Chapter 5
Coal

5.1 Summary

KEY MESSAGES

- Australia is the fourth largest producer, the largest exporter, and has the fourth largest reserves of coal in the world.
- Coal accounts for around three quarters of Australia's electricity generation, with coal-fired power stations located in every mainland state.
- Australia is well-placed to take advantage of increasing global demand for coal because of its large low-cost, high quality reserves.
- In export markets, coal remains the fastest growing fuel, driven by strong investment in coal-fired power stations in China and other developing economies.
- Within Australia, the share of coal in the energy mix is expected to decrease with the Renewable Energy Target and a proposed emissions reduction target.
- Government and industry initiatives are expected to play important roles in accelerating the construction, demonstration and commercial deployment of large-scale integrated carbon capture and storage (CCS) projects.
- Continuing investment in infrastructure will be necessary to enable Australia to remain a major player in the world coal market.

5.1.1 World coal resources and market

- World coal production and consumption was 6.7 billion tonnes (Gt) or around 133 000 petajoules (PJ) in 2008, and has grown at a rate of 5.2 per cent per year since 2000.
- Global proved coal reserves (both black and brown) were estimated at 826 Gt at the end of 2008.
- Trade in black coal was 939 million tonnes (Mt) in 2008, with thermal coal at 704 Mt and metallurgical coal at 235 Mt.
- Coal accounted for 26 per cent of world primary energy consumption and 42 per cent of world total electricity generation in 2007.
- Global coal consumption slowed in 2008 but coal remained the fastest-growing fossil fuel with a 5 per cent growth in consumption: China accounted for most of the growth.
- In its reference case, the IEA projects world coal demand to increase at an average annual rate of 1.9 per cent between 2007 and 2030. Non-OECD demand is projected to increase at an average annual rate of 2.8 per cent, while OECD demand is projected to decline by 0.2 per cent per year.
- The share of coal-fired electricity generation is projected to increase from 42 per cent in 2007 to 45 per cent in 2030.

5.1.2 Australia's coal resources

- Coal is Australia's largest energy resource. It is low cost and located close to areas of demand.
- Australia has substantial reserves of both black and brown coal, including high quality thermal and metallurgical coal.
- At end of 2008, Australia's recoverable Economic Demonstrated Resources (EDR) of black coal amounted to 39.2 Gt, some 6 per cent of the world's recoverable EDR. In addition there are another 8.3 Gt of Sub-economic Demonstrated Resources (SDR).
- At the 2008 rate of production of around 490 Mt per year the EDR are adequate to support about 90 years of production.
- In addition to EDR and SDR there is 66.6 Gt of recoverable Inferred Resources of black coal, which require further exploration to delineate their possible extent and determine their economic status.
- Queensland (56 per cent) and New South Wales (40 per cent) have the largest share of Australia's black coal EDR with the Sydney (35 per cent) and Bowen (34 per cent) basins containing most of the recoverable black coal EDR (figure 5.1).

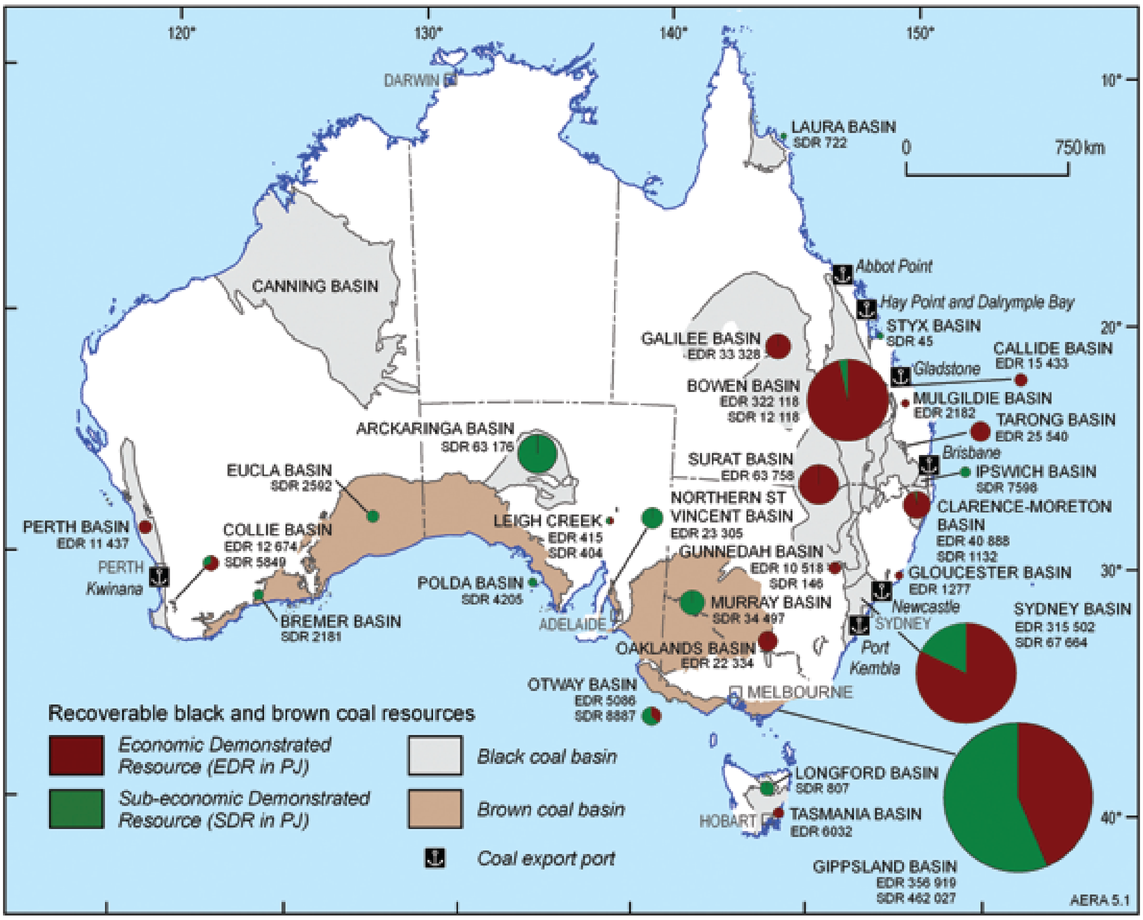

Figure 5.1 Australia's total recoverable resources of black and brown coal as at December 2008

Source: Geoscience Australia

- Australia has about 25 per cent of the world's recoverable brown coal EDR. Australia's recoverable EDR of brown coal stand at 37.2 Gt, with another 55.1 Gt in the SDR category and a further 101.8 Gt in the Inferred category. Brown coal EDR are sufficient for around 490 years at current rates of production.
- The potential for further discoveries of coal resources in Australia is significant and is probably over one trillion tonnes given that there are over 25 sedimentary basins with identified resources or coal occurrences and that there are significant areas within these basins that are under-explored.
- At end of 2009, there were over 100 operating coal mines and more than 35 proposed new mines and expansions at various stages of development ranging from scoping studies to construction (figure 5.2).
- Australia's coal industry provides direct employment for about 30 000 people.

5.1.3 Key factors in utilising Australia's coal resources

- World demand for energy and the evolution of coal prices over the period to 2030 will affect the export market and, thus, Australia's black coal production.
- Exports and domestic use of coal in electricity generation are likely to be strongly influenced by:
  - increasing electricity demand in non-OECD economies associated with economic growth;
  - global and domestic emissions reduction policies;
  - cost and rate of deployment of new low emissions technologies (e.g. carbon capture and storage); and
  - competition and substitution from other forms of energy including gas, nuclear, wind, geothermal and solar.
- Adequacy and ease of access for exporters to infrastructure, particularly port and rail.
- Government and industry initiatives such as the Global Carbon Capture Storage Institute, the Carbon Capture Storage Flagships program, and the Coal21 program are likely to play an important role in the development and commercial deployment of new low emissions technologies in the outlook period.

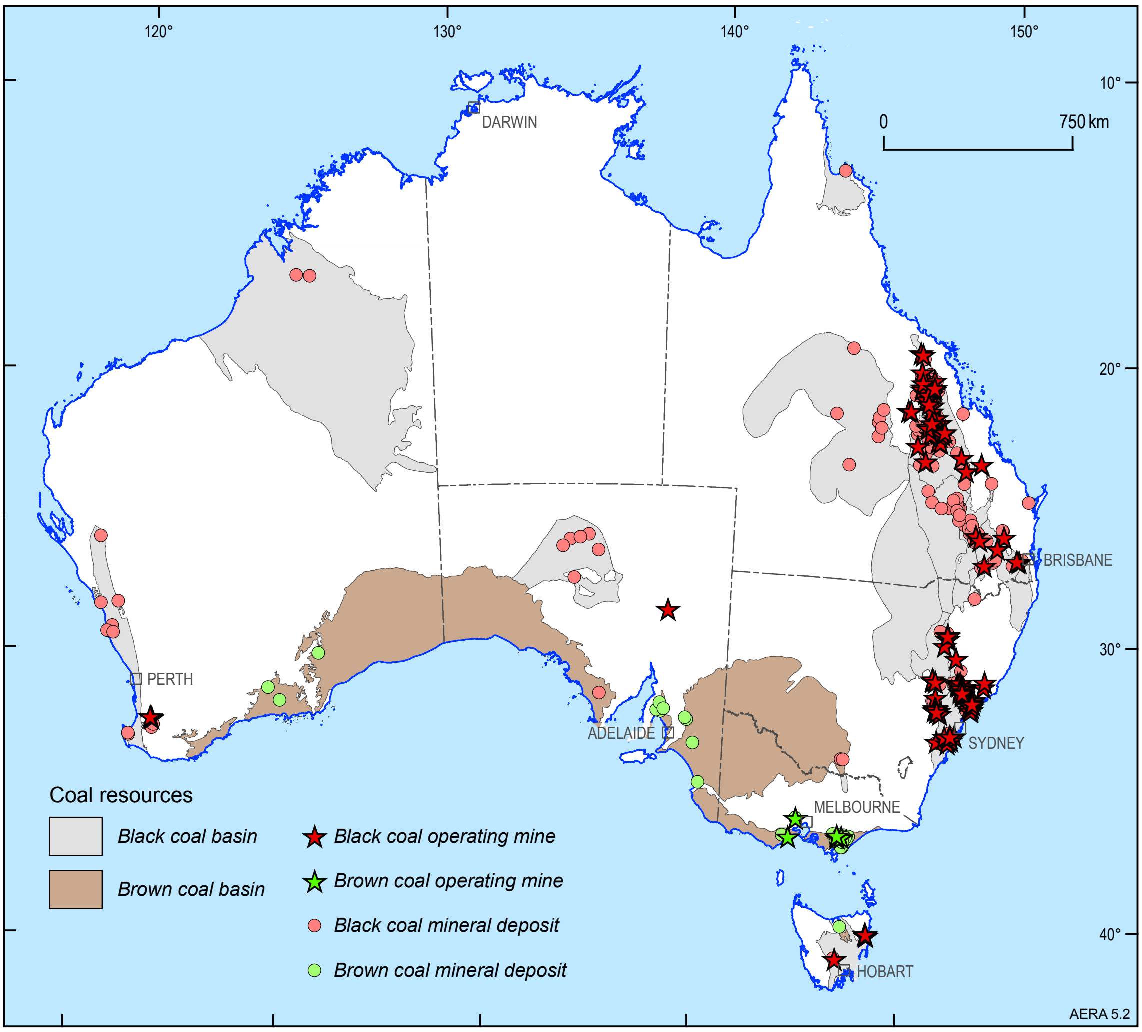

Figure 5.2 Australia's operating black and brown coal mines as at December 2008

Source: Geoscience Australia

5.1.4 Australia's coal market

- Australian coal production has increased at an average annual rate of 3.3 per cent between 2000 and 2008 and domestic consumption has increased at an average annual rate of 1.6 per cent over the same period.
- Coal is currently used to generate around three quarters of Australia's electricity, and in 2007–08 accounted for 40 per cent of total primary energy consumption.
- New South Wales and Queensland are the largest producing states in Australia.
- Australia exported 7183 PJ (252 Mt) of black coal in 2007–08, of which around 54 per cent was metallurgical coal and 46 per cent was thermal coal. Exports were valued at $24.4 billion.
- In the latest ABARE energy projections that include the RET and a 5 per cent emissions reduction target, Australia's coal production is projected to increase at an average annual rate of 1.8 per cent to 13 875 PJ between 2007–08 and 2029–30.
- Over the same period, domestic coal consumption is projected to decline at an average annual rate of 0.8 per cent to around 1763 PJ in 2029–30.

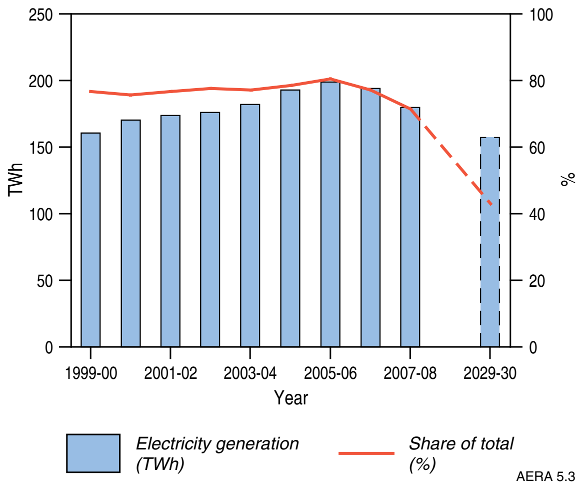

Figure 5.3 Australia's coal-fired electricity generation to 2029–30

Source: IEA 2009b; ABARE 2010

- Coal's share of primary energy consumption is projected to decline to about 23 per cent in 2029–30.
- Coal's contribution to Australia's electricity generation is also projected to decrease to around 43 per cent in 2039–30 (figure 5.3).
- This decline in coal's contribution to electricity generation is expected to be taken up by gas and to a lesser extent renewable energy sources.
- Exports are projected to increase at an average annual rate of 2.4 per cent to 12 100 PJ (450 Mt) in 2029–30. The increase in exports reflects strong growth in coal demand in China, India and other developing economies, a proportion of which will be imported.

5.2 Background information and world market

5.2.1 Definitions

Coal is a combustible sedimentary rock formed from ancient vegetation which has been consolidated between other rock strata and transformed by the combined effects of microbial action, pressure and heat over a considerable time period. This process is commonly called 'coalification'. Coal occurs as layers or seams, ranging in thickness from millimetres to many tens of metres. It is composed mostly of carbon (50–98 per cent), hydrogen (3–13 per cent) and oxygen, and smaller amounts of nitrogen, sulphur and other elements. It also contains water and particles of other inorganic matter. When burnt, coal releases energy as heat which has a variety of uses.

Coal is broadly separated into brown and black which have different thermal properties and uses.

Brown coal (lignite) has a low energy and high ash content. Brown coal is unsuitable for export and is used to generate electricity in power stations located at or near the mine.

Black coal is harder than brown coal and has a higher energy content. In Australia anthracite, bituminous and sub-bituminous coals are called black coal whereas in Europe, sub-bituminous coal is referred to as brown coal (table 5.1) .

Thermal (steaming) coal is black coal that is used mainly for generating electricity in power stations where it is pulverised and burnt to heat steam-generating boilers.

Metallurgical (coking) coal is black coal that is suitable for making coke, which is used in the production of pig iron. These coals must also have low sulphur and phosphorus contents, and are relatively scarce and attract a higher price than thermal coals.

Coke is a porous solid composed mainly of carbon and ash and is used in blast furnaces that produce iron.

Table 5.1 Coal classification terminology used in Australia and Europe

Coal Rank	Australian Terminology	European Terminology
Anthracite	Black Coal	Black Coal
Bituminous Coal	Black Coal	Black Coal
Sub-bituminous Coal	Black Coal	Brown Coal
Lignite	Brown Coal	Brown Coal

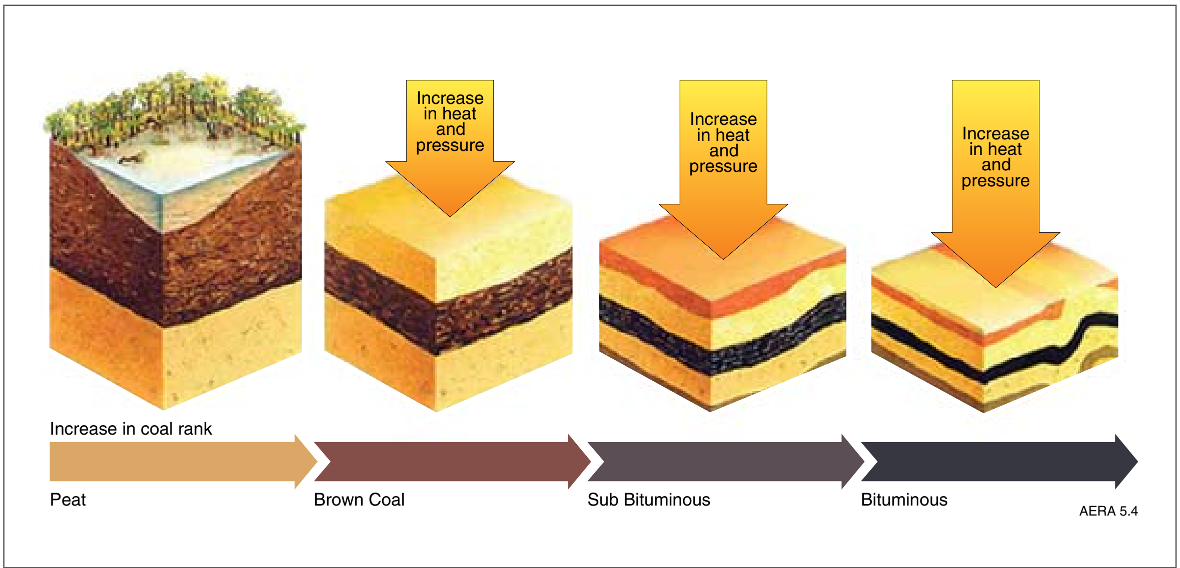

Figure 5.4 Diagrammatic representation of the transformation of peat to brown and black coal (increasing coal rank)

Source: Australian Coal Association 2009

Coal has a wide range of chemical and physical properties, reflecting its transformation by increasing pressure and temperature from peat, the precursor of coal, to the low rank (low organic maturity) lignite or brown coal and to the more mature sub-bituminous coals and ultimately to the harder, mature (higher rank) black coals (figure 5.4). The lower rank sub-bituminous coals, with lower energy contents (lower carbon and higher moisture contents), and lignite are mainly used for power generation. Bituminous coal (table 5.1) has a higher volatile content, lower fixed carbon and therefore a lower energy content than anthracite. It is used for power generation, metallurgical applications, and general industrial uses including cement manufacture. Anthracite, the highest rank of the black coals, has the lowest moisture content and the highest carbon and energy content, and is used mainly by industry for steel and cement manufacturing. Most Australian black coals are of good quality with low ash and sulfur contents.

In the remainder of this chapter, coal is the sum of brown and black coal unless otherwise specified. All production referred to is saleable coal, rather than raw, unless stated otherwise.

5.2.2 Coal supply chain

Figure 5.5 gives a schematic view of the coal industry in Australia. Coal resources are delivered to domestic and export markets through the successive activities of exploration, development, production, processing and transport.

Exploration

Coal reserves are discovered through exploration. Modern coal exploration typically involves extensive use of geophysical surveys, including 3D seismic surveys aimed at providing detailed information on the structures with the potential to affect longwall operations, and drilling to determine coal quality and thickness.

Mining

Coal is mined by both surface or ‘opencut’ (or opencast) and underground or ‘deep’ mining methods, depending on the local geology of the deposit. Underground mining currently accounts for about 60 per cent of world coal production but around 80 per cent of Australia’s coal is produced from opencut mines. Opencut mining is only economic when the coal seam(s) is near the surface. It has the advantage of lower mining costs and it generally recovers a higher proportion of the coal deposit than underground mining, as most seams present are exploited (90 per cent or more of the coal can typically be recovered).

