A Clean Energy Future for Australia

A Study by
Energy Strategies for the
Clean Energy Future Group

Consisting of:

Australasian Energy Performance Contracting Association

Australian Business Council for Sustainable Energy

Australian Gas Association

Australian Wind Energy Association

Bioenergy Australia

Renewable Energy Generators of Australia

WWF Australia

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Clean Energy Future Group

AEPCA is the **Australasian Energy Performance Contracting Association**. Its members are formed from energy service companies, state government departments and private companies interested in the performance contracting process. Energy performance contracting is a smart, affordable and increasingly common way to make building improvements that save energy and money. Its mission is to act as the Peak Body to support the commercial growth of members and their market through education, industry promotion, self-regulation and industry standards. www.aepca.asn.au

The **Australian Business Council for Sustainable Energy (BCSE)** represents the interests of the broader sustainable energy industry including, renewables energy, cogeneration, gas-fired generation, waste-to-energy and energy efficiency industry. It has more than 250 organisations as members. It formed in September 2002 through the merger of the Australian EcoGeneration Association and the Sustainable Energy Industry Association. www.bcse.org.au

The Australian Wind Energy Association (AusWEA)'s vision is for a robust Australian Wind Community that makes a significant contribution to safe, reliable, economically and environmentally sustainable energy supply in Australia. AusWEA's mission is to represent the Australian Wind Energy Community and promote the sensitive and appropriate uptake of wind energy. www.auswea.com.au

Bioenergy Australia was established in 1997 as a government-industry forum to foster and facilitate the development of biomass for energy, liquid fuels, and other value added bio-based products. Bioenergy Australia is concerned with all aspects of biomass and bioenergy, from production through to utilisation, and its work embraces technical, commercial, economic, societal, environmental, policy and market issues. This report does not necessarily reflect the views of all individual Bioenergy Australia members. www.bioenergyaustralia.org

The **Renewable Energy Generators of Australia (REGA)** was formed in 1999 as an industry association with a common purpose of supporting the development of generation of electricity from truly renewable resources. REGA represents all sectors of the renewable energy industry; members represent 95% of the existing renewable energy generation capacity, and include equipment suppliers, developers and industry specialists. www.rega.com.au

WWF Australia is part of the WWF International Network - the world's largest independent conservation organisation. With the help of more than 50,000 supporters across Australia, we're helping to protect and conserve our most biologically outstanding land, freshwater and marine habitats and reduce the causes and impacts of climate change. www.wwf.org.au

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Copies of this study can be down loaded from each Clean Energy Future Group's web sites

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GLOSSARY

Absorption chiller	A chiller (*q.v.*) which is operated by heat rather than by mechanical energy as in the more common type of chiller using vapour compression refrigeration. It uses the cyclic separation (by heating) and absorption of a pair of fluids (termed refrigerant and absorbent) having a strong affinity for each other. Heat is absorbed, i.e. "coolth" is produced in the process of absorption.
Anaerobic digestion	A fermentation process for producing gas from biomass in a wet, oxygen-free environment.
Backcast	To develop a scenario by choosing a future state of society or a technology and then working out how to get from the present state to that future state.
Back pressure turbine	A turbine (usually a steam turbine) in which the steam exits the turbine chamber at significant positive pressure and thus with significant remaining energy available to be used in another process.
Bagasse	The fibrous residue of sugar milling that is used as a fuel to raise steam in the mills.
Base-load	Power stations that are designed to run 24 hours per day, 7 days per week. They usually have high capital cost and low running cost.
Biogas	Gas produced from biomass: e.g. from animal manure and garbage tips, by anaerobic digestion (*q.v.*).
Biomass	Material produced by photosynthesis or an organic by-product from a waste stream. It includes a wide variety of renewable organic materials, including forestry and agricultural wastes and residues, urban tree trimmings, food processing wastes, woody weeds, oil bearing plants, animal manures and sewage, energy crops and the organic fraction of municipal solid waste.
Boiler	A reactor where a fuel is burnt to heat water in order to produce steam or hot water.
Bottoming cycle	A type of cogeneration system in which hot exhaust gases from a kiln or similar high temperature process are used to produce steam which is then passed through a turbine to generate electricity. The steam exits from the turbine at close to atmospheric pressure and cannot be used to provide further useful energy.
Bottom up model (of greenhouse response)	A computer model of all or part of the energy sector that is based directly on data on the cost and performance of specific energy technologies and services.
Brown coal	Sometimes called lignite. The type of coal used to generate electricity in Victoria and South Australia. It has a very high water content and low carbon content and so has among the highest greenhouse intensities of all fossil fuels.
Capacity (of power station)	Rated or peak power, measured in megawatts or similar units.
Capacity credit	The effective capacity of an 'intermittent' or 'unreliable' power station to meet demand, divided by the capacity of a hypothetically totally reliable power station, often expressed as a percentage. All real power stations are unreliable to some degree and so have capacity credit less than 100%.
Capacity factor	The annual energy generated by a power plant divided by the energy that it would have generated if it had operated continuously at its rated or peak power, often expressed as a percentage.
Chiller	A device for producing "coolth" (as opposed to heat), which can be used to lower the internal temperature of a building.
Coal-bed methane	Methane gas that occurs naturally in black coal seams.
Cofiring	Burning two or more fuels together (e.g. coal and biomass) in the boiler of a power station.
Cogeneration	The production of electricity and useful heat together from the same power plant. Sometimes called 'combined heat and power'.
Combined cycle	A power station that generates electricity by means of one process (e.g. gas turbine) and then uses the waste heat from that process to generate more electricity from another process (e.g. waste heat boiler plus steam turbine). Combined cycle power stations have higher thermal efficiencies (*q.v.*) than ordinary 'single cycle' power stations.

Coppice	To cut off the above-ground branches of a tree so that they re-grow rapidly.
Dematerialisation	The process whereby advanced economies become relatively less dependent on the production of material commodities and their conversion into physical goods, and more dependent on the production and consumption of services, with the result that the consumption of raw materials per unit of GDP decreases.
Discount rate	An interest rate used to discount (i.e. reduce the value of) income or expenditure in the future (see Net Present Value) due in part to preference for consumption now rather than later. It is often expressed in 'real' terms, i.e. adjusted to exclude the effects of inflation..
Dispatchable power station	A power station that produces power upon demand. Usually refers to either a thermal or a hydro-electric power station based on a dam. Could also be used for an 'intermittent' power plant, such as solar or wind, which has dedicated storage. Concept is an idealisation, since 'dispatchable' power stations may fail to operate unexpectedly at some time or other
Distribution line	Power line for the local distribution of electricity. In Australia, it usually has voltage below 66 kV.
End-use energy	Final energy consumption (*q.v.*).
Energy intensity (of an economy)	Annual national energy consumption divided by GDP.
Energy service	A service that is provided by a combination of energy supply and a pattern of energy use: e.g. a warm home in winter; clean clothes; access to a school.
Fermentation	One of several methods for converting biomass into a gas or liquid, involving the use of micro-organisms (yeast or bacteria) which change the chemical composition of the biomass by means of enzymatic (biological) reactions that occur in a moist environment with little or no oxygen present.
Final energy consumption	Energy consumed in the 'final' or end-use sector. It equals primary energy consumption less energy consumed or lost in the conversion, transmission and distribution processes.
First Law of Thermodynamics	The conservation of energy, which states that energy cannot be created or destroyed, but only converted from one form to another.
Forecast	To develop a scenario by projecting from the present into the future, based on past trends. (Becomes increasingly unreliable as the future time increases.)
Fossil fuel	A primary fuel (*q.v.*) consisting of the fossilised organic material derived from plants and animals which lived in the remote geological past; the main fossil fuels are coal, petroleum and natural gas.
Fuel cell	An electrochemical system that converts hydrogen and oxygen into water, producing electricity and heat in the process, thereby providing a high efficiency means for converting the energy in a fuel(hydrogen) directly to electricity.
Fugitive emissions	Greenhouse gas emissions not resulting from the combustion of fossil fuels, but rather from mining, transmission, distribution and storage of fuels.
Gas turbine	An engine that burns a liquid or gaseous fuel to produce an expanding gas that drives a turbine. The turbine can be used to drive a generator (as in a power station), a piece of major mechanical equipment such as a pump or compressor (as in large industrial plants, gas pipelines etc.), or a propeller (as in aircraft engines).
GDP	Gross Domestic Product, a measure of economic activity, formally defined to be the total monetary value of 'final' goods and services produced in a country in a year. 'Final' excludes 'intermediate' goods and services which are used as inputs into the production of other goods and services.
Geosequestration	The capture of CO_2 gas from a large point source, such as a power station, and its storage deep underground.
Greenhouse (gas) intensity (of power station)	Megatonnes of CO_2 produced divided by electricity sent out in TWh, which is equivalent to kg of CO2 produced divided by electricity sent out in kWh.
Grid	Network of electricity powerlines.
Gross Calorific Value (GCV)	The quantity of heat energy released when a fuel is burned completely with oxygen, and the products of combustion are returned to ambient temperature and pressure. It is normally measured per unit mass or unit volume of a fuel.

	Sometimes termed Higher Heating Value (HHV). GCV is generally used in Australia and the USA, while Net Calorific Value (*q.v.*) is more often used in other countries.
Higher Heating Value (HHV)	See Gross Calorific Value.
Insolation	Solar energy input as sunshine.
Integrated gasification combined cycle (IGCC)	Combined cycle power station (*q.v.*) that gasifies solid fuel before burning it.
Intermediate load	A power station whose operation is between that of base-load and peak-load. Output can be varied more rapidly than base-load but more slowly than peak-load. Capital/fuel cost lower/higher than base-load but higher/lower than peak-load. Generally operates for several hours per day during medium to high demand periods.
Inverter	An electronic device that converts direct current (DC) electricity into alternating current (AC) with a specified frequency.
Least-cost planning	A method of planning the future development of an energy supply system that identifies the lowest cost means of meeting the final demand for energy services by assessing both supply-side options (new power stations, power lines etc.) and demand side options (increased energy use efficiency) on an equal basis.
Levelised cost / annuity	An amount of money which, if paid annually over the life of an asset, such as a power station, will fully repay the capital cost plus interest over the life. The term is sometimes used to include also the annual operating costs (fuel, operation and maintenance etc.), and thereby express the full cost of producing electricity from the power station.
Liquefied natural gas (LNG)	Natural gas which is kept in the liquid state at very low temperatures to facilitate storage and transport.
Loss-of-load probability	The average number of hours per year that electricity supply fails to meet demand.
Lower Heating Value (LHV)	See Net Calorific Value.
Mallee	A type of eucalypt which has multiple stems sprouting from a long-lived underground stem, termed a lignotuber (mallee root). Mallees have the ability to re-shoot repeatedly from the lignotuber and so are ideally suited to coppicing (*q.v.*).
Microturbine	A very small gas turbine that can be used to generate both useful heat and electricity at the point of use in commercial and (possibly in the near future) in residential buildings
MRET	Mandatory Renewable Energy Target
NEM	National Electricity Market
NEMMCO	National Electricity Market Management Company
Net Calorific Value (NCV)	This is equal to GCV (*q.v.*) minus the latent energy contained in the water vapour (in the exhaust gas) which is produced when hydrogen (from the fuel) is burned. Sometimes termed Lower Heating Value (LHV). Therefore, the difference between GCV and NCV increases as the hydrogen content of the fuel increases. As a result, the thermal efficiency of a coal-fired power station based on NHV is typically 2-3% higher than its thermal efficiency based on GCV; in the case burning natural gas, the NHV thermal efficiency may be 10-15% higher than the GCV thermal efficiency.
Net Present Value (NPV)	The value today of a future stream of revenue (income) and expenses, calculated by discounting future costs and revenues at a chosen discount rate and summing the discounted quantities. The effect of discounting is to make revenue and expenses in the more remote future relatively less important than those in the immediate future.
Off-grid	Not connected to the electricity network.
Peak-load	Power stations that are designed to run for only short periods to meet the peaks in demand. If they are thermal power stations (*q.v.*) (gas turbines), they have low capital cost and high running cost..
Peak watt	The rated or nameplate power capacity of an energy source, often applied to

	PV modules.
Photovoltaic (PV) cell and module	An electronic device that converts solar energy directly into electricity without any moving parts (apart from the electrons).
Primary energy	The chemical energy stored in a primary fuel (qv).
Primary fuel	Fuel that is extracted directly from the natural environment, such as coal, natural gas, crude oil, uranium, wood, bagasse, wind, solar energy.
Pyrolysis	One of several thermochemical methods for converting biomass or coal into a gas or liquid, involving heating the biomass or coal within a closed chamber in the almost complete absence of oxygen.
Reciprocating engine	An engine whose central elements are a cylinder and piston which moves up and down inside the cylinder, as in a standard car engine.
Remote area power supply	Power plant not connected to a large electricity grid. (However, it may be connected to a small local grid.)
Reformer (in chemistry)	A chemical method of converting alcohols and hydrocarbons into hydrogen, usually for use in a fuel cell.
Scenario	An evolutionary pathway between the present and a future state of society or technology.
Second Law of Thermodynamics	When energy is transformed from one form to another, it tends to flow from a higher grade or more ordered form -- such as mechanical, electrical energy, chemical or high-temperature heat -- to a lower-grade or more disordered form, ultimately low-temperature heat. So energy becomes degraded and less useful to humans. It is possible to reverse this natural flow, pushing low-grade energy 'uphill', but only by expending more high-grade energy at the input than is received at the output.
Secondary fuels	Fuels produced from primary (or other secondary) fuels by conversion processes to produce the fuels commonly consumed: e.g. thermal electricity, coke and refined petroleum products.
Sensitivity analysis	Repetition of a calculation a number of times to investigate the effect of changing an assumption or the data used.
STP	Standard temperature and pressure, comprising 0˚C and 1 atmosphere (101.3 kPa)..
Steam turbine	A turbine driven by steam that is produced by burning fuel to boil water.
Supercritical	New kind of boiler used in coal-fired power stations which operates under higher steam pressures and temperatures and so gains higher thermal efficiency. Two new power stations in Queensland are using supercritical boilers.
Thermal efficiency (of power station)	Electrical energy sent out divided by energy input, sometimes expressed as a percentage. In the case of thermal power stations, the energy input is the chemical energy stored in the fuel. There are two ways of calculating the latter, called Higher Heating Value (HHV), which is used in this report and generally in Australia, and Lower Heating Value (LHV), which is sometimes used overseas.
Topping cycle	A type of cogeneration system in which steam direct from the boiler, at high temperature and pressure, is passed through a steam turbine to generate electricity, from which it exits at a lower temperature and pressure to be used for thermal processes.
Transmission line	An electricity power line designed to carry a large quantity of electricity over a long distance. In Australia, a transmission line generally operates at a voltage of at least 132 kV, and most major lines operate at 330 or 500 kV.
Turbine	A motor whose central elements are a series of blades attached to a shaft, which rotates, usually within a chamber. Steam turbines, gas turbines, hydro turbines and wind turbines are used extensively in modern energy systems.
Wind farm	An array of wind turbines located in proximity to one another and generally using the same substation (transformer) and power line to connect to an electricity grid.

Units and Conversion Factors

Powers of 10

Prefix	Symbol	Value	Example
kilo	k	10^3	kilowatt kW
mega	M	10^6	megawatt MW
giga	G	10^9	gigajoule GJ
tera	T	10^{12}	terawatt-hour TWh
peta	P	10^{15}	petajoule PJ

SI units

Basic unit	Name	Symbol
length	metre	m
mass	kilogram	kg
time	second	s
temperature	Kelvin	K

Derived unit	Name	Symbol
energy	joule	J
power	watt	W
potential difference	volt	V
pressure	pascal	Pa
temperature	degree Celsius	˚C
time	hour	h

Conversion factors

Type	Name	Symbol	Value
energy	kilowatt-hour	kWh	3.6×10^6 J = 3.6 MJ
energy	terawatt-hour	TWh	3.6×10^{15} J = 3.6 PJ
energy	litre of petrol	L	3.2×10^7 J
energy	m^3 of natural gas at STP		3.4×10^7 J
energy	tonne of NSW black coal	t	23 GJ
energy	tonne of Vic. brown coal	t	10 GJ
energy	tonne of green wood	t	10 GJ
energy	tonne of oven-dried wood	t	20 GJ
power	kWh per year	kWh/y	0.114 W
time	year	y	8760 h
pressure	atmosphere		101.325 kPa

1. Introduction

1.1. Why this study has been done

> *"Energy is vital to a modern economy. We need energy to heat and light our homes, to help us travel and to power our businesses. Our economy has also benefited hugely from our country's resources of fossil fuels – coal, oil and gas.*
>
> *"However, our energy system faces new challenges. Energy can no longer be thought of as a short-term domestic issue. Climate change – largely caused by burning fossil fuels – threatens major consequences in the UK and worldwide, most seriously for the poorest countries who are least able to cope … We need urgent global action to tackle climate change. We are showing leadership be putting the UK on a path to a 60% reduction in its carbon dioxide emissions by 2050…*
>
> *"Our analysis suggests that, by working with others, the costs of action will be acceptable and the costs of inaction are potentially much greater. And as we move to a new, low carbon economy, there are major opportunities for our businesses to become world leaders in the technologies we will need for the future…"*
>
> Tony Blair, Foreword to UK White Paper on Energy (DTI, 2003)

> *"The world is in the early stages of an inevitable transition to a sustainable energy system that will be largely dependent on renewable resources."*
>
> International Energy Agency (1999)

What this study does

This study explores the potential for deep cuts in emissions of the principal greenhouse gas, carbon dioxide (CO_2), in Australia. It focuses on stationary energy, that is energy that is used in the form of electricity, heat that is not produced from electricity, and mechanical energy. The study does not examine transport, which must be left for a separate study.

The principal goal of the present study is to investigate whether it is possible to achieve a 50% reduction in CO_2 emissions from stationary energy by 2040, by using a mix of existing technologies, with small improvements, in order to produce and use energy more efficiently and more cleanly. So, in our principal scenarios there are no dramatic breakthroughs in technologies: no cheap electricity from solar photovoltaic cells; no cheap capture and sequestration underground of CO_2 emitted by coal-fired power stations; and no cheap methods of producing hydrogen as a means of storing and transporting renewable energy. In practice, however, there will be innovation between now and 2040. In Chapter 11 we offer a glimpse of how, with innovation, we might achieve 80% or more reductions in CO_2 emissions beyond 2050 – but these are not the principal scenarios of this study. If we can reach our 2040 target with small improvements to existing technologies, then reductions beyond 2050 will be even easier with innovation.

Our method is to take existing technologies and develop a workable and credible stationary energy supply system for 2040 that meets our target and then to identify the key strategies that will allow us to get from the present to that 2040 state. In moving from the present to the future we take account of the main driving forces for increasing energy consumption: economic growth and population growth.

Our study is inspired by several earlier energy and greenhouse scenario studies performed overseas (RCEP, 2000; Interlaboratory Work Group, 1997, 2000; Marsh *et al*., 2003) and a pilot study published by the Australia Institute (Turton *et al*., 2002). These and other scenario studies are reviewed briefly in Chapter 13. However, the present study is different from earlier studies because of its focus on existing technologies and because it presents new scenarios on future energy use and greenhouse gas emissions in Australia.

The principal motivation for this study is similar to that expressed in the above quotation from the British Prime Minister: the need to bring human-induced climate change under control. By describing and analysing a feasible long-term future in which energy demand and supply mix are radically different from today's, decision-makers, professionals, environmentalists and the community at large can form a picture of how Australia and the world could have a much cleaner and more efficient energy system while still being prosperous. The present study is a contribution to this longer-term thinking about Australia's response to climate change.

Climate change[1]

The world's most authoritative body on climate change, the Intergovernmental Panel on Climate Change (IPCC), has warned that the nations of the world will need to shift to a low-carbon future in order to avoid dangerous changes to the global climate.

The IPCC has developed a number of climate change scenarios to evaluate future impacts. Even the most optimistic scenario, involving rapid change in economic structure and technology, shows CO_2 concentrations doubling by the end of the century, resulting in an increase in average global temperatures of around 2° C and a sea-level rise of 30 cm.[2] The IPCC notes that the climate system is subject to great inertia so that '[s]tabilization of CO_2 concentrations at any level requires eventual reduction of global CO_2 net emissions to a small fraction of the current emission level' (IPCC, 2001a, p. 16). There are advantages in beginning the task of reducing emissions sooner rather than later: 'The greater the reductions in emissions and the earlier they are introduced, the smaller and slower the projected warming and the rise in sea levels' (IPCC, 2001, p. 19).

Doubling of atmospheric concentrations of CO_2 is expected to be associated with global warming in the range 1.4-2.6°C by the end of the century (IPCC 2001a, Figure 22, p. 209). The United Nations Framework Convention of Climate Change

[1] This subsection reproduces several paragraphs from Turton *et al*. (2002) with permission from the Australia Institute.
[2] Scenario B1 in IPCC (2001), pp. 10-11.

(UNFCCC) commits nations (including Australia) to taking measures to prevent 'dangerous' levels of climate change. It is widely accepted that concentrations in excess of 550 ppm, or double the pre-industrial levels, would be dangerous, and that even a doubling is likely to be associated with major negative impacts (see IPCCa, 2001). According to the IPCC, stabilising concentrations at double pre-industrial levels will require deep cuts in annual global emissions, eventually by 60 per cent or more (see IPCCa, 2001, Figure 25).[3]

The need for deep cuts has been formally acknowledged by the Australian Government. The Foreign Minister, Alexander Downer, has stated:

> *"If we are going to achieve stability in global temperatures in the years ahead then CO_2 emissions will have to be reduced by between one half and two thirds".*[4]

Given the wide variation between nations in levels of emissions per capita and income per capita, it would be infeasible and unfair to require all nations to cut their emissions by 60 per cent of current levels. Developing countries might expect to reduce their emissions by less than this amount and wealthy countries with high per capita emissions, such as Australia, should expect to cut their emissions by more than 60 % in the longer term[5] , possibly by 80%.Table 1.1 shows Australia's greenhouse gas emissions in 1990, 1995 and 2001, as reported in the most recent National Greenhouse Gas Inventory (Australian Greenhouse Office, 2003). Emissions are expressed in units of carbon dioxide equivalent (CO_2-e). It can be seen that stationary energy combustion, the main focus of this study, contributed 259.5 Mt, or 47.8% of Australia's total emissions. Moreover, emissions from stationary combustion grew faster and by more than any other sector over the eleven year period. Australia's total net emissions remained effectively constant over the period, mainly because of a large reduction in emissions from Land Use Change and Forestry, which fell by 82 Mt CO_2-e. But growth in total emissions over the period more than offset the decline in Land Use Change and Forestry emissions. By 2001 emissions from Land Use Change had fallen to 37 Mt, partly offset by removals of 23 Mt from managed forestry. Hence, further reductions in emissions from Land Use Change, if achieved, could continue to offset growth in energy related emissions for a few more years. However, unless there is a decisive change in policy, within a few years growth in energy sector emission will start to drive Australia's greenhouse emissions inexorably upward.

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[3] IPCC 2001a, Figure 25(c) shows that to achieve stabilisation of atmospheric CO_2 concentrations at 550 ppm it is necessary to reduce emissions by 40-60 per cent by the end of the century and 65-85 per cent by 2150. Further reductions will be required beyond 2150.

[4] ABC Radio News, 28 June 2002. http://www.abc.net.au/news/politics/2002/06/item20020627170339_1.htm

[5] This was reaffirmed in the decision adopted by the UNFCCC in Bonn in 2001 '[t]hat the Parties included in Annex I [industrialised countries] shall implement domestic action…with a view to reducing emissions in a manner conducive to narrowing per capita differences between developed and developing country Parties while working towards achievement of the ultimate objective of the Convention' (Decision 5/CP.6).

Table 1.1: Changes in Australia's greenhouse net gas emissions, 1990 to 2001

Sector	Net Emissions (Mt CO2-e)			Increase 1990 to 2001	
	1990	1995	2001	Mt CO2-e	Percent
Stationary energy	195.5	214.0	259.5	64.0	32.7%
Transport	62.0	69.0	77.2	15.2	24.5%
Fugitive energy	28.8	30.4	32.2	3.4	11.8%
Total energy	286.2	313.4	369.0	82.8	28.9%
Land use change and forestry	93.1	42.9	11.4	-81.7	-87.8%
All other sectors	136.5	131.1	147.7	11.3	8.2%
TOTAL NET EMISSIONS	515.8	487.4	528.1	12.3	2.4%

In order to set Australia on the necessary path towards a long-term 80% reduction in total CO_2 emissions, including those from land clearing, we choose in this study a substantial but achievable target for emissions from stationary energy: a 50% reduction compared with 2001.

Lessons for Australia from global responses

In 2000, the UK Royal Commission on Environmental Pollution brought down a report examining the feasibility of achieving a 60 per cent reduction in Britain's emissions by 2050 (RCEP, 2000). The report observed:

Human use of energy has grown enormously, based overwhelmingly on burning fossil fuels. This is causing a significant change in the composition of the atmosphere which, unless halted, is likely to have very serious consequences. ….

> *In addition to previously recognised risks from obtaining and using energy, the world is now faced with a radical challenge of a totally new kind, which requires an urgent response. The longer the response is deferred, the more painful the consequences will be.* (RCEP 2000, pp. 13, 16)

The Blair Government has responded with detailed study and discussion of how such a reduction might be achieved (DTI, 2003; Marsh *et al*., 2003). Noting that the UK 'is likely to face increasingly demanding carbon reduction targets', the UK Government concludes:

> *Credible scenarios for 2050 can deliver a 60% cut in CO_2 emissions, but large changes would be needed both in the energy system and in society. …Given the strong chance that future, legally binding, international targets will become more stringent beyond 2012, a precautionary approach suggests that the UK should be setting about creating a range of future options by which low carbon futures could be delivered, as, and when, the time comes.* (Cabinet Office, 2002, p. 9)

To implement a process for achieving its substantial target for the reduction of CO_2 emissions, namely a 60% reduction by 2050; the UK Government has set a renewable energy obligation of 10.4% of electricity supply by 2010 from eligible technologies that exclude large hydro-electric plants commissioned before April 2002, and have recently extended the obligation to 15.4% by 2015-16. It is providing considerable financial support[6] for industry development; research, development and demonstration (where the latter is focused on offshore wind, energy crops and photovoltaics), and the development of scenarios where in some cases coal use is phased out within 20 years.

In 2002 Denmark obtained 18% of its electricity from wind power and a significant fraction of electricity and district heating from crop residues. Denmark plans to reduce its greenhouse gas emissions by 50% by around 2030.

The European Union has committed to introduce emissions trading by 1 January 2005. The scheme will work on a “cap and trade” basis with an emissions target allocated to each country. Coverage will initially be limited to combustion plants in excess of 20 MW capacities. It is estimated that 14,000 industrial as well as power generation facilities will fall under the scheme and be allocated emissions allowances. Each country is to establish its own target and develop a National Allocation Plan that needs to be submitted to the European Commission before the end of March 2004.

In the United States, although the Federal Government has not set a target, there is considerable action at State level (WWF USA, 2003).

- Five States have imposed mandatory limits on CO_2 emissions including three policies directed specifically at electricity sector emissions: In June 2003, Maine became the first US state to enact legislation requiring a statewide reduction in greenhouse gas emissions. In 2002 New Hampshire passed a law to regulate power plant emissions of CO_2 through a multiple pollution reduction program. The program requires a reduction of CO_2 emissions to 1990 levels by 2010 with a lower future cap to be recommended by 2004. In 2001 Massachusetts passed legislation requiring that six of its oldest, dirtiest power plants reduce their emissions of key air pollutants. The law requires the power plants to reduce their CO_2 emissions by 10% below a 1997 -1999 baseline by 2006.

- Thirteen States have passed legislation mandating that a specific portion of their electricity be generated by non-emitting renewable energy resources. These targets range from 2.2% by 2009 in Texas to 18% by 2012 in California.

In Asia there are some substantial actions.

- The Indian Government has strongly supported wind power, with the result that there is a thriving industry with 1700 MW installed by 2002.

- Although developing countries are not required to ratify the Kyoto Protocol, China has done so and has set in place programs to encourage the efficient use of energy and renewable energy. From 1996 to 1999, China reduced its CO_2 emissions[7], despite one of the highest rates of economic growth in the world (over 7% p.a.).

- Japan is subsidising the conversion of old coal-fired power stations to natural gas; and is funding new energy efficient industrial processes, photovoltaics and other

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[6] See www.dti.gov.uk.
[7] More recently, emissions have resumed an upward path.

renewable energy sources. It is also extending the application of its Law Concerning the Rational Use of Energy from large factories to large office buildings.

Compared with the responses of the other governments summarised here, the response by federal and state governments in Australia has not been strong. Funding for fossil fuels continues to be increased whilst research and development support for efficient energy use and renewable sources of energy has been substantially decreased. Specifically:

- Australia is one of only two countries that are signatories to the Kyoto Protocol, yet have said they will not ratify it. Nevertheless, the Government has stated that it intends to work to limit emissions to the level specified for Australia in the Kyoto Protocol[8].
- The only CRC devoted to renewable energy and efficient energy use has not had its funding renewed, yet there are three federally-funded Cooperative Research Centres devoted to fossil fuels.
- There are large subsidies to the production and use of fossil fuels (Riedy and Diesendorf, 2003; Riedy, 2003) and only small subsidies for renewables, most notably the temporary waiving of excise on ethanol and other bio-fuels produced from crop residues[9].
- The only industry and market development initiative for renewable energy is the Mandatory Renewable Energy Target (MRET). This has proven highly successful in driving investment but by 2010 it will have delivered less than a 1% increase is renewable energy use in Australia over 1997 levels. Compared with double figure targets in the EU and US states, this is insufficient to create internationally competitive renewable energy industries.

1.2. Structure of this report

Chapter 2 sets out the assumptions and method of this study. Chapter 3 reviews current energy demand and supply in Australia, drawing upon the latest published data (2000-01), and explains the basic concepts and terminology. Chapter 4 presents the economic model that is used to derive the energy demand in 2040. This generates the Baseline scenario which only has a weak implementation of efficient energy use. Its demand in 2040 is 57% above that of 2001. Then in Chapter 6 a medium-strength of efficient energy use is implemented, producing a new, lower level of energy demand for 2040, which we term the Medium Efficiency case. Even in this case, demand in 2040 is 25% higher than in 2001.

In Chapter 7 we turn to the supply side, considering the principal existing renewable energy technologies that could make contributions to our ‘clean’ energy scenarios. Chapter 8 summarises basic information on the fossil fuelled technologies. Chapter 9 brings this information to bear by specifying ways to increase the efficiency of energy supply and switch to fuels and technologies with lower greenhouse emissions.

[8] An 8% increase compared with the 1990 level.
[9] The Government plans to commence phasing out the excise exemption from biofuels and LPG in 2008.

The supply and demand sides are integrated in Chapter 10, where a Baseline – Scenario 1 – is specified with CO_2 emissions 21% higher than in 2001 and contrasted with a Clean Energy – Scenario 2, in which CO_2 emissions are 50% lower than in 2001 and 59% lower than in Scenario 1. Two variants on Scenario 2, Scenarios 3 and 4, are also constructed. The low emission scenarios all have a very large reduction of emissions from electricity generation, and modest increases in emissions form all other stationary energy applications. One of the main problems in comparing the costs of various scenarios is the uncertainty in the prices of fossil fuels in 2040. So the costs of Scenario 2 are compared with those of four different fossil fuel scenarios, each with a large proportion of coal.

Chapter 11 removes the restriction limiting the analysis to small improvements to existing technologies. It finds that, starting from Scenario 2, there are several possible pathways for achieving 80-100% reductions in CO_2 emissions from stationary energy in the period beyond 2040. These pathways are all based on substantial improvement to existing technologies that are currently commercial but only in small markets.

Since the barriers to achieving Scenario 2 is not primarily technological, the proposed policies and strategies for facilitating the transition are set out in Chapter 12. These appear to be inexpensive and achievable, given appropriate policy settings. Finally, Chapter 13 reviews some earlier studies from Australia and overseas that investigated deep cuts in greenhouse gas emissions.

2. Methodology and assumptions

2.1. Study method

Scenario back-casting

This study is concerned with the demand for energy services by Australians and the Australian economy, and the mix of fuels and technologies which could be used to meet that demand. For addressing future energy supply it uses an approach that is commonly termed ‘scenario back-casting’.

The essence of the back-casting approach is that it first leaps a considerable number of years into the future – in our case nearly 40 years – to describe, in some detail, possible patterns of energy demand and supply at that time. The range of possible futures is of course very large, even when constrained by realistic assessments of technological capabilities and available energy resources. However, the objective of this study is to explore whether it is realistically possible to achieve significant reductions in greenhouse gas emissions associated with the supply and use of energy in Australia. We therefore describe an energy future which places strong emphasis on efficiency in energy use and reliance on renewable energy in energy supply.

The choice of the 36 year time horizon is deliberate and important. It is long enough for almost all existing energy supply infrastructure and almost all energy using plant and equipment to be fully amortised, and therefore replaced with higher efficiency and/or lower emission equivalents without costly write-offs. It is also long enough for a large fraction of existing residential and commercial buildings to either be replaced or, if not replaced, to undergo one major refurbishment. Consequently, over the 36 year period, major improvements in energy efficiency can be achieved at minimal economic cost.

However, these efficiency improvements will only occur if, from now on, investments in new energy infrastructure and equipment are made on the basis, not of today’s costs of energy and greenhouse gas emissions, but on the basis of costs that can be expected to apply over the whole economic life of the investment concerned. This will not occur unless governments, and particularly the Commonwealth government, provide the certainty that investors require by establishing the appropriate long term policy framework.

For estimating future demand for energy, this study uses both back-casting and forecasting. The starting point for forecasting, as for any approach to projecting into the future, is the actual pattern of energy use and the actual structure of the economy in the most recent past year for which the necessary data are available. That year for this study is the financial year 2000-01, referred to as 2001 for brevity. Australia’s pattern of energy use and supply in 2001 is described in Chapter 3 and the structure and size of the economy are described in Chapter 4. In Chapter 5 we allow economic growth to drive the growth in energy demand, a forecasting method. However, in Chapter 6 we apply the full economic potential (defined in that Chapter) for efficient energy use to cut back on this demand in 2040, thus drawing upon a method similar to back-casting.

All these steps, and the linkages between them, have been built into a spreadsheet model, especially developed for this study. Figure 2.1 shows the structure of the model, and readers may find it helpful to refer regularly to this Figure as they read the next few descriptive pages.

Chapter 7 offers an up-to-date account of renewable energy technologies and Chapter 8 does the same concisely for fossil fuel technologies. Chapter 9 is the essence of back-casting, where we choose a much cleaner mix of energy supply technologies than is used in 2001 to meet the energy demand with enhanced energy efficiency.

The Australian economy in the future

The objective of the study is also to describe a future for Australia in which all the major economic activities which make up today's Australian economy are still represented, and in which the overall size of the economy is significantly larger than it is today. This study does not envision a future that is radically disconnected from today's economy and society, because to do so would involve great economic waste and inefficiency and potentially significant social disruption and hardship for many.

Our projected 2040 economy is in effect an extrapolation from today's economy, with changes in the relative size of sectors within the economy, reflecting our "most likely" expectations of the changes that will occur. This is essentially a highly conservative approach to describing the future. For the most part, our projected sizes of the various economic sectors are unaffected by our views about the most likely national and global context so far as energy costs and availability and greenhouse emissions are concerned. The exceptions are those sectors that are particularly exposed to these issues, of which the most important are the productions for export of coal, LNG, alumina and aluminium metal.

Such an approach is explicitly designed to demonstrate that, with good policy and planning, in the future we can still live a life that is remarkably similar to that which we live today. The source of energy will be quite different, but the uses to which it is put need not change radically.

The approach we take to projecting the future economy is described in detail in Chapter 4. It should be noted that there, and throughout this report, the sectoral disaggregation we use to describe the economy has been designed to focus particular attention on those sectors which use the greatest amounts of energy. This involves disaggregating to a fairly low level in some parts of manufacturing industry, and greater aggregation elsewhere in the economy.

We also distinguish those economic sectors which are concerned with the supply of energy to the rest of the economy and whose level of activity therefore depends directly on the demand for energy from the rest of the economy. The most important of these industries is electricity generation and supply, but they also include petroleum refining, natural gas processing and supply and a few others. While the level of economic activity within these sectors, which account for only a small fraction of total GDP, is specified exogenously, as for all other sectors, their demand for energy is determined endogenously within our model of the energy economy in 2040. The analytical logic behind this distinction is described more fully in Chapters 3 and 4. The economic projections are fully consistent with our assumptions about the global energy future, in terms, for example, of international demand for fossil fuels and for metals, but have been prepared independently from (exogenous to) the main energy system model. The economic projections are shown in the top right hand sector of Figure 2.1.

The scenario approach we use in this study to explore our energy and greenhouse future differs significantly from the modelling approaches that are more familiar to most participants in Australian energy policy debates. We use back-casting for energy supply, together with a combination of forecasting and back-casting for future energy demand. However, traditional approaches are purely forecasting and are based on economic modelling to estimate levels of energy consumption associated with future levels of economic activity. The advantages of these models is that they incorporate feedbacks between energy and greenhouse costs and prices, and the demand for energy from and overall level of economic activity in various sectors and the economy as a whole. In this sense they provide a more realistic way of representing the interaction between the energy and the economy as a whole.

The great drawback of such models is that they usually rely largely (in some cases exclusively) on past relationships between economic activity and the requirements for the various inputs to economic activity – labour, capital, energy, and other material inputs to determine how the economy will respond in the future. Yet these relationships are largely determined by the technology used and the policies in place at the time. If the policy question being asked is “How can changing technology affect the requirement for energy from a given level of economic activity?”, such models are effectively useless, because they define away the topic of interest. All the models can say is what the future may be like if there are no technology changes affecting energy use efficiency. This is not a great problem if projecting a relatively few years into the future. But the longer one projects, the more unrealistic the fixed technology assumptions become.

Economic modellers have attempted to address this concern by adding an additional so-called endogenous energy efficiency improvement factor, again determined by examining past relationships between economic activity and energy use. This factor is commonly set at rates of between 0.5% and 1% per annum. Only in recent years have more sophisticated attempts been made to incorporate processes of technology adoption into the models, and examples of this practice (which is very complex) remain few.

Another weakness of the standard economic modelling approach is that, in its simple form, it assumes that the complex network of policies, institutions, organisational structures and practices that determine the framework within which markets for energy services operate also remains unchanged. Again, more complex models can describe the consequences of particular policy changes, but these have to be individually characterised to do so. Moreover, since the existing market framework is implicit within the relationships between model parameters, not explicitly defined, it is hard to be confident that the exogenous introduction of a few explicit policy changes will accurately capture their full ramifications across the economy.

This kind of economic model is obviously also poorly suited to capturing the consequences of major external events which impose discontinuities on key parameters, such as a change in the world oil price or the emergence of a significant new technology, or, indeed, significant impacts from climate change on the economy or infrastructure.

All in all, the economic modelling approach finds it difficult to describe a future that is anything other than a continuation of the recent past with all relationships unchanged. It is for this reason that studies that seek to look longer into the future almost always use some variant of the scenario back-casting approach we use in this study.

This approach avoids the difficulties associated with the economic modelling approach by asking a different question: not "What *will* or *may* the future system of energy supply and use be like?" but "What *could* it be like?" Assuming the adoption of new or improved technologies is central to this modelling approach. So too is the subsequent question: not "What *will* or *may* be the effect of policies A, B or C?" but "What policies will take us from where we are today to the future described in our scenario?"

These are the questions which this study seeks to address.

Energy demand in the future economy

The next step in our method is to estimate the levels and types of demands for energy services in 2040 which will be generated by our projected levels of economic activity that year. Our starting point is the structure of energy demand in 2001. We first reallocate energy use by sector into two groups: those sectors concerned with producing and processing energy for use by the rest of the economy, and the remainder, making up the great majority of the economy. These are termed respectively Energy production and processing and Final demand. These terms are explained more fully in Section 3.1. The split into these two groups can be seen in the middle of the top of Figure 2.1.

Demand in 2040 is estimated in Chapter 5, by examining each sector in turn to see how its energy intensity has been changing in recent years and consider how it may change in the future. Energy intensity means energy demand per dollar of value added in the sector concerned. If the energy intensity of an economic sector does not change, then any change in value added (the economic size) of a sector will result in a proportionate change in energy consumption.

This is seldom the case, because a number of dynamic factors affect energy intensity. The two most important of these, and the ones which we explicitly model, are structural changes within a sector and long term trends in the technical efficiency of energy use.

Regarding structural change, it is quite clear that in some sectors, such as Food etc. and Chemicals, the dematerialisation[1] trend, which can also be described as a trend towards greater value adding, is significant and long term. Similarly, regarding energy efficiency, it appears that in many of the more energy intensive sectors of manufacturing there is a longstanding gradual trend towards increased energy efficiency. This is to be expected; it is in these sectors that energy purchases account for the highest proportion of the total cost of production and, consequently, in which new, more efficient energy using technologies are likely to be of most effect and therefore most quickly adopted as they become available. However, some energy-intensive industries are heavily subsidised and so do not reach their full potential for implementing energy efficiency.

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[1] The term dematerialisation is used to describe the process whereby advanced economies become relatively less dependent on the production of material commodities and their conversion into physical goods, and more dependent on the production and consumption of services, with the result that the consumption of raw materials per unit of GDP decreases.

The study uses a total of 15 final energy consumption sectors, i.e. excluding the endogenous energy supply and processing sectors. Energy use in each sector is distributed between the following six groups or types of fuel:

- coal, including coke
- biomass fuels
- petroleum products, including LPG
- natural gas (including coal seam methane)
- solar heat
- electricity

For each of the sectors used in our modelling we estimate the contribution which internal structural change/value adding and long term energy efficiency increases will make to energy intensity. For each sector, these factors are assumed to be the same for each type of fuel used in the sector. We then combine these factors with the projected growth in economic output for each sector to calculate what we term Baseline energy demand for 2040. This is effectively equivalent to what is commonly called business-as-usual demand, but we find the many connotations of that term unhelpful and potentially confusing, and therefore do not use it in this study.

Increasing efficiency of energy use

It is now almost universally accepted within the energy policy community that all economies contain significant, unrealised opportunities for increasing the efficiency use that are cost effective in technical terms. By this is meant that the annualised capital cost of the new or modified energy using equipment is less than the reduction in energy purchase costs resulting from the new equipment. There is now a voluminous literature on the reasons why markets for energy services fail by not allowing these opportunities to be taken up (see, for example, IPCC 2001b, Chap.5).

In this stage of the analysis we take the baseline demand for energy derived in the previous stage and estimate the economic potential for reducing demand for energy if the full economic potential for use of energy efficient technologies is realised. The precise meaning of these terms is explained at some length in the opening section of Chapter 6. The most important assumptions underlying our analysis are:

- all the technologies used are available and commercially proven today;
- on the basis of the known characteristics of the technologies, they will be cost effective at the level of energy costs expected to prevail in 2040 (see Section 2.2);
- there is no premature retirement of energy using equipment.

The potential for energy efficiency in each sector depends, among other factors, on the purposes or types of equipment for which energy is used in that sector and on the type of fuel used. It was therefore necessary to allocate fuel use to purpose or equipment in each sector. For 13 of the 15 sectors analysed the following equipment types were used:

- boiler systems including cogeneration boilers,
- kilns, furnaces etc.,
- other non-electrical equipment (includes chemical reactor vessels, dryers and others),
- non-electric motors (principally diesel engines and gas turbines) used to provide mechanical power,

- electric motors,
- other electrical equipment (includes electrolysis, lighting etc.).

For the commercial/services sector the following types of energy use were applied:
- air handling,
- cooling,
- heating,
- pumping,
- water heating, cooking etc.,
- lighting,
- other.

For the residential sector the following types of energy use were applied:
- water heating,
- space heating and cooling,
- cooking,
- electrical appliances.

An estimate of the economic potential for increased energy efficiency for each type of fuel used for each type of equipment in each sector was made, based on our extensive reading of the technical literature on energy efficiency technologies and opportunities. In doing so, account was taken of the underlying energy efficiency improvement trend which was identified in some sectors at the previous stage of the analysis. For some of the energy intensive sectors this meant that there was no additional increase in energy efficiency, i.e. the long term trend took up all opportunities for increased energy efficiency, for the reasons given above.

The result of this stage of the analysis is a complete schedule of energy demand by sector, fuel and equipment type, with maximum economic efficient adoption of energy efficient technologies, but no changes in the mix of fuels used, other than those resulting from differential rates of energy efficiency improvement between fuels and equipment types. We term this the Medium Efficiency case.

The reductions in energy demand resulting from more efficient energy use will mean that less energy will need to be supplied, and therefore emissions will be less, to provide the same level of energy services, than if energy were used less efficiently. To achieve further emission reductions, changes will need to be made on the supply side of the energy system.

This study is not directly concerned with energy use in transport. However, transport cannot be ignored, because its demand for energy will affect the endogenous demand in the energy production and processing sectors, and will also have implications for the overall call on energy resources. Accordingly, some relatively simple, default assumptions about demand for transport energy were made. These are described in Section 6.6.

De-carbonising energy supply

In the final stage of the analysis, the focus shifts from demand for energy and energy services to the mix of fuels, energy sources and technologies which can be used to meet the projected demands. The shift is made because opportunities to reduce emissions on the supply side are less costly than further reductions in demand by means of increased energy use efficiency. The key concept underlying this approach is marginal abatement cost, which is defined as the additional cost of the low emission technology compared with "conventional" technology, divided by the quantity of emissions abated, where both cost and abatement are calculated on a whole of life basis. For example, the marginal abatement cost associated with supplying electricity to a house by building integrated photovoltaics, rather than from a coal fired power station through the grid, is equal to the lifetime incremental cost of the photovoltaic electricity at the house, relative to the grid alternative, divided by the lifetime emission abatement.

In a fully specified and detailed optimisation model such as MARKAL (see Chapter 13), demand and supply side options are all evaluated simultaneously[2], and the least cost mix of technologies is chosen. However, it is an almost impossibly difficult task to specify such models for 40 years into the future, and it certainly has not been attempted, let alone achieved, for Australia.

In this study we use what might be termed qualitative optimisation. We make estimates of the costs of all relevant technologies, both supply and demand side, which necessarily cover a range of uncertainty. For energy efficiency, and for some individual supply technologies such as wind, the marginal cost of applying the technology begins to increase as adoption or market penetration becomes widespread (the most egregious cases of inefficient energy use and the best wind resource sites are taken up first and after a time the remaining opportunities become less economically attractive). We use the best available data, coupled with our professional judgement, to determine the proportions of the different technologies, for both energy demand and energy supply, at which marginal costs are equal, and the cost of the energy system as a whole is therefore minimised for a given level of demand for energy services. The shift from demand to supply side focus occurs where we judge that this point lies on the combined supply curve for energy efficiency, i.e. at the point where it is more costly to reduce emissions by further energy efficiency than to do so by switching to low emission supply technologies.

Continuing this step by step analytical approach on the supply side, we successively analyse several distinct groups of supply side technologies.

Firstly, fuel substitution was introduced in a number of sectors. These substitutions mainly involved:

- the replacement of coal and petroleum as fuel for boilers by a mix of natural gas and solar thermal energy,
- the replacement of coal and petroleum as fuel for non-metallurgical kilns by natural gas,
- in the commercial/services and residential sectors partial displacement of natural gas and electricity used for water heating by solar heat.

Secondly, extensive uptake of gas-fired cogeneration of heat and electricity (sometimes termed combined heat and power – CHP) was introduced into all sectors of the economy with demands for low temperature heat (boiler systems in industry, space heating and hot water in the commercial/services sector). Installing a cogeneration system has the effect of

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2 Provided that all relevant technologies are specified in the model, which is often not so in the case of demand side technologies.

increasing the consumption of natural gas in the establishment where the plant is installed, but the increased consumption is much less than the quantity of gas which would be needed to produce the same quantity of electricity in a stand alone power station, with corresponding energy efficiency and greenhouse emission benefits. For modelling purposes, we allocate the estimated additional natural gas consumption required for cogeneration to the electricity generation sector, although in practice this consumption would appear as additional demand in the economic sector where the cogeneration plant is installed.

Thirdly, the electricity supply industry is independently modelled in terms of the mix of fuels and generation types which could be used to meet the demand for electricity at least cost, given the emissions constraint. This constraint is that greenhouse gas emissions from stationary combustion as a whole be reduced to 50% of their level in 2001, while the technical characteristics of the electricity supply mix allows the projected demand for electricity to be met with levels of supply security no less than those provided by Australia's present electricity supply system. Modelling this industry requires the inclusion of three additional types of fuels or energy sources which are important as primary fuels, but not as end use fuels (see Section 3.1 below for a definition of these terms). The additional fuels/energy sources are:

- brown coal,
- hydro,
- wind.

In following this sequence of analytical steps we are in effect allocating the electricity supply sector the role of marginal supplier of abatement. We do this because most of the very low or zero emission technologies, such as hydro, wind and biomass, that are needed to achieve the 50% emission abatement goal, are best suited for the generation of electricity. The result, as will be seen, is that the electricity sector makes a far larger contribution to the overall reduction in emissions, relative to 2001, than does direct use of fuels, such as gas, by end users.

