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Acknowledgments

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1. EXECUTIVE SUMMARY

New technology development and deployment is expected to play a major role in shaping the future affordability, competitiveness and environmental standing of the Australian energy sector as it responds to the challenges of rising demand and pressure to reduce greenhouse gas emissions.

The *Australian Energy Resource Assessment* published in March 2010 (Geoscience Australia and ABARE 2010) provides a comprehensive assessment of Australia's resource endowment, their relative competitiveness and their potential to contribute to the energy mix, including renewable energy resources.

This report, commissioned by the Department of Resources Energy and Tourism, extends that body of knowledge in the following ways:

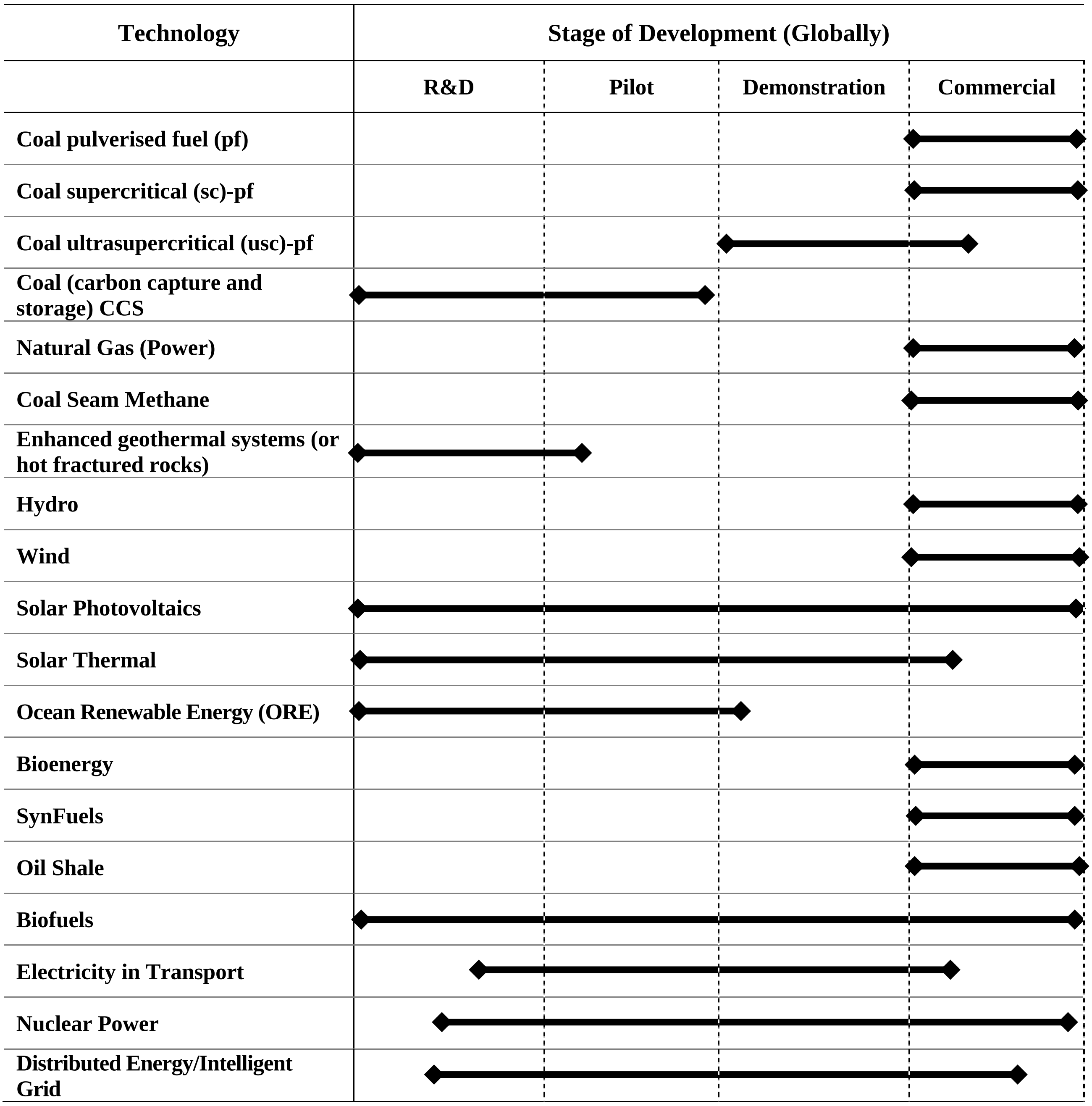
- Qualitatively assessing the development stage of each of the key renewable and fossil energy technologies groups, and
- Synthesising the projected levelised costs of different electricity generation technologies, drawing on a broad range of comprehensive studies that have been published over the past 18 months.

1.1 Technology Opportunities

The feasibility and extent of future technology deployment will depend on the evolution of each technology on the maturity curve. This report describes in detail each technology or technology group, its strengths, challenges to deployment, and potential areas for future development. While it is difficult to summarise such detail, Table 1 provides an overall qualitative and simplified estimate of the global stage of maturity of a select range of energy technologies.

The categories used are based on the well-known "S" curve representation of technology development. Technology developments usually starts with research and development (R&D) and progresses through various stages of supported piloting and demonstration at various sizes to full, stand-alone commercial operations. Throughout the development, the penetration of the technology into the existing energy infrastructure rises gradually initially, and then more rapidly with the commercial deployment of successful technologies.

Table 1: Maturity of energy technologies



1.2 Cost competitiveness

In the past 18 months five organisations – the Electric Power Research Institute (EPRI), ACIL Tasman, the United States Department of Energy (US DOE), the International Energy Agency (IEA) and CSIRO – released their projections of the levelised cost of electricity for a broad range of fossil and renewable generation technologies. The availability of five broad, high quality cost projection studies has provided an unprecedented opportunity to compare and synthesise the outlook for costs of electricity generation technologies in Australia.

At first glance there may have appeared to be significant differences in the projections presented in each of the studies, particularly in relation to technologies such as coal with carbon capture and storage, some solar technologies and natural gas. However, levelised cost of electricity (LCOE) projections cannot be compared without considering the assumptions and parameters underpinning their calculation. Small variations can make big differences in the calculated LCOE. Rather than reflecting fundamental uncertainty about technology costs, many of the differences in assumptions employed represent alternative views about the cost of local resources such as fuel or operational factors such as capacity factor. Even where these data inputs are aligned, the calculation methodology used to convert that data into LCOEs can also be a source of divergence in results.

This report has compared data assumptions and calculation methodologies in five key LCOE analyses. Using a single methodology and averaging for non-technology assumptions, a harmonised set of LCOE estimates have been calculated. This approach means that the input data of each of the five studies can be compared on a common basis.

The process harmonised the data across the five reports to deliver a common harmonised set of input data, developed and compared on their capital cost assumptions. This simplifying assumption was used as it is possible to demonstrate with cost component impact analysis that, capital costs for the majority of technologies is the most important data input and best reflects the basis upon which most expected cost improvements in new technology are to be achieved. The harmonised data set for each technology effectively averages key inputs such as fuel costs and capacity factors between the studies. However it should be remembered that, in reality, these inputs will vary across Australia due to different climatic and resource endowments.

The harmonised data reduced the differences in the reported LCOEs from over 100% in some technology categories to around 10% in most cases. Given various projection techniques used by the five studies it is possible to conclude there is considerable convergence of views in relation to energy technology development potential.

For the whole technology set the harmonised projected cost of electricity generation technologies is between $71/MWh and $421/MWh in 2015 and $60/MWh and $222/MWh in 2030. Several conclusions can be drawn from this analysis:

- Electricity will cost more in the future, with or without the uptake of low emission technologies. This is because the LCOE of new and replacement technologies is higher than prevailing electricity market prices. (Even the lowest end of the projected range ($71/MWh) is around 50-90% above current wholesale (energy only) electricity prices in Eastern Australia.) While LCOE costs cannot be equated to prices generated by a market, nonetheless, the comparison demonstrates that higher market prices will be required to bring forward investment in new capacity. The cost of electricity generation plant has increased globally over the past few years.
- Australia has a wide variety of electricity generation options that may be commercially viable (although most low emission technologies will require market interventions such as the Renewable Energy Target to be adopted commercially).

- Australia will need a mix of technologies since each state has a different set of resource endowments and climatic conditions.
- Operational characteristics of each technology, such as the intermittency of some electricity generation technologies and the slow or inflexible ramp rates of others will also create the need for a mix of technologies rather than ‘silver bullet’ solution. There are significant opportunities for synergies amongst the technology sets.

1.3 Implications for Australia

Australia must examine social, technological and economic drivers to understand the range of technologies which may be suitable for our future energy mix. There are a broad range of technological opportunities for reconfiguring the electricity system. However no single technology can address all of Australia’s needs. Indeed many technologies are viable within a given cost and operational range. As a consequence, local resource conditions and synergistic benefits such as flexibility/intermittency pairing and social acceptance will all play a role in determining the likely future mix in any region and across the system as a whole.

The challenge for Australia, therefore, is how to realise technological change while still allowing energy investors to obtain a return on their investment and providing energy at a competitive price for industry and householders. Business, government and the research community are partnering locally and globally to invest in cost reducing research, development and deployment and also working to address the social acceptability of some technologies.

However there are some significant barriers. For some technologies the scale required for demonstration adds significantly to the cost Another major concern is that it is often unclear what role Australia can play in reducing technology costs relative to the global research effort. While we benefit substantially as a nation from global technology development ‘spillover’ effects which can occur through global collaborations, CSIRO research demonstrates that local technology development does play a role in reducing local component costs. Australia will also receive other benefits such as reduction in per capita emission levels and contribution to global effort.

The complex interplay of factors – social and technical; global and local; intermittent with non-intermittent technologies –lead to some level of confusion about how various technologies compare, what they cost and what is required to advance them to a stage of being a significant part of Australia’s future energy supply. The challenge for all energy sector stakeholders is to develop more integrated road mapping approaches that address this whole range of complex drivers in delivering a sustainable energy future.

2. INTRODUCTION

The *Australian Energy Resource Assessment* has demonstrated that Australia has an abundance of different energy resources (Geoscience Australia and ABARE 2010). State of technology development and cost are the key factors that will determine how successfully we exploit this resource endowment. These factors will be amongst the main determinants of the future cost of electricity.

This report, commissioned by the Department of Resources, Energy and Tourism, addresses the prospects for technology development and deployment in three ways. First, Section 3 of this report qualitatively assesses the development stage of each of the key renewable and fossil energy technologies groups. For each technology, or groups of technologies, this report summarises the:

- Technology Description
- State of Development
- Technology Strengths and Challenges
- Priorities for Further Development and Demonstration

The descriptions include both existing and potential technologies that might be deployed in Australia and does not assess the role that the technology might deliver in the overall future energy mix. It is not intended to be an exhaustive list and is restricted to technologies that could be introduced into Australia from now up to 2030.

In Section 4, the report synthesises the projected levelised costs of electricity generation from different technologies. Electricity generation capital and fuel cost projections and technology performance are essential to understanding the cost of lowering greenhouse gas emissions in the electricity sector over time. A variety of international organisations publish levelised cost projections on a regular basis. In Australia publications of this type tend to be more *ad hoc* although several have appeared in the last 18 months. Section 4 provides a discussion of the observed differences surrounding the underlying data assumptions behind levelised cost of electricity (LCOE) projections from five available studies. The studies were selected on the basis that they cover a significant number of electricity generation technologies. The authors of the reports are ACIL Tasman (2010), Hayward et al. (2010)[1], EPRI (2010), IEA (2010) and US DOE (2009).

The report summarises a substantial body of data which may be of use to other research. Accordingly we have provided data appendices.

[1] Hayward et al. (2010) will be referred to as CSIRO (2010) in the body of the report.

3. TECHNOLOGY OPPORTUNITIES

3.1 Introduction

The following technology overview presents summaries of the conversion (energy resources to power/fuel) technologies that align with Australia's resource endowment.

For each technology, or groups of technologies, the technology summary sheets are laid out under the following headings:

- Technology Description
- State of Development
- Technology Strengths and Challenges
- Priorities for Further Development and Demonstration

The descriptions include both existing and potential technologies to 2030 and concentrate on the technology rather than the role that the technology might deliver in the overall future energy mix. It is not intended to be an exhaustive listing.

3.2 Coal Power

3.2.1 Conventional Coal Fired Electricity Generation

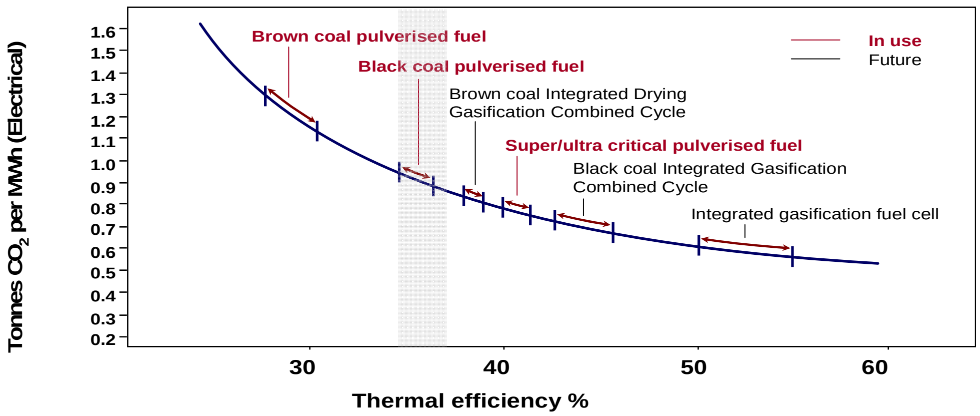
Technology Description

The current principal technology for coal-fired electricity generation involves combustion of pulverised coal in boilers that raise steam for turbine electricity generation. Efficiencies vary significantly, from 20% to more than 40%, depending upon the coal used and the specific design of the power plant. This results in CO_2 emissions in the range 800-1400 $kgCO_2/MWh$, respectively. Efficiency increases with increasing steam temperature and pressure and the sequence is often referred to as sub-critical, super-critical and ultra-supercritical steam conditions. Ultra-supercritical pulverised fuel (pf) boilers offer the potential of over 45% efficiency (700-750 $kgCO_2/MWh$).

A newer technology, which also has a higher efficiency (>40%) than sub-critical pf boilers, is Integrated Gasification Combined Cycle (IGCC). Here coal is reacted at high temperatures and pressures with oxygen and steam to convert coal to synthesis gas (syngas), predominantly a mixture of Hydrogen (H_2) and Carbon Monoxide (CO). The syngas is combusted in a high efficiency combined cycle system, which comprises a gas turbine driving a generator. The hot exhaust gas from the gas turbine raises steam for a steam turbine operating a second generator.

Supercritical and ultra-supercritical pf boilers and IGCC systems without Carbon Capture Storage (CCS) are sometimes referred to as cleaner coal technologies, but are not generally considered to be Clean Coal Technologies (CCTs) since there are limits to the reduction in GHG emissions to the atmosphere that can be achieved with higher efficiencies alone (Figure 1).

Figure 1: Thermal efficiencies and carbon dioxide emissions from various coal-fired power generation technologies (without CCS). Technologies in red indicate those currently in use, whereas those in black are still to be deployed in Australia. Modified from (Smith and Kelly, 1990).



State of development

Supercritical technology is readily available and most new coal-fired plants are built using this technology. The development of ultra-supercritical pf plants depends on improvements in materials technologies and the integration of high temperature/pressure materials into the newer plants.

There are six demonstration scale coal-fired IGCC power stations operating in the USA (2), the Netherlands, Spain, the Czech Republic and Japan. The first of these was operational in 1994, and the plants have outputs ranging from 250-400 MWe. Although most of these first-of-a-kind plants were established with capital subsidies, they are now operating commercially in their respective power systems. All use variants of the leading entrained flow gasification technologies, except the Czech Republic's Vresova plant, which uses a number of fixed bed gasifiers. Some of these plants are also being used as the basis for further technology development and demonstration projects for advanced syngas cleaning, processing and CCS.

While the use of gasification for power generation is relatively new, gasification is a mature technology used in approximately 140 gasification plants (with more than 400 gasifiers) in the chemical, refining and fertiliser industries worldwide. World gasification capacity is projected to grow by about 70% by 2015, 80% of this growth will be in China, which has built 29 new plants since 2004. These industrial plants are not producing power commercially, however many include the necessary technology steps for CO_2 capture and resultant hydrogen production.

There are currently no commercial or demonstration scale IGCC plants operating with CCS. The key challenges for deployment of commercial IGCC power generation with CCS are improving the cost effectiveness of the unit operations required for CO_2 capture and storage from power generation.

Technology Strengths and Challenges

Pulverised fuel (pf) technology is readily available and currently is the cheapest large scale electricity generation process. IGCC without CCS is approaching commercial viability and it can have a small efficiency advantage over pf, although advances in materials allowing higher stream conditions may limit this advantage in the future.

Both technologies are approaching efficiency, and hence GHG emission intensity, limits. To achieve lower GHG emissions and reach near-zero emissions will require CCS.

Priorities for Further Development and Demonstration

Further development is limited, particularly in GHG emissions from conventional coal fired electricity generation. There will be some increase in efficiency from ultra-supercritical developments in pf and engineering/learning experience in IGCC and both will result in small reductions in GHG intensity.

The next stage in the development of coal-fired power generation will be the capture of CO_2, which imposes an increased energy load and loss of process efficiency. Recovering these penalties through targeted efficiency increases is a priority.

Another step in the process is to develop coal fired plants in a 'capture ready' state. This will require considerable engineering changes to conventional designs. Location - as an investment decision variable - will gain increasing significance to minimise future transportation costs of the captured CO_2. In addition, 'capture ready' still needs to be appropriately defined.

3.2.2 Clean Coal Technologies (CCT)

Technology Description

Large-scale CCS has the potential to significantly reduce greenhouse gas (GHG) emissions from coal-fired power stations.

A CCT can be defined as a technology that comprises:

- Energy conversion processes where coal is utilised to produce heat which in one form or another is used for power production;
- Separation and capture of the CO_2 (as a supercritical fluid) from the product gases; and
- Transportation and permanent storage of the CO_2, usually in suitable geological formations.

The latter two components are often referred to as carbon capture and storage/sequestration (CCS), but are quite distinct and different, but dependent, technologies.

Clean Coal Technologies (CCTs) are usually classified by their pre- and post-combustion CO_2 capture techniques.

Pre-Combustion Capture

An example of pre-combustion CCT is IGCC with CCS (Figure 2). Here, coal is gasified in air or oxygen. The syngas produced in the gasifier is cleaned and reacted with water to produce more H_2 and convert the CO to CO_2 (water-gas shift reaction). The CO_2 is separated for storage and the H_2 is used for power generation via a combined cycle gas turbine plant. The combustion product of H_2 in the gas turbine is predominantly water vapour. The ZeroGen[2] project in Australia is an example of this technology.

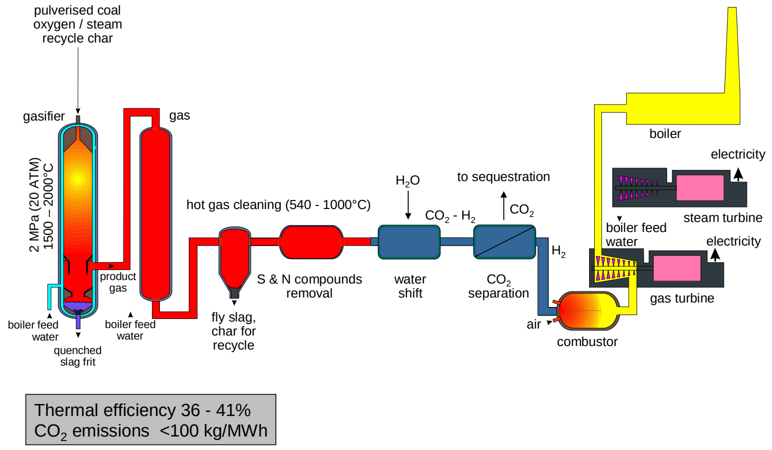


Figure 2: Integrated Gasification Combined Cycle (IGCC) with carbon capture and storage/sequestration (CCS)

Post-Combustion Capture

The most advanced post-combustion capture process uses a chemically reactive solvent to capture CO_2 from power station flue gases. The CO_2 is subsequently removed from the absorbing solution at higher temperatures using steam, allowing the absorbing solution to be used again for capture. The CO_2 is subsequently compressed to a "liquid" state and transported to an underground storage location.

[2] ZeroGen: Smarter Cleaner Power http://www.zerogen.com.au/

An example of a post-combustion CCT is conventional pf boiler technology with integrated post combustion capture (PCC) technology. CO_2 is captured from the flue by a sorbent and subsequently separated (stripped) from the sorbent before being compressed to a supercritical fluid for transport and sequestration (Figure 3).

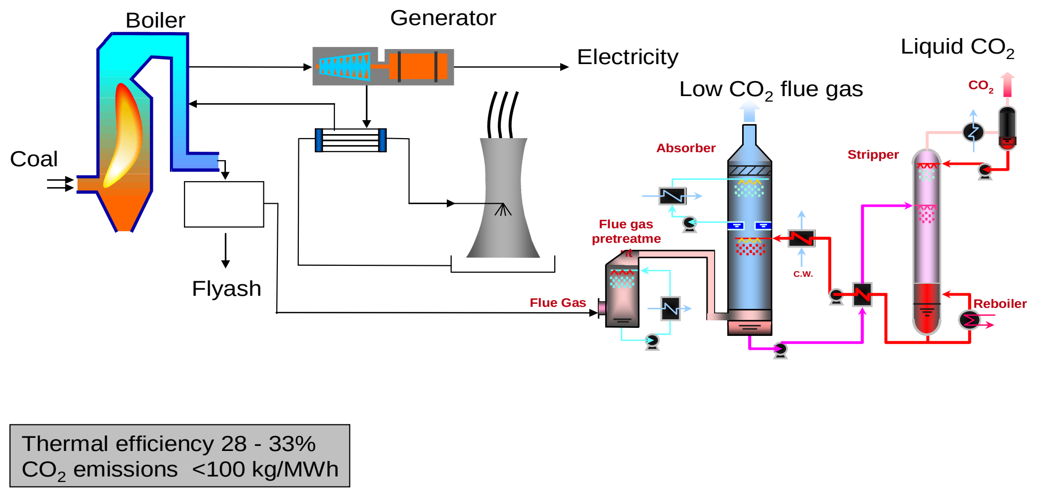


Figure 3: pf Boiler with PCC

Another example of post-combustion CCT is oxygen fired pf boiler technology. Coal is combusted with oxygen and re-cycled flue gas in a pf boiler. The flue gas produced contains mainly CO_2 and water vapour. It has small amounts of nitrogen present and, in principle, should be suitable for storage without further treatment or separation (other than drying) before compressing it to a supercritical fluid for disposal.

State of Development

Post-Combustion Capture

The core technology for PCC, gas/liquid absorption based on a solvent chemically reactive to CO_2, has been available for 75 years. It has been commercially applied for the production of CO_2 for food and industrial applications and in enhanced oil-recovery. The large scale and integrated application in power plants has only been considered relatively recently as a means of large scale mitigation of CO_2 from power plants. PCC technology development is now rapidly expanding with more than 20 small scale pilot plants (50-2000 kg/h CO_2) in operation or under construction at various power plant locations globally. The main suppliers of PCC technologies are Fluor, Mitsubishi Heavy Industries, HTC PureEnergy and Cansolv (now Shell), with all major power plant equipment suppliers (Alstom Power, Siemens, Toshiba, Babcock & Wilcox, Aker Clean Carbon and Hitachi) involved in development of PCC technologies. It is a key technology that can potentially reduce CO_2 emissions from existing and future coal-fired power stations by more than 80 percent. However, it has not been demonstrated at large scale, nor has it been fully integrated into power plants at any scale. Large scale demonstration plants including CO_2 storage are expected to start operation in 2012, with an aim to have the technology commercially available by 2020.

In Australia, a broad program of technology assessment and supporting research is being conducted[3], and includes pilot plants in Victoria (Loy Yang Power), New South Wales (Delta Electricity),

[3] Demonstration in Australia. http://co2crc.com.au/print.php?id=demo/ausprojects.htm

Queensland (Tarong Energy) and Victoria (International Power). These research programmes are providing options to reduce the cost of the PCC process in the medium term.

Technology Strengths and Challenges

The principal disadvantage of PCC processes is the additional equipment and operation of the necessary gas separation and handling processes. In pf plants this involves separation of CO_2 (at about 12-14% concentration) from the flue gas. Oxygen fired plants require large volume oxygen separation. Both require additional plant and consume energy that reduces the overall plant efficiencies. Not all pre-combustion technologies require the use of oxygen, and instead are air blown with proposals to include CO_2 removal prior to the gas turbine. This variation still involves the processing and handling of inert gases.

IGCC-CCS has the advantage that the syngas produced can also be used for co-production of power, fuels and chemicals. It is also the only practical technology path for converting coal to large scale hydrogen production. In addition to product flexibility, the technology also has the advantage that CO_2 capture can be added incrementally as technology and market requirements develop.

The pf boiler-PCC technology has a number of potential advantages. It can be retrofitted to existing power plants and integrated into new super or ultra-supercritical power plant. The technology has high operational flexibility offering partial retrofit and flexible operation from zero to full capture over relatively short timeframes. . This is particularly important as it provides the opportunity to adopt the technology subject to commercial conditions.

Oxy-firing can also be retrofitted to existing plants[4].

The challenges are that the pf boiler-PCC technology requires the capture of CO_2 from 'dirty' flue gas containing particulates, oxides of nitrogen, sulfur and oxygen. Oxy-fired plants in Australia will also require gas cleaning processes to manage sulfur and nitrogen oxides which could otherwise progressively reduce the effectiveness of the chemical used to recover the CO_2. In both cases plant operation requires additional power which lowers the efficiency of the overall processes, effectively requiring more coal per unit of power produced compared to non-CCS power generation. This is also the case for IGCC processes.

Priorities for Further Development and Demonstration

Development priorities vary greatly with the technology. For PCC, increasing the capture efficiency and reducing the capture energy by the development of advanced solvents and engineering systems is essential. For IGCC/CCS, development of more cost effective systems and materials for the cleaning and processing of dirty coal gas (synthesis gas) is required. This includes the development of innovative solutions (e.g. membranes) for high volume separation of CO_2 from hydrogen (H_2).

For both oxygen-blown IGCC/CCS and oxy-firing, reductions in the cost of large-scale oxygen production would offer a significant advantage.

So far, there has not been any demonstration of a complete, integrated CCT/CCS process and this is a priority for the technology.

[4] Callide Oxyfuel Project Fact Sheet
http://www.csenergy.com.au/_CMSImages/csenergy/pdfs/080821Oxyfuel_facts.pdf

3.2.3 Future High Efficiency Coal Technologies

The current focus in developing the Clean Coal Technologies (CCTs) described above is to use CCS to reduce GHG emissions. These technologies are critically important for the intermediate term. However, to achieve the necessary CCS from coal-fired, stationary power generation, the amount of CO_2 to be captured and stored will be very large.

Part of the problem is that CO_2 capture results in an energy penalty which reduces the output of power plants by up to 25% (depending on the technology and starting efficiency of the plant). This energy loss further increases the amount of CO_2 to be captured and stored. A global CCS industry would be expected to approximate the current global oil and gas industry in size. In addition, there is uncertainty concerning the availability of suitable geo-sequestration sites that are within practical distances of present and future power generation plants.

Over the longer term, new technologies could be developed to increase the efficiency of coal -fired power generation significantly above the levels of current 'best practice' technologies. This would reduce the magnitude of the GHG intensity of the plant and hence reduce the amount of CO_2 that must ultimately be stored.

Technology Description

A number of ultra high efficiency technologies have been identified that have the potential to significantly increase coal fired generation efficiencies over current technologies.

Direct Injection Coal Engines (DICE)

One option is based on the Direct Injection Coal Engine (DICE) – large diesel engines modified to use coal-water fuels. Used in relatively smaller applications, these highly efficient heat engines (>50%) could support the development of renewables by providing cost effective and efficient backup and provide benefits through decentralisation of generation plant (through reduced power transmission losses). PCC can be combined with DICE to achieve the final reduction in GHG intensity. In this application, the energy penalty for CO_2 capture can be reduced by utilising waste heat in the capture process from the coal engine (Wibberley, 2007).

Direct Carbon Fuel Cells (DCFC)

Another technology in the early stage of development is the Direct Carbon Fuel Cell (DCFC) that could offer conversion efficiencies of up to 80%.

Power is generated by elemental carbon particles (immersed in molten electrolyte) and atmospheric oxygen. Fuel is made by thermally decomposing coal at low temperatures yielding very reactive carbon and off-gas[5] rich in hydrogen and simple hydrocarbons. Flue gas from the fuel cell itself is near pure CO_2, thus avoiding the need for capture.

While DICE technology could be commercially available within a decade, DCFC technology is unlikely to be available for large scale power production for several decades.

[5] Off-gas is gas off given during a chemical process

Integration of Renewables into Coal Fired Power Stations

The focus of this research is exploring the potential for integration of renewables, particularly high temperature solar thermal, into pf boiler power stations so that some of the energy input would be derived from solar energy. Hence, while maintaining the power station output, a proportion of the heat provided from combustion of coal may be replaced by steam provided by high temperature solar thermal processes. This will substantially reduce the greenhouse gas emissions of the plant. An example of this approach is the use of solar to boost the output of an existing coal-fired plant in the Hunter Valley[6].

CO_2 output from coal fired power stations can also be integrated into algal production facilities to enhance growth. Biofuels are discussed in more detail below.

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[6] Project Proposal for a Compact Linear Fresnel Reflector Solar Thermal Plant in the Hunter Valley. http://solar1.mech.unsw.edu.au/glm/papers/Mills_projectproposal_newcastle.pdf

3.2.4 Geological Carbon Dioxide Storage

Technology Description

Geological carbon dioxide storage is the process of injecting high-pressure CO_2 into deep saline aquifers, depleted oil and gas fields, or unminable coal seams. This process seeks to mimic natural accumulations of CO_2 that have existed underground for geological time periods in both porous sandstone reservoirs and coal seams. Figure 4 illustrates generic production, transportation and storage[7].

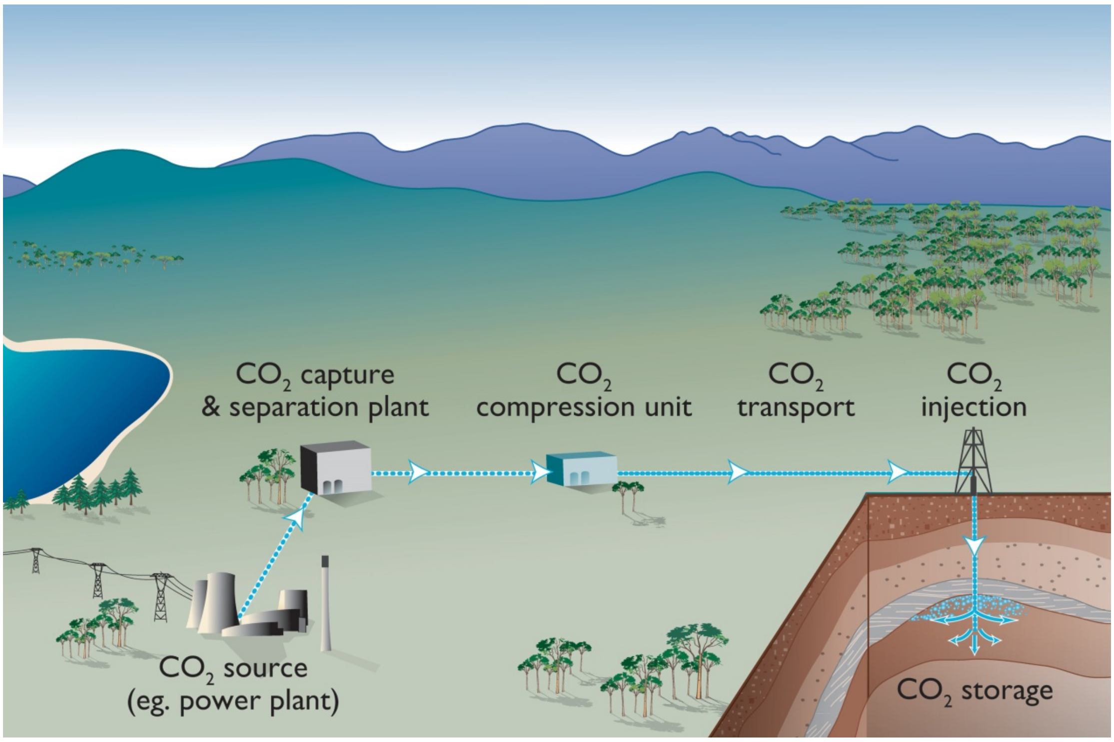


Figure 4: A simplified over view of the geosequestration process. © CO2CRC

State of Development

Geological carbon dioxide storage is actively being undertaken at several sites around the world, with the most notable being the Sleipner site in the North Sea where around one million tonnes per year has been injected for more than a decade. In Australia there is a demonstration project, the CO2CRC Otway Project[8], where more than 60,000 tonnes of 90%CO_2 (by weight) has been injected into a depleted gas reservoir since March 2008. This depleted reservoir is in a sandstone formation 2 km below the surface. Plans for large-scale storage have been developed for other sites in Australia, most notably the Gorgon Liquefied Natural Gas (LNG) project[9].

[7] CO2CRC Image Library. http://www.co2crc.com.au/imagelibrary
[8] CO2CRC Otway Project Overview. http://www.co2crc.com.au/otway/
[9] Massive Gorgon project gets signoff http://www.theajmonline.com.au/mining_news/news/2009/september/september-10th-09/gorgon-set-to-be-world2019s-biggest-co2-storage-project

Technology Strengths and Challenges

The technology for geological carbon dioxide storage adapts technology used in the petroleum industry, and experience from decades of injecting carbon dioxide for enhanced oil recovery, mainly in North America. The challenge for geological storage is demonstrating and verifying security over timescales well beyond industry experience, although observations of natural analogues provide a level of confidence. Challenges tend to be site specific as the local geological environment can vary greatly. Figure 5 shows areas that are prospective for CO_2 storage[10].

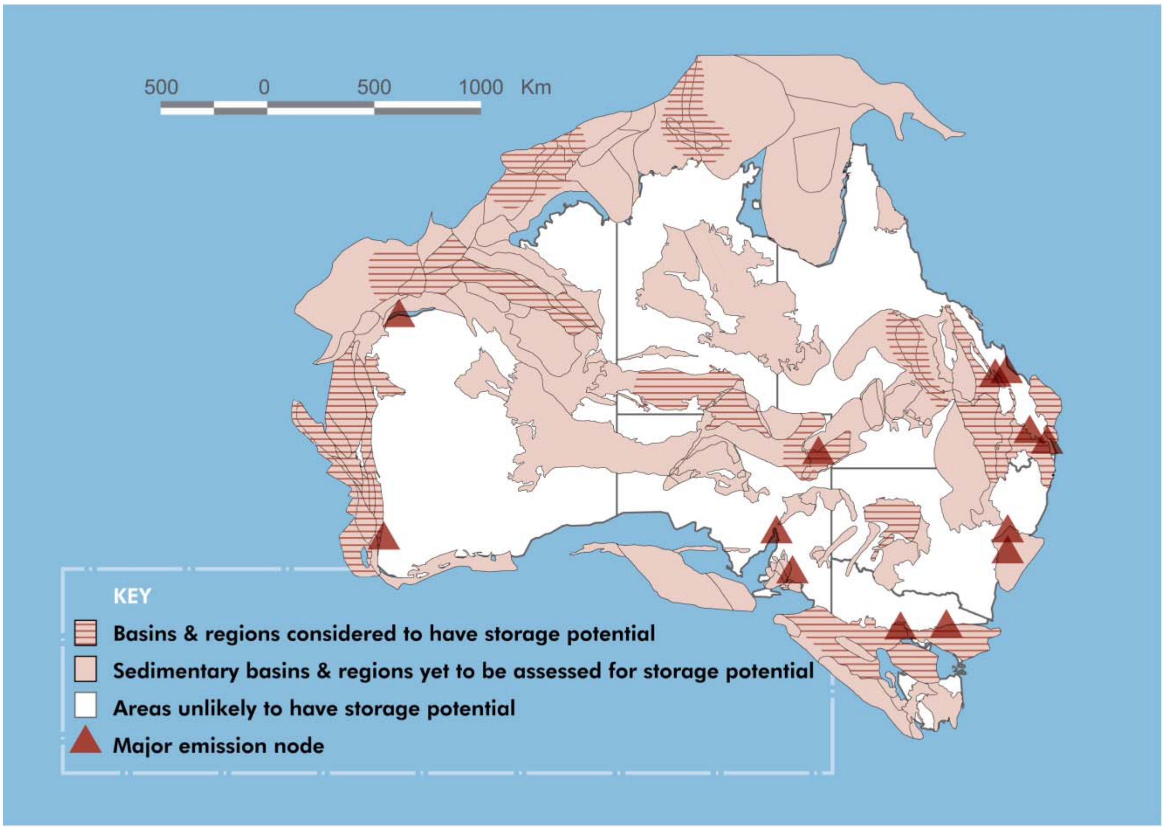


Figure 5: Australian basins and regions considered to have CO_2 storage potential © CO2CRC

Priorities for Further Development and Demonstration

A priority is to establish combined capture and storage. Each of these technologies has been proven independently but not in combination within a power generating system at commercial scale. At the storage end this requires exploration and appraisal similar to petroleum exploration and appraisal to define sites. The development and exploitation of various trapping mechanisms is also a priority to prove the security of stored CO_2 in a wide variety of geological environments. The selection of sites and the accompanying long-term monitoring requirements need to be tailored to fit within the economic constraints to make CCS viable.

[10] CO2CRC Image Library. http://www.co2crc.com.au/imagelibrary

3.2.5 Underground Coal Gasification

Current Australian conventional mining technologies are currently accessing only the higher quality or easily-accessed coal deposits, often limited to sites close to transport and other infrastructure. As a result of this there are many billions of tonnes of coal in Australia that are not currently exploited (due to depth, quality, technical or other economic reasons) that could provide feedstock for underground coal gasification (UCG), if the technology can be proven to perform reliably within acceptable environmental and operational parameters. The coal quality guidelines for underground coal gasification are quite broad and almost anything that is classified as coal is suitable. However, seam thickness needs to exceed 1 metre for self-sustaining operation and thicknesses greater than 5 metres are recommended for performance comparable to conventional surface coal utilisation. There are numerous other geological factors which influence the performance of the technology at specific sites, so a detailed assessment needs to be made before suitability can be confirmed. To date, there has not been a comprehensive analysis of the full scope of coal resources in Australia that are suitable for UCG technology. A study by Stewart (1984) indicated approximately 2.8 billion tonnes of coal were suitable in the existing mining areas of the Newcastle Coal Measures in New South Wales (NSW), Ipswich Coal Field in Queensland (Qld), Collie Coal Field in Western Australia (WA) and Leigh Creek Coal Field in South Australia (SA). Notably, this neglects resources in Surat, Galilee and Tarong Basins (Qld), Walloway and Arckaringa Basin (SA), Gippsland Basin (Vic), Perth Basin (WA) and off-shore deposits (NSW) that have either active projects or proposed operations by one or more companies that have publicly stated an interest in using the technology in Australia. While it is difficult to accurately determine the quantity of coal that is suitable in these due to limited exploration information, a World Energy Council (2007) report estimated that 44 billion tonnes of coal in Australia could be suitable for UCG, based on an estimated proportion of Australia's recorded coal deposits that are likely not to be suitable for conventional underground mining. Given this scale of resource, it is likely that the environmental impacts of large operations are likely to limit the scale of adoption to a greater extent than the availability of suitable coal.

Technology Descriptions

In basic terms, underground coal gasification covers any technique that reacts the coal in situ underground to produce a gaseous product. In the past this has included the use of conventional mining to construct the reactors underground and this approach is still being used in China. However, in an Australian context, the technology that is most likely to be applied would use a series of wells drilled from the surface to the coal seam. These can be conventional wells drilled vertically or directionally drilled wells that use steering devices to curve the well into the desired shape, typically running along the lower part of the coal seam.

For a single gasifier operation, the coal between two wells is ignited and an oxidant gas is injected into one well to maintain partial combustion of the coal and the product gas is extracted from the other well. The product gas typically has high concentrations of hydrogen and carbon monoxide, plus methane, carbon dioxide and other gases. The exact composition of the gas is a complex issue involving chemical kinetics and heat transfer, but will depend on factors including: coal properties; gasifier design; oxidant quality; groundwater availability; and operating pressure. Typical uses of coal gasification product gas include the synthesis of chemicals, such as ammonia, methanol or even liquid fuels, but it can also be used as a fuel gas for power production via boiler or gas turbine power plants.

State of Development

Experimentation with underground coal gasification has occurred worldwide since the 1930s with the bulk of experience being in countries of the former Soviet Union (USSR). Several large-scale sites have operated in Russia, Ukraine and Uzbekistan. A plant currently in operation at Angren in Uzbekistan has operated since the 1960s and has provided fuel gas to a neighbouring power station. Experimental trials in the USSR covered a wide range of coal deposits with varying properties, providing a significant quantity of analytical data. Other large experimental projects have occurred in the United Kingdom, the United States of America, Canada, China and Western Europe since the late 1940s. The global experience to date provides a strong basis for the analysis of site suitability, technology, well arrangement design and operating parameters, including minimising environmental disturbance. Currently, the emphasis has shifted from research efforts to development, with numerous companies worldwide attempting commercial development of UCG projects (Beath 2009).

To date, three pilot-scale operations have been conducted in the Surat Basin, Qld using technology variants. Linc Energy, a pioneer of the worldwide growth in the technology, started a demonstration plant in late 1999 based on Soviet technology supplied by Ergo Exergy. This has since been modified by a new technology provider Yerostigaz, the operator of the Angren site, and has been used to supply feed-stock to a small synthetic liquid fuel plant. Stated objectives for Linc Energy are a 100,000 barrel per day plant in South Australia and a 20,000 barrel per day plant in Queensland based on UCG, although additional electricity generation plans incorporating fuel cell technology have also been proposed. A second operator, Carbon Energy, has demonstrated a different technique based primarily on a directional drilling approach developed during trials in the USA in the 1980's. They have stated a mixture of objectives ranging from synthesis gas for ammonia and methanol production to fuel gas for small to large power generation in Queensland. Another company, Cougar Energy, has had a brief demonstration that ended with well failures that used technology support from Ergo Exergy. Their plans are for large scale power generation using a gas turbine power plant.

Linc Energy, Carbon Energy and Cougar Energy all have prospective developments in other states and internationally, plus there are a number of other Australian companies with less mature plans for Australian and international sites.

Overseas there has also been interest in UCG Eskom in South Africa has a long-running small trial and has proposed a large plant for power generation. In China, ENN Group has operated a demonstration plant for methanol synthesis and Xinwen Mining Group has several plants producing town gas for domestic usage. New Zealand coal miner Solid Energy has recently announced a NZ$22 million pilot plant to test the technology as a provider of feedstock for a broad range of chemical production processes. Sasol in South Africa has proposed a demonstration plant to provide a small flow of synthesis gas to their large coal to liquids plant. Several companies in the United Kingdom, parts of Europe, the United States of America and Canada are also attempting to get developments underway. Notably, Swan Hills Synfuels in Canada has announced a deep coal demonstration aimed at proving the potential for combined synthesis gas production and carbon dioxide sequestration and a large collaborative European Union-funded research project, HUGE, is attempting to get a demonstration of a new form of the technology in Poland for hydrogen production.

Technology Strengths and Challenges

UCG has a long history of experimental trials and some large-scale operations worldwide which have generated a large quantity of published data on operational performance under different conditions and details of problems that occurred during operations. Analysis of this can assist modern operators in selecting suitable sites and operating methods to optimise performance. Improvements in the accuracy and reliability of modern drilling and remote monitoring equipment should also assist in making the plant easier to construct and operate. However, the major commercial driver for the technology is the reduction in capital cost compared to construction of conventional gasification plant. When the technology is matched to a good quality site, this has the potential for high efficiency fuel gas to be produced that could be used for the provision of low emission electricity or chemicals at relatively low cost. There is also a good match between the product gas properties and conventional gas cleaning technologies that means that carbon dioxide can be removed with minimal energy consumption compared to higher temperature conventional coal gasification (Beath, et al. 2004).The major challenges of underground coal gasification relate to uncertainty in the geological environment and how this will impact on the operational and environmental performance. Despite improvements in remote sensing instrumentation, it is still difficult to ensure that there is an accurate understanding of the underground environment at a specific site. Coupled to the operation of a high temperature reactor in this environment, this leads to the possibility of unexpected geological responses that can result in failure of equipment and loss of gas into the surrounding strata. This can cause loss of operating efficiency, but also may result in contamination of groundwater resources with toxic organic materials. It appears that the only reliable method of verifying the suitability of the technology for a given site is the operation of a trial, but even then subsequent larger scale operations could develop problems. Current best practice is to avoid the use of sites that are near sensitive groundwater supplies in order to minimise the impact of plant failure. The use of deeper coal seams has also been proposed as a method of minimising the risk of environmental impact, as deep groundwater is less likely to be used and subsidence impact is likely to be reduced. Proof that long-term large operations can be operated reliably and efficiently is necessary to validate the technology and provide justification for its use relative to other forms of resource utilisation (Beath 2009).

Priorities for Further Development and Demonstration

Currently, UCG is proceeding through a commercial demonstration phase at a number of sites in Australia and worldwide. Current commercial drivers appear to favour coal seam depths of between 100 and 300 metres due to the acceptability of drilling costs. However, it is likely that the benefits of the technology will be improved through the use of deeper coal seams. Combinations of environmental and operational benefits mean that it is likely that long-term viability of the technology relies upon the proving of reliable construction and operation at depths greater than 300 metres. As these coals are less likely to be economically extractable using conventional technologies UCG could provide a technology to increase the scale of coal resources that can be readily used. A long-term commercial operation with a saleable product is needed to verify that consistent product gas can be produced without unacceptable environmental impact. This would provide a testing facility for improvement of techniques for the use remote sensing equipment to monitor and control the operation at optimal performance.

3.3 Natural Gas/Coal Seam Methane

3.3.1 Technology Description

Natural gas use in Australia is growing rapidly. In April 2010, 57% of committed new power generation projects were natural gas-fired, vs. 9% black coal-fired[11]. However, significant technological and commercial hurdles need to be overcome if the potential for natural gas to substantially reduce Australia's GHG emissions is to be realised. These hurdles have distinctly Australian dimensions, demanding local solutions.

Resource Availability

Australia's gas resources are second to coal in years of supply at current production rates. The significantly lower GHG emissions from gas as opposed to oil or coal could offer immediate carbon pollution reductions. The rate of uptake of gas will depend on its availability at a sufficiently

[11] ABARE, Major development projects – April 2010 listing.

competitive price compared to alternative energy sources, taking into account penalties (carbon price or carbon tax) for greenhouse gas emissions.

3.3.2 State of Development

Our gas industry differs sharply between the east and west of the country. More than 90% of our conventional gas reserves (estimated conventional gas reserves are 180,500 PJ) lie offshore in the northwest in challenging deepwater environments with relatively high production costs(Geoscience Australia and ABARE, 2010). This gas supply is an important source of energy to Western Australia (WA) (including for power generation) and supports our current liquefied natural gas (LNG) exports.

Higher gas prices in WA are encouraging the development of tight gas resources closer to the Perth market as well as greater levels of exploration in prospective sedimentary basins. Successful exploration and development would improve domestic gas security. Given the specific geology of WA, there remain technical challenges to the development of tight gas resources which will need to be overcome.

In contrast, south-eastern Australia holds less than 10% of current reserves. Its future lies in unconventional gas, especially coal seam gas (CSG). This resource is large and its associated industrial base is developing rapidly.

Optimal CSG exploitation requires a much better understanding of gas distribution and mapping of prospectivity where co-located high gas saturation and permeability can produce large volumes of deliverable gas. Water treatment and disposal will become increasingly significant in CSG production. The volumes of gas required, and the volumes of water produced by converting CSG resources to LNG increases both the magnitude and the importance of these challenges, particularly given the quantities of LNG production required for a commercial LNG operation.

3.3.3 Technology Strengths and Challenges

Australia may have significant but as yet unquantified gas resources in low permeability tight and shale reservoirs. Pre-competitive science could better delineate these resources and produce technologies for future production.

Other potential applications for gas may result from further technology development, such as:

- Using gas as a feedstock for synthetic fuels, either as fuel in its own right or as a blending stock;
- Using gas directly as a transport fuel, as LNG or Compressed Natural Gas (CNG);
- Using gas in micro-generators in a smart electricity grid, reducing the need for peak load power generation and its associated transport infrastructure.

The potential to use gas directly to replace electricity needs careful study to optimise the investment in and deployment of electrical and gas transport and distribution networks.

The gas industry also has the potential to use its knowledge and technologies, which underpin CO_2 storage in conventional and unconventional reservoirs. Given the potential of carbon capture and storage, continued gas exploration and production research could contribute to the knowledge base for CO_2 storage.

3.3.4 Priorities for Further Development and Demonstration

Support for an Australian gas technology and services industry is an important element to ensure advances in technology are made available across the industry in Australia, and to generate wealth beyond the simple exploitation and export or domestic use of the resource.

Key technology issues in relation to each part of the gas value chain are listed below.

Exploration

Australia has good gas prospectivity. Australia has several under-explored basins, both onshore and offshore. There are many large undeveloped gas fields, and new gas discoveries are often remote from markets and difficult to commercialise.

Production

International oil companies will prioritise the development of their worldwide gas resources based on maximising returns and minimising risk. Sovereign risk, legal and regulatory processes, stability of the political and economic environment and technical cost and risk are all factors.

Reducing the cost and risk of production from conventional deep water reservoirs should be a key technology development focus for Australia.

Technologies for platform free fields (subsurface separation and processing), long deep water gas pipelines and offshore conversion are relatively new and need development or adaptation to Australian conditions.

Production of CSG and processing of LNG from it at the scale being proposed in Queensland brings new challenges. The CSG production process requires the drilling of thousands of wells. Whilst drilling technologies are mature, optimising CSG wells for production requires further development.

The production of salty organic-contaminated water in CSG production (at a rate of 10’s to 100’s of ML per day) requires cost and emissions effective treatment options. Water treatment technologies such as reverse osmosis are mature but are energy intensive. Development of more energy efficient water treatment technologies and processes at lower cost should be a key technology development area. Finding commercial uses for the by-products of CSG production (water and salt) needs further investigation.

Flaring of gas during production occurs in both conventional and CSG operations. The gas could be converted and used economically provided small conversion plants were available. This technology is at the early stages of development and needs further work. The same technology could be used to make production from smaller and / or remote gas reservoirs commercial.

Reduction of corrosion in production, transport and processing infrastructure is essential and further work is required to understand and limit corrosion.

Transport

Long, deep-water gas pipelines are key features of Australia’s northwest gas fields.

Deployment of pipelines can be expensive. Development of pipe laying technologies that reduce the cost of deployment could be considered. Some technologies exist but still require demonstration and piloting at commercial scale.

Operational issues such as hydrates formation can be costly as they either result in down time or require treatment of the gas being transported. Some research is taking place (e.g. hydrates loop at Australian Resources Research Centre (ARRC) in Perth, subsea pipelines for reliable and environmentally safe development led by UWA) and should continue. Other approaches that have a risk management focus should also be considered.

Conversion

Many of the gas reserves in Australia's northwest have a high CO_2 content. Technologies for the separation of this CO_2 from the gas exist, but efficiency improvements are possible. The technical knowledge for underground storage of CO_2 originated in the oil and gas industry, particularly the industry's work on enhanced oil recovery processes.

Long term carbon storage requires more rigorous operations. Significant improvement in our understanding of the CO_2 storage capacity and containment security of saline aquifers is essential for the industry. CO_2 monitoring and verification technologies are available and will require significant work to enable reliable deployment at scale under a number of conditions.

The basic LNG process is mature and efficient. There is scope to improve the efficiency of energy use in the facilities, including through cogeneration, utilising waste heat, increasing operating efficiency, better on-line control and higher efficiency compressors. Improvement of pre-treatment processes to remove CO_2 and water are also potential areas for development.

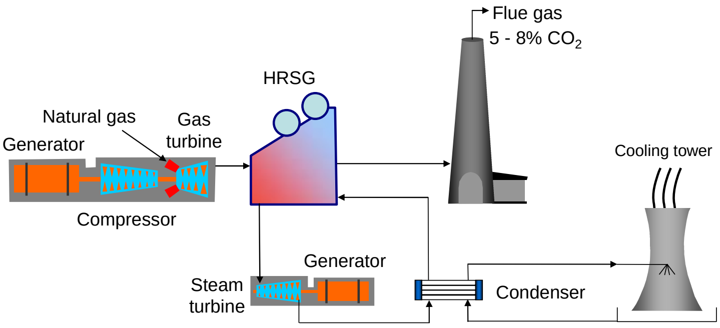
Floating LNG facilities (FLNG) will remove the need to transport gas to land for processing and liquefaction (and hence remove the pipeline issues), reduce the environmental impact and related approvals complexity, and as a result may reduce risk and costs. FLNG will face movement issues and there will also be a need to reduce the equipment footprint. Transfer of LNG to transport vessels in open seas and stability during cyclonic conditions also requires work. Some technologies exist in this area and the challenge is to integrate them into projects as a cost effective working solution. FLNG may require carbon storage options in the vicinity of the FLNG facility rather than at the LNG plant on-shore.

The basic CNG process is also mature and efficient and the issues are less pressing. CNG may be an excellent application for remote gas that would require the economic shipping range to be reviewed and maybe further process optimisation to reduce the cost of compression and transport.

The Gas to Liquids (GTL) process is a well understood two-step process to convert natural gas into fuels and other products, as described above.

End use

Baseload and peak power generation from natural gas uses turbine technologies that are mature and stable**.** Figure 6 shows a schematic of a conventional combined cycle gas turbine/generation system.



Operation Mode	Thermal Efficiency (%)	CO_2 Emissions (Kg/MWh)
Open cycle	35 - 40	480 - 520
Combined cycle	55 - 60	360 - 350

Figure 6: Schematic of gas combined cycle power generation

Carbon capture for gas fired power stations presents issues that are different to those from coal fired power stations. With the expected increase of gas-fired power stations in Australia there will need to be some focus on this aspect.

Gas and electricity transport and distribution networks both transport energy to end users. Generation of electricity using gas at the point of use may remove the transport and distribution losses associated with centralised electrical power generation. The use of micro turbines in distributed generation networks will reduce the peak power demand. The optimisation of gas and electrical power generation, including distributed generation, and the associated transport and distribution networks needs to be understood.

The introduction of gas powered cars with home refuelling may require significant technology development to enable the safe distribution and use of gas for this purpose.

3.4 Geothermal Energy

Australia's geothermal energy resources are a potential significant source of secure, renewable, low-emission baseload power for the future. Preliminary resource evaluation by Geoscience Australia has suggested that extracting just 1 percent of the energy from rocks hotter than 150°C and shallower than 5,000 m would yield approximately 190 million PJ of energy or about 25,000 times Australia's primary energy use.

During the last decade, interest in geothermal energy has increased significantly due to the increased research into Australia's geothermal resources and debate over climate change policy. As a result, there has been significant growth in the number of private sector companies seeking to produce geothermal energy in Australia. Industry is confident that a proof of concept Hot Rock development in Australia and demonstration of the capacity for commercial power generation is possible by 2012.

3.4.1 Technology Description

Australia's geothermal energy resources exist in two forms, which present different technical and economic opportunities and challenges.

Hot Rock Technologies

Hot Rock (HR), includes Hot Fractured Rock (HFR) and Hot Dry Rock (HDR) technologies. HR resources are found mainly in high heat producing granites. These granites accumulate heat from the decay of radioactive elements or from the absorption of heat from surrounding material. The temperature of these granites can reach 250°C - 300°C at economically drillable depths. Geothermal projects of this type will need careful development in order to be economically viable, especially when located in remote regions, as they generally require stimulation in order to produce a viable reservoir.

A feature of the resources in Australia's Cooper Basin, on the border between Queensland and South Australia, is extremely high fluid pressures. This has not been seen elsewhere in the world and it is unclear whether this will apply in other locations in Australia. This feature means that wells will self-discharge and no fluid has to be added, but it does present some unique challenges for well and surface plant design. More importantly, it means that the granite reservoir will be of overall higher permeability since the fractures are already pressured to a higher level.

A variation of the technology involves setting up of a fractured heat exchange zone above the granite called "Heat Exchange Within Insulator" (HEWI). This offers the potential advantages of shallower drilling, easier drilling in the overlying insulating sedimentary rock and potentially lower over pressure. The disadvantages are that the temperatures will be lower and the system still has to be tested at a pilot scale.

The HR geothermal resource in Australia is poorly understood in terms of location, quality and yield potential due to a lack of accurate data. Mapping has shown that the temperature at 5 km indicates potential sites in several areas across Australia. Further exploration and proof-of-concept investment is required to confirm these resources.

Over the past 35 years there has been considerable research into the use of engineered geothermal systems, notably in Europe, the USA and Japan. However, nowhere have such systems been brought into commercial production. While the core technologies exist and are available from the petroleum and conventional geothermal industries they will need to be adapted. In many respects, Australia is now leading the world in developing this technology.

Hot sedimentary aquifers

Hot Sedimentary Aquifers (HSA) are more ‘conventional’ forms of geothermal energy in that they exhibit naturally convective fluid systems. HSA resources tend to be shallower and cooler than the HR systems, but will yield large volumes of hot water without stimulation. The only existing geothermal power plant in Australia, at Birdsville in Queensland, uses HSA.

The Great Artesian Basin (GAB) is the world’s largest artesian groundwater basin, underlying about 22% of the Australian continental landmass. Groundwater from the GAB comes out at wellheads at temperatures ranging from 30°C to 100°C and, in most cases, has to be cooled before it can be used as town or stock water. The sheer size and temperature of the underground water resource makes it an attractive geothermal target.

Petroleum wells also often demonstrate prospectivity for HSA, and examples exist in the Otway Basin (Victoria and South Australia), Gippsland Basin (Victoria) and in the Perth Basin (Western Australia). The challenges in these systems are also economic, requiring incremental technological development rather than major technological breakthroughs. HSA systems have been used for 150 years, and there is a significant pool of knowledge globally. Further technology development is taking place as more plant is brought into production around the world.

Direct use

Direct heat use is one of the oldest, most versatile and also the most common form of geothermal energy utilisation. Examples include bathing, district heating, agricultural applications and desalination. Ground-source heat pumps use the earth or groundwater as a heat source in winter and a heat sink in summer, and operate with resource temperatures of 4 °C to 38 °C.

One benefit of this system is its versatility. Groundwater can be used for space or district heating, greenhouse heating, and water heating. Other uses, including use in desalination, are being developed.

3.4.2 State of Development

The Global Geothermal Environment

Geothermal energy has over one hundred years of successful development and deployment. In 2007, the total electricity generation capacity from geothermal sources around the world was 9,732 MW. The leading countries in terms of installed capacity are: the USA (25% world capacity), the Philippines (20% world capacity), Mexico, Indonesia, Italy, Japan, New Zealand and Iceland.

A report into the potential of HR geothermal energy, prepared by Massachusetts Institute of Technology, demonstrated that HR geothermal energy could support a generating capacity of around 100,000 MW by 2050.

Existing geothermal energy is 'conventional', in that it is usually based on hydrothermal aquifers commonly associated with volcanic systems. More recently, the potential of HR, or enhanced geothermal systems, has been recognised. Evidence suggests that Australia has very large HR potential, as well as some conventional geothermal resources.

3.4.3 Technology Strengths and Challenges

Australian resources require deep drilling to obtain access and are not associated with magmatic activity. For both HR and HSA systems, there is considerable work required on resource location and definition. However, valuable knowledge is available worldwide in 'conventional' geothermal developments and to a lesser extent in HSA developments. This information will need to be adapted to Australian conditions and circumstances.

Because of the lower temperatures of geothermal energy compared with fossil fuel combustion, it is not possible to extract as much energy using geothermal systems. The lower temperatures mean that there is less work-producing potential and lower heat to power efficiencies. Increasing the temperature and pressure can result in non-linear increases in the work-producing potential, which would make the systems more economic (MIT-led panel, 2006).

There are also a number of non-technical barriers and constraints to the use of geothermal energy. These constraints range from availability of resources to undertake exploration and scheme implementation through to environmental, cultural, energy market and fiscal barriers. There may also be significant regulatory challenges in the future usage of HSA resources, due to water restrictions. Technology is being developed to limit water use.

There are overlaps between technological and other constraints that cannot be divorced. Some problems such as the need for development of improved downhole packers – devices that are inserted into the wellbore and once inside expand to seal the wellbore - and measurement tools are technical constraints that will have to be overcome for the industry to be feasible. Other requirements, such as improving power plant efficiency will change the economic feasibility of projects and so have a large effect on what is considered economically viable resources.

3.4.4 Priorities for Further Development and Demonstration

To develop the geothermal industry the "Australian Geothermal Industry Development Framework" (Australian Government, DRET, 2008) made a number of recommendations:

- Increase investment into the geothermal industry

- Acquire and manage geoscientific data specifically for the geothermal industry
- Develop robust networks for the geothermal industry
- Develop international linkages and partnerships
- Research and development to support the Australian geothermal industry
- Human capital development
- Communication
- Understanding the policy environment and contributing to policy development
- Legislation and regulation
- Implementation

Some priorities for geothermal energy R&D include:

- Surface and subsurface studies, including subsurface imaging
- Optimisation of heat extraction and long term deliverability of heat for both low and high temperature applications
- The direct use of geothermal energy in heating, cooling and desalination applications
- Reservoir engineering including aquifers and fractured reservoirs
- Reservoir stimulation and fracture mechanics, including fluid flow modelling, monitoring and seismic risk assessment
- Novel drilling technologies including those for use in hostile environments and tools for working at high temperatures in wells
- Environmental implications associated with geothermal energy generation.

3.5 Hydro Power

3.5.1 Technology Description

Hydroelectricity is produced from the kinetic energy contained in falling water. The energy is captured by directing the water through turbines used to drive electricity generators. The three main types of large scale water turbines (>10MW) are; Pelton wheels, Francis turbines and Kaplan, or propeller-type turbines[12]. Small scale systems can be divided into three classes – small (1MW to <10MW), mini (100kW to <1MW) and micro (<10 kW)[13]. These systems use variations of the three main turbine types, known as impulse (Pelton and Turgo wheels for medium and high head applications) and reaction turbines (propeller types for lower head applications).

3.5.2 State of Development

Hydroelectric power is a mature technology and further development in turbines and generation technology is minimal. There is some development in the engineering and application of small to micro hydro power, and these improvements largely are concerned with site engineering and increase in efficiency of low-head applications. A recent study has found that there are 36 sites with a potential generation capacity greater than 1GWh/yr that could be installed without major inundation schemes or alteration of river flows. In Queensland, there are five to eight projects with capacities of 1-3 MW capacity at the evaluation stage.

[12] RISE – Microhydro. http://www.rise.org.au/info/Tech/hydro/small.html
[13] Renewable Energy Used for Electricity Generation in Australia. http:www.aph.gov.au/library/pubs/rp/2000-01/01RP08.htm

3.5.3 Technology Strengths and Challenges

Hydro can provide base load, low to zero emissions, renewable energy. It is also useful as a back-up and/or peaking generator, as it can be stopped and started relatively quickly to match/balance short term load variations.

Its disadvantages in Australia are that its large scale applications are restricted due to the limited rainfall, low river flow and lack of easily-developed new large scale reservoirs in a relatively flat country. There is also an increasing awareness of the environmental impact of large dams and there is considerable public opposition to their construction.

3.5.4 Priorities for Further Development and Demonstration

It is unlikely Australia will put into place any new large scale hydro-electric developments.

Small to micro developments and applications will continue, but these will also be limited by climate/geographical difficulties. The added supply capacity from these will be relatively small.

3.6 Wind Energy

3.6.1 Technology Description

Wind power largely comes from the use of high aerodynamic efficiency wind turbines and associated components to extract the kinetic energy of moving air and turn it into electricity.

3.6.2 State of development

Wind energy is a mature technology in widespread use. At the end of 2008, more than 120 GW of wind generating capacity had been installed globally. The industry represents an annual capital investment of $US50 billion and employs 400,000 workers worldwide. The installed capacity growth rate is a compound 25% per annum, with wind power being the fastest growing energy source in Europe.

More than 20 years of incremental development has seen the size of wind turbines increase by a factor of 100 to more than 5 MW per machine, standing at hub height over 100 m and with blade diameters of 120 m or more.

The resulting cost of electricity generated on some sites has fallen to US 8¢ / kWh. The familiar three-bladed turbines are now mass produced by large publicly listed companies such as Vestas, GE and Siemens. Development is generally led by large national utilities and multinational energy concerns such as BP. Land-based developments are approaching 1,000 MW in scale and large offshore wind farms are now becoming routine developments. The processes of wind resource assessment, wind farm design and environmental impact assessment are all well established.

3.6.3 Technology Strength and Challenges

By strength we refer to the size and momentum of the industry. The industry is large enough to support a very significant Research and Development (R&D) effort, reducing the cost of generation and pushing the technology into areas of future growth such as larger offshore wind farms, technology transfer to developing countries and high-reliability installations in remote areas such as Antarctica. Support industries, such as engineering, finance and insurance now understand the needs of wind power developments and often have developed specialised departments, such as a wind financing group within the bank ABN-AMRO.

The major challenges lie with integrating wind power into the electricity grid and energy market systems.

The growth of wind power as a proportion of capacity within a system has often created difficulties for electricity transmission and market systems to integrate energy production and production patterns in a way that maintains systems stability and safe, reliable, secure supply to consumers. This will be a major issue wherever wind power becomes a major power generation source (as is already the case in South Australia). The variable nature of the power delivery and the dispersed, often remote wind generation areas, combine to present new challenges for electricity system operators. These issues have led to cooperative efforts between regulators, utilities, transmission service operators and wind turbine designers.

3.6.4 Priorities for Further Development and Demonstration

Key future developments present an important step in overcoming challenges associated with significant penetration of wind power in the electricity system. The most urgent priorities lie in a range of developments which will significantly increase the amount of wind power that can be hosted on the electricity transmission and distribution system. These include:

- Wind turbine development – Full DC-AC-DC conversion generators and adaptive blade pitch control, which enables wind turbines to improve grid compatibility
- Grid integration – development of active compensation systems, including short-term storage, to enable wind farms to behave more like controllable power stations with, smooth, reliable delivery
- Wind forecasting – predicting wind power delivery, especially in extreme conditions where large swings in wind power generation are likely, and
- Grid enhancements – designing the necessary enhancements to the grid to meet increasing demand while integrating the distributed and variable nature of wind power generation. Grid design and simulation tools need to be upgraded to include wind energy sources and the ability to incorporate adaptive network theories.

Further, significant effort is being put into wind turbine design and offshore engineering technologies by overseas manufacturers.

Demonstration priorities focus around grid integration

Each of the development priorities listed above lead to a number of demonstration needs. Promising new solutions need to be trialled locally. These include:

- The use of short-term storage on wind farms, including integration into the wind farm control systems, trialled at large, grid-connected scale
- Established grid design and simulation tools need to be upgraded to include wind energy sources in high temporal and spatial detail, and
- Wind forecasting systems which are designed to forecast wind power delivery in extreme conditions.

3.7 Solar

3.7.1 Solar Photovoltaics

Technology Description

Also known as solar cells or solar panels, photovoltaic (PV) devices convert sunlight directly into electricity. The electricity is generated with zero GHG emissions, other than that produced during the manufacture, installation and disposal of the PV system itself.

While PV technology is seen as a significant likely component of the future global energy mix, PV only represents less than 1% of electricity production worldwide due to its relatively high current cost.

Small scale ‘off-grid’ systems have been used for many years, providing electricity in locations remote from electricity grids. To significantly mitigate GHG emissions, however, will require widespread use across areas serviced by electricity grids.

At present, such systems are not cost-competitive in Australia. Support schemes have assisted a steady decrease in cost, mainly through increased economies of scale throughout the supply chain. The relative cost-competitiveness of PV systems is expected to improve over time.

State of Development

The price of an installed PV system depends on the market value of raw and refined materials, the nature and scale of the manufacturing process for the specific technology used and the supporting infrastructure and installation.

Several technologies exist and are classified according to their maturity.

`First Generation’ PV is dominated by cells made from wafers of monocrystalline or multicrystalline silicon. This technology is at an advanced stage of development. It dominates the global PV market and is becoming cheaper primarily through increases in the scale of manufacture.

`Second Generation'’ PV is a potentially cheaper technology, with cost savings made through the use of a very thin film of the active materials on cheaper substrates such as glass. At present, Second Generation PV is responsible for around 13% of the global market. This share is likely to grow significantly over the next decade as manufacturing costs decrease due to experience and economies of scale.

