Chapter 4

Gas

4.1 Summary

KEY MESSAGES

- Australia has significant gas resources; gas is Australia's third largest energy resource after coal and uranium.
- Most of the conventional gas resources are located off the north-west coast of Australia and are being progressively developed for LNG export and domestic use.
- Significant coal seam gas resources exist in the major coal basins of eastern Australia and are being developed for domestic use and potential export.
- Australia's gas resources are large enough to support projected domestic and export market growth beyond 2030 and are to expected grow further.
- Gas is a relatively flexible and clean energy source and is projected to be the fastest growing fossil fuel over the period to 2030.
- Gas is expected to significantly increase its share of Australia's energy production and exports, and make a substantially greater contribution to electricity generation.

4.1.1 World gas resources and market

- Gas is the third largest global energy source, currently accounting for around 21 per cent of global primary energy consumption. Global gas consumption has increased by 2.8 per cent per year since 2000, to reach 121 280 PJ (107 tcf) in 2008.
- Global LNG trade has expanded even more rapidly – by 6.1 per cent per year since 2000 – to reach 8850 PJ (168 Mt, 8 tcf) in 2008. LNG trade accounts for around 7 per cent of global gas consumption.
- Global gas proved reserves are estimated to have been around 7.2 million PJ (6534 tcf) at the end of 2008. This is equal to more than 60 years' supply at current production rates. While information is limited, global unconventional gas resources in place are estimated to be more than four times this amount, in the order of 35.8 million PJ (32 500 tcf).
- Australia accounted for nearly 2 per cent of world gas reserves and production in 2008. However, Australia is the world's sixth largest LNG exporter and accounted for 9 per cent of world LNG trade in 2008.
- Global gas demand is projected by the International Energy Agency (IEA) in its reference case to increase by 1.5 per cent per year to reach 149 092 PJ (132 tcf) in 2030.
- This expansion in global demand will increasingly be met by imports, including LNG from countries such as Australia. Global LNG trade is projected by the IEA to rise by 3.7 per cent per year to reach 17 104 PJ (314 Mt, 15 tcf) in 2030.
- The recent rapid growth in unconventional gas resources and production worldwide could reduce LNG export opportunities in some markets but is likely to have less impact on Asian markets.

4.1.2 Australia's gas resources

- Gas is Australia's third largest energy resource after coal and uranium. This is unlikely to change in the period leading up to 2030.
- Most (around 92 per cent) of Australia's conventional gas resources are located in the Carnarvon, Browse and Bonaparte basins off the north-west coast. There are also resources in south-west, south-east and central Australia. Large coal seam gas (CSG) resources exist in the coal basins of Queensland and New South Wales. Tight gas accumulations are located in onshore Western Australia and South Australia, while potential shale gas resources are located in the Northern Territory (figure 4.1).
- In 2008, Australia's economic demonstrated resources (EDR) and subeconomic demonstrated resources (SDR) of conventional gas were estimated at 180 400 PJ (164 tcf). At current

production rates there are sufficient EDR (122 100 PJ, 111 tcf) of conventional gas to last another 63 years (figure 4.2).

- In addition there is a possible 22 000 PJ (20 tcf) of inferred conventional gas resources in recently discovered fields and other fields not booked as part of EDR and SDR.
- Gas exploration has a sustained record of success, with the strong likelihood of finding more conventional gas resources. Field growth and new discoveries will help offset increasing production so that identified conventional gas resources in 2030 will remain substantial and capable of supporting several decades of future production.
- Australia also has significant unconventional gas resources – CSG, tight gas and shale gas. Coal seam gas economic demonstrated resources (EDR) at the end of 2008 were 16 590 PJ (15.1 tcf), smaller recoverable resources than several of Australia's individual conventional gas fields but equal to more than 100 years of CSG production at current rates. Total identified resources of CSG are estimated to be around 168 600 PJ (153 tcf), including sub-economic resources (SDR) estimated at 30 000 PJ (27.3 tcf) and inferred of 122 020 PJ (111 tcf).
- Tight gas resources are estimated at around 22 000 PJ (20 tcf). Australia may also have significant but as yet unquantified shale gas resources. No reserves of tight gas or shale gas are currently booked.

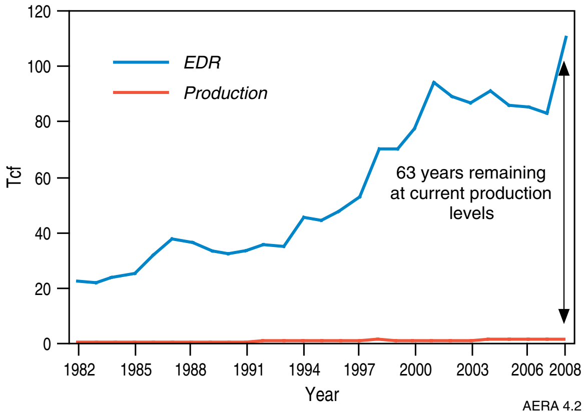


Figure 4.2 Conventional gas resources and production

Source: Geoscience Australia 2009

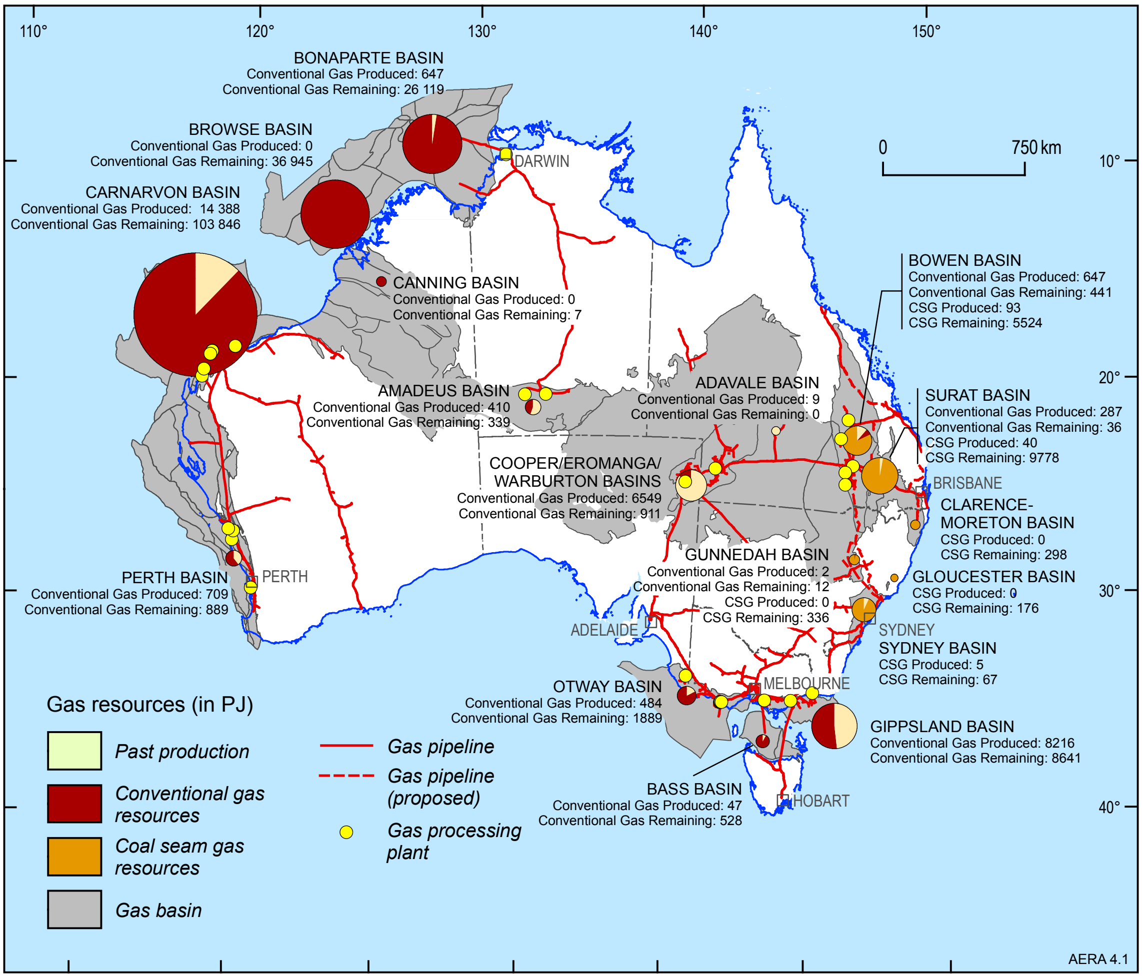


Figure 4.1 Location of Australia's gas resources and infrastructure

Source: Geoscience Australia

- Total identified gas resources are sufficient to enable significant expansion in Australia's domestic and export production capacity. Australia's combined identified gas resources are in the order of 393 000 PJ (357 tcf). This is equal to around 180 years of gas at current production rates, of which EDR accounts for 67 years.
- The distribution of gas resources in 2030 is expected to follow a similar pattern with substantial conventional gas resources offshore and unconventional resources identified across several onshore basins.

4.1.3 Key factors in utilising Australia's gas resources

- Most of Australia's conventional gas resources are located offshore far from domestic gas markets, which affects the costs of bringing the resource to market.
- Development of secure long-term markets is necessary to underpin the major capital investment required for development of the offshore gas resources of north-west Australia.
- Potential environmental issues raised by gas development may include the disposal of water produced from onshore coal seam gas operations and carbon dioxide contained in some large offshore gas fields.
- New gas pipelines will be required, particularly in eastern Australia, to provide sufficient supply for new gas-fired electricity generation in response to demand for cleaner energy.

4.1.4 Australia's gas market

- Australian gas consumption has grown by 4 per cent per year over the past decade. Gas accounted for 22 per cent (1249 PJ) of Australia's primary energy consumption in 2007–08, and 16 per cent of electricity generation.
- The main gas users in Australia are the manufacturing, electricity generation, mining and residential sectors.
- The expansion in gas production over this period has been even stronger. Gas production was 1833 PJ (1.6 tcf) in 2007–08. Unconventional gas production, in the form of coal seam gas, accounted for 7 per cent of this production. No tight or shale gas is currently produced in Australia.
- Around 44 per cent (802 PJ, 14.3 Mt) of Australian gas production was exported as LNG, valued at $5.9 billion, in 2007–08. Higher export volumes and international oil prices increased the value of exports in 2008–09 to $10.1 billion.

4.1.5 Outlook to 2030 for the Australian gas market

- Growth in gas consumption is expected to be driven by investment in new gas-fired power generation and by policy initiatives supporting gas uptake as a relatively clean energy source.
- An emissions reduction target is expected to enhance the role of gas as a transitional fuel to a low carbon economy. Gas-fired electricity generation has lower carbon emissions than coal-fired electricity without carbon capture and storage, and can also be linked with intermittent renewable energy resources such as wind to provide a flexible and reliable power source.
- Demand for LNG is likely to grow in overseas markets, driven by similar factors to those in Australia.

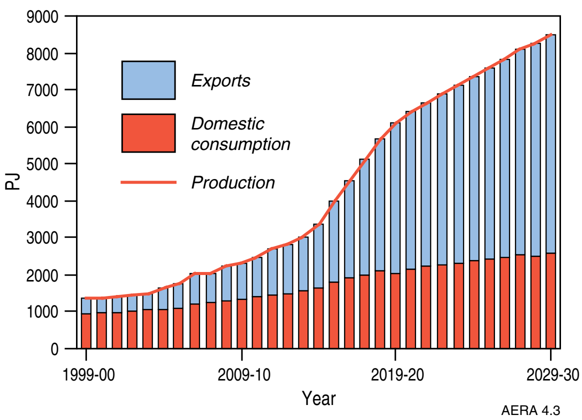


Figure 4.3 Outlook to 2030 for the Australian gas market

Source: ABARE 2009a, 2010

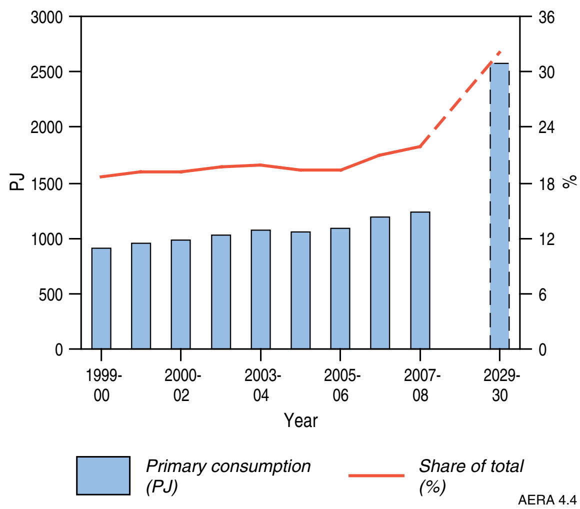


Figure 4.4 Outlook to 2030 for Australian gas consumption

Source: ABARE 2009a, 2010

- In ABARE's latest long-term projections which include a 5 per cent emissions reduction target, the Renewable Energy Target and other government policies, gas consumption in Australia is projected to increase by 3.4 per cent per year to reach 2575 PJ (2.3 tcf) in 2029–30. Its share of primary energy consumption is projected to rise to 33 per cent in 2029–30 (figures 4.3 and 4.4).
- Australian gas production is projected to reach 8505 PJ (7.7 tcf) in 2029–30. Coal seam gas is projected to account for 29 per cent of this total.
- LNG exports are expected to account for around 70 per cent of Australian gas production in 2029–30, with exports projected to increase to 5930 PJ (109 Mt) in 2029–30. As well as the major announced and potential LNG developments in north-west Australia, there are well-advanced plans to export coal seam gas as LNG from Queensland in the next decade.

4.2 Background information and world market

4.2.1 Definitions

Natural gas is a combustible mixture of hydrocarbon gases. It consists mainly of methane (CH_4), with varying levels of heavier hydrocarbons and other gases such as carbon dioxide. Natural gas is formed by the alteration of organic matter (box 4.1). When accumulated in a subsurface reservoir that can be readily produced it is known as **conventional gas**. Conventional gas can also be found with oil in oil fields. Conventional gas fields can be **dry** (almost pure methane) or **wet** (associated with the 'wet gas' components – ethane, propane, butanes and condensate). Dry gas has a lower energy content than wet gas. Natural gas can also be found in more difficult to extract **unconventional** deposits, such as coal beds

BOX 4.1 NATURAL GAS CHEMISTRY AND FORMATION

Natural gas is composed of a mixture of combustible hydrocarbon gases (figure 4.5). These include methane (CH_4), ethane (C_2H_6), propane (C_3H_8), butane (C_4H_{10}) and condensate (C_{5+}). Most natural gas is methane but because of the variable additions of the heavier hydrocarbons, gas accumulations vary in their energy content and value (Appendix E).

Liquefied Natural Gas (LNG) is primarily composed of the lightest hydrocarbons, methane (CH_4) and ethane (C_2H_6). It is produced by cooling natural gas to around -160°C where it condenses to a liquid taking up about 1/600th the volume of natural gas in the gaseous state.

Liquefied Petroleum Gas (LPG) is a mixture of the light hydrocarbons propane (C_3H_8) and butane (C_4H_{10}) and it is normally a gas at surface conditions,

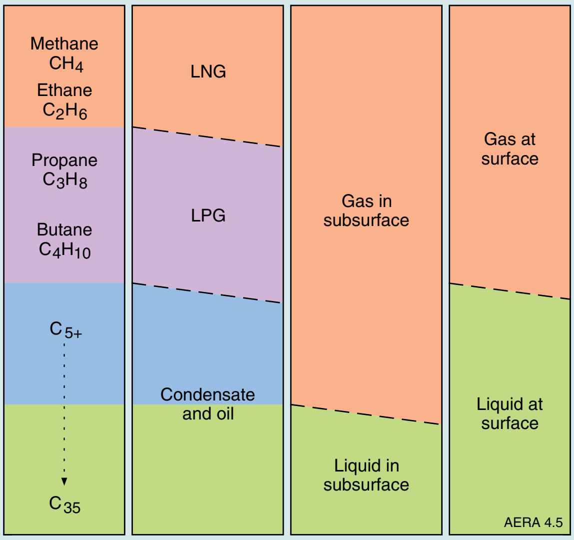


Figure 4.5 Petroleum resources nomenclature in terms of chemical composition, commercial product, physical state in the subsurface and physical state at the surface

Source: Geoscience Australia

though it is stored and transported as a liquid under pressure (for example in domestic barbecue gas bottles). Condensate is a mixture of pentane (C_5H_{12}) and heavier hydrocarbons that condense at the surface when a gas accumulation is produced. The gas liquids, LPG and condensate, are discussed in Chapter 3 (Oil).

Natural gas is formed by the alteration of organic matter. This can occur through biogenic or thermogenic processes. The bacterial decomposition of organic matter in oxygen-poor environments in the shallow subsurface produces biogenic gas, for example landfill gas – see Chapter 12 (Bioenergy). Biogenic gas is very 'dry', being almost pure methane.

Thermogenic natural gas is derived from the thermal alteration of organic matter buried deep within sedimentary basins over geological time. Thermogenic gas is generated with oil as the organic matter is heated and buried; with further burial and heating, oil will be 'cracked' to gas and pyrobitumen. Hence, natural gas is preserved within a sedimentary basin over a greater depth and temperature range than oil.

There are isotopic methods to distinguish biogenic from thermogenic gas. Evidence of thermogenic gas indicates that a petroleum system is working and leaves open the possibility that oil may also occur. Most Australian conventional gas accumulations are considered to be thermogenic in origin (Boreham et al. 2001), though some of the dry gas accumulations such as Tubridgi in the onshore Carnarvon Basin (Boreham et al. 2008) have a biogenic source input. A significant biogenic contribution is recognised in Australian coal seam gas (Draper and Boreham 2006).

(coal seam gas), or in shales (shale gas), low quality reservoirs (tight gas), or as gas hydrates (box 4.2).

Coal seam gas (CSG) is naturally occurring methane gas in coal seams. It is also referred to as coal seam methane (CSM) and coal bed methane (CBM). Methane released as part of the coal mining operations is called coal mine methane (CMM). Coal seam gas is dry gas, being almost entirely methane with the gas molecules remaining adsorbed in the coal rather than migrating to a conventional gas reservoir.

Tight gas occurs within low permeability reservoir rocks, that is rocks with matrix porosities of 10 per cent or less and permeabilities of 0.1 millidarcy (mD) or less, exclusive of fractures (Sharif 2007). Tight gas can be regionally distributed (for example, basin-centred gas), or accumulated in a smaller structural closure as in conventional gas fields.

Shale gas is natural gas which has not migrated to a reservoir rock but is still contained within low permeability, organic-rich source rocks such as shales and fine-grained carbonates.

Gas hydrates are a potential unconventional gas resource. Gas hydrates are naturally occurring ice-like solids (clathrates) in which water molecules trap gas molecules in deep-sea sediments or in and below the permafrost soils of the polar regions.

Liquefied natural gas (LNG) is natural gas that is cooled to around -160°C until it forms a liquid, to make it easier and cheaper to transport long distances in LNG tankers to markets.

As an end-use product, unconventional gas is similar to conventional natural gas. It can be added to natural gas pipelines without any special treatment and utilised in all natural gas applications such as electricity generation and commercial operations.

4.2.2 Gas supply chain

Figure 4.6 illustrates the simplified operation of the gas industry in Australia. Resources are delivered to domestic and export markets through the successive activities of exploration, development, production, processing and transport. While different technologies can be used for extracting CSG and other unconventional gas, once extracted it is indistinguishable from conventional natural gas, and the supply chain is the same.

Resources and exploration

Exploration for conventional gas follows the same process as for oil. Geoscientists identify areas where hydrocarbons are liable to be trapped in the subsurface, that is in sedimentary basins of sufficient thickness to contain mature petroleum source rocks as well as suitable reservoir and seal rocks in trap configurations. The search narrows from broad regional geological studies through to determining an individual drilling target. Reflection seismic is the primary technology used to identify likely hydrocarbon-bearing structures in the sub-surface (figure 4.7). There must also be evidence of a working petroleum system (box 4.2). Such evidence includes the presence of other petroleum discoveries in the case of a proven basin, or indications of the presence of organic-rich rock to act as a gas

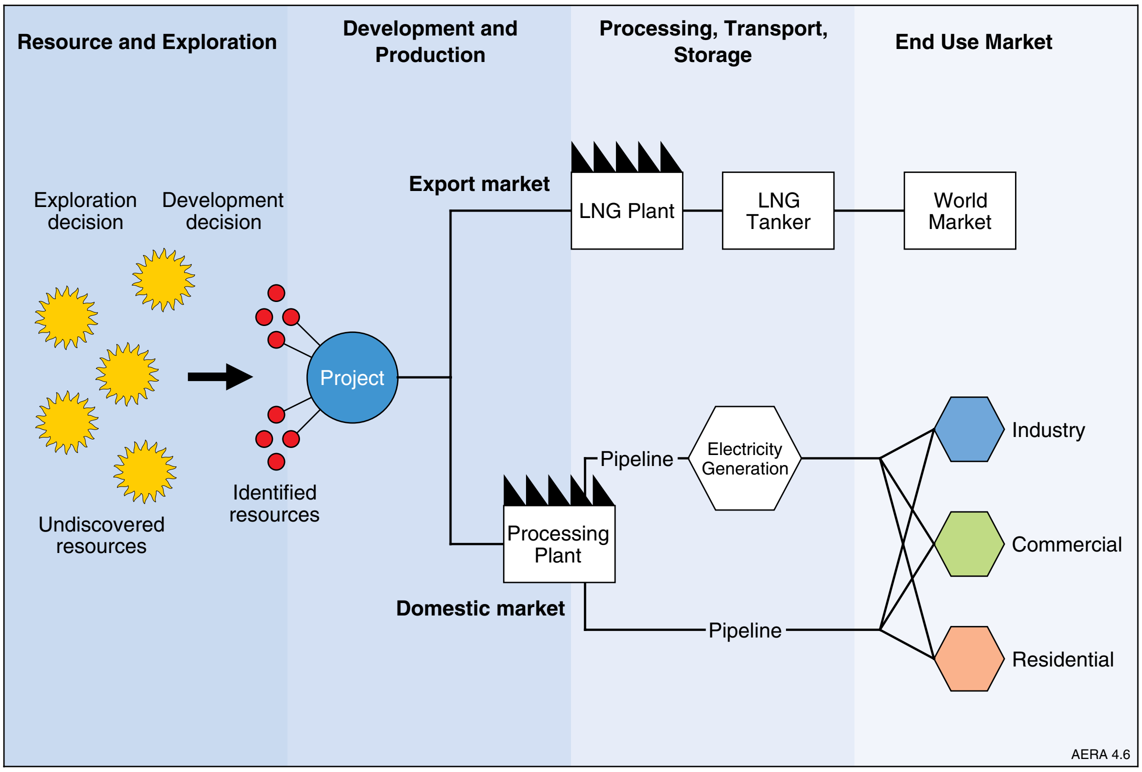


Figure 4.6 Australia's gas supply chain

Source: ABARE and Geoscience Australia source in the case of frontier basins. Drilling is required to test whether the putative hydrocarbon trap contains oil or gas, both, or neither. Successful wells are commonly tested to recover a sample of the hydrocarbons for analysis to determine gas quality (liquids content, presence of CO_2) and to determine likely production rates. The initial discovery well may be followed by appraisal drilling and/or the collection of further survey data to help determine the extent of the accumulation.

In Australia, government has taken a key role in providing regional pre-competitive data to encourage private sector investment in exploration. Company access to prospective exploration areas is by competitive bidding, usually in terms of proposed work program, or by taking equity ('farming-in') in existing acreage holdings.

Exploration for unconventional gas differs somewhat from the search for conventional hydrocarbons, especially when the target is a broadly distributed stratigraphic formation such as a coal bed or shale. Seismic surveys and drilling still constitute the major exploration technologies. However, the distribution of the prospective formation is usually well known at the regional scale, and exploration success depends on identifying parts of the formation where the gas resource and reservoir quality are sufficient to sustain a flow of gas on a commercial scale.

Most of Australia's conventional gas exploration occurs in the offshore basins, sometimes in water depths beyond 1000 m and with target depths from about 2000 to over 4000 m below the sea floor. The search for CSG, tight gas and shale gas is restricted to onshore basins and target depths range from a few hundred metres to about 1000 m. The costs of the different exploration components – especially seismic and drilling – vary markedly depending on the scope and location of the project, logistics, and other factors. Many shallow onshore CSG wells can be drilled for the cost of one deep well in deep water.

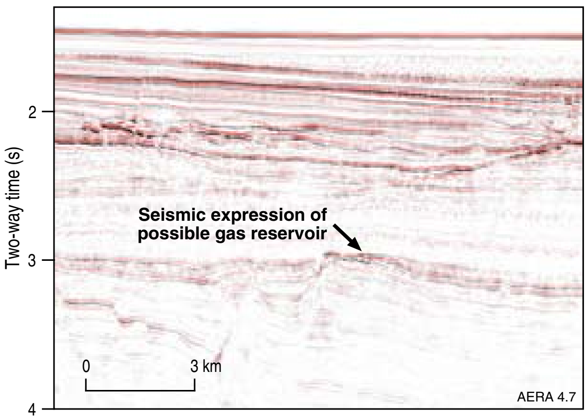


Figure 4.7 Seismic section across a prospective gas accumulation on the Exmouth Plateau, Carnarvon Basin

Source: Williamson and Kroh 2007

For example, an offshore well drilled to 3000–4000 m in water depth of 100–200 m typically costs $30–50 million (roughly $1 million per day of drilling), depending on location, water depth and other considerations. Shallow wells drilled to 200–1000 m in CSG exploration and development typically cost around $300 000 to $1 million (around $1000 per metre) with an average cost of around $500 000 per well (company reports and Geoscience Australia estimates).