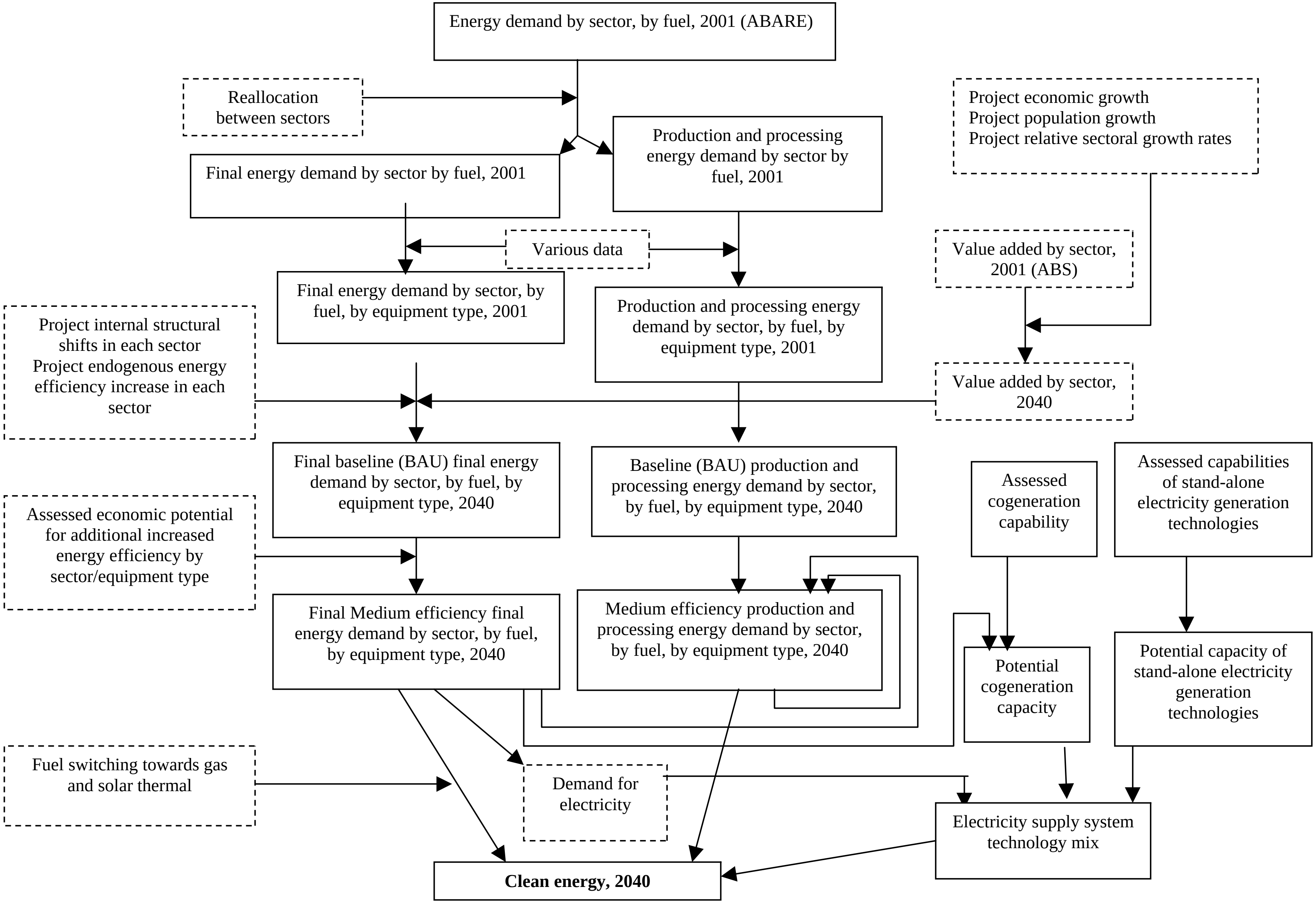
Finally, the demand for energy by the endogenous (energy production and processing) sectors was determined. This was done by using the change in demand for the different types of fuel from 2001 to 2040 to determine the activity level in each of the industries concerned and applying additional improvements in energy efficiency as relevant to the types of activities involved. These calculations involved feedback loops, because each of the industries concerned uses some of the energy it produces itself and/or is produced by the other energy supply industries. This can be seen in the middle towards the bottom of Figure 2.1.

The end point of this modelling is a complete schedule of energy demand by fuel, equipment type and economic sector in 2040, which can be compared directly with the actual pattern of energy demand in 2001. The CO_2 emissions resulting from the mix of primary fuels consumed are calculated, and both energy demand and CO_2 emissions compared with the corresponding figures for 2001. Combustion related emissions of other greenhouse gases are ignored, as these are generally very small (other than in transport) and in any case are roughly proportional to CO_2 emissions, and so do not affect the relativities between fuels.

Readers should note that this is one of a number of detailed methodological differences between this study and the National Greenhouse Gas Inventory (NGGI). Other differences relate to classification/allocation; for example, the NGGI classifies the very considerable CO_2 emissions from iron and steel production as an industrial process rather than an energy sector emission, and allocates these emissions accordingly; the treatment of chemical feedstocks also differs. For these reasons, the emission estimates for 2001 in this study differ from those reported in the NGGI[3], but the differences are systematic and the two can be reconciled, albeit with a number of detailed adjustments.

[3] Specifically, the NGGI figure for 2001 stationary energy emissions of CO_2 is 257.1 Mt and the figure used in this study is 261.7 Mt. The NGGI figure for emissions of all greenhouse gases is 259.5 Mt CO_2-e.

Figure 2.1: Structure of energy system model



2.2 Future energy costs and prices

The price of energy from different sources is a fundamental element of any study of the energy system today and of how the system may change in the future. Energy prices have the following effects.

- The general or average level of energy prices is one factor determining the level of demand for energy, not because consumers actually want to use more energy *per se* when it is cheaper (though they usually want to use less when it is more expensive), but because more technically efficient energy using equipment is often (though by no means always) more expensive, and cheap energy makes it less cost effective to invest in more efficient equipment. For example, in the early 1980s, demand for energy fell rapidly around the world in response to the much higher level of energy prices, following the second oil shock. When prices fell again from the mid 1980, this trend slowed greatly in most countries and in a few actually reversed, as investment in more efficient equipment slowed.

- Changes in energy prices also affect the relative prices of energy intensive products and services, relative to less energy intensive products and services, and so affect consumers' patterns of spending. For example, when oil prices are low, airline ticket prices fall relative to other goods and more people travel by air, other things being equal, leading to an increase in energy demand, because air travel is a very energy intensive activity.

- The relative level of energy prices is a major influence on choice of fuel and of energy supply technology. Looking back twenty five years or so, the oil price rises of the 1970s resulted in the widescale replacement of petroleum products by natural gas and, to a lesser extent, coal, in most stationary energy applications. Today, in the National Electricity Market, it is the relative prices of electricity supplied by coal fired and natural gas fired generators that determines the mix of fuels used for electricity generation. Without the Mandatory Renewable Energy Target program, the relative price of electricity from renewable sources such as wind would almost totally exclude these sources of generation from the Market.

It should be noted that throughout this discussion we have referred to prices, and not costs. Cost affect prices, but they are not the only factor to do so. The behaviour of market participants will affect how they set prices in relation to their costs. Prices will also be affected by the structure and rules of the particular market concerned, noting that all markets are social constructs, and as such given structure by laws, rules and societal decisions. For example, in the National Electricity Market, market rules specify that transmission costs are averaged across the whole market, rather than being charged to individual generators who use the transmission network to deliver their electricity to consumers (except in the case of new entrant generators, which do have to pay their own costs for accessing the grid). This rule means that in South Australia, electricity from distant coal fired power stations in NSW is cheaper to buy than electricity from local gas fired generators, which would not be the case if the coal fired generator were bearing the cost. The result is that electricity is produced by high emission coal power stations rather than lower emission gas power stations, and that more electricity is transported over longer distances with proportionately greater losses, an outcome which is perverse both for the economy and the environment. In its submission to the National Electricity Code Administrator in April 1998 on the transmission and distribution pricing review, the Commonwealth Government expressed similar concerns:

> "Current arrangements, which restrict transmission charging to generators to shallow entry costs, while leaving the bulk of costs to be recovered from customers, provide a substantial subsidy to remote, usually coal fired generation to the competitive disadvantage of more greenhouse friendly natural gas and renewable generation typically located closer to loads. Pursuit of demand management options is also acutely disadvantaged. (p 7)

What energy prices are we projecting for our 2040 scenarios? This is a complex question that confronts everyone who tries to think about energy futures, and requires a fairly complex answer, in several parts.

Firstly, the most important single influence on energy prices everywhere is the world price of crude oil. This directly determines the price of all petroleum products and indirectly affects the price of most other energy sources. As is now well recognised, many factors influence the world oil price. Some relate to the supply/demand balance and the cost of producing crude oil, and can in principle be investigated by quantitative modelling. Many others, however, are political and geopolitical in nature; they may be qualitatively predictable, although there is always wide disagreement between analysts, but they are certainly not susceptible to quantitative modelling. Consequently, all models as well as other energy future studies specify future world crude oil prices exogenously, on the basis of a qualitative consideration of the relevant factors.

Our view is that by 2040 the balance between potential demand for crude oil and available supply will have shifted markedly from what it is today (Hall et al., 2003). We do not adopt the more apocalyptic visions of a world where oil production has collapsed. But we do take the view that the cost of production from the marginal source of crude oil will, as always, set a floor under oil prices over the long run, and that this cost will be substantially higher than it is today.

Secondly, international commodity prices for coal and natural gas (as LNG) will be affected by the higher crude oil prices, as they are both partial substitutes for petroleum products. However, the prices for these other fossil fuels will also be affected by their own supply/demand balance and their own costs of production. Regarding the supply and demand, we expect that coal supply will comfortably exceed potential demand. For natural gas, the supply situation in 2040 will also be fairly comfortable, particularly in the Asia-Pacific region, though it may become much less so later in the century. Regarding cost of production, for coal we do not see much scope for a continuation of the increases in mine productivity, which have enabled the industry to remain profitable despite steady falls in real prices over recent years, reflecting an excess of supply over demand. Indeed, we consider it more likely that costs of production will rise as the industry moves towards mining thinner or deeper seams with more overburden. Regarding LNG, we also expect that costs of production will rise as the industry exploits smaller reserves in deeper or more intractable fields.

Thirdly, we assume that the world of 2040 will be subject to significant constraints on emissions of fossil CO_2 and other anthropogenic greenhouse gas emissions. The costs of this constraint will be internalised into the international traded prices of sources of these emissions, increasing the price of all fossil fuels. Coal will be the most severely affected fossil fuel and natural gas the least affected.

How will these factors affect prices in the Australian domestic energy markets?

In the case of petroleum, we assume that Australia will be a net importer and will have to pay the going world price, whatever that may be. In the case of natural gas, a more complex situation applies. At present, and for some years to come, the large gas reserves in north west Australia are not accessible to the major domestic markets in southern and eastern Australia. This means that domestic and export markets are not substitutable, and makes it possible for domestic wholesale prices to diverge. We project that by 2040, however, there will be a transcontinental pipeline, carrying gas from west to east and allowing domestic and export prices to converge. Nevertheless, constraints on infrastructure capacity may mean that the two markets are not completely substitutable. The relative levels of export and domestic prices will be determined by the supply/demand balance in each market.

The relationship between domestic and international coal prices is still more complex and less direct. Some black coal currently used for electricity generation could be directly substituted into export markets (given the required transport infrastructure) but other power stations use lower quality coal. Victorian brown coal has no alternative use at all, i.e. its opportunity cost is zero, and thus could continue to be priced, as it is today, at the cost of extraction, which is extremely low. The resultant price of electricity generated from this coal is thus determined by the extraction cost of coal, plus the capital and operating costs of the power station. By similar reasoning, the opportunity cost of most renewable energy resources is zero, and the price of wind or solar thermal electricity will be determined entirely by the cost of building and operating the generation equipment.

If Australia is unconcerned in 2040 about its level of greenhouse gas emissions, it will, in principle, have the option of continuing to price fuels such as brown coal at close to extraction cost and use them to generate low cost electricity. Coal will continue to be the predominant fuel for electricity generation, emissions will continue to grow, in defiance of probable international trends and opinion, but Australia will have “cheap” electricity. It seems much more likely, however, that Australia will seek to place some limits on greenhouse gas emissions. As is now acknowledged by all governments in Australia, this can only be achieved by limiting the emissions from using coal to generate electricity. Several options are available: use “end of pipe” technology, such as CO_2 capture and geosequestration, levy a carbon tax (with or without emissions trading), or limit coal fired generation capacity by regulatory action. We discuss these alternatives in later Chapters. From an economic perspective, however, they will all have the effect of increasing the cost of coal fired electricity. In other words, their effect will be the same as increasing the input price of coal.

To summarise, therefore, we expect that in 2040 the prices of all fossil fuels will be significantly higher than they are today. In the case of coal, we note that this higher price may arise from the cost to the user of technology to make coal “clean”, or from the scarcity value of a regulatory "right" to use coal for electricity generation, rather than the price at which a generator can obtain coal itself. It will be important to recognise this distinction in undertaking subsequent analysis and modelling; for example, the more that demand can be reduced by energy efficiency, the more scope there will be to use conventional coal fired electricity and the lower the cost will be of the "right" to use coal, all else being equal.

Many greenhouse related energy policy studies use economic models, with feedback between price and demand, in an attempt to estimate the additional cost of achieving defined levels of abatement of energy related greenhouse gas emissions. However, such models require the exogenous specification of energy prices, exclusive of any greenhouse abatement costs, which means that the modeller faces the heroic task of making judgements about the effect on energy prices of all the other highly complex factors described above. In addition, we consider, as explained in Section 2.1, that these models contain deficient descriptions of the mechanisms through which energy prices and demand for energy interact, because they do not contain adequate characterisations of energy efficiency technologies and the processes driving the choice of such technologies. Consequently, we consider that the apparent precision of estimates of the cost of reducing greenhouse emissions from the energy sector, provided by such models, is largely spurious.

The spreadsheet model which we use for this study defines all components of energy prices, including any greenhouse related component, exogenously. Our modelling of both energy efficiency and renewable energy supply technologies is not so detailed as to require precise estimates of prices, which would, in any case, be of little value for the purpose, since the costs, forty years hence, of the various energy technologies on both demand and supply sides are quite uncertain. Approximate costs of technologies and energy systems are discussed in Sections 7.12, 9.5 and 9.6.

Much of the rest of this report is devoted to estimating the economic potential of energy efficiency technologies and determining a least cost mix of low emission energy supply technologies. The price assumption underlying our modelling of the low emission scenarios is that prices of primary fossil fuels across the board will be between 25% and 50% higher than they are today in real terms. The lower end of the range will apply to low grade coals, which have no alternative markets, and the upper end will apply to petroleum (net of taxes), and may well be an understatement. In addition, if the prices of these fuels come to reflect their full external costs, it is likely, as discussed in Chapter 10, that the increase in cost of derived fuels, such as electricity, and of the energy system as a whole, will be somewhat greater.

We also prepare a baseline or business as usual scenario in which prices of coal, and hence coal fired electricity, are assumed to be little different from today.

Finally, we have not linked these assumptions about energy prices to our projections of the economy of 2040, contained in Chapter 4. We do not consider that such energy price increases would have any significant effect on overall economic growth, since the relative prices of energy compared to the rest of the OECD are likely to remain largely unchanged. However, the increases will express themselves as significant cost increases for some of the energy intensive sectors of the economy. We have not attempted to include such effects in our projections for these sectors. For that reason, it is probable that our modelling over-estimates the level of energy demand in 2040.

3. Energy in Australia today

3.1. How energy systems are described

For this study we use the energy balance method of describing Australia's supply and use of energy. This is the internationally accepted method of presenting energy statistics in a standardised format. The energy balance approach is based on a physical understanding of processes for supplying and using energy, but is also consistent with a common sense economic understanding of energy, moving through successive stages of production, supply (or delivery) and use by final consumers.

This representation of the energy system is greatly facilitated by the use of a single common unit for measuring quantities of energy. Australian energy statistics use the petajoule (abbreviation PJ), equal to 10^{15} joules, as the unit. All energy data in this report are expressed in PJ, or smaller multiples such as terajoules (TJ), gigajoules (GJ) of megajoules (MJ). Discussions of electricity alone usually use units of terawatt-hours (TWh), and smaller multiples GWh and MWh. 1 TWh = 3.6 PJ. (See also page viii on Units and Conversion Factors.)

Energy balances start with the extraction or harvesting of what are termed primary fuels; these include fossil fuels such as coal, crude oil and natural gas, which are extracted from the earth, and renewable energy sources such as wind, hydro, biomass and solar thermal energy, which are harvested from the atmosphere, from rivers, from the sea or directly from solar radiation.

Some of these sources of energy can be and are used directly by final consumers, but many of them undergo conversion or transformation to end-use fuels, which are more convenient or efficient for final consumers to use. The most important energy conversion processes are thermal electricity generation and oil refining. Each of these processes uses considerable quantities of energy, so the quantity of end-use fuel produced is significantly less than the quantity of primary energy going into the conversion process. Further quantities of final energy are used or lost in the process of delivering to final consumers. As a result, the total quantity of energy available for use by final consumers is significantly less than the quantity of primary energy supplied to the economy.

The third and last stage of the energy balance representation is final consumption by end users of energy, who use energy for all activities other than the production of energy in another form.

For most forms of renewable energy other than biomass, the distinction between primary and final energy has less practical significance. For example, the total quantity of energy contained in a mass of falling water or moving air is of little practical importance for the energy system unless or until it is converted into final energy, usually in the form of electricity. Therefore the quantity of primary energy produced from these sources is defined by the quantity of hydro or wind electricity which can be produced by generators installed to harvest these renewable resources. Engineering improvements which increase the efficiency with which the energy is captured are expressed as increases in the available hydro or wind resource. Similar considerations apply to direct solar thermal energy. Some of the energy generated is lost in transmission and distribution to the point of final consumption. Therefore, in all these cases, the quantity of final energy is equal to the quantity of primary energy produced less transmission and distribution losses.

Economic descriptions of the energy system usually refer to energy being consumed through these processes. In physical terms, however, energy is not (and cannot be) consumed. Rather, it is converted from a highly concentrated form, notably as the chemical energy contained in fossil fuels, to other forms, such as the chemical energy in an aluminium ingot or the mechanical energy of a rotating pump. Ultimately, most of the energy used by final consumers ends up in the form of low grade heat. The difference between the chemical energy of a fossil fuel and low grade heat is that the former contains far more *useful* energy than low grade heat. (Note that the energy contained in low grade heat has not disappeared, but rather has dispersed into the general environment; it is obvious, for example, in the so-called urban heat island effect, whereby the climate of large cities is typically a few degrees warmer on average than the climate of rural areas surrounding the city.)

The physical concept of useful energy is a key to understanding the potential for improvements in technical energy efficiency. In general terms, efficiency is maximised by maximising the quantity of useful energy which can be obtained from a given quantity of fuel supplied to a process or activity. Most energy efficiency technologies represent ways of applying basic physical principles, such as temperature cascading, to energy using processes, so that extraction of useful energy is increased. The concept of useful energy is also important in understanding many renewable energy technologies. Renewable energy sources occur naturally in a relatively diffuse form, from which it is difficult to extract much useful energy. Most renewable energy technologies aim to extract energy from the environment and deliver it to consumers in a more concentrated form, such as electricity, from which much more useful energy can be extracted.

Electricity obtained from renewable sources, such as hydro and wind, appears in energy balance tables as a form of primary energy, which is supplied directly to final consumers with no intermediate conversion step (but with some proportionate loss in transmission and distribution). The system of energy statistics, which was constructed to suit the centralised, fossil fuel based energy economies of the mid-20th century, has some difficulties in accommodating more extensive use of some forms of decentralised renewable sources of primary energy, because these are often not measured.

Energy statistics have always had difficulty dealing with biomass fuels, such as fuel wood and crop residues, when these are directly collected by final users and do not pass through any market transaction. For this reason, statistics on biomass energy use are subject to a high level of uncertainty. A different sort of uncertainty is associated with figures for the solar contribution to the total energy provided by a solar water heater, which is also not measured, but in this case for reasons of technical practicality, and can only be estimated by indirect methods with a high level of uncertainty. The same usually goes for the electrical energy supplied to a house with a rooftop photovoltaic panel. For yet other ways in which solar energy is used, such as passive solar heating of buildings, it is not even sensible to try to estimate quantities of energy being supplied. It is much better to think of passive solar building design as a type of energy efficiency. Solar water heating and other forms of active solar heating can be similarly thought of as technologies which greatly multiply the useful energy, or, more accurately, the quantity of energy services that can be extracted from a given quantity of energy supplied by conventional (mainly fossil fuel based) energy systems. Of course these measurement difficulties do not arise with renewable energy sources such as wind, which are converted directly to electricity and fed into the supply system, together with electricity generated from fossil fuels.

In this study we have adopted the following conventions for presenting data on energy.

- Passive use of solar energy to heat buildings (and to provide other services, such as clothes drying) is not shown directly, but is expressed as reduced demand for other energy sources to provide the heating and other energy services concerned.
- Active use of solar energy to produce hot water or steam is shown as an energy source, the quantity of which is defined by the amount of alternative (usually fossil) fuel it displaces. This is important to give some idea of the size of the contribution this source of energy can make to meeting Australia's energy demand and of the investment in active solar thermal systems which will be required. The small quantities of electricity used by these generating systems are ignored.
- Renewable energy sources used to generate electricity, such as hydro, wind and direct solar radiation (whether captured by photovoltaic devices or solar thermal electric systems) are defined by the quantity of electricity they supply. Note that this differs from the approach sometimes adopted in international energy statistics, by which renewable sources of electricity are defined in terms of the quantity of fossil fuel they displace, assuming that the fossil fuel is used to produce electricity in a thermal power station with a typical First Law efficiency (33% is normally used).
- Biomass energy sources are defined, like fossil fuel sources, by the quantity of heat energy they release when they undergo complete combustion, i.e. when they are fully oxidised. Note that Australian energy statistics define the calorific value of fuels in terms of their gross calorific value (sometimes termed higher heating value or HHV). This also differs from common international practice, which is to use net calorific value (sometimes termed lower heating value or LHV)[1].
- In calculating the quantities of fossil or biomass fuels required to provide a given quantity of electricity from a thermal power stations, account is taken of the quantities of electricity used within the power station, which for coal fired power stations in particular are quite large, typically about 7% of electricity generated.

There are several ways, apart from the energy balance, of describing or providing important information about a country's energy system. Two of the most valuable are energy use by economic sector and energy use by equipment type.

Energy use by economic sector breaks the economy down into sectors, defined by the standard classification system used for compiling economic statistics, which for Australia is the Australia and New Zealand Standard Industrial Classification (ANZSIC). This presentation can provide far more detail about how and where energy is used in the economy than the energy balance presentation. However,

[1] See the Glossary for definitions of HHV and LHV

ANZSIC does not recognise the distinction between economic activities which are producing primary energy, processing or transforming primary energy, or using final energy. A good deal of “unravelling” is therefore needed to convert the standard energy use by economic sector statistics into the energy balance format.

Energy use by equipment type is very important for assessing the potential for improving the efficiency of energy use, because many of the technical efficiency improvement opportunities are specific to a particular type of equipment.

The Australian Bureau of Agricultural and Resource Economics (ABARE), the Australian Government body which produces Australia’s energy statistics, provides data in all the formats described here (and in a number of others). The ABARE energy statistics are the main source of data for the modelling work undertaken for this study. The most recent year for which ABARE has published a complete set of Australian energy statistics is 2000-01. We have therefore used that year as the baseline for this study and for the description of Australia’s current pattern of energy use and supply in the next Section of this report.

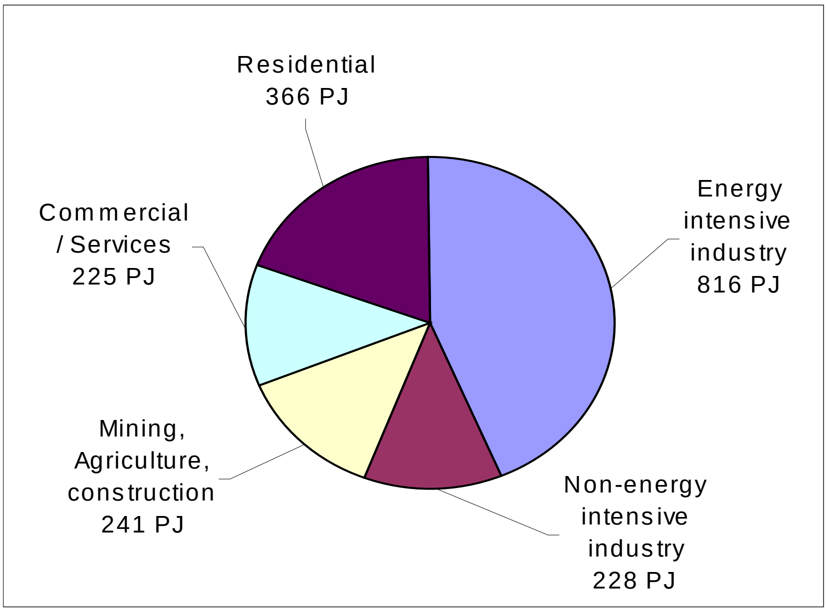
3.2. Australia’s current pattern of energy use and supply

In 2001, total stationary final energy use in Australia was 1,888 PJ. This equals about 97 GJ per head of population. By stationary energy use is meant all energy use other than energy used for transport. This figure has been derived from the energy consumption figures published by ABARE by subtracting fossil fuel (mainly petroleum products) used as solvents, lubricants and bitumen. The estimated quantities of fossil fuels (mainly petroleum products and natural gas) used as chemical feedstocks have also been subtracted. Data on feedstock consumption was in some cases provided on a confidential basis by the chemical companies and in other cases has been estimated, using our knowledge of the industries concerned. Our estimate of the total quantity of fossil fuels used for these non-energy purposes in 2001 is about 5 PJ of coal by-products, 87 PJ of petroleum products and 50 PJ of natural gas and ethane, which is about 3.0% of Australia’s total fossil fuel consumption in that year (measured in energy units).

For the purposes of this study, we have also defined energy use in fuel production and processing to be final energy use, where the fuel produced is exported rather than being used within Australia. Specifically, energy used for mining export coal and energy use for processing and liquefying natural gas that is exported as LNG have been defined as final energy consumption. Australia has a large export trade in crude oil, but this is more than offset by imports of different (mainly heavier) grades of crude oil. We have therefore not included energy used in producing export crude oil in our estimate of final energy consumption.

Figure 3.1 shows how total final energy use was distributed between the various major groups of economic sectors, and Table 3.1 shows a more detailed breakdown of energy consumption by each economic sector modelled in this study. Note that, since the commercial and residential sector are heavy users of electricity, their shares of final energy are significantly smaller than the shares of primary energy required to supply them, as discussed in later Chapters.

Figure 3.1: Total stationary final energy use by major sectoral group, 2001



In preparing these estimates from the original ABARE data, we have subtracted estimates of fossil fuels used for the various purposes described above, and also the estimated incremental consumption attributable to cogeneration of electricity in various sectors. Although this can only be an estimate, given the integrated nature of cogeneration operation, it is a necessary step for the accurate modelling of a major expansion of cogeneration in our future scenarios.

Table 3.1: Final demand for energy, 2001 (PJ)

Economic sector	**Energy consumption (PJ)**	
Mining (incl. LNG and coal exports)	180	
Manufacturing	982	
Iron and steel		178
Food, beverages, tobacco		164
Basic chemicals		76
Cement, lime, plaster and concrete		42
All other non-metallic mineral products		49
Non-ferrous metals		339
Wood, paper and printing		70
All other manufacturing		64
Construction	51	
Commercial/Services	225	
Agriculture/Forestry/Fishing	72	
Residential	366	
TOTAL final stationary energy consumption	1,876	

It can be seen that manufacturing accounted for 52% of the total. We have divided manufacturing into two groups, termed energy intensive and non-energy intensive. Energy intensity, as used here, means energy consumption per dollar of value added from the industry. Examination of the data shows a very clear difference between energy intensive manufacturing sectors and the rest of the economy. The energy intensive sectors of final energy consumption are listed in Table 3.2 below.

Table 3.2: Energy intensive sectors of manufacturing

ANZSIC Subdivision/ Group	Description	Energy intensity 2001 (TJ/$ million value added)
271	Iron and steel	70
252-53	Basic chemicals	34
263	Cement, lime, plaster and concrete	20
261, 262, 264	All other non-metallic mineral products	32
272	Non-ferrous metals	69
23,	Wood and paper product manufacturing	30

These sectors together accounted for 24% of total final energy use (including transport) in 2001 and 40% of total final energy consumption, but only 2.4% of GDP. The average energy intensity of the whole economy in 2001 was 8 TJ per $million. It should be noted that this average includes the energy production and processing industries, such as electricity generation and oil refining, which are also very energy intensive. Transport is also relatively energy intensive. By contrast, the other stationary energy final consumption sectors are far less energy intensive. For example, the intensity of construction is 1.5 TJ/$million value added and the average figure for all service industries is 0.7 TJ/$million value added.

The energy intensive sectors can be further divided into two groups: those which have a predominant or significant export orientation, and those which supply predominantly domestic markets.

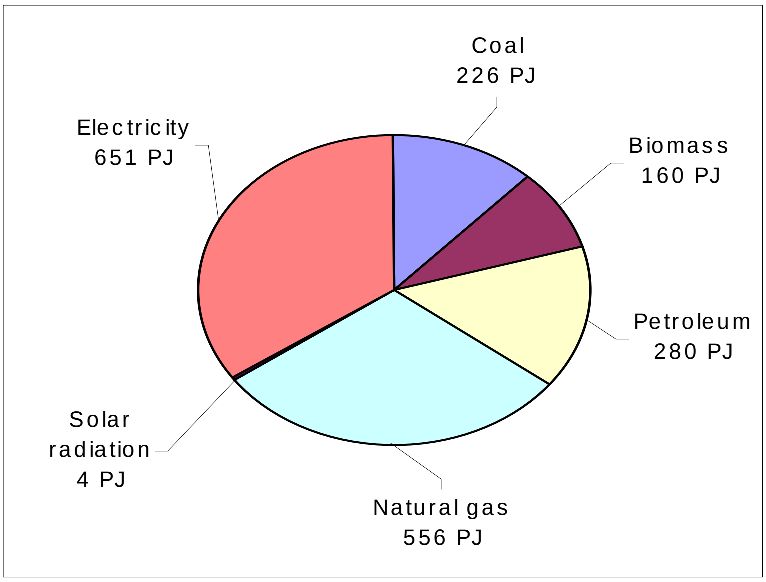
The export focussed groups consist mainly of the non-ferrous metals sector, comprising the production of alumina and aluminium in particular, and also of nickel, copper, zinc, lead and other metals. Production of directly reduced iron (see Chapter 6 for details) is also in this category. While relatively small at present, some analysts expect this to become a major new export industry in the future. Australia also exports significant quantities of steel, but exports have always accounted for less than half of total production. Finally, the production of LNG should be included in this group. However, since there is at present only one LNG producer (the North West Shelf consortium, led by Woodside Petroleum) all relevant economic information about this industry, such as value added, is confidential.

The domestically focussed groups comprise basic chemicals, cement, other non-metallic mineral products, and wood and paper products. At present, none of these sectors has significant exports. There have been sporadic attempts ever since the 1970s to establish some large, export oriented petrochemical manufacturing activities, and several such projects remain under consideration for north west WA. Should one or more such projects be built, the basic chemicals sector would come to resemble the iron and steel sector in having a mix of domestic and export oriented activity.

The energy intensive sectors listed above are all specified and modelled separately in our analysis. The food, beverages and tobacco industry, which is moderately energy intensive, is also modelled as a separate sector. All remaining sectors of manufacturing, which account for the great bulk of value added, but only a small fraction of energy use, are modelled as a single group.

In 2001, a further 1,267 PJ of energy was used in transport. This study is concerned with stationary energy consumption only, so most of the remaining data presented exclude energy used for transport. The mix of the various fuels contributing to total final stationary energy consumption is shown in Figure 3.2.

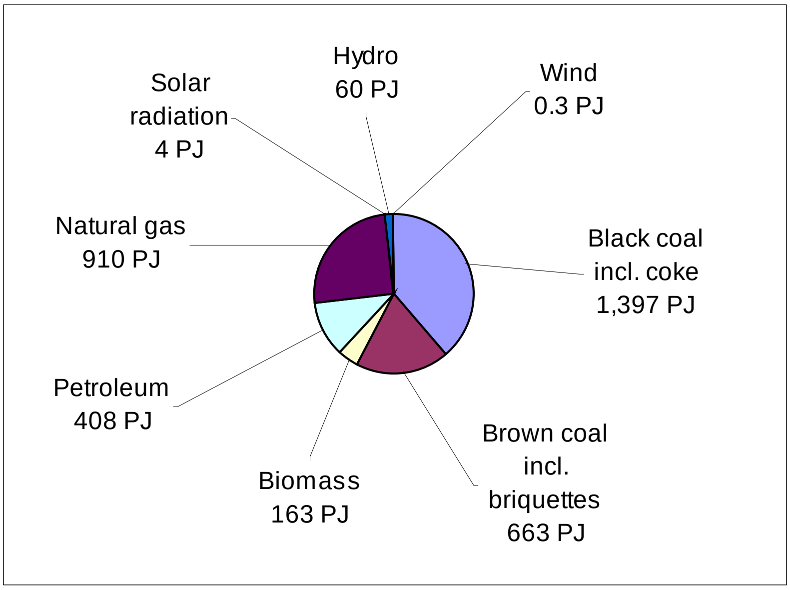
Figure 3.2: Total stationary final energy use by fuel, 2001



It can be seen that electricity and natural gas are the two most important fuels, and relatively small quantities of coal are used in final consumption. When transport is included, petroleum products become the most important fuel used for final energy consumption.

However, as noted in the previous Section, very large quantities of fuel are used to generate electricity and somewhat smaller quantities are used in other energy processing activities, such as oil refining. Total primary energy use in stationary consumption in 2001 was 3,606 PJ. This figure includes all energy use, except final energy consumption of fuels other than electricity for transport, and is equivalent to 186 GJ per head of population. It is this total energy use figure that is the focus of the present study, and the mix of fuels which make up the total is shown in Figure 3.3. It will be noted that it includes energy sources such as hydro and wind that are used directly to produce electricity, following the convention explained in the previous Section. This means that one unit of hydro or wind as primary energy is equivalent to roughly three units of coal or other fossil fuel used for electricity generation. Of the total 3,606 PJ, 2,139 PJ were used in electricity generation and supply, and 229 PJ in other energy processing activities, such as oil refining. It can be seen that coal, most of which is converted to electricity for final use, accounts for well over half of total stationary primary energy consumption. Quantities of petroleum used are relatively modest, as this is predominantly the fuel used for transport.

Figure 3.3: Total stationary primary energy use by fuel, 2001



The modelling of energy demand that we used for this study uses different approaches for final energy demand energy used by the energy supply industries. For the former, the level of economic activity in each sector is exogenously determined, on the basis of projected economic growth, absolute and relative, described in Chapter 4, and anticipated changes in energy intensity of the sector, described in Chapter 5. For the latter, the size of the sector is defined by the quantity of fuel (electricity, petroleum products, coal etc.) which the particular sector produces or processes, and this is determined endogenously by the model. The level of demand for the respective fuels by final energy consumers is the main determinant, but the energy producing and processing sectors themselves also contribute because, for example, some petroleum products are used to generate electricity, and some electricity is used in petroleum refining.

These modelling steps determine the baseline level of demand for each fuel from all stationary combustion sectors. In the subsequent stages of the analysis, enhanced energy efficiency is applied to all sectors. Then active fuel switching towards primary energy sources with inherently lower emissions, such as natural gas, biomass and solar heat, is introduced into the modelling across all sectors.

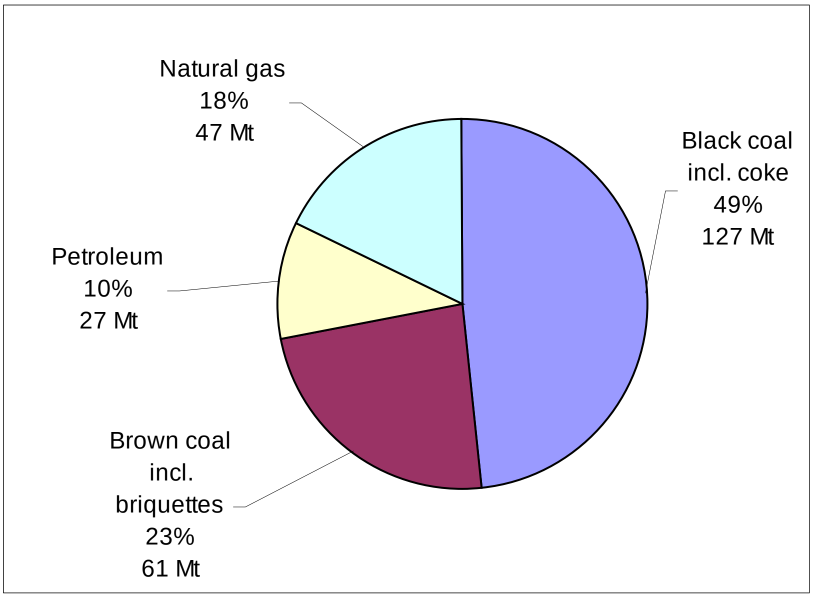
The complete list of energy production and processing sectors used in the model is as follows:

mining of coal for domestic consumption,
production and field processing of oil and gas for domestic consumption,
natural gas transmission and distribution,
electricity generation, transmission and distribution,
petroleum refining,
manufacture of coke,
manufacture of brown coal briquettes.

We assume that the production of brown coal briquettes will cease within a few years.

The primary fuel mix is the most important determinant of the level of greenhouse gas emissions from the energy sector. Anthropogenic emissions of CO_2 from stationary energy combustion in 2001 totalled 262 Mt, which is equivalent to 13.5 tonnes per head of population. The relative contributions to this total of the various primary fuels are shown in Figure 3.4. It can be seen that coal accounts for over 70% of the total emissions. As explained in Section 2.1, in this study we use CO_2 emission as a proxy for total greenhouse gas emissions from combustion of fossil fuels. We also assume that CO_2 emissions from the combustion of biomass fuels do not contribute to anthropogenic greenhouse gas emissions. In this we follow the international greenhouse emission accounting conventions agreed by the IPCC, which specify that if biomass fuels are not produced on a sustainable basis, the resultant CO_2 emissions should be accounted under the category of land use change. Our scenario for 2040 includes a large consumption of biomass fuel and it is of course axiomatic that this fuel be produced sustainably. Chapter 7 describes how this could be achieved.

Figure 3.4: Total stationary energy CO_2 emissions by fuel, 2001

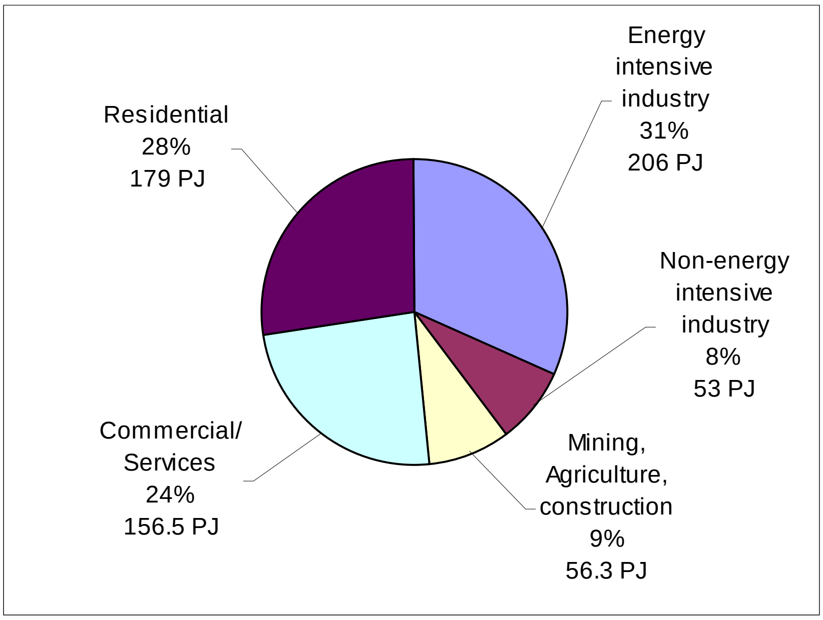


When CO_2 emissions are grouped by sectoral group/activity, it is found that electricity generation accounts for 69% of emissions and all other stationary uses of energy for the remaining 31%. This distribution of emissions of course reflects the fact that most coal is used for electricity generation and most electricity is generated using coal, with over two-thirds of the energy in the coal being lost during generation and delivery. Clearly, if stationary energy emissions are to be halved by 2040, the electricity industry will have to undergo profound changes in the technologies used to generate electricity.

Given the importance of electricity generation, and thus of demand for electricity by final consumers, we conclude this Section with some information about the demand for and the production of electricity.

Figure 3.5 shows demand for electricity by major sectoral group. It can be seen that both the Commercial/Services and the Residential sectors account for much larger shares of demand for electricity than they do of demand for energy in total. This means that measures to limit growth in demand for energy from these sectors, and in particular measures to stimulate greater energy efficiency, will be much more important for limiting greenhouse gas emissions than their shares of final energy consumption might suggest at first glance.

Figure 3.5: Electricity use by major sectoral group, 2001



Figures 3.6 and 3.7 show respectively the mix of fuels used to generate electricity and the CO_2 emissions produced by each of these fuels. The very great importance of coal in both cases can be clearly seen.

Figure 3.6: Primary energy use in electricity generation by fuel, 2001

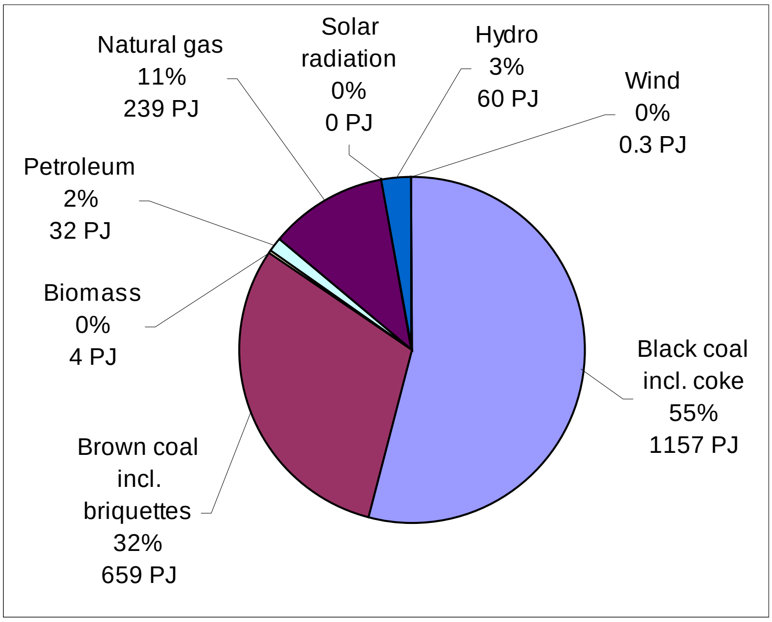
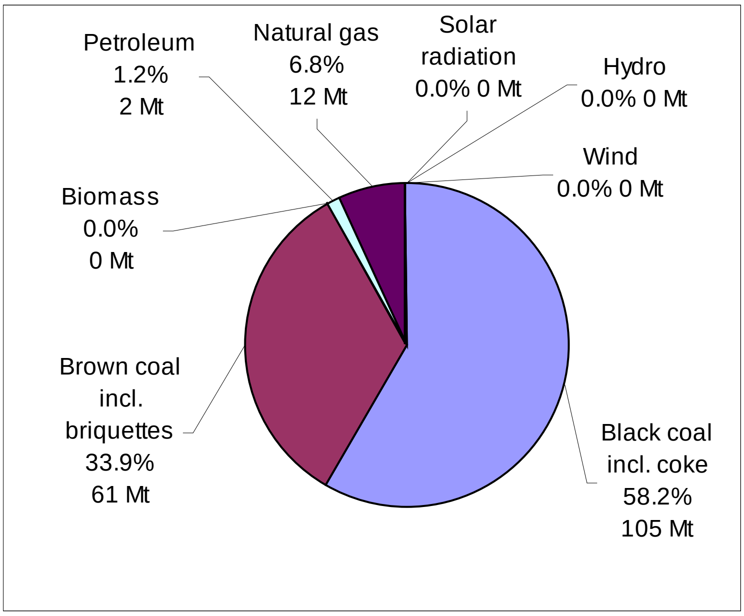


Figure 3.7: CO_2 emissions from electricity generation by fuel, 2001



4. Future levels of economic activity

4.1. Introduction

The level of future economic activity will be a major determinant of the future demand for energy. This section provides an estimate of the amount and composition of economic activity in the years 2013, 2020, 2040 and 2050.

No economic estimates over such a long period of time can be considered to be accurate 'forecasts' as the potential for unexpected technological, social and economic transformations to occur is too great. However, using a range of plausible assumptions it is possible to develop future scenarios which provide a sound foundation for current day policy making.

The long lifespan of electricity generation infrastructure makes it necessary to attempt to describe the economy so far into the future. Decisions made today about electricity generation will still have an impact on Australia's greenhouse gas emissions in 40 years time. The need to scrap electrical generation capacity before it reaches the end of its economic life will significantly increase the cost of greenhouse gas abatement. It is therefore necessary for policy makers to be aware of the future energy needs of the Australian economy, and the capacity to meet those needs from alternative sources, if they are to facilitate a low cost transition to the sustainable emissions of greenhouse gases in Australia.

This chapter is organised as follows. Section 4.2 provides an overview of the methodology used to estimate future economic activity in Australia. Section 4.3 provides a discussion of the contemporary Australian economy and the factors that are likely to shape its development over the next 50 years. Section 4.4 provides the estimates of Australian economic activity for the years 2013, 2020, 2040 and 2050. Section 4.5 offers some conclusions.

4.2. Methodology

The process used to estimate future economic activity is as follows:

1) Determine output by sector for the base year (2001).

The sectoral data for the base year was purchased from the Australian Bureau of Statistics (ABS). For most industries data were collected at the two-digit level in the ANZSIC classification system. However, for some highly energy intensive industries such as manufacturing and mining, more disaggregated three-digit ANZSIC data were used.

2) Determine the growth rate(s) for individual sectors between the base year, the point estimates and the end point.

While most sectors were assumed to grow in line with the economy overall (see below) a number of sectors were assumed to grow faster or slower than average. A discussion of the more significant assumptions concerning sectoral growth patterns is provided below.

3) Forecast the output of each sector.

The sectoral growth rates were applied to the base year estimates of sectoral output to determine the first estimate of sectoral output. Refinements to these estimates, however, are necessary to ensure that the combined output of each sector does not exceed the forecast potential output for the economy as a whole. Steps 4-6 outline the process for estimating future output for the economy as a whole.

4) Determine the total output of the economy in the base year.

ABS output data were purchased as described above.

5) Estimate the potential growth rate.

Long run economic growth is constrained by the available resources and technology. The two factors that are most important in determining the long run rate of economic growth are labour force growth and labour productivity (which is assumed to capture technological change). The rates of employment growth and labour productivity used in the *Intergenerational Report* (Costello 2002) were used in estimating the overall level of economic activity. These forecasts however, end in 2040. The employment and productivity growth rates used in the *Intergenerational Report* for 2040 were therefore assumed to hold until the end of the current analysis in 2050. The forecasts from the *Intergenerational Report* are provided in Table 4.1.

Table 4.1: Growth in labour productivity, employment and GDP

Decade	Labour productivity growth (% p.a.)	Employment growth (% p.a.)	Real GDP growth (% p.a.)
2000s	1.7	1.5	3.1
2010s	1.75	0.6	2.3
2020s	1.75	0.2	2.0
2030s	1.75	0.1	1.9

Source: Costello (2002) p. 30.

6) Estimate output for the end point.

The sectoral growth and overall growth then need to be reconciled. If all sectors were assumed to grow at the forecast average rate of growth then such reconciliation would not be necessary. However, given that differential sectoral growth rates were assumed to exist the sectors for which differential growth were assumed to occur were estimated first and then the average rate of growth for the remaining sectors was estimated subject to the constraint that the sum of sectoral outputs must equal the estimated size of the economy as a whole.

4.3. The contemporary Australian economy

The Australian economy, like that of all developed economies, has been shaped by a wide range of historical, technological, cultural and political forces. The nature and extent of the impact of individual factors on Australia's economic development has been highly contestable in the past (see for example EPAC 1986; Bureau of Industry Economics 1992, Howe 1993, Dao *et al*. 1993) and will, no doubt, continue to remain that way.

That said, it is possible to identify particular trends that have occurred in recent times and, in turn, to suggest trends which may continue or are likely to emerge. As stated above, however, the following estimates can not be considered as forecasts due to the long length of the period under examination and the inevitability of new technological, social and cultural trends emerging.

Table 4.2 shows the share of GDP by industry for Australia in 2000-01. Manufacturing and property and business services are by far the largest industries accounting for 11.6% and 11.5% of GDP respectively. However, given the length of the time period being analysed in this study it is important to note that relative growth rates, rather than current industry size, will be the major determinants of the composition of economic activity in 2050.

Table 4.2: Australian industry share of GDP, 2000-01

Industry	Share of GDP (%)
Agriculture forestry and fishing	3.0
Mining	4.6
Manufacturing	11.6
Electricity gas and water supply	2.5
Construction	4.6
Wholesale trade	5.0
Retail trade	5.1
Accommodation, cafes and restaurants	2.3
Transport and storage	4.9
Communication services	3.2
Finance and insurance	6.3
Property and business services	11.5
Government administration and defence	3.9
Education	4.3
Health and community services	5.5
Cultural and recreational services	1.9
Personal and other services	2.4

Source: ABS 5204.0

Table 4.3 shows the growth rates of each industry for each of the years between 1993-94 and 2000-01 as well as the simple average growth rate over that period. The highest rate of growth has been in the communication services industry, which averaged 10.37 % growth over the period. The lowest growth rate, on the other hand, was achieved in the education industry, which grew by only 1.73 % over the period, less than half the growth rate for the economy as a whole.

Table 4.3: Australian industry growth rates 1993-94 to 2000-01

	Average (% p.a.)
Agriculture forestry and fishing	3.13
Mining	4.75
Manufacturing	2.67
Electricity gas and water supply	2.28
Construction	2.66
Wholesale trade	5.76
Retail trade	3.89
Accommodation, cafes and restaurants	4.89
Transport and storage	4.07
Communication services	10.37
Finance and insurance	4.62
Property and business services	6.23
Government administration and defence	2.42
Education	1.73
Health and community services	3.46
Cultural and recreational services	4.06
Personal and other services	5.10
Ownership of dwellings	4.01
GDP	3.98

Source: ABS 5204.0

It is important to note that energy intensive industries such as manufacturing, electricity, gas and water and construction all grew at well below average over the period 1993-94 to 2000-01. Similarly, industries with low energy intensity, including property and business services and wholesale trade have expanded much more rapidly than the economy as a whole. In other words, the economy is gradually becoming less energy intensive.

Table 4.4 provides recent ABARE estimates of future economic growth and industry output for highly energy intensive manufacturing industries. It shows that, excluding direct reduced iron production, metal production is expected to grow at a substantially slower rate than the economy as a whole.

