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Geoscience Australia

Bureau of Resources and Energy Economics

Australian Energy Resource Assessment

Second Edition

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Foreword

Australia's abundant and diverse energy resources make a key contribution to the economic prosperity of the country. Australia is well positioned to maintain its role as an important supplier of the world's energy needs while our energy resources continue to provide Australian households and businesses with a secure and reliable domestic energy supply.

This edition of the *Australian Energy Resource Assessment* provides a snapshot of the nation's current energy resources and the factors likely to influence their future use. The report covers the full spectrum of energy resources, including renewables, fossil fuels and uranium.

Australia's high-quality energy resources are widely distributed across the country. Australia has substantial uranium, coal and gas resources. There remains under-explored and large undercover areas essentially untested, creating opportunities for future resource discovery. The vast under-explored offshore sedimentary basins on Australia's continental margin are regarded internationally as prospective frontier regions and hold significant promise for future oil and gas resources.

The nation's renewable wind, solar, geothermal, ocean and bioenergy energy resources are already being developed and utilised at both a large scale and household level. The role of renewable energy is likely to increase over time, as Australia, and the energy sector in particular, undergoes transformational change.

This publication highlights Australia's potential to increase its energy resource base as more resources are discovered, and as new technologies to improve the efficiency of extracting and using resources come on line.

The *Australian Energy Resource Assessment* provides governments, industry and the community with the information they need to participate in an informed discussion of Australia's energy future.

The Hon Ian Macfarlane MP
Minister for Industry

Preface

In economic terms, the energy sector makes a substantial contribution to the nation's gross domestic product, export earnings, and employment. A secure supply of affordable, reliable, environmentally sustainable energy is essential to Australia's future economic growth and prosperity. Australia's future energy supply will need to have lower emissions in order to meet the challenges posed by rising levels of carbon dioxide in the Earth's atmosphere. This requires a higher level of understanding of Australia's energy resources and the factors likely to affect their development and use.

Geoscience Australia and the Bureau of Resources and Energy Economics were commissioned by the Australian Government Department of Industry to produce a comprehensive and integrated scientific and economic assessment of Australia's energy resources. This is the second edition of the Australian Energy Resource Assessment, the first edition being published in 2010. This edition focusses on the current state of the energy sector and does not include market projections.

Geoscience Australia is the Australian Government's geoscience agency which provides geoscientific information and knowledge to enable government and the community to make informed decisions about the exploitation of resources, the management of the environment, and the safety of the community and critical infrastructure.

The **Bureau of Resources and Energy Economics (BREE)** is the Australian Government's economic research agency which provides independent economic research, analysis and forecasting on issues relating to Australia's energy and resources sectors.

The assessment brings together public energy resource information from a wide range of domestic and international sources, as well as the information held by Geoscience Australia and BREE. For each energy resource, information and analysis is provided on current and potential resource size, distribution and characteristics, as well as Australian and world markets comparisons. Key factors likely to affect the development and utilisation of each energy resource, including the analysis of prices, costs, government policies, technological developments, environmental considerations are presented.

Non-renewable energy resources will continue to play an important role in Australia and overseas. These resources are dominated by the fossil fuels, which include: crude oil, condensate, liquefied petroleum gas and shale oil; conventional gas, coal seam gas, tight gas and shale gas; and black and brown coal, as well as the nuclear energy fuels uranium and thorium (potential). The stock of non-renewable energy resources is ultimately finite, but there is still good potential for discovering new economic resources to replace the resources that are mined or produced, and so ensure future indigenous supply.

Renewable energy resources—energy resources that are replaced naturally on a time scale similar to their use—are expected to play an increasingly important role in Australia's energy mix as the country transitions to a lower emissions economy. Australia's renewable energy resources are rich and diverse. They include geothermal; hydro; wind; solar; ocean; and bioenergy sources.

The assessment covers the following energy resources:

- crude oil, condensate, liquefied petroleum gas, and shale oil;
- conventional gas, coal seam gas, tight gas, shale gas, and gas hydrates;
- black and brown coal;
- uranium and thorium;
- geothermal;
- hydro;
- wind;
- solar;
- ocean (wave, tidal, and ocean thermal); and
- bioenergy,

and is structured as follows.

Chapter 1 presents a summary of the assessment with comparisons to the 2010 first edition of the Australian Energy Resource Assessment.

Chapter 2 is an overview of Australia's energy resource base and market. It provides a holistic assessment of our combined energy resources, energy-related infrastructure, and Australian energy consumption, production and trade, as well as our place in the world energy market. It also assesses the key factors likely to affect the development and utilisation of Australia's energy resources in the next two decades, including economic and population growth, energy prices, cost competitiveness of energy sources, and technological developments.

Chapters 3 to 12 contain detailed individual assessments for each of Australia's key energy resources. Each resource assessment follows a similar structure. The first part is a summary of the key information in the chapter. The second part includes background with definitions, the structure of the industry and the world market. The third part covers detailed information on the resources, such as economic and total demonstrated resources, location and characteristics. It also provides information on the Australian market for that resource, including production, consumption, recent growth, and any trade that occurs. The fourth part contains outlooks over the next few decades, which includes an assessment of the key factors that will affect the resource over that timeframe, including prices, cost of development, technological developments, and infrastructure considerations.

These assessments are supported by a number of Appendices.

Appendix A contains a list of abbreviations used in this report.

Appendix B provides a glossary of energy-related terms.

Appendix C provides an explanation of how resources are classified and quantified, based largely on the McKelvey resource classification system. Renewable energy resources are commonly transient and not always available, and hence not readily classified using the McKelvey system. The authoritative and rigorous form of resource classification, particularly for non-renewable resources, is central to ensuring that investment decisions can be made with confidence. Renewable resources are often reported in terms of output or installed capacity.

Estimates of renewable resource potential are based on maps that show the energy (or power) potentially or theoretically available at the site and detailed studies of the annual and diurnal variation in the energy to determine the capacity factor (the average actual energy output compared with the theoretical maximum possible output if the energy was continuously and fully available for use).

Appendix D lists the energy measurement and conversion factors, as, energy resources, production, consumption and trade have generally been converted to a common energy unit—petajoules (PJ)—to enable direct comparison of different energy sources. Mineral and petroleum resources are also presented in volume or mass units commonly used in industry. The energy content of the different energy sources varies significantly. Fuels such as oil, natural gas, LNG and LPG generally have a high energy content, whereas brown coal and biomass generally have a low energy content for an equivalent weight. The energy content in this context is the gross energy content of the fuel—that is, the total amount of heat that will be released by combustion. Average energy contents and conversion factors are given. The values are indicative only because the quality of any fuel varies according to factors such as location and air pressure, grade of the resource, and so on.

Appendix E displays the geological time scale and the timing of major energy forming events in Australia. Australia's petroleum and mineral resources have been formed by geological processes acting within a time scale of millions of years.

Contents

Chapter 1

Executive Summary

1.1 Summary

KEY MESSAGES

- This is an update to the first national assessment of Australia's energy resources released in 2010. This assessment provides a snapshot of Australia's identified and potential energy resources—ranging from fossil fuels and uranium to renewables—and reviews the factors likely to influence the future use of Australia's energy resources.
- Australia has an abundance and diversity of energy resources. Since 2010, the estimated total demonstrated non-renewable energy resources, with the exception of oil, has increased. Australia continues to have the world's largest economic uranium resources, the fourth largest coal (black and brown) resources, and substantial conventional and unconventional gas resources. This globally significant resource base is capable of meeting both domestic and increased export demand for coal and gas, and uranium exports, during the next several decades. There is good potential for further growth of the resource base through new discoveries. Identified resources of crude oil, condensate and liquefied petroleum gas are more limited, and Australia is increasingly reliant on imports for transport fuels.
- Australia has a rich diversity of renewable energy resources (wind, solar, geothermal, hydro, wave, tidal, bioenergy). Hydro energy resources are already mostly developed. Since 2010, wind and solar energy resources use has grown strongly, and is continuing to do so. Geothermal and ocean energy resources remain largely undeveloped. Renewable energy resources could contribute significantly more to Australia's future energy supply.
- Australia's transformation to lower emissions energy sources has commenced under the influence of the renewable energy target and initiatives such as the Australian Renewable Energy Agency.
- Technology development and commercialisation to improve efficiency in the extraction and use of energy, and to reduce the emissions intensity of the sector, will play a critical role in the transition to a lower emissions economy.
- Australia's energy demand is expected to rise during the next few decades; however, the rate of growth is expected to slow. This slowing is partly due to expected energy efficiency improvements and higher energy prices. The primary fuel mix is expected to change. Although coal is expected to continue to dominate Australia's electricity generation, a shift to lower emissions fuels is expected to result in increases in gas and renewable energy—particularly wind and solar.
- Australia's energy infrastructure is concentrated in areas where energy consumption is highest and major fossil fuel energy resources are located. Greater use of new energy resources, particularly renewable energy sources, will require more flexible and decentralised electricity grids.

1.2 Introduction

Australia's abundance of energy resources is a key contributor to Australia's economic prosperity. In 2011–12, the Australian energy sector continued to account directly for 5 per cent of industry gross value added, contributed 24 per cent of total export value, supported a large range of manufacturing industries, and provided significant employment and infrastructure.

Australia's economy, and the energy sector in particular, is undergoing transformational change to a lower emissions economy. The energy sector currently accounts for three-quarters of Australia's greenhouse gas emissions. Australia's energy needs have been met largely by fossil fuels; however, the transformation to a lower emissions economy has begun. In 2007–08, coal resources generated three-quarters of domestic electricity; in 2011–12 coal resources accounted for about two-thirds of Australia's electricity generation. Renewables energy sources accounted for about 7 per cent of electricity generation in 2007–08, which grew to 10 per cent in 2011–12. Australia's transport system is heavily dependent on oil, much of which is imported.

Global and national energy demand will continue to grow; however, rising prices and government policies to reduce greenhouse gas emissions and encourage energy efficiency are expected to moderate the rate of growth. The global energy system will change fundamentally during the coming decades—lower emissions energy sources and technologies will progressively capture market share and diversify the world's energy supply. All three of the International Energy Agency's (IEA's) modelling scenarios (current policies, new policies and 450 parts per million policy) for the global energy demand from 2010 until 2035 indicate that world primary energy demand will increase, although the strength of the global response to reducing greenhouse emissions will determine the rate of growth.

Australia has a diverse portfolio of energy resources, and is in a good position to take advantage of growing global energy markets. Australia's energy future will be influenced by:

- the need to deliver secure, reliable and competitively priced energy for a growing population and economy
- the further expansion of Australia's energy exports to Asia and other growth markets
- the need to become more energy efficient across the economy and transform to a clean energy economy.

The objective of this report by Geoscience Australia and the Bureau of Resources and Energy Economics (BREE) is to provide a 'stocktake' of Australia's energy resources from 2008 to 2012, a review of the technologies and consideration of other factors (e.g. the global energy market) that are likely to influence the development and use of Australia's energy resources in the next decades.

1.3 Australia in the world energy market

Australia is richly endowed with natural energy resources that enable it to play an important role in supplying the world with its energy needs. Australia has the largest uranium economic resources in the world (estimated 32 per cent of world resources), is the fourth largest holder of coal economic resources in the world (estimated 9 per cent of world resources), and has large and growing gas resources (currently 1.6 per cent of the world natural gas resources). Australia has limited oil reserves, currently accounting for about 0.3 per cent of world reserves. Our potential renewable energy resources base is very large and widely distributed across Australia.

Australia is the world's ninth largest energy producer, accounting for around 2.4 per cent of world energy production. Australia produces energy for meeting our domestic energy needs and for exports. Australia is currently one of the world's largest exporters of coal and uranium, and is the fourth largest exporter of liquefied natural gas (LNG). In contrast, Australia has limited domestic supplies of crude oil and is increasingly reliant on imports for its transport fuels.

Australia is a net energy exporter, with 80 per cent of total energy production being exported. In 2011–12, Australian energy resources generated A$77 billion worth of energy exports, supported by high world prices.

Australia is the world's 21st largest consumer of energy (compared with 20th in 2008) and the 18th largest energy user per capita (compared with 15th in 2008).

Australia's energy market differs from that of many other Organisation for Economic Co-operation and Development (OECD) countries and world energy markets. Coal plays a much larger role in Australia's fuel mix, reflecting our large, low-cost resources located near demand centres. The penetration of gas in Australia is similar to that of the OECD and world averages, as is that of wind and solar. On the other hand, Australia has fewer hydro energy resources, makes less use of bioenergy than some countries and does not use nuclear power.

1.4 Australia's energy resources and market

Australia's energy production was 17 460 petajoules (PJ) in 2011–12, which was up from 17 360 PJ in 2007–08 (table 1.1, figure 1.1). In 2011–12, the main energy sources produced, on an energy content basis, were coal (60 per cent, an increase from 54 per cent in 2007–08), uranium (20 per cent, a decrease from 27 per cent in 2007–08) and gas (13 per cent, an increase from 11 per cent in 2007–08). Renewable energy accounts for nearly 2 per cent of total production in 2011–12 (the same percentage share as in 2007–08).

Primary energy consumption increased to 6194 PJ in 2011–12, compared with 5772 PJ in 2007–08 (table 1.1, figure 1.1). Oil accounted for around 39 per cent (an increase from 34 per cent in 2007–08), followed by black and brown coal, accounting for around 34 per cent (a decrease from 40 per cent in 2007–08), and gas (22 per cent, the same percentage share as in 2007–08). Renewable energy accounted for 4.6 per cent of primary energy consumption in 2011–12 (similar to 2007–08), most of which is bioenergy. Wind and solar accounted for 0.7 per cent of primary energy consumption in 2011–12, which is a rise from 0.3 per cent in 2007–08. There has been strong growth of solar energy since 2010.

Total electricity production was around 914 PJ (254 terawatt hours [TWh]) in 2011–12, which is slightly lower than 2007–08 electricity production of 925 PJ (257 TWh; table 1.1, figure 1.1). In 2011–12, coal accounted for about two-thirds of Australia's electricity generation, followed by gas (19 per cent) and renewables (10 per cent). Renewables were predominantly hydro, with contributions from bioenergy, wind and solar photovoltaic (PV). This contrast with 2007–08, when coal accounted for three-quarters of Australia's electricity generation, followed by 16 per cent for gas and 7 per cent for renewables, most of which was hydro.

Table 1.1 Summary of Australia's energy production and consumption, 2007–08 and 2011–12

	Energy production (PJ)	Primary energy consumption (PJ)	Electricity generation (PJ)
2007–08	17 360	5772	925
2011–12	17 460	6194	914

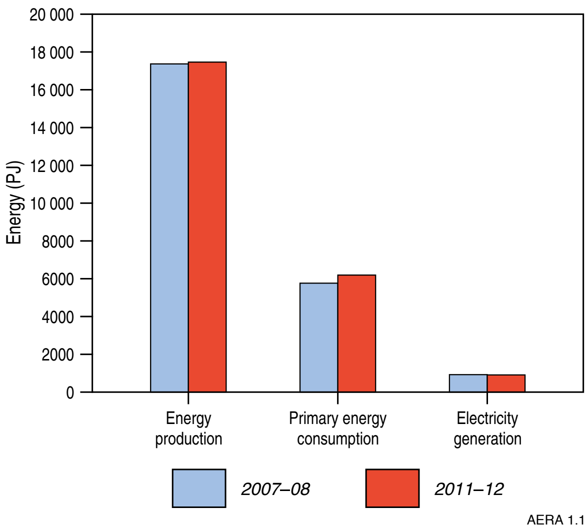

Figure 1.1 Australia's energy production, primary energy consumption and electricity generation, 2007–08 and 2011–12

Source: Bureau of Resources and Energy Economics

Australia has abundant high-quality fossil fuel resources, notably coal (black and brown) and gas (conventional, coal seam gas and potentially shale and tight gas) resources, which are widely distributed across the country (figure 1.2). Resources of oil (crude oil, condensate and liquefied petroleum gas [LPG]) are more limited (especially crude oil resources), and Australia relies increasingly on imports to meet demand for transport fuels. With the exception of crude oil, Australia's fossil fuel resources are expected to last for many more decades, even with increased levels of production.

Coal is Australia's largest energy resource. At the end of 2012, Australia's recoverable Economic Demonstrated Resources (EDR) of black coal were 1 641 863 PJ (61 082 million tonnes [Mt]), an increase from the 2008 estimate of 883 400 PJ (39 200 Mt; figure 1.3). Most of these resources are located in the Sydney and Bowen basins, and there are also significant black coal resources in the Surat, Galilee and Clarence–Moreton basins. Australia's EDR of black coal are sufficient for about 110 years at current production rates, which is an increase from 2008 production levels (90 years).

In 2012, Australia's recoverable EDR of brown coal resources were estimated to be 435 577 PJ (44 164 Mt), increasing from 2008 (362 000 PJ, 37 200 Mt; figure 1.3). Almost all these resources (99 per cent) are located in the Gippsland Basin, Victoria, where they are used for electricity generation. There are also substantial undeveloped resources in the Murray Basin. Australia's EDR of brown coal are sufficient for about 510 years at 2012 production levels, which is an increase from 500 years at 2008 production levels.

Australia has the world's largest uranium EDR, estimated to be 657 440 PJ (1174 kilotonnes [kt]) at the end of 2012; this is equivalent to about 170 years at 2012 production levels. This increase from 2008 resource estimates of 651 280 PJ (1163 kt) is a result of high levels of exploration (figure 1.3). There is potential for further increase in resources—in 2012, the Queensland Government lifted the 23-year ban on uranium mining, resulting in renewed interest in uranium projects in the state. In addition, the New South Wales Government removed its ban on uranium exploration, which had been in place for 30 years, although the ban on uranium mining remains in place. Australia also has a major share of the world's thorium resources, a potential future nuclear fuel.

In March 2011, Japan suffered a major earthquake and tsunami, which caused damage to the Fukushima Daiichi nuclear power plant and led to a decision to shut down 50 nuclear power plants (30 per cent of Japan's total electricity generating capacity) for inspection. The Fukushima accident has affected nuclear power projects and policies in many countries, and has had an impact on nuclear power projections and future uranium requirements.

Gas is Australia's third largest energy resource after coal and uranium. Australia's has significant conventional gas resources lying mostly offshore in the Carnarvon, Browse and Bonaparte basins off the north-west coast of Western Australia, and smaller resources in south-east (Gippsland Basin) and central Australia. Conventional gas EDR was estimated to be 109 433 PJ (99 trillion cubic feet [tcf]) at the beginning of 2012, which is a decrease of 7 per cent from 122 100 PJ (111 tcf) in 2008 (figure 1.3). At current production levels, this is enough conventional gas resources for 51 years.

Australia also has significant unconventional gas resources—coal seam gas (CSG), tight gas and shale gas. CSG resources are associated with the major coal basins in Queensland and New South Wales, with further potential resources in South Australia. Current EDR of CSG stand at 35 905 PJ (33 tcf), more than twice the 2008 EDR estimate of 16 590 PJ (15 tcf; figure 1.3). The high levels of CSG exploration are likely to add significantly to known resources. Many Australian sedimentary basins also have potential for shale and tight gas. In 2012, tight gas resources were estimated at around 22 052 PJ (20 tcf). Shale gas resources are now being explored, but their size remains to be defined.

Australia's oil resources are decreasing. Australia's total liquid petroleum resources in 2012 were estimated to be 29 019 PJ (5316 million barrels [mmbbl]), which is a decrease of 5 per cent in total resources from the 2008 estimate of 30 794 PJ (figure 1.3). Total crude oil demonstrated resources in 2012 were estimated to be 7382 PJ (1255 mmbbl) compared with 8414 PJ (1431 mmbbl) in 2008. Most of the remaining crude oil is located in the Carnarvon, Bonaparte and Gippsland basins. In 2012, condensate demonstrated resources were estimated to be 15 973 PJ (2716 mmbbl) compared with 16 170 PJ (2750 mmbbl) in 2008. LPG resources are associated with major, largely undeveloped gas fields in the Carnarvon, Browse and Bonaparte basins off the north-west coast of Australia. In 2012, LPG demonstrated resources were estimated to be 5664 PJ (1345 mmbbl), compared with 2008 resources of 6210 PJ (1475 mmbbl). Australia's oil resources could be extended by new discoveries in deepwater basins (both proven and untested) and further growth at existing fields. Without significant new discoveries of crude oil, or development of condensate and LPG resources associated with offshore gas resources or other alternatives, Australia is likely to be increasingly dependent on imports for transport fuels.

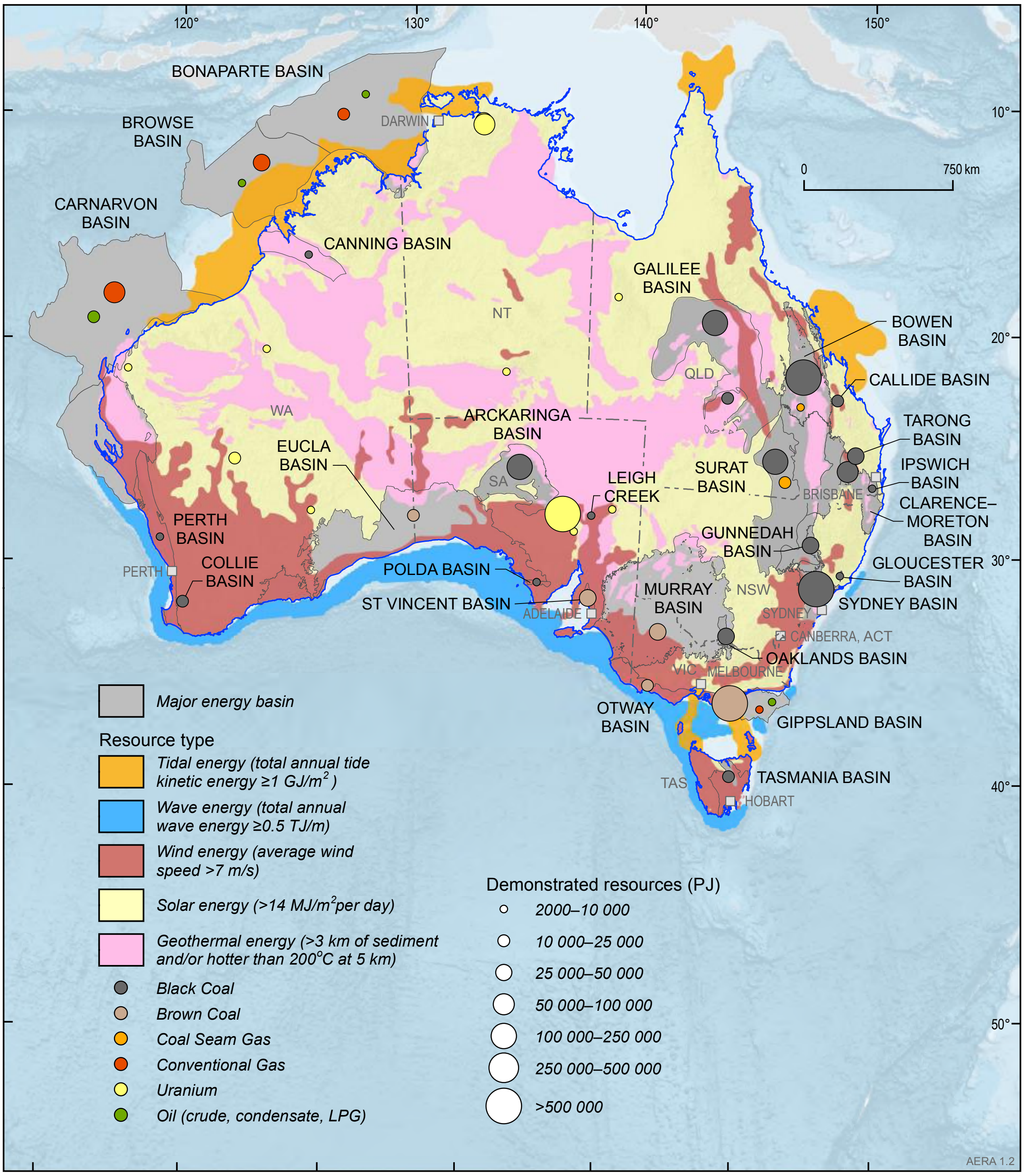

Figure 1.2 Australia's major energy resources, excluding hydro and bioenergy

Note: Total resources are in many cases significantly larger than the remaining demonstrated resources, which do not include inferred and potential (yet to be discovered) resources

Source: Geoscience Australia

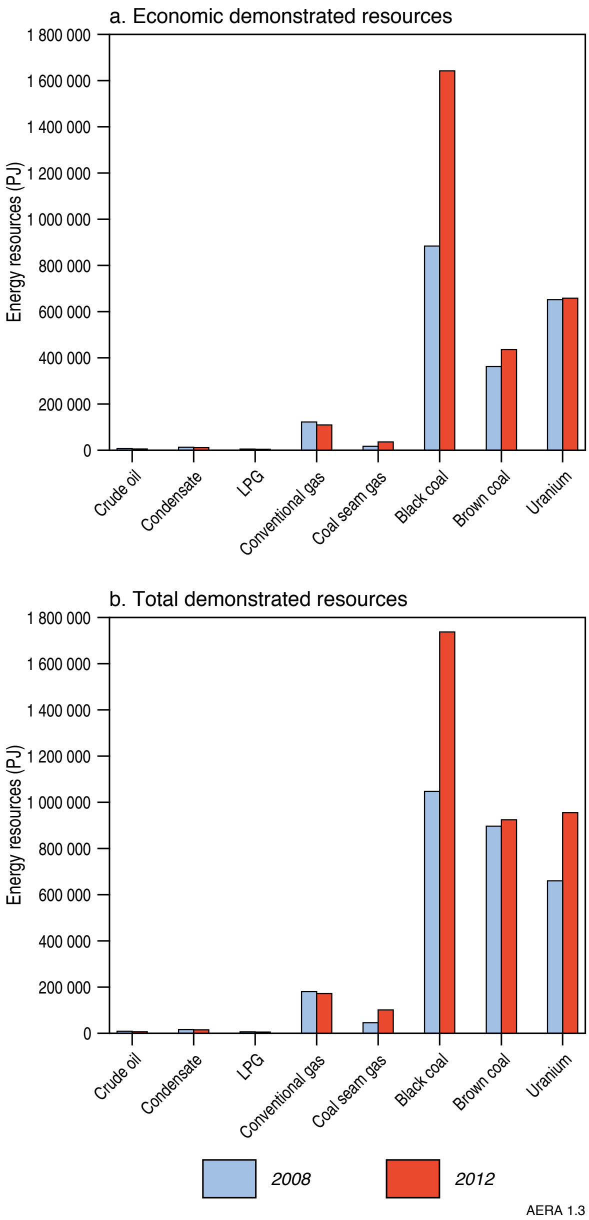

Figure 1.3 Comparison of non-renewable energy resources, 2008 and 2012

Source: Geoscience Australia

Australia has total identified shale oil resources of around 131 659 PJ (22 391 mmbbl) that are not used currently. A demonstration plant, located at Gladstone, produced its first crude oil in 2011. Some sedimentary basins also have potential for hydrocarbon liquids that are generally associated with shale and tight gas occurrences. These resources await further exploration and quantification.

Australia's potential renewable resource base is also very large, and includes wind, solar, bioenergy, geothermal, ocean and hydro resources. The uptake of renewable energy is growing, and wind- and solar-generated electricity are the fastest sectors. Australia's renewable energy resources are largely undeveloped; a number involve technologies that are still at the development or early stages of commercial demonstration.

Australia's hydroelectricity stations have a combined installed capacity of 8.5 gigawatts (GW), an increase from 7.8 GW in 2008 (figure 1.4). This is the due to modernising existing plants and commissioning miniplants. Most of the installed capacity is located in New South Wales and Tasmania—60 per cent and 27 per cent, respectively. However, water availability is a key determinant of future growth in hydroelectricity generation in Australia.

Australia's wind resources are among the best in the world, primarily located in western, south-western, southern and south-eastern coastal regions, but also extending hundreds of kilometres inland. These resources are being progressively used by an increasing number of large-scale (more than 100 megawatts [MW]) wind farms using large, modern wind turbines. In 2012, the installed capacity of wind energy farms was about 2.58 GW, compared with an installed capacity of about 1.7 GW in 2008 (figure 1.4).

High solar radiation levels over large areas of the continent provide Australia with some of the best solar resources in the world. There is a wide range of solar energy technologies at different stages of development. Small-scale rooftop solar PV systems have grown rapidly in Australia from 100 MW capacity in 2008 to about 1.4 GW in 2011 (figure 1.4). At the end of 2012, total solar PV reached 2.3 GW capacity. Development of thermal energy storage technologies will allow storage of excess energy to be used at a later time and can address fluctuations in supply. The outlook for commercial-scale solar PV and thermal electricity generation depends on demonstration at commercial scale, which will reduce investment risks and encourage deployment.

Australia has significant potential geothermal energy associated with buried heat-producing (from natural radioactive decay) granites that could be a source of low-emissions base-load electricity generation. Lower temperature geothermal resources are associated with naturally circulating waters in aquifers deep in sedimentary basins, and are potentially suitable for electricity generation and/or direct use. There are currently two geothermal projects in operation in Australia—a 0.08 MW capacity power plant in Birdsville, Queensland, and a 1 MW capacity pilot plant at the Innamincka Deeps project, South Australia. Potential also exists for use of ground-source heat pumps in heating and cooling buildings.

Ocean energy (wave and tidal) is an undeveloped but potentially substantial renewable energy source. Australia has a world-class wave energy potential along its south-western and southern coast, which have high energy densities, and large areas experiencing constant favourable wave heights (exceeding 1 m). Australia also has significant tidal energy resources, including an average kinetic energy resource of around 2.4 PJ at any time, located mostly along Australia's northern coastline. There are currently three commercial-scale projects at stages of development—the Clarence Strait Tidal Energy project (450 MW) in the Northern Territory, the Banks Straight Tidal Energy project (302 MW) in Tasmania and the Port Phillips Heads Tidal project (34 MW) in Victoria.

Bioenergy is a diverse energy source based on biomass (organic matter) that can be used to generate heat and electricity, and to produce liquid transport fuels. In 2012, bioenergy accounted for 68 per cent of Australia's renewable energy use, but only 3.1 per cent of Australia's primary energy consumption. The biggest contributors to bioenergy are bagasse (sugar cane residue) and wood waste in heating and electricity generation, along with some capture of methane gas from landfill and sewage facilities. About 401 megalitres (ML) of biofuels (ethanol and biodiesel) were produced in 2012, compared with 199 ML in 2008. Greater use of bioenergy could be made through increased use of agricultural residues and wastes, wood waste and non-edible biomass, including new-generation crops.

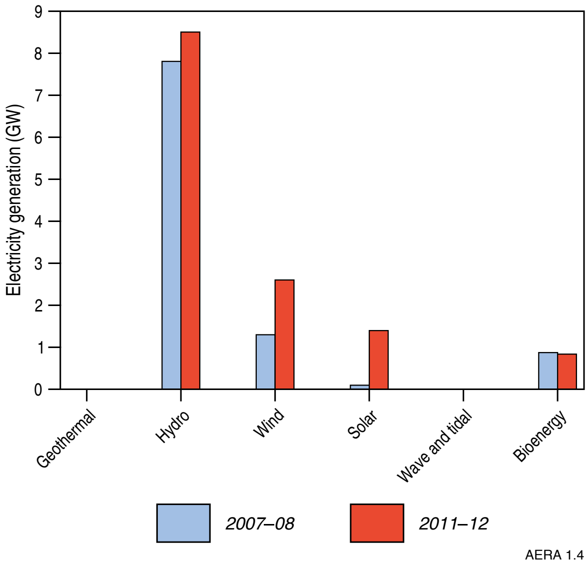

Figure 1.4 Comparison of renewable electricity generation, 2007–08 and 2011–12

Source: Bureau of Resources and Energy Economics; Geoscience Australia

1.5 Outlook for Australia's energy resources and market

Significant changes are anticipated in the Australian energy market for the next two decades as Australia journeys towards a lower emissions economy, which has begun with the introduction of the renewable energy target (RET) and other government policies. Other factors expected to affect the market include the rate of economic and population growth, energy prices, and costs and developments in energy technologies.

In 2012, the Australian Government established the Australian Renewable Energy Agency (ARENA) to deliver funding for research, development and demonstration of renewable energy technologies. ARENA will help to improve the competitiveness of renewable energy technologies and contribute to increasing the supply of renewable energy in Australia. ARENA initiatives include supporting demonstration projects to help move renewable energy technologies closer to commercialisation, growth of renewables in regional areas where there is growing demand for energy and distributed generation, and initiatives that provide system-wide solutions to renewable energy output variability.

Technology is expected to play a critical role in the transition towards a lower emissions economy. This includes technology to improve efficiency in extraction and use of energy, to reduce costs of cleaner technologies, and to develop and commercialise new technologies to access new energy sources.

Australia's energy demand will continue to rise during the coming decades, but the rate of growth is expected to slow. This reflects the long-term trend in the Australian economy towards less energy-intensive sectors and energy-efficiency improvements, both of which can be expected to be reinforced by policy responses. The contribution of gas and renewables is expected to increase significantly.

Australia's total energy production and primary energy consumption is expected to increase over the next few decades.

Net energy trade is expected to increase. Exports of coal and LNG are expected to rise significantly to meet growing world energy requirements. Net imports of liquid fuels are expected to increase reflecting declining oil production.

Australia's energy infrastructure is concentrated in areas where energy consumption is highest and major energy resources are located, particularly along the eastern seaboard of Australia. A significant expansion in Australia's energy infrastructure, particularly electricity generation and transmission, will be required in the next two decades if Australia is to meet its changing demand for energy. Using new energy resources, particularly renewable energy sources, will require a more flexible and decentralised electricity transmission grid.

The IEA's 2012 *World energy outlook* presents three scenarios of the global market: new policies (existing policy commitments), current policies (no new policies) and the 450 scenario (policies to stabilise emissions to 450 ppm in the atmosphere).

The IEA's new policies scenario projects world primary energy demand to increase by 35 per cent between 2010 and 2035 (from around 532 980 PJ to around 720 004 PJ). This represents an average annual growth rate of 1.2 per cent. China and India are expected to account for more than half of the increase in world primary energy demand during this period, driven by continuing strong economic growth.

Around 59 per cent of the increase in energy demand in the IEA's new policies scenario is projected to be met by fossil fuels. Renewable energy demand is also expected to rise rapidly, although from a much smaller base. Renewables are projected to account for 17.8 per cent of world primary energy supply in 2035.

The IEA's current policies scenarion forecasts the highest increase in world primary energy demand by 47 per cent to 781 927 PJ. The fuel mix does not change drastically for primary energy demand under this scenario.

Under the IEA's scenario where countries adopt emissions reduction policies to stabilise the concentration of greenhouse gases in the atmosphere at 450 parts per million of CO_2-equivalents (450 scenario), growth in world energy demand to 2035 is significantly constrained to 619 353 PJ—it is projected to rise by only 16 per cent on current levels. The share of coal in the primary energy mix is projected to fall sharply to 15.8 per cent in 2035 from 27.3 per cent in 2010. In contrast, the share of renewable energy is projected to rise to 26.5 per cent in 2035 from 13.2 per cent in 2010. This reflects the increased competitiveness of renewable technologies relative to coal with the introduction of emissions reduction policies.

The energy sector, especially fossil fuels, will continue to play an important role in the Australian economy, both in terms of domestic energy supply and increasingly in exports. It is clear that if Australia is to transition to a lower emissions economy, a long term structural adjustment to the Australian energy sector will be required.

Although Australia has an abundance of energy resources, this transformation will need to be underpinned by significant investment in energy supply chains to allow for better integration of renewable energy sources and emerging technologies into our energy systems.

Chapter 2
Australia's Energy Resources and Market

2.1 Summary

KEY MESSAGES

- Australia has a large, diverse energy resource base (including fossil fuels, energy minerals and renewables) that supports domestic consumption and sizeable energy exports around the world.
- Australia's very large low-cost coal resources underpin cheap, reliable electricity, and exports of thermal and metallurgical coal. Australia has a substantial uranium resource base that supports world-leading exports. Gas is used domestically and is increasingly being exported as liquefied natural gas. However, Australia has limited crude oil resources and is increasingly reliant on imports for its transport fuels.
- Australia has plentiful and widely distributed wind, solar, geothermal, ocean and bioenergy resources. Wind and solar energy resources are being increasingly exploited; however, the other renewable energy resources remain largely unused. Hydro energy resources are largely developed.
- Australia's energy resource base could increase even more during the next two decades as more resources are discovered, and technology to harness and economically use energy improves.
- Domestic and international demand for Australia's energy resources continues to rise. However, the energy intensity of the Australian economy is expected to continue to fall over the next few decades through energy efficiency gains and the trend to lower emissions energy sources.
- The role of renewable energy is likely to increase significantly, reflecting government policies such as the—solar on roofs, and Renewable Energy Target and the establishment of the Australian Renewable Energy Agency. Advances in renewable energy technologies will also be important.

2.1.1 Australia in the world energy market

- Australia is the world's 21st largest consumer of energy, and 18th largest in terms of energy use per capita.
- Australia's large energy resource endowment and comparative advantages enable it to play an important role in supplying the rest of the world's energy needs.
- Australia is currently one of the world's largest exporters of coal and uranium, and is ranked fourth in terms of liquefied natural gas (LNG) exports.
- Australia holds an estimated 32 per cent of the world's uranium economic resources, 9 per cent of the world's coal resources and 1.6 per cent of the world's natural gas resources.
- Australia also has substantial renewable energy resources, including solar, ocean, wave, geothermal and bioenergy.
- Australia's energy fuel mix is dominated by coal, reflecting our large, low-cost resources. Our energy market therefore differs from those of many other Organisation for Economic Co-operation and Development (OECD) countries and the world energy market where coal is less dominant, and hydro and nuclear energy are significant contributors to the fuel mix.
- The penetration of gas in Australia's energy market is similar to that of the OECD and world average, as is that of wind and solar.
- In its 2012 *World Energy Outlook*, the International Energy Agency (IEA) presents projections to 2035 for world energy demand under three scenarios:
  - new policies—existing policy commitments
  - current policies—no new policies
  - 450 scenario—policy action to stabilise the concentration of greenhouse gas emissions in the atmosphere at 450 parts per million (ppm) of carbon dioxide (CO_2) equivalent.
- Under the IEA's new policies scenario, world primary energy demand will increase by 35 per cent between 2010 and 2035—from around 532 980 petajoules (PJ) to around 720 004 PJ. This represents an average annual growth rate of 1.2 per cent.
- China and India are expected to account for more than half of the increase in world primary energy demand during this timeframe.

- Renewable energy demand is also expected to rise rapidly, albeit from a much smaller base. Renewables are projected to account for 17.8 per cent of world primary energy supply in 2035. Wind will drive much of the growth in renewable energy, although demand for hydro, bioenergy and solar energy will also increase significantly.
- Under the current policies scenario, world energy demand grows significantly (47 per cent) to reach 781 927 PJ in 2035. The fuel mix does not change drastically under this scenario. Gas continues to increase its share of the mix from 21.5 per cent in 2010 to 23.5 per cent in 2035, as does coal (27.3 per cent in 2010 to 29.6 per cent in 2035).
- Under the 450 scenario, growth in world energy demand is significantly constrained—projected to rise by only 16 per cent on current levels. The share of coal in the primary energy demand is projected to fall sharply to 15.8 per cent in 2035 from 27.3 per cent in 2010. In contrast, the share of renewable energy is projected to rise to 26.5 per cent in 2035 from 13.2 per cent in 2010. This reflects the increased competitiveness of renewable technologies relative to coal with the introduction of carbon pricing.

2.1.2 Australia's energy resources and infrastructure

- Australia's high-quality energy resources are widely distributed across the country. With the exception of oil, these resources are expected to last for many more decades, even as production increases.
- The fossil fuel resources available to Australia include coal (black and brown), gas (conventional and unconventional) and oil (crude oil, liquefied petroleum gas [LPG], condensate and unconventional oil). However, Australia has only limited domestic supplies of crude oil, and increasingly relies on imports to meet demand.
- As of December 2012, Australia's Economic Demonstrated Resources (EDR) of black coal was estimated to be about 1 641 863 PJ (figure 2.1a). Conventional gas EDR was estimated to be 109 433 PJ and coal seam gas was 35 905 PJ. Crude oil EDR are estimated to be 7382 PJ, condensate to be 15 972 PJ and LPG to be 5664 PJ.
- Australia has extensive uranium and thorium resources. At the end of 2012, Australia's EDR of uranium are estimated to be around 657 440 PJ (1174 kilotonnes [kt], figure 2.1a). Australia's total *in situ* Recoverable Identified Resources of thorium amount to 595 kt.
- Australia's potential renewable resource base is very large. This includes some of the best solar and wind energy resources in the world. Australia has a world-class wave energy potential along its south-western and southern coast, and significant (hot rock) geothermal energy potential, associated with buried heat-producing granites.
- There is significant potential to increase the importance of bioenergy in Australia through greater use of biomass and greater production of biofuels for use in transport.
- Although hydro energy currently accounts for the major share of Australia's renewable electricity generation, water availability limits any significant expansion.
- Most of Australia's installed renewable electricity generation capacity is hydro and wind energy (figure 2.1b). The next largest are solar and bioenergy (biomass and biogas). Australia has significant geothermal and wave energy resources, but these industries are currently at pilot or demonstration stages, and are not yet commercialised.
- Energy infrastructure is concentrated in areas where energy consumption is highest and major energy resources are located, particularly along the eastern seaboard of Australia.

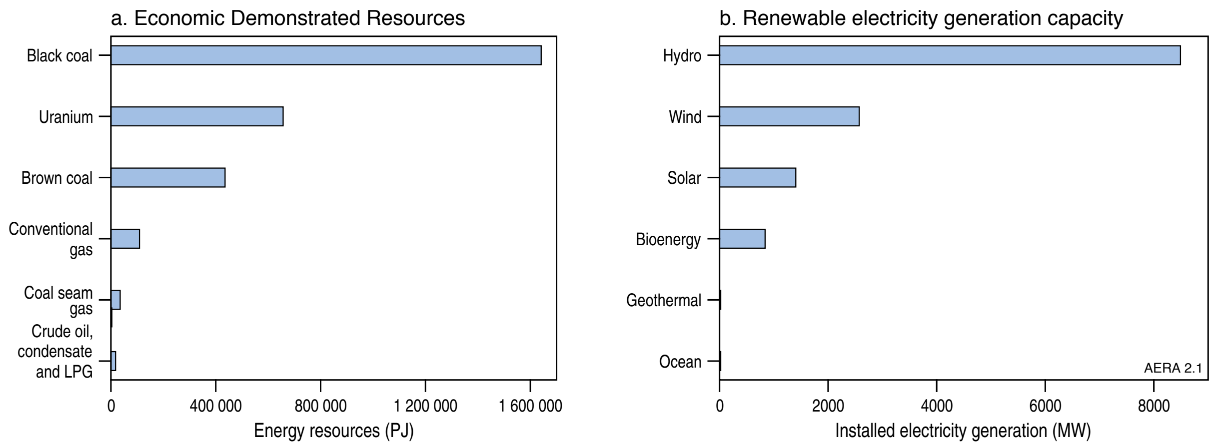

Figure 2.1 Australia's energy resources in terms of Economic Demonstrated Resources of non-renewable resources and installed renewable electricity generation capacity

Source: Geoscience Australia; BREE 2012b

- A significant expansion in Australia's energy infrastructure will be required in the next two decades if Australia is to meet its demand for energy. Using new energy resources, especially renewable energy sources, will require a more flexible and decentralised electricity grid.

2.1.3 Australia's energy market

- The energy sector plays an important role in Australia's economy. It accounts for around 5 per cent of industry gross value added, and 24 per cent of total export value. It also provides significant employment and infrastructure, and supports a range of manufacturing industries.
- Australia's energy production was 17 460 PJ in 2011–12. The main energy sources produced, on an energy content basis, are coal (60 per cent), uranium (20 per cent) and gas (13 per cent). Oil comprises around 6 per cent while renewable energy accounts for nearly 2 per cent of total production.
- Primary energy consumption was 6194 PJ in 2011–12. Oil accounts for around 39 per cent of this total, followed by coal (black and brown coal, 34 per cent) and gas (22 per cent) (figure 2.2). Renewable energy accounts for over 4 per cent of primary energy consumption, most of which is bioenergy (3.1 per cent). Wind and solar energy sources account for only 0.7 per cent of primary energy consumption.
- Total electricity production was around 914 PJ (254 terawatt hours [TWh]) in 2011–12. Coal accounts for more than two-thirds of Australia's electricity generation, followed by gas (19 per cent). Renewables account for an estimated 10 per cent of electricity generation, most of which is hydro.

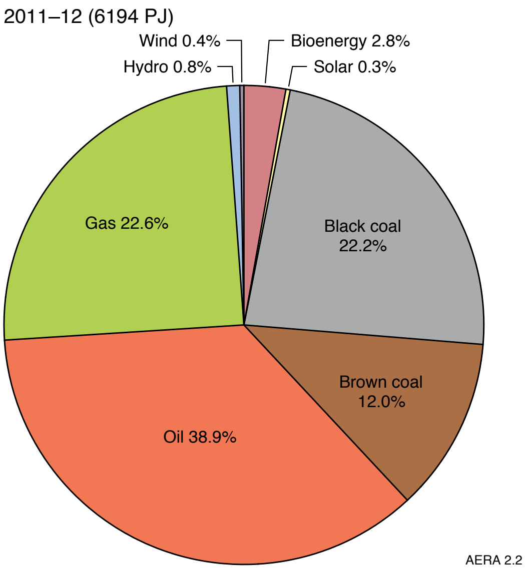

Figure 2.2 Australia's primary energy consumption in 2011–12

Source: BREE 2013b

- Australia is a net energy exporter, exporting 80 per cent of its total energy production. Australia's energy resources generated over A$77 billion worth of exports in 2011–12 and were supported by higher world prices.
- Coal accounted for about 60 per cent of energy exports on an energy content basis, followed by uranium (25 per cent). In contrast, Australia imports more than 80 per cent of its oil requirements.
- Major changes are anticipated in the Australian energy market during the next two decades, reflecting new policy initiatives.
- Other factors expected to affect the market include the rate of economic and population growth, energy prices, and costs and developments in alternative energy technologies.
- Technology is expected to play a critical role in the transition to a low-emissions economy. This includes the development and commercialisation of technology to improve efficiency in the extraction and use of energy, and to reduce the emissions intensity of the sector.

2.2 Australia in the world energy market

As outlined in Chapter 1, Australia has comparative advantages that enable it to play an important role in supplying the rest of the world with its energy needs (figure 2.3). Coal plays a much larger role in Australia's fuel mix, compared to the rest of the world, reflecting the large and low cost energy resource. This section provides a brief overview of the world energy market and the role of Australia, as well as some comparisons between the Australian, OECD and world markets. It also summarises the outlook for the world energy market presented by the IEA, in its *World Energy Outlook* released in October 2012.

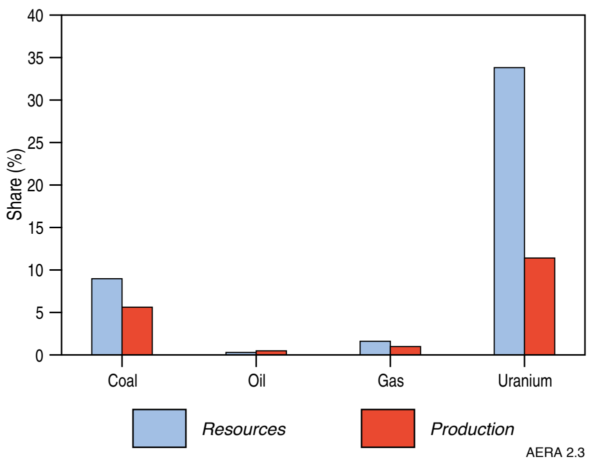

Figure 2.3 Australia's share of world energy resources and production, 2011–12

Note: Resources data are for financial year 2010–11 and production data are for calendar year 2010

Source: BP 2012; IEA 2012a

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2.2.1 Current world market snapshot

Resources and production

World energy resources are widely dispersed. Some countries have large amounts of single or multiple energy resources, whereas others have limited indigenous energy resources and rely on imports to meet requirements.

Large, proved coal reserves are located in the United States, the Russian Federation, China and Australia. Significant proved crude oil reserves are located in Saudi Arabia, Iran, Iraq, Kuwait and the United Arab Emirates; most of the world's proved conventional gas reserves are in the Russian Federation, Iran and Qatar. Australia has the world's largest uranium resources, followed by Kazakhstan and Canada.

Most countries have some potential for renewable energy resources, although these resources in some regions and countries are of higher quality and more readily accessible than in others. Asia, Africa and the Americas have the highest potential for hydroelectricity. Geothermal potential is generally the highest in countries located near chains of active volcanoes; however, technological improvements have made it possible for most countries to use shallow low-temperature geothermal resources. Solar potential is greatest in the Red Sea area, including Egypt and Saudi Arabia, but Australia and the United States also have above average potential. Locations with the highest wind energy potential include the coastal regions of western and southern Australia, New Zealand, southern South America, South Africa, northern and western Europe, and the north-eastern and western coasts of Canada and the United States. Some of the coastlines with the greatest wave energy potential are the western and southern coasts of South America, South Africa and Australia.

In 2010, world energy production was around 537 588 PJ. The largest energy producers include China, the United States and the Russian Federation. Australia is the world's ninth largest energy producer, accounting for 2.4 per cent of world energy production (IEA 2012a). Australia is the world's 3rd largest producer of uranium, 4th largest producer of coal and 14th largest producer of gas.

Primary energy consumption

World primary energy consumption increased by 2.3 per cent per year between 2000 and 2010. In 2010, China (17.4 per cent) overtook the United States (17.3 per cent) to become the world's largest energy consumer; India (5.3 per cent), the Russian Federation (5.1 per cent) and Japan (3.7 per cent) are the next three largest users. Australia is the world's 21st largest consumer of energy (0.9 per cent) and 18th highest in terms of energy use per capita (IEA 2012a).

Oil is the world's main energy source, currently accounting for around 32 per cent of total primary energy consumption, followed by coal (27 per cent) and gas with (21 per cent) (figure 2.4a). This fuel mix has been relatively stable during the past decade. Nuclear accounts for 5.7 per cent of the world primary energy consumption mix. Renewables account for around 13 per cent of world energy consumption—most of which is bioenergy, with much smaller contributions from hydro, geothermal and wind sources.

Coal plays a more significant role in Australia's energy mix than in other OECD markets (figure 2.4a). Australia's dependence on oil is similar to the OECD average; the penetration of gas is similar to world levels, but below the OECD averages. Australian solar penetration is similar to both OECD and world averages, while the use of hydro and bioenergy is significantly lower than world energy markets.

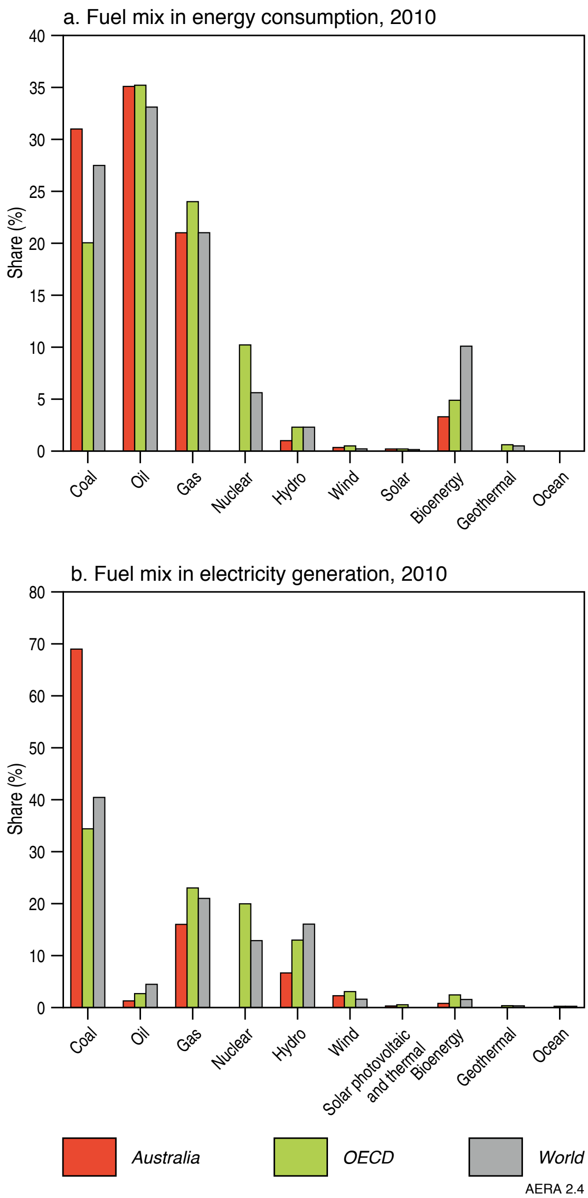

Figure 2.4 Fuel mix in primary energy consumption and electricity generation, 2010

Source: IEA 2012a

Electricity generation

Gross electricity generation has increased by 3.5 per cent per year since 2000 to reach 21 396 TWh in 2010 (IEA 2012a).

Coal and gas are also the largest sources of world electricity generation, with 40 per cent and 22 per cent in 2010, respectively (figure 2.4b). Nuclear power comprises 12.9 per cent of world and 21 per cent of OECD electricity production. Renewables contribute around 19 per cent of global electricity generation—most of which is hydro energy.

Australia relies more heavily on coal for electricity generation than the world and OECD averages, where the balance of base-load power generation comprises a larger proportion of nuclear and hydro energy (figure 2.4b). The use of gas-fired electricity in Australia is lower than the world and OECD average. However, the share of wind and solar in Australia is similar to the world average (although still below OECD averages).

Trade

With a number of energy resources located long distances from major energy consumers, there has been considerable growth in world energy trade during the past decade. World energy imports have increased by 2.7 per cent per year since 2000 to account for 38 per cent of primary energy consumption in 2010. The main energy exporters include the Russian Federation, Saudi Arabia and Canada (IEA 2012a).

Australia plays an important role in supplying regional and global energy demand, particularly for coal and uranium, and—increasingly—natural gas (figure 2.5). Australia is the world's third largest energy exporter overall—and one of the world's largest exporters of coal, uranium and natural gas.

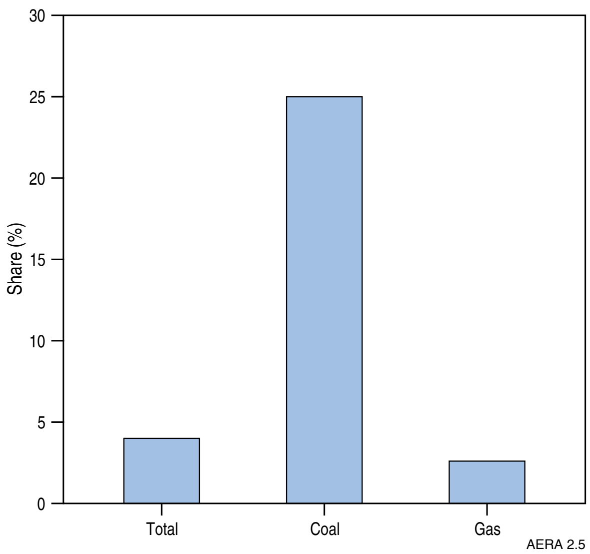

Figure 2.5 Australia's share of world energy trade, 2011

Source: IEA 2012a

2.2.2 World energy market outlook

As part of its annual *World energy outlook*, the IEA provides three modelling scenarios of the global energy market to 2035 (IEA 2012b):

- a new policies scenario based on existing policy commitments, as well as assuming that announced policies are cautiously implemented
- a current policies scenario, which assumes that no new policies beyond those adopted by mid-2012 will be implemented
- a 450 scenario, which assumes international policy action sufficient to limit the concentration of greenhouse gas emissions in the atmosphere at 450 ppm of CO_2 equivalent.

IEA new policies scenario

In the new policies scenario, which predicts how global energy markets would evolve if governments made no changes to their existing policies and measures, world primary energy demand is projected to increase by 35 per cent (from around 532 980 PJ to around 720 004 PJ) between 2010 and 2035 (IEA 2012b; table 2.1). This represents an average annual growth rate of 1.2 per cent, with the majority of this increase expected to be driven by non-OECD countries.

China and India are expected to account for more than half of the increase in world primary energy demand during 2010–35, driven by continuing strong economic growth. Energy demand in the Middle East and Latin America is also projected to grow strongly during this period.

Global demand for coal is expected to grow by an average of 0.8 per cent each year between 2010 and 2035, with its share of global energy demand falling from 27.3 per cent in 2010 to 24.5 per cent in 2035 (figure 2.6, table 2.1). The vast majority of this increase in world coal demand is expected to come from China and India. China is also projected to account for slightly less than half of the increase in global coal production during the period. The United States, India, Indonesia and Australia are expected to remain the next largest coal producers.

World demand for gas is projected to grow at an annual average rate of 1.6 per cent during the outlook period, with its share of world energy use to grow to 23.9 per cent in 2035 (figure 2.6b, table 2.1). Slightly less than 80 per cent of the increase in demand is projected to be from non-OECD countries, particularly China, India and the Middle East. The United States, China, Australia, and countries of the former Soviet Union, Middle East and Africa are expected to account for the majority of increases in natural gas production during the period to 2035.

The IEA forecasts that the rise in unconventional gas production, comprising around half of the increase in total gas projection to 2035, will contribute to an oversupply of gas in the next few years. This has implications for prices, as well as energy trade. For instance, increasing LNG supplies, particularly from North America, are likely to find their way to Asia, thereby connecting prices in Pacific and Atlantic regions, and increasing the globalisation of natural gas markets.

Global demand for oil is projected to grow by 0.5 per cent per year on average to 2035. Oil is expected to remain dominant in the primary fuel mix, but its share of world energy use is expected to decline from 32.3 per cent in 2010 to 27.1 per cent in 2035 (figure 2.6, table 2.1). More than 80 per cent of the global increase in oil demand is expected to come from China and India, offsetting falling OECD demand. Most of the increase in oil production during the period is projected to come from conventional resources in OPEC countries (mainly in the Middle East). Growing unconventional resource exploitation, predominantly in non-OPEC countries, will serve to offset falling conventional production in those countries. The OPEC share in total oil production is projected to increase from an estimated 42 per cent in 2011 to 48 per cent in 2035.

From 2010 to 2035, the share of nuclear power in primary energy demand is projected to increase slightly, from 5.6 per cent to 6.6 per cent, as demand increases by 1.9 per cent per year during this period (figure 2.6, table 2.1).

Most of the projected growth in nuclear power is expected to be in China, with the remainder coming predominantly from India and the United States. Nuclear power capacity in Europe, however, is projected to decline during the outlook period. Australia is expected to remain a key provider of uranium exports to the growing Asian markets.

Globally, renewable technologies are expected to grow faster than any other energy source between 2010 and 2035, but from a smaller base. Excluding bioenergy

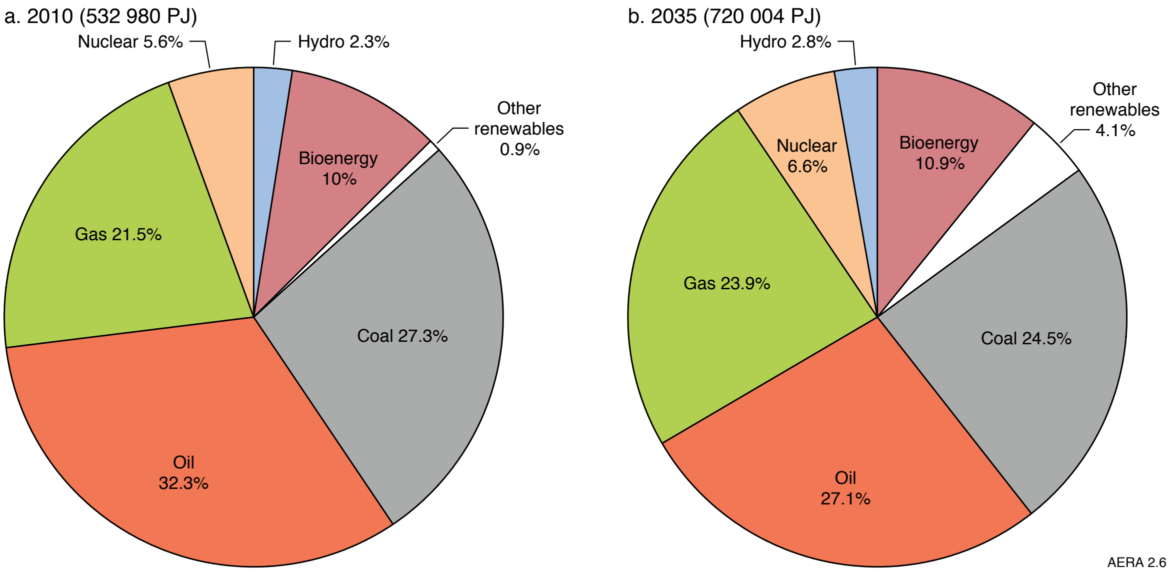

Figure 2.6 Outlook for world primary energy demand under the International Energy Agency new policies scenario

Source: IEA 2012a

Table 2.1 Outlook for world primary energy demand under the International Energy Agency new policies scenario

Energy source	2010 (PJ)	2010 (%)	2035 (PJ)	2035 (%)	Average annual growth 2010–2035 (%)
Coal	145 449	27.3	176 599	24.5	0.8
Oil	172 203	32.3	194 937	27.1	0.5
Gas	114 718	21.5	171 910	23.9	1.6
Nuclear	30 103	5.6	47 646	6.6	1.9
Hydro	12 351	2.3	20 432	2.8	2
Bioenergy	53 465	10	78 754	10.9	1.6
Other Renewables	4689	0.9	29 726	4.1	7.7
Total	**532 980**	**100**	**720 004**	**100**	**1.2**

PJ = petajoule

Note: Totals may not add due to rounding. Data are converted from million tonnes of oil equivalent (Mtoe) to PJ by multiplying by 41.868

Source: IEA 2012b

and hydro energy, electricity generation from renewable energy sources such as wind, solar, geothermal, and wave and tidal (ocean) are projected to grow at an annual average rate of 7.7 per cent (table 2.1). The share of these renewables in total primary energy demand is also expected to increase from 0.9 per cent in 2010 to 4.1 per cent in 2035.

World demand for hydro energy is forecast to grow at an average annual rate of 2 per cent between 2010 and 2035, with its share of world energy demand increasing from 2.3 per cent to 2.8 per cent (figure 2.6, table 2.1). The use of bioenergy is expected to increase by 1.6 per cent per year on average during the outlook period, with its share to grow from 10 per cent to 10.9 per cent of primary energy demand.

World electricity generation is projected to increase by 2.2 per cent per year, to reach 36 637 TWh by 2035 (table 2.2). The share of wind-generated electricity is projected to rise to 7.3 per cent in 2035 (figure 2.7, table 2.2). Other fuels expected to increase their share of electricity generation by 2035 include gas (to 23.1 per cent), bioenergy (to 4.1 per cent), solar photovoltaic (PV, to 2.3 per cent) and geothermal (to 0.9 per cent). In contrast, the shares of coal, oil, nuclear and hydro in world electricity generation are expected to fall.

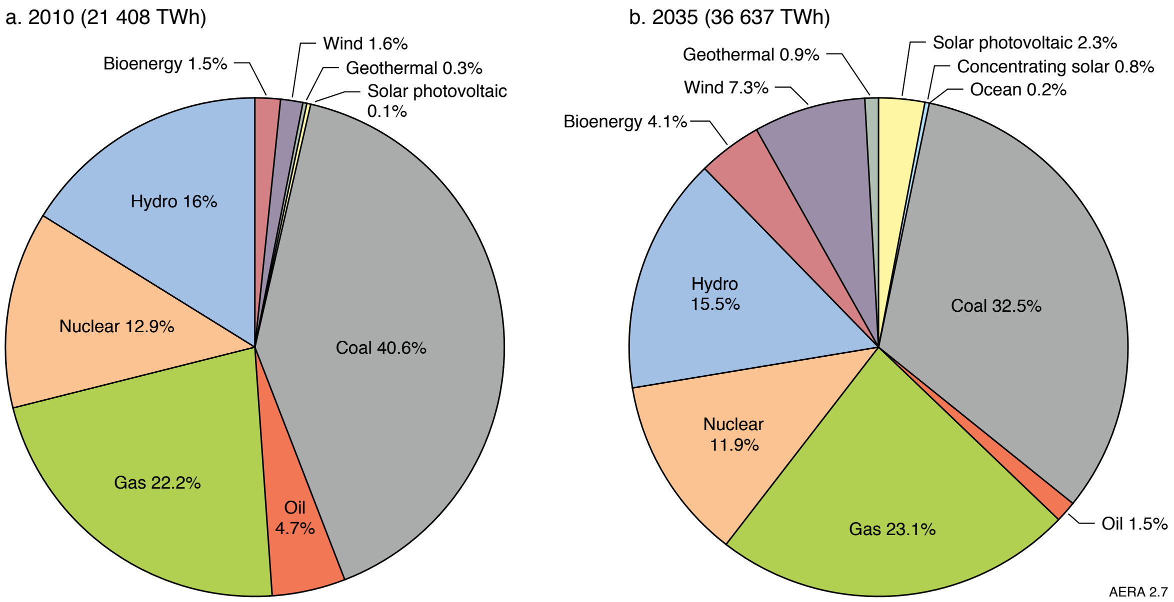

Figure 2.7 Outlook for world electricity generation under the International Energy Agency new policies scenario

Source: IEA 2012b

Table 2.2 Outlook for world electricity generation under the International Energy Agency new policies scenario

Energy source	2010 (TWh)	2010 (%)	2035 (TWh)	2035 (%)	Average annual growth 2010–35 (%)
Coal	8687	40.6	11 908	32.5	1.3
Oil	1000	4.7	555	1.5	–2.3
Gas	4760	22.2	8466	23.1	2.3
Nuclear	2756	12.9	4366	11.9	1.9
Hydro	3431	16.0	5677	15.5	2.0
Bioenergy	331	1.5	1487	4.1	6.2
Wind	342	1.6	2681	7.3	8.6
Geothermal	68	0.3	315	0.9	6.3
Solar PV	32	0.1	846	2.3	14.0
Concentrating solar	2	0.0	278	0.8	23.0
Ocean	1	0.0	57	0.2	10.4
Total	**21 408**	**100.0**	**36 637**	**100.0**	**2.2**

PV = photovoltaic; **TWh** = terawatt hour

Source: IEA 2012b

IEA current policies scenario

The IEA's current policies scenario provides projections for world energy demand if economics continue with policies that have been adopted by mid-2012 with no large changes in underlying trends (IEA 2012b).

The fuel mix in both primary energy demand and electricity generation does not change drastically to 2035 in this scenario. Gas becomes slightly more dominant in both categories, which reflects increasing supply. Coal increases; however, oil loses ground in both categories, becoming the second largest component of primary energy demand behind coal in 2035.

All renewables continue to grow under this scenario, from 13.2 per cent of primary energy demand to 14.5 per cent in 2035 (figure 2.8). The majority of this growth is driven by increases in wind and solar energy generation. Hydroelectricity increases marginally, whereas bioenergy falls.

The IEA's current policies scenario forecasts the greatest rise in global primary energy demand (to 781 927 PJ) and electricity generation (to 40 364 TWh) by 2035. This represents 47 per cent and 89 per cent rise, respectively, on 2012 levels (figure 2.9).

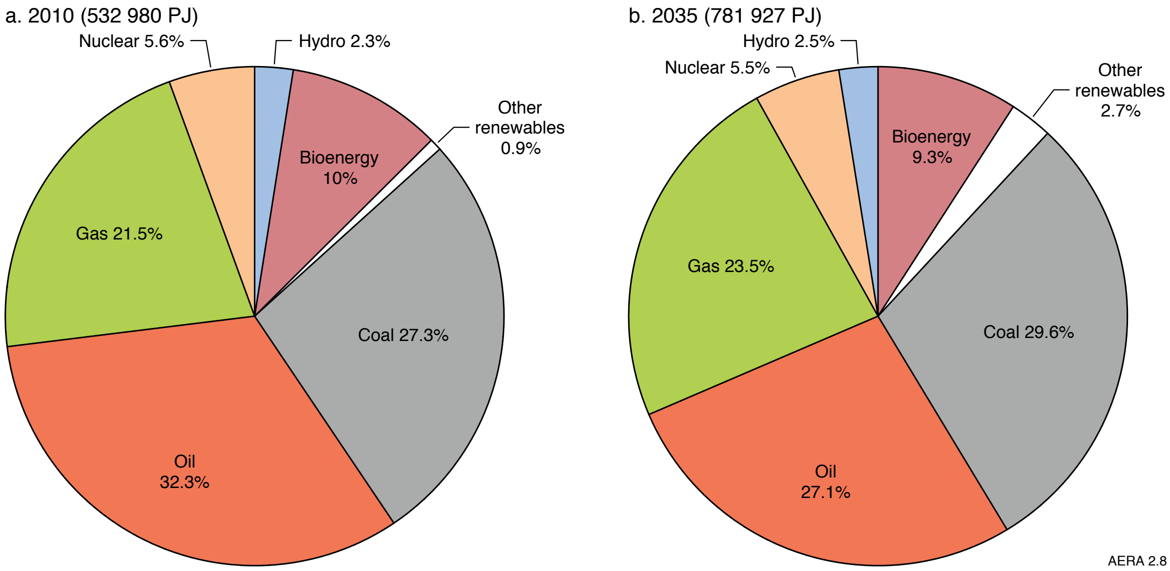

Figure 2.8 Outlook for world primary energy demand under the International Energy Agency current policies scenario

Source: IEA 2012b

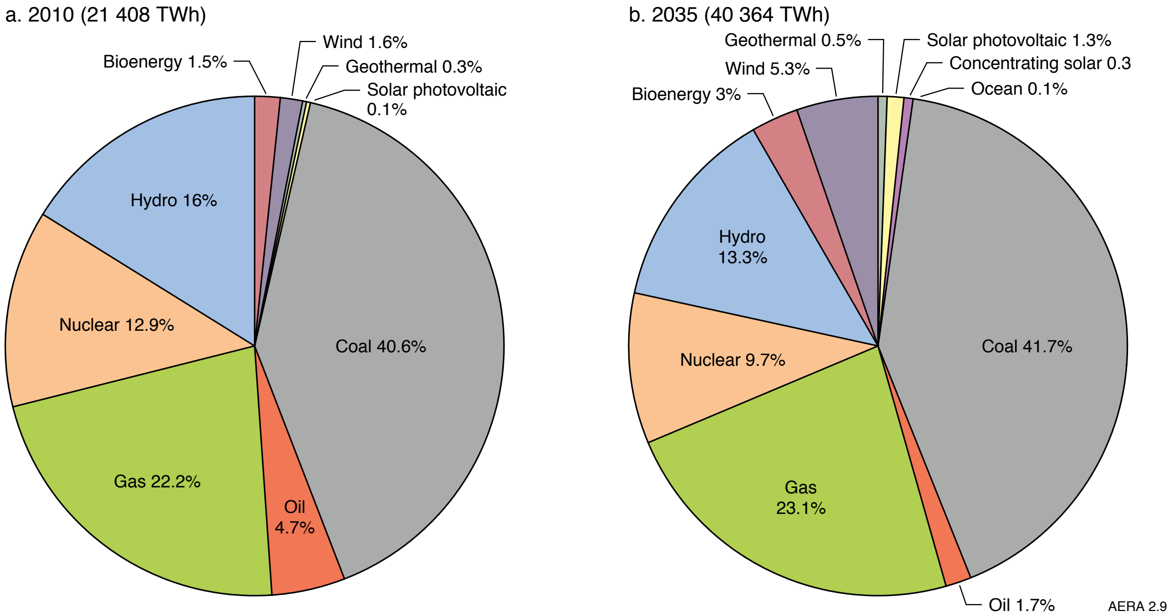

Figure 2.9 Outlook for world electricity generation under the International Energy Agency current policies scenario

Source: IEA 2012b

IEA 450 scenario

The IEA's 450 scenario presents projections for world energy demand if economies adopt emissions reduction policies to stabilise the concentration of greenhouse gas emissions in the atmosphere at 450 ppm of CO_2-equivalent (IEA 2012b).

Under this 450 scenario, projected growth in world energy demand to 2035 is slightly constrained, rising by only 16 per cent on current levels to reach 619 353 PJ in 2035 (around 100 651 PJ lower than in the new policies scenario and 162 574 PJ lower than in the current policies scenario). This is equal to average annual growth of around 0.6 per cent.

The fuel mix in primary energy demand would be significantly different to both the current mix and to the forecast reference scenario mixes in 2035. The share of coal is expected to fall sharply to 15.8 per cent in 2035, as coal demand contracts by 1.6 per cent per year (figure 2.10). The share of gas is also projected to rise to 22.3 per cent, with demand to increase by 0.7 per cent per year to 2035. This means that measures to encourage low-carbon technologies such as renewables, as well as overall energy efficiencies, more than offset the effect on demand of the increased competitiveness of gas relative to coal and oil. The share of renewables is projected to rise sharply to 26.5 per cent by 2035 (figure 2.10).

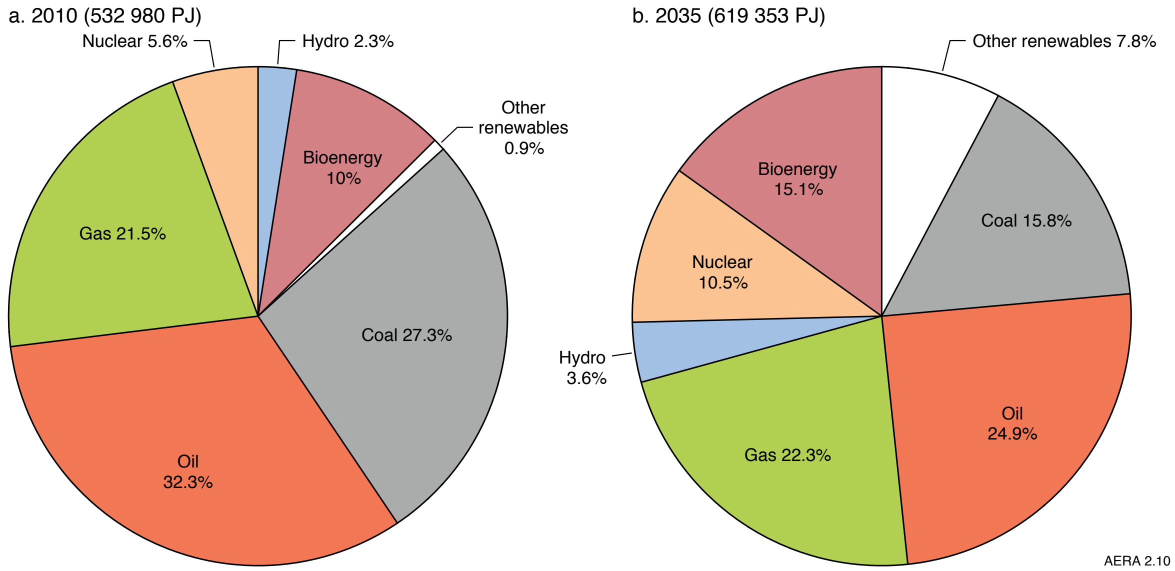

Figure 2.10 Outlook for world primary energy demand under the International Energy Agency 450 scenario

Source: IEA 2012b

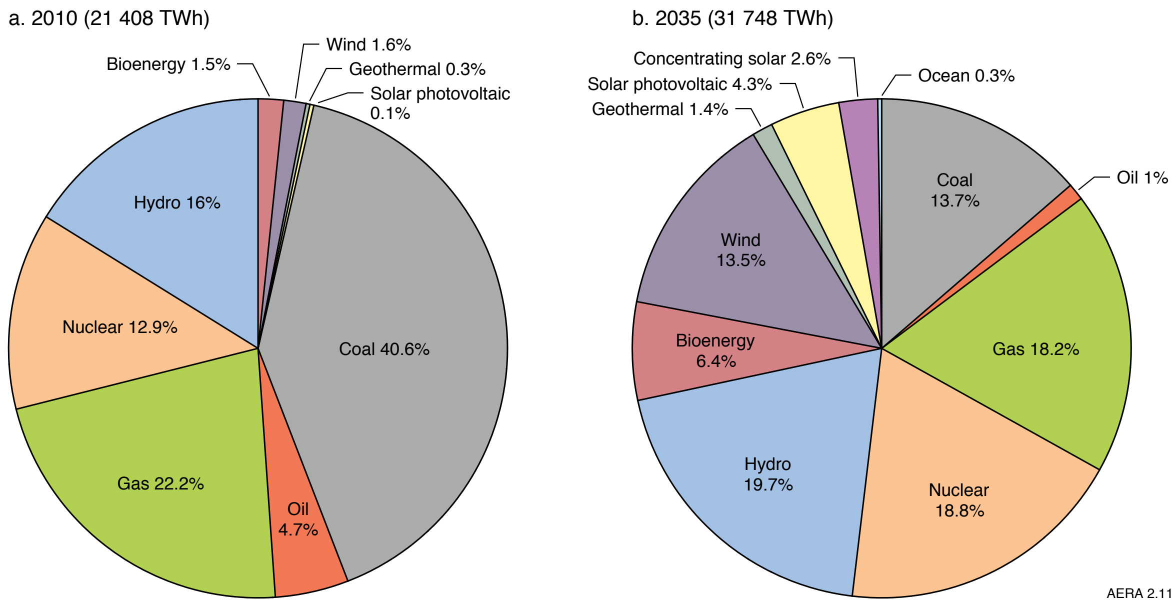

Figure 2.11 Outlook for world electricity generation under the International Energy Agency 450 scenario

Source: IEA 2012b

The share of coal in total electricity generation is also projected to fall sharply in the 450 scenario to 13.7 per cent in 2035 (figure 2.11). As with primary energy, the share of gas in 2035 is projected to be similar to current levels. Nuclear power increases its share of electricity generation significantly to 18.8 per cent in 2035. In addition, all renewables expand their role in electricity generation under a 450 scenario, reflecting favourable government policies and an increased competitiveness against fossil fuels under carbon pricing. The strongest growth is expected in energy derived from wind (to 13.5 per cent), solar (to 6.9 per cent), geothermal (to 1.4 per cent) and ocean (to 0.3 per cent) (IEA 2012b).

2.3 Australia's energy resources and infrastructure

Australia has abundant, high-quality energy resources that are widely distributed across the country. With the exception of oil, these resources are expected to last for many more decades, even as production increases. Australia has a significant proportion of the world's uranium and coal resources, and large resources of conventional and unconventional gas. Australia has access to a range of high-quality renewable energy sources, many of which are yet to be developed. This section provides an overview of the size and distribution of Australia's energy resources and related infrastructure. More detailed information on specific resources is contained in the individual resource chapters.

2.3.1 Australia's energy resource base

Non-renewables

Australia's non-renewable energy resources include fossil fuels—coal, gas and oil—and nuclear energy fuels—uranium and potentially thorium. Table 2.3 provides a summary of current resource estimates and figure 2.12 shows their distribution.

Australia's liquid hydrocarbon resources include crude oil, as well as condensate and LPG resources associated with gas (chapter 3). Australia also has significant oil shale resources, and potential for tight oil and shale liquids, which could provide additional liquid fuels if developed. Crude oil EDR are estimated to be 5467 PJ (930 million barrels, mmbbl) as of December 2012. This is equal to around 9 years remaining at current rates of production. Australia's crude oil resources are only small by world standards and are being depleted at a faster rate than the resources are being replenished by discovery. As a result, Australia's domestic production of oil is declining, and Australia increasingly relies on imports to meet requirements. However, the oil potential

Table 2.3 Australian non-renewable energy resources, December 2012

Resource	Unit	Economic Demonstrated Resources	Total Demonstrated Resources[a]	Resource life at current production rates (years)
Black coal	PJ	1 641 863	1 737 156	
	Mt	61 082	66 200	110
Uranium[b]	PJ	657 440	955 360	
	kt	1174	1706	170
Brown coal	PJ	435 577	924 140	
	Mt	44 164	92 751	510
Conventional gas	PJ	109 433	172 097	
	tcf	99	156	51
Coal seam gas	PJ	35 905	101 434	
	tcf	33	93	150
Condensate	PJ	11 275	15 973	
	mmbbl	1917	2716	26
Crude oil	PJ	5467	7382	
	mmbbl	930	1255	9
LPG	PJ	3922	5664	
	mmbbl	932	1345	16
Shale oil	PJ		84 601	
	mmbbl		14 388	
Thorium[c]	PJ[d]			
	kt		595	

kt = kilotonne; **mmbbl** = million barrels; **Mt** = million tonnes; **PJ** = petajoule; **tcf** = trillion cubic feet; **TWh** = terawatt hour

a Includes Economic Demonstrated Resources and Sub-economic Demonstrated Resources. **b** Recoverable resources at <US$130/kg. **c** Total identified resources. **d** A conversion into energy content equivalent for thorium was not available at the time of publication.

Source: Geoscience Australia

of Australia's frontier basins has not yet been adequately assessed and further exploration may yield additional resources. Australia also has more substantial liquid hydrocarbon resources in condensate (EDR of 11 275 PJ, 1917 mmbbl) and LPG resources (3922 PJ, 932 mmbbl), but access to these depends on the development of the associated gas resources.

Australia has significant resources of gas. These include the substantial conventional gas resources located mostly off the northwest coast of Western Australia and the coal seam gas resources of eastern Australia (chapter 4). Conventional gas EDR are estimated to be 109 433 PJ (99 trillion cubic feet, tcf) at the beginning of 2012. This is equal to around 51 years remaining at current rates of production. The EDR estimate does not include some significant recent discoveries that are yet to be proven economic and, hence, total identified gas resources are significantly larger. These are expected to grow with further exploration, even as production increases. Coal seam gas EDR have grown substantially in recent years and are estimated to be 35 905 PJ (33 tcf), with substantial inferred resources of 122 020 PJ (111 tcf). Coal seam gas exploration in Australia is relatively immature and high levels of current exploration are likely to add significantly to known resources. There are also shale and tight gas resources held in low-permeability reservoirs in several basins, although these are not yet well defined. Unconventional hydrocarbon resources are outlined in box 2.1.

Australia's coal resources are world class in magnitude and quality. Australia's EDR of black and brown coal are estimated to be 2 077 440 PJ (105 246 million tonnes [Mt]) as of December 2012 (chapter 5). Black coal EDR are estimated to be 1 641 863 PJ (61 082 Mt). This is equal to around 110 years remaining at current rates of production. Resources of black coal are distributed in most states,

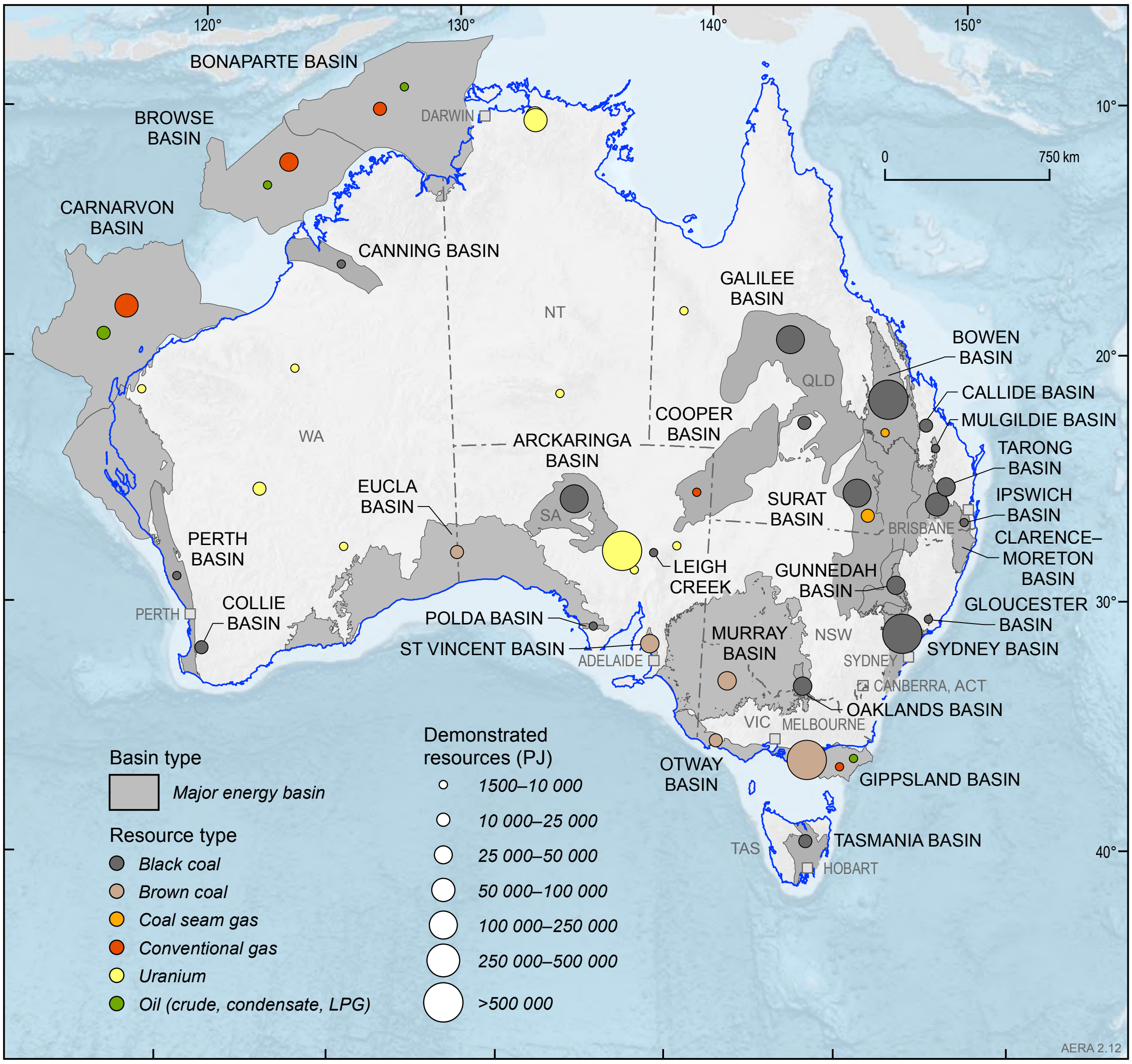

Figure 2.12 Distribution of Australia's major (containing more than 2000 PJ) non-renewable energy resources

Source: Geoscience Australia

with the largest resources located in the Bowen–Surat and Sydney basins in Queensland and New South Wales, respectively. Australia has similar-sized resources of brown coal, although these are much lower in energy content terms. Brown coal EDR are estimated to be 435 577 PJ (44 164 Mt), and are located mainly in Victoria. At current rates of production, there are more than 510 years of brown coal resources remaining. In addition to the large EDR of coal, Australia has even larger coal resources in the sub-economic and inferred resource categories. The true size of Australia's coal resources could be even larger as potential coal resources have not yet been fully assessed because the existing identified resource base is so large.

More than one-third of the world's known uranium resources are located in Australia (chapter 6). Australia's EDR of uranium are estimated to be 657 440 PJ (1174 kt) as of December 2012. The estimated accessible uranium resources will last about 170 years at current production rates. Major uranium deposits are located in South Australia, the Northern Territory and Western Australia. Australia also has a major share of the world's thorium resources. Although not currently in use as an energy resource, thorium could play a role in the long term as an alternative to uranium as a nuclear fuel. Given there is no active exploration for thorium, resource estimates are uncertain.

BOX 2.1 UNCONVENTIONAL HYDROCARBON RESOURCES IN AUSTRALIA

The unprecedented recent growth in unconventional hydrocarbon exploration has transformed the Australian upstream petroleum industry. Since 2000, coal seam gas (CSG) has become a major supply to the eastern states gas market and, more recently, Australian sedimentary basins are being increasingly explored for shale, tight gas and associated liquids (oil and condensate). The first shale-gas production in Australia commenced in the Cooper Basin in 2012, and a series of discoveries have been made in other basins. The key drivers for this growth have been the domestic and Asia–Pacific energy demand, recent advances in extraction technologies such as multistage hydraulic fracturing and pad drilling, and the success of the shale-gas industry in North America.

Unlike conventional oil and gas, unconventional hydrocarbon resources do not rely on buoyancy-driven processes, or structural and stratigraphic trapping mechanisms, because the resources are often distributed over a large area of the sedimentary basin (figure 2.13; Law and Curtis 2002). Moreover, unconventional hydrocarbon reservoirs (which, in the case of coal seam gas, shale gas and shale liquids, are the same as the source rock) have low permeabilities that effectively prevent the mobilisation of trapped hydrocarbons. These characteristics necessitate extractive methods that are intensive in technological, capital and energy inputs, such as hydraulic fracturing and horizontal drilling (McCabe 1998; Geoscience Australia and BREE 2012). As a result, unconventional hydrocarbon resources have become economic only in recent times.

Unconventional hydrocarbon resources of current exploration interest in Australia are CSG, shale, and tight gas and associated liquids. CSG consists primarily of methane, which is generated and held within micropores and cleats (natural fractures) in coal seams. Production requires initial dewatering to lower the hydrostatic pressure within the coal seams, and hydraulic fracturing may subsequently be used to improve the gas flow. To date, CSG exploration and production has targeted the Permian and Jurassic bituminous to sub-bituminous coals of eastern Australia (e.g. in the Bowen, Surat, Sydney–

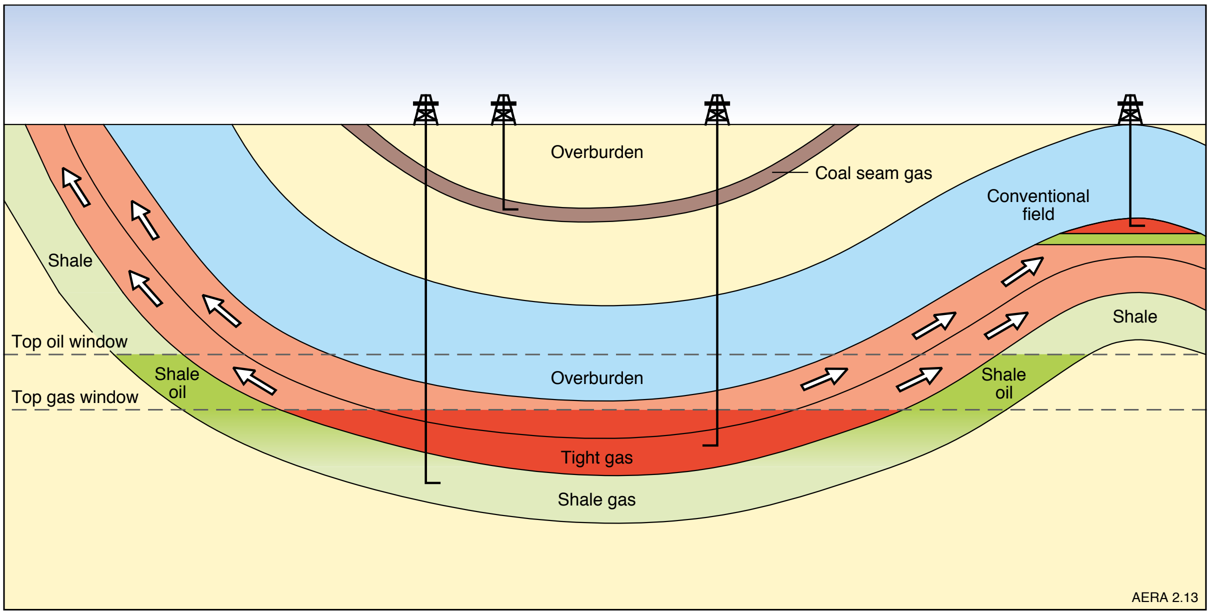

Figure 2.13 Schematic cross-section of unconventional and conventional petroleum systems

Source: Geoscience Australia

Gunnedah, Gloucester and Clarence–Moreton basins; figure 2.14), mostly located at depths less than 1000 m. However, deeper seams (e.g. in the Bowen and Cooper basins) and biogenic coal seam gas in Cenozoic brown coals (e.g. in the Gippsland Basin) are now also being explored. Additional potential exists in the Permian coals of central and western Australian basins (e.g. the Perth, Canning and Arckaringa basins) and in the Triassic to Cretaceous coals of eastern Australian basins (e.g. the Ipswich, Nymboida, Maryborough and Eromanga basins).

Shale gas and liquids are generated and trapped within organic-rich, fine-grained rocks—including shale, siltstone, fine-grained sandstone, limestone or dolomite. On the other hand, tight gas and oil are conventionally generated and migrated hydrocarbons hosted in very low permeability sandstone or carbonate reservoirs with less than 10 per cent porosity and less than 0.1 millidarcy (mD) permeability (Holditch 2006). Accumulations may be laterally continuous as with CSG and shale plays, or they may be trapped conventionally. The production of shale and tight gas, and associated liquids, relies on hydraulic fracturing to initiate flow.

A number of Australian basins have shale and tight gas potential (figure 2.15). The age of target formations varies widely from the Proterozoic (e.g. Beetaloo and McArthur basins) to the Cretaceous (e.g. Gippsland and Eromanga basins). These formations developed under a variety of depositional conditions from fluvio-lacustrine to marine, and are often dominated by type II or III kerogen (organic matter), implying that they are generally gas-prone (as opposed to liquids-prone). Much of the shale and tight gas exploration so far has been in basins with proven potential for conventional hydrocarbons, existing production infrastructure and significant associated potential for hydrocarbon liquids. For example, in the Cooper Basin, the Permian Roseneath–Epsilon–Murteree succession, and the Patchawarra and Toolachee formations are being explored for thick basin-centred gas accumulations. In the onshore Perth Basin, exploration of the long-known Permian to Jurassic tight and shale gas targets has been revitalised by recent technological advances and a growing domestic gas demand. Other basins in this category include the Otway, Gippsland and Amadeus basins.

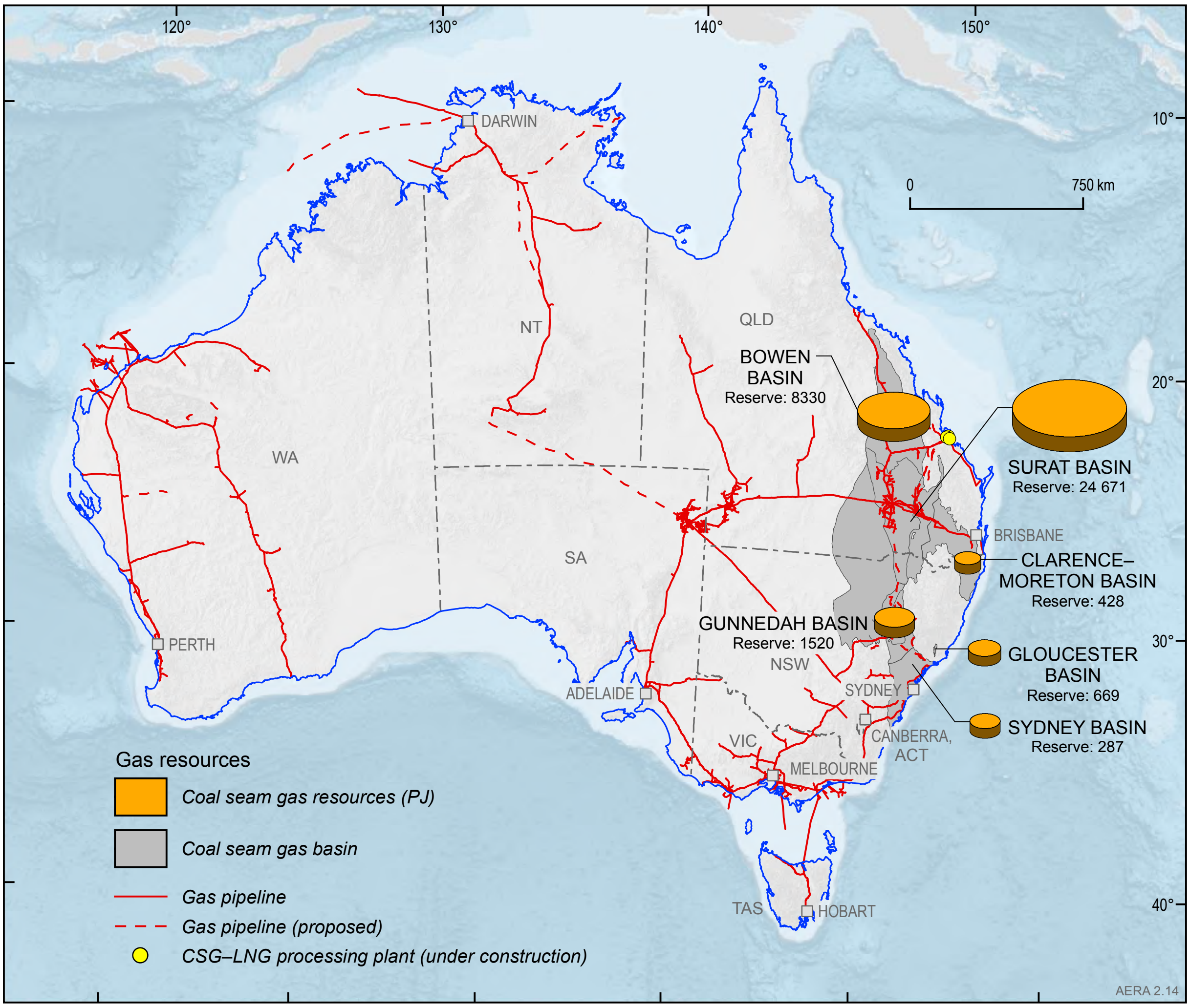

Figure 2.14 Location of Australia's coal seam 2P gas reserves and gas infrastructure

Source: DEEDI 2012; Geoscience Australia

Exploration results in some remote frontier basins, such as the Canning, Georgina, McArthur and Eromanga basins have also been encouraging. Some of these plays have the potential to host large, liquids-prone, accumulations, and frontier exploration is likely to increase in the coming years.

The main challenges to exploring and developing unconventional hydrocarbon resources in Australia include:

- geological uncertainties arising from the short history of exploration and production, and significant geological differences between Australian and the well-studied North American unconventional plays
- the limited access to specialised drilling technology, such as that required for hydraulic fracturing
- restricted existing production infrastructure and pipeline capacity
- the potential effects on the environment, especially on water resources, and public and political concerns about these effects
- the potential effects of unconventional hydrocarbon resource development in other countries of the Asia–Pacific region on regional energy markets.

The commencement of CSG-based liquefied natural gas (LNG) export from Queensland scheduled in 2014 will expose the eastern states gas markets to international pricing, and provide an additional economic impetus for the exploration and development of unconventional hydrocarbon resources in Australia, particularly in frontier basins. Further development of LNG export facilities in Darwin may also open up export opportunities for shale and tight gas from some central and northern Australian basins, which do not have a ready domestic market at this stage.

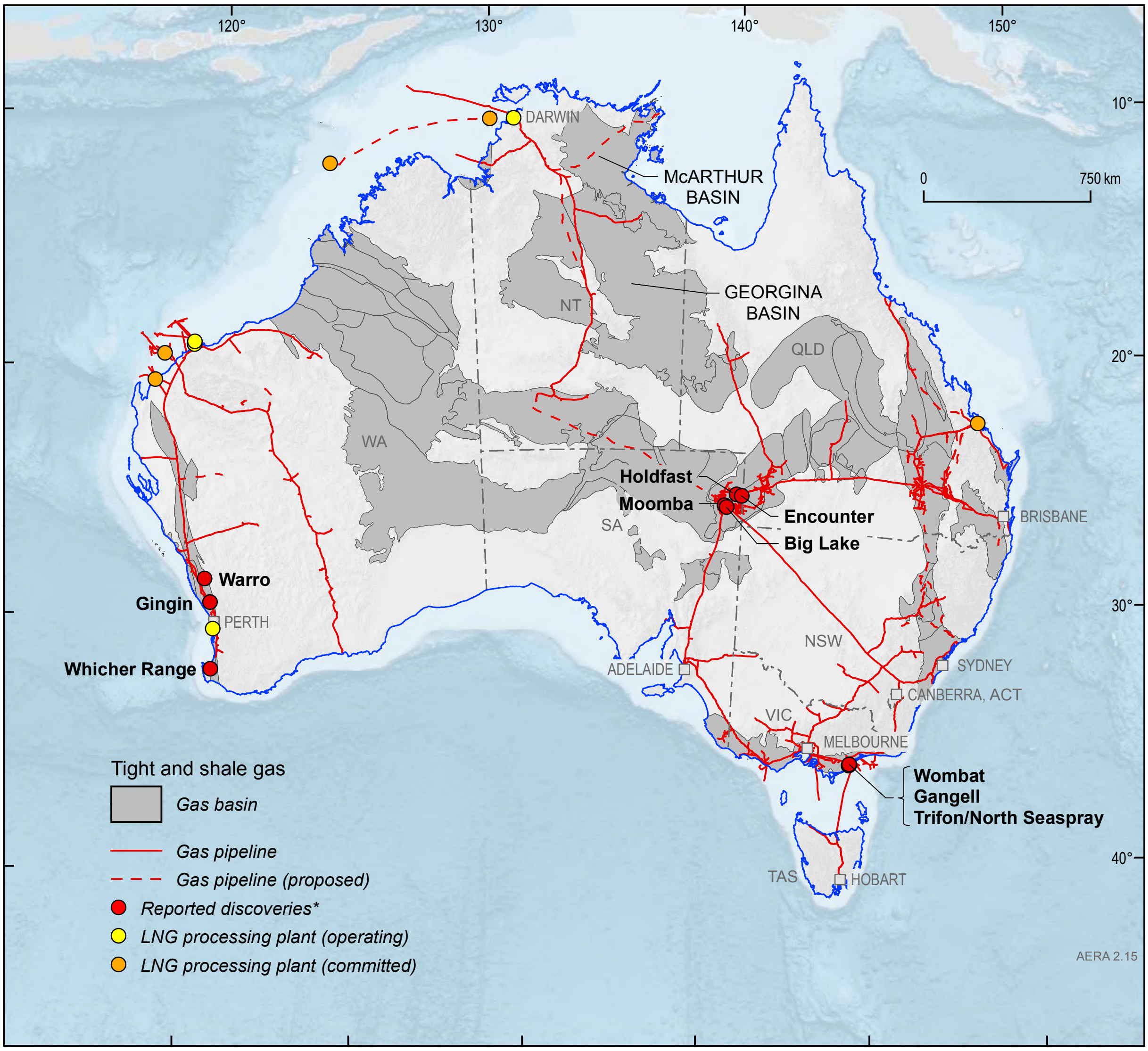

Figure 2.15 Basins with tight gas and shale gas resource potential and gas infrastructure

LNG = liquefied natural gas

Source: Geoscience Australia

Renewables

Australia's potential renewable resource base is very large and widely distributed across the country (figure 2.16). However, there are significant constraints on the commercial-scale use of Australia's renewable resources in the immediate future. At present, these generally have higher transformation costs relative to other energy sources (except for hydro), many are often long distances from markets and infrastructure, and the technologies to use these resources are generally immature. The uptake of renewable energy in Australia is growing rapidly—wind- and solar-generated electricity is the fastest growing renewable energy sector. Expanded government support for renewable energy sources is expected to underpin a significant expansion in their use for electricity generation during the coming decades. Government support for renewables is discussed further in section 2.4.1.

Renewable energy resources are usually transient and not always available, and, hence, not readily classifiable and comparable to non-renewable resources. Renewable resources are often reported in terms of installed capacity. Installed capacity for renewables in Australia is provided in table 2.4. Estimates of potential renewable resources can be made based on maps that show the energy—potentially or theoretically—available at a site and detailed studies of the annual and diurnal variation in the energy to determine the capacity factor. This is the average actual energy output compared with the theoretical maximum possible output if the energy was continuously and fully available for use.

Table 2.4 Renewable electricity generation capacity in Australia, 2011–12

Energy resource	Capacity (MW)
Geothermal	1.08
Hydro	8506
Wind	2584
Solar	1400.0
Ocean	0.8
Biogas	215.0
Bagasse	475.0
Wood waste	64.0
Other[a]	84.0
Total	**13 329.7**

MW = megawatt
a Other biomass and biodiesel

Source: Geoscience Australia

Australia has very large—but as yet inadequately defined and quantified—geothermal energy resources that are the subject of active exploration (chapter 7). In particular, Australia has significant hot rock geothermal resources that could be used to produce super-heated water or steam suitable for base-load electricity generation by artificially circulating fluid through the rock. There are also lower temperature geothermal resources present in deep aquifers in a number of sedimentary basins that are potentially suitable for electricity generation or direct use. Identified geothermal resources as of December 2012 are estimated at around 440 570 PJ. Electricity generation from geothermal energy in Australia currently has two pilot power plants. The Birdsville plant in south-west Queensland produces 0.08 megawatt (MW). The Innamincka Deeps Project in the Cooper Basin, South Australia, is a 1 MW plant, and the plant has commenced a demonstration trail and testing period until late 2013. There are also a number of small direct-use applications of geothermal energy resources. Other pilot projects are expected to be advanced within the next few years.

Hydro power was developed early in Australia, particularly in south-eastern Australia (chapter 8). As of December 2012, Australia had 124 operating hydroelectric power stations, with a total installed capacity of 8506 MW. These coincide with the areas of highest rainfall and elevation and are mostly in New South Wales and Tasmania. However, a dry climate coupled with a low runoff over much of Australia limits substantial expansion of hydro power.

Australia has some of the best wind resources in the world, primarily located in the western, south-western, southern and south-eastern coastal regions, but extending hundreds of kilometres inland and including highland areas in south-eastern Australia (chapter 9). Wind energy technology is relatively mature, and its uptake is growing quickly in Australia and is supported by government policies. In early 2012, Australia had 66 operating wind farms in Australia with a combined installed capacity of 2584 MW.

Solar power is a vast potential source of energy (chapter 10). The Australian continent has the highest solar radiation per square metre of any continent in the world. The annual solar radiation falling on Australia is approximately 58 000 000 PJ. The best solar resources are largely located in the north-west and centre of Australia—commonly in areas that do not have access to the electricity grid, and are distant from the major population centres and key energy markets. However, some of these high-quality resources are close to new and emerging demand centres such as the Pilbara region, Western Australia. There are also significant and adequate solar energy resources in areas with access to the electricity grid and close to the major demand centres. To date, relatively high capital costs have limited widespread use of solar energy resources. The total installed PV capacity in Australia is estimated to have been 2 gigawatts (GW) at the end of 2012. Significant global investment in research and development (R&D) is aimed at increasing the efficiency and cost-effectiveness of solar power, including the development of solar thermal power stations.

There are also opportunities for ocean energy, including mechanical energy from the tides and waves, and thermal energy from the sun's heat (ocean thermal) (chapter 11). The best tidal energy resources are located along the northern margin, especially the north-west coast of Western Australia, and largely removed from the major demand centres. Australia also has a world-class wave energy resource along its western and southern coastline, especially in Tasmania. Most ocean energy technologies are relatively new and still need to be proven in pilot and demonstration plants. In Australia, four electricity generation units based on either tidal or wave energy are operating or under construction (totalling around 3.4 MW of generating capacity).

Bioenergy is another significant potential energy resource in Australia (chapter 12). Biomass (organic matter) can be used to generate electricity generation and heat, as well as for the production of liquid fuels for transport. Currently Australia's use of bioenergy for electricity generation is limited to bagasse (sugar cane residue), wood waste, and gas from landfill and sewage facilities. Biofuels for transport represent a small proportion of Australia's bioenergy: ethanol is produced from sugar by-products, waste starch from grain, and biodiesel is produced from used cooking oils, tallow from abattoirs and oilseeds. Commercialisation of second generation (advanced) bioenergy technologies is likely to increase the range of resources, such as the non-edible (woody) parts of plants and, potentially, algae, which are available for both biofuels and electricity generation.

2.3.2 Distribution, ownership and administration of energy resources

Australia's energy resources are widely but not evenly distributed across Australia's states and territories. Certain regions within the states and the Northern Territory are highly endowed in particular energy (and other mineral) resources. Many of Australia's known and, potentially, undiscovered oil and gas resources lie offshore within Australia's large maritime jurisdiction.

Under the Australian Constitution, mineral and petroleum resources are owned either by the Australian or state/territory governments. Exploration and development of these resources is undertaken by companies operating under licences and permits granted by government. Australian and state/territory governments actively encourage investment in Australia's energy resources. Resources onshore and out to three nautical miles from the baseline of the territorial sea are the responsibility of the state and territory governments. Responsibility for resources beyond three nautical miles—which extend to cover Australia's entire offshore jurisdiction—rests with the Australian Government.

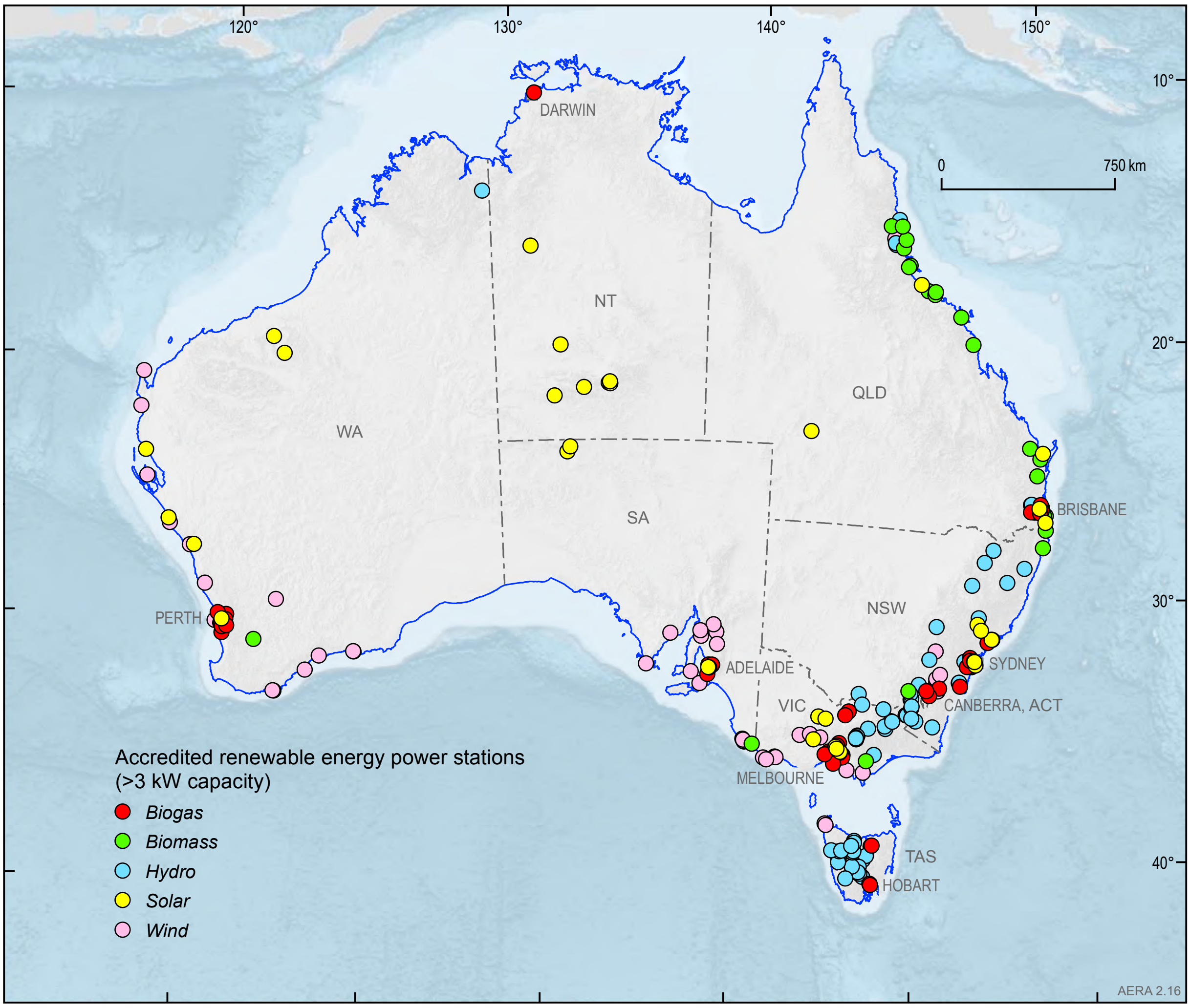

Figure 2.16 Distribution of Australia's accredited renewable energy power station sites, above 3 kilowatt capacity

Source: Geoscience Australia for the Office of the Renewable Energy Regulator

The National Offshore Petroleum Titles Administrator (NOPTA) was established in 2012 as a branch of the Resources Division of the Australian Government Department of Resources, Energy and Tourism. NOPTA is responsibile for titles administration and data management functions in relation to offshore petroleum activities in Commonwealth waters. Further information about NOTPA can be found at www.nopta.gov.au.

Exploration for and development of non-renewable resources is administered under the relevant state/territory legislation relating to minerals and petroleum by state/territory department or agency. The legislation varies between jurisdictions, but is similar in content and administration, and is based on a two-stage process of exploration permit and production licence.

The jurisdictions all allocate and manage mineral and petroleum property rights, have primary responsibility for land administration, regulate operations (including environmental, and occupational health and safety), and collect royalties on the resources produced. However, the minimum area, initial term of the permits, and charges and royalties levied vary between states and territories. More information is provided in the *Mineral and petroleum exploration and development in Australia: a guide for investors* (www.industry.gov.au/resources), and from the state/territory mineral and petroleum departments/agencies (www.geoscience.gov.au). The development of non-renewable resources is similarly governed by relevant state/territory planning and development legislation, and administered by designated departments and agencies charged with those functions.

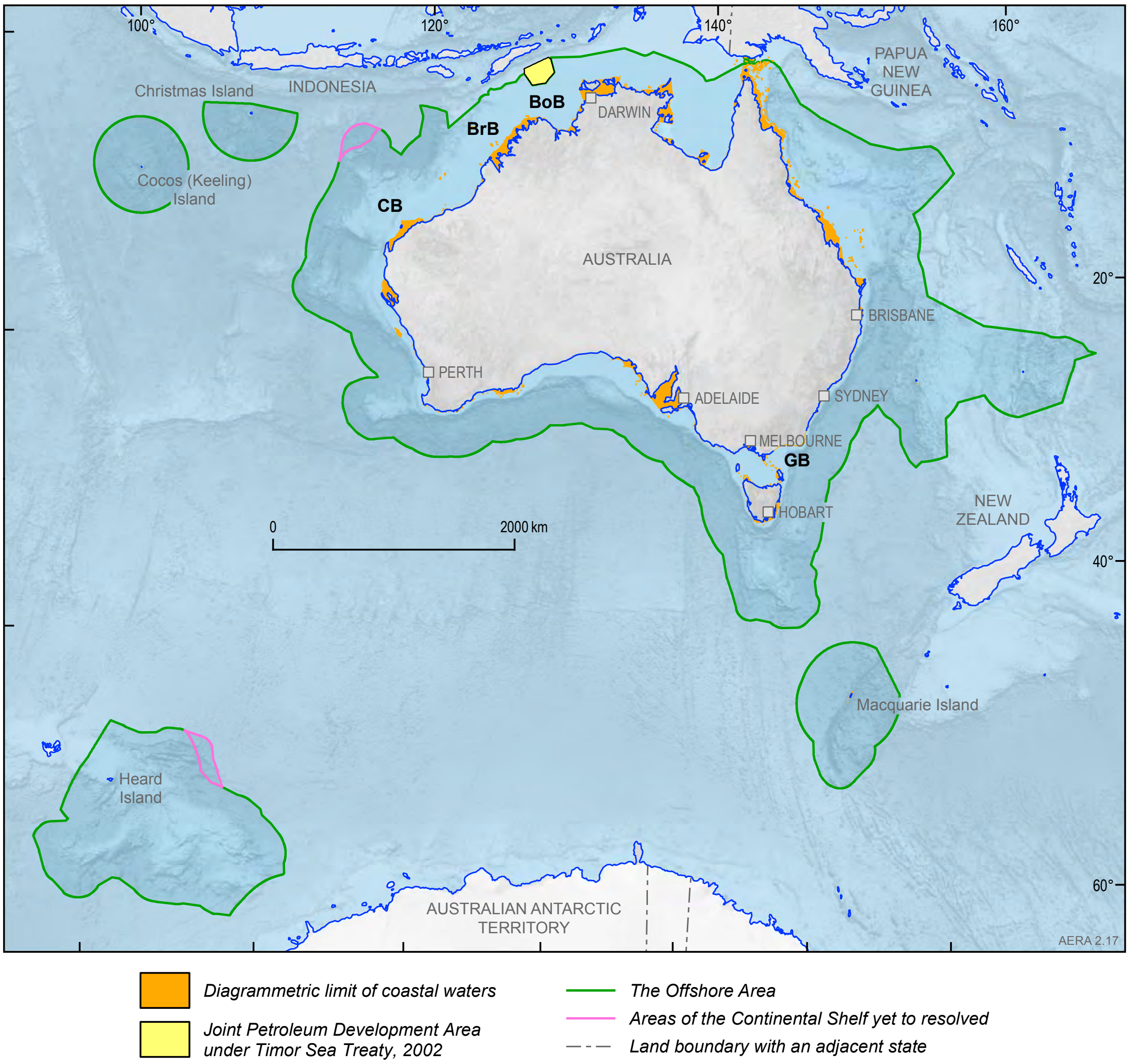

Figure 2.17 Australia's jurisdiction boundaries including the extent of Australia's marine jurisdiction and major offshore energy provinces

BoB = Bonaparte Basin; **BrB** = Browse Basin; **CB** = Carnarvon Basin; **GB** = Gippsland Basin

Source: Geoscience Australia

Australia's large marine jurisdiction has recently been increased by more than 2 500 000 km^2 of seabed by the United Nations (UN) Commission on the Limits of the Continental Shelf. The UN Commission confirmed the location of Australia's continental shelf outer limit in nine distinct marine regions, which entitles Australia to large areas of shelf beyond 200 nautical miles (figure 2.17), including exclusive rights to what exists on and beneath the seabed, including oil, gas and resources.

2.3.3 Energy infrastructure

Australia's energy production facilities and transport infrastructure (including mines, power stations, rail, ports and pipelines) can be affected by climatic events such as intense precipitation, storms, bushfires, heat waves and floods. Any future expansion of Australia's energy market, including access to new energy resources, will require investment in energy infrastructure, particularly electricity generation and transmission. Additional investment will be required not only to replace aging energy assets, but also to allow for the integration of renewable energy into existing energy supply chains.

Electricity

Australia has five electricity systems and numerous stand-alone, remote electricity systems. The largest of these systems is the National Energy Market (NEM) in eastern Australia, followed by the south-west and north-west interconnected systems (SWIS and NWIS) in Western Australia, and the Darwin–Katherine and Alice Springs systems in the Northern Territory. The NEM, established in 1998, allows power to flow across the Australian Capital Territory, New South Wales, Queensland, South Australia and Victoria, with Tasmania joining in 2005. This market is the foundation of Australia's electricity infrastructure, including transmission lines and generators (figure 2.18).

The NEM is linked by six major transmission interconnectors. The transmission and distribution network of the market consists of more than 43 000 km of overhead transmission and distribution lines, and more than 767 000 km of underground cables. There are also a number of projects under construction to expand the interconnector system. This interconnected electricity

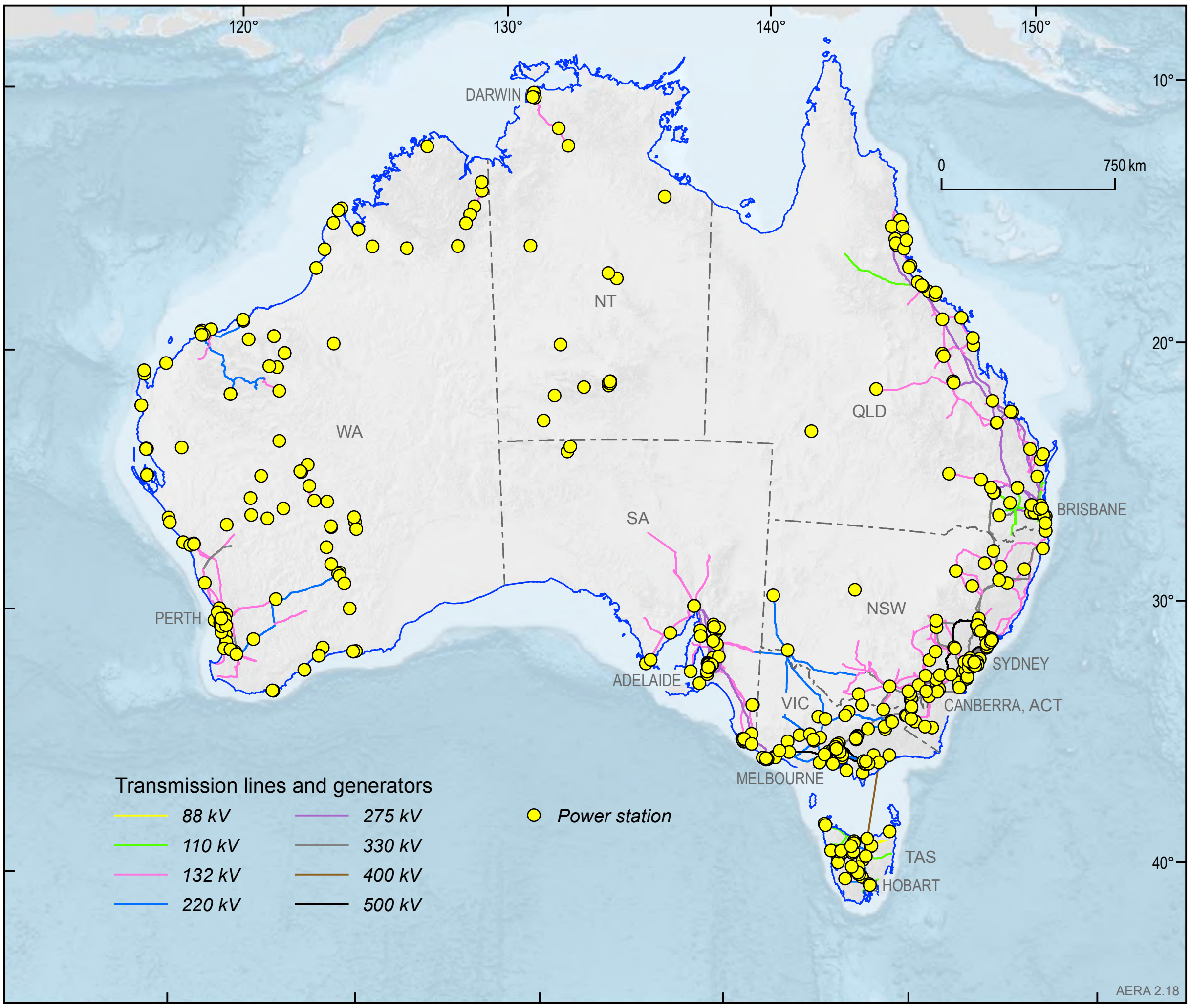

Figure 2.18 Australia's electricity infrastructure

Source: Geoscience Australia

grid is the world's longest interconnected power system extending from Port Douglas, Queensland, to Port Lincoln, South Australia, including an interconnector to Tasmania, a distance of about 5000 km (AEMO 2012a). There is also a 290-km, 400-kilovolt, direct-current seabed cable—the longest of its type in the world—that connects Loy Yang, Victoria, with Bell Bay, Tasmania (the Basslink Interconnector), and allows trade of electricity between Tasmania and the mainland.

The various assets that comprise Australia's electricity infrastructure are owned and operated either by state/territory governments or the private sector. Wholesale markets have been established for the dispatch and trade of electricity in the NEM and SWIS. Exchange between electricity producers and electricity consumers is facilitated through a pool where the output from all generators is aggregated and scheduled to meet demand through the use of information technology systems. These systems balance supply with demand, maintain reserve requirements, select which components of the power system operate at any one time, determine the spot price and facilitate the financial settlement of the market (AEMO 2012a).

The grid connects and is relatively centralised around power stations at the fuel sources, especially the major coal resources and gas supply infrastructure, and the main electricity demand centres. As other resources are being used for power generation, including wind and coal seam gas, new nodes have been added. For example, the Australian Energy Market Operator forecasts around $50 billion being invested in the NEM during the next 25 years (AEMO 2012b).

The development of new sources of electricity, particularly renewables, will require further expansion of the grid and increased flexibility, particularly into new areas not previously connected. The impacts of increasingly semi- or non-scheduled generation (from wind and solar, predominantly) combined with increasingly decentralised generation (from solar PV) present challenges to the reliable and stable operation of integrated networks.

Ports

Australia has around 70 trading ports, a number of which are involved in exporting coal, oil, gas and uranium (Ports Australia 2013). There are nine major coal-exporting ports around the country, the majority of which are in New South Wales and Queensland. There are also 16 ports with facilities to export petroleum liquids and two ports from which uranium is shipped (figure 2.19).

Infrastructure capacity constraints (including port and rail) have limited the Australian coal industry's ability to respond to growing global demand during the past few years. However, recent additions to capacity, together with more expansions planned over the short to medium term, will help alleviate these constraints. As at October 2013, there were four port infrastructure projects in Queensland and New South Wales at a committed stage of development, which will add a combined 40 Mt to annual capacity (BREE 2013c).

Rail

Australia has substantial rail infrastructure (figure 2.19). In New South Wales and Queensland, rail is used to transport coal from mines to loading ports. In Western Australia, some of the heaviest gauge rail in the world transports iron ore from mine to port. As of October 2013, a number of rail expansion projects were underway or planned in Western Australia, Queensland and New South Wales. Rail is also used to transport uranium to Adelaide and Darwin, the only ports open for uranium exports.

Gas pipelines

Gas pipelines in Australia are focused around delivering gas (petroleum gas, natural gas and coal seam gas) from where it is collected (gas and coal basins) or processed (gas or liquid-processing facilities) to where it is consumed or exported (figure 2.19). Major pipelines connect the conventional gas resources of the Cooper Basin and offshore Gippsland and Otway basins to the major population and industrial centres of the eastern seaboard (Brisbane, Sydney, Melbourne and Adelaide) as well as Mt Isa, Queensland. The coal seam gas production from the Bowen and Surat basins also feeds into this network. The gas resources off the north-west coast of Western Australia are distributed to supply the mining and urban centres of Western Australia via the Dampier–Bunbury, Pilbara and Esperance pipelines. Another pipeline system connects gas resources in Amadeus and offshore Bonaparte basins to service the northern gas market. There are currently more than 20 000 km of gas transmission pipelines in Australia (AER 2012). The total length of Australia's gas distribution network is more than 87 000 km and it serves more than 4 300 000 customers (AER 2012; ATCO 2013). As of October 2013, further transmission capacity is under construction in Western Australia, Queensland and New South Wales (BREE 2013c). Demand for further gas pipeline infrastructure is likely to increase as gas-fired peaking plants play an increasingly significant role in stand-by electricity generation in support of expanded electricity production from renewables such as wind.

2.4 Australia's energy market

Australia's large and diverse resource base is reflected in its energy market. Coal plays a dominant role in production, consumption and trade, while the contribution from gas and renewables continues to grow.

The energy sector is an important part of the Australian economy. Australia's energy production and exports have grown strongly during the past 30 years, especially in recent years in response to strong global demand for energy. The energy industries contributed around A$68 billion to industry gross value added in 2009–10, or around 5 per cent of the Australian total. Energy exports were valued at A$77 billion in 2011–12, which is around 24 per cent of Australia's total exports value. Australia's relatively low energy prices also support a large range of manufacturing industries. The energy sector also provides employment and significant infrastructure development in remote and regional areas.

This section examines the key factors that affect energy markets in Australia, such as economic and population growth, energy prices, government policy and technological development, as well as an overview of current Australian energy production, consumption and trade.

2.4.1 Energy market drivers

Demand for energy is driven by a range of factors, including the growth and structure of the economy, its stage of development, population and government policies. The choice of energy is based on prices, resource endowment, location and availability, and available technologies, as well as government policies. Some of these key drivers are discussed in more detail in the following subsections.

Economic growth and structure

Energy is an essential input into economic activity, and growth in the economy is one of the main drivers of increases in energy demand. Australia's real gross domestic product (GDP) has increased by 3.2 per cent per year since 2000–01. In 2011–12, Australia's real GDP increased by 3.6 per cent, following a growth of 2.2 per cent in 2010–11. Except for a slight dip during the global financial crisis of 2008–09, Australia's GDP growth during the past decade has been strong and sustained. The Australian economy is expected to continue to shift structurally away from agriculture and manufacturing towards the services sector. The services sector tends to use less energy per unit of output than manufacturing (Che and Pham 2012). This shift will continue to dampen the expected growth in energy demand during the next two decades.

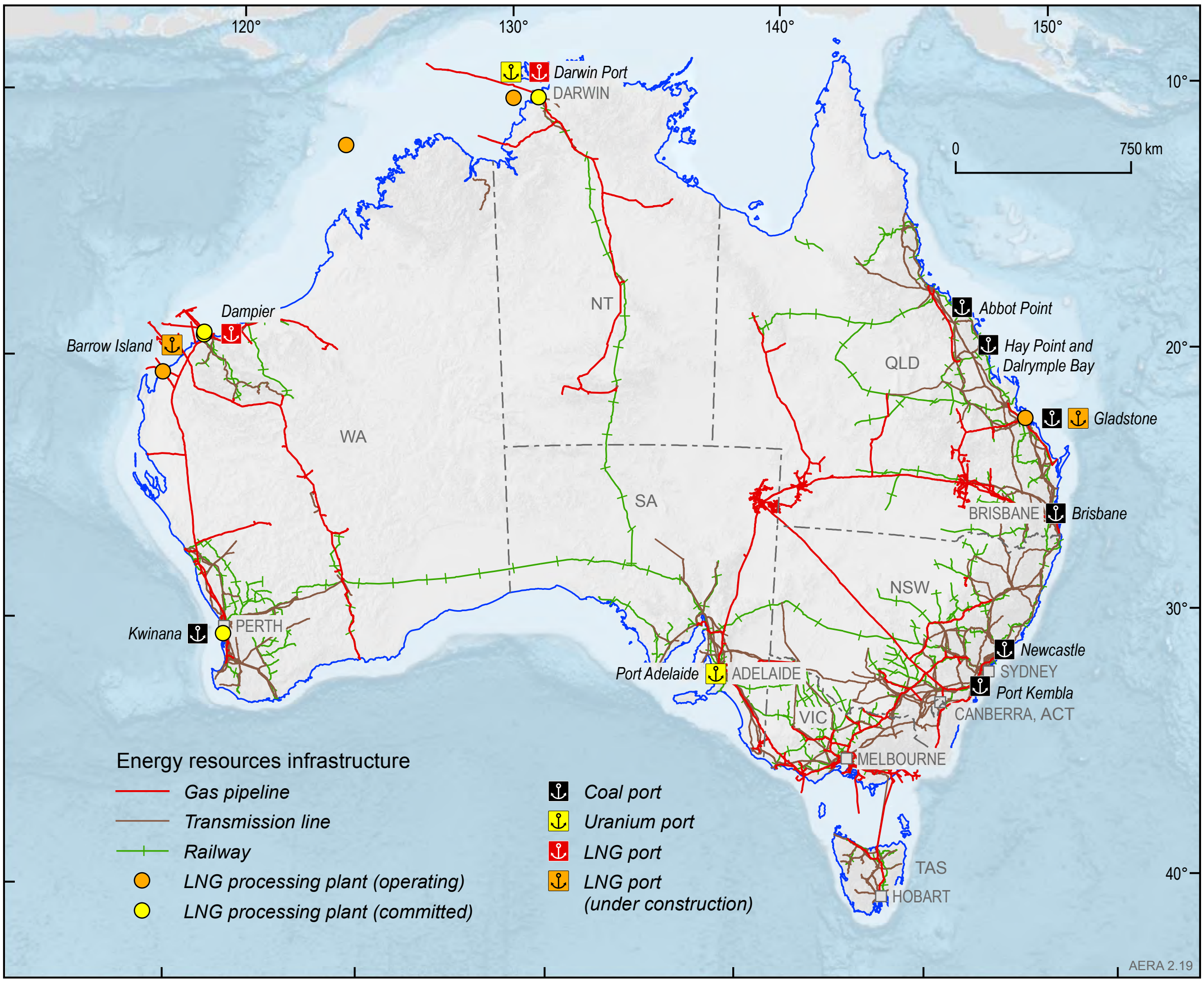

Figure 2.19 Australia's energy resources infrastructure

LNG = liquefied natural gas

Source: Geoscience Australia

Population growth

Population growth affects the size and pattern of energy demand. All else being equal, an increase in energy use is needed to support an increase in population. The Australian population is assumed to increase from 22.7 million in 2011–12 to over 36 million in 2049–50 (BREE 2012a).

Government policy

Government policies can affect the pace of energy demand growth and the type of energy used. Policies designed to improve energy efficiency, for instance, would slow the pace of energy demand growth. Policies designed to increase energy security may encourage diversity in the types of fuels used in an economy, or diversity in where the energy is sourced. Policies to address environmental issues such as climate change may target a greater uptake of renewable energy technologies.

One government policy currently in place that is reshaping the energy market is the Renewable Energy Target (RET).

The RET scheme is designed to ensure that 20 per cent of Australia's electricity supply comes from renewable sources by 2020. This will be achieved through an expansion of the previous mandatory Renewable Energy Target scheme, which began in 2001. As of January 2011, the RET operates in two parts: a mandatory Large-scale Renewable Energy Target (LRET) and a voluntary small-scale renewable energy scheme (SRES). The LRET encourages the deployment of large-scale renewable generation by legislating that wholesale electricity purchasers must source and surrender certificates to the Clean Energy Regulator. Certificates are awarded to large-scale renewable generators based on output. The RET legislation requires that 41 850 gigawatt hours (GWh) worth of certificates—equivalent to that quantity of renewable generation—be surrendered in 2020. SRES certificates are created by small-scale systems such as solar water heaters, residential solar panels, and small-scale wind and hydro systems. Small-scale generators may voluntarily participate by selling certificates to the Clean Energy Regulator, but there is no legal incentive for them to do so. Small-scale certificates are anticipated to provide more than 4000 GWh of renewable generation by 2020. The aim of the RET scheme is to accelerate the uptake of renewable energy for both on- and off-grid power generation and to contribute to the development of internationally competitive renewable energy industries. It is also designed to bring existing state-based RETs into a single, national scheme.

The Australian Government is also supporting renewables through a number of other initiatives. These include the establishment of the Australian Renewable Energy Agency (ARENA), the Clean Technology Innovation Fund (CTIF), the Carbon Capture and Storage Flagships Program, energy efficiency and savings schemes, and land-use programs.

ARENA is an independent agency tasked with increasing the supply, and improving the competitiveness of, renewable energy in Australia. It incorporates programs such as Solar Flagships, the Australian Solar Institute and the Australian Centre for Renewable Energy, and has $3.2 billion in funding to disburse.

The CTIF is a competitive grants program that supports applied R&D, proof of concept and early-stage commericialisation activities that contribute to clean technology development. Under the Carbon Capture and Storage Flagships Program, support has been provided for the construction and demonstration of large-scale integrated carbon capture and storage projects in Australia, with a target to create 1000 MW of low-emissions fossil fuel electricity generation capacity.

Other programs to support energy efficiency, such as the energy efficiencies opportunities program and the energy savings initiative, aim to reduce Australia's carbon emissions by reducing energy demand. Land-use programs aim to increase the amount of carbon stored on the land through natural sequestration by vegetation.

Energy prices

Energy prices affect the demand for, and supply of, energy. Australia's energy prices are affected by direct and indirect influences on domestic and world supply, and demand for energy commodities. For example, climatic events may increase the demand for heating and result in increased world oil prices. Geopolitical factors that could potentially reduce world supply of oil, such as tensions in the Middle East, generally result in increases in the world oil price. Conversely, events such as the global financial crisis, which reduce the demand for oil as economic activity declines, result in oil prices falling.

Australia has some of the lowest prices in the OECD for electricity, coal and gas. The abundance of Australia's coal and gas resources, and the proximity of those resources to areas of high energy demand along the east and west coasts of Australia, results in low electricity and gas prices for consumers. However, Australia imports a sizeable proportion of oil to meet demand, so there is considerable susceptibility to price and supply fluctuations in the global market.

Real energy prices have, except for a dip in mid-2008, risen steadily during the past decade following a period of low prices, which discouraged investment in new energy supplies. The rise in prices reflected strong growth in demand for energy, particularly in China, with suppliers struggling to bring additional production online to meet requirements. Energy prices fell sharply in mid-2008 as a result of the global economic downturn, but have rebounded since as economic growth has returned.

After significant declines in energy commodity prices in 2008–09 as a result of the global economic downturn, world prices recovered in-line with the improved outlook for a recovery in world economic growth. For the medium term, it is expected that a strengthening in global demand, underpinned by the assumed economic recovery, will once again place upward pressure on energy prices, with significant volatility expected to remain. A more detailed assessment of the medium-term outlook for energy commodities is provided in *Resources and Energy Quarterly* (BREE 2013a).

In the longer term, energy price trends will hinge on a number of factors including both global demand and constraints on supply, notably the level of investment in additional production capacity, costs of production and technology.

During the past few years, international thermal coal prices have generally followed a similar trajectory to oil and gas prices, as a reflection of interfuel substitution possibilities. Despite increased consumption demand, thermal coal contract prices are expected to decline from 2010–11 levels, as a result of lower spot prices and increased competition to supply seaborne trade market. In the short term, global thermal coal prices are projected to increase, but will decrease in the medium term due to large additions to supply coming online and strong competition among coal producers (figure 2.20).

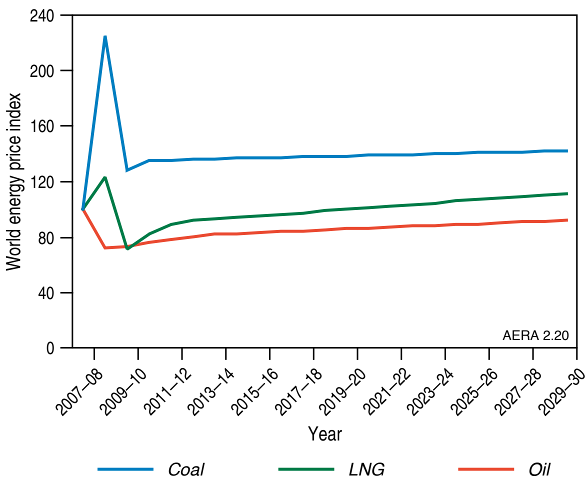

Figure 2.20 Outlook for world energy prices

LNG = liquefied natural gas

Source: Syed et al. 2010

Key factors that are expected to drive long-term oil prices are the cost of developing remaining oil reserves, the level and timing of investment in production and refining capacity, and technological development in relation to alternative liquid fuels. The estimated capital and production costs for conventional oil sources have increased in recent years due to rising materials, equipment and labour costs. Although a rise in the marginal cost of production is expected over time, technological developments associated with non-conventional liquids, such as coal-to-liquids, gas-to-liquids, shale oil and second-generation (advanced) biofuels, have the potential to play a major role in maintaining oil prices at a level that is below what would otherwise be the case without these backstop technologies. There are clearly uncertainties surrounding this price profile, particularly in terms of the costs of alternative technologies and how these may evolve over time as a consequence of technological developments.

For the long term, Asian LNG prices are assumed to follow a similar trajectory to oil prices, reflecting an assumed continuation of the established relationship between oil prices and long-term LNG supply contracts through indexation, and substitution possibilities in electricity generation and end use sectors.

Development of new low-emissions energy technologies

A technology's stage of development will be a key determinant of uptake during the coming decades. Most new technologies, including energy technologies, initially have higher costs than incumbent technologies. But over time, the costs of the new technology may decrease through technology learning—as its production costs decrease and its technical performance increases (IEA 2012c; figure 2.21).

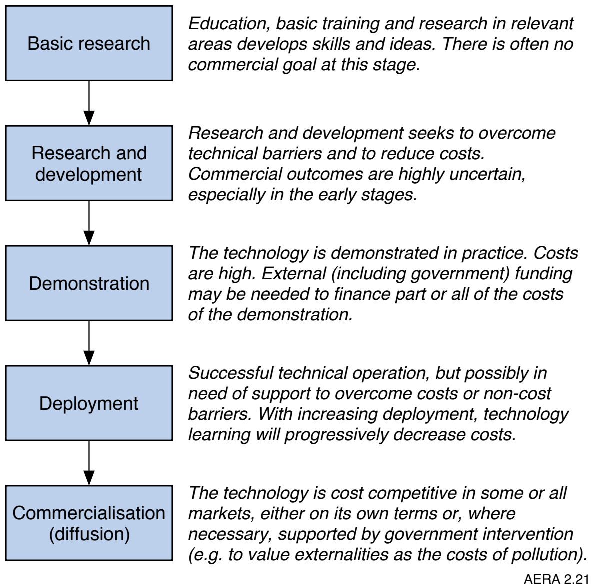

Figure 2.21 Stages in technology development

Source: IEA 2012c

As an example, wind—as a proven and widely used technology—generally costs less per unit of electricity generation than many other renewable technologies. Those still at development and demonstration stage include a number of solar, ocean and geothermal technologies. The stage of development of key renewable technologies and the relationship of the stage of development to the costs of that technology are shown in figure 2.22.

As these technologies advance and technical issues are resolved, it is expected that costs will decrease, encouraging more widespread uptake. The rate of switching from older technologies to these new technologies will depend on both

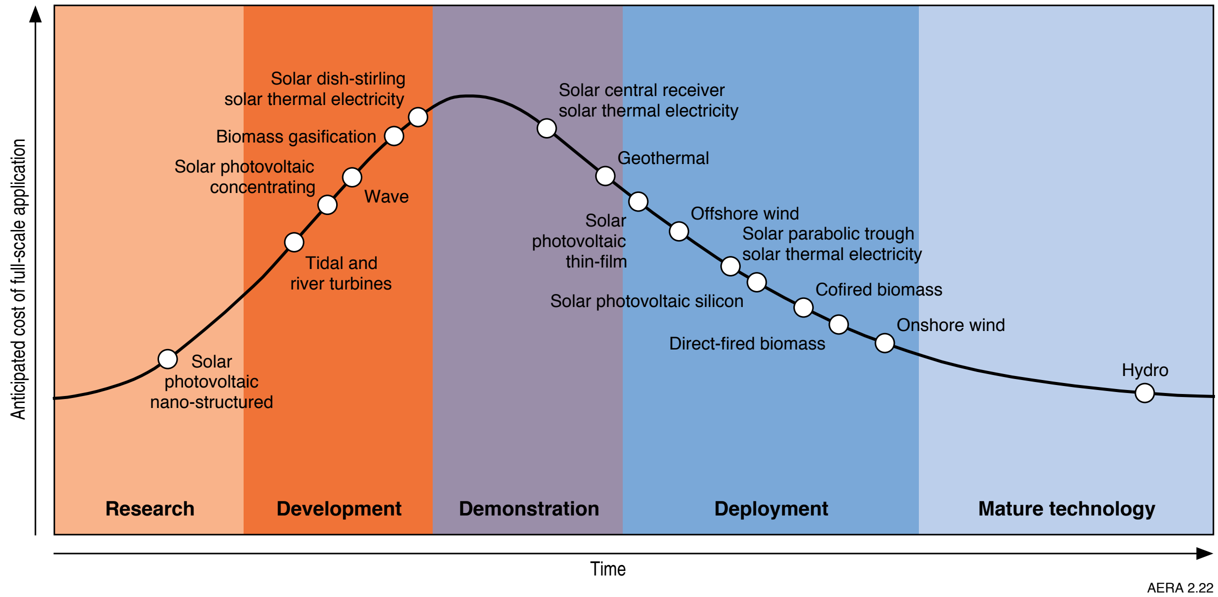

Figure 2.22 Grubb curve for a range of renewable energy technologies

Source: EPRI 2010

relative costs and on the extent to which consumers value the long-term—often at that stage, uncertain—benefits of the new technology (IEA 2012c).

Governments can also influence the rate at which a technology advances, through assistance in R&D and in demonstration projects for new technologies. For example, the Australian Government has committed A$2.5 billion to ARENA, which aims to increase the supply of renewable energy in Australia.

Each individual resource chapter includes information on emerging technologies, including their development status, potential benefits and potential barriers to deployment.

Future energy investment

A significant expansion in Australia's energy infrastructure—particularly electricity generation and transmission—will be required in the next two decades if Australia is to meet its growing and changing demand for energy. Using new energy resources, particularly renewables, will require a more flexible and decentralised electricity grid.

The AEMC has recently published forecasts of energy investment requirements to 2050 and 2035, respectively.

The AEMC provides annual forecasts for NEM investment in generation capacity, as well as transmission networks. The 2012 National Transmission Network Development Plan's planning, or core, scenario forecasts A$5.2 billion in transmission and A$45.6 billion in generation investment to 2036–37. This forecast only relates to the NEM and thus does not cover investment in Western Australia, the Northern Territory or any off-grid infrastructure in NEM states.

2.4.2 Overview of Australian energy production, consumption and trade

Production

Australia is the world's ninth largest energy producer, accounting for around 2.4 per cent of the world's energy production (IEA 2012a). Australia produces energy for meeting our domestic energy consumption needs and for export. Around 80 per cent of Australia's energy production is currently exported (BREE 2012b; 2013b).

Australia's energy production has been increasing at a modest rate in recent years, as increasing natural gas and renewable production has been offset by falling crude oil and uranium output. Oil output from Australia's mature fields has been declining. Natural disasters have affected coal output in recent years, as well as uranium demand from Japan. The global financial crisis of 2008–09 also muted demand. From 2006–07 to 2011–12, energy production increased at 1.2 per cent per year to 17 460 PJ (figure 2.23).

The main fuels produced in Australia, on an energy content basis, are coal, uranium and gas. In 2011–12, Australia's energy production was dominated by coal, which accounted for 60 per cent of total energy production in energy content terms, followed by uranium (20 per cent) and gas (13 per cent) (table 2.5). Crude oil, condensate and LPG represented 6 per cent of total production and renewables represented less than 2 per cent.

Australian production of renewable energy is dominated by hydroelectricity and bioenergy (predominantly bagasse, wood and wood waste), which combine to account for around 86 per cent of renewable energy production in 2011–12. Wind, solar and other biofuels accounted for the remainder of Australia's renewable energy production.

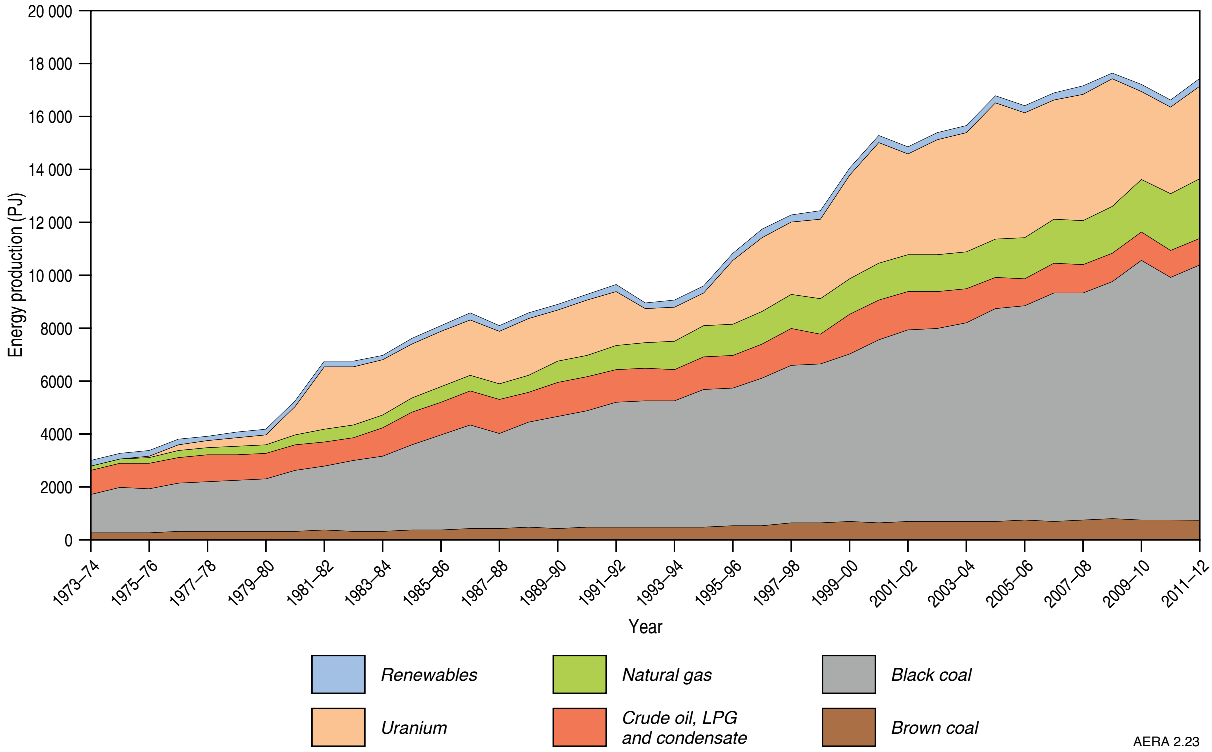

Figure 2.23 Australian energy production

LPG = liquefied petroleum gas

Source: BREE 2013b

Table 2.5 Australian energy production, 2011–12

Energy source	Production (PJ)	Share (%)	Average annual growth 2000–01 to 2011–12 (%)
Non-renewables			
Black coal	9672	55.4	3.1
Brown coal	735	4.2	0.9
Crude oil, LPG, condensate	994	5.7	–3.9
Gas[a]	2254.4	12.9	4.7
Uranium	3525	20.2	–2.3
Renewables			
Hydro	50.7	0.3	–1.7
Wind	22	0.1	35.9
Bioenergy	191.1	1.1	–1.8
Solar	16.9	0.1	32.6
Total	**17 460**	**100.0**	**1.2**

LPG = liquefied petroleum gas; **PJ** = petajoule

a Excludes biogas. 2013 AES publication includes biogas

Source: BREE 2013b

Primary energy consumption

Australia is the world's 21st largest primary energy consumer, and ranks 18th on a per person basis (IEA 2012a). In 2011–12, energy consumption was 6194 PJ, representing 36 per cent of total Australian energy production (BREE 2013b).

Although Australia's energy consumption is growing, the rate of growth has been decreasing during the past 50 years. Following annual growth of around 5 per cent during the 1960s, growth in energy consumption fell during the 1970s to an average of around 4 per cent per year, largely as a result of the two major oil price shocks. During the 1980s, economic recession and sharply rising energy prices resulted in annual growth falling to an average of 2.3 per cent. Strong economic growth through the 1990s resulted in slightly increased energy demand growth of 2.7 per cent. Recently, energy consumption has grown by 2.0 per cent a year from 2006–07 to 2011–12, despite robust economic growth.

This trend indicates a longer term decline in energy intensity of the Australian economy, which can be attributed to two main factors. First, greater efficiency has been achieved through technological improvements and fuel switching. Second, growth has occurred in less energy-intensive sectors, such as the commercial and services sector, relative to the more moderate growth of the energy-intensive manufacturing sector.

Australian primary energy consumption consists mainly of oil and coal. In 2011–12, oil overtook coal to become the largest source of primary energy with 39 per cent. Black and brown coal accounted for the second greatest share of the fuel mix, at around 34 per cent, followed by gas (22 per cent) and renewable energy sources (4.6 per cent) (table 2.6, figure 2.24).

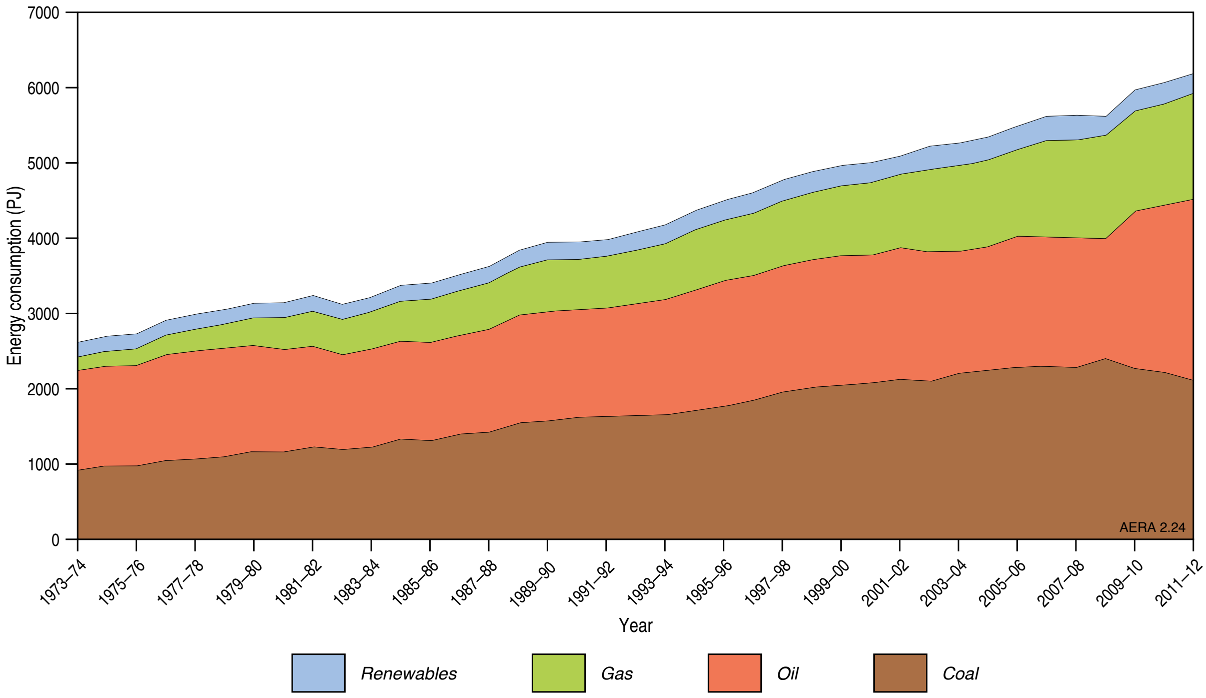

Figure 2.24 Australian primary energy consumption, by fuel

Source: BREE 2013b

Table 2.6 Australian primary energy consumption, 2011–12

Energy source	Consumption (PJ)	Share (%)	Average annual growth 2000–01 to 2011–12 (%)
Non-renewables			
Coal	2118	34.2	0.6
Oil	2411	38.9	3.2
Gas[a]	1383.4	22.3	3.5
Renewables			
Hydro	50.7	0.8	–1.7
Wind	22	0.4	35.9
Bioenergy	191.1	3.1	–1.8
Solar	16.9	0.3	32.6
Total	**6194**	**100.0**	

PJ = petajoule

a Excludes biogas. 2013 AES publication includes biogas

Source: BREE 2013b

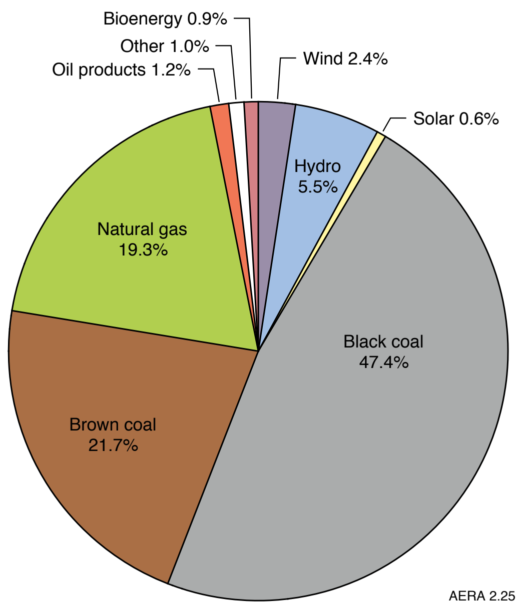

Figure 2.25 Electricity generation by fuel, 2011–12

Source: BREE 2013b

Electricity generation

Total electricity production in Australia was around 914 PJ (254 TWh) in 2011–12. More than two-thirds of Australia's electricity generation is coal-fired, with a much smaller but increasing contribution from gas (19 per cent) and renewables (10 per cent). Renewable energy is predominantly from hydro, with lesser contributions from bioenergy, wind and solar (figure 2.25). Australia's abundant coal resources, located mostly on the eastern seaboard close to the largest electricity market, have historically provided a relatively low-cost source of fuel.

Trade

Australia is a net energy exporter. Around 80 per cent of Australia's total domestic energy production is exported. However, Australia is a net importer of crude oil and refined petroleum products. Imports account for around 35 per cent of Australia's total primary energy consumption (BREE 2012b; 2013b).

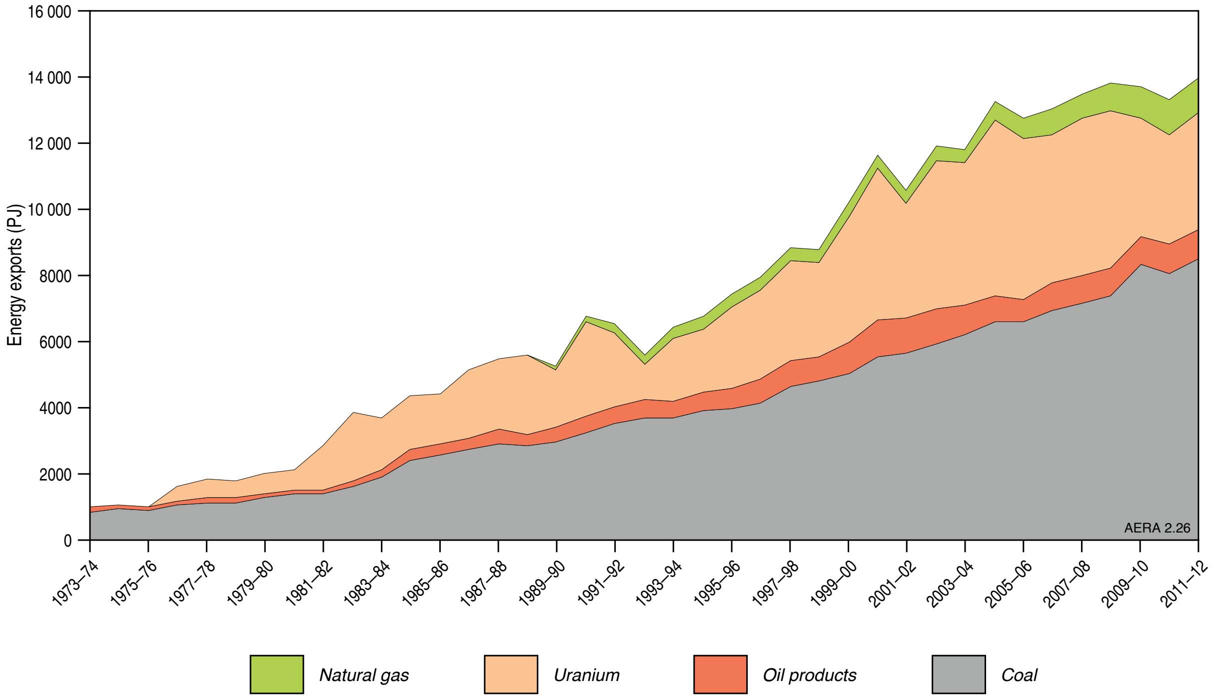

Figure 2.26 Australian energy exports

Source: BREE 2013b

Energy exports accounted for 20 per cent of Australia's total earnings from exports of goods and services in 2011–12. Energy export earnings increased by 20 per cent in 2010–11 to A$67.7 billion, and then to A$77 billion in 2011–12 (BREE 2013a).

The value of Australia's energy exports has grown at an annual rate of around 10 per cent during the past 20 years. Much of this growth has been driven by coal exports—both thermal and metallurgical. LNG and oil exports have also increased in value—supported by increases in international oil prices and higher export volumes (figure 2.26).

Coal is Australia's largest energy export earner, with a value of A$48 billion in 2011–12, followed by crude oil and LNG (table 2.7). More than three-quarters of Australia's black coal production is destined for export. In volume terms, coal was also the largest energy export, accounting for more than half of Australia's energy exports in 2011–12 (on an energy content basis) followed by uranium exports which accounted for about one quarter of total exports.

Despite the strong growth in energy exports, Australia's petroleum trade has declined from a surplus of A$3.6 billion in 2000–01 to a deficit of A$11 billion in 2011–12 (2011–12 dollars), despite a A$9.8 billion surplus for LNG (BREE 2013a).

Table 2.7 Australian energy trade, 2011–12

Energy source	Export volume (PJ)	Export value (A$ million)	Import volume (PJ)	Import value (A$ million)
Coal	8516	47 818		
Oil and oil products	897	16 655	1961	37 845
LNG	1048	11 949	232[a]	2151
Uranium	3284	607[b]		
Total	**13 985**	**77 029**	**2193**	**39 996**

LNG = liquefied natural gas; **PJ** = petajoule

a Natural gas produced in the Joint Petroleum Development Area is counted as imports. It is exported from Darwin as LNG. **b** ASNO estimate

Source: BREE 2013a, 2013b

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Chapter 3
Oil

3.1 Summary

KEY MESSAGES

- Oil is the most widely used primary source of energy globally. It plays a critical role as a transport fuel in most countries, including Australia.
- Australia has about 0.3 per cent of world oil reserves. Australia has limited reserves of crude oil, and most of Australia's known remaining oil resources are condensate and liquefied petroleum gas associated with giant offshore gas fields.
- There is scope for growth in Australia's oil reserves in existing fields, and for new oil discoveries in both proven basins and in underexplored frontier basins that are prospective for petroleum. Liquids associated with new shale gas developments and light tight oil may add further oil resources in the future.
- There is also potential to develop alternative transport fuels such as biofuels, coal-to-liquids, gas-to-liquids (GTL) and products derived from the mining and processing of oil shales.
- Australia's oil consumption is projected to increase over the two next decades but the rate of growth is expected to be slower than in the past 20 years. Domestic crude oil production is projected to continue to decline.

3.1.1 World oil resources and market

- Oil is an important energy source, accounting for around 33 per cent of world primary energy consumption in 2011. However, its importance has been declining steadily since the 1970s when its share of primary energy consumption was around 44 per cent.
- World proven oil reserves were estimated at some 1.6 trillion barrels (equivalent to 9.4 million PJ) at the end of 2011. This is equal to around 55 years supply at current production rates.
- World oil production was around 30.1 billion barrels (Bbbl, 172 089 PJ) in 2011. Major oil producers include Saudi Arabia, the Russian Federation, the United States, Iran and China, with the Middle East accounting for 32 per cent of the world's production in 2011.
- The cost of oil production is expected to increase with the development of offshore fields in deeper water and the use of enhanced recovery technologies.
- World oil consumption has increased at an annual average rate of 1.3 per cent since 2000, to reach 29.9 Bbbl (171 042 PJ) in 2011. At present, more than half of world oil consumption is used in the transport sector.
- The fastest growing oil consuming region is non-OECD Asia, which includes China and India.
- World oil demand is projected by the International Energy Agency (IEA) in its new policies scenario to increase by around 0.6 per cent per year to reach 34.9 Bbbl (199 278 PJ) in 2035. Demand growth is expected to be concentrated in non-OECD economies.
- World oil supply is also projected to increase at an average annual rate of 0.6 per cent from 2011 to 2035. OPEC's oil production is projected to grow, as is supply from unconventional sources such as oil sands, light tight oil, gas-to-liquids (GTL), coal-to-liquids (CTL) and oil shale.

3.1.2 Australia's oil resources

- In 2012, Australia's total demonstrated oil resources were estimated at 20 664 PJ, made up of 11 275 PJ (1917 million barrels or mmbbl) of condensate, 5467 PJ (930 mmbbl) of crude oil and 3922 PJ (932 mmbbl) of LPG (liquefied petroleum gas). This is a decline of about 8.5 per cent on the 2008 estimate for the previous Australian Energy Resource Assessment.
- Australia has limited domestic supplies of crude oil, and relies increasingly on imports to meet demand.
- Crude oil exploration in Australia has not repeated the early success of the 1960s when the first offshore exploration yielded giant field discoveries in the Gippsland Basin. Although Australia has over 300 crude oil fields, most production has come from only seven major fields.
- Estimates of undiscovered crude oil in four proven basins range from 14 900 PJ (2534 mmbbl) to

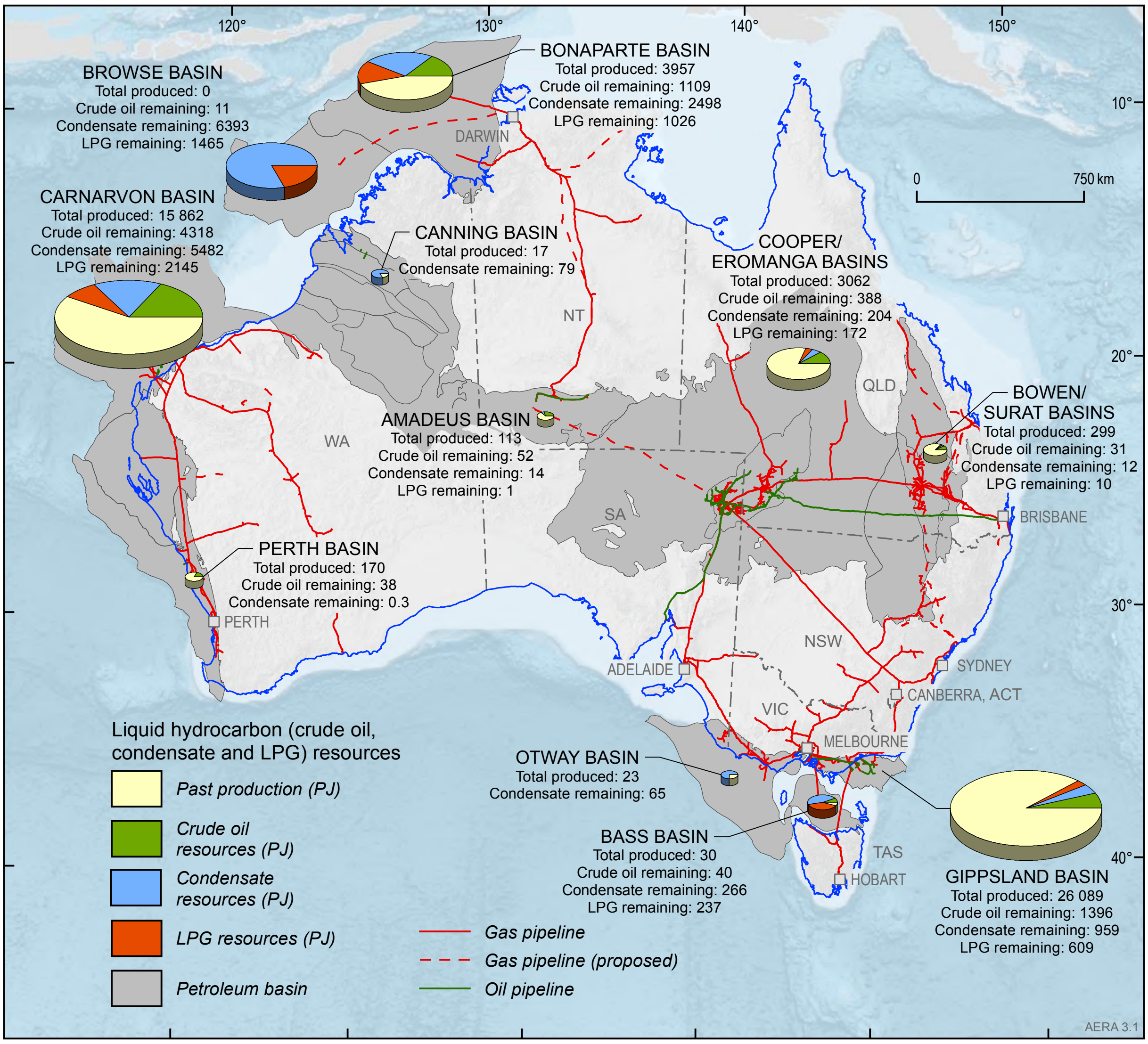


Figure 3.1 Australian crude oil, condensate and naturally-occurring LPG resources, infrastructure, past production and remaining resources

LPG = liquefied petroleum gas

Source: Geoscience Australia

45 041 PJ (7660 mmbbl), and undiscovered natural gas liquids from 13 485 PJ (3203 mmbbl) to 60 599 PJ (14 394 mmbbl). Petroleum potential exists in deep-water frontier basins but the oil resource remains unknown.

- Australia's largest remaining discovered liquid petroleum resource is now the condensate and LPG in the Ichthys gas field in the offshore Browse Basin (figure 3.1).
- Australia has large unconventional oil resources hosted in oil shales. These resources, along with the recently recognised potential for shale gas liquids and light tight oil, could potentially contribute to future oil supply if economic and environmental challenges can be overcome. Identified shale oil resource contained in immature oil shale deposits is estimated at 131 659 PJ (22 391 mmbbl). The potential resource in liquids-rich shale gas and light tight oil is yet to be assessed.

3.1.3 Australia's oil market

- In 2011–12, oil and oil products accounted for the largest share (39 per cent) of primary energy consumption in Australia, but domestic primary oil (crude oil, condensate and LPG) production accounted for only 6 per cent of total energy production. Australia's net imports of oil and oil products represented 58 per cent of consumption in 2011–12.
- Australian primary oil production (crude oil, condensate and LPG) peaked in 2000–01 at 1540 PJ (275 mmbbl). Since then, primary oil production has been declining at an average rate of 4 per cent per year to 994 PJ (183 mmbbl, 27.9 GL) in 2011–12.
- Oil production from small offshore fields such as Fletcher/Finucane, Vincent/Van Gogh, Coniston/Novara and the Pyrenees development will reach

peak production relatively quickly. However, the increase in the number of smaller producing fields will not be enough to offset Australia's general decline in production.

- Australia is a net importer of crude oil and oil products. In 2011–12, Australia's imports of refined oil products feedstock were around 792 PJ (133 mmbbl, 21 GL), valued at A$16.7 billion.
- Australian refineries consumed 1474 PJ (251 mmbbl, 40 GL) of crude oil and condensate, mainly from imports, in 2011–12.
- The transport sector is the largest consumer of oil, accounting for around 96.6 per cent of Australia's total use of oil products.

3.2 Background information and world market

3.2.1 Definitions

The term 'oil' encompasses the range of liquid hydrocarbons and includes crude oil and condensate. LPG is considered along with oil in this study. Oil that has been refined into other products is referred to as refined products, oil products or petroleum products. Chemistry, geological occurrence and methods of extraction are variously used to define the different forms of liquid hydrocarbons. With the increasing importance of unconventional oils, there is a current revision of definitions and the introduction of new terms.

Crude oil is a naturally occurring liquid consisting mainly of hydrocarbons derived from the thermal and chemical alteration of organic matter buried in sedimentary basins. It is formed as organic-rich rocks are buried and heated over geological time. Crude oil varies widely in appearance, chemical composition and viscosity. Most Australian crude oils are classified as light sweet oil. Light crude oils are liquids with low density and low viscosity that flow freely at standard conditions: they have high API gravity[1] due to the presence of light hydrocarbons. Heavy oils, on the other hand, have higher density and viscosity, do not flow readily and have low API gravity (less than 20°) having lost the lighter hydrocarbons. Sweet oils are those that are low in sulfur. Crude oil is found in deposits with or without associated gas; this gas may include natural gas liquids – condensate and LPG. Crude oil can also be found in semisolid form mixed with sand and water (oil or tar sands) or as an oil precursor, also in solid form, called oil shale. Oil from oil sands, oil shale, and shale and tight reservoir rocks is known as unconventional oil (box 3.1).

Condensate is a liquid mixture of pentane and heavier hydrocarbons found in oil fields with associated gas or in gas fields. It is a gas in the subsurface reservoir, but condenses to form a liquid when produced and brought to the surface (figure 3.2).

1 API gravity is a scale developed by the American Petroleum Institute (API) for measuring the relative density of various petroleum liquids.

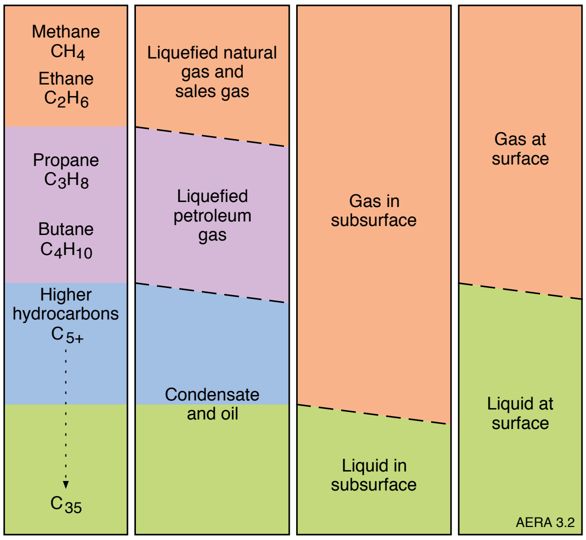


Figure 3.2 Petroleum resources nomenclature in terms of chemical composition, commercial product, physical state in the subsurface and physical state at the surface

Source: Geoscience Australia

Liquefied petroleum gas (LPG) is a mixture of lighter hydrocarbons, such as propane and butane, and is normally a gas at the surface. It is usually stored and transported as a liquid under pressure. In addition to naturally occurring LPG, it is also produced as a by-product of crude oil refining. LPG has lower energy content per volume than condensate and crude oil (Appendix D).

Refined products include petroleum products used as fuels (LPG, aviation gasoline, automotive gasoline, power kerosene, aviation turbine fuel, lighting kerosene, heating oil, automotive diesel fuel, industrial diesel fuel, fuel oil, refinery fuel and naphtha) and refined products used in non-fuel applications (solvents, lubricants, bitumen, waxes, petroleum coke for anode production and specialised feedstocks).

Primary oil consumption includes all petroleum used directly as fuel—crude oil, condensate, LPG and petroleum products.

Primary oil production includes crude oil, condensate and naturally occurring LPG prior to use in refineries.

Oil shale is a fine-grained sedimentary rock containing large amounts of organic matter (kerogen), which can yield substantial quantities of hydrocarbons after mining and processing. Oil shale is essentially a very rich thermally immature source rock; it requires heating to high temperatures to convert the organic material within the shale to liquid hydrocarbons – shale oil. The term, kerogen oil, rather than shale oil is sometimes used to clearly distinguish this product from the liquids produced with shale gas and light tight oil (IEA 2012). Shale oil is considered an alternative transport fuel, readily substitutable for high-grade crude oil.

Oil sands, or tar sands, are sandstones impregnated with bitumen, the very viscous, heavy hydrocarbons remaining after the more volatile components of crude oil have been lost. Mining and processing are required to recover the oil. Tar sands are a major component in recent large additions to oil reserves in Canada and Venezuela (IEA 2012).

Shale liquids are natural gas liquids (condensate) extracted from liquids-rich or 'wet' shale gas. They have been generated by thermal maturation within fine-grained, organic-rich source rocks, and may not have migrated to a separate reservoir rock because of the low permeability of source rock (in effect, also the reservoir rock). Natural or hydraulically induced fracture networks are needed to produce shale liquids at economic rates and volumes.

Light tight oil or tight oil is crude oil occurring within low-permeability reservoir rocks with matrix porosities of ≤10 per cent and permeabilities of ≤0.1 millidarcy (mD). The use of the term, light tight oil (IEA 2012) distinguishes this liquid hydrocarbon from shale (kerogen) oil and from the other abundant unconventional oil, the heavy oils from tar sands and bitumen deposits. Light tight oils may be considered to be transitional in nature between conventional oil and shale liquids, that is, they are generally conventionally generated and migrated, but are hosted in low-permeability reservoirs. Some light tight oil may be produced directly from shale, but most tight oil is produced from low-permeability siltstones, sandstones, limestones and dolostones that are associated with the shales from which the oil has been generated (Natural Resources Canada 2012). As with shale liquids, natural or hydraulically induced fracture networks, or chemical treatments (e.g. acidisation), are needed to produce tight oil at economic rates and volumes. Enhanced oil recovery (EOR) techniques to improve oil recovery are being applied to tight oil reservoirs in the United States (further information on EOR is in section 3.4.1 under 'Technology developments').

