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Foreword

Australia is blessed with abundant fossil fuel and renewable energy sources, which have helped our nation to achieve the high standard of living that Australians currently enjoy. These resources generated $77 billion worth of energy exports in 2011–12 while also providing Australian households and businesses with a secure, reliable and affordable domestic energy supply.

Having quick and easy access to up-to-date information on the state of our energy sector is essential as we seek to smooth the way from traditional energy sources to new and sustainable technologies.

In order to achieve this transition, the Australian Government has developed a policy framework based on rigorous analysis and data that promotes a secure, resilient and efficient energy system. As outlined in the Energy White Paper, released at the end of 2012, our policy priorities are to:

(1) Develop better energy market outcomes for consumers;

(2) Accelerate our clean energy transformation;

(3) Develop Australia's critically important energy resources; and

(4) Strengthen the resilience of our energy policy framework.

As Energy in Australia 2013 shows, Australia has a bright future with ample opportunities for growth. Investments, supported by a market-based policy framework, will ensure that Australia will maintain its' pre-eminence among developed economies

as a major energy producer. Continued support for research and development means that we are projected to become a leader in the deployment of renewable energy technologies. In addition, ongoing support for energy efficiency initiatives by the Australian Government will help the private sector and households to reduce their electricity costs and improve energy productivity.

I highly recommend Energy in Australia 2013 to all Australians. It provides a valuable 'state of play' as well as the facts and figures to help maintain a robust approach to achieving a clean, bright and secure energy future.

The Hon Gary Gray AO MP
Minister for Resources and Energy

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Data sources

The information contained in *Energy in Australia 2013* is obtained from a number of BREE and other sources. Key amongst which are:

Australian Bureau of Statistics—abs.gov.au

Australian Energy Market Commission—aemc.gov.au

Australian Energy Market Operator—aemo.com.au

Australian Energy Regulator—aer.gov.au

Australian Institute of Petroleum—aip.com.au

Bureau of Resources and Energy Economics—bree.gov.au

BP Statistical Review of World Energy—bp.com

Clean Energy Council—cleanenergycouncil.org.au

Clean Energy Regulator—ret.cleanenergyregulator.gov.au

Department of Climate Change and Energy Efficiency—climatechange.gov.au

Department of Resources, Energy and Tourism—ret.gov.au

EnergyQuest—energyquest.com.au

Energy Supply Association of Australia—esaa.com.au

Geoscience Australia—ga.gov.au

Global Roam Pty Ltd—nem-review.info

International Energy Agency—iea.org

Ports Australia—portsaustralia.com.au

Abbreviations and acronyms

ABS	Australian Bureau of Statistics
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ARENA	Australian Renewable Energy Agency
BREE	Bureau of Resources and Energy Economics
CCS	carbon capture and sequestration
CSG	coal seam gas
EDR	economic demonstrated resources
ERA	Economic Regulation Authority (Western Australia)
ESAA	Energy Supply Association of Australia
IEA	International Energy Agency
LNG	liquefied natural gas (principally methane)
LPG	liquefied petroleum gas (principally propane and butane)
LRET	Large-scale Renewable Energy Target
NEM	national electricity market
NER	national electricity rules
NGL	natural gas liquid hydrocarbons, other than methane, derived from the natural gas stream in separation and/or liquefaction facilities

OECD	Organisation for Economic Cooperation and Development
OPEC	Organization of the Petroleum Exporting Countries
ORF	other refinery feedstock
R&D	research and development
RET	Department of Resources, Energy and Tourism
RET	Renewable Energy Target
SRES	Small-scale Renewable Energy Scheme
STTM	Short Term Trading Market (gas)

Glossary

Advanced biofuels: High energy drop-in liquid fuels derived from sustainable sources of organic matter that do not typically compete with food or feed production, for example, biofuels produced from wood residues, non-edible oilseeds or algae.

Bagasse: The fibrous residue of the sugar cane milling process that is used as a fuel (to raise steam) in sugar mills.

Biogas: Landfill (garbage tips) gas and sewage gas. Also referred to as biomass gas.

Black coal: Hard coal with high energy content. In Australia, anthracite, bituminous and sub-bituminous coals are referred to as black coal.

Brown coal: Has a low energy content (gross calorific value less than 17 435 kJ/kg) and high ash content. It is unsuitable for export and is used to generate electricity in power stations located at or near the mine. Also referred to as lignite.

Coal by-product: By-products such as blast furnace gas (from iron and steel processing), coal tar and benzene/toluene/xylene (BTX) feedstock and coke oven gas (from the coke making process).

Coal seam gas: Methane held within coal deposits, bonded to coal under the pressure of water. It may also contain small amounts of carbon dioxide and nitrogen. Also referred to as coal seam methane and coal bed methane. Included in natural gas in BREE's Australian Energy Statistics.

Conversion: The process of transforming one form of energy into another (derived) form before final end use. Energy used in conversion is the energy content of fuels consumed as well as

transformed by energy producing industries. Examples are gas and liquefied petroleum gas used in town gas manufacturing, all hydrocarbons used as feedstock in oil refineries, and all fuels (including electricity) used in power stations. Thus, energy used in conversion also includes energy lost in the production, conversion and transport of fuels (such as energy lost in coke production) plus net energy consumed by pumped storage after allowance for the energy produced.

Crude oil: Naturally occurring mixture of liquid hydrocarbons under normal temperature and pressure.

Condensate: Hydrocarbons recovered from the natural gas stream that are liquid under normal temperature and pressure.

Conventional gas: Generally refers to methane held in a porous rock reservoir frequently found in combination with heavier hydrocarbons. It may contain small amounts of ethane, propane, butane and pentane as well as impurities such as sulphur dioxide, and inert gases such as nitrogen.

Economic demonstrated resources: The quantity of resources that is judged to be economically extractable under current market conditions and technologies.

Electricity generation capacity: The maximum electricity output of generators technically possible at a given hour. The maximum annual output from generators is equal to generation capacity multiplied by the number of hours in a year.

Electricity generation capacity utilisation: Actual electricity generation output as a proportion of generation capacity.

Gas: Methane that has been processed to remove impurities to a required standard for consumer use. It may contain small amounts of ethane, propane, carbon dioxide and inert gases such

as nitrogen. In Australia, gas comes from conventional gas and coal seam gas. Landfill and sewage gas are some other potential sources.

Liquid fuels: All liquid hydrocarbons, including crude oil, condensate, liquefied petroleum gas and other refined petroleum products, and liquid biofuels.

Non-renewable energy resources: Resources, such as fossil fuels (crude oil, natural gas, coal) and uranium that are depleted by extraction.

Petajoule: The joule is the standard unit of energy in general scientific applications. One joule is the equivalent of one watt of power radiated or dissipated for one second. One petajoule, equivalent to 10^{15} joules or 278 gigawatt hours, is the heat energy content of about 43 000 tonnes of black coal or 29 million litres of petrol.

Petroleum: Generic term for all hydrocarbon oils and gases, including refined petroleum products.

Petroleum products: All hydrocarbons used directly as fuel. These include liquefied petroleum gas, refined products used as fuels (aviation gasoline, automotive gasoline, power kerosene, aviation turbine fuel, lighting kerosene, heating oil, automotive diesel oil, industrial diesel fuel, fuel oil, refinery fuel and naphtha) and refined products used in nonfuel applications (solvents, lubricants, bitumen, waxes, petroleum coke for anode production and specialised feedstocks). Included in oil aggregates in the Australian Energy Statistics.

Primary production: The forms of energy obtained directly from nature, involving only the extraction or collection of the energy source. They include non-renewable energy sources such as coal,

uranium, crude oil and condensate, naturally occurring liquefied petroleum gas, ethane and methane, and renewable energy sources such as wood, bagasse, landfill gas, hydroelectricity, wind energy, solar energy and geothermal energy. Also referred to as indigenous production.

Renewable energy 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 energy.

Secondary fuels: The forms of energy that result from transforming primary energy. They include electricity, petroleum products, LPG produced in refineries and liquid biofuels produced through the transformation of agricultural or waste feedstocks. Also referred to as derived fuels production.

Total final energy consumption: The total amount of energy consumed in the final or end use sectors. It is equal to total primary energy supply less energy consumed or lost in conversion, transmission and distribution.

Total net energy consumption: A measure of the total energy used within the economy. At an aggregate level, total net energy consumption is equivalent to total primary energy supply.

Total primary energy supply: A measure of the total energy supplied within the economy. It is equal to indigenous production plus imports minus exports, plus stock changes and statistical discrepancies. It includes the supply of both primary and secondary fuels.

Unconventional gas: Generally refers to gas trapped deep underground by impermeable rocks such as coal, sandstone and shale. The most common types of unconventional gas are coal seam gas, shale gas and tight gas.

1. Overview

Australia has a large, diverse energy resource base which includes coal, uranium, natural gas, oil and renewable energy resources. With the exception of oil, these resources are expected to last for many more decades, even as production increases. Australia's energy resource base could even increase over the next two decades, as more resources are discovered and renewable energy technology develops and extraction costs decrease. The fossil fuel resources available to Australia include coal (black and brown), gas (conventional, coal seam gas, shale gas and tight gas) and oil (crude oil, LPG, condensate and oil shale). Australia has only limited domestic resources of crude oil.

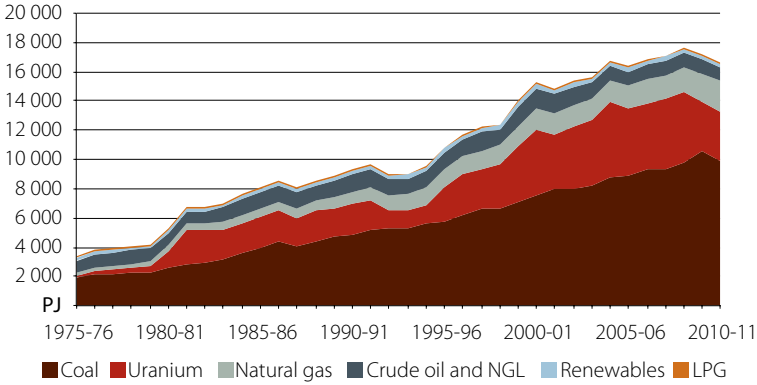
Energy production

In 2010-11, Australia's energy production was 16 640 petajoules (Figure 1). Australia produces energy for both domestic consumption and for export. Net energy exports (exports minus imports) accounted for 63 per cent of total energy production in 2010-11, while domestic consumption accounted for the remaining 37 per cent. Australia was the world's ninth largest energy producer, accounting for around 2.7 per cent of world energy production. Given its large energy resources, Australia is well positioned to continue its role as an important supplier of world energy needs, while maintaining domestic energy supply.

All of Australia's energy production, barring uranium (which is only exported), serves both domestic and international markets. Increasing demand from both those markets has spurred strong growth; between 2000–01 and 2010–11 total energy production increased by 9 per cent per year. In 2010–11, coal accounted for 59 per cent of Australia's primary energy production, in energy

content terms, followed by uranium (20 per cent) and gas (13 per cent). Crude oil and LPG represented a further 6 per cent of total energy production in energy content terms, and renewables 2 per cent.

Figure 1: Australia's primary energy production



Source: BREE 2012, Australian Energy Statistics.

The energy industry is a significant contributor to the Australian economy, worth 6 per cent in terms of gross value added (Table 1). The coal and petroleum industries contributed around $54 billion to industry gross value added in 2010–11, representing 4 per cent of the Australian total. The electricity and gas supply industries contributed another $24 billion to industry gross value added. These industries also provide significant employment and infrastructure.

Table 1: Energy-related industries in Australia, 2010–11

	gross value added	gross fixed capital formation	employment
	A$b	A$b	'000
Coal mining	27	7.6	38
Oil and gas extraction	27	17.8	15
Petroleum and coal product manufacturing	1.8	0.4	6
Electricity supply	22.5	11.5	51
Gas supply	1.1	0.6	2
Energy Total	79.3	37.8	112
Australian Total	**1 320.1**	**370.5**	**11 354.5**
Share of Australian total (%)	6.0	10.2	1.0

Sources: Australian Bureau of Statistics 2012, Australian Industry, cat. no. 8155, Australian System of National Accounts, cat. no. 5204, Australian Labour Market Statistics, cat. no. 6291.

Domestic energy consumption

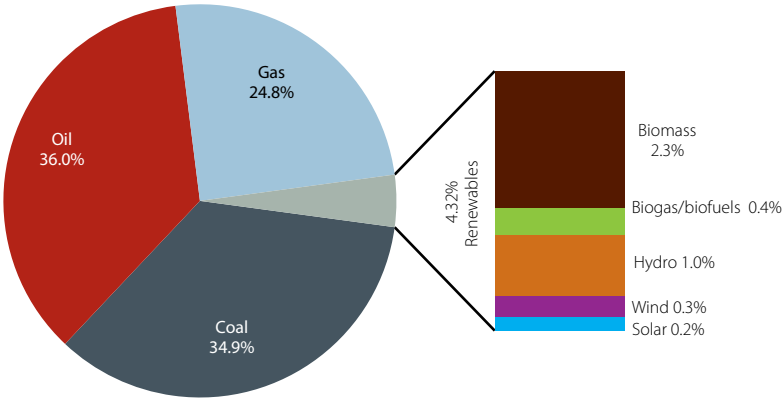
Although Australia's energy consumption continues to increase, the rate of growth has slowed in recent years. Australia's net energy consumption increased at an average annual rate of 1.98 per cent over the period 2000-01 to 2010–11, compared with 2.01 per cent over the previous decade. In 2010–11, net energy consumption increased by 3 per cent relative to 2009-10 to 6100 petajoules; equivalent to 37 per cent of total Australian energy production.

Over the past 20 years, domestic energy consumption has increased at a slower rate than production. Rapid growth in global demand for Australia's energy resources has been the

primary driver of increasing domestic production. As a result, the share of domestic consumption in Australian energy production has declined, from an average of 49 per cent in the 1980s to an average of 42 per cent in the 1990s, and has continued to decline, to an average of 34 per cent over the past decade.

In 2010–11, black and brown coal accounted for around 35 per cent of total consumption, its lowest contribution since the 1970s. Oil accounted for 36 per cent of total consumption in 2010–11, while gas and renewable energy sources accounted for 25 per cent and 4 per cent, respectively (Figure 2). Of the 4.3 per cent of total energy consumption provided by renewables, bioenergy represented 63 per cent, hydro 27 per cent, with the remainder from wind and solar.

Figure 2: Energy consumption in Australia, 2010–11



Source: BREE 2012, Australian Energy Statistics.

BREE's latest energy projections for Australia – to 2050 – were released in December 2012. These projections present a scenario for energy development based on a number of assumptions including the latest electricity generation cost estimates from the Australian Energy Technology Assessment (2012) and recent developments in government policy including carbon price projections provided by the Australian Treasury.

Total primary energy consumption is projected to grow by around 21 per cent (0.5 per cent per year) over the period 2012-13 to 2049-50, to reach 7369 petajoules in 2049-50. BREE's outlook of energy consumption reflects two sizable shifts in the sector. Firstly, the long-term decline in the energy intensity of the Australian economy. Secondly, the increased use of renewables (particularly in electricity generation) resulting from decreasing costs and policy measures designed to increase their competitiveness.

Table 2: Primary energy consumption projections to 2049-50, by energy type (PJ)

Energy type	Amount (PJ)			Share of total electricity generation (%)		Average annual growth (%)
	2012-13	2034–35	2049-50	2012–13	2049–50	2012-13 to 2049-50
Non-renewables	5793	5980	6337	95	86	0.2
Coal	1882	1036	478	31	6	-3.6
black coal	1212	962	478	20	6	-2.5
brown coal	670	74	0	11	0	-21.7
Oil	2359	2888	3391	39	46	1.0
Gas	1552	2056	2469	26	34	1.3
Renewables	276	755	1032	5	14	3.6
Hydro	62	62	62	1	1	0.0
Wind	51	231	282	1	4	4.7
Bioenergy	149	299	346	2	5	2.3
Solar	14	104	236	<1	3	7.8
Geothermal	0	59	106	0	1	na
Total [a]	**6069**	**6735**	**7369**	**100**	**100**	**1**

a totals may not add due to rounding.

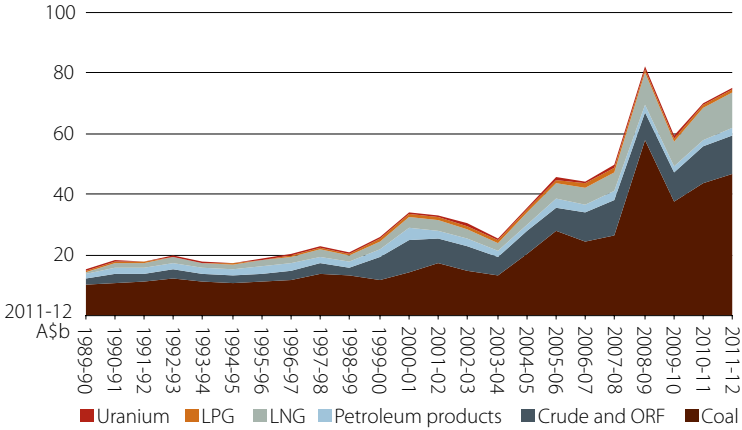
Source: BREE 2012, Australian Energy Projections to 2049–50.

Energy exports

Australia is a net energy exporter (imports minus exports), with 63 per cent of total energy production being exported. However, Australia is a net importer of crude oil and refined petroleum products. Coal is Australia's largest energy export earner, with a value of around $48 billion in 2011–12, followed by crude oil and liquefied natural gas (LNG) (Figure 3). Energy exports accounted for 34 per cent of the value of Australia's total commodity exports in 2011–12.

Since 1988–89, the value of Australia's energy exports (in 2011–12 Australian dollars) has increased at an average rate of 7 per cent per year. In 2011–12, energy export earnings increased by 10 per cent compared with 2010–11, largely as a result of increased exports of coal and LNG.

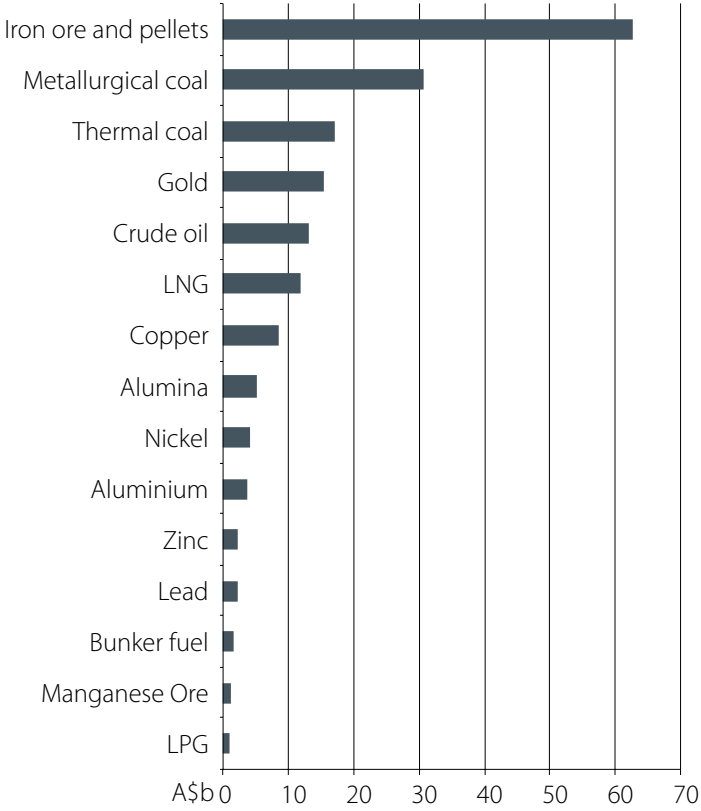
Figure 3: Australia's energy exports, 1990–2012



Note: ORF is other refinery feedstock.

Source: BREE 2013, Resources and Energy Quarterly.

Figure 4: Australia's major resource and energy exports, 2011-12



Source: BREE 2013, Resources and Energy Quarterly.

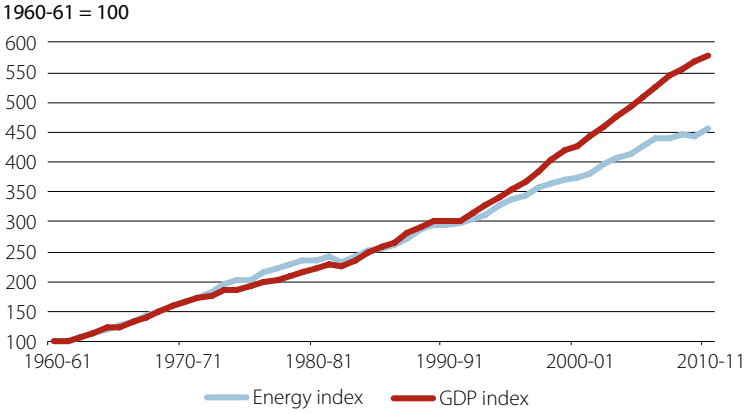
2. Energy consumption

Australia is the world's seventeenth largest consumer of non-renewable energy resources and ranks eighteenth on a per person basis. Australia's energy consumption is primarily composed of non-renewable energy resources (coal, oil, gas and related products), which represent 96 per cent of total energy consumption. Renewables, the majority of which is bioenergy (wood and woodwaste, biomass and biogas), account for the remaining 4 per cent of consumption. Renewable energy consumption, while low, has been growing strongly in recent years.

While continuously increasing, growth in Australia's total energy consumption has been slowing over the past five decades. 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 a year, largely as a result of the two oil price shocks of that decade. During the 1980s, an economic recession in 1982–83 and rising energy prices resulted in annual energy consumption growth falling again, to an average of around 2.3 per cent. In the 1990s, economic recession early in the decade contributed to slower energy consumption growth. However, falling energy prices (in real terms) and a turnaround in economic growth resulted in annual growth in energy consumption remaining at around 2.3 per cent for the decade as a whole.

Over the past five years, growth in energy consumption has averaged 0.8 per cent, primarily as a result of the on-going decline in the energy intensity of the Australian economy (Figure 5).