Table 4.4: ABARE estimates of growth in selected manufacturing industries

	% change
GDP	
2000-01 to 2005-06	3.7
2000-01 to 2019-20	3.4
Direct reduced iron production	
2000-01 to 2005-06	21.0
2000-01 to 2019-20	11.6
Steel production	
2000-01 to 2005-06	1.7
2000-01 to 2019-20	2.6
Aluminium production	
2000-01 to 2005-06	2.2
2000-01 to 2019-20	1.4
Alumina production	
2000-01 to 2005-06	2.2
2000-01 to 2019-20	1.3

Source: Dickson, Akmal and Thorpe, 2003, p. 11.

In line with reduced shares of activity in the energy intensive manufacturing sectors the coal mining industry is expected to grow at a slower than average rate. Such shifts, combined with policy changes aimed at reducing the subsidies to coal mining relative to the cost of renewable energy, are likely to result in a substantial decline in worldwide demand for coal. The International Energy Agency, for example, forecasts a 17 % decline in coal use in the OECD by 2020 (IEA 2002, p. 336).

Another important recent trend that is likely to continue is the relative growth of the services sector, particularly communications, banking and finance and hospitality (See for example HSBC 1999; National Office for the Information Economy 2003). These sectors have demonstrated strong growth in recent years and can be expected to continue to do so.

A further note is required on the treatment of the more important of the economic sectors which are determined endogenously in our energy model. These are Oil and Gas Production, Petroleum Refining and Electricity. In the case of Oil and Gas, current expectations are for a decline in Australian production of crude oil, as reserves are depleted, but for this to be offset by a large expansion in natural gas production to supply rapidly growing domestic and international demand. The latter will be supplied by LNG, the production of which constitutes a high value added element of the Oil and Gas sector. We assume that the net effect of these changes will be that economic value added of the sector as a whole grows slightly faster than the economy as a whole, and that demand for energy services for LNG production grows at the same rate. The growth in demand for energy services in processing natural gas for domestic markets is determined endogenously within the energy system model.

In our scenario, physical demand for both electricity and petroleum products grows much more slowly than the economy. This implies that the conventional businesses supplying these commodities will also grow more slowly. However, the lower level of physical demand growth is largely brought about by significant growth in expenditure on energy efficiency – *negawatts* displacing megawatts in the terminology coined by Amory Lovins. This implies greatly increased growth in the diverse industries that supply energy efficiency services, some of which may well be undertaken by electricity supply businesses. We have modelled this change by defining growth in the Electricity and Petroleum Refining industries to be equal to the growth in demand (including demand from transport) for these fuels in the Baseline energy demand projections, i.e. energy demand without the implementation of strong energy efficiency measures.

Table 4.5 provides the relative growth rates for industries that have been assumed to grow at above or below average rates of growth. The figures in Table 4.5 are expressed relative to the assumed rate of growth for the economy as a whole (which change over time as shown in Table 4.1). That is, the figure of 0.9 for Metal Ore and Other Mining suggests that these parts of the mining industry will grow at 90% of the average rate of growth for the economy as a whole while a figure of 1.3 for Accommodation, cafes and restaurants suggests that the industry will grow at 30% above the average rate of growth.

Table 4.5: Relative growth rates for selected industries (% p.a.)

Coal Mining	0.5
Oil & Gas	1.1
Metal Ore Mining	0.9
Other Mining	0.9
Petroleum Refining	0.9
Petroleum and Coal Product Manufacturing n.e.c.	0.4
Basic Chemicals	0.4
Ceramic products	1.1
Cement, lime, plaster & concrete products	0.9
Iron & steel	0.4
Basic Non-Ferrous Metal	based on ABARE[1]
Non-Ferrous Basic Metal Products	0.7
Paper & Paper Product	0.4
Accommodation, café's and restaurants	1.3
Road transport	0.9
Rail transport	1.2
Air transport	1.1
Communication services	1.2
Finance and insurance	1.2
Education	1.1
Health and Community services	1.2

[1] The growth rate of aluminium production was assumed to change over time in line with Dickson, Akmal and Thorpe (2003). It is assumed to grow at 2.2% p.a. from 2001-2006 and 1.4% p.a. until 2050.

4.4. Estimates of future economic activity

Estimates of the size of individual sectors and the economy as a whole are derived from the application of the differential growth rates for each sector to the base year estimates of the size of each sector. The results of this process for the years 2013, 2020, 2040 and 2050 are shown in Table 4.6.

Table 4.6: Estimated output by industry 2013, 2020, 2040 and 2050 ($million)

	2013	2020	2040	2050
Coal mining	6659	7203	8742	9609
Oil & gas	24433	29009	44300	54479
Metal ore mining	12987	14950	21154	25062
Other mining	1205	1387	1963	2326
Petroleum refining	1800	2072	2932	3474
Petroleum and Coal Product Manufacturing n.e.c.	67	71	83	90
Basic chemical	2503	2666	3113	3358
Plastic product	3225	3771	5543	6691
Ceramic product	829	984	1502	1847
Cement, lime, plaster & concrete product	2778	3197	4524	5360
Iron & steel	2947	3138	3665	3953
Basic non-ferrous metal	6338	6985	9225	10601
Non-ferrous basic metal product	660	736	965	1101
Other chemical product	4991	5834	8577	10353
Paper & paper product	2822	3005	3509	3785
Accommodation, café's and rest.	22754	27860	45906	58592
Road	12902	14852	21015	24898
Rail	5491	6621	10503	13159
Air	8402	9976	15234	18734
Water	760	881	1264	1506
Other transport	1222	1417	2034	2423
Communication services	28728	34638	54948	68843
Finance and insurance	67008	80792	128164	160573
Education	43153	51235	78242	96221
Health and Community serv.	57094	68839	109202	136817
Agriculture, forestry and Fishing	29757	34500	49519	58990
Services to Mining	1286	1491	2139	2549
Food, beverage & tobacco	20247	23474	33693	40137
Textile, Clothing, Footwear and Leather]	3556	4123	5918	7049
Log sawmilling & timber dressing	1323	1533	2201	2622
Other wood product	2070	2400	3444	4103
Printing, Publishing and Recorded Media	9084	10532	15116	18008
Rubber product	699	810	1163	1385
Glass and Glass Product	912	1057	1518	1808
Non-Metallic Mineral Product Manufacturing n.e.c.	436	506	726	865
Structural metal product	2603	3018	4331	5160
Sheet metal product	1699	1970	2828	3368
Fabricated metal product	3135	3634	5217	6214
Machinery and Equipment Manufacturing	18565	21524	30895	36804
Other manufacturing	3327	3857	5536	6595

Electricity	13125	15217	21841	26019
Gas	2194	2544	3651	4350
Water	5812	6738	9671	11521
General construction	20515	23784	34139	40668
Construction trade services	27563	31956	45867	54640
Wholesale trade	46125	53477	76758	91438
Retail trade	45220	52427	75250	89643
Services	16310	18910	27142	32333
Storage	1890	2191	3145	3747
Property and bus. Services	101251	117388	168492	200717
Govt. admin and defence	34665	40189	57686	68719
Cultural and Rec. Services	16218	18803	26989	32150
Personal and other services	20253	23480	33702	40148

The data presented in Table 4.6 are summarised in Table 4.7, which shows the proportionate increase in value added between 2001 and 2040 for each sector of the economy that was separately analysed in the model. Note that this sectoral breakdown was adopted in order to focus analytical attention on industries which use large amounts of energy, or have particularly distinctive and important energy use characteristics (such as the sugar industry), rather than basing breakdown solely on economic size.

This summary shows clearly that service industries as a whole (termed Commercial/institutional) grow faster than the total economy, though, within this large grouping, accounting for about half of total GDP, some sectors grow faster than others, as shown in Table 4.6. All other sectors of the economy grow at less than the average rate for GDP as a whole, but they all nevertheless show significant growth. Export coal mining, for example, is 55% larger in 2040 than in 2001, making it larger than today's total coal mining industry that supplies both export and domestic markets. There will, therefore, be no need for substantial job losses in any industries on the basis of limited growth alone.

Table 4.7: GDP and Sectoral value added growth ratios, 2001 to 2040 (%)

Category	Output ratio
GDP	2.40 [a]
Domestic energy supply industries	N/A [b]
Coal mining for export	1.55
LNG production for export	2.62
Mining (non energy)	2.2
Iron and Steel	1.42
Food, beverages, tobacco	2.3
Sugar industry	1.21
Basic chemicals	1.42
Cement, lime, plaster and concrete	2.2
All other non metallic mineral products	2.3
Non-ferrous metals	1.79
Wood, paper and printing	1.42
All other manufacturing	2.3
Construction	2.3
Commercial/ institutional	2.5
Agriculture/ Forestry/ Fishing	2.3
Residential	2.3

a: *Intergenerational Report* (Costello, 2002)
b: endogenously determined

4.5. Conclusions

The scenario presented above is, by design, highly conservative. That is, the nature and structure of the contemporary economy is used as the starting point for the analysis and the application of differential growth rates is such that no industries are assumed to disappear and no new industries are assumed to emerge.

As discussed above, the objective of this analysis is not to provide a forecast of the likely industry composition of the Australian economy in the future. Rather, the purpose is to highlight the fact that, using plausible increases in energy efficiency and technological change, it would be possible to meet the likely energy demands of an Australian economy which, while broadly similar to the contemporary economy, had experienced long periods of subsequent economic growth.

5. Energy and the economy

5.1. Economy wide trends in energy intensity over recent years

Notwithstanding the strictures about using past relationships to describe the future, which we made in Chapter 2, an understanding of the current and recent past relationships between economic activity and energy use by different sectors of the economy is an important starting point for thinking about what might occur in the future. We have drawn on a study which the Commonwealth Government commissioned from the IEA (Schipper *et al*., 2001) that examines the relationships between energy use and economic activity in Australia from 1974 to 1995, and on a more recent study by ABARE (Tedesco and Thorpe, 2003). We have supplemented these studies with our own analysis.

Table 5.1 shows trends in aggregate energy intensity, i.e. energy use per unit of value added, for the period 1993-94 to 2000-01. The analysis is performed at the ANZSIC Division level (for Manufacturing at the 2 digit sub-Division level)

Table 5.1: Sectoral trends in Australian energy intensity, 1993-94 to 2000-01

ANZSIC economic sector		Energy intensity 2001 (TJ/$M value added)	Average annual intensity change 1994 to 2001 (%)
Div B	Mining	7.92	1.2%
	Manufacturing		
21	Food, beverages, tobacco	11.43	-1.5%
23	Wood and paper products	13.89	0.1%
25	Petroleum and chemicals incl. oil refining	27.17	-1.6%
26	Non-metallic mineral products	22.42	-1.8%
27	Metal products	46.86	0.7%
22, 24, 28, 29	All other manufacturing	1.58	-1.1%
Div C	All manufacturing	16.24	-1.1%
Div E	Construction	1.46	0.2%
37, Divs F, G, H, J,K, L, M, N, O, P, Q	Commercial/Services	0.64	-0.3%
Div A	Agriculture/Forestry/Fishing	3.31	-1.8%
	Ownership of dwellings	6.66	-1.8%
	Total of above sectors, i.e. economy excluding electricity generation and transport	3.91	-1.9%
	Whole economy (primary energy)	7.53	-1.2%

The ABARE study provides a more sophisticated analysis of energy intensity trends, using the so-called factorisation approach, which provides insights into the underlying processes which explain the trends. This analysis separates a change in aggregate energy intensity over a given period into two components:

- the structural effect, meaning changes attributable to changes in the relative shares in total production of less and more energy intensive economic sectors, and
- the real intensity effect, meaning changes occurring within component sectors.

The most recent ABARE analysis of trends in Australian energy intensity (Tedesco and Thorpe, 2003) used a similar sectoral disaggregation of economy as for this study, as defined above. The results reported for the period 1994-95 to 2000-01 are as follows:

Aggregate intensity effect	-1.7% p.a.
Structural effect	-1.8% p.a.
Real intensity effect	+0.2% p.a.

What this means is that, over the period analysed, aggregate energy intensity decreased at a significant rate, but that changes in the relative shares of total economic output between sectors at this level more than account for the observed change in aggregate energy intensity. In other words, there was shift within the economy towards a greater emphasis on sectors which are inherently less energy intensive, such as services, and away, in relative terms, from more energy intensive sectors, such as chemicals and metal processing. Changes within each sector, including "pure" technical efficiency of energy use, actually contributed to increasing energy consumption. However, this does not necessarily mean that within each sector the efficiency of energy use actually decreased. It could equally be explained by a reallocation within individual sectors, at the level the analysis was performed, resulting in shifts from less energy intensive to more energy intensive component sub-sectors. Alternatively, or in addition, if prices (and resulting value added) per unit of output decline, then real intensity increases (as discussed later).

Our analysis found that for the same period as ABARE used, i.e. 1994-95 to 2000-01, the energy intensity change for the whole economy, i.e. aggregate energy intensity of the Australian economy, was -1.4% p.a.. The difference between this figure and ABARE's estimate of -1.7% p.a. appears to be attributable to the fact that ABARE uses a composite measure of overall production which differs from GDP, whereas this study simply used GDP.

The ABARE study goes on to analyse trends in final energy consumption, meaning consumption by sectors excluding the major energy conversion industries (mainly electricity generation, oil refining and gas supply). The results show a significantly larger decrease in aggregate energy intensity, with both the structural effect (changes between sectors) and the real intensity effect (changes within sectors) contributing to the decrease. Thus the overall result for total energy consumption of an increase in real energy intensity can be explained by a major shift in fuel mix towards electricity, which is very technically efficient at the point of use, but not particularly technically efficient (in terms of the first Law of Thermodynamics) at the point of generation and through the transmission and distribution system. The electricity sector itself showed a large positive change in energy intensity, i.e. energy consumption per dollar of output value increased at a large rate. This reflects increased use of old, less efficient coal plant at the expense of hydro and more efficient gas plant, such as Melbourne's Newport power station.

These results from the ABARE study are entirely consistent with the data shown in Table 5.1 above. This shows that the energy intensity of all stationary combustion final consumption sectors, representing final demand for energy services, decreased by 1.9% p.a. over the study period, while the energy intensity of the economy as a whole decreased by only 1.2% p.a.. Given that economic output as a whole over the period grew at 4.0% p.a., this result means that final demand for energy services grew at little more than half the rate of overall economic growth. It is also noteworthy that total energy use per head of population grew at an average annual rate of 1.5% over the period analysed.

For the purpose of understanding the processes which may determine future demand for energy services, further examination of the individual sectors shown in Table 5.1 is required, in an attempt to determine whether the sectoral intensity changes that occurred can be explained by structural changes at the sub-sectoral level, by real changes in the technical efficiency of energy use, by a combination of these effects, or by other factors.

5.2. Analysis of individual sectors

Mining: In this sector energy consumption grew faster than value added, and as a result the energy intensity of the sector increased by 1.2% p.a.. The output of the mining sector is various minerals, mineral ores and concentrates, which are sold as commodities, partly into domestic markets but mainly into export markets, at prices mainly set in global markets. One explanation for the observed trend in energy intensity could be a relative deterioration in commodity prices. To test this hypothesis, average export commodity prices in 1994 and 2001 (measured as total value of exports divided by total volume) were examined for Australia's seven most valuable export commodities, excluding crude oil. These commodities are coking coal, steaming coal, iron ore, gold, LNG, zinc concentrates and diamonds. Crude oil was excluded from the analysis because prices contain a very large component of tax and are therefore not a good proxy for value of production and, furthermore, crude oil production is not an energy intensive process and therefore makes only a minor contribution to energy consumption by this sector. The weighted (by 1994 production export value) average real change in unit prices for these seven commodities was found to be –0.1% p.a.. What this means is that the large increase in sector value added (4.3% p.a.) was more than achieved by an increase in the volume of output, with price changes making a small negative contribution. For the production of mineral commodities, an increase in production volume will require an increase in energy consumption, other things being equal. The progressive move over time towards lower grade resources, as the highest grade, lowest course resources are exploited first, will also tend to increase energy consumption per unit of output. Such trends are not sustainable over the long term. It is probable that this trend can also be partly explained by an increase, relative to the rest of the sector, in the output of natural gas and LNG production, which are very energy intensive activities. However, value added data on these industries is not separately available, so it is difficult to be certain. For this study we assume that there will be some continuation of the trend of increasing energy intensity for mining, other than natural gas and LNG production, which we model separately. We model this by assuming that, in the absence of efficiency improvements, energy consumption grows 0.5% p.a. faster than sector value added.

Food beverages and tobacco. This sector includes the sugar milling industry, which uses very large quantities of bagasse (crushed sugar cane residue) as a boiler fuel at very low thermodynamic efficiency. An estimate was made of the energy intensity of sugar milling, assuming that bagasse is the only source of energy. This understates energy consumption, because the industry also uses modest quantities of coal and fuel oil as boiler fuels, and also purchases some electricity. Even so, the energy intensity of this industry was found to be nearly 400 TJ/$M value added, which is much higher than any of the major sectors shown in Table 5.1.

The balance of the food, beverages and tobacco sector, without sugar milling, was much less energy intensive (5.1 TJ/$M value added, which is less than the economy average) but the trend in intensity over time was unchanged at -1.5% p.a.. In this sector, most energy consumption is associated with cooking processes, mostly using low temperature process steam, and, in some cases, subsequent refrigeration. Natural gas, coal and LPG are all used as boiler fuels and the sector also uses significant quantity of electricity for a variety of functions. The total quantity of energy required will be largely related to the quantity of food that is cooked, refrigerated, frozen or dried, and not to the complexity or sophistication of the preparation and cooking processes themselves, within each type of process. Noting that exports account for a relatively small proportion of the output of this sector, it was hypothesised that energy consumption may be more closely related to total population than to the value added in the sector. This was found to be the case; energy use per head of population declined by a modest 0.1% p.a., whereas energy intensity declined by 1.5% p.a.. What this result suggests is that in this sector the increase in value added is attributable to more valuable products, and more than offsets any increase in energy intensive processing which may also be occurring. The shift in the beer market away from mass brands and towards premium brands may be an example of this process, where there is a decrease in energy efficiency, through use of smaller plants, but it is more than offset by the higher margin on the premium brands.

It is possible that the future of this sector may see strong growth in high value exports, partly replacing some unprocessed resource exports, and thus weakening the link between population and activity, but we have not explicitly allowed for this in our projection. Accordingly, output for this sector is assumed to grow at the same average rate as GDP, i.e. 3.1% p.a.. By contrast, our energy projections are based on an average population growth rate of only 0.68% p.a.. Having regard to these considerations, we assume that energy intensity will continue to decline at an average rate of 1.5% p.a.. We also analyse the sugar industry separately. Having regard to the difficult outlook for this industry, we assume that physical output, and hence the availability of bagasse as fuel, will grow by 0.5% p.a. over the study period.

Wood and paper products. Value added in this industry sector divides roughly equally between sawmilling and timber product manufacturing on the one hand and paper and paper product manufacturing on the other. The latter is an energy intensive process, using large quantities of thermal energy, mainly as steam, in the processes that are required to separate the cellulose fibres, of which paper consists, from the other constituents of wood. Some of the boiler fuel required is sourced from the waste biomass streams containing these other constituents (termed black liquor) and some from wood processing residues. Natural gas and coal are also important boiler fuels in this sector. The sector hosts several cogeneration plants and has the potential to support a number of others, including some very large installations. Energy intensity of this sector has remained virtually unchanged over the analysis period. During the period some older, and presumably less technically efficient paper mills have closed and some new ones have opened. Sub-sectoral value added data are not available for the whole analysis period, but over the three years to 2001 the available data show that the more energy intensive paper manufacturing sub-sectors grew much faster than timber product manufacturing. This suggests that there has been a real increase in the technical efficiency of energy use in the sector overall. Increased use of recycled paper may be contributing to this reduction in intensity. We have not undertaken the additional data collection and analysis needed to further explore these issues.

Chemicals. When oil refining is excluded from this sector, the remaining industries fall into two distinct groups, so far as their energy use is concerned. Basic chemical manufacturing includes the production of fertilisers, bulk plastic materials, industrial gases and other bulk chemicals. It is highly energy intensive (and also uses large additional quantities of fossil fuels as feedstocks, i.e. raw materials. Energy is used in a variety of ways, including process steam, higher temperature reactor vessels and gas turbine powered compressors. Natural gas and petroleum products (in some cases "waste" products from process reactions) are the major energy sources, with some use of coal as a boiler fuel. There is some use of electricity in electrolytic production processes, as well as the usual consumption in a wide variety of electric motor applications. The Basic chemicals sector hosts several cogeneration installations, including one very large plant, and has the potential to support more.

All remaining chemical manufacturing includes the production, largely from raw materials produced in the Basic chemicals sub-sector, of such products as paints, detergents, explosives, pharmaceuticals and cosmetics, none of which is particularly energy intensive. This latter group of activities account for three quarters of the value added, but less than one quarter of the energy use, and thus has an energy intensity which is less than one tenth that of the Basic chemicals sub-sector.

Overall, the industry supplies largely a domestic market, with relatively little of its output being exported. For nearly thirty years there has been talk of the potential for establishing a large scale, export oriented basic chemicals industry, using Australia's natural gas as raw material. The first such project is finally being built – a worldscale plant to produce ammonia for export, located on the Burrup Peninsula in WA, near the North West Shelf LNG plant. Our projection assumes that in broad terms the historic experience will continue, as natural gas resources are used preferentially to supply growing domestic and export (as LNG) energy market demands, and very few new export chemical plants. This means that growth of the chemicals industry will be aligned with the growth in the Australian economy.

The output of the sector grew only slowly over the analysis period. Energy consumption grew somewhat faster, with the result that energy intensity also increased at about 1% p.a.. Sub-sectoral value added data is available only from 1997-98. Analysis of the three year period to 2001 is interesting but not conclusive. Energy intensity of the Basic chemicals sub-sector decreased appreciably, while that of the remaining sub-sectors was unchanged. However, the Basic chemicals sub-sector increased its share of total value added with the result that overall energy intensity increased. This is a very clear example of how sub-sectoral structural shifts can be entirely responsible for what looks like a real intensity change at a higher level of aggregation. However, this is a trend that cannot continue over the long term in the absence of major export markets for basic chemical products. In fact, the opposite trend towards more value added products, as in other sectors of manufacturing, is considered to be more likely. Accordingly, we project a long term structural decline in intensity of 1% p.a..

Non-metallic mineral products. This is an energy intensive sector of manufacturing which mainly uses high temperature thermal energy in kilns and furnaces. It includes the production of glass and glass products, cement and lime, plaster and plaster products, concrete and concrete products, ceramics of all kinds (bricks, tiles, pipes, tableware) and other similar products. The cement industry includes some kilns fired with coal and some with natural gas. Natural gas is the dominant fuel in the rest of the sector. With no significant use of steam, this industry sector has negligible capacity to support conventional cogeneration, though use of so-called bottoming cycle installations (see Chapter 8) would be technically possible. Most major sub-sectors are broadly similar in terms of energy intensity, the main exceptions being production of concrete and plaster products. Over the period of analysis, energy intensity has fallen by an average of 1.8%p.a.. It is likely that this reflects a mix of shifting to more value added products and increases in technical energy efficiency, with the latter mainly occurring through the shutting down of older, less technically efficient plant. We assume that this trend will continue.

Basic metal products. Most of the energy used in this sector is accounted for by the production of steel, alumina and aluminium. Aluminium in particular is the most energy intensive major sub-sector within this sector, in terms of both MJ/$ value added and MJ/tonne produced. Steam, high temperature thermal and electrolytic processes are all used extensively, with the choice of process determined by the chemical properties of the metal being produced. Most value added and most energy use is accounted for by the production of steel, alumina and aluminium metal. The main fuel used in steel production is coke which, as in other metallurgical processes, is used in blast furnaces where it functions as a chemical reductant of the metal ores. Natural gas is used as a reductant in BHP-Billiton's hot briquetted iron plant, and also as a supplementary fuel in blast furnaces and in re-heating processes. Electricity is used to produce steel from scrap and iron briquettes in electric arc furnaces. World wide, there is a significant trend away from blast furnace production (so-called integrated steelworks) and towards the use of directly reduced iron and electric arc furnaces. The production of alumina requires the use of both steam and high temperature process heat (in calcining kilns). Four of the current six alumina plants in Australia use natural gas for both processes, one uses coal as boiler fuel and gas for calcining, and one uses fuel oil for both purposes. All six support cogeneration installations and there is potential for a considerable increase in capacity. The production of aluminium metal uses an electrolytic process and Australia's six aluminium smelters currently account for over 20% of Australia's end use consumption of electricity.

Production of aluminium metal has grown at nearly 5% p.a. over the analysis period, average export price by over 5% p.a., and the volume and price of alumina nearly as rapidly also. Thus the increase in energy intensity for the sector as a whole can be explained by sub-sectoral shifts within the sector towards the more energy intensive aluminium metal sector and away from other, less energy intensive production of other metals, which include steel and non-ferrous metals such as copper, nickel and zinc. Data are insufficient to estimate with any certainty the underlying trends in technical energy efficiency within the sector. However, the fact that production of all the major non-ferrous metals increased much faster than total energy consumption over the analysis period indicates an underlying trend of increased technical efficiency. We assume that technical efficiency in non-ferrous metals production will increase by 1.0% p.a..

In the case of steel production, both output and energy use fell, but energy use fell faster, by about 0.6%, again consistent with an underlying increase in technical efficiency. However, the closure of the Newcastle steelworks, the oldest and least efficient in Australia, occurred during this period, which would have affected overall energy efficiency. We assume continuing improvement in technical efficiency of iron and steel production of 0.3% p.a..

All other manufacturing. All the remaining sectors of manufacturing industry are what is often termed elaborately transformed manufactures; they include the manufacture of textiles and clothing, machinery and equipment of all kinds, and all types of household goods. None of these activities are particularly energy intensive. Electricity is the most important energy source used. In terms of value added these sectors account for about 40% of all manufacturing, and are growing faster than manufacturing as a whole. Energy intensity has declined at about 1% p.a. since 1994. However, further disaggregation shows that part of this change can be explained by a structural shift away from the Textiles, clothing and footwear sector, which is more energy intensive than the other sectors, and has been becoming more so, while its already small relative size in terms of value added (only about 10% of this whole group of sectors) has decreased. When this effect is corrected, it is found that the energy intensity of the remaining sectors has decreased at an average 0.9% p.a.. We assume that this is a real intensity (efficiency) effect.

Construction. Almost all energy use in this sector occurs in various types of off road mobile equipment, such as earth moving equipment. Petroleum products, particularly diesel fuel, are the main fuel used. The sector is not particularly energy intensive, but intensity has increased slightly over recent years, as the sector has grown more slowly than the economy as a whole. This may be caused by a trend towards more mechanised, larger scale construction methods, or by more productive use of other inputs, leading to relatively lower prices.

Agriculture, Forestry and Fishing. This sector also uses predominantly diesel fuel in off-road mobile equipment such as tractors, harvesters, logging equipment and fishing boats. Electricity is used for water pumping and other stationary farm machinery. Energy intensity varies considerably between activities, with cropping activities that involve ploughing being relatively energy intensive, particularly when yields per hectare are low. Overall energy intensity has fallen at nearly 2% p.a., with energy consumption growing at only about half the rate of output. This trend could be explained both by increased technical efficiency of energy use, e.g. by a shift towards minimum tillage cropping, and by a shift to higher value added outputs. We expect that environmental and other factors will mean that Australian agriculture continues to shift away from broad scale cropping and towards higher value added activities, and therefore project, with output growing at 2.32% p.a. on average, an average fall in intensity of 1.2% p.a..

Commercial and service industries. This is a composite sector comprising all of the so-called service sector industries, which in the ANZSIC classification account for eleven different Divisions (Divisions F, G, H, J, K, L, M, N, O, P, Q). Altogether they account for just over 7% of total final energy use (12% of final stationary energy consumption). On the other hand, these sectors account for over half of total GDP, and thus are clearly not energy intensive. However, their importance in terms of energy policy is greater than these figures would suggest, firstly because they are growing faster than the rest of the economy and secondly because electricity accounts for a large (almost 70%) and growing share of total energy use. In fact, these sectors account for as much electricity consumption (about one quarter) as the basic metal manufacturing sector.

The best public estimate of the types of activities for which energy is used derives from work originally done from a 1990 baseline (EMET Consultants and Solarch Group, 1999), since updated to a 2000 baseline (Pupilli 2002)which is shown in Table 5.2. It can be seen that nearly two thirds of all energy is used for the heating, cooling and ventilation of buildings, with lighting accounting for a further 18%. The use of office equipment accounts for a quite modest share of total consumption; some commentators believe it may be growing more rapidly than other activities, but this is not borne out by the EMET/Pupilli data. Natural gas is the main fuel used for space heating, water heating and cooking, while use of electricity dominates all other activities. There are a number of small-scale cogeneration installations in this sector, particularly at hospitals, which have a steam load, unlike most of the rest of the sector. There is great potential for far more extensive use of small scale cogeneration, as discussed in Chapter 8, but it is not financially attractive at current electricity and gas prices, and with presently available technology. However, technology trends, institutional change and increasing summer peak electricity charges could well drive change.

Table 5.2: Energy use by activity in the commercial and services sector

Activity	Share of total energy use
Air handling	15%
Space cooling	18%
Space heating	32%
Pumping	3%
Water heating, cooking etc.	6%
Lighting	18%
Other	8%

Energy intensity fell slightly (-0.3% p.a.) over the analysis period, but total energy use grew rapidly. Our baseline projection assumes that this trend in energy intensity was attributable to technical efficiency, and will continue. A “no change” structural effect trend has been assumed.

We have modelled a continuing trend towards greater use of electricity and relatively less use of other fuels, which can be attributed to increasing use of a continually widening diversity of electrical and electronic office equipment. This has been done by assuming a differential structural change effect, with structural change causing the energy intensity of "all other" energy use to increase by 0.9% p.a. and the energy intensity of all other categories of energy use to fall by 0.2% p.a., giving an overall "no change" structural effect.

Residential sector. In terms of energy use, the residential sector is defined to comprise all energy using activities which people undertake in their homes and gardens. It does not include private use of motor vehicles, boats, aircraft or public transport. The residential sector, defined in these terms, does not form part of the system of national accounts, as private citizens are defined as consumers, rather than as producers contributing to national economic production. However, GDP does contain a sector termed Ownership of dwellings, which includes an estimate of imputed rent for owner-occupiers.

A model which allocated residential energy use between the major types of energy using activity was developed by Energy Efficient Strategies *et al*. (1999) for a 1997 baseline, and is shown in Table 5.3. The main energy sources used in the residential sector are electricity and natural gas. As with the commercial/services sector, the use of electricity is increasing faster than overall use of energy, i.e. the sector is becoming more electricity intensive. Electricity is used for all four major activities and is the most important source of energy for all but space heating and cooling.

Natural gas is the main energy source for space heating, and second to electricity for water heating and cooking. ABARE estimates that the residential sector uses a very large quantity of biomass fuel (fuel wood) for space heating. Many analysts consider that the ABARE estimate is overstated. Energy Efficient Strategies *et al*. (1999) estimate fuel wood consumption to be about half the ABARE figure, setting it at 44 PJ for 1999, compared with 81 PJ by ABARE. We use the latter estimate as the basis for the figures in Table 5.3, and throughout this study. On the other hand, ABARE data includes an estimate of the energy supplied by solar water heaters, which is put at 4.3 PJ in 2001. Adding this quantity of energy to the total would increase the share of water heating to 28%.

Table 5.3: Energy use by activity in the residential sector

Activity	Share of total energy use
Electric appliances etc.	29%
Water heating	27%
Cooking	4%
Space heating and cooling	39%

If the estimate of economic output attributed to ownership of dwellings is taken as a measure of economic activity associated with the residential sector, then the energy intensity of the sector appears to fall over the analysis period by an average of 1.8% p.a.. This could be interpreted as evidence that the sector is becoming more technically efficient, as might be expected given the achievements in appliance energy efficiency and the strengthening of requirements for improved thermal energy performance of new houses (see Chapter 6). Offsetting these trends has been increased adoption of residential air conditioning (cooling) and of inefficient low voltage halogen lighting.

Another way of looking at residential energy consumption is to relate it to total household final consumption expenditure, which, over the long term, can be expected to grow at the same rate as GDP. Over the seven year analysis period, GDP grew at an average rate of 4.0% p.a., while residential energy consumption grew at an average rate of 2.1% p.a., representing an average fall in energy intensity of 1.8% p.a.. This difference can be interpreted as either an actual increase in technical energy efficiency, as described above, or as a structural change in which some of the increase in household consumption is due to expenditures which do not increase energy consumption in the home, e.g. overseas holidays. Probably both are occurring. A further factor to consider is the decline in average household size, which in recent decades has tended to increase energy use per head of population, but in the future must eventually slow down and cease.

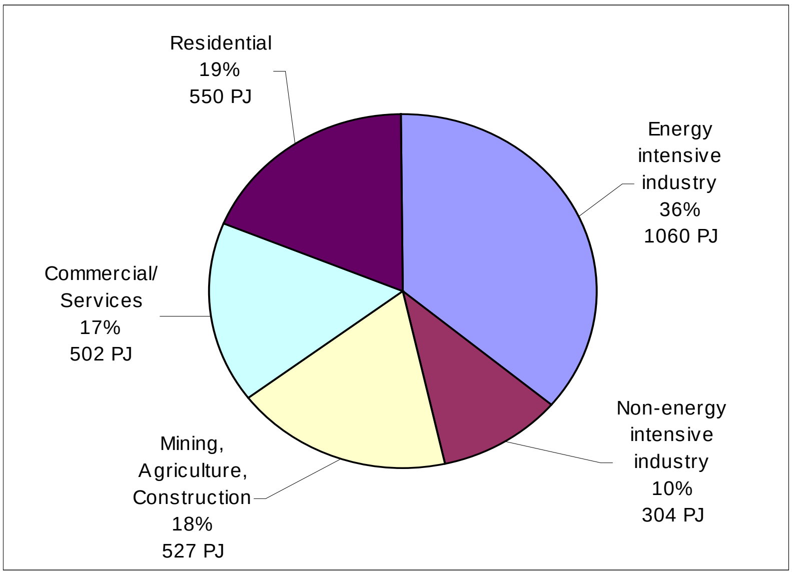
We expect this general trend to continue. Hence, while projecting future economic growth of 2.2% p.a., household energy consumption is projected to grow at 1.1% p.a. on average, representing a decline in energy intensity of 1.1% p.a., of which we attribute 0.5% to technical efficiency and 0.6% to structural change. Additionally, as for the Commercial/ Services sectors, we have modelled increasing ownership and use of a continually increasing diversity of electrical appliances and equipment by assuming a differential structural change effect. The energy intensity of electricity for electrical appliances etc. is assumed to be unchanged by structural change, while structural change causes the intensity of consumption of all other fuels to decline by 0.09% p.a. because of structural change. The combined effect is a structural change decrease of 0.06% p.a. for all energy applications.

5.3. Baseline energy demand

The assumptions about economic growth, structural change and trends in energy efficiency described in the preceding Sections of this Chapter have been used to generate what we call the Baseline final energy demand case in 2040 in the stationary energy sectors, meaning the demand for final energy which can be expected with the projected slight rise in energy costs, but no change in policy settings. Total demand is projected to reach 2,955 PJ in 2040, compared with 1,888 PJ in 2001. Related to population, this equates to an increase from 97 to 118 GJ per head. The increase, compared to the corresponding final demand for energy in 2001, is 57% in absolute terms and 21% in per capita terms. By contrast, economic activity, measured by GDP, is projected to increase more than twice as fast, by 140%. Demand for energy grows much more slowly than economic activity for the two reasons that have been explored throughout this Chapter: structural changes in the economy are progressively shifting economic activity towards less energy intensive activities, and many sectors can be expected to gradually increase their technical energy use efficiency, albeit at a rate much less (in most cases) than the economic optimum.

The distribution between major sectors is shown graphically in Figure 5.1, and more detail is provided in Table 5.4. As previously mentioned, this pattern of demand should be interpreted as the demand for energy which would result from the projected growth in economic activity, sector by sector, with no additional policies or other stimulus to increase the uptake of cost effective energy efficiency technologies.

Figure 5.1: Baseline stationary final energy demand by major sectoral group,



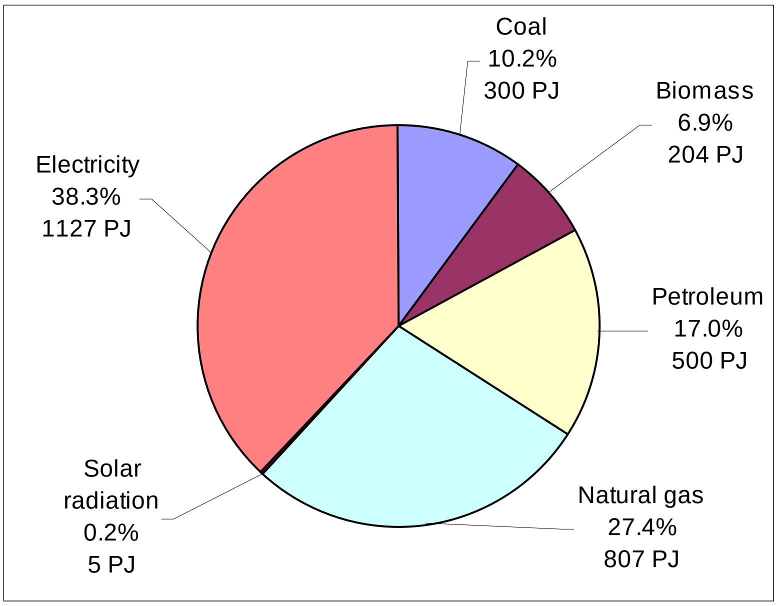
2040

Table 5.4: Baseline (BAU) stationary final demand for energy by sector, 2040 (PJ)

Economic sector	Energy consumption (PJ)	
Mining (incl. LNG and coal exports)	416	
Manufacturing	1,253	
Iron and steel		226
Food, beverages, tobacco		203
Basic chemicals		73
Cement, lime, plaster and concrete		63
All other non-metallic mineral products		76
Non-ferrous metals		412
Wood, paper and printing		100
All other manufacturing		100
Construction	117	
Commercial/Services	502	
Agriculture/Forestry/Fishing	104	
Residential	550	
TOTAL final stationary energy consumption	2,943	

Figure 5.2 shows baseline final energy demand in terms of fuels.

Figure 5.2: Baseline stationary final energy demand by fuel, 2040



Figures 5.3 and 5.4 compare the projected baseline final demand for stationary energy in 2040 with actual 2001 final demand, by major sectoral group and by fuel.

Figure 5.3: Baseline final stationary energy demand by major sector, 2040 compared with 2001 (PJ)

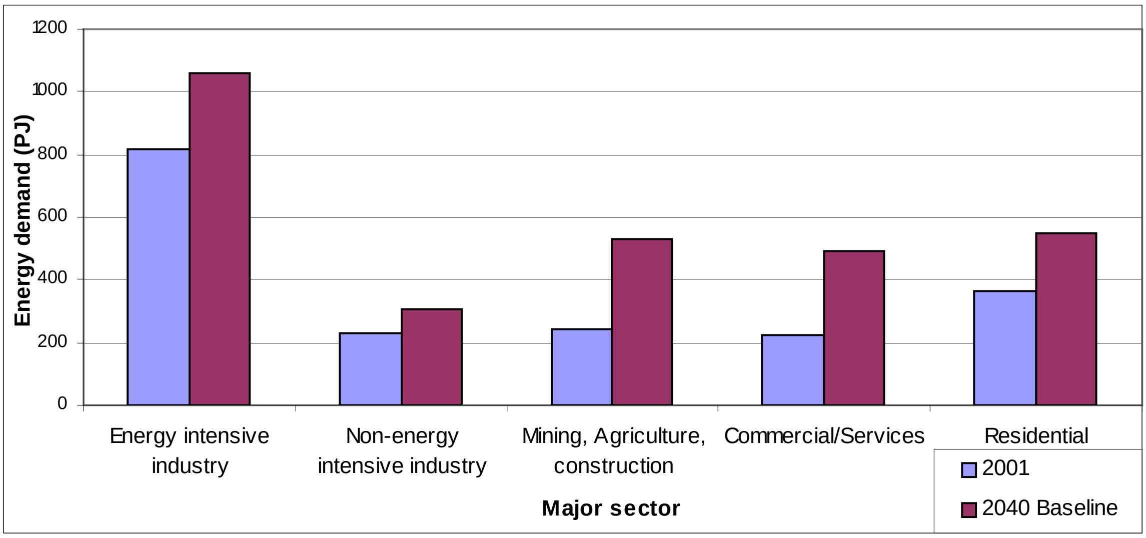
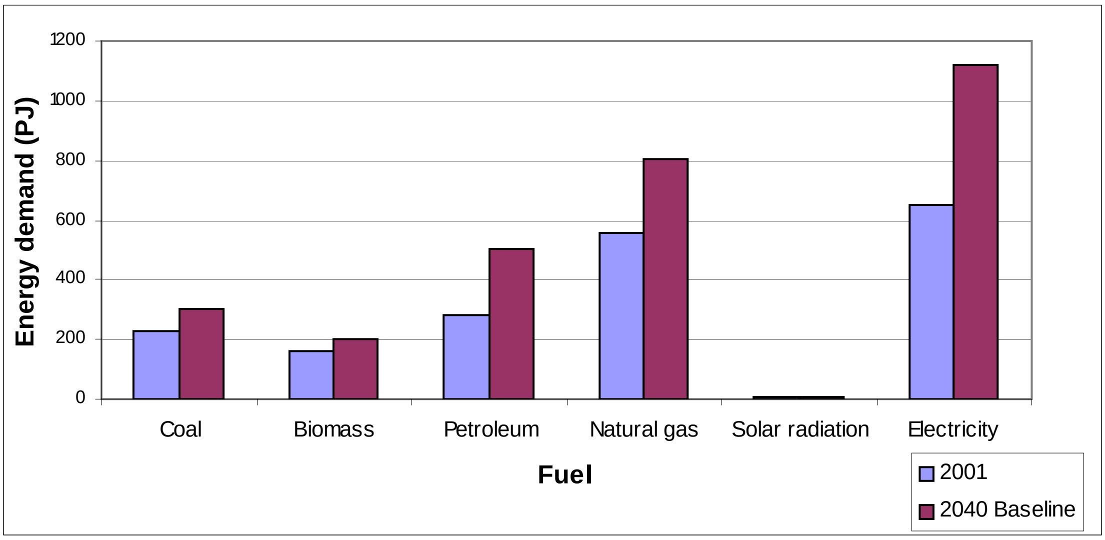


Figure 5.4: Baseline final stationary energy demand by fuel 2040, compared with 2001 (PJ)



These comparisons show that energy demand from the Mining, Construction and Agriculture sectors and from the Commercial/Services sectors is projected to grow rapidly, more than doubling between 2001 and 2040. Considerably slower growth is projected for the Energy intensive industry and the Residential sectors, reflecting respectively the assumed slower growth for much of the former and the progressive decrease in energy intensity of the latter, as discussed earlier in this Chapter. The data appear to indicate that growth in demand for electricity from Non-energy intensive industry is also relatively slow. However, this is in part attributable to our assumed slow growth of the sugar industry, which forms part of Food, Beverages and Tobacco and uses very large quantities of biomass fuel at currently very low thermal efficiency. More rapid growth is projected for general manufacturing (roughly corresponding to elaborately transformed manufacturing), though total demand and energy intensity remain low.

The fuel mix depicted in Figure 5.4 shows a marked shift towards greater use of electricity, and, to a lesser extent, natural gas and petroleum. This shift is a consequence of the more rapid growth in demand from those sectors, such as Commercial/Services, which already have a high proportion of these fuels in their demand mix. The growth in demand for petroleum products is particularly attributable to the assumed high growth rates in the mining sector.

As described, most of our projections are based on exponential change factors from the 2001 patterns of energy demand by sector and fuel. For comparative purposes, we have constructed a linear interpolation between 2001 and our 2020 projection for the year 2021. At the low rates of change used in our modelling, the difference between linear and exponential interpolation is not great, but, as a generalisation, linear is consistent with slightly faster change in the earlier years and slower in the later years. This interpolation has been compared with ABARE's projection of Australian energy supply and demand in 2020 (Dickson, Akmal and Thorpe, 2003). In order for the comparisons to be on the same basis, some adjustments had to be made to both sets of projections. The Clean Energy Future figures were adjusted by combining some sectors and by including the use of fossil fuels as chemical feedstocks and carbon anodes for aluminium production in the relevant sectors. The ABARE figures were adjusted by subtracting an estimate of energy used to mine coal for domestic supply from the Mining sector and by adding estimated energy used for LNG production to the same sector.

Table 5.5: Comparison of 2020 Baseline energy demand estimates between interpolation of this study (CEF) and ABARE

Economic sector	**Energy demand (PJ)**	
	CEF	**ABARE**
Mining (incl. LNG and coal exports)	300	484
Manufacturing	1223	1611
Iron and steel	202	329
Food, beverages, tobacco	183	Included with All other manuf.
Chemicals	163	185
Cement, lime, plaster and concrete	52	121
All other non-metallic mineral products	62	Included with All other manuf.
Non-ferrous metals	397	513
Wood, paper and printing	86	99
All other manufacturing	77	364
Construction	82	Included with All other manuf.
Commercial/Services	360	361
Agriculture/Forestry/Fishing	87	99
Residential	472	591
	2,525	3,146

The ABARE figures are significantly higher than the CEF figures. About 30 PJ of the difference is caused by the exclusion of fuel used in cogeneration from this study. However, most of the difference arises from a small number of easily identified differences in assumptions about the future.

- In the Mining sector, ABARE has much higher consumption of natural gas, which is attributable to its assumption of a very high level of LNG exports (growth by a factor of 4.2 from 2001 to 2020).

- In the Iron and Steel sector ABARE has much higher consumption of both coal and natural gas. This implies major expansion of both conventional (integrated) steel production, using coal and coke, and of directly reduced iron, using natural gas, presumably to supply export markets.

- In the Non-Ferrous Metals sector, ABARE has much higher consumption of natural gas and somewhat higher consumption of electricity, implying an assumption of higher growth in production of alumina, and, to a lesser extent, aluminium metal, plus some magnesium smelting (another exceptionally energy intensive process).

- In the Residential sector, ABARE has much higher consumption of both natural gas and electricity. This seems inconsistent with the rapidly spreading introduction of mandatory requirements for improved building envelope thermal performance (albeit much less than could be economically achieved – see Chapter 6), the similar rapid spread of Mandatory Energy Performance Standards for a wide range of residential equipment, and our view that the current "regulatory subsidy" for residential air conditioning simply cannot last. All of these considerations have been factored into our assumptions about the Residential sector.

Apart from these four differences, the ABARE projections are surprisingly close to our interpolated baseline projection for 2020.

In overall terms, the ABARE figures are equivalent to an increase of 48% in total stationary energy consumption and an increase of 40% in associated CO_2 emissions. Emissions increase less than energy consumption because of a decrease in the share of coal in electricity generation, and a corresponding increase in the shares of natural gas, biomass and, to a small degree, wind.

In Chapters 7 and 8 of this report we demonstrate that there is far greater potential than ABARE assumes for shifting the electricity supply mix towards low emission generation sources. In Chapter 6 we examine the extent to which the wider adoption of currently available, cost effective energy efficiency technology could further moderate growth in demand for energy across the economy.

6. Energy efficiency technologies and potential

6.1. Concepts and approaches to assessing the potential

Concepts and their application

Studies which seek to assess the potential for increased energy efficiency commonly make use of a three level definition of potential.

Technical potential represents the minimum consumption of energy for a given output of required energy services, irrespective of cost. In almost all situations, some of the possible improvements in technical energy efficiency will not be cost effective. Thus technical potential by itself is not a direct guide to what is achievable in practice. However, it is often very valuable as a tool for gaining better understanding of energy using processes and the potential for improving them significantly, and it is the ultimate indicator of what might be possible in the future if costs of the relevant energy efficiency technologies fall, which they usually will, and/or the cost of purchased energy rises.

Economic potential represents full adoption of all opportunities for improved energy efficiency that are cost effective, in the sense given above, at a discount rate which is appropriate, given the relatively risk-free nature of the investment. Most of the practical difficulties in applying this concept arise because the main element of the cost of energy efficiency is the capital investment required, while the main element in the offsetting savings is the recurrent cost of avoided energy purchases. Equating the two requires choosing what discount or return on investment rate to use and the break-even point is usually very sensitive to changes in the rate chosen.

If all the relevant economic agents used similar rates in their normal investment decisions, the choice would be simple. In practice, however, energy users almost always use high investment hurdle rates, or short payback periods (typically maximum 5 year payback and mostly 1-3 years), when deciding whether or not to invest in energy efficiency. These much higher rates take account of the high transaction costs, poor information and uncertainties faced by an individual investor in the present imperfect markets for energy services, and constitute one of the major market barriers or imperfections relating to energy efficiency. In contrast, government regulatory agencies use quite low rates, mostly in the range 8-10% real, in determining the prices they allow electricity and gas transmission and distribution businesses to charge. The average rates achieved by electricity generators and gas producers (the competitive parts of the energy supply industries) are not much greater.

Nationally, economic resources will be allocated with maximum efficiency if energy investment decisions use similar return on investment rates. Maximising economic efficiency also requires that costs of purchased energy be defined to include environmental and social externalities, if they have not already been internalised by policy actions, as has been done in this study. Naturally, the choice of a lower discount rate makes a big difference in the range of technologies which are assessed to be cost effective

The wide gap between the high discount rates used in practice by energy users and the much lower rates built into the prices of energy supplied, means that most of the unrealised opportunities for energy efficiency will yield rates of return somewhere between the two. It is only the relatively few marginal projects which will yield a return as low as that embodied in the prices of energy supplied. The average rate of return on increased energy efficiency will be much higher than the marginal rate or, to put it another way, the resource cost to the economy of the additional energy efficiency will be much lower than the resource cost of an equivalent increase in energy supply. This obviously has important consequences when comparing the total economic costs of scenarios that include different mixes of increased energy efficiency and expanded energy supply.