3.2.2 Oil supply chain

Figure 3.3 provides a representation of the oil industry in Australia. The oil industry undertakes the exploration, development and production of crude oil, condensate and LPG. More generally, the petroleum industry also includes downstream activities such as petroleum refining, and the transport and marketing of refined products, as well as non-energy products such as petrochemicals and plastics.

Resources and exploration

The supply of oil begins with undiscovered resources that must be identified through exploration. Geoscientists identify areas where hydrocarbons are likely to be trapped in the subsurface, that is, in sedimentary basins of sufficient thickness to contain mature petroleum source rocks, as well as suitable reservoir and seal rocks in trap configurations (box 3.1). The search narrows from broad regional geological studies through to determining an individual drilling target.

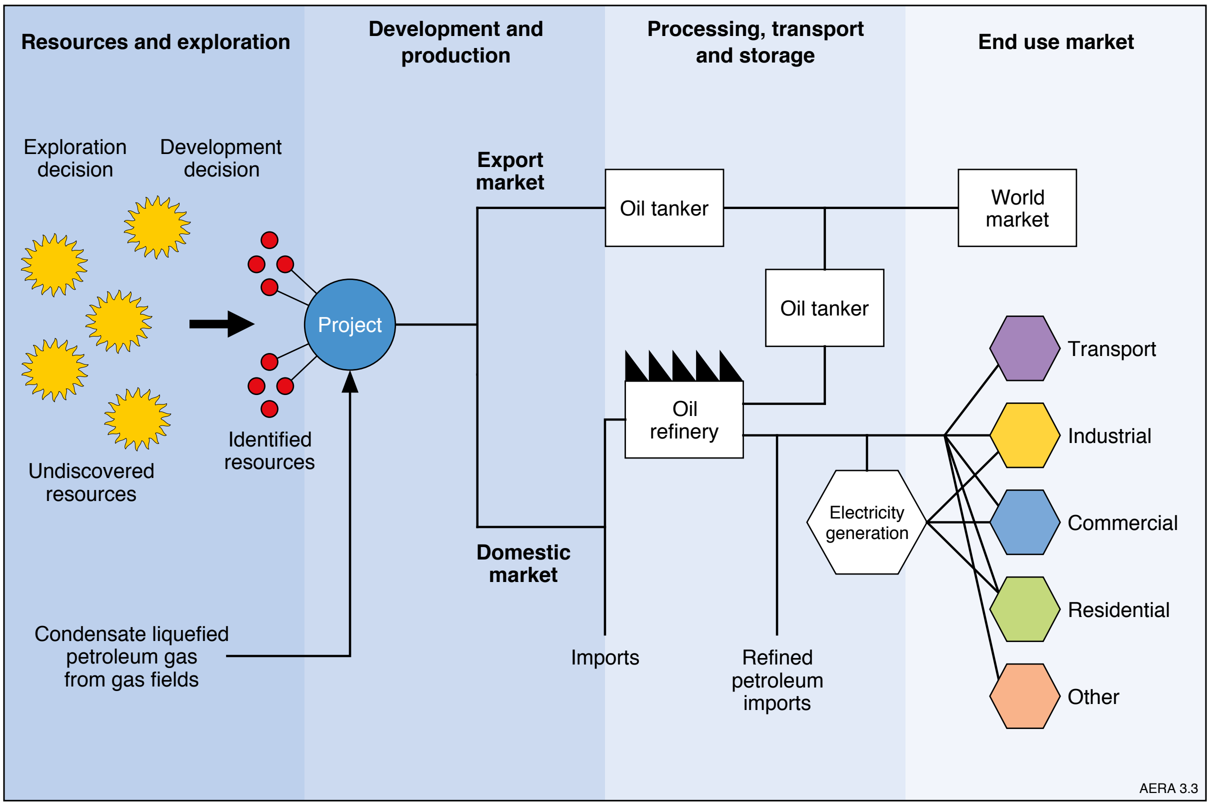


Figure 3.3 Australia's oil supply chain

Source: Bureau of Resources and Energy Economics and Geoscience Australia

In the Australian context, governments have taken a key role in providing regional precompetitive data to encourage investment in exploration by the private sector (figure 3.4). Company access to prospective exploration areas is by competitive bidding, usually on the basis of proposed work program (intended exploration effort) or by taking equity in ('farming-into') existing acreage holdings.

Reflection seismic, both 2D and 3D, is the primary technology used to identify likely hydrocarbon-bearing structures in the subsurface. Drilling is then required to test whether the structure contains oil or gas, or both, or neither. The initial discovery well may be followed by appraisal drilling and/or the collection of further survey data (often 3D seismic) to help determine the extent of the accumulation.

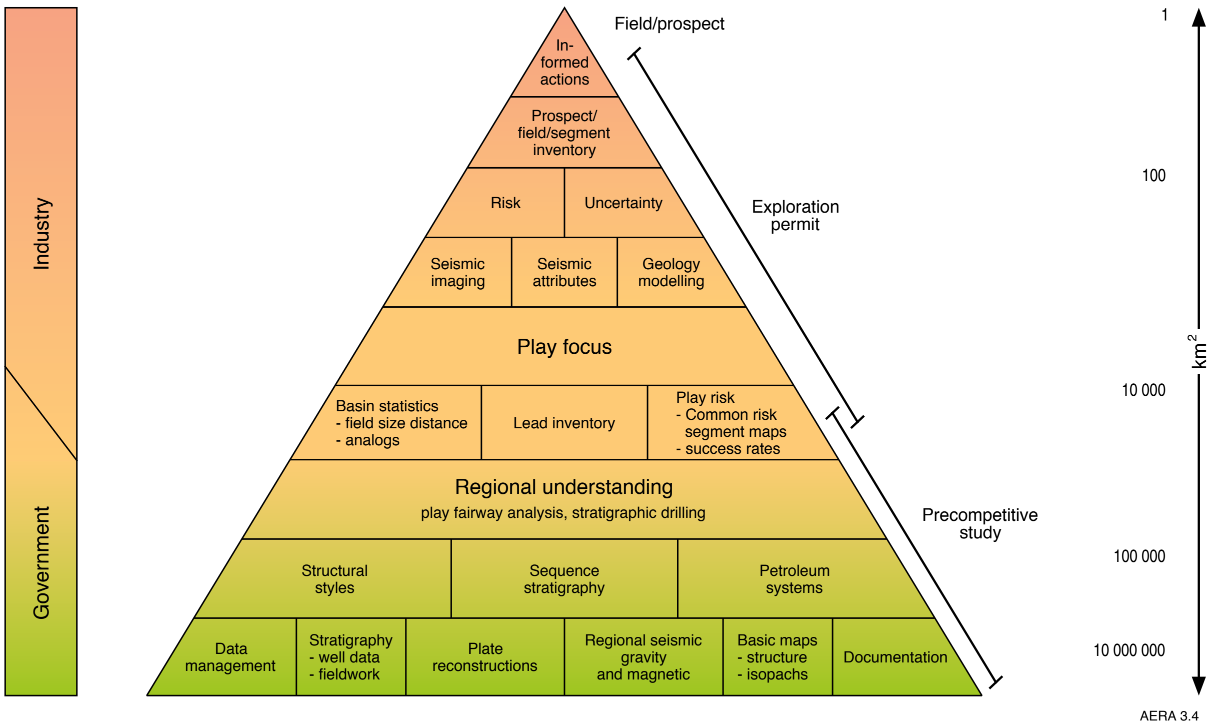


Figure 3.4 The resource discovery triangle

Source: Geoscience Australia (adapted from BP)

BOX 3.1 PETROLEUM SYSTEMS AND RESOURCE PYRAMIDS

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

- source—an organic-rich rock, such as an organic-rich mudstone
- reservoir—porous and permeable rock, such as sandstone
- seal—an impermeable rock such as a shale or mudstone
- trap—a subsurface structure that contains the accumulation, such as a fault block or anticline
- overburden—sediments overlying the source rock required for its thermal maturation
- migration pathways to link the mature source to the trap (figure 3.5).

In addition to these static elements, the actual processes involved—trap formation, hydrocarbon generation, expulsion, migration, accumulation and preservation—must occur, and in the correct order, for the petroleum system to successfully operate and for oil accumulations to be formed and preserved. It is essential that the source rock has been through (or is still within) the oil window, the zone in the subsurface where temperatures are sufficient for thermal alteration of the organic matter to oil. At higher temperatures, below the bottom of the oil window, oil starts to be broken down (cracked) to gas.

Unconventional oil accumulations reflect the failure or underperformance of the petroleum system. Oil shale is an example where a thermally immature source rock has not generated and expelled hydrocarbons. Oil or tar sands occur where conventional crude oil has failed to be trapped at depth and has migrated near to the surface, and has become degraded by evaporation, biodegradation and water washing to produce a viscous, heavy oil residue. Shale liquids and light tight oil occur within low-permeability reservoir rocks that prevent further migration of hydrocarbons, and necessitate specialised technology to achieve flow for production.

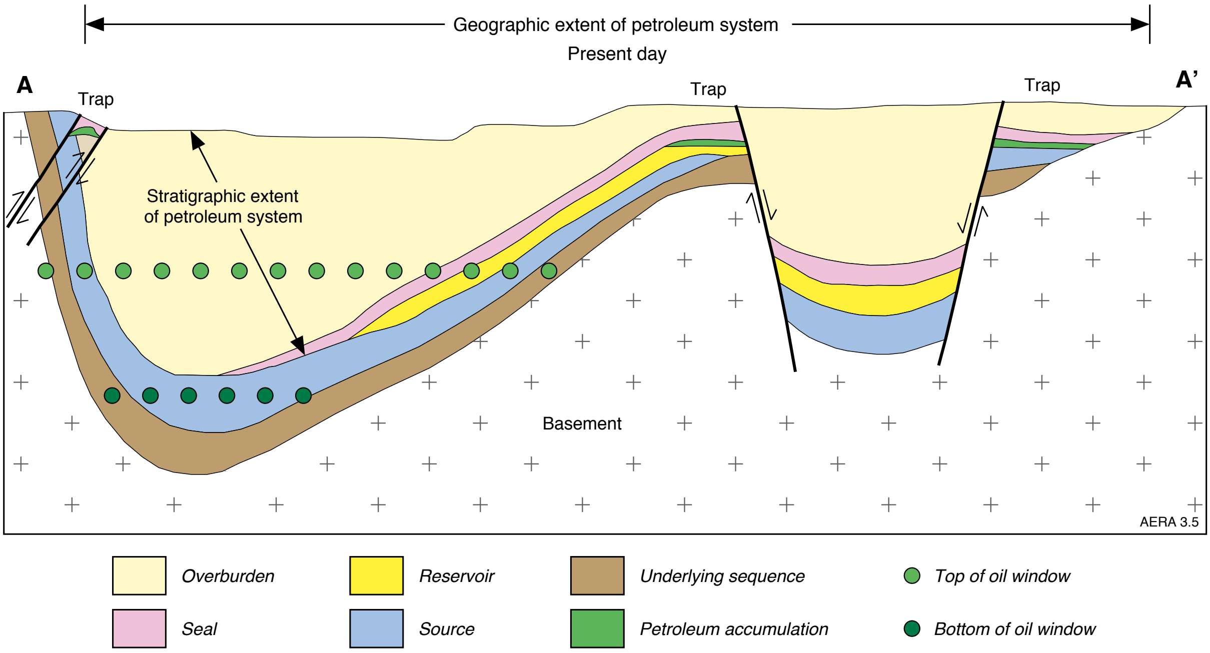


Figure 3.5 Petroleum system elements

Source: Magoon and Dow 1994 (modified)

The petroleum resource pyramid (McCabe 1998) describes how a smaller volume of easily extracted conventional gas and oil is underpinned by larger volumes of more difficult and more costly to extract unconventional gas and oil (figure 3.6). For the unconventional hydrocarbon resources, additional technology, energy and capital has to be applied to extract the gas or oil, replacing the natural action of the geological processes of the petroleum system. Technological developments and rises in price can make the lower parts of the resource pyramid accessible and economic to produce. The recent development of oil sands in Canada and of shale gas in the United States are examples where rising energy prices and technological development have facilitated the exploitation of unconventional hydrocarbon resources lower in the pyramid.

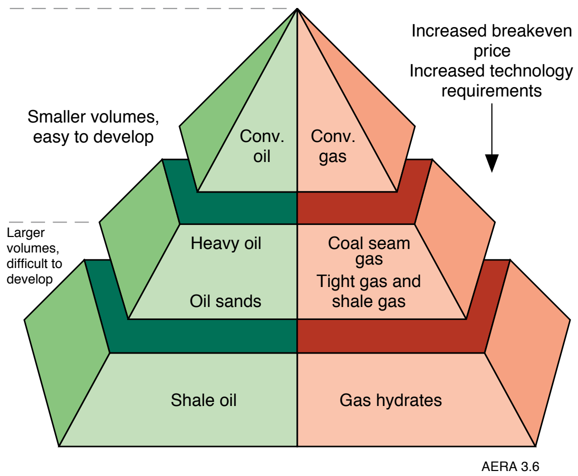


Figure 3.6 Petroleum resource pyramid

Source: Geoscience Australia (adapted from McCabe 1998 and Branan 2008)

Development and production

Once an economically recoverable resource has been identified, it is a matter of deciding whether to proceed to development based on project economics, market conditions (oil prices, and cost of extraction technologies and facilities) and the availability of finance.

The development phase involves the construction of the infrastructure required for the production of the oil resource. Depending on the location, this infrastructure includes development wells, production facilities, a gathering system to connect individual wells to processing facilities, temporary storage and transport facilities.

In Australia, the options for offshore development include a floating production, storage and offloading facility (FPSO)—for example, the Enfield oil development in the Carnarvon Basin; or building a production platform and piping the oil ashore, as at the Cliff Head field in the Perth Basin. Where the pipeline infrastructure is well established, new crude oil discoveries can be rapidly brought on stream, such as in the inshore Carnarvon Basin. Onshore, the options are to link into or extend the oil pipeline network or, in cases of small, remote fields, such as at Blina in the Canning Basin, to transport the oil by road.

Table 3.1 Key oil statistics

	Unit	Australia 2012	Australia 2011	World 2011
Reserves	PJ	20 664	22 151	9 443 493
	Bbbl	3.8	4	1653
share of world	%	0.3	0.2	100
Production	PJ	1076	994	172 089
	mmbbl	183	176	30 128
Share of world	%	0.5	0.5	100
Oil refining capacity	kb/d	663	740	91 616
Share of world	%	0.7	0.8	100
Consumption of oil products	PJ	2411	2196	171 042
	mmbbl	410	336	29 945
Share of world	%	1.2	1.1	100
Share of transport sector consumption	%	96.6		
Oil share of primary energy consumption	%	39	35.2	33.1
Annual growth in oil consumption, since 2000	%	2.0	1.7	1.3

Bbbl = billion barrels; **mmbbl** = million barrels; **kb/d** = thousand barrels per day

Sources: BP 2012; IEA 2012; Bureau of Resources and Energy Economics

The production phase includes extracting oil from the reservoir and separating impurities. At the initial stage of extraction, the natural pressure of the subsurface reservoir is generally sufficient for the oil to flow to the surface. If the reservoir pressure is insufficient, an advanced recovery method is used to increase reservoir pressure.

Condensate is a component of natural gas and is produced during gas or crude oil production. In some cases, the condensate is extracted and the gas is reinjected in a process called gas recycling.

Processing, transport and storage

Crude oil and condensate is not generally used in its raw or unprocessed form, apart from some light-sweet crude oil with low sulfur content, which can be used as a burner fuel for steam generation in industrial applications. The majority of crude oil is processed in a refinery to produce refined products, such as gasoline, diesel, aviation fuel, fuel oil, kerosene and LPG. Some crude oil and condensate can also be converted into non-energy products and used as a feedstock in the petrochemical industry.

Once refined, end-use products can be stored and transported to the demand centre via road, rail, sea or pipeline.

End-use market

The major end-use market for refined products is the transport sector. Refined petroleum products are transported to local distribution points, from where they are delivered either directly to end-users or to retail outlets, predominantly as petrol, diesel and LPG.

3.2.3 World oil market

Table 3.1 provides a snapshot of the Australian oil market within a global context. Australia's reserves account for only a small share of global reserves, and Australia is a relatively small producer and consumer.

Oil reserves and production

World proven oil reserves were estimated to be around 1.6 trillion barrels (equivalent to around 9.4 million PJ) at the end of 2011. At the current rate of world production, the estimated proven oil reserves and resources are enough to last for about 55 years (IEA 2012). Since 2008, proven oil reserves have increased as new discoveries are made and new reserves are developed each year, including those from unconventional sources. Heavy oil and tar sands have already changed the reserves picture for Venezuela and Canada, and light tight oil and shale liquids in the United States and elsewhere may prove to be a major new component of world oil supply.

Nearly half of total world reserves are located in the Middle East. Three countries in this region are in the top five of the world's largest reserves: Saudi Arabia, Iran and Iraq (figure 3.7). Saudi Arabia alone accounted for 16 per cent (1 516 600 PJ, 265 Bbbl) of world reserves. However, Venezuela has the largest share of world oil reserves, accounting for about 18 per cent. Canada has the third largest share of world oil reserves, although oil sands totalling some 966 762 PJ (169 Bbbl) account for around 97 per cent of these reserves. The Asia–Pacific region account for 2 per cent of world oil reserves. The largest oil reserves in this region are located in China.

In 2012, Australia ranked 29th in the world in terms of proven oil reserves, accounting for around 0.3 per cent of global reserves.

World total oil production in 2011 was some 30.1 Bbbl (equivalent to around 172 089 PJ). In 2011, production of crude oil represented more than 81 per cent of total oil production, which includes crude oil, natural gas liquids and unconventional oil. The major oil producers are located in the Middle East, which has a 30.5 per cent share of world production. Saudi Arabia is the largest single producer, accounting for around 13 per cent of world production (figure 3.7). The Russian Federation and the United States are also major producers: 12.5 per cent and 9.6 per cent of world production, respectively. Australia is only a small oil producer, accounting for 0.5 per cent of total oil production in 2012.

Petroleum refining

Because virtually all oil, conventional and unconventional, needs to be processed before end-use, refinery capacity and throughput are significant indicators of supply of end-use products. Table 3.2 summarises world refining capacity and production, by region.

The largest share, accounting for around 31 per cent of world refinery capacity and output, is in the Asia–Pacific region. China, Japan, India and the Republic of Korea are the major producers of refined products in the region, although Japan and the Republic of Korea rely almost entirely on imported crude oil. The largest single producer is the United States, accounting for about 21 per cent of world production of oil products. Australia accounted for less than 1 per cent of world refining capacity and production.

Consumption

Oil is an important energy source, currently accounting for around 33 per cent of world primary energy requirements. However, its share of primary energy has been declining steadily since the 1970s from around 44 per cent (figure 3.8). World oil consumption grew at a moderate rate of around 1.3 per cent per year since 2000 to reach 29.9 billion barrels (171 042 PJ) in 2011.

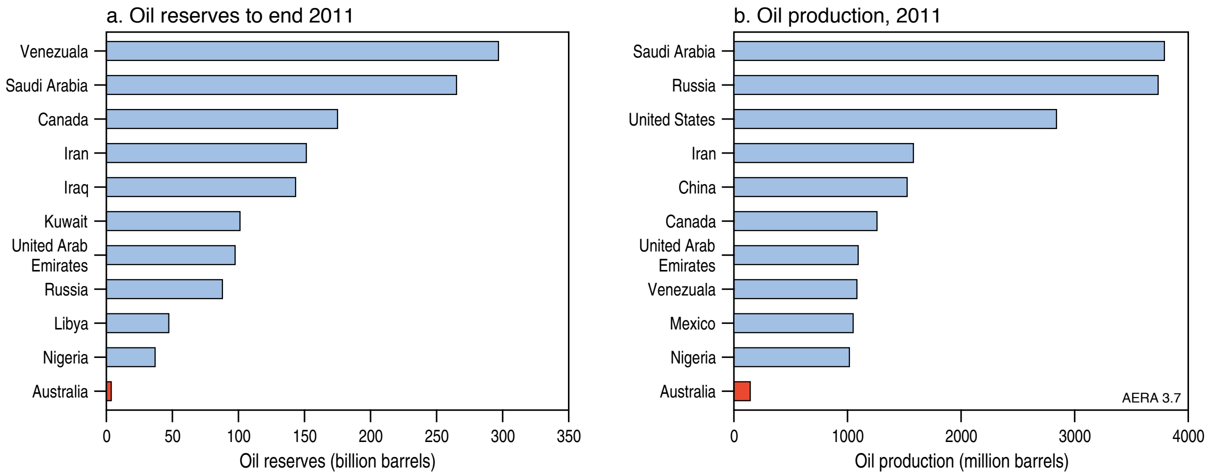


Figure 3.7 World oil reserves and production, major countries, 2011

Source: BP 2012; IEA 2012

Table 3.2 World refinery capacities and petroleum production, 2010

	Refineries capacities (kb/d)	Share of world capacity (%)	Refinery output (kb/d)	Share of world production (%)
North America	21 008	22.9	20 753	25.5
Latin America	6653	7.3	5102	6.3
Europe and Eurasia[a]	24 435	26.7	21 077	25.9
Middle East	7923	8.6	6773	8.3
Africa	3192	3.5	2416	3.0
Asia Pacific	28 405	31.0	25 135	30.9
World	**91 616**	**100.0**	**81 256**	**100.0**
Australia	**740**	**0.8**	**663**	**0.8**

a Former Soviet Union and Europe
kb/d = thousand barrels per day
Note: Includes capacity and production from unconventional oil

Source: BP 2012; IEA 2012

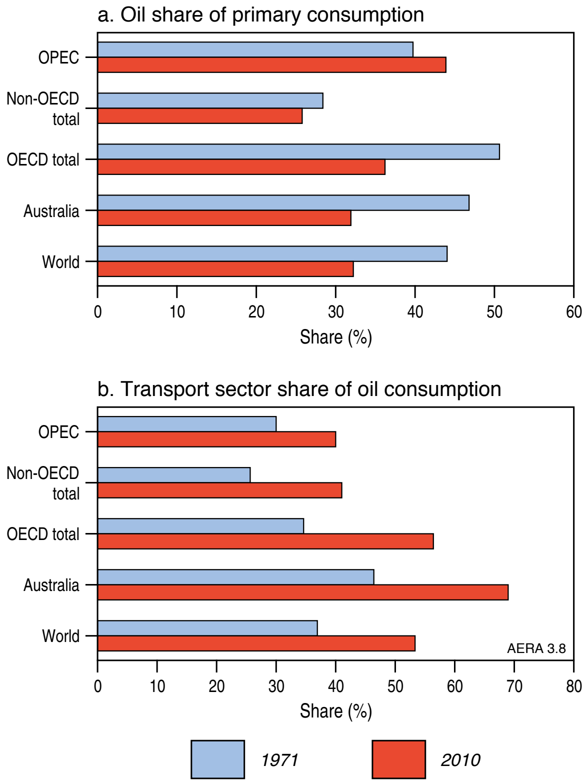


Figure 3.8 Oil share of total energy consumption and transport sector usage

OECD = Organisation for Economic Co-operation and Development;
OPEC = Organisation of the Petroleum Exporting Countries

Source: IEA 2012

In 2011, more than 50 per cent of world oil consumption was used in the transport sector, compared with about 37 per cent in 1971 (figure 3.9; IEA 2012). The global shares of oil consumption in the industry and electricity generation sectors have been steadily declining over the past 20 years. In 2011, industry and electricity generation represented 8 per cent and 7 per cent, respectively, of total oil consumption (IEA 2012).

Figure 3.9 shows world oil consumption by region. North America and the Asia–Pacific region are the major consuming regions, responsible for nearly 60 per cent of world oil consumption in 2011. Oil consumption in non-OECD countries has grown more rapidly than the world average, at an average rate of 2 per cent per year between 1971 and 2011. The fastest growing oil consuming region is non-OECD Asia, growing at an average rate of about 5 per cent per year over the same period.

Australia is ranked 22nd in the world in terms of oil consumption in 2012, accounting for around 1 per cent of the world total. About 96.6 per cent is consumed in the transport sector.

Trade

Given the significant separation of major producing and major consuming countries, there is a substantial level of trade in oil. Over the past 20 years, oil trade has increased as oil production reserves in the Asia–Pacific region and North America failed to keep pace with growth in demand. In the mid-1980s, around 40 per cent of world oil consumption was supplied through international trade. This increased to around 65 per cent in 2008.

World oil trade in 2011 was 54.6 million barrels per day (BP 2012). The largest export region was the Middle East, which accounted for around 36 per cent of world oil exports (table 3.3). North America, Africa and the former Soviet Union countries together accounted for 42 per cent of world oil exports. The largest importer of oil, the Asia–Pacific region, accounted for around 46 per cent of world oil trade in 2011. North America and Europe together accounted for about 45 per cent of world trade.

In 2011, around 57 per cent of Asia–Pacific oil imports were sourced from the Middle East, and regional trade within the Asia–Pacific accounted for a further 18 per cent. In North America, 37 per cent of imports are sourced from within the region, specifically oil exports from Canada and Mexico to the United States. Significant quantities of oil are imported into North America from Latin America, the Middle East and Africa. The majority of Europe's imports are sourced from the former Soviet Union, Africa and the Middle East.

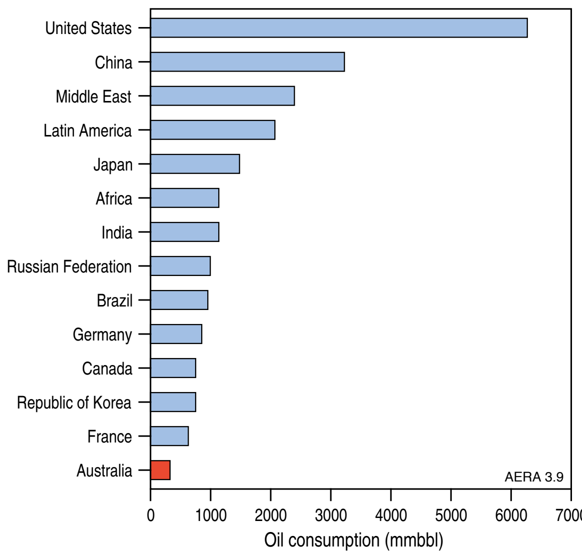


Figure 3.9 World oil consumption, by region

Source: IEA 2012

Australia is a net importer of crude oil and condensate and of refined oil products, but is a net exporter of LPG. Since the mid-1990s, Australia's imports of crude oil from the Middle East have been gradually declining and have been increasingly sourced from South-East Asia, mainly from Vietnam.

World oil market outlook

In its new policies scenario, the IEA projects world demand for primary oil—and the supply to meet that demand—to grow by 0.6 per cent per year, from 30 590 mmbbl (174 693 PJ) in 2011 to 34 895 mmbbl (199 278 PJ) in 2035 (table 3.4).

Table 3.3 World oil trade by region, 2011

Shares	To							
%	North America	Latin America	Europe	Africa	Australasia	Asia Pacific	Rest of World	Total exports
From								
North America	37	53	6	5	1	2	12	13
Latin America	18	0	3	0	0	4	0	7
Europe	7	4	0	43	1	1	40	4
Former Soviet Union	6	2	50	1	3	7	35	16
Middle East	16	7	21	38	19	57	0	36
Africa	16	19	18	0	9	9	3	13
Australasia	0	1	0	0	0	2	0	1
Asia Pacific	1	14	2	14	67	18	10	11
Total imports	23	3	22	3	2	46	1	100

Source: BP 2012

Table 3.4 IEA new policies scenario projections for world oil outlook

	Unit	2011	2035
World oil supply	**PJ**	**173 094**	**199 278**
	mmbbl	30 310	34 895
Share of OPEC supply	%	42	48
Share of supply from unconventional oil	%	4	13
Annual growth, 2011–35	%		0.6
World primary oil demand	**PJ**	**174 693**	**199 278**
	mmbbl	30 590	34 895
Share of non-OECD demand	%	43	55
Share of transport sector demand	%	53	60
Annual growth, 2011–35	%		0.6

OECD = Organisation for Economic Co-operation and Development;
OPEC = Organisation of the Petroleum Exporting Countries

Note: Data are converted from million barrels per day to million barrels by multiplying 350, consistent with BP, 2009a.

Source: IEA 2012

Oil demand in non-OECD economies is expected to grow at a faster rate than in OECD economies. By 2035, non-OECD economies are expected to represent more than half of world oil demand, up from 43 per cent in 2011.

The majority of the increase is expected to be supplied by OPEC countries, where significant proven reserves of conventional crude oil exist. OPEC's share of world oil supply could increase from around 41 per cent in 2011 to 48 per cent in 2035.

Some 53 per cent of the oil was used in the transport sector in 2011. This share is expected to rise further to 60 per cent in 2035. Viable alternatives for transport fuels are expected to remain relatively limited throughout the outlook period, while the share of oil use in other sectors, including industry and electricity generation, is expected to decline further.

Production of conventional oil, including crude oil and condensate, is expected to slow towards the end of the outlook period. To meet oil demand, increased production is expected to come from unconventional sources, mainly oil sands, extra-heavy oil, light tight oil, GTL and CTL. As a result, the share of unconventional oil is expected to rise from 4 per cent in 2011 to 13 per cent in 2035.

The IEA projects world demand for oil to grow steadily under its new policies scenario, with most of the net growth coming from the transport sector in emerging economies (IEA 2012). Government policies and energy efficiency measures are expected to slow oil demand over the forecast period. According to the IEA, measures to promote more efficient oil use and switching to other fuels, together with higher prices that result from price rises on international markets, reduced subsidies in some major consuming countries and increased taxes on oil products, help to offset much of the underlying growth in demand for mobility, especially in non-OECD countries.

3.3 Australia's oil resources and market

Australia's total demonstrated oil resources (crude oil, condensate and LPG) were estimated at 20 664 PJ (3779 mmbbl) as at 1 January 2012. In addition, Australia had a large unconventional oil shale identified resource of 131 659 PJ (22 391 mmbbl) in 2011. There are currently no resource estimates for shale liquids and tight oil; however, exploration is still at an early stage.

3.3.1 Crude oil resources

Australia's crude oil resources were estimated at 5467 PJ (930 mmbbl) as at 1 January 2012. Crude oil represents 24.6 per cent of liquid petroleum resources, with the remainder being made up of condensate (11 275 PJ, 50.7 per cent) and naturally occurring LPG (3922 PJ, 24.7 per cent) (figure 3.10).

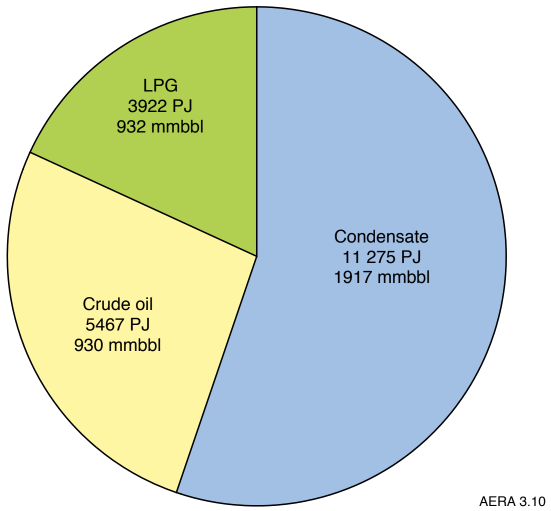


Figure 3.10 Australia's liquid petroleum resources by energy content and volume, as at 1 January 2012

LPG = liquefied petroleum gas

Source: Geoscience Australia

As shown in table 3.5, most of Australia's identified crude oil resource is in the Economic Demonstrated Resource (EDR) category, and only a small volume is considered sub-economic given current relatively high oil prices.

Resource classification is more fully discussed in Appendix D, but note that EDR are resources with the highest levels of geological and economic certainty and include remaining proved plus probable commercial reserves of petroleum. Sub-economic Demonstrated Resources (SDR) are resources for which profitable extraction has not yet been established. Inferred Resources are those with a lower level of confidence that have been inferred from more limited geological evidence and are assumed, but not verified.

A potential source of additional crude oil resources is reserves growth (Geoscience Australia, 2001, 2004, 2005), when successive estimates of reserves in existing fields increase as more information is acquired during their development and production. In North America and elsewhere, EOR technologies such as miscible gas flooding (e.g. using nitrogen or carbon dioxide) can increase the oil recovery factor of a field significantly beyond the 30–50 per cent typically recovered using combined primary and second recovery methods. However, many Australian oil reservoirs achieve recovery rates well above 50 per cent without enhanced technologies, and EOR is not currently undertaken at any Australian oil field.

Most (74 per cent) of the remaining identified crude oil resource is located in the Carnarvon (4318 PJ) and Bonaparte (1109 PJ) basins. Despite its 44 years of production, the Gippsland Basin remains a significant resource (1369 PJ); there are smaller volumes in a number of onshore (Cooper-Eromanga, Bowen-Surat and Amadeus) and offshore (Browse, Perth and Bass) basins (figure 3.11, table 3.9).

Table 3.5 Australian crude oil resources represented as McKelvey classification estimates as at 1 January 2012

Crude oil resources	PJ	mmbbl
Economic Demonstrated Resources	5467	930
Sub-economic Demonstrated Resources	1915	325
Total	**7382**	**1255**

Source: Geoscience Australia

While crude oil resources are identified across nine basins and through much of the stratigraphic column, the significant volumes are restricted to the offshore Mesozoic basins on the north-west margin and in Bass Strait. The onshore basins currently contribute only about 9.6 per cent of the total crude oil resources. However this looks set to change with a resurgence of onshore exploration resulting in recent conventional oil discoveries in the Cooper Western Flank, Canning and Amadeus basins, and the investigation of shale liquids potential in a number of onshore basins.

Australia's remaining identified crude oil resources are dwarfed by past production, which has come mainly from a few super-giant fields in the Gippsland Basin and the Barrow Island field in the Carnarvon Basin, all discovered in the 1960s (figure 3.12). Many smaller oil fields have been found since, mostly in the Carnarvon and Bonaparte basins. The impact of these initial discoveries on crude oil resources and the reserves to production ratio is illustrated in figures 3.13 and 3.14.

The EDR to production (R/P) ratio has been relatively steady at around 7 to 10 years since the 1980s. However, it must be recognised that both production volumes and reserves have declined markedly in recent years. To date, 83 per cent of the crude oil reserves discovered in Australia have been produced.

3.3.2 Condensate resources

Condensate exists as a hydrocarbon gas in the subsurface reservoir that condenses to a light oil at the surface when a gas (or a gas and oil) accumulation is produced. Condensate now represents more than half of Australia's remaining liquid hydrocarbon resources. In 2012, the demonstrated condensate resource totalled 15 973 PJ (2716 mmbbl), most of which was assessed as EDR (table 3.6).

As most Australian crude oils are light sweet crudes and are very similar to the condensate produced from gas fields, both are considered to have equivalent energy value per volume (5.88 PJ/mmbbl) in this report.

Condensate resources are located across ten basins, but the offshore basins along the North West Shelf—Bonaparte, Browse and Carnarvon—contain 90 per cent of the resource (figure 3.15). The bulk of this resource is contained in a small number of giant 'wet' gas fields. The Ichthys gas resource in the Browse Basin, for example, is estimated to contain 3099 PJ (527 mmbbl)

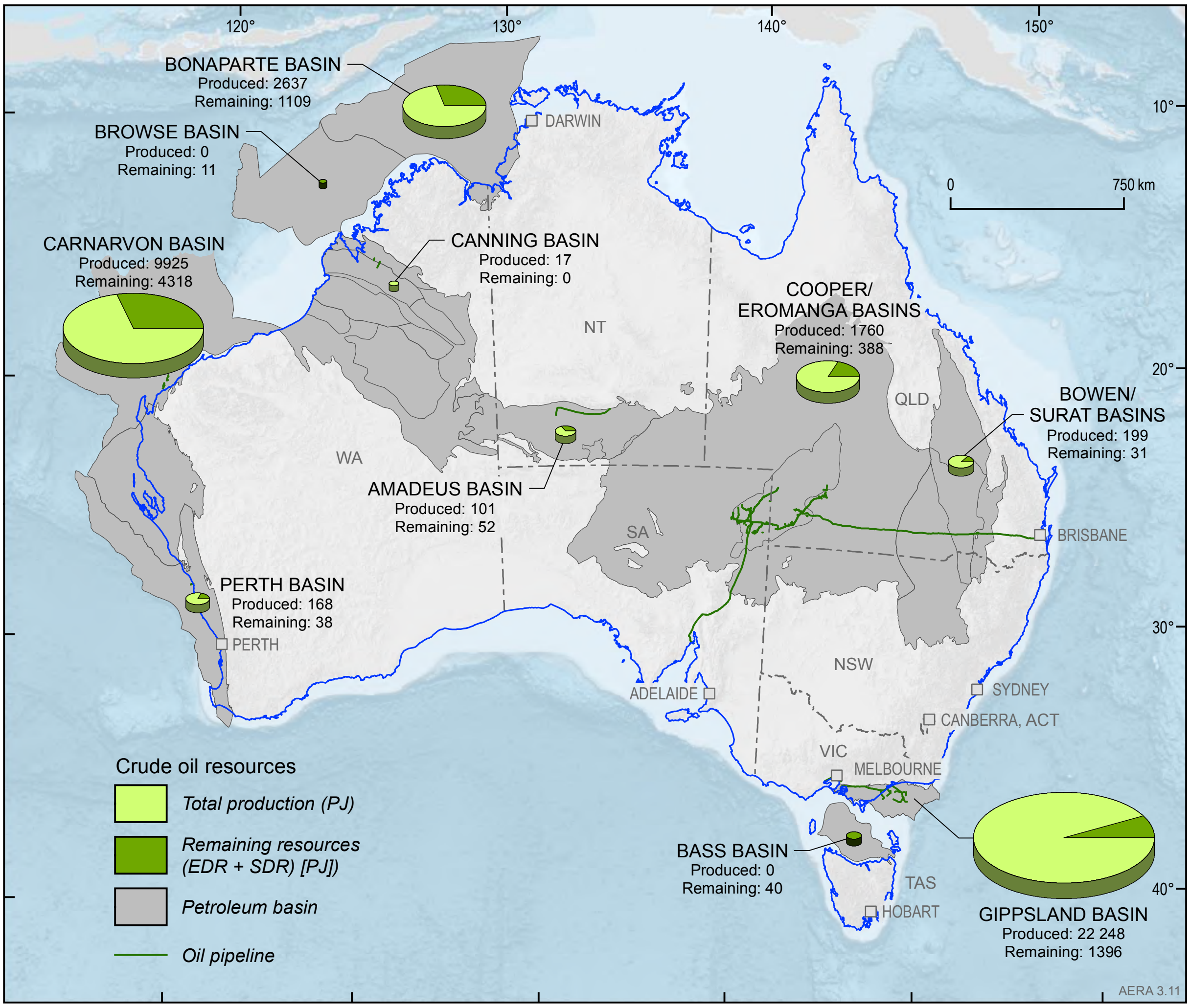


Figure 3.11 Australia's known crude oil resources, by basin and oil pipelines

EDR = Economic Demonstrated Resources; **SDR** = Sub-economic Demonstrated Resources

Source: Geoscience Australia

or 19 per cent of Australia's condensate resources and is the largest liquid hydrocarbon resource found since the Bass Strait oil fields in the Gippsland Basin in the 1960s. The Ichthys project is currently under development, with production planned to commence in 2017.

Proportionally, the Carnarvon Basin gas fields tend to be leaner in condensate than those in the Browse and Bonaparte basins because of the dominance of the super-giant dry gas accumulations of Io-Jansz and Scarborough.

The identified condensate has strategic importance as it constitutes more than half of Australia's liquid fuel resource. Access to this resource requires development of the giant wet gas fields, of which several also contain considerable volumes of carbon dioxide (CO_2).

Australia's condensate resources have grown substantially since the discovery of the super-giant and giant gas fields along the North West Shelf in the early 1970s (North Rankin in the Carnarvon Basin, Scott Reef (Torosa) in the Browse Basin, Sunrise in the Bonaparte Basin). The big step in the condensate EDR in 2008 (figure 3.16) is largely due to the promotion of Ichthys into this category.

Table 3.6 Australian condensate resources represented as McKelvey classification estimates as at 1 January 2012

Condensate Resources	PJ	mmbbl
Economic Demonstrated Resources	11 275	1917
Sub-economic Demonstrated Resources	4698	799
Total	**15 937**	**2716**

Source: Geoscience Australia

The EDR to production ratio of condensate since 1980 has mostly been between 20 and 50 years, apart from a peak in the early 1980s (figure 3.17). In 2010, at current levels of production, Australia had about 25 years of condensate reserves remaining.

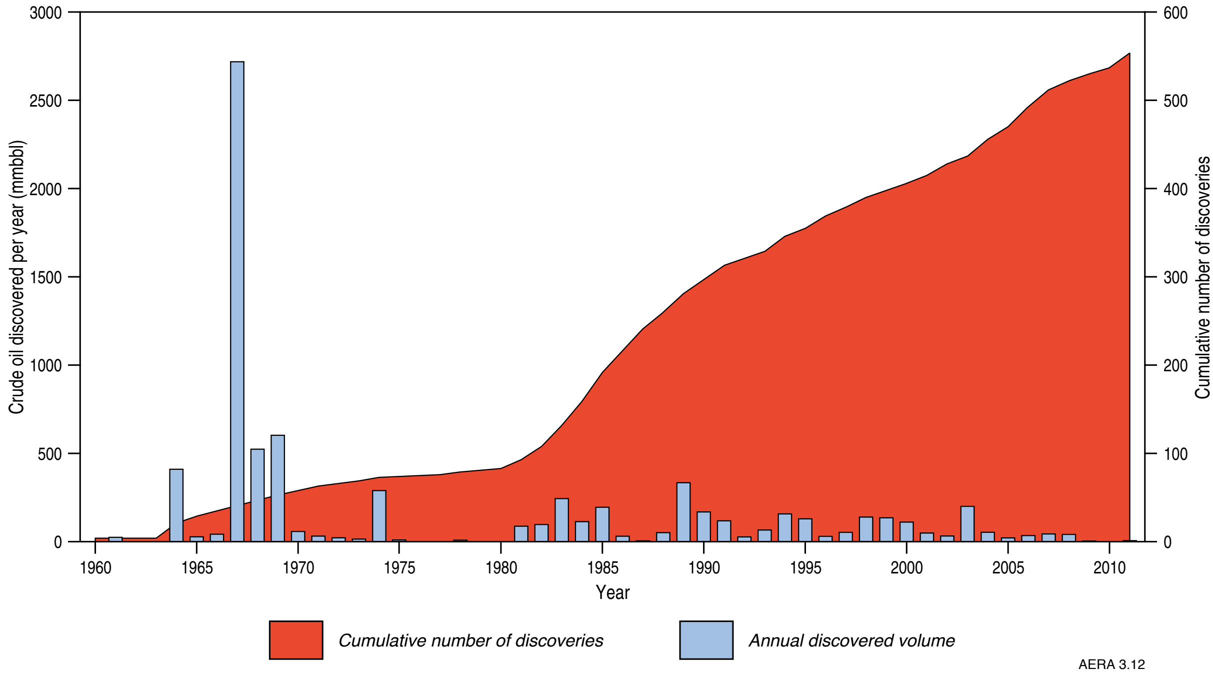


Figure 3.12 Australia's crude oil discoveries, annual discovered volume and cumulative number of discoveries, 1960–2011

Source: Geoscience Australia

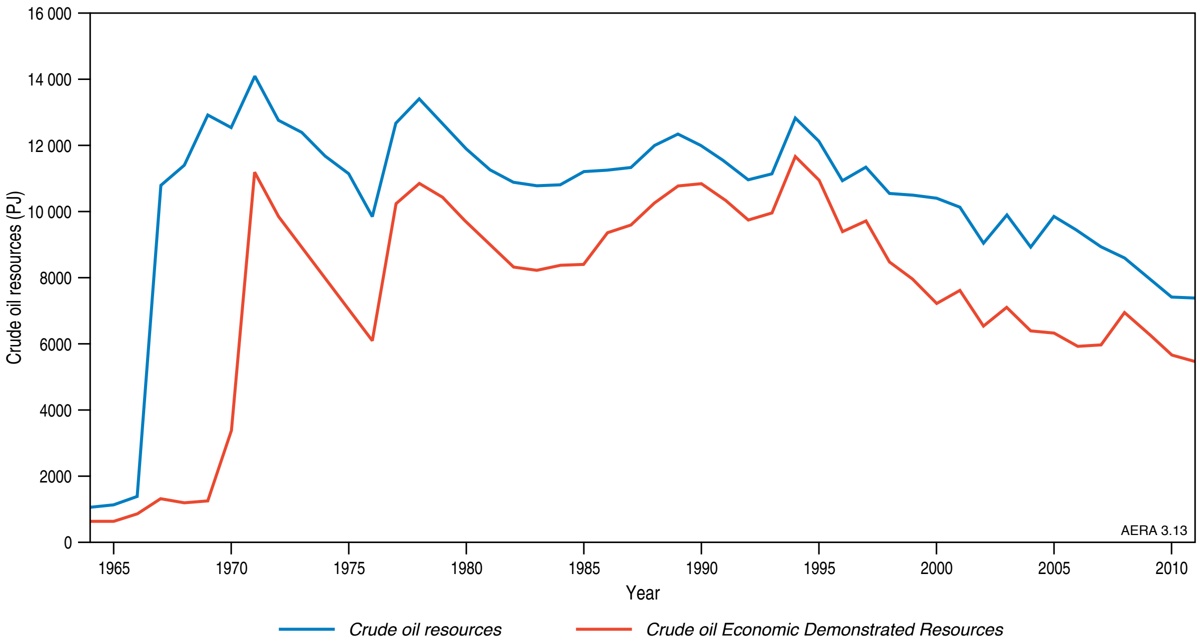


Figure 3.13 Australia's crude oil resources and Economic Demonstrated Resources (EDR), 1964–2011

Source: Geoscience Australia

3.3.3 LPG resources

The identified resource of naturally occurring liquid petroleum gas (LPG) in 2012 was estimated at 5664 PJ (1345 mmbbl), most of which was assessed as EDR (table 3.7). LPG represents 25 per cent of Australia's liquid hydrocarbon resource in energy content terms. LPG is less energy dense than crude oil and condensate. Hence, although Australia's naturally occurring LPG now volumetrically exceeds the crude oil resource, the crude oil has a higher energy content (7382 PJ in 1255 mmbbl of crude oil, compared with 5664 PJ in 1345 mmbbl of LPG).

LPG is a mixture of light hydrocarbons that is normally a gas in subsurface reservoirs and at the surface. However, LPG is stored and transported as a liquid under pressure and forms part of Australia's liquid fuel supply. In addition to the LPG occurring naturally in gas and oil fields, LPG is also produced during the refining of crude oil.

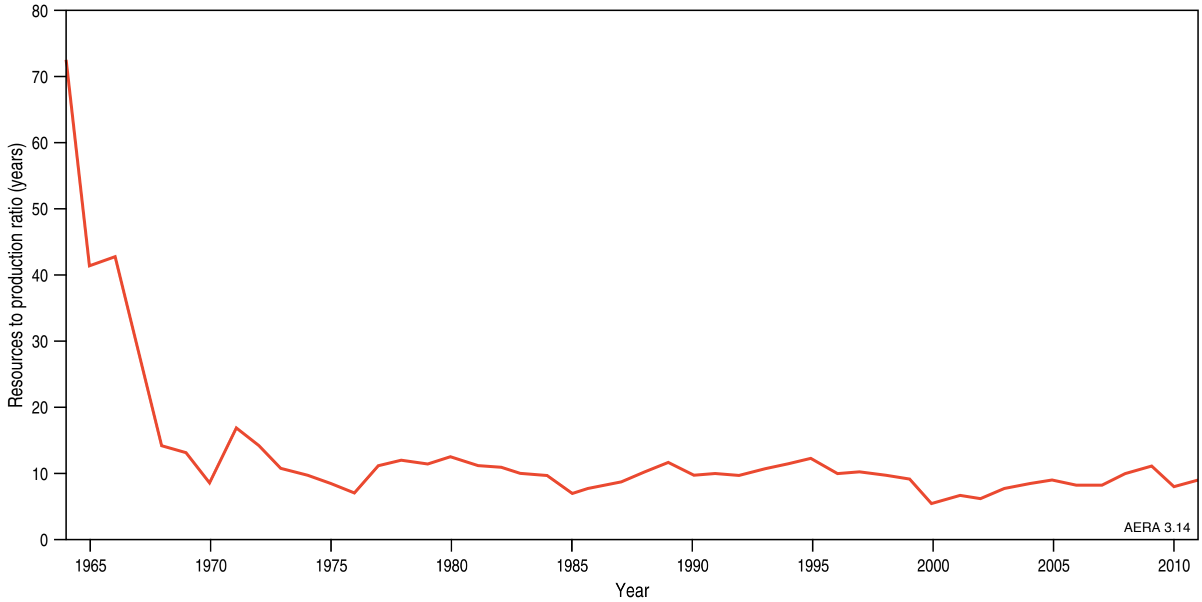


Figure 3.14 Australia's crude oil reserves to production ratio in years of remaining production, 1964–2011

Source: Geoscience Australia

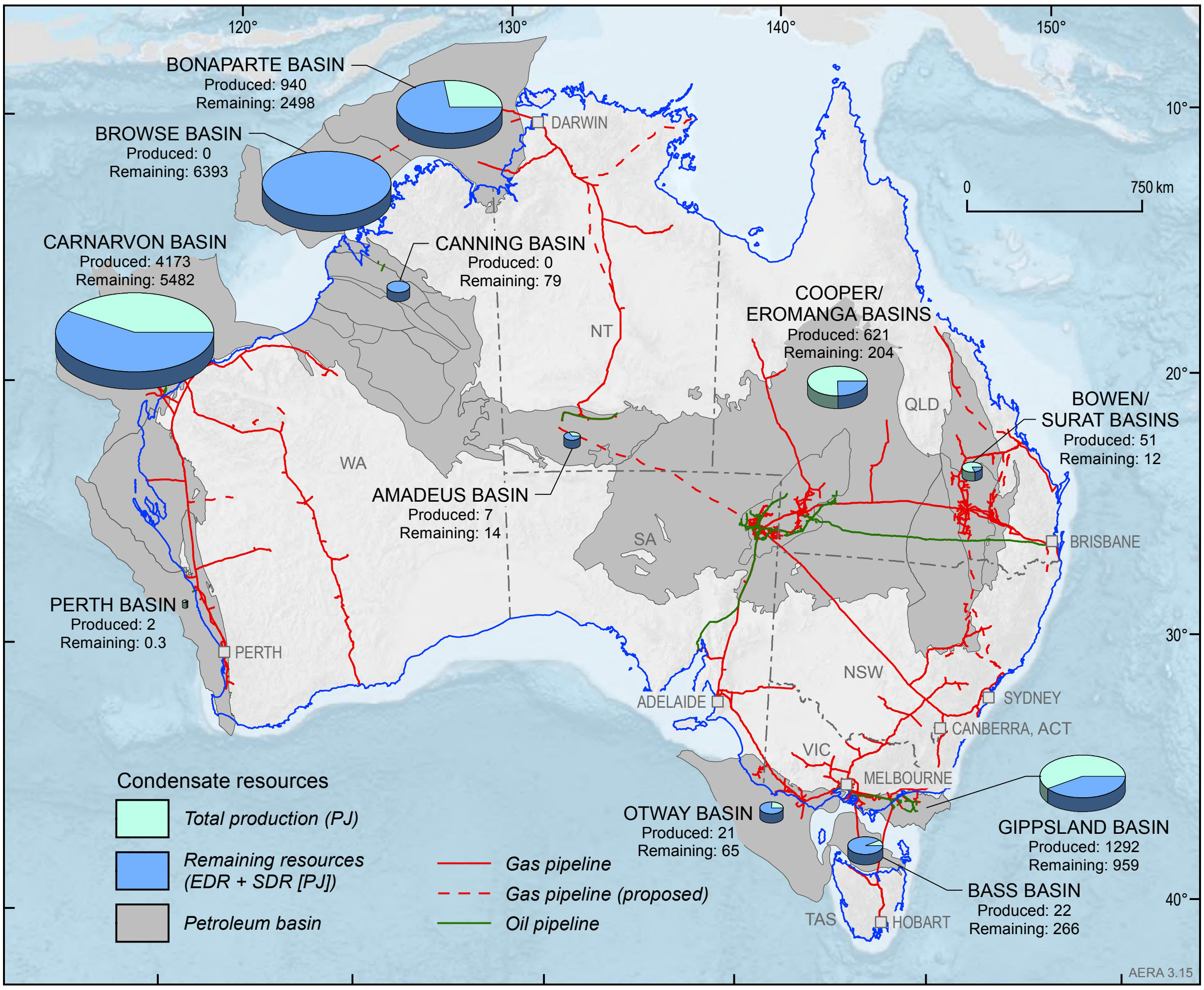


Figure 3.15 Australia's known condensate resources by basin, and gas and oil pipelines

EDR = Economic Demonstrated Resources; **SDR** = Sub-economic Demonstrate Resources

Source: Geoscience Australia

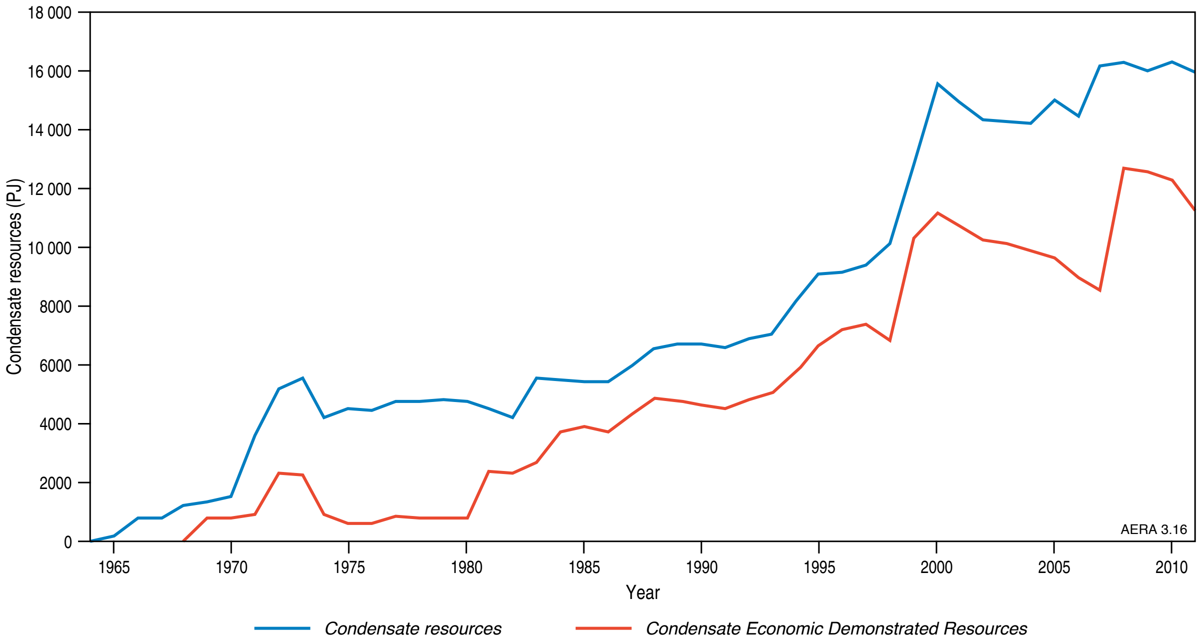


Figure 3.16 Australia's identified condensate resources, 1964–2011

Source: Geoscience Australia

Figure 3.17 Condensate Economic Demonstrated Resources to production ratio in years of remaining production, 1975–2011

Source: Geoscience Australia

Table 3.7 Australian naturally occurring LPG resources represented as McKelvey classification estimates, as at 1 January 2012

LPG resources	PJ	mmbbl
Economic Demonstrated Resources	3922	932
Sub-economic Demonstrated Resources	1742	413
Total	**5664**	**1345**

Source: Geoscience Australia

Naturally occurring LPG resources are identified in eight basins (figure 3.18). The distribution of LPG is similar to that of condensate, with the Carnarvon, Browse and Bonaparte basins again dominating (82 per cent of the remaining resource). The resource in the Gippsland Basin remains significant (11 per cent of the total), even though this represents only about a quarter of the initial resource in the basin.

In 2012, at current levels of production, Australia had 16 years of naturally occurring LPG remaining.

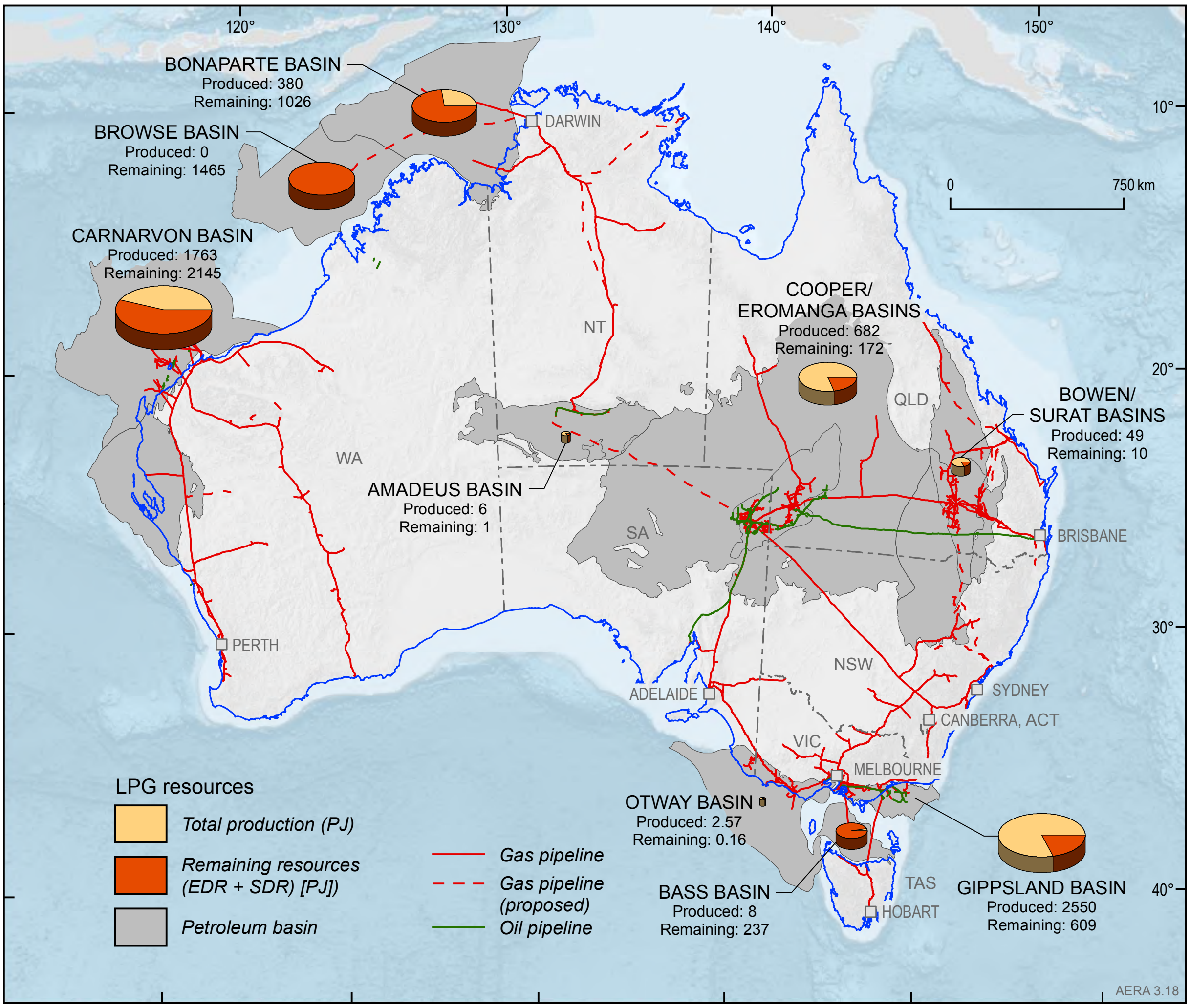


Figure 3.18 Australia's LPG resources by basin

EDR = Economic Demonstrated Resources; **SDR** = Sub-economic Demonstrate Resources

Source: Geoscience Australia

3.3.4 Shale oil resources

Australia has significant potential unconventional shale oil resources contained in oil shale deposits in several basins. Oil shale is essentially a petroleum source rock that has not undergone the complete thermal maturation required to convert organic matter to oil. In addition, the further geological processes of explusion, migration and accumulation that produce conventional crude oil resources trapped in subsurface reservoirs have not occurred. The unconventional shale oil (or kerogen oil) resource can be transformed into liquid hydrocarbons by mining, crushing, heating, processing and refining, or by *in situ* heating, oil extraction and refining (box 3.2).

Australia's total identified energy resource contained in oil shale was estimated at 131 659 PJ (22 391 mmbbl) in 2012 (table 3.8). However, all of this was classified as either recoverable contingent (84 601 PJ, 14 388 mmbbl) or inferred (47 058 PJ, 8003 mmbbl) resources. This is a large unconventional oil resource.

The majority of Australian shale oil resources of commercial interest are located in Queensland, in the vicinity of Gladstone and Mackay (figure 3.19). Thick Cenozoic lacustrine oil shale deposits (lamosite) of commercial interest are predominantly in a series of narrow and deep extensional basins near Gladstone and Mackay. From 1999 to 2003, oil was produced at a demonstration-scale processing plant (referred to as the Stuart Oil Shale Project) at the Stuart deposit in the Narrows Basin, near Gladstone. In September 2011, Queensland Energy Resources Ltd (QER) produced its first crude oil from its demonstration Paraho II™ vertical shaft kiln processing plant at the Stuart deposit. The oil shales are graded from about 60 litres per tonne at zero per cent moisture (LTOM) to over 200 LTOM, comfortably above the 50 LTOM cut-off generally regarded as the minimum required for profitable operation.

Oil shale deposits of varying quality also occur in New South Wales, Tasmania and Western Australia in sedimentary sequences of Permian, Cretaceous and Cenozoic age. There was some modest scale production from two of these deposits for periods up to the 1950s.

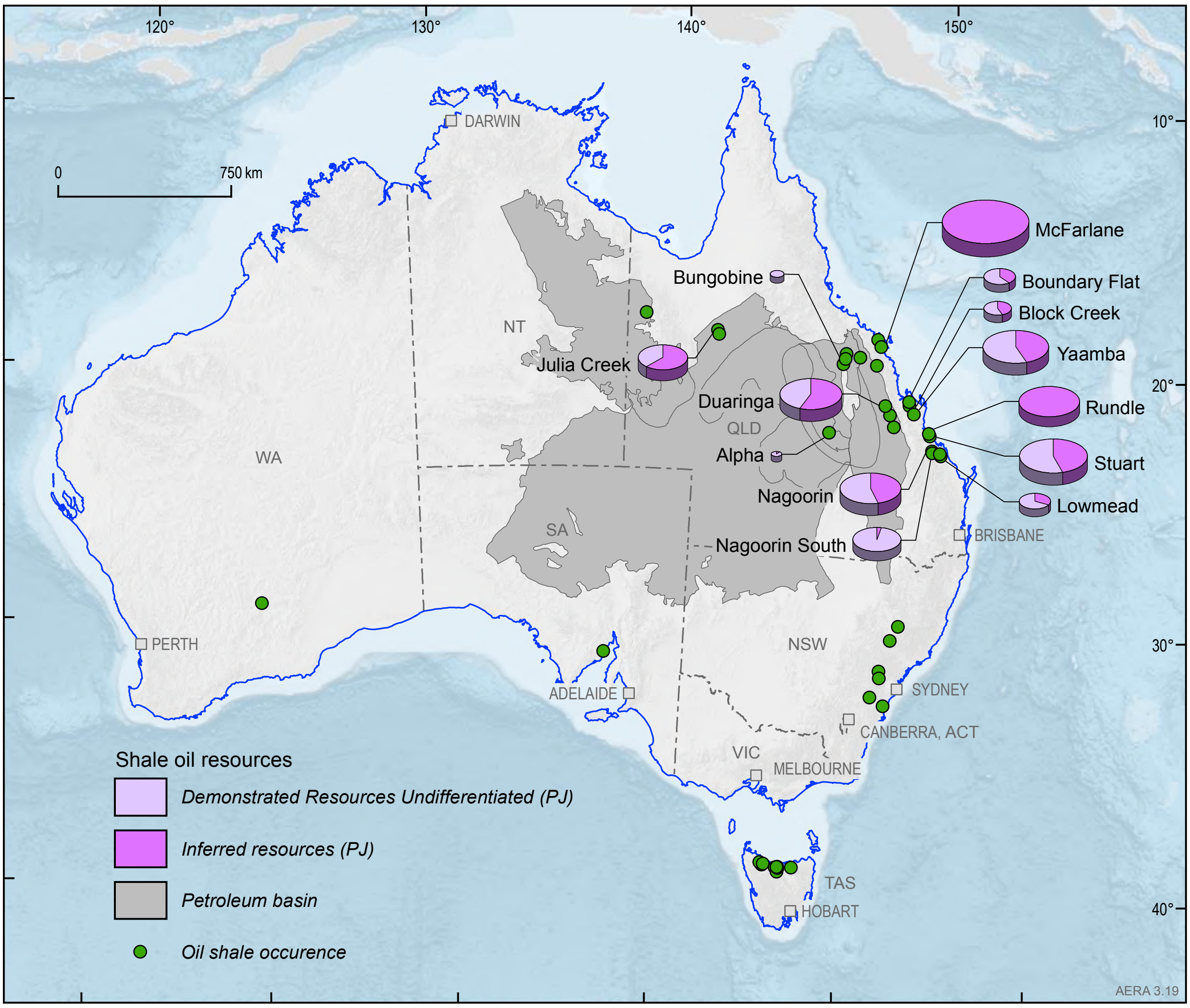


Figure 3.19 Distribution of Australian indicated shale oil resources

Source: Geoscience Australia

Table 3.8 Australian shale oil recoverable resources represented as McKelvey classification- estimates, as at 1 January 2012

Shale oil resources	PJ	mmbbl
Demonstrated resources	84 601	14 388
Inferred resources[a]	47 058	8 003
Total	**131 659**	**22 391**

a The total inferred resource does not include a 'total potential' low grade shale oil resource of the Toolebuc Formation, Queensland estimated to be about 9 061 100 PJ (equivalent to 1 541 000 mmbbl, 245 000 GL) by BMR and CSIRO in 1983.

Source: Geoscience Australia 2009b

A potential shale oil resource of approximately 1 541 000 mmbbl (9 061 080 PJ) was estimated for the Toolebuc Formation in north-western Queensland by the then Bureau of Mineral Resources (now Geoscience Australia) and the CSIRO (Ozimic and Saxby 1983). The Toolebuc Formation (figure 3.20) is very widespread but, at an average 37 LTOM, the resource is considered very low grade. It is not counted among the resources in table 3.8. The Toolebuc Formation is currently also being assessed for its shale gas potential by the Queensland Geological Survey and industry explorers.

In August 2008, the Queensland Premier announced a review into whether oil shale deposits can be developed in an environmentally acceptable way. The review report is to be prepared no earlier than two years from the commencement of operation of the Queensland Energy Resources (QER) Stuart demonstration facilities in order to allow that research to come to fruition. In November 2008, Queensland Government amendments to the *Mineral Resources Act 1989 (Qld)* placed a 20-year moratorium on oil shale mining in the Whitsunday region around Proserpine. The granting of new tenures and variation of existing entitlements relating to oil shale were suspended until the Queensland Government considers the review report on oil shale. QER submitted a final report to the Queensland Government in September 2012 indicating that there were no reportable environmental incidents at the plant during all phases of construction, commissioning and operations. In February 2013, the Queensland Government lifted the moratorium on shale oil except for the McFarlane oil shale deposit. The government will allow the development of oil shale projects under strict environmental conditions and will consider all projects on a case-by-case basis (Geoscience Australia 2013).

3.3.5 Shale liquids and light tight oil resources

Some sedimentary basins currently being explored for shale and tight gas in Australia have potential to host significant resources of associated shale liquids and light tight oil. Unlike shale oil, these hydrocarbon resources are generated through natural thermal maturation of source rocks, and reservoired in low-permeability rocks. In the case of natural gas liquids produced from shale gas, the hydrocarbons largely remain within the source rock after generation, such that the source rock becomes the reservoir rock. Tight oil, on the other hand, has been generated conventionally but has migrated into a porous reservoir rock that is very low in permeability. The low reservoir permeability necessitates specialised extractive methods, such as hydraulic fracturing and acidisation, to initiate flow.

Exploration for shale liquids and tight oil is still in its infancy in Australia, and there are no current national estimates for these resources. Challenges to their development include access to specialised drilling equipment and water supplies for hydraulic fracturing. Basins so far identified as having potential include the Perth, Canning, Georgina, Amadeus, Arckaringa, Cooper, Galilee and Otway basins (figure 3.21).

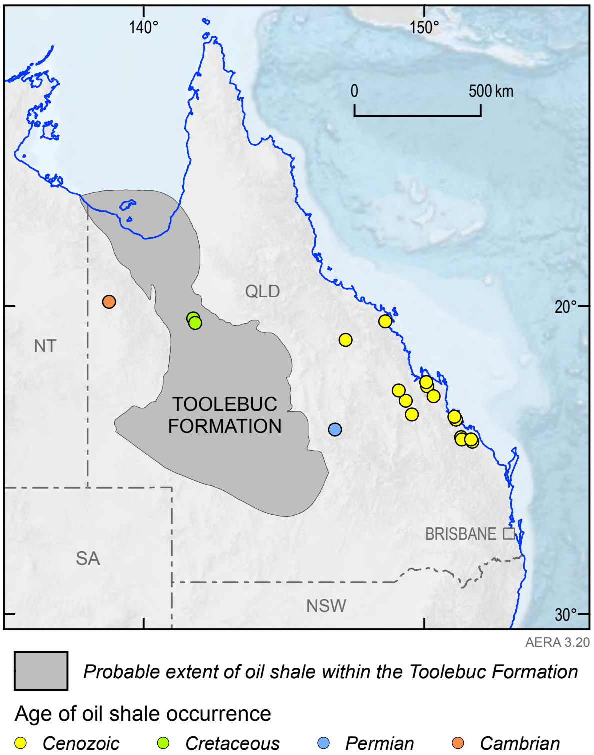


Figure 3.20 Oil shale occurrences in Queensland and the extent of the Toolebuc Formation

Source: Geoscience Australia

BOX 3.2 SHALE OIL

Resources

There is a significant but largely unutilised source of hydrocarbons (shale oil) contained in oil shale deposits. Global production has fallen from a peak in 1980 and its importance has recently declined in comparison with other unconventional oil deposit types, most notably oil sands, shale liquids and light tight oil. The 2010 Survey of Energy Resources by the World Energy Council (WEC) reported that a conservative total world in-place resources of shale oil are estimated to be 4.8 trillion barrels. Most of the resource is located in the Green River oil shale deposit in the United States. The United States Geological Survey (USGS) estimates the Green River oil shale to contain 1525 billion barrels of oil in-place in some 17 oil shale zones (Johnson et al. 2009). Other countries with significant in-place shale oil resources are the Russian Federation (247 883 mmbbl), the Democratic Republic of Congo (100 000 mmbbl), Brazil (82 000 mmbbl), Italy (73 000 mmbbl), Morocco (53 381mmbbl), Jordan (34 172 mmbbl), Australia (22 391 mmbl) and Estonia (16 286 mmbbl; WEC 2010, Geoscience Australia).

Production

Small-scale production of hydrocarbons (kerosene, lamp oil, fuel oil, and other products) from oil shale began in several countries in the late 1800s including Australia with production from the torbanite deposits at Joadja Creek near Bowral and at Glen Davis near Lithgow (both in New South Wales) from 1865. This production continued through World War II until 1952. There was also production in the period 1910–34 from the Mersey River tasmanite deposits in Tasmania. Production in most western countries ceased after World War II because of the availability of cheaper supplies of conventional crude oil. However, production continued in Estonia, the then USSR, China and Brazil, peaking at 46 Mt of oil shale per year in 1980 (WEC 2007). In 2008, production of shale oil was limited to Estonia, China and Brazil with several countries, including Israel, Morocco, Thailand and the United States, investigating the potential production of shale oil or use of oil shale in electricity generation. The 2010 WEC survey reported that total oil production at the end of 2008 was equal to 17 700 barrels per day (b/d), of which China produced 7600 b/d, Estonia 6300 b/d, and Brazil 3800 b/d. In comparison, production of conventional oil and natural gas liquids in 2008 amounted to 82.12 million b/d (WEC 2010).

Geology and extraction

Oil shale deposits range in age from Cambrian to Cenozoic and were formed in a wide range of depositional environments, ranging from freshwater and saline ponds and lakes commonly associated with coastal swamps (including peat swamps) to broad marine basins. Oil shales have a wide range of organic and mineral compositions and are classified according to their depositional environment, either terrestrial, lacustrine or marine. Terrestrial oil shales are composed mostly of resins and other lipid-rich (naturally occurring molecules that include fats, waxes and sterols) organic matter and plant material. Lacustrine oil shales (known as lamosite and torbanite) contain lipid-rich material derived from algae, whereas marine oil shales (tasmanite and marinite) are composed of lipid-rich material derived from marine algae and other marine microorganisms.

The organic matter in oil shale (which contains small amounts of sulfur and nitrogen in addition to carbon, hydrogen and oxygen) is insoluble in common organic solvents and is mixed with variable amounts of mineral matter, mostly silicate and carbonate minerals. There are currently two main methods for recovering oil from oil shale. The first involves mining (commonly by opencut means) and crushing the shale, and then retorting (heating) it, typically in the absence of oxygen, to about 500 °C. A large number of oil shale retorting technologies have been proposed but only a limited number are in commercial use. A second, more recent approach involves *in situ* extraction of shale oil by gradually heating the rocks over a period of years to convert the kerogen. Both approaches rely on the chemical process of pyrolysis, which converts the kerogen in the oil shale to shale oil (synthetic crude oil), gas and a solid residue. Conversion begins at lower temperatures but proceeds faster and more completely at higher temperatures.

A large number of technologies have been proposed and many trialled to produce shale oil. A report by the United States Department of Energy summarises those being investigated to produce shale oil (USDOE 2007). In-situ methods include injecting hot fluids (steam or hot gases) into the shale formation via drill holes or heating using elements or pipes drilled into the shale with the heat conducted beyond the walls. Other approaches rely on heating volumes of shale using radio waves or electric currents. In-situ extraction has been reported to require less processing of the resultant fuels before refining, but the process uses substantial amounts of energy. Both methods use substantial amounts of water and typically produce more greenhouse gases than does extraction of conventional crude oil.

Australia

From 2000 to 2004, the Stage 1 demonstration-scale processing plant at the Stuart deposit near Gladstone in central Queensland produced more than 1.5 mmbbl of oil using a horizontal rotating kiln process (Alberta Taciuk Process). The demonstration plant achieved stable production capacity of 6000 tonnes of shale per day and oil yield totalling 4500 barrels per stream day while maintaining product quality and adhering to Environment Protection Authority emissions limits. The demonstration plant produced Ultra Low Sulfur Naphtha (ULSN), accounting for about 55 to 60 per cent of the output, and Light Fuel Oil, about 40 to 45 per cent of output. The ULSN, which can be used to make petrol, diesel and jet fuel, had a very low sulfur content of less than 1 part per million. Production ceased in 2004, and the facility has been dismantled and the site remediated.

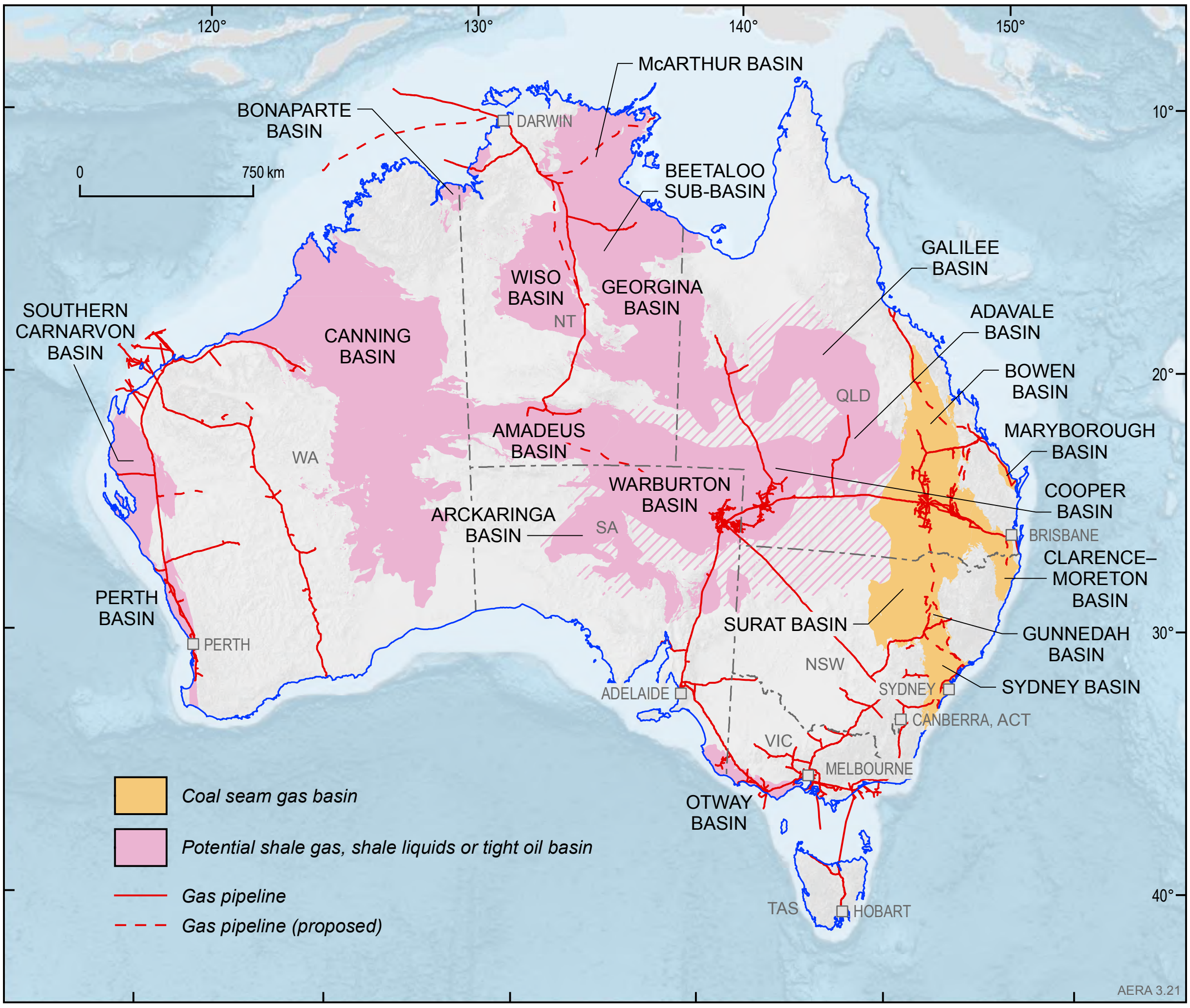
Since acquiring the Stuart oil shale project, Queensland Energy Resources (QER) has undertaken a detailed testing program of processing of the Queensland oil shale at a pilot plant in Colorado, United States, and successfully demonstrated the use of the Paraho II vertical kiln technology to extract shale oil. In September 2011, QER produced its first crude oil from its demonstration processing plant at the Stuart deposit. The oil is being stored in secure tanks on-site, awaiting commissioning of the oil upgrading unit (refinery). QER submitted a final report to the Queensland Government in September 2012 indicating that there were no reportable environmental incidents at the plant during all phases of construction, commissioning and operations, and that there were no community complaints about odour or noise. Other Australian oil shale industry developments are summarised elsewhere (Geoscience Australia 2013).

3.3.6 Total oil resources

Australia's oil resources are predominantly made up of conventional liquid hydrocarbons (table 3.9). Crude oil reserves are in decline, but there is a substantial remaining resource of condensate and naturally occurring LPG associated with undeveloped offshore gas fields. Oil shale deposits contain a large, unconventional resource, which does not currently contribute to Australia's liquid fuel supplies. Other options for future liquid fuel supply are light tight oil and natural gas liquids from 'wet' shale gas as well as GTL, CTL and biofuels; these are discussed in other chapters in this assessment.

The resource pyramid (figure 3.22) highlights how a smaller volume of more readily accessible, high-quality resources are underpinned by larger but less accessible resources. However, these unconventional oil resources come with development costs and risks. Technology, price and their own environmental impacts can influence access to them.

Conventional hydrocarbon liquid resources are located across ten basins, but most remaining resources are in the Carnarvon, Browse and Bonaparte basins (table 3.9). The initial liquid resources of the Carnarvon Basin were nearly equivalent to those of the crude oil-rich Gippsland Basin (figures 3.11 and 3.23).



The map is intended as a schematic depiction of the location of sedimentary basins with predicted potential for shale oil or gas based on their gross geological characteristics. Many basins highlighted do not have proven potential for shale oil or gas, and not all of the highlighted areas are necessarily prospective. Shale oil or gas may also occur outside of the highlighted areas.

Figure 3.21 Distribution of Australian basins with unconventional hydrocarbon potential

Source: Geoscience Australia

3.3.7 Oil market

Oil production

Most of Australia's current crude oil production is from the mature oil provinces—the Carnarvon and Gippsland basins—which in 2011–12 accounted for 74 per cent and 13 per cent respectively of crude oil production (EnergyQuest 2013). The Gippsland Basin also accounts for almost half of Australia's naturally occurring LPG production, although this has been declining steadily since production peaked in the mid-1980s (figure 3.24). In 2012, Australian oil production fell to its lowest level since 1971; however, oil production from the Cooper Basin was the highest since 1991 (EnergyQuest 2013).

Australia's annual crude oil production progressively declined between 1985–86 and 1998–99 from 1102 PJ to 738 PJ (187.4 to 125.2 mmbbl, 29 794 to 19 905 ML). However, following the start-up of a number of new oil fields, including the Laminaria/Corallina, Elang/Kakatua and Cossack/Wanaea fields (all offshore north-western

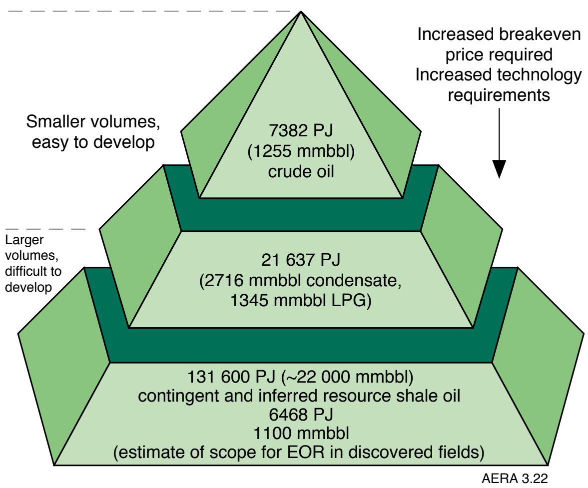


Figure 3.22 Australian oil resource pyramid

EOR = enhanced oil recovery

Source: Geoscience Australia (adapted from McCabe 1998 and Branan 2008)

Australia), oil production increased rapidly, peaking at 1209 PJ (205.7 mmbbl, 32.7 GL) in 2000–01. Since then, crude oil production has declined at a rate of 7 per cent per year, to 641 PJ (109 mmbbl, 17.3 GL) in 2010–11. In 2011–12, crude oil production further declined to 613 PJ (104 mmbbl, 16.6 GL; BREE 2013).

In contrast, domestic production of condensate increased from around 36 PJ (6.1 mmbbl, 1096 ML) in 1982–83 to 312 PJ (53 mmbbl, 8.4 GL) in 2010–11; production fell in 2011–12 to 277 PJ (47 mmbbl, 7.5 GL). Naturally occurring LPG production in Australia also increased from around 80 PJ (19 mmbbl, 3021 ML) in 1979–80 to 125 PJ (29.7 mmbbl, 4721 ML) in 2005–06, mainly from the Carnarvon Basin in Western Australia. LPG production declined to 103 PJ (24.6 mmbbl, 3.9 GL) in 2010–11 and further fell in 2011–12 to 101 PJ (24 mmbbl, 3.8 GL; BREE 2013).

Over the past two years, a number of oil projects have been developed, with new fields coming on stream in the Carnarvon and Bonaparte basins (table 3.10). The Fletcher/Finucane, Pyrenees and Van Gogh fields are located in the deeper waters of the offshore Exmouth Sub-basin, Carnarvon Basin (figure 3.25), and signal the continued development of a significant new oil-producing area for Australia: recoverable crude oil volumes across a dozen fields total around half a billion barrels. The NWS CWLH project is a redevelopment of the Cossack, Wanaea, Lambert and Hermes fields in the Dampier Sub-basin of the Carnarvon Basin. The Kitan oil field is in the Bonaparte Basin and is located in the Joint Petroleum Development Area between Australia and Timor-Leste.

In contrast to the nearly 6 billion barrels of conventional oil produced in Australia since the 1960s, only a few million barrels have been produced from oil shale. There was intermittent and small-scale production from 1865 to 1952 when there was no indigenous conventional crude oil production. Another unconventional oil resource, tar sands in the onshore Gippsland Basin, was exploited during World War II and in the post-war period (Bradshaw et al. 1999).

The high-quality oil shale deposits in the Narrows Basin, near Gladstone, have been the subject of predevelopment studies for several decades (McFarland 2001). The Stuart Oil Shale Project achieved production from a demonstration-scale processing plant in the period 1999 to 2004, producing more than 1.5 million barrels of oil using a horizontal rotary kiln retort. In September 2011, Queensland Energy Resources Ltd (QER) produced its first crude oil from its demonstration Paraho II^{TM} vertical shaft kiln processing plant at the Stuart deposit (box 3.2).

Petroleum refining

The petroleum refining industry in Australia produces a wide range of oil products, such as gasoline, diesel, aviation fuel and LPG, from crude oil and condensate feedstock. In 2011–12, Australian refineries consumed 1474 (234 mmbbl, 39.9 GL) of crude oil and condensate, mainly sourced from imports (figure 3.27, BREE 2013). Most of the imports are used in the domestic petroleum refining industry in Eastern Australia, to offset the declining production from the Gippsland Basin.

There are six major petroleum refineries currently operating in Australia, managed by four companies—BP, Caltex, Mobil and Shell (table 3.11). These six refineries have a combined capacity of around 40.4 billion litres a year. The largest of these are BP's Kwinana refinery in Western Australia and Caltex's Kurnell refinery in New South Wales. However, recently Caltex's Kurnell refinery—the second largest refinery in Australia—is confirmed to be closed in the second half of 2014 to be converted to an import terminal. This is expected to cause a decline in total refinery output. Furthermore, the closure of the Clyde refinery in September 2012 has caused a decline in total refinery output, which has led to increased imports of refined petroleum products.

Table 3.9 Crude oil, condensate and LPG McKelvey classification estimates by basin, as at 1 January 2012

McKelvey	Basin	Total energy (PJ)	Crude oil (PJ)	Crude oil (mmbbls)	Condensate (PJ)	Condensate (mmbbls)	LPG (PJ)	LPG (mmbbls)
EDR	Bonaparte	3547	711	121	1811	308	1026	244
EDR	Browse	3907	0	0	3907	665	0	0
EDR	Carnarvon	10 044	3248	552	4705	800	2091	497
EDR	Gippsland	2200	1040	177	552	94	609	145
EDR	Other	965	469	80	300	51	197	47
EDR	**Total**	**20 664**	**5467**	**930**	**11 275**	**1917**	**3922**	**932**
SDR	Bonaparte	1085	398	68	687	117	0	0
SDR	Browse	3961	11	2	2486	423	1465	348
SDR	Carnarvon	1901	1070	182	777	132	54	13
SDR	Gippsland	764	357	61	407	69	0	0
SDR	Other	644	80	14	341	58	223	53
SDR	**Total**	**8355**	**1915**	**326**	**4698**	**799**	**1742**	**414**
EDR+SDR	**Total**	**29 019**	**7382**	**1255**	**15 972**	**2716**	**5664**	**1345**

EDR = Economic Demonstrated Resources; **SDR** = Sub-economic Demonstrate Resources

Source: Geoscience Australia

Table 3.10 Crude oil and condensate projects completed, October 2013

Project	Company	Basin	Start up	Capacity (kb/d)	Capital expenditure (A$million)
Montara/Skua	PTTEP	Bonaparte	2013	35	680
Fletcher-Finucane	Santos/KUFPEC/Nippon Oil/Tap Oil	Carnarvon	2013	15	490
Kitan	Eni/Inpex/Talisman Energy	Bonaparte	2011		583
NWS CWLH	Woodside Energy/BHP Billiton/BP/ Chevron/Shell/Japan Australia LNG	Carnarvon	2011		1430
Halyard	Apache Energy/Santos	Carnarvon	2011		US$115
Pyrenees	BHP Billiton/Apache Energy	Carnarvon	2010	96 (23 PJ pa gas)	1900
Van Gogh	Apache Energy/Inpex Alpha	Carnarvon	2010	38	620

kb/d = thousand barrels per day

Source: Bureau of Resources and Energy Economics; Geoscience Australia

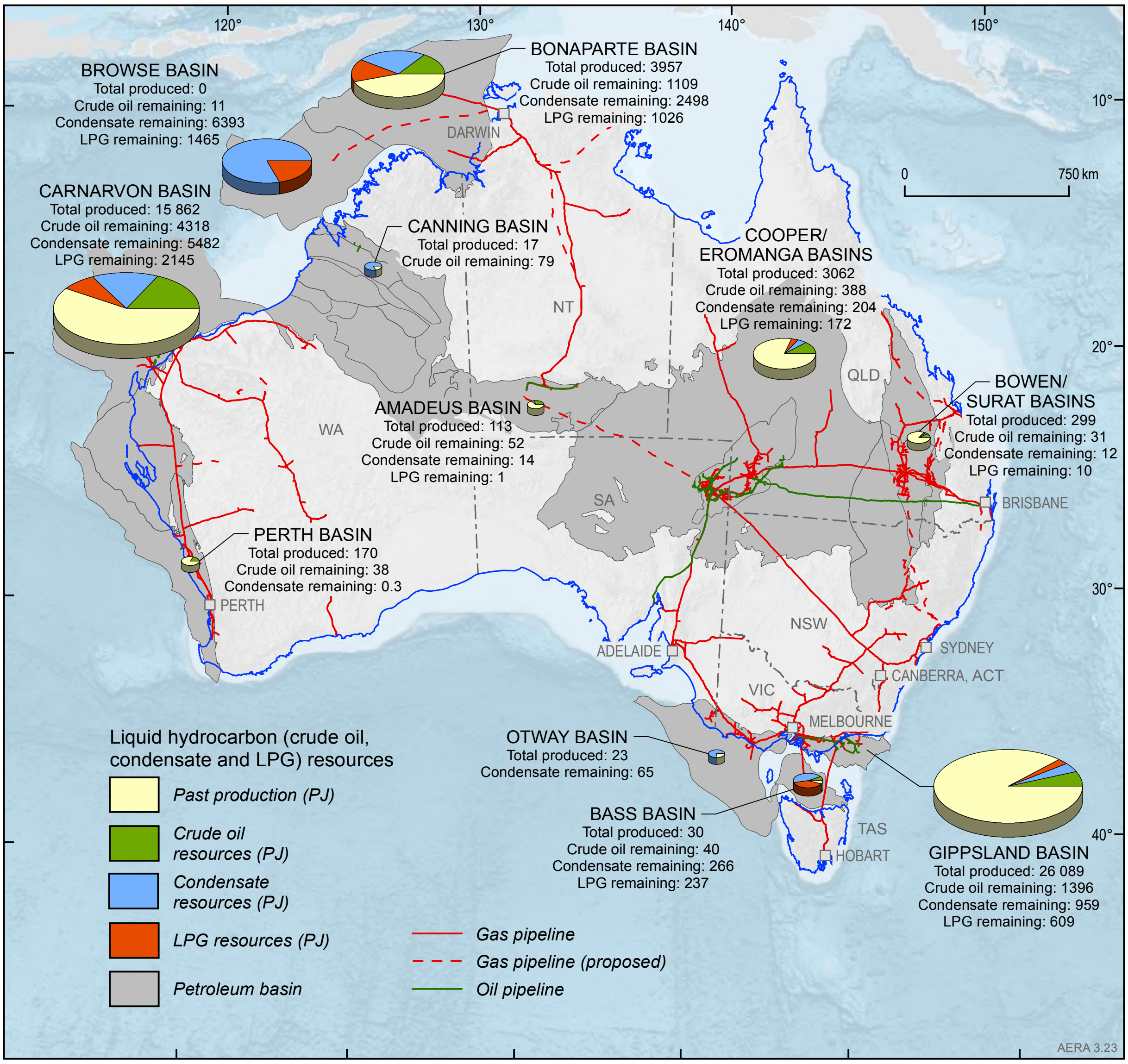


Figure 3.23 Australian crude oil, condensate and naturally-occurring LPG resources, infrastructure, past production and remaining resources

LPG = liquefied petroleum gas

Source: Geoscience Australia

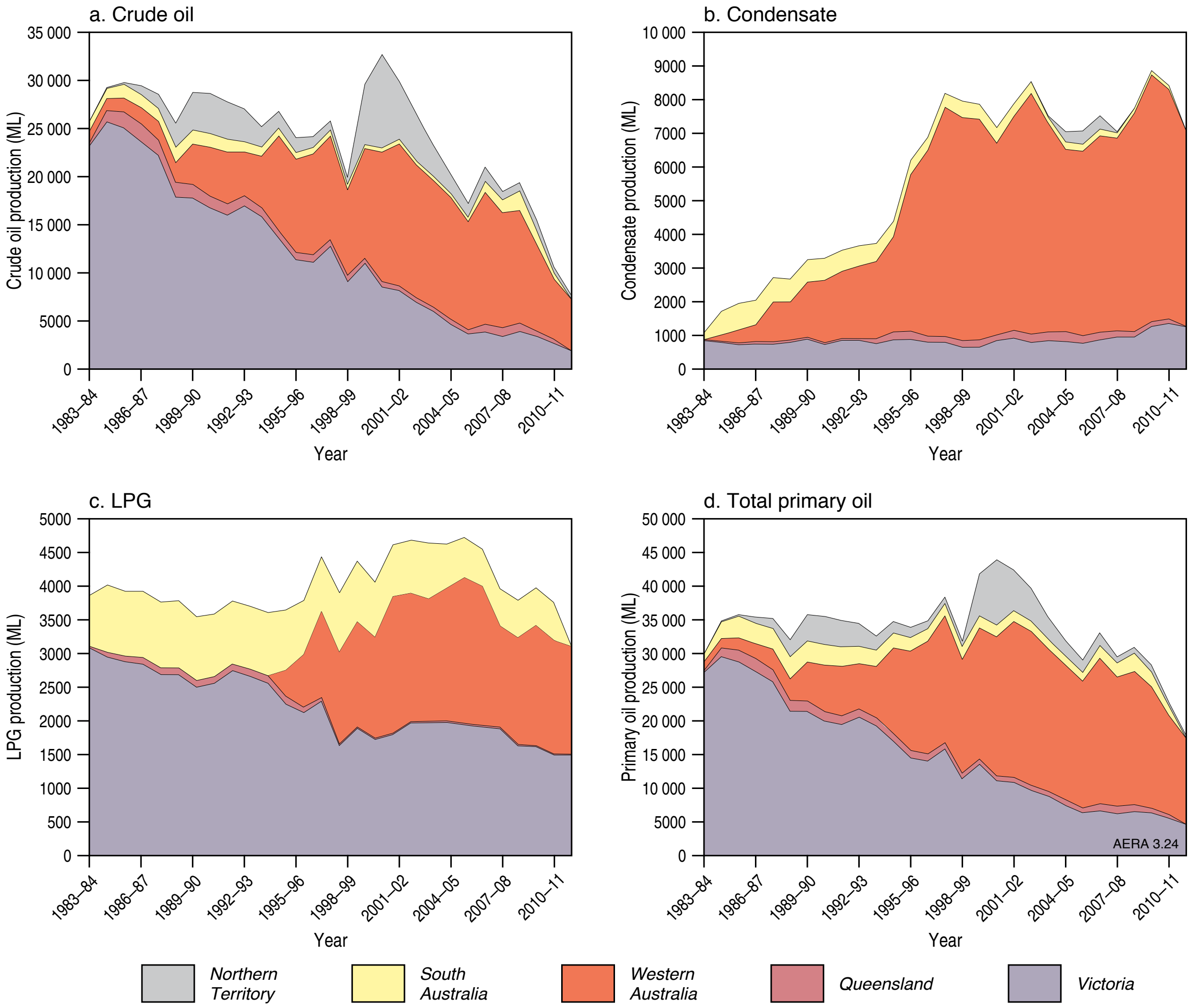


Figure 3.24 Australian oil production

Source: Bureau of Resources and Energy Economics

Consumption

In 2010–11, oil had surpassed coal to account for largest share in Australian primary energy consumption although its share has been declining steadily, from around 50 per cent of primary energy use in the late 1970s to around 38 per cent in 2011–12. Prior to 1979, Australia's primary oil consumption had grown strongly at a rate of around 5 per cent per year. However, since then, consumption has been growing at a moderate rate of around 2 per cent per year to reach 2411 PJ (410 mmbbl, 65 GL) in 2011–12.

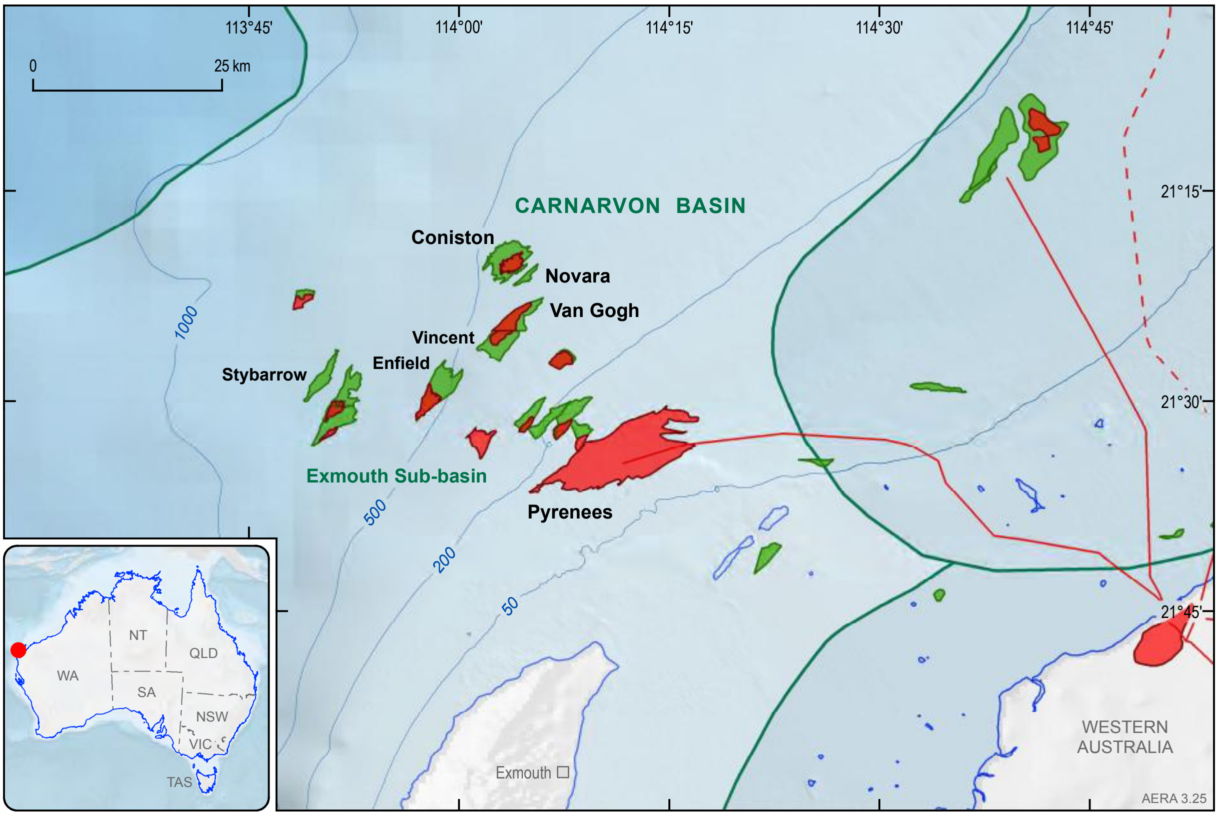
The transport sector is the largest consumer of oil products in Australia, currently accounting for around 96.6 per cent of total use, compared with 50 per cent in the 1970s (figure 3.27). The increased share has offset the decline in the manufacturing sector's share, down from about 30 per cent in the late 1970s to about 20 per cent in 2010–11.

Table 3.11 Australian refinery capacity

	Operator	Year commissioned	Capacity (MLpa)
New South Wales			
Clyde[a]	Shell	1928	(4990)
Kurnell	Caltex	1956	7820
Queensland			
Bulwer Island	BP	1965	5910
Lytton	Caltex	1965	6300
South Australia			
Port Stanvac[a]	Mobil	1963	(4520)
Victoria			
Altona	Mobil	1949	4640
Geelong	Shell	1954	7470
Western Australia			
Kwinana	BP	1955	8300
Total[b]			**40 440**

MLpa = million litres per annum
a The Clyde refinery ceased production in September 2012. The Port Stanvac refinery ceased production in July 2003. **b** Total of currently operating refineries

Source: Australian Institute of Petroleum 2011



Pipelines and field outlines are provided by Encom GPinfo, a Pitney Bowes Software (PBS) Pty Ltd product. Whilst all care is taken in the compilation of the field outlines by PBS, no warranty is provided re the accuracy or completeness of the information, and it is the responsibility of the Customer to ensure, by independent means, that those parts of the information used by it are correct before any reliance is placed on them. Accurate ay November 2013.

Oil field · *Gas field* · *Basin outline* · *Bathymetry contour (depth in metres)* · *Gas pipeline* · *Gas pipeline (proposed)*

Figure 3.25 Oil and gas fields and bathymetry, Exmouth Sub-basin, Carnarvon Basin

Source: Geoscience Australia

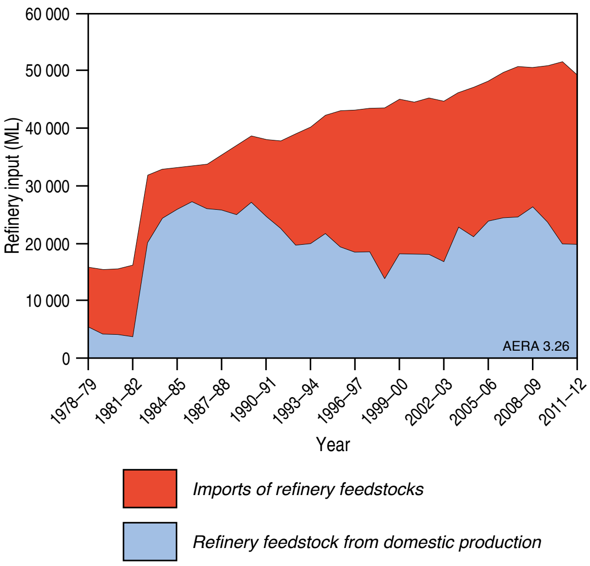


Figure 3.26 Sources of Australian refinery inputs

Source: Bureau of Resources and Energy Economics

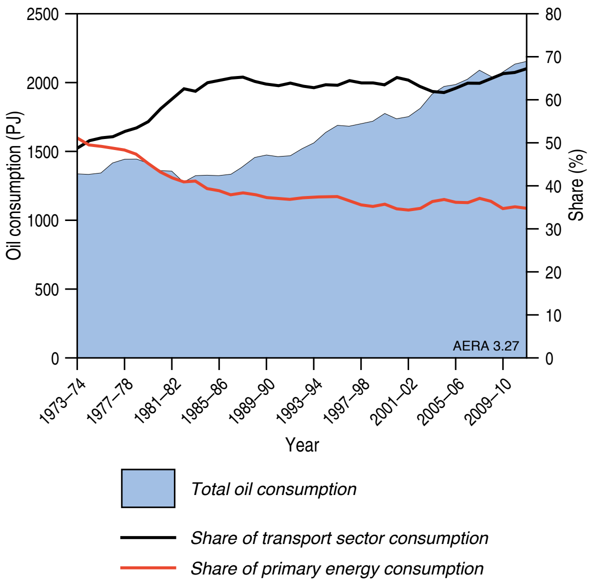


Figure 3.27 Australian oil consumption, share of total energy consumption and transport sector consumption

Source: Bureau of Resources and Energy Economics

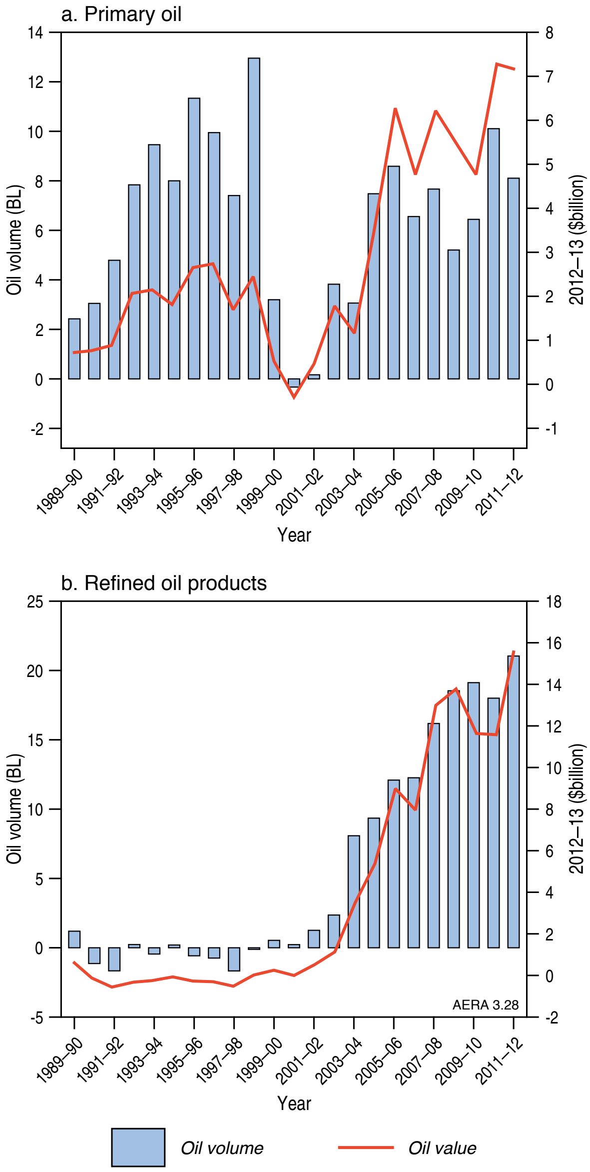


Figure 3.28 Australia's net oil imports—volume and value

Source: Bureau of Resources and Energy Economics

Trade

Australia is a net importer of crude oil. In 2011–12, around 80 per cent of Australia's crude oil and condensate production was exported, due to it physical characteristics being more suitable for higher-value products to Asian refineries (BREE 2013). About 30 per cent of Australia's refinery input requirements was imported in 2011–12 from Malaysia, Indonesia and the United Arab Emirates (BREE 2013).

For most of the 1990s, Australia was a net exporter of refined oil products. Strong growth in consumption resulted in net imports from around 1999–2000 (figure 3.29). In 2011–12, Australia imported about 21 GL (792 PJ, 133 mmbbl) of refined oil products valued at around A$16.7 billion.

Oil supply–demand balance

Figure 3.29 provides a supply–demand balance for primary oil – production from oil fields and consumption in domestic refineries (refinery feedstock). Except for a brief period in the mid-1980s, Australia has relied on net imports to meet domestic refineries' needs. In 2010–11, refineries in Australia used 1474 PJ (39.9 GL) of crude oil and other refinery feedstock with around 77 per cent of this input met from imports.

Figure 3.30 provides a supply–demand balance for refined oil products, that is, oil products produced from domestic refineries to meet domestic demand for liquid fuels. In contrast to primary oil, Australia was generally self-sufficient in terms of refined oil products for substantial periods during the 1980s and 1990s, because Australia had enough crude oil supply and refinery capacity to meet domestic demand for oil products. Since 2002–03, net imports of oil products have risen steadily, and account for around 30 per cent of total consumption.

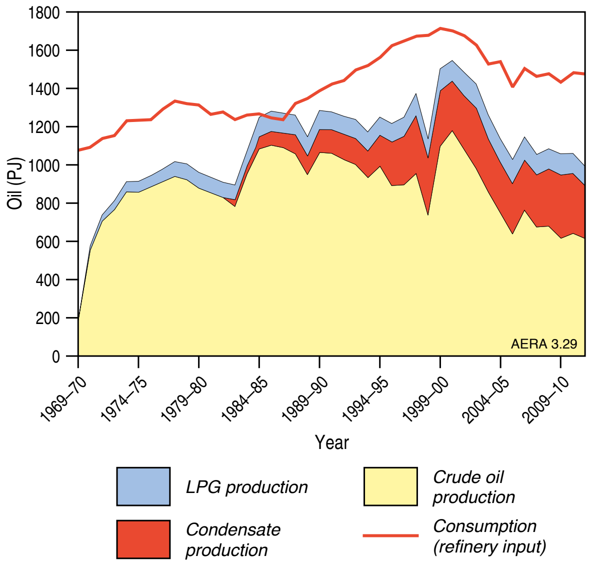


Figure 3.29 Australian primary oil supply–demand balance

LPG = liquefied petroleum gas

Source: Bureau of Resources and Energy Economics

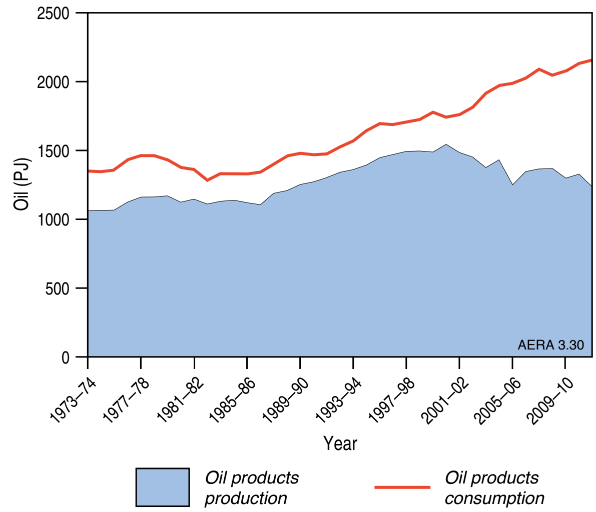


Figure 3.30 Australian refined oil products supply–demand balance

Source: Bureau of Resources and Energy Economics

3.4 Outlook for Australia's oil resources and market

3.4.1 Key factors influencing the outlook

The demand for oil will continue to grow and will be met from a variety of sources, including imports, domestic conventional crude oil and condensate production, and unconventional sources. Given the rapid changes in the past decade when Australia moved from being a net exporter to an importer of oil, further significant change is expected in the next few decades. There will be continued production from known fields, and the dominance of the basins offshore north-western Australia will be entrenched as production comes on stream from condensate-rich gas fields such as Ichthys in the Browse Basin, and as the newly developed Exmouth Sub-basin of the Carnarvon Basin reaches peak production. The major uncertainties in indigenous oil supply are whether exploration efforts in frontier basins will be successful in finding a new oil province; whether discovered resources are commercialised; and the role of unconventional oil sources (light tight oil, liquids associated with shale gas, GTL, CTL, and shale oil), as well as alternative transport fuels such as biofuels.

This outlook is affected by various factors, including the geological characteristics of the resource (such as location, depth, quality), economic characteristics of the resource (such as cost), developments in technology, infrastructure issues, fiscal and regulatory regime, and environmental considerations. The market price of oil is perhaps the most important factor in determining the incentives for oil exploration and development, especially for unconventional oil resources.

Oil prices

Australia is a producer, exporter and importer of crude oil and refined products. Since deregulation of the oil sector in the late 1980s, Australia's oil market has been open, competitive and fully linked to global market conditions.

Global oil prices are subject to both short-term price movements and longer term price trends. Short-term oil price movements relate to influences on demand and supply of oil in the marketplace. These include cyclical/seasonal oil demand; the impact of supply disruptions, such as hurricanes, accidents or sabotage, risk premiums associated with geopolitical tensions, and extraneous shocks to the economy such as the global financial crisis. Disruptions to supply pushed the oil price above US$100 per barrel in 2011, this represented the second highest on record behind 1864 (inflation-adjusted prices; BP 2012). In domestic market terms, significant exchange rate variations and market speculation can also affect short-term oil price movements.

In the longer term, an important driver of oil prices will be the underlying marginal cost of oil production, which will have implications for oil supply, and a combination of long-term economic growth and demand-side efficiency improvements, which will have implications for oil demand.

The IEA's representation of the availability of oil resources and associated production costs is shown in figure 3.31. It shows that just over 1 trillion barrels of oil have already been produced at a cost of below US$30 per barrel. There are potentially around 2 trillion barrels of oil remaining that can be produced at a cost below US$40 per barrel; around three-quarters of them in OPEC member countries in the Middle East and North Africa (MENA). Reflecting its large, low-cost reserves, OPEC's share of production is projected to increase from 42 per cent in 2011 to 48 per cent by 2035 (IEA 2012). OPEC's decisions on oil field development will become progressively more important for the world oil market.

The importance of OPEC's investment decisions will be underpinned by the increasing cost of non-OPEC production. The majority of new non-OPEC investment is likely to be in offshore oil fields, increasingly in deeper water, further below the seabed and a greater distance from shore (including fields within the Arctic Circle). The cost of oil production from deepwater sources and those needing advanced techniques such as EOR is estimated to be between US$35 and US$80 per barrel, similar to the cost of production from oil sands. The cost of producing oil from the Arctic could reach US$100 per barrel because of the large cost associated with developing infrastructure in an environmentally challenging area (IEA 2008).

The increase in oil prices over the past five years has encouraged exploration activity in frontier regions such as the Campos Basin off the coast of Brazil and in deeper water in the Gulf of Mexico. The Brazilian Tupi field, for example, one of the most significant oil discoveries in the past 20 years, is 5 km below the surface of the Atlantic Ocean and below a salt layer up to 2 km thick. In 2009, BP announced the discovery of the Tiber oil field in the Gulf of Mexico. The oil field is 10 700 m below the ocean floor and in water that is around 1200 m deep, making it one of the deepest drilled in the industry (BP 2009b). The continued development and application of deepwater drilling and field development will eventually lead to lower production costs and the expansion of frontier areas where new oil fields can be developed in deeper water and further below the seabed, but the process at present is costly. The Macondo disaster and oil spill in the Gulf of Mexico in 2010 highlighted the environmental risks of deepwater exploration and the potential costs of compensation, remediation and legal penalties (Oil Spill Commission 2012).

Light tight oil is an increasing component of production in the United States. Modeling by Schlumberger (Petroleum Economist 2012) indicates that in North America, with the advantages of an established pipeline infrastructure and service industry, the cost of production can be as low as US$50 per barrel, ranging up to US$100 per barrel. This is comparable to the deepwater cost of production, estimated in the same study to range between US$55 and US$80 per barrel; and less expensive than production from oil sands, with a cost of US$70 to US$120 per barrel.

Synthetic oil production, such as shale oil, CTL and GTL, has the highest production costs, estimated by the IEA at up to US$110 per barrel. This makes no allowance for any costs associated with the abatement of greenhouse gas emissions that are by-products of the process. At present, there are very few commercial CTL and GTL projects, reflecting large capital and production costs and technically challenging production processes.

The future expansion of GTL capacity will depend on competing uses for gas, such as for electricity generation, transport or export by pipeline, or as LNG. One of the challenges for CTL is managing the high CO_2 output. Each barrel of oil produced from this technology releases between 0.5 and 0.7 tonnes of CO_2, compared with around 0.2 tonnes of CO_2 from a barrel of oil from the GTL process (IEA 2008). GTL plants are operating in Qatar, South Africa and Malaysia and there has been output from an experimental (500 bbls per day) plant in Japan. There is one CTL plant in South Africa.

In comparison to GTL and CTL, production from oil shale is more uncertain, given its energy and carbon intensity. There is some oil production from oil shale in Brazil, China and Estonia. The introduction of a price for carbon would further increase the cost of shale oil extraction.

With the significant increase in shale gas production in the United States and the corresponding fall in gas prices, the United States producers are increasingly turning their focus to associated liquids. In 2011, about 1.2 mmbbl per day of light tight oil was produced in the United States (EIA 2013). Potential United States shale gas LNG and tight oil exports are likely over the coming decade, with LNG seen as a way of monetising gas at an economic rate of return for producers and as the United States oil refineries are at near capacity for refining the light tight oil.

Recent high oil prices have encouraged investment in technology to improve extraction of oil from oil sands and research to commercialise oil production from coal and gas. If the research and development is successful, it should enable production of increased quantities of oil from unconventional sources. However, despite the recent R&D effort, production costs for these unconventional sources have all increased, associated with higher capital and operating costs.

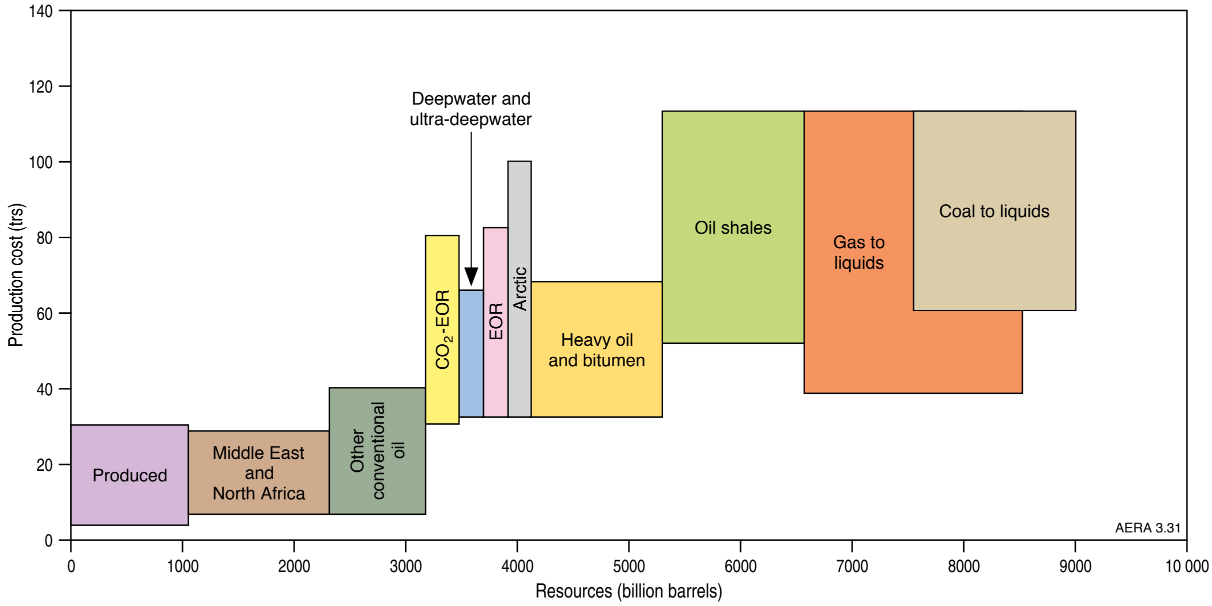


Figure 3.31 Long-term oil supply cost curve

EOR = enhanced oil recovery

Source: IEA 2008

Oil demand

The two factors expected to influence oil demand over the next two decades are the continued decrease in oil intensity in OECD economies and the increased oil consumption in non-OECD economies associated with strong economic growth.

In the OECD, oil intensity (the amount of oil consumed per unit of GDP) has been decreasing since the oil shocks of the 1970s (figure 3.32). One of the drivers of this trend has been the move away from oil-fired electricity generation capacity, to coal, gas or nuclear power. In the IEA (2012) projections, oil demand in the OECD will continue to fall over the outlook period to 2035. Improved fuel efficiency, increased uptake of alternative transport fuels and development of alternative transport modes, and higher prices are likely to contribute to this decline. The continued decrease in oil intensity also complements broader environmental and energy security policy goals.

Non-OECD economies, including China and India, are projected to grow strongly over the outlook period. Strong population and economic growth will be the key drivers for oil demand in non-OECD economies, which largely offset the efficiency gains in transport. The IEA projects that, by 2035, non-OECD economies will account for around 63 per cent of world oil consumption, compared with just under half today (IEA 2012).

Resource characteristics

In Australia, the initial depositional environments and subsequent maturation history after burial that are required to produce and preserve crude oil accumulations box 3.1) have occurred less frequently than the geological conditions that have resulted in natural gas accumulations. Australia's identified conventional petroleum resources are dominated by widely distributed natural gas. In contrast, the major known accumulations of conventional crude oil are restricted to the Gippsland Basin and five 'oily' sub-basins (Longley et al. 2002) along the north-west margin. This distribution is controlled by the occurrence of deep, narrow troughs containing mature oil source rocks, which were formed around the continent's margins as Gondwana broke apart. The Gippsland Basin is a world class oil province with a number of giant fields; it is exceptional in the Australian context, having the greatest thickness of young (Cenozoic) sediments. Most of Australia's crude oil has come from this one small basin, being sourced from an oil kitchen (the Central Deep) only about 50 km wide (figure 3.33).

Similarly, the crude oil in the Exmouth, Barrow and Dampier sub-basins of the Carnarvon Basin, and in the Vulcan Sub-basin and the Laminaria High—Flamingo Syncline of the Bonaparte Basin is derived from narrow Late Jurassic troughs filled with oil-prone source rocks. Some crude oil accumulations have been preserved in the older (Paleozoic) largely onshore basins, but the major discovered resources and the greatest potential for future finds are offshore. However, the recent increase in frontier onshore exploration has resulted in new conventional oil discoveries (e.g. Ungani in the Canning Basin and Surprise in the Amadeus Basin).

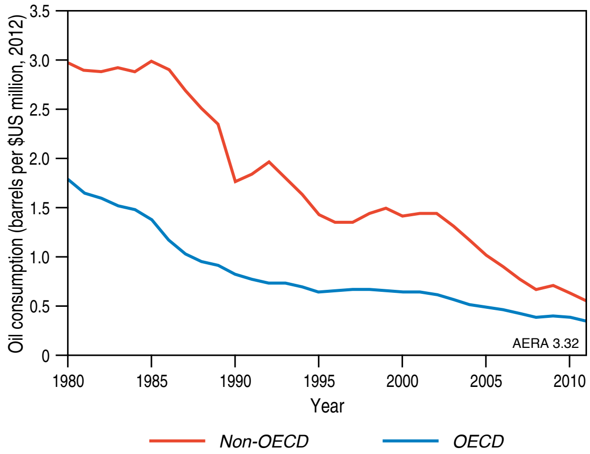


Figure 3.32 Oil intensity of GDP: oil consumption (barrels per US$ million at 2012 prices)

OECD = Organisation for Economic Co-operation and Development

Source: Bureau of Resources and Energy Economics estimates from IEA 2012 and International Monetary Fund

The condensate and LPG resources are also predominantly located in offshore basins, especially in giant gas fields on the North West Shelf. Gas liquids are not present in the large coal seam gas (CSG) resources identified in onshore eastern Australia.

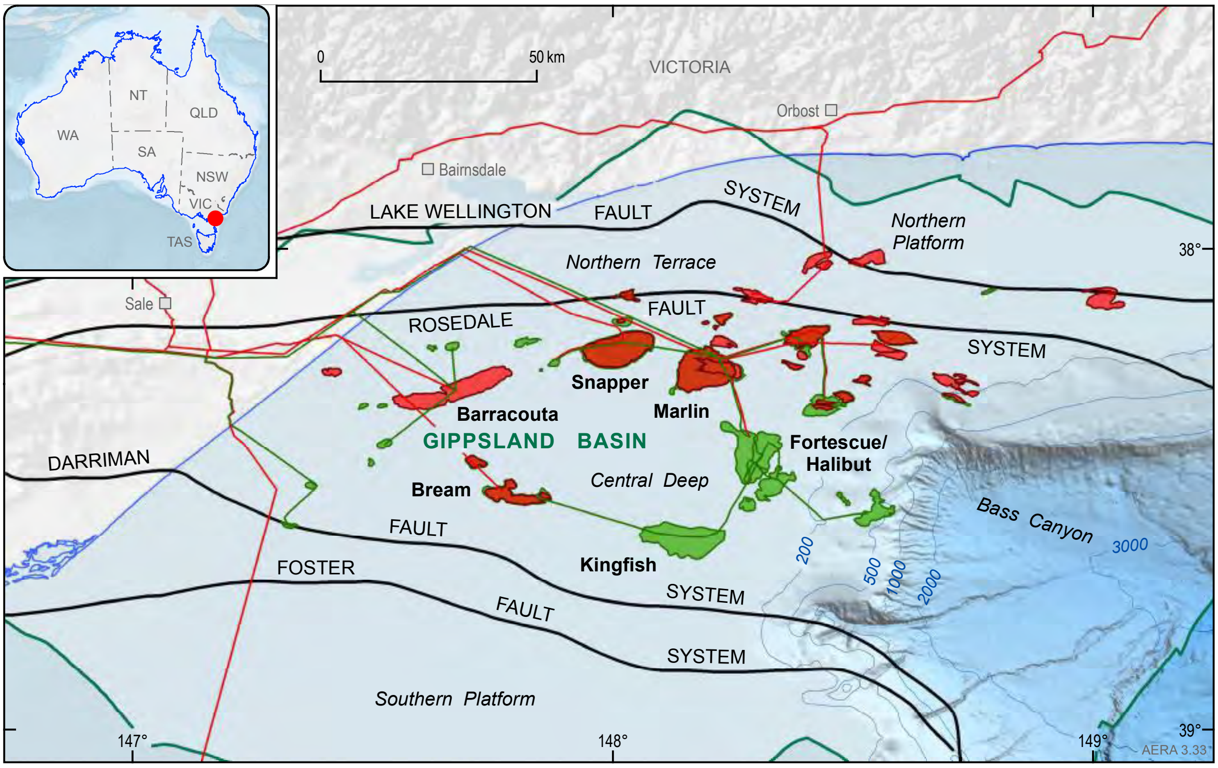
A number of Australian onshore basins have the potential for shale gas liquids and light tight oil resources. Organic-rich rocks that have generated liquid hydrocarbons occur in formations of variable age, including the Cambrian, Ordovician, Permian and Cretaceous. Depositional environments range from shallow marine within an intracratonic basin (e.g. the Toolebuc Formation in the Eromanga Basin), to restricted marine within glacially scoured troughs (e.g. the Stuart Range Formation in the Arckaringa Basin), to lacustrine within rift depocentres (e.g. the Casterton Formation in the Otway Basin).

Technology developments

The development of conventional oil resources in the past has benefited from significant technological change over a sustained period of time, leading to increased access to reservoirs, increased recovery of reserves, reduced costs of exploration and production, and reduced technical and economic risks to the development of oil projects. There are similar technological advances—and needs —in developing unconventional resources. Both are discussed in more detail below.

Development of exploration technology

Exploration involves a number of geophysical and drilling activities to determine the location, size, type (oil or gas) and quality of a petroleum resource. Prior



Pipelines and field outlines are provided by Encom GPinfo, a Pitney Bowes Software (PBS) Pty Ltd product. Whilst all care is taken in the compilation of the field outlines by PBS, no warranty is provided re the accuracy or completeness of the information, and it is the responsibility of the Customer to ensure, by independent means, that those parts of the information used by it are correct before any reliance is placed on them. Accurate at November 2013.

Oil field
Gas field
Basin outline
Fault
200 *Bathymetry contour (depth in metres)*
Gas pipeline
Oil pipeline

Figure 3.33 Gippsland Basin, showing oil and gas fields and structural elements

Source: Geoscience Australia, from data provided by GeoScience Victoria

to area selection, initial regional studies (figure 3.34) may use non-seismic survey techniques (gravity, magnetic and geochemical surveys, satellite imagery and seabed sampling) to define sedimentary basins and to determine if there are any indications of natural hydrocarbons seepage. Technological developments, such as accurate global positioning systems, improved computing power, algorithms for processing of new and reprocessing of existing seismic data and advanced visualisation techniques used to combine different datasets (Wilkinson 2006), have enhanced the value of this phase of the exploration process, especially in offshore frontier basins. In Australia, with its largely under-explored vast on- and offshore jurisdiction, government has taken an active role in providing this regional scale precompetitive information to stimulate exploration.

Hashimoto et al. (2008) demonstrate how a variety of geophysical and other datasets can be integrated to assess the structure and petroleum potential of the remote frontier Capel and Faust basins offshore from eastern Australia. Figure 3.34 is a 3D view across the undrilled Capel and Faust basins, showing seismic lines integrated with gravity imagery. These datasets have assisted in the identification of potentially prospective thick sedimentary depocentres, bounding faults and structural highs underlain by shallow basement within this vast frontier area.

Once the prospective area is located, more detailed seismic survey techniques are used to determine subsurface geological structures. Advances in 3D seismic imaging can now display the subsurface structure in greater detail (Wilkinson 2006), and seismic attribute analysis can reveal potential petroleum-bearing reservoirs, contributing to recent high drilling success rates in the Carnarvon Basin (Williamson and Kroh 2007). Developments in exploration drilling now allow prospective structures to be identified on seismic images to be tested in water depths beyond two and half kilometres.

Development of production technology

For onshore fields, development proceeds in step with the appraisal drilling. In offshore fields, however, the optimal number and location of development wells must be identified prior to proceeding with the development.

Oil production requires the establishment of production wells and facilities. At the initial stage of production, the natural pressure of the subsurface oil reservoir forces oil to flow to the wellhead. This primary recovery commonly accounts for 25 to 30 per cent of total oil in the reservoir (CEM 2004), although some offshore Australian reservoirs have recovery rates of 70 or 80 per cent supported by a natural strong water drive, as in the case of the Gippsland Basin. More commonly, advanced recovery techniques are employed to extract additional oil from the reservoir, including injecting water or gas into the reservoir to maintain the reservoir's pressure. Pumps can also be used to extract oil. These conventional techniques can increase the amount of recoverable oil by around 15 per cent.

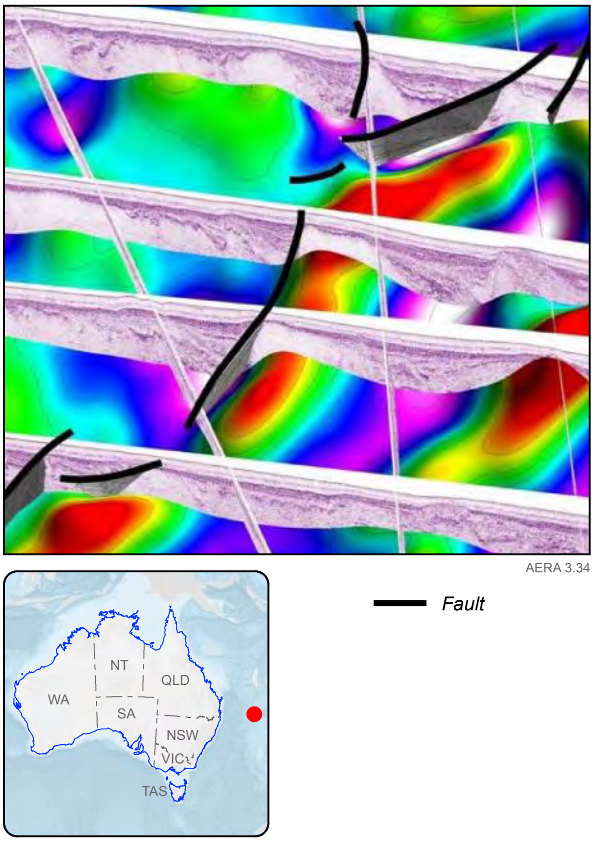


Figure 3.34 Integrated seismic and gravity data showing the location of major faults, sedimentary depocentres (gravity lows denoted in blue tones) and areas of shallow basement (gravity highs denoted in red tones) from the remote Capel and Faust basins

Source: Geoscience Australia

EOR is a more advanced technique that has been developed to extract additional oil from the reservoir. This technique alters the oil properties, making it flow more easily, by injecting various fluids and gases, such as complex polymers, CO_2 and nitrogen, to enable more oil to be produced. This technique could increase oil recovery by an additional 40 per cent, but is costly to implement (IEA 2007). Currently, there are 14 countries, including Australia, participating in the IEA's EOR Implementing Agreement, which encourages international collaboration on the development of new oil recovery technologies, including less costly EOR technology. While these techniques have been employed in the past, currently there is no EOR in Australia.

In addition to EOR from conventional oil reservoirs, an important new technological development has been the use of techniques developed in the shale gas industry to extract light tight oil and natural gas liquids from unconventional reservoirs. Recent advances in drilling and reservoir stimulation technology have enabled large-scale commercial gas and liquids production from shale and tight reservoirs in North America. Techniques such as horizontal drilling, pad drilling, multi-stage hydraulic fracturing and acidisation are now routine practices. These technological developments have also encouraged unconventional gas and oil exploration in Australia; however, the current shortage of equipment and skilled labour poses a major obstacle in the deployment of such technologies.

Reflecting the large number of oil resources located offshore, a focus for R&D has been offshore technologies. There are several possible development options for offshore oil projects, based on bottom-supported and floating production facilities. The development of these options is dependent on several factors, including resource type, reservoir size, water depth and distance from shore. Bottom-supported platform developments are suitable for relatively shallow water depth (figure 3.35).

Access to deepwater fields has become technologically feasible with the development of floating facilities and tension leg platforms (Wilkinson 2006). The maximum water depth at which oil projects can be developed increased from 6 m in 1947 to 312 m in 1978 and 1027 m in 1995 (Hogan et al. 1996). More recently, maximum water depths for petroleum production have increased further to beyond 2300 m with the Cheyenne field (Anadarko 2007) and the Perdido development (Shell 2009) in the Gulf of Mexico. However, the Macondo disaster and oil spill in 2010 led to a prolonged moratorium on further deepwater developments in the Gulf of Mexico and a slowdown of development elsewhere, as safety procedures were reviewed (IEA 2012).

There have also been technological developments in shale oil production, particularly in the United States, where several companies are testing *in situ* technologies to extract shale oil at more than 300 m depth (USDOE 2007). In comparison, Australia's oil shales are relatively shallow deposits, and the focus has been on surface extraction technologies (Geoscience Australia 2009b).

Oil supply economics

The process of supplying oil is complex, involving steps such as exploration, development, production, processing/refining and transport (section 3.2). Upstream oil costs (exploration, project development and production) are a major component of total costs within the oil and refined products industry.

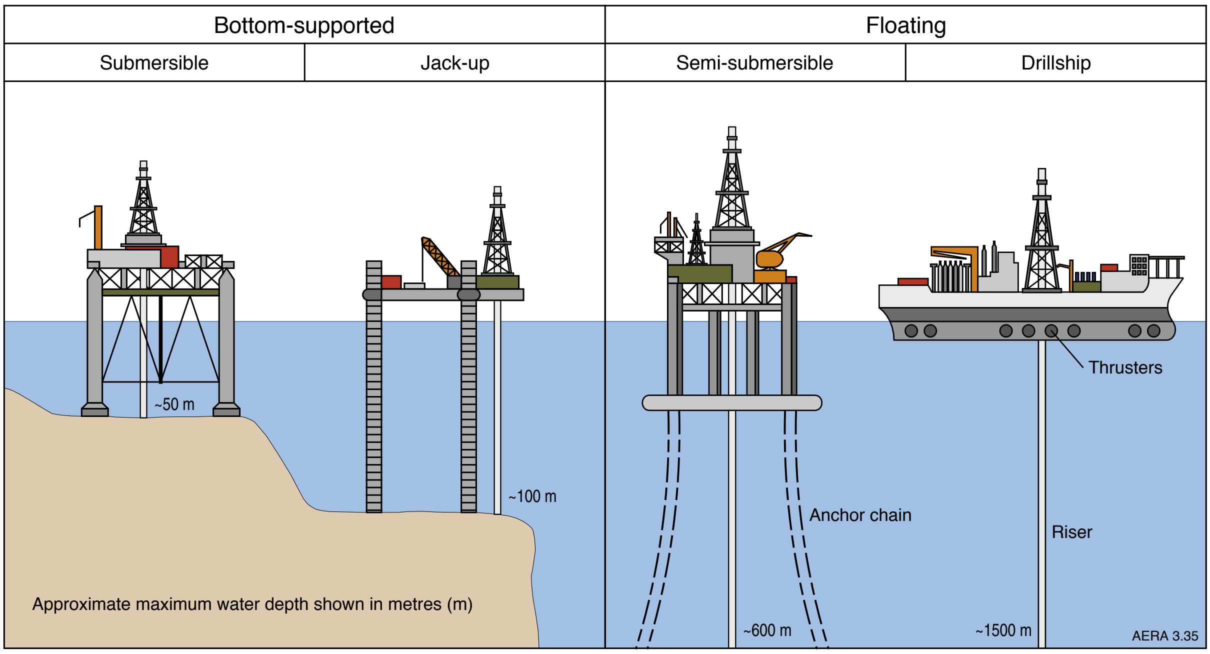


Figure 3.35 Types of offshore drilling vessels

Source: Wilkinson 2006

Over the past few years, there has been a considerable increase in exploration, project development and production costs. This increase in costs largely relates to increased competition for inputs (drilling rigs, production equipment, labour) as oil fields were developed in response to higher prices. In Australia, costs have increased as a result of global demand for inputs, but also because of the nature of resources. Australia's remaining undeveloped conventional oil resources are generally located in fields that are further offshore, in deeper water and further below the ocean floor. These factors increase the technical and economic challenges associated with exploration, development and production of Australia's oil resources.

Exploration

Oil exploration is fundamentally concerned with the management of risks (Jones 1988). The expected location, size and quality of oil reservoirs are crucial in decision-making because large oil deposits generally mean large payoffs. When an exploration well is drilled, there is a risk that no oil will be found and therefore no revenue generated. Even if oil is found, there is still a risk that it will not be available in commercially exploitable quantities or that the costs of development and production will be sufficiently high to render the new discoveries non-viable. Because of this risk, a large exploration expenditure is generally required, and only a small portion of this expenditure will actually lead to the discovery of resources that are economically viable to extract.

Since 1980, more exploration wells have been drilled onshore in Australia than offshore. This reflects the relatively lower cost of onshore oil exploration. Figure 3.36 provides key indicators of exploration expenditure and activity, in terms of the number of exploration wells drilled, for Australia's petroleum resources, both oil and gas. Between 2002 and 2007 there was a significant increase in the number of exploration wells drilled. Higher oil prices encouraged companies to explore because of the increased potential returns associated with a discovery. In 2008, the number of exploration wells decreased significantly even though the level of exploration expenditure continued to rise. The number of onshore exploration wells drilled declined steeply from more than 150 in 2006 and 2007 to 80 in 2008, whereas the number of offshore exploration wells increased slightly, reaching an all time high of 74 wells in 2008. The cost associated with drilling each well increased dramatically in the first half of 2008 associated with a worldwide shortage of drilling equipment and labour. The oil price fell dramatically in the second half of 2008 but recovered in 2009 to levels well below the highs reached the previous year. The fall in oil price may have discouraged discretionary onshore exploration as some companies sought to reduce expenditure as global capital markets dried up. Oil price fluctuations tend to have a less immediate impact on offshore exploration. Permit drilling commitments and rig contracts delay response to oil price signals and many offshore exploration wells now target gas rather than oil.

In 2008–09, offshore exploration expenditure decreased from its peak of A$3.32 billion to A$2.28 billion in 2011–12, however onshore exploration expenditure increased from A$0.49 billion to A$0.92 billion in 2011–12. Drilling accounted for about 65 per cent of onshore and offshore exploration expenditure in 2008–09, increasing to about 70 per cent in 2011–12 (Australian Bureau of Statistics 2011, 2013).

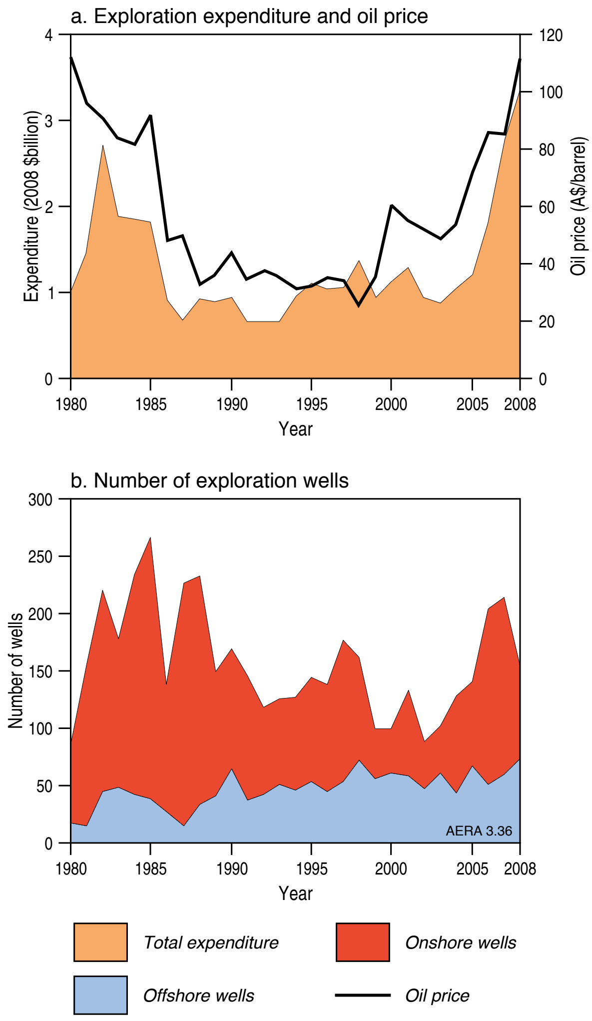


Figure 3.36 Exploration for Australia's petroleum resources

Source: Geoscience Australia, Australian Bureau of Statistics 2009

Development

Figure 3.37 shows the flow of activities from exploration to production of an oil field. During exploration and appraisal, the oil field is discovered and the reserves estimated for potential development. The development of an oil field includes the planning and construction processes. Planning involves a preliminary design (or feasibility study) followed by a front-end engineering and design (FEED) study. The FEED study provides definitive costs and technical details to enable a final investment decision (FID). After a FID has been made, construction can commence. The average time from discovery to production for Australian new field crude oil discoveries is about five years (Powell 2004).

The development and production of oil is technically complex which results in large capital expenditure. In Australia, the majority of oil production occurs below the seabed, often in water that is hundreds of metres deep. This requires specialised equipment that can withstand the pressure and temperatures of deepwater and deep within the sedimentary section.

Project development costs have increased significantly in recent years, both in Australia (figure 3.38) and globally. The reason for this increase in expenditure is twofold. Firstly, the increase in oil prices has encouraged the development of new capacity, which has placed upward pressure on prices for inputs such as labour and equipment globally. Secondly, newly developed oil fields in Australia tend to be in deeper water and further offshore (table 3.12), which increases the technical complexity of the project and hence cost. Extensions to existing projects, such as Laminaria Phase 2 (table 3.12), can achieve additions to capacity at lower cost than entire new developments.

Production

Each oil field has a unique production profile, depending on the natural characteristics of the reservoirs including locations, depth and size of the reservoirs and the nature of production from an oil field including commercial and policy decisions. However, a typical production profile of an oil field looks similar to a bell-shaped curve that skews to the left and can be divided into three phases. These include a build-up phase where production rises as new wells are developed, a plateau phase where production from new wells offsets a natural decline from old wells, and a decline phase.

A typical oil production profile for various types of oil fields is shown in figure 3.39, by plotting annual and cumulative production from the sample of oil fields with respect to their reserves. In general, the build-up to peak production is longer for a larger oil field, whereas smaller fields reach their peak sooner and decline more rapidly than large fields. Figure 3.39 shows that, for an average onshore oil field, around 20 per cent of reserves from a small field are produced during the build-up phase, compared with just over 10 per cent for a larger field.

For some large fields, such as the Zakum field in the United Arab Emirates, where production started in the late 1960s, the build-up period took more than several decades before the oil field reached peak production in 2002. In contrast, the smaller Hassi Berkine Sud field in Algeria, where production started in 1998, has already passed its peak production (IEA 2008).

In addition, oil fields that are located offshore generally reach peak production in a shorter time than reserves that are located onshore. For oil fields that contain reserves of less than 500 mmbbl, around 25 per cent of reserves from an offshore oil field are produced by the time production reaches its peak (figure 3.40). This compares with cumulative production of around 20 per cent for fields of the same size that are located onshore. The production profile of offshore fields reflects their higher development costs relative to onshore fields, which generally trigger the project developer to recover oil more quickly in order to keep the cash flows for further development. Offshore oil fields in deeper water tend to reach peak production early.

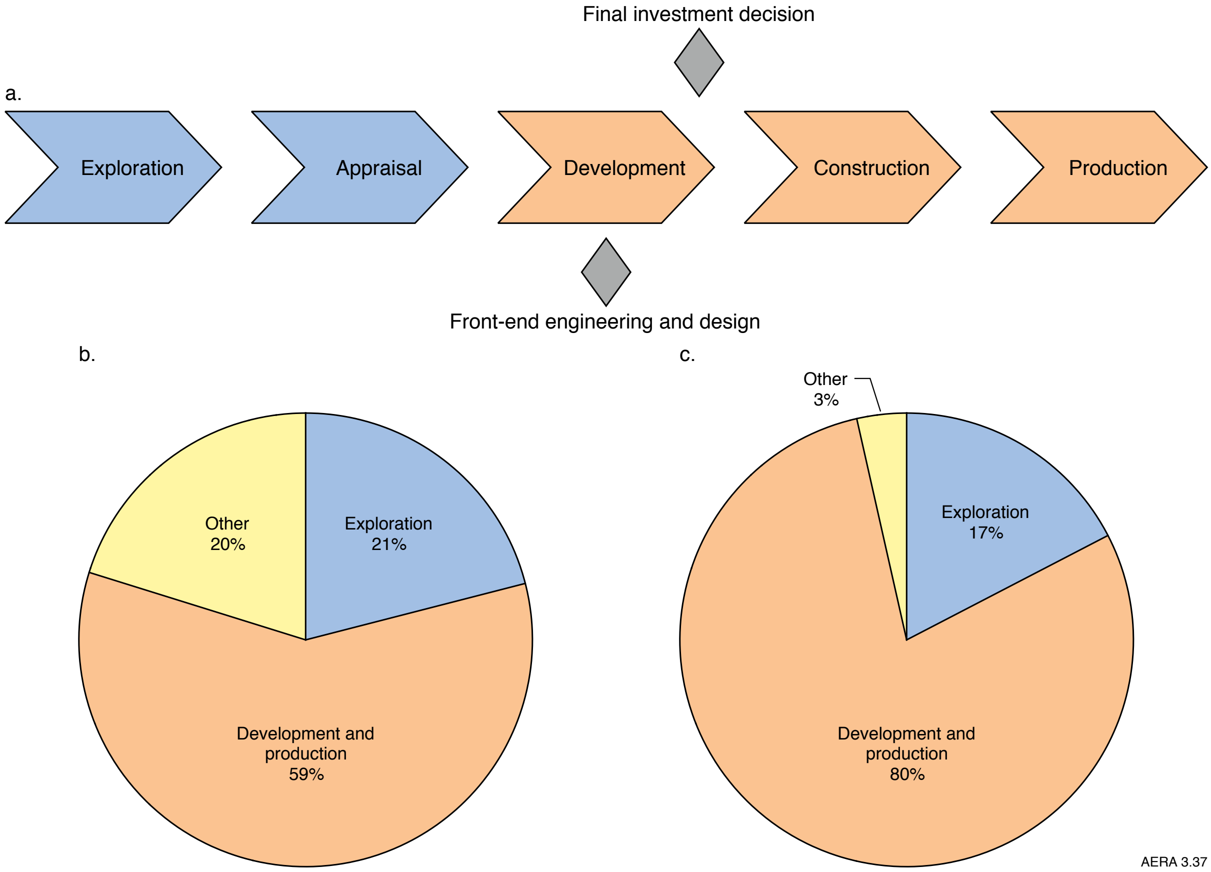


Figure 3.37 Components of upstream petroleum expenditure; **a** steps in development process; **b** expenditure by activity in 1999; **c** expenditure by activity in 2005

Source: Geoscience Australia 2008

Table 3.12 Australian oil projects, capital costs, unit costs

Project	State	Year completed	Capital cost (A$million)	Additional capacity (kb/d)	A$/bpd	Water depth (m)
Roller/Skate	WA	1994	170			10
Elang/Kakatua	WA	1998	42	40	1050	
Stag	WA	1998	180	50	3600	49
Cossack/Wanaea	WA	1999	190	25	7600	80
Laminaria/Corallina	WA	1999	1370	155	8839	
Buffalo	WA	2000	145	40	3625	
Lambert/Hermes	WA	2000	120	16	7500	126
Legendre	WA	2001	110	40	2750	52
Laminaria Phase 2	WA	2002	130	65	2000	
Mutineer-Exeter	WA	2005	440	90	4889	168
Basker and Manta	Vic	2005	260	20	13 000	
Enfield	WA	2006	1480	74	20 000	544
Cliff Head	WA	2006	285	12.5	22 800	
Puffin	NT	2007	100	25	4000	
Vincent (stage 1)	WA	2008	1000	100	10 000	
Stybarrow	WA	2008	874	80	10 925	800
Woollybutt	WA	2008	143	7	20 429	100

kb/d = thousand of barrels per day; A$/bpd =cost in Australian dollars per additional barrel per day production capacity

Source: Bureau of Resources and Energy Economics

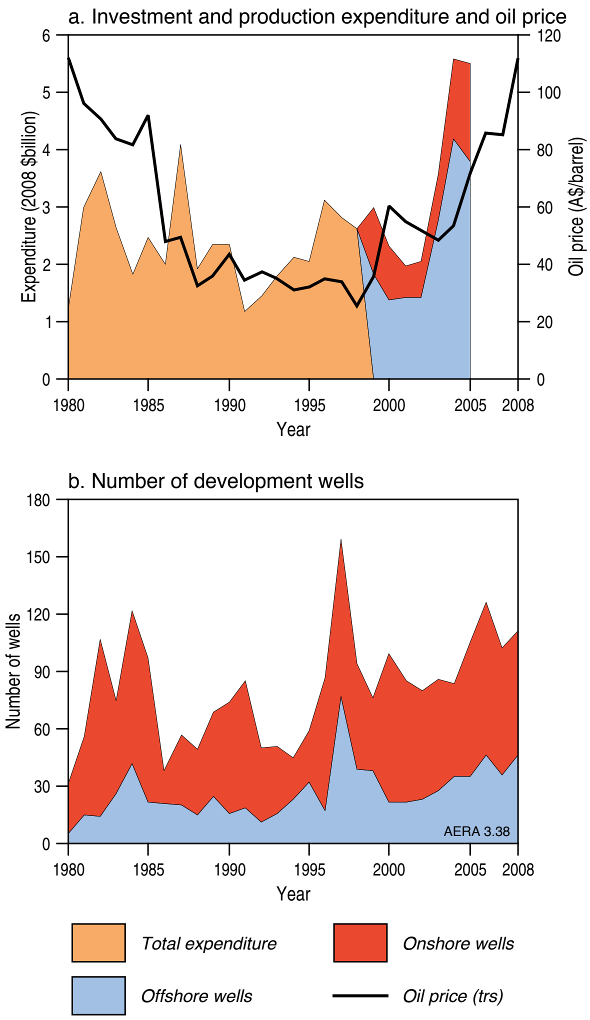


Figure 3.38 Development and production of Australia's petroleum resources

Source: Geoscience Australia

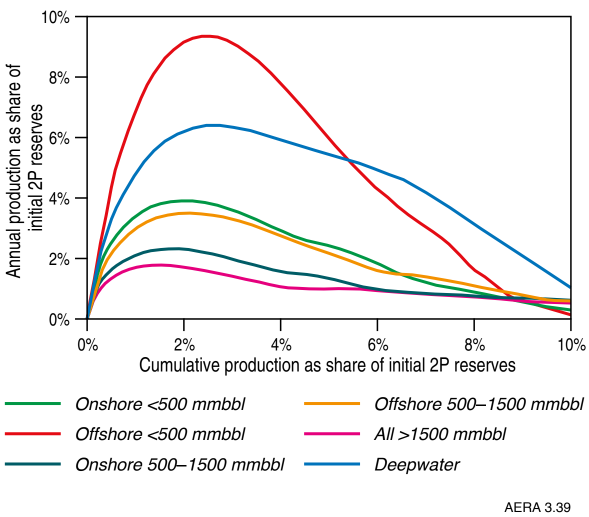


Figure 3.39 Typical oil production profiles

2P = proven plus probable

Source: IEA 2008

In Australia, total conventional oil production (including crude oil, condensate and LPG) is increasingly from offshore oil fields with deeper oil accumulations (table 3.12) and fields that contain smaller reserves than those developed in the past. Given the typical production profile of these types of reserves, increased exploration activity is required and more oil wells need to be drilled if the current production level is to be maintained.

Infrastructure issues

Australian oil infrastructure is generally well developed, from upstream oil developments to processing at refineries. There have not been any recent significant increases in Australia's oil refinery capacity, however substantial capital is spent on existing refineries to ensure continued and reliable production of clean fuels. Australia's liquid fuel supply has also been enhanced by imports from refineries in the Asia–Pacific region. Supply chain diversity and flexibility provide continued security of supply. Only in the unlikely situation of no refining sector coupled with a failure of physical oil markets does Australia lose the flexibility to redirect and refine some crude oil (Haley and Twomey 2012).

Given the likely increased levels of imports of refined product, investment in import/export infrastructure, including the possibility of greater storage capacity to mitigate supply disruption will be of growing importance.

The development of unconventional oil resources, such as those from shale and tight reservoirs, may require considerable infrastructure investment, given that some of the potentially prospective basins are located in remote regions. As a result, initial exploration and development are likely to take place in basins near existing production infrastructure for conventional oil.

Environmental considerations

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

Under the *Offshore Petroleum and Greenhouse Gas Storage Act 2006* (OPGGS Act), petroleum activities in Commonwealth waters (three nautical miles from the baseline from which the breadth of the territorial sea is measured, and extending seaward to the outer limits of the continental shelf) are regulated by the National Offshore Petroleum Safety and Environmental Management Authority (NOPSEMA).

The objective based *OPGGS (Environment) Regulations 2009*, administered by NOPSEMA, use a risk-based approach for managing environmental performance through the Environmental Plan regime. This regime requires the operator to demonstrate that the environmental impacts of petroleum activities are of an acceptable level and are reduced to as low as reasonably practicable (ALARP) in order for a petroleum activity to proceed.

If a petroleum activity is likely to have an impact on a matter of national environmental significance, it must be referred to the Australian Government Department of the Environment, under the EPBC Act for approval. The department assesses and considers whether an action that is referred will have a significant impact on a matter of national environmental significance and whether or not to approve that action. Petroleum exploration and development are prohibited in some marine protected areas offshore (such as the Great Barrier Reef Marine Park) and tightly controlled in others where multiple marine uses have been sanctioned (figure 3.40).

Environmental impact assessments may require environmental monitoring over a period of time as a condition to the approval before the development can commence. In some cases, regional-scale precompetitive base line environmental information is available from government in the form of regional syntheses containing contextual information that already characterises the environmental conditions for the proposed development. In the offshore area the typical datasets that are required for marine environmental impact assessments in EPBC Act referrals and that can be synthesised and made available by the Australian Government include bathymetry, substrate type, seabed stability, ocean currents and processes, benthic habitats and biodiversity patterns.

The mining, processing and refining of shale oil involve a somewhat different range of environmental issues, including disposal of spent shale, impacts on air and water quality, and greenhouse gas emissions. Heating oil shale, whether above or below ground, requires energy inputs and entails emissions. Australian oil shales are low in carbonates, making carbonate decomposition to CO_2 less of a problem in Australia than in some other deposits.

There has been recent political and public concern over the environmental effects of large-scale shale gas production in North America, and of coal seam gas (CSG) in eastern Australia. Concerns have centred on the possible impacts on groundwater aquifers and surface water bodies of hydraulic fracturing, use of water resources and chemical additives during hydraulic fracturing, the disposal of produced water, and competition with other land uses. Similar concerns may accompany the future development of shale liquids and light tight oil resources in Australia. However, many of the potentially prospective basins are located in remote areas with a relatively low population density, which may reduce the potential for land use conflicts.

3.4.2 Outlook for oil resources

For conventional liquid petroleum resources, additions will come from several potential sources:

- field growth–extensions to identified fields and revisions to recovery factor estimates
- EOR from existing fields
- discovery of new fields in established hydrocarbon basins
- discovery of new fields in frontier basins that become commercial by 2050.

Field growth

Growth in reserves in existing fields can add significantly to total reserves–for example, by 40 per cent for sandstone reservoirs in the North Sea (Klett and Gautier 2003). It has been estimated that more than 70 per cent of the increase in proven reserves since 2000 has come from revisions to reserves in discovered fields (IEA 2012). These increases are based on new information gathered about the extent and nature of the initial oil pool intersected by the discovery well during the development and production phases. Factors that can contribute to field growth were listed by Powell (2004) as including:

- increases in the known volume of discovered pools from drilling and geophysical data
- new pool discoveries often by development wells
- improved development technology allowing a greater proportion of the oil-in-place to be produced
- revised assessment of reservoir and fluid properties leading to higher recovery factors than those originally calculated, with real-world reservoir performance data substituting for initial generic assumptions.

Geoscience Australia estimated that there was scope for an additional 5880 PJ (1000 mmbbl) of liquid petroleum resource (crude oil and condensate) from field growth in identified fields. Some of this potential may have already been realised as these estimates were made several years ago (Geoscience Australia 2004, 2005).

Enhanced oil recovery

Geoscience Australia estimated in 2005 that there was scope for about an additional 6468 PJ (1100 mmbbl) of crude oil from EOR. However, currently there is no EOR production in Australia.

Application of EOR depends on the availability (supply) and cost of miscible gases such as CO_2 or nitrogen (Wright et al. 1990), oil price, technology advances and the geology of the reservoir. Because of initial recoveries of up to 60 per cent or more of the oil-in-place, it is considered unlikely that EOR from Australia's major oil reserves in offshore basins will contribute significantly to liquid fuel supply in the outlook period. Field growth through improved reservoir performance also reduces the target volume of oil-in-place for EOR. The extraction of oil from unconventional reservoirs may prove to be of more importance than EOR in the Australian context (see 'Outlook for unconventional oils', below).

Discovery of new fields in established hydrocarbon basins

Successful exploration in hydrocarbon producing basins is a major potential contributor to Australia's conventional oil resources. The volume of new reserves added is dependent on the number of exploration wells drilled, the size of the prospects tested and the success rate for oil discoveries that can be commercially developed. Perceptions of prospectivity and the economic, regulatory and fiscal environment influence the number of exploration

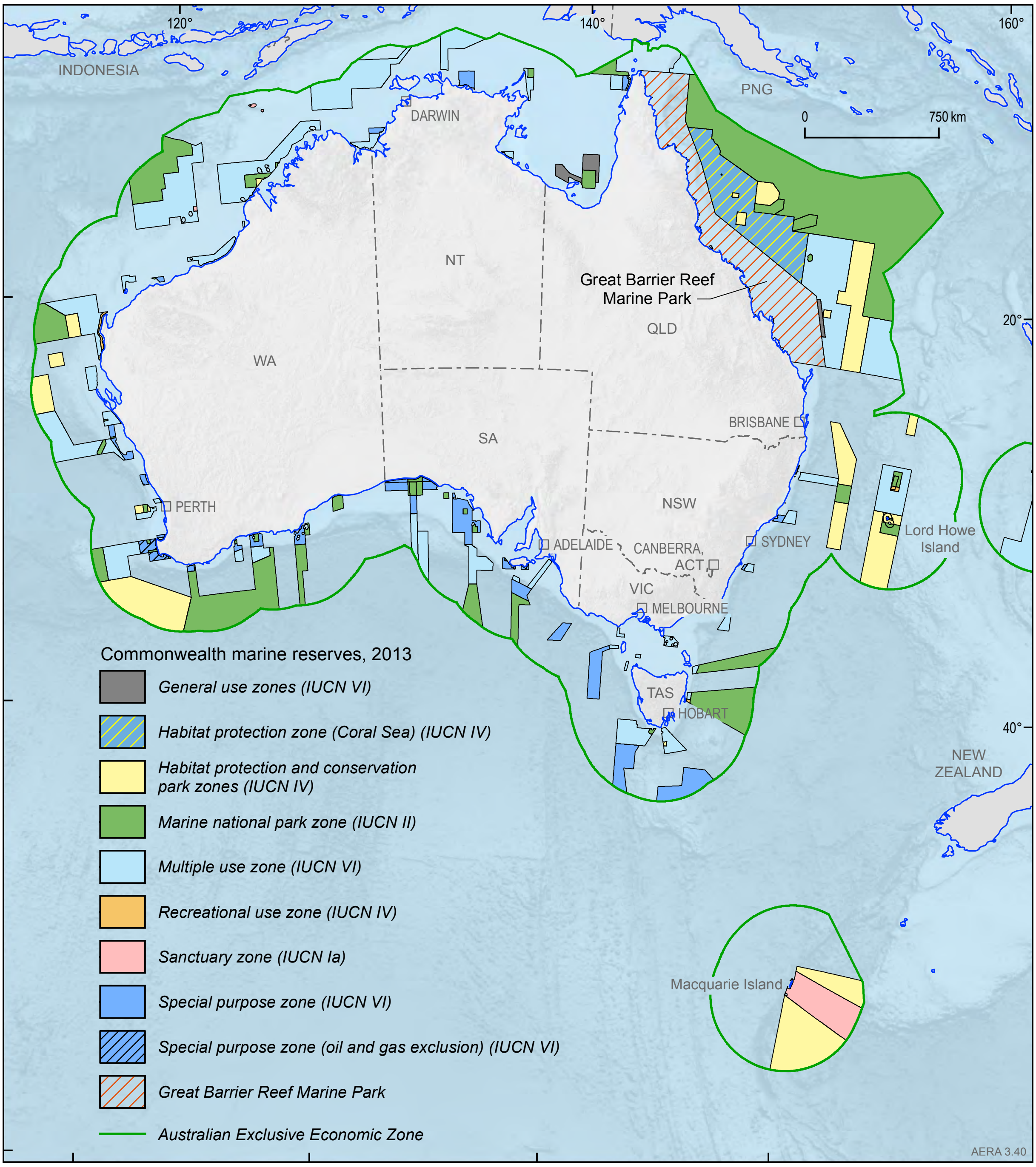


Figure 3.40 Current marine protected areas of Australia

IUCN = International Union for Conservation of Nature

Source: Deprtment of Sustainability, Environment, Water, Population and Communities wells drilled (Bradshaw et al. 1999), while geological factors, as outlined in box 3.1, determine the field size distribution and the chance for oil. As a basin is explored, the size of prospects tested generally decreases, because the largest structures are usually those first drilled. However, application of new geological concepts and new technology can reverse this trend.

The number of exploration wells drilled in Australia and the relative importance of onshore and offshore activity have varied through time. The long-term decline in onshore drilling since the 1980s has recently been reversed as the potential for unconventional oil and gas resources has drawn explorers back to Australia's onshore basins (figure 3.36). The historical success rates are around 20 per cent for petroleum exploration in Australian basins, but lower when crude oil only is considered.

A number of assessments of the undiscovered oil potential of Australia's major hydrocarbon producing basins have been undertaken using different methods, including those used by the United States Geological Survey (USGS) and the more conservative approach employed by Geoscience Australia (box 3.3). As noted by Powell (2001), undiscovered resource assessments have multiple inbuilt uncertainties and only have validity in the context of the method used and the purpose for which they were undertaken. Estimates in established hydrocarbon basins can be based on the known discovery history trends and field size distributions, and a substantial geological dataset that has sampled the natural variability in the basin. They are also dynamic and change as knowledge improves and uncertainties are resolved. Assessments of frontier basins are more uncertain because there is no local history of exploration outcomes on which to base the estimates. The results of undiscovered resource assessments are best considered as probability distributions rather than as a single raw number (figure 3.41); this explains the range of values given in table 3.13.

The USGS (2011) estimates that the mean undiscovered conventional resources in the four geological provinces assessed are around 27 642 PJ (4701 mmbbl) of oil and 32 215 PJ (7652 mmbbl) of natural gas liquids, including condensate (table 3.13).

Geoscience Australia has commenced an assessment of the unconventional hydrocarbon potential of Australian basins, in collaboration with the states and the Northern Territory authorities and the USGS. The project aims to systematically assess Australia's onshore sedimentary basins for undiscovered unconventional hydrocarbon resources.

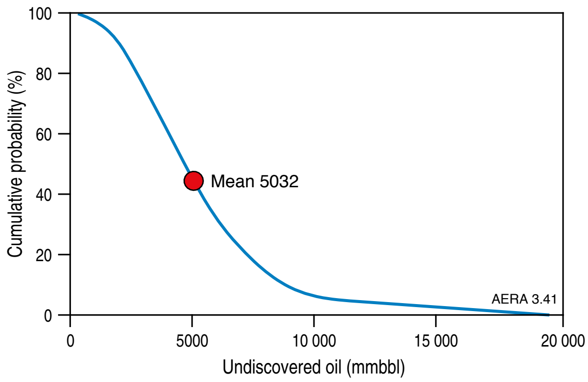


Figure 3.41 Australia's undiscovered oil resources

Source: USGS 2011

The USGS assessment focused only on the most prospective of Australia's established hydrocarbon basins and only on the most prolific of the assessment units or play types. The assessment did not include the producing Cooper-Eromanga, Bowen-Surat, Perth, Otway and Bass basins, all of which have had oil discoveries in the past decade, although of only modest size (20 mmbbl, 118 PJ or considerably less).

There is still crude oil to be found in the established basins, especially in the less explored zones, such as the deepwater extensions of the proven areas, but giant oil field discoveries are considered unlikely in the context of current play concepts and technology. The analysis of Powell (2004) showed that most established basins demonstrated 'a very strong creaming effect', implying that the large oil fields had already been found in these basins. The exceptions were the Carnarvon and Perth basins. In the Carnarvon Basin, the successful exploration of the deepwater Exmouth Sub-basin has provided the

Table 3.13 Estimates of undiscovered potential in Australian basins

Basin	Oil						Natural Gas Liquids					
	95 %		Mean expectation		5 %		95 %		Mean expectation		5 %	
	mmbbls	PJ	mmbbls	PJ	mmbbls	PJ	mmbbls	PJ	mmbbls	PJ	mmbbls	PJ
Bonaparte	427	2511	930	5468	1654	9726	1165	4905	3164	13 320	6399	26 940
Browse	325	1911	633	3722	1077	6333	470	1979	1176	4951	2204	9279
Carnarvon-Roebuck	1695	9967	3001	17 646	4729	27 807	1511	6361	3191	13 434	5573	23 462
Gippsland	87	512	137	806	200	1176	57	240	121	509	218	918
Total	2534	14 900	4701	27 642	7660	45 041	3203	13 485	7652	32 215	14 394	60 599

Note: 95 per cent, mean expectation and 5 per cent denote the probability of the resources exceeding the stated value

Source: USGS 2011

BOX 3.3 RESOURCE ASSESSMENT METHODOLOGIES

USGS World Petroleum Resources Project is an assessment of the undiscovered, technically recoverable, conventional oil and gas resources for 171 geological provinces around the world that was completed between 2009 and 2011. The assessment methodology is based on a geological framework description of each province and the definition of petroleum systems and assessment units. Exploration and discovery histories or analogs were used to determine field sizes and numbers of undiscovered accumulations in each assessment unit. Probability distributions were then computed for undiscovered oil and gas accumulations, and gas/oil ratios were used to calculate the volumes of associated gas (gas in oil fields) and natural gas liquids in gas fields. Ranges of resource estimates are given, reflecting the geological uncertainty in the assessment (table 3.13). In the study, a total of 313 assessment units were analysed, including seven from across five Australian basins; these are summarised at the geological province level in table 3.13 (USGS 2011). This assessment is for conventional oil and gas only; there are separate USGS studies for unconventional resources, but none have been yet conducted for Australian basins. http://energy.usgs.gov/OilGas/AssessmentsData/WorldPetroleumAssessment.aspx

Geoscience Australia assessments are discovery forecasts for a limited time horizon (typically 5–15 years) and an emphasis on discovery modelling using known exploration trends (Powell 2001). Assessments can be made for various drilling trends. This method is used in the production forecast shown in figure 3.39. Assessments for the Browse and Bonaparte basins and some of the sub-basins within the Carnarvon Basin were undertaken between 2001 and 2005.

largest additions to crude oil reserves (around 500 mmbbl, 2940 PJ), but in the Perth Basin the early promise of the offshore Cliff Head discovery has not been followed up with more substantial finds in the surrounding area. However, most of the deepwater offshore Perth Basin remains untested, and it is the focus of new exploration efforts following the acquisition of precompetitive data by Geoscience Australia.

In comparison, the North West Shelf is more fully explored. Longley et al. (2002) reviewed the chances of finding a new oil province, similar in size and significance to the Exmouth Sub-basin, on the shelf and concluded that it was unlikely. Since this prediction, a number of the less explored sub-basins have been drilled, including deepwater tests at Maginnis-1 in the Seringapatam Sub-basin, Browse Basin; Huntsman-1 in the Rowley Sub-basin, offshore Canning Basin; and Wigmore-1 in the Beagle Sub-basin and Herdsman-1 in the southern Exmouth Sub-basin, Carnarvon Basin (Walker 2007). However, none of these were successful in finding a new oil trend, and the pattern of known oil occurrence on the North West Shelf remains confined within the proven parts of the Bonaparte, Browse and Carnarvon basins. Successful exploration has proceeded in these basins but with the focus on gas, and giant gas fields continue to be found.

Crude oil discoveries tend to be developed relatively quickly, with most coming into production within five years of discovery (Powell 2004) and sometimes within months if they are close to infrastructure (e.g. inshore fields in the Carnarvon Basin). Development of gas liquid (condensate and LPG) accumulations, which now account for most of Australia's oil resources, on the other hand, can be delayed, sometimes for decades. Powell's 2004 analysis shows that most gas fields take 11–15 years from discovery to development. A high liquids content can accelerate development, although Ichthys, with more than 500 mmbbl of condensate and Australia's largest remaining oil field, was discovered by the Brewster well in 1980 and is only now being developed. Hence, the oil resource outlook to 2050 is in part dependent on the rate of development of liquids-rich gas fields. Factors that may influence development timetables include market demand, environmental approvals, the challenge of any associated CO_2, and technological developments such as floating LNG facilities discussed in Chapter 4.

Discovery of new fields in non-producing and frontier basins

Frontier basins have a low level of exploration activity compared with established hydrocarbon basins. There are rank frontiers that have had no exploration drilling (e.g. the Bremer Sub-basin) and other frontier areas where only a handful of wells has been drilled and major trends remain untested (e.g. the Ceduna Sub-basin, where only one well has been drilled in the main depocentre, with others drilled on the margin; figure 3.42). In Australia's poorly explored frontier basins, many of the largest structures remain untested, and vast areas of sedimentary basins, especially off the south-western, southern and eastern margins, have not been drilled. These offshore areas offer the greatest potential for major new oil discoveries. The deepwater Ceduna Sub-basin in the Great Australian Bight is considered to represent the highest probability for finding a new oil province (Totterdell et al. 2008), given the presence of an oil-prone source rock within a thick Cretaceous delta sequence.

Geoscience Australia has undertaken a program of precompetitive data acquisition and interpretation to assess the petroleum potential of selected frontier basins (Geoscience Australia 2011). New seismic, potential field data and seabed samples have been collected from a number of offshore basins (Bight, Mentelle, Perth, Offshore Canning, Arafura, Otway and Sorell) to better understand the geological history and hydrocarbon resource potential of these areas. These studies have underpinned subsequent acreage release with uptake of exploration acreage in previously neglected areas (in the Bight, Perth and Offshore Canning basins). Industry work in these new exploration permits is at an early stage; 2D and 3D seismic data have been acquired but exploration wells are yet to be drilled, although several of these are planned to test the Ceduna Sub-basin.

Geoscience Australia has also undertaken precompetitive studies of two basins in the remote deepwater frontier of the Lord Howe Rise. Early results have identified a number of depocentres that have sedimentary thickness (up to 7 km) and volume (100 km long and 30 km wide) sufficient to have generated significant hydrocarbons if source rocks are present at depth (figure 3.32). While these structural results from new seismic acquisition are encouraging, no petroleum source rocks are known because the area has not been drilled for hydrocarbons. Precompetitive data acquisition programs in the onshore frontier Amadeus, Georgina, Darling, Arrowie, Arckaringa and Officer basins have been undertaken by Geoscience Australia in cooperation with relevant state geological surveys. The discovery of the Millungera Basin in onshore Queensland was an outcome of this program (Geoscience Australia 2011, Korsch et al. 2011).

The size, number and geological diversity of Australia's frontier basins are consistent with the presence of major undiscovered petroleum resources. The petroleum resources likely to be discovered in the years to 2050 depend on the amount of exploration activity, the success rate and the size of prospects. Current frontier exploration rates are low, averaging in the past decade less than 2 wells per year offshore and around 10 per year onshore (APPEA 2009), and are likely to remain so without the stimulus supplied by access to regional precompetitive data. Success rates in frontier basins can be lower than 10 per cent but can be improved with new information and new technologies and, as discussed above, prospect sizes can be large as the largest structures are yet to be drilled. Current low frontier drilling rates and low success rates make it unlikely that a frontier oil discovery will be made in any particular year. The only new oil province discovered since 2000 was the Abrolhos Sub-basin in the offshore Perth Basin, where the Cliff Head field was found in 2001 as an offshore example of a proven trend onshore. The offshore Exmouth Sub-basin, which has materially added to Australia's oil production, was already established as a proven hydrocarbon province with oil discoveries in the 1980s and 1990s. Recent increased onshore exploration efforts, in part stimulated by the prospects for unconventional oil and gas, have resulted in two conventional oil discoveries–Buru's Ungani

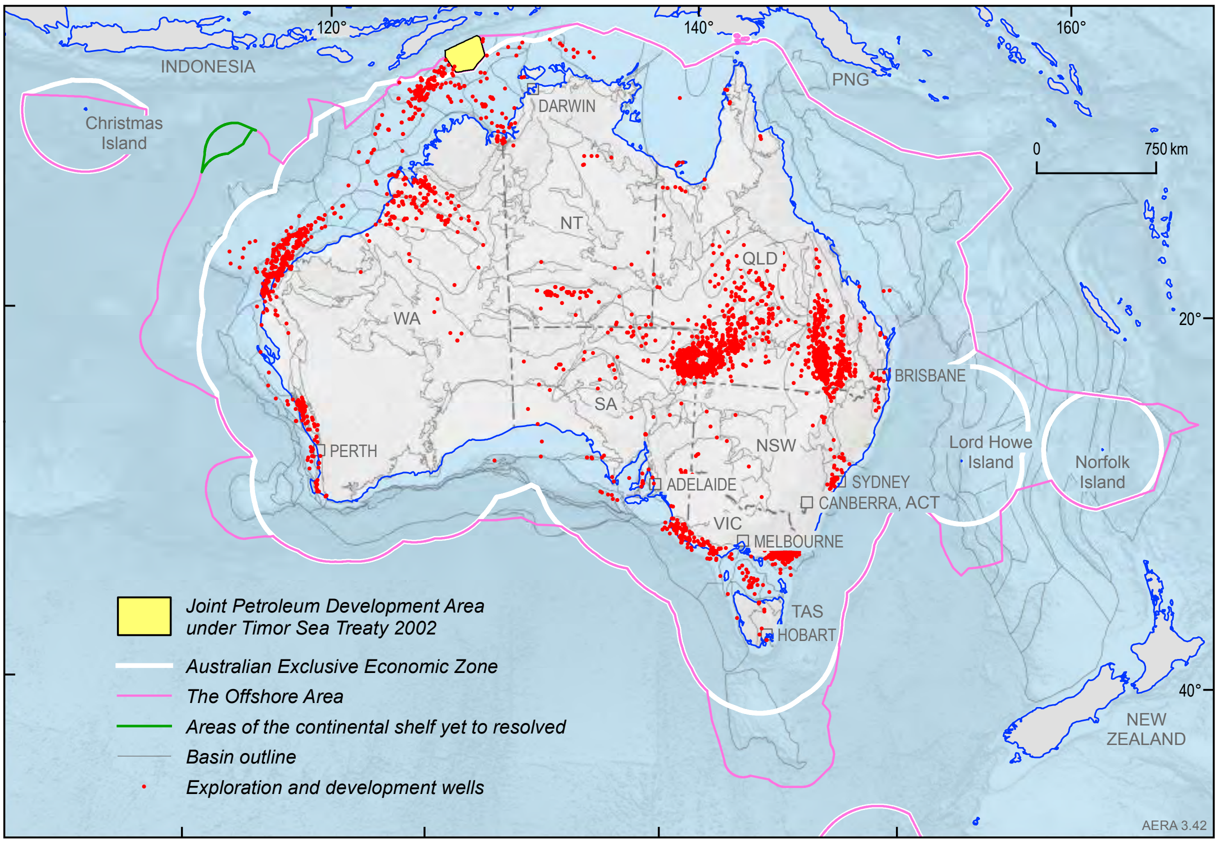


Figure 3.42 Sedimentary basins and petroleum exploration wells

Source: Geoscience Australia

discovery in the Canning Basin and Central Petroleum's Surprise 1 find in the Amadeus Basin. These are the first oil discoveries in these basins since the 1980s.

