Australian Government

AUSTRALIAN ENERGY

national and state projections to 2019-20

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ABARE is a professionally independent government economic research agency.

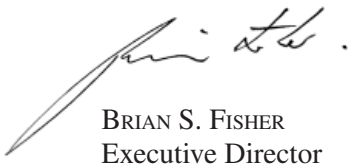
ABARE project 1644

foreword

In this report ABARE revises its most recent detailed medium to long term projections of Australian energy consumption and production and, in so doing, continues to support decision makers in Australia's energy industries and in government who are focused on future energy trends.

The analysis covers the period from 2001-02 to 2019-20, with a focus on the medium term period from 2001-02 to 2008-09. The projections are prepared using ABARE's *E_4cast* energy forecasting and environmental policy analysis tool. The medium term analysis also draws on ABARE's regular analysis of Australian commodity markets. Since publishing Australia's energy outlook in June 2003, *E_4cast* has been further refined and enhanced in a number of important areas. The model now incorporates peak and offpeak electricity demand as well as fresh estimates of the end use demand parameters, ensuring that demand relationships embody recent energy trends.

In June 2003 when ABARE last released a set of long term energy projections, the global outlook was particularly uncertain; unfortunately, little has changed since then. Nevertheless, it is hoped that this revised outlook will continue to assist policy makers to lead the Australian energy industry into the 21st century.



BRIAN S. FISHER
Executive Director

August 2004

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contents

figures

tables

statistical tables

glossary

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.

Coal byproducts Byproducts such as coke oven gas, blast furnace gas (collected from steelworks blast furnaces), coal tar and benzene/toluene/xylene (BTX) feedstock. The latter two are both collected from the coke making process.

Conversion The process of transforming one form of energy into another before use. Energy consumed in conversion is the energy content of fuel consumed by energy producing industries — such as natural gas and liquefied petroleum gas used in gas manufacturing, petroleum products used in oil refineries, and all fuels (including electricity) used in power station — plus the energy lost in the production, conversion and transport of fuels, such as electricity or energy lost in coke production, plus energy used in pumped storage, less the energy produced.

Gas pipeline operation Natural gas used in pipeline compressors and losses and leakage during transmission.

Levelised costs of electricity The costs of electricity generation calculated as the sum of input fuel, operating and investment costs expressed on a per energy unit basis.

Natural gas Gases that include commercial quality sales gas, liquefied natural gas, ethane, methane (including coal seam and mine mouth methane and gas from garbage tips and sewage plants) and plant and field use of noncommercial quality gas. In this report, natural gas also includes town gas.

Petroleum Crude oil and natural gas condensate used directly as fuel, 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).

In this report, all petroleum products are defined as primary fuels despite the fact that most petroleum products are transformed (refined). Accordingly, the distinction

between the consumption of petroleum at the primary and final end use stages relates only to where the petroleum is consumed, not to the mix of different petroleum products consumed. The consumption of petroleum at the primary energy use stage is referred to collectively as oil. The consumption of petroleum at the final end use stage is referred to as petroleum products.

The one exception to this is liquefied petroleum gas (LPG). LPG is not included in the definition of end use consumption of petroleum and is modeled separately.

Petajoule The joule is the standard unit of energy in electronics and general scientific applications. One joule is the equivalent of one watt of power radiated or dissipated for one second. One petajoule, or 280 terawatt hours, is the heat energy content of about 43 000 tonnes of black coal or 29 million litres of petrol.

Primary fuels The forms of energy obtained directly from nature. They include nonrenewable fuels such as black coal, brown coal, uranium, crude oil and condensate, naturally occurring liquid petroleum gas, ethane and natural gas, and renewable fuels such as wood, bagasse, hydroelectricity, wind and solar energy.

Secondary fuels Fuels produced from primary or other secondary (or derived) fuels by conversion processes to provide the energy forms commonly consumed. They include refined petroleum products, thermal electricity, coke, coke oven gas, blast furnace gas and briquettes.

Total primary energy consumption (Also referred to as total domestic availability.) The total (in energy units) of the consumption of each primary fuel in both the conversion and end use sectors. It includes the use of primary fuels in conversion activities — notably the consumption of fuels used to produce electricity — and also includes own use and losses in the conversion sector.

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

Town gas All manufactured gases that are typically reticulated to consumers. These include synthetic natural gas, reformed gas, tempered liquid petroleum gas and tempered natural gas. In this report, town gas is included with natural gas.

units

J	joules
L	litres
t	tonnes
g	grams
Wh	watt-hours
b	billion (or 1000 million), used only in money quantities ($b)

Standard metric prefixes

k	kilo	10^3 (thousand)
M	mega	10^6 (million)
G	giga	10^9 (1000 million)
T	tera	10^{12}
P	peta	10^{15}
E	exa	10^{18}

Standard conversions

1 barrel = 158.987 L
1 kWh = 3600 kJ

Indicative energy content conversion factors

Black coal production	28.5 GJ/t
Brown coal	9.7 GJ/t
Crude oil production	37 MJ/L
Naturally occurring LPG	26.5 MJ/L
LNG exports	54.4 GJ/t
Natural gas (gaseous production equivalent)	40 MJ/kL
Biomass	11.9 GJ/t
Hydroelectricity, wind and solar energy	3.6 TJ/GWh

Conventions used in tables

0.0 is used to denote a negligible amount.
Small discrepancies in totals are generally the result of the rounding of components.

summary

Medium to long term projections of Australia's energy consumption, production and trade are presented in this report, updating those published in June 2003 (Dickson et al. 2003). The projections are prepared using *E_4cast* — ABARE's energy forecasting and environmental policy analysis framework. The analysis also draws explicitly on ABARE's regular analysis of Australian commodity markets, particularly for the medium term forecasts.

Key highlights

- Over the long term, primary energy consumption in Australia is projected to grow on average by 2.2 per cent a year, to 7544 petajoules in 2019-20. In the medium term (2001-02 to 2008-09), growth in energy use is projected to be relatively strong — 2.5 per cent a year.
- Economic output is by far the most critical determinant of longer term energy consumption trends. For the period to 2019-20, growth in national output is assumed to average 3.3 per cent a year.
- Coal and oil will continue to meet the bulk of Australia's energy needs, accounting for more than 70 per cent of primary energy consumption in 2019-20.
- With an estimated growth rate of 2.4 per cent a year, gross electricity generation is forecast to increase by 53 per cent to reach 344 TWh by 2019-20.
- Growth in domestic use of gas is projected to remain strong (4.8 per cent a year in the medium term and 3.7 per cent in the long term). At the same time, liquefied natural gas (LNG) exports are projected to increase almost fourfold to 35 million tonnes in 2019-20, to account for more than half of total gas production in that year.
- Coal exports are forecast to increase from less than 200 million tonnes currently to 291 million tonnes by 2019-20. The share of (black) coal production that is accounted for by exports is forecast to remain around 80 per cent.

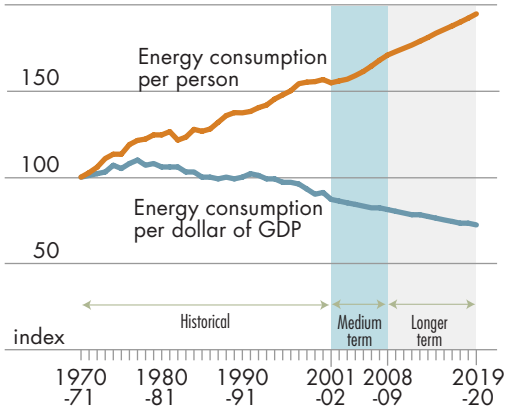
- Although, on average, Australia is projected to remain an energy exporter, its reliance on imported liquid fuels — crude oil or refined petroleum products — is expected to increase considerably over the outlook period, from 17 per cent currently to 46 per cent by 2019-20.

Energy consumption

Primary energy consumption in Australia is projected to increase by 48 per cent to reach 7544 petajoules by 2019-20, growing at an average rate of 2.2 per cent a year. A key driver of the outlook is economic growth. In the medium term, gross domestic product (GDP) is forecast to grow by 3.4 per cent a year and by 3.2 per cent a year thereafter. Similarly, the assumed expansion in energy intensive refining and minerals processing industries is relatively more pronounced over the medium term. Therefore, energy use is projected to grow relatively strongly over the medium term — by 2.5 per cent a year.

Placed in an historical context, the rate of growth of Australian energy consumption has consistently decelerated over the past four decades. During the 1960s, primary energy use grew by a robust 5.0 per cent a year. The rate fell to 3.8 per cent a year during the next decade (which included two major oil price shocks). During the 1980s, economic recession and sharply rising energy prices resulted in the growth rate falling to a more moderate 2.6 per cent a year. Falling (real) energy prices and robust economic growth during the 1990s slowed the forces of moderation, leading to annual average growth of 2.5 per cent a year.

A Energy use in Australia



The aggregate energy intensity of the Australian economy, measured as total primary energy consumption per dollar of GDP, fell by an average 1.1 per cent a year during the 1990s, after remaining more or less stable during the 1970s and 1980s. Energy intensity is forecast to continue to decline by 1.1 per cent a year over the outlook period (figure A). This suggests that 18 per cent less energy will be needed to produce a dollar of economic output (measured in 2001-02 dollars) in 2019-20.

In contrast, per person energy consumption is projected to continue to rise over

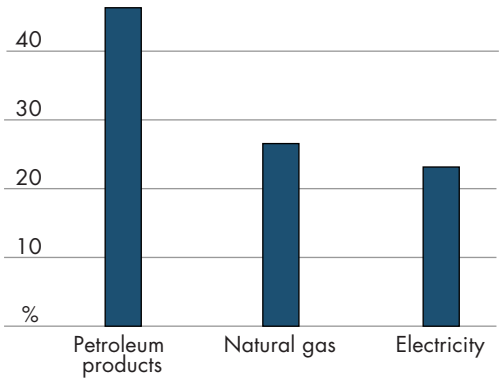
the outlook period. Growing on average by 1.3 per cent a year, energy use per person increased from less than 170 gigajoules in the early 1970s to about 260 gigajoules in 2000. Over the outlook period, per person energy consumption is estimated to increase to more than 325 gigajoules by 2019-20 (using population projections sourced from the Australian Bureau of Statistics).

Growth in primary energy use is projected to vary considerably across the states and territories. With an estimated growth rate of 4.6 per cent a year, primary energy consumption in the Northern Territory is forecast to more than double to 186 petajoules by 2019-20. Fueled by strong economic growth, particularly in energy intensive refining and minerals processing industries, primary energy consumption in Queensland and Western Australia is also forecast to grow strongly — at 3.0 per cent a year in both cases.

Energy use growth rates for New South Wales, Victoria and South Australia are all forecast to be relatively modest. This is particularly true for Victoria and South Australia, where primary energy consumption over the projection period is projected to grow by just 1.6 per cent a year. In the case of Tasmania, primary energy consumption is projected to grow by only 1.5 per cent a year, largely reflecting low economic growth prospects.

At the national level, final end use energy consumption is projected to grow by 2.3 per cent a year, with the fuel mix continuing to be dominated by petroleum products. These are forecast to account for 46 per cent of the total increase in final energy consumption between 2001-02 and 2019-20 (figure B). Consumption of natural gas is also projected to increase strongly, at 3.3 per cent a year, accounting for 27 per cent of the total increase in final energy consumption.

B Contribution to growth in final energy consumption in Australia



The growth in final gas use is closely linked to developments in the iron and steel and basic nonferrous metals sectors. Total direct reduced iron (DRI) production in Australia is assumed to reach 6.8 million tonnes by 2019-20, up from only 1.0 million tonnes in 2001-02. The DRI production process

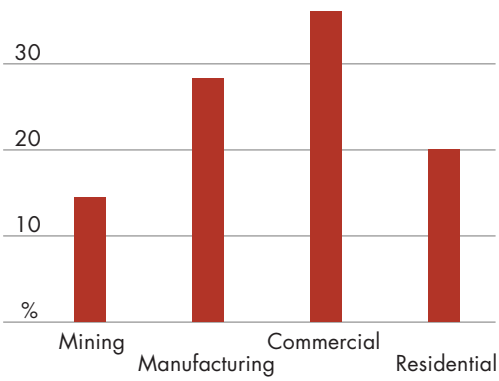
is particularly gas intensive and, hence, this positive outlook for DRI underpins a forecast 6.2 per cent a year growth in gas use in the iron and steel sector.

Reflecting major additions to Australia's alumina refining capacity as well as the emergence of an Australian magnesium industry, gas consumption in the nonferrous metals sector is also projected to grow strongly — by 3.7 per cent a year (8.1 per cent a year in the medium term).

Final energy use in the residential sector was 393 petajoules in 2001-02, representing approximately 13 per cent of total final energy consumption. Over the outlook period, residential sector energy use is projected to increase by 1.9 per cent a year to around 548 petajoules in 2019-20. Currently, electricity accounts for 47 per cent of residential sector energy demand and gas 32 per cent. Over the projection period gas is expected to increase its share to 36 per cent by 2019-20, principally at the expense of wood, while electricity is expected to maintain its relative position.

The commercial and services sector, although a relatively small energy user with a share of about 7.6 per cent, is projected to grow by 3.0 per cent a year. The sector is particularly electricity dependent — electricity currently accounts for around 73 per cent of commercial and services sector energy use — and is expected to be a major source of the projected growth in electricity consumption over the medium to longer term. Currently the commercial and services sector accounts for more than a third of total final electricity consumption and is projected to account for more than 36 per cent of the total projected increase in electricity use; this compares with 28 per cent for the manufacturing sector and 20 per cent for the residential sector (figure C).

C Contribution to electricity consumption growth in Australia, by sector 2001-02 to 2019-20



Electricity generation

Gross generation of electricity in Australia is projected to increase by an average 2.4 per cent a year over the long term — from 224 TWh in 2001-02 to 344 TWh by 2019-20.

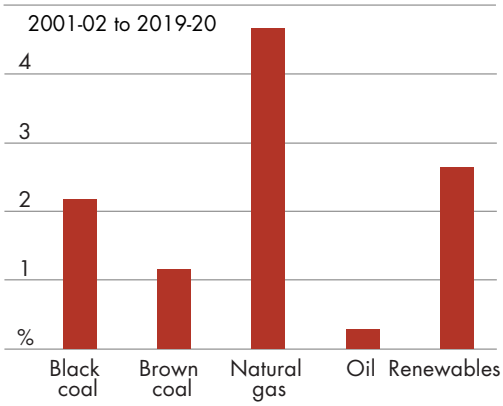
The recently introduced mandatory renewable energy target policy, along with the Queensland Government's 13 per cent gas scheme and the New South Wales Government's greenhouse gas emissions benchmark scheme, are all explicitly modeled in E_4cast in the reference case.

A mix of renewables is expected to be developed to meet the renewable energy target. Wind power, for example, is projected to grow by an average 16 per cent a year (from a very small base) over the entire outlook period and to contribute around 36 per cent to the additional renewable energy generated between 2001-02 and 2010-11. Electricity generation from biomass (mainly bagasse and bagasse cofired with wood waste) is estimated to increase by 10 per cent a year, accounting for 33 per cent of total growth in the renewable electricity to 2010-11.

Over the long term, hydroelectricity is projected to grow by just 0.6 per cent a year, reflecting the limited availability of suitable locations for the expansion of grid based hydroelectricity generation. As hydroelectricity accounts for more than 90 per cent of total electricity sourced from renewables, total renewable electricity is forecast to grow by 2.6 per cent a year over the outlook period (figure D).

Largely reflecting some existing capacity overhang and the influence of a number of government policy initiatives, electricity generation from black coal is estimated to grow by an average 2.2 per cent a year over the outlook period, to 185 TWh in 2019-20 (an increase of almost 60 TWh). The projected growth in brown coal fired electricity generation is significantly more modest — 1.2 per cent a year over the outlook period, reflecting high capital costs and significant policy uncertainty.

D Electricity generation growth rates, by technology in Australia



In contrast, electricity generation from natural gas Australiawide is forecast to grow by 4.7 per cent a year, more than doubling total output to 69 TWh by 2019-20. Growth in gas fired electricity generation is projected to be particularly strong in the medium term (6.2 per cent a year), largely reflecting the impact of Australian government policy initiatives and investment in peak capacity.

On the basis of this electricity generation outlook, new investment needed by 2019-20 in gas and coal fired electricity generation capacity is estimated to be around $11.0 billion.

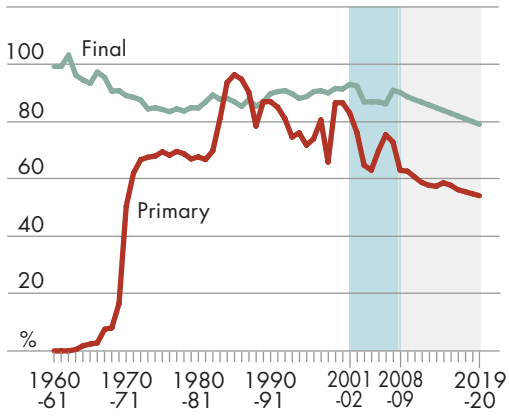
Energy production and net trade

Total primary energy production — excluding uranium (U_3O_8) — in Australia is projected to increase by more than 50 per cent to 16 583 petajoules by 2019-20, growing by an average 2.4 per cent a year. As primary energy consumption is forecast to increase by 2.2 per cent over the same period, Australia's energy surplus is expected to increase slightly over the outlook period. Currently, primary energy consumption constitutes 47 per cent of total primary energy production (again excluding uranium).

In contained energy terms, black coal accounts for around 66 per cent of total production of energy and over 90 per cent of net energy exports. Over the outlook period, black coal production is projected to increase by 2.1 per cent a year, while exports are forecast to increase by 2.2 per cent a year to reach 291 million tonnes in 2019-20.

The outlook for Australia's LNG industry is for continued strong growth, with exports forecast to increase to 20 million tonnes by 2008-09 and 35 million tonnes by 2019-20.

E Production to consumption ratios for the liquid fuels sector Australia



The combined output of crude oil and naturally occurring LPG is forecast to decline from 1459 petajoules now to 1362 petajoules by 2019-20. Over the same period the consumption of all liquid fuels is projected to increase by 43 per cent to 2515 petajoules. Therefore, primary production of liquid fuels relative to total liquid fuels consumption in Australia is forecast to fall from 83 per cent currently to 54 per cent by 2019-20, leading to increased dependence on imported liquid fuels — in crude or refined form — over the outlook period (figure E, primary ratio).

Petroleum refining

With the mothballing of the Port Stanvac refinery in Adelaide on 1 July 2003, gross refinery output, including that of petrochemicals, in Australia is estimated to have fallen by more than 4 per cent to 1576 petajoules in 2003-04. The fall in industry output is less than the total output from Port Stanvac as the rest of the industry is assumed to have made up approximately a third of the decline in output. Over the three years 2004-05 to 2006-07, refinery output is assumed to increase by an average 1.4 per cent a year to 1644 petajoules.

With a consistent increase in the domestic consumption of petroleum products over the medium term and an improvement in the economics of petroleum refining in Australia, the Port Stanvac refinery is assumed to resume production in 2007-08, leading to a significant increase in industry output and a fall in (net) imports of petroleum products. Beyond 2009-10, both refining capacity and refinery output is assumed to increase by around 1 per cent a year.

Overall, output of petroleum products is forecast to increase from 1634 petajoules in 2001-02 to 1989 petajoules by 2019-20, a total increase of around 22 per cent or 354 petajoules of refined products. However, at the same time, the consumption of petroleum products in Australia is projected to increase by around 2 per cent a year. As a result, the share of petroleum products sourced from local refineries (as opposed to imports) is projected to fall from the current level of 93 per cent to less than 80 per cent by 2019-20 (figure E, final ratio).

introduction

In this report, ABARE's latest assessment of the medium and long term outlook for Australian energy consumption, production and trade is presented. The analysis covers the period from 2001-02 to 2019-20, with a focus on the medium term period from 2001-02 to 2008-09. The projections are prepared using ABARE's *E4cast* energy forecasting and environmental policy analysis tool. The short to medium term analysis also draws on ABARE's regular analysis of Australian commodity markets. This outlook updates the projections released by ABARE in June 2003 (Dickson, Akmal and Thorpe 2003).

Since publishing Australia's energy outlook in June 2003, *E4cast* has been refined and enhanced in a number of important areas. For example, the electricity generation module has been improved and now incorporates peak and offpeak electricity demand at the state and territory level. This refinement has helped to improve the treatment of investment in the electricity generation sector (particularly for peak capacity) and the fuel use (or fuel mix) projections in electricity generation. The end use demand parameters have also been re-estimated using data for the period 1973-74 to 200-01, ensuring that the demand relationships embody recent energy trends. Previously, the parameters were based on data for the period from 1973-74 to 1994-95.

Another notable enhancement relates to the way in which the demand and supply parameters are represented in the model. Previously, demand and supply elasticities were linearised (that is, in a fixed linear relationship, using base year data), before being incorporated into the model. This was done principally to keep the entire modeling framework tractable. Now, particularly given advancements in computing, the current version of *E4cast* is able to be highly nonlinear and hence does not require linearisation of the demand and supply parameters.

In the following chapter an overview of the *E4cast* modeling framework, along with a discussion of key parameter assumptions, is provided. In chapter 3 the long term energy consumption and production projections, covering the period 2001-02 to 2019-20, are presented. Medium term trends evident in the period from 2001-02 to 2008-09 are also discussed.

In developing the reference case set of projections, four alternative cases were modeled to assess the particular importance of key assumptions. Two cases analyse the impact of higher and lower growth assumptions. A third scenario focuses on an assumption that the Aldoga aluminium smelter in Queensland will be operational by 2005-06. This project is

so large and intensive in its use of electricity that the alternative scenario was modeled to examine the sensitivity of the results to the inclusion of this project in the outlook.

The fourth scenario is designed to assess the impact of an alternative outlook for the refining industry in Australia. In the reference case it is assumed that refining at Port Stanvac, which was mothballed in July 2003, will resume operations in 2007-08 and that all other refineries will continue operating over the outlook period. In the alternative scenario it is assumed that, in addition to the Port Stanvac refinery not reopening, the Altona refinery in Victoria closes down in 2006.

A comprehensive set of statistical tables covering consumption, production and trade in Australian energy, both at the national level and for each of the states and territories, is freely available on ABARE's web site (www.abareconomic.com). The statistical tables provide data covering the period 2001-02 to 2019-20. For more information on this report or statistical tables, contact Muhammad Akmal on +61 2 6272 2099 or email Muhammad.Akmal@abare.gov.au.

overview of the *E4cast* model and key assumptions

E4cast overview

ABARE uses the *E4cast* modeling framework to develop detailed and consistent projections of Australian energy consumption and production. *E4cast* is a dynamic partial equilibrium model of the Australian energy sector that approximates the principal interdependencies between energy production, conversion and consumption in Australia. It is used to project, on an annual basis, energy consumption, by fuel type, by industry and by state or territory, explicitly taking into account real incomes and industry production trends, fuel prices and technical change (or energy efficiency improvements). The first version of the model was documented in Dickson et al. (2001). A detailed technical outline of the current version of the model is provided in appendix A. A brief overview of the key features of the current version of *E4cast* is provided in box 1.

Regional coverage of the model comprises: New South Wales, including the Australian Capital Territory; Victoria; Queensland; South Australia; Western Australia; Tasmania; and the Northern Territory.

The broad fuel and industry coverage of the model is outlined in tables 1 and 2. *E4cast* explicitly covers the demand for seventeen fuels across twenty end use and seven conversion sectors. The industry coverage includes specific representation of all of Australia's major energy intensive industries, including: wood, paper and pulp; petroleum refining; chemicals; nonmetallic mineral products; direct reduced iron; other iron and steel manufacturing; aluminium; other basic nonferrous metals; and electricity generation. The transport division is also represented in a detailed manner, covering: passenger motor vehicles; road freight; rail; water (international, domestic); and air transport (international, domestic); as well as fuel used in pipeline operations.

The demand functions for each of the main fuel types (such as electricity, natural gas, coal and petroleum products), in each sector (by state and territory) have been estimated

1 Fuel coverage

Black coal
Brown coal
Coal byproducts
– coke oven gas
– blast furnace gas
Coke
Crude oil
Solar (includes residential solar hot water heating)
Biomass (includes bagasse and wood and wood waste)
Liquefied petroleum gas (LPG)
Other petroleum products
Electricity
– peak
– offpeak
Hydroelectricity
Wind energy
Petroleum products
Natural gas
Biogas (includes sewage and landfill gas)

Box 1: Key features of E_4cast

In 2000, ABARE commenced development of its E_4cast energy forecasting and environmental policy analysis framework. The first version of the model was documented in Dickson et al. (2001). Since then the model has been enhanced and refined in a number of directions, providing a sound platform for the development and analysis of medium and long term energy and greenhouse gas emissions projections. Key features of the current 2004 version of E_4cast are outlined below.

- E_4cast is a dynamic partial equilibrium framework that provides a complete treatment of the Australian energy sector, representing energy production, trade and consumption in a comprehensive manner.
- The Australian energy system is divided into seven conversion sectors and twenty end use sectors.
- Fuel coverage is comprehensive, including seventeen primary and secondary fuels in total.
- Results for all states and territories (the ACT is included with New South Wales) are provided.
- Detailed representation is provided of energy demand. The demand for each fuel is modeled as a function of income or activity, fuel prices (own and cross) and efficiency improvements.
- Primary energy consumption is distinguished from final (or end use) energy consumption. This convention is consistent with the approach used by the International Energy Agency (IEA 2002).
- The current version of E_4cast covers the period 2001-02 to 2019-20.
- Demand parameters are estimated econometrically using data for the period 1973-74 to 2000-01.
- Business activity is generally represented by gross state product (GSP). Energy intensive industries are modeled explicitly, taking into account large and lumpy capacity expansions. The industries modeled in this way are:
  - aluminium
  - other basic nonferrous metals (mainly alumina)
  - direct reduced iron
  - other iron and steel.
- Peak and offpeak electricity demands are modeled explicitly.
- The electricity generation module includes 11 generation technologies — three peak and eight base load technologies.
- Key policy measures modeled explicitly are:
  - the Australian Government's Mandatory Renewable Energy Target scheme,
  - the New South Wales Government's greenhouse gas benchmarks scheme, and
  - the Queensland Government's cleaner energy strategy (the so-called 13 per cent gas scheme).

econometrically and incorporate own price, cross price, income or activity, and technical change effects.

The *E4cast* modeling framework incorporates domestic as well as international trade in energy sources. Export forecasts for black coal and liquefied natural gas (LNG), as prepared by ABARE commodity analysts, are represented in the model directly. Net trade in crude oil and refined petroleum products is determined endogenously. Interstate flows in electricity and natural gas are also modeled explicitly, with the direction of trade determined by the model. However, for reasons of simplicity, interstate trade in refined petroleum products and coal is not modeled.

E4cast provides a complete treatment of the Australian energy sector, representing energy production, trade and consumption at a detailed level. As a result, the model can be used to produce a full range of results, including Australian energy balance tables.