`Third Generation PV’ describes a range of relatively new PV technologies that promise a major reduction in the cost per watt of electricity, either through performance gains, cheaper materials, or a cheaper manufacturing process. Some examples of this technology are organic PV and concentrating PV.

Technology Strengths and Challenges

The most significant feature of PV that distinguishes it from other clean sources of electricity is its granularity (scalability). Whether it is used to power a pocket calculator, a house, shopping mall, or for utility-scale electricity generation, the technology is basically the same. Consequently, it is ideally suited for generating electricity at the point of use.

However, where PV electricity at point-of-use lacks a distribution network, it must overcome the variability of sunlight and for continuous supply will need an appropriate system for electrical storage. Currently, no technology can provide this on a large scale. The option of large-scale implementation of grid-connected PV presents a comparable challenge to wind in the management of the electricity grid, which becomes more complex as the number of individual and variable sources increase.

Comparison with more centralised technologies must consider the full cost of the distribution networks they require, and offset this against the storage and backup capacity required by solar technologies.

Priorities for Further Development and Demonstration

First and Second Generation silicon technologies are now past the demonstration stage and will be the first forms of PV to contribute significantly to global electricity demand. Initiatives that maintain demand will ensure it becomes a commercial energy technology option in the free market.

The widespread implementation of these PV systems will promote, and require, the development of either: (a) affordable and environmentally-friendly small-scale energy storage technology, and/or (b) appropriate strategies for grid-management.

One or more Third Generation PV technologies are likely to provide a significant reduction in the cost of PV systems to the consumer. Development priorities include:

- Dye-sensitised solar cells have been demonstrated on a pilot scale, but failures at slightly larger scales and uncertainties around long-term reliability have prevented investment in full-scale manufacturing. Consequently, the true manufacturing cost is unclear. Priorities include large-scale demonstration based on lessons learned, together with research into more stable cell designs. Improvement in the efficiency of the devices through further research will also offer a greater impact in terms of cost.

- Organic solar cells face a number of critical challenges before they become competitive with existing PV technology. The largest issue is durability, as their lifetime is much shorter than established technology. More stable materials and device designs will be important, as will new flexible encapsulation systems, to take full advantage of the high flexibility of organic PV. Improving the efficiency of organic devices is also a high priority, as, at around one third the efficiency of established technology, savings achieved through cheaper manufacturing will be eroded by the need for larger systems. Efficiency improvements will be made through research in both materials and design. Equally important is the development of large-scale printing of organic PV, where much can be learned from the printing industry.

3.7.2 Solar Thermal

Technology Description

Often known simply as concentrating solar power (CSP), this is the concentration of solar energy to create a hot fluid which drives a process to create electricity or fuel.

CSP is most often characterised by the type of solar reflector used to concentrate the sun. The main technology types are:

Parabolic Troughs

Curved mirrors which form troughs that focus the sun's energy onto a pipe, through which a fluid, typically oil, is circulated and then used to drive a conventional generator to create electricity.

Linear Fresnel

These employ long lines of flat or slightly curved linear mirrors which move individually to concentrate the sun onto a fixed linear receiver tube. They can generate similar temperatures to troughs and are cheaper, but they, are optically less efficient than troughs.

Parabolic Dish systems

Use a parabolic-shaped concentrator (similar in shape to a satellite dish) that reflects solar radiation onto a receiver mounted at the focal point at the centre. The collected heat is used directly by a heat engine mounted on the receiver which generates electricity, or can generate high temperature fluids.

Solar Towers

Concentrate the sun’s energy using large array of heliostats (mirrors that track the sun) to heat a fluid to high temperature and which in turn is used to power a turbine or a thermochemical process for solar fuel production.

Towers and dishes achieve temperatures suitable for the most advanced steam turbines and can be used to run gas turbines or enhance fuels by incorporating additional solar energy into them (Figure 7).

State of Development

Over 350 MW of trough systems have been operating successfully in California for 20 years. This has laid the foundation for a global resurgence of activity in deployment and R&D into CSP systems. There are 1,000 MW of plant either under construction or about to begin construction in Spain. Approximately double these capacities are at advanced stages of planning and/or financial costing in the USA. The Middle East/ North Africa region, with its high solar energy, is also hosting new plants. Most of these plants use a working fluid temperature in the range of 300°C - 400°C.

New plants are using the latest technology in troughs, as well as towers and dish systems. There is a general move towards higher temperature systems (> 1000 °C) to benefit from their higher energy conversion efficiencies.

Many CSP systems are now being installed with 6-7 hours of heat storage, making them intermediate load plants. There is thus sufficient solar energy to continue to produce power into the evening, when electricity demand is often highest.

Technology Strengths and Challenges

The advantages of CSP are that it:

- Involves replacing the fossil fuel combustion processes of today with heat from the sun. Thus much of today's power generation technology and knowhow remains highly relevant to CSP – this will smooth the transition to solar and reduce the risk
- Will benefit as improvements are made in advanced gas turbine cycles, fuel cells, etc
- Integrates readily into storage CSP systems, and
- No exotic materials are required and the energy payback time is low.

Though the CSP concept is not new, it is only now emerging as a technology with great potential. Its slower emergence is due to large capacities required for scale benefits, and the limited market and commercial signals required to balance the inherent financial risk in large CSP power stations. However, with the stronger political and community focus on reductions in GHG emissions, the potential commercial case for large capacity CSP plant investments is increasing.

However, cost reduction presents challenges. By applying learning rates appropriate to similar technologies, CSP may be cost-effective against all other forms of zero-GHG technologies. The three main ways in which costs will be reduced are through:

- CSP consists of repeated components such as mirrors and actuating systems - greater volumes will reduce cost
- Most power generating technologies benefit from economies of scale, due to associated fixed costs becoming a proportionally smaller cost component, and higher efficiencies of larger turbines, and
- Technology development and R&D which seeks to develop higher temperature systems with improved components that increase efficiency.

Figure 7: The CSIRO Tower Array

Priorities for Further Development and Demonstration

Presently, the ‘incumbent’ CSP technology is the trough using oil as the heat transfer fluid. Though offering the least risk, it does not offer the same level of future cost reduction as higher temperature CSP technologies. Higher temperatures lead to higher conversion efficiencies and thus a much greater potential for lower capital cost. These higher temperatures can be achieved by continued development of high concentration reflectors such as towers and dishes, both by research (to improve precision) and industry (to lower production cost). Development work is then needed in high temperature receivers capable of producing:

- High temperature air (>800°C) for Brayton (gas turbine) cycles
- High temperature steam for advanced steam turbines (>500°C)
- Reactors that use the sun to carry out high value thermochemical reactions, and associated work in novel catalysts, and
- Receivers that can heat fluids such as molten salt for storage of solar energy in high temperature tanks for subsequent use in energy cycles on a 24/7 basis.

Modelling has suggested that 10,000 MW is needed to make CSP technology competitive with other zero emission technologies. There is now over 100,000 MW of wind generated electricity in the world. Solar can reach similar levels globally. Australia does not have the capacity to absorb this level of investment, capacity and technology risk on its own. However, by being part of a global deployment, Australia could establish itself as one of the lead countries in this field.

3.7.3 Solar Air Conditioning

Solar air conditioning has been included in the technology summaries as it is considered to be a highly prospective future low emission technology for Australia.

It utilises heat from solar thermal collectors to generate cooling for buildings. This displaces fossil fuel derived electricity, which would otherwise be consumed in conventional mechanical air conditioners. It will be especially useful as a ‘peak shaving’ technology as it works with maximum efficiency during the hottest part of the day.

Solar air conditioning has been technically proven for many years and can be constructed from readily-available solar collectors and sorption chillers which use environmentally friendly refrigerants and have a low electricity demand. However, a number of developments are required to reduce the cost of the technology so that it becomes cost-competitive in Australia.

3.8 Ocean Renewable Energy (ORE)

There are four principal resource types of ocean renewable energy. These can be described as tidal, wave, current and thermal.

Tides are the result of the earth rotating with respect to the gravitational attraction of the sun and moon. The resultant waves have complex structures, with high amplitudes at certain places where the energy can be most economically extracted. Waves are driven by the winds. Sites suitable for energy extraction are exposed to very long ‘fetches’, the distance over which the wind can build up the wave height.

Ocean currents are the result of solar thermal forcing, partly via the influence of surface wind stress. Complex physics associated with the rotation of the earth leads to the formation of narrow, fast-flowing 'boundary currents' such as the East Australian Current, where the energy accumulated over vast areas is concentrated.

Thermal energy employs the gradient that exists between the warm surface layers of the ocean and cold, deep layers. Australia does not have many regions where thermal energy is as attractive at it is for places like Hawaii and other equatorial, volcanic (and therefore steep-sided) islands. Similarly, the strength of Australia's ocean currents, both tidal and non-tidal, is not as high as they are at the best locations elsewhere. Australia's wave environment along the southern coastline from Perth to southern Tasmania, however, is as superior as any location in the world.

3.8.1 Technology Description

While each of the four resource types has undergone extensive research and technology development, with many decades of pilot-scale development projects (including electricity generation and hydraulic pressure), there are still technical hurdles to overcome to develop mature technologies to exploit ocean sources of energy economically.

Ocean Tides

The technologies used for tidal barrages are adapted from hydropower systems. Tidal barrages consist of a 'dam' across an estuary or suitable area of water affected by a large tidal range. Water flows through the barrage via turbines and power can be delivered two or four times a day depending on the turbine configuration.

Ocean Waves

Wave energy can be extracted at many locations along a coastline or further offshore. Technologies for capturing wave energy are very diverse, not only in the way the energy is captured but also in the power take-off systems which convert the energy to electricity. The basic technologies use oscillating water columns (OWC), absorber systems which capture wave energy at one or several points on a wave front, devices designed to have the waves wash over a structure and generate power as the water drains (overtopping devices) or a variation on a tethered pendulum that is operated by wave energy.

Delivered power from wave energy devices is quite variable due to the action of waves and some form of output smoothing may be required analogous to the smoothing of wind energy outputs.

Ocean Current

Ocean current devices are dominated by horizontal or vertical axis turbines (with or without shrouds) with venturis and oscillating hydrofoils also under development. There are a variety of ways of fixing the devices in place, either fixed on or in the ocean bed or by using floating or semi-floating platforms.

Ocean Thermal Energy Conversion (OTEC)

OTEC makes use of the temperature difference between the surface waters and colder water at depth. In closed systems, warm surface water is used to boil a low boiling point fluid which passes through a turbine to generate power and the vapour is then condensed using cold water from the lower depths at several hundred meters. OTEC is best suited to tropical areas with warm surface waters.

3.8.2 State of Development

There are more than 200 ocean energy systems in various stages of development ranging from concept design, part scale development, full scale prototype and pre-commercial demonstration. The majority of technologies under development are in the categories of ocean wave energy and ocean currents. While several devices have been demonstrated at scale (approaching 1MW) and in the ocean, many of these trials have only been for several months and the units then removed for further improvements and development. There has been one wave farm trial off the coast of Portugal, with a capacity of 2.25 MW. One of the most recent wave farm test sites is currently being deployed off the coast of Sweden. In 2010 a wave hub opened in the UK, which is essentially a sea floor grid connection that allows wave energy developers to test their devices in a wave farm configuration.

Some commentators on the ocean energy industry have noted that it shares several features with the wind energy industry of 15 to 20 years ago, namely rapid development, a multiplicity of designs, a growing engagement with the regulations that will govern the industry and a low installed capacity (excluding tidal barrage) of around 10 MW globally. With continued development, it is likely that some standardisation of design will occur and a supply chain will be established to support the ORE industry.

3.8.3 Technology Strengths and Challenges

Each technology can be said to have its strengths and challenges and yet there are some common features that will need to be addressed. The first of these is the survivability of the technologies. Ocean wave energy, for instance, has a logarithmic relationship between the wave power and the likelihood of achieving that power. Structures have to be designed for the extreme power situations (over 1000 kW/m) to ensure long life and yet will operate for most of their life in a narrower band of power (perhaps 30 to 100 kW/m).

Ocean energy is also variable on the short and long timescale and hence the variability of energy output will need to be managed especially for large scale grid connections.

In recent years, access to finance has also posed a challenge to technology developers, even for those technologies which are closest to market deployment.

Technology cost and the delivered cost of electricity is difficult to estimate reliably. This is due to the lack of installed plant for guidance and a need to standardise and confirm the developers’ cost claims. The final cost of power depends on the estimate of capacity factor for the technology and the location as well as assumptions about how soon the technology is deployed and the rate of cost reduction arising from large scale, widespread deployment. Capacity factors for long established technologies such as the La Rance tidal barrage in France are less than 30%. Newer systems will have to establish their performance.

The challenge that ORE faces in Australia is that it will compete with other renewable energies including wind and solar. Success will depend on the relative costs of the technologies, their technical attributes, supporting infrastructure requirements (i.e. transmission infrastructure) and the timeframe required for deployment.

3.8.4 Priorities for Further Development and Demonstration

In Australia there are a number of initiatives which could help the ORE industry establish itself. These include:

- Higher resolution and more-accurate modelling of the ocean (especially wave) energy resource. This would improve financial attractiveness to backers of any technology
- Multi-year device performance prediction to provide improved time-history of power output at any proposed location. This would provide greater certainty for performance optimisation and financial performance calculations
- Field performance modelling for large scale deployment of many large scale devices. This would address issues such as the scale of the deployment, the interaction between devices on variability of output and resource extraction efficiency, and
- Development of the environmental regulations for ORE deployment in conjunction with the industry to identify all the requirements for offshore and onshore components of the technologies.

Each individual technology could probably identify specific financial support required for next stage commercialisation, whether at the concept or pre-commercialisation scale.

3.9 Bioenergy

Biomass energy or bioenergy is comprised of heat, electricity (termed here bioelectricity) or liquid fuels (biofuels – considered in the Alternative Transport Fuels section) from biomass. Biomass can be biological material, often originating from agriculture, forestry and related industrial operations and organic waste.

In terms of electricity generation in Australia, bioenergy is a very small contributor. In 2006/07, 227 TWh of electricity was generated in Australia, of which approximately 1.6 TWh was produced from biomass or 0.7 % of the total (Australian Bureau of Agricultural and Resource Economics, 2009) (Table 2). Between 1997 and 2007 there was a doubling of the amount of renewable generation from biomass due mainly to bagasse - a by-product of the sugar industry.

Table 2: Production of bioenergy in Australia from 1991 to 2007[14]

	1991 (GWh)	**2007 (GWh)**
Bagasse (a)	513	1029
Black liquor (b)	154	267
Wood Waste	63	213
Other (c)	4	83
Totals	734	1572

a) Electricity and heat is produced from bagasse and used in the operation of sugar mills. In 2006 more than 50% of the electricity produced from bagasse in Queensland was exported to the distribution network (Australian Sugar Milling Council)
b) Black liquor, a by-product of the paper industry used in paper mills.
c) Other – includes municipal solid waste combustion and food and agricultural waste.

[14] FO Licht, World Ethanol & Biofuels Report, Volume 7, Number 4 [2009]

The increase in international use of biofuels over the last ten years has created sustainability concerns about the use of food, arable land and water for energy production.

3.9.1 Technology description

The term 'technology' in the case of bioenergy needs to consider the value chain, because the technologies required to realise bioenergy as a major energy contribution must consider:

1. The source of the biomass
2. The conversion technology to bioelectricity and/or heat, and
3. The technology for using the bioenergy.

The type of biomass used depends on the technology used for producing the energy. The various bioenergy technologies are known as:

- First generation technologies - those which are currently deployed with a proven technology, existing commercial enterprises and mature markets. For example, a coal-fired power station accepting up to 10% of its feedstock as biomass. There are many different co-firing and gasification technologies, as well as use of biogas for generation of bio-heat and/or bio-electricity

- Second generation technologies are those which have been physically demonstrated at pilot scale, but are not yet commercially viable. There are several different types of biochemical or thermochemical transformation processes that can convert non-edible fibrous or woody portions of plants (called lignocellulose) to liquid fuel, and

- Third generation technologies are those where the process is at the conceptual planning or demonstration stage, but has a long way to go before it can be used. There is potential for many types of bio-refineries which could use biomass to feed integrated processes producing energy and multiple co-products. There is a great deal of investigation into bio-refineries globally[15], but less so in Australia.

Biomass production technologies

There are several ways by which biomass production technologies may influence future biomass production. These include:

1. Changing the management of existing species and areas (e.g. rotations in farming to optimise energy production)
2. Changing the harvesting/extraction strategies of existing species in existing areas (e.g. using in field agricultural residues such as wheat stubble, or in forest residues and thinnings from plantations)
3. Growing currently commercial species in new areas (e.g. short rotation forest plantations across lower production landscapes)
4. Growing new species (e.g. new oilseed trees such as Pongamia), currently non-commercial species (e.g. oil mallee), modified existing species (e.g. high fibre sugar or GM) on land
5. Completely different production systems and species (e.g. algae), and
6. Organic waste.

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[15] 15th European Biomass Conference and Exhibition. From Research to Market Deployment. 7th – 11 May 2007

Each of these options in developing biomass production technologies may influence the cost of commercialisation of technologies to a greater degree than changes to the technology itself, either by reducing the cost of the feedstock or by increasing the volume feedstock available for use, without affecting world food supplies.

Conversion technologies

There are primarily two processes from which energy can be derived from biomass:

- Electricity and heat, primarily by combustion (burning wood for electricity), gasification, cogeneration (combined production of electricity and surplus steam for use in heating and/or drying) and co-firing (burning wood with other fuels such as coal), or from methane gas from landfill and other waste, and
- Liquid fuels (to be considered in more detail in the Alternative Transport section), such as bio-oil formed from pyrolysis (the chemical decomposition of a condensed substance by heating), methanol and diesel by gasification, ethanol from hydrolysis and fermentation, and ethanol from gasification followed by microbiological conversion of syngas.

In order to produce electricity and heat, there are four main types of biomass combustion technologies used commercially. These are[16]stokers, including spreader and retort (underfeed) (Stucley, et al., 2004; Taylor, et al., 2008):

- Grate systems, including travelling, chain, vibrating, and inclined grates
- Fluidised bed combustors, either bubbling, or circulating, and
- Pulverised fuel furnaces.

3.9.2 State of Development

Biomass fuels cover a wide range of applications from domestic wood fires to co-generation of electricity, heat and steam at the scale of tens of megawatts with biomass only, or in the hundreds when combined with coal or other fuel firing in special or conventional power stations.

Biomass power generation is well known with many international companies specialising in providing plant and equipment.

If the biomass, such as bagasse, a by-product from sugar mills, is produced on site, the size of the plant is usually limited by the local supply. If biomass comes from further afield, then the logistics of transport and uniformity of the feed to the power plant will determine the economic viability of the operation.

3.9.3 Technology Strengths and Challenges

The technology is well known and operates around the world. It is classed as a renewable fuel with low net GHG emissions and it utilises what otherwise might be waste materials.

A major challenge, particularly for a centrally based power plant, is the uniform supply and variability of the feed biomass. As a high volume, relatively low energy content material with a variable composition, particularly moisture content, it requires a high degree of logistical management to ensure

[16] EUBIA European Biomass Industry Association. http://www.eubia.org

smooth and economic operation of the generation technology. The development of suitable feed collection, preparation and delivery systems are critical to bioenergy viability.

3.9.4 Priorities for Further Development and Demonstration

Biomass production and use

- The distribution, availability, of current feedstocks, and scenarios for future feedstocks need to be quantified
- New feedstocks need to be robustly evaluated
- Development and implementation of a sustainability assessment system has to be compatible with those being developed internationally, and
- The sustainability implications of using biomass by different means have to be assessed. Assessment would include quantifying the tradeoffs between use of land, water and biomass for energy as against use for food, fibre, biodiversity or carbon sequestration.

Conversion technologies

The priorities for the future development of most biomass energy technologies focus on increasing the efficiency of the production of energy or process heat in relation to the capital cost of the equipment itself. For leading technologies – gasification and enzymatic conversion - capital costs are very high and may limit the development of commercial-scale operations. However, further research which enables the use of a mix of feedstocks and a range of commercial end-products other than electricity and heat is being considered.

In addition to the complication of different rates of conversion for various technologies, the main determinant of cost efficiency and effectiveness for any technology in Australia is the availability of reliable biomass sources. Factors such as the type of biomass, burning characteristics (e.g. calorific value), seasonal availability and cost (e.g. transport), will determine if the technology is feasible for Australia.

For example, most of Australia's renewable energy capacity using bagasse-fuelled production is located in Queensland and northern NSW. These facilities provided 3.8% of the total renewable electricity generation capacity in Australia in 2007, equivalent to 380 MW. Wood waste provided another 73 MW, located in NSW, Qld, SA and WA.

3.10 Alternative fuels

This section deals with the principal technologies that could be applied to potentially produce a range of non-petroleum transport fuels that could be of interest/application in Australia. The range is restricted to technologies for the production of synthetic fuels from Australia's abundant coal and gas resources, biofuels and electrification of the transport fleet. The direct use of CNG and LNG for transport, are not included as minimal processing is required for these fuels. Hydrogen for transport in Australia is also not included as it is considered that that it is a technology that currently has too long a take-up timeframe.

3.10.1 Synthetic Fuels

Australia is in the fortunate position of having vast reserves of natural gas and coal from which synthetic transport fuels could be derived. Biologically and solar derived synthetic fuels are also possible.

Technology Description

There are a number of technologies available to convert non-oil feedstocks into liquid fuels. A process overview for synfuel production technologies is shown in Figure 8.

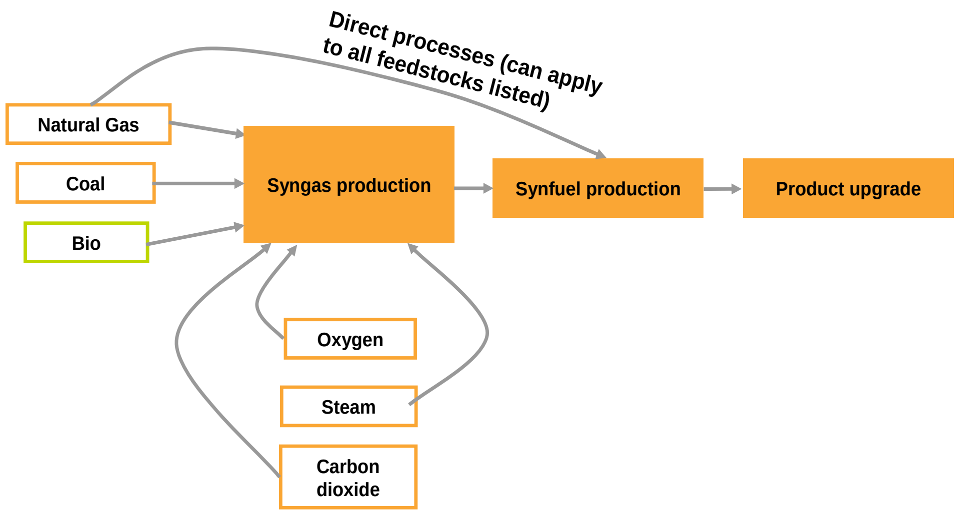

Figure 8: Steps in the Synfuel production process

GTL fuels technologies

Production via a syngas intermediate

The oldest and most commonly used technology for GTL conversion is a two-step process that firstly makes syngas (synthesis gas – a mixture of hydrogen and carbon monoxide) by reaction of the feedstock material, in this case natural gas, with water and/or carbon dioxide in the so-called reforming reactions or with air or oxygen in partial oxidation reactions. Secondly, the carbon monoxide and hydrogen mixture is converted to fuels by way of further chemical reaction. Depending on the process conditions of this second step, fuels produced can be methanol, hydrogen, gasoline, jet fuel and diesel to name the main types. Often there are some additional steps required to increase the yields of the desired products. These are known as product upgrade steps. In the case of dimethyl ether (DME) production a third step to convert methanol to DME by dehydration is required. In the case of gasoline from methanol, another step to convert methanol to gasoline is required. All of the industrial-scale GTL operations use variants of this two-step process.

Non-syngas routes to fuels

Production of synfuels from natural gas that does not involve production of syngas as a first stage has been shown to be technically feasible. Direct conversion to light fuel products by pyrolysis (non-oxidative conversion of natural gas) has been investigated, but it is not practiced on an industrial scale at this time. Oxidative coupling of methane (main component of natural gas) has also been demonstrated, but again is not practiced on an industrial scale. Novel engineering approaches have also been investigated for synfuels production from natural gas with emphasis on obtaining easily separable carbon dioxide streams to lower the greenhouse gas impact from the production of synfuels by this method.

CTL fuels technologies

As with GTL technologies, CTL may proceed via a syngas intermediate or may proceed directly to the liquid product with upgrading steps to maximise yield of the desired synfuel product. If the two-step (syngas intermediate) route is used, the main difference between GTL and CTL technologies is in the syngas production step. While feedstock composition can differ greatly from location to location, syngas can be produced from virtually any coal using appropriate gasification technology.

With the direct route, coal is reacted with hydrogen and/or hydrogen donor solvents in the presence of a catalyst at high pressures and moderate temperature. This route also includes pyrolysis where coal is thermally decomposed to generate tar, which is then reacted with hydrogen to produce liquid fuels. The claimed advantages of the direct route are that it has higher efficiency, higher product yield, and lower capital cost and CO_2 emissions than the indirect route.

State of Development

GTL fuels technologies

Production of methanol from natural gas is the main means of methanol production globally. In excess of 80,000 tonnes per day methanol is produced from coal and natural gas feedstocks. The technology for the production of methanol is mature and very large scale plants such as the Atlas facility in Trinidad, which produces approx. 7,000 tonnes per day methanol, are now in operation and, while smaller, are comparable in size to oil refineries and LNG facilities. Methanol is made predominantly as a feedstock for the chemical industry but can be used as a fuel additive or can be converted into gasoline or DME as mentioned above. DME production in China has grown appreciably in the last decade with most of the production from coal. DME can be used as a transport fuel as is, but is normally used for other purposes. In Australia, the methanol plant in Laverton, Victoria uses a two-step process to convert natural gas into methanol, producing up to 190 tonnes per day.

Currently there are five commercial GTL plants in operation worldwide. They vary in size from 14,000 barrels of oil equivalent (boe) per day to 140,000 boe/day. Despite increases in the scale of production of methanol and DME, total production remains low compared to the overall liquid fuel production (approximately 0.5%). However, the technologies are a commercial reality and there are different technologies in use. Shell uses a combination of partial oxidation and reforming and Sasol Chevron uses reforming and combustion. Both employ a process known as Fischer Tropsch Synthesis (FTS) to convert syngas to synfuels. Each has proprietary reactor technology for the FTS reaction.

Non-syngas routes to liquid fuels are not practiced commercially. However, development work is being undertaken both in Australia and internationally to determine the commercial feasibility of some of these processes.

CTL fuels technologies

CTL on a commercial scale is, and has been practiced in South Africa and Germany. There are plans to build CTL facilities in China given the country’s scarcity of oil and natural gas and their abundance of coal. All of these plants are based on the two-step syngas production process.

Direct coal liquefaction has been tested on a pilot scale and demonstration plant scale using a range of processes, most notably in Australia at the Brown Coal Liquefaction venture at Morwell in Victoria during the 1980s and early 1990s. Recently a 20,000 barrel/day commercial-scale direct liquefaction plant was commissioned by the Shenhua Group in China.

Technology Strengths and Challenges

GTL technologies

The strengths of the technologies for synthetic fuels derived from natural gas are:

- Plentiful feedstock in Australia
- Products derived from the GTL process contain fewer contaminants than oil-based equivalents
- The products are of higher value and can be used as blending stock to ensure refinery products meet necessary specifications
- There is a certain amount of flexibility in what products can be made, allowing for some adjustment of product depending on demand
- Technical and industrial feasibility has been established
- A large amount of the technology used in GTL processes can also be used for other feedstocks such as coal and biomass synfuel production, and
- Methanol production requires less plant equipment land area than other GTL processes.

The challenges of the technologies for GTL are:

- Large capital investment required to build a large-scale plant
- Large volumes of gas required to meet demands of large-scale plants
- Carbon efficiency is relatively low compared to competing technologies. Carbon efficiencies of GTL processes are in the order of 75-80% whereas LNG and oil refineries are in the order of 85-90% carbon efficient. The relative inefficiency of GTL processes is a reflection of the energy requirements, and
- Novel direct conversion technologies have not been industrially proven.

Greenhouse gas emissions associated with GTL fuels are similar to those derived from crude oil (+/- 20%)[17,18].

CTL fuels technologies

The strengths of the technologies for synthetic fuels derived from coal are:

- Plentiful feedstock in many parts of the world
- Established technologies for CTL conversions
- There is a certain amount of flexibility in what products can be made, allowing for some adjustment of product depending on demand
- Range of coal gasification technologies available for application in CTL processes, and
- Direct CTL processes breaks down coal structures in a manner that optimises liquid production.

The challenges of the technologies for CTL are:

- Direct coal liquefaction yet to be industrially proven
- Relatively poor carbon efficiencies compared to competing technologies
- Heterogeneity of feedstock that pose additional challenges in the processing of coal for synfuels production, and
- High greenhouse gas intensity. There is need to reduce the carbon footprint of CTL processes relative to competing technologies.

[17] CSIRO, 2008
[18] Sasol, 2007

Priorities for Further Development and Demonstration

GTL fuels technologies

Given that the majority of Australia's gas reserves are remote and/or not considered large enough to warrant significant capital investment, priority should be given to developing technologies that require less capital investment including smaller plants that can be relocated as necessary. Carbon efficiencies of GTL processes also need to be addressed. These can be improved thorough modification of established technologies and demonstration of novel technologies. Use of waste heat, lower temperature processes, more efficient and stable catalytic materials and processes with improved selectivity to the desired products will all enhance the commercial viability of GTL processes. In order to succeed in these priority areas, maintenance and development of capabilities in gas processing and synfuels production is necessary.

CTL fuels technologies

Reducing the carbon footprint of the process so that it is more comparable to competing technologies will be a challenge. This can be achieved by optimising CTL technology enhancements as well as carbon capture and storage. Because it is a less mature technology, more scope exists for improving direct CTL through developments such as selective mining, pre-treatment of coal to reduce mineral matter and development of improved hydrogenation catalysts. Integrating carbon capture and storage into production and, where possible, renewable energy will reduce the carbon footprint to a level comparable with conventional petroleum.

3.10.2 Oil Shale Technology

Oil shale is a sedimentary rock that contains substantial amounts of organic material in a form called kerogen, which is hydrogen-rich compared to coal. It is normally formed from algal remains deposited in lakes but can also form in brackish conditions or even shallow seas. The nature of the organic component is a strongly cross-linked aliphatic material with some aromatic component which is not extractable by solvents.

Technology Description

The usual approach to extracting the organic part of oil shales from the minerals, with which it is intimately bound, is thermal treatment in a process called pyrolysis – rapid heating in the absence of oxygen. The kerogen in the oil shale decomposes on heating to around 500^{o}C, at pressures close to ambient, to form material that is volatile and hence removable from the mineral part of the oil shale. In normal pyrolysis, not all the organic component is recovered; the rest forms an intractable char or coke. Research and development has been focussed on developing techniques which maximise the conversion of the organic part of the oil shale to liquid and gaseous products.

There are a number of pyrolysis-based processes that have been developed to treat oil shales and these can be characterised as those that involve:

1. Shale moving downwards through a vertical shaft retort with heat supplied by hot gases - Paraho, Petrosix, Fushun and Kiviter are proven systems
2. Movement of the shale upwards through the retort by use of a rock pump – Union Oil
3. Recycle of hot inert solids or hot combusted shale to provide the heat to drive the process. Processes include; TOSCO, Lurgi-Ruhrgas, HRS, Kentort, Galoter and AOSTRA Taciuk Processor, and
4. Heating of the shale on a circular travelling grate – Superior Oil, Dravo.

The pyrolysis process requires a large input of energy to heat the organic and mineral matter to reaction temperatures and then to provide the heat to drive the endothermic reactions. This heat can be provided by burning the char remaining in the spent shale. Since Australian oil shales are high in mineral matter (generally > 80% ash content), many of the process options which have been given serious consideration have involved the recycle of hot (800 ^{o}C) combusted shale ash to be mixed with the raw shale feed to provide the required heat input (see Figure 9).

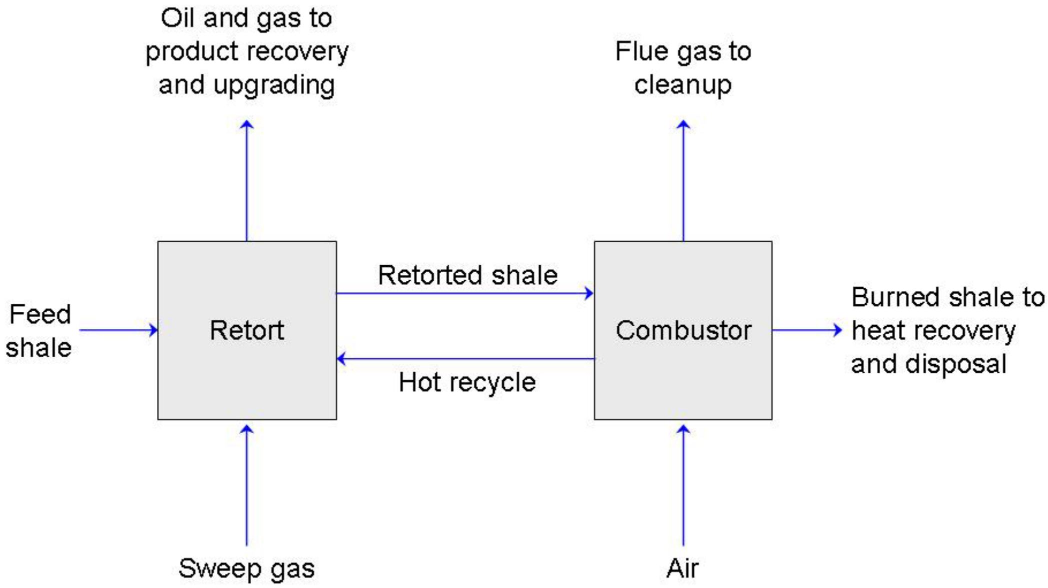

Figure 9: Pyrolysis process with recycle of hot combusted spent shale

State of Development (in Australia)

The major Australian oil shale commercial development projects during the 1980s and early 1990s were based around the Rundle/Stuart, Condor (now called McFarlane) and Julia Creek deposits. In addition to these major development projects, there were varying levels of assessment conducted on other major Australian oil shale deposits that included Nagoorin-Nagoorin South, Lowmead, Yaamba, Duaringa and Alpha, all located in Queensland. While this work was largely confined to resource definition, there were some small-scale pyrolysis of shale samples and preliminary pre-feasibility studies conducted.

The largest Australian demonstration was based around the use of the AOSTRA Taciuk Processor (ATP) that was originally developed in Canada for the simultaneous extraction and primary upgrading of oil sands bitumen. A schematic of the ATP is shown in Figure 10.

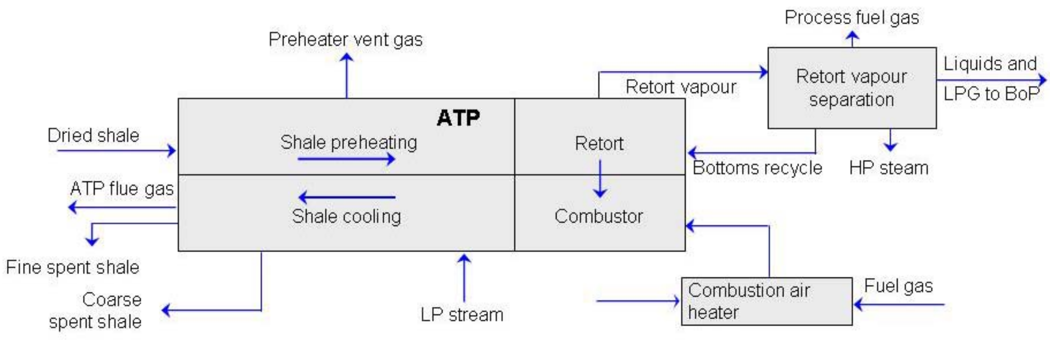

Figure 10: Schematic of the AOSTRA Taciuk processor

The process consists of a single horizontal, rotating vessel that has preheat, reaction, combustion and cooling zones together with a hot solids recycle system in which a continuous stream of hot solids provides the primary heat input to the pyrolysis reaction zone.

The 6,000 tonnes shale per day demonstration plant was designed and installed on-site at Stuart near Gladstone, Qld, by Southern Pacific Petroleum NL. The Stage 1 demonstration plant operated intermittently during the period 2000-2004. In 2003, the ATP was operated at a 60% on-stream factor producing 629,000 barrels of oil, with a yield of 82% of the Fischer assay (the standard reference yield) with shale feed rates ranging from 3,790 to 4,460 tonnes per day.

QER Pty Ltd. took over Southern Pacific Petroleum NL in 2005 and ultimately decided to discontinue with the ATP technology in any future commercial development of the Queensland oil shale leases and is currently pursuing development of the Paraho technology.

Technology Strengths and Challenges

There is a range of technically proven processes for extracting oil from shale that can be tailored to suit individual oil shale types and grades.

The major drawbacks to extraction of oil from shales is that the current technology is GHG-intensive and because most shales are relatively low in the active oil-producing components, large amounts of spent shale are produced that have to be disposed of in an environmentally acceptable manner.

Priorities for Further Development and Demonstration

OER Pty Ltd.'s decision to abandon the ATP was at least partly made because of issues such as complexity of solids flow within the processor, gas sealing, operating flexibility and difficulty in scaling up this technology to the much larger unit capacities required for a commercial plant. The drawback of the ATP was that it allowed little variation in spent shale: raw shale recycle ratios as this were determined by internal geometry, and once at temperature, shutdown required hundreds of tonnes of material to be purged from the system with inert solids. Thus, power failures presented a particular operational problem.

The Paraho technology involves the pyrolysis of shale in a vertical shaft retort where heat can be supplied indirectly by contact with hot recycle gases that are heated external to the retort in gas furnaces, or directly by the addition of air to the retort to burn part of the residual carbon on the spent shale. The hot gases thus produced flow up through the retort to heat, dry and pyrolyse the shale in the upper sections of the retort. This Paraho process is closely related the Petrosix technology which has accumulated considerable operating experience in Brazil since the 1980s.

Another option that has been proposed for the Julia Creek deposit, which is more like coal in terms of its aromatic content, is the direct hydrogenation route (e.g. the Rendall[19] process) similar to what has been applied to the direct conversion of CTL. While it does offer the possibility of much higher oil yields than might otherwise be obtained through pyrolysis of the more aromatic oil shales, there are significant challenges associated with processing a stream with high mineral matter content at high temperatures and pressures under a hydrogen atmosphere.

A major issue associated with all shale oil processing is reduction of GHG emission intensity. This will need to be tackled by overall process efficiency increases and perhaps use of CCS technology as it is developed.

3.10.3 Biofuels

Australian production of biofuels is small, but growing steadily (Table 3). The total 2008 production of biofuels consisted of 100 ML of ethanol from C-Molasses or waste flour starch and 68 ML of biodiesel from used cooking oil and tallow. Together, this represented 0.45% of the total 37,500 ML of automotive gasoline and diesel consumed in Australia that year. Because production was from co-products and not primary production, there was virtually no impact on existing food chains. The supply of these co-products is small and this limits the amount of biofuel that can be produced from these feedstocks.

Table 3: Production of biofuels in Australia from 2004 to 2007

Production ML/yr	**2004**	**2005**	**2006**	**2007**	**2008**
Fuel ethanol	24	27	63	80	100
Biodiesel	10	57	91	59	68
Total Biofuels	34	84	154	139	168

Production of first generation biofuels in Queensland will rise due to the introduction of a biofuels mandate in New South Wales and Queensland. While Queensland continues to source ethanol from sugar with CSR Ethanol’s Sarina distillery producing up to 60 ML/yr, a sorghum based refinery at Dalby in Queensland began operation in December 2008 and at full production, will use 220,000 tonnes/yr of locally grown sorghum to produce approximately 90 ML/yr of ethanol.

The rapid international scale up of biofuels over the last ten years has created sustainability concerns about the use of food, arable land and water for energy production. These concerns are very important to future technology deployment.

Technology Description

The various biofuels technologies are known as:

[19] Innovation in the Oil from Shale market.
http://findarticles.com/p/articles/mi_m3251/is_11_234/ai_n25015648/

- First generation technologies - for liquid fuels, first generation technologies refer to fermentation of sugar and starch crops to ethanol; or trans-esterification of plant and animal oils to biodiesel
- Second generation technologies are those which have been demonstrated at pilot scale, but are not yet commercial due to scale-up issues, or due to high costs. There are several different types of biochemical or thermochemical transformation processes that can convert non-edible fibrous or woody portions of plants to liquid fuel. There are also opportunities being investigated to use algae to produce biodiesel, and
- Third generation technologies are those where the process is at the conceptual planning stage, or at benchtop demonstration stage, but are yet to be deployed. There is potential for many types of bio-refineries which could use biomass to feed integrated processes producing multiple co-products.

Different technologies are suited to specific types of biomass. CSIRO has proposed a simple matrix for relating the range of technologies to the various biomass types. The current production base, as well as future production base and the technologies for which they can be used are shown in Table 4.

Biomass production technologies

There are several pathways by which biomass production technologies may influence future biomass production. These include:

1. Changing the management of existing species and areas
2. Changing the harvesting/extraction strategies of existing species in existing areas
3. Growing currently commercial species in new areas
4. Growing new species, currently non-commercial species, or modified existing species
5. Completely different production systems and species
6. Organic waste, and
7. Algae growth - Australia, with a large land area, high insolation and warm temperatures has a competitive advantage in relation to growing algae.

Conversion Technologies

There are four main categories of liquid fuels that can be obtained from woody biomass. These are:

- Pyrolysis oils (obtained in highest yield using ‘fast pyrolysis’)
- Methanol
- Synthetic Diesel via Fischer Tropsch, and
- Ethanol.

Pyrolysis, the heating of wood in the absence of oxygen, is used both commercially and experimentally to produce three main by-products: oil, charcoal (char), and combustible gases. Fast pyrolysis produces higher oil yields, whilst slow pyrolysis produces higher quantities of charcoal and combustible gases[18,19]. The combustible gases can be used to then generate electricity or process heat using secondary energy conversion technologies (such as driving a steam turbine[18,20]. The oil produced by pyrolysis is very unstable and unsuitable for use in vehicle engines; however, it can be converted to transport fuel via the gasification route.

[20] Biomass Conversion: Engineering technologies, feedstocks and products. United States Environmental Protection Agency, EPA/600/R-07/144, Washington DC, 30pp, 2007

Table 4: Biomass feedstocks from current and future production base, and the technologies that may be used to transform them to bioenergy and bioproducts

Technology	Current Production Base	Future Production Base
1st Generation Biofuels • Ethanol from sugar and starch • Biodiesel from oil.	• Sugar • Starch crops (e.g. grains) • Oilseed crops • Used vegetable oil • Tallow.	Current production base PLUS • Genetically modified (GM) crops • New oilseed crops (e.g. Pongamia, Jatropha) • New sugar crops (e.g. agave).
2nd Generation Biofuels • Alcohols (inc. ethanol, butanol) • Synthetic diesels, gas from lignocellulose. 1st and 2nd generation Heat and Power • Wood fires for heating • Power from coal fired power station • Gasification.	• Agricultural in-field residues (e.g. cereal stubble, sugar trash) • Agricultural processing residues (e.g. husks from rice or cereal, bagasse from sugar) • Grasses – improved pasture and native • Plantation forestry – including different components such as in-field residues, harvest residues, thinnings, or diversion of low value products such as pulp logs • Native forest – as above • Dedicated energy crops (e.g. mallee rows in agricultural land) • Forest processing residues (e.g. sawmill waste) • Organic waste in landfill • Woody weeds.	Current production base PLUS • Expansion of plantation forestry • Expansion of grasses by cultivating specifically for energy • Expansion of dedicated energy woody crops (e.g. coppicing crops such as mallee, short-rotation forestry) • New/GM modified crops • Algae in open ponds or bioreactors • Possible contraction of organic waste in landfill.
3rd Generation Bio-refineries • Heat, power, liquid fuels • High-value bioproducts as petrochemical replacements • No 'waste'.	• All of the above.	

State of development

Second Generation Technologies

By mid 2008 there were at least 42 facilities operating or under construction at pilot scale internationally, converting second generation sources to fuels. The major technologies in use are equally divided between the most common routes: thermochemical and enzymatic conversion. There is currently one facility in Australia that can produce fuel (Ethtec Technologies) and several that are using pyrolysis to produce oils, gas and char.

A number of commercial and demonstration scale ligno-cellulosic-to-fuels facilities are in the planning stage.

Technology Strengths and Challenges

Second Generation Technologies

Table 5: Lignocellulose biomass to fuels (second generation) conversion technologies

	Strengths	**Challenges**
Pyrolysis	Minimal pre-treatment; fast, largely established technology/knowledge; continuous; reasonably flexible feedstock requirements	Large infrastructure; high capital costs, pressurised vessels; energy intensive; further processing required to produce a fuel
Gasification then Fischer-Tropsch (FT)	Minimal pre-treatment; fast, largely established technology/knowledge; continuous; somewhat flexible feedstock requirements	Sometimes multiple product streams that need separating; expensive catalysts; Large infrastructure; high capital costs; pressurised vessels; energy intensive; biomass contaminants can cause poisoning of catalysts
Enzymatic	Mild operating conditions, usually one product stream; fully compatible with first generation ethanol plants	High capital costs; energy intensive; pre-treatment can add substantially to overall cost and cause contaminants downstream; longer treatment times; high enzyme requirement; overall efficiency needs improvement; R&D further behind than thermochemical

Priorities for Further Development and Demonstration

Biomass production and use:

- The distribution and availability of current feedstocks, and scenarios for future feedstocks needs to be better quantified
- New and novel feedstocks (e.g. oilseed trees) to be evaluated
- Development and implementation of a sustainability assessment system compatible with those being developed internationally, and
- Sustainability implications of using biomass via different technology pathways needs to be assessed.

Algal production:

- Algae biomass is dilute - one litre of biodiesel production corresponds to the processing of approximately ten tonnes of algae sludge/water. Minimising energy consumption in processing is an important challenge
- Development of algae harvesting/concentration methods
- Conversion of the algae into commercial products that fit seamlessly into the market, and
- Algae production plants may be able to absorb some of the CO_2 waste from power plants and increase the algal growth.

Second generation lignocellulosic biofuels include:

- Technologies developed and tailored for conversion of Australian lignocellulose sources
- New technology advances directed at smaller infrastructure and lower capital costs and higher efficiency of conversion
- Assessment of the environmental impact and compatibility with current fuel infrastructure for new fuel types
- Australian based life cycle assessment and techno-economic modelling to assess the impacts on fuel cost and commercial viability of the industry of different technology choices and advances, and to predict fuel costs, greenhouse gas emissions savings and capacity for petroleum replacement
- Identify and develop bio-refinery product streams that can value-add to the fuel production stream for ligno-cellulosics, and
- Collection of geographically diverse biomass requires consideration. This may result in the establishment of multiple processing centres in remote regions if is economical. In the case of thermochemical process the biomass can be densifed[21] into bio-oil using pyrolysis. This would the increase energy content in a smaller volume thus improving the economics in transporting biomass to a central processing site. In the latter case, non-thermochemical means might be employed to increase the energy density of biomass.

Conversion technologies:

Future development of biomass energy technologies is focussed on increasing the efficiency of the production of energy or process heat in relation to the capital cost of the equipment itself. Further research enabling the use of a mix of feedstocks, and a range of commercial end-products other than electricity and heat, are being considered.

[21] Densified means the biomass has been made denser by subjecting it to pressure to remove the air. The process is called densification.

3.10.4 Electricity for transport

In recent years there has been an increased interest in electricity for transport purposes to the extent that it is likely to become a viable transport ‘fuel’ of the future. There is an emerging view that transport electrification will transplant the early adoption of hydrogen powered vehicles.

Technology Description

The electricity for an Electric Vehicle (EV) can either be stored in batteries or generated on-board with a petrol or diesel engine. An electric motor can deliver very high torque over a wide range of revolutions-per-minute, whereas a petrol or diesel engine has a relatively narrow efficiency range.

While EVs depend upon a battery system for energy, an added advantage is that the battery system can be used to capture and store energy that is otherwise wasted when slowing and braking. It can also be used to operate ancillary systems in the vehicle when the vehicle is stationary. This can result is significant savings in operating cost and reduced emissions.

State of development

A Chinese battery manufacturer (Build your dreams), one of the world’s largest, is planning on releasing an all-electric car in August 2010[22].The battery pack is a Canadian-Chinese development on lithium-ion technology.

Mitsubishi has been developing EVs for some years and its i-MiEV car has been available in Japan since July 2009. Mitsubishi is sending a shipment of 40 of its i-Miev vehicles to Australia in the second half of 2010.

Hybrid-electric buses and depot-based vehicles have been in use in several countries for ten years.

Hybrid-electric technology is useful for city buses because the constant stopping and accelerating allows for large amounts of energy to be captured and re-used. Australian truck and bus suppliers offer imported transmissions that incorporate hybrid-electric technology.

The limitation faced by EVs is the battery system. Traditional battery technology cannot cope with the need for rapid energy uptake, and delivery of an EV without unacceptable limitations on the cost or life of the batteries. Batteries developed for hybrid cars have proved to be extremely reliable, but are still expensive. Newer cars are using lithium-ion technology for the batteries which has been used in smaller applications such as cameras, but has only been seen in small-scale vehicle production. Technological breakthroughs could reduce the cost of lithium-ion batteries or improve the performance of other battery technologies to make them economically attractive.

The past decade has seen extensive battery technology research and development.

In 1996, General Motors launched its EV1 electric car that used traditional, lead-acid battery technology. Toyota released its first Toyota Prius hybrid-electric car in 1997 using nickel-metal-hydride battery technology. This type of battery is lighter than the traditional technology and more suited to the rapid cycling requirements of hybrid-electric cars, but the technology is substantially more expensive. More recently, smaller companies have offered EVs using lithium-ion technology, which is lighter, but even more costly.

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[22] http://www.byd.com

CSIRO has developed the UltraBattery that combines low-cost traditional battery technology with supercapacitor technology that improves the performance and durability of the battery making it a potential contender for EVs. The technology is licensed to several overseas battery manufacturers and is likely to debut in small Japanese hybrid cars in 2010-2011.

Technology Strengths and Challenges

Electric motors are highly efficient (better than 80%) while petrol and diesel engines lose much or most of their energy in heat and friction losses. Typically, internal combustion engines operate in the range of 20% to 28% efficiency.

An electric motor has the ability to operate as a generator when the vehicle is slowing. This captures some or much of the energy that in a traditional car is lost as heat.

EVs are mechanically much less complex than petrol or diesel cars and may therefore require less maintenance.

The challenges for EVs to overcome all relate to the battery pack – cost, energy density and reliability. High energy density requires technology such as lithium-ion technology, which is expensive. Claims that increased production volume will yield lower costs have yet to be demonstrated.

Battery technologies lack a device that can measure the condition of the battery, identify the weakest cells within the battery pack, and accurately predict the remaining life of the battery pack. Without such a device, used EV sales would be less secure. Such a device could be an important aid for the vehicle servicing industry.

Priorities for Further Development and Demonstration

Demonstration projects are needed to:

- Show the possibilities of integrating an EV with the home electricity supply, including the technical barriers to the wide scale uptake of EVs
- Investigate the requirements for software and hardware for lithium-ion technology batteries in EVs within the Australian environment
- Development of a battery-condition indicator that can be used with all EV battery technologies
- Investigation of alternative rapid-charge technologies, and
- Full life cycle analyses of the electricity supply and GHG implications of a substantial uptake of EVs in Australia.

3.11 Nuclear Power

The production of energy from nuclear reactions comes from two basic processes – fission and fusion. Only nuclear fission will be presented in this technology summary as commercial fusion processes are still only a long-term possibility.

3.11.1 Technology Description

Nuclear fission energy is released when a heavy atomic nucleus absorbs a neutron and splits into two lighter fragments. This is a highly energetic reaction, releasing up to 10 million times more energy than the combustion of one atom of carbon[23].

Uranium provides the basic heavy element fuel for fission reactions. Natural uranium consist of 99.3% U-238 and 0.7% U-235. Conventional light water reactors use uranium with an initial U-235 concentration enriched to around 3.5%. The heat from the nuclear reactions comes from the fission of U-235 and Pu-239 (plutonium). Pu-239 is formed by neutron capture on U-238. The heat from the reactions is used to drive steam turbines for electricity generation. Typically, the reactor fuel is replaced once the U-235 concentration falls below 1.2%[24].

3.11.2 State of Development

Currently, there are 441 nuclear plants operating world-wide. They have a combined generating capacity of 386GW and produce around 16% of the world's electricity. Of these plants, 147 are in Europe, 104 in the USA, 31 in Russia, 17 in India and 11 in China[29].

Reactor technology is classed into first to fourth generation types. The United Kingdom (UK) is the only country still operating Generation I reactors and these are scheduled to close within the next few years. Generation II reactors are largely Light Water Reactors (LWR) in which the water acts as a coolant and neutron moderator. The fuel is enriched uranium. Variations of the technology include; pressurised water reactors (PWR), boiling water reactors (BWR) and heavy water reactors (HWR). Generation II reactors account for 90% of existing reactors and 88% of new builds. Generation II technologies will dominate until at least 2025[25].

Generation III reactors are generally of the Advanced Water Reactor (AWR) type. Some designs are slowly entering commercial operation. There are many designs in various stages of development, mainly evolving from Generation II technology. There is also a class of generation III+ reactors, the most well known of these being the Pebble Bed Modular Reactor (PBMR) that uses helium coolant to directly drive a turbine. PBMR are safer, modular, lower cost and non-prolific [26].

Generation IV reactors are intended to be revolutionary. In 2002, the Gen IV International Forum (GIF) nations, a consortium of 10 nations proposed a long term R&D program to investigate 6 new designs – the gas-cooled fast reactor (GFR), very high temperature reactor (VHTR), supercritical water cooled reactor (SCWR), sodium cooled fast reactor (SFR), lead cooled fast reactor (LFR) and the molten salt reactor (MSR). While all these conceptual designs face considerable challenges, they have the potential to use uranium more efficiently, use "spent" fuel from current reactors, destroy some nuclear waste via transmutation and be inherently "fail safe" compared to current technology. Some of the designs can also use thorium, rather than uranium as a fuel, so substantially increasing the nuclear fuel resource base while reducing the waste level. Another advantage is reactors that use thorium are non-prolific[27].

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[23] Everything you want to know about Nuclear Power. http://nuclearinfo.net/Nuclearpower/PhysicsOfFission

[24] The Oil Drum, discussions about energy and our future. http://www.theoildrum.com/story/2006/8/7/195721/3132

[25] Nuclear Power – A Quick State of Play. http://thinkcarbon.wordpress.com/2009/03/24/nuclear-power-a-quick-state-of-play/

[26] World nuclear association: Advanced power reactors. http://www.world-nuclear.org/info/inf08.html

[27] World nuclear association: Advanced power reactors. http://www.world-nuclear.org/info/inf08.html

3.11.3 Technology Strengths and Challenges

Perhaps the biggest strength of nuclear power generation is that it provides a source of large scale, base load, very low GHG emission, electricity. It is an off-the-shelf technology with prospects of evolutionary and revolutionary future improvements, including in safety, non-proliferation and lower waste production.

The major challenge for the nuclear industry is the management of the waste that all fission reactors produce. Fission products include various isotopes of barium, strontium, cesium and iodine. These products remain in the spent fuel, together with left over uranium and plutonium. The wastes are hot and highly radioactive, and have to be stored for a ‘cooling off’ period and then reprocessed to extract unused fuel. The remainder can be stored permanently in geological repositories. Spent fuel volumes are around 2 to 3 cubic metres per year for a 1,000 MW power station if reprocessed, and around 10 cubic metres if not[28]. Currently, no country has a complete system for permanent storage of high-level waste, but many have plans to do so[27]. Storage facilities can and do generate social resistance on environmental safety grounds.

3.11.4 Priorities for Development and Demonstration

Australia has one research fission reactor at Lucas Heights. OPAL was opened in 2007 and is a research instrument and production facility for radiopharmaceuticals[29]. The Government’s policy is not to introduce nuclear power into Australia.

From a theoretical perspective, if Australia was to add nuclear power to our future supply mix, there are many issues to be resolved, including[31]:

- Legislative and regulatory framework development, including for protection, operational safety, waste storage and decommissioning
- Education and science and technical skills development
- Commercial and economic frameworks to support significant up-front capital costs and eventual plant decommissioning
- A 10-15 year interval for start up of a first reactor
- Reactor locations
- Water use (nuclear plants use more cooling water than coal/gas plants), and
- Political and social acceptance of nuclear power

There are no universities in Australia offering courses in nuclear engineering and there is little nuclear engineering experience. Ramping up nuclear engineering education and development of nuclear R&D activities would be a priority if nuclear energy were to be seriously considered as part of Australia’s energy future.

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[28] A Nuclear Future for Australia. http://www.warren.usyd.edu.au/bulletin/NO59/ed59art2.htm
[29] Nuclear options: many countries have faced the same issues.
http://www.atse.org.au/index.php?sectionid=1229

3.12 Distributed Energy and Intelligent Grids

3.12.1 Technology Description

Distributed Energy (DE) covers the deployment of small scale (< 30 MW close to load) energy technologies. It may also include DE system solutions which enable the deployment of cost effective, large scale DE. The deployment of DE has the potential to reduce greenhouse gas emissions in the near term while other technologies are brought online. It comprises a range of technologies such as: reciprocating engines, small gas turbines, fuel cells, energy storage, PV, wind, solar thermal and low grade heat utilisation.

It also contains systems for improving operation and efficiency of energy use. For instance: demand side management, communications and control to improve the quality of supply and security.

DE is also use for systems such as: virtual utilities, miniGrids, embedded generation and Tri/Co generation solutions.

A Smart Grid is an electricity network that can intelligently integrate the actions of all users connected to it - generators, consumers and those that do both – in order to efficiently deliver sustainable, economic and secure electricity supplies.

A Smart Grid uses products and services together with monitoring, control, communication, and self-healing technologies to:

- Better facilitate the connection and operation of generators of all sizes and technologies
- Allow consumers to play a part in optimising the operation of the system
- Provide consumers with greater information and choice of supply
- Significantly reduce the environmental impact of the whole electricity supply system, and
- Deliver enhanced levels of reliability and security of supply.

Smart Grid deployment will also need to take into account market and commercial considerations, environmental impact, regulatory framework, standardization usage, ICT (Information & Communication Technology) and migration strategy, societal requirements and governmental policy.

3.12.2 State of development

DE technologies are in the start up phase of adoption as evidenced by domestic solar panels, increasing co-generation in buildings and small industries. There has been an accelerated uptake in recent years with government subsidies and incentives. Research is still required to match these technologies to Australian requirements including solar heating and cooling.

DE systems such as demand response and mini-grids have been adopted but they are still small in number in Australia, compared to the rest of the industrialised world.

The Smart Grid movement offers the potential to act as a major vehicle for large scale deployment of renewables, upgrading of network assets and extension of the existing telecommunications infrastructure. A Smart Grid can provide a range of facilities, such as smart meters and last mile communications, which could facilitate the wider use of DE technologies (embedded generation, local renewals and storage, demand management and energy efficiency).

3.12.3 Technology Strengths and Challenges

At face value DE options are more expensive than centralised generation; however their viability as an alternative source of generation increases when the full economic and environmental costs are taken into account[30]. The strength of DE options is that, when combined with smart grids, they provide the opportunity to capture significant whole-of-system optimisation benefits.

DE technologies are small and flexible so they can be positioned close to consumption (minimising losses) and sized to match the consumption growth accurately (optimising cost). They generally have lower emissions, or zero, compared to centralised coal-fired generation and use heat recovery and recycling of energy.

The challenge for DE in Australia is to demonstrate its viability and benefits in a low cost (high emissions) electricity supply environment and to encourage the industry to work together to deliver a paradigm shift in electricity supply and demand.

Smart Grids could offer significant benefits to industry and consumers. These include:

- Strengthening the grid – bringing consumers and producers together to reduce the economic, environmental and energy security impact of meeting peak demand through supply infrastructure and investment
- Developing decentralised architectures – enabling smaller scale electricity supply systems to operate harmoniously with the total system
- Communications – delivering the communications infrastructure to allow more parties to operate and trade in the single market
- Active demand side – enabling all consumers, with or without their own generation, to play an active role in the operation of the system
- Integrating intermittent generation – finding better ways of integrating intermittent generation including residential micro generation
- Enhanced intelligence of generation and demand, most notably in the grid
- Capturing the benefits of DG and storage, and
- Preparing for EVs – the widespread deployment of these vehicles could present a challenge for future electricity networks.

3.12.4 Priorities for Further Development and Demonstration

The adaption and demonstration of DE technologies need to be encouraged particularly in the residential and commercial areas as they are the main contributors to peak demand, which drives generation capacity, transmission and distribution infrastructure investment.

DE systems such as miniGrids and business cases for Virtual utilities around local solar and wind generation aggregation need to be further developed. Co -generation to reduce emissions from commercial buildings could be encouraged through building standards.

Energy efficiency measures for heating/cooling and appliances need to be pursued so that the overall base load is reduced on our networks.

The Smart Grid initiative in Australia needs to encourage wide scale deployment of energy efficiency measures, local renewables and efficient and cost effective systems.

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[30] CSIRO (2009) Intelligent Grid.

Further research is needed in the Smart Grid field to ensure that developments consider the longer term future as well as the needs of the utilities.

4. ECONOMIC COMPETITIVENESS

4.1 Introduction

Electricity generation capital cost projections are essential to understanding the cost of lowering greenhouse gas emissions in the electricity sector over time. A variety of international organisations publish these projections on a regular basis. In Australia, publications of this information tend to be on a more *ad hoc* timing with several appearing in the last 18 months. The recent availability of several electricity generation cost reports has provided an unprecedented opportunity to better understand the confidence we can put in such projections through comparison of assumptions, methods and synthesis of their findings.

There appears in the first instance to be considerable variability in the reported capital costs for each technology. However, when analysis unpacked the underlying data and assumptions, there is a significant amount of common.

The role of this section is to provide a clear discussion of the observed differences surrounding the underlying assumptions applying to capital and operating and maintenance (O&M) costs and the assumptions and methodology used to calculate levelised cost of electricity (LCOE) projections of five available studies. The studies were selected on the basis that they were published circa 2010 so that they were comparable in knowledge at the time of publishing and that they covered a significant number of electricity generation technologies rather than simply one or two. The authors of the reports are: ACIL Tasman (2010), Hayward et al. (2010), EPRI (2010), IEA (2010) and US DOE (2009). Note for readability and consistency Hayward et al. (2010) will be referred to as CSIRO (2010) in this report as the other studies use organisation rather than individual author names.

In order to aid in understanding the basis for differences in the LCOE between the five studies, this section has been divided into sections that reflect key areas where differences can occur. That is: effect of assumptions on LCOE, scope, regional differences, and methodology. This section begins with an examination by technology and year (2015 and 2030) the effect different assumptions can have on the LCOE. This is done in three ways: firstly, the effect of the individual reports' assumption data on LCOE is examined; secondly, the effect of a general variation in assumptions is examined to determine the assumptions that have the most influence on LCOE; and finally, assumptions that have large variations in their values across the reports are highlighted. Comparisons are then made in LCOE across technologies and reasons why differences occur in reported and calculated LCOEs are explained. Next is a discussion of differences in scope between the studies. This includes factors such as plant type and size, capacity factors, efficiencies and differences between suppliers if they are specified. It then follows with a description of regional factors that may be treated differently between the reports. This includes factors such renewable resources, ambient temperature and fuel costs. This section also includes a discussion of methodological differences in the capital cost projections and LCOE calculations for those reports where such information is available.

4.2 Differences in LCOE

Levelised cost of electricity (LCOE) reflects the minimum price that the electricity generator must sell its electricity for (at the perimeter of the study) in order to receive a return to all of its factors of production including investors return on capital, payments to fuel suppliers, payments to parts and labour, payments to construction contractors and other miscellaneous fees and lastly, purchases of greenhouse gas emission permits if required. It can also be equated with the cost of electricity as generated by each technology at the boundary of the study. LCOE calculations cannot reflect market conditions and competitive pressures. The calculation of LCOE requires a significant number of data assumptions and methodologies (e.g. fuel costs, capacity factors, amortisation period). Where differences arise in LCOE estimates it is this base data which must be interrogated to determine the underlying differences.

The first step was to extract the key data from each study. With both the published LCOE and the underlying data assumptions we are able to produce three sets of data for comparison:

A. The published or 'reported' LCOE for each technology as provided by each report
B. A 'calculated' LCOE for each technology and for each report where the only assumption in common is the methodology used to calculate LCOE. This calculation methodology is described in detail in Appendix C. This means that while the calculation methodology is the same, the data input into the calculation is unique for each study
C. The 'harmonised' LCOE for each technology where again a common calculation methodology for LCOE is used in addition to, by technology, using the mean across the reports for each of the data assumptions with the exception of one of these data assumptions. This then allows us to interrogate the role of each assumption separately from the others.

Because many of the assumptions for calculating a LCOE for the US DOE (2009) were not published, in addition to the fact that they are from another region and therefore capacity factors and plant efficiencies will be different, we did not use the US DOE (2009) data in the harmonisation process. The harmonised values used in this report are shown in Table 6 for the year 2015 and Table 7 for the year 2030. The actual individual values that have been harmonised for each assumption per technology, including their percentage variation from the mean and the standard deviation from the mean can be found in Appendix G - Data Tables at the back of the report. These tables are organised by data assumption category.

Capital costs and efficiencies are reported in the studies and in this report as sent-out or net values. This means that the capital cost, in $/kW, refers to the net power of the plant, rather than the gross power. Because the net output of a plant is less than the gross output due to parasitic loads, the reported capital cost is higher in $/kW on sent-out or net rather than gross or installed basis.

Parasitic loads refer to electricity usage within the plant itself to keep the plant operational. Parasitic loads reduce the output of the plant. Efficiency, which is defined as how much energy in the form of electricity is either produced (gross) or sent-out (net) for a given input of energy in the form of a fuel source. When efficiency is defined as sent-out, as has been done for the studies used in this analysis, it means that the effect of the parasitic load is also included. Thus, for CCS plants for example, which have high parasitic loads, the efficiency is lower.

LCOE needs to be calculated on a sent-out basis because this is the amount of electricity the generator provides to meet demand and thus the amount of electricity that the costs of generation can be recovered from.