A number of estimates of undiscovered hydrocarbon potential derived from a variety of methods are available for individual frontier basins and for Australia as a whole (Bradshaw et al. 1998, Longley et al. 2001). The publicly available assessments have not integrated the results from the current rounds of precompetitive data acquisition. Even in deepwater frontier basins, oil discoveries can be expected to be developed within a few years using FPSOs, if they are of commercial size.

Outlook for unconventional oils

Oil shale contains a large unconventional oil resource for Australia. However, there is currently no production. Some of the challenges for the oil shale industry include technical issues associated with achieving large-scale commercial production in the face of uncertainty and volatility of future crude oil prices. There are also environmental challenges, including reducing CO_2 emissions and water usage, and issues associated with disposal of spent shale. These challenges need to be overcome and oil prices need to remain high for shale oil to contribute significantly to resources in the outlook period.

Some development of natural gas liquids from shale gas and light tight oil resources is likely in Australia in the coming decades, given the rapid emergence of unconventional gas exploration in recent years. As in North America, shale and tight gas exploration is increasingly targeting basins with potential for liquid hydrocarbons, in an attempt to improve the economics of production. However, further exploration is required to define the size and distribution of shale liquids and tight oil resources. The shortage of specialised equipment and skilled labour required for the exploration and production of these resources, in addition to the potential environmental effects and the associated public and political concerns, is likely to pose challenges.

Other unconventional sources of liquid fuels include GTL and CTL technologies. Although Australia has abundant gas and coal resources, it is not anticipated that these technologies will significantly add to liquid fuel supplies in the outlook period. Biofuels make a small contribution to current oil supply in Australia and, even with expanded production, are not expected to impact significantly on Australian oil production until second-generation (advanced) biofuels become available. Biofuels are discussed in more detail in Chapter 12.

Total resource outlook

Figure 3.43 plots Australia's potential total oil resources, including known and undiscovered resources. The following section details the potential demands on these resources over the next 20 years.

There is no currently publicly available resource assessment of Australia's undiscovered oil resources that adequately reflects the new knowledge gained in recent years during the active programs of government precompetitive data acquisition and increased company exploration during the recent resource boom. The knowledge base for unconventional oil is at a low level.

3.4.3 Outlook for oil market

Without a major discovery, Australian oil production is expected to continue to decline over the two next decades. In contrast, domestic oil consumption is projected to increase moderately over the same period, increasing the reliance on imports.

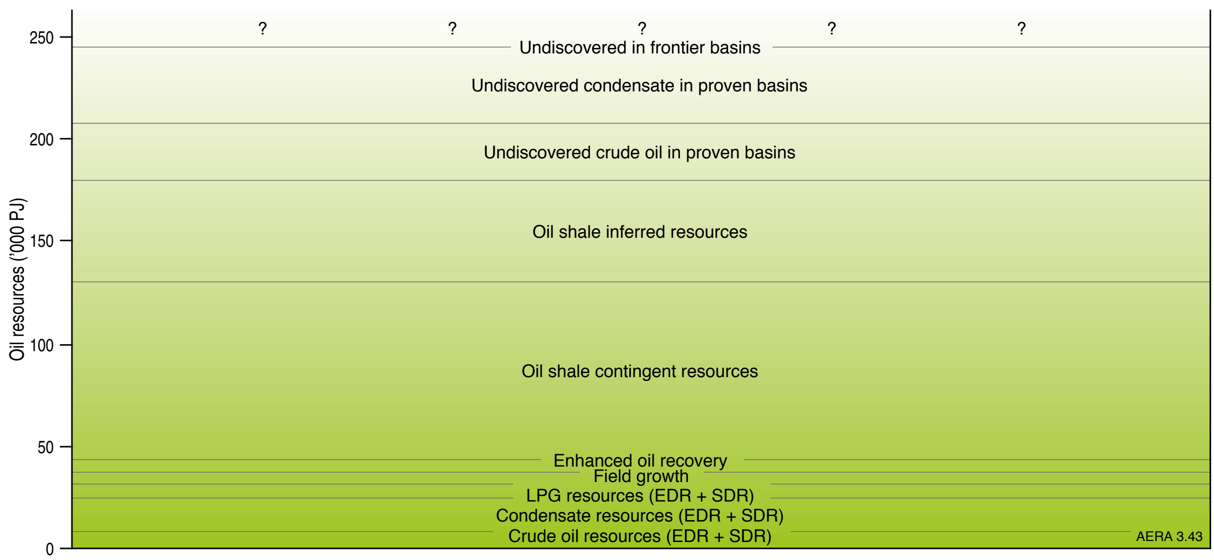


Figure 3.43 Total oil resources (identified and potential) and estimating cumulative consumption

EDR = Economic Demonstrated Resources; **SDR** = Sub-economic Demonstrated Resources; **LPG** = liquefied petroleum gas

Source: Geoscience Australia

Table 3.14 Projects at the committed stage, October 2013

Project	Company	Basin	Type	Start up	Capacity (kb/d)	Capital expenditure (A$million)
Turrum	ExxonMobil/BHP Billiton	Gippsland	New project	2013	11	2600
Coniston Oil Field Project	Apache Energy/Inpex	Carnarvon	Expansion	2014	22	526
Balnaves Development Project	Apache Energy/KUFPEC	Carnarvon	New project	2014	30	429

kb/d = thousand of barrels per day

Source: BREE 2013b

Production

In the next few years, the production of oil in Australia is expected to fluctuate as developments now under construction or in the advanced stages of planning are completed. As with current production, the majority of future production is likely to be sourced from offshore basins in north-western Australia.

Production forecasts by Geoscience Australia show that condensate is expected to outstrip crude oil production by about 2014, and new discoveries within the established basins could add to production in the the next few decades. Major new oil discoveries could reverse this trend, just as the discovery and development of new oil fields in the Carnarvon and Bonaparte basins replaced the declining production from the Gippsland Basin in the late 1980s (Powell 2001). Frontier basins, such as the deepwater Ceduna Sub-basin in the Great Australian Bight, are seen as offering the best chance for finding a major new oil province; increased frontier drilling rates would improve the likelihood of this outcome in the outlook period.

Consumption

Australia's primary oil consumption is expected to grow faster than production.

The transport sector is expected to continue to rely heavily on oil over the next 20 years. Consumption of oil and petroleum products in the transport sector is expected to grow steadily over the next few decades, driven largely by economic growth.

Trade

Continued growth in domestic oil demand and declining domestic oil production are expected to result in an increase in Australia's oil imports over the next few decades.

Exacerbating this gap between supply and demand is the fact that a significant proportion of the growth in domestic production of crude oil, condensate and naturally-occurring LPG will be concentrated in the Carnarvon and Browse basins, in north-western Australia. As a result, it is reasonable to assume that this supply of crude oil, condensate and naturally-occurring LPG will largely be exported to Asia for processing, rather than being supplied to the domestic market. As a result, the ability of domestic production to meet domestic demand is likely to be lower than implied by the simple comparison of production and consumption.

The demand for petroleum product imports is determined not only by domestic oil production and end-use consumption of petroleum products, but also by domestic petroleum refining capacity. Australia's refining capacity is not expected to expand significantly given increasing competitive pressures from larger refineries in South-East Asia in particular. For a given domestic production and consumption outlook, petroleum refining capacity constraints may result in lower crude oil imports and, simultaneously, higher imports of refined products.

Australia's net trade position for liquid fuels is expected to worsen over the next few decades.

Major project developments

As at the end of October 2013, there were five committed projects, of which the Montara - Skua project was under construction (table 3.14). These five projects have a combined peak oil production capacity of around 113 000 barrels per day at an estimated capital cost of around A$4.7 billion.

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Chapter 4: Gas

4.1 Summary

KEY MESSAGES

- Australia has substantial gas resources. Gas is Australia's third largest energy resource after coal and uranium.
- Most of the conventional gas resources are located off the north-west coast of Australia and are being progressively developed for domestic use and liquefied natural gas (LNG) export.
- Significant coal seam gas (CSG) resources exist in the major coal basins of eastern Australia and are being developed for domestic use and LNG export.
- It is likely that Australia possesses significant shale gas and tight gas resources, but these are poorly quantified because exploration for these commodities within Australia has only recently commenced.
- Australia's gas resources have grown recently as a result of successful exploration programs and are large enough to support expected domestic and export market growth.
- Gas is expected to increase its share of Australia's energy production and exports over the next few decades.

4.1.1 World gas resources and market

- Proved global gas reserves at the end of 2010 were estimated to be around 7.3 million PJ (6608 tcf). This was equal to around 59 years of production. A more recent estimate of global gas reserves to production is 55.7 years (BP 2013).
- The International Energy Agency (IEA) estimates that globally there are more than 15.5 million PJ (14 124 tcf) of remaining recoverable resources of conventional gas. This is equivalent to around 120 years of production at current rates. Although uncertain, unconventional recoverable resources are estimated to be a similar size, bringing total gas reserves to around 250 years of production (IEA 2011b).
- Gas is the third largest global energy source, accounting for around 28 per cent of global primary energy consumption in 2011. Global gas consumption has increased at an average annual rate of 3 per cent since 2000, to reach 127 109 PJ (116 tcf) in 2011.
- Global LNG trade has expanded rapidly–by 8 per cent per year during 2000 to 2011–to reach around 12 760 PJ (~329 bcm, 232 Mt, 11.6 tcf) in 2011. LNG trade fell slightly in 2012 due to declines in LNG imports to Europe and United States, although growth remained strong in Asia (BP 2013, IEA 2013). LNG trade accounts for around 10 per cent of global gas consumption.
- Australia accounted for around 2 per cent of world gas reserves and 1.7 per cent of world production in 2011. However, Australia is the world's fourth largest LNG exporter and accounted for 8 per cent of world LNG trade in 2011.
- Global gas demand is projected by the IEA, in its new policies scenario, to increase by 1.6 per cent per year to reach 171 910 PJ (151.8 tcf) in 2035 (IEA 2012).
- This expansion in global demand will increasingly be met by imports, including LNG from countries such as Australia. LNG trade is projected to increase by around 9263 PJ (176 Mt, 8.4 tcf) between 2009 and 2035 to around 18 632 PJ (354 Mt, 17 tcf; IEA 2011b).
- The recent rapid growth in unconventional gas production in the United States and the abundance of gas resources worldwide could have implications for future LNG trade flows.

4.1.2 Australia's gas resources

- Gas is Australia's third largest energy resource after coal and uranium.
- Most (around 92 per cent) of Australia's conventional gas resources are located in the Carnarvon, Browse and Bonaparte basins off the north-west coast (figure 4.1). There are also resources in south-west, south-east and central Australia. Large CSG resources exist in the coal basins of Queensland and New South Wales, with further potential

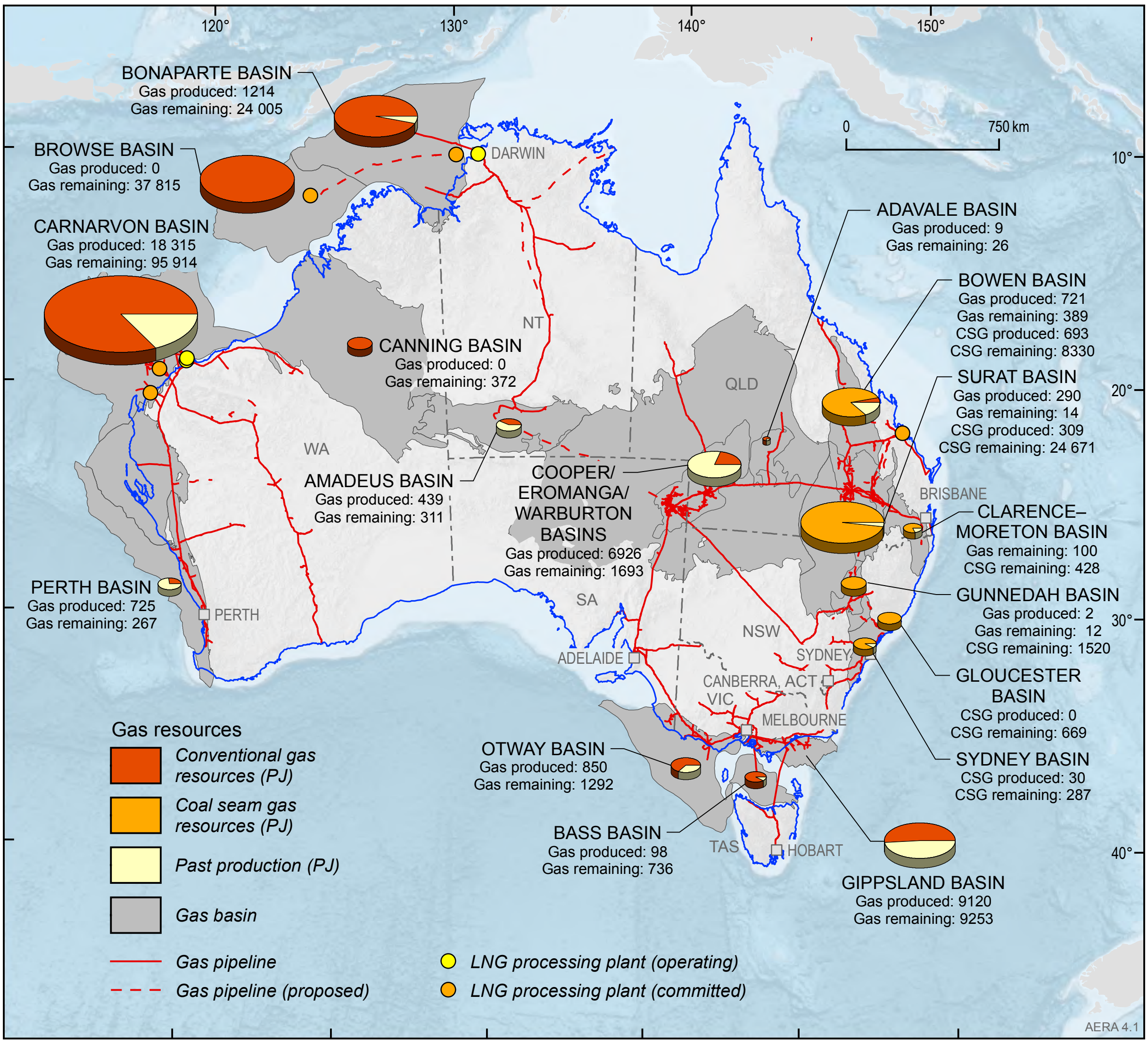


Figure 4.1 Location of Australia's gas resources and infrastructure

CSG = coal seam gas; **LNG** = liquefied natural gas

Note: For remaining resources, conventional gas values represent total demonstrated resources; CSG values show 2P reserves.

Source: Geoscience Australia

resources in South Australia (figure 4.1). Known tight gas accumulations are located onshore in South Australia, Western Australia and Victoria, while contingent and potential shale gas resources are located in Queensland, the Northern Territory, South Australia and Western Australia.

- At the beginning of 2012, Australia's Economic Demonstrated Resources (EDR) and Sub-economic Demonstrated Resources (SDR) of conventional gas were estimated at 172 100 PJ (156 tcf). At current production rates, there are sufficient EDR (109 433 PJ, 99 tcf) of conventional gas to last another 51 years (figure 4.2). It is noted that production is projected to increase substantially.
- An additional 11 000 PJ (10 tcf) of inferred conventional gas resources is estimated in recently discovered fields and other fields but not booked as part of EDR and SDR.
- Historically, gas exploration has a sustained record of finding reserves. Thus, there is a strong likelihood of finding more conventional gas resources. However, the rate of reserve additions has recently slowed and additions have been exceeded by production (figure 4.2). Further opportunities for large discoveries remain with the development of new technologies and play concepts, and the advance of exploration into frontier areas (e.g. Bight Basin).
- Australia also has significant unconventional gas resources–CSG, tight gas and shale gas. Coal seam gas EDR have doubled in the past three years to an estimated 35 905 (32.6 tcf). This is equivalent to about a quarter of the recoverable reserves from Australia's conventional gas fields. Total identified

resources of CSG are estimated to be around 223 454 PJ (203 tcf), including SDR estimated at 65 529 PJ (60 tcf) and inferred resources of 122 020 PJ (111 tcf).

- Total identified tight gas resources are currently estimated at around 22 052 PJ (20 tcf). Substantial ongoing exploration activity suggests that these values are likely to grow, especially in basin-centred gas provinces with established infrastructure (e.g. Cooper and Perth basins).
- Australia may have significant shale gas resources, but such resources are poorly understood and quantified, and any estimates of potential resources have a high degree of uncertainty. Such recent estimates include technically recoverable resources of 435 600 PJ (396 tcf) for four basins (EIA 2011), revised upwards to 480 700 PJ (437 tcf) with the inclusion of another two basins (EIA 2013) and a value in excess of 1 100 000 PJ (1000 tcf) if all prospective basins are considered (Cook et al. 2013). In 2012, the first contingent shale gas resources were reported in the Cooper Basin (2200 PJ, 2 tcf), and in 2012 Santos booked the first shale gas reserves. The amount of exploration activity has significantly increased in the past few years, suggesting future growth in this area.
- Total identified gas resources are sufficient to enable expansion in Australia's domestic and export production capacity. Australia's combined identified gas resources are of the order of 430 803 PJ (391 tcf). This is equal to around 184 years of gas at current production rates, of which EDR account for 67 years.
- The distribution of gas resources is expected to shift as finds of conventional gas resources offshore level off, CSG exploration and production continue to increase, and new tight/shale gas resources are identified and developed.

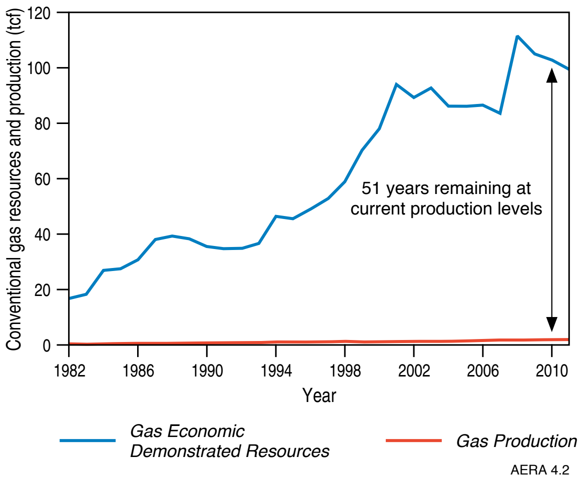


Figure 4.2 Conventional gas resources and production

Source: Geoscience Australia

4.1.3 Key factors in utilising Australia's gas resources

- Most of Australia's conventional gas resources are located offshore, far from domestic gas markets, which adds to the cost of bringing the resource to market.
- Development of secure long-term markets is necessary to underpin the major capital investment required for development of gas resources in Australia, including the building of new pipelines.
- Potential environmental issues raised by gas development include the disposal of water produced from onshore CSG operations, below-ground water impacts, carbon dioxide contained in some large offshore gas fields, the siting of onshore LNG liquefaction plants in environmentally sensitive areas and increased shipping movements through the Port of Gladstone and the Great Barrier Reef. These issues can be mitigated by the existence and enforcement of conditions before project approvals.

4.1.4 Australia's gas market

- Australian gas consumption has grown by 4 per cent per year over the past decade. Gas accounted for 23 per cent of Australia's primary energy consumption in 2011–12, and 19 per cent of electricity generation.
- The main gas users in Australia are the manufacturing (32 per cent), electricity generation (31 per cent), mining (19 per cent) and residential (11 per cent) sectors.
- Gas production was 2200 PJ (2 tcf) in 2011–12. Unconventional gas production, in the form of CSG, accounted for about 13 per cent of gas production. Currently, there is only minor production of tight and shale gas in Australia.
- Around 50 per cent (20 Mt, 1052 PJ, 1 tcf) of Australian gas production was exported as LNG in 2010–11. Higher export volumes and international oil prices increased the value of exports in 2011–12 to A$12 billion.

4.1.5 Outlook for the Australian gas market

- Growth in gas consumption will be influenced by policy initiatives supporting uptake of gas as a relatively clean energy source. Gas-fired electricity generation has lower carbon emissions than coal-fired electricity without carbon capture and storage. Gas can also be linked with intermittent renewable energy resources such as wind to provide a flexible and reliable power source.

4.2 Background information and world market

4.2.1 Definitions

Natural gas is a combustible mixture of hydrocarbon gases. It consists mainly of methane (CH_4), with varying levels of heavier hydrocarbons and other gases such as carbon dioxide. Natural gas is formed by the alteration of organic matter (box 4.1). When accumulated in a subsurface reservoir that can be readily extracted, it is known as conventional gas. Conventional gas can also be found with oil in oil fields. Conventional gas fields can be dry (almost pure methane) or wet (associated with the 'wet gas' components–ethane, propane, butane and condensate). Dry gas has a lower energy content than wet gas. Natural gas can also be found in more difficult-to-extract unconventional deposits, such as coal beds (CSG), shales (shale gas), or low-quality reservoirs (tight gas), or as gas hydrates (box 4.2).

Coal seam gas (CSG) is naturally occurring methane in coal seams. It is also referred to as coal seam methane (CSM) and coal bed methane (CBM). Methane released as part of coal mining operations is called coal mine methane (CMM). CSG is dry gas, being almost entirely methane. The gas molecules are trapped in the coal, are adsorbed onto the coal surfaces or occur as free gas in cleats and micropores, held in place by reservoir and water pressure.

Tight gas occurs within low-permeability reservoir rocks—that is, rocks with matrix porosities of 10 per cent or less and permeabilities of 0.1 millidarcy (mD) or less, exclusive of fractures (Sharif 2007). In practice, it is a poorly defined category that merges with conventional and shale gas, but generally tight gas can be considered as being found in low-permeability reservoirs that require large-scale hydraulic fracture treatments and/or horizontal wells to produce gas at economic flow rates or to recover economic volumes (Holditch 2006). Tight gas can be regionally distributed (for example, basin-centred

BOX 4.1 NATURAL GAS CHEMISTRY AND FORMATION

Natural gas is composed of a mixture of combustible hydrocarbon gases (figure 4.3). These include methane (CH_4), ethane (C_2H_6), propane (C_3H_8), butane (C_4H_{10}) and condensate (C_{5+}). Most natural gas is methane but because of the variable additions of the heavier hydrocarbons, gas accumulations vary in their energy content and value (Geoscience Australia and ABARE 2010; see Appendix D).

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

Liquefied Petroleum Gas (LPG) is a mixture of the light hydrocarbons propane and butane, and it is normally a gas at surface conditions, although it is stored and transported as a liquid under pressure (e.g. in domestic barbecue gas bottles). Condensate is a mixture of pentane (C_5H_{12}) and heavier hydrocarbons that condense at the surface when a gas accumulation is produced. The gas liquids, LPG and condensate, are discussed in Geoscience Australia and ABARE (2010; chapter 13—Oil).

Natural gas is formed by the alteration of organic matter. This can occur through biogenic or thermogenic processes. The bacterial decomposition of organic matter in oxygen-poor environments in the shallow subsurface produces biogenic gas–for example landfill gas, (see Geoscience Australia and ABARE 2010, Chapter 12—Bioenergy). Biogenic gas is very 'dry', being almost pure methane.

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

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

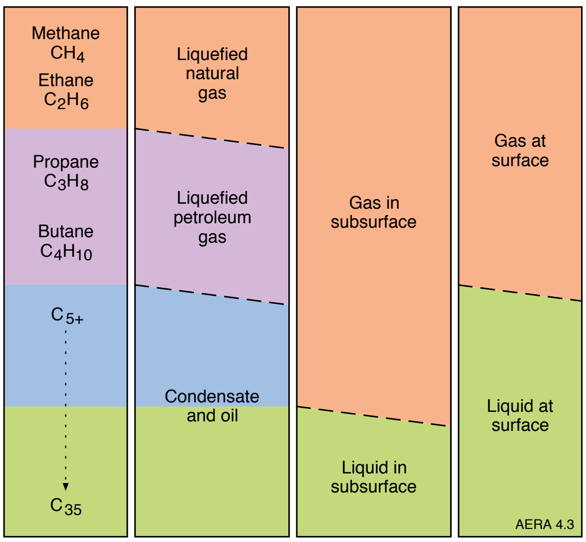


Figure 4.3 Petroleum resources nomenclature in terms of chemical composition, commercial product, physical state in the subsurface and physical state at the surface

Source: Geoscience Australia

gas), or accumulated in a smaller structural closure or stratigraphic trap as in conventional gas fields.

Shale gas is natural gas that has not migrated to a reservoir rock, but is still contained within low-permeability, organic-rich source rocks such as shales and fine-grained carbonates. Natural or hydraulically induced fracture networks are needed to produce shale gas at economic rates.

Basin-centred gas is a term used to describe 'regionally pervasive gas accumulations that are abnormally pressured, commonly lack a downdip water contact and have low-permeability reservoirs' (Law 2002). In the deeper parts of basins that are actively generating gas, there can be hundreds of metres of stacked reservoirs of different lithologies with gas in tight sandstones, siltstones, shales and coals.

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

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

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

4.2.2 Gas supply chain

Figure 4.4 illustrates the simplified operation of the gas industry in Australia. Resources are delivered to domestic and export markets through the successive activities of exploration, development, production, processing and transport. While different technologies can be used for extracting CSG and other unconventional gas, once extracted it is similar to conventional natural gas, and the supply chain is the same.

Resources and exploration

Exploration for conventional gas follows the same process as for oil. Geoscientists identify areas where hydrocarbons are likely to be trapped in the subsurface—that is, in sedimentary basins of sufficient thickness to contain mature petroleum source rocks, as well as suitable reservoir and seal rocks in trap configurations. The search narrows from broad regional geological studies through to determining an individual drilling target. Reflection seismic is the primary technology used to identify likely hydrocarbon-bearing structures in the subsurface (figure 4.5). There must also be evidence of a working petroleum system (box 4.2). Such evidence includes the presence of other petroleum discoveries in the case of a proven basin, or indications of the presence of organic-rich

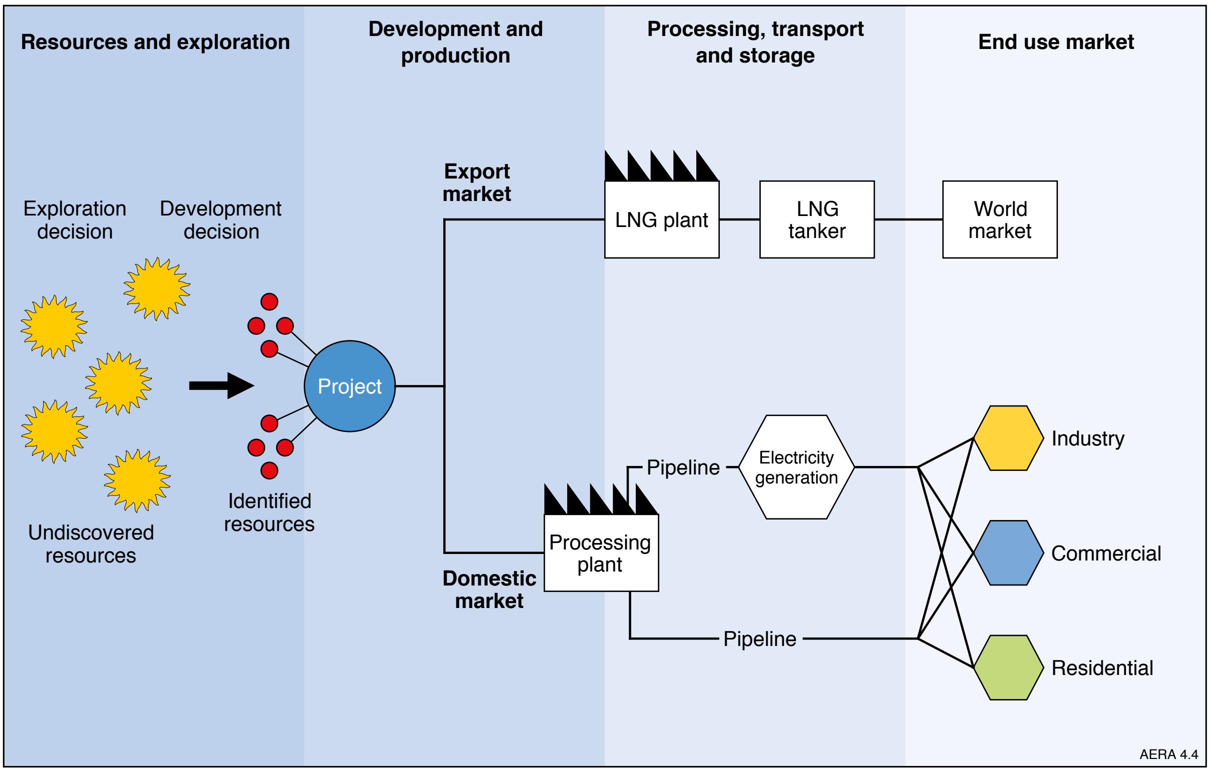


Figure 4.4 Australia's gas supply chain

LNG = liquefied natural gas

Source: Bureau of Resources and Energy Economics; Geoscience Australia

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

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

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

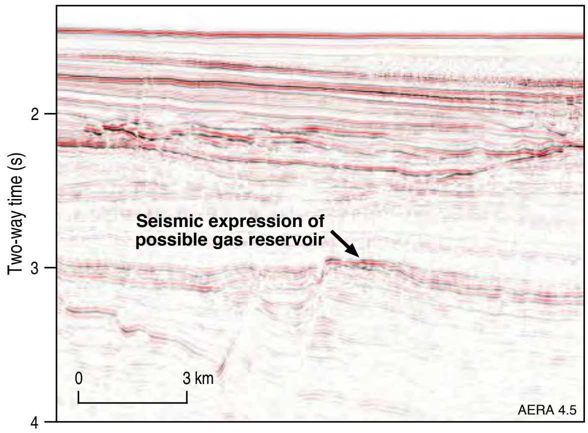


Figure 4.5 Seismic section across a prospective gas accumulation on the Exmouth Plateau, Carnarvon Basin

Source: Williamson and Kroh 2007

Most of Australia's conventional gas exploration occurs in the offshore basins, sometimes in water depths beyond 1000 m and with target depths from about 2000 m to more than 4000 m below the seafloor. The search for CSG, tight gas and shale gas is restricted to onshore basins. Target depths range from a few hundred metres to about 1200 m for CSG and down to depths of 4000 m or greater for tight and shale gas. The costs of the different exploration components—especially seismic work and drilling—vary markedly depending on the scope and location of the project, logistics, and other factors. Many shallow CSG wells can be drilled for the cost of one deep well in deep water. For example, an offshore well drilled to 3000–4000 m in water depths of 100–200 m typically costs $30–50 million (roughly $1 million per day of drilling), depending on location, water depth and other considerations. Shallow wells drilled to 200–1000 m in CSG exploration and development typically cost around $300 000 to $1 million (around $1000 per metre), with an average cost of around $500 000 per well (using data from company reports and Geoscience Australia estimates).

Development and production

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

Processing, transport and storage

The gas extracted from the well requires processing to separate the sales gas from other liquids and gases that may be present, and to remove water, CO_2 and other impurities before the gas can be transported efficiently by pipeline or liquefied and shipped to customers overseas. As a result, onshore processing tends to occur near the production well.

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

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

End-use market

Whereas major industrial users and electricity generators tend to receive natural gas directly, most users receive gas through distribution companies. As an end-use product, unconventional gas may be added to gas pipelines without any special treatment and utilised in all gas appliances and commercial applications.

BOX 4.2 PETROLEUM SYSTEMS AND RESOURCE PYRAMIDS

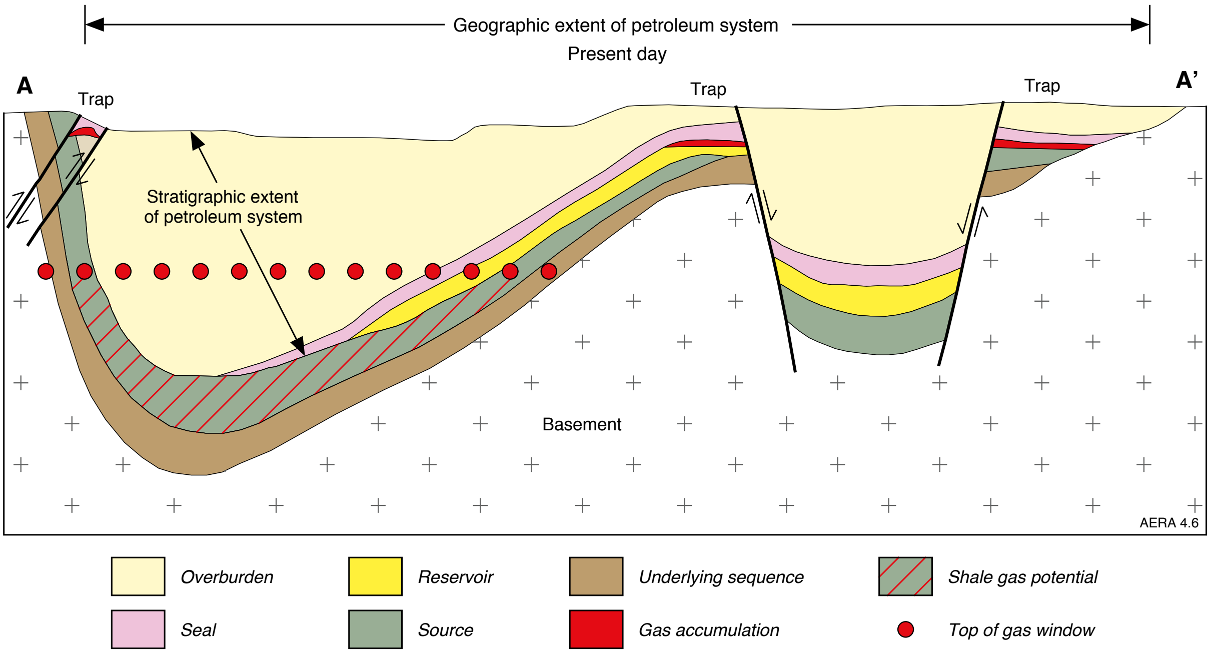


Figure 4.6 Petroleum system elements

Source: Magoon and Dow 1994 (modified)

Conventional accumulations of oil and gas are the products of a 'petroleum system' (Magoon and Dow 1994). The critical elements of a petroleum system (figure 4.6) are:

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

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

Unconventional gas accumulations reflect the failure or underperformance of the petroleum system. Shale gas and CSG arise where the natural gas is still within the source rock, not having migrated to a porous and permeable reservoir. Tight gas accumulations are within a poor-quality reservoir. The petroleum resource pyramid (McCabe 1998) illustrates how a smaller volume of easy-to-extract conventional gas and oil is underpinned by larger volumes of that are more difficult and more costly to extract (figure 4.7). For the unconventional hydrocarbon resources additional technology, energy and capital have to be applied to extract the gas or oil, replacing the action of the geological processes of the petroleum system. Technological developments and rises in price can make the lower parts of the resource pyramid accessible and commercial to produce. The recent development of oil sands in Canada and of shale gas in the United States are examples where rising energy prices and technological development have facilitated the exploitation of unconventional hydrocarbon resources lower in the pyramid.

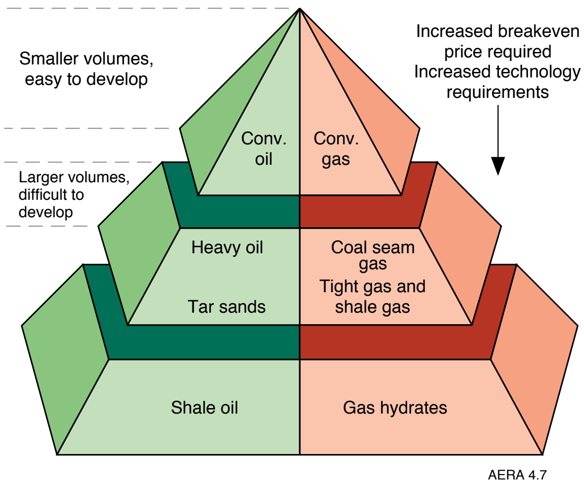


Figure 4.7 Petroleum resource pyramid

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

4.2.3 World gas market

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

Reserves and production

Proved world gas reserves—those quantities that geological and engineering information indicates with reasonable certainty can be recovered in the future from known reservoirs under existing economic and operating conditions—were estimated to be more than 7.3 million PJ (6608 tcf) at the end of 2010. This was equal to around 59 years of supply at current production. A more recent estimate of global gas reserves to production is 55.7 years (BP 2013). The Russian Federation, Iran and Qatar together hold more than half of the world's proved gas reserves (figure 4.8). Australia accounts for around 2 per cent of global reserves (table 4.1).

The IEA estimates that there are more than 15.5 million PJ (14 124 tcf) of remaining recoverable resources of conventional gas (IEA 2011b). This is equivalent to around 120 years of production at current rates. Unconventional recoverable resources are estimated to be a similar size, bringing total gas reserves to around 250 years of production (IEA 2012).

World gas production in 2011 was estimated at 127 109 PJ (116 tcf). The largest gas producers are the Russian Federation and the United States. Australia is the world's 14th largest gas producer, accounting for around 1.7 per cent of world gas production (figure 4.8; IEA 2011c).

Consumption

Natural gas currently accounts for around 28 per cent of world primary energy consumption. World gas consumption has grown steadily over the past few decades, by around 3 per cent per year between 2000 and 2010 (IEA 2012). Contributing factors include increased emphasis on environmental issues, which favours the clean combustion properties of gas relative to other fossil fuels; the uptake of technologies such as integrated gas combined cycle

Table 4.1 Key gas statistics

	Unit Australia	Australia 2011–12	Australia 2011	OECD 2011	World 2010
Resources	PJ	172 100	148 000	663 360	7 261 120
	tcf	156	135	604	6608
Share of world	%		2	9	100
World ranking	no.		13		
Production	PJ	2200	2303	46 120	127 326
	tcf	2	2.1	42	116
Share of world	%	1.6	1.8	36	100
World ranking	no.		15	na	na
Annual growth in production 2000–11	%	4.3	4.4	0.6	2.8
Primary energy consumption	PJ	1399	1478	616 684	128 166
	tcf	1.2	1.3	56	117
Share of world	%	1.0	1.2	48	100
World ranking	no.		27	na	na
Share of total primary energy consumption	%	23	25	28	21
Annual growth in consumption 2000–11	%	4.1	3.6	1.3	2.8
Electricity generation	TWh	49	49	2544	4301
Share of total	%	19	19	23	21
Export					
LNG export volume	Mt	20	21	24	219
	tcf	1.0	1.0	1.1	10.5
Share of world	%		9.6	11	100
World ranking	no.		4	na	na
LNG export value	A$billion	12	10	na	na
Annual growth in export volume 2000–10	%	9.8	10	na	7.8

LNG = liquefied natural gas; **Twh** = terawatt-hours; **tcf** = trillions of cubic feet

Note: World share of total primary energy consumption and electricity generation are 2009 data, LNG export values in nominal Australian dollars, Australian production excludes imports from JPDA.

Source: ABARES 2011; BP 2011; DEEDI 2012; Geoscience Australia; IEA 2011b; IEA 2011c power plants; and the commercialisation of abundant gas reserves. Energy security and fuel diversification policies have encouraged gas demand as a means of reducing dependence on imported oil.

Natural gas is used all around the world (figure 4.9). The largest gas consumers are the United States and the Russian Federation, followed by Iran, China and Japan. The Asia – Pacific region accounted for around 18 per cent of world natural gas consumption in 2011, with Australia accounting for 0.8 per cent (BP 2012).

In 2010, about 40 per cent of world gas consumption was used for power generation, with the industrial sector and the residential sector accounting for a further 17 and 22 per cent, respectively (IEA 2012). The share of gas in total world electricity generation was 22 per cent in 2010, although this varies widely among countries (figure 4.9). In Australia, the share of gas in total electricity generation was around 19 per cent in 2011–12 (BREE 2012a).

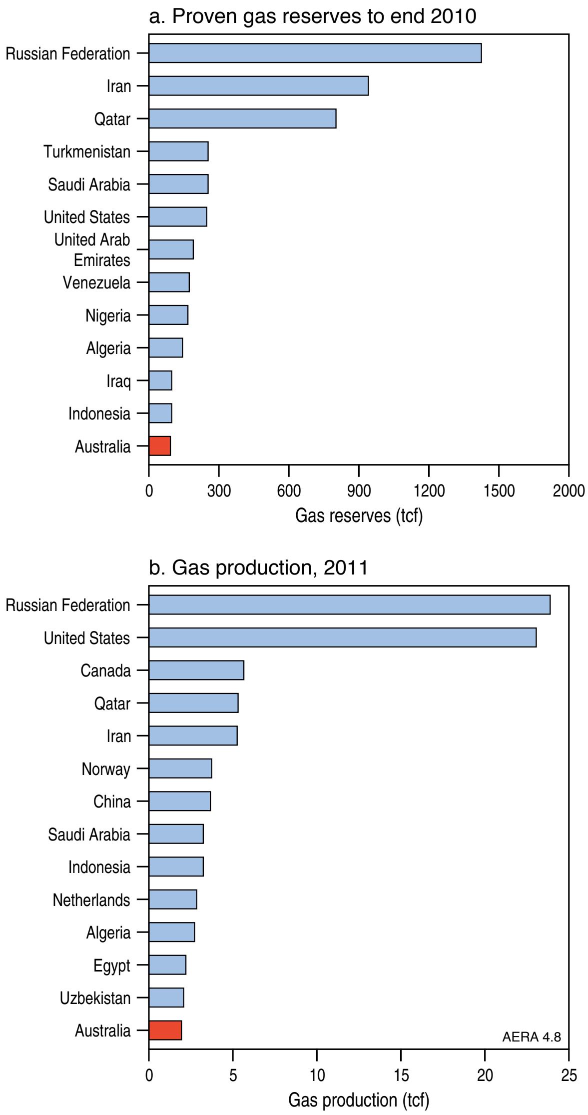


Figure 4.8 World natural gas reserves (2010) and production, major countries (2011)

Source: BP 2011; IEA 2011b

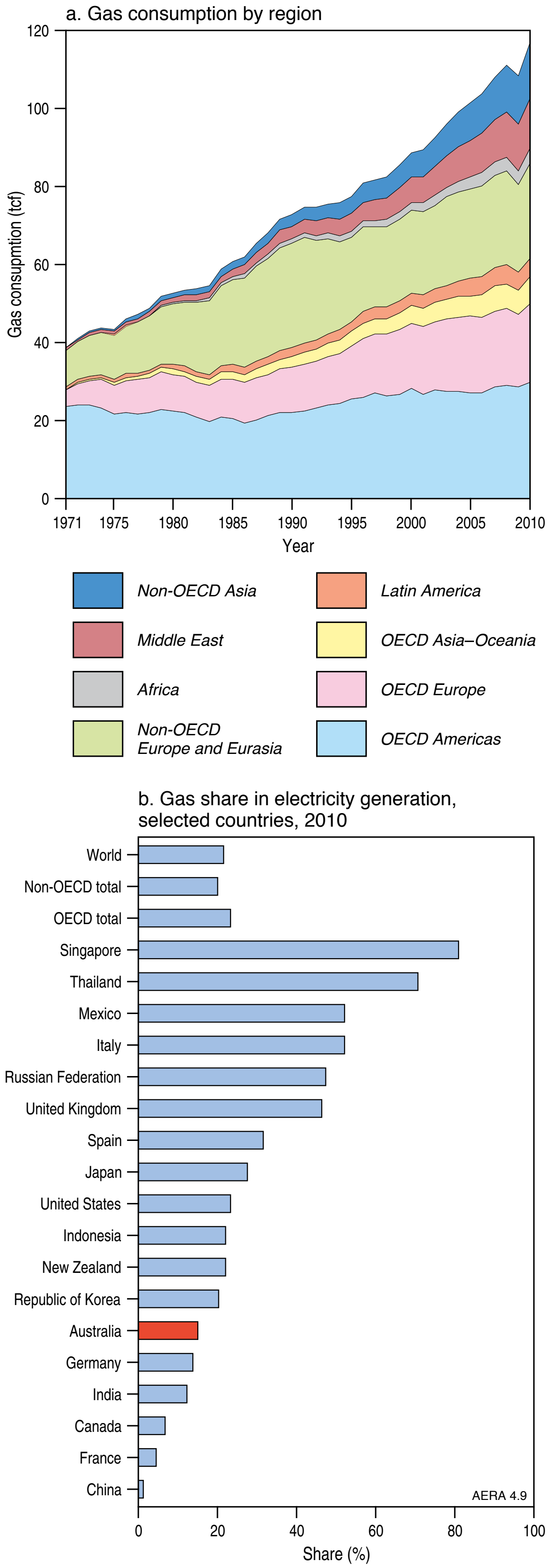


Figure 4.9 World gas consumption and the role of gas in electricity generation

OECD = Organisation for Economic Co-operation and Development

Note: share in 11b for non-OECD and world data are 2009 data

Source: BREE 2012b; IEA 2011a; IEA 2011b

Trade

With gas reserves located some distance from key gas-consuming countries, world gas trade has increased as a proportion of total consumption. In 2011, about 31 per cent of world gas consumption was supplied through international trade. Trade as a proportion of gas consumption is higher in the Asia–Oceania region, where countries such as Japan and the Republic of Korea are totally reliant on imports for their gas needs.

LNG imports accounted for about 29 per cent of total world gas trade in 2011, equal to 9 per cent of world gas consumption; the remainder was transported by pipeline. With fewer international pipelines in the Asia–Pacific region, the share of gas trade met by LNG imports is much higher, at 88 per cent (around 34 per cent of consumption; BP 2012).

World LNG trade reached a new high of around 12 760 PJ (~232 Mt, 11.6 tcf) in 2011 (figure 4.10; BP 2012). The International Gas Union (IGU 2012) considers the new trade to be primarily driven by the sharp increase in demand from Japan (by 8.2 Mt) arising from the severe earthquake and tsunami in March 2011, as well as the tragedy that struck the Fukushima nuclear power plant. World LNG trade is characterised by a small but increasing number of suppliers and buyers. In 2011, there were 25 countries importing LNG and 18 countries exporting LNG (IGU 2012). Qatar is the world's largest LNG exporter, accounting for 31 per cent of total world trade in 2011 (figure 4.11; BP 2012; IGU 2012). Malaysia and Indonesia are the second and third largest exporters, accounting for a further 10 and 9 per cent, respectively, of world trade in 2011. Japan is the world's largest LNG importer, accounting for 33 per cent of the market (IGU 2012). Australia is the world's fourth largest LNG exporter, accounting for 8 per cent of world LNG trade in 2011, and 13 per cent of the Asian LNG imports (IGU 2012).

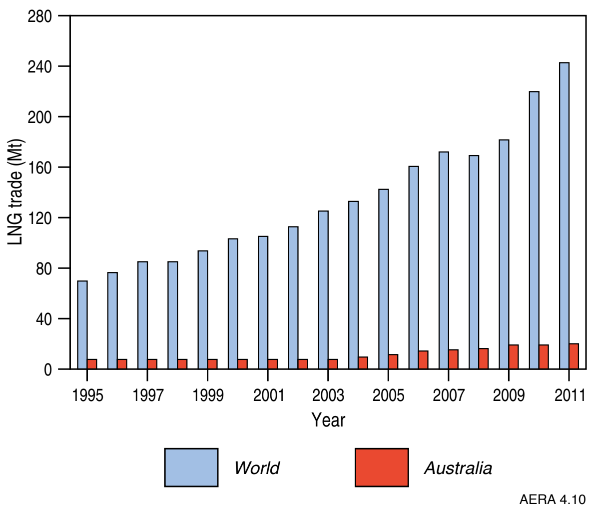


Figure 4.10 World LNG trade

LNG = liquefied natural gas

Source: IEA 2011c

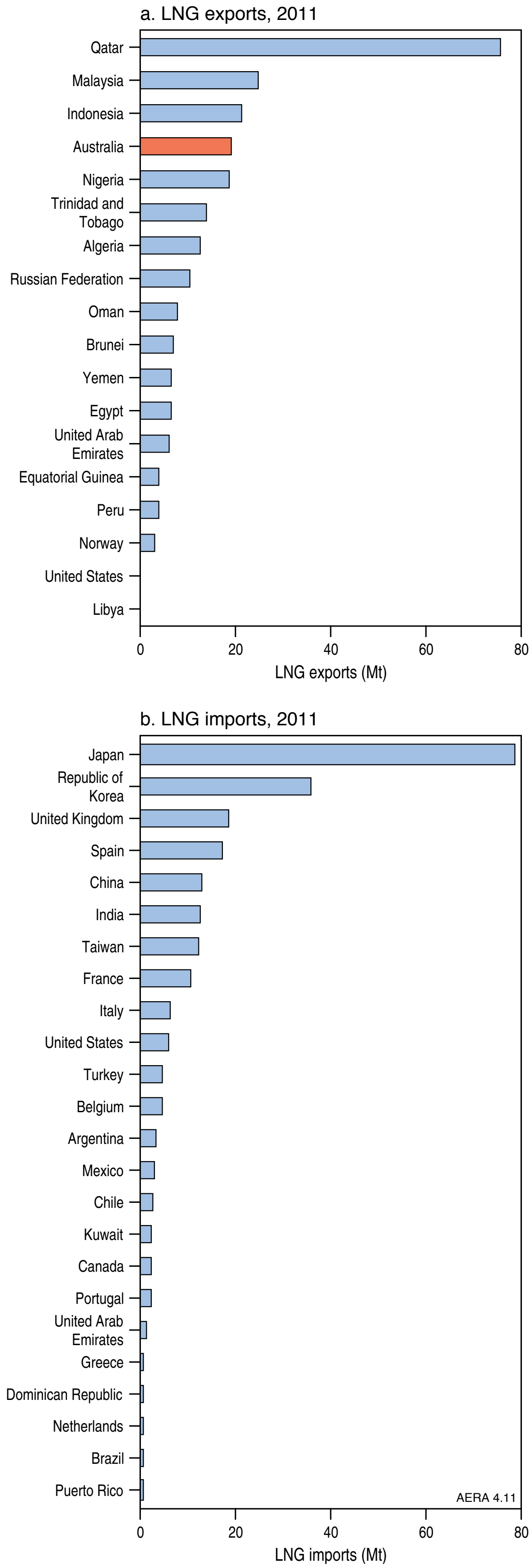


Figure 4.11 World LNG trade, by country, 2011

LNG = liquefied natural gas

Source: BP 2011

The role of unconventional gas

Information about global unconventional gas resources is much less complete than for conventional resources, and is less reliable. Although the resources worldwide are thought to be very large, they are currently poorly quantified and mapped. Exploration and delineation of resources are still at an early stage.

According to the IEA, unconventional gas (including CSG, shale gas and tight gas) now amounts to around half of recoverable gas resources, or around 16 million PJ (14 336 tcf; IEA 2011a). Around 20 per cent of these resources are in the Asia–Pacific region (including China and Australia), 29 per cent are in North America, and 23 per cent are in non-OECD Europe and central Asia (IEA 2011a).

Unconventional gas production accounted for 13 per cent of global gas production in 2010 (IEA 2012). Growth in unconventional gas production has been especially strong in North America, particularly the United States. North American unconventional gas production totalled around 13 600 PJ (12.4 tcf) in 2010, which accounted for around 80 per cent of global unconventional gas production. In 2010, unconventional gas production represented more than half of total United States gas production.

World CSG resources are estimated to be around 4.6 million PJ (4167 tcf; table 4.2; IEA 2012). The majority of these resources are in the former Soviet Union, North America, and the Asia–Pacific region.

Table 4.2 Key coal seam gas statistics, 2011

	Unit	Australia	World
CSG resources[a]	PJ	258 888	4 583 700
	tcf	235	4167
Share of world	%	6	100
CSG production	PJ	240	2700
	tcf	0.22	2.3
Share of world	%	8.9	100
CSG share of total gas production	%	10	5

CSG = coal seam gas
a Total resources (discovered and undiscovered)

Source: APPEA 2011; BP 2011; DEEDI 2011;DEEDI 2012; Geoscience Australia

CSG is produced in more than a dozen countries, including the United States, Canada, Australia, India and China. The United States is the world's largest CSG producer, with production of around 2200 PJ (2.0 tcf) in 2009 (EIA 2012). In Australia, CSG production was 296 PJ (0.2 tcf) in 2011–12.

World resources of tight gas and shale gas are also relatively large, but very uncertain, requiring further drilling and exploration to quantify. It is estimated that world tight gas resources are around 3.3 million PJ (2966 tcf; table 4.3). Around one-quarter of these are in the Asia–Pacific region. Other regions with significant tight gas resources include North and Latin America, the Middle East and non-OECD Europe and Eurasia. Shale gas resources are estimated at around 7.9 million PJ (7203 tcf). Large shale resources are in North America, Asia–Pacific region, and Latin America (IEA 2011a).

There is limited world production data for shale and tight gas. Tight gas production is not, generally, reported separately from conventional sources. The United States is the world's only large-scale producer of shale gas, producing approximately 3700 PJ (3.4 tcf) in 2009 (EIA 2012).

Table 4.3 Key tight and shale gas statistics, 2011

	unit	Australia	World
Tight gas resources	PJ	22 052[a]	3 259 604[b]
	tcf	20[a]	2966[b]
Share of world	%	0.7	100
Shale gas resources	PJ	435 600[b]	7 916 216[b]
	tcf	396[b]	7203[b]
Share of world	%	5.5	100

a Total discovered resources; **b** Total resources (discovered and undiscovered)

Source: Campbell 2009; EIA 2011; IEA 2011a; Lakes Oil 2011

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

Currently, commercial production of gas hydrates is limited to the Messoyakha gas field in western Siberia, where gas hydrates in the overlying permafrost are contributing to the flow of gas being produced from the underlying conventional gas field (Pearce 2009). However, exploitation of gas hydrates is a rapidly evolving field, with Japanese researchers recently (JOGMEC 2013) announcing the first production of methane from subsea hydrate deposits. There are also active research programs or experimental production in Canada, the Republic of Korea and the United States, but gas hydrates are not expected to contribute appreciably to supply in the next two decades.

The development of unconventional gas resources is most advanced in the United States, and impacts on the global LNG market are already evident, including reduced demand for LNG imports into the United States. The United States will become an LNG exporter from the middle of this decade. During an initial period of rising United States domestic gas prices from about 2004, the commercial-scale exploitation of unconventional resources was driven by the successful development and deployment of technologies (horizontal drilling and hydraulic fracturing) that enabled these resources to be extracted. Increased production of unconventional gas in the United States has put downward pressure on the domestic gas price, also known as the Henry Hub price. The Henry Hub price averaged around US$2 per GJ during the March quarter of 2012, less than half the average price over the period 2001 to 2010 and 80 per cent lower than when gas prices peaked in the middle of 2008. In 2013, Henry Hub gas prices have edged back towards US$4 per GJ.

World gas market outlook

In its 2011 *World Energy Outlook* new policies scenario (IEA 2012), the IEA projects world demand for natural gas to expand by 1.6 per cent per year between 2010 and 2035, to reach 171 910 PJ (151.8 tcf) in 2035 (table 4.4). The share of gas in total world primary energy demand is projected to increase to 24 per cent in 2035 from 22 per cent in 2010.

Table 4.4 IEA new policies scenario projections for primary gas demand

	Unit	2010	2035
OECD	PJ	55 140	66 905
	tcf	48.7	59.1
Share of OCED total	%	24	29
Average annual growth, 2010-35	%		0.8
Non-OECD	PJ	59 578	105 047
	tcf	52.6	92.8
Share of non-OECD total	%	20	23
Average annual growth, 2010-35	%		2.3
World	PJ	114 718	171 910
	tcf	101.3	151.8
Share of world total	%	22	24
Average annual growth, 2010-35	%		1.6

Note: Totals may not add due to rounding

Source: IEA 2012a and 2012

The majority of the increase in global gas use over the projection period—more than 82 per cent in total—comes from non-OECD countries (IEA 2012). Demand growth is strongest in China (6.6 per cent per year) and India (5.1 per cent per year). In China and India, the share of gas in the energy mix will remain relatively low; however, the volumes consumed will be significant in terms of global gas consumption and imports. There will be relatively low rates of demand growth in the more mature markets of North America and Europe to 2035, although they are expected to remain the largest markets in absolute terms.

The electricity sector is projected to account for 53 per cent of the increase in world gas demand to 2035, with gas-fired power generation projected to increase by 2.3 per cent per year, to reach 8466 TWh (table 4.5; IEA 2012). Low capital costs, short lead times and a relatively lower environmental impact make gas-fired power generation an attractive option, particularly where uncertainties exist for longer term low-emission technology requirements.

Table 4.5 IEA new policies scenario projection for gas-fired electricity generation

	Unit	2010	2035
OECD	TWh	2544	3517
Share of OCED total	%	23	26
Average annual growth, 2010-35	%		1.3
Non-OECD	TWh	2216	4949
Share of non-OECD total	%	21	21
Average annual growth, 2010-35	%		3.3
World	TWh	4760	8466
Share of world total	%	22	23
Average annual growth, 2010-35	%		2.3

Note: Totals may not add due to rounding

Source: IEA 2012a and 2012

Global gas resources are sufficient to meet the projected increase in global demand, provided that the necessary investment in gas production and transport infrastructure is made. Production is expected to become more concentrated in the regions with large reserves, with more than one-fifth of the projected growth to come from the Middle East. Non-OECD economies are projected to account for more than 90 per cent of increases in world production between 2010 and 2035.

The share of gas produced from unconventional gas sources is projected to rise, from around 13 per cent in 2009 to nearly 22 per cent in 2035. A significant proportion of this increase is expected to come from the United States, where unconventional gas production has increased substantially in recent years. Output of unconventional production is also expected to increase in China, India, Australia and Europe, although the share of unconventional relative to conventional gas production in these regions remains small. The expected rise in unconventional gas sources has implications for prices and energy security, as well as energy trade.

Between 2009 and 2035, the world (inter-regional) gas trade is projected to increase by around 22 158 PJ (20.2 tcf) from around 15 522 PJ (14.1 tcf) in 2009. Around 58 per cent of this increase is projected to come from pipeline imports, with the remaining 42 per cent coming from LNG. Pipeline trade is expected to be supported by developments in central Asia (around the Caspian Sea) and the Russian Federation that will transport gas to Europe and China.

LNG trade is projected to increase by around 9263 PJ (176 Mt, 8.4 tcf) between 2009 and 2035 to around 18 632 PJ (354 Mt, 17 tcf; IEA 2012). LNG imports over the outlook period are expected to be underpinned by growth in China, India, Japan and the European Union, while increased exports will originate from Australia, Canada, the United States and, potentially, east Africa, the eastern Mediterranean and the Russian Federation.

Globally, around 84 Mt of additional LNG capacity is either committed or under construction (figure 4.12). Australia accounts for nearly two-thirds of this new capacity.

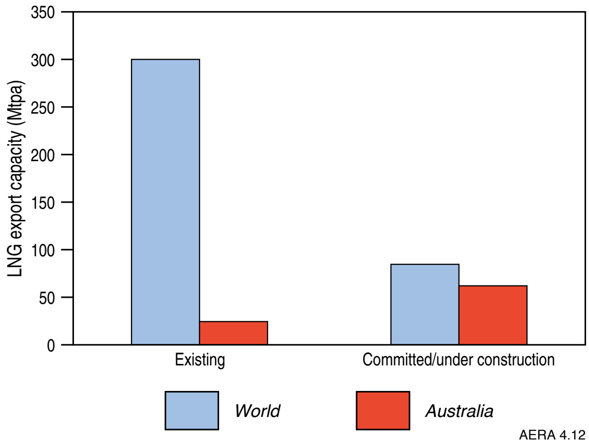


Figure 4.12 World LNG export capacity, existing and committed, as of 2011

LNG = liquefied natural gas

Source: BREE 2011b; IEA 2011c; IEA 2011d

4.3 Australia's gas resources and market

4.3.1 Conventional gas resources

Australia's identified conventional natural gas is a major energy resource, with significant potential for further discoveries. Box 4.3 provides an overview of the geology of Australia's major conventional gas fields.

Australia's conventional gas resources at the beginning of 2012 are presented in table 4.6 under the McKelvey classification of EDR and SDR (Geoscience Australia 2012). Australia has around 172 100 PJ (156 tcf) of demonstrated gas resources, most of which are considered as EDR. These resources are located across 15 basins, but the bulk of this resource (92 per cent) lies in the offshore basins along the north-west margin of Western Australia (figure 4.15), a geological region known as the North West Shelf (Purcell and Purcell 1988)–the Bonaparte, Browse and Carnarvon basins (table 4.7). Similarly, the bulk of this amount is in 10 super-giant fields, although more than 590 fields are included in the EDR and SDR compilation.

Table 4.6 Conventional gas resources, as of 1 January 2012

Conventional gas resources	PJ	tcf
Economic Demonstrated Resources	109 433	99
Sub-economic Demonstrated Resources	62 664	57
Inferred Resources	~11 000	~10
Total	183 097	166

Source: Geoscience Australia 2012

Table 4.7 McKelvey classification estimates by basin, as of 1 January 2012

McKelvey classification	Basin	Gas (PJ)	Gas (tcf)
EDR	Bonaparte	10 177	9
EDR	Browse	18 141	16
EDR	Carnarvon	71 410	65
EDR	Gippsland	6195	6
EDR	Other	3510	3
Total EDR		**109 433**	**99**
SDR	Bonaparte	13 828	13
SDR	Browse	19 674	18
SDR	Carnarvon	24 504	22
SDR	Gippsland	3058	3
SDR	Other	1601	1
Total SDR		**62 664**	**57**
Total (EDR + SDR)		**172 097**	**156**

EDR = Economic Demonstrated Resources; **SDR** = Sub-economic Demonstrated Resources

Note: For data quoted in PJ, rounding errors result in a small discrepancy between individual basin values and totals

Source: Geoscience Australia

In addition to these demonstrated Australian conventional gas resources (EDR and SDR), another 11 000 PJ (10 tcf) are estimated to be in the inferred category, arising from recent discoveries and previous finds that require further appraisal.

BOX 4.3 GEOLOGY OF AUSTRALIA'S MAJOR CONVENTIONAL GAS FIELDS

Australia's identified and potential gas resources occur within a large number of sedimentary basins (Boreham et al. 2001) that stretch across the continent and its vast marine jurisdiction. Identified conventional gas resources are predominantly located in offshore basins along the north-west margin. Much of the undeveloped resource and the undiscovered potential is in deep water (figures 4.30 and 4.31; see discussion below). The gas habitat includes:

- large fault block traps, Triassic to Jurassic sandstone reservoirs sealed by Cretaceous shales and sourced from Triassic coaly sediments (e.g. North Rankin, Gorgon)
- drape anticlines and structural/stratigraphic traps related to Late Jurassic and Early Cretaceous sand bodies (e.g. Io-Jansz, Scarborough; figure 4.30)
- low-relief anticlines with Permian sandstone reservoirs (e.g. Petrel; figure 4.31).

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

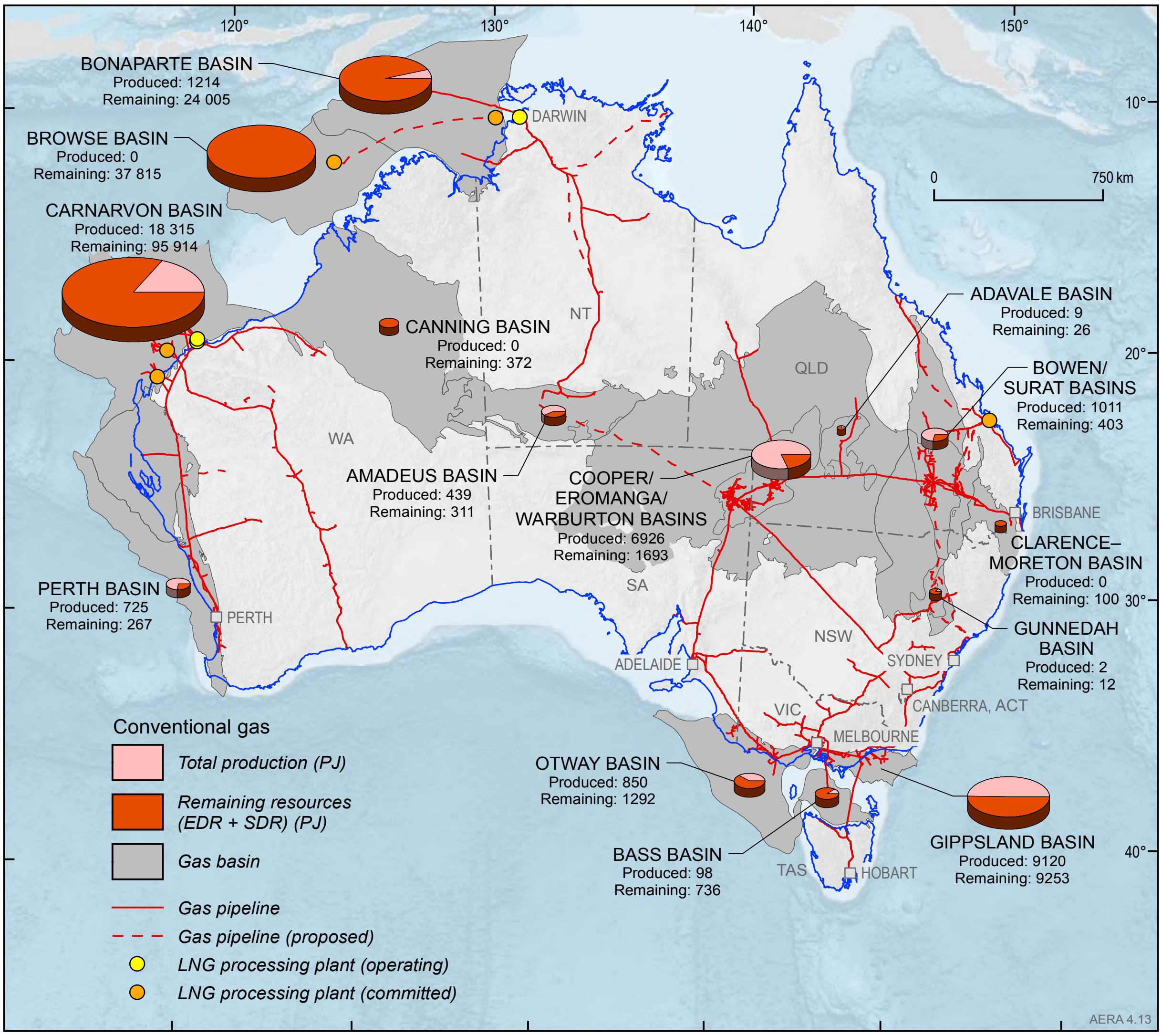


Figure 4.13 Australia's demonstrated conventional gas resources, proven gas basins and gas infrastructure

EDR = Economic Demonstrated Resources; **SDR** = Sub-economic Demonstrated Resources; **LNG** = liquefied natural gas

Source: Geoscience Australia

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

The offshore Gippsland Basin in south-eastern Australia still has significant reserves after more than 40 years of production, but onshore basins account for only around 2 per cent of Australia's remaining conventional resources (figure 4.13). Gas accumulations in the Gippsland, Bass and Otway basins in Bass Strait are trapped in some of Australia's youngest petroleum reservoirs (Late Cretaceous to Paleogene sandstones), while onshore are some of the oldest (Ordovician sandstones in the Amadeus Basin, Permian sandstones in the Cooper Basin). Boreham et al. (2001) provide a detailed discussion of the origin and distribution of Australia's conventional gas resources.

Development of some of the largest of the super-giant (>10 tcf) undeveloped fields in the basins off the northwest margin, the Io-Jansz, Gorgon and Ichthys fields (table 4.8), is under way, with the first gas from the Gorgon project expected in 2015.

Additions to Demonstrated Resources

Australia's identified conventional gas resources have grown substantially since the discovery of the super-giant and giant (>3 tcf) gas fields along the North West Shelf in the early 1970s. Gas EDR has increased more than four-fold over the past 30 years. Even so, many offshore gas discoveries have remained sub-economic until recently and are only now being considered for development. For example, the Ichthys field in the Browse Basin, which adds significantly to Australia's reserves of both gas and condensate

Table 4.8 Major gas fields: development status, as of October 2012

Field	Basin	Gas resources (tcf)	Condensate resources (mmbbl)	Total resources (PJ)	Status
Greater Gorgon (including Gorgon, Io–Jansz, Chrysaor, Dionysus, Tryal Rocks West, Spar, Orthrus, Maenad, Geryon and Urania)	Carnarvon	>40		>44 000	Under construction
Ichthys	Browse	12.8	527	17 179	Under construction
Woodside Browse project, including Torosa, Brecknock and Calliance	Browse	14	370	17 576	Undeveloped
Greater Sunrise (including Sunrise and Troubadour)	Bonaparte	5.13	226	6972	Undeveloped
Evans Shoal	Bonaparte	6.6	31	7442	Undeveloped
Scarborough	Carnarvon	5.2		5720	Undeveloped
Pluto (including Xena)	Carnarvon	5.05	72.6	5982	In production
Wheatstone	Carnarvon	4.5		4950	Under construction
Clio	Carnarvon	3.5		3850	Undeveloped
Chandon	Carnarvon	3.5		3850	Undeveloped
Prelude (including Concerto)	Browse	2.5	120	3456	Under construction
Thebe	Carnarvon	2.3		2200–3300	Undeveloped
Crux	Browse	1.8	66	2368	Undeveloped

Mmbbl = millions barrels

Source: Geoscience Australia

(12.8 tcf, 14066 PJ, 527 mmbbl), was determined to be uneconomic when first drilled in 1980, not least because of its remote location. The big increase in the gas EDR in 2008 (figure 4.14) is a result of the recategorisation of large accumulations, such as Ichthys, as an EDR.

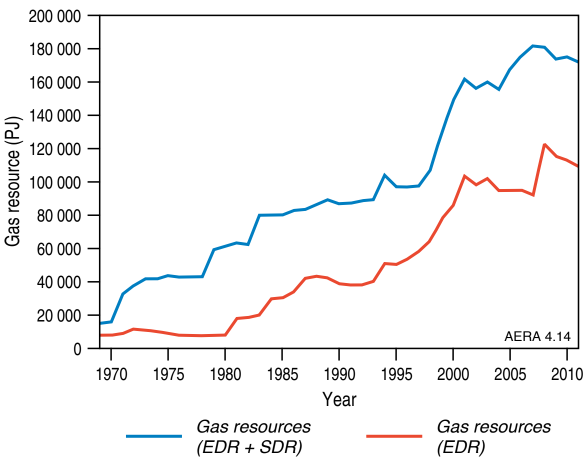


Figure 4.14 Australia's demonstrated conventional gas resources, 1969–2011

EDR = Economic Demonstrated Resources; **SDR** = Sub-economic Demonstrated Resources

Source: Geoscience Australia

Australia's conventional gas resources have mostly been discovered during the search for oil; this has occurred continuously but at irregular intervals (figure 4.15; Powell 2004). However, from the late 1990s there has been exploration aimed specifically at large gas fields in the deeper water areas of the Carnarvon Basin, which has met with considerable success, including the discovery of Io-Jansz in 2000, one of Australia's largest gas accumulations. In the past two years, drilling results have shifted the proven extent of gas discoveries in the Carnarvon Basin hundreds of kilometres to the west, out to the edge of the Exmouth Plateau. Currently active exploration programs in frontier basins may also add to resources of gas and/or oil—for example, the Ceduna and Duntrooon sub-basins of the Bight Basin on Australia's southern margin. The current upswing in onshore exploration for unconventional targets may also yield conventional oil and gas discoveries—for example, in the Canning and Officer basins.

Resource life

The gas resources to production ratio (R/P ratio) is a measure of the remaining years of production from current EDR at current production levels. Since production was established and stabilised in the mid-1970s, the R/P ratio for conventional gas has fluctuated between 20 and 80 years. Major discoveries in the 1980s and in the late 1990s and early 2000s (figure 4.15) have been sufficient to maintain an inventory of more than 40 years of production since the mid-1980s (figure 4.16), despite the establishment of the export LNG industry over this timeframe.

At current levels of production, Australia had 51 years of conventional gas remaining; this R/P ratio is set to decline as production approximately doubles with the commissioning of four new LNG projects along the north-west margin over the next few years.

Overall, the plot of gas discoveries by year against cumulative volume discovered shows a strong record of discovery and addition of new resources, with the cumulative volume of resources found climbing steadily over the past five years (figure 4.15).

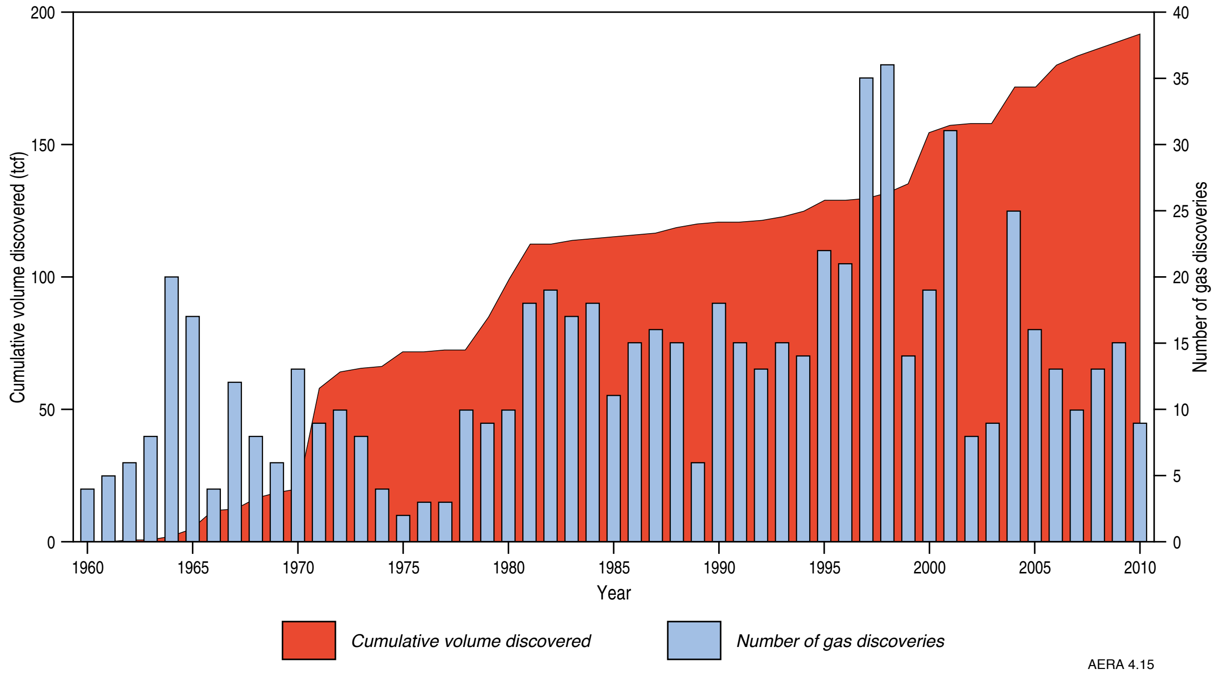


Figure 4.15 Gas volumes discovered and number of discoveries by year, 1960–2010

Source: Geoscience Australia

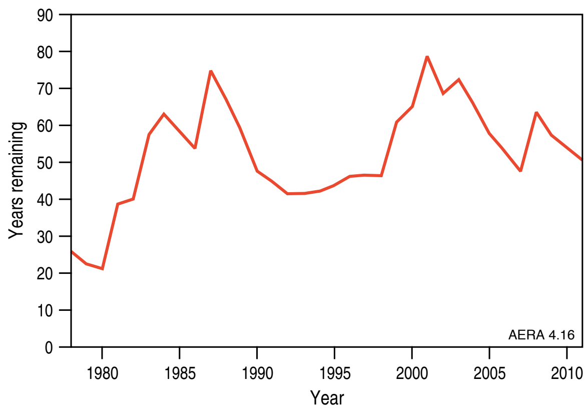


Figure 4.16 Conventional gas EDR to production ratio in years of remaining production, 1978–2011

EDR = Economic Demonstrated Resources

Source: Geoscience Australia

4.3.2 Coal seam gas (CSG) resources

Australia's identified CSG reserves have grown substantially in recent years. In 2012, the EDR of CSG in Australia was 35 905 PJ (33 tcf; table 4.9) and accounted for about 24 per cent of the total gas EDR. Reserve life is around 150 years at current rates of production. However, production is projected to increase substantially with the establishment of the CSG LNG industry. In addition to EDR, Australia has substantial SDR (65 529 PJ; 60 tcf; AEMO 2011; table 4.9) and very large inferred CSG resources. There are even larger estimates of in-ground potential CSG resources, potentially in excess of 258 888 PJ (235 tcf; table 4.10).

Table 4.9 CSG resources, as of 1 January 2012

Coal seam gas resources	PJ	tcf
Economic Demonstrated Resources	35 905	33
Sub-economic Demonstrated Resources	65 529	60
Inferred Resources	122 020	111
Total	223 454	203

Source: AEMO 2011; DEEDI 2011; DEEDI 2012; Geoscience Australia

Queensland has 33 001 PJ (92 per cent) of the reserves (DEEDI 2012), with the remaining 2904 PJ in New South Wales. Nearly all current reserves are contained in the Surat (69 per cent) and Bowen (23 per cent) basins, with small amounts in the Clarence-Moreton (1 per cent), Gunnedah (4 per cent), Gloucester and Sydney basins (figures 4.17 and 4.18). The CSG productive coal measures are of Permian (Bowen, Gunnedah, Sydney and Gloucester basins) and Jurassic (Walloon Coal Measures of the Surat and Clarence-Moreton basins) age, although the Permian coals are of higher rank, are more laterally continuous and have greater gas contents (Draper and Boreham 2006).

Over the past 5–10 years, CSG exploration has increased substantially in Queensland and New South Wales as a result of the successful development of CSG production in Queensland. The search has expanded beyond the high-rank Permian coals, encouraged by the success in producing CSG from low-rank coals in the United States. These successes have also stimulated exploration for CSG in South Australia, Tasmania, Victoria and Western Australia. Nonetheless, CSG exploration in Australia is still relatively immature. The current high levels of exploration have significantly increased known resources: in mid-2011, proved plus probable (2P) reserves were more than three times higher than in mid-2008 (figures 4.19 and 4.20).

During 2011–12, CSG activity in Queensland continued at record levels with about 735 CSG production and exploration wells drilled (DEEDI 2012). Exploration in Queensland continues to concentrate in the Bowen, Galilee and Surat basins; in New South Wales, exploration continues in the Sydney, Gunnedah, Gloucester and Clarence–Moreton basins. All except the Galilee Basin have 2P reserves. Other prospective basins include the Pedirka, Murray, Perth, Ipswich, Maryborough and Otway basins (figure 4.36).

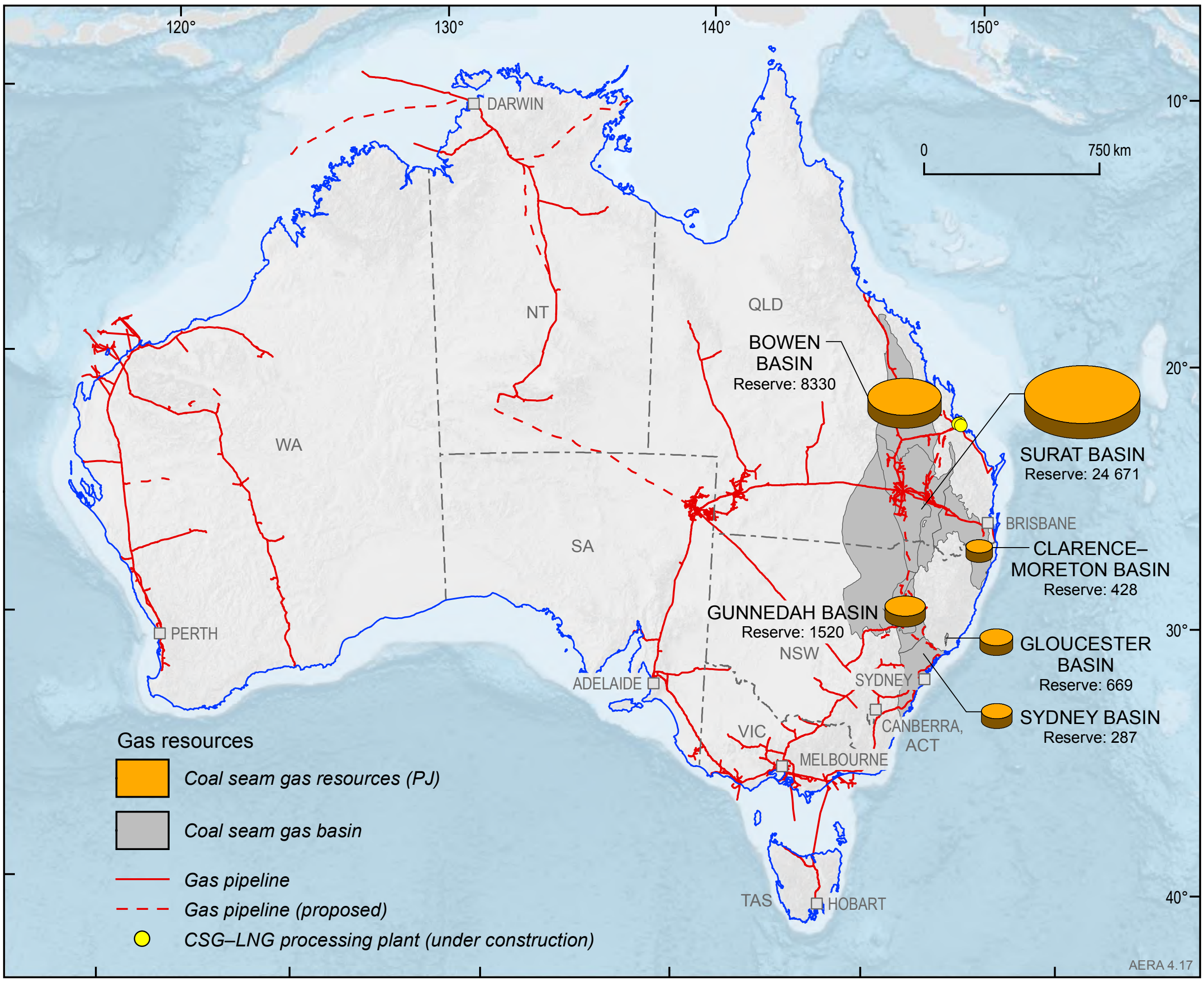


Figure 4.17 Location of Australia's coal seam gas reserves and gas infrastructure

LNG = liquefied natural gas; **CSG** = coal seam gas

Source: DEEDI 2012; Geoscience Australia

Table 4.10 Total Australia gas resources

Resource category	Conventional gas		Coal seam gas		Tight gas		Shale gas		Total gas	
	PJ	tcf	PJ	tcf	PJ	tcf	PJ	tcf	PJ	tcf
EDR	109 433	99	35 905	33			~3		145 341	132
SDR	62 664	57	65 529	60			2200	2	130 393	119
Inferred	~11 000	~10	122 020	111	22 052	20			155 072	141
All identified resources	183 097	166	223 454	203	22 052	20	2200	2	430 806	392
Estimates of potential resources—undiscovered, in ground and preliminary	249 700	227	258 888	235	Unknown	Unknown	480 700	437		

EDR = Economic Demonstrated Resources; **SDR** = Sub-economic Demonstrated Resources

Note: Conventional gas as of 1 January 2012; CSG as of January 2012; CSG 2P (proven plus probable)reserves and 2C (contingent) resources are used as proxies for EDR and SDR estimates respectively; shale gas estimates are Energy Information Administration estimates (EIA 2013)

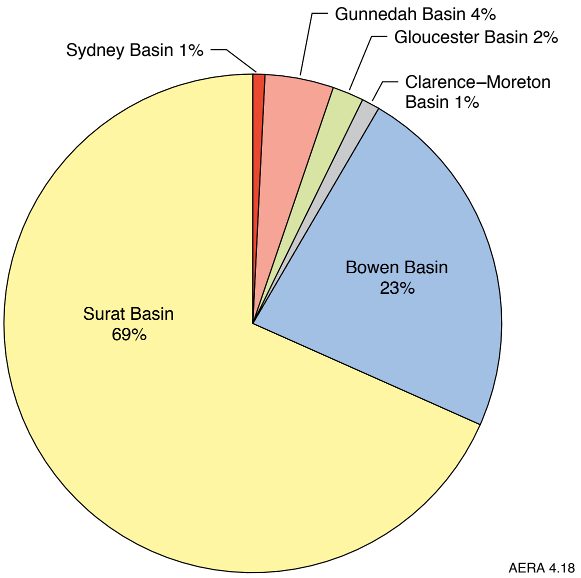


Figure 4.18 Coal seam gas 2P reserves by basin

Source: DEEDI 2012; Geoscience Australia.

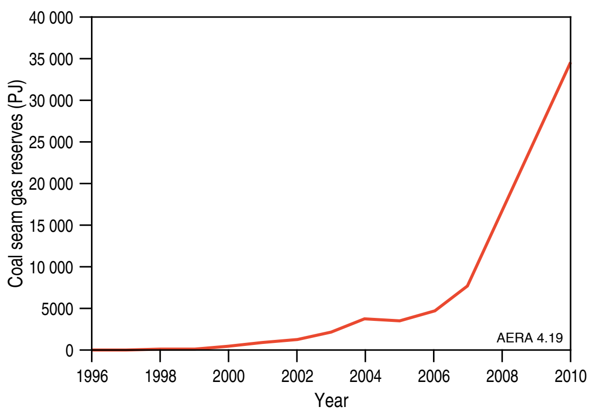


Figure 4.19 Coal seam gas 2P reserves since 1996

Source: AEMO 2011; DEEDI 2012; Geoscience Australia

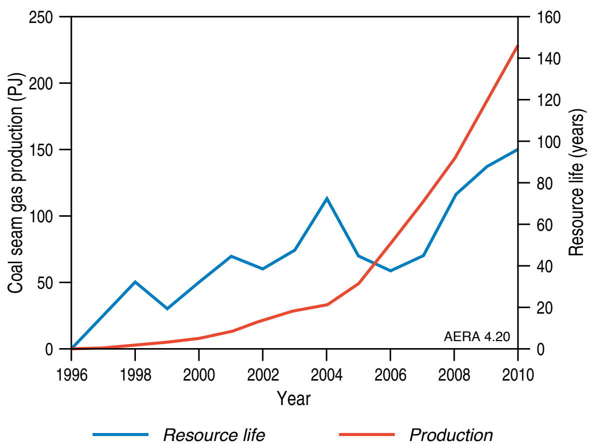


Figure 4.20 Coal seam gas EDR to production ratio since 1996

Source: APPEA 2011; AEMO 2011; DEEDI 2012; Geoscience Australia

4.3.3 Tight gas, shale gas and gas hydrates resources

Currently, Australia has no reserves of tight gas, but identified in-place resources of tight gas are estimated at around 22 052 PJ (20 tcf; table 4.10). The largest known resources of tight gas are in low-permeability sandstone reservoirs in the Perth, Cooper and Gippsland basins (figure 4.21). The Perth Basin is estimated to contain about 11 400 PJ (10 tcf) of tight gas, the Cooper Basin to contain about 8800 PJ (8 tcf) (Campbell 2009) and the Gippsland Basin to contain about 1853 PJ (2 tcf; Lakes Oil 2011).

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

Although shale gas exploration in Australia is still in its infancy, the amount of exploration activity has significantly increased in the past few years. The first vertical wells specifically targeting shale gas (Encounter 1 and Holdfast 1) were drilled in the Copper Basin by Beach Energy in early 2011, and significant exploration is now under way in the Paleozoic Canning Basin of Western Australia (figure 4.21). Paleozoic and Proterozoic shales within the Georgina, McArthur, Amadeus and Perth basins have also seen some exploration activity (figure 4.21). Cost-effective horizontal drilling and hydraulic fracturing techniques are enabling unconventional gas resources to be assessed.

Definition of shale gas resources is most advanced in the Cooper Basin, where Beach Energy reported the first contingent shale gas resources (2200 PJ, 2 tcf) in 2011; and in 2012 Santos booked the first shale gas reserves (2P ~3 PJ, 3 bcf) on the results of production from the Moomba 191 well. In contrast, there are very large estimates of potentially recoverable shale gas resources of about 480 700 PJ (437 tcf) reported by the EIA (2013) based on the assessment of six basins; and a value in excess of 1 100 000 PJ (1000 tcf) documented by Cook et al. (2013) that aggregates the estimates from 16 basins (table 4.10). However, given that these are based on limited data and little or no production history information, the initial estimates may decline with actual well performance data.

No definitive gas hydrates have been identified in Australian waters. The occurrence of gas hydrate was inferred from the presence of biogenic methane in sediments cored in the Timor Trough during the Deep Sea Drilling Program (DSDP 262) (McKirdy and Cook 1980), but to date none have been recovered around Australia.

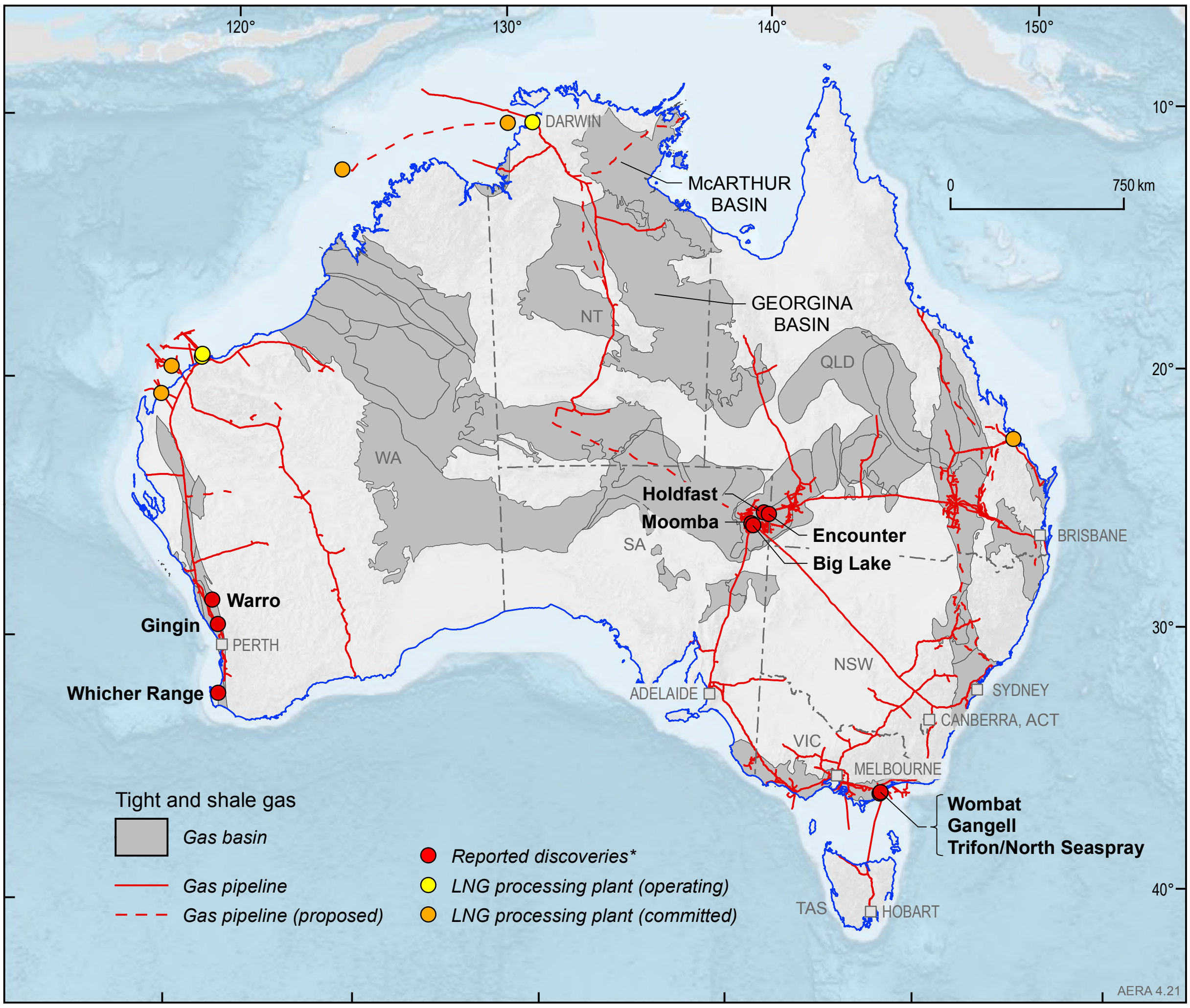


Figure 4.21 Tight gas and shale gas resource locations and gas infrastructure

LNG = liquefied natural gas
Note: * shows the locations of all shale and tight gas discoveries with reported contingent resources.
Source: Geoscience Australia

4.3.4 Total gas resources

Australia has large and growing gas resources. CSG EDR values are now approximately a third of the conventional gas EDR. However, the total identified resources for CSG are significantly larger than the EDR and now surpass estimates of total identified conventional gas (table 4.10). The potential in-ground CSG resource is more than double the demonstrated resources (table 4.10, figure 4.22). Australia's combined identified gas resource is in the order of 430 806 PJ (392 tcf; table 4.10), equal to around 184 years at current production rates. However, production from conventional gas and CSG is projected to increase substantially.

The gas resource pyramid (figure 4.22) depicts these various types of gas resource. A smaller volume of conventional gas and CSG identified reserves are underpinned by larger volumes of inferred and potential unconventional gas resources. The estimated undiscovered conventional gas resources of varying uncertainties can also be mapped to the resource pyramid.

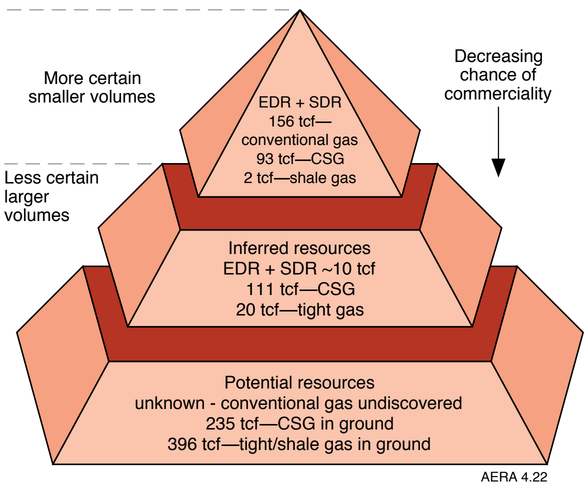


Figure 4.22 Australian gas resource pyramid

EDR = Economic Demonstrated Resources; **SDR** = Sub-economic Demonstrated Resources; **CSG** = coal seam gas

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

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

4.3.5 Gas market

Conventional gas production

Conventional gas production has increased strongly over the past 20 years (figure 4.23), with a major contributor being the North West Shelf LNG project in the Carnarvon Basin. In 2011–12, conventional gas production was about 2200 PJ (2 tcf) that came from nine producing basins, with the Carnarvon Basin dominating (table 4.11). Next ranked is the Gippsland Basin, followed by the Bonaparte Basin. Statistical reporting issues of gas production are explained in box 4.4.

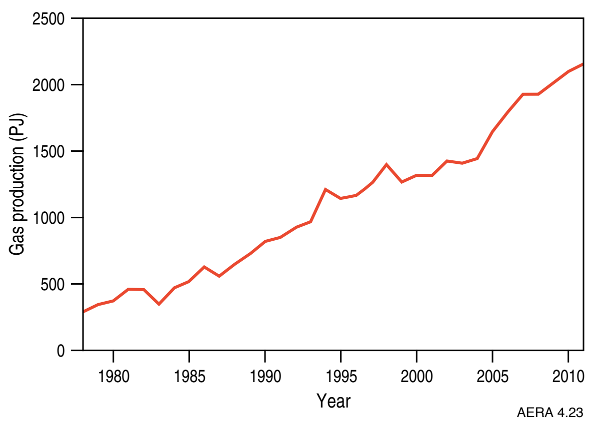


Figure 4.23 Conventional gas production, 1978–2011

Source: Geoscience Australia

Gas production as shown in table 4.11 includes production from Bayu—Undan, a giant field located in the Bonaparte Basin, some 500 km north-west of Darwin in the Timor Sea Joint Petroleum Development Area (JPDA), which is shared by Australia and Timor-Leste. Geoscience Australia production and reserve data for Bayu—Undan include all production and reserves, although Australia has only a 10 per cent share of royalties from the JPDA.

Australia's past conventional gas production has been overwhelmingly from the Carnarvon, Cooper and Gippsland basins, with smaller contributions from the Perth, Bonaparte, Bowen, Amadeus, Otway, Surat and Adavale basins (table 4.11). Conventional gas production from the Cooper Basin has been in decline, however, and currently 86 per cent of production is from the three main offshore basins (Carnarvon, Gippsland and Bonaparte basins). About 62 per cent of production is from the Carnarvon Basin, which contains the giant Goodwyn, North Rankin and Perseus accumulations that form part of the North West Shelf Venture Project. In 2012, there was also production from the Perth, Bowen, Surat and Otway Basins. In the Amadeus Basin, there was minor production—mostly solution gas associated with oil production at the Mereenie field, with the gas being reprocessed and reinjected into the main oil production reservoir to assist in maintaining pressure (Department of Mines and Energy, Minerals and Energy Group 2012). Gas production from a single field in the Adavale Basin, Gilmore, ceased in 2002. Conventional gas production in all basins, other than the Carnarvon and Bonaparte basins, is directed solely to domestic consumption.

There are a number of LNG projects completed to 2012 (see table 4.12). Australia's LNG export capacity is expected to increase to more than 86 Mt per year by 2017.

Table 4.11 Australian conventional gas production by basin for 2011 and cumulative production

Basin	2011 (PJ)	Total (PJ)
Carnarvon	1327	18 315
Gippsland	329	9120
Bonaparte	194	1214
Cooper-Eromanga	137	6926
Otway	115	850
Bowen-Surat	22	1011
Bass	20	98
Amadeus	7	439
Perth	6	725
Adavale	0	9
Gunnedah	0	2
Total	**2158**	**38 711**

Note: Includes imports from JPDA

Source: Geoscience Australia 2012

BOX 4.4 STATISTICAL REPORTING ISSUES

Historical gas production data presented in this *Australian energy resource assessment* are from two sources. Figures that illustrate the historical balance of production, consumption and trade are derived from the Australian Energy Statistics (AES) (BREE 2013a). Production in these figures refers to sales gas, which has been processed to remove impurities to a required standard for consumer use. Figures that illustrate changes in historical production and reserves are derived from Geoscience Australia sources. Geoscience Australia production data generally refer to total produced gas.

The treatment of gas resources and production in the Joint Petroleum Development Area (JPDA) also differs between sources. The AES accounts for gas production in the JPDA as an import. LNG produced in Darwin from this gas is then exported. Geoscience Australia includes the JPDA in the resources and production totals.

Unconventional gas production

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

Australia's annual CSG production has increased from 1 PJ in 1996 to 296 PJ (0.2 tcf) in 2011–12, and accounts for about 13 per cent of Australia's total gas production (figure 4.24). In the five years from mid-2006 to mid-2011, production has more than tripled (table 4.13). Of the 2011–12 production of CSG, Queensland produced 289 PJ (0.2 tcf; 97 per cent), and New South Wales produced the remainder (6 PJ; BREE 2013).

Gas is not currently produced from any specifically described tight gas field in Australia. However, some of the gas production from the Cooper and Amadeus basins are from low-porosity reservoirs. There are also several planned projects for commercial production of tight gas fields, notably in the Perth Basin in Western Australia. The first commercial shale gas production was announced by Santos in late 2012 with the connection of the Moomba 191 well to the Cooper Basin pipeline network.

Total gas consumption

Gas is the third largest contributor to Australia's primary energy consumption after coal and oil. In 2011–12, gas accounted for 23 per cent of Australia's total energy consumption. Australia's primary gas consumption increased from 74 PJ (0.1 tcf) in 1970–71 to 1400 PJ (1.3 tcf) in 2011–12—an average rate of growth of 6 per cent per year (figure 4.25). The robust growth in gas consumption over this period is due primarily to sustained population growth and strong economic growth, as well as government policies to support its uptake.

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

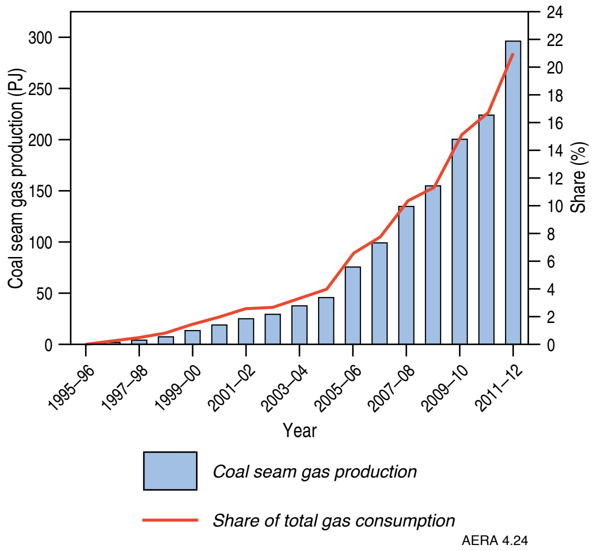


Figure 4.24 Australian coal seam gas production and share of total gas consumption

Source: BREE 2013; BREE 2012b

Table 4.12 Conventional gas projects completed, to 2012

Project	Company	Basin	Start-up	Capacity (PJ per year)
Bassgas	Origin	Bass	2006	20
Casino	Santos	Otway	2006	33
Otway	Woodside	Otway	2007	60
Angel	Woodside	Carnarvon	2008	310
Blacktip	ENI Australia	Bonaparte	2009	44
Henry	Santos/AWE/Mitsui	Otway	2010	11
Longtom	Nexus Energy	Gippsland	2010	25
Halyard	Apache Energy/Santos	Carnarvon	2011	18
Reindeer/Devil Creek	Apache Energy/Santos	Carnarvon	2012	78
Pluto	Woodside	Carnarvon	2012	–

Source: BREE 2013b

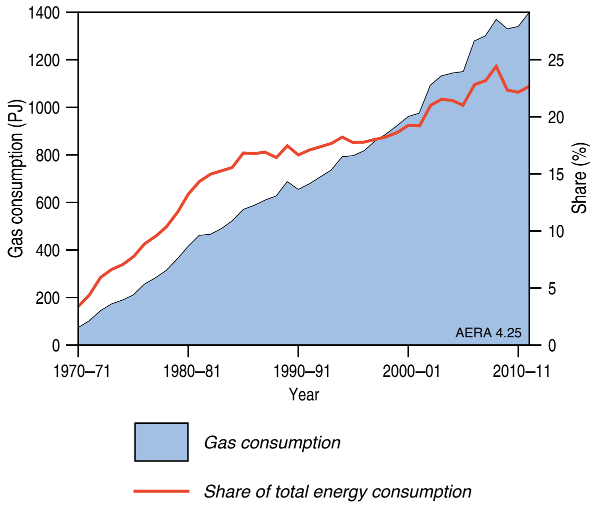


Figure 4.25 Australian gas consumption and share of total primary energy consumption

Source: BREE 2013a

The share of gas-fired electricity has increased in recent years. Gas accounted for an estimated 19 per cent of electricity generation in 2011–12 (BREE 2012d). The mining sector is also a large consumer of natural gas in the process of creating LNG. The residential sector is characterised by a large number of small-scale consumers. The major residential uses of gas include water heating, space heating and cooking.

Gas trade

Up to 1989, Australia consumed all of the natural gas that was produced domestically. Following the development of the North West Shelf Venture, gas, in the form of LNG, was exported to overseas markets. Around half of Australia's gas production is now exported. In 2011–12, the volume of LNG exports was estimated to be about 1000 PJ (19 Mt, 1.0 tcf), valued at approximately $12 billion (BREE 2012b).

Japan is Australia's major export market for LNG, followed by China and the Republic of Korea (figure 4.26). In 2010, Japan accounted for around 70 per cent of Australia's LNG exports, followed by China (21 per cent) and the Republic of Korea (5 per cent) (BP 2011). In contrast, Australia accounts for 19 per cent of Japan's LNG total imports and 41 per cent of China's LNG imports (BP 2011). The 2012 data (BP 2013) reflected some changes to this pattern, with LNG imports to Japan representing 78 per cent of Australia's output, while Australian cargoes contributed about 24 per cent and Qatar 34 per cent of China's growing LNG imports.

LNG projects are under construction in Queensland, and the first of these is expected to start exporting CSG LNG from 2014–15. Increased international demand for LNG, together with rapidly expanding CSG reserves in Queensland, have enabled the development of LNG export facilities in eastern Australia. As of October 2013, there are three CSG-sourced projects currently under construction, which will have a combined capacity of 25.3 Mt per year (1095 PJ, 1.0 tcf).

Gas supply—demand balance

The supply—demand balance presented in figure 4.27 incorporates production, domestic consumption and trade (exports). It highlights steady growth in domestic consumption, the increase in production associated with LNG exports and the emerging impact of CSG. Figure 4.28 shows Australia's gas facilities.

Table 4.13 Coal seam gas projects completed, to 2012

Project	Company	Location	Start-up	Capacity (PJ per year)	Capital expenditure (A$ million)
Berwyndale South CSM	Queensland Gas Company	Roma, QLD	2006	na	52
Argyle	Queensland Gas Company	Roma, QLD	2007	7.4	100
Spring Gully CSM (phase 4)	Origin Energy	Roma, QLD	2007	15	114
Tipton West CSM	Arrow Energy/Beach Petroleum/Australian Pipeline Trust	Dalby, QLD	2007	10	119
Darling Downs development	APLNG (Origin/ ConocoPhillips)	North of Roma, QLD	2009	44 (includes wells from Talinga)	500
Talinga (stage 2)	APLNG (Origin/ ConocoPhillips)	160 km east of Roma, QLD	2010	33	260

CSM = coal seam methane

Source: BREE 2013b

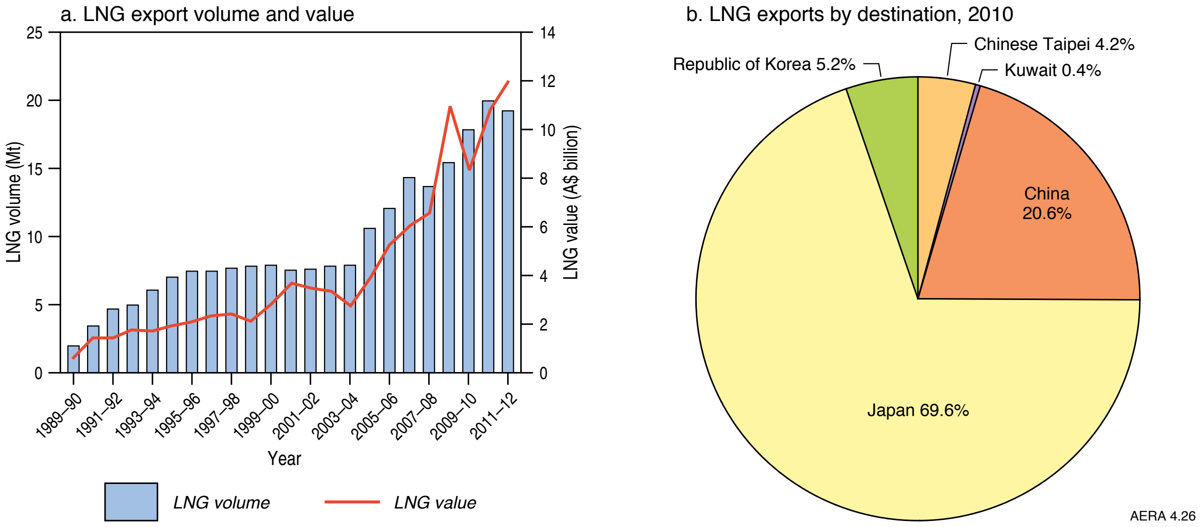


Figure 4.26 Australian LNG exports

LNG = liquefied natural gas

Source: BREE; BP 2011

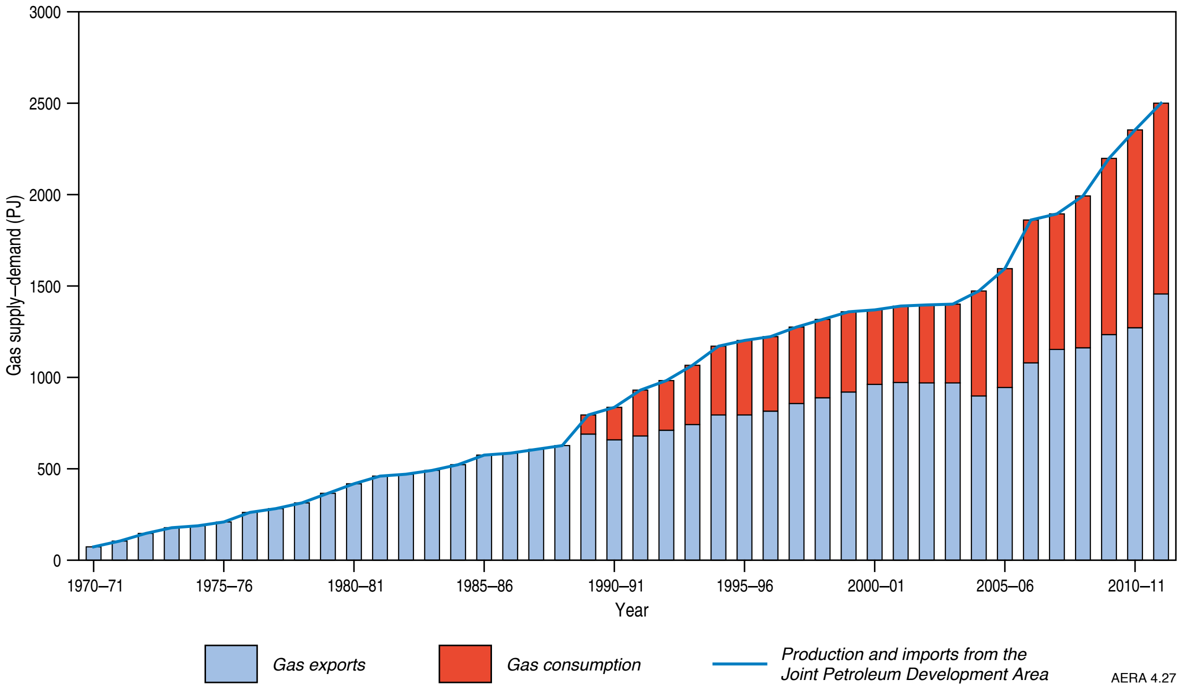


Figure 4.27 Australia's gas supply–demand balance

Note: Adjusted for stock changes and statistical discrepancy

Source: BREE

Regional gas markets

The Australian domestic gas market consists of three distinct regional markets: the eastern market (Queensland, New South Wales, Australian Capital Territory, Victoria, South Australia and Tasmania), the western market (Western Australia) and the northern market (Northern Territory) (figure 4.29). These markets are geographically isolated from one another, making transmission and distribution of gas between markets uneconomic at present. As a result, all gas production is either consumed within each market or exported as LNG.

The eastern gas market accounted for around a third of Australia's gas production in 2011–12 (BREE 2013). It is the only region where CSG supplements conventional gas supplies (mainly in Queensland) and accounts for more than quarter of total gas production in the region (BREE 2013). This market is the largest consumer of natural gas in Australia and represented around 54 per cent of Australian gas consumption in 2011–12 (BREE 2013). Over the period 1970–71 to 2009–10, consumption in the region increased at an annual average rate of 6.1 per cent, largely driven by growth

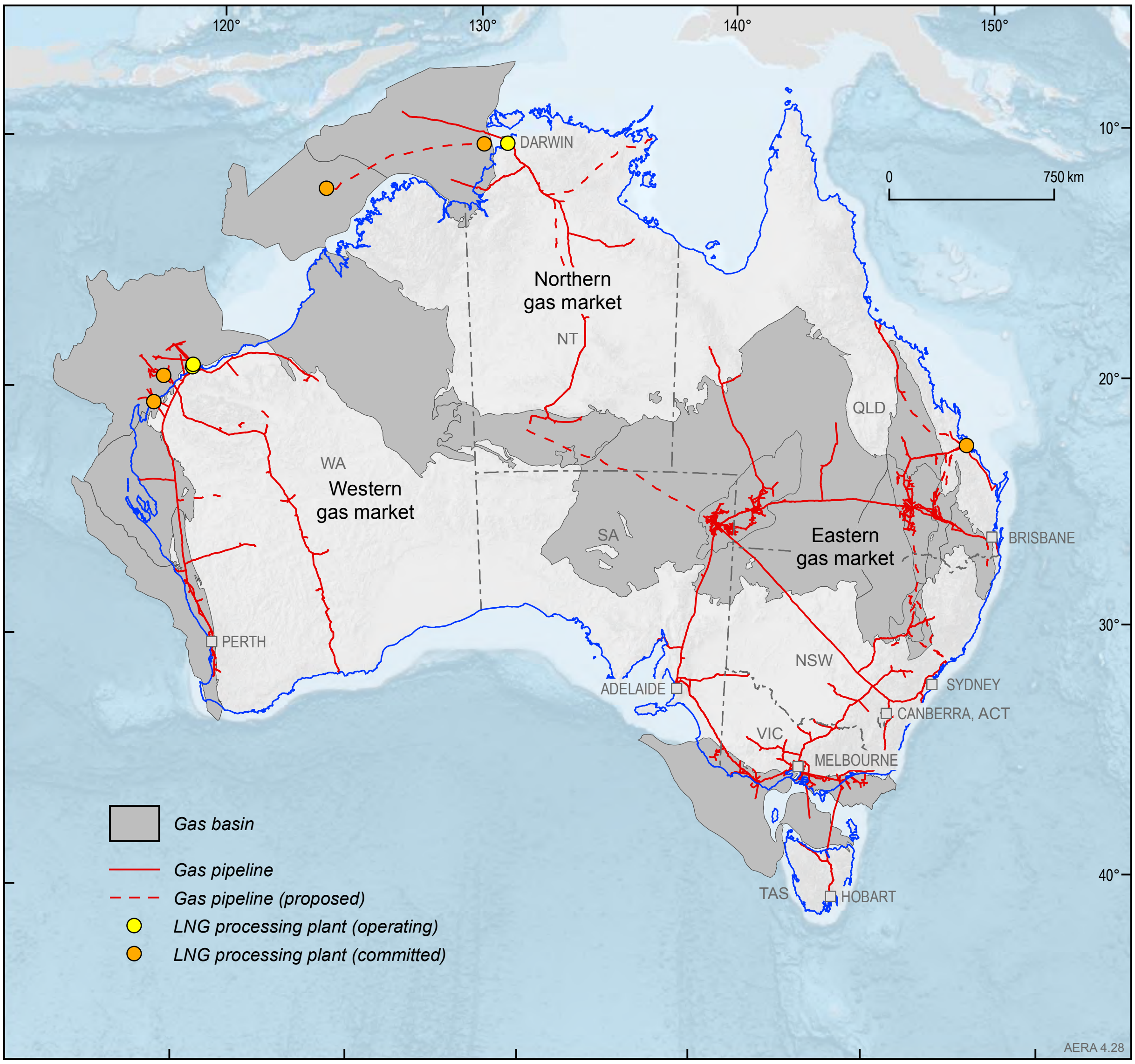


Figure 4.28 Australia's gas facilities

LNG = liquefied natural gas

Source: Geoscience Australia

in the consumption of the electricity generation and manufacturing sectors (BREE 2013). Since 1970–71, the Eastern gas market has consumed all of the gas produced in the region (figure 4.29, panel a). From 2014–15, the eastern market is expected to export gas following the start-up of LNG facilities in Queensland.

The western gas market accounted for around 68 per cent of Australia's gas production in 2011–12 (figure 4.29). The region is also a large consumer of gas, accounting for around 35 per cent of Australia's gas consumption. The mining sector is the largest consumer of gas in the western market, followed by the manufacturing sector and electricity generation sector. From 1989–90, the western gas market produced significantly more gas than it consumed (figure 4.29, panel b), following the development of the North West Shelf Venture and the establishment of long-term export LNG contracts.

The northern gas market is the smallest producer and consumer of gas in Australia, accounting for 9 per cent of Australian gas production and 4 per cent of Australian gas consumption in 2010–11 (figure 4.29; BREE 2013). Production began in the northern gas market in the early 1980s with the development of the onshore Amadeus Basin. In 2005–06, production in the region increased substantially with the development of the Bayu–Undan field in the offshore Bonaparte Basin. Mining and electricity generation account for the vast majority of gas use in the northern gas market. Until 2005–06, all of the gas produced in the region was consumed locally. Following the development of the Darwin LNG plant, gas has also been exported as LNG (figure 4.29, panel c). In September 2009, the offshore Blacktip gas field in the Petrel Sub-basin of the Bonaparte Basin came on stream. Gas from this field is piped onshore to a processing plant at Wadeye and then to the Amadeus Basin-Darwin pipeline.

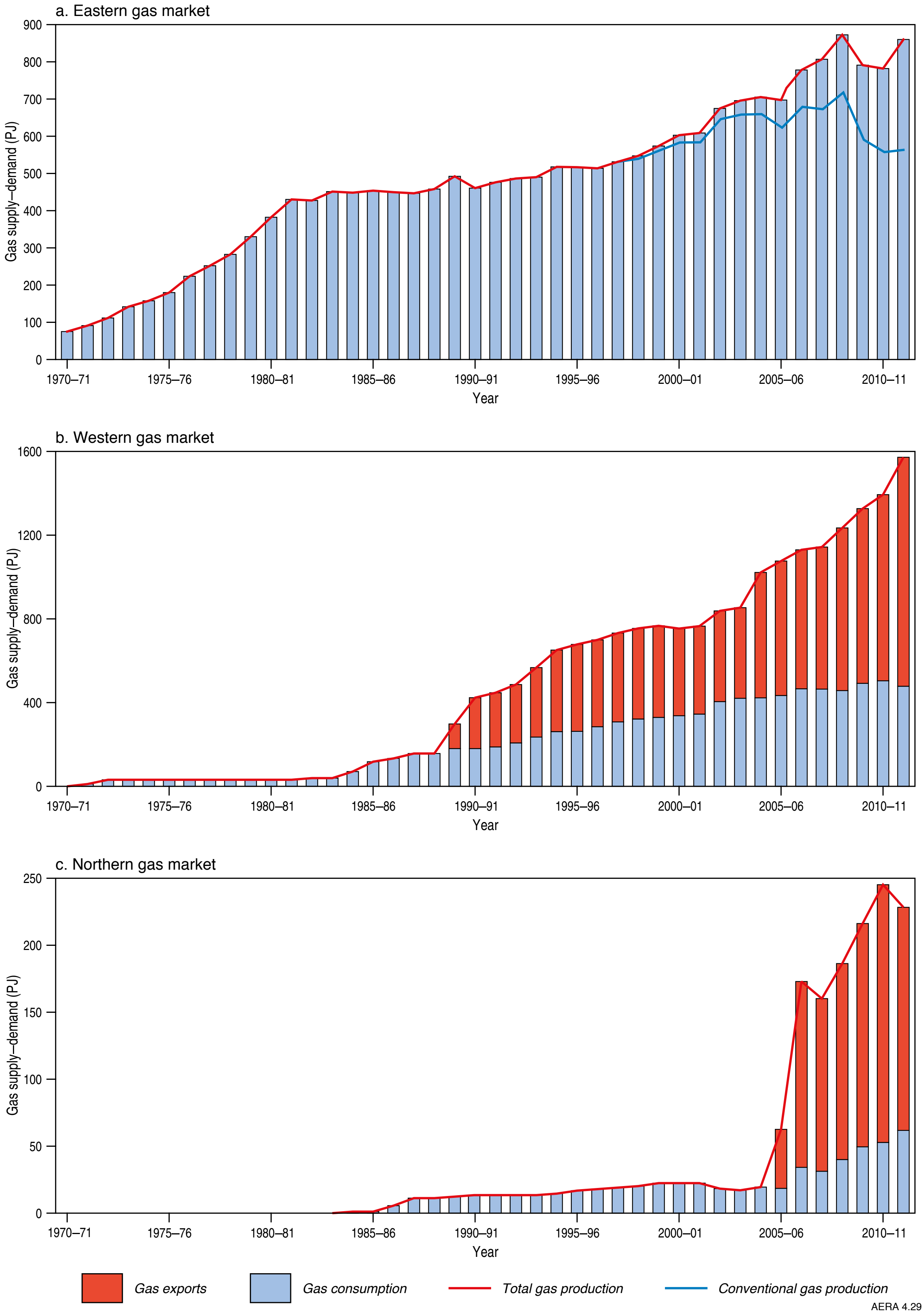


Figure 4.29 Regional gas market supply–demand balances

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

Source: ABARES 2011; BREE 2013a

4.4. Outlook for Australia's resources and market

There is expected to be continued growth in the use of gas in the Australian economy, as well as increased LNG exports. Australia's existing resources are sufficient to meet expected increases in domestic and export demand over the next few decades. There is also scope for Australia's resources to expand further, with major new discoveries of conventional gas in offshore basins, the re-evaluation of the large CSG potential resources that may result in reclassification into the EDR category, and the appraisal and development of tight and shale gas resources.

4.4.1 Key factors influencing the outlook

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

Gas prices

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

For the domestic market, Australia has historically provided some of the lowest cost gas in the world. These low gas prices are generally the result of mature long-term contracts for output from the Cooper and Gippsland basins and the North West Shelf fields.

Australian gas prices have historically been relatively stable (table 4.14) because of provisions in long-term contracts that include a defined base price that is periodically adjusted to reflect changes in an index such as the consumer price index (CPI). In addition, prices have been capped by the price of coal (a major competitor for use in electricity generation).

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

- the expiration of mature long-term contracts
- increasing domestic consumption and export demand through the development of additional LNG facilities
- sustained pressure on exploration and development costs, which has increased the cost of development
- the development of higher cost sources of gas (e.g. CSG and deep offshore fields)
- high oil prices that have flowed through to Australian LNG contracts and accentuated the gap between domestic and international (netback) prices. This has encouraged companies to put their efforts into developing projects destined for export rather than domestic demand
- increasing network charges to reflect rising capital and operating costs of transmission and distribution.

Wholesale gas trading occurs through private negotiations between buyers and sellers. The terms, quantities and prices are confidential and can vary significantly across contracts. Typically, these contracts contain take-or-pay components, where shippers agree to pay for a specified quantity of gas, regardless of whether they are able to on-sell it.

Given the commercial nature of the contract negotiations between suppliers and consumers, there is very little publicly available contract price data. However, gas spot markets are a recent and valuable addition to Australia's gas market framework, especially in terms of the price information that they provide. Spot markets exist in the Victorian Wholesale Gas Market (VWGM) and Short Term Trading Market (STTM) hubs in Adelaide, Sydney and Brisbane. Although these gas markets allow supply or demand balances to be traded, the majority of gas is still negotiated through contractual arrangements,

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

Table 4.14 Australian gas prices (2011-12 dollars)

	2000–01	2001–02	2002–03	2003–04	2004–05	2005–06	2006–07	2007–08	2008–09	2009–10	2010–11	2011–12
Natural gas (A$ per GJ)	3.56	3.55	3.63	3.70	3.67	3.59	4.17	4.19	3.58	2.14	2.48	3.13
LNG (A$ per tonne)	481.9	454.0	426.8	343.9	369.1	434.6	419.2	476.2	705.7	459.7	534.9	623.5
LNG (A$ per GJ)	8.9	8.3	7.8	6.3	6.8	8.0	7.7	8.8	13.0	8.4	9.8	11.5

LNG = liquefied natural gas
Note: Natural gas price is a financial year average of daily sport prices in the Victorian gas market; LNG price is an export unit value.

Source: Bureau of Resources and Energy Economics

There have been three reasonably distinct global gas markets for LNG, each with its own pricing structure. In the United States, pipeline natural gas prices have been used as the basis for determining the competitiveness of LNG imports. Gas prices are generally traded against the Henry Hub price. In Europe, LNG prices are set against different sources of gas supply (indigenous production and pipeline imports from the Russian Federation) and against other fuels such as low-sulphur residual fuel oil and coal. In the Asia–Pacific region, Japanese crude oil prices have historically been used as the basis for setting the price of LNG under long-term contracts. Asian prices are generally higher than prices elsewhere in the world.

Over the longer term, LNG prices in the Asia–Pacific region are expected to remain linked to oil prices. Many of the sales and purchase agreements that have been recently signed are due to expire beyond 2030 and were negotiated on the basis of oil linked prices. Unless these contracts can be renegotiated, oil prices will remain a price setter for gas in the Asia–Pacific region. However, the emergence of LNG exports from the United States to Asia may result in some LNG imports being set by alternative mechanisms such as the Henry Hub price in the United States plus processing and delivery costs.

Exports of Australian LNG from the eastern market are scheduled to start in 2014 and are projected to reach 25 Mt (1332 PJ, 1.2 tcf) by the end of the decade. Once operational, CSG LNG projects will connect Australia's eastern market to the Asia – Pacific market. These projects will increase the demand for domestically produced gas and are likely to put upward pressure on domestic prices. Over time, it is expected that domestic prices will converge to the netback price of LNG—the market price received for LNG less the transport, marketing and liquefaction costs.

Resource characteristics

The decision to develop a gas field also depends on its characteristics. They include its size, location and distance from markets and infrastructure; its depth subsurface and its water depth, in the case of offshore fields; and the quality of the gas, such as CO_2 content and presence of natural gas liquids. Table 4.15 lists these characteristics for a number of Australian conventional gas fields.

Resource characteristics influencing the development of unconventional gas resources partly diverge from those relevant to conventional gas fields. Location and size of accumulation remain important, but reservoir performance is crucial and can only be definitively determined by production testing. There are no associated hydrocarbon liquids with CSG, although gas liquids associated with shale gas can enhance the value of these resources. As all current identified unconventional resources in Australia are onshore, distance to market and infrastructure are key location factors.

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

Location and depth

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

Table 4.15 Resource characteristics of selected Australian conventional gas fields

Basin/ Discovery date	Field	Initial recoverable volumes			CO_2 (%)	Water depth (m)	Distance to landfall (km)	Status
		Gas (tcf)	Liquids (mmbbl)	Total (PJ)				
Carnarvon								
1971	North Rankin	12.28	203	~14 700	<5	122	130	Export LNG 1989
1980	Gorgon	17.2	121	~19 630	>10	259	120	Construction, LNG 2015
1980	Scarborough	5.2	0	~5720	<5	923	310	Undeveloped
2006	Pluto	5.05	0	~5060	<5	900	190	Production, LNG 2012
1993	East Spar	0.25	14	~360	<5	98	100	Domestic production 1996
Browse								
1980	Ichthys	12.8	527	~17 180	>5	256	220	Construction LNG 2016
1971	Torosa	11.4	121	~13 250	>5	50	280	FEED

LNG = liquefied natural gas; **FEED** = front end engineering design

Source: Geoscience Australia

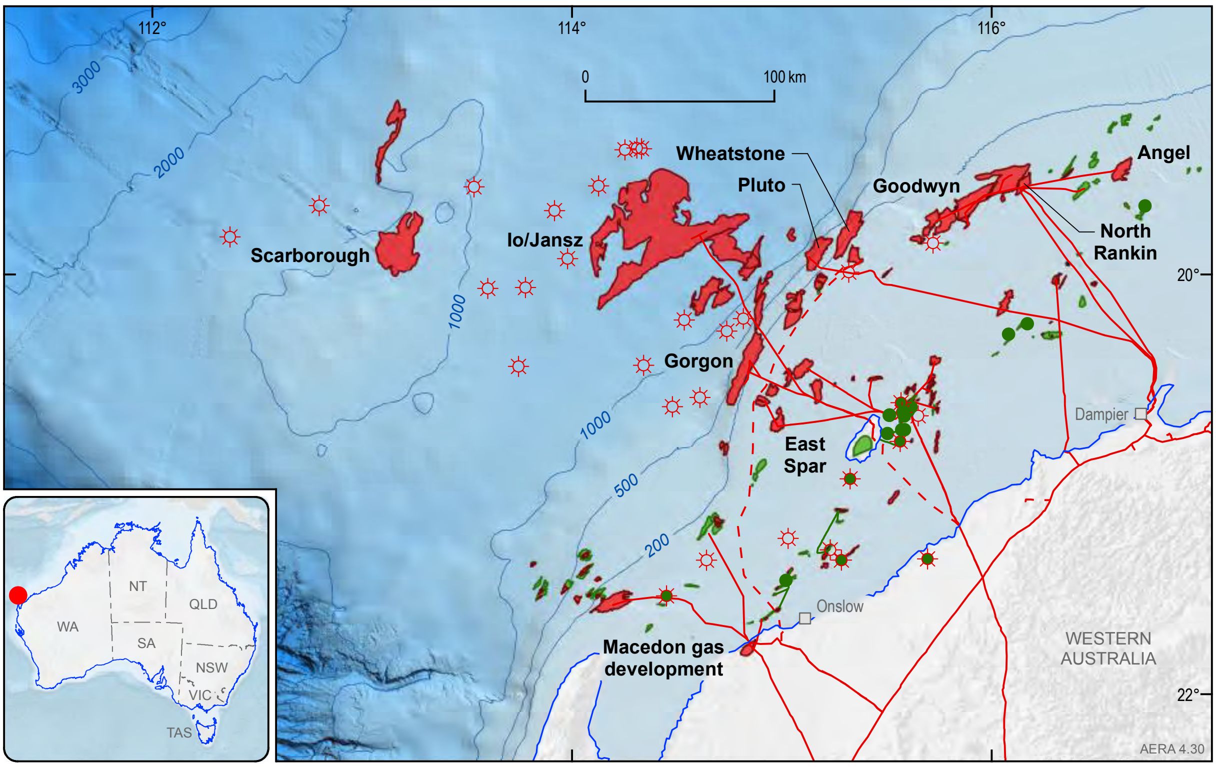
The Australian gas industry is moving away from the development of fields in shallow water (Gippsland Basin) and near shore (Carnarvon Basin) that have a low marginal cost to fields in deeper water that have higher marginal costs.

For decades, the Goodwyn gas field, in the Carnarvon Basin, in 125 m of water has been Australia's deepest producing gas field, but with Pluto (the field in 400–1000 m of water and the platform in 85 m), which began production in April 2012, there has been a step change in access to deepwater gas resources (figure 4.30). The Ichthys and Gorgon projects are developing gas resources in water depths of several hundred metres or more (figure 4.31; table 4.15), and gas exploration on the Exmouth Plateau routinely targets prospects in water depths beyond 1000 m (Walker 2007), including Cadwallon 1, which was drilled in more than 2000 m of water in 2011. A number of large gas accumulations in deep water remain to be developed (e.g. Scarborough), whereas smaller accumulations in shallower water have been developed (figure 4.30).

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

Co-location with other resources

A resource that contains only gas can be left undeveloped until market conditions warrant its development. However, gas that is rich in condensate or associated with oil will become available when the liquid resource is produced, and must be sold (piped), flared or reinjected to maintain reservoir pressure. Depending on the nature of the reservoir, up to 80 per cent of reinjected gas can be recovered once oil production or condensate stripping has ceased (Banks 2000). Around 94 per cent of operating fields producing conventional gas in Australia also produce oil or condensate, or both. When oil, gas, LPG and condensate are produced jointly, the cost of production is shared, and the cost of each product is not distinguishable. This can result in greater returns on the sale of valuable by-products and can speed development of the gas accumulation, as for example at the East Spar and Ichthys projects (table 4.15).

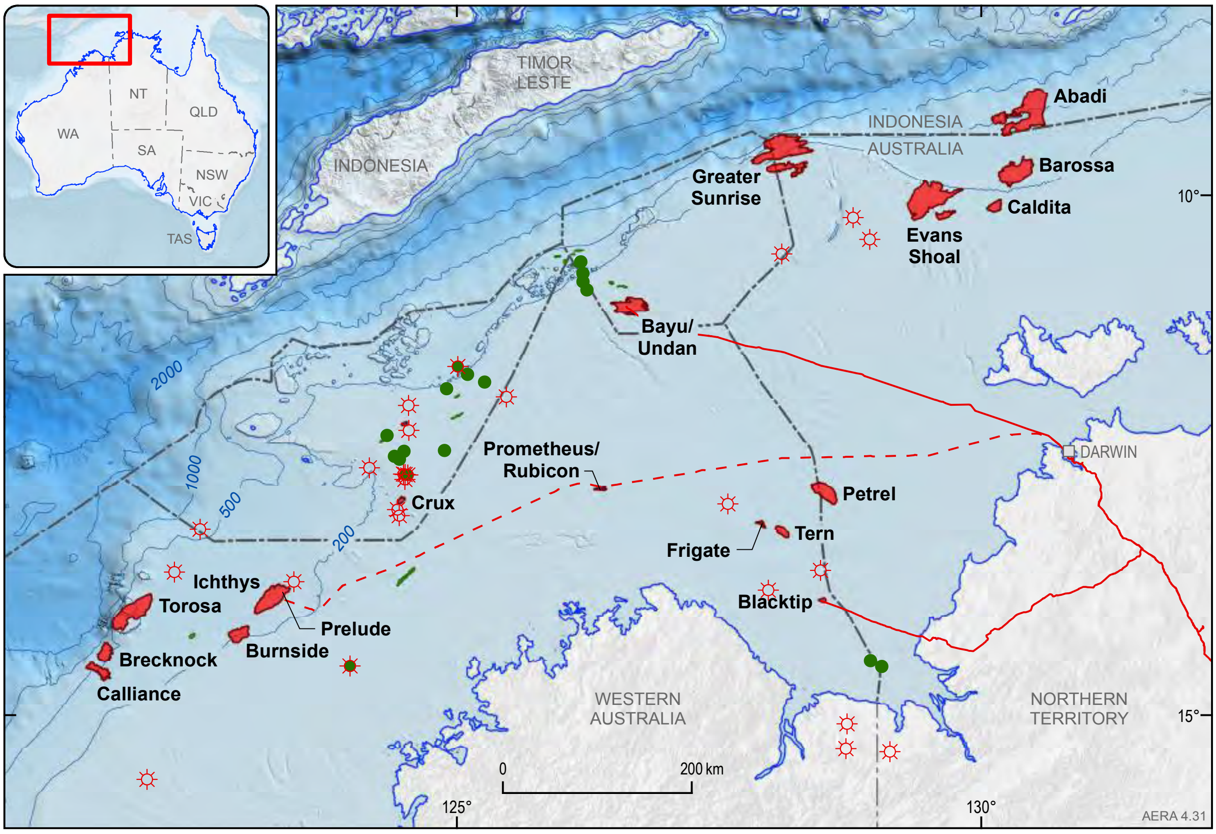


Pipelines and field outlines are provided by Encom GPinfo, a Pitney Bowes Software (PBS) Pty Ltd product. Whilst all care is taken in the compilation of the field outlines by PBS, no warranty is provided re the accuracy or completeness of the information, and it is the responsibility of the Customer to ensure, by independent means, that those parts of the information used by it are correct before any reliance is placed on them.

Oil field | *Gas field* | *Gas pipeline* | *Gas pipeline (proposed)* | *200 Bathymetry contour (depth in metres)* | *Gas discovery* | *Oil discovery* | *Gas and oil discovery*

Figure 4.30 Gas fields in the Carnarvon Basin

Source: Encom; Geoscience Australia



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Oil field
Gas field
Gas pipeline
Gas pipeline (proposed)
200 *Bathymetry contour (depth in metres)*
Scheduled area boundary (OPGGSA 2006)
Gas discovery
Oil discovery
Gas and oil discovery

Figure 4.31 Gas fields in the Browse and Bonaparte basins

Source: Encom; Geoscience Australia

CSG is almost entirely methane and, unlike many conventional gas fields, has no associated petroleum liquids. However, CSG is associated with groundwater, and coal formations have to be de-watered to lower the pressure before the CSG can be produced. This can involve the production of large volumes of saline water to be disposed of (for example, by deep reinjection in the subsurface) or treated (for example, by desalination). In 2010–11, Queensland CSG fields produced 234 PJ (0.2 tcf) of gas but also 15 427 million litres (ML) of water, roughly 66 ML for each petajoule of gas (DEEDI 2012). Scaling up for LNG production may produce up to 40 ML per day from an LNG project. In some cases, water resources for industrial and agricultural uses or environmental flows are produced, such as the Spring Gully Reverse Osmosis Water Treatment Plant, which has a capacity of 9 ML per day (Origin Energy 2009).

Gas, both conventional and unconventional, can partner with intermittent renewable energy sources to maintain a sustained power output. Analysis of solar, wind and wave energy potential around Australia suggests that the North Perth and Otway basins are areas where identified gas resources and high wind and wave potential energy occur relatively close to existing pipeline and electricity grid infrastructure and to domestic markets (Geoscience Australia and ABARE 2010). This linkage between gas-fired electricity and wind generation via the transmission network has been identified in various projections, such as the Vision 2030 by Vencorp (2005) and the recent AEMO update (AEMO 2011).

Technology developments

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

Technological improvement has had a significant influence on exploration activity by increasing the accessibility of resources. In the period 1989–98, for example, technological advances (mainly 3D seismic) were the principal driver of new discoveries and rising success rates in offshore

Australian exploration (Bradshaw et al. 1999) and continue to yield gains, especially in the basins along the north-west margin (Longley et al. 2002, Williamson and Kroh 2007).

Offshore gas production is more challenging than onshore conventional production. The majority of Australia's conventional gas resources are located offshore, and consequently the majority of research and development has been directed towards improving offshore technologies. However, with the development of the CSG, tight and shale gas industries, this is changing, with dedicated programs at CSIRO and a number of universities to improve the technologies and practices in unconventional gas. New drilling technologies used in the production phase allow better penetration rates even in very deep water (beyond 3000 m), with lower costs and higher efficiency. Such technologies include multilateral drilling (multiple well bores from a single master well), extended reach drilling (up to 11 000 m) and horizontal drilling with paths through the reservoir of up to 2 km.

Subsea production facilities, instead of above-water platforms, are lower cost developments that reduce weather and environmental risks. Significant development of subsea technologies for the transport of natural gas includes deepwater pipeline installation through the J-lay method (as distinct from the S-lay method traditionally used for up to 2500 m depth). This allows pipelines to be laid up to several kilometres in depth, and increasingly longer pipelines are being built. One of the world's longest subsea pipelines will link the Ichthys field to the LNG processing plant over 880 km away in Darwin (figure 4.30; Inpex 2012)

There have also been improvements to LNG technologies over time to improve efficiency and reduce costs, including increasing LNG train size and developing more suitable liquefaction methods to suit gas specifications (box 4.5). Australia's first FLNG project, Prelude, is currently under construction in a Korean shipyard. It will unlock the Prelude field in the Browse Basin and demonstrate the benefit of FLNG by commercialising relatively small and previously stranded gas resources (Costain 2009; Shell 2012).

Gas-to-liquids (GTL) provides another option for bringing gas to markets. It allows the production of a liquid fuel (petrol or diesel products) from natural gas, which can be transported in normal tankers like oil products. GTL is a potential solution to stranded gas reserves that are too remote or small to justify the construction of an LNG plant or pipeline. The Pearl GTL project in Qatar commenced in 2011 and at full production is expected to have a peak capacity of 140 000 barrels per day. Currently, low gas prices in North America have reignited interest in GTL, with a feasibility study under way for a GTL plant fed by shale gas in Louisiana (BREE 2012a).

Recent advances in gas-fired electricity generation technology have improved the competitiveness of gas compared with coal. Open-cycle (or simple-cycle) gas combustion turbine is the most widely used, as it is ideal for peaking generation. Significant efficiency gains have been recognised with the natural gas combined-cycle (NGCC) electricity generation plant, which currently has world's best practice thermal efficiencies (box 4.6).

BOX 4.5 DEVELOPMENTS IN LNG TECHNOLOGIES

Over the past five years, different sources of gas have emerged as LNG feedstock. In addition to conventional natural gas, LNG plants are now being based on CSG and shale gas. Floating LNG projects have also emerged as a new technology.

In Australia, the existing projects, North West Shelf, Pluto and Darwin LNG, use natural gas that is produced offshore and piped back to the LNG plant onshore. The production of natural gas is characterised by the gas fields being located in deep water and some distance from land. Production from these fields occurs through a small number of wells that are drilled to access the gas. The drilling of individual wells is generally expensive given the complexities of accessing the gas in deep water and considerable distances below the seabed. The individual wells are capable of producing vast quantities of gas.

Coal seam gas and shale gas production itself is not a new technology, but the three projects under construction in Queensland will be the first in the world to use CSG as a feedstock. By the middle of this decade, LNG exports from the United States (via the Sabine Pass project) are expected to be based on shale gas. The production of CSG and shale gas differs considerably from conventional natural gas, even though the end product is generally the same. The use of CSG and shale gas in LNG will require the drilling of thousands of wells, reflecting the productivity of each individual well. However, compared with offshore conventional natural gas wells, the cost of drilling each well is far smaller. The wells are located onshore and the target depth of the coal seam is generally far shallow. However, the challenge in extracting such large quantities of CSG is sequencing the drilling of wells, aggregating the gas and then piping it to an LNG plant.

Float LNG is a new technology with projects under construction in Australia, Malaysia and Colombia. Shell's Prelude project has its LNG plant located on a large vessel that will be moored above the gas field, several hundred kilometres from the coast. The successful deployment of floating LNG is seen as important because it could allow the monetisation of smaller or more remote fields or avoid the complications of siting an LNG plant on land. Because they are located on vessels, floating LNG projects will generally be better suited to smaller gas fields.

Cost-competitiveness

Brownfields projects, which are an expansion of an existing project, tend to be more attractive on both capital and operating cost grounds than new projects (often referred to as greenfield projects). This is because existing infrastructure and project designs can be used, among other reasons. For example, the fourth and fifth trains in the North West Shelf Venture have significantly lower unit costs than the greenfield Pluto and Gorgon developments, which are currently producing and under construction (table 4.16). The unit costs of the CSG LNG projects are comparable with these greenfield developments.

The cost of new developments has increased rapidly, with the average cost worldwide more than doubling between 2004 and 2008. Over the same period, development costs in Australia have increased sharply (APPEA 2009), and more recently an example has been given of an offshore gas development costing more than twice as much to install in 2011 as a very similar project brought onstream in 2005 (APPEA 2012).

The capital costs of LNG liquefaction plants fell from approximately US$600 per tonne per year of installed capacity in the 1980s to US$200 in the 1990s. However, the range for Australian projects commissioned between 2010 and 2012 was between A$2100 and A$4000 per tonne per year. However, unit costs are highly dependent on site-specific factors, and a tight engineering and construction market has contributed to the cost increases. Material costs have increased sharply, particularly for steel, cement and other raw materials. Limited human resources—in terms of the number of capable engineering companies and engineers, as well as skilled labour for construction—have also been a factor in raising costs.

Generally, CSG can be produced using similar technologies to those used for the development of conventional gas. Compared with conventional gas projects, which often require most of the investment to occur prior to production, CSG projects have a different cost profile, with lower initial capital expenditure relative to ongoing and operating costs. CSG projects can generally be developed at a lower capital cost because the reserves are typically located at a shallow depth and, hence, require smaller drilling rigs. The production of CSG can also be increased incrementally given the shallow production wells. Although hundreds of wells are needed to produce a CSG field, compared with a few dozen, at most, in a giant conventional gas field, which are hundreds of metres rather than kilometres deep, and take a few days to drill, versus several weeks to drill in some conventional gas fields (Geoscience Australia and ABARE 2010). Nonetheless, they have their own particular engineering requirements.

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

Development timeframe

The time taken to bring a resource to market affects the economics of a project. Typically, developing gas fields for the domestic market takes less time than LNG export projects. The size of a project is also likely to affect the time that it takes to come on line. Geoscience Australia and ABARE (2010) reported that almost 70 per cent of all projects then producing gas in Australia were completed within 10 years of initial discovery and that, on average, gas projects took around 8.5 years to bring into production (figure 4.32).

Table 4.16 Australian LNG projects, capital costs and unit costs

Project	State	Year completed	Capital cost (A$billion)	Capacity (Mt)	Unit cost ($/t)
North West Shelf 4th train	WA	2004	2.5	4.4	568
Darwin LNG	NT	2006	3.3	3.2	1031
North West Shelf 5th train	WA	2008	2.6	4.4	591
Pluto LNG	WA	2012	14.9	4.3	3465
Gorgon LNG	WA	2015	54	15	2867
Queensland Curtis LNG	QLD	2014	US$20.4	8.5	2329
Gladstone LNG	QLD	2015	US$18.5	7.8	2307
Prelude	Floating	2016	12.6	3.6	3500
APLNG	QLD	2016	US$24	9	2555
Wheatstone	WA	2016–17	29	8.9	3258
Ichthys	NT	2016–17	33	8.4	3928

LNG = liquefied natural gas

Source: BREE 2012d; Geoscience Australia

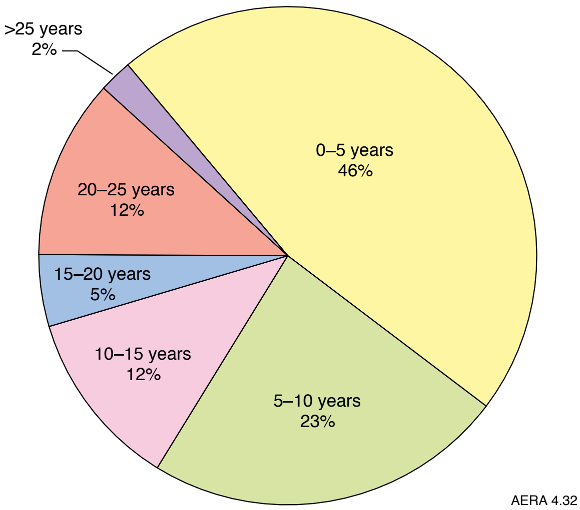

Figure 4.32 Development time for gas production projects in Australia

Source: ABARES 2010; Geoscience Australia

LNG projects in Australia and worldwide often have a significant lag between first announcement, final investment decision and development, as proponents undertake various studies to determine project feasibility, its design and its market prospects (seeking to secure long-term markets) before construction commences. Construction alone can take at least three years, and often longer. The Darwin LNG project, for example, took 32 months from notice of construction in June 2003 to the first delivery of LNG in February 2006. The larger Pluto project took seven years and is the fastest LNG project (from discovery to production) to be developed in Australia and one of the world's fastest .

Transmission and distribution infrastructure

The past two decades have seen large investments in transmission pipelines and distribution networks to meet the steady growth in domestic gas demand. Before the 1990s, Australia's transmission pipelines were a series of individual pipelines, each supplying a demand centre from a specific gas field. The majority were government owned, and there was little interconnection. Since the early 1990s, the eastern states have become interconnected, with Adelaide, Canberra, Melbourne and Sydney each now being supplied by two separate pipelines. Since 2000, several billion dollars has been invested in new pipelines and the expansion of pipeline capacity; major investments include the Eastern Gas Pipeline, the South East Australia Gas Pipeline and expansion of the Dampier to Bunbury Pipeline (AER 2011).

This level of investment is expected to continue in the short term. A further $2.7 billion of investment, in various stages of commitment, has been announced for the next five years, with major projects including the Queensland to Hunter Gas Pipeline and expansion of the Southwest Queensland Pipeline (BREE 2011c).

The National Gas Law (NGL) and National Gas Rules (NGR) provide a regime to give third parties access to transmission pipelines and distribution networks. Pipelines and networks that have undue market power are regulated

BOX 4.6 GAS COMBINED-CYCLE POWER PLANTS

This technology is based on generating electricity by combining gas-fired turbines and steam turbine technologies. It uses two thermodynamic cycles—the Brayton and Rankine cycles. Electricity is first generated in open-cycle gas turbines (Brayton cycle) by burning the gas, and the exhaust heat is then used to make steam to generate additional electricity using a steam turbine (Rankine cycle). This is shown schematically in figure 4.33.

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

As of 2009–10, there were 20 GCC power plants operating in Australia, with a combined capacity of around 4 GW (ESAA 2011). Since then, the Mortlake Stage 1 project has been completed by Origin Energy, and two additional units became operational within the Channel Island Power Station, increasing total capacity to around 4.7 GW. Of the 4.7 GW of GCC capacity, around 1.5 GW of capacity is fueled by CSG.

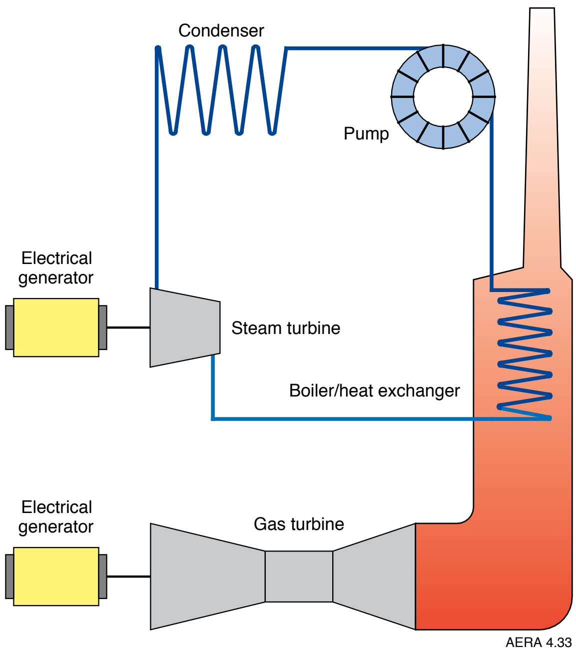

Figure 4.33 Schematic picture of gas combined-cycle turbine

Source: Wikipedia (http://en.wikipedia.org/wiki/Combined_cycle_gas_turbine) under the NGL and NGR, which requires the publication of tariffs that must be approved by the AER and which can be enforced by the AER in the event of a dispute. Eleven of Australia's 32 major transmission pipelines are regulated and, with a few exceptions, all distribution networks are regulated (AER 2011).

Most domestic gas is traded through bilateral contracts between producers and users (retailers and large customers) and, with the exception of the Victorian Gas Market, there is little price transparency. Currently, the capacity on some transmission pipelines is fully contracted, which also makes it difficult for new players to enter some gas markets. The Council of Australian Governments, through the Standing Council on Energy and Resources (SCER), has introduced reforms to Australia's gas markets to promote their ongoing development and address some of these issues.

These reforms include:

- the National Gas Market Bulletin Board (Gas BB), whose website publishes daily supply and demand data for transmission pipelines in the eastern states with the aim of facilitating trade in gas and pipeline capacity
- the Gas Statement of Opportunities (GSOO), an annual publication that provides 20-year forecasts of gas reserves, demand, production and transmission capacity for Australia's eastern and south-eastern gas markets. The GSOO aims to assist existing industry participants and potential new investors in making commercial decisions about entering into contracts and investing in infrastructure
- the Short Term Trading Market (STTM), which is intended to bring price transparency to these markets by setting a daily price for gas. The STTM commenced initially in Adelaide and Sydney in September 2010 and was followed by Brisbane in December 2011. Ultimately, the SCER intends to expand the STTM into other jurisdictions.

Ongoing SCER reform initiatives aim to encourage the efficient development of new supply and improve market transparency to relieve supply and price pressures. These include:

- the development of a gas supply hub trading market in Wallumbilla, Queensland, to improve gas market efficiency through increased trading opportunities and price transparency
- exploring the scope for improved pipeline capacity utilisation. More flexible capacity trading opportunities could lead to more efficient upstream competition and thus better allocation of gas and increased gas delivery of gas to the market
- endorsement of a National Harmonised Regulatory Framework for Natural Gas from Coal Seams to ensure robust and efficient regulation of Australia's CSG resources.

Environmental and other considerations

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

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

As of 2012, the Australian Government plans to invest $150 million over five years to support the work of a new Independent Expert Scientific Committee that will provide scientific advice to governments about relevant CSG and large coal-mining approvals where they have significant impacts on water. The committee will commission bioregional assessments and research into the impacts of CSG and coal-mine developments on water resources and methods for minimising those impacts (IIESC 2012).

The Australian Government is also working with all state and territory governments through the SCER to develop a National Harmonised Regulatory Framework for Natural Gas from Coal Seams to facilitate leading practice regulation of the industry on issues such as well integrity, water management and hydraulic fracturing. This will ensure that petroleum activities are undertaken in a responsible and sustainable manner and with the confidence of the Australian community.

Under the *Offshore Petroleum and Greenhouse Gas Storage Act 2006* (OPGGS Act), petroleum activities in Commonwealth waters (three nautical miles from the baseline from which the breadth of the territorial sea is measured, and extending seaward to the outer limits of the continental shelf) are regulated by the

National Offshore Petroleum Safety and Environmental Management Authority (NOPSEMA). The objective-based OPGGS Environment Regulations 2009, administered by NOPSEMA, use a risk-based approach for managing environmental performance through the Environmental Plan regime. This regime requires the operator to demonstrate that the environmental impacts of petroleum activities are of an acceptable level and are reduced to as low as reasonably practicable (ALARP) in order for a petroleum activity to proceed.

If a petroleum activity is likely to have an impact on a matter of National Environmental Significance (NES), it must be referred to the Australian Government Department of the Environment, under the EPBC Act for approval. The department assesses and considers whether an action that is referred will have a significant impact on a matter of NES and whether or not to approve that action. Petroleum exploration and development are prohibited in some marine protected areas offshore (such as the Great Barrier Reef Marine Park) and tightly controlled in others where multiple marine uses have been sanctioned (figure 4.34).

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

The content of CO_2 in natural gas is an environmental consideration in some fields. The CO_2 content in gas fields varies widely; the liquids-rich gas accumulations of the Browse and Bonaparte basins tend to have relatively high CO_2 contents. Accessing this gas may require disposal of significant volumes (several tcf) of CO_2. Geological storage is a possible option and is being facilitated by the current carbon capture and storage (CCS) acreage release (Department of Resources, Energy and Tourism 2011). The Gorgon Project includes a major CO_2 injection component.

There are also jurisdictional considerations. An offshore gas field that supplies an onshore gas plant requires Australian, state or territory and local government coordination in resource management and development approvals processes (Productivity Commission 2009). One of the responses to the Productivity Commission (2009) Review of Regulatory Burden on the Upstream Petroleum (Oil & Gas) Sector was the establishment on 1 January 2012, of NOPTA, the National Offshore Petroleum Titles Authority, as a branch of the Resources Division in the Department of Industry, headquartered in Perth with a regional office in Melbourne (NOPTA 2012).

Geological provinces containing gas resources that are contiguous across international boundaries, such as the JPDA in the Timor Sea, require international coordination.

4.4.2 Conventional gas resource outlook

Proven world natural gas reserves have grown at an annual rate of 3.4 per cent since 1980—a rate greater than oil reserve growth—as a result of significant discoveries and better assessments of existing fields (World Energy Council 2007). In Australia, future growth in conventional gas, CSG and other unconventional gas resources is expected to add to an expanded total gas inventory over the next two decades, even with an increase in gas production.

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

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

Field reserves growth

Growth in reserves in existing fields can add significantly to total reserves. Geoscience Australia and ABARE (2010) estimated that the additional conventional gas resource contributed by field growth over the next few decades was between 35 200 and 46 200 PJ (32 and 42 tcf). This projection is consistent with historical data, where reserves in fields discovered before 2002 have increased by 5.6 per cent in the period 2002 to 2007 or at an annual rate at the lower end of the projected range.

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

Identified resources not yet included in EDR or SDR

In addition to more than 490 conventional gas fields in 16 basins aggregated in the EDR and SDR categories (Geoscience Australia 2012). In Australia, there are a number of other known gas accumulations. They include recent discoveries (Cooney 2012, Lavin 2011) not yet appraised, such as the Equus development in the Carnarvon Basin, Frigate Deep in the Bonaparte Basin

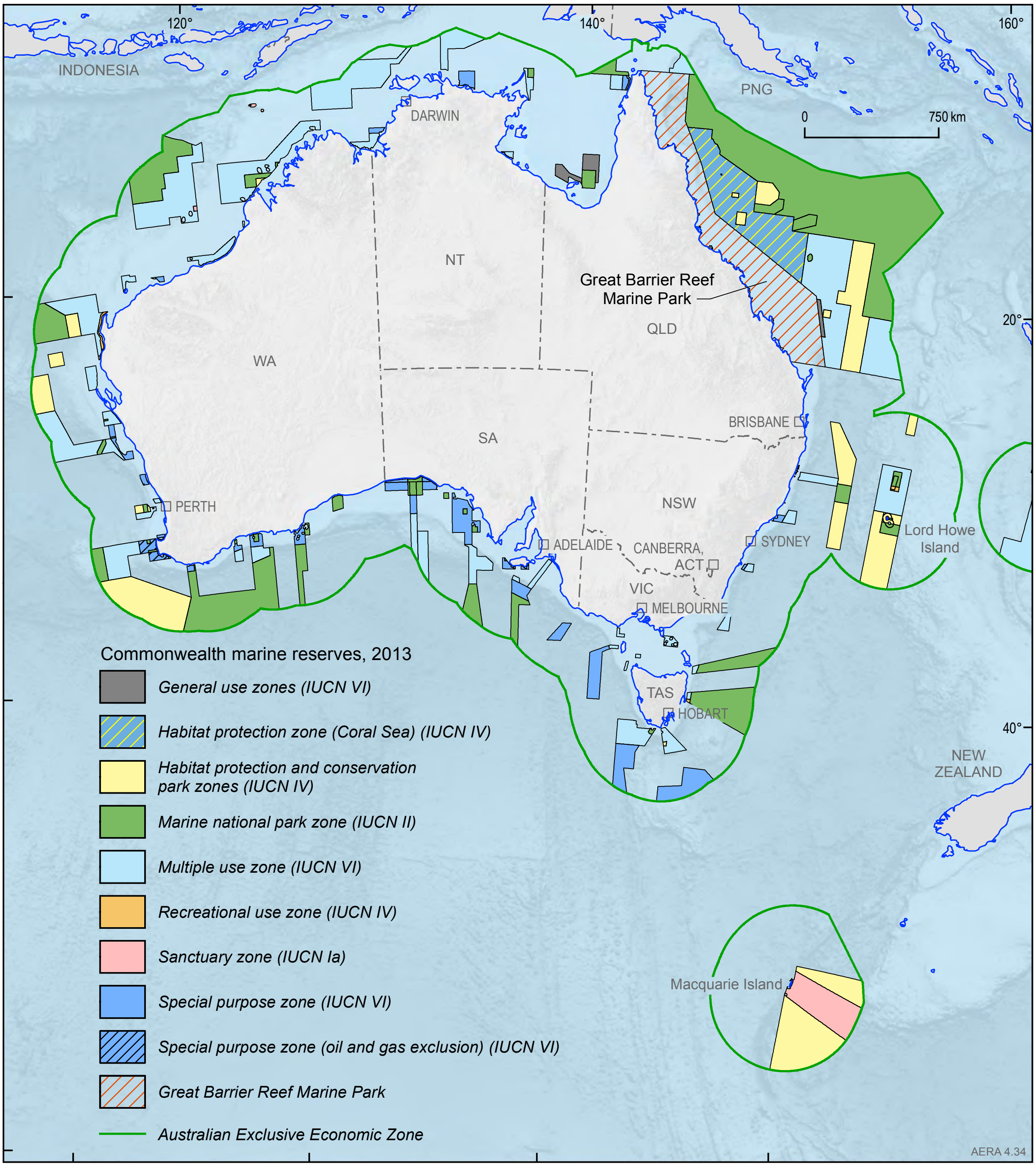

Figure 4.34 Current marine protected areas of Australia

IUCN = International Union for Conservation of Nature

Source: Department of Sustainability, Environment, Water, Population and Communities

and Poseidon in the Browse Basin. Although located in deepwater, these accumulations could add significantly to gas resources when they are appraised. The potential and timing of development of these discoveries will vary depending on location, resource size, quality (CO_2 and liquids content) and commercial factors (table 4.15).

In addition to very recent discoveries in established gas producing basins, there are a number of conventional gas accumulations in undeveloped basins, both onshore and offshore (table 4.17) that are not aggregated in EDR or SDR. Examples include the Phoenix gas accumulation in the Bedout Sub-basin of the Roebuck Basin (offshore Canning) and gas flows from wells in the onshore Canning, Georgina and Ngalia basins. Remote location, size of the resource and resource quality are factors limiting their development, but some of these accumulations may move into EDR and SDR in the next few decades. For example, there may be local niche markets for conventional gas in power generation related to mineral processing or co-location with renewable, but intermittent, energy sources. Technological advances in producing gas from poor reservoirs may also lead to additional resources, and some of these accumulations may eventually be produced as tight gas fields.

Discovery of new fields in established hydrocarbon basins

A major potential contributor to Australia's future conventional gas resources is the discovery of new fields in the established hydrocarbon-producing basins. Unlike the identified resources, discovery risk applies, so that the resource found is dependent on the number of exploration wells drilled, the size of the prospects tested and the success rate. Active exploration programs are under way in the Carnarvon, Browse and Bonaparte basins, with a trend towards deeper water exploration.

Geoscience Australia and ABARE (2010) provide a discussion of undiscovered conventional gas resources. Most of the potential was considered to be in the offshore basins, with a total of 125 400 PJ (114 tcf) for the yet-to-find recoverable gas in Carnarvon, Bonaparte, Browse and Gippsland basins at the mean expectation. The recent United States Geological Survey assessment of these four basins (Pollastro et al. 2012) has considerably upgraded this estimate to 249 700 PJ (227 tcf), with a range between 117 700 PJ (107 tcf) and 431 200 PJ (392 tcf) (table 4.10).

Table 4.17 Status of gas exploration and discovery in Australia by basin

Basin	First gas indication or discovery	Gas production status
Adavale	1964—Gilmore 1 gas flow	Past producer: 1995–2002—Gilmore gas piped to Blackall
Amadeus	1963—Ooraminna 1 gas flow	Producer: 1983—Palm Valley gas piped to Alice Springs
Bass	1967—Bass 3 gas recovery	Producer: 2006—BassGas project (Yolla)
Bonaparte	1964—Bonaparte 1 gas show	Producer: 2006—Darwin LNG production (Bayu/Undan)
Bowen	1961—Cabawin 1 gas flow	Producer: 1990—Denison Trough gas piped to Brisbane
Browse	1971—Scott Reef 1 gas flow	Potential producer: 2009—Ichthys project FID 2012
Canning—onshore	1966—Saint George Range 1 gas flow	Potential producer: 2007—Drilling campaign in western Canning
Canning—offshore	1980—Phoenix 1 gas show	Indications
Carnarvon—onshore	1966—Onslow 1 gas flow	Producer: 1991—Tubridgi gas production
Carnarvon—offshore	1971—North Rankin 1 gas flow	Producer: 1984—NWSJV gas piped to Perth
Carnarvon—Exmouth Plt	1979—Zeewulf 1 gas recovery	Potential producer: Gorgon project under construction
Cooper	1959—Innamincka 1 gas show	Producer: 1969—Moomba area gas piped to Adelaide
Duntroon	1993—Greenly 1 gas show	Indications
Eromanga	1976—Namur 1 gas flow	Producer: 1979—Namur gas production
Galilee	1964—Marchmont 1 CSG show	Potential producer: CSG potential
Georgina	1963—Ammaroo 2 gas flow	Indications
Gippsland	1962—North Seaspray 1 gas flow	Producer: 1969—Barracouta gas piped to Melbourne
Gunnedah	1985—Wilga Park 1 gas flow	Producer: 2004—Coonarah production to Wilga Park power station
Maryborough	1966—Gregory River 1 gas flow	Potential producer: CSG potential
McArthur	1979—Mineral hole GRNT-79-9 gas flare	Indications; shale gas potential (Beetaloo Sub-basin)
Ngalia	1981—Davis 1 gas flow	Indications
Officier	2004—Vines 1 gas indications	Indications
Otway—onshore	1959—Port Campbell 1 gas flow	Producer: 1986—North Paaratte gas piped to Warrnambool
Otway—offshore	1967—Pecten 1A gas flow	Producer: 2005—Minerva gas production
Pedirka	2008—Blamore 1 CSG show	Potential producer: CSG potential
Perth—onshore	1961—Eneabba 1 gas show	Producer: 1971—Dongara gas piped to Perth
Perth—offshore	1978—Houtman 1 gas show	Indications
Surat	1901—Hospital Hill 2 gas flow	Producer: 1969—Roma area gas piped to Brisbane
Sydney	1937—Mulgoa 1 gas flow	Producer: 2006—Camden CSG production
Tasmania	1920s—Bruny Island wells gas shows	Indications
Warburton	1990—Lycosa 1 gas flow	Potential producer
South Nicholson	1991—Egilabial gas shows 2013—Egilabial gas flow	Indications

CSG = coal seam gas

Source: Geoscience Australia

Discovery of new fields in non-producing and frontier basins

In addition to the 15 basins that have identified commercial conventional gas resources, many other Australian basins have gas occurrences (figure 4.35). Apart from the gas accumulations already recognised in these basins, there is also the potential for the discovery of new fields.

As gas exploration matures in the established basins, the size of drilling targets and, correspondingly, the size of discovered fields is likely to decline, unless reversed by new opportunities created by new play concepts and technologies and, in the case of offshore basins, opportunities identified in deeper water. However, Australia's frontier basins are poorly explored, and the large structures remain untested. Significant new exploration efforts are under way in the offshore Bight and Roebuck (offshore Canning) basins and onshore in the Canning and Officer basins.

In contrast to Australia's producing basins, there is a higher degree of uncertainty in estimating the undiscovered resources in the poorly explored frontier and non-producing basins. A number of estimates of undiscovered hydrocarbon potential are available for individual frontier basins, and for Australia as a whole. The publicly available assessments have not been integrated with the results from the current rounds of precompetitive data acquisition and focus on oil rather than gas resources.

4.4.3 Unconventional gas resource outlook

For unconventional gas, inclusion of additions to the inventory of reserves from field growth and new discoveries is less well established than for conventional gas. CSG is expected to remain the most important sector of the unconventional gas industry and is already a significant source of gas in eastern Australia. Currently, production of CSG is mainly from the Bowen and Surat basins in Queensland, with some production from

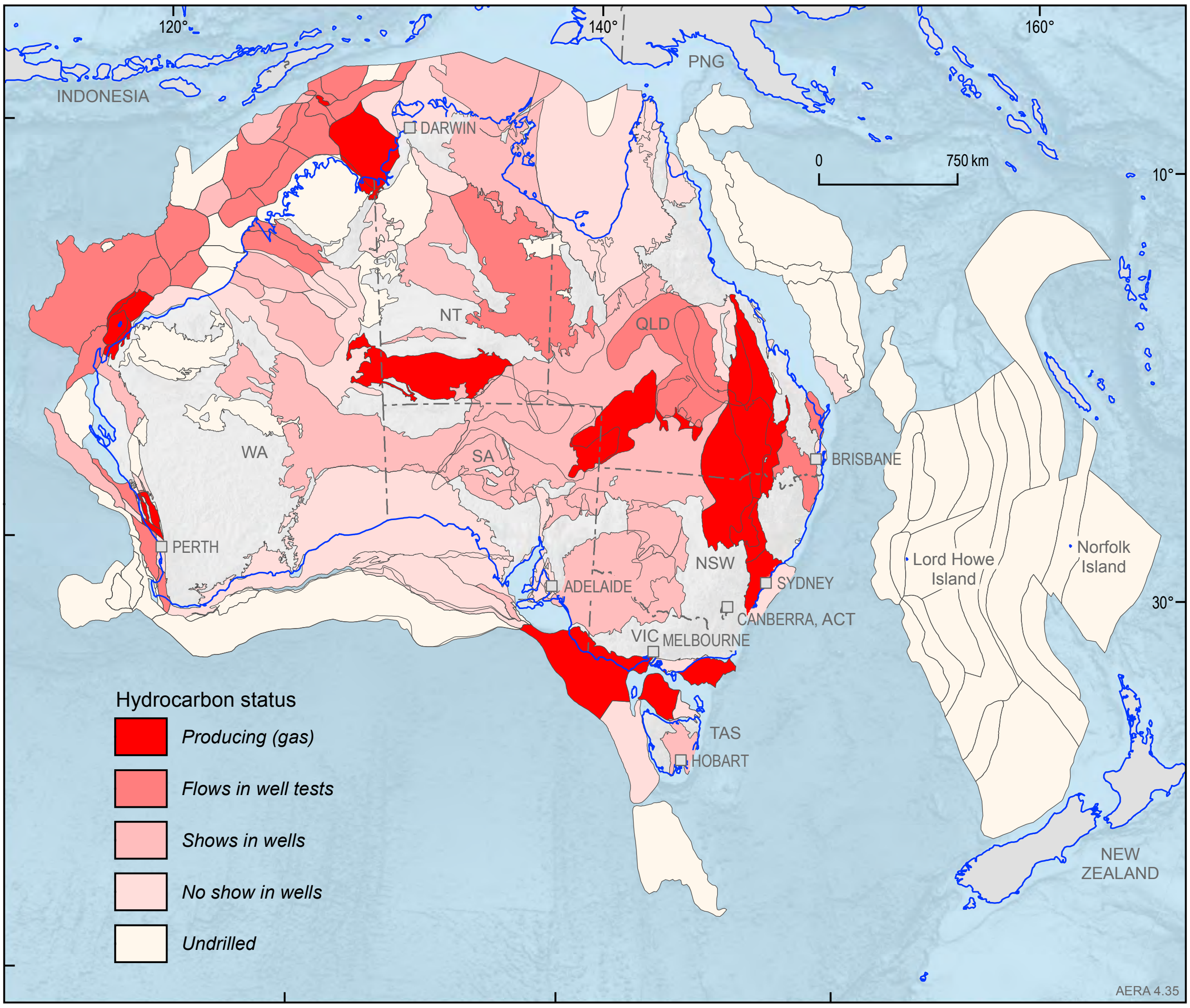

Figure 4.35 Australian gas occurrences, showing basins with conventional gas production, gas flows and gas shows; drilled basins with no shows; and undrilled basins

Source: Geoscience Australia

the Sydney Basin in New South Wales (figure 4.36). Production is from Permian and Jurassic coals.

Over the past five years, the focus of CSG exploration has expanded into other coal basins and into other parts of the stratigraphy, to coal deposits of widely differing geological age. Triassic and Cretaceous strata are now also an exploration target, as well as the Permian coals of the Gondwana basins. CSG exploration is active in the Clarence-Moreton and Galilee basins, and potential is recognised in many of Australia's black and brown coal basins (figure 4.36).

Estimates of aggregate CSG potential in Australia are substantial (Baker and Slater 2009). At the end of 2011, the Queensland Department of Employment, Economic Development and Innovation estimated total identified and prospective resources of 154 634 PJ (141 tcf) for Queensland and 64.8 tcf (71 254 PJ) for New South Wales (DEEDI 2011). Other Australia-wide industry estimates range from 250 tcf (275 000 PJ), according to Santos (2009), to more than 300 tcf (330 000 PJ) of gas in place (Arrow Energy 2009). In addition to the new CSG resources identified by current active exploration, it is expected that part of the large inferred resource will move into the EDR and SDR categories over the next few decades. There appears to be significant potential for around seven times more CSG than the current EDR.

Understanding of the future potential tight gas and shale gas resource in Australia is very limited. Likely shale gas candidate formations have been identified in many basins including the Cooper, Perth, Amadeus, Canning, Georgina and McArthur basins. Tight gas resources are under investigation in the Cooper, Perth and Gippsland basins. As exploration and development of Australia's gas resources proceeds, several basins—notably the Cooper Basin—are likely to emerge as having conventional, CSG, tight and shale gas resources. A significant advantage of exploring in the Cooper Basin is that substantial gas infrastructure, including a gas pipeline servicing South Australia, Queensland and New South Wales markets, already exists.

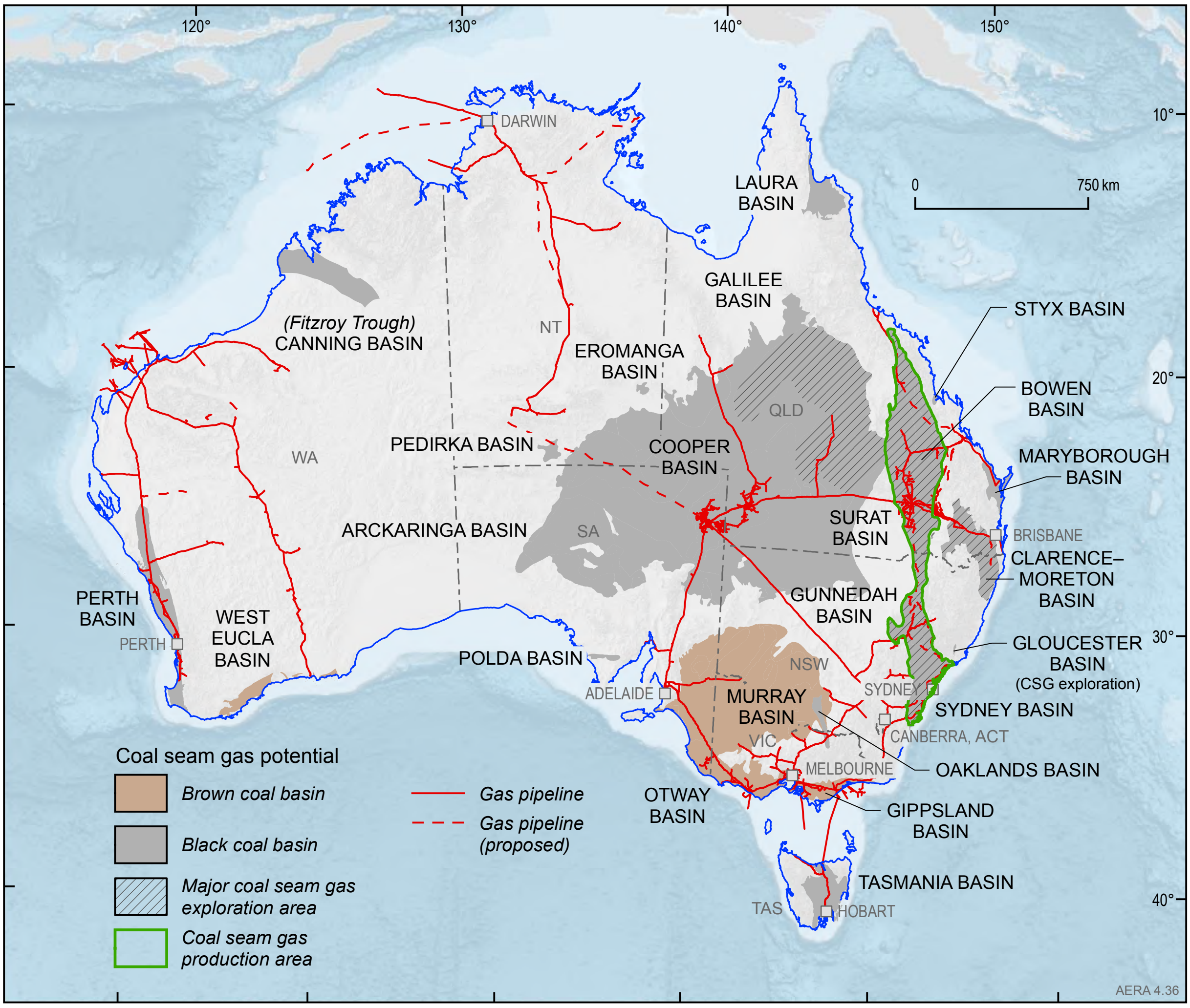

Figure 4.36 Basins with coal seam gas potential

Source: Geoscience Australia

4.4.4 Total gas resource outlook

Australia's EDR of gas, both conventional and unconventional, at 145 341 PJ (132 tcf; table 4.10), is equivalent to a reserves to production ratio of around 67 years at current rates. Australian gas production, however, is projected to increase substantially over the next few decades, but demonstrated gas resources (275 734 PJ, 251 tcf) are still expected to exceed the estimated cumulative gas production over the same period. Total identified gas resources (431 706 PJ, 392 tcf; table 4.10) are nearly three times the EDR . Over the next few decades it is expected that some of the currently SDR and large inferred (mostly CSG) gas resource will be converted to EDR and enter production. Australia's gas resource base is, therefore, adequate to support projected increases in production into the future.

