Projections of the future costs of electricity generation technologies

An application of CSIRO's Global and Local Learning Model (GALLM)

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1 INTRODUCTION

The study of quantifiable relationships explaining the phenomenon of technological change has a long history dating back to at least the beginning of last century when it was observed by Wright (1936) that the cost of producing military aircraft declined at a more or less constant rate for each doubling of aircraft produced. At present, the energy sector's focus on this subject is to be able to create projections of the future cost of electricity generation technologies. Of particular interest are lower greenhouse gas emission intensity technologies which can be economically viable following the expected introduction of policies that will provide incentives to the sector to reduce emissions, most likely via a price signal of one type or another.

While there is a plethora of literature available which makes desired cost projection data available, there are often a number of key elements lacking in this literature which detracts from its usefulness. One key element is transparency. Very few studies supply a full description of their projection methodology or the assumptions used in each step. The other major concern is the methodologies themselves. While the science of understanding technological change is well established and continuing to improve, the methodologies employed by practitioners are for the most part based on the application of relatively simple methods (e.g. one factor experience curves) and the parameters employed based on a small number of international studies or expert opinion.

However, we do not argue that the most sophisticated and transparent method will always provide projections of a greater confidence or reliability. The expert opinion of scientists and engineers would be preferable in most cases if not for two difficulties. The first is that the breadth of knowledge sought is so wide that it is difficult for any one organisation to have sufficient staff spanning every desired technology. There are some thirty or more broad technologies of interest within which each technological group consists of various subsets and technology variations. The second difficulty is that there will always exist a healthy scepticism that scientists and engineers will sometimes become too close to their expert subject and consequently be incapable of providing an objective opinion. It is impossible to separate biased from objective opinion about future states of the world which cannot be tested. Commercial interests may also result in conflicts of interest where the cost of a technology may be underestimated to promote public interest and its uptake.

Our ultimate goal has been to improve our projections of electricity generation in Australia, in particular the projected capital costs as capital cost is a big decider in technology uptake. And, as the vast majority of electricity generation technologies are developed and sold internationally, we needed to develop a model based on a global framework but which can also cover scales down to individual countries.

With these considerations in mind CSIRO developed a quantitative model based on several new approaches to the study of technological change. The model requires significant data inputs but not overly-detailed expert knowledge of each technology category. This report seeks to present the methodology, inputs and outputs of that modelling framework in a transparent way. However, recognising that models are no substitute for expert opinion we draw on the most recent reputable studies available to create a context and uncertainty range to assist readers in understanding with what level of confidence they should regard the modelling projections.

CSIRO's Global and Local Learning Model (GALLM) is at its core a model of global electricity production and consumption over time where the uptake of different electricity technologies affects and is affected by changes in the costs of technology. The methodology is based on the robust one-factor experience curve that is widely used in the literature. However, the difference with GALLM is that the global electricity generation technology market context provides a transparent and adjustable method of creating the necessary technology uptake data to which experience curves can be applied. GALLM is structured in a way that allows for global learning spill-over effects as well as local learning with respect to some technology components, so called “compound learning”. This approach was applied to wind and solar photovoltaics. We also adjust for a tendency towards optimism in cost estimates at the concept stage.

One more feature of GALLM that has received close attention is its treatment of technology market forces. In recent years the price of all electricity generation technologies increased, most notably so for wind turbines, photovoltaics (PV) and PV installation, although now the price of PV modules and installation has fallen. The price increase was not factored into the experience curves as it is the result of market forces including high demand, profit-making and materials shortages and thus a separate phenomenon from learning. Rather the price increase has been interpreted as a “penalty” or price premium that entered the market once demand for popular technologies such as wind turbines and their installation exceeded the capacity of their raw material suppliers and component manufacturers. This penalty has been represented in the model as an additional payment to energy technology suppliers when investment in a technology category is high relative to the total size of the power plant market.

GALLM will continue to be improved over time. The most challenging area for new model development is how to deal with breakthrough technologies. That is, those technological changes where we see rapid acceleration or a fundamentally new technology enter the market. While CSIRO is exploring various approaches, in the interim we have sought to address this issue in a qualitative way. Appendix D – Speculative Technological Changes of this report provides a brief overview of some emerging technologies that could in time have the potential to become disruptive technologies.

The following sections provide more detail about the general theory of technological change and learning. Following that we discuss models of electricity generation that are in current use, we then include a discussion of GALLM including our development of the experience curves and how we deal with market forces and government policies. A brief discussion is given of our methodology for the calculation of long run marginal cost (LRMC) of electricity generation. Results from GALLM are then provided and comparisons are made between the LRMC calculated using GALLM capital costs and those from three other recent studies. Finally results are presented which show the effect the GALLM capital costs and other studies’ capital costs have on future projected electricity generation in Australia, up to the year 2030.

2 REPRESENTING TECHNOLOGICAL CHANGE

It is possible to represent technological change qualitatively and quantitatively. Qualitatively, progress of a technology can be examined in the context of other technologies that have a similar purpose and, based on expert opinion, the likely progression of that technology, the prospects for further development and when it is expected to be achieved. Quantitatively, the most widely-used measure of technological change is the experience curve, which will be discussed in the next section.

2.1 EXPERIENCE CURVES

The phenomenon of "technology learning" has been observed for the development of new technologies and processes since the 1930's when it was noted by Wright for airplane production (Wright, 1936) and later more extensively by the US Air Force for airframe production (Alchian, 1949, Hirsch, 1956). The term "learning-by-doing" was coined by Arrow (Arrow, 1962) and was used to explain the effect increasing the knowledge or experience of the labour force had on the economics of production of technology and processes (improvements in per capita income).

Grübler et al (1999) discussed and demonstrated how technology learning and diffusion for energy technologies can be incorporated into economic models of electricity generation. (Schrattenholzer and McDonald, 2001) calculated experience curves and rates of learning for many energy-related technologies as, up until then, learning rates from other technologies (Dutton and Thomas, 1984) were being used. Interestingly, the majority of learning rates were estimated to be ~20%.

(Wene, 2007) later investigated the reasons for this in a non-trivial machine-based model of the process of technology learning. It was found that when output doubles between each measurement point, then the following learning rates (corresponding to nodes 0,1, and 2) can describe this system: L(0) = 20%, L(1) = 7%, L(2) = 4%. In the literature, learning rates often differ by these values and there are several reasons why. These will be discussed below. Technology learning is typically represented in the form of an "experience curve[1]", where unit costs of a technology or process decrease by a certain percentage (the learning rate) for every doubling of cumulative capacity or output i.e.

$$IC\ CC = IC\ CC_0 \times CC^{-b}$$

where $IC\ CC$ is the investment cost of a technology at CC cumulative capacity, $IC\ CC_0$ is the investment cost at CC_0 unit cumulative capacity, and b is the learning index. The learning index is related to the learning rate LR by the following equation:

$$LR = 100 - 2^{-b}$$

where LR is represented as a percentage of cost.

[1] Experience curves are also commonly known as learning curves. We have used the term experience curve as defined in INTERNATIONAL ENERGY AGENCY (2000) Experience curves for energy technology policy. Paris, France OECD.

However, the validity of using the single factor experience curve for predicting future cost reductions has always been under question as the actual factors that lead to the cost reduction are not just from increasing learning, knowledge, economies of scale, experience or investments in a technology but may be quite complex and vary between technologies and even producers of the same commodity and/or within the same factory (Dutton and Thomas, 1984, Alberth, 2008).

Nevertheless, four broad factors that can influence the slope of an experience curve have been identified (International Energy Agency, 2000):

- Positive changes in the technology, termed “technology structural changes” lead to a sharp decrease in the experience curve (increased rate of learning, thus sharp increase in b and resultant decrease in the investment cost IC) over a short period of cumulative capacity increase, where learning switches from one curve (or rate of learning) to another.

- Market shakeout, which happens when price is observed instead of cost, can also result in a sharp increase in the learning rate. A shakeout can be observed after the early stages of the development of a technology. When more competitors enter the market, the price umbrella the original manufacturers held when they were exclusive suppliers is lost and the price returns closer to the marginal cost curve cost (Staff of the Boston Consulting Group, 1968). This has little to do with learning since it may represent little or no change in costs. However, more often only price data is available and consequently this phenomenon can have significant impact on construction and application of learning curves.

- Government policy and research, development and demonstration project spending can affect the slope of the realised learning curve by accelerating the learning process via accumulation of knowledge and experience. Policies can also influence the choice of technology, through mandates for a percentage of renewable energy by a given date, emissions trading schemes, feed-in tariffs, tax concessions etc.

- Finally, experience curves can be a compounded effect of experience curves for different and interacting parts of a system. For example, PV installations are made up of PV modules and balance of systems (BOS) which includes the inverter. These are reported to have quite different learning rates and may be sourced globally (module) while theBOS is local (Shum and Watanabe, 2008, International Energy Agency, 2000, Junginger et al., 2005).

Experience curves calculated for energy technologies using national or local cumulative capacities and costsoften do not consider the source of the technology and thus where the learning has occured and this can result in a higher local learning rate. Since all the learning has happened elsewhere or globally and yet the importing country benefits from the cost reductions (Junginger et al., 2005). This is also known as knowledge transfer or “spillover” (Grübler et al., 1999, Barreto and Kemp, 2008).

An alternative way to represent compound learning is to split a technology into learning and non-learning parts, so-called “component learning” (Ferioli et al., 2009). The justification for this separation is that there are parts of a technology, such as raw materials, which undergo no learning and may even increase in cost over time. Another whole-technology example is a carbon capture and storage (CCS) retrofit to an existing power station. The CCS part undergoes learning but the power station does not. The learning part begins as the most expensive part of the technology but after increases in cumulative capacity it experiences cost reductions.

Eventually learning is saturated and the non-learning part provides a lower-bound to cost reductions (Ferioli et al., 2009).

Other methods have been used to predict the future uptake of energy technologies. Two factor experience curves have been developed to better mimic the actual technological development process. These are useful when tracking the total cost, including research and development (R&D) that is required to bring a technology into the marketplace. One factor is called learning by searching (LSR) which represents the initial R&D process before there is much cumulative capacity. The second, learning by doing (LDR) represents expenditure on R&D when the technology is in the marketplace. The two factors are multiplied together to give the total investment cost for a technology so that the standard formula becomes a Cobbs-Douglas-type function (Miketa and Schrattenholzer, 2004, Kouvaritakis et al., 2000, Barreto and Kypreos, 2004).

Diffusion of the technology into the market as a function of time and/or space (i.e. between countries or firms) may be used as an alternative to the experience curve (Barreto and Kemp, 2008, Grübler et al., 1999, Kemp and Volpi, 2008). However, the predictive power of time diffusion of a technology vs. experience curves based on cumulative capacity is not as accurate (Alberth, 2008). Furthermore, experience curves can be directly employed in economic models to determine the likely diffusion rate, yielding more useful data than if the diffusion rate is constant.

2.2 EARLY STAGES OF TECHNOLOGICAL PROGRESS

Experience curves are useful when at least some commercial deployment of a technology has occurred. However, when technologies are at the pre-commercial stages and engineering estimates are the only cost indicators caution needs to be taken with formulating an experience curve. This is shown in Figure 1, where estimates of the expected cost of the technology when it is commercialised increases during the progression from research, through to development and demonstration as more is understood about the technology. The actual cost, which is known at deployment, only starts to decrease after the deployment of the first four commercial units (Kydes, 2009a). The average learning rate observed during the early stages is 20%, so one strategy would be to use a 20% learning rate in conjunction with an adjusted engineering cost estimate to take into account the expected rise in costs with deployment. Another strategy is to apply learning rates for similar technologies.

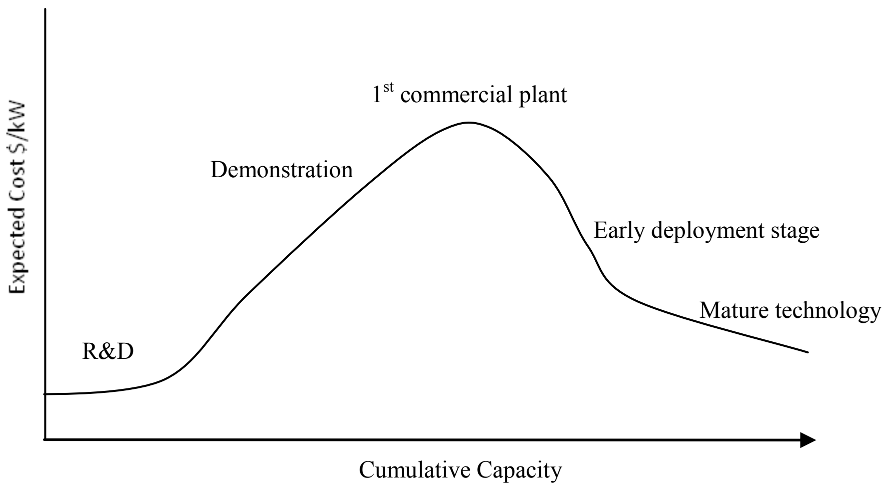

Figure 1 Technology progression with change in cost with increasing cumulative capacity

3 MODELS OF ELECTRICITY GENERATION

The international modelling community has been developing models and sharing methodologies to project the future technology mix for electricity generation for many years. This section gives an overview of some international models and Australian electricity models.

3.1 INTERNATIONAL MODELS

In order to accurately represent technological change in economic models it should be included endogenously. That is, as an outcome of the modelling process rather than a fixed input. This is particularly important for models of an international scope where it would be difficult to argue that the change in the costs of technologies is independent of the policies and activity levels in that market.

Various models have been developed over the past few decades to model international or regional electricity generation technology uptake. MARKAL-TIMES is an example of a model used by the International Energy Agency that includes endogenous technological change and has global coverage but can also model regions and nations (ETSAP, 2008).

The National Energy Modeling System (NEMS) is the U.S. Department of Energy's modelling suite that covers the whole of the U.S. energy system. It has endogenous technological change with three stages of learning (with different learning rates) used for each energy technology instead of one. The rate of learning slows as the technology matures. For example, for concentrating solar thermal electricity, the technology is considered to be revolutionary and the rate over the first three doublings of cumulative capacity is 20%, for the next 5 doublings the technology is considered to be intermediate and the rate is 10% and then for the rest of the cumulative capacity the technology is considered to be mature and the rate is 1%.

For technologies that have shared components (e.g. an advanced gas combined cycle turbine is used in integrated gasification combined cycle (IGCC) and advanced biomass) NEMS assumes there is a separate learning rate for this component and it accumulates capacity from each technology it is a part of. Consequently shared component technologies may learn at a faster rate than each whole technology. NEMS also includes an optimism factor to account for the underestimation of capital cost estimates for emerging technologies as discussed in Section 4.3 (Kydes, 2009a, Kydes, 2009b, Energy Information Administration, 2009a, Energy Information Administration, 2009b).

3.2 AUSTRALIAN ELECTRICITY MODELS

There are a small number of electricity market dispatch algorithm based models used in Australia which solve for the half hour electricity spot market. Given their focus on the short term these models generally use exogenous technology cost inputs and a wide variety of investment decision making models. There are three models which use a long term partial equilibrium investment modelling framework. One is a version of MARKAL with the capability to employ endogenous learning which is used by an Australian organisation called Intelligent Energy Systems. The Australian Bureau of Agricultural and Resource Economics (ABARE) uses a similar long term investment model called E4Cast which has a highly developed representation of energy end user segments and their own and cross price elasticities for different fuels and electricity.

CSIRO's Energy Sector Model (ESM) (Graham et al., 2008b) was developed in 2006 in collaboration with ABARE. It has been designed to have a very rich representation of centralised and decentralised electricity generation technologies as well as a detailed representation of road vehicles and fuels. It is a partial equilibrium model of the Australian electricity and transport sector.

Earlier versions of ESM included endogenous technological change in the electricity sector (Graham and Williams, 2003). However, this approach was abandoned when it became clear that a global modelling framework was necessary to capture offshore technological change and thus capital costs.

A global modelling framework could be a much more accurate approach for determining capital costs for several reasons. International estimates of learning rates may not be valid in a local setting. International rates are based on international cumulative capacity and, since Australia's cumulative capacity is much lower, Australia's incremental additions to global capacity would generate small changes in costs. Alternatively, estimating experience curves specifically for Australian cumulative capacity and costs would not be appropriate since most technological components are imported and are thus better explained by global developments. Applying international prices to changes in Australian cumulative capacity alone would lead to the erroneous conclusion that much faster learning is possible in Australia than internationally (Junginger et al., 2005).

Consequently, ESM is now configured to import exogenous cost data directly from GALLM, the design of which will now be discussed

4 GLOBAL AND LOCAL LEARNING MODEL – THE GALLM METHODOLOGY

Taking consideration of the models discussed in Section 3, an alternative methodology has been developed in the form of a global and local learning model (GALLM) which attempts to better mimic likely technological development in electricity generation technologies available to Australia. The experience curves, the four factors described in Section 2 that can affect the shape of experience curves and the mechanics behind the model will be described in the following subsections.

4.1 GALLM EXPERIENCE CURVES

In order to avoid the error of using global experience curves in a regional setting we have calculated experience curves for Australia when it can be determined that there is an Australian component to the technological learning and appropriate data is available.

4.1.1 WIND

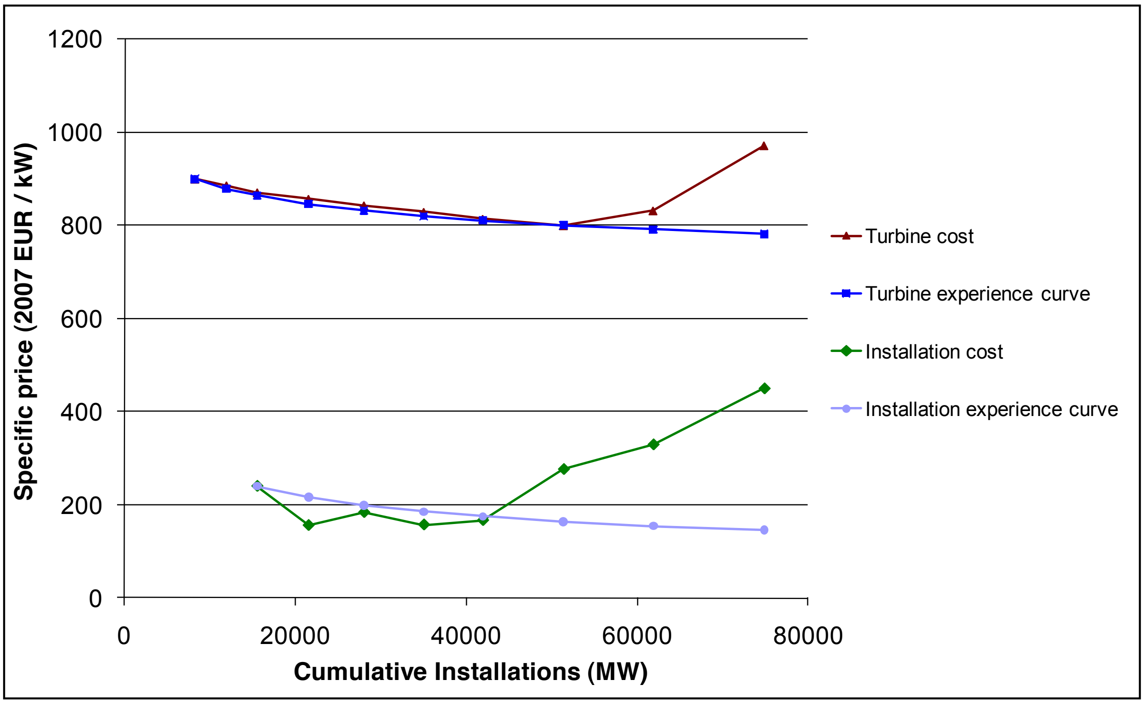

Figure 2: International turbine wind turbine data with the experience curve and international installation data with the experience curve. Each data point represents a year where the first data point for turbines is from 1998 and the first data point for installation is from 2000.

