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Geosequestration

What is it and how much can it contribute to a sustainable energy policy for Australia?

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Discussion Paper Number 72

September 2004

ISSN 1322-5421

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Acknowledgements

The authors wish to thank Keith Tarlo, formerly Senior Research Consultant, Institute for Sustainable Futures, University of Technology, Sydney for his stimulating ideas and hard work initiating the proposal to write this paper. They are grateful to Iain MacGill of the University of New South Wales for his many helpful comments and suggestions on drafts. They also wish to thank Hal Turton of the International Institute for Applied Systems Analysis, Laxenburg, Austria, and Richard Begley of The Allen Consulting Group for refereeing this paper. The conclusions drawn are, however, the sole responsibility of the authors.

The Australia Institute would like to thank Peter Szental and SZENCORP for providing financial support for this project.

The report also received financial support from the Australian Conservation Foundation and Greenpeace Australia/Pacific.

Abbreviations

ABARE	Australian Bureau of Agricultural and Resource Economics
ACA	Australian Coal Association
APEL	Australian Power and Energy Limited
APPEA	Australian Petroleum Production and Exploration Association
BAT	best available technology
BAU	business as usual
CCGT	combined cycle gas turbine
CCS	CO_2 capture and storage
CCSD	CRC for Coal in Sustainable Development
CEFG	Clean Energy Future Group
CO	carbon monoxide
CO_2	carbon dioxide
CO_2-e	carbon dioxide equivalent
CRC	Cooperative Research Centre
CSIRO	Commonwealth Scientific and Industrial Research Organisation
CSLF	Carbon Sequestration Leadership Forum
DEST	Department of Education, Science and Technology
ECBM	enhanced coal bed methane
EGR	enhanced gas recovery
EOR	enhanced oil recovery
ESAA	Energy (formerly Electricity) Supply Association of Australia
GEODISC	Geological Disposal of Carbon Dioxide
GGAS	NSW Greenhouse Gas Abatement Scheme
GHG	greenhouse gas(es)
H_2	hydrogen
HHV	higher heating value
IDGCC	Integrated Drying Gasification Combined Cycle
IEA	International Energy Agency
IEAGHG	IEA Greenhouse Gas R&D Programme
IGCC	integrated gasification combined cycle

IPCC	Intergovernmental Panel on Climate Change
LHV	lower heating value
LNG	liquefied natural gas
LPG	liquefied petroleum gas
MPa	megapascal
MRET	Mandatory Renewable Energy Target
MW	megawatt
MWh	megawatt-hour
NFEE	National Framework for Energy Efficiency
NO_X	oxides of nitrogen
O_2	oxygen
OCGT	open cycle gas turbine
PF	pulverised fuel
R&D	research and development
RD&D	research, development and demonstration
RE	renewable energy
SACS	Saline Aquifer CO_2 Storage
SO_X	oxides of sulfur

Summary

Geosequestration of carbon dioxide (CO_2) means injecting it into geological formations deep underground, where it will be held away from the atmosphere for hundreds, if not thousands, of years. The oil and gas industry has been investigating the potential of geosequestration to deal with the large amounts of CO_2 that occur naturally mixed with methane in many natural gas fields. One large-scale trial of this process is underway at a gas field in the Norwegian sector of the North Sea.

In the last few years, much more ambitious proposals intend using geosequestration to reduce greenhouse gas emissions (GHG) released when fossil fuels are burned, especially when coal is used to generate electricity. Around 80 per cent of Australia's electricity is supplied by coal-fired power stations, and these are currently responsible for greenhouse gas emissions of nearly 170 Mt CO_2-e per annum, about 30 per cent of Australia's total emissions. A technical system that could reduce these emissions to a small fraction of their present level, while allowing continued burning of coal, has great superficial appeal.

A partnership called COAL21 has been established by the coal mining industry, the coal-fired electricity generation industry, Commonwealth and state governments and research bodies, including CSIRO, to support and promote research on the technologies that will be needed for geosequestration. In March 2004, COAL21 launched its national action plan for reducing GHG emissions arising from coal-fired electricity generation.

Ministers of the Commonwealth Government give the impression, perhaps unintentionally, of having seized on this vision as the key to solving Australia's GHG emission problem. The same emphasis, though not explicitly stated, runs through the recent Energy White Paper and was strongly supported by the Prime Minister when launching it.

However, there is no publicly available analysis to demonstrate that this is the best energy policy option. A following statement by the responsible Federal Minister is certainly not an adequate basis for sound policy.

> The coal industry produces 80 per cent of our energy and the reality is that Australia will continue to rely on fossil fuels for the bulk of its expanding power requirements, for as long as the reserves last.

This discussion paper examines how much emissions abatement geosequestration may be able to deliver, how soon it may be able to do so, what the cost of such abatement may be and how it compares with other energy policy options to reduce emissions.

Technology status

A system to geosequester CO_2 will be very complex, and involves much more than burying the gas underground. It would first involve either converting the fossil fuel to a gas before combustion and extracting the CO_2, or capturing the CO_2 from the stream of combustion gases. It would require a mechanism to transport the CO_2 from the point of production to the geosequestration site, and then to inject the CO_2 into the geological

formation. The CO_2 capture step is in many ways the most complex and difficult. On the other hand, it is the final geosequestration step that is most uncertain over the long term. For these reasons we use the term CO_2 capture and storage, abbreviated to CCS, in the remainder of this paper, to include all elements of the whole system.

Capturing CO_2 from existing power stations would require the use of large and expensive equipment and use large amounts of energy, thereby reducing overall power station efficiency. For these reasons, retrofitting existing power stations to capture CO_2 is not considered by the industry and research communities to be a cost-effective route to CCS. A very large research effort is therefore being committed to new coal utilisation technologies that would reduce the cost and complexity of capturing CO_2. Technologies that could be applied directly to electricity generation include integrated gasification combined cycle (IGCC) and oxy-fuel combustion. The production of hydrogen or liquid fuels from coal could also be associated with CO_2 capture. IGCC is perhaps the most advanced of these, but it is still much more expensive than conventional coal-fired generation and requires further technical improvements. There are a small number of commercial-scale plants in operation around the world but the technology is not used in Australia.

Transport of CO_2 is perhaps the best understood and least complex part of the whole system, but is also relatively energy intensive and will require large investments in pipeline infrastructure. Research over recent years has improved knowledge of areas where the geology may be suitable for long-term underground storage of CO_2. At present, sites have been identified within a reasonable distance of coal-fired power stations (and associated coal mines) in Queensland, Victoria and Western Australia. However, there are no identified sites within 500km of the coal-fired power stations in the Newcastle-Sydney-Wollongong area of NSW and at Port Augusta in South Australia, which together account for about 39 percent of Australia's current net CO_2 emissions from electricity generation. This is considered to present a formidable cost barrier to the use of CCS technology with electricity generation in these areas.

Overall, the main barriers to large-scale application of CCS are the immaturity of the technology, the energy penalty and the cost of capture. A technology roadmapping exercise supported by COAL21 set 2014-15 as the earliest possible date for operation of a pilot-scale coal-fired electricity generation project with CCS. Given the size and complexity of the technology development task required, this may be optimistic. CCS power station technology systems are not yet operating on a commercial scale anywhere in the world.

Cost and cost effectiveness

In order to determine the potential performance of coal-fired electricity generation with CCS, in terms of both electricity generation and emission abatement, it is necessary to draw together data on:

- the capital and operating costs of the system (with a given cost of coal);
- the overall thermodynamic efficiency of supplying electricity, allowing for the energy penalty of CCS; and

- the ultimate level of emissions.

When this is done, taking appropriate account of the large uncertainty in the cost of CCS, it is clear that coal-fired generation with CCS will be more costly than a number of other low-emission electricity generation options including natural gas-fired combined cycle gas turbines, gas-fired cogeneration, wind and many types of biomass. All these technologies are far more mature than CCS; they are proven, already in widespread commercial use, but also, particularly in the case of wind, likely to fall considerably in cost over time as further experience with the technologies is gained. Importantly, increasing the efficiency of energy use is much more cost-effective than any of these electricity supply technologies, having negative costs after a much shorter payback time.

When account is taken of the costs of abatement (measured by \$/tonne CO_2-e of abatement), energy efficiency, natural gas, wind and biomass are more economically attractive than CCS as abatement options. It is difficult to see how coal-fired power stations with the additional cost of CCS will be able to compete with the alternative means of cutting emissions, at least for some decades. This conclusion applies not only to the period between now and when CCS technology is ready for commercial use, which will be 2020 at the earliest, but also for a considerable period after CCS could begin to be widely used.

This conclusion takes no account of the risk that one or more of the technologies involved in a complete CCS system will prove to be unviable, i.e. cannot be made to operate reliably at the expected cost. History, including recent Australian history, is replete with examples of ambitious attempts to develop new technologies which either failed to realise the hopes held for them, or failed altogether. Two examples are BHP Billiton's Boodarie hot briquetted iron plant and Australian Magnesium Corporation's Stanwell Magnesium Project. The conclusion also takes no account of environmental risks, particularly the risk that CO_2 may escape from some storage sites.

How much can CCS reduce emissions?

A spreadsheet model has been developed to estimate the potential for CCS to reduce emissions from coal-fired electricity generation in Australia. CCS is assumed to have a 'best case' abatement capacity in that it is technically feasible, capable of long-term storage, environmentally safe and commercially viable. CCS demonstration power stations are assumed to be built between 2016 and 2020, with commercial viability being achieved in 2020. CCS is not applied in NSW and South Australia because of lack of sequestration sites. It is applied only to new plant, and modelling is extended out to 2030.

The most recent ABARE projections are taken as the base case for energy demand, and two other scenarios with increased end-user energy efficiency are also modelled. The ability of CCS to reduce emissions from coal-fired electricity generation was compared to the abatement potential of increased end-user energy efficiency, and replacement of new coal-fired generation with gas-fired generation and renewable energy.

It was found that use of CCS alone would reduce emissions by about 9 percent in 2030, and cumulative emissions from 2005 to 2030 by only 2.4 percent. A scenario with modestly increased energy efficiency, corresponding to the efficiency potential assumed in the Energy White Paper, could reduce emissions in 2030 by about the same amount, and cumulative emissions by twice as much. This would be achieved at zero or even negative cost.

If gas-fired generation and renewable energy were built instead of new coal-fired generation, to achieve the same cumulative abatement by 2030 as CCS would require only a doubling of the current very modest MRET target, and double that of additional gas-fired generation.

Scenarios that include more extensive energy efficiency improvements, though still well within identified technical potential, combined with use of gas-fired generation and renewables instead of new coal-fired plant, could reduce emissions in 2030 by more than five times as much as CCS alone, and cumulative emissions by ten times as much.

The key to these results is that end-use efficiency, gas-fired generation, wind power and some types of bioenergy are currently commercially available, and so do not have to wait until 2020. While it is possible CCS may be an effective abatement option after 2030, use of currently available technologies will reduce emissions much sooner and at lower cost, and make any abatement task for CCS easier.

Is CCS good energy policy?

In the absence of a decisive change in policy, growth in Australia's energy-related greenhouse emissions will mean that national emissions exceed the Kyoto commitment level by around 2009, and keep growing thereafter. The present policy of modest energy efficiency improvement plus CCS for electricity generation may slow but not reverse the growth in emissions from about 2020 onward. It is not difficult to envisage international pressures, both diplomatic and economic, that could place Australia under strong pressure to reduce emissions well before this time. Present policy does nothing to shield Australia from such a risk and is unlikely to be the best way of maximising Australia's overall energy security.

For the foreseeable future, end-use efficiency, gas-fired generation and wind will continue to have lower costs than coal-fired generation with CCS. Over the longer term, notwithstanding its cost disadvantage, CCS may become more attractive as the scale of necessary GHG emission reductions increases. It may, for example, be needed to reduce emissions to 50 percent below 1990 levels by 2050, which is the sort of emission reduction needed to achieve ultimate stabilisation of atmospheric CO_2 concentrations. Over the next two decades, however, a policy that neglects or excludes other low-emission technologies, in favour of coal with CCS, will place Australia on an unnecessary high-cost path to reducing emissions. This is not an economically optimal policy for reducing greenhouse gas emissions from the energy sector.

1 Introduction

Geosequestration of carbon dioxide (CO_2) means injecting it into geological formations deep underground, within which it is expected to be held for hundreds, if not thousands, of years.

The oil and gas industry has been investigating geosequestration of CO_2 for some time. Around the world each year, the industry vents to the atmosphere many millions of tonnes of CO_2 that are removed from raw natural gas (meaning natural gas as it emerges from the gas well) in the course of processing the raw gas to pipeline gas or LNG (liquefied natural gas) specification. One major gas project in the Norwegian sector of the North Sea is currently injecting CO_2 into a deep geological formation. In Australia geosequestration is being proposed as an integral part of the development of Gorgon, a major new gas field in Western Australian offshore waters.

In the last few years interest has grown around the world in the possibility of using geosequestration as a means of disposing of the CO_2 produced by combustion of fossil fuels, thereby preventing it from entering the atmosphere and contributing to the enhanced greenhouse effect. Most attention has been focused on coal-fired power stations, which constitute most of the world's large point sources of fossil CO_2.

This is of particular relevance here because Australia has a more coal-intensive economy than most other countries, as a consequence of our large, high quality, low extraction-cost coal resources. In 2001-02, coal supplied 42 per cent of Australia's total primary energy (Donaldson 2004) and combustion of coal emitted 33 per cent of Australia's total greenhouse gas (GHG) emissions. Most coal is used for electricity generation and Australia generates a higher proportion of its electricity from coal than any other OECD country. In 2001-02 coal-fired electricity generation accounted for 30 per cent of total GHG emissions (Australian Greenhouse Office 2004). Moreover, in the absence of decisive new policy initiatives, emissions from coal-fired electricity generation are expected to grow significantly; the Australian Bureau of Agricultural and Resource Economics (ABARE) projects that the consumption of coal for electricity generation will grow at an average growth rate of nearly 1.5 per cent per annum from 2002 to 2020 (Akmal *et al*. 2004). It is therefore crucially important to consider how emissions from coal-fired electricity generation might be reduced.

A system to geosequester CO_2 will be very complex. It would first involve either converting the fossil fuel to a gas before combustion and extracting the CO_2 or capturing the CO_2 from the stream of combustion gases. It would then require a mechanism to transport the CO_2 from the point of production to the geosequestration site, and then to inject the CO_2 into the geological formation. The CO_2 capture step is in many ways the most complex and difficult, as we explain in Section 2, and the whole system is much more than simply geosequestration. On the other hand, it is the final geosequestration step that is subject to the most uncertainty about its performance over the long term. For these reasons we use the term CO_2 capture and storage, abbreviated to CCS, in the remainder of this paper, to include all elements of the whole system.

In North America and Europe growing resources are being committed to researching the many technologies that a commercial CCS system will require. Australia has joined this effort with a number of initiatives, including establishment in 2003 of the Cooperative Research Centre (CRC) for Greenhouse Gas Technologies, which is entirely devoted to the topic.[1]

In 2003 the Australian Coal Association was instrumental in establishing a partnership, called COAL21, that includes the coal mining industry, the coal-fired electricity generation industry, Commonwealth and state governments and research bodies, including CSIRO and the three CRCs devoted to coal related research. In March 2004, COAL21 launched its national action plan for reducing GHG emissions arising from coal-fired electricity generation (COAL21 2004). The document presents a case for greater public support for the research needed to bring CCS technologies to commercial reality, and suggests priority areas for R&D.

Ministers of the Commonwealth Government give the impression, perhaps unintentionally, of having seized on the vision of commercial CCS systems as the key to solving Australia's GHG emission problem. This apparent enthusiasm from political leaders is mirrored by the strong advocacy of Australia's Chief Scientist (Batterham 2002) and the support of the Prime Minister's Science, Engineering and Innovation Council (2002).

The strength of support at these most senior levels inevitably causes concern that, given Australia's limited availability of resources to support large technology RD&D (research, development and demonstration), support for CCS may come at the expense of other technologies for reducing GHG emissions. It has not been demonstrated that CCS is so clearly the most effective option that it is worthy of the preference it seems to be receiving. It is very likely that a suite of options will be required to reduce Australia's GHG emissions; favouring one technology at the expense of others is a very high-risk public policy approach.

Indeed, this discussion paper has been inspired by concern at the lack of publicly available analysis to demonstrate that such a strong commitment to CCS is in fact the best energy policy option. Certainly, the following statement by the responsible Federal Minister is not an adequate basis for sound policy.

> The coal industry produces 80 per cent of our energy[2] and the reality is that Australia will continue to rely on fossil fuels for the bulk of its expanding power requirements, for as long as the reserves last (Macfarlane 2004).

The only CCS applied to coal-fired electricity generation in the world today is a demonstration project in Canada linked to enhanced oil recovery, greatly improving the economics. It is not expected to be commercially available in Australia until well after 2015. We do not know how much GHG abatement it may be able to deliver, how soon it may be able to do so, and what the cost of such abatement may be. This means that we do not know how CCS may compare with other options that are already commercially available, such as improved energy efficiency, increased use of high

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[1] This CRC has developed from the previous Australian Petroleum CRC, which operated a research program from 1999 to 2003, under the name of GEODISC, that studied geosequestration, *sensu strictu*, initially from an oil and gas industry perspective.

[2] This is incorrect. While coal provides about 80 per cent of Australia's electricity generation, it provides only about 42 per cent of total primary energy (ABARE 2004).

efficiency gas-fired electricity generation, or wind and other renewable energy resources. This discussion paper seeks to provide answers to these questions, and thereby help the reader to decide how much dependence on CCS, compared with other options, would be appropriate. We hope it will contribute to a better informed public debate on these important energy and environmental policy issues.

To keep the paper to a reasonable length, some of the detailed supporting analysis is provided separately as Supporting Online Material (SOM). The SOM can be accessed at www.tai.org.au.

2 What is being proposed?

This section provides more detail on the technologies introduced in Section 1, including technological descriptions, an outline of current technology development proposals and an assessment of net energy production and gross CO_2 emissions for different technologies.

2.1 Existing power stations

It is surprisingly difficult to determine precisely how much of the electricity used in Australia is supplied from coal-fired power stations. According to the Electricity Supply Association of Australia (ESAA 2003), coal-fired power stations generated 84 per cent of total electricity in 2001-02. However, this figure should be treated with caution. ESAA statistics generally cover only the larger power stations operated by major electricity-generating companies. They exclude a great many smaller generators, particularly so-called embedded generators (those which are embedded in the medium/low voltage distribution networks and do not use the high voltage transmission network), and generators serving isolated communities unattached to major electricity supply grids. These small generators include a high proportion using various renewable energy technologies. In addition, using data based on generated electricity rather than sent-out electricity inflates the contribution of coal-fired generators to total electricity supply. Coal fired generators use more of the electricity they generate to power ancillary machinery within the power stations than do either natural gas or renewable generators.