Table 6: Harmonised data for the year 2015

	Amortisation period	Construction time	Capture Rate	CO_2 storage cost	Fuel cost	Capital cost	Variable O&M cost	Fixed O&M cost	Capacity factor	Efficiency	Transmission cost	Discount rate	Emission Factor	LCOE from Report
	years	years	%	$/tCO_2e$	$/GJ	$/kW	$/MWh	$/MWh	rate	rate	$/MWh	%	kg CO_2/GJ Fuel	$/MWh
Brown coal pf	35.0	3.7	-	20.0	0.7	3258.7	3.68	5.16	83.75%	32.93%	1.1	8.47%	90.00	89.65
Brown coal pf with CCS	35.0	3.7	90.00%	18.2	0.7	6240.7	14.33	8.71	83.75%	25.54%	1.1	8.47%	90.25	146.56
Black coal pf	35.0	3.7	-	20.0	1.4	2631.6	3.37	4.79	83.75%	38.24%	1.1	8.47%	90.51	80.67
Black coal pf with CCS	35.0	3.7	90.00%	18.2	1.4	5318.5	13.26	7.62	83.75%	28.85%	1.1	8.47%	90.68	135.06
Black coal IGCC with CCS	36.7	4.0	87.33%	20.0	1.5	6417.5	13.28	12.00	85.00%	32.29%	-	9.20%	92.64	161.53
Gas combined cycle	30.0	3.0	-	20.0	7.1	1412.2	3.22	3.23	83.75%	49.50%	1.1	8.47%	55.83	93.57
Gas with CCS	30.0	3.0	90.00%	18.2	7.8	3070.2	10.34	8.08	82.50%	40.40%	1.1	7.70%	57.17	149.51
Gas peak	30.0	3.0	-	20.0	7.0	794.7	6.98	12.78	31.61%	31.80%	1.1	8.47%	55.95	176.33
Nuclear	30.0	5.0	-	20.0	1.1	5247.0	4.73	12.17	83.33%	33.50%	1.1	7.70%	1.89	133.36
Biomass	30.0	3.0	-	-	0.7	3471.0	3.30	12.55	50.00%	26.95%	3.3	7.00%	-	99.58
Solar thermal PT w 6hrs	30.0	-	-	-	-	8500.5	-	29.60	28.82%	13.60%	-	8.40%	-	438.00
Solar thermal PT w/out	25.0	2.0	-	-	-	4918.2	1.65	27.52	23.90%	13.60%	6.3	7.70%	-	321.46
Solar thermal CR w 6hrs	30.0	-	-	-	-	6475.0	-	26.37	31.60%	15.50%	-	8.40%	-	330.00
Solar thermal CR w/out	25.0	2.0	-	-	-	3908.4	1.65	28.10	22.82%	15.50%	6.3	7.70%	-	277.96
PV roof top	20.0	1.0	-	-	-	3811.7	2.35	0.00	21.43%	-	6.3	7.00%	-	208.60
PV fixed plate	30.0	-	-	-	-	6132.5	-	23.92	21.21%	12.40%	-	8.40%	-	431.00
PV single axis tracking	25.0	1.0	-	-	-	5893.2	1.65	18.37	22.95%	12.40%	6.3	7.70%	-	294.99
PV two axis tracking	30.0	-	-	-	-	7548.0	-	22.83	26.21%	20.20%	-	8.40%	-	327.00
Wind - small	20.0	-	-	-	-	3216.5	-	16.21	31.60%	-	-	8.40%	-	188.00
Wind - medium	21.7	1.0	-	-	-	2657.0	7.89	15.11	30.80%	-	7.9	8.47%	-	135.46
Wind - large	20.0	-	-	-	-	2778.0	-	14.83	31.60%	-	-	8.40%	-	168.00
Geothermal hot rocks	35.0	2.0	-	-	-	6316.6	4.46	14.43	82.50%	26.00%	7.4	8.47%	-	135.53
Geothermal conventional	30.0	3.0	-	-	-	3935.1	2.20	10.98	80.00%	-	7.4	7.00%	-	71.14
Geothermal hot aquifers	-	-	-	-	-	5711.0	-	16.79	85.00%	-	-	8.40%	-	116.00
Hydro	100.0	5.0	-	-	-	3410.3	2.20	21.96	20.00%	-	4.0	7.00%	-	191.81
Wave	20.0	1.5	-	-	-	5217.2	26.46	16.50	48.00%	-	7.4	8.50%	-	208.07
Current	20.0	2.0	-	-	-	5241.8	122.94	23.49	32.71%	-	7.4	8.50%	-	362.13

Table 7: Harmonised data for the year 2030

	Amortisation period	Construction time	Capture Rate	CO_2 storage cost	Fuel cost	Capital cost	Variable O&M cost	Fixed O&M cost	Capacity factor	Efficiency	Transmission cost	Discount rate	Emission Factor	LCOE from Report
	years	years	%	$/tCO_2$-e	$/GJ	$/kW	$/MWh	$/MWh	rate	rate	$/MWh	%	kg CO_2/GJ Fuel	$/MWh
Brown coal pf	35.0	3.5	-	-	0.7	2845.4	1.51	4.97	82.50%	41.00%	1.1	7.00%	93.55	103.80
Brown coal pf with CCS	33.3	3.5	90.00%	18.2	0.7	4612.2	13.40	8.18	83.33%	32.95%	1.1	7.70%	89.86	151.89
Black coal pf	35.0	3.5	-	-	1.5	2151.9	1.51	4.97	82.50%	43.00%	1.1	7.00%	96.65	93.07
Black coal pf with CCS	33.3	3.5	90.00%	18.2	1.5	3942.1	13.14	7.18	83.33%	35.60%	1.1	7.70%	90.98	136.18
Black coal IGCC with CCS	35.0	4.0	88.50%	20.0	1.7	4298.1	12.59	9.30	85.00%	37.80%	-	8.40%	93.45	213.00
Gas combined cycle	30.0	3.5	-	-	6.2	1098.6	3.22	3.65	82.50%	54.49%	1.1	7.00%	59.95	93.74
Gas with CCS	30.0	3.0	90.00%	18.2	7.8	2158.5	10.34	7.70	82.50%	45.78%	1.1	7.70%	57.31	139.15
Gas peak	30.0	3.5	-	20.0	7.6	887.9	6.16	12.75	14.52%	32.00%	1.1	7.70%	61.43	236.46
Nuclear	30.0	5.0	-	-	1.0	4575.0	4.73	11.17	83.33%	34.04%	1.1	7.70%	1.89	115.13
Biomass	30.0	3.0	-	-	7.6	3452.3	3.30	10.91	36.07%	28.08%	3.3	7.00%	-	212.76
Solar thermal PT w 6hrs	30.0	-	-	-	-	6125.0	-	17.72	32.90%	-	-	8.40%	-	438.00
Solar thermal PT w/out	25.0	2.0	-	-	-	2977.1	1.65	21.46	23.93%	-	6.3	7.70%	-	295.51
Solar thermal CR w 6hrs	30.0	-	-	-	-	4209.0	-	16.61	32.60%	-	-	8.40%	-	330.00
Solar thermal CR w/out	25.0	2.0	-	-	-	2499.6	1.65	20.44	24.18%	-	6.3	7.70%	-	252.01
PV roof top	20.0	1.0	-	-	-	2470.8	2.35	0.00	23.57%	-	6.3	7.00%	-	126.47
PV fixed plate	30.0	-	-	-	-	4072.0	-	15.55	21.00%	-	-	8.40%	-	431.00
PV single axis tracking	25.0	1.0	-	-	-	3348.6	1.65	13.46	24.79%	-	6.3	7.70%	-	256.63
PV two axis tracking	30.0	-	-	-	-	4490.0	-	14.84	31.00%	-	-	8.40%	-	327.00
Wind - small	20.0	-	-	-	-	3360.0	-	13.45	38.20%	-	-	8.40%	-	188.00
Wind - medium	20.0	1.0	-	-	-	2274.5	1.76	13.03	34.85%	-	7.9	7.70%	-	124.02
Wind - large	20.0	-	-	-	-	2902.0	-	11.30	38.20%	-	-	8.40%	-	168.00
Geothermal hot rocks	30.0	3.0	-	-	-	7444.1	2.20	17.71	82.50%	-	7.4	7.70%	-	140.26
Geothermal conventional	30.0	3.0	-	-	-	4184.3	2.20	10.98	80.00%	-	7.4	7.00%	-	74.34
Geothermal hot aquifers	-	-	-	-	-	5325.0	-	14.64	85.00%	-	-	8.40%	-	116.00
Hydro	100.0	5.0	-	-	-	3163.3	2.20	21.96	20.00%	-	4.0	7.00%	-	179.96
Wave	20.0	2.0	-	-	-	2588.4	18.68	16.30	43.00%	-	7.4	7.00%	-	112.39
Current	20.0	3.0	-	-	-	3279.7	18.68	23.07	35.43%	-	7.4	7.00%	-	160.65

4.2.1 Effect of differences in assumptions

Tornado plots have been used to show the differences in underlying assumptions behind the LCOE. Before analysing the detailed results by technology, some explanation is required as to what these plots represent. Shown below in is an example tornado plot for brown coal pulverised fuel (pf) plant.

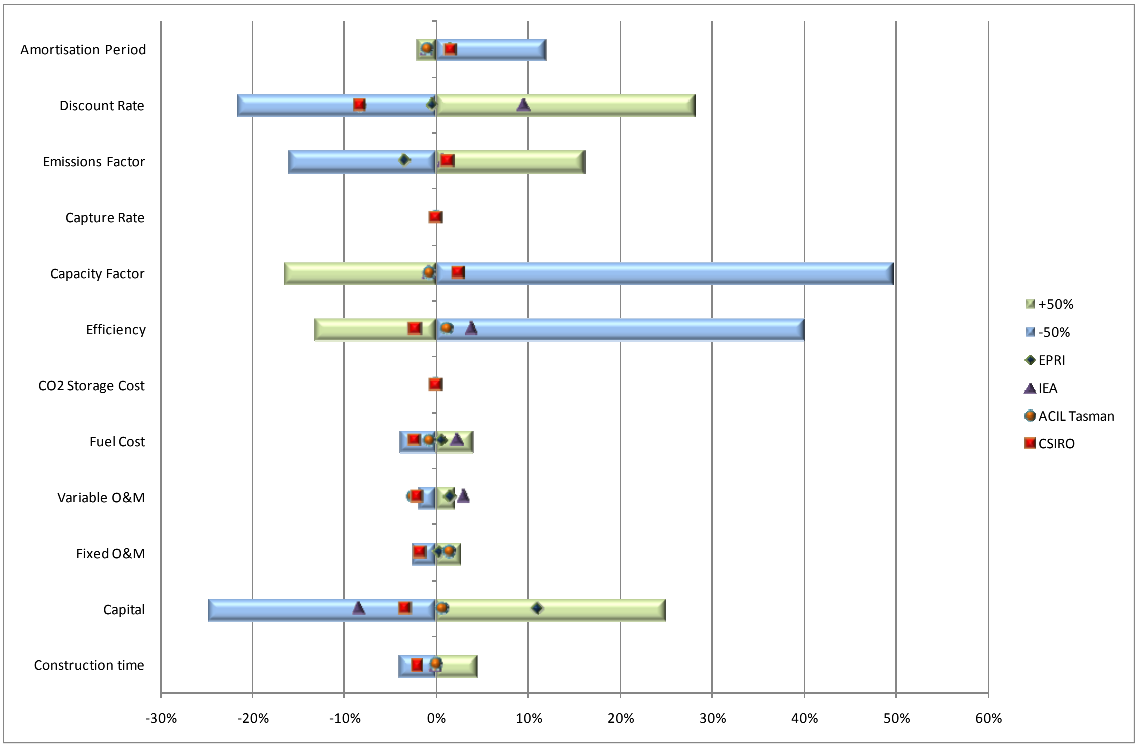

Figure 11: Example tornado plot for brown coal pf plant. An emission permit price of $28/t$CO_2$ has been included in the LCOE calculation

The x-axis of the tornado plot is percentage variation in LCOE from the mean, where the mean is at 0%. The mean LCOE is the mean over every report for every assumption per technology. That is, a total harmonisation. The y-axis lists the assumptions that are inputs into the LCOE calculation and thus those that have been harmonised.

Variation in reported assumptions

If we examine one assumption, such as amortisation period, the points along the x-axis for amortisation period represent the percentage variation from the mean caused by the use of each individual reported value. Accordingly, if we take the ACIL Tasman (2010) value (yellow circle) it has a value on the x-axis of ~-1%. This means that when all other values are harmonised (including capital) except for amortisation period and we use the ACIL Tasman (2010) value for amortisation period, the LCOE will be 1% less than the totally harmonised LCOE. Alternatively, if we take the CSIRO (2010) value for amortisation period (red square), the variation from the harmonised LCOE is 2%. That is, the use of the CSIRO (2010) value for amortisation period increases the LCOE by 2%.

The explanation is the same for each assumption, where all of the values are harmonised except for the values for that assumption, and the non-harmonised values are the values taken from each report.

By comparing the range of values between assumptions, we can form an understanding of which assumptions are causing the most variation in LCOE between the reports. From a quick glance at the tornado plot, it can be seen that the biggest range between individual report values is for capital. Therefore, within the scope of the reports for this technology, differences in capital are driving the variation in LCOE.

General variation in assumptions

Apart from interrogation of the assumptions from each report, we can also examine in general the relative importance of each assumption on the resultant LCOE by looking at the effect on LCOE of ±50% variation in each assumption from the mean or harmonised value. This is shown by the blue and green bars on the tornado plot. If we examine capacity factor for example, an increase in capacity factor by 50% will reduce the LCOE by 17%. Decreasing the capacity factor by 50% will increase the LCOE by 50%. Note however that for some technologies which already have a high capacity factor such as all of the coal-based technologies, nuclear and all geothermal technologies, it was not possible to increase the capacity factor by 50% since it would then be greater than 100%. Alternatively, we increased it to the highest possible value, 100% although in reality 100% is not achievable due to the need for maintenance shutdowns.

By comparing the length of the bars between each assumption we can then form an understanding of which assumptions in general can have the greatest effect on LCOE. From a quick glance at the tornado plot, variations in capacity factor have the greatest effect on LCOE.

Large variation between reported assumptions

The tornado plot also tells us when the value of any individual assumption from a report is greater than 50% or less than 50% from the mean value of that assumption. That can be seen under variable O&M, where the IEA (2010) value lies just to the right of the green +50% bar. However, due to the overall closeness of the variable O&M values, such a variation has very little effect on the LCOE, less than ±5%, as evidenced by the location of the values and the bars along the x-axis.

Again, by comparing the outliers between each assumption we can then form an understanding of which assumption category has the greatest variation between reports. From the tornado plot, variable O&M shows the greatest variation in reported values of all of the assumption categories (although as, discussed, the variation in O&M has little impact on the LCOE).

When all values sit over each other and there is no range it means that there is no value for this assumption for this technology. In the above example, CO_2 storage cost is not included.

We will now go through and describe the tornado plots by technology.

Brown coal pulverised fuel (pf)

This technology has cost projections from EPRI (2010), IEA (2010), ACIL Tasman (2010) and CSIRO (2010) for the year 2015 and ACIL Tasman (2010) and CSIRO (2010) for 2030. The 2015 tornado plot is shown above in Figure 11 and the 2030 tornado plot in Figure 12.

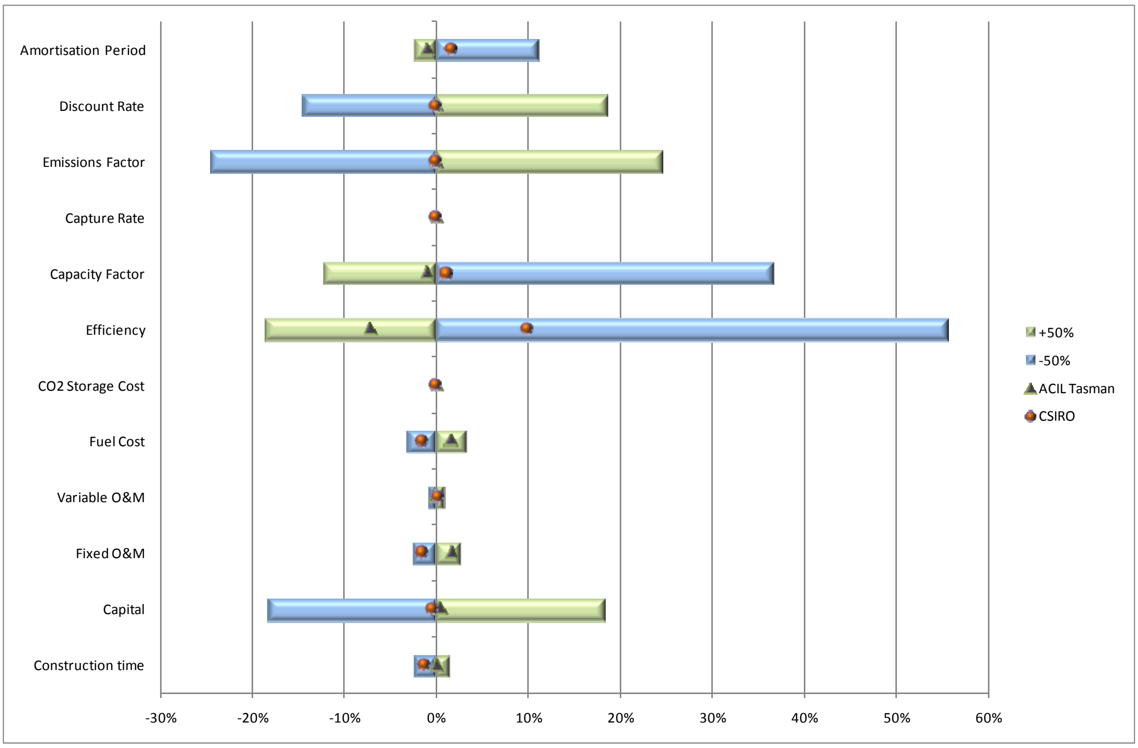

Figure 12: Tornado plot showing variation in LCOE for brown coal pulverised fuel (pf) plant in 2030. An emission permit price of $52/tCO_2$ has been included in the LCOE calculation

Variation in reported assumptions - 2015

The individual assumption that has the greatest effect on the LCOE is capital, where the lower value reported by the IEA (2010) ($2709/kW) reduces the LCOE by 8% compared to the harmonised value ($3259/kW). EPRI (2010) report a higher value ($3979/kW) which increases the LCOE by 11% compared to the harmonised value.

The source of differences in capital costs are not wholly due to basic plant differences as both plants are assumed to be supercritical AC plants. IEA (2010) specify a smaller plant size (686 MW) than EPRI (2010) (750 MW) (Section 4.3.1 Black and brown coal pf without CCS); and generally smaller plants cost more per kW than large plants whereas the opposite is occurring here. We do know that EPRI (2010) include more charges into their capital cost such as a 7.5% allowance for covering real project costs and that the IEA (2010) capital costs are lower overall. Therefore, we can say the differences are partly due to the different methodologies behind the capital cost estimates and these are not unique to brown coal pf. The methodologies are described in Section 4.5.1.

Even though there is variation in the LCOE based on differences in the capital values, the actual variation is relatively minor at less than ±12 %.

The assumption that has the second-greatest effect on LCOE is discount rate, where the lower value reported by CSIRO (2010) (7%) reduces the LCOE by 8% from the harmonised value

(8.47%). The IEA (2010) value (10%) increases the LCOE by 9% from the harmonised value. Differences in discount rates arise due to differences in the ratio of equity to debt used and the cost of that debt and the cost of that equity. Various formulas can be used to calculate the discount rate. In this case, CSIRO (2010) have chosen a discount rate of 7% and IEA (2010) in their report have a 5% and a 10% discount rate. We chose to use the 10% discount rate in this report as it is closer to the other values. Discount rate has an effect on LCOE because of the high capital and fixed O&M components (see Figure 13).

General variation in assumptions - 2015

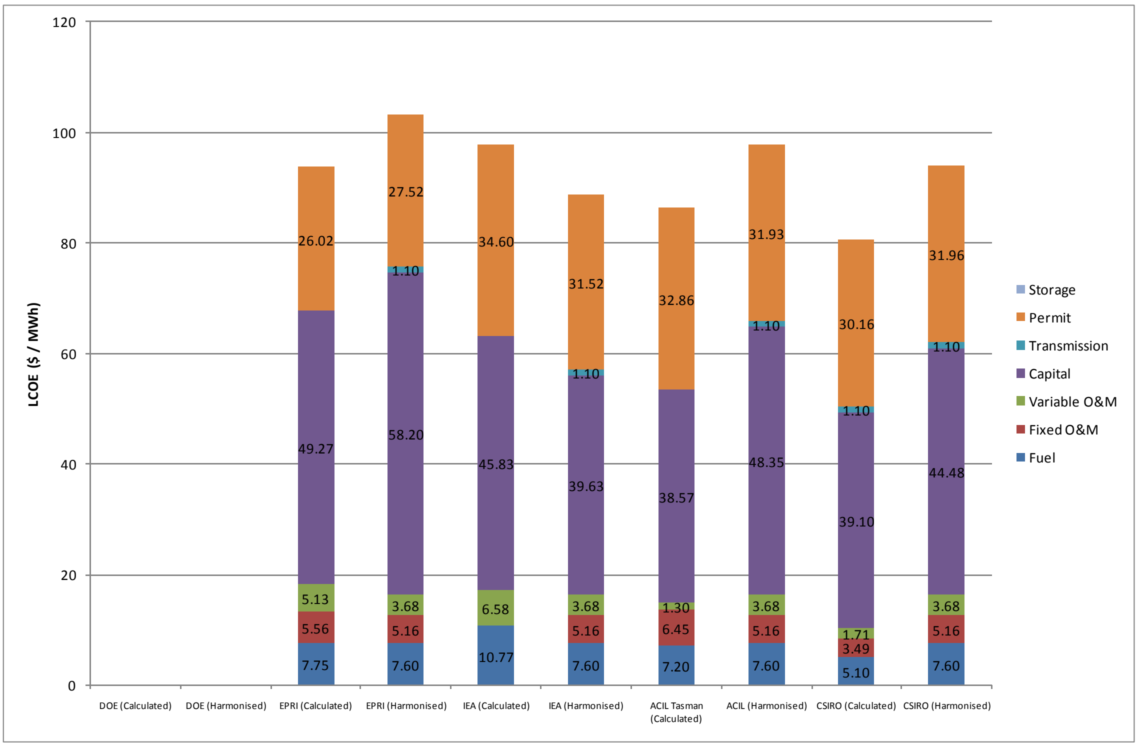

Figure 13: Calculated and harmonised LCOE breakdowns for brown coal pf in 2015. A carbon permit of $28/tCO_2$ has been included in the calculated and harmonised LCOE.

Variation in capacity factor has the greatest effect on LCOE of all of the assumptions; when the capacity factor is reduced by 50% from the harmonised value of 83.75%, the LCOE increases by 50%. Similarly, when the capacity factor is increased to its maximum value of 100% (an increase of 19.4% from the harmonised value) the LCOE is reduced by 17%. This emphasises the role capacity factor plays in the formula for the capital cost component and fixed O&M component of the LCOE calculation as can be seen in Appendix C. In Figure 13 the capital cost component is the largest contributor to the LCOE, therefore changes in capacity factor will have a large effect on LCOE. We do not have any insight into the choice of capacity factor by each report, but these are less uncertain and generally understood to be between 80-90% for coal-based technologies. Capacity factors are the ratio of how much energy a plant produces over a period of time to its rated capacity.

The next greatest effect on LCOE comes from variations in efficiency; an increase in efficiency of 50% reduces the LCOE by 13% and a decrease in efficiency of 50% increases the LCOE by 40%. Changes in efficiency affect the LCOE indirectly via the consumption of fuel and the emissions of the plant and therefore the number of carbon permits that need to be purchased.

From Figure 13 it can be seen that the carbon permit forms a large portion of the total LCOE and therefore any changes factors that affect carbon permits (i.e. efficiency) will affect the LCOE.

Large variation between reported assumptions - 2015

The IEA (2010) variable O&M cost ($6.78/MWh) is more than 50% higher than the harmonised value ($3.68/MWh). The IEA (2010) report a single total O&M value. Since it was impossible to know which part is fixed and which part is variable, we have placed all of the O&M costs for the IEA (2010) under variable. However, from Figure 11, it can be seen that the effect of this variation on LCOE is negligible (3%).

Other than variable O&M there are no other variations of ±50% between reported assumptions and the harmonised value.

Variation in reported assumptions – 2030

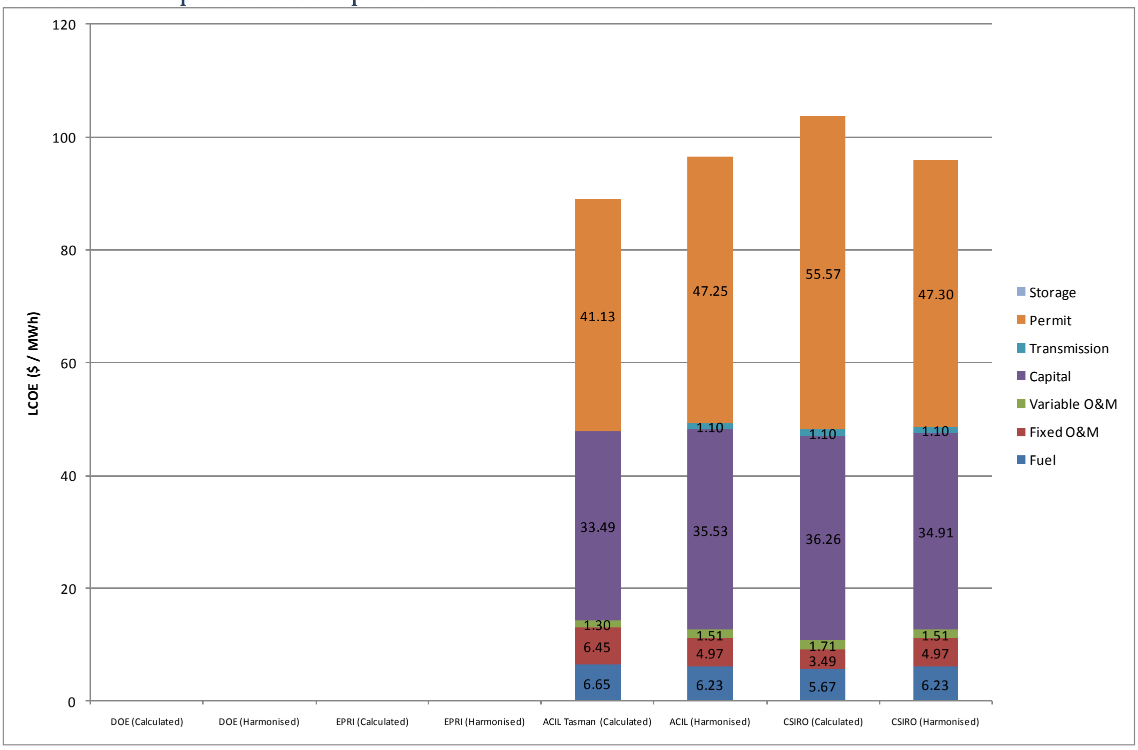

Figure 14: Calculated and harmonised LCOE breakdowns for brown coal pf in 2030. A carbon permit of $52/t$CO_2$ has been included

In 2030 as shown in Figure 12 only CSIRO (2010) and ACIL Tasman (2010) report values for brown coal pf.

The reported assumption that has the greatest effect on LCOE is efficiency, where the CSIRO (2010) value (34.9%) increases the LCOE by 11% compared to the harmonised value (41%). The ACIL Tasman (2010) efficiency (47.1%) lowers the LCOE by 8%. Changes in efficiency have a great effect on LCOE because of the carbon permit price, which is higher in 2030 ($52/t$CO_2$) and makes a great contribution to LCOE which can be seen in Figure 14.

General variation in assumptions – 2030

By 2030 because of the high permit price, efficiency is the assumption that has the greatest effect on LCOE in general, as can be seen in Figure 12. An increase in efficiency of 50% decreases the LCOE by 20% whereas a decrease in efficiency of 50% increases the LCOE by 60%. For the same reasons, emissions factor is the next assumption to have a big effect on LCOE. A ±50% change in emissions changes the LCOE by ±27% in the same direction.

Large variation between reported assumptions – 2030

In this case there is no ±50% between reported assumptions.

Brown coal pf with Carbon Capture and Storage (CCS)

This technology has cost projections from EPRI (2010), IEA (2010), ACIL Tasman (2010) and CSIRO (2010) for the year 2015 and EPRI (2010), ACIL Tasman (2010) and CSIRO (2010) for 2030. The 2015 tornado plot is shown in Figure 15.

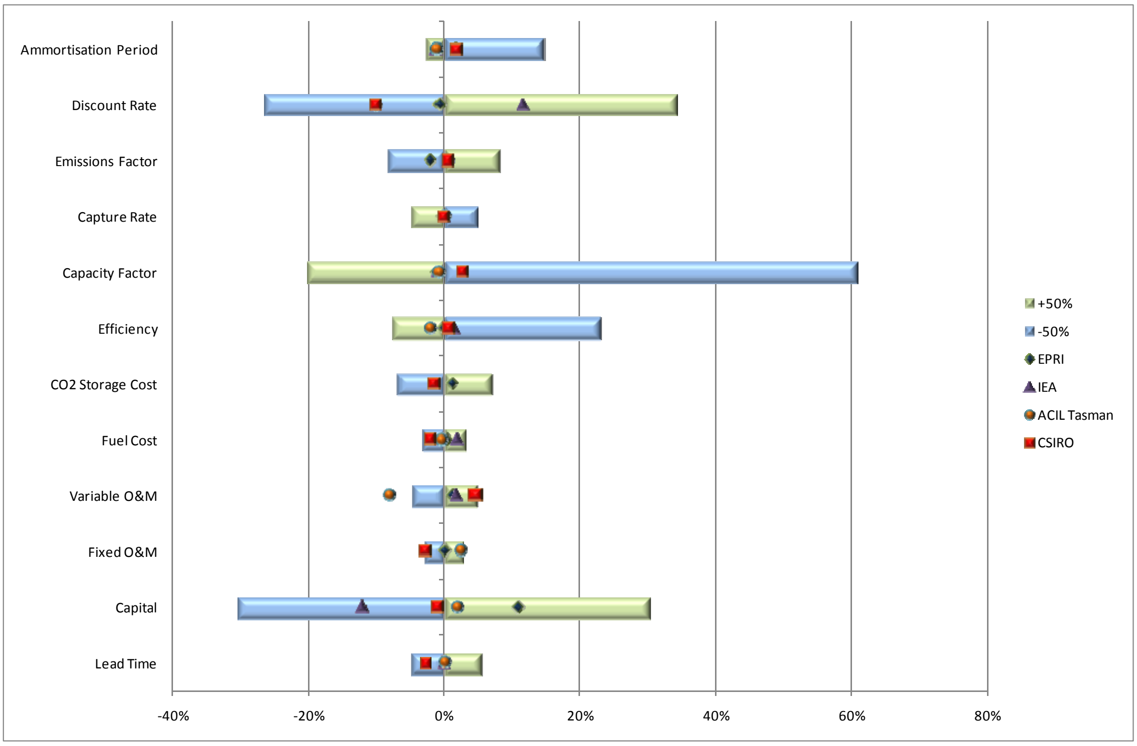

Figure 15: Tornado plot showing variation in LCOE for brown coal pf with CCS plant in 2015. An emission permit price of $\$28/tCO_2$ has been included in the LCOE calculation

Variation in reported assumptions – 2015

The reported assumption that has the greatest effect on LCOE is capital, where the lower value reported by the IEA (2010) ($5019/kW) reduces the LCOE by 12% compared to the harmonised value ($6241/kW). EPRI (2010) report a higher value ($7363/kW) which increases the LCOE by 11% compared to the harmonised value.

The source of differences in capital costs are partially due to basic plant differences as firstly EPRI (2010), ACIL Tasman (2010) and CSIRO (2010) provide data for supercritical AC plants. The IEA report on an ultra supercritical AC plant and this technology tends to have a higher capital cost. In addition, the IEA (2010) plant is considerably smaller (434 MW) than the EPRI (2010) and ACIL Tasman (2010) plants (both 750 MW). In this case the smaller and most advanced plant is actually the lowest in cost, which is not normally the case (see Section 4.3.1 Black and brown coal CCS for plant data). The differences are due to the different methodologies behind the capital cost estimates as IEA (2010) also tend to have lower capital costs (see brown coal pf), which is a function of the methodology and assumptions behind the capital cost estimate. The methodologies are described in Section 4.5.1.

The reported assumption that has the second greatest effect on LCOE is discount rate, where the value used by CSIRO (2010) (7%) decreases the LCOE by 10% relative to the harmonised value (8.4%) and the value used by the IEA (2010) (10%) increases the LCOE by 12% relative to the harmonised value. See "Brown coal pulverised fuel (pf) - Variation in reported assumptions - 2015" for more on discount rates.

As can be seen in the LCOE breakdown chart in Figure 16 the largest component of LCOE is capital cost. Therefore, any changes to the capital cost component will have a large impact on LCOE. This can mean changes to the capital cost itself but also to assumptions such as the discount rate can affect the LCOE.

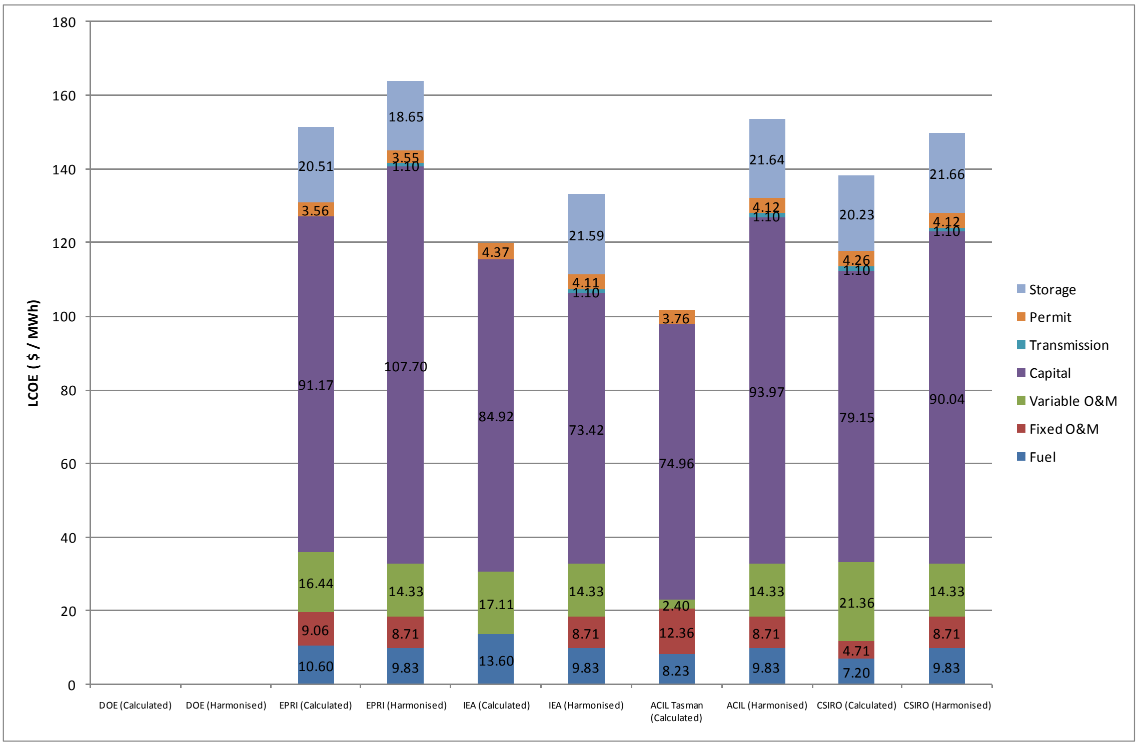

Figure 16: Calculated and harmonised LCOE breakdowns for brown coal pf with CCS in 2015. A carbon permit of $28/tCO_2$ has been included

General variation in assumptions - 2015

Variation in capacity factor has the greatest effect on LCOE of all of the assumptions; when the capacity factor is reduced by 50% from the harmonised value of 83.75%, the LCOE increases by 61%. Similarly, when the capacity factor is increased to its maximum value of 100% (an increase of 19.4% from the harmonised value) the LCOE is reduced by 20%. This emphasises the role capacity factor plays in the formula for the capital cost component and fixed O&M component of the LCOE calculation, as for brown coal pf. However, in this case, capital makes up an even larger share of the LCOE than for brown coal pf, because this technology is more expensive. It can be seen in Figure 16 the capital cost component is the largest contributor to the LCOE, therefore changes in capacity factor will have a large effect on LCOE.

The assumption that has the second-greatest effect on LCOE in general is discount rate (but only 1% more than capital). An increase in discount rate of 50% from the harmonised value (8.47%) increases the LCOE by 34%. A 50% decrease in discount rate from the harmonised value reduces the LCOE by 27%. Changes in discount rates affect the capital cost and fixed O&M components. For this technology, since capital is a large component of LCOE, any changes to the capital component will result in large changes to the LCOE.

Large variation between reported assumptions – 2015

The only assumption that has a variation in the reported values more than ±50% is variable O&M, where the ACIL Tasman (2010) value ($2.40/MWh) is 83.25% less than the harmonised value ($14.33/MWh) and all of the other reported values are considerably higher (more than $16/MWh) (see Appendix G - Data Tables: Variable O&M Costs for Non-Renewables 2015). ACIL Tasman have based their O&M values on actual operating plant data and this can result in variation in the ratio between the fixed and variable O&M[31]; the fixed O&M value reported by ACIL Tasman is the highest of all the reports. However, there are no operating brown coal pf with CCS plants which means the assumptions behind these values are unknown. Nevertheless, the effect of variations in O&M on LCOE is less than ±9%.

Variation in reported assumptions – 2030

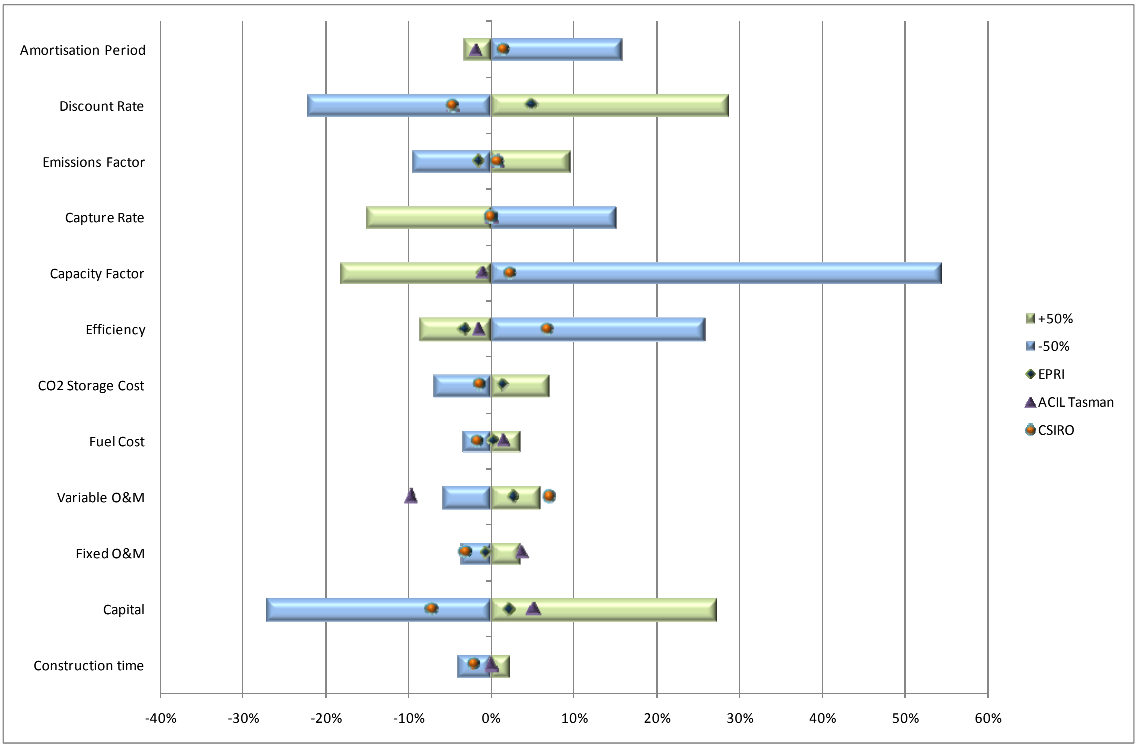

Figure 17: Tornado plot showing variation in LCOE for brown coal pf with CCS plant in 2030. An emission permit price of $52/tCO_2$ has been included in the LCOE calculation

[31] Personal communication, DRET.

The largest variation on LCOE from reported assumptions occurs for variable O&M in 2030. The ACIL Tasman (2010) value ($2.40/MWh) reduces the LCOE from the harmonised value ($13.40/MWh) by 10%. The CSIRO (2010) value ($21.36/MWh) increases the LCOE from the harmonised value by 7%. The reason for the lower ACIL Tasman (2010) variable O&M cost is described above (Large variation between reported assumptions – 2015). The CSIRO (2010) value is based on an O&M estimate for brown coal pf with CCS plants Dave (2009). However, the actual effect on LCOE is only low at less than ±10%.

Variable O&M is having an effect on LCOE for brown coal pf with CCS in 2030 as firstly there is a large degree of variation in the reported values and secondly it makes up approximately 15% of the LCOE as can be seen in Figure 18.

The reported assumption with the second-largest affect on LCOE is capital. The CSIRO (2010) capital cost ($4008/kW) reduces the LCOE from the harmonised value ($4612/kW) by 7% whereas the ACIL Tasman (2010) capital cost ($5036/kW) increases the LCOE by 5%. The plant types specified are the same as in 2015. CSIRO (2010) has a lower capital cost because of the methodology behind the capital cost projections; the use of learning curves has lead to reductions in the cost of this plant type by 2030 (Section 4.5.1 - Model using learning curves). Capital cost forms the largest share of the LCOE and differences in capital effect the LCOE more than other assumptions (see Figure 18 below).

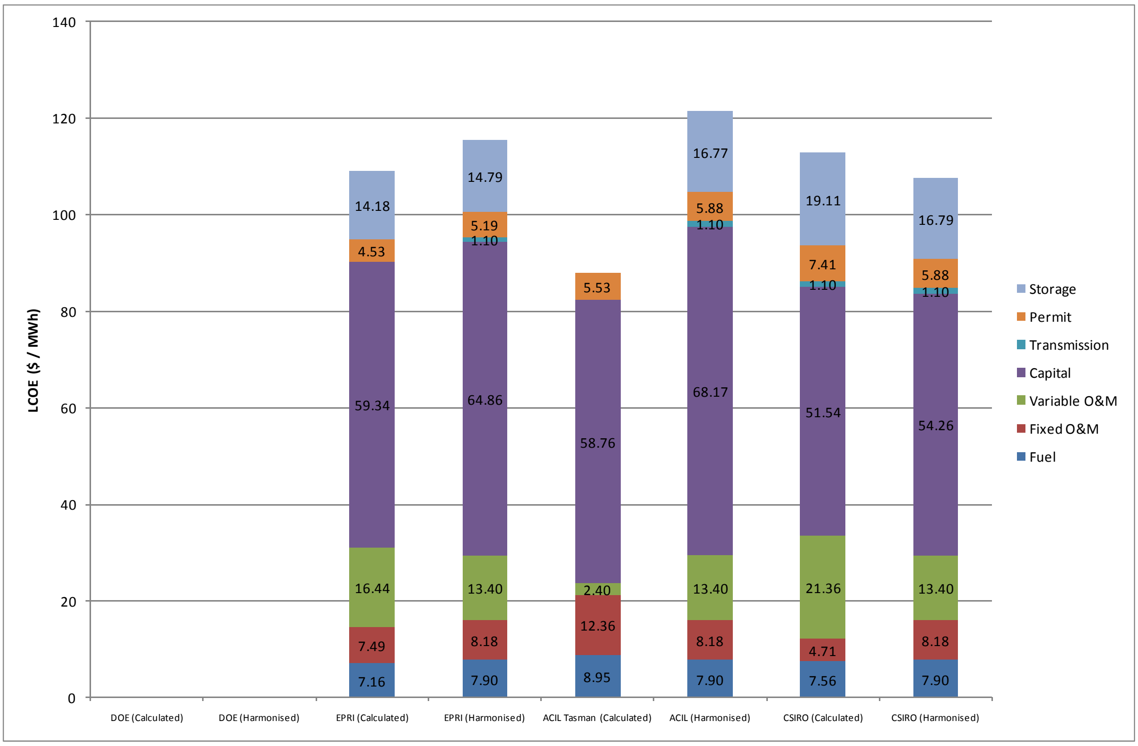

Figure 18: Calculated and harmonised LCOE breakdowns for brown coal pf with CCS in 2030. A carbon permit of $52/tCO_2$ has been included

General variation in assumptions – 2030

Capacity factor is the assumption that has the greatest general effect on LCOE. A decrease of 50% increases the LCOE relative to the harmonised value (83.33%) by 54% and an increase in capacity factor to the maximum value (100%) (an increase of 20%) decreases the LCOE by 18%. The reasons for this effect are the same as in 2015 (see General variation in assumptions –

2015). However, the effect on LCOE is not as pronounced as in 2015, because of the smaller capital cost component due to improvements in technology that reduce its cost by 2030.

The second assumption to have a large effect on LCOE in general is capital cost. This is different to 2015, when discount rate had a slightly greater effect on LCOE than capital. By 2030, when the capital cost has been reduced, changes in discount rate do not increase the LCOE by the same margin as when the capital cost was higher. In 2030, when the capital cost is changed by ±50%, the LCOE changes by ±27% from the harmonised value in the same direction.

Large variation between reported assumptions – 2030

Variable O&M fits into this category and has already been covered in detail under "Variation in reported assumptions – 2030".

Black coal pf

All reports provide projections for this technology for 2015 and all with the exception of EPRI (2010) and IEA (2010) for 2030.

Variation in reported assumptions – 2015

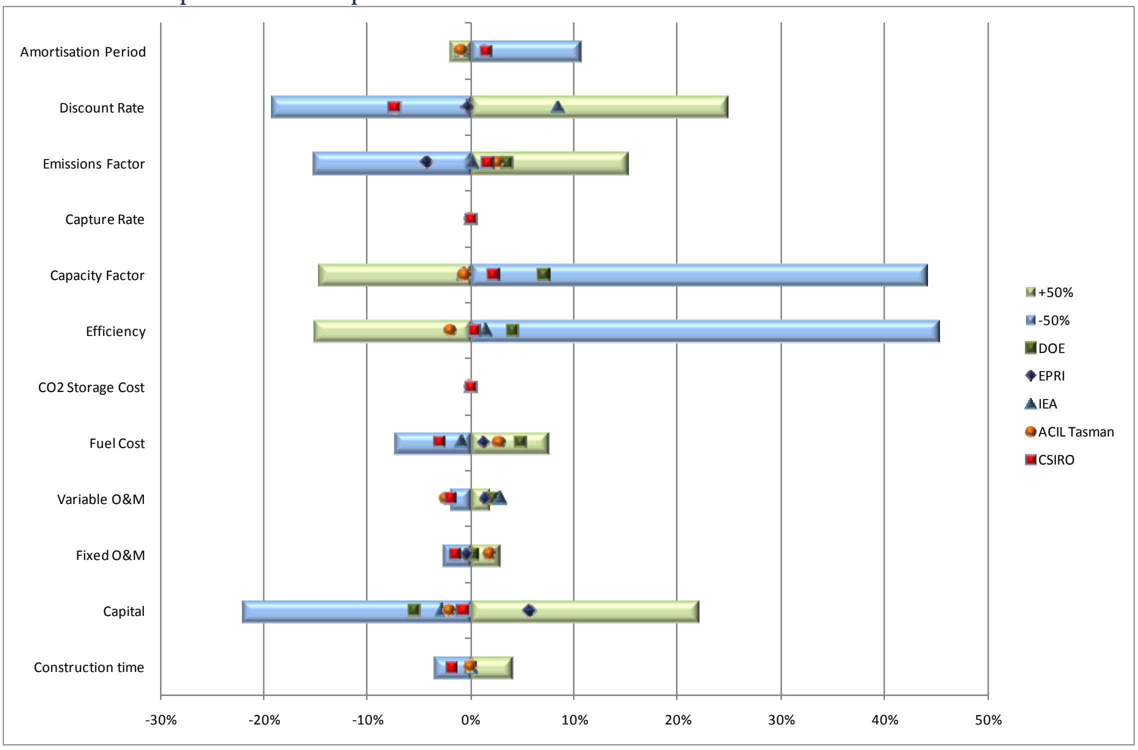

Figure 19: Tornado plot showing variation in LCOE for black coal pf plant in 2015. An emission permit price of $28/tCO_2$ has been included in the LCOE calculation

From the tornado plot Figure 19 it can be observed that the reported assumption with the greatest effect on LCOE is the discount rate. The CSIRO (2010) value (7%) reduces the LCOE by 7% from the harmonised value (8.47%) and the IEA discount rate (10%) increases the LCOE from the harmonised value by 8%. Changes in the discount rate affect the LCOE when there is a large capital cost component and/or fixed O&M component; and this is the case for black coal pf in 2015, as can be seen in Figure 20. However, the overall effect on LCOE is not great – less than ±9%.

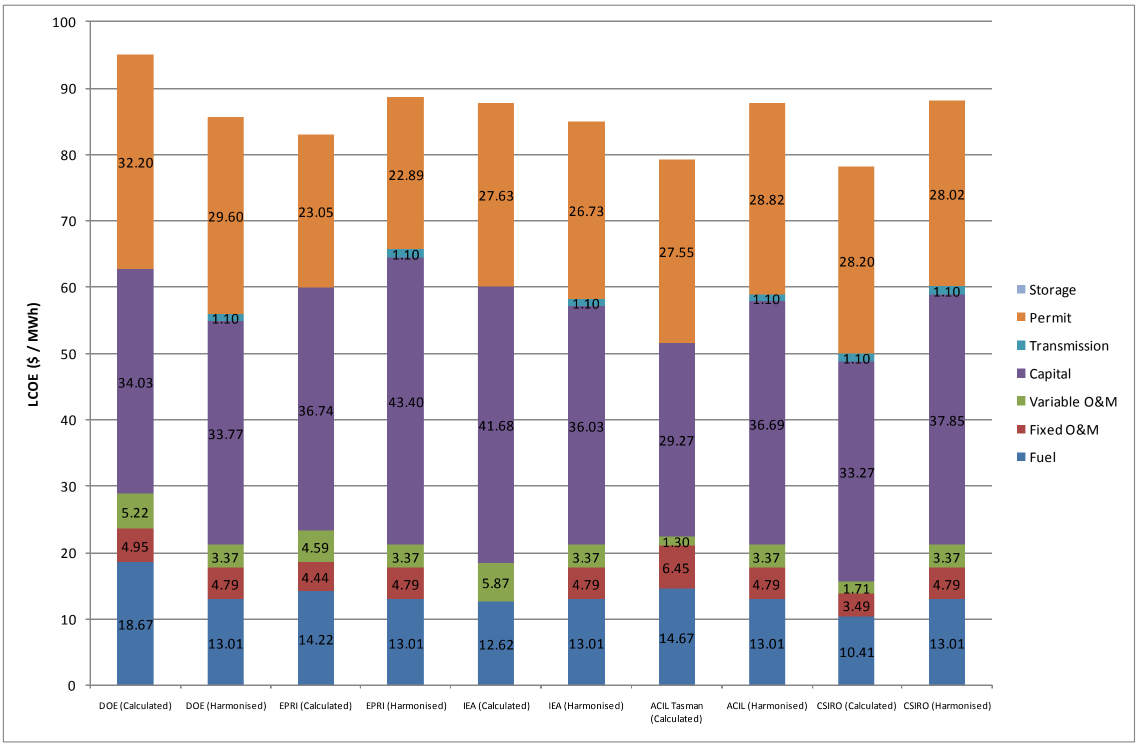

Figure 20: Calculated and harmonised LCOE breakdowns for black coal pf in 2015. A carbon permit of $28/tCO_2$ has been included

The reported assumption with the second greatest effect on LCOE is capital cost, and this is due to two values only; the US DOE (2009) capital cost ($2309/kW) reduces the LCOE from the harmonised value ($2632/kW) by 5% and the EPRI (2010) capital cost ($2967/kW) increases the LCOE from the harmonised value by 6%. The other reported capital costs are less than $100 different. Overall the effect on LCOE is very small. EPRI (2010) tend to have a higher capital cost because of the inclusion of a 7.5% real project cost on top of the normal capital cost. US DOE (2009) are lower as the US capital costs are generally lower. These differences are also due to the methodology used to project capital costs as described in Section 4.5.1.

General variation in assumptions – 2015

Efficiency is the assumption that has the greatest general effect on the LCOE; an increase in efficiency of 50% from the harmonised value (38.2%) decreases the LCOE by 15% and a decrease in efficiency of 50% from the harmonised value increases the LCOE by 45%. Changes in efficiency affect the amount of fuel required and the emissions released. A decrease in efficiency means more fuel is burned and more emissions generated for the same level of output. This raises the fuel and permit components of the LCOE. An increase in efficiency has the opposite effect (i.e. less fuel is burned and fewer emissions are released). From Figure 20 it can be seen that approximately half of the LCOE is from fuel and permit combined and thus any changes to these assumptions will have a large effect.

The assumption that has the second-greatest effect on LCOE in general is capacity factor. A decrease in capacity factor by 50% from the harmonised value (83.8%) increases the LCOE by 44% and an increase in capacity factor to 100% (an increase of 19%) decreases the LCOE by 15%. Capacity factor affects the capital cost and fixed O&M components of LCOE. Since capital cost is large, any changes to that will alter the LCOE. For a more detailed discussion of the effect of capacity factor, see Section 4.2.1- Brown coal pulverised fuel (pf).

Large variation between reported assumptions – 2015

Variable O&M is the only assumption that falls into this category. ACIL Tasman (2010) reports a low value ($1.30/MWh) which is 61.4% lower than the harmonised value ($3.37/MWh). At the other end of the scale, US DOE (2009) have a value ($5.22/MWh) which is 55% higher than the harmonised value and EPRI (2010) is even higher ($5.87/MWh) and 74.3% greater than the harmonised value. Firstly, ACIL Tasman (2010) has a different treatment of O&M which has been discussed under “Brown coal pf with Carbon Capture and Storage (CCS): Large variation between reported assumptions – 2030”. EPRI (2010) use average cost for O&M rather than the marginal but it is not clear why this should be higher than the ACIL Tasman (2010) figure. The US has different prices to Australia which explains why their O&M cost is higher.

Nevertheless, the effect on LCOE is minor at less than ±4%.

Variation in reported assumptions – 2030

The 2030 tornado plot is shown in Figure 21 below.

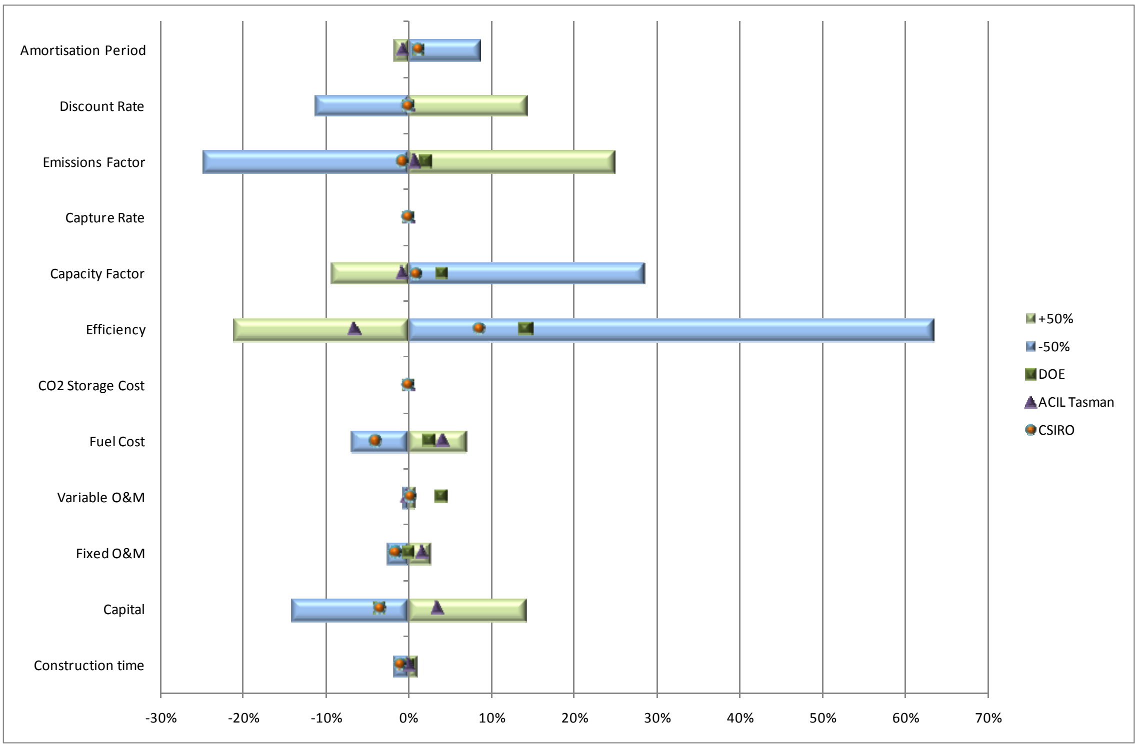

Figure 21: Tornado plot showing variation in LCOE for black coal pf plant in 2030. An emission permit price of $52/tCO_2$ has been included in the LCOE calculation

Efficiency is the assumption where the reported values have the greatest effect on LCOE. The ACIL Tasman (2010) value (48%) reduces the LCOE by 7% compared to the harmonised value (43%) and the US DOE (2009) value (35.2%) increases the LCOE by 15% relative to the harmonised value. Differences in efficiency arise due to differences in assumptions behind the plant design and location. Plant location should not be an issue for the Australian studies since all use standard Australian conditions (see Section 4.4.1: Ambient conditions). We do not know the ambient conditions used in the US but we could assume it would be colder and therefore the efficiency should be greater. We also don't know if the US DOE use a higher heating value (HHV) or lower heating value (LHV) or what plant type is assumed. ACIL Tasman (2010) assume a supercritical air cooled plant (see Section 4.3.1: Black and brown coal pf without CCS).

Efficiency affects the LCOE through the fuel cost and emissions. See "Black coal pf "General variation in assumptions -2015" for a thorough explanation. By 2030, the permit price has increased (see Figure 22) and now makes up the largest portion of LCOE, which is why changes in efficiency have such a large effect on LCOE.

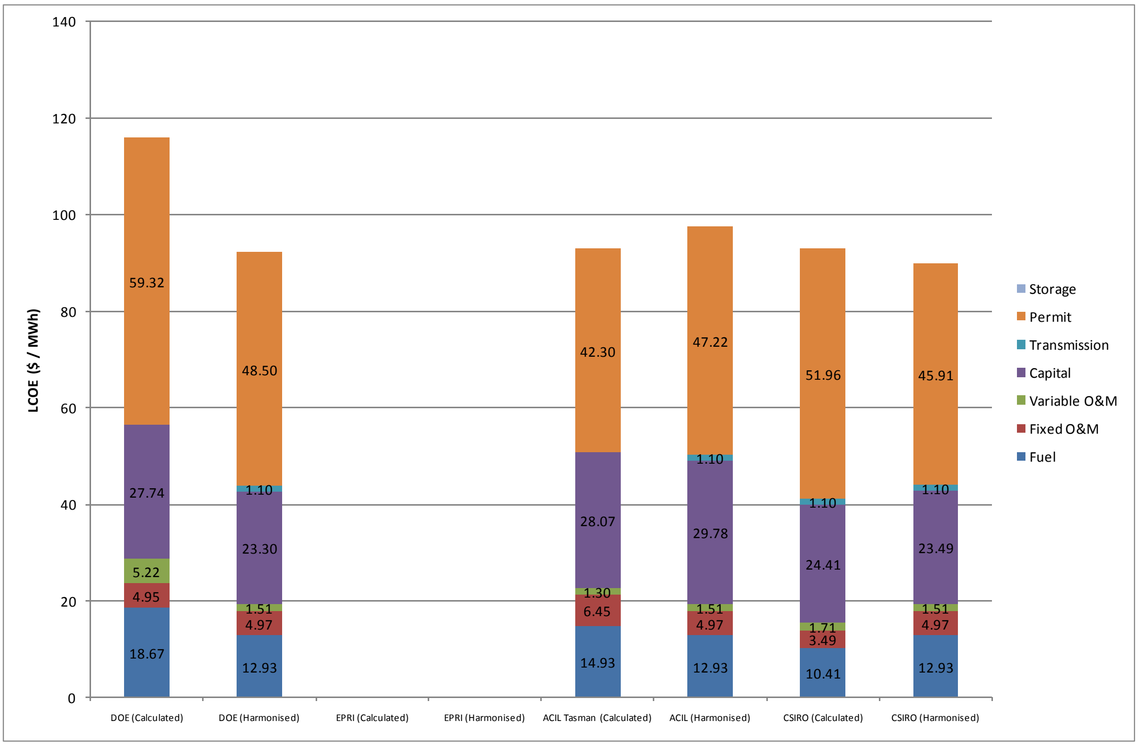

Figure 22: Calculated and harmonised LCOE breakdowns for black coal pf in 2030. A carbon permit of $52/tCO_2$ has been included

The reported assumption that has the next greatest effect on LCOE is fuel cost. The CSIRO (2010) value ($1.10/GJ) reduces the LCOE by 4% from the harmonised value ($1.54/GJ) and the ACIL Tasman (2010) value ($1.99/GJ) increases the LCOE by 4%. There is variation in the black coal price as CSIRO (2010) use Queensland black coal and ACIL Tasman (2010) use Hunter Valley black coal. Further explanation is given in Section 4.4.1: Coal Price.

General variation in assumptions – 2030

As with the reported assumptions, the two assumptions that have the greatest effect on LCOE in general are efficiency and emission factor. This is again due the fact that the permit price makes up the greatest share of the LCOE so any assumptions that affect this will change the LCOE.

Large variation between reported assumptions – 2030

The variable O&M value reported by the US DOE (2009) ($5.22/MWh) is actually 247% higher than the harmonised value ($1.51/MWh), but the US DOE (2009) data is not used in the harmonisation process which increases their difference. It is unknown why this value is higher than the Australian values, except perhaps for basic country differences. Even though there is this large difference, the effect on LCOE is minor; the US DOE (2009) variable O&M increases the LCOE by 4%.

Black coal Integrated Gasification Combined Cycle (IGCC)

This technology is reported on in 2015 and 2030 by all of the reports except for IEA (2010).

Variation in reported assumptions – 2015

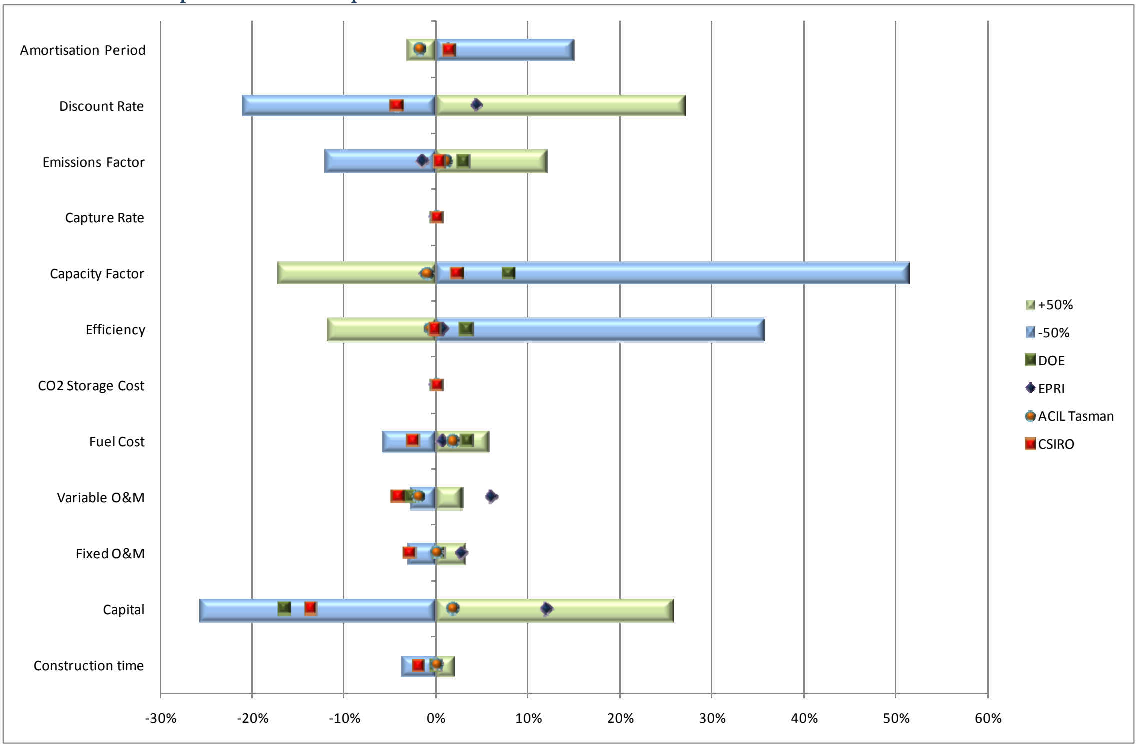

Figure 23: Tornado plot showing variation in LCOE for black coal IGCC plant in 2015. An emission permit price of $28/tCO_2$ has been included in the LCOE calculation

The 2015 tornado plot is shown below in Figure 23. From the figure, it can be seen that the largest effect on LCOE from the reported assumptions is capital cost. The capital cost reported by US DOE (2009) ($2813/kW) reduces the LCOE from the harmonised value ($4134/kW) by 16% (cost is 32% lower than harmonised capital) and the higher capital cost reported by EPRI (2010) ($5099/kW) increases the LCOE by 12% from the harmonised value (cost is 26% higher than harmonised). EPRI (2010) specify the plant as having two GE9F turbines followed by a steam turbine. The US DOE (2009) do not specify the plant configuration. However, from Table 13 we know that the EPRI (2010) plant is much larger, with a higher efficiency (see Section 4.3.1). Larger plants should be cheaper per kW, but more efficient plants are generally more expensive. EPRI (2010) capital costs tend to be higher due to their inclusion of an additional 7.5% real project cost. US DOE (2009) also tend to be lower because the costs are from the US. Differences also arise due to differences in the methodology behind the capital cost estimates. Details can be found in Section 4.5.1. However, even though the differences in capital are quite large, they still only affect the LCOE by less than ±18%. From Figure 24 it can be seen that capital does form the largest share of LCOE.

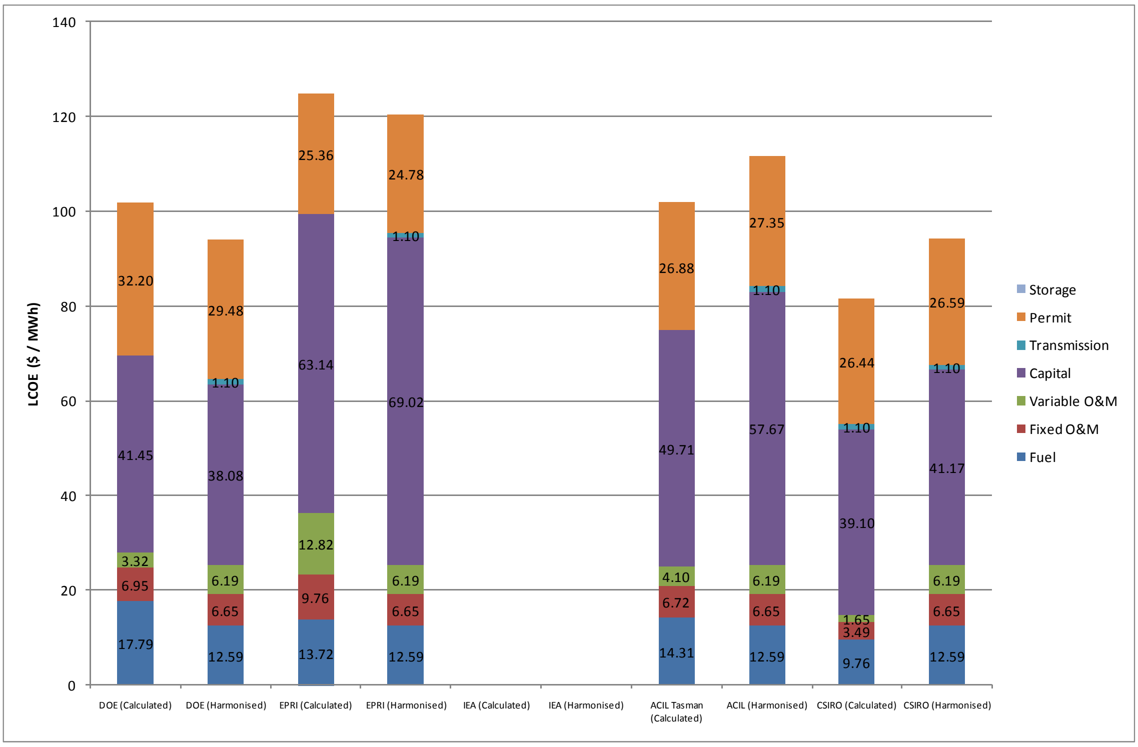

Figure 24: Calculated and harmonised LCOE breakdowns for black coal IGCC in 2015. A carbon permit of $28/tCO_2$ has been included

The reported assumption that has the second greatest effect on LCOE is variable O&M. The low value reported by CSIRO (2010) ($1.65/MWh) reduces the LCOE by 4% from the harmonised value ($6.19/MWh) whereas the high value reported by EPRI (2010) ($12.82/MWh) increases the LCOE by 6%. Note also that these two values have a variation from the harmonised value of more than ±50%. CSIRO (2010) based the variable O&M cost on the other black coal technologies, which may mean that it is too low for this technology type. EPRI (2010) use average costs and build their O&M costs from the 'bottom-up' and thus it is based on black coal IGCC plant[32]. Nevertheless, the differences do not have a great affect on LCOE; less than ±7%. This is because variable O&M is not a big contributor to LCOE, as can be seen in Figure 24.

General variation in assumptions – 2015

Capacity factor is the assumption that in general has the largest effect on LCOE. A decrease in capacity factor by 50% from the harmonised value (83.8%) increases the LCOE by 51% and an increase in capacity factor to 100% (an increase of 19%) decreases the LCOE by 17%. Capacity factor affects the capital cost and fixed O&M components of LCOE. Since capital cost is large, any changes to that will alter the LCOE. For a more detailed discussion of the effect of capacity factor, see Section 4.2.1: Brown coal pulverised fuel (pf).

The assumption to have the second-greatest effect on LCOE in general is capital cost. Changing the capital cost by ±50% changes the LCOE by ±26% in the same direction. Capital has been discussed under "Variation in reported assumptions – 2015".

The fact that both capital cost and capacity factor result in the largest level of general variation on LCOE means that the capital cost component is relatively high for this technology.

[32] From Stakeholder Reference Group comments

Large variation between reported assumptions – 2015

This variation occurs for variable O&M and has already been covered under "Variation in reported assumptions – 2015".

Variation in reported assumptions – 2030

The 2030 tornado plot is shown in Figure 25 below.