Wind energy has been split into two parts – turbines and installation including BOS costs. Turbines are developed and sold on an international market and the model reflects this with an international experience curve and learning rate for turbines based on IEA data (International Energy Agency, 2009). While in more recent years turbines have increasingly been installed in non-IEA countries, prices for those regions are difficult to obtain and may be significantly lower than in IEA countries because of the local manufacturing capability. These turbines are not as reliable as those sourced from IEA countries and have higher operation and maintenance costs and lower capacity factors (Cyranoski, 2009).

Wind installation happens locally, so experience curves have been devised for the three regions in the model. However, for the developing world, because of the lack of price data, the IEA data has been used but the prices are 8.5% cheaper. Half of all developing world wind capacity is assumed to have been installed in China so that their prices are 17% less. This implies that the rate of learning in China is relatively high reflecting knowledge transfer from the developed world. This has in fact been observed to be the case (Koenemann, 2008a, Koenemann, 2008b, Cyranoski, 2009).Figure 2 shows the international turbine and installation (developed world only) data and the corresponding experience curve fit to that data. The increase in price shown in both experience curves after 40000 MW of cumulative installations will be discussed in Section 4.2.

The Australian experience curve for wind installations is shown in Figure 3. Each point corresponds to one year, and the gap is due to the lack of capital cost data for 2004.

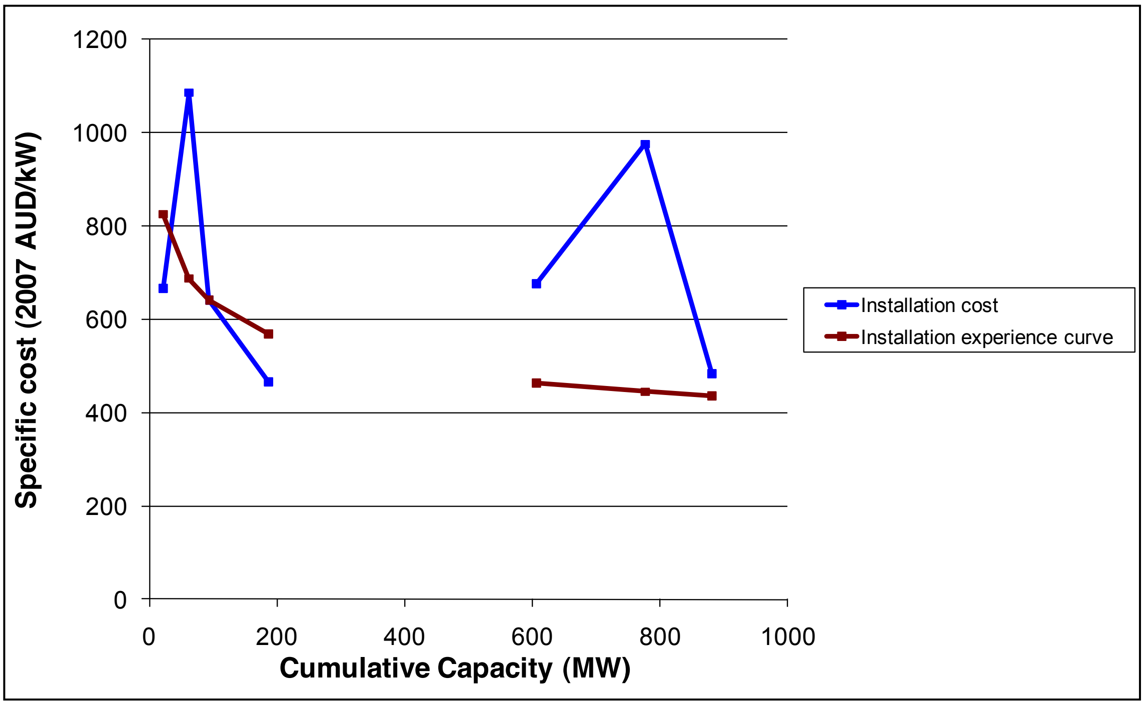

Figure 3: Australian wind installation data and experience curve.

4.1.2 CONCENTRATING SOLAR THERMAL

Concentrating solar thermal electricity is a technology where Australia has a plentiful resource for its application. There are various solar thermal technologies available in the market with and without the option of storage; so long as the storage increases the plant's output enough it can lead to an overall reduction in the costs of delivered electricity. There have been far fewer solar thermal installations globally than wind and more importantly for this model, very few in Australia on a viable commercial scale (more so as demonstrator projects). This has made it difficult to obtain accurate price estimates for a commercial plant. Consequently no experience curve has been developed for Australia. Moreover, since each technology subset has similar prices, only one experience curve has been developed for solar thermal for the world. The cost data along with the fitted experience curve is shown in Figure 4. Each point on the solar thermal cost line represents the average cost of solar thermal plants over one year, beginning in 1981 up to 2010. The 2010 data is for plants that have been commissioned in 2010 and are currently under construction and should be commissioned in 2010 (SolarPACES, 2009, Ritchie, 2009).

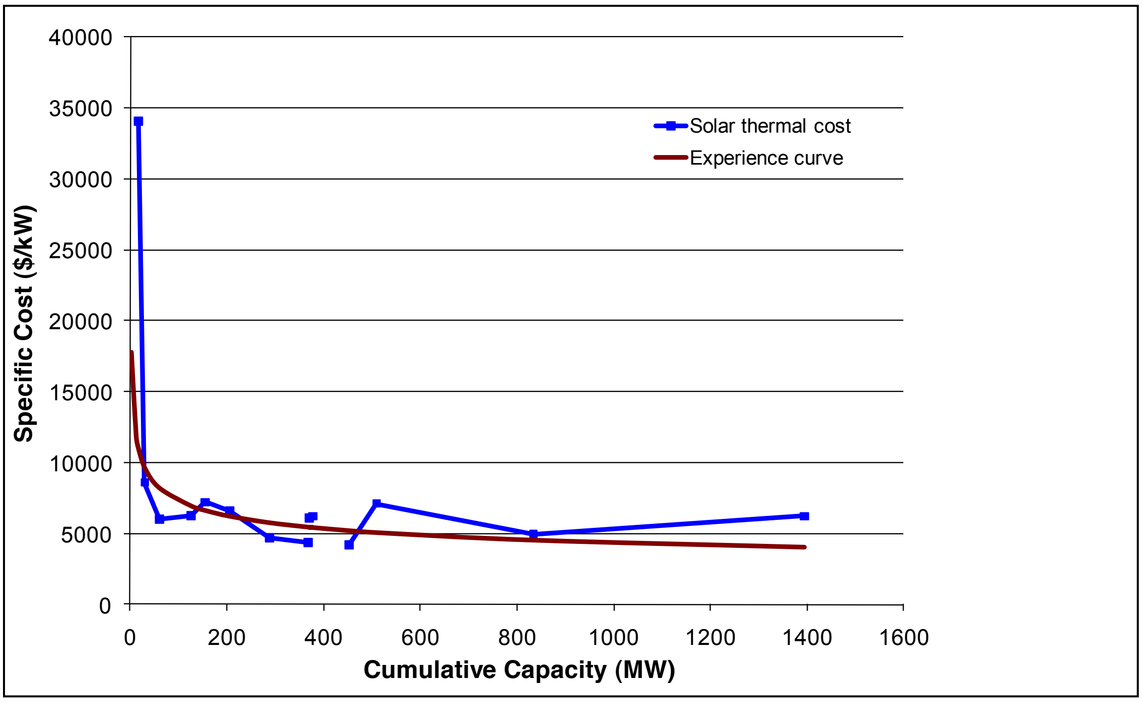

Figure 4: Global solar thermal data and experience curve.

4.1.3 WAVE AND OCEAN CURRENT/TIDAL ENERGY

Australia also has a good ocean resource, in particular for wave and ocean current energy. However, there have been very few local installations of either of these technologies even at the prototype scale. The study of technological change of this technology is also complicated by the many variations of plant design to harness wave and ocean current/tidal energy which varies the prices and performance capabilities considerably. As a result it was not possible to generate experience curves using available data.

Given the significant potential of wave and ocean energy in Australia we did not want to simply remove it from the study. Instead we decided to adopt the learning rate for another ocean-based technology, offshore wind, which has a learning rate of 9% (International Energy Agency, 2008b). With a very rough average price of $7000/kW at present and using the currently observable installed capacity, an experience curve was interpolated.

An experience curve for ocean current/tidal energy was constructed in a similar manner using observed data in relation to tidal projects already installed (given their similarity to the more speculative ocean current technologies).

4.1.4 PHOTOVOLTAICS

Photovoltaics is another technology that is represented in GALLM as being influenced by both global and local learning. The modules are represented by the global component as they are produced and sold internationally. The BOS are produced locally in Australia as the systems are installed locally and therefore the BOS features local learning. The inverters, while part of the BOS, can be sourced locally or globally and are given a fixed cost in the model. Because they also need to be replaced approximately every 12 years the cost of two inverters are paid for every PV system installed in the model.

Photovoltaics also had severe price increases from 2002-2003 up until 2007 (Mints, 2007), 2007) but then system prices fell by ~40% in 2008-2009 (International Energy Agency, 2010a). To avoid building a temporary scarcity premium into the cost curve, the price and capacity data needed to calculate the experience curves had to be older than 2002. Unfortunately, it was not possible to obtain reliable price data for rooftop and large scale installations for Australia older than 2002 simply because the majority of installations were off-grid. Indeed data from the IEA shows a constant price for systems in Australia implying that no learning had occurred during that period of time (Watt, 2008).

Given the recent high number of rooftop PV installations in Australia due to introduction of subsidies by state and commonwealth governments it seems unreasonable to expect the trend of no learning to continue (Photovoltaic Power Systems Programme, 2009). Therefore, as a compromise estimates of German and Netherlands learning rates were used for the BOS in conjunction with Australian cumulative capacities (Navigant Consulting, 2006). This approach is not ideal but is likely to give reasonable results. The estimates were taken before the large price increase (1995-2002) and the cumulative capacity in the proxy countries was similar to Australia's present capacity (~20 -120MW for Germany; Netherlands was ~1 – 10 MW). Furthermore we expect Australia to increase its installations as government financial support continues. The same approach was also used for developing countries since again most applications have been off-grid and no price data is available.

The experience curves for all components for rooftop and large scale PV were assumed to be the same. It was not possible to separate data for rooftop and large scale PV installation but the model assumes that rooftop PV does not have a transmission and distribution cost. As such it is modelled as a retail technology and only indirectly competes with the broader wholesale electricity technology set. Large scale PV systems generally have scale efficiencies such that their capital costs are approximately 1/3 cheaper or less than rooftop (Mints, 2007, Earthscan, 2006). This relationship is maintained as a constant throughout the projection period of the model.

4.1.5 GEOTHERMAL

GALLM features both conventional geothermal and hot fractured rocks. The reason for having both is that conventional geothermal energy has been used in countries with that resource for many years; it is a cheap, renewable source of energy. While not as low cost, hot fractured rocks are included because it is expected to undergo a surge of development in Australia due to the quality and quantity of resource available. It is also being developed in the United States but the US still has access to many conventional geothermal sites, whereas Australia does not.
The costs associated with developing any type of geothermal power plant can be broken into two components: the drilling cost and the balance of plant (BOP). The cost of drilling can be as much as 80% of the cost of the plant for hot fractured rocks and approximately 60% for conventional geothermal but the cost varies considerably for different conventional geothermal sites depending on how deep the resource is. Another major source of variation in drilling cost is the price of oil, because the drilling rigs are used for oil and gas wells as well as geothermal plants.

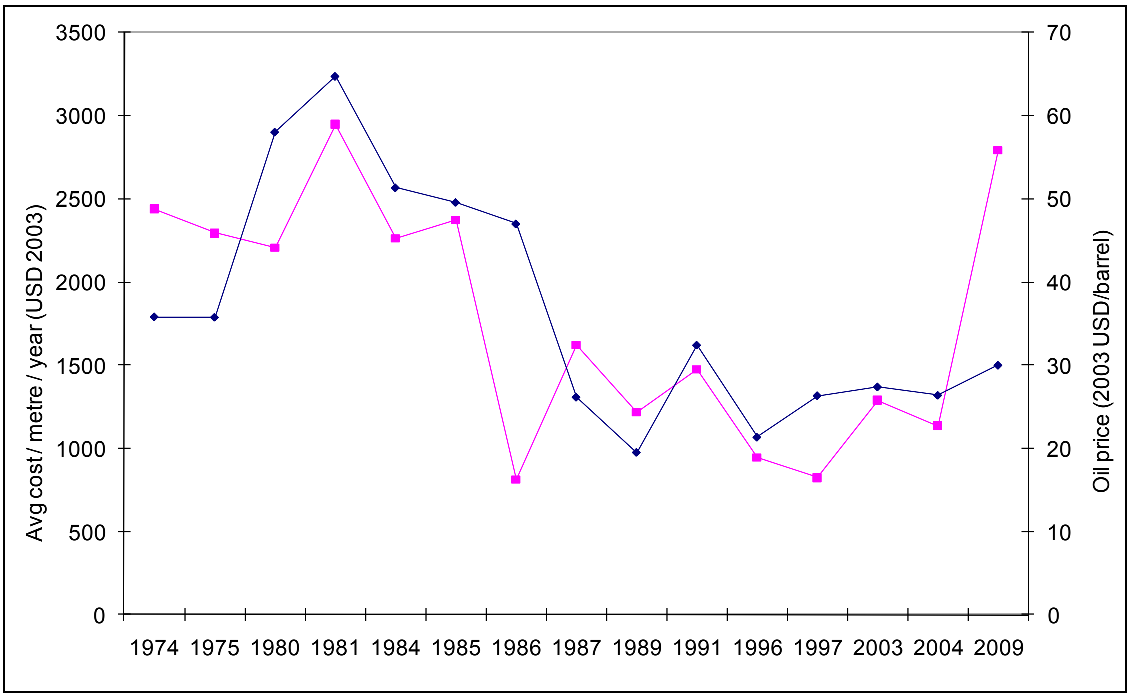

Figure 5: Geothermal well drill cost per metre and oil price over time. Note that data was not available for some years (Augustine et al., 2006).

When the price of oil is high, drilling rigs for geothermal wells are scarcer as they are used to (Bloomfield and Laney, 2005, Cosgrove and Young, 2009) drill for oil which pushes up the rig price. The correlation between cost of drilling for geothermal and the price of oil can be seen in Figure 5. The data for the drilling cost are based on wells deeper than 2Km as the cost per metre for drilling deeper wells is higher than for shallower wells (Chad et al., 2006).

Because of this high degree of correlation, the cost of drilling a well for both conventional geothermal and hot fractured rocks was based on the price of oil. To extrapolate the price of oil into the future, the reference case estimate from the US DOE Annual Energy Outlook 2009 was used. The price projection is from the present up until the year 2030 and from that point we assume the drilling cost will be constant. This is based on an assumption that demand for oil will decrease as alternative fuels are taken up in the transport sector.

To counterbalance the high drilling cost, a high degree of learning occurs when drilling at one site, especially when the same rig and crew are used (Williamson, 2010, Brett and Millheim, 1986, Pinto et al., 2004a), and when more than one well is required for any geothermal plant. Therefore, for subsequent wells drilled at any one site a learning rate has been applied to the cost of drilling. The learning rate is based on the cumulative number of wells per site, rather than cumulative capacity. The rate is quite high – 20% and this is based on general estimates from onshore oil drilling rigs (Brett and Millheim, 1986). We assume that for a conventional geothermal plant 15 wells are required to produce 50MW and the drill depth is 1500m. For a hot fractured rocks power plant 14 wells are required to produce 50MW and the drill depth is 4000m (Cosgrove and Young, 2009, Geodynamics, 2009, Di Pippo, 2008, Huddlestone-Holmes, 2010).

The BOP for both types of geothermal plants is essentially the same. Therefore, there is one global experience curve for geothermal BOP and the learning is shared between hot fractured rocks and conventional geothermal. The learning rate for the BOP is based on the US DOE estimate (Energy Information Administration, 2009a).

4.1.6 OTHER TECHNOLOGIES

Table 1: Assumed learning rates for each technology

Technology	Learning rate (%)
Brown/black coal pulverised fuel (pf)	**NA**
Brown/black coal IGCC	**2.0**
Brown/black coal with CCS	**5.0**
Gas peak	**NA**
Gas combined cycle	**2.0**
Gas combined cycle with CCS	**2.2**
Hydro	**NA**
Biomass	**5.0**
Solar thermal	**14.6**
Geothermal & Hot Fractured Rocks BOP	**8.0**
Nuclear	**3.0**
Wave	**9.0**
Ocean current	**9.0**
Wind (turbine)	**4.3**
Wind (installation)	**11.3 (Aus), 19.8 (Global)**
PV module	**20.0**
PV BOS	**17.0 (all regions locally)**

For the remaining technologies in the model the learning rates were taken from an earlier version of the Energy Sector Model (ESM) which are consistent with learning rates used in global models (Graham et al., 2008a). All of the learning rates used in GALLM are shown in Table 1. Mature technologies, specifically black and brown coal pulverised fuel (pf), hydro and gas peaking plant have no learning rate assigned to them. Instead, their costs are reduced by 0.5% every year to take into account small cost improvements associated with changing commodity prices, labour rates etc.

4.2 DEALING WITH MARKET FORCES

It can be seen from Figure 2 that the price of wind turbines and their installation increased from 2004-2005 up until the present time. With the wind industry expanding at up to 25% per annum in recent years wind power prices have moved in the opposite direction to what "learning by doing" would suggest.

The higher prices are the result of increasing input material prices, labour shortages and for the most part, profit-making by the wind industry, which was made possible by the extremely high demand for wind energy (Milborrow, 2008), i.e. market forces allowed prices to rise above cost plus normal profits.