2 Industry coverage

Sectors/subsectors	ANZSIC code
Agriculture	Div A
Mining (includes own use in gas manufacture and LNG liquefaction)	Div B
Manufacturing and construction	Divs C, E
Wood and paper products, printing, publishing and recorded media	23–24
Petroleum refining (includes own use in refining)	2510–2515
Basic chemical products	2520–2599
Nonmetallic mineral products	26
Iron and steel	271
Basic nonferrous metals	272–273
Aluminium	2722
Other basic nonferrous metals	2720–2721, 2723–2729
Other manufacturing and construction	na
Electricity generation (includes own use and transmission losses)	361
Transport	na
Road transport	61
Passenger motor vehicles	na
Other road transport	na
Railway transport	62
Water transport	63
International water transport	6301
Domestic water transport	6302
Air transport	64
International air transport	6401
Domestic air transport	6402
Pipeline operations	6501
Commercial and services	3700, 6700 and Divs F, G, H, J, K, L, M, N, O, P, Q
Residential	na
Solvents, lubricants and bitumen	na

Source: Modified from Australian Bureau of Statistics and New Zealand Department of Statistics, Australian and New Zealand Standard Industrial Classification, 1993 edition.

Activity or growth assumptions

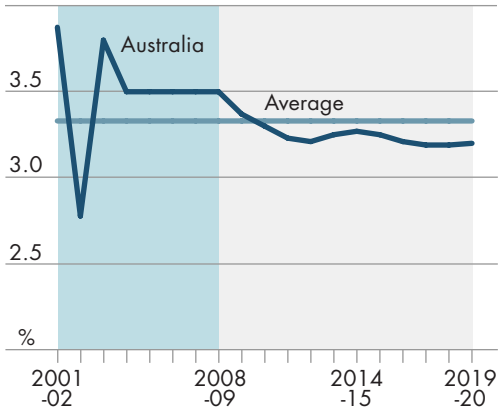
The 'activity' variable that is used in each of the fuel demand equations is arguably the most important determinant of the model results. For all nonenergy intensive sectors gross state product (GSP) is used to approximate changes in income or business activity, at the state level. For energy intensive industries, typically characterised by large and lumpy capacity expansion, projected industry output (production) at a state level is used to represent business activity. The energy intensive industries modeled in this way are: aluminium; other basic nonferrous metals; direct reduced iron; and other iron and steel manufacturing.

National and state level economic growth

After growing by 3.9 per cent and 2.8 per cent over the past two years, the Australian economy is forecast to grow by 3.8 per cent in 2003-04 and 3.5 per cent a year for the rest of the medium term period to 2008-09 (Penm and Fisher 2004). Following the approach used in the reference case of ABARE's global trade and environmental model (GTEM), growth in gross domestic product (GDP) is projected to settle around 3.2 per cent a year over the period from 2008-09 to 2019-20 (figure F). As the medium term GDP outlook in the GTEM reference case is also sourced from Penm and Fisher (2004), the treatment of GDP in the two models is identical. Over the full outlook period (2001-02 to 2019-20) the annual growth rate is assumed to average 3.33 per cent. In the last cycle of ABARE's energy projections, which were published in June 2003, GDP was assumed to grow by an average 3.36 per cent a year between 2001-02 and 2019-20.

In order to calculate economic growth at the state level, the following procedure is adopted. Regional (state and territory) output elasticities with respect to national GDP are estimated using historical data. State and territory level yearly growth rates are calculated by multiplying the regional elasticities by the annual GDP growth rate. The resulting state and territory level growth rates are reported in table 3.

F Economic growth rate assumptions
Australia



3 Economic growth, by region

	Annual growth		
	2001-02 to 2008-09	2008-09 to 2019-20	2001-02 to 2019-20
	%	%	%
New South Wales **a**	3.2	3.1	3.1
Victoria	3.3	3.2	3.2
Queensland	4.5	4.1	4.2
South Australia	2.1	2.2	2.2
Western Australia	3.8	3.5	3.6
Tasmania	1.4	1.4	1.4
Northern Territory	2.6	2.9	2.8
Australia	3.4	3.2	3.3

a Includes the Australian Capital Territory.

Growth is projected to be the highest in Queensland (4.5 per cent a year in the period to 2008-09 and 4.2 per cent a year overall), followed by Western Australia (3.8 per cent and 3.6 per cent a year). The two most populous states, New South Wales and Victoria, are estimated to grow by 3.1 per cent and 3.2 per cent, respectively, over the long term. In contrast, Tasmania is forecast to grow modestly (1.4 per cent a year), in both the medium and long term.

Growth in energy intensive industries

In *E_4cast*, the production of hot briquetted iron is used as the activity variable in the specification of natural gas demand in the direct reduced iron industry. Starting from 1.0 million tonnes a year in 2001-02, direct reduced iron production in Western Australia is assumed to grow rapidly to 3.7 million tonnes in 2008-09 and 6.8 million tonnes by the end of the projection period; an implied average growth rate of close to 11 per cent a year (table 4). This level of production (6.8 million tonnes) is approximately equivalent to assuming the direct reduced iron industry will comprise three plants (in total) of similar proportions to BHP Billiton's Port Hedland DRI plant.

The expected growth in other iron and steel is considerably lower, particularly in Victoria, where the industry is estimated to grow by 1.2 per cent a year. Overall, the production of other iron and steel is assumed to grow by 2.8 per cent a year, increasing from 7.3 million tonnes in 2001-02 to 12 million tonnes in 2019-20. Growth in the industry is projected to be relatively strong in the medium term; total output of other iron and steel is forecast to increase by 41 per cent to 10 million tonnes by 2008-09 (as opposed to just 16 per cent over the next twelve years, to 12 million tonnes by 2019-20).

Australian aluminium production is assumed to increase by around 48 per cent to 2.7 million tonnes in 2019-20 (table 4), growing at an average rate of 2.2 per cent a year — noting that the year on year movements are not necessarily smooth. Growth in aluminium production in Queensland is expected to be particularly strong, at 4.4 per cent a year (9.8 per cent to 2008-09). In contrast, growth in this sector in Tasmania is projected to be relatively weak. These state level trends reflect ABARE's March quarter 2004 outlook for metals (Maurer et al. 2004). In this outlook, relatively small capacity additions at the Kurri Kurri (15 000 tonnes) and Tomago aluminium smelters (70 000 tonnes) in New South Wales are incorporated. Also, in the case of Queensland, it was assumed that the Aldoga aluminium smelter would be developed and operational by 2005-06. However, there is considerable uncer-

4 Output of energy intensive industries

	Production			Annual growth	
	2001-02	2008-09	2019-20	2001-02 to 2008-09	2001-02 to 2019-20
	Mt	Mt	Mt	%	%
Direct reduced iron	1.0	3.7	6.8	19.8	11.0
Other iron and steel	7.3	10.2	11.9	5.0	2.8
Primary aluminium	1.8	2.5	2.7	4.8	2.2
Alumina	16.4	20.8	22.2	3.4	1.7

tainty about the startup date of the Queensland smelter. Therefore, an alternative scenario has been modeled that excludes this project from the outlook. The results of this analysis of projected energy consumption in Queensland are reported in box 5 (chapter 3).

In the other nonferrous metals sector, production of alumina is used as a proxy for activity across the sector more generally. Australiawide the production of alumina is forecast to grow by around 1.7 per cent a year to reach 22 million tonnes by the end of the projection period, with strong growth expected in the Northern Territory (3.8 per cent) and Queensland (2.6 per cent) and lower growth prospects in Western Australia (0.9 per cent). In states where there is currently no alumina production, but nevertheless prospects for other nonferrous metals (such as for magnesium in South Australia), energy use in the nonferrous metals sector is increased directly by appropriately shifting fuel demand functions.

In ABARE's previous set of medium and long term projections, Australian alumina production was assumed to grow by 17 per cent over the period 2001-02 to 2008-09. For the current outlook, this growth is now close to 27 per cent and is a key difference between the current and previous energy outlook. This more positive outlook for alumina reflects a planned expansion (600 000 tonnes) at the Pinjarra refinery in Western Australia in 2005.

Energy efficiency

Autonomous fuel efficiency improvements are assumed to occur across all of the end use sectors and this factor is modeled exogenously in each fuel demand equation. The treatment of energy efficiency in the model is flexible: energy efficiency improvements can be made to vary by fuel, industry and region, as well as over time. Using this feature, *E_4cast* can be used to model the impact of energy efficiency improvements on a sector by sector basis.

For the sake of simplicity in this outlook a pragmatic approach to modeling energy efficiency improvements has been adopted. The demand for each fuel source is assumed to decline by 0.5 per cent a year over the outlook period as a result of efficiency improvements. A higher rate of 0.75 per cent has been assumed for electricity demand in New South Wales and accounts for the New South Wales state government's greenhouse gas benchmarks (discussed below). In the case of energy intensive industries, where industrial production rather than GSP is used as the activity variable, the rate of efficiency improvement is assumed to be 0.2 per cent a year.

In the electricity generation sector, thermal efficiency rates are exogenously given and are assumed to vary by technology and over time (generally falling). For example, the thermal efficiency of natural gas plants is assumed to improve by an average 1.3 per cent a year between 2001-02 and 2009-10 and by 0.6 per cent thereafter. In contrast, thermal efficiency improvements in coal fired plants are assumed to be modest; the average thermal efficiency of all coal fired plants is projected to increase from around 37 per cent in the base year to 39 per cent by 2019-20, implying an average growth rate of 0.4 per cent a year.

Production and trade

In *E*$_4$*cast*, the supply structure of internationally traded fuels, such as black coal and crude oil, is represented by exogenously determined (real) price paths. In the case of black coal this implies that production will match demand (export and domestic) at a given price level. The outlook for black coal exports is exogenously given and is sourced from ABARE's most recent medium term commodity outlook (Ball, Johnston, Wells and Haine 2004). In the case of crude oil, the outlook for domestic production is exogenous (and hence net imports of crude oil are endogenously determined in the model) and again sourced from ABARE's most recent medium term outlook for the minerals and energy sector (Ball et al. 2004). Net trade in petroleum products is similarly determined within the modelling framework.

The supply of natural gas, brown coal and nontraded black coal (black coal produced in states other than New South Wales and Queensland) is approximated using state specific upward sloping supply curves. Own prices and an autonomous productivity improvement term are the two main arguments of this specification. For simplicity, the supply of other fuels such as biomass, biogas and solar power are assumed to be perfectly elastic, with supply assumed to equate to demand at given prices.

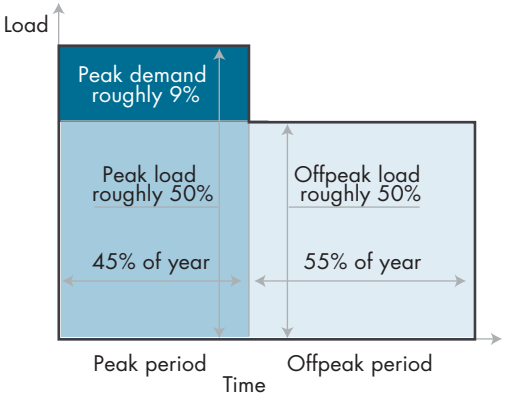
Interstate trade in electricity and natural gas is modeled on a net basis in *E*$_4$*cast*. The direction of net trade in the two energy sources is endogenously determined, accounting for differences in regional prices, transmission costs and capacities. Upper limits on interstate electricity flows are imposed and broadly reflect interconnector capacities assumed in the latest NEMMCO Statement of Opportunities (NEMMCO 2003). Likewise, natural gas pipeline capacities function as an upper limit on interstate natural gas flows.

Electricity generation parameters

To improve the treatment of investment in peak capacity and to improve the model projections, especially those relating to the electricity generation mix, the demand for both peak and offpeak (or base load) electricity is modeled explicitly.

Annual electricity demand is split into peak and offpeak periods. The peak period is defined to extend from 7.00 am to 10.00 pm weekdays, covering 45 per cent of the year. Base load demand is assumed to cover the remaining time. Using NEMMCO half hourly demand data, load duration curves were constructed for New South Wales, Victoria, Queensland and South Australia. Total yearly demand for each of the four states was found to be approximately equally distributed between the peak and offpeak periods, as defined. In other words, almost 50

G Load duration curve



per cent of annual electricity consumption occurs during the peak period and 50 per cent during the offpeak period. This implies a total peak demand (or peak load) of about 9 per cent (figure G). As fuel dispatch data are not readily available for other regions and states, the same load profile has been assumed for all regions and states.

Currently, in the electricity generation module, *E_4cast* incorporates eleven generation technologies (three peak and eight off-peak) using black coal, brown coal, natural gas, diesel, biomass, biogas, hydroelectricity and wind. Peak technologies are peak gas, hydro and diesel. Offpeak technologies include coal — both brown and black — base gas and hydro, in addition to biomass, biogas (landfill and sewage gas) and wind plants. The main biomass fuel is bagasse, with some supplementary use of wood and wood waste products. Based on ABARE research, these four renewable options are considered to be the most prospective sources for renewable electricity generation in the foreseeable future (Naughten and Noble 2001; Short and Dickson 2003).

The Australian Government's Mandatory Renewable Energy Target (MRET) scheme, along with the Queensland Government's 13 per cent gas scheme and the New South Wales Government's greenhouse gas emissions benchmark scheme, are all explicitly modeled in *E_4cast*.

The MRET scheme requires the generation of 9500 GWh of extra renewable electricity a year by 2010 compared with 2000. Interim targets have been set (commencing at 300 GWh in 2000) to ensure that there will be consistent progress toward achieving the 9500 GWh target by 2010. In *E_4cast* the renewable energy target is modeled as a simple lower constraint on sent out electricity. Starting in 2001-02, the level of the constraint is set to ramp up each year to replicate the mandatory renewable energy target level.

The mix of renewables developed to meet the target is a product of both model outcomes and judgment on the part of the authors. Most of the increase in the generation of electricity from renewable sources over the projection period is expected to be biomass (mainly bagasse, woodwaste and bagasse cofired with woodwaste) and wind.

On 24 May 2000, the Queensland Government announced the Queensland Energy Policy – A Cleaner Energy Strategy, with the key objectives of the policy being to diversify its energy mix, facilitate the supply and use of natural gas in Queensland, especially in electricity generation, and reduce growth in greenhouse gas emissions (Queensland Treasury 2002, p. 5). A key component of the energy policy is the state's 13 per cent gas scheme, which requires electricity retailers and other liable parties to source at least 13 per cent of their electricity from natural gas fired generation. The scheme will commence on 1 January 2005 and will remain in place until 31 December 2019. This scheme is implemented in the model in an approximate manner, requiring the share of natural gas based electricity to increase to 12 per cent in 2004-05 and to 13 per cent for the subsequent outlook period.

As mentioned above, *E_4cast* also incorporates the New South Wales Government's greenhouse gas emissions benchmark scheme for electricity retailers and other liable parties. Currently the benchmark is set as a 5 per cent reduction in per person greenhouse gas emissions from the 1989-90 level by 2007, implying a per person target of 7.27 tonnes of carbon dioxide equivalent (CO_2-e) in 2007.

The scheme began on 1 January 2003, with a benchmark of 8.65 tonnes of CO_2-e for the year. Annual targets for the subsequent years will follow a linear path to achieve the benchmark of 7.27 tonnes of CO_2-e in 2007. The target will be maintained at that level until at least 2012 (George Wilkenfeld and Associates 2002). Population projections for the state are sourced from the Australian Bureau of Statistics (ABS 2003), which assume a fertility

Box 2: ABARE's 2003-04 fuel and electricity survey (FES)

In the 2003-04 cycle of ABARE's fuel and electricity survey, ABARE introduced an important change to the data estimation approach to improve the quality of the final statistics. The new approach involves benchmarking ABARE estimates to a new statistical collection established by the Australian Bureau of Statistics (ABS).

In 2003 the ABS conducted the Energy Survey 2001-02 through which it collected data on energy use across the nonresidential sectors of the Australian economy, covering a range of energy and fuel types including electricity, natural gas, petroleum products, coal and renewable energy (ABS cat. no. 4649.0.55.001). National level statistics from the Energy Survey 2001-02 were published in December 2003 and are located on the ABS web site (www.abs.gov.au/ausstats/).

For the Energy Survey 2001-02 the ABS surveyed approximately 600 businesses in the petroleum refining, electricity generation, transmission and distribution, and gas production sectors, in addition to a sample of approximately 14 800 businesses covering the remaining industries. This compares with ABARE's (partial census) approach, which is primarily focused on energy intensive manufacturing sectors, for which approximately 1400 businesses are surveyed. Across the energy intensive industries the coverage of both the ABS and ABARE surveys are similar; however, across the board, the ABS survey has significantly greater depth in its sample. It is also relevant to note that the ABARE survey is entirely voluntary and that the ABS survey was not; hence the response rates for the ABS Energy Survey 2001-02 were significantly higher than for ABARE's survey.

Given these factors, it is anticipated that the Energy Survey 2001-02 provides an accurate source of energy consumption data, against which the ABARE survey can be benchmarked. However, the ABS statistics do not provide comprehensive coverage of all sectors. It is also anticipated that the ABS Energy Survey will not be conducted annually.

For the 2001-02 energy consumption data, ABARE used the published ABS statistics to benchmark sections of the ABARE energy database. That is, it was ensured that ABARE's detailed estimates accord with the ABS benchmarks at various levels of aggregation — by fuel, industry or region.

In many cases the benchmarking process confirmed that ABARE's current and previous estimates of energy consumption are accurate and consistent with the new ABS benchmarks. However, in some cases the benchmarking process revealed that ABARE's previous estimates of energy consumption were not consistent with the ABS benchmarks.

For the projections presented here, the 2001-02 base year data are drawn from the latest ABARE survey estimates. Total primary energy consumption is broadly consistent with historical trends. However, some breaks in time series are evident and users of ABARE's survey statistics and the energy projections should be aware of this.

rate of 1.6 per cent, net overseas migration of 100 000 persons a year and a life expectancy (at birth) of 84.2 years for males and 87.7 years for females.

In accounting for the New South Wales benchmark scheme, *E_4cast* requires total emissions from state electricity generation to be less than or equal to the product of per person emissions and state population. *E_4cast* also accounts for biological carbon sequestration, which is explicitly modeled in the current version of the model. The carbon sequestration function includes a carbon price and the underlying forest growth characteristics as its main arguments.

E_4cast model rebase and definitions of energy statistics

Before employing *E_4cast* for this cycle of projections, the model was rebased using ABARE's energy statistics for 2001-02. In estimating Australian energy consumption and production data for 2001-02, ABARE made a number of important changes to the estimation approach. Details of these changes and their implications are provided in box 2.

Readers familiar with ABARE's previous projections work should also note that beginning in 2001, ABARE changed the way it reports energy statistics, adopting the convention of distinguishing between final energy use and primary energy use. This is consistent with the approach used by the International Energy Agency (see, for example, IEA 2002). A full definition of primary energy consumption and final energy consumption and a description of other changes made to the reported statistics was first provided in Dickson et al. (2001). For convenience, the distinction between the two energy concepts is again explained in box 3.

Box 3: Definition of aggregate energy statistics

Primary and final energy consumption

In energy statistics a distinction is made between two definitions of energy consumption: total primary energy consumption (TPEC); and total final or 'end use' energy consumption (TFEC). These statistical aggregates are defined in the context of the common energy balance table. An energy balance table presents a comprehensive account (or balance), in this case for the Australian economy, of the supply of energy, by fuel source and the disposal of energy, and by fuel source and activity (industry or sector). The structure of the balance table — and the definitions of TPEC and TFEC — is based on the distinction between primary and secondary (or transformed) fuels and between conversion and end use activities.

Primary and secondary fuels

Primary fuels are forms of energy obtained directly from nature. They include nonrenewable fuels such as black coal, brown coal, uranium, crude oil, naturally occurring liquid petroleum gas (LPG) and condensate (also called natural gas liquids), ethane and natural gas, and renewable fuels such as bagasse, wood, biogas, hydroelectricity, and wind and solar energy.

continued

Box 3: Definition of aggregate energy statistics *continued*

Secondary fuels are those produced from primary or other derived fuels by conversion processes to provide the final energy forms commonly consumed. They include refined petroleum products, thermal electricity, coke, coke oven gas, blast furnace gas and briquettes. By convention, the production of a secondary fuel is recorded in the energy balance tables as a negative.

Conversion and end use activities

Conversion activities are those that generate secondary energy supplies while final end use activities are all those pursued by firms and households nationwide, excluding conversion activities.

Total primary energy consumption

A simple definition of TPEC is that it is total energy used in the economy. It includes the use of primary fuels in conversion activities — notably the consumption of fuels used to produce electricity — and also includes own use and losses in the conversion sector.

TPEC is also equivalent to total primary energy supply (TPES), defined as indigenous production; plus imports; minus exports; minus international marine bunkers; and plus/minus stock changes.

Total final energy consumption

TFEC can be simply defined as the total amount of energy used by final consumers. It can include both primary or secondary fuels but does not include the energy used in conversion activities. Hence, TFEC is the sum of all the demands for all fuels in final end use.

medium to long term energy outlook

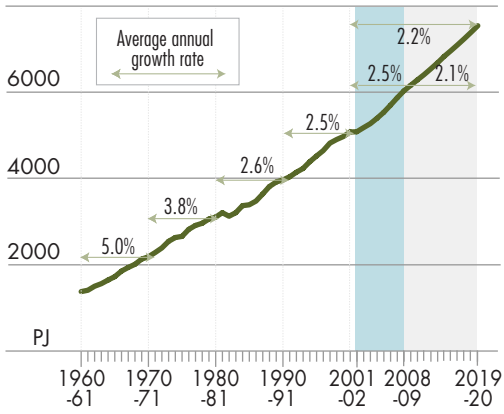
In this chapter the outlook for Australian energy consumption, production and trade is presented. The discussion is organised as follows. First, projections of primary energy consumption are described, covering fuel, regional and sectoral structures. Trends in Australian energy intensity, both historical and projected, are presented next. This is followed by a discussion of final energy consumption — the final domestic demand for energy — by fuel and end use activity. Following this is a detailed discussion of the outlook for the electricity generation sector, before the projections for production and trade are briefly described in the final section.

For reasons of brevity the discussion here focuses principally on national trends; nevertheless, where warranted, key developments at the state level are also highlighted. Statistical tables providing results from 2001-02 to 2019-20, covering consumption, production and trade in Australian energy, both at the national level and for each of the states and territories, are freely available on ABARE's web site (www.abareconomic.com).

Primary energy consumption

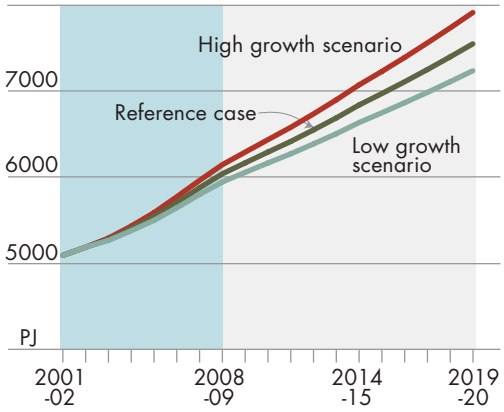
Primary energy consumption in Australia is projected to grow by an average 2.2 per cent a year between 2001-02 and 2019-20, reaching 7544 petajoules in 2019-20 (figure H). One of the most important drivers of the outlook for energy consumption in Australia is the growth in economic activity. In the medium term — 2001-02 to 2008-09 — the value of economic output, as measured by gross domestic product (GDP), is assumed to grow by 3.4 per cent a year (Penm and Fisher 2004). In the period from 2008-09 to 2019-20 GDP is assumed to grow by 3.2 per cent a year, with the average over the full outlook period assumed to be 3.3 per cent a year. The assumed growth in key energy intensive industries is also critical to the outlook. Most of the assumed expansion in the iron and steel and basic nonferrous metals sectors is expected to occur in the medium term (Maurer, Wells and Haine 2004). For instance, 80 per cent of projected

H **Primary energy consumption**
Australia



growth in aluminium output and 76 per cent of that in alumina is assumed to occur over the medium term period. Reflecting these trends, energy consumption in the medium term is forecast to increase by 2.5 per cent a year, reaching 6032 petajoules in 2008-09. Thereafter, growth in energy consumption is projected to slow, to average 2.1 per cent a year between 2008-09 and 2019-20.

I Primary energy consumption under alternative scenarios Australia



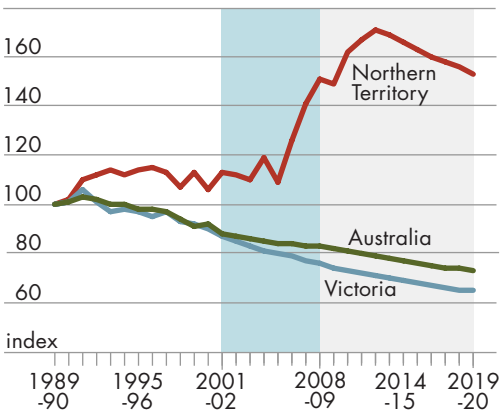
The time series of energy consumption data presented in figure H also places the current projections in a historical context. During the 1960s, energy use grew by a robust 5.0 per cent a year. This growth rate fell to 3.8 per cent a year during the 1970s largely as a result of the two major oil price shocks. During the 1980s, economic recession and sharply rising energy prices resulted in growth falling to 2.6 per cent a year before falling (real) energy prices and robust economic growth during the 1990s arrested this decline. In the medium term, growth in Australian energy consumption is projected to continue to moderate and reflects the impacts of government environmental and energy conservation measures as well as autonomous energy efficiency improvements.

Of course the outlook for Australia's economic growth is subject to considerable uncertainty. In figure I, results from a high and low economic growth scenario are presented. Compared with the reference case, the high (low) growth scenario assumes 10 per cent higher (lower) growth in GDP and industrial production between 2003-04 and 2019-20. As illustrated, the growth rate of primary energy consumption is projected to vary between 2.0 per cent a year and 2.5 per cent a year. To place this range in context, the additional energy consumed over the entire outlook period in the high growth scenario relative to the low growth case, amounts to some 5600 petajoules, or 9 per cent more than current energy consumption. If considered in terms of gasoline, this extra fuel consumption could be enough to power the entire Australian motor vehicle fleet for seven years.

Aggregate energy intensity trends

The aggregate energy intensity of the Australian economy, measured as total primary energy consumption per dollar of GDP, fell by an average 1.1 per cent a year during the 1990s, after remaining more or less stable during the 1970s and 1980s. In the period to 2019-20, aggregate energy intensity is projected to decline by a further 1.1 per cent a year (figure J). This suggests

J Energy intensity trends
Australia



that in 2019-20, 18 per cent less energy will be needed to produce a dollar of output (measured in 2001-02 dollars) compared with 2001-02.

The trends in Australia's aggregate energy intensity indicate the important role that energy plays in the fabric of the Australian economy and the critical role played by major energy intensive refining and minerals processing industries, such as iron and steel and basic nonferrous metals. This can perhaps be better understood by looking at the extreme case of the Northern Territory. The aggregate energy intensity of the Northern Territory regional economy increased by 1.1 per cent a year during the 1990s and is projected to increase by 1.7 per cent a year over the outlook period, reflecting, in this case, the strong growth anticipated in the territory's LNG exports. In contrast, in Victoria, where growth is more broadly based and far less dependent on major energy intensive projects, aggregate energy intensity is projected to decline by 1.6 per cent a year over the full outlook period.

Primary energy consumption, by fuel

Coal, including Victorian brown coal, is Australia's major energy source and accounts for 42 per cent of total primary energy consumption and more than 82 per cent of the electricity generation sector's energy mix (table 5). Indeed, 90 per cent of Australia's domestic consumption of coal occurs in the power sector. Oil is the second major energy source (35 per cent of primary energy consumption) and accounts for nearly 98 per cent of the transport sector's energy mix. After growing by an average 4.3 per cent a year over the past two decades, natural gas has emerged as an integral part of the energy mix, with a share of 19 per cent in 2001-02. Renewables are dominated by biomass and hydroelectricity, and currently account for less than 5 per cent of total energy consumption.