Figure 5: Annual growth in Australia's energy consumption, 1960 - 2011



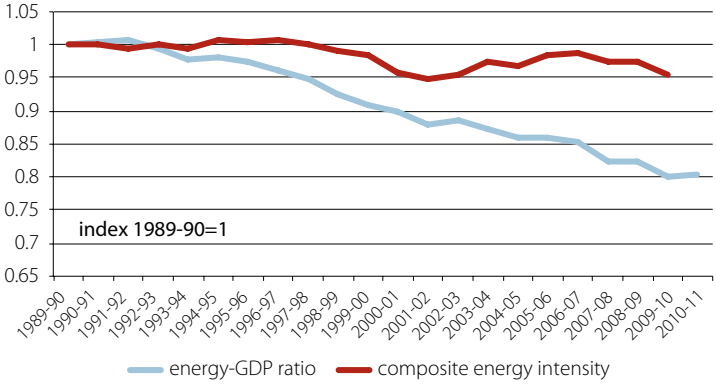
Sources: BREE 2012, Australian Energy Statistics; ABS 2012, Australian National Accounts: State Accounts, cat. no. 5206.

End-use energy intensity

The Australian economy has experienced a long-term decline in energy intensity (energy consumption per unit of gross domestic product). Energy efficiency improvements have been achieved through technological change, fuel switching, and structural changes. Government policies at both the national and state/territory level have contributed to the implementation of new technologies that improve energy efficiency and increase the incentives for more efficient fuel use. Growth in less energy-intensive sectors, such as the commercial and services sector, relative to higher energy-intensity sectors, such as manufacturing, has also resulted in structural shifts in the economy towards lower energy intensity.

The energy–GDP ratio provides information on how many units of energy are required for a unit of gross value of production. Thus, a declining trend of energy-GDP ratio implies that an equivalent amount of energy demand is able to generate greater value added. The aggregate energy-GDP ratio for Australia as a whole declined at an average annual rate of 1.2 per cent over the period 1989–90 to 2010–11 (Figure 6).

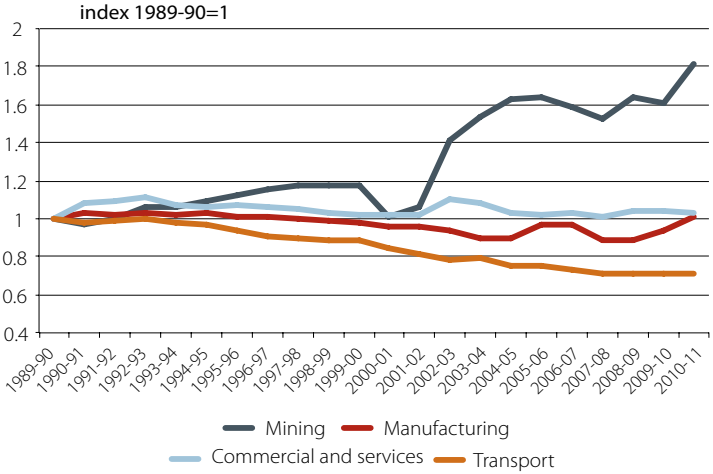
Figure 6: Trends in energy-GDP ratio and the composite energy intensity indicator in Australia



Sources: BREE 2012, End-use energy intensity in Australia; BREE Estimates.

The composite energy intensity indicator computes economy-wide energy intensity by aggregating energy intensities derived for individual sectors or subsectors. Composite energy intensity in the Australian economy declined at an average rate of 0.2 per cent a year from 1989-1990 to 2010-11 (Figure 6). The transport and manufacturing sectors are the main sources of Australia's declining energy intensity (Figure 7).

Figure 7: Trends in energy-Gross Value Added ratio of selected Australian industries



Sources: BREE 2012, End-use energy intensity in Australia; BREE Estimates

The transport sector accounts for the largest share of final energy consumption in Australia, followed by the manufacturing, mining, residential, services, and agriculture sectors. Energy intensity in the transport sector decreased between 1989-90 and 2010-11. The mining sector, on the other hand, has shown an upward trend in energy intensity over the same time period. Energy intensity in the manufacturing and commercial and services sectors was largely unchanged over the period.

The decline in energy intensity in the transport sector is considerable; falling at an average rate of 1.9 per cent per year over the twenty years to 2010-11. This can be attributed to rising fuel prices combined with technical advances in fuel efficiency, aerodynamics and lightweight materials. Furthermore,

Government policies to improve vehicle fuel efficiency, such as mandatory efficiency standards, and greater use of public transport have also contributed.

In the manufacturing sector and the commercial and services sector the structural effect of shifts in activity from higher to lower energy intensity subsectors and improved efficiency (due to technological improvements and rising energy prices) reduced energy demand growth. Increased activity in both sectors, however, more than offset these effects and resulted in net energy consumption growing from 1989-90 to 2010-11.

During 1989-90 to 2010-11, energy consumption in the mining sector increased by an average growth rate of 6.3 per cent a year due to a strong increase of mining activity and depletion effects. By contrast, the energy-Gross Value Added ratio increased by 2.9 per cent over this period.

Energy consumption, by energy type

Total primary energy supply (TPES) can be used as a proxy for the total amount of energy consumed in the Australian economy, including energy consumed in the conversion sector, such as electricity. Australian total primary energy supply is dominated by coal, petroleum and gas.

The share of black and brown coal in the energy mix has been declining over the past two years, primarily as a result of substitution towards gas and cleaner energy sources, particularly in the electricity generation sector (Figure 8). In 2010–11, coal represented around 35 per cent of the energy mix, slightly less than petroleum products (36 per cent). The share of gas in Australian energy consumption has increased over the past 30 years and currently represents around 25 per cent. The share of

renewables in Australia's total energy mix has remained largely constant at around 4 per cent over the last decade (Table 3).

Currently, around 53 per cent of Australia's renewable energy is comprised of biomass (wood and bagasse). Hydro power for electricity generation makes up 23 per cent of renewables consumption, with the remaining 24 per cent comprising biofuels, wind and solar energy consumption. In recent years, a decline in the use of biomass has been partially offset by increasing use of all other renewable energy sources.

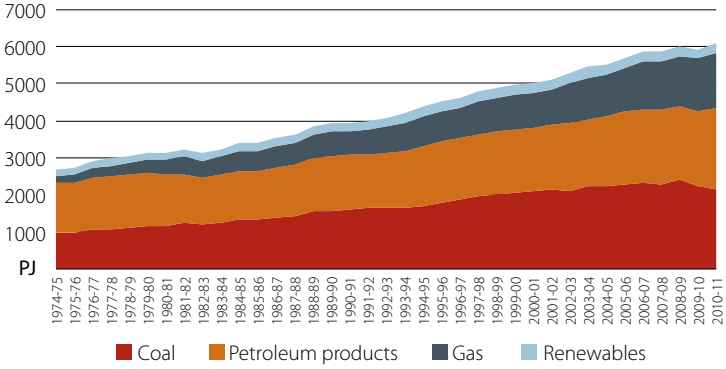
Table 3: Australia's total energy consumption, by energy type

	2006-07	2007-08	2008-09	2009-10	2010-11
	PJ	PJ	PJ	PJ	PJ
Consumption of fuels	8381	8414	8475	8356	8559
Black coal	1602	1580	1598	1475	1402
Brown coal/lignite	722	725	805	742	728
Coke	73	75	63	73	87
Coal by-products	69	71	52	62	67
Liquid biofuels	3	4	7	10	14
Wood, woodwaste	97	106	95	95	95
Bagasse	111	111	53	50	43
Refinery input	1506	1465	1481	1439	1524
Petroleum products	2032	2089	2043	2077	2164
Natural gas	1279	1302	1371	1414	1515
Town gas	7	4	3	0	1
Solar energy [a]	6	7	8	10	11
Total electricity	875	876	898	908	909
of which hydro electricity	52	43	43	49	61
wind energy	9	11	14	18	21
solar electricity	0	0	1	1	3
Production of derived fuels	2518	2548	2507	2447	2472
Coke	90	90	69	76	87
Coal by-products	68	69	49	61	68
Petroleum products [b]	1542	1565	1544	1471	1492
Town gas	5	4	3	0	0
Thermal electricity	813	821	841	840	825
Total energy consumption [c]	5871	5876	5982	5923	6100

a Solar energy is from solar hot water systems. **b** Production may exceed refinery input as some petroleum products are produced from other petroleum products. **c** Total energy consumption is the total quantity (in energy units) of primary and derived fuels consumed less the quantity of derived fuels produced. Totals may not add due to rounding.

Source: BREE 2012, Australian Energy Statistics.

Figure 8: Australia's total energy consumption, by energy type



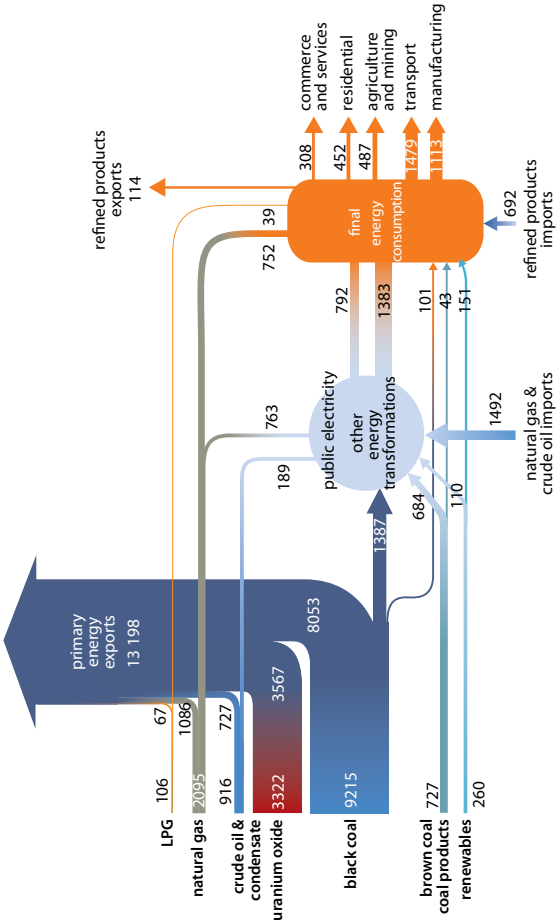
Source: BREE 2012, Australian Energy Statistics.

Energy consumption, by sector

Australia's total primary energy supply is estimated to have risen by 3 per cent relative to 2009-10 to 6100 petajoules in 2010–11. Figure 9, which shows Australia's energy flows from the supply point to final distribution to industries and households. Domestically produced or imported primary energy may be used directly by industries and households, but is generally first consumed by transformation sectors such as refineries and power plants for use as petroleum products and electricity. In addition, many final energy products are not manufactured in Australia, but are directly imported for use by Australian industries and households. Australia is a net exporter of primary energy, with a far greater amount of primary energy production exported than consumed domestically. Australia's energy resources generated $77 billion worth of energy exports in 2011–12 while also providing Australian households and businesses with a secure, reliable and affordable domestic energy supply.

The major energy using sectors of electricity generation, transport and manufacturing together account for around 75 per cent of Australia's energy consumption (Figure 10). The transport sector accounts for the largest share of Australia's end use consumption. During 2000–01 to 2011–12, energy consumption of transport increased by an average of 2.4 per cent per year (BREE estimate). The next largest energy-consuming sectors are the mining (which has seen a particularly large increase over the last decade, Table 4), residential and commercial and services sectors.

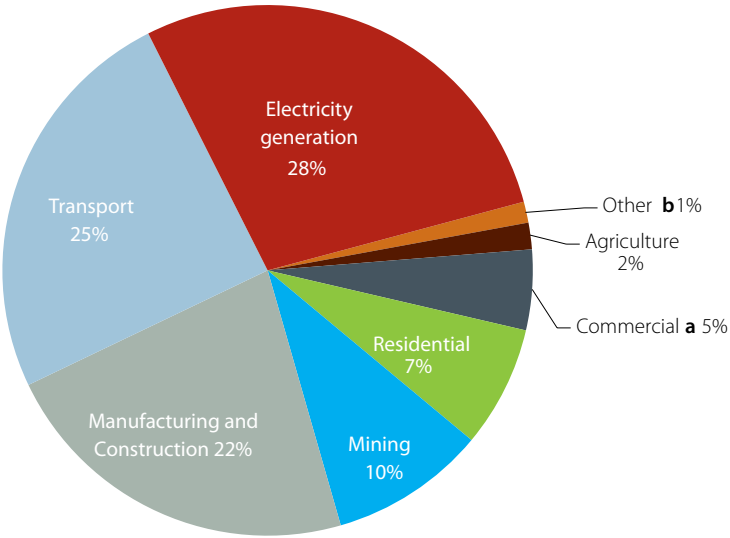
Figure 9: Australia's energy flows, 2010–11, petajoules



Note: Some totals do not add due to statistical discrepancies and rounding.

Source: BREE 2012, Australian Energy Statistics.

Figure 10: Australia's total energy consumption, by sector, 2010–11



a Includes ANZSIC Divisions F, G, H, J, K, L, M, N, O, P, Q and the water, sewerage and drainage industries. **b** Includes consumption of lubricants and greases, bitumen and solvents, as well as energy consumption in the gas production and distribution industries and statistical discrepancies. Totals may not add due to rounding.

Source: BREE 2012, Australian Energy Statistics.

Table 4: Australia's total energy consumption, by sector

	1975-76	1980-81	1990-91	2000-01	2010-11
	PJ	PJ	PJ	PJ	PJ
Agriculture	40	49	56	86	99
Mining	67	71	165	254	580
Manufacturing	926	946	1074	1188	1338
Electricity generation	560	778	1065	1508	1724
Construction	29	38	37	28	25
Transport	715	835	1003	1249	1505
Commercial [a]	90	107	157	223	299
Residential	246	263	328	398	452
Other [b]	58	60	64	78	78
Total	**2731**	**3146**	**3950**	**5012**	**6100**

a Includes ANZSIC Divisions F, G, H, J, K, L, M, N, O, P, Q and the water, sewerage and drainage industries. **b** Includes consumption of lubricants and greases, bitumen and solvents, as well as energy consumption in the gas production and distribution industries and statistical discrepancies. Totals may not add due to rounding.

Source: BREE 2012, Australian Energy Statistics.

Table 5: Australia's energy supply and consumption, 2010–11

		Coal and coal by-products	Natural gas, CSM	Crude oil and ORF	Propane, butane, LPG	Refined products	Liquid/ gas biofuels
		PJ	PJ	PJ	PJ	PJ	PJ
Supply							
Primary indigenous		9 941.4	2 094.8	915.6	105.5		27.2
plus	all imports		261.0	1 229.3	24.0	667.9	
less	all exports [a]	8 052.5	1 085.7	726.6	66.7	113.6	
less	stock changes and discrepancies	- 238.0	- 245.2	- 105.6	8.6	- 62.9	
Total primary energy supply [b]		2 128.5	1 515.4	1 523.9	54.2	617.2	27.2
less conversions							
Coke ovens		29.4				0.6	
Petroleum refining			15.8	1 519.9	- 28.1	- 1 451.9	
Gas manufacturing			0.2		0.1		
Electricity generation [a]		1 874.8	505.6	1.0	0.0	33.1	12.6
Other conversion [c]		78.6	209.3	0.8	- 12.0	24.9	
Fuel use in conversion			32.2		0.2	106.7	
Consumption							
Total final energy consumption [d]		139.9	752.4	2.2	93.9	1 903.8	14.6
Agriculture			0.1		1.8	88.9	
Mining		5.9	151.0	1.5	1.7	145.1	1.0
Food, beverages, textiles		11.9	37.5	0.7	1.7	2.1	0.6
Wood, paper and printing		2.9	22.6		0.1	0.3	1.0
Chemical		7.2	114.8		12.8	73.1	0.2
Iron and steel		33.5	23.5		0.0	0.4	
Non-ferrous metals		46.0	124.0		0.7	72.9	0.2
Other industry		26.8	74.8		6.0	7.3	1.2
Construction			3.0		0.2	21.8	
Road transport			2.5		53.6	1 040.3	10.2
Rail transport			0.0		0.0	38.8	
Air transport						262.7	
Water transport		5.3				57.0	
Commercial and services		0.4	50.6		3.4	25.9	0.3
Residential			148.1		11.7	1.1	
Lubes, bitumen, solvents						66.0	

Table 5: Australia's energy supply and consumption, 2010–11 (Continued)

		Biomass	Wind electricity	Solar	Hydro-electricity	Total electricity	U3O8 Uranium	Total
		PJ	PJ	PJ	PJ	PJ	PJ	PJ
Supply								
Primary indigenous		137.6	20.9	14.0	60.5		3 322.4	16 640.0
plus	all imports							2 183.9
less	all exports [a]						3 266.7	13 311.8
less	stock changes and discrepancies						55.8	- 587.9
Total primary energy supply [b]		137.6	20.9	14.0	60.5			6 100.1
less conversions								
Coke ovens						0.1		30.1
Petroleum refining						7.6		63.3
Gas manufacturing								0.3
Electricity generation [a]		12.6	20.9	3.1	60.5	- 909.4		1 615.9
Other conversion [c]								301.6
Fuel use in conversion						108.7		248.2
Consumption								
Total final energy consumption [d]		125.0		11.0		792.4		3 839.2
Agriculture						7.9		98.8
Mining		0.0				82.3		388.6
Food, beverages, textiles		33.6				22.6		113.2
Wood, paper and printing		29.2				17.9		73.9
Chemical		2.2				16.7		227.5
Iron and steel						15.7		73.1
Non-ferrous metals		1.4				146.3		391.6
Other industry		0.8				25.7		142.5
Construction						0.3		25.3
Road transport								1 106.5
Rail transport						8.2		47.0
Air transport								262.7
Water transport								62.4
Commercial and services		0.3		0.4		225.9		307.9
Residential		57.5		10.6		223.1		452.1
Lubes, bitumen, solvents								66.0

a Includes air and water transport bunker fuels. **b** Total primary energy supply is a measure of the total energy supplied within the economy. It is equal to indigenous production plus imports minus exports, plus stock changes and statistical discrepancies. **c** Includes return streams to refineries from the petrochemical industry, consumption of coke in blast furnaces, blast furnace gas manufacture, briquette manufacturing and lignite tar in char manufacture. **d** Total final energy consumption is the total energy consumed in the final or 'end-use' sectors. It is equal to total primary energy supply less energy consumed or lost in conversion, transmission and distribution. Totals may not add due to rounding.

Source: BREE 2012, Australian Energy Statistics.

Energy consumption, by state

The energy mix across the states and territories largely reflects the population, industry structure, geography and resource endowments of each region. For example, in Western Australia the size of the mining sector and its proximity to abundant gas resources results in gas supplying more than half of the state's total energy consumption.

New South Wales accounted for the largest share of total energy consumption in 2010–11 (Table 6), with a substantial proportion of electricity generation, transport and manufacturing activity based in this region (Figure 11). New South Wales also contributes the largest share of renewable energy consumption reflecting extensive use of biomass consumption in the residential sector and wood, paper and printing industries, and biofuels in the transport sector.

Tasmania has the highest renewable energy penetration and is the third largest consumer of renewable energy. More than two fifths of total energy in Tasmania is contributed by renewable energy, reflecting hydro power's role as the main source of electricity generation. Renewable penetration in the other states and territories ranges from 6 per cent in South Australia (which has a high proportion of the nation's wind generation) to 0.3 per cent in the Northern Territory (which is dominated by petroleum and gas).

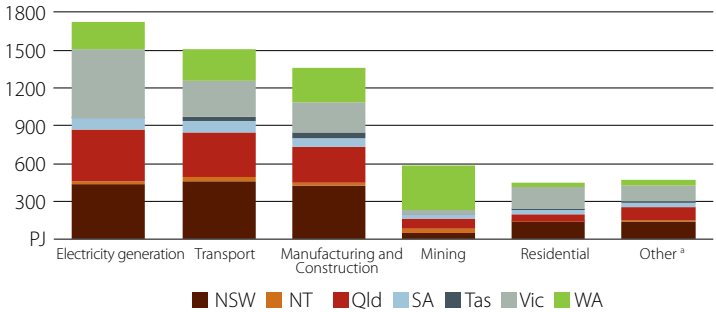
Table 6: Total energy consumption, by state, by energy type, 2010–11

	Coal	Petroleum products	Gas	Renewables	Total
	PJ	PJ	PJ	PJ	PJ
NSW	735	634	165	77	1639
NT	0	67	53	0	120
Qld	501	530	240	58	1306
SA	74	122	127	22	350
Tas	6	39	14	47	109
Vic	683	414	270	40	1393
WA	131	389	646	16	1182
Australia	2129	2195	1516	260	6100
Share of total	34.9%	36.0%	24.8%	4.3%	100%

Note: Totals may not add due to rounding.

Source: BREE 2012, Australian Energy Statistics.

Figure 11: Total primary energy supply, by state and sector, 2010–11



a includes consumption by the agricultural , commercial and services, gas production and distribution industries, and consumption of lubricants, greases, bitumen and solvents. Totals may not add due to rounding.

Source: BREE 2012, Australian Energy Statistics.

3. Electricity

The electricity industry consists of generators, transmission and distribution networks, and retailers. It is one of Australia's largest industries and comprised 1.7 per cent of industry gross value added in 2010-11. Between 2000–01 and 2010–11, Australia's electricity generation increased at an average rate of 1.2 per cent a year. However, in 2010–11, electricity generation remained relatively unchanged compared to the previous year at around 253 terawatt hours. In 2011–12, Australia's electricity generation is estimated to have increased by less than 1 per cent relative to 2010–11 to total 255 terawatt hours.

Industry structure

The current structure of Australia's eastern and southern electricity market was shaped by industry reforms in the early 1990s. A key element of these reforms was the establishment of the National Electricity Market (NEM), which began operation in 1998. The NEM facilitates market determined power flows across the Australian Capital Territory, New South Wales, Queensland, South Australia, Victoria, and, from May 2005, Tasmania. Western Australia and the Northern Territory are not connected to the NEM, primarily because of their geographical distance from the east coast.

The NEM operates as a wholesale spot market in which generators and retailers trade electricity through a gross pool managed by the Australian Energy Market Operator (AEMO) (Figure 12). AEMO is responsible for aggregating and dispatching supply to meet demand in the lowest cost manner available. In addition to the physical wholesale market, retailers may also contract with generators through financial markets to better manage any price risk associated with trade on the spot market.

The Australian Energy Market Commission (AEMC) is responsible for reviewing, amending and expanding the National Electricity Rules (NER) which govern the operations of the NEM. The enforcement of these rules, in addition to the economic regulation of electricity transmission and distribution networks and covered gas pipelines, is the responsibility of the Australian Energy Regulator (AER). The AER is also responsible for reporting on generator bidding behaviour in the NEM and compliance with the National Gas Rules. The interaction between these three bodies (AEMO, the AEMC and the AER) allows a consistent near-national approach to regulating Australia's energy markets.