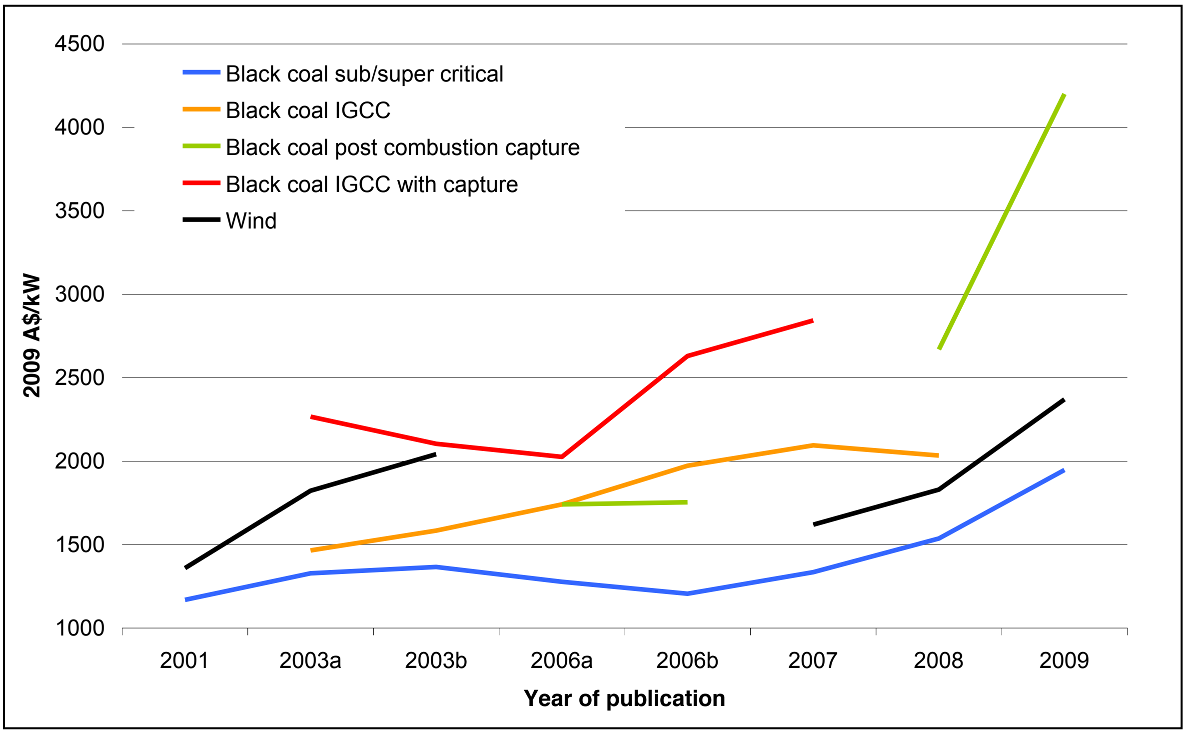

Figure 6: Change in CSIRO current price estimates (Graham and Williams, 2003, Graham et al., 2008b, Cottrell et al., 2003, Reedman et al., 2006a, Reedman et al., 2008, Reedman et al., 2006b, Graham and Williams, 2001, Dave et al., 2008, Graham et al., 2003)

Higher prices have been observed across the board for electricity generation technologies. For example, Figure 6 shows CSIRO cost estimates for various technologies over different years which show a general increasing trend. Note that the years on the x-axis are not consecutive. For emerging technologies such as post combustion capture the price increases may be because more accurate engineering bottom-up cost assessments are made as the technology is tested and demonstrated. However, for mature technologies such as sub/super critical black coal the prices are clearly increasing and this is due to the high demand in the electricity generation technology market.

If the current increase in costs is a permanent (i.e. not a temporary scarcity premium) then future changes in costs can simply be modelled by increasing the current capital cost and starting the adjusted learning curves from that point onwards. However, if it is not a cost but a price increase (which is the case for wind), then when more manufacturers come onto the market and supply can catch up with demand then the price can be expected to drop closer to the "real" cost level. As can be seen in Figure 7 if a temporary price increase is suspected, it is important to have a methodology for adjusting the price down. Otherwise the price of the technology may be over-estimated in the long term.

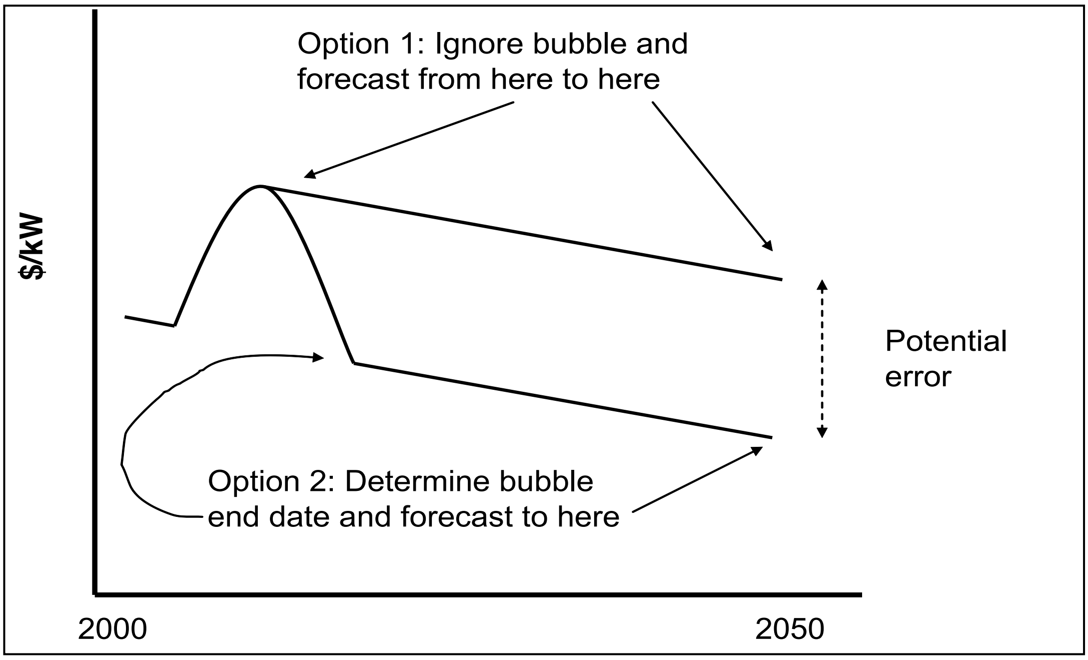

Figure 7: Options for addressing price bubbles.

In order to deal with these potential market forces within the model we have added what we have called a penalty constraint. The penalty constraint is based around the increase in wind turbine and installation costs observed in Figure 2 although price premiums have also potentially been a factor in coal and PV plants. For wind turbines the price increased by 24% and 48% in consecutive years. For wind installations the price increased by 113% and 249% in consecutive years. The model assumes that these price increases are a function of new builds of generation capacity in any year. The penalty constraint says that, if in any year the new builds of one technology exceed one third of new capacity required then a price premium based on the observed changes in wind power prices will be added onto the price of that technology; and if the new builds of one technology exceed one half of new capacity required than the penalty increases further. That is, the premium in the wind power market where the data is richest is assumed to be indicative of scarcity premiums that could also be charged to other power plants.

Because the penalty constraint is endogenous it can be invoked at any stage in the model. This model formulation provides a strong deterrent effect whereby the model will often prefer to find a future technology mix which does not rely too heavily on any single technology. However, if at various times the technology mix available points strongly toward a single technology, the model may still find it optimal to pay the penalty and build substantial amounts of one technology. This accurately reflects the investment case for wind power in Australia in recent years.

4.3 GOVERNMENT POLICY AND R&D SPENDING

Government policy and the selection of which technologies receive R&D spending can have a significant influence on technological development and choice. Results of changing government policy are described in Section 6.3. The main government policy included in GALLM is the Australian Carbon Pollution Reduction Scheme's (CPRS) which is a type of Emissions Trading Scheme (ETS) and is currently under review (Commonwealth of Australia, 2008). Four different carbon price scenarios have been extracted from the Treasury analysis which accompanied the development of the policy. Three of these carbon price trajectories have been included in the model as scenarios since two of them (CPRS-5 and Garnaut-10) are quite similar in terms of price and therefore the widely-used CPRS-5 has been adopted. The carbon prices begin in 2011 for Australia and the developed world and in 2025 for the developing world. The carbon price from 2025 onwards is the same in all regions i.e. it is a global carbon price.

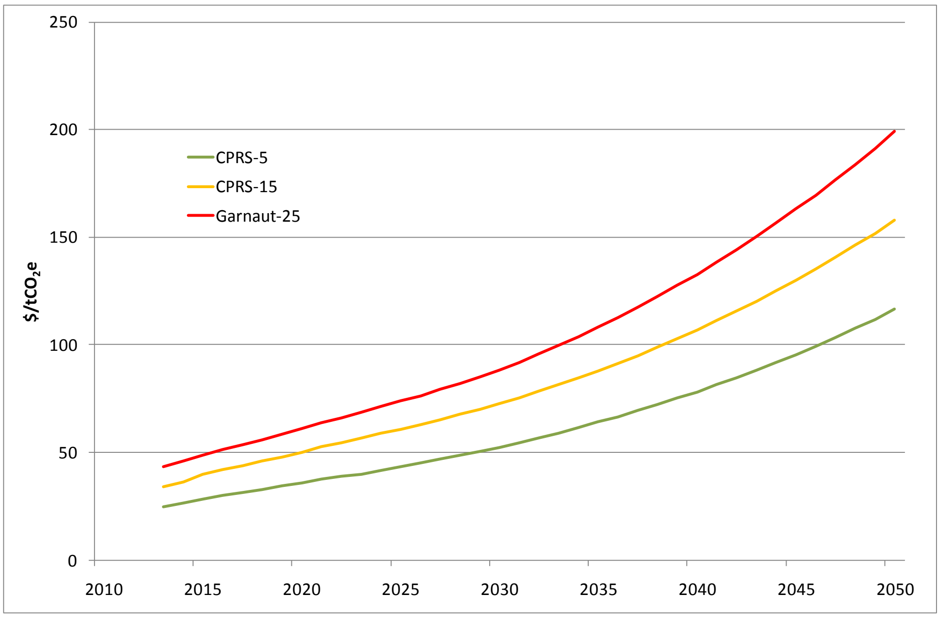

Figure 8: Carbon price trajectories under a proposed ETS.

The characteristics of each carbon price path are as follows:

- CPRS-5 should result in a 5 percent reduction in Australian emissions below 2000 levels by 2020. By 2100 the total concentration of CO2 in the atmosphere should be stabilised at 550ppm.

- CPRS-15 should result in a 15 percent reduction in Australian emissions below 2000 levels by 2020. By 2100 the total concentration of CO2 in the atmosphere should be stabilised at 510ppm.

- Garnaut-25 should result in a 25 percent reduction in Australian emissions below 2000 levels by 2020. By 2100 the total concentration of CO2 in the atmosphere should be stabilised at 450ppm.

Australia has also mandated that 20% of electricity generated in Australia by 2020 should be from renewable sources (Commonwealth of Australia, 2008). This has been implemented in GALLM but only for Australia's share of electricity generation.

The various global wind and photovoltaic incentive schemes have been included in the model for the regions where these policies are in place (Johns, 2008, World Wind Energy Association, 2009, Aubrey, 2008, Photovoltaic Power Systems Programme, 2009, European Photovoltaic Industry Association, 2009).

For technologies that are at the early demonstration and testing phases in the model, namely all CCS technologies, hot fractured rocks, wave and ocean current; some forced deployment at low rates is included to simulate the building of demonstration plants as funded by government and private R&D schemes up to a maximum year of 2030 for ocean current. This helps push these technologies down the learning curve so they become competitive with mature technologies. While this modelling approach tends to favour these technologies we also limit them at the same time by including an optimism factor. The optimism factor is a capital cost add-on which can be as high as 10% for the less well-developed technologies in these early stages to account for conceptual engineering cost assessments that tend to underestimate the final commercial cost (Kydes, 2009a).

4.4 GALLM MECHANICS

The objective function, which is the sum of all discounted costs to year 2006 in the system and basic constraints of GALLM were adapted from the ERIS model which was published by (Kypreos et al., 2000). The approach outlined in the ERIS model was to construct learning curves that are cut into eleven segments of various lengths forming a mixed-integer linear representation of the notionally non-linear learning curve. This approach largely avoids the problems of high computational resources and path dependency that are almost insurmountable in a non-linear framework (perhaps with the exception of using a Monte Carlo approach).

Using the key technological learning features of ERIS, GALLM was designed to have three regions: developed world, developing world and Australia. Each region has different initial generation capacities (International Energy Agency, 2008a), wind installation and photovoltaic BOS learning curves (Section 4.1), carbon price path starting dates (Section 4.3), different resources (Jacobson, 2009, Carnegie Wave Energy, 2010b, International Energy Agency, 2008b, Fridleifsson et al., 2008) and different electricity demand growth (International Energy Agency, 2008b). The developed world includes countries that have signed the Kyoto protocol; the developing world does not.

A low capital cost price floor has been placed on solar thermal (2050 $/kW), photovoltaic BOP (Australia - 1050 $/kW, developed world – 1180 $/kW and developing world - 1185 $/kW), wave energy (2400 $/kW) and ocean current/tidal energy (2200 $/kW) (International Energy Agency, 2010a). After this point the capital cost drops by 0.5% per year, which is the same rate as the mature set of technologies. The price floor was added to reflect the fact that there will always be a minimum cost of materials and labour into constructing the plants, no matter how much they improve.

New nuclear capacity has been constrained to builds that are already being constructed, have now been proposed and/or planned up to the year 2030, on the basis that the industry has demonstrated long planning cycles in the past. These are current generation reactors and the model does not include generation IV technologies (World Nuclear Association, 2010, European Nuclear Society, 2010). Because of this, constraints have been placed on the availability of high quality ore.

In addition to the financial penalty constraint discussed in Section Dealing with market forces we have also included in GALLM a constraint where the installed capacity of a technology can no more than double from one year to the next i.e. at most a 100% growth rate is allowed. This only takes effect after the first 100 MW of that technology is installed and it is most relevant in the early stages of infant technologies reflecting the delays in building up the skills to support these industries. This constraint complements the penalty constraint to prevent large new builds of a technology where previously there had been little deployment.

An intermittent constraint has been included which limits the total electricity produced by wind solar thermal, PV, wave and ocean current to only 30% of electricity supply. This has been added to take account of the fact that at present electricity grids can only handle a certain percentage of intermittent generation.

Other assumptions used in GALLM are described in Section 11.

5 THE LONG RUN MARGINAL COST

The long run marginal cost (LRMC) provides an estimate of the cost of electricity generation from a particular technology in $/MWh. Readers may also be familiar with the term – levelised cost of electricity (LCOE) and have different views about how they differ. The LRMC is used in this report interchangeably with the LCOE. The LRMC is defined as the sum of fixed and variable contributions to the cost of electricity from a technology. The fixed costs include capital cost and interest during construction, fixed operations and maintenance and transmission and distribution costs. The variable costs are fuel, variable operations and maintenance, CO_2 storage costs for CCS technologies and emissions permits for fossil-fuel based technologies. A description of the inputs to the LRMC is given in Appendix B – Components of the LRMC but the reader is also referred to (Graham et al., 2009) for more information

5.1 TOOL FOR ELECTRICITY COST COMPARISON (TECC)

The LRMC is calculated using the CSIRO TECC model which accepts input in the form of the components of the LRMC from GALLM and the output is the yearly LRMC for all of the technologies in GALLM up to the year 2050 (Graham et al., 2009). The model is implemented in Microsoft Excel for ease of distribution. The user is able to select various carbon prices and formats for viewing the projected LRMC.

5.2 BUILDING AN UNCERTAINTY RANGE

Given the uncertainty in future electricity generation technology costs, projections are best thought of as existing in a range. Rather than apply an arbitrary percentage uncertainty range TECC has been designed to build an uncertainty range by including projections of LRMC from other studies that have different capital cost projections. Currently, TECC has capital cost projections from CSIRO, EPRI and the US DOE. Note that the only source of variability in calculating the LRMC from these different studies is the capital cost – all of the other studies use the O&M costs, T&D costs etc from CSIRO or the average of all of the studies. By making capital cost the only source of variability we can understand how differences in capital cost affect the LRMC. These different studies provide “error bars” or upper and lower estimates on what we can expect the LRMC to look like in the future.

Each report included different technologies, particularly so for EPRI where there were more choices for fossil fuel technologies and much more technical detail was provided. In CSIRO’s GALLM and in the US DOE model, no detail was given about technology type; it is a generic black coal or brown coal fired pulverised fuel plant. To facilitate comparison in TECC, the best match has been made between the technologies from different reports.

5.2.1 EPRI PROJECTIONS

The data is published in: Electric Power Research Institute (EPRI) “Assessment of Low Emissions Technologies in Australia” (2010). The approach undertaken by EPRI is the US Technical Assessment Guide (TAG®) methodology. The methodology is described as an engineering-based understanding of the different components and aspects of a technology and how these can be improved over time.

At face value, the future capital costs projected by EPRI on the whole tend to be higher than other studies. However, underlying assumptions often differ between studies. EPRI include additional costs such as a 7.5% real project cost and various taxes. It may also be because this type of projection methodology does not account for the possibility that current technology prices may only be temporarily inflated due to high demand in the electricity generation technology market. Increases in economies of scale and competitors (supply exceeding demand) can drive prices down. Alternatively, as has been the case with wind and PV in particular in recent years, market forces can drive up the price as demand exceeds supply. It is not possible to model this effect with an engineering-based study of a technology in isolation.

Present day capital costs were developed by EPRI's subcontractor using a mixture of recent quotes, actual cost data and "in-house database and conceptual estimating models" (page 4-1). The costs for Australia 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's report. Thus, they may be projecting off the top of the price bubble. Whether this is appropriate or not depends on how the power plant and raw materials markets develop in the future.

This report had capital cost data for the years 2015 and 2030 only. When applied in GALLM and TECC, data for intervening years was interpolated between these points and for the years prior to 2015 it was held fixed at 2015 values.

The EPRI values have recently had some slight adjustments made, mainly to PV costs and were published by the Australian Energy Market Operator (AEMO) (AEMO, 2010). These capital costs have been used in a recent report published by the Australian Academy of Technological Sciences and Engineering (Burgess, 2010). Unfortunately, due to time restrictions it was not possible to include these adjusted capital costs in this body of work.

5.2.2 US DOE PROJECTIONS

The Energy Information Administration (EIA) data was published in: "Annual Energy Outlook 2009: with projections to 2030", US Department of Energy, Washington DC (2009).

The approach undertaken by the US DOE is to include experience curves in an energy market model. The US DOE has the National Energy Modeling System (NEMS) that models the whole of the US energy sector. NEMS includes detailed information on supply components such as oil and gas, coal and renewables, and it has four demand components. NEMS has been discussed in Section: 3.1.

Because of the methodology used by the US DOE and the large size of the US energy market, it is expected that projected capital costs of some technologies will tend to be lower than other studies.

The published capital cost projections were for the years 2008, 2015 and 2030. For intervening years the data was extrapolated and the trend from 2015 to 2030. Four different cost cases were presented for all technologies however only the reference case will be discussed here.

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6 ELECTRICITY GENERATION TECHNOLOGY MIX PROJECTIONS

By virtue of the methodology employed, the projection of electricity generation technology capital costs in GALLM also provides a projection of the global electricity technology mix. Also, by feeding the projected technology costs into CSIRO's ESM model an Australian electricity generation technology mix can be projected. ESM is a detailed model in terms of scale and complexity of the electricity and transport sector in Australia. Projections of electricity generation mixes and the cost of electricity supplied to different users under the same carbon price scenarios as used in GALLM are provided by the model out to the year 2050.

Given that we also have electricity generation technology costs projections available from the EPRI and US DOE studies, we also present projected Australian technology mixes under those assumed costs. This helps us to understand how the uncertainty in the costs projections effects the electricity generation technology mix projections.

6.1 GLOBAL RESULTS

The results section will firstly present a global overview of electricity generation out to the year 2050 with the resultant technology mix under the four different carbon price scenarios. A comparison will then be made between the GALLM-based LRMC and those calculated using other report's capital costs – namely, EPRI and the US DOE. The other components of the LRMC such as fuel price etc are taken from CSIRO costs. Therefore, the only difference in LRMC is due to the capital cost. This will allow us to examine the effect variations in the capital cost have on the LRMC.