Technological advancements have made coal mining today more productive than it has ever been. Modern large opencut mines can cover many square kilometres in area and commonly use large draglines to remove the overburden and bucket wheel excavators and conveyor belts to transport the coal. Modern equipment and techniques allow opencut mining to around 200 m. Many underground coal mines in Australia use longwall mining methods,

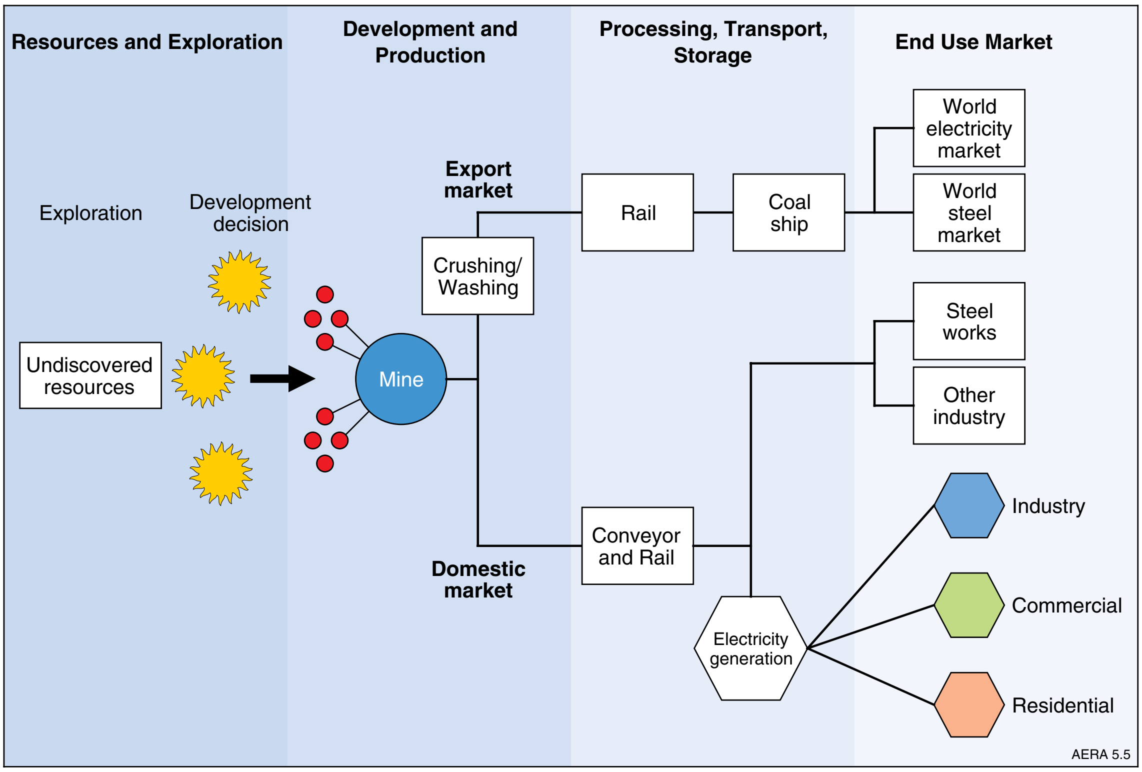

Figure 5.5 Australia’s coal supply chain

Source: ABARE and Geoscience Australia which enable extraction of most of the coal from a seam using mechanical shearers. The mining 'face' can be up to 250 m long. Self-advancing, hydraulic-powered supports temporarily hold up the roof while the coal is extracted. The roof over the area behind the face, from which the coal has been removed, is then allowed to collapse. Over 75 per cent of the coal in the deposit may be extracted using this method (World Coal Institute 2009).

Processing

Black coal may be used without any processing other than crushing and screening to reduce the rock to a useable and consistent size and remove some contaminants. However, coal for export is generally washed to remove pieces of rock or mineral which may be present. This reduces ash and increases overall energy content. Coal is separated into size fractions, with coarse coal usually separated by dense medium cyclones using a slurry of magnetite and water. High density particles with concentrations of mineral matter sink and particles with low mineral matter concentrations float. Fine coal (minus 1 mm) is usually cleaned by flotation, where the addition of reagents enables the coal to attach to bubbles and is separated from mineral matter. Coal is dewatered after washing for efficient transport and use.

Transport

Australia's coal is transported by conveyor or rail to power stations for domestic electricity production or via rail to coal export terminals from where it is shipped in Panamax and Capesize vessels to markets all over the world. In New South Wales, coal for export is loaded at two ports: Port Kembla (80 km south of Sydney) and Newcastle (150 km north of Sydney). Port Kembla serves the western and southern coalfields. The port of Newcastle serves mines in the Hunter Valley and Gunnedah basins and is the world's largest coal export port. In Queensland, there are six coal loading terminals:

Table 5.2 Key coal statistics

	unit	Australia 2007–08	Australia 2008	OECD 2008	World 2008
Reserves	Mt	-	76 400	352 095	826 001
Share of world	%	-	9.2	42.6	100
World ranking	No	-	4	-	-
Production (Raw Coal)	PJ	9431	9691	-	-
	Mt	487	497	2127	6666
Share of world	%	-	7.4	31.9	100
World ranking	No	-	4	-	-
Annual growth in production 2000-08	%	-	3.3	0.7	5.2
Primary energy consumption	PJ	2292	2309	47 461	133 215[a]
	Mt	135	136	2329	6767[a]
Share of world	%	-	2.0	34.4	100
World ranking	No	-	10	-	-
Share of primary energy consumption		40	-	21	26[a]
Annual growth in consumption 2000–08	%	-	1.6	0.7	4.8
Electricity generation					
Electricity output	TWh	-	202	3947	8216[a]
Share of total	%	-	76	33	42[a]
Exports	Mt	252	261	385	939
Thermal coal	Mt	115	126	175	704
Share of world	%	-	18	25	100
World ranking	No	-	2	-	-
Export value	A$b	8.4	14.4	-	-
Metallurgical coal	Mt	137	135	210	235
Share of world	%	-	57	89	100
World ranking	No	-	1	-	-
Export value	A$b	16.0	32.3	-	-

a 2007
Source: ABARE 2009a, b; IEA 2009a, b

Abbot Point, Dalrymple Bay, Hay Point, Gladstone (RG Tanna and Barney Point) and Fisherman Island in the port of Brisbane. The port of Brisbane services the Clarence-Moreton Basin with the other five terminals loading coal produced in the Bowen Basin. Some coal has recently been exported from Kwinana in Western Australia.

5.2.3 World coal market

Table 5.2 provides key statistics for the Australian coal market within a global context. Australia is a major producer and exporter of coal, having large, low-cost reserves available. Coal also plays a dominant role in Australia's and the world's energy mix.

Reserves and production

Over 70 countries worldwide have proven reserves of coal totalling approximately 826 Gt (World Coal Institute 2009), At current rates of production, these reserves are estimated to last 122 years (BP 2009). The United States has large reserves of both black and brown coal, and accounts for 29 per cent of total world coal reserves (figure 5.6). China and India also hold large reserves of black coal, while China and the Russian Federation hold large reserves of brown coal. Australia's reserves of black coal are the fifth largest in the world, while its reserves of brown coal are the fourth. Total coal reserves (based on EDR) in Australia are 76.4 Gt, 9 per cent of the world's total.

In 2008, world coal production totalled 6.7 Gt, of which the largest producers, China, United States and India accounted for 40 per cent, 16 per cent and 8 per cent respectively. Australia's production of 497 Mt was the fourth largest and accounted for about 7 per cent of world production (figure 5.7).

Of total coal production, black coal accounted for 86 per cent, while brown coal accounted for the remaining 14 per cent (figure 5.8).

Primary energy consumption

In 2008, world coal consumption was around 6.8 Gt (IEA 2009a). The major use of coal is for electricity generation (accounting for around 67 per cent of consumption) and steel production (16 per cent). Other uses include cement production and chemical processing.

Coal is an important energy source, reflecting its wide availability and relatively low cost compared with other fuels. In 2007 it accounted for 26 per cent of global primary energy consumption, the second largest share of world energy consumption after oil. Around 42 per cent of the world's electricity is generated using coal and around 70 per cent of the world's steel production is from the coal-based blast furnace process.

China is the largest coal consumer accounting for around 41 per cent of world consumption in 2008 (figure 5.9). China's consumption has increased at

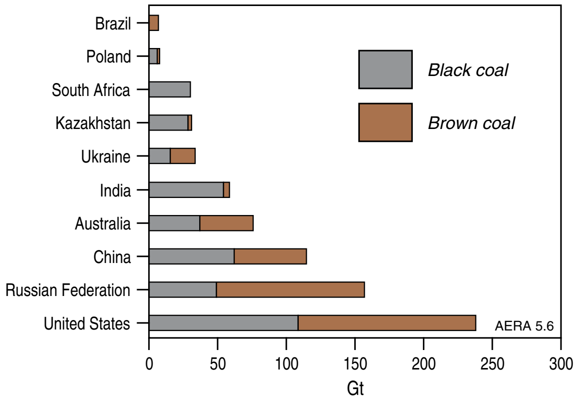

Figure 5.6 Black and brown coal reserves, major countries, 2008

Note: BP defines black coal as anthracite and bituminous coal, and brown coal as sub-bituminous and lignite

Source: BP 2009

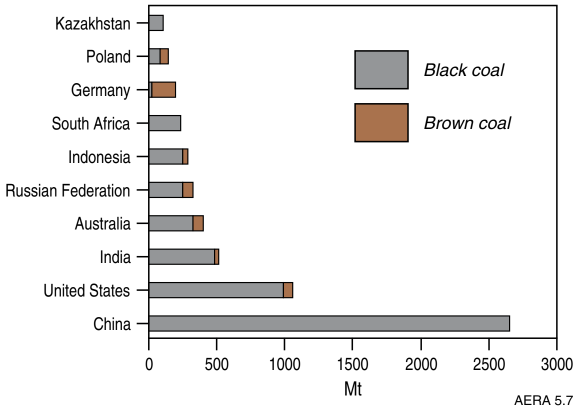

Figure 5.7 Black and brown coal production, major countries, 2008

Source: IEA 2009a

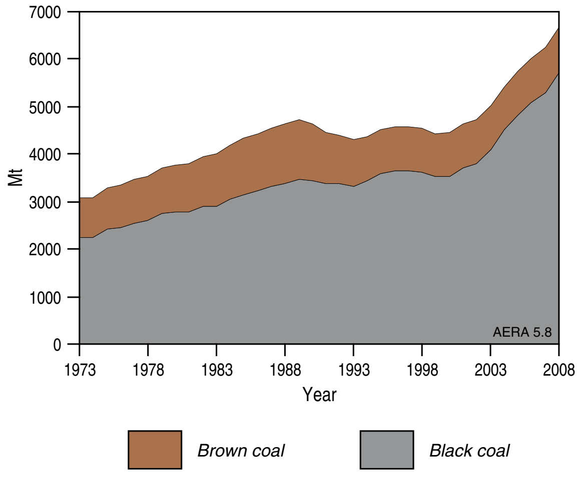

Figure 5.8 World production by coal type

Source: IEA 2009a

an average annual rate of 11 per cent since 2000 reflecting rapid expansions to its electricity generation and steel making capacity. The United States and India are also large coal consumers, accounting for around 15 per cent and 9 per cent of world consumption, respectively.

In the OECD, European coal consumption declined by a third between 1971 and 2008 as policies have encouraged the use of nuclear, gas and renewable energy fuels for electricity generation.

Electricity generation

In 2007, electricity generation in China and the United States from coal-fired power plants was 2600 TWh and 2100 TWh, respectively (figure 5.12a). In China, coal accounts for around 80 per cent of electricity generation, while it is around 50 per cent in the United States (figure 5.12b). Other countries reliant on coal for over 90 per cent of their electricity generation are South Africa and Poland. Australia has a relatively high reliance on coal-fired electricity generation, at around 75 per cent in 2007–08.

Between 2000 and 2007, world coal-fired electricity generation increased by around 38 per cent to 8200 TWh. As a result, the share of coal-fired electricity generation increased from 38 per cent to 42 per cent of total electricity generation. The principal driver was China where coal-fired electricity generation increased by 150 per cent between 2000 and 2007 (figure 5.13). Coal-fired generation capacity has also increased strongly in non-OECD Asia (excluding China) and OECD Asia Pacific (particularly Japan and the Republic of Korea).

Trade

Around 14 per cent of world coal production is traded and almost all of it is black coal. Around 90 per cent of this trade is seaborne, with a small amount of coal traded via rail or truck.

Seaborne trade in thermal coal has increased on average by around 8 per cent per year and seaborne metallurgical coal trade has increased by nearly 3 per cent per year since 2000 (ABARE 2009d).

International trade in thermal coal is effectively divided into two regional markets: the Atlantic and Pacific markets. In the Pacific market the major importers include Japan, the Republic of Korea, Taiwan and China and the major exporters are Australia, Indonesia and the Russian Federation (from ports on its east coast). In the Atlantic market, major importers are in the European Union (notably the United Kingdom, Germany and Spain), the United States and north Africa. Supply is largely sourced from Colombia, South Africa, the Russian Federation and the United States. Thermal coal is generally not traded between the Atlantic and Pacific markets

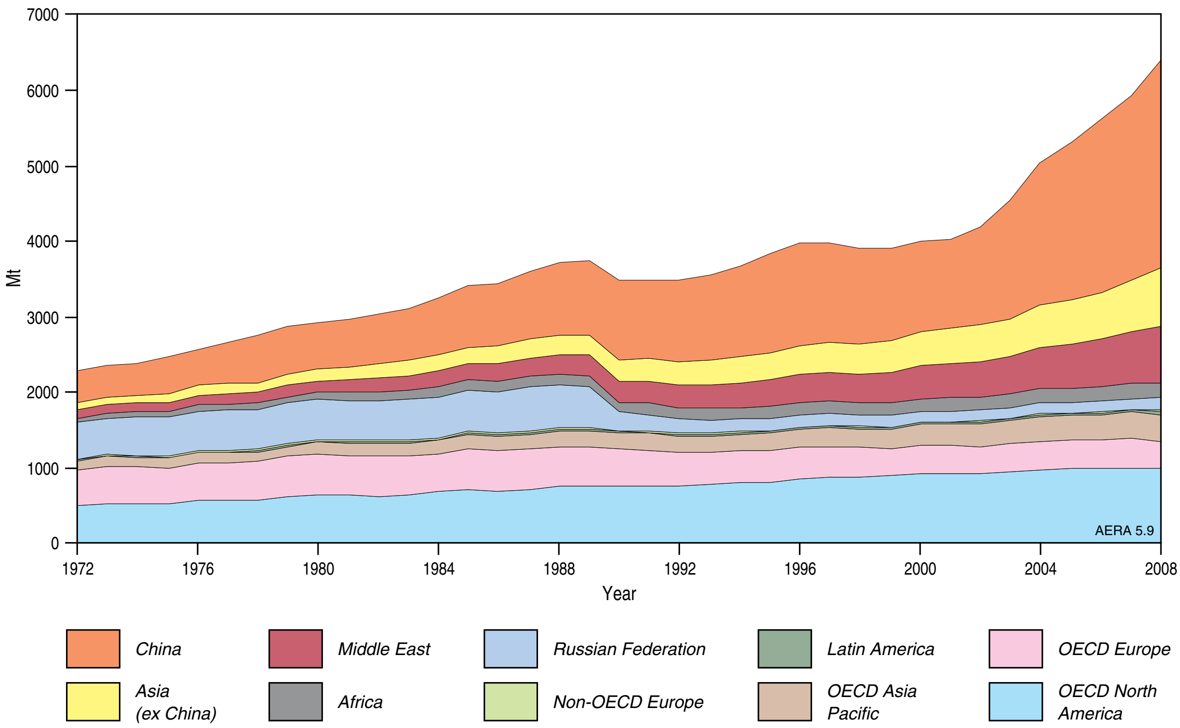

Figure 5.9 Black coal consumption by region

Note: from 1971 to 1989, the USSR is counted as the Russian Federation. Black coal is used as most regions consume only small amounts of brown coal

Source: IEA 2009a

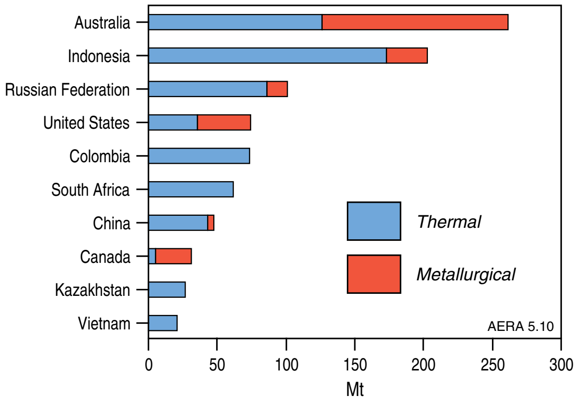

Figure 5.10 Thermal and metallurgical coal exports, major countries, 2008

Source: IEA 2009a

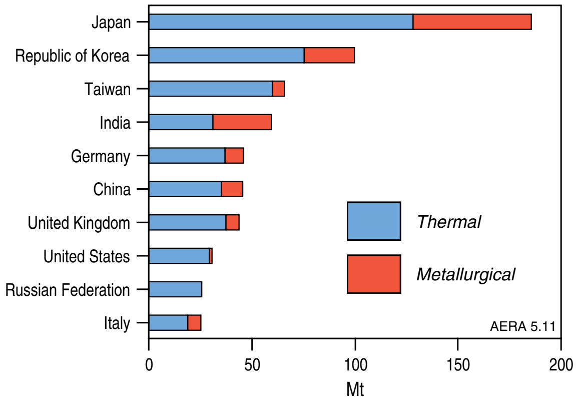

Figure 5.11 Thermal and metallurgical coal imports, major countries, 2008

Source: IEA 2009a

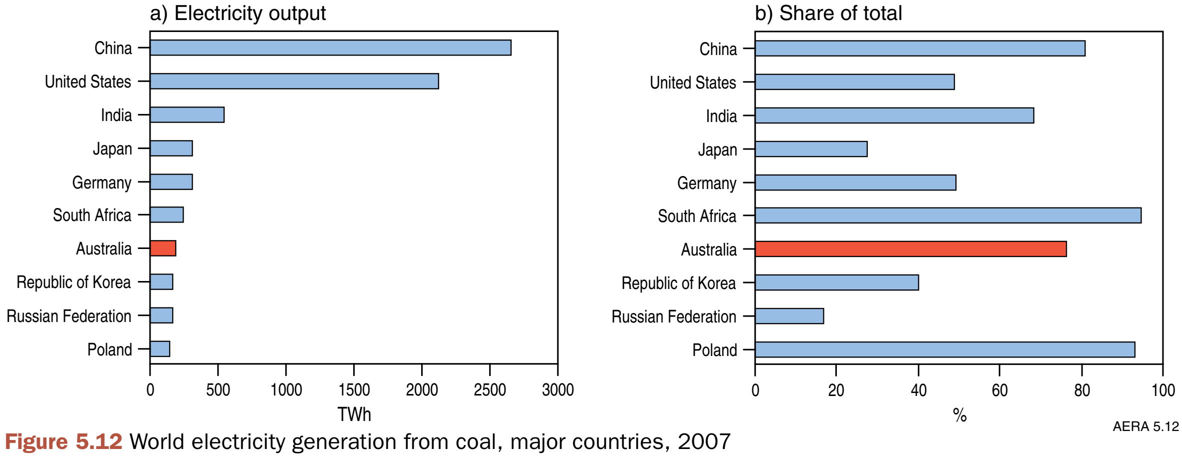

Figure 5.12 World electricity generation from coal, major countries, 2007

Source: IEA 2009b

because of the freight costs that increase with distance travelled.

Some metallurgical coal is traded across markets, most notably exports from Australia to Brazil and the European Union. This reflects Australia's position in the world metallurgical coal market, in which it accounts for almost 60 per cent of exports. The major metallurgical coal markets include Japan, the European Union, India and the Republic of Korea. After Australia, the main metallurgical coal exporters include the United States, Canada and the Russian Federation.

In 2008, Australia exported over 260 Mt of coal, making it the world's largest exporter (figure 5.10). Exports of metallurgical coal were 135 Mt and thermal coal 126 Mt. Australia is the world's largest exporter of metallurgical coal and the second largest exporter of thermal coal (ABARE 2009c). The world's largest exporter of thermal coal in 2008 was Indonesia, which exported around 173 Mt.

In 2008, the world's largest coal importer was Japan, importing 186 Mt, of which 128 Mt was thermal coal and 57 Mt was metallurgical coal (figure 5.11). Japan's imports account for around 20 per cent of world imports. The Republic of Korea and Taiwan are also large coal importers, accounting for around 11 per cent and 7 per cent, respectively, of world coal imports.

Outlook for world coal market to 2030

In its reference case, the IEA projects world coal demand to increase at an average annual rate of 1.9 per cent to 204 609 PJ in 2030 (table 5.3). Coal demand as a share of total energy demand is also projected to increase from 27 per cent in 2007 to 29 per cent in 2030. In the non-OECD, coal consumption growth is projected to be particularly strong at an average annual rate of 2.8 per cent. Much of the growth is anticipated to come from China and India where growth in electricity demand and steel production is expected to underpin coal consumption.

However, in the OECD coal demand is projected to decrease by around 5 per cent over the period 2007 to 2030. The outlook for coal consumption in the European Union is particularly weak – falling by 1 per cent per year – reflecting an increase in market

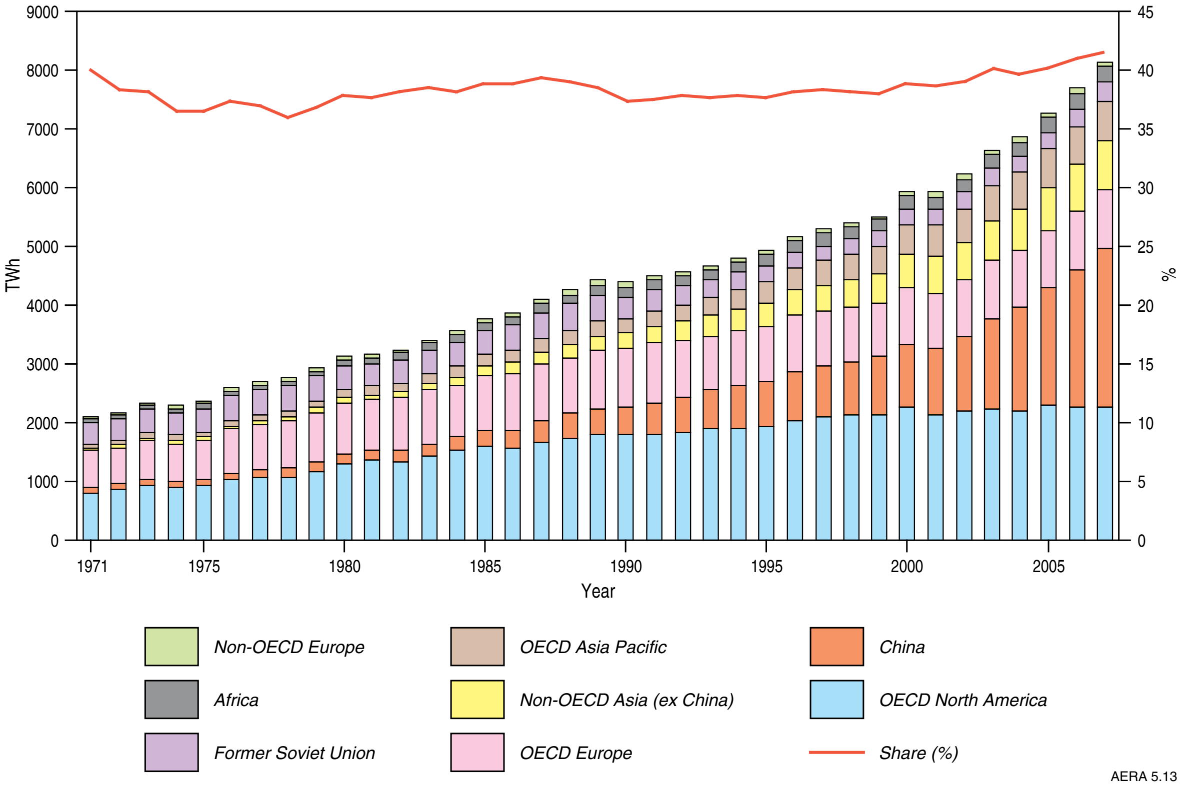

Figure 5.13 World coal-fired electricity generation and coal's share of total electricity generation by region

Source: IEA 2009b

share of gas, nuclear and renewable energy in the electricity generation sector.