Development and production

Once a decision to proceed has been made and financial and regulatory requirements addressed, infrastructure and production facilities are developed. For offshore conventional gas accumulations this involves the construction of production platforms with the gas piped to onshore processing plants, although there are proposals to develop some remote gas fields with floating LNG processing facilities on-site. Production of CSG resources requires the drilling of many shallow wells and removal of water to de-pressurise the coal formation before gas flow is established. Hydraulic fracturing combined with horizontal drilling is used to achieve commercial flow rates from tight gas and shale gas formations.

Processing, transport and storage

The gas extracted from the well requires processing to separate the sales gas from other liquids and gases that may be present, and to remove water, carbon dioxide and other impurities before it can be transported efficiently by pipeline or ship. As a result, processing tends to occur near the production well.

Apart from small quantities used on site for electricity generation or other purposes, gas usually requires transport for long distances to major markets. This is managed in Australia by gas pipeline (for domestic use), and in liquefied form (LNG) by tanker (for export). Gas in pipelines travels at high pressures, which reduces the volume of the gas being transported as well as providing the force required to move through the pipeline. LNG is natural gas that has been cooled to around -160°C at which temperature it becomes a liquid and has shrunk in volume some 600 times. Liquefaction reduces the volume and the cost of transportation over long distances. However, it typically consumes 10–15 per cent of the gas in the process.

Natural gas not used immediately can be placed in storage until it is needed. Normally, it is stored underground in large reservoirs, but can also be stored in liquefied form. Gas can be reinjected into depleted reservoirs for later use following the extraction of oil and other liquids.

End use market

While major industrial users and electricity generators tend to receive natural gas directly, most users receive gas through distribution companies. As an

BOX 4.2 PETROLEUM SYSTEMS AND RESOURCE PYRAMIDS

Conventional accumulations of oil and gas are the products of a 'petroleum system' (Magoon and Dow 1994). The critical elements of a petroleum system (figure 4.8) are:

- source – an organic-rich rock, such as an organic-rich mudstone;
- reservoir – porous and permeable rock, such as sandstone;
- seal – an impermeable rock such as a shale;
- trap – a sub-surface structure that contains the accumulation, such as a fault block or anticline;
- overburden – sediments overlying the source rock required for its thermal maturation; and
- migration pathways to link the mature source to the trap.

In addition to these static elements, the actual processes involved – trap formation, hydrocarbon generation, expulsion, migration, accumulation and preservation – must occur, and in the correct order, for the petroleum system to operate successfully and gas and oil accumulations to be formed and preserved.

Unconventional gas accumulations reflect the failure or under-performance of the petroleum system. Shale gas and coal seam gas arise where the natural gas is still within the source rock, not having migrated to a porous and permeable reservoir. Tight gas accumulations are within a poor quality reservoir. The petroleum resource pyramid (McCabe 1998) illustrates how a smaller volume of easy to extract conventional gas and oil is underpinned by larger volumes of more difficult and more costly to extract unconventional gas and oil (figure 4.9). For the unconventional hydrocarbon resources additional technology, energy and capital has to be applied to extract the gas or oil, replacing the action of the geological processes of the petroleum system. Technological developments and rises in price can make the lower parts of the resource pyramid accessible and commercial to produce. The recent development of oil sands in Canada and of shale gas in the United States are examples where rising energy prices and technological development has facilitated the exploitation of unconventional hydrocarbon resources lower in the pyramid.

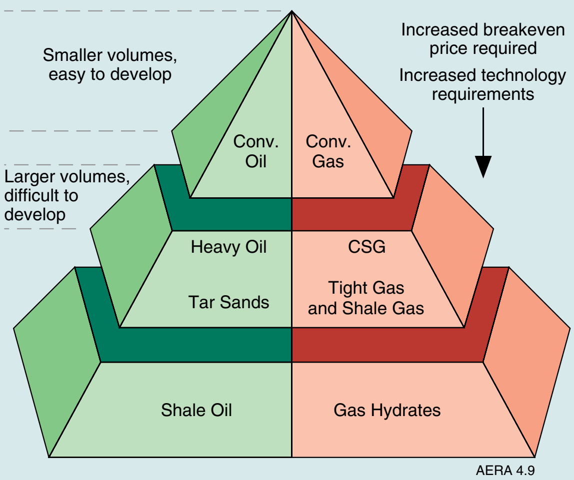


Figure 4.9 Petroleum resource pyramid

Source: Geoscience Australia, adapted from McCabe 1998 and Branan 2008

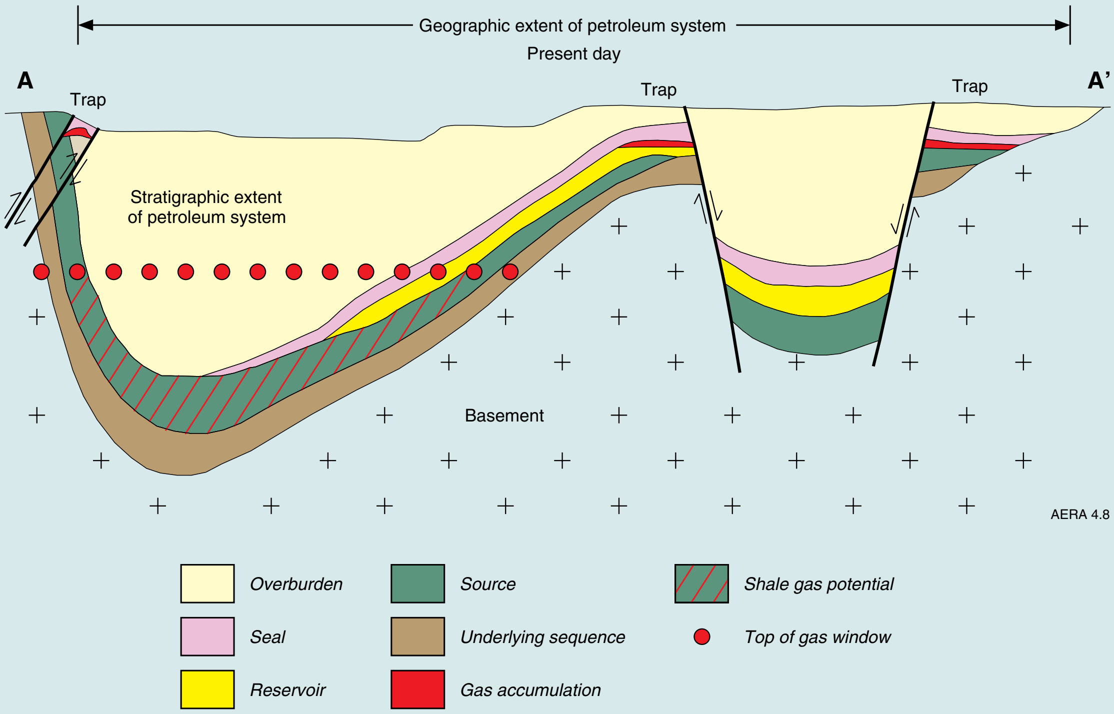


Figure 4.8 Petroleum system elements

Source: Modified after Magoon and Dow 1994 end-use product, unconventional gas may be added to gas pipelines without any special treatment and utilised in all gas appliances and commercial applications.

4.2.3 World gas market

Table 4.1 provides a snapshot of the Australian gas market within a global context. Australian reserves account for only a small share of global reserves, and Australia is a relatively small producer and consumer. However, natural gas reserves are significant at the national level, and natural gas plays an important role in the Australian energy mix. Australia has also emerged as a significant player in world LNG trade.

Reserves and production

Proved world gas reserves – those quantities that geological and engineering information indicates with reasonable certainty can be recovered in the future from known reservoirs under existing economic and operating conditions – were estimated to be more than 7.2 million PJ (6534 tcf) at the end of 2008. At current rates of world production, this is sufficient for more than 60 years (BP 2009). The Russian Federation, Iran and Qatar together hold more than half of the world's proved gas reserves (figure 4.10). Australia accounts for around 1.7 per cent of global reserves (table 4.1).

The IEA estimates that there are nearly 15.7 million PJ (14 285 tcf) of remaining recoverable resources of conventional gas. This is equivalent to almost 130 years of production at current rates (IEA 2009c).

World gas production in 2008 was estimated at 120 711 PJ (107 tcf). The largest gas producers are the Russian Federation and the United States. Australia is the world's nineteenth largest gas producer, accounting for around 1.5 per cent of world gas production (IEA 2009b, figure 4.10).

Consumption

Natural gas currently accounts for around 21 per cent of world primary energy consumption. World gas

Table 4.1 Key gas statistics, 2008

	Unit	Australia 2007–08	Australia 2008	OECD 2008	World 2008
Reserves	PJ	-	122 100	645 700	7 187 400
	tcf	-	111	587	6534
Share of world	%	-	1.7	9	100
World ranking	no.	-	14	-	-
Production	PJ	1833	1832	44 773	120 711
	tcf	1.6	1.6	40	107
Share of world	%	-	1.5	37	100
World ranking	no.	-	19	-	-
Annual growth in production 2000–2008	%	4.2	4.1	0.7	2.8
Primary energy consumption	PJ	1249	1351	59 992	121 280
	tcf	1.1	1.2	53	107
Share of world	%	-	1.1	49	100
World ranking	no.	-	27	-	-
Share of total primary energy consumption	%	21.6	20.5	23.7	20.9
Annual growth in consumption 2000–2008	%	4.0	5.3	1.4	2.8
Electricity generation	TWh	-	42	2343	4127
Share of total	%	-	15.9	22.0	20.9
Export					
LNG export volume	Mt	14.3	15.0	146	168
	tcf	0.7	0.7	7.0	8.0
Share of world	%	-	8.9	87	100
World ranking	no.	-	6	-	-
LNG export value	A$b	5.9	9.2	-	-
Annual growth in export volume 2000–08	%	-	8.5	-	6.1

Note: World share of total primary energy consumption and electricity generation are 2007 data; Australian production excludes imports from Joint Petroleum Development Area (JPDA)
Source: BP 2009; IEA 2009a, b; ABARE 2009a, b

consumption has grown steadily over the past few decades, by around 2.9 per cent per year between 1971 and 2008 (IEA 2009b). Contributing factors include increased emphasis on environmental issues, which favours the clean combustion properties of gas relative to other fossil fuels, the uptake of technologies such as integrated gas combined cycle power plants, and the commercialisation of abundant gas reserves. Energy security and fuel diversification policies have helped encourage gas demand as a means of reducing dependence on imported oil.

Natural gas is used all around the world (figure 4.11). The main gas consumers are the United States and the Russian Federation, followed by Iran and Japan. The Asia Pacific region accounted for around 16 per cent of world natural gas consumption in 2008, with Australia accounting for around 1.1 per cent (IEA 2009b).

Some 39 per cent of world gas consumption is for power generation, with the industry and residential sectors accounting for a further 18 per cent and 16 per cent respectively (IEA 2009b). The share of gas in total world electricity generation was 21 per cent in 2007, although this varies widely among countries (figure 4.11; IEA 2009a). In Australia, the share of gas in total electricity generation is around 16 per cent.

Trade

With gas reserves located some distance from key gas consuming countries, world gas trade has increased as a proportion of total consumption. In 2008, 30 per cent of world gas consumption

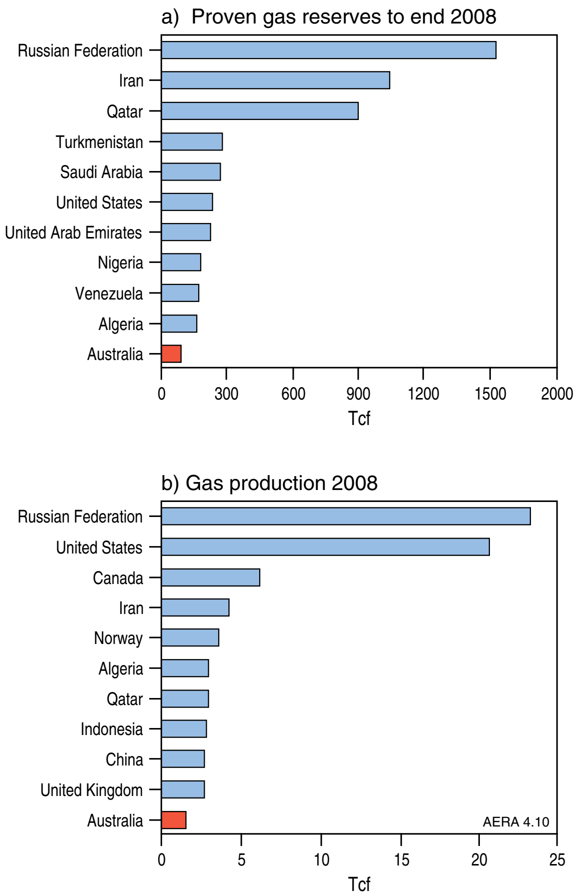


Figure 4.10 World gas reserves and production, major countries, 2008

Source: BP 2009; IEA 2009b

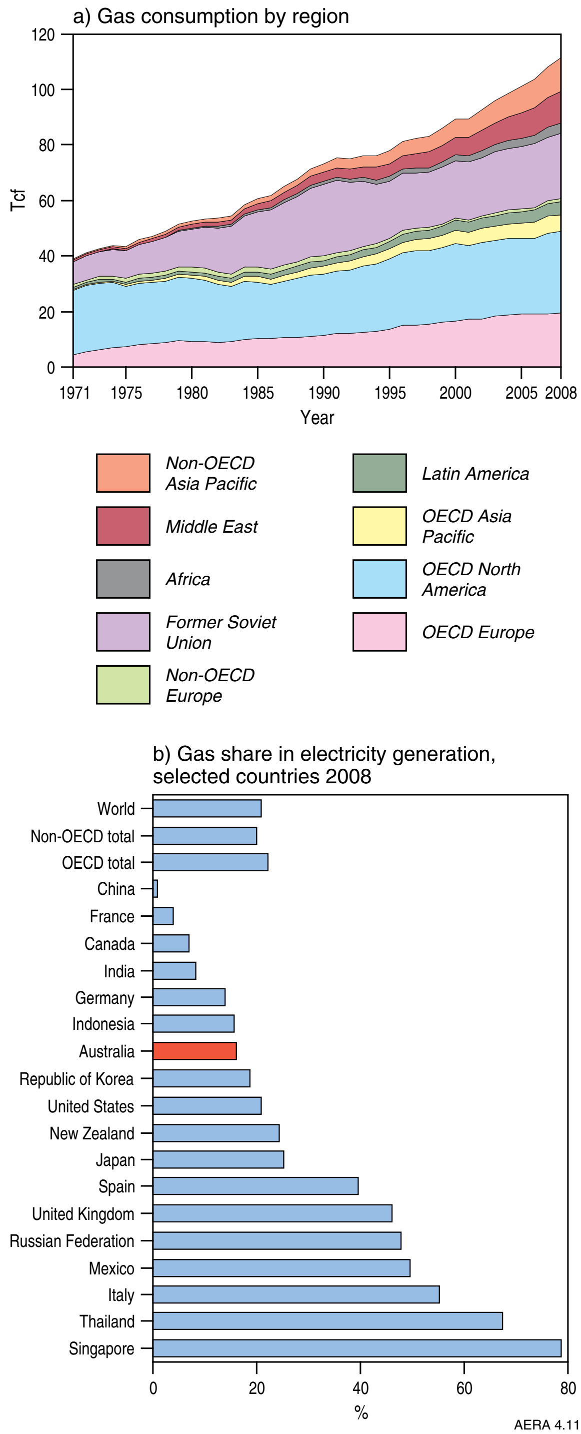


Figure 4.11 World gas consumption and the share of gas in electricity generation

Note: Shares in 4.11b for non-OECD and world are 2007 data

Source: IEA 2009a, b

was supplied through international trade. Trade as a proportion of gas consumption is much higher in the Asia Pacific region, where countries such as Japan and the Republic of Korea are reliant on imports for much of their gas needs.

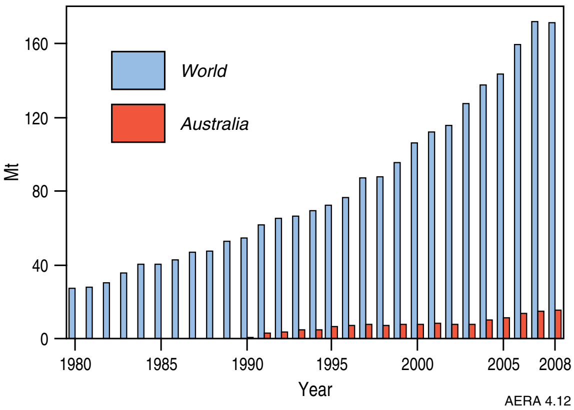


Figure 4.12 World LNG trade

Source: BP various years

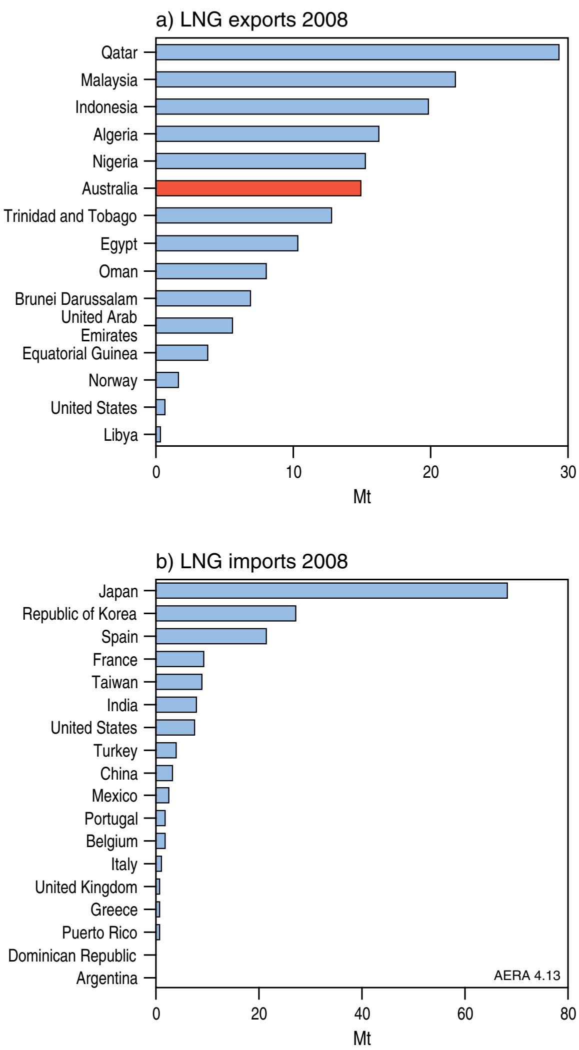


Figure 4.13 World LNG trade, by country, 2008

Source: BP 2009

LNG imports accounted for one quarter of world gas trade in 2008, equal to 7 per cent of world gas consumption; the remainder was transported by pipeline. With fewer international pipelines in the Asia Pacific region, the share of gas trade met by LNG imports is much higher, at 83 per cent (around 31 per cent of consumption) (IEA 2009b).

World LNG trade in 2008 was 9118 PJ (168 Mt) (figure 4.12). World LNG trade is characterised by a small but increasing number of suppliers and buyers. In 2008 there were 15 countries exporting LNG and 18 countries importing LNG, with the Russian Federation and Yemen commencing exports in 2009. Qatar is the world's largest LNG exporter, with 18 per cent of world trade in 2008 (figure 4.13). Japan is the world's largest LNG importer, accounting for 41 per cent of the market. Australia is the world's sixth largest LNG exporter, accounting for 9 per cent of world LNG trade in 2008, and 13 per cent of the Asia Pacific LNG market (BP 2009).

The role of unconventional gas

Information about global unconventional gas resources is much less complete than for conventional resources, and is less reliable. Although the resources worldwide are thought to be very large, they are currently poorly quantified and mapped (IEA 2009c).

According to the IEA, unconventional gas (including coal seam gas, shale gas and tight gas) now amounts to around 4 per cent of global proven reserves, or around 0.3 million PJ (257 tcf). World unconventional gas resources in place are much larger, estimated to be around 35.8 million PJ (32 500 tcf). Around 30 per cent of these resources are in the Asia Pacific, 25 per cent in North America, and 17 per cent in the Former Soviet Union (IEA 2009c).

Unconventional gas production accounted for 12 per cent of global gas production in 2008. Growth in unconventional gas production has been especially strong in North America. The United States accounted for three-quarters of global unconventional production with around 12 000 PJ (10.6 tcf). Unconventional production represents more than half of total US gas production. Canada was the second largest producer of unconventional gas, at nearly 2400 PJ (2.1 tcf), or around one third of its total gas output (IEA 2009c).

World coal seam gas resources in place are estimated to be around 10.2 million PJ (9047 tcf, table 4.2). The majority of these resources are in the Former Soviet Union, North America, and the Asia Pacific (IEA 2009c).

Coal seam gas is produced in more than a dozen countries, with the United States, Canada, Australia, India and China (IEA 2009c) predominating. The United States is the world's largest CSG producer, at around 2200 PJ (2.0 tcf) in 2008 (EIA 2009a). In Australia CSG production was 139 PJ (0.1 tcf) in 2008 (table 4.2).

World resources of tight gas and shale gas are also relatively large, but very uncertain, requiring further drilling and exploration to quantify. It is estimated that world tight gas resources are around 8.4 million PJ (7400 tcf, table 4.3). Around one-quarter of these are in the Asia Pacific. Other regions with significant tight gas resources include North and Latin America, the Middle East and the Former Soviet Union. Shale gas resources are estimated at around 18.2 million PJ (16 000 tcf). Similarly, large resources are in the Asia Pacific, North America, and the Former Soviet Union (IEA 2009c).

There is limited world production data for shale and tight gas. Significant quantities of tight gas are now being produced in more than ten countries. While tight gas production data in the United States and Canada are available, in other countries tight gas production is not generally reported separately from conventional sources (IEA 2009c).

The United States is the world's only large-scale producer of shale gas, producing approximately 2200 PJ (2 tcf) in 2008 (EIA 2009b). Canadian production has also risen in recent years.

Gas hydrates are widely distributed on the continental shelves and in polar regions (Makogon 2007). Sub-sea deposits have been identified in the Nankai Trough south-east of Japan, offshore eastern Republic of Korea, offshore India, offshore western Canada and offshore eastern United States. Total worldwide resources are estimated to be between 40 and 200 million PJ (35 000 to 177 000 tcf) (Milkov 2004). Very large but unproven potential gas hydrate resources are reported from the Arctic (Scott 2009).

Table 4.2 Key coal seam gas statistics, 2008

	unit	Australia	World
CSG resources	PJ	168 600[a]	10 240 000[b]
	tcf	153[a]	9047[b]
Share of world	%	1.6	100
CSG production	PJ	139	2700[c]
	tcf	0.1	2.3
Share of world	%	5.1	100
CSG share of total gas production	%	8.4	5.0

a Total identified CSG resources **b** Total CSG resources in place
c Estimate includes United States, Canada and Australia only
Source: IEA 2009c; EIA 2009a; Geoscience Australia

Table 4.3 Key tight and shale gas statistics, 2008

	unit	Australia	World
Tight gas resources	PJ	22 000	8 400 000
	tcf	20	7400
Share of world	%	0.3	100
Shale gas resources	PJ	-	18 240 000
	tcf	-	16 000
Share of world	%	-	100

Source: IEA 2009c; Campbell 2009; Lakes Oil 2009

Currently, commercial production of gas hydrates is limited to the Messoyakha gas field in western Siberia, where gas hydrates in the overlying permafrost are contributing to the flow of gas being produced from the underlying conventional gas field (Pearce 2009). However, exploitation of gas hydrates is a rapidly evolving field. There are active research programs or experimental production in Canada, Japan, the Republic of Korea and the United States, but gas hydrates are not expected to contribute appreciably to supply in the next two decades (IEA 2009c).

The development of unconventional gas resources is most advanced in the United States and impacts on the global LNG market are already evident, including reduced demand for LNG imports into the United States. The main driver of commercial scale exploitation of unconventional resources has been the successful development and deployment of technologies that enable these resources to be produced at costs similar to those of conventional gas in these countries, particularly with recent high gas prices (IEA 2009c).

World outlook to 2030

In its 2009 *World Energy Outlook* (IEA 2009c) reference case, the IEA projects world demand for natural gas to expand by 1.5 per cent per year between 2007 and 2030, to reach 149 092 PJ (132 tcf) in 2030 (table 4.4). The share of gas in total world primary energy demand is projected to remain at 21 per cent in 2030.