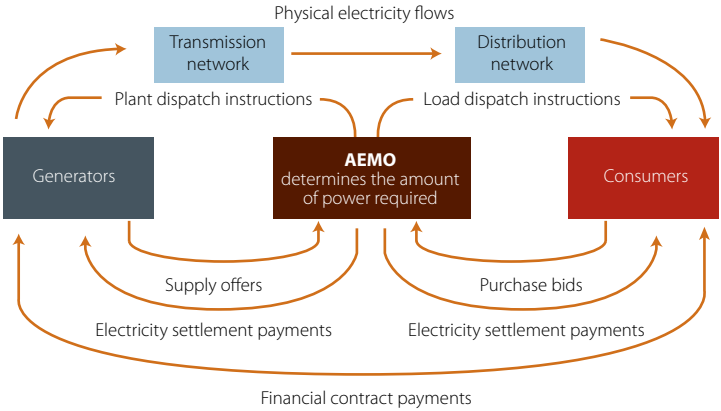
There is no formal, integrated electricity market in Western Australia (Figure 13). Electricity infrastructure is organised in several distinct systems including the South West Interconnected System (SWIS); the North West Interconnected System (NWIS); and a number of regional, non-interconnected power systems. The SWIS is the largest network, serving Perth and other major population centres in the south-west.

The SWIS became a wholesale market (where generators sell directly to retailers) in 2006. The Independent Market Operator (IMO) is responsible for the administration and operation of this market. Because of the small scale of the other systems in Western Australia it is impractical to introduce a wholesale market. Instead, they operate as retail markets where consumers purchase from competing retailers.

Western Australia retains state-based regulation of its electricity sector. The regulation of electricity transmission and distribution networks is the responsibility of the local Economic Regulation Authority (ERA). The ERA interprets, applies, and enforces the Electricity Networks Access Code which governs the operations of these networks.

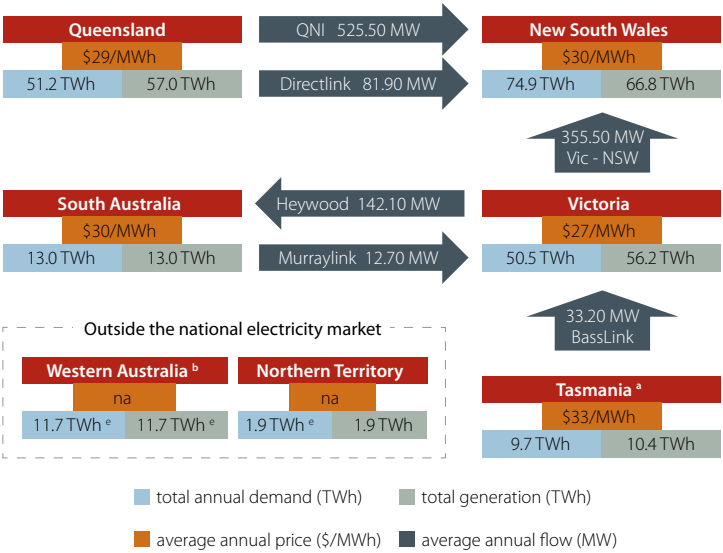
In the Northern Territory, market reforms were undertaken from 2000 to phase in competition of electricity supply and reduce the Power and Water Corporation's natural monopoly. New entrants into the Northern Territory electricity markets are permitted to use existing infrastructure (transmission and distribution) after signing an access agreement and paying a network charge. The Utilities Commission of the Northern Territory is responsible for the regulation of the market.

Figure 12: National electricity market structure



Source: AEMO 2010, An introduction to Australia's electricity market.

Figure 13: Regional electricity market activity, 2011–12



a Officially connected to the NEM in May 2005. b Sum of SWIS and NWIS markets, does not include off-grid generation.

Sources: Global Roam, NEM Review; NT Power and Water Corporation, Annual Report 2012; Horizon Power, Annual Report 2011/12; Verve Energy, Annual Report 2011-12

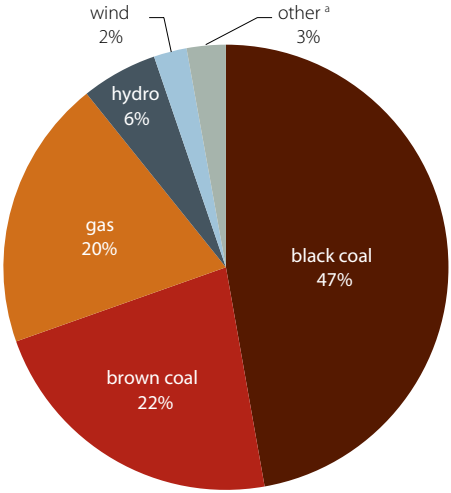
Production

In 2011–12, BREE estimates that Australian's total electricity generation was around 255 terawatt hours, a slight increase on 2010–11. Moderate economic growth, energy efficiency measures, and milder weather in the eastern and south eastern states helped to offset growing demand from the mining sector (Table 8).

Most of Australia's electricity is produced using coal, which is estimated to account for 70 per cent of total electricity generation in 2011–12 (Table 7). This is because coal is a relatively low cost energy source in Australia. It also reflects the abundance of coal reserves along the eastern seaboard, where the majority of electricity is generated and consumed.

Gas is Australia's second largest source of electricity generation, accounting for 20 per cent of generation in 2011–12. Renewable energy sources, mainly hydroelectricity, wind and bioenergy, accounted for the remaining 10 per cent of the electricity generation mix in 2011–12.

Figure 14: Australia's electricity generation, by energy source, 2011–12



a Other includes oil, bioenergy , solar PV, and multi-fuel fired power plants.

Source: BREE preliminary estimates.

Table 7: Australia's electricity generation, by energy source

	2006-07	2007-08	2008-09	2009-10	2010-11	2011-12 p
	TWh	TWh	TWh	TWh	TWh	TWh
black coal	132.4	129.6	127.3	123.7	116.9	120.3
brown coal	54.4	54.7	57.0	56.1	55.3	57.0
gas	31.8	35.0	38.9	44.6	49.0	50.0
hydro	14.5	12.1	11.9	13.5	16.8	14.1
wind	2.6	3.1	3.8	5.1	5.8	6.1
other [a]	7.4	8.9	9.9	9.2	8.8	7.2
total	**243.2**	**243.2**	**248.7**	**252.2**	**252.6**	**254.7**

a Includes oil, bioenergy, solar PV and multi-fuel fired power plants.
p BREE preliminary estimates.

Source: BREE 2012, Australian Energy Statistics; BREE estimates

Table 8: Key performance indicators for the Australian electricity industry

	Unit	2006-07	2007-08	2008-09	2009-10	2010-11
Generation capacity	GW	47	49	51	54	54
Capacity utilisation	%	55	54	52	49	48
Electricity generation [a]	TWh	227	228	230	229	228
Employment	('000)	44	46	44	52	59
Number of customers	('000)	9684	9892	10011	10166	10268
Wholesale price [b]						
- nominal	c/kWh	62	54	49	45	37
- real [c]	c/kWh	72	61	54	48	38
System reliability [d]	SAIDI [e]	264	208	243	247	399
System energy not supplied	MWh	1915	994	2102	1606	1690
Distribution losses	%	6	5	6	5	5

a Represents electricity generation for public consumption only. Does not include generation for own use and should not be compared with data in Table 7.

b Volume weighted average price (National Electricity Market). **c** 2012–13 A$. **d** Australian weighted average. System reliability figures represent the total of all distribution events, planned and unplanned, including significant events such as severe storms. **e** System Average Interruption Duration Index (minutes per customer per year).

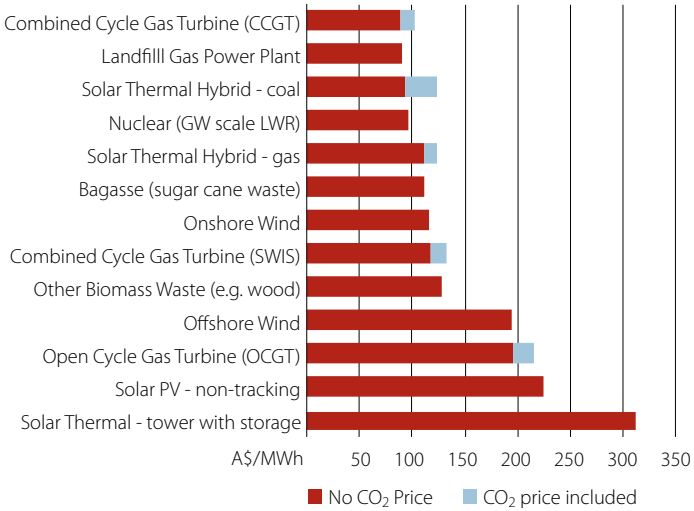
Sources: Energy Supply Association of Australia 2012, Electricity Gas Australia 2012; ABS 2012, Australian Labour Market Statistics, cat. no. 6105.0.

Generation costs in Australia

The electricity generation mix in Australia is determined by a number of factors, including natural resource endowment and the cost of generation. The long-run marginal cost of electricity generation can be represented by the Levelised Cost of Electricity (LCOE). The LCOE of a technology is the price per unit of output, usually expressed in dollars per megawatt hour ($/MWh), required to cover all costs incurred over the life of the plant. These costs include capital costs, cost of financing the project, operation and maintenance costs, and fuel costs. The LCOE provides a tool for comparison of costs across technologies.

Figure 15 depicts the estimated LCOE of selected generation technologies in Australia. The red bars illustrate the LCOE of new-build electricity generation in 2012. The navy bars represent the estimated increase in LCOE arising from the introduction of a carbon price. A number of renewable energy technologies, on a purely $/MWh basis, have comparable costs to natural gas based technologies (CCGT and OCGT). The combination of falling renewable capital costs, rising fossil fuel prices, and the carbon price is estimated to have improved the competitiveness of renewable energy technologies. Other considerations that affect the attractiveness of a generation technology, such as dispatchability and intermittency, are not factored into LCOE calculations.

Figure 15: LCOE, selected technologies, 2012 [a]



a Default region is NSW

Source: BREE 2012, Australian Energy Technology Assessment.

The relative costs of different technologies are constantly evolving in response to the policy environment, learning effects as technologies mature, economies of scale and changes to the price of input costs. For example, supportive government policy, 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 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.

These factors are expected to continue to make renewable energy technologies more cost competitive with fossil fuel-fired technologies over the next four decades. As a result, the Australian generation mix will evolve to reflect these developments. BREE projects that by 2049–50 the share of renewable energy sources in the electricity generation mix will increase dramatically to 51 per cent, from 10 per cent in 2010–11 under Treasury's carbon price projections.

More information on LCOEs and electricity generation costs in Australia can be found in the Australian Energy Technology Assessment (AETA) (BREE, 2012). The AETA will be refreshed in 2013 and updated in 2014.

Capacity

In 2010–11, Australia's principal electricity generation capacity was around 54 gigawatts. Average capacity utilisation remained between 48 per cent and 55 per cent over the past five years. The majority of Australia's electricity generation is supplied by steam plants, using coal or gas (Table 9). Most of Australia's black coal-fired generation capacity is located in New South Wales and Queensland, while Queensland also has the largest gas-fired generation capacity. A discussion on renewable electricity generation capacity is contained in the Clean Energy chapter.

As of October 2012, there were 20 major electricity generation projects at an advanced stage of development (Appendix 1). These projects, from a range of energy sources, have a combined capacity of 3 017 megawatts and a capital cost of around $6.5 billion. 12 of these projects are wind-powered, representing 65 per cent of all advanced electricity projects. Gas-fired projects account for a further 18 per cent of planned capacity, black coal-fired projects 15 per cent, and hydroelectricity and solar-powered projects account for the remaining 2 per cent. A further 133 major

electricity generation projects were at a less advanced stage of development and have a combined potential generation capacity of 39 281 megawatts (Table 9).

Table 9: Australia's thermal electricity generation capacity, 2010–11

	NSW [a]	NT	Qld [b]	SA	Tas	Vic	WA [c]	Aus
	MW	MW	MW	MW	MW	MW	MW	MW
Steam								
- black coal	11973	0	8805	0	0	0	1745	22 487
- brown coal	0	0	0	780	0	6630	0	7 410
- gas	0	0	132	1280	0	510	268	2 190
- multi-fuel	0	0	0	0	0	0	640	640
Reciprocating engine	0	77	0	50	0	0	0	127
Open cycle gas turbine								
- conventional gas	1332	322	1067	777	283	1321	1771	6 873
- coal seam gas	0	0	519	0	0	0	0	519
- oil products	50	30	457	113	0	0	83	733
- multi-fuel	0	0	0	0	0	0	586	586
Combined cycle gas turbine								
- conventional gas	595	131	215	663	208	0	800	2 612
- coal seam gas	0	0	1395	0	0	0	0	1 395
Total thermal capacity	**13 950**	**560**	**12 590**	**3 663**	**491**	**8 461**	**5 893**	**45 572**

a includes the ACT. **b** Includes generating capacity at Mt Isa. **c** Includes plants owned by Western Power Corporation (now Verve Energy) in the South West Interconnected System, and excludes plants operated under power purchase agreements.

Source: Energy Supply Association of Australia, Electricity Gas Australia 2012.

Transmission

The NEM is connected by six major transmission interconnectors. These interconnectors link the electricity networks in New South Wales, Queensland, South Australia, Tasmania and Victoria (Table 10). The NEM electricity transmission and distribution networks consist of around 785 000 kilometres of overhead transmission and distribution lines and around 124 000 kilometres of underground cables.

Maintaining and improving system reliability is a key priority for the market operator and requires significant long term investment in both transmission and distribution infrastructure. AEMO's National Transmission Network Development Plan lists 15 committed projects scheduled to be completed by 2016 (Table 11).

The SWIS network comprises 76 051 km of overhead and 21 507 km of underground transmission and distribution lines. While the SWIS stretches from Kalbarri in the north to Albany in the South and Kalgoorlie in the West it has no interconnectors due to its geographical isolation from other major networks (the NEM in South Australia and the NWIS in the Pilbara are the two closest major networks). Western Power's (the Government owned operator of the SWIS transmission network) 2012 annual planning report outlines a number of transmission and distribution projects aimed at maintaining system reliability. These include new and upgraded poles and transformers to accommodate additional demand, entirely new substations, and line upgrades, and represent $6 billion worth of investment to 2017.

Table 10: Australia's major power network transfer capabilities, 2010–11

Interconnector	Location	Forward capability	Reverse capability
		MW	MW
NSW to Qld (QNI)	Armidale to Braemar	300.00	900.00
NSW to Qld (Terranora)	Terranora to Mullumbimby	122.00	220.00
Vic to NSW	Buronga to Dederang	983	456
Vic to SA (Heywood)	Heywood to Tailem Bend	360.00	400.00
Vic to SA (Murraylink)	Red Cliffs to Berri	220.00	136.02
Tas to Vic (Basslink)	Seaspray to Georgetown	594.00	390.00
Transmission and distribution		**Overhead**	**Underground**
length (km)		785 355	123 984

Sources: Australian Energy Market Operator 2011, 2011 National Transmission Network Development plan; Global Roam 2011, NEM Review; Energy Supply Association of Australia 2012, Electricity Gas Australia 2012.

Table 11: Major committed transmission projects for Australia's National Electricity Market

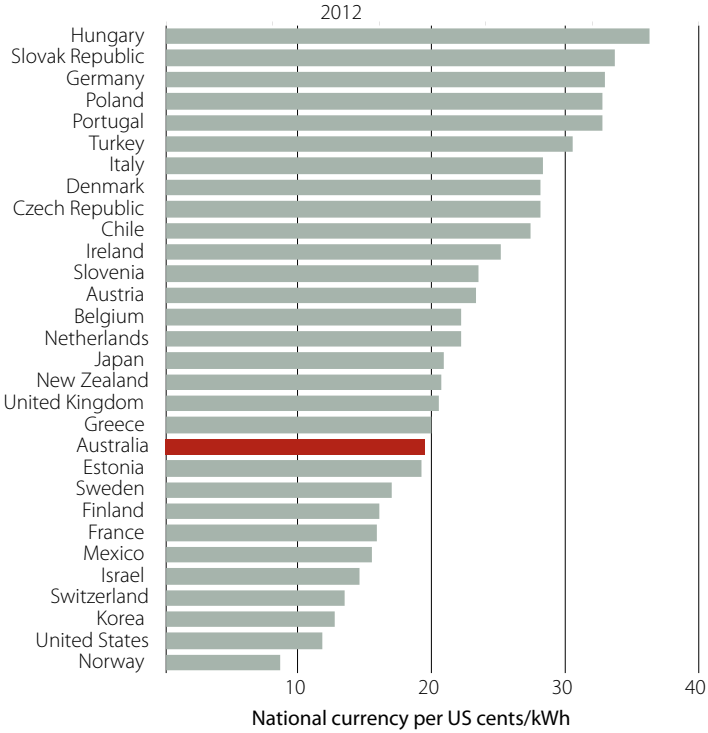
Region	Project details	Anticipated timing
Queensland	The Calvale-Stanwell 275 kV double circuit line.	Summer 2013-14
Queensland	The Columboola-Wandoan South 275 kV line (operating at 132 kV).	Winter 2013
Queensland	The Columboola-Wandoan South 275 kV line.	Winter 2014
New South Wales	An Armidale SVC power oscilation damper.	2012
New South Wales	Establishment and connection of the Holroyd and Rookwood Road Substations.	2013-14
New South Wales	A 200 MVAr capacitor at Armidale.	2013
New South Wales	Establishment of the Wallaroo Substation and Yass/Canberra line rearrangements.	2018
New South Wales	Beaconsfield West-Haymarket 330 kB cable (operated at 132 kV).	2012-13
New South Wales	Establishment and connection of a new Tomerong 330/132 kV substation to supply the Nowra area.	2015
New South Wales	Line ratings increased on the Marulan-Avon, Marulan-Dapto and Kangaroo Valley-Dapto 330 kV lines.	2015
Victoria	Macarthur Wind Farm connection, involving 420 MW at the 500 kV Tarrone Terminal Station.	December 2012
Victoria	Tarrone Terminal Station cut into the existing Moorabool-Heywood 500 kV No. 1 line.	Completed
South Australia	A Tungkillo 275 kV 100 MVAr capacitor bank.	2012
South Australia	A Cultana 275 kV augmentation.	2014
Victoria and South Australia	The incremental augmentation of the Victoria to South Australia interconnector (Heywood).	2016

Source: Australian Energy Market Operator 2012, National Transmission Network Development Plan.

Prices

International comparisons of residential electricity prices are sometimes used as an indicator of the relative price of electricity. Figure 16 shows household electricity prices in Australia compared to other OECD countries using the purchasing power parity (PPP) measure.

Figure 16: Real household electricity price indices, OECD economies, 2012



Notes: AEMC electricity price for Australia is GST inclusive. IEA 2012 electricity price data not reported for Australia, Spain, Luxembourg, Iceland and Canada. 2012 electricity prices for Belgium, Estonia, Greece, Israel and Sweden estimated by averaging data published for the first two quarters of 2012.

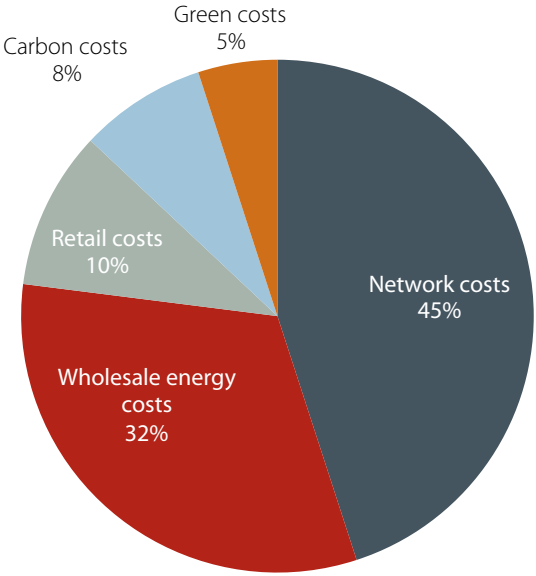
Sources: BREE; Australian Energy Market Commission (AEMC), Future Possible Retail Electricity Price Movements: 1 July 2012 to 30 June 2015; International Energy Agency (IEA), 2013 Electricity Prices and Taxes, Quarterly Statistics, First Quarter 2013; OECD. Stat.

There are a range of factors that differ between countries that affect electricity prices such as the size of electricity network, the geographic spread of the population and the availability of sources of fuel to population.

In Australia, the price of electricity is determined by a number of factors such as transmission and distribution network costs, the wholesale electricity price faced by retailers, and government policies. Recently, a major driver of rising retail electricity prices has been the significant investment in new, and upgrade of existing, transmission and distribution infrastructure required to support increasing (peak rather than overall) demand for electricity.

The Australian Energy Regulator estimates that transmission and distribution network costs will represent around 45 per cent of the retail electricity price faced by NEM-connected households in 2012–13, with wholesale electricity prices representing on average a further 32 per cent (Figure 17).

Figure 17: Composition of Residential electricity costs, NEM, 2012-13



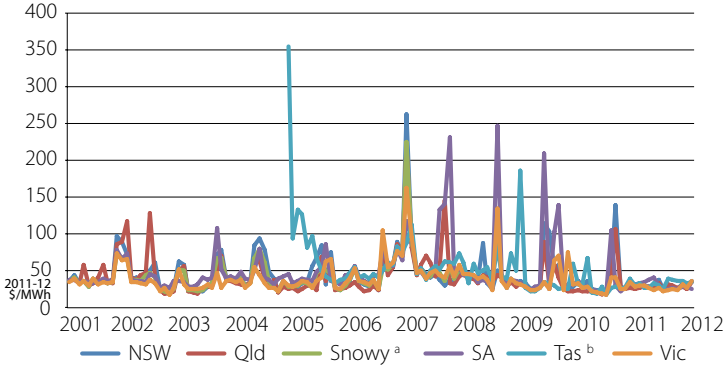
Source: Australian Energy Regulator 2013, State of the Energy Market.