It is most important to recognise that at any particular point in time an energy user is likely to be in a situation where he or she is using a piece of energy using equipment which has not been fully amortised, i.e. still has both economic and technical life remaining, while at the same time being aware that if she or he were choosing new equipment it would be possible to make a cost effective decision to choose a newer, more efficient technology. In such circumstances, premature scrapping of the existing equipment would impose an economic cost, even though the new equipment would subsequently provide cost savings. As we have previously explained, by choosing a 40 year projection, we are able to achieve the full economic potential for energy efficiency, without the cost of any premature replacement of existing equipment. To allow for the turnover of household appliances, a 10 to 15 year period is generally sufficient.

Finally, note that it is the existence of various types of market failure in markets for energy services, usually causing individual decision makers to face high transaction costs when choosing energy efficient technologies, that make economic potential an important concept and a useful analytical tool, but not a description of reality. That is encompassed by the concept of market potential.

The **market potential** is a concept linked to economic modelling approaches to projecting energy futures. It is an estimate of the extent to which economic decision makers in each sector would actually take up the various available energy efficiency technologies. In other words, it is an attempt to represent the behaviour of economic agents within the context of the existing, highly defective markets for energy services. It can be estimated with no change in existing policies, in which case it is equivalent to a Business as Usual projection, or it can be estimated with one or more explicit policy changes that are assumed to influence the behaviour of the relevant economic agents. It is a complex, hard to define and frequently confusing construct, and one of the advantages of the scenario back-casting modelling approach that we are using is that there is no need to be concerned with the market potential for energy efficiency.

The market potential take-up of energy efficient technologies within a given policy environment is what drives autonomous energy efficiency improvement. As described in the previous Chapter, experience over recent years suggests that this varies greatly between economic sectors. In general endogenous energy efficiency improvement is larger in energy intensive sectors, where energy purchases are a larger component of total operating costs. This experience, which means that these sectors take up most energy efficiency opportunities as they arise, has been used, together with projected structural shifts within sectors, to generate the Baseline final energy demand structure summarised in Table 5.4.

Approach

Although it is much easier to assess the economic potential than the market potential of energy efficiency, it is still not easy. To do it thoroughly requires cost and performance data about hundreds of different technical options, together with similarly detailed data about the energy using equipment currently in place across all sectors of the economy. Self-evidently, this would be a very large task, greatly beyond the resources of this study. Moreover, most of the necessary data on stocks of energy using equipment are not available in Australia at the required level of detail.

Consequently, our assessment has been performed at a more generalised level. For the Residential and the Commercial/Services sectors we have drawn on relatively recent Australian studies which did undertake some of the required analysis and modelling. For other sectors, we have used published literature on the performance of a wide variety of energy efficiency technologies, together with the experience and achievements of government programs intended to promote adoption of energy efficiency, notably the former Energy Efficiency Best Practice program. For some particular industries, such as cement and alumina, the industries have themselves commissioned studies which provide considerable information about their current use of energy, and these have been used where available.

Our assessments assume that energy prices will have risen to the levels described in Section 2.2, which will have the effect of making economic a number of technical options which are not economic at current energy prices. We focus on using existing technologies, i.e. hardware, with continuing small improvements, but also assumes that policies, institutions, organisational structures and management practices are changed to ensure that best available, proven and cost effective technology is used when new investment decisions are made.

While falling short of the ideal, the approach we have taken is no less rigorous than previous general assessments of the Australian energy efficiency potential, and clearly more rigorous and detailed than most such assessments. We note that our estimates of the efficiency potential are in general conservative, i.e. smaller than those contained in the recently released discussion paper of the Energy Efficiency and Greenhouse Working Group of the Ministerial Council on Energy (2003), a joint Commonwealth and State/Territory government body.

6.2. Manufacturing

In assessing the potential for increased energy efficiency in manufacturing, we use a combination of specific assessments for selected sectors and generic equipment type assessment for the remaining sectors. In this Section, we discuss first the specific sectoral assessments and then turn to the generic equipment type assessments.

Sectoral assessments

Iron and Steel

In Australia most steel is produced at two integrated steel works, at Port Kembla and Whyalla. The term integrated steel works refers to the production of steel by the chemical reduction of iron ore to pig iron in a blast furnace, using coke (produced from coal in on-site coke ovens) as the reductant and principal source of thermal energy, followed by conversion of pig iron to steel in a steel furnace, which in all modern steel mills is a type called basic oxygen furnace. The steel is then rolled and formed into products.

Smaller quantities of steel are produced from scrap at several so-called mini-mills using electric arc furnaces. Around the world, electric arc furnaces are rapidly becoming the preferred technology for most new steel making investment, because their optimal economic size is much smaller than that of an integrated steel mill and the investment required is correspondingly much less, greatly reducing financial risks. These new mini-mills use both scrap and virgin metal in the form of so-called directly reduced iron (DRI). Although the process has been under development for some decades, commercial production of DRI is relatively new. Production of DRI usually occurs at completely separate locations from the subsequent production of steel, i.e. it is not integrated. Different proprietary DRI processes use different fossil fuels as reductant, not including coke, but natural gas is most commonly used. There is one commercial DRI plant in Australia, BHP-Billiton's plant in Western Australia, using its hot briquetted iron process.

The commissioning of this plant resulted in a significant increase in consumption of natural gas in iron and steel production in Australia. The production of DRI is essentially a way of adding significant value to Australia's current exports of iron ore, and a number of companies are exploring the possibility of building DRI plants to export DRI to mini-mills in Asia and elsewhere round the world.

Some analysts, including ABARE, expect that this will lead to rapid growth in the iron and steel sector in coming years, with concomitant increase in demand for natural gas. For this study, we have not assumed such growth, so that the assumed growth in the iron and steel sector of 42% represents growth in production for mainly domestic markets. We have also assumed no change in the current mix of plant types, with growth in output at the two integrated steel works, but no new integrated steel plant, and some new electric arc furnace capacity, possibly using DRI, but no additional export DRI plants. Hence the consumption of electricity in this sector remains relatively low and the consumption of coke relatively high, with significant consumption also of natural gas for DRI production.

Over the past two decades, the former BHP Steel (now BlueScope Steel and OneSteel) have made significant investments in technologies that increase energy efficiency. There are opportunities for further efficiency improvements, notably by making major investments in near net shape casting, together with increased recovery of energy from waste gases. Much of the potential for improvement in technical efficiency by these means are captured by the efficiency improvement trend included in the baseline improvement of 0.3% p.a.. We assume that greater emphasis on energy efficiency will result in improvements of a further 0.2% p.a..

Chemicals

Most major Australian chemical plants were first built several decades ago, though they have undergone progressive modifications. It is most unlikely that many of them will still be operating in 2040. In general, these plants are below "world scale" in size, meaning that they are smaller than the optimally efficient size. Over the past decades there have been some closures of Australian capacity, e.g. production of vinyl chloride monomer, the precursor of PVC, and some analysts expect that Australia may cease producing many other bulk petrochemicals. However, our projections assume that economic output of the sector as a whole will grow by 140%, and even allowing that there will be a shift towards the non-energy intensive value added parts of the industry, the assumption implies significant growth in production of basic chemicals. This must imply construction of new, more efficient plants.

General options for increasing energy efficiency in chemical production include:

- more efficient boilers and boiler systems,
- process optimisation through improved control systems,
- more effective catalysts, new and improved separation technologies,
- improved waste recovery and associated use of waste products as fuel.

The US Interlaboratory study (Interlaboratory Working Group, 2000) estimated that the technical energy efficiency of that country's bulk chemicals sector could reduce energy intensity by 14% by 2020. The UK study (Jonathan Fisher *et al*., 1998) estimated that the technical energy efficiency of the British chemical industry could reduce energy consumption by 36% below BAU by 2020.

For this study, we have assumed a relatively modest improvement in the technical efficiency of the industry of 20% to 2040, which implies a 17% reduction in energy intensity.

Cement

The cement industry is a major user of high temperature process heat in kilns, in which limestone undergoes calcination (thermal decomposition to calcium oxide and CO_2). The current Australian cement industry comprises four large, relatively modern plants, accounting for about three quarters of total production, and a number of smaller, older and much less energy efficient plants. When these are shut down there will be an appreciable increase in the overall energy efficiency of the sector. Another important means to reduce energy consumption is greater use of so-called blended cements, in which clinker (the product of cement kilns) is mixed with one or more additives or extenders, such as fly ash or blast furnace slag. The use of blended cements is a particularly attractive efficiency option since the inter-grinding of clinker with other additives not only leads to a reduction in energy use (and carbon emissions) in clinker production, but also results in a concomitant reduction in carbon dioxide emissions in calcinations (which we are not modelling in this study).

There are also significant opportunities for further increases in technical energy efficiency, through changing the design of kilns to achieve greater recovery of waste heat. These include multi-stage pre-heater kilns and pre-calciner kilns (the latter alone is estimated to reduce energy consumption, relative to a modern dry-process kiln, by 12%).

We estimate that the overall potential for energy efficiency improvement, i.e. increase in output per unit of energy consumed, in the cement industry, relative to 2001, is 45%, which would reduce energy intensity by about 31%. Since the baseline trend incorporates an energy intensity reduction of about 18%, enhanced efficiency is estimated to contribute a further 16% (13% of 2001 consumption).

Non-ferrous metals

Although Australia is a major produced of nickel, copper and zinc, all of which require relatively energy intensive processing, the production of alumina and aluminium metal accounts for most of both the value added and the energy use in this sector. Discussion of the efficiency potential therefore focuses largely on these two materials, both of which are highly energy intensive.

In general, energy used in the production of aluminium can be greatly reduced by increased recycling of scrap aluminium. However, this is not of great relevance to the Australian industry, as its major role is as a producer of virgin metal for world markets.

Energy use in the production of alumina is in two main forms: steam to provide heat for the alkaline digestion of bauxite to produce hydrated alumina, and high temperature heat in calcination kilns to produce anhydrous alumina. There are opportunities to improve the efficiency of the boilers and boiler systems, mainly by reducing heat losses. Substantial improvements in kiln efficiency can be achieved by adoption of a new type of kiln, termed gas suspension calciners, which provide increased opportunities for waste heat recovery. A recent study estimated the overall average energy consumption for alumina production in Australia to be about 12,300 MJ/t, compared to world's best practice of 9,000 MJ/t achieved by the German company AOS (DISR Energy Efficiency Best Practice Program, 2000).

Production of aluminium metal from alumina uses an electrolytic process and electricity accounts for by far the largest proportion of total energy consumption in this process. Electricity intensity of electrolysis at present in Australia is 13-15 MWh/tonne of aluminium, over twice the absolute theoretical limit of 6.34 MWh/t. A realistic eco-technical potential is 10-11 MWh/t, which will require the use of new materials and improved pot design (DISR Energy Efficiency Best Practice Program, 2000). Since all existing pot lines will be replaced by 2040, this is quite feasible by that date. Improved heat recovery also offers potential for further savings.

Our baseline projection assumes a steady improvement of technical efficiency in this sector of 1% p.a., which equates to an energy intensity reduction of 32% by 2040. We assume no additional efficiency improvements will be possible.

Pulp and paper

Energy use in this sector is affected by both structural factors, notably the extent of recycling and the mix of technologies (chemical/mechanical) used to produce virgin pulp, and by the use of a wide variety of specific technical means to increase energy efficiency. Most energy use is in the form of steam, which is used in all chemical pulping processes and also for most types of dryers. There is also significant use of mechanical energy, usually provided by electric motors.

The US and UK studies differ in their assessments of the potential for energy efficiency improvements in the paper industries of their respective countries. The UK study estimates that specific energy consumption could be reduced by 36% beyond BAU, while the US study estimates an improvement of less than 3%. It is not clear why these two studies reach such different conclusions about their respective countries.

Our 2040 baseline includes a trend improvement in the technical energy efficiency of the paper industry of 1% p.a., which equates to a total reduction in energy intensity of 32% by 2040. We assume zero additional efficiency improvement through pursuit of further efficiency options.

Sugar milling

The sugar milling industry constitutes, in terms of value added, a relatively small part of the Food, Beverages and Tobacco sector of manufacturing. We analyse it separately because the industry is extremely energy intensive by virtue of the quantities of bagasse (the fibrous residue from sugar cane crushing) used as boiler fuel. Much lesser quantities of coal and petroleum products are also used as supplementary boiler fuels. Most sugar mills also host small cogeneration installations, which are sized to supply most of the mills' own electricity requirements, but with little surplus for export to the grid.

The boiler plant in most Australian sugar mills is quite old, in part because the poor economics of the sugar industry over recent years has made it difficult to justify new investment. Furthermore, bagasse is essentially a waste product, with no demonstrated alternative uses, making low efficiency combustion a least cost waste disposal option.

We assume that sugar mills will continue to use bagasse as their primary energy source in 2040. However, all mills will be rebuilt (as a few have been over the last few years) to incorporate much larger and more efficient cogeneration plant. As a result, the quantity of bagasse required per tonne of raw sugar produced will be halved, i.e. the efficiency of producing and using process steam is doubled. The remaining bagasse is then available as a fuel for electricity production in the associated cogeneration plant. We make no assumption as to whether bagasse is gasified or simply undergoes direct combustion (as in all current sugar mills).

Generic equipment assessments

As previously noted, we allocate energy use in manufacturing into one of six major equipment or process types, each of which offers distinctive opportunities for energy efficiency improvement. We apply these generic assessments of potential to all the remaining sectors of manufacturing industry.

These remaining sectors, in the classification used for this study, are: Food, Beverages and Tobacco (excluding sugar milling), All Other Manufacturing, and Other Non-metallic Minerals (i.e. excluding Cement). With the exception of the latter sector, which includes the manufacture of glass, bricks and other ceramic products, these industries are much less energy intensive than the major process industry sectors discussed above. They also include the great majority of individual manufacturing establishments, including many relatively small ones. For these reasons, consumption of energy typically attracts a lower attention from management and is a lower priority for capital investment. Accordingly, the potential for energy efficiency improvement beyond the current levels will in general be greater than in the energy intensive process industry sectors.

Boiler systems

The term boiler systems refers to both the boiler itself, where combustion of fuel heats water to produce steam, but also the system of pipes for delivering the steam to where it is required and the great diversity of equipment in which steam is used as a source of heat.

Some studies of energy efficiency potential concern themselves only with the boiler itself, where there are certainly significant opportunities for efficiency improvement, notably by the progressive replacement of older boilers with newer models incorporating more efficient combustion and heat transfer designs and also by the general adoption of condensing (latent heat recovery) boilers, which provide efficiency improvements of up to 15%. However, much greater savings are usually available elsewhere in the system. These include improved insulation of steam pipes, elimination of leaks and other “good housekeeping” measures, and improved control of boiler operation, such as matching steam output to steam demand, rather than operating the boiler continuously at full capacity. Improvements in the design and operation of steam using equipment can result in further major savings in boiler energy demand.

It is understood that the former Energy Efficiency Best Practice program of the Department of Industry, Tourism and Resources identified energy savings of 40% or more in selected case studies.

For this study we assume that the average increase in boiler system efficiency will be 50%, i.e. energy intensity will be reduced by a factor of 0.67. When allowance is made for the efficiency improvement included in the respective baseline trends, the factors by which energy intensity will be additionally reduced are:

Food, Beverages and Tobacco	0.67
All Other Manufacturing	0.91

Kilns, furnaces etc.

In high temperature thermal equipment the main opportunities to improve technical efficiency are improving combustion efficiency, improving heat transfer efficiency from flame to the kiln chamber (depending on the type of kiln or furnace), reducing the amount of energy needed to bring fuel and combustion air up to combustion temperature, and, most importantly, reducing the amount of energy lost in exhaust gases.

As with many relatively mature technology systems, incremental improvements are continually being made in the various components of kiln systems, so that new equipment will generally be more efficient than older existing equipment. This turnover of stock is the major source of the trend for gradually increased technical efficiency across most sectors and types of equipment.

Major efficiency improvements, going beyond trend, are possible through the widespread adoption of the most efficient types of regenerative combustion systems. This is a well established, but still not widely used technology that recovers much of the heat contained in flue gases, with resultant large increases in overall efficiency. There is also a range of advanced burner designs which can provide modest, but useful, efficiency increases.

We assume that such technologies can be in general use in kiln systems by 2040, providing an average increase in the energy efficiency in kilns, furnaces and other high temperature thermal process equipment of 35%, i.e. energy intensity will be reduced by a factor of 0.74. When allowance is made for the efficiency improvement included in the respective baseline trends, the factors by which energy intensity will be additionally reduced are:

Other Non-metallic Mineral Products	0.87
All Other Manufacturing	0.97

Electric motor drive systems

Although individual motors can achieve efficiencies of near or above 90 %, the total system (including motor, shaft coupling, pump and throttle valve, etc.) may achieve an overall efficiency of 50 % or less. Ways to increase the efficiency of electric motor systems include the following.

- adoption of Minimum Energy Performance Standards (this took effect in October 2001 for three phase motors between 0.73 kW and 185 kW in size);
- shift to high efficiency motors;
- better sizing motors to the load they supply so that they run nearer full load most of the time (the efficiency of electric motors is much lower under part load);
- more extensive use of variable speed drives in applications where load varies, such as fans, pumps and conveyors,
- improved lubrication, maintenance and installation practices.

Energy consumption by electric motors is also reduced by improving the performance of equipment powered by electric motors, such as commercial refrigerators, air conditioning systems, air compressors and a wide variety of equipment used in manufacturing.

We assume that the average increase in electric motor drive systems will be 40%, i.e. energy intensity will be reduced by a factor of 0.71. When allowance is made for the efficiency improvement included in the respective baseline trends, the factors by which energy intensity will be additionally reduced are:

Food, Beverages and Tobacco	0.74

Other Non-metallic Mineral Products	0.90
All Other Manufacturing	1.00

Non-electric motors, Other non-electrical equipment, Other electrical equipment

Each of these types of equipment accounts for relatively little energy use in these sectors. For each, energy intensity is assumed to decrease by a factor of either 0.83 or the sectoral trend in technical intensity improvement, whichever is the greater reduction.

6.3. Mining, Construction and Agriculture etc.

In this Section we deal with energy use in Mining of non-energy minerals, Mining of coal for export, LNG production, Construction, and Agriculture, forestry and fishing.

The common feature of all these sectors is that they mainly use energy in various kinds of motors. These include:

- diesel engines:
    - shovels, dump trucks, generators etc. in coal and other mining,
    - earth moving and other equipment in construction,
    - tractors, pumps, other farm machinery, logging equipment, fishing boats in agriculture, forestry and fishing;
- gas turbines:
    - providing power for compressors and most other equipment used in LNG production;
- electric motors:
    - shovels, drag lines, underground mining equipment and mineral processing equipment (crushers, conveyors, pumps etc.) in mining,
    - pumps and miscellaneous farm equipment.

Other uses of energy include boilers, kilns and driers used for mineral processing in the mining sector, and relatively small amounts of energy used for space heating in agriculture.

For the Mining (including coal mining) sector our baseline projection assumes no trend increase in energy efficiency. The following improvements in energy efficiency for the various equipment categories are assumed:

boiler systems	40%
kilns and furnaces	40%
non-electric motors	20%
electric motor drives	35%
all other equipment	20%

These rates of efficiency improvement assume the same sorts of technology changes and adoptions as were described in the previous Section for the Manufacturing sector. However, it is assumed that energy using equipment in the Mining sector is on average larger in scale and more modern than equivalent equipment in the Food and All Other Manufacturing sectors, and that the potential for efficiency improvement is correspondingly less.

For the LNG industry, our baseline assumes a trend improvement in energy efficiency of 1.0% per annum across all types of energy use in the industry, which equates to an improvement in energy efficiency of 47% over the entire period to 2040. We allow no additional efficiency increase in the "efficiency" scenario.

For Construction, the baseline, as for Mining, assumes zero increase in energy efficiency. The efficiency improvement potential by 2040 is assumed to be 20% for non-electric motors, which account for the great bulk of consumption, and other non-electric equipment. An improvement potential of 35% is assumed for the relatively small amount of energy used by electric motor drives.

6.4. Commercial and services sectors

Energy use in the commercial and services sector essentially means energy use in buildings of all kinds. It is almost universally recognised that the potential for increased energy efficiency is very large in this sector. Moreover, electricity accounts for nearly 70% of total final energy use and 90% of greenhouse gas emissions in this sector, and its share is growing, so reductions in energy use will result in large emission reductions.

The EMET/Solarch study (EMET Consultants and Solarch Group, 1990) estimated abatement achievable by 2010, relative to a BAU baseline projected forward from 1990. The study estimates are structured in two tranches: firstly what was termed BAU abatement, defined as all abatement available at zero or negative cost, and secondly what was termed technical improvement potential, defined as all abatement with a positive NPV when an 8% discount rate is used. The more recent study (Pupilli 2002) estimated total energy savings with a payback period of 3 years or less to be 32% of projected energy consumption in 2010. However, an unspecified proportion of this 32% was said to be included in the BAU projection, i.e. actual additional savings with payback of 3 years or better is less than 32% by an unspecified amount. While it is difficult to equate the EMET/Solarch results, all expressed in terms of emissions, with the data used in this study by ABARE and by the more recent Pupilli update, all expressed as energy, it appears that the EMET/Solarch estimate of BAU + economic potential abatement is over 25% of the 2010 baseline. The EMET/Solarch estimates are based mainly of retrofitting and refurbishment, combined with enhanced performance levels for new building. They do not include substantial replacement of old buildings. Hence potential abatement over the longer period to 2040 should be significantly greater.

The discussion paper of the Ministerial Council on Energy (2003) estimates that the cost-effective energy consumption reduction in the commercial sector is over 25% under a so-called low energy efficiency improvement scenario (current technologies with a 4 year payback) and up to 70% under a high energy efficiency improvement scenario (existing and developing potential technologies with an 8 year payback).

The UK study (Jonathan Fisher *et al*., 1998) estimated that by 2010 BAU energy consumption in the UK service sector would be 9.4% below the level it would have reached had there been no improvement in technical efficiency (termed "frozen efficiency"), which is equivalent to efficiency improvement of 0.7% p.a. from the study's 1996 base year. The technical potential was estimated to be a further 25% lower.

The overall assumption for this sector is that the potential for technical improvements in energy efficiency is for a saving of 40%, relative to the baseline, in all applications. Taking into account the efficiency improvement trend of 0.3% p.a. which is included in the baseline, the total energy demand reduction relative to current efficiency levels is 47%.

6.5. Residential sector

The residential sector affords great opportunities for limiting the growth in fossil fuel derived energy for the three main categories of energy use by:

- increased use of solar energy both actively, for water heating, and passively, through improved building design to reduce active use of energy for space heating,
- more efficient use of energy to achieve required energy service levels for heating and cooling by improved building shell design and construction, to reduce or eliminate the need for active energy using systems, and
- continuing improvements in the efficiency of both electrical and gas appliances and equipment.

Water heating

Our model assumes a large scale shift to solar water heating for the provision of residential hot water. It assumes:

- a modest underlying shift from electricity to gas in non-solar water heating (levelling out a trend which has operated for many years),
- that these shares of electricity and gas will determine the shares of these two fuels for boosting solar systems,
- that solar systems displace 75% of current electrical water heating and 90% of current gas water heating,
- that the average solar fraction Australia-wide is 70%,
- that the performance parameters for the various types of water heater specified in the standards for conventional and solar water heaters (Standards Australia, 1990, 1994) apply, and
- that the average fuel efficiency in the market (fuel to delivered hot water) of electric and gas water heaters are at present 76% and 65% respectively and that these increase at the sectoral trend rate of 0.5% p.a..

The overall effect of these assumptions is that electricity consumption for water heating is decreased by 59% and gas consumption is reduced by 56%, relative to the baseline.

Space heating and cooling

Examination of the data on residential energy use of Energy Efficient Strategies *et al.* (1999) shows that natural gas (used for heating) accounts for most of the energy used for space heating and cooling and that most of this occurs in Victoria. Our modelling therefore focuses on the thermal performance of residential buildings in that State (though it would also apply to Canberra, and the tableland areas of NSW).

The underlying baseline trends for technical efficiency and structural change in the residential sector, described in Section 4.2 above, are assumed to incorporate both increased technical efficiency of space heating equipment and any take up of improved technical performance as increased comfort, rather than reduced energy consumption. Other assumptions are:

- 50% of current electricity use is for heating and 50% for cooling,
- technical efficiency improvements in all types of heating and cooling equipment are 0.5% p.a., as in the sectoral trend, and
- there is an additional improvement of 0.5% p.a. in the technical efficiency of wood heating and a market shift from wood to gas.

Against this background, our model assumes that 50% of the 2040 housing stock in areas with significant heating load will achieve the equivalent of 5 star or above house energy rating, and the other 50% will achieve a 2.5 star rating. These building envelope performance levels equate respectively to heating energy consumption of about 140 and 280 MJ/m^2 in the Melbourne climate. We also assume, based on data contained in Energy Efficient Strategies *et al*. (1999), that the 2001 average performance of Melbourne housing stock is 500 MJ/m^2.

The overall effect of these modelled assumptions is that electricity consumption for space heating and cooling is decreased by 21% and consumption of natural gas and LPG is reduced by 42%, relative to the baseline

Electric appliances, lighting etc.

The Mandatory Energy Performance Standards (MEPS) program has already resulted in worthwhile reductions in energy demand from appliance use. A recent study of the effect of both current MEPS and those foreshadowed, i.e. announced but not yet in force, (National Appliance and Equipment Energy Efficiency Program, 2003) estimated that existing MEPS would reduce demand by about 9% below BAU by 2020 and one new MEPS alone, the "One Watt" standby power requirement, will achieve a further 9% by the same date. Other new MEPS will achieve further reductions.

Such detailed modelling has not been undertaken for other appliance and lighting applications in Australia.

The UK study (Jonathan Fisher *et al*., 1998) summarises the findings of several other British studies which conclude that adoption of the full technical potential for improvements in the efficiency of lighting and appliances could results in reductions in energy demand from these applications of between one third and one half.

The total potential for improvement in the technical efficiency of all types of electrical equipment and appliances is assumed to be for energy consumption savings of 40% beyond the sectoral trend of 0.5% p.a.. This equates to a total reduction of energy consumption, relative to 2001 performance, of 51%. Note that the discussion paper by the Ministerial Council on Energy (2003) estimates the overall potential for energy savings from the Residential sector to be about 35% under the low scenario and 70% under the high scenario. For cooking, a relatively minor use of energy in this sector, we assume a more modest potential reduction in energy demand of 10% beyond the sectoral trend, equivalent to a total reduction of 24% compared with 2001 performance.

6.6. Transport

In order to estimate the possible call on energy resources by transport, and also to estimate the energy which may be required to process fuel for transport, we make some very simple assumptions about the future of the Australian transport system. The assumptions are:

- no change in the current mix of fuels, i.e. almost complete dependence on petroleum products, with the exception of electricity use for part of the rail transport task;
- an overall reduction in the energy intensity of road, rail and air transport of 36% (equivalent to 1.1% p.a.);
- an overall reduction in the energy intensity of water transport of 65% (equivalent to 2.0% p.a.).

These reductions in energy intensity arise through a combination of greater technical efficiency and structural change within the sectors.

As described in Chapter 4, the economic projections are for differential rates of growth for the various transport modes, with rail growing most and road transport least. The overall outcome is that energy consumption by transport is projected to increase by 45%, with a consequent large increase in consumption of petroleum products.

Our stationary energy consumption scenarios incorporate the additional energy consumption in oil refineries to produce this quantity of petroleum products. However, given the scope of this study, we have not considered whether crude oil resources available in 2040 will be sufficient to support this level of petroleum consumption. Neither have we explored fuel and technology options to petroleum. These could include greater use of electricity, or of natural gas or, conceivably, use of coal with CO_2 capture to produce hydrogen.

6.7. Fugitive emissions

The production and supply of energy from fossil fuel sources is associated with emissions of CO_2 and methane from a variety of activities not directly related to the combustion of the fuels to produce useful energy. As a group, these emissions are termed fugitive emissions.

In 2001 fugitive emissions were estimated to be about 32 Mt CO_2-e, which was 9.5% of emissions from fossil fuel combustion. This study is not directly concerned with fugitive emissions. However, because they are an important source of emissions from the energy sector, we consider it important to briefly describe what we consider to be achievable in terms of reducing emissions from this source.

The most important sources of fugitive emissions in 2001 were:

- uncontrolled venting of methane from underground coal mines 12.3 Mt CO_2-e
- escape of methane from open cut coal mines 6.2 Mt CO_2-e
- flaring of combustible waste gases at oil refineries, petroleum production facilities and gas processing plants 3.9 Mt CO_2-e
- venting of CO_2 removed from raw natural gas at gas processing plants 3.7 Mt CO_2-e
- leakage of methane from natural gas transmission and distribution systems 3.6 Mt CO_2-e

The means to reduce substantially the emissions from most of these sources are available, technically proven and to some degree already in use.

- Some underground coal mines already capture fugitive methane and use it to generate electricity, while others capture and flare the methane, which does not completely eliminate greenhouse gas emissions, but reduces them by about 87%, by converting methane to CO_2. Most other mines could similarly oxidise waste methane at an abatement cost of a few dollars per tonne of CO_2-e abated.

- Oil and gas companies have for some years been progressively reducing emissions from flaring by undertaking incremental process modifications. We expect that this trend will continue, and would be accelerated if the costs of greenhouse gas emissions were internalised or if oil and gas prices increase.

- Venting of CO_2 from gas processing can be almost completely eliminated by reinjecting the extracted CO_2 into suitable geological formations, which are normally readily available nearby, e.g. depleted petroleum reservoir formations. Such geological sequestration is already occurring on a fully commercial scale at one large gas field in the Norwegian sector of the North Sea. It is likely to become a condition of development approval for new natural gas projects, particularly those with high concentrations of CO_2 in the raw gas, and will in any case be undertaken when there is a price on greenhouse emissions.

- Most methane leakage from natural gas distribution comes from old and/or poorly maintained pipes. Leakage from high pressure transmission pipelines is very low, as it is from new low pressure distribution networks. Several Australian gas companies have made significant (commercially justified) investments to reduce gas leakage from older pipe networks and further reductions are achievable with a very modest price on greenhouse emissions or, in some cases, simply a change in regulatory incentives.

Of the current major sources of fugitive emissions, only those from open cut coal mines are relatively intractable. Consequently, we expect that in our clean energy scenario fugitive emissions will be much lower than they are today, notwithstanding the continued high level of coal mining for export markets, the level of natural gas production and processing for both domestic and export markets, and the high level of natural gas use in domestic markets.

6.8. The Medium Efficiency demand case

The effect of the foregoing assumptions about energy efficiency is to reduce energy demand in 2040 from the baseline value of 2,955 PJ to 2,352 PJ, a reduction of 20%. We have termed this demand projection the Medium Efficiency final energy demand case, because it includes a significant increase in energy efficiency, compared with the Baseline case, but nevertheless contains a number of conservative assumptions about the take-up of energy efficiency. For example, as already pointed out, the improvement in energy efficiency overall is less than that estimated in the report from the Ministerial Council on Energy (2003).

The distribution between major sectors is shown graphically in Figure 6.1, and more detail is provided in Table 6.1. Figure 6.2 shows the mix of fuel type in this Medium Efficiency demand scenario for 2040.

Figure 6.1: Medium Efficiency stationary final energy demand by major sectoral group, 2040

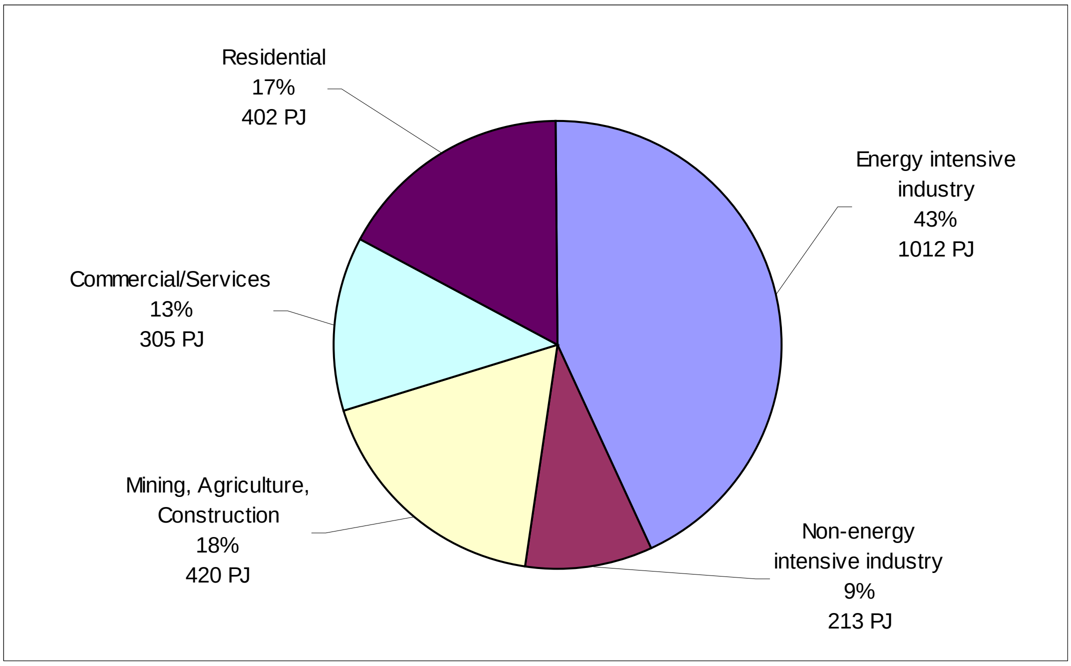
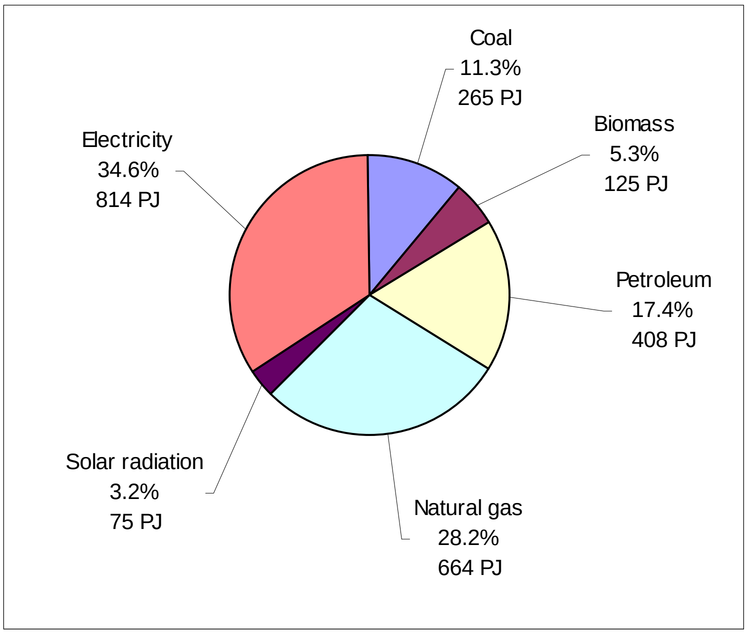


Table 6.1: Medium Efficiency stationary final demand for energy by sector, 2040

Economic sector	Energy consumption (PJ)	
Mining (incl. LNG and coal exports)	350	
Manufacturing	1,115	
Iron and steel		209
Food, beverages, tobacco		117
Basic chemicals		61
Cement, lime, plaster and concrete		53
All other non-metallic mineral products		68
Non-ferrous metals		412
Wood, paper and printing		100
All other manufacturing		95
Construction	97	
Commercial/Services	305	
Agriculture/Forestry/Fishing	83	
Residential	402	
TOTAL final stationary energy consumption	2,352	

Figure 6.2: Medium Efficiency stationary final energy demand by fuel, 2040



The effect of enhanced efficiency, relative to the baseline demand in 2040, is shown by sectoral group and by fuel in Figures 6.3 and 6.4 respectively. In the sectoral analysis, it can be seen that the enhanced efficiency has relatively little effect on demand from the energy intensive industries, because these are assumed to be taking up most efficiency opportunities as they arise, with consequent significant efficiency improvements in the baseline case, whereas increased efficiency has a big effect on the Commercial/ Services and Residential sectors, since these are where markets for energy services are least effective. The analysis by fuel shows that, as would be expected, the larger gains in energy efficiency in the Commercial/ Services and Residential sectors have most effect on demand for electricity, since that is the most important fuel for those sectors.

The energy intensive sectors have grown, in terms of value added, more slowly than the economy as a whole, so that in 2040 they account for just over 1.7% of GDP. However, their share of total final energy consumption has fallen only slightly, to 38, because, as explained, these sectors have less opportunity for really large gains in energy efficiency than the less energy intensive sectors.

The increased use of solar thermal energy is the result of the switch to solar water heating in the Residential sector, which in our modelling is analysed jointly with increased efficiency in this sector. In Chapter 9 we describe the effect of further fuel switching towards both solar thermal and natural gas, which forms part of the last stage of our analysis – decarbonising energy supply.

Figure 6.3: Medium Efficiency and Baseline final stationary energy demand by major sector, 2040

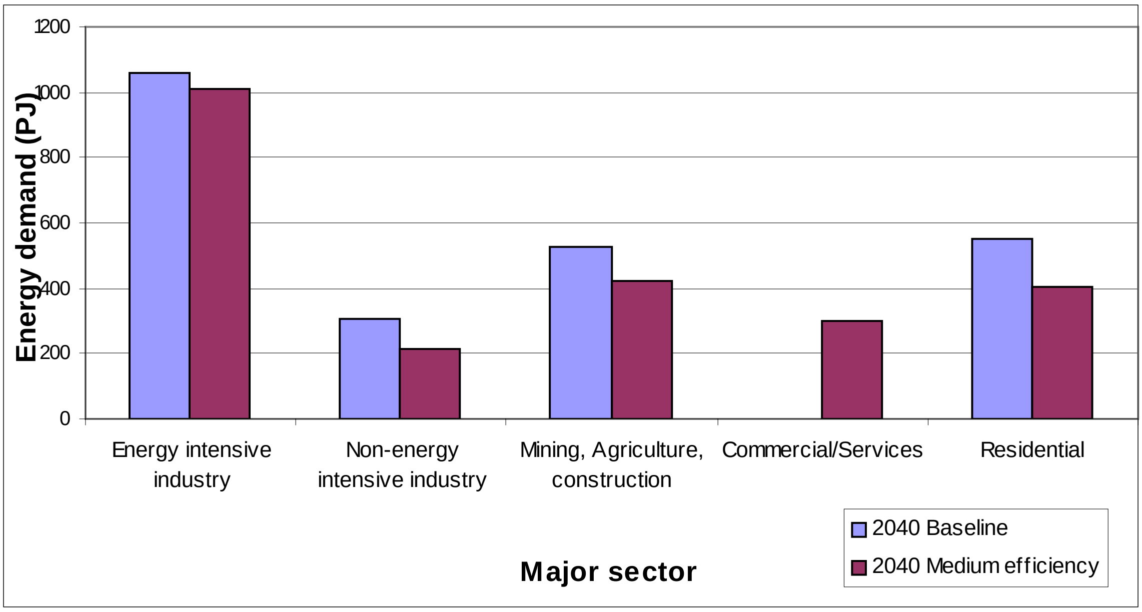
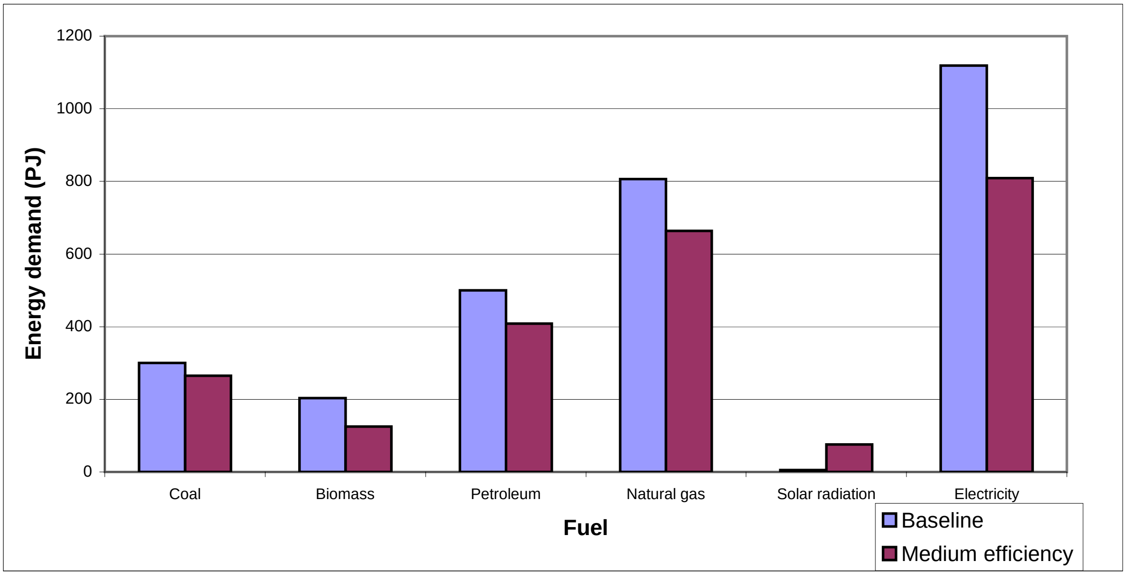


Figure 6.4: Medium Efficiency and Baseline final stationary energy demand by fuel, 2040 (PJ)



Figures 6.5 and 6.6 show the comparisons between the Medium Efficiency demand in 2040, and demand in 2001. The overall effect is to increase stationary final energy demand from 1,888 PJ in 2001 to 2,363 PJ in 2040, an increase of 25%. This compares with growth of 57% for the baseline case Energy demand per capita actually falls slightly, from 97 GJ in 2001 to 94 GJ in 2040.

It will be noted that demand for biomass is actually less than in 2001. This is caused by the great increase in efficiency of bagasse use in the sugar milling industry, which frees up a significant biomass fuel resource for additional generation of electricity. The greater technical efficiency in the sugar industry is also the reason that total demand for energy in the non-energy intensive manufacturing sectors is actually less than in 2001. Energy demand in the Residential sector is also less than in 2001, reflecting the great potential for increased energy efficiency in this sector.

Economic modelling for the Ministerial Council on Energy (2003) shows that a 50% penetration of a low energy-efficiency scenario over a 12 year period would deliver the following substantial economic benefits:

- real GDP would be $1.8 billion higher (+0.2%);
- employment would increase by about 9000 (+0.1%);
- stationary final energy consumption would be reduced by 9% (-213 PJ);
- greenhouse gas emissions from stationary energy would be reduced by 9%.

Accessing these benefits would require an investment in energy efficiency over the 12 years of approximately $12.4 billion (NPV terms) generating lifetime energy savings of approximately $26.9 billion (NPV terms). Overall these measures would achieve a 26% internal rate of return on investment.

The Ministerial Council's strong energy efficiency scenario, which envisages 100% penetration of end-use energy efficiency measures with a four year payback period or less, would achieve double the above greenhouse benefits (18% reduction). This is very similar to our own results for 2040, namely a 20% reduction in energy demand. Given that we are assuming a time period of nearly 40 years to achieve our assumed energy efficiency target we believe that this represents a reasonably conservative and readily achievable estimate.

Figure 6.5: Medium Efficiency final stationary energy demand by major sector, 2040 compared with 2001 (PJ)

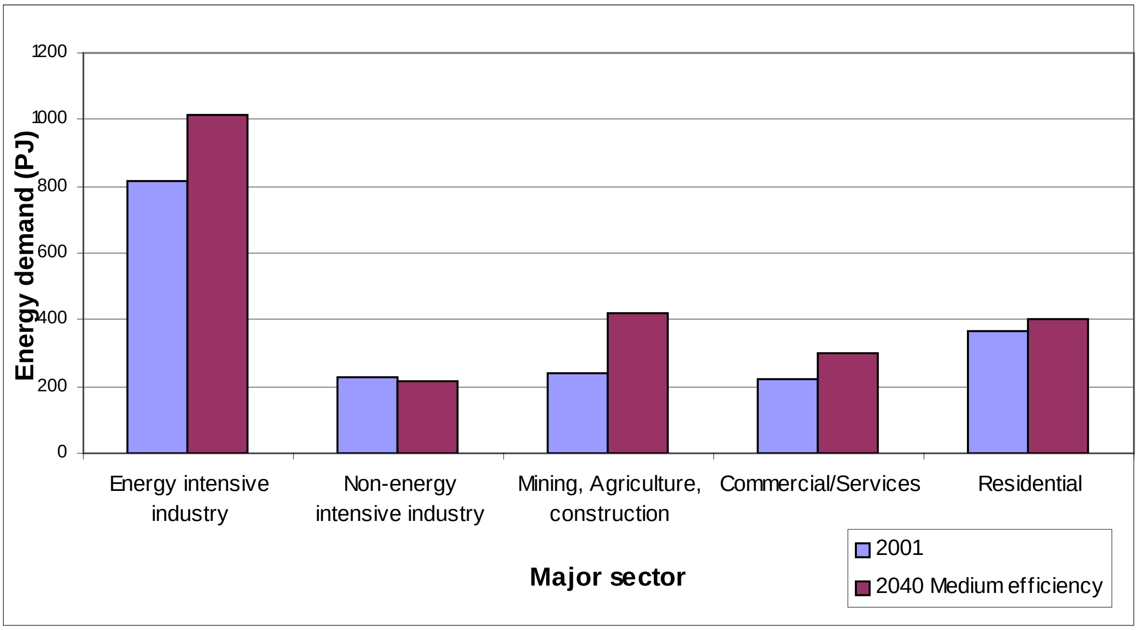
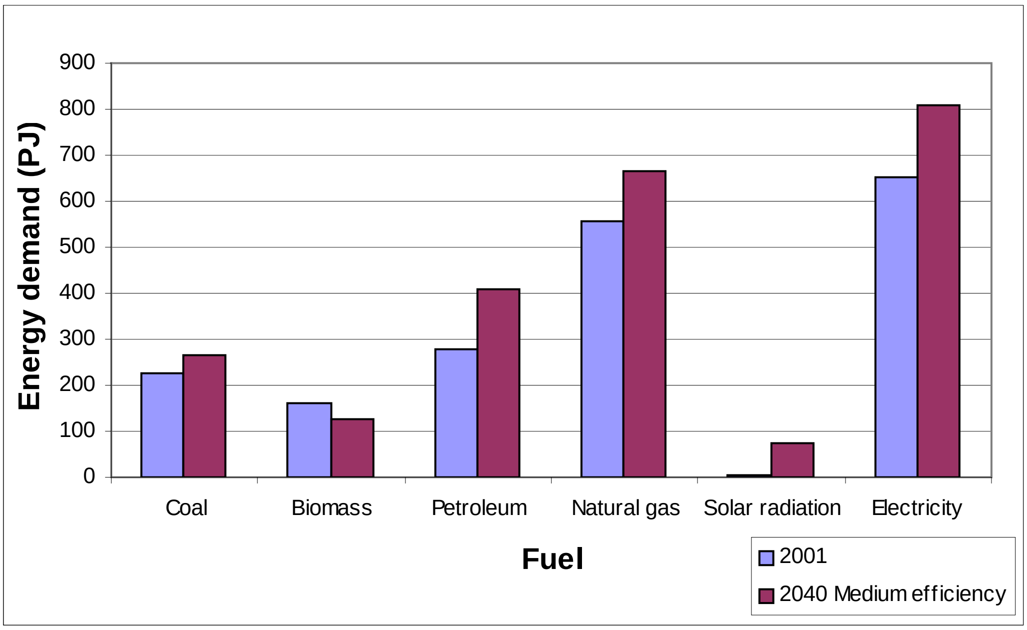


Figure 6.6: Medium efficiency final stationary energy demand by fuel 2040, compared with 2001 (PJ)



7. Present and Future Renewable Energy Technologies

Chapter 6 established a scenario for the demand for energy in 2040 based on a medium level of implementation of efficiency of energy use. At this stage we prepare the ground for the cleaner energy supply mixes presented in Chapters 9 and 10. To this end Chapter 7 reviews the present status and potential future development of several renewable energy technologies and Chapter 8 fulfils a similar role for fossil fuel technologies. The present chapter considers resources, technology development pathways, future costs and alleged limitations on deployment (e.g. land-use, grid integration). It is based on recent review articles, on Web sites and on interviews with several leaders in R & D and business in each of the major technologies being considered.

In our principal Clean Energy Scenarios (see Chapters 9 and 10), the main renewable sources are biomass, wind and solar heat. There are also a significant contributions from hydro-electricity (mostly existing) and, to a lesser degree, direct solar electricity. These are now discussed in approximate order of importance in the 2040 scenarios.

7.1. Biomass energy

Background

Biomass is material produced by photosynthesis or is an organic by-product from a waste stream. It includes a wide variety of renewable organic materials, including forestry and agricultural wastes and residues, urban tree trimmings, food processing wastes, woody weeds, oil bearing plants, animal manures and sewage, energy crops and the organic fraction of municipal solid waste. In photosynthesis, growing plants capture solar energy and carbon dioxide from the atmosphere to form carbohydrates. These may be used either by combustion of the solid fuel, or by converting them into other useful forms of stored energy, namely biogas (which is mainly methane) or liquid fuels such as methanol and ethanol. The energy conversion paths for biomass are diverse and include gasification for heat and power; pyrolysis to produce liquid and gaseous fuels; anaerobic digestion to produce a combustible gas; and fermentation to produce ethanol.

In 2000 combustible renewables and waste provided 11% of the world's total primary energy supply, dwarfing hydro (2.2%) and the other renewables such as geothermal, solar and wind (0.5%) (IEA, 2002). At present Finland derives over 20%, Sweden 17%, Austria 11% and Australia about 3.3% (about 170 PJ) of total primary energy supplies from biomass[1].

In terms of stationary energy consumption, Australia obtains about 9% from biomass. This includes about 120 PJ of process heat, but so far only about 500 MW of installed electricity generating capacity (slightly more than 1% of total capacity). Most of this biomass is bagasse, the fibrous residue of the sugar industry, and some is black liquor, a by-product of wood processing, which is used mainly in paper manufacturing.

[1] ABARE gives 202 PJ of biomass energy, but firewood experts suggest that the residential firewood component of this amount should be about 48 PJ instead of ABARE's 80 PJ.

About 48 PJ biomass is burned as firewood in our homes[2], often used inefficiently and producing significant air pollution. In addition, a small amount of biomass is co-fired with coal in a few base-load power stations.