On the back of major industrial developments and aided by various policy initiatives of both state and federal governments, natural gas is projected to maintain its strong growth.

5 Primary energy consumption, by fuel

	Consumption			Annual growth	
	2001-02	2008-09	2019-20	2001-02 to 2008-09	2001-02 to 2019-20
	PJ	PJ	PJ	%	%
Black coal	1 472	1 641	2 027	1.6	1.8
Brown coal	665	695	771	0.6	0.8
Oil	1 757	1 990	2 515	1.8	2.0
Natural gas	951	1 320	1 828	4.8	3.7
Renewables	238	387	403	7.2	3.0
– hydro	57	62	64	1.3	0.6
– biomass	170	281	292	7.5	3.1
– biogas	7	31	28	22.8	7.6
– wind	1	9	15	35.3	15.9
– solar	3	3	4	2.6	2.6
Total	5 084	6 032	7 544	2.5	2.2

Consumption of natural gas is projected to increase by 3.7 per cent a year over the outlook period (by 4.8 per cent in the medium term). The use of natural gas is projected to double to 1828 petajoules in 2019-20, accounting for 36 per cent of the growth in total energy consumption over the entire outlook period. As a result of this, the share of natural gas in the energy mix is estimated to increase by 5 percentage points to more than 24 per cent by the end of the outlook period. Although growth in the use of natural gas is expected to be high across most sectors, almost 87 per cent of the increase in gas use is projected to occur in just three sectors: mining (21 per cent), manufacturing (33 per cent) and electricity generation (33 per cent).

Reflecting the impact of a number of policy measures — especially the Australian Government's Mandatory Renewable Energy Target scheme, the Queensland Government's 13 per cent gas scheme and the New South Wales Government's greenhouse gas benchmarks scheme — coal consumption is projected to grow only moderately over the outlook period, at 1.5 per cent a year.

Primary energy consumption, by state

Projected energy consumption for each of the Australian states and territories (the Australian Capital Territory is included in New South Wales) over the medium and longer term is presented in table 6. Despite relatively moderate economic growth prospects, energy consumption in the Northern Territory is projected to more than double to 186 petajoules by 2019-20. Approximately half of this projected growth is accounted for by growth in the region's LNG export sector. Fueled by strong economic growth and major project developments, energy consumption in Queensland and Western Australia is also forecast to grow strongly.

The growth prospects for New South Wales, Victoria and South Australia are forecast to be relatively modest. This is particularly true for Victoria and South Australia where energy consumption over the outlook period is projected to grow by just 1.6 per cent a year. In the

6 Primary energy consumption, by state

	Consumption			Annual growth	
	2001-02	2008-09	2019-20	2001-02 to 2008-09	2001-02 to 2019-20
	PJ	PJ	PJ	%	%
New South Wales **a**	1 450	1 648	2 017	1.8	1.9
Victoria	1 353	1 497	1 786	1.5	1.6
Queensland	1 060	1 385	1 794	3.9	3.0
Western Australia	698	872	1 178	3.2	3.0
South Australia	336	376	446	1.6	1.6
Tasmania	104	120	137	2.1	1.5
Northern Territory	82	134	186	7.2	4.6
Total	5 084	6 032	7 544	2.5	2.2

a Includes the Australian Capital Territory.

case of Tasmania, energy consumption is projected to grow by 1.5 per cent a year, largely reflecting low economic growth prospects.

At 24 per cent in 2019-20, Queensland's share of Australia's primary energy consumption is forecast to exceed that projected for Victoria by 0.1 a percentage points. Currently the share of Queensland in total primary energy use is lower than that of Victoria by 6 percentage points. Nevertheless, on the strength of its size, both in terms of population and economic output, New South Wales will continue to claim the largest share of primary energy consumption over the projection period. Queensland will, however, account for the largest absolute increase over the forecast period at 30 per cent, compared with 23 per cent for New South Wales and less than 18 per cent for Victoria.

Primary energy consumption, by sector

The projections of primary energy consumption, by sector, are presented in table 7. The electricity generation sector is the largest energy consuming sector in the Australian economy, currently accounting for almost 46 per cent of all primary energy use, in addition to 84 per cent of all domestic consumption of black coal. If brown coal is included, the electricity sector accounts for closer to 90 per cent of primary energy use. In the period to 2019-20, energy use in electricity generation is projected to grow by 2.0 per cent a year and to account for almost 40 per cent of the total increase in primary energy use over the period. The outlook for the electricity generation sector is discussed in more detail in the following section.

The transport sector is the second largest energy consuming sector, and currently accounts for 25 per cent of total primary energy consumption and 70 per cent of total oil use (in this context oil is used to describe the full range of petroleum products, such as gasoline, diesel,

7 Primary energy consumption, by sector

	Consumption			Annual growth	
	2001-02	2008-09	2019-20	2001-02 to 2008-09	2001-02 to 2019-20
	PJ	PJ	PJ	%	%
Agriculture	80	87	103	1.3	1.4
Mining	188	299	518	6.9	5.8
Petroleum refining	124	141	167	1.9	1.7
Manufacturing and construction **a**	766	958	1 161	3.2	2.3
Electricity generation	2 326	2 724	3 311	2.3	2.0
Transport	1 265	1 445	1 823	1.9	2.1
Commercial and services	64	75	97	2.4	2.3
Residential	208	236	290	1.8	1.8
Other **b**	64	67	74	0.7	0.8
Total	5084	6032	7544	2.5	2.2

a Excludes petroleum refining. **b** Includes solvents, lubricants, greases and bitumen.

aviation turbine fuel, etc). The manufacturing and construction sector follows, with total consumption of 766 petajoules currently, and is projected to grow relatively strongly (by 2.3 per cent a year over the entire outlook period and by 3.2 per cent over the medium term). On the back of strong growth forecasts for Australia's LNG exports, energy consumption in the mining industry is also projected to grow strongly (5.8 per cent a year), nearly tripling total energy consumption in the mining sector by 2019-20.

Electricity generation

Gross generation of electricity in Australia is projected to grow over the outlook period by an average 2.4 per cent a year, increasing from 224 TWh (807 petajoules) in 2001-02 to 344 TWh (1238 petajoules) by 2019-20 (table 8). Gross generation is defined here to include electricity purchased by all consumers and includes own use by generators, onsite private generation and/or cogeneration and transmission and distribution losses. That is, it is the total amount of electricity generated in Australia.

Largely reflecting some existing capacity overhang and the influence of a number of government policy initiatives, electricity generation from black coal is estimated to grow by an average 2.2 per cent a year over the outlook period, increasing by almost 60 TWh to 185 TWh in 2019-20. Generation from natural gas in Australia is forecast to grow by 4.7 per cent a year, more than doubling total output to 69 TWh by 2019-20. Growth in gas fired electricity generation is projected to be particularly strong in the medium term (6.2 per cent a year), largely reflecting the impact of a number of policy initiatives (discussed below) and investment in peak capacity.

On 24 May 2000, the Queensland Government announced the Queensland Energy Policy – A Cleaner Energy Strategy, with the key objectives of the policy being to diversify its energy mix, facilitate the supply and use of natural gas in Queensland, especially in electricity generation, and reduce growth in greenhouse gas emissions (Queensland Treasury

8 Electricity generation, by fuel

	Generation			Annual growth	
	2001-02	2008-09	2019-20	2001-02 to 2008-09	2001-02 to 2019-20
	TWh	TWh	TWh	%	%
Black coal	125.7	142.4	185.3	1.8	2.2
Brown coal	48.3	52.4	59.4	1.2	1.2
Oil	2.3	2.3	2.4	0.3	0.3
Natural gas	30.5	46.5	69.3	6.2	4.7
Renewables	17.2	25.3	27.5	5.7	2.6
– hydro	15.9	17.3	17.8	1.3	0.6
– biomass	0.7	4.1	4.1	28.1	10.1
– biogas	0.3	1.5	1.5	24.1	8.8
– wind	0.3	2.4	4.1	35.3	15.9
Total	224.1	269.0	343.9	2.6	2.4

2002, p. 5). A key component of the energy policy is the state's 13 per cent gas scheme, which requires electricity retailers and other liable parties to source at least 13 per cent of their electricity from natural gas fired generation. The scheme will commence on 1 January 2005 and will remain in place until 31 December 2019. This scheme is implemented in the model in an approximate manner, requiring the share of natural gas based electricity to increase to 12 per cent in 2004-05 and to 13 per cent for the subsequent outlook period.

Reflecting the impact of this policy measure, gas fired electricity generation in Queensland is projected to grow threefold in the medium term (table 9). This expansion in the state's gas fired electricity includes the now completed development of Swanbank, its expected expansion and the expected development of the Townsville gas fired power station. During the last decade of the projection period the outlook for gas fired generation in Queensland is still positive, but growing at a rate more consistent with longer term trends (2.6 per cent), and closely tracking growth in total electricity generation in Queensland. Overall, Queensland is projected to account for around 24 per cent of the growth in gas fired electricity generation in Australia over the period to 2019-20 (nearly 40 per cent in the medium term).

ABARE's forecasting model *E*$_4$*cast* also incorporates the New South Wales Government's greenhouse gas emissions benchmark scheme for electricity retailers and other liable parties. Currently the benchmark is set as a 5 per cent reduction in per person greenhouse gas emissions from the 1989-90 level by 2007, implying a per person target of 7.27 tonnes of carbon dioxide equivalent (CO_2-e) in 2007.

The scheme began on 1 January 2003, with a benchmark of 8.65 tonnes of CO_2-e for the year. Annual targets for the subsequent years will follow a linear path to achieve the benchmark of 7.27 tonnes of CO_2-e in 2007. The target will be maintained at that level until at least 2012 (George Wilkenfeld and Associates 2002). Population projections for the state are sourced from the Australian Bureau of Statistics (ABS 2003), which assume a fertility rate of 1.6 per cent, net overseas migration of 100 000 persons a year and a life expectancy (at birth) of 84.2 years for males and 87.7 years for females.

9 Gas fired electricity generation, by state

	Generation			Annual growth	
	2001-02	2008-09	2019-20	2001-02 to 2008-09	2001-02 to 2019-20
	TWh	TWh	TWh	%	%
New South Wales **a**	2.1	3.1	5.7	5.9	5.8
Victoria	2.1	3.6	6.8	7.9	6.8
Queensland	3.1	9.4	12.4	17.2	8.1
Western Australia	13.6	17.9	27.2	3.9	3.9
South Australia	7.5	9.2	12.4	3.0	2.8
Tasmania	0.0	0.6	0.9	–	–
Northern Territory	2.1	2.8	3.8	3.8	3.3
Total	30.5	46.5	69.3	6.2	4.7

a Includes the Australian Capital Territory.

In accounting for the New South Wales benchmark scheme, *E4cast* requires total emissions from state electricity generation to be less than or equal to the product of per person emissions and state population. *E4cast* also accounts for biological carbon sequestratio, which is explicitly modeled in the current version of the model. The carbon sequestration function includes a carbon price and biological forest growth statistics as its main arguments.

The scheme is expected to provide economic incentives to investment in gas fired electricity in New South Wales — forecast to grow by 5.8 per cent a year over the full outlook period (table 9) — although the exact impact of the New South Wales scheme cannot be fully anticipated at this time.

The outlook for gas fired electricity in other regions/states is also positive, despite the absence of state based interventions. In Western Australia, gas fired electricity generation is forecast to grow by 3.9 per cent a year and is set to dominate outcomes in this sector in Western Australia in coming years (the growth in black coal fired generation in Western Australia is forecast to grow by only 0.9 per cent a year, largely reflecting improvements in utilisation and efficiency). In the Northern Territory, gas fired electricity generation is forecast to grow by an average 3.3 per cent a year, picking up all the growth in electricity consumption in that state. The use of natural gas in the electricity generation sector is also projected to commence in Tasmania around 2004-05, reflecting the completion of the gas pipeline from Victoria to Tasmania and the conversion of existing oil fired generating facilities at Bell Bay, Tasmania, to natural gas. Over the remainder of the projection period the use of natural gas in the electricity generation sector in Tasmania is expected to increase to some 6.3 petajoules, providing approximately 0.9 TWh of electricity.

Based on the projections of growth in electricity generation provided here, required additions to coal and gas fired capacity have been estimated, along with the corresponding investment costs for the two technologies. These estimates of new investment in electricity generation are discussed in box 4.

The projected growth in brown coal fired electricity generation is relatively modest. Electricity generation based on brown coal is projected to increase by 1.2 per cent a year over the outlook period, reflecting high capital costs and significant policy uncertainty. Nevertheless, even this outlook implies the need for new investment in brown coal generation capacity in the foreseeable future.

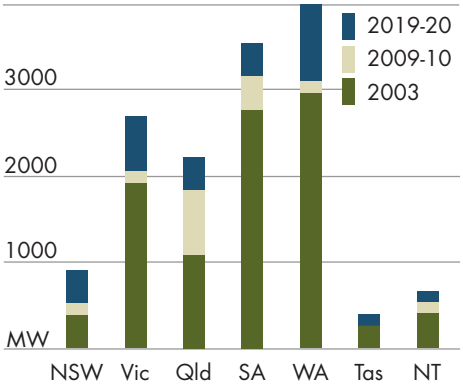
The Commonwealth Government's MRET scheme is also explicitly modeled in ABARE's energy modeling framework. The MRET scheme requires the generation of 9500 GWh of extra renewable electricity a year by 2010. Interim targets have been set (commencing at 300 GWh in 2000) to ensure that there will be consistent progress toward achieving the target by 2010. In *E4cast* the renewable energy target is modeled as a simple lower constraint on sent out electricity. Starting in 2001-02, the level of the constraint is set to ramp up each year to reflect annual increases in the level of the target.

As modeled, most of the increase in the generation of electricity from renewable sources over the projection period is expected to be wind and biomass based (mainly bagasse,

Box 4: Investment in coal and gas fired electricity capacity

Gross generation of electricity in Australia is projected to increase by more than 50 per cent to 344 TWh by 2019-20. *E4cast* provides a detailed view of expected generation, by level and load. Based on these generation forecasts, indicative estimates of the additions to gas and coal fired electricity generation capacity implied by this outlook are provided. To meet the projected outlook, an additional 8410 MW of gas and coal fired capacity will be required by 2019-20, at an expected cost of $11.0 billion (in 2001-02 dollars).

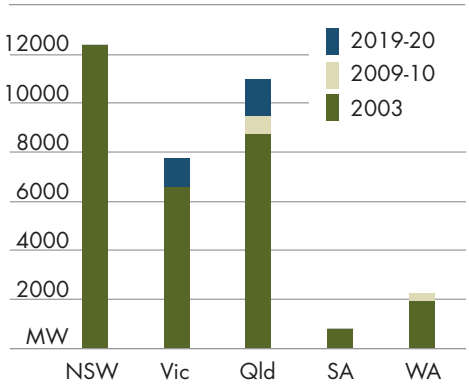
Gas capacity and additions
Australia



ABARE's energy projections imply the addition of 4660 MW of gas fired capacity at a cost of approximately $5.0 billion. Most of this investment is expected to be in Queensland, Western Australia, Victoria and South Aus-tralia. In Queensland, where gas fired electricity generation is expected to quadruple by 2019-2020 as a result of the Queensland Government's 13 per cent gas scheme, an additional 1135 MW of gas fired capacity would be required to meet the outlook for generation. In Western Australia, gas fired electricity is projected to grow by 3.9 per cent a year, requiring 1040 MW of additional capacity by 2019-20.

The projections also imply the addition of approximately 3750 MW of coal fired capacity, at a cost of around $6.0 billion. Currently, there is approximately 8680 MW of installed coal fired capacity in Queensland, with a potential output of 58 TWh. Given projected growth in electricity consumption of around 3.5 per cent a year and the relative economics of alternative electricity generation technologies, generation from coal in the state is projected to increase from 48 TWh currently to 60 TWh in 2009-10 and to 79 TWh by 2019-20. This implies, in broad terms, one new coal fired plant will be required by 2009-10 and another two in the following decade, with a total increase in capacity of approximately 2250 MW. (The capacity required by 2009-10 will be accounted for by the recently announced Kogan Creek project of 750 MW, which is the next large scale generation project to be developed in Queensland under the state government's Clean Energy Policy.) Without the Aldoga aluminium smelter, coal fired electricity generation in Queensland is projected to grow by 2.3 per cent compared with 2.8 per cent in the reference case. As a result, the number of coal fired plants required to meet the projected outlook is likely to drop to two, at a cost of $2.2 billion compared with $3.3 under the reference case (see box 5 for more details).

Coal capacity and additions
Australia



Coal fired generation in Victoria is projected to increase by approximately 1.2 per cent a year over the outlook period. As the output from existing brown coal plants is already nearing the maximum potential output, this outlook implies that at least one new brown coal fired power station will be required in Victoria by 2019-20, with a capacity of approximately 1200 MW, at a cost of approximately $2.2 billion (in 2001-02 dollars).

woodwaste and bagasse cofired with woodwaste). The projected annual growth in wind power is very high (16 per cent a year) but comes from a negligible base.

New (greenfields) hydroelectricity generation is constrained to grow only modestly over the projection period, reflecting the limited availability of suitable locations for the expansion of large grid based hydroelectricity generation. The expansion in hydroelectricity capacity that is modeled reflects upgrading of existing equipment and facilities and/or increasing utilisation (optimising maintenance and scheduling). Total hydroelectricity generation is estimated to grow by 0.6 per cent a year, reaching around 18 TWh by 2019-20.

Final energy consumption

Over the period to 2019-20, total final energy consumption is forecast to grow by an average 2.3 per cent a year (2.4 per cent over the medium term), reaching 4714 petajoules by the end of the period (table 10). Overall, the final end use fuel mix will continue to be dominated by petroleum products, with petroleum's share of final energy consumption in 2019-20 estimated to be around 50 per cent. Nevertheless, the substitution away from petroleum products toward gas that has occurred in the past is expected to continue, albeit at a reduced rate. In addition to this, new growth in the use of natural gas is expected, with developments in the iron and steel, basic nonferrous metals and LNG industries being the principal driving forces, particularly in Western Australia and the Northern Territory (from 2006-07). In absolute terms, of the 1583 petajoules projected increase in final energy consumption by 2019-20, 46 per cent is accounted for by petroleum products, 27 per cent by gas and 23 per cent by electricity, with renewables and coal byproducts constituting the rest.

Transport is the largest energy consuming sector at the end use stage, accounting for 42 per cent of final energy consumption (table 11). Growing at an average rate of 2.0 per cent a

10 Final energy consumption, by fuel

	Consumption			Annual growth	
	2001-02	2008-09	2019-20	2001-02 to 2008-09	2001-02 to 2019-20
	PJ	PJ	PJ	%	%
Black coal	129	146	155	1.8	1.0
LPG	104	144	236	4.8	4.7
Other petroleum products	1 525	1 705	2 126	1.6	1.9
Natural gas	534	715	955	4.2	3.3
Electricity	690	827	1 056	2.6	2.4
Biomass	146	158	183	1.1	1.2
Solar	3	3	4	2.6	2.6
Total	3 132	3 699	4 714	2.4	2.3

11 Final energy consumption, by sector

	Consumption			Annual growth	
	2001-02	2008-09	2019-20	2001-02 to 2008-09	2001-02 to 2019-20
	PJ	PJ	PJ	%	%
Agriculture	85	93	110	1.3	1.4
Mining	161	226	396	5.0	5.1
Manufacturing and construction	919	1 126	1 350	2.9	2.2
Transport	1 272	1 454	1 833	1.9	2.0
Commercial and services	238	290	403	2.9	3.0
Residential	393	443	548	1.7	1.9
Other **a**	64	67	74	0.7	0.8
Total	3 132	3 699	4 714	2.4	2.3

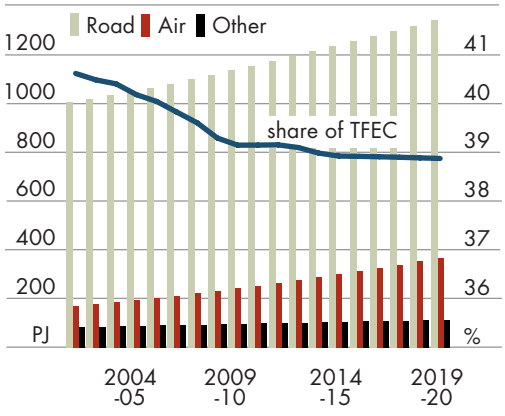
a Includes solvents, lubricants, greases and bitumen.

year over the outlook period, the transport and storage sector is expected to account for 35 per cent (or 561 petajoules) of the total projected increase in final energy consumption.

Across the states, energy use in the transport sector is forecast to grow relatively strongly in Queensland (2.7 per cent) and Western Australia (2.6 per cent), tracking closely the corresponding growth in gross state product. In contrast, transport sector energy use in Tasmania is forecast to grow only modestly — by 0.6 per cent a year — over the projection period, again reflecting modest economic growth prospects for that state. With a long term growth rate of 2.0 per cent, Victoria is projected to grow at close to the national average, followed by New South Wales with a growth rate of only 1.7 per cent a year.

Within the transport sector, road transport dominates current energy use patterns, accounting for around 80 per cent of the energy used in the sector in 2001-02. With a current share of 62 per cent, passenger motor vehicles in turn dominate the road transport sector (figure K). Energy use in the road transport sector is projected to grow by 1.6 per cent a year over the full projection period. This growth is largely driven by other road transport (mainly road freight) for which energy use is projected to grow by around 2.5 per cent a year, substantially higher than the 1.0 per cent a year projected for the passenger car sector. This outcome reflects, in large part, the relatively

K Transport sector energy consumption, by subsector Australia



stronger role that economic growth is assumed to have in determining energy use in the freight transport area, compared with the passenger motor vehicle sector.

Over the outlook period, continued strong growth is expected in both the domestic and international air transport sectors reflecting strong growth in private passenger demand. With a long term growth rate of 4.3 per cent a year, energy use in the sector over the next two decades is projected to more than double to 368 petajoules, accounting for nearly 36 per cent of the transport sector's additional use of petroleum products over the projection period. As a consequence, the share of air transport in total transport sector energy use is projected to increase steadily over the projection period.

However, the overall share of the transport sector in total energy consumption is projected to continue to fall, both in terms of final energy consumption (a reduction of 1.7 percentage points by 2019-20) and primary energy use (0.7 percentage points), which is consistent with recent historical experience.

Energy consumption in other end use sectors

Electricity generation and transport sectors aside, ABARE's medium to long term projections are heavily influenced by the outlook for gas, and particularly the outlook for gas within manufacturing. In turn, within manufacturing the nonferrous metals and direct reduced iron sectors are critical (table 12). Together these two sectors account for 63 per cent of the projected increase in manufacturing sector energy use over the outlook period.

Gas use in the iron and steel sector, which is dominated by the Western Australian direct reduced iron industry, is projected to increase by around 6.2 per cent a year out to 2019-20 (9.3 per cent in the medium term). Gas use in nonferrous metals (principally alumina refining) is also projected to increase strongly, at around 3.7 per cent a year.

12 Final energy consumption, by manufacturing subsector

	Consumption			Annual growth	
	2001-02	2008-09	2019-20	2001-02 to 2008-09	2001-02 to 2019-20
	PJ	PJ	PJ	%	%
Wood, paper and printing	55	61	75	1.5	1.7
Basic chemicals	155	171	206	1.3	1.6
Iron and steel	101	162	227	6.9	4.6
… *of which natural gas*	50	92	147	9.3	6.2
Nonferrous metals	318	417	466	3.9	2.1
… *of which natural gas*	80	137	153	8.1	3.7
Aluminium smelting	101	134	138	4.1	1.7
Other nonferrous metals	217	283	328	3.8	2.3
Nonmetallic mineral products	96	105	123	1.3	1.4
Other manufacturing **a**	192	211	254	1.3	1.6
Total manufacturing	919	1126	1350	2.9	2.2

a Includes construction.

In both the nonferrous metals and iron and steel industries, growth in the medium term is expected to be significantly stronger than over the longer term and reflects the assumed timing of a number of key project developments in these industries. Overall, just three or four large projects make up the bulk of the projected increase in manufacturing sector gas use.

In the case of the alumina industry a new greenfield plant is assumed to be online in Queensland from 2004-05 (Comalco's 1.4 million tonne plant at Gladstone); a $440 million technology upgrade is expected to increase production capacity at Alcoa's 3.4 million tonne Pinjarra refinery in Western Australia by 0.6 million tonne from 2004-05; and the 1.5 million tonne Alcan refinery at Gove in the Northern Territory is expected to be converted to gas from 2006-07.

For the aluminium industry it has been assumed that: capacity of the Tomago Aluminium Company's 0.44 million tonne smelter at Tomago, New South Wales will be increased by 70 000 tonnes a year from 2003-04; capacity of VAW's Kurri Kurri smelter at Kurri Kurri, New South Wales will be increased by 15 000 tonnes in 2004 as a result of an efficiency upgrade program; and the greenfield Aldoga aluminium smelter at Gladstone, Queensland (capacity 0.42 million tonnes a year) will commence operations from 2005-06.

Whether or not the Aldoga project will be completed and operational by 2005-06 is a significant risk factor in this outlook. As the project is particularly large and highly intensive in the use of electricity, an alternative scenario has been conducted to assess the impact of the project on projected energy consumption trends. The results of this analysis are discussed in box 5.

In the case of the iron and steel industry, ABARE's outlook takes account of the changing nature of iron and steel production in Australia. To understand by this is the case, it is instructive to understand iron and steel making and the development of a number of new production processes. (For a detailed description of steel making, see www.steelprofiles.com/segment/process/d GetIron.asp)

Steel is manufactured from iron or from a mixture of iron and steel scrap. Iron itself is manufactured from iron ore. There are basically two alternative iron making processes (blast furnace and direct reduction) and two alternative steel making or smelting processes (basic oxygen and electric arc furnaces). The principal energy input into a blast furnace (used in the production of molten iron) is coke, which is made from coal in coke ovens. The principal energy input to most direct reduction processes is reformed natural gas.

The direct reduction iron process produces iron from iron ore without going through the molten pig iron stage. Direct reduced iron (DRI) is obtained when iron ore is processed into partially metallised iron granules using reformed natural gas. Some DRI processes require the granules to be compressed into small briquettes (called hot briquetted iron or HBI) for use in electric arc or blast furnace operations. This is the model used at BHP Billiton's Port Hedland DRI refinery in Western Australia. DRI and HBI are both generally considered purer forms of feedstock than old scrap.

Starting from around 1 million tonnes a year in 2001-02, direct reduced iron (DRI) production in Western Australia is assumed to grow rapidly to 4.2 million tonnes in 2009-10 and to 6.8 million tonnes by the end of the projection period — an implied average growth rate of close to 19 per cent a year. This level of production (6.8 million tonnes) is roughly equivalent to assuming two additional plants, similar in magnitude to BHP Billiton's existing Port Hedland facility, will be constructed over the projection period.

The production of DRI at BHP Billiton's Port Hedland facility in Western Australia increased to 1.6 million tonnes in 2002-03 and is projected to reach around 2 million tonnes in 2003-04. Rio Tinto's 800 000 tonnes HISmelt iron plant at Kwinana, Western Australian is expected to be commissioned in late 2004.