Average wholesale electricity prices in the NEM increased in 2007, largely as a result of record average demand over the year combined with a tight supply situation caused by drought conditions. However, wholesale electricity prices have generally moderated since then. In 2011–12, wholesale electricity prices averaged around 8 per cent lower than in 2010–11.

Occasional wholesale price spikes are often caused by factors such as widespread heat waves or supply disruptions caused by natural disasters or generator malfunctions (Figure 18). For example, increased demand associated with a heat wave in NSW and SA led to prices around $640/MWh in February 2011. Recent price-highs occurred in early 2013 as a result of record breaking temperatures across the continent.

In contrast to wholesale prices, retail electricity prices have been steadily increasing in recent years. Since about 2007, both household and business prices have risen sharply, especially for households (Figure 19). Rising network charges associated with transmission and distribution continue to be the largest contributor to price rises. Over the past two decades, electricity prices paid by households have increased at a faster rate than those paid by Australian businesses. This is partly because of the removal of cross-subsidies from business to household customers in the 1990s.

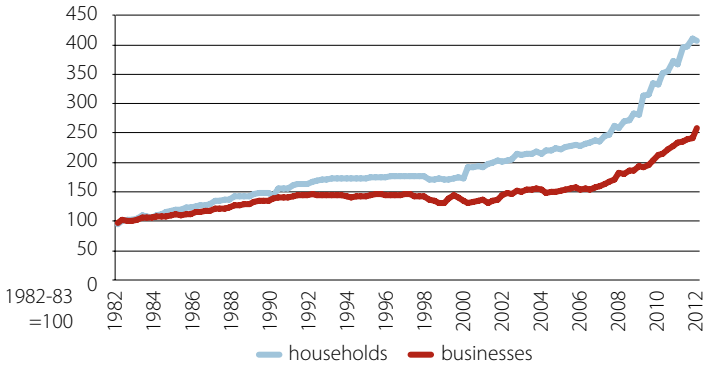
Figure 18: Average monthly spot prices in the National Electricity Market



a Snowy jurisdiction was discontinued in 2008. **b** Tasmania joined the NEM in 2005.

Sources: Global Roam 2012, NEM Review; ABS 2012, Consumer Price Index, Australia, cat. no. 6401.0.

Figure 19: Electricity price indices for households and businesses, Australia



Sources: ABS 2012, Producer Price Indexes, Australia, cat. no. 6427.0; Consumer Price Index, Australia, cat. no. 6401.0.

Table 12: Australia's principal generation businesses, 2011–12

	Generation (GWh)	Share of Australian generation (%)
New South Wales [a]		
Acciona Energy	151	0.06
Delta Electricity	21334	8.38
Eraring Energy	12220	4.80
Infigen Energy	413	0.16
Macquarie Generation	26146	10.27
Marubeni	1001	0.39
Origin Energy	271	0.11
Redbank Energy	1039	0.41
Snowy Hydro	1887	0.74
TRU Energy	2332	0.92
Queensland		
AGL Energy Siemens	839	0.33
BG Group	5011	1.97
Callide	570	0.22
CS Energy	11633	4.57
Ergon Energy	14	0.01
ERM Power	984	0.39
Millmerran	5887	2.31
Origin Energy	5124	2.01
Rio Tinto	1360	0.53
Stanwell Corporation	15519	6.09
Tarong Energy	9746	3.83
South Australia		
AGL Energy	3888	1.53
Alinta Energy	2999	1.18

Table 12: Australia's principal generation businesses, 2011–12 (Continued)

	Generation (GWh)	Share of Australian generation (%)
Flinders Power	1182	0.46
Infigen Energy	471	0.19
Infratil Energy	1	0.00
International Power (Pelican)	2602	1.02
International Power (Synergen)	9	0.00
Millmerran	188	0.07
Origin Energy	346	0.14
Pacific Hydro	175	0.07
Transfield	86	0.03
TRUenergy	319	0.13
TRUenergy & Acciona	185	0.07
TrustPower	373	0.15
Tasmania		
Aurora Energy	1556	0.61
Hydro Tasmania	8888	3.49
Victoria		
Acciona	646	0.25
AGL Energy	633	0.25
Alinta	62	0.02
Ecogen Energy	476	0.19
Energy Brix	1194	0.47
Eraring Energy	14	0.01
International Power	20996	8.24
LYMMCO	17148	6.73

Table 12: Australia's principal generation businesses, 2011–12 (Continued)

	Generation (GWh)	Share of Australian generation (%)
Origin	198	0.08
Pacific Hydro	235	0.09
Snowy Hydro	1356	0.53
TRUenergy	11419	4.48
Vicpower	1236	0.49
Western Australia [b]		
Horizon Power	994	0.39
Verve Energy	8834	3.47
Nothern Territory [b]		
Power and Water Corporation	1612	0.63

a Includes the Australian Capital Territory. **b** Not part of the National Electricity Market.

Sources: Global Roam 2013, NEM Review; NT Power and Water Corporation 2012, Annual Report 2012; Verve Energy 2012, Annual Report 2011–12; Horizon Power 2012, Annual Report 2011–12; BREE Estimates.

4. Clean Energy

Australia has abundant and diverse clean energy resources with significant potential for future development. Currently, renewable energy resources are used for heating and cooling, electricity generation, and as transportation fuels. Renewable resources currently utilised on a commercial scale include hydro and wind energy for electricity generation, and bioenergy and solar energy for both heating and cooling and electricity generation. Other renewable resources are mostly undeveloped at present and involve technologies still at the proof of concept stage or early stages of commercialisation.

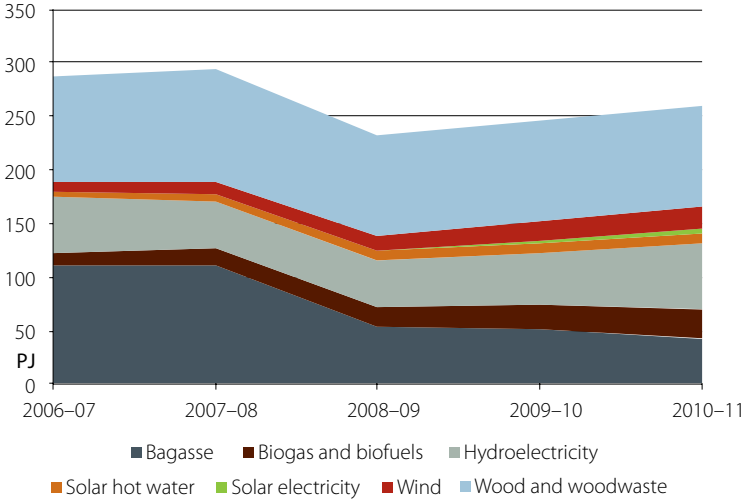
A number of significant barriers still face the large-scale utilisation of Australia's clean energy resources. Changed regulatory and approval processes are affecting well-established technologies like wind farms in some locations. Relatively high upfront capital costs, lack of familiarity with renewable energy technologies and the nature of Australia's capital markets can make it difficult to secure project financing. For some technologies, such as geothermal, energy conversion resources can be located long distances from transmission and distribution infrastructure and markets, and the technologies to utilise these resources are, in some cases, immature. Despite these challenges, the deployment of clean energy technologies is gathering pace, and is expected to play a critical role in moving to a low emissions future while meeting Australia's continued demand for energy.

Production

Renewable energy accounted for around 4 per cent of Australia's energy consumption in 2010–11, or around 260 petajoules (Table 13). While the composition is constantly changing, the overall share of renewables in Australia's energy mix has been reasonably constant over the past two decades. Hydroelectricity and various forms of bioenergy have been the dominant sources of renewable energy for a number of decades. In recent years, a number of new technologies such as wind and solar energy have emerged to gain increasing shares of the fuel mix. There is also potential for growth in other emerging technologies such as geothermal and ocean energy in coming decades.

Australian production of renewable energy (including both electricity generation and direct use) was dominated by wood and wood products (36 per cent), hydroelectricity (23 per cent) and bagasse (16 per cent) in 2010–11. Wind (8 per cent), solar (5 per cent) and other forms of bioenergy (10 per cent) accounted for the remainder (Figure 20). Most solar energy is used for residential water heating, which accounts for around 2 per cent of final energy consumption in the residential sector.

Figure 20: Australia's energy production, by renewable energy source [a]



a Includes both electricity and heat.

Source: BREE 2012, Australian Energy Statistics.

Renewable energy production declined at an average rate of 2.4 per cent a year in the five years to 2010–11, primarily as a result of falling bagasse use by sugar manufacturers in Queensland and New South Wales. However, in 2010–11, renewable energy production increased by 6 per cent from the previous year, largely a result of increased hydroelectricity generation (24 per cent growth). In 2010–11, the strongest growth in renewable energy production occurred in solar-powered electricity generation, which increased by 204 per cent, albeit from a small base. Wind-powered electricity generation and solar hot water also increased considerably, by 15 per cent and 8 per cent, respectively.

Table 13: Australia's energy production, by renewable energy source [a]

	2006–07	2007–08	2008–09	2009–10	2010–11
	PJ	PJ	PJ	PJ	PJ
Bagasse	110.8	110.8	52.8	50.2	42.8
Biogas and biofuels	10.8	15.2	20	23.1	27.2
Hydroelectricity	52.3	43.4	42.7	48.8	60.5
Solar hot water	6	6.7	8.2	10.1	11
Solar electricity	0.4	0.4	0.6	1	3.1
Wind	9.4	11.1	13.8	18.2	20.9
Wood and woodwaste	96.7	105.9	94.7	95.2	94.8
Total	**286.3**	**293.6**	**232.8**	**246.5**	**260.3**

a Includes both electricity and heat.

Source: BREE 2012, Australian Energy Statistics.

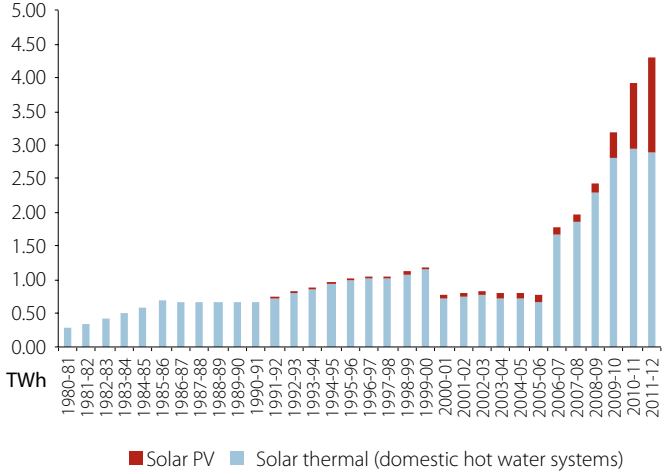
Solar energy in Australia

Solar energy is generated when energy from the sun is converted into electricity or used to heat air, water or other fluids. There are two main types of solar energy technologies in Australia – solar thermal and solar photovoltaic (PV).

Solar thermal covers technologies that convert sunlight into heat – thermal energy. This heat is typically used directly for space heating (as in solar hot water systems) or to generate electricity (using steam and turbines). Solar PV technologies convert sunlight into electricity through photovoltaic cells. These cells have traditionally been used on rooftops or at smaller scale, but are beginning to be expanded to larger scale grid connected systems.

Australia's primary solar energy consumption accounted for 4.2 per cent of all renewable energy use and around 0.2 per cent of total primary energy consumption in 2010–11. Primary solar consumption has increased significantly since 2006–07 at an average growth rate of 22 per cent per year. The bulk of the growth over this period has been from installations of domestic solar hot water systems. Solar PV systems made a smaller contribution, but installations have been growing more rapidly in recent years (Figure 21). In total, Australia's solar energy consumption in 2010–11 was 4.3 TWh (14 PJ), of which more than 90 per cent was used in the residential sector.

Figure 21: Solar energy production, by technology



Source: BREE 2012, Australian Energy Statistics; BREE estimate.

New South Wales contributed 30 per cent of Australia's total solar thermal use in 2011–12. Western Australia and Queensland contributed another 26 per cent and 19 per cent, respectively. During the period 1999–00 to 2010–11, Victoria had the highest growth rate of solar use (28 per cent per year). This was followed by New South Wales and South Australia (both at 20 per cent a year) and Queensland (18 per cent per year) (BREE estimation).

Electricity generation from solar energy in Australia is currently mainly sourced from PV installations; primarily residential grid-connected systems. Electricity generation from solar thermal systems is currently limited to small pilot-scale demonstration projects, although interest for large scale electricity generation is increasing. In 2011–12, 1.4 TWh (5.1 PJ) of electricity was generated from solar energy, representing 0.56 per cent of Australian electricity generation.

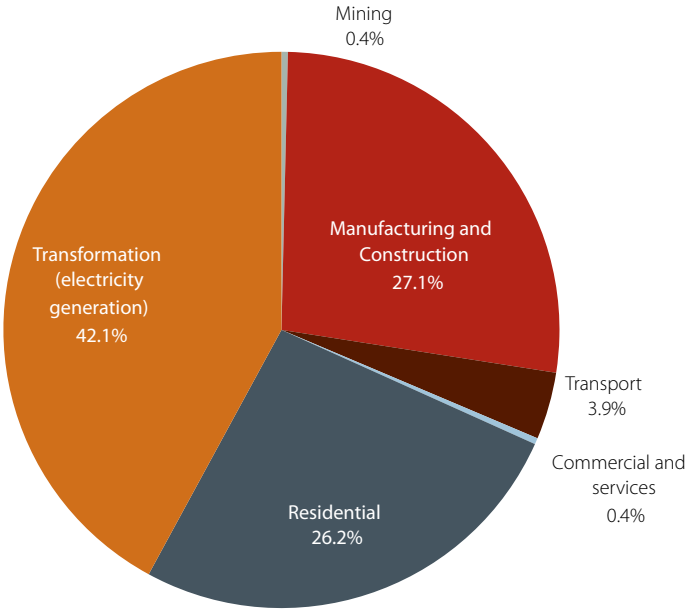
Electricity generation from solar energy has increased rapidly in recent years. This reflects both falling capital costs associated with PV panels as well as Federal and State/Territory support in the form of feed-in-tariffs and rebate schemes. Over the period 2002-03 to 2011–12, electricity generation from solar energy grew at an average rate of 46 per cent a year, from 0.06 TWh (0.21 PJ) in 2002–03 to 1.4 TWh (5.1 PJ) in 2011–12 (BREE estimate).

Electricity generation

The electricity generation sector is the largest user of primary renewable energy in Australia, accounting for 42 per cent of the total in 2010–11 (Figure 22). This figure represents the renewable energy inputs, including hydro, bioenergy, wind and solar PV, used to generate electricity. The manufacturing sector is the next largest user, accounting for 27 per cent of total consumption. This largely represents use by the food, beverage and tobacco and the wood, paper and printing industries, which utilise bagasse and wood for heating in their manufacturing processes.

The residential sector accounted for 26 per cent of primary renewables consumption in 2010–11, predominantly from firewood, with a smaller proportion from solar hot water. The transport sector accounts for around 4 per cent of renewable energy use in Australia, which includes biofuels such as biodiesel and ethanol used for road transport.

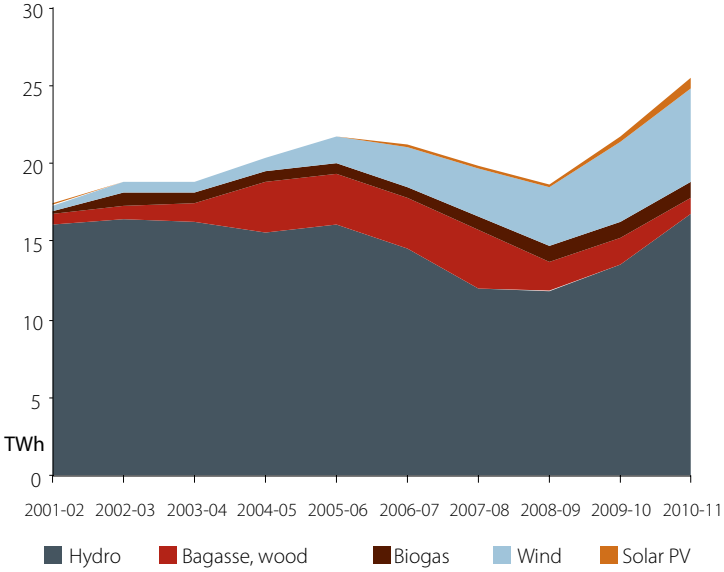
Figure 22: Renewable energy consumption, by sector, 2010–11



Source: BREE 2012, Australian Energy Statistics.

In 2010–11, renewable energy contributed around 10 per cent of energy used in electricity generation. This share has not changed substantially over the past two decades, except in in the past two years, mainly because of greater hydro utilisation after a period of drought as well as rapid expansion in wind generation. Hydro power accounted for two-thirds of total renewable electricity generation in 2010–11, followed by wind, bioenergy and solar PV (Figure 23). Wind-powered electricity and solar electricity have grown particularly rapidly since 2004–05, albeit from a low base, increasing at an average annual rate of 31 per cent and 41 per cent, respectively.

Figure 23: Australian electricity generation from renewable energy



Source: BREE 2012, Australian Energy Statistics.

The distribution of clean energy production facilities in Australia reflects the climatic and geographical characteristics of different regions. Hydroelectricity capacity in Australia is located mostly in New South Wales, Tasmania, Queensland and Victoria; while wind farms are most abundant in South Australia, Victoria and Western Australia (Table 14). Almost all bagasse-powered energy facilities are located in Queensland where sugarcane production is located. By contrast, there is a more even distribution of biogas-powered facilities across Australia, as these facilities are mostly based on gas generated from landfill and sewerage.

Tasmania generates the largest volume of renewable electricity in Australia. In 2010–11, renewable energy accounted for 86 per cent of its total electricity generation. New South Wales was the second largest producer of renewable electricity, but the share of renewables in total generation was much lower. In South Australia, wind accounts for 20 per cent of total electricity generation; among the highest penetration rates in the world.

Table 14: Capacity of renewable electricity generation in Australia, MWs, 2012[a]

Fuel type	NSW & ACT	VIC	QLD	SA	WA	TAS	NT	TOTAL
Hydro	2 488.2	2 313.3	164.2	3.7	30.1	2 295.7	0.0	7 295.2
Bagasse	75.5	0.0	362.6	0.0	6.0	0.0	0.0	444.1
Biomass	4.4	0.2	38.0	0.0	1.0	0.0	0.0	43.6
Black liquor	20.0	54.5	2.0	0.0	0.0	0.0	0.0	76.5
Geothermal	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.1
Landfill gas	66.1	46.8	22.1	13.1	25.2	4.9	1.1	179.3
Sewage gas	7.9	21.5	4.5	5.5	1.8	0.1	0.0	41.2
Solar [b]	4.8	1.2	0.5	1.7	1.0	0.1	1.6	10.9
Wave	0.5	0.2	0.0	0.0	0.1	0.0	0.0	0.8
Wind	187.4	427.9	12.5	1 151.5	205.1	142.5	0.1	2 126.9
Total	**2 854.7**	**2 865.5**	**606.5**	**1 175.4**	**270.4**	**2 443.4**	**2.8**	**10 218.7**

a Figures include correction of plant capacity **b** Solar capacity does not include solar hot water installations and rooftop solar.

Sources: ESAA, company annual reports, Clean Energy Council, AEMO, IMO, WA Public Utilities Office; Geoscience Australia.

Clean energy development

The Australian Government has implemented a number of measures to increase the uptake of renewable energy in Australia. Key amongst these is the Renewable Energy Target (RET), carbon pricing, the Australian Renewable Energy Agency (ARENA), and the Clean Energy Finance Corporation (CEFC).

The Renewable Energy Target (RET) is a legislative scheme that aims to:

(i) encourage the additional generation of electricity from renewable sources;

(ii) reduce emissions of greenhouse gases in the electricity sector; and

(iii) ensure that renewable energy sources are ecologically sustainable.

The RET achieves this by creating a guaranteed market for renewable energy deployment, using a mechanism of tradable certificates created by large-scale renewable energy generators and owners of small-scale solar, wind, and hydro systems. Demand for these certificates is created by placing a legal obligation on entities that buy wholesale electricity (mainly electricity retailers), to source and surrender certificates to the Government's independent market operator - the Clean Energy Regulator.

Certificates can be created by:

(i) the installation of solar water heaters and small-scale solar PV, wind or hydro systems under the Small-scale Renewable Energy Scheme (SRES). These are known as Small-scale Technology Certificates (STCs); and

(ii) renewable energy power stations under the Large-scale Renewable Energy Target (LRET). These are known as Large-scale Generation Certificates (LGCs).

The RET will ensure that at least 20 per cent of Australia's electricity generation comes from renewables in 2020 by requiring 41 850 GWh worth of certificates be surrendered in that year. In 2013, 19 088 GWh of certificates are legally required to be surrendered.

Operating in tandem with the RET is the Australian Government's Clean Energy Future Plan. The plan consists of a raft of measures introduced under the Clean Energy Future Legislative Package that aims to cut pollution and increase investment. The Package (together with the RET) specifically targets the reduction of Australia's carbon emissions to 5 per cent below 2000 levels by 2020, and up to 80 per cent below 2000 levels by 2050. This target is to be achieved through carbon pricing, the RET, and a package of complementary measures. The carbon price, which commenced on 1 July 2012, makes large emitters of carbon financially liable for their emissions. The price will be fixed for three years before transitioning to an emissions trading scheme. The complementary measures include household and industry assistance and funding directed towards the development of renewable energy, energy efficiency and low emissions technologies.

Two new agencies created by the Clean Energy Future Package will specifically drive renewable energy growth in Australia over the coming years. These are the Australian Renewable Energy Agency (ARENA, in operation from 1 July, 2012) and the Clean Energy Finance Corporation (CEFC, in operation from 1 July, 2013).

ARENA's legislative mandate is to improve the competitiveness and increase the supply of renewable energy in Australia. ARENA will achieve this by providing financial assistance, from a $3.1 billion fund, for:

(i) the research, development, demonstration, deployment and commercialisation of renewable energy and related technologies; and

(ii) the storage and sharing of knowledge and information about renewable energy technologies.

ARENA will also collect, analyse and share information and knowledge about renewable energy and related technologies and provide advice to the Minister for Resources and Energy regarding renewable energy and related technologies.

The objective of the commercially oriented Clean Energy Finance Corporation is to overcome capital market barriers that hinder the financing, commercialisation and deployment of renewable energy, energy efficiency and low emissions technologies.