6.1.1 GLOBAL ELECTRICITY GENERATION

Global electricity generation refers to a summation of results for electricity generation for the developed and developing world. Note that the LRMCs in this section were calculated using only GALLM data, not average data.

6.1.1.1 CPRS-5

Under CPRS-5 as can be seen in Figure 9 generation by black coal pulverised fuel (pf) power stations is projected to hold onto its share until the year 2026 when the carbon price and plant age (45 AUD/tCO_2) forces a retirement of these plants and the emergence of black coal combined cycle followed by black coal with CCS plants in the year 2030. Nuclear, solar thermal, rooftop and large scale PV and biomass increase their generation at this time. Wind makes up a fairly constant part of the mix. Wave energy contributes in the middle years of the model run but by the year 2050 has been replaced by cheaper renewables such as large scale PV. The assumed high gas price results in little gas generation throughout the model projection period except for gas combined cycle.

The penalty constraint is paid for wind energy up until the year 2025 and after that point solar thermal, PV and nuclear are more rapidly deployed, probably to avoid further payment of the penalty for wind. The penalty is also paid for black coal pf and PV. It is paid for PV in 2018, then from 2027-2028, from 2037-2041 and finally from 2047 to 2048 and for black coal pf in the early years of the model. Therefore, it would appear that once the carbon price is introduced into the developing world in 2025 the financial impetus is sufficient to switch from black coal fired generation to renewable forms of energy quite rapidly. This partly reflects the expectations effect. In the model and in the real life scenario the developing world will have foreknowledge of the impending carbon price introduction and will have prepared to adopt new technology at or before the planned introduction.

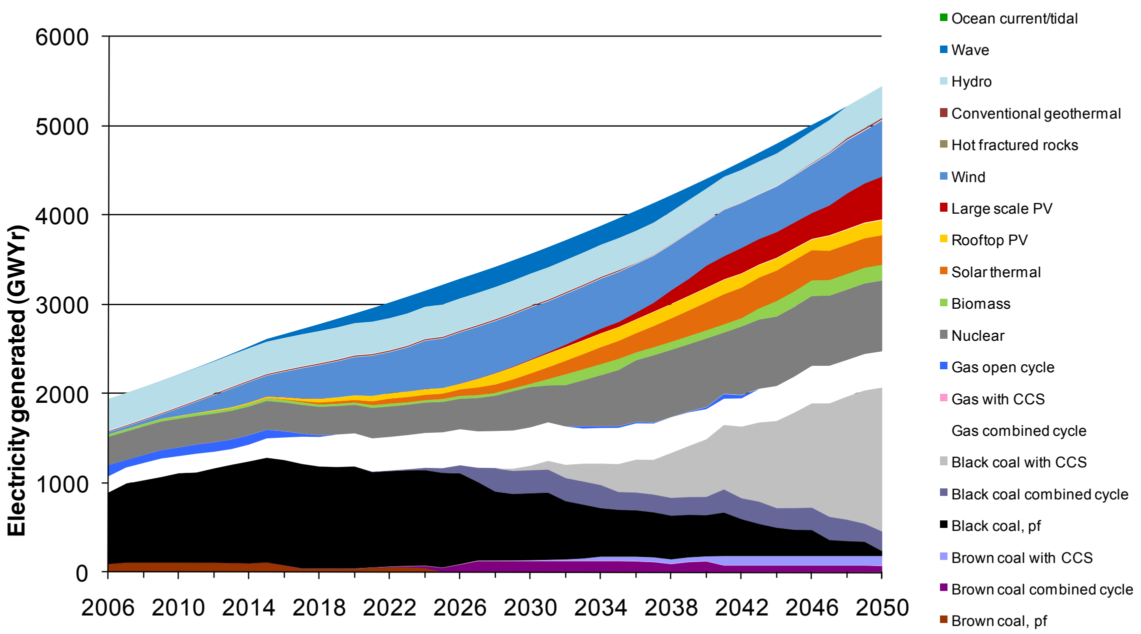

Figure 9: Global electricity generation under the CPRS-5 carbon price scenario.

For comparison the projected LRMC in Australia in the years 2015, 2030 and 2050 for key technologies is shown in Table 2 below. The assumed high learning rate coupled with sufficient deployment pushes the cost of electricity from both types of PV down from the high price in 2015 to be almost equivalent to wind generation by 2050. Solar thermal sees a large drop in LRMC to 2030 but this slows down to 2050. Wave energy has fewer cost reductions as limits are placed on the total wave energy resource but because of it has a high average power per capital cost compared to other intermittent renewable forms of generations its LRMC is fairly low. Nuclear becomes slightly cheaper over time, whereas black coal pf is slightly increasing in cost because of the carbon price. Black coal CCS, while expensive compared to most of the renewables, is required along with nuclear as baseload generation as the carbon price increases. Even though the LRMC of nuclear is low it cannot supply all of the baseload generation as there are limitations placed on the availability of uranium and the construction rate of nuclear plants in GALLM.

Table 2: LRMC ($/MWh 2009) inclusive of carbon price for selected technologies in the years 2015 and 2030 under CPRS-5

	Wind	Solar thermal	Rooftop PV	Large scale PV	Wave	Black coal pf	Black coal with CCS	Nuclear
2015	**87**	**157**	**184**	**180**	**105**	**71**	**121**	**76**
2030	**69**	**108**	**91**	**92**	**103**	**85**	**96**	**74**
2050	**65**	**102**	**65**	**67**	**102**	**141**	**91**	**72**

6.1.1.2 CPRS-15

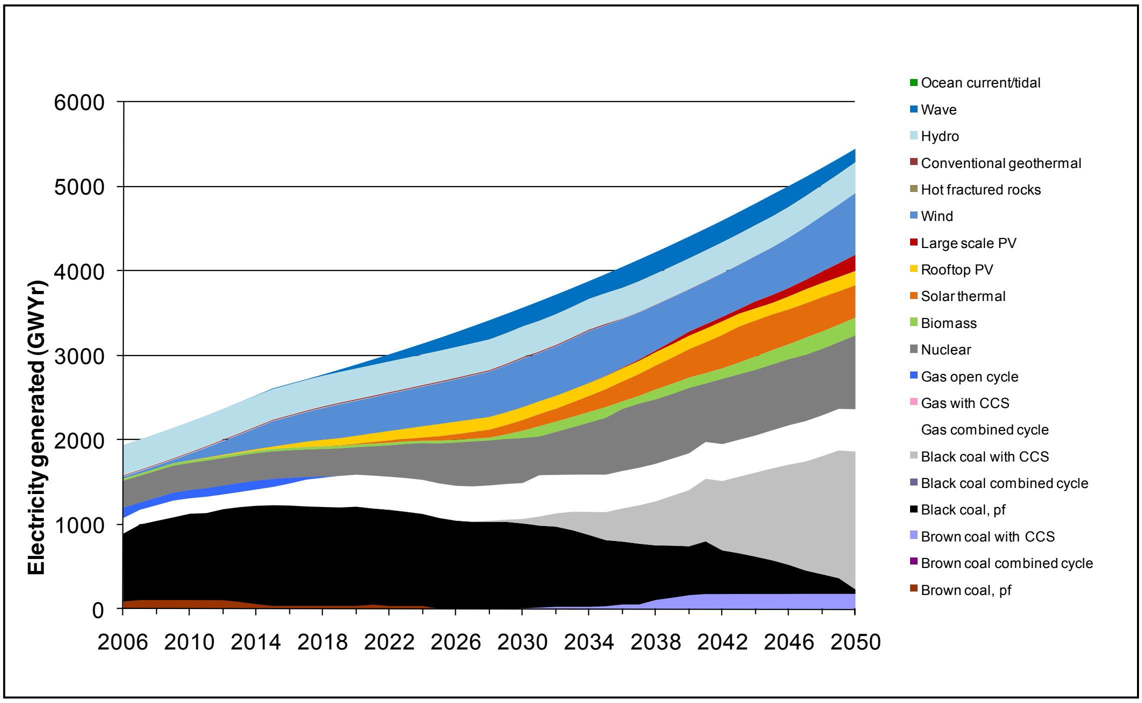

Figure 10: Global electricity generation under the CPRS-15 carbon price scenario.

The GALLM results under the CPRS-15 carbon price scenario are shown in Figure 10. As with CPRS-5, black coal pf is projected to dominate the generation mix before the introduction of a global carbon price in 2025. However, from 2026 nuclear replaces a portion of black coal pf before the introduction of black coal with CCS in 2030 rather than the gradual switch to black coal combined cycle followed by black coal with CCS that was observed under CPRS-5.

Of the intermittent generators, wind again makes up the largest share and it has an even greater cumulative capacity under this scenario than CPRS-5. The reason for that is under a higher carbon price more generation from low-cost and low-emission technologies are required. There is more solar thermal and wave energy under CPRS-15 than CPRS-5, however before 2025 there is more solar thermal and wave energy under CPRS-5 then CPRS-15. Deployment of renewables is more gradual under the lower than the higher carbon price. This has been done as there is not as urgent a need for low emission technologies and it avoids paying any price premiums. Under the higher carbon price, more nuclear power plants are constructed before 2025 as there is a greater need for low cost and low emission baseload under this scenario and this strategy ensures these plants are operational throughout the lifetime of the model run. Renewables such as wave and and solar thermal are built more strongly after 2025, and by 2040 the installed capacity of wave energy is greater under CPRS-15 than CPRS-5.

There is less PV under CPRS-15 than CPRS-5; after 2025 the installed capacity of PV under CPRS-5 is double that of CPRS-15. Thus, because nuclear power plants have not been constructed, PV becomes locked-in as the technology of choice under CPRS-5 whereas there are more options such as wave, nuclear and solar thermal under CPRS-15. Wave energy has fewer opportunities for cost reductions than PV but it has a lower initial (2006) cost and remains a relatively-inexpensive technology throughout most of the model run. With a higher carbon price by 2025 low cost low emission options are essential and wave energy is more suitable in that regard than PV.

The penalty constraint is paid for wind up until the year 2019, black coal pf up to 2015 and for PV from 2015 to 2018. Fewer penalties are paid under CPRS-15 than CPRS-5. This means that the higher carbon price, in combination with the penalty, is resulting in a balanced mix of zero emission technologies. Because of the feed in tariffs (FIT), it is economic to construct more PV and wind early and pay the premium than miss out on the FIT.

Table 3: LRMC ($/MWh) inclusive of carbon price for key technologies in the years 2015 and 2030 under the CPRS-15 carbon price scenario.

	Wind	Solar thermal	Rooftop PV	Large scale PV	Wave	Black coal pf	Black coal with CCS	Nuclear
2015	**144**	**213**	**192**	**188**	**107**	**81**	**122**	**76**
2030	**78**	**110**	**111**	**112**	**103**	**103**	**97**	**74**
2050	**66**	**102**	**80**	**81**	**101**	**178**	**95**	**71**

The projected LRMC in Australia for key technologies are shown in Table 3 in the years 2015, 2030 and 2050. Because of the slower construction of the majority of renewables under this scenario compared to CPRS-5 they have a greater LRMC in 2015 and 2030. In addition, the LRMC is significantly higher for wind in 2015 because of the addition of the penalty premium. The technologies have a LRMC in 2030 that is fairly consistent with CPRS-5 results when consideration is given to the higher carbon price added onto the LRMC for black coal pf. By 2050 nuclear and wave are marginally lower cost under CPRS-15, solar thermal has the same cost and PV is more expensive. This reflects the electricity generation profile for CPRS-15.

6.1.1.3 Garnaut-25

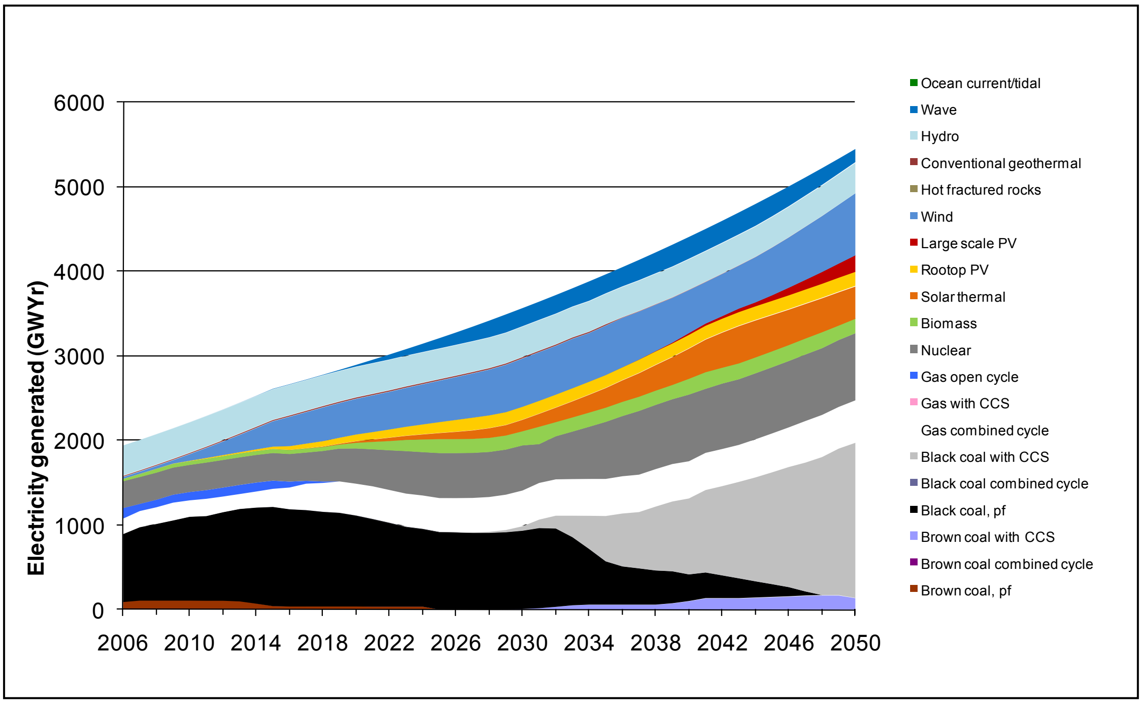

Figure 11: Global electricity generation under the Garnaut-25 carbon price scenario.

Black coal pf starts to retire quite rapidly from the year 2032 when the global carbon price reaches 96 AUD/tCO_2 and is replaced by black coal with CCS. There is slightly more nuclear generation under this scenario than CPRS-15 in the early stages of the model run before the contribution of large quantities of black coal with CCS; by 2025 there is 531 GWYr of nuclear generation compared to 475 GWYr under CPRS-15. Rooftop PV dominates the solar portion of generation before the year 2032 and beyond that point solar thermal increases its share. However, by 2050 the total PV and solar thermal contributions are approximately equal. As in the other scenarios wind makes up the largest share of renewable generation. Wave energy reaches its maximum installed capacity of 500 GW in the year 2039 and this falls to 300 GW by 2050. There is also more generation using biomass under this scenario to replace the loss of black coal pf.

The penalty constraint is paid for wind continuously up until the year 2018, for biomass from 2031 to 2041, for black coal pf up to 2015and for PV from 2015 to 2018 only. As with CPRS-15, fewer penalties are paid under Garnaut-25 than CPRS-5. This means that the higher carbon price, in combination with the penalty, results in a balanced mix of zero emission technologies. Because of the feed in tariffs (FIT), it is economic to construct more PV and wind early and pay the premium than miss out on the FIT.

The LRMC in Australia for selected generation is shown in Table 4 below.

Table 4: LRMC ($/MWh) inclusive of carbon prices under Garnaut-25 for selected technologies in the years 2015 and 2030.

	Wind	Solar thermal	Rooftop PV	Large scale PV	Wave	Black coal pf	Black coal with CCS	Nuclear
2015	**141**	**196**	**196**	**192**	**109**	**89**	**124**	**76**
2030	**73**	**111**	**113**	**114**	**103**	**117**	**99**	**74**
2050	**66**	**101**	**79**	**81**	**101**	**215**	**99**	**72**

The projected LRMCs reflect the electricity generation profile under Garnaut-25. In 2015 wave is certainly the cheapest renewable option but there is little installed capacity as it is an emerging technology and thus it cannot make a great contribution to global electricity generation. Wind is the next lowest-cost renewable and as it is an established technology it can ramp up wind turbine production and meet growing demand. However by 2030, while wind is still cheaper, rooftop PV and solar thermal have similar costs and are less expensive than black coal pf. Black coal with CCS is more expensive than the majority of the renewables but it is required for baseload generation.

6.1.1.4 Conclusions from global electricity generation results

The choice of carbon price has an effect on technology uptake, where the greatest difference is seen between the lowest carbon price, CPRS-5 and the two higher carbon prices, CPRS-15 and Garnaut-25. The differences are more subtle between CPRS-15 and Garnaut-25 and are around the baseload rather than intermittent renewable technologies. The lowest carbon price actually resulted in the greatest amount of technological diversity, since both black and brown coal combined cycle were developed. However, all carbon prices have the same diversity in terms of zero emission technologies. These were used as an interim, low-cost solution before the construction of large amounts of CCS power plants and to avoid further nuclear power plant construction and an expansion of the uranium supply curve. Black and brown coal combined cycle plants have a higher efficiency than the other coal technologies and under a lower carbon price there is less of an incentive to reduce emissions and the move to CCS plants can be made later. However, under the higher carbon prices the construction of more nuclear plants was used as a solution to reduce emissions quickly and for a long period of time. Expanding the uranium supply curve into more expensive mines was still a lower cost option than rapid expansion of renewables or combined cycle power plants.

The lowest carbon price also resulted in the earlier expansion of wave and solar thermal compared to the higher carbon prices. This was also to avoid construction of nuclear power plants and to avoid paying a high premium for overly high demand of one technology, such as wind. However, from ~2030 onwards the effect of higher carbon prices resulted in a greater installed capacity of wave and solar thermal than under CPRS-5. CPRS-5 saw a lock-in effect of large scale PV after 2030. PV is particularly susceptible to lock-in as the modules have the highest learning rate of any technology and can thus achieve cost reductions quickly. And, coupled with fewer nuclear installations, cost-effective low emissions technologies are required.

The contribution of Rooftop PV to global electricity generation was not affected by carbon price. This exists in a different market as it does not have any transmission and distribution charges. Rooftop PV has been installed widely and will probably continue to do so around the world. The incentive for doing so is on a personal level and is promoted by government schemes. It was not possible to include personal incentives in the model and all government schemes given that the model has not been developed to that level of granularity.

It would seem that low carbon prices may result in lock-in of a technology when the carbon price reaches a certain high level, as was the case for large scale PV. Higher initial carbon prices avoid this problem by ensuring there is a big enough market for zero emission technologies creating the incentive to develop a wide range of technologies at a slower pace.

Some technologies were not developed to any great extent under any of these three carbon price scenarios. They were conventional geothermal, hot fractured rocks, gas with CCS and ocean current. Ocean current, because it is an intermittent source of generation, has to compete with wind, PV, solar thermal and wave energy. It was less costly in the model to develop these technologies rather than ocean current. Ocean current is costly to begin with and coupled with a low learning rate, low resource availability and small initial capacity means that it was not worth the financial investment for a low level of electrical output. Gas with CCS is a higher cost technology with few initial installations. The O&M cost is high as is the price of gas in later stages of the model and thus the cost of electricity is too expensive in the model for this technology.