In terms of reducing greenhouse gas emissions, biomass energy offers three different types of contribution.

- Solid and gaseous biofuels can substitute for fossil fuels (mainly coal and oil) in the generation of electricity and useful heat.
- Liquid and gaseous biofuels can substitute for oil in transportation.
- Biomass, especially timber, can be used in place of much more greenhouse intensive materials, such as concrete (e.g. in power poles and railway sleepers).

The present report is only concerned with the first of these greenhouse benefits.

For the purpose of generating electricity and heat in Australian sustainable energy scenarios, the key issues are:

- resource assessment and hence land and water availability,
- the choice of energy conversion paths and the allocation of a finite quantity of biomass fuels between heat and electricity on one hand and transport on the other,
- obtaining multiple benefits from bioenergy crops, in order to offset the additional costs compared to fossil fuels.

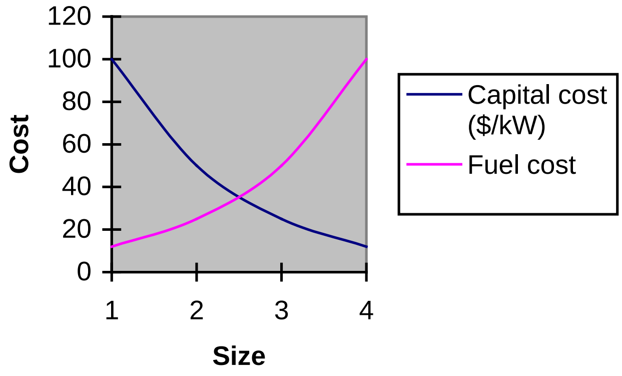
One important additional issue merits highlighting. Biomass energy can create far more jobs per unit of energy generation than fossil fuels and any other renewable source of energy (ERDC, 1994; MacGill, Watt & Passey, 2002). These jobs are diverse, ranging from extensions to existing agricultural and forestry activities through to specialised engineering and electronic functions. Many of them are located in rural areas where there is the greatest need for employment.

Solid biomass

The combustion of solid biomass is well understood, straight-forward, commercially available, readily integrated with existing infrastructure and low in cost, provided the fuel does not have to be transported long distances or stored under cover. As shown schematically in Figure 7.1, as the size or capacity of the power station increases, its capital cost in $/kW decreases, while its fuel cost increases as fuel has to be transported from further afield. There is an optimal size of power that minimises total cost. The optimum varies with geographic region, however it is usually much smaller than the economic optimal size of a coal-fired power station.

[2] See previous footnote.

Fig. 7.1. Optimal size of biomass power station in arbitrary units



The cheapest way to convert solid biomass into useful energy is to avoid the capital cost of a dedicated facility by co-firing the biomass in an existing coal-fired power station. In Australia, this is already occurring in a few power stations with typically about 5% biomass (in energy terms) combusted with coal.

There are also several small power stations burning 100% solid biomass, mainly bagasse and forestry residues. In some regions there is a potentially large market for small cogeneration plants fuelled with biomass. Such regions have a large local availability of biomass and large potential demand for both heat and electricity in small industries, horticulture and buildings. A well-designed biomass-burning power station emits similar particulates and much less nitrogen oxides and sulphur dioxide than a coal-fired equivalent.

Solid biomass fuels, in the form of wood and wood chips, and low calorific value biogas are relatively expensive to transport due to their low bulk and energy densities, and so transportation distances rarely exceed 40-80 km[3]. They may also decay slightly during the time required for transport and storage. On the other hand, wood pellets and liquid and medium to high calorific value gaseous fuels made from biomass are better suited to long-distance transport, as the energy inputs for transport are usually a small fraction of the energy content of the fuel. Domestic heating by burning wood pellets is much more efficient and less polluting than traditional wood-burning. It is expanding rapidly in northern Europe and could play a role in parts of Australia[4].

Gaseous and liquid biofuels

Compared with solid fuels, there is much less experience with the production and use of gaseous fuels and alcohols derived from biomass in Australia. However, ethanol is a mature industry here, albeit small. There is a need for demonstration projects to assist in choosing the most appropriate technology for a given fuel and circumstances, and estimating its likely future cost. Biomass may be gasified by heating it with steam and air/oxygen, but less oxygen than that required for conventional combustion. The resulting gas is of a low or medium calorific value compared with a higher calorific

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[3] In northern Europe, 40 km tends to be the limit. However, this depends on the prices of the biomass transported and the transport fuel.
[4] E.g. in Hobart, Launceston, Canberra, Cooma, Tamworth and Armidale, provided the source of the pellets satisfies environmental requirements.

value for natural gas and can be used in gas turbines and internal combustion engines. Alternatively, the biomass derived gas may be upgraded to a higher quality and may be converted to methanol. Potentially gasification could improve the efficiency of energy conversion, transportability and clean burning of biomass fuels. Of the gaseous fuels, landfill gas is the most widely used at present, with some 100 MW of installed generation in Australia. However, because most sustainable development practitioners consider that it is essential to phase out landfills, this source is not included in the 2040 scenario. It is well accepted that the priorities are to reduce the production of wastes, then to reuse and only after that to recycle or burn as a fuel. In the long run, biogas could play a substantial role in the generation of electricity and heat in 2040. This is likely to be via bioreactor cells and engineered anaerobic digesters.

The liquid fuels, methanol, ethanol and bio-oil[5], can be produced from biomass. At the present time methanol is exclusively produced from natural gas. With quite high energy densities (but significantly below that of petrol) and ease of handling, methanol, ethanol and bio-oil can be used conveniently for both stationary energy and motor vehicles. In future, these liquid fuels may be more convenient forms of energy storage and transportation than hydrogen in its gaseous, liquid or metal hydrate forms. Methanol burns more cleanly and efficiently than petrol in internal combustion engines[6]. More important from the perspective of the present report, methanol can be fed directly into some types of fuel cell to generate electricity (see Section 7.8).

Environmental and resource constraints

The large-scale production and use of biomass is subject to natural constraints. Bioenergy can have significant beneficial environmental, economic and social advantages. However, as with any development, care needs to be taken to ensure sustainability criteria are met. For instance, this could be achieved through independent certification of biomass sources and setting standards for its conversion and use. The main constraints, both natural and human, on the sustainable production and use of biomass fuels are:

- the land area required to grow biomass and the balance of food, fodder and bioenergy produced on that land; however, even a small reduction in meat eating or meat exports would make a large amount of pasture available for fuel;
- the availability of water, a particular problem in large areas of Australia;
- the environmental constraint to produce biomass crops from plantations on land that was cleared pre-1990;
- avoiding pests and diseases through selection of biomass varieties;
- the need to use biomass at a rate no faster than the rate it regrows;
- the management of any ‘wastes’, including reuse where possible; in particular, the need to return nutrients to land from which biomass is cropped;
- the cost in relation to the multiple socio-economic and environmental benefits;

[5] Produced by pyrolysis
[6] Indeed some racing cars run on methanol.

- the need to avoid further land clearing or conversion of forests into managed plantations (which have reduced biodiversity) for biomass production.

Properly sourced, collected and converted, using biomass energy has lower local air and water pollution and land degradation than coal use, as well as much lower net greenhouse gas emissions than all fossil fuel combustion processes. It can enhance energy security by substituting for imported oil. It also has value for adding to animal habitat and biodiversity.

Using agricultural and forestry residues

The cheapest sources of biomass energy are the limited resources of urban wastes and landfill gas; agricultural residues (including bagasse) and forestry residues. For these sources the cost of the fuel, where it lies on the ground, may be zero or even negative. Provided the processing plant is located near its fuel source and not too distant from consumers of the electricity, heat, or gaseous or liquid fuel produced, electricity generation and especially cogeneration of heat and electricity from residues may not be much more expensive than fossil fuels.

Australia is one of the worlds lowest cost sugar producers. Combustion of a sugar cane residue, known as bagasse, can produce both steam to run the sugar mill and electricity for the grid. Bagasse is available for about 8 months in the year and cannot be stored cheaply, and so supplementation by another fuel is advisable. At Rocky Point power station, sawmill waste plays this role. Dixon and Bullock (2003) find that, given appropriate capital investment in new plant, the total cogeneration potential of sugar mills in Queensland and New South Wales is considerable. They calculate that, based on high-pressure steam boilers that burn both bagasse and 80% of the 'trash' recovered from the fields[7], there is potential for total generating capacity of 1.65 GWe and energy generation of 9.8 TWh (35 PJ)[8]. However, the future potential of bagasse is uncertain, because in the short term it is dependent on possible restructure of the Australian sugar industry and in the long term industry viability depends on the level of sugar prices and alternate use to which the harvested land can be placed. The ability to produce renewable electricity would help to diversify revenue and assist in underpinning the economic viability of the industry.

Kelleher (1997) has estimated that the harvestable stubble residues from Australian grain crops (mostly wheat) and cotton in 1996-97 amounted to 68 Mt. Previously, stubble used to be burned off and this led to the structural degradation of soil, erosion and fertility decline in many areas. Nowadays conservation farming methods are prevalent and so crop residues are retained in many areas to protect the soil surface and conserve nutrients.

Since the area under all agricultural crops (not trees) in 1997 was about 20 million ha (Mha), this is equivalent to 3.4 green t/ha. Kelleher assumes that 1 green t/ha would be retained on the land to maintain sustainability of the soil. This leaves 48 Mt green

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[7] This level of recovery leaves sufficient 'trash' in the field for normal agronomic benefit.
[8] Dixon and Bullock (2003) estimate that a further advance in technology to biomass-fired integrated gasification combined cycle (see Section 8.3 for a discussion of the coal-fired equivalent)) could lift the potential capacity to 5.65 GWe and potential output to 34.5 TWh (124 PJ).

residue, which is approximately equivalent to 24 dry Mt[9]. Given that this has an energy content of about 20 GJ/ dry tonne, we obtain total energy available in the fuel of 480 PJ. Assuming that this is all converted to bioelectricity by direct combustion at 35% efficiency[10], it would generate 47 TWh (169 PJ), which is about 23% of Australia's electricity generation in 2001. This source would be further boosted by adding the residues from the existing plantation forestry. However, it would also be reduced by the lack of proximity of much of our agricultural crops to towns and cities. Some authors are also concerned that returning 1 green t/ha to the land may not be sufficient, so we assume here that 1.4 green tonnes/ha are retained, reducing the stubble contribution to electricity generation to 39 TWh (140 PJ) or 19% of electricity in 2001.

We have not attempted to evaluate the size of the resource from plantation forestry residues and the cost of generating electricity from it. However, we note that the Forest and Wood Products Action Agenda has a target of tripling Australia's plantation estate by 2020, and plantation residues (thinnings and logging residues) are likely to be quite large.

While biomass residues could make a substantial contribution to electricity and heat generation, they may not be enough to supply a zero coal energy mix (our Scenario 3 in Chapter 10), which may require about 330 PJ (92 TWh) of biomass electricity, and so dedicated energy crops may also form part of the future Australian clean energy mix.

Obtaining multiple benefits from biomass crops

Enecon (2002) have estimated the cost of electricity generated in a 30 MWe wood-burning power station to be 9.5 c/kWh. This may be compared with electricity from a new 1000 MWe coal-fired power station at 3.5-4.0 c/kWh. However, biomass electricity plants that are located close to country towns and regional centre may not have to pay transmission costs, which can be large in rural areas. Enecon points out that the remaining large price gap could be closed by assuming that growing and burning biomass has a substantial greenhouse gas reduction benefit and a value in reducing dryland salinity. We support the payment of salinity credits to farmers. However, we suggest that it would be less risky to grow an energy crop which has immediate multiple commercial benefits.

An example is the demonstration integrated wood processing plant that has just been built (but not yet commissioned) at Narrogin W.A., which will produce electricity,

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[9] Green biofuel contains a lot of moisture and typically has an energy content of about 10 GJ/green tonne. If it is oven dried, it loses about half its mass and its energy content becomes 20 GJ/dry tonne. In practice, it dries partially outdoors to the extent that its mass decreases by about 37% and energy content becomes about 16 GJ/tonne. For our 'back of the envelope' calculations of energy content, we reduce mass of fuel to hypothetical oven-dry tonnes by halving the green tonnage.

[10] The thermal energy conversion efficiency is largely a design parameter. If fuel is expensive, it is worth going to higher steam temperatures and pressures to get efficiencies equal to those of coal-fired power plants, i.e. 35-38%. Currently fluidised bed boilers being delivered to Germany at 20 MWe scale have efficiency of 35%. For 5-10 MWe plants, efficiency is typically 20-30% at present, however there is no technical barrier to increasing this to at least 35% too. Therefore we assume that 35% will be the norm for direct combustion of biofuels 2040. However, for integrated gasification combined-cycle power stations, 40% would be readily achieved.

activated carbon and eucalyptus oil from mallee eucalypts grown on farms in the wheatbelt of Western Australia. Mallee is the common name given to a tree that has many stems shooting out from an underground root mass just below the soil surface, known as the lignotuber or 'mallee root' (a prized source of firewood). During fire or harvest, the above-ground mallee stems are lost, but the starch-rich lignotuber remains intact underground. The mallee is able to sprout back from buds on the surface of the lignotuber, enabling the tree to survive. This process is known as coppicing. Benefits associated with planting mallees and other eucalypts on existing agricultural land include:

- decreased waterlogging and therefore increased cropping yields;
- reduction of dryland salinity;
- shelter for stock, and therefore increased lambing rates;
- reduced erosion by wind and water;
- increased biodiversity and aesthetic value.

Once established, mallees have the potential to generate multiple revenue streams However, at present the sizes of the markets for eucalyptus oil and activated carbon are limited. The first harvest is at age 4 or 5 and then re-harvests are every 2 or 3 years (depending upon the site) in perpetuity. Experience in the eastern States confirms that mallees may be harvested regularly for 100 years or more with no negative effects. This suggests that requirements for fertiliser may be very small[11]. Moisture supplies mainly determine mallee biomass yield and frequency of harvest. Mallees appear to be a promising option in terms of both economics and environmental benefits. (See www.oilmallee.com.au)

Mallee are arranged in belts along contours where they intercept the downslope movement of the water that is surplus in the annual plant agriculture. This is the unused rainfall that drives groundwater accumulation and hence salinity. Production of mallee on wheat farms will be low, on average about 3 dry tonnes per ha of farmland per harvest, assuming that mallee occupies 15% of the wheat farm. To assess the total resource, it is assumed conservatively that the period between harvests is 3 years and so the average annual yield is 1.0 dry tonnes/ha of farmland which is equivalent to 6.7 dry tonnes/ha of land actually planted with biomass. Given that there is 15.4 million ha of wheatbelt farmland in Western Australia alone and sticking with the 15% planting, the annual yield of mallee biomass in that state could be as much as 15.4 million dry tonnes/year. In one year an integrated wood processing plant would take in 100,000 green tonnes (50,000 dry tonnes) feed and produce 37.5 GWh of electricity, 3,450 tonnes activated carbon and 1,050 tonnes of eucalyptus oil (Western Power et al., c.2002). Therefore, the whole W.A. wheatbelt could produce 308 times as much of each product, including 11.6 TWh of electricity, equivalent to 1.54 GWe of capacity. This is more than W.A.'s baseload electricity generation in 2001/02. However, a more detailed examination may reveal that somewhat less than 15.4 Mha of wheatbelt farmland is suitable for growing mallee. At present about 4.4 Mha (5-year average to 2002) is actually planted with wheat. This suggests that mallee need not displace any food crops.

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[11] This depends on location and the presence or absence of nitrogen-fixing crops. In Western Australia there is a large reservoir of nutrients under many farms, too deep for annual crops but well within reach of tree roots.

On the basis of wheatbelt land areas, possibly 8-9 TWh of electricity could be generated from mallee grown in NSW, and 2-3 TWh in each of South Australia, Victoria and Queensland. Then total Australian electricity generation from mallee could be 25-30 TWh, still assuming 15% of land planted.

However, if we assume that the area of wheatbelt land that is not planted with wheat could be planted with oil mallee at a much higher density than 15%, so that the average density over 60 Mha of the Australian wheatbelt becomes (say) 40% (see Bartle, 2001), electricity generation would be 67-80 TWh. To confirm this, a detailed investigation of land use would be required.

Dedicated energy crops

If we take the annual electricity generation estimates of 39 TWh from stubble residues and wastes (based on Kelleher, 1997), 8 TWh from bagasse and sugar cane field residues (Dixon, 1997) and about 27 TWh from mallee in the wheatbelt, then, to supply 92 TWh in 2040, there is a shortfall of 18 TWh. (With a 40% planting of the wheatbelt there would be no shortfall.) To cover the shortfall, dedicated energy crops would be required.

Crops dedicated to bioenergy alone in economic terms are going to be less viable than crops with multiple economic benefits. To combat dryland salinity very large biomass plantings are required. Water will not be a problem, since they will draw upon underground water from the high water table which is bringing the salt to the surface. Giving an economic value to combating dryland salinity as well as the reduction of greenhouse gas emissions could improve the economics of dedicated energy crops.

Tree crops may also be planted to clean up waste water and to rehabilitate land that has been polluted with heavy metals, other toxic chemicals and excess nitrogen and other nutrients (Nicholas & McGuire, 2003).

Short rotation crops, with rotation periods typically 2-5 years, offer much higher annual yields of biofuels than long term tree crops (typical harvest periods 20 years or more).

In the UK it has been estimated that short rotation coppice grown on 15% of agricultural land could supply 20% of the country’s electricity (DTI, 1999, Annex 3, Fig.2). Although Australia generally has a much drier climate with poorer soils, its trees are not deciduous and grow in a warmer climate. The net result is that Australian yields per hectare are about *twice* those of northern Europe, where there are some thriving biomass energy industries. Furthermore, Australia has a lot more land that is suitable for tree crops, although much of this land is a long distance from potential consumers of the biomass energy. A comprehensive survey of Australia’s bioenergy resources has not been performed, although some valuable initial studies have been made, such as ERDC (1994) and the Bioenergy Atlas (accessible from www.brs.gov.au), which provides excellent maps and is currently developing its ability to provide quantitative tabulated data. Estimates of bioenergy potential have been made for particular sources such as grain crops (Kelleher, 1997) and bagasse plus sugar cane field residues (Dixon, 1997).

To obtain a rough estimate of the land area required for tree plantation crops (other than mallee in the wheatbelt) dedicated to bioenergy and grown on short rotation to generate biomass electricity and heat, we assume that on average 10 tonnes of dry matter can be harvested per hectare per year in Australia. Actually there is a wide range of variation, from 10 dry t/ha/yr for densely packed eucalyptus plantations in the dry Murray Darling basin to 35 dry t/ha/yr for eucalypts and other trees in moist south-east Queensland (Enecon, 2003). For average energy content of biomass we take 20 GJ/ dry tonne (20 PJ/ dry Mt). It seems reasonable to assume that in the future biomass from dedicated crops will be converted to electricity in integrated gasification combined cycle (IGCC) power plants with thermal efficiency of 40%. Then, to supply the remaining 18 TWh we require biofuel with energy content 45 TWh thermal or 162 PJ. This corresponds to 8.1 Mt of dry wood which requires 0.81 million ha (Mha) of land, which is about half the area of land currently under tree plantations in Australia.

In addition a much larger plantation area would be required for the production of liquid fuels, methanol and/or ethanol, to substitute for declining oil supplies[12] (Foran & Mardon 1999; Foran & Crane, 2002). These authors modelled the transition to an Australian biofuel economy in which dedicated short-rotation perennial tree plantations provide most of our liquid fuel and large fractions of our electricity demands in 2050. Table 7.1 summarises some aspects of the base case and three scenarios that each involve electricity generation and liquid fuel production together.

Table 7.1: CSIRO scenarios for biofuels for both electricity and transport

Scenario	Australia's CO_2 emissions in 2050[a] (Mt)	Land area under biofuel plantation[b] (Mha)	Bioelectricity generated in 2050[c] (TWh)
Base	1,200	6 (trees only)	negligible
Methanol + bioelectricity	800	31 (trees only)	194
Ethanol + bioelectricity	700	20 (trees + agricultural crops + residues)	no data supplied
'Radical' economy[d] + methanol + bioelectricity	270	16 (trees only)	116

Source: From data provided by Foran & Crane (2002) and Foran & Mardon (1999)

Notes:

a. For comparison, in 2001 Australia's total net CO_2 emissions amounted to 362 Mt and total net emissions to 528 Mt CO_2-e, including 38 Mt from Land Use Change.
b. This land area serves both liquid fuel and electricity production together.
c. The report does not state explicitly how much electricity is generated in each scenario. We have made the estimates in the 4th column by the same assumptions as set out above.
d. 'Radical economy' has a lower rate of economic growth than the other scenarios.

Concluding remarks on bioenergy

More detailed work is needed to evaluate the bioenergy potential of all the different climatic regions of Australia and to evaluate its economics, taking into account multiple economic and environmental values and proximity to population centres and powerlines. However, on the basis of the above estimates, it appears that biomass could make a substantial contribution to electricity, heat and transport in Australia and at most only a minor fraction would have to come from dedicated energy crops.

[12] However, this does not have to be all forest. Oil seed crops and high lipid content algae could also play a role.

Specifically for electricity generation it appears that all biomass crops and residues could together supply considerably more than 92 TWh (330 PJ) of Australia's electricity in 2040, without competing with food production. Furthermore, this outcome could be achieved without using residues from native forests. To permit this scenario to develop, it is essential to modify the MRET rules that currently do not allow trees to be grown specifically for bioenergy.

In the coming decades, there will be a need to use increasing amounts of biomass for both electricity generation and liquid fuels for transportation. Some recent studies envisage factories that produce both together in a flexible manner. During peak periods of electricity demand they could produce mainly electricity, thus gaining the best price for that product which is expensive to store, while during off-peak periods the factories can produce mainly methanol, which is itself a storable fuel. (Enecon, 2002)

For further reading, a wealth of general information on biomass energy around the world may be obtained from Bioenergy Australia, website www.bioenergyaustralia.org/. The international bioenergy collaboration within the International Energy Agency may be accessed via www.ieabioenergy.com. A valuable international journal is *Biomass and Bioenergy*.

7.2. Wind power

Background

Over the past decade, wind power has been the fastest growing energy technology in the world, growing at about 25% p.a. on average. At the end of 2002, global installed capacity was nearly 32 GW (32,000 MW); Denmark had the largest percentage contribution to electricity generation from wind power, 18%; Germany had the largest installed wind power capacity, 12 GW; and Australia's installed wind power capacity was 104 MW[13].

A wind farm, when installed on agricultural land, has one of the lowest environmental impacts of all energy sources.

- It occupies less land area per kilowatt-hour (kWh) of electricity generated than any other energy conversion system[14], apart from rooftop or building-integrated solar energy, and is compatible with grazing and almost all crops.
- It generates the energy used in its construction in just 3 months of operation, yet its operational lifetime is at least 20 years.
- Greenhouse gas emissions and air pollution produced by its construction are very tiny and declining. There are no emissions or pollution produced by its operation.
- In substituting for base-load (mostly coal power) in mainland Australia (see Myth 1, below), wind power produces a net decrease in greenhouse gas emissions and air pollution, and a net increase in biodiversity.

[13] At the time of writing (November 2003), Australian wind power capacity had reached 196 MW.
[14] Typically less than 2% of land area within the boundaries of a wind farm is actually used for roads and tower bases.

- Modern wind turbines are almost silent and rotate so slowly (in terms of revolutions per minute) that they are rarely a hazard to birds.
- Currently wind farms in Australia have about 40% Australian content and create 2-3 times as many local jobs per kWh generated as coal power (McGill, Watt & Passey, 2003). However, as wind power expands, Australian content is expected to rise to about 80% and so the number of local jobs per kWh will rise to 4-6 times those of coal[15].

The siting issue

Although wind farms are not permitted in national parks, there are some local community concerns about erecting them near other places of wild scenic beauty, such as at some sites along the Great Ocean Road in Victoria. The problem for wind farm developers is that the power in the wind is proportional to the cube of the windspeed. A reduction in annual mean windspeed from 8 to 7 m/s reduces the available wind energy by one-third and therefore entails a corresponding increase in the cost of electricity. Clearly, the planning authorities must weigh up the range of environmental, social and economic impacts of any wind farm project in their decision-making process. Stakeholders must recognise that we need a number of high-wind sites to assist in building up the industry and reducing greenhouse emissions, while protecting some special sites outside national parks.

The cost of electricity from a wind farm decreases as the annual mean wind power and the size of the wind farm increase. Currently land-based wind power has an installed capital cost in some overseas countries of about US $1000/kW peak. However, a very large order (500-1600 wind turbines) can reduce the price per kW by up to 45% from the list price (Junginger et al., 2003). Capacity factors at 'excellent' on-land sites are about 35% and at 'good' sites are 25-30%. Assuming a real discount rate of 8%, electricity from large (50-100 MW) wind farms at 'excellent' sites currently costs US 4-5 c/kWh. In Australia, corresponding prices, allowing for the cost of imported components, are 7.5-9 Ac/kWh.

By 'excellent' sites, we mean that the annual mean wind speed at hub height is 8 m/s or more. As the scale of installation increases both internationally and within Australia, the capital cost of machines and installation cost will decrease and it will become economically viable to install large wind farms at sites with annual mean wind speeds of 7 m/s. Wind energy prices are currently falling at a rate of around 4% per annum and this suggests that the cost at excellent overseas sites will decline to US 3 c/kWh by some time in 2010-2020. Whether Australian prices reach the corresponding level of A 4.3-5.0 c/kWh (as the A$ varies from US$0.7-0.6) will depend partly upon international trends, partly upon the exchange rate and partly upon whether the scale of installation increases to the extent that 80% or more Australian content is reached. A strengthening of the MRET would make today's more marginal sites more attractive, easing development pressure on sensitive parts of the Victorian coast.

[15] Since this was written the world's largest wind turbine manufacturer, Vestas, has opened a factory for manufacturing nacelle components in Wynyard, Tasmania.

At ‘good’ sites with 7 m/s annual mean windspeed the amount of land available increases by a factor of 20 over that available in excellent (8 m/s) sites (Gareth Johnston, WindLab Systems Pty Ltd, personal communication, 2003). Most of this land is inland pasture and is unlikely to been seen as important landscape to be preserved. On this land it should be possible to install at least 20 GW of wind capacity, as proposed in our scenarios. However, detailed published resource assessments still need to be done. The problem is building up the scale of installations in Australia to the extent that such ‘good’ wind sites become economically viable.

In our cleaner energy scenarios, we have assumed conservatively that mainly ‘good’ sites with capacity factor 30% will be occupied by wind farms in 2040 and that the average price of electricity at these sites will be 5.5 c/kWh.

Clarifying myths

In order to justify our scenario with 20% wind energy generation, we respond to three myths about wind power that are being spread by vested interests and some local groups.

Myth 1. Since wind power is an intermittent source, it cannot replace coal-fired power unless it has expensive, dedicated, long-term storage.

This claim was refuted 20 years ago in a series of scientific papers by a team of Australian scientists in CSIRO and ANU, who showed that wind power, like coal power, is a partially reliable source of power. In technical jargon, wind power has ‘capacity credit’ (Martin and Diesendorf, 1980; Haslett and Diesendorf, 1981). This was shown by means of three different methods: Monte Carlo computer simulations, numerical probabilistic models and mathematical probabilistic models of electricity grids containing various amounts of wind power capacity. The numerical probabilistic models used hourly-averaged real data to generate probability distributions for available capacity of thermal power stations, electricity demand and wind speeds. The scientists calculated loss-of-load probability (LOLP) for generating plant in the grid. In this way they addressed intermittency quantitatively. This early work has been confirmed and extended overseas by several different authors (e.g. Michael Grubb from UK and Alkemade and Turkenburg from the Netherlands) using a number of different probabilistic methods.

For relatively small penetrations of wind power into an electricity grid, the capacity credit of wind power is equal to the annual average wind power generated. In generation planning models, wind farms displace the amount of base-load power plant that has approximately the same annual average power output as the wind power plant. For example, in an electricity grid with total generating capacity of 10,000 MW, 2,000 MW of wind power would have an annual average power output of about 660 MW, so this amount of base-load capacity (coal in eastern Australia) could be retired or deferred. At the same time, to maintain the reliability (e.g. as measured by LOLP) of the grid at the pre-wind level, up to about 300 MW of peak-load gas turbines may have to be installed in grids without sufficient hydro plant. Because these gas turbines have low capital cost and rarely have to be operated, they are like reliability insurance with a low premium (Martin & Diesendorf, 1982, 1983).

It may be possible to operate an electricity grid with 40% or more of its energy generated from the wind, without highly expensive long-term storage. The small stand-alone wind-diesel system at Denham W.A. is currently generating 42% of its annual electricity output from the wind, without any storage. This has been achieved by using specially developed 'low-load' diesels, whose output can be varied down to zero or even negative load, together with a boiler into which excess wind electricity is dumped and sophisticated power electronics. Wind farms feeding into state or national grids have the advantage of spatial diversity of wind power, back-up gas turbines, which are cheaper and more convenient to operate than diesels, and the generalised back-up that the whole grid can supply. Nevertheless, as more and more wind power is connected into the grid system, it needs more and more peak-load back-up and some wind energy is wasted during off-peak periods. Therefore costs increase. Computer modelling shows that the average cost of 40% wind power penetration plus gas turbine back-up would be considerably higher than if only 8% of grid energy came from the wind (Martin & Diesendorf, 1982). However, in the real world, this cost increase would be offset to some extent by the reduced cost of wind turbines in large-scale mass production.

In most of the Australian States (though less in Victoria), it is possible to vary the output of coal-fired power stations substantially over a period of an hour or so to help follow variations in demand and in wind power. In this case, these coal power stations are said to be operating as intermediate load. Since the main changes in weather patterns and associated wind conditions tend to occur every 5-8 days or so, intermediate load stations can help handle the slower variations in the output of a large amount of wind power plant.

To be fair, before charging the additional costs of peak-load back-up and intermediate load power variations against wind power, we should also take into account the cost of backing up coal-fired stations. Although the latter break down less frequently than the wind farms suffer calms, the duration of breakdowns of coal stations is generally longer than that of wind calms. Backing up an electricity grid's coal-fired power stations requires additional base-load. In the interconnected eastern Australian grid, the National Electricity Market Management Company (NEMMCO) currently requires a total of 750 MW back-up for existing base-load plants. Whether this back-up is provided by the other coal-fired stations (the usual case) or by gas-fired stations that have to be run for quite long periods, this is expensive. An isolated electricity grid, such as Western Australia's, has to provide a much larger proportion of back-up for its fossil-fuelled base-load stations, possibly 20% or more of total grid capacity.

Thus, large blocks of wind power, with rapid response back-up either from hydro or gas turbines and slow response from intermediate load stations, can provide reliable base-load power and substitute for some coal power. This is not just theory, but is actually happening in countries that have made a major commitment to wind generation. In 2002 Denmark generated 18% of its electricity from wind power and still plans to increase this substantially. There are problems and costs with handling such large wind inputs, but they appear to be manageable. As wind capacity and generation have increased in Denmark, coal capacity and generation have decreased.

The operation of electric generation systems containing large amounts of wind power capacity is being facilitated by improved wind forecasting models, increasing geographic diversity of wind farms and improvements in the control of individual wind turbines and wind farms. Recognising these advances, the German Government is planning for the generation of 25% of electricity by 2030.

Myth 1a: Because of wind power's intermittency, it has no value in meeting peak demands

This is a variant of Myth 1. It is often presented in a context that assumes incorrectly that peak demands are the only times that loss-of-load events occur due to insufficient generation. In practice, such events occur at other times as well (e.g. when one or more base-load power stations have breakdowns), and the only accurate way to assess their risk with different generation mixes is to perform probabilistic calculations, as done in response to Myth 1. As indicated there, the combination of wind farm and gas turbine or hydro back-up can be just as reliable as a coal fired power station. An aeroderivative gas turbine would be particularly valuable as backup, because it can be brought from cold to full power with 3 minutes. There seems to be no good reason why such a combination should be denied status as dispatchable power.

Myth 2: To maintain a steady state of voltage and frequency requires much additional expense.

In Australia, with its centralised generation and long-distance transmission lines, maintaining voltage and frequency is already an expense, even where there is no wind power plant installed. Until recently, installing a large wind farm increased voltage and frequency fluctuations and required additional equipment at additional cost. However, new types of large wind generators that are already coming on line, with variable speed drives and power electronics, can control voltage and frequency *locally* at no extra cost.

Although local fluctuations in voltage and frequency can be handled, there are still problems for the whole grid if there are big power fluctuations resulting from sudden changes in wind speed, or a sudden shut-down or start up of large amounts of wind power capacity. These can be ameliorated to some extent by installing wind farms separated by large distances in different wind regimes, and by using computer control to stagger start-ups and shut-downs of individual wind turbines in a wind farm. These precautions are already being done with new large wind farms in Europe. Then, it becomes very unlikely that the whole wind input to the grid would be lost simultaneously. Further protection can be obtained by using an aeroderivative gas turbine with a wind farm, or allocating some occasional hydro back-up, if such plant are part of the grid.

This issue is discussed in much more detail by Outhred (2003).

Myth 3. There are necessarily large energy losses in transmitting wind power to end users.

Currently about 10% of electricity sent out from centralised power stations is lost in long-distance transmission and local distribution. The transmission component of this loss is about 3% in NSW and Victoria, and is somewhat higher in the other mainland states. Distribution loss varies with locality. In some localities where there are regional population centres, the electricity from local wind farms has less transmission losses than electricity from more distant coal-fired generators. However, electricity generated by the majority of wind farms in 2040 will have to be transmitted to the major population centres. Although losses can be significant where wind power feeds into weak transmission systems, for large wind power generation connected by extra high voltage transmission lines, losses are small.

Rather it is the capital cost of transmission lines that constrains locating such wind farms a long distance from the grid. The capital cost means that decisions on the locations of wind farms involve some degree of trade-off between high wind speed and distance from the existing grid. Wind farm proponents argue that, if State governments are serious about renewable energy and decentralised development, they will fund grid extensions to tap our best wind resources.

There is precedent for this. In the 1940s and 1950s small battery-charging wind generators were widely used on farms. This domestic wind power industry was wiped out by the spread of the (then) heavily subsidised transmission and distribution lines into rural areas, carrying electricity from centralised coal-fired power stations. More recently Victorians funded an expensive transmission line from the power stations of the Latrobe Valley right across the state to the ALCOA aluminium smelter at Portland[16]. The Murraylink (Vic – SA) interconnector, which provides increased access for NEM generators into the SA market, has been given regulated status and will be paid for by Victorian and South Australian electricity customers. The Business Council for Sustainable Energy argues that network access principles should be applied in a consistent manner to both incumbent and new generators. All generators should receive distribution and transmission augmentation up to a pre-determined level that reflects the benefits that customers receive. This should form part of the regulated cost recovered from customers

Further information on wind power is available from the websites of Australian, US, British and Danish Wind Energy Associations: see www.auswea.com.au, www.awea.org, www.bwea.com, www.windpower.dk.

7.3. Solar heat

Solar energy, collected with either flat-plate or evacuated tube collectors, is an established commercial energy technology for heating water to temperatures below 100˚C. When solar energy is collected with concentrators, which are more expensive than flat-plate collectors, it can be used for producing low-temperature commercial and industrial heat for a variety of purposes. In this case there are several pilot plants in Australia and a niche market is opening up. With more intense concentration of sunlight, still higher temperatures can be achieved and electricity can be generated, as discussed in Section 7.6.

Solar hot water

Domestic sales of solar water heaters (SWH) have been growing by more than 30% over the last two years due principally to MRET. Sales of SWH are currently running at 36,000 units per annum which is 5% of total water heater sales in Australia.

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[16] This is a separate subsidy to the ongoing subsidy paid by Victorian electricity consumers on electricity purchased by the Portland aluminium smelter – see Turton (2002).

Hot water accounts for 27% of residential energy use. Our principal scenario for 2040 assumes that essentially all residential hot water in mainland Australia is provided either by solar or, if the roof is shaded or building is high-rise, by electric heat pump. Where natural gas is available, it is assumed that gas-boosted solar systems are used on half the rooftops and solar electric or heat pump systems on the other half[17].

According to SEDA's hot water cost calculator on the Energy Smart Website, www.energysmart.com.au/les/, for an additional investment of $800-$2,100 above the price of a conventional electric hot water system, a solar hot water system installed in NSW can pay for itself in approximately 5-10 years, depending on a household's water consumption and the strategy chosen for boosting. The solar hot water system boosted by electricity and the electric heat pump system pay for their additional up-front costs the fastest. Although it is more expensive, the solar gas system reduces greenhouse gas emissions to a much greater degree than solar-electric or heat pump (although this is not shown in the calculator) and its total capital plus operating cost is still less than that of conventional electric after 10 years.

At present the main disadvantages of solar hot water are its high up-front cost, the very low cost of off-peak electricity used by standard electric water heaters, the lower price of standard water heaters and the situation that some Councils require planning permission to install solar hot water, but not its competitors.

As in the case of photovoltaics (see below), there are two approaches to address the up-front cost of solar hot water. First is to produce low-cost solar hot water systems by moulding them from plastic and combining the collector and tank into a single unit. A commercial example is the Solco Industries system, for which the compact manufacturing plants have been exported to tropical developing countries for decades. The Solco system is now being sold in Australia. Another plastic system, based on similar principles, is under development by Gough Industries.

Solar heat at temperatures above 100˚C

The second approach is to produce more efficient but more expensive systems than the traditional flat plate solar collector. Since 2001 Solahart has been manufacturing such a system based on evacuated tubes originally developed at the University of Sydney. It works in both hot and cold climates and can generate heat at 150˚C or more. Therefore, it is not limited to producing residential hot water, but can also be used in space heating and in industrial applications such as food processing, desalination and brewing, which require large volumes of very hot water, and solar air conditioning and refrigeration that require the production of temperatures above 150˚C.

CSIRO has developed a hybrid energy system, that uses solar heat collected with a paraboloidal dish developed by Solar Systems Pty Ltd, to convert natural gas into a fuel with higher energy content and higher economic value. The process is known as 'reforming' natural gas. The gas is combined with steam to form a 'synthesis gas' which is a mixture of carbon monoxide and hydrogen. This gas can either be used as it is, or further upgraded into hydrogen and CO_2, followed by recovery of CO_2 in a

[17] Gas-boosted solar hot water systems are much more efficient in terms of greenhouse gas emissions, but are considerably dearer than electricity-boosted or heat pumps systems.

concentrated form, as required for a subsequent CO_2 disposal process such as geosequestration. For further information see http://www.energy.csiro.au/factsheets/solarthermal.htm.

7.4. Hydro-electricity

Hydro generation currently represents over 90% of Australia's existing renewable electricity generation capacity with total energy production of 16 TWh (60.4 PJ) per annum, about 8% of Australia's total electricity generation. Most is generated from large dams in the Snowy Mountains Scheme near the NSW/Victoria border, from Southern Hydro's power stations in Victoria, and in various schemes in Tasmania. The International Hydropower Association (2003) estimates that for Australia only 49% of technically feasible hydropower has been developed. However, strong and consistent public opposition has made it unlikely that any more large dams will ever be built. Nevertheless, there is potential for increasing the TWh contribution from hydro-electricity through maintaining and refurbishing existing assets.

Existing hydro generation assets are old, on average 45 years old. The hydro-electricity industry states that, in a competitive electricity market, there are significant pressures on maintaining the existing output and that with ageing assets this task is a big challenge. Hence, the industry seeks incentives under MRET to maintain the existing output and deliver the expected amount in 2040.

This would stimulate the hydro power industry in a number of ways:

- changing water storage management practices so that output is increased;
- improving the efficiency of the way stored water is used to increase output and also plant capacities (i.e. ability to meet peak demands);
- upgrading and refurbishing turbines, generators and other plant to increase output; and
- constructing new hydro plants, such as micro and mini hydro, and adding generators to existing dams and structures.

The industry estimates that as a result of such stimulus the efficiency of existing plants could be increased by 6% on average and capacities by up to 30%. To enable MRET to assist existing hydro as well as new renewable electricity sources and solar heat, we recommend in Chapter 11 a large increase in MRET.

Australian Governments are investigating the potential for water trading schemes in a number of Australian states. Such schemes will put a true value on water at different locations, thus encouraging users of this precious resource to optimise water releases for both irrigation and energy production.

In the electricity supply mix of our principal scenario for 2040, we assume that Australia's hydro-electric generation has increased by 10% over that of 2001.

7.5. Photovoltaics (PVs)

At the end of 2002 the total capacity of PV installed in IEA countries was 1334 MW and its rate of growth about 30% p.a. over the past 5 years. Australian installed capacity at the end of 2002 was 39 MW. PVs are one of the most promising renewable sources of electricity, but also currently by far the most expensive.

They are promising because:

- there has been rapid progress made over the past two decades in R & D, improving manufacturing processes, reducing costs and establishing small but rapidly growing niche markets;
- PVs can be readily installed in a modular fashion on rooftops and integrated with building envelopes near electrical loads. The total potential capacity far exceeds Australia's current electricity demand;
- PVs require very little maintenance, apart from occasional cleaning and replacement of the inverter once in their lifetimes, and so are highly suitable for ordinary households.

They are expensive because of the costs of PV modules, balance of system (inverter to produce AC from DC electricity, mounting, meter, cabling and accessories) and installation, and because of their low capacity factors (see below).

They can be used in three principal ways:

- installed on rooftops at the points of use where they have to compete with retail electricity prices;
- installed as small grid-connected power stations more distant from consumers, where they must compete with the generation costs of conventional power stations. In this case their land requirements and maintenance costs (for tracking systems) are larger than for fixed household systems, but still relatively small.
- installed as stand-alone power supplies with battery storage, or in hybrid systems with diesel or petrol generators as back-up, for homes and farms in more remote areas, and industries and infrastructure in niche markets in many locations (e.g. telecommunications, telemetry, beacons, public lighting, portable signs, water pumps).

The potential for the third category of use is very small in terms of its potential contribution to Australia's greenhouse gas reductions, because the vast majority of Australians are connected to the grid. However, in terms of industry development, the off-grid market offers about 500 MW of peak and billions of dollars of value and is therefore an excellent means of building up the industry (Blakers and Diesendorf, 1996). At present excise exemptions for rural diesel users and cross-subsidies on the price of rural grid electricity are undermining PV's potential in rural and remote areas.

The future of PVs in the first two categories of use depends critically upon whether the price reductions of the past 20 years can be continued into the future. Currently, PV modules in bulk cost about US$2.7 per peak watt, having declined from about US$20 per peak watt in 1981, using fixed year 2000 currency. Whole PV systems connected to the grid (i.e. no batteries) cost US$6.5-8.1 per peak watt if less than 10 kW and US$5.4-7.1 if greater than 10 kW. A major international study (Music FM, 1997) suggests that, if global production could be increased to 500 MW peak per annum, the cost of PV modules would decline to below 1 ECU per peak watt (or approximately US$1 per peak watt). The study focuses on conventional crystalline silicon PV modules. Strong targets established for PV in Japan, Germany and the US, that are supported by domestic policy measures, are underpinning the rapid growth that has been observed over recent years (over 35% per annum) with prices falling by 18% in real terms with every doubling of installed capacity.

Two Australian PV experts from different R & D groups have reservations about this decrease in price continuing at the current rate. Martin Green (2003) from the University of New South Wales, supported by Peter Lawley from Pacific Solar (personal communication, 2003), argue that current bulk wafer and ribbon approaches are too material-intensive for this to occur. They expect the rate of cost decline to slow, as indeed it has for wind power. Green (2003) suggests that shifting to 'rugged' thin films will be required to achieve the US$1/watt target. He points out that thin films are cheaper than bulk silicon for a given production volume and that this suggests a greater potential for low costs in the long term as production volume increases. Andrew Blakers from the Australian National University also believes that technological innovation, possibly Sliver® Solar Cells[18], will be required to achieve the target. This means that the timescale for achieving the target and the risk of not succeeding may both be greater than expected in the Music-FM study.

Even if this target is achieved, PV systems are likely to be still one of the most expensive sources of electricity. This is because the module cost is only one component of the total system cost, and because the capacity factor[19] is quite small, taken to be equal to 15.8% in the MRET Zone 3 which includes Sydney, Brisbane, Perth, Adelaide and Canberra. Although the MRET value is a little below optimum values that are technically possible (0.17 for Sydney), Lawley argues that it takes into account non-optimal installations and gradual reductions in output with PV module age.

Other significant cost components are the inverter, which will have to be replaced once or twice during the expected 25 year lifetime of the system, installation cost, quite significant on rooftops, and mark-up between wholesale and retail prices. Accepting the US$1/watt target for PV modules, assuming that inverter prices will decline to A$1/W under mass production, that two inverters will be required over the system lifetime, that installation price is about A$1/W, and using levelised annuity over 25 years at 5% real discount rate[20], gives a projected economic price in 2003 Australian currency of about 19 c/kWh for rooftop systems. In the case of PV power stations we use 8% discount rate and obtain a price of 18 c/kWh.[21].

The rooftop price of 19 c/kWh is only a few c/kWh above current retail prices of electricity for small business consumers in several capital cities (15-17 c/kWh) and (cross-subsidised) rural electricity prices in several states (15-19 c/kWh), and so we consider in our scenarios that a large fraction of this market will have PVs in 2040.

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[18] The Sliver® Solar Cell uses one tenth of the silicon used in conventional solar panels while still matching power, performance and efficiency. Origin Energy has announced December 2003 that construction of a manufacturing plant for these cells is under way in Adelaide and that the cells will be on the market in early 2005.

[19] Average annual electrical power output from the inverter divided by peak or rated power, usually expressed as a percentage.

[20] We have used a 5% discount rate for residential PVs, because it is close to a home mortgage rate and therefore seems more appropriate for this case. If we had used 8% (as we have done for all grid-connected power stations) the price of residential PV electricity would become 25 c/kWh.

[21] Installation and maintenance are cheaper than in the residential case.

However, 19c/kWh is far above current residential electricity prices (typically around 11-13 c/kWh) in capital cities other than Darwin (16 c/kWh). (ESAA, 2003).

One way that PVs could possibly come close to competing in the residential electricity market of most cities is for energy retailers to supply consumers with time-of-day meters and introduce peak-load pricing[22]. There is also potential for further reduction in installation, retail and distribution costs, beyond the levels assumed above. Retail outlets could expand as grid-connected PV becomes more like other mass marketed white goods (including air conditioners). Our scenarios assume that these changes have occurred by 2040 and as a result the gap between conventional grid electricity and PV electricity has been reduced to the extent that a small but significant fraction of urban residential consumers install PVs on their roofs.

Since PV power stations, located at a distance from consumers, must compete with conventional power stations and much cheaper renewable energy sources such as biomass and wind power, their prospects do not appear to be promising in economic terms. Their main hope is to be high-value providers of peak power. To do this, they would have to be granted value for meeting the summer peaks with a high degree of probability. Some utility engineers may argue that PV power stations would need the equivalent of overnight electrical storage, which is currently expensive. However, we assume conservatively that cheap electrical storage will *not* be available by 2040, that in future the height of summer peaks will be controlled by a price mechanism and therefore that PV power stations will make a small but significant contribution to summer peaks without overnight storage.

7.6. Solar thermal electricity

While PV has growing commercial niche markets, solar thermal electricity (STE) exists as a few experimental and demonstration power plants of various types scattered around the world. While PV currently seems most suitable for rooftop supply in competition with retail prices for small business and rural areas, STE is more suitable for power stations. Nevertheless, STE has a potential advantage: to become a high value source of peak-load electricity, since in that role it only needs thermal storage, which is generally less expensive than electrical storage. A new STE plant to be built in Spain will use molten salt storage at a low cost (see below). So, there is the possibility of complementary roles being played by STE and PV.

Several different types of solar collector are used in STE and indeed can also be used by PV:

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[22] The growth in air conditioner sales across most states in Australia is significantly increasing peak power demands. This not only requires considerable investment in additional peak-load generation but also considerable network investment. As an example, network businesses in NSW expect to spend $5 billion over the next five years to meet growing power demands. Power produced from a PV system has a good correlation with peak summer power needs. Unfortunately consumers do not pay for the full costs that they impose on the electricity system. The Charles River Associates report for Integral Energy, dealing with the impact of air conditioning on Integral Energy's network, identified that customers without air conditioners were subsidising customers with them by some $80 to $100 million per annum. The cost to add network related to peak demand was found to be $91 per kW per annum (page 26 of the report). The contribution of customers with air conditioners was about $1 per annum.

- parabolic trough;
- paraboloidal dish;
- an array of flat mirrors focusing on a 'power tower';
- others, such as Fresnel focusing.

The largest collection of STE power stations in the world is rated at 354 MWe, is based on parabolic trough collectors, with sections of these stations having operated for up to 15 years in southern California. After a long period of neglect by governments world-wide, there are now improved prospects of an increase in demonstration STE plants, because it is being included under solar feed laws and renewable energy portfolios in several places overseas. Spain is paying Euro 0.12/kWh plus about Euro 0.04/kWh wholesale electricity price for this source of electricity. In Germany STE is to be included under the Solar Feed Law in 2004; in the USA, Nevada and probably New Mexico and California will include STE in mandatory renewable energy portfolios.

The University of Sydney's approach

Much of the following is based on an interview in September 2003 with Dr David Mills of Sydney University, where a new company, Solar Heat & Power, has been established. For Australia, Mills proposes a two-step process for industry development of STE:

Step 1: Further experience and acceptance of the technology are gained by installing it to preheat feed-water going into coal-fired power stations. Feed-water is the water that is heated by burning coal to produce steam to turn the turbines. Preheating by solar energy will save a little coal. Mills estimates that the maximum contribution per power station is about 7% of energy generation, provided land is available. Because there is no need for storage and because the land, owned by the generator, is free, the cost of electricity is quite low, estimated to be 5-6 c/kWh. Taking into account the area of suitable land available close to power stations, Mills estimates that there is a niche market in Australia equivalent to about 1000 MWe.

The first of these plants is currently (October 2003) being installed by Macquarie Generation at Liddell Power station, which has an installed capacity of 2000 MW of coal power. The land area and funding are limited, and so the solar contribution has capacity 35 MW, with capacity factor 14%. The solar collectors are mirrors that are almost flat, are set up close to the ground in 300 m lines, and are lower in cost than collectors used overseas in STE plants. These collectors cost only $\$65/m^2$, compared with solar hot water collectors at $\$200/m^2$. In general, this system covers one-third the land of ordinary trough collectors, because of less shading between lines of collectors.