The CEFC has $10 billion to invest in firms and projects utilising these technologies as well as manufacturing businesses that focus on producing the inputs required. It is intended to be commercially oriented and to make a positive return on its investments. Capital that is returned from investments will be retained for reinvestment by the CEFC, with the Board to determine the quantum of any dividends payable to the Australian Renewable Energy Agency.

Outlook

Significant growth in renewable energy electricity generation is expected in the coming years. As of October 2012, there were 14 renewable energy projects at an advanced stage of development on BREE's major electricity projects listing (Table 15; Appendix 1). The total capacity of both advanced and less advanced renewable projects that are proposed to commence up to 2018 is 19 Gigawatts, with an estimated capital expenditure of $40 billion (Table 15).

Table 15: Major renewable electricity generation projects, October 2012

	Number of projects	New Capacity MW	Capital Expenditure (if applicable) $m
Advanced			
Wind	13	1945	4487
Hydro	1	40	20
Solar	1	44	105
Total	**14**	**2029**	**4612**
Less advanced			
Wind	72	14676	na
Hydro	1	37	na
Ocean	3	786	na
Biomass	1	83	na
Solar	11	1035	na
Geothermal	3	220	na
Total	**91**	**16837**	**na**

Sources: BREE 2012, Major electricity generation projects.

The quantity of wind projects currently in development reflects a number of key factors. Firstly, wind resources along the Southern coasts of Australia are amongst the best in the world. Secondly, wind generation technology has matured and fallen in cost over recent years; increasing competitiveness and spurring growth. Finally, the carbon price and the RET have, and will continue to, fuel the growth in wind energy generation by making it relatively cheaper compared to fossil fuel based generation.

Investment in large-scale solar electricity generation is also increasing rapidly. Australia has the highest average solar radiation per square metre of any continent and has world-leading

capabilities in solar PV research and technology development. In 2012 the 10MW Greenough River Solar Farm in Western Australia commenced operation and Australia's first reverse auction bidding process was completed in the Australian Capital Territory (with the 20 MW Royalla Solar Farm being announced as the winner). Furthermore, the Australian Government, through ARENA, is currently providing over $300 million to support a range of solar energy projects and technologies.

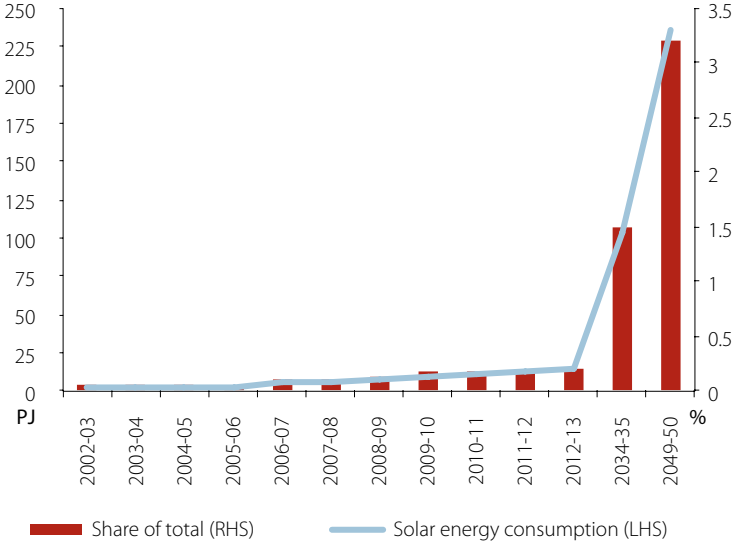
Australia has considerable hot rock geothermal energy potential. There is also potential for lower temperature geothermal resources associated with naturally circulating waters in aquifers (Hot Sedimentary Aquifer Geothermal). There is one geothermal electricity project operational in Australia, an 80 kilowatt facility in Birdsville, Queensland. There are also several large projects at the feasibility study and approval stage in Victoria and South Australia. The Australian Government, through ARENA, is providing almost $170 million in funding for six geothermal projects.

Carbon Capture and Storage (CCS), particularly when applied to coal-fired power generation, has significant potential to reduce Australia's greenhouse gas emissions while contributing to energy security and reliability. Governments and industries are aiming to demonstrate the commercial viability of integrated CCS projects. Towards this goal, the CCS Flagships program is supporting the South West Hub and CarbonNet CCS Flagship projects to demonstrate large-scale integrated CCS projects in Australia.

Interest in clean energy investment is continuing to grow, supported by technology advancements, improving commercial viability and supportive government policies such as the carbon price and RET. Over time this will contribute to a major shift in the Australian energy landscape, with clean energy playing a larger role in the energy mix.

BREE's latest long term projections (to 2050) of Australian energy reflect these coming changes under existing policies. Primary energy consumption of renewables is expected to grow at around 3.6 per cent from 2012-13 to 2049-50, to account for 14 per cent of total energy consumption with 1032 PJ. Solar growth is expected to be particularly strong at 7.8 per cent per year, increasing from 14 PJ in 2012-13 to 236 PJ in 2049-50 (Figure 24).

Figure 24: Projected primary consumption of solar energy to 2049-50



Source: BREE 2012, Australian Energy Statistics; BREE 2012, Australian Energy Projections to 2049-50; BREE Estimates.

Renewables are forecast to supplant non-renewables as the dominant source of electricity generation by 2049-50, comprising 51 per cent of the energy mix (Table 16). Solar electricity generation is expected to grow strongly from 1 TWh in 2012-13 to 62 TWh, and around 16 per cent of total generation, in 2049-50. Wind and geothermal are also forecast to increase rapidly, reaching 62 TWh and 29 TWh of generation in 2049-50, respectively.

Table 16: Projected renewable electricity generation, by energy type (TWh)

	Amount (TWh)			Share of total electricity generation (%)		Average annual growth (%)
	2012-13	2034-35	2049-50	2012-13	2049-50	2012-13 to 2049-50
Renewables	34	130	194	13	51	4.8
Hydro	17	17	17	7	5	0
Wind	14	64	78	6	21	4.7
Bioenergy	2	7	7	1	2	3.9
Solar	1	25	62	<1	16	12.3
Geothermal	0	17	29	0	8	na
Total [a]	**253**	**324**	**377**	**100**	**100**	**1.1**

a Renewable and non-renewable electricity generation.

Source: BREE 2012, Australian Energy Projections to 2049-50.

5. Coal production and trade

Coal is one of Australia's largest commodity exports, with earnings of around $48 billion in 2011–12. Australia's success in world coal markets has been based on reliable and competitive supplies of high quality metallurgical and thermal coal.

Coal is also a significant component of Australia's domestic energy needs, accounting for around 70 per cent of electricity generation in 2011–12.

Production

Australia accounts for around 6 per cent of world coal production, and 27 per cent of world coal trade, around 97 per cent of which is sourced from New South Wales and Queensland. The majority of Australia's metallurgical (coking) coal is produced in Queensland, while production in New South Wales is largely classed as thermal (steaming) coal (Table 17). More than three-quarters of this output is sourced from open cut mines.

Table 17: Australia's coal production[a], by state

	2007-08	2008-09	2009-10	2010-11	2011-12
	Mt	Mt	Mt	Mt	Mt
Brown coal					
Vic	66	68.3	68.8	65.7	na
Total	66	68.3	68.8	65.7	na
Black coal					
Qld	180.5	190.4	207.4	179.8	171.6
NSW	135	137.8	147.3	156.9	167.2
WA	6.2	7	6.7	4	4
SA	3.9	3.8	3.8	3.8	3.8
Tas	0.6	0.6	0.6	0.6	0.6
Total	**326.2**	**339.6**	**365.9**	**345.2**	**347.2**

a Saleable production.

Source: BREE 2013, March Resources and Energy Quarterly.

Australian black coal production increased at an average annual rate of 1.4 per cent between 2007–08 and 2011–12, as strong global import demand was offset somewhat by weather events. This growth was supported by the commissioning of new mines, rail networks and ports in Queensland and New South Wales. In 2010–11, Australian black coal production declined by 10 per cent as production was hampered by floods in Queensland and heavy rainfall over New South Wales in January and June 2011. Growth in production rebounded in 2011–12 as production began increasing at flood affected mines before yet more flooding in early 2012.

Over the medium term Australia's coal production is likely to increase significantly as a result of investment in new mining and export capacity (and the assumed resumption of more normal weather patterns). Investment in the Australian coal mining

sector continues to be robust. As of October 2012, there were 17 committed coal mining projects and 63 projects at the feasibility stage of BREE's major resource project listing (see Appendix 1).

Trade

Around 87 per cent of Australia's black coal production is destined for export. Australia accounts for 27 per cent of world black coal exports—51 per cent of metallurgical coal exports and 18 per cent of thermal coal exports (Figure 25). In the past, infrastructure has been a constraint on Australian coal exports. However, expansions to port capacity have alleviated some of these constraints. For example, in 2011–12, growth in Australia's thermal coal exports was supported by infrastructure upgrades at the Newcastle Coal Infrastructure Group terminal and the Kooragang Island Coal Terminal. Upgrades to rail infrastructure at Goonyella in Queensland (among other projects) have also increased metallurgical coal export capacity. Another key factor increasing export capacity has been increasing efficiency in the use of existing resources (in Newcastle in particular).

Figure 25a: World metallurgical coal trade, major exporters, 2011

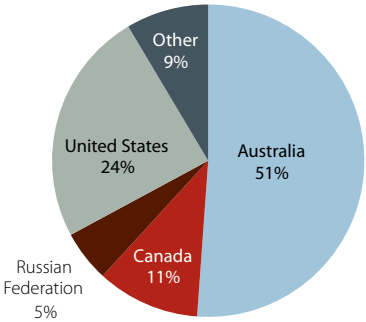
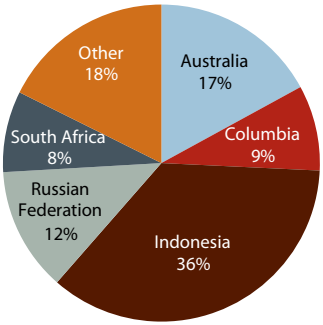


Figure 25b: World thermal coal trade, major exporters, 2011



Source: BREE 2012, Resources and Energy Statistics.

Most of Australia's metallurgical coal exports are destined for Asia and Europe where it is used for steel manufacture. The largest importers of Australian metallurgical coal are Japan, India, China, the Republic of Korea and the European Union (Table 18). Australia's thermal coal exports are mainly destined for Japan, the Republic of Korea, China and Chinese Taipei. The fastest growing export destination for both metallurgical and thermal coal is China; imports from Australia have increased more than sevenfold since 2006–07.

Table 18: Australia's coal exports, by type, by destination

	2007-08	2008-09	2009-10	2010-11	2011-12
	Mt	Mt	Mt	Mt	Mt
Metallurgical coal					
Brazil	3.87	4.19	4.23	2.88	2.34
China	1.53	14.75	27.28	15.72	21.2
Chinese Taipei	6.39	2.66	5.36	8.05	8.59
European Union 27	24.51	14.69	15.61	17.07	17.71
India	24.23	24.28	31.38	30.91	29.26
Japan	50.2	42.22	48.46	42.61	40.25
Korea, Rep. of	8.36	13.05	15.86	16.44	16.37
Other	17.83	9.4	9.08	6.77	6.67
World	136.92	125.24	157.26	140.45	142.39
Thermal coal					
China	1.48	8.4	13.92	16.67	28.48
Chinese Taipei	18.56	20.3	19.55	20.12	17.34
European Union 27	2.15	3.72	0.28	0.14	0.04
Japan	66.92	62.58	66.41	66.96	69.71
Korea, Rep. of	18.55	30.14	24.84	28.19	28.85
Other	7.41	11.22	9.98	11.24	14.02
World	115.07	136.36	134.98	143.32	158.44
Total coal	**251.99**	**261.6**	**292.25**	**283.77**	**300.83**

Source: BREE 2012, Resources and Energy Statistics.

Australian exports of coal increased by 6 per cent in 2011–12 largely due to strong growth in thermal coal exports, in turn driven by increasing Chinese demand.

Metallurgical coal exports increased at an average annual rate of 2 per cent between 2007–08 and 2011–12 (Table 19). Growth in metallurgical coal exports has been primarily driven by increasing growth in Chinese, Indian and Republic of Korean steel production and associated import demand. Output rebounded slightly in 2011-12 following production declines caused by heavy rain and flooding in Queensland in late 2010 and early 2011.

Over the period 2007–08 to 2011–12, Australia's thermal coal exports increased at a robust average annual rate of 7 per cent. This strong growth was underpinned by rising import demand from Asian economies including China and the Republic of Korea. In 2011–12, Australian exports of thermal coal increased by 11 per cent relative to 2010–11 to 158 million tonnes, supported by the completion of infrastructure projects in New South Wales.

Table 19: Australian coal exports

		2007-08	2008-09	2009-10	2010-11	2011-12
Metallurgical coal, high quality						
Volume	Mt	83.65	79.63	97.72	91.6	91.59
Value	2010-11 $m	11 802	26 737	17 589	21 146	21 714
Unit value	2010-11 $/t	141.07	335.78	180	230.85	237.07
Excluding high quality						
Volume	Mt	53.27	45.61	59.55	48.85	50.8
Value	2010-11 $m	5 648	12 100	7 696	8 650	9 020
Unit value	2010-11 $/t	106.04	265.28	129.25	177.06	177.56
Total metallurgical coal						
Volume	Mt	136.92	125.24	157.26	140.45	142.4
Value	2010-11 $m	17 450	38 837	25 285	29 796	30 734
Unit value	2010-11 $/t	127.44	310.11	160.78	212.14	215.83
Thermal coal						
Volume	Mt	115.07	136.36	134.98	143.32	158.44
Value	2010-11 $m	9 101	18 868	12 255	13 956	17 124
Unit value	2010-11 $/t	79.1	138.37	90.78	97.37	108.08

Source: BREE 2013, March Resources and Energy Quarterly.

Prices

Since April 2010, contract prices for most metallurgical coal from major producers have been set on a quarterly basis, a significant departure from the decades-old annual price-setting system. The majority of thermal coal contract prices are still set on a Japanese Fiscal Year (JFY, April to March) basis.

Average high quality hard coking coal (a grade of metallurgical coal) prices for 2012 were US$210 a tonne; a 27 per cent fall from

the previous year (Table 20). Thermal coal contract prices for JFY 2012 were settled at around US$115 a tonne, 11 per cent lower than the previous year, and US$95 a tonne for JFY 2013. While average contract prices for high and low quality metallurgical coal and thermal coal were down over the past twelve months, they rose strongly in the aftermath of the 2008-09 global financial crisis. Medium term growth has been underpinned by strong increases in demand, particularly in developing economies, and supply disruptions in key producing countries. Since 2008, real contract prices are down on pre-financial crisis highs, however, they still remain well above long term trend.

Table 20: Coal prices [a]

	2008	2009	2010	2011	2012	
Metallurgical coal, hard [b]						
US$/t	300.00	128.00	214.75	291.25	192.5	es
A$/t	377.68	150.07	227.73	279.03	186.67	
Real A$/t	417.80	162.87	240.05	287.12	188.02	
Metallurgical coal, other [c]						
US$/t	240.00	80.00	191.94	179.28	131.25	es
A$/t	302.14	93.79	203.54	171.76	127.28	
Real A$/t	334.24	101.79	214.55	176.74	128.20	
Thermal coal [d]						
US$/t	125.00	70.35	98.00	129.85	115	
A$/t	157.37	82.48	103.92	124.40	111.52	
Real A$/t	174.08	89.51	109.55	128.01	112.33	

a Japanese fiscal year beginning 1 April. Prices are fob Australia basis; real prices are in 2010 Australian dollar terms. **b** For example, Goonyella export coal. **c** Non-hard coking coal price based on Australian/Japanese contract settlements. **d** For thermal coal with a calorific value of 6700 kcal/kg (gross air dried). **e** Average of first three quarters of year. **s** BREE estimate.

Sources: BREE; IEA, Coal Information.

6. Gas production and trade

Gas (conventional and unconventional) is becoming increasingly important for Australia, both as a domestic energy source and as a provider of export income. Australia is a significant exporter of liquefied natural gas (LNG), with around half of all gas production exported. In 2011–12, the value of Australian LNG exports was $12 billion. Since 1999–2000, domestic gas consumption has increased at an average annual rate of 4 per cent. Gas accounted for 25 per cent of Australian energy consumption, and around 20 per cent of electricity generation in 2010–11.

Production

Australia's conventional gas production is predominantly sourced from three basins: the Carnarvon (north-west Western Australia), the Cooper/Eromanga (central Australia) and the Gippsland (Victoria). These basins accounted for 83 per cent of production in 2011–12.

Western Australia is the largest gas producing state in Australia, representing about two thirds of national production in 2011–12 (Table 21). The Western Australian gas market is geographically and economically separate to the interconnected eastern gas markets. With the bulk of Western Australia's gas supply produced as part of LNG projects, the domestic market is uniquely exposed to international energy market conditions. Gas production in Western Australia has grown at an average annual rate of around 7 per cent over the past five years, to reach 1458 petajoules in 2011–12. The majority of gas production in Western Australia is

sourced from the Carnarvon Basin, a significant proportion of which comes from the North West Shelf Venture.

The Gippsland Basin in Victoria is Australia's longest producing basin, accounting for around 12 per cent of national production in 2011–12. The remaining Victorian gas production is attributable to the offshore Otway and Bass basins. Gas sourced from the Gippsland, Otway and Bass basins (comprising around 20 per cent of production) is primarily for electricity generation and direct-use in south-east Australia.

The Northern Territory is the smallest gas market in Australia, with supply historically sourced from the onshore Amadeus Basin. Gas production in the Northern Territory totalled 20 petajoules in 2011–12. Until 2005–06, all of the gas produced in the Northern Territory gas market was consumed locally. The development of the offshore Bayu Undan field in 2005–06 saw Darwin host Australia's second LNG facility. In 2009, the offshore Blacktip gas field in the Bonaparte Basin started production with gas being piped onshore to supplement the declining Amadeus Basin supply.

Production of coal seam gas (CSG) has increased significantly in the past five years, with its share of total Australian gas production, on an energy content basis, increasing from 2 per cent in 2002–03 to 12 per cent (and 39 per cent of Eastern market production) in 2011–12. Most CSG production is sourced from Queensland, which accounted for around 98 per cent of total CSG production in 2011–12 (New South Wales produces the remainder). Production of CSG is expected to continue to grow, with a number of projects under construction and planned in both states, including three CSG export projects in the form of LNG under construction in Queensland, due for completion in the middle of this decade.

Table 21: Australia's gas production, by state[a]

State	2007-08	2008-09	2009-10	2010-11	2011-12
	PJ	PJ	PJ	PJ	PJ
Qld					
Conventional	28	27	21	10	4
Coal seam gas	129	150	195	233	241
Total	157	177	216	243	245
NSW					
Coal seam gas	5	5	6	6	6
Vic	313	274	270	342	334
SA	78	134	107	41	45
WA	1143	1235	1371	1439	1458
NT b	22	22	27	20	20
Australia	1717	1846	1997	2091	2353

a Data converted from volume to energy content using average conversion factors as detailed in Appendix 2. **b** Joint Petroleum Development Area gas used in Darwin LNG not included.

Sources: BREE.

Unconventional gas in Australia

Gas is a combustible mixture of hydrocarbon gases, including methane, ethane, propane, butane and condensate. It is formed by the alteration of organic matter. When accumulated in a subsurface reservoir that can be readily exploited (or with oil in oil fields), it is known as conventional gas. Gas can also be found in more difficult to extract unconventional deposits, such as coal beds or in shales, low quality reservoirs or as gas hydrates.

Australia potentially has access to gas from several different sources, including both conventional and unconventional gas resources.

Coal seam gas (CSG) is naturally occurring methane gas in coal seams. It is also referred to as coal seam methane and coal bed methane. The first stand-alone commercial production of CSG in Australia commenced in late 1996 in Queensland, and has grown rapidly since then. This expansion has been underpinned by strong demand growth in the eastern gas market and the recent recognition of the large size of the coal seam gas resource.

Tight gas occurs within low permeability reservoir rocks. The largest known resources of tight gas in Australia are in low permeability sandstone reservoirs in the Perth, Cooper and Gippsland basins. Tight gas is not currently produced in Australia, although there are some projects planned.

Shale gas is gas which has not migrated to a reservoir rock but is still confined within low permeability, organic rich source rocks such as shales. Shale gas exploration is in its infancy in Australia, but the organic rich shales in some onshore basins have been assessed for their shale gas potential. Australia's first shale gas well began operation in the second half of 2012.

No definitive gas hydrates have been identified in Australian waters.

As the unconventional gas industry in Australia matures, it is expected that exploration will add to the inventory of these resources. As an end use product, unconventional gas is similar to conventional gas. It can be added to gas pipelines without any special treatment and utilised in gas applications such as electricity generation and commercial operations.

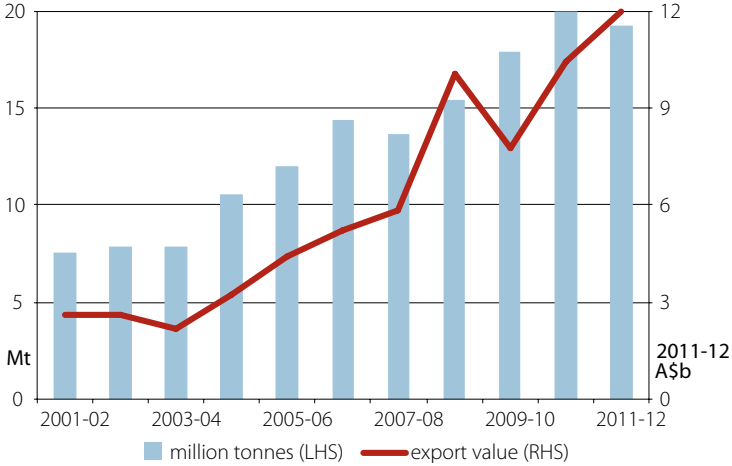
Trade

The geographical distance between Australia and its key gas export markets prevents trade by conventional pipeline transport. Instead, cooling the gas to a liquefied state (at –161ºC) allows the volume to be reduced to enable it to be shipped as LNG.