Hot fractured rocks and conventional geothermal share learning for the BOS but the assumed drilling cost is high and the global resource potential is perhaps not great enough that the cost reductions gained from constructing either plant type are sufficient to overcome the high drilling cost hurdle. Perhaps if the model were run to 2100 or beyond conventional geothermal and hot fractured rocks plants may be built. If other low cost drilling technologies could be found then these technologies could contribute to the global generation mix.

6.1.2 LRMC COMPARISONS

The LRMC calculated from CSIRO's GALLM model and two other studies ((Energy Information Administration, 2009a, EPRI Palo Alto CA and Commonwealth of Australia, 2009), which will be referred to as US DOE (2009) and EPRI (2010) respectively) using the methodology described in TECC and the same costs for the assumptions (except for capital costs) are shown below under CPRS-5. Results under only one carbon price are shown since there was no change in the EPRI and US DOE capital costs under the different carbon prices. A comparison of CSIRO's LRMCs for various technologies from 2015 up to 2050 is also provided at the end of this section, to show the effect carbon price has on the LRMC.

6.1.2.1 CPRS-5

The LRMC in 2030 is shown in Figure 12 below.

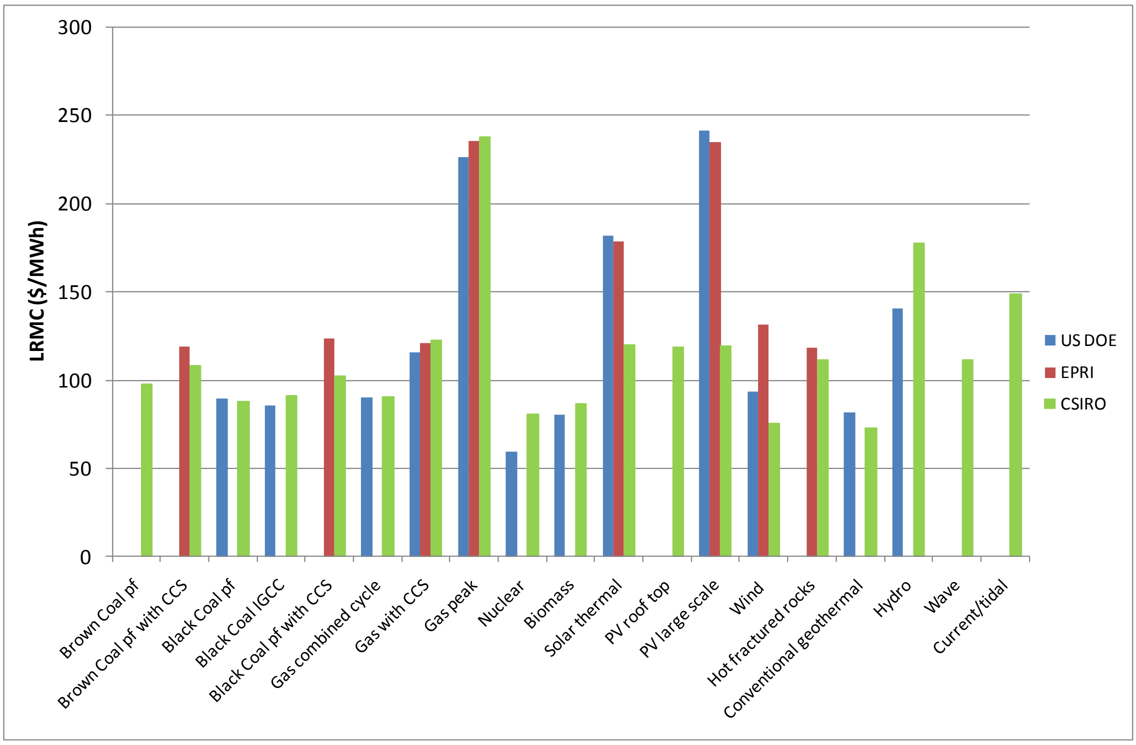

Figure 12: CPRS-5 LRMC in 2030 calculated using capital costs from the US DOE, EPRI and GALLM (CSIRO).

In general there is little difference in LRMC between the different studies. However, some differences are apparent for large scale PV, solar thermal and wind. There are also differences between the US DOE and CSIRO for hydro and nuclear. The simplest explanation for this is that the capital costs in the US are generally lower than in Australia and these results tend to reflect that.

In order to more closely examine the technologies where differences have occurred the LRMC breakdown is shown in Figure 13. Capital forms overwhelmingly the largest portion of LRMC, which is to be expected given that renewables have no fuel or permit costs. We know already that the observed differences in LRMC are due to differences in capital cost (since capital is the only unique component), however, because of the large capital share in LRMC it means that differences in capital will have large effects on LRMC.

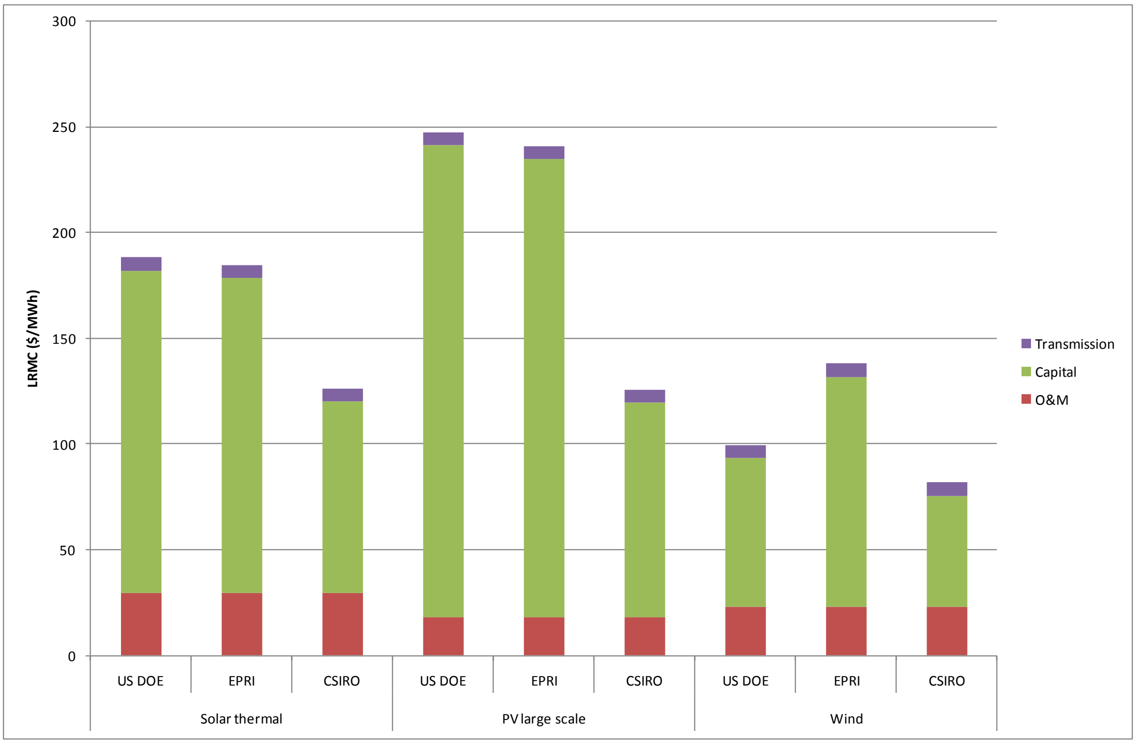

Figure 13: LRMC breakdowns in 2030 under CPRS-5 carbon price scenario for solar thermal, PV large scale and wind using capital costs from the above mentioned studies.

The actual capital costs from each study for these technologies are shown in Table 5 below.

Table 5: Capital costs for solar thermal, large scale PV and wind from US DOE (2009), EPRI (2010) and GALLM (CSIRO) in 2030 in $/kW.

	US DOE	EPRI	CSIRO
Solar thermal	**4314**	**3690**	**2264**
Large scale PV	**5352**	**4544**	**2153**
Wind	**2261**	**3052**	**1497**

From this table and comparing with Figure 13 it can be seen that the differences in LRMC follow those of capital cost.

The capital cost projected by US DOE (2009) and EPRI (2010) for solar thermal is ~35% greater than that of GALLM. The large scale PV projected capital cost is also higher for US DOE and EPRI than GALLM. These differences are due to the methodology behind the capital cost projections. Both GALLM and the US DOE's NEMS model use experience curves, however, shown here are the US DOE's results under a zero carbon price case and ours are under a carbon price which would be expected to lead to more deployment and learning. Wind is slightly different because, even though US DOE (2009) is lower in cost than EPRI (2010), it is closer to the GALLM result than EPRI (2010)'s capital cost perhaps reflecting that wind power development is proceeding globally with or without a carbon price due to various alternative government policy support mechanisms.

In Figure 14 the LRMC for black coal pf, black coal with CCS, combined cycle gas turbine, wind, solar thermal and rooftop PV are shown in the years 2015, 2030 and 2050 to see the effect carbon price and technological change has on the LRMC over time. Black coal pf has a large increase in the permit part of its LRMC over time as the carbon price increases it needs to pay more for its emissions. In contrast to this, black coal with CCS actually decreases in LRMC over time as it benefits from technological learning and so its capital cost decreases. Its permit costs increase as it still emits CO_2, however this is much smaller compared with the reduction in capital. The storage cost decreases slightly over time as the efficiency of the plant improves. Combined cycle gas turbines increase in LRMC over time as the permit costs increase as with black coal pf and because its capital component is so low the permit costs dominate. All of the renewable have similar profiles, where capital is the dominant component. As the capital cost decreases over time because of technological learning the LRMC decreases. Large scale PV sees the greatest cost reductions as it has a higher learning rate and PV makes a significant contribution to global electricity generation. Wind actually makes a greater contribution but because it is starting from a more mature base it needs to build more capacity to see further cost reductions.

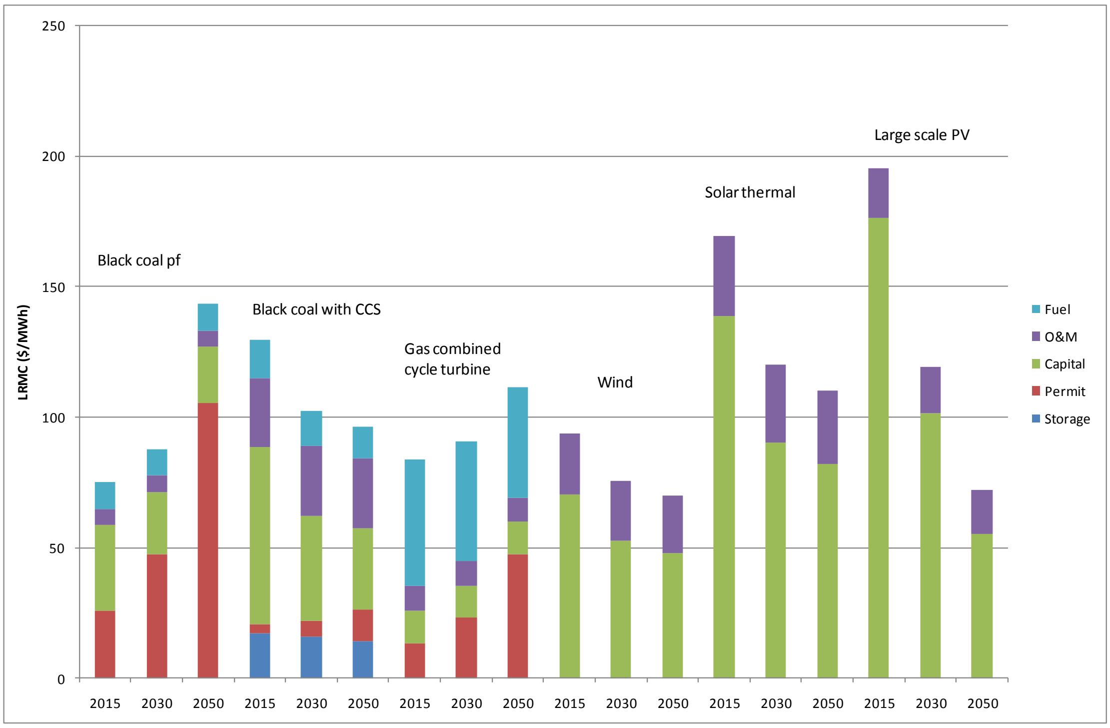

Figure 14: LRMC breakdowns in 2015, 2030 and 2050 for various technologies under CPRS-5 carbon price scenario using CSIRO capital costs.

6.1.2.2 Carbon price comparison

To show the effect carbon price has on the LRMC, LRMC breakdowns for various technologies in the year 2030 and 2050 by carbon price are shown in Figure 15 and Figure 16 respectively. The actual price of carbon under each carbon price trajectory and by year is shown in Table 6.

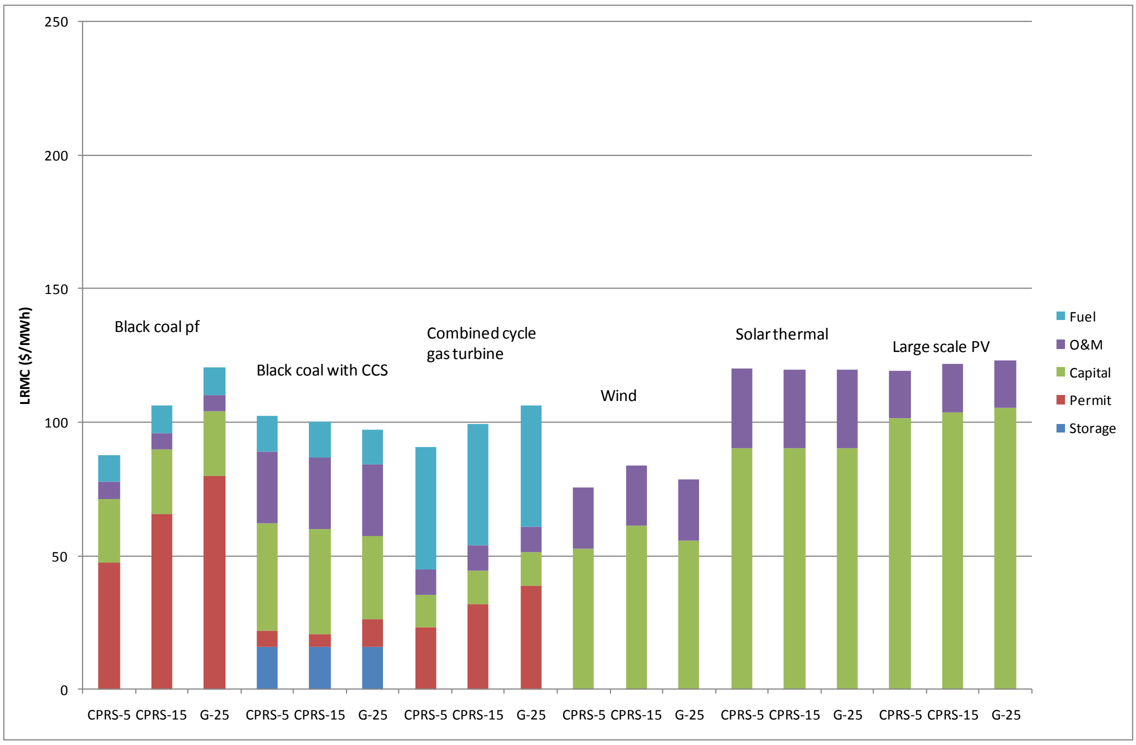

Figure 15: LRMC breakdowns in the year 2030 for various technologies under CPRS-5, CPRS-15 and Garnaut-25 carbon price scenarios using CSIRO capital costs.

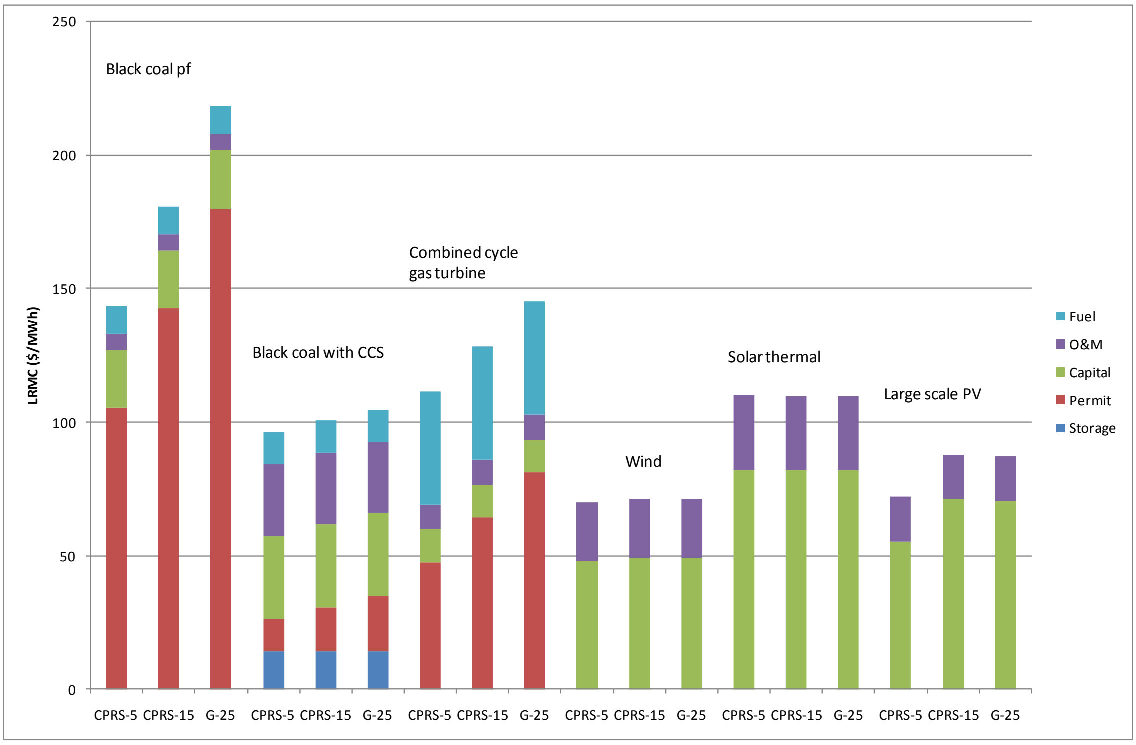

Figure 16: LRMC breakdowns in the year 2050 for various technologies under CPRS-5, CPRS-15 and Garnaut-25 carbon price scenarios using CSIRO capital costs.

The effect carbon price is having in 2030 and 2050 is on the permit price. Higher carbon prices mean that more must be paid to emit, which is particularly the case for black coal pf and combined cycle gas turbines. Black coal with CCS shows a decreasing LRMC with carbon price in 2030 since the higher carbon prices are driving the construction of more black coal with CCS plants which is bringing the cost down due to technological learning. However, by 2050 learning effects have been saturated and thus the capital component of the LRMC is invariant to carbon price so the LRMC actually increases with carbon price because of the higher permit cost.

The renewables are largely invariant to differences in the carbon price, since they are all developed under every carbon price. In 2030 wind is slightly more expensive under CPRS-15 since the price premium is paid in that year as there was a high demand for wind. In 2050 Large scale PV is less expensive under CPRS-5 since more PV was constructed in place of wave, nuclear and other renewables.

Table 6:Carbon prices in $/tonne CO_2-e for the years 2030 and 2050 under different emissions reductions trajectories.