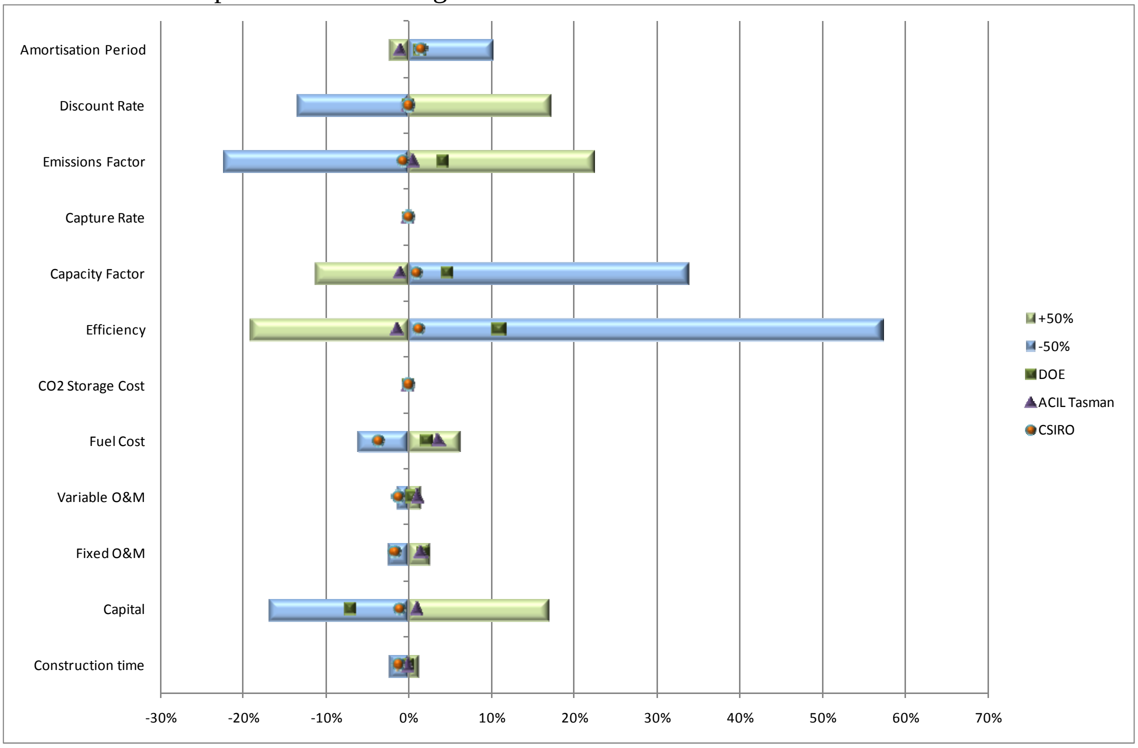

Figure 25: Tornado plot showing variation in LCOE for black coal IGCC plant in 2030. An emission permit price of \$52/tCO_2 has been included in the LCOE calculation

As with black coal pf in 2030, efficiency is the assumption where the reported values have the greatest effect on LCOE. The ACIL Tasman (2010) value (45%) reduces the LCOE by 1% compared to the harmonised value (44%) and the US DOE (2009) value (36.9%) increases the LCOE by 11% relative to the harmonised value. Differences in efficiency arise due to differences in assumptions behind the plant design and location. We do not have any details of the plant design for the US DOE (2009) or ACIL Tasman (2010). For a discussion of location effects see "Black coal pf Variation in reported assumptions – 2030".

Efficiency affects the LCOE through the fuel cost and emissions. See "Black coal pf General variation in assumptions -2015" for more explanation. By 2030, the permit price has increased (see Figure 26) and now makes up the largest portion of LCOE, which is why changes in efficiency have such a large effect on LCOE.

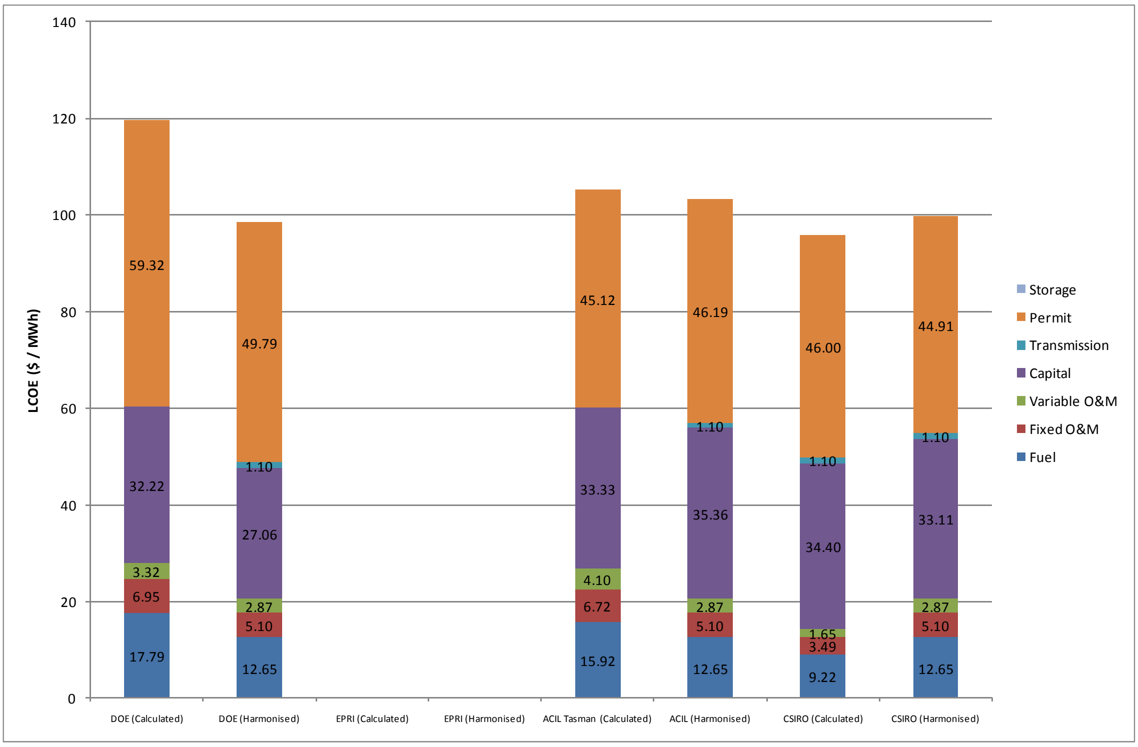

Figure 26: Calculated and harmonised LCOE breakdowns for black coal IGCC in 2030. A carbon permit of $52/tCO_2$ has been included

Capital cost is the reported assumption that has the second greatest effect on LCOE. US DOE (2009) report a low capital cost ($2186/kW) which reduces the LCOE by 7% relative to the harmonised value ($2766/kW) and ACIL Tasman (2010) record a higher capital cost ($2857/kW) which increases the LCOE by 1% relative to the harmonised value. Note that both the ACIL Tasman (2010) and CSIRO (2010) capital costs are within 200 $/kW of each other. US DOE (2009) also reported the lowest capital cost for black coal IGCC in 2015 and so we could expect that trend to continue, as it is based on basic differences in plant cost between Australia and the US. In any case, the effect on LCOE is now reduced from 2015 (±18%) to be less than ±10%.

General variation in assumptions – 2030

Efficiency is the assumption where general variations have a large impact on LCOE. An increase in efficiency of 50% decrease the LCOE by 19% and a decrease in efficiency of 50% increases the LCOE by 57%. Efficiency has a large effect on LCOE because permit price now makes up the greatest share of LCOE. Efficiency has been discussed in detail under "Variation in reported assumptions – 2030".

Capacity factor is the second assumption where general variations will have an impact on LCOE. A decrease in capacity factor by 50% from the harmonised value (82.5%) increases the LCOE by 34% and an increase in capacity factor to the maximum of 100% (a 21% increase reduces LCOE by 11%. Changes in capacity factor affect the capital cost and fixed O&M components of LCOE. Since the capital cost component is still quite large it makes sense that capacity factor should affect LCOE.

Large variation in reported assumptions – 2030

There are none to report for this technology in 2030.

Black coal pf with CCS

All studies report on black coal pf with CCS in 2015 except for the US DOE (2009) and additionally in 2030 the IEA (2010) do not report on it. The tornado plot for 2015 is shown in Figure 27 below.

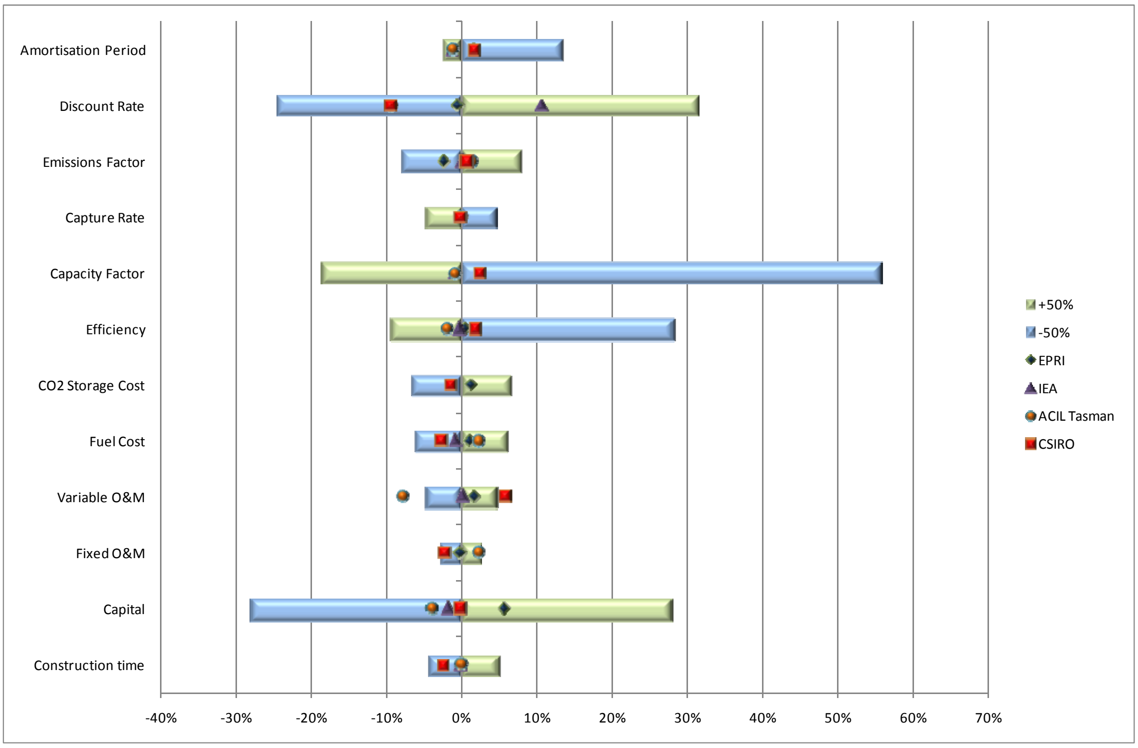

Figure 27: Tornado plot showing variation in LCOE for black coal pf with CCS plant in 2015. An emission permit price of $28/t$CO_2$ has been included in the LCOE calculation

Variation in reported assumptions – 2015

The reported assumption that has the biggest effect on LCOE is discount rate. The lower value reported by CSIRO (7%) reduces the LCOE from the harmonised value (8.47%) by 9% and the higher value reported by the IEA (10%) increases the LCOE from the harmonised value by 11%. Discount rate can have a large effect on LCOE when the capital cost and/or fixed O&M component is high. From Figure 28 we can see that is indeed the case for this technology in 2015. However, the overall effect on LCOE is minor at less than ±12%.

The assumption that has the second biggest effect on LCOE is variable O&M. This is due to two values lying outside the ±50% variability zone: ACIL Tasman (2010) and CSIRO (2010). ACIL Tasman (2010) report a variable O&M value ($2.40/MWh) that decreases the LCOE from the harmonised value ($13.26/MWh) by 8% and the CSIRO (2010) use a value ($21.36/MWh) that increases the LCOE by 6%. Differences in O&M have arisen due to the different methodologies used to estimate these values. CSIRO (2010) is based on a detailed engineering assessment of this technology and the likely entailed O&M cost (Dave et al., 2008). ACIL Tasman (2010) has used working power plant data and this has affected the ratio of fixed to variable O&M. However, there are no commercial black coal pf with CCS plants in Australia so it is unclear where this data has been sourced from.

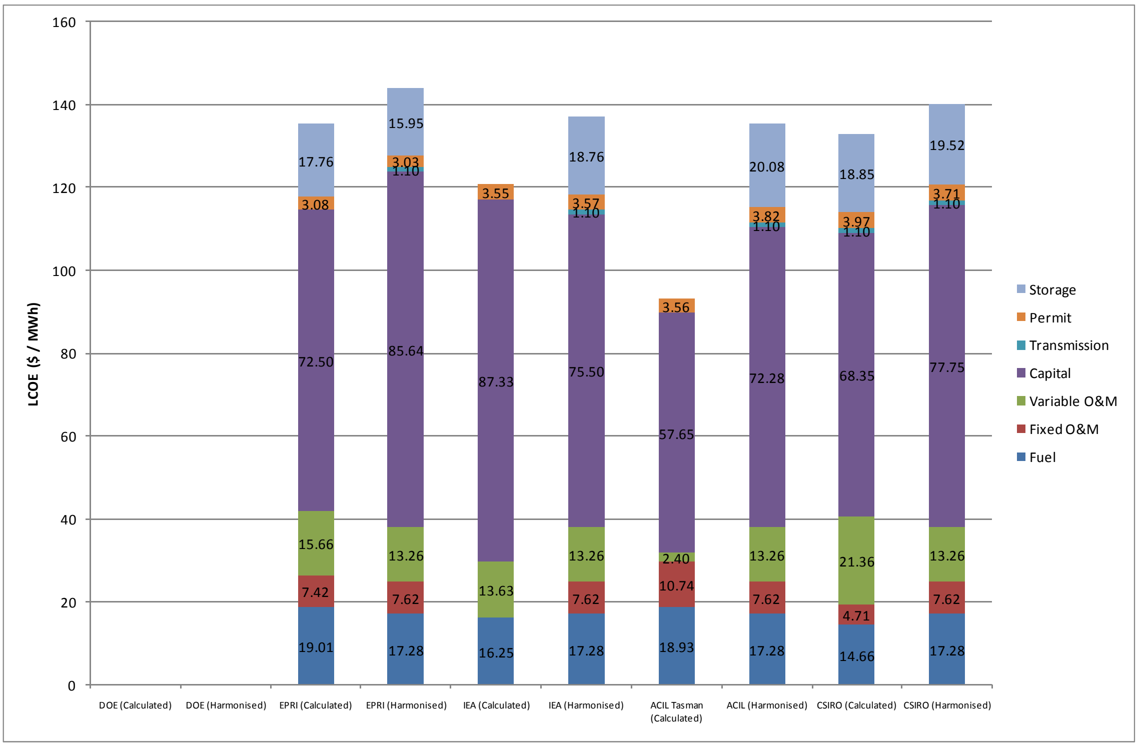

Figure 28: Calculated and harmonised LCOE breakdowns for black coal with CCS in 2015. A carbon permit of $28/tCO$_2$ has been included

General variation in assumptions – 2015

Changes in capacity factor have the greatest overall effect on LCOE. By decreasing the capacity factor from the harmonised value by 50%, the LCOE increases by 56%. Increasing the capacity factor to its maximum value of 100% (a 19% increase) reduces the LCOE by 19%. Capacity factor plays such a large role in LCOE because of the high capital cost component. This has already been discussed for earlier technologies, see Section 4.2.1 Brown coal pulverised fuel (pf).

Both capital and discount rate have the second greatest overall effect on LCOE. A ±50% change in capital from the harmonised value ($5318/kW) results in a ±28% change in LCOE in the same direction. And an increase in discount rate of 50% increases the LCOE by 32% whereas a decrease in discount rate of 50% reduces the LCOE by 24%. Like capacity factor both capital and discount rate affect the large capital component of LCOE.

Large variation between reported assumptions – 2015

This has already been covered under "Variation in reported assumptions – 2015".

Variation in reported assumptions – 2030

The 2030 tornado plot for black coal pf with CCS is shown in Figure 29.

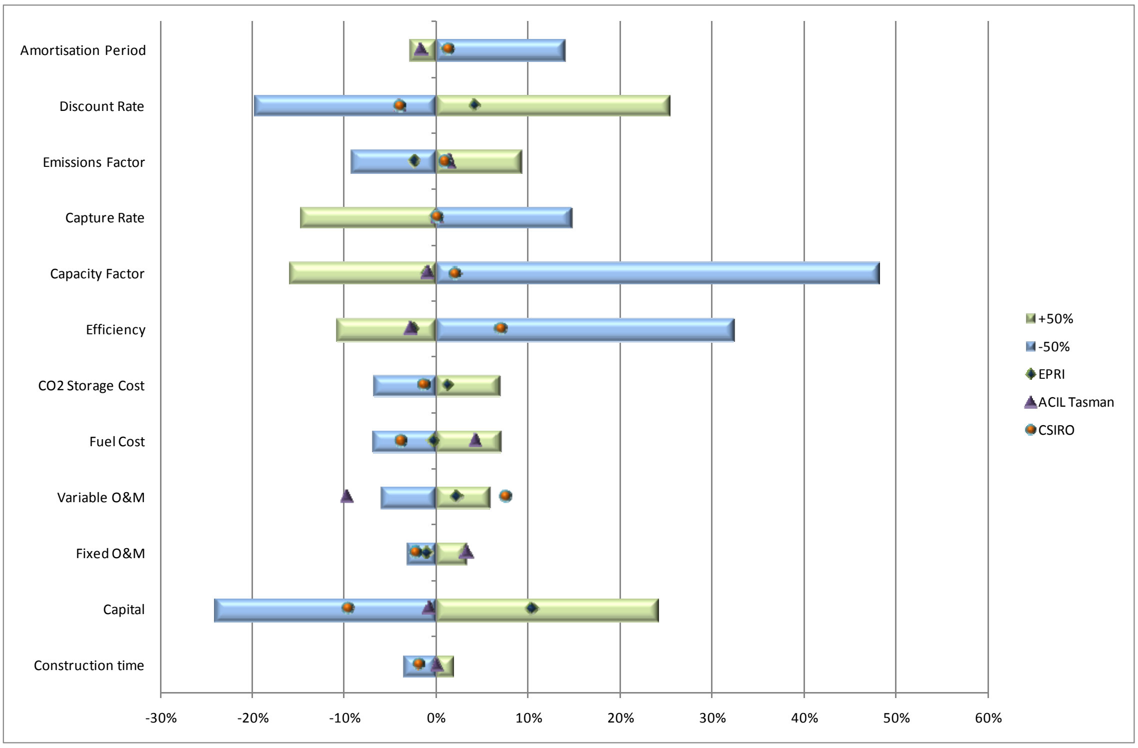

Figure 29: Tornado plot showing variation in LCOE for black coal pf with CCS plant in 2030. An emission permit price of $52/tCO_2$ has been included in the LCOE calculation

The reported assumption with the largest effect on LCOE is capital. The CSIRO (2010) value ($3160/kW) reduces the LCOE from the harmonised value ($3942/kW) by 10% whereas the EPRI (2010) value ($4792/kW) increases the LCOE from the harmonised value by 10%. As discussed earlier, EPRI (2010) add 7.5% onto their capital cost to cover real project costs. The actual plant types will differ and as EPRI (2010) have a higher efficiency (see Section 4.3.1: Black and brown coal CCS) we could assume it is a superior plant and therefore more expensive. The methodologies employed to obtain the capital cost projections will also be a factor here. By 2030 in the CSIRO (2010) model, black coal pf with CCS has pushed down the learning curve due to uptake of plant in the model. This then reduces the capital cost. Discussion of the methodologies can be found in Section 4.5.1.

The reported assumption with the second greatest effect on LCOE is variable O&M. This is the same as in 2015 and the actual values are the same. However, the effect on LCOE is slightly greater (by 2%). This is because from inspection of the LCOE breakdown charts for 2030 (Figure 30) and 2015 (Figure 28) it can be seen that by 2030 the variable O&M share of LCOE is slightly greater.

General variation in assumptions – 2030

Changes in capacity factor have the greatest overall effect on LCOE. By decreasing the capacity factor from the harmonised value by 50%, the LCOE increases by 48%. Increasing the capacity factor to its maximum value of 100% (a 20% increase) reduces the LCOE by 16%. Capacity factor plays such a large role in LCOE because of the high capital cost component. This has already been discussed for earlier technologies, see Section 4.2.1: Brown coal pulverised fuel (pf). Note however that in 2030 the capital cost component is lower than in 2015 and hence the overall effect of capacity factor on LCOE is lower.

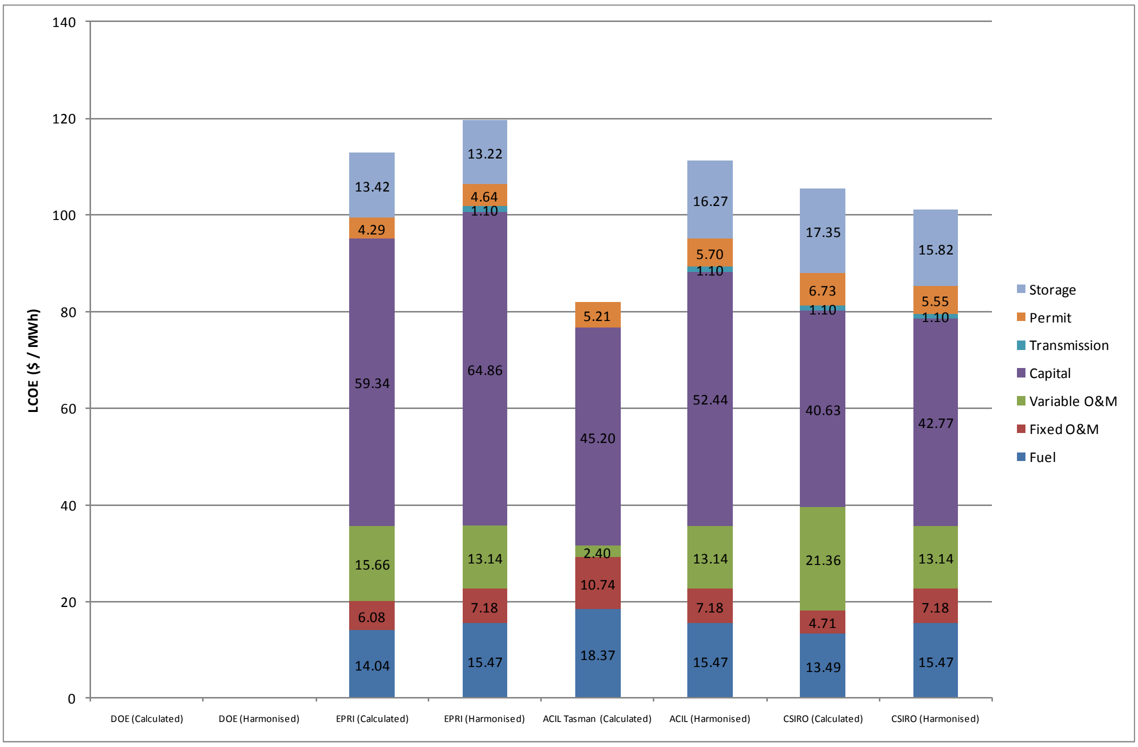

Figure 30: Calculated and harmonised LCOE breakdowns for black coal with CCS in 2030. A carbon permit of $52/tCO_2$ has been included

Capital has the second greatest overall effect on LCOE. A ±50% change in capital from the harmonised value results in a ±24% change in LCOE in the same direction. Capital has already been discussed under "Variation in reported assumptions – 2030".

Large variation between reported assumptions – 2030

This occurs for variable O&M which has already been covered under "Variation in reported assumptions – 2030".

Black coal IGCC with CCS

All reports provide data for the year 2015 for this technology except for CSIRO (2010) and in 2030 the IEA (2010) and CSIRO (2010) do not publish data. The tornado plot for 2015 is shown in Figure 31.

Variation in reported assumptions – 2015

Reported capital cost is the assumption that has the greatest effect on LCOE. The capital cost reported by US DOE (2009) ($3831/kW) reduces the LCOE by 25% from the harmonised value ($6417/kW) whereas the capital cost reported by EPRI (2010) ($7715/kW) increases the LCOE by 12%. US DOE (2009) already had a low capital cost for black coal IGCC and EPRI (2010) also reported the highest cost for black coal IGCC, therefore it follows that the same technology with the addition of a capture plant should follow the same trends (see "Black coal IGCC: Variation in reported assumptions – 2015"). However, if it were not for the low US DOE (2009) capital cost, the effect of capital on LCOE would not be as great.

Discount rate is the reported assumption that has the second largest effect on LCOE. Only two of the studies reported a discount rate: EPRI (2010) (8.47%) and IEA (10%). The effect on the LCOE from the harmonised value (9.2%) is only ±6% in the same direction.

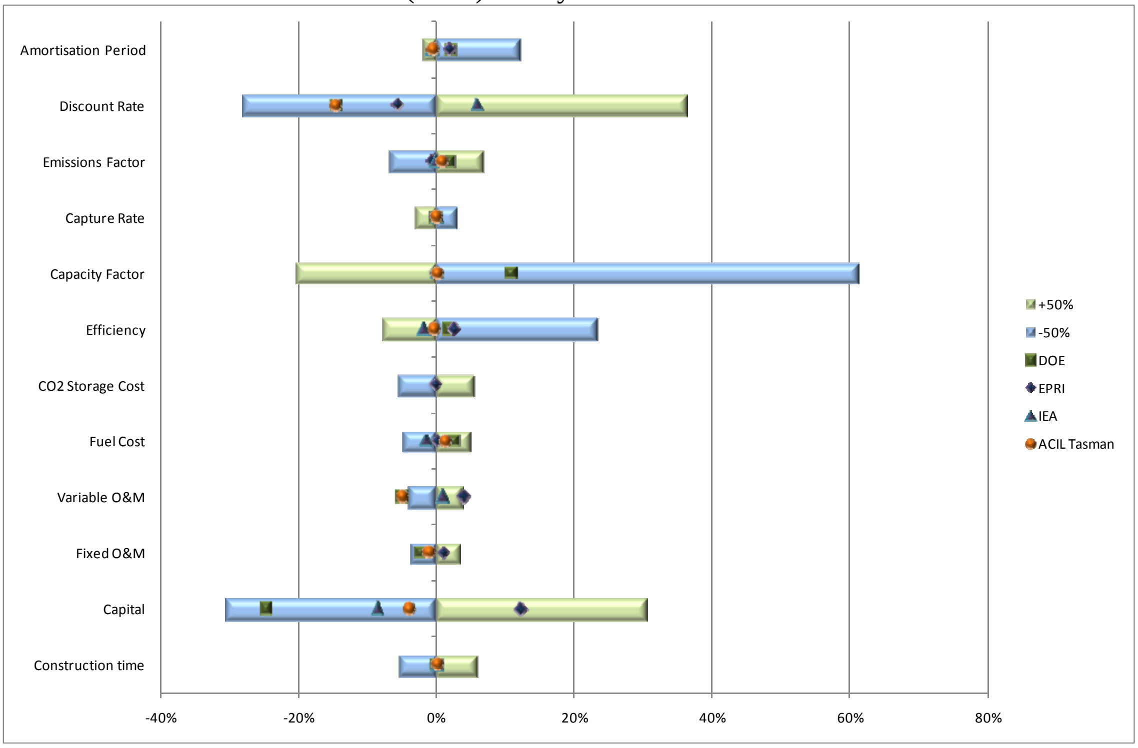

Figure 31: Tornado plot showing variation in LCOE for black coal IGCC with CCS plant in 2015. An emission permit price of $28/tCO_2$ has been included in the LCOE calculation

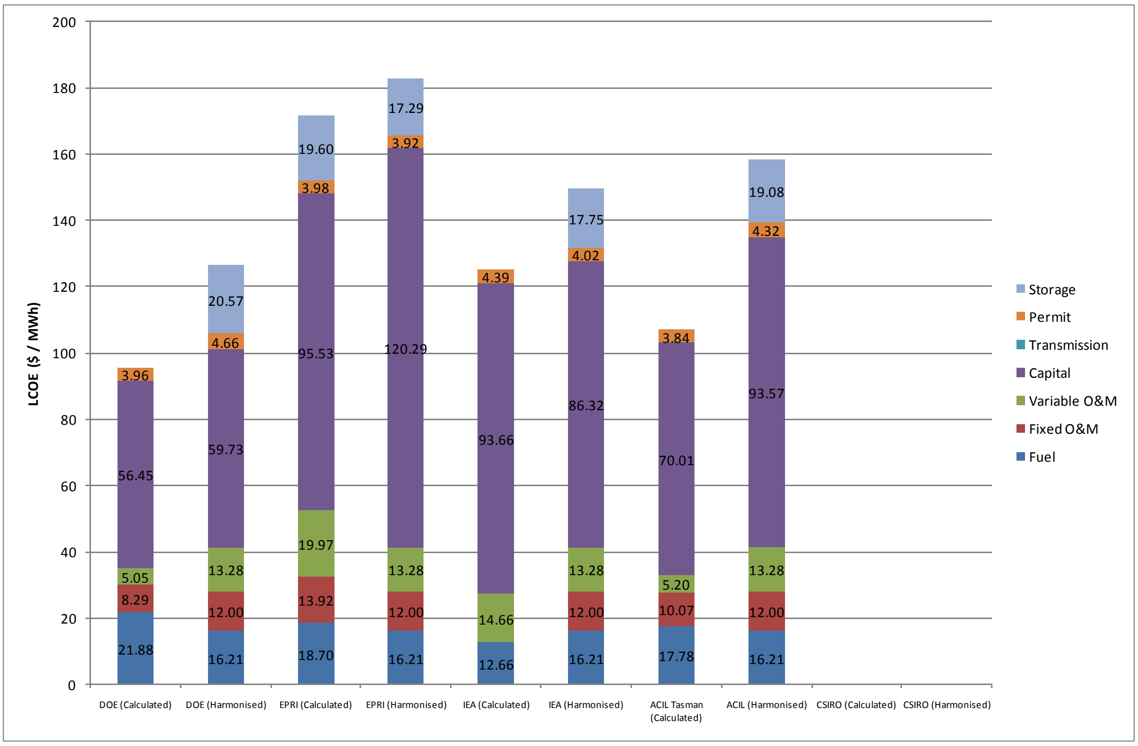

Figure 32: Calculated and harmonised LCOE breakdowns for black coal IGCC with CCS in 2015. A carbon permit of $28/tCO_2$ has been included

Because both capital and discount rate are affecting the LCOE it means that the capital and/or fixed O&M components must be large for this technology. From Figure 32 we can see that is indeed the case.

General variation in assumptions – 2015

The assumption that has the potential to have the largest effect on LCOE is capacity factor. A decrease in capacity factor by 50% from the harmonised value (85%) increases the LCOE by 61% and an increase in capacity factor to the maximum value (100% - an 18% increase) decreases the LCOE by 20%.

Discount rate is the next assumption to have a large impact in general on LCOE. A 50% increase in discount rate increases the LCOE by 36% and a 50% decrease in discount rate reduces the LCOE by 28%.

Capacity factor and discount rate affect the capital cost and fixed O&M components of the LCOE. Since capital is such a large component, any changes to capacity factor or discount rate have a large effect on LCOE.

Large variation between reported assumptions – 2015

Variable O&M is the assumption where reported values vary by more than ±50%. Both US DOE (2009) ($5.05/MWh) and ACIL Tasman (2010) ($5.20/MWh) have variable O&Ms that are lower than the other studies and the harmonised value ($13.28/MWh). Black coal IGCC with CCS is a new technology and thus it would not be possible to base these estimates on commercial plant O&M data. However, the total O&M values do not have this large variation (see Appendix G - Data Tables), so perhaps it is due to the ratio between fixed and variable O&M.

Variation in reported assumptions – 2030

The tornado plot for 2030 is shown in Figure 33 below.

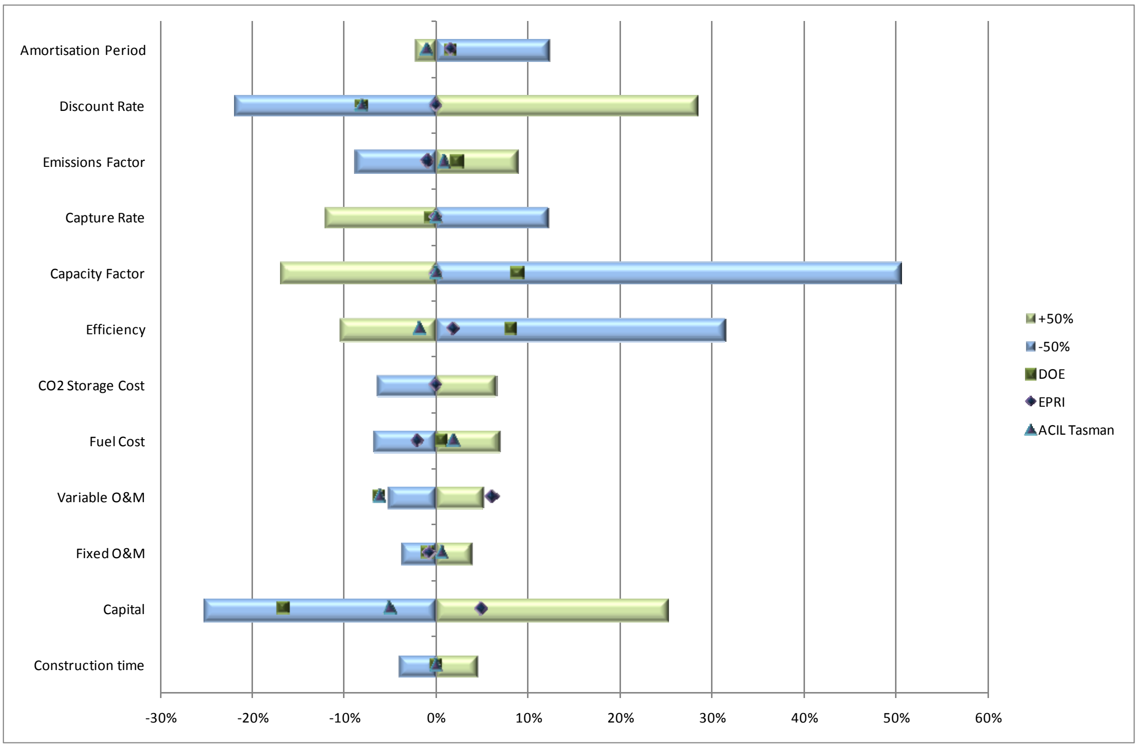

Figure 33: Tornado plot showing variation in LCOE for black coal IGCC with CCS plant in 2030. An emission permit price of $52/tCO_2$ has been included in the LCOE calculation

As in 2015, capital is the reported assumption that has the greatest effect on LCOE. The lower value reported by the US DOE (2009) ($2883/kW) reduces the LCOE by 17% from the harmonised value ($4298/kW) whereas the higher value reported by EPRI (2010) ($4721/kW) increases the LCOE by 5%. The effect on LCOE is lower now than in 2015. This is because the capital costs have reduced and thus the capital cost component of LCOE, as can be seen in Figure 34.

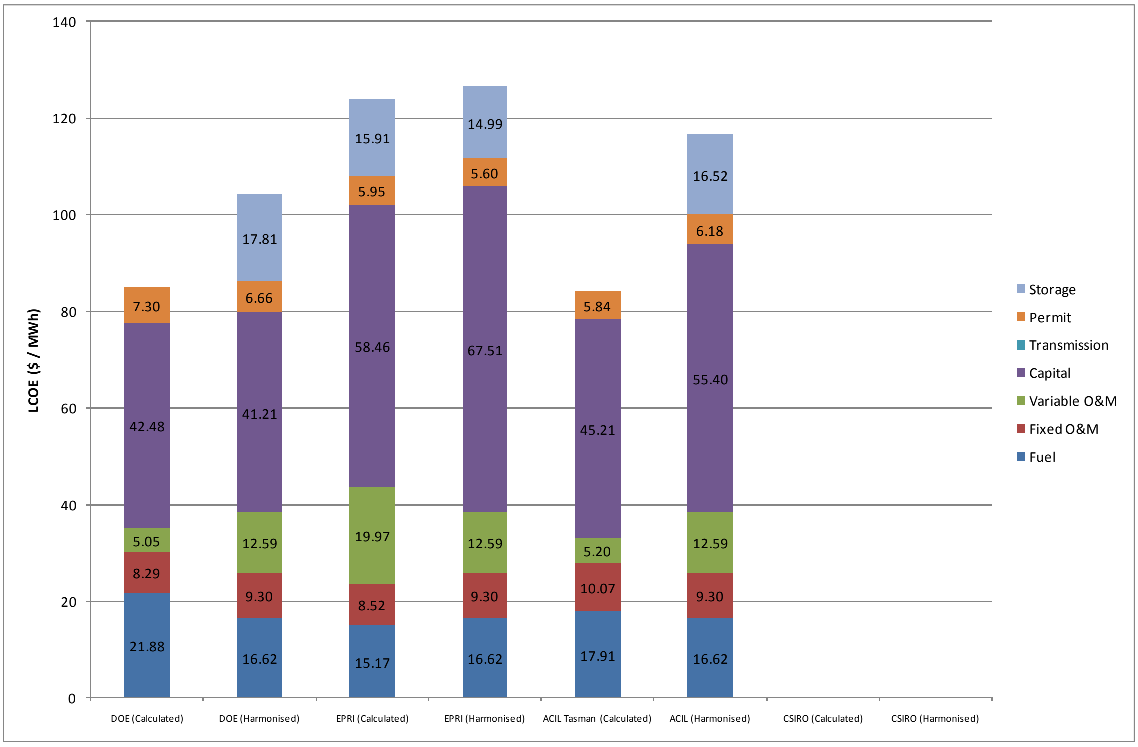

Figure 34: Calculated and harmonised LCOE breakdowns for black coal IGCC with CCS in 2030. A carbon permit of $52/tCO_2$ has been included

Variable O&M is the reported assumption that has the next greatest effect on LCOE. It also lies outside the ±50% range and so has a lot of variation in reported values. EPRI (2010) again report the highest variable O&M ($19.97/MWh) and US DOE (2009) and ACIL Tasman (2010) have the same low values as in 2015. However, the effect on LCOE is minor at only ±6%. For further discussion of variable O&M see "Large variation between reported assumptions – 2015".

General variation in assumptions – 2030

Capacity factor again is the assumption that has the greatest general effect on LCOE. Decreasing capacity factor by 50% from the harmonised value (85%) increases the LCOE by 51% and increasing the capacity factor to the maximum value (100% - an 18% increase) reduces the LCOE by 17%. Notice that the effect on LCOE is not as great in 2030 as in 2015. This reflects the reduction in the capital cost component.

Both discount rate and capital cost effect the LCOE to the same degree. A ±50% change in capital cost changes the LCOE by ±25% in the same direction. An increase in discount rate by 50% increases the LCOE by 28% and a decrease in discount rate by 50% reduces the LCOE by 22%. Again both of these factors affect the capital cost and fixed O&M components as capital is the largest component it follows that these assumptions will have an effect on LCOE.

Large variation between reported assumptions – 2030

This is variable O&M which has already been covered under "Variation in reported assumptions – 2030".

Gas combined cycle.

In 2015 all reports have data on gas combined cycle or combined cycle gas turbine (CCGT). The IEA (2010) do not report any 2030 data.

Variation in reported assumptions – 2015

The 2015 tornado plot is shown in Figure 35 below. Fuel cost is the reported assumption that has the greatest effect on LCOE. The ACIL Tasman (2009) gas price ($5.11/GJ) reduces the LCOE from the harmonised value ($7.15/GJ) by 16% and the EPRI (2010) gas price ($9.00/GJ) increases the LCOE by 15%. Even though the difference between the gas prices is approximately $2/GJ, because of the high contribution of fuel cost to the LCOE (see Figure 36), any small changes in fuel price can have a large effect on LCOE.

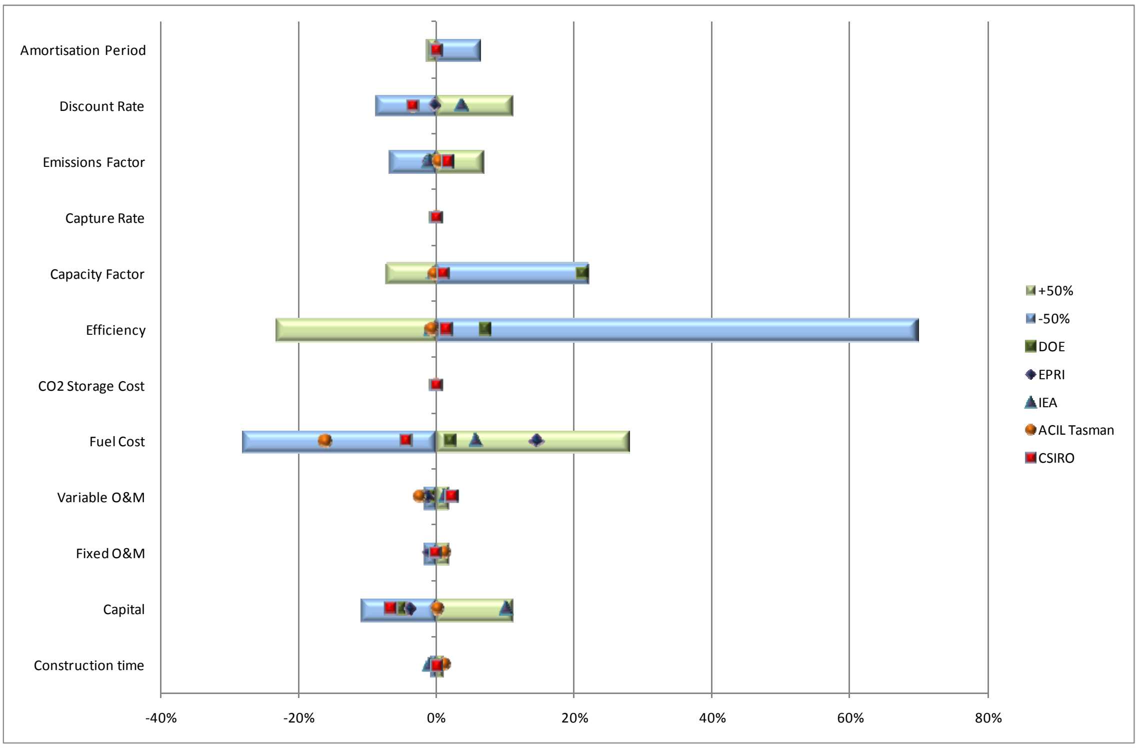

Figure 35: Tornado plot showing variation in LCOE for gas combined cycle plant in 2015. An emission permit price of $28/tCO$_2$ has been included in the LCOE calculation

The gas price reported by ACIL Tasman is from an earlier publication ACIL Tasman (2009) which we used as they did not report any gas price in ACIL Tasman (2010). The gas price is based on their *GasMark* model, which takes into account contracts between suppliers and power plants. The EPRI (2010) gas price is consistent with the average East and West Coast gas prices. The gas price methodologies are described in Section 4.4.1: Gas price. Because ACIL Tasman (2009) considers long-term contracts, this leads to a lower gas price.

Capacity factor is the next reported assumption to have a large effect on LCOE. However, this is due to one value, US DOE (2009) having a much lower capacity factor (42.9%) than the harmonised value (83.8%) and the other studies. Their capacity factor increased the LCOE by 21%. US DOE (2009) did not report any capacity factors and thus they were estimated based on electricity generated and installed capacity (see – Section 4.3.1: Combined cycle gas turbines with and without CCS).

General variation in assumptions – 2015

Efficiency has the largest overall effect on LCOE. A 50% increase in efficiency reduces the LCOE by 23% and a 50% decrease in efficiency increases the LCOE by 70%. Efficiency affects fuel consumption, which in turn affects the fuel and permit LCOE components. Fuel is such a big component as can be seen in Figure 36 that it follows that efficiency will have a big impact.

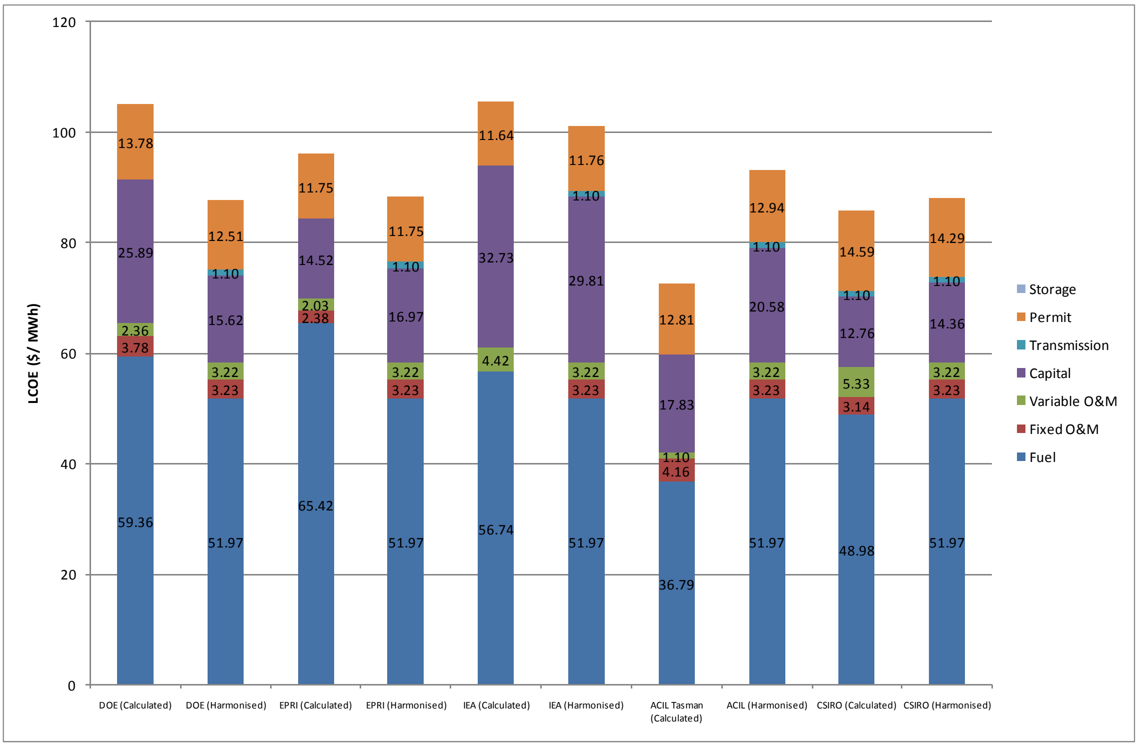

Figure 36: Calculated and harmonised LCOE breakdowns for gas combined cycle in 2015. A carbon permit of $28/tCO_2$ has been included

Fuel cost itself has the second greatest overall impact on LCOE. A ±50% change in fuel cost results in a ±28% change in LCOE, in the same direction. Again this is due to the large contribution fuel makes to the LCOE.

Large variation between reported assumptions – 2015

Variable O&M is the assumption where differences of more than ±50% between reported values have occurred. ACIL Tasman (2010) report a value ($1.1/MWh) which is 66% less than the harmonised value ($3.22/MWh) whereas CSIRO (2010) report a value ($5.33/MWh) which is 66% higher than the harmonised value. However, the total O&M reported by ACIL Tasman (2010) is only 21% different than the total harmonised O&M value and thus it seems that again the accounting between fixed and variable O&M is causing this difference. However, CSIRO (2010) reports the highest total O&M for this technology (see Appendix G - Data Tables). CSIRO (2010) values were sourced from the literature which constitutes older data. The effect of variable O&M on LCOE is very minor at ±2%.

Variation in reported assumptions – 2030

The tornado plot for the year 2030 is shown in Figure 37 below.

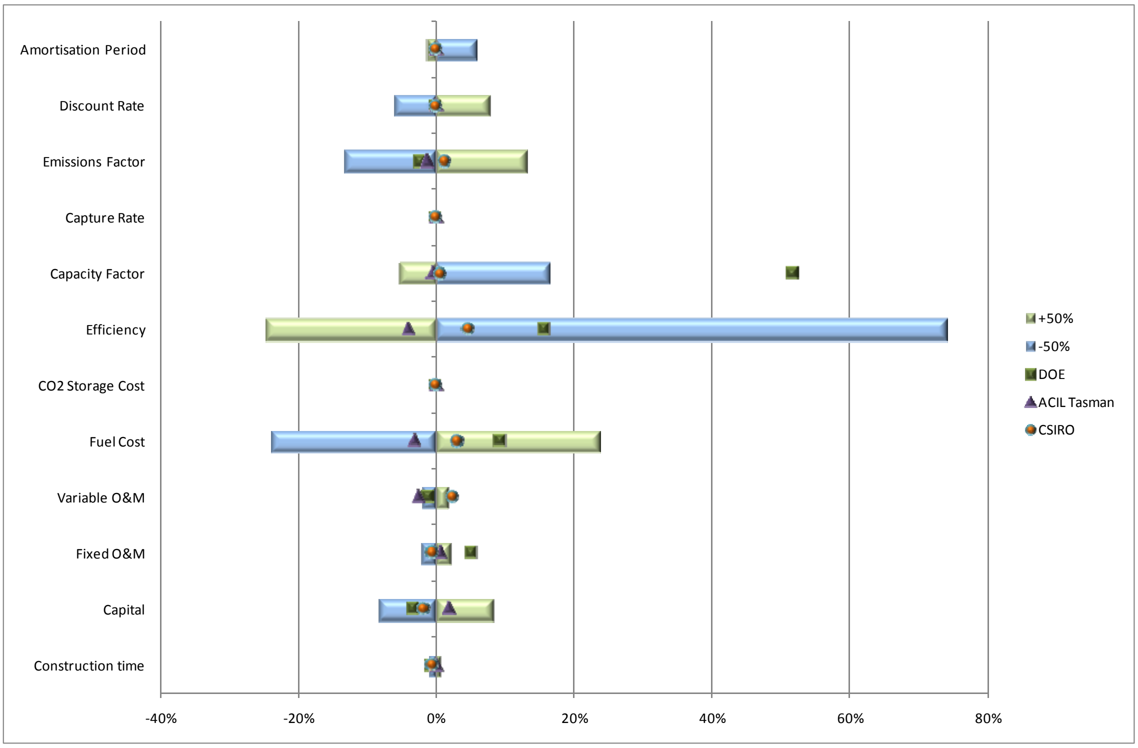

Figure 37: Tornado plot showing variation in LCOE for gas combined cycle plant in 2030. An emission permit price of $52/t$CO_2$ has been included in the LCOE calculation

Capacity factor is the reported assumption with the greatest effect on LCOE. This is because of the calculated capacity factor for the US DOE (2009) (20%) which is more like that of a peaking plant. It increases the LCOE by 52% compared to the harmonised value (82.5%). It may be that the in the US DOE's National Energy Modelling System (NEMS) gas combined cycle plant can be used as peaking plant.

The reported assumption with the second greatest effect on LCOE is efficiency. The US DOE (2009) efficiency (44.9%) increases the LCOE by 16% and the ACIL Tasman (2010) efficiency (57.6%) lowers the LCOE by 4%. Differences in efficiency can arise when turbines from different manufacturers or ages of turbines are used. The size of the plants in these studies is quite different – ACIL Tasman report on a 700 MW plant and US DOE on a 250 MW plant (see Section 4.3.1: Combined cycle gas turbines with and without CCS), but we do not have any other information. Because of the ambient conditions in the US, we would expect their plant to have a higher efficiency. The fact that it is lower points to it being an older type. Nevertheless, efficiency has an impact on LCOE because of the high fuel and permit price component, which can be seen in Figure 38.

General variation in assumptions – 2030

Efficiency is also the assumption that has the greatest impact on LCOE in general. Reducing the efficiency by 50% increases the LCOE by a huge 74%. Increasing efficiency by 50% reduces the LCOE by 25%. Efficiency was discussed above.

The assumption with the second greatest general effect on LCOE is fuel cost. Changing the cost of fuel by ±50% changes the LCOE by ±24%. Again, anything that affects the largest component of LCOE (which in this case is fuel) has the biggest impact.

Large variation between reported assumptions – 2030

Efficiency has already been discussed under "Variation between reported assumptions – 2030". The trends in variable O&M are the same as in 2015 so these have already been covered under "Large variation between reported assumptions – 2015".

The US DOE (2009) is outside of the ±50% range for fixed O&M; its reported value ($8.11/MWh) is 122% greater than the harmonised value ($3.65/MWh). However, its total O&M value does not show as much variation. Again the ratio between fixed and variable O&M is resulting in differences.

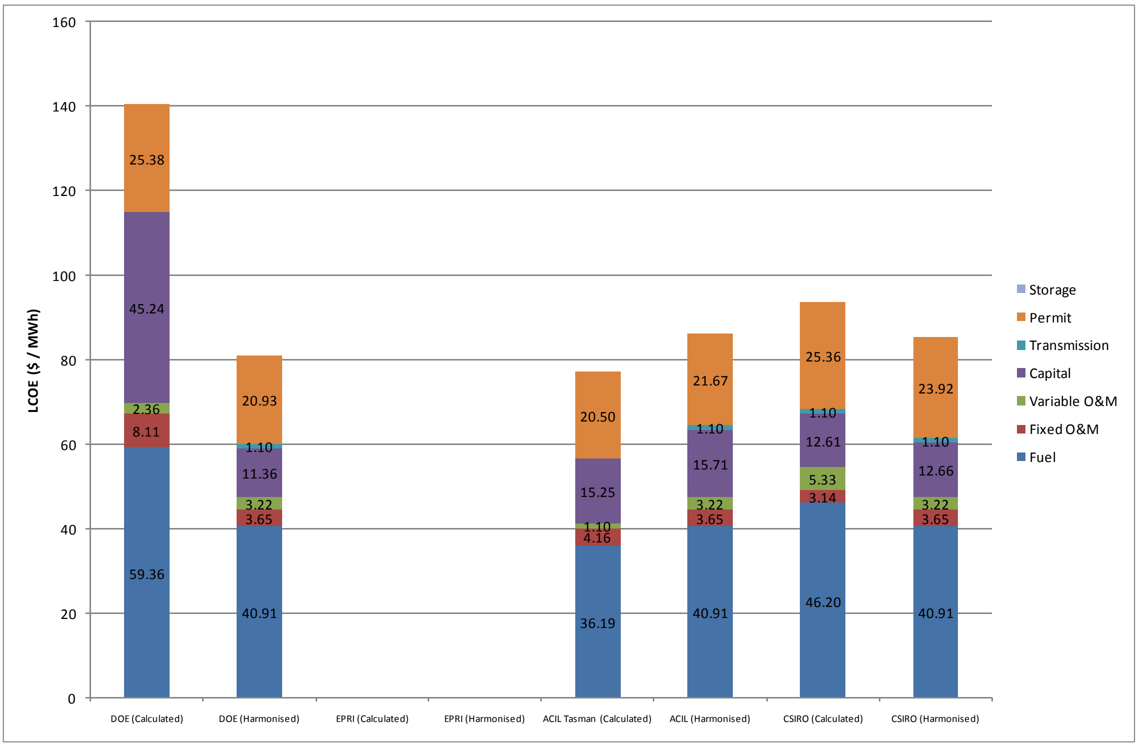

Figure 38: Calculated and harmonised LCOE breakdowns for gas combined cycle in 2030. A carbon permit of $52/tCO_2$ has been included

Gas with CCS

US DOE (2009), EPRI (2010) and CSIRO (2010) have projections for this technology. The 2015 tornado plot is shown in Figure 39.

Variation in reported assumptions – 2015

Capacity factor is the reported assumption that has the largest effect on LCOE. However, this is due to one value, US DOE (2009) having a much lower capacity factor (42.9%) than the harmonised value (82.5%) and the other studies. Their capacity factor increased the LCOE by 27%. US DOE (2009) did not report any capacity factors and thus they were estimated based on electricity generated and installed capacity (see Section 4.3.1: Combined cycle gas turbines with and without CCS).

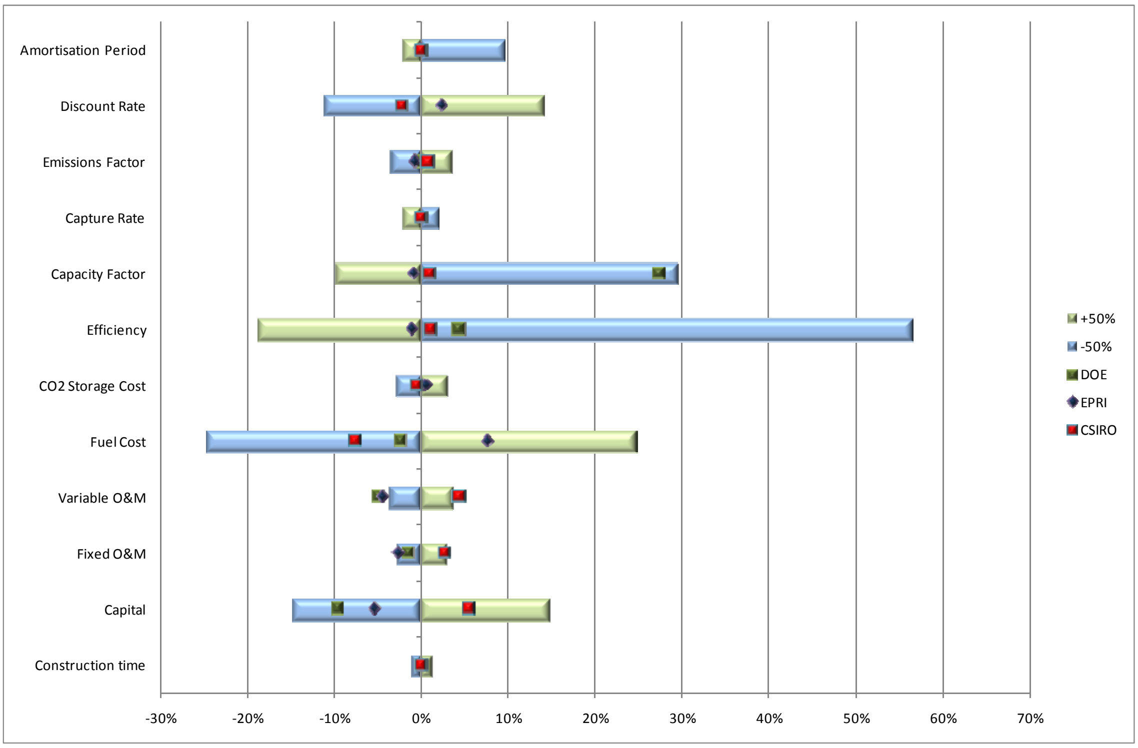

Figure 39: Tornado plot showing variation in LCOE for gas with CCS plant in 2015. An emission permit price of $28/tCO$_2$ has been included in the LCOE calculation

Fuel cost is the reported assumption with the second greatest effect on LCOE. The CSIRO value (2010) ($6.59/GJ) reduces the LCOE by 8% from the harmonised value ($7.80/GJ) whereas the EPRI (2010) value ($9.00/GJ) increases it by 8%. Fuel cost has a large impact on LCOE because of the large fuel component, which is shown in Figure 40. Differences have arisen as the CSIRO (2010) gas price is based on Australian East Coast prices whereas that of EPRI (2010) is a combination of East and West Coast gas prices (see Section 4.4.1: Gas price). The impact on LCOE is low at less than ±9%.

General variation in assumptions – 2015

As with gas combined cycle, efficiency and fuel cost are the two assumptions that have the greatest general effect on LCOE. An increase in efficiency of 50% reduces the LCOE by 19% but a decrease in efficiency of 50% increases the LCOE by 57%. The impact of efficiency is not as great as in gas combined cycle, because here the permit component is small and the capital cost component is larger. A ±50% change in fuel cost changes the LCOE by ±25%. Again, not as great an impact as for gas combined cycle.

Large variation in reported assumptions – 2015

Variable O&M is again showing large variations in the reported data, all are more than ±50% from the harmonised value. This is probably a reflection of the difficulty in estimating O&M data for this technology as there are only a handful of demonstration projects at most in the world. The CSIRO (2010) value is based on a demonstration plant in Norway. It is unknown where the EPRI (2010) or US DOE (2009) are from. However, as with all of the other technologies discussed thus far, the impact of this large variation on LCOE is insignificant at less than ±5%.

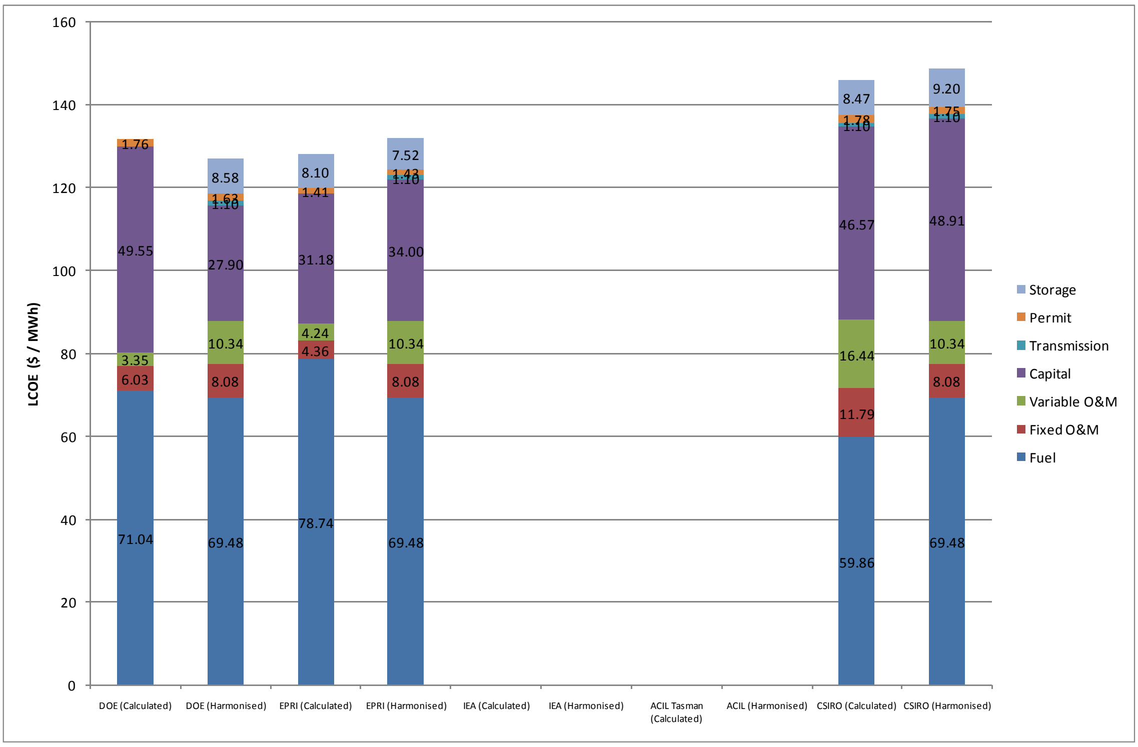

Figure 40: Calculated and harmonised LCOE breakdowns for gas with CCS in 2015. A carbon permit of $28/tCO_2$ has been included

Variation in reported assumptions – 2030

The tornado plot for the year 2030 is shown in Figure 41. The reported assumption with the largest effect on LCOE is capacity factor, because of the low calculated value for the US DOE (2009) (20%) as in 2015. It increased the LCOE by 76% from the harmonised value (82.5%). This has resulted in a large capital cost component for US DOE (2009), which can be seen in Figure 42.

Capital is the reported assumption that has the second largest effect on LCOE. The low value reported by the US DOE (2009) ($1525/kW) reduces the LCOE by 7% from the harmonised value ($2158/kW) and the high capital cost reported by CSIRO (2010) ($2240/kW) increases the LCOE by only 1%.

General variation in assumptions – 2030

As with gas combined cycle and this technology in 2015, efficiency and fuel cost are the two assumptions that have the greatest general effect on LCOE. An increase in efficiency of 50% reduces the LCOE by 20% but a decrease in efficiency of 50% increases the LCOE by 60%. The impact of efficiency is 3% greater than in 2015, because even though improvements in efficiency have been taken into account in the EPRI (2010) and CSIRO (2010) estimates, the contribution of the fuel component to LCOE has actually increased in 2030 as the capital component has decreased by a greater amount. A ±50% change in fuel cost changes the LCOE by ±26%, which is 1% more than in 2015; this is also due to a decrease in the capital cost component relative to the fuel component.

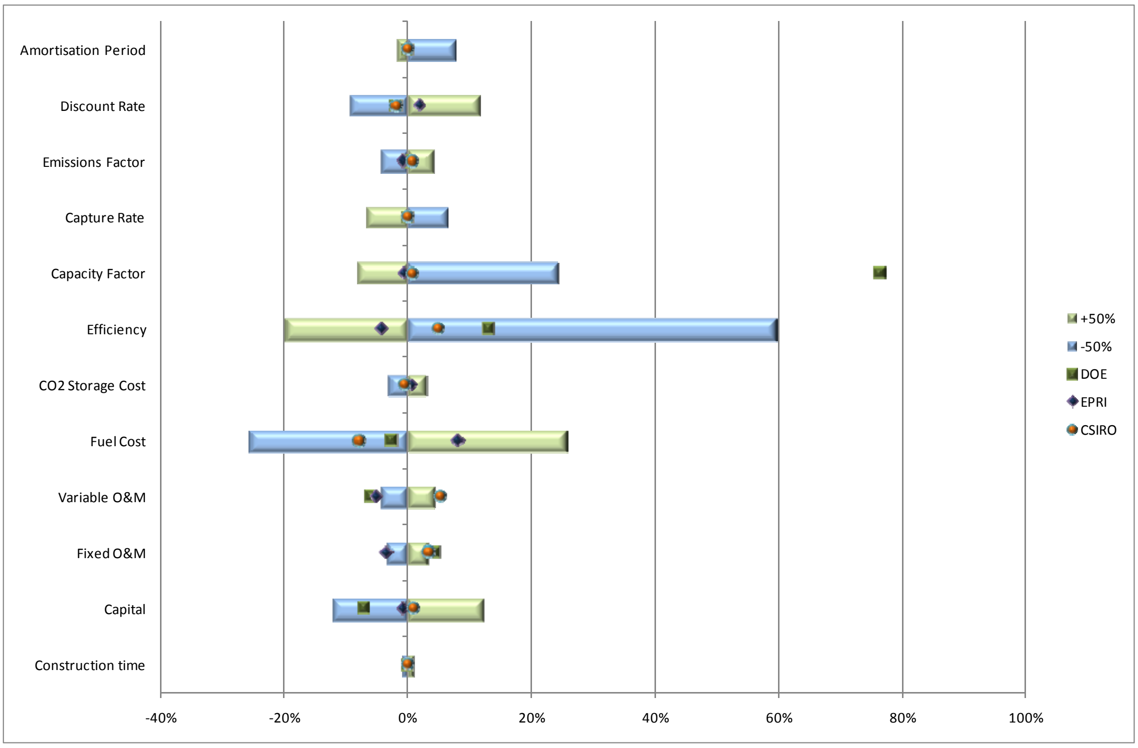

Figure 41: Tornado plot showing variation in LCOE for gas with CCS plant in 2030. An emission permit price of $52/tCO_2$ has been included in the LCOE calculation

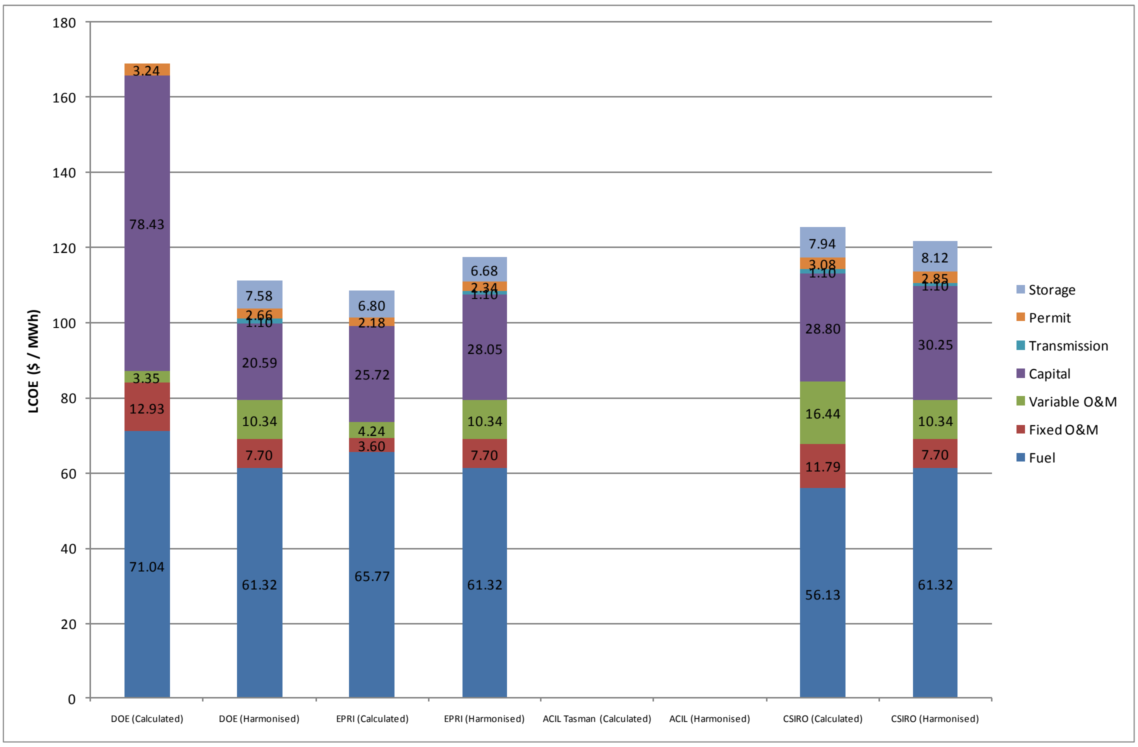

Figure 42: Calculated and harmonised LCOE breakdowns for gas with CCS in 2030. A carbon permit of $52/tCO_2$ has been included

Large variation between reported assumptions – 2030

All of the reported O&M values are outside the ±50% range. This has already been discussed under “Large variation between reported assumptions – 2015”. However, the impact of this variation on LCOE is minimal at less than ±6%.