Until 1989–90, Australia consumed all of the gas that was produced domestically. Following the development of the North West Shelf Venture gas fields, located in the Carnarvon Basin (off the north-west coast of Western Australia), Australia began exporting LNG to overseas markets. Since 2005–06, LNG has also been exported from Darwin. In 2012, Pluto LNG became Australia's third gas export facility. More than three quarters Australia's LNG capacity is located in Western Australia.

Australia's LNG exports in 2011–12 were 19 million tonnes, a slight decrease of 4 per cent relative to 2010–11 (Figure 26). This was primarily a result of maintenance at key LNG facilities (North West Shelf LNG in late 2011 and Darwin LNG in early 2012). Export value increased to just under $12 billion, however, as rising prices more than offset falling output. This was primarily caused by oil market price rises, to which most Asian LNG prices are linked. Australia's major LNG trading partners include Japan, China and the Republic of Korea.

Figure 26: Australia's LNG exports



Source: BREE 2013, March Resources and Energy Statistics

LNG exports into the Asia Pacific region will grow strongly over the next few years, as multiple projects under construction or committed are expected to significantly expand Australia's LNG capacity (Table 22). These include the conventional LNG projects at Pluto (4.3 million tonnes a year), Gorgon (15.6 million tonnes), Wheatstone (8.9 million tonnes), and Ichthys (8.4 million tonnes). Australia's first floating LNG project, Prelude (3.6 million tonnes a year), is also under construction, and is expected to operate off the coast of Western Australia.

Exports of LNG are also expected to commence from Australia's east coast, with three projects based on coal seam gas—Queensland Curtis LNG (8.5 million tonnes a year), Gladstone LNG (7.8 million tonnes) and Australia Pacific LNG (9.0 million tonnes)—committed or under construction.

Table 22: LNG export projects, Australia, as of March 2013

Project name	Owner	Location	Start up	Capacity (Mt/pa)
Existing				
Darwin LNG	ConocoPhillips (operator); Eni; Santos; INPEX; Tokyo Electric ; Tokyo Gas	NT	2006	3.7
North West Shelf	Woodside Energy Ltd (operator); BHP Billiton Petroleum (North West Shelf) Pty Ltd; BP Developments Australia Pty Ltd; Chevron Australia Pty Ltd; Japan Australia LNG (MIMI) Pty Ltd; Shell Development (Australia) Pty Ltd	WA	1989	16.3
Pluto	Woodside Energy Ltd (operator); Kansai Electric; Tokyo Gas	WA	2012	4.3
Under construction/ committed				
Australia Pacific LNG	Origin Energy Ltd (operator); ConocoPhillips; Sinopec	Qld	2015	9
Gladstone LNG	Santos (operator); Petronas; Total; Kogas	Qld	2015	7.8
Gorgon LNG	Chevron (operator); Shell; ExxonMobil; Osaka Gas; Tokyo Gas; Chubu Electric	WA	2015	15.6
Ichthys LNG	INPEX (operator); Total	NT	2017	8.4
Prelude (floating LNG)	Shell	WA	2016	3.6
Queensland Curtis LNG	QGC (BG Group)	Qld	2014	8.5
Wheatstone LNG	Chevron (operator); Apache; KUFPEK; Shell	WA	2016	8.9

Sources: BREE 2013, March Resources and Energy Quarterly; Company websites.

Prices

The Australian domestic gas market consists of three distinct regional markets: the eastern market (Australian Capital Territory, New South Wales, Victoria, Queensland, South Australia and Tasmania); the western market (Western Australia); and the northern market (Northern Territory). The geographical isolation of these markets makes interconnection costly and currently uneconomic.

Until recently, and with the exception of Victoria, wholesale gas was sold under confidential long term contracts between producers, pipeline operators, major users and retailers. The Victorian Wholesale Gas Market was established in 1999 to increase the flexibility of market participants in buying and selling gas. Overall, gas traded at the spot price accounts for around 10 to 20 per cent of wholesale volumes in Victoria, with the balance sourced through bilateral contracts or vertical ownership arrangements between producers and retailers.

In September 2010, the Sydney and Adelaide hubs of the Short Term Trading Market (STTM) commenced operation. An additional hub in Brisbane commenced on 1 December 2011. The STTM is a day-ahead wholesale spot market for gas that aims to increase price transparency and improve efficiency and competition within the gas sector.

In 2011–12, the average Victorian wholesale gas spot price was $3.42 a gigajoule (Table 23). The average STTM ex post price in 2010–11 was $5.26 a gigajoule in Sydney and $3.29 a gigajoule in Adelaide (the STTM price includes both the commodity and the cost of transportation to the hub, unlike the Victorian price which is commodity only).

Prices in the western market have also been increasing over the past decade, with Western Australian domestic gas prices increasing by 42 per cent between 2000–01 and 2010–11 in real terms. Rising production costs and strong gas demand, particularly in the mining sector, has put upward pressure on prices, as have relatively higher international LNG prices.

Table 23: Australian gas prices

			2007-08	2008-09	2009-10	2010-11	2011-12
Natural Gas	Nominal	$A/GJ	3.77	3.32	2.03	2.42	3.42
	Real	$A/GJ	4.12	3.52	2.10	2.43	3.42
Natural Gas	Nominal	$A/GJ	2.94	3.77	3.71	4.11	4.20
	Real	$A/GJ	3.21	3.99	3.84	4.12	4.20
LNG	Real	$A/t	465.66	690.00	449.45	522.98	623.64
		$A/GJ	8.56	12.68	8.26	9.61	11.46

Source: BREE 2012, Resources and Energy Statistics; AEMO 2012; WA Department of Mines and Petroleum 2012.

LNG contract prices are generally indexed to world oil prices, with higher world oil prices leading to higher LNG contract prices. Higher oil prices underpinned strong increases in oil-linked LNG contract prices between 2005 and 2008. In line with this trend, Australian LNG export prices increased by an average of 18 per cent a year between 2004–05 and 2008–09. However, in 2009, world LNG prices fell significantly, including price declines in Japan (24 per cent), the United States (54 per cent) and European Union (32 per cent) (Table 24). Contributing to this decline was the global economic downturn, which led to lower oil prices and weaker demand from major gas consuming economies, coinciding with higher LNG export capacity in the Middle East, the Russian Federation and Indonesia. Prices rebounded in 2010

as gas demand recovered and oil prices rebounded. In 2011–12, Australia's LNG export prices rose dramatically by 50 per cent to A$624 a tonne, equivalent to A$11.47 a gigajoule. This largely reflected increasing crude oil prices in Asia and stronger demand from Japan in the wake of the shutdown of the nation's nuclear electricity generation sector.

Table 24: International LNG prices

	average					US$/tonne
		2007	2008	2009	2010	2011
Australia exports	all destinations	305	365	519	401	624
Japan imports	from Australia	359	602	459	590	717
	all origins	402	651	485	551	709
Korea imports	all origins	519	729	541	515	609
US imports	all origins	358	507	233	237	266
US pipeline imports	all origins	345	433	209	237	266
EU imports	all origins	332	473	320	343	451

a Export unit value.

Sources: BREE 2012; IEA 2012.

7. Petroleum production and trade

Australia is a net importer of crude oil and condensate. In volume terms, Australia's crude oil and condensate production was equivalent to 58 per cent of refinery feedstock in 2011–12. Australia exports 78 per cent of its crude oil and condensate production, with the majority being sourced from the north-west coast of Australia. Around 85 per cent of input into refineries, which are largely based on the east coast of Australia, is sourced from imports. Domestic refineries account for around 68 per cent of Australia's refined product consumption. Australia is a net exporter of liquefied petroleum gas (LPG), with net exports equating to around 55 per cent of total naturally occurring production in 2011–12.

Production

In 2011–12, Australia's production of crude oil and condensate declined by 13 per cent from the previous year to 22.4 gigalitres (Table 25). This decline was primarily because of cyclone related disruptions and planned outages to oil production facilities on the north-west coast of Australia and falling production from maturing Victorian fields. LPG production (from naturally occurring sources) declined by 2 per cent to 3.8 gigalitres in 2011–12.

Australia's largest petroleum producing basins are the Carnarvon Basin in the north-west of Australia and the Gippsland Basin in Bass Strait. While production from the Carnarvon Basin is mostly exported, production from the Gippsland Basin in south-eastern Australia is predominantly used in domestic refining.

Table 25: Australia's production of primary petroleum

	2007–08	2008–09	2009–10	2010–11	2011-12
	ML	ML	ML	ML	ML
Crude oil	18234	18356	16638	17333	14932
Condensate	7376	8051	8945	8435	7476
Liquefied petroleum gas	3971	3929	4097	3909	3815

Sources: BREE 2013, January Australian Petroleum Statistics; BREE

Trade

Australia is a net importer of refinery feedstock (crude oil and condensate) and refined petroleum products, but a net exporter of LPG. In 2011–12, Australia imported 29.5 gigalitres of crude oil and other refinery feedstock (Table 26). The high proportion of imports as a share of total production is because a significant percentage of Australia's oil production is exported. Two factors contribute to this. Firstly, the majority of Australia's oil production is off the north-west coast of Western Australia, so is closer to Asian refineries than domestic refineries on the east coast. Secondly, crude grades produced in Australia are generally not as well suited for use by Australian refineries as those from some foreign countries (for example, a sizable proportion of imports come from the Middle East and Africa; considerably further afield than Western Australia).

Since the mid-1990s, Australia's imports of crude oil from South-East Asia have been increasing, but they fell over the past 12 months. Malaysia was the largest source for Australian crude oil and other refinery feedstock imports in 2011–12, accounting for 17 per cent of crude oil and other refinery feedstock imports. The United Arab Emirates (16 per cent) and Nigeria (13 per cent) are the next two largest sources (Table 26).

Table 26: Australia's imports of petroleum, by source

	2007-08	2008-09	2009-10	2010-11	2011-12
	ML	ML	ML	ML	ML
Crude oil and other refinery feedstock					
Indonesia	3289	3666	4178	4805	3310
Malaysia	4103	4461	5319	5930	4942
New Zealand	1974	2313	2569	2565	2195
Nigeria	na	na	1110	2050	3764
Papua New Guinea	2190	1349	1580	1612	1475
Saudi Arabia	573	775	478	156	216
Singapore	713	555	605	497	554
United Arab Emirates	3660	2918	3846	4683	4599
Viet Nam	6318	5277	3904	2554	1788
Other	3403	2987	3695	6915	6651
Total	**26223**	**24302**	**27284**	**31766**	**29495**
Refined products					
Indonesia	11	45	95	259	293
Korea, Rep. of	785	1704	1960	2013	2596
Malaysia	316	184	249	263	672
Middle East	1044	1050	1070	897	1011
New Zealand	40	215	4	9	31
Singapore	10215	10217	10249	9471	11064
United States	421	473	301	400	115
Other	5149	5808	6039	5459	5406
Total	**17982**	**19697**	**19967**	**18771**	**21188**

Sources: BREE 2013, January Australian Petroleum Statistics; BREE

Despite being a net importer, Australia exports significant quantities of crude oil and other refinery feedstock. In 2011–12, crude oil and other refinery feedstock exports decreased by 11 per cent to 17.4 gigalitres (Table 27). This reflects falling overall production off the north-west coast of Australia, where the majority of production is sold to Asian refineries. In 2011–12, around 64 per cent of Australia's crude oil and other refinery feedstock was exported to China, Singapore, the Republic of Korea, and Japan. Japan is also Australia's largest market for LPG, accounting for 65 per cent of exports in 2011–12.

Australia's exports of refined petroleum products are much lower, amounting to 1.2 gigalitres in 2011–12. Around 58 per cent of these exports went to Singapore and 15 per cent to New Zealand.

Table 27: Australia's exports of petroleum, by destination [a b]

	2007-08	2008-09	2009-10	2010-11	2011-12
	ML	ML	ML	ML	ML
Crude oil and other refinery feedstock					
China	972	1009	2185	3632	4403
Chinese Taipei	343	403	261	266	413
Japan	2280	2485	1931	2002	1796
Korea, Rep. of	3701	4395	3710	3794	1807
New Zealand	600	321	235	56	126
Singapore	3089	3543	3838	2648	3221
United States	1157	1421	622	189	451
Other	3833	3011	5283	7050	5207
Total	**15975**	**16588**	**18064**	**19636**	**17424**
Liquefied petroleum gas					
China	465	354	383	256	0
Japan	1587	1474	1965	1509	1371
Korea, Rep. of	178	292	80	190	242
Other	359	380	347	516	501
Total b	**2589**	**2500**	**2776**	**2471**	**2115**
Refined products					
Fiji	3	2	2	1	1
Japan	71	56	31	15	37
New Zealand	837	400	317	223	184
Singapore	505	426	363	407	715
Other Pacific	275	256	73	87	112
United States	3	0	19	1	0
Other	113	25	45	26	186
Total	**1807**	**1164**	**850**	**760**	**1234**

a Does not include LNG exports or ship and aircraft stores. **b** Actual values are used and aggregated for each category. **c** Includes confidential exports.

Sources: BREE 2013, January Australian Petroleum Statistics; BREE

Australia's earnings from crude oil and other refinery feedstock exports increased by 1 per cent to $12 billion in 2011–12, as higher prices offset falling volumes from 2010–11 (Table 28). Earnings from exports of refined petroleum products increased significantly from $530 million to $872 million, reflecting higher export volumes and higher prices compared with 2010–11.

Table 28: Value of Australia's trade in petroleum

	2007-08	2008-09	2009-10	2010-11	2011-12
	$m	$m	$m	$m	$m
Exports					
Automotive gasoline	444	171	138	120	127
Diesel fuel	363	225	131	94	115
Aviation turbine fuel	120	69	41	8	2
Fuel oil	130	96	54	99	314
Aviation gasoline	73	45	30	22	18
Kerosene	0	0	0	0	0
Lubricants	152	148	151	154	261
Other products	41	34	22	29	35
Total refined products	1323	788	566	526	872
Liquefied petroleum gas	1182	1044	1105	1068	971
Bunkers [a]	1457	1537	1315	1508	1592
Crude oil and other refinery feedstock	10484	8757	9534	11773	11947
Imports					
Automotive gasoline	2719	2784	2447	1838	2915
Diesel fuel	6155	6314	5270	6246	8829
Aviation turbine fuel	1505	1393	1283	1440	1742
Fuel oil	831	867	910	836	1059
Lubricants	477	629	519	671	825
Liquefied petroleum gas	436	382	405	375	452
Other products	1331	2927	1683	2581	480
Total refined products	12730	13129	11296	12059	16301
Crude oil and other refinery feedstock	17149	14727	15031	19579	21125

a Ships and aircraft stores.

Sources: BREE 2013, January Australian Petroleum Statistics; BREE

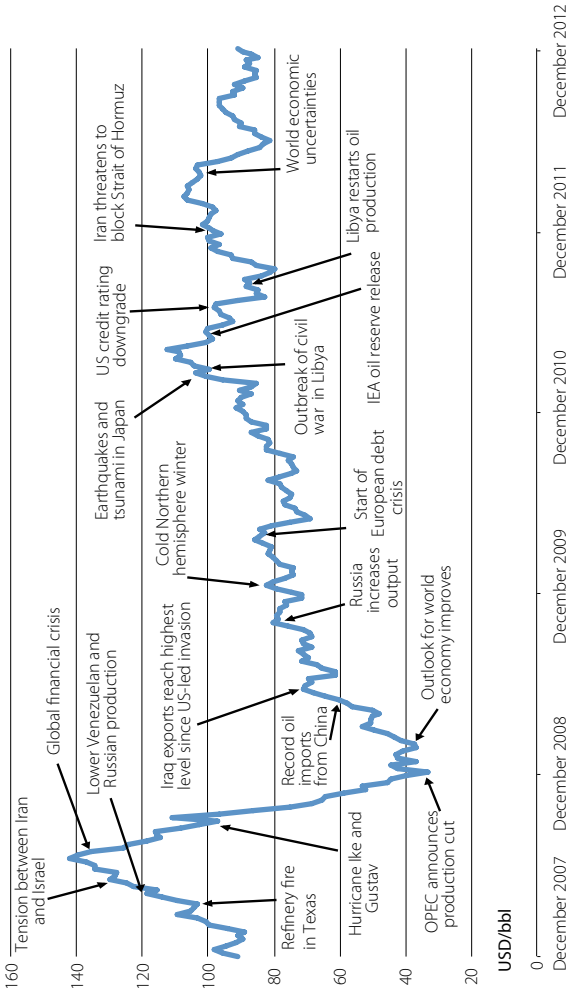
Prices

In 1970, the world trade weighted average oil price (in 2012 dollar terms) averaged US$10 a barrel. Oil prices increased during the 1970s as a result of the oil price shocks in both 1973 and 1979. By 1980, the oil price averaged US$103 a barrel. Oil prices dropped during most of the 1980s and in the 1990s. However, the loss of crude oil production from Venezuela and Iraq in 2003, combined with growing demand in the United States and Asia, caused oil prices to increase from the early 2000s (Figure 27).

Continued political instability in a number of oil producing countries, increasing demand in Asia (particularly China) and speculative demand, drove oil prices to average US$122 a barrel in the June quarter 2008. However, by the December quarter of 2008, oil prices had fallen by more than half to around US$57 a barrel due to falling demand caused by the global financial crisis.

Between 2009 and 2012, oil prices increased as a result of greater oil demand associated with economic recovery. In 2012, oil prices decreased slightly given market concerns regarding sovereign debt issues in the United States and Europe, to average US$94.4 a barrel. Price increases were supported by relatively low OPEC spare production capacity, a range of disruptions to both OPEC and non-OPEC supply and continued growing oil demand from emerging economies.

Figure 27: Crude oil prices



Source: BREE

8. Liquid fuels refining

In 2011–12, Australia's consumption of refined liquid fuels, excluding non-commercial sales and non-commercial consumption, was 53.8 gigalitres. Domestic production of marketable refined liquid fuels, excluding by-products of petrochemical and downstream processing, totalled 36.4 gigalitres (around 68 per cent of consumption), while imports (including LPG) totalled 21.2 gigalitres. Australian exports of refined liquid fuels, excluding naturally occurring LPG, were around 1.2 gigalitres in 2011–12, equal to about 3 per cent of production. Australian consumption of refined petroleum products has increased at an average rate of 2.6 per cent a year over the past five years as a result of consumption growth in the road and air transport sectors, which account for the vast majority of refined liquid consumption.

Production

The petroleum refining industry in Australia produces a wide range of petroleum products such as gasoline, diesel, aviation turbine fuel and LPG, which are derived from crude oil and condensate feedstock. In 2011–12, Australian refineries produced 15.6 gigalitres of petrol and 12.3 gigalitres of diesel, comprising 43 per cent and 34 per cent of Australia's total production of petroleum products, respectively. In 2011–12, total Australian refinery production decreased by 5 per cent (from 2010-11) to 36.4 gigalitres (Table 29).

Table 29: Australia's production of marketable refined petroleum products

	2007-08	2008-09	2009-10	2010-11	2011-12
	ML	ML	ML	ML	ML
Automotive gasoline	17079	17159	16771	16643	15638
Automotive diesel oil	12177	12231	11720	12858	12312
Aviation turbine fuel	5182	5494	5341	5448	5450
Fuel oil	979	872	846	952	954
Liquefied petroleum gas	1515	1477	1204	1467	1198
Industrial and marine diesel fuel	3	13	3	0	0
Bitumen	1452	1294	690	476	440
Lubricants	121	114	74	64	0
Aviation gasoline	119	105	104	91	90
Heating oil	102	69	35	16	12
Other	845	718	412	378	341
Total products [a]	**39575**	**39546**	**37200**	**38393**	**36436**

a excludes byproducts of petrochemical and downstream processing.

Source: BREE 2013, January Australian Petroleum Statistics; BREE

Capacity

There are six major petroleum refineries currently operating in Australia, which are managed by four companies—BP, Caltex, Mobil and Shell. These refineries have a combined capacity of around 40 gigalitres a year (Table 30). The largest of these are BP's Kwinana refinery in Western Australia and Caltex's Kurnell refinery in New South Wales.

Table 30: Australia's refinery capacity

Location	Operator	Year commissioned	Capacity (ML/pa)
New South Wales			
Kurnell	Caltex	1956	7820
Queensland			
Bulwer Island	BP	1965	5910
Lytton	Caltex	1965	6300
Victoria			
Altona	Mobil	1949	4640
Geelong	Shell	1954	7470
Western Australia			
Kwinana	BP	1955	8300
Total			**40440**

ML/pa: Million litres per annum.

Source: Australian Institute of Petroleum, Downstream Petroleum 2011.

In October 2012, Shell stopped refining operations at the Clyde refinery in Sydney which had been in operation since 1928. Also in 2012, Caltex announced their intention to proceed with a proposal to close the Kurnell refinery and convert the facility into a major import terminal in the second half of 2014. These moves highlight the increasingly competitive international market Australian refineries face. Specifically, high labour and construction costs (compared to nearby Asian markets), combined with the need to build at huge volume to fully utilise economy of scale benefits, are key drivers of falling domestic refining capacity.

Fuel standards

Fuel quality standards have progressively improved in Australia, with the aim of reducing the adverse effects of motor vehicle emissions on air quality and human health and to enable Australia to effectively adopt new vehicle engine and emission control technologies. Currently, gasoline standards are in place that require a maximum sulphur content of 50 parts per million (ppm) for premium unleaded petrol. The standard grade of unleaded petrol remains at a maximum of 150 ppm sulphur. A grade of standard unleaded petrol with 10 per cent ethanol (E10) is also offered as an alternative to unleaded petrol, largely in eastern Australia. Another grade of standard unleaded petrol with up to 85 per cent ethanol (E85) is also supplied through a small number of metropolitan fuel outlets. The fuel quality standard for diesel in Australia includes a maximum sulphur content of 10 ppm and allows up to 5 per cent biodiesel fuel without a labelling requirement.

In the Asia–Pacific region, many countries have implemented stricter fuel quality standards in response to environmental concerns resulting from rapidly increasing gasoline and diesel consumption. New Zealand currently has the same sulphur content requirements as Australia, having reduced maximum sulphur levels in diesel to 10 ppm in 2009. China implemented maximum sulphur levels in gasoline of 150 parts per million (ppm) in 2009, with a 350 ppm sulphur limit in diesel postponed from 2010 until 2013. India reduced sulphur levels in gasoline to 150 ppm and in diesel to 350 ppm from 2010. Indonesia currently has a 500 ppm fuel sulphur limit in gasoline and diesel. Increasing international fuel standards are making a wider range of imports available to Australian consumers at Australian standards.