The majority of the increase in global gas use over the projection period – more than 80 per cent in total – comes from non-OECD countries, particularly in the Middle East. Demand growth is also strong in China and India (more than 5 per cent per year). In both of these countries, while the share of gas in the energy mix will remain relatively low, the volumes consumed will be significant in terms of global gas use and trade. There will be relatively low rates of demand growth in the more mature markets of North America and Europe to 2030, although they are expected to remain the largest markets in absolute terms.

The electricity sector is projected to account for 45 per cent of the increase in world gas demand to 2030, with gas fired power generation projected to increase by 2.4 per cent per year, to reach 7058 TWh (table 4.5). Low capital costs, short lead times and a relatively lower environmental impact make gas-fired power generation an attractive option, particularly where uncertainties exist on longer term low emission technology requirements.

Table 4.4 Outlook for primary gas demand, IEA reference scenario

	unit	2007	2030
OECD	PJ	52 712	60 834
	tcf	47	54
Share of total	%	23	25
Average annual growth 2007–2030	%	-	0.6
Non-OECD	PJ	52 502	88 258
	tcf	46	78
Share of total	%	20	20
Average annual growth 2007–2030	%	-	2.3
World	PJ	105 172	149 092
	tcf	93	132
Share of total	%	21	21
Average annual growth 2007–2030	%	-	1.5

Source: IEA 2009c

Table 4.5 Outlook for gas-fired electricity generation, IEA reference scenario

	unit	2007	2030
OECD	TWh	2307	2962
Share of total	%	22	22
Average annual growth 2007–2030	%	-	1.1
Non-OECD	TWh	1819	4097
Share of total	%	20	19
Average annual growth 2007–2030	%	-	3.6
World	TWh	4126	7058
Share of total	%	21	21
Average annual growth 2007–2030	%	-	2.4

Source: IEA 2009c

The IEA reference case presents a business as usual outlook in the absence of any significant policy changes, such as the introduction of carbon pricing. Any eventual introduction of a carbon price would adjust the relative prices of all fuels, reflecting their different carbon intensities and, other things being equal, influencing both the level of consumer demand and the direction of supplier investment accordingly. The strength of these influences, and overall impact on gas demand, will be governed in substantial measure by market responses to the carbon price level.

Global gas resources are sufficient to meet the projected increase in global demand, provided that the necessary investment in gas supply infrastructure is made. Production is expected to become more concentrated in the regions with large reserves, with more than one-third of the projected growth to come from the Middle East. Africa, Central Asia, Latin America and the Russian Federation are also projected to experience significant growth in production.

The share of gas produced from unconventional gas sources is projected to rise, from around 12 per cent in 2007 to nearly 15 per cent in 2030. Most of this increase is expected to come from the United States. Output is also expected to increase in China, India, Australia and Europe, although the share of unconventional relative to conventional gas production in these regions remains small. The expected rise in unconventional gas sources has implications for prices and energy security, as well as energy trade. Increased unconventional gas production in the United States to more than half of its total gas production, for example, is reducing its reliance on imports of LNG.

Trade is expected to rise more quickly than demand (by 2.0 per cent per year over the period 2007–2030), reflecting the imbalance between the location of reserves and the sources of demand. Inter-regional gas trade is projected to rise from 27 080 PJ (24 tcf) in 2007 to 42 760 PJ (38 tcf) in 2030. Most of the increase in inter-regional gas trade is in the form of LNG, with its share of trade rising from 34 per cent in 2007 to 40 per cent in 2030. LNG trade is projected to rise by 3.7 per cent per year to 17 104 PJ (15 tcf, 314 Mt) in 2030.

Globally, more than 400 million tonnes of additional LNG capacity is either under construction, planned or proposed (figure 4.14). However, it is unlikely that many of these projects will proceed as proposed, at least in the medium term. Australia accounts for a significant share of the new capacity.

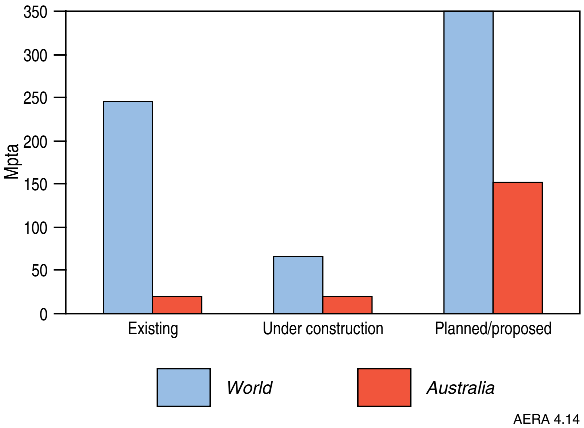


Figure 4.14 World LNG export capacity, current and proposed

Source: ABARE

4.3 Australia's gas resources and market

4.3.1 Conventional gas resources

Australia's identified conventional natural gas is a major and growing energy resource with significant potential for further discoveries.

Australia's conventional gas resources at the beginning of 2009 are presented in Table 4.6 under the McKelvey classification of economic and sub-economic demonstrated resources (Geoscience Australia 2009). Australia has around 180 400 PJ (164 tcf) of gas, most of which are considered as EDR. These resources are located across fourteen basins, but nearly all (92 per cent) lie in the offshore basins along the north-west margin of Western Australia (figure 4.15), a geological region known as the North West Shelf (Purcell and Purcell 1988) – the Bonaparte, Browse and Carnarvon basins (table 4.7). Similarly, the bulk of this amount is in ten super-giant fields, although a total of 590 fields are included in the EDR and SDR compilation.

In addition to these demonstrated Australian conventional gas resources (EDR and SDR), another 22 000 PJ (20 tcf) are estimated to be in the inferred category, arising from recent discoveries and previous finds that require further appraisal.

Geologically these world class gas resources are related to the major delta systems that were deposited along the north-west margin during the Triassic and Jurassic periods as a prelude to Australia's separation from Gondwana. The gas is contained in Mesozoic sandstone reservoirs and largely sourced from Triassic and Jurassic coaly sediments. Marine Cretaceous shales provide the regional seal for fault block and other traps.

The offshore Gippsland Basin in south-eastern Australia still has significant reserves after 40 years of production but onshore basins only account for 2 per cent of Australia's remaining resources (figure 4.15). Gas accumulations in the Gippsland, Bass and Otway basins in Bass Strait are trapped in some of Australia's youngest petroleum reservoirs (Late Cretaceous to Paleogene sandstones) while onshore are some of the oldest (Ordovician sandstones in the Amadeus Basin, Permian sandstones in the Cooper Basin). Boreham et al. (2001) provide a detailed discussion of the origin and distribution of Australia's conventional gas resources.

Table 4.6 Australian conventional gas resources represented as McKelvey classification estimates as of 1 January 2009

Conventional Gas Resources	PJ	tcf
Economic Demonstrated Resources	122 100	111
Sub-economic Demonstrated Resources	58 300	53
Inferred Resources	~22 000	~20
Total	**202 400**	**184**

Source: Geoscience Australia 2009

Table 4.7 McKelvey classification estimates by basin as at 1 January 2009

McKelvey Class.	Basin	Gas	
		PJ	tcf
EDR	Carnarvon	81 400	74
EDR	Browse	18 700	17
EDR	Bonaparte	11 000	10
EDR	Gippsland	7 700	7
EDR	Other	3 300	3
Total EDR		**122 100**	**111**
SDR	Carnarvon	22 000	20
SDR	Browse	17 600	16
SDR	Bonaparte	15 400	14
SDR	Gippsland	1 100	1
SDR	Other	2 200	2
Total SDR		**58 300**	**53**
Total (EDR + SDR)		**180 400**	**164**

Source: Geoscience Australia 2009

Development of two of the largest of the giant undeveloped fields in the basins off the northwest margin, the Io-Jansz and Gorgon fields (table 4.8), has recently been announced, with the first gas from the Gorgon project expected in 2015.

Resource growth

Australia's identified conventional gas resources have grown substantially since the discovery of the super giant and giant gas fields along the North West Shelf in the early 1970s. Gas EDR has increased more than fourfold over the past 30 years. Even so, many offshore gas discoveries have remained subeconomic until recently and are only now being considered for development. For example, the Ichthys field in the Browse Basin, which adds significantly to Australia's reserves of both gas and condensate (12.8 tcf, 527 mmbbls), was determined to be uneconomic when first drilled in 1980, not least because of its remote location. The big step in the gas EDR in 2008 (figure 4.16) reflects the promotion of large accumulations such as Ichthys and Wheatstone into this category.

Australia's conventional gas resources have mostly been discovered during the search for oil and have occurred continuously but at irregular intervals and include a number of super-giant fields (figure 4.17; Powell 2004). However, from the late 1990s there has been exploration aimed specifically at large gas fields in the deeper water areas of the Carnarvon Basin, which has met with considerable success, including the discovery of Io-Jansz in 2000, one of Australia's largest gas accumulations.

Resource life

The gas resource to production ratio (R/P ratio) is a measure of the remaining years of production from current economic demonstrated resources (EDR) at current production levels. Since production was established and stabilised in the mid-1970s the EDR to production ratio has fluctuated between 20 and 80 years, boosted by the major discoveries in the 1980s and in the past 10 years (figures 4.17 and 4.18).

In 2008 at current levels of production, Australia had 63 years of conventional gas remaining.

The plot of gas discoveries by year against cumulative volume discovered shows a strong record of discovery and addition of new resources (figure 4.17).

4.3.2 Coal seam gas (CSG) resources

Australia's identified CSG resources have grown substantially in recent years. As at December 2008, the economic demonstrated resources of CSG in Australia were 16 590 PJ (15.1 tcf; table 4.9). In 2008, CSG accounted for about 12 per cent of the total gas EDR in Australia. Reserve life is more than

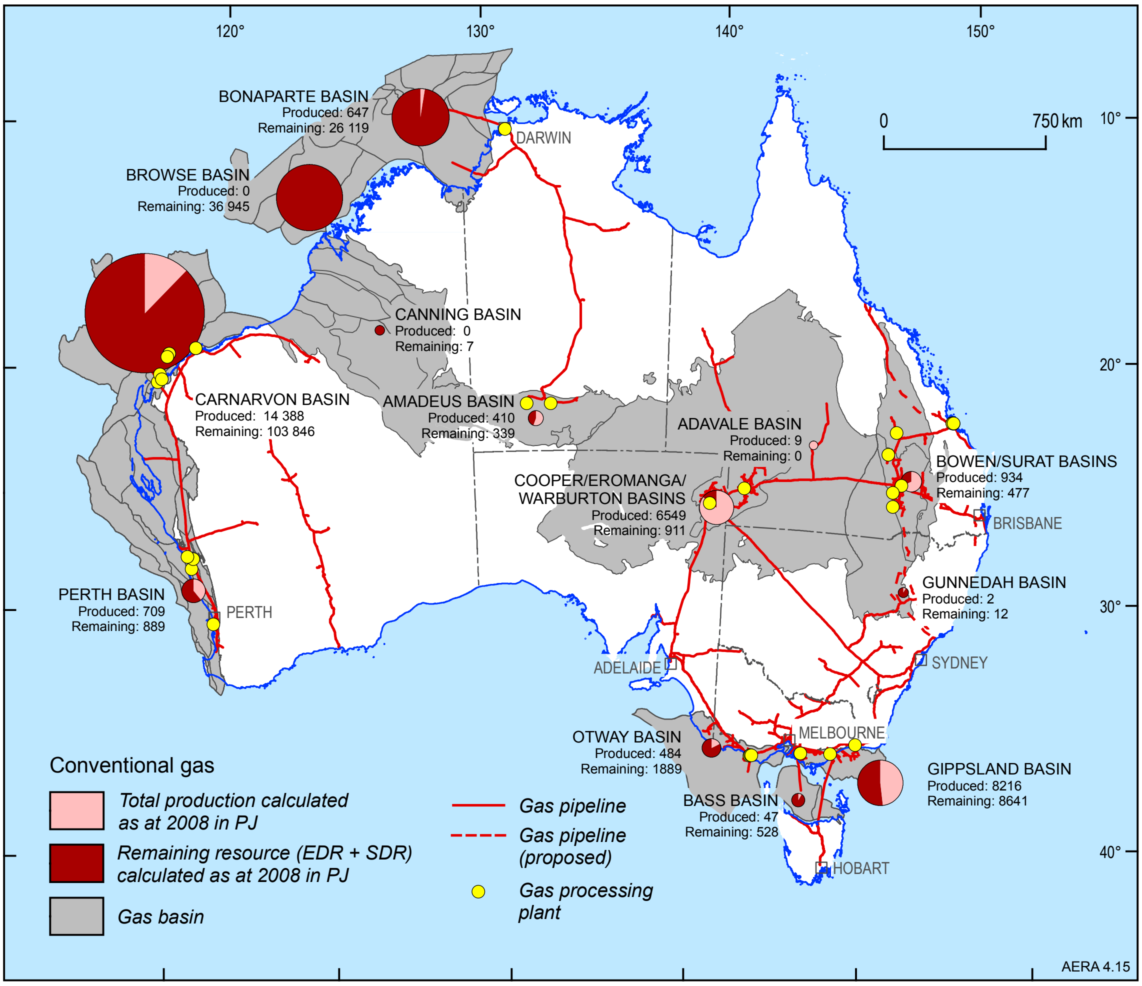


Figure 4.15 Australia's conventional gas resources, proven gas basins and gas infrastructure

Source: Geoscience Australia

100 years at current rates of production. In addition to EDR Australia has substantial subeconomic demonstrated resources (nearly double the EDR) and very large inferred CSG resources. There are even larger estimates of in-ground potential CSG resources, potentially in excess of 250 tcf (275 000 PJ) (Baker and Slater 2009; Santos 2009).

Queensland has 15 714 PJ (or 95 per cent) of the reserves with the remaining 887 PJ in New South Wales. Nearly all current reserves are contained in the Surat (61 per cent) and Bowen (34 per cent) basins with small amounts in the Clarence-Moreton (2 per cent), Gunnedah (2 per cent), Gloucester and Sydney basins (figures 4.19 and 4.20). The CSG productive coal measures are of Permian (Bowen, Gunnedah, Sydney and Gloucester basins) and Jurassic (Walloon Coal Measures of the Surat and Clarence-Moreton

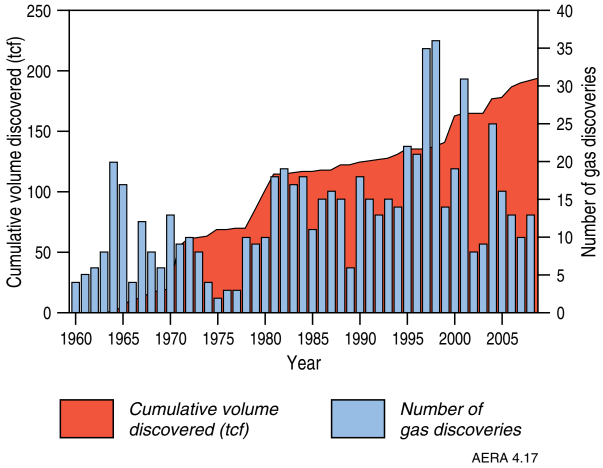


Figure 4.17 Gas volumes discovered and number of discoveries by year, 1960–2008

Source: Geoscience Australia

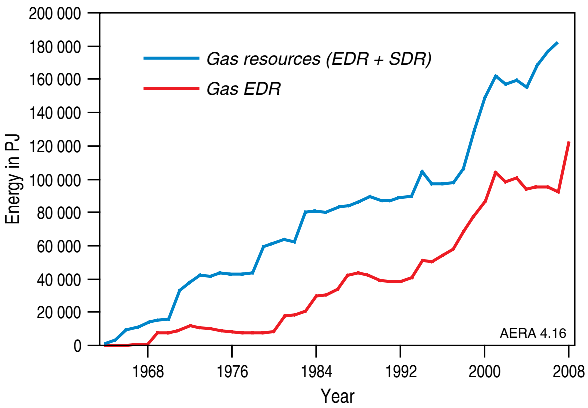


Figure 4.16 Australia's demonstrated conventional gas resources 1964–2008

Source: Geoscience Australia

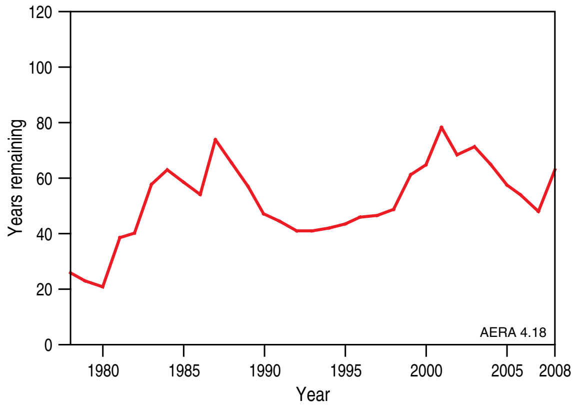


Figure 4.18 Conventional gas EDR to production in years of remaining production, 1978–2008

Source: Geoscience Australia

Table 4.8 Major gas fields: development status

Field	Basin	Gas Resources tcf	Condensate Resources mmbbl	Total Resources PJ	Status
Greater Gorgon (including Gorgon, Io/Jansz, Chrysaor, Dionysus, Tryal Rocks West, Spar, Orthrus, Maenad, Geryon and Urania)	Carnarvon	>40	-	>44 000	under construction
Ichthys	Browse	12.8	527	17 137	FEED
Woodside Browse project, including Torosa, Brecknock and Calliance	Browse	14	370	17 546	undeveloped
Greater Sunrise (including Sunrise and Troubadour)	Bonaparte	7.7	-	8470	undeveloped
Evans Shoal	Bonaparte	6.6	-	7260	undeveloped
Scarborough	Carnarvon	5.2	-	5720	undeveloped
Pluto (including Xena)	Carnarvon	4.65	55.3	5436	under construction
Wheatstone	Carnarvon	4	-	4400	FEED
Clio	Carnarvon	3.5	-	3850	undeveloped
Chandon	Carnarvon	3.5	-	3850	undeveloped
Prelude (including Concerto)	Browse	2.5	40	2982	undeveloped
Thebe	Carnarvon	2 - 3	-	2200–3300	undeveloped
Crux	Browse	1.3	48	1708	under construction

Note: Data compiled from various public sources, including company reports to the Australian Securities Exchange

Source: Geoscience Australia

basins) age, although the Permian coals are of higher rank, more laterally continuous and have greater gas contents (Draper and Boreham 2006).

Over the past five years, CSG exploration has increased substantially in Queensland and New South Wales as a result of the successful development of CSG production in Queensland. The search has expanded beyond the high rank Permian coals encouraged by the success in producing CSG from low rank coals in the United States. These successes have also stimulated exploration for CSG in South Australia, Tasmania, Victoria and Western Australia.

Table 4.9 CSG Resources at December 2008

CSG Resources	PJ	tcf
Economic Demonstrated Resources	16 590	15.1
Sub-economic Demonstrated Resources	30 000	27.2
Inferred Resources	122 020	111
Total	**168 610**	**153**

Source: Geoscience Australia 2009; Queensland Department of Mines and Energy 2009; subeconomic and inferred resources compiled by Geoscience Australia from company reports and other pubic domain information

Nonetheless, CSG exploration in Australia is still relatively immature. The current high levels of exploration are expected to add to known resources: in the five years to 2008 2P reserves increased at a rate of about 46 per cent per year, significantly increasing resource life (figures 4.21 and 4.22).

During 2007–08 CSG activity in Queensland continued at record levels with about 600 CSG production and exploration wells drilled. Exploration in Queensland continues to concentrate in the Bowen, Galilee and Surat basins while in New South Wales exploration continues in the Sydney, Gunnedah, Gloucester and Clarence-Moreton basins. All have 2P reserves. Other prospective basins include the Pedirka, Murray, Perth, Ipswich, Maryborough and Otway basins.

4.3.3 Tight gas, shale gas and gas hydrates resources

Currently Australia has no reserves of tight gas, but the in-place resources of tight gas are estimated at around 22 000 PJ (20 tcf). The largest known resources of tight gas are in low permeability sandstone reservoirs in the Perth, Cooper and Gippsland basins (figure 4.23). The Perth Basin is

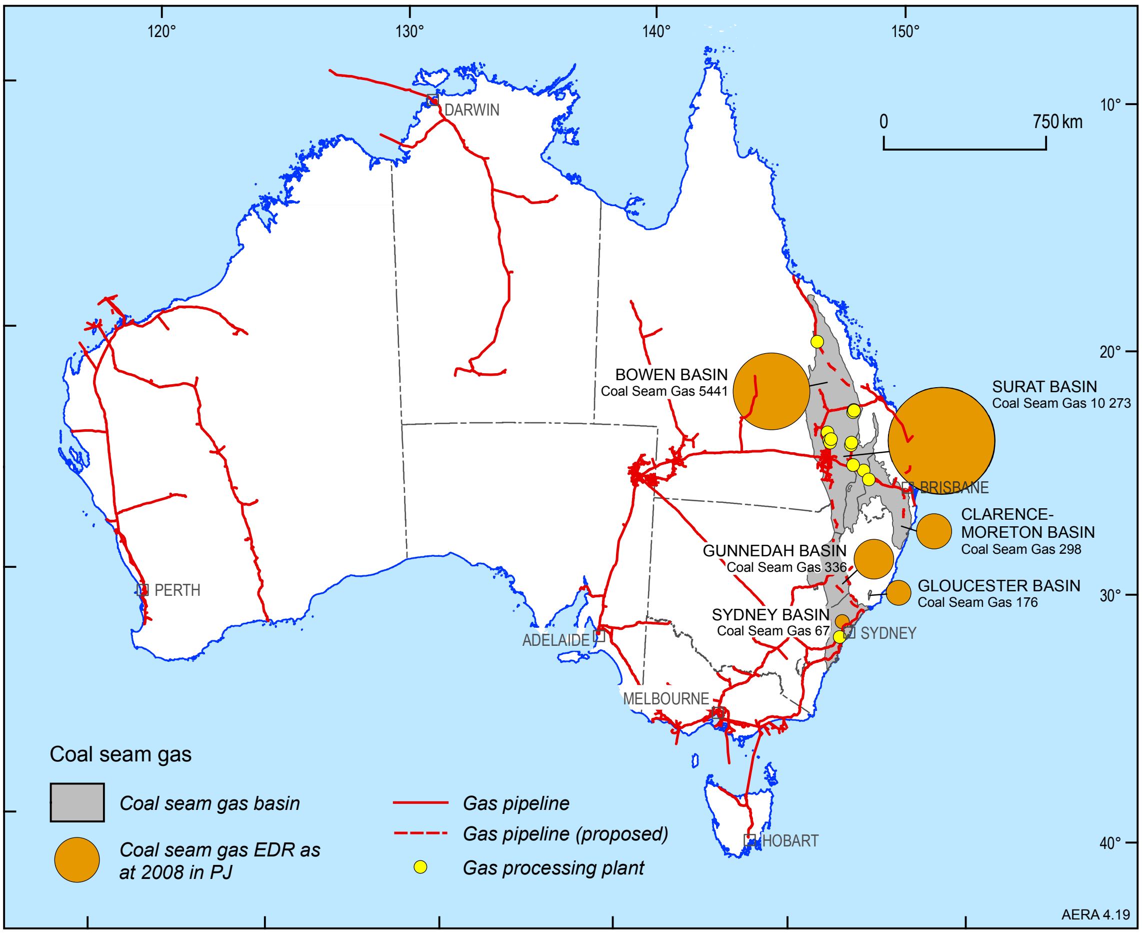


Figure 4.19 Location of Australia's coal seam gas reserves and gas infrastructure

Source: Geoscience Australia

estimated to contain about 11 000 PJ (10 tcf) of tight gas, the Cooper Basin to contain about 8800 PJ (8 tcf) (Campbell 2009) and the Gippsland Basin is considered to contain approximately 2200 PJ (2 tcf) of tight gas (Lakes Oil 2009).

Tight gas resources in these established conventional gas producing basins are located relatively close to infrastructure and are currently being considered for commercial production. Other occurrences of tight gas have been identified in more remote onshore basins and offshore. In general, Australian tight gas reservoirs are sandstones from a wide range of geological ages with low permeability due to primary lithology or later cementation.

Shale gas exploration is in its infancy in Australia, but the organic rich shales in some onshore basins have been assessed for their shale gas potential (Vu et al. 2009). Lower Paleozoic and Proterozoic shales within the Georgina and McArthur basins in the Northern Territory (figure 4.23) are likely candidates for further investigation. Cost effective horizontal drilling and hydraulic fracturing techniques are enabling unconventional gas resources to be assessed.

No definitive gas hydrates have been identified in Australian waters. The occurrence of gas hydrate was inferred from the presence of biogenic methane in sediments cored in the Timor Trough during the Deep Sea Drilling Program (DSDP 262) (McKirdy and Cook 1980) but to date none have been recovered around Australia. Bottom simulating reflectors (BSRs) that are considered as possible indicators of gas hydrates have been observed from seismic records in deep water at various locations around Australia. However, further investigations are yet to confirm the presence of gas hydrates. Anomalous pore water chemistry can also indicate gas hydrates and has been observed in several offshore Ocean Drilling Program drill cores (ODP 1127, 1129, 1131) (Swart et al. 2000) from the Eyre Terrace in the Great Australian Bight (figure 4.23).

