports of natural gas. If this eventuates with multiple gas field developments as outlined, exports will substantially surpass domestic consumption by 2020. A recurring issue in natural resource use and development questions the logic of exporting a commodity with an important domestic use? This is particularly so for an important energy source which is an environmentally better energy alternative to other fossil fuels. The answer invariably relates to economics and the adequacy of the resource base to supply the domestic market well into the future.

Figure 2: Australian natural gas consumption and exports



Data source: Australian bureau of agricultural and resources economics (abare) and energy supply association of Australia (esaa).

For example, the huge North West Shelf oil and gas venture—Australia's largest resource project involving capital expenditure of some $19 billion to date—would never have been undertaken without the domestic and export markets operating in tandem. Additionally, Australia currently exports far greater quantities of a number of commodities than it uses domestically, including coal, iron ore, aluminium, base metals, titanium minerals, diamonds and gold. Commodity exports provide close to 40 per cent of Australia's export income.

An element of this issue is reflected in the recent announcement of the Western Australian Government to reserve 15 per cent of the gas reserves in a particular gas field for domestic use in that state. Obviously, the state is keen to retain sufficient gas supplies for domestic use into the long term. On the other hand the policy should not deter major gas field development with exports earnings accounting for a substantial component of project earnings together with the added economic benefits of major resource development in Australia. As stated the bulk of Australia's gas reserves are located in the north-west of Western Australia. While Western Australia presently consumes about 35 per cent of Australia's domestic gas use, and the bulk of LNG exports, there is still a very healthy reserve to production ratio in excess of 100 years.

Domestic gas use

As at June 2006, the number of natural gas customers in Australia, having steadily increased over the years, stood at 3.832 million (comprising 3.755 million residential and 77 040 commercial customers). The natural gas transmission and the distribution networks covered 103 521 kilometres.[18] As noted above, natural gas consumption for the fiscal year June 2006 amounted to 1 184.6 PJ. On a state and territory basis, Western Australia was the largest consumer followed by Victoria, NSW/ACT, Queensland, and South Australia. (Table 1).

Table 1: Natural gas consumption by State

State	**PJ**	**% Australian consumption**	**% of state primary energy use**
Western Australia	411.2	34.7	54.1
Victoria	277.6	23.4	19.1
NSW/ACT	156.4	13.2	10.2
Queensland	152.5	12.9	11.5
South Australia	139.5	11.8	41.8
Northern Territory	35.7	3.0	44.6
Tasmania	11.7	1.0	10.0
Total	**1184.6**	**100.0**	

Data sources: esaa, abare.

As is readily apparent that some states depend more on gas for their primary energy use than others. Western Australia, South Australia and the Northern Territory depend on gas for more than 40 per cent of their primary energy demand. While Victoria is dependent on gas just above 20 per cent of its primary energy demand, the larger states of New South Wales and Queensland depend on gas for just over 10 per cent of their primary energy needs. These patterns have important environmental implications: the larger the dependency on primary energy sources such as coal and oil as apposed to natural gas, the higher the environmental footprint with reference to greenhouse gas emissions.

18. esaa, 'Electricity Gas Australia 2007', Melbourne, pp. 44–45.

Sectoral use of gas

In 2005–06, on an Australia wide basis, the manufacturing sector (which includes minerals and metals processing) was the largest consumer of natural gas using some 425.9 PJ or 36 per cent of total gas consumption (Figure 3). Electricity generation was the second largest gas consumer using some 384.9 PJ (32.5 per cent of the total) with mining the third largest user accounting for 148.8 PJ or 12.6 per cent of total gas consumption. The residential sector accounted for 142.4 PJ or 12 per cent of total gas consumption.

The industrial/commercial market is comprised of relatively few large gas consumers. In 2005–06 there were 77 040 industrial/commercial users in Australia. The largest natural gas consumers are the metal product industries (predominantly alumina kilns and ore smelting), the chemical industry (where natural gas and ethane are used as a feedstock for fertilisers and plastics), and the glass, brick and cement industries (where natural gas is used mainly in the kilns).