In contrast to the outlook for DRI the outlook for conventional iron and steel manufacture in Australia is relatively modest. For example, coke production is forecast to increase by only 2.1 per cent a year over the short term and 2.9 per cent over the longer term.

The commercial and services sector comprises wholesale and retail trade, communications, finance, government, community services and recreational industries. In 2001-02 this sector accounted for around 7.6 per cent of total final energy use (table 11). However, the commercial sector is particularly electricity intensive (currently electricity accounts for

Box 5: Impact of the exclusion of the Aldoga smelter

As there is uncertainty about the commencement date of the Aldoga smelter in Queensland, an alternative scenario has been conducted in which the project is excluded from the outlook.

The impact of this change on final energy consumption in Queensland is summarised in the table below. Projected electricity consumption in 2008-09 is estimated to be 21 petajoules (or 10 per cent) lower under the alternative scenario. Such a reduction in projected electricity consumption would have significant implications for investment in new capacity. Rather than requiring upwards of three new baseload power stations in Queensland by 2019-20 as discussed earlier, without Aldoga this figure is likely to drop to two. Overall, the estimated decline in Queensland's energy consumption is 3 per cent in 2008-09, moderating to around 2.4 per cent by 2019-20.

Final energy consumption in Queensland, under alternative scenarios

	2008-09			2019-20		
	Reference case	Without Aldoga	Change	Reference case	Without Aldoga	Change
	PJ	PJ	%	PJ	PJ	%
Natural gas	72	70	–2.5	101	99	–2.0
Electricity	208	188	–10.0	283	261	–7.9
Other	553	551	–0.4	743	740	–0.4
Total	834	809	–3.0	1 127	1 100	–2.4

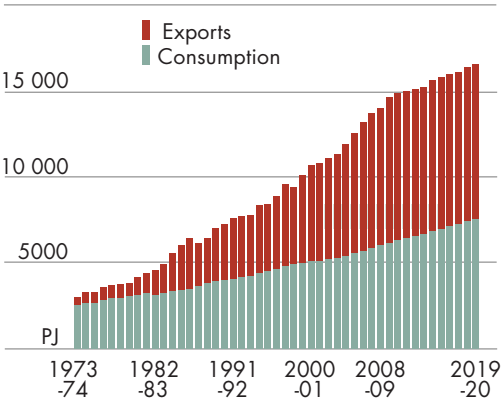
around 73 per cent of commercial sector energy use) and is expected to be a major source of growth in electricity consumption over the medium to longer term. Over the outlook period commercial sector energy use is projected to grow by 3.0 per cent a year and the consumption of electricity by 3.2 per cent a year. Currently the commercial sector accounts for over a quarter of total electricity consumption and is projected to account for over 36 per cent of the total projected increase in electricity use. This compares with a share of 28 per cent for the manufacturing sector and 20 per cent for the residential sector.

Final energy use in the residential sector was 393 petajoules in 2001-02, representing approximately 13 per cent of total final energy consumption (table 11). Over the outlook period, residential sector energy use is projected to increase at 1.9 per cent a year to around 548 petajoules. Currently electricity accounts for 47 per cent of residential sector energy demand and gas for 32 per cent. Over the projection period, gas is expected to increase its share to 36 per cent by 2019-20, principally at the expense of wood, while electricity is expected to maintain its relative position.

Energy production and trade

Australia is a net exporter of energy (figure L, table 13). Currently, domestic energy consumption accounts for 49 per cent of total energy produced, excluding uranium. In addition, uranium (U_3O_8) exports in 2001-02 were 5988 tonnes, equivalent to an estimated 3463 petajoules. ABARE's medium term outlook is for uranium exports to increase to around 12 000 tonnes by 2009-10, equivalent to an additional 5640 petajoules. Taking account of uranium, in addition to the medium term projections for the other major

L **Energy production and trade**
Australia



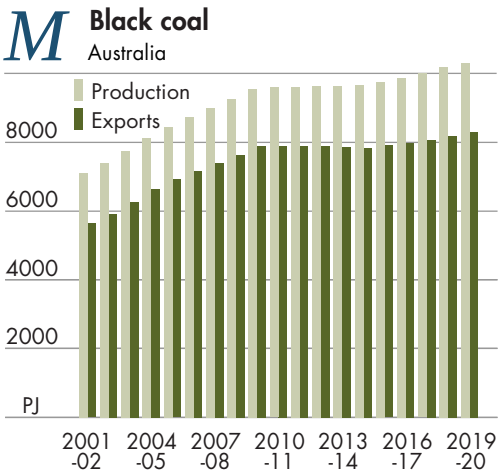
13 **Net trade in Australian energy**

	Net exports				
	Black coal	LPG	Other petroleum products	LNG	Net imports of crude oil and ORF
	PJ	PJ	PJ	PJ	PJ
2001-02	5 639	66	–64	413	300
2004-05	6 632	50	–167	577	566
2008-09	7 629	43	–100	1 066	679
2009-10	7 905	38	–127	1 338	669
2014-15	7 837	11	–224	1 899	719
2019-20	8 293	–24	–344	1 899	785
Annual growth rate	%	%	%	%	%
2001-02 to 2008-09	4.4	–5.8	6.5	14.5	12.4
2001-02 to 2019-20	2.2	–	9.7	8.8	5.5

energy commodities, Australia's consumption of primary energy is expected to account for only 30 per cent of total energy production by 2009-10.

This broad picture abstracts from a large number of fuel and industry specific issues. For example, Australia is a net importer of liquid fuels. Similarly, while Australia is a net exporter of natural gas, most (if not all) of the gas is exported from the north western region of Australia, an area remote from the south eastern demand centres. Equally Australia is not in a position (nor could it be in a position in the short term) to utilise uranium energy resources domestically.

Black coal production and exports



In 2001-02, almost 80 per cent of Australian black coal production was exported (figure M). This balance is expected to remain largely unchanged over the projection period. The key role that coal plays as a low cost, base load fuel in electricity generation, not only worldwide but particularly in the rapidly growing Asian region, is expected to continue to underpin firm demand for Australian thermal coal in the medium and long term. Currently more than 90 per cent of thermal coal exports and more than 60 per cent of Australia's metallurgical coal exports are destined for the Asian region. In the medium term, Australian thermal coal exports are projected to grow by 5 per cent a year to 130 million tonnes in 2008-09. Over the same period Australia's metallurgical coal exports are expected to grow by 3.8 per cent a year to reach 138 million tonnes in 2008-09.

In the short term, coal exports are expanding strongly but the industry's full growth potential is somewhat constrained because of constraints in transport infrastructure. Coal exporters were forced to pay considerable demurrage costs (the costs payable to ships waiting to be loaded) during the first quarter of 2004 (Burg, Richmond and Haine 2004). The average demurrage cost in April 2004 was US$1.87 a tonne, compared with the 2003 average of US$0.90 a tonne. However, these problems are expected to be rectified without affecting Australia's medium to long term coal export prospects.

Largely reflecting this positive outlook for exports, Australian black coal production is projected to increase to 362 million tonnes (10 320 petajoules) by 2019-20, an increase of nearly 113 million tonnes over the 2001-02 level (table 14). In contained energy terms black coal will continue to dominate Australia's trade in energy products (excluding uranium), although the production of natural gas is also projected to increase significantly.

14 Australian energy production

	Production			Annual growth	
	2001-02	2008-09	2019-20	2001-02 to 2008-09	2001-02 to 2019-20
	PJ	PJ	PJ	%	%
Black coal	7 111	9 270	10 320	3.9	2.1
Brown coal	665	695	771	0.6	0.8
Crude oil **a**	1 336	1 117	1 206	–2.5	–0.6
LPG **b**	123	137	156	1.6	1.3
Natural gas	1 365	2 386	3 727	8.3	5.7
Hydro	57	62	64	1.3	0.6
Biomass	170	281	292	7.5	3.1
Biogas	7	31	28	22.8	7.6
Wind	1	9	15	35.3	15.9
Solar	3	3	4	2.6	2.6
Total	10 838	13 992	16583	3.7	2.4

a Includes condensate. **b** Naturally occurring LPG.

Natural gas production and LNG exports

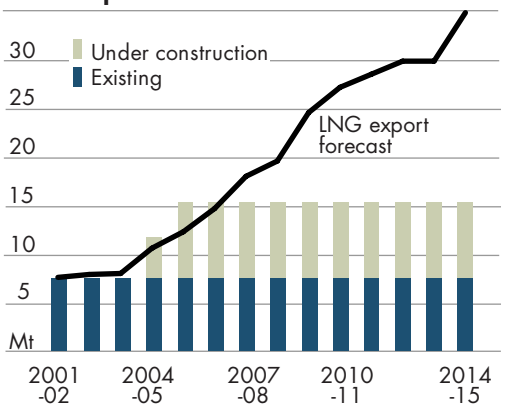
As reported in table 7, primary energy consumption in the Australian mining sector is forecast to grow by around 5.8 per cent a year over the outlook period. The principal reason behind this trend is the strong growth forecast in the oil and gas extraction industry and the gas production sector in particular. Onsite use of natural gas in the oil and gas extraction industry is assumed to grow proportionately with domestic production of natural gas, which operates to serve both the domestic gas market and, more importantly, the rapidly growing LNG export market.

Australia currently has one LNG export project, the North West Shelf project, with annual supply capacity of 7.5 million tonnes from three trains, although actual production can vary above or below this level from year to year. A 'train' is the typical terminology used to refer to LNG liquefaction units. A liquefaction train is a discrete processing unit that is used to convert natural gas to a liquid state cryogenically (or using very low temperatures). Each train is a series of processing units that perform various tasks (scrubbing, drying, separating, freezing) set in a line (like carriages). The process has an optimal scale of production, so that trains are typically operated as separate processing units instead of being joined together to make a single plant. For the same reason, capacity expansions are typically added as separate units or trains.

The majority of Australia's LNG is currently sold under long term contracts with Japan. Australia has existing contracts for 7.3 million tonnes a year with Japanese electricity and gas utilities. After being relatively stable in recent years, LNG exports are expected to increase significantly in the short to medium term (table 13). The main contributors to this will be the addition of a 4.2 million tonne fourth train at the North West Shelf project (due to commence operations in mid 2004) and the 3.5 million tonne a year Darwin LNG

plant (due to commence operation in 2006). By 2006-07 Australia is projected to export approximately 15 million tonnes of LNG valued at over $4.6 billion (in 2003-04 Australian dollars).

N LNG production capacity and exports Australia



In the longer term, LNG is expected to be Australia's fastest growing energy export. By 2019-20, LNG exports are projected to be 35 million tonnes, implying an average growth rate of 8.8 per cent a year. This outlook is based on the assumption that a fifth train will be added to the four already in operation and under construction on the North West Shelf project, and that two to three additional greenfield export projects will be operational. These could include the 10 million tonne a year Gorgon LNG development on Barrow Island, Western Australia and the 5.3 million tonne a year Sunrise LNG development in the Timor Sea. The Gorgon project is currently expected to commence in late 2008, with Sunrise projected to follow in 2010, although the startup dates are not yet firm.

If the currently proposed projects were to come on stream as planned, Australia's LNG supply capacity would increase to around 35 million tonnes by 2010, significantly in excess of current export projections (figure N). However, the timing of planned projects could vary as decisions to proceed with these projects will depend crucially on the availability of export markets in a competitive global LNG environment. Equally, all the projects will not necessarily immediately ramp up to full capacity. Some projects may increase capacity incrementally over a period of some years. However, by 2014-15, all the currently proposed projects will be required to service expected export demand. Any further growth in LNG exports (above 35 million tonnes) will require either the expansion of existing capacity or the development of new greenfield projects.

With this export driven outlook, consumption of natural gas in the mining sector is projected to increase from around 103 petajoules in 2001-02 to almost 285 petajoules by 2019-20 (an implied growth rate of 5.8 per cent a year). Approximately three-quarters of this additional gas use is projected to occur in Western Australia (46 per cent) and the Northern Territory (28 per cent). Total Australian domestic gas production is expected to increase by 5.7 per cent a year (table 14) and the share of total production accounted for by LNG exports is projected to increase from 30 per cent currently to 51 per cent by 2019-20.

Petroleum refining and crude oil production

It is important to note that Australia's total exposure to imported liquid fuels is determined by the underlying outlook for indigenous or domestic crude oil production in combination with the outlook for the end use consumption of petroleum products. In turn, domestic crude oil production is determined by a range of factors, both geological and economic.

Key among these is the outlook for world oil prices and the impact that these have on exploration effort.

The price of crude oil has been at historically high levels in recent years and for much of 2003 oil prices were above US$26 a barrel in world average trade weighted terms. ABARE's current forecast is for a gradual easing in oil prices over the medium term (Burg et al. 2004). On a world average trade weighted basis, world crude oil prices averaged around US$27 a barrel in 2003 and ABARE forecasts prices to average around US$31 a barrel in 2004 and US$27 a barrel in 2005.

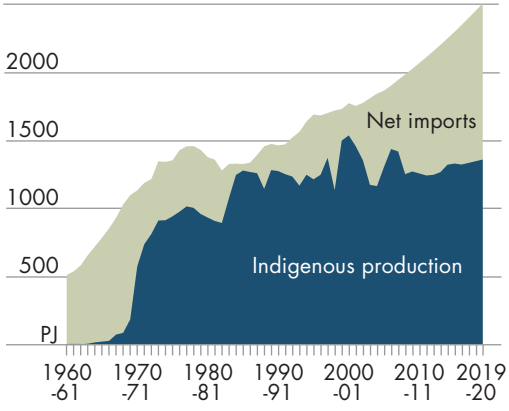
Over the medium term ABARE forecasts that world oil prices will ease further to settle around the US$21 level in the period 2008–15 (in 2004 dollars). This assessment largely reflects the potential for Iraq to increase output significantly over the medium to longer term and the increased availability of non-OPEC capacity — for example, from the Gulf of Mexico and Kazakhstan.

The current outlook for world oil prices presented by the International Energy Agency is also for world oil prices to ease to around US$21 a barrel in the period to 2010 before rising moderately thereafter to around US$25 a barrel by 2020 (IEA 2002).

ABARE's current outlook for Australian production of crude oil and condensates is summarised in figure O and table 14. Australia is currently around 80 per cent self sufficient in the production of crude oil and natural gas liquids. In 2003-04 Australian crude oil and condensate production is projected to fall by 15 per cent to 28.4 gigalitres, or 490 500 barrels a day, compared with 2002-03. In 2004-05, production of crude oil and condensate is forecast to decline by another 1 per cent before rising in 2005-06 and 2006-07 with the commencement of two new liquids projects.

Although much of the current oil production in Australia is sourced from mature oil and gas provinces, many prospective areas offshore are yet to be fully explored. For example, using a geology based assessment framework, the US Geological Survey (USGS 2000) has assessed potential undiscovered oil and gas resources for four major offshore regions of Australia. The four regions include the Gippsland basin in Victoria, the Bonaparte basin in the Northern Territory and the Browse and Carnarvon basins in Western Australia. At the 95 per cent level of confidence, there are 3339 million barrels of undiscovered resources of oil and condensate in the four offshore basins, equal to approximately 87 per cent of the corresponding identified reserves in 2000 (Geoscience Australia 2001). The continued development of technology is also bringing the economic production of oil from gas (gas to liquids) closer to economic reality.

O Oil and condensate production and consumption Australia



Reflecting these trends, as well as the overarching outlook for world crude oil prices, Australian crude oil production is projected to increase by around 0.8 per cent a year in the period 2010-11 to 2019-20. However, over the full projection period (from 2001-02 to 2019-20), Australian production of crude oil is projected to fall by around 5.5 per cent in total.

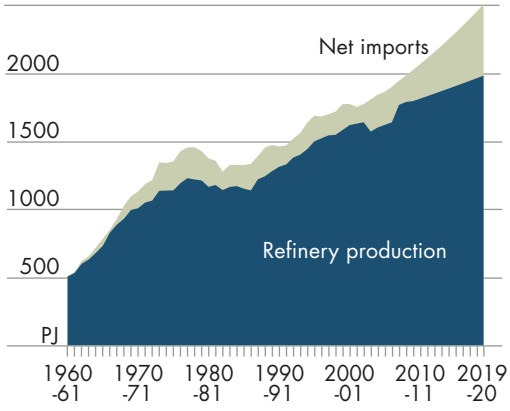
Largely on the basis of increasing production of natural gas, Australian naturally occurring LPG production is expected to reach almost 5177 million litres by 2008-09, up from 4645 million litres in 2001-02. Australia currently produces significantly more LPG in total than is consumed and is projected to remain self sufficient in LPG for many years. This is even without the additional contribution from domestic refineries (a range of LPG is produced as a byproduct of petroleum refining) and although propane is likely to remain in short supply, Australia is expected to export increasing quantities of butane.

In summary, the combined output of crude oil and naturally occurring LPG is forecast to decline from 1459 petajoules in 2001-02 to 1362 petajoules by 2019-20. Over the same period the consumption of liquid fuels is projected to increase by 43 per cent to 2515 petajoules in 2019-20. As a result, Australia's reliance on imported oil — in crude or refined form — is expected to increase from 17 per cent currently to 46 per cent in 2019-20.

For a given outlook for Australian crude oil production and end use consumption of petroleum products, the extent of petroleum refining capacity in Australia will determine whether liquid fuel imports are required. That is, for a given production and consumption outlook, more (or less) domestic petroleum refining capacity will equate to higher (or lower) crude oil imports and, simultaneously, lower (higher) imports of refined products. However, whether or not Australia is required to import liquid fuels (crude oil or refined products) is ultimately determined by the balance of crude oil production and petroleum products consumption (figure P), as discussed above, and not the quantity of domestic refining capacity.

The refining industry converts crude oil feedstock into a range of petroleum products and requires energy inputs to do this. Roughly 6 per cent of gross refinery output is used on site in the conversion process, while small quantities of natural gas and electricity are also used. ABARE's current outlook for the Australian petroleum refining sector and the degree to which domestic consumption is expected to be serviced by local refining capacity, is summarised in figure P.

P Petroleum products self sufficiency
Australia



With the mothballing of the Port Stanvac refinery in South Australia on 1 July 2003, gross refinery output, including that of petrochemicals, in Australia is expected to fall by more than 4 per cent to 1576 petajoules in 2003-04. Not surprisingly, the projected fall in industry output is less than the total output from Port Stanvac as the rest

of the industry is assumed to make up approximately 33 per cent of the decline in output. Over the next three years (2004-05 to 2006-07), refinery output is assumed to increase by an average 1.4 per cent a year to 1645 petajoules in 2006-07.

With a consistent increase in the domestic consumption of petroleum products over the medium term and an improvement in the economics of petroleum refining in Australia, the Port Stanvac refinery is assumed to resume production in 2007-08. This is expected to result in an 8 per cent increase in industry output and more than a 50 per cent fall in (net) imports of petroleum products in 2007-08.

The assumption that Port Stanvac will resume production in 2007-08 is an important assumption in this outlook. An alternative view is that the refinery economics will not improve and in fact refining capacity in Australia will contract further. In order to assess the impact of this assumption and to provide an indication of the potential range of outcomes, an alternative scenario was simulated in which it was assumed that, in addition to the Port Stanvac refinery not reopening, the Altona refinery in Victoria closes down in 2006. The results of this analysis are reported in box 6.

Over the period 2010-11 to 2019-20, refining capacity as well as refinery output in Australia is assumed to increase by around 1 per cent a year. Reflecting this, output of petroleum products is forecast to increase from 1634 petajoules in 2001-02 to 1989 petajoules by 2019-20, an overall increase of around 22 per cent or 354 petajoules of refined products. However, at the same time, the consumption of petroleum products in Australia is projected to increase by around 2 per cent a year; consumption of refined products and LPG is projected to grow by 1.9 per cent and 4.7 per cent a year respectively (table 10). As a result, the share of petroleum products sourced from local refineries (as opposed to being imported) is projected to fall from the current level of 93 per cent to less than 80 per cent by 2019-20.

Box 6: Impact of the exclusion of Port Stanvac and Altona refineries

The assumption that refining at Port Stanvac will resume in 2007-08 is a risk factor in this outlook. Mobil owns the Port Stanvac refinery in South Australia. Mobil also owns and operates the Altona refinery in Melbourne which, as at August 2004, was the only refinery that had yet to confirm its plans to meet the tighter fuel standards that will become effective in 2006. If production at Port Stanvac is not resumed and it is decommissioned permanently, an additional risk may be that Mobil will choose to withdraw from petroleum refining in Australia and also close the Altona refinery. An alternative scenario was conducted to assess the implications of this outcome. The impact of this analysis is summarised in the table below.

Under this alternative scenario Australia's refinery output is projected to decrease from 1634 petajoules in 2001-02 to 1400 petajoules in 2008-09. Thereafter, refinery output is projected to increase modestly, to 1550 petajoules by 2019-20. Compared with the reference case, the projected refinery output is approximately 22 per cent lower in 2008-09 and 2019-20. Reflecting this, Australia's exposure to imported liquid fuels is projected to increase from 21 per cent in 2019-20 in the reference case to 38 per cent in this alternative case.

Refinery output and petroleum consumption under alternative scenarios

	2001-02	2008-09	2019-20
	PJ	PJ	PJ
Refinery output			
Reference case	1 634	1 794	1 989
Alternative scenario	1 634	1 400	1 552
Petroleum consumption			
Reference case	1 757	1 990	2 515
Alternative scenario	1 757	1 970	2 493
Import dependence	%	%	%
Reference case	7	10	21
Alternative scenario	7	29	38

conclusion

In this set of projections ABARE has used the *E4cast* model as the basis for developing the long term energy outlook. In this cycle, significant development was undertaken to broaden the modeling framework to incorporate trends in peak and offpeak electricity demand. In addition, demand parameters, including income and price effects, were re-estimated using recent time series data. The outlook also draws explicitly on ABARE's regular analysis of Australian commodity markets.

Over the longer term, primary energy consumption is forecast to grow by an average 2.2 per cent a year, with relatively stronger growth forecast for the medium term. Queensland, Western Australia and the Northern Territory continue to provide strong stimulus to the energy outlook, with growth in the energy intensive minerals and gas processing sectors being particularly important. Coal and oil will continue to supply the vast bulk of Australia's domestic energy needs although natural gas use is projected to continue to grow relatively strongly. Gas use in the iron and steel sector, in particular, is projected to grow rapidly on the strength of the development of Western Australia's direct reduced iron sector. Electricity generation in Australia is forecast to grow by 2.4 per cent a year and black coal is expected to continue to account for well over 50 per cent of the electricity fuel mix. Renewable electricity, particularly wind energy and biomass, is also forecast to grow relatively strongly, although in the case of wind this is coming from a low base.

Key risk factors to the projections include the outlook for Australia's energy intensive industries (the assumptions for growth in aluminium production are particularly important to the outlook for Queensland's electricity generation sector) and domestic petroleum refining. A number of key federal and state government policy measures also directly affect the outlook.

On the basis of the outlook, new investment needed by 2019-20 in electricity generation capacity is estimated to be around $11 billion. Across the energy sector more broadly this investment figure is estimated to be closer to $30–35 billion. A key challenge facing all decision makers will be to deliver these investments to underpin the continued strong growth in Australia's energy economy.

the *E4cast* energy use projection model

The purpose in this appendix is to provide a description of the *E4cast* energy use projections model. The description covers the projection method and the model. The scope of the model is Australian electricity generation and consumption as well as use of energy fuels. The model is not a model of the whole Australian energy market, as it does not include a determination of production and net exports of the energy fuels: black coal, crude oil and (liquefied) natural gas. For these fuels, either net exports or production are projected separately and, together with the domestic fuel use projections from the model, this implies domestic fuel production, or exports and imports in the cases of black coal and crude oil respectively. For the reference case projections, it is assumed that domestic production or imports of fuels will be forthcoming to meet these demands at the independently projected world prices of these fuels. In sensitivity and scenario analyses, domestic production of these fuels will be responsive to price, centred at the levels of the reference projections unless these are explicitly altered for the purpose of sensitivity or scenario analysis. The model is specified in the following section as a set of general competitive equilibrium conditions on prices and volumes in inequality form. Mathematically, the resulting problem of finding the prices and volumes that satisfy the competitive equilibrium conditions is known as a mixed complementarity problem. The specification and solution of economic equilibrium models in the form of mixed complementarity problems has become common in recent years. The variables and parameters of the model are then defined and the sets of commodities and activities over which they are defined listed. The model is solved using GAMS software (www.gams.com/docs/intro.htm).

Specification of the competitive equilibrium conditions – a mixed complementarity problem

As stated above, the competitive equilibrium conditions take the form of a mixed complementarity problem (MCP). MCP formulations are becoming more common for applied equilibrium economic models. Like competitive equilibrium conditions, MCP formulations involve well defined primal (quantity) and dual (price) conditions, complementary slackness conditions (when primal or dual conditions are in the form of inequalities) and non-negativity constraints.

In the specification below, the convention is used that the relevant primal or dual condition is specified first and then the complementary slackness condition is indicated where required. For each set of conditions a header is given describing briefly the nature of the

conditions, followed by their detailed mathematical description and economic interpretation. The notation is given in a following section.

Flow variables and their prices are measured over a year and stock variables and their prices are measured at the start of a year. All prices are real (expressed in dollars of the base year) per volume unit.

System of demand functions for fuels and electricity, by end use, region and year

$$(1) \qquad q^d_{fjr}(t) = \frac{a^d_{fjr}}{tech_{fjr}(t)} y_{fjr}(t)^{\eta_{fjr}} \prod_k p^d_{kjr}(t)^{\varepsilon_{fkjr}}, \text{ for } f,k = \text{all fuels and electricity.}$$

For each year, the quantities used of electricity and each fuel, by end use and region, are specified as a system of constant elasticity functions of regional activity or level of final use, a technology index and the user prices of electricity and each of the fuels.

Demand for electricity, by load segment

$$(2) \qquad q^d_{fjr}(t) = q^d_{fjr}(t) b_{lfjr} \left[\frac{p^d_{fjr}(t)}{p^d_{lfjr}(t)} \right]^{\sigma_{fjr}}, \text{ for } f = \text{electricity.}$$

Each year, for each use in each region, the substitution between use in peak and offpeak load segments is given by a CES (constant elasticity of substitution) specification such that the quantity used in a load segment depends on the total quantity used in all load segments and the price in that segment relative to the average electricity price.

Average price of electricity to users over all load segments

$$(3) \qquad p^d_{fjr}(t) = \left[\sum_l b_{lfjr} p^d_{lfjr}(t)^{1-\sigma_{fjr}} \right]^{1/(1-\sigma_{fjr})}, \text{ for } f = \text{electricity.}$$

The average electricity price depends on the electricity price by load segment as specified. This relationship is the price dual of the CES relationship specified for the substitution between load segments.

Total generator output over all load segments

$$(4) \qquad q^s_{fri}(t) = \sum_l q^s_{lfri}(t), \text{ for } f = \text{electricity.}$$

For each year and region, an electricity generator's output is the sum of the outputs over all the load segments it services.

User price, producer price and distribution cost

(5) $$p^{d}_{lfjr}(t) = p^{s}_{lfr}(t) + d_{lfjr}, \text{ for } f = \text{electricity.}$$

For each use in a region, the user price of electricity by load segment equals the regional producer price for that load segment plus distribution cost (including commodity taxes) for that load segment,

(6) $$p^{d}_{lfjr}(t) = p^{s}_{lfr}(t) + d_{lfjr}, \text{ for } f = \text{gas, brown coal and other fuels.}$$

For each region, the user price of a fuel equals the regional producer price plus distribution cost (including commodity taxes).