ABARE collects more complete information about the performance of small generators, through its Fuel and Electricity Survey. The baseline data for its most recent modelling of future energy demand and supply sets the contribution of coal-fired plant to total electricity supply at 78 per cent (Akmal *et al*. 2004). The most recent set of Fuel and Electricity Survey results released by ABARE (Donaldson 2004) suggests that this figure may be slightly low, and that the best estimate of the contribution of coal-fired generators to total Australian electricity supply is about 80 percent.

It can be calculated from the ABARE data (Donaldson 2004) that this 80 per cent of sent out electricity equates to about 540 PJ (150 TWh) of electricity delivered to consumers.[3] This was supplied in 2002 by 30 operating coal-fired power stations (ESAA 2003).[4] All of these power stations use conventional pulverised fuel (PF) boilers (COAL21 2004). In PF power stations, coal is crushed to a powder and blown into the boiler where it is burnt to generate steam at high pressure. The high-pressure steam drives a steam turbine and electrical generator. Combustion of the coal generates CO_2 and other greenhouse gases (GHGs). These emissions are released to the atmosphere in power station flue gases.

Twenty four coal-fired power stations in Queensland, New South Wales, South Australia and Western Australia are fuelled with bituminous or sub-bituminous black coal and six in Victoria are fuelled with lignite (or brown coal). Most of these power

[3] Calculated from electricity generated minus own use of electricity at power stations minus electricity losses in transmission and distribution.
[4] Excluding coal-fired cogeneration plants and other embedded generation.

stations use steam at subcritical temperature and pressure. [5] However, three newer plants in Queensland (Millmerran, Callide C and Tarong North) use steam at supercritical temperature and pressure.

Natural gas power stations are of three types. The first type burns gas in a boiler to generate steam, which then drives a steam turbine, as in conventional coal-fired power stations. Some older major stations and a large number of smaller cogeneration plants are of this type. In newer natural gas power stations the fuel gas is burnt directly in a gas turbine to generate electricity. Open cycle gas turbine (OCGT) plants have only this single generation step. Combined cycle gas turbine (CCGT) plants add a second step, where the hot exhaust gas from the gas turbine is fed into a boiler to generate steam, which is then used to drive a separate steam turbine. As a result, CCGT power stations are more efficient than both OCGT power stations and coal-fired power stations. As well as being used in these three power station types, natural gas is normally the preferred fuel in cogeneration plants, which generate both electricity and industrial heat, at high overall thermal efficiency.

Capturing CO_2 emissions from existing power stations, though technically feasible, is expensive (COAL21 2004). The main problems are the large total volume of flue gas and the low concentration of CO_2 in the flue gas. CO_2 makes up about 14 per cent by volume of the flue gas from a PF coal power station and about 4 per cent of the flue gas from a natural gas combined cycle power station (Davison, Freund and Smith 2001). Other gases in the flue gas include nitrogen, oxygen and water vapour. Currently, the volume of flue gas emitted each year from Australia's coal-fired power stations is about 20 times the volume of natural gas produced from all Australia's gas fields. This scale means that capturing, compressing, transporting and storing all of the flue gas would be very expensive, and would use an excessive proportion of the electricity generated at the power station (Davison, Freund and Smith 2001). Therefore, methods are needed to separate the CO_2 from the other flue gases.

Separation of CO_2 from a mixed gas stream is a well-established practice in the natural gas production industry, however the technologies used are not directly transferable to separating CO_2 from flue gases. Methods shown to be capable of separating CO_2 from a mixed gas stream (such as flue gas) include solvent scrubbing systems, cryogenics, membranes and adsorption. Each of these methods will be discussed in Section 2.3. None of these methods were developed specifically for large-scale carbon sequestration projects (IEA 2002) and none has been demonstrated on the scale of a typical coal-fired power station (MacGill, Outhred and Passey 2003).

The development of these CO_2 capture technologies for application in coal-fired power stations will require a number of technical challenges to be addressed. For example, most practical experience with CO_2 capture is with chemically reducing gases, whereas power station flue gases are chemically oxidising (Davison, Freund and Smith 2001). Further, Australia faces some particular challenges, as SO_X and NO_X emission standards

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[5] Subcritical and supercritical are terms referring to the steam temperature and pressure in the power station. Subcritical power stations operate at around 540°C and a pressure of about 16.5 MPa. Supercritical power stations operate at up to 650°C and 34 MPa. Higher steam temperatures and pressures increase generation efficiency, so supercritical power stations are generally more efficient than subcritical power stations.

here are less stringent than those in Western Europe and North America. The concentrations of SO_X and NO_X in Australian flue gases may adversely impact solvent scrubbing technologies designed to suit the lower European and American concentrations of these gases (Dave *et al*. 2000).

Further, although CO_2 separation and capture technologies can be retrofitted to existing power stations, the low CO_2 concentration in power station flue gases and the large total volume of flue gas are again obstacles. The separation equipment would be large and expensive and the substantial energy inputs required would reduce overall power station efficiency. For these reasons, retrofitting of existing power stations to capture CO_2 is not considered to be a cost effective route to CCS, and, in the view of the coal research community, new coal utilisation technologies are likely to provide a lower cost route to CO_2 capture (COAL21 2004, p. 28). The electricity supply and demand modelling described in Section 4 therefore excludes this option.

2.2 Advanced coal utilisation technologies

Advanced coal utilisation technologies, currently under development, have the potential to simplify CO_2 capture from coal-fired power stations. These technologies include oxy-fuel combustion, hydrogen or liquid fuel production plants and integrated gasification combined cycle (IGCC) power stations. Each of these technologies is described below.

Oxy-fuel combustion

Oxy-fuel combustion could potentially be used with conventional, supercritical and ultrasupercritical PF power stations to increase the concentration of CO_2 in the power station flue gas (COAL21 2004). The process goes by several different names, including oxygen combustion, O_2/CO_2 recycle and flue gas recycle. Instead of air, a relatively pure stream of oxygen is used to burn the coal, giving a CO_2-rich flue gas. Oxygen combustion raises furnace temperatures so some of the power station flue gas is recycled to the furnace to keep temperatures down. Oxy-fuel combustion reduces the volume of inert gas in the boiler, thereby increasing boiler efficiency (IEA 2002).

A typical oxy-fuel combustion process would give CO_2 concentrations of 55 to 60 per cent in the flue gas (IEA 2002), although concentrations greater than 90 per cent are feasible at very high oxygen concentrations (Davison, Freund and Smith 2001). These concentrations make CO_2 capture much simpler and cheaper. Oxy-fuel combustion is considered one of the most promising technologies for retrofits of existing power stations (COAL21 2004).

However, the technology is still experimental and has not yet been demonstrated commercially. One of the main problems is the capital cost and energy consumption associated with oxygen generation using conventional cryogenic air separation plants. The additional energy required to generate oxygen outweighs the improvement in boiler efficiency. Alternative oxygen generation techniques, including membrane and air separation techniques, are currently undergoing pilot testing (COAL21 2004).

Hydrogen or liquid fuel production

Coal, natural gas and biomass can be used to produce hydrogen, liquid hydrocarbons and alcohols. In hydrogen production, the fuel is reacted with oxygen and steam to produce a synthesis gas (syngas), mainly comprising carbon monoxide (CO) and hydrogen (H_2). The CO is then reacted with steam in a catalytic shift reactor to produce CO_2 and more H_2, giving a syngas stream that mainly comprises H_2 and CO_2. The CO_2 can be separated from the H_2, and captured, using methods such as chemical or physical absorption (IEA 2002). The H_2 is then available for use as a fuel in a range of diverse applications.

Hydrogen can be combusted in a gas turbine or internal combustion engine, or reacted in a fuel cell, to generate electricity. It can also be used to supply thermal needs in much the same way as natural gas, or combusted in an internal combustion engine to provide torque. Hydrogen is seen as a promising clean fuel option at the point of use; when burned with oxygen or reacted in a fuel cell, the only by-product is water.[6] If the CO_2 generated during H_2 production is captured and sequestered, or renewable energy is used to generate the H_2, then very few GHG emissions are generated over the entire fuel cycle.

An alternative to H_2 production is synthetic liquid hydrocarbon production. The initial part of the process is the same as the process described above. However, after CO_2 capture, the H_2-rich syngas is fed into a Fischer-Tropsch synthesis reactor, where a catalytic reaction generates synthetic liquid hydrocarbons (syncrude) and steam. This process has been used extensively in Germany and South Africa (see Section 2.7). The Victorian Power and Liquids Project, proposed by Australian Power and Energy Limited (APEL) plans to use this type of process. In 2002, the Victorian Government granted APEL a brown coal exploration licence in the Latrobe Valley. Its proposed plant, which is currently in the design phase, will generate electricity, diesel, naptha and liquefied petroleum gas (APEL 2004). It is envisaged that the project would require geosequestration, probably in saline aquifers under Bass Strait, to meet Victorian Government licence requirements for CO_2 emissions (UK DTI 2004).

Integrated Gasification Combined Cycle (IGCC) power stations

An IGCC plant uses a process much like the one described above, but to generate electricity rather than produce a pure stream of hydrogen. Coal is reacted with oxygen and steam to produce a syngas, mainly comprising carbon monoxide (CO) and hydrogen (H_2) (IEA 2002). The syngas is cleaned and combusted in a gas turbine to generate electricity and to produce steam to drive a steam turbine (COAL21 2004). As a consequence of this combined cycle, an IGCC plant is significantly more efficient than conventional coal-fired power stations (Davison, Freund and Smith 2001).

An IGCC plant also has significant advantages for CO_2 capture. If the syngas is reacted with steam (a process called reforming) prior to combustion, separate streams of hydrogen and highly concentrated CO_2 are produced (COAL21 2004). The CO_2 stream may then be captured and stored. As a result, the cost of CO_2 capture from an IGCC

[6] When hydrogen is burned in air, there are also NO_x emissions.

plant is much lower than from a conventional PF power station. Gasification approaches are expected to provide the most economic route to large scale CO_2 capture (COAL21 2004).

IGCC technology without reformation has been demonstrated at a commercial scale in the USA, Netherlands and Spain, although long-term reliability problems still need to be solved and operating flexibility needs to be improved (Davison, Freund and Smith 2001). Reforming on a large scale is well-established in the chemical and oil refining industries. However, large-scale gas turbines suitable for combustion of hydrogen-rich syngas are still under development (COAL21 2004). In addition, the capital cost of an IGCC power station is higher than that of a conventional PF power station. As a consequence, IGCC plants are not yet commercially competitive with conventional PF generation and may not become so given ongoing advances with conventional plant technologies.

In Australia, HRL Developments Pty Ltd is developing Integrated Drying Gasification Combined Cycle (IDGCC) technology, suitable for generation of power from brown coal. The extra drying stage is necessary due to the higher moisture content of brown coal compared to black coal. The technology has been demonstrated in a 10MW plant. The Victorian Government has granted HRL Developments a brown coal exploration licence in the Latrobe Valley to support the development of its IDGCC technology (HRL 2004). The status of this technology is discussed in Section 2.7.

2.3 Carbon capture technologies

Capture or separation of CO_2 from gas streams is common in natural gas production and in gasification processes at petrochemical refineries, although there have so far been few attempts to apply these technologies to power stations (COAL21 2004). Relatively mature technologies available to capture CO_2 from dilute or concentrated gas streams include solvent scrubbing systems, cryogenics, membranes and adsorption (IEA 2003). Each of these technologies is described below. There are also various novel concepts for CO_2 capture, such as chemical looping combustion, dry ice co-generation, biological CO_2 fixation with algae and direct capture of CO_2 from air (IEA 2002), however these technologies are not sufficiently developed to warrant further discussion here.

Solvent scrubbing systems

Solvent scrubbing systems were developed for the chemical and oil industries. They use a chemical or physical solvent, usually an amine solution, to remove CO_2 from exhaust gases. Amine scrubbers rely on chemical absorption (IEA 2002). The flue gas is cooled, cleaned and passed into an absorption tower where the scrubbing solution selectively absorbs the CO_2 by chemically reacting with it (IEA 2003). The CO_2-rich solvent is then heated to release high-purity CO_2, and the solvent is recirculated (Davison, Freund and Smith 2001). The CO_2 is compressed for transport.

Solvent scrubbing is also very widely used in the natural gas industry to remove CO_2 from raw natural gas. Raw natural gas from some gas fields has a high intrinsic CO_2 concentration, which must be reduced to around 2 per cent to meet pipeline quality specifications and close to zero for LNG production. In Australia, the natural gas processing plants at Moomba and Dampier (North West Shelf) currently separate over 3 Mt CO_2 per year from raw natural gas using solvent scrubbing processes.

Amine scrubbing systems can achieve a CO_2 recovery rate of up to 98 per cent (IEA 2003). Absorption technology is mature, although it has not yet been utilised for large-scale power generation. Some of the problems in power station applications include solvent corrosion in the presence of O_2, high solvent degradation, dealing with impurities and the large amount of energy required for solvent regeneration, which reduces the overall power station efficiency (IEA 2002). Nevertheless, amine scrubbers are the most widely adopted form of CO_2 capture for power stations, although only a small number of coal- and gas-fired power plants are currently using this technology.

Various proprietary solvents are also available for concentrated CO_2 streams, such as those generated by IGCC systems (IEA 2003). These solvents typically rely on physical absorption (IEA 2002). Development of new or improved solvents is seen as a high priority for commercial development of solvent scrubbing systems for CO_2 capture from power stations (IEA 2002).

Cryogenics

Cryogenic processes use cooling and condensation to separate CO_2 from other gaseous compounds, relying on differences in the boiling points of gases. At present, this method is mainly used for purification of gas streams that already contain a high percentage of CO_2 (greater than 90 percent) and has not been applied to dilute flue gases (IEA 2003). The process is energy intensive, significantly reducing overall energy efficiency (IEA 2002). It is unlikely to be commercially competitive for dilute flue gas; it is better suited for use in IGCC power plants or oxy-fuel combustion plants (IEA 2002).

Membrane separation

Because gases pass through particular types of membranes at different rates, membranes can potentially be used to separate gases (IEA 2003). The two types of membrane considered for CO_2 separation are gas separation membranes (ceramic and polymeric) and gas absorption membranes (IEA 2002). Gas separation membranes are thin films that selectively transport gases. Gas absorption membranes are microporous solid membranes used as the contact point between a CO_2 gas stream and an absorption liquid (IEA 2002).

With both types of membrane system, the degree of separation is relatively modest, multiple stages are required, costs are high and energy consumption is often high (IEA 2002; 2003). The use of membranes for gas separation is a relatively new application and membranes have not yet been utilised for power station applications (IEA 2002).

Adsorption

Some materials with high surface area, including activated carbon and certain zeolites, can be used to separate CO_2 from gas mixtures by adsorption (IEA 2002). Adsorption techniques are not yet attractive for power plant applications as they operate at low temperature, the capacity and CO_2 selectivity of the adsorbents is low, and the energy required for regeneration is high (IEA 2002; 2003).

2.4 Carbon transport technologies

Transport of CO_2 from the point of capture to a storage site would typically use high-pressure pipelines. About 3,000 km of large land-based CO_2 pipelines already exist around the world, mainly in North America (IEA 2002). The cost of establishing a pipeline network to transport CO_2 to the storage site needs to be added to the costs of capture and storage. Existing oil and gas pipeline infrastructure may be suitable for CO_2 transport in some applications, particularly for offshore CO_2 storage (IEA 2002).

There are fewer safety risks involved with transport of CO_2 than with other gases, such as natural gas, since CO_2 is inert and not explosive. However, CO_2 is an asphyxiant at high concentrations and tends to collect in depressions because it is heavier than air (Davison, Freund and Smith 2001). Safety precautions would be required to address pipeline leakage.

Carbon dioxide could potentially be transported over long distances by ship, using tankers similar to those currently used to transport LPG (Davison, Freund and Smith 2001). However, this would add significantly to the cost.

2.5 Carbon storage technologies

The main CO_2 storage options currently under consideration internationally are geological storage and deep ocean storage. This paper focuses on geological storage options, or geosequestration, as geological storage is the main option under consideration in Australia. Potential geological storage options for large volumes of CO_2 include deep saline reservoirs, depleted oil and gas reservoirs and unmineable coal seams (Davison, Freund and Smith 2001). All these options are the subject of substantial research and development activity internationally. Research is focusing in particular on the behaviour of CO_2 after injection, the permanence (or otherwise) of the storage options and their potential cost. Each of the geological storage options is considered below.

Deep saline reservoirs

Deep, saline aquifers are potentially suitable for long-term CO_2 storage. When CO_2 is injected into a deep, saline aquifer it partially dissolves in the groundwater and, in some cases, slowly reacts with minerals to form carbonates. Suitable aquifers need to have an impermeable cap rock to minimise CO_2 leakage (Davison, Freund and Smith 2001). Injection wells would need to be drilled to access the aquifer.

The Sleipner project, in Norway, is injecting CO_2 into a deep saline aquifer under the North Sea (Davison, Freund and Smith 2001). The CO_2 is stripped from raw gas extracted from the Sleipner Vest gas field (IEAGHG 2004). The CO_2 content of the raw gas (9 percent) is too high for direct sale to markets. The project commenced in 1996 and is injecting nearly a million tonnes per year of CO_2 into the Utsira sand formation at a depth of about 800m (Davison, Freund and Smith 2001).

The decision to inject CO_2 at Sleipner instead of venting it to the atmosphere was taken after the introduction, in 1991, of a CO_2 emission tax in Norway. In 2002, the tax was about $A65 per tonne of CO_2 released (Norway Ministry of the Environment 2002). This substantial CO_2 tax made CO_2 injection commercially competitive with the alternative of venting the CO_2 and paying the tax. In jurisdictions with a lower CO_2 tax (or none), a project like Sleipner might not be commercially viable.

The Saline Aquifer CO_2 Storage (SACS) project was established to monitor and model the flows of CO_2 in the storage aquifer at Sleipner (IEAGHG 2004). The SACS project produced a Best Practice Manual for saline aquifer storage in 2002 (IEAGHG 2002). Monitoring results indicate that the injected CO_2 has not behaved as originally modelled. For example, thin layers of shale within the sand bed meant that the CO_2 did not rise and 'fan out' as expected. While this does not necessarily mean that storage will not be effective, it does indicate that there is a great deal of uncertainty regarding the behaviour of CO_2 in geological formations.