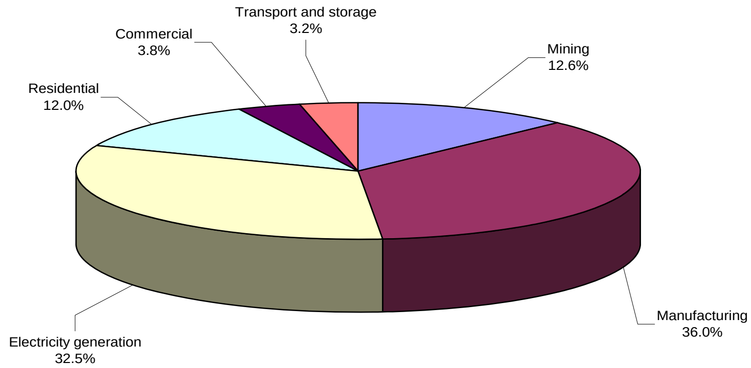
Consumption in the electricity generation sector has been historically higher in South Australia, Western Australia, and Victoria. However following recent energy market reforms, the emergence of privately owned gas-fired electricity generation has been a feature in New South Wales and Queensland.

In the residential sector, the major uses are for water heating, space heating and cooking. The pattern of use in the residential sector is characterised by a high number of small consumers.

As with natural gas consumption in general, residential consumption is concentrated in states with high availability through the pipeline network. Victoria currently accounts for more than two-thirds of total Australian residential consumption. The other states where residential consumption is significant are New South Wales and the Australian Capital Territory, South Australia and Western Australia.[19]

19. ibid., p. 44.

Figure 3: Natural gas consumption by sector



Source: energy supply association of Australia.

The export market

The natural gas export market is presently supplied from the North West Shelf (NWS) and more recently from Bayu-Undan, processed in Darwin. Natural gas is converted to LNG for transportation in speciality shipping to overseas markets—presently Japan, Korea, China and Taiwan with other shipments to single spot markets including Spain, Turkey, India and the United States. Additional export volumes are expected from the NWS when a fifth LNG processing train, a $2 billion investment comes on stream in late 2008. This additional capacity of 4.2 million tonnes will bring total project capacity to 15.9 million tonnes, one of the world's biggest LNG projects.

Additional exports are expected from a number of ventures in Western Australia including Greater Gorgon, Browse Gas, and Pilbara LNG (development of the Scarborough gas fields to the west of the North West Shelf). Additionally, there is a proposal to build a 3 to 4 Mt LNG capacity project at Gladstone, Queensland based on CSG as feedstock. This would be the first use of CSG in the world in an LNG plant. There is a degree of uncertainty as to the timing of these projects and as to eventual capacity of the plants, which makes the projection in Figure 2 somewhat speculative. Some of the projects have target starting dates around 2010 to 2012. Brief descriptions of the gas fields that are presently supplying LNG, together with fields mooted for development, are outlined below.

The North West Shelf

As noted, the NWS project is Australia's largest resources project involving some A$19 billion of capital expenditure to date. Woodside was first granted the NWS oil and gas tenements in 1963. The company joint-ventured the project as time progressed because of the huge capital expenditure and technical expertise required for its development. Woodside is now the operator of the NWS in partnership with other co-ventures including: BHP Billiton Petroleum (North West Shelf), BP Developments Australia, Chevron, LNG (Mimi) Pty Ltd and Shell Developments (Australia) Pty Ltd. The WA gas domestic contract (DOMGAS) was signed in 1980 with the first gas delivered in 1984 and the LNG contract with Japanese buyers first signed in 1981 with first deliveries in 1989. Domestic gas sales are piped southwards via the Dampier to Bunbury and Goldfields gas pipelines (Figure 1).

LNG exports from the NWS began in 1989 and were running at about 7.5 million tonnes (Mt) per annum up until 2004. Export LNG volumes increased to around 11.7 Mt per annum following the commissioning of the fourth LNG processing train in 2004. With the completion of a fifth LNG processing train, production capacity is expected to increase to 15.9 million tonnes a year by the fourth quarter of 2008.

