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.

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[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.

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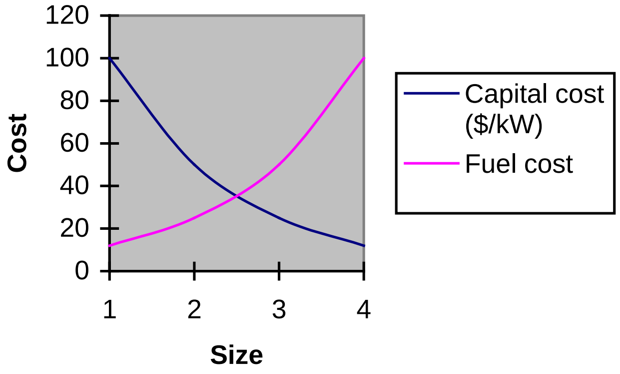
[2] See previous footnote.

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;

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[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.

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[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.

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[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.

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[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

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[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

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[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^{TM}, 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.