Global electricity generated from coal is projected to increase at an average annual rate of 2.7 per cent to 15 259 TWh in 2030 (table 5.4). However, coal's share of total electricity generation is projected to decline in the OECD. This reflects the increased competition from gas, nuclear and renewable sources, especially with the potential advent of policies to reduce emissions. However, coal-fired electricity generation is expected to grow the fastest in developing economies, where economic growth will require the expansion of electricity generation capacity.

Table 5.3 IEA world outlook for coal demand, reference case

	unit	2007	2030
OECD	PJ	48 483	46 180
Share of total	%	36.4	22.6
Average annual growth	%	-	-0.2
Non-OECD	PJ	84 825	158 429
Share of total	%	63.6	77.4
Average annual growth	%	-	2.8
World	PJ	133 308	204 609
Share of total	%	100.0	100.0
Average annual growth	%	-	1.9

Source: IEA 2009c

Under the IEA's 450 scenario – predicated on countries taking collective action to limit global emissions to 450 ppm of CO_2 – the projected demand growth for energy is reduced from 1.5 per cent per year under the reference scenario to 0.8 per cent per year between 2007 and 2030. Demand for coal is significantly reduced compared with the reference scenario and, after reaching a plateau in 2015, coal demand is projected to decline to 2003 levels by 2030. Coal demand in 2030 would be about 47 per cent lower in 2030 than in the reference case, representing a decline of 0.9 per cent a year between 2007 and 2030 (IEA 2009c).

Table 5.4 IEA world outlook for coal electricity generation, reference case

	unit	2007	2030
OECD	TWh	3947	4241
Share of total electricity generation	%	37.2	32.1
Average annual growth	%	-	0.3
Non-OECD	TWh	4258	11 019
Share of total electricity generation	%	41.6	52.3
Average annual growth	%	-	4.2
World	TWh	8216	15 259
Share of total electricity generation	%	41.6	44.5
Average annual growth	%	-	2.7

Source: IEA 2009c

5.3 Australia's coal resources and market

5.3.1 Coal resources

Coal occurs and is mined in all Australian states. Queensland and New South Wales have the largest black coal resources and production whereas Victoria hosts the largest resources and the only production of brown coal. Black coal has been mined in New South Wales for more than 200 years, while significant production of brown coal began in Victoria in 1920s. The most important black coals range in age from Permian to Jurassic (from about 280 to 150 million years ago) but the major resources are of Permian age. Australia's major deposits of brown coal are of Tertiary age (50–15 million years).

Australia's principal black coal producing basins are the Bowen (Queensland) and Sydney (New South Wales) Basins. The Permian coal measures in the Bowen Basin outcrop or lie beneath a thin cover of younger sediments over an area of some 120 000 km². Both metallurgical and thermal coals occur in numerous coal-bearing sequences throughout the basin.

Other basins with significant coal resources in Queensland include the Permian-aged Galilee Basin which lies to the west of the Bowen Basin and covers an area of some 200 000 km². There has been no production to date but the Galilee Basin is emerging as an area of considerable exploration interest for thermal coal and is estimated to contain some 6 Gt of coal. The southern half of the Bowen Basin is overlain by the Jurassic-Cretaceous sediments of the broad intra-cratonic Surat Basin which covers an area of 270 000 km² in Queensland and New South Wales. The Surat Basin contains the Jurassic Walloon Coal Measures which are a source of thermal coal and, more recently, coal seam gas. Similarly, the Jurassic coals of the Clarence-Moreton Basin and the Triassic coals of the Ipswich Basin have provided coal for electricity generation and industrial uses in the Brisbane region and for export. Other coal basins in Queensland include: Styx (Cretaceous), Mulgildie (Jurassic), Maryborough (Cretaceous), Tarong (Triassic) and Laura (Jurassic).

The Sydney Basin is approximately 350 km long, has an average of width of 100 km, and covers some 35 000 km². The Sydney Basin is geologically contemporaneous with the Bowen Basin but, unlike the Bowen Basin, the Sydney Basin coal sequences are

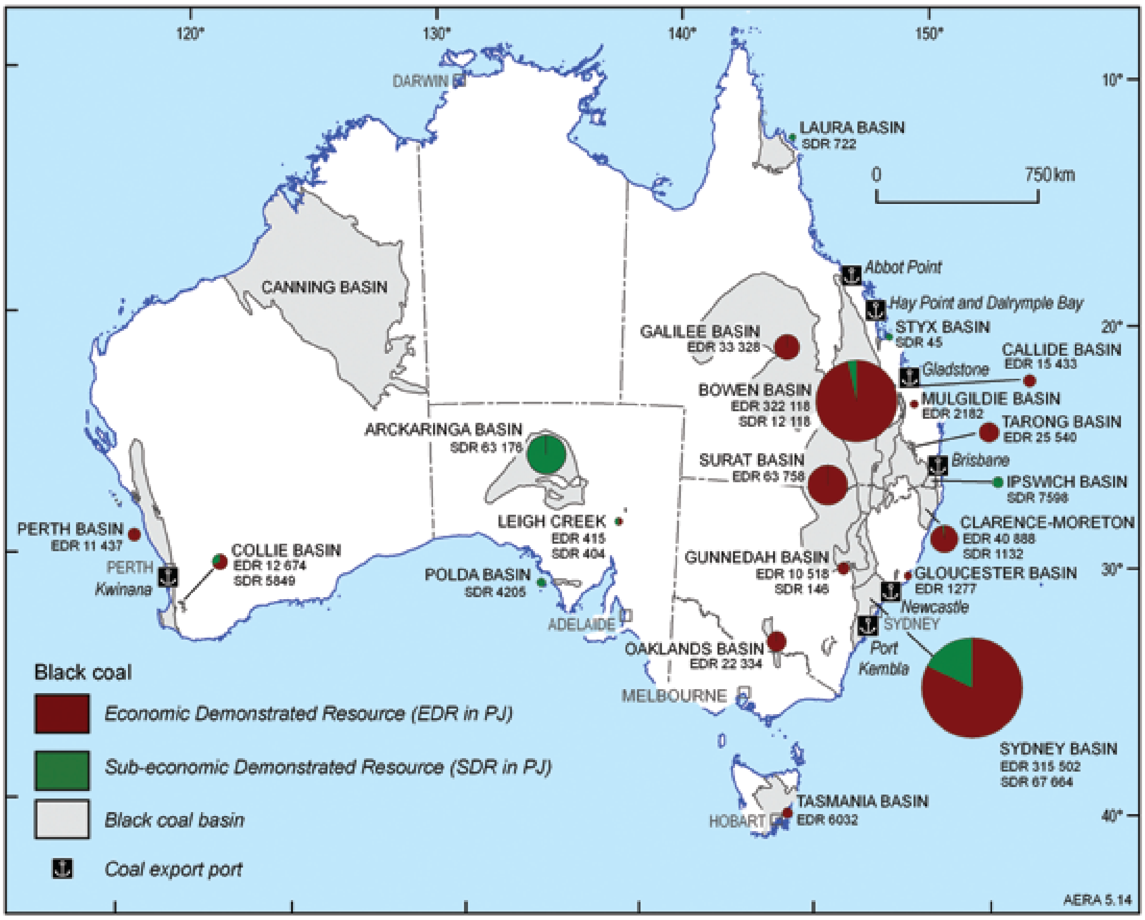

Figure 5.14 Black coal resources in Australia

Source: Geoscience Australia

overlain by a thicker and more continuously preserved cover of Triassic sediments. As a consequence, development of coal resources has concentrated on coal deposits near the basin margins where the cover is thinner. The Sydney Basin passes to the north into the Gunnedah Basin, which covers some 15 000 km^2 and comprises rocks of Permian and Triassic age and is estimated to contain more than 18 Gt of coal (both metallurgical and thermal).

The Triassic-Jurassic age coals in the Clarence-Moreton Basin in New South Wales are not mined. Thermal coal is produced from the small (3000 km^2) Gloucester Basin to the north of Newcastle. Substantial thermal coal resources are known to occur in the Permian Coorabin Coal Measures of the Oaklands Basin in the Riverina District of New South Wales.

The sub-bituminous coal measures of Permian age in the Collie Basin in Western Australia are mined for electricity generation. In South Australia, sub-bituminous Triassic coal measures at Leigh Creek are mined for electricity generation. Major resources of sub-bituminous coal of Permian age occur in the Arckaringa Basin in central South Australia. The black coal measures in the Tasmania Basin are of sub-bituminous rank and Triassic in age.

Australia's brown coal resources are of Tertiary age and are dominated by those in the Gippsland Basin in Victoria where coal is mined to generate electricity. Significant brown coal resources are also found in the Otway Basin in Victoria where they are used to produce electricity at Anglesea. Large brown coal resources are also known to occur in the Murray Basin in western Victoria and South Australia, and in the North St Vincents Basin in South Australia. Brown coal resources have been discovered in Western Australia in the Eucla Basin (e.g. Balladonia) and in the onshore part of the Bremer Basin (e.g. Scaddan). Minor brown coal resources occur in Tasmania in the Longford Basin and an occurrence of brown coal is known in Queensland at Waterpark Creek north of Yeppoon.

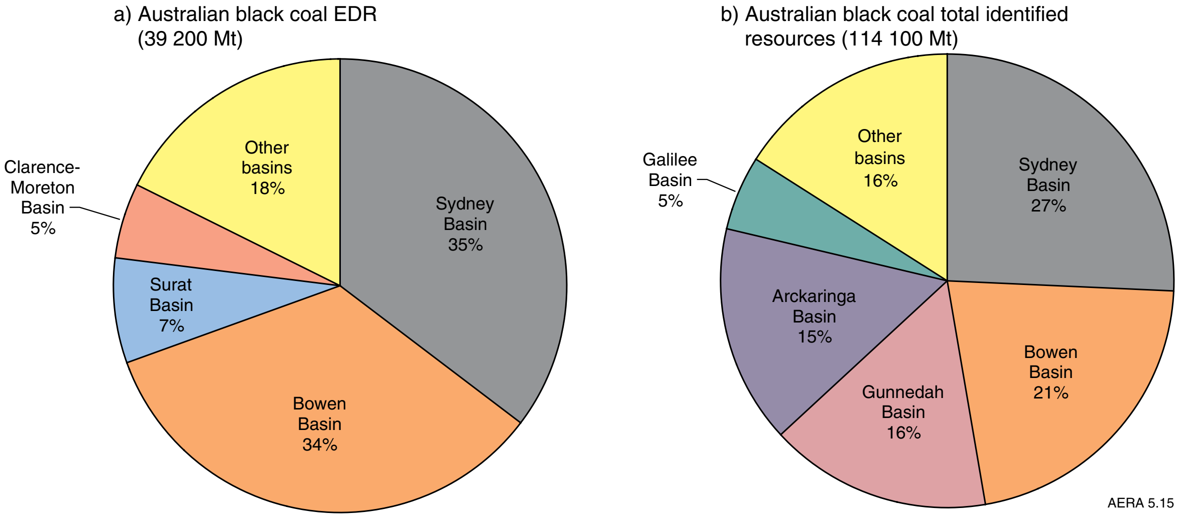

Figure 5.15 Australia's black coal resources by major basin, 2008

Source: Geoscience Australia

Table 5.5 Australia's recoverable black and brown coal resources, December 2008

Recoverable Resources	Black Coal (Mt)	Black Coal (PJ)[a]	JORC Reserves (Mt)
Economic	39 200	883 400	13 400
Sub-economic	8 300	163 100	-
Inferred	66 600	1 468 900	-
Black Coal Total	**114 100**	**2 515 400**	**13 400**
	Brown Coal (Mt)	**Brown Coal (PJ)**	**JORC Reserves[b] (Mt)**
Economic	37 200	362 000	4800
Sub-economic	55 100	534 300	
Inferred	101 800	990 300	
Brown Coal Total	**194 000**	**1 886 600**	**4800**
Coal Total	**308 100**	**4 402 000**	**18 200**

a Includes estimates where operating mines have no JORC reserves. **b** No brown coal JORC Reserves are available (Geoscience Australia estimate)

Source: Geoscience Australia 2009

Australia's coal resources are published under the McKelvey classification of Economic and Sub-economic Demonstrated Resources and Inferred Resources used by Geoscience Australia (table 5.5; Appendix D). JORC (industry) reserves are also shown to provide information on the proportion of Australia's EDR that is currently considered commercially viable by privately owned companies.

Black coal

Recoverable economic demonstrated resources (EDR) of black coal in 2008 were estimated at 39.2 Gt with Queensland (56 per cent) and New South Wales (40 per cent) having the largest shares (figure 5.14). The Sydney Basin (35 per cent) and Bowen Basin (34 per cent) contain most of Australia's recoverable EDR of coal on both a tonnage and energy basis. These world-class coal basins contain nearly half of Australia's black coal total resources and dominate production. There are also significant black coal EDR in the Surat, Galilee and Clarence-Moreton basins (figures 5.14 and 5.15). Effectively all black coal EDR is accessible.

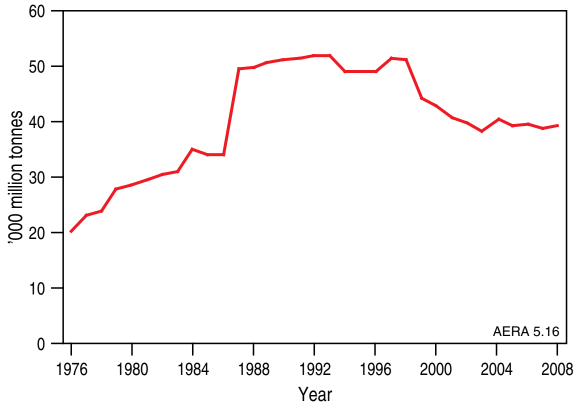

Figure 5.16 Black coal economic demonstrated resources, 1976 to 2008

Source: Geoscience Australia

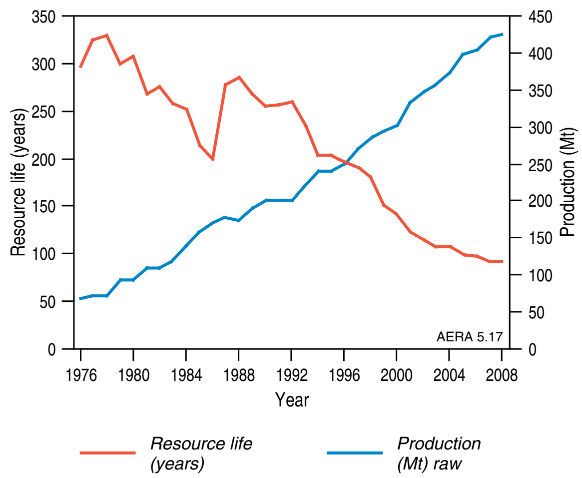

Figure 5.17 Black coal resource life and production, 1976 to 2008

Source: Geoscience Australia

The resource life of the EDR of 39.2 Gt is about 90 years at current rates of production. The black coal JORC reserves are 13.4 Gt or 34 per cent of EDR. Included in the 13.4 Gt are Geoscience Australia estimates of reserves at some operating mines for which no JORC reserves have been reported. This constituted 1.9 Gt or about 14 per cent of JORC reserves. BHP Billiton, Rio Tinto and Xstrata Coal manage about 57 per cent of JORC reserves in Australia. The resource life of the JORC reserves of 13.4 Gt is 31 years at current rates of production.

Australia also has some 8.3 Gt of sub-economic black coal resources, mostly within the Sydney and Arckaringa basins. In addition there are very substantial inferred black coal resources – about 66.6 Gt, almost double the current EDR of black coal – lying mostly in the Gunnedah, Arckaringa, Sydney, and Bowen basins (table 5.6). Renewed exploration interest in the past decade has resulted in a significant increase in inferred coal resources, notably in the Gunnedah and Galilee Basins.

Table 5.6 Recoverable black coal resources by basin as at 31 December 2008

Category	Basin	Mt	PJ
EDR	Sydney	13 800	315 500
EDR	Bowen	13 400	322 100
EDR	Surat	2900	63 800
EDR	Clarence-Moreton	2000	40 900
EDR	Galilee	1700	33 300
EDR	Other	5400	107 900
Total EDR		**39 200**	**883 400**
SDR	Sydney	3000	67 700
SDR	Bowen	500	12 100
SDR	Ipswich	340	7600
SDR	Collie	300	5800
SDR	Arckaringa	3800	63 200
SDR	Other	360	6700
Total SDR		**8300**	**163 100**
INF	Sydney	12 600	286 600
INF	Bowen	10 600	253 400
INF	Galilee	4500	89 700
INF	Gunnedah	17 700	461 300
INF	Arckaringa	13 900	233 400
INF	Other	7300	144 500
Total INF		**66 600**	**1 468 900**
Total EDR + SDR + INF		**114 100**	**2 515 400**

Source: Geoscience Australia

The changes in Australia's black coal resources with time are shown in figure 5.16. The steep increase in EDR in 1987 is due to a major reassessment of New South Wales coal resources in 1986 by the then New South Wales Department of Mineral Resources and the Joint Coal Board. The decline in EDR since 1998 results from industry re-estimating reserves and mineral resources more conservatively in order to comply with the requirements of the JORC Code as well as increased mine production.

Major increases in production over the past 40 years has seen the resource life of Australia's black coal resources fall from about 300 years to around 90 years (figure 5.17).

Brown coal

Recoverable EDR of brown coal for 2008 were estimated to be 37.2 Gt, all located in Victoria and about 93 per cent of the total EDR is in the La Trobe Valley (figure 5.18). The Gippsland Basin contains 99 per cent of the total recoverable brown coal EDR of Australia. Approximately 86 per cent of brown coal EDR is accessible. Quarantined resources include the APM Mill site that has a 50 year mining ban that commenced in 1980 and coal that is under the Morwell township and the Holey Plains State Park.

Table 5.7 Recoverable brown coal resources by basin as at 31 December 2008

Category	Basin	Mt	PJ
EDR	Gippsland	36 800	356 900
EDR	Otway	400	5100
EDR	Murray	0	0
EDR	Other	0	0
Total EDR		**37 200**	**362 000**
SDR	Gippsland	47 600	462 000
SDR	Otway	800	8900
SDR	Murray	3500	34 500
SDR	Other	3200	28 900
Total SDR		**55 100**	**534 300**
INF	Gippsland	76 400	740 900
INF	Otway	7300	76 700
INF	Murray	15 300	148 400
INF	Other	2800	24 300
Total INF		**101 800**	**990 300**
Total EDR + SDR + INF		**194 100**	**1 886 600**

Source: Geoscience Australia

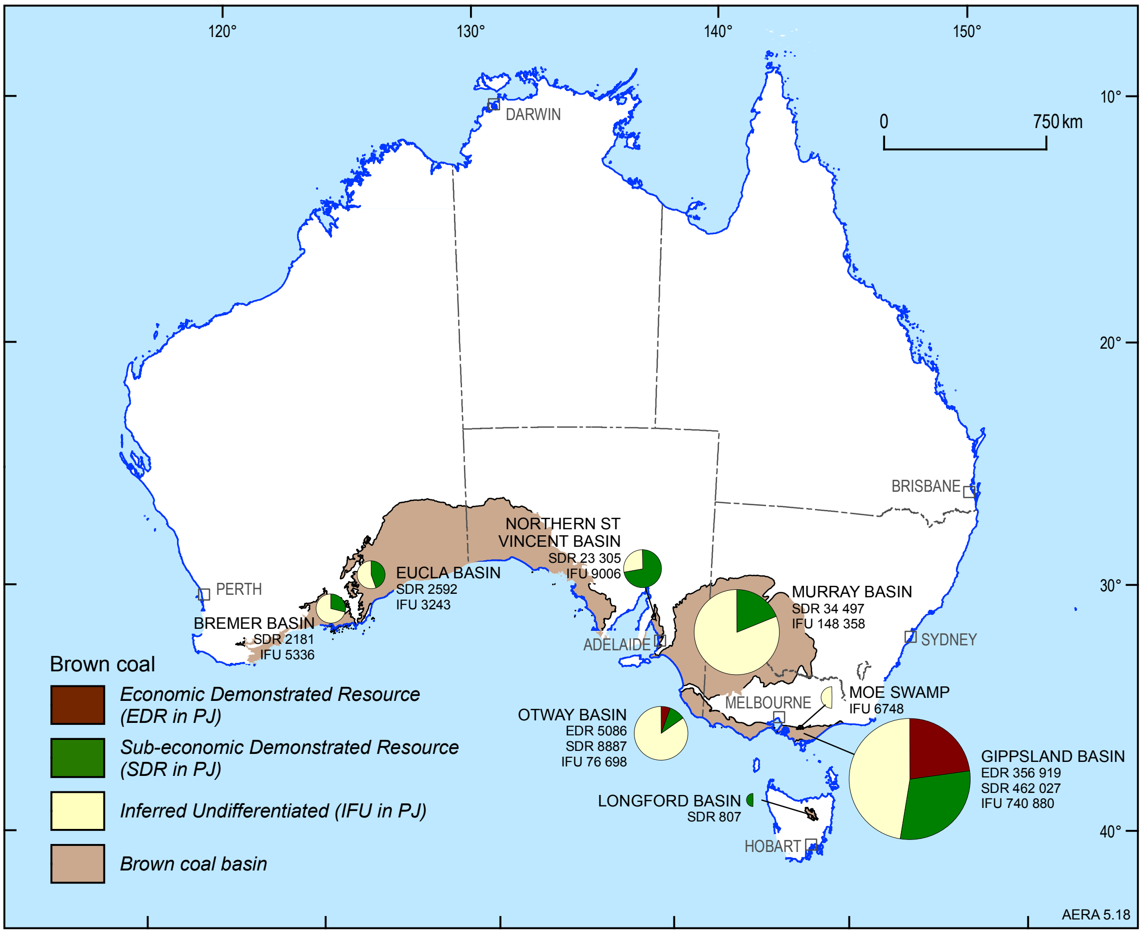

Figure 5.18 Brown coal resources in Australia

Source: Geoscience Australia

The resource life of accessible EDR of 32.2 Gt is about 490 years. JORC reserve estimates are not available for brown coal resources. Geoscience Australia estimates from published information that the reserves at operating mines are about 4.8 Gt, and have a resource life of about 70 years.