Non-conventional liquid fuels

The main alternatives to petrol and diesel that are currently used for motor vehicles in Australia are LPG and biofuels (comprising ethanol and biodiesel). Compressed natural gas is also used in a very small number of metropolitan buses and purpose built vehicles such as garbage trucks. Likewise, liquefied natural gas is in limited use in heavy duty vehicles.

Biofuels production in 2011-12 represented around 1 per cent of Australia's petrol and diesel production. There are currently three major fuel ethanol production facilities in Australia, with a combined capacity of 440 million litres a year. These facilities produce ethanol primarily from wheat starch, grain sorghum and molasses. Around 68 per cent of ethanol production capacity is located in New South Wales, at a single production facility in Nowra (Table 31).

Table 31: Liquid biofuels production facilities in Australia, 2012

Location	Capacity (ML/pa)	Feedstocks
Fuel ethanol		
Manildra Ethanol Plant, NSW	300	Waste starch
Dalby Biorefinery, Qld	80	Sorghum
Sarina Distilleries Qld	60	Molasses
Biodiesel		
In production		
Australian Renewable Fuels Barnawatha, Wodonga, Vic	60	Tallow, used cooking oil
Australian Renewable Fuels Largs Bay, Adelaide, SA	45	Tallow, used cooking oil
Australian Renewable Fuels Picton Plant, Picton, WA	45	Tallow, used cooking oil
Biodiesel Industries Australia Biodiesel Plant, Maitland, NSW	20	Used cooking oil, vegetable oil
Not in production		
Vopak, Darwin, NT	130	Palm oil
Smorgon Fuels - BioMax Plant, Melbourne, Vic	15-100	Tallow, canola oil, dryland juncea (oilseed crop)

ML/pa: Million litres per annum.

Source: Biofuels Association of Australia 2012.

There are also four major biodiesel production facilities in Australia, with additional facilities producing small quantities. Total biodiesel operating capacity is around 170 million litres a year. The majority of Australia's biodiesel production currently occurs in Victoria. Biodiesel facilities in Australia use a range of vegetable tallow (animal fats), used cooking oil and vegetable oils as feedstock, which are selected according to price and availability.

Non-conventional transport fuels in Australia

The transport sector is one of the largest energy consuming sectors in the Australian economy. Conventional fuels (petrol, diesel and jet fuel) currently account for around 95 per cent of Australia's transport fuel consumption, while non-conventional transport fuels (mainly LPG and biofuels) account for the remaining 5 per cent.

Australia's imports of petroleum products are expected to continue to rise. Increasing the use of alternative fuels and diversifying the fuel mix in the transport market can help mitigate some of the risks Australia is exposed to in the conventional fuel market. Some alternative transport fuels also assist in lowering emissions from the transport sector.

In late 2011, the Australian Government released its Strategic Framework for Alternative Transport Fuels. This document sets out a long-term strategic framework to support the market-led development of alternative transport fuels in the context of maintaining liquid fuel security while moving toward a low emission economy.

Alternative transport fuels available for use, or expected to become available over the medium to longer term, include biofuels (such as ethanol and biodiesel), gaseous fuels (compressed natural gas, liquefied natural gas and liquefied petroleum gas) and synthetic fuels (coal to liquids, gas to liquids, biomass to liquids and shale to liquids). Australia's electricity grid could also support the uptake of electric vehicles and further electrification of the rail network.

There are already a number of policies in place to encourage the production and use of alternative transport fuels in Australia. For example, under the Ethanol Production Grants program, grants of 38.143 cents a litre are provided for the domestic production of ethanol. The Energy Grants (Cleaner Fuels) Scheme provides 38.143 cents a litre for the domestic use of biodiesel and renewable diesel. There are also

concessional excise arrangements in place for gaseous fuels (LPG, CNG and LNG). The LPG Vehicle Scheme provides grants for the purchase of a new LPG vehicle or the conversion of an existing vehicle to LPG. Fuel tax credits are also available to heavy duty vehicles in some circumstances.

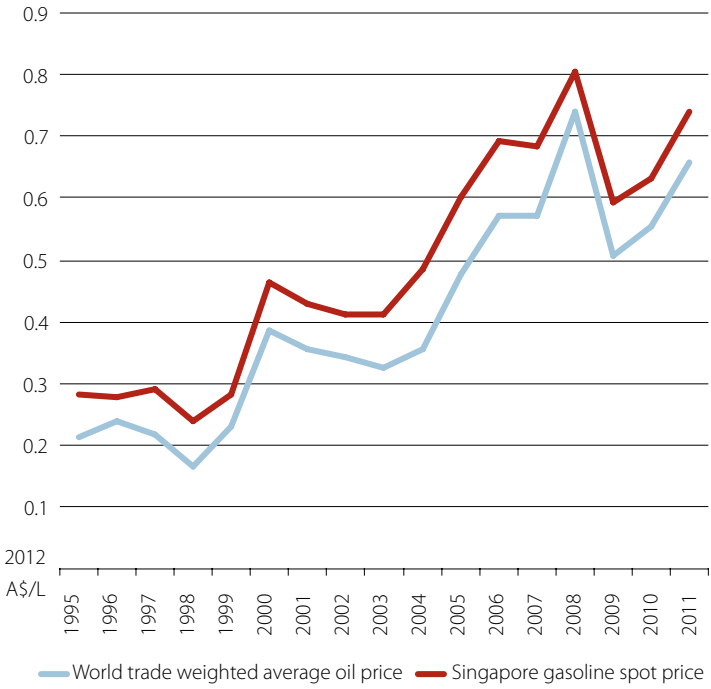
The Australian Government also supports the development and commercialisation of advanced biofuels via the Advanced Biofuels Investment Readiness Program. This initiative is managed by the Australian Renewable Energy Agency (ARENA).

Prices

The pre-tax component of Australian gasoline prices remains among the lowest in the OECD and the tax-inclusive gasoline price is the fourth lowest, following Mexico, the United States and Canada (Figure 29). Similarly, the pre-tax component of Australian diesel prices is the fifth lowest, following Mexico, the United States, New Zealand, and Canada (Figure 30).

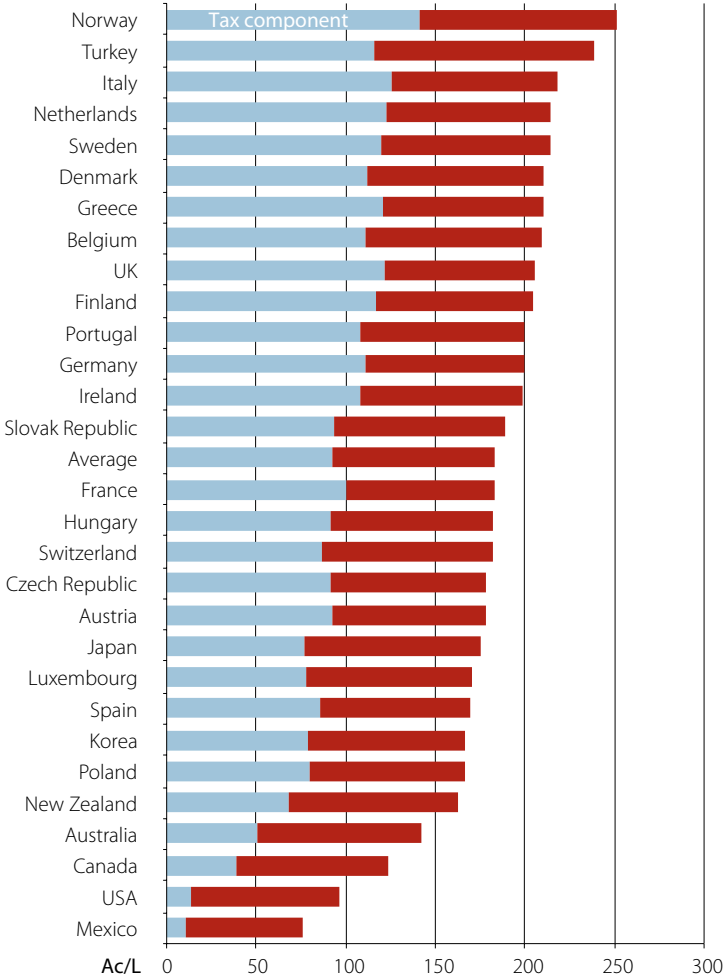
Australian wholesale gasoline and diesel prices closely follow movements in Singapore gasoline prices, which are in turn largely set by world oil prices. In 2011–12, 55 per cent of Australia's imports of refined petroleum products came from Singapore. The Singapore gasoline spot price declined to average A$0.60 a litre in 2009 reflecting the effect of the global economic slowdown on demand for petroleum products. Since 2010 the Singapore gasoline spot price has gradually recovered. In 2011, the Singapore gasoline spot price averaged A$0.74 a litre. The change in gasoline prices closely followed movements in crude oil prices–the world trade weighted average price of crude oil increased by 9 and 18 per cent in 2010 and 2011, respectively (Figure 28).

Figure 28: Petrol price indicators



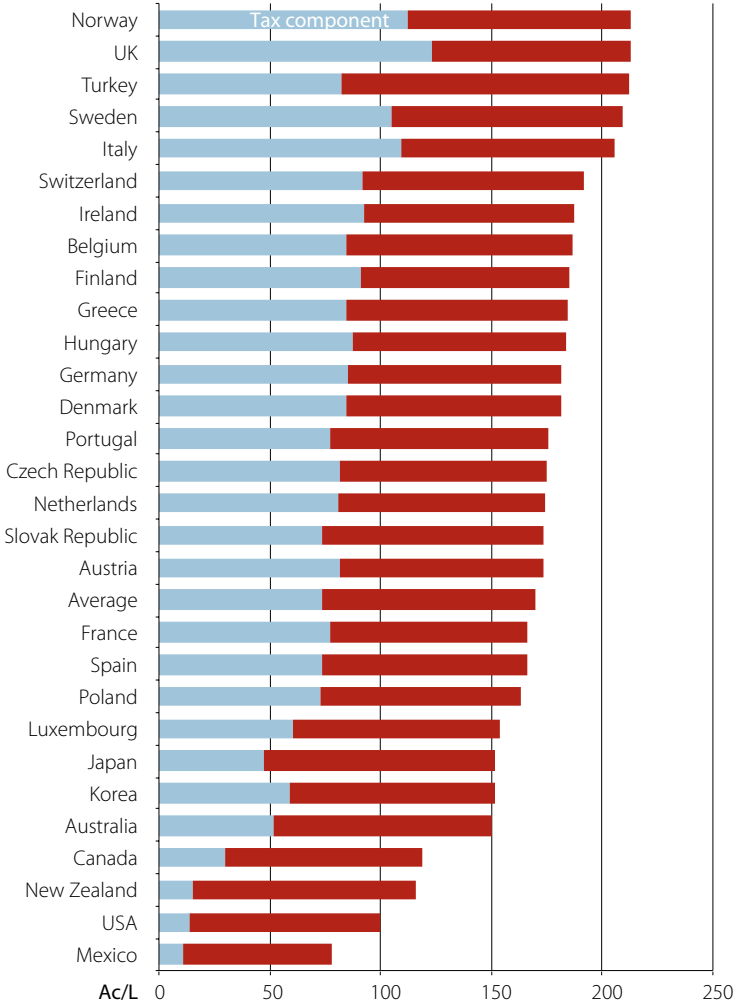
Sources: IEA 2012, Energy Prices and Taxes; BREE 2012, Resources and Energy Statistics.

Figure 29: OECD gasoline prices



Source: BREE 2012, December Australian Petroleum Statistics

Figure 30: OECD diesel prices



Source: BREE 2012, December Australian Petroleum Statistics

9. Transport and infrastructure

The transport sector is the largest end user of energy in Australia. More than 38 per cent of Australia's final energy use is employed in moving people and goods across the country. As a large continent characterised by major population centres located along its coastline, Australia requires goods to be transported long distances. The transportation sector is by far the largest consumer of liquid fuels (including LPG and refined products), accounting for around 73 per cent of final use.

Energy consumption

Within the transport sector, road transport is the largest user of final energy, accounting for 74 per cent of the sector's liquid fuel consumption. Largely reflecting improvements in fuel efficiency, average growth in road transport fuel consumption has moderated over the past 30 years, falling from around 3 per cent a year in the 1980s to average 1 per cent a year in the 2000s (Table 32).

Table 32: Energy consumption in the transport sector [a]

	1979-80	1989-90	1999-00	2009-10	2010-11	2011-12
	PJ	PJ	PJ	PJ	PJ	PJ
Road transport	594.1	792	942	1080.4	1118.2	1163.2
Railway transport	30.9	30.7	29.7	48.4	45.7	45.3
Water transport	97.6	55.7	55.7	67.3	62.2	66.7
Air transport	58.9	103	180.2	243.7	255.6	243.1
Other	3.5	6.2	12.7	25.6	26.6	25.5
Total	**785**	**987.6**	**1220.3**	**1465.4**	**1508.3**	**1543.8**

a Net energy consumption (defined as total fuel input less energy produced).

Sources: BREE 2012, Australian Energy Statisitics; BREE estimation.

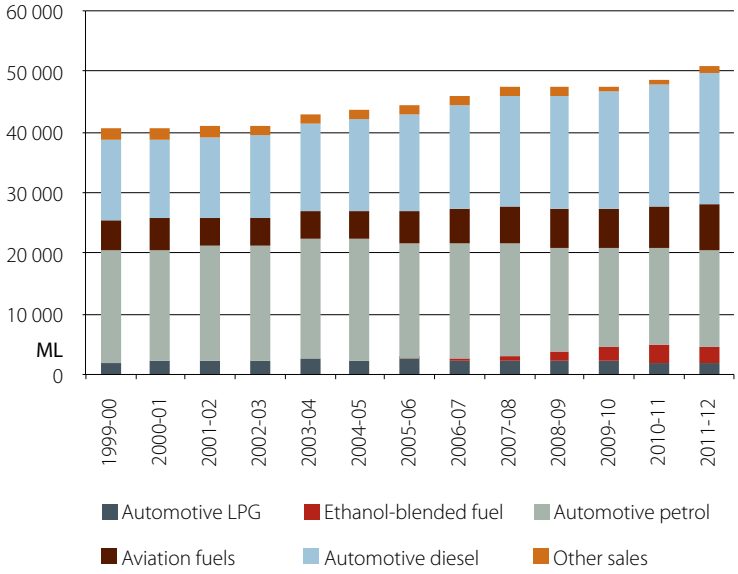
Air transportation has been the fastest growing consumer of transport fuels in Australia. After growing by more than 5 per cent a year in the 1990s, energy consumption growth in the sector has slowed to 2 per cent a year between 1999–2000 and 2011–12. This slow down largely reflects lower passenger traffic between 2001 and 2003 following the collapse of Ansett, the terrorist attacks in the United States and the outbreak of SARS. Despite this, the long term increase in international air transportation has been at the expense of international sea transportation. As such, energy use in the water transport sector declined steadily through the 1980s and 1990s, although it has increased in the past few years.

Australian demand for transport fuels has been rising steadily over the past 12 years, increasing almost 20 per cent from 40 765 megalitres in 1999–2000 to 50 734 megalitres in 2011–12. The majority of Australia's sales of transport fuels are diesel, followed by petrol and aviation fuels (Figure 31).

Automotive gasoline is the main fuel used in the transportation industry, accounting for around 41 per cent of total energy use in the sector. This reflects the large share of road transportation in transport sector consumption.

The phasing out of leaded automotive gasoline, starting in 1986, was completed in 2001. Over the same period, consumption of automotive LPG, which was excise free, increased at an average rate of 10 per cent a year. In 2004 demand for LPG declined slightly following the announcement of the phase-in of taxes on excise exempt fuels, and has been stagnant since.

Figure 31: Australia's sales of transport fuels



Source: BREE 2013, January Australian Petroleum Statistics.

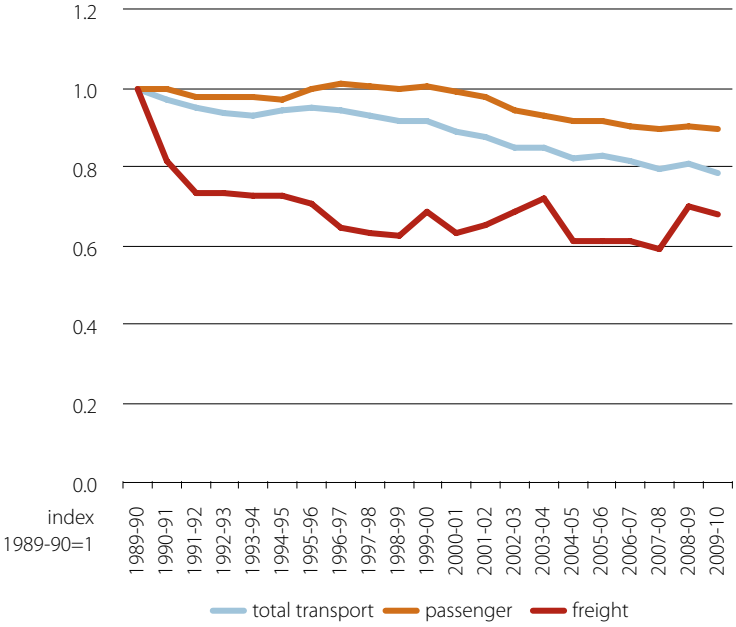
Fuel efficiency

In 2010–11, the transport sector accounted for 6 per cent of economic output in terms of real gross value added and around 36 per cent of final energy use in Australia. About 63 per cent of energy consumed in the transport sector is associated with the movement of passengers, with the remainder accounted for by the movement of freight.

Transport energy consumption of road transport, rail transport and air transport grew at an average annual rate of 1.7, 2.0 and 3.5 per cent, respectively, between 1989–90 and 2010–11. Over this period energy consumption in passenger and freight transport sub-sectors grew at an average annual rate of 1.5 per cent and 2.3 per cent, respectively.

Despite substantial variability, a declining trend in energy intensity in the transport sector has occurred over the period 1989–90 to 2009–10 (Figure 32). While the passenger transport sub-sector increased energy intensity in the mid to late 1990s, overall energy intensity declined at an average rate of 0.6 per cent a year (as falls in the 2000s offset earlier rises). Energy intensity in the freight transport sector declined more rapidly at an average annual rate of 1.3 per cent.

Figure 32: Trends in composite energy intensity indicators in the transport sector



Note: These energy intensity trends do not imply any weighting of energy consumption by sector.

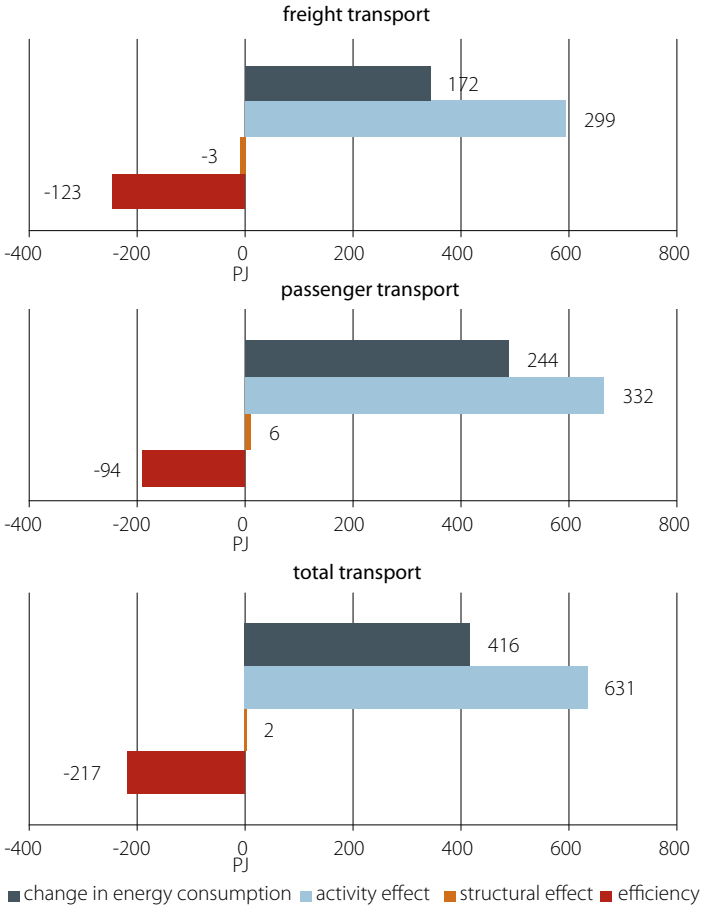
Source: BREE 2012, Economic analysis of Australian end-use energy intensity.

The energy intensity indicator for passenger transport, as measured by energy use per passenger-kilometre, takes into account the fuel efficiency of vehicles as well as the number of passengers in a vehicle (or occupancy). If the vehicle occupancy rate declines, energy intensity tends to increase even without changes in vehicle efficiency. Figure 33 shows the change in energy consumption driven by changes in energy efficiency from

1989-90 to 2009-10. The analysis suggests that freight transport made larger, more sustained energy efficiency savings compared with passenger transport.

Activity and efficiency effects have both had a considerable impact on the transport sector over the past two decades. Figure 33 shows that the activity effect resulted in transport energy consumption increasing by 631 petajoules over that period (due to increased use), comprising 332 petajoules from passenger transport and 299 petajoules for freight transport. The efficiency effect had the opposite impact in both sectors. The passenger transport and freight transport subsectors had 94 and 123 petajoules of reduced demand, respectively.

Figure 33: Decomposition of change in energy consumption in the transport sector, 1989-90 to 2009-10



Source: BREE 2012, Economic analysis of Australian end-use energy intensity.

Port capacities

The ability to import and export energy in Australia depends heavily on the capacity of major ports. Australia has nine coal exporting terminals, most of which are located in New South Wales and Queensland. In 2011–12, these ports loaded just over 302 million tonnes of coal (Table 33). Australian ports did not operate at capacity in 2011–12 for a number of reasons including weather-related incidents.

Table 33: Loadings and capacity for major coal ports

	Loadings 2011-12 Mt	Capacity 2011 Mtpa	Capacity 2015 Mtpa
New South Wales			
Newcastle [a]	122	163	211
Port Kembla	15	30	30
Queensland			
Abbot Point	14	50	50
Brisbane	9	9	9
Gladstone [b]	60	75	75
Hay Point [c]	83	129	140

a Includes Carrington, NCIG and Kooragang Island terminals. **b** Includes RG Tanna and Barney Point terminals. **c** includes Dalrymple and Hay Point terminals.