In Australia, the Gorgon natural gas development project is proposing sequestration of CO_2 in a deep saline aquifer. The Gorgon Project is a joint venture of ChevronTexaco, Shell and ExxonMobil. The companies propose to extract raw gas from the Gorgon gas field, off the northwest coast of Western Australia, and pipe it to a processing facility on Barrow Island. The raw gas has a relatively high CO_2 content of about 14 per cent by volume. The proponents are planning to strip the CO_2 from the natural gas stream using an amine solvent scrubber, compress it, and inject it into the Dupuy saline reservoir under the north end of Barrow Island, as long as this is proven to be technically feasible and costs are not prohibitive. The top of the reservoir is about 2.3km below Barrow Island and is capped by thick shale. The project aims to sequester over 4 million tones per annum when operating at its full capacity of 10 million tonnes of LNG per year. Production of LNG and sequestration of CO_2 could start as soon as 2010 (ChevronTexaco Australia 2003).

The proponents of the Gorgon Project are currently seeking environmental approvals from the Western Australian and Commonwealth Governments and undertaking detailed design work. Local environmental groups have raised strong concerns about the possible impacts of the proposal on biodiversity in the Barrow Island A-Class Nature Reserve and about the reliance on unproven geosequestration techniques to manage CO_2 emissions (Conservation Council of WA 2003).

Analysis by the Geological Disposal of Carbon Dioxide (GEODISC) project indicates that deep saline aquifers make up 94 per cent of the total environmentally and economically feasible geological storage capacity in Australia (Bradshaw *et al*. 2002a). The CO_2 storage capacity of Australian geological formations assessed by GEODISC is 740 Gt, sufficient to store all of Australia's present net CO_2 emissions for 1,600 years. However, when the location of major CO_2 sources is compared to suitable storage locations, only the CO_2 emission sources in Victoria, Queensland and Western Australia currently appear to have technically and economically realistic storage potential (Bradshaw *et al*. 2002b).

The coal-fired power stations in the Newcastle-Sydney-Wollongong area of NSW and at Port Augusta in South Australia, which together account for about 39 per cent of

Australia's current net CO_2 emissions from electricity generation, are more than 500km from an identified suitable CO_2 storage location. Transport of CO_2 over such a distance was considered by the GEODISC researchers to make geosequestration economically unviable (Bradshaw *et al*. 2002b). This would constrain the potential of geosequestration to reduce Australia's current CO_2 emissions. Ultimately, the economic feasibility of long distance CO_2 transport will depend on its cost, but it is clear this cost will be significant.

Depleted oil and gas reservoirs

Oil and gas reservoirs are porous geological formations, capped with impermeable rocks that are often dome shaped. Oil and gas reservoirs that are reaching the end of their economically productive lives are being considered as storage sites for CO_2. There is potential to use some of the existing hydrocarbon production equipment to transport and inject CO_2 into the reservoirs (Davison, Freund and Smith 2001). The geology of these sites is reasonably well known and they have already proven capable of storing liquids and gases (oil and natural gas) for millions of years. Of course, CO_2 has different properties to oil and natural gas and interference with the reservoirs during oil and gas extraction may reduce their effectiveness for CO_2 storage.

Injection of CO_2 into oil reservoirs is already routine for enhanced oil recovery (EOR) (COAL21 2004) and enhanced gas recovery (EGR), though to date this has been confined to onshore production facilities, and no attempt has been made to ensure that CO_2 is effectively stored. The injected CO_2 displaces remaining oil in the reservoir, typically improving oil recovery by 10-15 percent. There are more than 70 EOR sites operating around the world, although most use CO_2 extracted from natural reservoirs (Davison, Freund and Smith 2001). However, research by the GEODISC project indicates that there are few viable opportunities for EOR in Australia (Gale 2002).

The Weyburn project in southern Saskatchewan, Canada is currently storing captured CO_2 emissions from a commercial-scale lignite gasification plant in North Dakota (the Great Plains Synfuels Plant) in the depleted Weyburn oilfield (Davison, Freund and Smith 2001). Over the 20-year lifetime of the project, it is anticipated that 20 million tonnes of CO_2 will be stored at Weyburn. The IEA Greenhouse Gas R&D Programme has organised an international monitoring project to assess the long-term effectiveness of CO_2 storage at the site.

The GEODISC project found that depleted oil and gas fields account for less than 4 per cent of the economically and environmentally feasible CO_2 storage potential in Australia (Bradshaw *et al*. 2002b). Nevertheless, given the large total storage capacity and the relatively high quality of geological knowledge about existing oil and gas fields, depleted oil and gas fields may provide significant local storage opportunities at particular CO_2 emission sites. However, most of this storage capacity will not be available for 30 to 40 years, as this is the likely timeframe for depletion of major oil and gas fields in Australia (Gale 2002).

Unmineable coal seams

The third potential geological storage medium is unmineable coal. When CO_2 is injected into suitable coal seams it is adsorbed onto the coal and could be permanently stored, unless the coal is eventually mined. Some deep or otherwise unmineable coal seams have significant quantities of methane adsorbed to the coal. Extraction of methane from such coal seams is assuming growing importance as a new commercial source of methane (natural gas) in both North America and Australia. Carbon dioxide adsorbs to coal more easily than methane, so injection of CO_2 into coal seams can potentially displace the methane and enhance its recovery (Davison, Freund and Smith 2001). Enhanced coal bed methane (ECBM) projects are underway in Alberta, Canada and the San Juan Basin in northwest New Mexico (IEAGHG 2004; 2004).

In Australia, the GEODISC project found that ECBM sites comprise much less than 1 per cent of the economically and environmentally feasible geological storage potential, although only two potential sites were considered (Bradshaw *et al*. 2002b). Enhanced coal bed methane projects face several difficulties. CO_2 injection rates are low due to low permeability in coals, which means that a large number of injection wells are required (Bradshaw *et al*. 2002b). In addition, CO_2 injection may prompt uncontrolled leakage of methane, which would reduce the net impact on GHG emissions. The main advantage of storage in unmineable coal seams in Australia, with or without extraction of methane, is the proximity of potential sites to CO_2 emission sources at coal-fired power stations, some of which may have no other viable geosequestration options.

2.6 Research and development

International R&D

Advanced coal utilisation, carbon capture and carbon storage technologies are the subject of substantial research, development and demonstration efforts around the world. The United States, Canada, the European Union and Japan have major R&D programs (COAL21 2004). The International Energy Agency (IEA) coordinates several collaborative research efforts in this area, including the IEA Greenhouse Gas R&D Programme (IEAGHG) and the IEA Clean Coal Centre. Australia is a member of IEAGHG and an Australian Coal Industry Consortium is one of the sponsors of the IEA Clean Coal Centre.

The Intergovernmental Panel on Climate Change (IPCC) is currently preparing a special report on carbon capture and storage that will outline the feasibility and state of development of geosequestration technology. Australia is contributing to the development of this report. Australia is also involved in the Ministerial-level Carbon Sequestration Leadership Forum (CSLF) that is focusing on the development and deployment of technologies for carbon capture and storage. The CSLF has 16 member countries and Ministers met most recently in September 2004 in Melbourne (UK DTI 2004).

Australian R&D

Overall funding for Australian research and development of carbon capture and storage technologies amounts to about $35 million per year (UK DTI 2004). The Cooperative Research Centre (CRC) for Greenhouse Gas Technologies, also known as the CO_2CRC, coordinates a major research effort on carbon capture and storage. The CO_2CRC was established in July 2003, with a total budget of $117.4 million over a seven-year period, including $21.8 million from the Commonwealth Government (DEST 2004). The CO_2CRC grew out of the earlier GEODISC Programme that ran from July 1999 to August 2003 as part of the previous Australian Petroleum CRC.

Another CRC with an interest in carbon capture and storage is the CRC for Coal in Sustainable Development (CCSD). The CCSD commenced in July 2001 and is investigating coal gasification, oxy-fuel combustion and carbon capture and storage. It has a budget of $8-9 million per year, 25 per cent of which ($2.1 million per year) comes from the Commonwealth Government (DEST 2004).

The CRC for Clean Power from Lignite also considers technologies relevant to geosequestration. It was formed in July 1999 and is focusing on current and future technologies for utilisation of brown coal, particularly the resources in the Latrobe Valley. It has a budget of $52 million over seven years, including $14 million from the Commonwealth Government and $5 million from the Victorian Government (DEST 2004).

The Commonwealth Scientific and Industrial Research Organisation (CSIRO) is also conducting research in this area through its Energy Transformed Flagship and its Energy, Technology and Petroleum Divisions. Annual CSIRO funding for energy research and development is around $25-30 million (UK DTI 2004).

State research centres include the Centre for Low Emission Technology in Queensland ($27 million funding over four years) and the Centre for Energy and Greenhouse Technologies in Victoria ($14 million funding from the Victorian Government since August 2003). Several universities are also active in geosequestration-related research, including Curtin University of Technology, Monash University, the University of Adelaide, the University of New South Wales, the University of Melbourne and the University of Queensland.

Industry involvement in research and development is coordinated through the CRCs, the COAL21 National Action Plan (COAL21 2004) and industry associations including the Australian Coal Association (ACA), the Australian Petroleum Production and Exploration Association (APPEA) and the Energy Supply Association of Australia (ESAA). COAL21 is an initiative managed by the ACA that seeks to maintain the role of coal in Australia's economy.

2.7 Technology status and roadmaps

The IEA Clean Coal Centre, based in London, has reviewed clean coal technology roadmaps from around the world (Henderson 2003). In Australia, the CO_2CRC coordinated a comprehensive carbon capture and storage technology roadmapping exercise in the second half of 2003 (CO_2CRC 2004). The COAL21 National Action Plan reports further develops these earlier efforts (COAL21 2004). A brief summary of the status and prospects of different geosequestration technologies in Australia, based on these sources, is provided below.

Oxy-fuel combustion

In Australia, oxy-fuel combustion is at the evaluation stage and has not yet been piloted. COAL21 proposes a technology roadmap for oxy-fuel combustion (COAL21 2004). Phase 1 comprises an R&D program over 2004 and 2005 to modify an existing Australian pilot-scale test furnace to obtain design data for a demonstration plant. Phase 2, during 2006 and 2007, would develop an oxygen separation pilot-plant using a technically innovative process. Phase 3, starting in mid-2007, would involve the design, construction and operation of an oxy-fuel retrofit to an existing 60 MW coal-fired boiler, with CO_2 capture. Phase 4, to commence from mid 2010, would involve the design and construction of a 450 MW commercial plant without geosequestration to commence operation in 2014.

Hydrogen or liquid fuel production

The technologies for producing hydrogen and synthesis gas (syngas) from coal, and technologies for subsequent production of liquid fuels from syngas, are well established. Coal gasification was discovered over two hundred years ago and was first used in Australia by the Australian Gas Light Company in 1837. Hydrogen and syngas production were developed in Germany a century ago and used to make synthetic ammonia and other chemicals during the First World War. Liquid fuel production from syngas using the Fischer-Tropsch process was widely deployed in Germany during the Second World War. The South African Coal, Oil and Gas Corporation (Sasol) developed a coal to liquid fuel production process based on Fisher-Tropsch synthesis in the 1960s in response to trade embargoes imposed during the apartheid regime, and is still producing liquid fuels by this means. Sasol's facility currently produces 150,000 barrels of synfuel per day on a commercial basis.

With hydrogen or liquid fuel production technologies, the limiting factor for demonstration and commercialisation is the integration of the technology with combined cycle power generation and/or CO_2 capture. In the United States, the Integrated Sequestration and Hydrogen Research Initiative, otherwise known as the *FutureGen* project, is planning a US$1 billion, 275 MW coal-to-hydrogen prototype plant with CO_2 capture to test integration of these technologies (US DOE 2003). The plant is due to commence operation in 2011 (COAL 21 2004) though this has now been pushed back to shakedown/operation over the 2012-15 period (Der 2004).

In Australia, the APEL project has completed a feasibility study and is currently in the design phase. The proponents are planning to produce 10,000 barrels per day of synthetic crude during the first stage of the project. It was originally thought that the plant could be operational by 2007 but this now seems unlikely.

Integrated Gasification Combined Cycle

Outside Australia, IGCC is a near-commercial technology that has been demonstrated in Europe and North America. Although the technology is not yet fully mature, international roadmaps envisage that the current first generation IGCC plants will be superseded by IGCC with hot gas clean up and advanced turbines by 2010. IGCC technology will be integrated with fuel cells and chemical production by 2020 (Henderson 2003).

In Australia, COAL21 notes that a 'first of a kind demonstration' is still needed to build expertise with IGCC technology and assess the performance of Australian black coal in this application (COAL21 2004, p. 51). The COAL21 technology roadmapping project concluded that a 65 MW IGCC demonstration plant should be developed in Australia with CO_2 capture and storage. The following timeline was proposed:

- engineering concept and project feasibility assessment (2004);
- final project design (first half of 2005);
- construction of 65 MW demonstration plant (mid 2005 to mid 2007);
- plant commissioning (mid 2007 to mid 2008); and
- operation from the second half of 2008.

This is an ambitious timeline and allows little scope for unexpected delays or barriers to project development. Even if this timeline were achieved, a subsequent large-scale commercial IGCC plant (100 to 400 MW) in Australia would not be operational before 2014 at the earliest (CO_2CRC 2004). At 400 MW, this would be about 1 per cent of Australian projected coal-fired generation at that time, based on current projections.

Integrated Drying and Gasification Combined Cycle

The IDGCC technology for brown coal has been developed and demonstrated at a 10 MW scale in HRL's Coal Gasification Development Facility at Morwell. According to COAL21, successful development of IDGCC technology could allow the development of oxygen-blown brown coal IGCC suitable for CO_2 capture and storage in the period 2010 to 2020. HRL has already tested oxygen-blown brown coal gasification at pilot scale in Mulgrave, Victoria (COAL21 2004).

The next planned step in IDGCC development is the construction, by HRL, of a 100 MW IDGCC plant in the Latrobe Valley in the next four years as a demonstration of the technology. This plant is not expected to be commercially competitive. HRL is planning to construct an 800 MW brown coal IDGCC plant in the Latrobe Valley to be commissioned by 2012 (COAL21 2004). This commercial plant will be 'CO_2 capture ready' but there are no current proposals to capture CO_2 from such a plant (UK DTI 2004).

Carbon capture and storage

The main barriers to large-scale application of carbon capture and storage are the energy penalty and the cost of capture (COAL21 2004). At present, the energy penalty for carbon capture and storage is likely to be from 6 to 12 per cent (Henderson 2003). That is, from 6 to 12 per cent of the electrical energy generated at the plant is used to capture, compress and store the CO_2. The IEA review of international technology roadmaps envisages that the energy penalty will fall to between 2 per cent and 4 per cent by 2020 (Henderson 2003). All these figures apply to capture from an IGCC or oxy-fuel plant; the energy penalty for capture from a conventional PF plant would be much higher.

In addition, although carbon capture and storage technologies have been applied elsewhere in EOR projects, geological variability means that site-specific issues will need to be addressed in Australia. The CO_2CRC roadmap envisages two pilot CO_2 capture and storage projects (without electricity generation) in Australia in the period 2003-2006, with total injection of 5,000 to 10,000 tonnes of CO_2 and post-injection monitoring (COAL21 2004). One of these pilot projects would be in eastern Australia and one in Western Australia. As of publication of this report in late 2004, no pilot CCS projects have commenced in Australia.

The Gorgon LNG project is the most advanced project contemplating commercial scale CCS in Australia but it will use 'standard' gas industry capture technology, which is not directly applicable to capture at a power station. As already noted, planning for the project is underway, with CO_2 injection and monitoring possible as early as 2008 (COAL21 2004) though 2010 is a more likely date.

A larger demonstration project, with injection of up to 100,000 tonnes of CO_2, will only be possible if a suitable IGCC or oxy-fuel demonstration plant is commissioned (COAL21 2004). This could be possible in conjunction with the 65 MW IGCC demonstration plant discussed above.

Conclusions

The CO_2CRC roadmapping exercise found that:

> … whilst there is some very early consideration to the development of a fully commercial IGSS plant, with a capacity ranging from 100-400 megawatts, it is unlikely that a generation facility on this scale could be commissioned before 2014 (CO2CRC 2004, p. 37).

The Gorgon natural gas project is the most likely first commercial geosequestration project in Australia. The FutureGen project in the United States, a demonstration plant with funding of $US1 billion, is aiming to commence operation by 2012 at the earliest and by validating the technical and economic viability of such technology, lead to development of commercial plant by 2020 (Der 2004).

2.8 Technology performance

This section briefly considers the performance of conventional fossil fuel power stations, advanced coal utilisation technologies and geosequestration technologies. The focus is on generation efficiency, sent-out efficiency and greenhouse gas emissions.

Generation efficiency

Table 1 provides data on average generation efficiency for Australian fossil fuel-fired power stations in 2001-02, calculated from figures in Akmal *et al*. (2004).[7] The figures are presented according to the fuel used for generation, as the type of fuel is an important determinant of achievable efficiency. The relatively low generation efficiency shown for natural gas is due to the inclusion of inefficient gas-fired steam turbines and OCGT power stations in addition to efficient CCGT power stations and cogeneration. New CCGT power stations are significantly more efficient than this average (see Table 2).[8]

Table 1 Australian average generation efficiency for fossil fuel power stations in 2001-02

Fuel	Generation Efficiency (%)
Brown coal	26.2
Black coal	36.7
Natural gas	35.1

Source: Akmal *et al*. (2004)

Sent-out efficiency

The efficiency figures quoted in Table 1 are for generation efficiency, which is the ratio of the total quantity of electricity generated to the total energy content of fuel consumed. However, not all the electricity generated at a power station is sent out to the electricity transmission system because power stations use some of it for their own operation. It is this sent out efficiency that is the most important indicator of the overall efficiency of a generator and of greenhouse gas emissions.

The amount of electricity consumed by the generator depends on the type of power station. Hydro and wind generators use very little electricity on site, gas turbine generators somewhat more and coal-fired generators considerably more, because of the energy needed to crush and feed the coal, as well as to circulate boiler feedwater and cooling water, as in all steam power stations. In Victoria and Queensland in 2001-02, with generation systems dominated respectively by brown and black coal, sent out electricity was around 92 per cent of generated electricity, whereas in Tasmania, with its predominantly hydro system, the proportion was over 99 per cent (ESAA 2003). While there are other factors, such as use of pumped storage, contributing to this discrepancy between generated and sent out, the significance of power station own use is clear.

[7] The efficiency figures throughout this section are based on the Higher Heating Value (HHV) of the fuel, as is common practice in Australia. Some international efficiency figures use the Lower Heating Value (LHV) of the fuel.