Step 2: If thermal storage can be achieved at low cost, Mills proposes that large STE systems could be established in high-insolation regions where there are large flat inexpensive land areas and rural load centres near the end of transmission lines. Possibly suitable sites are near Moree and Cobar, NSW, each town being at the end of a 132 kV transmission line. With a big array, a steam turbine designed for pressurized water reactors could be purchased relatively cheaply. The potential size of the total Australian STE resource near the electricity grid has not been estimated. The costs of storage in molten salt are currently about US$25 of capital cost per daily kWh stored[23].

Because this is new technology, we only include Step 1 in our principal sustainable energy scenarios to 2040. However, it is clearly one of the potential big resources for the new technology scenarios.

The Australian National University's approach

Another STE technology, based on paraboloidal dish collectors, has been developed at the Australian National University. The collector produces steam which generates electricity by means of a steam engine/generator. The largest version of this system, the 'big dish', has an area of 400 m^2 and generates peak electric power of about 50 kW (Lovegrove et al., 2003a).

Another team at ANU has developed a thermochemical storage system based on the dissociation of ammonia. This storage could be used either with a paraboloidal dish or a parabolic trough collector to produce 24 hour power.

Cost estimates for both the steam version and the ammonia storage version under future mass production are both about 15-16 c/kWh (Lovegrove et al., 2003b). If this could really be achieved with storage, the system would be competitive with the real cost of rural electricity both on-grid and off-grid, and with peak-load residential and small business electricity in urban areas, provided time-of-day pricing is introduced.

7.7. Other renewable energy technologies

The following renewable energy technologies are either limited in terms of siting, or are not sufficiently developed to permit good estimates of future costs. Therefore they are not part of our principal sustainable energy scenario, which is based on small improvements to existing technologies. Nevertheless, some could possibly become major contenders in a future energy mix.

7.7.1. Hot dry rock geothermal

Heat is generated by the decay of radioactive isotopes in granites located 3km or more below the Earth's surface. The heat inside these granites is trapped by overlying rocks which act as an insulating blanket. The heat is extracted from these granites by circulating water through them in an engineered, artificial reservoir or underground heat exchanger, bringing steam to the surface. Standard geothermal power stations (e.g. as located in New Zealand and California) convert the extracted heat into baseload electricity by using steam turbines.

Hot dry rock (HDR) geothermal energy relies on existing technologies and engineering processes such as drilling and hydraulic fracturing, techniques established by the oil and gas industry. HDR is 'firm' base-load power and is relatively

[23] This rather confusing method of measuring storage cost means that, if the lifetime of the system is 20 years, the actual energy stored 'per daily kWh' is 20 x 365 = 7300 kWh, and so the cost of storage in more familiar units becomes US$25/7300 = US 0.34 c/kWh.

environmentally benign, as it does not produce greenhouse gases. However there are concerns relating to handling of contamination built up in circulated water. Australia’s potential HDR resource is very large, but at this stage it is uncertain whether a large resource is located near the electricity grid. The cost of proving the potential by drilling is significant and the cost of a demonstration HDR plant is likely to be higher than most direct solar and biomass power demonstrations.

An Australian public company, Geodynamics Ltd, has secured two HDR geothermal tenements in the Hunter Valley in New South Wales and two in the Cooper Basin in South Australia. The company’s business plan is based on three stages, (i) development of an underground heat exchanger (currently in progress); (ii) development of a demonstration HDR geothermal power plant (10-15MWe) and (iii) a commercial scale HDR geothermal power plant capable of generating hundreds of megawatts. (For further information see www.geodynamics.com.au)

7.7.2. Conventional tidal power

This source usually involves the construction of a large dam across an estuary and the generation of electricity from both incoming and outgoing tides. The power output is predictable, although it is not constant in time. Tidal power can have huge impacts on biodiversity in estuaries, similar to the impacts of large dams across rivers. Sites with sufficiently high tides and low potential environmental impact are scarce globally. A 240 MW tidal power station has been operating since 1967 at La Rance, France. Several other tidal power stations are being considered, including the Severn project in England.

In Australia the main potential site is in the north-west, very remote from the main centres of electricity demand. However, if a pipeline is eventually built to bring natural gas from the North-West Shelf to the eastern States, it could make sense to design it to a standard where it can carry a large percentage of hydrogen produced from tidal power. A proposed tidal project at Derby is understood to have more recently run into problems with environmental impacts on mangrove habitats and there has been some discussion about a new project involving offshore islands.

7.7.3. Ocean currents

This is an entirely different approach from the ‘large dam’ approach of conventional tidal power. It involves immersing turbines under water in powerful ocean currents that may or may not be tidal. So, the energy conversion system has more in common with wind power than conventional tidal and its environmental impact is very low. Although the speeds of ocean currents are generally less than those of wind, the density of water is much greater than that of air, and so the net effect is that ocean currents can provide the same power output with smaller turbines than wind power. Ocean currents are a predictable source of power, but not always constant in time. An experimental 300 kW tidal current turbine is being installed about 1 km off the coast of Devon, UK.

To the best of our knowledge, there has been no survey of the potential resource in Australian waters. As in the case of wind power, proximity to the main centres of electricity demand would be an advantage.

7.7.4. Wave power

There are several different technologies proposed for the conversion of wave energy into electricity, including:

- oscillating air columns that drive air turbines;
- tapered channels that focus incoming waves into a reservoir on cliffs. Electricity is then generated by running falling water through a standard hydro-electric turbine. Appropriate sites are rare;
- floating vanes or ‘ducks’ that oscillate in the waves, driving turbines directly.

Energetech Australia Pty Ltd (www.energetech.com.au) received a grant from the Australian Greenhouse Office to construct a 300 kW wave power generator on the breakwater at Port Kembla. The system uses a parabolic wall to focus wave energy into the column. It then uses an air turbine and so has features of both the first two types of wave power converter.

Ocean Power Technologies (Australasia) Pty Ltd has built a 20 kW pilot scale prototype PowerBuoy™, to be moored to the sea-bed several km off the Victorian coast near Portland. The buoy floats underwater and its up-and-down motion drives a hydraulic cylinder and thus generates power. A ‘farm’ of many such buoys would be required to generate sufficient electricity to meet the cost of transmission and the buoys themselves.

Because the best wave power potential lies in the deep ocean, the transmission of energy from such sites to the user could be quite expensive. If an underwater transmission line is used, there is a trade-off between wave energy available and the cost of transmission.

Other problems encountered in wave power include survival in extreme wave conditions, operation of equipment in salt water environment and impact on navigation.

7.7.5. Solar chimney/tower

Enviromission Ltd has proposed a 200 MWe system to be built near Mildura, Vic. (see www.enviromission.com.au). A pilot 50 kW system operated successfully in Spain for 7 years in the 1980s. The full-sized system would comprise a circular greenhouse of diameter 5 km which warms air that then rises through a hollow cylindrical tower 1 km high located at the centre of the greenhouse. As the air is drawn into the tower, it passes through air turbines that generate electricity. Under the greenhouse is thermal storage in the form of rocks or water in tanks, and so the tower can operate for 24 hours. According to different press reports, its expected energy generation is either 500 GWh or 650 GWh per year, corresponding to capacity factors of 29% and 37%, respectively. The first capacity factor is about the same as that of a wind farm at a good site. But it is unclear whether the output and the estimated cost of $700 million assumes thermal storage. The electricity generated by solar tower will be much dearer than from wind power located at a good site, but possibly cheaper than electricity from PV or conventional STE.

The greenhouse will occupy quite a large area of land for the amount of electricity generated and the tower could be intensive in its use of materials. Nevertheless, the solar tower could be an option in areas that are not windy if the cost reductions envisaged for PV and STE do not eventuate.

7.8. Advanced energy storage

In our principal scenario, which achieves a 50% reduction in greenhouse gas emissions from stationary energy by 2040, natural gas and biomass energy are the main energy sources and the ‘intermittent’ renewable energy sources, wind and direct solar, together contribute almost 30% of electricity. Under these circumstances, we find that additional energy storage is unnecessary, since the fluctuations in renewable power are compensated for by backup from gas turbines and hydro electricity and from intermediate load natural gas and biomass-fuelled power plants.

However, to obtain much larger greenhouse gas reductions than envisaged in our 2040 scenario, it may be necessary to develop energy supply systems in which the major contributions come from direct solar energy and wind power. Then low-cost electrical and thermal storage become essential. At present electricity storage is either commercially available at high prices, or still under development, and cheap commercial storage of solar heat is limited to water storage at temperatures below 100˚C. This Section reviews some existing and potential storage technologies for the future.

To store effectively high-quality energy forms, such as electrical and mechanical energy, requires low losses while in the store (called ‘standing losses’) and low losses in transfer to and from the store. The latter is generally measured as ‘cycle efficiency’ on a scale of 0 to 1, where cycle efficiency = 0 means that all the energy transferred to store is lost, while cycle efficiency = 1 is the ideal but unachievable case when no energy is lost in transfer. Cycle efficiencies are less important when storing low-quality energy (i.e. heat at low temperatures). The other important parameters are the energy stored per kg and per cubic metre of the store. Several different forms of energy storage, their status and properties are summarised in Table 7.2.

Table 7.2: Properties of different forms of energy storage

Storage form	Properties and comments
Conventional fuels	
Coal	Long-term storage of black coal; no standing loss; energy density of NSW black steaming coal 23,000 kJ/kg & 22 GJ/m^3; Vic. brown coal 10,000 kJ/kg not stored after mining.
Crude oil	Long-term storage; no standing loss; energy density 42,000 kJ/kg, 37 GJ/ m^3.
Natural gas	Long-term storage, no standing loss, but significant energy use in compression for liquefaction or for transportation in pipelines. Energy density is 51,000 kJ/kg and at standard atmospheric pressure (STP) is 38 GJ/m^3. However, can be compressed to hundreds of atmospheres or liquefied at –162C at STP to increase the energy stored/m^3 .
Dry wood	Long-term storage; low standing loss; energy density 20,000 kJ/kg, 10 GJ/ m^3.
Electrical & mechanical energy	
Lead-acid battery	In commercial mass production for decades. Significant standing loss; energy density 40-140 kJ/kg & 100-900 MJ/ m^3; cycle efficiency 0.7-0.8; short cycle life.
Nickel-cadmium battery	Energy density about 350 kJ/kg & 350 MJ/ m^3
Vanadium redox battery	Developed at University of New South Wales and now in small-scale commercial production. No standing loss; long cycle life; energy density 72-108 kJ/kg & 90-144 MJ/m^3; cycle efficiency 0.8-0.85. Very expensive at present, but there are prospects for reduction.
Flywheel	Storage period of several minutes; cycle efficiency 0.95 for advanced carbon-fibre flywheels under development overseas, which have energy density >200 kJ/kg & >100MJ/m^3.
Storage dams and pumped hydro, 100 m head	Large dams provide long-term storage (seasonal or longer) with low energy density 1 kJ/kg & 1 MJ/m^3; and cycle efficiency 0.65-0.8. Further large dams unlikely in Australia because of environmental constraints.
Compressed air	Long-term storage; energy density about 15 MJ/m^3; cycle efficiency low at 0.4-0.5
Methanol	Long-term; no standing loss; energy density 21,000 kJ/kg, 17 GJ/m^3.
Ethanol	Long-term; no standing loss; energy density 28,000 kJ/kg, 22 GJ/m^3.
Hydrogen, compressed gas	Long-term storage; energy density 120,000 kJ/kg & 1.9-2.7 GJ/m^3 at pressures of 20-30 MPa; cycle efficiency 0.4-0.6
Hydrogen, liquid	Long-term storage; energy density 120,000 kJ/kg & 8.7 GJ/m^3
Hydrogen, metal hydride	Long-term storage; energy density 2,000-9,000 kJ/kg & 5-15 GJ/m^3
Heat	
Thermo-chemical	E.g. closed loop thermochemical energy storage system using ammonia, being developed at Australian National University, see http://solar.anu.edu.au/. Long-term; high energy density in terms of both mass and volume and high cycle efficiency.

Table 7.2, *continued*

Phase change materials	Commercially available products include those based on paraffins and waxes (see www.rubitherm.com) and those based on hydrated salts (see www.teappcm.com). They can be used to store heat at many different temperatures, from below 0˚C to above 100˚C. The best products are environmentally harmless, stable (i.e. have no standing losses) and have low transfer losses.
Water, 100˚C → 40˚C	In commercial mass production for solar hot water. Overnight storage; energy density 250 kJ/kg & 250 MJ/m^3;
Rocks, 400˚C → 200˚C	Overnight storage; energy density about 160 kJ/kg & 430 MJ/m^3
Molten sodium	Overnight storage for high-temperature solar heat. Standing loss overnight from well-insulated tank about 1%; energy density about 900 MJ/m^3

Sources: Partly Sørensen (2000), who gives a detailed scientific discussion in his Chap. 5, partly personal communications from Australian technical experts, and partly Web searches.

The conventional fuels, coal and oil, have very high energy densities, both in terms of mass and volume occupied. Methanol and ethanol are nearly as high. They can both be produced from biomass. Compared with coal, dry wood has one-third the energy density per kg and one-quarter the energy density per m^3. Hydrogen in liquid and metal hydride forms is next. Commercial gaseous hydrogen containers at present use pressures of 20-30 million Pa, corresponding to energy densities of 1900-2700 MJ/m^3, which is less than 7% of oil's. Recent research suggests that it may be possible to increase the pressure to 70 MPa by using high-strength composite materials such as Kevlar fibres. All the other forms of energy storage have much lower energy densities per cubic metre and so are unsuitable for small vehicles (i.e. cars and motor bikes) unless they are much more fuel efficient than those of today. However they may be used in large vehicles, such as trucks and buses, and stationary sources of energy.

Lead-acid batteries have low energy density, medium cycle efficiency, significant standing losses and short lifetimes. Vanadium redox batteries have low energy density, high cycle efficiency and are potentially cheap in mass production, with cost per kWh declining as the storage capacity increases. At present they are in the early, small-scale stages of commercial production and are very expensive. Zinc bromine batteries are similar in some ways to vanadium redox and seem to be progressing through commercialisation a little more quickly. A load-levelling Zn-Br plant is under trial in Nunawading now.

Ideally, flywheel storage would be used to back up wind farms over periods of up to an hour. This would significantly reduce the output variability of wind farms, and provide time for conventional intermediate-load power plant to be brought on line in the event of unexpected drop-outs. But, because of costs, flywheel storage is mainly limited to smoothing short-term fluctuations (over several minutes) in the output of wind turbines in order to improve power quality. It was planned to install flywheel storage with the existing wind-diesel systems at Denham W.A. and the Australian Antarctic base at Mawson, but at the time of writing (October 2003) they are not installed because of technical problems. Flywheels may be unnecessary for short-term storage anyway, because having a diversity of sites within and between wind farms will smooth fluctuations on the timescale of a few minutes, while gas turbines and hydro-electricity can provide fast response back-up on timescales from minutes to an hour.

7.9. The 'hydrogen economy'

Hydrogen is potentially a means of storing and transporting renewable energy on a large scale. It is of interest to both fossil fuel and renewable energy proponents, because when it is burned in a turbine or converted into electricity by means of a fuel cell, its only 'waste' product is water. So, it is a clean fuel at the point of use. However, hydrogen can be produced from coal, natural gas or biomass by chemical means, or from the electrolysis of water using electricity generated from fossil fuels or renewable energy. If it is produced from fossil fuels, it is not low in greenhouse gas emissions or local pollution at the place of production.

Hydrogen has a very low energy density in terms of volume. This means that, in order to store and transport hydrogen, it has to be compressed at high pressures. This could take up to 10% of its internal energy. Hydrogen can only be liquefied at very low temperature and this could take up to 30% of its internal energy, and so liquefaction does not look promising.

Hydrogen pipelines exist in Europe and the USA. These generally have a larger diameter than a natural gas pipeline and have to hold higher pressures. Therefore the cost of transporting hydrogen in pipelines is higher than that of natural gas. However, in the transition to a hydrogen economy, some hydrogen can be mixed with natural gas and transported through natural gas pipelines. As the fraction of hydrogen in a pipeline is increased, it may be possible to contain it by putting liners within existing natural gas pipelines. For transporting 100% hydrogen, special hydrogen pipelines are required. The existing natural gas infrastructure is useful for this transition, even if the pipes themselves cannot be used, because it already has established easements and access points, making up a significant part of the cost of the pipeline.

Hydrogen's low energy density, and the high energy inputs required for its use, have led some authors to propose that methanol may be a better means of storing and transporting renewable energy. Ethanol, bio-oils and ammonia may also have significant roles.

7.10. Fuel cells

A fuel cell is an electrochemical system that converts hydrogen and oxygen into water, producing electricity and heat in the process. This is the reverse of a battery process. In a sustainable energy system the hydrogen has been previously produced by renewable sources of energy and the oxygen comes from the air. By using a fuel cell the hydrogen can be converted into electricity, when and where the power is required. Because hydrogen is difficult to handle, it may actually be transported and stored in the form of biogas (mostly methane) or methanol. Then, by means of a reformer, these fuels can be converted into hydrogen and fed into the fuel cell. This is not entirely satisfactory, because the reforming processes uses energy and produces impurities and CO_2, as well as hydrogen. Fortunately several types of fuel cell can take methanol directly as the feedstock, without reforming it first into hydrogen.

Most fuel cells operating today use natural gas as the fuel and pass it through a reformer at the point of use. In terms of greenhouse gas emissions and local pollution, this is cleaner than using coal-fired electricity. But, in the long run, producing the feed by means of renewable sources of energy is essential for a sustainable energy system.

Fuel cells may be used as stationary sources of energy, to power a home or an office or even a laptop computer, or in vehicles. Fuel cells that are currently available are either prototypes or in very small-scale commercial production.

7.11. Transmission and distribution infrastructure

An electricity supply system, comprising one third natural gas and more than one-half biomass and wind energy, in the form of many distributed power stations, will require a somewhat different transmission and distribution system than one comprising a few large centralised power stations based on coal.

The sheer quantity of natural gas used will entail new natural gas pipelines, such as the proposed Papua New Guinea to south-east Queensland pipeline and North-West Shelf to Cooper Basin and hence to the eastern States, which would be a major undertaking costing billions of dollars. Such infrastructure will be required under almost any long-term energy scenario. Another energy source to be transported by pipeline is coal seam methane. Combined cycle natural gas power stations are generally smaller than coal-fired power stations (typically hundreds of megawatts rather than 1-2 thousand megawatts) and cogeneration by natural gas involves a huge range of sizes from hundreds of megawatts down to kilowatts. Therefore, much greater flexibility in siting natural gas power stations is possible, but this requires investment in pipelines.

Biomass power stations of up to 20 MWe, scattered through Australia’s wheatbelt and elsewhere, may require additional distribution lines, with voltages in the range 11-33 kV, to feed the electricity to transmission lines and hence to the cities where most Australians live. Large wind farms located at excellent sites that are remote from cities, such as Eyre Peninsula in South Australia, north-west Tasmania and parts of the Victorian coastline, may require dedicated transmission lines.

As indicated in Section 7.2 there is a case for customers funding the additional electricity transmission and distribution so as to be consistent with the treatment for existing coal fired generators. It must also be considered that the reduction in energy demand resulting from efficient energy use (see Chapter 6) will avoid substantial investment in new transmission and distribution lines.

7.12. Projected costs of electricity

For some of the principal renewable energy technologies, the average costs of electricity projected by ABARE for 2020 and the Clean Energy Scenario project for 2040 are compared in Table 7.3. For new renewable energy sources our 2040 our estimated prices are mostly greater or equal to those projected by ABARE. However, we are being deliberately cautious, and present average prices for much larger capacities than those conceived of by ABARE. This entails that the average site is less favourable than that of ABARE.

Table 7.3: Projected average costs[a] of generating electricity from various technologies

Technology	ABARE[b] 2020 (c/kWh)	This study 2040 (c/kWh)
Biomass co-fired with coal	2.3	3
Bagasse, new	4.2	5[c]
Other crop residues (e.g. wheat stubble)	N/A	5.0
Forest residue and wood waste	5.9	N/A
Wind (Tasmania)	2.8	N/A
Wind (other states)	3.5	5.5[d]
Energy crops[e]	9.2	9.0
Hydro, small	4.8	5.0
Hydro, large	7.8-8.2	Not costed[f]
Solar thermal electric	9.7	19.0[g]
Photovoltaics, residential	22.0	19.0
Photovoltiacs, grid connected	20.6	18.0
Black coal[h], IGCC (NSW & Qld) with geosequestration	N/A	10.0

Notes.

a. Includes capital, fuel, operation and maintenance costs
b. Short and Dickson (2003)
c. This allows for the economic benefit of cogenerated heat to run the sugar mills.
d. Australian average with 20% penetration into grids
e. Does not include environmental credits (e.g. for reducing salinity and erosion) and economic credits (from sale of co-products) which we envisage will reduce the price to 6 c/kWh or less.
f. Costs of large hydro vary greatly, depending upon site.
g. Grid connected with dedicated thermal storage
h. Included for comparison. Price based on IEA estimates reported in Section 8.4.

8. Present and Future Fossil Fuel Technologies

This Chapter reviews the current status and likely future development of fossil fuel technologies. It considers resources, technology development pathways, present and future costs, and limitations on deployment and operation. It is based on recent review articles, data both new and old, and interviews with several leaders in R & D and business in each of the technologies.

First, existing coal-fired power stations and possible improvements to coal burning technologies are considered. An important indicator of performance of power stations is the thermal efficiency, which is the electrical energy sent out from the power station divided by the chemical energy stored in the fuel, expressed as a percentage. The best thermal efficiencies obtained by Australian conventional black coal-fired power stations up to 2001 were about 36% (HHV).

Another important power station operating parameter is the capacity factor, which is total annual generation divided by total annual generation that it would have achieved if it had operated at its nameplate capacity for the full year, usually expressed as a percentage. Capacity factor of thermal power stations measures both performance and operating strategy. For instance, base-load power stations are operated as much as possible at full power because of high capital costs and low fuel costs. Gas turbine peak-load stations have low capital costs, are operated as little as possible because of high fuel costs, and so have low capacity factors, typically 2-10%. In the case of hydro-electric peak-load stations, there are also constraints on operation because the amount of stored water is limited. Intermediate-load stations are operated just as the name suggests and so have capacity factors falling between those of base-load and peak-load.

At current rates of consumption and export, Australia has 200-300 years of steaming coal, probably 50-100 years of natural gas (depending on the quantity to be exported) and probably only two decades of cheap oil.

8.1. Conventional (pulverised fuel) coal-fired power stations

The combustion of coal is by far the largest contributor to Australia’s greenhouse gas emissions, producing 186 million tonnes of CO_2 in 2000. The vast majority of this, about 170 Mt, was emitted by coal-fired power stations. Coal is also the fuel with the highest greenhouse intensity.

With the restructuring of the electricity industry in the mid-1990s, it has become much more difficult to obtain data on the performance and costs of power stations. The following data have been collected from public sources, some extrapolated from before restructuring, and current expert opinion. Different sources use different methods and obtain different results, even disagreeing on whether electricity from black coal is dearer than from brown -- e.g. compare ACIL Tasman (2003) with SKM (2003).

A typical modern black coal-fired power station, rated at (say) 2000 MW (2 GW) and put into operation in the 1990s, has a thermal efficiency of about 36%, a capacity factor of 75-85%, sends out about 14,000 GWh p.a. of electricity and consumes about 6 million tonnes of black coal in the process. Its greenhouse gas intensity is typically 0.85-1.0 Mt CO_2 emitted per TWh of electricity sent out. Its capital cost in 2001 Australian dollars was about $1400/kW installed, including interest during construction. Its fuel cost is about $1/GJ[1] or 1 c/kWh and its other operation and maintenance costs amount to about 0.39 c/kWh. With refurbishment, its operational life may be extended to about 40 years. However, since refurbishment is not included in the above costings, an economic lifetime of 30 years has been assumed. With a discount rate of 8% and 10% real and using the levelised annuity formula, the cost of electricity including all fixed and variable costs becomes 3.6 and 4.0 c/kWh, respectively.

The typical modern brown coal-fired power station, rated at (say) 2000 MW (2 GW) and put into operation in the 1990s, has a thermal efficiency of about 28%, a capacity factor of about 85%, sends out about 15,000 GWh p.a. and consumes about 19 million tonnes of brown coal in the process. Its greenhouse gas intensity is typically 1.2-1.45 Mt CO_2 emitted per TWh of electricity sent out. Its capital cost in 2001 Australian dollars was about $1800/kW installed, including interest during construction. Its fuel cost is about 0.4 c/kWh and its other operation and maintenance costs amount to about 0.37 c/kWh. With refurbishment, its operational life may be extended to about 45 years. However, since refurbishment is not included in the above costings, an economic lifetime of 30 years has been assumed. With a discount rates of 8% and 10% real and using the levelised annuity formula, the costs of electricity including all fixed and variable costs become 3.6 and 4.1 c/kWh, respectively.

The lower capacity factors of black coal power stations compared with brown reflect the situation that the output of the former can be varied within bounds, allowing the stations to follow variations in demand on timescales of an hour or two. Thus black coal stations can be operated as both base-load and intermediate load. In Victoria, the brown coal stations are strictly base-load and natural gas stations fill the role of intermediate load.

The greatest uncertainties seem to be the magnitudes of capital costs of coal-fired power stations. There is also uncertainty about whether the usually quoted capacity factors are typical of 'normal' operating conditions or whether they reflect lifetime averages in which there may be occasionally long breakdowns in 'abnormal' years. In practice, there also will be variations in the costs depending upon how the power stations are financed – e.g. how much debt and how much equity.

Within the category of pulverised fuel coal-fired power stations, the main pathway to improvements in thermal efficiency and hence reductions in greenhouse gas emissions is to increase the steam temperature and pressure in the boilers. The first power stations with *supercritical* boilers, having steam temperature around 538˚C and pressure around 24 MPa, were installed in Queensland in 2002-2003. The generators expect thermal efficiency of around 40% and greenhouse intensity of about 0.8 Mt CO_2/TWh sent out. *Ultra-supercritical* boilers, with temperatures around 600˚C and pressure around 36 MPa, are beginning to be installed overseas. These have thermal

[1] One of the new coal-fired power stations commissioned recently in Queensland, Millmerran, is located inland and has considerably cheaper coal. However, because it is air-cooled rather than water-cooled, its capital cost is higher.

efficiencies of 42-45% and manufacturers claim that they will soon be able to reach 50% in the foreseeable future. However, none of these new coal-fired power stations can reduce greenhouse gas emissions to anywhere near that of today's combined cycle natural gas-fired power stations.

8.2. Combined cycle gas-fired power stations

Combined cycle power stations use a gas turbine, fuelled by liquid or gaseous fuels, to generate electricity and take the waste heat from that process to generate steam to drive a steam turbine to generate additional electricity. Because they waste less heat than conventional steam or turbine power stations, combined cycle power stations have one of the highest thermal efficiencies of all non-renewable generating plant currently available. (Cogeneration is currently the most efficient way of generating electricity and usable heat together -- see Section 8.6.) Pelican Point in South Australia is the largest Australian combined cycle power station fuelled by natural gas. Such power stations currently have thermal efficiencies around 50 – 55% -- new models are just coming onto the market with thermal efficiencies of 60% and these will become state-of-the-art by 2010. Greenhouse intensities are currently around 0.4 Mt CO_2/TWh of electricity sent out and declining. In base-load operation capacity factors should be 85-90%, i.e. slightly better than those of base-load coal. It is possible to fuel combined cycle power stations with biogas or coal bed methane.

According to Geoscience Australia (2002), natural gas reserves on 1 January 2001 amounted to 157,343 PJ, of which about 20% is economically recoverable in today's market. The gas industry is confident that the major gas fields of the North-West Shelf and in other remote locations have the capacity to supply both very large export contracts of liquefied natural gas and, as required by our clean energy scenarios, greatly expanded domestic supplies of natural gas. To utilise these fields, pipelines would have to be built to connect remote gas supplies to the existing transmission pipeline networks of the eastern States.

In addition, most black coal seams contain methane gas, naturally held within pores and tiny fractures of the coal. In Queensland and NSW there are substantial reserves of this coal-bed methane in coal seams which are too deep or otherwise considered to be uneconomic or unsuitable for mining. These gas reserves could become a substantial source of gas supply in each of these states. However, only a small fraction of the reserves is actually recoverable and most of this at a higher price than conventional natural gas. In Queensland coal-bed methane is already being produced commercially at several separate fields and is connected to the state-wide pipeline network. In NSW there is active exploration but as yet no commercial production. In both States there are plans to expand the production of this gas.

Coal seam methane must be distinguished from waste coal mine methane, which is methane extracted from coal seams during or just prior to mining. Mine safety and productivity are usually the main drivers for waste coal mine methane collection, but this methane, if not collected, is also a significant source of fugitive energy greenhouse emissions (see Section 6.7). There are projects in both NSW and Queensland which collect waste coal mine methane and use it to produce useful energy in various ways, including one that has been operating since the early 1990s in NSW, generating about 100 MW of electricity.

8.3. Integrated gasification combined cycle (IGCC) coal-fired power stations

IGCC is a combined cycle process fuelled by gasified coal. Coal is gasified by heating it in a gasifier in the presence of steam and oxygen. This produces a fuel gas made up mainly of hydrogen and carbon monoxide. The fuel gas is cleaned of impurities and burnt in a gas turbine, producing electricity, carbon dioxide and water vapour. The waste heat from the gasification process is partially recovered and used to generate steam to drive a steam turbine, thus providing a second ‘cycle’ to generate electricity. There are currently no coal-fired combined cycle power stations in Australia, although there are several demonstration plants overseas[2].

In our future energy scenarios, we consider that any black coal-fired power stations existing in 2040 will use IGCC with thermal efficiency of about 43% HHV. However, even these stations are expected to have a greenhouse intensity of about 0.7 Mt CO_2/TWh of electricity sent out. Since the gasification of coal is a low efficiency process that produces CO_2, the reduction of greenhouse intensity achieved by burning coal gas is partially offset by the emissions from gasification. The net result is that building an IGCC power station makes little sense unless it is combined with the capture of CO_2.

8.4. Geosequestration of CO_2

One technically possible way of substantially reducing greenhouse gas emissions from coal-fired power stations would be to capture the CO_2, compress it and transport it by pipeline and/or ship to a secure storage location. Capture of the CO_2 can in principle be done in two different ways:

- after the gas turbine ‘cycle’ in an IGCC power station; or
- after fuel combustion in a conventional (pulverised coal or natural gas) power station, by extraction of CO_2 from flue (exhaust) gas as it passes up the chimneys.

The CO_2 produced in the gasification process is more concentrated than in the flue gas and so is easier to extract.

The main option for storage of CO_2 from a large point source such as a power station is deep underground, either in depleted oil and gas fields, or in un-minable coal mines or in saline aquifers located in sedimentary rocks. In Australia, oil and gas fields will not be sufficiently depleted to be used before about 2030 and deep un-minable coal mines would not absorb the CO_2 fast enough to be effective. Therefore, the principal option for the period up to 2030 or 2040 is saline aquifers (Bradshaw et al., 2002). For secure storage suitable saline aquifers have to have caps composed of rock that is impervious to CO_2 and have no exit holes. Saline aquifers are not well mapped and the science of storing CO_2 in them is not fully understood.

The main concerns about geosequestration are:

- the amount of CO_2 that could be stored annually;
- ensuring secure storage of CO_2;

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[2] The first full-size IGCC (253 MWe) based on coal is in trial operation in Buggenum (the Netherlands) with a thermal efficiency of about 43 %.

- the environmental and health impacts of an escape of CO_2;
- the cost.

According to a preliminary study by the GEODISC group of the Australian Cooperative Research Centre for Greenhouse Gas Technologies, the largest storage potential is in Western Australia but almost all of the biggest point sources emitters are in eastern Australia. As a result Australia only has the potential to store 100-115 Mt per year of CO_2, corresponding to 27%-31% of total annual CO_2 emissions (Bradshaw et al., 2002). Therefore geosequestration is at best a partial solution and Australia would do well to continue with and expand the development of efficient energy use and renewable sources of energy.

The risks of escape comprise the hazards of global climate change; the danger of CO_2 (which is heavier than air) filling a valley near the escape point and asphyxiating every person who is submerged in it[3]; and local environmental impacts on soil and waterway ecosystems. These risks can be reduced at a price.

The cost of capture and geosequestration of CO_2 from fossil fuelled power stations has been calculated by the International Energy Agency (Davison, Freund & Smith, 2001; Freund & Davison, 2002). At the rate of exchange of 1 AUD = 0.67 USD and fuel costs of 1.0 AUD per GJ of black coal and 3.1 AUD per GJ of natural gas, the estimated cost of avoiding CO_2 emissions through geosequestration is US$45/t CO_2 (A$67.5/t) for IGCC, US$55/t CO_2 (A$82.5/t) for conventional (pulverised) coal power stations and US$45/t CO_2 (A$67.5/t) for natural gas combined cycle. Other international studies, such as US Department of Energy, give higher costs. Therefore, it is surprising that the Prime Minister's Science, Engineering and Innovation Council (PMSEIC) is claiming costs of only A$10/t CO_2, without providing any published study to support this extraordinary result. Recent presentations of this claim indicate that it may only represent the geosequestration part of the costs, but not the gasification, combustion or collection of the CO_2 parts. It is unclear whether the cost of transporting CO_2 is included. However, it should be noted that these recent presentations compare the partial cost of so-called 'clean coal' electricity with the full costs of gas fired and renewable sources of electricity.

Continuing with the IEA calculations, the above costs of geosequestration translate into electricity costs in Australian currency of about 10 c/kWh for IGCC and conventional coal-fired power stations and about 7 c/kWh for combined cycle natural gas. Since the projected coal electricity plus geosequestration costs are well above current biomass and wind electricity prices, we do not consider this option as part of our principal scenarios to 2040. However, natural gas combined cycle generation plus geosequestration seems to be a real option for Victoria and Western Australia. We also consider that all new natural gas production at the North-West Shelf, such as the proposed Gorgon field, must capture and store securely the CO_2 that comes up with the gas.

A more detailed discussion of CO_2 emissions from Australia's coal-fired power stations and the limitations of geosequestration is given by Diesendorf (2003).

[3] In 1986 a large amount of CO_2 that had been produced by volcanic action escaped from Lake Nyos in the Cameroons. It filled neighboring valleys out to a distance of nearly 30 km and killed 1700 people.

8.5. Oil substitutes from oil sands, shale and coal

The vast majority of liquid fuels from petroleum – such as petrol, diesel and LPG -- are used for transport. A small fraction is used to supply stationary energy in mines, farms, factories and remote homes, and a somewhat larger fraction to power mobile machinery, such as tractors and earth moving equipment, in the Mining, Construction and Agriculture, etc. sectors. Liquid fuels can also be used to generate electricity in power stations with boilers or gas turbines and are widely used for that purpose in many countries, but in Australia, where coal and natural gas are readily available and much cheaper, use of petroleum for electricity generation is limited to small power plants such as diesel and petrol generators.

As oil becomes scarcer and more expensive over the next few decades, non-renewable substitutes in the form of liquid fuels could be obtained from oil sands, shale oil and oil from coal processes, as is currently happening in some other countries, such as Canada (oil sands) and South Africa (oil from coal). In addition, a product called Ultra-Clean Coal, which is a solid fuel with very low ash content made from coal, has been developed in Australia for direct firing, as a very fine powder, in gas turbines.

The production and combustion of each of these potential oil substitutes emits much greater total amounts of CO_2 than the equivalent quantity of oil. Therefore, we do not consider that they will ever be used in significant quantities in Australia. Rather, we envisage liquid fuels from biomass – methanol, ethanol and bio-oils – being used increasingly as oil prices increase (see Chapter 7).

8.6. Cogeneration of heat and electricity

Cogeneration, also termed combined heat and power or CHP in many countries, is the simultaneous production of electricity and useful heat from the same energy source. The energy source is normally combustion of a fossil or biomass fuel. Cogeneration is a means of maximising the useful energy extracted from the combustion process and thereby maximising the efficiency of energy use in terms of both the First and Second Laws of Thermodynamics (see Glossary).

For this reason, cogeneration has long been recognised as a most important and effective means of increasing overall energy efficiency, and thereby reducing the level of greenhouse gas emissions per unit of fossil fuel consumed and of useful energy services delivered. Indeed, like distributed generation in general, cogeneration is a technology which was once much more widespread, and over the last 50 or 60 years has been driven out of the electricity supply mix by the shift to very large centralised power stations and long distance electricity transmission. One way of looking at the long historical trend is to regard the cost of cogeneration as broadly constant over the long term, having been displaced by large, low-cost coal fired power stations, and coming into its own again in the future as environmental considerations and other factors force up the costs of coal-fired generation.

Cogeneration can be used where there is a combined need for both electricity and process heat, the latter normally being supplied as steam, though not necessarily so. The combined need may either be at a single site or simultaneously at several neighbouring sites which are sufficiently close to allow economic and efficient transportation of the steam generated. If electricity can be sold into the wholesale market at a high enough price, a large heat load alone can suffice to support a cogeneration installation. Typical sites for large cogeneration projects include chemical plants, oil refineries, pulp mills, sugar mills and mineral processing plants which use aqueous phase digestion processes, such as alumina and nickel refineries. Smaller cogeneration projects are suitable for hospitals, larger educational institutions, leisure facilities and office buildings. In the case of office buildings, widespread adoption of absorption chillers (instead of compression cycle chillers, which are the norm today) would combine well with gas engine cogeneration. At present, most cogeneration capacity in Australia is at large industrial sites.

There are a number of different types of cogeneration technology. For many years, all cogeneration installations were based on the use of conventional fuel fired boilers, with steam turbines as the prime mover used for electricity generation. Two alternative configurations are possible: the so-called topping cycle[4], in which steam is passed first through a back pressure turbine[5] before going to the thermal load, and the so-called bottoming cycle, in which the sequence of the two components is reversed. The topping cycle is far more common than the bottoming cycle. The latter may be associated with either a boiler installation or a high temperature thermal process, such as a kiln or furnace, where the high temperature exhaust gases are passed through a heat exchanger to generate steam. There are currently a number of these projects associated with furnaces or kilns in Australia.

In recent decades a diversity of new technologies have emerged, as summarized in Table 8.1, and today gas turbine technology has largely superseded steam turbine technology for medium size installations.

Typical or representative characteristics of these various configurations are shown in Table 8.2, taken from a Canadian report (Strickland, 2002). It should be noted that 'high thermal quality' refers to high temperature/pressure steam, 'medium' thermal quality' to low temperature/pressure steam, and 'low thermal quality' refers to hot water.

[4] This terminology derives from thermodynamics; the passage of energy through a total process from high temperature/high quality to low temperature/low quality. It is described as moving from the "top" to the "bottom" in thermodynamic terms, so "topping" means taking energy out at the high temperature end and "bottoming" to taking energy out at the low temperature end.
[5] A back pressure turbine is one in which steam exits from the turbine at a significant positive pressure, and thus still contains considerable energy, to be used in thermal processes.

Table 8.1: Types of cogeneration

Generation prime mover	Thermal energy carrier	Thermal energy source	Typical size range (indicative only)	Typical host industry or sector
Back pressure steam turbine	Steam	Steam turbine exhaust	5-50 MWe	Manufacturing (various)
Condensing steam turbine	Steam or high temperature combustion gases	Boiler or kiln/furnace	5-50 MWe	Manufacturing (various)
Open cycle gas turbine	Steam	Exhaust gas heat exchanger	5-100 MWe	Manufacturing, large commercial
Reciprocating engine	Hot water or steam	Engine cooling water or exhaust gas heat exchanger	< 2 MWe	Commercial/ buildings, small industrial
Combined cycle gas turbine	Steam	Exhaust gas heat exchanger and/or Steam turbine exhaust	> 100 MWe	Large industrial/ manufacturing
Microturbine	Steam	Exhaust gas heat exchanger	< 100 kWe	Commercial/ buildings
Fuel cell	Steam or hot water	Cooling water	< 500 kWe	Demonstration stage only

Table 8.2: Typical performance characteristics of various types of cogeneration configuration

Cogeneration System	Electrical energy output (% of fuel input)	Overall efficiency (%)	Heat-to-power ratio	Thermal qualities
Back-pressure steam turbine	14-28	84-92	4.0-14.3	High
Condensing steam turbine	22-40	60-80	2.0-10.0	High
Gas turbines	24-42	70-85	1.3-2.0	High
Reciprocating engine	33-53	75-85	0.5-2.5	Low
Combined cycle gas turbine	34-55	69-83	1.0-1.7	Medium
Fuel Cells	40-70	75-85	0.33-1	Low to High
Microturbines	15-33	60-75	1.3-2.0	High

Source: Strickland (2002)

It is important to appreciate "that inherently, different types of configurations provide different natural quantities of steam and electricity" (Cogeneration Ready Reckoner Manual, p. 14), as Table 8.2 implies. They are also inherently suited, or most economically efficient, in different size ranges. Broadly speaking, reciprocating engines are the current optimal technology for installations of up to about 2 MWe capacity where relatively low grade heat is typically required. In coming years they will probably be superseded in that role by microturbines (which are very small gas turbines) and fuel cells. Fuel cells in particular may also become economic at sizes smaller than any current cogeneration installations (suitable for an individual house). However, since they are as yet not a fully commercially proven technology, we have not included fuel cells in our 2040 scenario.

At larger sizes, steam turbines and/or gas turbines come to the fore. The choice between the two will depend on a number of factors, including the balance of steam, the pressure and temperature of the heat/steam required, and electrical output desired. In general, a CHP system is designed to meet the heat needs of the host. Then, if a relatively small electrical output is required, as for example an establishment wishing to become partially self sufficient in electricity, but not a significant exporter, steam turbines would be the technology of choice. Otherwise, reciprocating engines would be used in small to medium installations and combined cycle gas turbines (CCGT) would be used in very large installations, where the objective is to maximize electrical production for export, relative to a large on-site steam load.

Looking at cogeneration as a whole, the mix of the different types of fully commercial technology, i.e. not including fuel cells and microturbines, across the whole potential size range for cogeneration installations is still a cost curve which declines with size. For example, a report by Sinclair Knight Merz (2001, pp. 56-7) estimates that the cost of cogenerated electricity for plants of 5 MW capacity or smaller is above $60 per MWh, falling to around $50 per MWh at sizes around 50 MW and flattening out at about $40 per MWh above 200 MW capacity. As fuel cells become fully commercially mature technologies, their costs will fall, but it seems probable that the foreseeable future they will be more costly than large steam and gas turbine plant in terms of $ per MW of capacity or per MWh of electricity generated. However, being much closer to the electrical loads, small plants can compete on a more equal basis when transmission and distribution costs are taken into account.

As the cost data above demonstrates, medium and larger cogeneration is currently more costly than coal-fired base-load electricity, but not greatly so, and full consideration of avoided transmission, distribution and greenhouse costs could tip the balance in favour of cogeneration. Technology improvements can be expected to reduce the cost of smaller cogeneration installations. Accordingly, our scenario includes widespread use of cogeneration in industries with a requirement for thermal energy in the form of steam (including both manufacturing and also hospitals, educational institutions etc. in the Commercial/Services sector). We also assume widespread use of absorption chillers and small cogeneration in commercial buildings, but do not include use of topping cycle installations in industries that make extensive use of kilns, such as cement and glass. It is assumed that all these installations will be fuelled by natural gas, except in the sugar and pulp and paper industries, which produce large quantities of biomass waste. It is assumed that all sugar mills will be associated with new, technologically optimised cogeneration plants, which can meet the in-house requirements of the mills for steam and electricity from only half the available quantity of biomass, leaving the remaining bagasse available to fuel additional electricity generation. The total electrical energy produced from this group of plants will of course depend on the total size of the sugar industry.

8.7. Phase-out of existing fossil fuelled power stations

One of the constraints on transforming the electricity industry into a much cleaner industry, both in terms of greenhouse gas emissions and other forms of pollution and land degradation, is the long lifetimes of existing power stations. Without a major refurbishment, power stations can be expected to run for 30-35 years. We assume that henceforth any proposal for a major refurbishment or for a new power station would have to meet very stringent conditions on greenhouse intensity: specifically that such stations would be required to have greenhouse intensities less than or equal to those of the best combined-cycle natural gas power stations in 2003. In practice this is likely to entail that all existing coal-fired power stations, with the possible exception of those commissioned on or after 2000, would have been closed down by 2040.

Table 8.3 lists all Australia's large power stations in order of decreasing total CO_2 emissions, giving their dates of commissioning. The data suggest that, on the basis of our assumed greenhouse constraint, only three existing coal-fired power stations may be still operating in 2040: Millmerran, Tarong North and Callide C. All are located in Queensland and together have a total generating capacity of 2130 MW. At the time of writing, a full year's energy generation data is not available for these stations. Nevertheless, an approximation can be obtained by assuming an average capacity factor of 86%, giving total annual electricity generation of about 16 TWh, which is about 8% of total Australian generation in 2001. Our principal scenario considered in Chapter 10 retains these three power stations.

Table 8.3: Dates of commissioning and greenhouse gas emissions of major existing power stations (Year 2000 or Financial Year 2000-01)

Power station	**State**	**Type of power station[a]**	**Year of commission**	**Capacity (MW)**	**Generating units (no. x MW)**	**Approx. CO_2 emissions[b] (Mt)**	**Approx. greenhouse intensity[c] (Mt CO_2/ TWh sent out)**
Loy Yang A	Vic	brown	1984/87	2,000	4x500	17.3*	1.28
Hazelwood	Vic	brown	1964/71	1,600	8x200	16.3*	1.46
Bayswater	NSW	black	1982/84	2,640	4x660	15.8*	0.93
Yallourn W	Vic	brown	1973/75	1,450	2x350 + 2x375	13.4*	1.43
Eraring	NSW	black	1982/84	2,640	4x660	12.4	0.9
Stanwell	Qld	black	1993/96	1,400	4x350	10.1	1.0
Gladstone	Qld	black	1976/82	1,680	6x280	9.8	1.0
Loy Yang B	Vic	brown	1993/96	1,000	2x500	9.7	1.15
Tarong	Qld	black	1984/86	1,400	4x350	9.4*	0.84
Mt Piper	NSW	black	1992/93	1,320	2x660	9.4	0.9
Liddell	NSW	black	1971/73	2,000	4x500	8.8*	0.98
Vales Point	NSW	black	1978	1,320	2x660	6.8	1.03
Muja	WA	black	1965,81,85/86	1,040	4x60+4x200	6.0	
Callide B	Qld	black	1988/89	700	2x350	5.6	1.0
Northern	SA	brown	1985	520	2x260	4.8	1.1
Wallerawang C	NSW	black	1976/80	1,000	2x500	4.3	1.0
Callide C	Qld	black	2001 2001	840	1x420 1x420	3.0 N/A	0.95
Swanbank A & B	Qld	black	1970/73 1966/69	908	4x125 + 6x68	2.8	1.06
Collie	WA	black	1999	330	1x330	2.5	
Torrens Island[e]	SA	gas		1280		1.9 (e)	0.56 (e)
Kwinana[d] A & C	WA	black	1970, 76	880	4x200 + 4x120	1.8	
Munmorah	NSW	black	1969	600	2x300	1.6	1.1
Pelican Point	SA	gas CC	2000	478	2x160+1x158	1.1	
Kwinana[d] B	WA	gas	1970	240		0.3	
Millmerran	Qld	black	2003	840	2x420	N/A	N/A
Tarong North	Qld	black	2003	450	1x450	N/A	N/A

Sources: ESAA (2003), websites of generators where they exist, and personal communications from some generators

Notes:

a. 'Brown' and 'black' denote boiler-type base-load power stations burning brown and black coal respectively; 'gas' denotes boiler-type natural gas-fired; 'gas CC' denotes combined-cycle natural gas.

b. CO_2 emissions with asterisk are obtained from company's published reports. The others are our estimates.

c. CO_2 intensity is given here in terms of Mt CO_2 produced divided by TWh of electricity sent out from the power station. Electricity generated is typically 6-8% higher than electricity *sent out*. The difference is used to operate the power station.

d. Here we assume that Kwinana units A & C burn coal, and unit B burns mainly gas.

e. Year 2000 data. CO_2 emissions from personal communication from TXU.

9. Decarbonising energy supply

9.1. Introduction

In Chapter 6 we describe a Medium Efficiency pattern of demand for energy in 2040 in which total demand for stationary energy is 25% higher than it was in 2001. As population is projected by the Australian Bureau of Statistics to grow by over 29% to 25 million, this represents a slight reduction in per capita energy demand. To achieve this result, we have modelled an extensive, but quite achievable uptake of energy efficiency technologies and practices across all sectors of the economy. In the absence of policies to support the wide adoption of cost effective energy efficiency, we project an increase in energy demand from 2001 of 57%. Our modelling of demand by itself assumes no change in the mix of fuels within each individual economic sector modelled; the only source of fuel mix change is the shift in relative sizes of the various economic sectors. The consequence is that the fuel mix does not differ greatly from that in 2001; coal and natural gas take slightly smaller shares of the total and petroleum products a slightly larger share. The analysis of demand makes no assumptions about the mix of generation technologies and fuels used to supply electricity.

The overall effect is that an increase in demand for energy of 25%, with no change in fuel mix in electricity generation, will cause greenhouse gas emissions also to increase by about 25%. As discussed in Chapter 2, at the assumed level of fossil fuel prices in 2040, we estimate, on the basis of marginal abatement costs, that it is more cost effective to achieve further emission reductions by adopting alternative low emission sources of energy supply, than by further reducing demand through increased energy efficiency.

Four distinct measures have been modelled and are discussed in the remaining sections of this Chapter:

1) introduction of solar thermal pre-heating into the supply of steam and hot water in industrial and commercial applications (widespread use of solar thermal technology is already factored into the Residential sector);
2) substitution of natural gas for coal in almost all non-metallurgical applications;
3) widespread adoption of cogeneration, as described in Section 7.6; and
4) a change in the mix of electricity generation technologies, away from coal and towards natural gas and renewable energy.

Changing the electricity generation mix is by far the most important of these and is discussed at greatest length. Consideration was given to using biomass as an additional substitute energy source in Steps (1) and (2) above, but it was judged that it would be more cost effective to use limited biomass resources for electricity generation and, if further resources were available, for the production of transport fuels.