	CPRS-5	CPRS-15	Garnaut-25
2030	52	73	88
2050	117	158	199

6.1.2.3 Conclusions on LRMC

In general across the various studies and within carbon prices there is not a lot of variation in LRMCs. Between studies most variation occurs for renewables where the fact that the capital cost makes up the largest share of LRMC means that any differences in capital cost will have a large effect on the LRMC. Solar thermal, PV and wind consistently were responsible for the greatest variation, where CSIRO tends to be lower than the other studies. This is a result of the method used in GALLM, where the carbon price pushes these more developed low emission technologies which have a higher learning rate and good natural resources down the experience curve.

Under the lowest carbon price scenario, non-CCS coal technologies are cheaper than CCS technologies in 2030, but then this is reversed by 2050. The renewables decrease in cost over time from 2015 to 2050. The LRMC of renewables is not affected by carbon price, however the cost of technologies that need to pay permits are strongly affected by carbon price.

6.2 AUSTRALIAN RESULTS

Australia’s projected electricity mixes up to the year 2050 are presented in the following sections. The projections have been generated under different carbon price scenarios and separately using the capital costs projected by GALLM, EPRI (2010) and the US DOE (2009). The purpose of these latter scenarios was to discern what impact the different cost projections have on the technology mix.

It is important to note that not every study published capital costs for every technology that is featured in ESM, our Australia energy sector projection model. There were at least two strategies we could have used to deal with this. One is to exclude the missing technology from the model and the second approach is to use other studies’ capital costs. We have used the second approach, where missing capital costs were replaced with CSIRO’s projected capital costs from GALLM with a 0.5% annual cost reduction rather than technology learning. Table 7 shows which capital costs were published by which study.

EPRI (2010) did not publish 2030 capital costs for brown and black coal pf, black coal IGCC, nuclear and CCGT. However, as these can be considered to be more mature technologies, the capital costs were kept constant up to the year 2030. Only results under the lowest carbon price scenario, CPRS-5, will be shown for the study comparison. This is because we are unsure in several studies what carbon price scenarios were assumed if any when their capital costs were generated. Therefore the lower carbon price scenario is the safest assumption.

In addition, ESM does not include large scale PV systems at the moment. Therefore, we have modelled "solar" as solar thermal and large scale PV.

Table 7: Technologies examined in each study and used in GALLM.

EPRI	DOE	CSIRO
PC, Brown coal, no NOx/SO2 controls, AC	-	Brown coal pf
-	-	Brown coal IGCC
PC, Brown coal, with CCS (90%) & NOx/SO_2 controls as reqd, AC	-	Brown coal, with CCS (90%)
PC, Black coal, no NOx/SO_2 controls, AC	Scrubbed coal new	Black coal pf
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	-	Black coal, with CCS (90%)
CTCC, Without CCS, AC	Conventional gas/oil combined cycle	CCGT
Advanced CTCC (with CCS), AC	Advanced CC with carbon sequestration	CCGT (with CCS, 90%)
CT, Heavy Duty	Conv Combustion Turbine	OCGT
Generation III/III+ (with seawater cooling)	Advanced nuclear	Nuclear
-	Biomass	Biomass
Parabolic trough w/o storage [DNI 6]	Solar thermal	Solar thermal
Utility scale centralized PV, single axis tracking PV 50MW	Photovoltaic	Large scale PV
-	-	Rooftop PV
On-Shore Wind: Class 4 Wind Speed - Size 200MW	Wind	Wind
Enhanced Geothermal System (EGS)	-	Hot fractured rocks
-	Geothermal	Conventional geothermal
-	Conventional Hydropower	Hydro
-	-	Wave
-	-	Ocean Currents

6.2.1 GALLM CAPITAL COSTS

6.2.1.1 CPRS-5

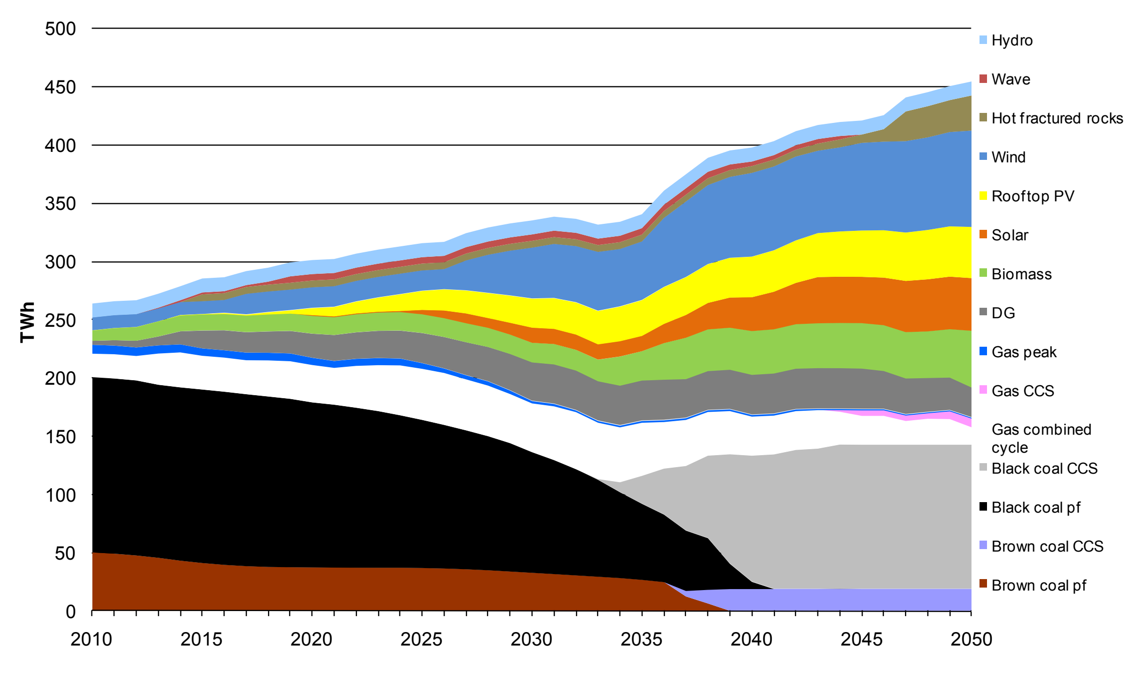

Figure 17: Projected Australian electricity generation mix under CPRS-5 carbon price scenario using capital cost projections from GALLM. DG=distributed generation.

Under CSIRO's capital cost projections generation from black coal pf is phased out under CPRS-5 carbon price scenario in Australia but it is not phased out globally (Figure 9). This may be because Australia has older coal plant and a lower gas price. Brown coal pf is phased out in 2039 in Australia and 2037 globally. Solar, a combination of solar thermal and large scale PV, is introduced earlier globally but ramps up more quickly in Australia from the year 2030 onwards. Wind also ramps up at about the same year, when black coal pf is being phased out. Rooftop PV makes a substantial contribution to the generation mix as distributed generation. Hot fractured rocks and wave also make a small contribution to the overall mix. Hot fractured rocks actually starts to increase its share in the year 2045, when gas begins to be phased out because of the higher gas price and carbon price. Also, the capital cost of hot fractured rocks will have decreased substantially by that time.

The larger global PV contribution did not make a difference to the uptake of PV in Australia under this carbon price scenario.

6.2.1.2 CPRS-15

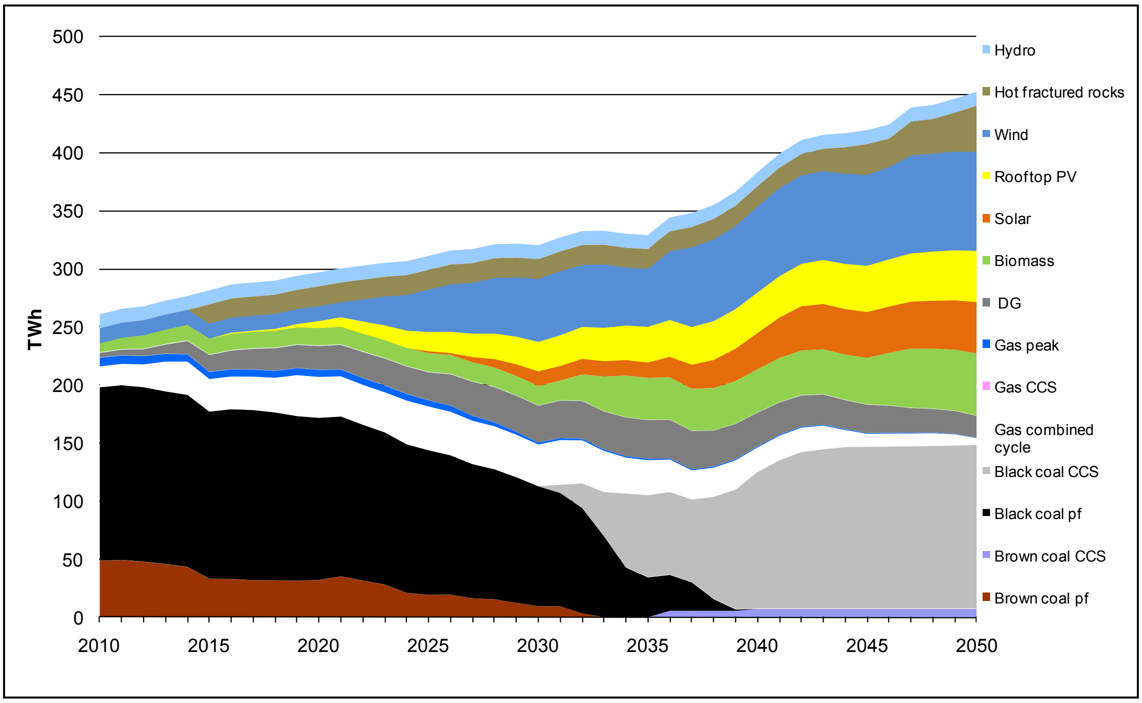

Figure 18: Australian electricity generation mix under CPRS-15 carbon price scenario using capital cost projections from GALLM.

Under CPRS-15, generation from black coal pf is phased out in 2039 under the mid-range carbon price scenario (Figure 18), which is earlier than occurs globally (Figure 10). However, brown coal pf is phased out in 2032 in Australia and by 2024 globally. Locally, baseload is then met by black coal with CCS, brown coal with CCS, gas combined cycle and hot fractured rocks. Biomass makes a greater contribution under this carbon price then under CPRS-5 as does hot fractured rocks. As under CPRS-5, hot fractured rocks replaces some gas combined cycle from the year 2045 onwards. The amount of wind is greater under this carbon price scenario, particularly up until the year 2025 to replace some black and brown coal pf but the amounts of solar and PV are similar to CPRS-5, which reflects the similarity of the capital costs under the two carbon price scenarios. There is no wave energy under this scenario which may be because of the greater amount of hot fractured rocks. Therefore, a high carbon price is required to make generation using hot fractured rocks cost-effective

6.2.1.3 Garnaut-25

The highest carbon price has a greater effect on the projected Australia than global technology mix in terms of phasing out of brown and black coal pf. In Australia brown coal pf and black coal pf cease generation in 2026 and 2034 respectively (Figure 19) and globally it is in 2024 and 2048 respectively (Figure 11). Globally, developing regions do not pay a carbon price until the year 2025 whereas in Australia it is paid from 2013 onwards which pushes forward the decommissioning of emissions-intensive assets. Both black and brown coal pf are also phased our earlier than under the lower carbon price scenarios, as is expected. Gas combined cycle makes a large contribution to the generation mix up until the year 2034 but as the carbon price increases and as the capital cost for coal CCS technologies and hot fractured rocks decreases the contribution of gas combined cycle decreases. This is similar to CPRS-15 but electricity production by gas is less under Garnaut-25. Globally, because of the high gas price, gas combined cycle does not make a large contribution except as peaking plant.

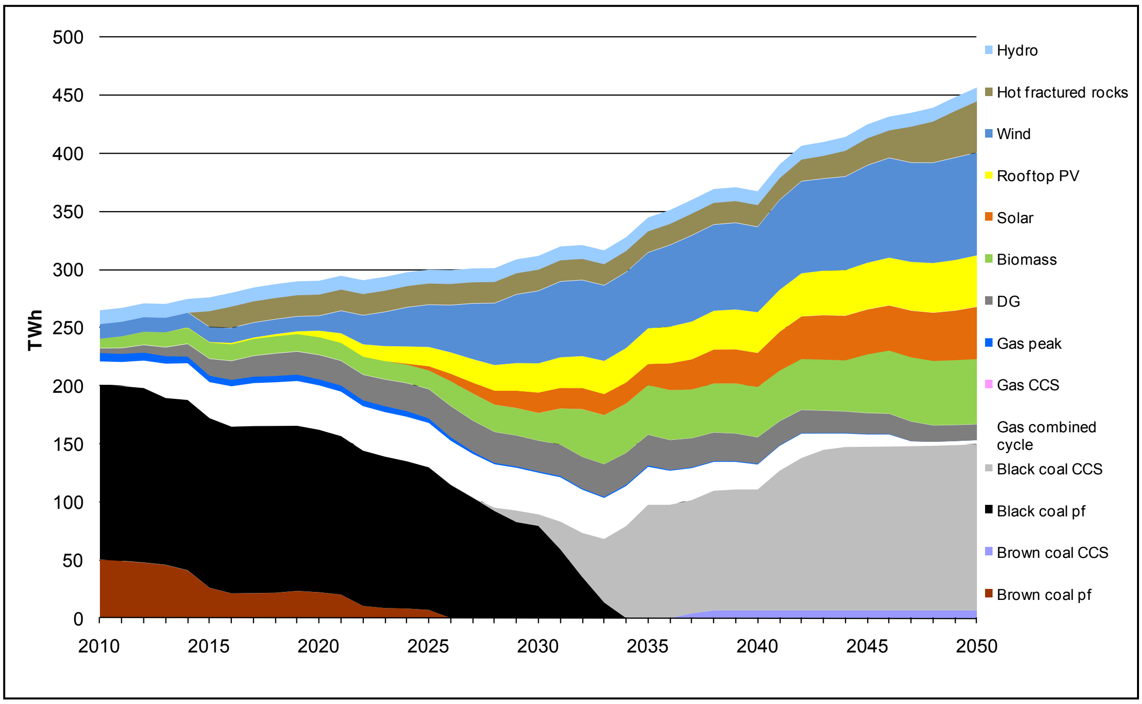

Figure 19: Australian electricity generation mix under Garnaut-25 carbon price scenario using capital cost projections from GALLM.

The contributions of hot fractured rocks, PV and solar to the mix are similar to that of CPRS-15. There is slightly more wind and biomass under Garnaut-25. The larger global PV contribution did not make a difference to the uptake of PV in Australia under this carbon price scenario.

6.2.1.4 Conclusion on Australian generation with GALLM capital costs

The influence of the carbon price on capital costs, the LRMC and the generation mix is apparent from the above projections taken from ESM. The lowest carbon price has the greatest variety of technologies which includes wave and gas with CCS but the overall contributions made by black coal with CCS, wind, Rooftop PV, biomass and solar are roughly similar across all of the carbon prices, particularly so by the year 2050. That is because these technologies are the most competitive in terms of price of the low emissions technologies and thus it makes sense to build them until learning effects are saturated. Hot fractured rocks has appeared under all carbon prices to the detriment of gas combined cycle and wave under the higher two carbon prices but not to other renewables.

Global modelling did not support significant uptake of HFR. However, once we consider HFR at the Australian level the resources available are substantially higher and consequently HFR is taken up. This demonstrates it is always beneficial to model at multiple scales. It happens that HFR is less prospective on a global than on a national scale. At the national scale we are able to take into account that coal with CCS is not viable in every state of Australia and consequently HFR has a role to play in base load power generation.

Wave is a technology that was built up to its maximum installed capacity under the two highest carbon price scenarios but does not make any contribution to Australian electricity generation under those same carbon price scenarios. Hot fractured rocks is more competitive in Australia under a higher carbon price than wave. Wave is built under the lowest carbon price because it had earlier capital cost reductions globally and thus makes it a more attractive choice than hot fractured rocks.

6.2.2 OTHER STUDY COMPARISONS

6.2.2.1 GALLM

The CPRS-5 results using CSIRO capital cost projections to 2030 are shown below. Even though this data has already been discussed above to the year 2050, since all of the other studies only project capital costs to 2030 we have shortened the time period of CSIRO projections included in the chart for easy comparison purposes.

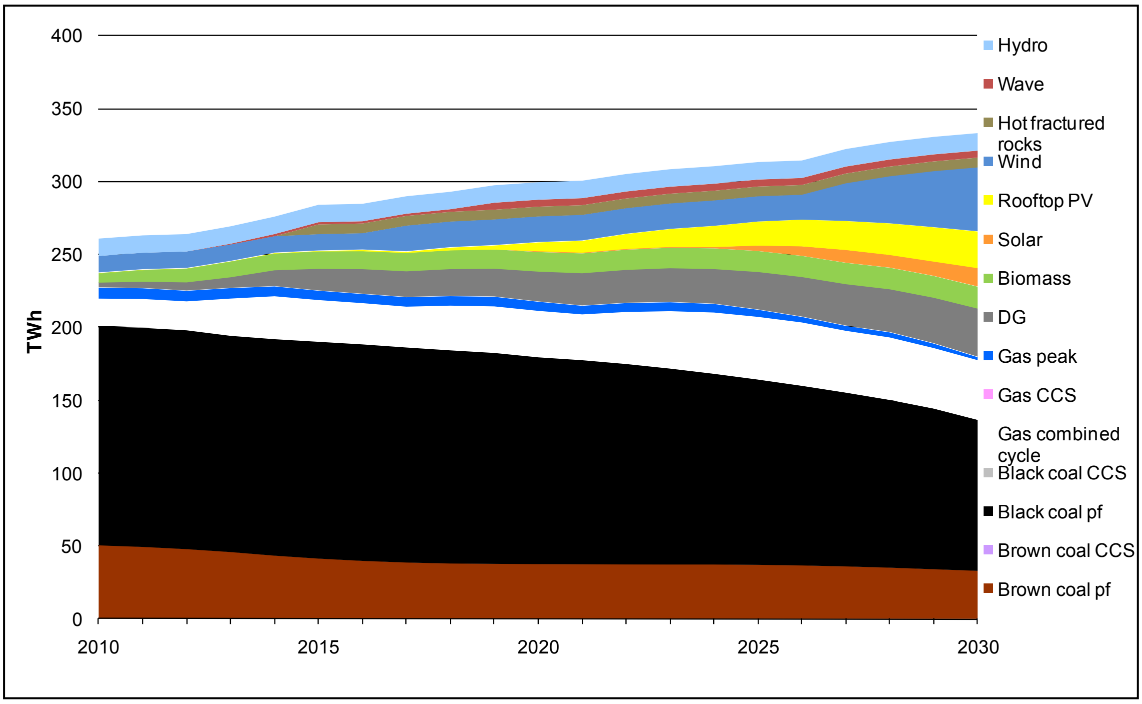

Figure 20: Australian electricity generation mix under CPRS-5 carbon price scenario using capital cost projections from GALLM.