[8] All these figures apply to stand-alone power stations, at which heat energy that cannot be converted to electricity is dissipated into the environment. Overall efficiency is much higher at cogeneration plants, where surplus heat energy is used to provide heat for other purposes, such as industrial processes or space heating.

Table 2 provides data on sent-out efficiency of Australian and international fossil fuel-fired power stations from various sources. The table also includes projected efficiencies for 2030 from the COAL21 Action Plan (2004). The figures in Table 2 indicate that natural gas CCGT power stations are significantly more efficient than coal-fired power stations and are expected to remain so in the future.

Some of the efficiency figures in Table 2, and their sources, warrant further discussion. The COAL21 National Action Plan (2004) includes future scenarios through to 2030 for the Australian generation mix. The business as usual (BAU) scenario assumes that brown and black coal generation capacity installed from 2003 will have sent-out efficiencies of 34 per cent and 41 per cent respectively. These figures are considerably higher than current best practice in Australia (29 per cent for brown coal, just under 37 per cent for black coal) but potentially achievable in new supercritical or ultra-supercritical power stations. COAL21 also includes a best available technology (BAT) scenario that assumes a linear increase in efficiency between 2003 and 2030, from 34 per cent to 45 per cent for brown coal and from 41 per cent to 52 per cent for black coal (COAL21 2004).

It is important to note that even if these technologies are available and used elsewhere in the world, they will not necessarily be used in Australia. For example, while new coal-fired power stations in Queensland use supercritical technology, the move to ultra-supercritical for subsequent stations is not currently being considered. High efficiency technologies have higher capital costs and will only be implemented if the final cost per MWh is lower than for conventional plant. In particular, when coal is relatively cheap, as in Australia, it does not pay to adopt high cost technologies so as to use it slightly more efficiently.

Table 2 also shows the implied sent-out efficiency required by the Victorian Government for licensing of new brown coal power stations using Latrobe Valley coal. The Victorian Government has stated that the companies awarded brown coal exploration tenders in the Latrobe Valley will need to achieve GHG emissions at least 33 per cent less than current best practice in Victoria to be awarded brown coal mining licences (DNRE 2002, p. 15). This implies a sent-out efficiency, without geosequestration, of 43.5 percent. If the Victorian Government keeps this commitment, new PF power stations using brown coal could only be approved in Victoria if they include geosequestration. However, it is theoretically possible that an IGCC or IDGCC power station could meet the licence requirements without geosequestration.

Table 2 Sent-out efficiency for Australian and international fossil fuel power stations

Technology	Sent-out efficiency (%)	Source
Brown Coal		
Australian best practice design efficiency 2000 (Loy Yang B)	29.0	Brockway and Simpson (1999)
World best practice 2000 (supercritical)	31.4	SKM (2000)
COAL21 BAU proposal 2003	34.0	COAL21 (2004)
Proposed IDGCC 120MW demonstration	40.2	UK DTI (2004)
Conventional brown coal IGCC	41.9	Graham *et al*. (2003)
Victorian brown coal tender requirement	43.5	Calculated by authors
World best practice IGCC 2000	44.7	SKM (2000)
COAL21 best-practice 2030	45.0	COAL21 (2004)
Conventional IGCC 2050	45.9	Graham *et al*. (2003)
Black Coal		
Australian best practice 2000	36.8	SKM (2000)
New Queensland supercritical	37-38	NRM&E Queensland (2004)
Conventional IGCC	40.2	Graham *et al*. (2003)
COAL21 BAU proposal 2003	41.0	COAL21 (2004)
World best practice 2000 (supercritical)	41.7	SKM (2000)
Ultra-supercritical PF	41.8	Graham *et al*. (2003)
World best practice IGCC 2000	49.4	SKM (2000)
Conventional IGCC 2050	49.7	Graham *et al*. (2003)
COAL21 best-practice 2030	52.0	COAL21 (2004)
Natural Gas		
Australian best practice OCGT 2000	35.1	SKM (2000)
Australian best practice CCGT 2000	40	SKM (2000)
World best practice CCGT 2000	52.0	SKM (2000)
New CCGT 2002	53.4	Graham *et al*. (2003)
CCGT 2050	65.0	Graham *et al*. (2003)

Note: Sent-out efficiency is the ratio of the amount of electricity sent out to the transmission network to the total energy consumed in generating the electricity, including any electricity consumed by the power station operator.

Table 3 shows the efficiencies used for the scenario modelling in Section 4. The first figure in Table 3 is the average sent-out efficiency for all existing power stations and any new power stations built by the end of 2005. The figures have been derived from ESAA (2003) data indicating that the average sent-out efficiencies of black and brown coal power stations in 2001-02 were 35 per cent and 25 per cent respectively. While new power stations commissioned between 2002 and 2005 (e.g. Tarong North and Millmerran) have slightly higher efficiencies than the 2001-02 average, the difference is not sufficient to raise the overall average efficiency.

The subsequent figures in Table 3 are the average sent-out efficiencies for new plant built in each five-year period. We have assumed the average sent-out efficiency of new black and brown coal-fired generation will be 37.5 per cent and 29 per cent respectively over 2006 to 2010. These estimates correspond to the design efficiency of new Queensland supercritical black coal power stations (NRM&E Queensland 2004) and current Australian best practice for brown coal generation at Loy Yang B (Brockway and Simpson 1999) respectively. The figures for subsequent five-year periods are derived by assuming that efficiency will improve by 0.4 per cent per year. This assumption was used by ABARE in its 2004 energy projections (Akmal *et al*. 2004).

While there could be step changes in efficiencies with, for example, IDGCC, as discussed below, pre-combustion CCS of such plant requires energy, making their final sent-out efficiency much the same as conventional plant (Davison *et al*. 2001).

Table 3 Assumed sent-out coal-fired generation efficiencies for modelling (%)

Year	Black coal	Brown coal
existing to 2005	35	25
2006 to 2010	37.8	29.2
2011 to 2015	38.6	29.8
2016 to 2020	39.3	30.4
2021 to 2025	40.1	31.0
2026 to 2030	40.9	31.7

The figures in Table 3 do not include the impact of CO_2 capture, transport and storage, which imposes a significant demand for electricity from the power station, with a consequent reduction in the overall or sent-out efficiency of a fossil fuel-fired power station (or a hydrogen/liquid fuel plant). The extra energy is required to capture, compress, transport and inject the CO_2. Table 4 shows the impact of the energy penalty associated with CCS on the sent-out efficiency of hypothetical power stations built in 2000, using estimates of the energy penalty from IEA (2002). For the PF coal-fired power station and the CCGT power station in Table 4, CO_2 capture is post-combustion, using amine scrubbers. For the IGCC power station, CO_2 capture is pre-combustion. The very high energy penalty for retrofitting to a PF power station demonstrates why this option is considered to be uneconomic, as discussed earlier in this section.

The base efficiencies in Table 4 were derived from the figures in Table 3. The base efficiency of a black coal PF power station is based on that of new supercritical power stations built in Queensland. For IGCC and CCGT power stations, the base efficiency was chosen as midway between conventional Australian efficiency and world best-practice efficiency. The figures in Table 4 indicate that an efficient IGCC power station, with CCS, has a theoretical sent-out efficiency comparable to best practice in conventional PF coal-fired power stations (both are around 38 percent). That is, the efficiency improvements achieved by using gasification and a combined cycle are approximately balanced by the extra energy required for CO_2 capture and storage. However, the comparable sent-out efficiency of IGCC with CCS is achieved at a much higher capital cost (see Section 3).

Table 4 Impact of the energy penalty associated with carbon capture and storage on the sent-out efficiency of hypothetical power stations built in 2000

Technology	Sent-out efficiency without CCS (%)	Energy penalty (% of sent out)	Sent-out efficiency with CCS (%)
PF black coal-fired power station	38.0	25.0	28.5
IGCC power station	45.0	14.6	38.4
CCGT power station	46.0	13.0	40.0

Source: IEA (2002).

The IEA (2002) expects the energy penalty to fall substantially over the next 10 years as a consequence of research and development. IEA (2002) provides estimates of the energy penalty in 2010-12 as 15 per cent for black coal PF, 9 per cent for IGCC and 10 per cent for CCGT. However, it should be noted that the estimates of the energy penalty discussed here are hypothetical, and quite possibly optimistic, since the CCS power station technology systems concerned are not yet operating anywhere in the world.

CO_2 emissions

In assessing the CO_2 emissions associated with different technologies, a distinction must be made between gross CO_2 emissions and net CO_2 emissions after geosequestration. Some advanced coal utilisation technologies, such as oxy-fuel combustion, have higher gross CO_2 emissions than conventional technologies. In theory, geosequestration can potentially reduce the gross CO_2 emissions by 90 per cent or more, but there is always a risk that geosequestration will not prove to be a viable technology, for one or more technical, environmental or social reasons. If this were the case, then plants based on these higher-emission coal utilisation technologies will have higher CO_2 emissions than conventional plant. Consequently, both gross and net CO_2 emissions are considered in this section.

Figure 1 shows estimates of CO_2 emissions from a selection of current and proposed future fossil fuel electricity generation technologies in gross and net terms, i.e. without and with CCS. Data for a more comprehensive set of technologies, including hydrogen and liquid fuel technologies, together with references to sources, can be found in the

Supporting Online Material (SOM). In Figure 1 and subsequent figures in this section, the lighter section at the top of each column shows the range of estimates (e.g. estimates for CO_2 emissions from brown coal range from 1,200 to 1,450 kg CO_2-e/MWh).

Figure 1 CO_2 emissions from fossil fuel power stations using current technology, with and without CCS

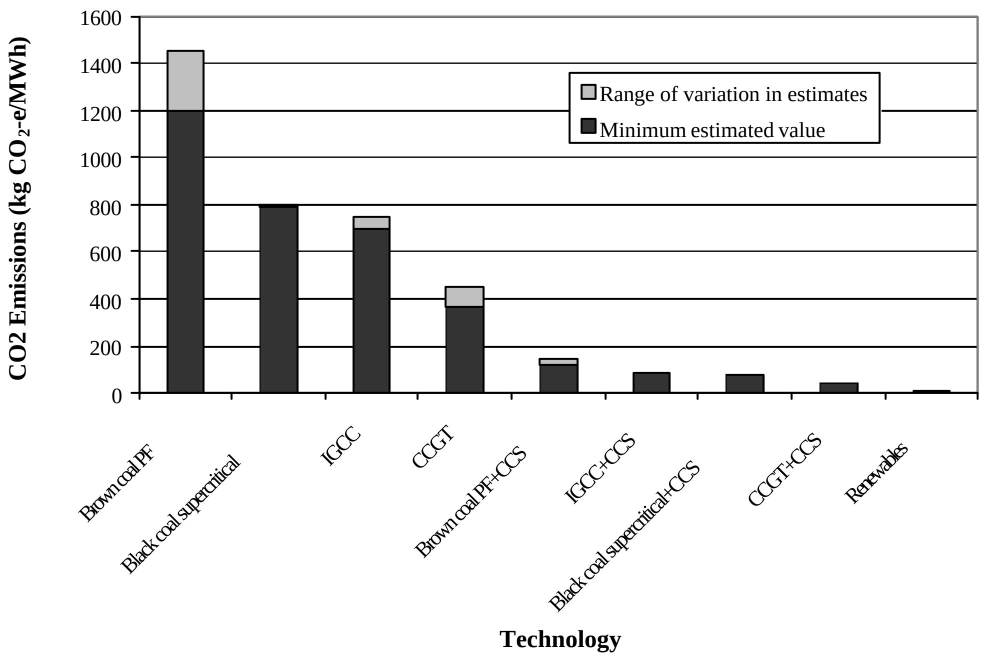


Figure 1 shows that renewables have the lowest emissions of all current technologies, followed by CCGT power stations. It can be deduced that coal-fired power stations need to capture and store at least half their gross emissions before the net emissions fall below those of CCGT power stations.

The IEA (2002) provides estimates of CO_2 emissions for different technologies in 2010-2012, taking into account projected technological improvements. These estimates are reproduced in Table 5.

Table 5 Estimates of future CO_2 emissions for various power generation technologies (2010-2012)

Technology	CO_2 Emissions (kg CO_2-e/MWh)	
	Gross	Net
Black coal PF	766	90
IGCC	664	73
CCGT	337	37

Source: IEA (2002)

For a given electricity generation technology, the difference between gross and net CO_2 emissions is the GHG emissions abatement that can be achieved by adding CCS to that particular technology. The above data is used in the next section, together with estimates of the cost of CCS technology, to estimate the marginal cost of the abatement CCS may provide.

3 What will it cost?

This section reviews the cost of CCS by examining generation costs for various fossil fuel technologies and the incremental costs of capture, transport and storage of CO_2 emissions. There are two main ways to compare the costs of CO_2 capture and storage. The first is to compare the additional cost of power generation, in $/MWh. The second is to compare the cost of greenhouse abatement, in $ per tonne of CO_2 avoided. Both approaches are used below. Where the original figures were in US dollars, a simple conversion assuming that A$1.00 = US$0.70 has been used. Although this conversion does not take into account the varying exposure of different capital items to international exchange rates, it provides a reasonable basis for comparison for the purposes of this analysis.

The section also provides a brief discussion of the technological and environmental risks associated with CCS, as these have the potential to increase its cost and environmental impacts.

3.1 Electricity generation costs without CCS

Figure 2 provides current average generation costs for various power generation technologies, without CO_2 capture and storage. Costs for subcritical black coal, brown coal, wind power and wood-fired power stations are taken from Saddler, Diesendorf and Denniss (2004). The cost of supercritical black coal power stations in Queensland is taken from Zauner (2001). The cost of CCGT is from COAG (2002) and IEA (2002), revised to incorporate Australian natural gas costs of $3.10/GJ. The current cost of IGCC is derived from estimates in IEA (2002), revised to incorporate lower Australian black coal costs of 1 c/kWh. The figures shown include an allowance for return on investment and the cost of servicing capital, as well as fuel costs and other operating costs.[9] Note that the cost of CCS is not shown here as no current commercial power station includes CCS technology.

If current generation costs are the only basis for comparing different power generation technologies, it is clear that coal-fired power stations are currently cheapest, closely followed by CCGT. However, there are two problems with comparing technologies only on the basis of current costs. First, it ignores varying future rates of cost reduction for different technologies. For example, there is strong evidence that the cost of wind power will fall substantially over the next two decades while the costs of conventional coal power and CCGT power will remain relatively steady (IEA 2000). Figure 3 shows estimates of the cost of conventional coal power, CCGT and wind power in Australia in 2020 by Mallon and Reardon (2004). By 2020, wind power could be competitive with both conventional coal power and CCGT. While IGCC is expected to achieve greater cost improvements than conventional coal power over the next two decades, it is unlikely that the cost will fall below that of conventional coal power.

[9] The discount rate chosen to derive costs is an important source of variation in published estimates. Of the sources referenced here, only Saddler, Diesendorf and Denniss (2004) state the discount rate used to derive the estimates. They use real discount rates of 8% and 10%.

Second, the generation cost does not consider the environmental impact of different power generation technologies. As discussed previously, CO_2 emissions from coal power are higher than those from CCGT, and wind power has extremely low CO_2 emissions. The CO_2 abatement cost of a technology, in $ per tonne of CO_2 avoided, is a better way to compare the environmental impact of different technologies, including CCS. Therefore, the next section considers incremental CO_2 abatement costs.

Figure 2 Current average generation costs for various technologies, without CO_2 capture and storage

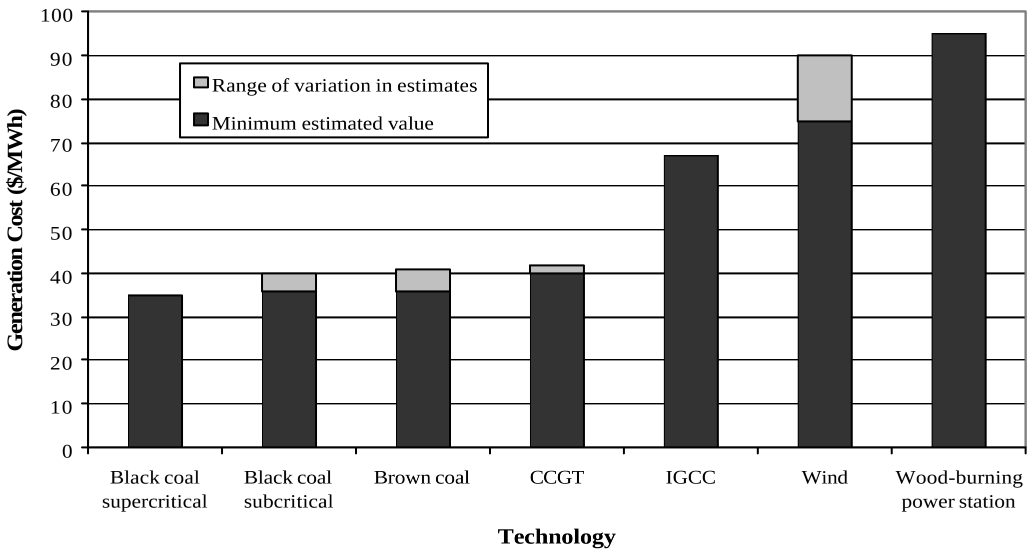
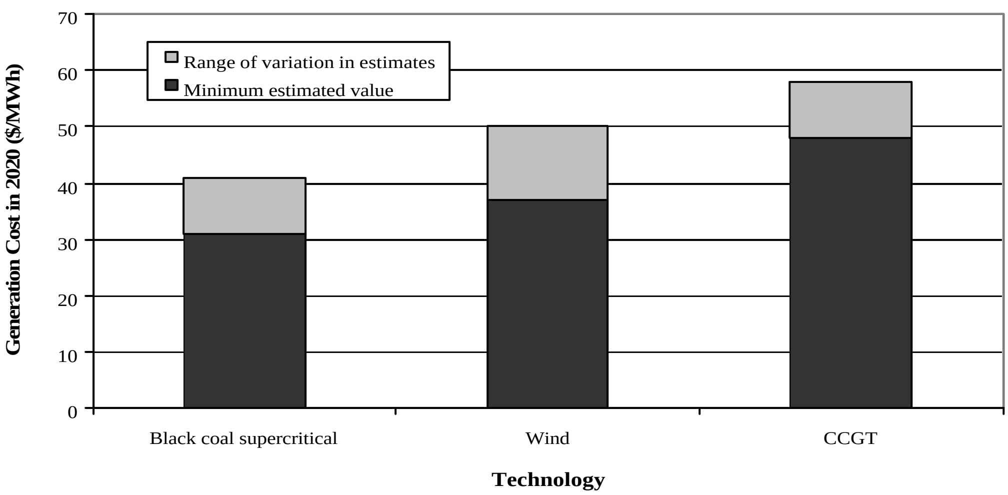


Figure 3 Estimated average generation costs for new coal, CCGT and wind power stations in 2020, without CCS



Source: Mallon and Reardon (2004)

3.2 Incremental cost of CCS

This section considers the incremental cost of CCS in Australian dollars per tonne of CO_2 avoided. This is the additional cost of CCS for a new or existing power station relative to the cost of an identical power station without CCS. Therefore, the costs reported here do not need to consider variations in the cost of the baseline power plant, such as the higher cost of an IGCC power station compared to a coal PF power station. The total abatement cost, relative to a baseline coal-fired PF power station, will be considered in Section 3.3.