Bayu-Undan

The Bayu-Undan gas and condensate fields lie between East Timor and Australia, about 500 kilometres north-west of Darwin. The development of Bayu-Undan was undertaken in two stages. The initial stage was the condensate stripping gas recycle phase. Condensate production began at Bayu-Undan in February 2004 at the rate of some 50,000 barrels per day (bbl/d) with a build up to 110,000 bbl/d by the third quarter of 2004. The second stage of the LNG development involved the construction of a pipeline from the gas field to the LNG plant in Darwin harbour. The first LNG cargo was shipped in February 2006. Capacity of the plant is 3.24 Mt per annum. The partners in the Bayu-Undan gas and condensate venture include ConnocoPhillips (operator), (57.15 per cent), Santos (11.39 per cent), INPEX (11.27 per cent), ENI (10.99), and Tepco and TG (9.19 per cent).[20]

Bayu-Undan had initial published reserves of the order of 400 million barrels of condensate and LPG and 3.4 tcf of natural gas.

Other fields

Other fields earmarked for development include: Greater Gorgon, Pluto, Browse Gas, Pilbara LNG, Greater Sunrise, and an LNG project in Gladstone, Queensland. Brief comments on a number of these developments are detailed below.

20. Nigel Wilson, 'Santos ups stakes in Bayu Undan', The Australian, 31 July 2007, p. 22.

The Greater Gorgon fields located to the south west and west of the NWS—including the massive Jansz field—contains somewhere in the order of 40 tcf, currently representing some 25 per cent of Australia's total gas resources.[21]

The Gorgon development is being pursued by three international energy companies: Chevron, Shell and ExxonMobil (the Gorgon Venture). Chevron, with a 3/7 interest, is the operator of the Gorgon development, and is leading the marketing and development of Gorgon area gas. Shell has a two-sevenths interest and ExxonMobil a one-seventh interest. Chevron is also the operator of the Barrow Island oil operation.

The development of the gas-processing facility would depend on market demand. Proposed initial development includes the construction of one LNG processing train with a nominal capacity of 5Mt/year. The construction of a second similar capacity train would follow with additional market demand. The preferred site for the LNG trains, depending on environmental assessments would be Barrow Island. LNG production from the Gorgon development is currently scheduled to commence in 2010. The proponents are currently assessing several alternatives for gas delivery to the mainland.

Woodside is looking to fast-track development of its 100 per cent owned Pluto gas field located to the south west of the NWS. The project is based on the development of the Pluto and Xena gas fields with reserves of around 5 tcf. First LNG is scheduled to be produced in 2010. Agreements have been reached with two Japanese companies to supply up to 3.75 million tonnes of LNG a year for at least 15 years in addition to the processing of gas for the Western Australian market. The project has approved funding of up to $11.2 billion.

There are a number of major gas fields (Torosa, Brecknock and Calliance) located in the Browse Basin located some 350 kilometres off the north western coastline from Derby in the Kimberley region of remote northern Western Australia. These fields are of the order of eight hundred kilometres north east from the major fields of the NWS. The development of these fields is being assessed by the Browse LNG consortium consisting of Woodside, BP, BHP Billiton, Chevron and Shell. Additionally, the development of the Ichthys field in the Browse basin is under consideration by a joint venture of the Japanese company Inpex and the French company Total. The resources of both these fields are very large. For example, the Torosa, Brecknock and Calliance fields contain in the order of 20 tcf of gas—around 20 times Australia's total present annual gas consumption—and Ichthys contains in the order of 10 tcf. The fields also contain limited amounts of condensate (light oil). The proposals to develop these gas fields are in the very early stages and production is unlikely to begin in either of these fields before 2012.

The federal and Western Australian governments—The Kimberley Strategic Assessment—are presently assessing whether Browse Basin gas LNG developments should operate out of a single industrial hub located at a suitable site in the Kimberley region. Possible benefits could

21. Gorgon Gas Development Fact Sheet, www.gorgon.com.au, viewed December 2007.

include site selection with least disturbance of pristine areas and better efficiency in terms of environmental impact assessments and project approval. From a company point of view there is concern that such a policy does not slow the development approval process.[22]

The Sunrise and Troubadour gas fields, known jointly as the Greater Sunrise field, are located offshore in the Bonaparte Basin, 350 kilometres north-west of Darwin. The Greater Sunrise field contains an estimated 295 million barrels of condensate and 8.4 tcf of gas. Development of these fields is on hold pending further economic assessment.