In addition to the EDR of brown coal there are larger sub-economic brown coal resources in the Gippsland Basin, and even larger inferred resources of brown coal, predominantly contained in the Gippsland, Murray and Otway basins (figure 5.18; table 5.7).

Australia's EDR of brown coal have remained relatively constant since 1976 (figure 5.19). A doubling of production over the past 40 years has resulted in a halving of the resource life to around 490 years.

Coal exploration

Australia is currently experiencing record levels of coal exploration. Data published by the Australian Bureau of Statistics (ABS 2009) show that over the past five years annual coal exploration expenditure has increased from $84.7 million to $276.3 million in 2008. The bulk of the exploration is focussed in Queensland (59 per cent) and New South Wales (34 per cent of the total) in 2008. The remaining expenditure occurred in South Australia, Western Australia, Tasmania and Victoria. In 2008 coal exploration expenditure contributed 10.6 per cent to the total mineral exploration expenditure in Australia. The last sustained period of high levels of coal exploration was during the early 1980s in response to world energy shocks and a broadly based resources boom and coincided with the major expansion of Australia's coal resources, particularly those in the Bowen Basin.

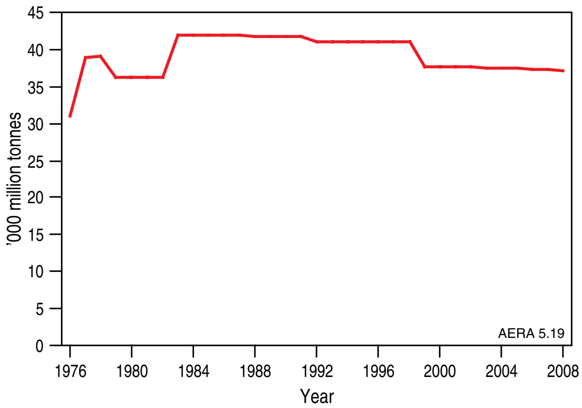

Figure 5.19 Brown coal economic demonstrated resources, 1976 to 2008

Source: Geoscience Australia

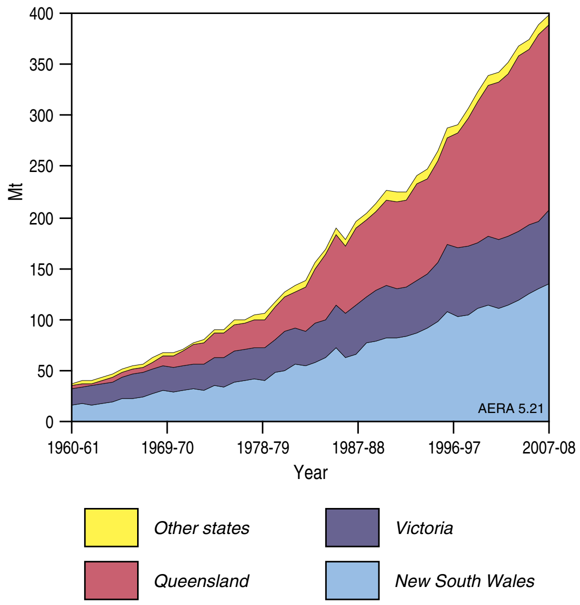

Figure 5.21 Production of saleable coal by state

Note: Victoria is brown coal and the other states black coal

Source: ABARE 2009d

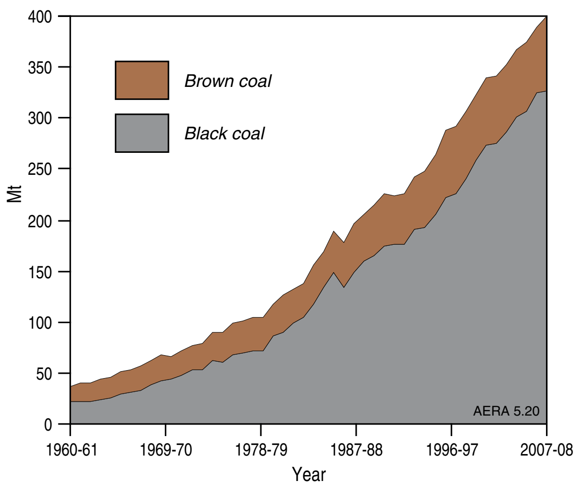

Figure 5.20 Australia's production of saleable black and brown coal

Source: ABARE 2009d

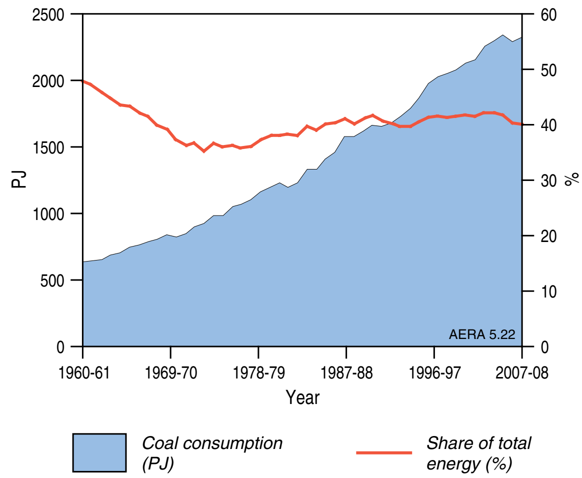

Figure 5.22 Australian coal consumption and share of total primary energy

Source: ABARE 2009a

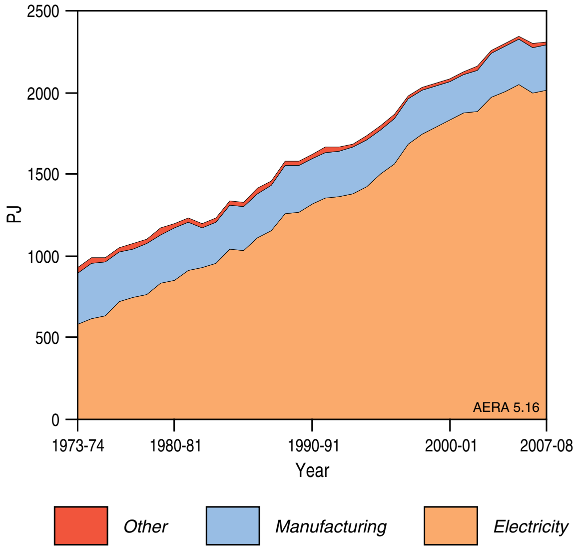

Figure 5.23 Australian coal consumption by sector

Source: ABARE 2009a

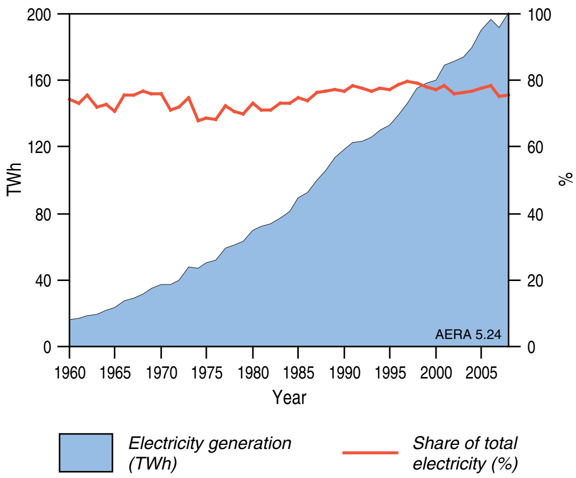

Figure 5.24 Australian use and share of coal in thermal electricity generation

Source: IEA 2009b

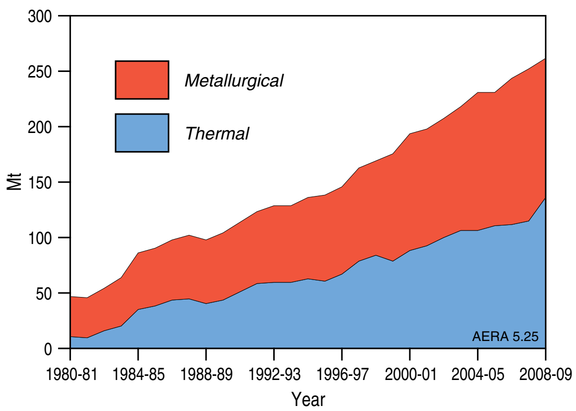

Figure 5.25 Australia's exports of thermal and metallurgical coal

Source: ABARE 2009d

5.3.2 Coal market

Production

Australia's combined production of saleable black and brown of coal is shown in figure 5.20. Raw coal production in 2007–08 was estimated to be around 487 Mt (9431 PJ) which represents an average annual increase of 5 per cent from 1960–61. Black coal accounted for 86 per cent or 421 Mt (8722 PJ). Queensland and New South Wales accounted for the majority of this production: 57 per cent and 41 per cent respectively.

Brown coal production in 2007–08 was estimated to be around 67 Mt (709 PJ), all from Victoria.

Figure 5.21 shows the breakdown of coal production by state. The majority of Queensland's coal production is in the Bowen Basin, around 150–200 km inland from the towns of Mackay and Gladstone. There are also a number of mines in the Clarence-Moreton Basin, around 50–100 km west of Brisbane, and in the Tarong, Callide and Surat Basins.

In New South Wales, the majority of coal production is in the Hunter Valley, extending 30–100 km northwest of Newcastle. There also a number of mines in the Gunnedah Basin (200 km northwest of Newcastle) and mines to the immediate south and west of Sydney. Relatively small amounts of coal are also produced in South Australia, Western Australia and Tasmania.

Primary energy consumption

In 2007–08, Australia's coal consumption was around 2292 PJ (135 Mt). Since 1960–61, Australia's coal consumption has increased at an average annual rate of 5 per cent (figure 5.22). The increase in consumption (figure 5.23) reflects increased demand for electricity associated with economic and population growth. Much of this increased electricity demand has been met through coal-fired generation.

Electricity generation

In 2007–08, around 75 per cent of Australia's electricity was generated from coal. Coal's share of electricity generation has ranged between 60 and 80 per cent since the 1960s (figure 5.24). The use of coal for electricity generation reflects its low cost relative to other fuels and the large resource base which is located close to electricity demand centres in south eastern Australia. Ready availability of low cost coal has underpinned relatively low cost electricity (by global standards) in mainland Australia.

Trade

In 2008–09, Australia exported around 65 per cent of its saleable black coal production. All brown coal production was consumed domestically. The majority of Australia's exported coal is produced in New South Wales and Queensland. Recently small amounts of coal

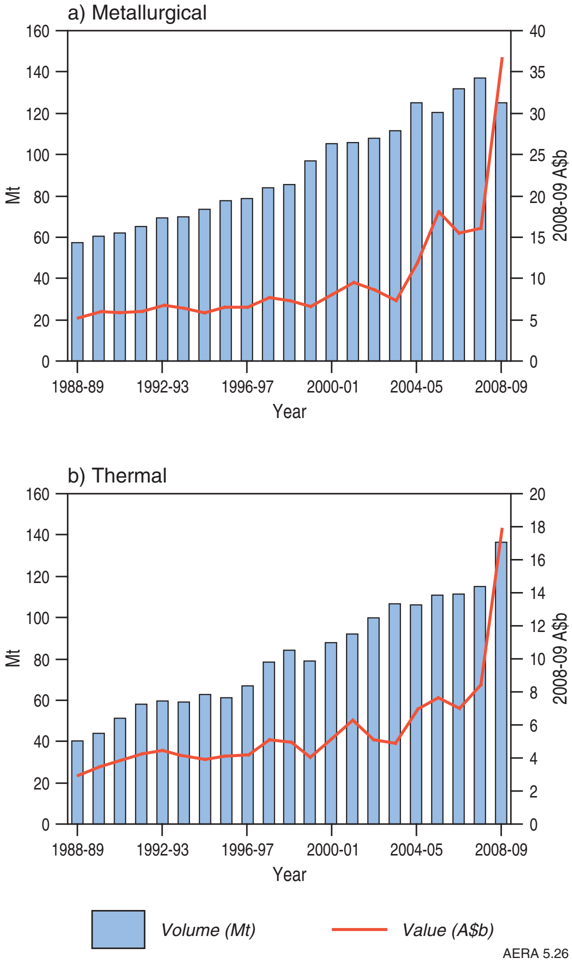

Figure 5.26 Australia's export volume and value of thermal and metallurgical coal

Source: ABARE 2009d

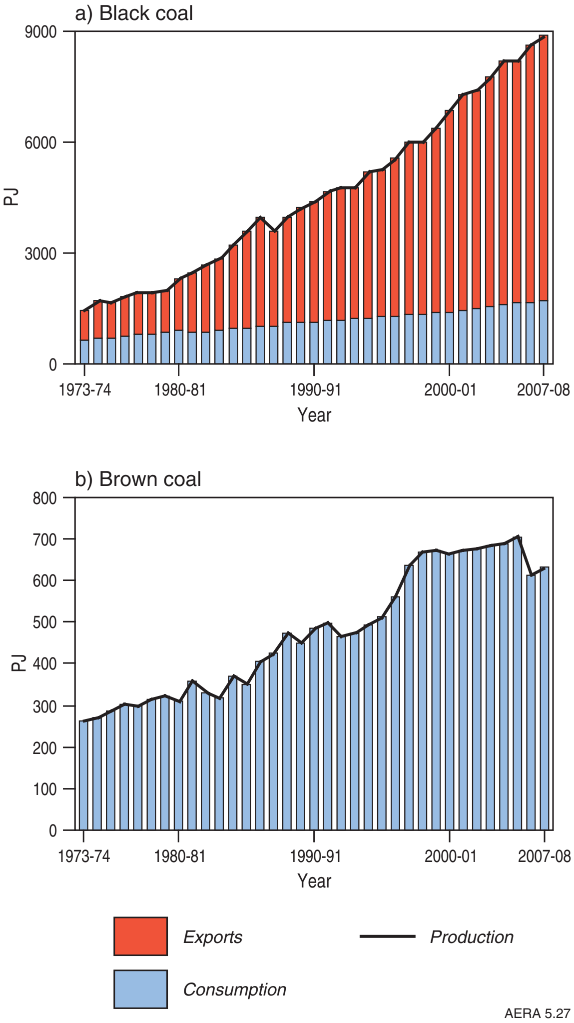

Figure 5.27 Australia's exports and consumption of black and brown coal

Source: ABARE 2009a

have been exported from Kwinana in Western Australia. Newcastle is the largest port and in 2008–09, coal exports from Newcastle totalled around 100 Mt.

In 2008–09, Australia exported around 261 Mt of coal – 135 Mt of metallurgical coal and 126 Mt of thermal coal (figure 5.25). Australia's major export markets for metallurgical coal are Japan, India, the European Union, the Republic of Korea and Taiwan. Japan, the Republic of Korea and Taiwan are Australia's major export markets for thermal coal. Coal exports have increased over the past 30 years underpinned by strong growth in demand from these major trading partners.

The value of Australia's coal exports in 2008–09 was a record $55 billion, an increase of 130 per cent from 2007–08. The value of metallurgical coal exports increased by 130 per cent to $37 billion and thermal coal exports increased 125 per cent to $18 billion (figure 5.26). The significant increase in export values, in part, reflects record contract prices for Japanese Fiscal Year (JFY) 2008 (April 2008–March 2009), when coal prices more than doubled. With contract prices for JFY 2009 having been settled at considerably lower levels, export earnings for 2009–10 are expected to recede from these record levels.

Supply-demand balance

Australia's black coal production has significantly exceeded domestic consumption and the surplus has been sold into international markets (figure 5.27a). Growing global demand for both good quality thermal and metallurgical coal has led to increased coal production and exports. Australia's substantial high quality coal resources and reputation as a country with low sovereign and security risks has encouraged important investments in the coal industry by consumers in major import markets such as Japan, the Republic of Korea, and increasingly China.

In contrast, all of Australia's brown coal production is consumed domestically (figure 5.27b). Production is

Table 5.8 Coal mining projects recently completed, as at October 2009

Project	Location	Start up	Capacity	Capital Expenditure
Lake Lindsay	Qld	2009	4 Mt coking and thermal	US$726 m
Abel underground	NSW	2008	4.5 Mt ROM semi-soft coking and thermal	$84 m
Dawson project	Qld	2008	5.7 Mt coking and thermal	$1.1 b
Glendell opencut	NSW	2008	2 Mt thermal	$123 m
Rocglen (Belmont) opencut	NSW	2008	1.5 Mt thermal	$35 m
Sonoma coal project	Qld	2008	1.8 Mt coking and 0.2 Mt thermal	$200 m
Vermont Coal Project	Qld	2008	4 Mt coking	$264 m
Ashton longwall	NSW	2007	3 Mt coking and thermal	$150 m
Boggabri opencut	NSW	2007	1.5 Mt thermal	$35 m
Curragh North	Qld	2007	2.4 Mt coking	$360 m
Ensham Central	Qld	2007	3 Mt thermal	$100 m
Isaac Plains	Qld	2007	1.6 Mt coking	$66 m
Kogan Creek opencut	Qld	2007	2.8 Mt thermal	$80 m
New Acland opencut	Qld	2007	1.5 Mt thermal	$60 m
Newpac longwall	NSW	2007	4 Mt coking	$75 m
North Wambo longwall	NSW	2007	3 Mt thermal	$101 m
Poitrel	Qld	2007	3 Mt coking	$330 m
Wilkie Creek	Qld	2007	0.6 Mt thermal	$15 m
Tarawonga opencut	NSW	2007	1.3 Mt thermal	$38 m
Wilpinjong opencut	NSW	2007	3 Mt thermal	$123 m

Source: ABARE 2009e

Table 5.9 Coal infrastructure projects recently completed, as at October 2009

Project	Location	Start up	Capacity increase	Capital Expenditure
Abbot Point Coal Terminal X21 expansion	Qld	2007	6 Mtpa (new capacity 21 Mtpa)	$116 m
Blackwater to Burngrove duplication (rail)	Qld	2007	na	$43 m
Bluff to Blackwater Duplication (rail)	Qld	2007	na	$58.5 m
Hay Point Coal Terminal Phase 2	Qld	2007	4 Mtpa (new capacity 44 Mtpa)	$70 m
Kooragang Island Coal Terminal	NSW	2007	16 Mtpa (new capacity 80 Mtpa)	$170 m
Broadlea to Wotonga duplication (rail)	Qld	2008	na	$70 m
Callemondah to RG Tanna (rail)	Qld	2008	na	$40 m
Dalyrmple Bay Coal Terminal 7X expansion Phase 1	Qld	2008	8 Mtpa (new capacity 68 Mtpa)	$530 m
RG Tanna Coal Terminal expansion	Qld	2008	28 Mtpa (new capacity 68 Mtpa)	$800 m
Abbot Point Coal Terminal X25 expansion	Qld	2009	na	$95 m
Dalrymple Bay Coal Terminal 7X expansion project Phase 2/3	Qld	2009	17 Mtpa (new capacity 85 Mtpa)	$679 m
Grantleigh to Tunnel (rail)	Qld	2009	na	$49 m
Jilalan Rail Yard Upgrade	Qld	2009	na	$500 m
Stanwell -Wycarbah upgrade (rail)	Qld	2009	na	$72 m
Vermont Rail Spur and Balloon Loop	Qld	2009	na	$70 m

Source: ABARE 2009e

closely matched to consumption at adjacent power stations, a link sometimes referred to as 'mine-mouth power generation'. After growing strongly during the early 1990s and then levelling off in the first half of the 2000s, brown coal production has fallen in recent years. The decline reflects competition from other fuels in Victoria, particularly gas.