It is important to appreciate that all the technologies deployed in Steps (1) to (4) are already commercially well established and in most cases are widely used throughout the energy system today. In most cases, their current market share is limited by relative costs and prices, as ultimately determined by the current underlying prices of coal and natural gas. It can be expected that, with no change in policy settings, all will continue to gain market share, as fossil fuel prices move gradually upward. Hence the full

Baseline scenario, where demand for energy is at the Baseline level described in Chapter 5, will also include a higher penetration than in 2001 of all the technologies considered in this Chapter.

We have therefore modelled two different levels of energy demand and associated levels of uptake of fuel substitution Steps (1), (2) and (3): one based on the Baseline energy demand of Chapter 5 and one based on the Medium Efficiency demand of Chapter 6. In addition, four different electricity supply system technology mixes were modelled, two for each energy demand/direct fuel substitution set. A complete definition of the four scenarios and of their associated energy use and emissions are given in the next Chapter. In this Chapter we describe the modelling assumptions lying behind each combination.

9.2. Solar thermal pre-heating

Solar thermal devices available today are capable of delivering energy, carried in the form of steam or other working fluids, at temperatures well in excess of 100^{o}C. Technically, they would be able to meet much of the industrial and commercial demand for steam and hot water. However, to achieve the higher temperatures more sophisticated equipment, such as evacuated tube collectors, is needed. The technology is most cost effective when used as a pre-heater, to raise the temperature of water from the environmental ambient to a temperature somewhat below 100^{o}C, as commercial solar water heaters do. Moreover, as explained in Chapter 8, establishments with a substantial demand for steam and hot water are ideally suited to host cogeneration plants, but this requires the use of combustion fuels, such as natural gas, which can achieve much higher temperatures than even the most sophisticated solar collector. Hence there is a partial trade-off between use of solar thermal heat and use of cogeneration.

With detailed information about an individual industrial site, it would be possible to determine a mix of solar thermal and cogeneration which minimizes total greenhouse gas emissions. Such optimisation is of course impossible in a high level national study. We have therefore used our professional judgment to estimate the substitution of solar thermal energy, in the form of pre-heaters in boiler systems in all end use sectors of the economy except Iron and Steel, where excess quantities of coal by-product gases are used to produce steam and generate electricity at integrated steel works, and sugar, where there is an excess of biomass fuel. We assume greater use of solar thermal in the Food, Beverages and Tobacco, and All Other Manufacturing sectors, because it is better suited to the smaller scale and lower steam temperature requirements that typify these sectors. A modest substitution of solar water heating for natural gas in the Commercial/Services sector is also assumed.

In the Medium Efficiency demand case a total of 51 PJ of boiler fuel is displaced in manufacturing and mining and a further 3 PJ in the Commercial/Services sector. In the Baseline demand case the quantity of boiler fuel displaced is 27 PJ in total.

Not included here is the extensive adoption of solar water heating in the Residential sector, which, for reasons of methodological simplicity, was modelled jointly with energy efficiency in the Residential sector, as described in Chapter 6. In the Medium Efficiency case residential solar hot water displaces 35 PJ of electricity, 32 PJ of natural gas and 3 PJ of LPG, a total of 70 PJ, while in the Baseline case 35 PJ are displaced.

9.3. Substitution of gas for coal and petroleum

Most sectors of the economy currently use limited quantities of coal as a boiler and kiln fuel. Ever since natural gas first became available in Australia, nearly thirty five years ago in some States, it has steadily been replacing both coal and petroleum products as the direct combustion fuel of choice in all areas of stationary energy use. It could readily substitute for all remaining non-metallurgical uses of coal, except the few without access to gas supplies. Gas is generally a technically superior alternative, but costs more. We expect that this substitution trend will continue, even in the absence of new policies to encourage reduced greenhouse gas emissions.

In the Medium Efficiency demand case, coal is almost completely displaced by natural gas in these applications. The greatest effect is in the Non-ferrous Metals sector, where currently two alumina plants and one nickel plant, among others, use very large quantities of coal as boiler fuel, and cement, where three of the four major plants currently use coal. We assume that where coal is used, in the form of coke, in metallurgical applications, there will be no fuel substitution. Coal by-products continuer to be used as boiler fuel in the Iron and Steel sector, for the reason given above.[1]

In total, 130 PJ of coal demand in the Medium Efficiency demand case are displaced. The use of natural gas instead of coal will lead to increased energy efficiency, because of the superior technical characteristics of gas. However, we have made no explicit allowance for this effect, which is a conservative element in our assumptions.

Petroleum products, mainly in the form of LPG and fuel oil, are also used in boilers, kilns and space heating installations. By far the largest user is the alumina plant at Gove, which will almost certainly switch from fuel oil to natural gas within the next few years. We assume some modest additional substitution in other sectors. However, much current use of LPG occurs where a gaseous fuel is required for technical reasons and natural gas is not available. While it is certain that by 2040 the natural gas distribution network will be more extensive than it is today, it is also certain that some locations will remain without a piped gas supply, and will continue to rely on LPG. We also assume continued use in the Basic Chemicals sector of petroleum in the form of “waste” by-products from the various chemical processes that use petroleum product feedstocks. Petroleum products continue to be the main source of energy in the Mining, Construction and Agriculture, Forestry and Fishing sectors. Outside these sectors, the assumed substitutions reduce demand for petroleum products by 48 PJ, from 115 to 67 PJ (of which 24 PJ are in Chemicals).

In the Baseline case there is also significant displacement of coal and petroleum by natural gas, totalling 96 PJ of coal and 32 PJ of petroleum products, but this is from a somewhat higher base consumption of coal and petroleum, since all fuels are used less efficiently in this case than in the Medium Efficiency case. In total, 61 PJ more coal and 36 PJ more petroleum are used in boiler and kiln processes in the Baseline case than in the Medium Efficiency demand case.

1 However, there is potential to use charcoal from biomass as an alternative to coke (see Section 11.2).

9.4. Greater use of cogeneration

ABARE reports that cogeneration plants supplied a total of 25 PJ (about 7 TWh) of electricity in 2001. This represents nearly 4% of total final demand for electricity. It excludes electricity generated at several new, large CCGT based cogeneration plants located at alumina, chemical and paper plants in several States, which both ABARE and the ESAA report as part of the electricity generation sector.

As explained in Section 2.1, in our model we subtract an estimate of the additional energy consumption associated with the 25 PJ of cogenerated electricity and re-allocate it to the electricity sector. This means that projected demand for thermal energy in the various host sectors represents the demand directly associated with the industrial process, and does not include any forward projection of demand from existing cogeneration plants.

In very broad terms, the capacity to support cogeneration at a site is proportional to the host steam load at the site. Consequently, reducing steam loads by increasing energy efficiency reduces potential cogeneration capacity. Substituting use of natural gas or other fuel with solar thermal collectors has a similar effect, as explained above. The logic of our energy system model therefore calls for cogeneration to be introduced into the supply mix following these fuel substitution steps.

In the Medium Efficiency case we introduce cogeneration into all sectors where there is a significant demand for energy in boiler systems. We assume that the following proportions of boiler fuel demand in each sector are suitable to host cogeneration:

Sugar	100%
Iron and Steel, Non-ferrous Metals	90%
Pulp and Paper	80%
All other industry sectors	50%

There is also significant potential for cogeneration in the Commercial/Services sector, in association with both heating and cooling loads in buildings. With heating, a gas engine or small gas turbine is used to generate electricity and the waste heat supplies the space heating demand. With cooling, the waste heat is instead used to drive an absorption chiller, which would replace an electric motor driven compressor chiller, with associated savings in electricity demand. Both types of installation were modelled, assuming that cogeneration installations could supply 50% of the heating and 50% of the cooling demand from the sector.

The results showed that while cogeneration supplying space heating reduced total greenhouse gas emissions, cogeneration with absorption chillers supplying cooling increased emissions. This is because, on the assumptions in our model, the additional gas consumption required for the absorption chillers exceeds the quantity of gas needed to generate the displaced electricity (previously driving a compressor chiller) in a stand-alone gas fired power station. Accordingly, we have not included gas cogeneration with space cooling in our Clean Energy scenario[2].

[2] However, other gas-based solutions show potential for lower emissions. For example, Hornsby Library is a site for CSIRO's trial micro-cogeneration system with its waste heat being used to regenerate a desiccant wheel which is then used for cooling.

The result of the analysis is that total cogenerated electricity in 2040 is 132 PJ (37 TWh), as shown, by fuel source, in Table 9.1 below.

In the Baseline case we make the simplifying assumption that uptake of cogeneration in the energy intensive manufacturing sectors (including sugar milling) where the economics are most favourable, is the same as in the Medium Efficiency case, but there is no additional cogeneration in other economic sectors. However, with a lower level of energy efficiency, host thermal loads are larger than in the Medium Efficiency case, so that for a given level of uptake of cogeneration, in terms of share of potential host thermal loads, there is actually more cogeneration capacity and more cogenerated electricity. Hence total cogeneration in the Baseline is only 19% less than in the Medium Efficiency case.

Table 9.1: Quantities of cogenerated electricity under the two demand scenarios

Fuel source	**Cogenerated electricity (PJ)**	
	Medium Efficiency	**Baseline**
Coal (including blast furnace gas)	2	19
Biomass	21	22
Petroleum (including petrochemical "waste" gases)	3	7
Natural gas	106	61
Totals	133	108

The final step in the analysis is to introduce cogenerated electricity into the total electricity system supply mix, that is described below. This we do by assuming that biomass cogeneration displaces electricity that would otherwise be generated at stand alone biomass power plants, on the basis of our modelled supply mix, while natural gas, coal and petroleum fuelled cogeneration displaces electricity from gas power plants.

9.5. Decarbonising the electricity supply mix

In 2001 energy which users obtained by direct combustion of fuels and collection of solar heat provided 69% of the energy supplied to users (including use in the production and processing of fuels other than electricity), but accounted for only 31% of greenhouse gas emissions from stationary energy. Electricity generation accounted for the other 69% of emissions.

In our Baseline demand case for 2040, the requirement for energy supplied by combustion and solar heat rises 42% to 2,069 PJ, while emissions increase by 37%. In the Medium Efficiency case, with additional substitution of low emission fuels as described above, the increase in energy supplied is limited to 22%, relative to 2001, and the increase in emissions to 12%.

Electricity requirements increase faster than requirements for other fuels in the Baseline case, but not in the Medium Efficiency case. In 2040 they are 69% higher than in 2001 in the Baseline case and 24% higher in the Medium Efficiency case. In Chapters 7 and 8 we described and reviewed the different technologies which might be used to meet these requirements. In this Section we describe how the electricity supply system has been modelled in the different scenarios constructed for this study.

In each case the system consists of a mix of different types of generating plant. The types of generation fuel and technology included are shown in Table 9.2, which also shows the key technical characteristics of each type.

For the coal and biomass technologies, thermal efficiency has been assumed to improve significantly, relative to current generating plant using those fuels. The effect will be an appreciable reduction in fuel use and, in the case of coal, greenhouse gas emissions, to generate a given quantity of electricity. For combined cycle gas turbine (CCGT) natural gas plant, a lesser improvement has been assumed, for two reasons: firstly, in order to err on the side of conservatism, so far as the characteristics of “cleaner” technologies are concerned and, secondly, because much of the CCGT plant will be required to operate in load following mode (or be substituted by less efficient open cycle plant), with consequently reduced thermal efficiency.

Table 9.2: Characteristics of different types of electricity generation

Generation fuel/technology	Generation efficiency (fuel to electricity)[a]	Own use of electricity (% of generated)	Transmission and distribution losses (% of sent out)
Black coal (conventional)	45%	5%	8%
Brown coal (conventional)	35%	8%	8%
Biomass	40%	5%	8%
Petroleum	45%	1%	8%
Natural gas (CCGT)	50%	1%	8%
Photovoltaics	*na*	*na*	2%
Hydro	*na*	*na*	8%
Wind	*na*	*na*	8%
Cogeneration	77%[b]	*na*	2%

Notes:
a. Thermal efficiency calculated according to Gross Calorific Value (see Glossary).
b. Except sugar, 140%, because of assumed concurrent improvements in overall efficiency of bagasse utilisation.

Own use of electricity is much the same as in current plant of the same technology type.

Transmission and distribution losses for the centralised generation technologies, including wind and biomass, are much the same as in the present transmission and distribution systems. Only cogeneration and photovoltaics are assumed to be distributed generation technologies in this sense, and allocated much lower losses. It may be argued that biomass and wind should also be treated as distributed technologies, with lower transmission and distribution losses. This would be true with low rates of penetration of these technologies, but, at higher rates of penetration, the electricity supplied by these technologies would exceed demand in the immediate locality. Much of it would require transmission to major urban centres of demand, thus taking on the characteristics of centralised generation.

It will be noted that the list of technologies includes neither coal with CO_2 capture and geosequestration, nor coal based IGCC; the coal technologies included are conventional thermal generation, with improved efficiency performance. These "low emission" coal technologies do not form part of our various low emission electricity supply system scenarios because, as described in Chapters 7 and 8, both are more costly incremental sources of electricity supply system greenhouse abatement than wind or biomass, up to the level that the latter are included in the various electricity supply system plant mixes modelled for this study (see below). (Incremental abatement is measured in terms of marginal dollars per tonne of marginal abatement relative to conventional coal, the lowest cost source of electricity.)

Baseline scenario (Scenario 1)

Our Baseline scenario consists of energy demand at the Baseline level, which includes 1,129 PJ (314 TWh) of electricity, direct fuel substitution at the level described earlier in this Chapter, and 108 PJ of electricity supplied by cogeneration. The mix of generating plant that supplies the remainder of the electricity demand is our estimate of that which will occur in the absence of further policy measures to limit greenhouse gas emissions from stationary energy.

The last few years have seen the beginning of a shift away from coal and towards natural gas for electricity generation. In common with most other observers, we expect this trend to continue, with current policy settings (including anticipated further changes to energy markets). For example, ABARE's projection for 2019-20 has coal's share of electricity generation falling from the current level of over 80% to about 71%. Natural gas makes up most of the difference, but there are also increases in biomass, hydro and wind. Our 2040 Baseline scenario is very similar, with coal having a share of 67%, natural gas (including cogeneration) 16%, and biomass 8%.

Table 9.3 shows the energy generation and corresponding approximate capacity for Scenario 1, and also Scenario 2 (see below) and compares them with actual figures for 2001. All these figures are in terms of electricity generated, rather than electricity supplied, and include electricity lost in transmission and distribution and electricity used at power stations. Note that the available data do not allow capacity corresponding to the 25 PJ of cogenerated electricity reported by ABARE for 2001 to be estimated. For 2040, cogeneration is calculated in relation to host thermal loads, without any assumptions about hours of operation, so calculating capacity has little meaning.

Clean Energy scenario (Scenario 2)

Our principal Clean Energy scenario is one in which greenhouse emissions from stationary energy in 2040 are 50% of their level in 2001. Significant reductions in emissions below the level of Scenario 1 are achieved by increased energy use efficiency, as specified by the Medium Efficiency demand case, and associated adoption of solar thermal pre-heating, increased substitution of natural gas for coal in direct combustion, and widespread uptake of cogeneration, as described in Sections 9.2, 9.3 and 9.4. In our model of the Australian energy system, further reductions in emissions are achieved by replacing coal as a fuel for electricity generation, using what we have termed a qualitative optimisation approach. The electricity supply system includes 133 PJ (37 TWh) from cogeneration. To construct the remainder of the supply mix, the following steps were taken.

Firstly, wind energy, a relatively low cost, zero emission technology, was adopted up to the point where it starts to require significant back-up generation (from gas turbine plant) in order to achieve acceptable levels of availability, having regards to the diversity available through differences in prevailing wind conditions at any given time across the extensive areas covered by the two major Australian grids (eastern and south west). As described in Chapter 7, we estimate this level to be 20% of total generation and we assess that there are sufficient suitable sites in Australia to be able to supply this level of wind generation (182 PJ or 51 TWh per year) at the costs given in Chapter 7.

Secondly, hydro generation was increased to about 10% above its current level (all four scenarios have the same level of hydro) and a small quantity of petroleum fuelled generation was retained (again, as in all four scenarios), for use in remote and off-grid locations.

Thirdly, photovoltaic generation was adopted to a level of 4.5% of grid generation (38 PJ or 11 TWh per year). Although more expensive on a purely energy basis than the other generation technologies, photovoltaic generation has the great advantage of producing all its electricity during the day and producing maximum output on bright sunny days. Consequently, almost all the output from photovoltaic installation occurs at times of intermediate and peak load, when wholesale electricity prices are considerably above their average level. Added to the fact that most of the output of building integrated photovoltaics can be used in the immediate vicinity of the installations, with consequent large savings in transmission and distribution costs, these conditions make a modest level of photovoltaic generation cost competitive with the other low emission generation technologies.

Finally, the remaining demand for electricity was supplied by a mix of biomass, natural gas and coal. The mix was adjusted to achieve the overall result of a 50% emission reduction. A significant proportion of gas fired generation was required because of its superior technical ability to follow variations in load so as to supply intermediate and peak demand. It was found that this requirement had the effect of constraining coal fired capacity to a relatively small proportion of total generation. Increasing coal (high emission) would have meant increasing biomass (zero emission) also, leaving insufficient capacity of medium emission natural gas generation.

The supply mix adopted for Scenario 2, shown in Figure 9.1, has 73 PJ (20 TWh) supplied by coal fired power stations, which is equivalent to retiring the vast majority of coal-fired power stations, retaining in 2040 only the three Queensland coal-fired power stations that were commissioned in 2000-2003, and adding no new stations from now on.

More details of this Scenario are shown in Table 9.3 and also Figure 9.1.

Other low emission scenarios

For illustrative purposes, two other low emission scenarios were also constructed.

Scenario 3 is identical with Scenario 2, except that coal fired generation is reduced to zero, with the extra generation coming from natural gas and biomass. This results in a further reduction in emissions. Scenario 4 is a low emission scenario with the higher, Baseline level of energy demand, as in Scenario 1. Meeting the higher demand for electricity requires significantly more generating capacity, and is much harder to achieve, in terms of both available energy resources, such as natural gas, biomass and wind, and in terms of cost.

Figure 9.2 compares all four Scenarios with each other and with 2001.

Table 9.3: Electricity generation[g] and approximate capacity by fuel source, 2001 and 2040 Scenarios 1 and 2

Generation technology/fuel	Generation (PJ[c])			Approximate capacity (GW)		
	2001	2040		2001[a]	2040 [b]	
		Scenario 1	Scenario 2		Scenario 1	Scenario 2
Black coal	414.9	625	84	22.0[e]	25	3.3
Brown coal	190.6	220	0	7.2	0	0
Natural gas (excl. cogeneration)	76.0[f]	124	154	6.6[d, f]	8	10
Petroleum	6.4	12	9	1.1	1.3	1
Hydro	60.4	68	68	7.7	9	9
Biomass (excl. cogeneration)	2.5	78	245	0.55	5.4	17
Wind	1	25	182	<0.1	2.6	19
Direct solar	<0.1	6	38	<0.01	1.2	7.5
Cogeneration (gas + biomass)	24.6 [f]	110	135	*na*	*na*	*na*
TOTAL	776.4	1,267	916	*na*	*na*	*na*

Notes:

a. Approximate capacities for 2001 based mainly on ESAA (2003), Tables 2.1, 2.3 and 2.4.
b. Approximate capacities for 2040 calculated by assuming the following average capacity factors. black coal 0.8; natural gas combined cycle 0.75, natural gas peak-load turbines 0.1; biomass 0.7, wind 0.3, direct solar 0.6. Excludes additional peak-load backup for wind.
c. 1 TWh = 3.6 PJ
d. Natural gas capacity in 2001 was about 2 GW steam, 1.5 GW combined cycle, 2.5 GW gas turbines (gas fuel) and 0.6 GW gas turbines (dual fuel, gas & oil).
e. Includes 1.9 GW dual fuel (black coal + gas).
f. Large CCGT cogeneration plants are included under gas fired generation, not under cogeneration, in 2001 data.
g. This table gives the final energy actually generated as electricity, not the primary energy input to electricity generation.

Fig. 9.1: Electricity generated by fuel/source, 2040, Clean Energy – Scenario 2

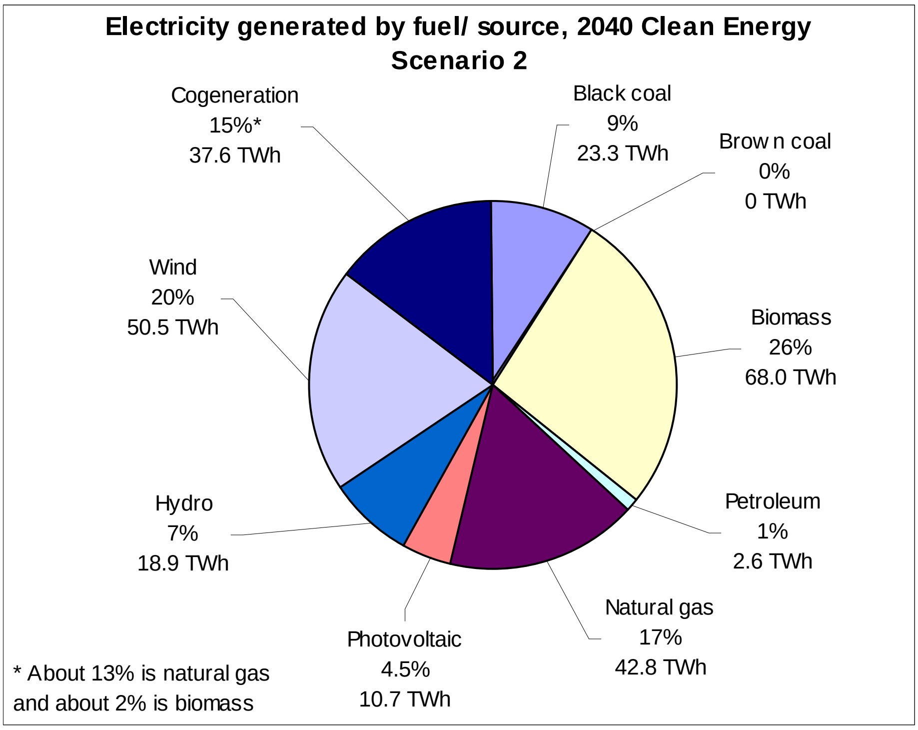
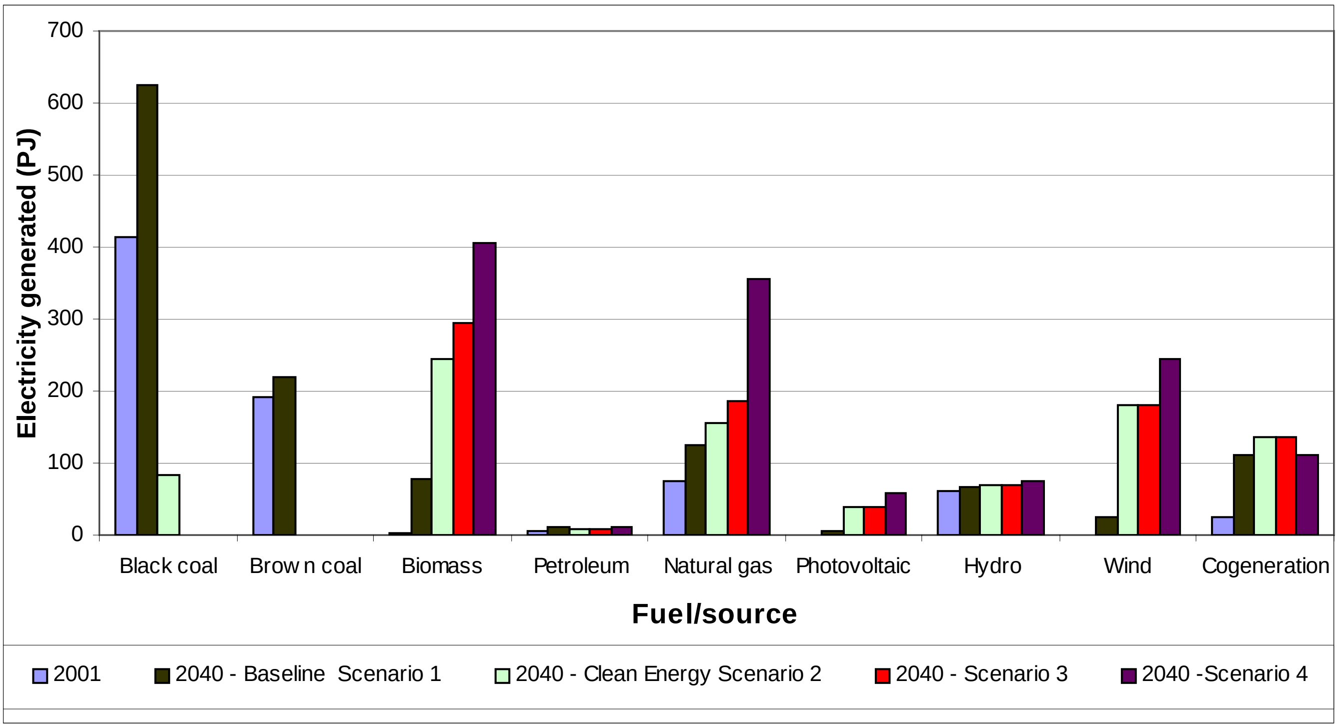


Fig. 9.2: Electricity generated by fuel/source, 2001 and all 2040 Scenarios



9.6. Decarbonising transport

Although the subject of the present report is stationary energy, we cannot ignore transport entirely because it is an input to stationary energy use. In Section 6.6 we considered a somewhat more efficient transport system based on the 2001 fuel mix. These efficiencies could be achieved by improving urban public transport and facilities for walking and cycling, combined with a comprehensive mix of transport and planning policies to make these modes more attractive, a small shift from road to rail freight (based on improved rail infrastructure), and improved fuel efficiency of road and air transport. This results in an increase of 45% in energy demand by transport between 2001 and 2040[3].

On the supply side we now investigate simple measures for reducing the greenhouse intensity of this demand. In the spirit of this report we keep with small improvements to existing technologies and assume that almost all road vehicles in 2040 are highly efficient hybrid petrol-electric or diesel-electric vehicles with half the greenhouse gas emissions per km travelled of the present road fleet. This is consistent with current fuel efficiency achievements of hybrid vehicles. These vehicles do not require an external source of electricity – rather the batteries are charged from the petrol or diesel engine, supplemented by regenerative braking. In addition it is assumed that the small minority of vehicles that are unsuitable for hybrid propulsion (e.g. because of size or type of use) have diesel engines fuelled by a 100% bio-oil from crops. It is further assumed as a rough approximation that the 45% increase in transport energy demand applies to each of cars, trucks and aircraft.

Thus, in this scenario, CO_2 emissions from road transport in 2040 decrease to 27.5% below those in 2001, while emissions from civil air transport increase to 45% above the 2001 value. But in 2001, road transport accounted for 90% of Australia's Transport emissions and civil air transport only 6%. Therefore, assuming to first approximation a similar pattern in 2040, the net effect is that transport emissions in this scenario in 2040 will be 25% below those of 2001. An effect of this will be to reduce slightly CO_2 emissions from stationary energy in 2040. However, since this is a small effect, we have not included it in our 2040 scenarios for stationary energy.

By 2040 it is probable that petrol and diesel will be scarce and priced considerably above current levels (Hall et al., 2003). So we assume that, in the absence of major technical breakthroughs, hybrid vehicles will be the standard kind of vehicle in large-scale mass production and so will be only a little more expensive than ordinary vehicles. Therefore it is plausible to assume that this supply-side transport scenario will have no additional net costs in 2040.

[3] Without these efficiency improvements, transport energy demand could have increased by about 100%. Nevertheless, we consider that strong demand-side measures could potentially limit the growth in vehicle-km travelled to much less than the 45% increase used here.

10. Scenarios for a clean energy future in 2040

10.1. Scenario results: changes in greenhouse gas emissions from stationary energy

Baseline – Scenario 1

In the Baseline Scenario for 2040, as shown in Table 10.1, total demand for primary energy in stationary consumption is 33% higher than in 2001, while CO_2 emissions are 21% higher. It will be noted that these increases are significantly less than the 57% increase in final energy demand.

Primary energy demand grows more slowly than final energy demand because of significant increases in the efficiency of electricity generation, arising both from expected improvements within technologies (coal fired generation) and a shift toward inherently more efficient technologies and fuels (natural gas, cogeneration). The efficiency of other energy production and processing also increases.

The slower growth in emissions is attributed to these factors, plus a greater use of zero and low emission energy sources in both direct combustion and electricity generation.

However, while these relatively modest increases may seem encouraging, relative to growth rates of recent years, they still represent a major increase in Australia's greenhouse gas emissions above 2001 levels. In absolute terms it is an increase of 48 Mt of CO_2.

Table 10.1: 2040 Baseline – Scenario 1 compared with 2001

	Increase in 2040 relative to 2001	
	Energy	**CO_2 emissions**
Final energy demand	57%	*na*
Primary energy:		
Electricity generation	26%	14%
All other stationary energy use	42%	37%
Total stationary energy	33%	21%

Clean Energy – Scenario 2

The overall result of our principal Clean Energy – Scenario 2 for 2040 is that CO_2 emissions are reduced to 130.9 Mt in 2040, compared with 261.7 Mt in 2001. This is a reduction of exactly 50% below stationary energy emissions in 2001 and roughly 35% below stationary energy emissions in 1990. Compared with the Baseline Scenario 1, the decrease in emissions is 59%. These comparisons are shown in Tables 10.2 and 10.3 respectively. The Tables show primary energy demand and associated emissions separated into two components:

- primary energy demand and CO_2 emissions related to electricity generation, and

- primary energy demand and CO_2 emissions related to all other stationary energy activities.

Figures 9.1 to 9.4 graph the absolute numbers for primary energy demand and greenhouse gas emissions in two different formats, again with emissions divided between the two major components. It can be seen very clearly that the adoption of zero and low emission energy supply technologies, and in particular the replacement of coal combustion for electricity generation with other generation technologies, makes a very large contribution to the reduction in emissions achieved in the Clean Energy Scenario.

Another way of understanding this is by noting that final demand for electricity and final demand by all other fuels are higher in the 2040 Clean Energy Scenario than in 2001 by almost the same amount, respectively 24.3% and 25.5%, giving the overall average of 25%. However, while emissions associated with electricity generation fall by 78%, those associated with all other fuels rise by 12%. This difference arises for two reasons. Firstly, because low-cost renewable energy can make a much larger contribution to the supply mix for electricity than to all other fuels, for which useful energy is provided directly by combustion at the point of use.

Table 10.2: 2040 Clean Energy – Scenario 2 compared with Baseline – Scenario 1

	Decrease: Clean Energy relative to Baseline	
	Energy	**Greenhouse emissions**
Final energy demand	-20%	*na*
Primary energy:		
Electricity generation	-43%	-81%
All other stationary energy use	-14%	-18%
Total stationary energy	-30%	-59%

Table 10.3: 2040 Clean Energy – Scenario 2 compared with 2001

	Decrease: Clean Energy relative to Baseline	
	Energy	**Greenhouse emissions**
Final energy demand	+ 25%	*na*
Primary energy:		
Electricity generation	-27%	-78%
All other stationary energy use	+ 21%	+ 12%
Total stationary energy	-8%	-50%

To understand the difference between Scenarios 1 and 2 it is important to note that the share of electricity in final energy demand is 38.5% in Scenario 1 but only 34.4% in Scenario 2, which is marginally less than the 2001 level of 34.7%. The difference between the two Scenarios is caused by the fact that end use efficiency increases are greatest in the electricity intensive Commercial/Services and Residential sectors. Since the losses inherent in thermal electricity generation account for most of the difference between final and primary energy demand, a fall in the electricity share of final demand brings a disproportionate fall in primary energy demand, and in greenhouse emissions, all else being equal. This effect demonstrates how important the realisation of full energy efficiency potential is to the final outcome.

The different processes at work can also be understood by comparing increases between 2001 to 2040 for Clean Energy – Scenario 2 in the following sequence.

GDP	+ 140%	
Baseline final energy demand	+ 57%	reduction caused by sectoral shifts within the economy and endogenous changes towards more efficient energy technologies
Medium Efficiency final energy demand	+ 25%	reduction caused by enhanced end use energy efficiency
Primary energy demand	-8%	reduction caused by 1) fall in the share of electricity in final demand, as a result of greater efficiency gains in the previous step in the electricity intensive Commercial/Services and Residential sectors, 2) adoption of cogeneration and other more energy efficient technologies for electricity generation and other energy supply, and 3) shift away from combustion based generation technologies
Greenhouse gas emissions	-50%	reduction caused by shift away from coal and towards low and zero emission fuels and technologies in electricity generation and other energy supply

It is clear that each stage contributes significantly to achieving the final Clean Energy Future:

- changes to the Australian economy that are already in train or can be expected to occur;
- enhanced energy efficiency that is economically beneficial but will require policy initiatives for its realisation, noting that energy efficiency increases in the Residential and Commercial/Services sectors bring further gains in reducing primary energy requirements because of the electricity intensiveness of these sectors;
- adoption of cogeneration and other more energy efficient technologies in energy supply, also requiring policy action; and
- replacement of high emission, mainly coal based energy supply technologies with low and zero emission technologies and fuels, which again will require the adoption and implementation of appropriate policies by governments.

Other low emission futures: Scenarios 3 and 4

Scenario 3 is identical with Scenario 2 except that coal fired power stations have been entirely phased out by 2040, while demand for all forms of energy is the same as in Scenario 2. The total emission reduction, relative to 2001, becomes 54.7% instead of 50%, and relative to 1990 is 40% instead of 36%. The emission reduction resulting from electricity generation is 84.6%, while that from all other energy sources remains unchanged, as shown in Figures 10.1 to 10.4.

In Scenario 4, energy demand is at the higher Baseline level, with final demand for stationary energy reaching 157% of the 2001 level by 2040, rather than the 125% of Scenarios 2 and 3. In view of growing international concern about climate change, and the cost effectiveness of a higher level of end use energy efficiency, such a large increase in demand seems an unlikely scenario. It is included here as a basis for comparison, and because it demonstrates the crucial role that enhanced energy efficiency will have if a clean energy future is to be achieved.

With the same energy supply mix as Scenario 3, CO_2 emissions in Scenario 4 in 2040 from electricity and stationary energy are 76% and 42% below the 2001 level, respectively. In this case wind energy generation becomes 247 PJ (69 TWh) and capacity is 26 GW, a more formidable challenge than the 182 PJ (50.5 TWh) and 19 GW required for Scenarios 2 and 3. Bioenergy generation becomes 1,044 PJ and its land requirements are 1.1 Mha, which is still less than the current area of plantation forest.

Changes in CO_2 emissions in all three scenarios are set out in Table 10.4.

Table 10.4:Change in CO_2 in 2040 for Scenarios 2, 3 and 4, relative to 2001

Scenario and Description		From electricity	From all other stationary energy	From all stationary energy
2	Clean Energy Future	-78%	+ 12%	-50%
3	Clean Energy Future plus zero coal in electricity	-85%	+ 12%	-55%
4	Baseline energy demand, energy supply as in Scenario 3	-76%	+ 34%	-42%

Fig. 10.1: CO2 emissions from electricity generation and all other stationary energy consumption in 2001 and all 2040 Scenarios

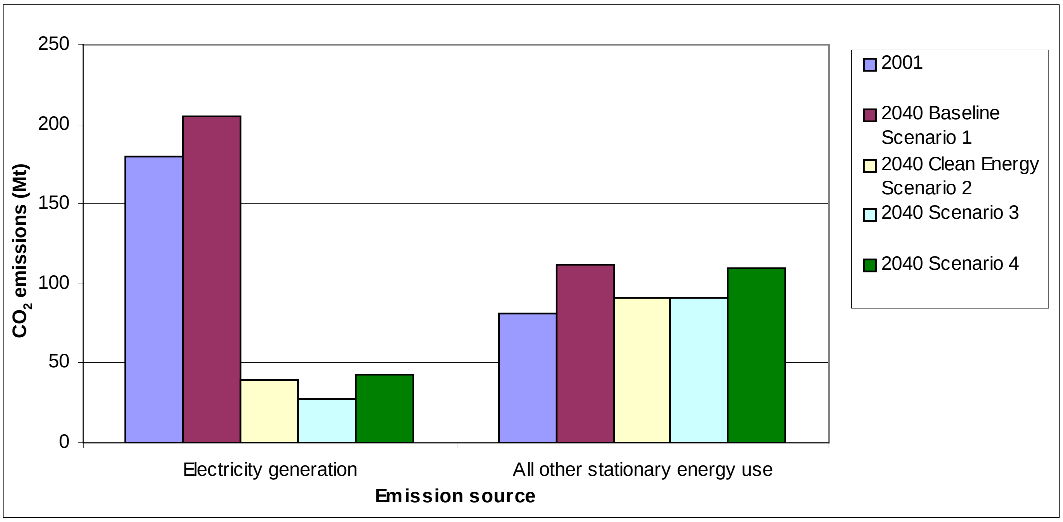


Fig. 10.2: Composition of total CO_2 emissions from stationary energy in 2001 and all 2040 Scenarios

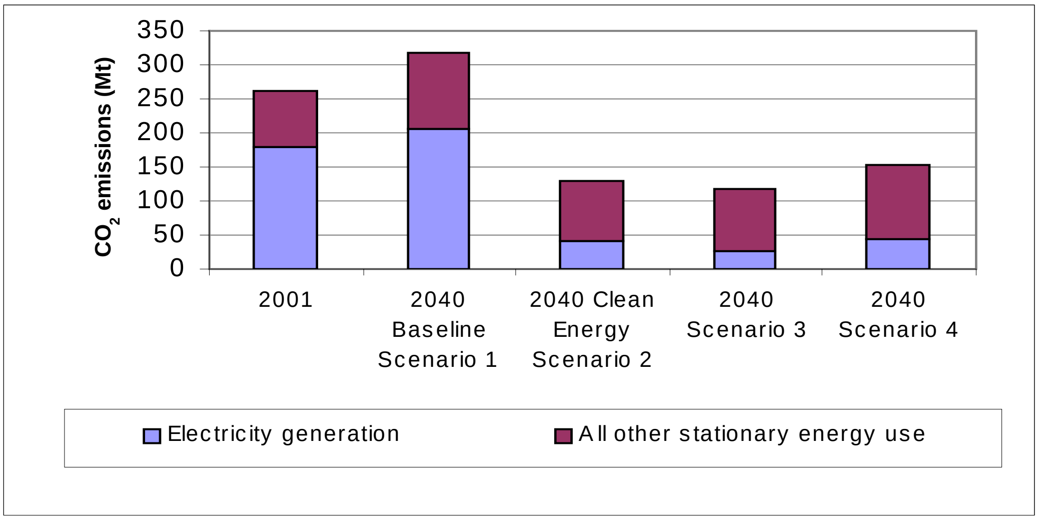


Fig. 10.3: Primary energy demand from electricity generation and all other stationary energy consumption in 2001 and all 2040 Scenarios

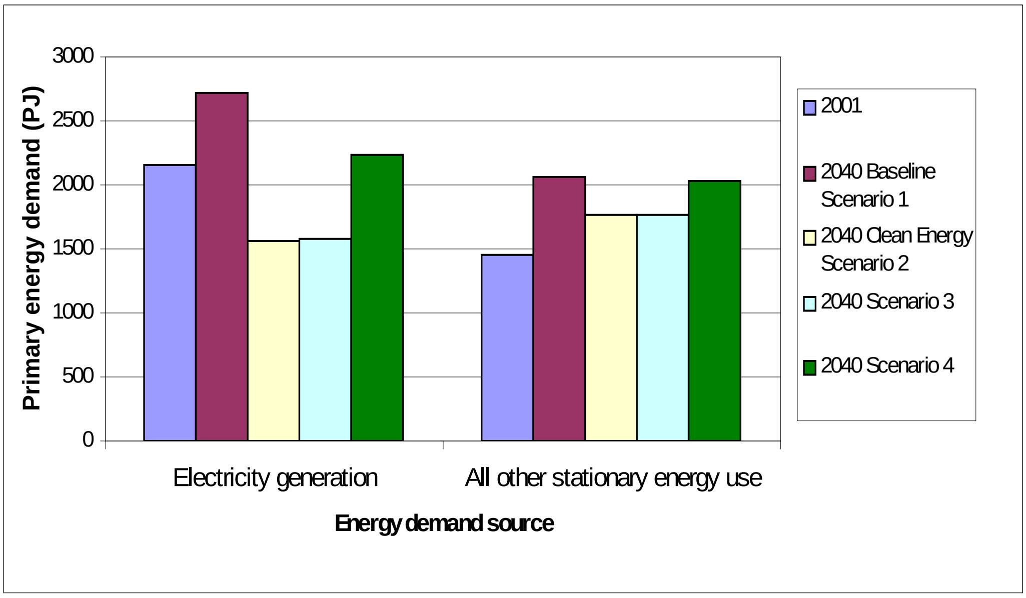
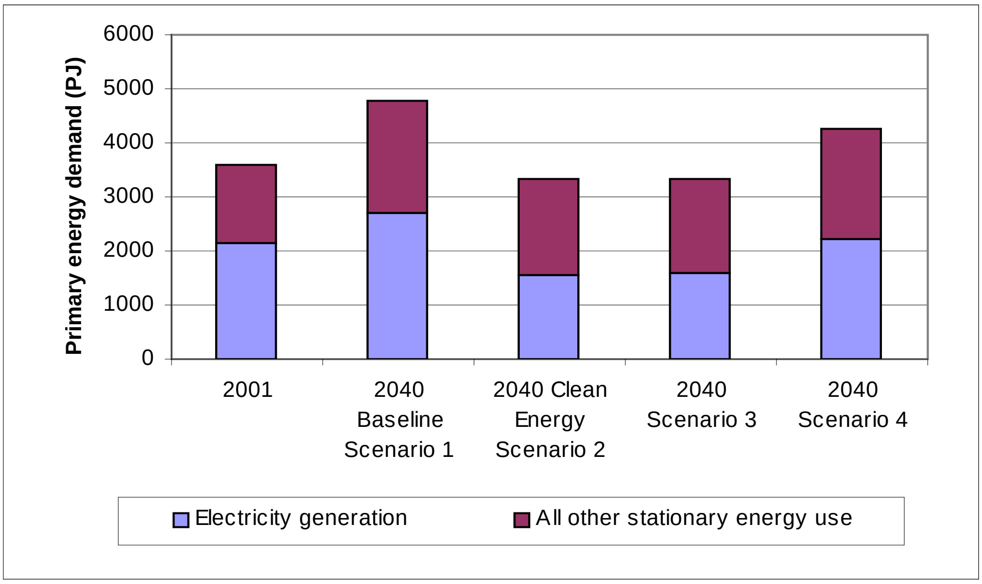


Fig. 10.4: Composition of total primary energy demand from stationary energy in 2001 and all 2040 Scenarios



10.2 Costs of the various scenarios

This report does not attempt to provide a full economic analysis of the 2040 scenarios. Indeed, as discussed in Section 2.1, we believe that this would be inappropriate for a time so far in the future, and we question the validity of the most commonly used integrated energy/macroeconomic models under these circumstances. Furthermore, there are some very large uncertainties, most notably the prices of fossil fuels and the extent of international and national constraints on greenhouse gas emissions in the long-term future. There can be little doubt that oil will be scarcer and more expensive in 2040 than it is today and that this will drive up the prices of Australia's LNG and coal exports. This in turn will draw up the prices of domestic natural gas and black coal that are capable of being exported. The extent of these increases cannot be predicted. Therefore, we do not think that a detailed attempt to evaluate the costs and economic benefits of a 'business-as-usual' scenario would be a meaningful exercise. Neither cost-benefit analysis nor the standard type of macroeconomic modelling seems appropriate.

The uncertainty about these key input cost parameters also calls into question the value of applying very detailed and complex energy system costing models, at least in the first instance. As a first step in analysing the economics of our scenarios, we offer here approximate estimates of the cost of electricity generation in the Baseline scenario (Scenario 1) and the Clean Energy scenarios (Scenarios 2 and 3), making several different but plausible alternative assumptions in each case. While this does not provide a complete economic assessment of the impact of Clean Energy scenarios, it serves to highlight the impact on electricity costs of different assumptions about fuel prices, electricity demand and supply mix.

The method of funding our Clean Energy Scenarios (see Section 10.3) can be summarised as follows:

> *In the cases where the fossil-fuelled scenarios are clearly more expensive than the Clean Energy Scenario, there are no costs to fund.*
>
> *In the cases where the fossil-fuelled scenarios are approximately the same cost or cheaper than the Clean Energy Scenario, the economic savings made by efficient energy use, together with the transfer of a fraction of the existing 'perverse' subsidies to the production and use of fossil fuels[1], pay for the additional costs of clean energy supply.*

The cost estimates have been constructed on the basis of levelised costs in 2040, using a real discount rate of 8%. Because of the complexities involved, we have not attempted to estimate the costs of transmission and distribution.

The following further simplifications and assumptions are adopted.

- Electricity prices in \$/MWh are average long-run prices, not short-run marginal. In other words they comprise the annualised capital, fuel, operation and maintenance costs.[2]

- Since the future costs of hydro and petroleum are uncertain and are the same in all scenarios, they have been omitted from the costings.

- For simplicity we do not consider the fuel costs of peak-load plant, which are small when spread over a year.

- Also for simplicity, it is assumed that, in the Clean Energy scenarios, solar electricity is peak-load costing \$20/MWh more than conventional (hydro+gas

[1] See Section 10.3.
[2] Note that \$10/MWh = 1 c/kWh.

turbine) peak-load generation. It is further assumed that in the Baseline scenario the very small quantity of solar electricity costs the same as conventional peak-load.

- We examine the Baseline scenario (i.e. Scenario 1) with four different sets of fossil fuel prices. These four cases A-D all have the same electricity generation (352 TWh including cogeneration) and fuel mixes in 2040.

- In Baseline Cases A-D we assume (as ABARE does to 2020) that the proportion of electricity generated from natural gas increases steadily. The result is that, in all our fossil fuel cases, by 2040 67% of total electricity generation (including cogeneration) comes from coal and 16% from natural gas.

- The Clean Energy scenarios all have the same electricity generation (255 TWh including cogeneration) in 2040. Scenarios 2 and 2a have the same low coal contribution (just under 9%), but different fossil fuel prices, while Scenario 3 has zero coal.

- For cogeneration, it is assumed that the electricity cost equals the grid electricity cost for that fuel. (Sales of useful heat are assumed to offset any higher price of cogenerated electricity compared with conventional fossil fuelled grid electricity.).

- Coal-fired power stations are retired at the ends of the operating lifetimes that they can reach without a major refurbishment. This lifetime is taken to be 35 years.

Baseline Case A

In this case it is assumed that national policy will require the greenhouse gas emission intensity of coal-fired power stations in 2040 to be less than or equal to that of the best practice combined cycle natural gas power station in 2001, i.e. about 0.34 Mt CO_2 emitted per TWh of electricity sent out.[3] Since the newest coal-burning technologies of 2003, such as ultra-supercritical boilers, have much higher emissions than this target, IGCC with geosequestration of CO_2 from both coal- and gas-fired power stations would seem to be the main option to explore. Therefore, the price of coal-fired electricity is likely to be around 10 c/kWh at the point of generation (see Section 8.4). Allowing 1 c/kWh for the additional cost of electricity generated from natural gas transmitted by pipeline to the eastern States from the North-West Shelf, the price of combined cycle gas-fired electricity with geosequestration is assumed to be around 7 c/kWh.

Baseline Case B

We assume no geosequestration, but rather that a carbon tax is placed on fossil fuels equivalent to their quantifiable external costs. As set out in Appendix A, we take the ExternE results for the costs of greenhouse gas emissions plus one-quarter of ExternE's air pollution costs for each of coal-fired and natural gas-fired electricity, and add them to the 2001 generation costs. The result is that electricity from coal is priced at 9.25 c/kWh and electricity from natural gas 7.0 c/kWh.

[3] Such a policy would greatly reduce emissions for electricity generation, but not to the levels in our Clean Energy Scenarios.

Baseline Case C

We assume no geosequestration, but rather that the price of coal-fired electricity has risen from its present range of 3.6-4.0 to 5.0 c/kWh (2001 value) and that the price of base-load natural gas-fired electricity has risen from around 4 c/kWh to 5.0 c/kWh. For NSW this is approximately equivalent to assuming that the cost of steaming coal doubles to about $2/GJ and that the cost of natural gas increases from $3/GJ to $4/GJ. For the purpose of comparison, we assume that these fossil fuel prices apply to both the Clean Energy scenario and to this fossil scenario.

Baseline Case D

As in Case C, but no significant increase in the cost of coal- and gas-fired electricity, which is held at 4 c/kWh for each. We compare Case D with a version of the Clean Energy Scenario (Scenario 2A) that has the same fossil fuel prices as Case D.

Clean Energy Scenarios

Our estimate of the costs is based on the following additional assumptions:

- Efficient energy use measures and solar hot water are implemented to the extent that they are cost effective over the lifetimes of the building, appliance or equipment concerned. Therefore, there are no net costs of efficient energy use (see Section 6.8). However, there are up-front costs. Because there are so many different technologies in third category, their average cost will be estimated as an output of the costs of energy supply in Table 10.5.

- Medium efficiency of energy use reduces demand for stationary energy in 2040 by 20%, as derived in Chapter 6. Further cost-effective reductions may be possible, although they are not considered in this study.

- The indirect economic benefits of efficient energy use that must be considered here include a reduction in the generation, transmission and distribution infrastructure required for 2040, as estimated below. This benefit will be offset to some extent by the costs of the energy efficiency measures, additional transmission and distribution costs of a more distributed electricity supply system and by the increase in peak-load gas turbine capacity required to back up wind power. These costs are very difficult to estimate accurately. For a first approximation we assume that the additional transmission and distribution costs of the centralised fossil fuel and more distributed Clean Energy scenarios are approximately equal. Because we expect most of the efficient energy use measures to pay for themselves within 8-10 years (compare Ministerial Council on Energy, 2003), the Clean Energy scenarios offer additional economic savings because they substitute for new power stations with lifetimes of 35-40 years. However, we do not attempt to calculate them, beyond suggesting that their magnitude is of the order of $10 billion.

- The price of renewable energy technologies, except for biomass, is as given in Column 3 of Table 7.3.