Natural gas prices

Natural gas remains relatively cheap in Australia. Prices are much lower in Australia than in the United States and Europe where gas prices tend to follow oil price trends. This has not been the case in Australia where domestic prices have reflected local supply and demand fundamentals, characterised by low consumption and high reserves.[23]

While publication of gas prices has been discontinued by the Australian Gas Association because of commercial reasons, there are broader price overviews for the retail gas sector by the Australian Energy Regulator. There are considerable differences in retail gas prices for each of the states, the cheapest being Victoria followed by Western Australia, South Australia, New South Wales, and Queensland.[24]

There is an order of magnitude of difference in prices in the domestic market compared to the wholesale market and to gas sold to industrial and large commercial customers. The wholesale and industrial/commercial customers are billed in gigajoule units as compared to megajoule units for the domestic customer. Wholesale and bulk tariffs charged to industrial/commercial customers in Eastern Australia ranged from around $3.50 to $3.80 GJ in 2006. Gas is sold to large entities from the gas fields mostly under confidential long-term take or pay contracts. Historically, contracts have lasted for up to 30 years, but more recently contacts have been shortened to 10–15 years.

While still cheap by international standards wholesale and retail gas prices in Australia have generally trended upwards in the last few years, especially in Western Australia. The main cause appears to be uncertainty about future gas field development costs in light of significant overall cost increases. Additionally, the advent better prices presently being received for LNG exports is expected to eventually impact on the domestic market leading to further gas price increases.

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22. Stephen Wisenthal, 'Producers want say on LNG sites', Australian Financial Review, 6 February 2008, p. 57.

23. Australian Energy Regulator, 'State of the Energy Market 2007', Melbourne, p. 235–236.

24. In 2006, the Australian Energy Regulator estimated retail prices in Victoria averaged around a low of $12/GJ to a high of $27/GJ in Queensland.

Industry gas pipeline developments

Natural gas consumption has increased steadily over the last few decades as has the development of natural gas infrastructure (Figure 1). In 2006, the high pressure transmission pipeline grid extended to just over 21 000 kilometres. Large industrial customers—manufacturers and gas-fired electricity generators—usually take their supply directly from selected points in this grid. Natural gas is delivered from the fields to designated points—termed city gates—for ongoing delivery to commercial and domestic customers via lower pressure distribution grids.

Over the period from the early 1990s to 2007, a number of new high pressure gas pipelines have been built. A significant element of this expansion has been associated with construction of interstate pipelines—the Eastern Gas pipeline (Longford to Horsley Park in 2000), the NSW-Victoria Interconnect (Wagga Wagga to Wodonga in 1998), the Tasmanian Gas Pipeline (from Longford, Vic to Bell Bay, Tas in 2002) and the SEA Gas pipeline (Port Campbell in Victoria to Adelaide in 2004). These developments in particular have greatly expanded gas availability, for example Gippsland gas now being piped into New South Wales. Other relatively recent major pipeline constructions includes the Goldfields Gas pipeline extending from Dampier through Kalgoorlie to Esperance, extensions of the Amadeus pipeline in the Northern Territory to McArthur River and Mt Todd, and the extensions of the Queensland pipelines networks linking Mt Isa and Barcaldine.

Despite the considerable development outlined above, an ongoing issue is the question of third party access (for new producers or traders) to high pressure pipelines and access prices determined by competition regulators. Access to the network of pipelines by new producers is paramount for increased wholesale and retail competition. However, prices of third party access to covered pipelines—that is ones subject to determination by an external regulator—may be considered inadequate by the pipeline owner. A pipeline developer would have a reluctance to build anything excess capacity unless there was a degree of certainty on earning a competitive rate of return on this additional investment. Additionally a new proponent may pay too high a price for a pipeline network. A case in point is a former purchaser of the Dampier to Bunbury pipeline, Epic Energy. This company went into liquidation as the determined regulated tariff was far lower than necessary for the company to earn a return on its investment. Recent trends include pipelines being built exactly to capacity which effectively restricts third-party access. This development however restricts gas transportation in Australia to a certain extent and poses a significant threat to the efficient use of natural resources.[25] This problem of regulated prices now deterring investment is not specific to pipeline infrastructure and it applies equally to other industry sectors where third party access is sought to established infrastructure, for example, to rail and telecommunications networks, and to ports.