The majority of Australia's coal consumption occurs in New South Wales, Queensland and Victoria (figure 5.28). In terms of tonnage, Victoria is responsible for just under half of Australia's coal consumption. However, in energy terms, New South Wales and Queensland account for nearly 70 per cent. The difference between weight and energy content across the states reflects the low rank of coal used in Victoria, where a tonne of coal contains around a third of the energy content of that consumed in New South Wales and Queensland.

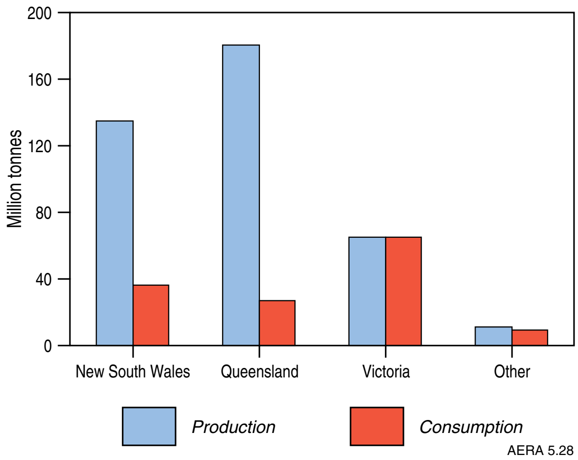

Figure 5.28 Production and consumption of saleable coal by state, 2007–08

Note: Victoria produces and consumes only brown coal. All other states produce and consume black coal

Source: ABARE 2009d

Major development projects recently completed

The recent completion of numerous coal mine and infrastructure projects has underpinned the expansion of Australia's coal exports. Over the past three years, 20 mine projects have been completed with a production capacity of 54 Mt and an estimated capital expenditure of over $4.3 billion (table 5.8).

Coal infrastructure projects (essentially upgrades and expansions of port and rail facilities) completed over the past three years are shown in table 5.9. These projects, at an estimated capital cost of $3.4 billion, have increased rail and port capacity by around 80 Mt per year. The expansion in mine and infrastructure capacity has been necessary to support the increase of Australia's coal exports from 233 Mt in 2005 to an estimated 260 Mt in 2009.

5.4 Outlook to 2030 for Australia's resources and market

The key messages from the outlook to 2030 are:

- Australia's coal production is projected to increase at an average annual rate of 1.8 per cent to about 13 875 PJ in 2029–30.
- Growth will be in increased exports which are projected to increase by 2.4 per cent per year to 2029–30.
- Domestic coal consumption is projected to decrease at an average annual rate of 0.8 per cent to 1763 PJ in 2029–30.
- Coal's share of domestic electricity generation is projected to decline from around 75 per cent in 2007–08 to 43 per cent in 2029–30.
- Gas and renewable energy sources (especially wind) are projected to make a greater contribution to electricity generation.
- The development of cost-effective lower emissions coal technologies, notably carbon capture and storage, will be critical to maintaining coal's position in electricity generation.
- Future growth of Australia's coal production and exports depend on global economic growth, carbon reduction policies, coal prices, adequacy of coal handling infrastructure, and local water and environmental issues.

5.4.1 Key factors influencing the outlook

The key factors influencing the future development of Australia's coal industry include:

- Global economic growth and demand for coal are projected to maintain coal's position as the fastest-growing energy source except for some renewable energy sources. Under the IEA reference scenario coal is projected to grow at an annual rate of 1.9 per cent to 2030 (IEA 2009c).
- Most (97 per cent) of the projected growth in demand is expected to come from non-OECD countries, mostly in Asia. More than 75 per cent of the increase is expected to be for thermal coal for power generation.
- Australia's ability to meet the increased demand for coal exports will require matching expansion of coal infrastructure, including rail and port (coal loading) capacity.
- Global growth in coal demand is likely to be influenced by global policies on carbon emissions.
- Domestic coal consumption and coal's share of electricity generation is projected to decline from its current very high level (75 per cent) as a consequence of policies to decrease national

greenhouse emissions, including the Renewable Energy Target and emission reduction targets that will encourage growth of renewable and other lower-emissions energy sources.

- Coal-fired electricity generation will be replaced by gas and, to a lesser extent, renewable energy.
- The future position of coal in electricity generation will be strongly influenced by the cost of electricity production from renewable energy sources compared with the cost of new low-emission coal technologies.
- Government and industry initiatives such as the Global Carbon Capture Storage Institute, the Carbon Capture Storage Flagships program, and the Coal21 program are likely to play an important role in the development and commercial deployment of new low-emission technologies in the outlook period.

BOX 5.1 EVOLUTION OF FLEXIBLE PRICING IN COAL MARKETS

Historically, seaborne trade of thermal coal has operated under long-term contracts which provide security for both suppliers and consumers. Contract terms defined the annual quantities to be purchased, including buyer and seller options as well as fixed prices for each year. Contracts usually contained a provision for price changes proportionate to changes in input cost indices. By the 1990s, a trend toward long-term contracts with annual price review became more common. These new contract arrangements allowed prices to be revised through annual negotiation of a benchmark price or through the use of spot price indices. The shift toward provisions for an annual price change in coal contracts reflected coal suppliers' and consumers' preferences for security while also ensuring prices reflected market fundamentals.

As trade in thermal coal has increased over the past 30 years, so has the proportion of trade occurring on spot markets. In 1990, Australian thermal coal sold on spot markets is estimated to have accounted for around 17 per cent of total trade. By 2007, this proportion is estimated to have increased to 30 per cent. Although long-term contracts still play a major role in the thermal coal market, spot sales have increased in importance.

Thermal coal sold on spot markets is subject to contracts which have a similar content to long-term contracts but cover a much shorter timeframe. Similar to long-term contracts, spot contracts specify agreement on each party's rights and obligations in the loading, travel, delivery, testing, weighing and rejection processes. Spot sales may be for a single cargo, part cargoes or for a series of cargoes. Spot coal transactions can occur in a variety of forums including established trading platforms such as globalCOAL, through traders or between producers and consumers.

Trading of coal as a commodity on spot markets has been further enhanced by the introduction of a number of coal indices that define and standardise provenance, quality, place of delivery as well as other conditions. The Barlow Jonker Index (BJI), the McCloskey Newcastle FOB and the globalCOAL index are examples of major indicators of the spot market price in the Asia Pacific market.

A significant change to the thermal coal market occurred in 2000 with the deregulation of the European electricity market. Deregulation removed the past certainty afforded by fixed coal and electricity prices and introduced competition between power generators for market share, resulting in volatility in both electricity and thermal coal prices. As a consequence, EU power generators have shifted their coal purchases from fixed long-term contracts to a spot basis.

The majority of seaborne metallurgical coal imports to Japan, the Republic of Korea and the European Union, still occur under long term contracts with annual price negotiations. The move towards flexible pricing has been much slower compared with changes in the thermal coal market. This is a result of two factors. Firstly, steel mills in Japan and the European Union place significant value on sourcing coal from particular mines, which limits their ability to purchase large proportions of coal requirements from the spot market. In turn this limits the size of the coking coal spot market which makes calculating an accurate price index more complicated. The preference of a number of Japanese and European steel mills to purchase coal from specific mines reflects the set up of blast furnaces which are designed to burn a very specific blend. Secondly, a number of steel mills receive annually fixed prices for their steel and hence prefer the stability of fixed input prices.

Over the next 20 years, Chinese and Indian steel mills are expected to increase their share of metallurgical coal imports. Generally, Chinese and Indian steel mills have greater flexibility in the coal blend they can use and hence would be more willing to purchase a coal via a spot or tender process. In China, variations in domestic metallurgical coal production mean that import requirements may change from year to year making it difficult for Chinese steel mills to commit to large tonnage, long term agreements. These factors may support an increase in metallurgical coal spot trade which in turn could increase the liquidity of a spot market and enable the development of metallurgical coal spot indices.

Source: Metal Bulletin 2008; Ekawan et al. 2006

Global growth and demand for coal

In the IEA reference scenario, world electricity demand is expected to grow at an annual rate of 2.4 per cent to 2030 and underpin strong demand for coal, maintaining its position as the fastest-growing energy source except for some renewable energy sources. Coal demand is expected to grow at an annual rate of 1.9 per cent in the period to 2030. Most (97 per cent) of the projected growth in demand is expected to come from non-OECD countries, notably those in Asia. Coal consumption in OECD countries is projected to fall at an annual rate of 0.2 per cent to 2030, continuing a long-term decline in the OECD share of global coal consumption. More than 75 per cent of the increase in global coal consumption is expected to be for thermal coal for power generation with the bulk of demand growth from China and India (IEA 2009c).

In the IEA's 450 scenario global coal demand declines by 0.9 per cent a year to 2030 and is 47 per cent lower in 2030 than under the reference scenario (IEA 2009c). This reduced global coal demand is expected to flow through to reduced production by exporting countries with almost three-quarters of the reduction in production borne by non-OECD countries. Global coal trade is expected to continue to grow even under the 450 scenario but is projected to be 53 per cent below the reference scenario. China is expected to account for more than half of the projected reduction in coal demand as it diversifies electricity generation away from coal. India's net coal imports are projected to double by 2020 compared with 2007, although this level of imports is down almost 60 per cent compared with the reference scenario. Australia is projected to remain the world's largest coal exporter with exports equivalent to 2005 volumes (IEA 2009c).

This strong demand for energy in the IEA's reference case from developing Asian economies, notably China and India, over the next 20 years will create significant scope for Australia to increase its coal exports. In addition, it is assumed that Australia will maintain its share of exports into traditional markets such as Japan and the Republic of Korea. Over the next 20 years, there is the potential for Australia's coal exports to exceed 450 Mt per year, from around 260 Mt in 2008–09. This potential growth includes both thermal and metallurgical coal underpinned by growing import demand throughout developing Asian economies, including China, India, Vietnam and other ASEAN countries. The common thread through all of these economies are the plans to substantially increase electricity generation and steel production capacity as their economies grow. A significant proportion of the planned electricity generation will be coal-fired, reflecting its competitiveness compared with other fuels, its reliability and its wide geographic availability.

Much of the coal required to support new electricity generation capacity is expected to be imported, even in countries that have indigenous coal deposits. This applies particularly in China, India and Vietnam, and reflects the faster rate of consumption growth compared with production growth. China has substantial coal reserves of widely varying quality but many of these have high production or transport costs because of the distance between production and consumption locations. India also has large coal reserves but most of these are located in the centre of the country, whereas a number of planned power stations will be sited along the coastal demand centres. The combination of high internal transport costs coupled with the lower quality of India's coal reserves is expected to underpin its future import growth.

Like thermal coal, increased import demand for metallurgical coal in China will reflect the cost competitiveness of imports. India has very few metallurgical coal reserves and is almost totally reliant on imports. Increased Indian steel production is likely to be based on increased coal imports.

Australia is well situated geographically to capitalise on increased coal demand from Asia. However, there are a number of other countries that also have the potential to increase exports to meet the growth in demand from developing countries. In the Pacific market, where the majority of Australia's coal is exported, other suppliers with growth potential include Indonesia, Mongolia and the Russian Federation (from eastern ports).

Indonesia has been able to increase its exports very rapidly since 2004, in response to growing demand from Asia and bottlenecks within the Australian supply chain that limited export growth. Part of the reason that Indonesia's exports have been able to grow so quickly is that much of the coal is transported from mines to export ships via water. Coal is transported domestically via barges, which load directly onto ocean going vessels. This avoids the long lead times and costs associated with building land-based transport such as railways and coal loading terminals. Indonesian government policies requiring diversification of its domestic energy mix away from the current dependence on oil, as well as general demand growth in the Indonesian economy, may see growth in domestic consumption of coal. However, given the size of Indonesia's coal reserves and the relative ease with which coal can be transported from mines to markets, Indonesia's coal exports seem likely to expand over the next two decades.

In 2008, Mongolia exported around 10 million tonnes of coal, all of which was to China. Mongolia has very large thermal and metallurgical coal deposits which the government aims to develop. For example, the Tavan Tolgoi deposit is estimated to contain reserves of up to 6 Gt, of which 2 Gt could be metallurgical coal, making it one of the largest undeveloped coal deposits in the world. The development of these resources faces a number of challenges including lack of infrastructure, remote location, harsh winter climate, and Mongolia's landlocked position. Despite the challenges, there is a strong likelihood that Mongolia's coal industry will develop and expand with a large proportion of coal production, at least initially, being exported into northern and western China.

Other countries which also have the potential to significantly increase coal exports are Colombia and South Africa. In the five years to 2008, Colombia's coal exports increased by around one third to 68 Mt. The strong growth reflects Colombia's production of high energy, low sulphur coal, which is exported to the United States and the European Union. Over the long term, Colombia's exports are projected to continue growing, reflecting growing demand in the United States (the low sulphur Colombian coal is blended with the higher sulphur domestic coal) and the European Union where domestic production is expected to continue to decline. Colombia's exports will be underpinned by large reserves and relatively low production costs.

South Africa's coal exports could also increase over the next 20 years. However, there is some uncertainty as to the extent of any growth given that South Africa's coal export growth over the past five years has been constrained by infrastructure bottlenecks. Expansions to infrastructure are expected to be in place from 2010 enabling export growth in the short and medium term. Over the longer term, increased domestic demand for coal associated with increased electricity generation capacity could limit potential export growth.

Strong demand for coal over the past five years has resulted in substantial increases in coal prices (see Box 5.1 for explanation of coal prices). From 1998

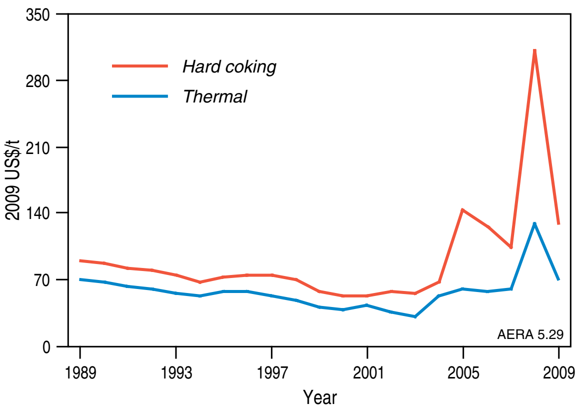

Figure 5.29 Australia-Japan coal contract prices

Source: ABARE 2009d

to 2003, thermal coal contract prices, in real terms (US$2008–09), were between US$32–52 per tonne (figure 5.29). Hard coking coal contract prices were settled around US$50–70 per tonne. This compares with the past four years when thermal coal prices have been settled above US$50 per tonne, peaking at US$125 per tonne in JFY 2008 and metallurgical coal prices being set above US$100 per tonne, including US$300 per tonne in JFY 2008.

Over the outlook period, strong demand for coal is expected to keep average coal prices within the range of prices seen over the past four years. That is, above US$60 a tonne for thermal coal and above US$110 a tonne for metallurgical coal. The higher coal prices, relative to the early part of this decade and the 1990s, reflect in addition to the strong and increasing demand, rising production costs in major coal exporting countries. For example, in Australia and Indonesia, production costs are expected to increase as coal is extracted from deeper seams, while transport costs could increase as new mines are located further inland, increasing the costs of delivering coal to export points.

In summary, projected demand for coal over the next 20 years creates significant opportunity for growth of Australian coal production and exports. However, the Australian coal industry will face a number of challenges in growing to capitalise on the opportunity. The most significant of these – access to substantial but undeveloped deposits and potential infrastructure constraints on exports – are considered in more detail later in this chapter.

Australia has a substantial coal resource base

Australia has 6 per cent of the world's recoverable EDR of black coal, ranking sixth behind the United States, the Russian Federation, China, India and South Africa. Australia also has the largest share of the world's recoverable economic resources of brown coal (about 25 per cent). Australia ranks fourth in the world in terms of combined recoverable economic coal resources. Australia's total coal resources are substantially larger than this with total identified resources of black coal being around 114 Gt and brown coal resources of 194 Gt. However, the full extent of Australia's very large coal resource base is not known: potential resources have not been assessed because the existing identified resource base is so large.

The resource potential of coal is probably in excess of one trillion tonnes. There are over 25 sedimentary basins with identified resources or coal occurrences and there are areas within these basins that need further exploration. Significant potential also exists in poorly explored basins across the continent (table 5.10).

Table 5.10 Australia's coal resource potential

Basin	Age (million years)	Potential (Gt)
Pedirka	Permo-Carboniferous (350–225)	600 to 1300 (above 1000 m)
Cooper	Permian (270–225)	+100 (1100–1600 m)
Canning	Permian (270–225)	30 to 36
Galilee	Permian (270–225)	Significant
Arckaringa	Permian (270–225)	Significant
Sydney	Permian (270–225)	Significant
Gunnedah	Permian (270–225)	Significant
Gippsland	Tertiary (70–10)	Significant
Murray	Tertiary (70–10)	Significant

Source: Geoscience Australia

The Pedirka, Cooper and Canning basins are all considered prospective for black coal. Given the high quality of coals and proximity to infrastructure in the major east coast basins, the search for coal in these basins has been of low priority.

Strong demand for coal in recent years has stimulated record levels of coal exploration. Although the focus continues to be in the established producing basins, there has been renewed interest in coal resources across the continent which has highlighted Australia's potential for further growth in the resource base.

Coal-bearing sediments extend across vast areas of the continent. This wide geographic spread reflects the variety of conditions under which coal was formed, ranging from tectonically active basin flanks and troughs, such as the Bowen and Sydney basins, to the stable interior basement areas such as the Galilee and Cooper basins.

The potential for building on the known resources can be considered in two categories: (1) discovery of new resources in coal basins with identified resources and (2) discovery of new resources in poorly explored basins. Most producing coal basins have potential for discovery of further resources. Basins with identified resources and significant potential for growth in resources include the Sydney, Gunnedah and Galilee basins.

The current total identified in-situ resources of over 50 Gt in the Sydney Basin cover an area which represents only a small part of the basin's extent. There is significant potential for additional resources at depth, as well as outside the current mining operations and in areas away from identified deposits. It should be noted, however, that although the potential coal resource within the Sydney Basin is significant there are major impediments to potential future use. These include large areas of the basin being covered by national parks, urban development, infrastructure, stored bodies of water, and prime agricultural land.

The Gunnedah Basin is estimated to contain more than 18 Gt of coal and recent regional exploration has identified substantial resources at depths of less than 300 m. Development of some of these resources will require resolution of competing land use issues and the challenge of new infrastructure requirements.

The Galilee Basin has potential for future discoveries of coal resources. Indicative of the potential of this under-explored basin is the fact that since early 2008 close to 7 Gt of in-situ coal resources have been added to Australia's identified resources. Exploration is continuing in the basin and additional resources are likely to be found. Development of new resources in the Galilee Basin will require extension and further development of infrastructure.

Infrastructure for new coal developments

Infrastructure is an essential component of the supply chain that links mines to the vessels that transport coal to export markets. In Australia, almost all of the coal is transported via rail from mine sites to ports. Expansion of Australia's coal exports to meet the anticipated demand over the next two decades will require alignment of infrastructure capacity with production capacity (see below). Over the past five years both rail and port infrastructure has been upgraded and capacity expanded (table 5.9). The significant number of new coal projects currently under construction or committed (tables 5.11 and 5.12) are supported by a significant number of planned infrastructure projects, including both expansion of capacity at existing facilities and new facilities that will help meet projected export demand over the next decade (tables 5.13 and 5.14).

In the Bowen Basin, rail infrastructure is well established and additional capacity is being created by expanding existing assets. New rail links will be required to unlock the potential of undeveloped coal basins such as the Galilee and, to a lesser extent, the Surat Basin. For example, Waratah Coal is proposing to construct a 490 km rail line from its proposed mine near Alpha in the Galilee Basin to Abbot Point. Large scale coal production in the Surat Basin will be possible once the Surat Basin Rail has been constructed – a 200 km rail link between Wandoan and Banana. Construction of rail links will be capital intensive. For example, Waratah Coal has estimated its 490 km rail link could cost around US$1.7 billion: this is in addition to a new coal terminal which could cost around US$1 billion.

In the Hunter Valley, frameworks are in place to increase the coal handling capacity of the rail and port networks and provide long term capacity coordination for the Hunter Valley operations by aligning the capacity of coal loading terminals with rail capacity and production. In the short term, port capacity will be increased by completion of stage 1 of the Newcastle Coal Infrastructure Group (NCIG) terminal (30 Mt per year) (ABARE 2009e). Further expansions over the medium term include 27 Mt per year stage 4 expansion of the Kooragang Island Terminal and the 30 Mt per year second stage of the NCIG terminal. These expansions, when complete would give the Port of Newcastle a capacity of over 200 Mt per year. The proposed increase in port capacity is supported by expansions of the rail network as shown in table 5.13. The future capacity expansions are in addition to recent expansions outlined in table 5.9.

In the first half of 2009, Queensland's port capacity was expanded by around 25 Mt a year following the completion of expansions to the Abbot Point, Brisbane and Dalrymple Bay coal terminals. A further 25 Mt a year expansion of the Abbot Point coal terminal is under construction and scheduled for completion in 2011. There are also several rail projects under construction in New South Wales and Queensland as of October 2009.

In addition to the above mentioned projects, there are 18 infrastructure projects that are at a planning stage, which will significantly increase capacity over the next 20 years. If completed as scheduled, Australia's infrastructure capacity in 2020 could increase to 642 Mt a year (table 5.14), compared with around 350 Mt in 2009.

New low emissions coal technologies – key to maintaining coal's competitiveness in electricity generation

Technological advances will play an important role in ensuring coal can continue to be consumed around the world in a manner that meets economic and environmental objectives. These advances are aimed at increasing the efficiency (amount of energy generated per unit of coal) and reducing greenhouse emissions. These low emissions coal technologies – also referred to as *clean coal technologies* – include dewatering lower rank coals (brown coals) to improve the calorific quality (increasing efficiency), treating flue gases, gasification (conversion of coal to gas, box 5.5), and technologies to capture and store carbon dioxide (CO_2).