4.3.4 Total gas resources

Australia has large and growing gas resources. CSG EDR represent only a tenth of the conventional gas EDR. However, the total identified resources for CSG are significantly larger than EDR (table 4.10). The potential in-ground CSG resource is, by some industry estimates, up to three times the undiscovered volumes in the proven gas basins (table 4.10; figure 4.24). Australia's combined identified gas resources are in the order of 393 000 PJ (357 tcf), equal to around 180 years at current production rates.

The gas resource pyramid (figure 4.24) depicts these varying types of natural gas resources. A smaller volume of conventional gas and CSG identified reserves are underpinned by larger volumes of unconventional gas inferred and potential resources.

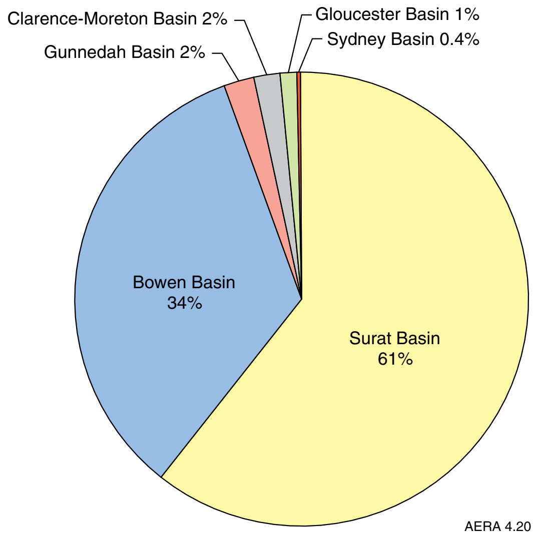


Figure 4.20 CSG EDR by basin, 2008

Source: Geoscience Australia

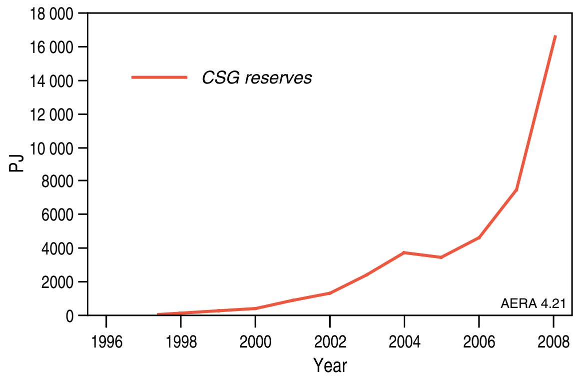


Figure 4.21 CSG 2P reserves since 1996

Source: Queensland Department of Mines and Energy 2009; Geoscience Australia

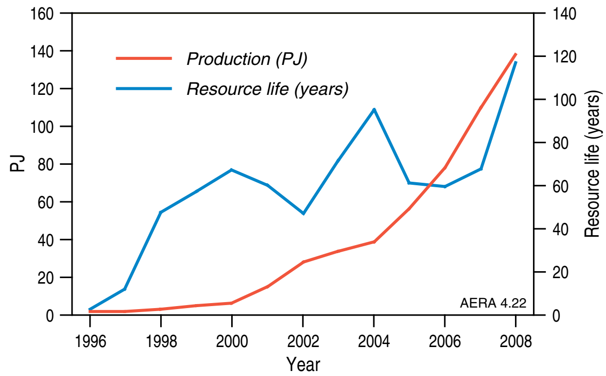


Figure 4.22 CSG resource life and production since 1996

Source: Queensland Department of Mines and Energy 2009; Geoscience Australia

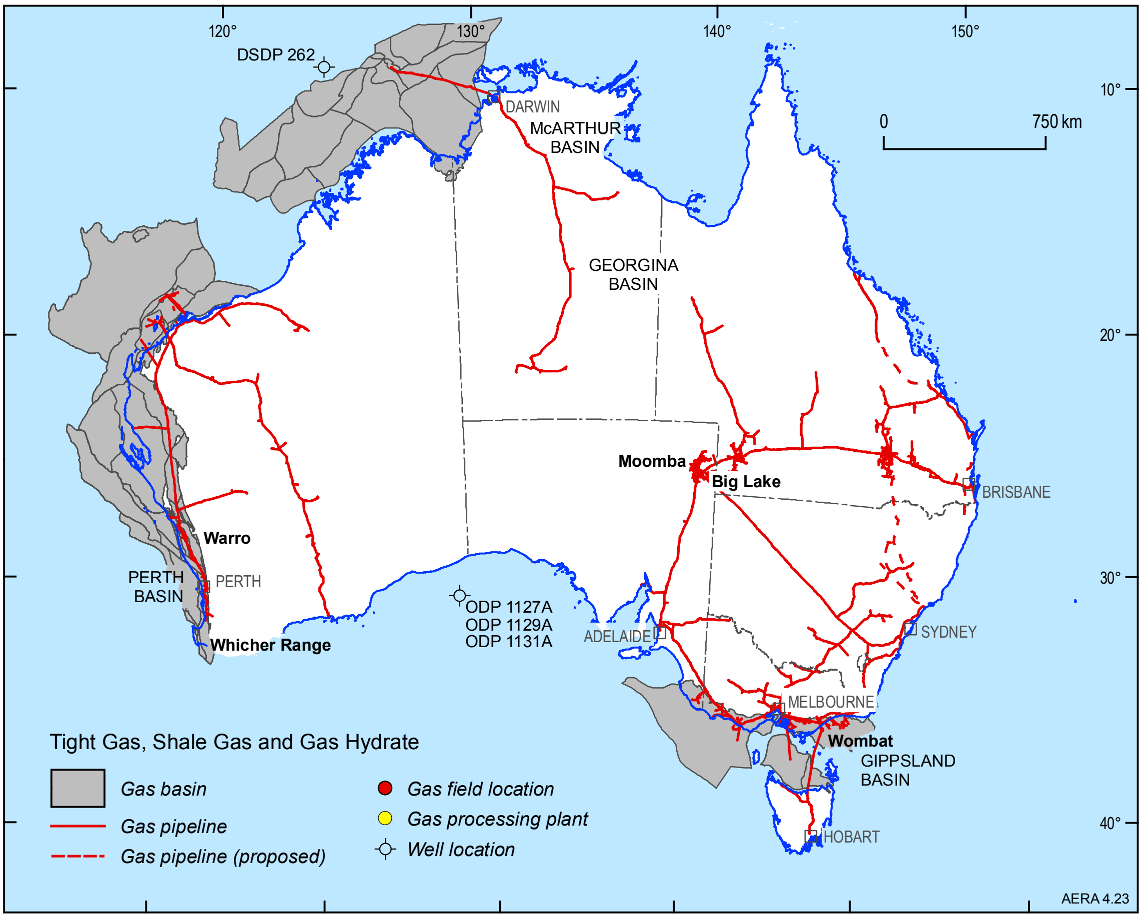


Figure 4.23 Tight gas, shale gas and gas hydrate resource locations and gas infrastructure

Source: Geoscience Australia

The estimated undiscovered conventional gas resources of varying uncertainties can also be mapped to the resource pyramid.

As the unconventional gas industry in Australia matures, it is expected that exploration will add to the inventory and that more of the CSG resources will move into the reserves category. CSG reserves are typically based on estimates of gas in place and a recovery factor once production has been established (Kimber and Moran 2004). Consequently the development of CSG will add to conventional gas resources to support domestic use, particularly in eastern Australia, and potentially for export.

4.3.5 Gas market

Conventional gas production

Conventional gas production has increased strongly over the last 20 years, with a major contributor being the North West Shelf LNG project in the Carnarvon Basin (figure 4.25). In 2008 conventional gas production was some 1930 PJ (1.75 tcf) and came from ten producing basins, with the Carnarvon Basin dominating (table 4.11). Next ranked is the Gippsland Basin, followed by the Bonaparte Basin.

Gas production as shown in Table 4.11 includes production from Bayu-Undan, a giant field located in the Bonaparte Basin, some 500 km north-west of Darwin in the Timor Sea Joint Petroleum Development Area (JPDA) shared by Australia and Timor Leste.

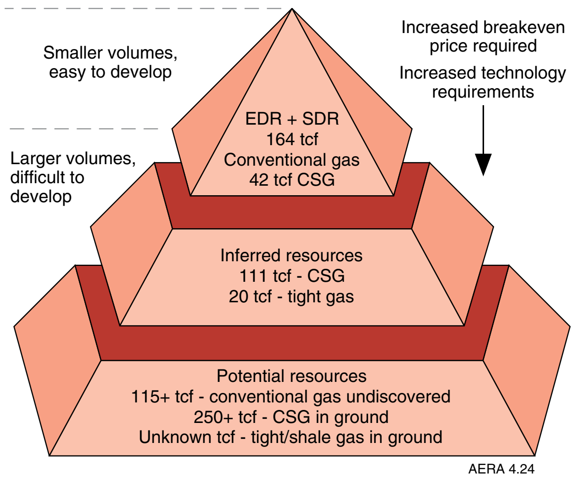


Figure 4.24 Australian Gas Resource Pyramid (adapted from McCabe 1998 and Branan 2008)

Source: Geoscience Australia

Table 4.10 Total Australian gas resources

Resource Category	Conventional Gas		Coal Seam Gas		Tight Gas		Total Gas	
	PJ	tcf	PJ	tcf	PJ	tcf	PJ	tcf
EDR	122 100	111	16 590	15.1	-	-	138 690	126
SDR	58 300	53	30 000	27.2	-	-	88 300	80
Inferred	22 000	20	122 020	111.0	22 000	20	166 020	151
All identified resources	202 400	184	168 600	153	22 000	20	393 000	357
Potential in ground resource	unknown	unknown	275 000	250	unknown	unknown	unknown	unknown
Undiscovered in four proven basins	125 400	114	unknown	unknown	unknown	unknown	unknown	unknown
Undiscovered frontier basins	unknown	unknown	unknown	unknown	unknown	unknown	unknown	unknown
Resources – identified, potential and undiscovered	327 800	298	443 600	403	22 000	20	793 400	721

Source: Geoscience Australia

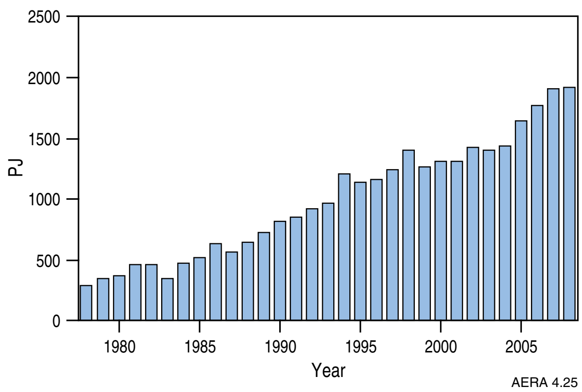


Figure 4.25 Australian conventional gas production 1978–2008

Source: Geoscience Australia

Table 4.11 Australian conventional gas production by basin for 2008, and cumulative production

Basin	2008 PJ	Total PJ
Carnarvon	1048	14 388
Gippsland	324	8216
Bonaparte	175	647
Otway	147	484
Cooper/ Eromanga	140	6542
Bowen/Surat	41	934
Amadeus	22	410
Bass	17	47
Perth	10	709
Warburton	6	7
Gunnedah	0	2
Adavale	0	9
Total	**1930**	**32 394**

Note: Includes imports from JPDA
Source: Geoscience Australia

Geoscience Australia production and reserve data for Bayu-Undan includes all production and reserves, rather than only Australia's 10 per cent share of royalties from the JPDA (chapter 2; box 2.2).

Australia's past conventional gas production has been overwhelmingly from the Carnarvon, Cooper and Gippsland basins with smaller contributions from the Perth, Bonaparte, Bowen, Amadeus, Otway and Surat basins (table 4.11). Now that conventional gas production from the Cooper Basin is in decline, more than 80 per cent of production is from the three main offshore basins (Carnarvon, Gippsland and Bonaparte basins). Most (54 per cent) is from the Carnarvon Basin which contains the giant Goodwyn, North Rankin and Perseus accumulations that form part of the North West Shelf Venture Project. There is also production from the Perth, Bowen/Surat and Otway Basins, as well as the Amadeus Basin which supplies Darwin with gas. Gas production from a single field in the Adavale Basin, Gilmore, ceased after 2002. Conventional gas production in all basins, other than the Carnarvon and Bonaparte basins, is directed solely to domestic consumption.

Over the past four years, new fields have been developed in the Carnarvon, Otway, Bass and Gippsland basins. In 2008, these fields produced in excess of 188 PJ accounting for 10 per cent of Australia's conventional natural gas production (table 4.12).

Unconventional gas production

Separate commercial production of CSG is relatively new, beginning in the United States in the 1970s. Exploration for CSG in Australia began in 1976. In February 1996 the first commercial coal mine methane (CMM) operation commenced at the Moura mine in Queensland methane drainage project (then owned by BHP Mitsui Coal Pty Ltd). In the same year, at the Appin and Tower underground mines (then owned by BHP Ltd), a CMM operation was used to fuel on-site generator sets (gas-fired power stations). The first stand-alone commercial production of CSG in Australia commenced in December 1996 at the Dawson Valley project (then owned by Conoco), adjoining the Moura coal mine.

Australia's annual CSG production has increased from 1 PJ in 1996 to 139 PJ in 2008, around 7 per cent of Australia's total gas production. In the five years to 2008 production increased by 32 per cent per year. Of the 2008 production of CSG, Queensland produced 133.2 PJ (or 96 per cent) from the Bowen (93 PJ) and Surat (40 PJ) basins. In New South Wales 5.3 PJ was produced from the Sydney Basin.

In 2007–08, CSG accounted for around 10 per cent of total gas consumption in Australia (figure 4.26) and 80 per cent in Queensland. The rapid growth of the CSG industry has been underpinned by the strong demand growth in the Eastern gas market and the recent recognition of the large size of the coal seam gas resource (table 4.13). The strong growth in CSG production reflects the Queensland Government's energy and greenhouse gas reduction policies, in particular the requirement that 13 per cent of grid connected power generation in the State be gas fired by 2005 (Baker and Slater 2009). Recent improvements in extraction technology have also supported the growth in CSG production.

Tight gas is not currently produced in Australia. However, there are several planned projects for commercial production of tight gas, notably in the Perth Basin in Western Australia. There is also no production of shale gas or from gas hydrates.

Total gas consumption

Gas is the third largest contributor to Australia's primary energy consumption after coal and oil. In 2007–08, gas accounted for 22 per cent of Australia's total energy consumption. Australia's primary gas consumption increased from 74 PJ in 1970–71 to 1249 PJ in 2007–08 – an average rate of growth of 7.9 per cent per year (figure 4.27). The robust growth in gas consumption over this period mainly reflects sustained population growth and strong economic growth, as well as its competitiveness and government policies to support its uptake.

The manufacturing, electricity generation, mining and residential sectors are the major consumers of gas. The manufacturing sector is the largest consumer of gas and is comprised of a few large consumers, including metal product industries (mainly smelting and refining activities), the chemical industry (fertilisers and plastics), and the cement industry.

The share of gas-fired electricity has increased in recent years, reflecting market reforms and an increase in gas availability. Gas accounted for an estimated 16 per cent of electricity generation in 2007–08. The strong share of the mining sector is attributable to the use of natural gas in the production of LNG. The residential sector is characterised by a large number of small scale consumers. The major residential uses of gas include water heating, space heating and cooking.

Gas trade

Until 1989–90, Australia consumed all of the natural gas that was produced domestically. Following the development of the North West Shelf Venture, gas, in the form of LNG, was exported to overseas markets. Nearly half of Australia's gas production (currently sourced from offshore basins in Western

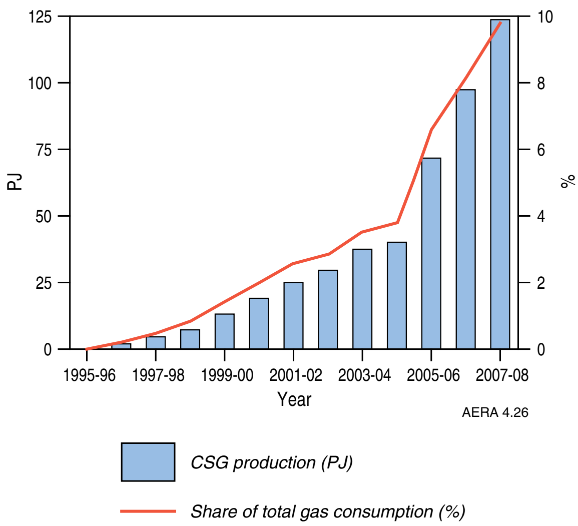


Figure 4.26 Australian CSG production and share of total gas consumption

Source: Geoscience Australia, ABARE 2009a

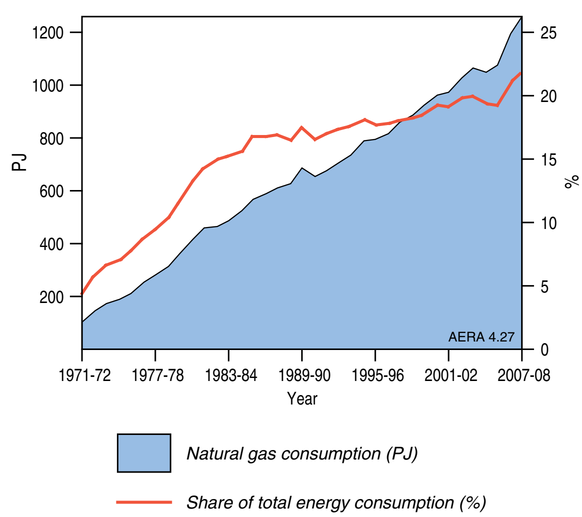


Figure 4.27 Australian gas consumption and share of total primary energy consumption

Source: ABARE 2009a

Australia and the Northern Territory) is now exported. In 2007–08, the volume of LNG exports was 14.3 Mt (787 PJ), valued at $5.9 billion. In 2008–09 higher export volumes and international oil prices led to an increase in exports to $10.1 billion (ABARE 2009b).

Japan is Australia's major export market for LNG, followed by China, the Republic of Korea and India (figure 4.28). In 2008, Japan accounted for more than three-quarters of Australia's LNG exports. In contrast, Australia accounts for 17 per cent of Japan's LNG total imports and 81 per cent of China's LNG imports.

There are also plans to export CSG in the form of LNG from Queensland. Increased international LNG prices together with rapidly expanding CSG reserves in Queensland have recently improved the economics of developing LNG export facilities in eastern Australia. There are at least five planned LNG projects in Queensland with a combined capacity of

Table 4.12 Conventional gas projects recently completed, as at October 2009

Project	Company	Basin	Start up	Capacity (PJ pa)	2008 production
John Brookes	Santos	Carnarvon	2005	58	61
Minerva	BHP Billiton	Otway	2005	55	32
Bassgas	Origin	Bass	2006	20	17
Casino	Santos	Otway	2006	33	34
Otway	Woodside	Otway	2007	60	44
Angel	Woodside	Carnarvon	2008	310	na
Blacktip	ENI Australia	Bonaparte	2009	44	na

Source: ABARE

Table 4.13 CSG projects recently completed, as at October 2009

Project	Company	Location	Start up	Capacity (PJ pa)	Capital Expenditure
Berwyndale South CSM	Queensland Gas Company	Roma, Qld	2006	na	$52 m
Argyle	Queensland Gas Company	Roma, Qld	2007	7.4	$100 m
Spring Gully CSM project (phase 4)	Origin Energy	Roma, Qld	2007	15	$114 m
Tipton West CSM project	Arrow Energy/Beach Petroleum/Australian Pipeline Trust	Dalby, Qld	2007	10	$119 m
Darling Downs development	APLNG (Origin/ ConocoPhillips)	North of Roma, Qld	2009	44 (includes wells from Tallinga)	$500 m

Source: ABARE 2009c

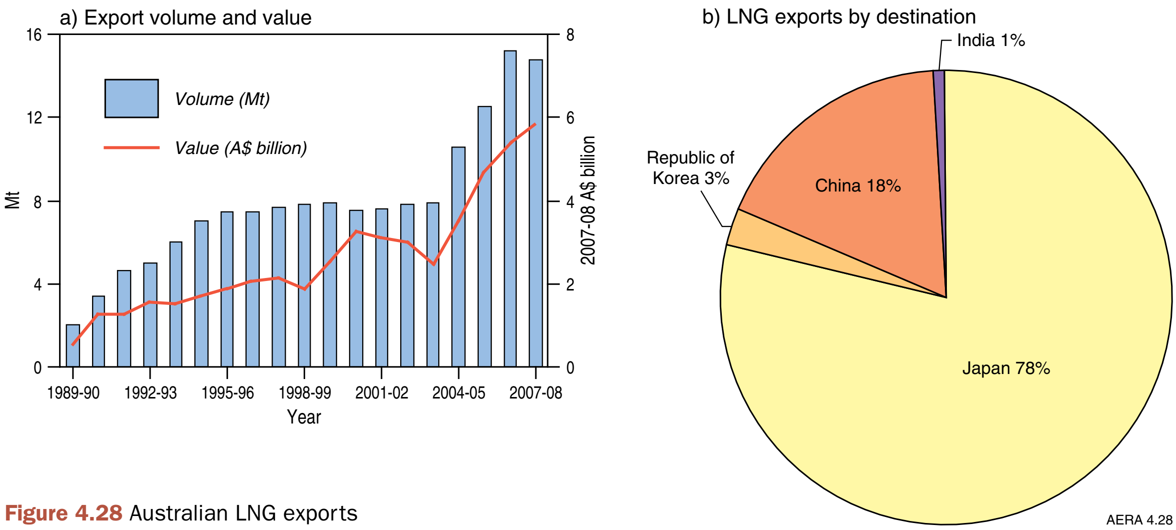


Figure 4.28 Australian LNG exports

Source: ABARE 2009b, d

around 35 Mt, and potentially up to 57 Mt (ABARE 2009c). This is equivalent to the existing LNG production capacity and that under construction from conventional gas located off the north-west coast of Australia.

Gas supply-demand balance

The supply-demand balance presented in figure 4.29 and table 4.14 incorporates production, domestic consumption and trade (exports). It highlights steady growth in domestic consumption, the boost in production with LNG exports and the emerging impact of CSG.

Regional gas markets

The Australian domestic gas market consists of three distinct regional markets: the Eastern market (Queensland, New South Wales, Australian Capital Territory, Victoria, South Australia and Tasmania); the Western market (Western Australia) and the Northern market (Northern Territory) (figure 4.30). These markets are geographically isolated from one another, making transmission and distribution of gas between markets uneconomic at present. As a result, all gas production is either consumed within each market or exported as LNG.