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25. T. Sykes, 'Rex's pipedream come true', Australian Financial Review, 9 October, 2004, pp. 26–27.

A number of new pipeline developments are planned. These include:

- the trans Northern Territory pipeline linking the Blacktip gas field in the Bonaparte basin to Darwin;
- the Amadeus Basin to Darwin pipeline linking to Mount Isa and onto Moomba;
- the linking of the South Australian and Queensland networks with a pipeline link between Moomba and Barcaldine and the linking of the South West Queensland pipeline (Ballera to Wallumbilla) through to northern New South Wales and on to Sydney;
- Additionally a number of new pipeline connections are expected from many of the newer coal seam gas accumulations in the Bowen Basin in Queensland and the Sydney Basin to major centres of population.

Natural gas use and the environment

As noted, one of the advantages of the use of natural gas is that it is less polluting than other hydrocarbon energy sources. Of course, its combustion still releases carbon dioxide, the main greenhouse gas. Combustion also produces small amounts of toxic gases such as carbon monoxide, formaldehyde and nitrogen oxides (principally nitrogen dioxide). Unintended or unavoidable releases of methane into the air (known as fugitive emissions), which may occur during extraction, processing and transport, are also a concern, because methane is a much more powerful greenhouse gas than carbon dioxide. However, compared to coal and oil, the use of natural gas produces less carbon dioxide, fewer particulates, and relatively small amounts of pollutant gases. It therefore enjoys a comparative environmental advantage.

Carbon dioxide emissions resulting from an array of fossil fuels are outlined in Table 2. It is clear that gas is some 65 and 70 per cent less greenhouse intensive than either brown or black coal.

Table 2: Average carbon emission intensity of selected fossil fuels.

Fuel	**Emissions of carbon dioxide per GJ of produced energy**
Brown coal	93.3 kg
Black coal	90.7 kg
Petroleum	68.2 kg
Gas	50.9 kg

source: Gas Statistics Australia, Australian Gas Association.

Natural gas can be used as an alternative fuel for transportation in the form of compressed natural gas (CNG) or LNG. Use of these fuels is becoming increasingly more common in the public transport and freight sector. Currently these fuels are available from a small number of centralised filling stations.

The fact that gas is less environmentally polluting than other fossil fuels means there is scope for the expansion of both gas-fired power plant and the use of natural gas or LNG for vehicular fuel. Combined cycle gas-fired turbines can have efficiencies of over 70 per cent compared to around 40–45 per cent for the best coal-fired plant. The additional efficiency is gained where excess heat from the gas-fired cycle is captured and used for an additional steam generated turbine at the back end of the plant.

Despite the array of environmental positives, a drawback for the LNG export business is that it is energy intensive to liquefy natural gas for transportation and re-gasify these shipments at the import terminal before use in that particular country market. Whilst it is difficult to find published data on the energy use and resultant emissions in these processes, these could range between 200 to 400kg of carbon dioxide emissions associated with the production of one tonne of LNG. With a projection of Australian output of some 50Mt of LNG for export by 2019–20, this would add some 10 to 20 Mt to greenhouse gas inventories, the bulk being generated in the liquefaction stage and as such to Australia's greenhouse gas emissions.

A further environmental offset would be encountered with the building of natural gas liquids plants. While there are definitive economic positives in producing liquid transport fuels from large stranded gas fields, such as adding to Australian oil self sufficiency, the process is substantially more energy intensive than the operation of LNG plants.

Pipeline network regulation

There have been substantial changes both in ownership of network gas pipeline infrastructure and subsequent regulatory arrangements since the early 1990s. These changes followed government restructuring of their single entity vertically integrated gas transport utilities. This involved the break-up of the individual entities into separate transmission and distribution businesses, a number of which have now been privatised.