CO_2 capture costs

According to the IEA (2002), capture costs are likely to amount to about 75 per cent of the total cost of CO_2 capture, transport and sequestration (IEA 2002). Figure 4 shows estimated incremental costs of CO_2 capture, in \$A per tonne of CO_2 avoided, for various technologies and fuels. As noted above, the costs shown in Figure 4 are additional costs incurred to incorporate CO_2 capture into a particular power station. The first three columns in Figure 4 are derived from figures in David and Herzog (2001), which are also used in IEA (2002). The remaining columns give published estimates of CO_2 capture costs from prominent international and Australian sources (IPCC 2001; Allinson *et al*. 2003).

The estimated capture costs in Figure 4 range from \$36 to \$100 per tonne of CO_2-avoided for plants if they were built today, illustrating the significant uncertainty in capture costs. However, most estimates of capture cost fall in the range from \$40 to \$80 per tonne of CO_2 avoided. Capture costs are clearly towards the low end of this range for IGCC however, IGCC power stations cost significantly more to build, which is not reflected by focusing on capture cost alone.

Figure 4 Cost of CO_2 capture for various technologies as incremental abatement cost

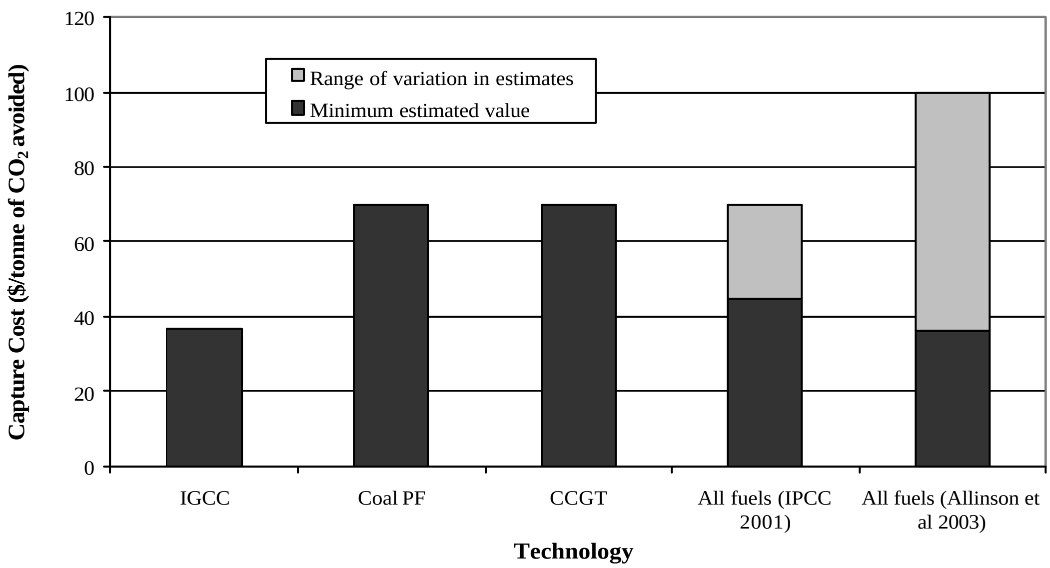


Figure 4 does not provide separate costs for retrofitting CO_2 capture to an existing power station and incorporating CO_2 capture into the design of a new power station as there is very little data on the cost of retrofits (Johnson and Keith 2004). Theoretically, it should be cheaper to add CCS to a PF or IGCC plant during the design phase, as the entire plant design can then be optimised for CCS. Modelling by Johnson and Keith (2004) indicates that retrofitting of existing coal plants does not result in lower overall CO_2 abatement costs. This conclusion is supported by the authors of COAL21, who see gasification plants as offering the most economic route to CCS (COAL21 2004).

Transport and storage costs

Davison, Freund and Smith (2001) estimate that pipeline transport of CO_2 costs between \$1.50 and \$4 for every tonne of CO_2 transported 100km. CICERO (2004a) report estimates ranging from \$2 to \$10 per tonne of CO_2 transported 100km. The distance from the power station to the storage location is clearly important in determining the total cost and the economic viability of geosequestration. Pipeline scale is also important; there are significant economies of scale for pipelines with larger throughput (Freund and Davison 2002).

Freund and Davison (2002) estimate the cost of transporting CO_2 by marine tanker, over a distance of 500km, at about \$3 per tonne of CO_2, although this figure excludes the cost of storage tanks at both the port and the injection facility.

Davison, Freund and Smith (2001) estimate the cost of injection into deep saline reservoirs and depleted oil and gas fields at \$1.50 to \$4 per tonne of CO_2 injected. CICERO (2004a) report estimates of storage costs ranging from \$1.50 to \$23 per tonne of CO_2 injected.

Allinson, Nguyen and Bradshaw (2003) consider the combined cost of transport and storage and find a range for Australia from \$7 to \$35 per tonne of CO_2 avoided. The variation is due to the rate of CO_2 injection, the transport distance and the properties of the injection reservoir (Allinson, Nguyen and Bradshaw 2003). CICERO (2004a) report estimates for the combined cost of transport and storage ranging from \$10 to \$63 per tonne of CO_2. The IPCC (2001) estimates the cost of transport and storage for a typical situation, where the transport distance is 300km, at \$14 per tonne of CO_2 avoided.

Clearly, there is significant variation in the estimated cost of CO_2 transport and storage, from \$3 to \$63 per tonne of CO_2 avoided. Much depends on the location of a geosequestration proposal. The GEODISC program in Australia examined potential geosequestration sites in light of the cost of transport from emission sources, and concluded that it may be technically and economically feasible to capture and store emissions from power stations in Queensland, Victoria and Western Australia, but not from those in New South Wales and South Australia (Bradshaw *et al*. 2002a).

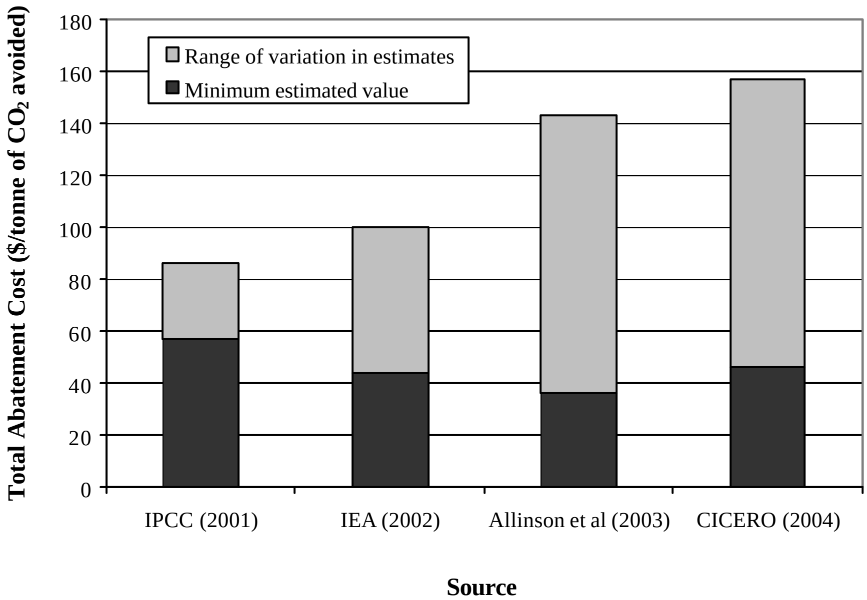
We are aware of no attempts to estimate the ongoing costs of monitoring and possibly maintaining CO_2 storage sites over the long-term and of maintaining a contingency fund to cover the proponent's liability in the event of CO_2 escape.

Total incremental cost

Given the variability in the costs quoted above, the total cost of CO_2 capture and storage is clearly uncertain. Figure 5 provides prominent estimates of the total cost of CO_2 capture and storage from various sources. Given the variability in cost estimates, no attempt has been made to distinguish between different fuels in this figure. The estimates range from \$36 to \$157 per tonne of CO_2 avoided.

This cost may be reduced if the process of CO_2 capture and storage generates useful by-products with economic value. For example, in EOR operations, additional oil production can be offset against the cost of CO_2 capture and injection (Davison, Freund and Smith 2001). As noted in Section 2.5, research by the GEODISC project indicates that there are few viable opportunities for EOR in Australia. Nevertheless, there may be niche opportunities to use EOR to offset high initial costs and gain more experience with CCS technology.

Figure 5 Total cost of CO_2 capture, transport and storage from published sources as incremental abatement cost



3.3 Economic analysis of CCS

From a national policy perspective, the wisdom of providing strong public support for electricity generation with CCS depends on the incremental cost of emission abatement provided by this technology, and how this compares with the cost of abatement achievable through use of other technologies and the application of other policies. Using economic terminology, where does electricity generation with CCS lie on the national abatement supply cost curve? If Australia has access to abatement activities in other countries, through international emissions trading or some other mechanism, then the scope of abatement cost comparison is global, rather than national.[10]

A supply curve shows the quantities of a particular product or output, in this case greenhouse emissions abatement, available at each cost level. In an efficiently operating market, supplies will be taken up progressively, starting with the least costly, until the total quantity supplied matches the quantity demanded.[11]

For greenhouse policy purposes, the easiest way to conceptualise the application of this simple economic principle is in terms of the permit price of CO_2 (or CO_2-e) in an emissions trading market. This will be determined by the interaction between the total permitted level of emissions (i.e. the total number of permits), and the quantity of emission abatement available at different cost levels (i.e. the abatement supply curve). The permit price is equal to the marginal cost of abatement, that is the cost of the last, and most costly, abatement action needed to balance the total level of emissions with the allowed number of permits. If the number of permits is relatively high and/or there is an abundance of low cost abatement opportunities, then the permit price will be low. If the number of permits is low and/or there are fewer low-cost abatement opportunities, the permit price will be high. Electricity generation with CCS will be economic for the nation if it can deliver abatement at a cost lower than the cost of alternatives (conventional coal-fired generation, gas-fired generation, renewable energy, and energy efficiency) plus the cost of any permits they may need.[12]

For a business considering investing in electricity generation with CCS, the crucial requirement will similarly be confidence that its abatement cost will be less than the permit price. The great uncertainty in the future costs of CCS means great uncertainty about what this ‘break even’ permit price will be.

CICERO (2004a) uses a scenario-based approach to compare different assumptions about the future cost of CO_2 capture and storage and future CO_2 emission permit prices. Their analysis is reproduced in Table 6, with some revisions to reflect Australian conditions. The table shows the net economic benefits of CCS for low, medium and high assumptions about net CCS cost and CO_2 permit price. The shaded boxes represent the realm in which CCS will have a net economic benefit. That is, for CCS to be good policy for the nation, and good business for an investor in a new power station, the net CCS cost must be at the low end of the range of published estimates, and the CO_2 permit price must be medium or high.

[10] Access to international emissions trading is unlikely to be available, at this point, unless Australia ratifies the Kyoto Protocol.
[11] It should be noted that this is an idealised approach that does not allow for the important effect of increasing scale of deployment in bringing down the costs of new technologies (whether absolutely new or new to Australia) such as wind or IGCC.
[12] Strictly speaking, the comparison is between the full cost of advanced generation with CCS and (near) zero emissions, on the one hand, and the cost of generation from a conventional power station plus the cost of permits that must be bought to cover the emissions, on the other hand.

Table 6 Net economic benefits of CCS under various assumptions ($A per tonne of CO_2 avoided)

	Net CCS cost		
	Low ($10 - $30)	Medium ($50 - $70)	High ($100 - $140)
Permit: Low ($0 - $10)	0 to -30	-40 to -70	-90 to -140
Permit: Medium ($15 - $25)	+15 to -15	-25 to -55	-75 to -125
Permit: High ($35 - $50)	+40 to +5	0 to -35	-50 to -105

Source: CICERO (2004a).

For those considering investment in geosequestration, there is a high risk that the required conditions for economic viability will not be met. If the cost of CCS is in the medium or high range of published estimates, or the cost of a CO_2 emission permit is low due to wide availability of cheaper abatement options, then geosequestration will not be economically viable without public subsidies. If there are cheaper abatement options available, then such subsidies would be very difficult to justify from a public policy perspective.

There is a great deal of evidence for the availability of low cost emission opportunities. Half of the potential 34 per cent GHG emission reductions identified by the IPCC to 2020 are possible at a negative net cost (IPCC 2001, p. 260). In Australia, the Energy Efficiency and Greenhouse Working Group established by the Ministerial Council on Energy found that ‘energy consumption in the manufacturing, commercial and residential sectors could be reduced by 20-30 per cent with the adoption of current commercially available technologies with an average payback of four years’ (E2G2 2003, p.6). Further work commissioned as part of the development of the National Framework on Energy Efficiency (NFEE) found abatement potential of around 10 per cent by using technologies with a simple payback of not more than four years (NFEE 2004).

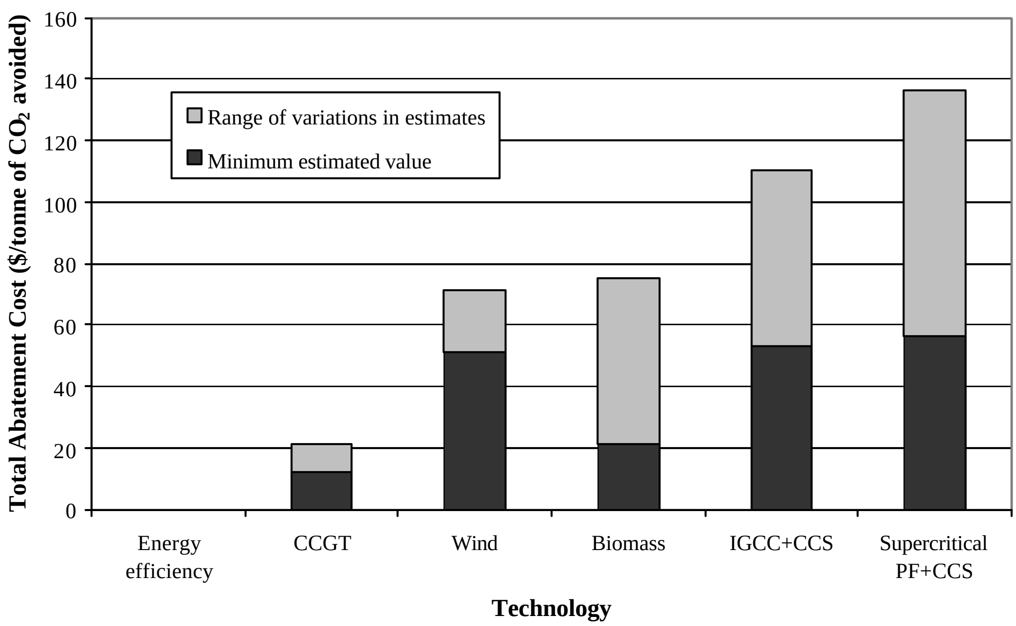
Figure 6 shows *current* estimates of abatement costs for different technological abatement options, some including CCS, compared to a supercritical PF coal-fired power station with an assumed generation cost of $35/MWh and greenhouse intensity of 800 kg CO_2-e/MWh. Energy efficiency is shown (conservatively) with zero abatement cost, given evidence from IPCC (2001) and E2G2 (2003) that substantial energy efficiency improvements are possible at negative or zero net costs. Abatement cost ranges for other technologies are calculated from data provided in Sections 2.8, 3.1 and 3.2, with some additional figures for coal power stations drawn from David and Herzog (2001), IEA (2002) and Dave *et al*. (2001) and additional figures for biomass drawn from SEDA (2002). As with other figures in this discussion paper, the costs for CCS are hypothetical as there are as yet no commercial power stations using CCS.

Figure 6 indicates that energy efficiency, CCGT, wind and biomass are generally more economically attractive than CCS as abatement options at present. However, there is substantial uncertainty in the range of CCS abatement costs. If the lowest cost estimates turn out to be accurate, then CCS may be competitive with renewable energy as an abatement option, but not with energy efficiency and natural gas substitution. If the higher cost estimates are accurate, CCS is not currently competitive with any of these technologies.

The overlap in the cost ranges for IGCC with CCS and supercritical PF with CCS makes conclusions about the relative costs of these two options difficult. While an IGCC plants costs more to build, it has lower CO_2 capture costs. At present, these cost differentials appear to roughly balance each other. The range of estimates indicates that IGCC with CCS may provide slightly cheaper abatement, on average, than supercritical PF with CCS.

As experience with each of the technologies in Figure 6 grows, their costs will tend to fall. However, there is strong evidence that the cost of wind power will fall more rapidly than the cost of CCGT and coal-fired power stations over the next two decades (IEA 2000; EWEA and Greenpeace 2004). Mallon and Reardon (2004) expect wind power in Australia to compete with CCGT and conventional coal power by 2020. Considering also the technical problems still to be solved, it is difficult to see how coal-fired power stations with the additional cost of CCS will be able to compete with energy efficiency, wind power, biomass or CCGT power stations as abatement options in the near future.

Figure 6 Estimated current costs for new abatement options relative to a new supercritical coal PF power station



3.4 Technological risk

The discussion in the previous section indicates that there is a significant risk that CCS from coal-fired power plants will not be an economically viable greenhouse abatement option compared to other options, including energy efficiency, natural gas substitution and some renewable energy technologies. This is only one example of technological risk and uncertainty in relation to CCS. As large-scale commercial capture and storage of CO_2 from coal-fired power stations has not yet been achieved anywhere in the world, there remains a real risk that one or more of the numerous technologies involved will not be viable.

Providing substantial research and development funding for a particular technology is no guarantee of its technical viability. In fact, most new technologies tend to fail. Scientists have been working to develop fusion power since the 1940s but the technology has so far failed to produce a net energy output and remains a long way from commercial realisation. While CCS relies largely on existing technologies, there is no guarantee that the integration of these technologies with power generation will prove viable.