Producer price, unit variable cost and rental to capacity

(7) $$p^{d}_{lfjr}(t)(1 - l_{lfr}) \leq uvc_{ri}(t) + r_{lri}(t),\ q^{s}_{lfri}(t)\left[p^{s}_{lfr}(t)(1 - l_{lfr}) - uvc_{ri}(t) - r_{lri}(t)\right] = 0$$
and $q^{s}_{lfri}(t) \geq 0, \text{ for } f = \text{electricity.}$

For each electricity generator in a region, first: the producer price for a load segment net of transmission loss cannot exceed the unit variable cost for that generator plus the rental to capacity for that load segment; second: if for a load segment the producer price net of transmission loss is less than the unit variable cost plus rental to capacity then production for that load segment will be zero; third: if for a load segment the production is positive, then the producer price net of transmission loss equals the unit variable cost plus rental to capacity for that load segment.

Breakdown of unit variable cost in fuel costs and other operating cost

(8) $$uvc_{ri}(t) = \sum_{f^{1} \neq f} p^{d}_{f^{1}r}(t) a_{f^{1}ri}(t) + u_{ri}\left(\frac{q^{s}_{fri}(t)}{techu_{i}(t)}\right)^{\gamma_{ri}}, \text{ for } f = \text{electricity.}$$

For each electricity generator in each region, the unit variable cost comprises fuel costs and other operating costs. The fuel costs depend on fuel prices and fuel requirements per unit of output. Fuel requirements change over time with assumed technological advances. Fuel prices are determined with the model for gas and brown coal and are given for other fuels. Other operating costs are assumed to increase with output and to decrease with an index of technological advance as specified.

Capacity limits

$$(9) \qquad q^{s}_{lfri}(t) \le \mu_l cap_{ri}(t),\ r_{lri}\left[q^{s}_{lfri}(t) - \mu_l cap_{ri}(t)\right] = 0 \text{ and } r_{lri} \ge 0, \text{ for } f = \text{electricity}.$$

For each electricity generator in each region, output for a load segment cannot exceed the generator's annual capacity times the proportion of the year for which that load segment applies. If output is less than the capacity for the load segment, then the rental to capacity for that segment is zero. If the rental to capacity for a load segment is positive, then output equals capacity for that segment.

Evolution of capacity

$$(10) \qquad cap_{ri}(t) = cap_{ri}(t-1) + inv_{ri}(t-1),$$

while capacity at the start of the first year is set at the given initial capacity.

For each electricity generator in each region, capacity at the start of a year equals capacity at the start of the previous year plus investment during the previous year. This is consistent with an assumption that there is no depreciation and that maintenance activity keeps existing capacity intact.

Marginal cost and marginal benefits of investment

$$(11) \qquad pinv_{ri}\left(1 + \phi_i \frac{inv_{ri}(t)}{cap_{ri}(t)}\right) \ge \frac{pcap_{ri}(t+1)}{1+r},$$

$$inv_{ri}(t)\left[pinv_{ri}\left(1 + \phi \frac{inv_{ri}(t)}{cap_{ri}(t)}\right) - \frac{pcap_{ri}(t+1)}{1+r}\right] = 0 \text{ and } inv_{ri}(t) \ge 0.$$

For each electricity generator in each region, the cost of investment per unit of capacity in a year cannot be less than the discounted price of capacity at the start of the next year, where it is assumed that the cost of investment rises proportionally with the size of the investment relative to existing capacity. If the investment cost per unit are greater than the discounted price of capacity the next year, then no investment takes place. If investment is positive, then the investment cost per unit of capacity equals the discounted price of capacity in the next year.

With respect to the price of capacity, it is further assumed that $pcap_{ri}(T+1) = pcap_{ri}(T)$, where T indicates the last year of the time horizon, so that any capacity left over at the start of the first year beyond the time horizon gets the same value as at the start of the last year within the time horizon.

Evolution of the price of capacity

$$(12) \qquad pcap_{ri}(t) = \frac{pcap_{ri}(t+1)}{1+r} + \sum_{l} \mu_l r_{lri}(t) + pinv_{ri} \frac{\phi_i}{2}\left(\frac{inv_{ri}(t)}{cap_{ri}(t)}\right)^2$$

For each electricity generator in each region, the price of a unit of capacity at the start of a year equals the discounted price of a unit of capacity at the start of the next year plus the sum of the rentals earned during the load segments of the year plus the benefit of lower investment costs per additional unit of capacity in the year (that is, a size benefit).

Production of gas and brown coal as functions of producer prices

$$(13) \qquad p^s_{fr}(t)(1-l_{fr}) = u_{fr}\left(\frac{q^s_{fr}(t)}{techu_{fr}(t)}\right)^{\gamma_{fr}}, \text{ for } f = \text{gas, brown coal.}$$

For each region and for each of these fuels, the producer price, net of any transport losses, is assumed to depend on quantity produced relative to a technological progress index with a constant elasticity.

Competitive trade in electricity and gas between regions

$$(14) \qquad p^s_{lfr}(t) \le p^s_{lfr'}(t) + t_{fr'r} + pt_{lfr'r}(t), qt_{lfr'r}(t)\left[p^s_{lfr}(t) - p^s_{lfr'}(t) - t_{fr'r} - pt_{lfr'r}(t)\right] = 0$$
$$\text{and } qt_{lfr'r}(t) \ge 0, \text{ for } f = \text{electricity.}$$

For each load segment and each region of destination for electricity trade, the producer price of electricity in the region of destination cannot exceed, for any region of origin, the producer price at origin plus unit transmission costs from origin to destination plus per unit rent to any transport limitation. If the producer price at destination is less than the producer price at origin plus the sum of unit transport costs, then there is no trade from this origin to this destination. Further, if trade from a region to another region is positive, then the producer price in the region of destination equals the producer price in the region of origin plus the sum of the unit transport costs from origin to destination.

$$(15) \qquad p^s_{lfr}(t) \le p^s_{lfr'}(t) + t_{fr'r} + pt_{lfr'r}(t), qt_{lfr'r}(t)\left[p^s_{lfr}(t) - p^s_{lfr'}(t) - t_{fr'r} - pt_{lfr'r}(t)\right] = 0$$
$$\text{and } qt_{lfr'r}(t) \ge 0, \text{ for } f = \text{electricity.}$$

Apart from the absence of load segments, these trade arbitrage conditions are similar to those for electricity described at (15) above.

Commodity balance conditions for electricity, gas and brown coal

$$(16)\qquad \sum_i q^s_{lfri}(t)(1-l_{fr}) + \sum_{r'} qt_{lfr'r}(t) - \sum_{r'} qt_{lfrr'}(t) = \sum_j q^d_{lfjr}(t), \text{ for } f = \text{electricity.}$$

For each load segment and each region, electricity from all generators plus imports from all other regions less exports to all other regions equals consumption in all uses.

$$(17)\qquad q^s_{fr}(t)(1-l_{fr}) + \sum_{r'} qt_{fr'r}(t) - \sum_{r'} qt_{frr'}(t) = \sum_j q^d_{fjr}(t) + \sum_i a_{fri}(t) q^s_{fri}(\mathrm{t}),$$

$$\text{for } f = \text{gas, brown coal.}$$

For each region, gas production plus imports from all other regions less exports to all other regions equals consumption in all uses including in all generators. For brown coal the same equation holds, except that imports to and exports from other regions are zero.

Capacities of electricity and gas trade between regions

$$(18)\qquad qt_{lfr'r}(t) \le qt^{\max}_{lfr'r}(t),\ pt_{lfr'r}(t)\left[qt_{lfr'r}(t) - qt^{\max}_{lfr'r}(t)\right] = 0 \text{ and } pt_{lfr'r}(t) \ge 0,$$

$$\text{for } f = \text{electricity.}$$

For each region of origin and each load segment, the quantity of electricity exported to a region of destination does not exceed the capacity of the link between these regions. If the quantity exported is less than the capacity, then the rental of this capacity is zero. If the rental to this capacity is positive, then the capacity is fully used.

$$(19)\quad qt_{fr'r}(t) \le qt^{\max}_{fr'r}(t),\ pt_{fr'r}(t)\left[qt_{fr'r}(t) - qt^{\max}_{fr'r}(t)\right] = 0 \text{ and } pt_{fr'r}(t) \ge 0, \text{ for } f = \text{gas.}$$

Conditions (19) are similar to conditions (18) for electricity.

Mandatory target for electricity generation from renewables

$$(20)\qquad \sum_{i\in ren}\sum_r q^s_{fri}(t) \ge qren(t),\ pren(t)\left[\sum_{i\in ren}\sum_r q^s_{fri}(t) - qren(t)\right] = 0,$$

$$\text{and } pren(t) \ge 0 \text{ for } f = \text{electricity.}$$

For each year, electricity generation from renewables cannot be less than the Australian Government's mandatory target for it. If generation from renewables exceeds the target, then the price of this target is zero. If the price of the target is positive, then generation

meets the target. This specification ignores that the target is not mandatory as generators are allowed to miss the target when they prefer to pay a penalty for nonconformance.

Unit variable cost taking into account the production taxes and subsidies implied in the mandatory renewable electricity generating scheme

(21) $$uvc_{ri}(t) = uvc_{ri}(t) - pren(t), \text{ for } i = \text{renewable electricity generator}$$

$$uvc_{ri}(t) = uvc_{ri}(t) + pren(t)\frac{\sum_{i\in ren}\sum_{r} q^{s}_{fri}(t)}{\sum_{i\notin ren}\sum_{r} q^{s}_{fri}(t)},$$

for i = nonrenewable electricity generator.

The mandatory renewable electricity generation scheme provides effectively a subsidy to generators consuming renewables that is paid out of the proceeds of a tax on generators consuming nonrenewables. Thus, for each year and region, generators consuming renewables have their unit variable cost reduced by the extent of the subsidy, while the other generators have their unit variable cost increased by the required tax rate.

Greenhouse gas emission limits and carbon sequestration

(22) $$\sum_{f'\notin electricity}\sum_{i} e_{f'r}a_{f'ri}(t)q^{s}_{fri}(t) \le e_r(t) + seq_r(t),$$

$$pem_r(t)\left[\sum_{f'\notin electricity}\sum_{i} e_{f'r}a_{f'ri}(t)q^{s}_{fri}(t) - e_r(t) - seq_r(t)\right] = 0$$

and $pem_r(t) \ge 0$, for f = electricity.

For each region and year, greenhouse gas emissions from electricity generation, in CO_2 equivalents, cannot exceed any emissions ceiling plus sequestration credits for that region in that year. If emissions are below the ceiling plus credits then the price of emissions is zero. If the price of emissions is positive, then emissions equal the ceiling plus sequestration credits.

Production of sequestration credits as function of the emissions price

(23) $$seq_r(t) = \beta 1_r(t)pem_r(t)^{\beta 2_r}$$

For each region and year, the supply of sequestration credits is a monotonically increasing constant elasticity function of the price of emissions.

Unit variable costs when there is an emission limit

$$(24) \qquad uvc_{ri}(t) = uvc_{ri}(t) + pem_r(t) \sum_{f' \in electricity} e_{f'r} a_{f'ri}(t).$$

For each region and year, the unit variable cost of an electricity generator are increased when regional emissions constraints are binding by the price of emissions multiplied by the emissions from the various fuels per unit of electricity output.

Minimum share for gas in electricity generation

$$(25) \qquad q^s_{fri}(t) \geq sgas_r(t) \sum_i q^s_{fri'}(t), \;\; pgas_r(t) \left[\frac{q^s_{fri}(t)}{\sum_i q^s_{fri'}(t)} - sgas_r(t) \right] = 0 \;\text{ and}$$

$$pgas_r(t) \geq 0, \;\text{for } i = \text{gas in } f = \text{electricity generation.}$$

For each region and year, there may be a requirement for a minimum share of electricity generated in the region to come from gas-powered generation. If this share is exceeded then there is no price associated with the requirement. If the price of the requirement is positive, then the requirement is exactly met.

The price of the requirement is the specific subsidy to electricity generation from gas that is necessary to reach the minimum share. This subsidy is funded out of a common specific tax on all generators.

Unit variable cost taking into account the implied production taxes and subsidies in a scheme for a minimum share for gas in electricity generation

$$(26) \qquad uvc_{ri}(t) = uvc_{ri}(t) - pgas_r(t) + sgas_r(t) pgas_r(t), \;\text{for } i = \text{gas fired}$$

$$uvc_{ri}(t) = uvc_{ri}(t) + sgas_r(t) pgas_r)(t) \;\text{ for } i = \text{not gas fired.}$$

For each region and year, the unit variable cost of all electricity generation is increased by the specific tax required to fund the specific subsidy to gas fired generation in order to meet any set minimum share for gas powered generation. The unit variable cost of gas fired generation is decreased by the specific subsidy.

Maximum output of electricity generator

$$(27) \qquad q^s_{fri}(t) \leq q^{\max}_{fri}(t), p^{\max}_{fri}(t) \left[q^s_{fri}(t) - q^{\max}_{fri}(t) \right] = 0 \text{ and } p^{\max}_{fri}(t) \geq 0.$$

For each year and region, a maximum output may be set for any generator. If output is less than the maximum, then the price of the maximum constraint is zero. If the price of

the maximum constraint is positive, then output equals maximum output. The price of the maximum constraint is equivalent to a specific tax on production. It is assumed that revenue from this goes into general revenue and thus has no further influence in this model.

Minimum output of electricity, by generator

$$(28) \qquad q^{s}_{fri}(t) \geq q^{\min}_{fri}(t), p^{\min}_{fri}(t)\left[q^{s}_{fri}(t) - q^{\min}_{fri}(t)\right] = 0 \text{ and } p^{\min}_{fri}(t) \geq 0.$$

For each year and region, a minimum output may be set for any generator. If output is greater than the minimum, then the price of the minimum constraint is zero. If the price of the minimum constraint is positive, then output equals minimum output. The price of the minimum constraint is equivalent to a specific subsidy for production. It is assumed that funding for this subsidy comes out of general revenue, so that this funding has no further influence in this model.

Unit variable cost taking into account the production tax associated with a maximum output and the subsidy associated with a minimum output limit

$$(29) \qquad uvc_{ri}(t) = uvc_{ri}(t) + p^{\max}_{fri}(t) - p^{\min}_{fri}(t).$$

For each region and year, the unit variable cost of an electricity generator is increased by the specific tax associated with any maximum output requirement and decreased by the specific subsidy associated with any minimum output requirement.

Notation

Subscripts

f commodities: electricity, gas, brown coal, black coal, oil, LPG, other petroleum products, hydropower, wind power, biomass power, biogas power, solar power

i types of electricity generation plant: black coal fired base load, brown coal fired base load, petroleum products fired peak load, petroleum products fired base load, gas fired peak load, gas fired base load, hydropower peak load, hydropower base load, wind power base load, biomass base load, biogas base load

j activities or demand categories that use the commodities listed above: agriculture, mining, coke manufacturing, petroleum refining, pulp and paper manufacturing, chemicals manufacturing, blast furnace steel making, other iron and steel making, nonmetallic minerals processing, alumina/aluminium refining/smelting, other basic nonferrous processing, other industry, passenger car transport, other road transport, rail transport, domestic air transport, international air transport, domestic water transport, international water transport, services, residential energy use, other use

l electricity load segments: offpeak, peak

r regions: NSW (incl. ACT), NT, Qld, SA, Tas, Vic, WA

t financial years ending 30 June: 2002 to 2026.

Superscripts

d use or demand

s production or supply

max an upper limit

min a lower limit

Endogenous variables

$q^d_{fjr}(t)$ quantity used of commodity f in end use j in region r in year t

$q^d_{lfjr}(t)$ quantity used of electricity in load segment l in use j in region r in year t

$p^d_{fjr}(t)$ user price of commodity f in use j in region r in year t

$p^d_{lfjr}(t)$ user price of electricity in load segment l in use j in region r in year t

$q^s_{fri}(t)$ quantity produced of electricity in region r by generator i in year t

$q^s_{lfri}(t)$ quantity produced of electricity for load segment l in region r by generator i in year t

$q^s_{fr}(t)$ quantity produced of fuel f in region r in year t

$p^s_{lfr}(t)$ producer price of electricity in load segment l in region r in year t

$p^s_{fr}(t)$ producer price of fuel f in region r in year t, for f = gas and brown coal

$r_{lri}(t)$ rental to generating capacity for load segment l in region r in year t

$uvc_{ri}(t)$ unit variable cost of electricity generator i in region r in year t

$cap_{ri}(t)$ capacity of generator i in region r at start of year t

$inv_{ri}(t)$ investment in capacity of generator i in region r in year t

$pcap_{ri}(t)$ price of capacity of generator i in region r at start of year t

$pt_{lfr'r}(t)$ rental to capacity in load segment l to transport electricity from region r' to region r in year t

$qt_{lfr'r}(t)$ transport of electricity in load segment l from region r' to region r in year t

$pt_{fr'r}(t)$ rental to capacity to transport fuel f from region r' to region r in year t

$qt_{fr'r}(t)$ transport of fuel f from region r' to region r in year t

$pren(t)$ price of mandatory national target for electricity production from renewables in year t

$pem_r(t)$ price of greenhouse gas emission limit for region r in year t

$seq_r(t)$ carbon sequestration credits in region *r* in year *t*

$pgas_r(t)$ price of target for gas fired generation share in total electricity generation in region *r* in year *t*

$p_{fri}^{\max}(t)$ price of maximum output limit for electricity generator *i* in region *r* in year *t*

$p_{fri}^{\min}(t)$ price of minimum output limit for electricity generator *i* in region *r* in year t

Parameters, including exogenous variables

r annual real discount rate

$p_{fr}^{s}(t)$ producer price of fuel *f* in region *r* in year *t*, for *f* other than gas and brown coal

$y_{fjr}(t)$ index of income or activity for end use *j* in region *r* in year *t*

$tech_{fjr}(t)$ index of technological change that reduces use of fuel or electricity *f* in region r in year

d_{lfjr} specific distribution cost of electricity by load segment *l* in end use *j* in region *r* in year *t*

d_{fjr} specific distribution cost of fuel *f* in end use *j* in region *r* in year *t*

l_{fjr} proportion of electricity generated lost in transmission to end use *j* in region *r*

$a_{fri}(t)$ requirements per unit of electricity output by generator *i* in region *r* for fuel *f* in year *t*

a_{fjr}^{d} scale constant in fuel or electricity demand function for end use *j* in region *r*

η_{fjr} elasticity of demand for fuel or electricity *f* with respect to end use or activity level *j* in region *r*

ε_{fkjr} elasticity of demand for fuel or electricity *f* with respect to the user price of fuel or electricity *k* in end use *j* in region *r*

σ_{fjr} elasticity of substitution between electricity demand by load segments in end use *j* in region *r*

b_{lfjr} scale constant in function for electricity demand by load segment *l* in end use *j* in region *r*

u_{ri} scale constant in other unit operating cost function for electricity generator *i* in region *r*

γ_{ri} elasticity of other unit operating cost for electricity generator *i* in region *r* with respect its output

$techu_i(t)$ index of technological change that reduces other unit operating cost for electricity generator *i* in year *t*

μ_l proportion of time for which load segment *l* applies

$pinv_{ri}$ price of investing in a unit of capacity for electricity generator *i* in region *r*, in the absence of investment adjustment costs

ϕ_i scale constant in investment adjustment cost for generator *i*, giving the proportionate increase in the price of investment per unit increase in the ratio of investment to existing capacity

l_{fr} proportion of fuel or electricity *f* lost in transmission in region *r*

u_{fr} scale constant in unit cost function for fuel *f* in region *r*

γ_{fr} elasticity of unit cost for fuel *f* in region *r* with respect to its output

$techu_{fr}(t)$ index of technological change that reduces unit cost for fuel *f* in region *r* in year *t*

$t_{fr'r}$ electricity or gas unit transmission cost from region *r'* to region *r* in year *t*

$qt^{\max}_{lfr'r}(t)$ maximum capacity of electricity transport link for load segment *l* in year *t* between region *r'* and region *r*

$qt^{\max}_{lfr'r}(t)$ maximum capacity of transport link for fuel *f* in year *t* between region *r'* and region *r*

$q^{\max}_{fri}(t)$ mandatory national target for electricity generation from renewables in year *t*

$e_r(t)$ maximum volume of greenhouse gas emissions, in carbon dioxide equivalent, from electricity production in region *r* in year *t*

e_{fr} greenhouse gas emissions, in carbon dioxide equivalent, per unit of fuel *f* used in electricity generation in region *r*

$\beta 1_r(t)$ scaling parameter, reflecting technological change, for the production of carbon sequestration credits, in carbon dioxide equivalent, in region *r* in year *t*

$\beta 2_r$ elasticity of production of carbon sequestration credits in region *r* with respect to the price of emissions

$sgas_r(t)$ minimum share of gas fired electricity generation in all generation in region *r* in year *t*

$q^{\max}_{fri}(t)$ maximum output of electricity by generator *i* in region *r* in year *t*

$q^{\min}_{fri}(t)$ minimum output of electricity by generator *i* in region *r* in year *t*

statistical tables

Data are presented in these tables as energy units (joules). The use of energy units enables comparisons between the relative contributions of different fuels to meeting total primary or final energy consumption, or their share of total supply. Energy units must also be used to determine total energy production or consumption, because litres of oil and tonnes of coal cannot be added.

Some forms of energy are used to produce other forms of energy that are then finally consumed. Thus some entries in the energy balance tables (tables A1–A5) are negative, and derivation of totals may not be obvious. See box 1 for a description of the definitions of primary energy consumption as opposed to final energy consumption.

The energy balances shown in tables A1–A5 summarise the overall energy situation in Australia. The first section of an energy balance presents the 'total domestic availability' of energy for domestic use. This is equal to indigenous production of primary fuels, plus imports of primary and derived fuels, less exports, less net changes in stocks. This supply of energy, which is mainly in the form of primary fuels, is equal to total energy consumption and is referred to as total primary energy consumption.

The second section of the energy balance describes the energy flows involved in converting primary fuels to secondary fuels. Inputs to the conversion process are shown as positive, and outputs (the secondary or derived fuels produced) as negative. The row relating to petroleum refining, for example, shows input of crude oil feedstock and fuels such as natural gas and electricity used to provide energy for refinery processes, and an output of refined petroleum products. The total for this row shows the amount of nonoil fuels (natural gas and electricity) consumed in the conversion process. The quantity of petroleum products consumed as refinery fuel is shown separately in the 'fuel use in conversion' row.

The net amount of each fuel available for final use, shown in the 'final domestic availability' row is equal to primary energy consumption less net losses resulting from conversion processes. For some fuels (such as coal), this supply available for final use is much less than total supply; most is either converted into other fuels (such as electricity and coke) or used as an energy source (with some loss) for the conversion process.

The final section shows how broad end use sectors use the supply of energy available for final consumption and equates to total final energy consumption.

Tables B1–B2 provide details on final energy consumption by industry grouping, for Australia and each of the states and territories (the Australian Capital Territory is included with New South Wales).

Tables C1–C2 provide details on final energy consumption, by fuel, for Australia and each of the states.

Tables D1–D2 and E1–E2 mirror the previous two sets of tables (the B and C tables), but relate to primary energy consumption rather than final energy consumption.

Table F provides a detailed picture of final energy consumption in Australia and covers energy consumed by industry sector and fuel type.

Table G provides a similar level of detail but, again, in this case relates to the primary consumption of fuels.

Table H covers the production of primary fuels, table I electricity generation in Australia and table J net trade, by fuel.

Tables K1–K2 provide details on carbon dioxide emissions, by industry grouping, for Australia and each of the states and territories.

A1 Australian energy supply and disposal, 2001-02

	Black coal	Brown coal	Coke	Coal by-products	Crude oil and ORF	LPG	Other petroleum products a	Natural gas b	Hydro	Wind energy	Biomass	Biogas	Electricity	Solar energy	Total
	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ
Supply															
Indigenous production	7 111.4	664.7			1 335.7	123.1		1 364.7	57.1	1.0	169.9	7.5		2.7	10 837.9
Net exports c	5 639.4				– 299.6	65.5	– 64.5	413.4							5 754.2
Total primary energy consumption	1 472.1	664.7			1 635.3	57.6	64.5	951.3	57.1	1.0	169.9	7.5		2.7	5 083.8
Conversion															
Coke ovens	133.6		– 73.8	– 13.4											46.4
Blast furnaces			73.8	– 12.4											61.4
Petroleum refining					1 642.0	– 46.1	–1 595.9	20.4					4.9		25.2
Petrochemicals					– 7.5		7.5								
Electricity generation d	1 234.9	664.7					24.5	313.1	57.1	1.0	23.5	7.5	– 806.7		1 519.7
Fuel use in conversion							103.2	83.7					27.9		214.9
Transmission losses													83.8		83.8
Final domestic availability	103.5	0.0	0.0	25.8	0.8	103.7	1 525.1	534.2	0.0	0.0	146.4	0.0	690.0	2.7	3 132.4
End use															
Agriculture						0.9	78.5	0.1					6.0		85.5
Mining	6.7				0.8	0.4	77.1	19.2					57.3		161.6
Wood, paper and printing	6.7					0.3	1.6	13.2			16.1		17.5		55.5
Chemicals	4.6					15.5	39.4	81.0					15.1		155.5
Iron and steel	0.8			25.8		0.3	2.4	49.6					22.2		101.0
Basic nonferrous metals	46.7					0.1	41.3	79.6					150.7		318.5
Non metallic mineral products	24.0					2.2	3.5	51.7			0.9		13.6		96.0
Other manufacturing e	10.0	0.0			0.0	4.2	25.3	47.3			63.8		41.5		192.3
Road transport						65.8	942.3								1 008.0
Rail transport							21.5	0.0					7.3		28.8
Air transport							172.0								172.0
Water transport	3.5						34.9	0.1							38.5
Pipeline operation								24.6							24.6
Commercial & services	0.4					3.3	17.1	42.7					174.2	0.2	237.7
Residential	0.1					10.8	4.2	125.2			65.7		184.6	2.6	393.0
Lubricants, greases bitumen & solvents							64.0								64.0
Final domestic consumption	103.5	0.0		25.8	0.8	103.7	1 525.1	534.2			146.4		690.0	2.7	3 132.4

a Includes naturally occurring LPG. **b** Includes town gas. **c** Includes stock changes and discrepancies. **d** Includes own use by generators, onsite private generation and/or cogeneration and transmission and distribution losses. **e** Includes construction.