The true size of Australia's potential gas resources is unknown and could be significantly larger than the identified resources. There is no current publicly available resource assessment of Australia's undiscovered conventional gas resources that adequately reflects the knowledge gained in recent years during the active programs of government precompetitive data acquisition and increased company exploration during the resources boom. In addition, the current knowledge base for unconventional gas, especially tight gas and shale gas, is inadequate for assessment. The potential size of Australia's CSG resources is as yet ill-defined; companies have reported very substantial in-place CSG resources. Cook et al. (2013) note that there is a high degree of uncertainty in the shale gas resource estimates and much more exploration to be done to convert any of the potential into economic reserves, as demonstrated by the gap between the estimate of more than 1 100 000 PJ (1000 tcf) and the ~3 PJ (3 bcf) of 2P shale gas reserves booked by Santos. Better assessment of Australia's potential gas resources may be aided by both more precompetitive geoscientific information and further exploration drilling and production data.

4.4.5 Outlook for gas market

Australian gas production is expected to increase over the next few decades. Gas exports, in the form of LNG are expected to expand over the same timeframe.

Production

Over the medium term, the production of gas is expected to continue to rise as developments now under construction or in the advanced stages of planning are completed (figure 4.37). As with current production, the majority of future conventional gas production is likely to be sourced from offshore basins in north, north-west and south east Australia.

CSG production is expected to increase considerably, with a number of projects under construction and planned in Queensland. A significant proportion of this CSG production will support LNG exports from Queensland.

Consumption

Gas is expected to be the fastest growing fossil fuel consumed over the next few decades. This consumption growth in demand is expected to be driven primarily by the electricity generation sector and the mining sector.

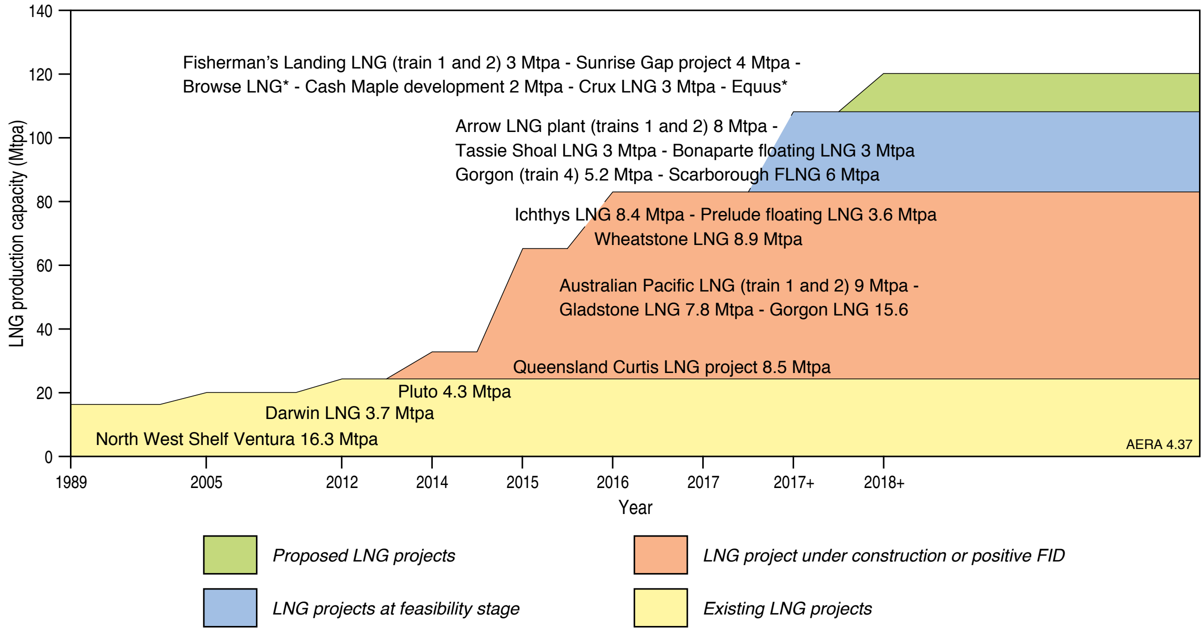

Figure 4.37 Outlook of Australian LNG production capacity

LNG = liquefied natural gas; **FLNG** = floating liquefied natural gas
Note: * production capacity not available
Source: BREE 2013

Gas-fired electricity generation, and its share in total electricity generation, are expected to increase over the long-term.

LNG exports

Upstream developments are expected to substantially expand LNG exports over the next two decades. This is a result of not only Australia's abundant gas reserves and their proximity to growing Asia–Pacific markets, but also Australia's attractiveness as a reliable and stable destination for investment. CSG LNG will provide an important contribution to the growth of the export sector.

In 2013, there were seven LNG plants that were committed or under construction (tables 4.23 and 4.24): the Queensland Curtis LNG project (8.5 Mt), the Gorgon LNG project (15.6 Mt), the Australia Pacific LNG project (4.5 Mt), the Gladstone LNG project (7.8 Mt), the Wheatstone LNG project (8.9 Mt), the Ichthys project (8.4 Mt) and the Prelude floating LNG project (3.6 Mt). These projects are scheduled to be completed between 2014 and 2017. The Pluto LNG project (annual capacity of 4.3 Mt) started production in April 2012 with production exceeding nameplate capacity. A number of other LNG plants that are at a less advanced stage (undergoing feasibility studies) are awaiting development.

Proposed project developments

Upstream

At the end of October 2013, there were seven conventional upstream gas projects under construction or committed across Australia (table 4.18). These projects were located in the Carnarvon and Gippsland basins. This capacity includes a combination of replacement for declining production at mature fields and increases in Australia's production capacity. Gas from the Julimar development will be supplied to the Wheatstone project (table 4.18), which will produce both export LNG and domestic gas. Table 4.19 identifies one project, the Kipper gas project (stage 2), that was at a feasibility stage of development (as at October 2013).

Five upstream CSG projects were at planning stage at the end of October 2013 (table 4.20). Three of these projects are located in New South Wales, and two are in Queensland. It should be noted that none of these projects in table 4.20 are associated with the three CSG LNG projects that are under construction in Queensland.

Pipeline

Accompanying the expansion of Australia's gas production capacity is an expansion to the transmission pipeline. The second- and third- stage expansion of the South West Queensland Pipeline was completed in December 2011 and will substantially increase capacity along the pipeline that connects southern Queensland to the Moomba gas hub in north-eastern South Australia. Several smaller pipeline expansions are committed or being constructed in New South Wales, Victoria, South Australia and Queensland (table 4.21).

Electricity generation

At the end of October 2013, there were four advanced gas-fired electricity generation projects with a combined capacity of 528 MW that are all scheduled to be in operation by the end of 2014 (table 4.22). Two of the projects are located in the Northern Territory, and there is one each in Queensland and Western Australia.

LNG

Australia's LNG industry is undergoing a transformation that will see capacity increase four-fold to 86 Mt (4200 PJ, 4 tcf) during the second half of the decade. In addition to the 24 Mt (1267 PJ, 1.2 tcf) of current export capacity, there is 62 Mt (3009 PJ, 2.7 tcf) of capacity at various stages of commissioning and construction. Four of these projects are based on conventional natural gas and located off the coast of Western Australia (table 4.23). In Queensland, there are three LNG projects under construction, all using CSG as a feedstock (table 4.24).

Beyond the seven projects under construction, there is further scope to increase Australia's LNG export capacity well beyond 100 Mt. There are a number of greenfield projects under consideration (Browse and Arrow LNG), while projects such as Gorgon, Wheatstone, Pluto and the CSG projects under construction in Queensland have the land footprint to add additional capacity.

Table 4.18 Conventional gas projects at a committed stage of development, as at October 2013

Project	Company	Basin	Start-up	Estimated capacity	Indicative cost estimate (A$million)
Greater Western Flank (phase 1)	Woodside Petroleum/ BHP Billiton/BP/ Chevron/Shell/Japan Australia LNG	Carnarvon	2016	n/a	2300
Julimar Development Project	Apache/KUFPEC	Carnarvon	2016	2.1 tcf	1200
Spar 2	Apache Energy/Santos	Carnarvon	2015	18 PJ pa	117
Xena Gas Field (phase 1)	Woodside Petroleum	Carnarvon	2015	n/a	370

na = not available

Source: BREE 2011b; BREE 2012d, BREE 2013b

Table 4.19 Conventional gas projects at feasibility stage of development, as at October 2013

Project	Company	Basin	Start-up	Capacity (PJ per year)	Capital expenditure (A$ million)
Kipper (stage 2)	Esso/BHP Billiton/Santos	Gippsland Basin	2016	27	200

na = not available

Source: BREE 2011b, BREE 2012d, BREE 2013b

Table 4.20 CSG projects at various stages of development, as at October 2013

Project	Company	Location	Status	Start-up	Capacity (PJ per year)	Indicative cost estimate (A$ million)
Bowen	Arrow Energy	Bowen Basin	Publicly announced	na	na	250–500
Casino	Metgasco	Casino	Publicly announced	na	18	0–250
Gloucester	AGL	Hunter Valley	Feasibility	2016	15	200
Narrabri	Santos	Narrabri	Feasibility	na	150	1300
Surat	Arrow Energy	Surat Basin	Feasibility	2016	180	1500

Source: BREE 2011b, BREE 2013b

Table 4.21 Gas pipelines at various stages of development, as of October 2013

Project	Company	Location	Status	Start-up	Capacity (PJ per year)	Capital expenditure (A$ million)
Moomba to Sydney	Australian Pipeline Group	Moomba, SA to Sydney, NSW	Committed	2015	na	100
Goldfields pipeline expansion	Australian Pipeline Group	Pilbara, WA	Committed	2014	16	150
Arrow Bowen pipeline	Arrow Energy	Moranbah to Gladstone. QLD (440 km)	Feasibility	2018+	50	1000
Gloucester CSG pipeline	AGL	Gloucester to Hexham, NSW (98 km)	Feasibility	na	22	80
Great Northern pipeline	Buru Energy	Broome to Port Hedland, WA (550 km)	Feasibility	na	90	500
Newstead to Bulla Park pipeline	Australian Pipeline Group	Newstead,Qld to Bulla park, NSW	Feasibility	na	na	500

Project	Company	Location	Status	Start-up	Capacity (PJ per year)	Capital expenditure (A$ million)
Arrow Surat pipeline	Arrow Energy	Surat Basin to Gladstone, QLD (450 km)	Feasibility	2018	360	600
Wellington Power Station Pipeline	ERM Power	Young to Wellington, NSW	Feasibility	2015	na	200

na = not available; **EIS** = Environmental Impact Statement; **FEED** = front end engineering design

Source: BREE 2011b; BREE 2012d, BREE 2013b

Table 4.22 Gas-fired power stations at committed stage of development, as of October 2013

Project	Company	Location	Start-up	Capacity (MW)	Capital expenditure (A$ million)
Diamantina power station (2 stages)	APA Group/AGL Energy	QLD	2014	242	570
McArthur River Mine—(phase 3) expansion	Energy Developments Ltd (EDL)	NT	2014	53	na
Weddell (stage 3)	Power and Water Corporation	NT	2013	43	50
Yarnima Power Station	BHP Billiton	WA	2014	190	597

na = not available

Source: BREE 2012e, BREE 2013b

Table 4.23 Conventional gas-based LNG projects at various stages of development, as of October 2013

Project	Company	Location	Status	Start-up	Capacity (Mt LNG)	Capital expenditure (A$ billion)
Gorgon	Chevron/Shell/ ExxonMobil	Carnarvon Basin	Committed	2015	15.6	52
Prelude (floating LNG)	Shell	Browse Basin	Committed	2017	3.6	12.6
Wheatstone	Chevron/Apache/ KUFPEK/Shell	Carnarvon Basin	Committed	2016	8.9	29
Ichthys gasfield (including Darwin LNG plant)	Inpex/Total	Browse Basin	Committed	2017	8.4	33
Bonaparte (floating LNG)	Santos/GDF Suez	Bonaparte Basin	Feasibility	2018+	2.4	13
Browse LNG development	Woodside Energy/ BP/ BHP Billiton/ Chevron/Shell	Browse Basin	Publicly announced	2018+	na	5+
Gorgon LNG T4	Chevron/Shell/ ExxonMobil	Carnarvon Basin	Feasibility	2018+	5	12
Pluto (train 2 and 3)	Woodside Energy	Carnarvon Basin	Publicly announced	na	2 x 4.3	na
Cash Maple development	PTTEP	Bonaparte Basin	Publicly announced	2018+	2	5+
Scarborough	ExxonMobil/BHP Billiton	Carnarvon Basin	Feasibility	2018+	6	14
Sunrise	Woodside Energy/ ConocoPhillips/ Shell/Osaka Gas	Bonaparte Basin	Feasibility	2018+	4+	5+
Tassie Shoal	MEO Australia	Bonaparte Basin	Feasibility	na	3	na
Crux	Shell/Nexus Energy/Osaka Gas	Browse Basin	Publicly announced	2018+	3	5+

Project	Company	Location	Status	Start-up	Capacity (Mt LNG)	Capital expenditure (A$ billion)
Equus	Hess	Carnarvon Basin	Publicly announced	2018+	na	1.5–2.5

LNG = liquefied natural gas; **na** = not available

Source: BREE 2011b, BREE 2012d, BREE 2013b

Table 4.24 Coal seam gas-based LNG projects at various stages of development, as of October 2013

Project	Company	Location	Status	Start-up	Capacity (Mt LNG)	Capital expenditure (A$billion)
Australia Pacific	Origin/ ConocoPhillips/ Sinopec	Gladstone	Committed	2015	9	24.7
Gladstone	Santos/ Petronas/ Total/Kogas	Gladstone	Committed	2015	7.8	18
Queensland Curtis	BG Group, CNOOC	Gladstone	Committed	2014	8.5	19.8
Arrow Energy	Shell/Petro China	Gladstone	Feasibility	2018+	8	20
Fisherman's Landing (train 1)	LNG Ltd	Gladstone	Publicly announced	2018+	1.5	1.5
Fisherman's Landing (train 2)	LNG Ltd	Gladstone	Publicly announced	2018+	1.5	0.5–1.0

FEED = front end engineering design; **LNG** = liquefied natural gas; **na** = not available

Source: BREE 2011b, BREE 2013b

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Chapter 5
Coal

5.1 Summary

KEY MESSAGES

- Australia is the fourth largest producer, the second largest exporter, and has the fourth largest reserves of coal in the world.
- Coal accounts for more than two-thirds 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, 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.
- Continuing investment in infrastructure and improved productivity will be necessary to enable Australia to remain a major player in the world coal market.

5.1.1 World coal resources and market

- In 2011, world coal production and consumption was estimated at 7.2 billion tonnes (Gt) or 143 500 petajoules (PJ). Production and consumption have grown at a rate of 3.6 per cent per year since 2008.
- At the end of 2011, global coal resources (both black and brown) were estimated at 861 Gt—an increase of 34 Gt over 2008 estimates.
- In 2011, 1137 million tonnes (Mt) of black coal was traded globally. Trade in thermal coal was estimated at 861 Mt and metallurgical coal at 276 Mt.
- Coal accounted for 27 per cent of world primary energy consumption and 40 per cent of world total electricity generation in 2010.
- In its new policies scenario, the International Energy Agency (IEA) projects world coal demand to increase at an average annual rate of 0.8 per cent between 2010 and 2035. Non-OECD demand is projected to increase at an average annual rate of 1.4 per cent, while OECD demand is projected to decline by 1.1 per cent per year.
- The share of coal-fired electricity generation is projected to decline from 40 per cent in 2010 to 33 per cent in 2035.

5.1.2 Australia's coal resources

- Coal is Australia's largest energy resource. Coal is a low-cost resource and deposits are generally located close to areas of domestic energy demand.
- Australia has substantial reserves of both black and brown coal that include high-quality thermal and metallurgical coal.
- At the end of 2012, Australia's recoverable Economic Demonstrated Resource (EDR) of black coal was estimated at 61.1 Gt. The resource constitutes 9 per cent of the world's recoverable EDR. In addition, it is estimated that there are a further 5.1 Gt of Sub-economic Demonstrated Resources (SDR) of black coal within Australia.
- At the 2012 rate of production (430 Mt per year), Australia's black coal EDR will support 110 years of production.
- In addition to EDR and SDR, it is estimated that there are 64.2 Gt of recoverable Inferred Resources of black coal within Australia. Further exploration is required to delineate these resources and to determine their economic viability.
- Most of Australia's recoverable black coal EDR is located in Queensland (61 per cent) and New South Wales (36 per cent). In Queensland and New South Wales, the coal is predominantly located in the Sydney Basin (30 per cent) and the Bowen Basin (31 per cent) (figure 5.1).
- Approximately 23 per cent of the world's recoverable brown coal EDR is found in Australia. At the end of 2012, Australia's recoverable brown coal EDR was estimated at 44.2 Gt. Australia is estimated to hold a further 48.6 Gt of brown coal SDR and 102.5 Gt of Inferred brown coal resources. At 2012 rates of production, accessible brown coal EDR will support 510 years of production.

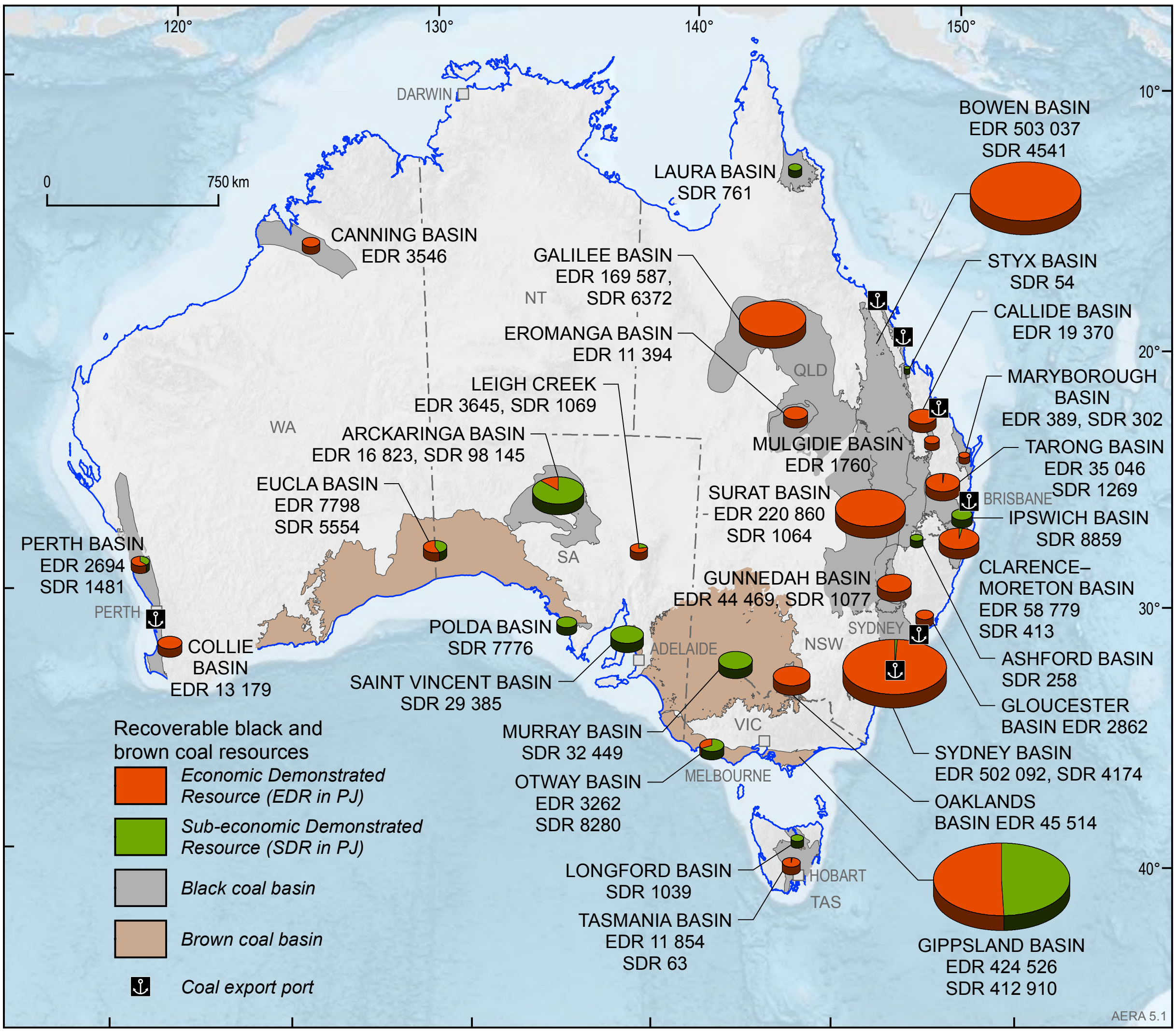

Figure 5.1 Australia's total recoverable resources of black and brown coal as at 31 December 2012

Source: Geoscience Australia

- There is significant potential for further discoveries of coal in Australia. It is estimated that over one trillion tonnes of additional coal resources could be present in more than 25 underexplored coal-bearing sedimentary basins within Australia.
- In 2012, there were over 120 operating coal mines and several new mines and expansions proposed. The proposed mines were at various stages of development that ranged from the scoping study phase to ongoing construction (figure 5.2).
- Australia's coal industry provides direct employment for approximately 40 000 people and indirect employment for a further 100 000.

5.1.3 Key factors in utilising Australia's coal resources

- World demand for energy, domestic energy policies and prices 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)
  - 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 may play an important role in the development and commercial deployment of new low-emissions technologies.

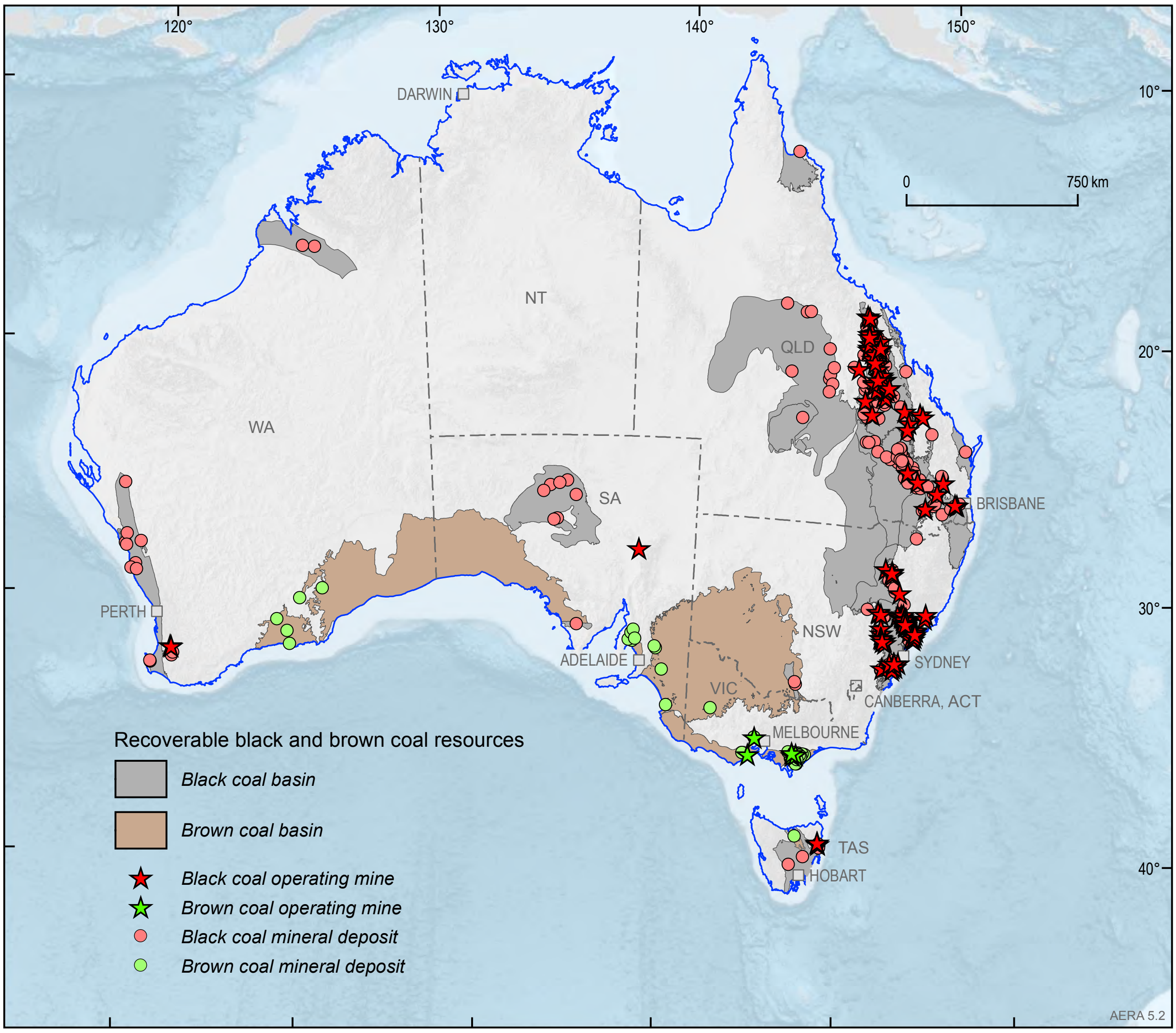

Figure 5.2 Australia's operating black and brown coal mines, 2012

Source: Geoscience Australia

5.1.4 Australia's coal market

- Australian saleable black coal production has increased at an average annual rate of 2.6 per cent between 2000 and 2012 and domestic consumption has increased at an average annual rate of 0.6 per cent over the same period.
- In 2011–12 coal generated around 70 per cent of Australia's electricity and account for 36.5 per cent of total primary energy consumption.
- Australia exported 301 Mt of black coal in 2011–12, of which around 47 per cent was metallurgical coal and 53 per cent was thermal coal. Exports were valued at A$48 billion.
- New South Wales and Queensland are the largest producing states in Australia.
- Australia's coal production and exports are projected to increase reflecting strong growth in coal demand in China, India and other developing economies, a proportion of which will be imported.
- Domestic coal consumption and electricity generation may decline with increased up take of gas and renewable energy sources (BREE 2012b).

5.2 Background information and world market

5.2.1 Definitions

Coal is a combustible sedimentary rock formed predominantly from plant material that was deposited in ancient marshy environments. Through burial and over long periods of geological time, the plant material is transformed by microbial action, pressure and heat into coal. This process is commonly called 'coalification'. Coal occurs as layers or seams, ranging in thickness from millimetres to many tens of metres. It is predominantly composed of carbon (50–98 per cent), hydrogen (3–13 per cent) and oxygen with smaller amounts of nitrogen, sulphur and other elements.

Coal also contains water and particles of other inorganic matter. When burnt, coal releases energy as heat.

Coal is broadly differentiated into brown and black coal. The two types of coal have different thermal properties and uses.

Brown coal (lignite) produces less thermal energy than black coal and typically has a high ash and moisture content. Brown coal is currently considered to be unsuitable for export and is used exclusively to generate electricity in domestic power stations.

Black coal is harder, and has a higher energy content and a lower moisture content than brown coal. 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 predominantly used to generate electricity in power stations. The coal is pulverised and combusted to provide heat for steam-generating boilers.

Metallurgical (coking) coal is black coal that is suitable for making coke. Coke is used in the production of pig iron. These coals have a low sulfur and phosphorus content. Due to its relative scarcity, metallurgical coal attracts a higher market price than thermal coal.

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

Coal has a wide range of chemical and physical properties. During the coalification process, peat (the precursor of coal) is transformed by increasing subsurface pressure and temperature first to lignite or brown coal and then to the more mature sub-bituminous and bituminous coals (figure 5.3). The degree of coalification or thermal maturity is referred to as coal 'rank'. Lignite and lower rank sub-bituminous coals that typically have a lower energy, lower carbon and higher moisture content are used predominantly for power generation.

Bituminous coal (table 5.1) has a higher volatile matter content, lower fixed carbon and a lower energy content than anthracite. It is used for power generation, metallurgical applications, and general industrial uses that include cement manufacture. Anthracite has the highest rank, the lowest moisture content and the highest carbon and energy content of all the black coals. Anthracite is used mainly in steel and cement manufacturing. Most Australian black coals are considered to be good quality and to have a low ash and sulfur content.

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.

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

Source: Geoscience Australia

5.2.2 Coal supply chain

Figure 5.4 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

Modern coal exploration typically involves a variety of geological techniques that include field mapping, interpretation of aerial photographs and satellite imagery and both airborne and ground-based geophysical (gravity, magnetic and seismic) surveying. Initial mapping and surveying is generally followed by drilling, geophysical

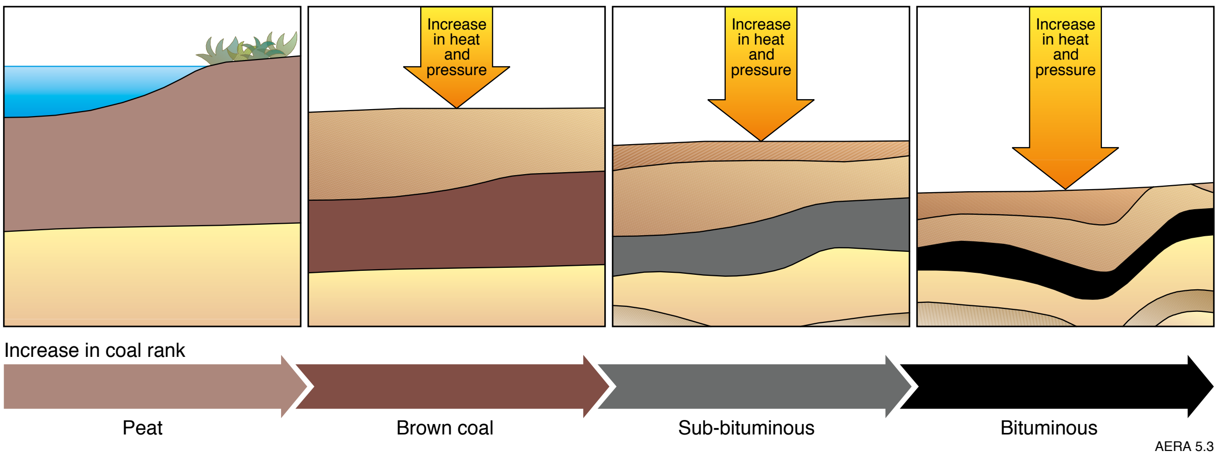

Figure 5.3 Diagrammatic representation of the transformation of peat to brown and black coal (increasing coal rank)
Source: Australian Coal Association 2009

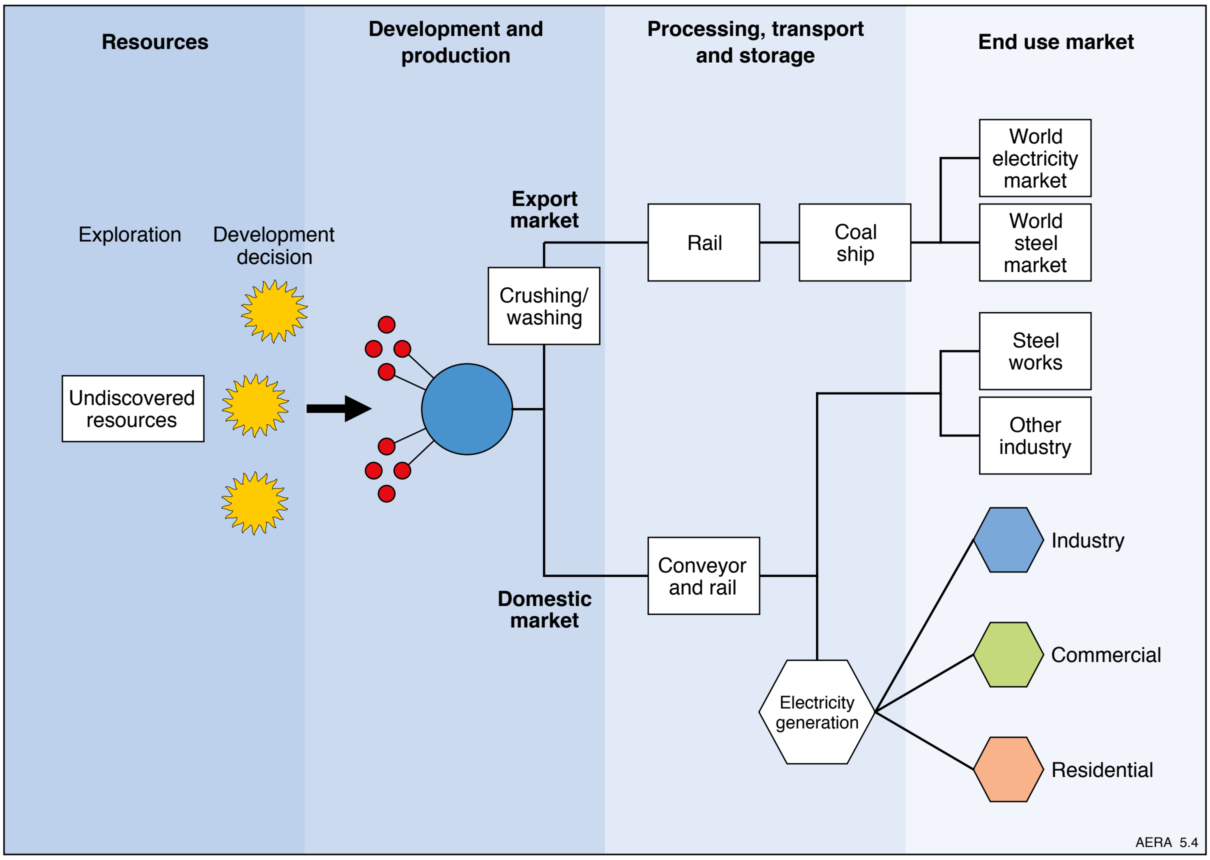

Figure 5.4 Australia's coal supply chain

Source: Bureau of Resources and Energy Economics; Geoscience Australia

logging and coring. The information from the mapping and drilling programs are integrated and used to determine coal seam thickness, quality and structure, the distribution and quality of associated groundwater systems and the mechanical properties of the rocks associated with the coal deposits. Finally, a three-dimensional model of the deposit is generated. The model is used to estimate the size of the coal resource and to plan a mining development.

Mining

Depending on the geology of the deposit, coal is usually mined by either surface ('open-cut') or underground ('deep mining') methods. Some coal deposits are developed using a combination of both open-cut and underground mining techniques. Underground mining currently accounts for approximately 60 per cent of world coal production. Nearly 80 per cent of Australia's coal, however, is produced from open-cut mines. Open-cut mining is only economic when the coal seam(s) either outcrop at the surface or occur at relatively shallow depths (less than 200 m). Open-cut mining is lower cost than underground mining and more than 90 per cent of the *in situ* coal can be recovered using this technique.

Over many years, technological innovation has led to significant productivity increases in the coal mining industry. Modern large open-cut mines cover many square kilometres. Large draglines are commonly used to remove the overburden. Bucket wheel excavators and conveyor belts are then employed to extract the coal and transport it to wash plants and rail loading facilities.

There are several mining techniques that can be used in underground coal mining operations. The most common are 'bord-and-pillar' and 'longwall' mining. The bord-and-pillar method involves cutting a regular grid of tunnels into the coal seam and then removing the coal in 'panels' to leave pillars of coal to support the mine roof. Bord-and-pillar mining is one of the oldest underground mining techniques. With the introduction of longwall mining in the 1960s, however, its use in Australia is in steady decline.

Many underground coal mines in Australia now use longwall mining techniques. Longwall mining is more efficient and cost effective than traditional bord-and-pillar mining. In longwall mining, the coal is cut from the coal face 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 can be extracted using this technique (World Coal Institute 2009).

Processing

Black coal mined for the domestic market is often crushed and screened and does not undergo further processing. Crushing and screening reduces the coal to a useable and consistent size and allows some contaminants to be removed. Export coal, however, is generally washed in a wash plant to remove rock and minerals that are associated with the raw coal. The washing process reduces the ash content and increases the overall energy content of the coal. The coal is then separated into fractions based on size. The coarse coal fraction is usually separated by dense medium gravity separation. In this technique, either cyclones in conjunction with magnetite slurries or flotation baths are used. The fine coal fraction (less than 1 mm) is usually separated and cleaned by flotation. After washing, the coal is dewatered using centrifuges, cyclones, screens or filters that reduce the mass of the coal prior to transport.

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: 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 that total approximately 847 Gt (WCA 2012). At current rates of production, these reserves are estimated to last 118 years (WCA 2012).

The United States has large reserves of both black and brown coal that account for 28 per cent of the world total (figure 5.5). China and India also hold large reserves of black coal, while China and the Russian Federation hold large reserves of brown coal.

In 2011, Australia's reserves of black coal ranked fifth in the world and its reserves of brown coal rank fourth. Total black and brown coal reserves in Australia are estimated at 76.4 Gt, 9 per cent of the world's total.

In 2011, total world coal production was estimated at 7.6 Gt. The three largest producers (China, United States and India) accounted for 45 per cent, 13 per cent and 8 per cent of world coal production, respectively. Australia ranked fourth in the world as a coal producer (414 Mt) and accounted for about 5 per cent of world production (figure 5.6).

Black coal accounted for 64 per cent of total coal production, while brown coal accounted for the remaining 36 per cent (figure 5.7).

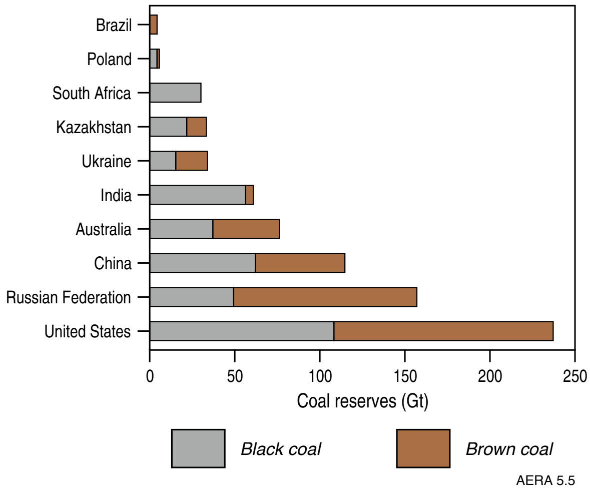

Figure 5.5 Black and brown coal reserves, major countries, 2011

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

Source: BP 2012

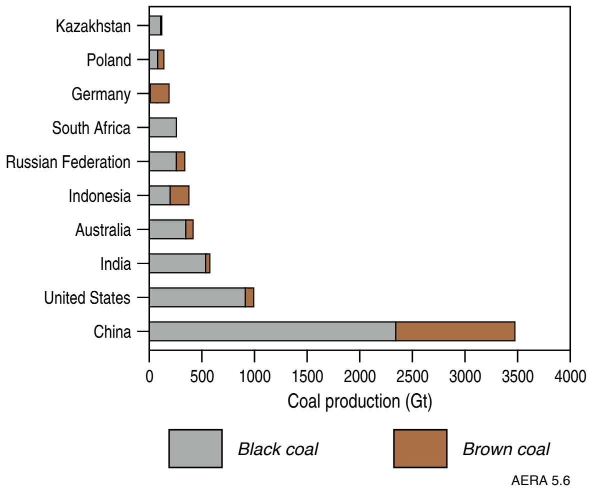

Figure 5.6 Black and brown coal production, major countries, 2011

Source: IEA 2012a

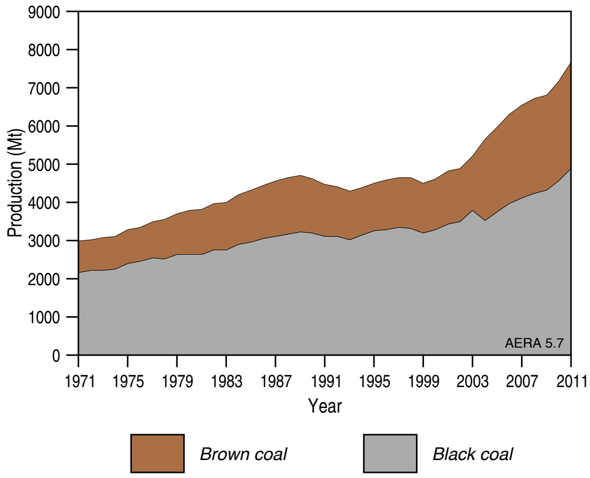

Figure 5.7 World production by coal type

Source: IEA 2012a

Primary energy consumption

In 2011, world coal consumption was around 7.6 Gt (IEA 2012a). The major use of coal is for electricity generation (accounting for around 65 per cent of consumption). Other uses include steel production, cement production and chemical processing.

Coal is an important energy source, reflecting its wide availability and relatively low cost compared with other fuels. In 2010 it accounted for 27 per cent of global primary energy consumption, the second largest share of world energy consumption after oil. Around 41 per cent of the world's electricity is generated using coal.

China is the largest consumer of black coal, accounting for around 49 per cent of world consumption in 2011 (figure 5.8). China's consumption of black coal has increased at an average annual rate of 5 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 18 per cent and 13 per cent of world consumption, respectively.

Table 5.2 Key coal statistics

	Unit	Australia 2011–12	Australia 2011	OECD 2011	World 2011
Resources	**Mt**	**66 200[a]**	**76 400**	**378 529**	**860 938**
Share of world	%	10	9	44	100
World ranking	Number		4		
Production (raw coal)	PJ	9767	9667		
	Mt	434	460	2087	7678
Share of world	%		6.0	27.2	100
World ranking	Number		4		
Annual growth in production 2000–11	%	2.6	3.1	0.3	5.1
Primary energy supply	**PJ**	**2045**	**2000**	**44 292**	**163 066**
	Mtce	135	68	1511	5564
Share of world	%		1.2	27.2	100
World ranking	Number		11		
Share of primary energy supply	%	36.5	34.7	19.9	27.5
Annual growth in supply 2000–11	%	0.6	-0.1	-0.4	5.5
Electricity generation					
Electricity output	TWh	176	165	3701	8653
Share of total	%	69.7	69.3	34.4	40.4
Exports	**Mt**	**301**	**280**	**440**	**1137**
Thermal coal	Mt	159	148	202	861
Share of world	%		17	23	100
World ranking	Number		2		
Export value	A$b	17.1	15.6		
Metallurgical coal	Mt	142	133	238	276
Share of world	%		48	86	100
World ranking	Number		1		
Export value	A$b	30.7	31.0		

a Black coal recoverable demonstrated resources, as at 31 December 2012

Source: BREE 2012c, 2012d; BP 2012; IEA 2012a, 2012b

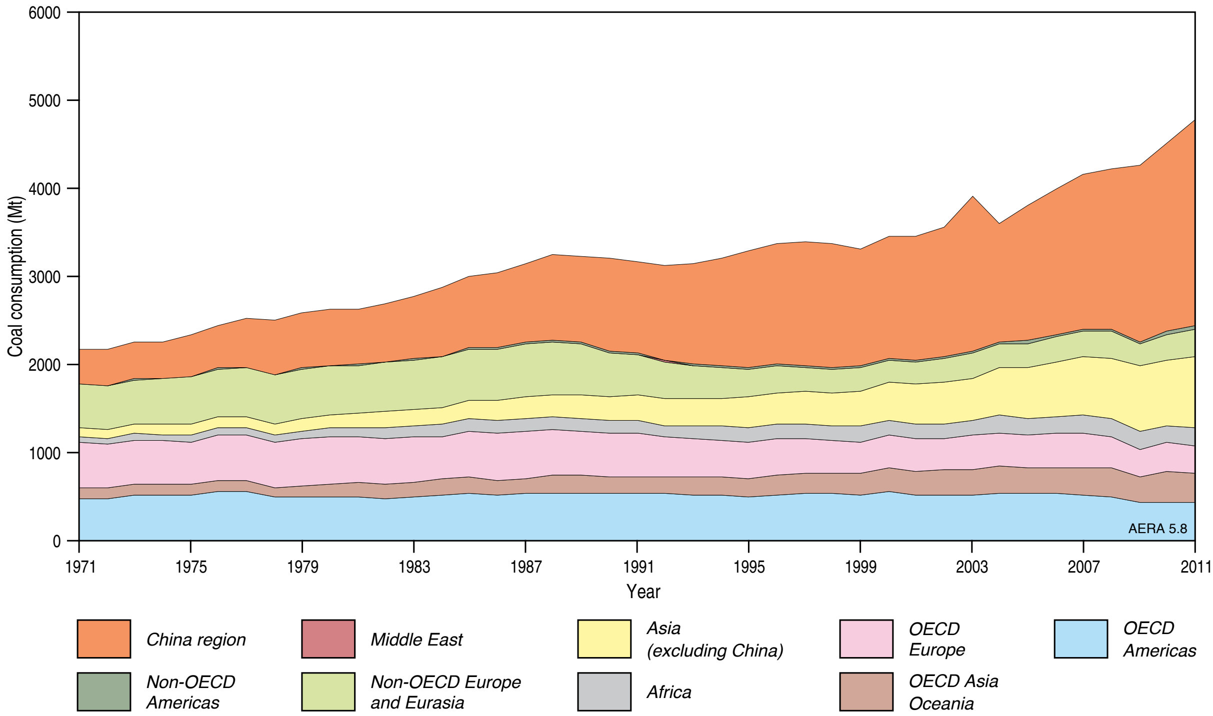

Figure 5.8 Black coal consumption by region

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 2012a

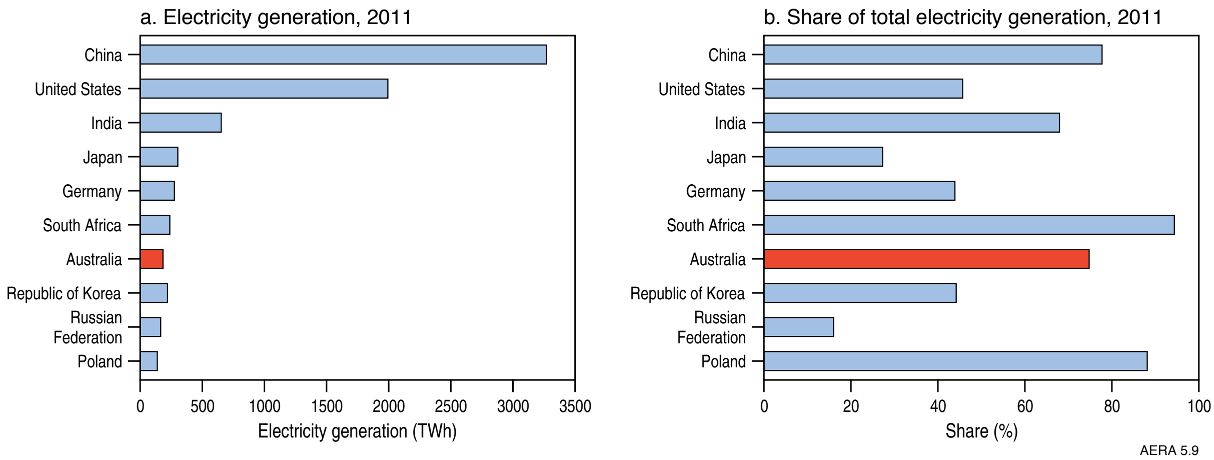

Figure 5.9 World electricity generation from coal, major countries, 2011

Source: IEA 2012a

In the OECD, European coal consumption declined by 38 per cent between 1971 and 2011 as policies have encouraged the use of nuclear, gas and renewable energy fuels for electricity generation.

Electricity generation

In 2010, electricity generation in China and the United States from coal-fired power plants was 3238 TWh and 1994 TWh, respectively (figure 5.9a).

In China, coal accounts for around 78 per cent of electricity generation, while it is around 46 per cent in the United States (figure 5.9b). South Africa is the only country reliant on coal for over 90 per cent of its electricity generation. Australia has a relatively high reliance on coal-fired electricity generation, at around 68 per cent in 2010–11.

Between 2000 and 2010, world coal-fired electricity generation increased by around 44 per cent to 8700 TWh. As a result, the share of coal-fired electricity generation increased from 39 per cent to 40 per cent of total electricity generation. The principal driver was China (including Hong Kong), where coal-fired electricity generation increased by 72 per cent between 2000 and 2010 (figure 5.10).

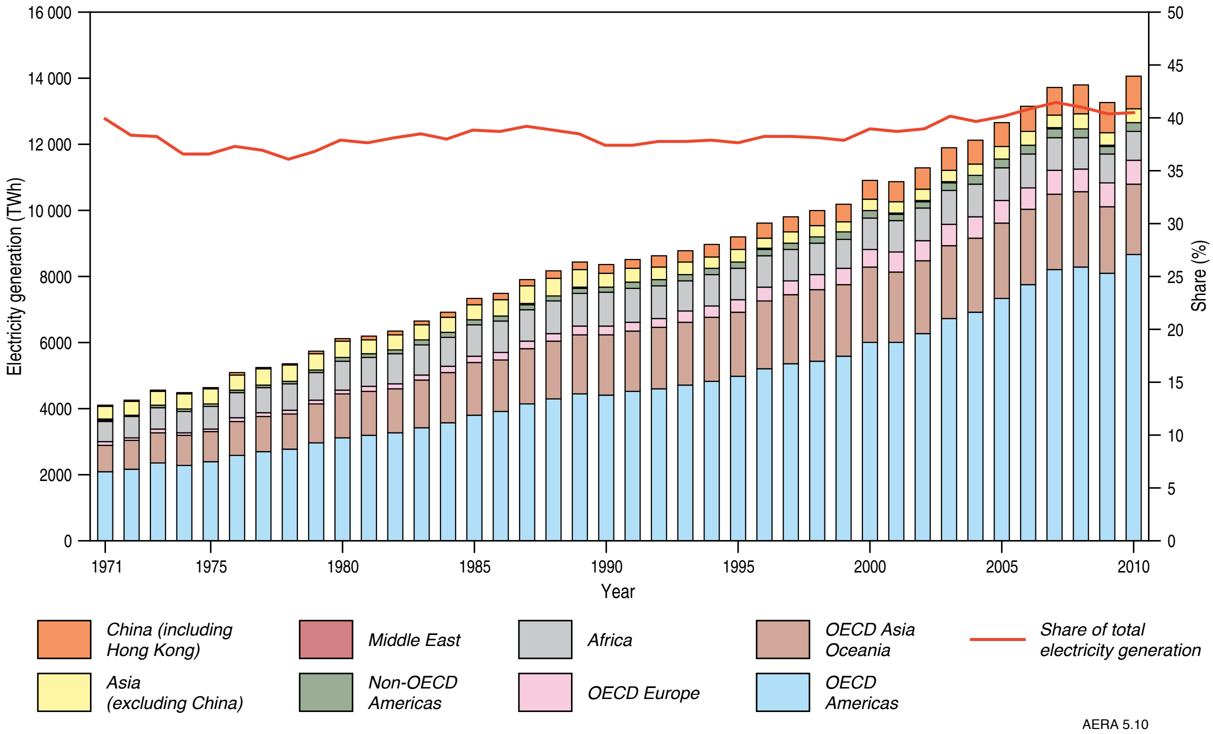

Figure 5.10 World coal-fired electricity generation and coal's share of total electricity generation by region

Source: IEA 2012b

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.

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) and north Africa. Supply is largely sourced from Colombia, South Africa, the Russian Federation and the United States.

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 more than half 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 2011, Australia exported over 280 Mt of coal, making it the world's second largest exporter of coal (figure 5.11).

Australian exports of metallurgical coal were 133 Mt and thermal coal 148 Mt. Australia is the world's largest exporter of metallurgical coal and the second largest exporter of thermal coal (figure 5.11). The world's largest exporter of thermal coal in 2011 was Indonesia, which exported around 309 Mt.

In 2011, the world's largest coal importer was China, importing 185 Mt, of which 146 Mt was thermal coal and 38 Mt was metallurgical coal (figure 5.12).

China's imports account for around 17 per cent of world coal imports. Japan and the Republic of Korea and Taiwan are also large coal importers, accounting for a further 16 per cent and 12 per cent of world coal imports in 2011.

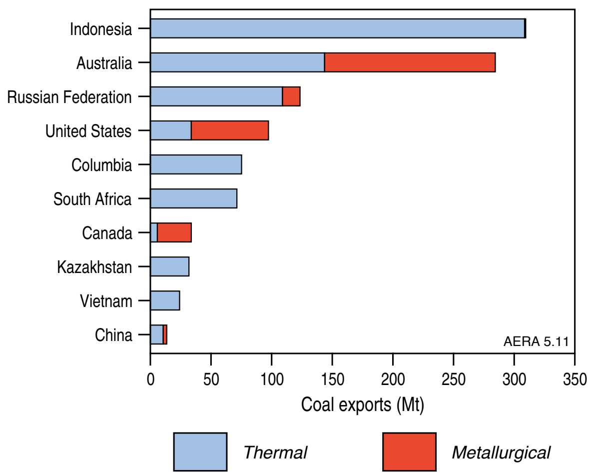

Figure 5.11 Thermal and metallurgical coal exports, major countries, 2011

Source: IEA 2012a

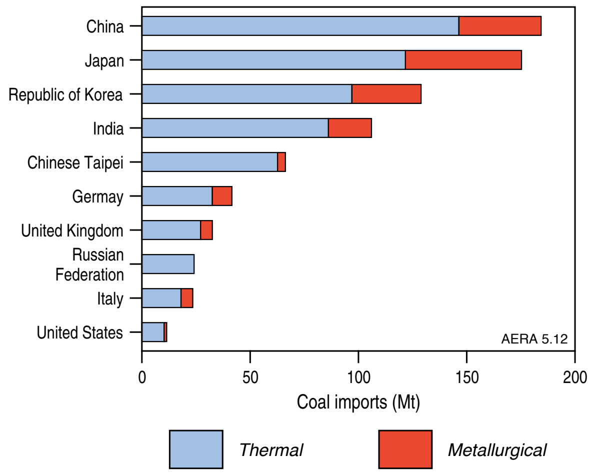

Figure 5.12 Thermal and metallurgical coal imports, major countries, 2011

Source: IEA 2012a

World coal market outlook

In its new policies scenario, the IEA projects world coal demand to increase at an average annual rate of 0.8 per cent to 176 599 TJ in 2035 (table 5.3). Coal demand as a share of total energy demand is projected to decrease from 27 per cent in 2010 to 25 per cent in 2035. In the non-OECD, coal consumption growth is projected to increase at an average annual rate of 1.4 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.

Table 5.3 IEA new policies scenario projections for world coal demand

	Unit	2010	2035
OECD	PJ	45 469	34 625
Share of total	%	20	15
Average annual growth	%		−1.1
Non-OECD	PJ	99 981	142 016
Share of total	%	34	30
Average annual growth, 2010–35	%		1
World	PJ	145 449	176 599
Share of total	%	27	25
Average annual growth, 2010–35	%		0.8

PJ = Petajoules; **Mtoe** = million tonnes of oil equivalent

Note: Data are converted from million tonnes of oil equivalent (Mtoe) to PJ by multiplying by 41.868

Source: IEA 2012c

OECD coal demand as a share of total energy demand is also projected to decrease by around 1.1 per cent over the period 2010 to 2035. The outlook for coal consumption in the European Union is particularly weak—falling by 2.6 per cent per year—reflecting an increase in market 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 1.3 per cent to 11 908 TWh in 2035 (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.

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 to 0.6 per cent per year between 2010 and 2035. Coal demand in 2035 would be about 45 per cent lower than in the new policies case, representing a decline of 1.6 per cent a year between 2007 and 2030 (IEA 2012c).

Table 5.4 IEA new policies scenario projections for world coal electricity generation

	Unit	2010	2035
OECD	TWh	3746	2794
Share of total electricity generation	%	34.5	21.0
Average annual growth, 2010–35	%		−1.2
Non-OECD	TWh	4940	9114
Share of total electricity generation	%	46.8	39.0
Average annual growth, 2010–35	%		2.5
World	TWh	8687	11 908
Share of total electricity generation	%	40.6	32.5
Average annual growth, 2010–35	%		1.3

Note: totals may not add due to rounding

Source: IEA 2012c

5.3 Australia's coal resources and market

5.3.1 Coal resources

Coal is produced in all Australian states. The largest resource and the greatest production of black coal are in Queensland and New South Wales. Victoria hosts the largest resource of brown coal and is the only state to produce brown coal. While black coal has been mined in New South Wales for more than 200 years, significant production of brown coal did not commence in Victoria until the 1920s. While Australia's mineable black coals range from Permian to Jurassic in age (280 to 150 million years old), most of Australia's black coal resources are of Permian age. Australia's brown coal deposits are predominantly Tertiary in age (50–15 million years old).

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 cover an area of approximately 120 000 km^2 and either outcrop along the basin margin or underlie a thin cover of younger sediments. Metallurgical and thermal coals are produced (predominantly for the export market) from numerous coal-bearing sequences throughout the basin.

The Galilee Basin is known to contain a significant resource of Permian black coal. Located to the west of the Bowen Basin and covering an area of some 200 000 km^2, as yet, there has been no coal produced from the Galilee Basin. Several major coal deposits have been identified and explorers are currently evaluating the potential of the Galilee Basin to sustain a viable coal seam gas (CSG) industry. Recoverable EDR for the identified deposits in the Galilee Basin are estimated at 6.3 million tonnes of black coal.

The southern half of the Bowen Basin is overlain by the Jurassic–Cretaceous sediments of the Surat Basin. The Surat Basin is a broad intra-cratonic basin that covers an area of 270 000 km^2 in Queensland and New South Wales. The basin hosts the Jurassic Walloon Coal Measures. The coal measures are a significant source of thermal coal for both the domestic and export market. In recent years, a major CSG industry has developed in Queensland. Three major CSG projects have been approved. The projects will produce gas from the Walloon Coal Measures and the Permian coals of the Bowen Basin and export it as LNG.

Thermal coal is also produced from the Jurassic coals of the Clarence–Moreton Basin and the Triassic coals of the Ipswich Basin. These basins are a source of coal for domestic electricity generation and industrial use in the Brisbane region and for export. Other Queensland coal basins include the Styx Basin (Cretaceous), the Mulgildie Basin (Jurassic), The Maryborough Basin (Cretaceous), the Tarong Basin (Triassic) and the Laura Basin (Jurassic).

The Sydney Basin covers an area of approximately 35 000 km^2 in New South Wales. The sediments of the Sydney Basin were deposited contemporaneously with the sediments of the Bowen Basin to the north. Unlike the Bowen Basin, however, the Sydney Basin coal sequences are overlain by a thick, uniform cover of Triassic sediments. As a consequence, coal developments in the Sydney Basin are focused near the basin margins where the overburden is relatively thin. The Sydney Basin passes to the north into the Gunnedah Basin. Both the Sydney and the Gunnedah Basins were active depocentres during the Permian and the Triassic. The Gunnedah Basin covers an area of approximately 15 000 km^2 and is estimated to contain approximately 1.3 million tonnes of recoverable metallurgical and thermal black coal EDR.

The Clarence–Moreton Basin straddles the state border between south-east Queensland and north-east New South Wales. While thermal coal is produced from the Jurassic Walloon Coal Measures in the Clarence–Moreton Basin in Queensland, coal is not mined in the basin within New South Wales.

The Gloucester Basin is a small (approximately 300 km^2) basin located 100 km to the north of Newcastle. Thermal coal is produced from the Permian coal measures from two mines within the basin.

Substantial resources of thermal coal are known to occur in the Permian Coorabin Coal Measures of the Oaklands Basin in the Riverina District of New South Wales. Currently, however, there is no coal produced from the basin.

In Western Australia, sub-bituminous Permian coals are mined for domestic electricity generation in the Collie Basin. While deposits of black coal have also been identified in the south-west (Perth, Wilga and Boyup Basins) and in the north-west (Canning Basin) of the state, none are mined at this time.

In South Australia, sub-bituminous Triassic coal measures at Leigh Creek are mined for domestic electricity generation. Major resources of sub-bituminous coal of Permian age occur in the Arckaringa Basin in central South Australia. While coal is not mined in the Arckaringa Basin, the potential for a commercial coal gas to liquids project using coal from the Arckaringa Basin is currently under evaluation.

The black coal measures in the Tasmania Basin are of sub-bituminous rank and Triassic in age. The Cornwall Colliery is Tasmania's principal operating mine and the colliery produces most of the black coal required by Tasmania's domestic market.

Australia's brown coal resources are of Tertiary age and are predominantly located in the Gippsland Basin in Victoria. Brown coal is mined in Australia exclusively for domestic electricity generation. Significant brown coal resources are also found in the Otway Basin in Victoria. Brown coal from the Otway Basin is used to produce domestic electricity at Anglesea. Significant resources of brown coal are also known to occur in the Murray Basin in western Victoria and South Australia, in the North St Vincents Basin in South Australia, and in the Eucla Basin in Western Australia. Minor brown coal resources occur in Tasmania in the Longford Basin. Brown coal is also known to occur at Waterpark Creek north of Yeppoon in Queensland.

Australia's coal resources are published under the McKelvey classification (table 5.5, Appendix D). Joint Ore Reserves Committee (JORC) (industry) reserves are also shown. JORC reserves provide an estimate of the proportion of Australia's EDR that is currently considered by companies to be commercially viable.

Black coal

In 2012, Australia's recoverable EDR of black coal were estimated at 61.1 Gt. Most of these resources are located in Queensland (61 per cent) and New South Wales (36 per cent) (figure 5.13). The Sydney Basin (30 per cent) and the Bowen Basin (31 per cent) contain most of Australia's recoverable EDR of black coal. These world-class coal basins contain nearly half of Australia's total resource of black coal and dominate black coal production in Australia. There are also significant black coal EDR in the Surat, Galilee and Clarence–Moreton Basins (figures 5.13 and 5.14). Most of Australia's black coal EDR is accessible.

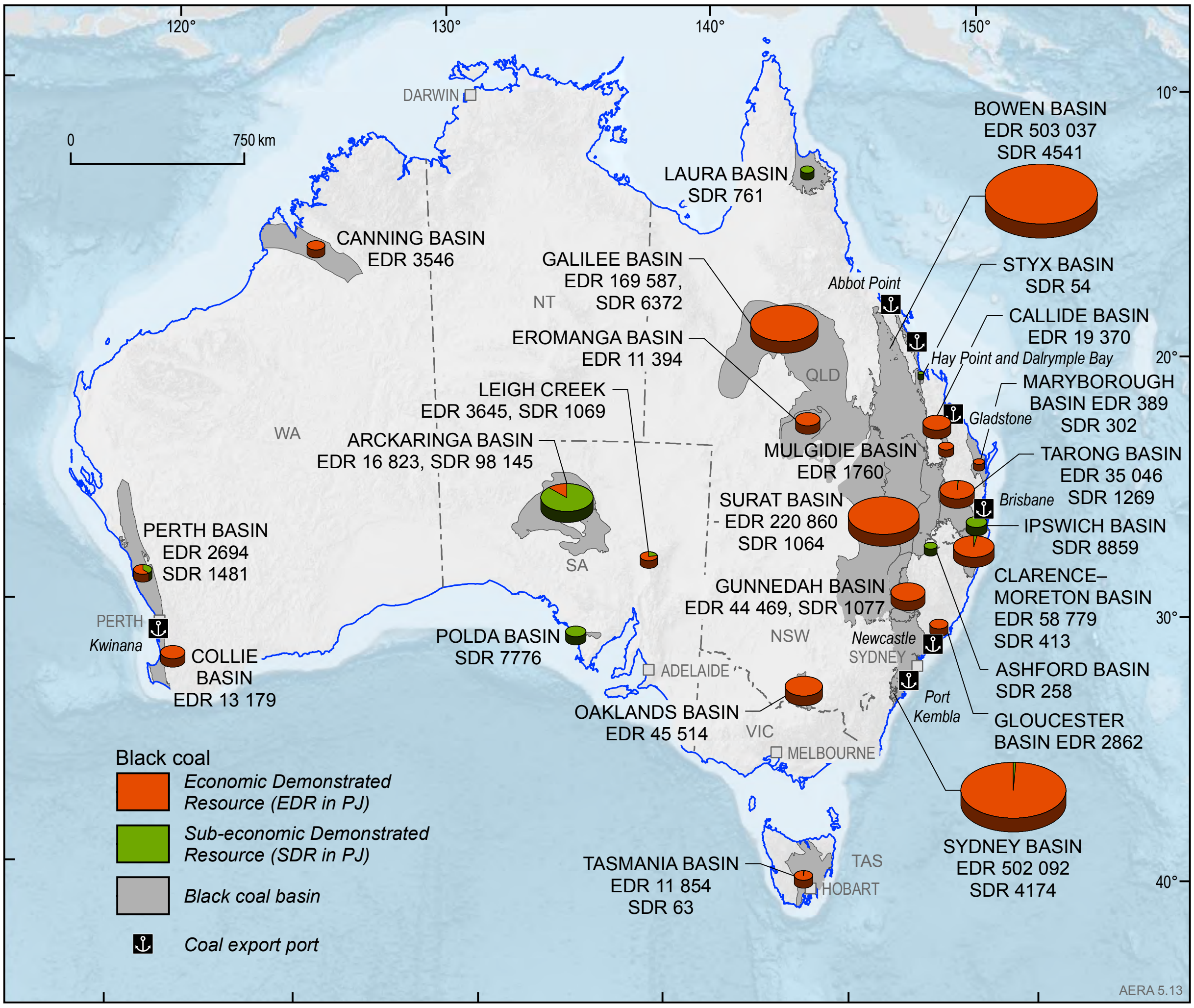

Figure 5.13 Black coal resources in Australia, as at 2012

Source: Geoscience Australia 2012

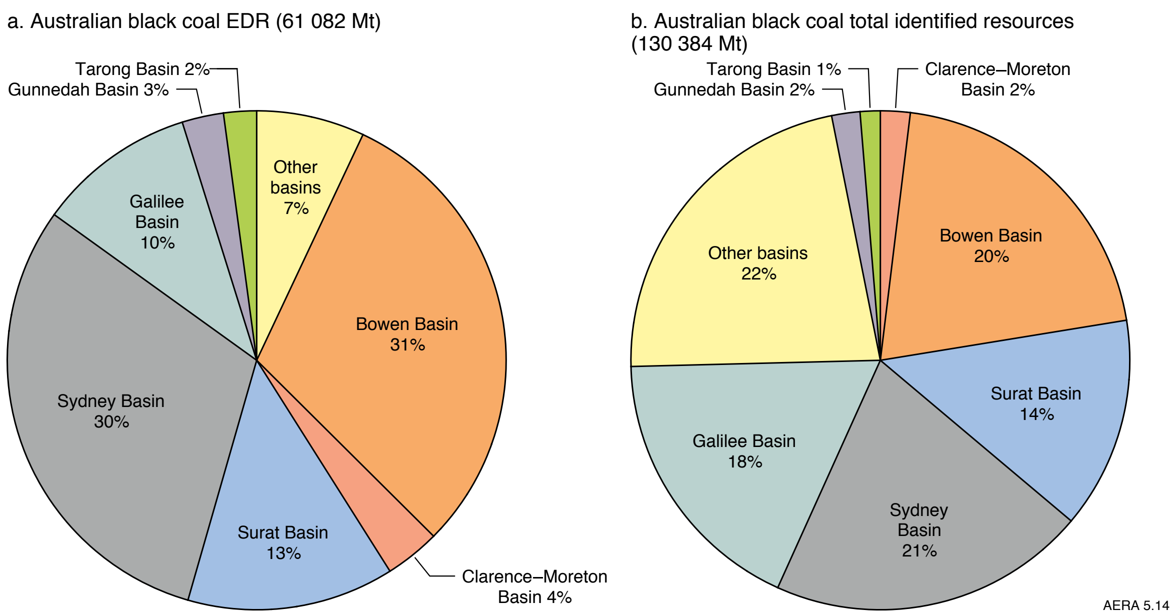

Figure 5.14 Australia's black coal resources by major basin, as at 31 December 2012

Source: Geoscience Australia 2012

Table 5.5 Australia's recoverable black and brown coal resources, as at 31 December 2012

Recoverable resources	Black coal (Mt)	Black coal (PJ)[a]	JORC reserves (Mt)
Economic	61 082	1 649 216	20 622
Sub-economic	5118	138 431	0
Inferred	64 184	1 621 198	0
Black coal total	**130 384**	**3 408 845**	**20 622**
	Brown coal (Mt)	Brown coal (PJ)	JORC reserves[b] (Mt)
Economic	44 164	435 586	0
Sub-economic	48 587	489 617	0
Inferred	102 502	1 022 587	0
Brown coal total	**195 253**	**1 947 790**	**0**
Coal total	**325 637**	**5 356 635**	**20 622**

JORC = Joint Ore Reserves Committee

a Includes estimates where operating mines have no JORC reserves. **b** No brown coal JORC reserves are available

Source: Geoscience Australia 2012

BHP Billiton Limited (BHPB), Glencore-Xstrata and Rio Tinto Limited (Rio) are the largest owners of black coal EDR in Australia. Together, the three companies own approximately 33 per cent of Australia's accessible black coal EDR. While BHPB, Glencore-Xstrata and Rio maintain dominant positions in the Australian coal industry, in recent years their dominance has been increasingly challenged by the acquisition of coal projects and operating mines by other foreign-owned companies.

The resource life of Australia's black coal EDR (61.1 Gt) is 110 years at current rates of production. Australia's black coal JORC reserves are estimated at 20.7 Gt or 34 per cent of EDR. Included in the JORC reserves are Geoscience Australia estimates of reserves (1.2 Gt) for some deposits for which JORC reserves have not been reported. The resource life of the JORC reserves is 40 years at current rates of production.

It is estimated that Australia also has 5.1 Gt of sub-economic black coal resources. Most of these are located within the Arckaringa Basin, South Australia. In 2012, estimates of Australia's sub-economic black coal resources fell slightly. In addition, there is a substantial resource of inferred black coal in Australia. In 2012, inferred black coal resources were estimated at 64.2 Gt and to be almost equivalent to estimates of recoverable black coal EDR. The inferred resources are predominantly located in the Bowen, Galilee, Arckaringa and Sydney basins (table 5.6). Increased expenditure on coal exploration during the past decade has resulted in a significant increase in estimates of inferred coal resources in the Gunnedah and Galilee Basins.

Estimates of Australia's black coal resources from 1976 to 2012 are shown in figure 5.15. The steep increase in EDR in 1987 was due to a major reassessment of New South Wales coal resources that was undertaken in 1986 by the then New South Wales Department of Mineral Resources and the Joint Coal Board. The decline in EDR between 1998 and 2008 resulted from increased mine production and revisions to reserves undertaken by industry as part of compliance with the JORC Code. Between 2008 and 2011, estimates of Australia's black coal EDR increased from 39.2 Gt to 61.1 Gt. This increase was driven by high levels of exploration expenditure that led to significant reassessment of coal resources in the Galilee Basin.

Major increases in black coal production over the past 40 years has seen the resource life of Australia's black coal fall from around 300 years to 110 years (figure 5.16).

Table 5.6 Australia's recoverable black coal resources by basin, as at 2012

Category	Basin	Million tonnes	Petajoules
EDR	Sydney	18 596	502 092
EDR	Bowen	18 631	503 037
EDR	Surat	8180	220 860
EDR	Galilee	6281	169 587
EDR	Gunnedah	1647	44 469
EDR	Arckaringa	623	16 823
EDR	Other	7124	192 348
Total EDR		**61 082**	**1 649 216**
SDR	Sydney	146	4174
SDR	Bowen	168	4541
SDR	Surat	39	1064
SDR	Galilee	236	6372
SDR	Gunnedah	40	1077
SDR	Arckaringa	3635	98 145
SDR	Other	854	23 058
Total SDR		**5118**	**138 431**
INF	Sydney	8043	217 161
INF	Bowen	12 892	348 084
INF	Surat	9640	260 280
INF	Galilee	16 731	451 737
INF	Gunnedah	710	19 170
INF	Arckaringa	9472	143 974
INF	Other	6696	180 792
Total INF		**64 184**	**1 621 198**
Total EDR + SDR + INF		**130 384**	**3 408 845**

Source: Geoscience Australia 2012

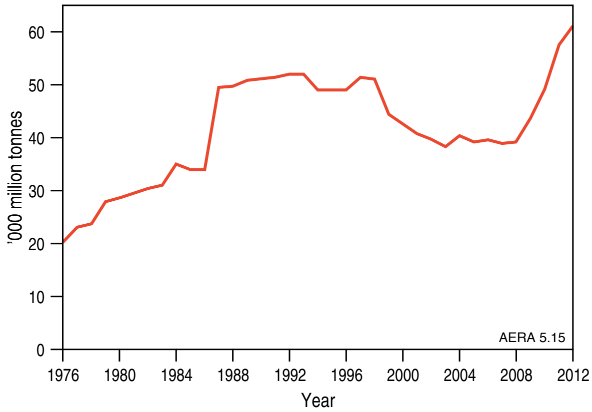

Figure 5.15 Black coal economic demonstrated resources, 1976 to 2012

Source: Geoscience Australia 2012

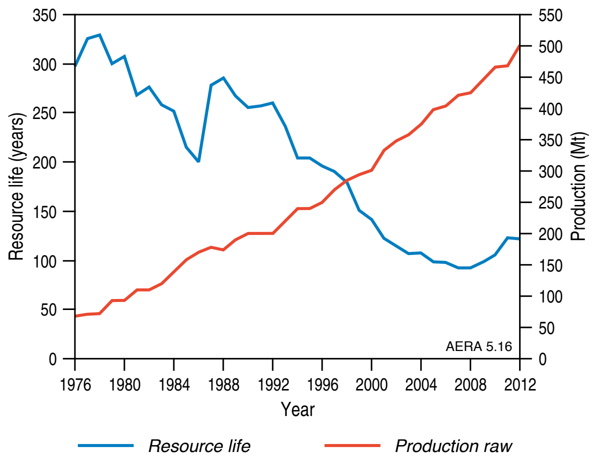

Figure 5.16 Black coal resource life and production, 1976 to 2012

Source: Geoscience Australia 2012

Brown coal

In 2012, Australia's recoverable EDR of brown coal was estimated at 44.2 Gt. Almost all of these resources (99 per cent) are located in the Gippsland Basin, Victoria. Approximately 90 per cent of the resources are located in the La Trobe Valley (figure 5.17).

Approximately 78 per cent of Australia's brown coal EDR is accessible. Quarantined resources include the APM Mill site (a 50-year mining ban was applied in 1980) and coal that lies under the township of Morwell and the Holey Plains State Park. JORC reserve estimates are not available for brown coal.

In addition to EDR, it is estimated that there are large sub-economic and inferred resources of brown coal in the Gippsland, Murray and Otway basins (figure 5.17, table 5.7).

Australia's EDR of brown coal has remained relatively constant since 1976 (figure 5.18). A doubling of production over the past 40 years has resulted in a reduction of the resource life of brown coal to around 510 years.

Table 5.7 Australia's recoverable brown coal resources by basin, as at 2012

Category	Basin	Million tonnes	Petajoules
EDR	Gippsland	43 318	424 526
EDR	Eucla	513	7798
EDR	Otway	333	3262
Total EDR		**44 164**	**435 586**
SDR	Gippsland	42 134	412 910
SDR	Murray	3311	32 449
SDR	St Vincent	1933	29 385
SDR	Otway	845	8280
SDR	Eucla	364	5554
Total SDR		**48 587**	**488 578**
INF	Gippsland	77 928	763 694
INF	Murray	13 307	130 409
INF	Otway	8961	87 818
INF	Eucla	1746	26 539
INF	Moe Swamp	573	5615
INF	St Vincent	560	8512
Total INF		**102 502**	**1 022 587**
Total EDR + SDR + INF		**195 253**	**1 946 751**

Source: Geoscience Australia 2012

Coal exploration

In 2011–12, expenditure on coal exploration in Australia reached record levels. Data published by the Australian Bureau of Statistics (ABS 2013) show that over the past five years, annual expenditure on coal exploration increased from A$192.6 million to A$834.3 million in 2011–12. In 2011, over 80 per cent of coal exploration expenditure occurred in the Bowen and Galilee basins, Queensland. The remaining expenditure occurred predominantly in the Sydney and Gunnedah basins, New South Wales. In 2011–12, the ABS reported a combined total of about A$12 million expenditure on coal exploration in South Australia, Western Australia, Tasmania, Northern Territory and Victoria.

In 2011–12, expenditure on coal exploration accounted for 21.1 per cent of the total expenditure on mineral exploration in Australia. The previous sustained period of high levels of coal exploration was during the early 1980s. This occurred in response to world energy shocks and a broadly based resources boom. The boom resulted in a significant upgrade of Australia's coal resources, particularly in the Bowen Basin.

5.3.2 Coal market

Production

Australia's combined production of saleable black and brown coal is shown in figure 5.19. Production in 2011–12 was estimated to be around 504 Mt (10 585 PJ), which represents an average annual increase of 5 per cent from 1960–61. Black coal accounted for 85 per cent or 430 Mt (9769 PJ). Queensland and New South Wales accounted for the majority of this production: 38 per cent and 43 per cent respectively.

Brown coal production in 2011–12 was estimated to be around 74 Mt (815 PJ), all from Victoria.

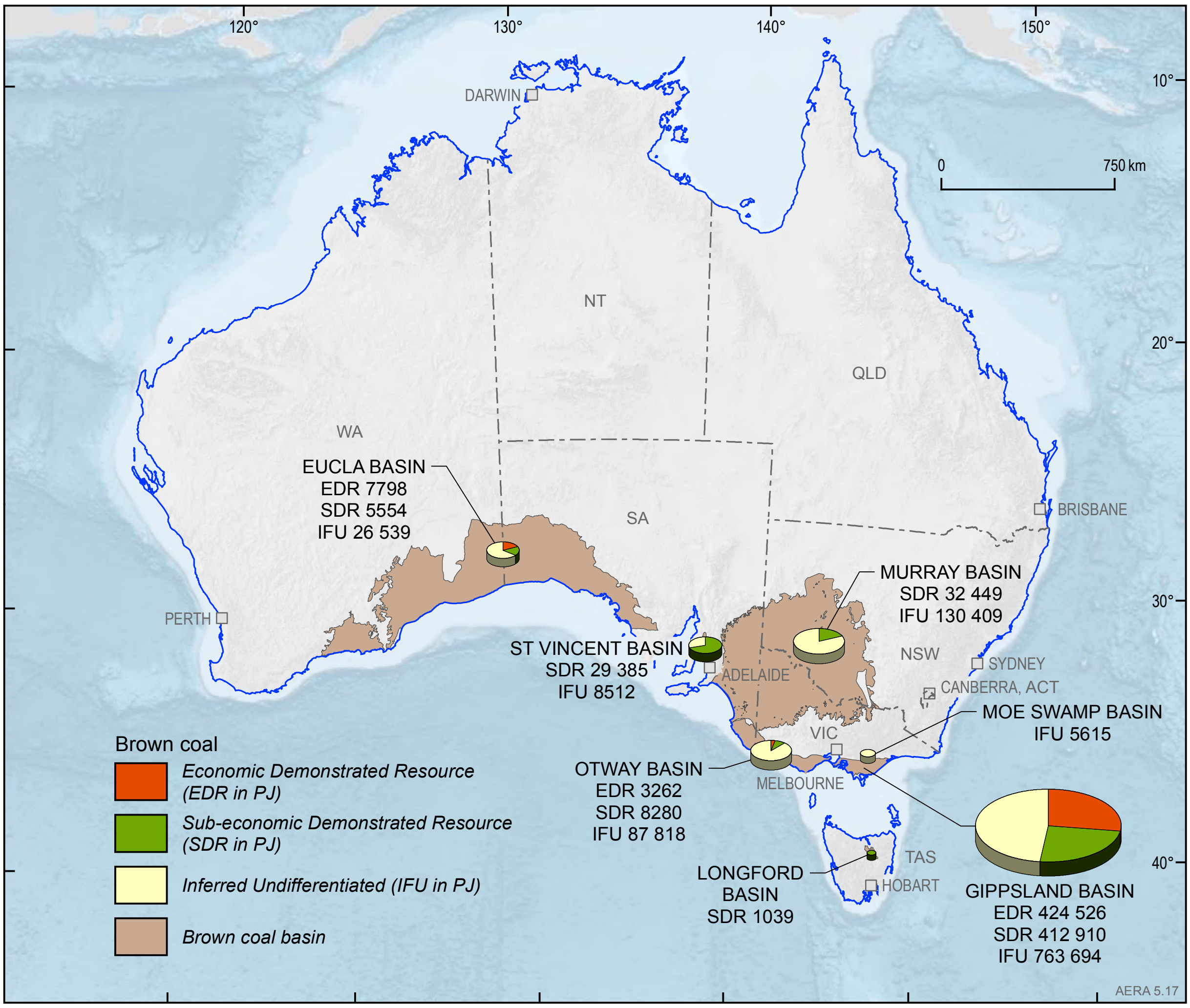

Figure 5.17 Brown coal resources in Australia, as at 2012

Source: Geoscience Australia

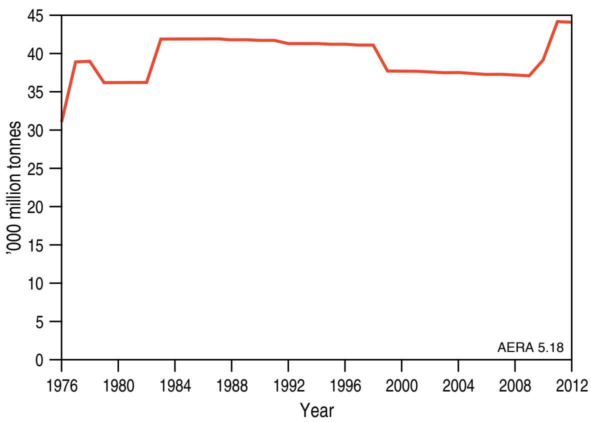

Figure 5.18 Brown coal economic demonstrated resources, 1976 to 2012

Source: Geoscience Australia

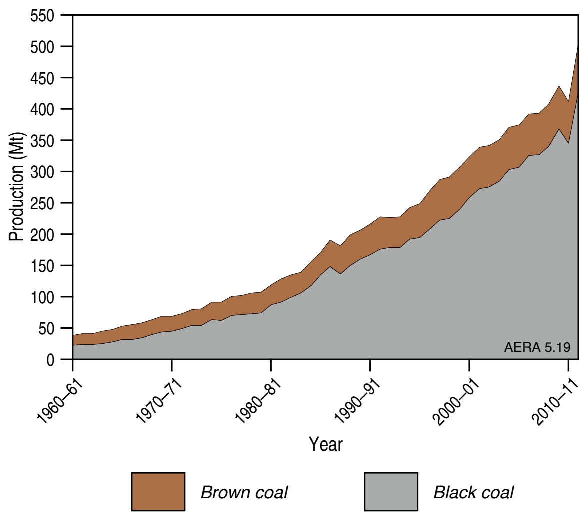

Figure 5.19 Australia's production of black and brown coal

Source: BREE 2012c

[Figure 5.20](#) 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 north-west of Newcastle. There are also a number of mines in the Gunnedah Basin (200 km north-west 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 2011–12, Australia's coal consumption was around 2045 PJ (135 Mt). Since 1973–74, Australia's coal consumption has increased at an average annual rate of 2 per cent (figure 5.21), mainly driven by increased demand for electricity associated with economic and population growth (figure 5.22). Coal consumption has been falling since 2008–09 reflecting substitution away from coal in electricity generation.

Electricity generation

In 2011–12, around 70 per cent of Australia's electricity was generated from coal. Coal's share of electricity generation has ranged between 65 and 85 per cent since the 1960s (figure 5.23). 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.

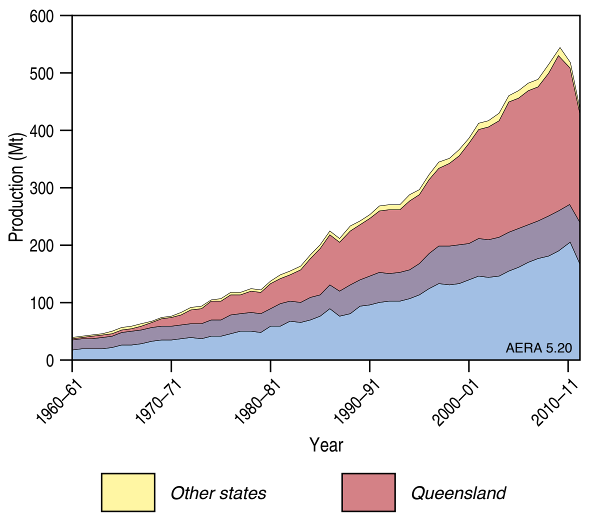

Figure 5.20 Production of coal by state

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

Source: BREE 2012c

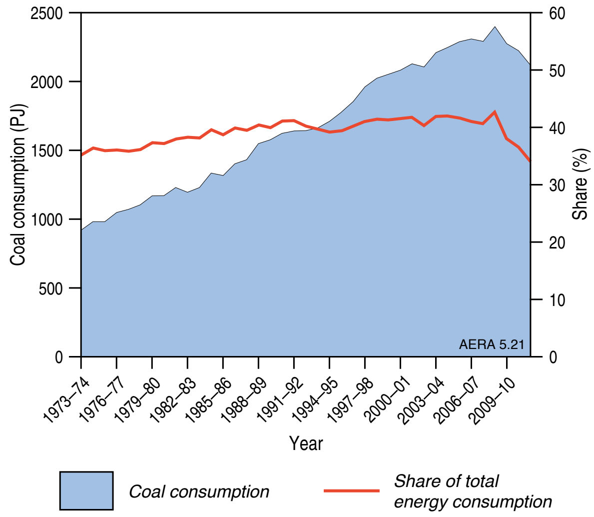

Figure 5.21 Australian coal consumption and share of total electricity generation

Source: BREE 2012a

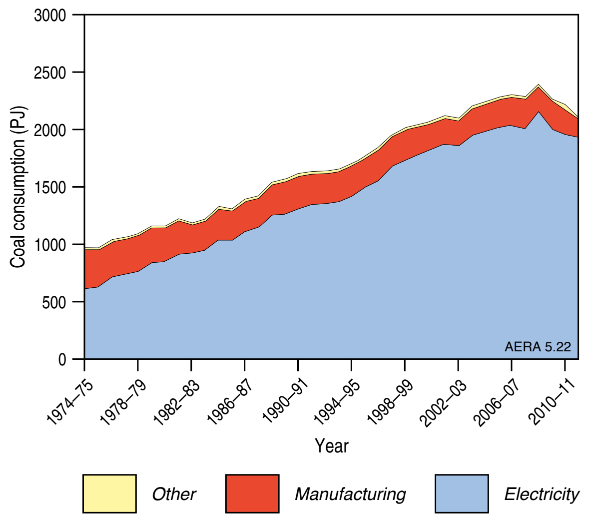

Figure 5.22 Australian coal consumption by sector

Note: other includes the residential, transport, services and mining sectors

Source: BREE 2012a

Trade

In 2011–12, Australia exported around 70 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 have been exported from Kwinana in Western Australia. Newcastle is the largest port and in 2011–12, coal exports from Newcastle totalled around 122 Mt.

In 2011–12, Australia exported around 301 Mt of coal—142 Mt of metallurgical coal and 159 Mt of thermal coal (figure 5.24). 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, China and Taiwan are Australia's major export markets for thermal coal, accounting for approximately 95 per cent of Australian exports. 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 2011–12 was A$48 billion, an increase of 9 per cent from 2010–11. The value of thermal coal exports increased by 23 per cent to A$17 billion and metallurgical coal exports increased 3 per cent to A$31 billion (figure 5.25).

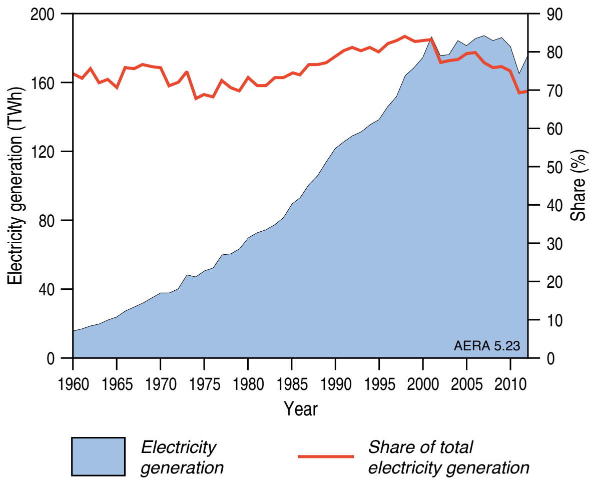

Figure 5.23 Australian use and share of coal in thermal electricity generation

Source: IEA 2012b

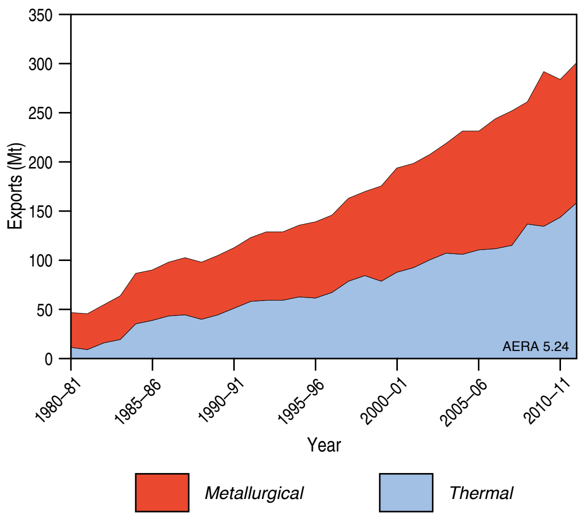

Figure 5.24 Australia's exports of thermal and metallurgical coal

Source: BREE 2012c

Supply–demand balance

Australia's black coal production has significantly exceeded domestic consumption and the surplus has been sold into international markets (figure 5.26a).

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 and India.

In contrast, all of Australia's brown coal production is consumed domestically (figure 5.26b). Production is 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.

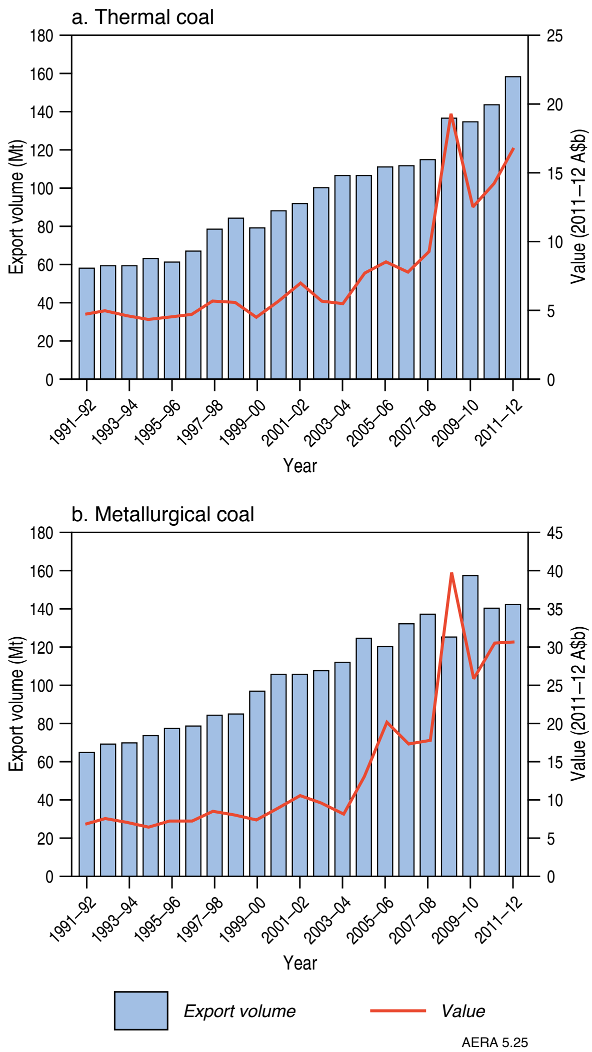

Figure 5.25 Export volume and value of thermal and metallurgical coal

Source: BREE 2012c

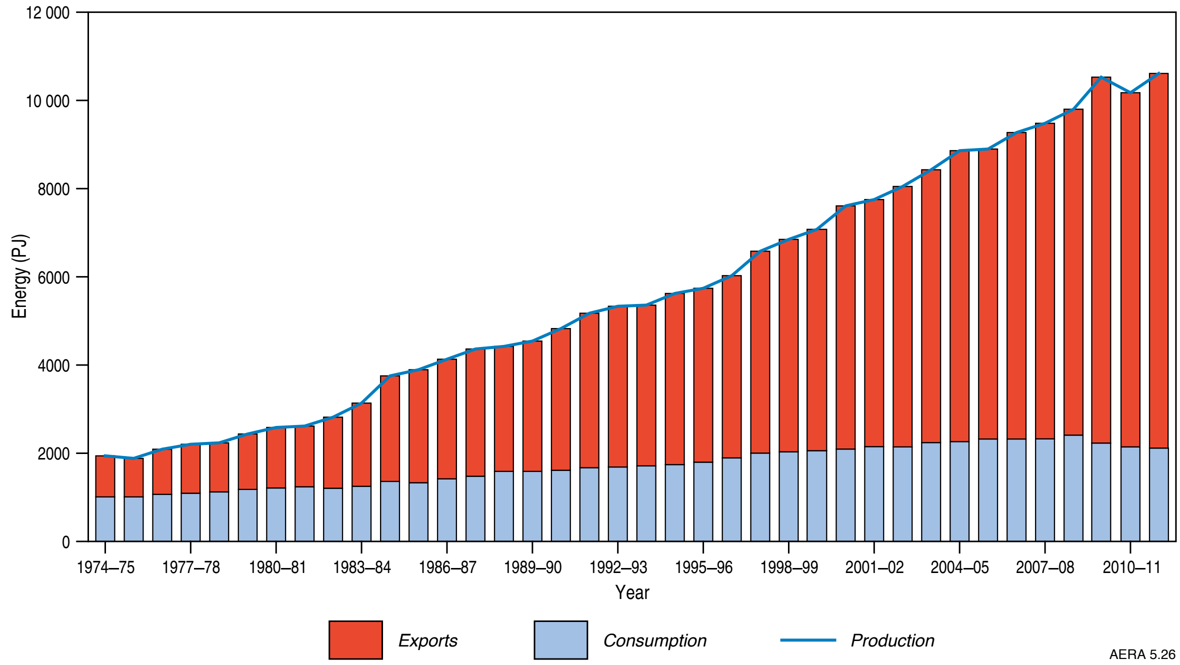

Figure 5.26 Australia's exports and consumption of black and brown coal

Source: BREE 2012a

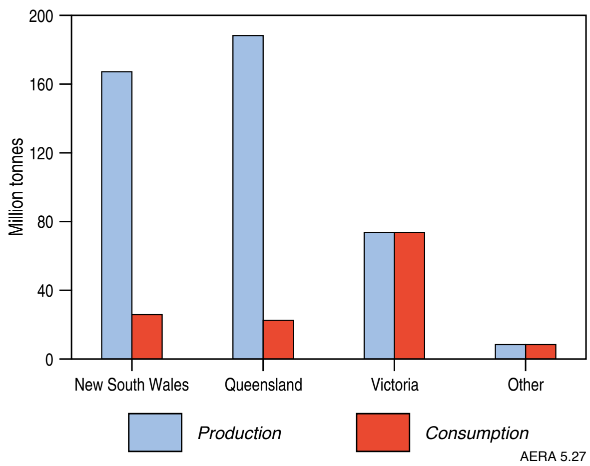

Figure 5.27 Production and consumption of saleable coal by state, 2011–12

Source: BREE 2012c, 2012d

The majority of Australia's coal consumption occurs in New South Wales, Queensland and Victoria (figure 5.27). In terms of tonnage, Victoria is responsible for just over half of Australia's coal consumption. However, in energy terms, New South Wales and Queensland account for nearly 60 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.

Major development projects recently completed

The recent completion of coal mine and infrastructure projects has underpinned the expansion of Australia's coal exports. In the three years to October 2013, 26 mine projects have been completed with an estimated capital expenditure of approximately A$6.5 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 were completed at an estimated capital cost of over A$5 billion. 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 301 Mt in 2012.

5.4 Outlook for Australia's resources and market

- Future growth of Australia's coal production and exports will depend on global economic growth, coal prices, adequacy of coal handling infrastructure, improved productivity, and local water and environmental issues.
- The development of cost-effective lower emission coal technologies will be critical if coal is to remain the dominant fuel used in electricity generation.

5.4.1 Key factors influencing the outlook

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

- Under the IEA new policies scenario world coal demand is projected to grow at an annual rate of 0.8 per cent to 2035 (IEA 2012c).

Table 5.8 Coal mining projects completed since April 2010

Project	Location	Capital expenditure (A$million)[a]	Completed in the six months prior to:
Austar underground (stage 3)	NSW	250	October 2013
Broadmeadow (mine life extension)	QLD	874	October 2013
Daunia	QLD	1553	October 2013
Kestrel	QLD	2105	October 2013
Millennium	QLD	270	October 2013
Bengalla expansion (stage 1)	NSW	141	October 2012
Burton	QLD	300	October 2012
Curragh Mine	QLD	286	October 2012
Hunter Valley Operations Expansion	NSW	255	October 2012
Mount Arthur (RX1)	NSW	388	October 2012
Narrabri Coal Project (stage 2)	QLD	300	October 2012
Middlemount (stage 1)	QLD	500 (includes stage 1 and 2)	April 2012
Newlands Northern Underground	QLD	147	April 2012
Oaky Creek	QLD	88	April 2012
Wilpinjong	NSW	95	April 2012
Integrated Isaac Plains Project	QLD	86	October 2011
Mangoola	NSW	US$80 million	April 2011
Moolarben	NSW	405	April 2011
Mount Arthur Open-cut	NSW	US$260 million	April 2011
Blakefield South	NSW	US$330 million	October 2010
Cameby Downs	QLD	250	October 2010
Clermont Open-cut	QLD	US$1300 million	October 2010
Narrabri	NSW	227	October 2010
Blackwater Creek Diversion	QLD	130	April 2010
Carborough Downs Longwall	QLD	375	April 2010
New Acland (stage 3)	QLD	36	April 2010

a unless stated otherwise

Source: BREE 2013a

Table 5.9 Coal infrastructure projects completed since April 2010

Project	Location	Capital expenditure (A$million)[a]	Completed in the six months prior to:
NCIG export terminal (stage 3)	NSW	1000	October 2013
Goonyella to Abbot Pt (rail) (X50)	QLD	1100	October 2012
Kooragang Island coal terminal expansion	NSW	670	April 2012
Abbot Point Coal Terminal X50 expansion	QLD	818	October 2011
Abbot Point Coal Terminal yard refurbishment	QLD	68	October 2011
Brisbane Coal Terminal Expansion	QLD	10	October 2010
Coppabella to Ingsdon Rail Duplication	QLD	80	October 2010
Kooragang Island Expansion	NSW	458	October 2010
Minimbah Bank Third Line (stage 1)	NSW	134	October 2010
NCIG export terminal	NSW	US$1100 million	October 2010

a unless stated otherwise

Source: BREE 2013a

- Growth in demand is expected to come from non-OECD countries, mostly in Asia. More than two-thirds 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.
- 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.

Global growth and demand for coal

In the IEA new policies scenario (IEA 2012c), world electricity demand is expected to grow at an annual rate of 2.2 per cent to 2035 and underpin strong demand for coal. Coal electricity generation is expected to grow at an annual rate of 1.3 per cent in the period to 2035.

Virtually all 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 1.1 per cent to 2035, continuing a long-term decline in the OECD share of global coal consumption. More than 68 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 2012c).

In the IEA's 450 scenario global coal demand declines by 1.6 per cent a year to 2035 and is 45 per cent lower in 2035 than under the new policies scenario (IEA 2012c). This reduced global coal demand is expected to flow through to reduced production by exporting countries with almost 60 per cent of the reduction in production borne by non-OECD countries.

Under the IEA's new policies scenario global coal trade is expected to continue to grow. However, Chinese import demand is expected to decline as it diversifies electricity generation away from coal. India's net coal imports are projected to increase fourfold between 2010 and 2035. Australia is projected to remain the world's largest coal exporter (IEA 2012c).

This strong demand for energy in the IEA's new policy scenario 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. Under the IEA's new policy scenario there is the potential for Australia's coal exports to exceed 380 Mt per year by 2035, from around 270 Mt in 2010 (IEA 2012c). 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 2011, Mongolia exported around 22 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 and foreign investment policy position.

Over the decade to 2011, Colombia's coal exports have nearly doubled to 76 Mt. The strong growth reflects Colombia's production of high-energy, low-sulfur coal, which is exported to the United States and the European Union. In the medium term, Colombian exporters are expected to begin exporting larger quantities to the Asia–Pacific market as a result of weakening import demand in the European Union and the United States. Although transportation costs from Colombia to East Asia are relatively high, export growth will be supported by low operating costs and high-quality coal (low sulfur content and high calorific value) as well as policies in some Asian countries that promote diverse import supply bases.

Strong demand for coal over the period 2000 to 2012 resulted in substantial increases in coal prices (see box 5.1 for explanation of coal prices). In the past few years, increasing supply and competition for key Asia-Pacific import markets have resulted in lower coal prices and both thermal and metallurgical coal contract prices have declined from the record high levels of 2011. Projected demand for coal over the next 20 years is expected to create significant opportunity for further 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 such as managing production costs, improving productivity, accessing undeveloped deposits and infrastructure constraints.

Australia has a substantial coal resource base

Australia has 9 per cent of the world's recoverable EDR of black coal and 23 per cent of the world's recoverable EDR of brown coal. Australia ranks fourth in the world (behind the United States, the Russian Federation and China) in terms of total recoverable economic coal resources. Australia also has substantial sub-economic and inferred resources of black and brown coal. Australia's total identified recoverable resource of black coal is estimated at about 130 Gt. Total identified recoverable brown coal resources are estimated at about 195 Gt. While the ultimate resource potential of Australia's coal-bearing basins has not been fully assessed, it could be in excess of one trillion tonnes.

There are over 25 Australian sedimentary basins in which either identified coal resources have been estimated or coal is known to occur. There are several underexplored basins where significant undiscovered coal resources are thought to exist (table 5.10).

The Pedirka, Cooper and Canning basins are all considered prospective for black coal. Due to the high quality of Queensland and New South Wales coals and the proximity of the coal deposits to infrastructure, however, coal exploration is predominantly focused on Australia's eastern sedimentary basins.

In 2010–11, strong demand for coal stimulated record levels of coal exploration. While the focus on established producing coal basins continues, there has been renewed interest in coal resources located in the more remote, frontier areas.

Table 5.10 Australia's coal resource potential

Basin	Basin age (million years)	Potential resources (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 2012

Coal-bearing sediments extend across vast areas of the continent. This broad geographic distribution reflects the variety of geological settings under which the coal was formed. These range from tectonically active basin margins and troughs (such as the Bowen and Sydney basins), to the more stable intra-cratonic areas (such as the Galilee and Cooper basins).

Future additions to Australia's identified coal resource base are likely to result from new discoveries both in established coal-producing basins and underexplored frontier basins. Most producing coal basins have potential for resource growth. Producing coal basins with the greatest potential for growth are the Sydney and Gunnedah basins.

In the Sydney Basin, total identified recoverable black coal resources are estimated at 26.8 Gt. These resources underlie a relatively small part of the basin. There is potential for additional coal resources to be present both at depth and in areas that are not currently mined. It should be noted, however, that although there is considerable potential for additions to be made to the coal resource base in the Sydney Basin, there are impediments to future mining developments. These include accessibility of the resource due to the presence of national parks, urban development, infrastructure, stored bodies of water, strategic agricultural land and the competing interests of a developing coal seam gas industry.

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. 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 and place of delivery as well as other conditions.

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, European Union 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 (figure 5.28). 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.

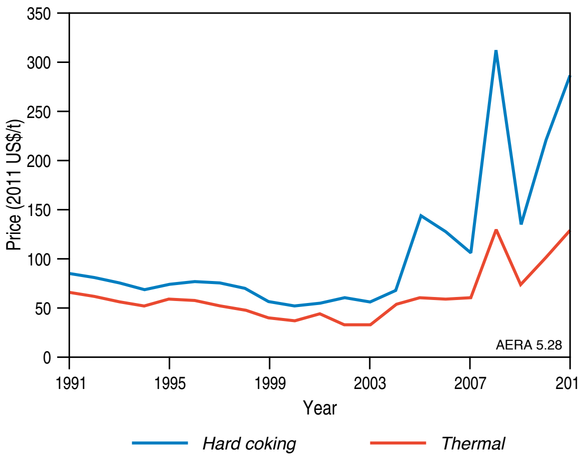

Figure 5.28 Australia–Japan coal contract prices

Source: BREE 2012c

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 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.

Recoverable identified coal resources in the Bowen Basin are estimated at 26.8 Gt. Recent exploration has identified substantial resources of coal at depths of less than 300 m. The development of some of these resources will require the resolution of competing land use issues and the construction of new infrastructure.

While coal production from the Galilee Basin has not yet commenced, the basin is emerging as a future producer of significant tonnages of thermal coal. Between 2008 and 2012, recoverable identified resource estimates for the basin increased from 7 Gt to 23.2 Gt. It is likely that the identified resource base will further increase as exploration of the basin progresses. Future developments in the basin will require the construction of significant infrastructure to facilitate the transport of coal from the projects proposed in the eastern Galilee Basin to coal export terminals located at Abbot Point, Hay Point and Dalrymple Bay.

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 at the announced, feasibility or committed stage (tables 5.11, 5.12 and 5.13) 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 5.14, 5.15 and 5.16).

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. Large-scale coal production in the Surat Basin will be possible once the Surat Basin Rail has been constructed—a 210 km rail link between Wandoan and Theodore. Construction of rail links will be capital intensive. For example, the Surat Basin rail is currently estimated to cost $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 has been increased by completion of stage 2 of the Newcastle Coal Infrastructure Group (NCIG) terminal (23 Mt per year) (BREE 2013b).

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 gas 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 5.3), 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 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 than 800 kg CO_2 per MWh with the use of supercritical and ultra-supercritical plants (figure 5.29). 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 subcritical 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 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 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

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 5.29). 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) (box 5.4).

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).

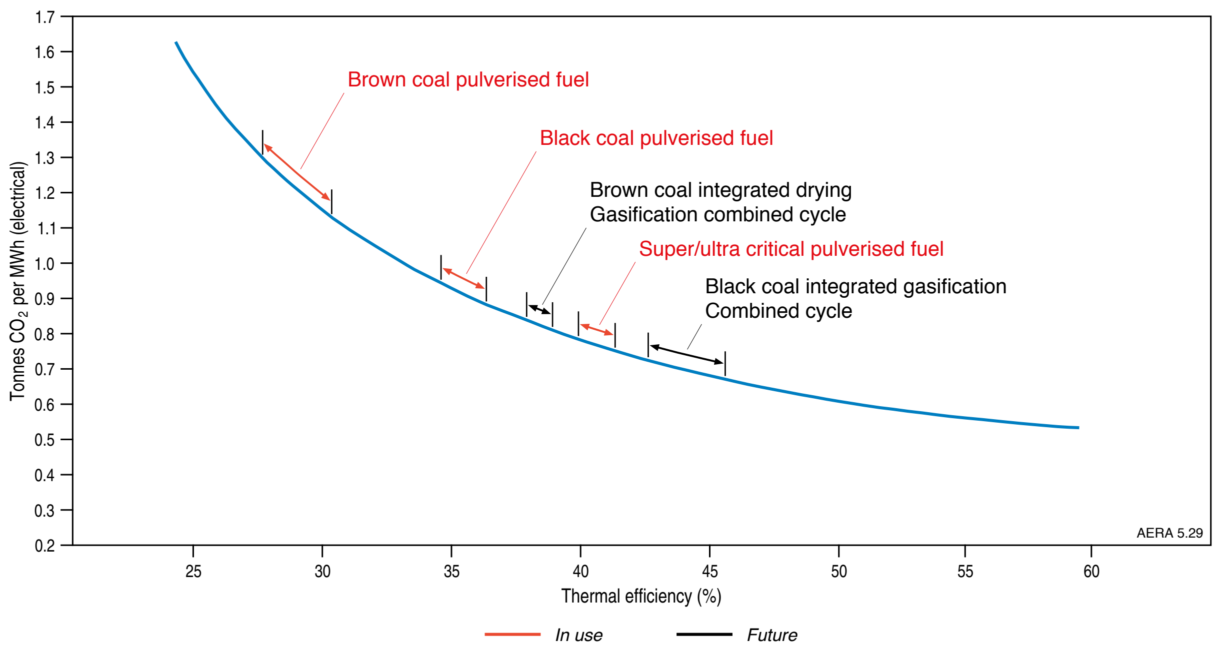

Figure 5.29 Thermal efficiencies and carbon dioxide emissions from various coal-fired power generation technologies (without CCS). Technologies in red indicate those in current use, whereas those in black are still to be deployed

Source: CSIRO 2009

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.

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).

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).

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).

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 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.

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).

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).

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.

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).

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 limited interest in CTL projects 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.

BOX 5.3 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 5.30). 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.

IGCC without carbon capture and storage is approaching commercial deployment. There are 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/ Mitsubishi Heavy Industries, and the 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.

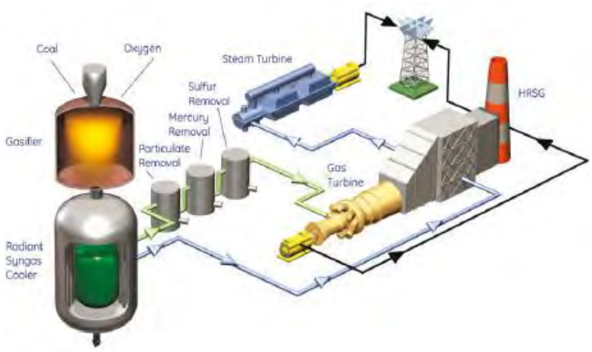

Figure 5.30 Integrated Gasification Combined Cycle with carbon capture and storage/sequestration

Source: Image Courtesy of GE Energy

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 551 Mt of GHG emissions are the result of fossil-fuel energy production (including electricity generation, transport, and manufacturing and construction) (DCCEE 2012). 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 almost 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 5.31). One of the most critical factors in geological storage is identifying rocks with suitable pore volumes for storage and cap rocks for sealing.

Many sedimentary rocks, particularly sandstones, contain large volumes of fluids and gases (including 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 5.32). 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 aquifers, 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 5.33). 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 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; 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

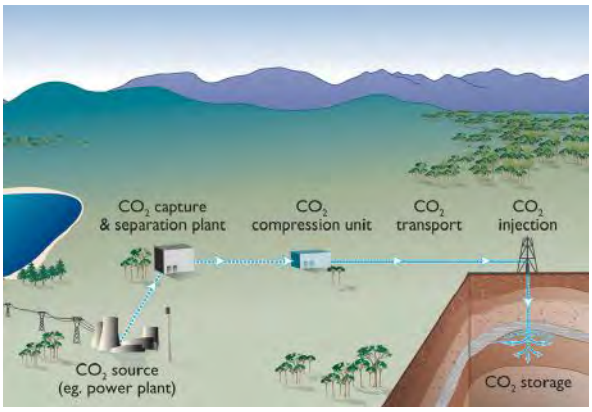

Figure 5.31 The carbon dioxide capture, transport, injection and storage process

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

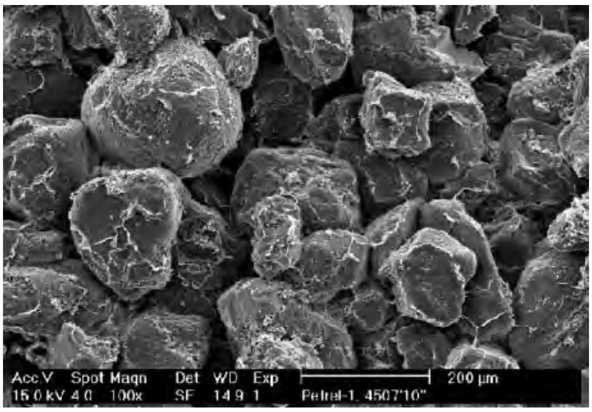

Figure 5.32 Microscope image of a reservoir rock—a porous and permeable sandstone

Source: Gibson-Poole et al. 2002

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 the 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 a commercial scale (more than 1 Mt CO_2 per year) at several locations globally. These include Statoil's Sleipner and Snøhvit gas fields in the North Sea and Barents Sea 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. The Gorgon natural gas project offshore Western Australia will store 125 Mt of naturally occurring CO_2 separated from the produced gas. Construction for this project has commenced. There are a number of other projects in various stages of planning or implementation (figure 5.34).

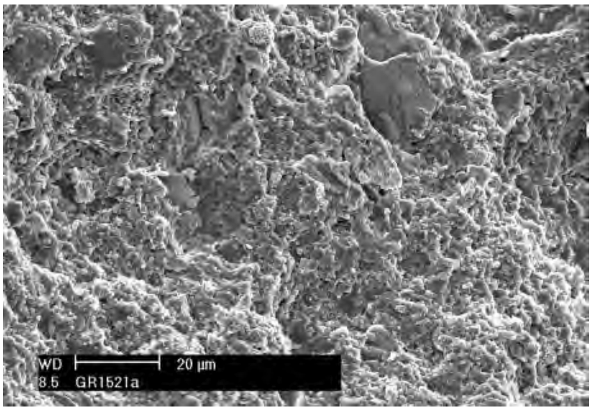

Figure 5.33 Microscope image of a cap rock—an impermeable mudstone

Source: Daniel 2006

Government initiatives in CCS

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

- **Carbon Capture and Storage Flagships Program**—supported the development, construction and demonstration of large-scale CCS projects in Australia. Currently, the South West Hub CCS Project in Western Australia and the CarbonNet project in Victoria are being funded through feasibility studies under the program.
- **National Low Emissions Coal Initiative**—includes support for the Australia National Low Emissions Coal R&D agency, the National Carbon Mapping and Infrastructure Plan, and the Advanced Lignite Demonstration Program. 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.
- **2010 National Carbon Mapping and Infrastructure Plan and the 2011 National CO_2 Infrastructure Plan**—Prioritisation of, and access to, national geological storage capacity and associated infrastructure requirements needed to accelerate deployment of CCS in Australia are being addressed through these plans. These initiatives are progressing recommendations of the Carbon Storage Taskforce.
- **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. In early 2012 the Victorian Government was awarded a greenhouse gas assessment permit; the VIC/GIP001 permit was

awarded for a six-year period and covers an area of about 4400 km[2] off the Gippsland coast. The permit gives the state the right to explore for potential greenhouse gas storage formations with a work program aligned with the CarbonNet CCS Flagships demonstration project.

- **Australia–China Joint Coordination Group on Clean Coal Technology (JCG)**—This group was established in 2007 to facilitate and enhance the mutually beneficial development, application and transfer of low emissions coal technology and is supported by A$20 million of Australian Government funding. Under the JCG the Australian Government is working closely with China's National Energy Administration (NEA). In December 2010, the Australian Government and the NEA signed a memorandum of understanding to collaborate on a feasibility study for a post-combustion capture (PCC) project with carbon capture and storage (CCS) in China. The feasibility study will draw on A$12 million committed under the JCG, and focus on a commercial-scale (600 MW), integrated CCS demonstration project using the PCC process. At the 6th JCG meeting in December 2012, the Australian Government and the NEA agreed to the commencement of stage 2 of the project by signing, with the operating entities, two Letters of Intent, which record the intention of parties to move forward with the project. The JCG also supports a range of collaborative projects that target a range of priorities along the low emissions coal technologies commercialisation curve.
- **Global Carbon Capture and Storage (CCS) Institute**—The Australian Government established the Global CCS Institute in 2009. The institute focused on addressing the barriers to the commercial deployment of CCS through fact-based advocacy and knowledge-sharing activities. The institute has an extensive international membership including governments, corporations, industry bodies and research organisations located in key markets around the world.

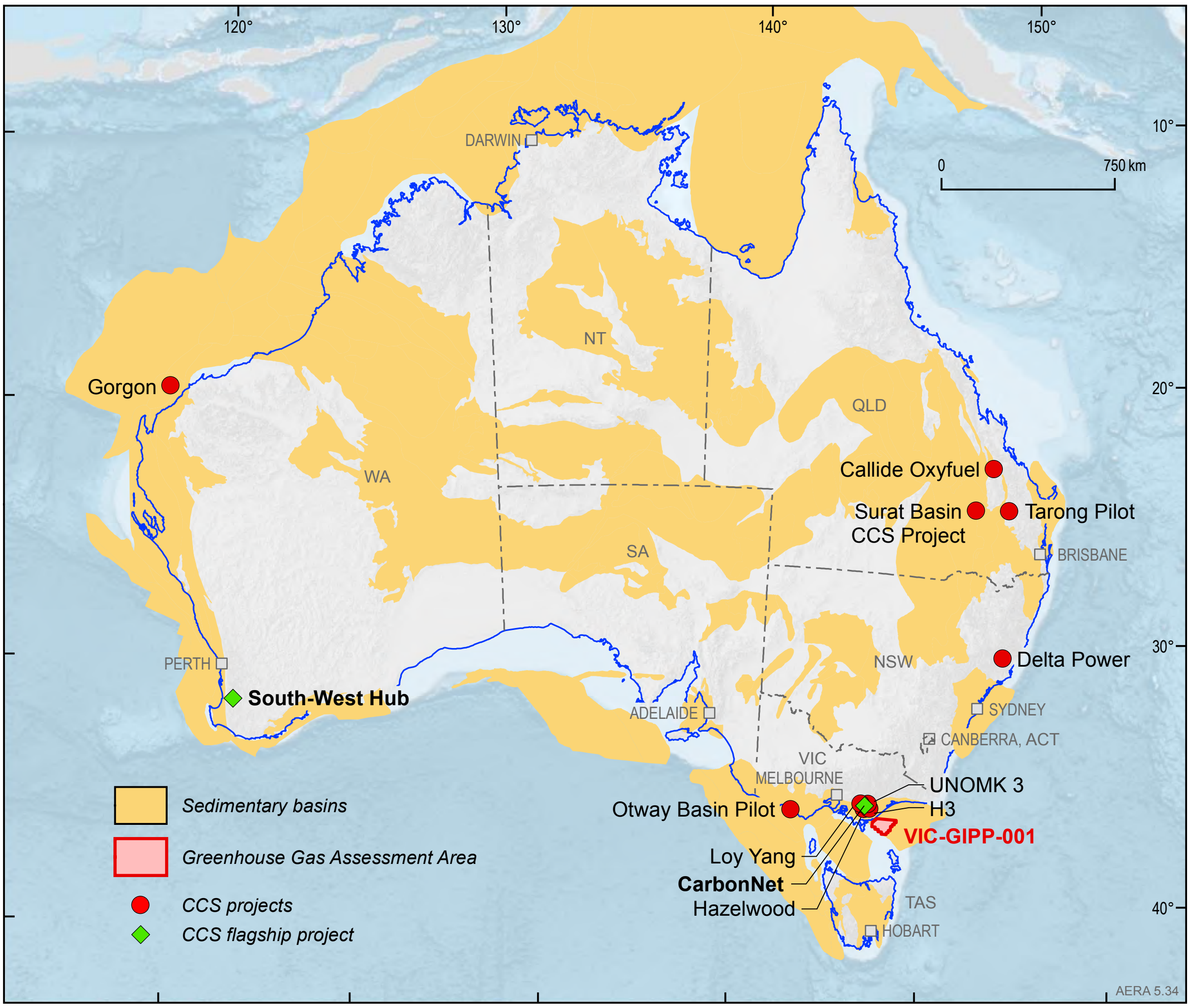

Figure 5.34 Active and proposed CCS projects in Australia

Source: Geoscience Australia

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 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 underground or *in situ* coal gasification (UCG) (box 5.5). 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.

UCG has been successfully demonstrated at the Chinchilla project (Linc Energy 2009) in the Surat Basin in Queensland. A major trial from 1999 to 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 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 stormwater, mine water, groundwater 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 groundwater in mining areas, arrangements can be put in place through catchment water sharing plans to use the water for other commercial purposes.

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 sulfur 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 5.35). Coal-derived fuels have the advantage of being sulfur-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.

Underground Coal Gasification (UCG)

Synthetic gas (syngas) can be produced also by underground or *in situ* coal gasification (figure 5.36). 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.

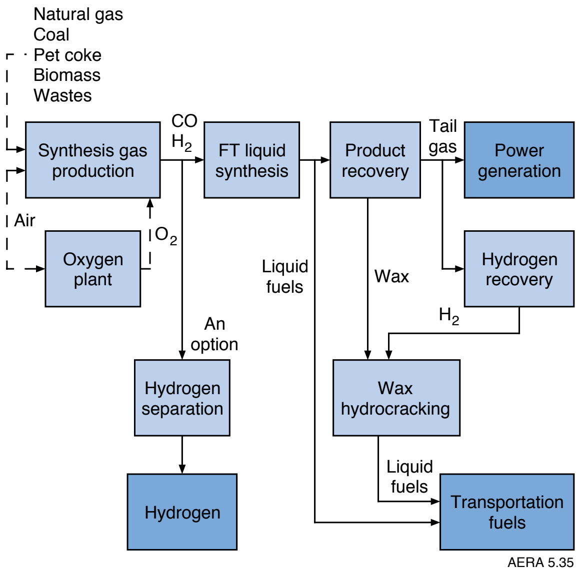

Figure 5.35 Fischer-Tropsch technology

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

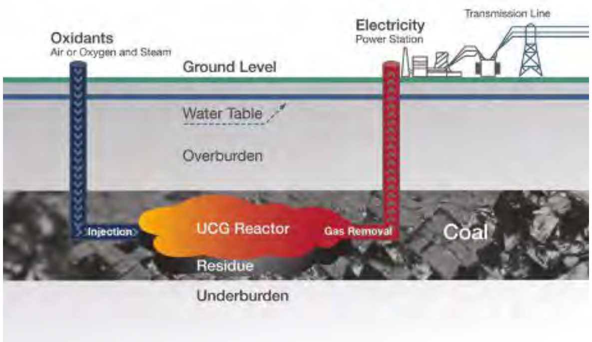

Figure 5.36 Underground Coal Gasification Process

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

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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. Capital requirements for projects at the committed stage total A$11.4 billion for coal mining projects and a further A$7.2 billion for coal infrastructure projects (tables 5.11 and 5.13). Capital requirements for projects which have been publicly announced or are at the feasibility stage are estimated to be between A$71 billion and A$74 billion for mining projects and between A$25.4 billion and A$27.9 billion for coal infrastructure (tables 5.12, 5.13, 5.15 and 5.16).

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$37.4 trillion between 2012 and 2035, amounting to an annual additional capital investment of around US$1.6 trillion, equivalent to 1.5 per cent of global GDP (IEA 2012c).

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. Over the past decade 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 2009 and 2012 was 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 new policies scenario to be 0.8 per cent per year over the period to 2035; IEA 2012c) is expected to result in increased Australian coal production and exports.

However, the impact of the Renewable Energy Target (RET) may result in a decline in coal's share of domestic electricity generation.

Production

Australia's coal production is expected to increase supported by strong demand from global markets. 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

The most important driver of lower Australian coal consumption is the expected reduction in electricity generation from coal-fired power plants. This reflects government policies to encourage increased electricity generation from renewable fuel sources, as well as the lower costs of renewable technologies.

Electricity generation

In 2011–12 coal accounted for around 70 per cent of Australia's electricity generation.

As of October 2013 there were five coal-fired power stations (black coal) at a feasibility stage, each of more than 200 MW, two in South Australia and three in Western Australia (table 5.17).

In addition, there is one brown coal power station at a feasibility stage (table 5.17).

Exports

Australia's coal exports are projected to continue to grow strongly, underpinned by growth in coal import demand, particularly from developing economies such as China and India.

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 are 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 committed or at various stages of planning (table 5.11 to table 5.17).

At the end of October 2013, there were 15 coal projects at the committed stage of development (table 5.11), scheduled to be completed at various times over the next four years. Of the 15 projects, seven are located in Queensland and eight are in New South Wales.

The projects have a combined coal capacity of around 68 Mt, at an estimated capital cost of A$11.4 billion. The largest of these, in terms of capacity, are Maules Creek and Ravensworth North, 10.8 Mt and 8 Mt, respectively.

In addition, a number of mine and infrastructure projects are at less advanced stages of development. There are 79 that are at either at the feasibility stage or have been publicly announced, of which 18 are in New South Wales, 59 in Queensland and one in Western Australia. These projects have a combined potential capacity of over 550 Mt.

In the short term, expanded infrastructure capacity will be achieved through the completion of five port and rail projects that are currently committed; of which four are in Queensland and one in New South Wales (table 5.14). When complete, Australia's coal export infrastructure capacity could increase by at least 76 Mt per year. The largest of these projects, in terms of capacity, is the 27 Mt per year Wiggins Island Coal Terminal and rail in Queensland. In terms of infrastructure, there are seven projects at a less advanced stage, which include rail and port projects in both New South Wales and Queensland (table 5.15).

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 the committed stage of development, as at October 2013

Project	Company	Location	Type	Estimated start-up	Estimated new capacity (million tonnes)	Resource	Indicative cost estimate (A$million)
Appin Area 9	BHP Billiton	Wollongong, NSW	Expansion	2016	3.5	Coking coal	889
Ashton South East opencut	Yancoal Australia	14 km north-west of Singleton, NSW	Expansion	2015	3.6	Thermal and semi soft coking coal	83
Boggabri opencut	Idemitsu Kosan	17 km north-east of Boggabri, NSW	Expansion	2014	3.5	Thermal coal	500
Caval Ridge	BHP Billiton Mitsubishi Alliance (BMA)	south-east of Moranbah, QLD	New Project	2014	5.5	Coking coal	1968
Eagle Downs (Peak Downs East underground)	Aquila Resources / Vale	25 km south-east of Moranbah, QLD	New Project	2016	4.5	Coking coal	1254
Grosvenor underground	Anglo American	8 km north of Moranbah, QLD	New Project	2014	5	Coking coal	1789
Lake Vermont	Jellinbah, Marubeni, Sojitz, AMCI	20 km north of Dysart, QLD	Expansion	2013	4	PCI and coking coal	200
Maules Creek	Whitehaven	18 km north-east of Boggabri, NSW	New Project	2015	10.8	Thermal and coking coal	767
Metropolitan	Peabody Energy	30 km north of Wollongong, NSW	Expansion	2015	1.5	Coking coal	70
Middlemount (stage 2)	Peabody Energy / YanCoal	6 km south-west of Middlemount, QLD	Expansion	2014	3.6	PCI and coking coal	500
North Goonyella	Peabody Energy	160 km west of Mackay, QLD	Expansion	2013	5	Coking coal	150
NRE No. 1 Colliery (preliminary works project)	Gujarat NRE Coking Coal	8 km north of Wollongong , NSW	Upgrade	2015		Coking coal	122
Ravensworth North (stage 1)	Glencore Xstrata, Itochu	22 km north-west of Singleton, NSW	Expansion	2013	8	Thermal and semi-soft coal	1400
Rolleston (phase 1)	Glencore Xstrata, Sumisho, IRCA	16 km west of Rolleston, QLD	Expansion	2014	3	Thermal coal	391
Ulan West	Glencore Xstrata, Mitsubishi	42 km NNE of Mudgee, NSW	Expansion	2014	6.7	Thermal coal	1300

PCI = pulverised coal injection

Source: BREE 2013b

Table 5.12 Coal mines at the feasibility stage of development, as at October 2013

Project	Company	Location	Type	Estimated start-up	Estimated new capacity (million tonnes)	Resource	Indicative cost estimate (A$million)
Alpha Coal Project	GVK/Hancock Coal	120 km south-west of Clermont, QLD	New project	2015	30	Thermal coal	10 000
Baralaba expansion	Cockatoo Coal	150 km west of Gladstone, QLD	Expansion	2014	4	PCI and thermal	413
Baralaba South	Cockatoo Coal	10 km south of Baralaba, QLD	Expansion	2013	4	PCI and thermal	300
Bengalla expansion (stage 2)	Wesfarmers/ Rio Tinto	4 km south-west of Muswellbrook, NSW	Expansion	na	1	Thermal coal	180
Byerwen Coal Project	QCoal/ JFE Steel Corporation	20 km west of Glenden, QLD	New project	2015	10	Coking coal	1591
Carmichael Coal Project	Adani	160 km north-west of Clermont, QLD	New project	2015	60	Thermal coal	6800
China First Coal project (Waratah Galilee)	Waratah Coal	36 km north-east of Jericho, QLD	New project	2014	40	Thermal coal	8000
Codrilla	Peabody Energy	62 km south-east of Moranbah, QLD	New project	2017+	3	PCI	500
Colton	New Hope	11 km north of Maryborough, QLD	New project	2015	1	Coking coal	84
Comet Ridge	Acacia Coal/ Bandanna Energy	20 km south of Comet, QLD	New Project	2015	0.4	Thermal and coking coal	50
Curragh	Wesfarmers	200 km west of Rockhampton, QLD	Expansion	na	2	Coking coal	200
Dingo West	Bandanna Energy	6 km west of Dingo, QLD	Expansion	2013	1	PCI and thermal	135
Drake Coal project	QCoal	17 km south of Collinsville, QLD	New project	2014	6	Thermal and coking coal	350
Drayton South	Anglo Coal Australia	13 km south of Muswellbrook, NSW	Expansion	2015	4	Thermal coal	520
Duchess Paradise	Rey Resources	150 km south-east of Derby, WA	New project	2014	3	Thermal coal	200
Eaglefield	Peabody Energy	36 km north of Moranbah, QLD	Expansion	2014	5	Coking coal	700
Elimatta	New Hope	36 km west of Wandoan, QLD	New project	2014	5	Thermal coal	600
Ellensfield coal mine project	Vale	175 km west of Mackay, QLD	New project	na	6	Thermal and coking coal	800
Grosvenor West	Carabella Resources	10km north-west of Moranbah, QLD	New Project	2016	3.5	Thermal and coking coal	1000
Jax	Qcoal	15 km south of Collinsville, QLD	New project	2012	2	Coking coal	280
Kevin's Corner	GVK	Galilee Basin, QLD	New project	na	30	Thermal coal	4200

Project	Company	Location	Type	Estimated start-up	Estimated new capacity (million tonnes)	Resource	Indicative cost estimate (A$million)
Minyango	Guangdong Rising Assets Management	15 km north of Cook, QLD	New project	2014	8	Thermal and coking coal	750
Moolarben (stage 2)	Yancoal Australia	40 km north of Mudgee, NSW	Expansion	na	3	Unknown	120
Mt Thorley – Warkworth extension	Rio Tinto	15 km south-west of Singleton, NSW	Expansion	na	0	Thermal coal	629
New Acland (stage 3)	New Hope Coal	150 km west of Brisbane, QLD	Expansion	na	5	Thermal coal	450
North Surat – Collingwood Project	Cockatoo Coal	12 km north-east of Wandoan, QLD	New project	2015	6	Thermal coal	652
NRE No. 1 Colliery	Gujarat NRE Coking Coal	8 km north of Wollongong, NSW	Expansion	2014	3	Coking coal	250
Oaky Creek (phase 2)	Xstrata, Sumisho, Itochu, ICRA OC	65 km north-west of Blackwater, QLD	Expansion	na	5	Coking coal	650
Orion Downs	Endocoal	60 km south-east of Emerald, QLD	New project	2013	3	Thermal coal	100
Rolleston (phase 2)	Xstrata, Sumisho, IRCA	16 km west of Rolleston, QLD	Expansion	na	3	Thermal coal	400
Sarum	Xstrata, Itochu, ICRA NCA, Sumisho	20 km south of Collinsville, QLD	New project	2014	7	Thermal and coking coal	1000
South Galilee Coal Project	Bandanna Energy	180 km west of Emerald, QLD	New project	2015	17	Thermal coal	4150
Springsure Creek–Golden Triangle	Bandanna Energy	36 km south-east of Emerald, QLD	New project	2014	9	Thermal coal	1100
Tarborah	Shenhuo International	22 km west of Emerald, QLD	New project	2014	2	Coking coal	400
Taroom	Cockatoo Coal	3 km south-east of Taroom, QLD	New project	na	8	Thermal coal	1120
Tarrawonga	Whitehaven	15 km north-east of Boggabir, NSW	Expansion	na	1	Thermal and PCI	142
Teresa	Linc Energy	17 km north of Emerald, QLD	New project	2013	8	PCI	750
The Range Project	Stanmore Coal	24 km south-east of Wandoan, QLD	New project	2016	5	Thermal coal	505
Vermont East/ Wilunga	Peabody Energy	75 km north-east of Clermont, QLD	New project	2015	3	PCI and thermal	300
Vickery	Whitehaven	22 km north of Gunnedah, NSW	New project	na	5	Thermal and coking coal	206
Wallarah underground longwall	Korea Resources Corp/Sojitz Corp	north-west of Wyong, NSW	New project	na	5	Thermal coal	700
Wards Well	BHP Billiton Mitsubishi Alliance	29 km south-west of Glenden, QLD	New project	2016	5	Coking coal	795

Project	Company	Location	Type	Estimated start-up	Estimated new capacity (million tonnes)	Resource	Indicative cost estimate (A$million)
Washpool coal project	Aquila Resources	60 km north-east of Emerald, QLD	New project	na	3	Coking coal	368
Watermark	Shenhua Energy	35 km south-east of Gunnedah, NSW	New project	na	6	Thermal coal	978
West Wallsend Colliery	Oceanic Coal Australia, Marubeni Coal, Xstrata, JFE Minerals	19 km west of Newcastle, NSW	Expansion	na	na	Thermal and coking coal	260
Wongai Project	Aust-Pac Capital	150 km north-west of Cooktown, QLD	New project	na	2	Coking coal	500
Wongawilli Colliery	Gujarat NRE Coking Coal	12 km west of Port Kembla, NSW	Expansion	2016	3	Coking coal	82
Woori	Cockatoo Coal	19 km south of Wandoan, QLD	New project	2016	na	Thermal coal	520

na = not available; **PCI** = pulverised coal injection

Source: BREE 2013b

Table 5.13 Coal mines at the announced stage of development, as at October 2013

Project	Company	Location	Type	Estimated start-up	Estimated new capacity (million tonnes)	Resource	Indicative cost estimate (A$million)
Belvedere underground	Vale	7 km north-east of Moura, QLD	New Project	2016	7	Coking coal	2814
Belview	Stanmore Coal	10 km east of Blackwater, QLD	New project	2017	na	Coking coal	869
Bundi Coal Project	MetroCoal	20 km west of Wandoan, QLD	New project	2018+	5	Thermal coal	300
Cook Colliery Expansion project	Caledon Resources Limited	30 km south of Blackwater, QLD	Expansion	na	3	Thermal and coking coal	0–250
Doyles Creek	Nucoal Resources/MMI	15 km west of Singleton, NSW	New project	na	4.8	Thermal coal	727
Grosvenor (phase 2)	Anglo American	8 km north of Moranbah, QLD	Expansion	2016	6	Coking coal	500–1000
Jellinbah East	Jellinbah, Marubeni, Sojitz	90 km east of Emerald, QLD	Expansion	2015	2	PCI and coking coal	75
Moorlands	Cuesta Coal Limited	25 km west of Clermont, QLD	New project	2016	2	Thermal coal	250–500
Mount Pleasant Project	Rio Tinto/ Mitsubishi	6 km north-west of Muswellbrook, NSW	New project	na	10.5	Thermal coal	2000
Mt Penny	Cascade Coal	3 km north of Bylong, NSW	New project	na	5	Thermal coal	450
New Lenton	New Hope Coal, MPC	20 km east of Moranbah, QLD	New project	2016	na	Coking coal	400
Project China Stone	MacMines Austasia	190 km north-west of Moranbah, QLD	New project	2017	45	Thermal coal	5000+

Project	Company	Location	Type	Estimated start-up	Estimated new capacity (million tonnes)	Resource	Indicative cost estimate (A$million)
Spur Hill	Malabar Coal	15 km south-west of Muswellbrook, NSW	New project	2018	6	Thermal and semi-soft coal	800
Styx	Waratah Coal, Queensland Nickel	North of Rockhampton, QLD	New project	na	1.5	PCI and thermal	0–250
Talwood Coking Coal Project	Aquila Resources	40 km north of Moranbah, QLD	New project	2016	3.6	PCI and thermal	700
Togara North	Xstrata	40 km south of Comet, QLD	New project	2017	6	Thermal coal	800
United Project	Glencore, Xstrata, CFMEU	17 km west of Singleton, NSW	Expansion	na	4	Semi-soft coking coal	250–500
Wilkie Creek	Peabody Energy	40 km west of Dalby, QLD	Expansion	na	10	Thermal coal	500–1000
Winchester South	Rio Tinto	40 km south of Moranbah, QLD	New project	2016	4	Thermal and coking coal	500–1000

na = not available; **PCI** = pulverised coal injection

Source: BREE 2013b

Table 5.14 Coal infrastructure at the committed stage of development, as at October 2013

Project	Company	Location	Type	Estimated start-up	Estimated new capacity (kilotonnes per annum)	Resource	Indicative cost estimate (A$million)
Goonyella System Expansion Project	Aurizon	Bowen Basin to Mackay	Expansion	2014	11 000	Black coal	130
Hay Point Coal Terminal (phase 3)	BHP Billiton Mitsubishi Alliance (BMA)	20 km S of Mackay	Expansion	2014	11 000	Black coal	3100
Hunter Valley Corridor Capacity Strategy (Contracted)	Australian Rail and Track Corporation	Hunter Valley	Expansion	various	na	Black coal	714
Wiggins Island Coal Terminal (stage 1)	Wiggins Island Coal Export Terminal	Gladstone	New project	2015	27 000	Black coal	2400
Wiggins Island rail project	Aurizon	Gladstone	New project	2015	27 000	Black coal	900

Source: BREE 2013b

Table 5.15 Coal infrastructure at the feasibility stage of development, as at October 2013

Project	Company	Location	Type	Estimated start-up	Estimated new capacity (kilotonnes per annum)	Resource	Indicative cost estimate (A$million)
Abbot Point Coal T3 (part of Alpha Coal Project)	GVK	Bowen, QLD	Expansion	2016	60 000	Black coal	na
Abbot Point T0 (phase 1 and 2)	Adani	Bowen, QLD	Expansion	2017	70 000	Black coal	1400
Central Queensland Integrated Rail Project	Aurizon	South Galilee Basin – Bowen, QLD	New project	2017	na	Black coal	2000

Project	Company	Location	Type	Estimated start-up	Estimated new capacity (kilotonnes per annum)	Resource	Indicative cost estimate (A$million)
Dudgeon Point	NQBP/Adani	40 km north of Mackay, QLD	New project	2018+	180 000	Black coal	12 000
Fitzroy Terminal	Mitchell Group	50 km south of Rockhampton, QLD	New project	2016	22 000	Black coal	1200
Hunter Valley Corridor Capacity Strategy (proposed)	Australian Rail and Track Corporation	Hunter Valley, NSW	Expansion	various	na	Black coal	1997
Moura Link – Aldoga Rail	Aurizon	Moura/Surat to Mount Larcom, QLD	New project	na	na	Black coal	1000

na = not available

Source: BREE 2013b

Table 5.16 Coal infrastructure at the announced stage of development, as at October 2013

Project	Company	Location	Type	Estimated start-up	Estimated new capacity (kilotonnes per annum)	Resource	Indicative cost estimate (A$million)
Surat Basin Rail (Southern Missing Link)	Aurizon/ATEC/ Xstrata Coal	Wandoan to Theodore (210 km), QLD	New project	na	42 000	Black coal	1000–1500
Wiggins Island Coal Terminal (stage 2 and 3)	Wiggins Island Coal Export Terminal	Gladstone, QLD	New project	na	54 000	Black coal	1500–2500
Yarwun Coal Terminal (stage 1)	Metro Coal/ 3TL	Gladstone, QLD	New project	2018+	25 000	Black coal	1500–2500

Source: BREE 2013b

Table 5.17 Coal-fired electricity projects at various stages of development, as at October 2013

Project	Company	Location	Type	Estimated Start Up	Estimated New Capacity (MW)	Resource	Indicative cost estimate (A$million)
Feasibility stage							
Arckaringa CTL and Power (phase 2)	Altona Energy/ CNOOC	120 km north of Coober Pedy, SA	Expansion	na	280	Black coal	na
Arckaringa CTL and Power (phase 1)	Altona Energy/ CNOOC	120 km north of Coober Pedy, SA	New project	na	560	Black coal	3500 (includes development of 10 mtpa mine)
Bluewaters (stage 3)	Bluewaters Power 3 Pty Ltd	5 km north-east of Collie, WA	Expansion	2019	208	Black coal	na
Bluewaters (stage 4)	Bluewaters Power 3 Pty Ltd	5 km north-east of Collie, WA	Expansion	2020	208	Black coal	na
Coolimba	Westgen	20 km south of Eneabba, WA	New project	2014	450 Coal, 380 Gas	Black coal	1600
Dual Gas Demonstration Project	Dual Gas Pty Ltd	Morwell, Latrobe Valley, VIC	New project	2013	600	Brown coal gasification	1100

na = not available
a million tonnes per annum

Source: BREE 2013a

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Chapter 6

Uranium and Thorium

6.1 Summary

KEY MESSAGES

- Australia has the world's largest Reasonably Assured Resources of uranium and about 8 per cent of the identified world thorium resources.
- Australia is the world's third largest producer of uranium. At present, there is no thorium production.
- In 2012, Australia had four uranium mines operating. Two projects are expected to commence production in 2014–15.
- World demand for uranium is projected to increase strongly over the next 10 years as new nuclear capacity is commissioned.
- There are currently no plans for Australia to have a domestic nuclear power industry.
- In the longer term there is potential for thorium-fuelled reactors, but currently there are no commercial scale thorium-fuelled reactors anywhere in the world.

6.1.1 World uranium and thorium resources and market

- Uranium and thorium can be used as nuclear reactor fuel. Uranium is currently the preferred fuel; thorium may be a future fuel.
- World Reasonably Assured Resources (RAR) recoverable at less than US$130/kg of uranium are estimated to be around 3471.5 kilotonnes kt (U) at the end of 2011. This is equal to about 50 years of current (2011) nuclear reactor consumption levels.
- World uranium mine production has increased by an average 1.8 per cent per year over the decade from 2001, reaching 30 576 PJ (54.6 kt U) in 2011.
- Secondary supplies of uranium from blended-down highly enriched uranium (HEU), government stocks and mixed oxide fuels accounted for around 16 per cent of global uranium supply in 2011. This compares with 44 per cent in 2000.
- World uranium consumption has increased at an average annual rate of 1.2 per cent per year from 2001 to 2010, reaching 65.8 kt U in 2011. Nuclear power accounted for 5.7 per cent of global primary energy consumption and 12.9 per cent of world electricity generation in 2010.
- World nuclear power consumption is projected to increase at about 2 per cent per year to 2035, reflecting the commissioning of new nuclear capacity worldwide. Generation III reactors incorporate advanced safety systems and have improved fuel technologies; Generation IV reactors, currently in research and development, will utilise uranium more efficiently, minimise waste and be proliferation resistant.
- Thorium-based fuels could be used in some existing uranium-fuelled reactors possibly in the medium term, but full-scale commercial thorium-fuelled reactors are not likely before 2030.

6.1.2 Australia's uranium and thorium resources

- Australia has the world's largest RAR recoverable at less than US$130/kg U with 1174 kt in this category at December 2012.
- Australia has substantial potential for the discovery of new uranium resources.
- New pre-competitive data released by Geoscience Australia—notably the radiometric map of Australia and regional electromagnetic survey data—are providing a further stimulus to uranium exploration and discovery.
- Australia has about 8 per cent of the world's thorium resources. Estimated total Identified Resources of thorium in Australia could amount to about 595 kt.
- There is currently no exploration specifically focused on thorium. All of the information available on thorium resources has been generated by exploration and mining activities aimed principally at other mineral commodities.

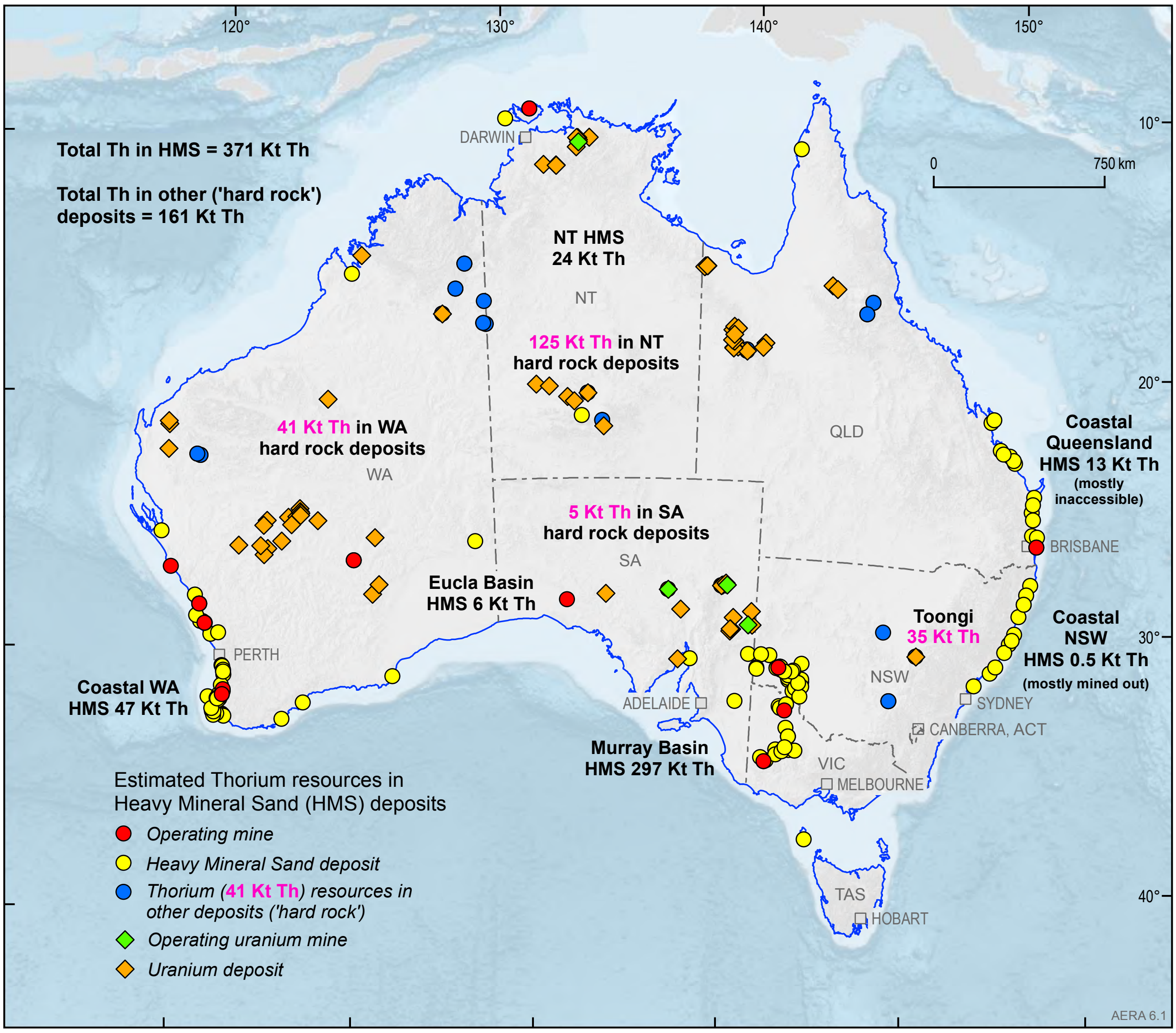

Figure 6.1 Australia's total identified uranium and thorium resources, 2012

Source: Geoscience Australia

6.1.3 Key factors in utilising Australia's uranium and thorium resources

- There is ongoing global interest in nuclear power as an alternative to burning fossil fuels, and hence demand for uranium is expected to increase.
- Successful exploration and development of uranium deposits is dependent on several factors including state government policy, prices, production costs, ability to demonstrate best practice environmental and safety standards, and community acceptance of uranium development.
- Limited commercially viable transport options and restriction of access to two ports may limit expansion of Australian uranium exports. A reduced number of shipping firms and routes that accept uranium may result in further delays and costs.
- Global demand for thorium is dependent upon the development of widespread commercial scale thorium-fuelled reactors for electricity generation.
- There has been renewed interest in development of thorium-fuelled reactors. This is partly because of greater abundance of thorium resources in some countries, greater resistance to nuclear weapons proliferation, and a substantial reduction in radioactive waste generated.

6.1.4 Australia's uranium and thorium market

- In 2012, Australia had four operating uranium mines: Ranger open pit mine in the Northern Territory and Olympic Dam underground mine, Beverley/Beverley North *in situ* recovery (ISR) mine and Honeymoon ISR mine in South Australia (figure 6.1).
- Australia has been a reliable producer of uranium since the early 1950s. Australia's uranium production in 2011–12 was 3898 PJ (6.96 kt U). Australia is the third largest uranium producer and for calendar year 2012 produced about 11 per cent of world production.
- Australia does not consume any of its domestic uranium production. In 2011–12, Australia exported

around 3282 PJ (5.86 kt U) with an export value of over A$600 million. Australia's major export destinations are the United States, Japan and France.

- Australian production and subsequent trade of thorium is not likely to occur on a large scale in the next few decades.
- If commercialisation of a thorium fuel cycle occurs more quickly than assumed, Australia is well positioned to supply world markets with low-cost reliable sources of thorium. Currently, thorium-bearing monazite is being diluted and disposed of at the mineral sand mine site, making these resources uneconomic to recover in the future.

6.2 Uranium

6.2.1 Background information and world market

Definitions

Uranium (U) is a mildly radioactive element that is widespread at levels of one to four parts per million (ppm) in the Earth's crust. Concentrations of uranium-rich minerals, such as uraninite, carnotite and brannerite can form economically recoverable deposits. Once mined, uranium is processed into uranium oxide (U_3O_8), also referred to as uranium oxide concentrate (UOC), and is exported in this form. Natural uranium (mine production) contains about 0.7 per cent of the uranium isotope U^{235} and 99.3 per cent U^{238}.

Enriched uranium is uranium with an enhanced concentration of the U^{235} isotope, up from 0.7 per cent to between 3 and 5 per cent. Uranium is required to undergo enrichment for use in most civilian nuclear reactors. Like all thermal power plants, nuclear reactors work by generating heat, which boils water to produce steam to drive turbines that generate electricity. In nuclear reactors, the heat is produced from nuclear fission of U^{235}. HEU is enriched to 20 per cent or more U^{235} and weapons-grade HEU is enriched to over 90 per cent.

Secondary sources arise from the reprocessing of spent nuclear fuel, blended-down HEU from nuclear weapons, or mixed oxide fuels. Currently, secondary sources supply about 16 per cent of uranium demand for nuclear reactors.

Uranium supply chain

A conceptual representation of the Australian uranium supply chain is given in figure 6.2. The supply chain is divided into four distinct phases: resources exploration; development and production; processing, transport and storage; and end-use markets. Australia's supply chain concludes with the exporting of uranium oxide to countries for processing, enrichment and use in nuclear power plants.

Resources exploration

There is a wide variety of geological settings that result in the formation of different types of uranium deposits. The main areas of exploration activities in Australia are:

- Gawler Craton/Stuart Shelf region (hematite breccia deposits) and Frome Embayment (sandstone deposits) in South Australia
- Paterson Province (unconformity type deposits) and Yilgarn Craton (calcrete type deposits) in Western Australia
- Pine Creek and Arnhem Land regions (unconformity type deposits) in Northern Territory
- Mt Isa region in Queensland (metasomatite type deposits).

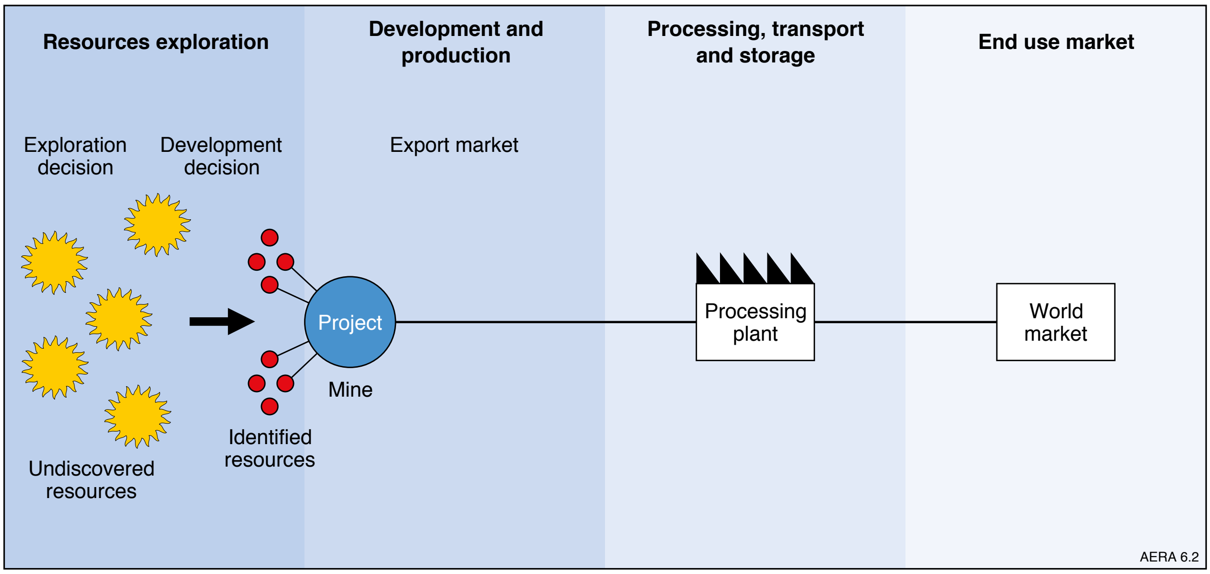

Figure 6.2 Australia's uranium supply chain

Source: Bureau of Resources and Energy Economics; Geoscience Australia

Exploration activities use geological and geophysical methods to locate and delineate potential uranium deposits. A deposit is systematically drilled and assayed to quantify the grade and tonnage of the deposit. The different types of deposits have a wide range of ore grades, tonnage and ore minerals.

Western Australia, South Australia and Northern Territory maintained the bulk of exploration activity in 2012. In recent years there have been changes in state government policies on uranium exploration and mining. In late 2008, Western Australia removed its six-year ban on uranium mining, which has resulted in renewed investment in uranium projects. Queensland Government policies allowed uranium exploration but mining was not permitted. However, in October 2012, the Queensland Government lifted the ban on uranium mining. In April 2012 the New South Wales Government removed its ban on uranium exploration which had been in place for 30 years; however, the ban on uranium mining remained.

Development and production

Once a resource has been quantified, a company makes a decision on whether to proceed with development based on underlying market conditions, including commodity prices and the ability to finance the project. If a decision to proceed with the project is made, construction of a mine site and processing facilities begins after approval by Australian and state/territory governments.

In Australia, uranium is recovered using both conventional and ISR mining techniques. Most of Australia's uranium production is from conventional (open cut or underground) mining techniques, followed by milling and metallurgical processing. There are currently two ISR mines and a satellite ISR operation; another ISR operation (Four Mile) is to begin production in 2014. ISR mining is used extensively in Kazakhstan, Uzbekistan and United States and accounted for about 42 per cent of global uranium mine production in 2011. The process involves recovering uranium without excavation of the ground. Uranium is extracted by means of an acid or alkaline solution which is pumped down injection wells into the permeable mineralised zone to remobilise uranium from the ore body. The uranium-bearing solution is pumped to the surface and recovered in a processing plant.

Processing, transport and storage

Conventionally extracted uranium is milled, and then processed to produce U_3O_8 concentrates. For ISR mining, the uranium-bearing solution is pumped to a processing plant (which commonly use ion exchange technologies) to recover concentrates of hydrated uranium oxide ($UO_4.2H_2O$), referred to as yellow cake. These concentrates of U_3O_8 or hydrated uranium oxide concentrates are not directly usable as a fuel for a nuclear power reactor and additional processing (conversion and enrichment) and fuel fabrication are required.

The processing path and amount of uranium required annually by a 1000 megawatt electric (MWe) light water reactor is illustrated in figure 6.3. The U_3O_8 is converted into uranium hexafluoride (UF_6), which is then enriched to increase the proportion of uranium isotope U^{235} from 0.7 per cent to between 3 and 5 per cent. The remaining U^{238} particles are collected as a by-product and are referred to as tails or depleted tails. The enriched UF_6 is converted to uranium dioxide (UO_2) and transferred to a fabrication plant. Solid ceramic pellets containing UO_2 are encased in metal tubes to form fuel rods used in the nuclear reactor. Typically, one tonne of uranium will produce 44 gigawatt hours of electricity (WNA 2009a).

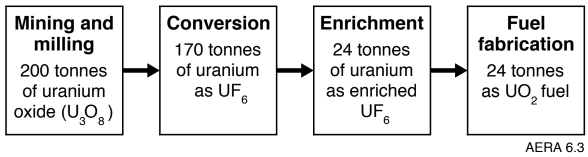

Figure 6.3 Typical annual quantity of natural uranium (200 tonnes U_3O_8) required for a 1000 MWe nuclear reactor
Source: Commonwealth of Australia 2006a

Each stage of the fuel cycle produces some radioactive waste, which is disposed of using proven technologies. International conventions such as the *Joint Convention on Nuclear Safety* and the *Joint Convention on the Safety of Spent Fuel Management and on the Safety of Radioactive Waste Management* assert that the ultimate responsibility for ensuring the safety of spent fuel and radioactive waste management rests with the state.

In the Australian uranium supply chain, uranium mining generates tailings, the radioactivity of which is low and is managed by disposal in site-specific engineered tailings dams. The Australian Government regulatory regime requires mines to be approved subject to best practice environmental and safety standards.

End-use market

Australia does not have a domestic nuclear power industry; all of Australia's uranium production is exported. Australia's existing stringent bilateral safeguards agreements with other countries specify that Australian uranium, and nuclear material derived from it, must be used exclusively for peaceful purposes in civilian nuclear fuel cycles. The material is also protected in accordance with internationally agreed standards for physical security.

Bilateral safeguards agreements ensure that countries to which Australia sells uranium are committed to International Atomic Energy Agency (IAEA) safeguards and international nuclear security standards. Under the bilateral agreements, countries receiving uranium must also report on their use of Australian nuclear material and seek Australian consent for any enrichment, reprocessing, or third-party transfer. Strict adherence to IAEA arrangements and strong bilateral obligations and transparency measures provide assurances that Australian uranium is used only for peaceful purposes.

Australian uranium producers sell their production through long-term contracts and on the world spot market.

At present U_3O_8 is exported through the Adelaide and Darwin container ports only. The U_3O_8 is shipped to international end-use markets, approved facilities which convert and enrich the U_3O_8 and fabricate fuel. The uranium fuel is used in civilian nuclear power reactors to generate electricity, and in the manufacture of radioisotopes for medical applications.

World uranium market

Table 6.1 provides a snapshot of the Australian uranium market in a global context. Australia has the world's largest uranium resources and is the third largest producer in the world.

Resources

Uranium resources are categorised using the OECD Nuclear Energy Agency (OECD/NEA) and the IAEA classification scheme. The uranium resource estimates are for recoverable uranium, which deducts losses due to mining and milling. Uranium recoverable at less than US$130/kg U is considered to be economic at current market prices.

World total Identified Resources (RAR and Inferred Resources) recoverable at less than US$130/kg U were estimated to be over 3 million PJ (5371.6 kt U) at 2011 (OECD/NEA-IAEA 2012, Geoscience Australia 2013). At current rates of world consumption for energy purposes this is enough to supply approximately 50 years.

Australia's total Identified Resources (RAR and Inferred) recoverable at less than US$130/kg U accounted for 32 per cent of global resources, as at December 2012 (table 6.2). Other countries with large resources include Kazakhstan (12 per cent), Canada (9 per cent), Brazil (5 per cent) and South Africa (5 per cent).

Mine production

Uranium production is focused in a small number of countries. In 2011, world uranium production was 30 582 PJ (54.6 kt U) with Kazakhstan (35.6 per cent), Canada (16.7 per cent), Australia (11 per cent), and Niger (8 per cent) accounting for nearly 70 per cent of this production (WNA 2012a; see figure 6.4). Australia was the world's second largest uranium producer from the mid-1990s through to 2007. Kazakhstan production has increased rapidly in recent years and in 2008 its production exceeded Australian production for the first time (WNA 2009b). In 2009 Kazakhstan became the world's largest producer and has maintained this leading position in recent years with production increasing by 27 per cent in 2010 and 9 per cent in 2011.

World uranium production peaked at 39 032 PJ (69.7 kt U) in 1980, reflecting strong demand for uranium in non-energy uses and increasing penetration of nuclear power (figure 6.5). At peak production, the largest uranium producers were the former Soviet Union, United States, Canada and East Germany. Since 1980, production in most of these countries has declined as a result of secondary sources entering the market, driving down prices and increasing competition and pressure on high-cost producers. World uranium production reached a low of 17 640 PJ (31.5 kt U) in 1994. Since then, uranium production has increased steadily, reflecting higher production in countries such as Kazakhstan, Australia and Namibia.

Table 6.1 Key uranium statistics

	Unit	Australia 2012	Australia 2011	OECD[b] 2011	World 2011
Resources[a]	PJ	955 360	971 600	1 383 760	3 008 096
	kt U	1706	1735	2471	5371.6
Share of world	%	31.6	32.1	45.8	100.0
World ranking	no.	1	1		
Production	PJ	3898	3289	10 619	30 582
	kt U	6.96	5.9	18.9	54 610
Share of world	%	11.4	10.9	59.3	100.0
World ranking	no.	3	3		
Annual average growth of production 2000–11	%	-1.7	–2.6	–2.3	4.1
Consumption[c]	PJ	0	0	26 600	35 029
	kt U	0	0	47.5	62.6
Annual average growth of consumption 2000–11	%	0	0	0.7	0.8
Nuclear share of primary energy consumption	%	0	0	10.2	5.6[d]
Nuclear share of electricity generation	%	0	0	19.2	12.8[d]

na = not available

a Identified resources recoverable at <US$130/kg U. Data for Australia compiled by Geoscience Australia and estimates for other countries are from OECD/NEA and IAEA 2012. **b** BREE estimates. **c** Amount of uranium used in nuclear power plants. **d** 2010 data.

Source: IEA 2012a; OECD/NEA and IAEA 2012; WNA 2012a;

Table 6.2 World total Identified Resources of uranium recoverable at less than US$130/kg U, 2011

Country[a]	Identified Resources (RAR and Inferred) <US$130/kg U		Reasonably Assured Resources (RAR) <US$130/kg U	
	Quantity (kt U)	Share of world (%)	Quantity (kt U)	Share of world (%)
Australia	1706.0	31.8	1174.0	33.8
Kazakhstan	629.1	11.7	319.9	9.2
Russian Federation	487.2	9.1	172.9	5.0
Canada	468.7	8.7	319.7	9.2
Niger	421.0	7.8	339.0	9.8
South Africa	279.1	5.2	144.6	4.1
Brazil	276.7	5.2	155.7	4.5
Namibia	261.0	4.9	234.9	6.8
United States	207.4	3.9	207.4	6.0
China	166.1	3.1	109.5	3.1
Ukraine	119.6	2.2	86.8	2.5
Other	349.7	6.5	207.1	6.0
Total	**5371.6**	**100.0**	**3471.5**	**100.0**

a Australian resources are as at December 2012, whereas other countries are as at 2011.

Source: Data for Australia compiled by Geoscience Australia and estimates for other countries are from OECD/NEA and IAEA. Figures are rounded to the nearest 100 tonnes

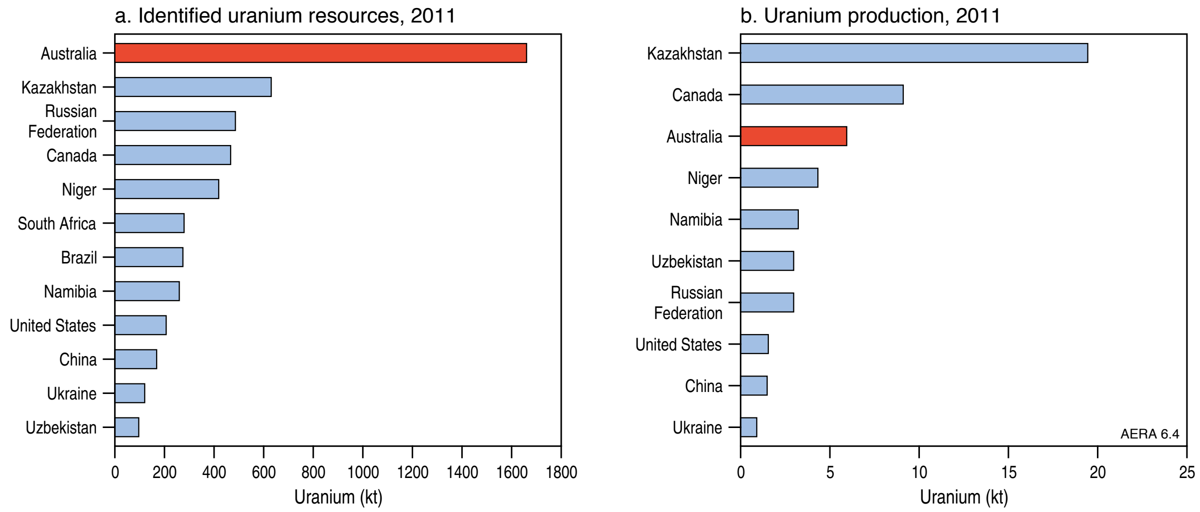

Figure 6.4 World uranium resources and production, by major country, 2011

Source: OECD/NEA and IAEA 2012; WNA 2012a

Secondary supply

Uranium production consistently exceeded requirements for energy purposes until 1989 as shown in figure 6.6 (WNA 2009c). Since 1990, global uranium demand for energy purposes has exceeded mine production, with the shortfall met from secondary supply sources.

Secondary sources include low enriched uranium (LEU), produced by blending down HEU from military stockpiles, mixed oxide fuels (MOX), depleted uranium tails from enrichment plants and government stocks (figure 6.7). Of these, the largest source currently is from military stockpiles of HEU, which are being progressively reduced under the terms of a number of international agreements, such as the United States – Russian Federation HEU purchase agreement and the HEU feed deal. The agreement between US and Russian governments required that 500 tonnes of HEU would be blended-down and recycled as LEU for use as fuel in US nuclear power plants. In August 2011, US Enrichment Corporation announced that it had recycled 425 tonnes of HEU into more than 12 000 tonnes of LEU (OECD/NEA and IAEA 2012). The total amount will be blended-down by the end of 2013 and the agreement will conclude. There will then be a sharp reduction in uranium supply from secondary sources. This agreement has extended over 20 years and at times this LEU has generated up to 10 per cent of US electricity generation for a particular year. In recent years the US Government has announced considerable

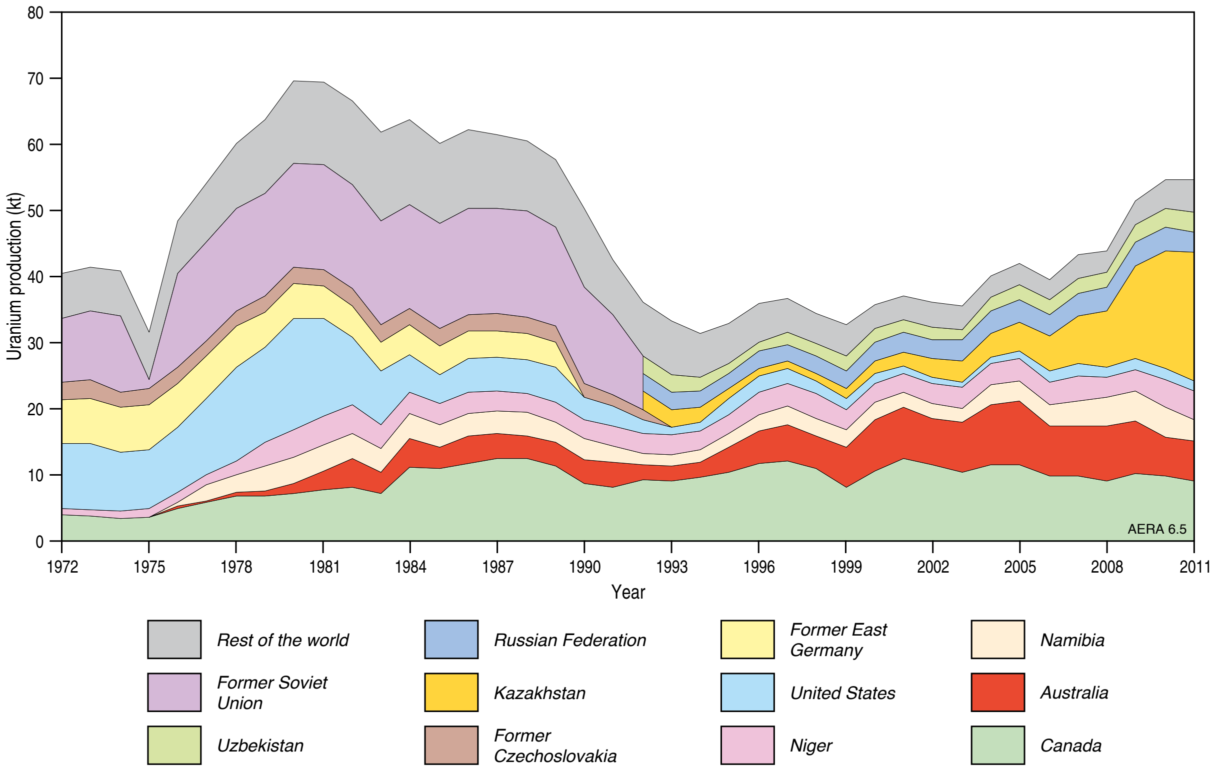

Figure 6.5 World uranium production, by major producer

Source: WNA 2012a

tonnages of HEU that are surplus to requirements and plans to sell this to the commercial market. This will be blended-down to LEU fuel for use in commercial reactors (OECD/NEA and IAEA 2012). The Euratom Supply Agency (2009) has forecast that secondary supplies could decline to around 10 kt U per year by 2030. Figure 6.7 illustrates a reference case which incorporates these factors, and assumes also no net changes in inventories and broadly constant supplies from government stocks over the period 2015–2025 and a decline in Russian supply after that time.

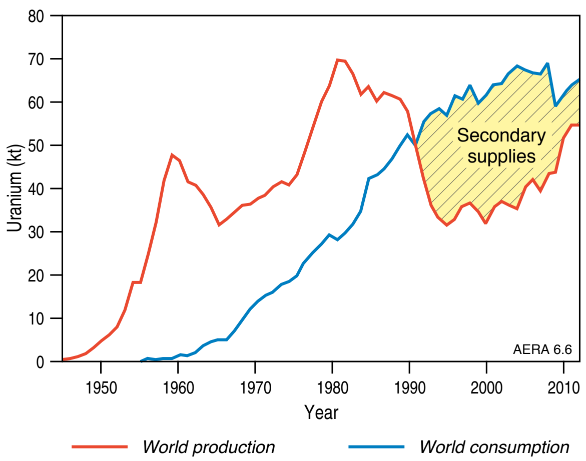

Figure 6.6 World uranium production and consumption for energy purposes

Source: IEA 2012a ; OECD/NEA and IAEA 2012; WNA 2012a

MOX is formed by mixing plutonium oxide and depleted uranium oxide. MOX is considered a viable fuel option, and is expected to be used in 15 per cent of world reactors by 2010 (Euratom Supply Agency 2009).

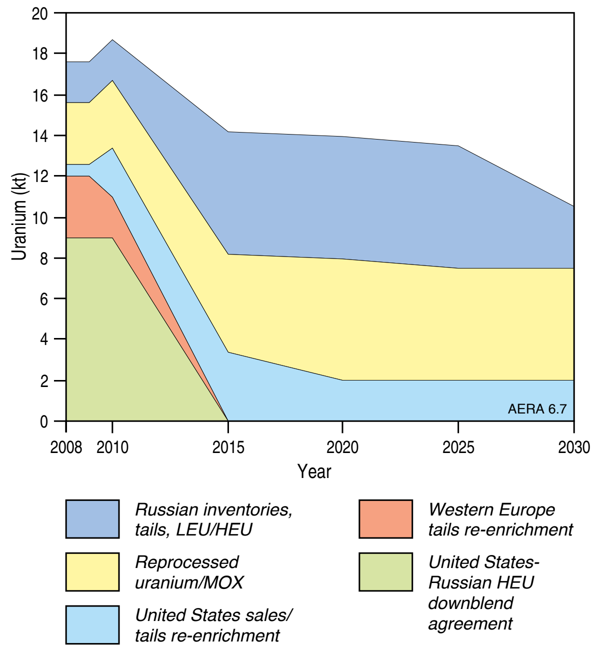

Figure 6.7 Sources of secondary supply in the world uranium market, projections to 2030

Source: Geoscience Australia, based on data provided by WNA 2009d

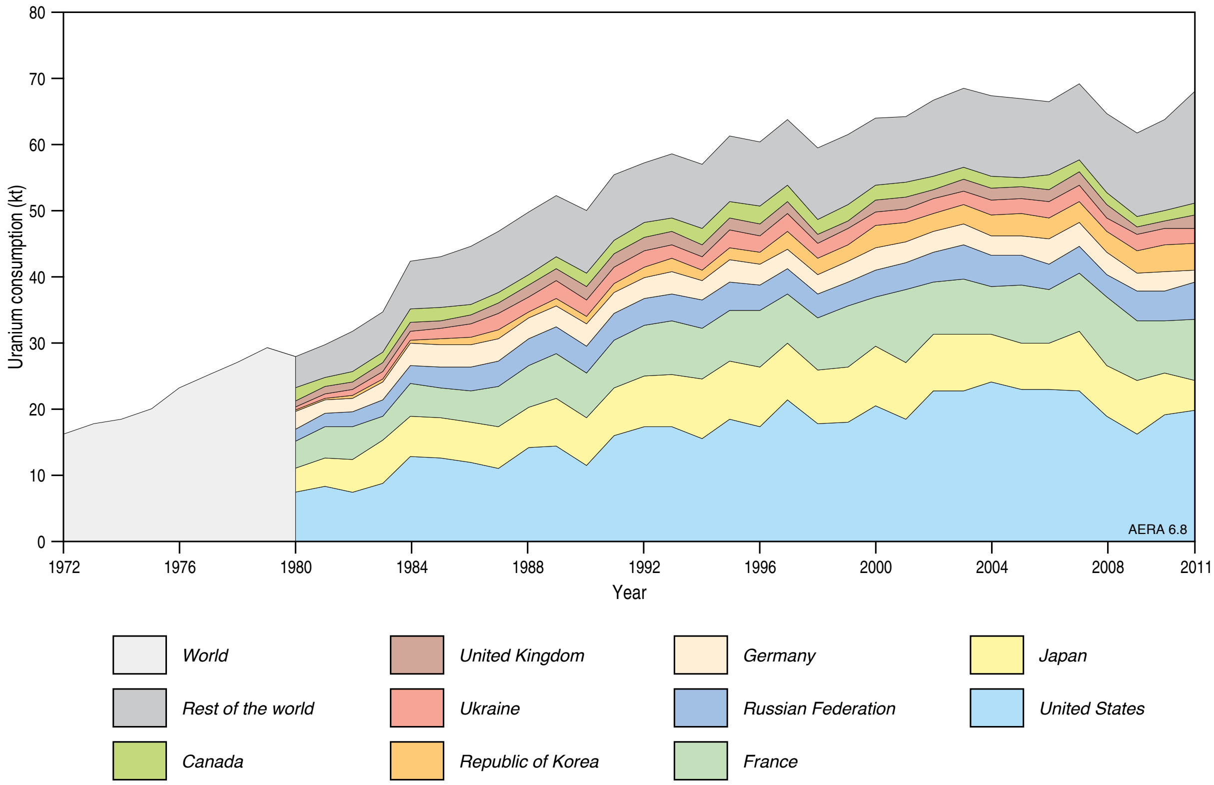

Figure 6.8 World uranium consumption for energy generation, by major country

Source: OECD/NEA and IAEA 2012; WNA 2012b

Consumption

Uranium is used as a fuel for nuclear power and to produce medical and industrial isotopes. The nuclear power industry requirements dominate.