Gas peak

All of the studies report values for gas peaking plant (or open cycle gas turbines) in 2015 and all with the exception of the IEA (2010) in 2030.

Variation in reported assumptions – 2015

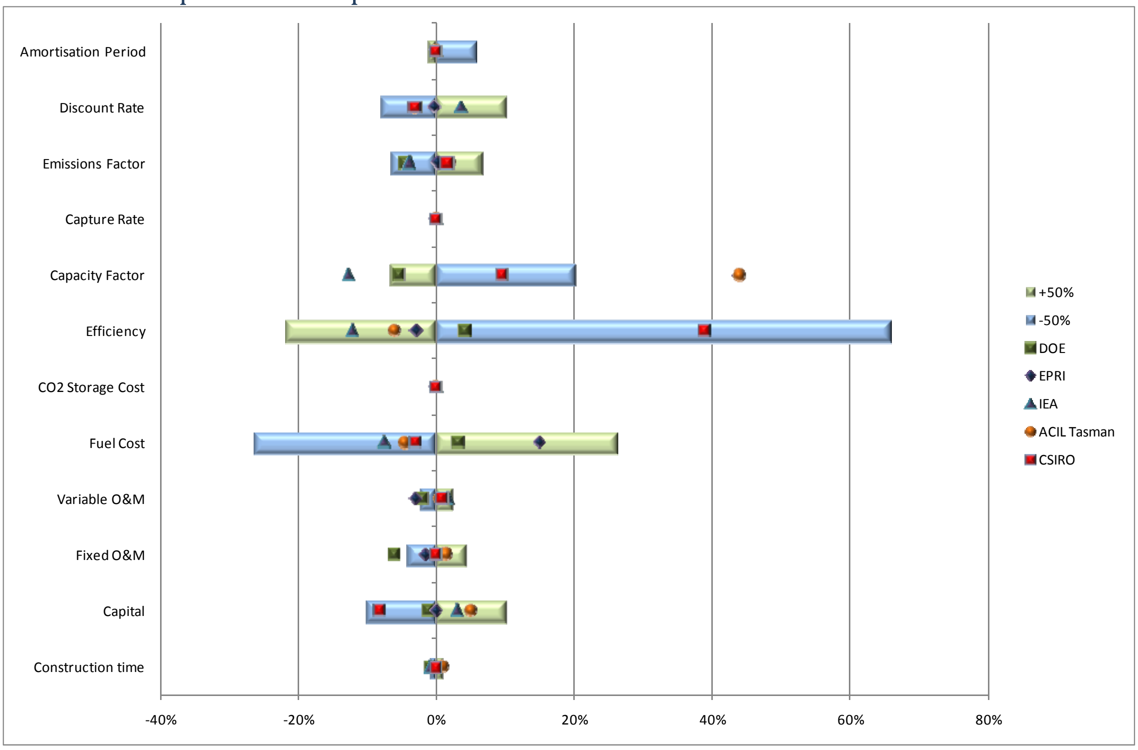

Figure 43: Tornado plot showing variation in LCOE for gas peaking plant in 2015. An emission permit price of $28/tCO_2$ has been included in the LCOE calculation

The 2015 tornado plot is shown above in Figure 43. The reported assumption with the greatest effect on LCOE is capacity factor. The IEA (2010) capacity factor (85%) reduces the LCOE by 13% from the harmonised value (31.6%) and the EPRI (2010) and ACIL Tasman (2010) capacity factor (10%) increases the LCOE from the harmonised value by 44%. Capacity factor affects the capital and fixed O&M components of LCOE. The effect can be seen in Figure 44, where the calculated capital components for EPRI (2010) and ACIL Tasman (2010) are quite large and on harmonisation (so an average capacity factor is used); the capital cost component is reduced. Based on the values, EPRI (2010) and ACIL Tasman (2010) are using this type of plant as peaking only. IEA (2010) are using this technology for baseload power. Note that the reported capacity factors from these three studies lie outside of the ±50% variability range.

Efficiency is the reported assumption that has the second largest effect on LCOE. The IEA (2010) efficiency (39%) reduces the LCOE by 12% from the harmonised value (33.5%) and the CSIRO (2010) efficiency (20%) increases the LCOE by 39% from the harmonised value. Because of the large fuel (and to a lesser extent permit) component, any changes in efficiency will have a large impact on LCOE. The efficiency reported by CSIRO (2010) is based on old technology and IEA (2010) for new plant. The actual turbine types are not reported.

General variation in assumptions – 2015

Efficiency and fuel cost are the assumptions that have the greatest overall effect on LCOE for gas peaking plant, and this has been in the case for all types of gas plant. An increase in efficiency of 50% reduces the LCOE by 22% and a decrease in efficiency of 50% increases the LCOE by 66%. This is slightly less (by 4%) than for gas combined cycle in 2015. A change in fuel price by ±50% changes the LCOE by ±26% in the same direction. This is only 2% less than gas combined cycle in 2015.

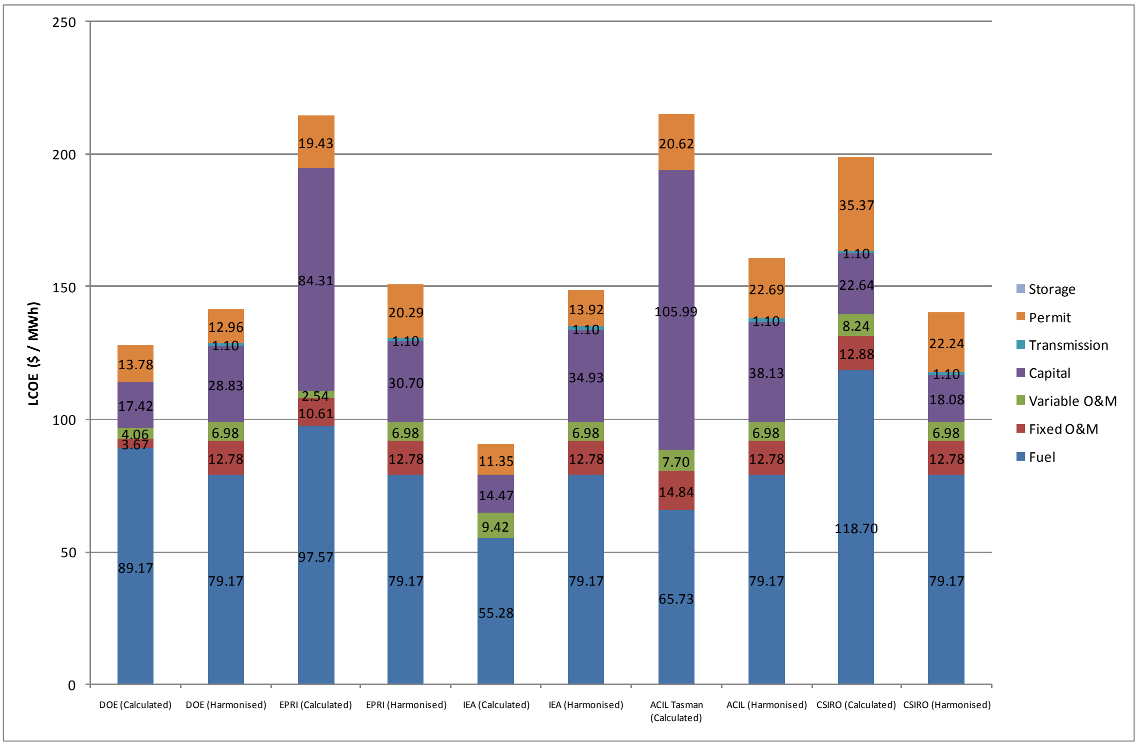

Figure 44: Calculated and harmonised LCOE breakdowns for gas peaking plant in 2015. A carbon permit of $28/tCO_2$ has been included

Large variation between reported assumptions – 2015

Capacity factor has the largest variation and has already been discussed under "Variation in reported assumptions – 2015".

US DOE (2009) has a fixed O&M ($3.67/MWh) that is lower than other studies and 71.3% lower than the harmonised value ($12.78/MWh). However, its influence on LCOE is minor at -6%. We do not know how the O&M values were determined for the US study.

Variation in reported assumptions – 2030

Efficiency is the reported assumption with the greatest effect on LCOE. This is mainly due to one value, CSIRO (2010) having a lower efficiency (20%) than the other studies and the harmonised value (32%). The CSIRO (2010) efficiency increases the LCOE by 35%. At the other end of the scale, the EPRI (2010) efficiency (40%) reduces the LCOE by 12%. EPRI (2010) have based their gas peaking plant on a General Electric (GE) 9E turbine which experiences improvements by 2030, since the efficiency has increased from the 2015 estimate (see Section 4.3.1: Open cycle gas turbine). CSIRO (2010) is not based on any particular plant type but on older estimates. Efficiency is important as it affects fuel consumption and permits paid, which are large components of the LCOE as can be seen in Figure 46.

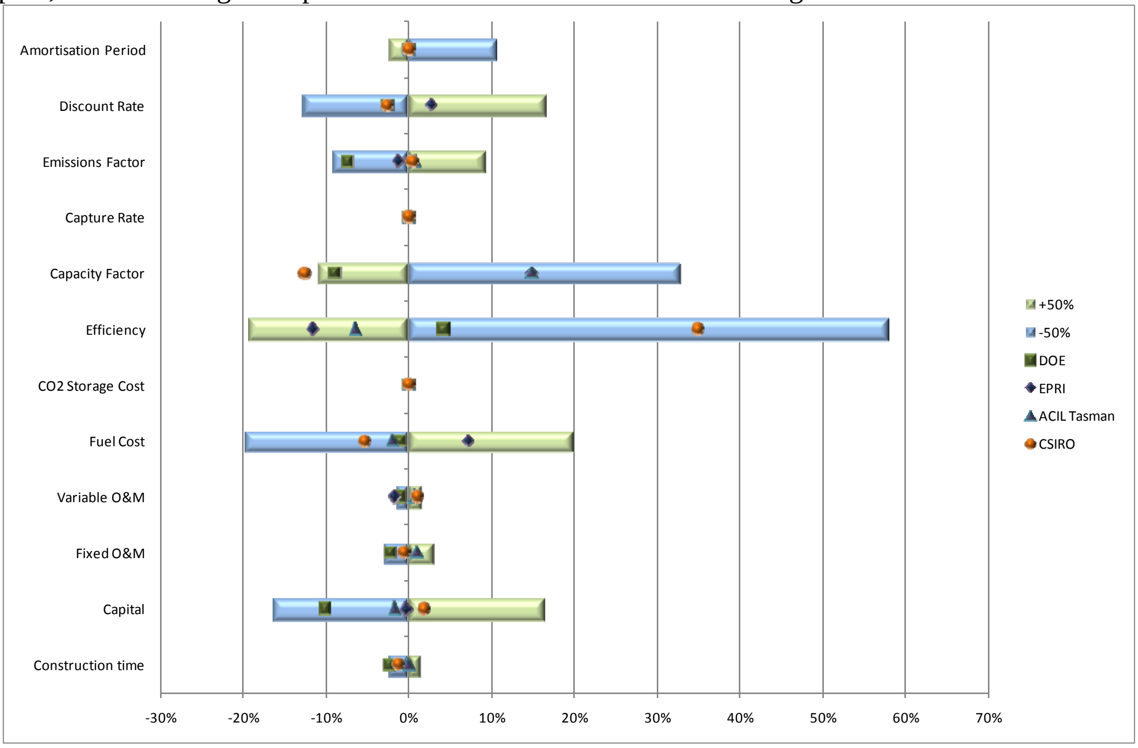

Figure 45: Tornado plot showing variation in LCOE for gas peaking plant in 2030. An emission permit price of $52/tCO_2$ has been included in the LCOE calculation

Capacity factor is the reported assumption with the next largest effect on LCOE. The larger CSIRO value (23.6%) reduces the LCOE by 13% from the harmonised value (14.5%) whereas the lower capacity factors reported by ACIL Tasman (2010) and EPRI (2010) (10%) increase the LCOE by 15%. Note the CSIRO (2010) capacity factor lies below the -50% variability range. Variations in capacity factor occur due to differences in the assumptions behind the use of the plant. All of these studies assume that this type of gas technology will be used for peak load, however, CSIRO (2010) assume the peak demand will be even higher than 10%. Capacity factor is important as, while the capital component of LCOE is not as great as in other technologies, it is still significant enough to be affected by large changes to capacity factor.

General variation in assumptions – 2030

Efficiency and capacity factor have the greatest overall effect on LCOE. An increase in efficiency of 50% reduces the LCOE by 19% and a decrease in efficiency of 50% increases the LCOE by 58%. The effect is less in 2030 than in 2015. An increase in capacity factor of 50% reduces the LCOE by 11% but a decrease in capacity factor of 50% increases the LCOE by 33%. The capital cost component is greater in 2030 than in 2015, which is why the effect of efficiency is lower and capacity factor now plays a more significant role.

Large variation between reported assumptions – 2030

This occurs for the CSIRO (2010) capacity factor and has already been covered under “Variation in reported assumptions – 2030”.

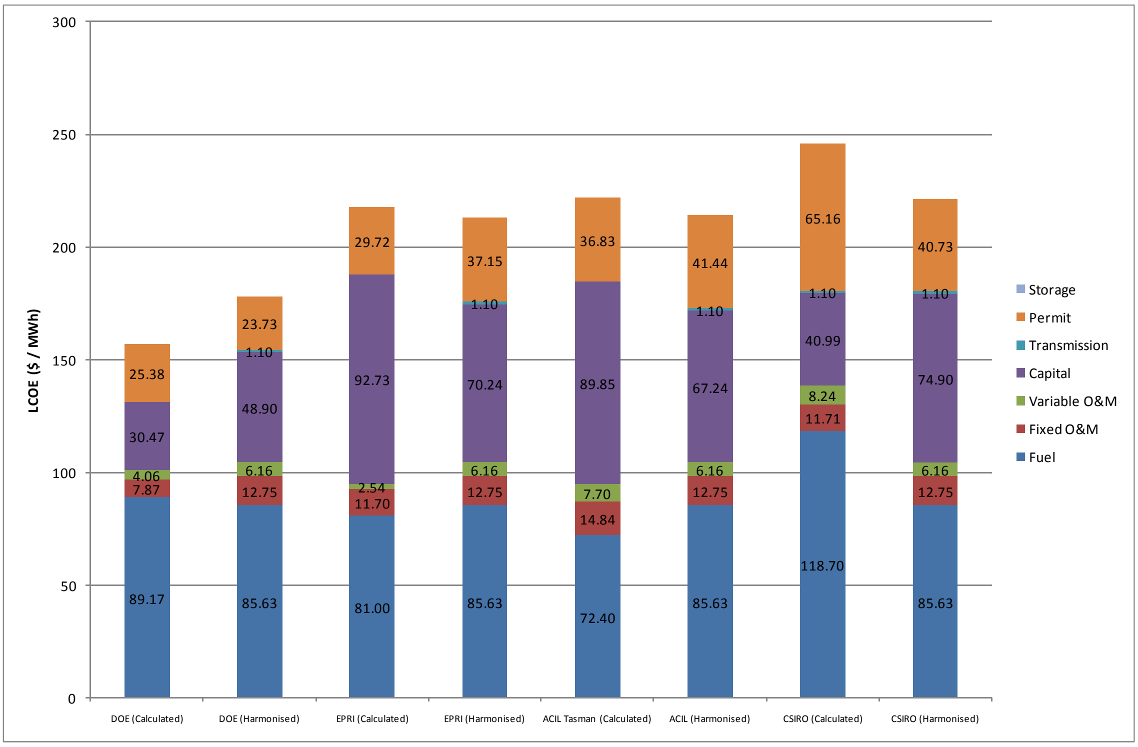

Figure 46: Calculated and harmonised LCOE breakdowns for gas peaking plant in 2030. A carbon permit of $52/tCO$_2$ has been included

Nuclear

All studies report on nuclear energy except for the IEA (2010).

Variation in reported assumptions – 2015

The 2015 tornado plot is shown in Figure 47. The reported assumption with the greatest effect on LCOE is capital cost. The US DOE (2009) capital cost ($3656/kW) reduces the LCOE by 22% from the harmonised value ($5247/kW) and the EPRI (2010) value ($5742/kW) increases the LCOE by 7% from the harmonised value. EPRI (2010) assume a generation III plant with seawater cooling. As this is a new technology it is expected to be more expensive. We do not know what is behind the US DOE (2009) assumption, however, as there are many nuclear plants in the US, the technology and skills required are well known and understood. Therefore constructing a new nuclear plant should theoretically be cheaper in the US than in Australia. Capital cost has a large effect on LCOE because of the large capital cost component to nuclear, as can be seen in Figure 48.

Fuel cost is the assumption that has the second greatest effect on LCOE. It is also the assumption that has the greatest variation between the different reports. The ACIL Tasman (2009) uranium price ($0.46/GJ) reduces the LCOE by 7% compared to the harmonised value ($1.15/GJ) and the CSIRO (2010) uranium price ($2.04/GJ) increases the LCOE by 9%. The ACIL Tasman (2009) uranium price is based on a recent estimate by the Australian Nuclear Science and Technology Organisation (ANSTO) and the CSIRO (2010) is from an older estimate. The effect of fuel price on LCOE is small at less than ±10%.

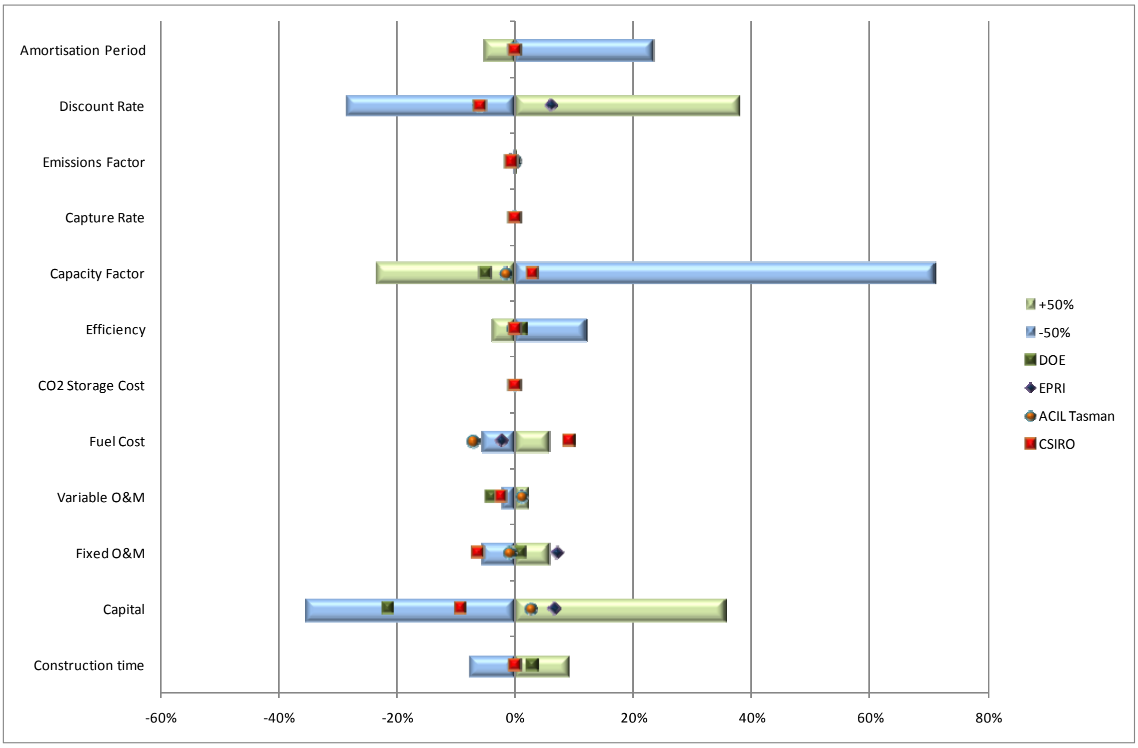

Figure 47: Tornado plot showing variation in LCOE for nuclear in 2015. An emission permit price of $28/tCO_2$ has been included in the LCOE calculation

General variation in assumptions – 2015

Capacity factor is the assumption that has the greatest overall effect on LCOE. A reduction in capacity factor of 50% increases the LCOE by 71% and an increase in capacity factor to the maximum value 100% (a 20% increase), reduces the LCOE by 24%. Capacity factor affects the capital and fixed O&M components and both of these are large for nuclear, as can be seen in Figure 48.

The assumption with the second greatest overall affect is capital, which has already been discussed in “Variation in reported assumptions -2015”. A ±50% change in capital changes the LCOE by ±35% in the same direction.

Variation between reported assumptions – 2015

Fuel cost has the most variation but that has been discussed above. Both fixed and variable O&M also have variation in reported values of more than ±50%. The CSIRO (2010) fixed O&M value ($5.49/MWh) is 55% lower than the harmonised value ($12.17/MWh), while the EPRI (2010) value ($19.73/MWh) is 62% higher than the harmonised value. The EPRI (2010) value is based on a bottom-up understanding of the O&M required for this type of plant. It is also an average value, rather than a marginal value. CSIRO (2010) estimated their value on older plant types. Even though there is significant variation, the effect on LCOE is small at less than ±7%.

The variable O&M reported by US DOE (2009) is very low ($0.56/MWh) and is 88% lower than the harmonised value ($4.73/MWh). However, the total O&M value is only 20% lower than the harmonised value and thus the difference in variable O&M may reflect the ratio between fixed and variable O&M accounting procedures. This variation only affects the LCOE by less than ±5%.

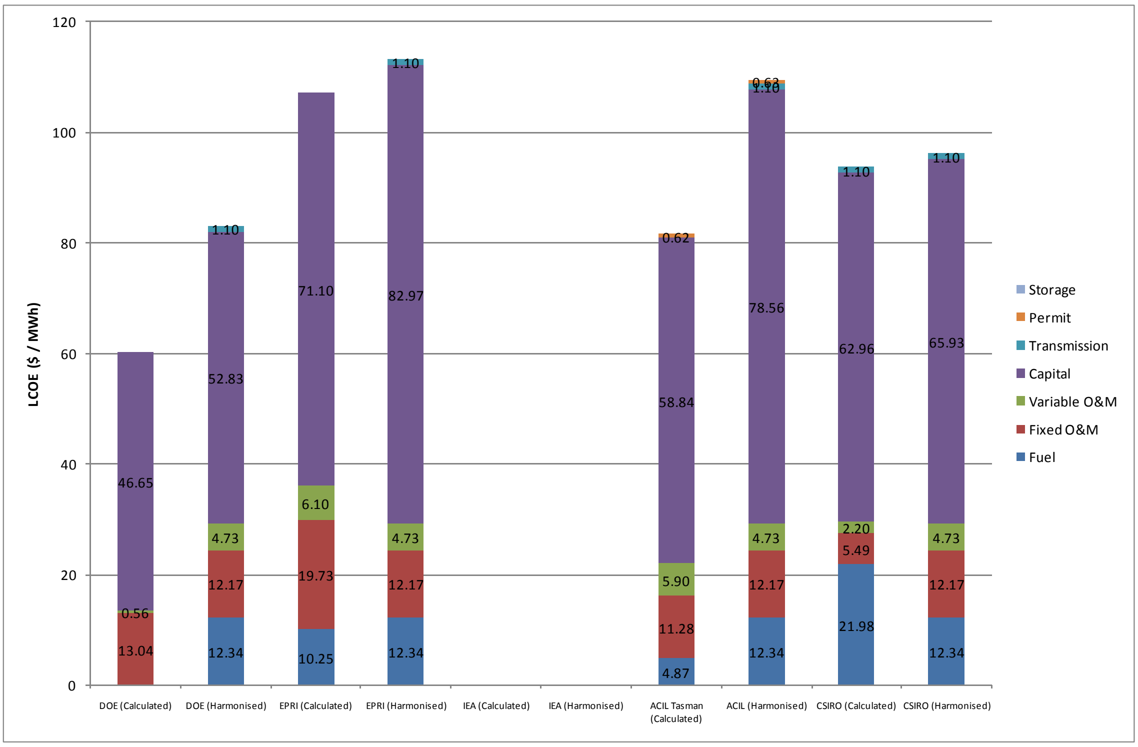

Figure 48: Calculated and harmonised LCOE breakdowns for nuclear in 2015. A carbon permit of $28/tCO_2$ has been included

Variation in reported assumptions – 2030

The trends are the same as in 2015, as can be seen from the tornado plot in Figure 49. Because of this, only the numbers will be reported here and the reader is referred back to 2015 for a discussion of the reasons behind the differences in assumptions and the effects on LCOE.

The reported assumption with the largest effect on LCOE is capital, due to the lower value reported by US DOE (2009) ($2699/kW), which reduces the LCOE from the harmonised value ($4575/kW) by 29%.The reported assumptions with the second greatest effect on LCOE is fuel cost, discount rate and fixed O&M. The ACIL Tasman (2010) uranium price ($0.46/GJ) reduces the LCOE by 6% from the harmonised value ($0.98/MWh) and the CSIRO (2010) price ($1.55/MWh) increases the LCOE by 6%. The CSIRO (2010) discount rate (7%) reduces the LCOE by 6% from the harmonised value (7.7%) and the EPRI (2010) value (8.4%) increases it by 6%. The fixed O&M value reported by CSIRO (2010) ($5.49/MWh) decreases the LCOE by 6% from the harmonised value ($11.17/MWh) and the EPRI (2010) cost ($16.75/MWh) raises it by 6%.

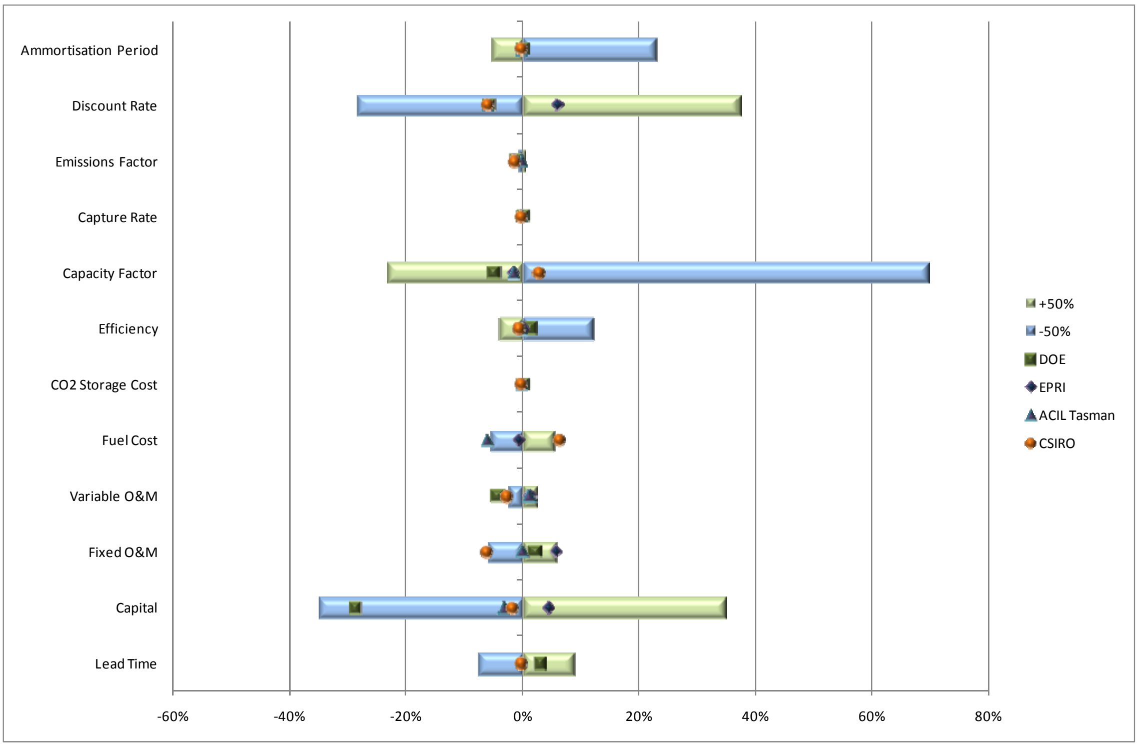

Figure 49: Tornado plot showing variation in LCOE for nuclear in 2030. An emission permit price of $52/tCO_2$ has been included in the LCOE calculation

General variation in reported assumptions – 2030

Capacity factor is the assumption that has the greatest overall effect on LCOE. A reduction in capacity factor of 50% increases the LCOE by 70% and an increase in capacity factor to the maximum value 100% (a 21% increase), reduces the LCOE by 23%. Capacity factor affects the capital and fixed O&M components and both of these are large for nuclear, as can be seen in Figure 50.

The assumption with the second greatest overall affect is capital, which has already been discussed in “Variation in reported assumptions -2030”. A ±50% change in capital changes the LCOE by ±35% in the same direction.

Large variation between reported assumptions – 2030

Fuel cost has variation in the reported values greater than ±53%. Fuel cost has already been discussed under “Variation in reported assumptions – 2030”. Both fixed and variable O&M have values outside of the ±50% range. . Fixed O&M has been discussed above. The CSIRO (2010) reported fixed O&M is 51% greater than the harmonised value. There is more variation in the variable O&M. The US DOE (2009) report a variable O&M ($0.56/MWh) that is 88% lower than the harmonised value ($4.73/MWh) and CSIRO (2010) report a value ($2.20/MWh) that is 54% lower than the harmonised value. However, some of this variation in O&M disappears on examination of the total O&M; the outlier is CSIRO (2010), which has a total O&M that is 51% greater than the harmonised value. Therefore, except for CSIRO (2010), the variations in O&M between the other studies may reflect the ratio between fixed and variable O&M accounting procedures. This variation only affects the LCOE by less than ±7%.

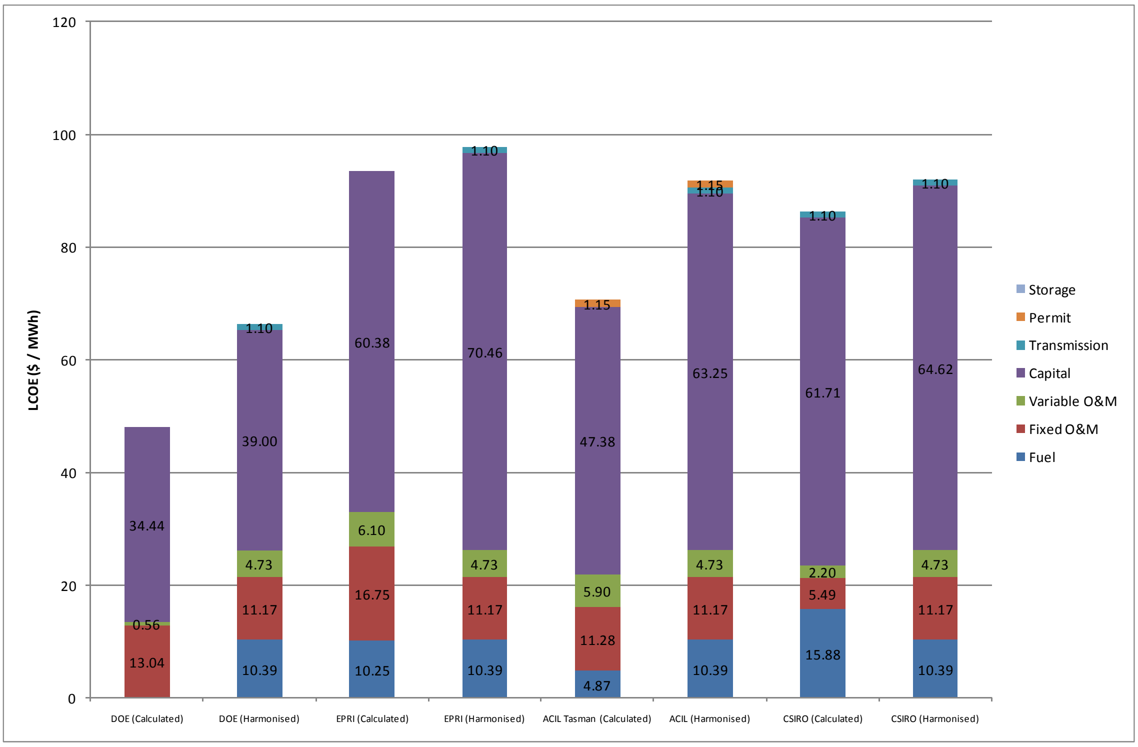

Figure 50: Calculated and harmonised LCOE breakdowns for nuclear in 2030. A carbon permit of $52/tCO_2$ has been included

Solar thermal parabolic trough without storage

All studies, with the exception of IEA (2010) report on this technology in 2015. In addition, by 2030, ACIL Tasman (2010) does not provide any data. CSIRO (2010) and US DOE (2010) do not specify any technology type: just solar thermal. Since parabolic troughs are the more common technology, we have included their estimates here. We will not discuss central receiver technology since only EPRI (2010) have data exclusively for this technology.

Because there are fewer assumptions for renewables we will only discuss one assumption per category.

Variation in reported assumptions – 2015

The reported assumption with the largest effect on LCOE is capacity factor as can be seen in the tornado plot in Figure 51. The US DOE (2009) estimated capacity factor (41.6%) reduces the LCOE by 37% from the harmonised value (23.9%) and the EPRI (2010) capacity factor (19.4%) increases the LCOE by 20%. As has been discussed earlier, the US DOE (2009) capacity factors were estimated from usage data. The EPRI (2010) estimate is based on a DNI of 6 kWh/m^2/day.

Capacity factor is important as the capital cost and fixed O&M components of LCOE are large for this technology, as can be seen in Figure 52.

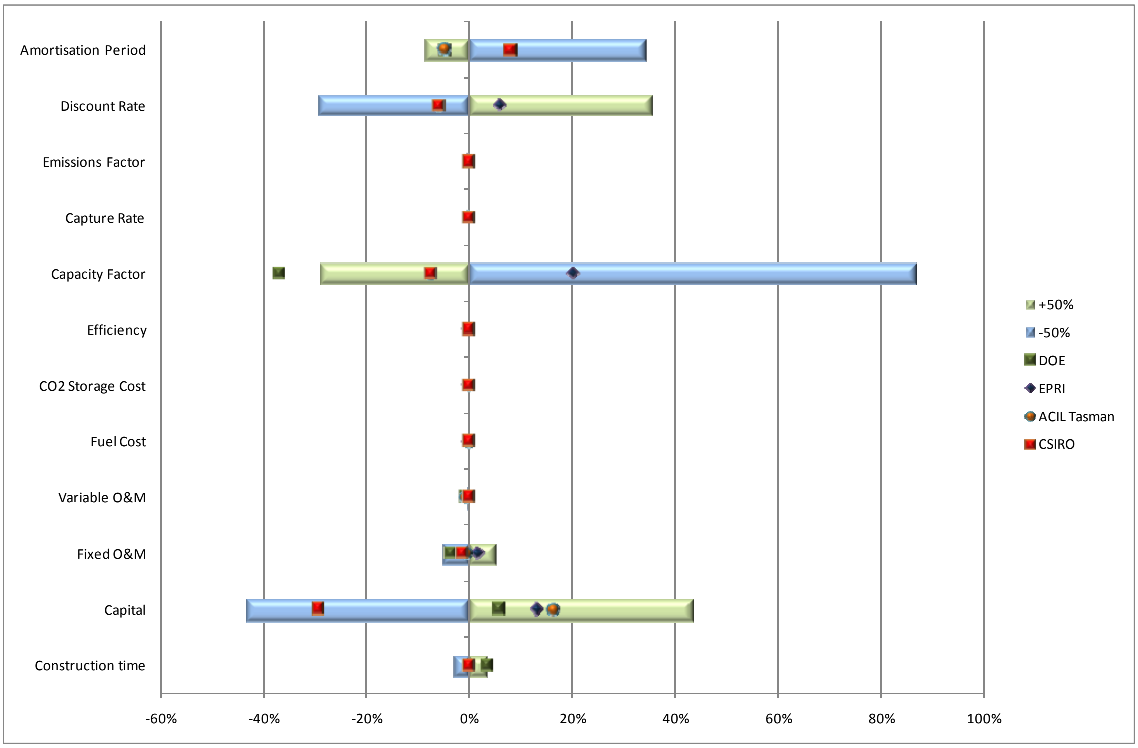

Figure 51: Tornado plot showing variation in LCOE for solar thermal in 2015

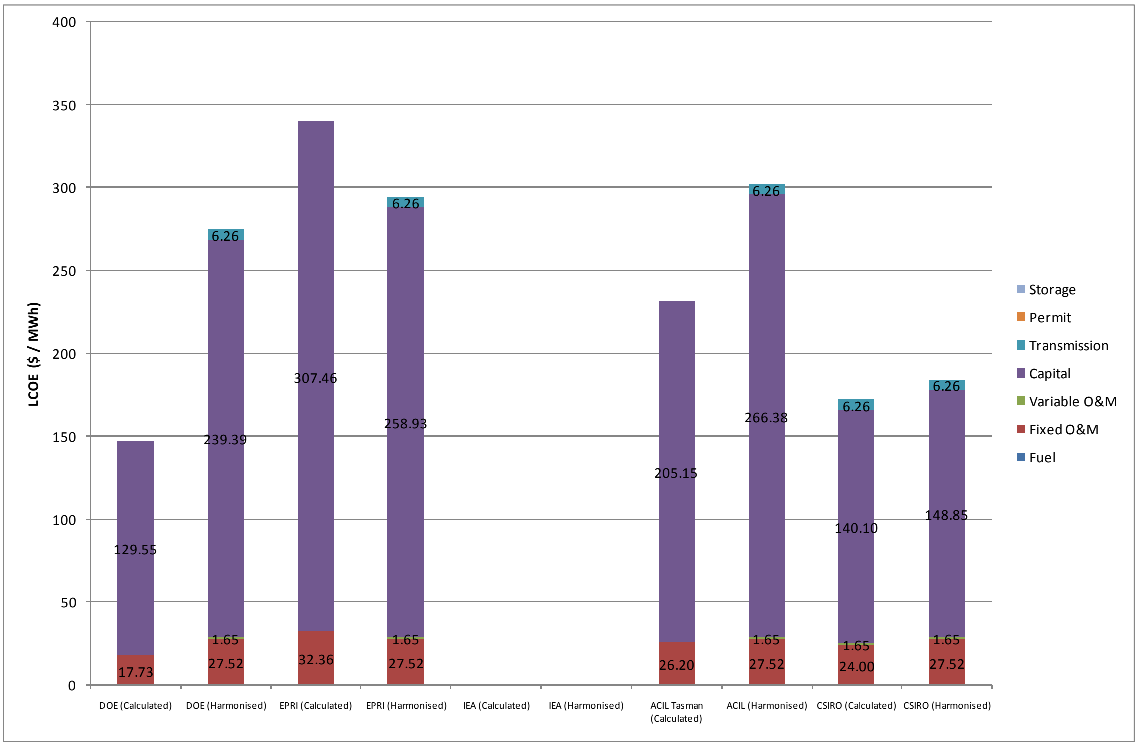

Figure 52: Calculated and harmonised LCOE breakdowns for solar thermal in 2015

General variation in reported assumptions – 2015

The assumption with the greatest effect on LCOE in general is capacity factor. An increase in capacity factor of 50% reduces the LCOE by 29% and a decrease in capacity factor of 50% increases the LCOE by 87%.

Large variation between reported assumptions – 2015

This has been observed for capacity factor and construction time. The US DOE (2009) construction time is three years compared to one year for all of the other studies. However, using 3 years only increases the LCOE by 3%.

Variation in reported assumptions – 2030

The reported assumption with the greatest effect on LCOE is capacity factor. As in 2015, the US DOE (2009) estimated capacity factor (41.6%) reduces the LCOE by 35% from the harmonised value (23.9%) and the EPRI (2010) capacity factor (20%) increases the LCOE by 16%.

General variation in assumptions – 2030

Capacity factor is the assumption that has the most effect on LCOE. A reduction in capacity factor of 50% increases the LCOE by 83% and a 50% increase in capacity factor reduces the LCOE by 28%. Capacity factor affects the LCOE though the capital and fixed O&M components and these dominate the LCOE as can be seen in Figure 54.

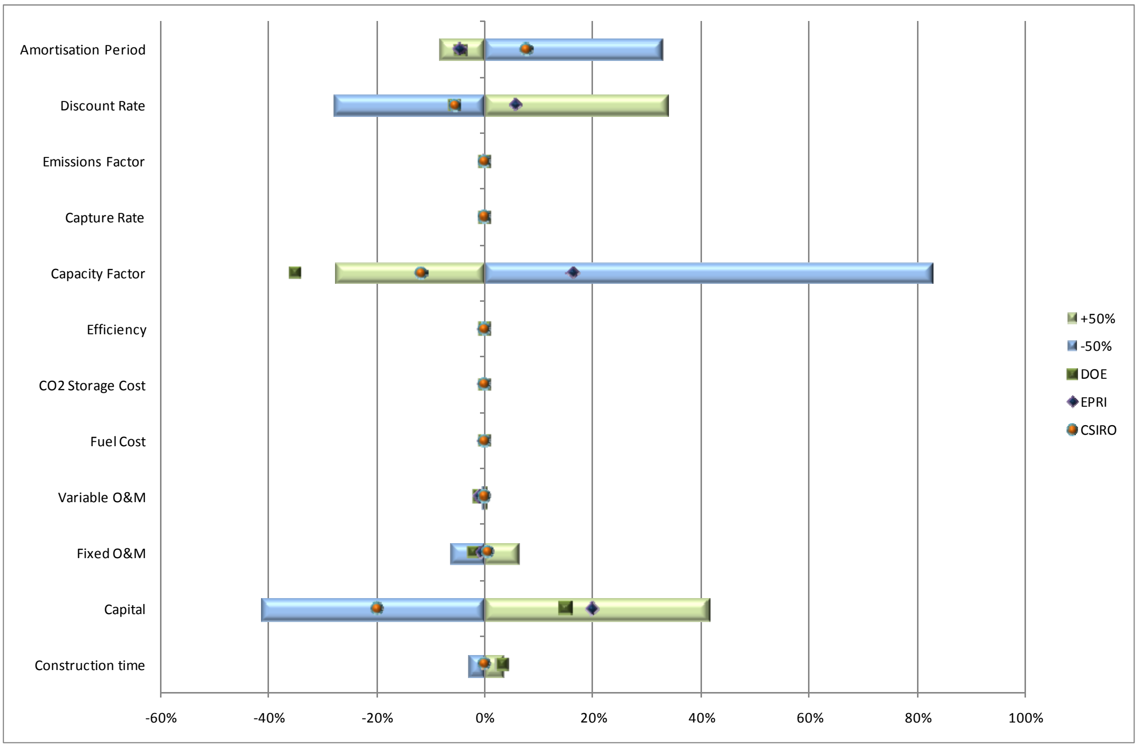

Figure 53: Tornado plot showing variation in LCOE for solar thermal in 2030

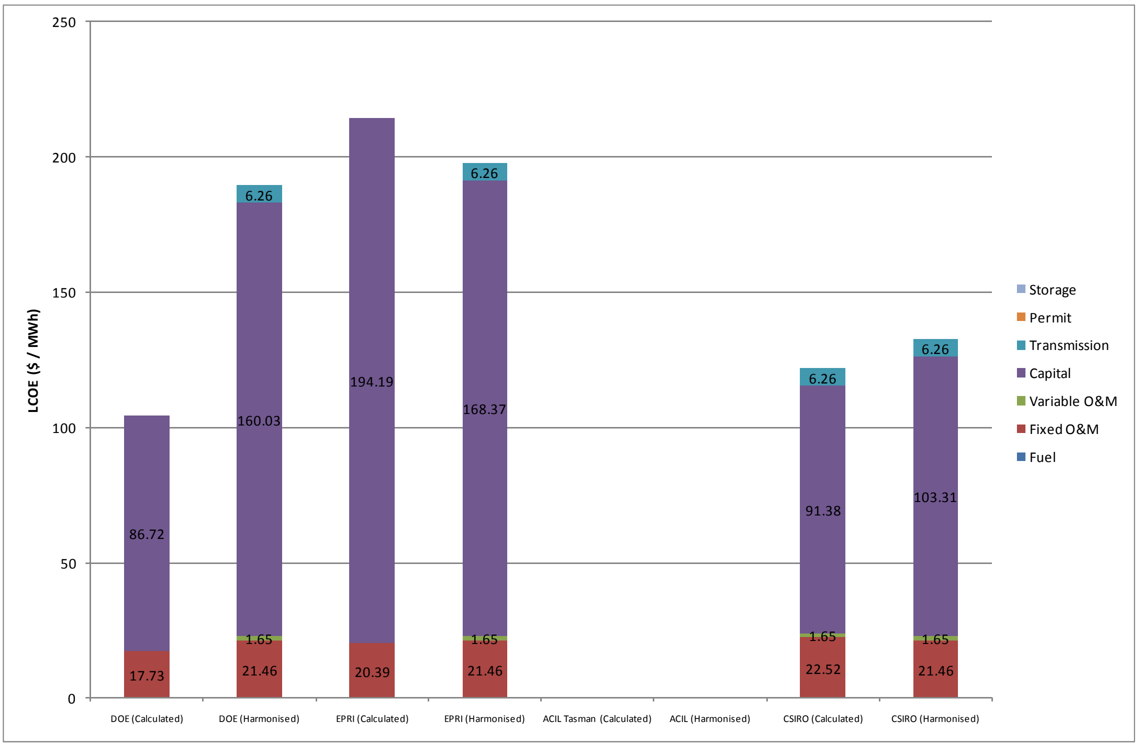

Figure 54: Calculated and harmonised LCOE breakdowns for solar thermal in 2030

Large variation between reported assumptions – 2030

This is the same as in 2015, i.e. the US DOE (2009) values for capacity factor and construction time lie outside the ±50% variation range. See “Large variation between reported assumptions – 2015” for a discussion of this.

Photovoltaic (PV) single axis tracking

All studies report values for PV except for the IEA (2010) in 2015, and in addition ACIL Tasman does not in 2030. Because US DOE (2009) and CSIRO (2010) only report on a generic PV plant, we will only discuss one type of PV plant: single axis tracking, in this review. In addition, we do not know if the US DOE (2009) are reporting on large scale or rooftop PV installations.

Variation in reported assumptions – 2015

The 2015 tornado plot is shown in Figure 55. Capital is the reported assumption that has the greatest effect on LCOE. This is due to the low capital value reported by CSIRO (2010) of $3400/kW, compared to the harmonised value of $5893/kW. The CSIRO (2010) value reduces the LCOE from the harmonised value by 39%. Conversely, the ACIL Tasman (2010) capital cost ($7289/kW) increases the LCOE by 22% with respect to the harmonised value. The CSIRO (2010) capital cost is much lower than the other studies because of the methodology used to generate the capital costs. More information can be found in Section 4.5.1.

General variation in assumptions – 2015

Capacity factor again has the greatest effect on LCOE. An increase in capacity factor of 50% reduces the LCOE by 30% and a decrease in capacity factor of 50% increases the LCOE by 91%.

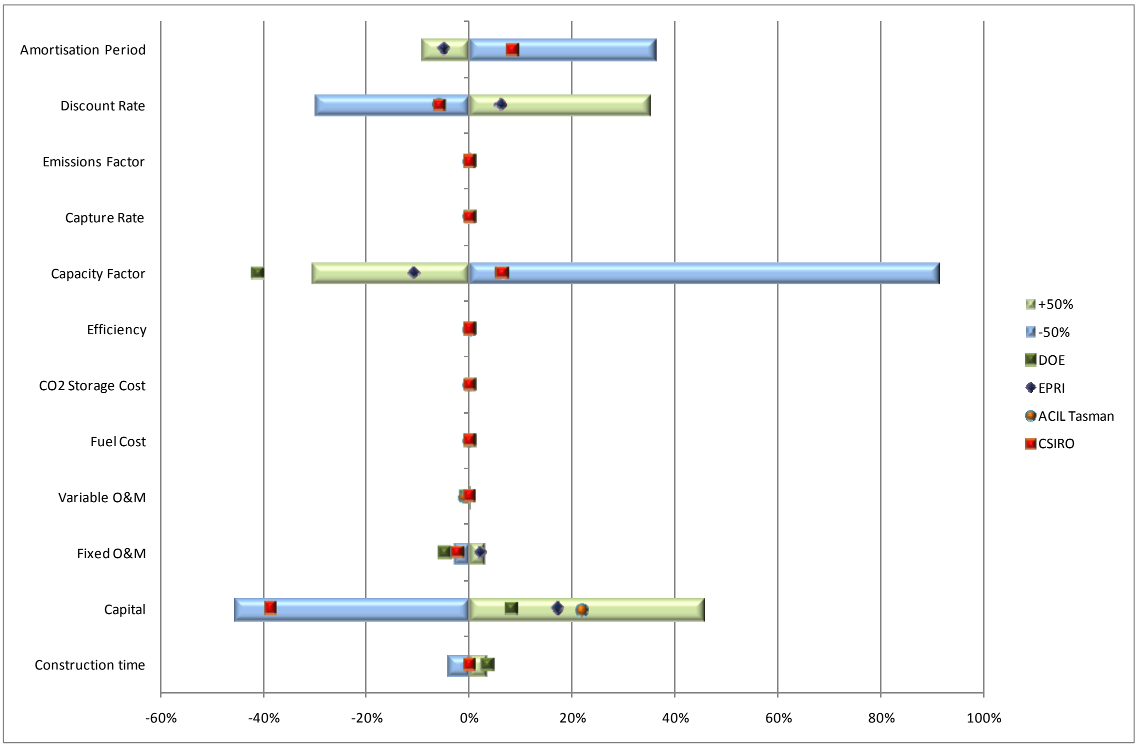

Figure 55: Tornado plot showing variation in LCOE for PV in 2015

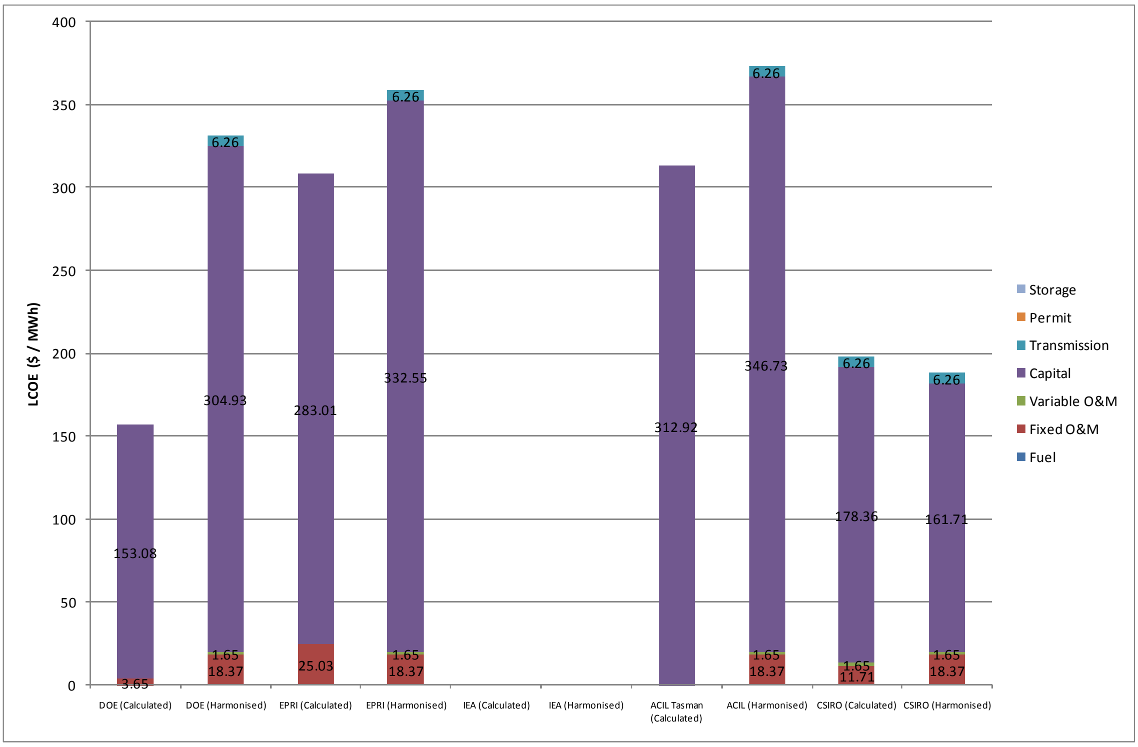

Figure 56: Calculated and harmonised LCOE breakdowns for PV in 2015

Large variation between reported assumptions - 2015

The US DOE (2009) capacity factor is 74% greater than the harmonised value.

Variations also occur outside the ±50% range for fixed O&M. The US DOE (2009) has a very low fixed O&M which may indicate that their plant-type is actually rooftop PV.

Variation in reported assumptions – 2030

Capital is the reported assumption that has the greatest effect on LCOE. This is because of the low CSIRO capital cost ($2153/kW), which is less than half of the other reported capital costs. It reduces the LCOE by 31% from the harmonised value ($3349/kW). The reasons why the CSIRO (2010) capital cost is lower are the same as in 2015.

General variation in assumptions – 2030

Capacity factor also has the greatest overall effect on LCOE. Increasing the capacity factor by 50% reduces the LCOE by 29% and reducing the capacity factor by 50% increases the LCOE by 87%. The effect is not as great as in 2015, because the overall LCOE has been reduced.

Large variation between reported assumptions – 2030

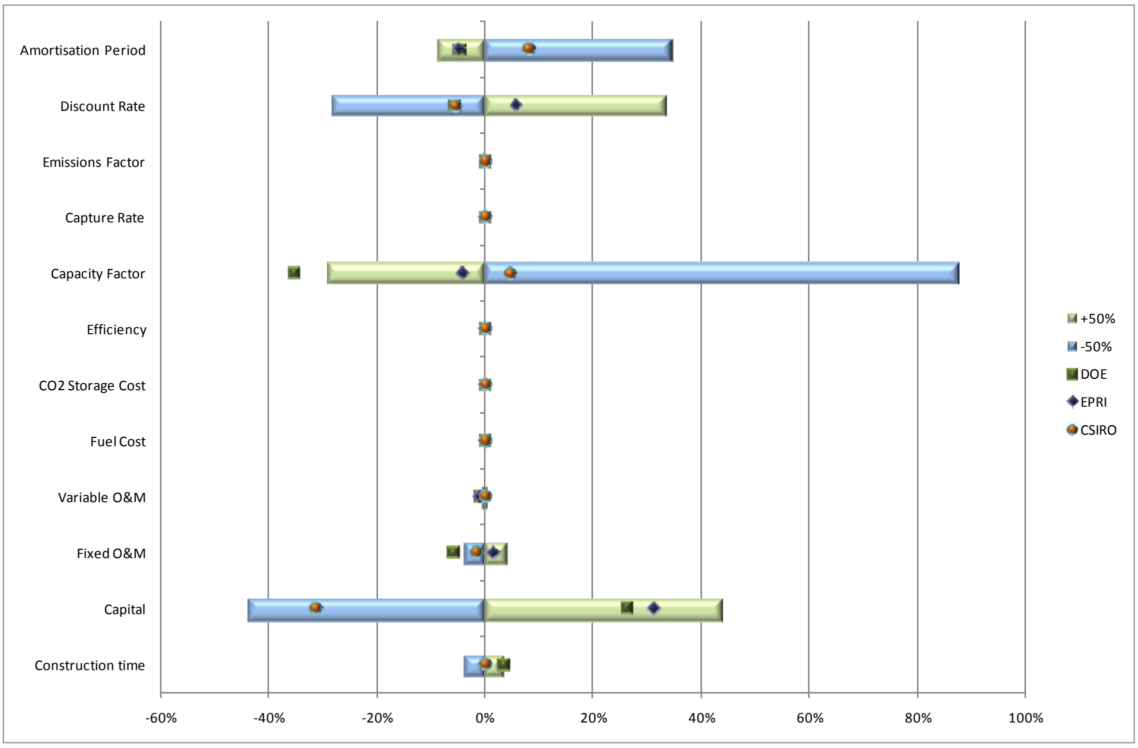

Figure 57: Tornado plot showing variation in LCOE for PV in 2030

This is again for the US DOE (2009) capacity factor, as has been discussed above. The US DOE (2009) fixed O&M cost ($3.65/MWh) is also more than 73% lower than the harmonised value of $13.46/MWh. As discussed above, this may indicate that they have reported on rooftop and not large scale PV.

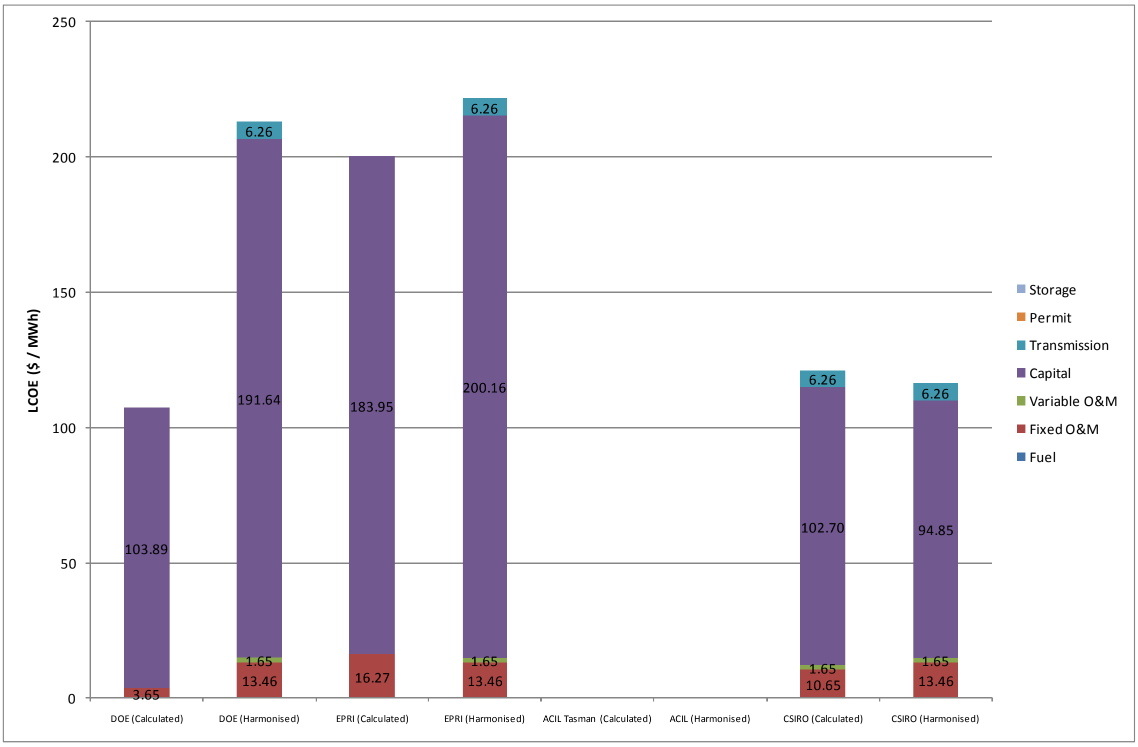

Figure 58: Calculated and harmonised LCOE breakdowns for PV in 2030

Wind – medium

All studies report on wind farms in 2015. EPRI (2010) and ACIL Tasman (2010) specify three types of wind farms (small, medium and large). CSIRO (2010), US DOE (2009) and IEA (2010) only have one type of onshore wind farm. Because of this, we have used the medium category for CSIRO (2010), US DOE (2009) and IEA (2010). In 2030, the IEA (2010) do not report on wind.

Variation in reported assumptions – 2015

The reported assumption with the greatest effect on LCOE is capital. The CSIRO (2010) capital cost ($1898/kW) reduces the LCOE by 22% compared to the harmonised value ($2657/kW) and the EPRI (2010) capital cost ($3392/kW) increases the LCOE by 21% compared to the harmonised value. The variation in capital costs is not great, but the effect on LCOE is significant as the capital cost component is large for all renewable technologies, including wind, as can be seen in Figure 60. CSIRO (2010) have a lower capital cost for wind because of the methodology used to determine technology prices in the model. As wind is a relatively inexpensive renewable technology, wind farms are constructed in the model and thus wind benefits from learning-by-doing (see Section 4.5.1).

General variation in assumptions – 2015

Capacity factor is the assumption that has the greatest overall effect on LCOE. This has been the case for every renewable technology thus far. Increasing the capacity factor by 50% reduces the LCOE by 26% and decreasing the capacity factor by 50% increases the LCOE by 77%.

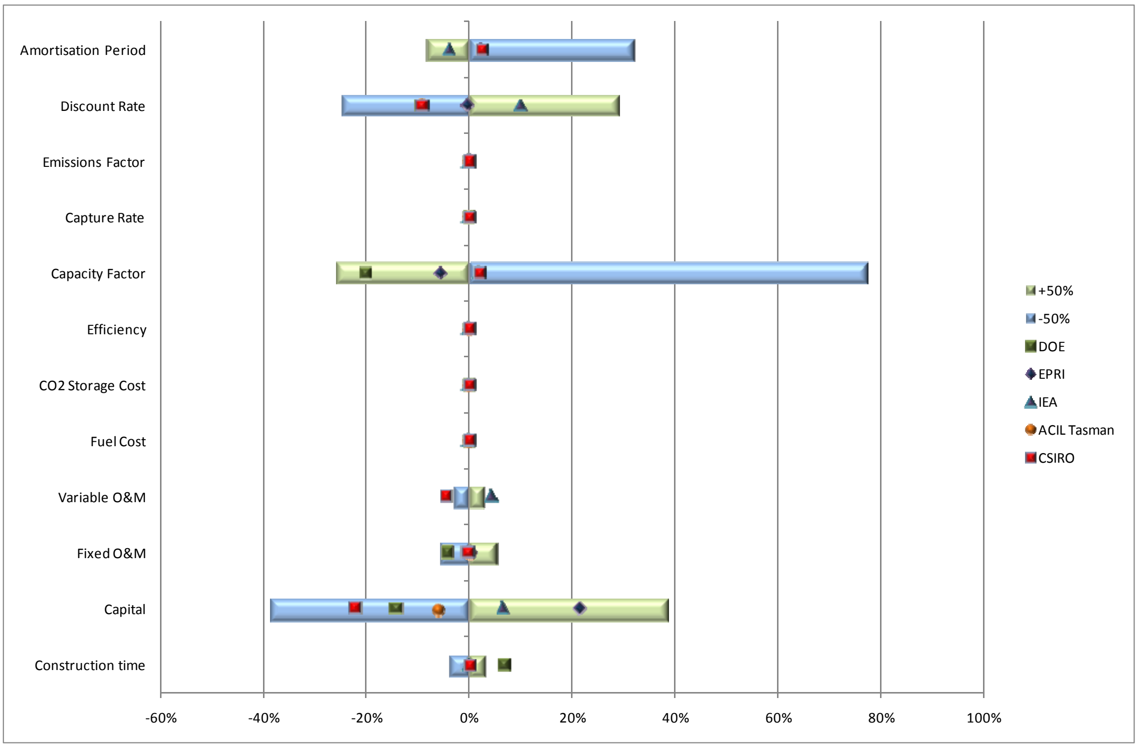

Figure 59: Tornado plot showing variation in LCOE for wind in 2015

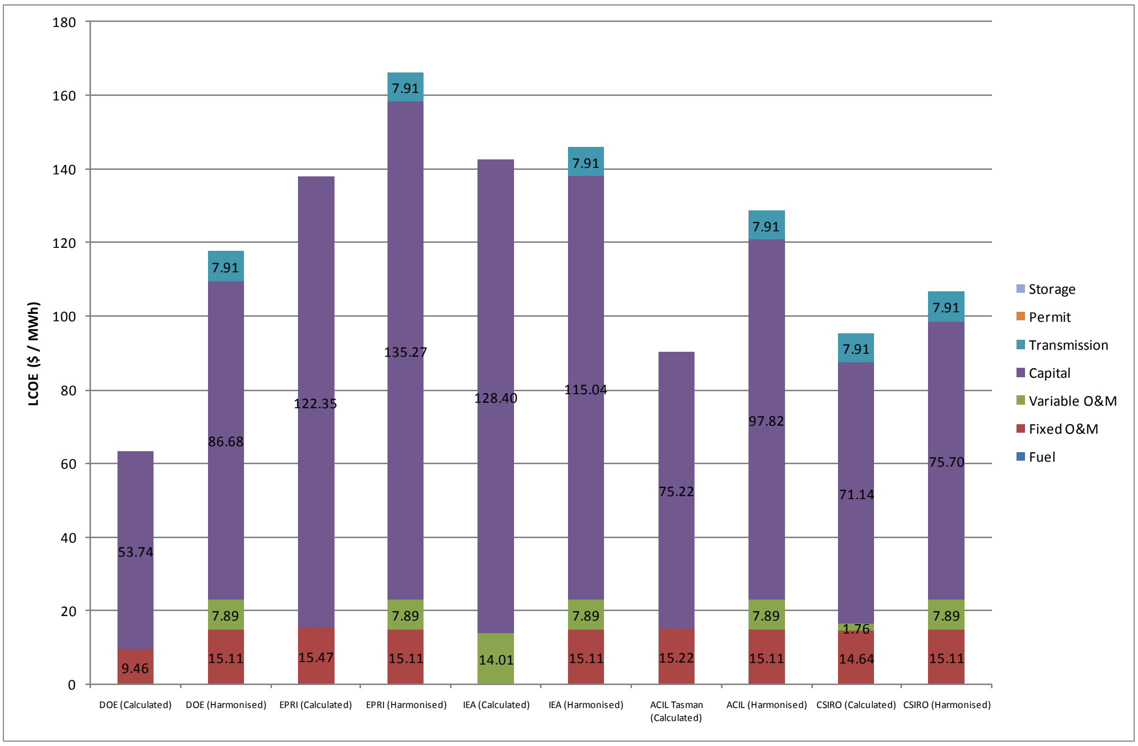

Figure 60: Calculated and harmonised LCOE breakdowns for wind in 2015

Capacity factor influences the capital and fixed O&M components and thus has a large effect on renewable technologies.

Large variation between reported assumptions – 2015

Variable O&M and construction time are the two assumptions that have large variation between the reported values. EPRI (2010), US DOE (2009) and ACIL Tasman (2010) do not consider a variable O&M for wind, solar and geothermal technologies. The IEA (2010) have a value of $14.01/MWh but they only specify a total O&M value, thus we do not know if it is correct to place it in the variable category for wind. Even though there is variation, the effect on LCOE is minor at less than ±6%.

The US DOE (2009) report a construction time of three years for a wind farm while CSIRO (2010) and IEA (2010) have a one year construction period. Again, the effect on LCOE is minor at less than 8%.