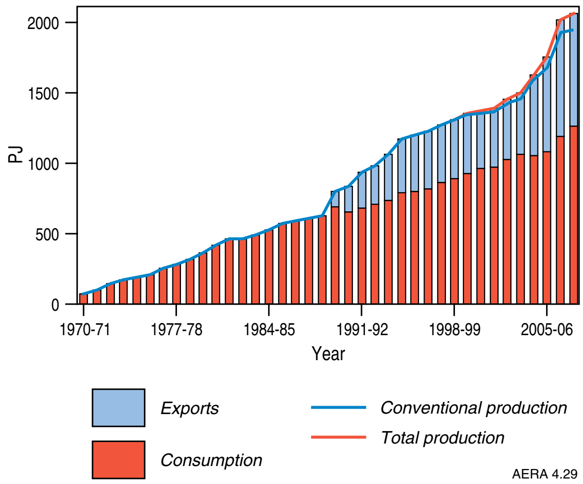


Figure 4.29 Australia's gas supply-demand balance

Note: Conventional production includes imports from JPDA. Adjusted for stock changes and statistical discrepancy

Source: ABARE 2009a

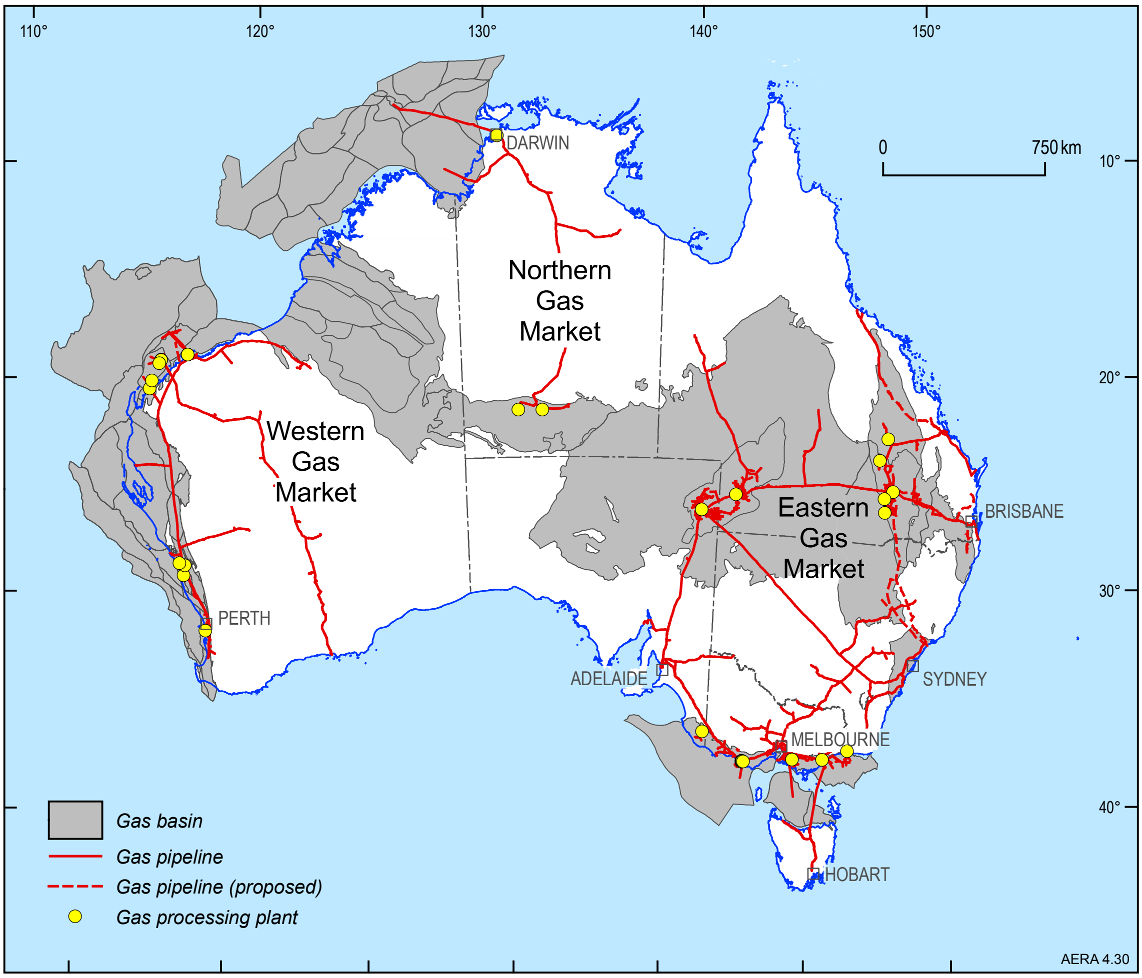


Figure 4.30 Australia's gas facilities

Source: Geoscience Australia

The Eastern gas market accounts for around 35 per cent of Australia's gas production. It is the only region where coal seam gas supplements conventional gas supplies (mainly in Queensland), accounting for nearly one fifth of total gas production in the region.

This market has traditionally been the largest consumer of natural gas in Australia, accounting for around 57 per cent of Australian gas consumption in 2007–08. Over the period 1970–71 to 2007–08, consumption in the region increased at an annual average rate of 6.3 per cent. Since 1970–71, the Eastern gas market has consumed all of the gas produced in the region (figure 4.31, panel a). The electricity generation and residential sectors are the largest consumers of gas in the Eastern market.

The Western gas market accounts for around 57 per cent of Australia's gas production. The region is also a large consumer of gas, accounting for around 41 per cent of Australia's gas consumption. The electricity generation and manufacturing sectors account for the majority of gas consumption in the Western gas market. From 1989–90, the Western gas market produced significantly more gas than it consumed (figure 4.31, panel b), following the development of the North West Shelf Venture and the establishment of long term export LNG contracts.

The Northern gas market is the smallest producer and consumer of gas in Australia, accounting for 8 per cent and 3 per cent of Australia's gas production and consumption in 2007–08, respectively. Production began in the Northern gas market in the early 1980s through the development of the onshore Amadeus Basin. In 2005–06, production in the region increased significantly with the development of the Bayu–Undan field in the offshore Bonaparte Basin. Electricity generation and mining account for the majority of gas use in the Northern gas market. Until 2005–06, all of the gas produced in the region was consumed locally.

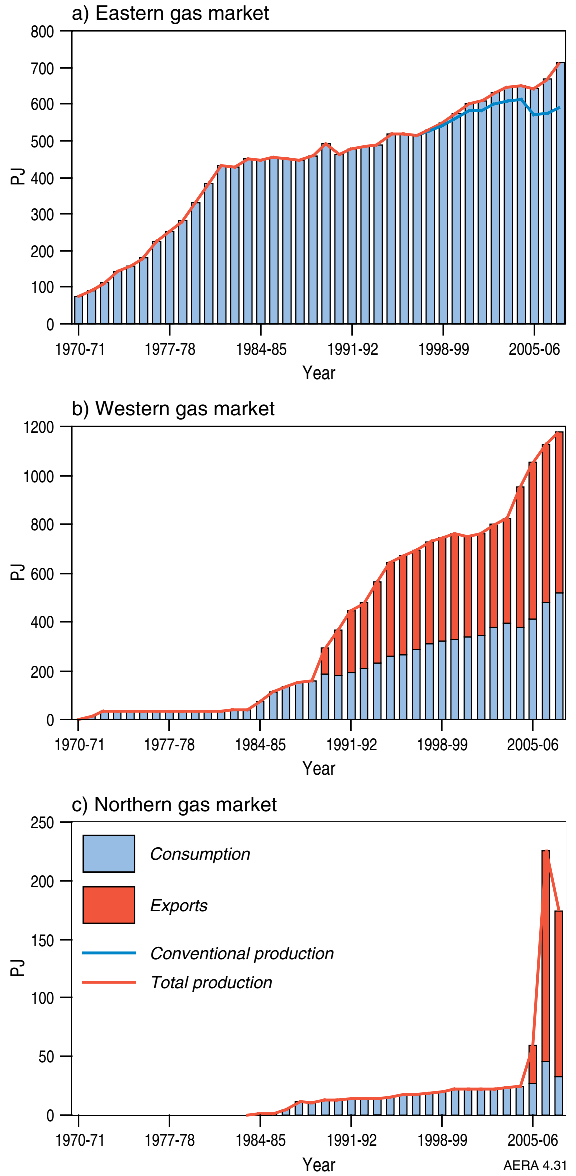


Figure 4.31 Regional gas market supply-demand balances

Note: conventional production includes imports from JPDA, stock changes and statistical discrepancy

Source: ABARE 2009a

Table 4.14 Australian gas supply-demand balance, 2007–08

	Unit	Eastern gas market	Western gas market	Northern gas market[a]	Australia
Production					
Conventional gas[b]	PJ	589	1179	175	1942
Coal seam gas	PJ	124	0	0	124
Total	PJ	713	1179	175	2066
Share of total	%	35	57	8	100
Primary gas consumption					
Total	PJ	713	516	33	1262
Share of total	%	57	41	3	100
LNG Exports[c]					
Total	PJ	0	663	141	804
Share of total	%	0	82	18	100

a Production includes imports from the JPDA in the Timor Sea. **b** Conventional production includes stock changes and statistical discrepancies. **c** ABARE estimate

Note: Australian totals may not match those in Table 4.1 due to statistical discrepancies between state and national data

Source: ABARE 2009a

Following the development of the Darwin LNG plant, gas has also been exported as LNG (figure 4.31, panel c). In September 2009, the offshore Blacktip gas field in the Petrel Sub-basin of the Bonaparte Basin, came on stream with gas being piped onshore to a processing plant at Wadeye and then to the Amadeus Basin-Darwin pipeline.

4.4 Outlook to 2030 for Australia's resources and market

The outlook to 2030 is expected to see the continued growth in the use of gas in the Australian energy mix and increasing LNG exports to meet growing global demand. In the latest ABARE long-term energy projections which incorporate the Renewable Energy Target, a 5 per cent emissions reduction target and other existing policies, gas is expected to increase its share of primary energy consumption to around 33 per cent (2575 PJ) in 2029–30, and account for 37 per cent of Australia's electricity generation (ABARE 2010). LNG exports are also projected to rise strongly to 5930 PJ (5 tcf) in 2029–30. Australia's existing resources are sufficient to meet these projected increases in domestic and export demand over the period to 2030. There is also scope for Australia's resources to expand further, with major new discoveries of conventional gas in offshore basins and the re-evaluation of the large CSG potential resources leading to their reclassification into the EDR category.

4.4.1 Key factors influencing the outlook

Broader economic, social and environmental considerations aside, the main factors impacting on the outlook for gas are prices, the geological characteristics of the resource (such as location, depth, quality), developments in technology, infrastructure issues, and local environmental considerations.

Gas prices

The future price of gas is one of the main factors affecting both exploration and development of the resource. Australian gas producers have typically faced different prices for domestic and export gas. Domestic prices have historically been much lower than international prices, although domestic gas prices have been rising in recent years.

For the domestic market, Australia provides some of the lowest cost gas in the world. These low gas prices are generally the result of mature long term contracts out of the Cooper and Gippsland basins and the North West Shelf fields (table 4.15).

Australian gas prices have historically been relatively stable because of provisions in long term contracts that include a defined base price that is periodically adjusted to reflect changes in an index such as the CPI. In addition, prices have been capped by the price of coal (a major competitor for use in electricity generation).

Domestic gas prices have increased over the past few years in response to a number of factors including:

- sustained pressure on exploration and development costs, that have increased the cost of development;
- the development of higher cost sources of gas (for example coal seam gas);
- the anticipated implementation of an emissions reduction target that will make gas a more valuable commodity (there is some evidence that this is being factored into contracts);
- strong coal prices that have been increasing rapidly (and remain high historically despite the drop in late 2008 and early 2009) and raising the cap on gas prices; and
- high oil prices that have flowed through to Australian LNG contracts and accentuated the gap between domestic and international (netback) prices. This has encouraged companies to put their efforts into developing projects destined for export rather than domestic demand.

Except for Victoria, there is currently no formal exchange for trading natural gas in Australia. In all jurisdictions except Victoria, wholesale gas trading occurs through private negotiations between buyers and sellers. The terms, quantities and prices are confidential and can vary significantly across contracts. Typically these contracts contain take-or-pay components where shippers agree to pay for a specified quantity of gas, regardless of whether they are able to on-sell it.

LNG contracts generally have a price component linked to world energy prices (typically crude oil) and also include the cost of processing and transport. Typically, LNG must travel large distances to markets. LNG transport costs are distance and time sensitive and, as such, can account for a significant proportion of overall LNG costs.

There have been three reasonably distinct markets for LNG, each with its own pricing structure. In the United States, pipeline natural gas prices have been used as the basis for setting the price of LNG. The benchmark price is either a specified market in long-term contracts or the Henry Hub price for short-term sales. In Europe, LNG prices are related to competing fuel prices, such as low-sulphur residual fuel oil, although LNG is now starting to be linked to natural gas spot and futures market prices. In the Asia Pacific region, Japanese crude oil prices have historically been used as the basis for setting the price of LNG under long term contracts. Asian prices are generally higher than prices elsewhere in the world. While still distinct, the markets are becoming more interconnected, not least because of the rapid growth in Middle East LNG supply to both regions (IEA 2008).

Over the long term, LNG prices are assumed to follow a similar trajectory to oil prices, reflecting an assumed continuation of the established relationship between oil prices and long-term LNG supply contracts through indexation, and substitution possibilities in electricity generation and end use sectors (ABARE 2010). In its 2009 World Energy Outlook, the IEA flags a potential relaxation of this relationship as significant new gas supplies come on line, thus placing some downward pressure on prices. However, indexation will still remain dominant in the Asia Pacific region, where most of Australia's gas trade will continue to occur (IEA 2009c).

At the domestic level, the Australian Energy Regulator also points to a number of factors in the east coast market that may reduce upward pressure on gas prices (AER 2009). These include the substantial volumes of 'ramp up' gas that are likely to be produced in the lead-up to the commissioning of CSG-LNG projects, the large number of gas basins ensuring diversity of supply, relatively low barriers to entry, and an extensive gas transmission network linking producing basins (ABARE 2010).

Resource characteristics

The decision to develop a gas field also depends on its characteristics. They include its size, location and distance from markets and infrastructure; its depth (in the case of offshore fields); and the quality of the gas, such as CO_2 content and presence of natural gas liquids. Table 4.16 lists these characteristics for a number of Australian conventional gas fields.

Resource characteristics influencing the development of unconventional gas resources partly diverge from those relevant to conventional gas fields. Location and size of accumulation remain important but there are no associated hydrocarbon liquids with CSG. As all current identified unconventional resources in Australia are onshore, distance to market and infrastructure are key location factors.

The geological factors which influence CSG resource quality include tectonic and structural setting, depositional environment, coal rank and gas generation, gas content, permeability and hydrogeology. Draper and Boreham (2006) concluded that, for Queensland GSG, neither rank nor gas content was critical, but rather permeability and hence deliverability, with structural setting being a strong determinant of permeability. For shale gas, resource quality is dependent on gas yield which is controlled by organic matter content, maturity and permeability, particularly that provided by natural fracture networks. Reservoir performance (porosity and permeability) is the primary determinant of the quality of all gas resources and the point of difference between conventional gas and tight gas.

Box 4.3 GEOLOGY OF AUSTRALIA'S MAJOR CONVENTIONAL GAS FIELDS

Australia's identified and potential gas resources occur within a large number of sedimentary basins (Boreham et al. 2001) that stretch across the continent and its vast marine jurisdiction. Identified conventional gas resources are predominantly located in offshore basins along the north-west margin. Much of the undeveloped resource and the undiscovered potential is in deep water (figures 4.32 and 4.33; see discussion below). The gas habitat includes:

- large fault block traps, Triassic to Jurassic sandstone reservoirs sealed by Cretaceous shales and sourced from Triassic coaly sediments (e.g. North Rankin, Gorgon);
- drape anticlines and structural/stratigraphic traps related to Late Jurassic and Early Cretaceous sand bodies (e.g. Io-Jansz, Scarborough; figure 4.32); and
- low relief anticlines with Permian sandstone reservoirs (e.g. Petrel; figure 4.33).

In the Bass Strait basins (Otway, Bass and Gippsland) along the south-east margin, conventional gas accumulations are contained in Late Cretaceous to Paleogene sandstone reservoirs in anticlinal, fault block and structural/stratigraphic traps. In addition there are known gas resources in a number of onshore basins usually in Paleozoic sandstone reservoirs in structural traps.

Table 4.15 Australian gas prices (2008–09 dollars)

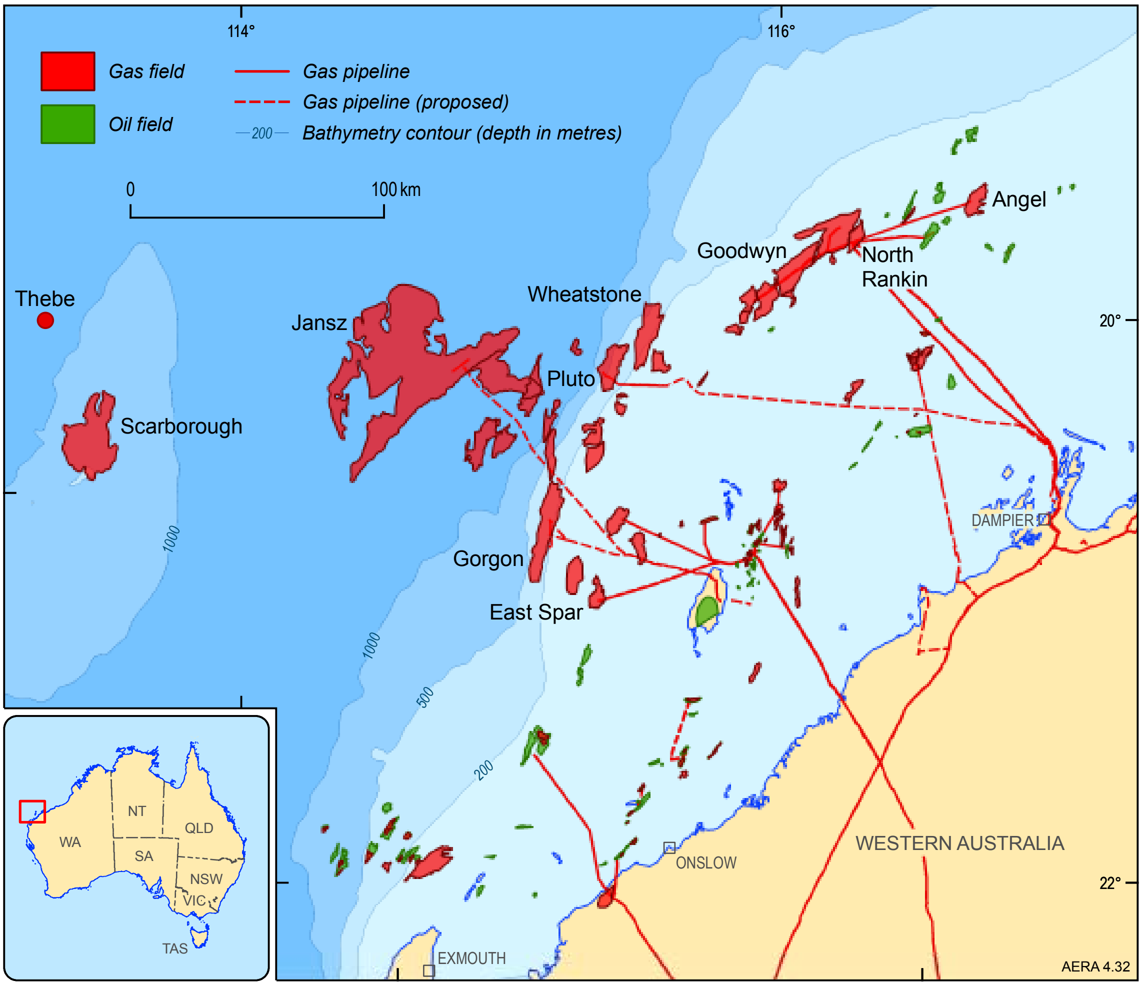
	2001–02	2002–03	2003–04	2004–05	2005–06	2006–07	2007–08	2008–09
Natural Gas[a] $A/GJ	$2.16	$2.34	$2.50	$2.59	$2.71	$3.34	$3.72	$3.32
LNG[b] $A/t	$428.17	$402.49	$324.32	$348.10	$401.94	$376.29	$428.63	$620.71
LNG[b] $A/GJ	$7.87	$7.40	$5.96	$6.40	$7.39	$6.92	$7.88	$11.41

a Financial year average of daily spot prices in the Victorian gas market. **b** Export unit value
Sources: ABARE 2009d; AEMO 2009a

Table 4.16 Resource characteristics of selected Australian conventional gas fields

Basin/ discovery date	Field	initial recoverable volumes			CO_2%	water depth m	km to landfall	status
		gas tcf	liquids mmbbl	Total PJ				
Carnarvon								
1971	North Rankin	12.28	203	~ 14 700	< 5%	122	130	export LNG 1989
1980	Gorgon	17.2	121	~ 19 630	> 10%	259	120	construction, LNG 2015
1980	Scarborough	5.2	0	~ 5 720	< 5%	923	310	undeveloped
2006	Pluto	4.6	0	~ 5 060	< 5%	900	190	construction, LNG 2011
1993	East Spar	0.25	14	~ 360	< 5%	98	100	domestic production 1996
Browse								
1980	Ichthys	12.8	527	~ 17 180	> 5%	256	220	FEED, LNG 2015
1971	Torosa	11.4	121	~ 13 250	> 5%	50	280	undeveloped

Note: Data compiled from various public sources, including companies' reports to the Australian Securities Exchange
Source: Geoscience Australia



Field outlines are provided by GPinfo, an Encom Petroleum Information Pty Ltd product. Field outlines in GPinfo are sourced, where possible, from the operators of the fields only.

Figure 4.32 Gas fields in the Carnarvon Basin

Source: Field outlines are provided by GPinfo, an Encom Petroleum Information Pty Ltd product. Field outlines in GPinfo are sourced, where possible, from the operators of the fields only. Outlines are updated at irregular intervals but with at least one major update per year

Location and depth

The location of the gas, onshore or offshore, in shallow or deep water, also affects development costs. Offshore development generally has higher cost and risk than conventional onshore development because of the specialised equipment required for exploration, development and production.

The Australian gas industry has moved from the development of fields in shallow water (Gippsland Basin) and near shore (Carnarvon Basin) that have a low marginal cost to fields in deeper water that have higher marginal costs.

In the Carnarvon Basin, the Goodwyn gas field in 125 m of water is currently Australia's deepest producing gas field, although Ichthys, Pluto and some fields linked into the Greater Gorgon Project will be in water depths of several hundred metres or more (figure 4.32; table 4.16) and gas exploration on the Exmouth Plateau now routinely targets prospects in water depths beyond 1000 m (Walker 2007). These projects have higher technological and economic risks and costs compared with onshore developments (Hogan et al. 1996). A number of large gas accumulations in deep water remain to be developed (for example Scarborough) whereas smaller accumulations in shallower water have been developed (figure 4.32).

Although the new CSG and the embryonic tight gas industries in Australia are onshore activities, they carry technological risks comparable to deepwater conventional gas developments. The Whicher Range tight gas field discovered in 1969 in the onshore southern Perth Basin, for example, has a history of unsuccessful attempts using the then latest drilling technology to commercially produce a multi-tcf in-ground resource (Frith 2004).

Co-location with other resources

A resource that contains only gas can be left undeveloped until market conditions warrant its development. However, gas rich in condensate or

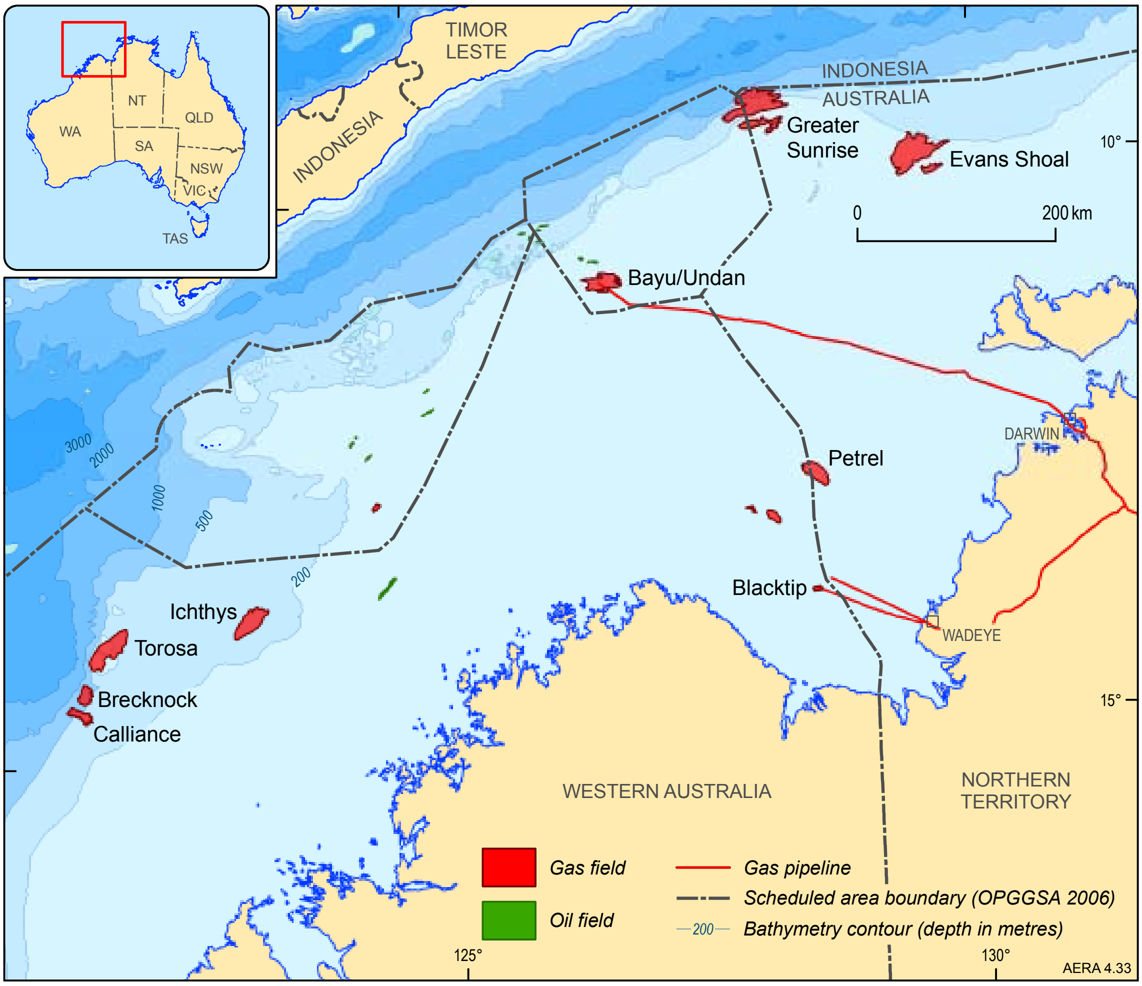


Figure 4.33 Gas fields in Browse and Bonaparte Basins

Source: Field outlines are provided by GPinfo, an Encom Petroleum Information Pty Ltd product. Field outlines in GPinfo are sourced, where possible, from the operators of the fields only. Outlines are updated at irregular intervals but with at least one major update per year. Field outline for Ichthys is sourced from IHS Energy, 2006 associated with oil, will become available when the liquid resource is produced, and must be sold (piped), flared or reinjected to maintain reservoir pressure. Depending on the nature of the reservoir, up to 80 per cent of reinjected gas can be recovered once oil production or condensate stripping has ceased (Banks 2000). Around 94 per cent of operating fields producing gas in Australia also produce oil or condensate or both. When oil, gas, LPG and condensate are produced jointly, the cost of production is shared and the cost of each product is not distinguishable. This can result in greater returns on the sale of valuable by-products and can speed development of the gas accumulation, as for example at the East Spar and Bayu-Undan projects (table 4.16).