A2 Australian energy supply and disposal, 2004-05

	Black coal	Brown coal	Coke	Coal by-products	Crude oil and ORF	LPG	Other petroleum products a	Natural gas b	Hydro	Wind energy	Biomass	Biogas	Electricity	Solar energy	Total
	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ
Supply															
Indigenous production	8 116.3	667.4			1 041.4	124.3		1 660.8	58.6	3.9	225.2	21.8		2.9	11 922.6
Net exports c	6 632.2				– 566.1	50.2	– 166.6	577.2							6 526.9
Total primary energy consumption	1 484.1	667.4			1 607.5	74.1	166.6	1 083.6	58.6	3.9	225.2	21.8		2.9	5 395.7
Conversion															
Coke ovens	143.5		– 79.7	– 14.4											49.3
Blast furnaces			79.7	– 13.4											66.3
Petroleum refining					1 613.9	– 44.0	–1 569.9	13.2					4.9		18.2
Petrochemicals					– 7.3		7.3								
Electricity generation d	1 235.8	667.4					24.1	371.6	58.6	3.9	74.2	21.8	– 858.7		1 598.8
Fuel use in conversion							105.8	98.5					29.8		234.1
Transmission losses													89.4		89.4
Final domestic availability	104.8	0.0	0.0	27.9	0.9	118.1	1 599.4	600.3	0.0	0.0	150.9	0.0	734.5	2.9	3 339.7
End use															
Agriculture						1.0	81.2	0.1					6.1		88.4
Mining	6.6				0.9	0.5	92.1	22.9					63.6		186.5
Wood, paper and printing	6.5					0.3	1.6	14.3			16.7		18.2		57.5
Chemicals	4.4					15.0	38.4	87.4					15.9		161.1
Iron and steel	0.8			27.9		0.3	2.4	67.6					23.4		122.4
Basic nonferrous metals	48.5					0.1	43.2	97.4					159.0		348.2
Non metallic mineral products	24.2					2.2	3.5	54.6			0.9		13.9		99.2
Other manufacturing e	9.8	0.0			0.0	4.4	26.3	48.6			68.0		43.1		200.1
Road transport						79.2	970.3								1 049.5
Rail transport							22.6	0.0					7.6		30.2
Air transport							194.7								194.7
Water transport	3.6						35.7	0.1							39.3
Pipeline operation								27.9							27.9
Commercial & services	0.4					3.5	17.9	45.8					189.9	0.2	257.7
Residential	0.1					11.6	4.5	133.7			65.4		193.8	2.7	411.8
Lubricants, greases bitumen & solvents							65.2								65.2
Final domestic consumption	104.8	0.0		27.9	0.9	118.1	1 599.4	600.3			150.9		734.5	2.9	3 339.7

a Includes naturally occurring LPG. **b** Includes town gas. **c** Includes stock changes and discrepancies. **d** Includes Includes own use by generators, onsite private generation and/or cogeneration and transmission and distribution losses. **e** Includes construction.

A3 Australian energy supply and disposal, 2009-10

	Black coal	Brown coal	Coke	Coal by-products	Crude oil and ORF	LPG	Other petroleum products a	Natural gas b	Hydro	Wind energy	Biomass	Biogas	Electricity	Solar energy	Total
	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ
Supply															
Indigenous production	9 565.0	694.5			1 133.7	140.1		2 719.8	64.4	11.6	281.9	31.0		3.3	14 645.1
Net exports c	7 904.7				– 668.6	38.4	– 126.9	1 338.3							8 485.9
Total primary energy consumption	1 660.3	694.5			1 802.3	101.7	126.9	1 381.5	64.4	11.6	281.9	31.0		3.3	6 159.2
Conversion															
Coke ovens	188.6		– 108.2	– 19.6											60.8
Blast furnaces			108.2	– 18.3											89.9
Petroleum refining					1 808.1	– 50.4	–1 757.7	27.1					6.2		33.3
Petrochemicals					– 7.0		7.0								
Electricity generation d	1 361.7	694.5					23.8	445.0	64.4	11.6	121.8	31.0	– 988.6		1 765.1
Fuel use in conversion							115.2	162.7					34.5		312.4
Transmission losses													103.6		103.6
Final domestic availability	110.0	0.0	0.0	37.9	1.2	152.1	1 738.6	746.7	0.0	0.0	160.1	0.0	844.2	3.3	3 794.0
End use															
Agriculture						1.2	87.2	0.1					6.3		94.9
Mining	6.6				1.2	0.6	124.5	30.6					76.0		239.5
Wood, paper and printing	6.2					0.3	1.6	16.8			18.0		19.6		62.5
Chemicals	4.1					14.5	36.9	100.2					17.7		173.3
Iron and steel	0.8			37.9		0.3	2.6	100.8					28.0		170.4
Basic nonferrous metals	54.3					0.1	32.8	140.1					196.7		423.9
Non metallic mineral products	24.7					2.2	3.5	60.8			1.0		14.3		106.4
Other manufacturing e	9.0	0.0			0.0	4.7	28.3	57.3			75.5		45.3		220.2
Road transport						111.0	1 025.0								1 136.0
Rail transport							23.0	0.0					8.2		31.2
Air transport							242.8								242.8
Water transport	3.8						37.1	0.1							40.9
Pipeline operation								33.9							33.9
Commercial & services	0.5					3.9	20.4	51.8					221.9	0.2	298.7
Residential	0.1					13.2	5.1	154.2			65.6		210.3	3.1	451.6
Lubricants, greases bitumen & solvents							67.9								67.9
Final domestic consumption	110.0	0.0		37.9	1.2	152.1	1 738.6	746.7			160.1		844.2	3.3	3 794.0

a Includes naturally occurring LPG. **b** Includes town gas. **c** Includes stock changes and discrepancies. **d** Includes Includes own use by generators, onsite private generation and/or cogeneration and transmission and distribution losses. **e** Includes construction.

A4 Australian energy supply and disposal, 2014-15

	Black coal	Brown coal	Coke	Coal by-products	Crude oil and ORF	LPG	Other petroleum products a	Natural gas b	Hydro	Wind energy	Biomass	Biogas	Electricity	Solar energy	Total
	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ
Supply															
Indigenous production	9 658.7	730.4			1 174.9	148.6		3 526.2	64.3	14.3	286.2	29.3		3.8	15 636.7
Net exports c	7 837.3				– 719.2	11.3	– 223.8	1 898.6							8 804.3
Total primary energy consumption	1 821.3	730.4			1 894.1	137.3	223.8	1 627.6	64.3	14.3	286.2	29.3		3.8	6 832.4
Conversion															
Coke ovens	202.9		– 115.8	– 20.9											66.2
Blast furnaces			115.8	– 19.5											96.3
Petroleum refining					1 899.4	– 53.0	–1 846.4	32.8					7.3		40.1
Petrochemicals					– 6.8		6.8								
Electricity generation d	1 508.3	730.4					23.7	518.4	64.3	14.3	115.4	29.3	–1 106.8		1 897.3
Fuel use in conversion							121.0	218.7					38.7		378.4
Transmission losses													116.0		116.0
Final domestic availability	110.2	0.0	0.0	40.4	1.5	190.2	1 918.7	857.7	0.0	0.0	170.8	0.0	944.8	3.8	4 238.1
End use															
Agriculture						1.5	93.8	0.1					6.7		102.1
Mining	6.3				1.5	0.9	168.2	40.7					91.9		309.4
Wood, paper and printing	5.9					0.3	1.5	19.6			19.5		21.4		68.2
Chemicals	3.8					13.9	35.8	115.5					19.7		188.7
Iron and steel	0.9			40.4		0.3	2.7	134.7					30.0		209.0
Basic nonferrous metals	54.7					0.1	34.6	146.5					208.2		444.0
Non metallic mineral products	25.4					1.9	3.4	67.6			1.0		15.1		114.4
Other manufacturing e	8.7	0.0			0.0	4.9	30.4	59.9			84.2		48.3		236.4
Road transport						147.4	1 086.4								1 233.8
Rail transport							23.4	0.0					8.9		32.3
Air transport							300.8								300.8
Water transport	3.9						38.5	0.1							42.5
Pipeline operation								39.7							39.7
Commercial & services	0.5					4.1	22.4	59.1					261.4	0.2	347.6
Residential	0.1					14.9	5.9	174.1			66.1		233.3	3.6	498.0
Lubricants, greases bitumen & solvents							71.0								71.0
Final domestic consumption	110.2	0.0		40.4	1.5	190.2	1 918.7	857.7			170.8		944.8	3.8	4 238.1

a Includes naturally occurring LPG. **b** Includes town gas. **c** Includes stock changes and discrepancies. **d** Includes Includes own use by generators, onsite private generation and/or cogeneration and transmission and distribution losses. **e** Includes construction.

A5 Australian energy supply and disposal, 2019-20

	Black coal	Brown coal	Coke	Coal by-products	Crude oil and ORF	LPG	Other petroleum products a	Natural gas b	Hydro	Wind energy	Biomass	Biogas	Electricity	Solar energy	Total
	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ
Supply															
Indigenous production	10 320.3	771.5			1 205.8	155.8		3 726.7	64.1	14.6	291.9	27.8		4.3	16 582.7
Net exports c	8 293.1				– 784.7	– 24.3	– 344.0	1 898.6							9 038.6
Total primary energy consumption	2 027.3	771.5			1 990.5	180.1	344.0	1 828.1	64.1	14.6	291.9	27.8		4.3	7 544.1
Conversion															
Coke ovens	218.5		– 124.2	– 22.4											71.9
Blast furnaces			124.2	– 20.9											103.3
Petroleum refining					1 995.3	– 55.6	–1 939.7	39.6					8.5		48.1
Petrochemicals					– 6.6		6.6								
Electricity generation d	1 697.5	771.5					24.0	602.6	64.1	14.6	109.3	27.8	–1 238.2		2 073.2
Fuel use in conversion							127.1	231.4					43.3		401.8
Transmission losses													129.9		129.9
Final domestic availability	111.3	0.0	0.0	43.3	1.8	235.7	2 126.0	954.5	0.0	0.0	182.6	0.0	1 056.4	4.3	4 715.9
End use															
Agriculture						1.9	101.0	0.1					7.1		110.1
Mining	6.1				1.8	1.1	224.5	53.6					110.3		397.5
Wood, paper and printing	5.7					0.3	1.5	22.7			21.1		23.4		74.6
Chemicals	3.6					13.5	34.8	132.7					21.9		206.5
Iron and steel	0.9			43.3		0.2	2.9	147.1					32.2		226.7
Basic nonferrous metals	55.8					0.1	36.7	153.4					219.6		465.6
Non metallic mineral products	26.1					1.7	3.3	74.9			1.1		16.0		123.1
Other manufacturing e	8.5	0.0			0.0	5.1	32.6	62.7			93.5		51.6		254.1
Road transport						191.0	1 151.0								1 342.0
Rail transport							23.9	0.0					9.6		33.5
Air transport							368.1								368.1
Water transport	4.0						39.8	0.1							43.9
Pipeline operation								45.1							45.1
Commercial & services	0.5					4.2	24.5	67.1					306.5	0.2	403.1
Residential	0.1					16.7	6.8	195.1			66.9		258.2	4.1	547.9
Lubricants, greases bitumen & solvents							74.4								74.4
Final domestic consumption	111.3	0.0		43.3	1.8	235.7	2 126.0	954.5			182.6		1 056.4	4.3	4 715.9

a Includes naturally occurring LPG. **b** Includes town gas. **c** Includes stock changes and discrepancies. **d** Includes Includes own use by generators, onsite private generation and/or cogeneration and transmission and distribution losses. **e** Includes construction.

B1 Final energy consumption in Australia, by industry

	Agriculture	Mining	Manufacturing and construction	Transport	Commercial and services [a]	Residential	Other [b]	Total
	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ
2001-02	85.5	160.7	918.7	1 271.9	237.7	393.0	64.0	3 131.5
2002-03	86.0	168.0	937.6	1 289.8	243.0	397.3	64.2	3 186.0
2003-04	87.2	176.8	957.3	1 316.3	250.5	405.1	64.7	3 257.9
2004-05	88.3	185.6	988.5	1 341.6	257.7	411.8	65.2	3 338.8
2005-06	89.6	194.7	1 014.2	1 367.8	265.2	418.7	65.7	3 415.8
2006-07	90.8	204.6	1 047.0	1 394.9	273.0	426.3	66.2	3 502.7
2007-08	92.1	215.2	1 081.3	1 423.4	281.3	434.1	66.7	3 594.1
2008-09	93.5	226.4	1 125.9	1 453.5	289.8	442.8	67.3	3 699.2
2009-10	94.9	238.4	1 156.7	1 484.8	298.8	451.6	67.9	3 792.9
2010-11	96.3	251.0	1 172.9	1 516.4	308.1	460.3	68.5	3 873.4
2011-12	97.7	264.2	1 188.0	1 548.0	317.6	469.2	69.1	3 953.8
2012-13	99.2	278.1	1 209.7	1 580.8	327.3	478.3	69.7	4 043.1
2013-14	100.6	292.7	1 238.5	1 614.6	337.4	487.6	70.4	4 141.8
2014-15	102.1	308.0	1 260.8	1 649.1	347.6	498.0	71.0	4 236.6
2015-16	103.7	324.0	1 277.9	1 684.0	358.2	507.6	71.7	4 327.0
2016-17	105.2	340.7	1 295.6	1 719.8	369.0	517.3	72.3	4 420.0
2017-18	106.8	358.2	1 313.5	1 756.4	380.1	527.3	73.0	4 515.3
2018-19	108.4	376.5	1 331.8	1 794.0	391.5	537.5	73.7	4 613.5
2019-20	110.1	395.6	1 350.4	1 832.6	403.1	548.0	74.4	4 714.1

a Includes ANZSIC Divisions F, G, H, J, K, L, M, N, O, P, Q, ANZSIC 3700 water, sewerage, drainage, and ANZSIC 6700 storage industries. **b** Includes consumption of lubricants and greases, bitumen and

B2 Final energy consumption in Australia, by industry, by state

	Unit	2001-02	2004-05	2009-10	2014-15	2019-20
New South Wales						
Agriculture	PJ	29.1	30.0	32.3	34.8	37.4
Mining	PJ	25.5	28.5	35.1	43.7	54.0
Manufacturing and construction	PJ	251.2	261.7	291.1	309.1	329.6
Transport	PJ	402.8	420.2	457.8	500.7	548.2
Commercial and services **a**	PJ	68.9	73.6	84.1	96.6	110.6
Residential	PJ	112.6	116.8	126.2	137.9	150.6
Other **b**	PJ	16.9	17.2	17.8	18.6	19.4
Total	PJ	907.0	948.0	1 044.4	1 141.2	1 249.9
Victoria						
Agriculture	PJ	16.6	16.9	17.7	18.5	19.4
Mining	PJ	4.2	4.7	5.8	7.1	8.7
Manufacturing and construction	PJ	184.6	192.1	206.8	223.8	242.7
Transport	PJ	310.1	325.8	359.8	399.8	445.9
Commercial and services **a**	PJ	69.8	75.5	87.3	101.3	117.1
Residential	PJ	148.6	156.4	174.4	193.1	213.7
Other **b**	PJ	18.5	18.9	19.6	20.5	21.4
Total	PJ	752.4	790.2	871.3	964.1	1 068.7
Queensland						
Agriculture	PJ	15.4	16.5	18.4	20.6	23.0
Mining	PJ	52.0	62.6	84.8	115.2	154.6
Manufacturing and construction	PJ	222.4	236.4	291.0	314.1	339.6
Transport	PJ	265.1	286.9	327.0	373.2	425.0
Commercial and services **a**	PJ	42.8	48.4	59.2	72.5	88.0
Residential	PJ	50.0	53.7	60.2	68.7	78.0
Other **b**	PJ	15.5	16.0	17.0	18.0	19.2
Total	PJ	663.1	720.5	857.7	982.3	1 127.4
Western Australia						
Agriculture	PJ	13.0	13.3	13.9	14.6	15.4
Mining	PJ	64.8	74.8	95.5	122.1	155.3
Manufacturing and construction	PJ	163.1	186.1	226.6	265.3	283.1
Transport	PJ	155.1	167.3	190.5	217.7	247.6
Commercial and services **a**	PJ	24.2	26.7	31.4	36.9	43.1
Residential	PJ	34.3	36.3	40.2	44.5	49.4
Other **b**	PJ	5.5	5.7	5.9	6.2	6.6
Total	PJ	460.1	510.2	604.1	707.4	800.4

Continued

B2 Final energy consumption in Australia, by industry, by state *continued*

	Unit	2001-02	2004-05	2009-10	2014-15	2019-20
South Australia						
Agriculture	PJ	5.4	5.5	5.7	6.0	6.3
Mining	PJ	5.8	6.1	7.1	8.2	9.5
Manufacturing and construction	PJ	37.1	37.8	45.9	50.1	53.5
Transport	PJ	91.4	92.8	97.7	102.4	107.1
Commercial and services **a**	PJ	18.8	19.4	21.3	23.4	25.8
Residential	PJ	29.3	29.7	31.4	33.3	35.3
Other **b**	PJ	5.5	5.5	5.6	5.8	5.9
Total	PJ	193.4	196.7	214.6	229.2	243.4
Tasmania						
Agriculture	PJ	2.5	2.4	2.5	2.5	2.6
Mining	PJ	4.7	4.8	5.2	5.6	6.1
Manufacturing and construction	PJ	41.7	47.9	54.5	55.5	56.6
Transport	PJ	23.8	24.2	25.1	25.9	26.8
Commercial and services **a**	PJ	6.6	7.4	7.8	8.2	8.7
Residential	PJ	15.9	16.6	16.5	17.6	17.9
Other **b**	PJ	1.3	1.3	1.3	1.3	1.3
Total	PJ	96.5	104.7	112.9	116.7	119.9
Northern Territory						
Agriculture	PJ	3.5	3.6	4.3	5.1	6.0
Mining	PJ	3.9	4.1	5.0	6.1	7.4
Manufacturing and construction	PJ	18.7	26.6	40.8	43.0	45.4
Transport	PJ	23.5	24.4	26.9	29.4	32.0
Commercial and services **a**	PJ	6.6	6.8	7.7	8.7	9.8
Residential	PJ	2.3	2.4	2.6	2.8	3.1
Other **b**	PJ	0.6	0.6	0.6	0.6	0.7
Total	PJ	59.0	68.5	87.9	95.7	104.4

a Includes ANZSIC Divisions F, G, H, J, K, L, M, N, O, P, Q, ANZSIC 3700 water, sewerage, drainage,and ANZSIC 6700 storage industries. **b** Includes consumption of lubricants and greases, bitumen and solvents.

C1 Final energy consumption in Australia, by fuel

	Black coal	LPG	Other petroleum products	Natural gas	Electricity	Biomass	Solar energy	Total
	PJ		PJ	PJ	PJ	PJ	PJ	PJ
2001-02	129.3	103.7	1 525.1	534.2	690.0	146.4	2.7	3 131.5
2002-03	130.1	107.0	1 543.4	550.4	704.6	147.7	2.8	3 186.0
2003-04	131.3	112.6	1 572.5	571.6	717.7	149.4	2.8	3 257.9
2004-05	132.7	118.0	1 599.4	600.3	734.5	150.9	2.9	3 338.8
2005-06	135.0	124.0	1 614.1	627.2	760.0	152.6	3.0	3 415.8
2006-07	138.7	130.3	1 643.8	645.8	786.8	154.3	3.1	3 502.7
2007-08	143.4	137.0	1 673.9	674.7	805.7	156.2	3.1	3 594.1
2008-09	146.2	144.3	1 705.5	714.9	827.1	158.1	3.2	3 699.2
2009-10	147.9	152.1	1 738.6	746.7	844.2	160.1	3.3	3 792.9
2010-11	148.4	160.3	1 772.2	762.9	864.1	162.1	3.4	3 873.4
2011-12	148.8	167.3	1 807.2	779.2	883.6	164.2	3.5	3 953.8
2012-13	149.4	174.6	1 843.4	802.2	903.5	166.4	3.6	4 043.1
2013-14	150.0	182.2	1 880.5	832.9	924.0	168.6	3.7	4 141.8
2014-15	150.6	190.2	1 918.7	857.7	944.8	170.8	3.8	4 236.6
2015-16	151.3	198.5	1 957.9	876.1	966.2	173.1	3.9	4 327.0
2016-17	152.1	207.3	1 998.3	894.9	988.1	175.4	4.0	4 420.0
2017-18	152.8	216.4	2 039.7	914.1	1 010.4	177.8	4.1	4 515.4
2018-19	153.6	225.9	2 082.3	934.0	1 033.3	180.2	4.2	4 613.5
2019-20	154.5	235.7	2 126.0	954.5	1 056.4	182.6	4.3	4 714.1

C2 Final energy consumption in Australia, by fuel, by state

	Unit	2001-02	2004-05	2009-10	2014-15	2019-20
New South Wales						
Black coal	PJ	41.4	43.2	52.9	55.3	57.9
LPG	PJ	26.5	28.4	32.8	36.8	41.0
Other petroleum products	PJ	482.2	501.2	543.3	592.0	646.9
Natural gas	PJ	109.4	116.4	133.0	149.3	167.2
Electricity	PJ	229.1	240.3	263.2	288.2	316.3
Biomass	PJ	17.7	17.8	18.3	18.8	19.5
Solar energy	PJ	0.7	0.7	0.8	0.9	1.0
Total	PJ	907.0	948.0	1 044.4	1 141.2	1 249.9
Victoria						
Black coal	PJ	0.0	0.0	0.0	0.0	0.0
LPG	PJ	46.5	54.4	73.3	96.4	125.0
Other petroleum products	PJ	332.4	340.0	355.7	373.5	392.4
Natural gas	PJ	196.4	209.5	238.4	268.7	302.0
Electricity	PJ	145.8	154.7	171.4	191.7	214.2
Biomass	PJ	31.1	31.4	32.4	33.5	34.8
Solar energy	PJ	0.2	0.2	0.2	0.2	0.2
Total	PJ	752.4	790.2	871.3	964.1	1 068.7
Queensland						
Black coal	PJ	49.2	50.7	55.8	56.3	57.5
LPG	PJ	10.1	11.7	15.0	18.4	22.2
Other petroleum products	PJ	336.2	365.6	423.5	491.6	571.9
Natural gas	PJ	51.6	58.5	75.1	87.0	101.3
Electricity	PJ	152.1	166.2	213.7	246.4	283.2
Biomass	PJ	63.4	67.2	74.1	82.0	90.5
Solar energy	PJ	0.4	0.5	0.6	0.7	0.8
Total	PJ	663.1	720.5	857.7	982.3	1 127.4
Western Australia						
Black coal	PJ	24.5	24.8	25.5	25.6	25.7
LPG	PJ	7.9	9.7	13.6	18.3	24.2
Other petroleum products	PJ	194.9	210.7	241.6	279.4	324.1
Natural gas	PJ	141.6	166.7	211.8	256.9	281.5
Electricity	PJ	76.2	82.9	95.1	109.6	125.9
Biomass	PJ	13.8	14.2	15.0	16.0	17.0
Solar energy	PJ	1.1	1.2	1.4	1.6	1.9
Total	PJ	460.1	510.2	604.1	707.4	800.4

Continued

C2 Final energy consumption in Australia, by fuel, by state *continued*

	Unit	2001-02	2004-05	2009-10	2014-15	2019-20
South Australia						
Black coal	PJ	1.5	1.6	1.7	1.7	1.8
LPG	PJ	11.7	12.8	16.1	19.1	22.1
Other petroleum products	PJ	96.6	97.0	99.3	102.0	104.8
Natural gas	PJ	34.8	35.6	39.8	43.5	47.2
Electricity	PJ	40.7	41.7	49.6	54.6	59.2
Biomass	PJ	7.9	7.8	7.9	8.1	8.2
Solar energy	PJ	0.2	0.2	0.2	0.2	0.2
Total	PJ	193.4	196.7	214.6	229.2	243.4
Tasmania						
Black coal	PJ	12.6	12.4	12.0	11.8	11.6
LPG	PJ	0.8	0.8	0.8	0.8	0.9
Other petroleum products	PJ	34.9	35.3	36.5	37.7	39.0
Natural gas	PJ	0.0	5.6	12.6	13.9	14.5
Electricity	PJ	35.8	38.2	38.6	40.0	41.5
Biomass	PJ	12.4	12.3	12.3	12.3	12.4
Solar energy	PJ	0.0	0.0	0.0	0.0	0.0
Total	PJ	96.5	104.7	112.9	116.7	119.9
Northern Territory						
Black coal	PJ	0.0	0.0	0.0	0.0	0.0
LPG	PJ	0.3	0.3	0.4	0.4	0.4
Other petroleum products	PJ	48.0	49.5	38.6	42.5	46.9
Natural gas	PJ	0.4	7.9	36.1	38.3	40.8
Electricity	PJ	10.1	10.6	12.7	14.3	16.0
Biomass	PJ	0.1	0.1	0.1	0.1	0.1
Solar energy	PJ	0.1	0.1	0.1	0.1	0.1
Total	PJ	59.0	68.5	87.9	95.7	104.4

D1 Primary energy consumption in Australia, by industry

	Agriculture	Mining	Manufacturing and construction	Electricity generation	Transport	Commercial and services a	Residential	Other b	Total
	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ
2001-02	79.5	188.0	889.3	2 326.3	1 264.6	63.6	208.4	64.0	5 083.8
2002-03	80.0	196.5	909.7	2 372.1	1 282.5	64.5	209.5	64.2	5 179.0
2003-04	81.2	204.9	919.0	2 410.9	1 308.8	66.3	214.7	64.7	5 270.5
2004-05	82.3	221.4	949.6	2 457.4	1 334.0	67.8	218.0	65.2	5 395.7
2005-06	83.5	236.0	963.1	2 533.6	1 360.1	69.6	222.4	65.7	5 533.8
2006-07	84.7	259.0	991.1	2 611.6	1 387.1	71.3	226.9	66.2	5 698.0
2007-08	85.9	282.4	1 051.1	2 664.1	1 415.5	73.1	231.0	66.7	5 869.9
2008-09	87.2	299.4	1 098.6	2 723.5	1 445.5	74.9	236.0	67.3	6 032.4
2009-10	88.6	326.2	1 128.2	2 753.7	1 476.6	76.9	241.3	67.9	6 159.2
2010-11	89.9	352.1	1 144.2	2 797.9	1 508.1	78.7	245.5	68.5	6 284.9
2011-12	91.2	371.9	1 159.8	2 846.3	1 539.6	80.5	249.9	69.1	6 408.4
2012-13	92.6	392.7	1 182.1	2 896.8	1 572.2	82.4	254.4	69.7	6 542.9
2013-14	94.0	407.2	1 211.5	2 949.3	1 605.9	84.3	259.0	70.4	6 681.5
2014-15	95.4	436.3	1 234.4	3 004.1	1 640.2	86.2	264.7	71.0	6 832.4
2015-16	96.9	451.2	1 252.2	3 060.4	1 674.9	88.2	269.5	71.7	6 965.1
2016-17	98.4	466.8	1 270.6	3 119.1	1 710.6	90.2	274.3	72.3	7 102.3
2017-18	99.9	483.1	1 289.1	3 180.5	1 747.1	92.3	279.3	73.0	7 244.4
2018-19	101.4	500.3	1 308.2	3 244.9	1 784.5	94.4	284.4	73.7	7 391.9
2019-20	103.0	518.5	1 327.7	3 311.4	1 823.0	96.5	289.8	74.4	7 544.1

a Includes ANZSIC Divisions F, G, H, J, K, L, M, N, O, P, Q, ANZSIC 3700 water, sewerage, drainage, and ANZSIC 6700 storage industries. **b** Includes consumption of lubricants and greases, bitumen and solvents.