Variation in reported assumptions – 2030

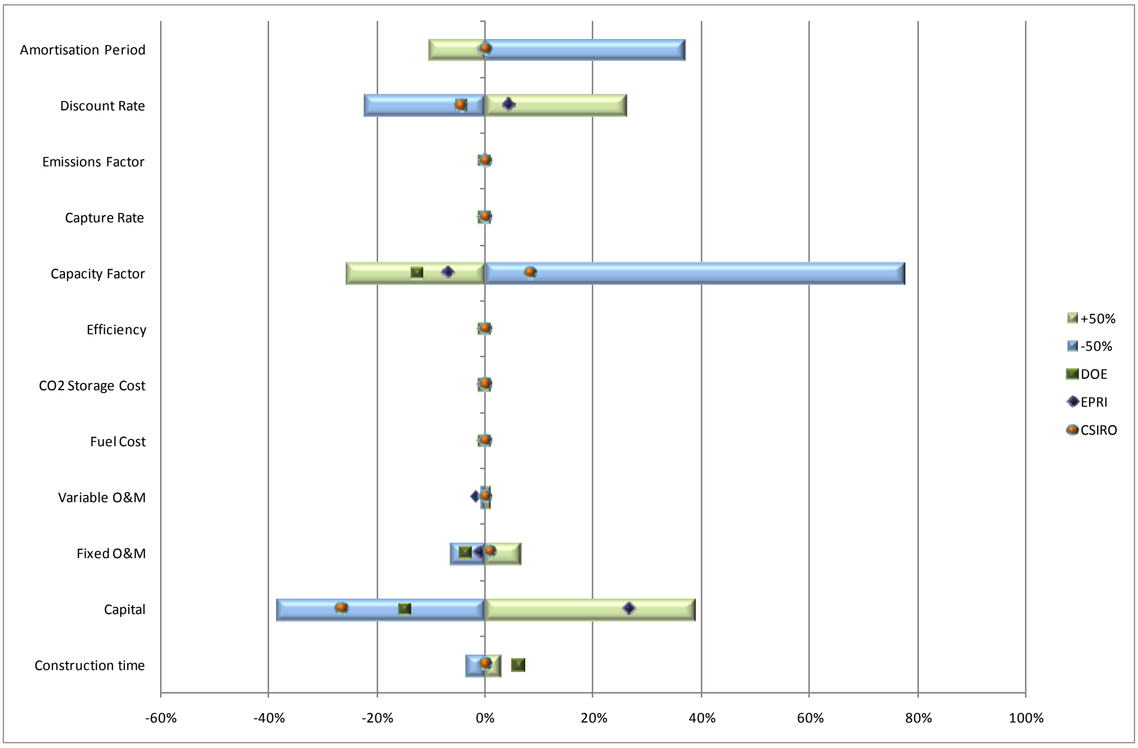

Figure 61: Tornado plot showing variation in LCOE for wind in 2030

As in 2015, capital is the reported assumption that has the largest effect on LCOE which can be seen in the tornado plot, Figure 61. The low capital cost reported by CSIRO (2030) ($1497/kW) reduces the LCOE from the harmonised value ($2274/kW) by 26%. The high value reported by EPRI (2010) ($3052/kW) increases the LCOE by 26%. CSIRO (2010) has a lower capital cost in 2030 compared to 2015 because many wind farms have been constructed in the model which has pushed wind down the learning curve (see Section 4.5.1 for more on methodology used). The EPRI (2010) capital cost is also lower in 2030, but the rate of change in capital cost is lower. EPRI (2010) consider a 2 MW wind turbine in their estimate (see Section 4.3.1: Wind).

EPRI (2010) capital costs tend to be higher because of the inclusion of a 7.5% real project cost estimate.

Capital cost has a large effect on LCOE because of the high capital component, as can be seen in Figure 62.

General variation in assumptions – 2030

Capacity factor is the assumption that has the greatest overall effect on LCOE. Increasing the capacity factor by 50% reduces the LCOE by 26% and decreasing the capacity factor by 50% increases the LCOE by 77%. Capacity factor influences the capital and fixed O&M components and thus has a large effect on renewable technologies. The effect is the same as in 2015.

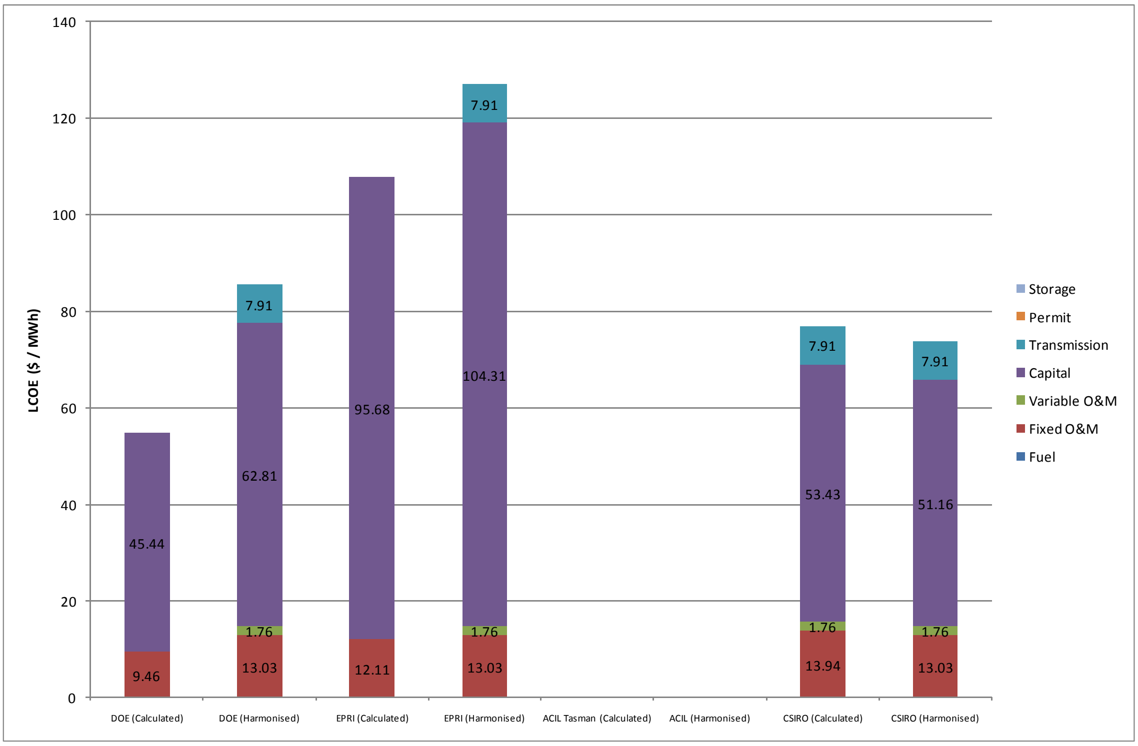

Figure 62: Calculated and harmonised LCOE breakdowns for wind in 2030

Large variation between reported assumptions – 2030

Construction time is the assumption that has variation in reported values greater than ±50%. This is due to the US DOE (2009) having a longer construction time (3 years) than the other studies, which have one year. This has increased the LCOE by 6%. Construction time has an effect as it influences the payment of interest during construction (IDC) and thus the capital component of LCOE. The longer the construction time the more interest is payable.

Geothermal – hot fractured rocks.

All of the studies except US DOE (2009) have 2015 data on hot fractured rocks and then in 2030 we only have data from EPRI (2010) and CSIRO (2010).

Variation in reported assumptions – 2015

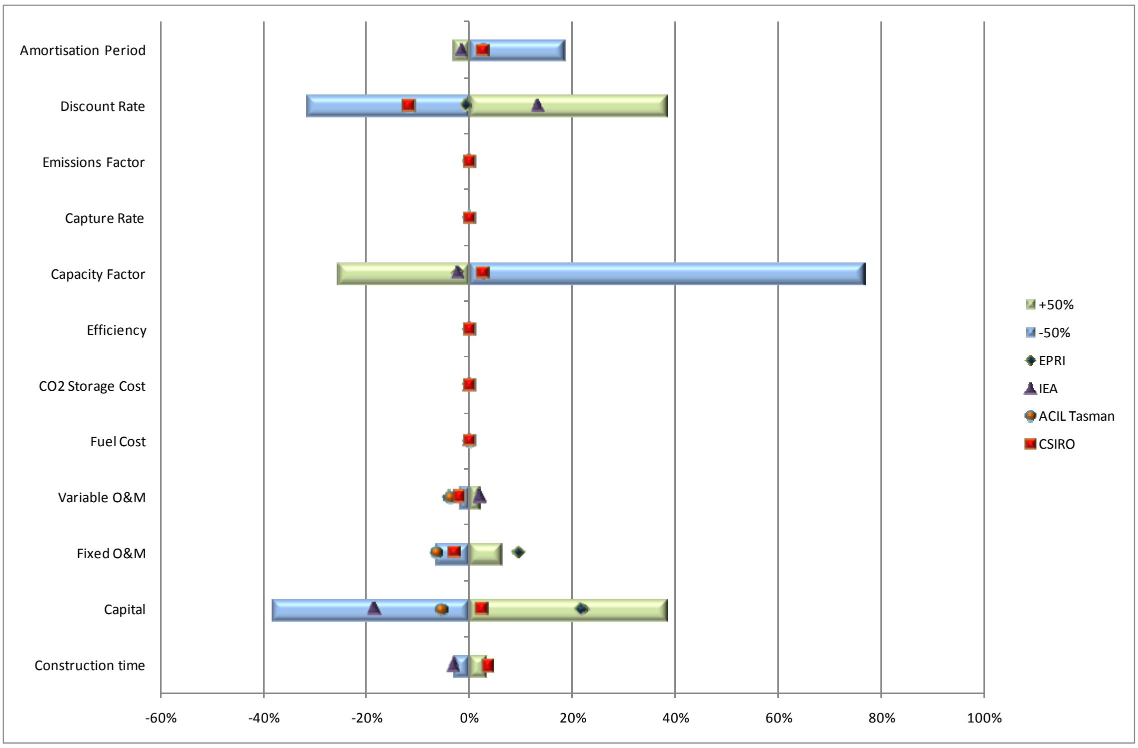

Figure 63: Tornado plot showing variation in LCOE for hot fractured rocks in 2015

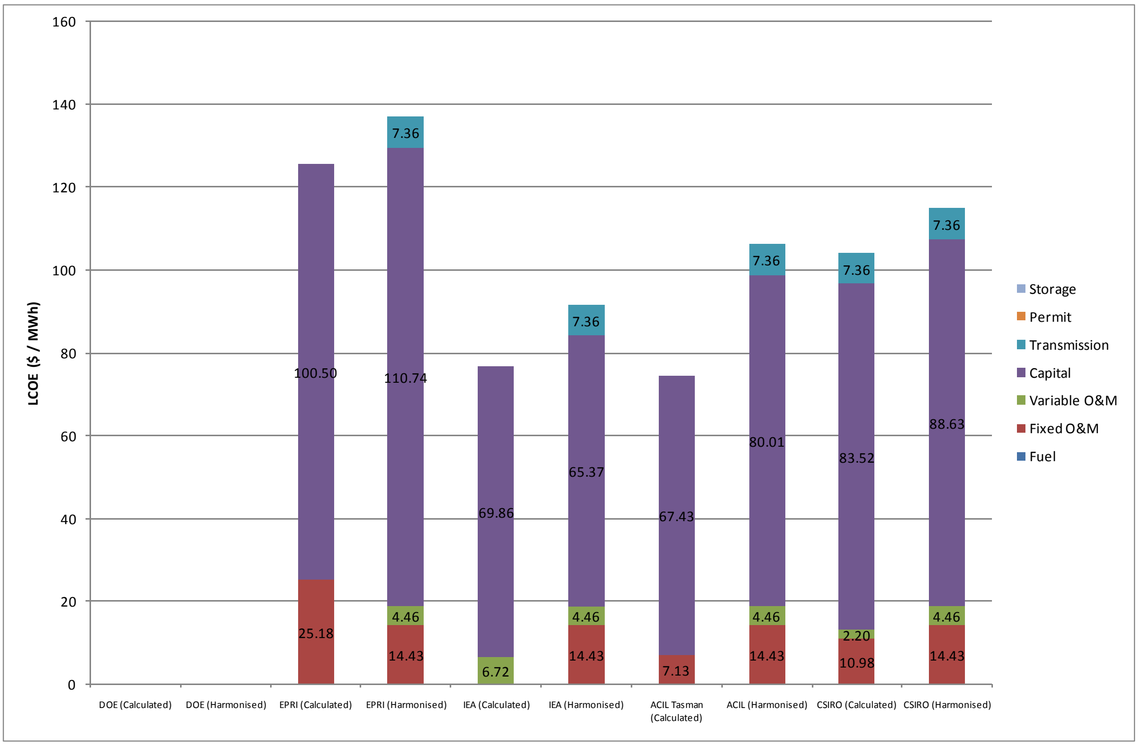

Figure 64: Calculated and harmonised LCOE breakdown for hot fractured rocks in 2015

The tornado plot for hot fractured rocks in 2015 is shown in Figure 63. The reported assumption with the largest effect on LCOE is capital cost. The low value reported by the IEA (2010) ($4791/kW) reduces the LCOE by 19% from the harmonised value ($6317/kW) and the high value reported by EPRI (2010) ($8116/kW) increases the LCOE by 22%. EPRI (2010) capital costs tend to be higher due to the inclusion of a 7.5% real project cost estimate. They also provided a range of costs for hot fractured rocks and we have included the midpoint in this analysis. EPRI (2010) estimate for a 50 MW plant whereas the IEA (2010) is for a 500 MW plant. Clearly on a per kW basis the larger plant should have lower cost.

Capital cost has a large effect on the LCOE because of the high capital component, which can be seen in Figure 64.

General variation in assumptions – 2015

Capacity factor is the assumption that has the greatest overall effect on LCOE. This has been the case for every renewable technology thus far. Increasing the capacity factor by 50% reduces the LCOE by 26% and decreasing the capacity factor by 50% increases the LCOE by 77%. Capacity factor influences the capital and fixed O&M components and thus has a large effect on renewable technologies.

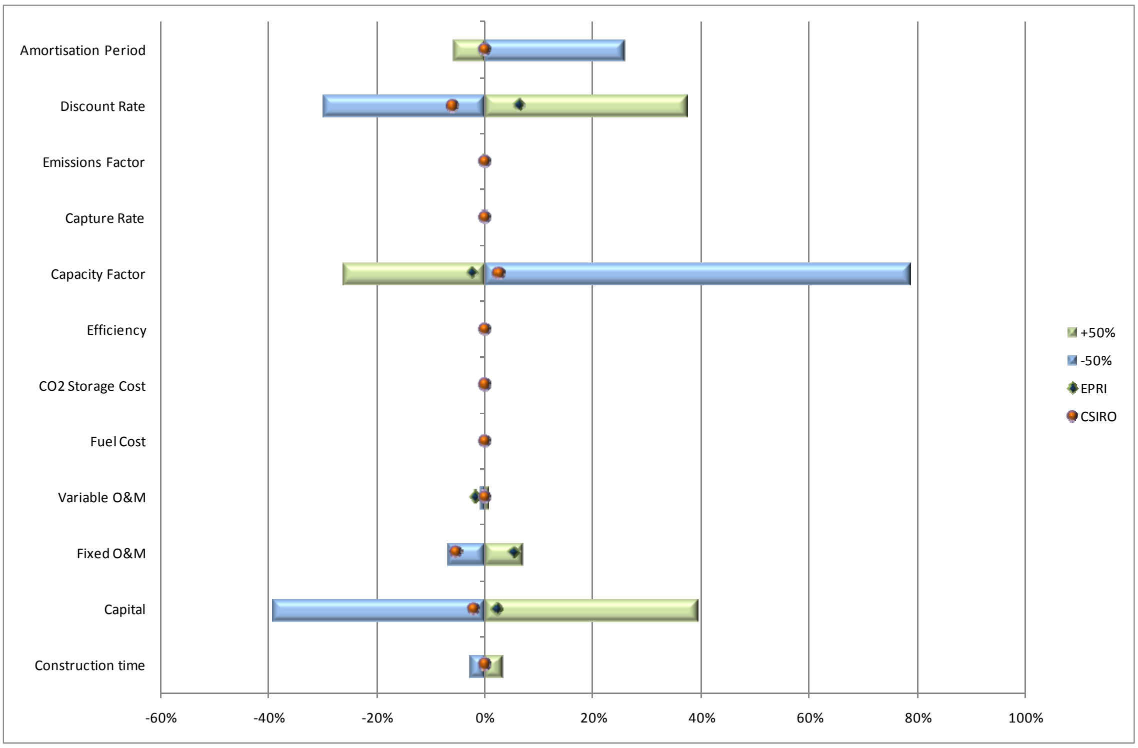

Figure 65: Tornado plot showing variation in LCOE for hot fractured rocks in 2030

Large variation between reported assumptions – 2015

There is some variation in O&M values. Firstly EPRI (2010) and ACIL Tasman (2010) have a variable O&M of zero which lowers the LCOE by 4%. EPRI (2010) has a higher fixed O&M ($25.18/MWh) which increases the LCOE by 10% and it is 74% greater than the harmonised O&M ($14.43/MWh). Each report has different ways of treating the ratio between fixed and variable O&M. In addition, for this technology it is difficult to get accurate estimates as no commercial scale plants have been built. In any case, the effect on LCOE is minor.

Points to note in 2030

Since only two studies have reported values for 2030 and the trends are the same as in 2015 we will only provide a very brief discussion here. The tornado plot in Figure 65 shows that now there is very little variation in capital; an approximate $400/kW difference. Other than that there is nothing to report.

Ocean renewable energy

Only two studies report on ocean renewable energy in 2015, IEA (2010) and CSIRO (2010). Because of this and the similarity to other renewable technologies we will only provide a brief discussion here. The tornado plot for wave energy is shown in Figure 66. There is a not a lot of variation between the reported parameters, except for capital, where IEA (2010) report a capital cost ($7802/kW) which is almost three times larger than the CSIRO (2010) capital cost ($2631/kW). These capital costs change the LCOE from the harmonised value ($5217/kW) by ±37%.

The tornado plot for tidal/ocean current energy is shown in Figure 67. This technology has a great deal of variation in the variable O&M cost. The IEA (2010) estimate for variable O&M is $227.2/MWh whereas CSIRO (2010) have $18.68/MWh. The IEA (2010) estimate is for tidal energy and CSIRO (2010) for ocean current, but the two technologies are similar. It may be that the IEA (2010) have taken the capacity factor into account for their O&M estimate. Tidal energy has a lower capacity factor (due to tidal fluctuations only occurring twice per day) whereas ocean currents flow continuously (but erratically). There is also a great deal of variation in the capital costs, even though the technologies are similar. CSIRO (2010) capital cost of $7277/kW is more than twice that of the IEA (2010) at $3207/kW.

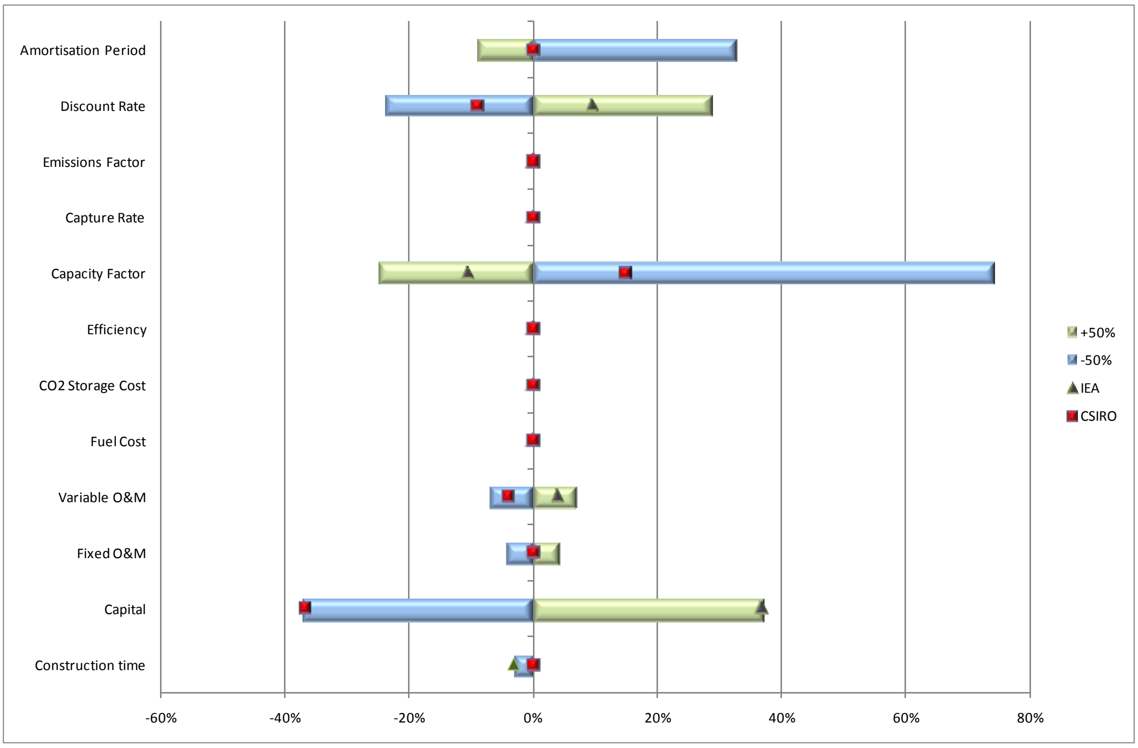

Figure 66: Tornado plot showing variation in LCOE for wave energy in 2015

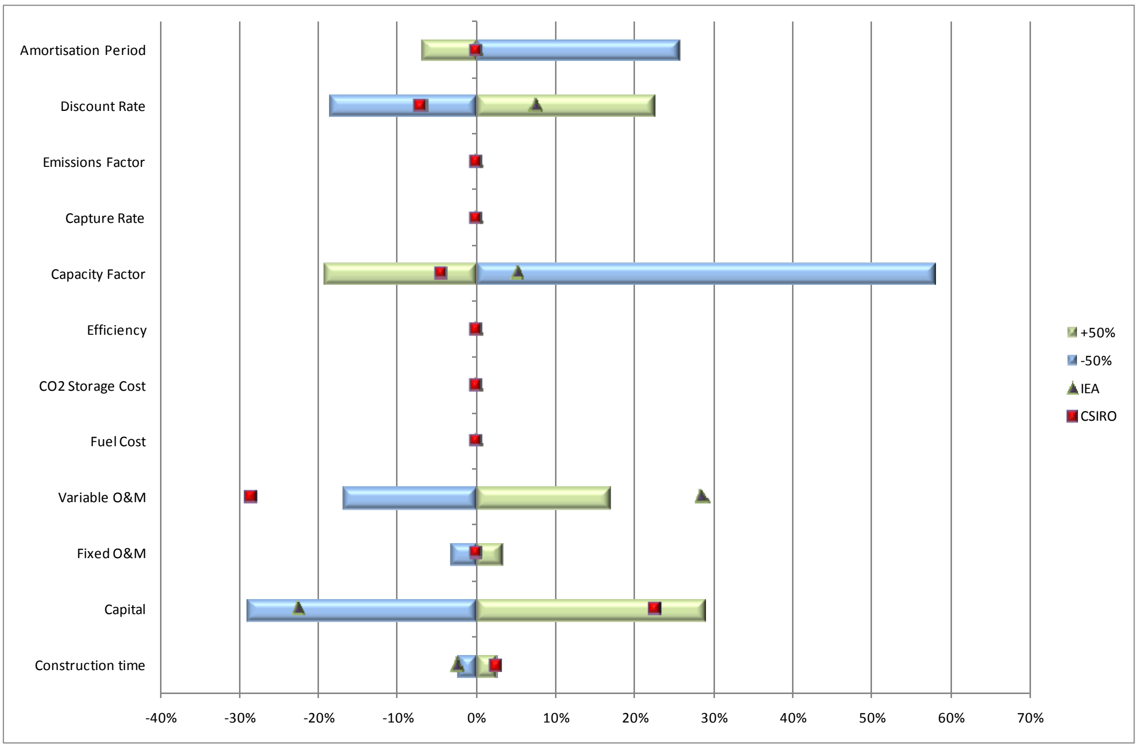

Figure 67: Tornado plot showing variation in LCOE for tidal/ocean current energy in 2015

4.2.2 Summary of results from tornado plot studies

Technologies have been grouped into five categories to summarise the results of the tornado plot analysis. The categories are: coal without CCS, coal with CCS, gas, nuclear and renewables. We have then tallied the number of times each assumption appeared as important under “Variation in reported assumptions” (1 in the table), “General variation in assumptions” (2) and “Large variation between reported assumptions” (3). The assumptions that scored the highest are shown in Table 8 below within their respective categories.

Table 8: Summary of highest contributing assumption across the three types of analysis (for selected technology categories)

	Coal no CCS	**Coal CCS**	**Gas**	**Nuclear**	**Renewables**
1	Capital	Capital	Capacity factor	Capital,	Capacity factor
2	Efficiency	Capacity factor	Efficiency	Capacity factor and capital	Capacity factor
3	Variable O&M	Variable O&M	Variable O&M	Fuel and all O&M	Capacity factor and all O&M

All coal technologies have relatively high capital costs and capital cost components to LCOE and therefore differences in capital between the reports have an influence on LCOE. However, when it comes to the general effect an assumption can have on LCOE, this differs between non-CCS and CCS technologies. Capacity factor is important for CCS technologies as they do not attract a high permit price and therefore capital stays as the highest contributor to LCOE; and capacity factor influences the capital and fixed O&M components of LCOE. On the other hand, non-CCS coal technologies attract a high permit price, particularly in the year 2030, and thus efficiency has a greater overall influence.

The gas technologies had a significant amount of variability in reported capacity factors, due to the different estimate of the US DOE (2009) and variations in the required capacity factor for a peaking plant. As a result of this, even though the capital and fixed O&M components are proportionally lower than for the other technologies, this variation in capacity factor had a strong effect on LCOE. However, when we examine the assumptions that have the most overall effect on LCOE for gas, efficiency is the leader. This is because of the high fuel price component of LCOE and the more efficient the plant, the lower the fuel cost.

Nuclear is in a category on its own because it is different from other technologies. Variations in the capital cost, mainly due to a lower capital cost from US DOE (2009) resulted in capital having the largest effect of the reported assumptions. Capital also shares the largest general effect on nuclear LCOE with capacity factor, and this is due to the large capital cost component of LCOE for a nuclear power plant.

All renewable technologies listed capacity factor as having the most important effect on LCOE. This is partially due to the estimations for the US DOE (2009) but overwhelmingly because of the high capital and fixed O&M components of LCOE.

Interestingly, variable O&M had the strongest variation among reports across all of the technologies. However, the effect on LCOE is always negligible for O&M. Reasons for this variation are difficult to determine, but a lot seems to be due to different ratios between fixed and variable O&M.

4.2.3 Differences in reported, calculated and harmonised LCOE

Tornado plots only examine what influences the LCOE and the harmonisation process. It is useful to go back one step and actually examine the reported LCOE (where it has been provided) and then see by technology how a common calculation methodology changes the LCOE. That is shown in Figure 68, Figure 69, Figure 70 and Figure 71, where reported, calculated and harmonised LCOE are plotted side-by-side for the fossil fuel and renewable technologies in the years 2015 and 2030. More reports appear under the calculated category because all reports provided the necessary data for this stage. Harmonised in this case refers to all data except capital being harmonised. The plotted range of harmonised values for each technology corresponds to the points along the capital assumption in the tornado plots.

When comparing the reported LCOEs it is clear that there are significant variations. The major differences are in solar thermal (163%), wave (150%), gas peaking plant (120%), PV (98%), nuclear (84%) and some CCS technologies (60-94%). In Table 9 the reported range in LCOE for fossil fuel and renewable technologies can be found for the years 2015 and 2030. The range is much greater for renewables than fossil fuel technologies and changes only slightly from 2015 to 2030. The range actually increases for fossil fuel technologies from 2015 to 2030.

Table 9: Reported and harmonised range of LCOE by broad technology type and year

	Fossil Fuel LCOE ($/MWh)		Renewable LCOE ($/MWh)	
	2015	**2030**	**2015**	**2030**
Reported	78-227	87-246	71-466	74-466
Harmonised	85-183	60-221	71-448	74-222

From the figures, it can be seen that in general the common calculation method has lead to a reduction in the LCOE range per technology. In some cases, it has increased the range but that is due to an expanding of the dataset with the addition of US DOE (2009) and ACIL Tasman (2010). The US DOE (2009) LCOE tends to sit at the lower end of the range because of their tendency to a lower capital cost for fossil fuel plant and a high estimated capacity factor for renewables. In particular, it has been found that a shrinking of the top of the range occurs, where the EPRI (2010) LCOE is lowered using a common calculation method. EPRI (2010) include other factors in their determination of LCOE which are not part of our method, and therefore their LCOE reduces.

On harmonisation, the range shrinks even further as now the only differences are due to differences in capital cost in these figures. For technologies where assumptions other than capital are driving the differences, this has resulted in a larger reduction in the range. For technologies where capital is important[33], there tends to be not as much difference between the calculated and harmonised LCOE.

The transition from reported to harmonised LCOE has reduced the major differences in reported values: solar thermal (64%), wave (116%), gas peaking plant (15%), nuclear (36%) and some CCS technologies (7-45%). The range did not reduce for PV because the capital cost differences are large and these aren't reduced on harmonisation and data from ACIL Tasman (2010) and US DOE (2009) were added. The overall range of LCOE for fossil fuel and renewable technologies has also reduced from reported to harmonised, as can be seen in Table 9. It is also interesting to examine the transition from 2015 to 2030 for the harmonised LCOE, as the carbon permit is higher in cost and this affects the relativity of costs between fossil fuel and renewable technologies. The high-end of the LCOE actually increases for the fossil fuel technologies from 2015 to 2030 and it drops significantly for the renewables over the same time period. This is because of the inclusion of the permit price. It has made the fossil fuel technologies more expensive and helps to push low emission technologies down the learning curve. The bottom-end of the LCOE for fossil fuel technologies is lower in 2030 than 2015 because of nuclear energy.

One observation of the 2030 cost projection data is that CSIRO (2010) has the lowest reported LCOE for renewables and low emission coal technologies. This is due to CSIRO (2010) having a lower capital cost in the year 2030, as a result of the modelling methodology employed to obtain capital cost projections. That is, in the CSIRO (2010) methodology low emissions plants are built under a carbon price regime, which pushes their costs down the learning curve and also current high prices for electricity generation technologies are interpreted as a price bubble which reduces to some extent. The EPRI (2010) and ACIL Tasman (2010) estimates, while lower, are still at the high end of the scale due to their different treatment of capital cost projections. On the other hand, EPRI (2010) have the greatest cost reduction for fossil fuel technologies.

For most of the renewable technologies on harmonisation, the US DOE (2009) LCOEs move towards the top end of the scale. That is firstly due to this report's use of their reference case capital cost projections, which means that the renewable technologies are not as low in cost as under their carbon price scenario. And secondly they have a high, inferred capacity factor of more than 70 percent, which drops dramatically to approximately 20 percent on harmonisation. The harmonisation process therefore shifts the capital cost component of the LCOE up from the low calculated value.

[33] These are in 2015: brown coal pf, brown coal pf with CCS, black coal IGCC, black coal IGCC with CCS, nuclear, wind, hot fractured rocks and ocean current. In 2030: Black coal pf with CCS, black coal IGCC with CCS, nuclear, solar thermal and wind.

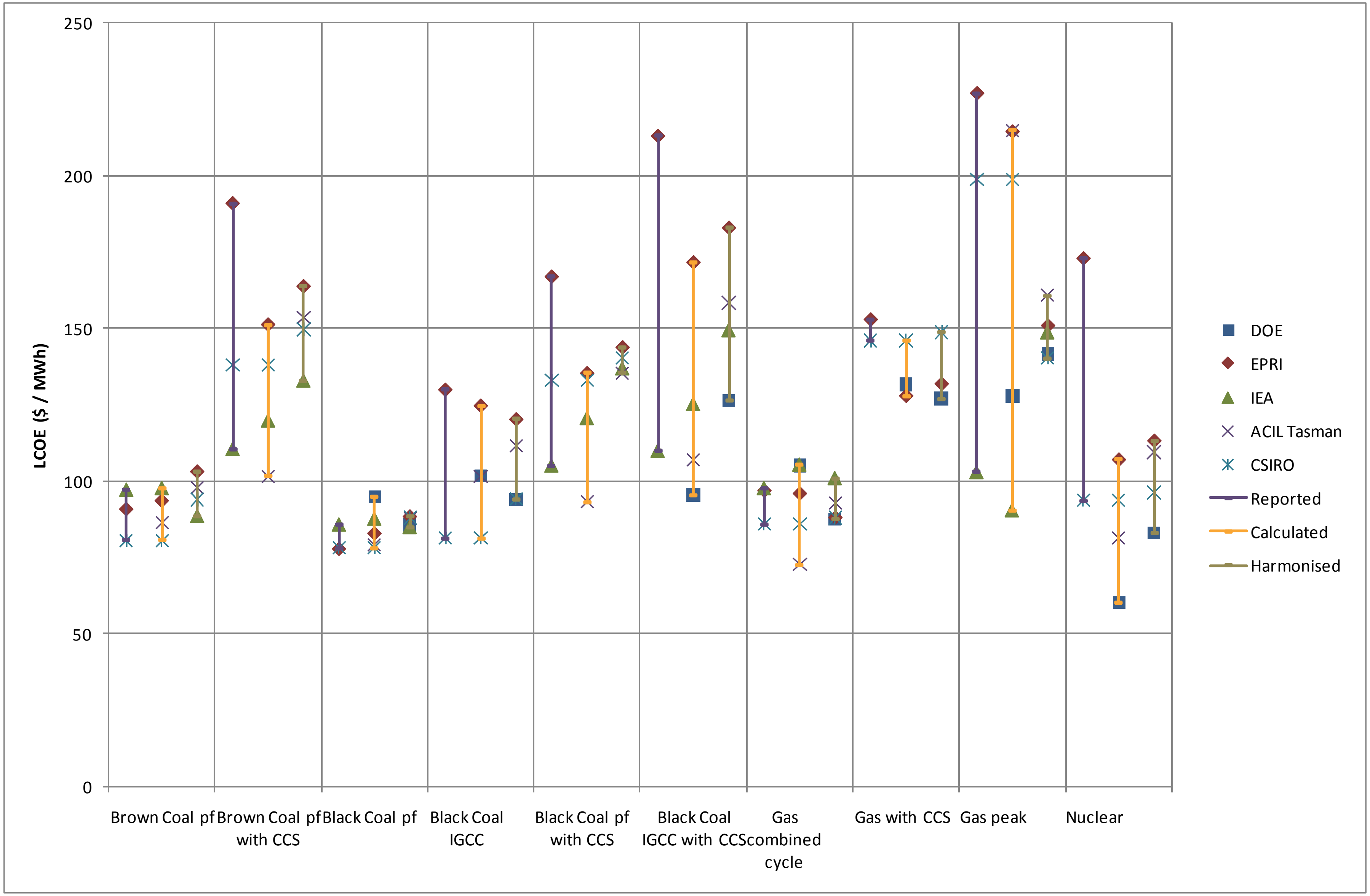

Figure 68: Reported, calculated and harmonised LCOE from each study for fossil fuel technologies in the year 2015

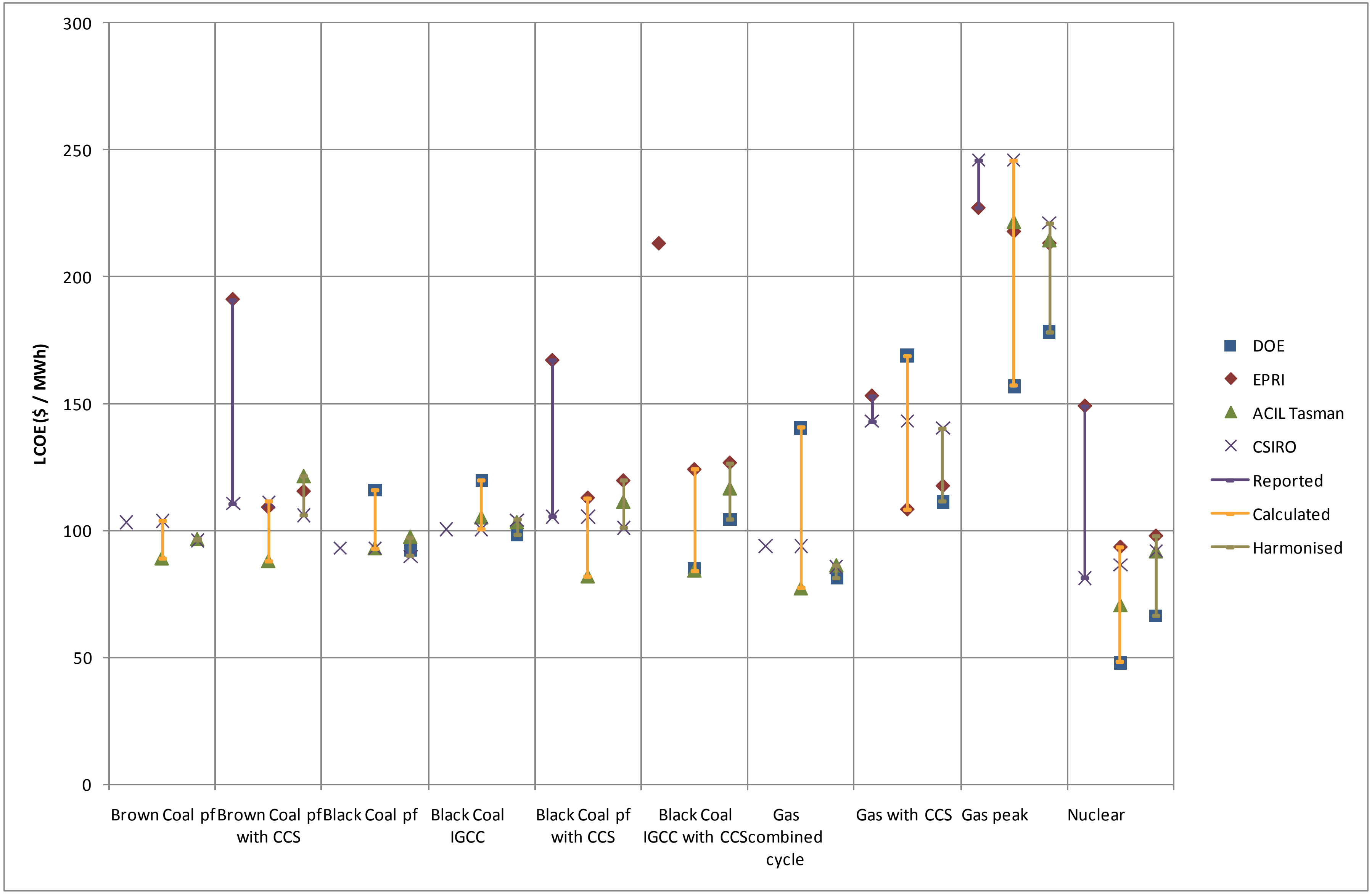

Figure 69: Reported, calculated and harmonised LCOE from each study for fossil fuel technologies in the year 2030

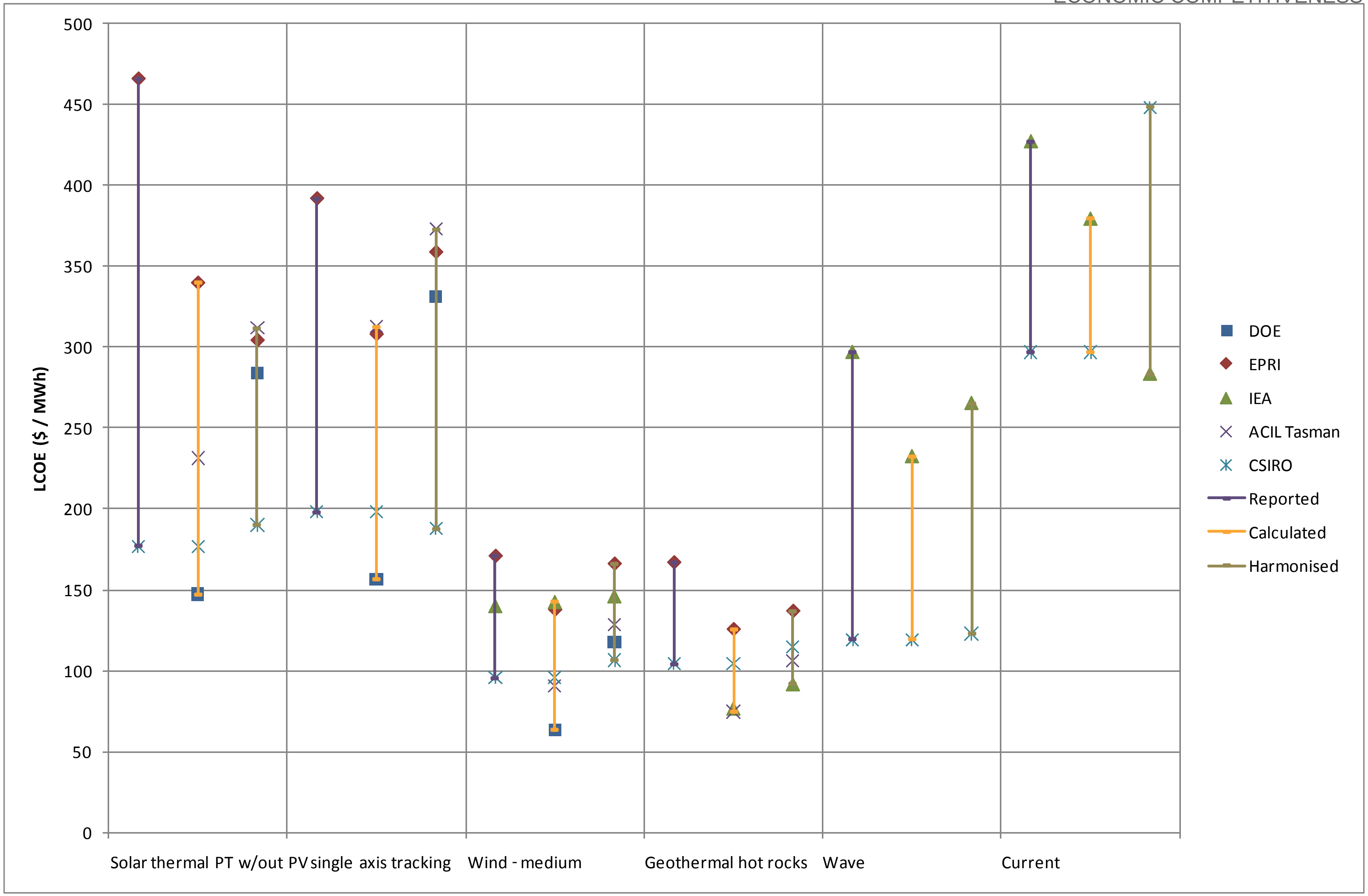

Figure 70: Reported, calculated and harmonised LCOE from each study for selected renewable technologies in the year 2015

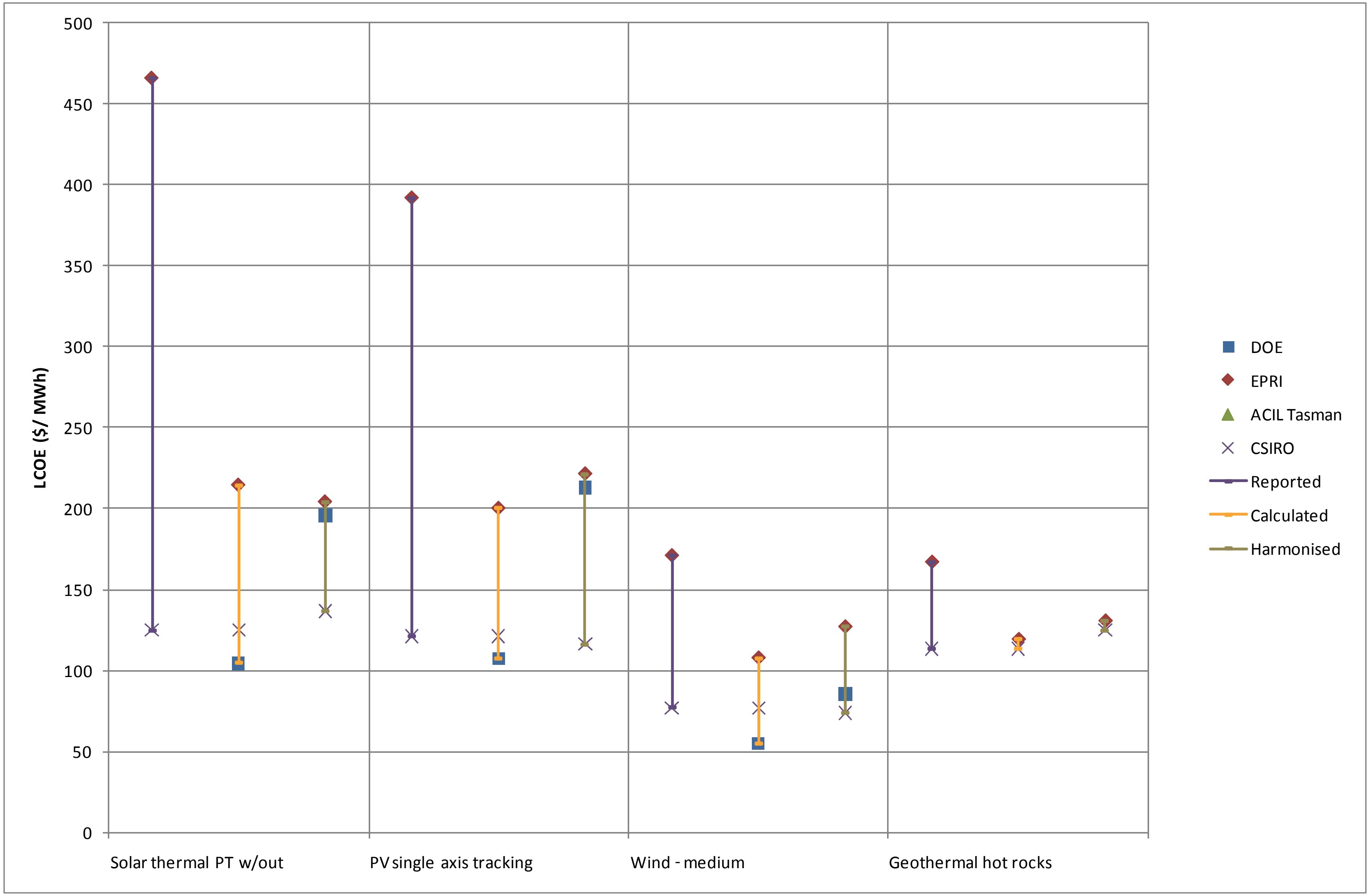

Figure 71: Reported, calculated and harmonised LCOE from each study for selected renewable technologies in the year 2030

4.3 Scope of studies

This section contains a discussion of the differences in scope of the studies under examination. By scope we mean the type and size of plants, whether any specific component suppliers' equipment and costs were used, and other issues such as the inclusion or exclusion of transmission and distribution costs and carbon pricing.

4.3.1 Plant Types

Each report provides cost projections for centralised generation plants and in some instances distributed generation technologies. The different plant types from each report are listed in Table 10. EPRI (2010) include a comprehensive list of plants. The report describes in detail the power plants being used in the study including any regional assumptions and size of plant. ACIL Tasman (2010) derives its performance data for new entrant technology from the EPRI report, however it does go on to provide time dependant data for efficiencies for each plant type when relevant. As such ACIL Tasman (2010) matches many of the EPRI (2010) plant types but not all.

IEA (2010) has many fossil fuel plants but few renewables. Each of the plant types are described but in lesser detail than EPRI (2010). The US DOE (2009) and CSIRO (2010) have few fossil fuel plants. Table 8.2 of US DOE (2009) states in its sources of data that the technologies presented:

" .. are not based on any specific technology model, but rather, are meant to represent the cost and performance of typical plants under normal operating conditions for each plant type."

They do however specify plant size. CSIRO (2010) has the widest set of renewable technologies including ocean wave and current and roof-top solar PV. However, it has fewer plant types within some renewable categories (e.g. only one type of large scale PV plant).

Because the methodology used by CSIRO (2010) and the US DOE (2009) simultaneously estimates the costs of their selected technologies sets all at once (Section 4.5.1), it is not practical to include many different plant types for two reasons. Firstly, the runs of the models applied by those organisations would become inordinately long due to high computational demands for larger sets and secondly detailed and reliable plant data may not be available for the methodologies employed by those models. In contrast, EPRI (2010), ACIL Tasman (2010) and the IEA (2010) model the costs of each plant individually. These three organisations also tend to have access to larger data sources for their cost projections.

In the sections below, we tabulate the key input assumptions across the studies for the common plant types covered in those studies. Two of these factors are explained further below:

- Capacity Factor: the percentage of a year that the power plant will produce electricity. The greater the value the more power is produced. This factor is used in the conversion of capital cost and fixed O&M cost from $/kW to $/MWh

- Efficiency (or heat rate): is how much energy in the form of electricity is produced for a given input of energy in the form of a fuel source. This value can be expressed in a number of ways. Firstly, it can be expressed as being based on the Higher Heating Value (HHV) of the fuel or as the Lower Heating Value (LHV). From IEA (2010) the difference between lower and higher heating value, based on IEA (2010) conventions, is 5% for coal and 10% for gas. Additionally, the efficiency reported can be based on the electricity generated, or on the electricity sent-out (i.e. the generated electricity less any electricity used internally).

The efficiency is used in the calculation of a number of costs. It is used to convert fuel cost from $/GJ to $/MWh. A decrease in efficiency will result in a greater fuel cost while an increase will lower fuel costs. Efficiency is also used in the conversion of CO_2 emissions per GJ of fuel to calculation of storage costs and greenhouse gas permit costs. Again a +/- variation on efficiency will have the same effect on the storage costs and the emission cost.

It is important to ensure that a consistent basis is taken for other costs in regard to whether they are based on sent-out or generated electricity.

The reader is referred to the Data Tables Appendix at the back of the report for detail on assumptions other than those covered here.

Table 10: Technologies examined in each study

EPRI	ACIL Tasman	US DOE	IEA	CSIRO
PC, Brown coal, no NOx/SO_2 controls, AC	PC, Brown coal, no NOx/SO_2 controls, AC	-	Brown supercritical AC	Brown coal pf
PC, Brown coal, with CCS (90%) & NOx/SO_2 controls as reqd, AC	PC, Brown coal, with CCS (90%) & NOx/SO_2 controls as reqd, AC	-	Brown ultra-supercritical AC 90% CC(S)	Brown coal, with CCS (90%) & NOx/SO_2 controls as reqd
PC, Black coal, no NOx/SO_2 controls, AC	PC, Black coal, no NOx/SO_2 controls, AC	Scrubbed coal new	Black supercritical AC	Black coal pf
IGCC, Black coal, AC	IGCC, Black coal, AC	Integrated coal-gasification combined cycle	-	Black coal IGCC
PC, Black coal, with CCS (90%) & NOx/SO_2 controls as reqd, AC	PC, Black coal, with CCS (90%) & NOx/SO_2 controls as reqd, AC	-	Black ultra-supercritical AC 90% CC(S)	Black coal, with CCS (90%) & NOx/SO_2 controls as reqd
IGCC, Black coal, with CCS (85-90%), AC	IGCC, Black coal, with CCS (85-90%), AC	IGCC with carbon sequestration	Black IGCC w/95% CC(S)	-
CTCC, Without CCS, AC	CTCC, Without CCS, AC	Conventional gas/oil combined cycle	CCGT AC	CCGT
Advanced CTCC (with CCS), AC	-	Advanced CC with carbon sequestration	-	CCGT (with CCS, 90%)
CT, Heavy Duty	CT, Heavy Duty	Conv Combustion Turbine	OCGT AC	OCGT
Generation III/III+ (with seawater cooling)	Generation III/III+ (with seawater cooling)	Advanced nuclear	-	Nuclear
-	-	Biomass	-	Biomass
Parabolic trough w/6 hours storage [DNI 6]	Parabolic trough w/6 hours storage [DNI 6]	-	-	-
Parabolic trough w/o storage [DNI 6]	Parabolic trough w/o storage [DNI 6]	Solar thermal	-	Solar thermal
Central receiver w/6 hours storage [DNI 6]	-	-	-	-
Central receiver w/o storage [DNI 6]	-	Solar thermal	-	Solar thermal
Utility scale centralized PV, fixed flat plate PV 50 MW	Utility scale centralized PV, fixed flat plate PV 50 MW	-	-	-
Utility scale centralized PV, single axis tracking PV 50 MW	Utility scale centralized PV, single axis tracking PV 50 MW	Photovoltaic	-	Large scale PV
Utility scale centralized PV, two axis tracking 50 MW	Utility scale centralized PV, two axis tracking 50 MW	-	-	-
On-Shore Wind: Class 4 Wind Speed - Size 50 MW	On-Shore Wind: Class 4 Wind Speed - Size 50 MW	-	-	-
On-Shore Wind: Class 4 Wind Speed - Size 200 MW	On-Shore Wind: Class 4 Wind Speed - Size 200 MW	Wind	Onshore wind	Wind
On-Shore Wind: Class 4 Wind Speed - Size 300 MW	On-Shore Wind: Class 4 Wind Speed - Size 300 MW	-	-	-
Enhanced Geothermal System (EGS)(1)	-	-	Geothermal	Hot fractured rocks
-	-	Geothermal	-	Conventional geothermal
Hot Sedimentary Aquifers (HSA)(1)	Hot Sedimentary Aquifers (HSA)	-	-	-
-	-	Conventional Hydropower	-	Hydro
-	-	-	Wave	Wave
-	-	-	Tidal	Ocean Currents

Black and brown coal pf without CCS

As detailed earlier the US DOE (2009) does not give any detail on technology used and does not actually specify what coal type is being used (i.e. either black or brown). However, it was assumed that it was for supercritical air cooled black coal. Additionally, it was not specified as to whether the efficiency and capital costs were on a sent-out or generated basis and whether efficiency was on a higher heating value (HHV) or lower heating value (LHV) basis. It was assumed for the calculation of LCOE that the values were for sent-out and HHV. No capacity factors were reported so a capacity factor was estimated using the reported value for Total Generation by Coal ($1934 * 10^9$ kWh) divided by generation capacity ($305.2 * 10^6$ kW) divided by (24 * 365) = 72.3%.

The description and relevant parameters provided by EPRI (2010) were the most detailed. Both the black and brown coal plants were supercritical single reheat type Rankine cycles with steam conditions of 267 bar/596ºC/596ºC. ACIL Tasman (2010) has based their non-renewable plants on the EPRI (2010) cases and so should have the same parameters.

IEA (2010) had costing and operating parameters for both brown and black coal fired power plants of both supercritical and ultra supercritical cycles. Both air cooled and wet cooled systems were also examined. For this comparison the data for air-cooled supercritical plants were used.

New plant is assumed to be supercritical in CSIRO (2010), with efficiencies based on current supercritical technology, taking into account Australia's ambient conditions. Of the relevant technical parameters the following range of values were reported:

Table 11: Technical parameters for coal fired pf plants without CCS from each study. * estimated

		US DOE		EPRI		ACIL Tasman		IEA		CSIRO	
Coal Type		***Brown***	***Black***	***Brown***	***Black***	***Brown***	***Black***	***Brown***	***Black***	***Brown***	***Black***
Size (MW)		NA	600	750	750	750	750	686	690	-	-
Capacity Factor (%)	***2015***	NA	72.3*	85	85	85	85	85	85	80	80
	2030	NA	72.3*	NA	NA	85	85	NA	NA	80	80
Efficiency (%)	***2015***	NA	35.2	34.8	38	32	40	30	37	34.9	38
	2030	NA	35.2	NA	NA	47.1	48	NA	NA	34.9	38

Black and brown coal CCS

The US DOE (2009) does not report on coal pf with capture.

EPRI (2010) is based on the use of a MEA-type absorption plant and is modelled to capture 90% of the CO_2. ACIL Tasman (2010) is based on the technologies of the EPRI (2010).

IEA (2010) only provides data for Ultra Supercritical power plants with CCS, so they were used in this study. Additionally the capture rate was not specified for Australia but was assumed to be 90%.

In CSIRO (2010) these are assumed to be supercritical, air cooled plants. The black coal CCS plant configuration was taken from an earlier CSIRO study into these types of plants (Dave et al., 2008). Unfortunately, there was no similar study into brown coal CCS plants, only into subcritical plants (Dave, 2009)(Dave 2009). However, based on the earlier studies it was possible to provide an estimate for brown coal CCS efficiencies. The learning rate is the same for both plant types and the efficiencies improve with time.

Table 12: Technical parameters for coal fired pf plants with CCS from each study

		US DOE		EPRI		ACIL Tasman		IEA		CSIRO	
Coal Type		**Brown**	**Black**	**Brown**	**Black**	**Brown**	**Black**	**Brown**	**Black**	**Brown**	**Black**
Size (MW)		NA	NA	NA	750	NA	750	NA	434	-	-
Capacity Factor (%)	***2015***	NA	NA	85	85	85	85	85	85	80	80
	2030	NA	NA	85	85	85	85	NA	NA	80	80
Efficiency (%)	***2015***	NA	NA	25.5	28.4	24	31	24	29	24.8	26.9
	2030	NA	NA	37.7	38.5	35	39	NA	NA	26.2	29.3
Capture Rate (%)		NA	NA	NA	90	NA	90	NA	90	90	90

Black integrated gasification combined cycle (IGCC)

As for all the US DOE (2009) technologies no description is provided as to the design basis besides the size.

EPRI (2010) uses a 2x1 arrangement for the power system, with two GE 9F gas turbines followed by one steam turbine.

ACIL Tasman (2010) has used different technology to EPRI (2010) for this case, as seen by the variation in parameters but no further information is given.

IEA (2010) does not report on IGCC without CCS.

CSIRO (2010) uses plant types IGCC for black coal as described in (Cottrell, et al. 2003b) which is based on overseas plants as in EPRI (2010).

Table 13: Technical parameter for black al IGCC plants without CCS from each study * estimated

		US DOE	EPRI	ACIL Tasman	IEA	CSIRO
Size (MW)		550	728.3	750	NA	-
Capacity Factor (%)	***2015***	72.3*	85	85	NA	80
	2030	72.3*	NA	85	NA	80
Efficiency (%)	***2015***	36.9	39.4	41	NA	40.6
	2030	36.9	NA	45	NA	42.9

Black IGCC with CCS

Only EPRI (2010) provided any detail on the capture plant used. For this study a two stage Selexol system was used, the first stage being to remove H_2S, and the second-stage to remove the CO_2. In order to achieve high levels of CO_2 removal, the syngas from the gasifier must be passed through a series of reactors to convert the CO to CO_2. As this reaction reduces the heating value of the syngas a trade-off between removal and efficiency must be made. Thus, in EPRI (2010) the capture rate was set at 88.5%.

ACIL Tasman (2010) is using a different technology to EPRI (2010), but no further information is available.

IEA (2010) and US DOE (2009) do not provide any details on the technology modelled, while CSIRO (2010) does not report on IGCC with CCS.

Table 14: Technical parameters for black coal fired IGCC plants with CCS from each study. * estimated

		US DOE	EPRI	ACIL Tasman	IEA
Size (MW)		380	576.2	650	523
Capacity Factor (%)	***2015***	72.3*	85	85	85
	2030	72.3*	85	85	NA
Efficiency (%)	***2015***	30	28.9	33	35
	2030	30	35.6	40	NA
Capture Rate (%)		-	88.5	88.5	85

Combined cycle gas turbines with and without CCS

US DOE (2009) reported on a combined cycle gas turbine and an advanced combined cycle gas turbine; however no detail is given as to what these were. For gas with capture, the advanced system was used but as no detail of capture rate was given, a value of 90% was assumed.

In US DOE (2009) capacity factor data are not reported. For our purposes, a value was estimated using data from the US DOE (2009) Tables A8 and A9. From Table A8, the total electricity generated in 2015 is 815,000 GWh while from Table A9 the total generating capacity by natural gas is 163.9 GW. Using these values the capacity factor can be estimated as:

Capacity factor
= Electricity generated ÷ Generating capacity ÷ hours per year
= 815,000 ÷ 163.9 ÷ 8760
= 56.7 %

EPRI (2010) was based on a multi-shaft system, consisting of two trains of a GE 9FA turbine and a heat recovery steam generator. The steam from the two trains is then passed to a single steam turbine. The steam cycle incorporates a reheat for the steam and so is of a high efficiency. Because of the discrete size nature of gas turbines the power output of the system is reduced in the case of CCS.

ACIL Tasman (2010) does not provide any details as to what configuration it is using. Additionally CCS was not reported on.

Combined cycle gas turbines were modelled in CSIRO (2010). It was assumed that combined cycle could be used for both peak and base load power. Combined cycle turbines have a learning rate and the efficiency improved slightly over time.

Table 15: Technical parameters for gas combined cycle plants with and without capture from each study. * estimated

		US DOE		**EPRI**		**ACIL Tasman**		**IEA**		**CSIRO**	
			CCS		***CCS***		***CCS***		***CCS***		***CCS***
Size (MW)		250	400	711.3	591	700	NA	480	NA	-	-
Capacity Factor (%)	***2015***	56.7*	56.7*	85	85	85	NA	85	NA	80	80
	2030	20*	20*	NA	85	85	NA	NA	NA	80	80
Efficiency (%)	***2015***	44.9	37.5	49.5	41.1	50	NA	50	NA	48.6	39.7
	2030	44.9	37.5	NA	49.3	57.6	NA	NA	NA	51.4	42.3
Capture Rate (%)		NA	90*	NA	90	NA	NA	NA	NA	NA	90

Open cycle gas turbine

Open cycle gas turbines are generally used for peaking power and so have a lower capacity factor, however IEA (2010) still used a baseload capacity factor of 85% which affects their reported value for the LCOE.

EPRI (2010) specified a GE 9E turbine which is an older design heavy duty single shaft machine.

Open cycle gas turbines were also modelled in CSIRO (2010). It was assumed that open cycle would be used for peaking plant only. All other reports gave no details as to what type of unit was being assumed.

Table 16: Technical parameters for open cycle gas turbines (peaking plant) from each study * estimated

		US DOE	**EPRI**	**ACIL Tasman**	**IEA**	**CSIRO**
Size (MW)		160	114.7	175	297	-
Capacity Factor (%)	***2015***	56.7*	10	10	85	21.4
	2030	20*	10	10	NA	23.6
Efficiency (%)	***2015***	29.9	33.2	35	39	20
	2030	29.9	40	36	NA	20

Nuclear

EPRI (2010) used Generation III nuclear reactor technology. This plant was assumed to be located on the coast and provided with seawater cooling.

CSIRO (2010) did not consider any particular nuclear plant type other than the current standard. However, because of the cost reductions associated with technology learning and because the efficiency of the plant increases over time, it was assumed that the technology will improve.

We do not know what technologies are behind the ACIL Tasman (2010) or US DOE (2009) estimates. The IEA do not report on this technology.

Table 17: Technical parameters for nuclear plants from each study * estimated

		US DOE	EPRI	ACIL Tasman	CSIRO
Size (MW)		1350	1117	-	-
Capacity Factor (%)	***2015***	89.7*	85	85	80
	2030	89.7*	85	85	80
Efficiency (%)	***2015***	31	33	34	33.6
	2030	31	33	34	35.1

Biomass

Only the US DOE (2009) and CSIRO (2010) provided data on biomass power generation.

A steam turbine was assumed for the biomass plant in CSIRO (2010) with some drying of the biomass, as standard. Gasification of the biomass was not considered to be an option. However, as with nuclear, the experience curve in conjunction with improvements in efficiency leads to technology improvements over time.

Table 18: Technical parameters for biomass plants from each study * estimated

		US DOE	CSIRO
Size (MW)		80	-
Capacity Factor (%)	***2015***	41.6*	50
	2030	41.6*	36.1
Efficiency (%)	***2015***	33.5	26.7
	2030	33.5	28.1

Wind

Across EPRI (2010) and ACIL Tasman (2010) three sizes of wind farms were reported: (S)mall, (M)edium and (L)arge. None of the studies provided design details of the individual turbines. However, EPRI (2010) specified the size of each of it turbines as 2 MW, so that the 50 MW farm would be made from 25 individual turbines. EPRI (2010) additionally provided data for different prevailing wind conditions. An increase in wind speed increased the capacity factor for the farm as well reducing fixed O&M costs per MWh. Shown below are results under Class 4 wind speed.
The other studies only specified one type of onshore wind and these were placed into the medium farm category.

Table 19: Technical parameters for wind farms from each study * estimated

		US DOE	EPRI			ACIL Tasman			IEA	CSIRO
Size Range		M	S	M	L	S	M	L	M	M
Size (MW)		50	50	200	300	50	200	500	149	-
Capacity Factor (%)	***2015***	41.6*	33.2	33.2	33.2	30	30	30	30	30
	2030	41.6*	38.2	38.2	38.2	NA	NA	NA	NA	31.5

Photovoltaics (PV)

Rooftop PV

Of the studies only CSIRO (2010) reported on rooftop PV installations.

Table 20: Technical parameters for Rooftop PV from each study

		CSIRO
Size (MW)		-
Capacity Factor (%)	***2015***	21.4
	2030	23.6

Centralised PV

Across EPRI (2010) and ACIL Tasman (2010) three types of centralised PV installations were reported: (Fixed) plate, (S)ingle Axis Tracking and (T)wo Axis Tracking. EPRI (2010) specified that its results were based on using flat plate crystalline silicon PV cells and considered different levels of solar flux. We chose the solar flux level DNI 6 to represent EPRI (2010) for this comparison report.

CSIRO (2010) and US DOE (2009) only reported data on one type of centralised PV and these were assumed to be single axis tracking. IEA (2010) did not report on PV.

Table 21: Technical parameters for Centralised PV from each study * estimated

		US DOE			EPRI			ACIL Tasman			CSIRO		
Type		F	S	T	F	S	T	F	S	T	F	S	T
Size (MW)		NA	5	NA	5	5	5	50	50	50	NA	-	NA
Capacity Factor (%)	***2015***	NA	41.6 *	NA	21	26	31	21.4	21.4	21.4	NA	21.4	NA
	2030	NA	41.6 *	NA	21	26	31	NA	NA	NA	NA	23.6	NA

Solar thermal

EPRI (2010) and ACIL Tasman (2010) reported on two types of solar thermal technology: parabolic trough (PT) and central receiver (CR). Also consideration was given to the technologies with and without 6 hours of storage and EPRI (2010) considered different levels of solar flux. As with PV, we chose DNI 6 results to represent EPRI (2010) in this comparison study.

EPRI (2010) assumed the thermal storage system to be two-tank molten salt. For generation of electricity from the thermal energy a subcritical steam cycle was assumed.

The experience curve for solar thermal in the CSIRO (2010) model is based on data from all types of operational solar thermal power plants therefore no distinction has been made between PT and CR plants in the model. It is assumed that a limited amount of for example molten salt storage is available (which appears in the model as an increase in capacity factor). It is planned in future versions of the model to explicitly add solar thermal storage capability.

US DOE (2009) reported on one type of solar thermal technology and IEA (2010) did not report on any solar technologies. Because US DOE (2009) and CSIRO (2010) do not specify any particular type of solar thermal technology, we have placed them within parabolic trough without storage as this is the current dominant technology.

Table 22: Technical parameters for solar thermal parabolic trough plants from each study * estimated

		US DOE		EPRI		ACIL Tasman		CSIRO	
Storage (hrs)		0	6	0	6	0	6	0	6
Size (MW)		10	NA	200	200	250	250	-	NA
Capacity Factor (%)	***2015***	41.6*	NA	19.4	31.5	26.1	26.1	21.4	NA
	2030	41.6*	NA	20	32.9	NA	NA	27.9	NA

Table 23: Technical parameters for solar thermal central receiver plants from each study

		EPRI		ACIL Tasman	
Storage (hrs)		0	6	0	6
Size (MW)		200	200	250	250
Capacity Factor (%)	***2015***	19.5	31.6	26.1	26.1
	2030	20.5	32.6	NA	NA

Geothermal

Across the studies three types of Geothermal technology was reported on. These were (C)onventional, (E)nhanced Geothermal Systems and (H)ot Sedimentary Aquifers.

In the CSIRO (2010) model it was assumed that in order to extract 50 MW of electrical energy from a hot fractured rocks plant (otherwise known as enhanced geothermal systems) 18 wells to a depth of 4 km will need to be drilled and each production well produces just over 5 MW (after auxiliaries are subtracted). For conventional geothermal, it was assumed that for a 50 MW plant 15 wells to a well depth of 1.5 km will need to be drilled.

It is not known what assumptions are behind the US DOE (2009), IEA (2010), ACIL Tasman (2010) or EPRI (2010) estimates.

Table 24: Technical parameters for all types of geothermal plants from each study * estimated

		US DOE			EPRI			ACIL Tasman			IEA			CSIRO		
Type		C	E	H	C	E	H	C	E	H	C	E	H	C	E	H
Size (MW)		50	NA	NA	NA	50	50	NA	50	50	NA	500	NA	-	-	NA
Capacity Factor (%)	***2015***	41.6 *	NA	NA	NA	85	85	NA	80	80	NA	85	NA	80	80	NA
	2030	41.6 *	NA	NA	NA	85	85	NA	NA	NA	NA	NA	NA	80	80	NA

Wave, tidal and ocean current

Only IEA (2010) and CSIRO (2010) report on power generation using ocean energy. The experience curve for wave energy in the CSIRO (2010) model was based on data for all of the different types of wave energy devices available. Therefore, no particular plant type has been assumed except that the device extracts wave energy with a capacity factor of 50% in the year

2015. Also, no particular plant type has been assumed for ocean current energy, although the available devices are similar to those for extracting tidal current energy.

We do not know what is behind the IEA (2010) assumptions.