CSG is almost entirely methane and unlike many conventional gas fields has no associated petroleum liquids. However, CSG is associated with groundwater, and coal formations have to be de-watered to lower the pressure before the coal seam gas can be produced. This can involve the production of large volumes of saline water to be disposed of (for example by deep re-injection in the sub-surface) or treated (for example by de-salination). In 2006–07 Queensland CSG fields produced 85 PJ of gas but also 9491 million litres (ML) of water, roughly 110 ML for each petajoule of gas (Green and Randall 2008). Scaling up for LNG production may produce up to 40 ML a day from a LNG project. In some cases water resources for industrial and agriculture uses or environmental flows are produced, for example, the Spring Gully Reverse Osmosis Water Treatment Plant which has a capacity of 9 ML a day (Origin Energy 2009).

Gas, both conventional and unconventional, can partner with intermittent renewable energy sources to maintain a sustained power output. Analysis of solar, wind and wave energy potential around Australia suggest the North Perth and Otway basins as areas where identified gas resources and high wind and wave potential energy occur relatively close to existing pipeline and electricity grid infrastructure and to domestic markets. This linkage between gas-fired electricity and wind generation via the transmission network has been identified in various projections such as the Vision 2030 by Vencorp in 2005 and the recent AEMO update (AEMO 2009b).

Technology developments

Advances in technology can increase access to reservoirs, increase recovery rates, reduce exploration, development and production costs, and reduce technological and economic risks.

Technological improvement has had a significant influence on exploration activity by increasing the accessibility of resources. In the period 1989–1998, for example, technological advances (mainly 3D seismic) were the principal driver of new discoveries and rising success rates in offshore Australian exploration (Bradshaw et al. 1999) and continue to yield gains especially in the basins along the north-west margin (Longley et al. 2002; Williamson and Kroh 2007).

Offshore gas production is more challenging than onshore production. The majority of Australia's conventional gas resources are located offshore and consequently the majority of research and development has been directed toward improving offshore technologies. New drilling technologies used in the production phase allow better penetration rates even in very deep water (beyond 3000 m), with lower costs and higher efficiency. Such technologies include multi-lateral drilling (multiple well bores from a single master well), extended reach drilling (up to 11 000 m) and horizontal drilling with paths through the reservoir of up to 2 km.

Sub-sea production facilities instead of above-water platforms are lower cost developments which also reduce weather and environmental risk. Significant development of sub-sea technologies for the transport of natural gas include deepwater pipeline installation through the J-lay method (as distinct from the S-lay method traditionally used for up to 2500 m depth). This allows pipelines to be laid up to several kilometres in depth (IEA 2008).

There have also been improvements to LNG technologies over time to improve efficiency and reduce costs, including increasing LNG train size and developing more suitable liquefaction methods to suit gas specifications. Innovations such as floating LNG facilities are also being explored. They would have a fundamental impact on the industry by commercialising relatively small and previously stranded gas resources (Costain 2009; see box 4.4 for more details).

Gas-to-liquids (GTL) provides another option for bringing gas to markets. It allows for the production of a liquid fuel (petrol or diesel products) from natural gas which can be transported in normal tankers like oil products. GTL is a potential solution to stranded gas reserves too remote or small to justify the construction of an LNG plant or pipeline. However, the commercial viability of GTL projects has not yet been widely established. There are currently only three commercial-scale plants in operation, in South Africa, Malaysia and Qatar. Two more plants are under construction in Qatar and in the Niger Delta, scheduled to commence operations in 2010 and 2012 respectively (IEA 2009c). A GTL demonstration plant that directly uses natural gas containing CO_2 as a feedstock was recently opened in Japan (Nippon GTL 2009). This technology may be applicable to some of Australia's gas fields.

Recent advances in gas-fired electricity generation technology have improved the competitiveness of gas compared with coal. Open cycle (or simple cycle) gas combustion turbine is the most widely used, as it is ideal for peaking generation. Significant efficiency gains have been recognised with the natural gas combined-cycle (NGCC) electricity generation plant, which currently has world's best practice thermal efficiencies (box 4.5).

Cost competitiveness

Brownfields projects, which are an expansion of an existing project, tend to be more attractive on both capital and operating cost grounds than new projects (often referred to as greenfield projects). This is because existing infrastructure and project designs can be used, among other reasons. For example, the fourth and fifth trains in the North West Shelf Venture have significantly lower unit costs than the greenfield Pluto and Gorgon developments currently under construction (table 4.17).

The cost of new developments has increased rapidly, with the average cost worldwide more than doubling between 2004 to 2008. Over the same period, development costs in Australia have also increased (APPEA 2009b) and are likely to increase further as a result of development of projects in deeper water that are typically more expensive than onshore and shallow water projects.

The capital costs of LNG liquefaction plants fell from approximately US$600 per tonne per year of installed capacity in the 1980s to US$200 in the 1990s, but in 2008 rose to around US$1000 or more for some new plants. It must be borne in mind, however, that unit costs are highly dependent on site-specific factors. A tight engineering and construction market has contributed to recent delays in LNG projects as well as cost increases. Material costs have increased sharply, particularly for steel, cement and other raw materials. Limited human resources – in terms both of the number of capable engineering companies and of engineers, as well as skilled labour for construction – have also been a factor (IEA 2008).

Generally, CSG can be produced using similar technologies to those used for the development of conventional gas. Compared with the conventional gas, CSG projects can generally be developed at a lower capital cost because the reserves are typically located at a shallow depth and hence require smaller drilling rigs. The production of CSG can also be increased incrementally given the shallow production wells. Although hundreds of wells are needed to produce a field as opposed to a few dozen at most in a giant conventional gas field, they are hundreds of metres rather than kilometres deep, and take a few days as opposed to weeks to drill (box 4.6). Nonetheless, they have their own particular engineering requirements.

BOX 4.4 DEVELOPMENTS IN LNG TECHNOLOGIES

Technological developments have focussed on optimising train size, choice of compressor drivers, and the suitability of different liquefaction technologies to certain gas qualities.

LNG trains have been increasing in size (figure 4.34), leading to economies of scale which, until relatively recently, contributed to a decline in unit costs for LNG projects. Trains of up to 8 Mt per year, often referred to as mega-trains, are being constructed in Qatar.

Smaller scale trains are now also being explored. Smaller scale export plants of 1–2 Mt per year, which were common in the early days of LNG in the 1960s and 1970s, were not constructed in the 1980s and 1990s, as liquefaction technology advanced and train size grew to reduce unit investment costs. Potential advantages of smaller trains include smaller feedgas and market requirements, smaller capital expenditure and potentially quicker decision-making and implementation. While smaller projects would not benefit from scale economies, which may result in a higher unit cost of gas, they may allow other companies to enter the LNG market (IEA 2008). Smaller LNG export projects that have emerged in Australia include some of the coal seam gas based proposed projects in Queensland.

Some offshore LNG liquefaction projects are also being planned for developing relatively small and stranded gas resources. These include the concept of liquefaction plants onboard LNG tankers, and floating production and storage operations. This could be particularly advantageous for developing offshore stranded gas deposits where the size of the reserve and the distance to shore does not justify a pipeline connection to an onshore liquefaction plant (IEA 2008). This prospect is currently being considered by several project proponents in Australia, including the proposed Prelude, Bonaparte and Sunrise projects (ABARE 2009c).

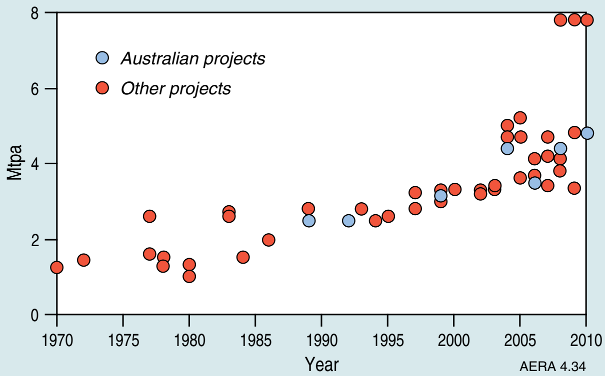


Figure 4.34 Annual liquefaction capacity of LNG trains
Source: ABARE

In some cases coal seam geology makes it difficult to extract gas, and advanced techniques are required to enhance well productivity. Moreover, the water contained in the coal seam needs to be removed before gas can be extracted. These difficulties associated with the development of CSG need to be carefully managed to avoid increased costs. In the Australian context, wide diameter holes with pre-slotted casing and under-reamed coal intervals have been found to improve CSG well performance.

Development timeframe

The time taken to bring a resource to market affects the economics of a project. Typically, developing gas fields for the domestic market takes less time than LNG export projects. The size of a project is also likely to affect the time that it takes to come online. Almost 70 per cent of all projects currently producing gas in Australia were completed within ten years of initial discovery (figure 4.36). On average, gas projects took around eight and a half years to bring into production.

On the other hand, LNG projects in Australia and worldwide often have a significant lag between first announcement, final investment decision, and development, as proponents undertake various studies to determine project feasibility, its design and its market prospects (seeking to secure long term markets) before construction commences.

Table 4.17 Australian LNG projects, capital costs and unit costs

Project	State	Year completed	Capital cost A$b	Capacity Mt	Unit cost $/t
North West Shelf 4th train	WA	2004	2.5	4.4	57
Darwin LNG	NT	2006	3.3	3.2	103
North West Shelf 5th train	WA	2008	2.6	4.4	59
Pluto LNG	WA	late 2010	12.0	4.3	279
Gorgon LNG	WA	2015	43.0	15.0	287

Source: ABARE

BOX 4.5 NATURAL GAS COMBINED CYCLE POWER PLANTS

This technology is based on generating electricity by combining natural gas fired turbines and steam turbine technologies. It uses two thermodynamic cycles — the Brayton and Rankine cycles. Electricity is first generated in open cycle gas turbines (Brayton Cycle) by burning the gas and the exhaust heat is then used to make steam to generate additional electricity using a steam turbine (Rankine Cycle). This is shown schematically in figure 4.35.

NGCC technology provides plant efficiencies of up to 50 per cent. Other advantages of NGCC plants are reduced emissions, high operating availability factors, relatively short installation times, lower water consumption, and flexibility in despatch. The size of combined cycle turbines has increased as the technology has matured; units up to 1000 MW capacity are now available.

As of 2009 there were 12 gas-fired combined cycle power plants operating in Australia with a combined capacity around 3 GW and a further four under construction with a combined capacity of around 2 GW. Three of the largest of the gas-fired combined cycle power plants are the 435 MW NGCC plant at Tallawarra near Wollongong, commissioned in March 2009, the 1000 MW Mortlake gas-fired power station in Victoria due for commissioning in 2010 and the 630 MW Darling Downs gas-fired power station at Braemar near Dalby due to be commissioned in early 2010. The Darling Downs plant will be fuelled by coal seam gas from reserves near Roma and Chinchilla. A proposed 550 MW combined cycle gas-fired power station at Morwell in Victoria will use a combination of natural gas and syngas produced from drying and gasification of brown coal from the Latrobe Valley.

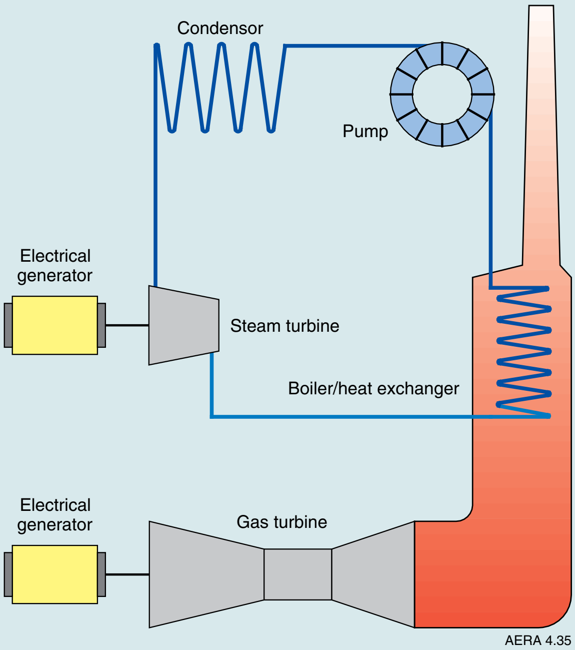


Figure 4.35 Schematic picture of combined cycle gas turbine

Source: Wikimedia ((http://en.wikipedia.org/wiki/Combined_cycle_gas_turbine)

Construction alone can take at least three years, and often longer. The Darwin LNG project, for example, took 32 months from notice of construction in June 2003 to the first delivery of LNG in February 2006. The larger Pluto project is anticipated to take five years (table 4.18) and will be the fastest LNG project (from discovery to production) to be developed in Australia and one of the fastest by world standards.

Transmission and distribution infrastructure

The last two decades have seen large investments in transmission pipelines and distribution networks to meet the steady growth in domestic gas demand. Before the 1990s Australia's transmission pipelines were a series of individual pipelines, each supplying a demand centre from a specific gas field. The majority were government owned and there was little interconnection. Since the early 1990s Australia's transmission pipeline network has almost trebled in length (AER 2008); and the eastern states have become interconnected, with Adelaide, Canberra, Melbourne and Sydney each now being supplied by two separate pipelines. Since 2000 more than $4 billion has been invested in new pipelines and the expansion of pipeline capacity with major investments including the Eastern Gas Pipeline, the SEA Gas Pipeline and expansion of the Dampier to Bunbury Pipeline (AER 2009).

This level of investment looks set to continue in the short term with a further $1.8 billion of investment, in various stages of commitment, announced for the next 4 years with major projects including the Queensland to Hunter Gas Pipeline and expansion of the Southwest Queensland Pipeline (AER 2008). All of this investment has been by the private sector, with the last government owned pipeline being sold in 2000.

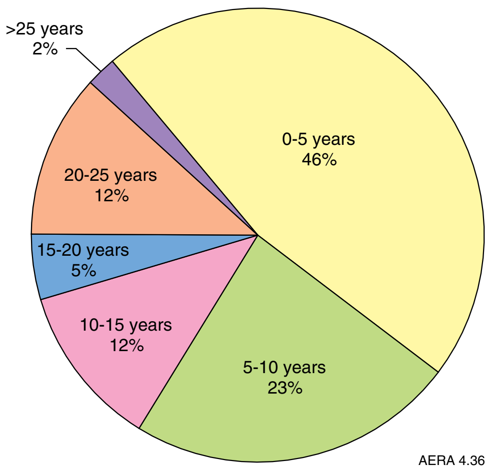


Figure 4.36 Development time for gas producing projects in Australia

Source: Geoscience Australia

There has also been significant investment in Australia's distribution networks, which have increased in length by around 20 per cent since 1997. Investment to expand and augment networks is forecast to grow by around $2 billion for the next Australian Energy Regulator regulatory five year cycle (AER 2009).

The National Gas Law (NGL) and National Gas Rules (NGR) provide a regime to give third parties access to transmission pipelines and distribution networks. Pipelines and networks that have undue market power are regulated under the NGL & NGR, which requires them to publish tariffs that must be approved by the AER and which can be enforced by the AER in the event of a dispute. Eleven of Australia's 28 major transmission pipelines are regulated and, with a few exceptions, all distribution networks are regulated.

Most domestic gas is traded through bilateral contracts between producers and users (retailers and large customers) and, with the exception of the Victorian Gas Market, there is little price transparency. Also, the capacity on some transmission pipelines is fully contracted, making it difficult for new players to enter some gas markets. The Council of Australian Governments, through the Ministerial Council on Energy, is introducing reforms to Australia's gas markets to promote their ongoing development and address some of these issues. These reforms include:

- the National Gas Market Bulletin Board (Gas BB): The Gas BB website publishes daily supply and demand data for transmission pipelines in the eastern states with the aim of facilitating trade in gas and pipeline capacity.
- the Gas Statement of Opportunities (GSOO): An annual publication that provides 20 year forecasts of gas reserves, demand, production and transmission capacity for Australia's eastern and south eastern gas markets. The GSOO aims to assist existing industry participants and potential new investors in making commercial decisions about entering into contracts and investing in infrastructure.
- the Short Term Trading Market (STTM): Commences initially in Adelaide and Sydney in June 2010 with the intention it will be expanded to other jurisdictions in the future. The STTM will bring price transparency to these markets by setting a daily price for gas.

Environmental and other considerations

The Australian state/territory governments require petroleum companies to conduct their activities in a manner that meets a high standard of environmental protection. This applies to the exploration, development, production, transport and use of Australia's gas and other hydrocarbon resources. Onshore and within three nautical miles of the coastline the relevant state/territory government has the main environmental management authority although the Australian Government has some responsibilities regarding environmental protection, especially under the *Environmental Protection and Biodiversity Conservation (EPBC) Act 1999.*

An issue of increasing significance in gas exploration and development onshore, particularly for CSG, is gas water management which includes not only the handling of the co-produced water but also the hydrogeological impacts on subsurface aquifers. The potential impacts on groundwater resource(s) in the Surat Basin as a result of CSG developments were considered in detail in a water management study (DNRME 2004). Under the Queensland Coal Seam Gas Water Management Policy use of evaporation ponds as a primary means of disposal of coal seam gas water is to be discontinued and CSG producers will be responsible for treating and disposing of coal seam gas water. Coal seam gas water will be required to be treated to a standard defined by the Environmental Protection Agency (EPA) before disposal or supply to other water users. There are a number of options for the disposal and treatment of the large volumes of water produced from CSG wells, such as deep injection into the subsurface, local use in coal washing and some rural purposes, and treatment to produce fresh water.

In the offshore areas beyond coastal waters the Australian Government has jurisdiction for the regulation of petroleum activities. The objective-based Petroleum (Submerged Lands) (Management

BOX 4.6 COMPARISON OF CONVENTIONAL AND UNCONVENTIONAL GAS DEVELOPMENTS

The properties of conventional gas and CSG accumulations have important implications for their development costs.

Conventional gas wells are generally drilled deep into highly pressured formations (2–4 km or more), and hence are relatively expensive. However, production wells can remain viable for 5 to 20 years and the often large, high pressure reservoirs can deliver gas at a faster rate than CSG.

CSG wells are shallow by comparison (less than 1 km), drilled into lower pressured formations and usually have a much shorter life (PricewaterhouseCoopers 2007). CSG typically emerges at a pressure of about one twentieth that of conventional gas and each well also normally produces a daily volume of only 5 per cent of a conventional gas well (Kimber and Moran 2004).

Conventional field developments tend to have high capital costs relative to operating costs, and long construction periods (up to five years for LNG projects).

CSG developments have lower capital costs, shorter construction times and minimal infrastructure per well, but higher operating costs. As CSG wells have significantly lower production rates, a larger number of wells are required to provide a level of production comparable to conventional offshore gas wells. The shorter well life for CSG wells also contributes to relatively higher operating costs. Further details on costs are in section 4.2.2

The IEA has produced a long term gas supply cost curve, which highlights the overall production costs of competing sources of gas, and the relative cost advantage of a conventional supply source. Other things being equal, conventional gas is likely to be developed first (figure 4.37).

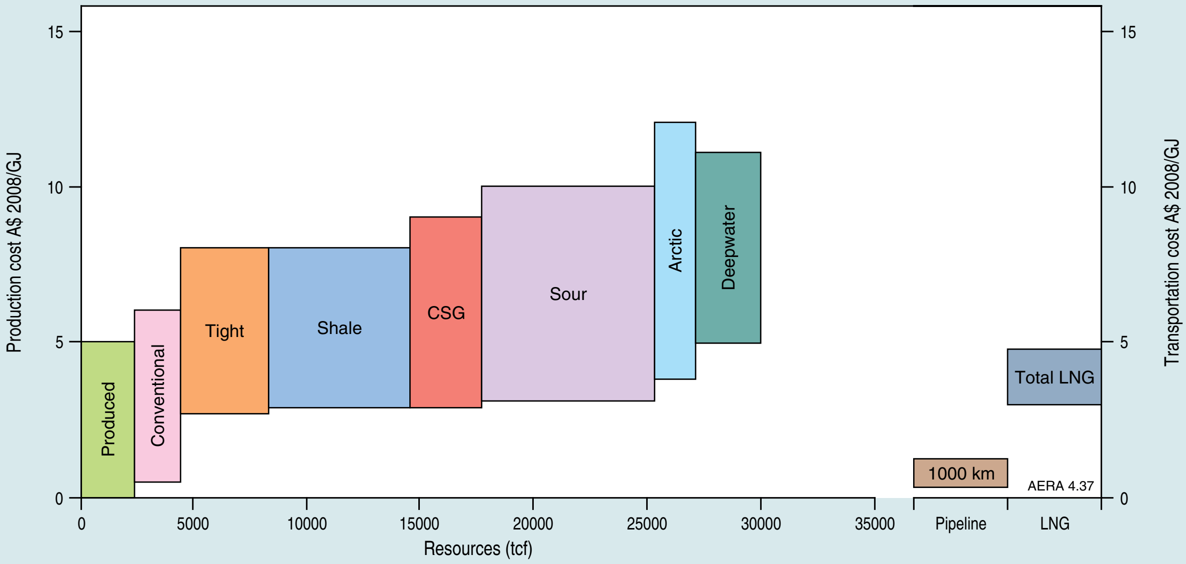


Figure 4.37 Long term gas supply cost curve showing relative production costs of different gas sources

Source: IEA 2009c

Environment) Regulations 1999 provide companies with the flexibility to meet environmental protection requirements. Petroleum exploration and development is prohibited in some marine protected areas offshore (such as the Great Barrier Reef Marine Park) and tightly controlled in others where multiple marine uses have been sanctioned (figure 4.38).

Environmental Impact Assessments (EIA) required as pre-conditions to infrastructure development applications – especially of larger projects – may require environmental monitoring over a period of time as a condition to the approval before the development can commence. In some cases regional-scale pre-competitive base line environmental information is available from government in the form of regional syntheses containing contextual information that already characterises the environmental conditions for the proposed development. In the offshore area typical data sets that are required for marine EIA in EPBC Act referrals and can be synthesised and made available by the Australian Government include: bathymetry, substrate type, seabed stability, ocean currents and processes, benthic habitats and biodiversity patterns.

The content of CO_2 in natural gas is an environmental consideration in some fields. The CO_2 content in gas fields varies widely and the liquids-rich gas accumulations of the Browse and Bonaparte basins tend to have relatively high CO_2 contents. Accessing this gas may require disposal of significant volumes (several tcf) of CO_2. Geological storage is a possible option (box 5.4 in Chapter 5 Coal) and is being facilitated by the current carbon capture and storage (CCS) acreage release (Department of Resources, Energy and Tourism 2009). The Gorgon Project includes a major CO_2 injection component (Chevron Australia 2009).

There are also jurisdictional considerations. An offshore gas field which supplies an onshore gas plant requires federal, state or territory and local government co-ordination in resource management and development approvals processes (Productivity Commission 2009). Geological provinces containing gas resources that are contiguous across international boundaries, such as the JPDA in the Timor Sea, require international coordination.