6.2.2.2 EPRI

The only capital costs taken from GALLM to be used in the EPRI data based projection of Australian electricity technology mix (Figure 21) are hydro, biomass, rooftop PV, wave and distributed generation (DG). As these technologies only make a small contribution to the overall generation mix, the capital costs from EPRI are main source of cost assumptions supporting the modelling results. The results show that wind makes a smaller contribution using EPRI (2010) capital costs as their capital cost is higher. Similarly, solar does not make a contribution using EPRI (2010) capital costs. Because of this, the contribution of wave energy and hot fractured rocks are actually higher as they use GALLM costs and are relatively cheaper. Gas combined cycle also makes a larger contribution using EPRI (2010) capital costs rather than GALLM costs due to higher cost of wind and solar thermal. However, the coal contributions are unchanged. These are affected more by the carbon price than by the capital cost.

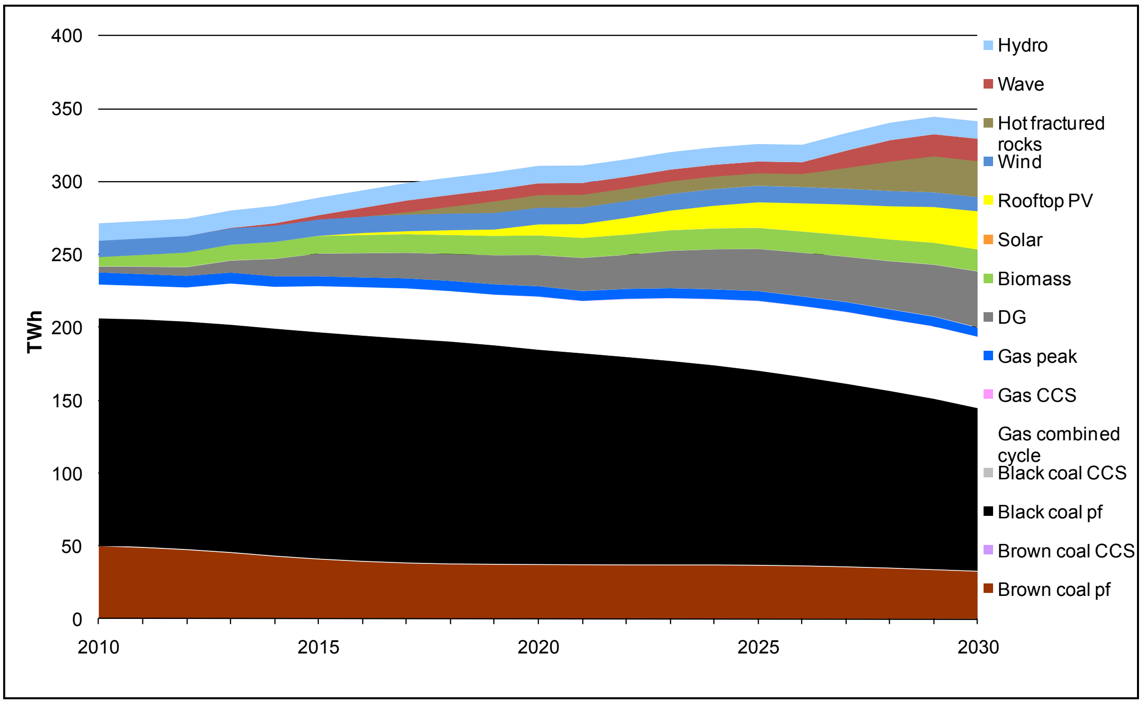

Figure 21: Australian electricity generation mix under CPRS-5 carbon price scenario using capital cost projections from EPRI (2010).

6.2.2.3 US DOE

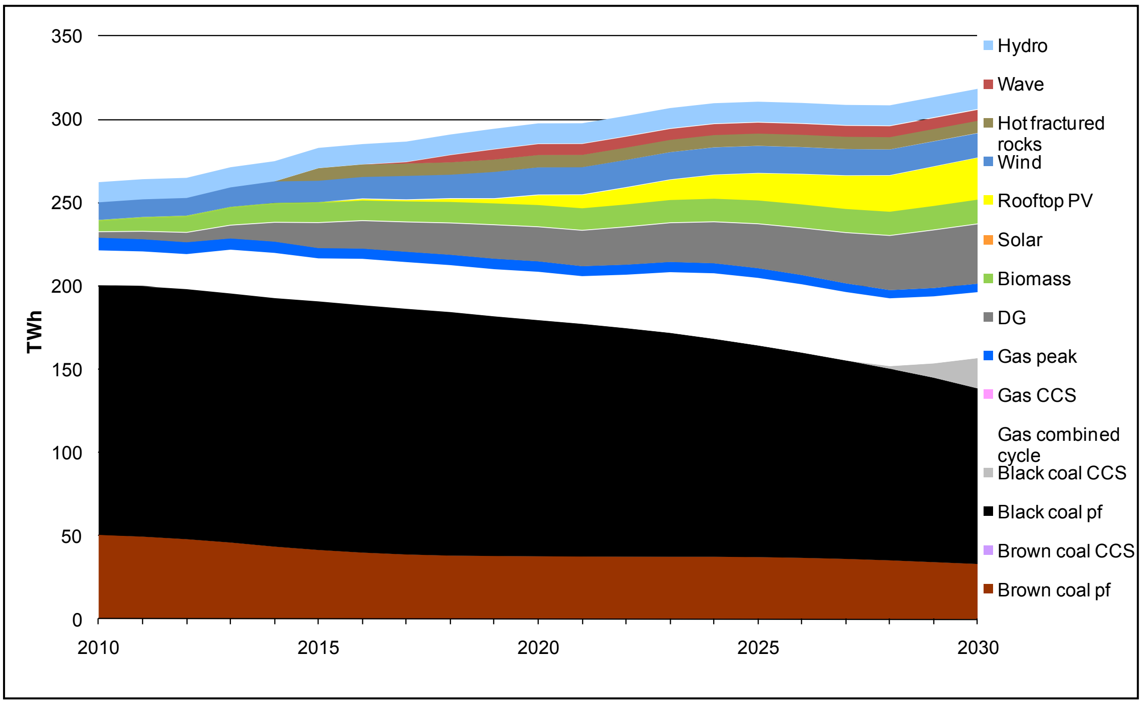

Figure 22: Australian electricity generation mix under CPRS-5 carbon price scenario using capital cost projections from US DOE (2009).

The only capital costs taken from GALLM to be used in the US DOE Australian electricity generation projections are brown coal pf, Rooftop PV, hot fractured rocks, wave and DG. The main differences are that solar is absent from the projections based on US DOE (2009) capital costs projections and there is less wind. This reflects their higher assumed cost. To make up the difference, black coal with CCS begins generation in 2028.

6.2.2.4 Conclusions from comparison with other studies

There is not a great deal of variation in the electricity generation mixes as a result of using different capital costs. Black coal pf is still dominant to the year 2030 and brown coal pf continues to contribute. The main differences are in the renewables, where the use of GALLM capital costs resulted in a greater variety of renewable technologies.

In order to discover more variation in the future Australian technology mix we would need consider other important variables besides capital costs such as the carbon price (which we have shown in another section of this report), fuel prices and the modelling framework itself.

6.3 SENSITIVITY ANALYSIS

There is great uncertainty surrounding technological change and society's attitudes towards technologies. Therefore, in order to examine how changes in technologies or how the addition/absence of some technologies may affect projections of electricity generation shares five different sensitivity analyses have been conducted for the lowest carbon price scenario only. The first two deal with cases where there is no global change to the uptake of a technology but because of societal changes in attitudes and/or government policy changes the uptake of these technologies is different in the future in Australia. The final three deal with technological uncertainty: the first examines the grid in Australia and its ability to cope with increased amounts of intermittent generation and the second and third specific renewable technologies for which Australia has vast resources. The list is as follows:

- **No CCS**: No CCS technologies are built in Australia, but they may be built overseas. It is important to make this distinction because if CCS is built overseas then the global cost curves for all technologies remain largely the same. However, if CCS is an unviable technology globally then there would be greater uptake of renewables and their costs would be subsequently reduced via learning effects. We expect this sensitivity case to lead to greater uptake of alternative base load electricity supplies from gas, hot fractured rocks or biomass generation in Australia.

- **Nuclear AUS**: Nuclear energy is allowed in Australia after 2025. This means that nuclear power plants are no longer prohibited and can begin producing energy in 2025 i.e. the legislative changes and construction period starts earlier. We expected this option could yield some nuclear energy but it was only an insignificant amount because our global assumptions about rising uranium prices meant that it was too costly. We subsequently tested this sensitivity case under the Garnaut-25 carbon price scenario where electricity prices are higher. Under Garnaut-25 nuclear power was taken up

(Figure 29). The LRMCs calculated elsewhere in this report (Figure 12) assume a constant fuel price for all technologies and under those assumptions nuclear power would appear to be one of the least expensive technologies. However, in ESM fuel prices change over time for different inputs including uranium, gas, coal and biomass which all tend to increase in cost while at the same time the costs of other technologies that do not require a fuel are falling (e.g. solar, wind and hot fractured rocks). Since the other cases are based on the CPRS-5 carbon price we do not include the *Nuclear AUS* case in comparisons between sensitivity cases.

- **20% intermittent**: The amount of intermittent generation allowed in Australia is fixed at 20%, whereas normally under the baseline case the amount of intermittent generation allowed into the grid is increased from 20% in 2021 up to 35% in 2030 and beyond.
- **Wave case**: the capacity factor of wave energy has been increased in Australia in states with good wave resources from 0.4-0.48 to 0.5-0.58. Since we have kept the same capital cost and rated capacity of the device, it means that the wave energy converter (WEC) is generating 25% more energy. This has been done to reflect uncertainty surrounding wave resources and the capabilities of different wave energy technologies (Behrens et al., 2011). We expect this to increase uptake of wave energy under CPRS-5 in Australia.
- **HFR case**: The capital cost of constructing a hot fractured rocks plant is lower. Given this technology has not been demonstrated at commercial scale its costs are highly uncertain. We considered a lower cost case by assuming the future oil price is that of the IEA World Energy Outlook (2010) 450ppm case, which is lower than the reference scenario and thus this reduces the drilling cost. Since drilling makes up roughly 80% of the cost of a HFR plant we expect this to have some impact on the capital cost. This was implemented in GALLM and the capital costs were then used in ESM. We expect there to be significantly more HFR in Australia under this scenario.

The “wedge” diagrams which show the electricity generation mix in total power generation are shown in Appendix C. Summarised results are shown here. The first, Figure 23, shows the percentage of electricity generated using fossil-fuel and renewable technologies for the baseline case and the sensitivity cases in the year 2030 in Australia.

There is only 1% difference from the baseline for the ratio of renewable to fossil-fuel based generation under the *No CCS* case in 2030, where *No CCS* has more renewables. This makes sense, given that there is no CCS in the year 2030 under the baseline scenario. However, under the *No CCS* case in later years as can be seen in Figure 28, the contribution normally made by black and brown coal with CCS generation is replaced by increases in gas combined cycle, biomass and especially HFR.

When the penetration of intermittent generation is limited renewables make a smaller contribution but that is to be expected as wind and solar make up the largest share of renewable generation (see Figure 17). And, it can be seen from Figure 30 that the shortfall in intermittent technologies is largely made up by HFR followed by gas combined cycle and gas peaking plant, black coal pf and DG in 2030. In later years the share of HFR increases substantially.

The *Wave case* has the same percentage of fossil fuel and renewable technologies as the baseline and from Figure 31 it can be seen that wave is replacing some wind and solar generation in 2030.

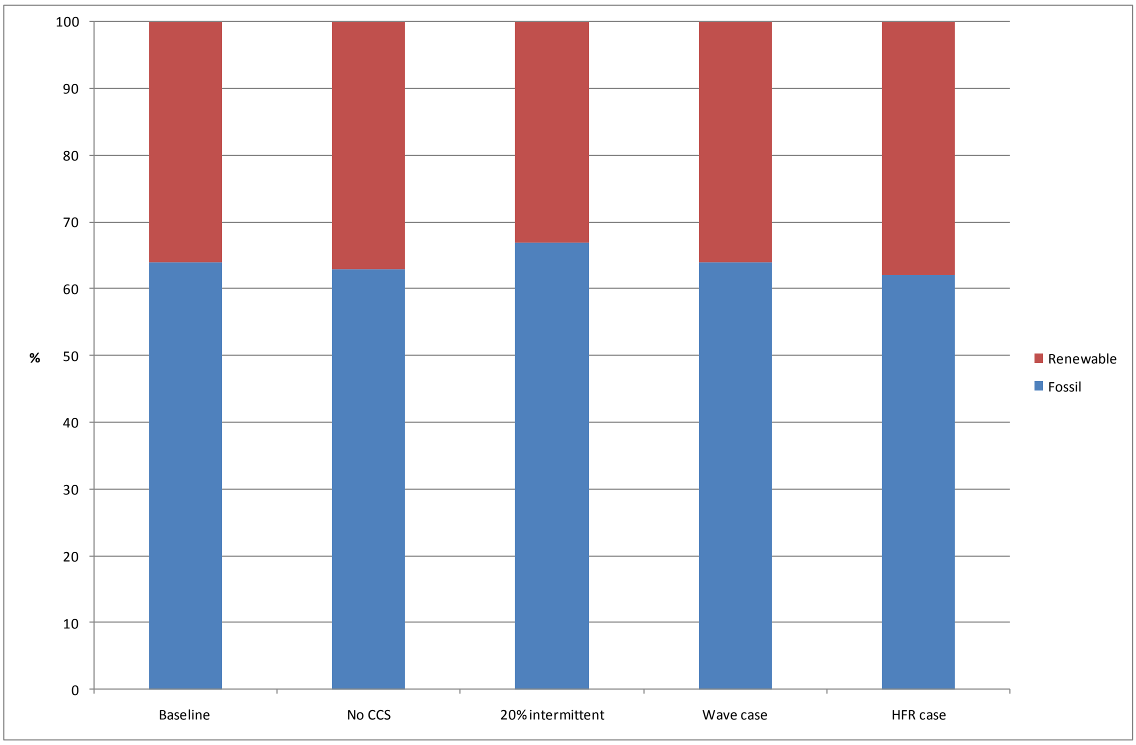

Figure 23: Percentage of electricity generation from fossil-fuel based sources and renewable sources under each sensitivity case and the baseline, under the CPRS-5 carbon price scenario in the year 2030.

HFR can supply baseload and therefore it is able to displace fossil-fuel based generation. Consequently when HFR costs are reduced under the *HFR case*, fossil fuel based generation declines slightly by the year 2030 as can be seen in Figure 32, but by the year 2050 practically all fossil fuel generation has been replaced by HFR. This has largely occurred as an Australian driven technological development as very few plants were built globally. HFR is more competitive in Australia than globally. The global size of the resource compared to that of other technologies is not as great as it is in Australia.

Figure 24 shows the percentage contribution made by each renewable source of generation in the year 2030. Under *No CCS*, there is less wave and more HFR generation as compared to the baseline which makes sense given that low-emission baseload generation is required under the *No CCS* scenario and wave is one of the more expensive forms of renewable intermittent generation. Similary, when intermittent generation is limited biomass and HFR make a greater contribution as they are baseload renewable technologies and wave is reduced substantially. The *Wave case* sees a ~8% increase in the share of wave generation and a similar drop in wind energy. Wave farms are replacing wind farms in regions where the wind resource is not as great. Under the *HFR case* HFR has increased more than doubled its share of generation by 2030 compared to the baseline. At the same time the amount of solar and wave are reduced and the amount of wind has increased. This likely reflects the improved costs position of wind over the long term compared to solar and wave. Wave is actually not developed at all as it is no longer economic to develop another emerging technology to commercialisation.

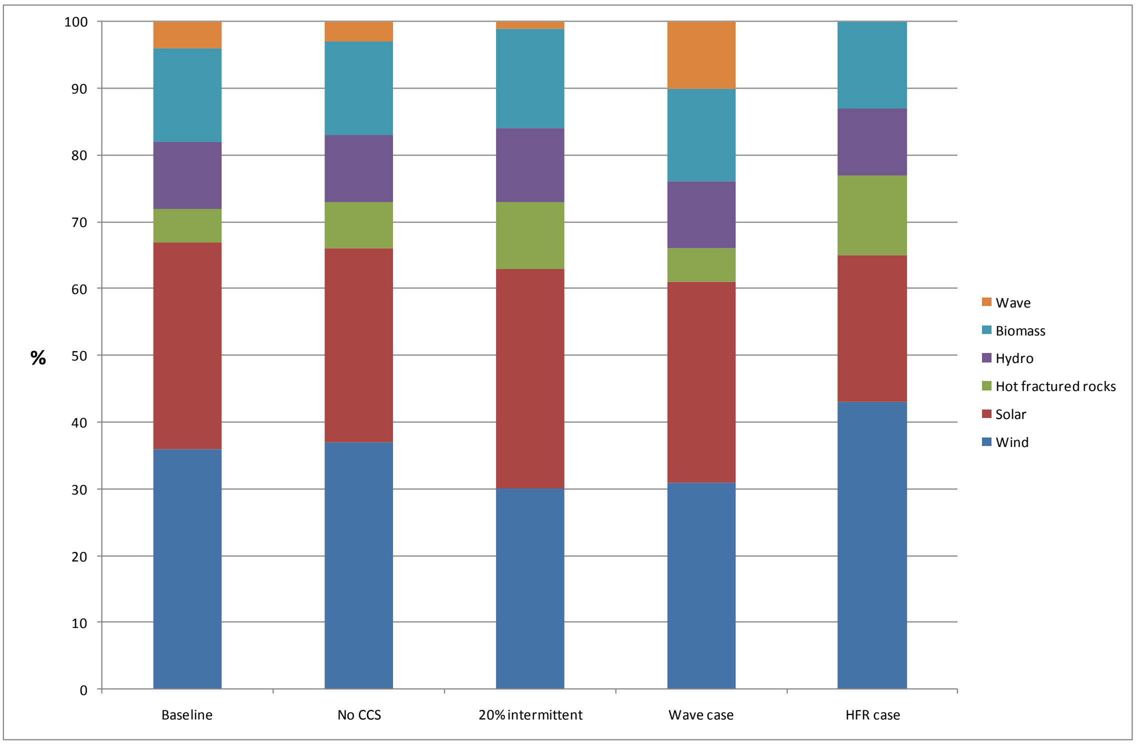

Figure 24: Contribution each renewable technology makes to overall renewable generation under each sensitivity case and the baseline, under the CPRS-5 carbon price scenario in the year 2030.

The average Australian wholesale electricity price and the total number of CO_2-e emissions in the year 2030 is shown in Figure 25 for the baseline and sensitivity cases. These prices are consistent with CSIRO projections that the LRMC of technologies such as wind will be below $100/MWh by 2030. However, note that these are Australian average prices. Each state will have higher or lower prices depending on their energy resources and level of interconnection with neighbouring states.

There is little difference in wholesale electricity price in 2030 between the baseline and *No CCS case* because CCS was not active at this point in the CPRS-5 scenario. However, the wholesale electricity price is higher in the long term by the absence of the option to deploy CCS, as can be seen in Figure 26. CCS is replaced by HFR which is a more expensive technology. However, by the year 2048 the No CCS option has a slightly lower electricity price than the baseline because of the increase in permit costs due to the higher carbon price.

The 2030 wholesale electricity price is higher under the 20% intermittent case, by ~3 AUD/MWh. This reflects the loss of inexpensive wind generation and the increase in HFR and gas combined cycle generation and the cost of gas associated with that. The *Wave case* has a similar price to the baseline, mainly because wave energy is now a much cheaper option. Under the *HFR case* the price has dropped by ~2 AUD/MWh, due to the increase and low cost of HFR and wind.