Development of the new low emissions coal technologies is especially important for Australian electricity generation which is overwhelmingly based on coal-fired power stations. Most coal-fired power stations in Australia (and globally) are based on combustion of pulverised coal (PC) in boilers to generate superheated steam that drives steam turbines to generate electricity. The heat and pressure of the steam determines the relative efficiency of the plant. Efficiencies vary from 20 to more than 40 per cent, depending on the thermal content of the coal used and specific design of the power plant. New generation thermal coal plants are being developed and deployed based on the enhanced efficiency and lower emissions achieved by increasing the temperatures and pressures in the steam turbines – from subcritical to supercritical conditions of temperature and pressure. Efficiency increases to above 40 per cent and emissions fall from around 1000–1400 kg of CO_2 per MWh to less

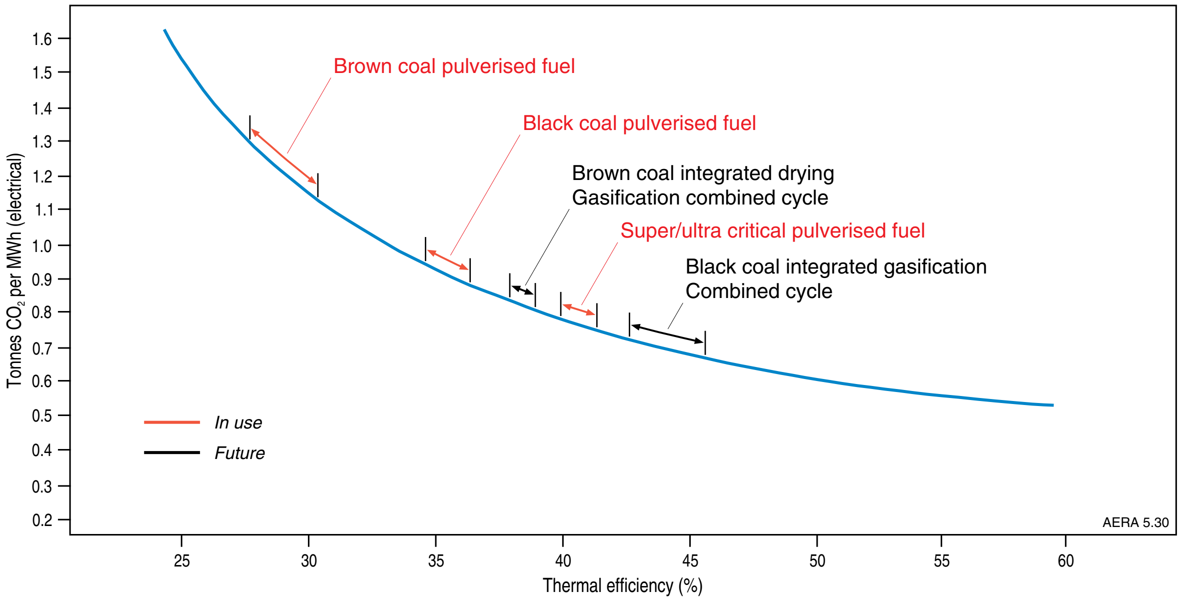

Figure 5.30 Thermal efficiencies and carbon dioxide emissions from various coal-fired power generation technologies (without CCS). Technologies in red indicate those current in use, whereas those in black are still to be deployed

Source: CSIRO 2009

than 800 kg CO_2 per MWh with the use of super and ultra-supercritical plants (figure 5.30). The ultra-supercritical pulverised coal boilers can potentially significantly increase efficiency (to over 45 per cent) and markedly reduce (by up to 40–50 per cent) CO_2 emissions to around 700–750 kg CO_2/MWh (CSIRO 2009). Direct injection plants with even higher thermal efficiencies through removal of impurities in coal and using coal-water mixtures or direct carbon fuel cells are also being developed.

Most new coal fired plants use supercritical pulverised coal technology and achieve efficiencies of 40 per cent or more and around 20 per cent reductions of CO_2 per MWh compared with the older sub-critical plants. The first ultra-supercritical pulverised coal plants with capacities of up to 1000 MW have begun to be deployed in a number of countries including China, Germany and the United States. There is continuing research and

BOX 5.2 ENHANCING THE EFFICIENCY OF EXISTING COAL PLANTS

A number of options are available to achieve modest improvements in efficiency and greenhouse gas reductions at existing coal plants.

1. **Higher efficiency steam turbines** – Recent research and development has improved the performance of steam turbine blades. Modern turbine blades can be retrofitted into existing steam turbines with an increase in turbine efficiency of up to 3 per cent. Some Australian power stations have already installed these modern blades (e.g. Loy Yang Power). Another 1 per cent efficiency gain is available by improving turbine seals (SKM 2009).
2. **Boiler efficiency improvement** – Boiler efficiency can be improved by increasing the boiler heat transfer surface area to remove more heat from the flue gas before discharging it to the atmosphere. This requires additional equipment and capital outlay (SKM 2009).
3. **Improved efficiency of auxiliary drives** – For power stations that are subject to varying demand there is a trend towards variable speed drives and away from the traditional fixed speed type. The use of variable speed drives enables the driven machine to be controlled to an optimum output. Improved pumps and fans can also be fitted in many instances to obtain power savings (SKM 2009).
4. **Pre-drying brown coal** – Brown coal can have up to 66 per cent moisture content. Pre-drying removes some moisture before the coal is burnt and avoids latent heat loss than if it remained in the fuel. Pre-drying brown coal reduces carbon dioxide emissions close to a level achieved by black coal. For example, at Loy Yang Power a $6.3 million Mechanical Thermal Expression (MTE) pilot plant was tested in 2007–08. The MTE process allows more than 70 per cent of the water in brown coal to be removed with the potential to significantly reduce CO_2 emissions when the dry coal is burnt to generate electricity.
5. **Biomass co-firing** – Biomass co-firing in coal-fired power stations can reduce carbon dioxide emissions approximately proportional to the proportion of biomass used. Wood waste is generally used because coal fired boilers can usually co-fire a small amount of wood waste without major modification to the existing equipment. It is unlikely for most large power stations that the biomass available to co-fire would represent more than 1 per cent of the fuel input on an energy basis (SKM 2009). A number of large coal fired power stations have trialled co-firing mainly wood waste including, Hazelwood, Bayswater, Liddell, Mt Piper, Muja, Vales Point B and Wallerawang. At Muja 78 000 tpa of sawmilling residue is burnt displacing 45 000 tpa of coal and saving an estimated 90 000 tpa of greenhouse gas emissions (www.verveenergy.com.au).
6. **Co-firing natural gas** – The conversion of coal fired power boilers in full or in part to use natural gas will reduce the greenhouse gas emissions because natural gas has lower carbon emissions than coal. However, this will incur higher fuel costs. Natural gas of up to 25 per cent of the fuel energy can be co-fired in black coal boilers without extensive modification to the heat transfer surfaces (SKM 2009).
7. **Solar heating** – Solar energy using high temperature solar thermal technology is being considered to provide steam and augment or replace boiler feed-water at existing coal power stations and result in reduced greenhouse gas emissions. Solar Heat and Power Pty Ltd has undertaken research and development on a Compact Linear Fresnel Reflector array which has been used to reheat water at the Liddell coal fired power station.
8. **Algal capture** – Algae can be used to capture carbon dioxide emissions and produce biofuel and livestock feed. Under an agreement with MBD Energy Ltd, Tarong Energy, Loy Yang Power and Eraring Energy will build an algal carbon capture, storage and recycling process. The MBD Energy process produces oil-rich micro algae suitable for oil for plastics or fuel and a stock feed. Pilot plants using MBD Energy's technology are planned to be constructed at the three companies coal fired power stations (www.mbdenergy.com).

BOX 5.3 NEW LOW EMISSIONS COAL TECHNOLOGIES

Oxyfuel combustion

Oxyfuel combustion involves firing a conventional coal-fired power station boiler with oxygen and recycled exhaust gases instead of air to produce a stream of highly concentrated CO_2 in the flue gas. This CO_2 can then be readily captured by cooling and compression to a liquid for separation and transport to geological storage. Oxyfuel combustion and capture has the advantages of relative simplicity of the process and potentially lower costs compared with other emergent CO_2 capture technologies. It can also be retrofitted to existing boilers in pulverised coal plants.

Oxy-fuel combustion boilers have been studied on a case-by-case basis in laboratory-scale and small pilot units. The Callide Oxyfuel project aims to demonstrate oxyfuel combustion and CO_2 capture by retrofitting a 30 MWe coal-fired boiler at CS Energy’s Callide ‘A’ coal power station in Queensland. This will create a highly concentrated stream of CO_2 suitable for capture and storage deep underground in geological formations west of the power station. The Callide project aims to demonstrate the viability of technology capable of reducing emissions from a typical coal-fired power station by 90 per cent.

Integrated Gasification Combined Cycle (IGCC)

IGCC power plants rely on a process known as coal gasification, which involves reacting coal with air or oxygen to create a synthetic gas or Syngas (also known as coal gas or ‘town’ gas), a mixture of carbon monoxide (CO) and hydrogen (H_2). Syngas is combustible but has only half the energy density of natural gas, and is used as a fuel or as an intermediate step for the production of other chemicals. Syngas was extensively used for street lighting prior to the development of electricity.

In the IGCC plant, syngas produced by reacting coal with air or oxygen under high temperatures and pressures is used as fuel in a gas turbine to produce electricity (figure 5.31). The carbon monoxide in the Syngas can be cleaned and reacted with water to convert it to CO_2. The CO_2 can then be separated for storage leaving a stream of pure hydrogen that is fed into the gas turbine. The combustion product of hydrogen in the gas turbine is principally water vapour. Heat recovered from both the gasification process and the gas turbine exhaust is used in boilers to produce steam in a steam turbine to produce additional electrical power. The IGCC process therefore combines the two cycles (Rankine and Brayton cycles) to achieve an operating efficiency of greater than 40 per cent. Research is being undertaken to improve the efficiency of combined cycle turbines, and to develop special turbines specifically to be used with hydrogen.

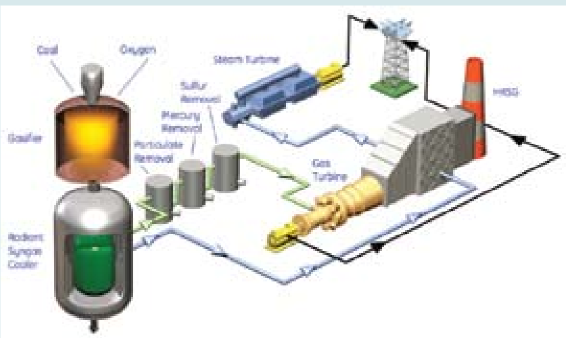

Figure 5.31 Integrated Gasification Combined Cycle with carbon capture and storage/sequestration

Source: Image Courtesy of GE Energy

IGCC without carbon capture and storage is approaching commercial deployment. There is a number of commercial-sized demonstration IGCC plants operating in several countries with outputs up to 400 MW and plans have been announced to develop several new IGCC power plants. As well as improved efficiencies and lower greenhouse gas emissions IGCC technology offers the potential to more economically capture CO_2 emissions.

There are several projects in Australia being developed to use IGGC, including some with CCS.

The Wandoan project in Queensland, currently in the development phase, proposes to build a 400 MW IGCC power station capable of capturing and storing up to 90 per cent of CO_2 emissions. This plant has a scheduled start up in late 2015 or early 2016. This project is being developed by a partnership between GE Energy and Stanwell.

ZeroGen Pty Ltd proposes to build a commercial-scale 530 MW IGCC plant with CCS technology in Central Queensland with a planned deployment date of 2015. The project partners include Mitsubishi Corporation (MC)/ Mitsubishi Heavy Industries (MHI), and project is supported by the Queensland Government and the Australian Coal Association (through their Low Emissions Technologies program).

HRL Ltd has developed Integrated Drying Gasification Combined Cycle technology based on brown coal. A proposed 550 MW power station project that will demonstrate the technology is planned at Morwell, in the Latrobe Valley, Victoria.

development into new materials (e.g. nickel-based alloys) that will enable operation at temperatures above 600°C and pressures above 25 MPa.

All but the most recent of Australia's 21 GW of black coal and 7.5 GW of brown coal-fired power plants are based on subcritical pulverised coal technology. Pulverised coal technology is currently the cheapest large scale electricity generation process. Most new pulverised coal power stations are likely to be of supercritical or ultra-supercritical type given substantial improvements in efficiency and greenhouse gas reductions offered by these technologies. Retirement of subcritical pulverised coal plants and replacement by supercritical plants could significantly enhance efficiencies and reduce CO_2 emissions. However, not only would this require major capital investment, but many of the existing subcritical plants have remaining technical operating lives.

A number of approaches are being and have been adopted to improve the efficiency of existing coal plants and achieve reductions in greenhouse gas emissions without incurring the major costs that are associated with significant changes to the design conditions, materials and equipment configuration of existing plants. These improvements include: more efficient steam turbines; improvements to

BOX 5.4 CARBON CAPTURE AND GEOLOGICAL STORAGE: CCS

CCS is a key greenhouse gas mitigation technology for Australia. Burning fossil fuels such as coal, natural gas and oil releases carbon dioxide (CO_2) and other greenhouse gases (GHG) to the atmosphere adding to the potential for climate change. Approximately 75 per cent of Australia's annual 550 Mt of GHG emissions are the result of fossil-fuel energy production (including electricity generation, transport, and manufacturing and construction) (DCC 2009). Due to the heavy reliance on coal and natural gas (in total providing over 95 per cent of fuel input), electricity generation alone accounts for over 200 Mt of GHG emitted annually. Australia's abundant supply of coal and natural gas, combined with Australia's status as the world's largest coal supplier and the increasing domestic demand for continued low cost energy means that the use of fossil fuels for energy and electricity generation will increase. CCS technologies could assist in mitigating a significant proportion of the GHG emissions resulting from our continued and increasing use of fossil fuels (Geoscience Australia 2008).

Geological storage is the process of capturing CO_2 from stationary emission sources such as power stations, industrial facilities, or natural gas production and injecting it deep underground as a dense fluid into geological formations, preventing it from entering the atmosphere (figure 5.32). One of the most critical factors in geological storage is identifying rocks with suitable pore volumes for storage and cap rocks for sealing.

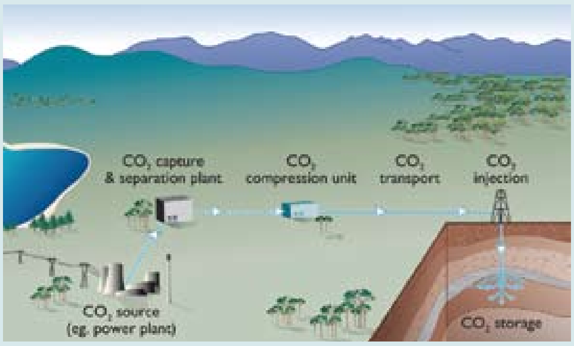

Figure 5.32 The carbon dioxide capture, transport, injection and storage process

Source: CO2CRC (www.co2crc.com.au)

Many sedimentary rocks, particularly sandstones, contain large volumes of fluids (these include: water, hydrocarbons, CO_2, and other gases) held in microscopic voids or pores between rock grains. These pores can form up to 30 per cent of the rock volume (figure 5.33). Where the pores are interconnected the rock has permeability, that is, fluids can flow through it. Deep in the geological section, rocks like sandstones are usually filled with highly saline water that moves very slowly over millions of years. They are called deep saline reservoirs, and they are the 'containers' proposed for storing greenhouse gases because they are too deep and too saline for any other practical use.

CO_2 injected into a saline reservoir becomes trapped in the rock through a number of mechanisms. Initially the CO_2, which is less dense than water, rises buoyantly through the reservoir until it meets a barrier – an impermeable cap rock (the seal, or 'lid', to the reservoir) such as a mudstone or shale (figure 5.34). The CO_2 will accumulate under the cap rock and spread out laterally beneath it. Some of the CO_2 will be caught in pores between grains of rock, and will not move any further. Over time, a significant portion of the rest of the CO_2 will dissolve in the saline formation water and be stored in solution while some of the CO_2 and water will react with minerals in the rock to precipitate new minerals. Storage sites are carefully selected and characterised to ensure that a suitable cap rock is present to prevent CO_2 from migrating out of the designated reservoir.

The most suitable reservoir and cap rocks are found in sedimentary basins, and particularly in hydrocarbon producing basins. In general, deep saline reservoirs have the greatest potential capacity to store CO_2, because they are widespread, large, and are presently not used for other purposes.

Depleted oil and gas fields may also be used to store CO_2, although these are much smaller in volume and in some cases are either not available for use (i.e. are still producing hydrocarbons) or will be used for other purposes such as natural gas storage. The advantage of using depleted fields is that they are well characterised and have already demonstrated that they can trap and retain large volumes of hydrocarbons. Other options include storage in deep coal seams, basalts, shales, as CO_2 hydrates beneath the sea floor, and through mineral carbonation. Many of these latter options are at early stages of development and may only provide niche storage opportunities. National geological assessments of storage resources in Australia (APCRC 2003; Carbon Storage Taskforce 2009), indicate that Australia has sufficient storage space to make a significant impact on our GHG emissions from stationary sources. For Australia, nearly all of this resource is in deep saline reservoirs where there is ample volume and no potential resource conflict (e.g. with hydrocarbon or fresh water production).

Many of the concepts around geological storage of CO_2 have been taken directly from the petroleum industry which has extensive experience with oil and natural gas (including naturally occurring CO_2) in the subsurface. Studies of hydrocarbon accumulations around the world have shown that fluids have remained trapped in deep geological formations and structures for tens to hundreds of millions of years. This gives confidence that injected CO_2 can be securely stored in similar geological settings for similar amounts of time. Demonstrating the security and safety of storage before, during and post injection is of particular concern to government, industry and the public. Potential points of leakage include faults, cap rocks, and pre-existing petroleum wells. The former two are mitigated through good geological characterisation of an injection site, while the latter is mitigated through careful design and engineering. In addition, both new and existing techniques are being used to track CO_2 in the subsurface, including seismic imaging, down-hole pressure measurement and gas and water sampling, and shallow aquifer groundwater sampling. Surface monitoring techniques such as atmospheric and soil gas sampling will ensure that in the unlikely event that any CO_2 migrates to the surface it will be detected and remedied immediately.

Capture, injection and geological storage of CO_2 is an established process in the petroleum industry and is already occurring at commercial scale (more than 1 Mt CO_2 per year) at several locations globally. These include Statoil's Sleipner and Snohvit gas fields in the North and Barents Seas respectively, BP's gas project at In Salah in Algeria, and the enhanced oil recovery project at the Weyburn and Midale fields in Canada. In addition, over 50 Mt of CO_2 are transported over more than 3000 km of dedicated CO_2 pipelines and injected each year for enhanced oil recovery in North America. In Australia, one of the largest research storage projects in the world, the CO2CRC's pilot CO_2 injection project in the Otway Basin in Victoria, has injected 65 000 t of CO_2 into a depleted gas field, and a further injection project into a saline reservoir is planned. The ZeroGen project in Queensland is developing a 530 MW IGCC power station with planned capture and storage of about 60 Mt of CO_2 in total. The Gorgon natural gas project offshore Western Australia will store 125 Mt of naturally occurring CO_2 separated from the produced gas. There are a number of other projects in various stages of planning or implementation (figure 5.35).

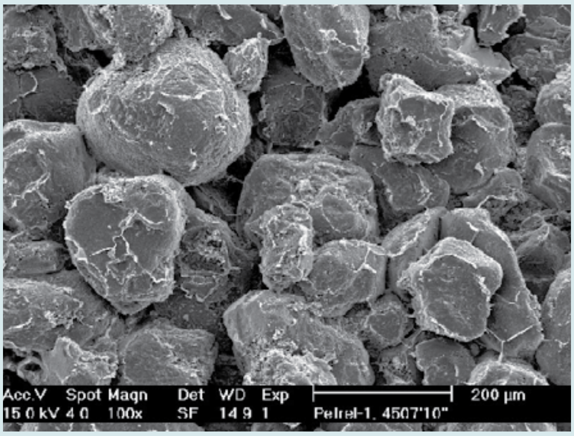

Figure 5.33 Microscope image of a reservoir rock – a porous and permeable sandstone

Source: Gibson-Poole et al. 2002

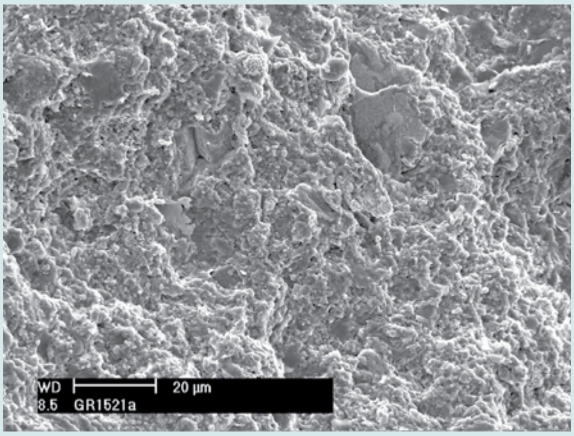

Figure 5.34 Microscope image of a cap rock – an impermeable mudstone

Source: Daniel 2006

Major Government initiatives in CCS

The Australian Government is supporting a range of initiatives and policies to accelerate the development and deployment of CCS in Australia (RET 2009). These include the:

- $4.5 billion **Clean Energy Initiative**, to support research, development and demonstration of low emissions energy technologies, including $2 billion to support the construction and demonstration of two to four large scale CCS projects from 2015 under the CCS Flagships Program.
- $400 million, over eight years, **National Low Emissions Coal Initiative**, which includes support for the CCS Flagships Program and the National Carbon Mapping and Infrastructure Plan. This initiative aims to accelerate the development and deployment of technologies to reduce emissions from coal-powered electricity generation, while securing the contribution that coal makes to Australia's energy security and economic wellbeing.
- Carbon Storage Taskforce, whose mission is to develop the **National Carbon Mapping and Infrastructure Plan**. The purpose of the NCMIP is to promote prioritisation of, and access to, national geological storage capacity and associated infrastructure requirements needed to accelerate deployment of CCS in Australia.
- **Commonwealth CCS Legislation**. *The Offshore Petroleum and Greenhouse Gas Storage Act 2006*, the world's first national legislation enabling CO_2 storage, provides a framework for access and property rights for the geological storage of greenhouse gases such as CO_2 in Commonwealth offshore territory, that is, greater than three nautical miles from the coast. In another world first, in March 2009 the Australian Government released ten offshore areas for bids for the rights to explore for greenhouse gas storage sites.
- **Global Carbon Capture and Storage Institute (GCCSI)**. In 2009, the Australian Government established the GCCSI with annual funding of up to $100 million in order to address barriers, and accelerate deployment of industrial scale carbon dioxide capture, transport, and storage technologies globally. The Institute aims to build sufficient confidence in the technology, by helping to facilitate the deployment of fully integrated large-scale carbon capture and storage projects globally.