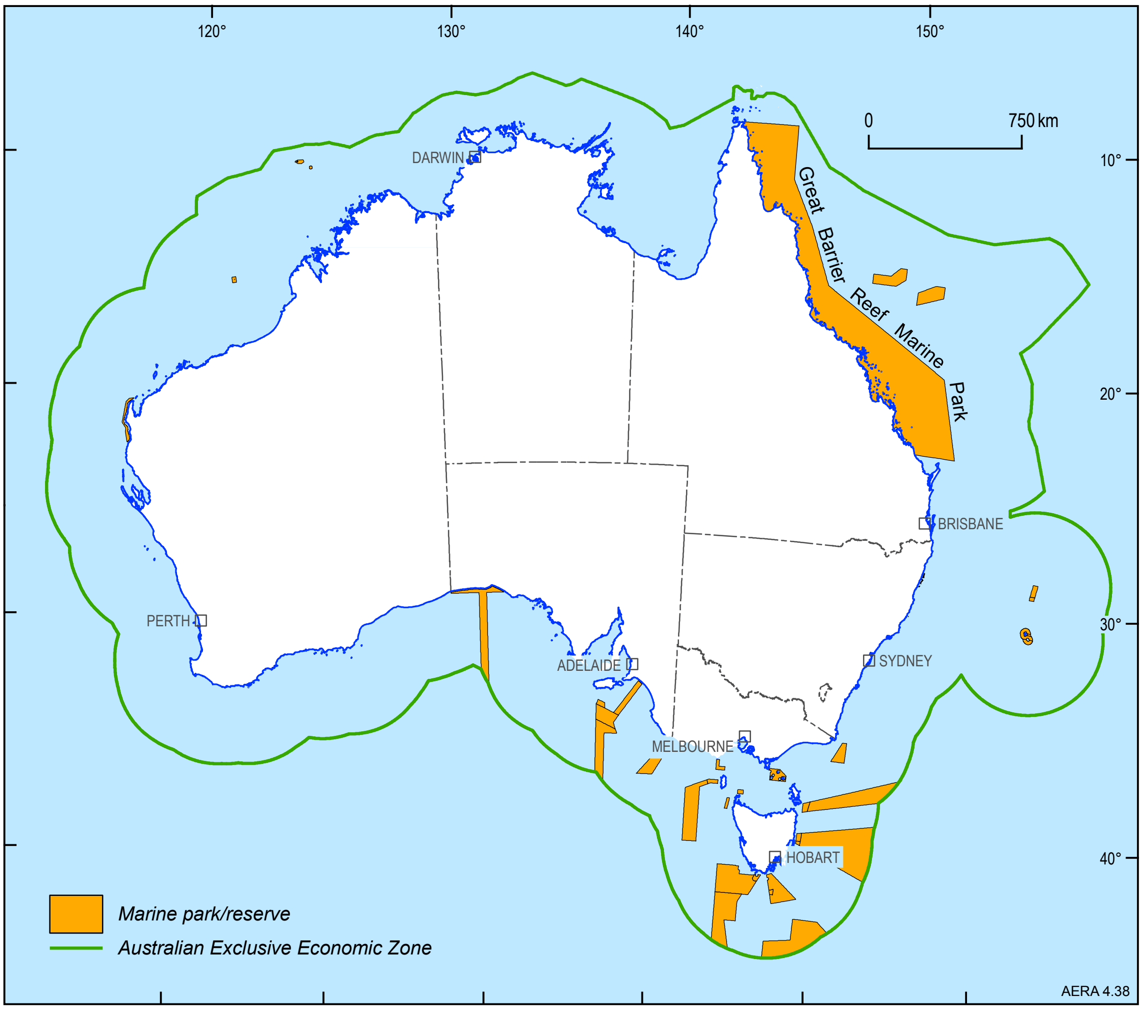


Figure 4.38 Current marine protected areas of Australia

Source: DEWHA 2009

4.4.2 Conventional gas resource outlook

Proven world natural gas reserves have grown at an annual rate of 3.4 per cent since 1980 – outstripping oil reserve growth – as a result of significant discoveries and better assessments of existing fields (World Energy Council 2007). In Australia, future growth in conventional gas, CSG and other unconventional gas resources will all add to an expanded total gas inventory by 2030, even with an increase in gas production.

For **conventional gas** resources, additions will come from several potential sources:

- field growth – extensions to identified commercial fields (growth in reserves) and to currently sub-economic fields;
- identified resources not yet booked – very recent discoveries, accumulations in non producing basins not in current EDR or SDR categories (inferred resources);
- discovery of new commercial fields in established hydrocarbon basins; and
- discovery of new fields in frontier basins that become commercial by 2030.

Field reserves growth

Growth in reserves in existing fields can add significantly to total reserves. The additional conventional gas resource contributed by field growth by 2030 is estimated at between 35 200 and 46 200 PJ (32 and 42 tcf). This projection is consistent with actual historical data where reserves in fields discovered before 2002 have increased by 5.6 per cent in the period 2002 to 2007 giving an annual increase at the lower end of the projected range.

Powell (2004) provided qualitative assessments of the potential for future growth of gas reserves and noted that, as a large proportion of Australia's gas fields are undeveloped, there should be considerable potential for reserve growth. However, the advent of 3D and 4D seismic imaging should provide greater geological certainty and reduce the extent to which initial estimates of reserves are understated in the future.

Identified resources not yet included in EDR or SDR

In addition to the 590 conventional gas fields in 14 basins aggregated in the EDR and SDR categories (Geoscience Australia 2009), there are a number of other known gas accumulations. They include recent discoveries not yet appraised (for example Martell, Glencoe, and Yellowglen in the Carnarvon Basin and Burnside and Poseidon in the Browse Basin). Although located in deep water these accumulations could add significantly to gas resources when they are appraised. The potential and timing of development of these discoveries will vary depending on location, resource size, quality (CO_2 and liquids content) and commercial factors (table 4.16).

In addition to very recent discoveries in established gas producing basins, there are a number of conventional gas accumulations in undeveloped basins both onshore and offshore (table 4.18) that are not aggregated in EDR or SDR. Examples include the Phoenix gas accumulation in the Bedout Sub-basin, the Hogarth accumulation in the Clarence Moreton Basin and gas flows from wells in the onshore Canning, Georgina and Ngalia basins. Remote location, size of the resource and resource quality (for example poor reservoir) are factors limiting their development but some of these accumulations may move into EDR and SDR in the years to 2030. For example, there may be local niche markets for conventional gas in power generation related to mineral processing or co-location with renewable but intermittent energy sources. Technological advances in producing gas from poor reservoirs may also lead to additional resources and some of these accumulations may eventually be produced as tight gas fields.

Discovery of new fields in established hydrocarbon basins

A major potential contributor to Australia's conventional gas resources to 2030 is the discovery of new fields in the established hydrocarbon producing basins. Unlike the identified resources discussed above, discovery risk applies, so that the resource found by 2030 is dependent on the number of exploration wells drilled, the size of the prospects tested and the success rate. Active exploration programs are underway in the Carnarvon, Browse and Bonaparte basins, and recent success rates for targeted gas exploration in deep water are greater

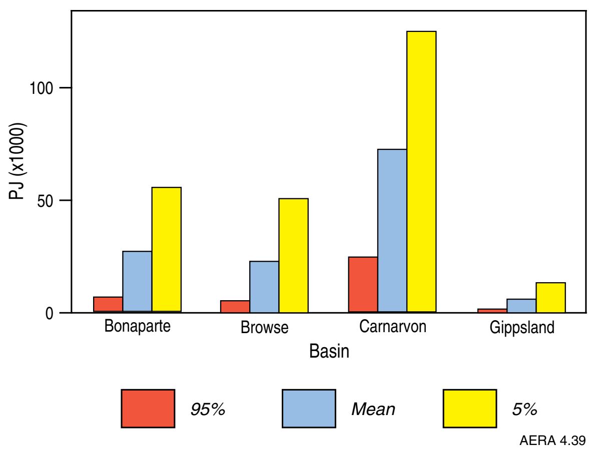


Figure 4.39 Estimates of undiscovered resources of conventional gas in four proven offshore basins

Note: 95%, Mean and 5% denote the probability of the resources exceeding the stated value

Source: USGS 2000

than 50 per cent. This is considerably higher than the historical success rates of around 20 per cent for petroleum exploration in Australian onshore and offshore basins.

Estimates of Australia's undiscovered conventional gas resources in four proven basins are shown in figure 4.39. This USGS (2000) assessment is substantially larger than the conservative short-time horizon Geoscience Australia estimates, to the extent that the P-95 per cent USGS estimates are closest to the P-5 per cent estimates by Geoscience Australia (Chapter 3 Oil provides a more detailed discussion of petroleum resource assessment methodologies). The USGS assessment represents the preferred indicative estimate of ultimate resource potential for these basins (Powell 2001) and is used to estimate potential resources from producing basins by 2030.

These estimates will have been influenced by a number of discoveries made since the USGS (2000) assessment was published. For example, the USGS (2000) mean estimate of 71 448 PJ (65 tcf) of gas remaining to be discovered in the Carnarvon Basin predates the giant Io-Jansz discovery which contains 20 tcf of gas (Walker 2007) and is one of the largest gas fields yet found in Australia. The gas is reservoired in Late Jurassic channel sands (Jenkins et al. 2003) rather than in a Triassic fault block – the usual habitat of the other giant gas accumulations on the North West Shelf – and thus demonstrates a limitation of forward modelling when dealing with new play types.

Similarly, the assessment predates the Wheatstone (2004, 4364 PJ), Pluto (2005, 5101 PJ), and Xena (2006, 539 PJ) gas discoveries which highlight the

Table 4.18 Status of gas exploration and discovery in Australia by basin

Basin	Status	First Discovery	Production/Commercial Discovery
Adavale	past gas producer	1964 – Gilmore	1995 – 2002 Gilmore gas production
Amadeus	gas producer	1965 – Palm Valley	1983 – gas piped to Alice Springs
Bass	gas producer	1967 – Bass–3 gas	2006 – BassGas project
Bonaparte	gas producer	1969 – Petrel	2006 – Darwin LNG production
Bowen	gas producer	1970 – Rolleston	1990 – Denison Trough gas piped to Brisbane
Browse	potential gas producer	1971 – Scott Reef	2009 – Ichthys project in FEED
Canning	potential gas producer	1966 – St Georges Range	
Carnarvon – onshore	gas producer	1966 – Onslow–1	1991 – Tubridgi gas production
Carnarvon – offshore	gas producer	1971 – North Rankin	1984 – NW Shelf gas piped to Perth
Carnarvon – Exmouth Plt.	potential gas producer	1980 – Scarborough	
Cooper	gas producer	1963 – Gidgealpa	1969 – gas piped to Adelaide
Eromanga	gas producer	1976 – Namur	1978 – Strzelecki 1st commercial oil
Georgina	gas flows	1973 – Ethabuka	
Gippsland	gas producer	1965 – Barracouta	1969 – gas piped to Melbourne
Gunnedah	gas producer	2000 – Coonarah	2004 – Wilga Park gas–fired power station
Maryborough	gas flows	1967 – Gregory River	CSG potential
Ngalia	gas flow	1981 – Davis	
Offshore Canning	gas flows	1980 – Phoenix	
Otway – onshore	gas producer	1959 – Port Campbell	1986 – gas piped to Warrnambool
Otway– offshore	gas producer	1993 – Minerva	2005 – Minerva gas production
Pedirka	gas shows		CSG potential
Perth – offshore	gas show	1978 – Houtman–1	
Perth – onshore	gas producer	1964 – Yardarino	1971 – Dongara production
Surat	gas producer	1900 – Hospital Hill	1969 – gas piped to Brisbane
Sydney	gas shows	1956 – Camden	CSG production
Tasmania	gas shows	1920 – Bruny Island	CSG, shale gas potential?

Source: Geoscience Australia

potential for further gas discoveries in the basin. More than 37 400 PJ (34 tcf) of conventional gas has been discovered in the Carnarvon Basin since 2000, exceeding the P50 Geoscience Australia estimate and representing approximately 40 per cent of the mean ultimate undiscovered gas resources estimated by the USGS.

Undiscovered gas potential estimates for the Bonaparte Basin range from the 3198 PJ (3 tcf) of gas assessed by Barrett et al. (2002), using a medium-term discovery process model which makes a projection of resources expected to be found in the next 10 to 15 years, to the 25 935 PJ (23 tcf) USGS (2000) estimate of the ultimate hydrocarbon potential in the basin. The recent Blackwood, Caldita and Barossa gas discoveries, where exploration is continuing to define the size and quality of the accumulations, confirm the potential for remaining resources to be found in the Bonaparte Basin. The development of the second LNG hub at Wickham Point in Darwin Harbour to serve the development of the Ichthys gas accumulation in the Browse Basin is an added stimulus to the search for gas in northern Australia.

The USGS (2000) assessed Australia's producing onshore basins as having only modest potential for discovery of new resources – around 3 per cent of mean undiscovered gas (3590 PJ, 3.3 tcf). Exploration is continuing, especially in the Cooper-Eromanga but also the Bowen-Surat, Canning and Perth basins where there is potential for further discoveries of both conventional gas and coal seam gas.

Discovery of new fields in non-producing and frontier basins

In addition to the 14 basins that have identified commercial conventional gas resources, many other Australian basins have gas occurrences (figure 4.40). Apart from the gas accumulations already recognised in these basins there is also the potential for the discovery of new fields.

As gas exploration matures in the established basins, the size of drilling targets and correspondingly the size of discovered fields is likely to decline, unless reversed by new opportunities created by new play concepts and

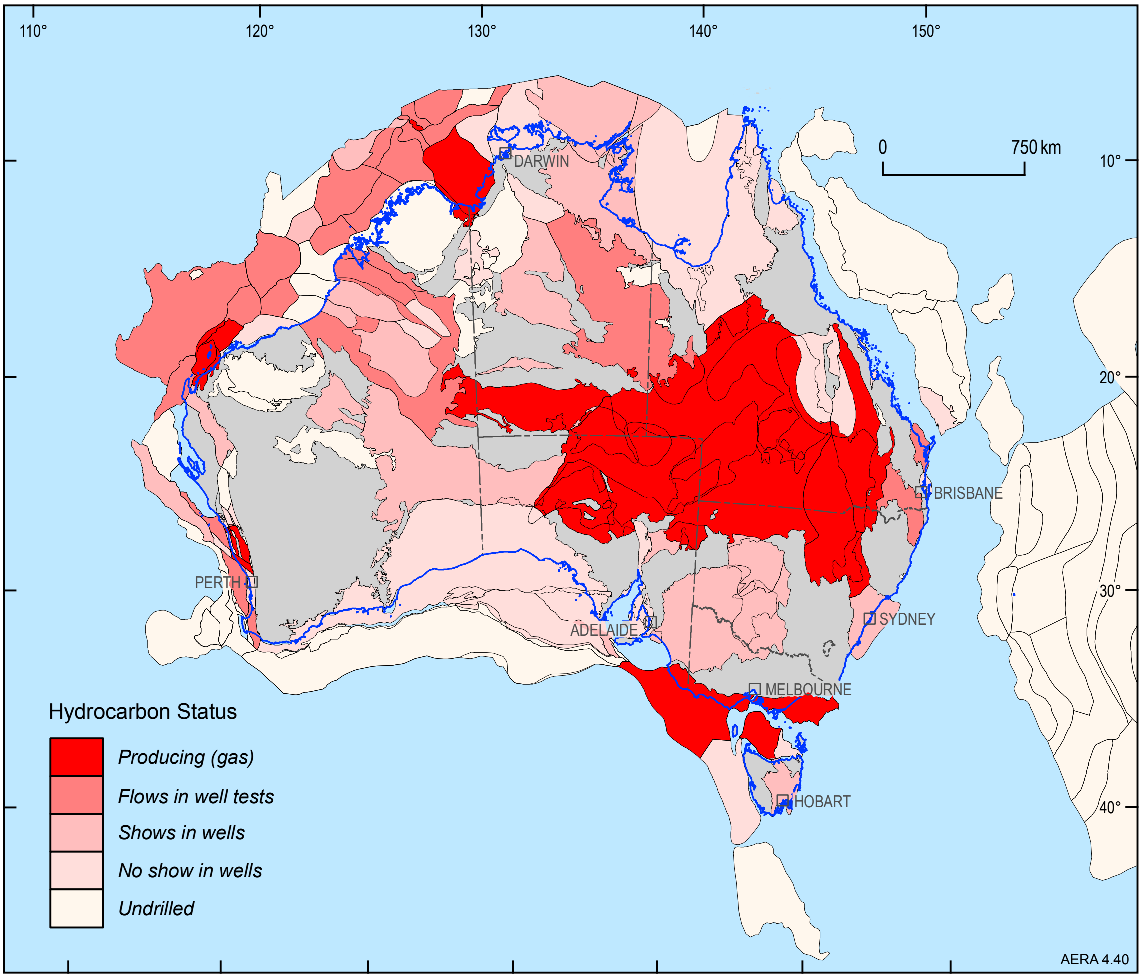


Figure 4.40 Australian gas occurrences, showing basins with conventional gas production, gas flows and gas shows, drilled basins with no shows and undrilled basins

Note: Identified gas resources, including relative size, shown in figure 4.1

Source: Geoscience Australia

technologies and, in the case of offshore basins, opportunities identified in deeper water. However, Australia's frontier basins are poorly explored and the largest structures remain untested.

Geoscience Australia is currently undertaking a program of pre-competitive data acquisition and interpretation to assess the petroleum potential of selected frontier basins. Most gas discoveries have been made during exploration for oil and that will lead the search into new deepwater basins; the potential of frontier basins is more fully discussed in Chapter 3 Oil.

In comparison to Australia's producing basins, there is a higher degree of uncertainty in estimating the undiscovered resources in the poorly explored frontier and non-producing basins. A number of estimates of undiscovered hydrocarbon potential are available for individual frontier basins and for Australia as a whole. The publicly available assessments have not integrated the results from the current rounds of pre-competitive data acquisition and focus on oil rather than gas resources. The recent USGS Circum-Arctic Resource Appraisal (2009) offers a possible approach to estimating undiscovered resources in frontier areas by using basin analogs.

4.4.3 Unconventional gas resource outlook

For unconventional gas the understanding of additions to the inventory of reserves from field growth and new discoveries is less well established than for conventional gas. In the outlook to 2030, CSG is expected to remain the most important sector of the unconventional gas industry; it is already a significant source of gas in eastern Australia. Currently, production of CSG is mainly from the Bowen and Surat basins in Queensland, with some production from the Sydney Basin in New South Wales. Production is from Permian and Jurassic coals.

Over the past five years the focus of CSG exploration has expanded into other coal basins and into other parts of the stratigraphy, to coal deposits of widely differing geological age. Triassic and Cretaceous strata are now also an exploration target as well as the Permian coals of the Gondwana basins (figure 4.41). CSG exploration in South Australia, Tasmania, Victoria and Western Australia has increased as a result of increasing CSG production in Queensland and the success in producing CSG from low rank coals in the United States. In South Australia, as at mid-2009, there were nine petroleum exploration licenses (PEL) granted and six under consideration for exploration rights to evaluate CSG potential (including underground coal gasification potential).

The Southern Cooper Basin is an area with potential for CSG resources contained within Permian coal seams intersected in previous petroleum exploration wells. The shallowest Permian coal measures in the Cooper Basin have thicknesses of up to 20 m with a total seam thickness of up to 80 m between depths of 1000 and 2000 m. There is also potential for shale gas and tight gas resources. A significant advantage of exploring for CSG in the Cooper Basin is that substantial gas infrastructure, including a gas pipeline servicing South Australia, Queensland and New South Wales markets, already exists.

Estimates of aggregate CSG potential in Australia are substantial (Baker and Slater 2009). Industry estimates range from 250 tcf (260 000 PJ) according to Santos (2009) to more than 300 tcf (300 000 PJ) of gas in place (Arrow Energy 2009).

In addition to the new CSG resources identified by current active exploration, it is expected that part of the large inferred in-ground resource will move into the EDR and SDR categories by 2030. There appears to be significant potential for at least 15 times more CSG than the current EDR.

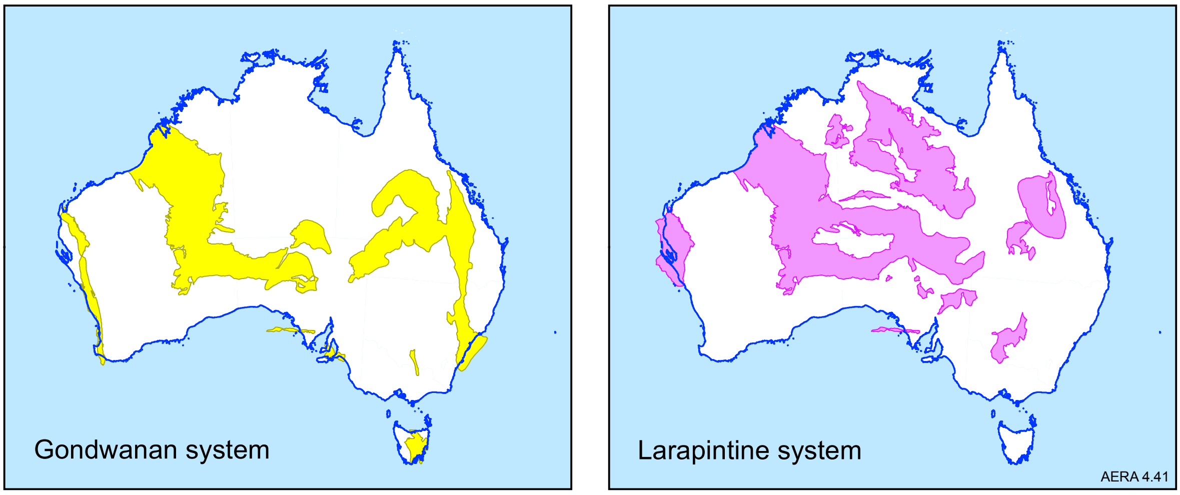


Figure 4.41 Distribution of Gondwanan (Permain) basins (potential CSG) and Larapintine (Early Paleozoic) basins (potential for shale gas resources)

Source: Bradshaw et al. 1994

Understanding of the future potential tight gas and shale gas resource in Australia is very limited. Likely shale gas candidate formations have been identified in the Cooper, Georgina and McArthur basins, where some exploration drilling has taken place in the Beetaloo sub-basin (Silverman et al. 2007). Apart from the organic rich shales in a number of Larapintine (figure 4.41) and Centralian basins (Bradshaw et al. 1994) across central and western Australia, there may also be shale gas potential in some of the less metamorphosed parts on the fold belts in eastern Australia. North American experience may provide a guide to future tight gas and shale gas potential in Australia. The rapid developments that have occurred there have resulted in shale gas reserves growing more than 50 per cent from 2007 to 2008. They now exceed CSG reserves (EIA 2009b).

As exploration and development of Australia's gas resources proceeds, several basins – notably the Cooper Basin – are likely to emerge as having conventional, CSG and tight or shale gas resources.

4.4.4 Total gas resource outlook

Australia's EDR of gas, both conventional and unconventional, at 138 700 PJ (126 tcf) is equivalent to more than 70 years of production at current rates. Australian gas production is projected to increase significantly over the period to 2029–30 but demonstrated gas resources (226 500 PJ, 206 tcf) exceed the estimated cumulative gas production from 2008–09 to 2029–30 (119 060 PJ, 108 tcf). Total identified gas resources (393 000 PJ, 357 tcf) are nearly three times EDR and substantially larger than the estimated cumulative gas production from 2008–09 to 2029–30. Current identified gas resources remaining in 2030 are estimated to be equivalent to nearly 50 years of production at the estimated 2030 production rates. Over the outlook period it is expected that some of the currently sub-economic demonstrated resources (SDR) and large inferred (mostly CSG) gas resource will be converted to EDR and enter production. Australia's gas resource base is therefore more than adequate to support projected increases in production beyond the outlook period.

The true size of Australia's potential in-ground gas resources is unknown and could be significantly larger than the identified resources. There is no current publicly available resource assessment of Australia's undiscovered conventional gas resources that adequately reflects the knowledge gained in recent years during the active programs of government pre-competitive data acquisition and increased company exploration during the resources boom. In addition, the current knowledge base for unconventional gas, especially tight gas and shale gas, is inadequate for assessment. The potential size of Australia's CSG resources is as yet ill-defined; companies have reported very substantial in-place CSG resources. Better assessment of Australia's potential gas resources would be aided by both more pre-competitive geoscientific information and further exploration drilling.

4.4.5 Outlook for gas market

In the latest ABARE long-term projections (ABARE 2010) which incorporate the Renewable Energy Target, a 5 per cent emissions reduction target and other government policies, Australian gas production is projected to increase by 6.7 per cent per year, to reach 8505 PJ (7.7 tcf) in 2029–30 (tables 4.19 and 4.20). Australian gas consumption is projected to rise by 3.4 per cent per year to reach 2575 PJ (2.1 tcf) in 2029–30. Gas exports, in the form of LNG, are projected to expand even more quickly, by 9.5 per cent per year to reach 5930 PJ (109 Mt) in 2029–30. These results are discussed in more detail below.

Production

Over the medium term, the production of gas is expected to continue to rise as developments now under construction or in the advanced stages of planning are completed (figure 4.42).

Over the longer term, natural gas production is projected to increase to 8505 PJ by 2029–30, growing at an average annual rate of 6.7 per cent (figure 4.42). As with current production, the majority of future conventional gas production is likely to be sourced from offshore basins in north, north-west and south-east Australia. Western Australia is projected to account for nearly two thirds of this increase.

By 2029–30, total natural gas production in the Eastern market is projected to be around 2861 PJ (table 4.20). CSG production is projected to reach 2507 PJ in 2029–30, with CSG accounting for 88 per cent of the eastern Australian gas production. A significant proportion of this CSG will be consumed

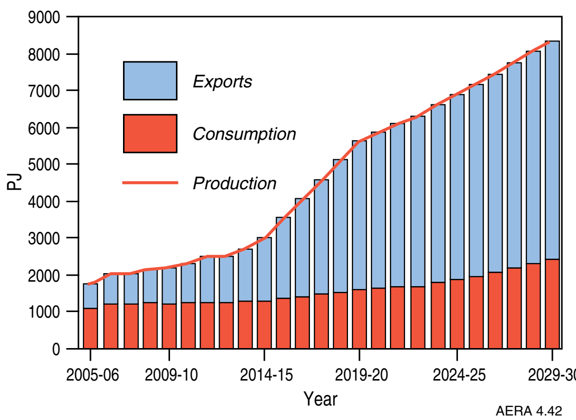


Figure 4.42 Outlook for Australian gas supply-demand balance

Source: ABARE 2010

domestically, supporting the projected growth in gas-fired electricity generation, particularly in Queensland and New South Wales. The substantial projected expansion of CSG in Queensland would suggest that gas flow patterns may also change, with relatively less gas flowing north from Victoria, and more gas flowing south from Queensland. The positive outlook for natural gas production from CSG projects is projected to result in the eastern gas market remaining in balance over the projection period.