There have been several recent examples in Australia of major technological projects that have not proven viable. BHP Billiton's $2.5 billion Boodarie hot briquetted iron plant, in Western Australia, has been plagued with planning, construction and mechanical problems and was recently closed indefinitely due to safety concerns (Maiden 2004). The plant was written off in 2001. Similarly, Australian Magnesium Corporation's $1.7 billion Stanwell Magnesium Project, in Queensland, collapsed in June 2003 after cost overruns linked to technology problems (Smith 2003). The development of technology as complex as CCS faces similar risks.

For CCS, the viability of IGCC power generation is a key technological risk. According to the International Energy Agency, IGCC technology:

> is not yet fully mature… currently, capital costs are high and operationally the plants do not match the availability or flexibility of conventional units… IGCC will require time before it is commercialised for use with coal, even with high value coals (Rousaki and Couch 2000, pp. 30, 69).

By comparison, the other technologies shown in Figure 6 are proven, currently available and likely to reduce in cost over time as experience grows, although they also face technological uncertainty. From a public policy perspective, it would be particularly risky to commit large sums of public funds *predominantly* to CCS technologies that may never be technically viable or commercially competitive when other viable abatement options are already available. This is not to say that CCS does not have a place in a portfolio of long-term abatement options. Indeed, CCS may be an important part of the transition to a sustainable energy system based on renewable flows of energy. However, support for CCS must be balanced with support for other attractive abatement options.

3.5 Environmental impact of geosequestration

In addition to its economic costs, geosequestration has potential environmental impacts that need to be considered when assessing proposals to implement the technology. Known environmental risks are listed in Table 7, adapted from Tarlo (2003) and MacGill *et al.* (2003). The probability of these risks is uncertain. Little is known about the geology of the deep saline aquifers in which geosequestration is proposed for Australia. Even less is known about how injected CO_2 will behave in deep saline aquifers.

Reservoir leakage could occur if geological formations are disturbed by seismic activity or if the injection point is compromised (e.g. through deterioration of the plug over time). Estimates of the possible rate of reservoir leakage are typically in the range of 0.1 to 1 per cent per year (CICERO 2004b). While these rates are small, they could have serious policy implications if CCS is adopted as the primary response to climate change. Any leak will mean that the entire quantity of CO_2 will eventually be released to the atmosphere. Actual rates of reservoir leakage are currently unknown, given the limited experience with CCS and the inability to accurately monitor and verify leakage with existing technologies.

Table 7 Environmental risks associated with geosequestration

Risk	Possible consequences
Slow, long-term release of CO_2 to the atmosphere (i.e. reservoir leakage)	Reduction in the net climate change mitigation achieved through CCS, resulting in worse than expected global warming
Sudden large-scale release of CO_2 to the atmosphere	Reduction in the net climate change mitigation achieved through CCS, resulting in worse than expected global warming Asphyxiation of humans, animals and plants
Escape of CO_2 to shallow groundwater	Water acidification, mobilised toxic metals, leached nutrients (Bruant *et al*. 2002)
Displacement of deep brine upward	Contamination of potable water sources
Escape of other hazardous captured flue gases (e.g. SO_x, NO_x)	Local air pollution

4 Comparison of CCS and other abatement options to 2030

4.1 Introduction

The capacity of CCS to reduce emissions in Australia over the short to medium term (e.g. to 2030) has not been examined with any rigour. The effectiveness of any measure to reduce greenhouse gas emissions will depend on the extent to which it can be deployed throughout the economy, the timing of that deployment, and the measure's technical effectiveness. In this Section the effectiveness of CCS as a means to reduce emissions from the Australian coal-fired electricity sector is assessed. This analysis does not claim to be a prediction but presents a number of scenarios based on the impact of different energy policy options. While scenarios cannot tell us the future, they have value in formulating policy if their estimations and assumptions are transparent (see MacGill *et al*. 2003).

This analysis starts with the current demand for electricity sent out by coal-fired electricity generators in 2001-02, the most recent year for which comprehensive 'measured' data are available. Demand is then projected forward in time to 2030. Projections are not continued beyond this point because further into the future the uncertainty of key factors that influence electricity demand greatly limits the robustness of any policy insights. By that time, the structure of the Australian economy, the rate at which the economy is growing, the purposes for which electricity will be required, and the technologies for using electricity, all of which profoundly influence demand, may be quite different from today.

Within this timeframe it is not possible to assess the full abatement potential of technologies that are not yet commercially available (for example CCS, electrolytic production of hydrogen and fuel cells). However, the emphasis here is on the key issues that need to be addressed in the short term for the stationary energy sector to meet greenhouse abatement objectives.

A spreadsheet model developed at the University of NSW (PGV-700) is used to explore the greenhouse emissions impacts of meeting the electricity demand projections using combinations of the following supply options: improved coal-fired generation, CCS, gas-fired generation and renewable energy.[13]

Introduction of CCS is modelled according to the parameters in the Supporting Online Material. Briefly, CCS is assumed to have a 'best case' abatement capacity in that it is technically feasible, capable of long-term storage, environmentally safe and commercially viable. It is assumed to be capable of 90 per cent capture of emissions per unit of electricity sent out. Only new plants are fitted with CCS, with about 400 MW of demonstration plant in place between 2016 and 2020, and increasing deployment from 2021 onwards as the technology is adapted to different site characteristics. Taking into

[13] This is not an electricity market model, seeking to describe the actual behaviour of electricity market participants. Using a market model to determine the deployment of generation technologies not yet commercially available would in fact do no more than spell out the consequences of the modelers' assumptions about the unknown technology. The emphasis here is on choices that society may make and their impact on Australia's energy future, given that the object of policy is to shape those choices towards optimal outcomes.

account the poor source to sink matching in NSW and SA, it is assumed that coal-fired generation in these states is not amenable to CCS. Each state is modelled separately, as are black and brown coal-fired generation. The model also includes estimated stock turnover times for existing plants.

Unlike CCS, many alternative abatement options are already commercially available and can be implemented earlier and on a significantly larger scale by 2030. Thus the abatement potential of replacing all coal-fired plants built from 2011 with either gas-fired generation or a combination of gas and renewables was also modelled. This helps to illustrate the abatement 'opportunity cost' of pursuing only a potential long-term abatement option such as CCS over this period.[14]

A brief note on costs: cost estimates were not included in this scenario analysis – the objective is to assess the greenhouse outcomes of different technology choices. However, the cost estimates discussed in Section 3 for the different technologies suggest that the CCS scenario will be higher cost than the others for an equivalent level of emission reductions.

4.2 Scenario 1: BAU demand growth and impact of CCS

To examine the abatement potential of different technologies, it is first necessary to define a business as usual (BAU) baseline. We have chosen to use the most recent ABARE projections for the period up to 2020 (Akmal *et al*. 2004), with respect to both total demand for electricity and the share of that demand supplied by coal-fired generation. In the ABARE model, called E_4cast, projected growth in demand for electricity (and other final demand fuels) is proportional to economic growth, by state and by economic sector, moderated by an assumed 0.5 per cent per year increase in energy efficiency in most states.[15] This projection includes the effects of the NSW Greenhouse Gas Abatement Scheme (GGAS), the Queensland 13 per cent Gas Scheme and the current 9,500 GWh Mandatory Renewable Energy Target.

To allow for the GGAS in NSW, ABARE assumes that the rate of efficiency increase is 0.75 per cent per year. However, ABARE makes no explicit allowance for the effect of other energy efficiency programs, such as the extended coverage of minimum energy performance standards for equipment and appliances, the strengthening of minimum residential building energy performance standards (energy star ratings) or the various programs which are helping to gradually improve the energy performance of commercial buildings.

The effectiveness in later years of the national and state measures included in ABARE's demand projections is unknown, especially past 2020, and so BAU growth may be higher. Other schemes such as the efficiency measures proposed by the National Framework for Energy Efficiency (NFEE), or policies which place a price on greenhouse emissions, may reduce demand growth.

[14] As noted previously, this analysis does not assess the effectiveness of different abatement options (including CCS) beyond 2030.
[15] Also known as autonomous energy efficiency improvement.

On the supply side, ABARE projects the share of coal-fired generation to fall by an average rate of 0.45 per cent per annum, with the rate of decline higher for brown coal and lower for black coal. This means that the share of electricity supplied by coal-fired power stations will fall gradually over the period to 2020, from about 78 per cent to about 71 percent. However, the high rate of growth in total electricity demand means that the absolute level of coal-fired generation increase significantly, at an average rate of 1.9 per cent per annum. Almost all the 7 per cent additional share of electricity supplied is provided by more rapid growth of gas-fired generation. BAU emissions from this gas-fired generation are not included in the modelling. In other words, the modelling examines alternatives only for that share of electricity which in the BAU case is supplied by conventional coal-fired generation.

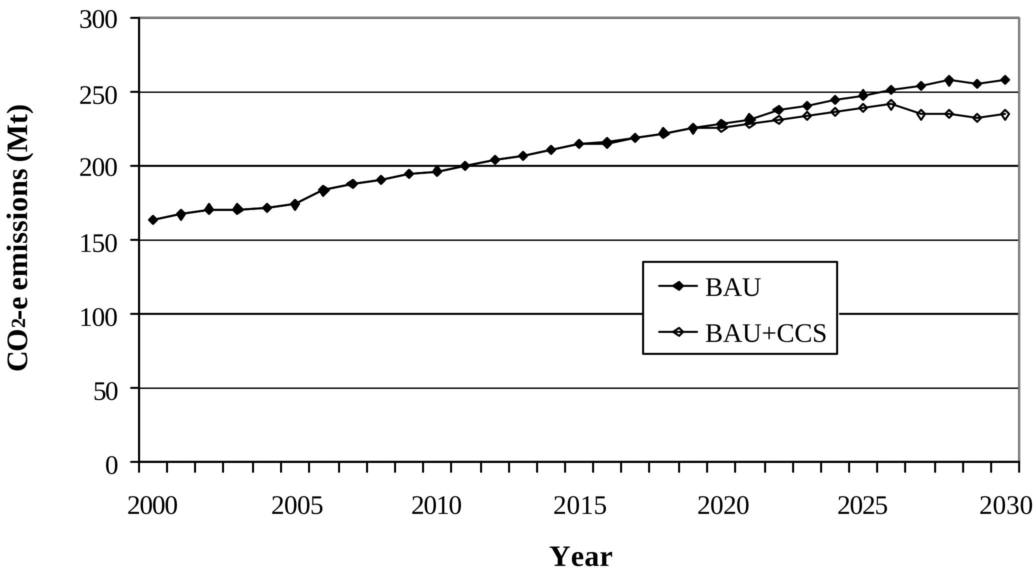
The economic growth rates assumed by ABARE between now and 2020 are significantly higher than those assumed by the Australian Treasury in the *Intergenerational Report* (Treasury 2002). A BAU scenario was constructed out to 2030 by extrapolating the ABARE demand figures and coal's share of generation for each State from 2020 on the basis of gradually falling rates of economic growth, all converging by 2030 on the national economic growth rate assumed for that year by the *Intergenerational Report* (1.9 per cent per annum).

Scenario 1 outcomes: BAU demand growth and impact of CCS

Annual emissions from coal-fired electricity generation between 2001 and 2030 were calculated based on ABARE BAU demand growth, both without and with CCS as shown in Figure 7. Under the reasonable assumptions made, CCS had very little impact on emissions by 2030. At this time annual emissions in 2030 were reduced to 234 Mt from the BAU projection of 258 Mt, a reduction of 9.3 percent. Cumulative emissions from 2005 to 2030 were reduced from 5,754 Mt to 5,616 Mt, a reduction of 2.4 percent. This highlights the extent to which the effectiveness of this technology to reduce greenhouse emissions is constrained by technical and commercial barriers to large-scale uptake prior to 2020.

This is a very different result to that presented in the COAL21 Action Plan which estimated between 35 per cent and 55 per cent reduction of emissions below BAU in 2030 (COAL21 2004). It is difficult to determine the reason for the difference, because the estimations and assumptions used in the COAL21 modelling are not provided.

Figure 7 CO_2 emissions from coal-fired electricity generation: BAU, BAU+CCS



4.3 Scenarios 2 and 3: Potential for energy efficiency to reduce emissions to 2030

Unlike CCS, energy efficiency improvements can be implemented on a large scale relatively rapidly. To compare the abatement potential of energy efficiency and CCS, two scenarios have been developed to 2030. The first (Scenario 2) is the NFEE 1 per cent target 'Low Scenario' (about 75 per cent penetration over 10 years of commercially available technologies with up to and including a 4 year simple payback time). The second (Scenario 3) comprises the measures outlined in *A Clean Energy Future for Australia* (Saddler, Diesendorf and Denniss 2004). These two scenarios illustrate the potential for greenhouse gas abatement from implementing energy efficiency measures beyond the BAU projection.

Scenario 2: NFEE modelling

The NFEE is a joint Commonwealth/state policy development process undertaken during 2003 and 2004. It aims to quantify the potential for energy savings through reduced demand, identify opportunities to achieve that potential and formalise the framework within which the savings can occur.

The NFEE scenario adopted here may be summarised as ABARE BAU projections plus end-use efficiency improvement potential as identified in studies undertaken for the NFEE process. It corresponds to the NFEE one per cent target, which, for a variety of reasons[16], actually resulted in projected demand reduction of only 5.4 per cent below BAU after 10 years (ACG 2004).[17]

It was assumed the potential for increased end use energy efficiency identified by the NFEE, which is expressed in terms of percentage reductions in energy use by fuel (electricity and natural gas) and by economic sector, will be progressively implemented over ten years. Starting in 2006 and ending in 2015, demand for electricity will be reduced below the ABARE BAU level. Thereafter, until 2030, growth in demand is assumed to be 10 per cent lower than growth in the corresponding economic sector, state and year in the BAU scenario. This may be thought of as a modest increase in autonomous energy efficiency improvement. For example, if demand for electricity increases by 3 per cent in a particular sector and year in the BAU scenario, then in the NFEE scenario it increases by 2.7 percent, which is equivalent to an autonomous energy efficiency improvement of 0.8 per cent instead of the 0.5 per cent in the BAU scenario.

The NFEE represents what appears to be the energy demand future anticipated or intended by the Energy White Paper of June this year (Australian Government 2004).

The White Paper observes:

> The potential economic and environmental gains from increasing the uptake of commercial energy efficiency opportunities warrant a high-priority response from government. Past efforts to improve energy efficiency have had successes, but have been focused largely on the residential and commercial sectors. More limited results have occurred in the industrial energy sector.
>
> The Australian Government is determined to improve the uptake of commercial energy efficiency opportunities by Australian businesses and households … (p. 110).

However, the White Paper announces only a few new policy measures to promote energy efficiency. The main new initiative is a reference to the Productivity Commission 'to examine the potential economic and environmental benefits from improving energy efficiency' (p. 111) and to report by late 2005. Achieving real energy savings, and the national financial benefits that result, requires a framework of integrated initiatives. It is highly unlikely the measures announced in the White Paper will be sufficient.

The abatement potential of the NFEE demand scenario is shown below in Figure 8 and Table 8.

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[16] Mainly due to the periods when measures were being ramped up and down (and therefore less than one percent) and the rebound effect (where lower energy costs and an expanding economy increase energy use).

[17] Note that much greater energy efficiency targets are possible. The NFEE industrial and commercial sectoral studies found that bundling measures together to achieve an *average* payback time of four years doubled the energy savings (Energetics 2004; EMET 2004).

Scenario 3: Clean Energy Future Group modelling

The Clean Energy Future Group (CEFG) scenario used back-casting, as opposed to projection, which means it does not plot a time course from the present into the future. Rather, it describes in considerable detail possible low emission energy futures for Australia in 2040, which are achievable given appropriate changes in policies and technology choices over the intervening years.

The CEFG scenario takes as its starting point continued economic growth at the same rates as assumed in the *Intergenerational Report*. In terms of energy demand, the study projects a large decrease in the energy intensity of the economy. Much of this derives from continuation of the structural change trend, towards greater reliance on service industries and less reliance on energy-intensive materials processing. It is also assumed that as energy-using plant and equipment reaches the end of its life, it is replaced by new generation equivalents with substantially improved energy efficiency. This minimises the overall cost of achieving large efficiency improvements over time.

The CEFG study focuses on much longer term changes than the NFEE modelling work, and also considers the shorter term effects of an intensive program to implement currently cost-effective efficiency improvement measures. For the present study, a time course of demand was constructed that follows a real one per cent per annum efficiency target sustained over 10 years, and thereafter shows slower growth in demand as the longer-term processes described above take effect and new, much more energy efficient equipment spreads through the economy. For the last few years up to 2030, demand grows steadily more slowly and eventually falls slightly.

The abatement potential of the CEFG demand scenario is shown below.

Scenario 2 and 3 outcomes: BAU, BAU+CCS, NFEE, CEFG

Annual emissions from coal-fired electricity generation between 2001 and 2030 for Scenarios 2 and 3 are shown in Figure 8.

Scenario 3 resulted in greater reduction of carbon dioxide emissions than CCS, both in 2030 and cumulatively between 2005 and 2030 (Table 8). Although the Scenario 2 emissions reductions were less than those of the CCS scenario in 2030, the cumulative reductions were double. Both the NFEE and CEFG scenarios reduce emissions through reduced demand, and so require less generation and occur at negative net cost. The Allen Consulting Group modelled the impact of the same one per cent per annum efficiency improvement target as used in Scenario 2 (but assumed that after 10 years end-use efficiency reverted back to 2005 levels). They found that between 2005 and 2025, Australia's net present value GDP increased by $12.4 billion and employment in 2014 increased by 1,900 people (ACG 2004).