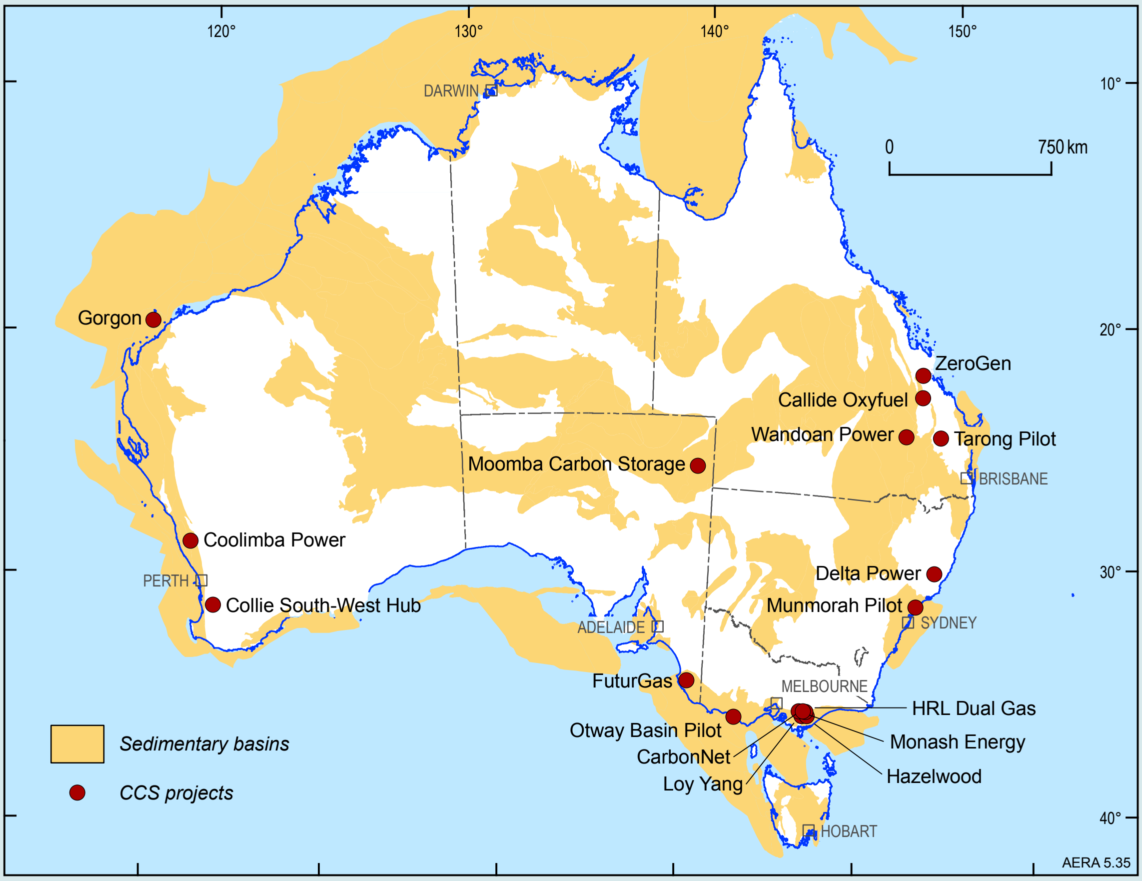

Figure 5.35 Active and proposed CCS projects in Australia

Source: Geoscience Australia 2008

boiler efficiency; pre-drying brown coal; co-firing with gas or biomass; the use of solar heating; and biosequestration of CO_2 emissions (box 5.2). On the other hand, the use of dry cooling in carbon capture and storage to reduce water usage has the effect of lowering efficiency.

Carbon capture and storage (CCS)

Carbon capture and storage (CCS) is a greenhouse gas mitigation technology that can potentially reduce CO_2 emissions from existing and future coal-fired power stations by more than 80 per cent. Current and new coal combustion technologies (based on pulverised coal technologies) are approaching maximum efficiency and greenhouse gas emission intensity limits (figure 5.30). Further reduction of CO_2 emissions requires the capture (as a supercritical fluid), transport and (geological) storage of CO_2. CCS has not yet been demonstrated at the scale needed for power plants, and until the technology matures implementation of CCS is likely to add significantly to the costs of production of electricity. Large scale demonstration plants with CO_2 storage are expected to start operation in 2015, with an aim to have the technology commercially available by 2020.

There are three main approaches to reducing emissions from coal use by removing CO_2. One of these removes CO_2 before the coal is burned to produce electricity (i.e. pre-combustion using Integrated Gasification Combined Cycle technology) whereas the other two remove the CO_2 after combustion (oxyfuel combustion and post-combustion capture).

Integrated Gasification Combined Cycle (IGCC) involves reacting coal at high temperatures and pressures with oxygen and steam to convert the coal to synthetic gas (Syngas). Syngas is predominantly a mixture of hydrogen (H_2) and carbon monoxide (CO) and commonly some carbon dioxide (CO_2). Syngas is combustible and can be used as a fuel although it has less than half the energy density of natural gas. In the IGCC the Syngas is combusted in a high efficiency combined cycle system, which comprises a gas turbine driving a generator (box 5.3). The hot exhaust gas from the gas turbine raises steam for a steam turbine.

Oxyfuel combustion involves burning pulverised coal with pure oxygen rather than air, to produce a stream of highly concentrated CO_2. This enables the CO_2 to be more readily captured (without the use of solvents) by cooling and compression to form liquid CO_2 for transport to geological storage (box 5.3).

Post-Combustion Capture involves the separation of CO_2 from the flue gases released in the combustion process. This is generally done by contacting the gases with a chemically reactive liquid (commonly an amine or ammonia solution) to capture the CO_2. The CO_2 is then removed from the absorbing solution by heating, compressed and transported to an underground storage location. Because post-combustion capture occurs after the combustion process, this technology can be retrofitted to existing combined cycle plants.

Other coal conversion technologies

Coal can also be converted into other synthetic fuels, including liquid fuels that can be used as transport fuels. Conversion of **coal to a liquid (CTL)** – a process also known as coal liquefaction – can be achieved directly or via synthetic gas (syngas). Direct liquefaction works by dissolving the coal in a solvent at high temperature and pressure. Although this process is highly efficient the liquid products require further refining to be suitable as high grade fuels. In the more common indirect CTL method coal is gasified to form syngas and then condensed over a catalyst – the 'Fischer-Tropsch' process – to produce high quality, ultra-clean fuel products (box 5.5).

There has been little interest in CTL projects until recently because of the ready availability of relatively low cost crude oil and the high capital and operating costs of CTL plants. South Africa has the largest CTL industry in operation today with a CTL capacity of more than 160 000 barrels of oil per day. CTL plants provide some 30 per cent of South Africa's liquid transport fuels needs. In Australia from 1985 to 1990 a Japanese consortium operated a CTL pilot plant at Morwell which demonstrated that hydrogenation of Latrobe Valley brown coal was technically feasible. A CTL project commenced production in China in late 2008.

However, rising oil prices and concerns about security of oil supply have prompted renewed interest in CTL technologies and there are currently more than 50 projects worldwide with two thirds of those in China and the United States (World CTL Association 2009). Significant challenges to the uptake of CTL projects are the high capital costs and the high greenhouse gas footprint of CTL projects. New CTL projects are likely to require some form of carbon capture and storage (CCS) to reduce the greenhouse gas emissions. The capital costs have been estimated at approximately US$60 000 to US$120 000 per barrel per day (excluding the costs of CCS), equivalent to a capital cost of US$4 billion for a 40 000 barrel per day CTL plant (World CTL Association 2009).

A number of companies are currently investigating the feasibility of CTL plants in Australia including New Hope Corporation at the New Acland mine (Queensland), Ambre Energy Ltd at Felton (Queensland), Spitfire Oil at Salmon Gums (Western Australia), Blackham Resources at Scaddan (Western Australia), Hybrid Energy Australia at Kingston

(South Australia), Altona Resources at Wintinna (South Australia) and Syngas Ltd at Clinton (South Australia).

A number of projects are actively considering projects involving **underground or in-situ coal gasification (UCG)**. In this method fuel gases are produced underground when a coal seam gets sufficient air to burn but insufficient for all consumable products to be consumed. The gasified coal can then be used to produce liquid fuels (or electricity).

UCG technology has evolved through numerous trials since the early 1900s but has been only used on a commercial scale for power generation in the former Soviet Union where it has operated for over 40 years. UCG provides access to deep coal and other stranded coal resources avoiding the need to mine and process it. There has been renewed interest in coal gasification in recent years with a number of projects at different stages of evaluation. There are about 30 underground coal gasification projects at various stages in China alone.

BOX 5.5 COAL CONVERSION TECHNOLOGIES

Coal to Liquids (CTL)

The production of liquids from coal requires the breakdown of the chemical structures present in coal with the simultaneous elimination of oxygen, nitrogen and sulphur and the introduction of hydrogen to produce a stable liquid product. Syngas produced from coal gasification can be converted into a variety of products including petrol, diesel, jet fuel, plastics, gas, ammonia, synthetic rubber, naptha, tars, alcohols and methanol using the Fischer-Tropsch process (figure 5.36). Coal-derived fuels have the advantage of being sulphur-free, low in particulates, and low in nitrogen oxides.

CTL technology was developed in the early 20th century and was used in Germany in the 1930s and 1940s. Since 1955 in South Africa, Sasol has operated CTL plants and in late 2008 the Shenhua Group commissioned a CTL plant at Ordos in China. There are some 50 CTL projects being considered around the world with the bulk of these in China and the United States. Synthetic fuels produced by CTL processes have been tested for suitability as jet fuel in aeroplanes. Coal as a potential source of liquid fuels has the advantage of being both widespread and relatively low cost. For some countries it may decrease reliance on oil imports and improve energy security.

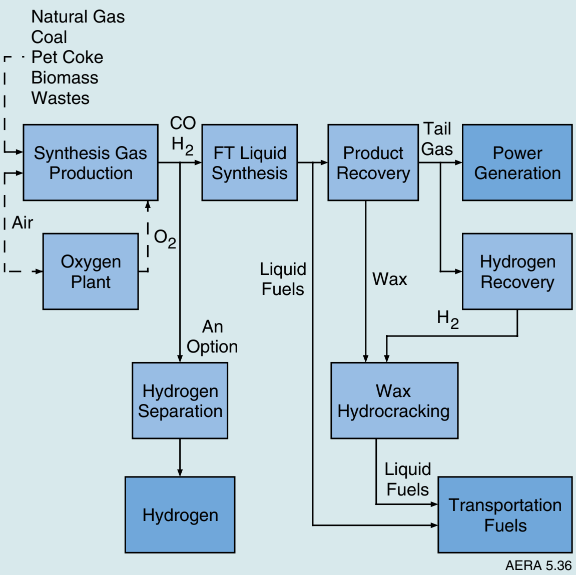

Figure 5.36 Fischer-Tropsch Technology

Source: Sustainable Design Update (www.sustainabledesignupdate.com)

Underground Coal Gasification (UCG)

Synthetic gas (syngas) can be produced also by underground or in-situ coal gasification (figure 5.37). In this method fuel gases are produced underground when oxidants (generally air) are injected into an unmined coal seam causing the coal to burn but combustion is insufficient to consume all combustible material. Carbon dioxide, carbon monoxide, hydrogen and methane are produced to yield a gas of low but variable heat content. Air is pumped into the burning coal bed through a well, and the gas is drawn off from a point behind the 'fire-front' through another well. The gasified coal can then be used to produce a range of liquid fuels (or electricity) as well as other chemical feedstocks and fertilisers. UCG technology could also have synergies with CCS as the CO_2 could be stored in the coal cavity after gasification.

The power station at Angren in Uzbekistan has the only operating underground coal gasification project in the world. At present, many projects are in various stages of development in the United States, Canada, South Africa, India, Vietnam, Australia, New Zealand and China to produce electricity, liquid fuels and synthetic gas. In Australia projects being developed include: Linc Energy's Chinchilla Project, Carbon Energy's Bloodwood Creek Project and Cougar Energy's Kingaroy Project, all in Queensland.

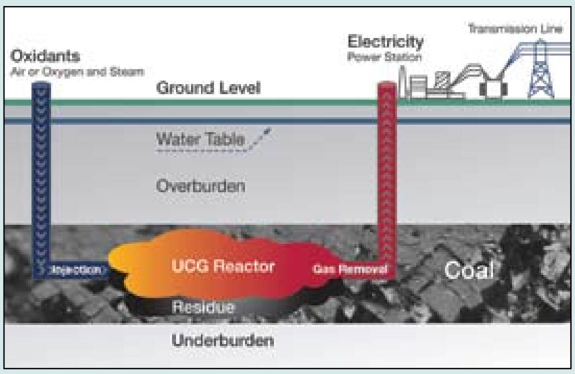

Figure 5.37 Underground Coal Gasification Process

Source: Cougar Energy (www.cougarenergy.com.au)

UCG has been successfully demonstrated at the Chinchilla project (Linc Energy 2009) in the Surat Basin in Queensland. A major trial from 1999–2003 achieved 95 per cent recovery of coal resource and 75 per cent total energy recovery with a high availability of produced syngas. A gas-to-liquid (GTL) plant to produce clean liquid fuels from UCG syngas began production in late 2008.

Utilisation of coal resources – competing land use

Australia's major coal resources are located mostly on the eastern seaboard in relatively close proximity to ports and the major industrial and urban power demand centres. Continued development of the coal industry, especially the development of new coal mines, will require access to land for mining and transport of the coal. Future development of these resources will need to take into account competing land uses and various environmental issues.

Companies lodging mine development proposals are required to consult with governments and community stakeholders and undertake assessments of the potential impact of any proposed mining project on the environment (including assessments of any impacts under the *Environment Protection and Biodiversity Conservation Act 1999*) and on third parties such as the community. Where land title is held privately, there is usually a legislative requirement to seek the consent of the land owner (or occupier) and negotiate compensation for access.

Coal mining has taken place in New South Wales for more than 200 years and many mines operate in close proximity to urban and semi-rural areas, high-value agricultural land, metropolitan water storages and in some locations national parks (e.g. south of Sydney). In Queensland, much of the coal production is from open cut (surface) mines in areas of low agricultural value and at locations remote from cities, although underground mining does takes place in central Queensland.

Development of new coal mining projects in areas with land of higher agricultural value and other existing land uses will require balancing competing land use interests, particularly those of agriculture, water management (both surface and ground water), and coal mining activities.

Future development of coal projects is likely to require planning for land access corridors. Proposals for new coal-fired power stations are likely to require the identification of suitable geological sites and pipeline infrastructure needed to support capture and storage of carbon dioxide. For geological storage, potential sites may need to be identified and assessed for suitability and approved for injection and storage.

Water management

Water is required at the coal mine site for a range of uses, including dust suppression, removal of mineral residues, washing of vehicles and for human consumption. Water is also a key input for coal washing, a cleaning process undertaken to reduce contamination prior to use. Water is also used for dust suppression at ports.

Water used by the coal industry is obtained from a variety of sources including mains supply, rivers, lakes, onsite surface runoff and storm water, mine water, ground water, and recycled water. This water is accessed in the context of competing uses, including for agriculture, industry, human consumption and environmental flows. The recent drought has highlighted the need to manage water more efficiently, and escalated the priority given to water management issues across all levels of government in Australia.

Both New South Wales and Queensland have water legislation and policies in place to support the sustainable and integrated management of their water resources. The *Water Management Act 2000* provides the statutory framework for water management in New South Wales, while water legislation in Queensland is embodied in the *Water Act 2000*. A key element of the legislation in both states is the voluntary trading of water entitlements, which is being implemented progressively. By allowing water to be allocated to those uses with the highest net benefit, water trading can contribute to a more efficient use of water resources. Another key element of the legislation in both states is the progressive introduction of water sharing resource plans. The aim of the plans is to balance future water demands across different types of water users, and provide a secure allocation of water for these uses.

Current legislation enables coal mining companies to better manage their water issues. Typically, coal mines have either too much water or too little water. Where water is in short supply, allocation can be bought from other allocation holders to fill a deficit. In the case of surplus water, arising for example from excessive ground water in mining areas, arrangements can be put in place through catchment water sharing plans to use the water for other commercial purposes.

More broadly, the National Water Commission is undertaking a $2 million study looking at the cumulative impacts of mining on groundwater resources. The study, due for completion in June 2010, will appraise the planning and permitting practices across jurisdictions and the work undertaken by the mining industry with water management. It will also develop consistent and rigorous methodologies that will improve the ability to assess and forecast the availability, condition and effects of mining on groundwater resources.

Capital and other issues

In conjunction with access to infrastructure, access to adequate capital and a supply of skilled labour will be critical to the growth of Australia's coal industry. Expansion of Australia's coal production and infrastructure to provide the export capacity to meet growing global demand for coal potentially involves major capital expenditure of at least $10 billion and potentially more than $50 billion over the next 10 years or so (ABARE 2009e). Capital requirements for advanced stage mining projects total $6.1 billion with a further $2.9 billion in coal infrastructure (tables 5.11 and 5.13). Capital requirements for the less advanced coal projects exceed $26 billion for mining projects and $13.5 billion in coal infrastructure (tables 5.12 and 5.14).

Modification and/or replacement of current coal-fired power stations (mostly subcritical pulverised coal technology) with lower emissions technology, including capture and geological storage of CO_2, to meet future emissions reduction targets will also require major capital investment.

These capital requirements need to be considered against the global demand for capital to meet growing energy needs and the global transition to lower emissions energy technologies. These capital requirements could be as large as US$10.5 trillion over the next 20 years, amounting to an annual additional capital investment of around US$430 billion, equivalent to 0.5 per cent of global GDP (IEA 2009c).

Another, although less substantial, potential constraint that may impact on the medium to long term prospects of the Australian coal industry is availability of an adequate pool of skilled labour. This will be particularly important as more technically advanced and capital intensive projects come on line. In the five years to the middle of 2008, demand for labour within the mining industry increased rapidly leading to labour shortages at some coal mines. Part of the cost inflation experienced at mining and infrastructure construction sites between 2005 and 2008 has been attributed to the short supply of essential skills which led to increased engineering and construction costs.

5.4.2 Outlook for coal market

Increased global demand for coal (projected by the IEA in its reference scenario to be 1.9 per cent per year over the period to 2030) is expected to result in increased Australian coal production and exports. However, the impact of the Renewable Energy Target (RET) and a 5 per cent emissions reduction target is projected to result in a decline in coal's share of domestic electricity generation. Details of the assumptions underpinning these projections can be found in Chapter 2.

Key projections to 2029–30

ABARE's latest long-term projections, assuming the RET, a 5 per cent emissions reduction target below 2000 levels by 2020 and other government policies (ABARE 2010), include:

- Coal production increases at an average rate of 1.8 per cent per year to total 13 875 PJ (720 Mt). Increased production will be underpinned by export demand.
- Coal consumption is projected to decrease at an average annual rate of 0.8 per cent to 1763 PJ in 2029–30. The share of coal in total primary energy consumption will fall to 23 per cent in 2029–30.
- Coal's share of domestic electricity generation is projected to decline to 43 per cent in 2029–30, as coal is replaced by renewable and other lower emissions energy sources.
- Australia's exports of coal are projected to increase by 2.4 per cent per year to 12 112 PJ (450 Mt) in 2029–30. Exports are likely to account for around 85 per cent of production in that year.

Production

Australia's coal production is projected to increase significantly over the next 20 years, supported by strong demand from global markets. This will more than offset the projected decline in domestic demand under a 5 per cent emissions reduction target. Production is expected to grow by nearly 50 per cent over the period to 2030, equivalent to an annual increase of 1.8 per cent to reach 13 875 PJ in 2029–30 (ABARE 2010). The majority of additional coal production is expected to be sourced from New South Wales and Queensland where export quality coal is mined and where necessary infrastructure is in place.

Consumption

Australia's coal consumption is projected to decline by an average annual rate of 0.8 per cent to reach 1763 PJ by 2029–30. Coal's share of total primary energy consumption is projected to fall to 23 per cent in 2029–30.