Between 1971 and 2011, uranium consumption for energy purposes grew by an average 4 per cent per year to 35 029 PJ, or 5.7 per cent of the world's primary energy consumption (IEA 2012a). In 2011, the largest consumers of uranium for power generation were the United States, France and the Russian Federation (figure 6.8). During the 1990s growth in uranium demand slowed as fewer reactors were built compared with the previous two decades. However, an increased focus on energy diversification and the need to reduce global greenhouse gas (especially carbon dioxide) emissions in recent years has stimulated renewed interest in nuclear power as a proven base load power source and low-emission technology (Commonwealth of Australia 2006b).

Trade

With the exception of Canada, uranium production is focused in countries without significant enrichment and conversion facilities, such as Australia, Kazakhstan, Namibia and Niger. Reflecting this, trade in U_3O_8 is common, although information on world trade is often not publicly available due to commercial sensitivities. Based on production and consumption, the largest importers of U_3O_8 in 2011 were likely to have been the United States, Japan, France, Germany and the Republic of Korea. The largest exporters of uranium were likely to have been Kazakhstan, Canada, Australia, Namibia and Niger.

World uranium market outlook

According to projections from the Energy Information Administration (EIA), world electricity generation from nuclear power is expected to increase by at least 75 per cent to 4916 TWh or around 17 500 PJ by 2035 (table 6.3; EIA 2012b). Growth in nuclear power is driven by concerns over increasing demand for electricity, rising fossil fuel prices, energy security, and greenhouse gas emissions. Despite this growth, the share of nuclear power as a proportion of world electricity generation is projected to decrease, from 13 per cent in 2010 to 12 per cent in 2035 (IEA 2012b).

Key growth markets for nuclear power are projected to be developing economies, where electricity consumption will increase significantly over the next 20 years. Countries with the largest growth in nuclear power capacity are expected to be China and India, where growing energy demand and favourable nuclear power policies are expected to drive growth. Nevertheless, growth in non-OECD Europe, Eurasia and North America is also likely to play a role in increasing nuclear power production as these economies maintain nuclear power electricity generation in their energy portfolios.

There is considerable uncertainty surrounding world economic growth, energy security, adoption of greenhouse gas emission reduction targets, relative costs of generating technologies and changes in policy relating to nuclear power. All present risks to the consumption projections shown in figure 6.9. In particular, there is potential for nuclear power, and thus demand for uranium, to grow faster than projected if the introduction of policies, such as emissions reduction targets, reduce demand for coal before alternative low-emission energy sources become economic.

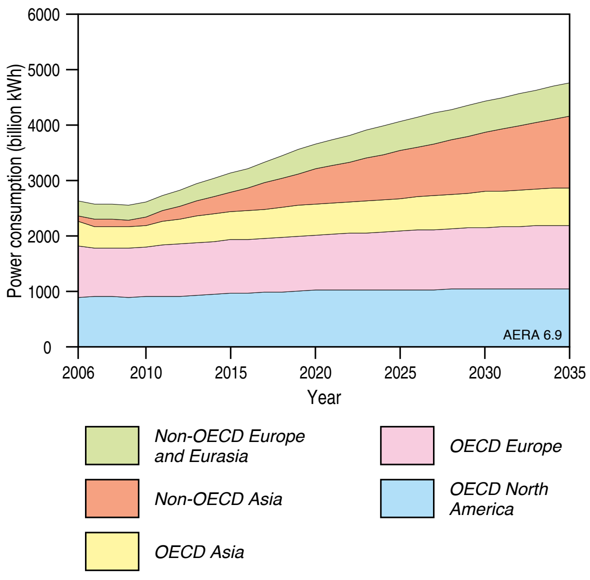

Figure 6.9 Projected world nuclear power consumption to 2035

Source: EIA 2012b

6.2.2 Australia's uranium resources and market

Uranium resources

Australia has the world's largest RAR of uranium recoverable at less than US$130/kg U, with 1174 kt of resources in this category at December 2012 (table 6.4, figure 6.11). Australia accounts for 34 per cent of world RAR recoverable at less than US$130/kg U. Based on current Australian production and RAR at 2012, the estimated resource life is about 170 years. However, if the production capacity of over 14 kt U is reached as anticipated (figure 6.18) then the resource life would be much shorter. Australia has an additional 532 kt of uranium in Inferred Resources recoverable at less than US$130/kg U, which are also the world's largest resources in this category.

Olympic Dam deposit (South Australia) is a world class polymetallic copper-uranium-gold-silver deposit. It is the world's largest uranium deposit. BHP Billiton reported the total Measured+Indicated+Inferred Resources as at June 2012 amounted to 9.576 billion tonnes averaging 0.82 per cent copper, 0.26 kg/tonne U_3O_8, 0.31 grams/tonne gold, 1.39 grams/tonne silver (BHP Billiton 2012). Geoscience Australia estimates that the Olympic Dam deposit contains 77 per cent of Australia's RAR recoverable at costs less than US$130/kg U. The company stated that the hydrometallurgical processing of the ore recovers 72 per cent of the contained U_3O_8.

Table 6.3 Projected nuclear electricity generation to 2030

Region/country	Actual electricity generation (TWh)	Projected electricity generation (TWh)		
	2011	2015	2020	2030
OECD				
North America	**901**	**963**	**1018**	**1047**
United States	803	839	877	877
Canada	89	113	131	152
Mexico	9	10	10	18
Europe	**941**	**965**	**998**	**1111**
Asia	**414**	**502**	**560**	**641**
Japan	264	319	342	388
Republic of Korea	150	183	218	253
Australia/New Zealand	0	0	0	0
Total OECD	**2256**	**2430**	**2576**	**2799**
Non-OECD				
Europe and Eurasia	**274**	**342**	**449**	**567**
Russian Federation	153	197	275	366
Other	121	145	174	201
Asia	**192**	**360**	**630**	**1063**
China	103	223	419	749
India	42	66	119	187
Other Asia	47	71	92	127
Other	**36**	**41**	**74**	**117**
Total Non-OECD	**502**	**743**	**1153**	**1747**
Total World	**2759**	**3173**	**3731**	**4546**

Source: EIA 2012b

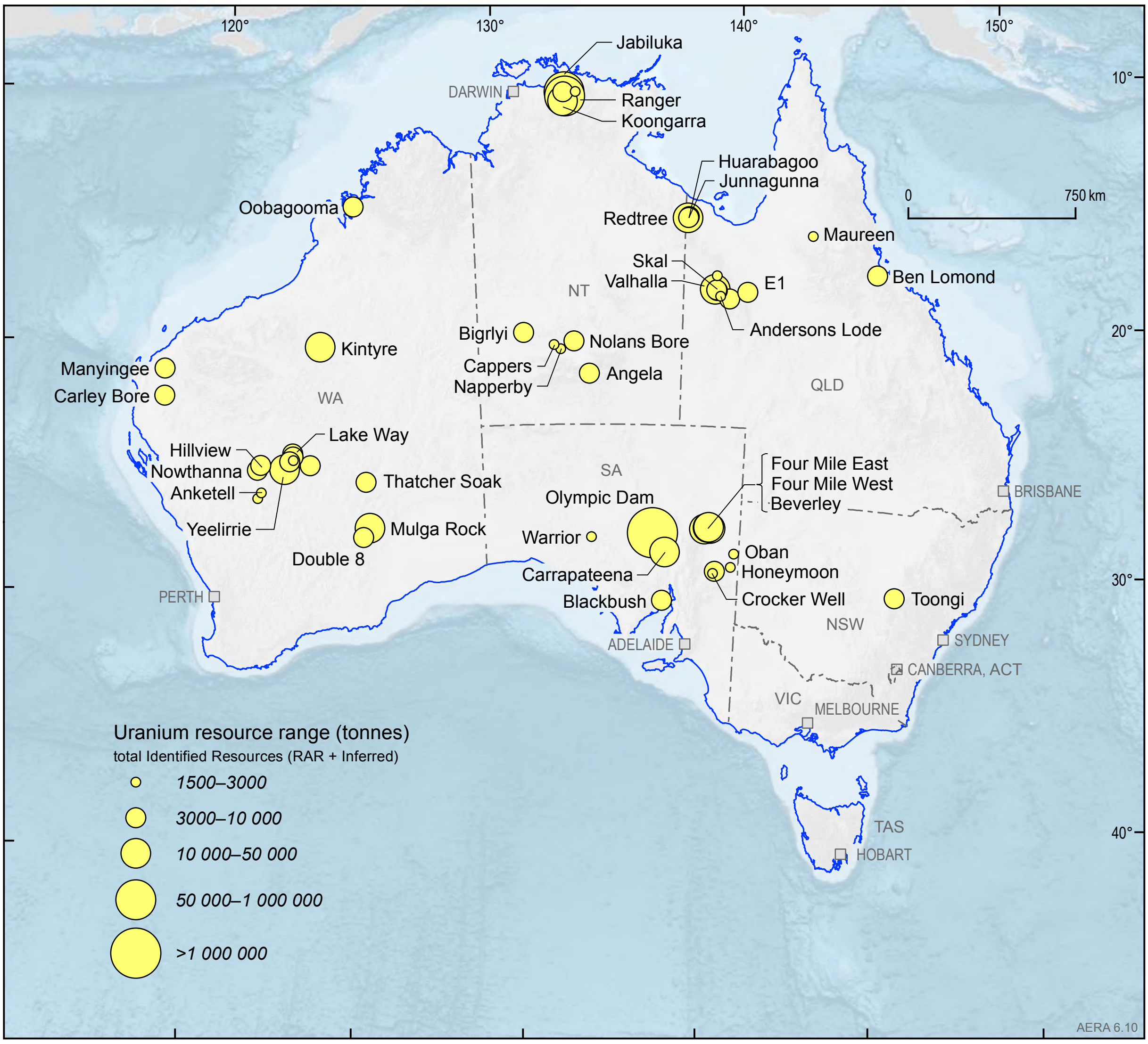

Figure 6.10 Australia's total identified uranium resources

Source: Geoscience Australia

Table 6.4 Australia's uranium resources as at 31 December 2012

	Recoverable <US$130/kg U (kt)	Recoverable in range US$130–260/kg U (kt)
Reasonably Assured Resources (RAR)	1174	34
Inferred Resources	532	58
Total Identified Resources	**1706**	**92**

Source: Geoscience Australia 2013

The location of Australia's uranium deposits and the relative size of resources are shown in figure 6.10.

The majority of Australia's uranium resources occur in four types of deposits, which vary significantly in both tonnage and grade:

- *Hematite breccia complex deposits* contain about 77 per cent of Australia's total Identified uranium resources and all of these resources are at Olympic Dam (South Australia).
- *Unconformity-related deposits* account for about 13 per cent of Australia's total resources. These deposits are mainly in the Alligator River region in the Northern Territory (Ranger, Jabiluka, Koongarra), and in one deposit in the Rudall Province, Western Australia (Kintyre). The unconformity-related deposits have the highest average grades overall but show a very wide range in size.
- *Sandstone deposits* account for about 3 per cent of Australia's total known Identified Resources, and

occur mainly in the Frome Embayment region in South Australia (Beverley, Four Mile, Honeymoon, East Kalkaroo, Goulds Dam) and the Westmoreland area in north-west Queensland (Redtree, Junnagunna, Huarabagoo). Other significant sandstone-type deposits include Manyingee, Mulga Rock and Oobagooma in Western Australia, and Angela in Northern Territory.

- *Calcrete deposits* have about 3 per cent of Australia's Identified Resources. Most calcrete deposits are low grade. The world class Yeelirrie deposit is the largest deposit of this type. Other calcrete deposits include Lake Way, Lake Maitland and Centipede (Western Australia).
- *Other types* of uranium deposits in Australia include metasomatite deposits (Valhalla, Skal and Anderson's Lode, Queensland). Australia has only small resources within metamorphic (remnant resources at Mary Kathleen, Queensland), volcanic (Ben Lomond, Maureen, Queensland) and intrusive deposits (Crocker Well, Mount Victoria, South Australia).

The major uranium ore minerals are uraninite and pitchblende, though a range of other uranium minerals are found in particular deposits. The total initial size of Australian deposits as uranium oxide grade and ore tonnage is plotted in figure 6.11. Whether a deposit has potential for development depends on several factors, including the relative tonnage to grade. For example, the Nabarlek mine (Northern Territory) was high grade, but relative low tonnage. In contrast, the Olympic Dam deposit has a very large tonnage but the uranium grade is relatively low. Although the uranium grade is low, Olympic Dam is a major copper and gold producer, which offsets the cost of mining uranium.

In recent years a number of Australian uranium deposits have been inaccessible for mining because of environmental and policy decisions. These included the uranium deposits in Queensland, where state government policies banned uranium mining. However, in October 2012, the Queensland Government lifted its ban on uranium mining so that these deposits are no longer inaccessible. The following deposits are inaccessible for mining: Jabiluka Northern Territory (Traditional owners have not given approval to mine the deposit), Koongarra Northern Territory (in Kakadu World Heritage Area), Oobagooma Western Australia (on military lands) and Mount Gee South Australia (in Arkaroola Protection Area). In total, the resources within these deposits represent 9 per cent of Australia's RAR recoverable at less than US$130/kg U.

There are several major undeveloped deposits that may be developed if proven economically feasible and all necessary approvals are granted. Table 6.5 summarises the total ore reserves and mineral resources of the main undeveloped deposits as reported by resources companies.

Uranium market

Production

In 2012, Australia had four operating mines: Energy Resources of Australia's Ranger mine in the Northern Territory, BHP Billiton's Olympic Dam underground mine, Heathgate Resources' Beverley/Beverley North ISR mine and Uranium One's Honeymoon ISR mine in South Australia.

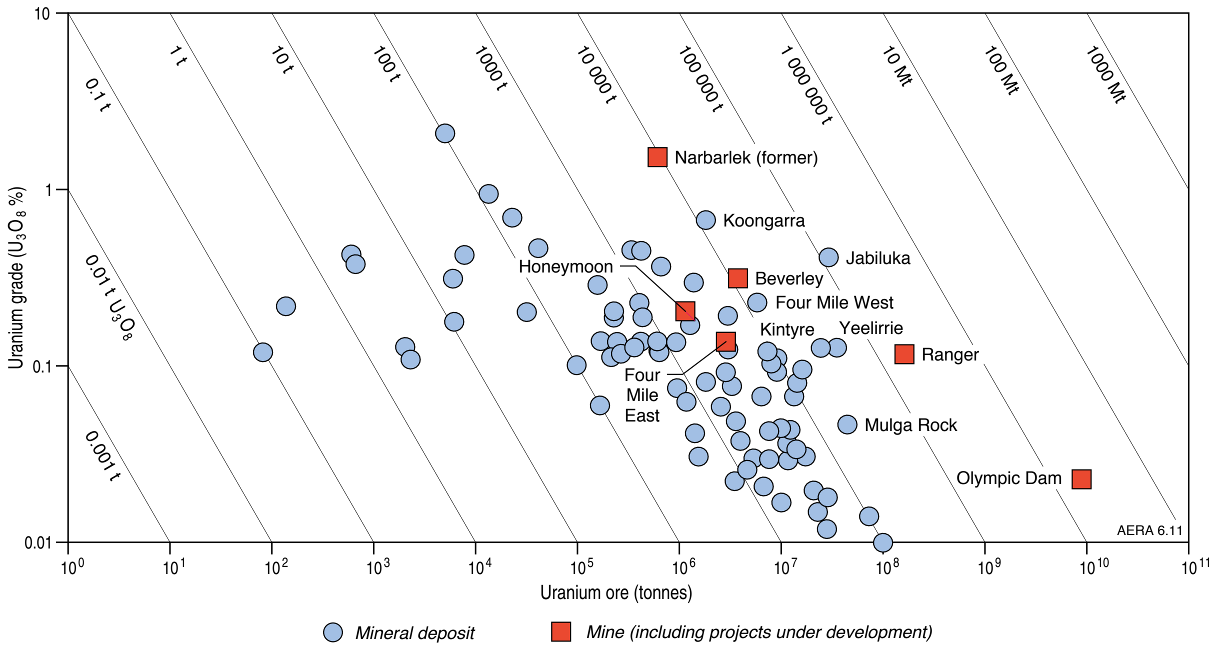

Figure 6.11 Australian mines and deposits (total resources, including past production and current remaining resources) by grade and tonnage

Source: Geoscience Australia

Table 6.5 Major undeveloped uranium deposits in Australia

Deposits	Ore reserves contained U_3O_8 (kt)	Mineral resources contained U_3O_8 (kt)
Northern Territory		
Jabiluka 2	67.70	73.94
Koongarra	14.50	
Bigrlyi	-	9.60
Angela	-	9.89
South Australia		
4 Mile West	-	18.70
Crocker Well and Mt Victoria	-	6.74
Queensland		
Valhalla	-	34.6
Westmoreland (Redtree, Junnagunna, Huarabagoo, Sue and Outcamp)	-	25.12
Western Australia		
Yeelirrie	-	52.50
Kintyre	-	29.39
Mulga Rock	-	27.10
Manyingee	-	10.90
Oobagooma	-	9.95
Centipede-Lake Way	-	11.81
Lake Maitland	-	10.11
Total	**82.20**	**330.35**

Note: Ore reserves and mineral resources are company estimates

Source: Geoscience Australia

In addition, Alliance Resources' (wholly owned subsidiary of Heathgate Resources) and Quasar Resources' Four Mile ISR project is expected to commence production from the Four Mile East deposit in South Australia in 2014.

Mining at Ranger open pit ended in November 2012 when the remaining ore in the bottom of the pit was mined out. The Ranger plant will continue processing stockpiled ores (including lateritic ores) from 2013 onwards. ERA Limited proposes to develop an underground mining operation for the Ranger 3 Deeps deposit immediately east of the open cut. A decline is currently being developed at Ranger 3 Deeps.

Beverley North comprises the Pepegoona and Pannikin deposits (12 km and 10 km north, respectively, of Beverley mine). These are satellite ISR operations comprising wellfields, pumps, pipelines and facilities for circulation of the mining (leach) solutions, and ion exchange columns. Uranium is captured on resins within the ion exchange columns and when the resin is completely loaded with uranium, it is transferred into a road tanker and transported to the Beverley plant for processing to recover the uranium.

In 2011–12, Australia was the world's third largest uranium producer, accounting for 11 per cent of world production. Australia produced around 3898 PJ (6.96 kt U) in 2011–12 from four operating mines. Ranger accounted for 43 per cent of Australian mine production, Olympic Dam produced 50 per cent, Beverley/Beverley North operation produced 6 per cent and Honeymoon operation accounted for about 1 per cent of Australia's uranium production.

Between 1954 and 1971, Australia produced a total of about 7.7 kt U from five mines: Radium Hill (South Australia), Mary Kathleen (Queensland), Rum Jungle (Northern Territory) and two sites in the South Alligator Valley (Northern Territory). The mines were developed to satisfy contracts with the United Kingdom Atomic Energy Authority and the Combined Development Agency, a joint United Kingdom and United States uranium purchasing agency. These mines were closed after fulfilling their contracts.

Increasing prices in the early 1970s as a result of improved demand for uranium for energy purposes led to the reopening of Mary Kathleen in 1975 and the opening of two new mines in the Northern Territory: Queensland Mines' Nabarlek mine and Energy Resources of Australia's Ranger mine, in 1979 and 1980 respectively (figure 6.12). Australian mine production increased strongly until the mid 1980s when both Nabarlek and Mary Kathleen mines were closed. The Olympic Dam operation, a major new mine in South Australia, commenced production in 1988, and offset some of the mine closures. However, reduced demand for uranium as a result of increased availability of secondary supplies resulted in Australia's uranium production declining until the mid-1990s.

Australian uranium production has expanded strongly over the past 10 years as producers have responded to growing export demand. South Australia has contributed to most of this growth, reflecting the expansion at Olympic Dam in 1999 and the development of the Beverley mine in 2001, and Beverley North satellite ISR and Honeymoon in 2011. Capital expenditure on the Beverley mine was A$30 million; it has a capacity of 1 kt U_3O_8 per year. The 1999 Olympic Dam expansion had a capital cost of nearly A$2 billion, which increased the capacity of the mine to 4.3 kt U_3O_8 per year (table 6.6), together with increased copper and gold production. Production at the Ranger mine in the Northern Territory has also contributed to higher production over this period. The addition of a radiometric sorter and laterite processing plant in 2008 and 2009 respectively will maintain production at the Ranger operation in the future.

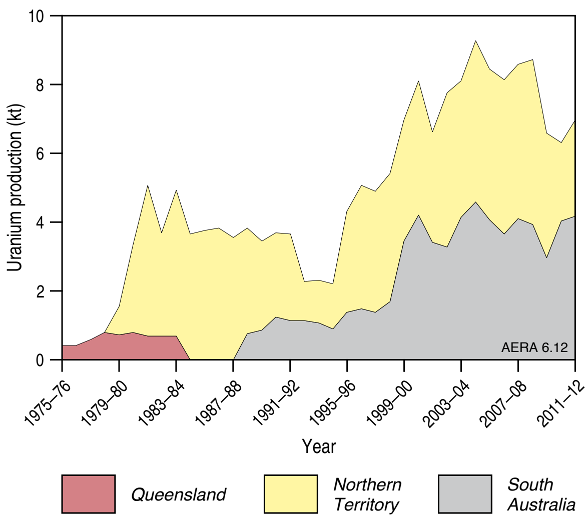

Figure 6.12 Australian uranium production, by state

Source: Bureau of Resources and Energy Economics, Geoscience Australia

In October 2011, BHP Billiton received government approvals for the Olympic Dam Expansion project based on a large open pit to mine the south-eastern portions of the deposit. In August 2012, the company announced that it would delay the proposed expansion and that it would investigate an alternative, less capital-intensive design of the open cut, involving new technologies, which would substantially improve the economics of the project.

Consumption

Australia does not consume any of its locally produced uranium. A small amount of LEU is imported for use at the Australian Nuclear Science and Technology Organisation's (ANSTO) Lucas Heights OPAL research reactor. The research reactor provides medical isotopes for nuclear medicine and treatment, scientific research and irradiation of industrial materials.

Trade

Australia exports all its uranium (figure 6.13) to countries within its network of bilateral safeguards agreements, which ensures that it is used only for peaceful purposes and does not enhance or contribute to any military applications.

Australian mining companies supply uranium under long-term contracts to electricity utilities in the United States, Japan, China, the Republic of Korea, Taiwan and Canada as well as members of the European Union including France, Germany, Sweden and Belgium (table 6.7). Since 2007 Australia has negotiated bilateral safeguards agreements for the export of uranium to China, Russia and the United Arab Emirates and in December 2011 negotiations commenced with India on a bilateral safeguards agreement. Australia's uranium exports contain sufficient energy to generate the equivalent of Australia's current annual electricity output (BREE 2012a).

In 2011–12, Australia exported 3284 PJ (5.86 kt U) valued at A$607 million (ASNO 2012). This was broadly consistent with the previous year. The value of Australia's

Table 6.6 Developments at Australian mines, as at December 2012

Project	Company	State	Start-up	Production capacity (kt U_3O_8 /year)	Capital expenditure (A$million nominal)
Olympic Dam 1999 expansion	BHP Billiton	SA	1999	4.3	1940[a]
Beverley ISR mine	Heathgate Resources	SA	2001	1.0	30
Ranger radiometric sorting plant	Energy Resources of Australia	NT	2008	1.1	19
Ranger laterite plant	Energy Resources of Australia	NT	2009	0.4	44
Beverley North satellite ISR operations	Heathgate Resources	SA	2011	b	b
Honeymoon ISR mine	Uranium One	SA	2011	0.34	146

a Capital expenditure covers total expansion of copper-gold-uranium-silver mining. **b** Uranium-bearing resins from Beverley North ISR operations are processed in the main Beverley plant to recover uranium. Beverley plant processes resin from both the Beverley and Beverley North operations

Source: ABARE 2006; BREE 2012b

uranium export earnings has increased substantially over the past 15 years, reflecting growth in both export volumes and prices; however, both of these have declined in the past 2 years (figure 6.14; BREE 2012a).

Table 6.7 Australia's uranium exports to end-users, 2012

Region	Uranium oxide concentrate (tonnes U_3O_8)	Share of total (%)
Asia	3531	48.5
Europe	1871	25.7
North America	1874	25.8
Total	**7276**	**100.0**

Source: ASNO 2012

Uranium is commonly traded through long-term contracts which are negotiated in both price (spot and long term) and quantity terms. In Australia, uranium producers sell their production through long-term contracts and on the world spot market. Historically, secure contract prices have been negotiated for long time periods. More recently, an industry trend of indexing contract prices to spot prices has emerged, although most of Australia's current long-term contracts do not have these provisions.

As most trade is conducted through long-term contracts, the uranium spot market is illiquid (small number of buyers and sellers), which can lead to volatility in prices. Reflecting this, the average export price for Australian uranium producers has been considerably less volatile than the spot price in recent years (figure 6.15). In late 2008, the spot price was also influenced by the development of a futures market resulting in speculative purchases of uranium by investment companies.

6.2.3 Outlook for Australia's resources and market

There is ongoing interest in nuclear power, particularly among developing economies in Asia. Demand for reliable supplies of uranium will therefore grow to meet the continued expansion of electricity generation from nuclear power. Australia is expected to continue to be a major producer and exporter of uranium as nuclear fuel to world markets out to 2020 due to its large reserves and stable commercial environment. Beyond this outlook period, there is potential for further expansion in Australia's uranium industry, although political decisions and regulations will have an important role in determining its magnitude. There are no plans for Australia to have a commercial nuclear power industry or enrichment facilities and all of Australia's uranium production will continue to be exported.

In the medium to long term, Australia's production of uranium is expected to increase significantly, reflecting Australia's large low-cost uranium resources, proposed new mines and increasing export demand.

Key factors influencing the outlook

A report to government on uranium mining, processing and nuclear energy in Australia (Commonwealth of Australia 2006a) noted that Australia was 'well positioned to increase production and export of uranium to meet market demand' and that 'downstream steps of uranium conversion, enrichment and fuel fabrication could add a further A$1.8 billion of value annually if Australian uranium was processed domestically'. The report noted, however, that there were commercial, technology and regulatory impediments to downstream processing.

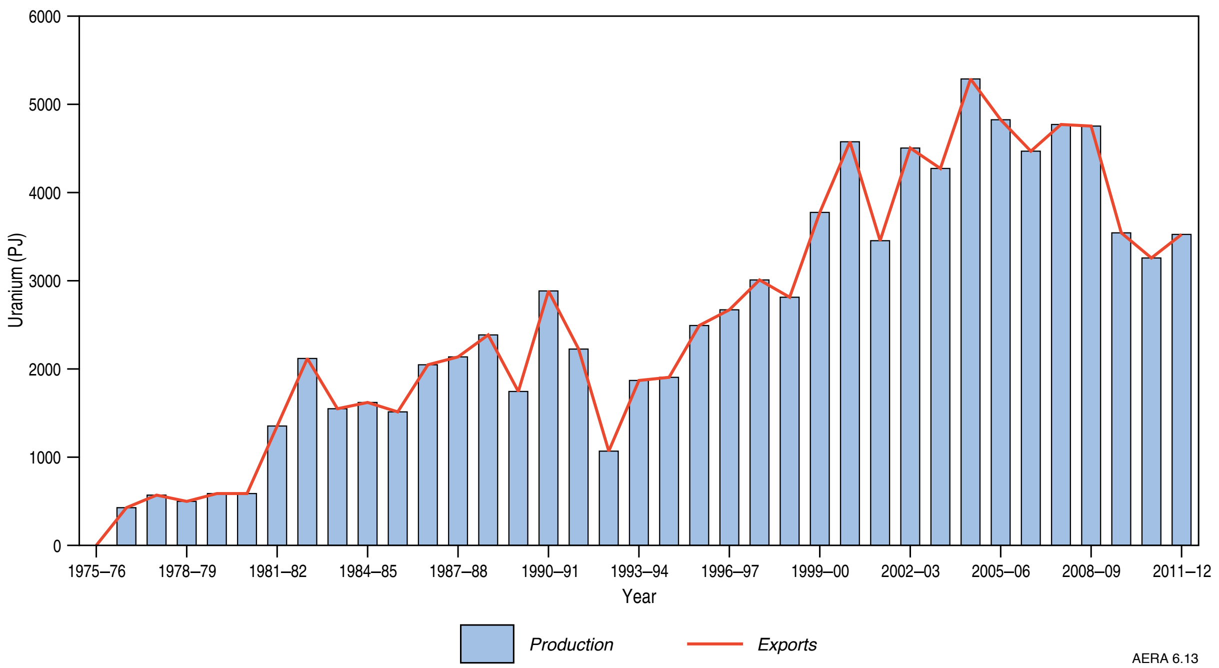

Figure 6.13 Australia's uranium supply–demand balance

Source: BREE 2012a

The report also considered issues associated with the potential development of nuclear power in Australia and concluded that even if the current legislative impediments were removed it would be at least 10 years and most likely 15 years before nuclear electricity could be delivered. By then, Generation IV reactors, which use uranium more efficiently, result in less waste and are less conducive to nuclear weapon proliferation, are likely to be the industry standard.

World demand for uranium as a nuclear fuel is expected to continue to grow with the expansion of nuclear power worldwide. The factors that will influence demand include:

- commitment to greenhouse gas emissions reduction targets
- increased demand for low-emission electricity generation provided by nuclear power
- increased demand for new reactors that provide greater security and safety, generate less radioactive waste and are more resistant to nuclear weapon proliferation.

Conversely, increased efficiency of reactors may constrain the expected growth in uranium demand through more efficient use of uranium and the ability to use reprocessed nuclear fuel.

As a reliable and secure supplier of uranium to the world market, Australia is well placed to meet a significant proportion of any increased demand for uranium for use as an energy resource. Any expansion of Australian uranium production and exports to meet this demand will be influenced by several factors, including:

- significant potential for new uranium discoveries
- undeveloped deposits that are capable of being developed at low-cost
- limited port and shipping company options for export uranium
- uranium mining prohibitions in New South Wales and Victoria.

Cost competitiveness—increased global competition

Australia is well placed to make a greater contribution to meeting the projected increase in global demand for uranium because of its large uranium resources. Australia is a reliable supplier of uranium, which is of strategic importance to utilities.

Uranium is produced using open pit and underground mining techniques, ISR and heap leaching techniques. Historically, uranium production worldwide has been mostly from open pit and underground mining. However, over the past two decades ISR mining has become increasingly important for production of uranium from sandstone-hosted deposits. Production from ISR mining has grown rapidly over the last five years from 27 per cent of world production in 2007 to 42 per cent in 2011. Over the same period, combined production from open cut and underground methods has declined from 61 per cent (in 2007) to 47 per cent in 2011. ISR is now the major source of production because of rapid growth of the use of this method in Kazakhstan and Australia.

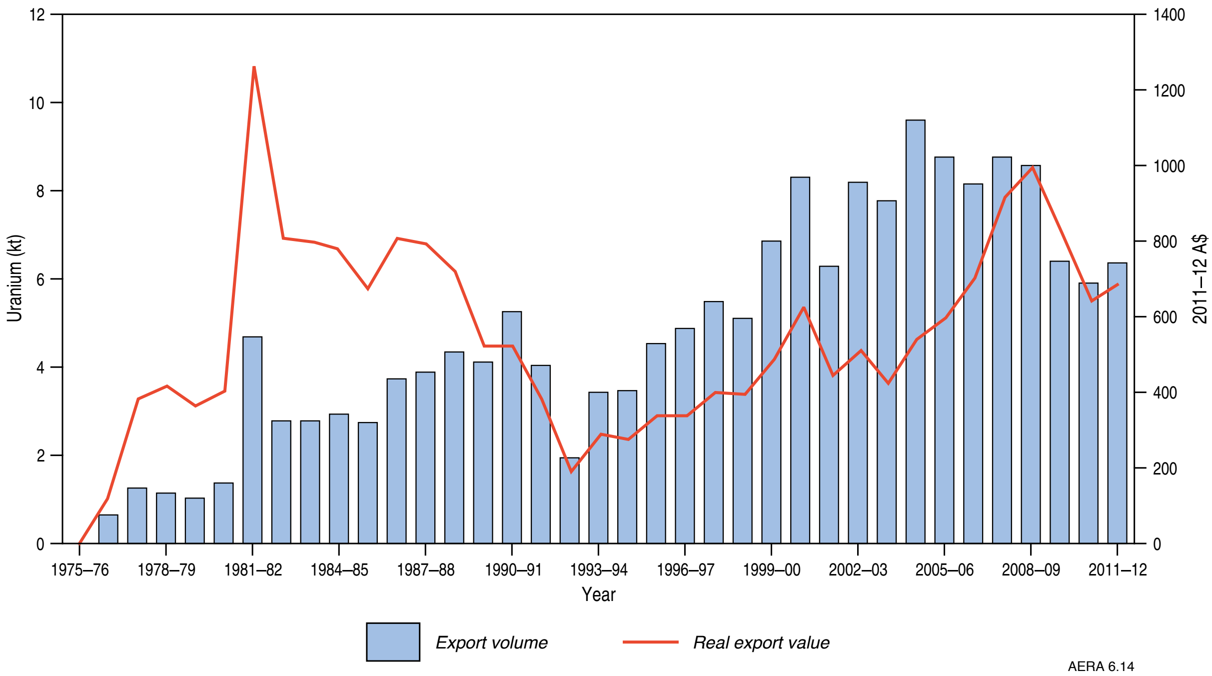

Figure 6.14 Australia's exports of uranium

Source: BREE 2012a

ISR mining also increased in the Russian Federation, USA and Uzbekistan (OECD/NEA and IAEA 2012).

The capital costs vary with mining method. In general, ISR operations are lowest cost, with underground and open pit mines being more expensive per tonne of uranium produced. For an operation of comparable size, open cut mining may be less capital-intensive than underground mining. However, large-scale bulk underground operations that achieve economies of scale can be comparable to open cut operations.

The differences in cost are dependent in part on ore grade and type, infrastructure requirements, and economies of scale. Operating costs are dependent on the metallurgical process required to produce U_3O_8. Uranium deposits comprising uraninite typically have a relatively simple acid leach metallurgy process. Calcrete deposits commonly require alkali leach and can have higher production costs. Recent company data compiled by Geoscience Australia shows that the costs for both ISR and alkaline leach are greater than US$50 per pound U_3O_8.

Cost pressures have influenced the development of uranium mines. A number of industry reports (including Port Jackson Partners 2012, Australian Uranium Association 2012) have reported that the Australian mining industry, including uranium mining, has experienced rapid increases in capital costs and costs for labour, fuel and power. These increases are associated with the recent mining 'boom' in Australia and are impacting the cost competitiveness of the Australian mining industry. In August 2012, BHP Billiton announced that it would delay development of the Olympic Dam Expansion in order to investigate alternative less capital-intensive designs and new technologies in order to substantially improve the economics of the project. In addition, the improvements in ISR technologies together with increased foreign investment have transformed Kazakhstan's uranium mining into a strong challenger to Australia and other countries.

Cameco Australia completed the prefeasibility study of Kintyre, which highlighted the project's challenging economics caused by low uranium prices and escalating costs in Western Australia. The company stated that it would carry out further drilling aimed at discovering more resources.

A further factor which may increase the cost of developing a mine is the site itself—the more remote and difficult the location, the higher the infrastructure costs (Schodde and Trench 2009).

The impact of high operating costs and relatively low uranium prices in the latter part of 2012 and into 2013 have meant that many proposed expansions or new mine developments have been deferred until market prices and demand improve. Cameco recently announced that the company will spread capital investments over a longer period than planned previously and will focus on existing mines rather than new developments.

Over the past decade, growth in new uranium mines has been slow and concentrated in a small number of countries, mainly Kazakhstan and Niger. The majority of the new mines developed to 2012 have been ISR projects (table 6.8).

ISR mines tend to be smaller with a limited surface disturbance; hence capital costs are lower than conventional mines reflecting reduced infrastructure requirements.

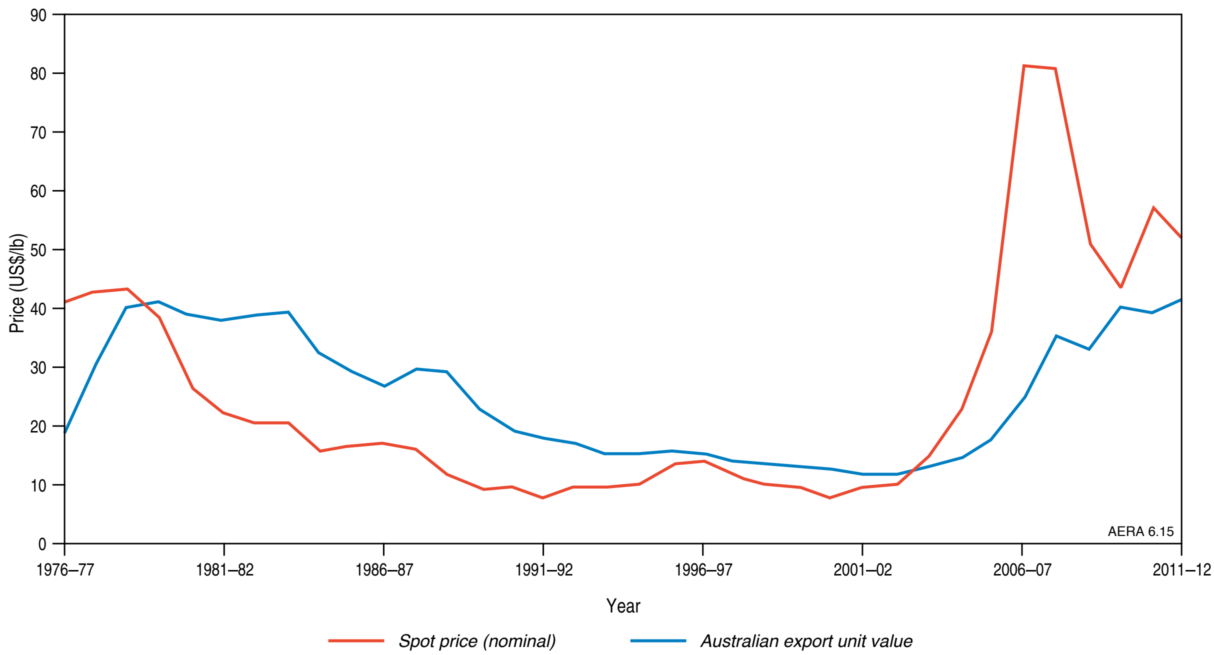

Figure 6.15 Uranium spot prices and average Australian export unit prices

Source: Bureau of Resources and Energy Economics; Ux Consulting 2009, 2012

Table 6.8 Selected uranium projects completed worldwide to 2012

Project	Location	Mining method	Commenced production	Capacity (kt U_3O_8/year)	Capital cost (US$m—nominal)	Unit cost (US$/t U_3O_8—nominal)
Kayelekera	Malawi	Open cut	2009	1.65	167	101 212
Irkol	Kazakhstan	ISR	2010	0.88		
Kharasan (1 and 2)	Kazakhstan	ISR	2010	5.9	430	72 931
Akbastau	Kazakhstan	ISR	2009	1.18		
Semizbai	Kazakhstan	ISR	2009	0.83		
Azelik	Niger	Open cut	2010	0.83		
La Palangana	United States	ISR	2010	0.45	na	na
Honeymoon*	Australia	ISR	2011	0.34	146	429 400

ISR = *in situ* recovery; **na** = not available
* Honeymoon was placed into care and maintenance in 2013
Note: Capacity is the nominal target production capacity
Source: World Nuclear Association country briefs

Table 6.9 Costs of Australian *in situ* Recovery uranium projects

Project	State	Commenced production	Capacity (kt U_3O_8/year—nominal)	Capital cost (A$million)	Unit cost (A$/t—nominal)
Beverley	SA	2000	1.00	58	58 000
Four Mile*	SA	2014	1.00	98	98 000
Honeymoon	SA	2011	0.34	146	429 400

* Four Mile operation will use the processing facilities at Beverley, commissioned in 2014
Source: BREE 2012b

However, ISR is only suitable for deposits in sandstones which are water saturated and where the mining solutions can be contained. It is estimated that sandstone-hosted uranium deposits account for approximately 28 per cent of world uranium resources and 3 per cent of Australia's total uranium resources (OECD/NEA and IAEA 2012).

In Australia, there are two ISR mines (Beverley/Beverley North and Honeymoon) and one ISR project commissioned in 2014 (Four Mile) (table 6.9). Capital costs per unit of production vary considerably between these projects reflecting the time of construction. The Four Mile ISR project has a capital cost per tonne of capacity of A$89 800. The low unit cost of the Four Mile ISR project is because the mined material will be processed at the nearby Beverley operation. In contrast, the Honeymoon operation has an expected capital cost of A$429 000 per tonne of capacity, reflecting the additional cost of constructing a processing facility.

The time and cost of the approval process is an additional factor in development costs. In Australia, new and expanding uranium mines require environmental and development approvals prior to any development occurring. The approval process period for the development of a uranium mine can be lengthy and costly if it is not well managed. Companies are required to provide a detailed environmental assessment for a uranium development proposal, which is assessed by both Australian and state/territory governments before approval to develop is granted. As demonstration of the detail involved in this process, BHP Billiton recently released an Environmental Impact Statement (EIS) for the proposed Olympic Dam expansion, which is a three-stage project from a current production of 4.3 kt to 19 kt per year of U_3O_8. Reflecting the complexity of the expansion and changes to project configuration, the EIS took the company nearly five years to complete. The approval process took a further six months following the release of the Supplementary EIS in May 2011. In contrast, the small Beverley North ISR project took 16 months from discovery to commencement of production (including an EIS assessment process). This reflects, in part, that it is a satellite ISR operation which uses pre-existing processing facilities at the adjacent Beverley mine.

Secondary supply—continues to fill demand

The uranium requirement for nuclear reactors is currently met from both mined uranium and secondary supply. Secondary supply from blending down HEU is expected to decline after 2013 (figure 6.7), but uranium from reprocessed nuclear fuel may play an important role in supplying uranium to meet demand.

According to Euratom, reprocessing is an attractive option, both environmentally and economically (Euratom Supply Agency 2009). Euratom considers that the process not only provides secondary supply (referred to as reprocessed uranium, or RepU) but also reduces the volume, and level of radioactivity of high-level waste material. It also reduces the possibility of plutonium being diverted from civilian use. Technically, at least, recovered uranium and plutonium can be recycled as fresh fuel, with a potential saving of up to 30 per cent of the natural uranium that would be required for fuel in nuclear reactors (figure 6.3).

Almost 90 kt (of the 290 kt discharged) of used fuel from commercial power reactors has been reprocessed. There are reprocessing plants in France, Japan, the Russian Federation and the United Kingdom. Annual reprocessing capacity is now some 4 kt per year for normal oxide fuels. Between 2009 and 2030 around 400 kt of used fuel is expected to be generated worldwide, which is a potential secondary source (WNA 2013b).

Technology developments—new generation of nuclear reactors

In 2012, there were 437 nuclear power reactors in operation in 30 countries requiring around 68.0 kt U per year. There are 64 reactors under construction in several countries including China, India, the Republic of Korea and the Russian Federation. Over 168 reactors are planned with approvals, funding or firm commitments in place; they are expected to be in advanced stages of construction, if not operating, within eight years. There are 317 further reactors proposed in over 30 countries. These proposals are expected to result in reactors in operation within 15 years (WNA 2013). Altogether, there are about 550 reactors under construction, planned or proposed.

The nuclear power industry has been developing and improving reactor technology for more than five decades (box 6.1). Generation I prototype reactors were developed in the 1950s. Generation II reactors were developed as commercial reactors in the late 1960s, and are currently operating for electricity generation in most countries with nuclear power. Over the last 20 years many of these reactors have received extensions of operating licences from 40 to 60 years. In addition, there have been increased operating efficiencies and improved maintenance have resulted in increased capacity and electricity output. The capacity factor is the ratio of actual output from a reactor to maximum possible output at the reactor's rated capacity. In the United States, the average capacity factor increased from 56 per cent in 1980 to over 90 per cent in 2002 (EIA 2009), meaning more electricity was entering the grid. Worldwide, the average unit capacity factor from 2006 to 2008 was 82.4 per cent (IAEA 2009). Consequently, electricity generation has increased markedly over the two decades despite little increase in installed capacity.

Generation III (and III+) reactors incorporate improved fuel technology, thermal efficiency and passive safety systems. The first Generation III reactors have been operating in Japan since 1996. Generation III reactors are currently being built (and planned to be built) in many countries.

Generation IV reactors are still being designed and none have been built to date. The Generation IV International Forum, representing 13 countries, has selected six reactor technologies which will form the future of the nuclear power industry (box 6.1). Generation IV reactors will operate at higher temperatures (in the range 500 °C to 1000 °C) than current commercial light water reactors (less than 300 °C). The technology and design of these new reactors are aimed at:

- using passive safety features which require no active controls or operational intervention to avoid accidents in the event of malfunction
- being more resistant to diversion of materials for weapons proliferation, and secure from terrorist attack
- using the uranium fuel efficiently by using U^{238} and plutonium, as well as all the U^{235}; and using spent fuel from current commercial reactors
- utilising uranium up to 60 times more efficiently
- greatly reducing amounts of high-level radioactive waste compared with current reactors.

Generation IV reactors will have a lower demand for uranium due to the more efficient fuel burn and will minimise high-level waste sent to repositories. These nuclear reactors will alter the nature and scale of high-level radioactive waste (HLW) disposal by substantially reducing the volume of these wastes (Commonwealth of Australia 2006a). Less HLW and less heat generated from radioactive waste (compared with current spent fuel) will enable more effective use of geological HLW repositories. Current planning for HLW repositories in many countries is based on assessment of the amount of waste from current commercial reactors. This will be modified when Generation IV reactors become commercially viable and advanced fuel processing is successful. It is too early to determine which of the Generation IV technologies will be commercially adopted.

BOX 6.1 GENERATION I TO GENERATION IV REACTOR TECHNOLOGIES

Nuclear reactors have been in commercial operation since the 1950s with reactors evolving from early designs (Generation I) to five Generation II reactor designs which today account for most nuclear reactors operating in the world. Reactors currently under construction are Generation II and III (III+) reactors.

Generation III reactors have standardised, more robust design with inherent safety features and higher 'burn-up' to maximise use of fuel and reduce the amount of waste created. The standardised design is reducing capital cost and construction time.

Generation IV reactors are currently in research and development and are not expected to be available for commercial construction before 2030. The goals of the Generation IV reactors are improved nuclear safety, proliferation resistance, increased fuel utilisation, minimised waste and decreased cost to build and operate. The six Generation IV systems selected for R&D are:

- Gas-Cooled Fast Reactor (GFR)—a fast-neutron-spectrum, helium-cooled reactor and closed fuel cycle
- Very-High-Temperature Reactor (VHTR)—a graphite-moderated, helium-cooled reactor with a once-through uranium fuel cycle
- Supercritical-Water-Cooled Reactor (SCWR)—a high-temperature, high-pressure water cooled reactor
- Sodium-Cooled Fast Reactor (SFR)—features a fast-spectrum, sodium-cooled reactor and a closed fuel cycle for efficient conversion of fertile uranium and management of actinides
- Lead-Cooled Fast Reactor (LFR)—features a fast-spectrum lead or lead/bismuth eutectic liquid-metal-cooled reactor and a closed fuel cycle for efficient conversion of fertile uranium and management of actinides
- Molten Salt Reactor (MSR)—uses a circulating molten salt fuel mixture with an epithermal-spectrum reactor and a full actinide recycle fuel cycle.

Nuclear reactors in operation

Table 6.10 provides an overview of the types of nuclear reactors currently in operation and under construction, followed by a summary of the features of the five common nuclear reactors types.

Pressurised Water Reactors (PWR) and Boiling Water Reactors (BWR) are collectively referred to as Light Water Reactors (LWR). These reactors are cooled and moderated using ordinary water (fresh or seawater). The designs are simpler and cheaper to build than other types of nuclear reactor, and they are likely to remain the dominant technology for the present.

Pressurised Water Reactors

The PWR consists of a primary and a secondary circuit of water; both circuits are closed systems. The primary circuit contains pressurised water (to prevent it from boiling), which is heated to over 300 °C as it moves through the reactor core. Once heated, water in the primary circuit circulates through heat exchangers which boil water in a secondary circuit. Steam produced in the secondary circuit drives a turbine to produce electricity—the water is then condensed and returned to the heat exchangers to be transformed back into steam. PWR are the most common nuclear reactors. There are 264 generating units currently in operation with a total capacity of 243.1 gigawatts electric (GWe).

Boiling Water Reactors

The BWR utilise a similar method to the PWR except that a single circuit is used to heat water and produce steam to generate electricity. Water in the circuit is maintained at a low pressure allowing it to boil at around 285 °C. The water is condensed and returned to the core to be transformed back to steam. BWR have a less complicated design and are often cheaper to build; however, this cost advantage is often offset by the increased costs incurred as a result of residual radiation on turbines. They are the second most common reactor design, accounting for around 21 per cent of the world's 436 nuclear reactors.

Table 6.10 Nuclear reactors in operation or under construction, by reactor type, in 2012

	Number	Capacity (GWe)
Operational		
Pressurised water reactors	272	250.3
Boiling water reactors	84	77.7
Pressurised heavy water reactors	49	24.8
Gas cooled reactors	15	8
Light water graphite-moderated reactors	15	10.2
Fast breeder reactors	2	0.5
Total	**437**	**371.5**
Under construction		
Pressurised water reactors	52	51.2
Pressurised heavy water reactors	5	3.2
Boiling water reactors	4	5.2
Fast breeder reactors	2	1.2
Light water graphite-moderated reactors	1	0.9
Total	**64**	**61.7**

Source: International Atomic Energy Agency

Pressurised Heavy Water Reactors (PHWR)/CANDU reactors

The PHWR or CANDU reactors are designed to use LEU directly as a fuel. The PHWR use a similar design to the PWR with a reaction in the core heating a coolant in a primary circuit which is then used to boil water in a secondary circuit. The PHWR differ from the PWR in that heavy water (water containing deuterium) is used as a coolant. The fuel rods are cooled by a flow of heavy water under high pressure in the primary cooling circuit. The pressure tube design means that the reactor can be refuelled progressively without shutting down. Forty-four PHWR are currently in operation (around 40 per cent in Canada) with a combined capacity of 22.4 GWe.

Gas Cooled Reactors (GCR) and Advanced Gas-cooled Reactors (AGR)

GCR are considered safer than traditional water cooled reactors as the cooling properties of gas do not change with temperatures. The GCR use natural uranium fuel and the AGR use an enriched uranium dioxide fuel. Carbon dioxide is used as coolant which circulates through the core, reaching 650 °C before passing through a steam generator creating steam in a secondary circuit. In the 1980s, following the success of LWR, the United Kingdom made the decision to adopt LWR technology. As a result no gas cooled reactors have been built since.

Light Water Graphite-moderated Reactors (LWGR)

The LWGR are Russian designed, based heavily on the BWR. The design operates with enriched uranium dioxide fuel at high pressure and uses a graphite moderator to slow down the reaction and water as a coolant which is allowed to boil at around 300 °C. This design can have a positive feedback problem that results in excessive heat being released from the core. For this reason there are no plans to build new LWGRs beyond the one currently under construction. Currently, 16 of these reactors are in operation in the Russia Federation and Lithuania.

Source: WNA 2009e, 2009f

Best practice sustainable uranium projects

The Australian Government supports the development of uranium deposits in line with world's best practice environmental and safety standards. New uranium mines are subject to approval by the Australian and state/territory governments. Development of uranium mines is permitted in South Australia, Northern Territory, Western Australia, Queensland and Tasmania. New South Wales now permits exploration. Victoria has legislated against uranium exploration and mining.

Uranium mining proposals involve integrated consideration under both the Commonwealth *Environment Protection and Biodiversity Conservation Act 1999* and state/territory legislation. Regulation of all mines in Australia focuses on the outcomes to be achieved and is largely the responsibility of state/territory authorities. The principles and approaches for all mining have helped achieve increased trust by stakeholders through a clear up-front agreement on the environmental outcomes to be achieved and a demonstration by the mining operator that environmental, social and economic elements of the project are being managed appropriately.

The Australian Government and the jurisdictions that currently permit uranium mining (South Australia, Northern Territory, Queensland and Western Australia) have prepared a national ISR uranium mining best practice guide, released in 2010, to ensure that ISR proposals represent best practice environmental and safety standards. The guide (Commonwealth of Australia, 2010) outlines and discusses the general principles and approaches that should apply to all mining in Australia, before considering ISR uranium mining more specifically.

With regard to radiation protection in mining, state and territory governments adopt the regulatory approach outlined in the Code of Practice and Safety Guide on Radiation Protection and Radioactive Waste Management in Mining and Mineral Processing (ARPANSA 2005), produced by the Australian Radiation Protection and Nuclear Safety Agency.

Sustainable growth of the uranium industry requires community engagement to communicate the environmental and safety practices built into the project and to demonstrate that there are effective regulatory controls. Engagement, consent and land use agreements with Indigenous communities are essential in areas where Indigenous groups hold rights over or interests in the land.

The Uranium Council (formerly the Uranium Industry Framework), set up in 2009, is an industry–government initiative which works to alleviate impediments to an internationally competitive Australian uranium industry, operating to world's best practice standards. The Australian Government recognises that effective engagement with the uranium industry is vital in this period of industry expansion.

Through the Uranium Council, significant achievements have been made towards a nationally consistent approach to the management of uranium. Such consistency is vital to secure a strong and stable uranium industry and to send a clear message to the broader community that this is an industry that is serious about safety, sustainability and social responsibility.

This forum has proven to be a valuable source of information dissemination across and between companies, regulators and jurisdictions, and has assisted in safe and controlled expansion of the industry. The Uranium Council has also facilitated greater transparency, consistency and understanding across jurisdictions, in turn strengthening public confidence in the industry.

Transportation issues

All Australian exports of radioactive material, such as U_3O_8, require an export permit. These are assessed by the Australian Government to ensure that Australia's uranium is exported to countries for peaceful purposes under Australia's network of bilateral safeguards agreements. Each shipment of uranium leaving Australia must be reported to the Australian Government and is tracked and accounted for in the international nuclear fuel cycle.

Any significant expansion of uranium exports will require improved access to transport options. Currently, uranium is exported from two ports, Darwin in the Northern Territory and Adelaide in South Australia.

In South Australia, uranium exports through the Adelaide port will continue as planned projects such as Four Mile commence shipping uranium through this port. In addition, the Olympic Dam Expansion plans to export uranium through both Adelaide and Darwin container ports with the uranium transported by train to both of these destinations.

Western Australian uranium production is likely to commence in the medium term with projects such as Wiluna, Yeelirrie and Kintyre potentially entering production. Current plans for uranium transport is by road to rail heads, loaded onto trains and transported to the Darwin or Adelaide ports for export.

Uranium oxide is classified as a Class 7 Dangerous Good which has specific handling and transport requirements. It is transported by rail, road and sea in 200-litre drums packed in secure shipping containers.

There are increased international transport constraints affecting Class 7 goods, such as the consolidation of the international shipping industry and associated reduction in scheduled routes, and reduction in ports where vessels carrying uranium can call or transit, even where this cargo remains on board. The consolidation of shipping firms and denial of routes result in increased delays and costs to the uranium industry. International transport issues, such as denial of shipping, are being progressed through the International Atomic Energy Agency's International Steering Committee on Denial of Shipping.

Outlook for uranium resources

Uranium deposits are known in all states (except Victoria and Tasmania, which only have uranium occurrences) and the Northern Territory. Favourable geological settings and limited exploration during two decades from 1983 to 2003 mean that there is significant potential for discovering new deposits. New discoveries are likely to significantly increase Australia's resource base and encourage further exploration in surrounding areas.

Uranium exploration expenditure in Australia has increased since 2003 mainly because of the significant increases in spot market uranium prices, which reached a peak in July 2007 (US$136/lb U_3O_8). Prices subsequently declined to the end of 2012 (figure 6.16). In 2008, uranium exploration expenditure reached a record of A$220.5 million (ABS 2009a). For 2011, exploration expenditure was $189.6 million which was virtually unchanged from expenditure in 2010 ($190 million). The majority of this expenditure was in Western Australia (47 per cent), followed by South Australia (24 per cent), the Northern Territory (21 per cent) and Queensland (8 per cent; ABS 2012).

Overall, there is a close correlation between spot price trends and uranium exploration spending, often with a one-year lag (figure 6.16).

A large number of new companies have been floated in recent years specifically to explore for uranium.

World uranium exploration expenditures increased rapidly from 2003 to reach a peak of US$2076 million in 2010; approximately 8 per cent of this was spent in Australia (OECD/NEA and IAEA 2012). Available data shows that world uranium exploration expenditures for 2011 are approximately the same as those for 2010.

Historically uranium exploration in Australia has been highly successful (figure 6.17). Of the 90 currently known uranium deposits in Australia, the overwhelming majority were discovered from 1969 to 1975 with another four discovered between 1975 and 2003. Annual expenditure on uranium exploration in Australia fell progressively for 20 years from the peak in 1980 until 2003 due to low

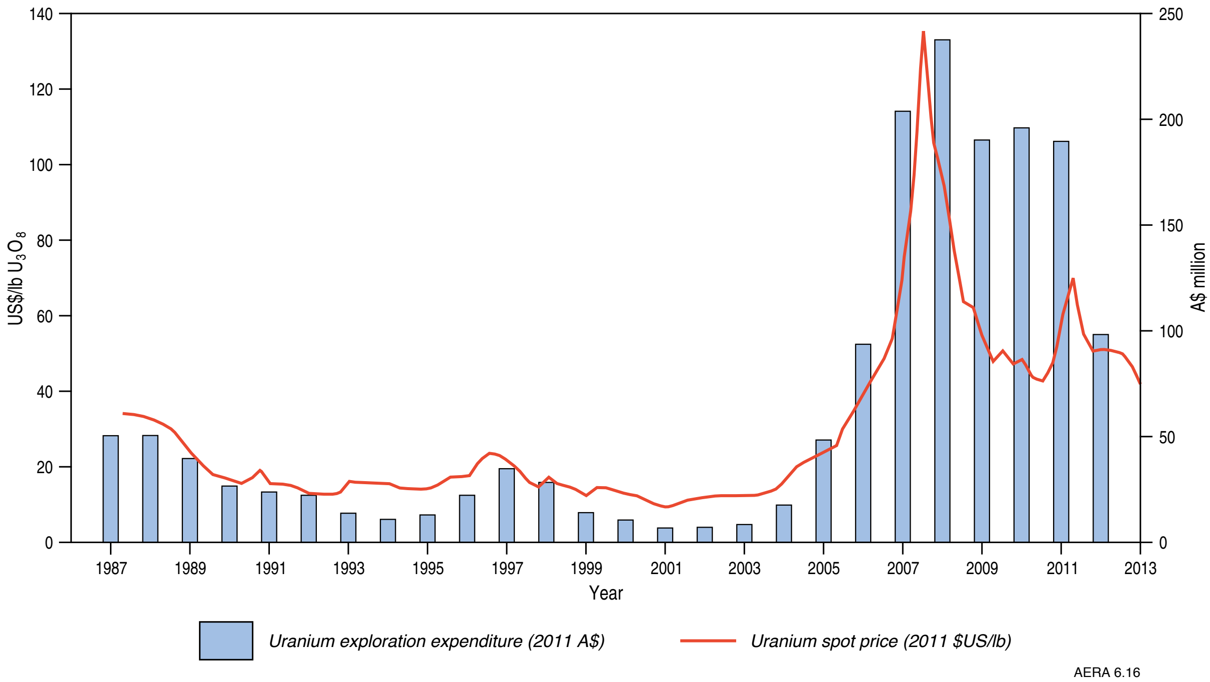

Figure 6.16 Australian exploration expenditure and uranium spot prices in real dollars

Source: Geoscience Australia; ABS 2009a; Ux Consulting 2009, 2012

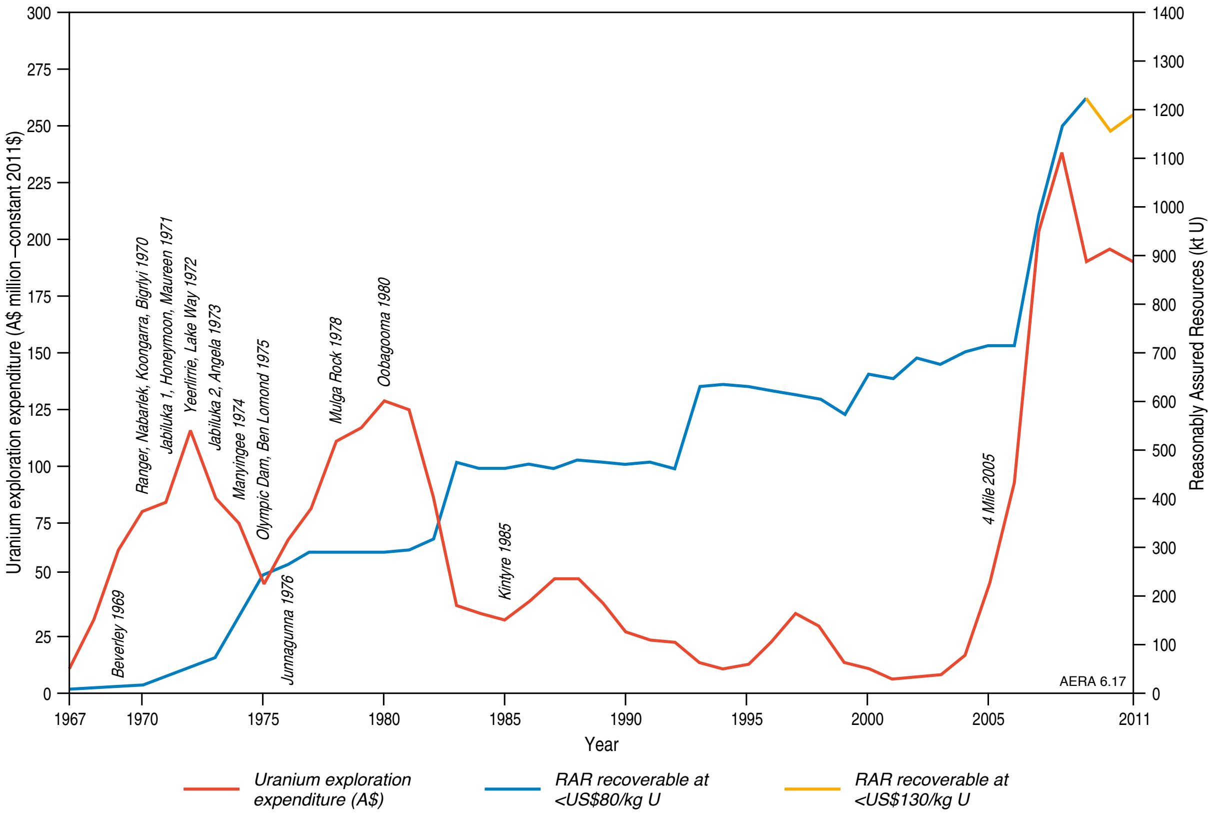

Figure 6.17 Australia's annual uranium exploration expenditure, discovery of deposits and growth of uranium resources

Source: Geoscience Australia

uranium prices and the Australian Government's 'three mines policy', which prohibited the development of new uranium mines. The most recent significant discoveries were Four Mile deposit in 2005 and Pepegoona deposit (Beverley North) in 2010, both in South Australia, which were the first new uranium mine proposals to be approved by the Australian Government since 2001.

More recently, discoveries of new uranium deposits have not significantly increased Australia's resources. Growth in Australia's uranium resources in recent years has been largely due to ongoing delineation of resources at known deposits. The Olympic Dam deposit in South Australia has been the major contributor to increases in Australia's uranium resources since 1983.

The recent strong exploration activity saw the reporting of a number of intersections of economic interest, including in the Pine Creek area, Northern Territory and Frome Embayment, South Australia. Whether intersections of uranium result in a new deposit will depend on further exploration. The discovery of a deposit may not be acknowledged until some years later, after subsequent exploration work. For example, the discovery year for the Olympic Dam deposit was 1975, but it was a few years later before the full significance of the discovery was appreciated; moreover, the published resources are still growing.

Discovery of new deposits takes time and requires considerable exploration expenditure. Exploration is an uncertain activity with only a small percentage of exploration expenditure leading directly to the discovery of an economic resource. However, exploration is essential to discovering new deposits and sustaining existing operations by replacing resources as deposits are mined. The price of uranium and future export demand are typically the most important factors affecting the level of expenditure in exploration as these factors influence the profitability of mining a deposit and the capital available to operations.

Not all discoveries result in mines. Recent studies found that less than half of the uranium discoveries made in the world since the 1970s have been developed into mines (R Schodde, personal communication, 2009). A major factor for the high level of failed projects is the low grade and/or small size of these discoveries. Only the best projects are developed; the rest are placed in inventory waiting better prices or improved business conditions.

Australia has a rich uranium endowment that is related to the widespread occurrence of uranium-enriched, felsic igneous rocks (Lambert et al. 2005). Major magmatic events during the Precambrian era (especially the Proterozoic) produced the greatest volumes of uraniferous igneous rocks, which are widespread in South Australia, Northern Territory and parts of Western Australia and Queensland. There is a clear spatial relationship between known uranium deposits and uranium-enriched bedrocks. While some uranium deposits, such as Olympic Dam, appear to have formed during these thermal events, most uranium deposits have formed from subsequent lower temperature geological/weathering processes that redistributed and concentrated the primary uranium to form new ore minerals.

In general, uranium mineralisation is younger than the spatially related igneous rocks. This is the case for sandstone, calcrete and unconformity-related deposits that appear to have formed as a result of remobilisation of uranium from older uranium-enriched rocks. In particular, the Cainozoic calcrete deposits in the western part of the continent, including the large Yeelirrie deposit, are spatially related to the Archaean felsic rocks; and the unconformity-related deposits are spatially associated with the Palaeoproterozoic to late Archaean felsic igneous rocks. Sandstone deposits are widely distributed in Australia. Those in the Frome Embayment, South Australia are believed to be derived from the adjacent exceptionally uranium-rich Proterozoic felsic rocks.

World uranium resources are dominated by sandstone, breccia complex and unconformity-style deposits. Unconformity deposits are dominant in Australia and Canada. Australia has the world's largest resources of uranium recoverable at low cost, principally in the Olympic Dam hematite breccia deposit and the unconformity-related deposits of Ranger and Jabiluka. Major sandstone-hosted uranium resources are known in Kazakhstan and the United States. Australia has only 3 per cent of the world's resources in sandstone-type deposits. In addition, uranium deposits related to magmatic processes appear under-represented in Australia, given the abundance of uranium-rich igneous rocks (Skirrow et al. 2009).

There are no published estimates for Australia's undiscovered uranium resources. Geoscience Australia has undertaken a preliminary assessment of specific undiscovered uranium deposits related to sedimentary basins, such as unconformity and sandstone-hosted deposits. This quantitative assessment for undiscovered uranium deposits was based on uranium ore density distribution in sedimentary basins that have the necessary geological features to form unconformity and sandstone-type deposits. The assessment does not include the hematite breccia complex or calcrete deposits, which currently account for about 80 per cent and 5 per cent of Australia's uranium resources respectively.

Geological settings considered favourable to host unconformity-related deposits, such as the Ranger deposit, exist in other areas in the Northern Territory and Western Australia. A quantitative assessment for those basins with all of the necessary geological features suggest that there is a 50 per cent probability that these basins contain up to 400 kt of undiscovered U_3O_8 in unconformity-related deposits.

Australia has many large sedimentary basins, many of which have had limited or no exploration for sandstone-hosted uranium deposits. The known paleochannel sandstone-hosted deposits are located in about 3 to 5 per cent of known paleochannels, which means some 95 per cent of paleochannels are unexplored and considered favourable for uranium mineralisation. It is reasonable to conclude that there is high potential for discovery of significant further sandstone-hosted uranium resources in Australia. Recent intensive exploration has resulted in new discoveries such as Four Mile and Pepegoona (Beverley North) deposits in the Frome Embayment area, South Australia.

A quantitative assessment of suitable basins to host sandstone-type deposits suggest that even if 10 per cent of the suitable basins were prospective there is a 50 per cent chance that these basins contain up to 370 kt U_3O_8 in sandstone-type deposits.

Regional and national assessments were undertaken as part of the Australian Government's Onshore Energy Security Program (OESP), which finished in mid 2011 (Geoscience Australia 2007). The OESP is aimed at boosting investment in exploration, especially in greenfield areas, by delivering reliable, pre-competitive geoscience data. Data and reports from the OESP are freely available at the Geoscience Australia website (www.ga.gov.au), some of which include:

- the radiometric map of Australia, which facilitates rapid assessment of uranium prospectivity from the national scale through to the local scale
- a geochemical survey of Australia, which provides a nationwide dataset on the geochemical composition of surface and near-surface materials
- airborne electromagnetic surveys, seismic acquisition and processing in under-explored areas that are considered to have potential for uranium and thorium mineralisation
- developing a new understanding of uranium mineralisation processes.

Outlook for uranium market

Uranium supply–demand balance

In the medium to long term, Australia's production of uranium is expected to increase significantly, reflecting Australia's large low-cost uranium resources, proposed new mines and increasing world demand for uranium. World demand is projected to grow strongly over the outlook period given the projected strong growth in world nuclear electricity generation. Given that there are no plans for Australia to have a commercial nuclear power industry or enrichment facilities, all of Australia's uranium production will continue to be exported.

Potential growth in uranium production could come from the Four Mile and Olympic Dam expansion projects in South Australia, the Ranger 3 Deeps project in the Northern Territory and the Yeelirrie, Kintyre and Wiluna uranium projects in Western Australia. In the

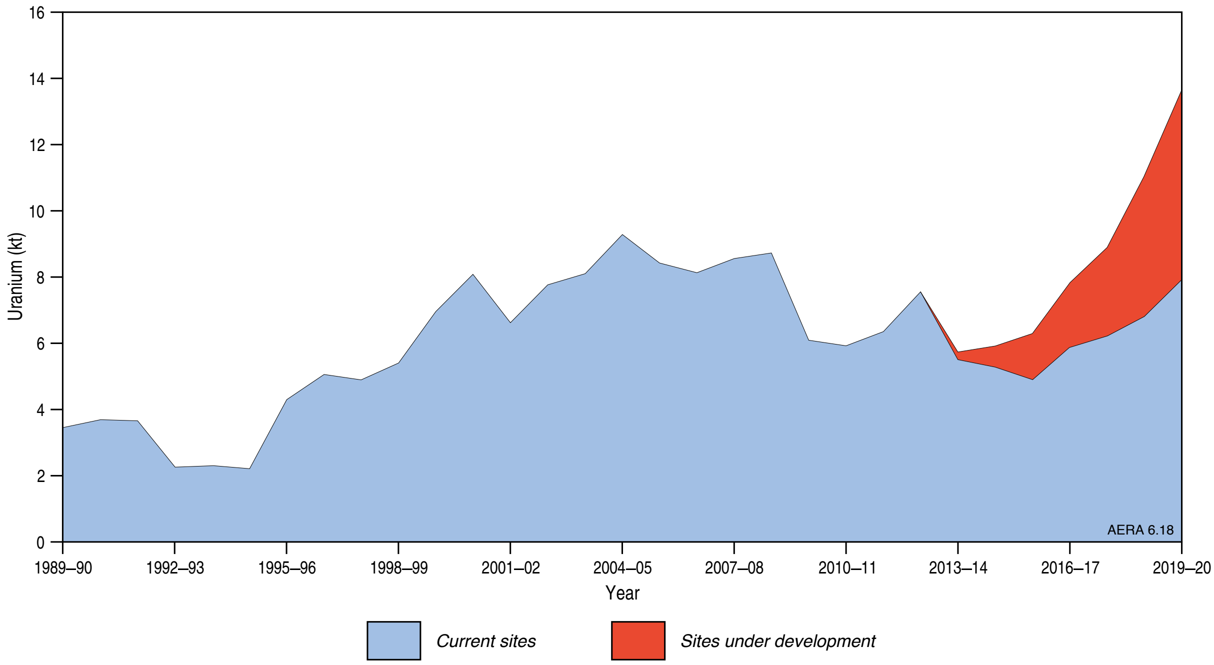

Figure 6.18 Potential Australian uranium mine capacity

Source: Bureau of Resources and Energy Economics

longer term, there is now the potential for additional projects in Queensland and New South Wales following legislation changes.

Uranium project developments in Australia

Australia has a number of uranium mining projects that may enter production over the next decade (table 6.11, box 6.2). If all of these projects are realised, Australian uranium mine production capacity has the potential to increase from around 8.5 kt U per year to about 14 kt U by 2019–20. The supply forecasts are based on current reported resources. In practice, it is highly likely that additional ore reserves will be found and mine lives extended and possibly expanded. Figure 6.18 illustrates this potential growth in mine capacity, assuming all projects begin production at times announced by project developers. It should be noted that there are substantial challenges to developing uranium mining projects and some of these projects may not be realised in the time frame announced.

BOX 6.2 URANIUM PROJECT DEVELOPMENTS IN AUSTRALIA

Projects that are expected to enter production in a few years include Four Mile ISR project in South Australia and Wiluna project in Western Australia.

Alliance Resources and Quasar Resources, a wholly owned subsidiary of Heathgate Resources, plan to commission the Four Mile ISR project in 2014. The project will use the nearby Pepegoona satellite ISR ion exchange columns with the resin trucked 8 km to Heathgate Resources' Beverley plant for recovery of uranium (table 6.11). The Four Mile project's expected production rate is 1.36 kt U_3O_8 per year.

Wiluna project operated by Toro Energy Limited comprises two shallow (less than 8 m deep) calcrete-hosted deposits, Lake Way and Centipede, which are located 15 km south and 30 km south of Wiluna respectively. At December 2011, Lake Way had Indicated+Inferred Resources of 9.95 million tonnes averaging 530 ppm U_3O_8 (5280 tonnes of contained U_3O_8) and Centipede had total Measured+Indicated+Inferred Resources of 11.31 million tonnes averaging 493 ppm U_3O_8 (5579 tonnes of contained U_3O_8). Toro also owns three other calcrete-hosted deposits in the Wiluna region—the Millipede, Lake Maitland, Dawson Hinkler Well and Nowthanna deposits. These have total Indicated+Inferred Resources of 30.98 million tonnes averaging 382 ppm U_3O_8 (11 782 tonnes of contained U_3O_8).

Metallurgical test work and studies showed that alkaline agitated leaching in tanks at elevated temperatures is the preferred process option. The company proposes to produce uranium concentrates containing approximately 820 tonnes U_3O_8 a year. Both Australian and state governments environmental approvals are in place. Mine design and construction phases are proceeding.

Low uranium prices during 2012 and early 2013 and increased costs of capital and labour have resulted in a number of companies announcing that new mine projects and mine expansions would be delayed. BHP Billiton has delayed the Olympic Dam expansion project while the company investigated less capital-intensive alternatives for the project. This anticipated expansion is based on a very large open pit to mine the south-east portion of the deposit. It was previously planned to commence mining of ore from the open pit in 2016. The new scheduled date for commencement of production is yet to be announced.

Ranger 3 Deeps ore body occurs at depth adjacent to the current operating open cut and is one of the most significant uranium deposits recently discovered in Australia. It is estimated at 10 million tonnes of mineralised material with an average grade of 0.34 per cent U_3O_8 for 34 000 tonnes of contained U_3O_8. ERA Limited proposes to mine the deposit by underground methods. In July 2012, excavation of the boxcut for the Ranger 3 Deeps decline was completed and work commenced on the decline in November 2012. Close-spaced underground exploration drilling will be carried out from the decline to further define the Ranger 3 Deeps ore body and to explore adjacent areas. In parallel to construction of the decline, work is proceeding to prepare a feasibility study and to detail the approvals process associated with a potential Ranger 3 Deeps underground mine. In January 2013, ERA Limited lodged a referral in relation to the Ranger 3 Deeps underground mine with the Australian Government under the *Environment Protection and Biodiversity Conservation Act 1999.*

Table 6.11 Uranium development projects

Project	Company	Location	Status	Potential production start	Capacity (kt U_3O_8/ year—nominal)	Capital (A$m—nominal)
Ranger 3 Deeps	Energy Resources of Australia	East of Darwin, NT	Pre-feasibility study under way	2015	3.0	250–500
Wiluna (Centipede-Lake Way)	Toro Energy	South-east of Wiluna, WA	Feasibility study completed	2016	0.82	269
Yeelirrie	Cameco	North of Kalgoorlie, WA	Pre-feasibility study under way	2018+	3.5	500–1000
Kintyre	Cameco/ Mitsubishi	North-east of Newmand, WA	Released Environmental Review and Management Programme	2018+	3.60	500–1000
Mulga Rock	Energy and Minerals Australia	North-east of Kalgoorlie, WA	Feasibility study under way	2018+	1.2	260
Valhalla	Summit Resources/ Paladin Resources	North of Mt Isa, Qld	On hold. Queensland Government recently removed the ban on uranium mining	2018+	4.1	250–500
Westmoreland	Laramide Resources	North-west of Burketown, Qld	On hold. As for Valhalla	2018+	1.4	250–500
Olympic Dam expansion	BHP Billiton	Roxby Downs, SA	Pre-feasibility study completed. Company announced that it would delay the expansion and investigate an alternative less capital-intensive design	na	na	na

na = not available

Source: BREE 2012b, BREE 2013

6.3 Thorium

6.3.1 Background information and world market

Definitions

Thorium (Th) is a naturally occurring slightly radioactive metal that belongs to the actinide series and is three to five times more abundant than uranium. The most common source of thorium is a rare earth phosphate mineral, monazite (WNA 2009g).

Thorium is a potential future nuclear fuel through breeding to U^{233}. Thorium has the potential to generate significantly more energy per unit mass of thorium than uranium (WNA 2009f).

Historically there has been only one commercial-scale thorium-fuelled nuclear plant—the Fort St Vrain reactor in the United States that operated between 1976 and 1989. It was a high-temperature (700 °C), graphite-moderated, helium-cooled reactor with a thorium/HEU fuel designed to operate at 330 MWe capacity. Almost 25 tonnes of thorium was used in fuel for the reactor (Anantharaman and Vasudeva Rao 2011, WNA 2012c).

Currently, there are no commercial-scale thorium-fuelled reactors in the world and therefore no demand for thorium as a fuel. Any future large-scale commercial demand for thorium resources will depend on development of economically viable thorium-fuelled reactors.

Thorium supply chain

Figure 6.19 provides a representation of the potential thorium supply chain in Australia. As with uranium, the supply chain is divided into four distinct processes: resources exploration; development and production; processing, transport and storage; and end-use markets.

As about 70 per cent of the thorium resources in Australia are in known heavy mineral sand deposits, thorium production could be initiated with the recovery of thorium and rare earth elements from the monazite in operating heavy mineral sand mines without the need for an exploration phase. Similarly, the remaining 30 per cent of Australia's thorium resources are associated with rare earth deposits where thorium could be sourced as a byproduct of rare earth mining as in the case of the Nolans Bore in Northern Territory and Mt Weld in Western Australia rare earth deposits.

World thorium market

Currently, there are no commercial-scale thorium-fuelled reactors. However, research continues in countries with abundant thorium but little uranium resources.

Resources

Thorium resources are categorised according to the OECD/NEA-IAEA classification scheme. OECD/NEA-IAEA (2008) published estimates of thorium resources on a country-by-country basis. The estimates are subjective because of variability in the quality of the data, much of which is old and incomplete. Table 6.12 has been derived by Geoscience Australia from information presented in the OECD/NEA-IAEA analysis.

Total world thorium resources are estimated at 6.64 to 7.5 million tonnes (table 6.12) (OECD/NEA-IAEA 2012). This figure includes both Inferred and subeconomic resources and in the absence of large-scale demand for thorium there is little incentive to undertake further work to upgrade these resources to economic RAR resource categories.

Australia's total *in situ* recoverable Identified Resources of thorium amount to 595 kt Th (Geoscience Australia 2012), about 8 to 9 per cent of total world identified thorium resources.

The OECD/NEA and IAEA (2008) have grouped thorium resources according to four main types of deposits as shown in table 6.13. Thorium resources worldwide appear to be moderately concentrated in carbonatite-type deposits (carbonate mineral rich intrusives), which account for about 30 per cent of the world total. The remaining thorium resources are more evenly spread across the other three deposit types in decreasing order of abundance—in placers (sand deposits), vein-type deposits, and alkaline rocks. In Australia, a large proportion of resources are located in placers, with heavy mineral sand deposits accounting for about 70 per cent of known thorium resources.

World production, consumption and trade

World production and consumption data are unavailable, but current production and consumption are thought to be negligible. There are at present no commercial-scale thorium-fuelled reactors for electricity generation in the world. Some of the reasons for the lack of a thorium-based nuclear fuel cycle in the past have included the high-cost of thorium fuel fabrication and the abundance of cheap uranium fuel for the established uranium-based reactors.

However, research into the thorium fuel cycle has continued, because it results in reduced nuclear waste, and represents increased energy security for countries with abundant thorium but little in the way of uranium resources. The construction of a 500 MWe prototype

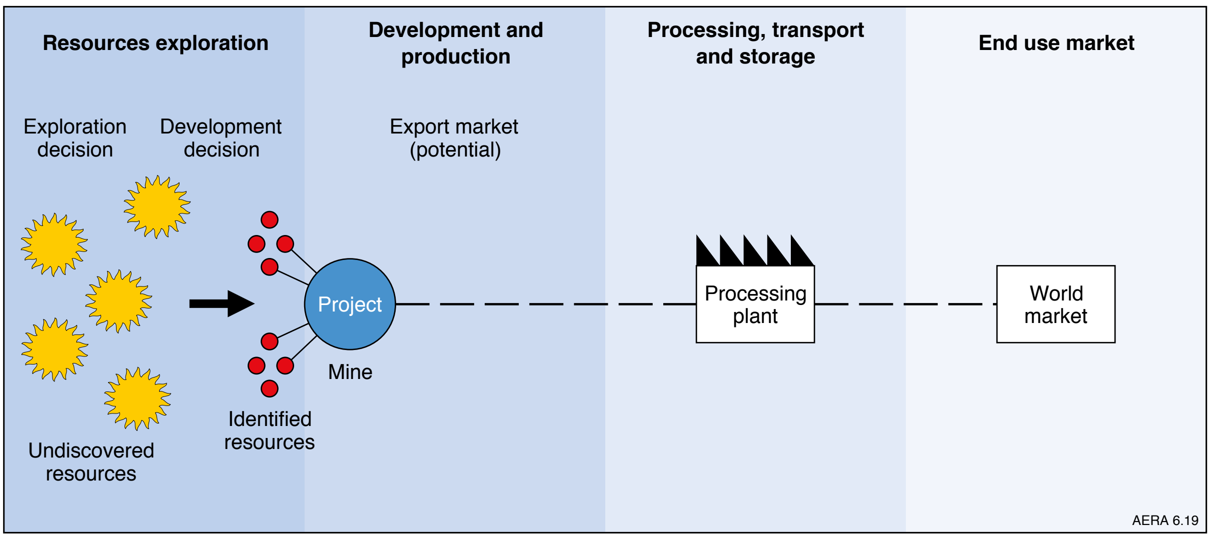

Figure 6.19 Potential Australian thorium supply chain

Source: Bureau of Resources and Energy Economics; Geoscience Australia

fast breeder reactor at Kalpakkam, India was about 95 per cent complete in July 2013. It is expected to start up in 2014, fuelled with uranium-plutonium oxide (the reactor-grade plutonium being from its existing PHWRs). This reactor will have a plutonium-based core and a thorium-uranium (Th^{232} – U^{238}) blanket and will breed both U^{233} from thorium and plutonium^{239} (Pu^{239}) from the uranium (U^{238}) in the blanket. India is also planning to commence construction of a 300 MWe technology demonstration thorium-fuelled Advanced Heavy Water Reactor (AHWR) after 2014. However, full commercialisation of the AHWR is not expected before 2030. The AHWR can be configured to accept a range of fuel types, including enriched uranium, uranium – MOX, thorium – plutonium MOX, and U^{233} – thorium MOX in full core (WNA 2012d).

6.3.2 Australia's thorium resources and market

Australia has 8 to 9 per cent of the world's Identified Resources of thorium. Almost three-quarters of Australia's thorium resources are in the mineral monazite within heavy mineral sand deposits.

Thorium resources

There are no published thorium resources in heavy mineral sand deposits in Australia. Geoscience Australia estimates Australia's monazite resources in the heavy mineral deposits to be around 7.4 million tonnes and inferred thorium resources in the heavy mineral sands to be around 386.8 kt Th. Australia's total indicated and

Table 6.12 World total Identified Resources of thorium, 2012

Region	Country	Identified (*in situ*)* thorium resources (kt Th)[a]
Australia	Australia	595.2
Americas		
	Brazil	606–1300
	United States	434
	Venezuela	300
	Canada	172
	Others	24.3
	Americas subtotal	**1536.3–2230.3**
Europe		
	Turkey	744–880
	Norway	320
	Greenland	86–93
	Others	166
	Europe subtotal	**1316–1459**
Asia		
	Commonwealth of Independent States[b]	1500
	India	846
	China	>100
	Chinese Taipei	9
	Iran	30
	Others	58.5–66.5
	Asia subtotal	**2543.5–2551.5**
Africa		
	Egypt	380
	South Africa	148
	Morocco	30
	Nigeria	29
	Madagascar	22
	Others	40.5–50.5
	Africa subtotal	**649.5–659.5**
	World total	6640.3–7495.3

a Currently there is no international or standard classification for thorium resources and identified thorium resources do not have the same meaning in terms of classification as identified uranium resources. b Commonwealth of Independent States excludes the Russian Federation European part

Source: Data for Australia compiled by Geoscience Australia; data for all other countries are from OECD/NEA and IAEA 2012 inferred *in situ* resources, including those in predominantly rare earth element deposits, amount to about 595.2 kt Th (table 6.14).

As there are no publicly available data on mining and processing losses for extraction of thorium from these resources, the 'recoverable' resource of thorium is not known.

About 70 per cent of Australia's thorium resources are in the rare earth thorium phosphate mineral monazite within heavy mineral sand deposits, which are mined for their ilmenite, rutile, leucoxene and zircon content (figure 6.20). Most of the known resources of monazite in mineral sands are in Victoria and Western Australia. The monazite in Australian heavy mineral sand deposits averages about 6 per cent thorium and 60 per cent rare earths. Prior to 1996, monazite was being produced from heavy mineral sand operations, including the Eneabba mineral sands area and exported for extraction of rare earths. Other thorium deposits are discussed in box 6.3.

In current heavy mineral sand operations, the monazite is generally dispersed back through the original host sand (to avoid the concentration of radioactivity) when returning the mine site to an agreed land use. In doing so, the rare earths and thorium present in the monazite are negated as a resource because it would not be economic to recover the dispersed monazite for its rare earth and thorium content. The monazite content of heavy mineral resources is seldom recorded by mining companies in published reports.

Table 6.14 Australia's thorium identified resources, 2012

	In situ resource (kt)
Total Identified Resources	595.2

Source: Geoscience Australia 2012

Thorium market

Historically, Australia has exported large quantities of monazite from heavy mineral sands mined in Western Australia, New South Wales and Queensland, for the extraction of both rare earths and thorium mainly used in lighting and gas mantles. Between 1952 and 1995, Australia exported 265 kt of monazite with a real export value (2008 dollars) of A$284 million (ABS 2009b). However, since production ceased in 1995 it is believed no significant quantities of thorium, or materials containing thorium, have been imported or exported by Australia.

Production of monazite no longer occurs in Australia as the high disposal cost of thorium is considered to make the extraction of rare earths from monazite uneconomic. Recently some companies have indicated that they may export monazite to China, possibly for extraction of rare earths.

Table 6.13 World and Australian thorium resources according to deposit type

Major deposit type	World resources (kt Th)	Share of total *in situ* world resources (%)	Australian resources (kt Th)	Share of total world resources (%)
Carbonatite	1900	31.3	30.5	5.1
Placer	1500	24.7	386.8	65
Vein-type	1300	21.4	125	21
Alkaline	1120	18.4	50.9	8.6
Other	258	4.2	2	0.3
Total	**6078**	**100.0**	**595.2**	**100.0**

Source: Data for Australia compiled by Geoscience Australia; data for world resources are from OECD/NEA and IAEA 2012

BOX 6.3 THORIUM DEPOSITS IN AUSTRALIA

Apart from heavy mineral sand deposits (placer deposits), thorium is present in other geological settings, such as alkaline intrusions and in veins and dykes.

A significant example is the Nolans Bore rare earth phosphate uranium deposit, which occurs in veins and dykes north of Alice Springs in the Northern Territory. This deposit contains at least 81.8 kt of thorium.

The Yangibana dykes (termed 'ironstones'), north-east of Carnarvon in Western Australia, crop out over an area of 500 km^2. Whole rock chemical analyses of a number of ironstone samples record more than 1000 parts per million of thorium.

In New South Wales, the Toongi intrusive, south of Dubbo hosts 35.7 million tonnes of Measured Resources and 37.5 million tonnes of Inferred Resources at a grade of 0.0478 per cent thorium, giving a total of about 35 kt contained thorium.

Other alkaline complexes with known rare earth and thorium mineralisation include Brockman (Hastings) in Western Australia. Exploration reports indicate thorium occurrences, but no estimates of thorium resources have been reported.

Data on the thorium content of carbonate mineral rich intrusions in Australia are sparse. Mount Weld and Cummins Range deposits in Western Australia are both known to contain some thorium.

Source: Geoscience Australia 2012

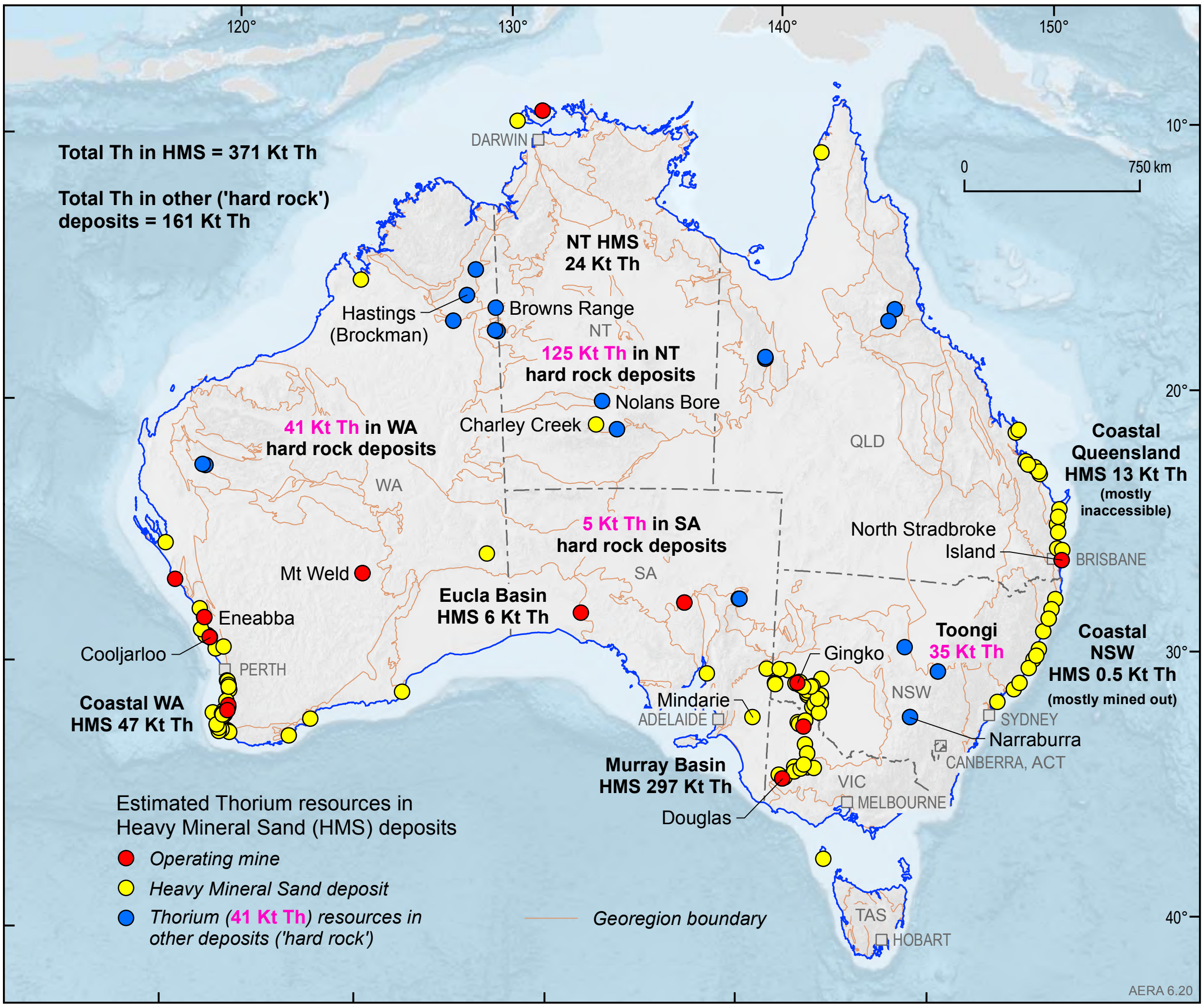

Figure 6.20 Australia's total *in situ* identified thorium resources, 2012

Source: Geoscience Australia

6.3.3 Outlook for Australia's resources and market

There is currently no large-scale demand for thorium resources and therefore no comprehensive, reliable body of data either on resources or projected demand. Australia has a significant share of the world's thorium resources, based on limited information available.

The full commercialisation of a thorium fuel cycle is unlikely to take place prior to 2030. As a result, large-scale Australian production and subsequent trade of thorium are not likely within this time period. If commercialisation of a thorium fuel cycle occurs more quickly than assumed, Australia is well positioned to supply world markets with cheap, reliable supplies of thorium from existing and future heavy mineral sand and rare earth mining operations.

Key factors influencing the outlook

There has been a significant renewal of interest in development of a thorium-fuelled nuclear cycle for electricity generation, partly because of the relative abundance of thorium, its greater resistance to nuclear weapons proliferation and the substantial reduction in radioactive waste generated from a thorium-fuelled nuclear cycle. However, much work remains to be done before a commercial-scale thorium-fuelled reactor for electricity generation can become a reality (IAEA 2005).

Technology developments—future development of thorium reactors

Demand for thorium resources depends upon the development and widespread adoption of thorium-fuelled reactors for electricity generation. The main drivers for interest in thorium-fuelled reactors are:

- Some countries, such as India, have much larger thorium resources than uranium and see thorium-fuelled reactors as a more secure source of energy.
- The thorium fuel cycle is considered to be less conducive to nuclear weapon proliferation than the uranium fuel cycle (IAEA 2005).
- The thorium fuel cycle generates much less radioactive waste than the uranium fuel cycle (IAEA 2005).

Current research and development for use of thorium in reactors for electricity generation are directed primarily towards:

- Research into thorium fuel designed to be used in currently operating uranium-fuelled reactors.
- Development and construction of a purpose-built thorium-fuelled reactor for electricity generation.
- Development of some other advanced nuclear reactors which could use thorium fuels.

Further details of the research and developments are presented in box 6.4.

Cost competitiveness

As there is no established large-scale demand and associated price information for thorium, there is insufficient information to determine how much of Australia's thorium resources are economically viable for electricity generation in thorium reactors.

However, as all of Australia's thorium resources occur either in the heavy mineral sand deposits or in rare earth mineral deposits, mining and processing cost for the extraction of thorium would be shared with other commodities.

Infrastructure, environment and other issues

Most thorium resources are contained in heavy mineral sand deposits and rare earth deposits that already have essential infrastructure. Some of these deposits are currently being mined or are in advanced stages of development with infrastructure costs being borne by the commodities being extracted.

Apart from improved resistance to proliferation of nuclear weapons, a thorium fuel cycle is generally considered to generate less radioactive waste and has fewer long-lived transuranic elements. The extent of these potential advantages over the current uranium fuel cycle varies according to different designs of the thorium fuel cycle (IAEA 2005).

There are little readily available nuclear industry data on the issues of nuclear proliferation and volumes and storage of nuclear waste because there are no currently operating commercial-scale thorium-fuelled reactors.

BOX 6.4 RESEARCH AND DEVELOPMENT—THORIUM PROJECTS

Thorium fuel design

At this stage it appears that thorium fuel could be used in existing uranium-fuelled reactors such as the Enhanced Candu 6 and ACR-1000 reactors fuelled with 5 per cent plutonium (reactor grade) plus thorium. In the closed fuel cycle, the driver fuel required for starting off the fuel cycle is progressively replaced with recycled U^{233}, so that on reaching equilibrium 80 per cent of the energy comes from thorium. Fissile drive fuel could be LEU, plutonium, or recycled uranium from LWRs. Fleets of PHWR with near-self-sufficient equilibrium thorium fuel cycles could be supported by a few fast breeder reactors to provide plutonium. The Canadian Nuclear Safety Commission (CNSC) gave pre-project design approval to the ACR-1000 in February and September 2009. The ACR-1000 development has been completed to the point that the design is ready for bidding and for discussion with interested utilities (Candu Energy, 2012).

In July 2009, a second-phase agreement was signed among Atomic Energy of Canada Limited, the Third Qinshan Nuclear Power Company, China North Nuclear Fuel Corporation (CNNC) and the Nuclear Power Institute of China to jointly develop and demonstrate the use of thorium fuel and to study the commercial and technical feasibility of its full-scale use in Candu units such as at Qinshan. This was supported in December 2009 by an expert panel appointed by CNNC. The panel noted the ability of Candu reactors to re-use uranium recycled from light water reactor fuel, and recommended that China consider building two new Candu units to take advantage of the design's unique capabilities in utilising alternative fuels. In particular, it confirmed that thorium use in the Enhanced Candu 6 reactor design is 'technically practical and feasible', and cited the design's 'enhanced safety and good economics' as reasons it could be deployed in China in the near term.

Thorium-fuelled reactors

A purpose-built thorium-fuelled reactor—the Indian 300 MWe AHWR—has been proposed for construction as a technical demonstration. It is designed to be self-sustaining in relation to U^{233} bred from Th^{232} and have a low plutonium inventory and consumption. It is designed for a 100-year plant life and is expected to utilise 65 per cent of the energy of the fuel, with two-thirds of the energy coming from thorium. The technical demonstration version is expected to be completed some time after 2017, but full-scale commercial AHWR reactors are not anticipated before 2030.

In 2009 India announced an export version of the AHWR—the AHWR-LEU. This design will use LEU plus thorium as a fuel, dispensing with the plutonium input. About 39 per cent of the power will come from thorium (via *in situ* conversion to U^{233}). The uranium enrichment level will be 19.75 per cent, giving 4.21 per cent average fissile content of the U-Th fuel. Plutonium production will be less than in LWRs, and the fissile proportion will be less, providing inherent proliferation resistance benefits (WNA 2009e, Kakodkar 2009).

India is the only country that has been involved in development of a full-scale thorium reactor, the AHWR in stage 3. This program had a high priority while India was under an international trade ban for nuclear technology and on imports of uranium. The Nuclear Suppliers' Group agreement in September 2008 and the United States–India nuclear agreement in October 2008 now allow India to trade in nuclear technology and import uranium fuel. In addition, India has also signed a nuclear cooperation agreement with France. India has continued with the development of its thorium fuel cycle.

During 2007 and 2008 a research program at Moscow's Kurchatov Institute involved the United States company, Thorium Power Ltd (now Lightbridge Corporation), and supported by funding from the United States Government, the program is working to develop thorium-uranium fuel for the existing Russian Vodo-Vodyanoi Energetichesky (VVER-1000) reactors (Thorium Power Ltd 2009). While normal fuel uses enriched uranium oxide (UO_2), the modified design has a demountable centre portion and blanket arrangement, with plutonium fuel in the centre surrounded by a blanket of thorium-uranium fuel. The Th^{232} becomes U^{233}, which is fissile, as is the core Pu^{239}. Blanket material remains in the reactor for nine years, but the centre portion is burned for only three years (as in a normal VVER). The Russian Federation has also investigated the use of thorium fuels in BN-800 fast neutron reactors with thorium blankets (BN-800-Th) (IAEA 2012).

Advanced reactors

Generation IV reactors will also be capable of using thorium fuel in the high-temperature gas-cooled reactors (HTGRs) or the molten salt reactors (MSR).

There are two types of HTGRs: prismatic fuel and pebble bed. General Atomics is developing a Gas Turbine Modular Helium Reactor (GT-MHR) that uses a prismatic fuel. The GT-MHR core can accommodate a wide range of fuel options, including HEU/Th, U^{233}/Th and Plutonium/Th. Pebble bed reactor development builds on previous work in Germany and is under development in China and South Africa. A pebble bed reactor can potentially use thorium in the fuel pebbles.

The MSR is an advanced breeder concept, in which the coolant is a molten salt, usually a fluoride salt mixture. The fuel can be dissolved enriched uranium, thorium or U^{233} fluorides. The fission products dissolve in the salt and are removed continuously in an online reprocessing loop and replaced with Th^{232} or U^{238}. Actinides remain in the reactor until they fission or are converted to higher actinides which do so. The MSR was originally studied in depth in the 1960s, but is now being revived because of the availability of advanced technology for the materials and components. There is renewed interest in the MSR concept in Japan, the Russian Federation, France and the United States and the MSR is one of the six Generation IV designs selected by the international forum of 13 countries for further development. In January 2011, the China Academy of Sciences launched a research and development program on a liquid fluoride thorium reactor, known at the academy as the thorium-breeding molten-salt reactor (Th-MSR or TMSR). A 5 MWe MSR is believed to be under construction at Shanghai, with an operational target date of 2015 (WNA 2012c).

As with a purpose-built thorium-fuelled reactor, these advanced HTGR and MSR reactors are not likely to come on stream much before 2030, and the extent to which they will use thorium rather than uranium is also uncertain.

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Chapter 7
Geothermal Energy

7.1 Summary

KEY MESSAGES

- Geothermal energy is a major potential source of low emissions renewable energy suitable for base-load electricity generation and direct-use applications, such as home and commercial heating.
- Australia has significant potential geothermal resources associated with volumes of rock with above average crustal heat flow buried beneath thick sedimentary basins. Some of the more prospective geothermal resources are located long distances from transmission and distribution networks and load centres.
- Geothermal projects in Australia are still mostly at the exploration stage, with only one in production (Birdsville) and a pilot plant in trial and testing phase (Geodynamics Ltd Innamincka Deeps project).
- Demonstration of the commercial viability of geothermal energy in Australia will assist in attracting the capital investment required for geothermal energy development. The off-grid market may provide both a higher power price plus co-location making initial development of the sector more commercially feasible.
- All of the component technologies required for utilising Australia's geothermal energy have been demonstrated here or overseas—the challenge remains to demonstrate power production or direct-use reliably for sufficiently long periods of time (20+ years) at a competitive price.

7.1.1 World geothermal resources and market

- Electricity has been produced commercially from geothermal resources for over 100 years. Conventional geothermal resources are based on hydrothermal systems associated with active volcanism or crustal extension and thinning, which Australia lacks. When exploited, these systems are generally very productive; that is, they flow hot water and steam readily.
- Significant geothermal resources can also be associated with basement rocks having above average crustal heat flow blanketed by thick sedimentary basins. The anomalous crustal heat flow results from a variable combination of mantle heat flow and heat production from natural radioactive decay of elements (such as uranium, thorium and potassium). These resources are termed 'unconventional'. Movement of water is usually through fault or fracture networks, with permeability enhancement usually necessary. Cool water is pumped from surface-down injection well(s), is heated as it is circulated through the created reservoir, then extracted back to the surface through production well(s). The water is recirculated after heat has been extracted for power generation or direct-use applications such as home and commercial heating.
- Geothermal energy is used in many countries for electricity generation and heat production (2398 PJ total consumption) and in direct-use applications (308 PJ total consumption), but accounted for only 0.5 per cent of world total primary energy consumption in 2010.
- Geothermal energy has the potential to sustainably provide large amounts of low-emission base-load electricity generation, and can also be used to power industrial processes via direct-use applications (including desalination, district heating and cooling), and for ground source heat pumps.
- Government policies, energy prices, falling costs and reducing technology and resource risks are projected to be the main factors underpinning future growth in world geothermal energy use.

7.1.2 Australia's geothermal resources

- Australia has considerable geothermal energy potential. This results from the widespread occurrence of basement rocks (granites in particular) in which heat is generated by natural radioactive decay, with an input of heat from the deeper mantle. Where hot rocks occur beneath thick blankets of thermally insulating strata, the thermal energy is retained in the basement rocks and overlying strata, causing elevated temperatures at relatively shallow depths. There are extensive areas where temperatures are estimated to reach at least 200 °C at around 5 km depth (figure 7.1).

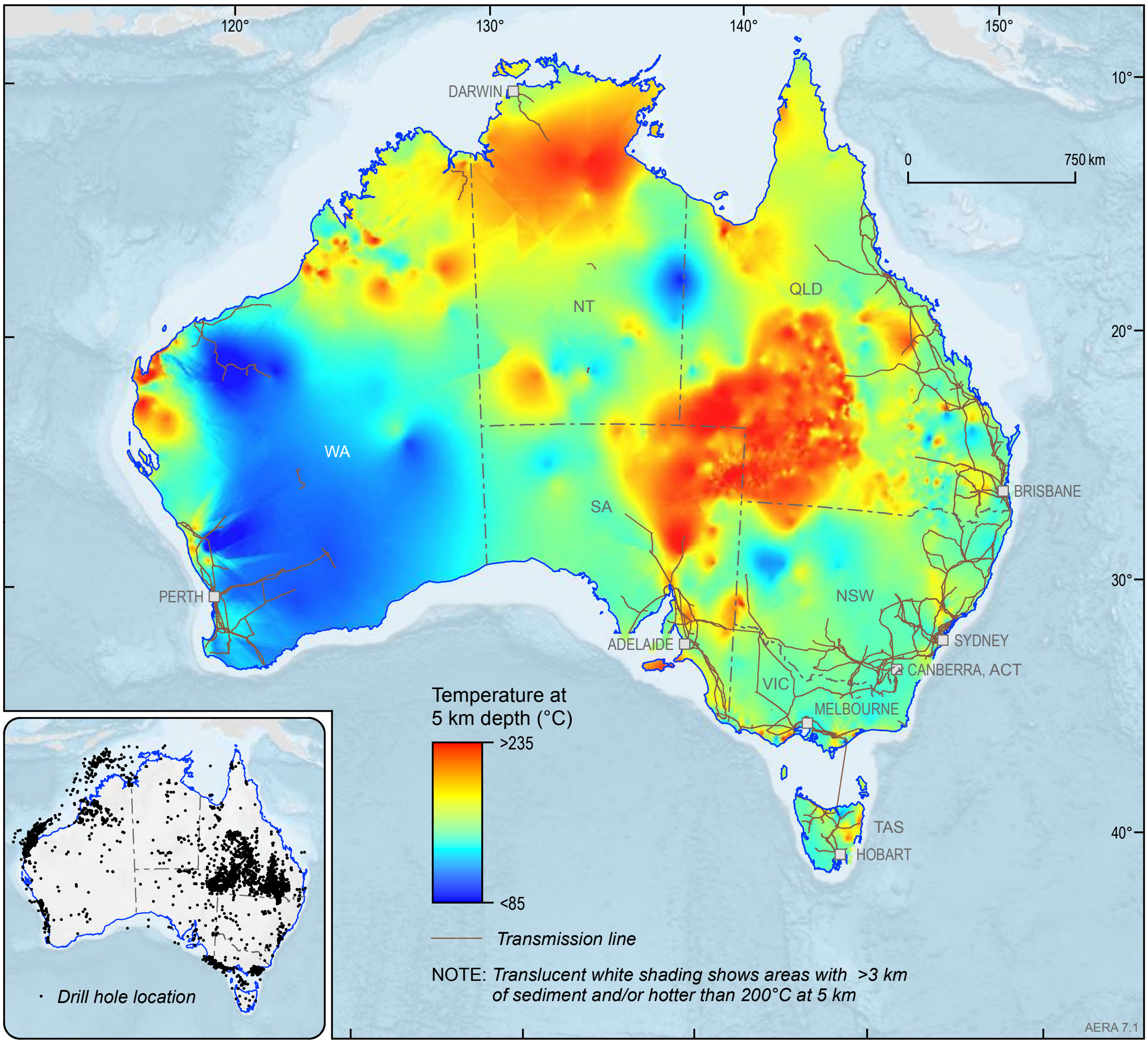

Figure 7.1 Predicted temperature at 5 km depth based mostly on bottom-hole temperature measurements in more than 5000 petroleum and water boreholes

Source: Data from OZTEMP database; Geoscience Australia

- There is also potential for lower temperature geothermal resources associated with naturally circulating waters in shallow aquifers in a number of sedimentary basins. These lower temperature resources will be mostly suitable for direct-use applications.
- A geothermal power plant has been periodically in operation at Birdsville, Queensland since 1992. It uses a bore that produces water from the Great Artesian Basin (Hot Sedimentary Aquifer) at 98 °C at the surface to generate approximately 0.08 MW, supplying about 30 per cent of the total plant output with the remainder being fuelled by diesel and LPG.
- In early 2013, a pilot plant was successfully commissioned at the Innamincka Deeps project in the Cooper Basin, South Australia. The 1 MW plant produced Australia's first Enhanced Geothermal System generated power. The plant has commenced a demonstration trial and testing period until late 2013.
- Australia's overall geothermal potential has only recently been appreciated. Consequently, there are significant gaps in the information required to adequately assess potential. It is likely that additional new data will lead to increases in the geothermal resource base.
- As of December 2012, ten companies have reported identified geothermal resources totalling 440 570 PJ of recoverable heat in compliance with the *Australian code for reporting of exploration results, geothermal resources and geothermal reserves, second edition*.

7.1.3 Key factors in utilising Australia's geothermal resources

- Geothermal energy research, development and demonstration are important to the outlook for electricity generation from geothermal energy.

- The demonstration of the path to economic viability of the extraction and use of geothermal energy both for electricity generation and direct use is important to attract the capital investment required.
- There are two main risk areas that need to be lowered in order to attract investment to the sector: resource risk (the probability of discovering a useable resource) and cost risk (the risk that the costs of developing a resource will make the costs of energy produced uncompetitively high).
- Improved information on geothermal energy resource potential in many parts of Australia—especially new geoscientific data designed to locate regions with temperature anomalies at relatively shallow depths (1–4 km)—may aid definition of geothermal energy resources and reduce exploration costs.
- There is significant potential for energy savings through greater use of ground source heat pumps in heating and cooling buildings in many regions of Australia.

7.1.4 Australia's geothermal energy market

- There are uncertainties in the outlook for geothermal energy over the next two decades, including the cost of electricity production as the technology has yet to be proven commercially viable. Present estimates show a wide range in the cost of geothermal electricity generation, reflecting the current pre-commercial stage of the industry, as the cost of electricity generation is highly dependent on the ability to access and utilise geothermal resources. This is dependent on using existing technologies for exploration, drilling and energy conversion in the best possible workflow in each new resource area.
- The Australian Government has supported the geothermal industry through its former programs Renewable Energy Demonstration Program (REDP) and Geothermal Drilling Program (GDP) in providing grants to support proof-of-concept projects. As of 1 July 2012, the Australian Government's Geothermal Exploration Tax Rebate provides an immediate tax deduction for the exploration of geothermal energy sources.

7.2 Background information and world market

7.2.1 Definitions

Geothermal energy

Geothermal energy is heat (thermal) derived from the Earth (geo). Geothermal energy is abundant, one of the cleanest (effectively no greenhouse gas emissions, minimal wastes or other pollutants) and reliable (renewable or sustainable) sources of energy. There is a steady flow of heat from the centre of the Earth (where temperatures are above 5000 °C) through the surface of the Earth (–30 to +40 °C) into space (–273 °C): heat flows from hot to cold. The heat is mostly generated by the natural decay over millions of years of radioactive elements including uranium, thorium and potassium, with some residual heat from planetary accretion.

Geothermal resources that have been utilised, or are prospective for development, range from shallow ground to hot water and rock several kilometres below the Earth's surface (Hulen and Wright 2001).

There are three basic requirements for a geothermal resource:

1. a persistent heat source (or sink)
2. a heat transfer and transport medium (usually water and/or steam)
3. sufficient permeability/transportability within the buried geothermal reservoir for the fluid to be able to pass through and gain (or lose) heat.

To some degree, the natural conditions can be modified. There is a large range of heat conversion technologies available, so that geothermal resources of almost any temperature can be utilised. If insufficient volumes of water exist naturally, this can be added into the reservoir from the surface. Permeability can be artificially enhanced, or pipes can be used in shallow systems.

It is useful to distinguish between hydrothermal and other geothermal resources. Conventional geothermal resources have been exploited globally for around a century. These are convective hydrothermal systems that are found in regions associated with tectonic plate boundaries and volcanic areas (e.g. west coast of the United States, New Zealand, Indonesia, Iceland, Italy and Japan), and extensional settings (e.g. Basin and Range province, western United States). These resources have high temperatures at relatively shallow depths because of the heat carried by magma and fluids into the upper layers of the Earth's crust. They typically have naturally occurring high permeability and significant volumes of fluid (steam and hot water) that can be extracted from the reservoir, allowing the heat to be brought to the surface. Natural flow of these fluids to the surface can form hot springs, fumaroles, and geysers, which provide good guidance for exploration. The permeability in these systems is primarily due to natural fractures in the reservoir. Reservoir depths are typically in the 1000 m to 3000 m range with temperatures of around 150 °C to 300 °C.

Conventional geothermal resources are not found in Australia's intra-plate tectonic setting, and the Australian geothermal sector is targeting unconventional geothermal resources (figure 7.2). Heat is provided as a combination of radiogenic heat production from rocks in the upper crust, and conducted heat from the mantle. An insulating layer of blanketing sediments is needed to allow heat to accumulate and high temperatures to be reached. The geothermal gradient is lower than in conventional geothermal systems, meaning that deeper wells must be used to attain desired temperatures. The permeability in unconventional geothermal resources may be through matrix permeability (interconnected pore space = primary permeability), fractures (secondary permeability), or a combination of both. However, deep unconventional geothermal resources typically have insufficient natural permeability to support economic rates of energy production per well, and their permeability requires enhancement by stimulation techniques, which can include hydraulic, chemical or thermal stimulation.

Australia's unconventional resources have often been categorised as either Hot Sedimentary Aquifers (HSA) or Enhanced (or Engineered) Geothermal Systems (EGS). Recently there have been other concepts such as Heat Exchanger Within Insulator (HEWI), Fractures at Basin-Basement Interface (FABBI) and Secondary Enhancement of Sedimentary Aquifer Plays (SESAP). These distinctions are attempts by project proponents to differentiate their resources within the investment market. While there is value in recognising different geological settings that give rise to permeable reservoirs, all of the above concepts lie on a continuum of heat sources and permeability mechanisms. In general, temperature increases with depth, but permeability decreases as the weight of overlying rock squeezes out porosity and, along with temperature increase, causes mineralogical changes.

The term Hot Sedimentary Aquifer may be suitably applied to those geothermal resource in the shallow parts of basins that do not require permeability enhancement. The Paris Basin (France) provides an international example, while the Great Artesian Basin resource at Birdsville provides an Australian example. Both are low-temperature resources. EGS are those resources that need permeability enhancement, which include 'deep sedimentary resources' (e.g. depths of greater than approximately 3000 m in Australian basins), and crystalline resources (e.g. in granites—the Innamincka Deeps project of Geodynamics Ltd, but also metasedimentary basement rocks).

Geothermal resources (excluding ground source heat pumps) may also be classified broadly according to temperature—high temperature (greater than 170 °C), moderate temperature (90 °C to 170 °C) and low temperature (less than 90 °C)—which influences the uses to which they may be applied (Geothermal Resources Council 2009). High-temperature systems are often exploited for electricity generation, while low-temperature systems are more suited to direct-use applications (figure 7.4). High and moderate temperature systems may be used for both electricity generation and direct-use applications in a cascading fashion (where the exhaust fluid from electricity generation can be used in direct-use processes).

Electricity generation

Hydrothermal systems are currently utilised in several countries for electricity generation. Geothermal power plants can provide base-load capacity 24 hours a day and have very high long-term availability and high capacity factors. Current technologies (box 7.1) include dry steam plants (uses steam at greater than 235 °C through production wells), flash steam plants (use hot water at temperatures in the range 150 °C to 300 °C) and binary-cycle plants (used for moderate temperature geothermal reservoirs between 100 °C and 180 °C). Temperature is only one parameter used to determine which conversion technology is utilised for any geothermal reserve. Electricity generation from geothermal water

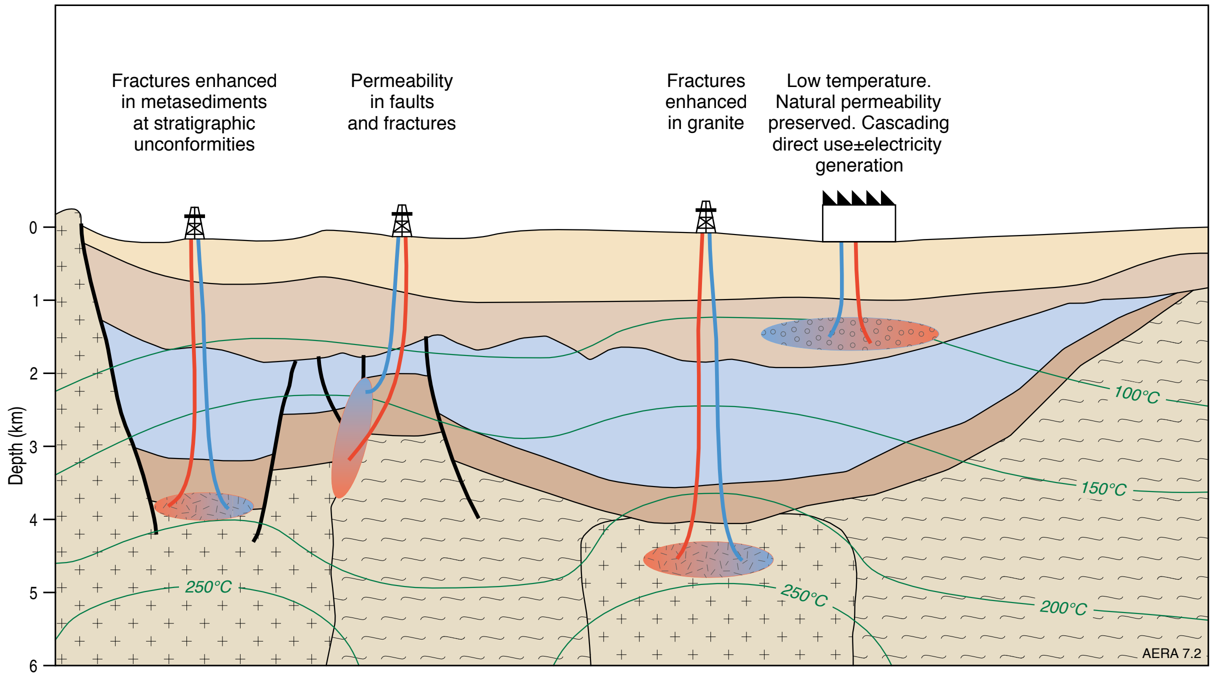

Figure 7.2 Unconventional geothermal systems

Source: Geoscience Australia

was pioneered at Larderello, Italy in 1904, and this steam field has been in continuous production since that time. The Wairakei geothermal power plant, located in New Zealand, built in 1958—the second geothermal power station built in the world and the first to use hot pressurised water—has generated electricity for more than 50 years. The largest geothermal development in the world at The Geysers in California, United States has an output capacity of 750 MW based on 22 separate power plants, some of which have been in operation for nearly 50 years.

Direct-heat uses for geothermal waters

Hot water may be piped directly into facilities for use in a range of applications such as district (and large commercial buildings) heating and greenhouses, heating water for fish farming (aquaculture), drying crops and building materials, and for use in resorts and spas (figure 7.4). The heat may be used directly in industrial processes including drying, for absorption chillers (including air conditioning), and in desalination of seawater by distillation. People have traditionally used hot water from geothermal springs for bathing, cooking and heating; for example, the Romans used geothermal waters at Bath in England.

Ground source heat pumps that utilise the ground as a heat source/sink

These systems are a direct-use technology that use the ground as a heat source or sink rather than natural hot water (i.e. they do not use 'geothermal resources') and are used to heat and cool buildings. Heat is extracted from the ground and delivered to the building in winter (heating mode) and heat is removed from the building and delivered for storage into the ground in summer (cooling mode). The ground source heat pump (GSHP) utilises an electric motor to circulate heat-carrying fluid, but energy consumption is significantly reduced compared with conventional heating and cooling systems.

BOX 7.1 GEOTHERMAL ENERGY TECHNOLOGIES FOR ELECTRICITY GENERATION

Current geothermal technologies for electricity generation are:

- Flash steam plants are used where abundant high-temperature water or vapour is available. Hot water is removed from the production well and sprayed into a separator (tank) held at a much lower pressure, causing some of the water to flash to steam (vaporise). The steam is used to drive the turbine and then condensed back to water and injected back into the reservoir.
- Dry steam plants use steam resources at temperatures of about 235 °C. The steam goes directly to a turbine which drives a generator that produces electricity. This was originally used in Larderello, Italy and is the technology used at the world's largest geothermal power field, The Geysers in California, United States.
- Binary power plants (figure 7.3) use a heat exchanger to transfer energy from the geothermally heated fluid to a secondary fluid ('working fluid', e.g. iso-pentane or ammonia–water mix) that has a lower boiling point and higher vapour pressure than steam at the same temperature. The working fluid is vaporised as it passes through the heat exchanger, and then expanded through a turbine to generate electricity. It is then cooled and condensed to begin the cycle again. The cooled geothermal fluid is also recirculated into the ground: the system comprises two closed loops.

Most Australian geothermal resources will be exploited using binary power generation systems, even those with temperatures of over 200 °C. Flash and dry steam plants lose water through evaporation, requiring makeup water to be injected into the reservoir. In most parts of Australia, additional water will not be available. Closed-loop binary systems are water-conservative. An additional benefit is that they will reduce the rate of energy drawdown of the geothermal reservoir, as water will be reinjected at the back-end temperature of the power plant (in general >80 °C), whereas 'fresh'water would be injected at ambient temperature (~30 °C).

Electricity generation costs are strongly influenced by the temperature and flow rate of the geothermal fluid produced, which dictates the size of the turbine, heat exchangers and cooling system. Access to a market (on or off grid) is also an important cost consideration for electricity generation projects.

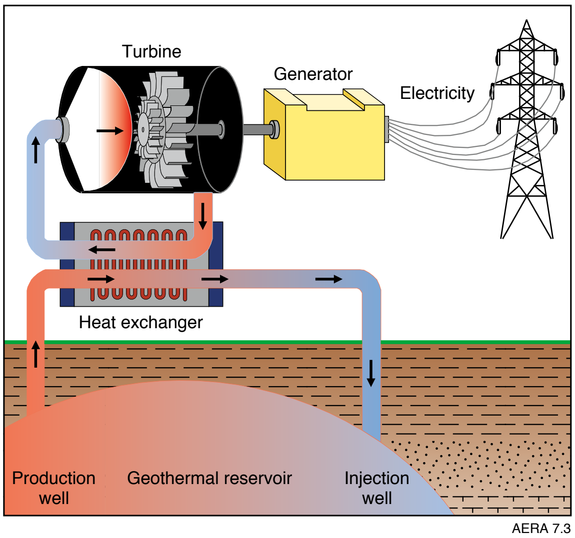

Figure 7.3 Design of a binary-cycle power plant

Source: Geoscience Australia

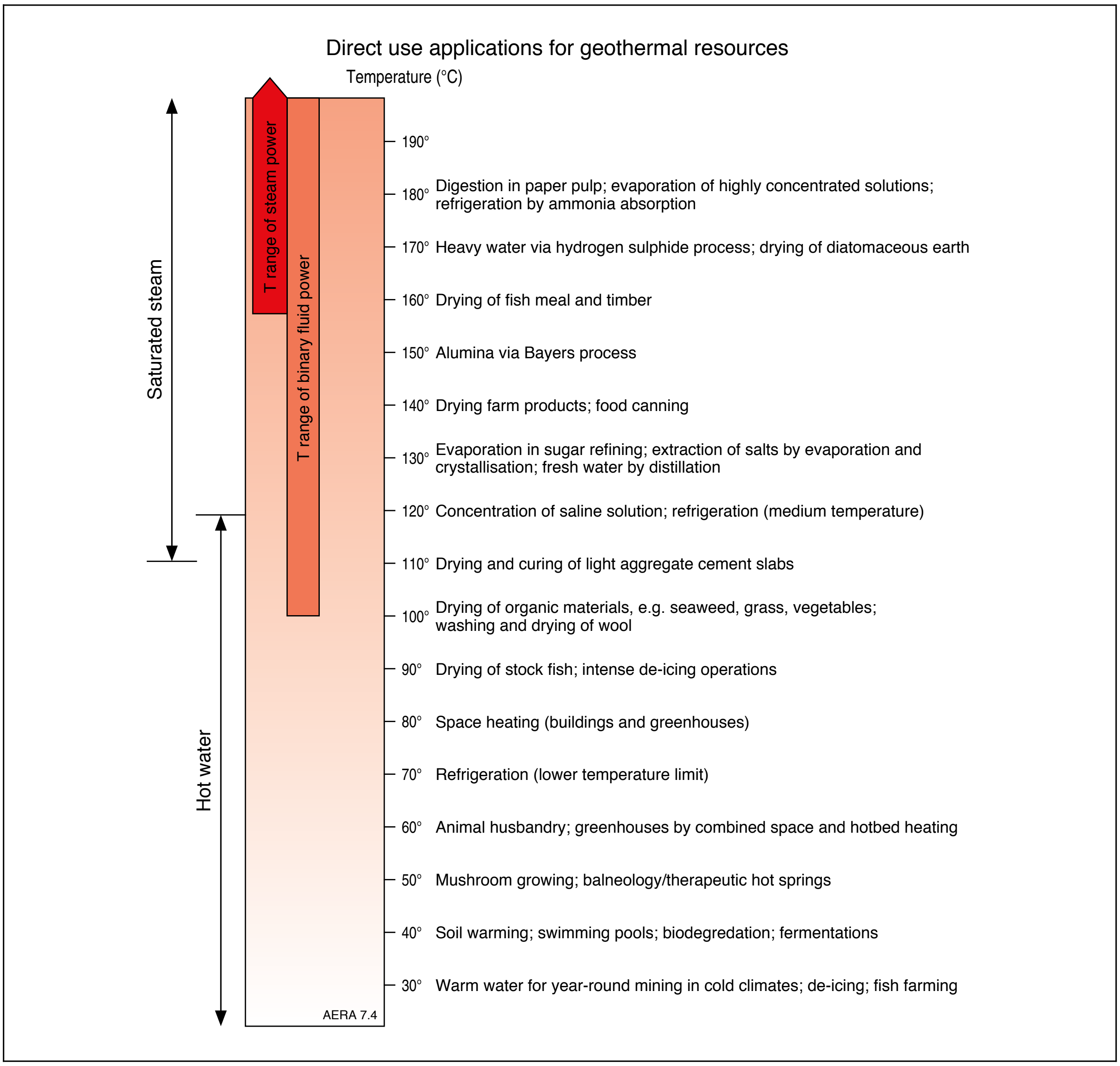

Figure 7.4 Direct-use applications of geothermal energy

Source: Geoscience Australia, modified after Lindal 1973; Ayling et al. 2007b

7.2.2 Geothermal energy supply chain

Figure 7.5 is a schematic representation of the potential geothermal energy market in Australia. At present geothermal energy resources in Australia are used only in limited local-scale applications. High and moderate temperature geothermal energy resources may in future be utilised to produce base-load electricity for distribution through the transmission grid or to off-grid users. In addition, lower temperature geothermal energy resources, particularly those found in shallow sedimentary aquifers, could be used for direct-use applications. Ground source heat pumps could be employed almost anywhere and on a range of scales to provide building heating and cooling.

Key stages in the geothermal energy supply chain are discussed further in box 7.2.

Important elements of unconventional geothermal energy developments are the definition of the geothermal resource by deep drilling and establishing a permeable reservoir in the hot rocks. The artificial creation of geothermal reservoirs in the hot rocks for water to flow through is commonly called EGS and involves a process known as 'stimulation' through either hydraulic shearing or fracturing, chemical dissolution, or thermal shocking. Once the reservoir in the hot rock is created and the flow of water established in a closed loop, the geothermal resource can be used to generate electricity using the technologies described in box 7.1 and the electricity connected to the transmission grid for distribution.

7.2.3 World geothermal energy market

The world has vast, largely unutilised geothermal energy resources. Geothermal energy currently accounts for only a small share of world primary energy consumption. Geothermal resources are mainly utilised for electricity generation, although direct-use applications are also significant.

BOX 7.2 STAGES IN DEVELOPMENT OF GEOTHERMAL ENERGY

- Resources exploration—usually involves site assessment, leasing and land acquisition, exploratory drilling, and well testing. Notably, exploratory drilling and reservoir assessment, as in oil and gas fields, are high-risk activities and an entire project may be cancelled if an adequate resource is not found (IEA 2003). Improvement in unconventional geothermal resource exploration and assessment will reduce costs at every stage of development and operation.
- Development and production—following successful exploration activity, a company will seek to confirm the energy potential of the resource, and then to produce hot water from the reservoir. The costs associated with drilling and well testing play a major role in determining the economic feasibility of producing energy from geothermal resources. Many unconventional geothermal resources will require the creation of a geothermal reservoir by hydraulic stimulation. Depending on the orientation of stresses in the earth, fractures can be horizontal, vertical, or at an angle in between. The hydraulic stimulation process can last for several weeks, depending on the degree of fracturing required. Hydraulic stimulation can induce local seismic activity but the risks associated with this are considered to be very low. Other stimulation methods include chemical treatment or thermal shock fracturing.
- Processing and distribution to end-use applications—once production of hot water from the reservoir has been achieved, the heat energy needs to be converted to usable energy, either by generating electricity or by direct use of the heat energy in (industrial) processes. Activities that bring a power plant on line include expansion of the geothermal field by additional drilling, project permitting, liquid and steam gathering system, and power plant design and construction (Kagel 2006). Information on geothermal electricity generation technologies is provided in box 7.1.

  The type of geothermal resource and its location are important from a commercialisation viewpoint. Access to a market (whether on or off grid and a short or long distance away) is important for electricity generation. Location adjacent to infrastructure is important for retrofitting or development of new direct-use applications.

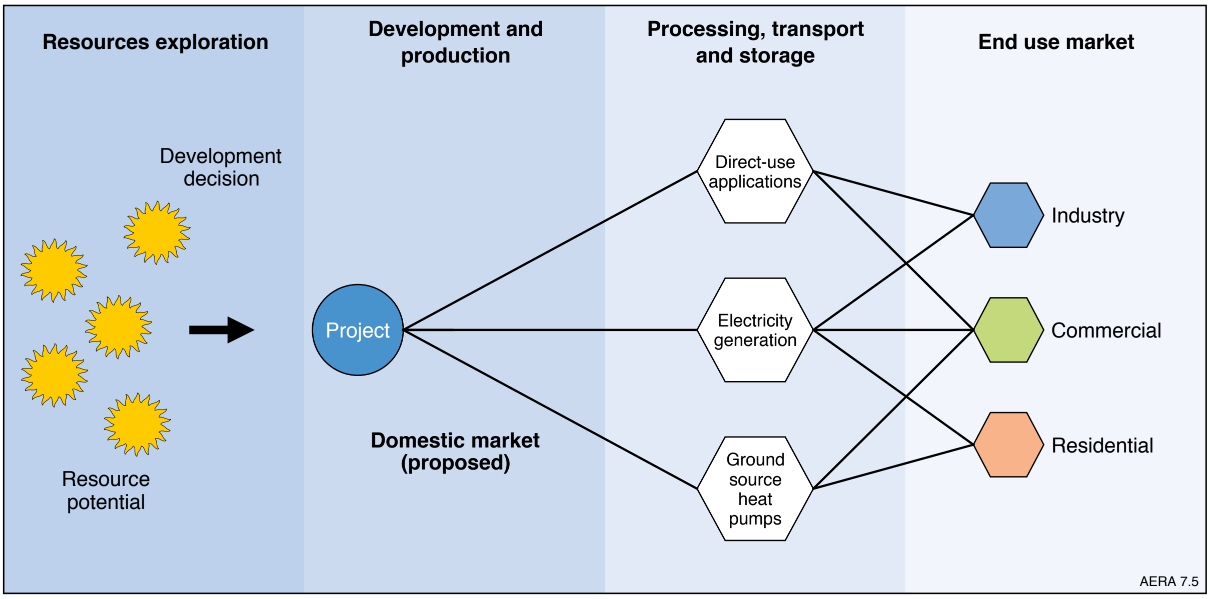

Figure 7.5 Australia's geothermal energy supply chain

Source: Bureau of Resources and Energy Economics; Geoscience Australia

Resources

Until recently, geothermal energy was considered to have significant economic potential only in areas with hydrothermal systems; that is, in countries with active volcanoes. Countries that have identified and are utilising significant amounts of these hydrothermal energy resources include the United States, the Philippines, Indonesia, Mexico, Italy, Iceland, New Zealand, Kenya and Japan.

Many countries have identified lower temperature geothermal resources and these are increasingly used for district heating and ground source heat pump systems (WEC 2007).

Primary energy consumption

Geothermal energy consumption is equal to geothermal energy production as geothermal energy is not traded in its primary form. Most geothermal plants are built close to the resource because it is generally not efficient to transport high-temperature steam or water over distances of more than 10 km by pipeline due to heat losses (or 60 km in thermally insulated pipelines; IGA 2004).

In 2010, geothermal energy accounted for around 0.5 per cent of world primary energy consumption (table 7.1). World geothermal energy consumption has increased slowly in recent years, at an average rate of 2.9 per cent per year between 2000 and 2010. In the OECD region, geothermal energy accounts for a relatively small share of total primary energy consumption (0.6 per cent in 2011) and growth in recent years has also been very slow (0.7 per cent per year between 2000 and 2011).

Geothermal resources are mainly utilised in the energy markets of Asia (44 per cent of world geothermal energy consumption in 2010), OECD North America (22 per cent of world geothermal energy consumption), OECD Europe (18 per cent) and the OECD Asia–Pacific (10 per cent) (figure 7.6). The main geothermal energy consumers are the United States, the Philippines, Indonesia, Mexico, New Zealand, Italy, Iceland, Japan, El Salvador and Kenya (IEA 2012a).

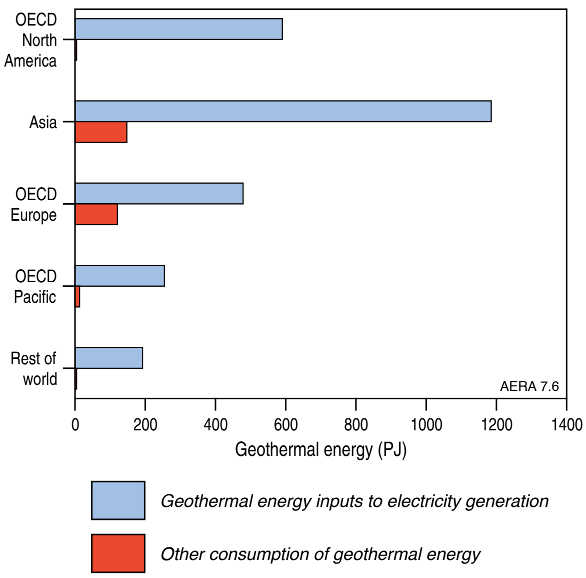

Figure 7.6 Primary consumption of geothermal energy, by region and use, 2010

OECD = Organisation for Economic Co-operation and Development

Source: IEA 2012a

Figure 7.7 provides information on the world use of geothermal energy as a fuel input to the transformation (or conversion) sector and a fuel input to other industries in direct-use applications, all measured in PJ. In 2010, 88 per cent of world geothermal energy consumption was used as a fuel input to the transformation sector (of which electricity plants accounted for 97.6 per cent, combined heat and power plants for 2 per cent, and heat plants for 0.4 per cent). The remaining 12 per cent was used in direct-use applications (for district heating, agriculture and greenhouses) including 7 per cent in the residential sector and 3 per cent in the commercial sector (IEA 2012a). Most direct-use applications of geothermal energy occur in the OECD Europe, North America and Asia Pacific regions (figure 7.6).

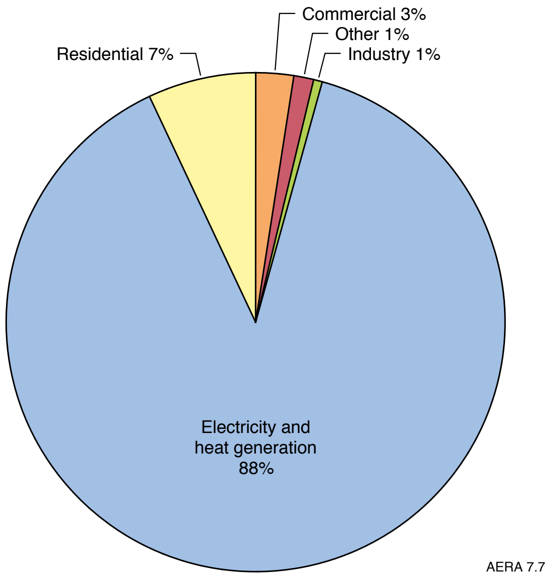

Figure 7.7 World geothermal energy consumption, by sector, 2010

Source: IEA 2012a

Electricity generation

The utilisation of geothermal energy for electricity generation has increased markedly since the 1970s (figure 7.8). World geothermal electricity generation increased from 4.5 TWh in 1971 to 130 TWh in 2010, which represents an average annual growth rate of 7.2 per cent. In recent years, however, this growth rate has been much slower, at 3.1 per cent per year between 2000 and 2010. Geothermal energy accounted for 0.3 per cent of world electricity generation in 2010 (IEA 2012a).

Electricity generation from geothermal energy has a low heat-to-electricity conversion efficiency compared with many other sources of electricity generation. For example, in 2010, geothermal inputs of 1884 PJ to electricity generation yielded 61.8 TWh (223 PJ), showing a 12 per cent aggregate conversion efficiency. Regional conversion efficiencies in 2010 ranged from 11.8 per cent to 14.7 per cent for those regions that provided data—the IEA assumes a 10 per cent conversion efficiency for countries that do not supply data. Technological advances in the geothermal energy industry have resulted in efficiency gains which has increased the conversion ratio and decreased the fuel inputs required for a unit of electricity generation.

In 2010, 28 countries were generating electricity from geothermal energy (IEA 2012a). The United States was the largest geothermal electricity generator, with output of 17.6 TWh. Other major producers include the Philippines, Indonesia, Mexico, New Zealand, Italy, Iceland and Japan (figure 7.9a).

Geothermal electricity generation represents a significant share of the total electricity requirements in some countries. In 2010, the three countries most dependent on geothermal energy for electricity generation were Iceland (26.2 per cent of total electricity generation), El Salvador (26 per cent) and Kenya (19 per cent) (figure 7.9b).

Direct-use applications

The largest direct applications of geothermal energy are in ground source heat pumps, industrial applications and space heating: together these accounted for more than 80 per cent of direct-use applications in 2004 (WEC 2007). In 2010, the People's Republic of China was the largest consumer of direct geothermal energy (308 PJ), followed by Turkey, Germany, Iceland and Switzerland (figure 7.10). Ground source heat pumps are mainly used in areas with noticeable seasonal temperature fluctuations, such as North America and Europe.

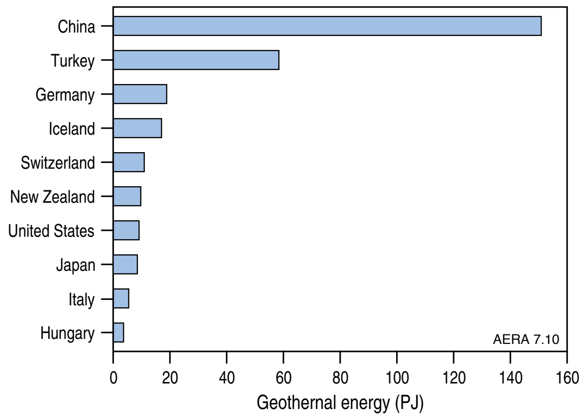

Figure 7.10 World direct use of geothermal energy, major countries, 2010

Source: IEA 2012a

Table 7.1 Key geothermal energy statistics

	Unit	Australia 2011	OECD 2011	World 2010
Primary energy consumption[a]	PJ		1379	2705
Share of total	%		0.6	0.5
Average annual growth, from 2000	%		0.7	2.9
Electricity generation				
Electricity output	TWh	0.001	44.8	68.1
Share of total	%		0.4	0.3
Average annual growth, from 2000	%		2.5	3.1
Electricity capacity	GW	0.001	6.1[c]	11[d]

OECD = Organisation for Economic Co-operation and Development
a Energy production and primary energy consumption are identical. **b** ESAA 2013. **c** 2010 data–IEA 2012c. **d** IEA 2012b

Source: IEA 2012a, 2012b, 2012c; ESAA 2013

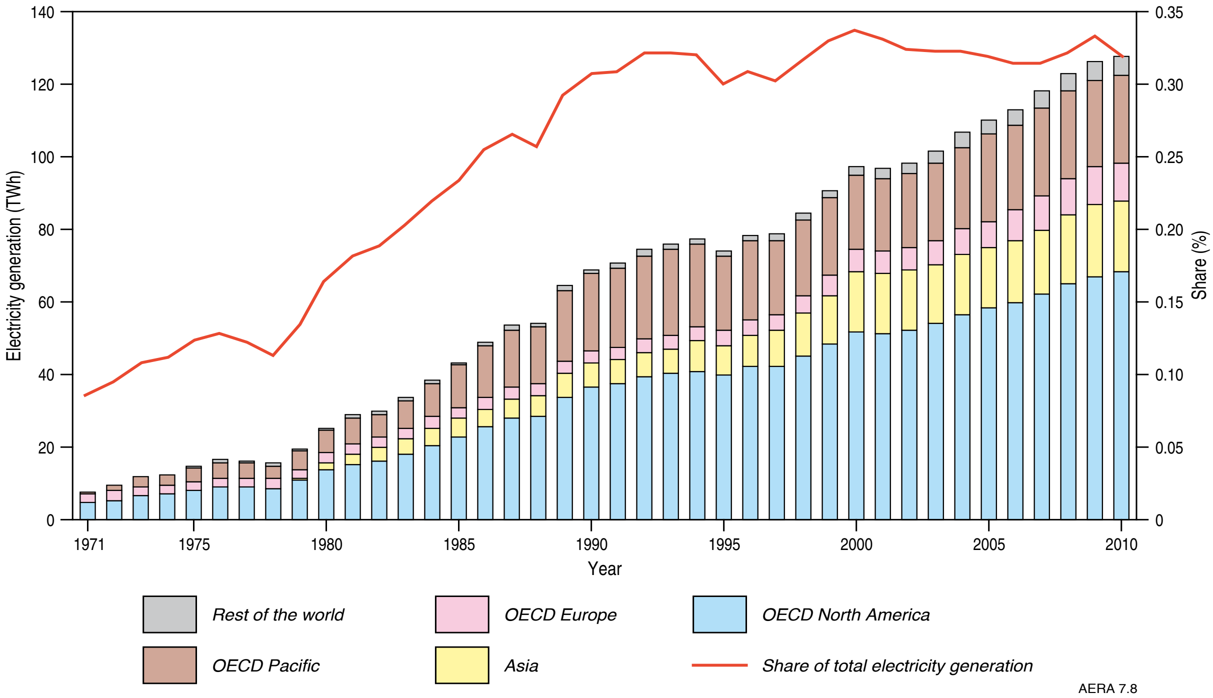

Figure 7.8 World geothermal electricity generation, by region

OECD = Organisation for Economic Co-operation and Development

Source: IEA 2012a

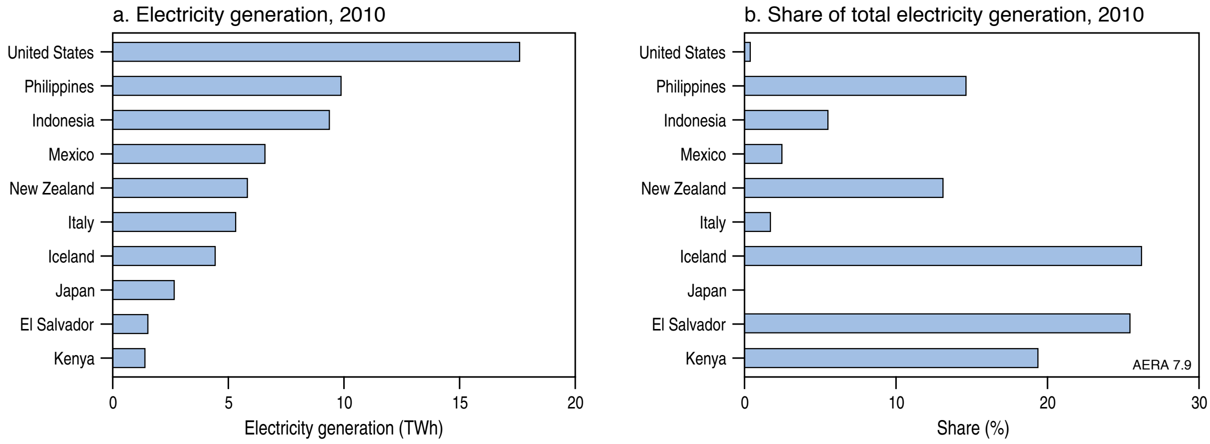

Figure 7.9 World geothermal electricity generation, major countries, 2010

Source: IEA 2012a

World geothermal energy market outlook

IEA new policies scenario projections for primary consumption of geothermal energy are not available; therefore, the outlook for the world geothermal energy market will focus on electricity generation. However, the increased global demand for renewable energy is expected to increase demand for geothermal energy both for electricity generation and for direct use. The strong growth in use of ground source heat pumps established over the past decade is expected to continue, supported by increased demand for renewable energy and increasing cost-effectiveness of direct use geothermal energy. Improvements in drilling technologies, improved reservoir management, and reduced operating and maintenance costs, coupled with further exploration, are likely to promote increased utilisation of geothermal resources, and hydrothermal resources in particular.

Table 7.2 IEA new policies scenario projections for world electricity generation from geothermal energy

	Unit	2010	2035
OECD	TWh	43	166
Share of total	%	0.4	1.2
Average annual growth, 2010–35	%		5.5
Non-OECD	TWh	25	149
Share of total	%	0.2	0.6
Average annual growth	%		7.5
World	TWh	68	315
Share of total	%	0.3	0.9
Average annual growth, 2010–35	%		6.3

OECD = Organisation for Economic Co-operation and Development
Note: totals may not add due to rounding

Source: IEA 2012b

World electricity generation from geothermal energy is projected to triple to 315 TWh by 2035, growing at an average rate of nearly 6.3 per cent per year (table 7.2). The share of geothermal electricity generation of total electricity generation is also projected to triple by 2035 to reach 0.9 per cent. Most of the projected growth in geothermal electricity is expected to occur in the United States, Japan, Philippines and Indonesia. Use of geothermal for electricity generation is also expected to increase in African countries, particularly North Africa (IEA 2012b).

7.3 Australia's geothermal resources and market

7.3.1 Geothermal resources

As there are no active volcanoes or rifting on the Australian continent (there are active volcanoes on Heard and McDonald Islands), Australia lacks conventional hydrothermal resources. However, Australia has substantial potential for unconventional geothermal resources.

The factors which combine to give Australia an excellent geothermal potential are:

- Widespread occurrence of basement rocks, especially granites, with unusually high heat-generating capacities because of abundances of the radioactive elements uranium, thorium and potassium which, over hundreds of millions of years, decay and produce heat. In particular, granites of Proterozoic age which occur throughout northern and central Australia are generally high heat-producing, but some occurrences of older Archean and younger Paleozoic granites are also high heat-producing (Budd 2007).
- Areas of anomalously elevated heat flow from the mantle beneath the upper crust.
- Large basins that are filled with thermally insulating sediments or volcanic rocks that can act as blankets.
- Where these sources of heat (high heat-producing granites or areas of high mantle heat input) are buried beneath blanketing basins, the heat energy is retained in the basement rocks and overlying strata and high temperatures are present at relatively shallow depths.

- The Australian plate is moving northwards and colliding with the Pacific plate, resulting in a general horizontal stress orientation in the Australian crust, which is favourable for the development during hydroshearing of sub-horizontal fracture networks that can connect adjacent wells at a similar depth (box 7.2; Hillis and Reynolds 2000). Geodynamics Ltd (2013) estimated that it had created an underground heat exchanger at Habanero (in the Cooper Basin of far north-east South Australia) four times larger than previously attained elsewhere in the world. Flow testing from Habanero 4 achieved one of, if not the highest, flow rate from an EGS well.

There is also potential for Hot Sedimentary Aquifer geothermal resources in a number of shallow sedimentary basins (e.g. Great Artesian Basin) where circulating groundwater systems may allow a high flow rate of moderate and low-temperature water. Although commonly at a lower temperature, the high flow rate allows significant energy delivery to the surface. Water temperatures, permeability and the depth at which useful geothermal waters can be tapped will depend on a number of factors, particularly the nature of the basement rocks underlying the basin and the local hydrology of the basin.

Australia's potential for high crustal temperatures has only recently been appreciated (box 7.3). As a consequence, there is incomplete knowledge of where geothermal potential exists, with some knowledge about the distribution of temperature, and less about zones of permeability. It is likely that further data acquisition will lead to increases in the geothermal resource base as geothermal resources have already been identified by company exploration programs in areas outside of those predicted to have geothermal potential in national-scale compilations (figure 7.11).

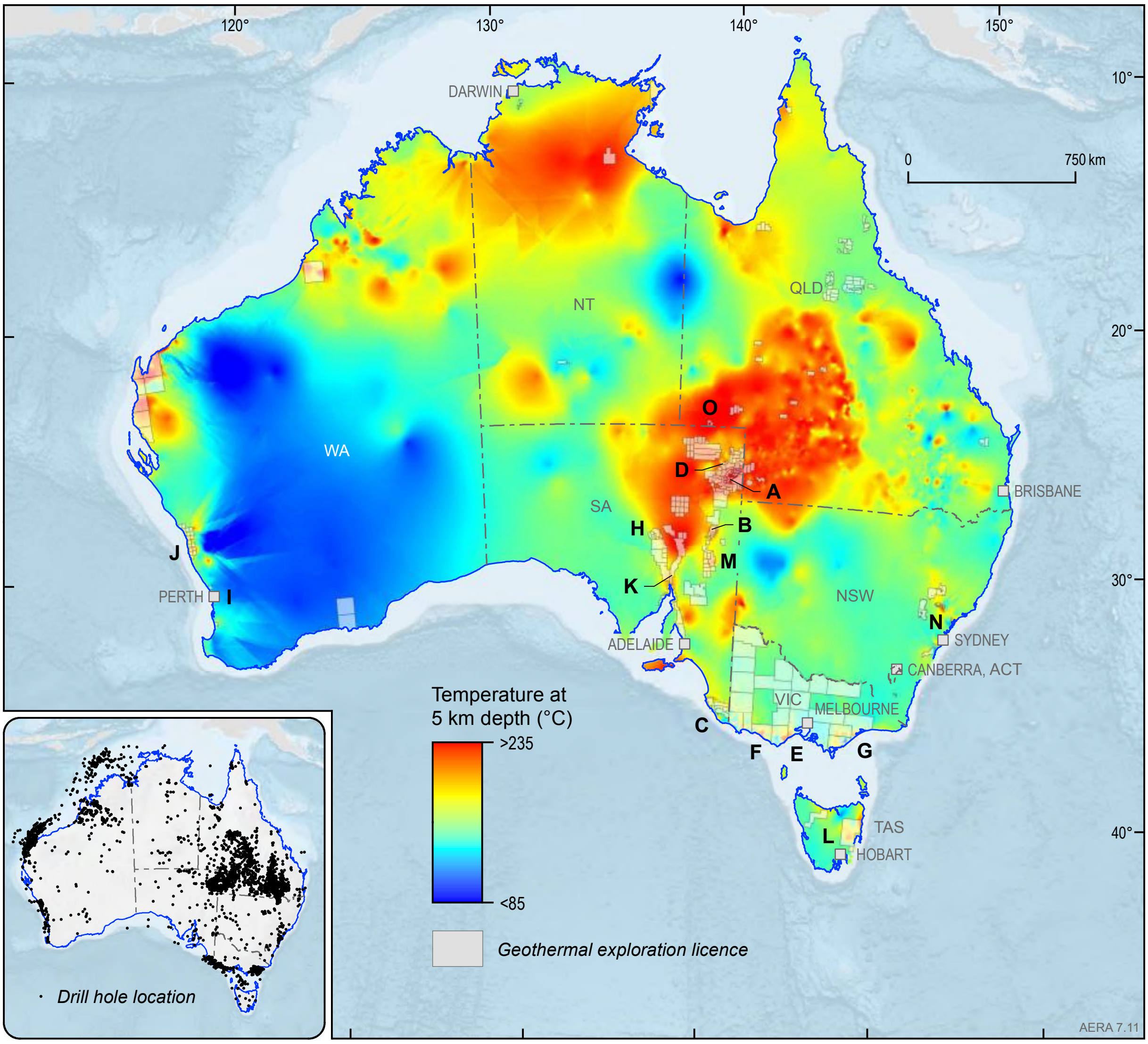

Figure 7.11 Predicted temperature at 5 km depth based mostly on bottom-hole temperature measurements in more than 5000 petroleum and water boreholes. Areas of current exploration discussed in the chapter are shown as overlaid letters (box 7.4)

Note: Inset map shows the distribution of data points used to construct the map and the paucity of data points over most of the continent
Source: Data from OZTEMP database; Geoscience Australia

Current knowledge is based on a database of temperatures recorded at the bottom of more than 5700 deep drill holes, most of which were drilled for petroleum exploration or for groundwater (figure 7.11) supported by more detailed local investigations by companies (box 7.3). National-scale maps published by Geoscience Australia showing the distribution of high heat-producing granites and sedimentary basins, together with other information such as basin depth, provide a national framework and basis for identifying areas likely to have the greatest geothermal potential (Budd 2007).

In addition to the national database, maps and assessments of a number of regional and local assessments have been undertaken. For example, an assessment of the geothermal potential of Victoria (SKM 2005) concluded that while the temperatures of geothermal water found within the top 2000 m of the surface of the state were not sufficiently high for generating electricity commercially, there was abundant and readily accessible geothermal water suitable for direct heating purposes.

The *Australian code for reporting of exploration results, geothermal resources and geothermal reserves, second edition* (2010) (available at www.agea.org.au) has been developed to provide a common framework for categorising geothermal resources and reserves for the information of potential investors. The various categories of the code describe the development process, which broadly consists of reducing geological uncertainty and completing technical (e.g. energy conversion), economic and regulatory requirements. Compared to the first edition, the second edition reports geothermal resources in terms of Recoverable Thermal Energy, and therefore the figures reported are lower than the total heat in place figures reported in the first edition.

Ten companies have declared identified geothermal resources in 51 leases across five states totalling 440 570 PJ of recoverable heat in place (table 7.3).

Other than at Birdsville, Australia's reported geothermal resources are currently all subeconomic: the commercial viability of utilising geothermal energy for large-scale electricity generation has not yet been demonstrated in Australia. Project economics is the main factor that has potential to impede the development of the industry. There is a need to progress a number of projects through all stages from resource definition to production and marketing to increase market confidence and therefore investment in the sector. All of the component technologies required for utilising Australia's geothermal energy have been demonstrated—but the challenge remains in demonstrating reliable geothermal electricity generation. Technology developments will reduce overall project costs. For example, improvements in the ability to reliably create multiple fracture horizons from a single well and have these connected to another well could result in a tripling of flow rates, which may result in project cost savings of 50 per cent.

Compilations of predicted temperature at 5 km depth (figure 7.11) suggest that there are substantial areas of the continent where temperatures exceed 200 °C at this depth, which is considered feasible for geothermal energy exploitation. This implies that Australia has world-class potential for unconventional geothermal energy resources.

A simple calculation suggests that if just 1 per cent of Australia's geothermal energy above a minimum temperature of 150 °C and at a maximum depth of 5 km were accessible, the total resource is of the order of 190 million PJ, which is roughly 25 000 times Australia's primary energy use (Budd et al. 2008). This calculation ignores the renewable nature of the resource, that it can be utilised at temperatures of less than 150 °C, and that improvements in drilling technology will mean that depths of greater than 5 km will be accessible.

The distribution of data points in the small inset map of figure 7.11 shows that there are extensive areas of the continent with little or no data. New geological data are needed to provide a better understanding of Australia's geothermal energy potential, particularly near potential major markets.

Table 7.3 Australia's reported geothermal resources as at December 2012[a]

	PJ
Identified geothermal resources (subeconomic)	440 570

a Includes measured, indicated and inferred resources reported as Recoverable Thermal Energy. *Australian code for reporting of exploration results, geothermal resources and geothermal reserves, second edition*. www.agea.org.au

Source: Geoscience Australia

Geothermal exploration

Figure 7.11 shows areas where exploration and development activities have been undertaken. It is important to note that many of the areas under exploration do not appear to be of high temperature on the map: this underscores the fact that bottom-hole temperatures used alone are an insufficient geological dataset.

Exploration drilling has been conducted in each of the Cooper Basin, the Mount Painter Inlier–Frome Embayment, and the Otway Basin, and many of the exploration companies have announced inferred geothermal resources in these areas. Other areas where resources have been announced include the Perth Basin (Western Australia); the broad area around Olympic Dam and Lake Torrens, Port Augusta (all within South Australia); central Tasmania; and the Gippsland Basin, Mildura (Victoria). Exploration projects listed in box 7.4 illustrate the range of geothermal targets.

EGS basement geothermal resources

Exploration has been largely focused on the high-temperature EGS basement geothermal resources of South Australia (Cooper Basin, Adelaide Fold Belt, and Mount Painter Inlier–Frome Embayment) (box 7.4). Each of these areas has an underlying basement that includes high-heat-producing granites of Proterozoic age. The depth of sedimentary cover varies from relatively shallow along the margins of the Mount Painter Inlier to more than 5 km in the Cooper Basin.

BOX 7.3 GEOTHERMAL EXPLORATION ACTIVITY AND DATA ISSUES IN AUSTRALIA

It has only become evident in the past decade that Australia has considerable geothermal potential. This is because of a perception that geothermal resources are found only in regions of active volcanism or rifting, which excludes Australia. The Hot Dry Rock concept originated at Fenton Hill, New Mexico, from the work by the Los Alamos Scientific Laboratories in the early 1970s. The concept was to replicate conventional geothermal systems in dry, unfractured rock by creating a reservoir with the required permeability and introducing the required fluid.

In the 1990s, the Australian Bureau of Mineral Resources first drew attention to Australia's EGS potential in the Cooper Basin, other sub-basins beneath the Eromanga Basin (Queensland, New South Wales, South Australia); the McArthur Basin (Queensland/ Northern Territory); the Otway Basin (Victoria, South Australia); the Carnarvon, Canning and Perth Basins (Western Australia); areas in east Queensland; and the Sydney Basin north-west of Newcastle (Somerville et al. 1994). In the Cooper Basin, they reported extrapolated temperatures in excess of 300 °C at 5 km depth, and estimated the heat energy available in rocks at temperatures above 195 °C at 7.8 million PJ. This work was based largely on a compiled database of temperatures recorded at the bottom of deep drill holes, most of which were drilled for petroleum exploration. This GEOTHERM database has evolved through work at the Australian National University, Earth Energy Pty Ltd and Geoscience Australia to become the OZTEMP database, maintained and updated by Geoscience Australia. Until recently, this has been the only database of significant use to geothermal explorers, and exploration in Australia was initially limited to areas of petroleum exploration activity because this was the only available relevant dataset. However, this dataset has a number of inadequacies and does not fully represent Australia's geothermal potential.

More recently, explorers have gained a better understanding of the geology of unconventional geothermal systems, and have expanded the range of geothermal exploration 'plays' by using a greater range of geoscience information. This, together with the acquisition of new data specifically for geothermal exploration, most notably heat-flow measurements, has increased the exploration search area.

Exploration models being implemented in Australia now cover a range of targeted temperatures from as low as 60 °C for direct-use applications, to as high as 275 °C. Reservoirs being targeted include granite and metasedimentary rocks requiring fracture enhancement for EGS developments, to shallow natural aquifers for Hot Sedimentary Aquifer systems. Most explorers are aiming to achieve suitable temperatures within 4 km depth from the surface, but some explorers are considering depths of 5.5 km and greater. These geological systems are being targeted for electricity generation or for direct-use applications, or both via cascading arrangements that enable multiple uses of the same fluid at successively lower temperatures.

Following a period of rapid expansion, exploration for geothermal resources has been in decline since 2010. The first geothermal exploration licence in Australia was granted in 2000 and by January 2010, 54 companies held 409 leases over an area of 432 000 km^2. In August 2012, 28 entities had applied for, or been granted, 232 geothermal exploration/development licences.

BOX 7.4 GEOTHERMAL EXPLORATION AND RESOURCES IN AUSTRALIA

This box summarises the exploration projects shown on figure 7.11 as letters A to O.

A: Innamincka Deeps and Shallows—Cooper Basin, South Australia

Geodynamics Ltd has drilled six deep wells in three prospect areas in their Innamincka Deeps project. The target is granites of the Big Lake Suite, overlain by >3500 m thickness of sedimentary rocks. A temperature of 278 °C was recorded in Jolokia-1 at a depth of 4911 m; however, hydraulic stimulation was unsuccessful in this well. Savina-1 was drilled to 3700 m but a stuck drill pipe caused the well to be suspended.

At the Habanero prospect, Geodynamics Ltd achieved proof-of-concept of sustained fluid flow between an injector and production well couplet (Habanero-1 and Habanero-3) and the surface in March 2009. Following the casing failure of Habanero-3 due to incomplete cement placement between steel casing and the surrounding rock, Geodynamics Ltd completed Habanero-4 well in 2012 and a major hydraulic stimulation program successfully extended the previously stimulated reservoir. Geodynamics Ltd established a closed circulation loop between Habanero-1 and Habanero-4 to pilot the generation of power using a 1 MW pilot plant in early 2013.

The development of the Habanero resource is being supported by a grant of A$90 million through the Australian Government's Renewable Energy Demonstration Program.

At the Innamincka Shallows project, Celcius-1 was drilled to a total depth of 2416 m in April 2011. The target was shallow sediments of the Hutton Sandstone. The well recorded a temperature in excess of 145 °C, but the flow rates achieved were determined to be too low to warrant further work at this stage (www.geodynamics.com.au).

B: Paralana—Mount Painter Inlier/Northern Flinders Ranges, South Australia

Petratherm Ltd (79 per cent, operator) has partnered with Beach Petroleum (21 per cent) on the Paralana project in the Mount Painter–Frome Embayment area of South Australia. The geological model here is a significant variant on the 'normal' EGS model, and Petratherm intend to create a 'Heat Exchanger Within Insulator' meaning fracturing within the metasedimentary insulating rocks rather than the heat-producing granite. The project received a A$7 million grant through the Australian Government's Geothermal Drilling Program, and completed the Paralana 2 well to a depth of 4 km in November 2009 as the first stage of that program grant. A large fracture stimulation program was undertaken successfully in April 2011, with temperatures recorded from subsequent flow tests reaching 171 °C.

Petratherm's plan is for a 30 MW commercial demonstration project to provide power to local consumers (particularly uranium mines) and this is being supported by a grant of A$63 million through the Renewable Energy Demonstration Program (www.petratherm.com.au).

C: Limestone Coast—western Otway Basin, South Australia

Panax Geothermal Ltd has a number of prospect areas in the western Otway Basin within South Australia. They are the Penola, Rivoli & St Claire, Rendelsham, and Tantanoola prosects. All prospects have as targets a sequence of sandstone aquifers within early Cretaceous sediments expected to contain water at temperatures in the range 140–180 °C at depths of between 2500 to 4000 m. Panax Geothermal Ltd received a A$7 million grant from Round 1 of the Australian Government's Geothermal Drilling Program, and drilled their first deep production well at the Penola prospect in early 2010. Salamander-1 reached a total depth of 4025 m, and recorded a maximum temperature during flow testing of 171 °C, but flow rates were substantially below those expected.

A research project is under way between CSIRO, University of Adelaide, Panax and Geodynamics to examine the reasons and possible remedies for the low flows in Salamander-1 and Celcius-1, including investigating the possibility that reservoir permeability is compromised by diagenetic processes (i.e. during compaction of the basin during basin filling), or whether the reservoir was damaged during the drilling process (i.e. by mud filling permeable pathways, or fines migration during acid treatment).

D: Tirrawarra—Cooper Basin, South Australia

Panax Geothermal Ltd has targeted the deep sandstone reservoirs of the Nappamerrie and Gidgealpa Groups in the Cooper Basin at depths from 2500 to 3000 m. In the area of the tenement, these sedimentary groups are productive for oil.

E: Geelong—eastern Otway Basin, Victoria

Greenearth Energy Ltd has conducted investigations in the area around Geelong, targeting deep sandstones of the Crayfish Group (including the Pretty Hill Formation) in the eastern Otway Basin. Target depths are between 3000 m and 4000 m, and temperatures modelled to average 188 °C. Greenearth Energy also recognises the potential for EGS in granitic basement at depths of greater than 4000 m.

Greenearth Energy Ltd was awarded A$25 million grant funding in December 2009 under the Victorian Government's Energy Technology Innovation Strategy program. The funding was awarded to assist two stages of the Geelong Geothermal Power Plant development, the first being A$5 million towards establishing proof of resource, with a further A$20 million awarded for stage 2 being a grid-connected 12 MW_e geothermal energy demonstration plant upon a successful proof of concept. The proposed stage 1 exploration stage and the stage 2, 12 MW_e demonstration stage of the project will be located on the Holcim (Australia) Pty Ltd Moriac quarry site, 8.5 km north-north-west of the Alcoa brown coal-fired power station at Anglesea, Victoria.

F: Koroit—central Otway Basin, Victoria

Hot Rock Ltd is targeting reservoirs having primary and/or secondary (i.e. faulted or fractured) permeability within the Crayfish Subgroup in the central part of the onshore Otway Basin. Targeted depths are 2800–4000 m with temperature estimated within that depth interval of 140–185 °C. In the Koroit Trough there is an abundance of data from extensive seismic surveys and exploration well drilling and testing carried out by oil and gas explorers over the past 40 years, including 14 oil and gas wells. None of these wells directly penetrate the interpreted geothermal reservoir.

G: Wombat-Seaspray—Gippsland Basin, Victoria

The Wombat Geothermal Play lies approximately 200 km east-south-east of Melbourne within the Gippsland Basin. Greenearth Energy Ltd is targeting a deep sedimentary geothermal play within the basal Rintouls Creek Formation of the Strzelecki Group. Average temperatures are modelled to be 157 °C.

H: Olympic Dam, South Australia

Green Rock Energy Ltd has drilled one deep (approximately 2000 m) exploration well, Blanche-1, only 10 km away from the BHP Billiton Ltd Olympic Dam Special Mining Lease and 5 km from a 275 kV and 132 kV transmission line connected to the NEM grid. The well provides good information on subsurface temperatures and an indication of the temperature gradient within the Roxby Downs Batholith granite body. The inferred temperature at 5500 m is 190 °C. Green Rock has discussed plans for drilling to the east of Blanche-1 where the sediment cover is interpreted to be thicker.

Green Rock has conducted mini-hydrofracturing experiments within Blanche-1 and successfully demonstrated the ability to enhance fractures within the granite, and to do so at multiple levels using removable packers. This demonstrated the ability to create sub-horizontal fracture networks including at deeper levels, and is an important step in testing expected reservoir conditions prior to more expensive drill testing (www.greenrock.com.au).

I, J: CSIRO Geothermal Project, Metropolitan Perth, Alkimos and North Perth Basin—Perth Basin, Western Australia

The Perth Basin is a 1000 km long geological rift containing sediments up to 15 km thick. It contains thick sequences of permeable aquifers with moderate to high thermal gradients recorded in drilling at depths of up to 2000 m.

CSIRO is developing a project at the Australian Resources Research Centre (ARRC) in Kensington with the aim of providing a geothermal solution for cooling the Pawsey Centre Supercomputer (I in figure 7.11) (CSIRO 2013). The first step in the project is to meet the cooling requirements of the supercomputer by using a very shallow (~150 m deep) groundwater cooling system. This system works by pumping cool water from an aquifer beneath the ARRC site, through an above-ground heat exchanger to cool the supercomputer, then reinjecting the now warmer water back into the same aquifer, slightly downstream, resulting in no net consumption of water.

The second phase involves drilling a 3 km-deep exploration well to assess the geothermal resource contained in the hot sedimentary aquifers beneath the ARRC facility. The deep drilling is scheduled to commence in the third quarter of 2013 and take approximately 40 days to complete. If the results obtained are favourable, then the well will be completed as one half of a geothermal production system. The project received a grant of A$19.8 million from the Australian Government's Education Investment Fund. The project is part of the Sustainable Energy for the Square Kilometre Array astronomy project supported by the Department of Industry, Innovation, Climate Change, Science, Research and Tertiary Education. The CSIRO Geothermal Project will also receive financial and in-kind contributions from GT Power Pty Ltd, CSIRO and the Geological Survey of Westren Australia.

In the Metropolitan Perth area, and at Alkimos (I in figure 7.11), Green Rock Energy Ltd is aiming for the development of Australia's first commercial geothermal-powered heating and air-conditioning unit in a commercial building. By replacing a conventional chiller that uses electric energy with an absorption chiller using geothermal energy, large commercial buildings, including universities, hospitals, hotels, airports, data centres and shopping centres can be air-conditioned using hot geothermal water as the principal power source. These projects will need to drill two wells to approximately 3000 m depth to extract water at temperatures greater than 75 °C.

In the North Perth Basin (J in figure 7.11), heat flow is higher than other parts of the basin. Green Rock Energy Ltd is targeting naturally permeable reservoirs, faulted sedimentary reservoirs, as well as deep EGS plays for large-scale electricity generation to supply power to the developing Mid West minerals mines (www.greenrock.com.au).

K: Parachilna, Port Augusta—Torrens Hinge Zone, South Australia

Torrens Energy Ltd considers that the general area of the Adelaide Fold Belt and the Torrens Hinge Zone has the right components for EGS potential, including high heat flow, good potential for high-heat-producing basement including granites, and thick insulating layers.

Torrens Energy received an Australian Government Renewable Energy Development Initiative grant of approximately A$3 million to conduct exploration via heat flow measurements and to build a three dimensional Thermal Field Model. The Treebeard 1A well was drilled to 1807 m and confirmed high heat flow with modelled temperatures in excess of 200 °C at 4500 m. Seismic surveying in the area indicates sediment thicknesses of between 3000 and 4500 m. A basement (i.e. granite) hosted reservoir is the primary target and preferred model for geothermal development at Parachilna. 213

Torrens Energy has also conducted exploration in the immediate vicinity of the Port Augusta power plant where it has demonstrated high heat flow (www2.torrensenergy.com).

L: Fingal and Lemont, Tasmania

The map of predicted temperature at 5 km based on bottom-hole temperature data (figure 7.11) suggests Tasmania has only limited geothermal potential. However, several old measurements show high heat flow values. KUTh Energy Ltd has undertaken an extensive drilling program and confirmed areas of anomalously high heat flows. They have also conducted other surveys and seismic and extensive thermal conductivity measurements to indicate that there is a considerable thickness of low-to-moderate thermal conductivity units above what is interpreted to be deeply buried granites. In addition to that work which has identified a potential EGS resource at Fingal in the north-east Tasmania, an extensive magnetotelluric survey has identified a possibly fractured reservoir in the area around Lemont in the Tasmania Midlands.

M: Frome Basin, South Australia

The Frome project comprises buried Cambrian basins known as the Moorowie and Yalkalpo sub-basins that are underlain by relatively radiogenic Precambrian volcanics and granites rocks of the Curnamona Craton. Frome-12 was drilled to a depth of 1761 m in the centre of a heat anomaly identified from earlier shallow drilling. A bottom of hole temperature of 93.5 °C was recorded shortly after drilling ceased. This can be extrapolated to a temperature of 200 °C at 4080 m (www.geothermal-resources.com.au).

N: Hunter Valley, New South Wales

The Somerville et al. (1994) report highlighted an area of high temperature in the upper Hunter Valley area. This was targeted by Australia's first geothermal company (now Geodynamics Ltd). Although there is little information publicly available about the project, Geodynamics Ltd has reported thermal gradients similar to those found in the Cooper Basin project. Geodynamics Ltd is targeting high-heat-producing Paleozoic granite buried beneath more than 3500 m of Sydney Basin sediments, including coal measures (www.geodynamics.com.au). This project was awarded a A$7 million Geothermal Drilling Program grant, but Geodynamics Ltd has not executed the grant in favour of focusing on other projects.

O: Great Artesian Basin, South Australia and Queensland

The Great Artesian Basin (GAB) is the largest artesian basin in the world, covering about 22 per cent of the Australian continent and has wells producing groundwaters of 30–100 °C at the well head. Australia's only operating geothermal power plant at Birdsville uses water at 98 °C drawn from the basin (O on figure 7.11). The temperature of the water varies across the basin, and is understood to be hottest in north-eastern South Australia. Several companies have exploration leases in this area. The maximum water temperature is thought to be less than 140 °C, which is at the lower limit for generating electricity at a large commercial scale. The added cost of transmission infrastructure is likely to make electricity generation for supply into the NEM uneconomic in the near future; however, local supply is likely to be competitive against power generated by diesel or gas generators (as is the case at Birdsville).

Deep sedimentary geothermal resources

There are several sedimentary basins in Australia where high geothermal gradients are known, including the Otway Basin (South Australia, Victoria), Gippsland Basin (Victoria), Perth Basin (Western Australia), Carnarvon Basin (Western Australia) and the Great Artesian Basin (Queensland, New South Wales, South Australia and Northern Territory). These basins have porous and permeable aquifers at shallow to moderate depths, which means that hot water circulating naturally within them can be readily extracted. However, some fracture enhancement may be necessary in deeper parts of the basins to increase flow rates.

This potential has stimulated significant interest in exploration for geothermal resources in a number of basins, notably the Otway, Gippsland and Perth Basins (box 7.4). For example, shallow groundwater systems in the Perth Basin are being investigated as a potential source of low-temperature energy that could be used for direct heating and other applications. The Otway Basin differs from the other areas in that there is also potential for heat input from dormant volcanic activity that occurred some 5000 years ago. However, previous regional heat-flow data showed no evidence of abnormal heat-flow in the region, including around Mount Gambier—the youngest volcano in the Newer Volcanics group in the south-west Victoria – south-east South Australia region. More detailed heat-flow measurements identified a 40 km-long zone of elevated heat-flow of uncertain origin (including potentially buried granite) along the northern margin of the Otway Basin (Matthews and Beardsmore 2009), and highlighted the need for higher resolution data to identify finer scale variations in heat flow.