Figure 8 CO_2 emissions from coal-fired electricity generation: BAU, BAU+CCS, NFEE, CEFG

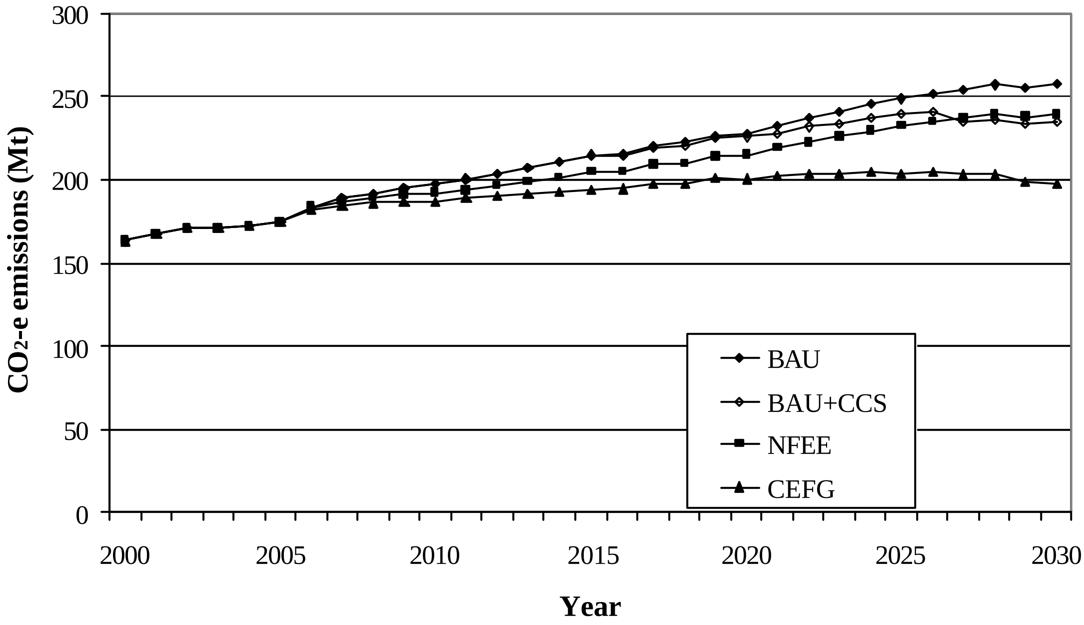


Table 8 CO_2 emissions from coal-fired electricity generation: BAU, BAU+CCS, NFEE, CEFG

	BAU	(1) BAU+CCS	(2) NFEE	(3) CEFG
CO_2 emissions in 2030 (Mt)	257.9	234.1	239.3	197.3
Change compared to BAU (Mt)	0.0	-23.8	-18.6	-60.6
% change compared to BAU	0%	-9.2%	-7.2%	-23.5%
Cumulative CO_2 2005 to 2030 (Mt)	5,754	5,616	5,477	5,068
Change compared to BAU (Mt)	0.0	-138	-277	-686
% change compared to BAU	0%	-2.4%	-4.8%	-11.9%

4.4 Scenarios 4, 5 and 6: Abatement through changes to the generation mix

Even greater emission reductions are possible if, in addition to reducing demand, gas-fired generation and renewable energy are used instead of coal.[18] Unlike CCS, which we have assumed is not applied on a wide scale until 2021, gas and renewable generation technologies are commercially available and can be deployed much sooner. The cost savings obtained through energy efficiency measures can be used to offset the additional costs of gas-fired generation and/or renewable energy. Gas-fired generation and renewables are also smaller scale than coal-fired plant, and this modularity enhances

[18] Despite demand decreasing in the CEFG scenario, because of retirement of old coal-fired plant, new generation is still required.

flexibility in their commissioning dates. Although increased demand for natural gas could increase its price, economies of scale and competition between gas suppliers, made possible by the growing national gas pipeline network, would have the opposite effect (Outhred and MacGill 2004).

In the CEFG+Gas scenario, all new coal-fired generation from 2011 onwards in the BAU case is instead baseload gas-fired generation. This generously allows six years for the necessary gas supply infrastructure to be developed. Although there is much variation in the emissions intensity of new entrant coal-fired plant, emissions from combined cycle gas turbines were taken on average to be half that of new entrant coal-fired generation (as per Davison *et al*. 2001).

In the CEFG+Gas/RE scenario, where both gas and renewable energy are used, appropriately designed gas-fired generation[19] meets baseload, intermediate and peaks in demand, and so compensates for the intermittent nature of renewables. The optimal mix would need to be calculated to minimise the cost of GHG abatement and such calculations are beyond the scope of this paper. Here, by way of example, one third of the additional gas-fired generation in the CEFG+Gas scenario has been replaced with a mixture of wind and bioenergy.

In 2030, the CEFG+Gas and CEFG+Gas/RE scenarios would require an additional 148,000 GWh of electricity demand to be supplied by gas-fired and/or renewable generation. In the CEFG+Gas scenario, assuming an average capacity factor of 85 per cent and an allowance of 9 per cent for transmission and distribution losses and power station own use, nearly 22,000 MW of additional gas plant would be needed Australia-wide. This would be additional to the BAU (ABARE projected) gas-fired generation, which in 2020 is 69,000 GWh, 20 per cent of total generation in that year, up from 13.6 per cent in 2001-02 (Akmal *et al*. 2004).

In the CEFG+Gas/RE scenario, a third of the additional gas-fired generation (49,330 MWh) needs to be replaced with renewable electricity. Renewable energy generators such as wind farms are intermittent and only partially predictable and so require a supply mix that includes dispatchable supply or large-scale storage (large hydro). Bioenergy from agricultural wastes and residues, possibly supplemented by plantation energy crops (both dispatchable and a form of storage) combined with gas-fired generation (dispatchable) should be suitable. For a more thorough discussion of this see Saddler *et al*. (2004).

As a first approximation, and assuming a capacity factor of 30 per cent for wind and 85 per cent for bioenergy, if 4,000 MW of bioenergy is used, about 7,450 MW of wind would be required to achieve the same theoretical capacity factor as 6,630 MW of gas-fired generation.[20] These amounts of bioenergy and wind are readily achievable over the next 25 years (Saddler *et al*. 2004).

[19] Dedicated peaking plant may not be combined cycle, if plant is to be used for both peaking and baseload (e.g. Swanbank), it should be built as CCGT.

[20] These were calculated by multiplying the capacity factors by the generation capacity so the total for gas equalled the total for wind and bioenergy (0.85 x 6,630 = 0.30 x 7,450 + 0.85 x 4,000).

Bioenergy can use a variety of fuels including agricultural and plantation residues, and municipal solid waste and commercial and industrial wastes. Although agricultural residues could provide significant amounts of feedstock, tree-based energy crops, which can also reduce dryland salinity risks, are likely to be required for substantial levels of energy production. About 60 million hectares are available for tree crops in Australia, which if planted at a conservative density of 10 per cent would supply enough feedstock for about 4,500 MW of generation (Cooper *et al*. 2004; Enecon 2001).

As at the end of 2002, 1,746 MW of wind farms were under development and 1,992 MW were under evaluation, making a total of 3,738 MW already being considered. The total figures for all renewable projects were 2,350 MW currently under development and 3,417 MW being evaluated, making a total of 5,767 MW (BCSE 2003).

This degree of penetration of renewable energy into the electricity market is not unreasonable. The 7,450 MW of wind capacity represents about 9 per cent penetration of wind energy into the electricity market for the CEFG demand scenario. Based on 2002 electricity demand (which is less than CEFG demand in 2030) it has been estimated that the NEM could readily accept 8,000 MW of wind farms provided appropriate planning and power system control strategies were implemented (Outhred 2003). Combining 7,450 MW of wind with 4,000 MW of bioenergy would bring the total penetration to about 22 per cent in 2030. The EU15 (the 15 core members of the European Union excluding the 10 recently accepted members), intends to produce 22 per cent of their electricity from renewable sources by 2010 (EU 2004).

As can be seen from Figure 9 and Table 9, emissions in both the CEFG+Gas and CEFG+Gas/RE scenarios are considerably less than in any of the above scenarios. Compared to gas-fired generation and renewable energy, CCS resulted in only modest additional abatement by 2030.

Figure 9 CO_2 emissions from coal-fired electricity generation: BAU, CEFG, CEFG+CCS, CEFG+Gas, CEFG+Gas/RE

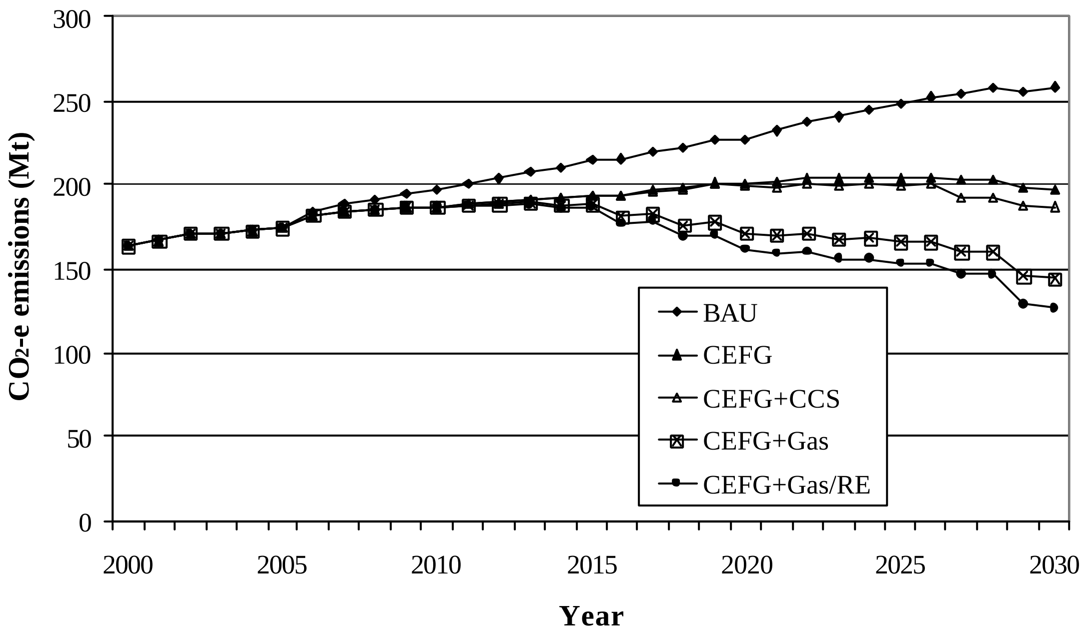


Table 9 CO_2 emissions from coal-fired electricity generation: BAU, CEFG, CEFG+CCS, CEFG+Gas, CEFG+Gas/RE

	BAU	(3) CEFG	(4) CEFG+CCS	(5) CEFG+Gas	(6) CEFG+Gas/RE
CO_2 emissions in 2030 (Mt)	257.9	197.3	187.1	144.2	126.5
Change compared to BAU (Mt)	0.0	-60.6	-70.8	-113.7	-131.3
% change compared to BAU	0.0%	-23.5%	-27.5%	-44.1%	-50.9%
Cumulative CO_2 2005 to 2030 (Mt)	5,754	5,068	4,998	4,550	4,378
Change compared to BAU (Mt)	0.0	-686	-756	-1,204	-1,376
% change compared to BAU	0.0%	-11.9%	-13.1%	-20.9%	-23.9%

4.5 Scenarios 7 and 8: How much generation from gas and renewables has the same abatement as BAU+CCS?

Another way of evaluating the effectiveness of CCS is to see how much gas-fired generation and/or renewable energy would be needed to achieve the same cumulative emission reductions over the period 2005 to 2030. To do this, the amount of new coal-fired generation that needs to instead be either (a) gas-fired generation or (b) a mixture of 67 per cent gas, 33 per cent renewable energy (RE), has been calculated.

If only gas-fired generation is used, 18 per cent of new coal-fired generation would need to be replaced to achieve the same reductions. If the gas/RE mixture is used, 9 per cent of new coal-fired generation would need to instead be gas-fired generation, and 4.5 per cent would need to instead be renewable generation.

In 2030, option (b) requires about 9,900 GWh of additional RE, and double that of gas. This amount of renewable energy is very close to the Mandatory Renewable Energy Target (MRET) of 9,500 GWh, meaning that doubling the target and including twice the amount of gas-generation so they could in combination replace base-load coal-fired generation, would have about the same cumulative impact by 2030 as the CCS scenario.

Scenarios 7 and 8: The 'White Paper' Scenario (NFEE+CCS) and NFEE+Gas/RE

The Energy White Paper appears to set a future energy demand based on NFEE reductions below BAU, then emphasises CCS to reduce coal-fired emissions (Australian Government 2004). Here, CCS was applied to the NFEE scenario. To put this in context of other abatement options, it was compared to NFEE plus the mixture of gas and renewables used above in the CEFG+Gas/RE scenario.

As in the BAU demand scenario, CCS has limited ability to reduce emissions in the NFEE scenario as shown in Figure 10 and Table 10. Compared to CCS, the combination of gas-fired generation and renewables reduces emissions in 2030 by more than four times as much, and reduces cumulative emissions between 2005 and 2030 by more than seven times as much.

Given that the NFEE+CCS scenario models the Commonwealth Government's current direction for the Australian energy sector, it is of considerable concern that cheaper options result in seven times greater abatement between 2005 and 2030. This highlights the need to support technologies other than CCS alone to achieve meaningful reductions over the next quarter of a century and improve flexibility over the longer term.

Figure 10 CO_2 emissions from coal-fired electricity generation: NFEE, NFEE+CCS, NFEE+Gas/RE

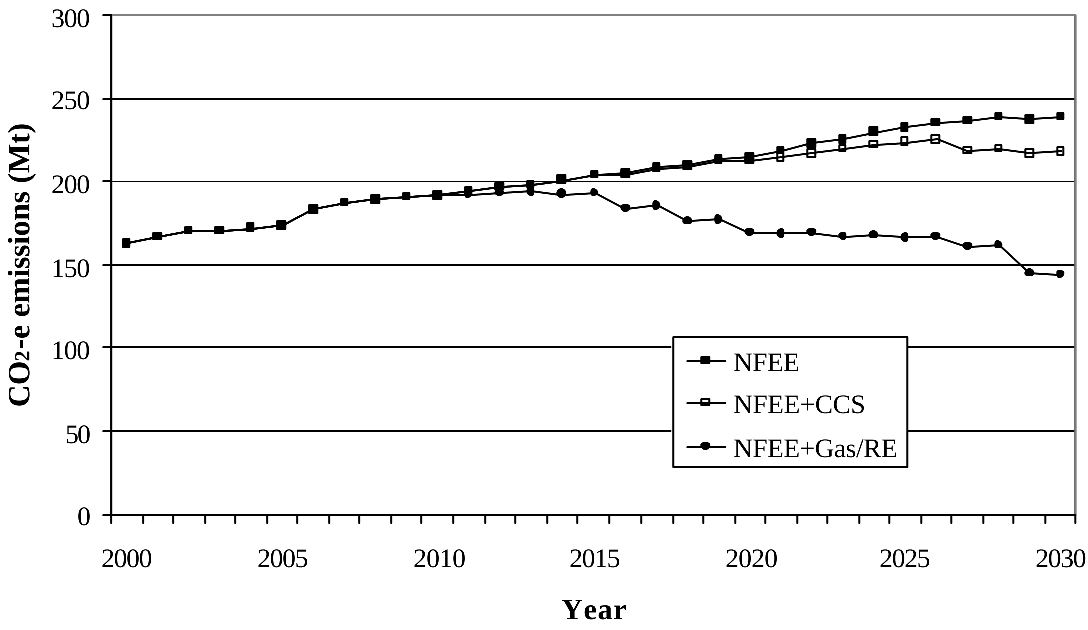


Table 10 CO_2 emissions from coal-fired electricity generation: NFEE, NFEE+CCS, NFEE+Gas/RE

	(2) NFEE	(7) NFEE+CCS	(8) NFEE+Gas/RE
CO_2 emissions in 2030 (Mt)	239.3	217.7	143.8
Change compared to BAU (Mt)	0.0	-21.6	-95.4
% change compared to BAU	0.0%	-9.0%	-39.9%
Cumulative CO_2 2005 to 2030 (Mt)	5,477	5,351	4,591
Change compared to BAU (Mt)	0.0	-126	-886
% change compared to BAU	0.0%	-2.3%	-16.2%

5 CCS, greenhouse gas emissions and energy policy

5.1 Introduction

Sooner or later Australia will have to take more decisive action to reduce its energy-related emissions of greenhouse gases. This proposition is now almost universally accepted in serious policy circles. For example, the Energy White Paper states:

> Australia recognizes (sic) the necessity of lowering global greenhouse emissions and that achieving this will require substantive action over the long term (Australian Government 2004, p. 137).

COAL21 (2004) states:

> The need for the provision of …. energy to be environmentally sustainable is now recognized as one of the major challenges facing Australia and the rest of the world in the 21st century (p. 4).

There is also no argument with the proposition that, whatever the level of emission reduction sought, this should be achieved in a way that maximises societal welfare. Serious policy debate is therefore focused on the relative risks, costs and potential scale of the various abatement options and hence on what the most appropriate options are, and on the timing of further action to reduce emissions.

5.2 The timing of further action

Meeting the Kyoto commitment

Figure 11 shows the historical trend in Australia's greenhouse gas emissions, as reported in Australia's National Greenhouse Gas Inventory, for each year from 1990 to 2002. Emissions are divided into three main groups: energy combustion (including both stationary combustion and transport), land use, land use change and forestry (LUCF), and all other source categories, which includes emissions from industrial processes (other than energy use), agriculture and waste. It can be seen that energy combustion emissions have been growing steadily. So have emissions from all other sectors other than LUCF, although much more slowly. By contrast, LUCF emissions have fallen sharply, because of decreased emissions from land clearing.

Figure 11 also shows a projection of emissions from energy combustion from now until 2020, calculated from the ABARE projections of BAU growth in energy demand and supply (Akmal *et al*. 2004). Even if it is assumed that all other sources of emissions, including LUCF, remain unchanged at their 2002 levels, then Australia's total greenhouse gas emissions will grow along the path shown by the solid line in Figure 11. It can be seen that, on these assumptions, Australia's emissions will exceed its Kyoto Protocol commitment level by 2008 and continue to grow throughout the 2008-12 commitment period.

The Australian Government is confident that it is 'on track' to meet the Kyoto commitment (Australian Government 2004, p. 138). Figure 11 suggests that to do so it will be relying on further reductions in land clearing emissions or on near term measures to reduce energy-related emissions that are not allowed for by ABARE's modelling, or some combination of both. The analysis shows that including the effect of the NFEE efficiency improvement (Scenario 2) will, at best, merely postpone from 2008 to 2009 the date at which Australia's emissions exceed the commitment level.