The most important driver of lower coal consumption is the projected reduction in electricity generation from coal-fired power plants. The RET will encourage increased electricity generation from renewable fuels sources, while the introduction of emissions reduction targets will make coal less cost competitive compared with other fuels such as gas.

Electricity generation

The nature of Australia's electricity generation is projected to change significantly in response to the introduction of the RET and emissions reduction targets. Coal has historically underpinned Australia's electricity production and in 2007–08 coal accounted for around three quarters of Australia's electricity generation. Coal is projected to account for 43 per cent of electricity generation in 2029–30 (figure 5.38).

Although coal-fired electricity generation is projected to decline in the period to 2030, new coal-fired electricity capacity is still planned in Australia. As of October 2009 there were two coal-fired power stations (black coal) at an advanced stage, each of more than 200 MW, one in New South Wales (upgrade) and one in Western Australia (table 5.15). In addition, there are a further six black coal and two brown coal power stations at a less advanced stage (table 5.15). A number of the less advanced coal projects incorporate CCS or coal-to-liquids or coal gasification as well as electricity generation.

Exports

Australia's coal exports are projected to continue to grow strongly with the strong growth in exports underpinned by growth in coal import demand, particularly from developing economies such as China and India. Australia's coal exports are projected to grow at an annual rate of 2.4 per cent and reach 12 112 PJ (450 Mt) by 2029–30 (figure 5.39).

The growth in exports is expected to occur in New South Wales and Queensland. In New South Wales continued expansion of the Hunter Valley and further development in the Gunnedah Basin is expected to underpin increased exports. Expansion of production capacity in the Bowen Basin and the development of mines in the Galilee Basin is expected to support increased coal exports from Queensland.

Proposed development projects

The long term expansion of Australia's coal production and exports will be underpinned by a number of projects that are currently under construction or at various stages of planning.

At the end of October 2009, there were 12 coal projects under construction (table 5.11), scheduled to be completed at various times over the next three years. Of the 12 projects, seven are located in Queensland and five are in New South Wales. The projects have a combined coal capacity of around 50 Mt, at an estimated capital cost of $6.1 billion. The largest of these, in terms of capacity, are Clermont (which is a replacement for the depleting Blair Athol mine) and Moolarben. Both have capacities in excess of 10 Mt per year.

In addition to the projects under construction, there a number of mine and infrastructure projects at a less advanced stages of development, that are either at feasibility study stage, in the process of receiving government approval or not yet subject to a final investment decision.

There are 49 mining projects at a less advanced stage of development, of which 16 are in New South Wales, 32 in Queensland and one in Western Australia (table 5.12). These projects have a potential capacity of over 300 Mt.

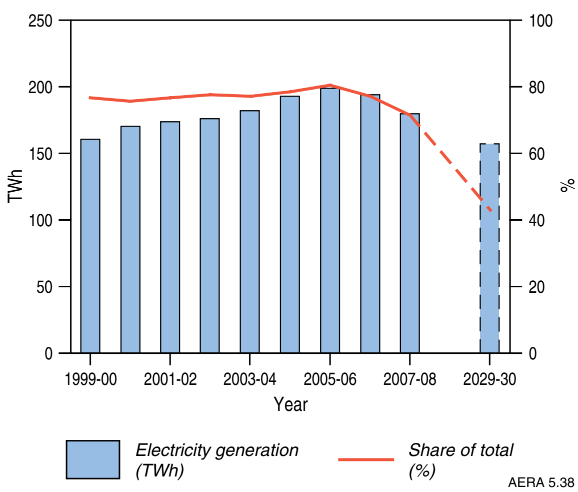

Figure 5.38 Australia's coal-fired electricity generation to 2029–30

Source: IEA 2009b; ABARE 2010

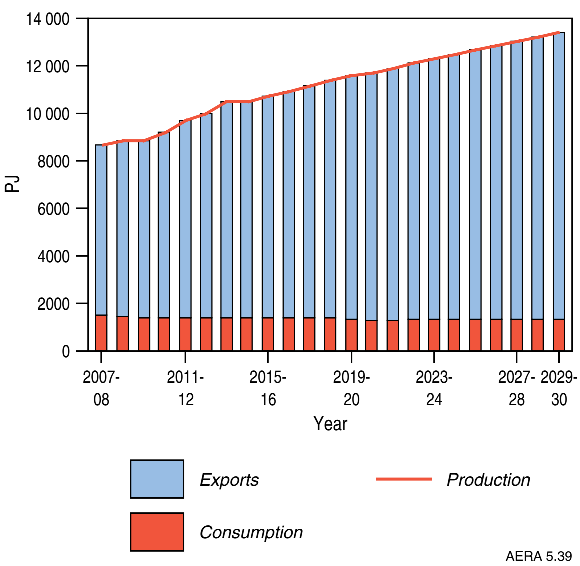

Figure 5.39 Australia's black coal projected supply-demand balance to 2029–30

Source: ABARE 2010

Expanded infrastructure capacity will be achieved through the completion of seven port and rail projects of which four are in Queensland and three in New South Wales (table 5.13). When complete, Australia's coal export infrastructure capacity could increase by 65 Mt per year. The largest of these projects, in terms of capacity, are the 30 Mt per year Newcastle Coal Infrastructure Group Coal terminal and the 25 Mt per year expansion to the Abbot Point Coal Terminal in Queensland. In terms of infrastructure, there are 18 projects at a less advanced stage, which includes rail and port projects in both New South Wales and Queensland (table 5.14).

Some of the projects at a less advanced stage of development may encounter changes in economic or competitive conditions, or may be targeting the same emerging market opportunities, necessitating rescheduling. In addition, securing finance for project development, even for high quality projects with a high probability of success, is not guaranteed. Despite the uncertainty inherent to projects at these earlier stages of consideration, the significant number of large scale projects at less advanced stages under consideration for development is expected to provide a firm platform for future growth of Australia's coal industry.

Table 5.11 Coal mines at an advanced stage of development, as at October 2009

Project	Company	Location	Status	Start up	Capacity	Capital Expenditure
Blackwater Creek Diversion	Wesfarmers	200 km W of Rockhampton, Qld	Expansion, under construction	2010	nil (extension of Curragh mine life)	$130 m
Blakefield South	Xstrata/ Nippon Steel	16 km SW of Singleton, NSW	New project, under construction	2010	nil (replacement for Beltana)	$375 m
Cameby Downs	Syntech Resources	100 km NE of Dalby, Qld	New project, under construction	2010	1.4 Mt thermal coal	$250 m
Carborough Downs longwall	Vale	20 km NE of Moranbah, Qld	Expansion, under construction	2011	4.2 Mt coking	US$330 m (A$398 m)
Clermont opencut	Rio Tinto	11 km N of Clermont, Qld	New project, under construction	2010	12 Mt thermal (replacing Blair Athol capacity)	US$1.3 b (A$1.57 b)
Curragh Mine	Wesfarmers	200 km W of Rockhampton, Qld	Expansion, committed	2011	Increase to 8.5 Mt	$286 m
Kestrel	Rio Tinto	51 km NE of Emerald, Qld	Expansion, under construction	2012	1.7 Mt coking	US$991 m (A$1.19 b)
Mangoola (Anvil Hill opencut)	Xstrata Coal	20 km SW of Muswellbrook, NSW	New project, under construction	2012	8 Mt thermal	$1 b
Moolarben stage 1	Felix Resources	Near Mudgee, NSW	New project, under construction	2010 (open cut) 2012 (underground)	8 Mt opencut; up to 4 Mt underground (ROM, thermal)	$405 m (incl coal preparation plant)
Mount Arthur opencut (MAC20)	BHP Billiton	5 km SW of Muswellbrook, NSW	Expansion, under construction	2011	3.5 Mt thermal	US$260 m (A$313 m)
Narrabri Coal Project (stage 1)	Whitehaven	20 km SE of Narrabri, NSW	New project, under construction	early 2010	1.5 Mt thermal	$185 m
New Acland (stage 3)	New Hope Coal	150 km W of Brisbane, Qld	Expansion, under construction	late 2009	0.6 Mt thermal	$36 m

Source: ABARE 2009e

Table 5.12 Coal mines at a less advanced stage of development, as at October 2009

Project	Location	Status	Start up	Capacity	Capital Expenditure
Alpha Coal Project	120 km SW of Clermont, Qld	New project, feasibility study under way	2013	30 Mt thermal	$7.5 b (inc. mine, port and rail)
Ashton South East opencut	14 km NW of Singleton, NSW	Expansion, feasibility study under way	2010	2.4 Mt thermal	$83 m
Austar underground (Stage 3)	6 km SW of Cessnock, NSW	Expansion, govt approval received	2012–13	3.6 Mt ROM hard coking	$80 m
Belvedere underground	160 km W of Gladstone, Qld	New project, prefeasibility study under way	2013	9 Mt hard coking	na
Bickham opencut	20 km N of Scone, NSW	New project, EIS under way	2011	2 Mt thermal	$50–100 m
Boggabri opencut	17 km NE of Boggabri, NSW	Expansion, feasibility study under way	2013	2.8 Mt thermal	11.5 b yen (A$140 m)
Canning Basin project	150 km SE of Derby, WA	New project, feasibility study under way	2012–13	2 Mt thermal	na
Caval Ridge (Peak Downs expansion)	20 km SW of Moranbah, Qld	Expansion, prefeasibility study under way	2013	5.5 Mt coking	na
Codrilla	62 km SE of Moranbah, Qld	New project, EIS under way	na	3.2 Mt PCI	na
Daunia	25 km SE of Moranbah, Qld	New project, govt approval received	2011	4 Mt coking	na
Dawson South (stage 2)	15 km NW Theodore, Qld	Expansion, EIS under way	na	5–7 Mt thermal (ROM)	na
Drayton mine extension	13 km S of Muswellbrook, NSW	Expansion, feasibility study under way	na	2.5 Mt thermal	$35 m
Eagle Downs (Peak Downs East underground)	20 km SE of Moranbah, Qld	New project, EIS under way	2014	4.6 Mt coking	$977 m
Ellensfield coal mine project	175 km W of Mackay, Qld	New project, EIS under way	na	4.5 Mt thermal and coking	na
Ensham bord and pillar underground mine	40 km NE of Emerald, Qld	New project, feasibility study under way	2011	1.5 Mt thermal	$120 m
Ensham Central longwall underground	40 km NE of Emerald, Qld	Expansion, prefeasibility study under way	na	7 Mt thermal	$700 m
Goonyella Riverside Expansion	30 km N of Moranbah, Qld	Expansion, prefeasibility study under way	na	up to 9 Mt hard coking	na
Grosvenor underground	8 km N of Moranbah, Qld	New project, EIS under way	2012	6.5 Mt hard coking	US$850 m (A$1 b)
Hail Creek expansion	120 km SW of Mackay, Qld	Expansion, prefeasibility study under way	2011	5.5 Mt thermal, 2.5 Mt hard coking	na
Hunter Valley Operations Expansion	24 km N of Singleton, NSW	Expansion, govt approval received	2011	3.6 Mt ROM semi-soft coking and thermal	$130 m
Intergrated Isaac Plains Project	180 km SW of Mackay, Qld	Expansion, EIS under way	na	2 Mt coking and thermal	$118 m
Kevin's Corner	Galilee Basin, Qld	New project, feasibility study under way	2013	30 Mt thermal	na
Kunioon	Kingaroy, Qld	New project, on hold	na	10 Mt thermal (ROM)	$500 m
Lake Vermont	60 Km SE of Moranbah, Qld	Expansion, prefeasibility study under way	2014	2 Mt	$100–200 m
Metropolitan longwall	30 km N of Wollongong, NSW	Expansion, govt approval received	na	3.2 Mt	$50 m

Project					
Middlemount (stage 1)	6 km SW of Middlemount, Qld	New project, environmental approval received	2010	1.8 Mt coking (ROM)	$65 m
Middlemount (stage 2)	6 km SW of Middlemount, Qld	New project, feasibility study under way	2012	3.2 Mt coking (ROM)	na
Millennium expansion	22 km E of Moranbah, Qld	Expansion, feasibility study under way	na	8.1 Mt (ROM)	na
Monto coal mine (stage 1)	120 km S of Gladstone, Qld	New project, feasibility completed	na	1.2 Mt thermal	$35 m
Monto coal mine (stage 2)	120 km S of Gladstone, Qld	Expansion, prefeasibility study under way	na	10 Mt	na
Moolarben (stage 2)	near Mudgee, NSW	Expansion, EIS under way	na	12 Mt opencut; up to 4 Mt underground (ROM, thermal)	$120 m
Moranbah South project	4 km S of Moranbah, Qld	New project, prefeasibility study under way	2014	6.5 Mt coking	US$1 b (A$1.2 b)
Mount Arthur North underground	5 km SW of Muswellbrook, NSW	New project, govt approval received	2011	8 Mt thermal (ROM)	$320 m
Mount Pleasant Project	6 km NW of Muswellbrook, NSW	New project, feasibility study completed, on hold	2013	10.5 Mt thermal	$1.3 b
Narrabri Coal Project (stage 2)	20 km SE of Narrabri, NSW	Expansion, feasibility study under way	2011	4.5 Mt thermal	$300 m
New Acland (stage 4)	150 km W of Brisbane, Qld	Expansion, EIS completed	na	5.2 Mt thermal coal	na
NRE No. 1 Colliery	Wollongong , NSW	Expansion, feasibility study under way	na	3 Mt	$250 m
Olive Downs North	30 km S of Coppabella, Qld	New project, feasibility study under way	2011	1 Mt coking	na
Red Hill underground	45 km N of Moranbah, Qld	New project, prefeasibility study under way	2014	2 Mt PCI and thermal	na
Saddler's Creek underground and opencut	15 km SW of Muswellbrook, NSW	New project, feasibility study under way	na	2 Mt thermal, 2 Mt coking	na
Ulan	Mudgee, NSW	Expansion, feasibility study under way	2010	nil (continuation of mining operations)	$500 m
Wallarah underground longwall	NW of Wyong, NSW	New project, feasibility study under way	late 2011	5 Mt thermal	$550 m
Wandoan opencut	60 km N of Miles, Qld	New project, feasibility study under way	2012	up to 22 Mt thermal	US$1.6 b (A$1.9 b)
Waratah Galilee coal project	450 km W of Rockhampton, Qld	New project, awaiting govt approval	2013	up to 40 Mt thermal	$7.5 b
Washpool coal project	260 km W of Rockhampton, Qld	New project, feasibility study under way	2012	1.6 Mt of coking	$402 m
Winchester South	40 km S of Moranbah, Qld	New project, prefeasibility study under way	2013	4 Mt of coking and thermal	na
Wonbindi	180 km W of Gladstone, Qld	New project, prefeasibility study under way	2013	3 Mt PCI and thermal	na
Wongawilli Colliery	12 km W of Port Kembla, NSW	Expansion, feasibility study under way	na	nil (continuation of mining operations)	$62 m
Woori	19 km S of Wandoan, Qld	New project, prefeasibility study under way	2013	3–4 Mt thermal coal	na

Source: ABARE 2009e

Table 5.13 Coal infrastructure at an advanced stage of development, as at October 2009

Project	Company	Location	Status	Start up	Capacity	Capital Expenditure
Abbot Point Coal Terminal X50 expansion	North Queensland Bulk Ports	Bowen, Qld	Expansion, committed	mid 2011	Terminal capacity increase from 25 to 50 Mtpa	$818 m
Abbot Point Coal Terminal yard refurbishment	North Queensland Bulk Ports	Bowen, Qld	Refurbishment, committed	mid 2011	na	$68 m
Brisbane Coal Terminal expansion	Queensland Bulk Handling	Brisbane, Qld	Expansion, under construction	2010	1 Mtpa	$10 m
Coppabella to Ingsdon rail duplication	Queensland Rail	Coppabella to Ingsdon, Qld	Expansion, committed	mid 2010	3 Mtpa	$80 m
Minimbah Bank Third Rail Line (stage 1)	Australian Rail and Track Corporation	Minimbah to Whittingham (10km), NSW	Expansion, under construction	2010	na	$134 m
NCIG export terminal (Newcastle Coal Infrastructure Group)	NCIG	Newcastle, NSW	New project, under construction	2010	Capacity of 30 Mtpa initially; ultimately 66 Mtpa	US$1.1 b (A$1.3 b)

Source: ABARE 2009e

Table 5.14 Coal infrastructure at a less advanced stage of development, as at October 2009

Project	Company	Location	Status	Start up	Capacity	Capital Expenditure
2 Export Terminal Arrival Tracks	Australian Rail and Track Corporation	Newcastle, NSW	Expansion, feasibility study under way	2011	na	$50 m
Koolbury – Aberdeen duplication	Australian Rail and Track Corporation	Koolbury – Aberdeen, NSW	Expansion, feasibility study under way	2013	na	$60 m
Kooragang Island coal terminal expansion	Port Waratah Coal Services	Newcastle, NSW	Expansion, feasibility study under way	na	Capacity increase to be decided	To be decided
Liverpool Range rail project	Australian Rail and Track Corporation	Willow Tree to Murrurundi (30 km), NSW	Expansion, feasibility study under way	2012	Capacity increase of 12.5 Mt	$290 m
Minimbah Bank Third Rail Line (stage 2)	Australian Rail and Track Corporation	Maitland to Minimbah (32 km), NSW	Expansion, planning approval under way	2012	na	$300 m
Nundah Bank 3rd Road (rail)	Australian Rail and Track Corporation	Minimbah to Maitland (30 km), NSW	Expansion, feasibility study under way	2012	na	$125 m
Scone – Parkville Duplication	Australian Rail and Track Corporation	Scone – Parkville, NSW	Expansion, feasibility study under way	2013	na	$60 m
Western Rail Coal Unloader	Delta Electricity	Mt Piper, 10 km W of Lithgow, NSW	New project, govt approval received	2012	8 Mt (ultimately)	$80 m
Abbot Point Coal Terminal X110 expansion	North Queensland Bulk Ports	Bowen, Qld	Expansion, EIS submitted, on hold	2014	Terminal capacity increase from 80 to 110 Mtpa	$1.8 b
Abbot Point Coal Terminal X80 expansion	North Queensland Bulk Ports	Bowen, Qld	Expansion, EIS submitted, on hold	2012	Terminal capacity increase from 50 to 75 Mtpa	$1.8 b
Balaclava Island coal terminal	Xstrata	50 km N of Gladstone, Qld	New project, EIS under way	2014	35 Mtpa	$1 b

Project						
Goonyella to Abbot Pt (rail) (X50)	Queensland Rail	North Goonyella to Newlands (70 km), Qld	Expansion, final stages of planning	early 2012	50 Mtpa	$1.1 b
Hay Point Coal Terminal Phase 3	BHP Billiton Mitsubishi Alliance (BMA)	20 km S of Mackay, Qld	Expansion, feasibility study under way	2014	Port capacity increase from 44 to 55 Mtpa	$500 m
Moura Link – Aldoga Rail	Queensland Rail	Moura/Surat to Mount Larcom, Qld	New project, EIS completed	mid 2013	na	$500 m
Surat Basin Rail (Southern Missing Link)	Queensland Rail/ ATECDV/ Xstrata Coal	Wandoan to Theodore (210 km), Qld	New project, EIS submitted	2012	42 Mtpa haulage capacity ultimately	$1 b
Wiggins Island Coal Terminal (stage 1)	Wiggins Island Coal Export Terminal	Gladstone, Qld	New project, EIS under way	2012	25 Mtpa	$1.4 b
Wiggins Island Coal Terminal (stage 2)	Wiggins Island Coal Export Terminal	Gladstone, Qld	New project, EIS under way	2016	Terminal capacity increase from 25 to 50 Mtpa	$1.4 b
Wiggins Island Coal Terminal (stage 3)	Wiggins Island Coal Export Terminal	Gladstone, Qld	New project, EIS under way	2020	Terminal capacity increase from 50 to 70 Mtpa	$1 b

Source: ABARE 2009e

Table 5.15 Coal-fired electricity projects at various stages of development, as at October 2009

Project	Company	Location	Status	Start up	Capacity	Capital Expenditure
Advanced Projects						
Black coal						
Bluewaters stage 2	Griffin Energy	5 km NE of Collie, WA	Under construction	late 2009	208 MW	$400 m
Eraring	Eraring Energy	40 km SW of Newcastle, NSW	Committed	2011	240 MW	$245 m
Less Advanced Projects						
Black coal						
Bluewaters stages 3 and 4	Griffin Energy	5 km NE of Collie, WA	EIS under way	2014	416 MW	na
Coolimba	Aviva Corporation	20 km S of Eneabba, WA	EIS under way	2013	400 MW	$1 b
Wandoan Power Project	Xstrata/GE Energy	Surat Basin, Qld	Prefeasibility study under way	2015-16	400 MW	na
ZeroGen stage 1 (demonstration phase)	ZeroGen Pty Ltd	Rockhampton, Qld	Feasibility study under way	2012	120 MW	$1.7 b
ZeroGen stage 2 (commercial phase)	ZeroGen Pty Ltd	to be determined, Qld	Prefeasibility study under way	2017	400 MW	$3 b
Arckaringa Phases 1 & 2	Altona Resources	200 km N of Coober Pedy, SA	New project, feasibility study under way	2014	560 MW	$520 m
Arckaringa Phase 3	Altona Resources	200 km N of Coober Pedy, SA	New project, feasibility study under way	na	280MW	na

Project						
Brown coal						
FuturGas project	Strike Oil	Kingston, SA	Prefeasibility study under way	2016	40 MW	na
HRL IDGCC project	HRL Technology/ Harbin	Latrobe Valley, Vic	Feasibility study under way	2013	400 MW	$750 m

Source: ABARE 2009f

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