Regional transmission and distribution systems are generally natural monopolies. To address risks associated with the market power of pipeline operators, governments introduced a regulatory regime for third-party access to natural gas pipelines to complement structural reform in the industry. Implementation with a satisfactory regulatory process has been protracted since the late 1990s. The pipeline access issue has been subjected to intensive evaluation by the Productivity Commission.[26]

Pipeline access is regulated under a National Third Party Access Code for Natural Gas Pipeline Systems (the Gas Code), which operates under the gas pipeline access Acts (Gas

26 Productivity Commission, 'Review of the Gas Access Regime', Productivity Commission Inquiry Report, No. 31, 11 June 2004, Melbourne.

Law) in each state and territory. The Gas Code applies only to pipelines assessed as meeting particular defined criteria.[27]

Under reforms agreed to in the Australian Energy Market Agreement 2004 (amended 2006) the current Gas Law and Gas Code are to be replaced with the National Gas Law and National Gas Rules. Under this law and rules, owners of covered pipelines are required to submit access arrangements to the nominated regulator for approval and comply with other Gas Code provisions, such as ring-fencing. Pipelines that are not covered are subject only to the general anti-competitive provisions of the *Trade Practices Act 1974*. Access to non-covered pipelines is a matter for commercial negotiation between the access provider and the access seeker, without regulation.[28]

Two separate peak industry bodies represent the high pressure pipeline transmission and the low pressure distribution sectors, the former being the Australian Pipeline Industry Association (APIA) and the later the Energy Networks Association (ENA).

Conclusions

Australia's natural gas industry has shown remarkable growth over the last few decades and this is projected to continue. Domestic use of natural gas continues to increase as does exports of LNG.

Whilst Australia has limited reserves of crude oil, it is relatively well endowed with natural gas resources. The most recent assessments indicate Australia has some 144 trillion cubic feet of natural gas, well over 100 times present annual domestic consumption. Somewhat inconveniently, however, Australia's gas reserves and resources are distributed unevenly throughout the continent, with the bulk of these located offshore northwest Western Australia and northern Australia.

The development of gas reserves both in the Bass and Otway Basins, offshore southern and south western Victoria has lessened supply constraints in eastern Australia. Additionally, the development of a new field—the Kipper project—in the long-producing oil and gas Gippsland Basin offshore south eastern Victoria will greatly assist the future supply of natural gas into the eastern Australian gas market. Also a tremendous fillip for future gas supply to this large geographical market is the development of the coal seam gas sector. Australia has extensive black coal deposits and associated coal seam gas in both Queensland and New South Wales. The development of the newer gas fields offshore Victoria and the coal seam gas sector may defer the need for gas to be piped from the bigger fields in the north west and the north of Australia for decades.

27. Australian Energy Regulator, 'State of the Energy Market 2007', Melbourne, p. 259.

28. ibid., p. 261.

It is readily apparent when analysing consumption statistics that some States depend more strongly on natural gas than others. Western Australia, South Australia and the Northern Territory depend on gas for more than 40 per cent of their primary energy demand, with Western Australia over 50 per cent. While Victoria is dependent on gas for some 20 per cent of its primary energy demand, the larger states of New South Wales and Queensland depend on natural gas for just over 10 per cent of their primary energy needs. These patterns have important environmental implications, as the larger the dependency on the primary energy sources such as coal and oil the higher the environmental footprint with reference to greenhouse gas emissions.

The liquefied natural gas export market has gradually expanded since the first shipments from the North West Shelf in 1989. Eventual output could near quadruple to over 50 million tonnes of LNG per year with the further expansion of the NWS and a number of other projects.

The use of natural gas is less polluting than the use of coal and oil. A major benefit is that natural gas is some 65 to 70 per cent less greenhouse gas intensive than either brown or black coal. Another decided advantage of gas is that it contains far fewer particulates and other elemental contaminants than either coal or oil. As a consequence natural gas can be used as an alternative fuel for transportation in the form of either compressed natural gas or liquefied natural gas especially in heavy transport such as public buses or road freight carriers that can use centralised refuelling points.

Considerable progress has been made in recent years in relation to third party access determinations to high pressure gas transmission and low pressure gas distributions networks freeing up lengthy determination. Under reforms agreed to in the Australian Energy Market Agreement 2004 (amended 2006) the current Gas Law and Gas Code are to be replaced with the National Gas Law and National Gas Rules with a single regulator, the Australian Energy Regulator.

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