The three technologies reported on in this category were (W)ave, (T)idal and (O)cean Current

Table 25: Technical parameters for all types of ocean energy plants from each study

		IEA			CSIRO		
Type		W	T	O	W	T	O
Size (MW)		50	104	NA	-	NA	-
Capacity Factor (%)	***2015***	56	30	NA	50	NA	35.4
	2030	NA	NA	NA	51.1	NA	35.4

4.3.2 Size of Plants

As with plant types, each report has projections for different sized plants as has been reported in the Tables in Section 4.3.1 for each technology. Ideally, especially for the bottom-up engineering estimate based reports, the plants should have a size that is consistent with what is currently in Australia and what is expected to be built in the near future. This will be affected by what is available overseas since most technologies are imported. For the US DOE (2009) and CSIRO (2010) projections, since experience curves are used to determine capital costs, plant size is not as important as cumulative capacity, not plant size or number of plants.

4.3.3 Conclusions on differences in scope

Many of the studies have the same or similar plant types across the range of those examined. The range of technologies also is a reflection of the methodology employed for obtaining capital cost projections. US DOE (2009) and CSIRO (2010) take a modelling approach and it is not practical to include many plant types with slight variations in the model (e.g. three different types of wind farms). However, it is possible to include these when detailed estimates and quotes form the basis of the projections. EPRI (2010) has the greatest number of plants, while IEA (2010) has the fewest.

In terms of plant technology, it was difficult to find differences between studies given that in most cases EPRI (2010) has been the only report to provide any details for this comparison. Generally, the fossil fuel plants reported were air cooled and similar capture rates reported for CCS plants. EPRI (2010) was also the only study that mentioned some suppliers: GE for gas turbines.

4.4 Regional factors

This section provides an examination of differences between the studies due to regional factors. Differences in solar radiation, wind speeds, ambient temperature and general plant operating conditions are regional factors. Differences in these factors can result in different thermal efficiencies for fossil fuel plants and different capacity factors for renewables and thus affect plant output and cost of electricity. In general, hotter ambient conditions result in a lower thermal efficiency and greater classes of wind speed and higher solar radiation result in a greater capacity factor.

4.4.1 Fossil fuel plant operating conditions

Ambient conditions

EPRI (2010) on page 3-2 states that the average Australian ambient conditions as provided in "Technical Guidelines – Generator Efficiency Standards"[34] were used throughout their study to determine the efficiencies of the fossil fuel plants in the study.

The fossil fuel plants in CSIRO (2010) also had the efficiencies calculated at the same conditions.

IEA (2010) does not discuss the fossil fuel plant operating conditions for each country. However, since ACIL Tasman (2010) provided much of the data for the Australian (ESAA) component of this study, we could assume that the IEA (2010) conditions are the same as ACIL Tasman (2010), which are the same as EPRI (2010).

This means the efficiencies of the same plant types should be very similar across the different Australian studies. The efficiencies taken from each study and plant type are compared in Table: "Efficiencies for Non-Renewables" of the attached Appendix G - Data Tables.

We do not have any information on the ambient conditions used in US DOE (2009) but since they are based in the USA we can assume they would be different to Australia.

Gas price

The gas prices taken from each study and by plant type are shown in Table: "Fuel Costs for Non-Renewables" of the attached Appendix G - Data Tables.

The US DOE (2009) has a gas price that indirectly follows the oil price. Their NEMS model has a Natural Gas Transmission and Distribution module that calculates consumption of gas and oil, the amount and price per source[35] (including imports) and then an overall gas price is calculated in the model based on those factors. Costs of pipelines and associated infrastructure can also be included if new infrastructure is required.

In the CSIRO (2010) GALLM model the gas price varies with demand, where the price versus demand is a step-function with five steps. That is, once consumption passes known limits the price increases. The step prices are based on international prices as GALLM is a global model.

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[34]Australian Greenhouse Office (2006), Technical Guidelines - Generator Efficiency Standards.
[35] The amount sourced from unconventional sources is projected to increase over time and therefore the price is expected to rise.

However, the gas prices in GALLM only affect technological uptake, as a high gas price means fewer gas power plants will be built. The gas prices used in the LCOE projections in this report are standard prices for the East coast of Australia.

The gas price in IEA (2010) was decided on by the Stakeholder Reference Group and is consistent with current Australian gas prices on both the East and West coasts.

EPRI (2010) use a natural gas price which is also consistent with current Australian prices at the upper end of the scale for the East coast and the low end of the scale for the West coast.

ACIL Tasman (2010) does not provide a gas price as they do not calculate a LCOE. However, in earlier studies such as ACIL Tasman (2009) "Fuel resource, new entry and generation costs in the NEM" the gas price was calculated using their proprietary *GasMark* model to determine the natural gas price for each node in the Eastern Australian gas grid. *GasMark* has detailed information on gas sources, pipelines and gas demand centres. The model also takes into consideration contractual arrangements between gas suppliers and gas power stations.

Coal Price

The type of coal used in CSIRO (2010) to calculate the energy content of the coal is Queensland black coal and Victorian brown coal. EPRI (2010) and ACIL Tasman (2010) use Hunter Valley black coal and Victorian brown coal. It is not known what IEA (2010) used. The US DOE (2009) NEMS model has several different local sources of coal. The heat rate for their coal for electricity generation is 23.157 MJ/kg[36], not dissimilar from the Australian studies.

Coal prices are less volatile than natural gas prices as can be seen in Table: "Fuel Costs for Non-Renewables" of the attached Appendix G - Data Tables but it is worth noting any differences here as it can have an effect on the LCOE. CSIRO (2010), EPRI (2010), and IEA (2010) use local black and Victorian brown coal prices and these are fixed throughout the model run in CSIRO (2010) and all of the LCOE calculations.

As with gas, ACIL Tasman (2010) does not provide a coal price in the report under review. However, in ACIL Tasman (2009) "Fuel resource, new entry and generation costs in the NEM" they forecast a constant reduction in black coal prices after the current volatile period ends in one or two years. They assume that brown coal prices will remain unchanged from the present cost. Their coal prices consider contractual agreements between mine and power station owners and other factors such as the cost of new coal production.

In US DOE (2009) the price of coal is also fairly stable. It does show a slight rise up to the year 2030 based on demand for new generating capacity and increasing rail costs for coal transport. It is calculated in the Coal Market Module of the NEMS model, and the operation of this module is similar to the Gas Market Module.

Overall, there is little difference between the coal prices across the studies in the LCOE calculations, even for US DOE (2009).

[36] Appendix G of Annual Energy Outlook 2009

Emission factors

Emission factors for the coal types used were specified as $kgCO_2$/MWh in EPRI (2010), ACIL Tasman (2010) and US DOE (2009). These were then converted to $kgCO_2$/GJ for comparison purposes for each technology using:

Emission Factor ($kgCO_2$/GJ Fuel) = Emission Factor ($kgCO_2$/MWh) / (1 – Capture Rate) * 1000 / Heat Rate

Heat Rate = 3600 / Efficiency

IEA (2010) provided emissions as USD/MWh so this was converted to $kgCO_2$/MWh using the permit price in IEA (2010) (USD30/tCO_2) and then the above equation applied to obtain emission factor as $kgCO_2$/GJ per fuel and by technology.

This does result in some differences in emission factors where ACIL Tasman (2010) is considerably higher for CCS technologies. Fugitive emissions are included but these are also included in CSIRO (2010). EPRI (2010) do not include fugitive emissions. Because this is inconsistent with an earlier publication by ACIL Tasman (2009) which has emission factors as tCO_2/GJ, we have used values from the older publication. Note also that the emission factor for combined cycle gas turbine (CCGT) is consistent with Queensland gas and for open cycle gas turbine (OCGT) (peaking plant) the emission factor is consistent with NSW gas ACIL Tasman (2009).

4.4.2 Renewable energy conditions

Note: the ACIL Tasman (2010) report is not discussed below since it does not provide the relevant details.

Solar

For all of the solar thermal technologies, EPRI (2010) calculated the LCOE at three different solar radiation conditions: DNI 5, 6 and 7 kWh/m^2/day. For PV, a DNI of 6.7 kWh/m^2/day was used. When a solar-to-electric thermal efficiency of 15.5 percent is taken into account, this essentially means that three different capacity factors were used for solar thermal, on top of which thermal storage was added which increases the capacity factor. The capacity factors for solar thermal and PV are given in Table 22 – 23 and Table 21 respectively.

Since the CSIRO (2010) GALLM model is a global model, we use an average value of solar radiation which corresponds to the capacity factors for solar thermal and PV in NSW.

US DOE (2009) assumes solar is viable in regions of the US with good solar insolation and in those regions nine different capacity factors were modelled, three times of day per three seasonal variations (summer, winter and spring/autumn).

Wind

Four different classes of wind speeds at a 50 m height were also included in the EPRI (2010) LCOE calculations: 3, 4, 5 and 6. As with the solar radiation inputs for solar thermal, the outcome of different wind speeds are different capacity factors. The wind capacity factors are shown in Table 19.

CSIRO (2010) use an average wind speed to calculate the wind capacity factor. This corresponds to an average value for New South Wales. IEA (2010) also uses an average value.

US DOE (2009) places restrictions on wind in terms of the availability of good wind resources and suitable construction sites. The capacity factor is calculated at different wind speeds, and the sites with good resources are depleted first in the model. The location and quality of the construction sites are also taken into consideration and this can increase the capital cost of building the wind farm if the sites are poor.

Geothermal

Geothermal is a technology that is strongly regional and even site-dependent. There are only certain places in the world where it is possible to build a conventional geothermal plant, and some of these are in the US. US DOE (2009) only considers sites in the NEMS model that have access to resource temperatures greater than 100 °C. They do not include enhanced geothermal systems (or hot fractured rocks) as the time horizon of the model (up to year 2030) is considered too short for the development of hot fractured rocks technology in the US. US DOE (2009) has a low capital cost for geothermal, since conventional geothermal plants are much cheaper to drill.

Australia has access to excellent resources for enhanced geothermal systems and hot sedimentary aquifers - and these technologies are included in the Australian reports. Geothermal is different from other renewables in that the capacity factor is the same in different regions but the quality of the resource at different depths will vary and therefore the cost to extract that useful resource varies.

Table 24 has the capacity factor used for geothermal from each study.

Ocean

The amount of energy extracted using wave or ocean current technology is also site dependent, and Australia has some of the world's best resources. Again, the differences come out in the capacity factor as can be seen in Table 25, where in CSIRO (2010) we assume that both the wave and ocean current plants are placed in the regions with the best resource: WA for wave energy and along the NSW/QLD coast in the East Australian Current for ocean current energy (CSIRO, 2011). We have chosen the best sites only as the plants should be built in these regions first and, if the model builds more in these regions than is physically possible the capacity factor can be altered to account for this.

IEA (2010) includes estimates for wave and tidal current capacity factors; it is not known what sites these correspond to.

US DOE (2009) and ACIL Tasman (2010) do not provide any estimates for this resource or technology.

EPRI (2010) have a general discussion of the global resource but do not provide any cost estimates or any detailed information on the Australian resource.

4.4.3 Conclusions

The ambient operating conditions are the same in the Australian studies. The gas price used in the LCOE for IEA (2010) and EPRI (2010) is higher than that reported from CSIRO (2010) and ACIL Tasman (2009). The US DOE (2009) gas price is more variable than Australian prices. The capacity factors for wind and solar power generation differ significantly across Australia and different approaches are used in each study to recognise this. For geothermal, the regional differences are expressed more so in the capital cost. CSIRO (2010) is the only report to give any detail on ocean energy but the capacity factor is similar to that from IEA (2010) for wave energy.

4.5 Comparison of Methodologies

This section discusses the different methodologies used in the reports to generate capital cost projections and convert all of the costs and performance assumptions into LCOE projections.

4.5.1 Capital cost projections

The process of technological change and improvement is driven by many different forces and consequently a variety of different approaches could be used for projecting future capital costs. No one approach could be said to be superior or without drawbacks. Some approaches that could be used are:

1. Bottom-up engineering estimate
2. Model with learning curves
3. Recent quotes and price estimates
4. Expert opinion / survey

   Or a combination of the above.

Each of these methods will now be briefly discussed.

Bottom-up engineering estimate

This methodology begins with a thorough engineering-based understanding of the different components and aspects of a technology and their cost. Where the technology is located in terms of its development stage on the Grubb curve is important as this helps in understanding the cost and how that cost can change as the technology progresses to maturity.

The next step in the process is to then look carefully at the components and form an estimation of how these can be improved and made cheaper with time and then scale that analysis up to the technology as a whole. The use of bottom-up engineering analysis has its strengths. It would be expected to deliver the most technically-robust projections and it allows the identification of bottlenecks and thus where research should be focused to deliver the greatest gains. A drawback is that effects such as economies of scale, expansion of competitors (supply exceeding demand) which can drive prices down and too few competitors (demand exceeding supply) which can drive prices up, would not be part of the estimation.

Model using learning curves

Learning curves refer to the observed phenomenon that the costs of new technologies tend to reduce with the cumulative production of the technology – that is, ‘learning-by-doing’. Furthermore, costs tend to reduce by an approximately constant factor for each doubling of cumulative production. The phenomenon has been observed since mid last century Alchian (1949), Arrow (1962), Dutton and Thomas (1984), Grübler et al. (1999), Hirsch (1956), Schrattenholzer and McDonald (2001), Wene (2007) and Wright (1936). This observation allows for the possibility of modifying cost projections based on projection of the future uptake of a technology. If the relevant learning rate and level of uptake for a given technology is known then we have the information we require for the following equation:

$$IC_t = IC_0 * CC_t^{-b}$$

where IC is the investment cost of a technology at CC cumulative capacity at a given future point in time t, IC_0 is the investment cost at given starting period and/or capacity, and b is the learning index. The learning index is related to the learning rate LR by: $LR = 100 – 2^{-b}$ where LR is represented as a percentage.

This equation can be used for each technology. So long as the technology has begun to be produced and installed, one can begin to observe the learning rate and include it in the calculation. For very new technologies, not yet deployed, no historical learning rate can be calculated. In this case assumed values, based on learning rates of similar previously emerging technologies, are often applied.

However, the difficulty in applying the methodology is that the projected future uptake of the technology is itself dependent upon the cost of the technology. Owing to the co-dependent nature of the relationship, to solve the problem, equilibrium or simultaneous equation modelling frameworks must be applied.

The disadvantage of the learning curve approach remains a simplification of the many factors impacting upon the rate of change in costs of technologies (see Appendix A for more on factors that can influence learning curves). It is unable to identify breakthroughs in technological development or bottlenecks that need to be addressed. The strength of this approach is that it is transparent and the electricity generation technologies are placed in the context of a competitive market influenced by government policies, both of which influence the price paid and rate of deployment for each technology.

Recent quotes and price estimates

This approach uses a database of capital costs and quotes sourced from recent projects, preferably within the region of interest. This provides an accurate approach to understanding costs in the short term for technologies which are currently being installed in the region.

Expert opinion / survey

This approach involves eliciting the opinion of subject matter experts (SMEs) in order to arrive at an understanding of capital cost projections for various technologies. SMEs could be approached individually or could discuss the options as a group. It can also be used as a “sounding-board” to test the validity of modelling or engineering-based cost projections. The advantage and disadvantage of this approach is that it is entirely dependent on the experience and knowledge of the SMEs and the group dynamics, if a group approach is taken.

Combination

A combination of approaches can also be used. For example, as stated above, expert opinion can be used to examine the results using other methodologies. Database and recent quote information is used to provide historical data for the learning curves. Bottom-up engineering estimates can also help in identification of the components of a technology that have the greatest 'learning' opportunity, and learning curves can be adjusted accordingly.

While not all reports provide a great deal of information on the methodology used, we can say that: US DOE (2009) and CSIRO (2010) used a modelling approach; EPRI (2010) used a combination of bottom-up engineering, recent quotes and price estimates and expert opinion; ACIL Tasman (2010) used recent quotes and price estimates and IEA (2010) used expert opinion / survey.

Capital cost inclusions

In addition to the method used, variations can occur into what actually is included in the capital cost estimate. This is described by report briefly below.

EPRI (2010)

EPRI (2010) provide costs in Australian dollars. The costs are based on US Gulf West Coast prices with appropriate adjustments to Australian conditions for differences in labour productivity, crew rates, material costs and currency as discussed in Section 4.3 of EPRI (2010). Engineering and construction management has been included in the capital estimate.

EPRI (2010) include a project contingency factor to account for project uncertainty and the cost of any additional equipment. In addition to this, to cover for uncertainties surrounding novel technologies, contingencies have been added for specific parts of the IGCC and CCS plants. A nominal 7.5% allowance has also been added to the capital cost to account for other project and site-specific factors that can occur in real projects.

US DOE (2009)

Capital costs are presented as overnight costs and include additional construction and labour charges depending on where the plant will be built in the US. A contingency factor and a technology optimism factor are included for first-of-a-kind plant. Recent price increases in electricity generation technologies and the impact of any future price increases have been included in the model by including a materials price index and modelling different capital cost projection scenarios. The US also has different regulations surrounding emissions from plants which can require the installation of additional pollution control equipment and these have been included in the capital cost estimates[37].

CSIRO (2010)

The capital costs are presented as overnight costs and include all construction costs and grid connection fees, legal fees, contingency and decommissioning. Miscellaneous fees and charges and taxes are not included. A technology optimism factor is applied to first-of-a-kind plant and the recent price rises and the impact of any future price rises that have been seen in the electricity generation technology market have been accounted for in the modelling of capital cost projections (see Appendix B for more information).

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[37] For a complete description of these systems the reader is referred to "Assumptions to the Annual Energy Outlook 2009" http://www.eia.doe.gov/oiaf/archive/aeo09/assumption/electricity.html

ACIL Tasman (2010)

ACIL Tasman capital costs are presented as overnight costs and IDC is added-on during the LCOE calculation process. They include factors such as contingency, labour, materials and equipment and professional services.

IEA (2010)

IEA include a contingency factor of 15% for nuclear and CCS plants and 5% for everything else. Decommissioning costs of 15% for nuclear and 5% for everything else have been included in the capital cost. All capital costs are presented as overnight costs and IDC is added on during the calculation of the LCOE. The capital cost includes all costs associated with construction and connection to the grid. Taxes are not included.

Conclusions

Distinctly different methodologies can be used for generating capital cost projections, including bottom-up engineering analysis, recent quotes and historical databases, surveys of expert opinion, energy economic modelling or a combination thereof. It is therefore no surprise that different outcomes are reached in the different reports. Each approach has its own advantages and disadvantages. The advantages of the energy economic modelling approach is that it is transparent and puts the electricity generation technologies in the context of a competitive technology market influenced by government policies, both of which have a large influence on the price paid and rate of deployment for each technology. A major disadvantage is that the experience curves applied are a substitute for real knowledge about the actual scientific and technological changes that may occur to the technology to make it cheaper and improve performance. The bottom-up engineering estimate approach, comes closest to identifying those necessary changes, but at the cost of isolating the analysis from the technology market. Because competition tends to result in cheaper prices, approaches which do not consider the technology competition effects would be expected to have higher capital cost projections. Expert opinion and use of databases and recent quotes have the potential to be reliable sources by drawing on a large number of experts, studies and projects across countries. However, they have the least transparency in terms of being able to understand what projection technique was applied and what other influences they took into account.

4.5.2 Levelised cost of energy (LCOE)

LCOEs reflect the price that the electricity generator must get for its electricity output (at the boundary of the analysis) in order to recover costs which includes investors return on capital, payments to fuel suppliers, payments to parts and labour, payments to construction contractors and other miscellaneous fees. The LCOE provides a useful analytical basis to compare technology costs on a level assumptions basis. Broadly speaking, if the market's average electricity price available to the technology during operation is below a technology's LCOE then the technology is unlikely to be deployed commercially. In order for that technology to be taken up some time in the future one of three things must occur. The average electricity price available to the plant during operation must rise, the investor must receive a subsidy, and/or some component of the LCOE must fall. The LCOE does not include or predict revenue to the plant owner; it is the price electricity would need to be sold for in order for the owner to recover his or her costs. The LCOE does not consider the market the electricity will be sold in and how different types of technologies will interact with each other in such a market.

It is possible to calculate the LCOE in various ways. The equations for converting power plant data into LCOE used in this report are presented in Appendix C. The long run average cost is a similar concept and is used by IEA (2010). The difference is that the costs are averaged over the actual lifetime of the plant, rather than the loan period as the LCOE is. Because both the components that go into the LCOE and the equations used can vary, the method used in each report will be discussed separately. In order to make comparisons easier a summary is given in Table 26 showing for each report the basic cost components that contribute to the LCOE. ACIL Tasman and the US DOE do not calculate a LCOE in their reports and so they are not included in this discussion.

Table 26: Cost components included in the LCOE calculation, by report

Inclusion in LCOE	**EPRI (2010)**	**CSIRO (2010)**	**IEA (2010)**
Fixed Costs:			
Interest during construction	✓	✓	✓
Capital	✓	✓	✓
Depreciation	✓	✗	✗
Income tax	✓	✗	✗
Insurance	✓	✓	?
Property taxes	✓	✗	✗
Fixed O&M	✓	✓	✓
Decommissioning	✓	✓	✓
Contingencies	✓	✓	✓
Variable Costs:			
Fuel	✓	✓	✓
Variable O&M	✓	✓	✓
CO_2 transport and storage	✓	✓	✗
Waste management	✗	✗	✓
Carbon price	✗	✓	✓

EPRI (2010)

In terms of contributions to the LCOE, EPRI (2010) varies from some of the other reports in the way the fixed cost is included. Their calculation includes accounting details such as depreciation, return on equity and interest on debt and taxes. It is relatively straightforward for EPRI to calculate these factors as they are based on the assumptions that are made in determining the weighted average cost of capital (WACC). The variable cost also includes a CO_2 transportation and storage charge of AUD20/MWh.

The approach undertaken in EPRI (2010) for determining the variable O&M cost is to use a short run average cost (SRAC) rather than a short run marginal cost (SRMC). This means that the O&M cost has been based on engineering and plant estimates over the average running life of the plant rather than the cost required to increase output of the plant by one unit. All of the O&M costs can be seen in the following tables of the attached Appendix G - Data Tables. Note however, that even though there is variation across the reports in estimating O&M costs, from the tornado plots in Section 4.2 we can see that their effect on LCOE is minimal.

IEA (2010)

IEA (2010) uses a 'social resource cost' approach. This means the capital cost is free of taxes and any government charges (i.e. it is the cost borne by society to build a plant). Interest during construction is included in the LCOE estimate and the amount varies depending on the discount rate. The components of the LCOE are quite similar to those of CSIRO (2010), with the exception of no cost for CO_2 transport and storage and the inclusion of waste management costs. The carbon price is held fixed at 30 USD/tonne. The total discounted costs and electricity generated are averaged over the lifetime of the plant to provide a LCOE at each discount rate. As part of this, IEA (2010) assume a constant discount rate of either 5 percent or 10 percent and a constant price of electricity. The process is described fully in Chapter 2 of IEA (2010).

CSIRO (2010)

CSIRO (2010) ignore taxes but do include interest during construction, at a fixed real discount rate of 7%.The construction period varies between plants as with the other reports. The variable costs include a CO_2 transport and storage charge of AUD20/tCO_2. The assumed fuel costs, plant efficiencies, O&M costs and capacity factors and the amount of electricity generated change over time (although with the exception of fuel they become constant once the plant is purchased), which changes the LCOE.

The equations used to calculate the LCOE in the CSIRO report are shown in Appendix C.

Conclusion

The key differences in LCOE calculation methodology between the three studies that make this calculation are that EPRI (2010) is the only study to include taxes. Based on this alone one would expect if they employed the same data EPRI (2010) would calculate the highest LCOEs followed by CSIRO (2010) and IEA (2010).

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ACRONYMS

AC	Air cooled
AGEA	Australian Geothermal Energy Association
ANSTO	Australian Nuclear Science and Technology Organisation
AOSTRA	Alberta Oil Sands Technology and Research Authority
ATP	AOSTRA Taciuk processor
AUD	Australian dollars
AWR	Advanced water reactor
boe	barrels of oil equivalent
BOS	Balance of System
BWR	Boiling water reactor
CBM	Coal bed methane
CC	Cumulative capacity
CCGT	Combined Cycle Gas Turbine
CCS	Carbon dioxide capture and storage
CC(S)	Carbon dioxide capture and storage
CCT	Clean coal technology
CNG	Compressed natural gas
CO_2	Carbon dioxide
CO_2-e	Carbon dioxide equivalent
CR	Central receiver
CSC	Carbon dioxide storage cost
CSG	Coal seam gas
CSIRO	Commonwealth Scientific and Industrial Research Organisation
CSP	Concentrating solar power
CTL	coal to liquids
DCFC	Direct carbon fuel cell
DE	Distributed energy
DICE	Direct injection coal engine
DME	Dimethyl ether
DNI	Direct Normal Irradiance
DRET	Department of Resources, Energy and Tourism
EPRI	Electric Power Research Institute
ESAA	Energy Supply Association of Australia
ETF	Energy Transformed Flagship
EV	Electric vehicle
FC	Fuel cost
FLNG	Floating liquefied natural gas
FT	Fischer Tropsch
FTS	Fischer Tropsch synthesis
GAB	Great Artesian Basin
GALLM	Global And Local Learning Model
GE	General Electric
GFR	Gas-cooled fast reactor
GHG	Greenhouse gas
GIF	Generation IV international forum
GJ	Gigajoule
GM	Genetically modified
GTL	Gas to liquids
GW	Gigawatt
GWh	Gigawatt-hour

HDR	Hot dry rocks
HEWI	Heat exchange within insulator
HHV	Higher heating value
HFR	Hot fractured rocks
HR	Hot rock
HRSG	Heat Recovery Steam Generator
HSA	Hot sedimentary aquifers
HWR	Heavy water reactor
IC	Investment cost
ICT	Information and communication technology
IDC	Interest during construction
IEA	International Energy Agency
IGCC	Integrated gasification combined cycle
IPCC	Intergovernmental panel on climate change
KC	Capital cost
kW	Kilowatt
kWh	Kilowatt-hour
LCOE	Levelised cost of electricity
LFR	Lead-cooled fast reactor
LHV	Lower heating value
LNG	Liquefied natural gas
LWR	Light water reactor
MJ	Megajoule
ML	Megalitre
MSR	Molten salt reactor
MW	Megawatt
MWe	Megawatt electric
MWh	Megawatt hour
NEMS	National Energy Modelling System
NSW	New South Wales
O&M	Operating and maintenance
OCGT	Open Cycle Gas Turbine
ORE	Ocean renewable energy
OTEC	Ocean thermal energy conversion
OWC	Oscillating water column
PBMR	Pebble bed modulator reactor
PC	Greenhouse gas emission permit cost
PCC	Post-combustion capture
pf	Pulverised fuel
PJ	Petajoule
PT	Parabolic trough
Pu	Plutonium
PV	Photovoltaic
PWR	Pressure water reactor
R&D	Research and Development
SC	Super critical
SCWR	Super critical water cooled reactor
SFR	Sodium-cooled fast reactor
SMEs	Subject matter experts
SRAC	Short run average cost
SRMC	Short run marginal cost
tCO_2e	Tonnes of carbon dioxide equivalent
TECC	Tool for Electricity Cost Comparison

TC	Transmission cost
TWh	Terawatt-hour
UK	United Kingdom
USA	United States of America
USC	Ultra super critical
USD	United States dollars
US DOE	United States Department of Energy
USSR	Union of Soviet Socialist Republics
UWA	University of Western Australia
VHTR	Very high temperature reactor
WA	Western Australia
WACC	Weighted Average Cost of Capital

APPENDIX A – FACTORS THAT INFLUENCE TECHNOLOGICAL CHANGE

Breakthroughs and positive changes in a technology (“technology structural change”) lead to a (once-off) sharp decrease in the experience curve and the learning rate may also change.

“Market shakeout” occurs when price instead of cost data is used and results in a sharp apparent increase in the learning rate. This can be observed after the early technological development stages when more competitors enter the market and the “Price Umbrella” the original manufacturers held (due to their market power) “closes” and the price reflects the cost Staff of the Boston Consulting Group (1968). This can also reflect achievement of economies of scale Nemet (2006).

Experience curves can be the result of a “compound” technological development system i.e. a conglomerate of experience curves for different and interacting parts of the technology. For example, photovoltaic (PV) installations consist of PV modules and several other parts which make up the “balance of system” (BOS). They are reported to have quite different learning rates. The modules are part of an international market while the BOS is typically sourced locally International Energy Agency (2000), Junginger et al. (2005) and Shum and Watanabe (2008).

Experience curves calculated for energy technologies using national data often do not consider the source of the technology and this can result in a higher learning rate, as all the learning has happened elsewhere and yet the importing country benefits from the lower price Junginger et al. (2005). This is also known as knowledge transfer or “spill over” Barreto and Kemp (2008) and Grübler et al. (1999). “Government policy” in the form of R&D spending starts the learning process and accumulation of knowledge and experience, leading to demonstration projects for viable technologies. Governments can also influence the choice of technology, through interventions such as renewable energy mandates, emissions trading schemes, feed-in tariffs and tax concessions.

APPENDIX B – TECHNOLOGY PRICE BUBBLES

The path we expect the underlying costs of technologies to take is a downward one. Even if the technology is mature we would not expect the real cost of producing the technology to increase. Contrary to these expectations, the prices of coal-fired plants and wind turbines have been increasing in recent years.

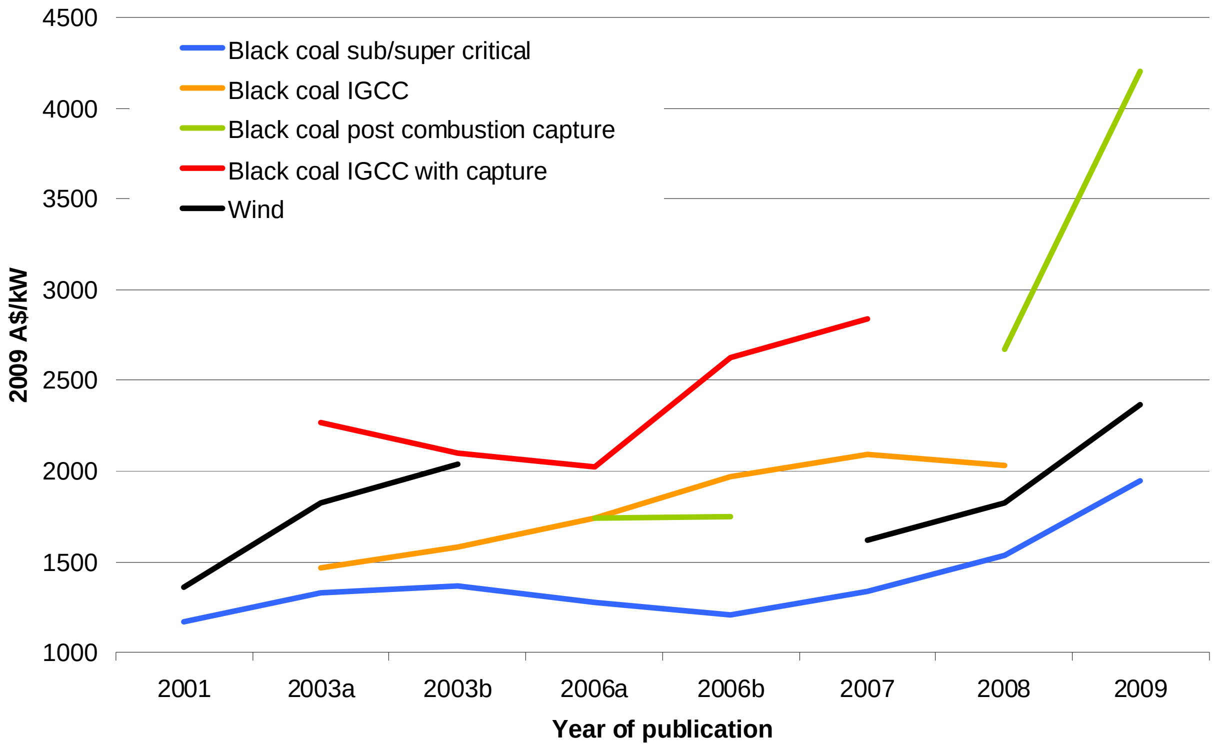

Figure 72: Changes in CSIRO published and unpublished costs estimates for wind and coal-fired electricity generation plants

Sources: A Cottrell et al. (2003a), Graham and Williams (2001), Graham et al. (2003), Graham et al. (2008), Reedman et al. (2006b), Reedman et al. (2006a) and unpublished CSIRO data.

Figure 72 presents technology capital cost estimates extracted from various published and internal CSIRO data, plotted against the year of publication of the estimate. The data has been converted to real 2009 dollars. It shows that there has been some significant volatility. However, in publications appearing around 2005 (and subsequently in those from 2006 onwards) CSIRO's estimates of plant capital costs have been rising unambiguously. The plant cost estimates appear to be accelerating, with the largest increases occurring in 2008 and 2009. Where data is available, the total increase in cost estimates from 2001 to date is in the order of 60-70 percent.

In the case of coal plants with CO_2 capture and storage (CCS) this could represent cost revisions flowing from more detailed engineering studies that reveal additional costs not discovered in the concept stage, as noted by the "Grubb curve" in the EPRI (2010). However, given the maturity of wind power and coal plants without CCS, increases in their costs cannot be explained via such processes of technological change.

Most likely the change in costs is due to factors outside of technology performance, such as the global demand for raw materials needed to produce the plant, higher oil prices, high demand for wind and coal-fired power plants, skilled labour shortages, and producer's profit Milborrow (2008).

The critical issue in understanding this trend is that of whether one should assume these are permanent increases in the costs of the technology or whether it represents a temporary technology price bubble. If the increase in the price of the technology is believed to be permanent then current prices can be used as a starting point for future costs decreases due to technological change. If the price increase is believed to be a bubble which will eventually end then it is important not to use current prices as the starting point for future projections. As shown in Figure 73, the error is potentially as large as the bubble itself.

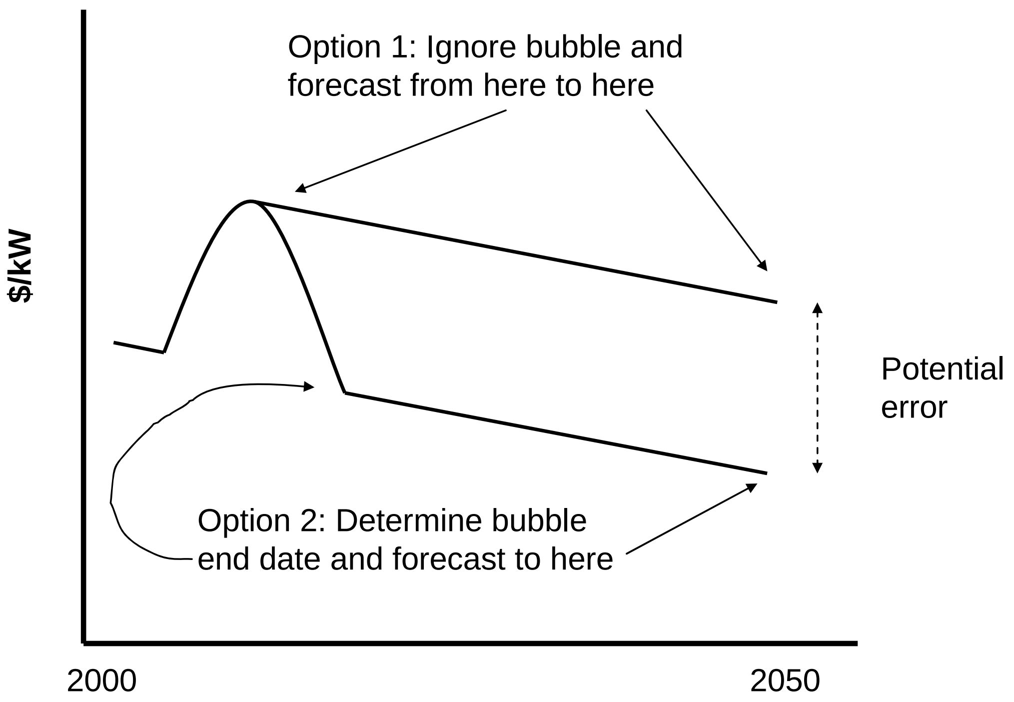

Figure 73: Options for addressing technology price bubbles in cost projections

APPENDIX C – EQUATIONS USED TO CALCULATE LCOE

The LCOE in \$/MWh is calculated using the equation shown below:

$$LCOE = FC + OandM_{fixed} + OandM_{var.} + KC + TC + PC + CSC$$

where $OandM_{fixed}$ is the fixed operating and maintenance cost in \$/MWh, $OandM_{\mathrm{var}}$ is the variable operating and maintenance cost in \$/MWh, *TC* is the transmission cost in \$/MWh, *CSC* is the carbon dioxide storage cost and *FC* is the fuel cost in \$/MWh according to:

$$FC = FC\ (in\ \$ / GJ) * 3.6 \div Efficiency$$

$OandM_{fixed}$ is the fixed operating and maintenance cost in \$/MWh:

$$OandM_{fixed} = OandM_{fixed}(in\ \$ / kW) * \frac{r(1+r)^L}{(1+r)^L - 1)} * \frac{1000}{\pi * 8760}$$

where π is the capacity factor, *L* is the life of the loan and r is the discount rate set at 7% in the model. The number 8760 is the number of hours in a year.

KC is the capital cost of the plant in \$/MWh according to:

$$KC = KC\ (in\ \$ / kW) * \frac{r(1+r)^L}{(1+r)^L - 1} * \frac{1000}{\pi * 8760}$$

PC is the price of carbon in \$/MWh calculated according to:

$$PC = Carbon\ content\ (in\ gCO_2 / MJ) * \frac{3.6}{Efficiency * 1000} * Permit\ \ price\ (in\ \$ / tCO_2)$$

CSC is the cost of CO_2 capture and storage in \$/MWh according to:

$$CSC = SC\ (in\ \$ / tCO_2) * Carbon\ content\ (in\ tCO_2 / MJ) * \frac{1}{Capture\ ratio} * \frac{3.6}{Efficiency * 1000}$$

APPENDIX D – DATA TABLES

Table 27: Projected LCOE for the year 2015 for each study.

	DOE			EPRI			IEA			ACIL Tasman			CSIRO		
	Reported	Calculated	Harmonised	Reported	Calculated	Harmonised	Reported	Calculated	Harmonised	Reported	Calculated	Harmonised	Reported	Calculated	Harmonised
Brown Coal pf	-	-	-	91.00	93.73	103.27	97.29	97.79	88.70	-	86.37	97.83		80.66	93.99
Brown Coal pf with CCS	-	-	-	191.00	151.35	163.86	110.66	119.99	133.07	-	101.70	153.69	138.00	138.00	149.79
Black Coal pf	-	95.06	85.63	78.00	83.04	88.55	85.84	87.79	85.02	-	79.24	87.77	80.66	78.18	88.13
Black Coal IGCC	-	101.71	94.09	130.00	124.80	120.33	-	-	-	-	101.72	111.55	81.53	81.53	94.29
Black Coal pf with CCS	-	-	-	167.00	135.43	143.88	105.20	120.76	137.09	-	93.28	135.44	78.18	132.99	140.25
Black Coal IGCC with CCS	-	95.62	126.44	213.00	171.69	182.98	110.06	125.38	149.56	-	106.91	158.46	- 132.99	-	-
Gas combined cycle	-	105.16	87.65	97.00	96.10	88.24	97.80	105.53	101.09	-	72.70	93.04		85.91	88.17
Gas with CCS	-	131.72	127.11	153.00	128.03	131.95	-	-	-	-	-	-	146.03	146.03	148.86
Gas peak	-	128.09	141.81	227.00	214.46	151.01	103.05	90.53	148.86	-	214.88	160.84	85.91	198.94	140.34
Nuclear	-	60.24	83.17	173.00	107.18	113.31	-	-	-	-	81.52	109.53	93.73 198.94	93.73	96.26
Biomass	-	133.68	113.26	-	-	-	-	-	-	-	-	-	99.58	99.58	99.58
Solar thermal PT w 6hrs	-	-	-	438.00	318.86	349.18	-	-	-	-	323.06	330.88	-	-	-
Solar thermal PT w/out	-	147.28	284.04	466.00	339.82	304.34	-	-	-	-	231.35	312.07		176.92	190.02
Solar thermal CR w 6hrs	-	-	-	330.00	242.04	242.04	-	-	-	-	-	-	- 176.92	-	-
Solar thermal CR w/out	-	147.28	296.32	379.00	278.27	262.52	-	-	-	-	-	-	176.92	176.92	197.87
PV roof top	-	-	-	-	-	-	-	-	-	-	-	-	208.60	208.60	208.60
PV fixed plate	-	-	-	431.00	337.92	334.75	-	-	-	-	257.58	321.60		-	-
PV single axis tracking	-	156.73	331.21	392.00	308.03	358.83	-	-	-	-	312.92	373.01	197.99	197.99	187.99
PV two axis tracking	-	-	-	327.00	257.37	300.19	-	-	-	-	351.51	351.58	-	-	-
Wind - small	-	-	-	188.00	151.84	157.67	-	-	-	-	98.01	118.53	-	-	-
Wind - medium	-	63.21	117.59	171.00	137.82	166.18	139.94	142.41	145.95	-	90.44	128.73	-	95.45	106.61
Wind - large	-	-	-	168.00	130.73	137.01	-	-	-	-	86.73	103.20	-	-	-
Geothermal hot rocks	-	-	-	167.00	125.68	136.99	-	76.57	91.62	-	74.56	106.26	95.45	104.06	114.88
Geothermal conventional	-	179.59	84.89	-	-	-	-	-	-	-	-	-	71.14 104.06	71.14	71.14
Geothermal hot aquifers	-	-	-	116.00	87.50	-	-	-	-	-	-	-	-	-	-
Hydro	-	74.58	154.74	-	-	-	-	-	-	-	-	-	191.81	191.81	191.81
Wave	-	-	-	-	-	-	297.04	232.61	265.51	-	-	-	119.10	119.10	122.88
Current	-	-	-	-	-	-	427.25	379.36	283.54			-	297.02	297.02	448.24

Table 28 Projected LCOE for the year 2030 for each study.

	DOE			EPRI			ACIL Tasman			CSIRO		
	Reported	Calculated	Harmonised	Reported	Calculated	Harmonised	Reported	Calculated	Harmonised	Reported	Calculated	Harmonised
Brown Coal pf	-	-	-	-	-	-	-	89.01	96.58	103.80	103.80	96.01
Brown Coal pf with CCS	-	-	-	191.00	109.14	115.43	-	88.00	121.40	112.78	112.78	107.51
Black Coal pf	-	115.90	92.30	-	-	-	-	93.04	97.50	93.07	93.07	89.91
Black Coal IGCC	-	119.60	98.58	-	-	-	-	105.18	103.27	95.85	95.85	99.74
Black Coal pf with CCS	-	-	-	167.00			-	81.92	111.30		105.36	101.02
Black Coal IGCC with CCS	-	84.99	104.19	213.00	123.99	126.60	-	84.23	116.60	-	-	-
					112.82	119.60				105.36		
Gas combined cycle	-	140.44	81.17	-	-	-	-	77.21	86.26	93.74	93.74	85.45
Gas with CCS	-	168.98	111.28	153.00	108.31	117.52	-	-	-	125.29	125.29	121.67
Gas peak	-	156.94					-	221.63	214.31		245.91	221.26
Nuclear	-	48.03	60.12	149.00	93.47	97.85	-	70.58	83.70	86.64	86.64	84.09
			178.27	227.00	217.69	213.03				245.91		
Biomass	-	100.28	195.05	-	-	-	-	-	-	212.76	212.76	212.76
Solar thermal PT w 6hrs	-	-	-	438.00	213.67	213.67	-	-	-	-	-	-
Solar thermal PT w/out	-	104.45					-	-	-	125.01	125.01	136.65
Solar thermal CR w 6hrs	-	-	-	330.00	152.50	152.50	-	-	-	-	-	-
			195.56	466.00	214.58	204.22						
Solar thermal CR w/out	-	104.45					-	-	-	125.01	125.01	134.53
PV roof top	-	-	-	-	-	-	-	-	-	126.47	126.47	126.47
			192.82	379.00	158.77	156.61						
PV fixed plate	-	-	-	431.00	219.64	219.64	-	-	-	-	-	-
PV single axis tracking	-	107.54	213.01	392.00	200.22	221.53	-	-	-	121.26	121.26	116.22
PV two axis tracking	-	-	-	327.00	167.29	167.29	-	-	-	-	-	-
Wind - small	-	-	-	188.00	118.78	118.78	-	-	-	-	-	-
Wind - medium	-	54.91	85.51	171.00			-	-	-	77.04	77.04	73.86
Wind - large	-	-	-	168.00	102.27	102.27	-	-	-	-	-	-
					107.79	127.01						
Geothermal hot rocks	-	-	-	167.00			-	-	-	113.53	113.53	124.92
Geothermal conventional	-	166.30	78.22	-	-	-	-	-	-	74.34	74.34	74.34
					119.24	130.65						
Geothermal hot aquifers	-	-	-	116.00	80.58	-	-	-	-	-	-	-
Hydro	-	62.98	132.99	-	-	-	-	-	-	179.96	179.96	179.96
Wave	-	-	-	-	-	-	-	-	-	112.39	112.39	112.39
Current	-	-	-	-	-	-	-	-	-	160.65	160.65	160.65

		WRT to Harmonised Value						Comments
		DOE	EPRI	IEA	ACIL	CSIRO	Harmonised	
Brown Coal pf	2009 AUD/kW	-	3,979	2,709	3,306	3,041	3,259	Small degree of difference. EPRI (2010) highest and IEA (2010) lowest due to capital cost methodological and assumption differences.
	%	-	22.10%	-16.86%	1.44%	-6.68%	±16.53%	
Brown Coal pf with CCS	2009 AUD/kW	-	7,363	5,019	6,425	6,156	6,241	Small degree of difference. EPRI (2010) highest and IEA (2010) lowest due to capital cost methodological and assumption differences.
	%	-	17.98%	-19.57%	2.95%	-1.36%	±15.46%	
Black Coal pf	2009 AUD/kW	2,309	2,967	2,464	2,509	2,587	2,632	Small degree of difference. EPRI (2010) highest and US DOE (2009) lowest due to capital cost methodological and assumption differences and US costs generally lower.
	%	-12.26%	12.74%	-6.39%	-4.67%	-1.68%	±9.33%	
Black Coal IGCC	2009 AUD/kW	2,813	5,099	-	4,261	3,041	4,134	Medium degree of difference. EPRI (2010) highest and US DOE (2009) lowest due to capital cost methodological and assumption differences and US costs generally lower.
	%	-31.95%	23.35%	-	3.07%	-26.43%	±25.94%	
Black Coal pf with CCS	2009 AUD/kW	-	5,855	5,162	4,942	5,316	5,318	V small degree of difference. Unusual given that this is an emerging technology.
	%	-	10.09%	-2.95%	-7.08%	-0.05%	±7.32%	
Black Coal IGCC with CCS	2009 AUD/kW	3,831	7,715	5,536	6,001	-	6,417	Medium degree of difference. EPRI (2010) highest and US DOE (2009) lowest due to capital cost methodological and assumptiondifferences and US costs generally lower.
	%	-40.31%	20.22%	-13.73%	-6.49%	-	±24.89%	
Gas combined cycle	2009 AUD/kW	1,080	1,173	2,061	1,423	992	1,412	Medium degree of difference. IEA (2010) highest due to methodology.
	%	-23.53%	-16.94%	45.92%	0.74%	-29.72%	±30.51%	
Gas with CCS	2009 AUD/kW	2,067	2,518	-	-	3,622	3,070	Medium degree of difference. CSIRO (2010) highest and US DOE (2009) lowest. CSIRO (2010) is high due to cost estimates from literature and US DOE (2009) lower as US is lower.
	%	-32.69%	-17.99%	-	-	17.99%	±26.07%	
Gas peak	2009 AUD/kW	752	801	911	995	472	795	Medium degree of difference. CSIRO (2010) is v low because of cost estimate from private source.
	%	-5.35%	0.79%	14.66%	25.19%	-40.64%	±25.12%	
Nuclear	2009 AUD/kW	3,656	5,742	-	5,437	4,562	5,247	Small degree of difference. EPRI (2010) highest and US DOE (2009) lowest due to capital cost methodological and assumption differences and US costs generally lower.
	%	-30.31%		-		-13.05%	±17.90%	

9.43%

Capital Costs For Non-Renewables (2015)

3.61%

		WRT to Harmonised Value						Comments
		DOE	EPRI	IEA	ACIL	CSIRO	Harmonised	
Biomass	2009 AUD/kW	4,135	-	-	-	3,471	3,471	Small degree of difference. May reflect use of different plant types (steam cycle vs. gasification) as would normally expect US DOE (2009) to be lower.
	%	19.15%	-	-	-		±13.54%	
Solar thermal PT w 6hrs	2009 AUD/kW	-	8,751	-	8,250	-	8,501	V. small degree of difference. Unusual given that emerging technology.
	%	-		-	-2.95%	-	±4.17%	
Solar thermal PT w/out	2009 AUD/kW	5,239	5,667	-	5,830	3,258	4,918	V. small degree of difference. Unusual given that emerging technology.
	%	6.53%	15.22%	-	18.54%	-33.76%	±24.13%	
Solar thermal CR w 6hrs	2009 AUD/kW	-	6,475	-	-	-	6,475	
	%	- 2.95%		-	-	-		
Solar thermal CR w/out	2009 AUD/kW	5,239	4,559	-	-	3,258	3,908	V. small degree of difference. Unusual given that emerging technology.
	%	34.05%	16.65%	-	-	-16.65%	±25.76%	
PV roof top	2009 AUD/kW	-	-	-	-	3,812	3,812	
	%	-	-	-	-			
PV fixed plate	2009 AUD/kW	-	6,265	-	6,000	-	6,133	V. small degree of difference. Unusual given that emerging technology.
	%	-		-	-2.16%	-	±3.06%	
PV single axis tracking	2009 AUD/kW	6,410	6,991	-	7,289	3,400	5,893	Small degree of difference. CSIRO (2010) has a lower cost due to inclusion of carbon price in methodology
	%	8.78%	18.63%	-	23.69%	-42.31%	±30.31%	
PV two axis tracking	2009 AUD/kW	-	6,908	-	8,188	-	7,548	Small degree of difference.
	%	- 2.16%	-8.48%	-	8.48%	-	±11.99%	
Wind - small	2009 AUD/kW	-	3,733	-	2,700	-	3,217	Medium degree of difference. May reflect methodological differences where ACIL Tasman (2009) base on past Australian costs and EPRI (2010) on adjusted US estimates.
	%	-	16.06%	-	-16.06%	-	±22.71%	
Wind - medium	2009 AUD/kW	2,174	3,392	2,885	2,453	1,898	2,657	Medium degree of difference. US DOE (2009) lowest as they have lower costs.
	%	-18.19%	27.66%	8.57%	-7.68%	-28.56%	±22.24%	
Wind - large	2009 AUD/kW	-	3,224	-	2,332	-	2,778	Medium degree of difference. May reflect methodological differences where ACIL Tasman (2009) base on past Australian costs and EPRI (2010) on adjusted US estimates.
	%	-	16.05%	-	-16.05%	-	±22.70%	
Geothermal hot rocks	2009 AUD/kW	-	8,116	4,791	5,864	6,496	6,317	Medium degree of difference. Since this is emerging technology differences are due to methodologies.
	%	-	28.49%	-24.16%	-7.17%	2.84%	±22.02%	
Geothermal conventional	2009 AUD/kW	5,005	-	-	-	3,935	3,935	Medium degree of difference. Unusual given that US tends to be cheaper.
	%	27.19%	-	-	-		±19.22%	
Geothermal hot aquifers	2009 AUD/kW	-	5,711	-	-	-	5,711	
	%	-		-	-	-		
Hydro	2009 AUD/kW	2,638	-	-	-	3,410	3,410	Small degree of difference.
	%	-22.65%	-	-	-		±16.02%	
Wave	2009 AUD/kW	-	-	7,803	-	2,631	5,217	Small degree of difference.
	%	-	-	49.57%	-	-49.57%	±70.10%	
Current	2009 AUD/kW	-	-	3,207	-	7,277	5,242	Large degree of difference. CSIRO (2010) is for ocean current and IEA (2010) is for tidal.
	%	-	-	-38.83%	-	38.83%	±54.91%	

Capital Costs For Renewables (2015)

		WRT to Harmonised Value						Comments
		DOE	EPRI	IEA	ACIL	CSIRO	Harmonised	
Brown Coal pf	2009 AUD/MWh	-		-	6.45	3.49	5.16	Medium degree of difference. CSIRO (2010) lower as O&M costs based on internal data on actual plant. ACIL Tasman (2010) higher as based on Australian costs from database.
	%	-		-	24.83%	-32.49%	±29.42%	
Brown Coal pf with CCS	2009 AUD/MWh	-		-	12.36	4.71	8.71	Large degree of difference. CSIRO (2010) lower as O&M costs based on internal data on estimated plant. ACIL Tasman (2010) higher as based on Australian costs from database.
	%	-		-	41.92%	-45.96%	±61.60%	
Black Coal pf	2009 AUD/MWh	4.95 5.56 7.66%	4.44	-	6.45	3.49	4.79	Large degree of difference. CSIRO (2010) lower as O&M costs based on internal data on estimated plant. ACIL Tasman (2010) higher as based on Australian costs from database.
	%	3.25%	-7.33%	-	34.55%	-27.23%	±50.32%	
Black Coal IGCC	2009 AUD/MWh	6.95 9.06 4.04%	9.76	-	6.72	3.49	6.65	Medium degree of difference. CSIRO (2010) lower as O&M costs based on internal data on estimated plant and this is a relatively new technology.
	%	4.43%	46.68%	-		-47.60%	±38.56%	
Black Coal pf with CCS	2009 AUD/MWh	-		-	10.74	4.71	7.62	Large degree of difference. CSIRO (2010) lower as O&M costs based on internal data on estimated plant and this is a new technology.
	%	-	-2.66%	-	40.94%	-38.28%	±59.58%	
Black Coal IGCC with CCS	2009 AUD/MWh	8.29	13.92	-	10.07	-	12.00	Large degree of difference as this is a new technology.
	%	-30.92%	16.04%	- 0.92%	-16.04%	-	±48.94%	
Gas combined cycle	2009 AUD/MWh	3.78 7.42	2.38	-	4.16	3.14	3.23	Large degree of difference. ACIL Tasman (2010) higher as based on Australian costs from database.
	%	17.12%	-26.24%	-	29.03%	-2.79%	±51.13%	
Gas with CCS	2009 AUD/MWh	6.03	4.36	-	-	11.79	8.08	Large degree of difference as this is a new technology.
	%	-25.39%	-46.02%	-	-	46.02%	±48.30%	
Gas peak	2009 AUD/MWh	3.67	10.61	-	14.84	12.88	12.78	Large degree of difference. ACIL Tasman (2010) higher as based on Australian costs from database. US DOE (2009) lower as US costs generally lower esp. established plant.
	%	-71.30%	-16.96%	-	16.15%		±49.41%	
Nuclear	2009 AUD/MWh	13.04	19.73	-	11.28	5.49	12.17	Large degree of difference. This is not available in Australia so CSIRO (2010) estimate may be too low.
	%	7.16%	62.16%	-	-7.28% 0.82%	-54.88%	±48.19%	

Fixed O&M Costs For Non-Renewables (2015)

		WRT to Harmonised Value						Comments
		DOE	EPRI	IEA	ACIL	CSIRO	Harmonised	
Biomass	2009 AUD/MWh	20.13	-	-	-	12.55	12.55	Large degree of difference. May reflect use of different biomass plant types.
	%	60.41%	-	-	-		±42.72%	
Solar thermal PT w 6hrs	2009 AUD/MWh	-	26.46	-	32.75	-	29.60	Small degree of difference. Unusual as this is an emerging technology.
	%	-	-10.63%	-	10.63%	-	±15.04%	
Solar thermal PT w/out	2009 AUD/MWh	17.73	32.36	-	26.20	24.00	27.52	Medium degree of difference. US DOE (2009) cost much lower.
	%	-35.57%	17.60%	-	-4.80%	-12.80%	±21.95%	
Solar thermal CR w 6hrs	2009 AUD/MWh	-	26.37	-	-	-	26.37	
	%	-		-	-	-		
Solar thermal CR w/out	2009 AUD/MWh	17.73	32.20	-	-	24.00	28.10	Medium degree of difference. US DOE (2009) cost much lower.
	%	-36.89%	14.59%	-	-	-14.59%	±25.82%	
PV roof top	2009 AUD/MWh	-	-	-	-		0.00	
	%	-	-	-	-			
PV fixed plate	2009 AUD/MWh	-	23.92	-	0	-	11.96	
	%	-		-	-100%	-	±141.42%	
PV single axis tracking	2009 AUD/MWh	3.65	25.03	-	0 0.00	11.71	12.25	Medium degree of difference. US DOE (2009) cost much lower.
	%	-70.21%	104.37%	-	-100%	-4.37%	±90.57%	
PV two axis tracking	2009 AUD/MWh	-	22.83	-	0	-	11.42	
	%	-		-	-100%	-	±141.42%	
Wind - small	2009 AUD/MWh	-	17.19	-	15.22	-	16.21	Small degree of difference.
	%	-		-	-6.08%	-	±8.60%	
Wind - medium	2009 AUD/MWh	9.46	15.47	-	15.22	14.64	15.11	Medium degree of difference. US DOE (2009) cost much lower.
	%	-37.38%		-	0.73%	-3.13%	±43.70%	
Wind - large	2009 AUD/MWh	-	14.44	-	15.22	-	14.83	Small degree of difference.
	%	- 6.08% 2.40%	-2.63%	-		-	±3.72%	
Geothermal hot rocks	2009 AUD/MWh	-	25.18	-	7.13	10.98	14.43	Large degree of difference. This is an emerging technology.
	%	-	74.49%	-	-50.56%	-23.93%	±73.43%	
Geothermal conventional	2009 AUD/MWh	51.41	-	-	-	10.98	10.98	Large degree of difference. Unusual given that US DOE (2009) tends to be lower.
	%	368.31%	-	- 2.63%	-		±260.44%	
Geothermal hot aquifers	2009 AUD/MWh	-	16.79	-	-	-	16.79	
	%	-		-	-	-		
Hydro	2009 AUD/MWh	4.26	-	-	-	21.96	21.96	Large degree of difference. Unusual given that US DOE (2009) tends to be lower.
	%	-80.61%	-	-	-		±57.00%	
Wave	2009 AUD/MWh	-	-	-	-	16.50	16.50	
	%	-	-	-	-			
Current	2009 AUD/MWh	-	-	-	-	23.49	23.49	
	%	-	-	-	-			

Fixed O&M Costs For Renewables (2015)

		WRT to Harmonised Value						Comments
		DOE	EPRI	IEA	ACIL	CSIRO	Harmonised	
Brown Coal pf	2009 AUD/MWh	-		6.58	1.30	1.71	3.68	V. large degree of difference. ACIL Tasman (2010) and CSIRO (2010) much lower.
	%	-	39.33%	78.79%	-64.69%	-53.43%	±70.22%	
Brown Coal pf with CCS	2009 AUD/MWh	-	16.44	17.11	2.40	21.36	14.33	Large degree of difference. ACIL Tasman (2010) v low. This is unknown new technology.
	%	-	14.76%	19.42%	-83.25%	49.07%	±57.54%	
Black Coal pf	2009 AUD/MWh	5.22	4.59	5.87	1.30	1.71	3.37	Large degree of difference. CSIRO (2010) and ACIL Tasman (2010) v low.
	%	55.06%	36.25%	74.26%	-61.41%	-49.10%	±62.12%	
Black Coal IGCC	2009 AUD/MWh	3.32	12.82	-	4.10	1.65	6.19	Large degree of difference. EPRI (2010) v high. This is a relatively new technology.
	%	-46.31%	107.12%	-	-33.76%	-73.36%	±80.84%	
Black Coal pf with CCS	2009 AUD/MWh	-	15.66	13.63	2.40	21.36	13.26	Large degree of difference. CSIRO (2010) v high and ACIL Tasman (2010) v low. This is a newtechnology.
	%	-	18.08%	2.79%	-81.90%	61.03%	±59.91%	
Black Coal IGCC with CCS	2009 AUD/MWh	5.05	19.97	14.66	5.20	-	13.28	Large degree of difference. US DOE (2009) and ACIL Tasman (2010) v low and EPRI (2010) v high. This is unknown new technology.
	%	-61.95%	50.40%	10.43%	-60.84%	-	±55.46%	
Gas combined cycle	2009 AUD/MWh	2.36	2.03	4.42	1.10	5.33	3.22	Large degree of difference. ACIL Tasman (2010) is v low. ACIL Tasman (2010) data based on Australian conditions.
	%	-26.87%	-36.98%	37.26%	-65.85%	65.57%	±54.70%	
Gas with CCS	2009 AUD/MWh	3.35	4.24	-	-	16.44	10.34	V large degree of difference. CSIRO (2010) v high as this is unknown new technology.
	%	-67.65%	-59.00%	-	-	59.00%	±70.76%	
Gas peak	2009 AUD/MWh	4.06	2.54	9.42	7.70	8.24	6.98	Medium degree of difference. EPRI (2010) v low. Unsure as to origin of differences.
	%	-41.76%	-63.59%	35.03%	10.38%	18.17%	±42.14%	
Nuclear	2009 AUD/MWh	0.56	6.10	-	5.9	2.20	4.73	Medium degree of difference. US DOE (2009) v low as nuclear is a familiar technology in the US.
	%	-88.22%	28.89%	-	24.66%	-53.55%	±58.16%	

Variable O&M Costs For Non-Renewables (2015)

		WRT to Harmonised Value						Comments
		DOE	EPRI	IEA	ACIL	CSIRO	Harmonised	
Biomass	2009 AUD/MWh	7.64	-	-	-	3.30	3.30	Large degree of difference. May reflect use of different biomass plant types.
	%	131.58%	-	-	-		±93.04%	
Solar thermal PT w 6hrs	2009 AUD/MWh	-		-	0.00	-		
	%	-		-		-		
Solar thermal PT w/out	2009 AUD/MWh	0.00	0.00	-	0.00	1.65	0.55	Large degree of difference. May reflect different ratios between fixed and variable O&M.
	%	-100%	-100%	-	-100%	200.00%	±150%	
Solar thermal CR w 6hrs	2009 AUD/MWh	-		-	-	-		
	%	-		-	-	-		
Solar thermal CR w/out	2009 AUD/MWh	0.00	0.00	-	-	1.65	0.82	Large degree of difference. May reflect different ratios between fixed and variable O&M.
	%	-100%	-100%	-	-	100%	±115.47%	
PV roof top	2009 AUD/MWh	-	-	-	-		2.35	
	%	-	-	-	-	0.00		
PV fixed plate	2009 AUD/MWh	-		-	-	-		
	%	-		-	-	-		
PV single axis tracking	2009 AUD/MWh	0.00	0.00	-	-	1.65	0.82	Large degree of difference. May reflect different ratios between fixed and variable O&M.
	%	-100%	-100%	-	-	100.00%	±100%	
PV two axis tracking	2009 AUD/MWh	-		-	-	-		
	%	-		-	-	-		
Wind - small	2009 AUD/MWh	-		-	0.00	-		
	%	-		-		-		
Wind - medium	2009 AUD/MWh	0.00	0.00	14.01	0.00	1.76	3.94	Large degree of difference. May reflect different ratios between fixed and variable O&M.
	%	-100%	-100%	255.40%	-100%	-55.504	±155.16%	
Wind - large	2009 AUD/MWh	-		-	0.00	-		
	%	-		-		-		
Geothermal hot rocks	2009 AUD/MWh	-	0.00	6.72	0.00	2.20	2.23	Large degree of difference. May reflect different ratios between fixed and variable O&M.
	%	-	-100%	201.38%	-100%	-1.38%	±142.07%	
Geothermal conventional	2009 AUD/MWh	0.00	-	-	-		2.20	
	%	-100.00%	-	-	-	0.00	±70.71%	
Geothermal hot aquifers	2009 AUD/MWh	-		-	-	-		
	%	-		-	-	-		
Hydro	2009 AUD/MWh	2.77	-	-	-	2.20	2.20	Small degree of difference.
	%	25.80%	-	-	-		±18.24%	
Wave	2009 AUD/MWh	-	-	34.23	-	18.68	26.46	Medium degree of difference. This is an emerging technology.
	%	-	-	29.37%	-	-29.37%	±41.54%	
Current	2009 AUD/MWh	-	-	227.2	-	18.68	122.94	Large degree of difference. This is an emerging technology and IEA (2010) is tidal and CSIRO (2010) is ocean current.
	%	-	-	84.80%	-	-84.80%	±119.93%	

Variable O&M Costs For Renewables (2015)

		WRT to Harmonised Value						Comments
		DOE	EPRI	IEA	ACIL	CSIRO	Harmonised	
Brown Coal pf	2009 AUD/MWh	-	10.69	6.58	7.75	5.20	7.55	Medium degree of difference. Total shows much less difference than variable component.
	%	-	41.50%	-12.87%	2.53%	-31.16%	±30.90%	
Brown Coal pf with CCS	2009 AUD/MWh	-	25.50	17.11	14.76	26.06	20.86	Medium degree of difference. Total shows much less difference than variable and fixed component
	%	-	22.26%	-17.97%	-29.25%	24.96%	±27.67%	
Black Coal pf	2009 AUD/MWh	10.17	9.03	5.87	7.75	5.20	6.96	Medium degree of difference. Total shows much less difference than variable and fixed component
	%	46.08%	29.71%	-15.68%	11.27%	-25.29%	±29.97%	
Black Coal IGCC	2009 AUD/MWh	10.27	22.58	-	10.82	5.14	12.84	Large degree of difference. Reflects large difference in variable O&M costs.
	%	-20.03%	75.81%	-	-15.79%	-60.02%	±57.44%	
Black Coal pf with CCS	2009 AUD/MWh	-	23.08	13.63	13.14	26.06	18.98	Medium degree of difference. Reflects large difference in fixed O&M costs.
	%	-	21.61%	-28.18%	-30.74%	37.31%	±34.63%	
Black Coal IGCC with CCS	2009 AUD/MWh	13.34	33.89	14.66	15.27	-	21.28	Medium degree of difference. Similar range as both variable and fixed O&M.
	%	-37.30%	59.29%	-31.08%	-28.21%	-	±45.90%	
Gas combined cycle	2009 AUD/MWh	6.13	4.41	4.42	5.26	8.47	5.64	Medium degree of difference. Total shows much less difference than variable and fixed component.
	%	8.75%	-21.82%	-21.63%	-6.70%	50.14%	±29.85%	
Gas with CCS	2009 AUD/MWh	9.37	8.60	-	-	28.24	18.42	Large degree of difference. Reflects large difference in variable O&M costs.
	%	-49.12%	-53.31%	-	-	53.31%	±60.38%	
Gas peak	2009 AUD/MWh	7.73	13.15	9.42	22.54	21.12	16.56	Medium degree of difference. Similar range as both variable and fixed O&M.
	%	-53.32%	-20.58%	-43.11%	36.12%	27.58%	±40.69%	
Nuclear	2009 AUD/MWh	13.59	25.83	-	17.18	7.69	16.90	Medium degree of difference. Total shows much less difference than variable and fixed component.
	%	-19.55%	52.84%	-		-54.51%	±44.92%	

Total O&M Costs For Non-Renewables (2015)

1.67%

		WRT to Harmonised Value						Comments
		DOE	EPRI	IEA	ACIL	CSIRO	Harmonised	
Biomass	2009 AUD/MWh	27.76	-	-	-	15.84	15.84	Large degree of difference. Reflects large difference in variable O&M component.
	%	75.22%	-	-	-		±53.19%	
Solar thermal PT w 6hrs	2009 AUD/MWh	-	26.46	-	32.75	-	29.60	Same as fixed.
	%	-	-10.63%	-	10.63%	-	±15.04%	
Solar thermal PT w/out	2009 AUD/MWh	17.73	32.36	-	26.20	25.65	28.07	Same as fixed.
	%	-36.83%	15.30%	-	-6.66%	-8.64%	±21.37%	
Solar thermal CR w 6hrs	2009 AUD/MWh	-	26.37	-	-	-	26.37	
	%	-		-	-	-		
Solar thermal CR w/out	2009 AUD/MWh	17.73	32.20	-	-	25.65	28.92	Same as fixed.
	%	-38.69%	11.33%	-	-	-11.33%	±25.05%	
PV roof top	2009 AUD/MWh	-	-	-	-		2.35	
	%	-	-	-	-			
PV fixed plate	2009 AUD/MWh	-	23.92	-	0	-	11.96	
	%	-	100%	-	-100%	-	±141.42%	
PV single axis tracking	2009 AUD/MWh	3.65	25.03	-	0 2.35	13.36	12.80	Large difference. Reflects difference in variable O&M.
	%	-71.49%	95.59%	-	-100%	4.41%	±87.54	
PV two axis tracking	2009 AUD/MWh	-	22.83	-	0	-	11.42	
	%	-	100%	-	-100%	-	±141.42%	
Wind - small	2009 AUD/MWh	-	17.19	-	15.22	-	16.21	Same as fixed.
	%	-		-	-6.08%	-	±8.60%	
Wind - medium	2009 AUD/MWh	9.46	15.47	14.01	15.22	16.40	15.28	Same as fixed.
	%	-38.06%	1.29%	-8.27%	-0.36%		±17.91%	
Wind - large	2009 AUD/MWh	-	14.44	-	15.22	-	14.83	Same as fixed.
	%	- 6.08%	-2.63%	-	7.34%	-	±3.72%	
Geothermal hot rocks	2009 AUD/MWh	-	25.18		7.13	13.18	13.05	Same as fixed.
	%	-	92.92%	-48.53%	-45.34%		±65.95%	
Geothermal conventional	2009 AUD/MWh	51.41	-	- 2.63%	-	13.18	13.18	V large degree of difference. Reflects difference in fixed O&M.
	%	290.19%	- 6.72	-	- 0.95%		±205.19%	
Geothermal hot aquifers	2009 AUD/MWh	-	16.79	-	-	-	16.79	
	%	-		-	-	-		
Hydro	2009 AUD/MWh	7.02	-	-	-	24.16	24.16	Large degree of difference. Reflects difference in fixed O&M.
	%	-70.93%	-	-	-		±50.16%	
Wave	2009 AUD/MWh	-	-	34.23	-	35.19	34.71	V. small degree of difference. Differences in variable and fixed O&M levelled out.
	%	-	-	-1.39%	-	1.39%	±1.96%	
Current	2009 AUD/MWh	-	-	227.19	-	42.18	134.69	Large degree of difference. Reflects difference in variable O&M.
	%	-	-	68.69%	-	-68.69%	±97.14%	