- Specifically, for the 65 TWh (234 PJ) of biomass energy (final consumption) required for Scenario 2, it is assumed that 15 TWh comes from bagasse and sugar-cane ‘trash’ at a generation cost of 5 c/kWh; 39 TWh from wheat stubble at the generation cost of 6 c/kWh; 10 TWh from forest residues also costing 6 c/kWh, and the remaining 1 TWh from oil mallee and other eucalyptus crops with multiple economic benefits that reduce the cost of electricity to 7 c/kWh.

- For the 77.4 TWh (343 PJ) of biomass energy (final consumption) required for Scenario 3, it is assumed that 15 TWh comes from bagasse and sugar-cane ‘trash’ at a generation cost of 5 c/kWh; 39 TWh from wheat stubble at the generation cost of 6 c/kWh; 10 TWh from forest residues also costing 6 c/kWh, and the remaining 13.4 TWh from oil mallee and other eucalyptus crops with multiple economic benefits that reduce the cost of electricity to 7 c/kWh.

- For direct solar electricity, we assume that the additional cost is 2 c/kWh above the average peak-load price paid by consumers.

Indicative comparison of costs

Based on these assumptions, Table 10.5 shows the results of our estimates of the relative costs of four different cases for electricity generation:

Table 10.5: Cost of Baseline Scenario, Cases A-D, and Clean Energy scenarios with various fuel prices in 2040

Scenario	**Electricity demand, 2040 (TWh)**	**Coal electricity price, 2040** ($/MWh)	**Natural gas electricity price** ($/MWh)	**Wind electricity price, 2040** ($/MWh)	**Solar electricity price, 2040** ($/MWh)	**Total cost of electricity 2040** ($ billion)	**Average cost of electricity**[a] ($/MWh)
1: Cost A	352	100	70	55	Extra 20	29.5	90
1: Cost B	352	92.5	70	55	Extra 20	27.7	84
1: Cost C	352	50	50	55	Extra 20	16.4	50
1: Cost D	352	40	40	55	Extra 20	13.2	40
2: Cost C	255	50	50	55	Extra 20	12.2	54
2: Cost D	255	40	40	55	Extra 20	11.1	50
3: Cost C	255	N/A	50	55	Extra 20	12.3	56

Notes:
a. This equals the total cost in billions of dollars (Column 7) divided by the energy generated by the sources considered here. The latter is equal to the total demand (Column 2) minus the generation from hydro and oil (not shown).
For other assumptions, see text.

The results are encouraging. Although the cost of electricity expressed in dollars per MWh (see Column 8 of Table 10.5) is lowest in Baseline Case D, there are fewer megawatt-hours generated in the Clean Energy scenarios. As a result, the total costs in billions of dollars of the Clean Energy scenarios are less than or approximately equal to those of all the Baseline scenario cases, even Baseline Case D with low-cost coal and gas. It appears that the only way the Baseline energy supply could compete with our Clean Energy scenarios would be to adopt an important component of the latter scenarios, namely, to implement Medium Efficiency energy use. In practice, this option seems very unlikely, since cheap fossil fuels discourage the efficient use of energy.

The calculation is now refined by including the average costs of efficient energy use, which are derived as an output of Table 10.5. For fuel cost combination D, the difference in the total cost of electricity in 2040 between Scenarios 1 and 2 is $(13.2 - 11.1) billion = $2.1 billion. The difference in demand is (352 – 255) TWh = 97 TWh. Therefore, the breakeven cost of efficient energy use is $2100/97 MWh = $21.6/MWh. In other words, so long as the cost of efficient energy use is less than $21.6/MWh saved, Scenario 2 (Clean Energy) is less expensive than Scenario 1 (Baseline). Similarly, for the fuel cost combination C, the breakeven cost of efficient energy use is $43.3/MWh saved. In other words, in Case C efficient energy use could make a much greater, cost-effective contribution to the Clean Energy scenarios. In Cases A and B, efficient energy use would be competing with the costs of wind power and biomass electricity.

Including part of the environmental and health costs of the fossil fuel scenarios, either by using the IEA estimates of the costs of geosequestration of CO_2 (Baseline Case A) or by using the ExternE estimates of the external costs of fossil fuels (Baseline Case B), makes the Baseline cases much dearer than our Clean Energy Scenario.

10.3 Paying for cleaner energy scenarios

Any additional costs of the Cleaner Energy Scenario could be readily paid out of the existing financial subsidies to the production and use of fossil fuels. A recent estimate of the minimum level of these subsidies is $6.5 billion p.a. (Riedy and Diesendorf, 2003). These subsidies include:

- electricity price subsidies to aluminium smelting;
- tax benefits for salary packaging motor vehicles;
- Greenhouse Gas Abatement Program (which goes mostly to fossil fuels);
- fuel excise reduction;
- fuel sales grants scheme;
- automotive industry support;
- land for roads and car parking;
- reduced import duty on 4WDs;
- inappropriate company tax concessions;
- R&D support for fossil fuels;
- non-recovery of government agency costs (e.g. AGSO, DITR, various State departments).

Subsequently this work has been extended by Riedy (2003), who has calculated additional subsidies that lift the total to $9 billion per year. Riedy has classified the subsidies into ‘positive’, ‘negative’ and ‘perverse’ subsidies. The latter category comprises subsidies that are both economically inefficient and environmentally damaging. Such subsidies amount to $5.2 billion per year. A small fraction of these could be used on a temporary basis to speed up the transition to a 50% reduction in CO_2 emissions from stationary energy.

Finally, it is important to realise that the macroeconomic benefits of increasing energy efficiency are conceptually identical to the macroeconomic benefits of increasing labour market efficiency. While the latter has been the objective of government policy in Australia for over 15 years, the former is generally seen as a peripheral problem to be pursued primarily for environmental reasons. In fact, minimising the amount of energy required to produce a given level of output is as economically beneficial as minimising the amount of labour or capital input. Reducing energy consumption per unit of output will free up resources, particularly resources that would otherwise be directed towards energy generation and distribution, that can be directed towards more productive purposes.

11. Innovative Scenarios for Beyond 2040

As discussed in Chapter 1, before the end of the 21st Century, Australia and other rich countries may have to reduce their anthropogenic greenhouse gas emissions by 80% or more. Furthermore, the energy sector, as the principal cause of these emissions, must carry the principal burden of this reduction.

The first step is for Australia to move to an economy where there is no longer any increase in the consumption of materials and energy. Any growth in GDP must be decoupled from these flows. There are examples where this has been achieved partially and temporarily, without a decline in living standards: Denmark enjoyed steady economic growth in the 1980s without growth in stationary energy; China's economy in 1996-1999 grew at over 7% p.a. while reducing greenhouse gas emissions. So, for all scenarios beyond 2040, we assume that the main drivers of energy demand are exhausted: energy intensive industries have peaked; economic structure has shifted further towards the service sector, within which travel has peaked; population has stabilised at around 25 million; and efficient energy use has been further implemented. The result is that energy consumption has been reduced to the 2001 level by 2050.

In our Clean Energy – Scenario 2, the main contributions to stationary energy come from natural gas, biomass, wind power and solar heat at low temperatures. But, in the long run, probably before the end of the 21st century, Australia's reserves of natural gas will become scarce. Biomass energy may have to take on a major role in fuelling transport and would then be making substantial additional demands on land use. Furthermore, wind power above 20 GW of capacity may be reaching the limits of available land.

Therefore, to gain further reductions in CO_2 emissions post-2040, it is essential that, in parallel with the further development of existing commercial technologies -- such as energy efficient appliances, equipment and buildings, wind and biomass -- that innovation is sought in new and existing technologies. To this end, we sketch three scenarios for 2040-2100 that are based on major improvements to existing technologies. In each case we assume that by 2040:

- Scenario 3 (i.e. zero coal-fired electricity) has been implemented;
- population growth has ceased;
- decline in household size has ceased;
- growth in GDP has been almost completely delinked from energy consumption.

First it is necessary to consider a scenario that is unlikely to work in the long term.

11.1 Scenario 5: Geosequestration of CO_2 from distributed sources

This scenario continues with the same energy supply mix as our Scenario 3 discussed in Chapter 10. The only difference is that CO_2 emissions from power stations and other large point sources that produce or burn natural gas or biomass are captured and subject to geosequestration.

Biomass energy produced in an environmentally sound manner should have no net CO_2 emissions, because the emissions produced by combustion are balanced by the

CO_2 absorbed during regrowth.[1] So, in theory, geosequestration of emissions from the combustion of biomass produces net emission reduction that can be offset against emissions from fossil fuels in the rest of the energy supply mix.[2]

In practice this would be an expensive scenario, because:

- CO_2 emissions from point sources in NSW would have to be piped 500-700 km to southern Victoria for geosequestration;
- instead of about 25 large centralised power stations, there would be hundreds of smaller natural gas and biomass fuelled, distributed power stations from which to separate the CO_2 emissions and pipe them into a pipeline distribution system that feeds into the main transmission pipelines.

Furthermore, this would only be a temporary solution, because natural gas is expected to become scarce in the second half of C21, especially if LNG exports continue at high levels.

11.2. Scenario 6: Low-cost renewable electricity without additional storage

Electricity

There are several possibilities for generating large quantities of low-cost electricity in the longer term future, which are not restricted by land-use limits. These sources include rooftop and building-integrated photovoltaics, solar thermal electricity and hot-rock geothermal, as discussed in Chapter 7. Here we focus on cheap photovoltaics.

If current R & D on thin film and other innovative solar PV systems is successful, we might obtain modules at US$0.5 per watt, inverters at A$0.5 per peak watt and installation atA$0.5 per peak watt (compare prices in Section 7.5), giving a price of electricity generated on suburban roofs of around 10 c/kWh in Australian currency. This would be competitive with centralised supply in every capital city and so all households with sufficient insolation on roofs or walls could switch to solar.

At first thought, this suggests that all natural gas-fired power stations, apart from cogeneration plants, could be replaced with direct solar. However, there would be times when the skies are overcast and there is little wind. Clearly, in the absence of cheap electricity storage, electricity generation comprising 39% solar and 20% wind cannot be backed up by 33% biomass and 7% stored hydro-electricity, especially since a significant fraction of the biomass would be in the form of cogeneration. In addition, a large amount of peak-load back-up would be required. This could take the form of gas turbines fuelled with (say) biofuels 67% and natural gas 33%. The largest contribution to capacity would be from gas turbines backing up the wind and solar. Although the capacity of these peak-load generators would have to be high, the capacity factor would be low. If this back-up provided (say) 15% of total grid electricity generation, and the 1% petroleum is replaced with biodiesel, the final electricity generation mix would become: 44% biomass, 24% solar, 20% wind, 7%

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[1] See Azar et al. (2003). In practice, there will be some CO_2 emissions if the biomass crops are harvested and transported by means of fossil fuels. However, with good system design, these can be kept small.

[2] If there are no fossil fuels in the energy supply mix, then geosequestration of emissions from biomass combustion could be used to reduce the concentration of CO_2 in the atmosphere.

hydro and 5% natural gas. Since electricity demand is postulated to be at the 2001 level, the quantity of biomass used annually for electricity generation would be only slightly greater than that of Scenario 3. In Scenario 6, the only CO_2 emissions from electricity generation would come from the small quantity of natural gas burnt as part of the peak-load back-up, amounting to about 4.1 Mt or 2.3% of the CO_2 emissions from electricity in 2001.

All other energy

Cheap photovoltaics would not be able to reduce emissions from the rest of stationary energy which come from natural gas, petroleum and coal in that order. Most of the 24 Mt of CO_2 emissions from petroleum could be replaced completely with bio-diesel, and this would be encouraged by the high prices of diesel expected in 2040. If the coal used (as coke) in metallurgical processes (about 130 PJ) could be replaced by either charcoal (produced from biomass, see Section 7.1) or hydrogen (produced by electrolysis using renewable electricity), then a further reduction of about 13 Mt CO_2 would be achieved. This would of course require the adoption of different metallurgical processes from blast furnace iron and steel production. The result is that CO_2 emissions from stationary energy that is not electricity are reduced to about 53 Mt (including energy used in oil refining and gas processing to supply natural gas and petroleum fuels for transport), which is a reduction of about 42% compared with 2001 emissions from the same category of stationary energy.

Total stationary energy

Scenario 6 starts with Scenario 3 and replaces most natural gas used for electricity generation with PV and all coal and petroleum for stationary energy with bioenergy or electricity. The net effect on stationary energy is that CO_2 emissions are reduced to 22% of the 2001 level. So, even without the assumption of additional low-cost storage, a reduction of nearly 80% in emissions from stationary energy could be achieved. Even greater reductions would be possible by using solar thermal systems with concentrators to produce both high-temperature heat and electricity.

11.3. Scenario 7: Cheap renewable electricity with cheap storage

As discussed in Sections 7.8 and 7.9, several kinds of storage are possible, for instance:

Advanced batteries with low-cost residential PV systems.

In this case an electricity supply mix of 39% direct solar, 33% biomass, 20% wind, 7% hydro and 1% biofuels is feasible and zero CO_2 emissions could be achieved from electricity generation. Low-cost advanced batteries would make solar energy a ‘dispatchable’ source of electricity, thus increasing its economic value. But, since PV systems do not address the non-electricity part of stationary energy, they are at best a partial solution.

Hydrogen produced by means of the electrolysis of water by low-cost renewable energy.

With low-cost storage the only limitation on total wind power capacity is the availability of sufficiently windy sites. Hydrogen may be converted back into electricity in fuel cells. However, since we can eliminate almost all emissions from electricity generation with low-cost solar and no storage (as in Section 11.2), our main interest in hydrogen is for the production of process heat at high temperature by combustion (substituting for natural gas), as a chemical reductant in metallurgical processes, and for mechanical energy (substituting for petroleum or biodiesel in stationary energy). To satisfy this demand and also to fuel large motor vehicles[3] (trucks and buses), would require substantial production of hydrogen, taking into account the low efficiencies involved. Currently wind power appears to be potentially one of the lowest cost renewable energy sources. To meet the kind of hydrogen demand envisaged here, the development of off-shore sites may be required.[4]

Low-cost, high temperature solar thermal systems with low-cost thermal storage

These technologies would directly address the non-electricity part of stationary energy, as well as electricity. Together with biomass energy, wind power and some hydro-electricity, they would enable a complete elimination of CO_2 emissions from stationary energy. Because thermal storage is potentially much less expensive than electrical storage, this pathway could turn out to be one of the most cost-effective.

11.4. Concluding remarks

Simply by considering some major improvements in a few existing technologies, such as PV   or high-temperature solar thermal with thermal storage, it is clear that there are several alternative pathways to 80% (or more) reductions in CO_2 emissions from stationary energy. Furthermore, Scenarios 2 and 3, that led to 50-55% reductions (as discussed in Chapter 10), can form the foundations of Scenarios 6 and 7 which achieve 80-100% reductions. The scenarios take account of limited land area and limited reserves of oil and, in the long term, natural gas. Entirely new technologies do not have to be postulated, although no doubt they will appear, giving us even more choices.

The main conclusion is that Australia should keep open its future energy options by:

- fostering the cleaner, youthful energy industries that form the basis for Scenarios 2 and 3, namely efficient energy use, biomass, wind and solar hot water; and
- expanding R & D support for a small portfolio of technologies that have the capacity to lead us from Scenarios 2 and 3 to a completely clean energy future. Among these are PV , thermal energy storage, high-temperature solar thermal, off-shore wind and further work on gasification and pyrolysis of biomass.

The R & D that is needed is not simply science and engineering, but must also encompass socio-economic, business development and policy aspects, which are most important for implementation. Specific policies and strategies are recommended in the next Chapter.

[3] Hydrogen is less suitable for motor cars because of its low energy density which entails a much larger fuel tank than for liquid petroleum or liquid biofuels, unless there is a substantial improvement in fuel efficiency.

[4] To the best of our knowledge there have been no published studies of Australia's off-shore wind energy potential. However, on the basis of near-coastal ocean depths, the potential is likely to be less than that of Europe.

12. Policy options and strategies

This chapter first sets out some axioms and broad principles and then proposes specific greenhouse response policies and strategies for all levels of government, business and other stakeholders in order to achieve our principal scenarios for 2040.

12.1. Axioms and principles

1. The human-induced greenhouse effect is real; its main cause is the combustion of fossil fuels; its result is global climate change which is already occurring; and it requires urgent, substantial, international, national and local action.

2. The main drivers of increasing combustion of fossil fuels are economic growth, the widespread use of inappropriate technologies and population growth.

3. The goal, core objectives and Precautionary Principle of ecologically sustainable development should be applied to this situation. Those accepted by the Australian Government (1992) are:

   Goal:
   Development that improves the total quality of life, both now and in the future, in a way that maintains the ecological processes on which life depends.

   Core Objectives*:*
   - To enhance individual and community well-being and welfare by following a path of economic development that safeguards the welfare of future generations.
   - To provide for equity within and between generations.
   - To protect biological diversity and maintain essential ecological processes and life support systems.

   One of the key Guiding Principles, ***the Precautionary Principle***, is:
   Where there are threats of serious or irreversible environmental damage, lack of full scientific certainty should not be used as a reason for postponing measures to prevent environmental degradation.

4. Following modelling by the IPCC, global greenhouse gas emissions will have to be reduced by 60-70% compared with current levels before the end of the 21st century.

5. Taking into account the needs of developing countries, this means that Australia's total greenhouse gas emissions may have to be reduced by at least 80% compared with current levels before the end of the 21st century.

6. The energy sector, as the principle source of Australia's emissions, cannot be sheltered from the implications of this large volume of emissions and therefore its emissions must be reduced by at least 80% compared with current levels before the end of the 21st century.

7. All levels of government, business, trade unions, community-based non-government organizations and individuals must play active roles in this transition.

8. The main barriers to making the transition are neither technical nor economic[1], but rather are social and institutional.[2] Therefore, the enhanced greenhouse effect cannot be simplistically attributed to perverse individual behaviour. An effective response requires governments to intervene to change the institutional structures and an economic system that fosters energy waste and excessive use of fossil fuels.

9. The environmental and social benefits of the efficient use of energy and the use of renewable sources of energy are large and should be reflected as far as possible in pricing and government funding.

10. Government action in Australia is currently inadequate for achieving a transition to an ecologically sustainable and socially equitable energy system. An adequate response must address all aspects and portfolios.

11. Australia is well placed to gain competitive advantage from building up its industries in efficient energy use and renewable energy. Given nurturing in their early years, these industries can provide substantial exports and import substitution.

The implications of these axioms and principles are that Australia needs visions of clean energy futures and public debate about policies and strategies for implementing them. It also needs firm targets and timescales for reducing greenhouse gas emissions in the energy sector and a wide range of economic social and regulatory instruments to encourage implementation, namely:

- shaping the market for energy services[3] in order to remove barriers to efficient energy use, renewable energy and natural gas;
- taxes and user charges;
- regulations and standards;
- organisational structures and processes;
- education, information, training; and
- targeted funding for infrastructure, R, D & D, retooling of manufacturing industry and alleviating energy poverty among low-income earners.

The barriers to efficient energy use, renewable energy and natural gas have been discussed by IPCC (2001b, Chap.5), Watt and Outhred (1999) and Greene and Pears (2003) and references therein. They need not be repeated here. They are implicit in the following specific proposed policies and strategies, which contain both short-term and long-term measures. The numbering is for ease of reference and does not reflect priority. The distinction between policies and strategies is not a sharp one, so we do not attempt to separate them here. There is a great need for both general and specific actions. Section 12.2 recommends policies and strategies that apply to all levels of government

[1] Taking into account the large economic subsidies to the production and use of fossil fuels and the failure so far to include environmental and health costs in the prices of fossil fuels.
[2] This is not simply an axiom, but is also a finding of IPCC (2001b) and is supported by the results of this and other Australian studies, such as Watt and Outhred (1999), Greene and Pears (2003) and references therein.
[3] Rather than for energy generation or use per se.

and would assist cleaner energy technologies in general. Section 12.3 addresses more specific policies and strategies for particular energy technologies and systems.

12.2. Policies for all spheres of government

1. Introduce separate targets for greenhouse gas reductions for Australia, each State and Territory, and each Local Government area. Require each responsible level of government to develop a publicly available strategic plan and action plan of implementation and to report publicly on progress each year.

2. Introduce separate targets for greenhouse gas reductions for the in-house operations of the Australian Government, each State and Territory Government, and each Local Government. Require mandatory annual public reporting of their own energy consumption and GHG emissions by all these governments and their public services.

3. Legislate to require businesses with annual turnover greater than $10 million to implement Policy 2.

4. Introduce in-house carbon levies to fund emission reduction within government's own operations, and encourage or require adoption of such internal levies by participants in Greenhouse Challenge and other government programs.[4]

5. Introduce minimum energy efficiency and greenhouse standards for the procurement by government of buildings, office and other equipment, appliances and hot water.

6. Substantially increase the Mandatory Renewable Energy Target (MRET) as an industry development measure to build industry capacity and capability. In the longer term this can be dovetailed into an emissions trading scheme as costs of renewable energy fall.

7. Increase funding for R, D & D on efficient energy use and renewable energy technologies, on socio-economic and policy aspects, and on the organisational and institutional changes required for dissemination of the technologies.

8. Foster public education and information about efficient energy use and renewable sources of energy.

9. Modify the National Electricity Code in order to:
   - include constraints on CO_2 emissions that are progressively tightened over the years;
   - recognise the additional economic value of renewable energy sources;
   - ensure that the sale of electricity to the National Electricity Market by natural gas and renewable energy generators is not treated less favourably than from any other energy source or technology.

[4] Such an approach means that governments and businesses will start to see carbon price signals, but the money will stay within the government programs and businesses and can be used to fund actions that reduce emissions and in many cases repay rapidly the initial investments.

10. Support the promotion of Australian technology and expertise internationally through the establishment of a specific export development fund to promote Australia as a provider of renewable energy technology, goods and services, especially in the Asian and Pacific-rim markets.[5]

11. In all policy contexts recognise the importance of minimising legislative and regulatory uncertainty in order to maintain investment confidence.

12.3. Specific policies to assist specific technologies and systems

For convenience, these recommendations have been organised in technology groups.

Efficient energy use[6]

1. Implement national mandatory energy and greenhouse labelling for all appliances and equipment with the capacity to use more than 50 watt of electricity or 5 MJ/hour of natural gas.

2. Implement national mandatory minimum energy and greenhouse performance standards for all appliances and equipment with the capacity to use more than 50 watt of electricity or 5 MJ/hour of natural gas. Make standards increasingly stringent every 5 years, publishing schedules for improvement 3-5 years ahead, so that businesses can plan, and with requirements based on the world's best practice, not just removal of the worst products from the marketplace.

3. Legislate for mandatory energy performance standards for all homes, with new and renovated homes to meet standards forthwith and existing homes to achieve specified standards increasing in 5-year steps. Since NatHERS simulation is only concerned with the building envelope, develop a more comprehensive indicator of factors influenced during construction, such as heater/cooler efficiency and fuel, cooking fuel, hot water system efficiency and fuel, installed lighting density, provision of solar clothes drying facilities (clothesline), etc.[7]

4. For all homes mandate energy and greenhouse gas ratings and require that these ratings be published in all advertisements and contracts for the sale or rental of the homes.[8]

5. For all commercial buildings mandate minimum energy and greenhouse performance standards based on the Australian Building Greenhouse Rating Scheme. Building owners to be given options to comply, including the use of Green Power and Renewable Energy Certificates (RECs) under MRET. The minimum performance standards should initially include a 5-star requirement for

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[5] For some young technologies, such as photovoltaics, the domestic market is still too small to support the industry, and so exports can play a vital role in industry development.
[6] For more detail see BCSE (2003).
[7] SEDA's Energy Smart Homes point score system is a step towards such an indicator and NatHERS now includes a statement of star rating for heater, cooler and water heater, but neither integrate the envelope/heater/cooler combination to provide a space conditioning energy estimate.
[8] As currently practised in the A.C.T.

new buildings including fitout, and a requirement for existing commercial buildings to be progressively improved to achieve 4-star rating.

6. Increase funding for the Cities for Climate Protection (CCP) program for local governments from the present level of $13M over 5 years to 10 times that level for the next 5 years and maintain that level to 2020 at least. The present funding only provides on average about $3,500 p.a. per Council. Considering the large number of local governments in Australia and the wide range of ways they could reduce GHG emissions, there would be no problem in spending the enhanced funding effectively. Require each local government to report annually on the use of the funding.

7. Award one-off grants to manufacturers of energy-consuming appliances and equipment, so enable them to retool in order to meet the mandatory energy performance standards.

Biomass energy

8. Change the MRET regulation to actively encourage dedicated tree energy crops for the purpose of growing biomass for fuel on land that has been cleared before 1990.

9. Pay an agreed contribution for the planting of energy (and other) crops grown for the purpose of limiting dryland salinity, erosion and other forms of land degradation.

10. Introduce biomass establishment grants for growing energy crops.

11. Provide specific support for the development of a national bioenergy roadmap for Australia and its implementation.

12. Provide a bioenergy showcase program to demonstrate a full-scale, integrated energy crops/energy conversion project in Australia.

13. Encourage the shift to highly efficient, low emission, biomass-burning stoves and heaters, especially in urban areas. The aim is to phase out polluting open fires and inefficient burners and to encourage the use of highly efficient biomass burners, such as pellet stoves and heaters. An initial step should be to ban open fires and open fireplaces in metropolitan and urban areas.

Wind power

14. With wide public consultation, develop and implement consistent planning guidelines across all levels of government for the establishment of wind farms.

15. Develop grid management policies that allow for the inclusion into Market rules of 24-48 hour wind farm output forecasting data. The use of such data will allow for the greater penetration of wind energy and optimised cost and/or emissions reductions.

16. Extend State and federal incentives for small renewable energy generation systems, such as solar thermal and solar photovoltaic rebates, to include small wind turbines of less than 100 kW capacity that service a similar need and market.

Solar hot water and direct solar electricity

17. Mandate that electric hot water services in mainland Australia be sold packaged with a lifetime Green Power purchasing requirement. The purchase package would have to include the installation of a time-of-day meter in cases where it is not already connected.[9]

18. Mandate that a solar, heat pump or solar compatible natural gas hot water system with low standby losses be installed in every proposal for a new or substantially renovated residential building. Where natural gas and sunshine are both available, mandate that the only system that may be installed be gas boosted solar.

19. Local governments to implement rules protecting solar access of all existing and new buildings.

20. Local governments to remove planning requirements on the installation of solar hot water and photovoltaic modules on residential buildings.[10]

21. Because of the huge potential for solar photovoltaic and solar thermal electric systems in Australia, include specific tranches for each of these technologies in the R, D & D funding addressed in Section 12.2.

Electricity generation and retailing

22. Mandate that there will be no new or refurbished base-load or intermediate-load power stations with emission intensities greater than that of the best available combined-cycle natural gas power station. Refurbishment is defined as an investment greater than $50 million 2003 Australian dollars.[11]

23. Mandate generator efficiency standards for existing base-load and intermediate-load power stations to ensure that the existing stock of power stations is reducing emissions and improving efficiency.

24. Require electricity retailers to reduce progressively the greenhouse intensity of electricity sold. Retailers must be able to meet these requirements in part by providing programs to reduce their customers' energy use.[12]

25. Establish a target for cogeneration and provide grants on a dollar for dollar basis to assist in funding feasibility studies for specific projects.

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[9] So that consumers can contribute to the additional infrastructure costs of using peak-load electricity.

[10] Currently, different Councils impose different conditions (including no constraints in some areas). Planning requirements generally take weeks to satisfy, and so disadvantage solar compared with electric and gas hot water.

[11] Until such time as the market reflects the full economic, environmental and health costs of burning coal, a mandatory constraint on emissions seems to be the only way of cleaning up electricity supply.

[12] This will encourage electricity retailers to become energy service providers rather than suppliers of a commodity.

Transmission and distribution

26 Treat the funding of new electricity transmission and distribution lines for wind power, biomass, other renewables and natural gas and on the same basis as the historic funding of network expansion for centralised power generation from fossil fuels.[13] Therefore, 'smear out' the cost over electricity charges for all consumers[14]. The impact may be softened by government capital contributions.

27. Similarly, treat the funding of new additions to the natural gas network on the same basis as the historic funding of network expansion. Therefore, 'smear out' the cost over gas charges for all consumers. The impact may be softened by government capital contributions.

28. Require all proposals for new transmission and distribution lines for the purpose of meeting increasing demand to assess the alternative option of reducing demand. This assessment should be adjudicated by State Environment Protection Authorities.[15]

29. Mandate that all new electricity connections for residential and business use have a time-of-day meter; that complete replacement of all existing meters with time-of-day meters be implemented over a decade; and that energy retailers must bill customers with these meters according to a published time-of day tariff.[16]

30. Revise the National Electricity Code to ensure that distributed generators receive fair network access and pricing, considering location of generators and time of day of generation.[17]

Prices and subsidies

31. Remove all subsidies and cross-subsidies from electricity and fuel prices in rural areas, and replace with direct payments of rural allowances.[18]

32. When existing State Government contracts with aluminium smelters come up for renewal, require State Governments to remove *de facto* subsidies for electricity

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[13] Transmission lines would never have been built to serve customers beyond the cities without this principle. Furthermore, we take into account the fact that cleaner energy scenarios have lower energy demand than baseline fossil fuel scenarios. This saves money that would otherwise have to be spent on extra generation, transmission and distribution for the latter scenarios. (See Section 10.3 under 'Clean Energy Scenario 1, 3rd dot point.)

[14] Since customers benefit from accessing additional generation, whether it is distributed or centralised.

[15] This is to counter a perceived cultural and institutional bias towards increasing supply.

[16] This will encourage efficient energy use by making electricity consumers pay a price for energy consumption during peak periods (e.g. from air conditioning) that better reflects infrastructure costs, and will also encourage the installation of solar electricity by reflecting its economic value better.

[17] Despite the good intentions of those who drafted the Code, it was framed at a time when the grid was (and still is) characterised by large thermal generators clustered in a few locations and joined to the major customer load centers by a few transmission lines. Renewable energy and most natural gas power plants tend to be smaller and less centralized.

[18] This would permit residents of rural areas the option to spend the payments on efficient energy use and renewable energy that are often more cost-effective in rural areas than supply from centralised power stations.

and infrastructure. Use part of the savings to facilitate the creation of new jobs in any region in which a smelter is subsequently closed down.[19]

33. Reform the pricing of access to and use of electricity transmission and distribution grids, in order to avoid overcharging small, dispersed generators of electricity that connect to the distribution network alone, or use only a short distance of transmission line.

12.4. Costing the recommendations

At first sight there appear to be many policies and strategies. However, it must be kept in mind that these span all three levels of government, all portfolios and a variety of types of measures that interlock and complement one another. They involve economic instruments, regulations and standards, targeted funding, organisational change, and education.

Only a few of the recommended policies involve significant costs.

- expansion of MRET; we envisage that this would be the largest item, possibly amounting to \$400-\$500 million p.a. until a self-funding carbon tax or tradeable emission permit system is implemented;[20]
- expansion of Cities for Climate Protection (\$130 million over 5 years);
- expansion of R, D & D (\$30 million p.a.);
- assistance to farmers for limiting dryland salinity and other forms of land degradation by planting biomass for energy crops, which will have to be done anyway (\$50 million p.a.);
- the creation of biomass establishment grants and showcase, and cogeneration grants. (\$5 million p.a. for 5 years.);
- retooling grants to manufacturers. (\$15 million p.a. for 3 years.);
- replacement of existing electricity meters with time-of-day meters over a decade, which will be paid by electricity consumers and merely brings forward an investment that will have to be made anyway (not costed).

These costs initially amount to less than \$630 million p.a. and are all temporary. The first and largest is paid for by electricity consumers and the others by government. They could be funded by reducing some of the perverse subsidies (over \$5 billion p.a.) to the production and use of fossil fuels (see Section 10.3).

[19] This is recommended on the basis that the aluminium industry is a huge greenhouse polluter, employs very few people in relation to the amount of capital invested, and receives large *de facto* subsidies (Turton, 2002), and that Australia is one of only a few countries where aluminium smelting is based substantially on burning coal.

[20] MRET is paid for by electricity consumers, rather than government, and corresponds to an increase in electricity price about 0.2 c/kWh. However, a reduction in demand for electricity, resulting from enhanced efficiency of energy use, could maintain electricity bills at the same level as before MRET.

13. Comparison with other 'deep cuts' studies

This chapter reviews briefly some of the other scenario studies of 'deep cuts' in CO_2 emissions from Australia and overseas.

13.1. ABARE's MENSA model, Australia

MENSA was developed from the International Energy Agency's MARKAL model by the Australian Bureau of Agricultural and Resource Economics (ABARE). It is the principal 'bottom-up' model of the Australian energy system. 'Bottom-up' or 'engineering' models start with a large database on the performances and costs of all conceivable energy supply and energy using technologies. Then, given scenarios for future growth in the demand for energy services, these models calculate the combination of technologies that gives the least cost within the energy sector. By its very nature MENSA cannot examine the impact of changes in the energy sector upon the rest of the economy.

However, a strength of MENSA is that, unlike 'general equilibrium' models, it does not assume that the present energy system or future business-as-usual energy scenarios are necessarily least-cost. As a result, MENSA and similar models generally find that some reductions in greenhouse gas emissions can be achieved with economic savings.

In the early 1990s, within the Ecologically Sustainable Development (ESD) Energy Production Working Group, MENSA was used to answer the question:

"If the government imposed a 20% reduction on greenhouse gas emissions from the electricity industry within a certain period and if the non-technical barriers to efficient energy use and renewable energy were removed, what would happen to the existing array of energy technologies and what would those changes cost?"

At the time of doing this study, Australia's proposed greenhouse gas reduction target was the Toronto Target, a 20% reduction in CO_2 emissions below the 1990 level by 2005. Applying this target as a constraint gave the result that by 2005 all brown coal power stations had been phased out and generation from black coal decreased by 80-90%. Their places were taken by natural gas and the cheaper renewable sources of energy. The cost of this transition was found to be about 2% of the total annual cost of the energy sector.

This rapid (15 year) phase-out scenario entailed that most coal-fired power stations had to be shut down before the ends of their operating lives. As a result, costs were higher than they would have been under scenarios that allowed them to retire at the ends of their lifetimes (30-40 years) and then replaced them with a combination of efficient energy use, natural gas generation and renewable energy sources.

This early work with MENSA also suffered because of the gaps in the database on technologies for efficient energy use. Subsequently, this part of MENSA's database was improved and it was found that some scenarios for greenhouse gas reductions in the residential sector led to substantial net cost savings.

References: ESD (1991); Naughten et al. (1994).

13.2. 'Deep cuts' study by the Australia Institute

The 'deep cuts' study by the Australia Institute (TAI) was one of the inspirations for the present study (see Turton et al., 2002).

TAI considers a 60% cut in greenhouse gas emissions from the energy sector (including transport) by 2050. It requires that technologies used be already proven, although not necessarily currently commercial. Unlike the MENSA model, it does not attempt an economic optimization and indeed argues that that would be inappropriate for such a large step into the future. However, it requires that the costs of energy production in 2050 must be no greater than current average energy prices in Western Europe, which are 50-100% higher than current energy costs in Australia. Having stated that, it does not present the actual costs of its 2050 scenario.

The basic assumption of the study is that the economy drives greenhouse gas emissions. So the study develops projections for the growth or decline of each sector of the economy. It then provides an analysis of opportunities for reducing emissions in each sector by implementing efficient energy use and fuel switching. The study covers the whole energy sector, including transport, and also all of the non-energy sources of greenhouse gas emissions. These are the main strengths of the study.

The study finds that, using available technologies, Australia could feasibly cut its greenhouse gas emissions by 60% by 2050. To achieve this would entail significant trade-offs: for example allocation of a significant fraction of Australia's arable land to biomass crops and plantations.

However, the study was conducted without external funding and this has inevitably resulted in several limitations:

- The description of the electricity supply system is very general and incomplete. We are told that grid-connected wind power will provide 50% of electricity, but it is unclear how much electricity and heat will come from natural gas and biomass.

- The reader is given the impression that most of the electricity supply system will actually be in the form of local cogeneration, which is presumably either entirely separate from the transmission grid or at best involved in small transfers in each direction between the grid and the cogeneration plant. If so, how will the large fluctuations in wind electric power be stabilised? Hydro-electricity will not be sufficient. An electricity grid with 50% windpower will require much long-term storage, which is not specifically described in the study.

- There are some inconsistencies in the treatment of population growth. For instance, a statement in the Summary assumes that a 60% decrease in greenhouse gas emissions by 2050 is equal to a 60% decrease in *per capita* emissions over the same period, which is incorrect when there is population growth.

- The study's principal scenario is one with a significant growth in aluminium production, in other energy intensive extractive and process industries, and in beef production (a major source of methane emissions). Sensitivity analyses of alternative economic structures, with a stronger shift towards elaborately transformed manufacturing and services, would probably have demonstrated that the same emission reductions could be achieved at lower cost (or greater reductions at the same cost).

13.3. Ecofys study on the EU

This study (Harmelink et al., 2003) focuses on the electricity industry and achieves a 60% reduction in CO2 emissions between 1997 and 2020, based mostly upon existing technology. Although such a rapid change in the industry would be technically possible, it would inevitably result in the premature retirement of many fossil-fuelled power stations. The cost of these ‘stranded assets’ would be substantial. However, it could be argued that, after internalising external costs, there would be net benefits, and the costs of ‘inaction’ would be much higher. However, this study does not attempt to evaluate costs apart from roughly estimating that this package costs 10- to 30 Euro per capita per year.

On the demand side, the EU has the advantage over Australia that the former’s population growth is much less. Therefore, over the 23 year period considered, efficient energy use can readily compensate for the effect of GDP growth.Even so, the reader is left with the feeling that the full potential of efficient energy use has not been achieved. The study focuses on ways of using *electricity* more efficiently and so misses out on opportunities to reduce electricity use by switching from electricity to solar for space heating and water heating.

On the supply side it is surprising that the study does not increase the use of natural gas, but rather assumes that biomass can rapidly fill the gap left by coal. Indeed, the report seems to assume that retired coal-fired power stations can readily be transformed into biomass power stations, which is doubtful. The most cost-effective biomass-burning power stations are smaller, situated near the biofuel sources and so are less centralised than coal-fired power stations, as discussed in Chapter 7.

In the Ecofys study wind power is a distant second in substituting for coal. This is surprising, considering Europe’s huge off-shore wind energy potential. In this study it appears that nuclear energy maintains most of its existing contribution.

13.4. Royal Commission on Environmental Pollution on the UK

The aim of the study by the UK Royal Commission on Environmental Pollution is to develop scenarios that achieve a 60% reduction in CO2 emissions from the energy sector by 2050 compared with the 1998 level (RCEP, 2000). The study disaggregates energy uses into the forms of electricity, high-temperature heat, low-temperature heat and transport.

It develops four scenarios with different levels of energy demand and different supply mixes in 2050. All scenarios have substantial implementation of efficient energy use, with the least efficient having the same energy use in 2050 as in 1998. This is more readily achievable in the UK, which has a much lower rate of population growth than

Australia. All scenarios have substantial contributions from renewable sources of energy. Two of the scenarios also have large contributions from fossil fuels with CO2 capture or and equivalent amount of nuclear power. The other two scenarios have neither of these conventional technologies.

Features of this study are:

- the careful calculation of available energy resources as a function of cost;
- a conclusion that energy demand must be curbed substantially or renewable energy and fossil or nuclear energy would be very intrusive environmentally;
- an observation of the need for a culture change within government;
- a recommendation for challenging national targets for improving energy efficiency and developing new energy sources;
- the strong recommendation for the introduction of a carbon levy, where the amount raised is spent to reduce fuel poverty in low-income homes and to assist the development of efficient energy use and renewable energy technologies.

13.5. Department of Trade & Industry on the UK

This study for the UK Department of Trade & Industry (DTI) focuses on the potential contribution of new and renewable energy sources to the reduction of greenhouse gas emissions in the UK. A valuable component is a consultancy by Future Energy Solutions from AEA Technology plc (Marsh et al., 2003) which builds on the earlier UK studies (RCEP, 2000). Like RCEP, the study considers both stationary energy and transport, and uses the IEA's 'bottom-up' MARKAL model of the energy sector. It finds that annual abatement costs in reaching the 60-70% greenhouse reduction target are generally less than 0.5% GDP. Annual GDP growth is only reduced by about 0.01% p.a. over the 50-year period. Achieving high levels of energy efficiency is a key factor in keeping down abatement costs. Reductions in CO_2 emissions are achieved through approximately equal contributions from the demand and supply sides.

13.6. Pew Center study on the USA

The Pew Center (Mintzer et al., 2003) considers three 'base-case' US energy scenarios to 2035. An economic model drives the increase in consumption. The study then applies carbon constraint policies to each of the base cases in order to reduce emissions in 2035 to 38% below the year 2000 level.

Across the three scenarios, efficient energy use and different mixes of supply technologies, existing and new, achieve the target. Coal use declines, but still is important, and natural gas use increases greatly, both for centralised and distributed generation. It is assumed that geosequestration locks up the CO_2, despite the high costs and limited contribution of this technology (see Chapter 8). Hydrogen is assumed to be important in all scenarios, but it is generated from coal in one and natural gas in another, not renewables. In all three scenarios renewable energy sources are only allowed to make modest contributions: wind contributing only 6-12.5% of electricity generation and biomass less than half of wind.

In summary, in this study the ‘new’ technologies are mixed up with the existing, but the only innovations occur in the use of fossil fuels.

13.7. US Interlaboratory studies

The first report (Interlaboratory Working Group, 1997) presents the results of a study conducted by five U.S. Department of Energy laboratories on the U.S. potential to reduce greenhouse gas emissions using energy-efficient and low-carbon technologies. Like the UK studies outlined above, the US study uses a ‘bottom-up’ engineering-economic model and places strong emphasis on efficient energy use. It focuses on four energy sectors: buildings, industry, transportation and utilities. The calculations show that numerous cost-effective energy-efficient technologies remain under-utilised in each sector. The report quantifies the reductions in CO2 emissions that could be attained by 2010. It also describes a wide array of advanced technology options that could be cost-competitive by the year 2020, given a strong and sustained national commitment to energy research and development.

For the assessment of potential carbon reductions by 2010, the study defines a Business-as-Usual (BAU) forecast as well three alternative scenarios. The BAU scenario, based on the Energy Information Administration’s Annual Energy Outlook, 1997, projects an increase of 390 million tonnes of carbon (MtC) per year (from 1340 to 1730 MtC) between 1990 and 2010. In the ‘efficiency’ scenario, the nation actively pursues policies and programs to promote market acceptance of energy efficiency while expanding commitments to research and development. In the two high-efficiency/low-carbon scenarios, under a carbon cap and trading system, permits for carbon sell for either US$25 or US$50/tonne C. The study concludes that, along with utility sector investments, a vigorous national commitment to develop and deploy energy-efficient and low-carbon technologies could cost-effectively reduce U.S. carbon emissions by approximately 390 MtC per year.

The second report (Interlaboratory Working Group, 2000) builds on the first report by extending the quantitative analysis from 2010 to 2020 and qualitative analysis out to 2050. Unlike the first report, the second identifies specific policies and programs needed to motivate consumers and business to purchase the energy efficient and renewable energy technologies that make up its scenario.

13.8. Study for WWF (USA)

A study conducted by the Tellus Institute and the Center for Energy and Climate Solutions develops policies for the *PowerSwitch!* Program of World Wildlife Fund in the USA (Bailie et al., 2003). The study is similar in several ways to the present Clean Energy Scenario study for Australia, also considering the effect of small improvements to existing technologies. But the US study focuses on the electricity sector, rather than the whole of stationary energy, and takes a shorter time horizon than ours, 2020. Within this domain it explores the ways and means, and costs and benefits, of reducing CO_2 emissions by 60% relative to the 2000 level by 2020.

The study takes its baseline energy scenario from the US Department of Energy's Energy Information Administration (DoE/EIA). Then, by drawing upon the work of the American Council for an Energy Efficient Economy, it develops its energy efficient scenario.

To overcome the diverse market barriers, the study considers and proposes a portfolio of diverse policies. To foster efficient energy use, there are building codes, minimum energy performance standards for equipment and appliances, tax incentives and a National Public Benefits Fund that is obtained from a small surcharge on electricity prices and is used to foster efficient energy use. On the supply side, there is a Renewable Portfolio Standard (similar in some ways to Australia's MRET), which fosters bioenergy, wind power and heat pumps based on geothermal energy; and tradeable emission permits that place caps on CO_2 and oxides of sulphur and nitrogen, and mercury. There are also specific strategies to foster cogeneration.

The proposed policies are applied to the National Energy Modeling System of DoE/EIA. This yields a 60% reduction in CO_2 emissions from the US electricity generation, with economic savings to households and businesses that total US$80 billion per year. Electricity prices increase, but demand decreases, with the net effect that electricity bills are lower. It is unclear whether the study considers the cost of premature retirement of coal-fired power stations.

13.9. Discussion

Almost all the studies reviewed here achieve large reductions in CO_2 emissions by a combination of strong energy efficiency and decarbonisation of supply. All regard energy efficiency as offering a wide range of cost-effective measures, however they find that energy efficiency alone is insufficient for large reductions.

There are big differences in the treatments of the supply side. The two UK studies and the study by the Australia Institute make substantial use of several renewable sources of energy. However, the two US studies use much smaller proportions, with the Pew Center focusing on cleaning up fossil fuels and the Interlaboratory Working Groups focusing on the demand side.

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Appendix A: External costs of fossil fuels

If we consider the environmental and health damage caused by the production and use of fossil fuels, the economic value of efficient energy use and renewable energy sources may be further increased. In recent years there has been much progress in the analysis of the *external* costs (costs of environmental and health damage that are not taken into account in the market prices) of energy supply in the US and EU. These costs are based on the full fuel cycles, e.g. from the mining of coal through to the disposal of fly ash from a coal-fired power station. They also trace all the main pathways of the pollutants from the points of emission to the various receptors (people, soils, crops, forests, buildings, etc.). The most comprehensive and recent set of studies is the ExterneE project carried out in 1998 on behalf of the European Commission.

There is of course much uncertainty in such calculations and the 1998 ExternE studies can be considered to be very cautious and conservative, because:

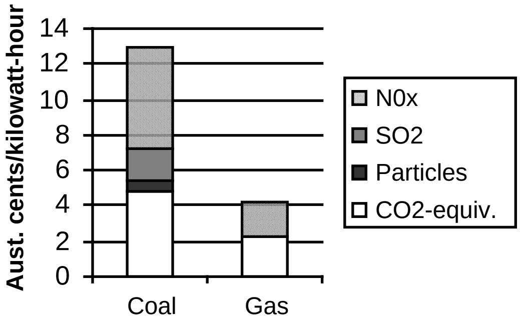
- They evaluate only a limited range of greenhouse impacts and focus on the impacts of the well-known air pollutants, oxides of nitrogen and sulfur, to which they add the impacts of fine particles and aerosols which became pollutants of concern in the mid-1990s. They omit health hazards that they cannot quantify, such as those of heavy metals, VOCs, fluoride, land degradation and waste management.

- They consider only the impacts of the most modern combined-cycle power stations, with flue gas desulfurization (i.e. collection of SO_2 emissions from smokestacks), electrostatic precipitators (to collect dust from smokestacks) and low NO_x emissions. They point out that, for existing power stations, the emissions of NO_2 and SO_2 can be several times higher.

- They calculate the value of deaths from air pollution by multiplying the reduction of life expectancy by the value of life per year. Most earlier studies obtained much higher values by multiplying the number of deaths by the value of statistical life.

With these assumptions, ExternE's calculated external costs of fossil-fuelled power stations, as reviewed by Rabl and Spadaro (2000), are shown in Figure A.1. To convert the results from Euro cents to Australian cents per kilowatt-hour of electricity generated, we have assumed that A$1 = 0.56 Euro. These results are intended to be added onto the existing economic costs of electricity generation from fossil fuels.

Figure A.1: Typical damage costs of new baseload coal and gas-fired power stations assuming average European conditions



Compared with these results for fossil fuels, the ExterneE studies find that the external costs of wind power, photovoltaic electricity and well designed biomass energy technologies are negligible.

The application of these European results to Australia is controversial, because exposure to sulfur dioxide and other air pollutants from power stations is much less here than in Europe and North America. So it could be argued that the European results should be scaled down to the lower population densities found in Australia. On the other hand, the ExternE studies omitted many pollutants and considered only the most efficient combined-cycle power stations, which do not exist among Australian coal-fired stations. So it is possible that the European results describe approximately the *present* situation in Australia. This can only be resolved by detailed measurements and calculations.

In applying the ExternE results to Australia in Fossil Case B (Section 10.2), we tentatively adopt the ExternE greenhouse costs and add to this one-quarter of the ExternE estimate of the air pollution costs.

Appendix B: Can renewable energy replace coal when demand is growing rapidly?

Coal-burning provides about 84% of Australia's electricity generation. Coal-burning makes by far the largest contribution to Australia's greenhouse gas emissions in millions of tonnes (Mt) of CO_2 and also in terms of Mt CO_2 per unit of electricity generated. Coal-burning is a big contributor to air and water pollution and land degradation. And coal mining is one of the three most dangerous occupations. Any sustainable development pathway must grapple with nettle of reducing coal use through a combination of using energy more efficiently and supplying energy with much cleaner energy sources.

Some people argue that, since emissions from coal power stations in Australia are rising an order of magnitude faster than they can be currently reduced by renewable energy, we should only address the causes of rising demand and forget about renewable energy.

This argument is fallacious. While it is true that the absolute growth of renewable energy generation is currently much less than the absolute growth in coal-fired generation in Australia, the *percentage* growth rate in renewable energy, especially wind power, is much higher than that of coal. It is essential to keep in mind the properties of exponential growth. Even though renewable energy has started from a small base, it is growing globally each decade by a factor of about 10.

For example, Australian wind energy capacity was only 104 MW at the end of 2002, but at 25% per annum, assuming no constraints, it would reach 20 GW in 2025, substituting for a lot of coal along the way. With a more modest growth rate of 20% p.a. it would reach 20 GW around 2030 and at 15% p.a. it would reach 20 GW around 2040. For comparison, ABARE (2001, Fig. 12) assumes that wind power will grow at a rate of 25.2% p.a. from 1998-99 to 2019-20.

Therefore, to substitute for a substantial proportion of coal burning, we must maintain a high rate of growth in renewable energy capacity *and* implement efficient energy use.