D2 Primary energy consumption in Australia, by industry, by state

	Unit	2001-02	2004-05	2009-10	2014-15	2019-20
New South Wales						
Agriculture	PJ	27.2	28.2	30.4	32.8	35.3
Mining	PJ	14.1	16.3	21.1	27.3	35.0
Manufacturing and construction	PJ	275.6	291.4	346.8	371.0	397.9
Electricity generation	PJ	662.6	687.6	735.2	815.1	909.6
Transport	PJ	399.8	417.2	454.6	497.3	544.6
Commercial and services **a**	PJ	13.7	14.5	16.5	18.4	20.5
Residential	PJ	40.2	41.8	46.6	50.6	55.1
Other **b**	PJ	16.9	17.2	17.8	18.6	19.4
Total	PJ	1 450.2	1 514.2	1 669.1	1 831.1	2 017.4
Victoria						
Agriculture	PJ	15.1	15.4	16.1	16.9	17.7
Mining	PJ	22.0	24.8	29.7	34.7	40.0
Manufacturing and construction	PJ	152.0	159.2	171.6	185.3	200.7
Electricity generation	PJ	696.1	709.4	753.4	802.6	855.2
Transport	PJ	308.8	324.4	358.3	398.2	444.2
Commercial and services **a**	PJ	28.5	30.5	34.6	39.5	44.8
Residential	PJ	111.8	117.7	132.2	146.3	161.8
Other **b**	PJ	18.5	18.9	19.6	20.5	21.4
Total	PJ	1 352.8	1 400.3	1 515.5	1 643.9	1 785.8
Queensland						
Agriculture	PJ	14.4	15.4	17.3	19.3	21.6
Mining	PJ	33.1	41.0	58.1	81.7	113.1
Manufacturing and construction	PJ	195.5	208.3	239.3	260.1	283.9
Electricity generation	PJ	522.1	587.4	739.9	809.5	910.3
Transport	PJ	262.3	284.0	323.9	369.7	421.3
Commercial and services **a**	PJ	5.6	6.1	7.2	8.0	9.0
Residential	PJ	11.4	12.0	13.1	14.4	15.9
Other **b**	PJ	15.5	16.0	17.0	18.0	19.2
Total	PJ	1 060.0	1 170.4	1 415.7	1 580.8	1 794.2
Western Australia						
Agriculture	PJ	12.3	12.6	13.2	13.8	14.5
Mining	PJ	83.7	102.1	153.1	192.9	223.5
Manufacturing and construction	PJ	164.9	189.0	229.0	267.4	284.7
Electricity generation	PJ	249.4	262.5	288.5	322.2	363.0
Transport	PJ	154.9	167.0	190.2	217.3	247.0
Commercial and services **a**	PJ	7.2	7.8	8.8	9.9	11.0
Residential	PJ	20.0	21.1	23.2	25.5	28.0
Other **b**	PJ	5.5	5.7	5.9	6.2	6.6
Total	PJ	698.1	767.8	911.9	1 055.1	1 178.2

Continued

D2 Primary energy consumption in Australia, by industry, by state *continued*

	Unit	2001-02	2004-05	2009-10	2014-15	2019-20
South Australia						
Agriculture	PJ	4.9	4.9	5.1	5.4	5.6
Mining	PJ	28.1	29.4	34.8	39.8	45.2
Manufacturing and construction	PJ	63.8	51.2	71.2	78.0	85.1
Electricity generation	PJ	121.7	130.9	146.2	158.8	171.1
Transport	PJ	91.4	92.8	97.7	102.4	107.1
Commercial and services **a**	PJ	5.7	5.8	6.3	6.8	7.3
Residential	PJ	15.2	15.4	16.3	17.2	18.1
Other **b**	PJ	5.5	5.5	5.6	5.8	5.9
Total	PJ	336.4	336.0	383.2	414.0	445.6
Tasmania						
Agriculture	PJ	2.2	2.2	2.2	2.3	2.3
Mining	PJ	2.6	2.7	3.0	3.3	3.6
Manufacturing and construction	PJ	21.0	26.0	32.7	33.0	33.5
Electricity generation	PJ	43.1	48.0	54.0	56.1	58.1
Transport	PJ	23.8	24.2	25.1	25.9	26.8
Commercial and services **a**	PJ	0.4	0.6	0.6	0.6	0.6
Residential	PJ	9.3	9.4	9.3	10.2	10.2
Other **b**	PJ	1.3	1.3	1.3	1.3	1.3
Total	PJ	103.8	114.5	128.3	132.7	136.5
Northern Territory						
Agriculture	PJ	3.4	3.6	4.2	5.0	5.9
Mining	PJ	4.2	5.2	26.4	56.6	58.1
Manufacturing and construction	PJ	16.6	24.4	37.6	39.6	41.8
Electricity generation	PJ	31.3	31.6	36.4	39.9	44.1
Transport	PJ	23.5	24.4	26.9	29.4	32.0
Commercial and services **a**	PJ	2.4	2.5	2.8	3.0	3.2
Residential	PJ	0.5	0.5	0.6	0.6	0.7
Other **b**	PJ	0.6	0.6	0.6	0.6	0.7
Total	PJ	82.5	92.7	135.6	174.7	186.4

a Includes ANZSIC Divisions F, G, H, J, K, L, M, N, O, P, Q, ANZSIC 3700 water, sewerage, drainage, and ANZSIC 6700 storage industries. **b** Includes consumption of lubricants and greases, bitumen and solvents.

E1 Primary energy consumption in Australia, by fuel

	Black coal	Brown coal	Oil	Natural gas	Biomass	Biogas	Hydro-electricity	Solar energy	Wind energy	Total
	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ
2001-02	1 472.0	664.7	1 757.4	951.3	169.9	7.5	57.1	2.7	1.0	5 083.8
2002-03	1 470.8	660.5	1 779.5	994.0	195.5	14.9	58.5	2.8	2.5	5 179.0
2003-04	1 474.6	665.0	1 813.8	1 021.9	212.0	18.8	58.3	2.8	3.1	5 270.5
2004-05	1 484.1	667.4	1 848.2	1 083.6	225.2	21.8	58.6	2.9	3.9	5 395.7
2005-06	1 519.7	670.7	1 870.0	1 140.6	241.3	24.9	59.0	3.0	4.7	5 533.8
2006-07	1 566.7	681.3	1 907.3	1 192.0	254.6	27.0	60.3	3.1	5.6	5 698.0
2007-08	1 608.1	685.5	1 949.3	1 258.2	268.1	29.4	61.3	3.1	6.9	5 869.9
2008-09	1 641.0	695.1	1 989.5	1 320.1	281.2	31.3	62.4	3.2	8.5	6 032.4
2009-10	1 660.3	694.5	2 030.8	1 381.5	281.9	31.0	64.4	3.3	11.6	6 159.2
2010-11	1 689.0	698.7	2 073.9	1 428.1	282.6	30.6	64.4	3.4	14.2	6 284.9
2011-12	1 720.4	705.8	2 117.0	1 469.5	283.4	30.3	64.4	3.5	14.2	6 408.4
2012-13	1 753.0	713.2	2 161.7	1 518.5	284.3	30.0	64.4	3.6	14.2	6 542.9
2013-14	1 787.0	721.0	2 207.7	1 568.8	285.2	29.6	64.3	3.7	14.3	6 681.5
2014-15	1 821.3	730.4	2 255.2	1 627.6	286.2	29.3	64.3	3.8	14.3	6 832.4
2015-16	1 859.6	737.7	2 303.9	1 665.1	287.2	29.0	64.2	3.9	14.4	6 965.1
2016-17	1 900.7	744.7	2 354.4	1 703.0	288.3	28.7	64.1	4.0	14.5	7 102.3
2017-18	1 943.5	752.3	2 406.3	1 741.9	289.4	28.4	64.1	4.1	14.5	7 244.4
2018-19	1 986.1	761.7	2 459.7	1 782.9	290.6	28.1	64.0	4.2	14.6	7 391.9
2019-20	2 027.3	771.5	2 514.6	1 828.1	291.9	27.8	64.1	4.3	14.6	7 544.1

E2 Primary energy consumption in Australia, by fuel, by state

	Unit	2001-02	2004-05	2009-10	2014-15	2019-20
New South Wales						
Black coal	PJ	744.1	760.5	833.0	918.0	1018.8
Oil	PJ	534.5	557.7	605.6	659.7	720.5
Natural gas	PJ	130.9	140.0	163.7	189.0	215.7
Biomass	PJ	23.0	33.9	41.6	40.5	39.6
Biogas	PJ	1.6	4.8	6.5	6.0	5.6
Hydroelectricity	PJ	15.3	16.1	17.4	16.6	15.8
Solar energy	PJ	0.7	0.7	0.8	0.9	1.0
Wind energy	PJ	0.1	0.4	0.5	0.5	0.5
Total	PJ	1 450.2	1 514.2	1 669.1	1 831.1	2 017.4
Victoria						
Brown coal	PJ	664.7	667.4	694.5	730.4	771.5
Oil	PJ	407.4	425.3	461.4	504.0	553.2
Natural gas	PJ	243.8	263.6	308.2	357.7	408.6
Biomass	PJ	31.2	31.7	32.8	34.0	35.2
Biogas	PJ	2.4	7.7	11.7	11.2	10.6
Hydroelectricity	PJ	2.7	2.9	3.1	3.0	2.9
Solar energy	PJ	0.2	0.2	0.2	0.2	0.2
Wind energy	PJ	0.4	1.3	3.5	3.5	3.6
Total	PJ	1 352.8	1 400.3	1 515.5	1 643.9	1 785.8
Queensland						
Black coal	PJ	517.1	511.6	609.5	678.3	774.8
Oil	PJ	373.7	405.4	467.8	540.5	626.0
Natural gas	PJ	85.6	126.6	164.8	185.2	212.4
Biomass	PJ	80.7	123.0	169.1	172.4	176.5
Biogas	PJ	0.2	0.7	1.2	1.1	1.1
Hydroelectricity	PJ	2.2	2.3	2.5	2.4	2.3
Solar energy	PJ	0.4	0.5	0.6	0.7	0.8
Wind energy	PJ	0.1	0.2	0.3	0.3	0.3
Total	PJ	1 060.0	1 170.4	1 415.7	1 580.8	1 794.2

Continued

E2 Primary energy consumption in Australia, by fuel, by state *continued*

	Unit	2001-02	2004-05	2009-10	2014-15	2019-20
Western Australia						
Black coal	PJ	123.1	123.9	127.2	131.0	135.5
Oil	PJ	234.7	254.5	290.6	334.6	386.7
Natural gas	PJ	323.1	369.3	471.8	566.3	631.7
Biomass	PJ	13.8	14.2	15.0	16.0	17.0
Biogas	PJ	1.2	3.2	4.0	3.8	3.7
Hydroelectricity	PJ	0.8	0.8	0.9	0.8	0.8
Solar energy	PJ	1.1	1.2	1.4	1.6	1.9
Wind energy	PJ	0.3	0.7	0.9	0.9	0.9
Total	PJ	698.1	767.8	911.9	1 055.1	1 178.2
South Australia						
Black coal	PJ	69.3	69.9	72.7	76.2	80.2
Oil	PJ	114.6	110.8	120.7	126.8	133.0
Natural gas	PJ	141.8	139.2	166.3	185.2	206.7
Biomass	PJ	8.7	9.8	10.9	10.9	10.9
Biogas	PJ	2.0	5.4	7.6	7.2	6.8
Hydroelectricity	PJ	0.0	0.0	0.0	0.0	0.0
Solar energy	PJ	0.2	0.2	0.2	0.2	0.2
Wind energy	PJ	0.0	0.6	4.8	7.5	7.7
Total	PJ	336.4	336.0	383.2	414.0	445.6
Tasmania						
Black coal	PJ	18.5	18.2	17.9	17.9	17.9
Oil	PJ	36.4	36.9	38.2	39.4	40.7
Natural gas	PJ	0.0	9.9	17.8	20.0	21.4
Biomass	PJ	12.4	12.3	12.3	12.3	12.4
Biogas	PJ	0.0	0.0	0.0	0.0	0.0
Hydroelectricity	PJ	36.2	36.4	40.4	41.5	42.4
Solar energy	PJ	0.0	0.0	0.0	0.0	0.0
Wind energy	PJ	0.1	0.7	1.6	1.6	1.6
Total	PJ	103.8	114.5	128.3	132.7	136.5

Continued

E2 Primary energy consumption in Australia, by fuel, by state *continued*

	Unit	2001-02	2004-05	2009-10	2014-15	2019-20
Northern Territory						
Black coal	PJ	0.0	0.0	0.0	0.0	0.0
Oil	PJ	56.1	57.4	46.4	50.2	54.6
Natural gas	PJ	26.2	35.1	88.9	124.2	131.6
Biomass	PJ	0.1	0.1	0.1	0.1	0.1
Biogas	PJ	0.0	0.0	0.0	0.0	0.0
Hydroelectricity	PJ	0.0	0.0	0.0	0.0	0.0
Solar energy	PJ	0.1	0.1	0.1	0.1	0.1
Wind energy	PJ	0.0	0.0	0.0	0.0	0.0
Total	PJ	82.5	92.7	135.6	174.7	186.4

F Final energy consumption in Australia, by industry and fuel type

	2001 -02	2002 -03	2003 -04	2004 -05	2005 -06	2007 -08	2009 -10	2012 -13	2014 -15	2016 -17	2018 -19	2019 -20
	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ
Div. A: Agriculture, forestry, fishing												
LPG	0.9	0.9	1.0	1.0	1.1	1.1	1.2	1.4	1.5	1.7	1.8	1.9
Other petroleum products	78.5	79.0	80.2	81.2	82.3	84.7	87.2	91.1	93.8	96.6	99.5	101.0
Natural gas	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Electricity	6.0	6.0	6.0	6.1	6.1	6.2	6.3	6.5	6.7	6.8	7.0	7.1
Energy consumption	85.5	86.0	87.2	88.3	89.6	92.1	94.9	99.2	102.1	105.2	108.4	110.1
Div. B: Mining												
Black coal	6.7	6.7	6.6	6.6	6.6	6.5	6.6	6.4	6.3	6.2	6.1	6.1
LPG	0.4	0.4	0.5	0.5	0.5	0.6	0.6	0.8	0.9	0.9	1.1	1.1
Other petroleum products	77.1	81.4	86.8	92.1	97.7	110.2	124.5	149.3	168.2	189.1	212.1	224.5
Natural gas	19.2	20.3	21.6	22.9	24.2	27.2	30.6	36.4	40.7	45.5	50.8	53.6
Electricity	57.3	59.2	61.4	63.6	65.8	70.7	76.0	85.3	91.9	99.0	106.5	110.3
Energy consumption	160.7	168.0	176.8	185.6	194.7	215.2	238.4	278.1	308.0	340.7	376.5	395.6
23–24 Wood, paper and printing												
Black coal	6.7	6.6	6.6	6.5	6.4	6.3	6.2	6.0	5.9	5.8	5.7	5.7
LPG	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Other petroleum products	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.5	1.5	1.5	1.5	1.5
Natural gas	13.2	13.4	13.9	14.3	14.8	15.7	16.8	18.4	19.6	20.8	22.0	22.7
Biomass	16.1	16.2	16.4	16.7	16.9	17.4	18.0	18.9	19.5	20.1	20.8	21.1
Electricity	17.5	17.7	17.9	18.2	18.4	19.0	19.6	20.7	21.4	22.2	23.0	23.4
Energy consumption	55.5	55.8	56.7	57.5	58.4	60.4	62.5	65.8	68.2	70.7	73.3	74.6
252-256 Chemicals												
Black coal	4.6	4.5	4.4	4.4	4.3	4.2	4.1	3.9	3.8	3.7	3.6	3.6
LPG	15.5	15.3	15.2	15.0	14.9	14.7	14.5	14.2	13.9	13.7	13.6	13.5
Other petroleum products	39.4	39.0	38.7	38.4	38.0	37.5	36.9	36.2	35.8	35.4	35.0	34.8
Natural gas	80.9	82.7	85.1	87.4	89.7	94.7	100.2	109.2	115.5	122.2	129.1	132.7
Electricity	15.1	15.3	15.6	15.9	16.2	16.9	17.7	18.8	19.7	20.5	21.4	21.9
Energy consumption	155.5	156.8	159.0	161.1	163.2	168.0	173.3	182.3	188.7	195.5	202.7	206.4
26 Non metallic mineral products												
Black coal	24.0	24.1	24.1	24.2	24.3	24.5	24.7	25.1	25.4	25.6	25.9	26.1
LPG	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.0	1.9	1.8	1.7	1.7
Other petroleum products	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.4	3.4	3.4	3.4	3.3
Natural gas	51.7	52.3	53.5	54.6	55.8	58.2	60.8	64.8	67.6	70.4	73.4	74.9
Biomass	0.9	0.9	0.9	0.9	0.9	0.9	1.0	1.0	1.0	1.0	1.1	1.1
Electricity	13.6	13.7	13.8	13.9	13.9	14.1	14.3	14.8	15.1	15.5	15.8	16.0
Energy consumption	96.0	96.6	98.0	99.2	100.6	103.3	106.4	111.1	114.4	117.7	121.3	123.1

Continued

F Final energy consumption in Australia, by industry and fuel type *continued*

	2001-02	2002-03	2003-04	2004-05	2005-06	2007-08	2009-10	2012-13	2014-15	2016-17	2018-19	2019-20
	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ
271 Iron and steel												
Black coal	26.6	28.2	28.2	28.7	28.8	36.0	38.7	40.2	41.3	42.4	43.6	44.2
LPG	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.2	0.2	0.2
Other petroleum products	2.4	2.4	2.4	2.4	2.5	2.5	2.6	2.7	2.7	2.8	2.9	2.9
Natural gas	49.6	58.5	64.8	67.6	68.9	77.7	100.8	112.3	134.7	139.5	144.5	147.1
Electricity	22.2	23.0	23.1	23.4	23.5	26.7	28.0	29.1	30.0	30.8	31.8	32.2
Energy consumption	101.0	112.4	118.7	122.4	124.0	143.3	170.4	184.6	209.0	215.9	223.0	226.7
272–273 Basic nonferrous metal products												
Black coal	46.7	45.9	47.4	48.5	50.8	52.4	54.3	54.5	54.7	55.1	55.5	55.8
LPG	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Other petroleum products	41.3	41.3	42.4	43.2	30.4	31.9	32.8	33.8	34.6	35.4	36.3	36.7
Natural gas	79.6	80.0	82.2	97.4	111.2	125.5	140.1	143.9	146.5	149.2	151.9	153.4
Electricity	150.7	153.7	155.2	159.0	173.0	188.6	196.7	203.8	208.2	212.6	217.3	219.6
Energy consumption	318.5	320.9	327.3	348.2	365.5	398.4	423.9	436.0	444.0	452.4	461.1	465.6
Other manufacturing and construction **a**												
Black coal	10.1	10.1	9.9	9.8	9.6	9.3	9.0	8.9	8.7	8.6	8.5	8.5
LPG	4.2	4.3	4.3	4.4	4.4	4.5	4.7	4.8	4.9	5.0	5.1	5.1
Other petroleum products	25.3	25.5	25.9	26.3	26.7	27.5	28.3	29.5	30.4	31.3	32.2	32.6
Natural gas	47.3	47.7	48.2	48.6	49.0	50.0	57.3	58.9	59.9	61.0	62.1	62.7
Biomass	63.8	65.2	66.6	68.0	69.4	72.3	75.5	80.6	84.2	87.8	91.6	93.5
Electricity	41.5	42.3	42.7	43.1	43.4	44.3	45.3	47.1	48.3	49.6	51.0	51.6
Energy consumption	192.3	195.0	197.6	200.1	202.6	207.9	220.2	229.8	236.4	243.3	250.5	254.1
Div. C and E: Manufacturing and construction												
Black coal	118.6	119.4	120.6	122.0	124.2	132.7	137.0	138.5	139.8	141.3	142.9	143.8
LPG	22.6	22.5	22.4	22.3	22.2	22.1	22.0	21.7	21.4	21.2	21.0	20.9
Other petroleum products	113.6	113.3	114.5	115.3	102.6	104.3	105.6	107.2	108.4	109.7	111.3	112.0
Natural gas	322.3	334.5	347.6	369.9	389.4	421.8	476.0	507.5	543.9	563.1	583.1	593.4
Biomass	80.8	82.2	83.9	85.5	87.2	90.7	94.5	100.5	104.7	109.0	113.5	115.7
Electricity	260.8	265.8	268.3	273.5	288.6	309.7	321.6	334.3	342.7	351.3	360.2	364.6
Energy consumption	918.7	937.6	957.3	988.5	1 014.2	1 081.3	1 156.7	1 209.7	1 260.8	1 295.6	1 331.8	1 350.4

Continued

F Final energy consumption in Australia, by industry and fuel type *continued*

	2001-02	2002-03	2003-04	2004-05	2005-06	2007-08	2009-10	2012-13	2014-15	2016-17	2018-19	2019-20
	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ
61 Road transport												
LPG	65.8	68.9	74.1	79.2	84.7	96.9	111.0	132.4	147.4	163.8	181.5	191.0
Other petroleum products	942.3	950.0	960.6	970.3	980.7	1 002.2	1 025.0	1 061.3	1 086.4	1 111.9	1 137.9	1 151.0
Energy consumption	1 008.0	1 018.8	1 034.7	1 049.5	1 065.4	1 099.2	1 136.0	1 193.7	1 233.8	1 275.6	1 319.5	1 342.0
62 Railway transport												
Petroleum products	21.5	21.5	22.0	22.6	22.6	22.8	23.0	23.3	23.4	23.6	23.7	23.9
Natural gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Electricity	7.3	7.4	7.5	7.6	7.7	7.9	8.2	8.6	8.9	9.2	9.5	9.6
Energy consumption	28.8	28.9	29.5	30.2	30.3	30.7	31.2	31.9	32.3	32.8	33.2	33.5
63 Water transport												
Black coal	3.5	3.6	3.6	3.6	3.6	3.7	3.8	3.9	3.9	4.0	4.0	4.0
Petroleum products	34.9	35.1	35.4	35.7	36.0	36.5	37.1	38.0	38.5	39.1	39.6	39.9
Natural gas	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Energy consumption	38.5	38.7	39.0	39.3	39.7	40.3	40.9	41.9	42.5	43.1	43.7	43.9
64 Air transport												
Petroleum products	172.0	177.7	186.4	194.7	203.5	222.2	242.8	276.5	300.8	326.5	353.8	368.1
Energy consumption	172.0	177.7	186.4	194.7	203.5	222.2	242.8	276.5	300.8	326.5	353.8	368.1
6501 Pipeline operation												
Natural gas	24.6	25.8	26.7	27.9	29.0	31.0	33.9	36.9	39.7	41.7	43.9	45.1
Energy consumption	24.6	25.8	26.7	27.9	29.0	31.0	33.9	36.9	39.7	41.7	43.9	45.1
Div. I: Transport												
Black coal	3.5	3.6	3.6	3.6	3.6	3.7	3.8	3.9	3.9	4.0	4.0	4.0
LPG	65.8	68.9	74.1	79.2	84.7	96.9	111.0	132.4	147.4	163.8	181.5	191.0
Other petroleum products	1 170.7	1 184.2	1 204.4	1 223.2	1 242.7	1 283.8	1 327.9	1 398.9	1 449.0	1 501.1	1 555.0	1 582.8
Natural gas	24.7	25.9	26.8	28.0	29.0	31.1	34.0	36.9	39.8	41.8	43.9	45.1
Electricity	7.3	7.4	7.5	7.6	7.7	7.9	8.2	8.6	8.9	9.2	9.5	9.6
Energy consumption	1 271.9	1 289.8	1 316.3	1 341.6	1 367.8	1 423.4	1 484.8	1 580.8	1 649.1	1 719.8	1 794.0	1 832.6

Continued

F Final energy consumption in Australia, by industry and fuel type *continued*

	2001-02	2002-03	2003-04	2004-05	2005-06	2007-08	2009-10	2012-13	2014-15	2016-17	2018-19	2019-20
	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ
Divs F, G, H, J, K, L, M, N, O, P, Q: Commercial and services **b**												
Black coal	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
LPG	3.3	3.3	3.4	3.5	3.6	3.7	3.9	4.0	4.1	4.1	4.1	4.2
Other petroleum products	17.1	17.1	17.6	17.9	18.5	19.4	20.4	21.5	22.4	23.2	24.1	24.5
Natural gas	42.7	43.6	44.7	45.8	46.9	49.3	51.8	56.1	59.1	62.2	65.4	67.1
Electricity	174.2	178.5	184.2	189.9	195.6	208.2	221.9	245.0	261.4	278.8	297.1	306.5
Solar energy	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Energy consumption	237.7	243.0	250.5	257.7	265.2	281.3	298.7	327.3	347.6	369.0	391.5	403.1
Residential												
Black coal	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
LPG	10.8	11.0	11.3	11.6	11.9	12.5	13.2	14.3	14.9	15.6	16.4	16.7
Other petroleum products	4.2	4.3	4.4	4.5	4.6	4.9	5.1	5.6	5.9	6.3	6.6	6.8
Natural gas	125.2	126.1	130.9	133.7	137.6	145.2	154.2	165.2	174.1	182.2	190.6	195.1
Biomass	65.7	65.5	65.4	65.4	65.4	65.5	65.6	65.9	66.1	66.4	66.7	66.9
Electricity	184.6	187.8	190.4	193.8	196.3	203.1	210.3	223.8	233.3	243.0	253.1	258.2
Solar energy	2.6	2.6	2.7	2.7	2.8	3.0	3.1	3.4	3.6	3.8	4.0	4.1
Energy consumption	393.0	397.3	405.1	411.8	418.7	434.1	451.6	478.3	498.0	517.3	537.5	548.0
Solvents, lubricants, greases and bitumen												
Petroleum products	64.0	64.2	64.7	65.2	65.7	66.7	67.9	69.7	71.0	72.3	73.7	74.4
Energy consumption	64.0	64.2	64.7	65.2	65.7	66.7	67.9	69.7	71.0	72.3	73.7	74.4
Total												
Black coal	129.3	130.1	131.3	132.7	135.0	143.4	147.9	149.4	150.6	152.1	153.6	154.5
LPG	103.7	107.0	112.6	118.0	124.0	137.0	152.1	174.6	190.2	207.3	225.9	235.7
Other petroleum products	1 525.1	1 543.4	1 572.5	1 599.4	1 614.1	1 673.9	1 738.6	1 843.4	1 918.7	1 998.3	2 082.3	2 126.0
Natural gas	534.2	550.4	571.6	600.3	627.2	674.7	746.7	802.2	857.7	894.9	934.0	954.5
Biomass	146.4	147.7	149.4	150.9	152.6	156.2	160.1	166.4	170.8	175.4	180.2	182.6
Electricity	690.0	704.6	717.7	734.5	760.0	805.7	844.2	903.5	944.8	988.1	1 033.3	1 056.4
Solar energy	2.7	2.8	2.8	2.9	3.0	3.1	3.3	3.6	3.8	4.0	4.2	4.3
Energy consumption	3 131.5	3 186.0	3 257.9	3 338.8	3 415.8	3 594.1	3 792.9	4 043.1	4 236.6	4 420.0	4 613.5	4 714.1

a Includes ANZSIC groups 21, 22, 26, 274-276, 28, 29 and Div. E. **b** Includes ANZSIC 3700 water, sewerage and drainage and ANZSIC 6700 storage.