Total O&M Costs For Renewables (2015)

		WRT to Harmonised Value						Comments
		DOE	EPRI	IEA	ACIL	CSIRO	Harmonised	
Brown Coal pf	2009 AUD/GJ	-		0.90	0.64	0.49	0.70	Medium degree of difference. CSIRO (2010) low which means lower LCOE.
	%	-		29.07%	-7.99%	-28.90%	±24.53%	
Brown Coal pf with CCS	2009 AUD/GJ	-	0.75	0.91	0.64	0.49	0.70	Medium degree of difference. CSIRO (2010) low which means lower LCOE.
	%	-		29.92%	-8.28%	-29.12%	±24.95%	
Black Coal pf	2009 AUD/GJ	1.82 0.75	1.50	1.30	1.63	1.10	1.38	Medium degree of difference. CSIRO (2010) low which means lower LCOE and US DOE (2009) high which means a higher LCOE.
	%	31.94%	8.57%	-6.11%	17.98%	-20.45%	±20.42%	
Black Coal IGCC	2009 AUD/GJ	1.82	1.50	-	1.63	1.10	1.41	Medium degree of difference. CSIRO (2010) low which means lower LCOE and US DOE (2009) high which means a higher LCOE.
	%	29.31%	6.41%	-	15.63%	-22.03%	±21.72%	
Black Coal pf with CCS	2009 AUD/GJ	-	1.50	1.31	1.63	1.10	1.38	Low degree of difference. CSIRO (2010) low which means lower LCOE.
	%	-		-5.44%	17.73%	-20.62%	±16.72%	
Black Coal IGCC with CCS	2009 AUD/GJ	1.82	1.50	1.23	1.63	-	1.45	Low degree of difference. US DOE (2009) high which means higher LCOE.
	%	25.40%	3.19%	-15.32%	12.13%	-	±17.09%	
Gas combined cycle	2009 AUD/GJ	7.41	9.00	7.88	5.11	6.59	7.15	Medium degree of difference. ACIL Tasman (2009) low and EPRI (2010) high.
	%	3.69% 8.34%	25.94%	10.27%	-28.49%	-7.72%	±20.38%	
Gas with CCS	2009 AUD/GJ	7.41	9.00	-	-	6.59	7.80	Low degree of difference. EPRI (2010) high which means a higher LCOE.
	%	-4.97%	15.42%	-	-	-15.42%	±15.69%	
Gas peak	2009 AUD/GJ	7.41	9.00	5.99	6.39	6.59	6.99	Low degree of difference. EPRI (2010) high which means a higher LCOE.
	%	5.96%	28.69%	-14.36%	-8.63%	-5.70%	±17.06%	
Nuclear	2009 AUD/GJ		0.94	-	0.46	2.04	1.15	High degree of difference. CSIRO (2010) very high which means a much higher LCOE.
	%	-100.00%	-18.12%	-	-59.93%	78.06%	±76.40%	

Fuel Costs For Non-Renewables (2015)

		WRT to Harmonised Value						Comments
		DOE	EPRI	IEA	ACIL	CSIRO	Harmonised	
Brown Coal pf	% HHV	-	34.8%	30.0%	32.0%	34.9%	32.9%	Low degree of difference, therefore fuel consumption approximately the same.
	%	-		-8.91%	-2.84%	5.97%	±7.22%	
Brown Coal pf with CCS	% HHV	-	25.5%	24.0%	28.0%	24.7%	25.5%	Low degree of difference, therefore fuel consumption approximately the same
	%	-	-0.32%	-6.05%	9.61%	-3.25%	±6.82%	
Black Coal pf	% HHV	35.2%	38.0%	37.0%	40.0%	38.0%	38.2%	Low degree of difference, therefore fuel consumption approximately the same. \
	%	-8.08% 5.78%	-0.70%	-3.25%	4.59%	-0.64%	±4.60%	
Black Coal IGCC	% HHV	36.9%	39.4%	-	41.0%	40.5%	40.3%	Low degree of difference, therefore fuel consumption approximately the same.
	%	-8.45%	-2.31%	-		0.58%	±4.55%	
Black Coal pf with CCS	% HHV	-	28.4%	29.0%	31.0%	27.0%	28.9%	Low degree of difference, therefore fuel consumption approximately the same.
	%	-	-1.54%	0.52%	7.45%	-6.43%	±5.76%	
Black Coal IGCC with CCS	% HHV	30.0%	28.9%	35.0%	33.0%	-	32.3%	Low degree of difference, therefore fuel consumption approximately the same
	%	-7.10%	-10.58%	8.39% 1.73%	2.19%	-	±8.66%	
Gas combined cycle	% HHV	44.9%	49.5%	50.0%	50.0%	48.5%	49.5%	Low degree of difference, therefore fuel consumption approximately the same.
	%	-9.20%	0.06%		1.01%	-2.08%	±4.31%	
Gas with CCS	% HHV	37.5%	41.1%	-	-	39.7%	40.4%	Low degree of difference, therefore fuel consumption approximately the same.
	%	-7.07%	1.84%	-	-	-1.84%	±4.48%	
Gas peak	% HHV	29.9%	33.2% 1.01%	39.0%	35.0%	20.0%	31.8%	Medium degree of difference. CSIRO (2010) has lower efficiency therefore fuel consumption will be higher.
	%	-5.93%	4.42%	22.63%	10.06%	-37.11%	±22.57%	
Nuclear	% HHV	31.0%	33.0%	-	34.0%	33.5%	33.5%	Low degree of difference, therefore fuel consumption approximately the same.
	%	-7.48%	-1.41%	-		-0.08%	±3.92%	

Efficiency For Non-Renewables (2015)

1.49%

		WRT to Harmonised Value						Comments
		DOE	EPRI	IEA	ACIL	CSIRO	Harmonised	
Brown Coal pf		-		85%	85.0%	80.0%	83.8%	Low degree of difference. Should have minimal impact on differences in capital cost component of LCOE.
	%	-		1.49%	1.49%	-4.48%	±2.99%	
Brown Coal pf with CCS		-	85.0%	85.0%	85.0%	80.0%	83.8%	Low degree of difference. Should have minimal impact on differences in capital cost component of LCOE.
	%	-		1.49%	1.49%	-4.48%	±2.99%	
Black Coal pf		72.3% 85.0%	85.0%	85.0%	85.0%	80.0%	83.8%	Low degree of difference. Should have minimal impact on differences in capital cost component of LCOE.
	%	-13.67% 1.49%	1.49%	1.49%	1.49%	-4.48%	±6.64%	
Black Coal IGCC		72.3%	85.0%	-	85.0%	80.0%	83.3%	Low degree of difference. Should have minimal impact on differences in capital cost component of LCOE.
	%	-13.24% 1.49%	2.00%	-	2.00%	-4.00%	±7.20%	
Black Coal pf with CCS		-	85.0%	85.0%	85.0%	80.0%	83.8%	Low degree of difference. Should have minimal impact on differences in capital cost component of LCOE.
	%	-		1.49%	1.49%	-4.48%	±2.99%	
Black Coal IGCC with CCS		72.3%	85.0%	85.0%	85.0%	-	85.0%	Low degree of difference. Should have minimal impact on differences in capital cost component of LCOE.
	%	-14.94%				-	±7.47%	
Gas combined cycle		42.9%	85.0%	85.0%	85.0%	80.0%	83.8%	Medium degree of difference. US DOE (2009) has a low capacity factor, which was an estimation. This increases LCOE cmpt of capital cost.
	%	-48.78% 1.49%		1.49%	1.49%	-4.48%	±21.97%	
Gas with CCS		42.9%	85.0%	-	-	80.0%	82.5%	Medium degree of difference. US DOE (2009) has a low capacity factor, which was an estimation. This increases LCOE cmpt of capital cost.
	%	-48.00%		-	-	-3.03%	±27.88%	
Gas peak		42.9% 1.49%	10.0%	85.0%	10.0%	21.4%	31.6%	Large degree of difference. This is due to peak plant usage. US DOE (2009) was an estimate, IEA (2010) use this plant as baseload. Has a large effect on LCOE.
	%	35.73%	-68.36%	168.93%	-68.36%	-32.20%	±99.93%	
Nuclear		89.7% 3.03%	85.0%	-	85.0%	80.0%	83.3%	Low degree of difference. Should have minimal impact on differences in capital cost component of LCOE.
	%	7.64%	2.00%	-	2.00%	-4.00%	±4.75%	

Capacity Factor For Non-Renewables (2015)

		WRT to Harmonised Value						Comments
		DOE	EPRI	IEA	ACIL	CSIRO	Harmonised	
Biomass		41.6%	-	-	-	50.0%	50.0%	Low degree of difference. LCOEBut because of large capital and fixed O&M component impacts the LCOE.
	%	-16.80%	-	-	-		±11.88%	
Solar thermal PT w 6hrs		-		-		-	28.8%	Low degree of difference. But because of large capital and fixed O&M component impacts the LCOE.LCOE
	%	-		-	-9.29%	-	±13.14%	
Solar thermal PT w/out		41.6%	19.4%	-	26.1%	26.1%	23.9%	Medium degree of difference. US DOE (2009) has v high capacity factor based on an estimation. This lowers the capital cost cmpt of LCOE.
	%	74.09%	-18.81%	-		9.41%	±39.36%	
Solar thermal CR w 6hrs		-31.5%		-26.1%	-	-		
	%	-9.29%		-	-	-		
Solar thermal CR w/out		41.6%	19.5%	-	-	26.1%	22.8%	Medium degree of difference. US DOE (2009) has v high capacity factor based on an estimation. This lowers the capital cost cmpt of LCOE. CSIRO (2010) is somewhat higher than EPRI (2010) so CSIRO has a lower capital cost cmpt of LCOE.
	%	82.28%	-14.55%	-9.41%	-	14.55%	±49.69%	
PV roof top		-31.6%	-	-	-	31.6%	21.4%	
	%	-	-	-	-			
PV fixed plate		-		-		-	21.2%	V small degree of difference.
	%	-	-1.01%	-		-	±1.43%	
PV single axis tracking		41.6%	26.0%	-	21.4% 21.4%	21.4%	23.0%	Medium degree of difference. US DOE (2009) has v high capacity factor based on an estimation. This lowers the capital cost cmpt of LCOE.
	%	81.24%	13.28%	-	-6.64%	-6.64%	±41.69%	
PV two axis tracking		-21.0%		-21.4%		-	26.2%	Medium degree of difference. EPRI (2010) is somewhat higher than ACIL Tasman (2010) and thus will have a smaller capital cost cmpt of LCOE.
	%	-	18.26%	-1.01%	-18.26%	-	±25.82%	
Wind - small		-		-		-	31.6%	Small degree of difference.
	%	-		-	-5.06%	-	±7.16%	
Wind - medium		41.6% 31.0%	33.2%	30.0% 21.4%	30.0%	30.0%	30.8%	Medium degree of difference. US DOE (2009) has v high capacity factor based on an estimation. This lowers the capital cost cmpt of LCOE.
	%	35.06%		-2.60%	-2.60%	-2.60%	±16.31%	
Wind - large		-33.2%		-30.0%		-	31.6%	Small degree of difference.
	%	-5.06%		-	-5.06%	-	±7.16%	
Geothermal hot rocks		- 7.79%	85.0%	85.0%	80.0%	80.0%	82.5%	Small degree of difference.
	%	-		3.03%	-3.03%	-3.03%	±3.50%	
Geothermal conventional		41.6% 33.2%	-	-30.0%	-	80.0%	80.0%	Medium degree of difference. US DOE (2009) has low capacity factor based on an estimation. This increases the capital cost cmpt of LCOE.
	%	-48.00% 5.06%	-	-	-		±33.94%	
Geothermal hot aquifers		-		-	-	-		
	%	-3.03%		-	-	-		
Hydro		41.6%	-	-	-	20.0%	20.0%	Large degree of difference. US DOE (2009) has v high capacity factor based on an estimation. This lowers the capital cost cmpt of LCOE.
	%	108.00%	-	-	-		±76.37%	
Wave		-85.0%	-		-	50.4%	53.2%	Small degree of difference.
	%	-	-		-	-5.23% 85.0%	±7.40%	
Current		-	-		-	35.4%	32.7%	Small degree of difference.
	%	-	-56.0%	-8.30%	-		±11.73%	

5.23%
30.0%

Capacity Factor For Renewables (2015)

8.30%

		WRT to Harmonised Value						Comments
		DOE	EPRI	IEA	ACIL	CSIRO	Harmonised	
Brown Coal pf	kg CO2 / GJ Fuel	-	80.6	92.31	93.50	93.60	90.00	Low degree of difference.
	%	-	-10.44%	2.56%	3.88%	3.99%	±6.99%	
Brown Coal pf with CCS	kg CO2 / GJ Fuel	-	80.6	93.3	93.50	93.60	90.25	Low degree of difference.
	%	-	-10.68%	3.37%	3.60%	3.71%	±7.12%	
Black Coal pf	kg CO2 / GJ Fuel	100.7	77.8	90.9	98.00	95.29	90.51	Low degree of difference.
	%	11.21%	-13.99%	0.42%	8.28%	5.28%	±9.91%	
Black Coal IGCC	kg CO2 / GJ Fuel	105.6	88.8	-	98.00	95.29	94.03	Low degree of difference.
	%	12.36%	-5.56%	-		1.34%	±7.42%	
Black Coal pf with CCS	kg CO2 / GJ Fuel	-	77.8	91.6	98.00	95.29	90.68	Low degree of difference
	%	-	-14.15%	0.98%	8.08%	5.09%	±9.87%	
Black Coal IGCC with CCS	kg CO2 / GJ Fuel	105.6	88.8	91.1	98.00	-	92.64	Low degree of difference.
	%	14.04%	-4.15%	-1.63% 4.22%	5.78%	-	±8.19%	
Gas combined cycle	kg CO2 / GJ Fuel	55.1	51.7	51.7	56.94	62.90	55.83	Low degree of difference.
	%	-1.39%	-7.35%	-7.31%	2.00%	12.66%	±8.27%	
Gas with CCS	kg CO2 / GJ Fuel	58.7	51.4	-	-	62.90	57.17	Low degree of difference.
	%	2.64%	-10.03%	-	-	10.03%	±10.14%	
Gas peak	kg CO2 / GJ Fuel	36.6	57.4	39.4	64.17	62.90	55.95	Medium degree of difference. ACIL Tasman (2010) using Queensland gas emissions factor. US DOE (2009) also lower.
	%	-34.49%	2.55%	-29.66%	14.69%	12.42%	±23.49%	
Nuclear	kg CO2 / GJ Fuel	0	0	-	1.89	0	0.63	Large degree of difference. ACIL Tasman (2010) only report to consider nuclear fugitive emissions.
	%	-100%	-100%	-	200%	-100%	±150.00%	

Emission Factor For Non-Renewables (2015)

		WRT to Harmonised Value						Comments
		DOE	EPRI	IEA	ACIL	CSIRO	Harmonised	
Brown Coal pf		-		10%	-	7%	8%	IEA (2010) has higher discount rate therefore higher capital cost component of LCOE. However, their capital cost itself is low so EPRI (2010) is actually highest for capital cmpt of LCOE.
	%	-	-0.79%	18.11%	-	-17.32%	±52.05%	
Brown Coal pf with CCS		-		10%	-	7%	8%	IEA (2010) has highest discount rate but not higher capital cost component of LCOE.
	%	-	-0.79%	18.11%	-	-17.32%	±52.05%	
Black Coal pf		-8.4%		10%	-	7%	8%	IEA (2010) has highest discount rate and highest capital cost component of LCOE.
	%	-	-0.79%	18.11%	-	-17.32%	±56.19%	
Black Coal IGCC		8.4%	8.4%	-		7%	8%	EPRI (2010) has higher discount rate and higher capital cost component of LCOE.
	%	-		-	-	-9.09%	±58.21%	
Black Coal pf with CCS		-8.4%		10%	-	7%	8%	IEA (2010) has highest discount rate and highest capital cost component of LCOE.
	%	-	-0.79%	18.11%	-	-17.32%	±52.05%	
Black Coal IGCC with CCS			8.4%	10%		-	9%	IEA (2010) has highest discount rate and highest capital cost component of LCOE.
	%	-9.09%	-8.70%	8.70%	-	-	±58.17%	
Gas combined cycle		8.4%	8.4%	10%		7%	8%	IEA (2010) has highest discount rate and higher capital cost component of LCOE.
	%	-	-0.79%	18.11%	-	-17.32%	±56.19%	
Gas with CCS			8.4%	-		7%	8%	EPRI (2010) has higher discount rate but nothigher capital cost component of LCOE.
	%	-		-	-	-9.09%	±58.45%	
Gas peak			8.4%	10%		7%	8%	IEA (2010) has highest discount rate but not higher capital cost component of LCOE.
	%	-	-0.79%	18.11%	-	-17.32%	±56.19%	
Nuclear			8.4%	-		7%	8%	EPRI (2010) has higher discount rate and highest capital cost component of LCOE.
	%	-9.09%		-	-	-9.09%	±58.21%	

Discount Rate For Non-Renewables (2015)

9.09%

		WRT to Harmonised Value						Comments
		DOE	EPRI	IEA	ACIL	CSIRO	Harmonised	
Biomass	 %	- -	- -	- -	- -	7%	7%	
Solar thermal PT w 6hrs	 %	- -		- -	- -	- -	8%	
Solar thermal PT w/out	 %	- -		- -	- -	7% -9.09%	8% ±58.21%	EPRI (2010) has higher discount rate and highest capital cost component of LCOE.
Solar thermal CR w 6hrs	 %	-8.4% -		- -	- -	- -		
Solar thermal CR w/out	 %	-8.4% -9.09%		- -	- -	7% -9.09%	8% ±58.45%	EPRI (2010) has higher discount rate and highest capital cost component of LCOE.
PV roof top	 %	-8.4% -	- -	- -	- -	7% 8.4%	7%	
PV fixed plate	 %	-8.4% -9.09%		- -	- -	- -	8%	
PV single axis tracking	 %	- -		- -	- -	7% -9.09%	8% ±58.21%	EPRI (2010) has higher discount rate therefore but not capital cost component of LCOE.
PV two axis tracking	 %	-8.4% -		- -	- -	- -	8%	
Wind - small	 %	-8.4% -9.09%		- -	- -	- -	8%	
Wind - medium	 %	-8.4% -	 -0.79%	10% 18.11%	- -	7% -17.32%	8% ±56.19%	IEA (2010) has higher discount rate but not higher capital cost component of LCOE.
Wind - large	 %	-8.4% -		- -	- -	- -	8%	
Geothermal hot rocks	 %	-8.4% -	 -0.79%	10% 18.11%	- -	7% -17.32%	8% ±52.05%	IEA (2010) has higher discount rate but not higher capital cost component of LCOE.
Geothermal conventional	 %	-8.4% -	- -	- -	- -	7%	7%	
Geothermal hot aquifers	 %	-8.4% -		- -	- -	- -		
Hydro	 %	- -	- -	- -	- -	7%	7%	
Wave	 %	-8.4% -	- -	10% 17.65%	- -	7% -17.65% 8.4%	9% ±24.96%	IEA (2010) has higher discount rate and higher capital cost component of LCOE.
Current	 %	- -	- -	10% 17.65%	- -	7% -17.65%	9% ±24.96%	IEA (2010) has higher discount rate but not higher capital cost component of LCOE.

Discount Rate For Renewables (2015)

		WRT to Harmonised Value						Comments
		DOE	EPRI	IEA	ACIL	CSIRO	Harmonised	
Brown Coal pf	years	-	30	40	40	30	35	ACIL Tasman (2010) and IEA (2010) have longest amortisation period but not lowest capital component of LCOE.
	%	-	-14.29%	14.29%	14.29%	-14.29%	±16.50%	
Brown Coal pf with CCS	years	-	30	40	40	30	35	ACIL Tasman (2010) and IEA (2010) has longest amortisation period and ACIL Tasman (2010) has lowest capital component of LCOE.
	%	-	-14.29%	14.29%	14.29%	-14.29%	±16.50%	
Black Coal pf	years		30	40	40	30	35	ACIL Tasman (2010) and IEA (2010) has longest amortisation period and ACIL Tasman (2010) has lowest capital component of LCOE.
	%	-	-14.29%	14.29%	14.29%	-14.29%	±46.95%	
Black Coal IGCC	years	-	30	-	40	30	33	ACIL Tasman (2010) has longest amortisation period but not lowest capital component of LCOE.
	%	-	-10.00%	-	20.00%	-10.00%	±51.96%	
Black Coal pf with CCS	years	-	30	40	40	30	35	ACIL Tasman (2010) and IEA (2010) has longest amortisation period and lowest capital component of LCOE.
	%	-	-14.29%	14.29%	14.29%	-14.29%	±16.50%	
Black Coal IGCC with CCS	years	-		40	40	-	37	ACIL Tasman (2010) and IEA (2010) has longest amortisation period but not lowest capital component of LCOE.
	%	-	-18.18%	9.09%	9.09%	-	±51.63%	
Gas combined cycle	years	-	30	30	30	30	30	No difference.
	%	-					±44.72%	
Gas with CCS	years	- 30	30	-	-		30	
	%	-		-				
Gas peak	years	-	30	30	30	30	30	No difference.
	%	-					±44.72%	
Nuclear	years	-	30	-		30	30	No difference.
	%	-		-			±57.74%	

Amortisation Period For Non-Renewables (2015)

		WRT to Harmonised Value						Comments
		DOE	EPRI	IEA	ACIL	CSIRO	Harmonised	
Biomass	years	-	-	-	-	30	30	
	%	-	-	-	-			
Solar thermal PT w 6hrs	years	-	30	-	-	-	30	
	%	-		-	-	-		
Solar thermal PT w/out	years	-	30	-	-	20	25	EPRI (2010) has longest amortisation period but not lowest capital component of LCOE.
	%	-	20.00%	-	-	-20.00%	±60.00%	
Solar thermal CR w 6hrs	years	-	30	-	-	-	30	
	%	-		-	-	-		
Solar thermal CR w/out	years	-	30	-	-	20	25	EPRI (2010) has longest amortisation period but not lowest capital component of LCOE.
	%	-	20.00%	-	-	-20.00%	±61.10%	
PV roof top	years	-	-	-	-	20	20	
	%	-	-	-	-			
PV fixed plate	years	-	30	-	-	-	30	
	%	-		-	-	-		
PV single axis tracking	years	-	30	-	-	20	25	EPRI (2010) has longest amortisation period but not lowest capital component of LCOE.
	%	-	20.00%	-	-	-20.00%	±60.00%	
PV two axis tracking	years	-	30	-	-	-	30	
	%	-		-	-	-		
Wind - small	years	-	20	-	-	-	20	
	%	-		-	-	-		
Wind - medium	years	-		25	-	20	22	IEA (2010) has longest amortisation period but not lowest capital component of LCOE.
	%	-	-7.69%	15.38%	-	-7.69%	±55.58%	
Wind - large	years	-	20	-	-	-	20	
	%	-		-	-	-		
Geothermal hot rocks	years	-	-	40	-	30	35	IEA (2010) has longest amortisation period but not lowest capital component of LCOE.
	%	-20	-	14.29%	-	-14.29%	±58.90%	
Geothermal conventional	years	-	-	-	-	30	30	
	%	-	-	-	-			
Geothermal hot aquifers	years	-		-	-	-	0	
	%	-		-	-	-		
Hydro	years	-	-	-	-		100	
	%	-	-	-	-			
Wave	years	-	-	20	-	20	20	No difference.
	%	-	-		-			
Current	years	-	-	20	-100	20	20	No difference.
	%	-	-		-			

Amortisation Period For Renewables (2015)

		WRT to Harmonised Value						Comments
		DOE	EPRI	IEA	ACIL	CSIRO	Harmonised	
Brown Coal pf	AUD per USD	-		1.19			1.21	EPRI (2010) has a greater exchange rate which raises capital cost component of LCOE when converting to AUD.
	%	-		-1.65%	-	-	±57.75%	
Brown Coal pf with CCS	AUD per USD	-		1.19	-	-	1.21	EPRI (2010) has a greater exchange rate which raises capital cost component of LCOE when converting to AUD.
	%	-		-1.65%	-	-	±57.75%	
Black Coal pf	AUD per USD	1.138	1.23	1.19	-	-	1.21	EPRI (2010) has a greater exchange rate which raises capital cost component of LCOE when converting to AUD.
	%	-5.95%	1.65%	-1.65%	-	-	±53.75%	
Black Coal IGCC	AUD per USD	1.138	1.23	-	-	-	1.23	EPRI (2010) has a greater exchange rate which raises capital cost component of LCOE when converting to AUD.
	%	-7.48%		-	-	-	±55.66%	
Black Coal pf with CCS	AUD per USD	-		1.19	-	-	1.21	EPRI (2010) has a greater exchange rate which raises capital cost component of LCOE when converting to AUD.
	%	-		-1.65%	-	-	±57.75%	
Black Coal IGCC with CCS	AUD per USD	1.138	1.23	1.19	-	-	1.21	EPRI (2010) has a greater exchange rate which raises capital cost component of LCOE when converting to AUD.
	%	-5.95%	1.65%	-1.65%	-	-	±49.11%	
Gas combined cycle	AUD per USD	1.138	1.23	1.19	-	-	1.21	EPRI (2010) has a greater exchange rate which raises capital cost component of LCOE when converting to AUD.
	%	-5.95%	1.65%	-1.65%	-	-	±53.75%	
Gas with CCS	AUD per USD	1.138	1.23	-	-	-	1.23	EPRI (2010) has a greater exchange rate which raises capital cost component of LCOE when converting to AUD.
	%	-7.48%		-	-	-	±55.70%	
Gas peak	AUD per USD	1.138	1.23	1.19	-	-	1.21	EPRI (2010) has a greater exchange rate which raises capital cost component of LCOE when converting to AUD.
	%	-5.95%	1.65%	-1.65%	-	-	±53.75%	
Nuclear	AUD per USD	1.138	1.23	-	-	-	1.23	EPRI (2010) has a greater exchange rate which raises capital cost component of LCOE when converting to AUD.
	%	-7.48%		-	-	-	±55.66%	

Exchange Rate For Non-Renewables (2015)

		WRT to Harmonised Value						Comments
		DOE	EPRI	IEA	ACIL	CSIRO	Harmonised	
Biomass	AUD per USD	1.138	-	-	-	-	0	
	%		-	-	-	-		
Solar thermal PT w 6hrs	AUD per USD	-		-	-	-		
	%	-		-	-	-		
Solar thermal PT w/out	AUD per USD	1.138	1.23	-	-	-	1.23	EPRI (2010) has a greater exchange rate which raises capital cost component of LCOE when converting to AUD.
	%	-7.48% 1.23		-	-	-	±55.66%	
Solar thermal CR w 6hrs	AUD per USD	-		-	-	-		
	%	-		-	-	- 1.23		
Solar thermal CR w/out	AUD per USD	1.138	1.23	-	-	-	1.23	EPRI (2010) has a greater exchange rate which raises capital cost component of LCOE when converting to AUD.
	%	-7.48% 1.23		-	-	-	±55.70%	
PV roof top	AUD per USD	-	-	-	-	-	0	
	%	-	-	-	-	- 1.23		
PV fixed plate	AUD per USD	-		-	-	-		
	%	-		-	-	-		
PV single axis tracking	AUD per USD	1.138	1.23	-	-	-	1.23	EPRI (2010) has a greater exchange rate which raises capital cost component of LCOE when converting to AUD.
	%	-7.48% 1.23		-	-	-	±55.66%	
PV two axis tracking	AUD per USD	-		-	-	-		
	%	-		-	-	- 1.23		
Wind - small	AUD per USD	-		-	-	-		
	%	- 1.23		-	-	-		
Wind - medium	AUD per USD	1.138	1.23	1.19	-	-	1.21	EPRI (2010) has a greater exchange rate which raises capital cost component of LCOE when converting to AUD.
	%	-5.95% 1.23	1.65%	-1.65%	-	- 1.23	±53.75%	
Wind - large	AUD per USD	-		-	-	-		
	%	-		-	-	- 1.23		
Geothermal hot rocks	AUD per USD	-		1.19	-	-	1.21	EPRI (2010) has a greater exchange rate which raises capital cost component of LCOE when converting to AUD.
	%	- 1.23		-1.65%	-	-	±57.75%	
Geothermal conventional	AUD per USD	1.138	-	-	-	-	0	
	%	1.23	-	-	-	- 1.23		
Geothermal hot aquifers	AUD per USD	- 1.65%		-	-	-		
	%	-		-	-	-		
Hydro	AUD per USD	1.138	-	-	-	-	0	
	%	1.23	-	-	-	-		
Wave	AUD per USD	-	-	1.19	-	-		
	%	-	-		-	- 1.23		
Current	AUD per USD	-	-	1.19	-	-		
	%	-	-		-	-		

1.19

Exchange Rate For Renewables (2015)

1.19

		WRT to Harmonised Value					Comments
		DOE	EPRI	ACIL	CSIRO	Harmonised	
Brown Coal pf	2009 AUD/kW	-	-	2,870	2,820	2,845	V little difference.
	%	-	-		-0.88%	±1.25%	
Brown Coal pf with CCS	2009 AUD/kW	-	4,792	5,036	4,008	4,612	Small degree of difference. Reflects differences in cost inclusions and methodologies.
	%	-		9.19%	-13.09%	±11.64%	
Black Coal pf	2009 AUD/kW	1,882	- 0.88%	2,406	1,898	2,152	Small degree of difference. Reflects differences in cost inclusions and methodologies.
	%	-12.53%	-	11.79%	-11.79%	±13.84%	
Black Coal IGCC	2009 AUD/kW	2,186 3.90%	-	2,857	2,675	2,766	Small degree of difference. Reflects differences in cost inclusions and methodologies.
	%	-20.95%	-		-3.28%	±12.53%	
Black Coal pf with CCS	2009 AUD/kW	-	4,792	3,875	3,160	3,942	Small degree of difference. Reflects differences in cost inclusions and methodologies.
	%	-	21.56%	-1.72%	-19.84%	±20.75%	
Black Coal IGCC with CCS	2009 AUD/kW	2,883	4,721 3.28%	3,875	-	4,298	Small degree of difference. Reflects differences in cost inclusions and methodologies.
	%	-32.93%		-9.85%	-	±21.41%	
Gas combined cycle	2009 AUD/kW	880	-	1,217	980	1,099	Small degree of difference. Reflects differences in cost inclusions and methodologies.
	%	-19.93% 9.85%	-	10.76%	-10.76%	±15.75%	
Gas with CCS	2009 AUD/kW	1,525	2,077	-	2,240	2,158	Medium degree of difference. Reflects differences in cost inclusions and methodologies and plant types.
	%	-29.35%	-3.78%	-	3.78%	±17.36%	
Gas peak	2009 AUD/kW	613	881	843	939	888	Small degree of difference. Reflects differences in cost inclusions and methodologies.
	%	-30.92%	-0.78%	-5.02%	5.80%	±16.09%	
Nuclear	2009 AUD/kW	2,699	4,876	4,377	4,472	4,575	Small degree of difference. Reflects differences in cost inclusions and methodologies and location of plant.
	%	-41.00%		-4.32%	-2.26%	±21.04%	

6.58%

Capital Costs For Non-Renewables (2030)

		WRT to Harmonised Value					Comments
		DOE	EPRI	ACIL	CSIRO	Harmonised	
Biomass	2009 AUD/kW	2,831	-	-	3,452	3,452	Small degree of difference. Reflects differences due to plant type
	%	-17.99%	-	-		±12.72%	
Solar thermal PT w 6hrs	2009 AUD/kW	-	6,125	-	-	6,125	
	%	-		-	-		
Solar thermal PT w/out	2009 AUD/kW	3,507	3,690	-	2,264	2,977	Medium degree of difference. Reflects differences in methodologies used to project capital costs.
	%	17.81%	23.95%	-	-23.95%	±26.06%	
Solar thermal CR w 6hrs	2009 AUD/kW	-	4,209	-	-	4,209	
	%	-		-	-		
Solar thermal CR w/out	2009 AUD/kW	3,507	2,735	-	2,264	2,500	Medium degree of difference. Reflects differences in methodologies used to project capital costs.
	%	40.32%	9.42%	-	-9.42%	±25.11%	
PV roof top	2009 AUD/kW	-	-	-	2,471	2,471	
	%	-	-	-			
PV fixed plate	2009 AUD/kW	-	4,072	-	-	4,072	
	%	-		-	-		
PV single axis tracking	2009 AUD/kW	4,351	4,544	-	2,153	3,349	Medium degree of difference. Reflects differences in plant type and capital cost methodologies and assumptions
	%	29.92%	35.70%	-	-35.70%	±39.66%	
PV two axis tracking	2009 AUD/kW	-	4,490	-	-	4,490	
	%	-		-	-		
Wind - small	2009 AUD/kW	-	3,360	-	-	3,360	
	%	-		-	-		
Wind - medium	2009 AUD/kW	1,838	3,052	-	1,497	2,274	Medium degree of difference. Reflects differences in methodologies used to project capital costs.
	%	-19.20%	34.18%	-	-34.18%	±35.94%	
Wind - large	2009 AUD/kW	-	2,902	-	-	2,902	
	%	-		-	-		
Geothermal hot rocks	2009 AUD/kW	-	7,656	-	7,232	7,444	V little difference
	%	-		-	-2.85%	±4.03%	
Geothermal conventional	2009 AUD/kW	4,486	-	-	4,184	4,184	V little difference
	%	7.21%	-	-		±5.10%	
Geothermal hot aquifers	2009 AUD/kW	- 2.85%	5,325	-	-	5,325	
	%	-		-	-		
Hydro	2009 AUD/kW	2,185	-	-	3,163	3,163	Small degree of difference. Reflects location differences.
	%	-30.93%	-	-		±21.87%	
Wave	2009 AUD/kW	-	-	-	2,588	2,588	
	%	-	-	-			
Current	2009 AUD/kW	-	-	-	3,280	3,280	
	%	-	-	-			

Capital Costs For Renewables (2030)

		WRT to Harmonised Value					Comments
		DOE	EPRI	ACIL	CSIRO	Harmonised	
Brown Coal pf	2009 AUD/MWh	-	-		3.49	4.97	Medium degree of difference. Reflects differences in obtaining O&M estimate and ratio between fixed and variable.
	%	-	-	29.80%	-29.80%	±42.14%	
Brown Coal pf with CCS	2009 AUD/MWh	-		12.36	4.71	8.18	Medium degree of difference. Reflects differences in obtaining O&M estimate and ratio between fixed and variable.
	%	-	-8.48% 6.45	50.98%	-42.51%	±47.32%	
Black Coal pf	2009 AUD/MWh	4.95	-		3.49	4.97	Small degree of difference. Reflects differences in obtaining O&M estimate and ratio between fixed and variable.
	%	-0.40%	-	29.80%	-29.80%	±29.80%	
Black Coal IGCC	2009 AUD/MWh	6.95 7.49	-		3.49	5.10	Medium degree of difference. Reflects differences in obtaining O&M estimate and ratio between fixed and variable.
	%	36.22%	-6.45	31.65%	-31.65%	±37.93%	
Black Coal pf with CCS	2009 AUD/MWh	-		10.74	4.71	7.18	Medium degree of difference. Reflects differences in obtaining O&M estimate and ratio between fixed and variable.
	%	-	-15.28% 6.72	49.71%	-34.44%	±44.11%	
Black Coal IGCC with CCS	2009 AUD/MWh	8.29	8.52	10.07	-		Small degree of difference. Reflects differences in obtaining O&M estimate and ratio between fixed and variable.
	%	-10.86%	-8.35%	8.35%	-	±10.44%	
Gas combined cycle	2009 AUD/MWh	8.11 6.08	-		3.14	3.65	Large degree of difference. Reflects differences in obtaining O&M estimate and ratio between fixed and variable.
	%	122.09%	-	14.06%	-14.06%	±71.88%	
Gas with CCS	2009 AUD/MWh	12.93	3.60	-	11.79 9.30	7.70	Large degree of difference. Reflects differences in obtaining O&M estimate and ratio between fixed and variable.
	%	67.93%	-53.23% 4.16	-	53.23%	±66.12%	
Gas peak	2009 AUD/MWh	7.87	11.70	14.84	11.71	12.75	Small degree of difference. Reflects differences in obtaining O&M estimate and ratio between fixed and variable.
	%	-38.31%	-8.24%	16.39%	-8.16%	±22.39%	
Nuclear	2009 AUD/MWh	13.04	16.75	11.28	5.49	11.17	Medium degree of difference. Reflects differences in obtaining O&M estimate and ratio between fixed and variable.
	%	16.68%	49.91%	0.96%	-50.87%	±41.99%	

Fixed O&M Costs For Non-Renewables (2030)

		WRT to Harmonised Value					Comments
		DOE	EPRI	ACIL	CSIRO	Harmonised	
Biomass	2009 AUD/MWh	20.13	-	-	10.91	10.91	Medium degree of difference. Reflects differences plant type and location.
	%	84.47%	-	-		±59.73%	
Solar thermal PT w 6hrs	2009 AUD/MWh	-	17.72	-	-	17.72	
	%	-		-	-		
Solar thermal PT w/out	2009 AUD/MWh	17.73	20.39	-	22.52	21.46	Small degree of difference. Reflects differences in obtaining O&M estimate and ratio between fixed and variable.
	%	-17.36%	-4.96%	-		±11.18%	
Solar thermal CR w 6hrs	2009 AUD/MWh	-	16.61	-	-	16.61	
	%	-		-	-		
Solar thermal CR w/out	2009 AUD/MWh	17.73	18.35	-	22.52	20.44	Small degree of difference. Reflects differences in obtaining O&M estimate and ratio between fixed and variable.
	%	-13.23%	-10.20%	-	10.20%	±12.75%	
PV roof top	2009 AUD/MWh	-	-	-		0.00	
	%	-	-	-			
PV fixed plate	2009 AUD/MWh	-	15.55	-	-	15.55	
	%	-		-	-		
PV single axis tracking	2009 AUD/MWh	3.65	16.27	-	10.65	13.46	Medium degree of difference. Reflects differences in obtaining O&M estimate and ratio between fixed and variable.
	%	-72.90%	20.90%	-	-20.90%	±46.99%	
PV two axis tracking	2009 AUD/MWh	-	14.84	-	-	14.84	
	%	-		-	-		
Wind - small	2009 AUD/MWh	-	13.45	-	-	13.45	
	%	-		-	-		
Wind - medium	2009 AUD/MWh	9.46	12.11	-	13.94	13.03	Small degree of difference. Reflects differences in obtaining O&M estimate and ratio between fixed and variable.
	%	-27.36%	-7.03%	-		±17.29%	
Wind - large	2009 AUD/MWh	-	11.30	-	-	11.30	
	%	-		-	-		
Geothermal hot rocks	2009 AUD/MWh	-	24.44	-	10.98	17.71	Medium degree of difference. Reflects differences in obtaining O&M estimate and ratio between fixed and variable.
	%	-	38.01%	-	-38.01%	±53.75%	
Geothermal conventional	2009 AUD/MWh	51.41	-	-	10.98	10.98	V large degree of difference. Reflects differences in obtaining O&M estimate and ratio between fixed and variable and location
	%	368.31%	-	-		±260.44%	
Geothermal hot aquifers	2009 AUD/MWh	-	14.64	-	-	14.64	
	%	-		-	-		
Hydro	2009 AUD/MWh	4.26	-	-	21.96	21.96	Medium degree of difference. Reflects differences in obtaining O&M estimate and ratio between fixed and variable and location
	%	-80.61%	-	-		±57.00%	
Wave	2009 AUD/MWh	-	-	-	16.30	16.30	
	%	-	-	-			
Current	2009 AUD/MWh	-	-	-	23.07	23.07	
	%	-	-	-			

Fixed O&M Costs For Renewables (2030)

		WRT to Harmonised Value					Comments
		DOE	EPRI	ACIL	CSIRO	Harmonised	
Brown Coal pf	2009 AUD/MWh	-	-		1.71	1.51	Small degree of difference. Reflects differences in obtaining O&M estimate and ratio between fixed and variable.
	%	-	-	-13.75%	13.75%	±19.45%	
Brown Coal pf with CCS	2009 AUD/MWh	-	16.44	2.40	21.36	13.40	Large degree of difference. Reflects differences in obtaining O&M estimate and ratio between fixed and variable.
	%	-	22.7[illegible]	-82.09%	59.39%	±73.42%	
Black Coal pf	2009 AUD/MWh	5.22	-		1.71	1.51	V large degree of difference. Reflects differences in obtaining O&M estimate and ratio between fixed and variable.
	%	246.54%	-	-13.75%	13.75%	±143.00%	
Black Coal IGCC	2009 AUD/MWh	3.32	-		1.65	2.87	Medium degree of difference. Reflects differences in obtaining O&M estimate and ratio between fixed and variable.
	%	15.61%	-	42.64%	-42.64%	±43.58%	
Black Coal pf with CCS	2009 AUD/MWh	-	15.66	2.40	21.36	13.14	Large degree of difference. Reflects differences in obtaining O&M estimate and ratio between fixed and variable.
	%	-	19.1[illegible]	-81.73%	62.54%	±74.03%	
Black Coal IGCC with CCS	2009 AUD/MWh	5.05	19.97	5.20	-	12.59	Large degree of difference. Reflects differences in obtaining O&M estimate and ratio between fixed and variable.
	%	-59.85%	58.68%	-58.68%	-	±68.10%	
Gas combined cycle	2009 AUD/MWh	2.36	-		5.33	3.22	Large degree of difference. Reflects differences in obtaining O&M estimate and ratio between fixed and variable.
	%	-26.76%	-	-65.80%	65.80%	±67.59%	
Gas with CCS	2009 AUD/MWh	3.35	4.24	-	16.44	10.34	Large degree of difference. Reflects differences in obtaining O&M estimate and ratio between fixed and variable.
	%	-67.65%	-59.00%	-	59.00%	±70.76%	
Gas peak	2009 AUD/MWh	4.06	2.54	7.70	8.24	6.16	Medium degree of difference. Reflects differences in obtaining O&M estimate and ratio between fixed and variable.
	%	-34.06%	-58.77%	24.98%	33.80%	±45.06%	
Nuclear	2009 AUD/MWh	0.56	6.10	5.9	2.20	4.73	Large degree of difference. Reflects differences in obtaining O&M estimate and ratio between fixed and variable and location.
	%	-88.22%	28.89%	24.66%	-53.55%	±58.16%	

Variable O&M Costs For Non-Renewables (2030)

		WRT to Harmonised Value					Comments
		DOE	EPRI	ACIL	CSIRO	Harmonised	
Biomass	2009 AUD/MWh	7.64	-	-		3.30	
	%	131.58%	-	-		±93.04%	
Solar thermal PT w 6hrs	2009 AUD/MWh	-		-	-	0.00	
	%	-		-	-		
Solar thermal PT w/out	2009 AUD/MWh	0.00	0.00	-3.30			
	%			-			
Solar thermal CR w 6hrs	2009 AUD/MWh	-0.00		-	-	0.00	
	%	-		-	-		
Solar thermal CR w/out	2009 AUD/MWh	0.00	0.00	-1.65			
	%			-			
PV roof top	2009 AUD/MWh	-0.00	-	-		2.35	
	%	-	-	-			
PV fixed plate	2009 AUD/MWh	-		-1.65	-	0.00	
	%	-		-	-		
PV single axis tracking	2009 AUD/MWh	0.00	0.00	-2.35			
	%			-			
PV two axis tracking	2009 AUD/MWh	-0.00		-	-	0.00	
	%	-		-	-		
Wind - small	2009 AUD/MWh	-		-1.65	-	0.00	
	%	-		-	-		
Wind - medium	2009 AUD/MWh	0.00 0.00	0.00	-			
	%			-			
Wind - large	2009 AUD/MWh	-0.00		-	-	0.00	
	%	-		-	-		
Geothermal hot rocks	2009 AUD/MWh	-		-1.76			
	%	-		-			
Geothermal conventional	2009 AUD/MWh	0.00 0.00	-	-		2.20	
	%	-100.00%	-	-		±70.71%	
Geothermal hot aquifers	2009 AUD/MWh	-0.00		-2.20	-	0.00	
	%	-		-	-		
Hydro	2009 AUD/MWh	2.77	-	-2.20		2.20	
	%	25.80%	-	-		±18.24%	
Wave	2009 AUD/MWh	-0.00	-	-	18.68	18.68	
	%	-	-	-			
Current	2009 AUD/MWh	-	-	-2.20	18.68	18.68	
	%	-	-	-			

Variable O&M Costs For Renewables (2030)

		WRT to Harmonised Value					Comments
		DOE	EPRI	ACIL	CSIRO	Harmonised	
Brown Coal pf	2009 AUD/MWh	-	-		5.20	6.47	Small degree of difference. Reflects differences in obtaining O&M estimate
	%	-	-	19.66%	-19.66%	±27.80%	
Brown Coal pf with CCS	2009 AUD/MWh	-	23.93	14.76	26.06	21.58	Small degree of difference. Reflects differences in obtaining O&M estimate
	%	-	10.88% 7.75	-31.63%	20.75%	±27.83%	
Black Coal pf	2009 AUD/MWh	10.17	-		5.20	6.47	Small degree of difference. Reflects differences in obtaining O&M estimate
	%	57.10%	-	19.66%	-19.66%	±38.38%	
Black Coal IGCC	2009 AUD/MWh	10.27	-	10.82	5.14	7.98	Small degree of difference. Reflects differences in obtaining O&M estimate
	%	28.79%	- 7.75	35.61%	-35.61%	±39.30%	
Black Coal pf with CCS	2009 AUD/MWh	-	21.74	13.14	26.06	20.31	Small degree of difference. Reflects differences in obtaining O&M estimate
	%	-		-35.30%	28.28%	±32.37%	
Black Coal IGCC with CCS	2009 AUD/MWh	13.34	28.49	15.27	-	21.88	Small degree of difference. Reflects differences in obtaining O&M estimate
	%	-39.04%	30.20%	-30.20%	-	±37.68%	
Gas combined cycle	2009 AUD/MWh	10.46 7.02%	-		8.47	6.87	Small degree of difference. Reflects differences in obtaining O&M estimate
	%	52.36%	-	-23.35%	23.35%	±38.20%	
Gas with CCS	2009 AUD/MWh	16.27	7.84	-	28.24	18.04	Medium degree of difference. Reflects differences in obtaining O&M estimate
	%	-9.79%	-56.54% 5.26	-	56.54%	±56.82%	
Gas peak	2009 AUD/MWh	11.93	14.24	22.54	19.95	18.91	Small degree of difference. Reflects differences in obtaining O&M estimate
	%	-36.92%	-24.70%	19.19%	5.51%	±26.02%	
Nuclear	2009 AUD/MWh	13.59	22.85	17.18	7.69	15.91	Small degree of difference. Reflects differences in obtaining O&M estimate
	%	-14.53%	43.65%	8.02%	-51.67%	±39.99%	

Total O&M Costs For Non-Renewables (2030)

		WRT to Harmonised Value					Comments
		DOE	EPRI	ACIL	CSIRO	Harmonised	
Biomass	2009 AUD/MWh	27.76	-	-	14.21	14.21	Large degree of difference. Reflects differences in plant type.
	%	95.41%	-	-		±67.46%	
Solar thermal PT w 6hrs	2009 AUD/MWh	-	17.72	-	-	17.72	
	%	-		-	-		
Solar thermal PT w/out	2009 AUD/MWh	17.73	20.39	-	24.17	22.28	Small degree of difference. Reflects differences in obtaining O&M estimate
	%	-20.41%	-8.48%	-		±14.52%	
Solar thermal CR w 6hrs	2009 AUD/MWh	-	16.61	-	-	16.61	
	%	-		-	-		
Solar thermal CR w/out	2009 AUD/MWh	17.73	18.35	-	24.17	21.26	Small degree of difference. Reflects differences in obtaining O&M estimate
	%	-16.60%	-13.68%	-8.48%	13.68%	±16.71%	
PV roof top	2009 AUD/MWh	-	-	-		2.35	
	%	-	-	-			
PV fixed plate	2009 AUD/MWh	-	15.55	-	-	15.55	
	%	-		-	-		
PV single axis tracking	2009 AUD/MWh	3.65	16.27	-2.35	12.29	14.28	Medium degree of difference. Reflects differences in obtaining O&M estimate and location
	%	-74.46%	13.92%	-	-13.92%	±45.19%	
PV two axis tracking	2009 AUD/MWh	-	14.84	-	-	14.84	
	%	-		-	-		
Wind - small	2009 AUD/MWh	-	13.45	-	-	13.45	
	%	-		-	-		
Wind - medium	2009 AUD/MWh	9.46	12.11	-	15.70	13.90	Small degree of difference. Reflects differences in obtaining O&M estimate
	%	-31.95%	-12.91%	-	12.91%	±22.51%	
Wind - large	2009 AUD/MWh	-	11.30	-	-	11.30	
	%	-		-	-		
Geothermal hot rocks	2009 AUD/MWh	-	24.44	-	13.18	18.81	Medium degree of difference. Reflects differences in obtaining O&M estimate
	%	-	29.94%	-	-29.94%	±42.34%	
Geothermal conventional	2009 AUD/MWh	51.41	-	-	13.18	13.18	V large degree of difference. Reflects differences in obtaining O&M estimate, and location.
	%	290.19%	-	-		±205.19%	
Geothermal hot aquifers	2009 AUD/MWh	-	14.64	-	-	14.64	
	%	-		-	-		
Hydro	2009 AUD/MWh	7.02	-	-	24.16	24.16	Medium degree of difference. Reflects differences in obtaining O&M estimate and location.
	%	-70.93%	-	-		±50.16%	
Wave	2009 AUD/MWh	-	-	-	34.98	34.98	
	%	-	-	-			
Current	2009 AUD/MWh	-	-	-	41.76	41.76	
	%	-	-	-			

Total O&M Costs For Renewables (2030)

		WRT to Harmonised Value					Comments
		DOE	EPRI	ACIL	CSIRO	Harmonised	
Brown Coal pf	2009 AUD/GJ	-	-		0.55	0.71	Same as 2015
	%	-	-	22.57%	-22.57%	±31.92%	
Brown Coal pf with CCS	2009 AUD/GJ	-	1.50	0.87	0.55	0.97	
	%	-	54.13%	-10.60%	-43.53%	±49.69%	
Black Coal pf	2009 AUD/GJ	1.82	- 0.87		1.10	1.54	
	%	18.02%	-	28.84%	-28.84%	±30.66%	
Black Coal IGCC	2009 AUD/GJ	1.82	-		1.10	1.54	
	%	18.02%	-	28.84%	-28.84%	±30.66%	
Black Coal pf with CCS	2009 AUD/GJ	-	1.50 1.99		1.10	1.53	
	%	-	-1.94%	30.09%	-28.15%	±29.17%	
Black Coal IGCC with CCS	2009 AUD/GJ	1.82	0.75 1.99	1.99	-		
	%	33.06%	-45.26%	45.26%	-	±49.11%	
Gas combined cycle	2009 AUD/GJ	7.41	- 1.99		6.59	6.19	
	%	19.67%	-	-6.50%	6.50%	±13.08%	
Gas with CCS	2009 AUD/GJ	7.41	9.00	-		7.80	
	%	-4.97%	15.42%	-	-15.42% 1.37	±15.69%	
Gas peak	2009 AUD/GJ	7.41	9.00 5.79	7.24	6.59	7.61	
	%	-2.65%	18.24%	-4.88%	-13.36%	±13.42%	
Nuclear	2009 AUD/GJ	-	0.94	6.59	1.55	0.98	
	%	-	-4.33%	-53.18%	57.51%	±67.46%	

Fuel Costs For Non-Renewables (2030)

0.46

		WRT to Harmonised Value					Comments
		DOE	EPRI	ACIL	CSIRO	Harmonised	
Brown Coal pf	% HHV	-	-		34.9%	41.0%	Same as 2015 with some improvements
	%	-	-	14.88%	-14.88%	±21.04%	
Brown Coal pf with CCS	% HHV	-		35.0%	26.2%	33.0%	
	%	-	14.39%	6.21%	-20.60%	±18.30%	
Black Coal pf	% HHV	35.2%	- 47.1%		38.0%	43.0%	
	%	-18.25%	-	11.63%	-11.63%	±15.69%	
Black Coal IGCC	% HHV	36.9% 37.7%	-		42.9%	44.0%	
	%	-16.07%	-		-2.36%	±9.57%	
Black Coal pf with CCS	% HHV	-	48.0%	39.0%	29.3%	35.6%	
	%	-		9.55%	-17.61%	±15.27%	
Black Coal IGCC with CCS	% HHV	30.0%	35.6% 45.0%	40.0%	-	37.8%	
	%	-20.63%	-5.83% 2.36%	5.83%	-	±13.26%	
Gas combined cycle	% HHV	44.9% 38.5%	-		51.4%	54.5%	
	%	-17.52% 8.06%	-		-5.70%	±11.61%	
Gas with CCS	% HHV	37.5%	49.3%	-		45.8%	
	%	-17.98%	7.61%	-	-7.61%	±12.87%	
Gas peak	% HHV	29.9%	40.0% 37.6%	36.0%	20.0%	32.0%	
	%	-6.51%	25.00% 5.70%	12.50%	-37.50%	±27.20%	
Nuclear	% HHV	31.0%	33.0%	34.0% 42.3%	35.1%	34.0%	
	%	-8.93%	-2.96%	-0.11%	3.07%	±5.10%	

Efficiency For Non-Renewables (2030)

		WRT to Harmonised Value					Comments
		DOE	EPRI	ACIL	CSIRO	Harmonised	
Brown Coal pf		-	-		80.0%	82.5%	Same as 2015
	%	-	-		-3.03%	±4.29%	
Brown Coal pf with CCS		-		85.0%	80.0%	83.3%	
	%	-		2.00%	-4.00%	±3.46%	
Black Coal pf		72.3%	- 85.0%		80.0%	82.5%	
	%	-12.36%	- 3.03%		-3.03%	±7.75%	
Black Coal IGCC		72.3% 85.0%	-		80.0%	82.5%	
	%	-12.36% 2.00%	-		-3.03%	±7.75%	
Black Coal pf with CCS		-	85.0%	85.0%	80.0%	83.3%	
	%	-	3.03%	2.00%	-4.00%	±3.46%	
Black Coal IGCC with CCS		72.3%	85.0% 85.0%	85.0%	-		
	%	-14.94%	3.03%		-	±8.63%	
Gas combined cycle		20.0% 85.0%	-		80.0%	82.5%	
	%	-75.76% 2.00%	-		-3.03%	±43.84%	
Gas with CCS		20.0%	85.0%	-		82.5%	
	%	-75.76%		-	-3.03% 85.0%	±43.84%	
Gas peak		20.0%	10.0% 85.0%	10.0%	23.6%	14.5%	
	%	37.70%	-31.15% 3.03%	-31.15%	62.30%	±47.91%	
Nuclear		89.7% 3.03%	85.0%	85.0% 80.0%	80.0%	83.3%	
	%	7.64%		2.00%	-4.00%	±4.75%	

Capacity Factor For Non-Renewables (2030)

2.00%

		WRT to Harmonised Value					Comments
		DOE	EPRI	ACIL	CSIRO	Harmonised	
Biomass	%	15.33%	- -	- -		36.1% ±10.84%	Same as 2015 with some improvements
Solar thermal PT w 6hrs	%	- -		- -	- -		
Solar thermal PT w/out	%	41.6% 73.85%	20.0% -16.42%	-36.1% -	16.42%	23.9% ±45.69%	
Solar thermal CR w 6hrs	%	- 32.9% -		- -	- -32.9%		
Solar thermal CR w/out	%	41.6% 72.05%	20.5% -15.21%	-27.9% -	15.21%	24.2% ±44.29%	
PV roof top	%	- 32.6% -	- -	- -	32.6%	23.6%	
PV fixed plate	%	- -		-27.9% -	- -		
PV single axis tracking 41.6%	%	41.6% 67.84%	26.0%	-23.6% -	-4.90%	24.8% ±39.47%	
PV two axis tracking	%	- 21.0% -		- -	- -21.0%		
Wind - small	%	- 4.90% -		-23.6% -	- -		
Wind - medium	%	41.6% 31.0% 19.37%	38.2% 9.61%	- -	-9.61% 31.0%	34.9% ±14.75%	
Wind - large	%	- 38.2% -		- -	- -38.2%		
Geothermal hot rocks	%	- -		-31.5% -	-3.03%	82.5% ±4.29%	
Geothermal conventional	%	41.6% 38.2% -48.00%	- -	- -	38.2%	80.0% ±33.94%	
Geothermal hot aquifers	%	- 85.0% - 3.03%		-80.0% -	- -		
Hydro	%	108.00%	- -	-80.0% -		20.0% ±76.37%	
Wave	%	- 85.0% -	- -	- -	85.0%	51.1%	
Current	%	- -	- -	-20.0% - 51.1%		35.4%	

Capacity Factor For Renewables (2030)

35.4%

41.6%

		WRT to Harmonised Value					Comments
		DOE	EPRI	ACIL	CSIRO	Harmonised	
Brown Coal pf	kg CO2 / GJ Fuel	-	-	93.50	93.60	93.55	V little difference.
	%	-	-	-0.05%	0.05%	±0.08%	
Brown Coal pf with CCS	kg CO2 / GJ Fuel	-		93.50	93.60	89.86	V little difference.
	%	-	-8.21%	4.05%	4.16%	±7.11%	
Black Coal pf	kg CO2 / GJ Fuel	100.7	-		95.29	96.65	V little difference.
	%	4.15%	-		-1.40%	±2.77%	
Black Coal IGCC	kg CO2 / GJ Fuel	105.6 82.5	-	98.00	95.29	96.65	V little difference.
	%	9.32%	-		-1.40%	±5.56%	
Black Coal pf with CCS	kg CO2 / GJ Fuel	-	98.0	98.00	95.29	90.98	V little difference.
	%	-	-12.46% 16.40%	7.72%	4.74%	±10.89%	
Black Coal IGCC with CCS	kg CO2 / GJ Fuel	105.6	88.9	98.00	-	93.45	V little difference.
	%	13.06%	-4.87% 1.40%	4.87%	-	±8.98%	
Gas combined cycle	kg CO2 / GJ Fuel	55.1 79.6	-		62.90	59.95	V little difference.
	%	-8.16%	-	-4.92%	4.92%	±6.81%	
Gas with CCS	kg CO2 / GJ Fuel	58.7	51.7	-	62.90	57.31	V little difference.
	%	2.38%	-9.75%	-		±9.85%	
Gas peak	kg CO2 / GJ Fuel	36.6	57.4 57.0	64.00	62.90	61.43	Small degree of difference due to use of lower gas price by US DOE (2009)
	%	-40.33%	-6.59%	4.19%	2.40%	±20.71%	
Nuclear	kg CO2 / GJ Fuel	0	0	1.89	0	0.94	Large degree of difference due to inclusion of fugitive nuclear emissions by ACIL Tasman (2010)
	%	-100.00%	-100%	100.00% 9.75%	-100.0%	±115.47%	

Emission Factor For Non-Renewables (2030)

		WRT to Harmonised Value					Comments
		DOE	EPRI	ACIL	CSIRO	Harmonised	
Brown Coal pf	%	- -	- -	- -	7%	7%	See 2015
Brown Coal pf with CCS	%	- -		- -	7% -9.09%	8% ±58.45%	
Black Coal pf	%	- -	- -	- -	7%	7%	
Black Coal IGCC	%	- 8.4% - 9.09%	- -	- -	7%	7%	
Black Coal pf with CCS	%	- -		- -	7% -9.09%	8% ±58.45%	
Black Coal IGCC with CCS	%	- -		- -	- -	8%	
Gas combined cycle	%	- 8.4% - 9.09%	- -	- -	7%	7%	
Gas with CCS	%	- 8.4% -		- -	7% -9.09%	8% ±58.45%	
Gas peak	%	- -		- -	7% -9.09%	8% ±58.21%	
Nuclear	%	- 8.4% -9.09%		- -	7%	8% ±58.21%	

8.4%
9.09%
8.4%
9.09%

Discount Rate For Non-Renewables (2030)

		WRT to Harmonised Value					Comments
		DOE	EPRI	ACIL	CSIRO	Harmonised	
Biomass	%	- -	- -	- -	7%	7%	See 2015
Solar thermal PT w 6hrs	%	- -		- -	- -	8.4%	
Solar thermal PT w/out	%	- -		- -	7% -9.09%	8% ±58.45%	
Solar thermal CR w 6hrs	%	- 8.4% -		- -	- -	8.4%	
Solar thermal CR w/out	%	- 8.4% - 9.09%		- -	7% -9.09%	8% ±58.45%	
PV roof top	%	- 8.4% -	- -	- -	7%	7%	
PV fixed plate	%	- 8.4% - 9.09%		- -	- -	8.4%	
PV single axis tracking	%	- -		- -	7% -9.09%	8% ±58.45%	
PV two axis tracking	%	- 8.4% -		- -	- -	8.4%	
Wind - small	%	- 8.4% - 9.09%		- -	- -	8.4%	
Wind - medium	%	- 8.4% -		- -	7% -9.09%	8% ±58.45%	
Wind - large	%	- 8.4% -		- -	- -	8.4%	
Geothermal hot rocks	%	- 8.4% - 9.09%		- -	7% -9.09%	8% ±12.86%	
Geothermal conventional	%	- 8.4% -	- -	- -	7%	7%	
Geothermal hot aquifers	%	- 8.4% - 9.09%		- -	- -	8.4%	
Hydro	%	- -	- -	- -	7%	7%	
Wave	%	- 8.4% -	- -	- -	7%	7%	
Current	%	- -	- -	- -	7%	7%	

Discount Rate For Renewables (2030)

		WRT to Harmonised Value					Comments
		DOE	EPRI	ACIL	CSIRO	Harmonised	
Brown Coal pf	years	-	-		30	35	See 2015
	%	-	-	14.29%	-14.29%	±20.20%	
Brown Coal pf with CCS	years	-	30		30	33	
	%	-	-10.00%	20.00%	-10.00%	±17.32%	
Black Coal pf	years	-	-		30	35	
	%	-	- 40	14.29%	-14.29%	±59.48%	
Black Coal IGCC	years	-	-		30	35	
	%	-	- 40	14.29%	-14.29%	±59.48%	
Black Coal pf with CCS	years	-	30		30	33	
	%	-	-10.00% 40	20.00%	-10.00%	±17.32%	
Black Coal IGCC with CCS	years	-		40	-	35	
	%	-	-14.29% 40	14.29%	-	±59.48%	
Gas combined cycle	years	-	-		30	30	
	%	-	- 40			±57.74%	
Gas with CCS	years	-	30	-		30	
	%	- 30		-			
Gas peak	years	-	30	30	30	30	
	%	-	30			±50.00%	
Nuclear	years	-	30	-		30	
	%	-		- 30			

Amortisation Period For Non-Renewables (2030)

30

		WRT to Harmonised Value					Comments
		DOE	EPRI	ACIL	CSIRO	Harmonised	
Biomass	years		-	-		30	See 2015
	%	-	-	-			
Solar thermal PT w 6hrs	years	-	30	-	-	30	
	%	-		-	-		
Solar thermal PT w/out	years	-	30	-		25	
	%	-	20.00%	-30	-20.00%	±61.10%	
Solar thermal CR w 6hrs	years	-	30	-	-	30	
	%	-		-	-		
Solar thermal CR w/out	years	-	30	-		25	
	%	-	20.00%	-20	-20.00%	±61.10%	
PV roof top	years	-	-	-		20	
	%	-	-	-			
PV fixed plate	years	-	30	-	-	30	
	%	-		-20	-		
PV single axis tracking	years	-	30	-		25	
	%	-	20.00%	-20	-20.00%	±61.10%	
PV two axis tracking	years	-	30	-	-	30	
	%	-		-	-		
Wind - small	years	-	20	-	-	20	
	%	-		-20	-		
Wind - medium	years	-	20	-		20	
	%	-		-		±57.74%	
Wind - large	years	-	20	-	-	20	
	%	-		-	-		
Geothermal hot rocks	years	-	-	-		30	
	%	-	-	-20			
Geothermal conventional	years	-	-	-		30	
	%	-	-	-			
Geothermal hot aquifers	years	-		-	-	0	
	%	-		-30	-		
Hydro	years	-	-	-		100	
	%	-	-	-30			
Wave	years	-	-	-		20	
	%	-	-	-			
Current	years	-	-	-		20	
	%	-	-	100 -			

20

Amortisation Period For Renewables (2030)

20

		WRT to Harmonised Value					Comments
		DOE	EPRI	ACIL	CSIRO	Harmonised	
Brown Coal pf	AUD per USD	-	-	-	-	0	See 2015
	%	-	-	-	-		
Brown Coal pf with CCS	AUD per USD	-		-	-	1.23	
	%	-		-	-		
Black Coal pf	AUD per USD	1.138	-	-	-	0	
	%		-	-	-		
Black Coal IGCC	AUD per USD	1.138 1.23	-	-	-	0	
	%		-	-	-		
Black Coal pf with CCS	AUD per USD	-		-	-	1.23	
	%	-		-	-		
Black Coal IGCC with CCS	AUD per USD	1.138	1.23	-	-	1.23	
	%	-7.48%		-	-	±55.70%	
Gas combined cycle	AUD per USD	1.138 1.23	-	-	-	0	
	%		-	-	-		
Gas with CCS	AUD per USD	1.138	1.23	-	-	1.23	
	%	-7.48%		-	-	±55.70%	
Gas peak	AUD per USD	1.138	1.23	-	-	1.23	
	%	-7.48%		-	-	±55.66%	
Nuclear	AUD per USD	1.138	1.23	-	-	1.23	
	%	-7.48%		-	-	±55.66%	

Exchange Rate For Non-Renewables (2030)

		WRT to Harmonised Value					Comments
		DOE	EPRI	ACIL	CSIRO	Harmonised	
Biomass	AUD per USD	1.138	-	-	-	0	See 2015
	%		-	-	-		
Solar thermal PT w 6hrs	AUD per USD	-		-	-	1.23	
	%	-		-	-		
Solar thermal PT w/out	AUD per USD	1.138	1.23	-	-	1.23	
	%	-7.48%		-	-	±55.70%	
Solar thermal CR w 6hrs	AUD per USD	1.23 -		-	-	1.23	
	%	-		-	-		
Solar thermal CR w/out	AUD per USD	1.138	1.23	-	-	1.23	
	%	-7.48%		-	-	±55.70%	
PV roof top	AUD per USD	1.23 -	-	-	-	0	
	%	-	-	-	-		
PV fixed plate	AUD per USD	-		-	-	1.23	
	%	-		-	-		
PV single axis tracking	AUD per USD	1.138	1.23	-	-	1.23	
	%	-7.48%		-	-	±55.70%	
PV two axis tracking	AUD per USD	1.23 -		-	-	1.23	
	%	-		-	-		
Wind - small	AUD per USD	-		-	-	1.23	
	%	-		-	-		
Wind - medium	AUD per USD	1.23 1.138	1.23	-	-	1.23	
	%	-7.48%		-	-	±55.70%	
Wind - large	AUD per USD	1.23 -		-	-	1.23	
	%	-		-	-		
Geothermal hot rocks	AUD per USD	-		-	-	1.23	
	%	-		-	-		
Geothermal conventional	AUD per USD	1.23 1.138	-	-	-	0	
	%		-	-	-		
Geothermal hot aquifers	AUD per USD	1.23 -		-	-	1.23	
	%	-		-	-		
Hydro	AUD per USD	1.138	-	-	-	0	
	%		-	-	-		
Wave	AUD per USD	1.23 -	-	-	-	0	
	%	-	-	-	-		
Current	AUD per USD	-	-	-	-	0	
	%	-	-	-	-		

Exchange Rate For Renewables (2030)

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