Sources: BREE 2012, Australian Bulk Commodity Exports and Infrastructure - Outlook to 2025; Ports Australia 2012; Port Waratah Coal Services; Port Kembla Coal Terminal; Gladstone Ports Corporation.

Past infrastructure capacity constraints (including port and rail) may have limited the Australian coal industry's ability to respond to growing global demand over the past few years. However, recent additions to capacity, together with further expansions

planned over the short- to medium-term have overcome previous constraints. As of October 2012 there were 9 coal infrastructure projects at the committed stage of development, with a combined capital cost of around $9.5 billion. Of these projects, three were committed terminal projects expected to add around 74 million tonnes to Australia's major ports' annual capacity. A further 13 coal infrastructure projects were at less advanced stages of planning (see Appendix 1).

Australia has 16 deepwater ports that exported petroleum liquids in 2011-12. The port at Dampier in Western Australia is Australia's largest exporting centre of oil and petroleum by far, accounting for around three-quarters of Australian exports (Table 34). Crude oil and condensate exports are increasingly sourced from the west coast, while exports of refined products are largely sourced from the east coast. A large proportion of Australia's oil is sourced from floating production and storage and off-take vessels which are located over the oil fields.

Gas is exported directly from on-shore LNG liquefaction facilities, which are located in relatively close proximity to extraction facilities. Australia currently has three LNG plants, two at Karratha in Western Australia (North West Shelf Venture and Pluto) and one in the Northern Territory (Darwin). A number of new LNG facilities are currently under construction in Western Australia, Queensland and the Northern Territory (see Gas chapter for further discussion). These facilities are a key component of new gas projects as international gas demand far outweighs domestic demand.

Table 34: Export loadings at major petroleum ports, 2011–12

	Oil and petroleum (Mt) [a]
Dampier, WA	23.87
Brisbane, Qld	2.69
Fremantle, WA	1.71
Geelong, Vic	1.54
Sydney, NSW	0.97
Hastings, Vic	0.9
Melbourne, Vic	0.42
Darwin, NT	0.06
Port Kembla, NSW	0.06
Bunbury, WA	0.02
Cairns, Qld	0.01
Total [b]	**32.28**

a includes crude oil, oil products, condensate, petroleum products and refined petroleum. **b** Total includes a number of smaller ports not listed above.

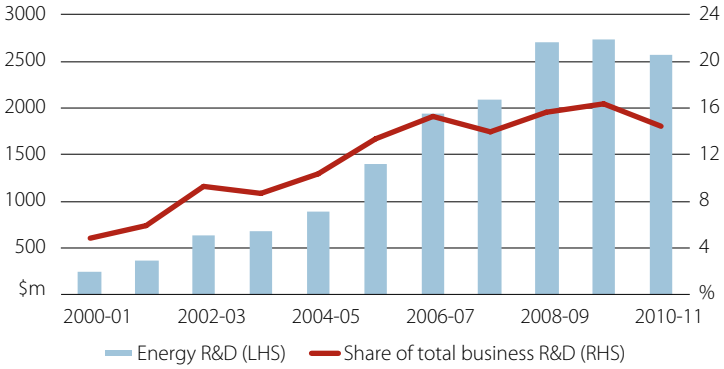
Source: Ports Australia 2012.

10. Energy Research and Development

Research and development (R&D) can be defined as innovative work that is undertaken on a systematic basis to increase knowledge, which may or may not have a specific practical application. In this context, energy R&D refers to the early stages of the innovation chain, rather than later stages such as demonstration and commercialisation.

In Australia, most of the R&D in the energy sector is undertaken by private businesses. Despite a fall in the last year, business spending on energy R&D increased at an average rate of 28 per cent a year from 2000–01 to 2010–11, reaching $2.6 billion in 2010–11 (Figure 34). This includes R&D related to energy resources (e.g. exploration for and mining of coal, uranium, oil, gas and geothermal energy), R&D related to preparing and transforming energy resources (e.g. preparing oil and coal and using it to generate electricity) and R&D for other aspects of energy (e.g. renewable energy, energy distribution and storage, energy efficiency, and waste management). Expenditure on energy R&D by Australian businesses represented around 14 per cent of total business R&D expenditure in 2010–11.

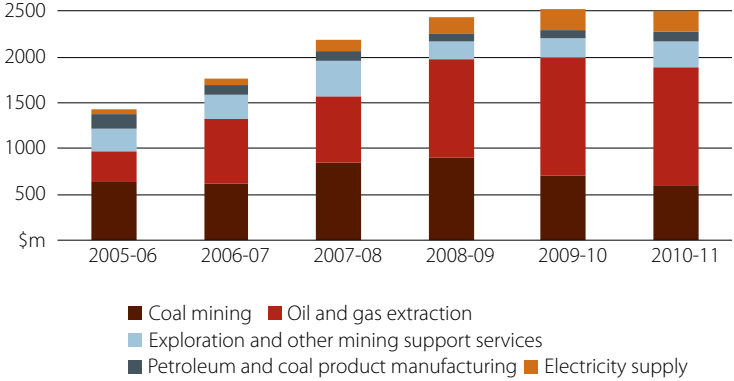
Figure 34: Australian business R&D in energy



Source: ABS 2012, Research and Experimental Development, Businesses, Australia, cat. no. 8104.0.

Of energy related industries, the oil and gas extraction industry had the largest R&D expenditure in 2009–10, with business spending of $1.3 billion. This was followed by the coal mining industry with $591 million of R&D expenditure (Figure 35).

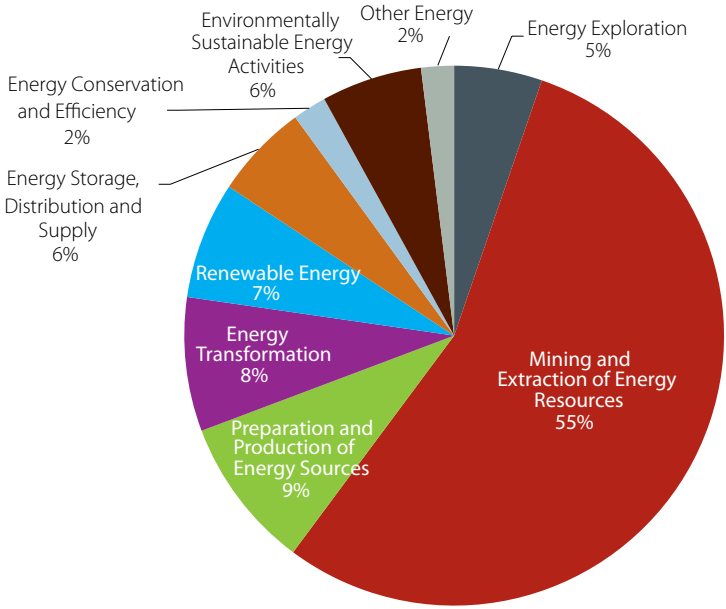
Figure 35: Australian business R&D by industry



Source: ABS 2012, Research and Experimental Development, Businesses, Australia, cat. no. 8104.0.

The majority of energy R&D expenditure by Australian businesses is devoted to the mining and extraction of energy resources, representing 55 per cent of energy R&D in 2010–11. Around 7 per cent of business R&D was spent on renewable energy and 2 per cent of spending had the objective of improving energy efficiency or energy conservation (Figure 36).

Figure 36: Australian business energy R&D, by objective, 2010-11



Source: ABS 2012, Research and Experimental Development, Businesses, Australia, cat. no. 8104.0.

Appendix 1—Current and proposed energy projects

Major electricity projects

New electricity generation projects as of October 2012 [a]

Project	Company	Location	Status	Expected Startup	New Capacity	Capital Expend. ($m)
Black Coal						
Eraring Power Station upgrade	Eraring Energy	40 km SW of Newcastle, NSW	Expansion; Committed	2012	240MW	600
Muja Power Station (Stages A and B)	Verve Energy/ Inalco Energy	200 km SE of Perth, WA	Refurbishment; Under construction	late 2012	220MW	150
Gas						
Channel Island Power Station - set 8 & 9	Power and Water Corporation	Channel Island, NT	Expansion; Completed	2012	90MW	120
Diamantina power station (Two Stages)	APA Group/AGL Energy	6 km S of Mount Isa, Qld	New project; Under construction	2013	242MW	500
Kwinana Power Station rebuild	Verve Energy	Kwinana, WA	Refurbishment; Completed	2012	200MW	263
McArthur River Mine – Phase 3 Expansion	Energy Developments Ltd (EDL)	McArthur River, NT	New project; Under construction	2014	53MW	na
Mortlake Stage 1	Origin Energy	12 km W of Mortlake, Vic	New project; Completed	2012	550MW	810

Project	Company	Location	Status	Expected Startup	New Capacity	Capital Expend. ($m)
Owen Springs	Power and Water Corporation	Alice Springs, NT	New project; Completed	2011	32.1MW	89.5
Weddell stage 3	Power and Water Corporation	40 km SE of Darwin, NT	Expansion; Under construction	2013	43MW	50
Yarnima Power Station	BHP Billiton	Newman, WA	New project; Under construction	1H 2014	190MW	597
Wind						
Ararat Wind Farm	RES Australia Pty Ltd	7 km N of Ararat, Vic	New project; Committed	2013	225MW	450
Collgar Wind Farm	UBS IIF/REST	25 km SE of Merredin, WA	New project; Completed	late 2011	206MW	750
Crookwell 2 Wind Farm	Union Fenosa Wind Australia	14 km SE of Crookwell, NSW	New project; Government approval received; Main construction work (Stage 2) to commence Q2 2013	2014	92MW	225
Gullen Range Wind Farm	Gullen Range Wind Farm	25 km NW of Goulburn, NSW	New project; Committed	late 2013	158.5MW	250
Hallett 5 (The Bluff)	AGL Energy / Eurus Energy	12 km SE of Jamestown, SA	Expansion; Completed	2012	53MW	118
Hawkesdale Wind Farm	Union Fenosa Wind Australia	35 km N of Point Fairy, Vic	New project; Extension for government approval received; Construction to commence early Q1 2013	2014	62MW	150
Macarthur Wind Farm	AGL Energy/ Meridian Energy	230 km W of Melbourne, Vic	New project; Under construction	2013	420MW	1000
Mount Gellibrand Wind Farm	Acciona Energy	15 km NE of Colac, Vic	New project; Under construction	2015	189MW	696

Project	Company	Location	Status	Expected Startup	New Capacity	Capital Expend. ($m)
Mount Mercer Wind Farm	Meridian Energy	30 km S of Ballarat, Vic	New project; Government approval received	2012	131MW	270
Mumbida Wind Farm	Verve Energy/ Macquarie Capital Group	40 km S of Geraldton, WA	New project; Under construction	late 2012/ early 2013	55MW	200
Musselroe Bay Wind Farm	Hydro Tasmania	Cape Portland, Tas	New project; Committed	mid 2013	168MW	400
Oaklands Hill Wind Farm	AGL Energy/ Oaklands Hill Pty Ltd	3 km S of Glenthompson, Vic	New project; Completed	2012	63MW	200
Ryan Corner Wind Farm	Union Fenosa Wind Australia	10 km NW of Port Fairy, Vic	New project; Extension for government approval received; construction to commence early Q1 2013	2014	134MW	327
Snowtown stage 2	TrustPower Limited	5 km W of Snowtown, SA	Expansion; Under construction	2013	270MW	439
Woodlawn Wind Farm	Infigen Energy	40 km S of Goulburn, NSW	New project; Completed	late 2011	48.3MW	115
Woolsthorpe Wind Farm	Wind Farm Developments	2 km W of Woolsthorpe, Vic	New project; Under construction	2012	40MW	60-100
Hydro						
Tumut 3 upgrade	Snowy Hydro	Talbingo, NSW	Expansion; Completed	late 2011	Up to 300MW	28
Upper Tumut expansion	Snowy Hydro	Cabramurra, NSW	Expansion; Under construction	2013	40MW	20
Solar						
Kogan Creek Solar Boost Project	CS Energy	near Chinchilla, Qld	Expansion; Under construction	2013	44MW	105

a Summary of projects classified as committed. For proposed projects please refer to source.

Source: BREE, Major electricity generation projects, November 2012.

Major new coal, oil and gas projects

New mining industry projects as of October 2012[a]

Project	Company	Location	Status	Expected Startup	Estimated New Capacity	Capital Expend. $m
Coal - mining projects - NSW						
Appin Area 9	BHP Billiton	Wollongong	Expansion	2016	3.5 Mt	820
Austar underground (stage 3)	Yancoal Australia (100%)	12 km SW of Cessnock	Expansion	2013	3.6 Mt	250
Boggabri opencut	Idemitsu Kosan	17 km NE of Boggabri	Expansion	2014	3.5 Mt	500
Metropolitan	Peabody Energy	30 km N of Wollongong	Expansion	2015	1.5 Mt	70
NRE No. 1 Colliery (preliminary works project)	Gujarat NRE Coking Coal	8 km N of Wollongong	Upgrade	2015	nil	122
Ravensworth North	Xstrata, Itochu	22 km NW of Singleton	Expansion	2013	8 Mt	1360
Ulan West	Xstrata, Mitsubishi	42 km NNE of Mudgee	Expansion	2014	6.7 Mt	1068
Coal - mining projects - Qld						
Broadmeadow (mine life extension)	BHP Billiton Mitsubishi Alliance (BMA)	30 km N of Moranbah	Expansion	2013	0.4 Mt	874
Caval Ridge	BHP Billiton Mitsubishi Alliance (BMA)	SE of Moranbah	New Project	2014	8 Mt	1870
Daunia	BHP Billiton Mitsubishi Alliance (BMA)	25 km SE of Moranbah	New Project	2013	4.5 Mt	1553
Eagle Downs (Peak Downs East underground)	Aquila Resources / Vale	25 km SE of Moranbah	New Project	2016	4.5 Mt	1254
Ensham	Ensham Resources	40 km NE of Emerald	Expansion	2012	1.7 Mt	166
Grosvenor underground	Anglo American	8 km N of Moranbah	New Project	2013	5 Mt	1650
Kestrel	Rio Tinto, Mitsui	51 km NE of Emerald	Expansion	2013	1.4 Mt	1942

Project	Company	Location	Status	Expected Startup	Estimated New Capacity	Capital Expend. $m
Lake Vermont	Jellinbah, Marubeni, Sojitz, AMCI	20 Km N of Dysart	Expansion	2013	4 Mt	200
Millennium	Peabody Energy	22 km E of Moranbah	Expansion	2013	1.5 Mt	270
Rolleston (phase 1)	Xstrata, Sumisho, IRCA	16 W of Rolleston	Expansion	2014	3 Mt	391
Coal - infrastructure projects - NSW						
Hunter Valley Corridor Capacity Strategy (Contracted)	Australian Rail and Track Corporation	Hunter Valley	Expansion	various	n/a	1025
Kooragang Island project 145	Port Waratah Coal Services	Newcastle	Expansion	late 2012	12000 ktpa	227
NCIG export terminal (Newcastle Coal Infrastructure Group) (stage 2)	NCIG	Newcastle	Expansion	2013	23000 ktpa	900
NCIG export terminal (Newcastle Coal Infrastructure Group) (stage 3)	NCIG	Newcastle	Expansion	2014	13000 ktpa	1000
Coal - infrastructure projects - Qld						
Blackwater System Power upgrade	QR National	Blackwater	Expansion	late 2012	9000 ktpa	195
Goonyella System Expansion Project	QR National	Bowen Basin to Mackay	Expansion	2014	11000 ktpa	185
Hay Point Coal Terminal (phase 3)	BHP Billiton Mitsubishi Alliance (BMA)	20 km S of Mackay	Expansion	2014	11000 ktpa	2710
Wiggins Island Coal Terminal (stage 1)	Wiggins Island Coal Export Terminal	Gladstone	New project	2014	27000 ktpa	2400
Wiggins Island rail project	QR National	Gladstone	New project	2015	27000 ktpa	900

Project	Company	Location	Status	Expected Startup	Estimated New Capacity	Capital Expend. $m
Gas (including LNG) projects						
Australia Pacific LNG	Origin / ConocoPhillips / Sinopec	Gladstone, Qld	new project	2016	9 Mt	23000
Casino Gas Project	Metgascp	Casino, NSW	new project	2014	18 PJ pa	50
Gladstone LNG	Santos / Petronas / Total / Kogas	Gladstone, Qld	new project	2015	7.8 Mt	18000
Gorgon LNG	Chevron / Shell / ExxonMobil	Barrow Island, WA	new project	2015	15 Mt	43000
Greater Western Flank - Phase 1 Gas	Woodside Energy / BHP Billiton / BP / Chevron / Shell / Japan Australia LNG	Carnarvon Basin, WA	expansion	2016	n/a	2300
Ichthys LNG	Inpex Holdings / Total	Darwin, NT	new project	2017	8.4 Mt	33000
Julimar Gas Development Project	Apache / KUFPEC	180 km NW of Dampier, WA	new project	2016	1.65 Mt	1200
Kipper Gas Project (stage 1)	Esso / BHP Billiton / Santos	42 km offshore Gippsland, Vic	new project	2016	30 PJ pa	1700
Macedon Gas	BHP Billiton / Apache Energy	100 km W of Onslow, WA	new project	2013	75 PJ pa	1470
NWS North Rankin B Gas	Woodside Energy / BHP Billiton / BP / Chevron / Shell / Japan Australia LNG	150 km NW of Dampier, WA	expansion	2013	967 PJ pa	5000
Prelude Floating LNG	Shell	Browse Basin, WA	new project	2016	3.6 Mt	12600
Queensland Curtis LNG project	BG Group	Gladstone, Qld	new project	2014	8.5 Mt	19800
Spar Gas	Apache Energy / Santos	120 km N of Onslow, WA	new project	2013	18 PJ pa	117
Wheatstone LNG	Chevron / Apache / KUFPEK / Shell	145 km NW of Dampier, WA	new project	2016	8.9 Mt	29000
Gas - pipeline infrastructure projects						
Moomba to Sydney	Australian Pipeline Group	Moomba (SA) to Sydney (NSW)	Expansion	2013	n/a	100
Goldfields pipeline expansion	Australian Pipeline Group	Pilbara, WA	Expansion	2014	16 PJ pa	150

Project	Company	Location	Status	Expected Startup	Estimated New Capacity	Capital Expend. $m
Petroleum projects						
Balnaves Development Project	Apache Energy / KUFPEC	180 km NW of Dampier, WA	new project	2014	30 kbpd	429
Coniston Oil Field Project	Apache Energy / Inpex	50 km N of Exmouth, WA	expansion	2014	22 kbpd	526
Fletcher-Finucane	Santos / KUFPEC / Nippon Oil / Tap Oil	Carnarvon Basin, WA	new project	2013	15 kbpd	490
Montara/Skua oilfield	PTTEP	650 km W of Darwin	new project	2013	35 kbpd	680
Turrum (includes gas)	ExxonMobil / BHP Billiton	Bass Strait, Vic	new project	2013	11 kbpd, 77 PJ pa	2600

a Summary of projects classified as committed. For recently completed and proposed projects please refer to source.

Source: BREE, Resources and energy major projects, October 2012.

Appendix 2— Units, prefixes and conversion factors

General

Units		Metric prefixes			Other abbreviations	
J	joule	k	kilo	10^3 (thousand)	bcm	billion cubic metres
L	litre	M	mega	10^6 (million)	m^3	Cubic metre
t	tonne	G	giga	10^9 (1000 million)	f^3	Cubic feet
g	gram	T	tera	10^{12}	bbl	barrel
W	watt	P	peta	10^{15}	Mtoe	million tonnes of oil equivalent
Wh	watt hour	E	exa	10^{18}	na	not available
		b	billion	10^9	pa	per annum
					Gcal	gigacalorie
					Btu	British thermal units

Conversion between units of energy

To:	TJ	Gcal	Mtoe	MBtu	GWh
From:	multiply by:				
TJ	1	238.8	2.388×10^{-5}	947.8	0.2778
Gcal	4.1868×10^{-3}	1	10^{-7}	3.968	1.163×10^{-3}
Mtoe	4.1868×10^{4}	10^{7}	1	3.968×10^{7}	11630
MBtu	1.0551×10^{-3}	0.252	2.25×10^{-8}	1	2.931×10^{-4}
GWh	3.6	860	8.6×10^{-5}	3412	1

Source: IEA Energy Statistics Handbook

Conversion factors

1 barrel = 158.987 L

1 mtoe = 41.868 PJ

1 kWh = 3600 kJ

1 MBtu = 1055 MJ

1 m^3 = 35.515 f^3

1 L LPG = 0.254 m^3 gas

1 L LNG = 0.625 m^3 natural gas

The factors used in the following tables are used when converting individual types of fuel from volume or weight to energy content, or vice versa. The values are indicative only because the quality of any fuel varies with factors such as location and air pressure. Values given here apply at a temperature of 15°C and a pressure of 1 atmosphere (101.3 kilopascals). The values are the gross energy content of the fuel—that is, the total amount of heat that will be released by combustion.

The usable energy content of uranium metal is 0.56 petajoules a tonne. Uranium oxide (U_3O_8) contains 84.8 per cent of the metal by weight.

Energy content of gaseous fuels

	To:	m3
From MJ:		divide by:
Natural gas (sales quality)		
Victoria		38.8
Queensland		39.5
Western Australia		41.5
South Australia, New South Wales		38.3
Northern Territory		40.5
Ethane (average)		57.5
Town gas		
synthetic natural gas		39.0
other town gas		25.0
Coke oven gas		18.1
Blast furnace gas		4.0

Sources: RET, BHP Billiton

Energy content of solid fuels

	energy content GJ/t		energy content GJ/t
Black coal		**Black coal**	
New South Wales		Western Australia	
Exports		Thermal coal	19.7
metallurgical coal	29.0	Tasmania	
thermal coal	27.0	Thermal coal	22.8
Electricity generation	23.4	**Lignite**	
Steelworks	30.0	Victoria	10.3
Washed thermal coal	27.0	Briquettes	22.1
Unwashed thermal coal	23.9	South Australia	15.2
Queensland		**Other**	
Exports		Coke	27.0
metallurgical coal	30.0	Wood (dry)	16.2
thermal coal	27.0	Bagasse	9.6
Electricity generation	23.4		
Other	23.0		