Direct heat geothermal resources

Direct-use applications generally require access to low to moderate temperature geothermal resources with at least moderate flow rates. Direct-use applications such as air conditioning for commercial and office buildings via absorption chillers or making fresh water via seawater distillation desalination will generally require access to moderate-depth sedimentary geothermal resources. As mentioned above, these resources are being examined in the Perth Basin.

Ground source heat pumps have potential in Australia, although this technology is most cost effective in geographic locations that have marked seasonal temperature fluctuations. Estimating the full resource potential is somewhat difficult—this technology can be applied anywhere, but local conditions and the cost competitiveness of the technology are important factors in influencing its uptake.

7.3.2 Geothermal energy market

Electricity generation

To date, three geothermal energy projects have been undertaken in Australia that demonstrated geothermal electricity generation technologies (table 7.4).

In 1986, Mulka Station in South Australia used a hot artesian bore (Great Artesian Basin) to produce a maximum 0.02 MW of power. However, as the project utilised a working fluid on the power plant site that was subsequently banned, it has since ceased operation.

The Birdsville plant in south-west Queensland generates 0.08 MW of power. The plant uses a binary-cycle power system, and sources hot (98 °C) waters at relatively shallow depths from the Great Artesian Basin. The water comes from the town's water supply bore, which was not drilled specifically as a geothermal bore. Total electricity generation in 2006 was 1.8 MWh, of which 0.5 MWh was provided by the geothermal power plant with the remainder provided by auxiliary LPG and diesel-powered generators (Ergon Energy 2009). The plant operator, Ergon Energy, has commenced a feasibility study into whether it can provide Birdsville's entire power requirements and relegate the existing LPG and diesel-powered generators to be used only as a back-up to meet peaks in electricity demand.

In early 2013, a pilot plant was successfully commissioned at the Innamincka Deeps Project in the Cooper Basin, South Australia. The 1 MW plant produced Australia's first EGS generated power. The plant has commenced a demonstration trial and testing period until late 2013.

Direct-use applications

There are a number of small direct-use applications of geothermal energy resources in Australia. At Portland in Victoria, water from a single well was used for heating several council-operated buildings including council offices, library and hospital for several years.

Numerous spas and baths using warm spring waters operate in several parts of Australia. These include spa developments (Mornington Peninsula, Victoria and Mataranka, Northern Territory), artesian baths (Moree, Lightning Ridge artesian baths, and Pilliga Hot Artesian bore, inland New South Wales) and swimming pool heating (Challenge Stadium, Western Australia). Ground source heat pumps are used in numerous public buildings, including the Geoscience Australia building in Canberra.

7.4 Outlook for Australia's geothermal energy and market

Australia's considerable high-temperature (above 180 °C) geothermal energy potential associated with deep EGS resources and lower temperature resources associated with hot waters circulating in aquifers in sedimentary basins have potential for electricity production and direct use. The requirements for development of geothermal electricity generation include significant investment, firstly in demonstration projects to prove viable generation, and then in commercialisation. RD&D are likely to continue to play an important role in this process until commercial viability can be established.

Geothermal power has significant benefits. It is environmentally benign (zero emission—one of the lowest life-cycle CO_2 emission profiles of any power generation technology, minimal waste and pollutants), renewable (temperature is renewed by conduction from adjacent hot rocks, and heat is generated by natural radioactive decay), and able to provide base-load power and heat for industrial processes. Ground source heat pumps have been proven to be viable in various parts of Australia, and widespread implementation could provide a significant energy efficiency and carbon reduction benefit.

7.4.1 Key factors influencing the future development of Australia's geothermal energy

The geothermal sector in Australia is characterised by being mostly at low commercial readiness levels, and at an early stage of the innovation cycle. Projects range from the pilot stage to early stage exploration. A number of research centres have been established in Australia, with several PhD projects having been completed and more under way. The success of the industry and research projects may assist in lowering the perception of risk and future investment in the sector.

In numerical terms, Australia's existing indicated geothermal resources are sufficient to meet expected domestic demand over the next few decades. However, in the period between these resources being identified and early 2013, demand in the National Electricity Market has fallen, meaning that several of these resources are unlikely to be developed. Some of Australia's geothermal resources lie remote from the existing electricity transmission grid, and may be well located to displace expensive diesel-fuelled generation.

There is scope for Australia's geothermal resources to expand substantially, based on further predicted temperature at 5 km data, heat-flow measurements and enhanced geological and engineering knowledge about how geothermal resources in Australia can be exploited. This in turn could affect the market outlook as several expected proof-of-concept projects demonstrate the suitability of the technology to Australia and commercial demonstration projects are established.

Government support for geothermal energy research, development and demonstration

Government policies relating to geothermal energy research, development and demonstration (RD&D) are important to the outlook for electricity generation from geothermal energy in Australia. Actions to accelerate the development of the geothermal industry include completion of the Australian Geothermal Industry Development Framework and the associated Australian Geothermal Industry Technology Roadmap (box 7.5). The Australian Government has supported the geothermal industry through its former

Table 7.4 Geothermal energy projects in Australia

Project	Company	State	Start-up	Capacity (MW)
Mulka Station	Mulka Station	SA	1986 (ceased operations)	0.02
Birdsville	Ergon Energy	QLD	1992	0.08
Innamincka Deeps	Geodynamics	SA	2013	1

Source: Compiled from publicly available reports by Geoscience Australia programs, Renewable Energy Demonstration Program and Geothermal Drilling Program in providing grants to support proof-of-concept projects. The current Australian Renewable Energy Agency A$126 million Emerging Renewables Program supports the development of renewable energy technologies in Australia across the innovation chain.

Better definition of geothermal resources—improved basic geoscientific data to enhance development prospects for geothermal energy

The OZTEMP database of bottom-hole temperatures is largely populated by petroleum drilling results. Of necessity, this dataset is biased towards particular geological settings (i.e. basins). Geothermal resources are not limited to the same geological settings as petroleum resources. Not only is the geographical distribution of this data uneven and inadequate, measurements of bottom-hole temperatures are not robust for predicting temperature at depth.

Heat-flow measurements are normally significantly more robust indicators of temperature at depth, as they incorporate temperature gradient and thermal conductivity data but only in the intervals measured. Regardless of whether using bottom-hole temperatures or heat-flow determinations, other geological data at depth, including lithology (and therefore thermal conductivity and capacity) are very important to make confident temperature extrapolations. Both the number and distribution of publicly available heat-flow measurements, and the knowledge of geology at depth, are inadequate for efficient geothermal exploration in Australia.

Given the potential for geothermal energy in the future, there is support for government programs to increase the collection and dissemination of pre-competitive geoscientific data to guide future geothermal exploration (see, for example, Hogan 2003). A geothermal resources database will also complement private sector activity in the geothermal industry and enhance prospects for future geothermal energy development in Australia (see box 7.6).

Geothermal RD&D and technology development

Development of a geothermal project involves the consideration and evaluation of a number of factors, such as site (geography), geology, reservoir characteristics, geothermal temperature, plant size and type, access to market and grid. The two main factors affecting the total cost of electricity in deep geothermal schemes include the cost of drilling each well, and the average productivity of the wells (BREE 2012a).

There is significant uncertainty associated with well completion cost because of the considerable variance between wells drilled to date in Australia. Further, the production rates of wells are not well defined, as there is only a limited database to draw upon with only seven wells having been drilled into geothermal reservoirs. Currently, it is necessary to drill expensive production-scale wells for exploration purposes to determine if there is sufficient permeability for a viable project.

Projections of costs to 2050 associated with existing technology for deep sedimentary and EGS schemes are illustrated in figure 7.12 using a levelised cost of energy (LCOE) approach for a very limited segment of the possible future market. Figure 7.12 indicates that the LCOE for deep sedimentary schemes and EGS is projected to increase slightly from 2012 to 2050 in New South Wales. However, looking further afield, fracturing technologies used to develop shale gas resources in the United States and Canada (and in other jurisdictions worldwide) have potential to reduce the per-well and electricity generation costs of deep sedimentary schemes and EGS in Australia by lowering the cost of wells. Further, the uptake of geothermal development will not be restricted to New South Wales, and this will lead to greater learning-while-doing and hence lowering costs. The adaptability and usability of fracturing technologies for deep sedimentary schemes and EGS has not yet been tested in Australian conditions, and therefore has not been taken into account in setting these future costings.

BOX 7.5 AUSTRALIAN GEOTHERMAL INDUSTRY DEVELOPMENT FRAMEWORK

The Australian Geothermal Industry Development Framework and the associated Australian Geothermal Industry Technology Roadmap were released in December 2008 (Australian Government Department of Resources, Energy and Tourism 2008a, 2008b). The framework recognised that Australia's geothermal industry is at a very early stage of development and identified major challenges for the future of the industry, including the development of:

- an attractive investment environment in which early stage ventures are able to mature to a level sufficient to attract private finance
- accurate and reliable information on geothermal energy resources in Australia
- networks that encourage sharing of information and experience between stakeholders including companies, researchers and governments in Australia and overseas
- geothermal technologies suited to Australian conditions
- a skilled geothermal workforce
- community understanding and support of the economic, environmental and social benefits of geothermal energy
- a geothermal sector which understands and contributes to the institutional environment within which it operates
- a consistent, effective and efficient regulatory framework for geothermal energy.

BOX 7.6 IMPROVING KNOWLEDGE OF AUSTRALIA'S GEOTHERMAL POTENTIAL

Because of the inadequate geoscience data available to the industry in Australia, exploration has only been undertaken in those areas having useful data. A good understanding of geology is a prerequisite for developing geothermal resources and the knowledge required is scale dependent.

In selecting tenement areas for more detailed exploration for geothermal resources in Australia, companies rely on publicly available, pre-competitive regional-scale geological data, as companies only have the right to collect information on ground that they have under lease. Once a company has taken out a lease area, it then explores in increasing detail for the small volume of rock that will produce the most profitable geothermal resource.

Publicly available geoscience data that is sought for evaluation by the geothermal exploration companies comes from:

- geophysics including seismic reflection, gravity, magnetic and magneto-telluric surveys
- stratigraphic drilling in key locations and thermal conductivity measurements for key stratigraphic units throughout the country
- accurate depth to conductive basement maps based on the activities above
- down-hole temperature measurements
- granite geochemistry, particularly of buried units
- stress measurements and geodynamic history so that fracture patterns may be predicted
- basin fill and inversion history so that permeability may be predicted, and also mapping of groundwater
- assessments of risks posed by geothermal developments (including radiation/radon, induced seismicity).

Many of these data types are already being collected to varying degrees by Geoscience Australia and state and territory geological surveys, but this has not been done in a systematic manner with geothermal energy in mind. Some database development is required to incorporate new data types (such as thermal conductivity) and to make existing data more accessible. Also, data generated by companies and reported as part of lease requirements needs to be captured and made available.

In order to evaluate reservoir quality and reservoir size, companies conduct all of the above as well as more detailed studies in their exploration leases, such as:

- *in situ* porosity and permeability measurements or their proxies
- detailed measurements of crustal stress distribution, including down-hole stress measurements
- enhanced seismic monitoring, including temporary deployment of detailed monitors during hydraulic stimulation
- fluid chemistry and rock mineralogy to predict the effects of scaling (mineral deposition that may inhibit fluid flow either in the rock fracture network or in the piping or power plant)
- fluid chemistry for use as a geothermometer in exploration, and for studies of fluid–rock interaction to predict and develop mitigation strategies for scaling and corrosion during production.

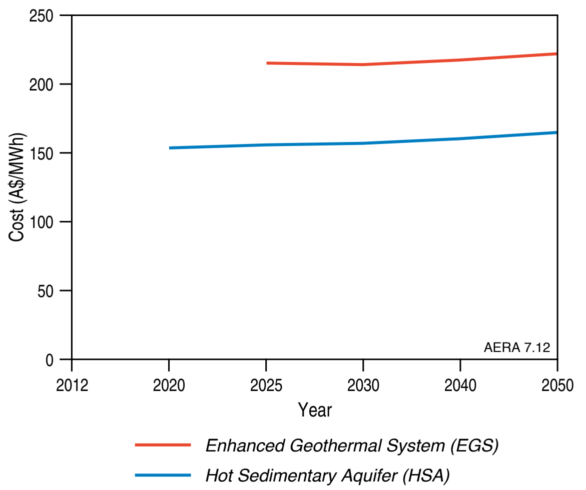

Figure 7.12 Levelised cost of energy for deep sedimentary system and Enhanced Geothermal System (EGS), in New South Wales

Source: BREE 2012a

Further research in the exploration and enhancement of reservoirs and in drilling and power generation technology, particularly for the exploitation of low-temperature geothermal resources, will be important in realising potential in this area (IEA 2008; box 7.3). Technology developments in oil and gas production and carbon storage, such as horizontal wells, expandable solid tube technology, rock fracturing and improved seismic technology, will also benefit geothermal electricity generation (IEA 2006).

The development of the geothermal industry in Australia is not dependent on technology breakthroughs—all of the required technology exists from the conventional geothermal and petroleum industries. The challenges in Australian geothermal systems are making exploitation more economically viable (for example, through cheaper drilling), which requires incremental technological adaptation and development.

The demonstration that geothermal technology is on the path to commercial readiness in the Australian energy market is required for the future development of the industry. Ground source heat pumps have already been demonstrated to be economically and environmentally beneficial in numerous installations in Australia.

The geothermal industry is relatively new to Australia; only limited research has been conducted to date. Several research centres have been established, but some have already run their term and others have a short remaining life. These centres include:

- The Queensland Geothermal Energy Centre of Excellence at the University of Queensland was established in 2009 to assist the uptake of geothermal power generation through research under the program headings of (a) Heat Source Discovery and Characterisation, (b) Power Conversion, (c) Air-Cooled Condensers (ACC) and (d) Transmission. The centre's funding term expires in 2014.
- The Western Australian Geothermal Centre of Excellence investigated direct-use applications of geothermal energy including absorption chillers, and completed its term in 2011.
- The University of Adelaide's South Australian Centre for Geothermal Energy Research was established in 2010 to research exploration and fracturing techniques. Funding expired in 2013.
- The University of Newcastle has a small program researching power cycle technology.

The cost of geothermal energy

The costs of hydrothermal energy have dropped substantially since the 1970s and 1980s—overall, costs fell by almost 50 per cent from the mid 1980s to 2000. Upfront costs, comprising mainly of exploration, well drilling and plant construction, can be up to 70–80 per cent of the overall costs of geothermal electricity, depending on the technology. For example, drilling costs can account for as much as one-third to one-half of the total cost of a geothermal project (IEA 2008). Operation and maintenance costs account for a very small percentage of total costs, but can vary depending upon the location of the plant.

Unconventional geothermal energy has only been deployed commercially in a few locations worldwide but is being tested and developed at a number of locations. Like conventional geothermal power systems, unconventional geothermal systems have high up-front costs, up to 70–80 per cent of total costs, in developing the well field at the geothermal resource. Hot Sedimentary Aquifer geothermal technology is expected to be cheaper than EGS technology because it generally involves shallower drilling; however, high flow rates are required meaning that overall resources risks may not be lower than for EGS. Geothermal drilling costs tend to rise exponentially with drilling depth because of the extra time taken in pulling drill lengths into and out of a deepening well (figure 7.13). Company reports indicate that the cost of wells drilled to a well depth of 4–5 km in Australia have been in the range of A$8–51 million.

The cost of electricity produced from unconventional geothermal energy sources is expected to rise over the next 10–20 years (figure 7.12). A considerable advantage that geothermal electricity generation has over other renewable energy generators is that it is base load with high capacity and availability factors (each greater than 90 per cent). It will classify as a 'scheduled generator' under the Australian electricity market rules in the eastern half of Australia.

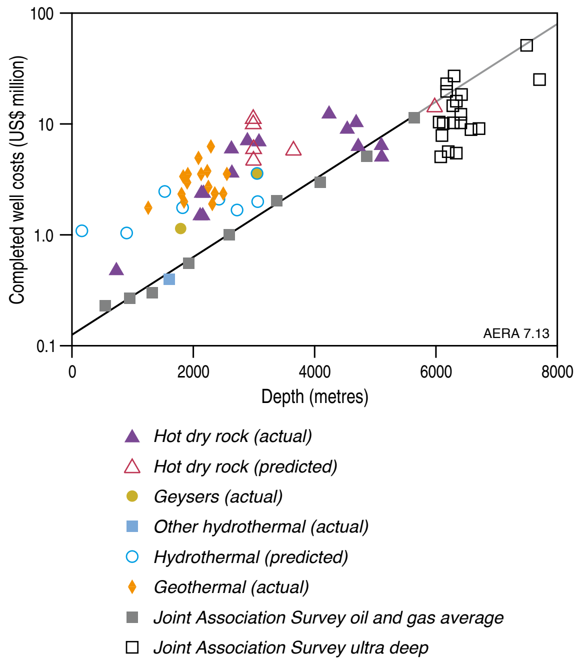

Figure 7.13 Completed well costs as a function of depth

Source: Augustine et al. 2006

Cost of access to the grid

An impediment to the development of some of Australia's geothermal resources for geothermal electricity generation is the distance of some of the resources from existing transmission lines or consumption centres. Geothermal plants are built at the site of the reservoir since it is not practical to transport geothermal resources (i.e. hot water) over long distances. High-voltage direct current transmission lines can be beneficial because for a given carrying power capacity they have less line loss (MIT 2006).

Additional power lines must be built if transmission infrastructure does not exist where a geothermal resource is located. Some of Australia's known geothermal resources are located in areas remote from the existing electricity transmission grid. Elsewhere in the world, geothermal developers pay the direct costs to connect their plant to the grid, and may incur additional transmission related costs, including the construction of new lines, upgrades to existing lines, or new transformers and substations (Kagel 2006).

This impediment may be lessened by the National Electricity Market rules by the Australian Energy Market Commission that include a framework for the connection of generation clusters in the same location over a period of time. The framework provides commercial incentives for network businesses to bear the risk of building assets to an efficient scale (AEMC 2009, 2014). This is called Scale Efficient Network Extension (SENE) and will assist geothermal (and other renewable energy) projects to overcome the relatively high cost of accessing the electricity grid. The geothermal industry is investigating the cost impacts of transmission connection to the National Electricity Market. One study focusing on connection from the Cooper Basin to Port Augusta via the Arrowie Basin suggests benefits to both generators and customers if the transmission network is built to coincide with the onset of geothermal production (MMA 2009).

There is scope for some industries to co-locate to new geothermal generators. For example, Geodynamics Ltd has been investigating the establishment of a large data centre at Innamincka in the Cooper Basin. In this case it is cheaper to lay fibre optic cable than power lines to the major centres.

The modular nature of geothermal developments (i.e. grown in increments of few megawatts with each additional injector/producer capacity), coupled with remote locations, is potentially well suited to off-grid markets (e.g. mine site developments, small to moderate sized communities), where geothermal may provide a cost-effective alternative to diesel-fuelled generation.

Environmental considerations

Geothermal energy is generally regarded as one of the most environmentally benign sources of electricity generation.

Air emissions and other pollutants

Geothermal fields in Australia will generally utilise deep groundwater systems (not used for any other purpose), and will have very few air emissions as the systems use closed-loop binary power plants at surface. Some concerns have been raised over radon release; however, these are projected to be well within Australian occupational health and safety guidelines (PIRSA 2009). The only emissions created are in building infrastructure (well completion, plant, power lines), which is necessary for all generation technologies. There are no emissions associated with the 'fuel'. Some volcanic systems used in other parts of the world emit CO_2 as a natural part of magma outgassing: this is a natural process that happens whether used for geothermal power production or not, and Australia has no such active volcanism. In comparison to other generation technologies, geothermal energy has a low life cycle emissions profile. Dissolution from within the geothermal reservoir may cause the deposition of a limited quantity of salts and minerals during flow testing and production.

Noise pollution

Geothermal plants produce noise during the exploration drilling and construction phases. With direct-heat applications, noise is usually negligible during operation. Noise from normal operation of power plants generally comes from the cooling tower fans, steam ejector and turbine.

Water usage

Geothermal systems in Australia are generally expected to be operated as closed-loop systems for a number of reasons, including water conservation. For Hot Rock developments, the loss of water injected into the artificial reservoir would result in operational inefficiencies through higher pumping costs and lower energy returns than optimal and are therefore to be avoided as much as possible. In Hot Sedimentary Aquifer systems, water needs to be returned to the originating aquifer otherwise the reservoir pressure will be depleted and water returns will be reduced. In Hot Rock systems requiring hydraulic stimulation to enhance the reservoir permeability, water will need to be introduced from the surface during the fracturing process. This is in the order of tens of megalitres to create a reservoir volume of up to 10 cubic kilometres. As it is a one-off use, this water will generally continue to serve as the circulation fluid during production. As they will generally be working in areas of very low rainfall, Australian geothermal developers are mostly planning to use air-cooled power stations. Some research is being conducted into using ground-loop cooling or novel air-cooled systems to assist power plant efficiency during peak daytime temperatures, and also to using solar energy to boost input water temperatures to increase power plant efficiencies. Other generators of power may also benefit from this technology.

Subsidence

This was found to be a problem during some early conventional geothermal developments overseas. Reinjection of groundwater became a common practice to prevent this. Geothermal reservoirs in Australia are considerably deeper than conventional reservoirs overseas, and this combined with reinjection mean that subsidence is unlikely to be of concern.

Induced seismicity

This term is used to describe earth movements generated by human activities. Induced earth movements are associated with the movement of material into or out of the earth; for example, during water reservoir filling, underground mining, oil and gas extraction, compressed carbon dioxide injection, and development of Hot Rock reservoirs. The hydraulic stimulation process employed in the creation of Hot Rock reservoirs will induce seismic activity, which can be detected by sensitive seismological instruments (Lewis 2008). In over 30 years of hydraulic stimulation in Hot Rock developments overseas and more recently in Australia, there have been no instances of damage caused by earthquakes directly attributed to hydraulic stimulation. Substantial knowledge is being gained about controlling the incidence of microfracturing by varying the rates and pressures of fluid injection. Ultimately this will lead to better reservoir development with minimal risk from unwanted seismicity. Earthquakes are commonly reported using a 'magnitude' scale, and this describes the intensity of the earthquake at its origin: it does not provide information on the effects at surface, which can be many kilometres above and away from the point of origin. Ground motion sensors provide information about the extent of movement at a point on the surface and are a significantly better way of monitoring the surface effects of induced seismicity.

Land Use

Geothermal power developments occupy relatively little ground compared to other types of power station, and have a low vertical profile. Geothermal developments can be compatible with other land uses such as forestry and farming.

7.4.2 Outlook for geothermal energy market

Geothermal energy developments occurring in Australia are focused on electricity generation (table 7.5). Several companies have plans for pilot and demonstration plants, and some for commercial generation.

The commercial development of the industry is dependent on the demonstration in Australia of a pathway to commercial readiness to show an acceptable investment risk, and this includes grid connection issues. No technology breakthroughs are needed, but advances in technologies that reduce costs will potentially lead to greater market penetration by geothermal energy.

Proposed development projects

The development of a geothermal project requires consideration and evaluation of a number of factors, such as site (geography), geology, reservoir characteristics, plant size and type. While the majority of the overall cost of a geothermal scheme is typically associated with power plant construction in hydrothermal schemes, well drilling comprises the major component of unconventional systems as found in Australia.

There are two main factors affecting the total cost of geothermal wells—the cost of drilling each well, and the average productivity of the wells. It is difficult to predict the well completion cost as there is significant variance in costs achieved to date in Australia. In addition to this uncertainty, the production rate of the wells is not well defined, with only four projects having been drilled and flow tested, and just one of those including flow testing through the reservoir between an injection and production well.

The Geodynamics Ltd project in the Cooper Basin in South Australia is one of the most advanced EGS projects in the world and Australia. Geodynamics Ltd completed proof-of-concept at their Habanero prospect in early 2009. A well-control incident caused the loss of the Habanero-3 well just prior to the establishment of a 1 MW pilot plant, but Geodynamics have completed Habanero-4 in preparation for pilot plant testing during early 2013. Geodynamics Ltd's tenements in the Cooper Basin have been shown to contain more than 400 000 PJ of high-grade thermal energy.

In November 2009 Geodynamics Ltd was awarded a A$90 million Renewable Energy Demonstration Program grant to assist the commercial demonstration project.

Petratherm Ltd has completed drilling well Paralana-2 at its Mt Painter Paralana project. Together with joint venture partner Beach Petroleum, the project aims to build a 7.5 MW pilot plant to supply power to nearby uranium mines by 2018 and to then scale up to a 30 MW demonstration plant connected to the NEM grid (table 7.5). In April 2009 Petratherm Ltd was awarded a A$7 million Geothermal Drilling Program grant, and in November 2009 was awarded a A$62.75 million Renewable Energy Demonstration Program grant to assist development of their demonstration project. In late 2012, although Petratherm Ltd successfully completed hydraulic stimulation and flow testing in Paralana-2, it has been unable to gain matching funding for the grants for the drilling of Paralana-3 and additional works, and activity has stalled.

Panax Geothermal Ltd drilled the Salamander-1 well at the Penola project, having received a A$7 million grant from round 1 of the Geothermal Drilling Program. Panax Geothermal Ltd had plans for the rapid development of a 59 MW (net) commercial plant at its Penola project in the Limestone Coast area of South Australia (Panax Geothermal Ltd 2009), but the failure to attain high flow rates from Salamander-1 has delayed activity while the causes are investigated, including through the 'Reservoir Quality in Sedimentary Geothermal Systems' research project.

The Geelong Geothermal Power Project, a power generation project being developed by Greenearth Energy, is initially planned to add 12 MW to capacity by 2016 and 140 MW ultimately by 2020. The site for the stage 1 exploration stage and the stage 2 demonstration stage (12 MW) of the project will be located on the Holcim (Australia) Pty Ltd Moriac quarry site, 8.5 km north-west of the Alcoa brown coal-fired power station at Anglesea, Victoria. The Victorian Government has awarded a A$25 million funding arrangement via the state government's Energy Technology Innovation Strategy program for drilling and a 12 MW power plant demonstration.

Green Rock Energy Ltd plans to develop the Mid West Geothermal Power Project in the North Perth Basin, Western Australia, initially targeting naturally permeable and faulted sedimentary reservoirs (Green Rock Energy Ltd 2012). In June 2012 the company successfully applied for A$5.38 million from the Western Australian Government's Low Emissions Energy Development program. Since then Green Rock Energy Ltd has been working on selecting the most prospective drilling location, and attracting further investment, with the intention of drilling the first well in 2014.

With the above number and diversity of advanced projects, and others at earlier stages, it is likely that at least one project will succeed commercially in the next decade. This can be expected to create a momentum that accelerates development of future projects.

Table 7.5 Projects at a feasibility stage of development, as at October 2013

Project	Company	Location	State	Estimated start up	Estimated new capacity (MW)	Indicative cost estimate (A$million)
Geelong Geothermal Power Project	Greenearth Energy Limited	Geelong	Vic	2016 (2020 Commercialisation)	12 intially (140 ultimately)	75
Koroit	Hot Rock Limited	15 km NE of Port Fairy	Vic	2016	50 (initial pilot)	na
Paralana	Petratherm/Beach Petroleum	Moomba	SA	2018 (7.5MW in 2018 and up to 600MW by 2025)	60	75

na = not available

Source: BREE 2012b; CSIRO 2013; Geodynamics Ltd 2012; Greenearth Energy Ltd 2012; Green Rock Energy Ltd 2012; Petratherm Ltd 2012

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Chapter 8

Hydro Energy

8.1 Summary

KEY MESSAGES

- Hydroelectricity is a mature electricity generation technology, currently used in some 150 countries.
- Hydroelectricity is an important energy source in a large number of countries, although its current share in total primary energy consumption is only 2.3 per cent globally and 0.8 per cent in Australia.
- Hydroelectricity currently accounts for the largest share of Australia's renewable electricity but there is limited potential for future further development.
- Water availability is a key determinant of future growth in hydroelectricity generation in Australia.
- Future growth in Australia's hydroelectricity generation will be underpinned by the development of small-scale hydroelectricity plants and efficiency gains from the refurbishment of large-scale hydroelectricity plants.
- Pumped storage hydroelectricity may be an important tool for managing variable renewable energy supply such as wind or solar energy.

8.1.1 World hydro energy resources and market

- Global technically feasible hydro energy potential is estimated to be over 15 500 TWh per year.
- World hydroelectricity generation was 3431 TWh in 2010, and has grown at an average annual rate of 2.7 per cent since 2000.
- The existing world hydro energy capacity was estimated to be about 1010 GW in 2010. The hydro energy sector is growing at more than 20 GW a year, with China accounting for the majority of new capacity.
- Hydro energy is the largest source of renewable energy, and currently contributes more than 16 per cent of world electricity production and about 85 per cent of global renewable electricity.
- Among the OECD economies, hydroelectricity generation is projected by the International Energy Agency (IEA) to increase at an average annual rate of only 0.6 per cent between 2010 and 2035. Growth will be restricted by limited undeveloped hydro energy potential.
- In non-OECD countries, hydroelectricity generation is projected by the IEA to increase at an average annual rate of 2.4 per cent between 2010 and 2035, reflecting large, undeveloped potential hydro energy resources in many of these countries.

8.1.2 Australia's hydro energy resources

- Australia's technically feasible hydro energy potential is estimated to be around 60 TWh per year.
- Australia is the driest inhabited continent on Earth, with over 80 per cent of its landmass receiving an annual average rainfall of less than 600 mm per year and 50 per cent of the landmass receiving less than 300 mm per year.
- Climate models suggest long-term drying over southern areas of Australia during autumn and winter, which will be superimposed on larger natural rainfall variability, resulting in Australia having variable surface water resources.
- Australia has 124 operating hydroelectricity plants with total installed capacity of about 8500 MW (figure 8.1).

8.1.3 Key factors in utilising Australia's hydro energy resources

- Potential for the development of new large-scale hydroelectricity plants in Australia is limited. However, the upgrade and refurbishment of existing hydroelectricity infrastructure will increase efficiency and extend the life of plants.
- There is potential for small-scale hydroelectricity developments in Australia, and this is likely to be an important source of future growth in capacity.

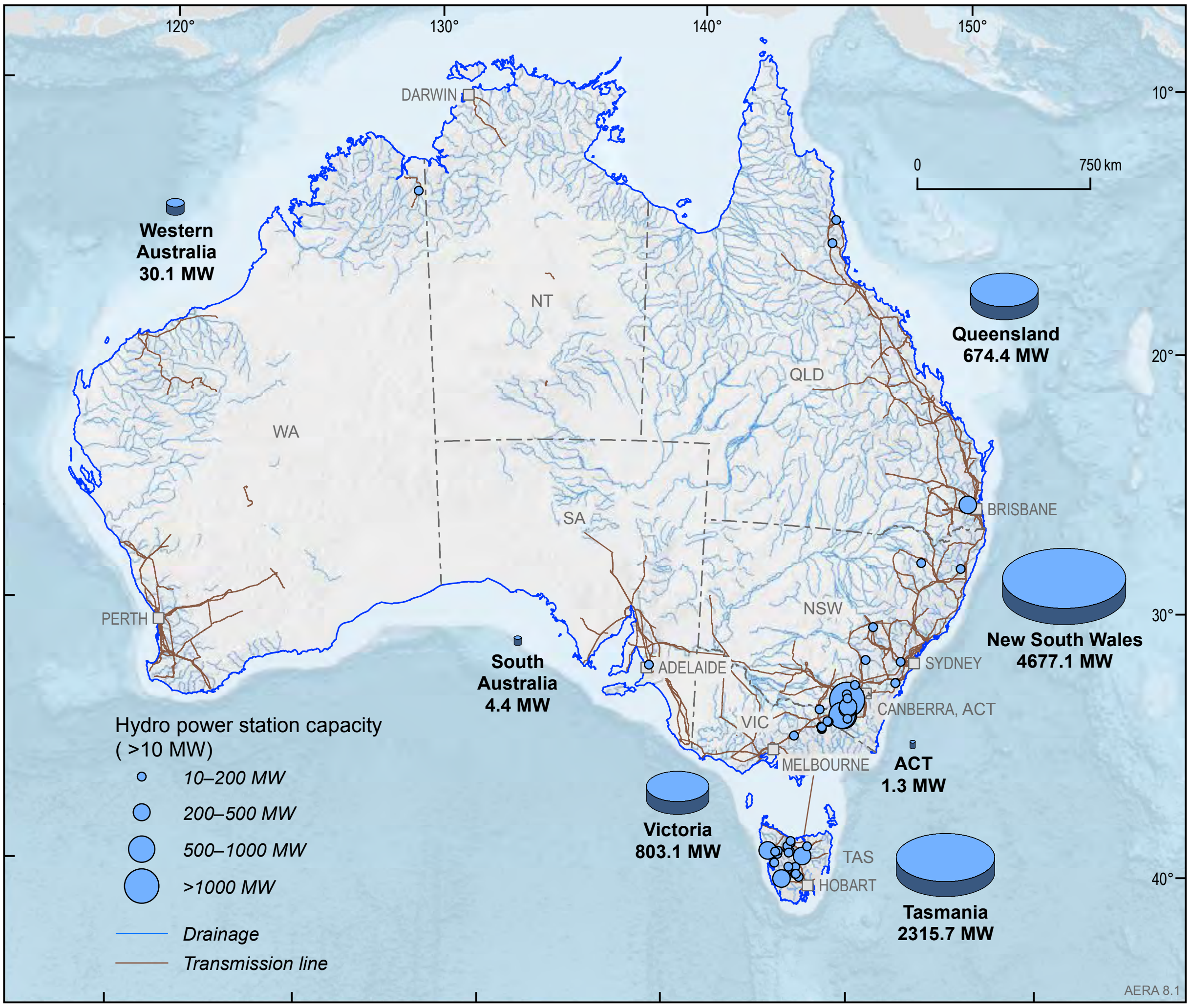

Figure 8.1 Major Australian operating hydroelectricity plants with capacity of greater than 10 MW

Source: Clean Energy Council; Geoscience Australia

- Pumped storage hydroelectricity as a form of energy storage may be important where it can be used for managing variable renewable energy supply such as wind or solar energy.
- Water availability, competition for scarce water resources, and broader environmental factors are key determinants of future growth in Australian hydroelectricity generation.

8.1.4 Australia's hydro energy market

- In 2011–12, Australia's hydroelectricity use represented 0.8 per cent of total primary energy consumption and 5.6 per cent of total electricity generation. Hydroelectricity use has declined on average by 1.6 per cent per year between 1999–2000 and 2010–11. However, hydroelectricity generation was higher in 2010–11, supported by increased water inflows after a sustained period of drought.
- In 2011–12, hydroelectricity was mainly generated in the eastern states, including Tasmania (60.5 per cent of total hydroelectricity generation), New South Wales (26.9 per cent), Victoria (7.5 per cent) and Queensland (5.1 per cent).
- Hydro energy is expected to be overtaken by wind as the leading renewable source of electricity generation in the next few decades.

8.2 Background information and world market

8.2.1 Definitions

Hydro energy is the energy taken from falling water from reservoirs or flowing water from rivers, streams or waterfalls (run-of-river) and is converted to electricity via water turbines. The pressure of the flowing water on the turbine blades causes the shaft to rotate and the rotating shaft drives an electrical generator which converts the motion of the shaft into hydroelectricity. Most commonly, water is dammed and the flow of water out of the dam to drive the turbines is controlled by the opening or closing of sluices, gates or pipes. This is commonly called penstock.

Hydroelectricity has been used in some form since the 19th century. The main technological advantage of hydroelectricity is its ability to be used for base or peak load electricity generation, or both. In many countries, hydroelectricity is used for peak load generation, taking advantage of its quick start-up and its reliability. Hydroelectricity is a relatively simple but highly efficient process compared with other means of generating electricity, as it does not require combustion. Hydroelectricity has the advantages of low greenhouse gas emissions, low operating costs, and a high ramp rate (quick response to electricity demand). Hydro energy is considered an option for synchronous generation, where a plant has a synchronous generator that provides some natural damping of any frequency deviation by automatically releasing or absorbing stored rotational energy as appropriate.

Hydroelectricity is the most advanced and mature renewable energy technology and provides some level of electricity generation in more than 150 countries worldwide.

Plants can be built on a large or small scale, each with its own characteristics:

- Large-scale hydroelectricity plants (greater than 50 MW) generally involve the damming of rivers to form a reservoir. Turbines are then used to capture the potential energy of the water as it flows between reservoirs. This is the most technologically advanced form of hydroelectricity generation.
- Small-scale hydroelectricity plants, including mini (less than 5 MW), micro (less than 500 kW) and pico plants, are still at a relatively early stage of development in Australia, and are expected to be the main source of future growth in hydroelectricity generation. While there is no universally accepted definition of small-scale hydroelectric projects, small projects are generally considered as those with less than 10 MW capacity.

Within these two broad classes of hydroelectricity plants, there are different types of technologies, including pumped storage and run-of-river (box 8.1). The type of system chosen will be determined by the intended use of the plant (base or peak load generation), as well as geographical and topographical factors. Each system has different social and environmental impacts which must be considered.

In this report, electricity generated from wave and tidal movements (coastal and offshore sources) is treated separately to that generated by harnessing the potential energy of water in rivers and dams (onshore sources). Wave and tidal energy is discussed in chapter 11.

8.2.2 Hydro energy supply chain

Figure 8.2 is a representation of hydroelectricity generation in Australia. In Australia virtually all hydroelectricity is produced by energy plants at water storages created by dams in major river valleys. A number have facilities to pump water back into higher storage locations during off-peak times for re-use in peak times. Electricity generated by the water turbines is fed into the electricity grid as base load and peak load electricity and transmitted to its end use market.

8.2.3 World hydro energy market

Hydro energy is a significant source of low-cost electricity generation in a wide range of countries. At present, production is largely concentrated in China, North America, OECD Europe and South America. However, many African countries are planning to develop their considerable hydro energy potential to facilitate economic growth. World hydroelectricity generation is projected to grow at an average annual rate of around 2 per cent to 2035, largely reflecting the increased use of hydroelectricity in non-OECD economies (IEA 2012b).

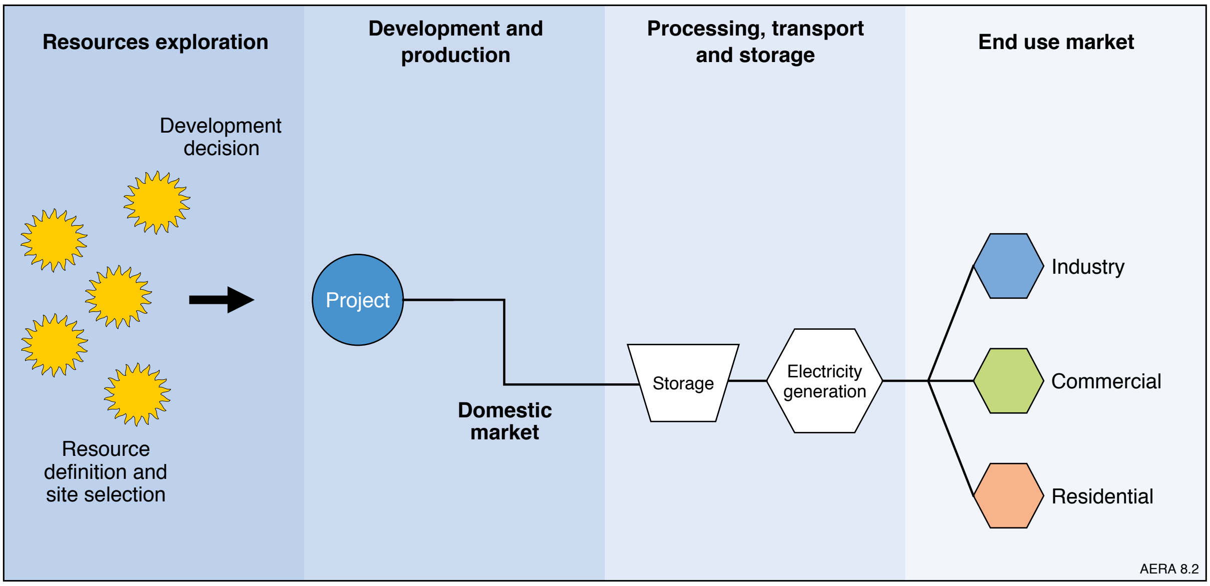

Figure 8.2 Australia's hydro energy supply chain

Source: Bureau of Resources and Energy Economics; Geoscience Australia

Resources

Most countries have some potential to develop hydroelectricity. There are three measures commonly used to define hydro energy resources:

- Gross theoretical potential—hydro energy potential that is defined by hypothesis or theory, with no practical basis. This may be based on rainfall or geography rather than actual measurement of water flows.
- Technically feasible—hydro energy potential that can be exploited with current technologies. This is smaller than gross theoretical potential.
- Economically feasible—technically feasible hydro energy potential which can be exploited without incurring a financial loss. This is the narrowest definition of potential and therefore the smallest.

The world's total technically feasible hydro energy potential is estimated to be over 15 500 TWh per year (UNESCO 2012). Regions with high precipitation (rainfall or melting snow) and significant topographic relief enabling good water flows from higher to lower altitudes tend to have higher potential, while regions that are drier, flat or do not have strong water flows have lower potential. Asia, Africa and the Americas have the highest feasible potential for hydroelectricity (figure 8.3).

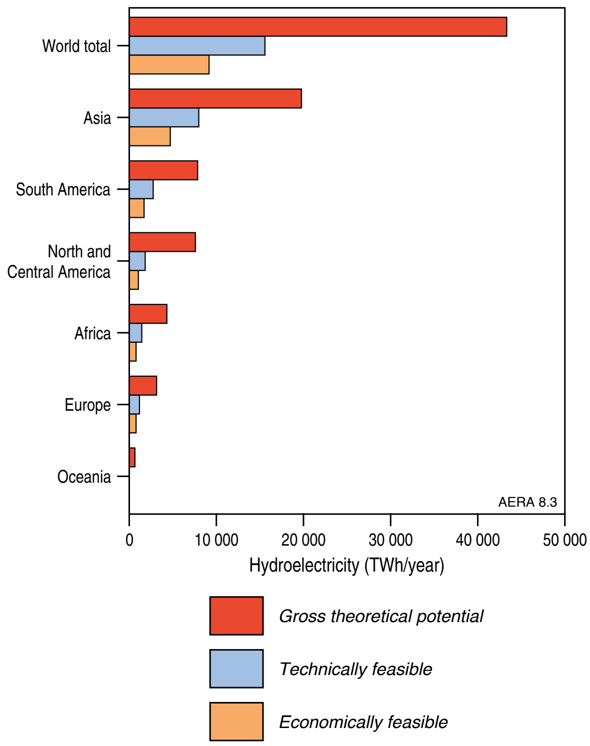

Figure 8.3 World hydroelectricity potential, by region

Source: UNESCO 2012

China's hydro energy resources are the largest of any country. China is estimated to have a theoretical potential of more than 6000 TWh per year, approximately double current world hydroelectricity generation, and a technically feasible hydro energy potential of more than 2470 TWh per year (UNESCO 2012). China is home to the largest single hydroelectricity plant in the world, Three Gorges, with an installed capacity of 22 400 MW and an expected annual electricity generation of 80 to 100 TWh (IPCC 2011). In 2012, China installed 14 000 MW of new hydro energy capacity, accounting for 64 per cent of the world's new additional hydro energy capacity (Bloomberg 2013).

In South America, the highest technically feasible hydro energy potential is in Brazil, where it exceeds 1250 TWh per year. The Itaipú hydroelectricity plant is the world's second largest plant, which supplies electricity to Brazil and Paraguay. The Itaipú hydroelectricity plant has an installed capacity of 14 000 MW with a maximum annual electricity generation of 94.7 TWh.

Other countries with substantial technically feasible hydro energy potential include Canada, Congo, Ethiopia, India, Indonesia, Norway, Peru, Russia and the United States. Nevertheless, almost all countries have some hydro energy potential.

Australia's theoretical hydro energy potential is estimated to be 265 TWh per year and has a technically feasible hydro energy potential of about 60 TWh per year, which is considered to be relatively small (figure 8.4). Rainfall in Australia is highly variable. Climate models suggest long-term drying over southern areas during autumn and winter, which will be superimposed on large natural variability such as wet years becoming less frequent and dry years more frequent (CSIRO and BOM 2012).

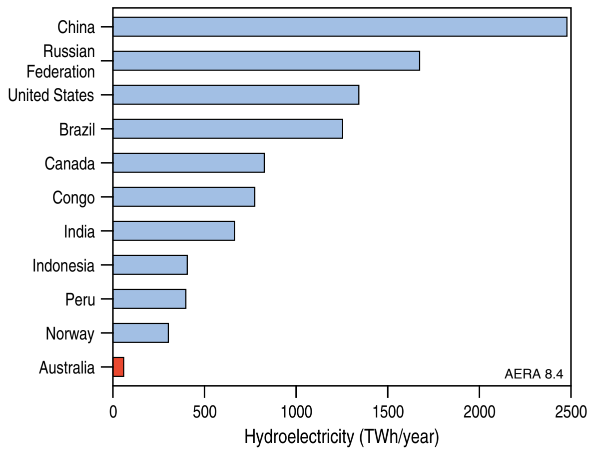

Figure 8.4 Gross theoretical hydroelectricity potential, major countries

Source: UNESCO 2012

Primary energy consumption

Hydroelectricity generation has been growing globally, reflecting its increasing popularity in developing economies as a relatively cheap, simple and reliable source of energy (figure 8.5).

BOX 8.1 HYDROELECTRICITY TECHNOLOGIES

Hydroelectricity generation

The energy created depends on the force or strength of the water flow and the volume of water. As a result, the greater the difference between the height of the water source (head) and the height of the turbine or outflow, the greater the potential energy of the water. Hydro energy plants range from very small (10 MW or less) to very large individual plants with a capacity of more than 2000 MW and vast integrated schemes involving multiple large hydro energy plants. Hydro energy is a significant source of base load and, increasingly, peak load electricity in parts of Australia and overseas.

Rivers potentially suitable for hydroelectricity generation require both adequate water volume through river flows, which is usually determined by monitoring using stream gauges, and a suitable site for dam construction. In Australia virtually all hydro energy is produced by plants at water storages created by dams in major river valleys. Many have facilities to pump water back into higher storage locations during off-peak times for re-use in peak times. In some cases, the hydro energy plant can be built on an existing dam. The development of a hydro energy resource involves significant time and cost because of the large infrastructure requirements. There is also a requirement for extensive investigation of the environmental impact of damming the river. This generally involves consideration of the entire catchment system.

Pumped storage hydroelectricity stores electricity in times of low demand for use in times of high demand by moving water between reservoirs. It is currently the only commercial means of storing electricity once generated. By using excess electricity generated in times of low demand to pump water into higher storages, the energy can be stored and released back into the lower storage in times of peak demand. Pumped-storage systems can vary significantly in capacity but commonly consist of two reservoirs situated to maximise the difference in their levels and connected by a system of waterways with a pumping-generating station. The turbines may be reversible and used for both pumping and generating electricity.

Pumped storage hydroelectricity is the largest capacity form of grid energy storage where it can be used to cover transient peaks in demand and to provide back-up to intermittent renewable energy sources such as wind. New concepts in pumped storage involve wind, solar or wave (ocean) energy to pump water to dams as head storage.

Mini hydro schemes are small-scale (typically less than 10 MW) hydroelectricity projects that typically serve small communities or a dedicated industrial plant but can be connected to an electricity grid. Some small hydro schemes in North America are up to 30 MW. The smallest hydro plants of less than 100 kW are generally termed micro hydro. Mini hydro schemes can be 'run-of-river', with no dam or water storage (see below), or developed using existing or new dams whose primary purpose is local water supply, river and lake water-level control, or irrigation. Mini hydro schemes typically have limited infrastructure requiring only small-scale capital works, and hence have low construction costs and a smaller environmental impact than larger schemes. Most recent hydro energy installations in Australia, especially in Victoria, have been small (mini) hydro systems, commencing with the Thompson project in 1989.

Small-scale systems have encountered difficulty obtaining environmental approval due to uncertainty regarding their impact on aquatic fauna. Australian Renewable Energy Agency (ARENA) is supporting a study to provide Australian developers of small-scale hydro energy technologies and projects with a more detailed understanding of the impacts from turbines on Australian native fish species.

Run-of-river systems rely on the natural fall (head) and flow of the river to generate electricity through energy plants built on the river. Large run-of-river systems are typically built on rivers with consistent and steady flow. They are significant in some overseas locations, notably Canada and the United States. Mini run-of-river hydro energy systems can be built on small streams or use piped water from rivers and streams for local electricity generation. Run-of-river hydro energy plants commonly have a smaller environmental footprint than large-scale storage reservoirs. The Lower Derwent and Mersey Forth hydro energy developments in Tasmania, for example, each comprising six plants up to 85 MW capacity, use tributary inflows and small storages in a step-like series.

Hydroelectricity generation accounted for 2.3 per cent of total primary energy consumption in 2010 (table 8.1). World hydroelectricity consumption has grown at an average annual rate of 2.7 per cent between 2000 and 2010, while in the OECD, hydroelectricity consumption increased at an average annual rate of 0.3 per cent.

Hydroelectricity generation in Australia was higher in 2010–11, particularly in New South Wales and Victoria, supported by increased water inflows after a sustained period of drought.

Electricity generation

Hydroelectricity's share in total electricity generation has declined from 23 per cent in 1971 to 16 per cent in 2010 (figure 8.5), because of the higher relative growth of electricity generation from other sources. The most rapid growth in hydroelectricity generation has occurred in China, which is now the largest producer of hydroelectricity. Latin America and OECD North America remain large generators of hydroelectricity. Many African economies are also developing their hydro energy potential, and have become a source of growth.

Table 8.1 Key hydro energy statistics

	Unit	Australia 2011–12	Australia 2010–11	OECD 2011	World 2010
Primary energy consumption[a]	PJ	50.7	60.5	5017	12 377
Share of total	%	0.8	1.0	2.3	2.3
Average annual growth, from 2000	%	–1.6	–0.1	0.3	2.7
Electricity generation					
Electricity output	TWh	14.1	17	1393	3437
Share of total	%	5.6	6.7	13.0	16.0
Electricity capacity[b]	GW	8.5	8.5	455	1033

OECD = Organisation for Economic Co-operation and Development
a Energy production and primary energy consumption are identical. **b** All data are for 2010

Source: BREE 2012; IEA 2012a, 2012b

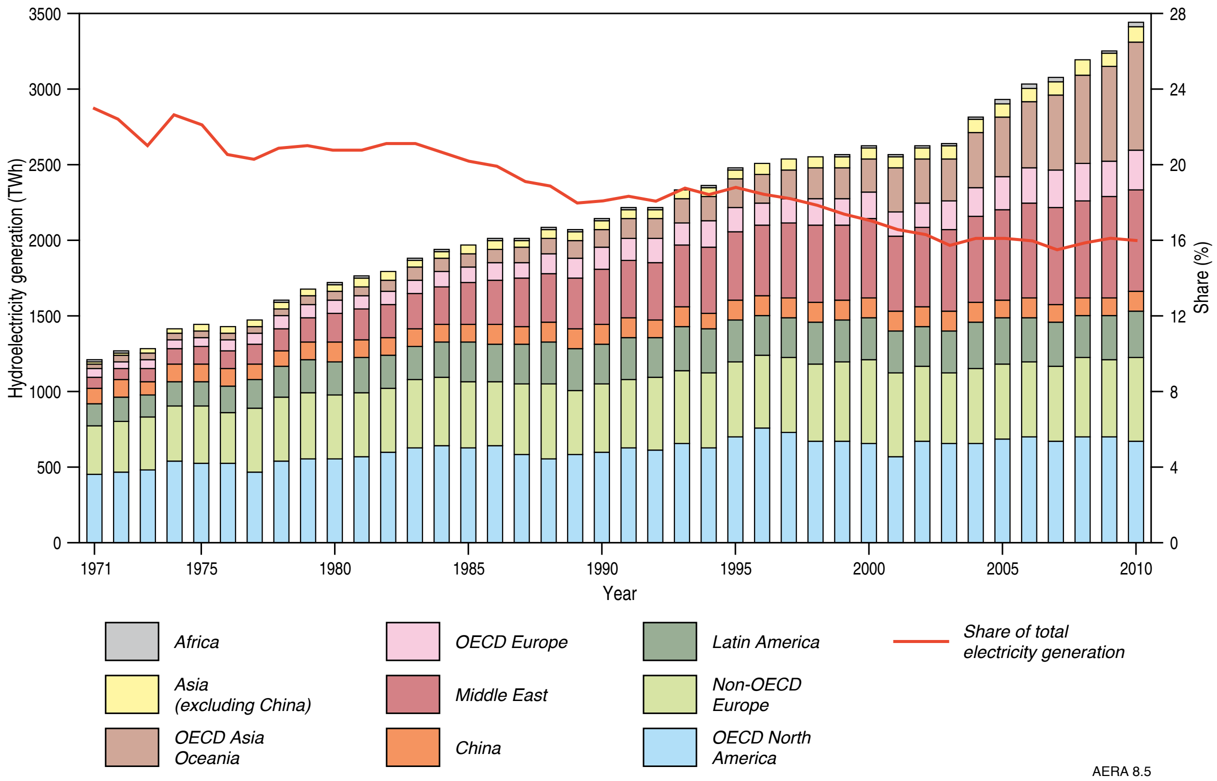

Figure 8.5 World hydroelectricity generation and share of total electricity generation
OECD = Organisation for Economic Co-operation and Development
Source: IEA 2012a

In 2010, the total installed hydroelectricity generation capacity was around 1010 GW, with around 30 GW of capacity added during 2010 (REN21 2012). China and Brazil are the most active regions for new hydro energy developments (REN21 2012). China has the world's largest installed hydroelectricity capacity with around 213 GW (21 per cent of world capacity), followed by Brazil (80.7 GW), the United States (78 GW), Canada (75.6 GW) and the Russian Federation (55 GW). These economies account for half of the world's installed hydroelectricity generation capacity.

In 2010, world production of hydroelectricity was 3431 TWh. The largest producers were China, Brazil, Canada and the United States (figure 8.6a). Australia ranked 39th in the world. Hydroelectricity accounted for a large share of total electricity generation in some of these countries including, Norway (94 per cent), Brazil (78 per cent), Venezuela (65 per cent), Canada (58 per cent) and Sweden (45 per cent) (figure 8.6b).

Hydroelectricity meets over 90 per cent of domestic electricity requirements in a number of other countries including the Democratic Republic of the Congo, Ethiopia, Mozambique and Zambia in Africa; Kyrgyzstan, Nepal and Tajikistan in Asia; Albania and Georgia in Europe; and Paraguay in South America (IEA 2012a).

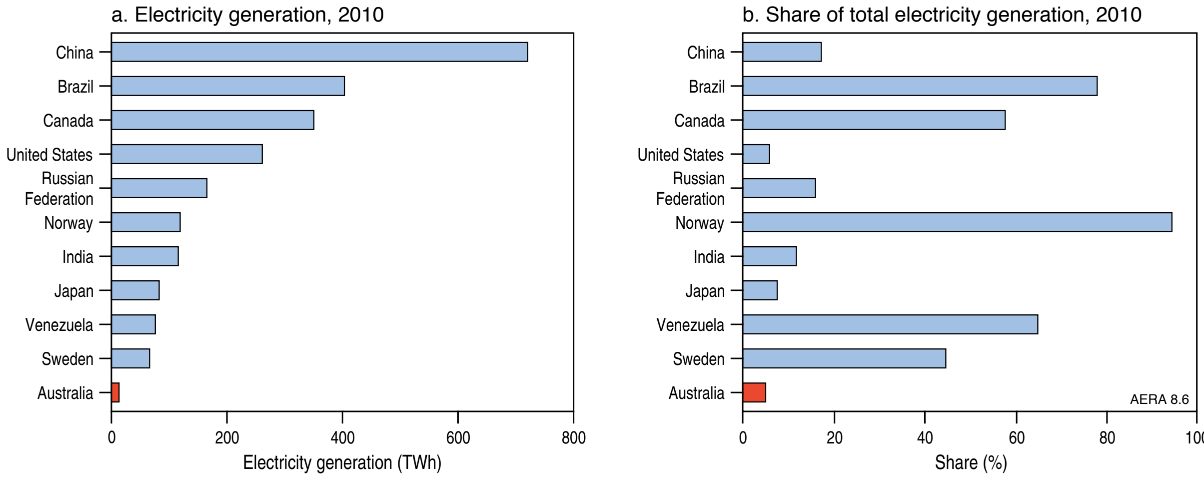

Figure 8.6 World electricity generation from hydro energy, major countries, 2010

Source: IEA 2012a

World hydro energy market outlook

In the IEA new policies scenario, world hydroelectricity generation is projected to increase at an average annual rate of 2 per cent to 5677 TWh in 2035 (table 8.2). Hydroelectricity generation is projected to grow in the OECD at an average annual rate of 0.7 per cent and in non-OECD countries by an average annual rate of 2.7 per cent.

The growth in hydroelectricity generation in the OECD is expected to come from utilisation of remaining undeveloped hydro energy resources. Growth is expected to occur in small (including mini and micro) and medium-scale hydroelectricity plants. Improvements in technology may also improve the reliability and efficiency and, hence, output of existing hydroelectricity plants, as would refurbishment of ageing infrastructure.

Nearly 90 per cent of the growth in world hydroelectricity generation over the projection period is expected to come from non-OECD countries. Strong demand and underutilised potential is expected to underpin growth in this region. Much of the growth is expected to be in small-scale hydroelectricity, although there are plans in many African countries to build large-scale hydroelectricity generation capacity. Growth is expected to occur in Asia, particularly China and India.

The implementation of global climate change policies is likely to encourage the development of hydroelectricity as a renewable, low emissions energy source. In the IEA's 450 policy scenario, the share of hydroelectricity in world electricity generation is projected to increase to 19.7 per cent in 2035, compared with 15.5 per cent in the new policies scenario. In the OECD regions the share of hydroelectricity in total electricity generation in the 450 policy scenario is projected to increase to 14.2 per cent in 2035 compared with 12.2 per cent in the new policies scenario.

Table 8.2 IEA new policies scenario projections for world electricity generation from hydro energy

	Unit	2010	2035
OECD	TWh	1351	1622
Share of total	%	12.5	12.2
Average annual growth, 2010–35	%		0.7
Non-OECD	TWh	2079	4054
Share of total	%	19.7	17.4
Average annual growth, 2010–35	%		2.7
World	TWh	3431	5677
Share of total	%	16.0	15.5
Average annual growth, 2010–35	%		2.0

OECD = Organisation for Economic Co-operation and Development
Note: totals may not add due to rounding

Source: IEA 2012a, 2012b

8.3 Australia's hydro energy resources and market

8.3.1 Hydro energy resources

Australia is the driest inhabited continent on Earth, with over 80 per cent of its landmass receiving an annual average rainfall of less than 600 mm per year and 50 per cent less than 300 mm per year (figure 8.7). There is also high variability in rainfall and temperatures between years, resulting in Australia having very limited and variable surface water resources. Of Australia's gross theoretical hydro energy resource of 265 TWh per year, only around 60 TWh is considered to be technically feasible (UNESCO 2012). Australia's economically feasible capacity is estimated at 30 TWh per year, of which about 56 per cent has already been harnessed (UNESCO 2012).

The first hydroelectric plant in Australia was built in Launceston in 1895. Australia has 124 operating hydroelectricity plants with total installed capacity of

8500 MW (figure 8.1). These coincide with the areas of highest rainfall and elevation and are mostly in New South Wales (55 per cent) and Tasmania (29 per cent). The Snowy Mountains Hydro-Electric Scheme, with a capacity of about 3800 MW, accounts for around half of Australia's total hydroelectricity generation capacity but considerably less of actual production. There are also hydroelectricity schemes in north-east Victoria, Queensland, Western Australia, and a mini hydroelectricity project in South Australia. Pumped storage accounts for about 1490 MW.

The Snowy Mountains Hydro-Electric Scheme is one of the most complex integrated water and hydroelectricity schemes in the world. The scheme collects and stores the water that would normally flow east to the coast and diverts it through trans-mountain tunnels and power plants. The water is then released into the Murray and Murrumbidgee rivers for irrigation. The Snowy Mountains Hydro-Electric Scheme comprises sixteen major dams, seven power plants (two of which are underground), a pumping station, 145 km of interconnected trans-mountain tunnels and 80 km of aqueducts. The scheme produces on average about 4500 GWh per year and provides around 70 per cent of all renewable energy that is available to the eastern mainland grid of Australia, as well as providing peak load power (Snowy Hydro 2012).

The hydroelectricity generation system in Tasmania comprises an integrated scheme of 30 power plants, numerous lakes and over 50 large dams with a total capacity of over 2600 MW. Hydro Tasmania, the owner of the majority of these hydroelectricity plants, supplies both base load and peak power to the national electricity market, firstly to Tasmania and then to the Australian network through Basslink, the undersea interconnector which runs under Bass Strait (Hydro Tasmania 2012). A potential future option for hydro energy in Tasmania is as energy storage for excess wind energy and wave energy, as is currently the case in Scandinavian countries.

8.3.2 Hydro energy market

Australia has developed much of its large-scale hydro energy potential. Electricity generation from hydro energy has declined in recent years because of an extended period of drought in eastern Australia, where most hydroelectricity capacity is located. However, the share of hydroelectricity increased in 2010–11 following higher inflows. Hydro energy is becoming less significant in Australia's generation mix as growth in generation capacity is being outpaced by that in other renewable energy technologies.

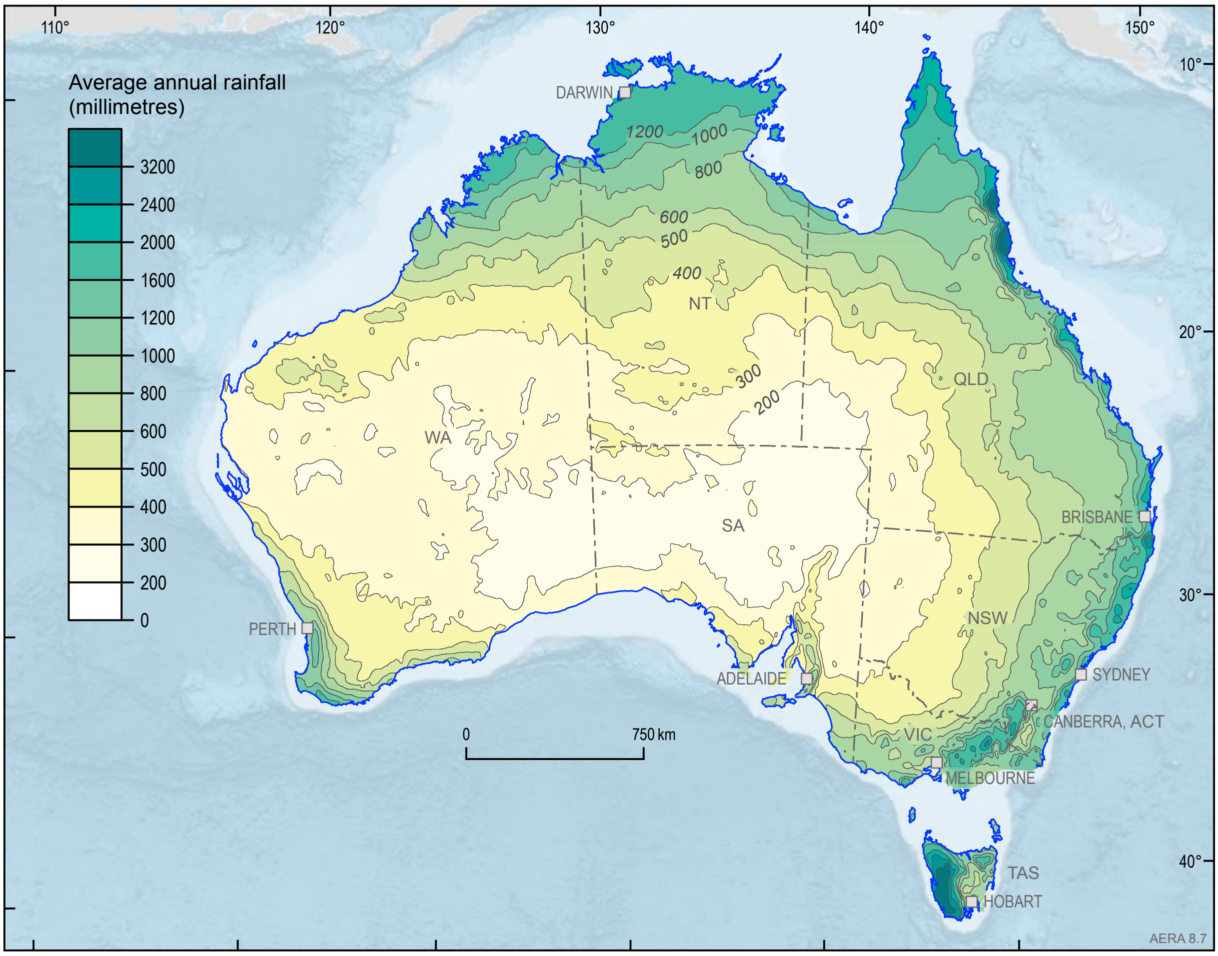

Figure 8.7 Average annual rainfall across Australia

Source: Bureau of Meteorology

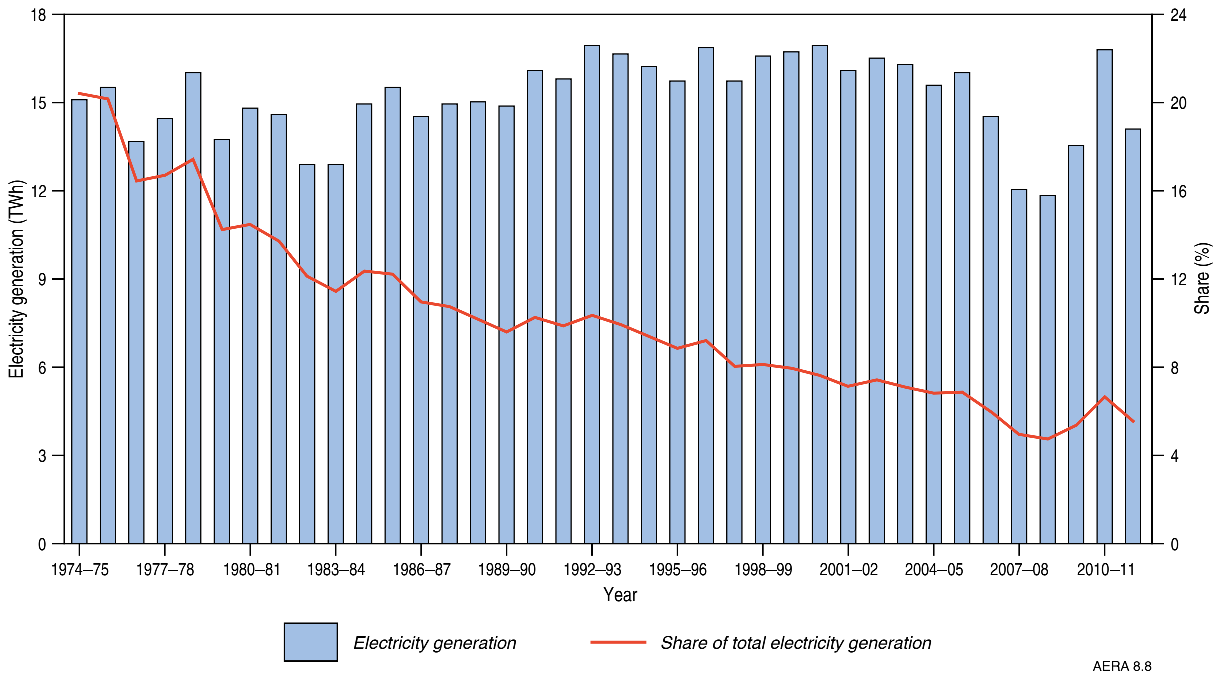

Figure 8.8 Australia's hydro generation and share of total electricity generation

Source: BREE 2012

Primary energy consumption

As hydro energy resources are used to produce electricity, which is used in either grid or off-grid applications, production is equivalent to hydro energy consumption. Hydroelectricity use has declined on average by 0.1 per cent per year between 1999–2000 and 2010–11. In 2011–12, hydroelectricity use represented 0.8 per cent of total primary energy consumption.

Electricity generation

In 2011–12, Australia's hydroelectricity generation was 14.1 TWh or 5.6 per cent of total electricity generation (figure 8.8). Over the period 1974–75 to 2011–12, hydroelectricity generation has fluctuated, reflecting periods of below or above average rainfall. However, the share of hydroelectricity in total electricity generation has generally declined over this period, reflecting the higher growth of alternative forms of electricity generation.

Tasmania has always been the largest generator of hydroelectricity in Australia, accounting for 60.5 per cent of total generation in 2011–12 (figure 8.9). New South Wales (including ACT) is the second largest, accounting for 26.9 per cent of total electricity generation in 2011–12 (sourced mostly from the Snowy Mountains Hydro-Electric Scheme). Victoria and Queensland account for the remainder.

Installed generation capacity

Ninety per cent of Australia's installed capacity is shared between New South Wales, Tasmania and Victoria (figure 8.10a). Australia has only four hydroelectricity plants with a capacity of 500 MW or more; three are located in the Snowy Mountains Hydro-Electric Scheme and the fourth is the Wivenhoe power station in Queensland (figure 8.10b). The largest hydroelectricity plant in Australia has a capacity of 1500 MW, which is mid sized by international standards. More than 75 per cent of Australia's installed hydroelectricity capacity is contained in 14 hydroelectricity plants with a capacity of 100 MW or more. At the other end of the scale, there are some 65 small and mini hydroelectricity plants (less than 10 MW capacity) with a combined capacity of just over 175 MW.

However, installed hydroelectricity generation capacity does not directly reflect actual electricity generation. The smaller installed capacity in Tasmania produces more than double the output of the Snowy Mountains Hydro-Electric Scheme. Tasmania is the only state that uses hydroelectricity as the main means of electricity generation.

8.4 Outlook for Australia's hydro energy resources and market

Growth in Australia's hydroelectricity generation is expected to be limited and outpaced by other renewables, especially wind energy.

Future growth in hydroelectricity generation capacity is likely to come mainly from the installation of small-scale plants. The use of pumped storage hydroelectricity as a form of energy storage may be important where it can be used for managing variable renewable energy supply such as wind or solar. There is potential for hydro energy to use synchronous generation, where a plant has a synchronous generator that provides some natural damping of any frequency deviation by automatically releasing or absorbing stored rotational energy as appropriate (AEMO 2013). Water availability will be a key determinant of the future expansion of hydroelectricity in Australia.

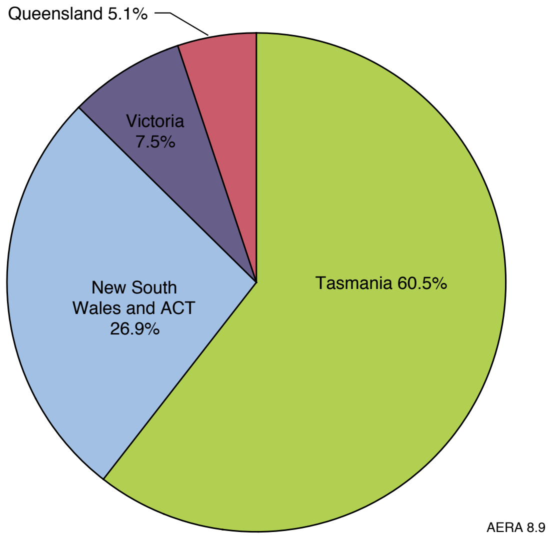

Figure 8.9 Australia's hydro generation by state, 2011–12

Source: BREE 2012

8.4.1 Key factors influencing the outlook

Opportunities for further hydroelectricity generation in Australia are offered by refurbishment and efficiency improvements at existing hydroelectricity plants, and continued growth of small-scale hydroelectricity plants connected to the grid. Hydroelectricity generation is a low-emissions technology, but future growth will be constrained by water availability and competition for scarce water resources.

Hydroelectricity is a mature renewable electricity generation technology with limited scope for further large-scale development in Australia

Most of Australia's best large-scale hydro energy sites have already been developed or, in some cases, are not available for future development because of environmental considerations. There is some potential for additional hydro energy generation using the major rivers of northern Australia but this is limited by the region's remoteness from infrastructure and markets and the seasonal flows of the rivers.

Upgrading and refurbishing ageing hydro energy infrastructure in Australia will result in capacity and efficiency gains

Many of Australia's hydro energy plants are now more than 50 years old and will require refurbishment in the near future. This will involve significant expenditure on infrastructure, including the replacement and repair of equipment. The refurbishment of plants will increase the efficiency and decrease the environmental impacts of hydroelectricity. Further technology developments will be focused on efficiency improvements and cost reductions in both new and existing plants (box 8.2).

The Snowy Mountains Hydro-Electric Scheme is currently undergoing a maintenance and refurbishment process, at a cost of approximately A$400 million over seven years. The modernisation will include the replacement of ageing and high-maintenance equipment, increasing the efficiency and capacity of turbines, and ensuring the continued reliable operation of the component systems of the scheme. Major works in the Lower Tumut region have been completed with the six generating units at Tumut 3, the largest power

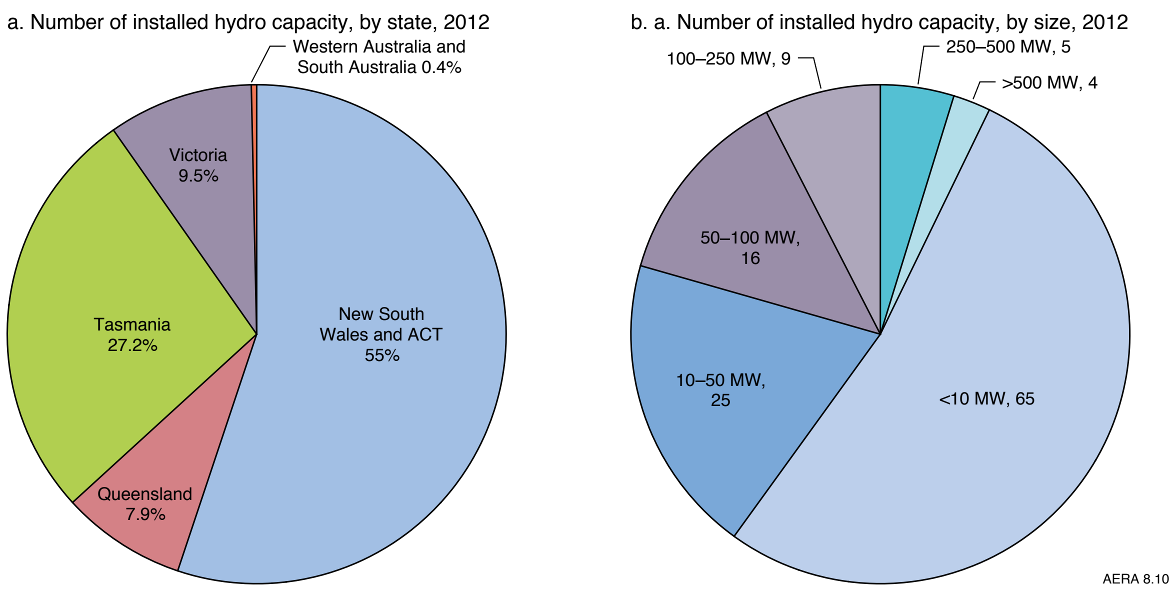

Figure 8.10 Installed hydro capacity by state and size, 2012

Source: Clean Energy Council 2012

station in the Snowy Hydro fleet, modernised and upgraded. Work has now commenced on the Upper Tumut project (Snowy Hydro 2012).

Refurbishment of the power station at Lake Margaret, Tasmania—one of Australia's oldest hydroelectricity facilities (commissioned in 1914)—commenced in 2008. The main objective of the project was to repair the original wooden pipeline, which had deteriorated (Hydro Tasmania 2008). The project involved additional maintenance on the dam, minor upgrade of the machines, as well as replacement of a transformer. This upgrade, completed in late 2009, cost about A$14.7 million to gain 8.4 MW of capacity at a capital spend rate of A$1.75 million per MW, considerably less than the costs of a new plant (Hydro Tasmania 2009). Hydro Tasmania is undertaking a number of maintenance and technical upgrade projects to maximise generation and ensure reliable supply. Projects that occurred over 2012–13 included the Tungatinah modernisation project, Kaplan turbine program and the Rowallan Dam upgrade (Hydro Tasmania 2012).

Small-scale hydro developments are likely to be an important source of future growth in Australia

With the exception of the Bogong project, most hydroelectricity plants installed in Australia in recent years have been mini hydro schemes. These plants have the advantage of lower water requirements and a smaller environmental impact than larger schemes, especially those with large storage dams.

Although the majority of Australia's most favourable hydroelectricity sites have been developed, mini hydroelectricity plants are potentially viable on smaller rivers and streams where large dams are not technically feasible or environmentally acceptable. They can also be retrofitted to existing water storages. At present mini hydro plants account for around 2 per cent of installed hydro capacity. Research, development and demonstration activity is likely to increase the cost competitiveness of small-scale hydro schemes in the future (box 8.3).

BOX 8.2 HYDROELECTRICITY COSTS

Hydroelectricity generation costs

The most significant cost in developing a hydro resource is the construction of the necessary infrastructure. Infrastructure costs include the dams as well as the power plant itself. Building the plant on an existing dam will significantly reduce capital outlays. Costs incurred in the development phase of a hydro facility include (Forouzbakhsh et. al. 2007):

- civil costs—construction of the project components including dams, headponds, and access roads
- electro-mechanical equipment costs—the machinery of the facility, including turbines, generators and control systems
- power transmission line costs—installation of the transmission lines.

Indirect costs include engineering, design, supervision, administration and inflation impacts on costs during the construction period. Construction of small and medium plants can take from 1 to 6 years, while large-scale plants can take up to 30 years (for example, the Snowy Mountains Hydro-electric Scheme took 25 years to build).

The costs of building Australian hydroelectricity generation plants have been varied. The Snowy Mountains Hydro-electric Scheme, Australia's largest hydroelectricity scheme, was constructed over a period of 25 years at a cost of A$820 million (Snowy Hydro 2007). Australia's most recent major hydroelectricity development, the Bogong project (site 1), commenced construction in 2006 and was commissioned in late 2009 at a cost of around A$234 million. The project—which includes the 140 MW Bogong power station, a 6.9 km tunnel, head works and a 220 kV transmission line—will provide fast peaking power. In comparison, the Ord River hydroelectricity scheme, which was built on the existing dam which created Lake Argyle in Western Australia, was constructed at a cost of A$75 million (Pacific Hydro 2009). While this plant is relatively small (30 MW), it demonstrates the potential reduction in construction costs where an existing dam can be used.

While hydroelectricity has high construction and infrastructure costs, it has a low cost of operation compared to most other means of electricity generation. In the OECD, capital costs of hydroelectricity plants are estimated at US$2400 per kW, and operating costs are estimated at between US$0.03 and US$0.04 per kWh (IEA 2008). For non-OECD countries, capital costs are often below US$1000 per kW. The operating costs of small hydroelectricity facilities are estimated at between US$0.02 and US$0.06 per kWh. Operating and capital costs depend on the size and type (for example, run-of-river) of plant, and whether it includes pumped storage capabilities. Most hydroelectric plants have a lifetime of over 50 years, during which minimal maintenance or refurbishment is required, so the relatively high capital costs are amortised over a long period.

The average investment cost for small-scale hydro is typically US$1300–8000 per kW, which is comparable to large-scale hydro average investment costs of US$1050–7650 per kW (IRENA 2012). The annual operations and maintenance costs are quoted as a percentage of the investment cost per kW. Large-scale hydro will average around 2 to 2.5 per cent, whereas small-scale hydro can range between 1 and 6 per cent (IRENA 2012).

Surface water availability and competition for scarce water resources will be a key constraint to future hydro developments in Australia

Australia has highly variable rainfall across the continent (figure 8.8). This means that annual inflows to storages can vary by up to 50 per cent and seasonal variations can be extreme. The recent drought in much of south-eastern Australia saw a substantial decline in water levels in the major storages in New South Wales (notably the Snowy Mountains Hydro-Electric Scheme), Victoria and Tasmania and declining capacity factors for hydroelectricity plants. Water levels in storages during the 2002 to 2009 drought declined to an average of below 20 per cent of capacity in the Murray–Darling Basin and below 40 per cent in Tasmania (BOM 2012). In contrast, water levels across Australia rose to over 80 per cent of capacity and hydroelectricity generation increased in 2010–11 following increased water availability.

The *State of the climate 2012* report notes that the long-term warming trend has not changed, and that there has been a general trend towards increased spring and summer monsoonal rainfall across Australia's north and a decrease in autumn and winter rainfall across southern Australia (CSIRO and BOM 2012). Record rainfall fell in spring and summer in the south-east of Australia in 2010 and 2011. Climate models suggest long-term drying over southern areas during autumn and winter, which will be superimposed on large natural variability such as wet years becoming less frequent and dry years more frequent. Droughts are expected to become more frequent in southern Australia; however, periods of heavy rainfall are still likely to occur (CSIRO and BOM 2012).

Competition for water resources will also affect the availability of water for hydroelectricity generation. Demand for water for urban and agricultural uses is projected to increase. It is likely that these uses for scarce water resources will take precedence over hydroelectricity generation. Generators face increasing demands to balance their needs against the need for greater water security for cities and major inland towns. The maintenance of environmental flows to ensure the environmental sustainability of river systems below dams is also an important future consideration which may further constrain growth of hydroelectricity generation.

Water policies may also play a role in the future development of hydroelectricity in Australia. Policies that limit the availability of water to hydro energy plants, restrict the flow of water into dams, require generators to let water out of dams, or prioritise the use of water for agriculture could change the viability of many hydroelectricity generators, and limit future growth. The extended drought in much of Australia has led to water restrictions being put into place in most capital cities, and regulation of the Murray–Darling Basin river systems has strengthened.

8.4.2 Outlook for hydro energy market

Hydroelectricity generation is projected to remain broadly unchanged in Australia due to the limited availability of suitable locations for the expansion of capacity and water supply constraints.

Due to increasing generation from other sources, the contribution of hydro energy is projected to fall in the future. The potential for return of hydroelectricity output to pre-2006 levels will be strongly influenced by climate and by water availability.

Recent and proposed development projects

- Since January 2010, there have been small hydroelectricity plants commissioned and upgrades to existing plants.
- Australia's first hydro generation plant using treated sewage water was commissioned in April 2010 at the Sydney Water's North Head wastewater treatment plant in New South Wales. The plant generates energy from treated waste water falling down a 60-metre shaft. In conjunction with a co-generation plant producing energy from methane, the combined power plant will generate 4.5 MW, and supply 40 per cent of the treatment plant power.
- In early 2010, Snowy Hydro commissioned a mini hydro electricity plant (14.4 MW) attached to the river diversion conduit of the Jounama Dam to capture energy from water releases.
- Snowy Hydro has embarked on a A$400 million scheme modernisation project. As at September 2012, the Lower Tumut project had been completed, with six upgraded units now capable of providing 25–50 MW of additional capacity each. Work is continuing on the Upper Tumut project, which is expected to expand capacity by 40 MW and is scheduled to be commissioned in 2014 (Snowy Hydro 2012).
- Hydro Tasmania completed significant redevelopment of its Lake Margaret mini hydro energy plants in 2010 and has commenced work on the A$60 million modernisation of the Tungatinah plant.
- Stanwell Corporation is at the feasibility stage of its Burdekin project (37 MW) in Queensland.

BOX 8.3 TECHNOLOGY DEVELOPMENTS IN HYDROELECTRICITY

Research is being undertaken to improve efficiency, reduce costs, and to improve the reliability of hydroelectricity generation. There are different research needs for small and large-scale hydro (table 8.3). Small hydro energy plants, including micro and pico plants, are increasingly seen as a viable source of energy because of their lower development costs and water requirements, and their lower environmental footprint. Small-scale hydropower plants require special technologies to increase the efficiency of electricity generation and thereby minimise both the operating costs and environmental impacts of hydroelectricity generation (ESHA 2006).

The environmental impacts of hydroelectricity are also being investigated, and ways to mitigate these impacts developed. This includes the development of new and improved turbines designed to minimise the impact on fish and other aquatic life and to increase dissolved oxygen in the water. The introduction of greaseless bearings in the turbines would reduce the risk of petroleum products entering the water, and is also currently being investigated (EERE 2005).

Table 8.3 Technology developments for hydro energy

Large hydro	Small hydro
Equipment Low-head technologies, including in-stream flow Communicate advances in equipment, devices and materials	**Equipment** Turbines with less impact on fish populations Low-head turbines In-stream flow technologies
Operation and maintenance Increasing use of maintenance-free and remote operation technologies	**Operation and maintenance** Develop package plants requiring only limited operation and maintenance
	Hybrid systems Wind-hydro systems Hydrogen-assisted hydro systems

Source: IEA 2008

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UNESCO (United Nations Educational, Scientific and Cultural Organisation) 2012, *Hydropower generation*, UNESCO, Paris. www.unesco.org/new/fileadmin/MULTIMEDIA/HQ/SC/temp/wwap_pdf/Table_Hydropower_Generation.pdf

Chapter 9

Wind Energy

9.1 Summary

KEY MESSAGES

- Australia has some of the world's best wind resources along its south-western, southern and south-eastern margins. More isolated areas of the eastern margin also have excellent wind resources.
- Wind energy is the fastest growing renewable energy source for electricity generation in Australia, increasing at an average annual rate of 35.9 per cent between 1999–2000 and 2011–12.
- Wind farm size in Australia has grown in terms of megawatt total capacity over the past three years. In 2012 large wind farms (greater than 100 megawatt capacity) comprised 11.5 per cent of operating wind farms but accounted for around 40.6 per cent of Australia's wind-generating capacity.
- Extension and other augmentation of the electricity transmission network may be required to access dispersed (remote) wind energy resources and to integrate the projected increase in wind energy electricity generation.

9.1.1 World wind energy resources and market

- The world's wind energy resource over land and near shore is estimated to be around 80 000 gigawatts (GW). The windiest areas are typically coastal regions of continents at mid to high latitudes.
- Wind electricity generation is the fastest growing energy source, increasing at an average annual rate of nearly 27.3 per cent between 2000 and 2010. The major wind energy producers are the United States, China, Spain, Germany and India (table 9.1).
- The world outlook for electricity generation from wind energy will be strongly influenced by government climate change policies and the demand for low emission renewable energy at affordable prices.
- The IEA projects the share of wind energy in total world electricity generation will increase markedly from 1.6 per cent in 2010 to 7.0 per cent in 2035—from 2.5 per cent to 11.0 per cent in OECD countries and from 0.7 per cent to 4.2 per cent in non-OECD countries.

9.1.2 Australia's wind energy resources

- Australia has some of the best wind resources in the world, primarily located in south-western, southern and south-eastern margins and extending hundreds of kilometres inland and including highland areas in south-eastern Australia (figure 9.1). There are large areas with average wind speeds suitable for high-yield electricity generation.
- Australia's exceptional wind resources have helped enable wind energy to make an increasing contribution to Australia's energy mix.
- Local topography and other variability in the local terrain such as surface roughness exert a major influence on wind speed and wind variability. This necessitates detailed local investigation of potential sites for wind farms.

9.1.3 Key factors in utilising Australia's wind energy resources

- Wind energy is a proven and mature technology with low operating costs. Both the size of turbines and wind farms have increased, with farms of more than 100 MW combined capacity now common and substantially larger wind farms proposed.
- Wind turbines superficially have not changed much for decades; however, the turbines (e.g. blades, tower and rotor) have become bigger as well as smarter. Sensors and software constantly monitor forces exerted on the blades, which can increase the amount of electricity generated and lower of the cost of wind power.
- Grid constraints—lack of capacity or availability—may limit the growth of wind energy in some areas that have good wind resources. In such areas, upgrades and extensions to the current grid may be needed to accommodate significant further wind energy development.
- Given the development of technology and the anticipated pace of deployment of wind energy in Australia, it is likely Australia will reach a high level of wind electricity generation in the next few decades. Deployment may be further accelerated by improvements in wind forecasting and more accurate estimates of the likely output from wind farms (allowing the grid to react to projected changes in wind conditions), demand side management

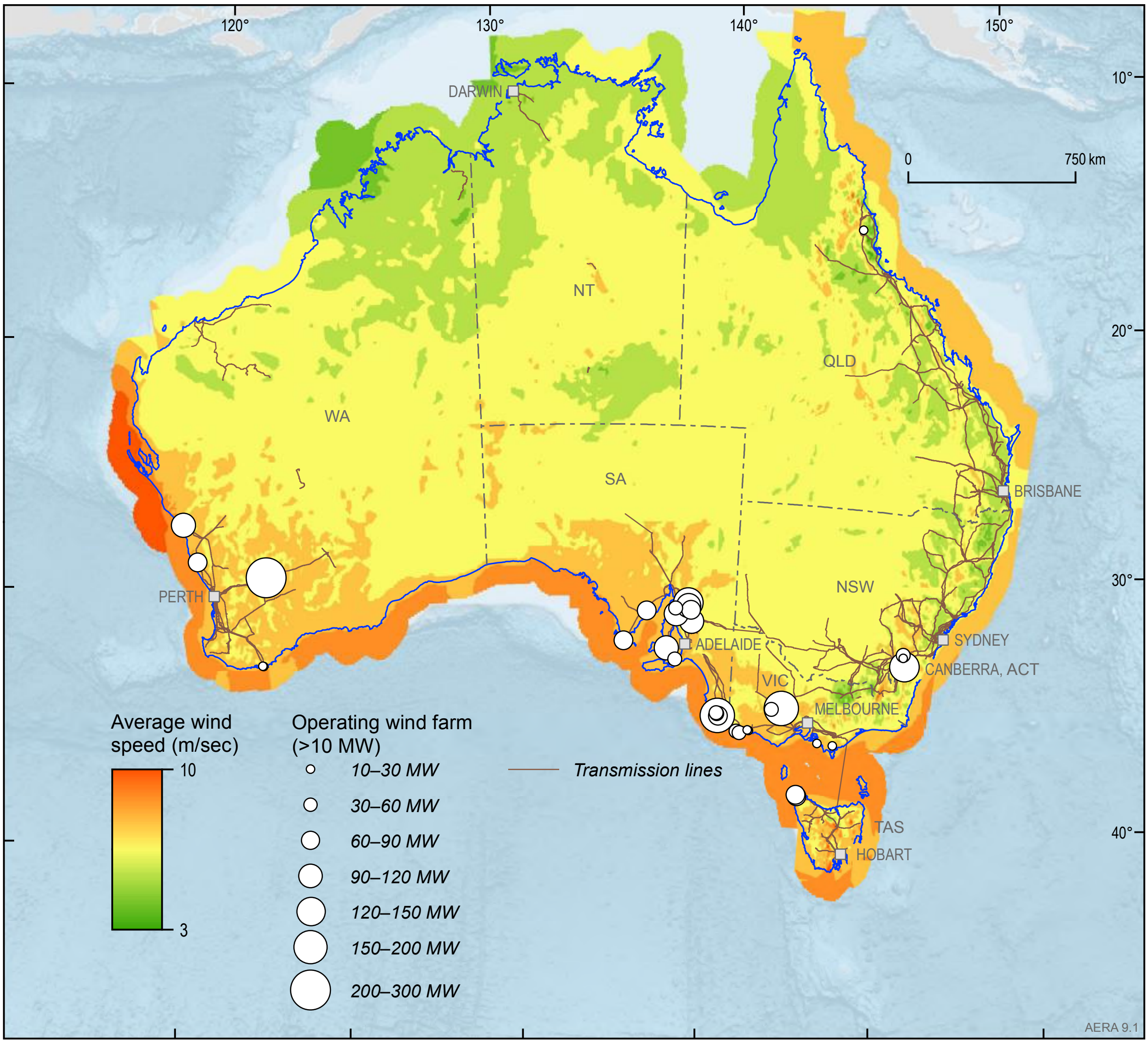

Figure 9.1 Australia's wind resources

Source: Windlab Systems Pty Ltd; Geoscience Australia

(shedding or adding load to match wind conditions) and the addition of storage nodes to the grid (moving excess wind energy to higher demand periods).

- The Australian Government funded the development of a wind energy forecasting system (Australian Wind Energy Forecasting System (AWEFS)), which was implemented in May 2010. The system provides a vehicle for improved research, development and application for forecasting of intermittent energy and facilitates the efficient operation of the National Electricity Market (NEM).
- Wind turbine manufacturing output has doubled in recent years. There is also a shift from European and United States' production to lower cost manufacturing centres in India and China. Both of these trends has resulted in a reduction in turbine costs.

9.1.4 Australia's wind energy market

- In 2011–12, Australia's wind energy use represented only 0.36 per cent of total primary energy consumption and 2.4 per cent of total electricity generation. However, wind energy is the fastest growing energy source in Australia with an average annual growth of 35.9 per cent from 1999–00 to 2011–12.
- In 2012, Australia had 1386 operating wind turbines across 61 wind farms with a total installed capacity of 2564.3 MW. The total installed capacity of wind power has grown by an average of 35 per cent per year over the past five years. As of October 2013, there were over 2500 MW (total capacity) of wind energy projects committed, with over 11 600 MW of projects at the feasibility stage.
- While the cost of wind energy continues to fall, government support such as the Renewable Energy Target (RET) supports continued investment in the industry and enables the wind power sector to play a major role in helping Australia's transition to a low carbon economy.

9.2 Background information and world market

9.2.1 Definitions

Wind is a vast potential source of renewable energy. Winds are generated by complex mechanisms involving the rotation of the Earth, heating from the sun, the cooling effect of the oceans and polar ice caps, temperature gradients between land and sea, and the physical effects of mountains and other obstacles.

Wind energy is generated by converting wind currents into other forms of energy using wind turbines (figure 9.2). Turbines extract energy from the passing air by converting kinetic energy from rotational movement via a rotor. The effectiveness of this conversion at any given site is commonly measured by its energy density or, alternatively, as a capacity factor (box 9.1). Wind energy is primarily used for electricity generation, both on-site and for transport to the grid. Wind energy is also used to pump bore water, particularly in rural areas. Wind energy is considered a non-synchronous energy generation source as it is subject to weather variation and forecast uncertainties.

Onshore wind generation represents the most mature form of renewable energy generation technology to emerge in the past 30 years. While there are a number of variations of the technology, the vast majority of recent installations globally are of a standard configuration, consisting of a tower mounted with three blades in an upwind turbine design (AETA 2012).

BOX 9.1 CAPACITY FACTOR

Estimates of electricity generation are generally calculated by modelling the interaction between the wind distribution and a particular turbine. The ratio of actual yield to the maximum output of the machine is commonly referred to as a capacity factor. Each type of turbine has a different capacity factor for any given site.

For example, a wind turbine with a 1 MW capacity and 30 per cent capacity factor will not produce its theoretical maximum annual production of 8760 MWh (1 MW * 24 hours * 365 days). Rather, it is expected to produce 2628 MWh (1 MW * 24 hours * 365 days * 0.3 capacity factor).

The capacity factor should not be confused with 'efficiency' which is a measure comparing the actual output with the energy contained in the passing wind. Wind turbines are limited by physical factors to an efficiency of about 60 per cent (Betz's Law). The wind turbines are typically between 35 and 45 per cent efficient.

Performance data of wind farms connected to the electricity grid in south-eastern Australia are available from Australian Energy Market Operator. On average, wind farms in south-eastern Australia operate at a capacity factor of around 30 to 35 per cent.

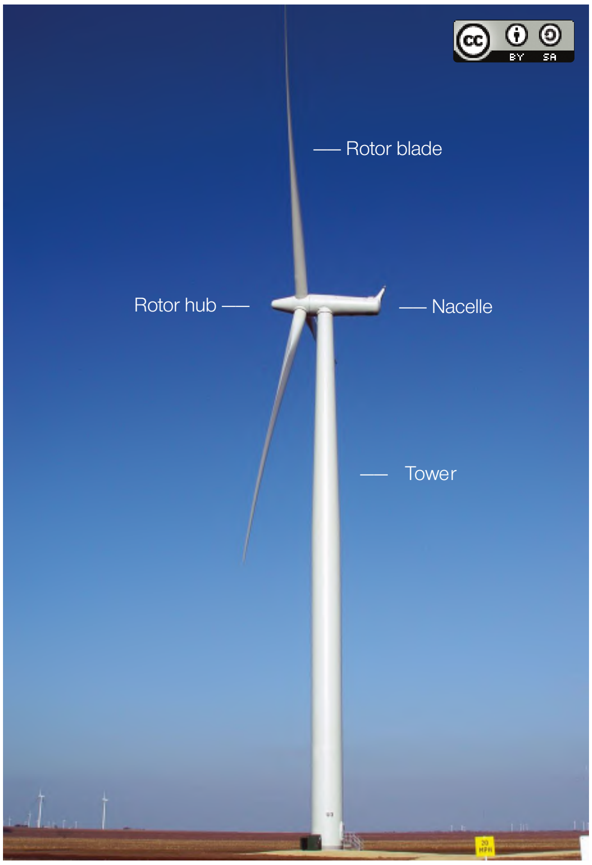

Figure 9.2 A modern wind turbine

Source: Wikimedia Commons

9.2.2 Wind energy supply chain

The wind energy supply chain is relatively simple (figure 9.3). In the energy market, wind resources are utilised for electricity generation, either linked to the grid or for off-grid applications in remote areas. Wind resources are also used to pump water, especially in rural Australia.

Modern wind energy prospecting typically uses three levels of wind resource mapping:

1. regional-scale 'mesoscale' wind speed maps, to identify favourable regions. These maps are compiled using atmospheric models and wind measurements from balloons
2. farm-level 'microscale' wind resource mapping to account for local variations in wind speed
3. micro-siting studies to determine optimal locations for siting of individual turbines. This mapping requires input from long-term sensors installed on the site.

Final siting of wind farms depends on both technical and commercial factors, including wind speed and topography,

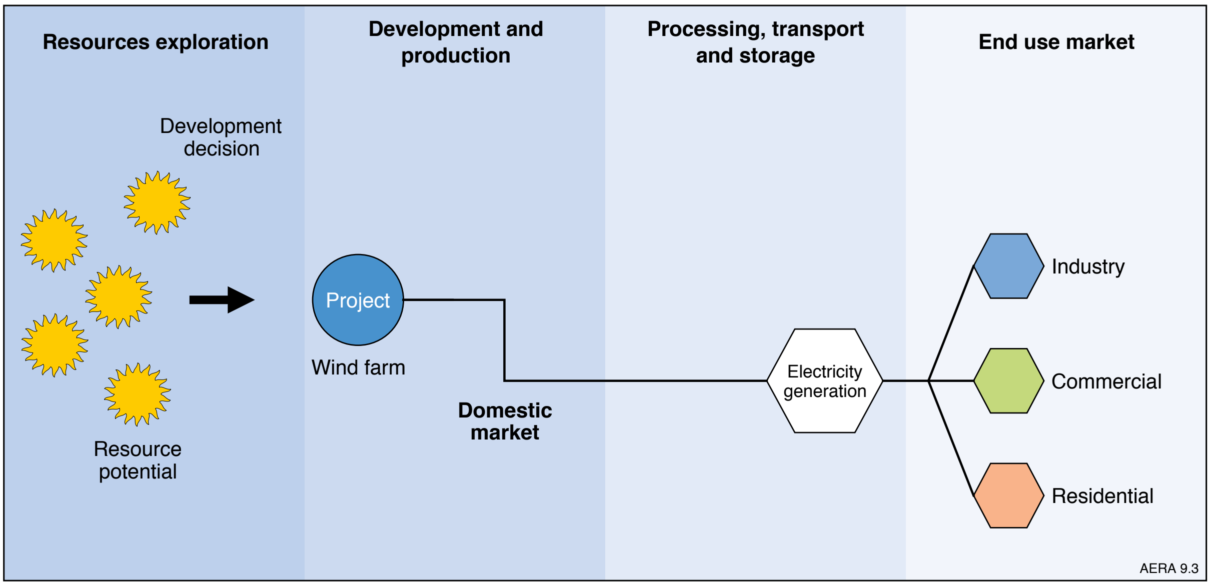

Figure 9.3 Australia's wind energy supply chain

Source: Bureau of Resources and Energy Economics; Geoscience Australia

as well as proximity to transmission lines, access to land, transport access, local development zoning and development guidelines, and proximity to markets.

In the National Electricity Market (NEM), which covers the eastern states, wind energy is automatically dispatched, meaning that the wind electricity must be consumed before other, more controllable, sources are dispatched. Since March 2009 new wind generators greater than 30 MW must be classified as 'semi-scheduled' and participate in the central dispatch process (AER 2009).

Electricity produced from the individual turbines is stepped up by means of a transformer and high-voltage switch and collected in the central switchyard of the wind farm. It is then fed to the electricity transmission grid substation with further transformers and switchgear. The electricity is distributed to the industrial, commercial and residential markets in the same manner as electricity generated from any other source.

Small wind turbines (typically less than 10 kW) are commonly used in remote locations isolated from the grid for a variety of industrial, commercial and household needs, usually in conjunction with some form of storage.

9.2.3 World wind energy market

The wind energy industry is the fastest growing renewable energy source in many countries and is expected to continue to grow rapidly over the period to 2035. Production of wind energy is largely concentrated in Europe and the United States. However, there has also been rapid growth in the wind energy industries in China and India.

Resources

A recent assessment of the world's wind energy resource over land and near shore estimated wind energy resources to be around 80 000 GW (Jacobson and Archer 2012). There is enough wind over land and near shore to exceed the total power demand of the world, even after accounting for reductions such as environmental conditions, wake effects and turbine performance.

The windiest areas are typically coastal regions of continents at mid to high latitudes and in mountainous regions. Locations with the highest wind energy potential include the westerly wind belts between latitudes 35° and 50° south. This includes the coastal regions of western and southern Australia, New Zealand, southern South America, and South Africa in the southern hemisphere, and northern and western Europe, and the north-eastern and western coasts of Canada and the United States. These regions are generally characterised by high, relatively constant wind conditions, with average wind speeds in excess of 6 metres per second (m/s) and, in places, more than 9 m/s.

Regions with high wind energy potential are characterised by:

- high average wind speeds
- winds that are either constant or coinciding with peak energy consumption periods (during the day or evening)
- proximity to a major energy consumption region (urban/industrial areas)
- smooth landscape, which increases wind speeds, and reduces the mechanical stress on wind turbine components that results from variable and turbulent wind conditions associated with rough landscape.

Because of wind variability, the energy density at a potential site—commonly described as its capacity factor (box 9.1)—is generally in the range of 20–40 per cent. While the majority of areas in locations convenient for electricity transfer to the grid are located onshore, offshore sites have also been identified as having significant potential for wind energy, both to take advantage of increased wind speeds and to increase the number of available sites. Offshore locations also help reduce turbulence and hence stress on machine components. There have been wind turbines deployed in shallow seas off northern Europe for more than a decade. Offshore sites are expected to make an increasingly significant contribution to electricity generation in some countries, notably in Europe, where there are increasing difficulties in gaining access to onshore sites.

Primary energy consumption

In the wind energy market, energy production, primary energy consumption and fuel inputs to electricity generation are the same as there is essentially no international trade and no ability to hold stocks of wind energy. Wind energy has increased from a 0.03 per cent share of global primary energy consumption in 2000 to around 0.2 per cent in 2010 (IEA 2012a).

Electricity generation

Wind energy accounted for 1.6 per cent of world electricity generation in 2010 and 3.1 per cent of OECD electricity generation in 2011. Global wind electricity generation has increased strongly, from 31 terawatt-hours (TWh) in 2000 to 341.7 TWh in 2010, representing an average annual growth rate of just over 27 per cent (IEA 2012a; table 9.1).

Wind energy use is growing rapidly in the industrialised world: capacity has been doubling about every three and half years since the early 1990s. The reasons for this rapid growth are primarily environmental; it is a renewable and low emission source of energy. Because of the simplicity of its technology, recent cost reductions and resource abundance, it has emerged as one of the leading renewable energy industries, well aligned with governments' search for commercially viable renewable energy sources. There is also increasing interest in the developing world because it can be readily installed to meet local electricity needs.

The wind energy market is dominated by two regions: Europe and North America (figure 9.4). In 2010, 44 per cent of the world's wind electricity generation was in OECD Europe and 31 per cent was in OECD North America, mainly in the United States (IEA 2012b).

The main wind energy producers in Europe are Spain (13 per cent of world wind electricity generation), Germany (11 per cent), the United Kingdom (3 per cent), France (2.9 per cent), Portugal (2.7 per cent) and Italy (2.7 per cent) in 2010 (figure 9.5a). While growth in wind electricity generation in Germany, Spain and Denmark has slowed in recent years, other major producers have emerged, including the United Kingdom, France and Italy (GWEC 2011).

The United States produced 95 TWh of wind energy in 2010, accounting for 28 per cent of world wind energy production. Currently, the United States legislative support for the wind energy industry is a 2.1 cents per kWh tax credit allowed for the production of electricity from utility-scale wind turbines (the Wind Energy Production Tax Credit). As of January 2012, the United States' renewable portfolio standards (RPS) is mandatory in 30 states. The RPS is similar to Australia's RET, and has played a key role in supporting renewable electricity generation, including wind energy.

The United States market posted annual market growth of more than 30 per cent in 2011, adding 6810 MW in 31 states for a total installed capacity of almost 47 GW, and cumulative market growth of nearly 17 per cent. Wind power now generates close to 2 per cent of the United States' electricity needs. The number of states with installed utility-scale wind projects sits at 38, with 31 states adding new capacity in 2011. Wind power is an established mainstream energy source in the United States today—adding 35 per cent of all of the United States' new electric generating capacity between 2007 and 2010 (GWEC 2011).

Table 9.1 Key wind energy statistics

	Unit	Australia 2011–12	Australia 2010–11	OECD 2011	World 2010
Primary energy consumption[a]	PJ	22.0	20.9	1204.5	1230.4
Share of total	%	0.36	0.3	0.5	0.2
Average annual growth from 2000	%	36.9	45.8	25.3	27.3
Electricity generation					
Electricity output	TWh	6.1	5.8	334.5	341.7
Share of total	%	2.4	2.3	3.1	1.6
Electricity capacity	GW	2.6	1.9	134.2	237.7[b]

OECD = Organisation for Economic Co-operation and Development
a Energy production and primary energy consumption are identical. **b** in 2011

Source: BREE 2013a; GWEC 2012a and 2012b; IEA 2012a

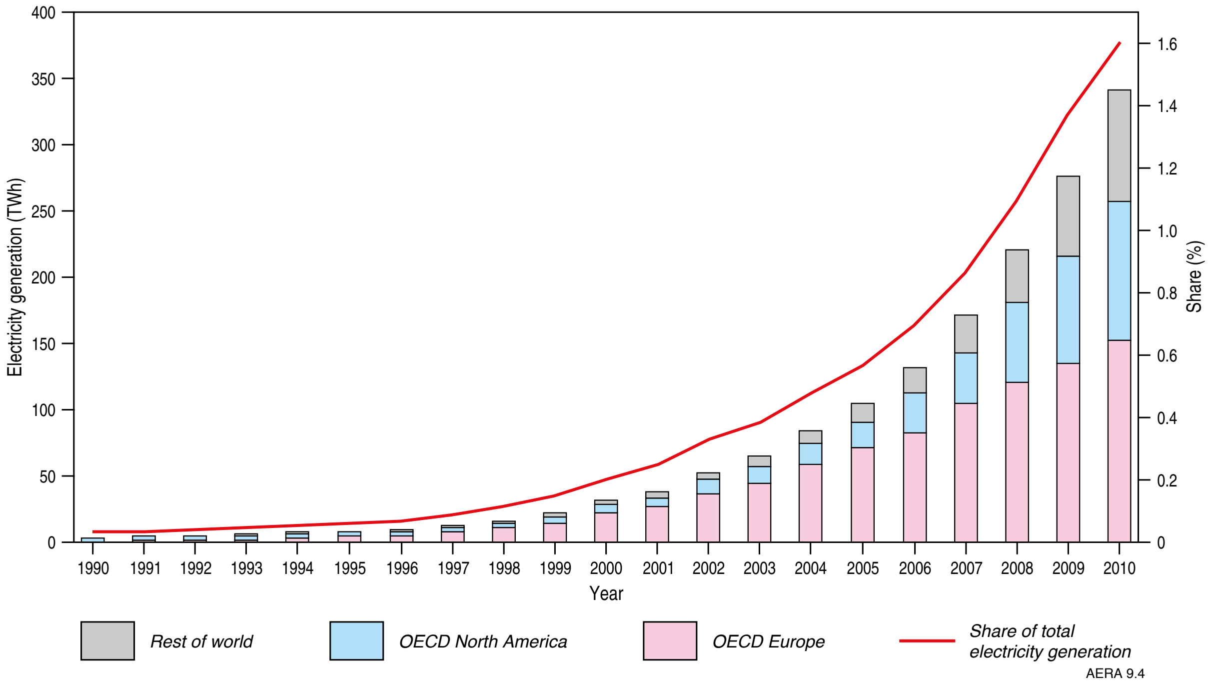

Figure 9.4 World wind electricity generation, by region

OECD = Organisation for Economic Co-operation and Development

Source: IEA 2012a

The main drivers of growth in the global market, as they have been for the past several years, are the Asian powerhouses of China and India. China (with 13 per cent of world wind electricity generation in 2010) and India (6 per cent) have emerged as significant wind energy producers. Both countries manufacture and export wind turbines.

While the era of double and triple-digit growth in China's wind market may be over for the time being, it still represented about 43 per cent of the global market, and India posted yet another year of record installations; the two countries together accounted for just over 50 per cent of the global market in 2011 (GWEC 2012a, 2012b).

Wind energy contributes a significant proportion of electricity in some countries, particularly Denmark (20 per cent in 2010), Portugal (17 per cent), Spain (15 per cent) and Germany (6 per cent) (figure 9.5b). Offshore installations in Europe decreased slightly last year, but strong growth figures were posted in Romania, Poland and Turkey; and a strong year in Germany reflects a renewed and even stronger commitment to renewables in the wake of the nuclear phase-out decision (GWEC 2011).

Australia is the twelfth largest wind producer in the world (figure 9.5a). Wind energy accounted for only 2.3 per cent of Australia's total electricity generation in 2010–11 (table 9.1).

Wind penetration metrics are useful to measure the wind energy generation integration. The Söder metric is considered the most useful for ranking the penetration of wind as it is based on the ratio of maximum wind (i.e. installed capacity) to minimum demand plus maximum export. South Australia and Ireland have the world's second penetration percentage after the Iberian Peninsula (south-west European coast), based on the Söder metric (AEMO 2009, 2011).

Installed generation capacity

The global installed electricity generation capacity for wind power at the end of 2011 was about 237.7 GW (figure 9.6). Of the new global installed capacity in 2011, China and the United States accounted for 43 per cent and 17 per cent, respectively (GWEC 2012a).

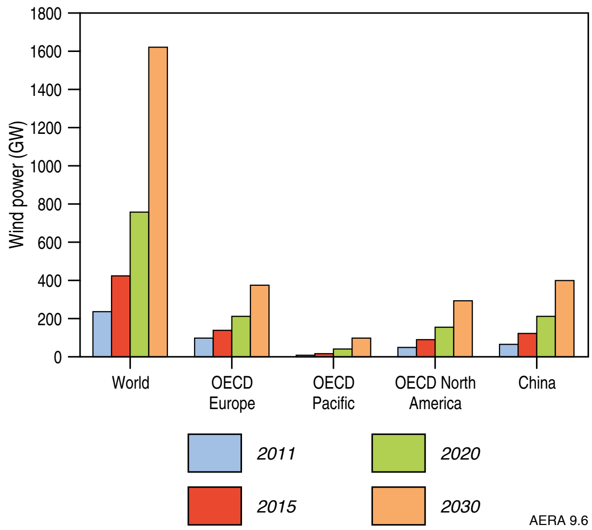

Figure 9.6 Projected world wind power capacity

OECD = Organisation for Economic Co-operation and Development

Source: GWEC 2012a

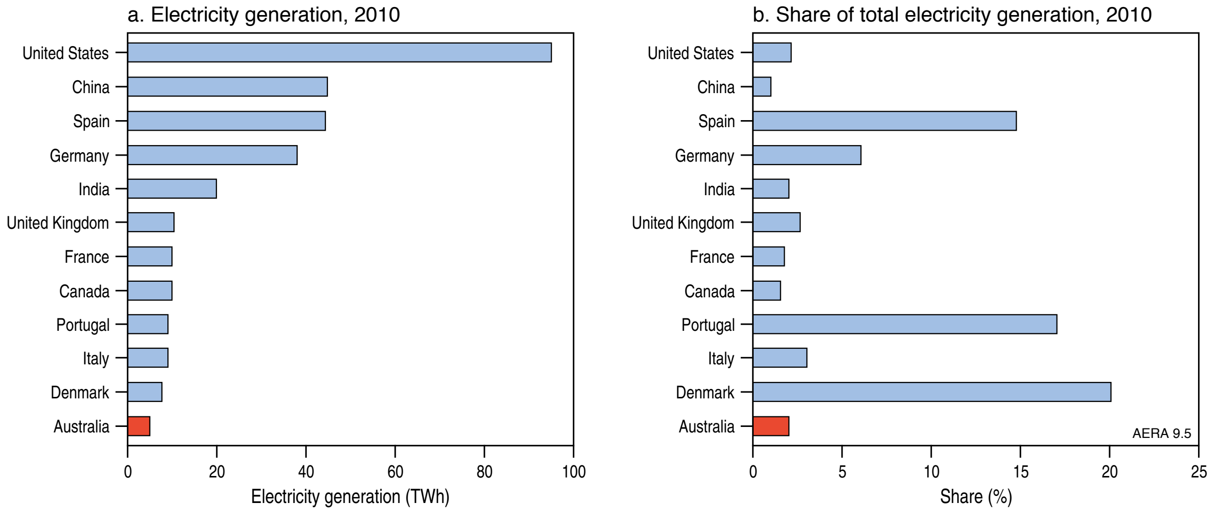

Figure 9.5 Wind electricity generation, major countries, 2010

Source: IEA 2012a

At the end of 2011 China had the highest installed capacity (62 GW) followed by the United States (47 GW), Germany (29 GW), Spain (21 GW) and India (16 GW). Together these five countries accounted for more than 74 per cent of global installed capacity (table 9.2).

Table 9.2 Installed capacity in wind electricity generating countries, 2011

Country	Installed capacity (GW)	Share of world (%)
1. China	62.364	26.24
2. United States	46.919	19.74
3. Germany	29.060	12.23
4. Spain	21.674	9.12
5. India	16.084	6.77
6. France[a]	6.8	2.86
7. Italy	6.737	2.83
8. United Kingdom	6.540	2.75
9. Canada	5.265	2.22
10. Portugal	4.083	1.72
11. Demark	3.871	1.63
12 Sweden	2.970	1.25
13. Netherlands	2.328	0.98
14. Australia	2.224	0.93
Rest of the world	20.750	8.73
World	**237.669**	**100**

a Provisional figure

Source: GWEC 2012b

World wind energy market outlook

According to the IEA (2012a), the global wind energy industry is projected to continue to grow strongly throughout the period to 2035, increasing its share of electricity generation in many countries. In the IEA new policies scenario projections, world electricity generation from wind energy is projected to increase at an average annual rate of 8.6 per cent between 2010 and 2035 (table 9.3). The share of wind energy in total world electricity generation is projected to increase from 1.6 per cent in 2010 to 7.3 per cent in 2035.

OECD countries are expected to continue to be the main wind energy producers over the outlook period. In the OECD region, the share of wind energy in total electricity generation is projected to rise from 2.5 per cent in 2010 to 10.7 per cent in 2035. By 2035, OECD countries are projected to account for 56 per cent of world wind electricity generation. In non-OECD countries, wind energy use is also projected to rise strongly and, by 2035, non-OECD countries are projected to account for 44 per cent of world wind electricity generation (figure 9.7).

Table 9.3 IEA new policies scenario projections for world electricity generation from wind energy

	Unit	2010	2035
OECD	TWh	269.1	1423.0
Share of total	%	2.5	10.7
Average annual growth, 2010–35	%		6.9
Non-OECD	TWh	72.6	1258.0
Share of total	%	0.7	5.4
Average annual growth, 2010–35	%		12.1
World	TWh	341.7	2681.0
Share of total	%	1.6	7.3
Average annual growth, 2010–35	%		8.6

OECD = Organisation for Economic Co-operation and Development
Note: totals may not add due to rounding

Source: IEA 2012a, 2012b

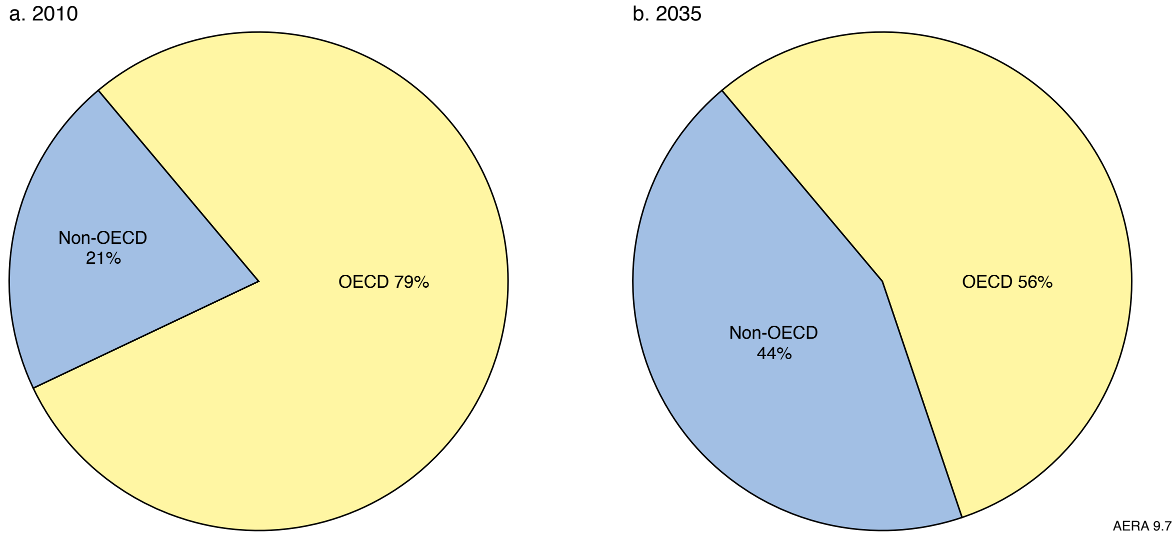

Figure 9.7 IEA new policies scenario projections for wind energy in the OECD and non-OECD regions, 2010 and 2035

OECD = Organisation for Economic Co-operation and Development

Source: IEA 2012a, 2012b

9.3 Australia's wind energy resources and market

9.3.1 Wind energy resources

Australia has some of the best wind resources in the world. Australia's wind energy resources are located mainly in the southern parts of the continent (which lie in the path of the westerly wind flow known as the 'roaring 40s') and reach a maximum around Bass Strait (figure 9.9). The largest wind resource is generated by the passage of low pressure and associated frontal systems whose northerly extent and influence depends on the size of the frontal system. Winds in northern Australia are predominantly generated by the monsoon and trade wind systems. Large-scale topography such as the Great Dividing Range in eastern Australia exert significant steering effects on the winds, channelling them through major valleys or deflecting or blocking them from other areas (Coppin et al. 2003). Deflection of weaker fronts from frontal refraction around the ranges of the Divide in south-eastern Australia creates winds with a southerly component ('southerly busters') along the east coast.

In addition to the refractions by topography and heat lows over northern Australia, other major factors influencing wind resources are seasonal and diurnal variation in wind speed. Winds are strongest in winter and spring in western and southern Australia but the monthly behaviour differs from region to region. Variations in average monthly wind speed of up to 15–20 per cent over the long-term annual average are not uncommon. There may be similar daily variations at individual locations, with increased wind speeds in the afternoon (Coppin et al. 2003).

Meso-scale maps show that Australia's greatest wind potential lies in the coastal regions of western, south-western, southern and south-eastern Australia (areas shown in orange to red colours in figure 9.9 where average wind speeds typically exceed 6.5 m/s). Coastal regions with high wind resources (wind speeds above 7.5 m/s) include the west coast south of Shark Bay to Cape Leeuwin, along the Great Australian Bight and the Eyre Peninsula in South Australia, to western Victoria and the west coast of Tasmania (figure 9.8). Good wind resources extend hundreds of kilometres inland and many of Australia's wind farms (current and planned) are located some distance from the coast. Inland regions of Western Australia, South Australia and western Victoria all have good wind resources. Areas with high wind potential also lie along the higher exposed parts of the Great Dividing Range in south-eastern Australia, such as the Southern Highlands and New England areas.

The *New South Wales wind atlas* (SEDA NSW 2002) shows that the areas with the highest wind energy potential lie along the higher exposed parts of the Great Dividing Range and very close to the coast except where there is significant local sheltering by the escarpment. The best sites result from a combination of elevation, local topography and orientation to the prevailing wind. Significantly, the map shows that some inland sites have average wind speeds comparable with those in coastal areas of southern Australia.

The Victorian wind atlas (SEAV 2003), shows a modelled average wind speed of 6.5 m/s across the state with the highest average wind speeds (>7 m/s) found in coastal, central and alpine regions of Victoria (figure 9.9). The atlas also presents modelled average wind speed data in relation to land title (national parks, other public land and freehold land), land use and proximity to the electricity network. Effective wind resources are defined as those located within a commercially viable distance from the electricity network. The atlas delineates corridors within 10 km and 30 km of the network. It presents wind resource maps for each of the local government areas in relation to the electricity network according to land title.

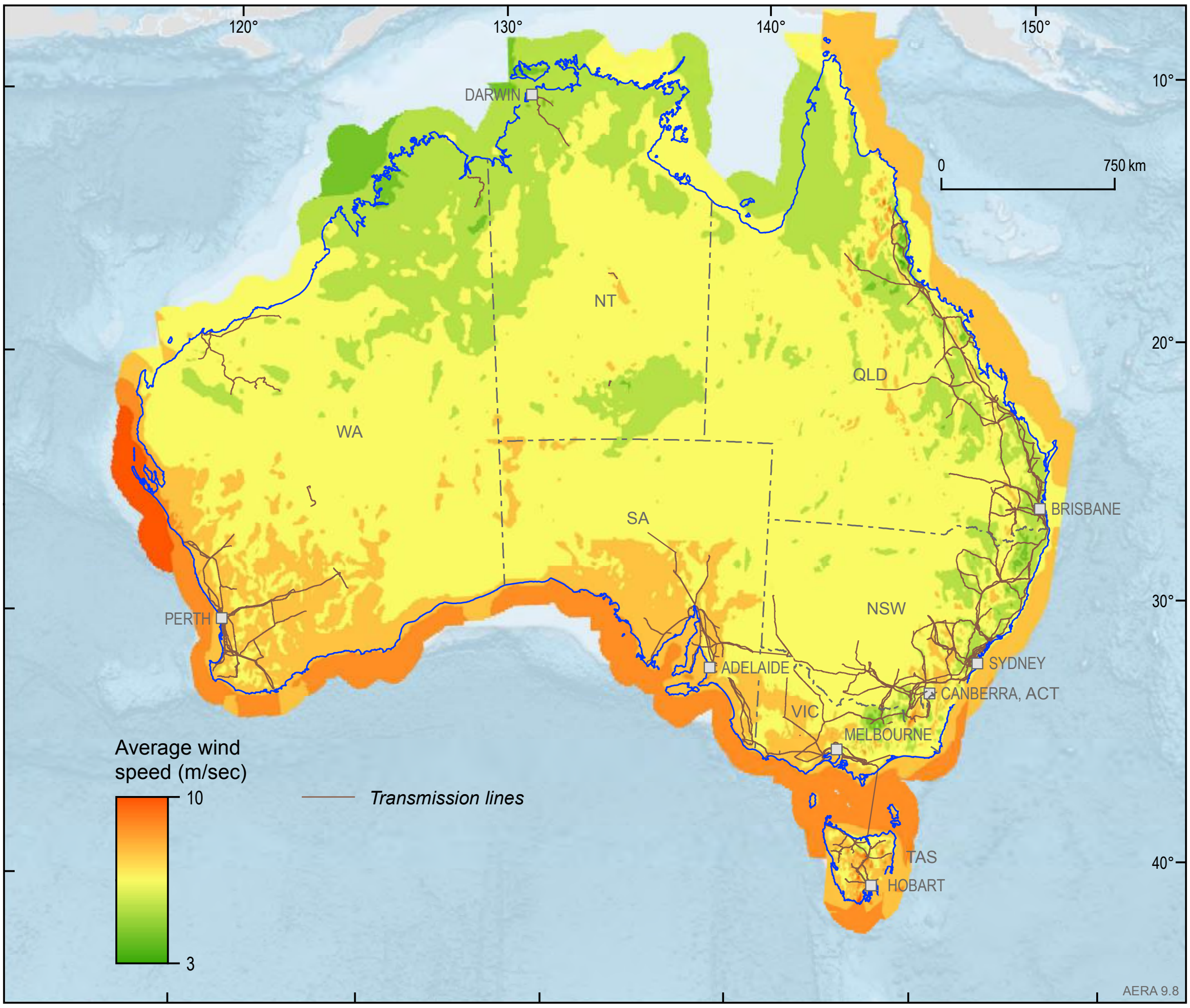

Figure 9.8 Predicted average wind speed at a height of 80 metres

Source: Geoscience Australia; Windlab Systems Pty Ltd

Local topography and other variability in the local terrain such as surface roughness exert a major influence on wind speed and wind variability. Wind speed varies with height and with the shape and roughness of the terrain. Wind speed decreases with an increasingly rough surface cover, but can be accelerated over steep hills, reaching a maximum at the crest and then separating into zones of turbulent air flow. There are also thermal effects and funnelling which need to be considered when assessing wind resources. All of these effects impact on capacity factors (Coppin et al. 2003, ESIPC 2005). Australia's high capacity factors reflect the large development potential.

Because of these factors, meso-scale maps such as figure 9.8 do not account for fine-scale topographical accelerations of the flow. In particular, the effect of any topographical feature smaller than 3 km is unlikely to be accounted for. In mountainous country, topographical accelerations (and decelerations) because of these finer scale features commonly exceed 20 per cent. As such, these maps are useful only for preliminary selection of sites: detailed assessment of wind energy resources for potential wind farm sites requires integration of high-quality monitoring measurements with a micro-scale model of wind flow incorporating the effects of topography and terrain roughness.

ROAM Consulting (2012) modelling indicates that all the National Electricity Market (NEM) regions have significant potential for onshore wind development. However, based on build limits (maximum installable capacity and the equivalent land-area required for maximum capacity) for onshore wind energy, some of the areas of higher potential are the mid-north region of South Australia, north and south coast of New South Wales, tropical North Queensland and the Eyre Peninsula in South Australia.

Some of the most available sites for offshore wind resource are located off the coast of South Australia and Tasmania. Queensland's offshore potential is limited by the Great Barrier Reef marine park, and there are limited suitable sites for New South Wales (ROAM Consulting 2012).

9.3.2 Wind energy market

The wind energy market in Australia is growing at a rapid pace, driven by an increasing emphasis on cleaner energy sources and government policies encouraging its uptake. The wind energy industry has been the fastest growing renewable energy source, largely because it is a proven technology, and has relatively low operating costs and environmental impact.

Primary energy consumption

In 2011–12, wind energy accounted for only 0.36 per cent of primary energy consumption (table 9.1). However, wind is the fastest growing energy source in Australia, increasing at an average annual rate of 35.9 per cent between 1999–00 and 2011–12.

Electricity generation

In Australia, wind energy was first utilised for electricity generation in 1994 and the industry has expanded rapidly in recent years (figure 9.9). Australia's wind electricity generation was 6.1 TWh in 2011–12, accounting for 2.4 per cent of total electricity output in Australia.

Installed electricity capacity

At the end of 2012, there were 66 wind farms with a total installed capacity of 2584.1 MW in operation in Australia (table 9.4). The total installed capacity of wind power has grown by an average of 35 per cent per year over the past five years. Although the cost of wind energy continues to fall, government support such as the Renewable Energy Target (RET) supports investment in the industry and enables the wind power sector to play a major role in helping Australia's transition to a low carbon economy.

In 2012, the majority of these power stations were located in South Australia (47 per cent), Victoria (20 per cent) and Western Australia (16 per cent) (figure 9.10 , table 9.4). Information on wind farms commissioned since January 2010 is provided in box 9.2.

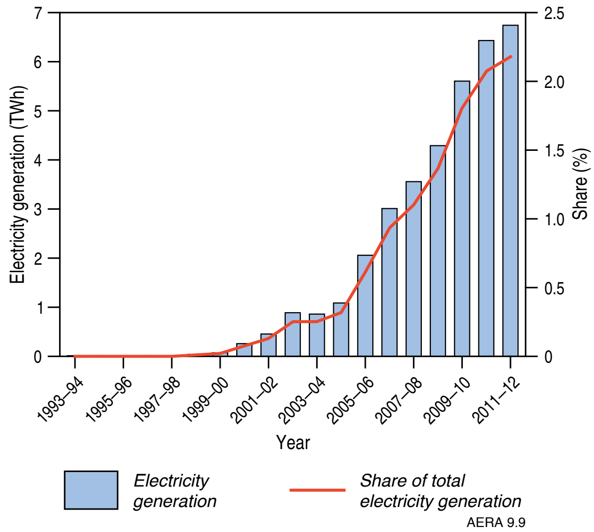

Figure 9.9 Australia's wind electricity generation

Source: BREE 2013a

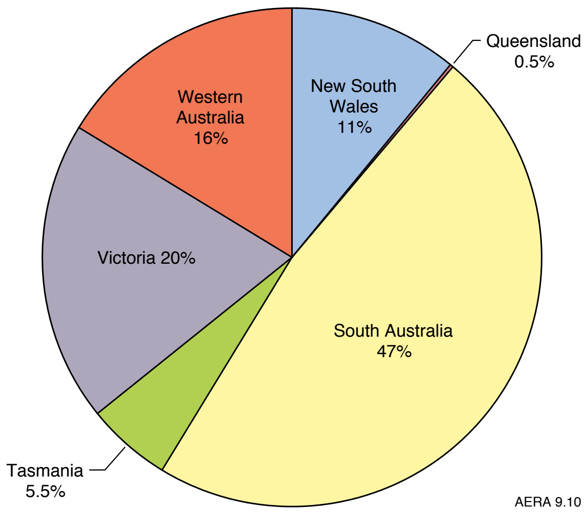

Figure 9.10 Installed wind energy capacity, by state, 2012

Source: Clean Energy Council 2012

Table 9.4 Australia's wind energy industry by state, 2012

State/Territory	Number of farms	Installed capacity (MW)	Share of total capacity (%)
South Australia	16	1205	47
Victoria	12	519	20
Western Australia	17	424	16
New South Wales	9	282	11
Tasmania	6	142	5.5
Queensland	2	12	0.5
Northern Territory[a]	4	0.1	0.0
Australia	**66**	**2584.1**	**100.0**

a Individual wind turbines in communities/urban locations

Source: Clean Energy Council 2012

The size of wind farms is increasing, as companies with capacity to install large farms take advantage of economies of scale and capitalise on sites with high wind potential. Australia's largest operating wind farms are Macarthur Wind Farm in Victoria (420 MW; commissioned in early 2013) and the Collgar Wind Farm in Western Australia (205.35 MW; commissioned in early 2012). However, wind farms up to 1000 MW are planned or under construction. More detailed information on project developments is provided in section 9.4.2.

9.4 Outlook for Australia's wind energy resources and market

Australia accounts for only a small share of world wind energy consumption, an estimated 0.36 per cent in 2011–12; however, it grew at a faster rate (45.8 per cent a year) than the world average between 1999–00 and 2010–11. Australia's total installed capacity of wind energy is about 1 per cent of the world's total installed capacity of wind energy. Currently electricity generated by wind accounts for only 2.4 per cent of Australia's total electricity generation (table 9.1).

Wind energy is likely to increase, driven substantially by government policies and because electricity generated by wind energy is a proven renewable energy technology with low emissions.

9.4.1 Key factors influencing the future development of Australia's wind energy resources

Worldwide, wind energy is the fastest growing form of electricity generation and is set to play an increasingly important role in the energy mix, including in Australia. It is a proven and mature technology and the output of both individual turbines and wind farms has increased significantly in the past five years. The wind energy market has reached a mature stage in some energy markets, such as in western Europe, because it is already cost competitive with other forms of electricity generation.

Wind is generally the second most cost competitive renewable source of electricity generation, after hydro. However, it has significantly more growth potential because of the greater level of as yet unutilised resources. Its cost competitiveness will be enhanced by a reduction in the cost of turbines, particularly through low-cost,

BOX 9.2 WIND ENERGY PROJECTS RECENTLY COMMISSIONED

Since January 2010, there have been some 16 wind energy projects completed in Australia, with a combined total installed capacity of over 1540 MW (table 9.5).

The 420 MW Macarthur Wind Farm in western Victoria is currently the largest operating wind farm in the southern hemisphere. The wind farm has the capacity to generate energy to power approximately 220 000 homes per year.

The Collgar Wind Farm in Western Australia is the second largest operating wind farm in Australia. The 205.35 MW capacity will supply electricity to the Western Australian South West Interconnected System power grid, producing enough electricity to power approximately 125 000 homes per year.

Table 9.5 Wind energy projects commissioned 1 January 2010 to 2012

Project	Company	State	Start up	Capacity (MW)
Albany II (Grasmere)	Verve Energy	WA	2012	13.8
Collgar	UBS IIF/REST	WA	2012	205.35
Hallet 5 (The Bluff)	AGL Energy/Eurus Energy	SA	2012	100.8
Oaklands Hill	AGL Energy/Oaklands Hill Pty Ltd	VIC	2012	67.2
Gunning	Acciona Energy	NSW	2011	46.5
Hallett 4 (North Brown Hill)	AGL	SA	2011	132.3
Hepburn (Leonards Hill)	Hepburn Wind	VIC	2011	4.1
Macarthur	AGL Energy/ Meridian Energy	VIC	2013	420
Mt Barker	Mt Barker Power	WA	2011	2.4
Mumbida	Verve Energy/Infrastructure Capital Group	WA	2013	55
Musselroe Bay	Hydro Tasmania	TAS	2013	168
Woodlawn	Infigen Energy	NSW	2011	48.3
Clements Gap	Pacific Hydro	SA	2010	56.7
Hallet 2 (Hallet Hill)	AGL	SA	2010	71.4
Lake Bonney 3	Infigen Energy	SA	2010	39
Waterloo	TRUenergy	SA	2010	111

Source: Clean Energy Council 2012

high-volume manufacturing in countries such as India and China, and to a lesser extent by further efficiency gains through turbine technology development. As existing turbines come to the end of their productive life around 2030–40, optimum sites will be refurnished with high-rated turbines, which will improve the economics for wind energy projects.

Factors that may limit development of wind energy on a localised basis include the lack of electricity transmission infrastructure to access remote wind resources and the intermittency and variability of wind energy. The variability of wind energy can create difficulties in integration into the electricity system where supply must balance demand in real time to maintain system stability and reliability. This becomes more of a problem as the amount of wind energy incorporated into the grid increases and can become significant in a localised context. However, at the levels of wind energy penetration projected, these issues should be effectively managed by greater geographic spread of wind resources and improvements to the response capabilities of the grid through improved forecasting.

Wind energy—an increasingly cost-competitive, mature, low emissions, renewable energy source

The expansion of wind energy over the past decade is the outcome of international research and development that has resulted in major improvements in wind turbine technology.

The most significant technological change in wind turbines has been substantial increases in the size and height of the rotor, driven by the desire to access higher wind speeds (wind speed generally increases with height above the ground) and thereby increase the energy extracted. The size of the rotor is determined by the maximum aerodynamic efficiency, which is adjusted to keep the tip speed under control, and so minimise noise concerns, and to spill wind when the turbine reaches maximum output.

The trend in turbine design over the past two decades has seen the consistent development of larger turbines, which is likely to continue into the future. Material and construction technique developments enable the use of taller towers and larger diameter rotors, which have the benefit of improving energy capture by accessing stronger and less turbulent wind at higher elevations as well as increasing the energy intercepted from the swept area of the rotor. There is an increasing trend to develop larger scale onshore wind projects in Australia; for example, the 420 MW Macarthur Wind Farm in Victoria commissioned in 2013 is the largest wind farm in the southern hemisphere. It is expected that greater than 100 MW wind farms will become more common over the forecast period with an ongoing trend towards deployment of fewer, larger capacity machines (AETA 2012).

Efficiency gains through onshore turbine technology are slowing, and further increases in cost competitiveness will be driven by reducing manufacturing costs. This is being achieved primarily through a move to low-cost, high-volume turbine production.

Cost of development

The costs specific to developing a new wind farm will vary across projects and locations. They will be influenced by a number of factors such as:

- the cost of turbines
- proximity to existing infrastructure
- ease of grid integration
- whether the development is onshore or offshore
- the life of the project
- government policies and regulations
- environmental impact
- community support.

These factors influence the variation in development costs across different countries.

The growth of the wind power industry in the world is attracting increased investment over the past few years, reaching A$68 billion in new wind power equipment in 2011 (GWEC 2012b).

Capital costs per kilowatt of installed capacity were considered to have averaged A$1686 in 2011. Based on the IEA reference case, a strong increase of wind power capacity to 2030 is expected to result in the capital cost per kilowatt of installed capacity to decrease slightly to A$1640/kW (figure 9.11; GWEC 2012b).

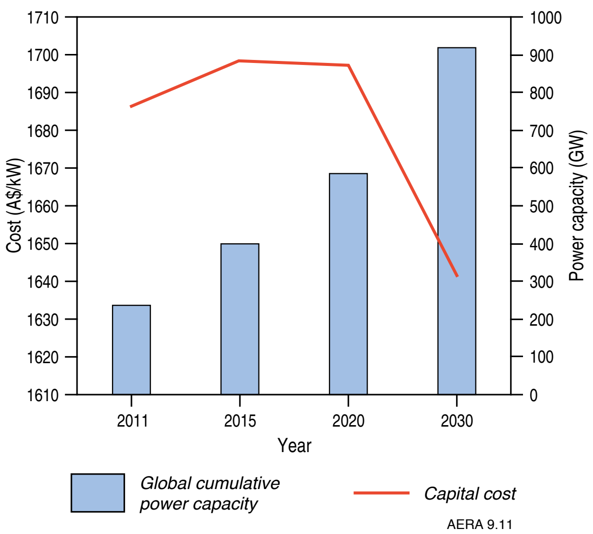

Figure 9.11 Projection of capital cost and global cumulative wind power capacity

Source: BREE 2012c; GWEC 2012b

The capital cost of turbines, which is the most significant portion of capital cost (figure 9.12), has been decreasing over the past several years, both in adjusted and in absolute terms (GWEC 2012b). In recent years, the major trends that have dominated the development of grid-connected wind turbines are:

- turbines have become larger and taller—the average size of turbines sold on the market has increased substantially. For example, the size increased from less than 0.5 MW in 1990 to more than 2 MW in 2008 in Germany, Spain, Denmark, the United States and the United Kingdom
- efficiency of turbine production has increased steadily
- investment costs per kW have decreased, although there has been a deviation from this trend in recent years.

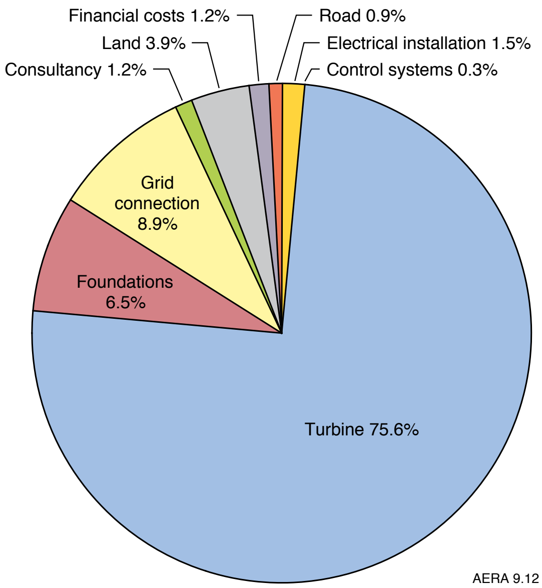

Figure 9.12 Capital costs of a typical wind farm

Source: Windfacts 2012

Lifecycle cost structure

The development of wind energy is relatively capital intensive compared with many other energy sources, estimated to typically comprise between 70 per cent and 80 per cent of a project's lifetime costs (Blanco 2009, Dale et al. 2004). This is primarily because of the high cost of turbines (figure 9.12) and grid integration infrastructure relative to the low variable costs. The only variable costs are operation and maintenance costs, as the resource used in electricity generation (i.e. wind) is free. Individual turbines can cost up to A$3 million. The capital cost components of a typical wind farm are indicated in figure 9.12.

A wind farm's revenue stream at its most basic level is the product of the amount and price of electricity sold to the grid. Higher income streams are favoured by a higher electricity price and by larger wind farms with larger turbines (and hence greater capacity). Consequently, countries with relatively more highly developed wind energy industries typically have a combination of good wind conditions and high electricity prices. Direct subsidies and other clean energy initiatives may further influence the uptake of wind energy.

Economies of scale

There has been a clear trend towards larger size of wind farms over the past three years in Australia. Since then the number of wind farms constructed per annum has reduced although they appear to have become larger in terms of MW capacity (Clean Energy Council 2012).

As at January 2012, large wind farms (greater than 100 MW capacity) comprised 11.5 per cent of operating wind farms but accounted for 40.6 per cent of Australia's wind-generating capacity. Medium-sized wind farms (10–100 MW capacity) accounted for the majority of wind

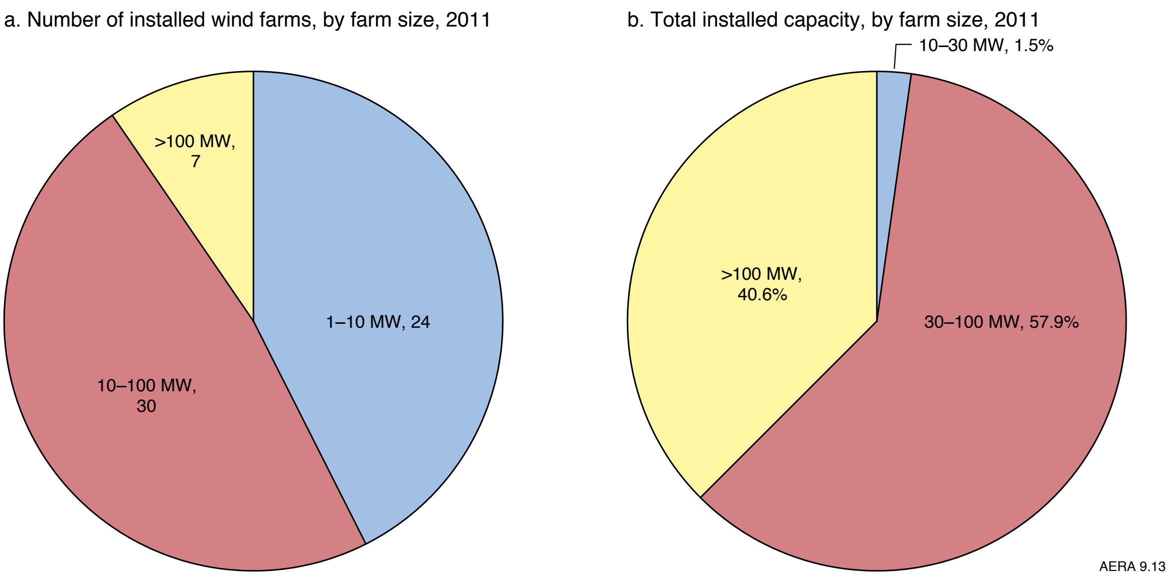

Figure 9.13 Current wind energy installations in Australia, by farm size, January 2012

Source: Clean Energy Council 2012

energy capacity in Australia with 57.9 per cent. Small wind farms (less than 10 MW capacity) comprised 39.3 per cent of operating wind farms accounting for only 1.5 per cent of total wind generating capacity (figure 9.13; Clean Energy Council 2012).

The increasingly large size of wind farms reflects the economies of scale to be gained through larger operations. Heavy utilisation of sites with high wind potential and consolidation of generating technology will significantly reduce grid integration costs and maximise the economic gains from wind energy. In addition, larger firms are more able to cover the considerable fixed costs of setting up larger wind farms, which is reflected in a trend toward industry consolidation.

Past barriers to the development of larger installations have been the large up-front capital costs and the associated uncertainty about achieving secure contracts for the electricity generated. However, this barrier is declining in importance because of the increasing demand for renewable energy. As returns to investments are proven and become more secure, larger investments are emerging.

Cost competitiveness

The future of wind power will depend a great deal on the ability of the industry to continue to achieve reductions in the cost of energy.

Between 1980 and the early 2000s, significant reductions in capital cost and increases in performance had the combined effect of dramatically reducing the levelised cost of energy (LCOE) for onshore wind energy. However, beginning in about 2003 and continuing through the latter half of the past decade, wind power capital costs increased, driven by rising commodity and raw materials prices, increased labour costs, higher manufacturing costs and turbine up-scaling, which pushed LCOE of wind upward in spite of continued performance improvements (figure 9.14a; Windfacts 2012).

The LCOE depends on some key factors, including whether the facility is onshore or offshore, wind speed and technology improvement. Based on BREE's estimation, the average LCOE for onshore New South Wales wind farms (A$116/MWh) is lower than for offshore New South Wales wind farms (A$194/MWh) (figure 9.14a, BREE 2012b). The long-term projection of LCOE in Australia shows the LCOE for both onshore and offshore wind will decrease from 2012 to 2020, and slightly increase from 2020 to 2050 (figure 9.14b).

On a levelised cost of technology basis (including capital; operating, fuel, and maintenance costs; and capacity factor) wind energy compares favourably with traditional sources of electricity generation, such as coal, oil, gas, nuclear and biomass . Lower manufacturing costs together with improvements in turbine efficiency and performance, and optimised use of wind-sensing equipment are expected to decrease the cost of wind technology in the future.

Time to develop

The development process after feasibility has been ascertained is relatively simple, comprising an approval stage and a building stage. The length of the approval stage can vary widely, depending on the relevant authorities' requirements and the complexity of the approval process. Construction time varies depending on a number of factors but is short compared with many other forms of electricity generation. Because of additional foundation and grid integration requirements, installation of offshore wind farms involves longer building times. Remoteness and complexity of terrain will also affect the building time. Conversely, one advantage of wind energy is that, compared with many other renewable technologies, it is a proven technology that is relatively straightforward to build and commission.

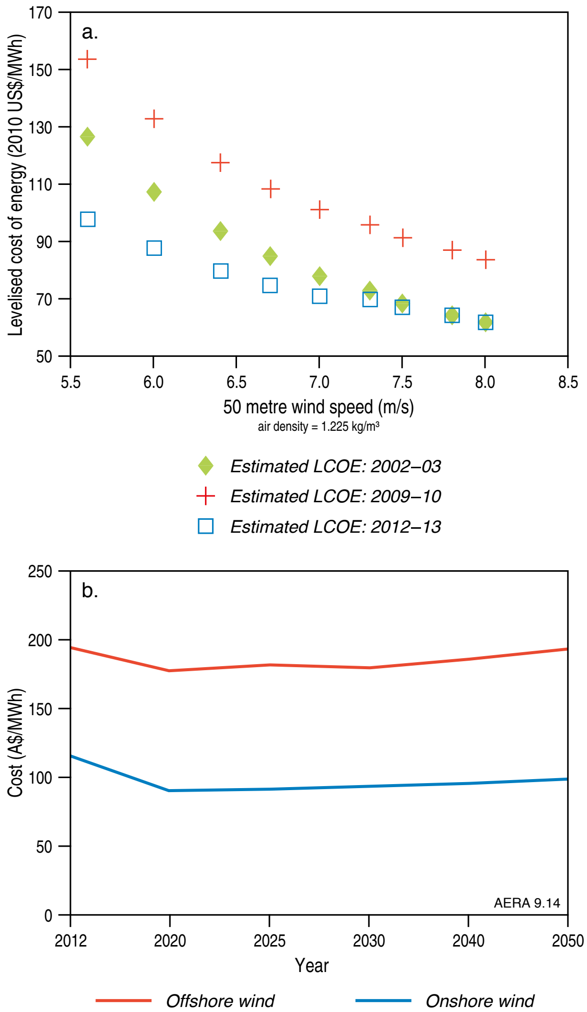

Figure 9.14 Wind levelised cost of technology, by farm size

Source: Windfacts 2012; BREE 2012b

Policy environment

The current and prospective policy environments within which a wind farm is operating are central to the effectiveness and competitiveness with which it operates. Direct support through subsidisation or favourable tax policies (as in some countries), or indirect support for renewables from costs imposed on greenhouse gas emissions will enhance the competitiveness of wind energy and other renewable sources of energy. The operation of wind turbines produces no carbon dioxide emissions, and emissions involved in the development stage are modest by comparison with electricity generation from other sources.

The Large-scale Renewable Energy Target (LRET) and the Small-scale Renewable Energy Scheme (SRES) provide incentives designed to bridge the gap between the price of black electricity and renewable energy, and are expected to yield more than 45 000 GWh in 2020.

Grid integration—managing variability

Wind is a highly variable resource and so, therefore, is wind energy production. The high ramp rate of wind energy production is an associated and equally important characteristic, particularly in integrating the electricity produced into the electricity grid. Because wind energy increases more than proportionately with wind speed, electricity generation from wind energy can increase very rapidly (point A to B in figure 9.15). Similarly, if wind speeds exceed the turbine rating the turbine shuts down and electricity generation can drop from maximum to zero very quickly (point C to D).

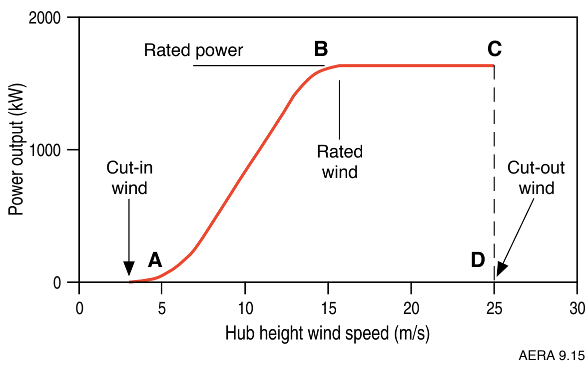

Figure 9.15 Power curve and key concepts for a typical wind turbine

Source: Ackermann 2005

The variability of wind energy can be managed through a combination of geographic distribution, a diverse range of renewable energy sources, demand management and supply of firming capacity from fast response electricity generation capacity—typically hydro energy or, increasingly, gas. In Australia's major interconnected electricity markets, power can be transferred quickly from different regions to firm supply when required. The United States Department of Energy estimated that between 20 and 30 per cent of renewable energy variable supply could be managed through geographic distribution and technology diversity.

Strong growth of wind energy poses challenges to successful integration of wind. There are several factors influencing wind power integration. These include:

- design and operation of power system—reserve capacities (capacity to generate more energy above normal peak demand) and balance management, short-term forecasting of wind power, demand-side management and storage, and optimisation of system flexibility
- grid infrastructure issues—optimisation of present infrastructure, extensions and reinforcements, offshore grids, and improved interconnection
- grid connection of wind power—grid codes (parameters required for a facility to connect to the grid), power quality (fitness of electric power to consumer devices) and wind power plant capabilities
- market redesign issues—market aggregation and adapted market rules increasing the market flexibility, particularly for cross-border exchange and operating the system closer to the delivery hour
- institutional issues—stakeholder incentives, non-discriminatory third-party grid access and socialisation of costs.

Because of wind energy's inherent supply variability, with electricity generation fluctuating according to the prevailing weather conditions, season and time of day, the penetration of wind energy in the Australian market will depend in part on improved grid management practice. A range of initiatives is being taken to enhance grid responsiveness (AER 2009).

Grids dominated by electricity generated from conventional fuels can face difficulties in dealing with renewables other than hydro and tend to be limited to 10–20 per cent penetration by power quality issues, installed capacity and current grid management techniques. Given that wind energy accounted for only 2.4 per cent of Australia's total electricity generation in 2011–12, this has only been an issue at a localised level, where wind energy penetration can be much higher. Wind accounts for around only 4 per cent of registered capacity in the National Electricity Market (NEM) but its role is expanding under climate change policies (AER 2011). As a result of significant investment in South Australia, Australian Energy Market Operator (AEMO) estimates that wind energy represents about 26 per cent of South Australia's electricity generation in 2011—12.

The limits for a particular grid are determined by a number of factors, including the size and nature of existing connected generating plants and the capacity for storage or demand management. In grids with heavy fossil fuel reliance and sufficient hydro for balancing, wind energy penetrations of less than 10 per cent are manageable; penetration levels above 20 per cent may require system and operational changes. Gas-fired electricity generation using gas turbines, as an alternative fast response energy source, is likely to play an increasingly important role as the proportion of wind and other intermittent renewable energy used increases (AER 2009).

Accurate and timely wind forecasting using a range of new techniques and real-time wind and generation modelling will also enhance wind energy penetration and grid integration (Krohn et al. 2009). The wind energy forecasting capability system is producing some of the world's most accurate forecasts of wind electricity generation over a range of forecast timeframes that are used by AEMO, wind farms and other market participants to better appreciate and manage the balance between supply and demand. AEMO has identified that reliable assessments of energy generation are important for proper evaluation of the output from wind farms.

The Australian Renewable Energy Agency will continue to work with network and distribution operators to review grid integration barriers and improve the efficiency and operation of renewable energy systems such as wind energy.

A report by the Australian Energy Market Commission (AEMC 2009) documented the need for increased flexibility and further expansion of the electricity transmission grid into areas not previously connected to allow for an expanded role of renewable energy sources. It suggests greater access to renewable resources clustered in remote geographic areas through development of connection 'hubs' or scale-efficient network extensions.

With the possible exception of localised areas with significantly higher than average wind resources (such as in South Australia and Western Australia), limits which place economic grid connection at risk are not likely to be reached in the outlook period.

Offshore wind energy developments

Sites with the highest wind energy potential tend to be developed first, therefore newer wind farms are likely to be sited in areas with progressively lower capacity factors. There has been some evidence of this in Europe, where land limitations have resulted in a declining average capacity factor. It has provided significant incentive to develop offshore sites. Community concerns have also been instrumental in shifting to offshore sites, as is the case in Demark.

Currently, development of wind farms offshore is limited by the high costs of offshore foundations and high costs of grid connection. Offshore locations also considerably raise the costs of operation and maintenance. However, because of substantially higher wind velocities, and therefore wind energy potential, compared with onshore sites, research and development into new technologies to increase the competitiveness of offshore wind farms is continuing. Offshore wind turbines are typically larger than those onshore to balance the increased costs of offshore marine foundations and submarine electric cables. Currently, commercial offshore wind farms are installed at shallow water depths (up to 50 m) with foundations fixed to the seabed, but large-scale floating turbines using ballast tied to the sea floor with cables are being tested. If successful this will allow offshore deployment in water more than 100 m deep.

Offshore sites are more important in countries with significant land access limitations, most notably in western Europe. Australia has sufficient onshore sites with high potential, therefore offshore sites are unlikely to be developed in the short term. Ocean water depth increases rapidly around most of Australia's coastline, therefore offshore sites are likely to be high cost due to ocean depth. There are some potential areas near population off Western Australia near the South West Interconnected System, and possible sites off New South Wales, Victoria, South Australia and Queensland (Messali and Diesendorf 2009).

Electricity transmission infrastructure—a potential long-term constraint

Proximity to a major energy load centre is an important element in a wind farm's economic viability, because the costs of transmission infrastructure and energy losses in transmission increase with distance from the grid. Reflecting this, wind farm developments to date have mostly been in close proximity (less than 30 km) to the grid (figure 9.16). As the size of wind farms has increased, so has the distance from the grid, with some proposed up to 100 km from the grid. The increased costs and transmission losses involved significantly affect the cost competitiveness of the wind farm overall, and are a key factor in project evaluation.

Development of remote wind energy resources will depend on extensions to the existing transmission grid. This is demonstrated by the significant reduction of the area with good wind resources (7 m/s and greater shown in figure 9.16) from about 600 000 km^2 to about 3300 km^2 when constrained to within 100 km of the existing electricity transmission grid (66 kV and greater). The actual area available for wind farm development is significantly less than this because of other limitations such as competing land uses, forest cover, access, and local planning and zoning laws (see, for example, SEAV 2003).

Social and environmental issues—potential local constraints

Although the low level of environmental impact has been a major driver of wind farm development, there are social and environmental aspects of its operation which have attracted criticism. The most common criticisms of wind farm developments are on the basis of aesthetics, low frequency noise pollution and impacts on local bird populations. These concerns have led several state governments to introduce restriction on wind farms being built within close proximity of residential or environmentally sensitive areas.

A growing sector is the community-owned wind farms, which promises to increase local energy independence. Community-owned wind farms are common in Denmark and Germany, and are emerging in Canada, the Netherlands, the United Kingdom and the United States. Australia's first community-owned wind farm is the Hepburn Wind Farm located 10 km south of Daylesford, Victoria. The 4.1 MW wind farm is estimated to produce 12 200 MWh per year, which is equivalent to the energy consumption of 2300 homes, more than the number of homes in Daylesford.

Modern wind turbines can generate noise across the frequency range of human hearing (20 to 20 000 Hertz), and extending to low frequency (in the range of 10 to 200 Hertz) and even infrasound (in the range of 20 Hz down to 0.001 Hz) levels, below the detection limit of the human ear. Concerns have been expressed that low-frequency noise emitted by wind turbines can cause illness to those living in close proximity to wind turbines. However, research has shown that the levels of low-frequency noise and infrasound emitted by modern wind turbines are below accepted thresholds (British Wind Energy Association 2005). There is a detailed approval process for every wind farm development which includes rigorous noise assessment. Compliance is required with relevant state Environmental Protection Agency guidelines and regulation.

The Clean Energy Council (2013) has developed best practice guidelines for the implementation of wind energy projects in Australia. The guidelines are intended to help industry and stakeholders understand the development process and provide confidence in the level of rigour that can be expected of proponents when preparing a wind farm proposal.

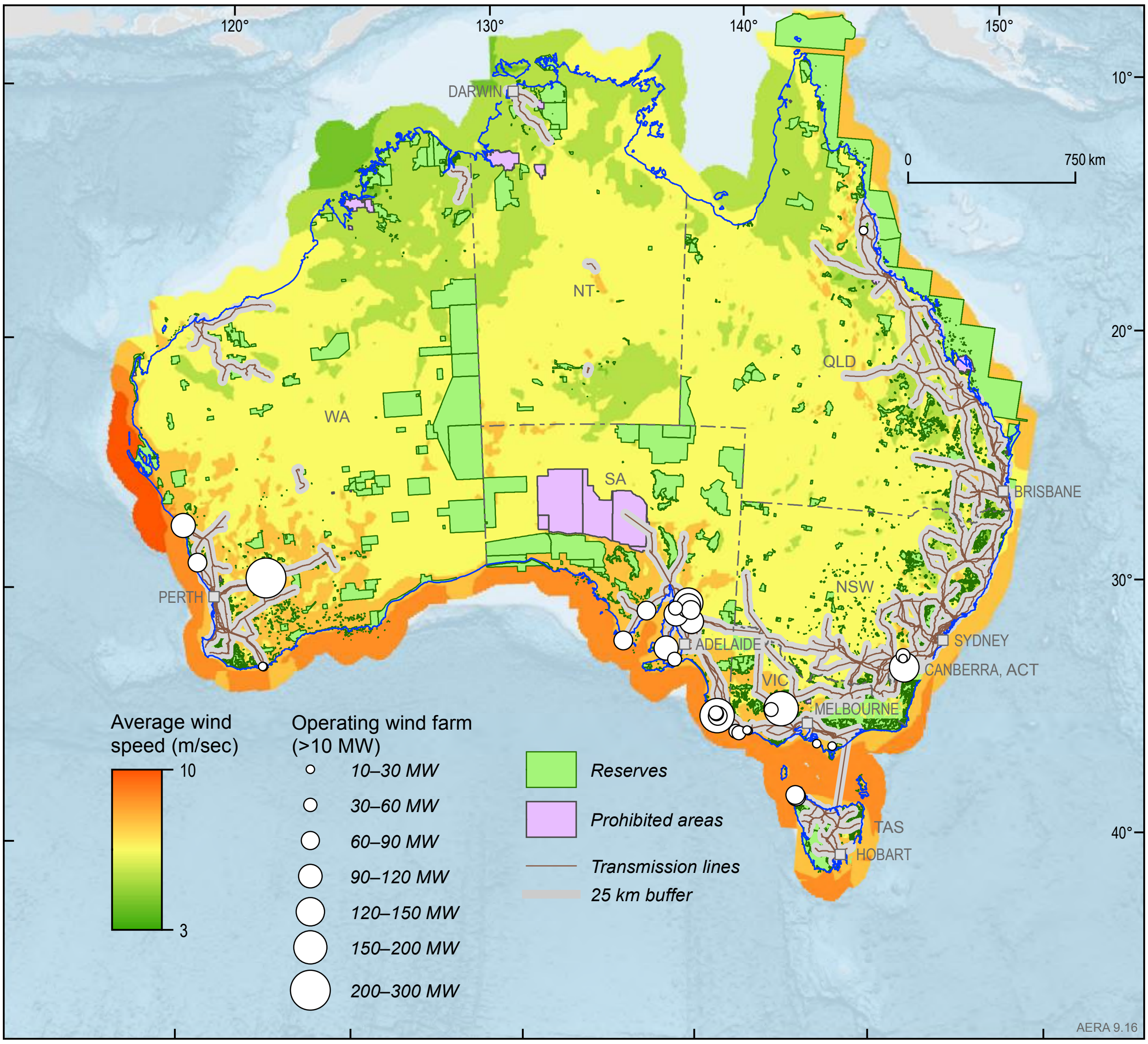

Figure 9.16 Wind energy resources in relation to reserved land and prohibited areas and the transmission grid. A 25 km buffer zone is shown around the electricity transmission grid

Source: Geoscience Australia; Windlab Systems Pty Ltd

BOX 9.3 THE WIND TURBINE—A MAJOR TECHNOLOGICAL DEVELOPMENT

The majority of wind turbines are based on the Danish three-blade design. This design differs from traditional windmills for which the force from high-velocity winds could potentially exceed the fatigue levels acceptable for components of the turbine. Therefore, instead of many broad, closely spaced blades, three long narrow blades achieve a balance between wind captured and an ability to manage extreme wind volatility (DWIA 2009).

Wind turbines capture wind energy within the area swept by their blades. The blades in turn drive a generator to produce electricity for export to the grid. The most successful design uses blades which generate 'lift' (the force that allows aircraft to fly), causing the rotor to turn. Some smaller turbines use 'drag' (the force felt pushing against you on a windy day) but they are less efficient. The common lift-style blades have a maximum efficiency of around 59 per cent, within the limits imposed by the designed maximum blade speed. Most modern wind turbines start producing energy at wind speeds of around 4–5 m/s and reach maximum energy at about 12–15 m/s. Wind turbines will have a cut-out wind speed (e.g above 25 m/s) to protect the turbine from damage, such as a brake mechanism or a spoiler to turn the turbine sideways.

Other considerations of turbine design include spacing between turbines, whether they are oriented upwind or downwind and the use of static (rigid) or dynamic (flexible) rotor designs. In each case a trade-off between size, cost, efficiency, aesthetics and a range of other factors is considered in the design of each farm.

Technology development has played an important role in increasing the competitiveness of wind energy in the electricity generation market. The size of wind turbines has reached a plateau after rising by a factor of ten (figure 9.17). The energy output increases with the rotor swept area (rotor diameter squared) but the volume of material (cost and mass) increases in proportion to the cube of the rotor diameter (USDOE 2008).

Until now, the additional benefits of size increases have outweighed the additional costs, which have resulted in the size of turbines increasing rapidly. While turbines are expected to continue to get bigger, the additional returns from those size increases are likely to diminish. Research into rotor design and materials is aimed at reducing loads on blades to allow development of larger, lighter rotors and taller towers with higher capacity factors. Wind turbines with capacities up to 7.5 MW are being considered for offshore deployment.

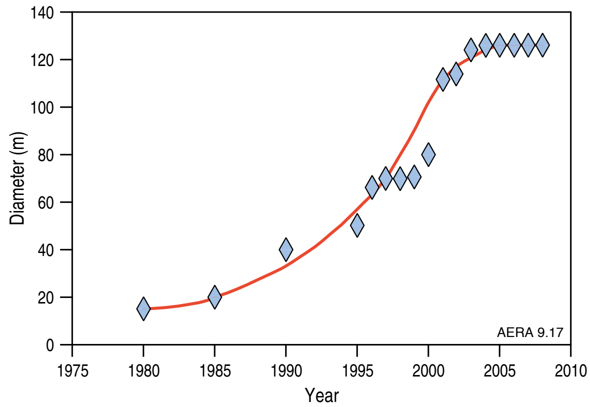

Figure 9.17 Increasing size of wind turbines over time

Source: Windfacts 2009

9.4.2 Outlook for wind energy market

Wind is expected to play an increasingly important role in the energy mix of many countries, including Australia.

Proposed development projects

The majority of the planned expansions in wind energy capacity are expected to occur in southern regions of Australia with high wind energy potential. The bulk of proposed developments are in New South Wales (32 per cent), Victoria (24 per cent) and South Australia (21 per cent), taking account of both wind energy potential in these areas and constraints imposed by the transmission grid (figure 9.18).

As of October 2013, there were 14 wind projects in Australia committed. In total, the projects have a planned capacity of over 1860 MW and a combined capital expenditure of over A$3.7 billion. Of the 14 projects, ten have a planned capacity of over 100 MW; the remainder varies between 40 and 84 MW (table 9.6, figure 9.19).

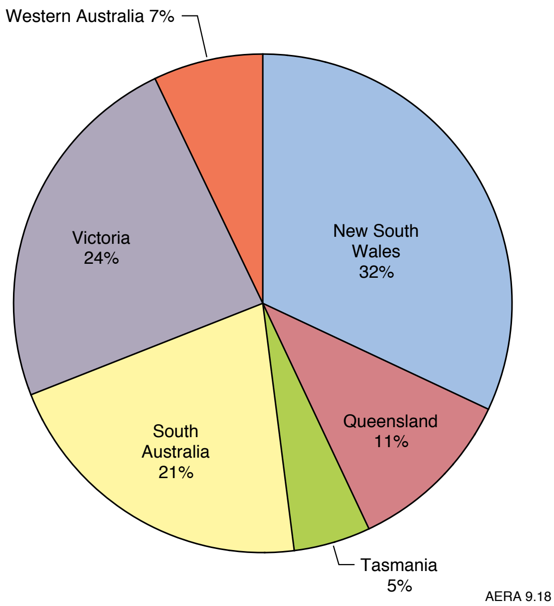

Figure 9.18 Proposed wind energy capacity by state (October 2013)

Source: Bureau of Resources and Energy Economics

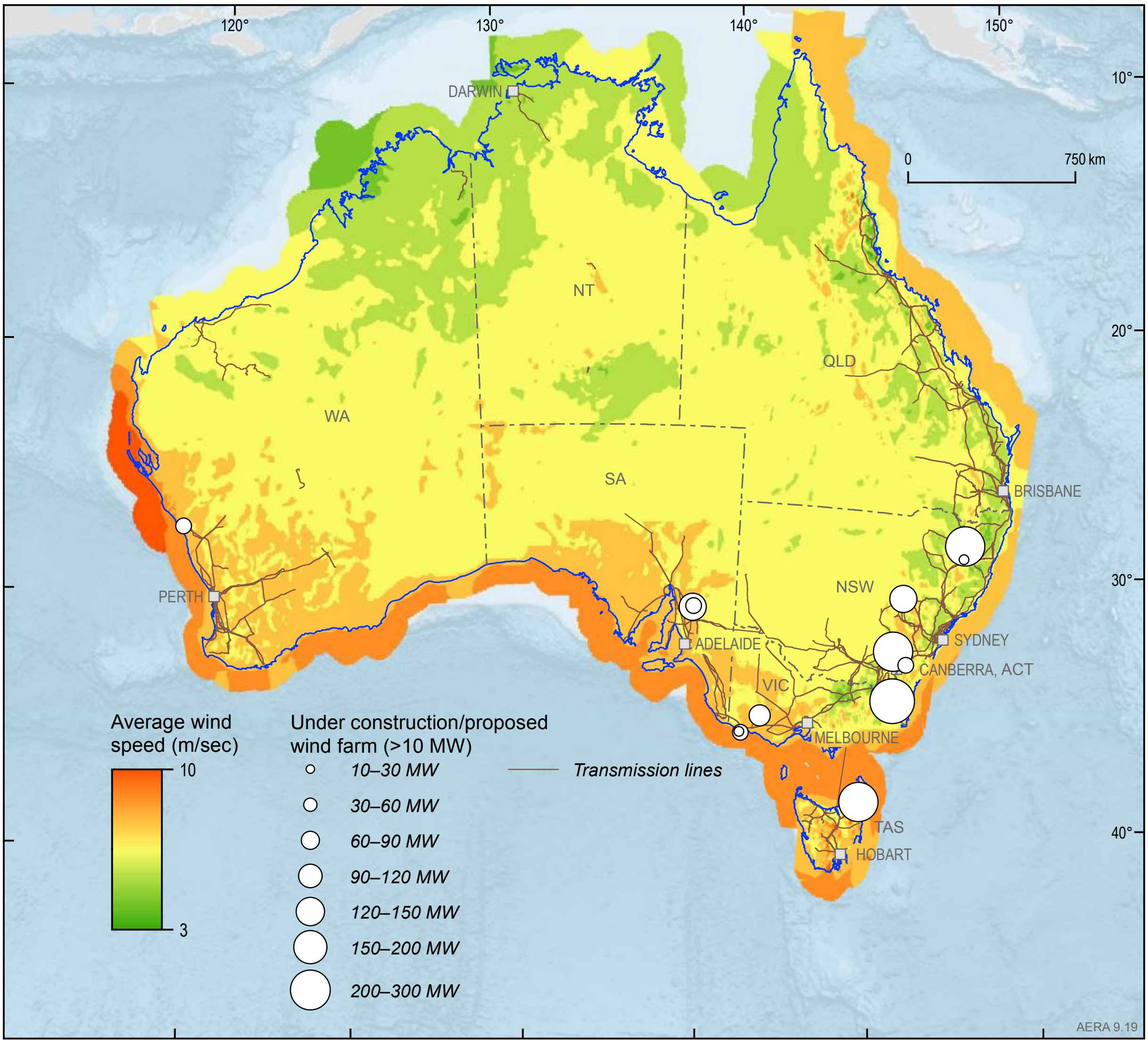

Figure 9.19 Committed and proposed projects

Source: Bureau of Resources and Energy Economics; Windlab Systems Pty Ltd; Geoscience Australia

Wind projects at a feasibility stage of development have over 11.6 GW of additional installed capacity (table 9.7). The development of these projects is not certain, as they are subject to further feasibility and approval processes. The planned capacity ranges from 30 MW to over 800 MW. The most significant of these prospective projects are the Uungula Wind Farm near Wellington and Liverpool Range Wind Farm, north of Sydney, both in New South Wales. The Uungula Wind Farm has a planned capacity of up to 800 MW and is planned to be commissioned in 2017. The Liverpool Range Wind Farm has a planned capacity of 864 MW, capital expenditure A$1.55 billion and is currently planned to be commissioned in 2015.

Australia has some of the world's best wind resources along south-western, southern and south-eastern margins. Wind variability imposes an upper limit on the level of wind energy penetration; however, this level is not likely to be reached in any Australian region with the level of wind energy projected to be generated.

Table 9.6 Projects that are committed, as of October 2013

Project	Company	State	Status	Estimated Start-up	Estimated New Capacity (MW)	Indicative cost estimate (A$million)
Glen Innes	Glen Innes WindPower Pty Ltd	Waterloo Range, NSW	Committed	2014	63	150
Gullen Range	Gullen Range Wind Farm	25 km north-west of Goulburn, NSW	Committed	2014	159	250
Taralga	Taralga Wind Farm Pty Ltd	3 km east of Taralga, NSW	Committed	2014	106	240
Boco Rock	Wind Prospect CWP	10 km south-west of Nimmitabel, NSW	Committed	2014–15	113	350
Lincoln Gap	Lincoln Gap Wind Farm Pty Ltd	near Port Augusta, SA	Committed	2014	177	350
Snowtown (stage 2)	TrustPower Limited	5 km west of Snowtown, SA	Committed	2013	270	439
Mount Gellibrand	Acciona Energy	15 km north-east of Colac, VIC	Committed	2015	189	696
Mortlake South	Acciona Energy	5 km south of Mortlake, VIC	Committed	2016	77	200
Mount Mercer	Meridian Energy Australia Pty Ltd	30 km south of Ballarat, VIC	Committed	2013	131	270
Bald Hills	Mitsui & Co (Australia) Ltd	10kms south-east of Tarwin, Gippsland, VIC	Committed	2015	104	300
Crowlands	Pacific Hydro	30 km north-east of Ararat, VIC	Committed	na	84	na
Ararat	RES Australia Pty Ltd	7 km north of Ararat, VIC	Committed	2015	225	450
Woolsthorpe	Wind Farm Developments	2 km west of Woolsthorpe, VIC	Committed	2013	40	60–100
Badgingarra	APA Group	200 km north of Perth, WA	Committed	2016	Up to 130	na

Source: BREE 2013b

Table 9.7 Projects at a feasibility stage of development, as of October 2013

Project	Company a	Location	Estimated Start Up	Estimated new capacity (MW)	Indicative cost estimate (A$million)
Ben Lomond	AGL Energy	62 km north of Armidale, NSW	na	150	350
Silverton (stage 1)	AGL Energy	25 km north-west of Broken Hill, NSW	2015	250	500
Birrema	Epuron	30 km west of Yass, NSW	2017	50–60	100
Liverpool Range	Epuron	370 km north of Sydney, NSW	2015	864	1550
Rye Park	Epuron	north of Yass, NSW	2015	378	680
White Rock	Epuron	Glen Innes, NSW	2015	240	432
Conroy's Gap	Epuron	17 km west of Yass, NSW	2015	40	72
Yass Valley	Epuron	20 km west of Yass, NSW	2016	300	540
Flyers Creek	Infigen Energy	20 km south of Orange, NSW	na	110–145	195

Project	Company a	Location	Estimated Start Up	Estimated new capacity (MW)	Indicative cost estimate (A$million)
Bodangora	Infigen Energy	25 km south-east of Dubbo, NSW	na	100	185
Capital 2	Infigen Energy	near Bungendore, NSW	na	112	180
Kyoto Energy Park	Pamada	10 km west of Scone, NSW	na	113	190
Collector	Ratch Australia	50 km north-east of Canberra, NSW	2015	200	400
Rugby	RE Power Australia/ Windlab Developments	50 km north of Yass, NSW	2014	166	230
Bango	Wind Prospect CWP	20 km north of Yass, NSW	2017	up to 250	na
Crudine Ridge	Wind Prospect CWP	45 km south of Mudgee, NSW	2017	up to 135	na
Sapphire	Wind Prospect CWP	Inverell, NSW	2016	up to 319	na
Uungula	Wind Prospect CWP	20 km east of Wellington, NSW	2017	up to 800	na
Cooper's Gap	AGL Energy	180km north-west of Brisbane, QLD	post 2016	350	800
Crows Nest	AGL Energy	43 km north of Toowoomba, QLD	na	150	350
Forsayth	Infigen Energy	100 km south-west of Townsville, QLD	na	70–80	145
High Road	Ratch Australia	70 km south-west of Cairns, QLD	2016	40	90
High Road—expansion	Ratch Australia	70 km south-west of Cairns, QLD	2017	40	90
Mount Emerald	Ratch Australia	50 km south-west of Cairns, QLD	2015	200	400
Kennedy	Windlab	290 km south-west Townsville, QLD	2016	Up to 200 first phase	1500
Exmoor	Acciona Energy	23 km north of Naracoorte, SA	2016–17	150–225	350–550
Barn Hill	AGL Energy	Barn Hill, SA	post 2018	180	400
Tungketta Hill (Elliston) (stage 2)	Ausker Energies	25 km S of Elliston, SA	2013–14	120	200–210
Tungketta Hill (Elliston) (stage 3)	Ausker Energies	25 km S of Elliston, SA	2015–16	145–185	250–260
Tungketta Hill (Elliston) (stage 1)	Ausker Energies	25 km S of Elliston, SA	2013–14	55	90
Robertstown	EnergyAustralia	123 km N of Adelaide, SA	2014	75	173
Woakwine	Infigen Energy	10 km east of Robe, SA		350	660
Willogoleche Hill	GDF SUEZ Australian Energy	4km west of Hallett, SA	2016	96–122	170–220
Hornsdale	Investec Bank (Australia) Limited	Jamestown, SA	2015	270	800
Keyneton	Pacific Hydro	10 km south-east of Angaston, SA	na	100	na
Carmody's Hill	Pacific Hydro	18 km north of Mt Misery, SA	na	140	350
Nilgen	Pacific Hydro	9 km east of Lancelin, SA	na	107	280
Mount Hill	Ratch Australia	80 km north-east of Port Lincoln, SA	na	150	na
Yorke Peninsula (Ceres Project)	RE Power	20 km south-west of Ardrossan, SA	na	600	1300

Project	Company a	Location	Estimated Start Up	Estimated new capacity (MW)	Indicative cost estimate (A$million)
Cattle Hill	Cattle Hill Wind Farm Pty Ltd	5 km east of Lake Echo, TAS	2015	240	500
White Rock (Robbins Island)	Eureka Funds Management	100 km north-east of Launceston, TAS	2017–18	440	1200
Cherry Tree	Infigen Energy	10 km north of Shepparton, VIC		40	76
Winchelsea	GDF SUEZ Australian Energy	35km west of Geelong, VIC	2015	30	55–70
Stockyard Hill	Origin Energy	35 km west of Ballarat, VIC	2017	300–450	1000–1400
Portland Wind Energy (PWEP) (stage 4)	Pacific Hydro	Cape Nelson North and Cape Sir William Grant, VIC	na	54	na
Yaloak South	Pacific Hydro	35 km south-east of Ballarat, VIC	na	30	na
Ben More	Ratch Australia	150 km north-west of Melbourne, VIC	2018	100	200
Penshurst	RES Australia Pty Ltd	23 km south-west of Hamilton, VIC	2018	400	800
Darlington	Union Fenosa Wind Australia	5 km east of Mortlake, VIC	2018	300	700
Tarrone	Union Fenosa Wind Australia	25 km north of Port Fairy, VIC	2018	57	75
Lal Lal	WestWind Energy	25 km south-east of Ballarat, VIC	2013	150	350
Moorabool	WestWind Energy	32 km south-east of Ballarat, VIC	2014	321	600
Walkaway 2 and 3	Infigen Energy/National Power Partners/Carbon Solutions	20 km south-east of Geraldton, WA	na	400	760
Milyeannup	Verve Energy	20 km east of Augusta, WA	na	55	160
Dandaragan (Waddi and Yandin sites)	Wind Prospect WA Pty Ltd	170 km north of Perth, WA	2017	513	804

Source: BREE 2013b

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Chapter 10

Solar Energy

10.1 Summary

KEY MESSAGES

- Solar energy is a vast and largely untapped resource. Australia has one of the highest average solar radiation per square metre of any continent in the world.
- There are a wide range of solar energy technologies at different stages of development. Rooftop solar photovoltaic systems and direct-use solar water heaters are considered mature technologies at a small scale.
- Small-scale rooftop solar photovoltaic systems have grown rapidly in Australia from 100 megawatt capacity in 2008 to about 2 gigawatt of capacity in 2012. This rapid increase is the result of falling costs for photovoltaic panels, making the panels increasingly economical for many household and off-grid installations.
- In Australia, solar energy accounted for 0.2% of total energy consumption in 2011–12.
- The outlook for commercial-scale solar photovoltaic and thermal electricity generation depends on demonstration at commercial scale that will reduce investment risks and encourage deployment.
- Research, development and demonstration investment will be crucial in accelerating the development and commercialisation of large-scale solar energy in Australia.