By 2029–30, gross natural gas production in the Northern Territory (including imports from the JDPA in the Timor Sea for LNG production) is projected to reach 677 PJ, growing at an average annual rate of 4.5 per cent. Gas supply to the Northern market (excluding LNG exports) is projected to meet demand over the outlook period, increasing to 93 PJ in 2029–30.

Gross natural gas production in the Western market, including LNG, is projected to grow strongly, at an average rate of 7.1 per cent per year, to reach 4968 PJ in 2029–30. This is underpinned by increasing demand in the domestic market and increasing global demand for LNG.

Consumption

Gas is projected to be the fastest growing fossil fuel over the period to 2029–30. Primary gas consumption is projected to rise by 3.4 per cent per year over the outlook period to reach 2575 PJ by 2029–30 (figure 4.43). The share of gas in total primary energy consumption is projected to rise to 33 per cent in 2029–30. This growth in demand is driven primarily by the electricity generation sector and the mining sector, and reflects the shift to less carbon intensive fuels in a carbon constrained environment.

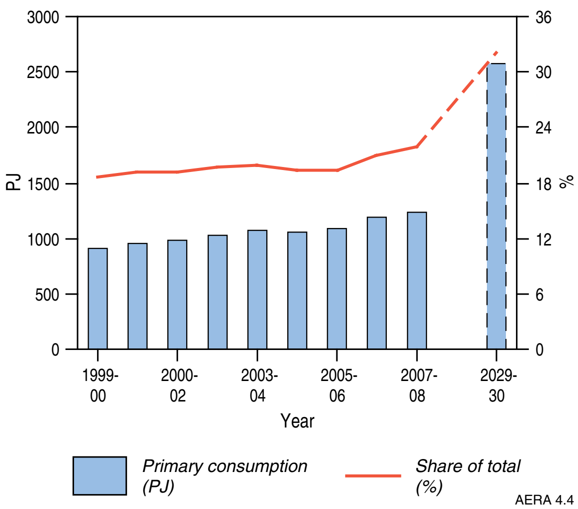


Figure 4.43 Outlook for Australian gas consumption,

Source: ABARE 2010

Table 4.19 Outlook for Australia's gas consumption, production and trade

	unit	2029–30	Average annual growth 2007–08 to 2029–30
Production	PJ	8505	6.7
	tcf	7.7	-
Share of total	%	24.3	-
Primary consumption	PJ	2575	3.4
	tcf	2.3	-
Share of total	%	33.4	-
Electricity generation	TWh	135	5.0
Share of total	%	36.8	-
Exports	PJ	5930	9.5
	Mt	109	-

Note: Production includes imports from JPDA
Source: ABARE 2010

Table 4.20 Outlook for Australia's gas markets,

	2029–30	Average annual growth 2007–08 to 2029–30
	PJ	%
Eastern gas market		
Production	2861	6.7
conventional gas	353	-2.2
coal seam gas	2507	14.9
Consumption	1501	3.6
Exports	1360	-
Northern gas market		
Production	677	4.5
Consumption	93	2.2
Exports	583	5.0
Western gas market		
Production	4968	7.1
Consumption	982	3.2
Exports	3986	9.0
Australian total		
Production	8505	6.7
Consumption	2575	3.4
Exports	5930	9.5

Note: Production includes imports from JPDA
Source: ABARE 2010

Gas-fired electricity generation and its share in total electricity generation are projected to increase considerably over the medium to long term. Electricity generation from natural gas is projected to grow at an average rate of 5 per cent per year to 135 TWh in 2029–30. The share of gas in total electricity generation is projected to grow to 37 per cent in 2029–30 (figure 4.44).

The projected increase in gas-fired electricity generation is supported by the significant volume of currently committed electricity generation capacity (see section on proposed project developments). Gas-fired electricity generation is based on mature technologies with more competitive cost structures relative to many renewable energy technologies. As such, it has the potential to play a major role in the transition period until lower-emission technologies become more viable.

LNG exports

Australia is expected to significantly expand LNG exports over the next two decades. This reflects not only Australia's abundant gas reserves and their proximity to growing Asian Pacific markets, but also Australia's attractiveness as a reliable and stable destination for investment. CSG LNG is also expected to contribute significantly to the growth of the sector.

At the end of October 2009, there were two LNG plants under construction, the Pluto LNG project (annual capacity of 4.3 Mt) and the Gorgon LNG project (annual capacity of 15.0 Mt). The projects are scheduled to be completed by late 2010 and 2015 respectively. There are a number of other LNG plants that are at a less advanced stage (undergoing FEED studies), awaiting various government or internal approvals.

By 2029–30, LNG exports are projected to reach 109 Mt, reflecting an average annual growth rate over the outlook period of 9.5 per cent. Production of LNG is projected to increase its share of total Australian gas production to 70 per cent by 2029–30.

Proposed project developments

Upstream

At the end of October 2009, there were eight upstream gas projects under construction or committed across Australia (table 4.21). Of these projects, four were located in the Carnarvon Basin, and others in the Otway and Gippsland basins. The projects have a combined gas production capacity of 1206 PJ per year. There are also five gas projects with a combined capacity of 176 PJ per annum at a less advanced stage of development (table 4.22).

There was also one upstream coal seam gas project under construction at the end of October 2009, located in the Bowen-Surat Basin in Queensland. This project will have a gas production capacity of 23 PJ per year. Several more CSG projects in Queensland and New South Wales are also at the planning stage (table 4.23).

There are also several tight gas projects which have been proposed (table 4.24).

Pipeline

Accompanying the expansion of Australia's gas production capacity is an expansion to the transmission pipeline. The largest expansion under construction, in terms of capacity, is the Stage 5B expansion of the Dampier Bunbury gas pipeline in Western Australia (table 4.25). The pipeline capacity will increase to 327 PJ per year when the Stage 5B expansion is completed. Several smaller pipeline expansions are committed or being constructed in New South Wales, Victoria, South Australia and Queensland.

Electricity generation

At the end of October 2009 there were four advanced gas-fired electricity generation projects with a combined capacity of 1352 MW that are all scheduled to be in operation by the end of 2010. There are also two CSG-fired projects under construction, which would add a further 770 MW of capacity by the end of 2010 (table 4.26). In addition, there are a further 35 gas- and CSG-fired generation

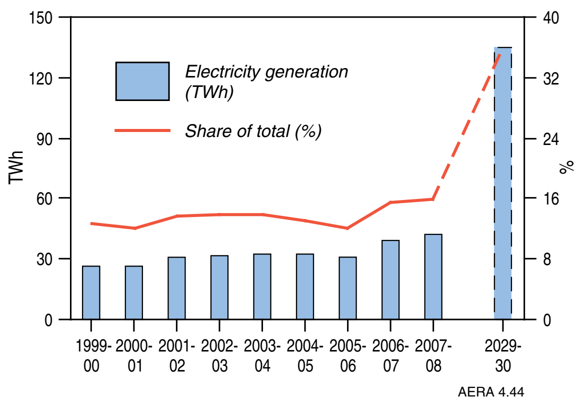


Figure 4.44 Outlook for Australian gas-fired electricity generation

Source: ABARE 2010; IEA 2009a

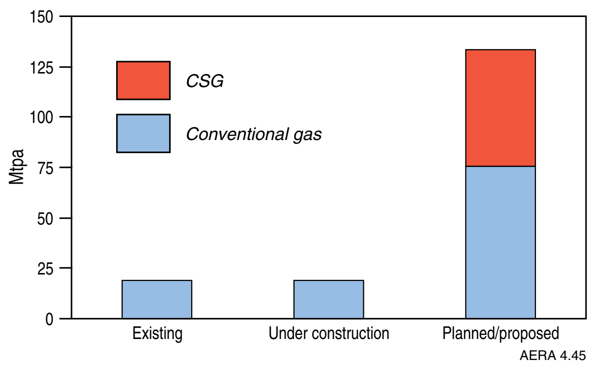


Figure 4.45 Proposed Australian LNG export capacity

Source: ABARE 2009c

projects at a less advanced stage with a combined capacity of more than 11 000 MW (table 4.27).

LNG

There are a significant number of new LNG projects proposed in Australia. In addition to the 19 Mt of export capacity under construction, there is at least another 60 Mt (and potentially up to 76 Mt) of LNG projects based on conventional gas fields at various stages of FEED, feasibility and prefeasibility studies (table 4.28).

There are also at least five CSG-based LNG projects currently under consideration (table 4.29). All these projects are expected to be located in Queensland, with a combined capacity of around 35 Mt by the middle of next decade. This is similar to the LNG production capacity from conventional gas currently in existence or under construction located off the northwest coast of Australia. CSG projects represent about 40 per cent of the planned or proposed new LNG export capacity (figure 4.45).

If all of these proposed LNG export projects are realised, it would amount to more than five times current export capacity. Several of the project developers have announced a planned or target start up date by the middle of this decade. However, it is not expected that all of these projects will actually be realised in the time frame announced.

Traditionally, LNG projects have not been developed until there is sufficient demand to underpin the required investment. A number of projects in table 4.28 have already been marketed for several years and their development date postponed to enable LNG markets to be secured. This is consistent with LNG projects in many other countries. Some of the projects are also targeting the same market opportunities.

While there is a move towards building some spare capacity, projects are still waiting to secure at least some long term contracts with buyers ahead of the commencement of construction. In addition to potential demand side constraints, Australia is competing with other planned projects around the world for limited resources to finance, design and construct LNG terminals.

Table 4.21 Conventional gas projects at an advanced stage of development, as of October 2009

Project	Company	Basin	Status	Start up	Capacity	Capital Expenditure
Henry gasfield	Santos/ AWE/ Mitsui	Otway	Under construction	early 2010	11 PJ pa	$275 m
Kipper gas project (stage 1)	Esso/ BHP Billiton/ Santos	Gippsland	Under construction	2011	30 PJ pa	US$1.1 b (A$1.3 b)
Longtom gas project	Nexus Energy	Gippsland	Under construction	2010	25 PJ pa	$300 m
NWS CWLH[a]	Woodside Energy/ BHP Billiton/ BP/ Chevron/ Shell/ Japan Australia LNG	Carnarvon	Under construction	2011	35 PJ pa	US$1.47 b (A$1.8 b)
NWS North Rankin B	Woodside Energy/ BHP Billiton/ BP/ Chevron/ Shell/ Japan Australia LNG	Carnarvon	Under construction	2012	967 PJ pa	$5.1 b (A$6.1 b)
Pyrenees[a]	BHP Billiton/ Apache Energy	Carnarvon	Under construction	early 2010	23 PJ pa	US$1.68 b (A$2 b)
Reindeer gas field/Devil Creek gas processing plant (phase 1)	Apache Energy/ Santos	Carnarvon	Committed	late 2011	40 PJ pa	US$744 m (A$896 m)
Turrum	ExxonMobil/ BHP Billiton	Gippsland	Committed	2011	75 PJ pa	US$1.25 b (A$1.5 b)

a Oil developments with gas production capacity
Source: ABARE 2009c

Table 4.22 Conventional gas projects at a less advanced stage of development, as of October 2009

Project	Company	Location	Status	Start up	Capacity	Capital Expenditure
Basker, Manta and Gummy gas development	Roc Oil/Beach Petroleum	Gippsland Basin	Feasibility study under way	na	up to 46 PJ pa	na
Brunello/Julimar (supply for Wheatstone LNG project)	Apache Energy/ KUFPEC	Carnarvon Basin	Feasibility study under way	2013	na	US$1.84 b (A$2.2 b)
Halyard	Apache Energy/ Santos	Carnarvon Basin	FEED studies under way	2011	26 PJ pa	US$110 m (A$133 m)
Kipper gas project (stage 2)	Esso/BHP Billiton/Santos	Gippsland Basin	Feasibility study under way	2015	27 PJ pa	na
Macedon	BHP Billiton/ Apache Energy	Carnarvon Basin	Prefeasibility study under way	2013	77 PJ pa	na

Source: ABARE 2009c

Table 4.23 CSG projects at various stages of development, as of October 2009

Project	Company	Location	Status	Start up	Capacity	Capital Expenditure
RTA development (Tallinga)	APLNG (Origin/ ConocoPhillips)	East of Roma, Qld	Under construction	2010	23 PJ pa	$260 m
Casino project	Metgasco	Casino, NSW	Feasibility study under way	2010	18 PJ pa	na
Gloucester project	AGL	Hunter Valley, NSW	Feasibility study under way	2010	15–25 PJ pa	$200 m
Camden Gas Project	AGL	Camden, NSW	Planning approval received	na	12 PJ pa	$35 m
Camden Gas Project	AGL	Camden, NSW	Planning approval under way	mid 2010	na	$100 m
Walloon gas field	BG Group	North of Roma, Qld	Feasibility study under way	2013	190 PJ pa	$230 m

Source: ABARE 2009c

Table 4.24 Tight gas projects at various stages of development, as of October 2009

Project	Company	Location	Status	Start up	Capacity
Warro gas field	Alcoa/ Latent Petroleum	Perth Basin, WA	feasibility study under way	2012	up to 58 PJ
Wellesley gas field	Empire Oil and Gas/ Allied Oil and Gas	Perth Basin, WA	feasibility study under way	2010	na
Wombat field	Lakes Oil	Gippsland Basin, Vic	feasibility study under way	na	na
Wakefield-1	Adelaide Energy/ Beach Petroleum Ltd	Cooper Basin, SA	feasibility study under way	na	na

Source: ABARE

Table 4.25 Gas pipelines at various stages of development, as of October 2009

Project	Company	Location	Status	Start up	Capacity	Capital Expenditure
Eastern Gas Pipeline	Jemena	Wollongong (NSW) to Longford (Vic)	Committed	2010	20 PJ pa	$41 m
Moomba to Sydney	APA Group	Moomba (SA) to Sydney (NSW)	Under construction	2010	na	$90 m
Queensland Gas Pipeline	Jemena	Wallumbilla to Gladstone (Qld) 550 km	Under construction	2010	25 PJ pa	$112 m

Project	Company	Location	Status	Start up	Capacity	Capital Expenditure
South Gippsland natural gas pipeline	Multinet Gas	South Gippsland (Vic) 250 km from Lang Lang to five regional towns	Under construction	2010	na	$50 m
Central Queensland gas pipeline	Arrow Energy/ AGL	Moranbah to Gladstone (Qld) 440 km	Feasibility study under way	na	20–50 PJ pa	$475 m
Dampier–Bunbury gas pipeline expansion (stage 5C)	DBP	Dampier to Bunbury (WA)	Feasibility study under way	na	100 PJ pa	$800 m
Gloucester Coal Seam Gas pipeline	Lucas Energy/ Molopo Australia	Gloucester to Hexham (NSW) 98 km	Feasibility study under way	2010	15–22 PJ pa	$50–80 m
Lions Way pipeline	Metgasco	Casino to Ipswich (Qld) 145 km	EIS under way	na	18 PJ pa	$120 m
Newstead to Bulla Park	Australian Pipeline Assets	Newstead (Qld) to Bulla Park (NSW)	Feasibility study under way	na	na	$500 m
Queensland–Hunter gas pipeline	Hunter Gas Pipeline	Wallumbilla (Qld) to Newcastle (NSW) 820 km	Govt approvals received	2012	85 PJ pa	$900 m
South West Queensland pipeline (stage 2 and 3)	Epic Energy	Wallumbilla to Ballera (Qld) 755 km	FEED study under way	2012	77 PJ pa	$900 m
Surat Basin to Gladstone pipeline	Arrow Energy	Surat Basin to Gladstone (Qld) 450 km	EIS under way	na	na	$600 m

Source: ABARE 2009c

Table 4.26 Gas-fired power stations at an advanced stage of development, as of October 2009

Project	Company	Location	Status	Start up	Capacity	Capital Expenditure
Conventional gas						
Colongra gas project	Delta Electricity	NSW	Under construction	late 2009	660 MW	$500 m
Owen Springs	Power and Water Corporation	NT	Under construction	2010	22 MW	$130 m
Mortlake Stage 1	Origin Energy	Vic	Under construction	2010	550 MW	$640 m
Kwinana Swift	Perth Energy	WA	Under construction	mid-2010	120 MW	$120 m
CSG						
Condamine	BG Group/ANZ Infrastructure Services	8 km E of Miles, Qld	New project, under construction	2010	140 MW	$170 m
Darling Downs	Origin Energy	40 km W of Dalby, Qld	New project, under construction	early 2010	630 MW	$951 m (inc pipeline)

Source: ABARE 2009e

Table 4.27 Gas-fired power stations at a less advanced stage of development, as of October 2009

Project	Company	Location	Status	Expected Startup	New Capacity	Capital Expenditure
Conventional gas						
ACT Peaker	AGL	8 km S of Canberra, ACT	New project, prefeasibility study under way	na	500 MW	$350–450 m
Bamarang stage 1	Delta Electricity	7 km SW of Nowra, NSW	New project, govt approval received	na	300 MW	$156 m
Bamarang stage 2	Delta Electricity	7 km SW of Nowra, NSW	Expansion, govt approval received	na	100 MW	$400 m
Centauri 1	Eneabba Gas	8 km E of Dongara, WA	New project, govt approval received, on hold	na	168 MW	na
Hanging Rock stage 1	Loran Energy Products	20 km SW of Moss Vale, NSW	New project, govt approval under way	na	300 MW	$360 m
Hanging Rock stage 2	Loran Energy Products	20 km SW of Moss Vale, NSW	Expansion, govt approval under way	na	300 MW	$240 m
Leafs Gully	AGL	65 km SW of Sydney, NSW	New project, govt approval received	2011	360 MW	$200 m
Marulan Gas Turbine Facility	EnergyAustralia	40 km NE of Goulburn, NSW	New project, EIS under way	2010	350 MW	$280 m
Marulan Gas Turbine Facility stage 1	Delta Electricity	40 km NE of Goulburn, NSW	New project, EIS under way	2013–14	250–350 MW	$280 m
Marulan Gas Turbine Facility stage 2	Delta Electricity	40 km NE of Goulburn, NSW	Expansion, EIS under way	2013–14	100–150 MW	$235 m
Mortlake stage 2	Origin Energy	12 km W of Mortlake, Vic	Expansion, EIS completed	na	450 MW	na
Munmorah rehabilitation	Delta Electricity	Munmorah, NSW	Expansion, EIS under way	2013–14	100 MW	$795 m
NQ Peaker	AGL	Townsville, Qld	New project, prefeasibility study under way	2011	360 MW	$252–324 m
Parkes	International Power	Parkes, NSW	New project, govt approval received	na	120–150 MW	$130 m
Pelican Point stage 2	International Power	20 km NW of Adelaide, SA	Expansion, prefeasibility study under way	na	300 MW	na
Port Kembla Steelworks Co-generation plant	BlueScope Steel	Port Kembla, NSW	New project, EIS under way	2012	220 MW	$750 m
SEQ1	AGL	Ipswich, Qld	New project, prefeasibility study under way	2011	360 MW	$252–324 m
SEQ2	AGL	Kogan, Qld	New project, prefeasibility study under way	2012	1150 MW	$805–1035 m

Project	Company	Location	Status	Expected Startup	New Capacity	Capital Expenditure
Shaw River stage 1	Santos	30 km N of Port Fairy, Vic	New project, EIS under way	2012	500 MW	$800 m (inc 105 km pipeline from Pt Campbell)
Shaw River stages 2 & 3	Santos	30 km N of Port Fairy, Vic	Expansion, EIS under way	na	2x500 MW	na
Swanbank F	CS Energy	Ipswich, Qld	Expansion, feasibility study under way	2012	400 MW	na
Tallawara stage 2	TRUenergy Tallawarra	13 km S of Wollongong, NSW	Expansion, EIS under way	2015	300–450 MW	$500 m
Tomago stage 1	Macquarie Generation	25 km N of Newcastle, NSW	New project, govt approval received, on hold	na	250 MW	$700 m (inc Stage 1–3)
Tomago stage 2	Macquarie Generation	25 km N of Newcastle, NSW	Expansion, govt approval received, on hold	na	250 MW	$700 m (inc Stage 1–3)
Tomago stage 3	Macquarie Generation	25 km N of Newcastle, NSW	Expansion, govt approval received, on hold	na	290 MW	$700 m (inc Stage 1–3)
Valley Power Station Augmentation project	Snowy Hydro	Latrobe Valley, Vic	Expansion, govt approval received	2011	50–100 MW	$80–100 m
Weddell stage 3	Power and Water Corporation	40 km SE of Darwin, NT	Expansion, feasibility study under way	late 2011	30 MW	$86 m
Wellington	ERM Power	4 km N of Wellington, NSW	New project, govt approval received	2012	640 MW	$350 m
CSG						
Braemar 3	ERM Power	40 km SW of Dalby, Qld	Expansion, govt approval received	2011	450 MW	na
Narrabri 1	East Coast Power	Narrabri, NSW	New project, planning approval under way	2012	30 MW	$150 m (inc stages 1 and 2)
Narrabri 2	East Coast Power	Narrabri, NSW	New project, planning approval under way	2013	180 MW	$150 m (inc stages 1 and 2)
Richmond Valley Power station and Casino Gas project	Metgasco	East Casino, NSW	New project, EIS under way	2010	30 MW	$50 m
Spring Gully stage 1	Origin Energy	80 km N of Roma, Qld	New project, govt approval under way	na	500 MW	na
Spring Gully stage 2	Origin Energy	80 km N of Roma, Qld	Expansion, govt approval under way	na	500 MW	na
Wilga Park B	Eastern Star Gas	Narrabri, NSW	Expansion, planning approval received	na	30 MW	$42 m

Source: ABARE 2009e

Table 4.28 Conventional gas-based LNG projects at various stages of development, as of October 2009

Project	Company	Location	Status	Start up	Capacity	Capital Expenditure
Pluto (train 1)	Woodside Energy	Carnarvon Basin	Under construction	late 2010	4.3 Mt LNG	$12 b (inc site works for train 2)
Gorgon LNG	Chevron/Shell/ ExxonMobil	Carnarvon Basin	Under construction	2015	15 Mt LNG	$43 b
Bonaparte (floating LNG)	Santos/GDF Suez	Bonaparte Basin	Prefeasibility study under way	na	2 Mt LNG	na
Browse LNG development	Woodside Energy/BP/ BHP Billiton/ Chevron/Shell	Browse Basin	Feasibility study under way	na	Up to 15 Mt LNG	na
Ichthys gasfield (incl Darwin LNG plant)	Inpex/Total	Browse Basin	FEED studies under way	2015	8 Mt LNG	US$20 b (A$24 b)
Pluto (train 2 and 3)	Woodside Energy	Carnarvon Basin	Feasibility study under way	na	8.6 Mt LNG	na
Prelude (floating LNG)	Shell	Browse Basin	Prefeasibility study under way	2016	3.5 Mt LNG	na
Scarborough Gas	ExxonMobil/ BHP Billiton	Carnarvon Basin	Prefeasibility study under way	na	6 Mt LNG	na
Sunrise Gas project	Woodside Energy/ ConocoPhillips/ Shell/Osaka Gas	Bonaparte Basin	Prefeasibility study under way	na	5.3 Mt LNG	na
Timor Sea LNG project	Methanol Australia	Bonaparte Basin	Prefeasibility study under way	na	3 Mt LNG	na
Wheatstone LNG	Chevron/ Apache Energy/ KUFPEK	Carnarvon Basin	FEED study under way	2016	8.6 Mt LNG (initially) 25 Mt LNG (ultimately)	US$17.8 b (A$21 b)

Source: ABARE 2009c

Table 4.29 CSG-based LNG projects at various stages of development, as of October 2009

Project	Company	Location	Status	Start up	Capacity	Capital Expenditure
Fisherman's Landing LNG project (Stage 1)	LNG Ltd/ Golar/Arrow Energy	Gladstone, Qld	environment approval granted	late 2012	1.5 Mt LNG	$500 m
Fisherman's Landing LNG project (Stage 2)	LNG Ltd/ Golar/Arrow Energy	Gladstone, Qld	Feasibility study under way	na	1.5 Mt LNG	$200–250 m
Curtis LNG project	BG Group	Gladstone, Qld	FEED study under way	late 2013	7.4 Mt LNG (12 Mt ultimately)	$8 b (includes production wells, LNG plant and 380 km pipeline)
Gladstone LNG project	Santos/ Petronas	Gladstone, Qld	EIS under way	2014	3.5 Mt LNG (initially)	$7.7 b (includes production wells, 1 LNG train and 435 km pipeline)
Shell LNG	Shell	Gladstone, Qld	feasibility study under way	2014	14 Mt LNG (ultimately 16 Mt)	na
Australia Pacific LNG	APLNG (Origin/ ConocoPhillips)	Gladstone, Qld	feasibility study under way	2014–15	7–8 Mt LNG (initially)	$35 b (based on 14–16 Mt LNG) (includes production wells, 4 LNG trains and 400 km pipeline)

Source: ABARE 2009c

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