Beyond Kyoto

It might be argued that larger reductions in emissions from other sources could compensate for continuing growth in energy related emissions. However, that is not the view of the Australian Government which states:

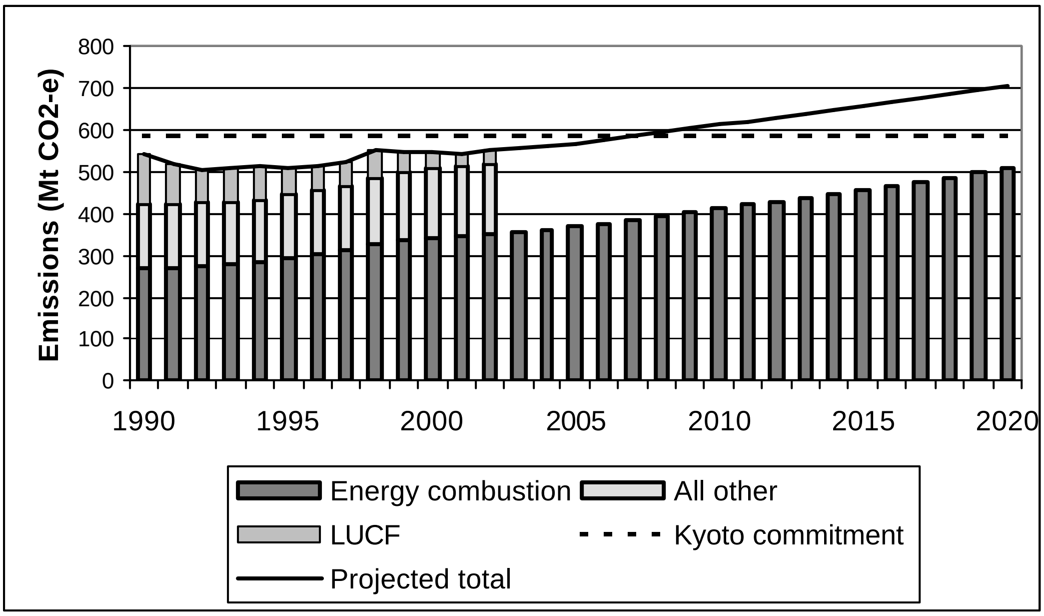
> Any significant reduction in Australia's long term greenhouse gas signature must involve changing the way we produce and use energy (2004, p. 134).

Chairman of COAL21, Mr Tim Besley, also states:

> Part of the solution [to the greenhouse problem] must therefore be to minimize emissions from our use of fossil fuels during the long transition to more sustainable energy systems… (COAL21 2004, p. iii).

Restraining the level of Australia's greenhouse gas emission must involve restraining the level of energy-related emissions, including those that result from the generation and use of electricity.

Figure 11 Australia's historic and projected GHG emissions, with projected energy combustion emissions at BAU levels and all other emissions held constant at 2002 levels

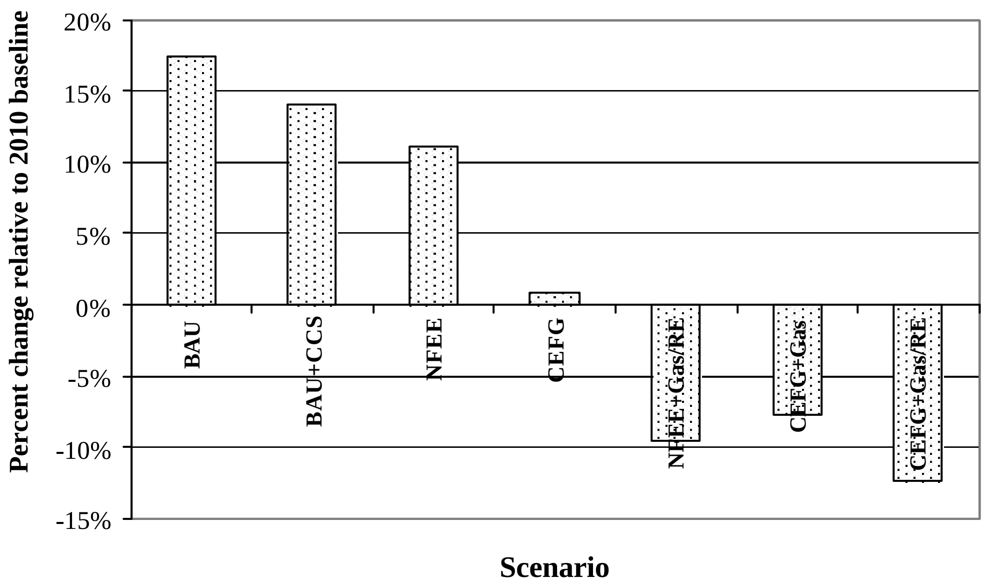


The modelling used here shows that, according to the ABARE BAU scenario, emissions from coal-fired generation are likely to continue to increase, reaching 65 per cent above the 1990 level by 2010 and 117 per cent by 2030. This means that once Australia has 'met' its Kyoto target, emissions from this source will continue to increase such that the cumulative coal-fired generation emissions from 2011 to 2030 will be 690 Mt (17.5 percent) higher than if emissions had been kept at 2010 levels – see Table 11 and Figure 12. CCS reduces this to being 14.0 per cent higher. The NFEE and CEFG demand-side scenarios alone can achieve significantly slower emissions growth and when combined with gas-fired generation and renewable energy can achieve cumulative reductions compared to the 2010 baseline. Thus there are many policy/technology options that could reduce emissions associated with the electricity sector by much more, and much more quickly, than CCS.

Table 11 Change in cumulative emissions compared to the 2010 baseline

	BAU	BAU+CCS	NFEE	CEFG	NFEE+Gas /RE	CEFG+Gas	CEFG+Gas /RE
2011 to 2030 total (Mt)	4625	4487	4361	3968	3474	3451	3278
Difference to 2010 baseline (Mt)	690	552	425	33	-364	-290	-462
% change to 2010 baseline	17.5%	14.0%	11.1%	0.9%	-9.5%	-7.7%	-12.4%

Figure 12 Change in cumulative emissions relative to the 2010 baseline



At present Australia is able to withstand international pressure in both economic and diplomatic form to restrain its emissions to the Kyoto commitment level. However, it is not difficult to envisage circumstances under which this could change. If the Kyoto Protocol comes into force, Australia could be exposed to significant economic costs on its trade account. A change in policy by a future US administration would certainly greatly exacerbate both economic and diplomatic pressure on Australia to follow suit.

Adopting a policy which cannot begin to significantly reduce energy-related emissions until 2025, as shown to be case with CCS even under highly optimistic assumptions, is clearly a high-risk strategy. As such, it is unlikely to be the best way of maximising Australia's overall energy security.

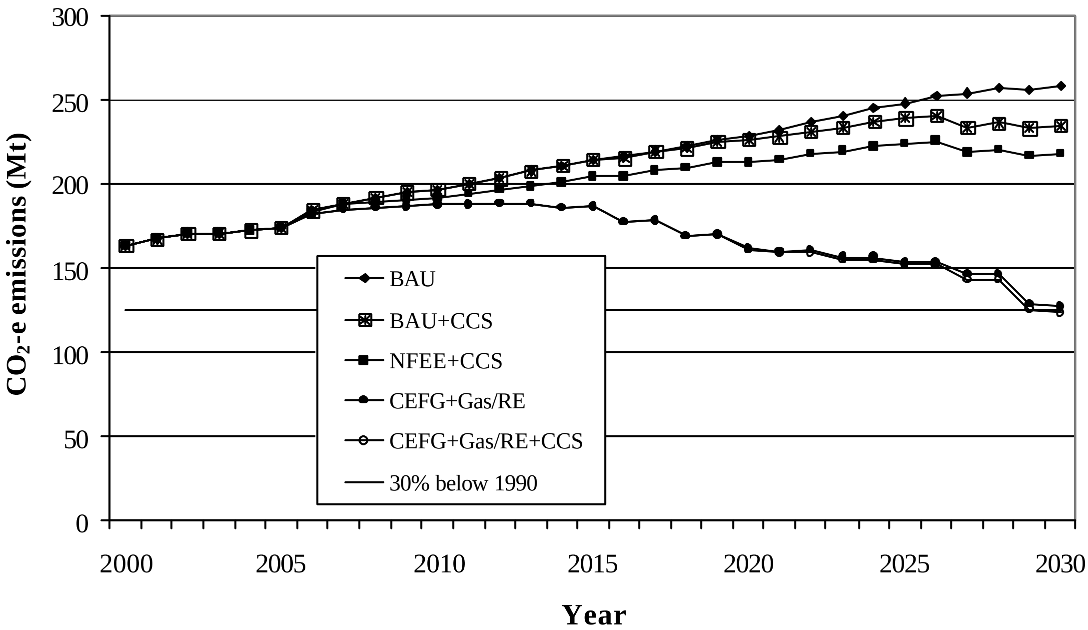
Reducing emissions by 50 per cent by 2050

It has been estimated that a 60 per cent reduction of world emissions below 1990 levels is required to avoid significant damage due to climate change (WMO/UNEP 1990). This has been acknowledged by the Australian Government (Kemp 2002). It is also the target set by the UK government in their Energy White Paper for Britain in 2050 (British Government 2003), which has also set interim targets of 20 per cent below 1990 by 2020, 30 per cent by 2030, 40 per cent by 2040, and 50-60 per cent by 2050.

For Australia, if the total 'land clearing bonus' outlined above is taken into account, all other sources could emit 127 Mt (emissions from land clearing in 1990) more than in 1990 while keeping total emissions at the 1990 level of 543 Mt. This is equivalent to an increase of about 4 per cent above current (2002) levels. To achieve total national emissions 20 per cent below 1990 levels would require a reduction of about 17 per cent below current levels for sources other than land clearing. The 30 per cent below 1990 interim target for 2030 corresponds to a reduction from current levels of 27 percent, which for coal-fired generation would mean total emissions of about 125 Mt.

None of the options modelled so far reduced coal-fired emissions to below either the 2020 or 2030 targets. The BAU emissions are 140 per cent above the 2030 target and CCS reduces this to being 119 per cent above. The CEFG+Gas/RE scenario comes close, with emissions of 126.5 Mt in 2030 – see Figure 13. Note that if CCS is added to the CEFG+Gas/RE scenario only 3.4 Mt of additional abatement is achieved.

Figure 13 CO_2 emissions compared to the 30 per cent reduction target: BAU, BAU+CCS, NFEE+CCS, CEFG+Gas/RE, CEFG+Gas/RE+CCS



It is possible that, in the best of all circumstances, reductions in CO_2 transport costs or electricity transmission costs could make CCS power stations feasible in NSW and SA, as well as other states, after 2030, and that the technology could be used at all new stations built between 2030 and 2050. It might then just be possible to reach a 50 per cent below 1990 emission reduction target by 2050 without significant demand-side management, gas-fired generation or renewable energy. However, such a strategy would make Australia highly vulnerable to the risk of technological failure in any part of the CCS system. It would also result in significant emissions over the next 20 or so years, before CCS technology is ready to be used.

Moreover, major energy infrastructure such as power stations have very long operational lives, so it is imperative that shifts towards lower emission technologies begin as soon as possible. A power station commissioned in 2020 will by 2050 still be technically capable of many years of productive life, unless it is prematurely retired because of its high greenhouse emissions.

For all these reasons, waiting for CCS to achieve commercial maturity before taking strong action to reduce emissions will make it most unlikely that Australia could achieve a 50 per cent emission reduction by 2050, as well as causing very high emissions over the intervening decades, before the widespread deployment of CCS. It is clear that a serious response to the greenhouse problem needs action to be taken immediately, not postponed until 2016 or 2020 and that a combination of measures is required.

5.3 The cost of further action

In the words of the Energy White Paper 'Australia has some of the lowest-priced energy in the world, due largely to the wide availability of inexpensive coal' (Australian

Government 2004, p. 134). When coal is priced into power stations at the cost of extracting it from the ground, as it is at present in Australia, coal-fired electricity in eastern Australia is cheaper than electricity from any other source. In many other parts of the world the use of natural gas in CCGT power plants can supply electricity more cheaply than a new coal-fired power station, with about half the greenhouse emissions. This is not generally the case in Australia, particularly in the three major eastern states which in 2002 accounted for over 77 per cent of Australia's electricity consumption.

The NFEE sectoral studies have made it clear that, even with low electricity prices, there are substantial cost-effective opportunities to reduce electricity consumption, reduce greenhouse emissions and increase economic productivity, by increasing the efficiency of energy use. Nevertheless, as the modelling shows, achieving significant emission reductions will require both improved energy use efficiency and a shift towards lower emission electricity sources. If action is taken now, that will mean a shift towards electricity sources that cost more to provide electricity than current coal-fired power stations, so long as coal continues to be priced without reference to the costs of greenhouse pollution. To quote again from the Energy White Paper:

> …wide-scale uptake of low-emission base load electricity generation at current costs [of low emission generation technologies] would lead to substantial increase in electricity prices … (Australian Government 2004, p. 135).

Some policy makers believe the ideal situation for Australia would be if, on the basis of what we know today, we could confidently expect the present generation of conventional coal-fired power stations to give to a new, near-zero emission substitute coal-based technology, with no increase in costs. Were this to be the case, and putting aside the arguments for early action to reduce emissions explored in the previous section, they argue that it would be economically sub-optimal to invest now in currently available, but more expensive, low emission energy supply technologies, since these would become redundant when the new technology became available.

Unfortunately, the information we have gathered and analysed in Sections 2 and 3 show that this supposed ideal is no more than wishful thinking.

On the basis of what we know today, it is not unreasonable to expect that it will eventually be possible to develop and integrate the various separate technologies required into a single commercially available, fully functional CCS electricity generation system. But we cannot be completely confident that this will be achieved, and we have much less certainty about when it will be achieved. It will certainly be very difficult for it to be achieved within the timeframe necessary to reduce greenhouse emissions by 50 per cent by 2050. Moreover, CCS is effectively an 'end of pipe' approach to reducing CO_2 emissions and, like all such approaches, carries the environmental risk that technical failure at any point along the 'pipe' could mean that CO_2 was again emitted. By contrast, the other technologies considered in this paper have intrinsically lower (in the case of gas) or zero emissions (in the case of efficiency and renewables) and so do not carry this environmental risk.

On the other hand, we can have considerable confidence that it will cost more to generate electricity using this system than it will using some of the other low emission technologies that are now commercially available, including CCGT and wind.

Table 12 summarises key cost estimates discussed in Section 3. With the exception of CCS, all cost estimates are based on experience with full scale commercial (near commercial for IGCC) operation, adjusted for Australian conditions as described in Section 3. Figures for CCS are based on estimates of what a hypothetical plant, scaled up from current small-scale demonstrations, might cost. Between now and 2020 a modest decrease in the cost of CCGT can be expected, but this is likely to be limited by movements in the price of natural gas, which accounts for a large proportion of the total generating cost. Over the same period, the cost of wind generation will fall with continuing improvements in technology.

If policy permits a steady expansion of Australian wind generation capacity, appreciable further cost reductions can be expected from the experience of 'learning by doing' in the construction of wind generators. While the cost of IGCC with CCS can also be expected to fall, the potential for reduction is limited, in the sense that the current estimates assume that a full-scale project can be built to achieve the performance so far only seen in small scale demonstrations. Achieving that goal will be the main focus of RD&D activity over the next 15 years, and only after that will the technology move into the incremental improvement phase, already achieved by CCGT and wind.

From a greenhouse, as opposed to an energy policy perspective, the relevant basis of comparison is not generation cost but marginal abatement cost. On this basis also CCS is more costly and therefore less economically efficient than other low emission technologies. It can therefore be concluded that CCS based electricity generation technologies, even with a highly successful RD&D program, will remain more costly than other low emission electricity generation options for well over two decades into the future, if not longer.

Table 12 Current generation and abatement costs of low emission electricity generation technologies

Generation technology	Generation cost ($/MWh sent out)	Marginal abatement cost ($/tonne CO_2-e)
CCGT	40-42	12 –21
Wind	75-90	51 – 71
Black coal IGCC + CCS	100 (middle of range)	53 – 110

If Australia is to take further action to reduce energy-related greenhouse gas emissions, it should do so in an economically optimal manner by turning first to the least-cost emission abatement options currently available and then moving up the abatement supply curve to successively higher cost options. On the basis of what is now known, and irrespective of when action to achieve further abatement were to be initiated, very considerable abatement could be realised before it became economically efficient to turn to CCS.

5.4 CCS and energy policy

Reducing Australia's greenhouse gas emissions to 50-60 per cent below 1990 levels by the mid-century will be a formidable challenge. A full range of technological and behavioural changes will be required, including a shift towards less materials-intensive consumption patterns, much greater end-use energy efficiency, greater energy supply efficiency and a decisive switch towards less carbon intensive fuels and low emissions energy supply technologies.

A correspondingly wide range of policy measures will be required to achieve these changes. Policies will be needed to overcome market failures and other institutional barriers that are holding back energy efficiency. Other polices will be needed to allow commercially available low emission supply technologies, such as CCGT, wind- and gas-fuelled cogeneration, to find a secure place in the energy market, which will both lead directly to accelerated emission reductions and also allow steady technology improvements to be funded from cashflow as part of the normal course of business.

Less mature technologies, such as photovoltaics, hot dry rock geothermal and CCS, will require policies that provide some public support for R&D and also encourage greater private sector investment. At this stage in the development of the new technologies that will be needed, all these technologies are potentially important for Australia. It is important that, within the overall limits of government R&D budgets, a wide range of technologies be explored, and is appropriate that Australia, as a large producer and user of coal, should contribute to CCS R&D. But for similar reasons it is equally important that it contribute to photovoltaic R&D.

Thus governments, and particularly the Commonwealth, have two separate but related responsibilities. They must put in place the policy framework and policy measures that allow commercially available technologies to enter the energy market on a scale sufficient to start moving Australia decisively along a lower emission path The Commonwealth must contribute financial support to R&D for currently immature technologies.

It is most important that these two responsibilities are not confused. In particular, it is essential that the uncertain prospect of promising longer term technologies, such as CCS, does not impede the near-term adoption of more mature technologies that are now available to help reduce emissions. This is particularly the case when these more mature technologies will clearly still be available, if and when CCS becomes available, and may also continue to be able to supply energy and reduce GHG emissions at a lower cost than CCS.

Perhaps most damaging of all is the continuing construction of conventional coal-fired power stations, at the expense of lower emissions gas-fired generation and cogeneration. These new coal power stations will have a technical life extending well beyond the possible date of introduction of CCS technologies, but will not be amenable to adaptation to CCS, except at even higher cost than 'standard' CCS. They will seriously impede Australia's progress towards a low emission energy future three or four decades hence.

Over the longer term, notwithstanding its cost disadvantage relative to end use efficiency, gas, wind and possibly some other renewables, CCS may become more attractive as the scale of necessary GHG emission reductions increases. It is not yet clear whether a combination of energy efficiency and renewable energy can provide the deep cuts in GHG emissions required to ultimately stabilise atmospheric GHG concentrations. Energy efficiency, though commercially attractive, cannot on its own provide the scale of emission cuts required. While some scenarios find that renewable energy can supply all global energy needs (Sørensen and Meibom 2000), it is possible that resource constraints and grid management problems may impose some limit on the emission cuts available from renewable energy. If this is the case, then more expensive abatement options, including CCS, may be a necessary part of the long-term response to climate change, provided that technical and environmental problems can be surmounted.

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