10.1.1 World solar energy resources and market

- Solar is the most abundant energy resource on the earth and may potentially be used in most regions of the world. The theoretical potential, which is the amount of irradiance at the earth's surface, has been estimated at 3.9 million exajoules (EJ) per year.
- The minimum world solar energy technical potential, which is the amount of solar irradiance output obtainable by full deployment of demonstrated and likely-to-develop technologies is estimated to be about 1575 EJ per year. The highest solar resource potential is in north Africa, sub-Saharan Africa and the Middle East.
- Global solar energy use has increased significantly in recent years, with significant deployment in China, the United States and European countries such as Germany, Spain, Italy and Greece. Total solar energy capacity grew by 73.3 per cent from 2007 to 2011 to 63.4 gigawatts (GW). In 2012, solar energy capacity rose to 104 GW.
- The International Energy Agency (IEA) in its new policies scenario projects the share of solar PV energy in total electricity generation will increase to 2.3 per cent in 2035—3 per cent in OECD countries and 1.9 per cent in non-OECD countries.
- Global investment in solar energy reached US$126 billion in 2012, which represented 58 per cent of total investment in clean energy by G20 nations.
- Government policies and falling costs are projected to be the main factors underpinning future growth in world solar energy use.

10.1.2 Australia's solar energy resources

- The annual solar radiation falling on Australia is approximately 58 million petajoules (PJ), which is approximately 10 000 times Australia's annual energy consumption.
- Solar energy resources are greater in the north-west and centre of Australia, in areas that do not have access to the national electricity grid. Locating utility-scale plants in these areas is likely to require investment in transmission infrastructure (figure 10.1).
- There are significant solar energy resources in areas with access to the electricity grid. The solar energy resource (annual solar radiation) in areas of flat topography within 25 km of existing transmission lines (excluding national parks) is nearly 500 times greater than the annual energy consumption of Australia.

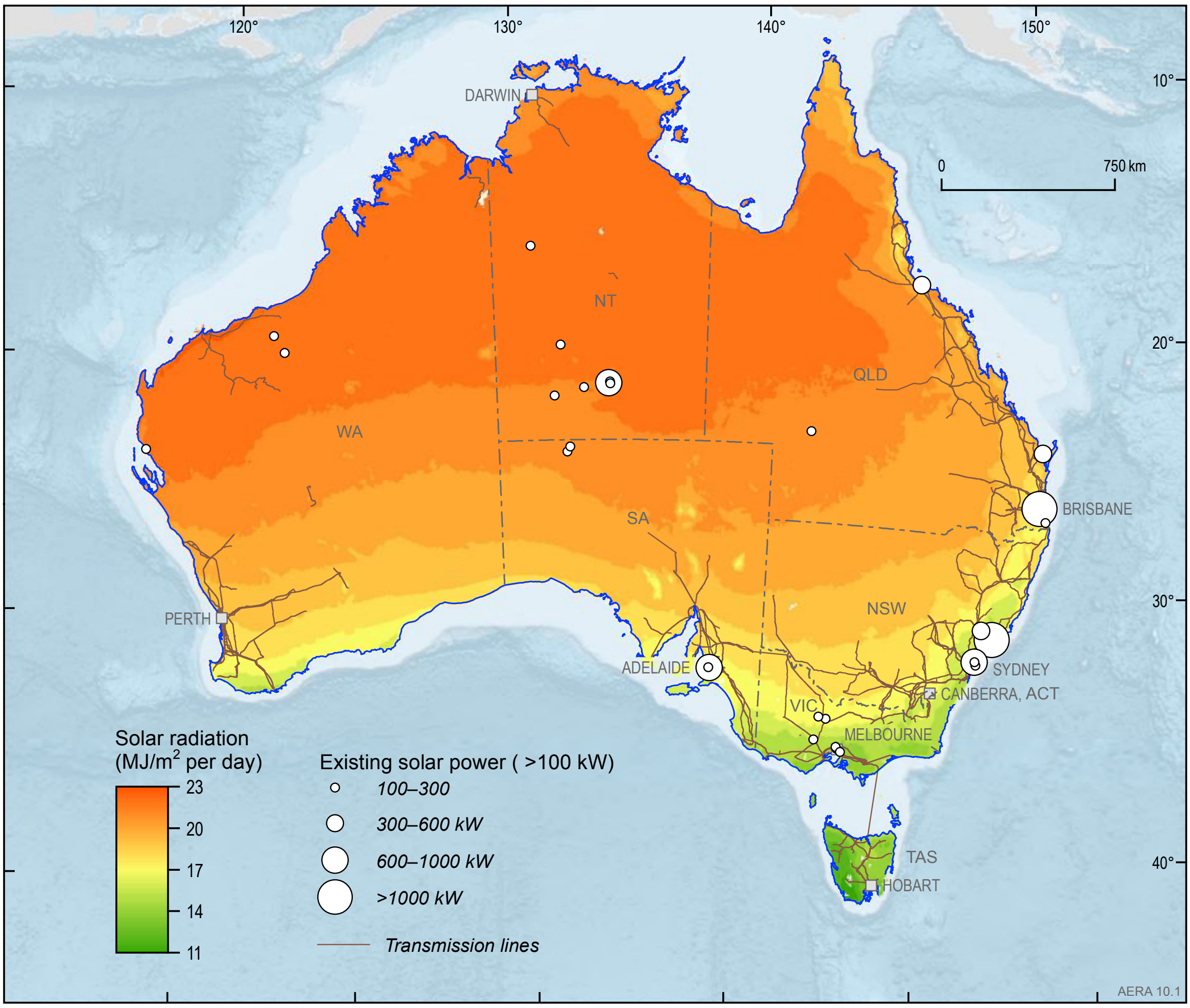

Figure 10.1 Annual average solar radiation and currently installed solar power stations with a capacity of more than 100 kW

Source: BoM 2009; Geoscience Australia

10.1.3 Key factors in utilising Australia's solar energy resources

- Solar radiation is variable because of daily and seasonal variations. However, the correlation between solar radiation and daytime peak electricity demand means that solar energy has the potential to provide electricity during peak demand times.
- Solar thermal technologies can also operate in hybrid systems with fossil fuel power plants and with appropriate storage systems to potentially provide base-load electricity generation. Hybrid plants could potentially be a cost-effective pathway to demonstrate solar thermal technologies at a commercial scale and improve competitiveness.
- Photovoltaic (PV) systems are well suited to off-grid electricity generation applications and where costs of electricity generation from other sources are high (such as in remote communities). In some areas, such as the Pilbara region of Western Australia, solar PV is either at or approaching parity with diesel for off-grid energy supply.
- Rooftop solar PV systems are becoming increasingly affordable for many Australian households and businesses due to the falling cost of PV panels.
- Research, development and demonstration (RD&D), access to risk capital, human capital and economies of scale are important to the continued growth of solar energy for electricity generation. Extensive RD&D has been conducted on large-scale solar thermal technologies.
- The Australian Renewable Energy Agency (ARENA) is supporting a collaborative research activity led by the Australian Solar Thermal Energy Association to quantify economic benefits from concentrating solar thermal electricity generation in the National Electricity Market (NEM).

10.1.4 Australia's solar energy market

- In 2011–12, Australia's solar energy represented 0.2 per cent of Australia's total primary energy consumption. Solar thermal water heating has been the predominant form of solar energy use to date,

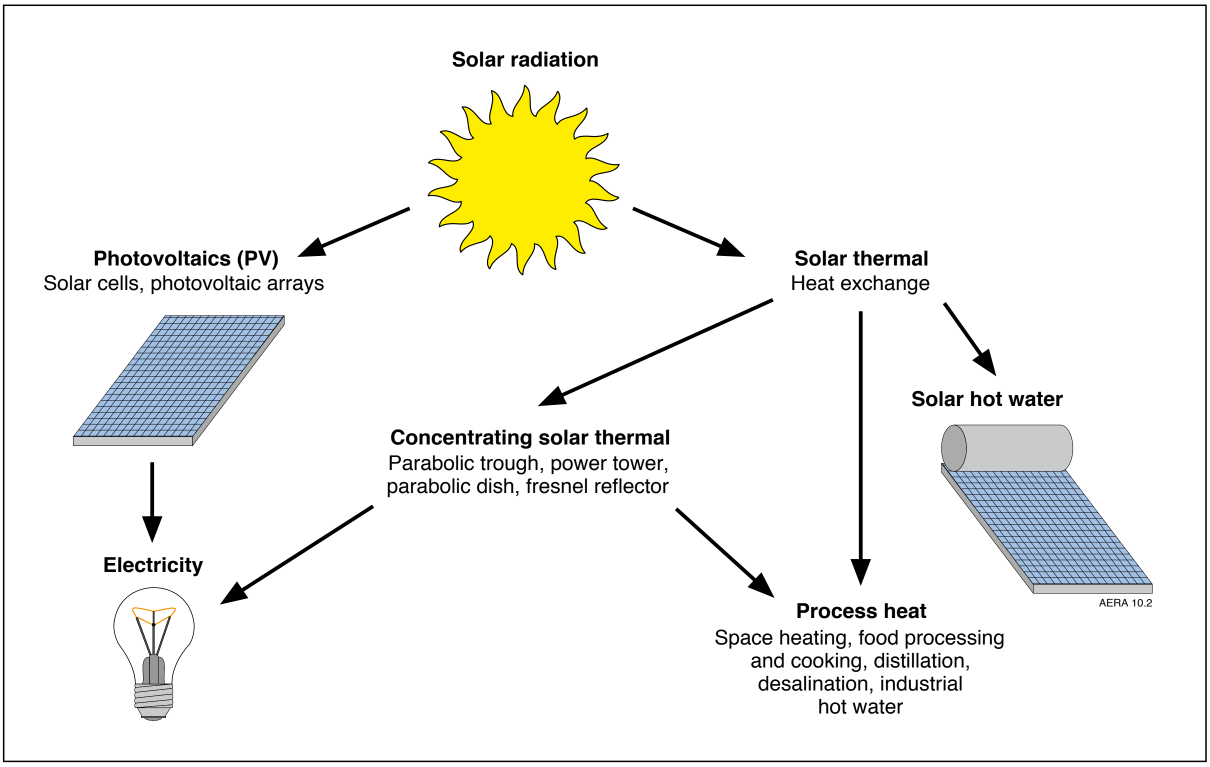

Figure 10.2 Solar energy flows

Source: Bureau of Resources and Energy Economics; Geoscience Australia

due to the support by government rebates and the phase-out of greenhouse emission intensive hot water systems. Electricity generation is increasing rapidly through the deployment of solar PV systems.

- Electricity generation from solar energy has been increasing significantly over the past five years, from 0.1 terawatt-hour (TWh) in 2007–08 to 1.49 TWh in 2011–12, representing 0.6 per cent of Australian electricity generation.
- One million Australian homes have PV solar systems on their roofs that are contributing about 2 GW of capacity, with about 1 GW installed in 2012. The growth in household PV solar systems has been due to cost reductions and government rebates and feed-in tariffs. In many residential areas, solar PV rooftop systems are now viable without subsidies. Improved resource estimation and knowledge regarding management of solar PV supply to the grid will be important to continued growth.

10.2 Background information and world market

10.2.1 Definitions

Solar power is generated when energy from the sun (sunlight) is converted into electricity or used to heat air, water, or other fluids. As illustrated in figure 10.2, there are two main types of solar energy technologies:

- Solar thermal is the conversion of solar radiation into thermal energy (heat). Thermal energy carried by air, water, or other fluid is commonly used directly, for space heating, or to generate electricity using steam and turbines. Solar thermal is commonly used for hot water systems. Solar thermal electricity, also known as concentrating solar thermal plants, is typically designed for large-scale power generation. Solar thermal systems can be used as energy storage for managing energy supply.
- Solar PV converts sunlight directly into electricity using PV cells. PV systems can be installed on rooftops, integrated into building designs and vehicles, or scaled up to megawatt (MW)-scale power plants. PV systems can also be used in conjunction with concentrating mirrors or lenses for large-scale centralised power.

Solar thermal and PV technology can also be combined into a single system that generates both heat and electricity. Further information on solar thermal and PV technologies is provided in boxes 10.1 and 10.2 (in section 10.4.1).

10.2.2 Solar energy supply chain

A representation of the Australian solar industry is given in figure 10.5. The potential for using solar energy at a given location depends largely on the solar radiation, the proximity to electricity load centres, and the availability of suitable sites. Large-scale solar power plants require approximately 2 hectares of land per MW of capacity.

Small-scale technologies (solar water heaters, PV modules and small-scale solar concentrators) can be installed on existing structures, such as rooftops. Once a solar project is developed, the energy is captured by heating a fluid or gas or by using PV cells. This energy can be used directly as hot water supply, converted to electricity, used as process heat, or stored by various means, such as thermal storage, batteries, pumped hydro or synthesised fuels.

10.2.3 World solar energy market

The world has large solar energy resources, which have not been fully utilised to date. Solar energy currently accounts for a very small share of world primary energy consumption, but its use is projected to increase strongly over the outlook period to 2050.

The highest solar resource potential per unit land area is in north Africa, sub-Saharan Africa and the Middle East. Australia also has higher incident solar energy per unit land area than any other continent in the world. However, the distribution of solar energy use among countries largely reflects government policies that encourage its use, rather than resource availability.

Resources

The annual solar resource varies considerably around the world. These variations depend on several factors, including proximity to the equator, cloud cover, and other atmospheric effects. Figure 10.6 illustrates the variations in solar energy availability.

BOX 10.1 SOLAR ENERGY TECHNOLOGIES FOR ELECTRICITY GENERATION

Sunlight has been used for heating by generating fire for hundreds of years, but commercial technologies specifically to use solar energy to directly heat water or generate power were not developed until the 1800s. Solar water heaters developed and installed between 1910 and 1920 were the first commercial application of solar energy. The first PV cells capable of converting enough energy into pVower to run electrical equipment were not developed until the 1950s and the first solar power stations (thermal and PV) with capacity of at least 1 MW started operating in the 1980s.

Solar thermal plants—concentrate solar power

Solar thermal plants convert sunlight into heat, and then use the heat to drive a generator. The sunlight is concentrated using mirrors, and focused onto a solar receiver. This receiver contains a working fluid that absorbs the concentrated sunlight, and can be heated up to very high temperatures. Heat is transferred from the working fluid to a steam turbine, similar to those used in fossil fuel and nuclear power stations. Alternatively, the heat can be stored for later use (see below).

There are four main types of concentrating solar receivers, shown in figure 10.3. Two of these types are line focusing (parabolic trough and linear Fresnel reflector); the other two are point focusing (paraboloidal dish and power tower (central receiver tower)). Each of these types is designed to concentrate a large area of sunlight onto a small receiver, which enables fluid to be heated to high temperatures. There are trade-offs between efficiency, land coverage, and costs of each type.

Parabolic troughs focus light in one axis only, which means that they need only a single axis tracking mechanism to follow the direction of the sun. The parabolic trough has the most widespread commercial use. An array of nine parabolic trough plants producing a combined 354 MW has operated in California since the 1980s. Several new ones have been built in Spain and Nevada in the last few years at around a 50–60 MW scale, and there are many parabolic trough plants either in the construction or planning phase.

The linear Fresnel reflector achieves a similar line focus, but instead uses an array of almost flat mirrors. Linear Fresnel reflectors achieve a weaker focus (therefore lower temperatures and efficiencies) than parabolic troughs. However, linear Fresnel reflectors have cost saving features that compensate for lower energy efficiencies, including a greater yield per unit land, and simpler construction requirements. A 30 MW Fresnel reflector has been in commercial operation in southern Spain since 2012.

The paraboloidal dish is an alternative design that focuses sunlight onto a single point. This design is able to produce a much higher temperature at the receiver, which increases the efficiency of energy conversion. The paraboloidal dish has the greatest potential to be used in modular form, which may give this design an advantage in off-grid and remote applications. However, to focus the sunlight onto a single point, paraboloidal dishes need to track the direction of sunlight on two axes. This requires a more complex tracking mechanism, and is more expensive to build. The paraboloidal dish has been demonstrated on a small scale, and there are plans for large-scale dish plants.

The other point-focusing design is the power tower (central receiver tower), which uses a series of ground-based mirrors to focus onto an elevated central receiver. Power tower mirrors also require two-axis tracking mechanisms; however, the use of smaller, flat mirrors can reduce costs. There are three solar tower power plants operating in Spain, with a total capacity of 48 MW. The Gemasolar plant in Spain is the first commercial-scale central receiver plant in the world to use molten salt heat storage technology. The molten salt storage allows independent electricity generation for up to 15 hours without any solar feed. Two solar tower power plants (combine capacity of about 500 MW) are under construction in the United States.

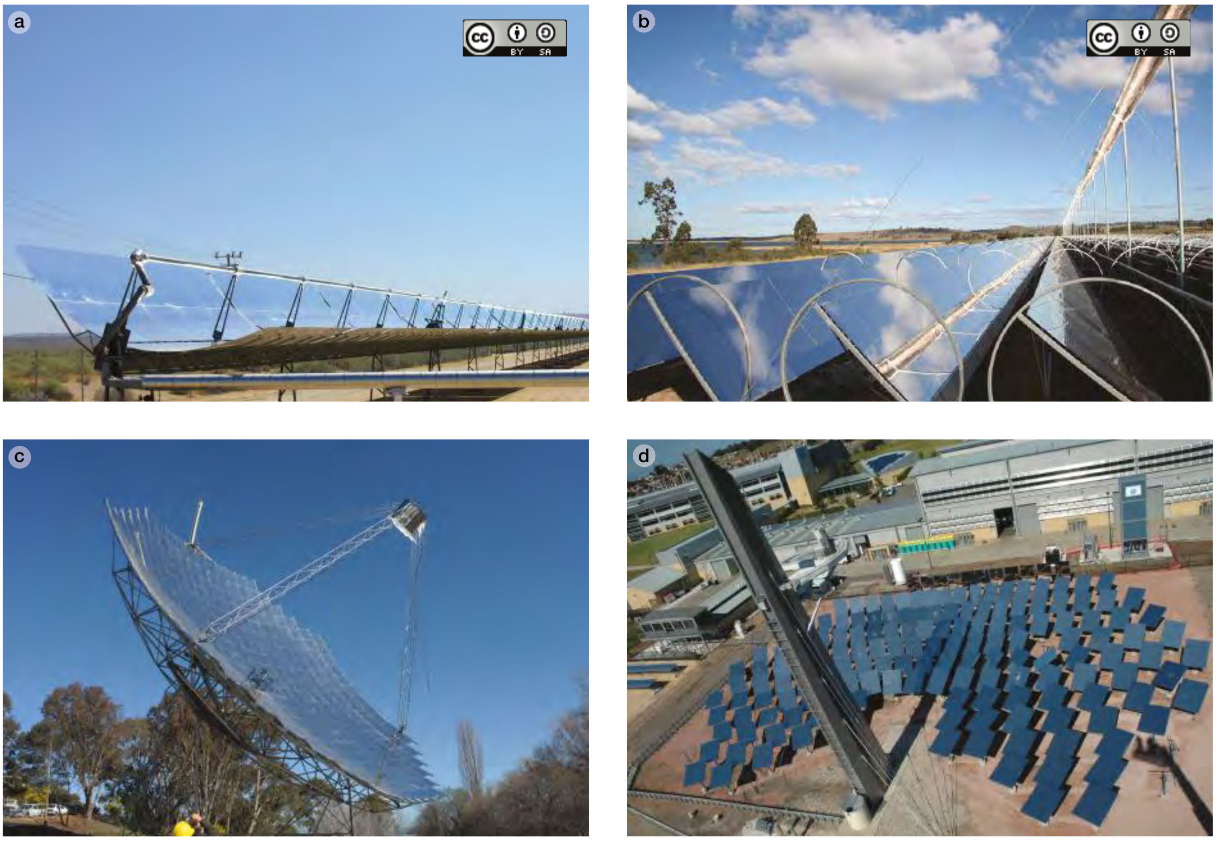

Figure 10.3 The four types of solar thermal concentrators: **a** parabolic trough, **b** compact linear Fresnel reflector, **c** paraboloidal dish, **d** power tower

Source: Wikimedia Commons, photograph by kjkolb; Wikimedia Commons, original uploader was Lkruijsw at en.wikipedia; ANU 2009; CSIRO

Methods of power conversion and thermal storage vary from type to type. While solar thermal energy generation is suited to large-scale plants (greater than 50 MW), the paraboloidal dish has the potential to be used in modular form. This may give dish systems an advantage in remote and off-grid applications.

The conversion efficiency of solar thermal power plants depends on the type of concentrator used and the amount of sunlight. In general, the point-focusing concentrators (paraboloidal dish and power tower) can achieve higher efficiencies than line-focusing technologies (parabolic trough and Fresnel reflector). This is possible because the point-focusing technologies achieve higher temperatures for higher thermodynamic limits.

The highest value of solar-to-electric efficiency ever recorded for a solar thermal system was 31.25 per cent, using a solar dish in peak sunlight conditions (Sandia 2009). Parabolic troughs can achieve a peak solar-to-electric efficiency of over 20 per cent (SEGS 2009). However, the conversion efficiency drops significantly when the radiation drops in intensity, so the annual average efficiencies are significantly lower. According to Begay-Campbell (2008), the annual solar-to-electric efficiency is approximately 12–14 per cent for parabolic troughs, 12 per cent for power towers (although emerging technologies can achieve 18–20 per cent), and 22–25 per cent for paraboloidal dishes. Linear Fresnel reflectors achieve a similar efficiency to parabolic troughs, with an annual solar-to-electric efficiency of approximately 12 per cent (Mills et al. 2002).

Photovoltaic systems

Photovoltaics is a method of generating electricity by converting solar radiation into direct current electricity using semiconductors that exhibit the photovoltaic effect. Photovoltaic power generation uses solar panels composed of a number of solar cells containing a photovoltaic material.

There are three main PV technologies: first generation wafer-based crystalline silicon, second generation thin film and third generation concentrating PV (IRENA 2012).

The first generation crystalline silicon is fully commercial and the most widespread technology. These cells are becoming more efficient over time and costs have fallen steadily.

The second generation thin-film PV is an emerging group of technologies, targeted at reducing costs of PV cells.

Thin-film PV are usually categorised according to the photovoltaic material used: amorphous and micromorph silicon, cadmium-telluride, copper-indium-gallium-selenide, and dye-sensitised and other organic solar cells. Currently the thin-film PV delivers a lower efficiency than crystalline silicon, estimated at around 10 per cent (Prowse 2009). However, this is compensated by lower costs, and there are strong prospects for efficiency improvements in the future. Thin-film PV can be installed on many different substrates, giving it great flexibility in its applications.

The third generation concentrating PV systems use either mirrors or lenses to focus a large area of sunlight onto a central receiver (figure 10.4). These systems increase the intensity of the light, and allow a greater percentage of its energy to be converted into electricity. These systems are designed primarily for large-scale centralised power, due to the complexities of the receivers. Concentrating PV is the most efficient form of PV, delivering a typical system efficiency of around 20 per cent, and has achieved efficiencies of just over 40 per cent in ideal laboratory conditions (NREL 2011). An advantage of using concentrating PV is that it reduces the area of solar cells needed to capture the sunlight.

A relatively recent area of growth for PV applications is in building-integrated PV (BIPV) systems. BIPV systems incorporate PV technology into many different components of a new building. These components include rooftops, walls and windows, where PV cells can either replace, or be integrated with, existing materials. BIPV has the potential to increase the surface area available for capturing solar energy within a building (NREL 2009).

The costs of producing PV cells have declined rapidly in recent years as uptake has increased and a number of PV technologies have been developed. The cost of modules can be reduced in four main ways:

- making thinner layers—reducing material and processing costs
- integrating PV panels with building elements such as glass and roofs—reducing overall system costs
- making adhesive on site—reducing materials costs
- improving decisions about making or buying inputs, increasing economies of scale, and improving the design of PV modules.

The maximum efficiency of commercially available PV modules is around 20 to 25 per cent, with efficiencies of around 40 per cent achieved in laboratories. Most commercially available PV systems have an average conversion efficiency of around 10 per cent. New developments (such as multi-junction tandem cells) suggest solar cells with conversion efficiencies of greater than 40 per cent could become commercially available in the future.

Energy storage

Thermal energy storage technologies allow the storage of excess energy to be used at a later time and can address fluctuations in supply. Several thermal energy storage technologies have been tested and implemented since the 1980s. Several constructed solar thermal power plants have included thermal storage of approximately seven hours power generation. In addition, there are power tower designs that incorporate up to 16 hours of thermal storage, allowing 24 hour power generation in appropriate conditions. The development of cost-effective storage technologies may enable a much higher uptake of solar thermal power in the future (Wyld Group and MMA 2008).

There are direct, indirect and thermocline energy storage systems. The working fluid (storage medium) used in the system temporarily stores heat, and can be converted into electricity as required. Thermal storage creates the potential for intermediate or base-load power generation. Working fluids include molten salts and mineral oils (US Department of Energy 2013).

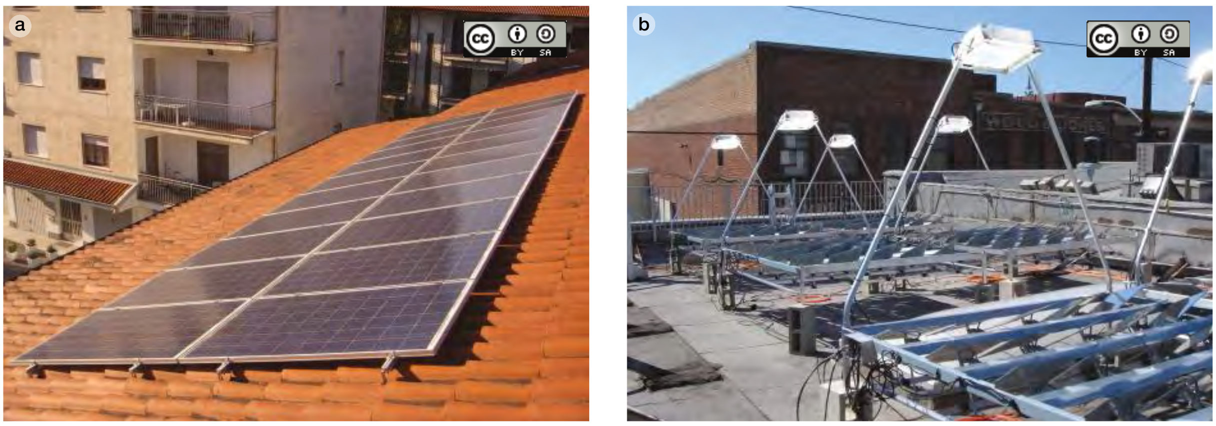

Figure 10.4 a Example of a rooftop PV system. **b** A schematic concentrating PV system, where a large number of mirrors focus sunlight onto central PV receivers

Source: CERP, Wikimedia Commons; Energy Innovations Inc. under Wikipedia licence cc-by-sa-2.5

In a direct system, fluid is stored in two tanks; one at high temperature and the other at low temperature. Fluid from the low-temperature tank flows through the solar collector or receiver, where it is heated to a high temperature, and then flows to the high-temperature tank for storage. Fluid from the high-temperature tank flows through a heat exchanger, where it generates steam for electricity production. The fluid exits the heat exchanger at a low temperature and returns to the low-temperature tank. In California, a two-tank direct storage using molten salt as a storage fluid was used at power tower plant and mineral oil as the heat transfer was used in early parabolic trough plants.

The indirect system functions in the same way as two-tank direct systems, except different fluids are used for heat transfer and storage. The storage fluid from the low-temperature tank flows through an extra heat exchanger, where it is heated by the high-temperature heat-transfer fluid. The high-temperature storage fluid then flows back to the high-temperature storage tank. The heat-transfer fluid exits this heat exchanger at a low temperature and returns to the solar collector or receiver, where it is heated back to a high temperature. Storage fluid from the high-temperature tank is used to generate steam for electricity production. An indirect system using organic oil as the heat-transfer fluid and molten salt as the storage fluid will be used in some of the parabolic power plants in Spain.

Single-tank thermocline systems store thermal energy in a solid medium, most commonly silica sand. At any time during operation, a portion of the solid medium is at high temperature, and a portion is at low temperature. The hot- and cold-temperature regions are separated by a thermocline (temperature gradient). High-temperature heat-transfer fluid flows into the top of the thermocline and exits the bottom at low temperature. This process moves the thermocline downward and adds thermal energy to the system for storage. Reversing the flow moves the thermocline upward and removes thermal energy from the system to generate steam and electricity.

Current research is developing alternative energy storage methods, including chemical storage, and phase-change materials (PCM). Chemical storage options include dissociated ammonia and solar-enhanced natural gas. PCM have a phase change (usually solid to liquid) at a temperature matching the thermal input source. Two principle approaches are being investigated: encapsulation of small amounts of PCM and embedding of PCM in a matrix made of another solid material with high heat conduction (e.g. graphite). Storages based on PCM are in an early stage of development.

Another energy storage medium is high-purity graphite, due to its property of increasing its heat-storage capacity as the temperature of storage rises. The relatively low temperatures of solar thermal systems are not optimal for this storage medium unless the graphite storage blocks could be positioned at the high-temperature focus of a concentrating solar collector.

Hybrid solar–fossil fuel plants

Solar thermal power plants can make use of existing turbine technologies that have been developed and refined over many decades in fossil fuel technologies. In addition, solar thermal heat collectors can be used in hybrid operation with fossil fuel burners. A number of existing solar thermal power plants use gas burners to boost power supply during low levels of sunlight.

Solar thermal heat collectors can be attached to existing coal or gas power stations to pre-heat the water used in these plants. This is possible since solar thermal heat collectors perform a very similar function to fossil fuel burners. In this way, solar thermal power can make use of existing infrastructure. This option means that plant operators can supply power using either fossil fuel or solar thermal energy. Integrated solar combined cycle plants are similar to combined cycle gas plants (using both a gas turbine and a steam turbine), but use solar thermal heat collectors to boost the steam turbine production.

ARENA is providing financial assistance to a broad renewable energy portfolio of projects, including the demonstration of hybrid systems. The CS Energy Kogan Creek Solar Boost project is currently under construction in Queensland. A 44 MW linear Fresnel reflector will be integrated with the Kogan Creek coal-fired power plant. RATCH-Australia Corporation Limited is assessing the viability of converting the existing coal-fired Collinsville Power Station in Queensland to a hybrid solar thermal–gas power station.

Solar updraft towers

An alternative solar thermal power technology is the solar updraft tower, also known as a solar chimney. The updraft tower captures solar energy using a large greenhouse, which heats air beneath a transparent roof. A very tall chimney is placed at the centre of the greenhouse, and the heated air creates pressure differences that drive air flow up the chimney. Electricity is generated from the air flow using wind turbines at the base of the chimney.

Solar updraft towers have been tested at a relatively small scale. A 50 kW plant in Spain has been operating for several years. There are plans to upscale this technology, including the Australian company EnviroMission's proposed 200 MW plant in the United States. The main disadvantage of solar updraft towers is that they deliver significantly less power per unit area than concentrating solar thermal and PV systems (EnviroMission 2009).

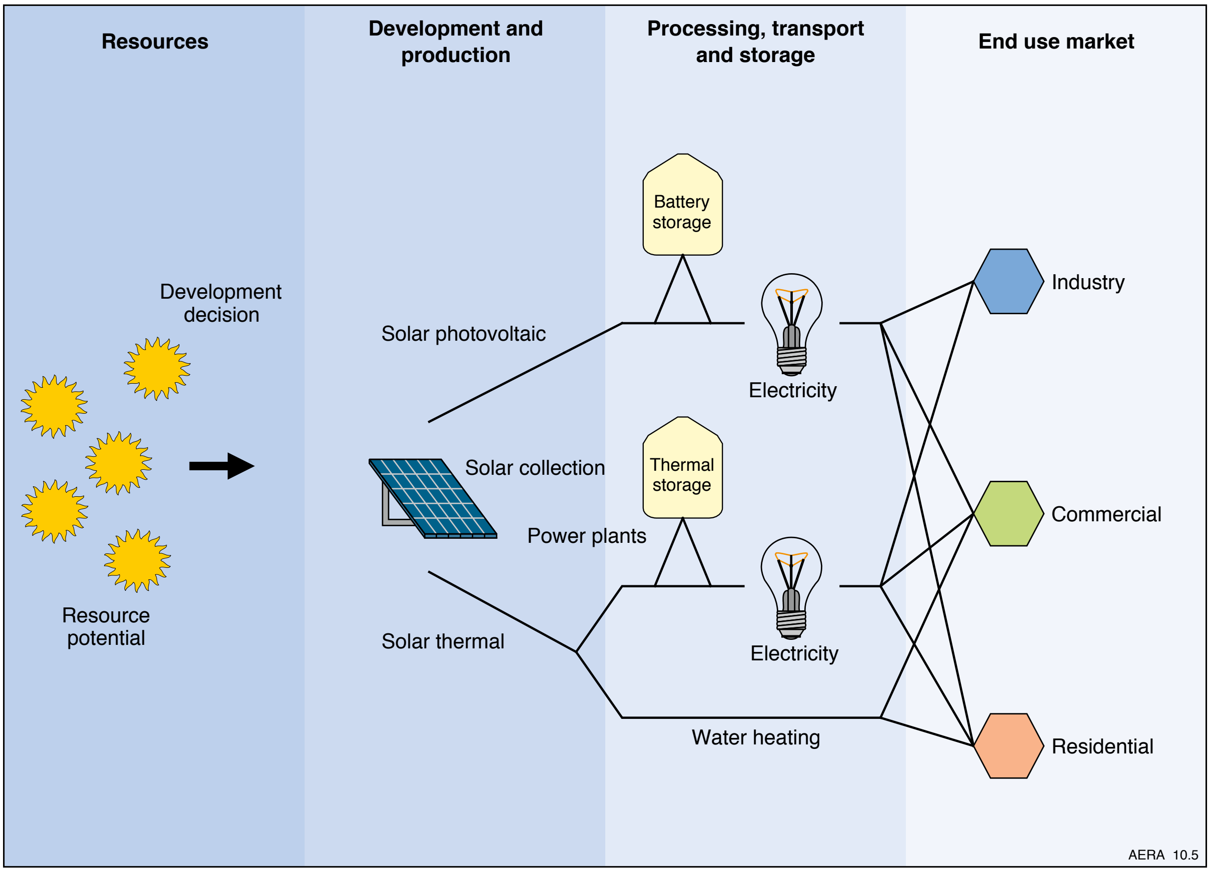

Figure 10.5 Australia's solar energy supply chain

Source: Bureau of Resources and Energy Economics; Geoscience Australia

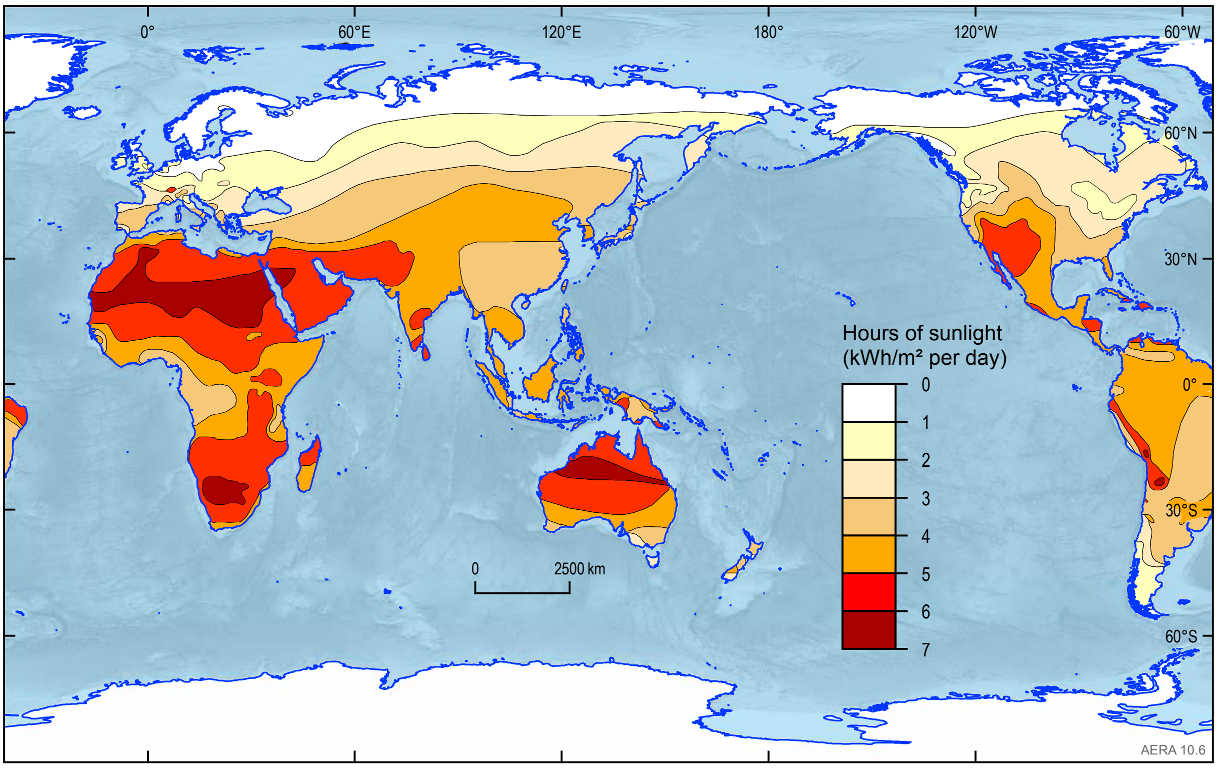

Figure 10.6 Hours of sunlight per day, during the worst month of the year on an optimally tilted surface

Source: Sunwize Technologies 2008

Table 10.1 Key solar energy statistics

	Unit	Australia 2011–12	Australia 2010–11	OECD 2011	World 2010
Primary energy consumption[a]	PJ	16.9	14.0	422.3	748.6
Share of total	%	0.3	0.18	0.19	0.14
Average annual growth, from 2000	%	18.6	13.9	8.7	13.3
Electricity generation					
Electricity output	TWh	1.49	0.85	54.3	33.5
Share of total	%	0.59	0.34	0.52	0.16
Average annual growth, from 2000	%	36.4	23.4	40.5	35.7
Electricity capacity	GW	1.4	0.84	38[b]	69.7[c]

a Energy production and primary energy consumption are identical; **b** in 2010; **c** in 2011

Source: BREE 2012a; IEA 2012b; Watt et al. 2012

The amount of solar energy incident on the world's land area far exceeds total world energy demand. Solar energy thus has the potential to make a major contribution to global energy needs.

The solar resource is practically inexhaustible and is available and able to be used in most regions of the world. The theoretical potential, which is the amount of irradiance at the earth's surface, has been estimated at 3.9 million EJ per year (IPCC 2011).

The minimum world solar energy technical potential, which is the amount of solar irradiance output obtainable by full deployment of demonstrated and likely-to-develop technologies is estimated to be about 1575 EJ per year. The highest solar resource potential is in north Africa, sub-Saharan Africa and the Middle East (IPCC 2011) (figure 10.6). Australia and the United States also have a greater solar resource potential than the world average. Much of this potential can be explained by proximity to the equator and average annual weather patterns.

Primary energy consumption

Solar energy contributes only a small proportion to Australia's primary energy needs, although its share is comparable to the world average. While solar energy accounts for only around 0.1 per cent of world primary energy consumption, solar energy use has been increasing. From 1990 to 1999, the rate of growth in global solar energy consumption was 8 per cent per year, increasing strongly from 2000 to 2010 at a rate of 13.9 per cent per year (table 10.1, figure 10.7).

The contribution of solar energy to primary energy consumption is expected to continue to grow. Falling costs of solar systems and increased concern with environmental issues surrounding fossil fuels, coupled with government policies that encourage solar energy use, will assist with the uptake of solar energy technologies.

Solar PV energy can be used immediately on-site, exported to the grid or stored in batteries for later use or export to meet demand. Solar thermal can also be stored for up to eight hours in molten salt storage. Storage for around two to four hours may allow export into the grid to match evening peak demand. Storage technologies are at the demonstration stage in Spain and the United States.

The majority of solar energy is produced using solar thermal technology; solar thermal comprised 85 per cent of total solar energy production in 2010 (figure 10.7). Around half is used for water heating in the residential sector. Most of the remainder is used for space heating either residentially or commercially, and for heating swimming pools. All of the energy used for these purposes is collected using solar thermal technology. Solar PV-generated electricity is mainly through household rooftop systems.

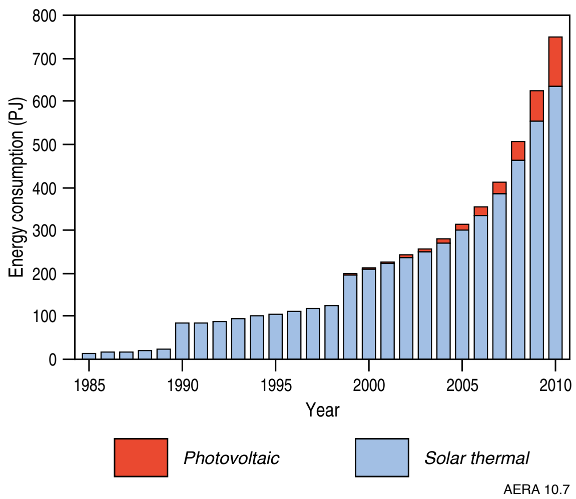

Figure 10.7 World primary solar energy consumption, by technology

Source: IEA 2012b

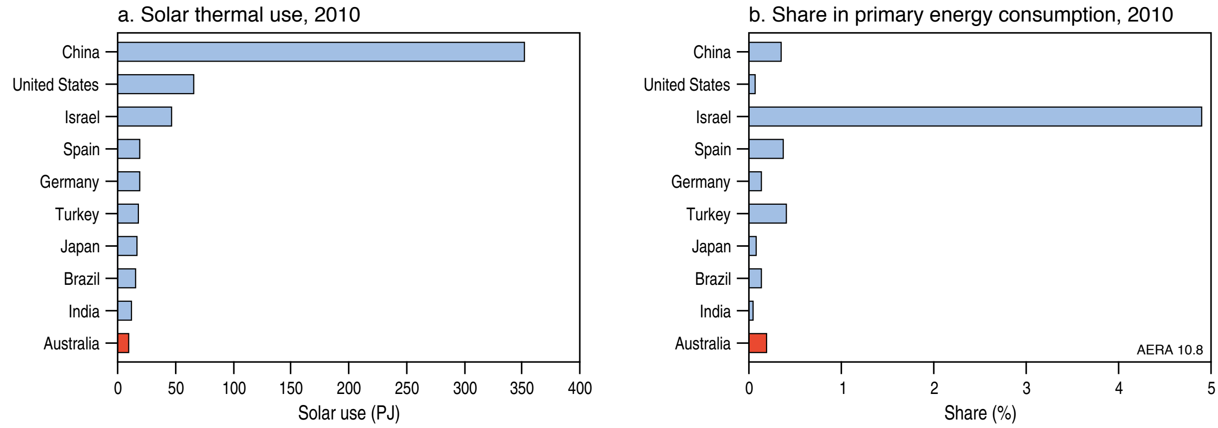

Figure 10.8 Direct use of solar thermal energy, by country, 2010

Source: IEA 2012b

Solar thermal energy consumption

The largest users of solar thermal energy in 2010 were China (352 PJ), the United States (66 PJ), Israel (47 PJ), Spain (20 PJ) and Germany (19 PJ). However, Israel has a significantly larger share of solar thermal in its total primary energy consumption than any other country (figure 10.8). Growth in solar thermal energy use in these countries has been largely driven by government policies.

Electricity generation

Electricity generation accounts for around 16 per cent of primary consumption of solar energy in 2010. All solar PV energy is electricity, while around 1 per cent of solar thermal energy is converted to electricity (IEA 2102b). Since 2005 the solar PV energy used to generate electricity has been increasing dramatically at an annual rate of about 53 per cent per year (figure 10.9).

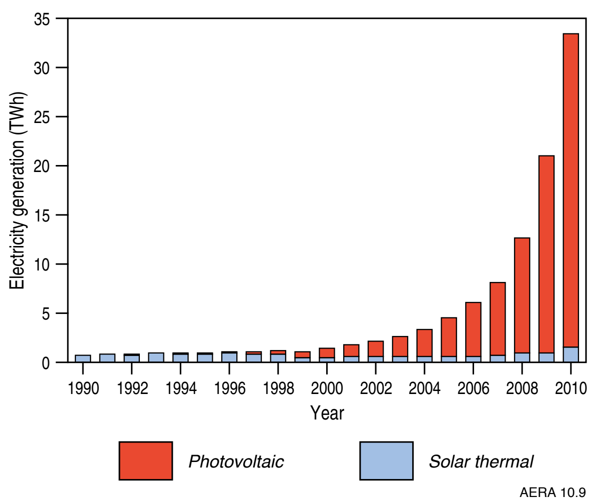

Figure 10.9 World electricity generation from solar energy, by technology, 2010

Source: IEA 2012b

The largest producers of electricity from solar energy in 2010 were Germany (12 TWh), Spain (7 TWh), the United States (4 TWh), Japan (3.9 TWh) and Italy (2 TWh), with all other countries each producing 1 TWh or less (figure 10.10). From 2000 to 2010, Germany had the fastest growth rate of electricity generation from solar energy in the world, with a growth rate up to 68 per cent per year on average. It is important to note that these electricity generation data do not include off-grid PV installations, which represent a large part of PV use in some countries.

Installed generation capacity

Solar PV grew the fastest of all renewable technologies from 2006 to 2011, with operating capacity increasing by an average of 58 per cent annually. Concentrating solar thermal power increased almost 37 per cent annually over this period from a small base (REN21 2012).

In 2011, globally the largest solar PV capacity (including off-grid generation) was Germany (24.8 GW), Italy (12.8 GW), Japan (4.9 GW), Spain (4.3 GW) and the United States (4 GW) (figure 10.11). Over 98 per cent of this capacity was connected to grids (IEA PVPS 2012).

By the end of 2012, it is estimated that PV represents at least 96.5 GW of installed solar capacity globally. Europe represents a major part of all installations, with Asia and the United States growing rapidly in 2012. Germany (32.4 GW) had the largest installed PV capacity followed by Italy (16.3 GW), the United States (7.24 GW), Japan (7 GW) and China (7 GW). During 2012, the largest installations were in Germany (7.6 MW), China (3.5 MW), Italy (3.3 MW) and the United States (3.3 MW) (IEA PVPS 2013).

World solar energy market outlook

Renewable power generation policies continue to be the driving force behind increasing markets for renewable energy (REN21 2012). IEA new policies scenario for world electricity generation from solar energy is projected to increase to 674 TWh by 2035, growing at an average of 23 per cent per year for concentrating solar power

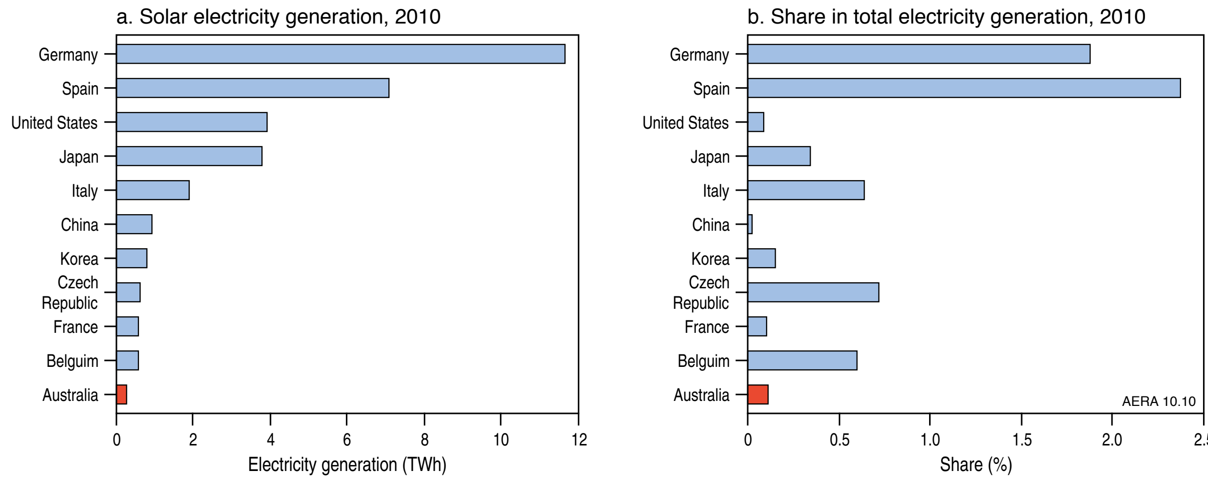

Figure 10.10 Electricity generation from solar energy, major countries, 2010

Source: IEA 2012b

Table 10.2 IEA new policies scenario projections for world electricity generation from solar photovoltaic and concentrating solar

	Unit	2010		2035	
		CSP	PV	CSP	PV
OECD	TWh	2	30.6	104	396
Share of OECD total	%	0	0.28	1	2.98
Average annual growth, 2010-35	%			18.2	10.8
Electricity capacity	GW	1	37	27	301
Non-OECD	TWh	0	1.3	175	450
Share of non-OECD total	%	0	0.01	1	1.93
Average annual growth, 2010–35	%			62.1	26.4
Electricity capacity	GW	0	1	45	302
World	TWh	2	31.9	278	846
Share of world total	%	0	0.15	0.8	2.31
Average annual growth, 2010–35	%			23	14
Electricity capacity	GW	1	38	72	602

Note: totals may not add due to rounding
CSP = Concentrating solar power, **PV** = Solar photovoltaic

Source: IEA 2012a, 2012b

and 14 per cent per year for solar PV (table 10.2). Solar electricity is projected to increase more significantly in non-OECD countries than in OECD countries, albeit from a much smaller base (IEA 2012a).

Solar PV produced only a small fraction of the world's total electricity in 2010, but installed solar PV capacity has grown rapidly in recent years and is expected to continue to do so in the future (IEA 2012a). Investment in solar PV installations has been encouraged in recent years by substantial falls in solar PV costs, which resulted largely from widespread deployment and substantial oversupply. The reduction in solar PV costs has been achieved through Chinese manufacturing capacity. Between the first quarter of 2010 and the first quarter of 2012, solar PV generating costs fell by 44 per cent. Solar PV costs continue to fall over the projection period, although at lower rates as the oversupply situation is corrected (IEA 2012a).

Globally, solar technologies attracted more clean energy financing than any other technology. Solar accounted for US$126 billion worth of clean energy investment in 2012. China, Europe and the United States were top markets for solar investment (PEW Charitable Trusts 2013).

10.3 Australia's solar energy resources and market

10.3.1 Solar energy resources

The Australian continent has the highest solar radiation per square metre of any continent (IEA 2003); however, the regions with the highest radiation are deserts in the north-west and centre of the continent (figure 10.12).

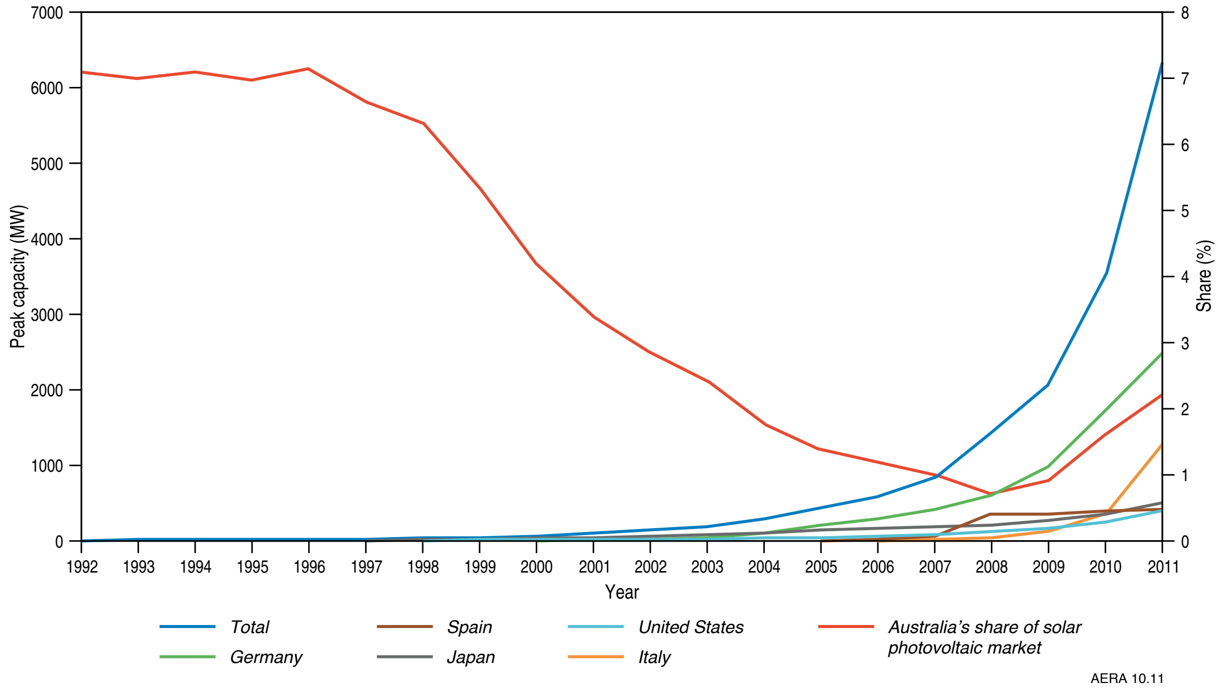

Figure 10.11 World PV capacity, 1992–2011, including off-grid installations

Source: IEA PVPS 2012; Watt et al. 2012

Australia receives an average of 58 million PJ of solar radiation per year (BoM 2009). Theoretically, if only 0.1 per cent of the incoming radiation could be converted into usable energy at an efficiency of 10 per cent, all of Australia's energy needs could be supplied by solar energy. Similarly, the energy falling on a solar farm covering 50 km by 50 km would be sufficient to meet all of Australia's electricity needs (Stein 2009a). Given this vast and largely untapped resource, the challenge is to find effective and acceptable ways of exploiting it.

While the areas of highest solar radiation in Australia are typically located inland, there are some grid-connected areas that have relatively high solar radiation. Wyld Group and MMA (2008) identified a number of locations that are suitable for solar thermal power plants, based on high solar radiation levels, proximity to local loads, and high electricity costs from alternative sources. Within the NEM grid catchment area, they identified the Port Augusta region in South Australia, north-west Victoria, and central and north-west New South Wales as regions of high potential for solar thermal power. They also nominated Kalbarri, near Geraldton, Western Australia, on the South-West Interconnected System, the Darwin-Katherine Interconnected System, and Alice Springs–Tennant Creek as locations of high potential for solar thermal power.

Concentrating solar power

Figure 10.12 shows the radiation falling on a flat plane. This is the appropriate measure of radiation for flat plate PV and solar thermal heating systems, but not for concentrating systems. For concentrating solar power, including both solar thermal power and concentrating PV, the direct normal irradiance (DNI) is a more relevant measure of the solar resource. This is because concentrating solar technologies can only focus sunlight coming from one direction, and use tracking mechanisms to align their collectors with the direction of the sun. The only dataset currently available for DNI that covers all of Australia is from the Surface Meteorology and Solar Energy dataset from the United States' National Aeronautics and Space Administration (NASA). This dataset provides DNI at a coarse resolution of 1 degree, equating to a grid length of approximately 100 km. The annual average DNI from this dataset is shown in figure 10.13.

Since the grid cell size is around 10 000 km^2, this dataset provides only a first-order indication of the DNI across broad regions of Australia. However, it is adequate to demonstrate that the spatial distribution of DNI differs from that of the total radiation shown in figure 10.12. In particular, there are areas of high DNI in central New South Wales and coastal regions of Western Australia that are less evident in the total radiation. More detailed mapping of DNI across Australia is needed to assess the potential for concentrating solar power at a local scale.

A collaborative project between Geoscience Australia and the Bureau of Meteorology and funded by ARENA developed the Australian Solar Energy Information System (ASEIS), a pre-competitive solar resource data product to assist regional analysis of areas suitable for large-scale solar power production. ASEIS is an interactive web mapping site available on the Geoscience Australia website.

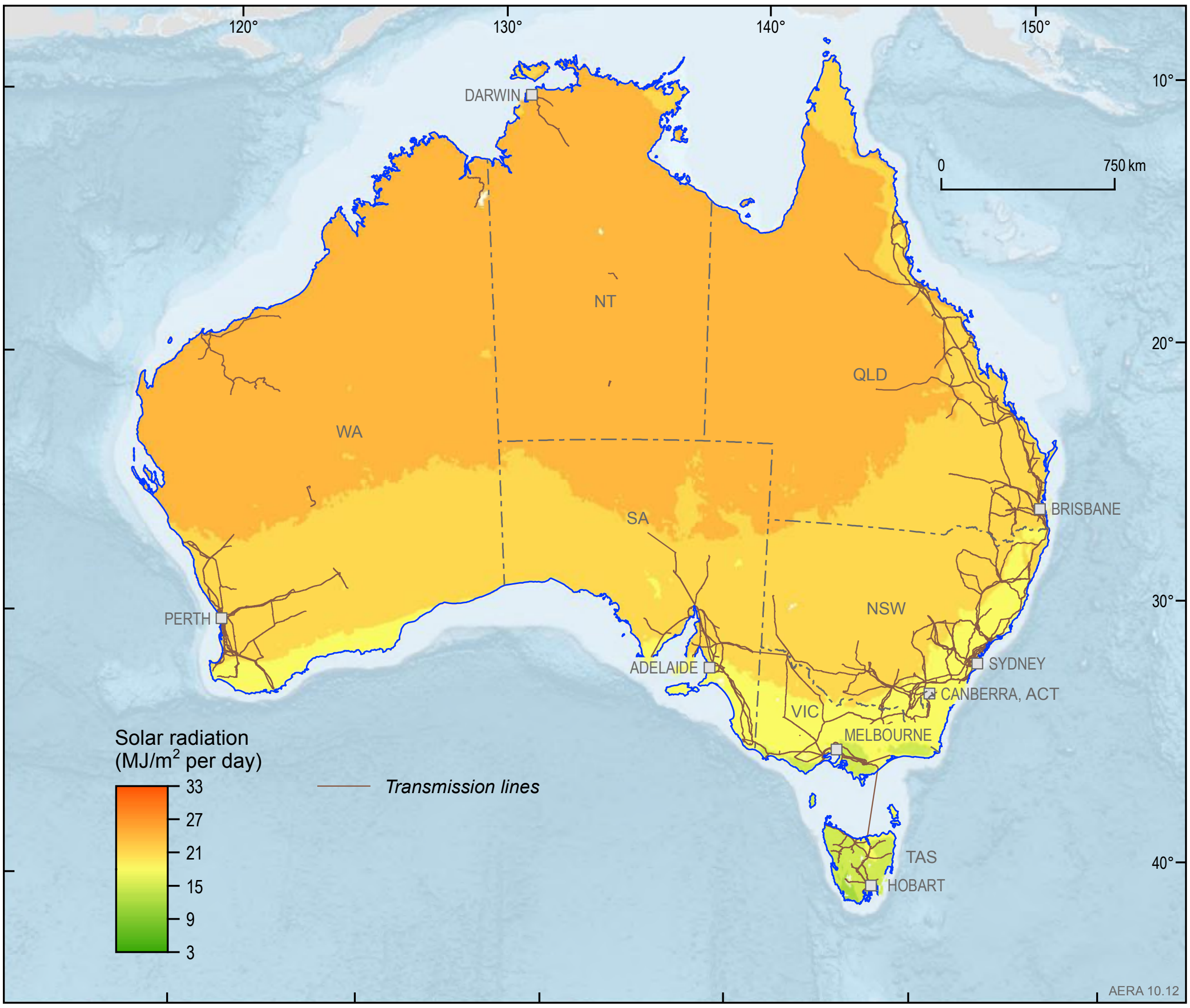

Figure 10.12 Annual average solar radiation

Source: BoM 2009

Short-term forecasting is valuable for grid operators to make immediate operational decisions, while long-term forecasting helps networks to plan the distribution of their generated energy. CSIRO's Australian solar energy forecasting system (ASEFS) will produce the most advanced operational solar forecasting system available, allowing the widespread integration of solar power into the NEM.

Some types of solar thermal power plants, including parabolic troughs and Fresnel reflectors, need to be constructed on flat land. It is estimated that about 2 hectares of land are required per MW of power produced (Stein 2009a). Figure 10.14 shows solar radiation, where land with a slope of greater than 1 per cent and land further than 25 km from existing transmission lines has been excluded. Land within national parks has also been excluded. These exclusion thresholds of slope and distance to grid are not precise limits but intended to be indicative only. Even with these limits, the annual radiation falling on the coloured areas in figure 10.14 is 2.7 million PJ, which amounts to nearly 500 times the annual energy demand of Australia. Moreover, power towers, dishes and PV systems are not restricted to flat land, which renders even this figure a conservative estimate.

Seasonal variations in resource availability

There are also significant seasonal variations in the amount of solar radiation reaching Australia. While summer radiation levels are generally very high across all of inland Australia, winter radiation has a much stronger dependence on latitude. Figures 10.15 and 10.16 show a comparison of the December and June average daily solar radiation. The same colour scheme has been used throughout figures 10.12 to 10.16 to allow visual comparison of the amount of radiation in each figure.

In some states, such as Victoria, South Australia and Queensland, the seasonal variation in solar radiation correlates with a seasonal variation in electricity demand. These summer peak demand periods—caused by air-conditioning loads—coincide with the hours that the solar resource is at its most abundant.

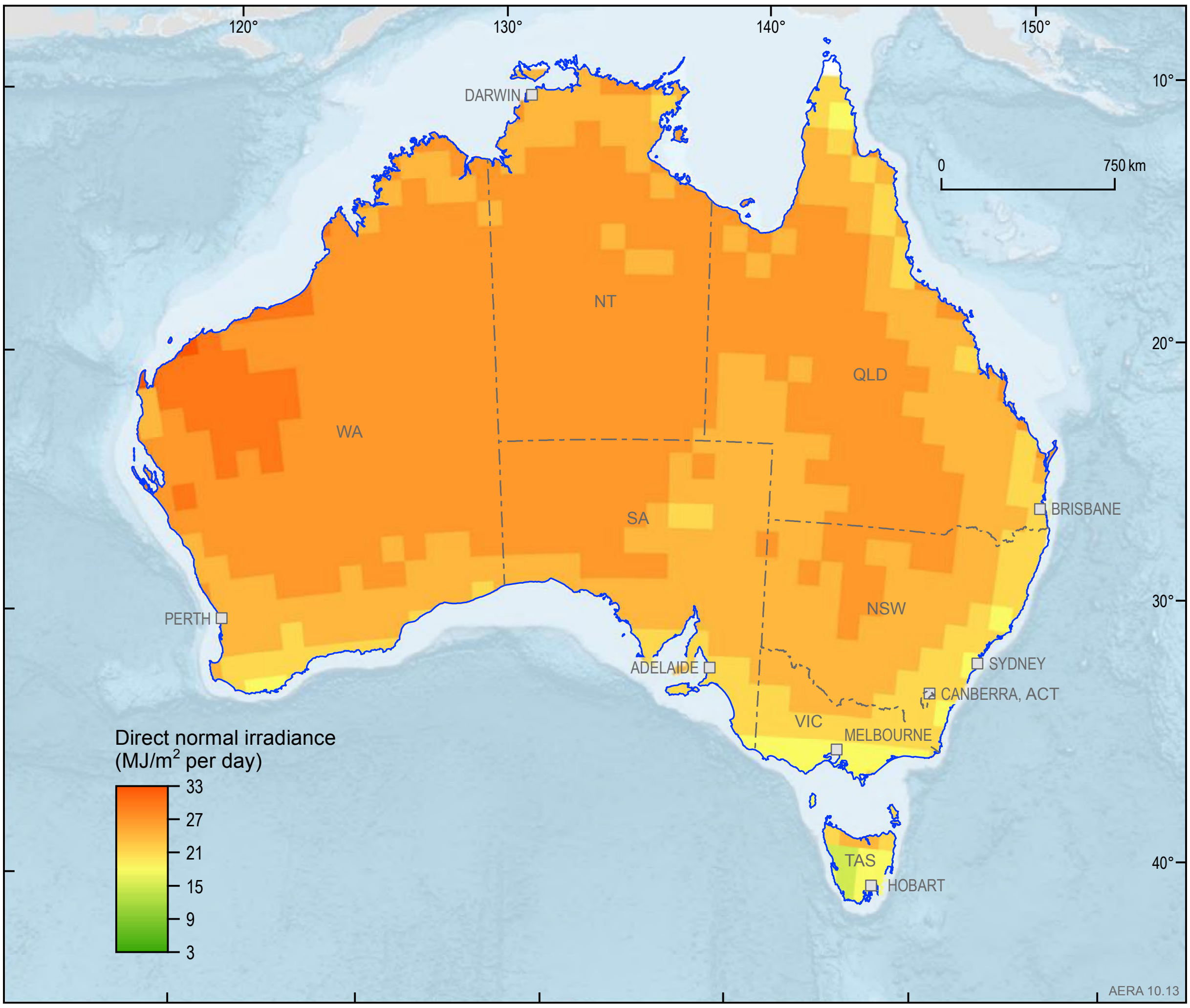

Figure 10.13 Direct normal solar irradiance

Source: NASA 2009

10.3.2 Solar energy market

Australia's modest production and use of solar energy is focused on off-grid and residential installations. While solar thermal water heating has been the predominant form of solar energy use to date, production of electricity from PV and concentrating solar thermal technologies is rapidly increasing.

The PV solar market in Australia grew rapidly in 2011, and remained strong in 2012. In response to the continuing high PV uptake rates, state governments closed most feed-in tariffs to new applicants, replacing them with a voluntary nominal payment for export related to the wholesale price, and the Australian Government reduced the incentives available for small PV systems via the Renewable Energy Target (RET) mechanism (IEA PVPS 2012). Streamlined PV system delivery and installation, combined with a rapid decline in module price from an average of around A$6 to around A$1 per watt peak. At this price, and with rapidly increasing grid electricity prices, the cost of PV electricity has reached parity with retail residential electricity prices. A more sustainable market with less reliance on subsidies is now being established.

Primary energy consumption

In 2011–12, renewable energy accounted for about 4.3 per cent of total primary energy consumption, with solar energy maintaining around 0.2 per cent of energy consumption (BREE 2013a).

Solar technologies were first installed in Australian in the mid-1970s (figure 10.17). The growth rate of solar consumption was high during the period 1974–75 to 1985–86 (33 per cent per year) and slowed during the period 1986–87 to 2005–06 (–1 per cent per year). However, solar consumption has increased dramatically since 2006–07 with an average growth rate of 22 per cent per year. The bulk of growth over this period was initially from solar thermal systems used for domestic water heating. Subsequently solar PV has grown significantly to about 2 GW of capacity.

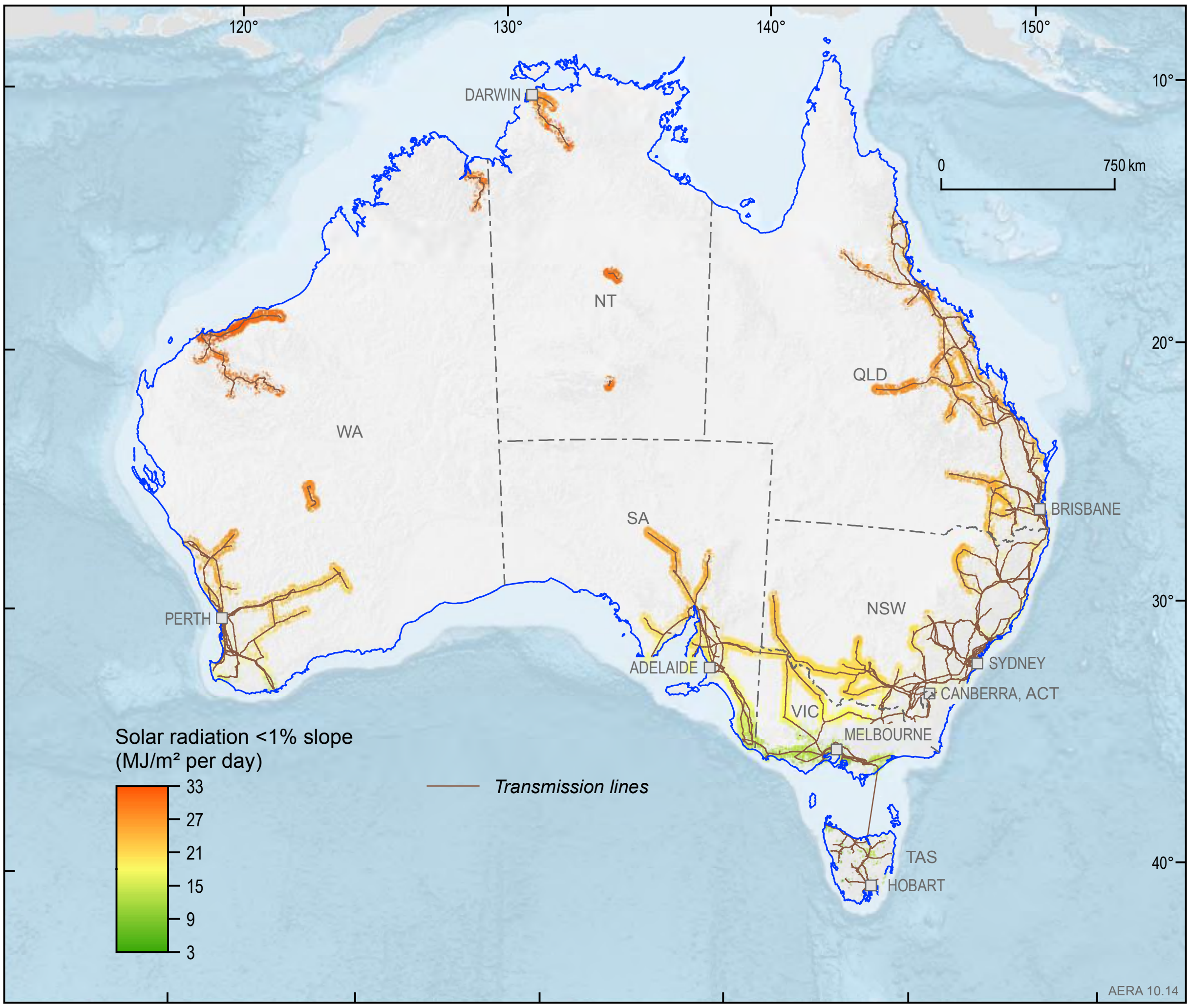

Figure 10.14 Annual solar radiation, excluding land with a slope of greater than 1 per cent and areas further than 25 km from existing transmission lines

Source: BoM 2009; Geoscience Australia

In 2011–12, Australia's solar energy consumption was 16.9 PJ, of which more than two-thirds was used in the residential sector (BREE 2013a).

Consumption of solar thermal energy, by state

New South Wales has the highest solar thermal energy consumption in Australia, contributing 30 per cent of Australia's total solar thermal use in 2011–12 (figure 10.18). Western Australia and Queensland contributed another 26 per cent and 19 per cent respectively. During the period 2000–01 to 2011–12, Victoria had the highest growth rate of solar use (22 per cent per year), followed by New South Wales (17 per cent a year) and Queensland (16 per cent per year).

Electricity generation

Electricity generation from solar energy has increased rapidly in recent years. Over the period 2000–01 to 2011–12, electricity generation from solar energy grew at an average rate of 23 per cent a year, from 0.05 TWh (0.2 PJ) in 2000–01 to 1.49 TWh (5.4 PJ) in 2011–12. In 2011–12, electricity generated from solar energy increased to 1.4 TWh, representing 0.56 per cent of Australian electricity generation (BREE 2013; figure 10.19).

Electricity generation from solar energy in Australia is currently almost entirely sourced from grid-connected PV systems. However, solar PV has a long history of supplying reliable off-grid power to regional and remote communities in Australia. Electricity generation from solar thermal systems is currently limited to small pilot projects, although interest in solar thermal systems for large-scale electricity generation is increasing.

Some care in analysis of generation data in energy statistics is warranted. For energy accounting purposes, the fuel inputs to a solar energy system are assumed to equal the energy generated by the solar system. Thus, the solar electricity fuel inputs in energy statistics represent the solar energy captured by solar energy systems, rather than the significantly larger measure of total solar radiation falling on solar energy systems. Fossil fuels such as gas and coal are measured in terms of both their

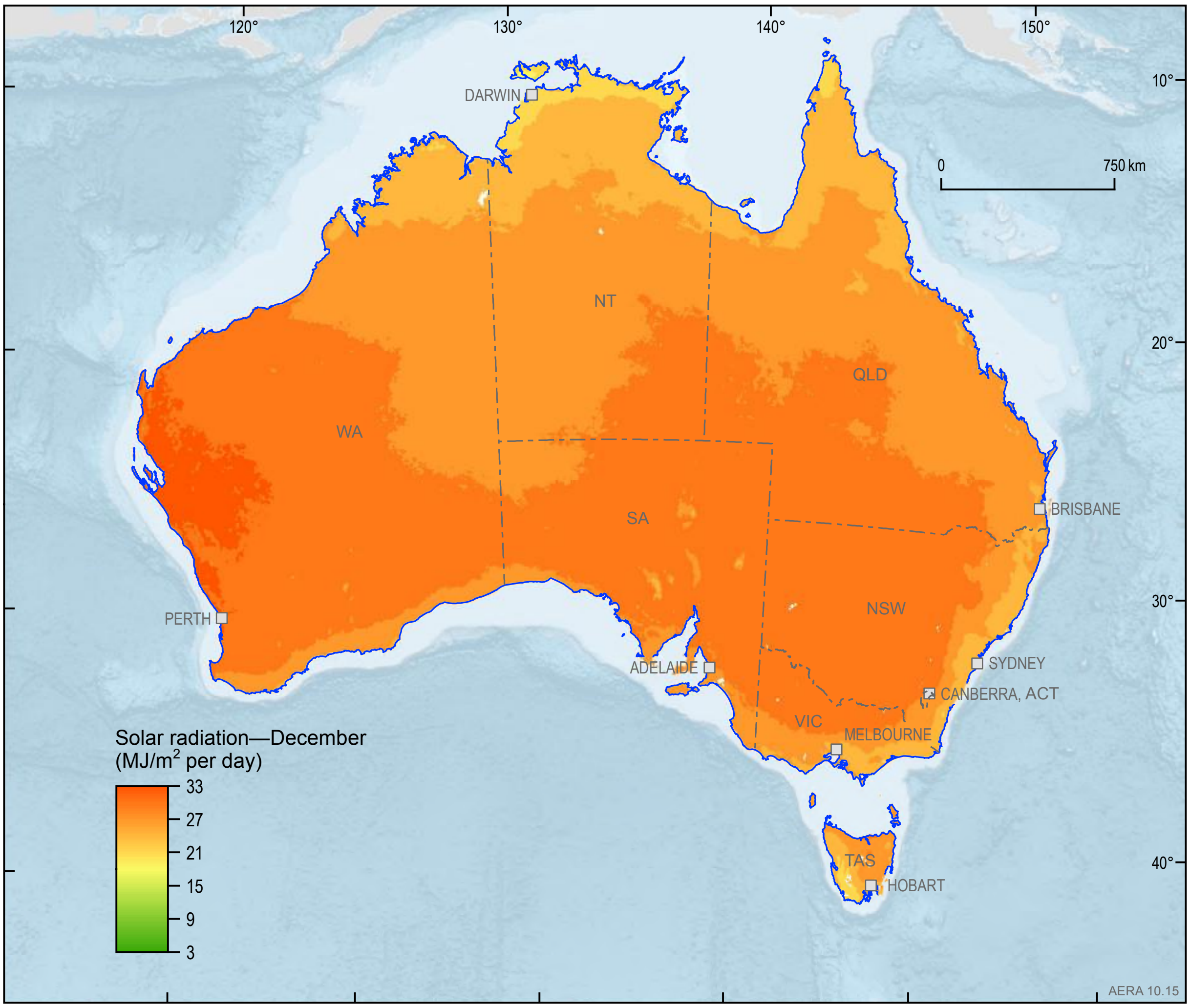

Figure 10.15 December average solar radiation

Source: BoM 2009

thermal fuel input and their electrical output. The result of this difference between fuel inputs and energy output for fossil fuels is that solar represents a larger share of electricity generation output than of fuel inputs to electricity generation. There is no marginal fuel cost for solar energy, hence solar electricity can be fed into the grid and sold at lower prices than fossil fuel–produced electricity.

Installed generation capacity

Australia's total PV capacity has increased significantly over the past decade (figure 10.20). Over the last two years, there has been a dramatic increase in the take-up of small-scale PV, with 837 MW installed in 2011, more than twice the capacity added in 2010 (APVA 2012).

Total installed capacity in Australia was around 1.4 GW in 2011 (APVA 2012). Of this, 88 per cent was grid connected, up from 84 per cent in 2010.

During 2012, 1038 MW PV capacity was installed with 1008 MW grid connected distributed. Total installed capacity reached 2.4 GW in 2012, with grid connected distributed representing 2276 MW and off-grid domestic 64 MW. In 2012, PV as a share of total electricity generation was 1.3 per cent (APVA 2012). One million Australian households had rooftop PV systems in 2012. PV power has now reached parity with retail residential electricity prices and government support programs are winding down (Watt et al. 2012).

Support for small-scale systems is via the Australian Government's Small-scale Renewable Energy Scheme. All PV systems up to 100 kW are also able to claim small-scale technology certificates up-front for up to 15 years of deemed generation, based on location. This means that the certificates for small systems act as an up-front capital cost reduction.

There is support for large systems from the Australian Government's Large-scale Renewable Energy Target, which increases from a 2012 target of 16 763 GWh to 41 850 GWh by 2020. It operates via a market for large-scale generation certificates, with 1 certificate created for each megawatt-hour (MWh) of electricity generated.

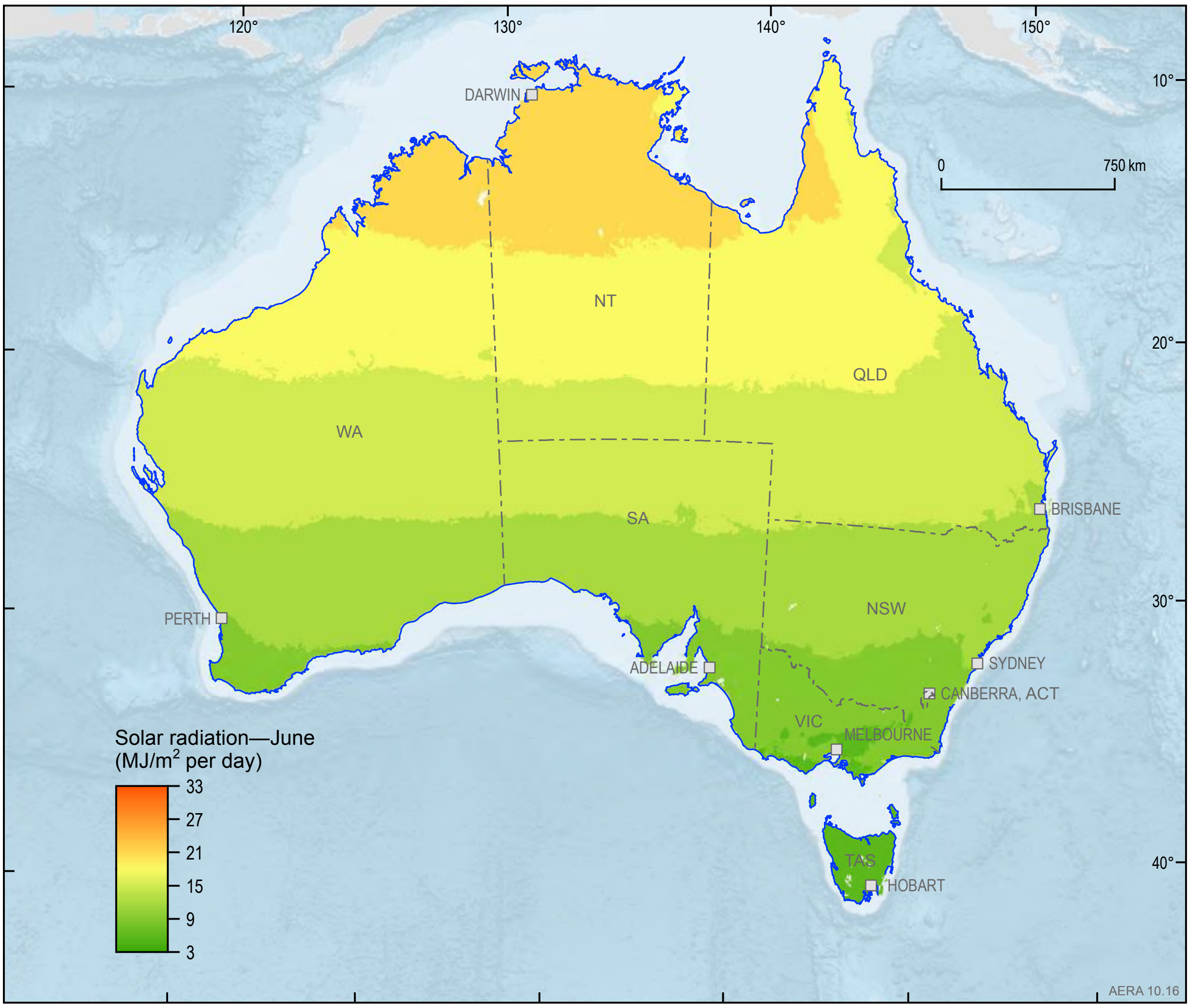

Figure 10.16 June average solar radiation

Source: BoM 2009

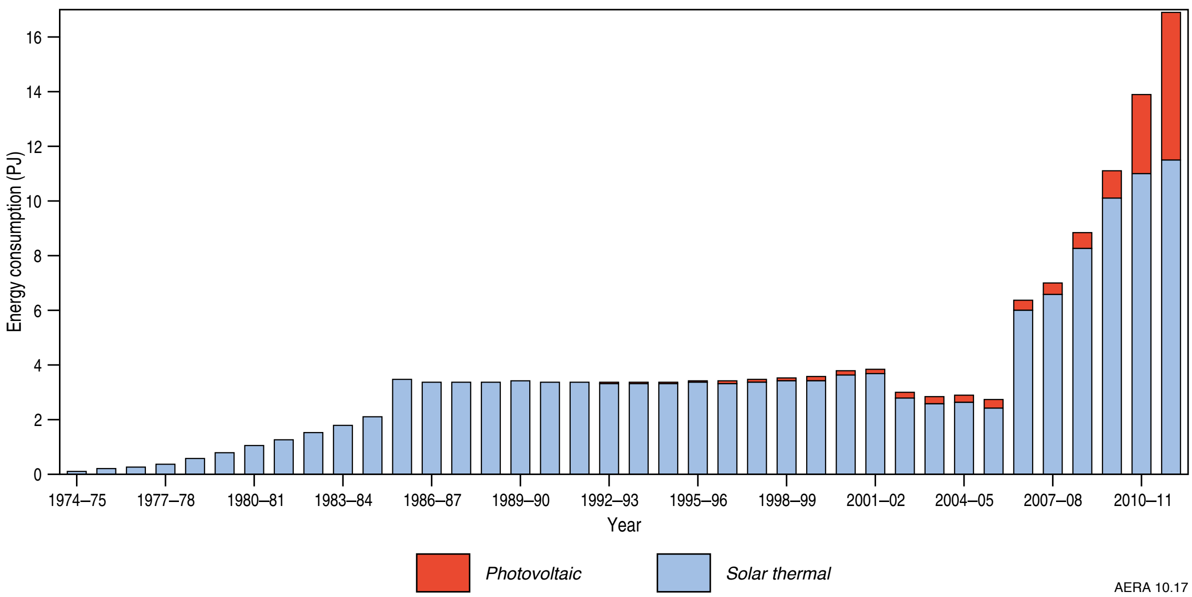

Figure 10.17 Australia's primary consumption of solar energy, by technology

Source: BREE 2012a; IEA 2012b

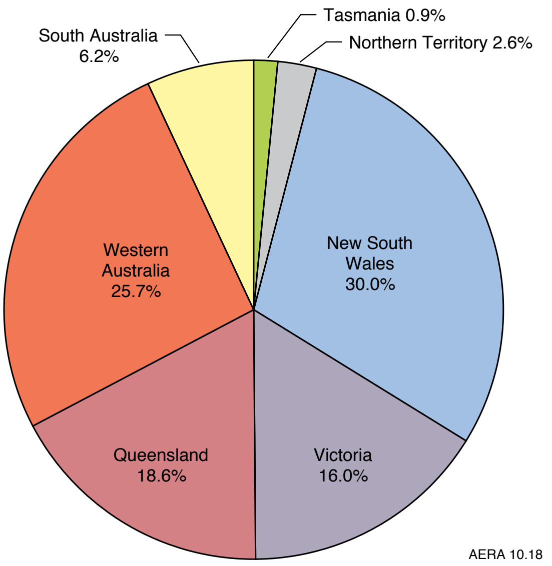

Figure 10.18 Solar thermal energy consumption, by state, 2011–12

Source: BREE 2012a

The Australian Government has invested A$370 million to support the development of large scale solar projects. ARENA manages these projects under its Deploying Utility Scale Renewable Energy strategic initiative.

Smart Grid, Smart City is a A$100 million Australian Government–funded project, led by Ausgrid and supported by consortium partners. The project is testing a range of smart grid technologies and gathering information about the benefits and costs of implementing these technologies in Australia. Up to 30 000 households will participate in the project, which runs between 2010 and 2013.

Recently commissioned solar projects

Between January 2010 and the end of 2012, 12 solar plants were commissioned (table 10.3).

Australia's first utility-scale PV farm was commissioned in October 2012. Verve Energy and GE Financial Services' 10 MW Greenough River Solar Farm is located 50 km south-east of Geraldton, Western Australia.

The Silex Systems' Mildura Stage 2 demonstration concentrating PV plant (1.5 MW) commenced operation in April 2013. Planning is under way for Mildura Stage 3, with a capacity of 100MW.

CS Energy's Kogan Creek Solar Boost Project is currently under construction near Chinchilla in Queensland. The solar thermal addition to the 750 MW Kogan Creek coal-fired power station involves the installation of 44 MW to existing capacity at a capital cost of A$105 million.

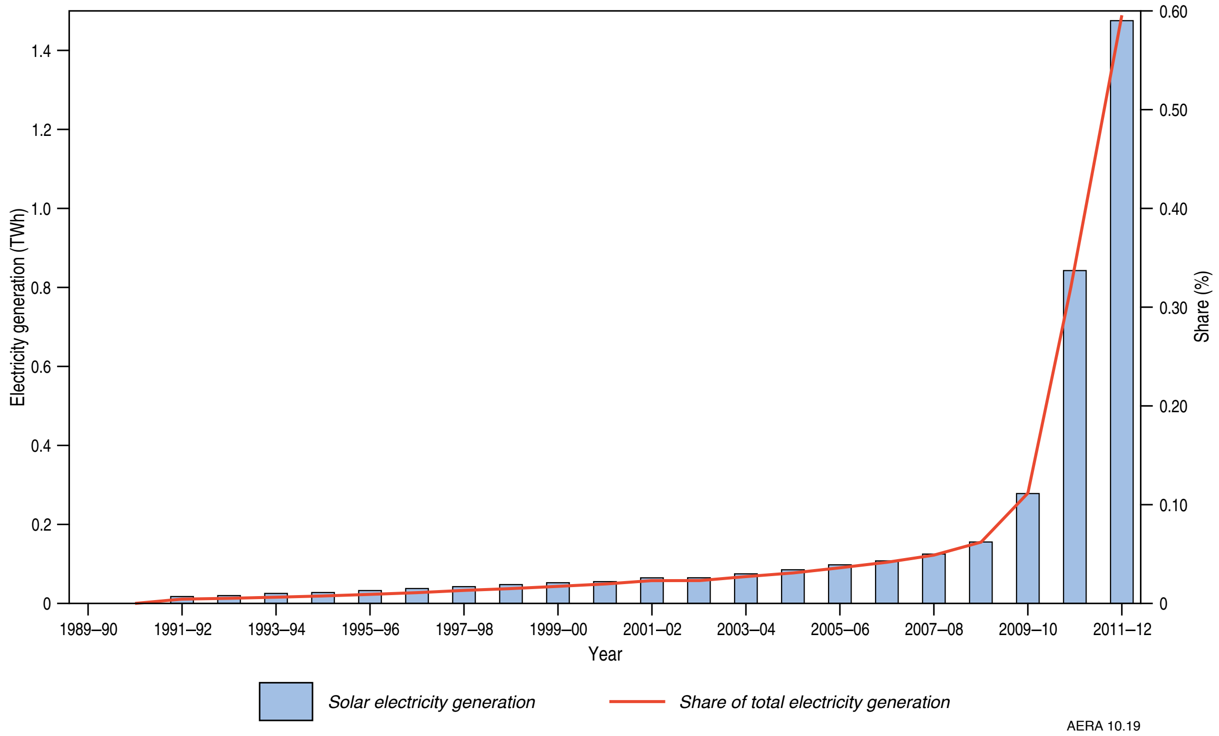

Figure 10.19 Australian electricity generation from solar energy

Source: BREE 2012a

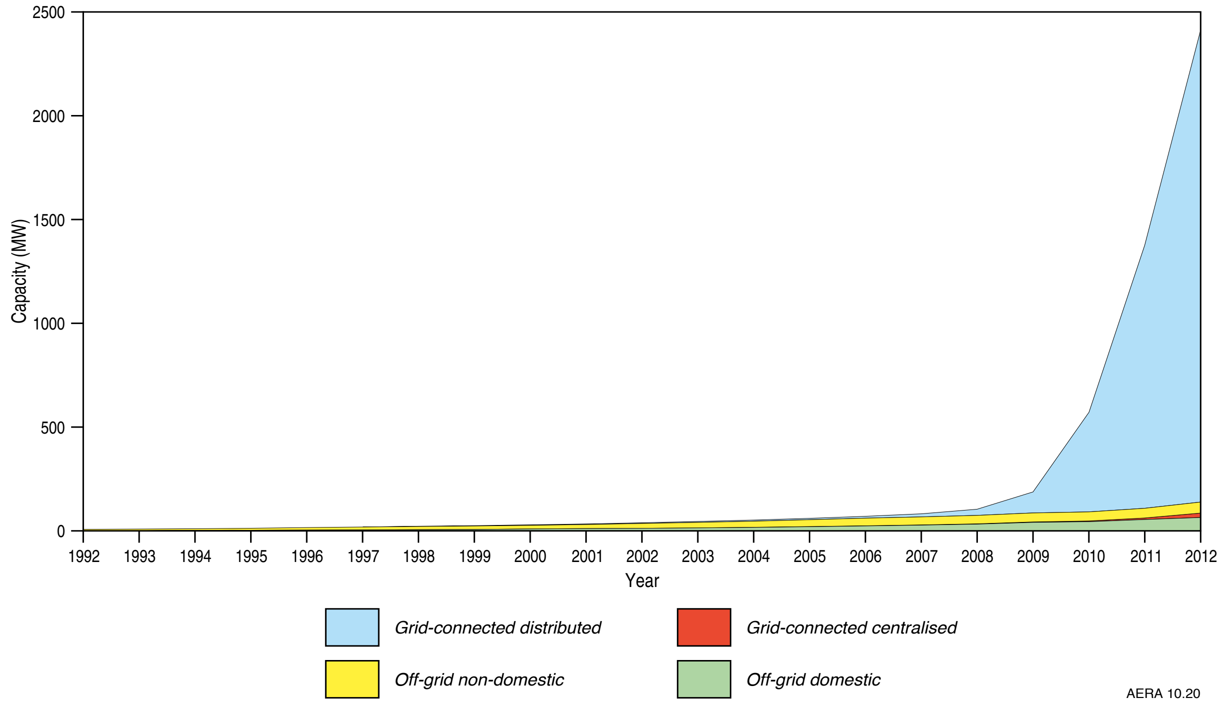

Figure 10.20 PV installed capacity,1992–2011

Note: These estimates represent the peak power output of PV systems. They do not represent the average power output over a year, as solar radiation varies according to factors such as the time of day, the number of daylight hours, the angle of the sun and the cloud cover. These capacity estimates are consistent with the PV production data presented in this report

Source: Watt et al. 2012

Table 10.3 Solar energy projects commissioned, January 2010 to 2012

Project	Company	State	Start-up	Capacity (MW)
Perth Zoo	Perth Zoo	WA	2012	2.4
Carnarvon Solar Farm	EMC Solar	WA	2011	0.29
Carrara Stadium	Carrara Stadium	QLD	2011	0.25
Mayfield	CSIRO	NSW	2011	0.2
St Lucia Campus, University of Queensland	University of Queensland	QLD	2011	1.2
Ilparpa (Uterne)	Alice Springs Consortium	NT	2011	0.97
Alice Springs Airport	Alice Springs Airport	NT	2010	0.24
Monash University	Monash University	VIC	2010	0.18
Marble Bar	Horizon Power	WA	2010	0.58
Nullagine	Horizon Power	WA	2010	0.2

Source: Clean Energy Council 2012

10.4 Outlook for Australia's solar energy resources and market

Solar energy is a renewable resource: increased use of the resource does not affect resource availability. However, the quantity of the resource that can be economically captured changes over time through technological developments.

The outlook for the Australian solar market depends on the cost of solar energy relative to other energy resources and the time of day value of the energy produced. Costs for rooftop solar PV systems have fallen dramatically in the past few years and are becoming increasingly affordable for many Australian households. The competitiveness of commercial-scale solar energy and renewable energy sources generally will also depend on government policies aimed at reducing greenhouse gas emissions.

Solar energy is an increasingly economically attractive option for remote off-grid electricity generation. The costs of solar energy are expected to fall as economies of scale reduce supply chain costs and experience with construction, installation and maintenance increases.

10.4.1 Key factors influencing the future development of Australia's solar energy resources

Australia is a world leader in developing solar technologies (Lovegrove and Dennis 2006). A number of factors may affect the uptake of technologies and the economic viability of solar installations.

Solar energy technologies and costs

Research into both solar PV and solar thermal technologies is largely focused on reducing costs and increasing the efficiency of the systems.

- Electricity generation—commercial-scale generation projects have been demonstrated and are operating in many countries, although investors attach a risk premium to the technology. Small-scale solar PV systems are currently well suited to off-grid applications and on-grid rooftop systems, with other applications dependent on government funding to make them viable. Information on solar energy technologies for electricity generation is presented in box 10.1. (section 10.2.1).
- Direct-use applications—solar thermal hot water systems for domestic use represent the most widely commercialised solar energy technology. Solar water heaters continue to be developed further, and can also be integrated with PV arrays. Other direct uses include passive solar heating and solar air conditioning. Information on solar energy technologies for direct-use applications is presented in box 10.2.

With both solar PV and solar thermal generation, the majority of costs are borne in the capital installation phase, irrespective of the scale or size of the project (figure 10.21). The inverter that converts the direct current to alternating current needs to be replaced approximately once every 10 years (Borenstein 2008). However, there are no fuel costs—once the system is installed, apart from replacing the inverter, there should be no costs associated with running the system until the end of its useful life (20 to 25 years).

The cost of installing solar capacity has generally been decreasing. Both PV and solar thermal technologies currently have research and development funds directed toward them, and new production processes are expected to result in a continuation of this trend (figure 10.22).

Supportive government policies, in combination with rapid expansion in the global production of PV modules and substantial decreases in the price of polysilicon, has contributed to dramatic reductions in the price of PV units and hence the levelised cost of electricity (LCOE) over the past two or three years. This has contributed to the 150 per cent increase in installed solar PV capacity in Australia between 2010 and 2011 (BREE 2013). As at 2012, BREE estimated LCOE for solar thermal technologies ranged from A$390/MWh to A$402/MWh, whereas PV technologies ranged from A$212/MWh to A$344/MWh (BREE 2012b). The ongoing cost reductions and difference in the cost of generating electricity between fossil fuels and renewable sources will diminish.

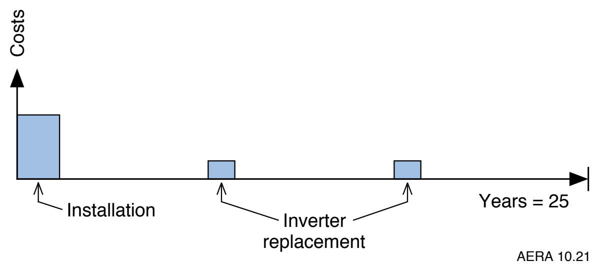

Figure 10.21 Indicative solar PV production profile and costs

Source: Bureau of Resources and Energy Economics

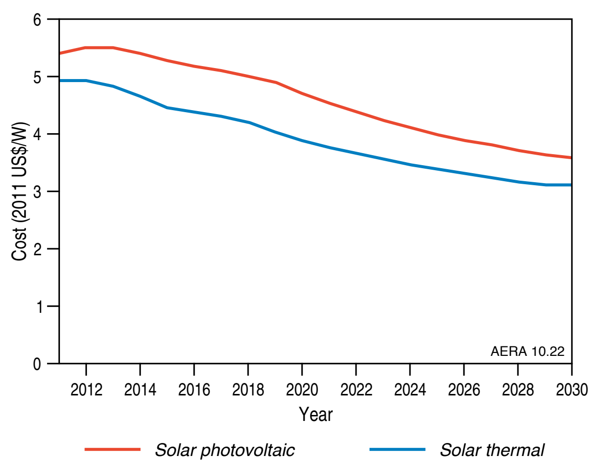

Figure 10.22 Projected average capital costs for new electricity generation plants using solar energy, 2011–2030

Source: Estimates based on EIA 2009; BREE 2012b

The time taken to install or develop a solar system is highly dependent on the size and scale of the project. Solar hot water systems can be installed in around four hours. Small-scale PV solar systems can similarly be installed quite rapidly. However, commercial-scale solar plants take considerably longer, depending on the type of installation and other factors, including location or environmental considerations.

For solar thermal technology options, as concentrating solar power plants increase their share of the utility market and their installed capacity expands, costs are expected to continue to decrease (figure 10.22). This is due to the higher production volume of key equipment and increased experience gained by manufacturers and engineers who are planning and building plants. Additionally, it is expected that cheaper heat transfer fluids will become available or that fluids that can handle higher temperatures, and therefore enable increased efficiency, will be used. The cost of storage systems is also expected to fall. Furthermore, improvements are expected in receiver tube absorption and steam turbine efficiencies that would increase the capacity factor for these plants. The combination of a decrease in capital cost and an increase in plant output will lead to a lower cost of electricity (BREE 2012b).

For solar PV, there have been significant increases in installation in recent years with significant price reductions per kW as large-scale manufacturing facilities reduce production costs. The cost of electricity from solar PV plants is expected to continue to decrease in the future, due to expanded manufacturing capacity and process, and cell efficiencies (figure 10.23). This is due both to expected reduction in solar panel costs and increased efficiency. The balance of system and inverter costs are also expected to decrease over time. Research continues to develop new PV configurations, such as multi-junction concentrators, that promise to increase cell and module efficiency (BREE 2012b).

Location of the resource

In Australia, the best solar resources are commonly distant from the NEM, especially the major urban centres on the eastern seaboard. This poses a challenge for developing new solar power plants, as there needs to be a balance between maximising the solar radiation and minimising the costs of connecting to the electricity grid. However, there is potential for solar energy systems to provide base and intermediate load electricity with fossil-fuel plants (such as gas turbine power stations) in areas with isolated grid systems and good insolation resources. A report by the Wyld Group and MMA (2008) identified Mount Isa, Alice Springs, Tennant Creek and the Pilbara region as areas with these characteristics. Access to Australia's major solar energy resources—as with other remote renewable energy sources—is likely to require investment to extend the electricity grid.

Stand-alone PV systems can be located close to customers (for example, on roofs of residential buildings), which reduces the costs of electricity transmission and distribution. However, concentrating solar thermal technologies require more specific conditions and large areas of land (Lorenz et al. 2008), which are often only available long distances from the customers needing the energy. In Australia, installing small-scale residential or medium-scale commercial systems (both PV and thermal) can be highly attractive options for remote areas where electricity infrastructure is difficult or costly to access and alternative local sources of electricity are expensive. Small-scale rooftop systems are also becoming increasingly viable for households and commercial operations in many locations across the NEM.

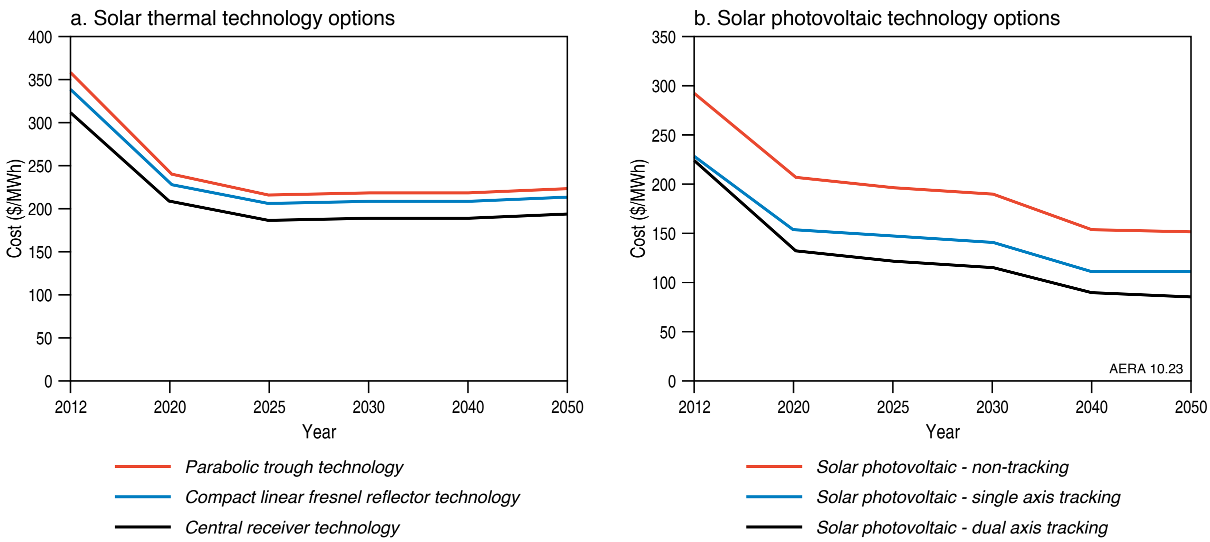

Figure 10.23 Solar technology options, levelised cost of energy, New South Wales

Source: BREE 2012b

BOX 10.2 SOLAR ENERGY TECHNOLOGIES FOR DIRECT-USE APPLICATIONS

Solar thermal heating

Solar thermal heating uses direct heat from sunlight, without the need to convert the energy into electricity. The simplest form of solar thermal heating is achieved by pumping water through a system of light-absorbing tubes, usually mounted on a rooftop. The tubes absorb sunlight, and heat the water flowing in them. The most common use for solar thermal heating is hot water systems, but they are also used for swimming pool heating or space heating.

There are two main types of solar water heaters: flat-plate and evacuated tube systems (figure 10.24). Flat-plate systems are the most widespread and mature technology. They use an array of very small tubes, covered by a transparent glazing for insulation. Evacuated tubes consist of a sunlight-absorbing metal tube inside two concentric transparent glass tubes. The space between the two glass tubes is evacuated to prevent losses due to convection. Evacuated tubes have lower heat losses than flat-plate collectors, giving them an advantage in winter conditions.

Solar thermal heating is a mature technology and relatively inexpensive compared to other solar technologies. This cost advantage has meant that solar thermal heating has the largest energy production of any solar technology. In some countries with favourable sunlight conditions, solar water heaters have gained a substantial market share of water heaters.

Solar air-conditioning

Solar thermal energy can also be used to drive air-conditioning systems. Sorption cooling uses a heat source to drive a refrigeration cycle, and can be integrated with solar thermal heat collectors to provide solar air-conditioning. Since sunlight is generally strong when air-conditioning is most needed, solar air-conditioning can be used to balance peak summer electricity loads. However, a number of developments are required before solar air-conditioning becomes cost competitive in Australia.

Passive solar heating

Solar energy can also be used to heat buildings directly, through designing buildings that capture sunlight and store heat that can be used at night. This process is called passive solar heating, and can save energy (electricity and gas) that would otherwise be needed to heat buildings during cold weather. New buildings can be constructed with passive solar heating features at minimal extra cost, providing a reliable source of heating that can greatly reduce energy demands in winter (AZSC 2009).

Passive solar heating usually requires two basic elements: a north-facing (in the Southern Hemisphere) window of transparent material that allows sunlight to enter the building; and a thermal storage material that absorbs and stores heat. Passive solar heating must also be integrated with insulation to provide efficient storage of heat, and roof designs that can maximise exposure in winter and minimise exposure in summer. Although some of these features can be retrofitted to existing buildings, the best prospects for passive solar heating are in the design of new buildings.

Combined heat and power systems

A technology under development in Australia and overseas is the combined heat and power system, combining solar thermal heating with PV technology (ANU 2009). Typically this consists of a small-scale concentrating parabolic trough system with a central PV receiver, where the receiver is coupled to a cooling fluid. While the PV produces electricity, heat is extracted from the cooling fluid and can be used in the same way as a conventional solar thermal heater. These systems can achieve a greater efficiency of energy conversion, by using the same sunlight for two purposes. These systems are being targeted for small-scale rooftop applications.

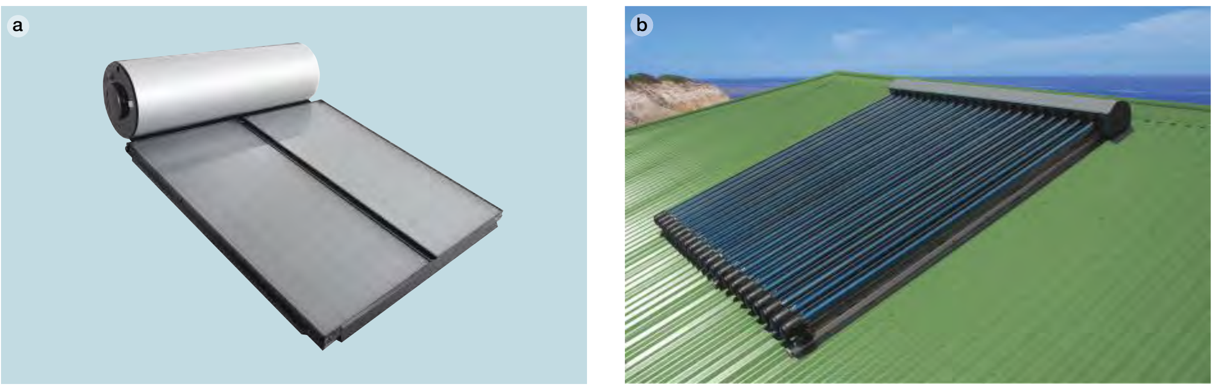

Figure 10.24 a Flat-plate solar water heater. **b** Evacuated tube solar water heater

Source: Hills Solar 2009; SEDO 2009

Government policies

Government policies have been implemented at several stages of the solar energy production chain in Australia. Rebates for solar water heating systems and residential PV installations have reduced the cost of these technologies for consumers and encouraged their uptake.

The Solar Homes and Communities Plan (2000 to June 2009) provided rebates for the installation of solar PV systems. The capacity of PV systems installed by Australian households increased significantly under this program. Although the program ended on 9 June 2009, a very large number of pre-approval applications were received in the closing days and installations under the program occurred through to 2011. A total of 155.62 MW of PV was installed under this program, with only 200 kW installed during 2011 (IEA 2012b).

The RET scheme included the Solar Credits initiative (ended 1 January 2013) that provided a multiplied credit for electricity generated by small solar PV systems. Solar Credits provided an up-front capital subsidy towards the installation of small solar PV systems.

In 2012, the Australian Government established ARENA to deliver funding for research, development and demonstration of renewable energy technologies. ARENA is also encouraging investment in solar energy projects by supporting the collection and publishing of solar irradiation data to assist the integration and financing of solar projects.

ARENA's strategic initiatives for large-scale projects include:

- Regional Australia's Renewables to demonstrate renewable energy in regional and remote locations with the objective of increasing the deployment of commercially prospective remote renewable energy generation systems.
- Deploying Utility Scale Renewable Energy to support the foundation for large-scale, grid-connected solar power to operate in Australia's competitive electricity market.

ARENA's supporting initiatives are of more limited scope and address specific roadblocks, such as:

- Regional and remote deployment; including system integration, intermittency, storage, technology demonstration and testing facilities.
- Building Australia's next generation solar energy technologies through funding for research and development. Solar energy technologies are also eligible for funding from the Australian Research Council.

The Australian Government established the Australian Solar Institute (ASI) in 2009. The institute has strong collaborative links with CSIRO and universities undertaking research and development in solar technologies. ASI aims to drive development of solar thermal and PV technologies in Australia, including the areas of efficiency and cost effectiveness (DRET 2009). Since its establishment, close to two-thirds of the A$150 million provided by the Australian Government has been invested in people and projects that will advance solar innovation (ASI 2012). From 2013, ASI is part of ARENA and will provide long-term financial assistance for solar technology development.

Other government policies, including feed-in tariffs in most Australian states and territories, may also encourage the uptake of solar energy. During 2011, state-based feed-in tariffs saw widespread reductions and closures. The Victorian Government's feed-in tariff (called the Premium Feed-in Tariff) closed on 30 September 2011 as it had reached its cap. Net metering (called the Standard Feed-in Tariff) continues to be available for systems up to 100 kW. The South Australian Government's feed-in tariff was reduced from A$0.44/kWh to A$0.16/kWh from 1 October 2011 and eligible systems receive the payment only until 30 September 2013. In the Australian Capital Territory, systems up to 30 kW were eligible for a A$0.457/kWh feed-in tariff until 31 May 2011. Systems from 30 kW up to 200 kW were eligible for a feed-in tariff of A$0.3427/kWh from April 2011 (capped at 15 MW). From 12 July 2011, both categories became eligible for the A$0.3427/kWh feed-in tariff. The 15 MW cap was reached by 13 July 2011 and the scheme was closed for all systems. The New South Wales Government's A$0.20/kWh gross feed-in tariff was closed to new applications from midnight 28 April 2011. The Western Australian Government's A$0.40/kWh net feed-in tariff was reduced to A$0.20/kWh from 30 June 2011, then closed to new applications from 1 August 2011.

Infrastructure issues

The location of large-scale solar power plants in Australia will be influenced by the cost of connection to the electricity grid. In the short term, developments are likely to focus on isolated grid systems or nodes to the existing electricity grid, since this minimises infrastructure costs.

In the longer term, the extension of the grid to access remote solar energy resources in desert regions may require building long-distance transmission lines. However, building a high-voltage direct current (HVDC) link to a solar power station in desert areas would require a large up-front investment.

The idea of generating large-scale solar energy in remote desert regions has been proposed on a much larger scale internationally. In June 2009 the DESERTEC Foundation outlined a proposal to build large-scale solar farms in the sun-rich regions of the Middle East and north Africa, and export their power to Europe using long-distance HVDC lines (DESERTEC 2009). An Asia Pacific Sunbelt Development Project has been established with the aim of moving solar energy by way of fuel rather than electricity from regions such as Australia to those Asian countries importing energy, such as Japan and Korea. These projects illustrate the growing international interest in utilising large-scale solar power from remote areas, despite the infrastructure challenges in transmitting or transporting energy over long distances.

Environmental issues

Over the 20-year lifespan of a rooftop, grid-connected solar system in Australia, estimated yield is more than seven times the energy required to produce it (MacKay 2009). The greenhouse gas emissions generated from the manufacture of solar energy systems are more than offset over the systems' life cycle, as there are no greenhouse gas emissions generated from their operation.

Most solar thermal electricity generation systems require water for steam production and this water use affects the efficiency of the system. The majority of this water is consumed in 'wet cooling' towers, which use evaporative cooling to condense the steam after it has passed through the turbine. In addition, solar thermal systems require water to wash the mirrors, to maintain their reflectivity (Jones 2008). It is possible to use 'dry cooling' towers, which eliminate most of the water consumption, but this reduces the efficiency of the steam cycle by approximately 10 per cent (Stein 2009b).

A further option under development is the use of high-temperature Brayton (thermodynamic) cycles, which do not use steam turbines and thus do not consume water. Brayton cycles are more efficient than conventional Rankine (steam) cycles, but they can only be achieved by point-focusing solar thermal technologies (power towers and dishes).

10.4.2 Outlook for solar energy market

Solar energy is more abundant in Australia than other renewable energy sources. The domestic solar energy industry is growing rapidly due to the increasingly favourable economics of rooftop PV systems. There are currently only a small number of proposed commercial solar energy projects. In the short term, solar energy may find it difficult to compete commercially with other forms of energy for electricity generation in the NEM. However, as global deployment of solar energy technologies increases, the cost of the technologies is likely to further decrease. Moreover, technological developments and greenhouse gas emission reduction policies are expected to drive increased use of solar energy in the medium and long term.

In 2012, PV solar systems dominated the small-scale solar electricity application and hold the majority of market share. Solar thermal technologies have the niche at the commercial scale and the ability to store thermal energy for up to 16 hours and dispatch energy later. Solar PV technologies have a lower LCOE compared to solar thermal technologies. A non-tracking solar PV plant in New South Wales has an LCOE of A$224/MWh (as at 2012) with an estimated LCOE of A$86/MWh in 2050. In contrast, a solar thermal tower in New South Wales has an LCOE of A$304/MWh (as at 2012) with an estimated LCOE of A$205/MWh in 2050 (BREE 2012b).

While high investment costs currently represent a barrier to more widespread use of solar energy, there is considerable scope for the cost of solar technologies to decline significantly over time. The RET, and the results of RD&D are all expected to underpin the growth of solar energy over the outlook period.

Proposed development projects

As at October 2013, there were 13 less advanced solar projects at the feasibility or committed stage, with a potential combined capacity of 840 MW (table 10.4).

In 2012, Australia's first reverse auction bidding process was completed in the Australian Capital Territory (ACT). The ACT Large-scale Solar Auction commenced on 27 January 2012 and provided opportunity for proponents to bid, in a competitive reverse auction process, for up to 40 MW of solar generation capacity in the ACT. The solar auction represents the first capacity release under the *Electricity Feed-in (Large-scale Renewable Energy Generation) Act 2011*. On 5 September 2012, FRV Royalla Solar Farm Pty Limited was announced as the sole successful proponent for a 20 MW solar generator at Royalla, south of the ACT.

Table 10.4 Projects at a feasibility and committed stage of development, as at October 2013

Project	Company[a]	Location	Status[b]	Expected start-up	New capacity (MW)	Capital expenditure[c] (A$million)
Broken Hill Solar Farm	AGL Energy	Broken Hill, NSW	Committed	2015	50	150
Capital Photovoltaic Solar Farm	Infigen Energy/ Suntech Australia	10 km north of Bungendore, NSW	Planning approval received	na	50	150
Chapman Solar Power Station	Investec Bank (Australia) Limited	14 km north-east of Geraldton, WA	Planning approved	2015	50 (solar) 50 (diesel)	200
Collinsville Photovoltaic	Ratch Australia	75km SW of Bowen	Feasibility	2015	30	60
Collinsville Solar-thermal	Ratch Australia	75km SW of Bowen	Feasibility	2017	30	180
Kalgoorlie Solar Power Station	Investec Bank (Australia) Limited	Mungari, 26km from Kalgoorlie	Feasibility	2015	50	200
Kogan Creek Solar Boost Project	CS Energy	near Chinchilla	Committed	2014	44	105
Mallee Solar Park	EnergyAustralia	near Mildura, VIC	Feasibility study under way	2015	180	na

Project	Company[a]	Location	Status[b]	Expected start-up	New capacity (MW)	Capital expenditure[c] (A$million)
Manildra Photovoltaic Solar Farm	Infigen Suntech Australia	5 km north-west of Manildra, NSW	Planning approval received	na	50	150
Moree Photovoltaic Solar Farm	Infigen Energy	5 km south-east of Moree, NSW	Planning approval received	na	50	180
Moree Solar Farm	Moree Solar Farm Consortium	near Moree, NSW	Government approval received	na	56	na
Nyngan Photovoltaic Solar Farm	Infigen Suntech Australia	2 km south of Nyngan, NSW	Planning approval received	na	100	300
Nyngan Solar Farm	AGL Energy	7.6 km west of Nyngan, NSW	Committed	2015	100	300

a Principal operating companies. **b** Feasibility stage is where the initial feasibility studies have been completed and the results support further development. Committed stage is where construction has commenced or is preparing to commence. **c** Total capital expenditure as reported by the company in current dollars. Includes cost of development, plant and equipment.

Source: BREE 2013b

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Chapter 11

Ocean Energy

11.1 Summary

KEY MESSAGES

- Ocean energy includes wave, tide, thermal and salinity gradient energy sources and is an underdeveloped but potentially substantial renewable energy source.
- Australia has world-class wave energy resources along its western and southern coastline, especially in Tasmania.
- Australia's best tidal energy resources are located along the northern margin, especially the north-west coast of Western Australia.
- Worldwide, ocean energy accounts for a negligible proportion of total electricity generation. The share of ocean energy in world electricity generation is projected to increase in the future, albeit from a modest beginning.
- Currently ocean energy use is mainly based on tidal power stations. Wave energy technologies are at early stages of commercialisation, and thermal and salinity gradient technologies are still at developmental stages.
- Adoption of ocean energy in Australia depends on further maturing of the industry, including tidal or wave energy proving commercially viable, as well as comprehensive assessments of potential environmental impacts. The cost of access to the transmission grid may also be an impediment for many sites in the future.

11.1.1 World ocean energy resources and market

- There are substantial ocean (tidal, wave, thermal and salinity gradient) energy resources that have potential for zero or low emission electricity generation.
- Ocean energy industries are at an early stage of development, and they are currently the smallest contributors to world electricity generation. Commercial applications of ocean energy are limited to tidal barrage power plants in five OECD countries: Republic of Korea (254 MW and 1.5 MW), France (240 MW), Canada (20 MW), China (3.2 MW) and Russia (1.7 MW). The world's first large-scale tidal stream generator commenced operations in 2008 in the United Kingdom (1.2 MW) (REN21 2012).
- Government policies and falling investment costs are projected to be the main factors underpinning future growth in world ocean energy use. World electricity generation from ocean energy is projected to increase at an average annual rate of 10.4 per cent between 2010 and 2035 (IEA 2012a).

11.1.2 Australia's ocean energy resources

- The northern half of the Australian continental shelf has limited wave energy resources but many areas have tidal energy resources, particularly the Northwest Shelf, Darwin, Torres Strait and the southern Great Barrier Reef (figure 11.1).
- The southern half of the Australian continental shelf has world-class wave energy resources along most of the western and southern coastlines, particularly the west and southern coasts of Tasmania (figure 11.2). In contrast, tidal energy resources are limited in this region.
- Areas in the Pacific Ocean approximately 100 km off the coast of Queensland are prospective for ocean thermal energy.
- Areas near the junction of rivers and the ocean are prospective for salinity gradient energy, but due to the comparatively low capacity are only likely to be considered in localised and remote areas.

11.1.3 Key factors in utilising Australia's ocean energy resources

- Global production costs for ocean energy systems are currently high but are expected to fall as technologies mature. While not currently used extensively in Australia, the cost of ocean energy technology is projected to be around A$303/MWh in 2020, declining to A$226/MWh in 2050. Ocean energy is expected to remain one of the more expensive technology options over this time frame, with tidal barrage systems at the lower end of this

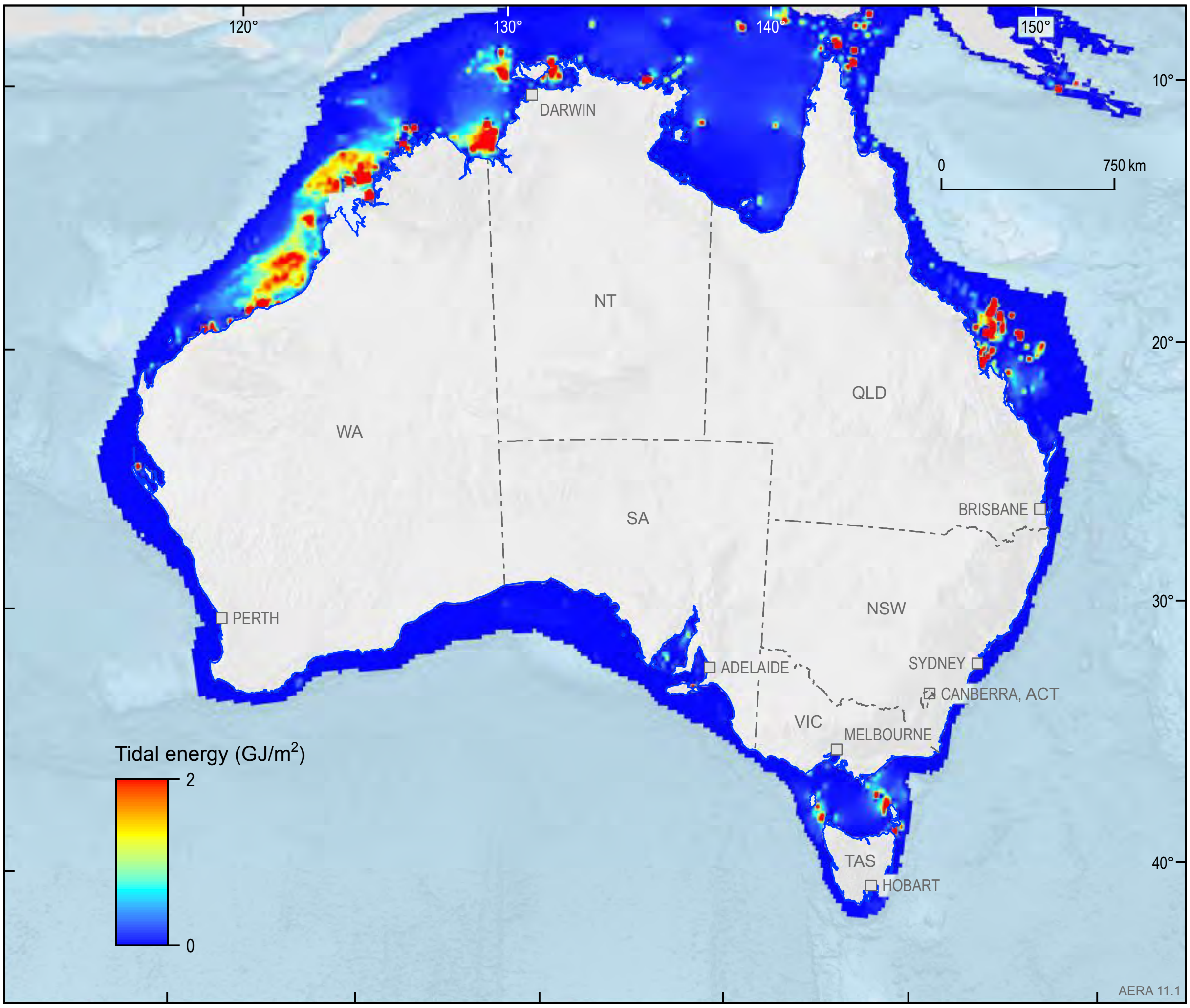

Figure 11.1 Total annual tide kinetic energy (in gigajoules per square metre, GJ/m²) on the Australian continental shelf (less than 300 m water depth)

Note: The low range of the colour scale is accentuated to show detail. The colour scale saturates at 2 GJ/m² but the maximum value present is 195 GJ/m²

Source: Geoscience Australia

range and ocean thermal and salinity gradient power plants at the higher end. However, improvements to technology and further deployment will contribute to declining technology costs (Clean Energy Council 2010, Lewis et al. 2011, BREE 2012a).

- Given the largely pre-commercial status of the current ocean energy systems, the outlook is highly dependent on research, development and demonstration (RD&D) activities and the associated outcomes, both in assessing energy potential and developing low-cost energy conversion technologies.
- Many of Australia's best tidal and wave energy resources are in areas distant from the electricity grid. Generally the proximity of the resource to major population centres and the electricity grid appears to be somewhat better for wave energy than for other ocean energy technologies.
- Some of Australia's best tidal energy resources are also located in environmentally sensitive areas, and there can be significant environmental impacts associated with tidal barrage systems.
- Tidal technologies based on the use of tidal currents have environmental advantages over tidal barrage systems, but—like wave, ocean thermal, and salinity gradient energy systems—are still at an early stage of development and impact assessment.

11.1.4 Australia's ocean energy market

- Ocean energy technologies have only been used at limited scales in Australia with a combined output of <1 MW. There are several companies scheduled to install small-scale systems by the end of 2013.
- There are plans to develop several large-scale tidal and wave energy projects in Australia (>10 MW). If successful, these projects could lead to commercial-scale plants generating electricity for the grid, for off-grid local domestic and industrial use, or to power desalination plants.

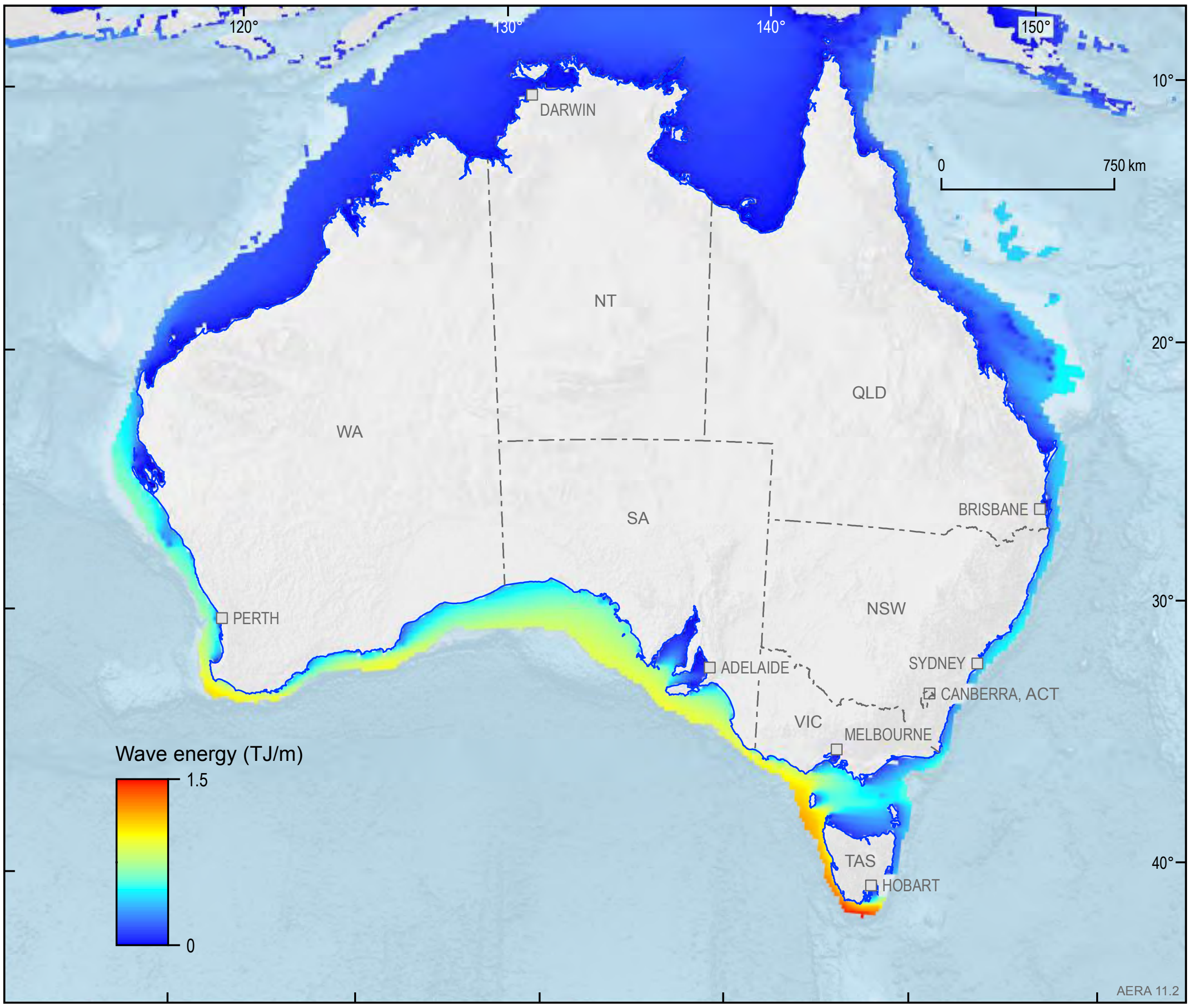

Figure 11.2 Total annual wave energy (in terajoules per metre, TJ/m) on the Australian continental shelf (less than 300 m water depth). This annual resource is expressed as the theoretical total annual wave energy available along a line orthogonal to the wave direction

Source: Geoscience Australia

1.2 Background information and world market

11.2.1 Definitions

There are three broad types of ocean energy: mechanical energy from the tides and waves, thermal energy from the sun's heat, and osmotic power from differences in salt concentrations between seawater and river water. In this report, ocean energy is classified as tidal energy, wave energy, ocean thermal energy, and salinity gradient energy. Potential energy resources associated with major ocean currents such as the East Australian or Leeuwin currents have been estimated at 44 TWh/year (CSIRO 2012), but such resources are not yet technically or economically feasible and are not considered further in this chapter.

Tidal energy

Tides result from the gravitational attraction of the Earth-moon-sun system acting on the Earth's oceans. Tides are long-period waves that result in the cyclical rise and fall of the ocean's surface together with horizontal currents. The rotating tide waves result in different sea levels from one place on the continental shelf to the next at any one time, and this causes the water column to flow horizontally back and forth (tidal currents) over the shelf with the tidal oscillations in sea level.

Tidal energy is energy generated from tidal movements. Tides contain both potential energy, related to the vertical fluctuations in sea level, and kinetic energy, related to the horizontal motion of the water column. It can be harnessed using two main technologies:

- Tidal barrages (or lagoons) are based on the rise and fall of the tides—these generally consist of a barrage that encloses a large tidal basin. Water enters the basin through sluice gates in the barrage and is released through low-head turbines to generate electricity.
- Tidal stream generators are based on tidal or marine currents—these are free-standing structures built in

channels, straits or on the shelf and are designed to harness the kinetic energy of the tide. They are essentially turbines that generate electricity from horizontally flowing tidal currents (analogous to wind turbines).

Wave energy

Waves (swell) are formed by the transfer of energy from atmospheric motion (wind) to the ocean surface. Wave height is determined by wind speed, the length of time the wind has been blowing, the fetch (distance over which the wind has been blowing), and the depth and topography of the seafloor. Large storms generate local storm waves and more distant regular waves (swell) that can travel long distances before reaching shore.

Wave energy is generated by converting the energy of ocean waves (swells) into other forms of energy (currently only electricity). It can be harnessed using a variety of technologies, several of which are currently being trialled to find the most efficient way to generate electricity from wave energy.

Ocean thermal energy

Oceans cover more than 70 per cent of the earth's surface. The sun's heat results in a temperature difference between the surface water of the ocean and deep ocean water, and this temperature difference creates ocean thermal energy.

Ocean thermal energy conversion (OTEC) is a means of converting into useful energy the temperature difference between surface water and water at depth (usually >1000 m). OTEC plants may be used for a range of applications, including electricity generation. They may be land based, shelf based or floating.

Salinity gradient energy

Freshwater from rivers continuously flows into the ocean, thus creating a salinity gradient at the point where rivers meet the ocean.

Salinity gradient power is a means of converting into useful energy the salinity differences between freshwater and saltwater. Associated technologies rely on the principle of osmosis in which solvent molecules (in this case water) move through a semi-permeable membrane to equalise solute concentrations (in this case salt) on each side.

More detailed information on tidal, wave, ocean thermal, and salinity gradient energy technologies is provided in box 11.2 in section 11.4.

11.2.2 Ocean energy supply chain

Figure 11.3 provides a schematic representation of the potential ocean energy industry in Australia. Ocean energy resources have the potential to generate electricity using various types of turbines and other energy converters. The electricity generated could be used either locally or fed into the electricity grid. As well as electricity generation, some ocean energy resources may be used for other purposes such as pumping seawater through desalinisation plants.

The supply of ocean energy requires firstly identifying the sites with the best energy resources matched to the energy converter technology being considered so that site potential for generating electricity can be determined. Whether or not a potential project is developed will require detailed economic and environmental assessment.

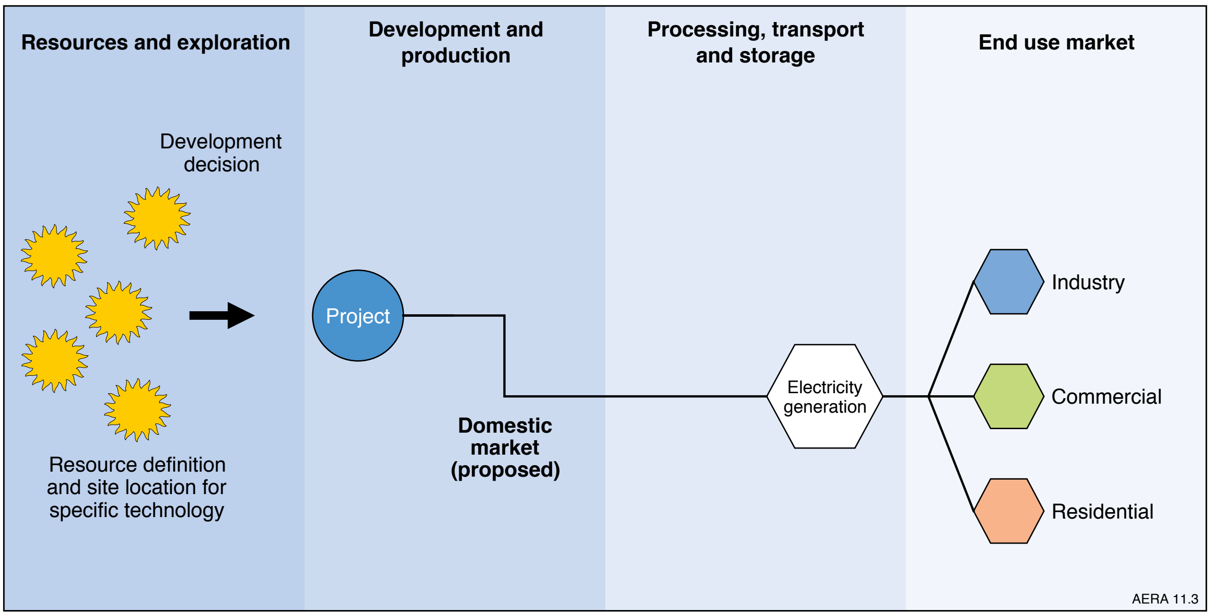

Figure 11.3 Australia's ocean energy supply chain

Source: Bureau of Resources and Energy Economics; Geoscience Australia

11.2.3 World ocean energy market

There is only a small market at present for ocean energy technologies. In 2012, large-scale and commercial applications (>10 MW) were limited to electricity generation based on tidal energy resources in France, Canada and the Republic of Korea. Other countries (Russia, the United Kingdom and China) have smaller tidal power plants with a capacity >1 MW, and significant investment in new ocean energy projects is taking place in Portugal, Australia, the United Kingdom, Canada, the United States and other countries (CSIRO 2012).

Resources

Tidal energy

The global tidal energy resource is vast and sustainable. However, this economically exploitable resource is currently small because of the considerable costs associated with energy extraction and ongoing maintenance of ocean energy devices, as well as the environmental impacts of some tidal energy technologies, notably barrages. There are only a few estimates of the world tidal energy resource potential, ranging from 0.0005 TW (REN21 2012) to 0.03 TW (Wick and Schmitt 1977) to 3 TW (Charlier and Justus 1993).

Wave energy

The global wave power resource in deep water (100 m or more) has been estimated at 1–10 TW, and the economically exploitable resource could be as high as 2000 TWh/year (WEC 2007). The average annual offshore wave power across the world is shown in figure 11.4; the available wave energy resource closer to shore is far less due to wave transformation processes which occur across the shelf. Some of the coastlines with the greatest wave energy potential are the western and southern coasts of South America, South Africa and Australia. These coasts experience the waves generated by the westerly wind belt between latitudes 40° and 50° south, which are blowing over an effectively infinite fetch. This produces some of the largest and most persistent wave energy levels globally.

Ocean thermal energy

Ocean thermal energy has an estimated power potential of 2.0 TW (Wick and Schmitt 1977), although estimates incorporating remote sensing data are warranted in order to provide more recent and accurate values. Figure 11.5 shows that the temperature difference between the surface water of the oceans in tropical and subtropical areas and water at a depth of around 1000 metres is generally sourced from temperate through to polar regions (WEC 2007). OTEC may be used in circumstances where there are temperature differences of at least 20°C between surface and bottom waters.

Salinity gradient energy

The global potential resource for salinity gradient energy is estimated at 2.6 TW and includes 150 GW of extractable energy (Wick and Schmitt 1977, CSIRO 2012). At a commercial scale, this resource is available to countries with large freshwater input to the sea (e.g. Norway, Denmark). At a local scale, this resource will be available in areas at the junction of rivers and ocean.

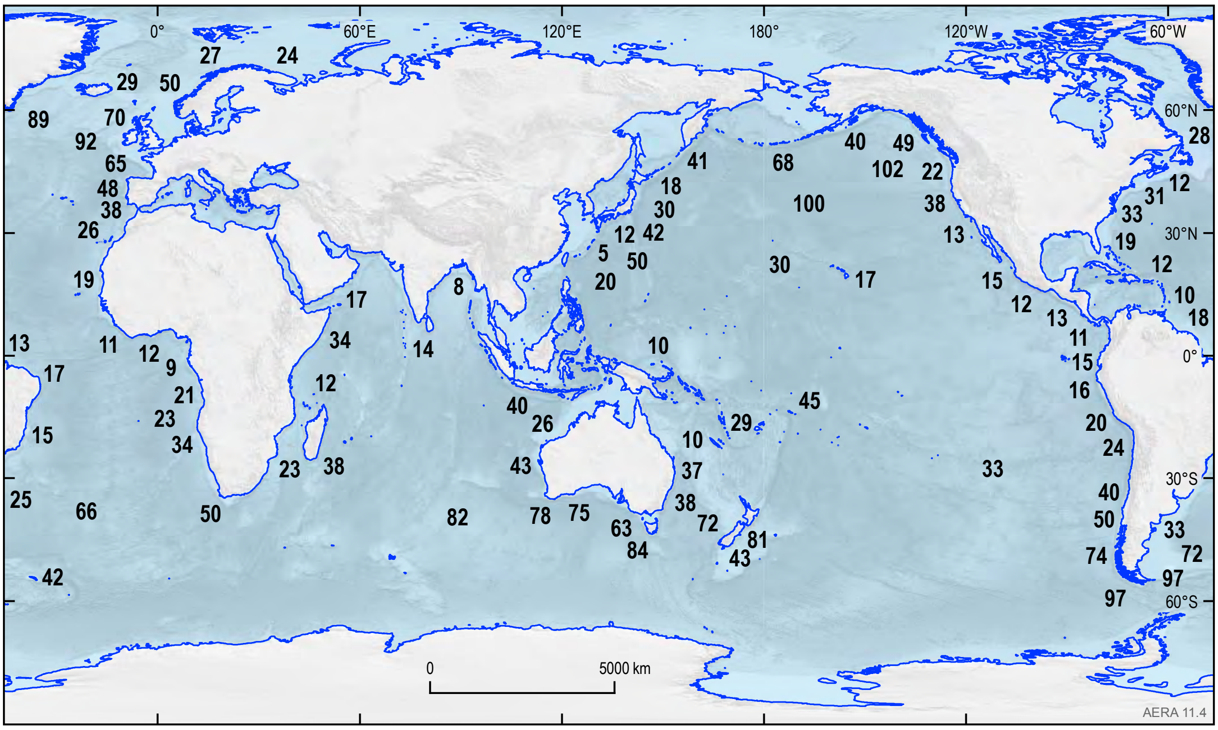

Figure 11.4 Annual average wave power levels (in kilowatts per metre length of wave crest)

Source: WEC 2007

Primary energy consumption

Ocean energy is currently only used to generate electricity so primary energy consumption of ocean energy is the same as electricity generation. World ocean energy use decreased at an average annual rate of 0.8 per cent between 2000 and 2010, and accounted for only a very small proportion of total primary energy consumption (table 11.1). To date, tidal energy has been used on a commercial scale only in OECD countries.

Electricity generation

In 2010, 0.6 TWh of electricity was generated from ocean (tidal) energy, representing only 0.003 per cent of world electricity generation (figure 11.6). Ocean energy has been generated from commercial-scale tidal energy plants in France, Canada and the Republic of Korea:

- France, the main producer of ocean energy, generated 530 GWh (1.9 petajoules [PJ]) in 2010. A 240 MW tidal barrage power plant has been operating at La Rance in France since 1966, which was the largest tidal power station in the world until the Sihwa Lake plant in the Republic of Korea (see below).
- Canada produced 28 GWh (0.1 PJ) in 2010. It has a 20 MW tidal barrage power plant in Annapolis Royal, Nova Scotia, which has been operating since 1984.
- The Republic of Korea finished construction of the largest tidal power station in the world (254 MW capacity) at Sihwa Lake in 2011 after which it began producing grid-connected electricity.

Globally, there is considerable RD&D activity that will contribute to the future commercialisation of ocean energy technologies. Information on global RD&D activity is provided in section 11.4.

World ocean energy market outlook

The International Energy Agency (IEA) projects some growth in ocean energy production over the period to 2035, although it is expected to remain the smallest supplier of electricity. In 2035, ocean energy is projected to account for 0.2 per cent of OECD electricity generation and 0.16 per cent of total world electricity generation (table 11.2).

Most of the growth is projected to occur in the European Union, which is expected to account for around 63 per cent of total ocean energy use in 2035. A further 10 TWh is

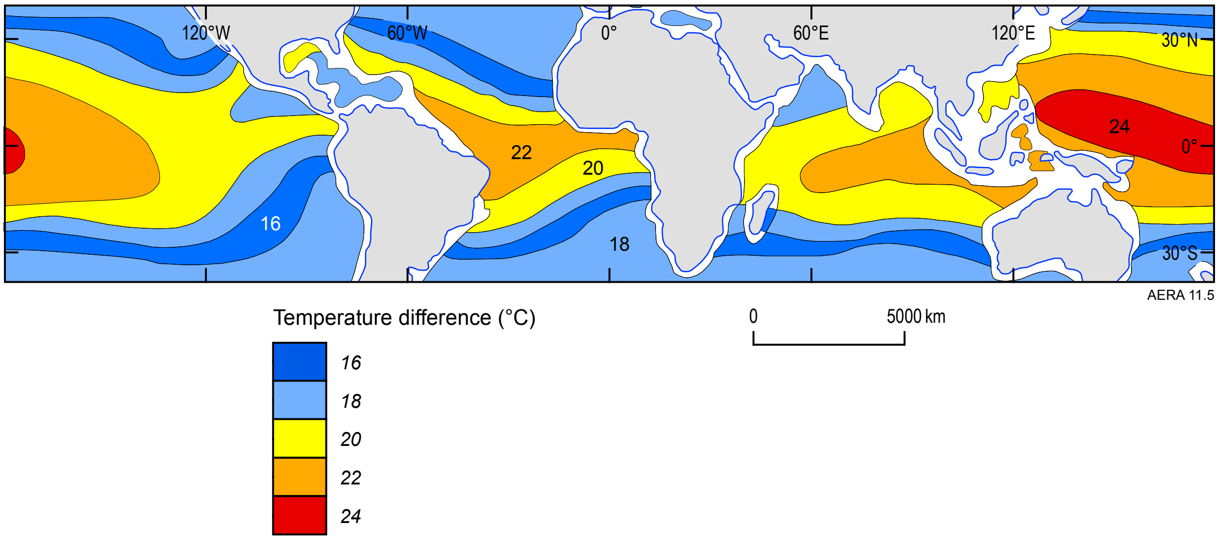

Figure 11.5 The areas available for ocean thermal energy conversion (OTEC) and the temperature difference (measured in °C)

Source: WEC 2007

Table 11.1 Key ocean energy statistics

	Unit	Australia 2011–12	OECD 2011	World 2010
Primary energy consumption[a]	PJ		2.2	2.0
Share of total	%		0.001	0.0004
Average annual growth, from 2000	%		0.0	–0.8
Electricity generation				
Electricity output	TWh		0.6	0.6
Share of total	%		0.006	0.003
Electricity capacity[b]	GW	0.0008	0.262	0.262

a Energy production and primary energy consumption are identical. **b** Data are for 2010 for OECD and world

Source: IEA 2012a

projected to be generated in the United States, Canada, Asia and the Pacific. The Republic of Korea's Renewable Portfolio Standard in 2010 requires companies to generate 8 per cent of their energy from renewable resources by 2020; investment in tidal power plants there has surged. In addition to the operational tidal barrage in Sihwa Lake, there are six large-scale tidal barrages proposed adjacent to the Republic of Korea. One proposed tidal barrage in Incheon Bay will have a 1140 MW capacity, making it the most productive tidal plant in the world after its planned completion in 2020.

Ocean energy has the potential to make a large contribution to meeting electricity demand, but the technologies are still in their early stages and require significant cost reductions to improve competitiveness. Despite the large resource potential, economic considerations will limit the pace of expansion (Lewis et al. 2011, IEA 2012a).

Table 11.2 IEA new policies scenario projections for world electricity generation from ocean energy

	Unit	2010	2035
OECD	TWh	1	55
Share of total	%	0.009	0.41
Average annual growth, 2010–35	%		10.1
Non-OECD	TWh	0	3
Share of total	%		0.013
Average annual growth, 2010–35	%		
World	TWh	1	57
Share of total	%	0.005	0.16
Average annual growth, 2010–35	%		10.4

Note: totals may not add due to rounding

Source: IEA 2012b

11.3 Australia's ocean energy resources and market

Resource assessments of renewable ocean energy are commonly expressed in terms of energy flux (or power) and use units involving joules per second or watts (e.g. watts per metre of wave crest length or per square metre of flow section). In this context, energy flux is the rate at which ocean energy is being delivered to a location on the shelf, and it generally varies with time. In order for this chapter to be comparable with other energy resource assessments described elsewhere in this report, the information in this section is also provided on the annual total energy. The units used are joules (e.g. joules per metre of wave crest length or per square metre of flow section). The annual total energy is the total energy delivered to a given location summed up over a year.

11.3.1 Ocean energy resources

A recent preliminary assessment of Australia's ocean energy resources was completed by CSIRO in its *Ocean Renewable Energy: 2012–2050* report. The majority of this report focused on wave energy, as that was deemed to have the most capacity and feasibility of all the ocean energy resources.

This section details Australia's ocean energy resources, summarising results from the CSIRO report as well as national assessments of tidal and wave energy undertaken as part of the current study. There has been limited progress in assessing Australia's ocean thermal and salinity gradient energy resources, not least because of the greater prospectivity of other renewable energy resources (WEC 2007).

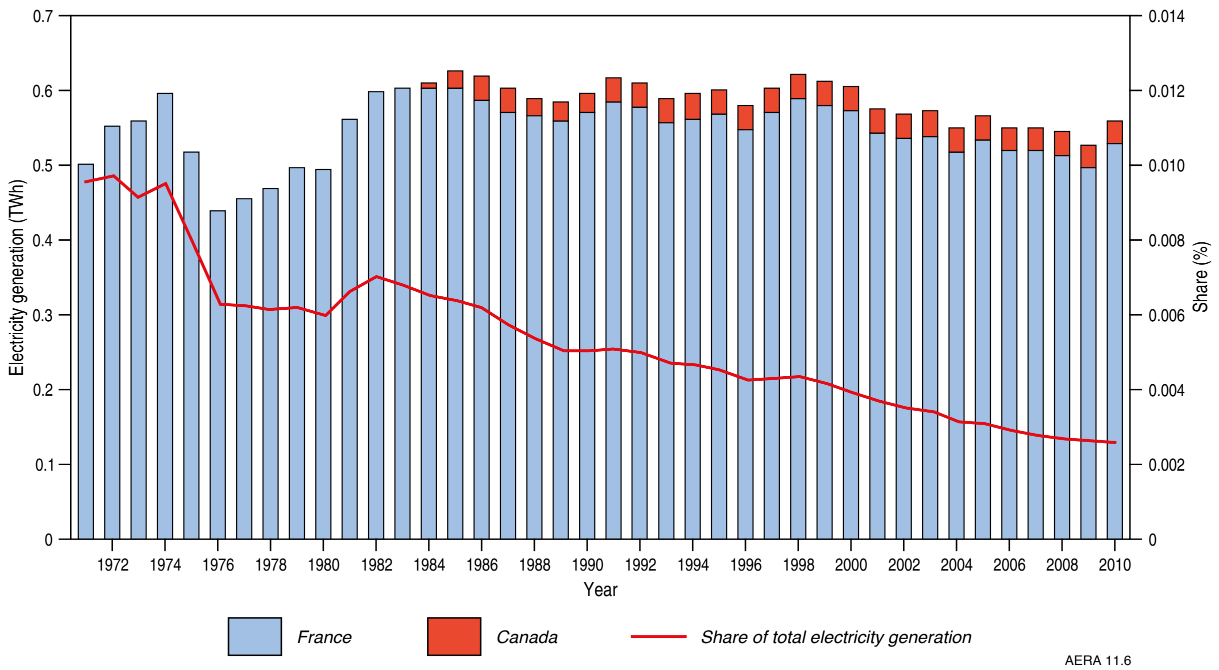

Figure 11.6 World wave and tidal electricity generation and share of total electricity generation

Source: IEA 2012b

Tidal energy

Assessments of Australia's tidal energy resources are restricted to the tidal energy present on Australia's continental shelf. Tidal currents off the shelf are minimal. Moreover, significant transmission losses would be expected for tidal energy converters located far from shore.

Indicative values for the mean spring tide range around Australia are shown in figure 11.7. A variety of tide energy converters are presently available to generate electricity. Barrage-type systems require specific coastal geomorphic settings—typically bays or estuaries—as they are designed to harvest the potential energy of the tide, which depends on both the tide range and the surface area of the basin (i.e. the tidal prism). Because of their site-specific requirements and the complex response of the tide in very shallow water, it is not practical to undertake a detailed national-scale assessment of the tidal potential energy. Nevertheless, figure 11.7 identifies in broad terms the regions that may support tide energy converters of the barrage type, and therefore highlights where more site-specific studies could be directed.

Barrage-type tide energy systems generally require macro-tide ranges (greater than 4 m), which are restricted to the broad northern shelf of Australia; from Port Hedland northwards to Darwin and the southern end of the Great Barrier Reef. Other types of tidal energy converters (tidal turbines) harness the kinetic component of tide energy. They are suitable for installation on the continental shelf, and while they do not necessarily require highly specific coastal configurations, they can be deployed in locations where local coastal configurations result in increased tidal flows.

Accurate large-scale assessments of tidal energy flux are not yet available for Australia. Rather, local-scale assessments are available for certain locations at which correct flux estimates can be achieved. The highest tidal current speeds in Australia occur in King Sound (Kimberly, Western Australia) and Banks Strait (north of Tasmania). Estimates of a hypothetical tidal barrage system at King Sound reveal capacity of 8 TWh/year, while a tidal stream system at Bass Strait may only produce 0.13 TWh/year (CSIRO 2012).

The continental shelf for this national assessment of total annual energy is defined as water depths less than 300 m. Details of the data and methods used in this assessment

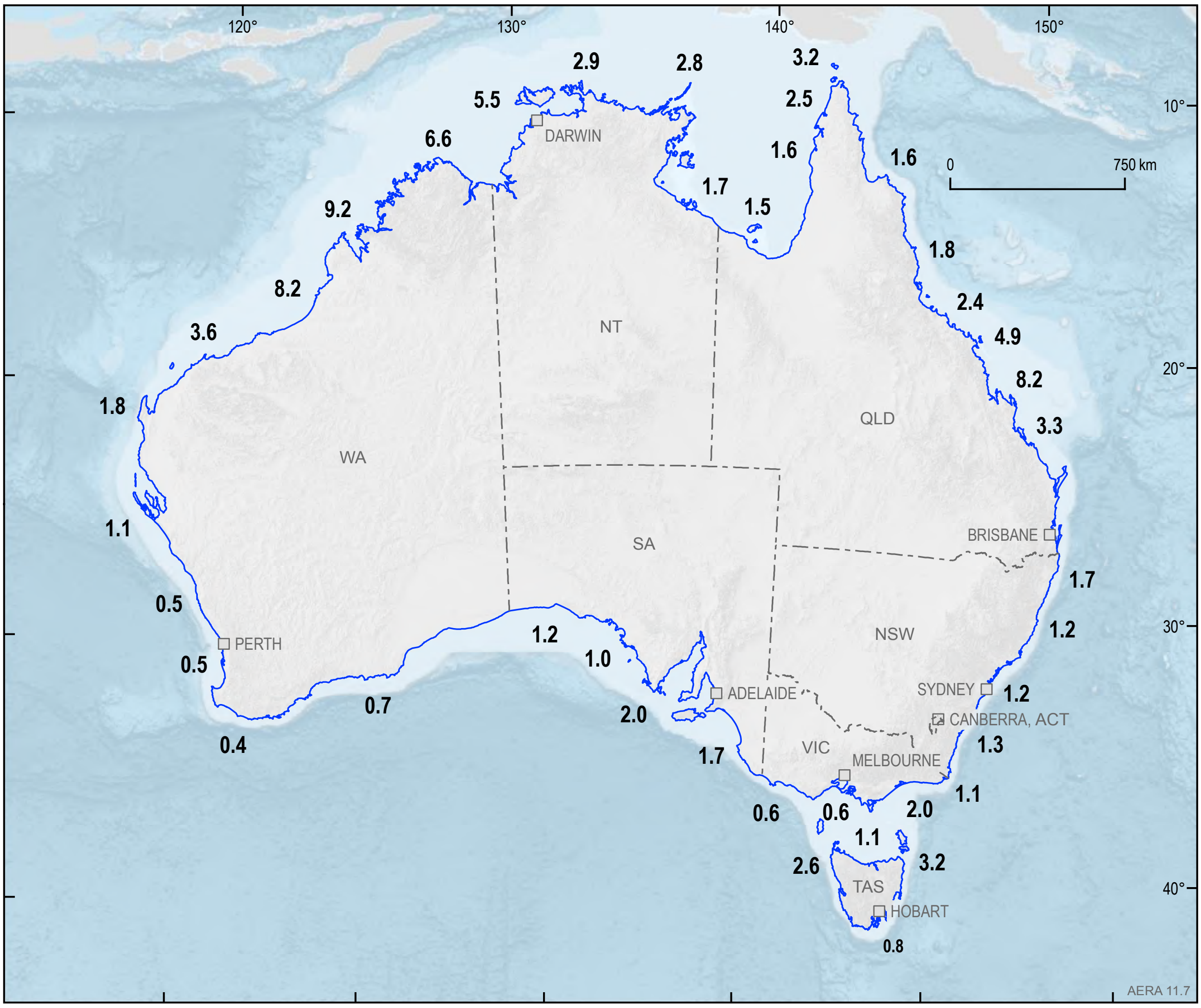

Figure 11.7 Tide ranges (in metres) for the main standard ports around Australia

Source: Australian National Tide Tables; Australian Hydrographic Service and its limitations are described in box 11.1. The total tidal kinetic energy on the entire Australian continental shelf at any one time, on average, is about 2.4 PJ. The rate of delivery of tidal kinetic energy, or energy flux, is also referred to as tidal (kinetic) power. The spatial distribution of time-averaged tidal (kinetic) power on the Australian continental shelf is shown in figure 11.8. Tidal (kinetic) power is greatest on the northern half of the Australian continental shelf, with many areas having more than 100 watts per square metre (W/m^2). The southern half of the Australian shelf (with the exception of Bass Strait) has relatively little tidal (kinetic) power (figure 11.8). The tidal kinetic energy delivered in a given time period, for example, in one year (annual total tidal kinetic energy), can be obtained by integrating the tidal (kinetic) power time series over one year.

The spatial distribution of annual total tidal kinetic energy is shown in figure 11.9. This annual resource is expressed in GJ/m^2 of tidal flow. For comparison purposes with other conventional energy sources, the annual total tidal kinetic energy adjacent to each state could be estimated by integrating with respect to the flow cross-sectional area, but it depends on where the cross-section is drawn and is not practical at the national scale. Therefore state values are restricted to the common practice of presenting the resources in terms of localised flux and localised annual total energy.

Statistics for the tidal (kinetic) power occurring at the most energetic location on the shelf adjacent to each state are listed in table 11.3. The mean as well as the 10th, 50th and 90th percentile power at that location is listed together with the total tidal kinetic energy delivered annually. In all cases the maximum tidal power occurs in water depths less than or equal to 50 m, which in all likelihood is the depth range in which the present generation of tidal energy converters could be installed.

The best-resourced jurisdictions are Western Australia, Queensland and the Northern Territory. Western Australia has locations off its coast where the average tidal (kinetic) power in water depths less than or equal to 50 m exceed 6.1 kW per square metre (kW/m^2), delivering a total tidal kinetic energy of over 195 GJ/m^2 annually.

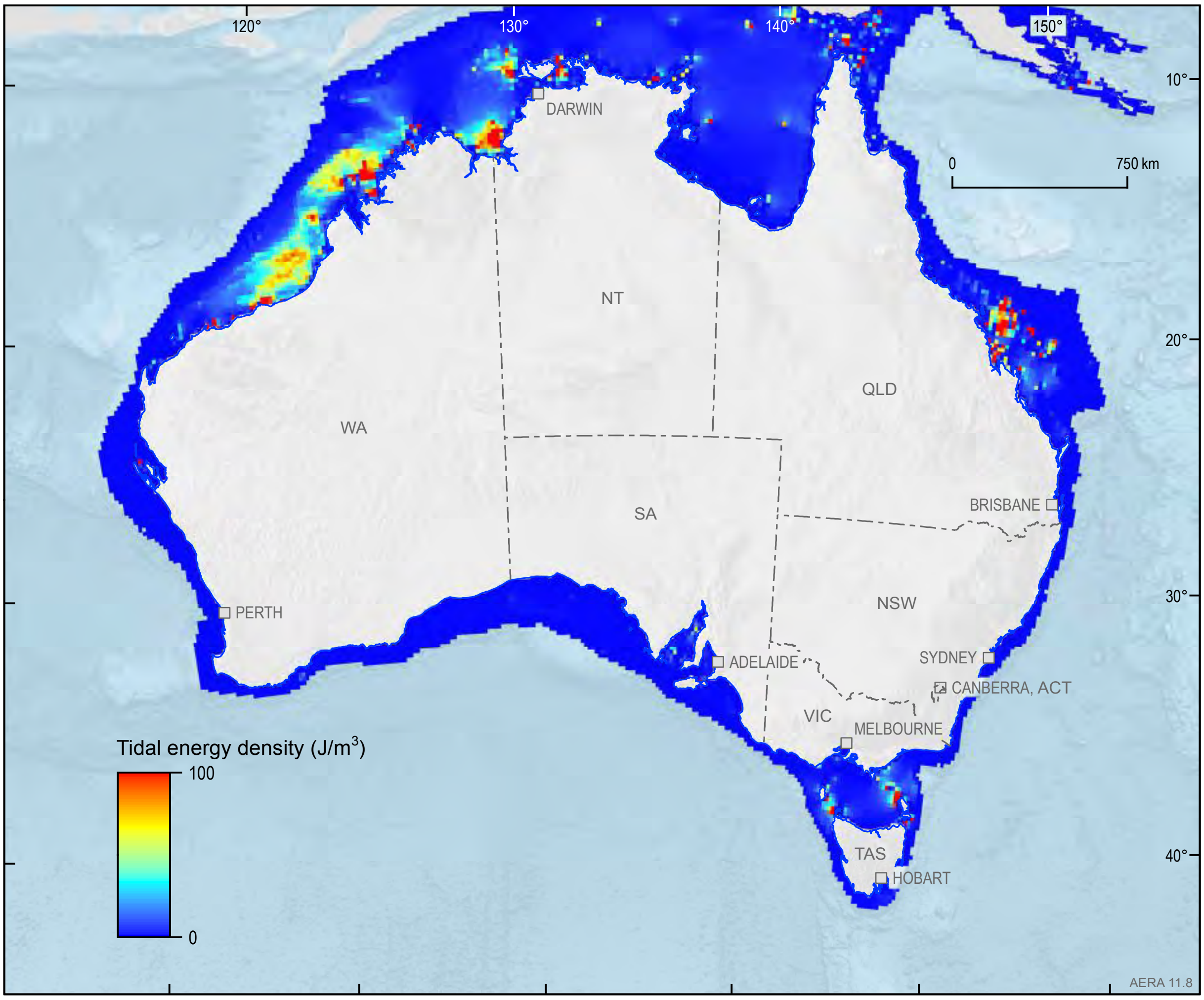

Figure 11.8 Time-averaged tidal (kinetic) power (J/m^3) (not depth integrated) on the Australian continental shelf (less than 300 m water depth). The (kinetic) power at each location represents a time-average over any one year. Note that the colour scale saturates at 100 W/m^2 to show detail; the maximum value present is 6179 W/m^2

Source: Geoscience Australia

BOX 11.1 DETAILS OF ASSESSMENT METHODS, DATA AND ANALYSIS: TIDAL AND WAVE ENERGY

Tidal energy

This assessment of Australia's tide energy resource is based on the mean spring tidal ranges calculated using the Australian National Tide Tables produced by the Australian Hydrographic Service (2006) together with the depth-averaged tidal current speed predicted using a hydrodynamic model. Tidal currents are one component of Geoscience Australia's GEOMACS Model (Geological and Oceanographic Model of Australia's Continental Shelf). A full description of the tide component of the model is presented in Porter-Smith et al. (2004).

Tidal water levels at a given site are highly predictable, provided more than a year of measurements is available. The tidal ranges presented in figure 11.7 are all from standard ports with long-term tide gauges installed and are therefore considered sufficiently reliable for use in the resource assessment. The prediction of tidal water levels at sites where no tide gauge measurements exist is less straightforward. The accuracy then depends on the nature of the hydrodynamic model used and the complexity of the shelf and coastal bathymetry. Predictions of tidal currents are even more sensitive to these natural complexities. The hydrodynamic model used in this assessment to predict tidal current speeds—and ultimately tidal kinetic energy and power—provides reasonable, but at best approximate and as yet unsubstantiated, estimates of current speed on the shelf. However, the model produces somewhat less adequate results in areas such as elongated coastal bays and in narrow seaways between islands and between islands and the mainland. For example, the predictions for tidal kinetic energy and power in King Sound, Western Australia are small, yet this is where the largest tides in Australia occur (figure 11.7, CSIRO 2012).

Overall, the tidal energy resource assessment presented here is acceptable as an estimate at the national scale. It indicates the relative importance of regions, but it cannot be considered accurate at a regional or local scale, and it cannot be relied upon to any degree other than on the open shelf. More developed national-scale hydrodynamic models should include the latest available national bathymetric grid and incorporate satellite altimetry, oceanographic moorings, and tidal stream data for validation. For example, high-frequency radar such as CODAR (Coastal Ocean Dynamics Applications Radar) combined with field mooring measurements are particularly useful for tidal stream model validation. For detailed site assessments, regional-scale hydrodynamic models suitable for elongate coastal bays and convoluted coastlines need to be developed.

Wave energy

The data used to undertake the wave energy resource assessment are wave conditions hindcast using a third-generation ocean wave prediction model (Hasselmann et al. 1988)—WAM; WAve Model—implemented by the Australian Bureau of Meteorology. The hindcast wave data from the WAM model were converted to wave energy and power (energy flux) using linear wave theory for arbitrary depth. Details of the methods used are discussed in full in Hughes and Heap (2010). The Australian WAM model grid has a resolution of 0.1 degree and the resolution for significant wave height in the hindcast wave data is 0.1 metre. The accuracy varies with conditions, but is nominally 0.25 metre for wave heights in the range used for electricity generation. The resolution of the wave period is 0.1 second and the accuracy is nominally 1 second. This equates to a percentage range of uncertainty in the calculated wave energy density and power of around 100 per cent for small wave heights (less than 1 metre), but decreasing rapidly to 17 per cent or less for larger wave heights (greater than 6 m). In essence, the percentage uncertainty related to model precision is least for the southern half of Australia's continental shelf where the wave heights are consistently large. In a study of model accuracy against independent data Hemer et al. (2007) point out, however, that the WAM model in southern Australia underestimates wave heights by about 20 per cent.

The results of this assessment appear broadly consistent with those of a study of Australia's wave energy resource by RPS MetOcean for the Carnegie Corporation (now Carnegie Wave Energy Limited), an extract of which was published in the corporation's 2007 annual report. The MetOcean wave energy resource assessment concluded that, on the southern half of Australia's shelf, there is an estimated resource of 525 000 MW in deep water and 171 000 MW in shallow water (a depth of less than 25 metres) (Carnegie Corporation 2008). The MetOcean rankings of each jurisdiction's resource are also consistent with the relative magnitudes of values in table 11.4, but cannot be directly compared because their data are presented in different units of measurement.

Overall, the wave energy resource assessment presented here is considered to be sufficiently reliable as a national-scale assessment. It is best suited to water depths greater than 25 m. In water depths less than 25 m the WAM model does not sufficiently account for shallow-water processes (e.g. friction effects and refraction) that dissipate or redistribute the wave energy. Given that many of the current technologies are designed for deployment in water depths of 25 m or less, and some on the shoreline, a more refined assessment is warranted. This would involve:

- using the spatially limited waverider buoy data to verify/calibrate the WAM model data, providing a more accurate dataset with complete coverage of the shelf
- integrating geographic information layers such as bathymetry, seabed type (gravel, sand, mud, reef), and coastal geomorphology into a GIS together with the wave climatology to identify the accessible resource. This integrated approach will have a strong influence on determining whether a site is suitable for a wave farm, beyond simple consideration of the wave climate alone.

Table 11.3 Mean and percentiles of tidal (kinetic) power (W/m²) and the total annual tide kinetic energy (GJ/m²) delivered to the most energetic shelf location adjacent to each state

Jurisdiction	Power (W/m²) mean	Power (W/m²) 10th percentile	Power (W/m²) 50th percentile	Power (W/m²) 90th percentile	Energy (GJ/m²)
Northern Territory	2069.50	18.07	1029.68	5979.38	65.45
Queensland	4153.19	33.97	2316.85	10 679.20	131.35
New South Wales	0.36	0.024	0.19	0.96	0.0011
Victoria and Tasmania	488.93	6.03	378.06	1193.56	15.46
South Australia	317.16	0.43	78.86	1014.65	10.03
Western Australia	6179.39	249.42	7529.65	10 679.20	195.43

Source: Geoscience Australia

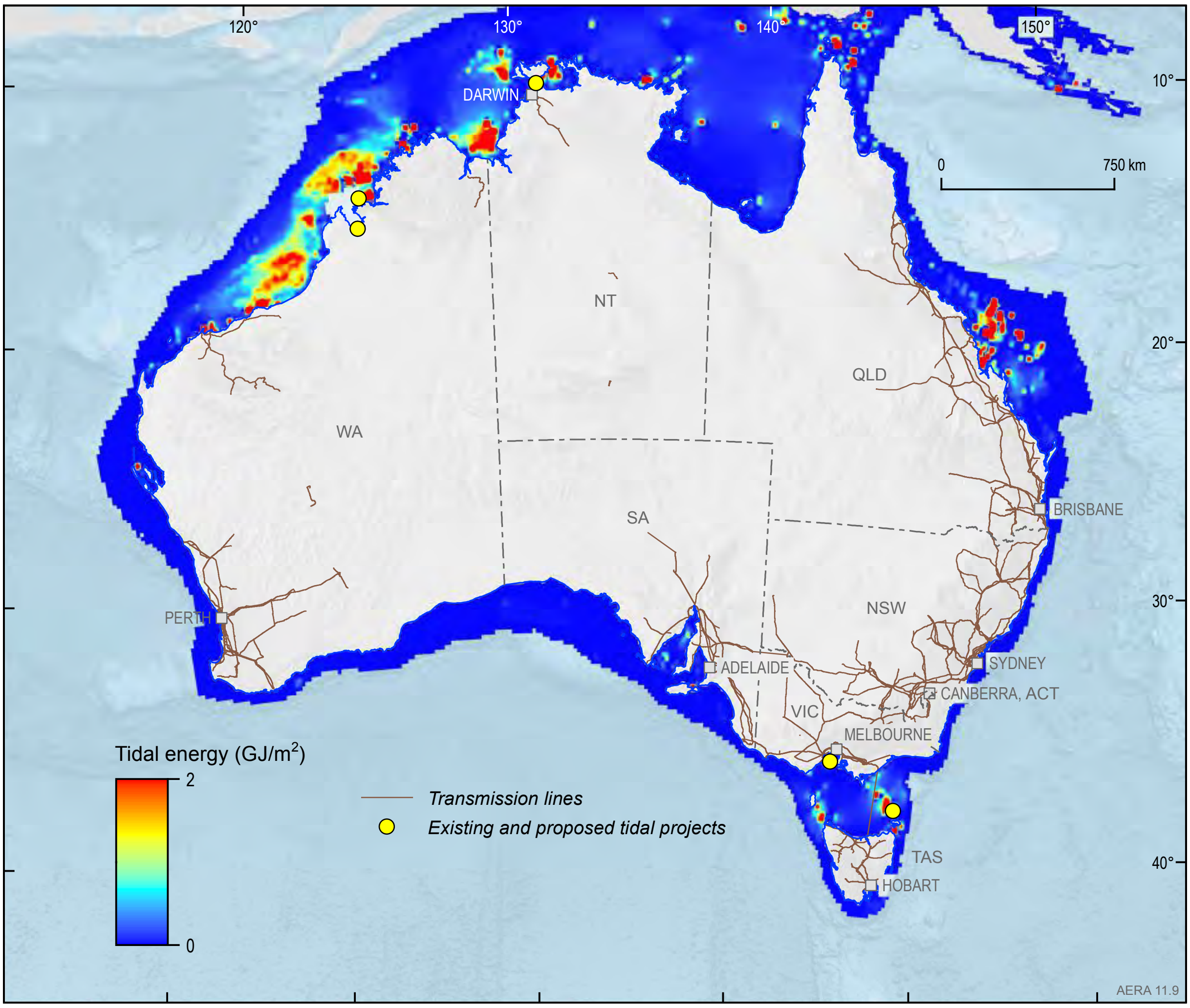

Figure 11.9 Annual total tidal kinetic energy (GJ/m²) on the Australian continental shelf (less than 300 m water depth), with existing and proposed projects

Note: The kinetic energy at each location represents the total delivered in a year. Data obtained from a linearised, shallow-tide model. The colour scale saturates at 2 GJ/m² to show detail; the maximum value present is 195 GJ/m²
Source: Geoscience Australia

Wave energy

Several types of wave energy converters are presently available to generate electricity. The choice of converter technology places limits on the locations from which wave energy can be harvested. For example, the Pelamis device (see box 11.2) is capable of generating electricity in water depths of 60 to 80 metres, whereas CETO™ is suited to shallower water depths (15 to 50 metres). Given these considerations, this resource assessment is restricted to the wave energy present on Australia's continental shelf.

Previous studies of Australia's wave energy have focused on the energetic southern margins of the continent. The total wave energy flux crossing the 25 m isobath in this region has been estimated at over 1300 TW/h per year (Hemer and Griffin 2010). Although this value is approximately five times greater than the country's annual energy requirements, the amount of energy that could realistically be extracted is far less but may still supply up to 10 per cent of Australia's electricity needs by 2050 (CSIRO 2012).

A complementary national assessment of Australia's wave energy resources is presented in the current report.

The wave energy resource assessment presented here is based on wave data hindcast by the Bureau of Meteorology at six-hourly intervals over an 11-year period from 24 090 locations evenly distributed over Australia's entire continental shelf using WAM (Hasselmann et al. 1988). The assessment methodology is described in more detail in Hughes and Heap (2010).

The continental shelf is defined for this national assessment as water depths less than 300 metres. The total wave energy on the entire Australian continental shelf at any one time, on average, is about 3.47 PJ. The rate of delivery of wave energy, or energy flux, is also referred to as wave power.

The spatial distribution of time-averaged wave power on the Australian continental shelf is shown in figure 11.10. Wave power is greatest on the southern half of the Australian shelf, with 25–35 kW/m being common on the outer shelf, whereas wave power on the shelf in the northern half of Australia is generally less than 10 kW/m and unsuitable for harvesting with current technologies.