G Primary energy consumption in Australia, by industry and fuel type

	2001-02	2002-03	2003-04	2004-05	2005-06	2007-08	2009-10	2012-13	2014-15	2016-17	2018-19	2019-20
	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ
Div. A: Agriculture, forestry, fishing												
Oil	79.5	79.9	81.1	82.2	83.4	85.8	88.4	92.5	95.3	98.3	101.3	102.8
Natural gas	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Energy consumption	79.5	80.0	81.2	82.3	83.5	85.9	88.6	92.6	95.4	98.4	101.4	103.0
Div. B: Mining												
Black coal	6.7	6.7	6.6	6.6	6.6	6.5	6.6	6.4	6.3	6.2	6.1	6.1
Oil	78.4	82.7	88.1	93.5	99.2	111.8	126.3	151.4	170.5	191.6	214.9	227.4
Natural gas	102.9	107.1	110.1	121.4	130.2	164.1	193.3	234.9	259.5	269.0	279.3	285.0
Energy consumption	188.0	196.5	204.9	221.4	236.0	282.4	326.2	392.7	436.3	466.8	500.3	518.5
23–24 Wood, paper and printing												
Black coal	6.7	6.6	6.6	6.5	6.4	6.3	6.2	6.0	5.9	5.8	5.7	5.7
Oil	2.0	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.8	1.8	1.8
Natural gas	13.2	13.4	13.9	14.3	14.8	15.7	16.8	18.4	19.6	20.8	22.0	22.7
Biomass	16.1	16.2	16.4	16.7	16.9	17.4	18.0	18.9	19.5	20.1	20.8	21.1
Energy consumption	37.9	38.1	38.8	39.4	40.0	41.4	42.9	45.2	46.8	48.5	50.3	51.3
251 Petroleum refining												
Oil	103.2	104.0	103.8	105.8	107.0	113.4	115.2	118.6	121.0	123.4	125.9	127.1
Natural gas	20.4	20.8	12.7	13.2	13.8	25.1	27.1	30.4	32.8	35.4	38.1	39.6
Energy consumption	123.6	124.8	116.4	119.0	120.8	138.5	142.3	149.1	153.8	158.8	164.0	166.7
252-256 Chemicals												
Black coal	4.6	4.5	4.4	4.4	4.3	4.2	4.1	3.9	3.8	3.7	3.6	3.6
Oil	54.9	54.4	53.9	53.4	53.0	52.1	51.4	50.3	49.7	49.1	48.6	48.3
Natural gas	80.9	82.7	85.1	87.4	89.7	94.7	100.2	109.2	115.5	122.2	129.1	132.7
Energy consumption	140.4	141.5	143.4	145.1	146.9	151.1	155.7	163.5	169.1	175.0	181.3	184.6
26 Non metallic mineral products												
Black coal	24.0	24.1	24.1	24.2	24.3	24.5	24.7	25.1	25.4	25.6	25.9	26.1
Oil	5.8	5.7	5.7	5.7	5.7	5.6	5.6	5.4	5.3	5.2	5.1	5.0
Natural gas	51.7	52.3	53.5	54.6	55.8	58.2	60.8	64.8	67.6	70.4	73.4	74.9
Biomass	0.9	0.9	0.9	0.9	0.9	0.9	1.0	1.0	1.0	1.0	1.1	1.1
Energy consumption	82.3	82.9	84.2	85.3	86.6	89.2	92.1	96.3	99.2	102.3	105.5	107.1

Continued

G Primary energy consumption in Australia, by industry and fuel type *continued*

	2001-02	2002-03	2003-04	2004-05	2005-06	2007-08	2009-10	2012-13	2014-15	2016-17	2018-19	2019-20
	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ
271 Iron and steel												
Black coal	134.4	141.3	141.7	144.2	145.4	177.0	189.5	197.9	203.8	209.9	216.2	219.4
Oil	2.7	2.7	2.7	2.8	2.8	2.8	2.9	3.0	3.0	3.1	3.1	3.1
Natural gas	49.6	58.5	64.8	67.6	68.9	77.7	100.8	112.3	134.7	139.5	144.5	147.1
Energy consumption	186.6	202.4	209.2	214.6	217.0	257.6	293.2	313.1	341.5	352.4	363.8	369.6
272–273 Basic nonferrous metal products												
Black coal	46.7	45.9	47.4	48.5	50.8	52.4	54.3	54.5	54.7	55.1	55.5	55.8
Oil	41.4	41.3	42.4	43.2	30.5	31.9	32.8	33.9	34.6	35.4	36.4	36.8
Natural gas	79.6	80.0	82.2	97.4	111.2	125.5	140.1	143.9	146.5	149.2	151.9	153.4
Energy consumption	167.7	167.2	172.0	189.2	192.5	209.8	227.2	232.2	235.9	239.8	243.8	246.0
Other manufacturing and construction [a]												
Black coal	10.1	10.1	9.9	9.8	9.6	9.3	9.0	8.9	8.7	8.6	8.5	8.5
Oil	29.5	29.8	30.2	30.6	31.1	32.0	33.0	34.4	35.3	36.3	37.3	37.8
Natural gas	47.3	47.7	48.2	48.6	49.0	50.0	57.3	58.9	59.9	61.0	62.1	62.7
Biomass	63.8	65.2	66.6	68.0	69.4	72.3	75.5	80.6	84.2	87.8	91.6	93.5
Energy consumption	150.8	152.7	154.9	156.9	159.1	163.6	174.9	182.7	188.1	193.7	199.5	202.5
Div. C and E: Manufacturing and construction												
Black coal	226.5	232.4	234.1	237.6	240.8	273.6	287.7	296.2	302.3	308.7	315.5	319.0
Oil	239.4	239.8	240.6	243.4	231.9	239.8	242.9	247.5	250.8	254.3	258.1	260.0
Natural gas	342.7	355.3	360.3	383.1	403.2	446.9	503.1	537.9	576.7	598.5	621.2	633.0
Biomass	80.8	82.2	83.9	85.5	87.2	90.7	94.5	100.5	104.7	109.0	113.5	115.7
Energy consumption	889.3	909.7	919.0	949.6	963.1	1 051.1	1 128.2	1 182.1	1 234.4	1 270.6	1 308.2	1 327.7
361 Total electricity generation												
Black coal	1 234.9	1 227.6	1 229.8	1 235.8	1 268.2	1 323.7	1 361.7	1 446.0	1 508.3	1 581.2	1 659.9	1 697.5
Brown coal	664.7	660.5	665.0	667.4	670.7	685.5	694.5	713.2	730.4	744.7	761.6	771.5
Oil	24.5	24.3	24.1	24.1	24.0	23.9	23.8	23.7	23.8	23.8	23.9	24.0
Natural gas	313.1	336.0	349.1	371.6	393.5	421.6	445.0	487.4	518.4	549.2	582.4	602.6
Hydroelectricity	57.1	58.5	58.3	58.6	59.0	61.3	64.4	64.4	64.3	64.1	64.0	64.1
Wind energy	1.0	2.5	3.1	3.9	4.7	6.9	11.6	14.2	14.3	14.5	14.6	14.6
Biogas	7.5	14.9	18.8	21.8	24.9	29.4	31.0	30.0	29.3	28.7	28.1	27.8
Biomass	23.5	47.9	62.7	74.2	88.7	111.9	121.8	117.9	115.4	112.9	110.5	109.3
Energy consumption	2 326.3	2 372.1	2 410.9	2 457.4	2 533.6	2 664.1	2 753.7	2 896.8	3 004.1	3 119.1	3 244.9	3 311.4

Continued

G Primary energy consumption in Australia, by industry and fuel type *continued*

	2001-02	2002-03	2003-04	2004-05	2005-06	2007-08	2009-10	2012-13	2014-15	2016-17	2018-19	2019-20
	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ
61 Road transport												
Oil	1 008.0	1 018.8	1 034.7	1 049.5	1 065.4	1 099.2	1 136.0	1 193.7	1 233.8	1 275.6	1 319.5	1 342.0
Energy consumption	1 008.0	1 018.8	1 034.7	1 049.5	1 065.4	1 099.2	1 136.0	1 193.7	1 233.8	1 275.6	1 319.5	1 342.0
62 Railway transport												
Oil	21.5	21.5	22.0	22.6	22.6	22.8	23.0	23.3	23.4	23.6	23.7	23.9
Energy consumption	21.5	21.5	22.1	22.6	22.6	22.8	23.0	23.3	23.4	23.6	23.7	23.9
63 Water transport												
Black coal	3.5	3.6	3.6	3.6	3.6	3.7	3.8	3.9	3.9	4.0	4.0	4.0
Oil	34.9	35.1	35.4	35.7	36.0	36.5	37.1	38.0	38.5	39.1	39.6	39.9
Natural gas	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Energy consumption	38.5	38.7	39.0	39.3	39.7	40.3	40.9	41.9	42.5	43.1	43.7	43.9
64 Air transport												
Oil	172.0	177.7	186.4	194.7	203.5	222.2	242.8	276.5	300.8	326.5	353.8	368.1
Energy consumption	172.0	177.7	186.4	194.7	203.5	222.2	242.8	276.5	300.8	326.5	353.8	368.1
6501 Pipeline operation												
Natural gas	24.6	25.8	26.7	27.9	29.0	31.0	33.9	36.9	39.7	41.7	43.9	45.1
Energy consumption	24.6	25.8	26.7	27.9	29.0	31.0	33.9	36.9	39.7	41.7	43.9	45.1
Div. I: Transport												
Black coal	3.5	3.6	3.6	3.6	3.6	3.7	3.8	3.9	3.9	4.0	4.0	4.0
Oil	1 236.4	1 253.1	1 278.4	1 302.4	1 327.4	1 380.7	1 438.8	1 531.4	1 596.5	1 664.8	1 736.6	1 773.8
Natural gas	24.7	25.9	26.8	28.0	29.0	31.1	34.0	36.9	39.8	41.8	43.9	45.1
Energy consumption	1 264.6	1 282.5	1 308.8	1 334.0	1 360.1	1 415.5	1 476.6	1 572.2	1 640.2	1 710.6	1 784.5	1 823.0

Continued

G Primary energy consumption in Australia, by industry and fuel type *continued*

	2001-02	2002-03	2003-04	2004-05	2005-06	2007-08	2009-10	2012-13	2014-15	2016-17	2018-19	2019-20
	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ
Divs F, G, H, J, K, L, M, N, O, P, Q: Commercial and services **b**												
Black coal	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Oil	20.3	20.4	21.0	21.4	22.0	23.1	24.3	25.6	26.4	27.3	28.2	28.7
Natural gas	42.7	43.6	44.7	45.8	46.9	49.3	51.8	56.1	59.1	62.2	65.4	67.1
Solar energy	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Energy consumption	63.6	64.5	66.3	67.8	69.6	73.1	76.9	82.4	86.2	90.2	94.4	96.5
Residential												
Black coal	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Oil	14.9	15.3	15.7	16.1	16.5	17.4	18.3	19.9	20.9	21.9	23.0	23.6
Natural gas	125.2	126.1	130.9	133.7	137.6	145.2	154.2	165.2	174.1	182.2	190.6	195.1
Biomass	65.7	65.5	65.4	65.4	65.4	65.5	65.6	65.9	66.1	66.4	66.7	66.9
Solar energy	2.6	2.6	2.7	2.7	2.8	3.0	3.1	3.4	3.6	3.8	4.0	4.1
Energy consumption	208.4	209.5	214.7	218.0	222.4	231.0	241.3	254.4	264.7	274.3	284.4	289.8
Solvents, lubricants, greases and bitumen												
Oil	64.0	64.2	64.7	65.2	65.7	66.7	67.9	69.7	71.0	72.3	73.7	74.4
Energy consumption	64.0	64.2	64.7	65.2	65.7	66.7	67.9	69.7	71.0	72.3	73.7	74.4
Total												
Black coal	1 472.0	1 470.8	1 474.6	1 484.1	1 519.7	1 608.1	1 660.3	1 753.0	1 821.3	1 900.7	1 986.1	2 027.3
Brown coal	664.7	660.5	665.0	667.4	670.7	685.5	694.5	713.2	730.4	744.7	761.7	771.5
Oil	1 757.4	1 779.5	1 813.8	1 848.2	1 870.0	1 949.3	2 030.8	2 161.7	2 255.2	2 354.4	2 459.7	2 514.6
Natural gas	951.3	994.0	1 021.9	1 083.6	1 140.6	1 258.2	1 381.5	1 518.5	1 627.6	1 703.0	1 782.9	1 828.1
Biomass	169.9	195.5	212.0	225.2	241.3	268.1	281.9	284.3	286.2	288.3	290.6	291.9
Biogas	7.5	14.9	18.8	21.8	24.9	29.4	31.0	30.0	29.3	28.7	28.1	27.8
Hydroelectricity	57.1	58.5	58.3	58.6	59.0	61.3	64.4	64.4	64.3	64.1	64.0	64.1
Solar energy	2.7	2.8	2.8	2.9	3.0	3.1	3.3	3.6	3.8	4.0	4.2	4.3
Wind energy	1.0	2.5	3.1	3.9	4.7	6.9	11.6	14.2	14.3	14.5	14.6	14.6
Energy consumption	5 083.8	5 179.0	5 270.5	5 395.7	5 533.8	5 869.9	6 159.2	6 542.9	6 832.4	7 102.3	7 391.9	7 544.1

a Includes ANZSIC groups 21, 22, 274-276, 28, 29 and Div. E. **b** Includes ANZSIC 3700 water, sewerage and drainage and ANZSIC 6700 storage.

H Australian production of primary fuels

	Black coal	Brown coal	Naturally occurring LPG	Crude oil and NGL	Natural gas	Biomass	Biogas	Hydro-electricity	Solar energy	Wind energy
	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ
2001-02	7 111.4	664.7	123.1	1 335.7	1 364.7	169.9	7.5	57.1	2.7	1.0
2002-03	7 391.4	660.5	124.0	1 232.9	1 423.8	195.5	14.9	58.5	2.8	2.5
2003-04	7 752.6	665.0	124.2	1 050.9	1 457.1	212.0	18.8	58.3	2.8	3.1
2004-05	8 116.3	667.4	124.3	1 041.4	1 660.8	225.2	21.8	58.6	2.9	3.9
2005-06	8 442.3	670.7	126.8	1 180.9	1 809.7	241.3	24.9	59.0	3.0	4.7
2006-07	8 727.8	681.3	129.3	1 309.8	1 991.7	254.6	27.0	60.3	3.1	5.6
2007-08	9 002.0	685.5	133.2	1 288.3	2 238.5	268.1	29.4	61.3	3.1	6.9
2008-09	9 270.0	695.1	137.2	1 116.5	2 386.4	281.2	31.3	62.4	3.2	8.5
2009-10	9 565.0	694.5	140.1	1 133.7	2 719.8	281.9	31.0	64.4	3.3	11.6
2010-11	9 594.7	698.7	139.1	1 119.9	2 907.8	282.6	30.6	64.4	3.4	14.2
2011-12	9 607.2	705.8	137.9	1 106.2	3 022.7	283.4	30.3	64.4	3.5	14.2
2012-13	9 642.9	713.2	139.1	1 109.6	3 145.1	284.3	30.0	64.4	3.6	14.2
2013-14	9 650.7	721.0	141.9	1 126.8	3 195.4	285.2	29.6	64.3	3.7	14.3
2014-15	9 658.7	730.4	148.6	1 174.9	3 526.2	286.2	29.3	64.3	3.8	14.3
2015-16	9 768.6	737.7	150.1	1 181.8	3 563.7	287.2	29.0	64.2	3.9	14.4
2016-17	9 884.5	744.7	150.0	1 174.9	3 601.6	288.3	28.7	64.1	4.0	14.5
2017-18	10 002.0	752.3	151.8	1 185.2	3 640.5	289.4	28.4	64.1	4.1	14.5
2018-19	10 183.2	761.7	153.8	1 195.5	3 681.5	290.6	28.1	64.0	4.2	14.6
2019-20	10 320.3	771.5	155.8	1 205.8	3 726.7	291.9	27.8	64.1	4.3	14.6

	2001-02	2002-03	2003-04	2004-05	2005-06	2007-08	2009-10	2012-13	2014-15	2016-17	2018-19	2019-20
	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ	PJ
Electricity generation, by fuel												
Black coal	452.6	452.6	456.1	461.0	475.8	502.0	521.3	560.3	588.1	619.4	651.9	667.1
Brown coal	174.0	174.0	176.2	177.8	179.6	185.3	189.2	196.0	201.6	206.1	211.1	213.9
Oil	8.2	8.2	8.2	8.3	8.3	8.4	8.4	8.5	8.5	8.6	8.7	8.7
Natural gas	109.9	120.1	126.6	136.9	147.0	161.1	173.4	194.6	209.8	224.7	240.3	249.6
Renewables												
Biomass	2.6	5.4	7.2	8.6	10.4	13.4	14.9	14.9	14.9	14.9	14.9	14.9
Biogas	1.2	2.4	3.1	3.6	4.1	5.0	5.4	5.4	5.4	5.4	5.4	5.4
Hydroelectricity	57.1	58.5	58.3	58.6	59.0	61.3	64.4	64.4	64.3	64.1	64.0	64.1
Wind energy	1.0	2.5	3.1	3.9	4.7	6.9	11.6	14.2	14.3	14.5	14.6	14.6
Total	806.7	823.8	838.8	858.7	888.9	943.4	988.6	1 058.3	1 106.8	1 157.6	1 210.9	1 238.2
Fuel inputs												
Black coal	1 234.9	1 227.6	1 229.8	1 235.8	1 268.2	1 323.7	1 361.7	1 446.0	1 508.3	1 581.2	1 659.9	1 697.5
Brown coal	664.7	660.5	665.0	667.4	670.7	685.5	694.5	713.2	730.4	744.7	761.6	771.5
Oil	24.5	24.3	24.1	24.1	24.0	23.9	23.8	23.7	23.7	23.8	23.9	24.0
Natural gas	313.1	336.0	349.1	371.6	393.5	421.6	445.0	487.4	518.4	549.2	582.4	602.6
Renewables												
Biomass	23.5	47.9	62.7	74.2	88.7	111.9	121.8	117.9	115.4	112.9	110.5	109.3
Biogas	7.5	14.9	18.8	21.8	24.9	29.4	31.0	30.0	29.3	28.7	28.1	27.8
Hydroelectricity	57.1	58.5	58.3	58.6	59.0	61.3	64.4	64.4	64.3	64.1	64.0	64.1
Wind energy	1.0	2.5	3.1	3.9	4.7	6.9	11.6	14.2	14.3	14.5	14.6	14.6
Total	2 326.3	2 372.1	2 410.9	2 457.4	2 533.6	2 664.1	2 753.7	2 896.8	3 004.1	3 119.1	3 244.9	3 311.4

J Australian net energy trade, by fuel

	Net exports				Net imports
	Black coal	LPG	Other petroleum products	LNG	Crude oil and ORF
	PJ	PJ	PJ	PJ	PJ
2001-02	5 639.4	65.5	– 64.5	413.4	299.6
2002-03	5 920.7	63.4	– 73.0	429.8	413.1
2003-04	6 277.9	54.8	– 167.4	435.2	526.1
2004-05	6 632.2	50.2	– 166.6	577.2	566.1
2005-06	6 922.6	47.3	– 163.9	669.1	445.7
2006-07	7 161.0	44.0	– 176.2	799.7	336.1
2007-08	7 394.0	45.8	– 88.1	980.3	485.6
2008-09	7 629.0	43.1	– 100.0	1 066.3	679.0
2009-10	7 904.7	38.4	– 126.9	1 338.3	668.6
2010-11	7 905.8	29.7	– 144.2	1 479.7	700.3
2011-12	7 886.8	22.1	– 162.7	1 553.2	732.3
2012-13	7 889.9	16.4	– 182.2	1 626.6	747.2
2013-14	7 863.7	12.1	– 202.5	1 626.6	748.5
2014-15	7 837.3	11.3	– 223.8	1 898.6	719.2
2015-16	7 909.0	5.0	– 245.9	1 898.6	731.2
2016-17	7 983.8	– 3.3	– 269.0	1 898.6	757.2
2017-18	8 058.6	– 10.0	– 293.1	1 898.6	766.1
2018-19	8 197.1	– 17.0	– 318.1	1 898.6	775.3
2019-20	8 293.1	– 24.3	– 344.0	1 898.6	784.7

K1 CO_2 emissions in Australia, by industry

	Agriculture	Mining	Manufacturing and construction	Electricity generation	Transport	Commercial and services a	Residential	Other b	Total
	Mt	Mt	Mt	Mt	Mt	Mt	Mt	Mt	Mt
2001-02	5.4	11.2	53.9	190.3	84.9	3.6	7.4	1.1	357.7
2002-03	5.4	11.7	55.1	190.4	86.1	3.6	7.5	1.1	360.9
2003-04	5.5	12.2	55.6	191.7	87.9	3.7	7.8	1.1	365.4
2004-05	5.5	13.1	57.2	193.6	89.6	3.8	7.9	1.1	371.9
2005-06	5.6	14.0	57.8	197.9	91.3	3.9	8.2	1.1	379.7
2006-07	5.7	15.2	59.6	201.1	93.1	4.0	8.4	1.1	388.3
2007-08	5.8	16.5	63.5	202.3	95.0	4.1	8.6	1.1	397.0
2008-09	5.9	17.5	66.3	205.2	97.0	4.2	8.9	1.1	406.1
2009-10	6.0	19.0	67.8	207.1	99.1	4.3	9.2	1.1	413.6
2010-11	6.1	20.5	68.7	209.8	101.2	4.4	9.4	1.2	421.1
2011-12	6.1	21.6	69.5	212.8	103.3	4.5	9.6	1.2	428.6
2012-13	6.2	22.8	70.7	215.9	105.5	4.6	9.8	1.2	436.8
2013-14	6.3	23.7	72.2	219.1	107.7	4.8	10.1	1.2	445.1
2014-15	6.4	25.4	73.4	222.6	110.0	4.9	10.3	1.2	454.3
2015-16	6.5	26.3	74.4	226.1	112.4	5.0	10.6	1.2	462.4
2016-17	6.6	27.3	75.4	229.7	114.7	5.1	10.8	1.2	470.8
2017-18	6.7	28.3	76.4	233.4	117.2	5.2	11.1	1.2	479.5
2018-19	6.8	29.4	77.4	237.5	119.7	5.3	11.3	1.2	488.6
2019-20	6.9	30.5	78.4	241.7	122.3	5.4	11.6	1.3	498.1

a Includes ANZSIC Divisions F, G, H, J, K, L, M, N, O, P, Q, ANZSIC 3700 water, sewerage, drainage, and ANZSIC 6700 storage industries. **b** Includes consumption of lubricants and greases, bitumen and solvents.

K2 CO_2 emissions in Australia, by industry, b state

	Unit	2001-02	2004-05	2009-10	2014-15	2019-20
New South Wales						
Agriculture	Mt	1.8	1.9	2.1	2.2	2.4
Mining	Mt	1.0	1.1	1.4	1.8	2.4
Manufacturing and construction	Mt	19.7	20.8	25.3	26.9	28.7
Electricity generation	Mt	56.3	57.1	56.2	58.6	61.0
Transport	Mt	27.0	28.1	30.6	33.5	36.7
Commercial and services **a**	Mt	0.8	0.8	1.0	1.1	1.2
Residential	Mt	1.4	1.5	1.7	1.9	2.1
Other **b**	Mt	0.3	0.3	0.3	0.3	0.3
Total	Mt	108.2	111.7	118.6	126.4	134.8
Victoria						
Agriculture	Mt	1.0	1.0	1.1	1.1	1.2
Mining	Mt	1.1	1.3	1.6	1.8	2.1
Manufacturing and construction	Mt	8.4	8.8	9.4	10.0	10.8
Electricity generation	Mt	63.9	64.3	67.4	71.5	76.0
Transport	Mt	20.7	21.7	24.0	26.7	29.7
Commercial and services **a**	Mt	1.5	1.6	1.8	2.0	2.3
Residential	Mt	4.6	4.9	5.7	6.4	7.2
Other **b**	Mt	0.3	0.3	0.3	0.3	0.4
Total	Mt	101.6	104.0	111.2	120.0	129.7
Queensland						
Agriculture	Mt	1.0	1.0	1.2	1.3	1.4
Mining	Mt	2.1	2.6	3.7	5.2	7.2
Manufacturing and construction	Mt	9.7	10.2	11.8	12.5	13.5
Electricity generation	Mt	43.5	44.5	53.8	60.2	69.2
Transport	Mt	17.7	19.2	21.9	25.0	28.4
Commercial and services **a**	Mt	0.4	0.4	0.5	0.5	0.6
Residential	Mt	0.3	0.3	0.4	0.4	0.5
Other **b**	Mt	0.3	0.3	0.3	0.3	0.3
Total	Mt	74.9	78.6	93.4	105.5	121.2
Western Australia						
Agriculture	Mt	0.8	0.8	0.9	0.9	1.0
Mining	Mt	5.0	6.1	8.9	11.2	13.1
Manufacturing and construction	Mt	9.4	10.6	12.7	14.7	15.6
Electricity generation	Mt	16.5	17.1	18.4	20.3	22.6
Transport	Mt	10.2	11.0	12.5	14.3	16.3
Commercial and services **a**	Mt	0.4	0.5	0.5	0.6	0.7
Residential	Mt	0.6	0.6	0.7	0.9	1.0
Other **b**	Mt	0.1	0.1	0.1	0.1	0.1
Total	Mt	43.1	46.9	54.8	63.0	70.2

Continued

K2 CO_2 emissions in Australia, by industry, b state *continued*

	Unit	2001-02	2004-05	2009-10	2014-15	2019-20
South Australia						
Agriculture	Mt	0.3	0.3	0.3	0.4	0.4
Mining	Mt	1.5	1.6	1.9	2.1	2.4
Manufacturing and construction	Mt	4.2	3.6	4.7	5.2	5.7
Electricity generation	Mt	7.8	8.0	8.4	8.9	9.6
Transport	Mt	6.1	6.2	6.5	6.8	7.1
Commercial and services **a**	Mt	0.3	0.3	0.4	0.4	0.4
Residential	Mt	0.5	0.5	0.6	0.6	0.7
Other **b**	Mt	0.1	0.1	0.1	0.1	0.1
Total	Mt	20.9	20.6	22.9	24.5	26.4
Tasmania						
Agriculture	Mt	0.1	0.1	0.2	0.2	0.2
Mining	Mt	0.2	0.2	0.2	0.2	0.3
Manufacturing and construction	Mt	1.4	1.7	2.0	2.0	2.0
Electricity generation	Mt	0.6	0.8	0.9	0.9	1.0
Transport	Mt	1.6	1.6	1.7	1.7	1.8
Commercial and services **a**	Mt	0.0	0.0	0.0	0.0	0.0
Residential	Mt	0.0	0.1	0.1	0.1	0.1
Other **b**	Mt	0.0	0.0	0.0	0.0	0.0
Total	Mt	4.0	4.6	5.0	5.2	5.4
Northern Territory						
Agriculture	Mt	0.2	0.2	0.3	0.3	0.4
Mining	Mt	0.2	0.3	1.4	3.0	3.0
Manufacturing and construction	Mt	1.1	1.5	2.0	2.1	2.2
Electricity generation	Mt	1.7	1.7	2.0	2.2	2.4
Transport	Mt	1.6	1.6	1.8	2.0	2.1
Commercial and services **a**	Mt	0.2	0.2	0.2	0.2	0.2
Residential	Mt	0.0	0.0	0.0	0.0	0.0
Other **b**	Mt	0.0	0.0	0.0	0.0	0.0
Total	Mt	5.1	5.6	7.7	9.7	10.4

a Includes ANZSIC Divisions F, G, H, J, K, L, M, N, O, P, Q, ANZSIC 3700 water, sewerage, drainage, and ANZSIC 6700 storage industries. **b** Includes consumption of lubricants and greases, bitumen and solvents.

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