The spatial distribution of annual total wave energy (the total wave energy delivered in a year) is shown in figure 11.11. This annual resource (expressed in joules per metre) is the annual total wave energy available along a line orthogonal to the wave direction. Generally, the further offshore the line is drawn the greater the total energy resource available, because waves lose energy and power as they approach the coast. In theory, the annual total wave energy resource adjacent to each state could be estimated but it depends on where the line is drawn and is not practical at the national scale. Therefore state values are restricted to the common practice of presenting the resources in terms of localised flux and localised annual total energy.

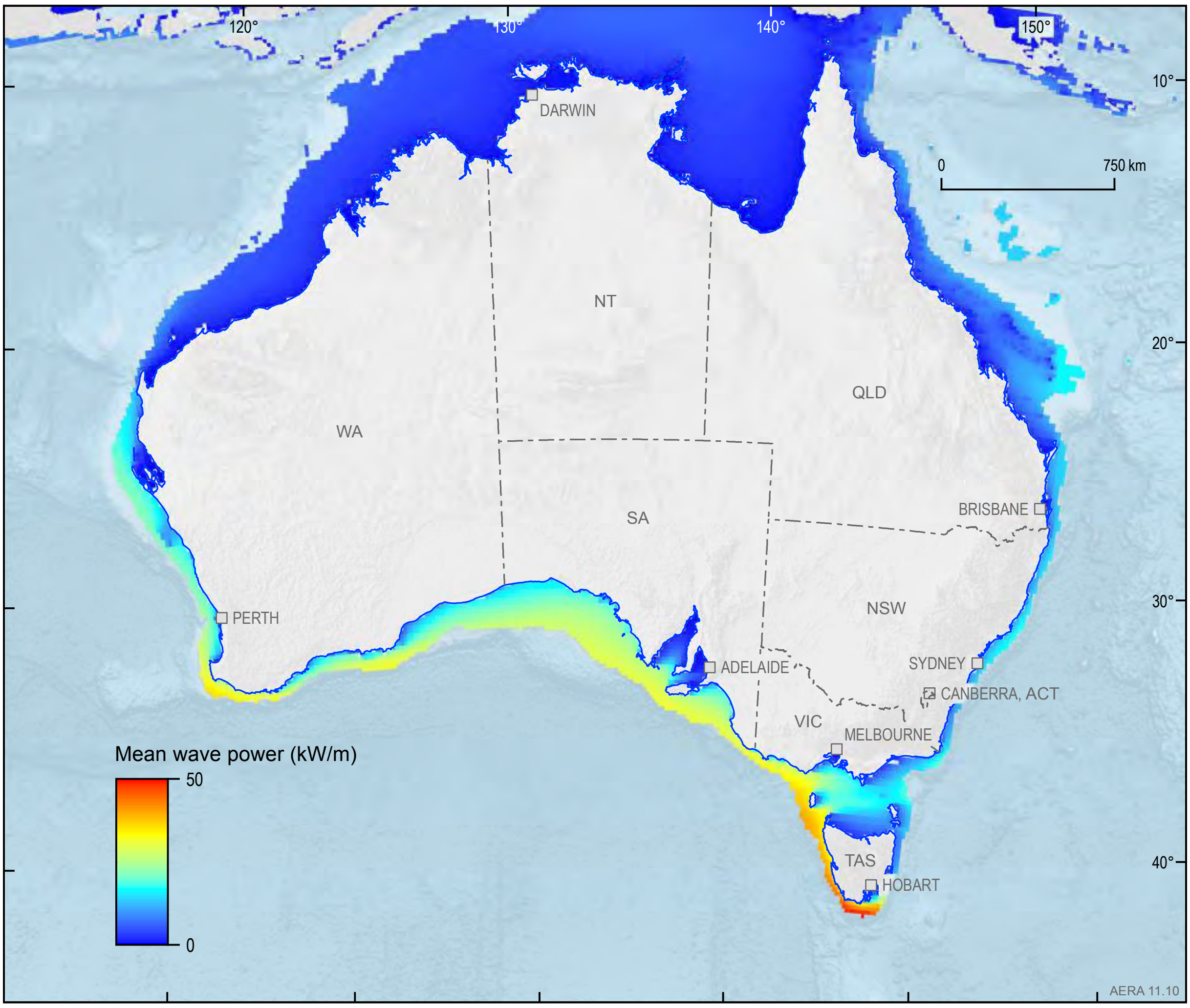

Figure 11.10 Time-averaged wave power (kW/m) on the Australian continental shelf (water depths less than 300 m). The wave power at each location represents a time average of the available 11-year time series from March 1997 to February 2008

Source: Geoscience Australia

Statistics for the wave power occurring at the most energetic location on the shelf in less than 50 m water depth adjacent to each state is listed in table 11.4. The mean as well as the 10th, 50th and 90th percentile power at that location is listed together with the total wave energy delivered annually. On the basis of this assessment, the states with the best wave energy resource are Western Australia, South Australia, Victoria and Tasmania. Tasmania is particularly rich in wave energy resources. There are locations off its coast where the average wave power in water depths less than or equal to 50 m reach almost 35 kW/m, delivering a total wave energy of 1100 GJ/m annually.

Ocean thermal energy

The most promising area for OTEC in Australian waters lies 100 km off the eastern coast of the York Peninsula at latitudes 13–16° south (CSIRO 2012). This area is most suitable due to its proximity to the coast in order to facilitate electricity transport, operations and maintenance. In addition, this area of tropical Australia shows a surface–bottom water temperature differential greater than 25 °C, making it suitable for OTEC technologies.

Salinity gradient energy

At present, it is not possible to nationally quantify salinity gradient energy potential. This resource will be available in Australia at localised areas at the junction of rivers and ocean.

11.3.2 Ocean energy market

In Australia, several pilot or demonstration plants based on either tidal or wave energy are operating or under construction (table 11.5). All facilities had capacities of less than 2 MW but represent an important stage in the technology innovation process for ocean energy in Australia (CEC 2010). In addition to these pilot plants, several large-scale wave energy projects are being planned for the near future (box 11.3 in section 11.4.2).

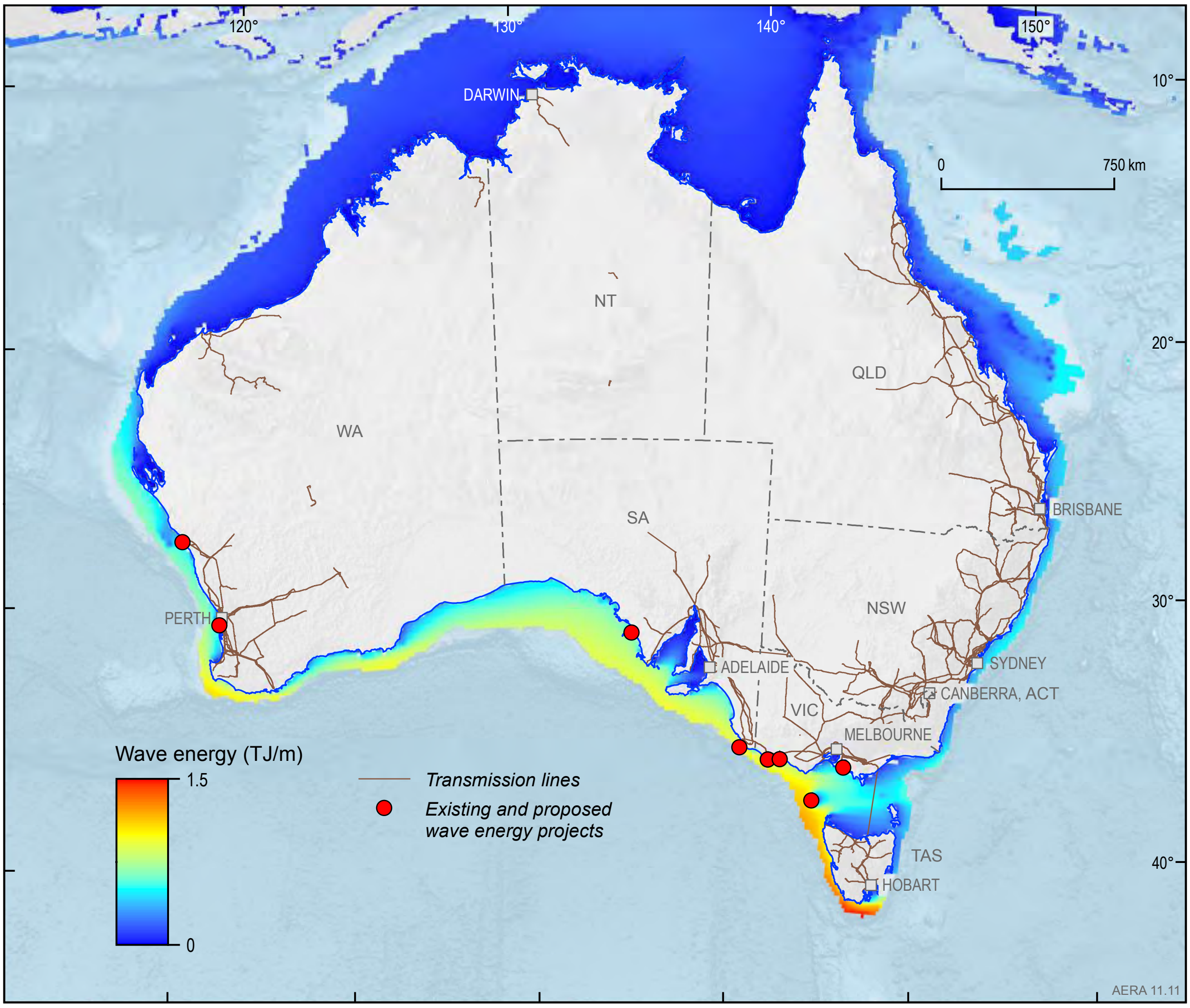

Figure 11.11 Annual total wave energy (TJ/m) on the Australian continental shelf (water depths less than 300 m) and wave energy projects. The annual total wave energy at each location represents an average of the 11 years from March 1997 to February 2008

Source: Geoscience Australia

Table 11.4 Mean and percentiles of wave power (kW/m) and the total annual wave energy delivered to the most energetic shelf location (in <50 m water depth) adjacent to each state

Jurisdiction	Power mean	Power 10th percentile	Power 50th percentile	Power 90th percentile	Energy mean
Northern Territory	5.32	0.33	2.68	13.09	167.90
Queensland	14.72	3.52	9.03	29.82	442.80
New South Wales	13.61	2.77	7.31	27.19	391.04
Victoria and Tasmania	34.87	4.88	18.22	70.66	1100.80
South Australia	25.51	4.28	15.35	54.96	885.13
Western Australia	26.38	4.65	15.05	56.86	901.44

Source: Geoscience Australia

Table 11.5 Ocean energy demonstration plants operating or under construction in Australia as at October 2013 (>0.1 MW)

Project	Company	State	Start up	Capacity (MW)
San Remo (tidal energy)	Atlantis Resource Corporation	VIC	2008	0.15
Garden Island (wave energy)	Carnegie Wave Energy	WA	2014	2
Port Fairy (wave energy)	BioPower Systems	VIC	2015	0.25
Port MacDonnell (wave energy)	Oceanlinx	SA	2013	1

Source: Atlantis Resources Corporation (http://www.atlantisresourcescorporation.com); Carnegie Wave Energy (http://www.carnegiewave.com); Biopower Systems (http://www.biopowersystems.com); Oceanlinx (http://www.oceanlinx.com)

11.4 Outlook for Australia's ocean energy and market

Ocean energy resources have significant potential for future use, and a preliminary estimate of extractable wave energy suggests that it could supply up to 10 per cent of Australia's energy needs by 2050 (Hemer and Griffin 2010). Although wave and other ocean energy technologies are at an early stage of development, given the level of global RD&D activity, technological and economic advances may increase the commercial attractiveness of ocean energy.

11.4.1 Key factors influencing the future development of Australia's ocean energy

Australia has a significant potential ocean energy resource, especially along the western, northern and southern coastlines if both waves and tides are considered. The Australian Renewable Energy Agency has allocated funding of about A$86 million for four ocean energy demonstration projects utilising a range of wave technologies. These include A$66.46 million to Victorian Wave Partners for a 19 MW PowerBuoy array, offshore near Portland, Victoria; A$9.9 million to Carnegie Wave Energy for a CETO grid-connected pilot system at Garden Island, Western Australia; A$5.6 million to BioPower Systems for a bioWAVE pilot, offshore near Port Fairy, Victoria; and A$3.9 million to Oceanlinx for its shallow water greenWave demonstration, offshore from Port MacDonnell, South Australia.

Despite its potential, there are significant constraints on the future development of ocean energy in Australia. Two limitations in particular need to be addressed: 1) technologies for the commercial conversion and utilisation of ocean energy are still immature, and 2) capital costs are high relative to other energy sources.

A number of technologies have passed proof-of-concept stage but are yet to deliver electricity to a grid. Some of them have reached the commercial-scale demonstration stage and may be in commercial operation by mid decade, but they will still be in competition with more mature and lower cost renewable energy technologies.

Ocean energy provides a low-emissions source of energy with potential for base-load electricity generation

Ocean energy is a potentially attractive source of electricity generated with low greenhouse gas emissions. The level of predictability is dependent on the type of energy:

- Tidal energy is very predictable but does not continuously generate electricity at consistent levels. Twice in every 12.42 hours (24 hours in some locations) the tidal current speed and hence the electricity generation capability falls to zero. However, tidal energy can provide more continuous power by using tidal ponds to store energy, converting energy from both incoming and outgoing tides, and deploying geographically distinct convertors with different tidal timing (CSIRO 2012).
- Waves are rarely of consistent length or strength. Wave energy levels may vary considerably from wave to wave, from day to day, and from season to season, because of variations in local and distant wind conditions. For example, there are sites on the western and southern coastlines where regular storms in the Southern Ocean generate consistent swells with periods of wave energy failure both of low frequency and short duration. This inherent variability needs to be converted to a smooth electrical output to be a reliable source of electricity supply. There is a higher degree of certainty and consistency with wave energy than with wind energy in Australia (CSIRO 2012).

- Ocean thermal energy is potentially suitable for base-load electricity generation, as the ocean temperatures on which it relies show only slight variation between seasons (WEC 2007).
- Salinity gradient energy is potentially suitable for low-power output since the power generation is based on consistent flows of freshwater into saltwater, but provides comparatively low power levels.

RD&D activity is important for the future development of ocean energy

Despite the large potential of ocean energy, the low level of market uptake can be largely attributed to the currently immature extraction technology and the large number of different technologies still being trialled (box 11.2). The outlook is highly dependent on the amount of resources devoted to RD&D in assessing energy potential and energy conversion technologies and the potential for cost reduction over time. Some different extraction technologies being trialled, include:

- Tidal energy technologies—tidal energy extraction technology is essentially analogous to that of wind energy. Both require a passing current (i.e. wind current for wind energy and tidal current for tidal energy) to drive a rotating turbine.
- Wave energy technologies—many different wave energy converters are at the prototype stage and are undergoing trials in a number of countries. This is partly explained by the lack of individual technologies that have been shown to be commercially viable and by the need to develop technologies for a range of different wave energy environments and climatic conditions, including severe storms.
- Ocean thermal energy technologies—ocean thermal energy conversion technologies are relatively new and still need to be proven in demonstration-scale plants. Japan has been a major contributor to the development of OTEC technology since the 1970s, and along with the United States and India, has developed small-scale OTEC test facilities. An important focus in RD&D activity, particularly in Europe, is the combination of OTEC technologies with other deepwater applications, such as potable water production, that result in benefits in addition to electricity generation (WEC 2007). Land-based, shelf-based and floating plants are all options, and there are currently three proposals to build OTEC plants: a 13 MW plant for the United States Navy which will also produce 5 ML of potable water; a 10 MW closed cycle system for Guam; and a 10 MW–100 MW plant for Hawaii due to begin operations in 2013. OTEC is best suited to tropical waters with warm surface waters.
- Salinity gradient technologies—the permeable membranes are currently very expensive, but as materials technology develops, lowering costs of membranes may make salinity gradient power a more attractive and viable energy source. The world's first salinity gradient power plant was opened in Norway on 24 November 2009 with an output of 4 kW and a proposed output of 10 kW with improved membranes. A commercial plant is planned for 2015.

Ocean energy technologies are expected to be relatively high-cost options until technologies mature

Although general estimates of ocean energy costs include a high level of uncertainty and speculation (Lewis et al. 2011), investment costs are currently lower for tidal barrage systems than for other ocean energy systems. Investment costs for tidal barrage systems are estimated to have been US$3000–5000 per kW in 2010 (IEA 2010) while estimated investment costs of tidal current systems are US$5400–16 100 per kW, wave energy systems are US$6200–16 100 per kW, and ocean thermal gradient systems are US$4200–12 300 per kW (table 6.3 in Lewis et al. 2011). Shoreline installations and tidal barrage systems typically have a lower production cost than deepwater devices, but most deepwater technologies are still at the research and development stage. Wave energy technologies tend to have higher costs because of unscheduled maintenance caused by storm damage.

Ocean energy technologies are expected to remain relatively high-cost options for development in the medium term. Investment and production costs for ocean energy systems are projected to fall over time. Tidal barrage production costs were estimated to have been US$120 per kWh in 2010. By 2050, the production cost of tidal barrage technologies is projected to be US$66 per kW.

While not currently used extensively in Australia, the cost of ocean energy technology is projected to be around A$303/MWh in 2020, declining to A$226/MWh in 2050 (IEA 2008; figure 11.12). Ocean energy is expected to remain one of the more expensive technology options over this time frame. However, improvements to technology and further deployment will contribute to declining technology costs (BREE 2012a).

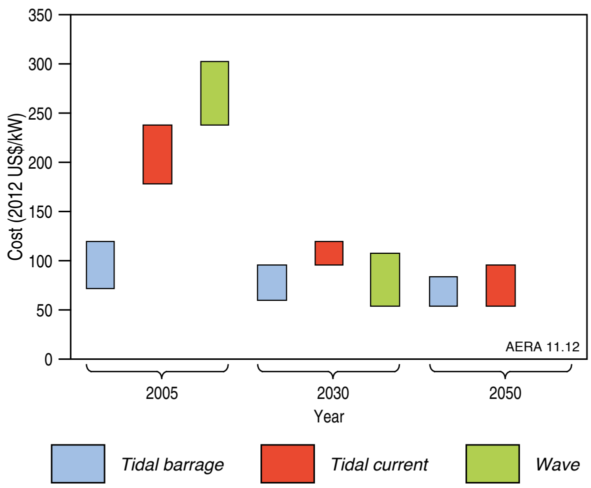

Figure 11.12 Ocean energy production costs
Source: IEA 2008

BOX 11.2 CURRENT OCEAN ENERGY TECHNOLOGIES

Tidal energy technologies

Tidal oscillations result in different sea levels from one place on the shelf to the next at any one time, and this causes the water column to flow horizontally back and forth (tidal currents) over the shelf. Two different technologies (tidal barrages and tidal current generators) have been developed to harness these tidal movements. Both are dependent on underwater turbines, and although the design of these has advanced considerably in recent years, there is still considerable research and development seeking to maximise efficiency and robustness while minimising overall size (figure 11.13).

Barrages harness some of the potential energy of the tide. In essence, a barrage with sluice gates allows water to enter the basin on the rising tide, and at high tide the sluice gates are closed, thus trapping a large body of water (figure 11.13a–b). As the water level on the ocean side of the barrage falls with the ebbing tide, the elevated water from behind the barrage is released through the sluice gates, where turbines are located, to generate

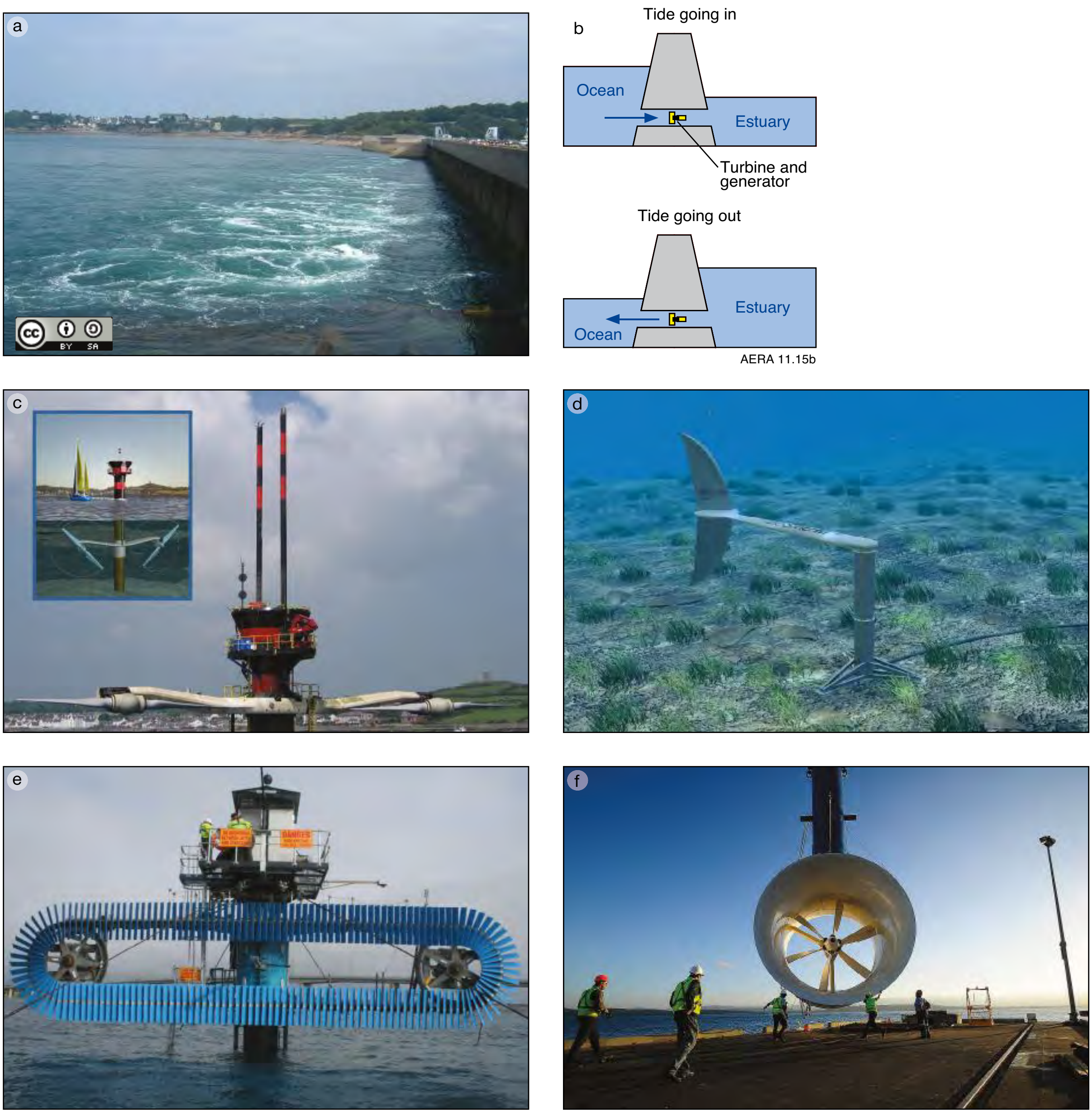

Figure 11.13 Examples of different types of tidal energy converters. **a** La Rance River estuary tidal barrage, France. **b** Schematic showing the water levels either side of a barrage during power generation. **c** Sea Generation Limited's SeaGen turbine with blades elevated for servicing. **d** BioPower System's bioStream turbine. **e** and **f** Atlantis Resources Corporation's Nereus and Solon turbines, respectively

Source: Wikimedia Commons; www.seageneration.co.uk; www.biopowersystems.com; Atlantis Resources Corporation electricity. The principle is similar to hydro-electric schemes on dammed rivers. More complicated systems of basins and barrages can be designed to generate electricity on both the ebbing and flooding tide. The potential energy that is available to be harnessed is related to the vertical tide range and the horizontal area of the basin (the tidal prism).

Tidal stream generators focus on the kinetic energy component of the tide. A turbine is placed within a tidal current and the kinetic energy associated with the horizontal motion of the water drives the turbine to generate electricity. There are turbines developed for relatively shallow water installation that rotate in a vertical plane and others that rotate in a horizontal plane. Tidal stream generators can be lined up in a row to intercept flow through a channel; this is referred to as a tidal fence.

The first tidal power station was built on the Rance River estuary in France, between 1961 and 1966. It has been operating continuously since then. It is a barrage-type system consisting of an 800-metre long dam enclosing a basin with a surface area of 22.5 km^2. The spring tide range is up to 13 m. The plant has a power generating capacity of 240 MW and it delivers 2.3 PJ of energy annually to the grid (WEC 2007). A smaller barrage-type station at Annapolis, on the Bay of Fundy, Canada was completed in 1984. The tide range in this location can exceed 12 m (Pugh 2004). This plant has a power capacity of 20 MW and delivers 108 TJ annually. The Republic of Korea completed the largest barrage-type power station (254 MW) at Sihwa Lake in 2011, with plans for several more large-scale stations. China has several small barrage-type power stations with a total capacity of 11 MW. India also has plans for a 50 MW barrage-type power station, with plans to increase capacity to 200 MW upon completion.

Power stations seeking to harness the kinetic energy of tidal currents are presently much smaller, with most still in the developmental phase. Norway had the first grid-connected underwater turbine located at Kvalsundet, which has a 300 kW power capacity (WEC 2007). There are similar pilot projects in the Russian Federation, the United Kingdom and the United States. The Republic of Korea has plans to increase the capacity of its Uldolmok tidal power station from 1 MW to 90 MW by the end of 2013.

In addition to barrages and tidal stream generators, other options for harnessing tidal power are in very early stages of research and development. Dynamic tidal power, for example, uses a pressure differential across a long wall traversing the tidal flow at an angle to provide current flow through a turbine (CSIRO 2012).

Wave energy technologies

To operate efficiently a wave energy converter must be tuned to the modal wave energy conditions, but also designed and engineered to withstand extreme energy conditions. This poses a significant challenge because it is the lower energy levels that produce the normal output, but the capital cost is driven by the design standard necessary to withstand extreme waves (WEC 2007). There are many designs for wave energy converters (Falcão 2010), but most can be broadly grouped into one of four types (table 11.6, figure 11.14):

Oscillating water columns (OWCs) consist of a chamber that is partially submerged. The passage of waves past the chamber causes the water level inside the chamber to rise and fall, and the oscillating air pressure drives air through a turbine to generate electricity. OWCs have been developed for installation on the shoreline, in shallow water resting on the seabed, and in deep water mounted on a surface buoy.

Hinged (and similar) devices are submerged units that consist of a paddle or buoy that oscillates with the passage of waves. Both the Oyster and CETO use this motion to pump high-pressure water ashore through pipelines to turbines located onshore for electricity generation.

Overtopping devices are designed to cause ocean waves to push water up to a reservoir situated above sea level, from which the water drains back to sea level through one or several turbines. These devices have been designed for both shoreline and offshore installation.

Of the remaining types, the Pelamis wave energy converter consists of two or more cylindrical sections linked together. The passage of waves causes the sections to undulate, and the movement at the hinged joints is resisted by hydraulic cylinders that pump high-pressure fluid through hydraulic motors and electrical generators. The Archimedes Waveswing consists of a sub-surface vertical cylinder tethered to the seabed. An air-filled upper cylinder moves against a lower fixed cylinder with the passage of each wave. The vertical oscillatory motion is converted to electricity with a linear generator.

Ocean thermal energy conversion technologies

There are three types of electricity conversion systems for ocean thermal energy: closed-cycle systems, open-cycle systems and hybrid systems (figure 11.15).

- Closed-cycle systems use the ocean's warm surface water to vaporise a working fluid with a low boiling point, such as ammonia. This vapour expands and turns a turbine which activates a generator to produce electricity.
- Open-cycle systems boil the seawater by operating at low pressures, producing steam that passes through a turbine to generate electricity.
- Hybrid systems combine both closed-cycle and open-cycle systems.

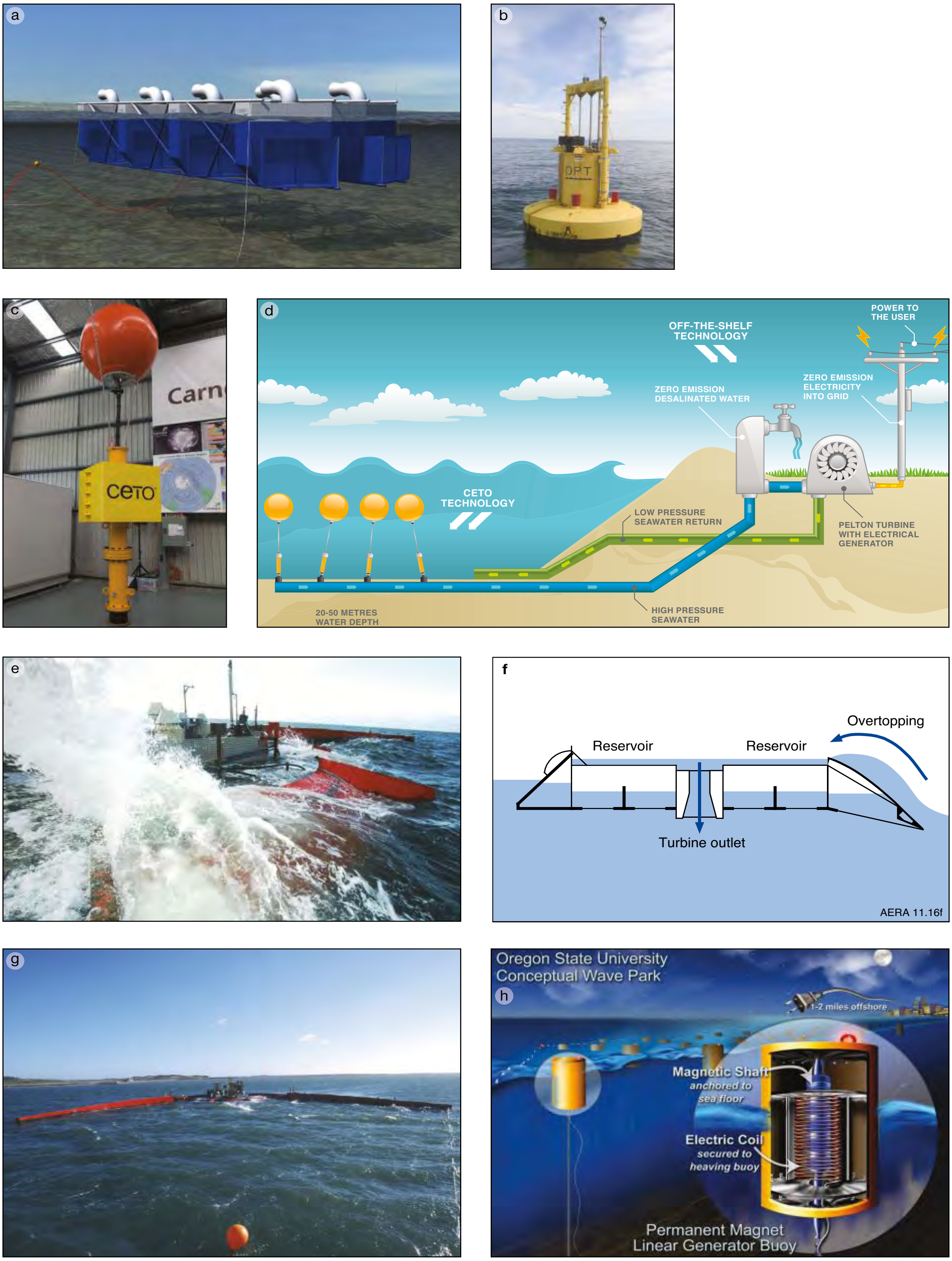

Figure 11.14 Examples of different types of wave energy converters. **a** Schematic of Oceanlinx oscillating water column. **b** Ocean Power Technologies' PowerBuoy®, Atlantic City, New Jersey. **c** CETO wave energy converter. **d** Schematic of CETO wave farm. **e** Wave Dragon overtopping device. **f** Schematic showing the operation of Wave Dragon. **g** Pelamis wave energy converter. **h** Schematic of Archimedes wave swing

Source: www.oceanlinx.com; www.oceanpowertechnologies.com; www.carnegiewave.com; www.wavedragon.co.uk; www.pelamiswave.com; Oregon State University

Table 11.6 Examples of different types of wave energy converters

Device	Example	Location of installation	Location of generator	Proof of concept	Electricity to grid
Oscillating water columns	LIMPET	Shoreline	Onshore	✓	✓
	Energetech OWC	Seabed, shallow water	Offshore	✓	✓
	blueWAVE OWC	Surface, tethered to seabed, deeper waters	Offshore	✓	✓
	OPT PowerBuoy	Seabed, shallow water	Offshore	✓	✓
	Nautilus	Surface, tethered to seabed, shallow water		✓	
Hinged (and similar) devices	Oyster	Seabed, shallow water	Onshore	✓	✓
	CETO	Seabed, shallow water	Onshore	✓	✓
	bioWAVE / O-Drive	Seabed, shallow water	Offshore	✓	
	Wave Roller	Seabed	Offshore	✓	✓
Overtopping devices	Wave Dragon	Surface, tethered to seabed	Offshore	✓	✓
	Seawave slot cone	Shoreline or offshore	Onshore or offshore	✓	✓
Other	Pelamis	Surface, tethered to seabed	Offshore	✓	✓
	Archimedes swing	Immediate	Offshore	✓	✓

OTEC plants may be land based, shelf based or floating:

- Land-based plants have the advantage of no transmission cable to shore and no mooring costs, but require a cold-water pipe to cross the surf zone and follow the seabed to the required depth. This results in lower efficiency because a longer pipe has greater friction losses and there is greater warming of the cold water before it reaches the heat exchanger.
- Shelf-based plants have the advantage of avoiding the surf zone and associated long cold-water pipe. The plant is fixed to the seabed, and associated costs and engineering requirements in open ocean conditions and energy delivery may make it less attractive than land-based plants.
- Floating plants require a transmission cable to shore and moorings in deep water, but have the advantage that the cold-water pipe is shorter. Technology developments in high-voltage direct current transmission and mooring in the offshore oil and gas industry may be used in floating plants.

Salinity gradient power technologies

The main method for extracting energy from the difference in salt concentration between seawater and freshwater is pressure-retarded osmosis, although other methods such as reverse electrodialysis are currently in the infant stages of development (figure 11.15).

- Pressure-retarded osmosis systems pump seawater into a chamber that is at a lower pressure than the difference between the pressures of seawater and freshwater. Freshwater is then pumped into the chamber so that both the volume and pressure of the chamber increase, spinning a turbine to create energy.

Hybrid technologies

In order to optimise energy extraction, wind and ocean energy technologies can be combined to take advantage of multiple sources of energy. The Poseidon Floating power plant (Poseidon P37) is a platform consisting of multiple wave-conversion devices on which wind turbines sit. The Poseidon P37 was deployed off the coast of Denmark in September 2012 where it became the first hybrid wind/ocean energy device to deliver electricity to the grid (www.floatingpowerplant.com).

Grid access may be a significant issue for more remote future ocean energy projects

The best tidal energy resources tend to be located off the more remote coastlines along the northern margin of Australia. With the present technology constraints, the most suitable harvesting sites combined with good access to the electricity grid favour only a few regional centres, although there are large resources within reasonable proximity to the major centres of Darwin and Mackay. The domestic demand for electricity is relatively small in the very well-resourced areas of the Kimberley and Pilbara, but tide-generated electricity could potentially contribute to the energy requirements of the mining sector.

The environmental impact of a barrage-type power station may not be acceptable in these environmentally sensitive regions, although there is the potential for converters that harvest kinetic energy from tidal currents with much lower environmental impact.

The best wave energy resources tend to be located off the more remote coastlines along the southern margin of Australia. With the current technology constraints, the most suitable sites for harvesting combined with access to the electricity grid favour only a few regional centres. This may change in time if the current small scale projects of 0.5 MW to 1 MW evolve into significant projects of 100 MW or more and if the possibility of connecting over longer distances to the grid (or expanding the grid) to take advantage of this resource is demonstrated to be economic.

Ocean energy is a zero or low emissions renewable resource, but other environmental impacts also need to be assessed

Electricity generation from ocean energy produces no greenhouse gas emissions, but the CO_2 emissions during construction and maintenance of energy plants must also be considered. Each type of ocean energy may also have direct environmental impacts, although the significance and even occurrence of these impacts are still uncertain. A review of potential environmental impacts associated with ocean energy development is given in Boehlert and Gill (2010).

For wave energy, multiple conversion devices must be installed at a given site for commercial-scale operations. Offshore systems may pose a navigation hazard to vessels and therefore must be located in areas that are not heavily navigated. These wave farms may also have environmental impacts such as wave calming, noise pollution, or interference with navigation of marine life. The magnitude of such impacts will likely vary among regions, with wave calming desirable in some locations but not in others (CSIRO 2012). Unfortunately, there is very little information on environmental impacts of wave energy extraction, and the extent of any potential impacts will depend on the type of wave energy converter technology.

For tidal energy, the main environmental impacts are associated with barrages rather than tidal current convertors. Barrages restrict tidal flows and spatial coverage and have the potential to dramatically alter an ecosystem through inundation, sediment transport, salinity changes and changes to tidal resonance. This may have negative impacts on water quality and biodiversity in the surrounding area and cause loss of habitat where intertidal zones are reduced in area (IEA 2008). Such concerns often raise enormous public criticism and may affect the success of the project. For example, Britain's largest environmental groups stated that a proposed tidal barrage in the Severn estuary could destroy 35 0000 hectares of protected wetlands, and the British Government eventually withdrew its support for the project in 2010. Similar concerns about habitat destruction and associated loss of fishermen's livelihoods were raised for the Incheon Bay tidal barrage in the Republic of Korea (Ko and Schubert 2011). In addition, barrages may also act as a trap for some larger marine species, with at least two trapped humpback whales recorded in the Annapolis Royal Generating Station, Canada. Ecosystem risk from barrage development will likely need to be assessed in a site-specific manner. Although tidal current convertors have far lower environmental impact than barrages, turbines and other underwater devices such as those also associated with wave convertors have the potential to harm marine organisms. Exclusion methods and slower operating speeds may mitigate the risk.

In addition to potential environmental impacts, ocean energy development must address competing interests from a range of stakeholders relating to the use of Australian waters. These may include native title and land rights, conservation areas, fishery and aquaculture activity, resource exploration and extraction (oil, gas, minerals), shipping, national security, and recreation. A detailed assessment of these competing interests is given in CSIRO (2012).

The development of ocean energy may benefit the environment. Infrastructure associated with wave farms and other underwater devices may act as artificial reefs for a range of organisms. Tidal barrages may help degraded habitats recover; for example, the Sihwa Lake tidal barrage in the Republic of Korea will help repair ecological damage due to stagnation caused by a sea wall.

11.4.2 Outlook for ocean energy market

Wave and tidal energy are non-depletable resources; increased use of the resources does not affect resource availability. However, estimates of resource availability may change over time as new measurement and impact assessment methods become available. In addition, the quantity of the resource that can be used will change over time as new technologies allow increased exploitation of ocean resources.

The tidal energy resource assessment presented in section 11.3.1 suggests that there is future development potential largely on the northern half of Australia's continental shelf and particularly in King Sound and the western Joseph Bonaparte Gulf (Western Australia), Darwin and the eastern Joseph Bonaparte Gulf (Northern Territory), and the Torres Strait and southern parts of the Great Barrier Reef (Queensland). The quality of the resource is spatially variable, but also highly predictable once field measurements of one year's duration have been obtained for a site. The suitability of sites will also be influenced by water depth and seabed type, which affect the engineering of tide energy converters and placement of cables across the seabed.

The wave energy resource assessment discussed in section 11.3.1 suggests that there is future development potential across the southern half of Australia's continental shelf from Exmouth around to Brisbane. The quality of the resource is variable, with the failure rate of the waves to deliver sufficient energy and the frequency of failures generally increasing in the more northerly waters. There may also be strong local variability in both the resource and its accessibility; the latter being determined by requirements for particular water depths and seabed types for installation of the wave energy converters and networks of pipes or cables across the seabed.

Australia's ocean energy industry is currently focused on developing and trialling technologies for tidal or wave energy. Several companies have planned commercial-scale plants (box 11.3). This is an essential step in demonstrating the technical and economic viability of these technologies. Early demonstration of the commercial viability of these or comparable technologies could well accelerate the development of wave and tide energy in Australia.

BOX 11.3 PROPOSED OCEAN ENERGY DEVELOPMENT PROJECTS IN AUSTRALIA

Australia currently has no commercial-scale ocean energy projects at an advanced stage of development.

There are three commercial-scale projects that are at less advanced stages of development. These projects are significantly larger than those previously commissioned in Australia, with an ultimate combined capacity of 786 MW (BREE 2013). Two projects account for around 96 per cent of this additional capacity—the Clarence Strait Tidal Energy project (450 MW capacity) in the Northern Territory and the Banks Strait Tidal Energy project (302 MW capacity) in Tasmania and are expected to enter production in 2014 and 2018, respectively. The third project is the Port Phillip Heads Tidal project (34 MW capacity) in Victoria, and is expected to be in production in 2016. All three projects have been proposed by Tenax Energy.

BioPower Systems Port Fairy pilot wave energy project in Victoria (250 kW) is scheduled to be commissioned in 2013 and connected to the grid via sub-sea cable. It is expected to operate for 21 months before being decommissioned. The pilot project is expected to provide information that will feed into the development of a 1 MW plant (BioPower Systems 2012).

Oceanlinx plan to develop a 1 MW wave energy greenWave convertor in Port MacDonnell, South Australia. The project is expected to be connected to the grid in 2014.

Carnegie Wave Energy announced plans for the 2014 completion of a 2 MW grid-connected wave energy plant on Garden Island, Western Australia, based on the CETO 3 wave-convertor. The company has five other project sites in Australia at the licensing agreement stage spread across the southern margin (Albany (Western Australia), Port MacDonnell (South Australia), Portland and Phillip Island (Victoria), Eden (New South Wales)) and is undertaking a feasibility study to assess the viability of using wave energy to supply power to the remote naval base at Exmouth in Western Australia.

Victorian Wave Partners, a subsidiary of Ocean Power Technologies Australasia, plans to develop a 19 MW wave energy plant near Portland in Victoria. The project will use Ocean Power Technologies' PowerBuoy® wave energy converter and have the capacity to meet the energy needs of 10 000 homes.

Several proposals have been put forward for a tidal energy plant at Derby, Western Australia including a 2001 proposal for a 5 MW plant to deliver 68.4 TJ per year (Hydro Tasmania 2001). It has been set aside because of the high grid-connection costs and potential environmental impacts to sensitive wetlands.

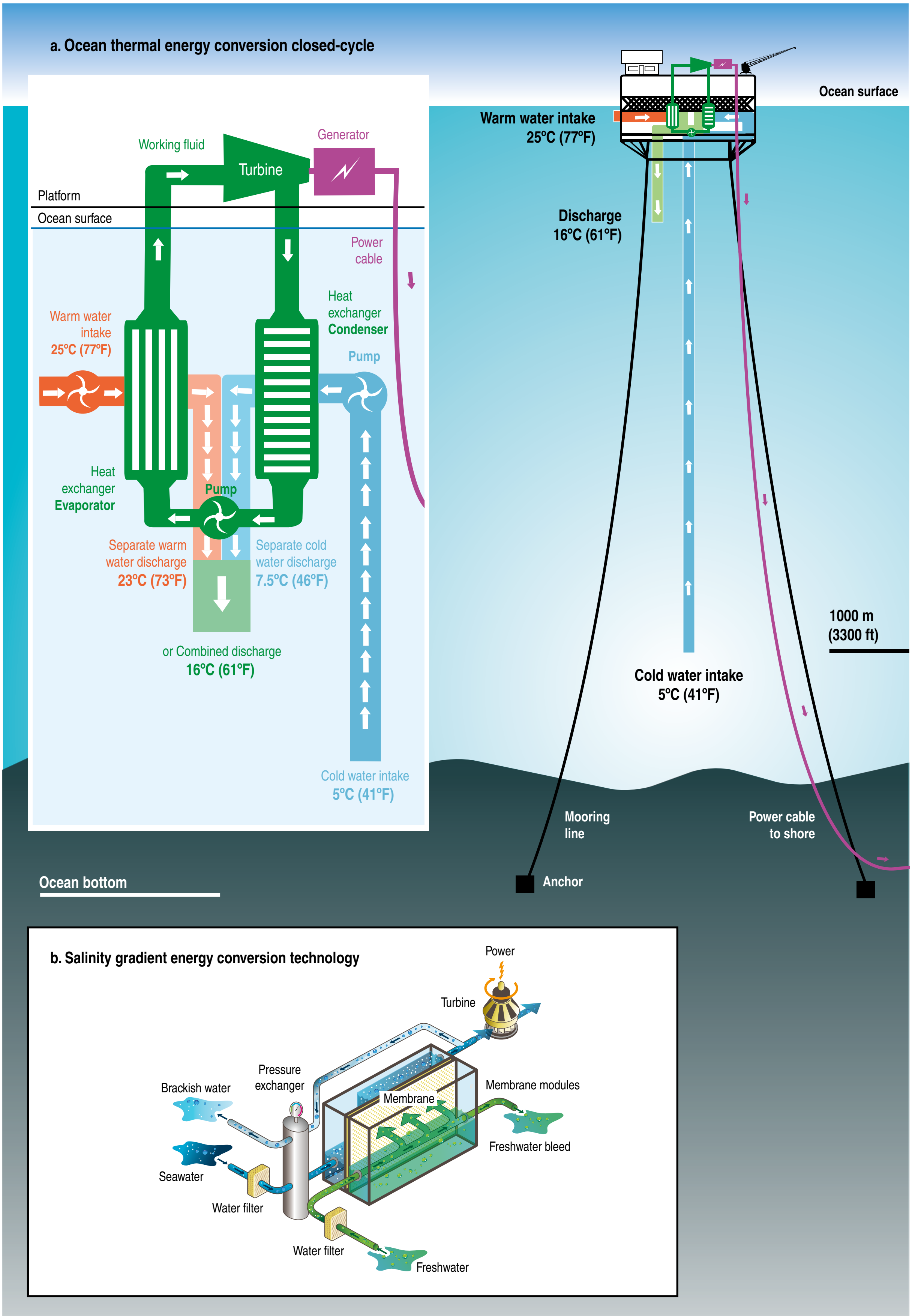

Figure 11.15 Examples of **a** ocean thermal and **b** salinity gradient energy conversion technology

Source: modified from National Oceanic and Atmospheric Administration (www.noaa.gov.au) and Statkraft (www.statkraft.com)

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Chapter 12

Bioenergy

12.1 Summary

KEY MESSAGES

- Bioenergy is a form of renewable energy derived from biomass (organic materials) to generate electricity and heat and to produce liquid fuels for transport.
- The potential bioenergy resources in Australia are large and diverse. Unused biomass residues and wastes are a significant underexploited resource.
- Bioenergy offers the potential for considerable environmental benefits. At the same time, good management of the resource is needed to ensure that issues associated with use of land and water resources are avoided.
- Commercialisation of second generation (advanced) technologies will result in a greater availability of non-edible biomass, reducing the risk of adverse environmental and social impacts.

12.1.1 World bioenergy resources and market

- Current global bioenergy resources used for generating electricity and heat are dominated by forestry and agriculture residues and organic waste streams. A small proportion of sugar, grain and vegetable oil crops are used for biofuel production.
- Bioenergy represents around 10 per cent of the world's primary energy consumption. Around 80 per cent of world bioenergy consumption occurs in non-OECD countries, where it is mostly used for direct burning.
- In 2010, the global share of bioenergy in total electricity generation was only 1.5 per cent. However, world electricity generation from bioenergy resources is to increase at an average rate of 6.2 per cent per year to 2035 and the share of bioenergy in electricity generation is projected to reach 4.1 per cent.
- Biofuels currently represent 1.9 per cent of global use of transport fuels. By 2035, the share of biofuels in total transport fuels is projected by the International Energy Agency (IEA) to increase to 6.3 per cent.
- Global biofuel production (bioethanol and biodiesel) grew from 16 billion litres in 2000 to an estimated 110 billion litres in 2012. The growth in biofuel production stalled in 2012 due to higher feedstock prices and lower production volumes as a result of extreme weather conditions.

12.1.2 Australia's bioenergy resources

- Currently Australia's bioenergy use for generating heat and electricity is sourced mainly from bagasse (sugarcane residue), and capture of gas from landfill and sewage facilities (figure 12.1).
- Biofuels for transport represent a small proportion of Australia's bioenergy. Ethanol is produced from sugar by-products, waste starch and grain. Biodiesel is produced from used cooking oils, tallow from abattoirs and oilseeds.
- There is potential to expand Australia's bioenergy sector with increased utilisation of wood residues from plantations and forests, waste streams and non-edible biomass.

12.1.3 Key factors in utilising Australia's bioenergy resources

- The proportion of biomass potentially available for bioenergy is dependent on a wide range of factors such as feedstock prices, seasonal availability and the relative value of biomass for the production of other commodities.
- A key consideration in the expansion of the bioenergy industry is to ensure sustainable use of resources to avoid any potential negative environmental and social impacts.

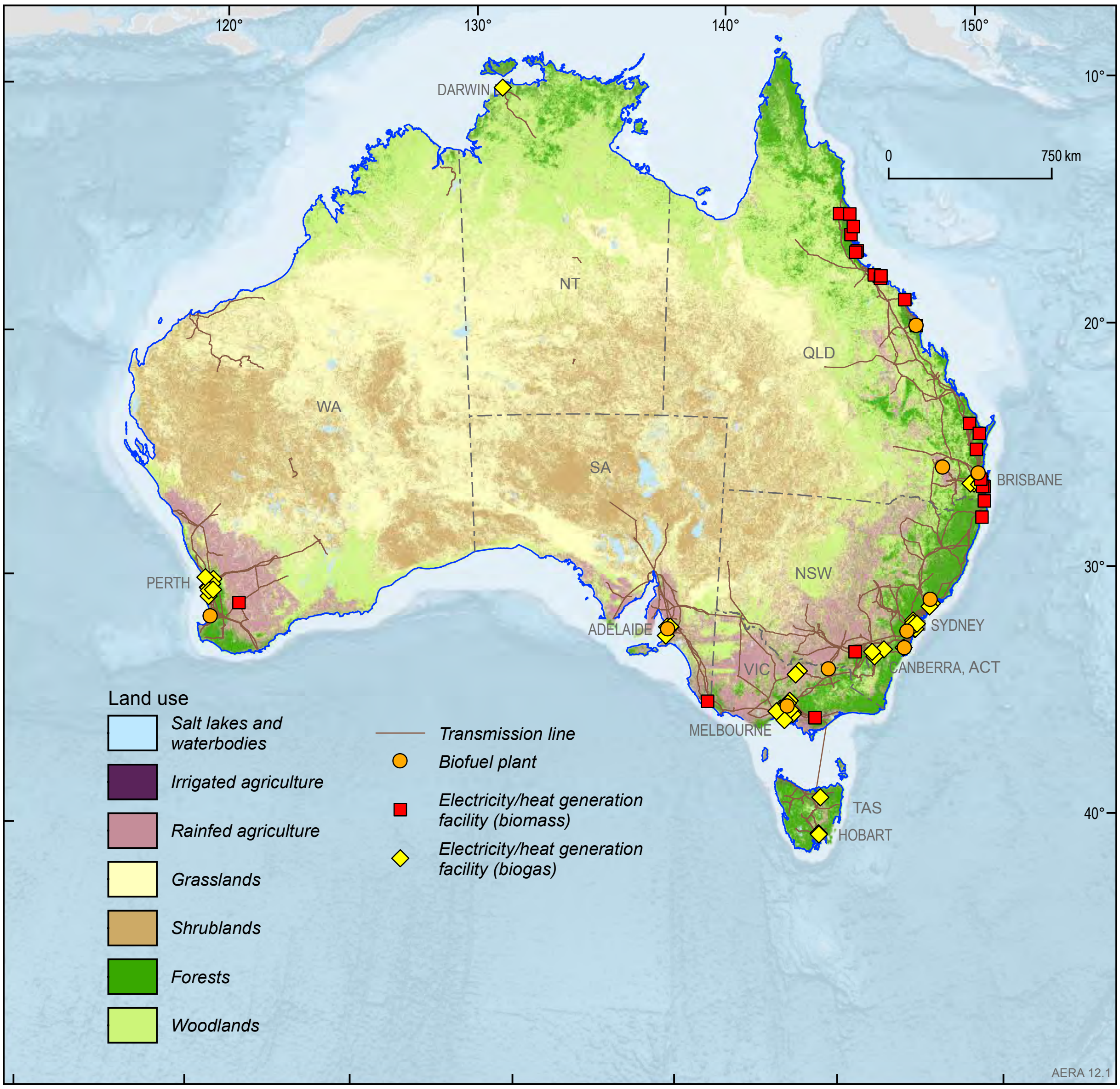

Figure 12.1 Land use and bioenergy facilities in Australia

Source: Geoscience Australia

- The commercialisation of second generation technologies will open up a range of new feedstocks from non-edible biomass (e.g. woody parts of plants) for biofuels and electricity generation. These second generation feedstocks can be produced on less fertile agricultural lands and can potentially provide environmental benefits. Some second generation feedstocks, such as algae, can be grown with saline or wastewater rather than utilising freshwater resources. Algae is considered a potential sustainable and scalable feedstock for biofuels.

12.1.4 Australia's bioenergy market

- Bioenergy accounted for only 3.1 per cent of Australia's primary energy consumption in 2011–12, but it represented 68 per cent of Australia's renewable energy use.
- The majority of Australia's bioenergy use is sourced from bagasse and wood waste, which represents 86 per cent of bioenergy use for direct heat and electricity generation. Biogas represents 8 per cent of bioenergy use and the remaining 6 per cent is biofuels for transport fuel.

12.2 Background information and world market

12.2.1 Definitions

Bioenergy denotes the use of organic material (biomass) as a source of energy for power generation and direct source heat applications in all energy sectors including domestic, commercial and industrial purposes as well as the production of liquid fuels for transport.

Bioenergy is a form of renewable energy. Biomass releases carbon dioxide (CO_2) and small amounts of other greenhouse gases when it is converted into another form of energy. However, CO_2 is absorbed during regrowth of vegetation through the photosynthesis process.

Biomass is vegetable- and animal-derived organic materials, which are grown, collected or harvested for energy. Examples include wood waste, bagasse and animal fats.

A conventional combustion process converts solid biomass through direct burning to release energy in the form of heat which can be used to generate electricity and heat. Chemical conversion processes break down the biomass into fuels, in the form of biogas or liquid biofuels, which are then used for electricity generation and transport.

Biogas is composed principally of methane and CO_2 produced by anaerobic digestion of biomass. It is currently captured from landfill sites, sewage treatment plants, livestock feedlots and agricultural wastes.

Biofuels are liquid fuels, produced by chemical conversion processes that result in the production of ethanol and biodiesel. Biofuels can be broadly grouped according to the conversion processes:

- First generation biofuels are based on fermentation and distillation of ethanol from sugar and starch crops or chemical conversion of vegetable oils and animal fats to produce biodiesel. First generation technologies are proven and are currently used at a commercial scale.
- Second generation biofuels (also known as advanced biofuels) use biochemical or thermochemical processes to convert lignocellulosic material (non-edible fibrous or woody portions of plants) and algae to biofuels. Second generation technologies and biomass feedstocks are in the research, development and demonstration stage.
- Third generation (advanced) biofuels are in research and development (R&D) and comprise integrated biorefineries for producing biofuels, electricity generation and bioproducts (such as petrochemical replacements).

12.2.2 Bioenergy supply chain

Figure 12.2 provides a conceptual representation of Australia's current bioenergy industry. Currently, there is a wide range of bioenergy resources potentially available for bioenergy utilisation. Biomass sources used to generate electricity and heat include agricultural and forest residues, and municipal wastes and residues. Biofuels are produced from waste products, grain (sorghum) and oil-bearing crops. Australian bioenergy production is mainly consumed domestically.

There is a range of technologies currently available for converting biomass into energy for electricity and heat generation and/or transport biofuels. The technologies are based on either thermal or chemical conversion processes or a combination.

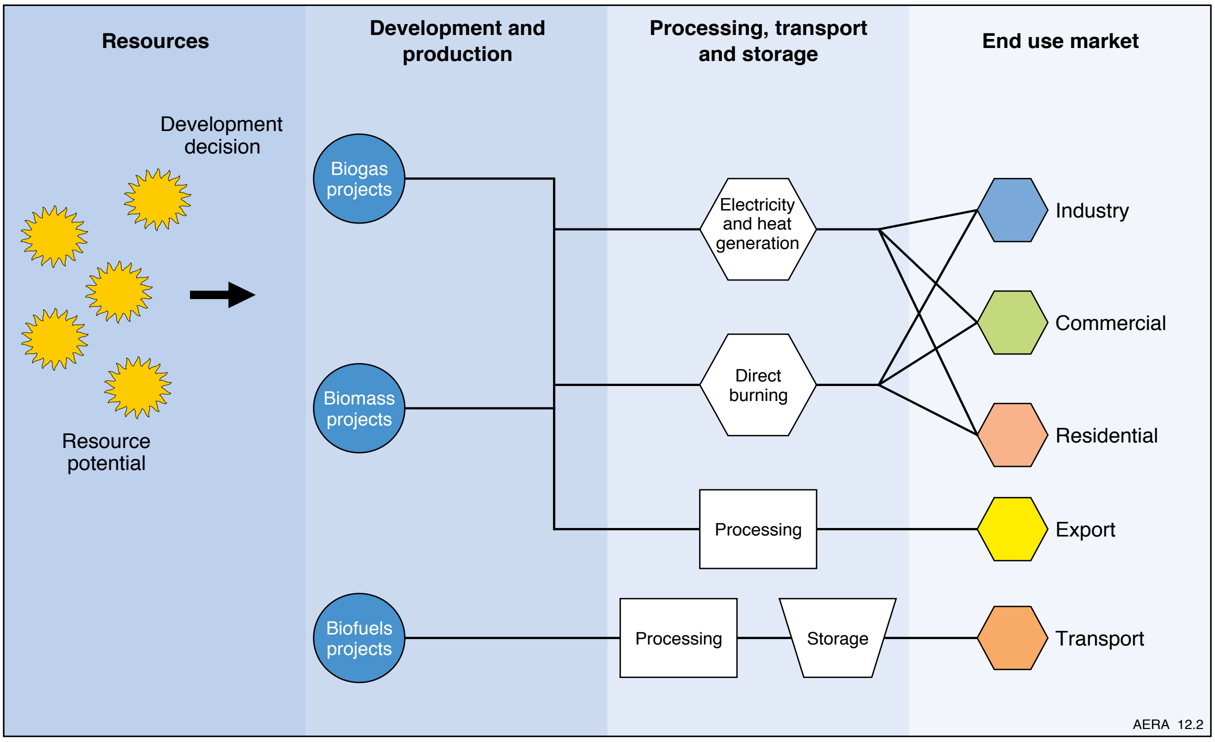

Figure 12.2 Australia's bioenergy supply chain

Source: Bureau of Resources and Energy Economics; Geoscience Australia

The fuel type (in particular the heating value and moisture) and the conversion technology have an effect on energy conversion efficiency. The energy conversion efficiency for wood waste in a direct combustion facility is about 35 per cent, compared to between 70 and 85 per cent efficiency in a combined heat and power facility.

Bioenergy can be easily integrated with conventional energy, by co-firing wood chips or pellets with coal, injecting biogas into natural gas pipelines and adding liquid biofuels to transport fuels (REN21 2012).

Electricity and heat generation

In Australia, biomass electricity generation is predominantly from bagasse (sugarcane residues) by steam turbine, with some cogeneration installation. Several wood waste bioenergy facilities use steam turbines and fluidised bed combustion technologies. There is minor electricity generation from co-firing with coal, and facilities using urban waste.

Biogas from landfill and sewage facilities are located in urban centres and generate electricity by means of reciprocating engine or gas turbine. Some facilities have cogeneration installations.

Transport biofuels

A small amount of biofuels is used in the transport sector. In Australia, first generation biofuels consist of ethanol produced from C-molasses and wheat starch by-products and grain (mainly sorghum), and biodiesel predominantly produced from tallow (animal fats) and used cooking oil.

12.2.3 World bioenergy market

Around 10 per cent of the world's primary energy consumption comes from bioenergy (table 12.1). The share of bioenergy in primary energy consumption is higher in non-OECD countries than in OECD countries. In Australia, the bioenergy share is comparable to the OECD average, at around 4 per cent. The majority of the world's bioenergy is used directly for heat production through the burning of solid biomass; only 4 per cent is used for electricity generation and another 2.4 per cent is in the form of biofuels used in the transport sector.

Resources

Global bioenergy resources are difficult to quantify due to the resources being committed to food, animal feed and material for construction. The availability of biomass for energy is also influenced by population growth, diet, agricultural intensity, environmental impacts, climate change, water and land availability (IEA Bioenergy 2009a).

Current bioenergy resources consist of residues from forestry and agriculture, various organic waste streams and dedicated biomass production from pasture land, wood plantations and sugar cane. Unused residues and waste are a significant underexploited resource.

At present, the main biomass resources for electricity and heat generation are forestry and agricultural residues and municipal waste in cogeneration and co-firing power plants. In 2007, fuel wood dominated (67 per cent) the share of biomass sources in the bioenergy mix (figure 12.3). Fuel wood is used in residential applications in commonly inefficient stoves for domestic heating and cooking, which is also considered a major health issue in developing countries (IEA Bioenergy 2009a). This traditional use is expected to grow with increasing population; however, there is scope to improve efficiency and environmental performance.

Biomass provided over 53 500 PJ per year of primary world energy supply in 2010 from a wide variety of resources. The potential deployment levels of biomass for energy by 2050 could be as large as 500 000 PJ. Reaching a fraction of the potential will require sophisticated land and water management (IPCC 2011).

Table 12.1 Key bioenergy statistics

	Unit	Australia 2011–12	Australia 2010–11	OECD 2011	World 2010
Primary energy consumption	PJ	191	178	10 968	53 509
Share of total	%	3.1	2.9	4.9	10.1
Average annual growth, from 2000	%	-1.8	–2.0	3.3	2.2
Electricity generation					
Electricity output	TWh	2.3	2.1	263	332
Share of total	%	0.9	0.8	2.4	1.5
Average annual growth, from 2000	%	2.7	4.6	3.3	6.9
Electricity capacity	GW	0.8	0.84	47.1	na
Transport	PJ	9	11.6	1686	2410
Share of total	%	0.6	0.8	3.4	2.4
Average annual growth, from 2000	%			25.9	19.2

Source: BREE 2012a; IEA 2012a

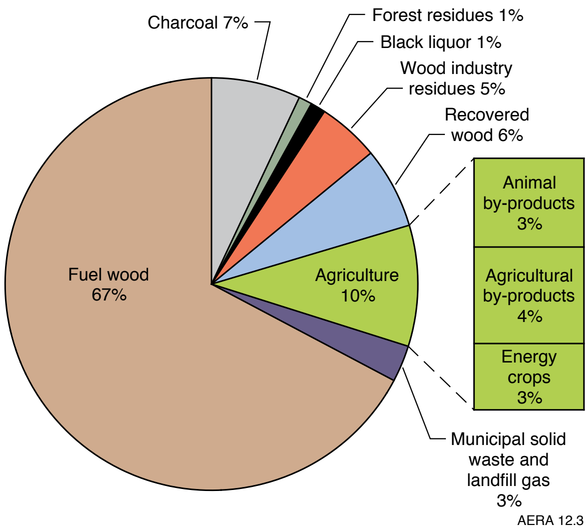

Figure 12.3 Share of biomass sources in the world primary bioenergy mix, 2007

Source: IEA Bioenergy 2009a

The significant producers of electricity generation from bioenergy are the United States, European Union, Brazil, China, India and Japan (REN21 2012). China continues to increase power generation from biomass with total installed capacity of 4.4 GW in 2011, a 10 per cent increase over 2010. Most sugar-producing countries in Africa have bagasse-based combined heat and power plants (REN21 2012).

A small share of sugar, grain and vegetable oil crops is used for the production of biofuels. There is increasing consumption of transport biofuels in North America, Latin America and Europe (REN21 2012). There is potential to expand the use of conventional crops for energy; however, careful consideration of land availability and food demand is required.

There is a mature commercial market for first generation biofuels. Biofuels from commercially available technology are more prospective in regions where energy crop production is feasible: for example, sugar cane in subtropical areas of South America and sub-Saharan Africa, and sugar beet in more temperate regions such as the United States, Argentina and Europe. In the longer term, lignocellulosic crops could provide bioenergy resources for second generation biofuels which are considered more sustainable, provide land use opportunities and will reduce the competition with food crops.

Primary energy consumption

World primary consumption of bioenergy was 53 509 PJ in 2010 (table 12.1). From 2000 to 2010 world bioenergy use increased at an average rate of 2.2 per cent per year. OECD countries accounted for 20 per cent (10 968 PJ) of world bioenergy consumption; however, the average rate of growth in consumption was 3.3 per cent per year from 2000 to 2011, faster than the world average.

In 2010, China was the largest user of bioenergy, consuming 8617 PJ, followed by India (7125 PJ) and Nigeria (3970 PJ) (figure 12.4). The majority of bioenergy use in China, India and Nigeria is solid biomass used in the residential sector. Bioenergy represented a relatively small proportion of China's total primary energy consumption, with a share of 8.5 per cent, while Nigeria's bioenergy use represented 84 per cent of its total primary energy consumption and Ethiopia's bioenergy use represented 93 per cent of its energy consumption (figure 12.4).

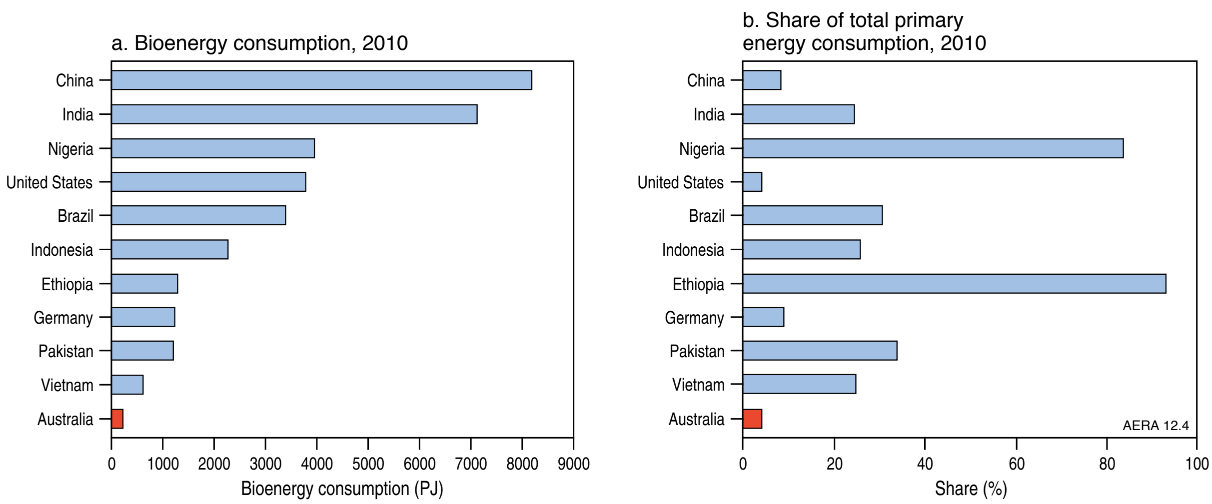

Figure 12.4 Primary consumption of bioenergy, by country, 2010

Source: IEA 2012a

Electricity generation

A small proportion of the world's electricity generation is sourced from bioenergy. In 2010, the global share of bioenergy in total electricity generation was only 1.5 per cent (table 12.1). Despite its small share, electricity generated from bioenergy increased at an average rate of 6.9 per cent per year from 2000 to 2010, to reach 332 TWh.

In some countries, the share of bioenergy in total electricity generation is significantly higher than the world average. Finland had a bioenergy share of electricity generation of more than 13 per cent in 2010 (figure 12.5). The United States is the largest contributor to total world electricity generation from bioenergy, followed by Germany and Japan.

Worldwide primary solid biomass is the major bioenergy fuel used for electricity generation. In 2010, electricity generated from solid biomass represented 59 per cent of bioenergy electricity, while biogas and waste represented the remaining.

Transport biofuels

Global biofuel production (bioethanol and biodiesel) grew from 16 billion litres in 2000 to an estimated 110 billion litres in 2012. The growth in biofuel production stalled in 2012 due to higher feedstock prices and lower production volumes as a result of extreme weather conditions (IEA 2013). Cost of biofuel production from sugar and starch is very sensitive to the feedstock prices, which can be volatile (IEA 2011b).

The United States is the world's largest consumer of biofuels, using 1063 PJ in 2010 (IEA 2012a; figure 12.6). However, biofuels represent only 4.35 per cent of total transport fuels use in the United States. Germany and Brazil follow the United States as large biofuels users. Biofuels represent a larger share of total transport fuels use in Brazil and Germany: 20.1 per cent and 5.7 per cent, respectively.

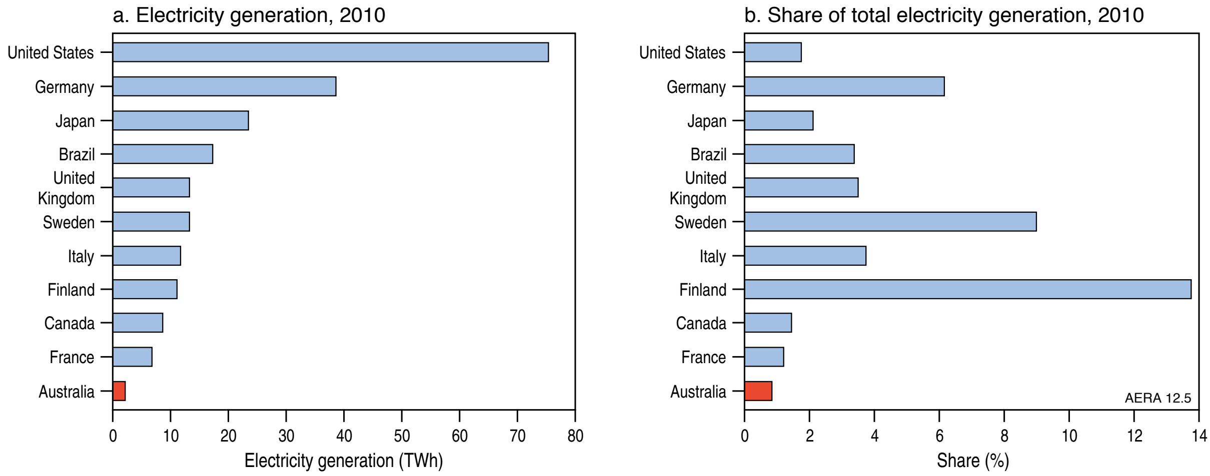

Figure 12.5 Electricity generation from bioenergy, by country, 2010

Source: IEA 2012a

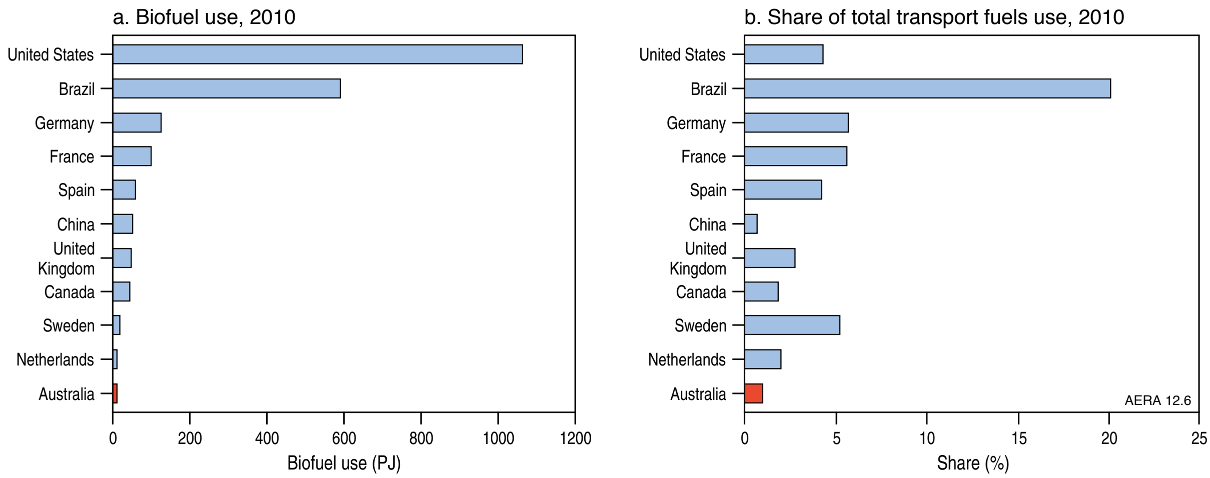

Figure 12.6 Biofuels use for transport, by country, 2010

Source: IEA 2012a

Trade

The increase in demand for biomass resources (e.g. wood chips, vegetable oils and agricultural residues) and bioenergy commodities (e.g. ethanol, biodiesel and wood pellets) has seen rapid growth in international trade. The main biomass resources traded and the trade routes include:

- ethanol from Brazil to Japan, United States and European Union
- wood pellets from North Amercia to European Union
- palm oil and agricultural residues from Brazil and South-East Asia to European Union (IEA Bioenergy 2013).

In addition, there is a substantial amount of trade within Europe. There are minor trade flows of wood pellets and ethanol from Australia to Europe and the United States, respectively.

In 2010, trade of solid biomass amounted to about 18 million tonnes (300 PJ); more than 90 per cent of this consisted of pellets, wood waste and fuel wood (REN21 2012). Trade of biofuel (ethanol and biodiesel) was about 20 million barrels of oil equivalent (120–130 PJ) in 2009 (REN21 2012).

World bioenergy market outlook

Bioenergy use is projected by the IEA to increase moderately to 2035, with transport biofuels growing at a slightly faster rate than electricity generation from bioenergy. Among non-transport uses, an increasing proportion of bioenergy is projected to be devoted to electricity generation rather than direct burning of biomass, in line with growing electricity demand, particularly in non-OECD countries.

Global demand for bioenergy resources is expected to increase with the projected growth in bioenergy use. In the short term, demand for bioenergy resources is likely to be met by sugar, starch and oilseed crops, as well as utilising the large volumes of unused residues and wastes. Lignocellulosic crops are expected to contribute in the medium to long term. Algae could make a significant contribution in the longer term (IEA Bioenergy 2009b).

Electricity and heat generation

World electricity generation from bioenergy is projected to increase to 1487 TWh by 2035, growing at an average rate of 6.2 per cent per year (table 12.2). The share of bioenergy in electricity generation is not projected to increase significantly, reaching only 4.1 per cent in 2035, from 1.5 per cent currently. Electricity generation from bioenergy is projected to increase at a faster rate in non-OECD countries than in OECD countries, although from a smaller base.

The biggest increases in electricity generation from bioenergy are projected to occur in the United States, Europe and China. The costs of power generation from renewables, including bioenergy, are expected to fall over time as a result of increased deployment.

Transport biofuels

Worldwide use of biofuels is projected to increase at an average rate of 5.6 per cent per year to 8625 PJ by 2035 (table 12.3). In non-OECD countries, biofuels use is projected to increase at an average rate of 6.4 per cent per year, whereas it is projected to increase at a rate of 4.4 per cent per year in OECD countries. However, the share of biofuels in total transport fuel use is projected to remain at less than 5 per cent in non-OECD countries, while in OECD countries it is projected to increase to almost 11.4 per cent.

Global biofuel production remained static in 2012, despite growth in the United States and Latin America. The slowdown in production growth reflected higher feedstock prices and lower production volumes due to extreme weather conditions (IEA 2013).

Over 50 countries have implemented biofuel blending mandates and targets, which has driven the steady pace of growth in world biofuel production over the past decade. However, few countries have put in place policies to support the development of advanced biofuels (second and third generation technologies), to promote the commercialisation of technologies (IEA 2013).

Table 12.2 IEA new policies scenario projections for world electricity generation from bioenergy

	Unit	2010	2035
OECD	TWh	264	671
Share of total	%	2.4	5.0
Average annual growth, 2010–35	%		3.8
Non-OECD	TWh	68	817
Share of total	%	0.6	3.5
Average annual growth, 2010–35	%		10.5
World	TWh	331	1487
Share of total	%	1.5	4.1
Average annual growth, 2010–35	%		6.2

OECD = Organisation for Economic Co-operation and Development
Note: totals may not add due to rounding

Source: IEA 2012b

12.3 Australia's bioenergy resources and market

12.3.1 Bioenergy resources

Bioenergy resources currently used, potential future resources and the bioenergy outputs are summarised in table 12.4. There is a range of bioenergy resources available for multiple conversion technologies to generate electricity and heat and produce biofuels. Bioenergy resources are difficult to estimate due to their multiple and competing uses. Bioenergy resources are embedded in biomass systems for food, feedstock, forest products and wastes and residue management. There are production statistics for current commodities such as grain, sugar, pulp wood and saw logs; however, these commodities are currently largely committed to food, animal feed and materials markets. They could be switched to the bioenergy market in certain conditions, but this may not be the highest order use for them.

Australia's potential bioenergy resources are large. There are under-utilised resources in crop residues, plantation and forest residues and waste streams. The majority of current agricultural and forestry production systems are located in south-eastern and eastern Australia and south-west Western Australia (figure 12.1). There is a significant expansion into a new range of non-edible biomass resources with the development of second generation technologies. Potential resources of the future include modifying existing crops and growing of new tree crops and algae.

There are many factors to be taken into account for each bioenergy resource, such as moisture content, resource location and distribution, and type of conversion process. Different sources of biomass have very different production systems and therefore can involve a variety of sustainability issues. These range from very positive benefits (e.g. use of waste material, or growing woody biomass on degraded agricultural land) through to large-scale diversion of high-input agricultural food crops for biofuels (O'Connell et al. 2009a). There is also a range of potential impacts on the resources including drought, flood, fire, climate change and energy prices. Future biomass resources from agricultural production are dependent on whether production areas expand or reduce or yields increase.

The proportion of biomass potentially available will depend on the value of biomass relative to competing uses, impact of its removal (retention of biomass *in situ* returns nutrients to soil, improves soil structure and moisture retention), and global oil prices. The right economic conditions may result in some of the biomass potentially being used for bioenergy production. Depending on the price point, biomass may be diverted to biofuels or electricity generation—sawmill residues otherwise sold for garden products, for example, or pulpwood chipped and exported or used for paper production may be diverted to bioenergy if it is a higher value product.

Farine et al. (2011) undertook a quantitative assessment of the prospect for current and future biomass for bioenergy in Australia. The assessment applied constraints on the biomass production including avoiding clearing of native vegetation, retaining a portion of agricultural and forest residues to protect soils, and minimising the diversion of agricultural and forest products to bioenergy. Farine et al. (2011) estimated that it would be possible to produce from current production systems:

- 9.6 GL per year of first generation ethanol
- 0.9 GL per year of biodiesel from waste oil, tallow and canola seed
- 9.5 GL per year of ethanol or 35 TWh of electricity per year from cellulosic biomass from agricultural and forest systems
- 4.3 GL per year of ethanol or 20.2 TWh per year from short-rotation eucalypt crops
- 3.96 GL per year and 0.9 GL per year of biodiesel from algae and oilseed tree respectively (new production systems).

Farine et al. (2011) consider there is sufficient available biomass to support a bioenergy industry in the short term (5–10 years); however, to develop the industry there will need to be a longer term (20–50 years) strategy. Mechanisms

Table 12.3 IEA new policies scenario projections—world biofuels consumption for transport

	Unit	2010	2035
OECD	PJ	1675	4899
Share of total	%	3.4	11.4
Average annual growth, 2010–35	%		4.4
Non-OECD	PJ	795	3726
Share of total	%	2.1	5.0
Average annual growth, 2010–35	%		6.4
World	PJ	2470	8625
Share of total	%	1.9	6.3
Average annual growth, 2010–35	%		5.6

OECD = Organisation for Economic Co-operation and Development
Note: data are converted from Mtoe to PJ by multiplying by 41.868

Source: IEA 2012b

Table 12.4 Current and future bioenergy resources

Biomass groups	Current resources	Bioenergy		Future resources	Bioenergy	
Agricultural related wastes and by-products	Livestock wastes: • manure • abattoir wastes solids By-products: • wheat starch • used cooking oil	P	T	Crop and food residues from harvesting and processing: large scale: rice husks, cotton ginning, cereal straw small scale: maize cobs, coconut husks, nut shells	P	
Sugar cane	Bagasse, fibrous residues of sugar cane milling process Sugar and C-molasses	P	T	Trash, leaves and tops from harvesting	P	
Energy crops	High yield, short-rotation crops grown specifically: • sugar and starch crops • oil bearing crops—sunflower, canola, juncea, soya beans		T	Woody crops (oil mallee) Genetically modified crops Tree crops Woody weeds (e.g. camphor laurel) Oilseed (*Pongamia pinnata*) and sugar (agave) crops Algae (micro and macro)	P	T
Forest residues	Wood from plantation forests	P		Wood from plantation forests and native forestry operations	P	T
Wood related waste	Sawmill residues: • wood chips, bark, sawdust Pulp mill residues: • black liquor and wet wastes	P				
Urban solid waste		P		Food-related wastes, garden organics, paper and cardboard material, urban timber	P	
Landfill gas	Methane emitted from landfills—mainly municipal solid wastes and industrial wastes	P				
Sewage gas	Methane emitted from the solid organic components of sewage	P				

P = electricity and heat generation; **T** = transport biofuel production

Source: Batten and O'Connell 2007; Clean Energy Council 2008

and policies will be needed to achieve linkages between producers and processors of feedstocks and purchasers of biomass products, biofuels and bioenergy.

Biofuels from advanced (second and third) technologies may provide an opportunity to increase Australia's fuel security. For Australia, LEK (2011) estimated the potential annual advance biofuel productions (gasoline equivalent per year) for a range of feedstocks:

- 11 GL per year base production from lignocellulose residues
- 10 GL per year base production up to a potential production of 30 GL from lignocellulose crops
- 2 GL per year base production up to 7 GL from oilseed crops
- 8 GL per year base production up to a potential production of 32 GL from algae.

Electricity and heat generation

Current bioenergy resources used for generating electricity and heat are predominantly from agricultural wastes and by-products, wood waste, landfill and sewage facilities (figure 12.7). The Clean Energy Council (2008) identified significant potential for growth in bioenergy production from waste streams such as landfill and sewage gas and urban waste.

Agricultural-related wastes in total are a very large resource. However, the resources are widely dispersed and can have a range of alternative uses including composting for garden product manufacture and stockfeed for animals. Currently, the bulk of biomass resources are not collected for bioenergy.

The sugarcane industry is one of few industries self-sufficient in energy, through the combustion of bagasse in cogeneration plants. The sugar mill directly consumes the heat and electricity generated and any surplus steam is used to generate electricity and fed into the power grid. The industry is located mainly in coastal Queensland, with a few mills in northern New South Wales. The total annual sugarcane crop is about 35.5 million tonnes (Mt), of which 14 per cent is cane fibre, resulting in a total available energy of above 90 PJ (Clean Energy Council 2008). Currently, the energy generation is dependent on the crushing periods and

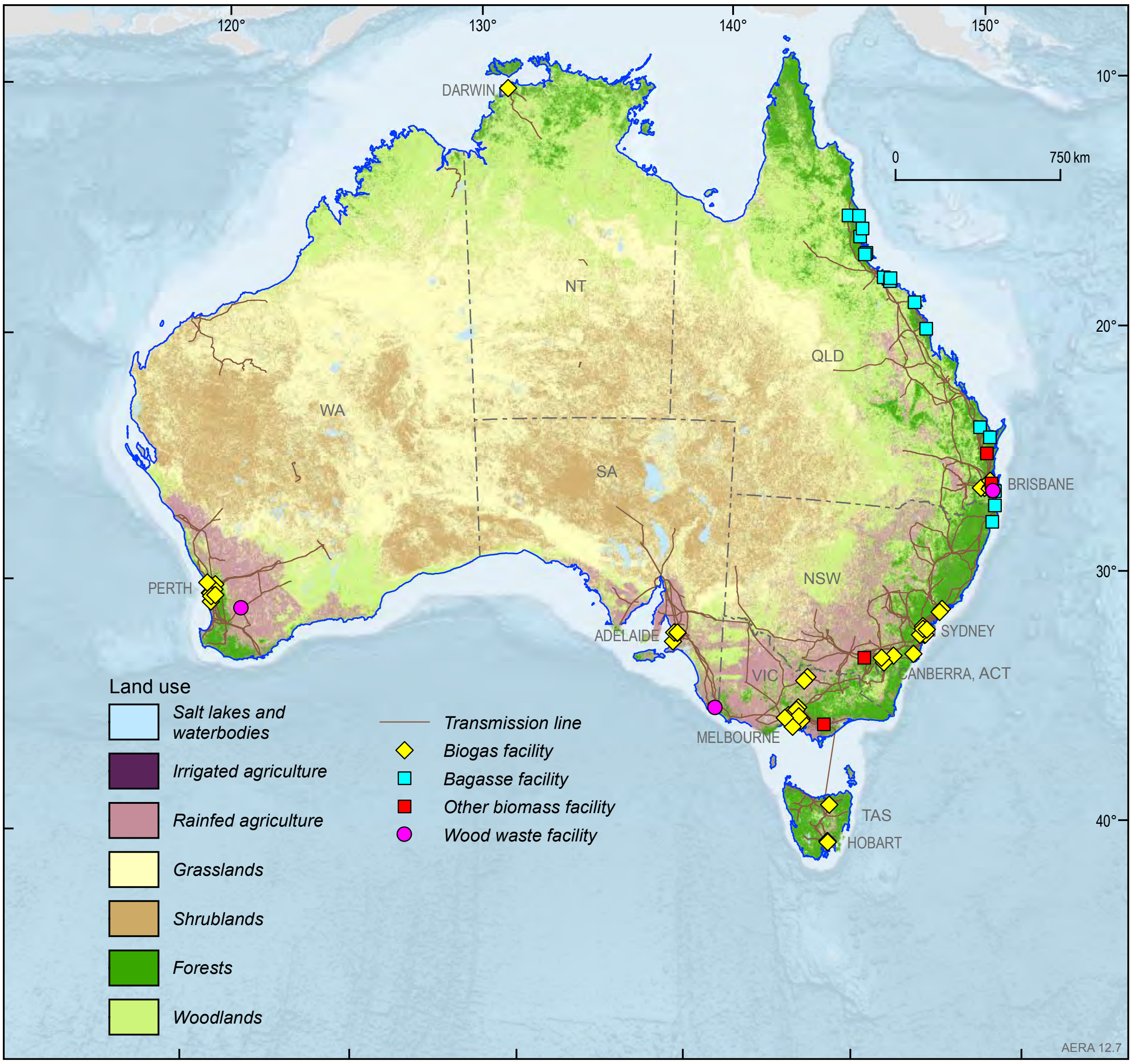

Figure 12.7 Distribution of bioenergy electricity and heat generation facilities

Source: Geoscience Australia

the availability of bagasse resources. There is potential to increase electricity generation efficiency with integrated gasification combined cycle technology and expand the biomass resources to include sugarcane trash, tops and leaves.

Other agricultural waste streams, including manure from livestock raised or yarded in concentrated areas, are suitable for generating bioenergy. Waste material can be used to produce stationary energy and assist in reducing environmental problems from waste disposal, methane emissions and pollution of water supplies.

Wood waste and forest residues are used in only a few bioenergy plants in Australia for generating electricity. For the purposes of resource assessment, it is assumed that native forest wood waste will remain constant; the potential from plantations may increase in line with plantation expansion. Wood-related waste for energy generation, while having economic benefits, also has to be managed in terms of environmental considerations. In Australia, governments at all levels, have established regulatory mechanisms, including regional forest agreements, as well as other specific provisions under the Renewable Energy Target concerning the eligibility for forest wood waste for bioenergy use in order to manage the sustainable use of these products. These regulatory frameworks place some limitations on the use of wood waste in Australia for electricity generation.

The use of landfill gas (mainly methane) to generate electricity is a relatively mature technology, which involves installing a network of perforated pipes into an existing landfill and capturing the gas generated from waste decomposition. The captured gas is used to generate electricity using reciprocating gas engines. Most facilities are near major urban centres and are used locally.

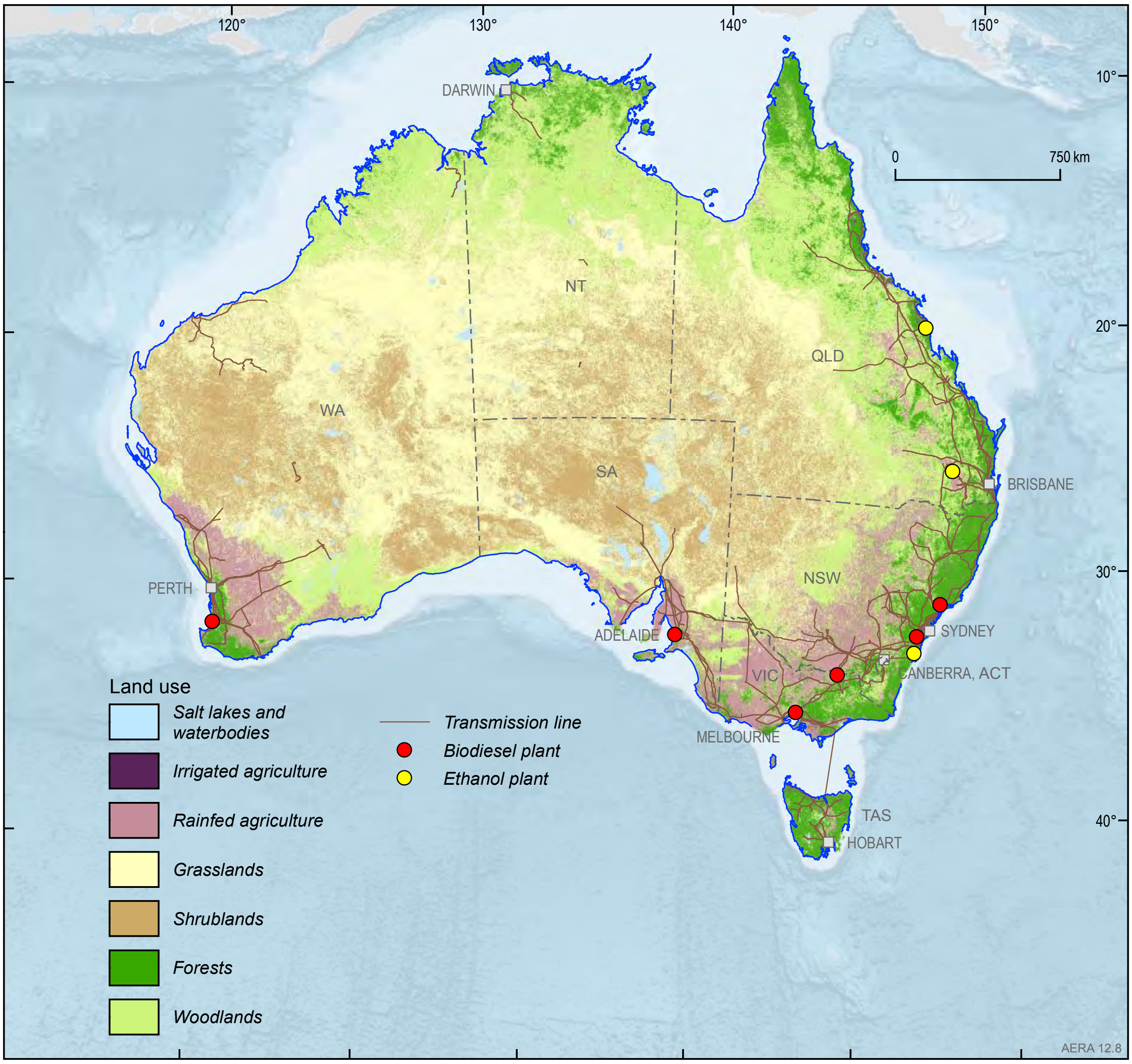

Figure 12.8 Distribution of biofuel plants

Source: Geoscience Australia

Bioreactor landfill technology accelerates the rate of waste decomposition, maximising gas production by recirculating water through a specially designed landfill. This technology is being used at the Woodlawn Bioreactor, a disused opencut mine near Goulburn, New South Wales and Ti Tree Bioenergy Facility, a former opencut coal mine, Willowbank, south-east Queensland. The Woodlawn Bioreactor accepts 300 000 tonnes of sorted residual waste per year and produces 3 MWh of electricity. The Ti Tree facility has a current capacity of 3.3 MW; however, there are plans to expand to 10 MW over the next 10 years.

Sewage gas can be collected at treatment plants to generate electricity and heat. Organic waste is fed into an anaerobic digester to produce a methane-rich biogas which is then combusted in customised gas engines or gas turbines. Thermal energy produced by the engine during combustion is recovered and used to heat the anaerobic digestion process.

Transport biofuels

As at January 2012, there are three major ethanol plants and five major biodiesel plants in operation, with a total production capacity of about 440 million litres (ML) and 305 ML, respectively (figure 12.8). Ethanol production is from C-molasses from sugar processing, grain (mainly sorghum) and starch from flour milling. Biodiesel production is from tallow and used cooking oil. Biodiesel production is constrained by a limited availability of low cost feedstocks, which are by-products or waste streams.

12.3.2 Bioenergy market

Primary energy consumption

Bioenergy accounted for 68 per cent of Australia's renewable energy use but only 3.1 per cent of Australia's primary energy consumption in 2011–12. In Australia,

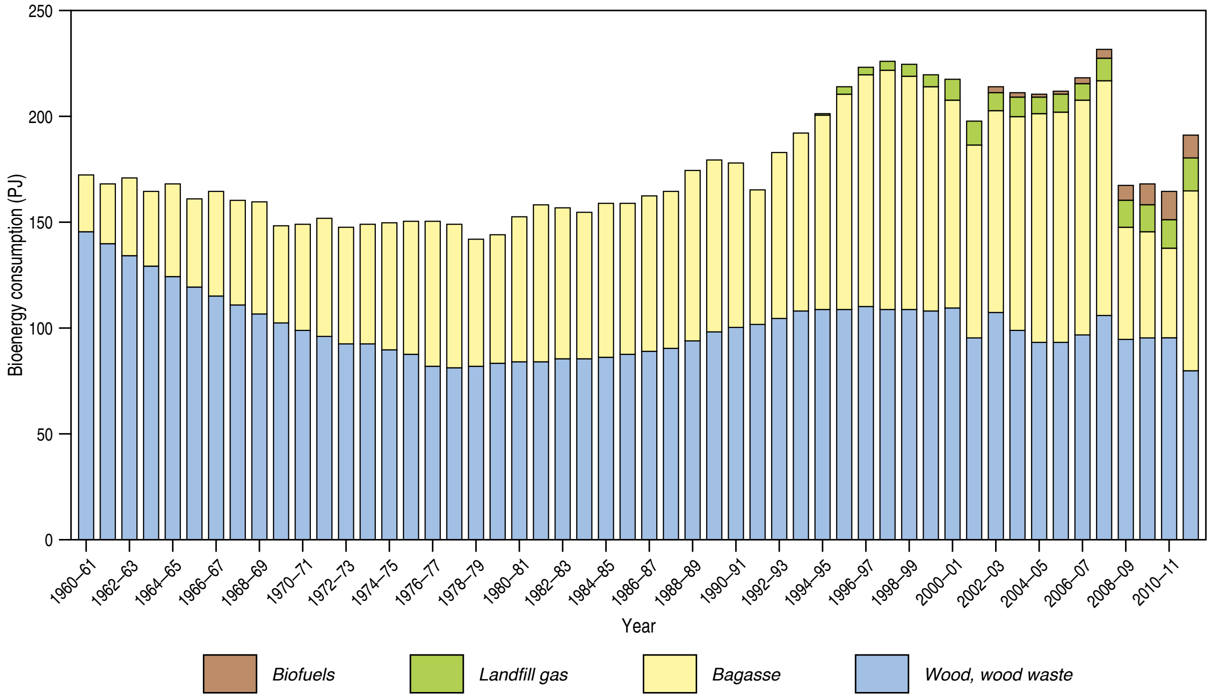

Figure 12.9 Australia's primary consumption of bioenergy

Source: BREE 2012a

production and consumption of bioenergy are the same, because there is currently only very small trade of bioenergy. Between 2000–01 and 2011–12, bioenergy use declined at an average rate of 1.8 per cent a year. The use of bioenergy was low between 2008 and 2011 due to reduced use of wood, wood waste and bagasse in the electricity generation sector.

The majority of Australia's bioenergy is from wood and wood waste and bagasse. Australia's use of wood and wood waste, predominantly for direct heat application, has generally declined over time. In the 1960s wood use represented between 70 and 85 per cent of total bioenergy use, but as bagasse use expanded, this share declined to 55–65 per cent in the 1970s and remained relatively constant in the 1980s and 1990s.

In 2011–12, wood and bagasse represented 42 per cent and 44 per cent of bioenergy use, respectively. Liquid biofuels represented 8 per cent of total bioenergy use and landfill and sewage gas comprised the remaining 6 per cent (figure 12.9).

Bioenergy use, by industry

Industry accounts for around 60 per cent of Australia's final bioenergy use, largely bagasse use in the food and beverages sector. The residential sector accounting for a further one third of bioenergy use, predominantly wood used for heating (figure 12.10). There are also small amounts of bioenergy used in the road transport sector as ethanol and biodiesel.

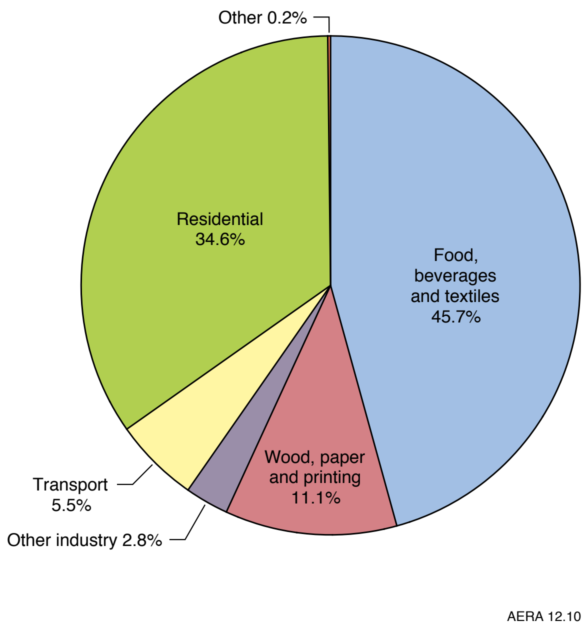

Figure 12.10 Australian bioenergy use, by industry, 2011–12

Source: BREE 2013

Electricity generation

In 2011–12, electricity generation using bioenergy was 2.3 TWh, representing around 0.9 per cent of total electricity generation (figure 12.11).

Australia's electricity generation from bioenergy sources increased between 1989–90 and 2011–12 at an average rate of 5.3 per cent per year. Since 2007–08, bioenergy electricity generation has declined by 16 per cent a year mainly due to the falling bagasse consumption in the food, beverage and textile industry (figure 12.9).

The total capacity of electricity generation from bioenergy represented 7.5 per cent of installed renewable electricity generation capacity in 2012. Bagasse-fuelled electricity generation facilities represent over 50 per cent of total bioenergy capacity, at 475 MW. These facilities are located mostly in Queensland sugar production near plants (table 12.5).

In contrast, biogas-fuelled plants at landfill and sewage facilities are located near major urban centres across Australia. There are landfill and sewage sites in all states and territories, comprising a total installed capacity of 215 MW. Wood waste and other bioenergy facilities represent 1.4 per cent of renewable energy capacity and have a total capacity of 148 MW (table 12.5).

Transport biofuels

Australian biofuels production increased by about 74 per cent between 2004–05 and 2010–11 to 12.9 PJ (figure 12.12). Biofuel production declined to 10.6 PJ in 2011–12.

In 2011–12, Australia's ethanol production is estimated at 316 ML and biodiesel production at 85 ML. Ethanol production has increased as a result of the Dalby plant in Queensland and a small expansion at the Manildra plant in New South Wales. Biodiesel production fell slightly from 2006–07 to 2007–08, due to three plants temporarily halting production in 2007 and 2008 (table 12.6).

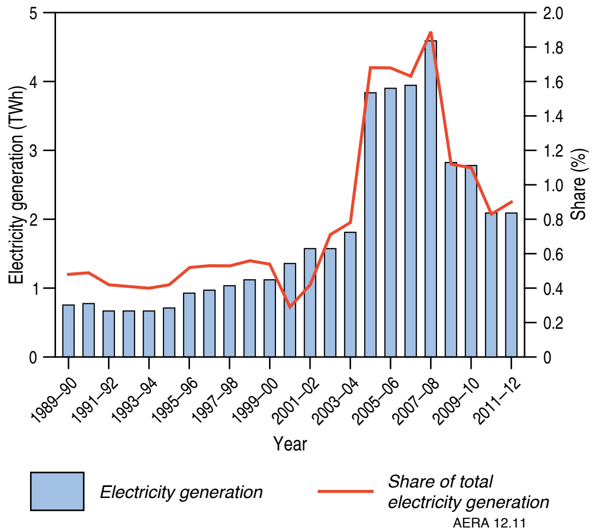

Figure 12.11 Australian electricity generation from bioenergy

Source: Bureau of Resources and Energy Economics

There are currently three major ethanol plants in operation. The largest operator is Manildra Group in New South Wales with total production capacity of 300 ML. Five major biodiesel plants are in production with a total production capacity of 305 ML. The total operating biofuels production capacity in Australia is around 745 ML a year (table 12.7).

Recent bioenergy projects

Since January 2010, six small-scale bioenergy projects have been commissioned in Australia (table 12.8). No biofuel facilities have been commissioned since January 2010.

Table 12.5 Capacity of electricity generation from bioenergy, 2011

	Biogas (MW)	Bagasse (MW)	Wood waste (MW)	Other bioenergy[c] (MW)	Total bioenergy (MW)
New South Wales[a]	75	75	38[b]	24	**212**
Victoria	58	0	0	55	**113**
Queensland	29	394	15	5	**443**
South Australia	20	0	10	0	**30**
Western Australia	27	6	1	0	**34**
Tasmania	5	0	0	0	**5**
Northern Territory	1	0	0	0	**1**
Australia	**215**	**475**	**64**	**84**	**838**
Share of total renewable electricity capacity (%)	2	4	0.6	0.8	**7.5**

a Includes the ACT. **b** Including 15 MW from co-firing wood waste in coal power plant. **c** Unspecified biomass and biodiesel

Source: Clean Energy Council 2012

Table 12.6 Biofuels production in Australia

	2005–06	2006–07	2007–08	2008–09	2009–10	2010–11	2011–12
Biodiesel (ML)	21	54	50	86	69	96	85
Ethanol (ML)	42	84	149	203	276	319	316
Total (ML)	63	138	199	289	345	415	401

Source: Department of Industry

Table 12.7 Liquid biofuels production facilities in Australia, as at 1 January 2012

Location	Capacity (ML/yr)	Feedstocks
Fuel ethanol		
Manildra Group, Nowra, NSW	300	Waste wheat starch, some low grade grain
Dalby Bio-refinery, Dalby, QLD	80	Sorghum
CSR Ltd, Sarina, QLD	60	C-molasses
Total	**440**	
Biodiesel		
Smorgon Fuels, Melbourne, VIC	100	Dryland juncea (oilseed crop), tallow, used cooking oil, vegetable oil
Australian Renewable Fuels Ltd, Wodonga, VIC	60	Tallow, used cooking oil
Australian Renewable Fuels Ltd, Adelaide, SA	45	Tallow, used cooking oil
Australian Renewable Fuels Ltd, Picton, WA	45	Tallow, used cooking oil
Consolidated Bio diesel	30	Tallow, used cooking oil
Biodiesel Industries Australia, Maitland, NSW	20	Used cooking oil, vegetable oil
Various small producers	5	Used cooking oil, tallow, industrial waste, oilseeds
Total	**305**	

Source: Biofuels Association of Australia 2012

Table 12.8 Bioenergy projects commissioned since 1 January 2010

Project	Company	State	Bioenergy resource	Start-up	Capacity (MW)
Victoria	Sucrogen	QLD	Bagasse	2011	19.0
Woodlawn	Veolia Environmental Services	NSW	Landfill methane	2010	1.06
Buttonderry	Landfill Management Services Ltd	NSW	Landfill methane	2010	1.1
Birkdale	Landfill Management Services Ltd	QLD	Landfill methane	2010	0.75
Melton	Western Water	VIC	Sewage methane	2010	0.2
Leongatha Dairy Plant	Quantam Bioenergy Ltd	VIC	Agricultural waste	2010	0.76

Source: Clean Energy Council 2012

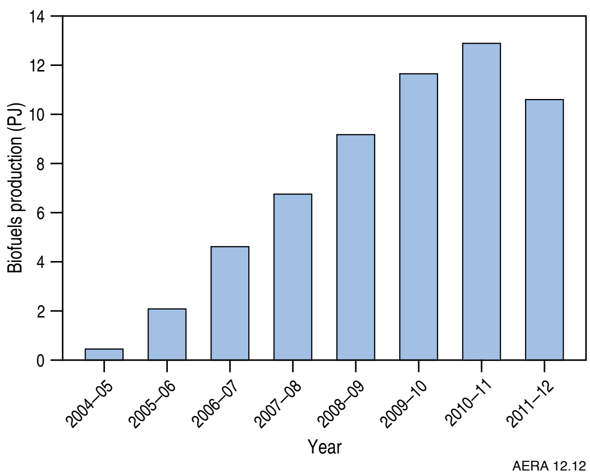

Figure 12.12 Australian biofuels production

Source: Bureau of Resources and Energy Economics

12.4 Outlook for Australia's bioenergy resources and market

There is significant potential to expand the use of biomass for electricity, heat and transport biofuels production. There is a diversity of bioenergy resources and conversion technologies that can provide greenhouse gas emissions savings and reduce waste disposal issues. There may be opportunities for the bioenergy sector to support agricultural industries and rural communities through growing complementary energy crops and in developing regional energy facilities.

12.4.1 Key factors influencing the outlook

The future growth of Australia's bioenergy industry will depend on its competitiveness against other energy sources, the commercialisation of efficient conversion technologies and availability of bioenergy resources.

The cost competitiveness of bioenergy with alternative electricity generation and transport fuels will depend on the cost of resources (both bioenergy and alternatives), conversion technologies and relevant government policies, particularly those that affect both the availability of resources and their price.

Cost factors aside, the growth of the bioenergy industry will be influenced by the commercialisation of second generation technologies, which will also increase the range of bioenergy resource options and reduce competition for resources between bioenergy resources and agricultural and forestry commodities. Development of effective harvesting and processing methods and improved transportation and storage will also be important factors in achieving efficiencies in bioenergy production.

Availability of biomass will be central to the expansion of the bioenergy sector. The availability of biomass is influenced by:

- diversion of current biomass production and waste and residues streams. Biomass residues from forestry, agricultural harvest and processing, and waste streams, such as landfill and sewage gas, offer a large under-utilised energy resource, which can also assist in waste disposal issues
- change in harvesting regimes for crops or forests (e.g. stubble from agricultural lands and thinnings from forests)
- new production systems which may include land use change, in turn influenced by available land, crop or forest types and productivity. The amount of land available for biomass depends on the amount of land used for agricultural and forestry products and that devoted to nature reserves. The demand for food, which is a function of population and diet, has a direct impact on land use and availability to grow primary biomass resources for bioenergy. The amount of biomass produced is a function of the quality of the land, the climate, water availability and management practices.

There are potential risks in the expansion of biomass production into areas that provide valuable ecosystems that support high biodiversity and may result in nutrient pollution.

Cost competitiveness

Bioenergy production costs are a function of biomass resources, labour, transportation, capital and operating costs.

The cost of biomass resources depends on whether it is a primary biomass (energy crop) or residue biomass from an agricultural, forestry or urban activity. Cost variations are due to input and harvest costs from production systems. Solid biomass can be bulky, difficult to handle and transport, and may decay over time.

On-site pre-processing of materials, such as chips or wood pellets, may increase the labour and processing costs, but reduce transport and storage costs.

Bioenergy becomes a competitive alternative in situations where cheap or 'negative-cost' residues or wastes are available and used on-site (IEA Bioenergy 2007). The most economical bioenergy production model is the production of energy at the biomass location such as at landfill and sewage sites, paper mills, sawmills or sugar mills. In Australia, a large proportion of bioenergy production occurs in small to medium cogeneration plants built at sugar mills and other food processing plants that have access to significant low-cost biomass waste streams.

Bioenergy has the benefit of being easily integrated with conventional energy by co-firing wood chips or pellets with coal, and adding biofuels to transport fuels (REN21 2012).

Electricity and heat generation

Electricity and heat generation through biomass combustion is a mature, efficient and reliable technology. In cases where low-cost biomass resources are available for co-firing schemes, electricity and heat production from bioenergy are approaching market competitiveness with conventional energy generation (IEA Bioenergy 2013).

An assessment of the electricity generation costs from biomass was undertaken by IEA (2011a), which provides a comparison for three biomass power plant types. For large-scale (>50 MW) biomass power plants, electricity generation can be at high efficiencies and relatively low costs. Co-firing biomass in coal-fired plants provides an opportunity for short-term and direct reduction of emissions, so avoiding the 'carbon lock-in effect'. Middle-scale (10 to 50 MW) plants have moderate electric efficiencies and costs. The electricity generation cost also depends on biomass types. Small-scale (<10 MW) plants have lower electric efficiencies and higher generation costs, and are best deployed in combined heat and power mode, when a sustained heat demand from processes or district heating is available. For small- and middle-sized power stations, it is more expensive to use collected fuels as bioenergy resources than residues. For large power stations, it is more expensive to use residues as bioenergy resources than collected fuels (table 12.9).

A relatively low capital cost option for improving system efficiency and reducing carbon emissions is retrofitting of co-firing boilers with biomass delivery systems. Total costs vary depending on the type and condition of the boiler being modified and the biomass delivery system, with separate feed systems costing up to four times as much as a blended delivery system (Grabowski 2004). In the United States, the annual fuel costs are often lower in co-firing plants than in plants burning pure coal. These annual savings can result in payback periods on initial investment of less than 10 years. In addition, the use of biomass as a supplementary fuel in coal-fired plants reduces sulfur dioxide and nitrogen oxide emissions (EESI 2009a).

Table 12.9 Electricity generation costs for biomass power plants

Size of power plant	Feedstock	Electricity generation cost (US cents/kWh)
<10 MW	Residues	10.2 to 17.9
	Collected fuels	17.4 to 35.9
10 to 50 MW	Residues	6.4 to 16.5
	Collected fuels	10.2 to 22.8
>50 MW	Residues	7.9 to 16.1
	Collected fuels	5.7 to 9.9

Source: IEA 2011a

Transport biofuels

The main component of biofuels production costs is the cost of feedstock, which varies considerably according to the type of feedstock used. Cost of biofuel production from sugar and starch is very sensitive to the feedstock prices, which can be volatile (IEA 2011b). Low-cost biofuels can be produced from crops grown in the most suitable climate zones and using commercially available technologies, such as ethanol from sugar cane grown in tropical regions. Ethanol production costs vary from US$0.20 to US$1.02 subject to the location and the feedstock used. Ethanol produced in Brazil from sugar cane costs about US$0.68 per litre, whereas in the United States ethanol produced from corn costs about US$0.40 per litre (REN21 2012).

The production cost of first generation biofuels in Australia is highly variable due to variations in the cost of feedstock.

In Australia, expansion and construction of first generation biofuel facilities were planned in 2007 as a result of government subsidies and high oil prices. However, many of these plans were postponed due to high feedstock prices and falling crude oil prices at the end of 2008. Uncertainty about future changes in oil and feedstock prices continues to restrict investment in new capacity.

The development of second generation (advanced) biofuels from lignocellulosic biomass will not only increase the range of low-cost feedstocks but will increase conversion efficiencies and lower production costs. Several second generation biofuel pilot and demonstration plants are operating in the United States and the European Union (IEA 2011b).

The main cost factor for first generation biofuels is the feedstock, which accounts for 45 to 70 per cent of total production costs, whereas for second and third generation biofuels the main factor is capital costs (IEA 2011b). In a low-cost scenario with minimal impact of rising oil prices on biofuel production, costs falls slightly. The 2050 projection for first generation biofuels is around US$0.60 per litre gasoline equivalent (Lge) for ethanol, and around US$0.90 per Lge for biodiesel (IEA 2011b). However, in a high-cost scenario with oil prices having a greater impact on feedstock and production costs, first generation biofuels will remain slightly more expensive than gasoline or diesel. The projected costs for 2050 are ethanol to increase to more than US$0.70 per Lge, and biodiesel to increase to about US$1.20 per Lge (IEA 2011b).

The IEA's 2050 projection of second generation biofuel production cost is estimated to be less than US$1.00 per Lge (IEA 2011b). The low-cost scenario for second generation production costs is estimated to be less than US$0.80 per Lge. The long-term production costs for second and third generation biofuels will depend on improvement in technologies and techniques, up-scaling of production facilities and lower feedstock cost using biomass residues.

Technology developments—more efficient, using a greater range of non-edible biomass resources

There is a range of technologies currently available and in development for converting biomass into energy (box 12.1). Energy is released either in the form of heat or is converted into another energy form such as liquid biofuels or biogas.

Electricity and heat generation

Electricity and heat are generated by combustion, cogeneration and gasification of biomass and from methane gas captured from landfill and sewage facilities. The burning of solid biomass is the dominant method of energy conversion for electricity and heat production. Increased efficiency can be gained through fluidised bed combustion and co-firing of biomass (e.g. wood residue) with coal. There is potential to increase bioenergy production through utilisation of under-exploited biomass residues and wastes from forestry and wood processing facilities. These residue and waste resources, if used more effectively, can assist in the reduction of greenhouse gas emissions.

Transport biofuels

First generation biofuels are mainly produced from sugar and starch by-products, grain oil crops, used cooking oil or animal fat (box 12.2). Given the limited supply of these feedstocks in Australia, first generation biofuels will not be able to supply a large proportion of transport fuel needs until second generation technologies become commercially viable.

BOX 12.1 BIOENERGY TECHNOLOGIES FOR ELECTRICITY AND HEAT GENERATION

Thermal conversion uses heat as the dominant mechanism to convert biomass to energy. Combustion is the simplest method by which biomass can be used for energy and has been used for millennia to provide heat. Conventional combustion technologies involve biomass being burnt in the presence of air in a boiler to generate heat to produce hot air, hot water or steam, which is used in a steam turbine to generation electricity.

Combustion technologies

The three main biomass combustion conversion technologies are grate boilers, fluidised bed combustion (gasification) and co-firing in utility boilers.

Grate boiler technology is the oldest combustion principle and was the most common design of small-sized boilers. It remains popular for relatively small boilers (less than 5 MW) in countries using fuels such as wood pellets, straw and municipal solid waste (IEA 2008).

Fluidised bed combustion uses upward-blowing jets of air to suspend solid fuels during the combustion process for increased efficiency. The process controls the supply of oxygen and/or steam. The biomass is devolatilised and combusted to produce a biogas that can be burnt for heat or used in a gas turbine for electricity generation.

There are two main technologies: bubbling fluidised bed (BFB) and circulating fluidised bed (CFB) technologies. BFB combustion offers better temperature control and is more suitable for non-homogeneous biomass. CFB combustion uses pulverised fuel that does not require a high-temperature flame and allows better control of the furnace temperature.

Co-firing refers to the simultaneous combustion of a biomass resource and a base fuel (e.g. coal) to produce energy. The most common biomass resources include low-value wood, crop-residues and municipal waste. Most biomass resources must undergo processing before they can be utilised for co-firing (EESI 2009b). Processed solid biomass is added to the co-fired boilers along with the fossil fuel. It helps reduce reliance on a finite resource and can make a significant contribution to CO_2 emission reductions (Massachusetts Technology Collaborative 2009).

Biomass co-firing in modern, large-scale coal power plants is efficient and can be cost effective. The technique has been successfully demonstrated in more than 150 installations worldwide. About 100 of these are operating in Europe, around 40 in the United States and a few in Australia. A number of fuels such as crop residues, energy crops and woody biomass have been co-fired. The proportion of biomass in the fuel mix has ranged between 0.5 and 10 per cent in energy terms (IEA 2008).

For co-firing of up to 10 per cent of biomass mixed with coal or fed through the coal-feeding system, only minor changes in the handling equipment are needed. For biomass exceeding 10 per cent, or if biomass and coal are burned separately, changes in mills, burners and dryers are needed.

The development of biomass fuel preparation and drying technologies, such as torrefaction (thermochemical treatment that lowers the moisture content and increases the energy content) and pelletising of biomass, increase the efficiency of plants. In addition, the biomass is compact, stable and easier to transport, store and handle.

Wood pellets are rapidly becoming an important source of fuel for co-fired plants. Wood pellets or densified biomass fuel are manufactured from low-value trees and from sawdust and other pulp waste. Wood pellets are increasingly used as a renewable fuel for power generation in countries such as Japan, Canada, South Africa and particularly in Europe. Much of the new generation capacity in Europe is based on dedicated pellet-fuelled combined heat and power plants. European production has been based on both scarce sawmill waste and, increasingly, imports. In Australia, wood pellet use remains limited but supply to the domestic and export markets is expected to increase.

Cogeneration technology

In the most efficient electricity generation plant, around 30 per cent of the energy in the biomass is converted into electricity; the rest is lost into the air and water. Cogeneration or combined heat and power plants have greater conversion efficiencies because they produce both electricity and process heat.

There is a number of different types of cogeneration technology. For many years, all cogeneration installations were based on the use of conventional boilers, with steam turbines for electricity generation. Gas turbine technology has largely superseded steam turbine technology for medium-sized installations. Bagasse, sludge gas from sewage treatment plants and methane from landfill sites are used as fuel in cogeneration plants. Where a cogeneration plant is powered by waste gases, fugitive gases are captured and utilised to drive gas turbines which in turn generate electricity. In Australia, sugar mills run cogeneration plants which are fuelled by bagasse left over after crushing the sugar cane.

Trigeneration technology

Trigeneration technology provides cooling in addition to heat and electricity generation. The process waste heat can be usefully applied for heating in winter and, via an absorption chiller or refrigation, for cooling in summer. Refrigeration and air-conditioning normally require a compressor driven by electricity. The absorption chiller uses a heat source to provide energy to drive the cooling system. The combination of technologies to convert waste heat into cooling can reduce peak summer electricity consumption and greenhouse gas emissions from air-conditioning by about 25 per cent.

A small-scale trigeneration option is an organic Rankine cycle (ORC) engine, which uses an organic fluid with a low boiling point, rather than steam, and hence has a lower cost in gathering heat. A biomass-fired ORC trigeneration system is able to generate electricity and provide heating and cooling demands.

Gasification and pyrolysis technologies (thermochemical processes)

The use of gasification is more efficient for energy recovery in terms of electricity generation than traditional combustion. In gasification, solid biomass is heated to high temperatures (800–1000°C) in a gasifier and converted to a syngas primarily composed of hydrogen, carbon monoxide, carbon dioxide, water vapour and methane. There are lower amounts of sodium oxide, nitrous oxide and dioxin emissions than in a traditional combustion process.

The syngas can be used in combustion engines (10 kW to 10 MW) with efficiency of 30 to 50 per cent in gas turbines or combined cycles (IEA 2007a). Biomass integrated gasification/gas turbines are being developed. Tar elimination is one of the areas of research expected to be overcome in the medium term. The first integrated gasification combined cycle plant running on 100 per cent biomass (straw) has been successfully operated in Sweden.

Pyrolysis is thermal degradation of biomass to produce bio-oil, syngas and charcoal at medium temperatures (350–800°C) in the absence of air. Pyrolysis encounters technical difficulties which have prevented its implementation on a commercial scale. These include effective heat transfer between the heat carrier and biomass particles or the quenching of vapours to stop further reactions that result in bio-oil quality variations.

Anaerobic digestion technology

Anaerobic digestion is a technique used for producing biogas that is used commercially worldwide, especially for waste effluents such as waste water, sewage sludge and municipal solid waste. Anaerobic bacteria digest organic material in the absence of oxygen and produce biogas. Anaerobic processes can be managed in a digester or airtight tank or covered lagoon. There is increasing use of this technology in small-scale, off-grid applications at the domestic and farm scale.

In modern landfill sites, methane production ranges between 50 and 100 kilograms per tonne of municipal solid waste. In general, some 50 per cent of biogas can be recovered and used for power and heat generation. After purification and upgrading, biogas can be used in heat plants and stationary engines, fed into the natural gas grid or used as a transport fuel (compressed natural gas) (IEA 2007b).

Second generation biofuels are the subject of active research, development and demonstration (box 12.2). They are produced from lignocellulosic feedstocks such as crop and forest residues and wood processing wastes, which do not compete directly with food crops. In Australia, second generation biofuels show promise for making a greater contribution to transport fuel supply, but this is dependent on sustainable production of biomass at a competitive cost (Wild 2009).

The farming of algae to produce biofuels is an area of active research worldwide. Algae cultivation is not new technology—it has been used to produce food supplements such as beta-carotene and spirulina. Both micro-algae and macro-algae (e.g. seaweed) are being investigated as feedstocks for biofuels. Algae can be grown on non-arable land, in salinewater and in wastewater and has a high oil yield. Micro-algae can fix CO_2 from the atmosphere, power plants, industrial processes and soluble carbonate; however, only a small number of micro-algae are tolerant to high levels of sulfur oxides and nitric oxides present in flue gases. There are challenges limiting the commercial development of algae biofuels such as algae species that balance the requirements of biofuel production; equipment and structures needed to grow large quantities of algae; and the negative energy balance after accounting for water pumping, harvesting and extraction.

Research is being undertaken into production systems such as open ponds and closed-loop systems, algal strains and fertilisation with nutrients and CO_2. Open-pond systems (e.g. sewage ponds) require an algae strain that is resilient to wide swings in temperature and pH, and competition from invasive algae and bacteria. In a closed system (not exposed to open air), also referred to as a photobioreactor, nutrient-laden water is pumped through plastic tubes that are exposed to sunlight. Photobioreactors have several advantages over open systems by reducing contamination by airbourne organisms, having controlled conditions (pH, light, temperature and CO_2) and preventing water evaporation.

In Australia, there are a number of R&D projects investigating biofuel technologies. In Victoria, the University of Melbourne is researching efficient separation, processing and utilisation of algal biomass. Algal Fuels Consortium is developing a pilot-scale biorefinery in South Australia for sustainable micro-algal biofuels. In December 2010, Muradel Pty Ltd was incorporated as a joint venture between Murdoch University, Western Australia, Adelaide Research and Innovation Pty Ltd and SQC Pty Ltd. Muradel is working on all steps in the process of micro-algal biofuels production, from micro-algae culture, harvesting of the algae and extraction of oil for biofuels production. A pilot plant to test the whole process on a larger scale in Karratha, north-west Western Australia has been operational since November 2010. United States biofuel producer, Aurora Algae, has built a demonstration facility that will produce 12–15 tonnes of algal biomass per month within six 4000 m^2 ponds at Karratha. The company plans to develop a commercial-scale plant at nearby Maitland capable of producing up to 600 tonnes of biomass per month.

Third generation technologies are in the R&D stage. The technology involves the development of lignocellulosic biorefineries that produce large volumes of low-cost biofuel and the overall process is supported through the production of bioenergy and high-value bioproducts. Internationally there is commercial and R&D interest in developing bio-based products from biorefineries. The National Renewable Energy Laboratory in the United States is involved with six major biorefinery development projects that are focused on integrating the production of biomass-derived fuels and other products in a single facility (National Renewable Energy Laboratory 2009).

Currently in Australia, only a few companies are pursuing the lignocellulosic biorefinery model. The Oil Mallee project successfully uses mallee eucalypts for producing eucalyptus oil, activated carbon and bioenergy from a 1 kW integrated wood processing demonstration plant in Narrogin, Western Australia. The mallee eucalypts are planted as a complementary crop on land used for growing grain. The re-sprouting ability of the mallee eucalypts allow for coppicing (harvesting of branches) every second year indefinitely without replanting. It also provides an environmental benefit as the deep mallee roots soak up groundwater and assist in mitigating dryland salinity (Oil Mallee Association 2012).

The Australian Government is supporting the development of biofuel technologies in Australia. Five projects were successfully completed in 2012 under the Second Generation Biofuel Research and Development (GEN 2) Program. The Australian Renewable Energy Agency (ARENA) Advanced Biofuels Investment Readiness (ABIR) program provided grant funding to selected projects undertaking activities that build the investment case for scalable pre-commercial demonstration biofuel in Australia. The program has closed.

The ABIR program provided funding to:

- James Cook University (A$5 million) to research, develop and demonstrate Australia's first freshwater and marine macro-algae to biofuels project in February 2012
- Licella Pty Ltd (A$5.4 million) to assess the feasibility of constructing its first pre-commercial biofuel plant
- Muradel Pty Ltd (A$4.4 million) to demonstrate its algal biofuel technology in February 2013.

Biomass resources—reliable and environmentally sustainable supply

Biomass production is a significant potential source of renewable energy that can provide greenhouse gas reduction benefits when replacing fossil fuels. However, a key factor in the growth of the bioenergy sector is the sustainable management of biomass exploitation and the avoidance of negative environmental impacts of bioenergy resource production.

The expansion of the bioenergy industry can provide greenhouse gas savings and other environmental benefits, such as improved biodiversity as well as opportunities for

BOX 12.2 BIOFUEL TECHNOLOGIES FOR TRANSPORT

Conversion technologies use a range of biochemical and thermochemical processes to convert biomass into biofuels.

First generation technologies use conventional processes: fermentation of sugar and starch crops for ethanol production and trans-esterification of oilseed crops, used cooking oil or animal fat (e.g. beef tallow) for biodiesel. The chemical reaction (trans-esterification) involves reaction of an oily feedstock with an alcohol (methanol or ethanol) and a catalyst to form esters (biodiesel) and glycerol.

Advances in first generation biofuels are focused on feedstocks, such as genetically modified crops, new non-edible oilseeds and new sugar (agave) crops. The use of non-edible oilseed plants, such as jatropha, has been explored as potential feedstock in Asia and some African countries. Jatropha production may be expanded without directly competing with natural forests or high-value agriculture lands used for food production, as it can grow on less fertile land (FAO 2013). In Australia, jatropha is banned as it is an invasive plant. However, there is potential for using other non-edible oilseed plants (e.g. pongamia and karanja).

Second generation technologies use biochemical and thermochemical processes to convert lignocellulosic and algae feedstocks to biofuels. Biochemical processes use enzymes and micro-organisms to convert feedstocks to sugar prior to fermentation to produce ethanol, butanol or potentially other fuels. Thermochemical processes use pyrolysis and gasification technologies. Pyrolysis processes produce bio-oil, syngas and biochar. The bio-oil is unstable and requires further refining to produce petrol, biodiesel and other high-value chemicals. Gasification methods produce syngas, which can be further processed using Fischer-Tropsch synthesis to produce syndiesel and aviation biofuels.

In Australia, R&D into second generation technologies and feedstocks for biofuels is being undertaken (section 12.4.3). CSIRO's Energy Transformed Flagship is conducting research into the potential for a sustainable and economically viable second generation biofuels industry. It has a research program covering sustainable biomass production, thermochemical conversion, enzymatic conversion and algal fuels (CSIRO 2009a).

social and economic development in rural communities. The greenhouse gas savings depend on the biomass resource cultivation method, changes in land use, the quantity of fossil fuel inputs and the technology used. Waste and residue biomass does not require significant energy input and generally has lower greenhouse gas emissions when compared to energy crops.

However, the expansion of bioenergy production creates some challenges, such as potential competition for land use, and biomass use for food and stockfeed and potential impacts on biodiversity. As already noted, the availability of biomass is also influenced by population growth, diet, water availability, agricultural density and the environment (Hoogwijk 2006).

Energy crops are dependent on land being available that is not being used for forestry, and agriculture, environmental protection or urban areas. The amount of biomass produced (crop productivity) is a function of the quality of the land, the climate, water resources and management practices. Increased use of fertilisers and pest control to improve crop yields may lead to increased pollution from nutrients, biocides and pesticides.

Residues from forests and wood processing and organic waste streams are large untapped resources, and effective and sustainable use of these resources can make a contribution to energy supply while reducing waste disposal problems and avoiding the potential environmental impacts of dedicated bioenergy crops.

Electricity and heat generation

In Australia, bioenergy for electricity and heat generation is produced predominantly from by-products of sugar production and waste streams. Future energy crops may include tree crops, woody weeds and algae as well as expansion into crop and food residues. The main factors are technology costs, reliable supply and consistent quality of biomass.

In urban regions, capturing waste gas from landfill and sewage facilities provides dual benefits of generating bioenergy and eliminating methane emissions. The waste stream supplies to these facilities are relatively constant and if waste gases are not collected and used for bioenergy production, the gas would be flared or vented into the atmosphere. Generation of electricity and heat from biogas will reduce emissions and can replace the use of fossil fuels as clean, cost effective, renewable energy.

Similarly, conversion of animal wastes to biogas can also provide energy and reduce environmental problems associated with animal wastes. The anaerobic digestion process can control manure odour and reduce harmful water run-off.

The Berrybank piggery near Ballarat, Victoria has a 0.225 MW plant that has been generating 3.5 MWh of electricity per day from animal manure since 1991. The Clean Energy Council (2008) estimates that about half of the existing pig herd in Australia is at piggeries of sufficient scale to allow economic implementation of energy generation from the waste stream, with a long-term potential from this industry of about 200 gigawatt-hours (GWh) per year.

Forestry and agricultural residue and wood waste bioenergy plants rely on a constant supply and consistent grade of biomass. Wood waste for electricity generation is predominantly used by co-fired coal plants. Forest residues, wood process wastes and municipal solid wastes have the potential to be used as lignocellulosic feedstock in second generation technologies.

Transport biofuels

First generation biofuels from energy crops are constrained by the amount of land available and the limited supply of sugar and starch by-products, animal fats and used cooking oil feedstocks. For biofuels to contribute significantly to transport fuel consumption, a large proportion of arable land would have to be devoted to energy crops production. In 2004, the world land requirements for biofuel production was about 1 per cent (13.8 million hectares), and based on trends the forecast land requirements by 2030 is 2.5 per cent (34.5 million hectares; FAO 2008).

First generation biofuels from energy crops require sustainable agricultural practices to minimise environmental impacts. The adoption of crop rotation with an energy crop diversifies the crops grown, which can improve the land for traditional cropping and provide a high-value crop (FAO 2013). In Australia, biofuel production is currently too low to affect the production of agricultural commodities.

Second generation biofuels will be produced from specialised energy crops, such as tree crops and algae, as well as from residue and waste streams. The utilisation of residue and waste material for biofuels requires no additional land. Second generation biofuel feedstocks may also be grown on less productive lands and degraded agricultural land to avoid competing directly with growing food, stockfeed and fibre crops (IEA Bioenergy 2008). Some second generation feedstocks, such as algae and oil mallee, do not compete for freshwater resources.

Worldwide, investment in second generation technologies is being undertaken to ensure these characteristics—environmental and economic viability and avoidance of competition for productive land with food and fibre production—are achievable and therefore that the future production of bioenergy can proceed in a sustainable way.

12.4.2 Outlook for bioenergy resources

The bioenergy supply chain is complex because of its interaction with other supply chains such as agriculture and forestry. There is scope to optimise current production systems for the bioenergy market without diverting biomass from current uses (e.g. plantation thinnings). The production of second generation feedstocks on less productive or under-utilised lands could potentially provide economic, environmental and social benefits (O'Connell et al., 2009a). The use of such land may provide opportunities for farmers to diversify existing systems, the development of industries in rural regions, and improvements in biodiversity. Currently, second generation biofuels are not commercially competitive in any country. The transition from first to second generation technologies will require significant R&D investment which, in turn, will only be attracted by an industry with a significant and sustainable future. The industry needs to demonstrate that the potential it offers meets these criteria.

Electricity and heat generation

Currently electricity from bioenergy resources is generated predominantly from bagasse and landfill and sewage sites and to a lesser degree wood waste, pulp and paper mill waste. The Clean Energy Council (2008) identified significant potential for growth in bioenergy production from waste streams, such as landfill and sewage gas and urban waste.

An appraisal of bioenergy resources, primarily waste streams, for stationary energy was undertaken by the Clean Energy Council in 2008 to estimate the potential by 2020 and in the long term (2050). The bioenergy resources are grouped into agricultural-related wastes, energy crops, woody weeds, forest residues, pulp and paper mill wastes, and urban wastes (table 12.10).

Agricultural-related wastes in total are a very large resource but currently are not used as bioenergy resource. The resources are widely dispersed and can have a range of alternative uses including composting and feed for animals.

The sugarcane industry, already one of the few industries self-sufficient in energy through its use of bagasse-fired cogeneration, has the potential to increase electricity generation efficiency with integrated gasification combined cycle technology as well as biomass expansion to include sugarcane trash, tops and leaves.

Crop residues from grain and cotton crops are a potential resource. However, crops can be subject to large annual variations of quantities produced due to environmental and climatic factors. An option to reduce the variability of resources is to process a wide range of biomass material such as residues from grain, rice, cotton crops and leftover plant matter from vegetables and fruits.

The potential estimated stubble residues that can be collected, taking into account that a proportion of the crop is left on the land for maintenance of soil health, is estimated to be 24 Mt per year. However, the high cost of transport of a highly dispersed resource means that there will be little or no contribution from this sector to 2020. For this sector to contribute to energy production there needs to be further investigation of energy conversion processes (e.g. gasification and pyrolysis) and ways to reduce transport costs. A long-term estimate of potential energy is 47 000 GWh per year (Clean Energy Council 2008).

Large-scale livestock feedlots, piggeries, dairy and poultry farms with their mixed waste streams of animal bedding and manure are suitable for generating bioenergy. Waste material can be used to produce stationary energy and assist in reducing environmental problems from waste disposal, methane emissions and pollution of water supplies.

The Clean Energy Council estimated that the long-term potential for feedlot cattle and piggeries is about 440 GWh per year and 200 GWh per year, respectively. However, there are uncertainties with moisture content and suitability for combustion or anaerobic digestion. Poultry farm waste is estimated to have a long-term potential in the range of 840 GWh per year. This estimate does not take into account that some operations may be too small to be viable or that poultry manure is used for fertiliser.

In addition, there is also the potential of solid wastes from abattoirs. The Clean Energy Council indicated that there are approximately 0.77 Mt to 1.8 Mt per year of solid waste produced from about 150 abattoirs. If, by 2020, 30 abattoirs implement anaerobic digestion cogeneration plants, these projects have the potential to produce about 340 GWh per year, with a long-term estimate of about 1770 GWh per year.

Native forest wood waste is assumed to remain relatively constant; however, the potential from plantation wood waste should increase in line with plantation expansion. Australian governments, at all levels, have established regulatory mechanisms concerning the eligibility for forest wood waste for electricity generation in order to manage the sustainable use of these products.

Urban waste, including food, garden, urban timber, paper and cardboard wastes, is steadily growing and has significant potential for energy generation. The decomposition of these wastes in landfill results in methane generation, which is not appropriately captured and utilised, particularly in older and smaller landfill sites. In 2002–03 approximately 9.5 Mt per year of organic urban waste was sent to landfill. The potential electricity generation for 9 Mt of urban waste is 103 GWh, with a long-term estimate of about 4300 GWh (Clean Energy Council 2008).

There is potential for growth of biogas power generation from landfill sites and sewage treatment plants in urban and rural centres for local use. Converting biogas to energy would provide dual benefits of energy supply and reduced greenhouse gas emissions. If these wastes are not collected and used for bioenergy production, the gas would be flared or vented into the atmosphere.

There are a number of potential energy crops that may provide fuel for future bioenergy as well as providing environmental benefits. The integration of complementary energy crops and woody perennials into existing agricultural systems may be beneficial to the overall productivity of the land.

Table 12.10 Potential for stationary bioenergy generation in Australia

Biomass	Quantity as at 2005–06	Conversion technologies	2010 Electricity generation (GWh/yr)	2020 Electricity generation (GWh/yr)	2050 Electricity generation (GWh/yr)
Agricultural-related wastes					
Poultry	94 384 000 population	AD/RGE		90	848
		P		207	207
Cattle (feedlots)	870 025 population	AD/RGE, DC/ST		112	442
Pigs	1 801 800 population	AD/RGE	1	22	205
Dairy cows	1 394 000 population	AD/RGE		22	89
Abattoirs	1 285 000 t	AD/RGE		337	1773
Nut shells		DC/T	1		1
Stubble residues from grain and cotton crops	24 000 000 t	DC/ST, G/GT, P			47 000
Bagasse (sugarcane residue)	5 000 000 t	DC/ST	1200	3000	4600
Sugarcane trash, tops and leaves	4 000 000 t	DC/ST		165	3200
Energy crops					
Algae		AD/RGE, P			
Oil mallee		DC/ST, G/GT, P		112	484
Woody weeds					
Camphor laurel		DC/ST, G/GT, P		83	20
Forest residues					
Native forest (public and private)	2 200 000 t	AD/RGE, DC/ST, briquetting and pelletising, G/GT, charcoal production, co-firing	79	2442	4554
Plantation (public and private)	3 800 000 t				
Sawmill and wood chip residues	2 800 000 t				
Pulp and paper mills wastes					
Black liquor		DC/ST	285	365	365
Wood waste		DC/ST	60	85	85
Recycled paper wet wastes		AD/RGE	2	8	8
Paper recycling wastes		DC/ST	12	48	48
Urban waste					
Food and other organics	2 890 000 t	AD/RGE	13	126	565
		DC/ST	16	141	189
Garden organics	2 250 000 t	P		37	186
		AD/RGE	29	84	275
Paper and cardboard	2 310 000 t	DC/ST			1548
		P		38	191
Wood/timber	1 630 000 t	DC/ST	45	295	1366
Landfill gas	9 460 000 t	Spark ignition engine, co-firing, flaring	772	1880	3420
Sewage gas	735 454 t	AD/RGE, DC/ST	57	901	929

AD = anaerobic digestion; **DC** = direct combustion; **G** = gasification; **GT** = gas turbine; **P** = pyrolysis; **RGE** = reciprocating gas engine; **ST** = steam turbine

Source: Clean Energy Council 2008

The Oil Mallee project in Western Australia successfully demonstrated the use of mallee eucalypts to produce eucalyptus oil, activated carbon and generate electricity. Woody weeds, such as camphor laurel, are abundant but either need research into their suitability as feedstock, or are too dispersed in nature to be economical to harvest.

R&D into algae is drawing attention because of its potential high hydrocarbon content, high oil yields and ability to be grown in salinewater and wastewater. Algae grown and harvested from purpose-built ponds and photobioreactors has the potential to be a feedstock for biofuels and power generation.

Transport biofuels

First generation biofuels are not expected to make a large contribution to Australia's future biofuels supply as there is limited availability of low-cost first generation feedstocks. Second generation technologies may provide a greater range of biomass feedstocks and potential greenhouse gas emissions savings. Second generation technologies will use lignocellulosic material, specialised crops such as oil mallee, non-food components of crops and algae.

CSIRO et al. (2009b) estimated yields of biofuels and electricity generation from different feedstock for the first and second generation technologies (table 12.11). The analysis was restricted to Queensland and did not provide spatially explicit analysis of biofuel feedstock production. However, it does provide useful 'first cut' estimates of the possibilities. Current technologies can produce 280 to 560 litres of ethanol per tonne of biomass and 400 litres of biodiesel per tonne of oilseeds. The second generation technologies will use a wider range of biomass feedstocks to produce ethanol, biodiesel, synfuel and generate electricity. The report estimated that approximately 55 Mt of stubble residue biomass per year can be produced based on 20 per cent of the current 45 million hectares of grazing and cropping land, and that there is potentially about 6 tonnes of biomass per hectare per year. This biomass resource could produce approximately 82 TWh per year of electricity or 17 GL per year of syngasoline and syndiesel.

Table 12.11 Estimated energy and fuel yields for different feedstocks

Feedstock	Ethanol (L/t)	Biodiesel (L/t)	Synfuel[a] (L/t)	Electricity (MWh/t)
First generation				
Cereals	360			
Oilseeds		400		
Sugar cane				
Molasses	280			
Sugar	560			
Second generation				
Cereals	335		246	1.02
Wood waste	240		246	1.35
Algae		495		0.27
Sugar cane				
Whole plant	465		246	0.80
Bagasse	300		246	0.80
Forestry				
Sawmill residues	233		246	1.35
Harvest residues	233		246	1.35
Pulpwood	240		246	1.35
Bioenergy plantations	260		246	1.35
Grasses	323		246	1.02

a Production using gasification, gas condition and cleaning followed by Fischer-Tropsch synthesis and refining to produce syngasoline and syndiesel

Source: CSIRO 2009b

12.4.3 Outlook for bioenergy market

Bioenergy has the potential to make a growing contribution to Australia's energy use, and to electricity generation in particular. Australia's current bioenergy production is principally sourced from by-products of production processes or waste products. There are still under-utilised waste products that may be used for bioenergy in the future.

Australia's large potential bioenergy resources, the Renewable Energy Target and the potential commercialisation of second generation technologies are all expected to drive an increase in electricity generation from bioenergy. However, growth is likely to be constrained to some extent by competition for land and water resources and logistical issues associated with handling, transport and storage. Some second generation feedstocks such as algae and solid biomass wastes may substantially reduce the problems associated with land use and water resources.

Bioenergy project developments

Currently, there is only one project at feasibility stage of development. North Queensland Bio-Energy Corporation Limited plans a A$500 million sugar/ethanol/power generation plant at Ingham, Queensland. The plant will have an ethanol distillation capacity of 200 000 litres of ethanol per day and a generation capacity of 80–85 MW. The project was approved by state government in February 2012. The plant is expected to be fully operational in 2016.

In addition, there are a number of R&D projects investigating bioenergy technologies and biomass potential across Australia.

Electricity and heat generation

There are several proposed bioenergy power plants using a range of biomass resources, such as animal wastes; municipal, sawmill and pulp mill wood wastes; and forestry and plantation residues. There are research projects on methane capture systems from uncovered effluent treatment lagoons and energy generation from intensive animal industries such as dairy farms, beef cattle feedlots and piggeries.

In Victoria, there is a proposal to use fire-affected tree residues from bushfire-affected areas. TreePower Australia has undertaken a feasibility study for a 1 MW biomass fired organic Rankine cycle cogeneration power plant near Marysville, Victoria. The company is considering a trigeneration option, in which some (or all) of the heat output would drive an absorption chiller process for cooling outputs.

Transport biofuels

The Australian Government announced A$15 million funding for projects under the Second Generation Biofuels Research and Development Program, in August 2009, to demonstrate the sustainable development of the biofuels industry. Six projects received funding over three years from 2009–10 to 2011–12:

- The University of Melbourne (A$1.24 million) is researching biofuel from micro-algae involving the efficient separation, processing and utilisation of algal biomass. The project is also supported by Bio Fuels Pty Ltd.
- Algal Fuels Consortium (A$2.724 million) is to develop a pilot-scale second generation biorefinery for sustainable micro-algal biofuels and value-added products. The participants are the South Australian Research and Development Institute, Flinders University and CSIRO, with the project located at Torrens Island, South Australia.
- Curtin University of Technology (A$2.5 million) is investigating the sustainable production of high-quality second generation transport biofuels from mallee biomass by pyrolysis and utilising the biorefinery concept. The project is also supported by Spitfire Oil Pty Ltd and is located in Perth, Western Australia.
- Bureau of Sugar Experiment Stations Limited (A$1.326 million) is developing an optimised and sustainable sugarcane biomass input system for the production of second generation biofuels, located at Indooroopilly, Queensland. The project is also supported by CSIRO.
- Microbiogen Pty Ltd (A$2.539 million) aims to produce commercial volumes of ethanol from bagasse using patented yeast strains. The project is located at Lane Cove, New South Wales.
- Licella Pty Ltd (A$2.288 million) will examine the commercial demonstration of lignocellulosics to stable bio-crude. The project is located at Somersby, New South Wales.

In February 2013, the Australian Renewable Energy Agency announced funding to two projects under its Advance Biofuels Investment Readiness (ABIR) program. The ABIR program builds on existing support for biofuels through the Second Generation Biofuels (Gen 2) Program to take the next step towards establishing a commercial advanced biofuels industry in Australia. The two projects were:

- Licella Pty Ltd ($5.4 million) to assess the feasibility of constructing its first pre-commercial biofuel plant
- Muradel Pty Ltd ($4.4 million) to demonstrate its algal biofuel technology.

The Rural Industries Research and Development Corporation (RIRDC) has a Bioenergy, Bioproducts and Energy program to conduct research into and develop sustainable and profitable bioenergy and bioproducts industries. Research has been completed on identifying and developing Australian native species as biofuel crops and research is in progress in evaluating biodiesel potential of Australian native plants and Indian mustard seed and biofuel production of giant reed grass. RIRDC is compiling a detailed listing of projects currently underway in Australia.

The National Collaborative Research Infrastructure Strategy (NCRIS), an Australian and state government partnership, is enhancing Australia's capacity to produce biofuels derived from non-food biomass. NCRIS involves the development of five integrated sites to provide researchers with access to quality facilities, technologically advanced equipment, and technical expertise. Macquarie University, University of Sydney and University of New South Wales are providing access to facilities for the conversion of lignocellulosic and micro-algae biomass to biofuels (ethanol and biodiesel). Two pilot-scale manufacturing facilities are also being established:

- a biomass biorefinery at Queensland University of Technology, for the conversion of lignocellulosic biomass to ethanol, lignin and other commodities
- a photobioreactor facility at South Australian Research and Development Institute for the demonstration of micro-algae biomass culture for biodiesel production.

The Biofuels Cooperative Research Centre, an initiative of the BioEnergy Research Institute at Southern Cross University, is researching non-food crops that will grow with a reduced reliance on water, such as Australian native species, which have the advantage of adaptation to marginal growing areas.

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Appendices

Appendix A: Abbreviations and Acronyms

ABS	Australian Bureau of Statistics (Australian Government)
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
APEC	Asia Pacific Economic Cooperation
APERC	Asia Pacific Energy Research Centre
APPEA	Australian Petroleum Production and Exploration Association
ARENA	Australian Renewable Energy Agency
ASX	Australian Securities Exchange
BOM	Bureau of Meteorology (Australian Government)
BREE	Bureau of Resources and Energy Economics (Australian Government)
CCS	carbon (dioxide) capture and storage
COAG	Council of Australian Governments
CSIRO	Commonwealth Scientific and Industrial Research Organisation (Australian Government)
EDR	Economic Demonstrated Resources
EIS	Environmental Impact Statement
EPA	Environment Protection Agency
EPBC	*Environment Protection and Biodiversity Conservation Act 1999* (Commonwealth of Australia)
EPRI	Electric Power Research Institute (United States)
GA	Geoscience Australia (Australian Government)
GHG	greenhouse gas (emissions)
IAEA	International Atomic Energy Agency
IEA	International Energy Agency
INF	inferred resource
JORC	Joint Ore Reserves Committee
LCOE	levelised cost of electricity
NEA	Nuclear Energy Agency
NEM	National Electricity Market
OECD	Organisation for Economic Co-operation and Development
OPEC	Organisation of the Petroleum Exporting Countries
R&D	research and development
RD&D	research, development and demonstration
RET	Renewable Energy Target
SDR	Sub-economic Demonstrated Resources
USGS	United States Geological Survey
WEC	World Energy Council
WEO	World Energy Outlook

Units

EJ	exajoule—10^{18} joules
GJ	gigajoule—10^{9} joules
Gt	gigatonne—10^{9} tonnes
GW	gigawatt—10^{9} watts
kt	kilotonne—thousand (10^{3}) tonnes
kW	kilowatt—thousand (10^{3}) watts
kWh	kilowatt-hours—thousand (10^{3}) watt-hours
ML	megalitre—million (10^{6}) litres
mmbbl	million (10^{6}) barrels
Mt	megatonne—million (10^{6}) tonnes
MW	megawatts—10^{6} watts
MWh	megawatt-hours—10^{6} watt-hours
PJ	petajoules—10^{15} joules
tcf	trillion (10^{12}) cubic feet
TJ	terajoules—10^{12} joules
TWh	terawatt-hours—10^{12} watt-hours

Appendix B: Glossary

Accumulation (petroleum)
An individual body of naturally occurring petroleum in a reservoir or a group of reservoirs that are related to a localised geological structural feature and/or stratigraphic condition (trap).

Availability factor
Percentage of time that an electricity-generating plant can be operated at full output.

Base load
The minimum level of demand (load) on an electricity supply system that exists 24 hours a day.

Basin
A geological depression filled with sedimentary rocks.

Biofuels
Liquid fuels (e.g. ethanol, biodiesel) produced directly or indirectly from biomass.

Biogas
Gas captured from landfill sites (garbage tips), sewage treatment plants and livestock feedlots.

Biomass
Vegetable and animal-derived organic materials, such as forestry residues, wood waste, bagasse (sugarcane residue), oilseed crops and animal waste.

Capacity factor
The amount of electricity that the plant produces over a given period divided by the amount of electricity it could have produced if it had run at full power over that same period.

Cogeneration
Also known as combined heat and power. Simultaneous production of heat and electricity in the one fuel combustion process.

Completion (petroleum)
The process by which a finished well (borehole) is either sealed off or prepared for production.

Conventional resources (petroleum)
Petroleum resources within discrete accumulations that are recoverable through wells (boreholes) and typically require minimal processing prior to sale. For natural gas, the term generally refers to methane held in a porous rock reservoir frequently in combination with heavier hydrocarbons.

Conversion
The process of transforming one form of energy into another before use. Conversion itself consumes energy, calculated as the difference between the energy content of the fuels consumed and that of the fuels produced.

Development
Petroleum: phase in which a proven oil or gas field is brought into production by drilling production wells.

Minerals: phase in which the mineral deposit is brought into production through development of a mine.

Discovered petroleum initially-in-place
Quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production.

Discovery
Petroleum: first well (borehole) in a new field from which any measurable amount of oil or gas has been recovered. A well that makes a discovery is classified as a new field discovery.

Minerals: first drill intersection of economic-grade mineralisation at a new site.

Enhanced oil recovery
The extraction of additional petroleum, beyond primary recovery, from naturally occurring reservoirs by supplementing the natural forces in the reservoir. It includes water flooding and gas injection for pressure maintenance (secondary processes) and any other means of supplementing natural reservoir recovery processes, including thermal and chemical processes to improve the *in situ* mobility of viscous forms of petroleum (tertiary processes).

Exploration
Phase in which a company or organisation searches for petroleum or mineral resources by carrying out detailed geological and geophysical surveys, followed up where appropriate by drilling and other evaluation of the most prospective sites.

Extension/appraisal wells (petroleum)
Wells (boreholes) drilled to determine the physical extent, reserves and likely production rate of a field.

Field (petroleum)
An area consisting of a single reservoir or multiple reservoirs grouped on, or related to, the same individual geological structural feature and/or stratigraphic condition.

Fossil fuels
A hydrocarbon deposit in geological formations that may be used as fuel such as crude oil, coal or natural gas.

Gas-to-liquids
Technologies that use specialised processing (e.g. Fischer-Tropsch synthesis) to convert natural gas into liquid petroleum products.

JORC Code
The Australasian Code for Reporting of Exploration Results, Mineral Resources and Ore Reserves, prepared by the Joint Ore Reserves Committee.

It is a principles-based code which sets out recommended minimum standards and guidelines on classification and public reporting in Australasia. Companies listed on the Australian Securities Exchange are required to report exploration outcomes, resources and reserves in accordance with the JORC Code.

Liquid fuels

All liquid hydrocarbons, including crude oil, condensate, LPG and other refined petroleum products.

Load factor

The ratio of the actual amount of kilowatt-hours delivered on a system in a given period of time to the total possible kilowatt-hours that could be delivered on the system over that same time period.

Megawatt, gigawatt, terawatt

10^6, 10^9, 10^{12} watts respectively. Measures of electricity generator capacity or output. Consumption is measured in multiples of watt-hours. See also Appendix D.

Non-renewable resources

Resources, such as fossil fuels (crude oil, natural gas, coal) and uranium that are depleted by extraction.

Peak load

Period of most frequent or heaviest use of electricity.

Petajoule

10^{15} joules, the standard form of reporting energy aggregates. One petajoule is equivalent to 278 gigawatt-hours. See also Appendix D.

Play (geological)

A model that can be used to direct petroleum exploration. It is a group of fields or prospects in the same region and controlled by the same set of geological circumstances.

Primary energy

Energy found in nature that has not been subjected to any conversion or transformation process.

Primary fuels

The forms of energy sources obtained directly from nature. They include non-renewable fuels such as black coal, brown coal, uranium, crude oil and condensate, and natural gas, and renewable fuels such as biomass, hydro, wind, solar, ocean and geothermal.

Primary recovery

The extraction of petroleum from reservoirs utilising the natural energy available in the reservoirs to move fluids through the reservoir rock to points of recovery.

Production

Petroleum: the phase of bringing well fluids to the surface, separating them and storing, gauging and otherwise preparing them for transport.

Minerals: the phase at which operations produce mined product.

Prospect (geological)

A potential accumulation of petroleum or minerals that is sufficiently well defined to represent a viable drilling target.

Renewable resources

Resources that can be replenished at a rate equal to or greater than the rate of depletion, such as biomass, hydro, solar, wind, ocean and geothermal.

Resources

A concentration of naturally occurring solid, liquid or gaseous materials in or on the earth's crust in such form and amount that its economic exploitation is currently or potentially feasible. See also Appendix C.

Total final energy consumption

The total amount of energy consumed in the final or end-use sectors. It is equal to total primary energy consumption less the energy consumed or lost in conversion, transmission and distribution.

Total primary energy consumption

Also referred to as total domestic availability. The total of the consumption of each primary fuel (in energy units) in both the conversion and end-use sectors. It includes the use of primary fuels in conversion activities—notably the consumption of fuels used to produce petroleum products and electricity. It also includes own-use and losses in the conversion sector.

Trap (geological)

Any barrier to the upward movement of oil or gas, allowing either or both to accumulate. The barrier can be a stratigraphic trap, an overlying impermeable rock formation or a structural trap as result of faulting or folding.

Unconventional resources (petroleum)

Resources within petroleum accumulations that are pervasive throughout a large area and that are not significantly affected by hydrodynamic influences. Typically, such accumulations require specialised extraction technology. Examples include coal seam gas, tight gas, shale gas, gas hydrates, natural bitumen and shale oil.

Undiscovered accumulation (petroleum)

Generally, all undiscovered petroleum deposits irrespective of their economic potential. All of the petroleum accumulations that may occur in multiple reservoirs within the same structural or stratigraphic trap are referred to as undiscovered fields.

Wildcat well

A petroleum exploration well drilled on a structural or stratigraphic trap that has not previously been shown to contain petroleum.

Appendix C: Resource Classification

Development of new energy sources requires reliable estimates of how much energy is available at potential development sites.

Mineral and petroleum resource classification

The non-renewable energy resources are geologically based and their classification is largely based on the McKelvey resource classification system.

The McKelvey resource classification system classifies known (identified) resources according to the certainty or degree of (geological) assurance of occurrence and the degree of economic feasibility of exploitation either now or in the future. The first takes account of information on the size and quality of the resource, whereas the economic feasibility considers the changing economic factors such as commodity prices, operating costs, capital costs and discount rates.

The assessments of identified resources—resources for which the location, quantity and quality are known from specific measurements or estimates from geological evidence—are based on and compiled from resource data reported for individual mineral deposits and petroleum and gas accumulations by companies, but take a long-term (20–25 year) view of the feasibility for economic extraction.

The Australian Securities Exchange mandates standards for the public reporting of mineral and petroleum resources by Australian-listed companies, although the estimation and classification of energy resources varies according to type. Oil and gas companies are required to follow the Petroleum Resources Management System of the Society of Petroleum Engineers in reporting petroleum resources or define the alternative standard used. Listed companies must follow the Joint Ore Reserves Committee (JORC) Code for the public reporting of ore reserves and mineral resources under their control. Data from company reports on specific projects are aggregated into categories in the national classification scheme to provide estimates of the national resource base.

In the national system used by Geoscience Australia (figure C.1), demonstrated resources are resources that can be recovered from an identified resource and whose existence and quality have been established with a high degree of geological certainty, based on drilling, analysis, and other geological data and projections.

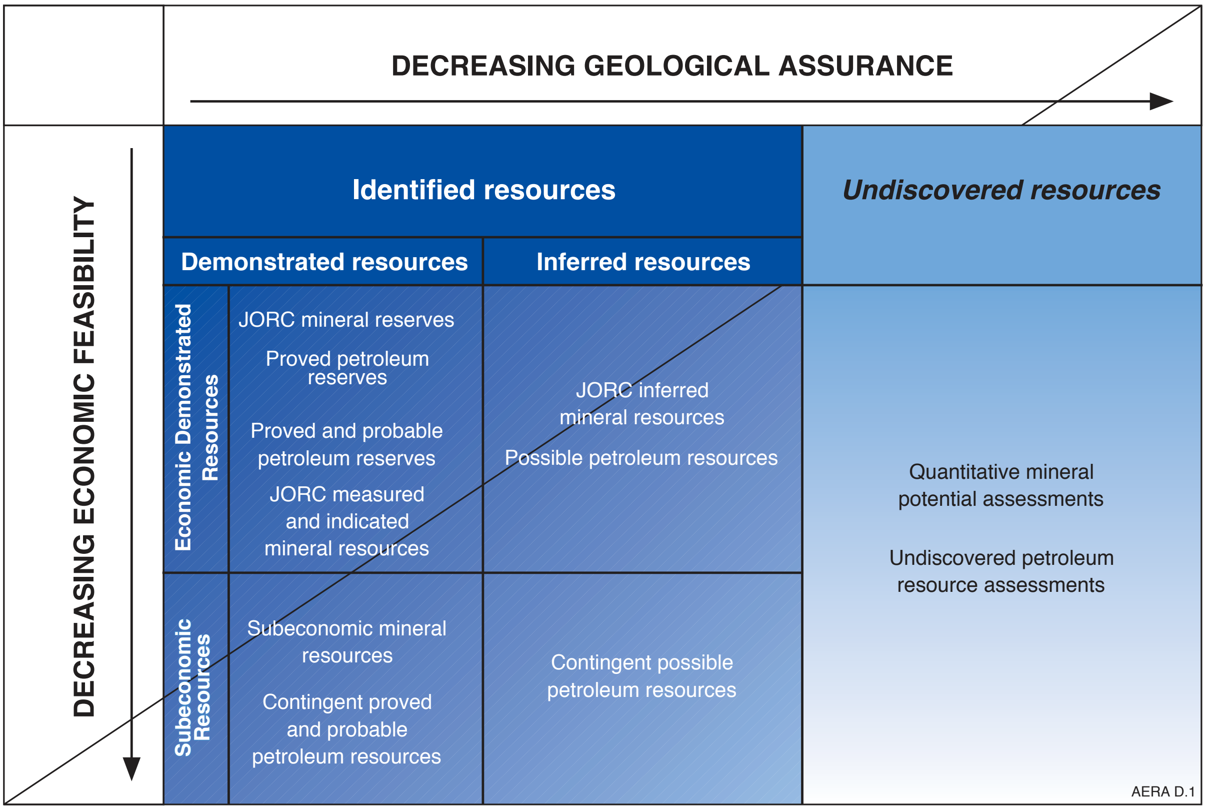

Figure C.1 Australia's national energy resources classification scheme (based on the McKelvey resource classification scheme). See text for explanation of terms

JORC = Joint Ore Reserves Committee

Source: Geoscience Australia

Economic demonstrated resources are resources with the highest levels of geological and economic certainty. For petroleum, these include remaining proved plus probable commercial reserves. For minerals, these include JORC Code proved and probable ore reserves and measured and indicated mineral resources. For these categories, profitable extraction or production has been established, analytically demonstrated or assumed with reasonable certainty using defined investment assumptions.

Subeconomic resources are resources for which, at the time of determination, profitable extraction or production under defined investment assumptions has not been established, analytically demonstrated, or cannot be assumed with reasonable certainty (this includes contingent petroleum resources).

Inferred resources are those with a lower level of confidence that have been inferred from more limited geological evidence and assumed but not verified. Where probabilistic methods are used there should be at least a 10 per cent probability that recovered quantities will equal or exceed the sum of proved, probable and possible reserves.

Undiscovered or potential resources are unspecified resources that may exist based on certain geological assumptions and models, and be discovered through future exploration. Undiscovered resource assessments have inbuilt uncertainties, and are dynamic and change as knowledge improves and uncertainties are resolved.

Uranium resources at the national level are commonly reported under the Nuclear Energy Agency/International Atomic Energy Agency uranium resources classification system. Economic demonstrated resources correlate with reasonably assured resources recoverable at less than US$80 per kilogram of uranium, and inferred resources are the same in both systems.

Coal resources are reported as recoverable coal resources to allow for losses during mining.

Renewable Energy Resource Classification

Renewable energy resources are commonly transient and not always available, and hence not readily classified using the McKelvey system. Renewable resources are often reported in terms of output or installed capacity. Estimates of renewable resource potential are based on maps that show the energy (or power) potentially or theoretically available at the site and detailed studies of the annual and diurnal variation in the energy to determine the capacity factor (the average actual energy output compared with the theoretical maximum possible output if the energy was continuously and fully available for use).

A code based on JORC—the Australian Code for Reporting of Exploration Results, Geothermal Resources and Geothermal Reserves—has been developed for the public reporting of geothermal exploration results and classification of geothermal resources and reserves, covering all forms of geothermal energy. Geothermal reserves are energy that is commercially recoverable now, whereas ‘geothermal resources’ require further work to be classified as geothermal reserves.

United Nations Framework Classification for Fossil Energy and Mineral Resources

The United Nations (UN) Economic Commission for Europe, under the global mandate given by the UN Economic and Social Council, has developed a common global standard, the United Nations Framework Classification for Fossil Energy and Mineral Resources 2009 (UNFC-2009).

The UNFC-2009 is a universally accepted and internationally applicable scheme for the classification and reporting of fossil energy and mineral reserves and resources. UNFC-2009 is a generic principles-based system in which quantities are classified on the basis of three fundamental criteria:

- economic and social viability (E)
- field project status and feasibility (F)
- geological knowledge (G).

Resource 'classes' are defined by using a numerical coding scheme ordered in a three-dimensional system along the three axes of E, F and G, with '1' being the highest category in terms of quality and knowledge and 4 the lowest (figure C.2). A resource class is defined by selecting from each of the three criteria a particular combination of a category or a subcategory. The codes are always quoted in the same sequence (e.g. E1, F1, G1). The letters may be dropped and just the numbers retained; for example, 111 at class level or 3.2, 2.2, 1.2 at subclass level; and these criteria may be further subdivided.

The UNFC-2009 has been developed in close cooperation with the Committee for Mineral Reserves International Reporting Standards (CRIRSCO) and the Society of Petroleum Engineers. UNFC-2009 maps directly to the CRIRSCO template and the Petroleum Resource Management System.

Currently, there is a review on using the UNFC-2009 to classify renewable energy resources and injection projects; in particular, the storage of carbon dioxide.

A full description of UNFC-2009 can be accessed at http://www.unece.org/energy/se/reserves.html.

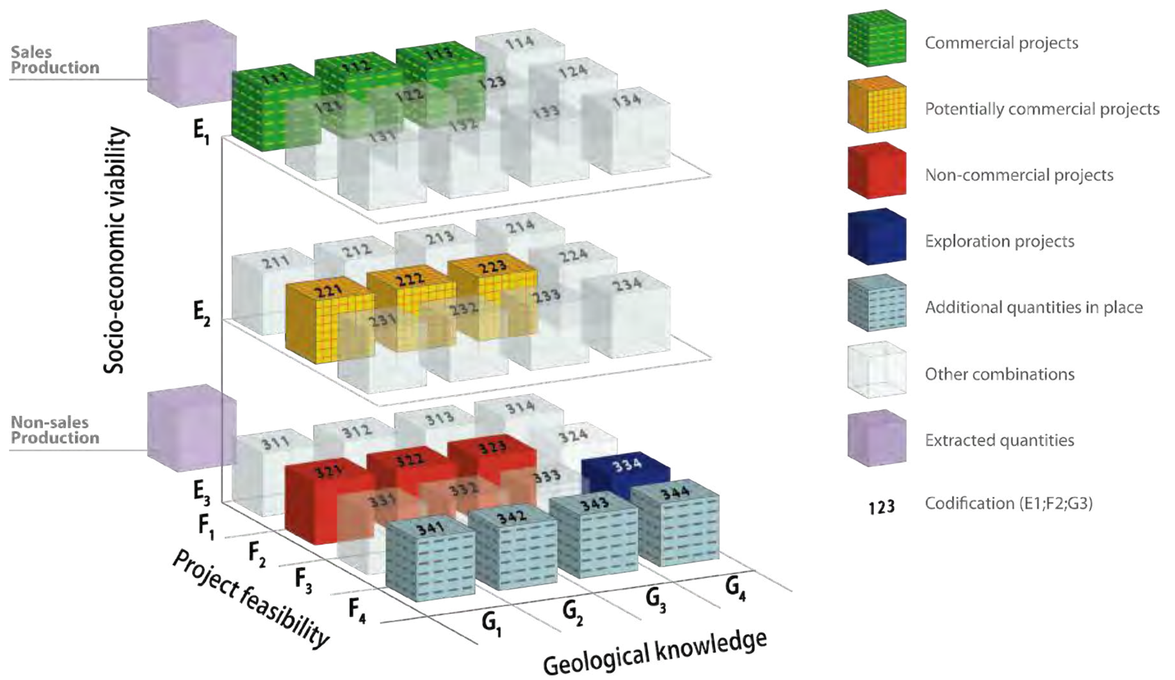

Figure C.2 United Nations Framework Classification for Fossil Energy and Mineral Resources

Source: UN Economic Commission of Europe—Sustainable Energy Division

Appendix D: Energy Measurement and Conversion Factors

Energy is the ability to do work. The International System of Units (SI) unit of energy across all energy types is the joule (J). It is defined as the amount of work done by a force of one newton exerted over a distance of one metre.

Power is the rate at which work is delivered. The SI unit of power is the watt (W). One watt is equal to one joule per second (1 W = 1 J/sec). Watt is the common unit for electrical power (sometimes expressed as W_e), although it may be used for thermal power (W_t).

Consumption of electric energy is measured in kilowatt-hours (kWh), which is equal to the power in kilowatts (kW) times the time period (hours (h)):

energy (kWh) = power (kW) x time (h)

The average annual energy production or consumption can be expressed in kilowatt-hours per year (kWh/year). For example, a power plant with a capacity of one MW produces 1000 kWh when the plant runs consistently for one hour. If the power plant runs consistently with no downtime for a year (8760 hours), the generator produces 8 760 000 kWh (8 760 MWh) in a year.

Both joules and watts are more commonly recorded in multiples.

Decimal numbering system

Multiples of energy measurements in Australia are expressed in standard international decimal classification terms:

Decimal numbering system

Multiple	Scientific notation	Term	Abbreviation
Thousand	10^3	Kilo	k
Million	10^6	Mega	M
Billion	10^9	Giga	G
Trillion	10^{12}	Tera	T
Quadrillion	10^{15}	Peta	P
Quintillion	10^{18}	Exa	E

Energy measurement

Energy production and consumption are typically reported in the SI unit as petajoules (PJ) but in some cases are reported in barrels of oil equivalent (BOE) and million tonnes of oil equivalent (MTOE).

Individual energy resources are commonly reported according to prevailing industry conventions. Petroleum is reported by volume and weight according to either the SI or the United States system as used by the American Petroleum Institute.

In this report, energy is reported in SI units (PJ) with the conventional industry volume or weight equivalent terms widely in use in parentheses.

Energy measurement

Energy resource	Measure	Abbreviation
Oil and condensate	Production, reserves: litres (usually millions or billions) or barrels (usually thousands or millions) Refinery throughput/capacity: litres (usually thousands or millions) or barrels per day (usually thousands or millions)	L, ML, GL bbl, kbbl, mmbbl ML, GL per day bd, kbd, mmbd
Natural gas	Cubic feet (usually billions or trillions) Or cubic metres (usually millions or billions)	bcf, tcf m^3, mcm, bcm
Liquified natural gas	Tonnes (usually millions) Production rate: million tonnes per year	t, Mt Mtpa
LPG	Litres (usually megalitres) or barrels (usually millions)	L, ML bbl, mmbl
Coal	Tonnes (usually millions or billions) Production rate: tonnes per year (usually kilotonnes or million tonnes per year)	t, Mt, Gt tpa, Mtpa
Uranium	Tonnes (usually kilotonnes) of uranium or uranium oxide	t U, kt U t U3O8, kt U3O8
Electricity	Capacity: watts, kilowatts, etc. Production or use: watt-hours, kilowatt-hours, etc.	W, kW, MW ... Wh, kWh, MWh ...
Bioenergy • bagasse, biomass	Tonnes (or thousands of tonnes)	t, kt

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Fuel-specific to standard unit conversion factors

Oil and condensate	1 barrel	=	158.987 litres
	1 gigalitre (GL)	=	6.2898 million barrels
	1 tonne (t)	=	1250 litres (indigenous)/ 1160 litres (imported)
Ethanol	1 tonne	=	1266 litres
Methanol	1 tonne	=	1263 litres
LPG			
• average	1 tonne	=	1760–1960 litres
• naturally occurring	1 tonne	=	1866 litres
Natural gas	1 cubic metre (m^3)	=	35.315 cubic feet (cf)
Liquefied natural gas	1 tonne	=	2174 litres
Electricity	1 kilowatt-hour (kWh)	=	3.6 megajoules (MJ)

Energy content conversion factors

The energy content of individual resources may vary, depending on the source, the quality of the resource, impurities content, extent of pre-processing, technologies used, and so on. The following table provides a range of measured energy contents and, where appropriate, the accepted average conversion factor.

a Gaseous fuels

	PJ/bcf	MJ/m^3
Natural gas		
• Victoria	1.0987	38.8
• Queensland	1.1185	39.5
• Western Australia	1.1751	41.5
• South Australia, New South Wales	1.0845	38.3
• Northern Territory	1.1468	40.5
• average	1.1000 (54 GJ/t)	38.8
Ethane (average)	1.6282	57.5
Town gas		
• synthetic natural gas	1.1043	39.0
• other town gas	0.7079	25.0
• coke oven gas	0.5125	18.1
• blast furnace gas	0.1133	4.0

b Liquid fuels

	PJ/mmbbl	By volume MJ/L	By weight GJ/t
Crude oil and condensate			
• indigenous (average)	5.88	37.0	46.3
• imports (average)	6.15	38.7	44.9
LPG			
• propane	4.05	25.5	49.6
• butane	4.47	28.1	49.1
• mixture	4.09	25.7	49.6
• naturally occurring (average)	4.21	26.5	49.4
Other			
• liquefied natural gas (North West Shelf)	3.97	25.0	54.4
Naphtha	4.99	31.4	48.1
Ethanol	3.72	23.4	29.6
Methanol	2.48	15.6	19.7

c Solid fuels

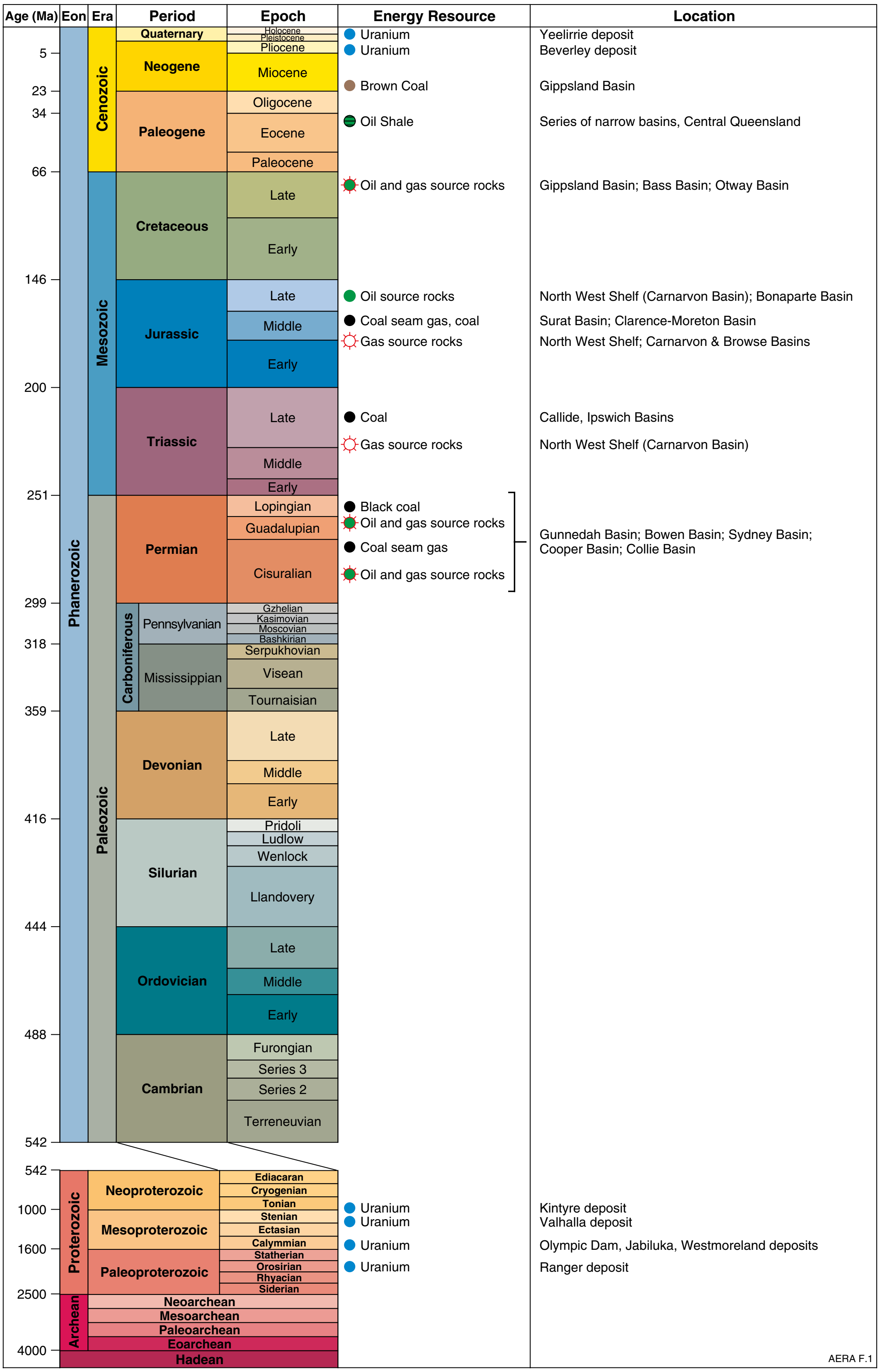
	GJ/t
Black coal	
New South Wales	
Exports—metallurgical coal	29.0
Exports—thermal coal	27.0
Electricity generation	23.4
Other	23.9–30.0
Queensland	
Exports—metallurgical coal	30.0
Exports—thermal coal	27.0
Electricity generation	23.4
Other	23.0
Western Australia	
Thermal coal	19.7
Tasmania	
Thermal coal	22.8
Lignite (brown coal)	
Victoria	9.8
Briquettes	22.1
South Australia	15.2
Uranium[a]	
Metal (U)	560 000
Uranium Oxide (U_3O_8)	470 000
Other	
Coke	27.0
Wood (dry)	16.2
Bagasse	9.6

a The usable energy content of uranium metal (U) is 0.56 petajoules per tonne, and that of uranium oxide (U_3O_8) is 0.47 petajoules per tonne. The oxide contains 84.8 per cent of the metal by weight

Source: Bureau of Resources and Energy Economics; Geoscience Australia

Appendix E: Geological Time Scale and Formation of Australia's Major Energy Resources

The geological timing of some of the major non-renewable energy resources in Australia are charted. The geological time scale is based on Gradstein FM, Ogg J and Smith AG, 2004 *A Geological Time Scale*, Cambridge University Press, New York.



Ma = million years

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