The level of emissions is consistent with the ratio of fossil based generation to renewable generation as seen in Figure 23.

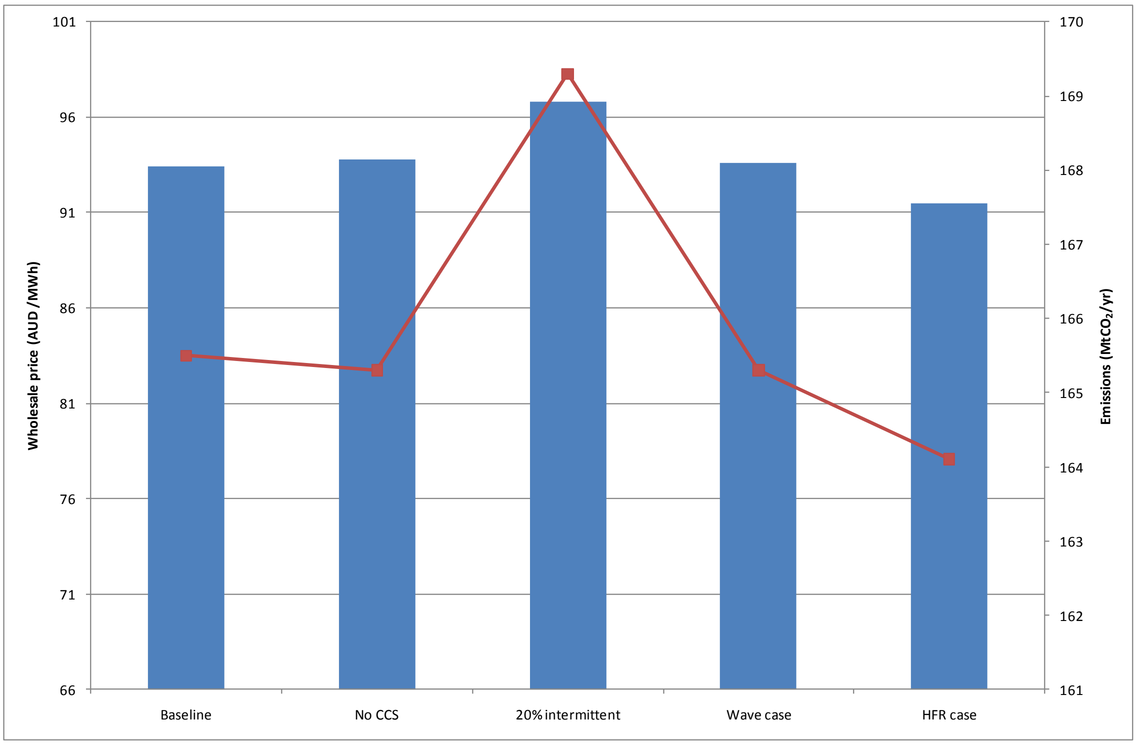

Figure 25: Projected average Australian wholesale electricity price (blue bars) and CO_2 emissions (red points) for the baseline and sensitivity cases, under the CPRS-5 carbon price scenario, in the year 2030.

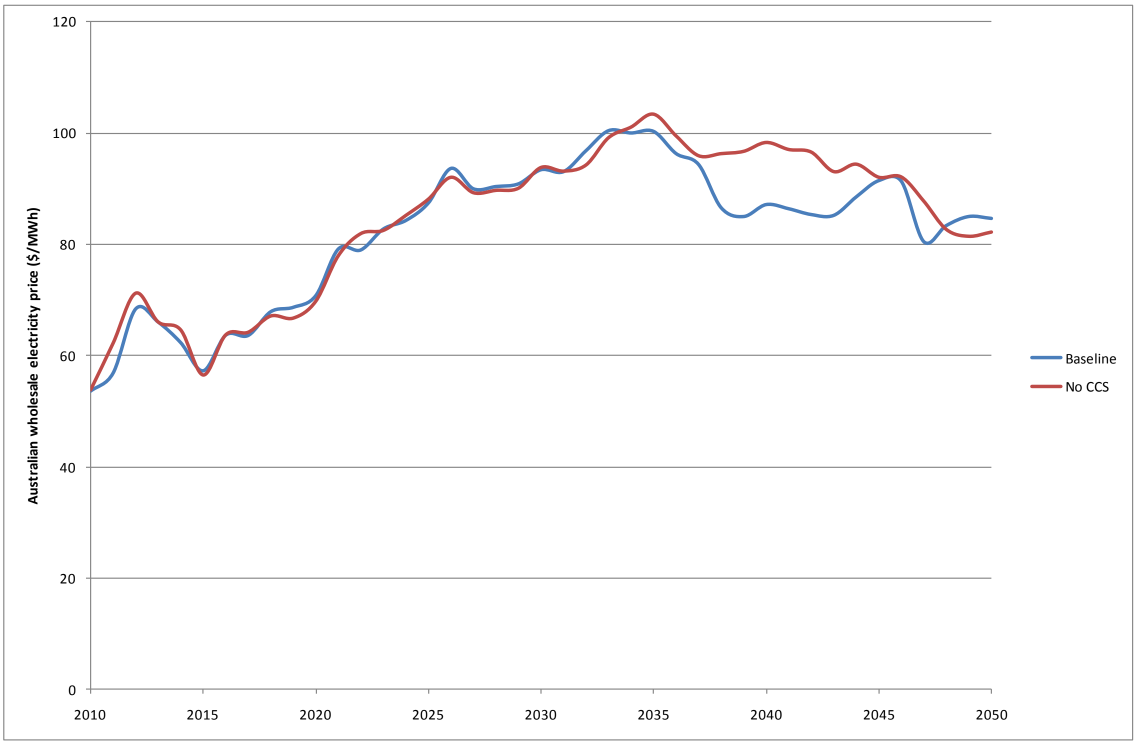

Figure 26: Projected average Australian wholesale electricity price for the baseline (Blue) and No CCS sensitivity case (Red) under the CPRS-5 carbon price scenario.

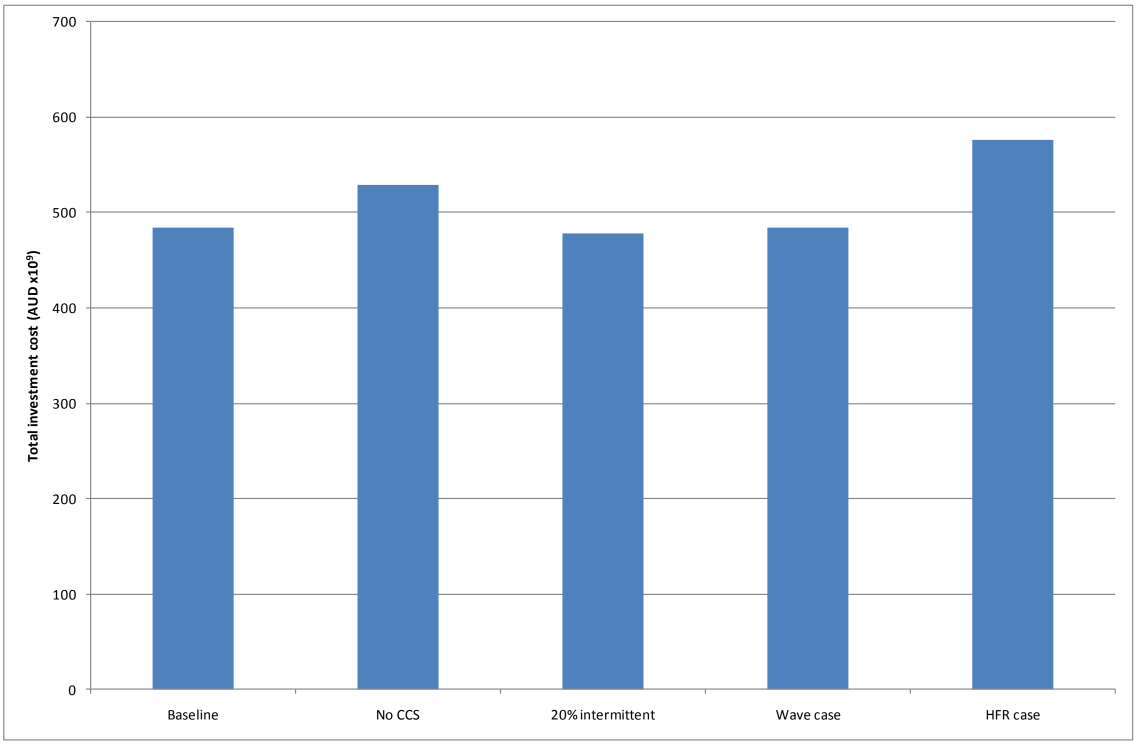

Figure 27: Total cumulative investment cost up to the year 2050 in power generation assets in Australia for the baseline and sensitivity cases, under the CPRS-5 carbon price scenario.

Figure 27 above shows the total cumulative investment cost under each sensitivity case and the baseline scenario. Because of the high capital cost of HFR, the total investment cost under the *No CCS* case is higher. CCS is replaced by wind (relatively low capital cost) and HFR (high capital cost) up to the year 2050 (Figure 28). Overall the total investment cost is higher.

The 20% intermittent case has the lowest total investment cost as renewables are relatively high in capital cost but low in running costs and thus by reducing the amount of intermittent renewables the cost decreased. The *Wave case* has an investment cost very similar to the baseline because wave farms now have a greater output for the same amount of capital investment and investment in alterative technologies is similar to the baseline. The HFR case has the highest investment cost, even though HFR is cheaper. It is still a capital-intensive technology, especially in the earlier years when it has not moved as far down the experience curve.

7 CONCLUSIONS

CSIRO's Global and Local Learning Model (GALLM) is at its core a model of global electricity production and consumption over time where the uptake of different electricity technologies affects and is affected by changes in the costs of technology. The methodology is based on the robust experience curve theory that is widely used in the literature. However, the key advantage of GALLM is that the global electricity market context provides a transparent and adjustable method of creating the necessary technology uptake data that is required to implement the learning curves. GALLM is structured in a way that allows for global learning spill over effects as well as local learning with respect to some technology components, so called "compound learning". This approach was applied to wind and solar photovoltaics. Another important feature of GALLM is its treatment of infant technologies. Because infant technologies are at the prototype/testing and demonstration phases (and thus there has been little deployment), there is insufficient data to generate experience curves. An alternative method was developed to generate experience curves for these technologies and to develop realistic deployment profiles. This approach was applied to hot fractured rocks and geothermal, however there are plans to extend it to other emerging technologies such as wave. We also adjusted for a tendency towards optimism in cost estimates at the concept stage.

One more feature of GALLM that has received close attention is its treatment of technology market forces. In recent years the price of all electricity generation technologies has been increasing, most notably so for wind turbines, photovoltaics (PV) and PV installation. The price increase has been interpreted as a "penalty" or price premium that entered the market once the capacity of the raw material suppliers and component manufacturers was exceeded by demand. This penalty has been represented in the model as an additional payment to energy technology suppliers when investment in a technology category is high relative to the total size of the power plant market

The inclusion of these novel features in the model has lead to a more plausible mix of electricity generation technologies being projected to be taken-up in the global electricity generation market to 2050.

The mix is also strongly affected by the carbon price. The lowest carbon price scenario, CPRS-5, leads to the greatest diversity of technology choices, which were the addition of black and brown coal combined cycle plants. The mid and highest carbon price scenarios, CPRS-15 and Garnaut-25 lead to more nuclear generation mid-term but a greater diversity of renewables in the longer term compared to CPRS-5.

Nuclear was seen as a suitable option for a rapid and early reduction in emissions under the two highest carbon prices as it is relatively low cost baseload technology. However, from the year 2030 onwards there was a greater expansion in renewable uptake under these carbon prices to avoid paying both carbon permits and the penalty premium for overly high demand of one technology. Nuclear was not as necessary under CPRS-5 because the carbon price was not high enough to force non-CCS coal generation out of the market. CPRS-5 saw a lock-in effect of large scale PV after 2030. PV is particularly susceptible to lock-in as the modules have the highest learning rate of any technology and can thus achieve cost reductions quickly. And, coupled with fewer nuclear installations, cost-effective low emissions technologies are required.

CSIRO's costs projections are consistent with the logic of the GALLM model however, there is of course considerable uncertainty in future costs that cannot be reduced via modelling. It is therefore important where possible to consider a wide range of views. In undertaking such a comparison, drawing on two other recent studies, we calculated the LRMC using available capital costs projections and CSIRO data for other inputs. We found that LRMC projections in the year 2030 under three carbon price scenarios are in most cases very similar. The greatest differences were observed for renewable technologies. One reason for the differences in LRMC in this category being higher is that the capital cost component makes up the largest share of LRMC for renewable technologies. The other major reason for the differences is the methodology. Specifically those studies including this one which use an experience curve methodology tend to project lower costs, particularly if they take into account the carbon price as driving accelerated deployment in the future.

The capital costs from GALLM and the two additional projections available from other studies were used as input into the Australian Energy Sector Model (ESM) to project the future Australian electricity generation technology mix and to observe what impact the differences in capital cost have on the projected electricity generation mix. ESM projects significant uptake of wind, natural gas and rooftop PV in the next decade and an increasingly diverse mix of renewables and coal with CCS over the long term with the rate of deployment and mix shifting depending on the carbon price. Reflecting the higher LRMCs of renewables projected by the other studies, we found that including the other cost projections leads to a slight reduction in renewable share to 2030. However, overall the technology mix was very similar. Different carbon prices lead to more substantial changes in the technology mix. Fuel price assumptions and differences in modelling frameworks are also likely to play an important role.

The sensitivity analysis under the CPRS-5 carbon price scenario shows that when policy options are changed in Australia (no CCS and nuclear allowed) the outcome in terms of share of renewables vs. fossil-fuel based technologies and the price of electricity is not very different from the baseline scenario in the year 2030. However, under the Garnaut-25 carbon price scenario almost half of Australia's electricity is sourced from nuclear by 2030. This means that carbon price has the greatest effect on nuclear uptake. When CCS is taken out as an option for Australia the total capital investment cost is greater and the price of electricity is generally higher in the longer term, but when permit prices become high enough having CCS results in a higher electricity price. When the amount of intermittent generation is held back to 20%, fossil-fuels naturally make a greater contribution and this increases the price of electricity slightly. When wave energy can generate 25% more energy than the base case, this reduces the share of wind and naturally increases wave energy but does not have an impact on the price of electricity of the total capital investment required. In the case when the drilling costs are lower for a HFR plant, this has an enormous impact on the generation mix by 2050; but by 2030 the results are not so different from the baseline case. This indicates that reducing the overall cost of HFR plants can have a large effect on the uptake of this technology.

CSIRO will continue to work to improve its cost and technology projection models. There is significant scope to improve the depth with which each technology's experience curve is included in the model. Ideally as data becomes available, each technology should have the potential for both local and global learning and be disaggregated into its key components in the model.

We will continue to use and update the most recent policy settings as they become available. We will also continue to scan for changes in the development of a technology e.g. improvements in geothermal and hot fractured rocks drilling techniques or new types of PV. Wildcard technologies may also appear on the market (see Appendix D) which may result in large adjustments to the global and local picture of electricity generation in the future.

8 FURTHER WORK

This is the first version of GALLM and there are many improvements that can be made. In order to have more accurate resource availabilities such as wind, solar, wave, fuels and land availability and to better reflect electricity demand we need to include more regions in the model. This may also allow us to refine our local learning, where we can include technology learning for countries rather than very broad regions. Another advantage of including more regions is we could also include more technologies which are gaining momentum, such as offshore wind, which are only being installed in Europe and the USA.

We would like to include a greater variety of distributed generation technologies which are expected to be widely employed to reduce demand, particularly during peak periods and thus avoid costly additions to electrical infrastructure. Currently, combined heat and power (CHP) with different fuels and fuel cells feature in ESM and at the moment ESM uses time-based constant cost reductions for those technologies, which are not as accurate as the experience curve approach.

Experience curves should also be calculated for other technologies when the data becomes available, particularly for CCS technologies since these are a prominent feature in projected future electricity generation. This would involve component learning, where part of the plant is a mature technology and thus has no learning and part of the plant has a high learning rate (Ferioli et al., 2009). We would also like to formulate a novel approach for calculating an experience curve for wave energy, since this is an emerging technology and equating its learning rate to that of offshore wind is an approximation.

We plan on modelling the disruptive technologies of generation IV nuclear and innovations in PV as a sensitivity case to see the effect these could have on future electricity generation. However, caution will need to be taken over when these technologies may be available.

It has become apparent with wave energy in particular that rated capacities and thus capacity factors can be arbitrarily set. While these factors are cancelled out in the modelling, the capacity factor in particular is useful for discussion purposes. Capacity factor also has different connotations in engineering and in other industries. Therefore, we would like to invent a new term which is well defined for describing the equivalent of capacity factor in economic modelling.

We will extend our cost comparison work in TECC to include new capital cost projections from other studies as they become available. At the moment we wish to update the US DOE 2009 costs with their current release and include costs published by AEMO.

Finally, we will continue to update GALLM with new data as it becomes available, such as changes in or new government policies and new costs for fuel and O&M.

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10 APPENDIX A – ABBREVIATIONS

ABARE: Australian Bureau of Agricultural and Resource Economics

AC: air cooled

AEMO: Australian Energy Market Operator

ATSE: Australian Academy of Technological Sciences and Engineering

AUD: Australian Dollar

BOS: balance of systems for photovoltaic systems or hot fractured rocks plants

CCS: carbon capture and storage

CTCC: combustion turbine combined cycle

CO_2-e: carbon dioxide and equivalent

CSP: concentrating solar power or solar thermal

DG: distributed generation

DNI: direct normal irradiance

EGS: enhanced geothermal system

ESM: Energy Sector Model

EPRI: Electric Power Research Institute

GALLM: Global and Local Learning Model

HFR: hot fractured rocks

IEA: International Energy Agency

IGCC: integrated gasification combined cycle

kW: kilowatt

LDR: learning by doing

LRMC: long run marginal cost

LSR: learning by searching

MWh: megawatt hour

NEMS: National Energy Market System

NO_x: nitrous oxides

O&M: operations and maintenance

pf: pulverised fuel

ppm: parts per million

PV: photovoltaics

R&D: research and development

SO_2: sulphur dioxide

T&D: Transmission and Distribution

TECC: Tool for Electricity Cost Comparison

US DOE: United States Department of Energy

WEC: Wave energy converter

11 APPENDIX B – COMPONENTS OF THE LRMC

The capital costs in the starting year of the model (2006) in 2006 AUD are shown in below as sent-out figures in AUD/kW. For the technologies with experience curves the starting cost may vary slightly from this value because of the segmentation of the experience curve. This is particularly the case for PV and wind, where there was already a price bubble in 2006. The experience curves are at a lower cost in the model but the penalty constraint ensures that the price in the objective function reflects the actual price paid. The efficiency of fossil fuel, biomass and nuclear technologies in 2006 are also given. The capacity factor of each technology in 2006 is also shown.

During the model run the efficiency and capacity factors are assumed to improve by incremental amounts in addition to continuing technological development captured in the experience curves.

The physical lifetime of the technology varies between technologies. For coal-based, hydro and nuclear it is 50 years. For biomass, conventional geothermal and hot fractured rocks it is 30 years and for all others it is 25 years. The assumed amortisation periods for capital cost calculation purposes are assumed to be shorter - between 20 to 30 years. The inverter used in PV is a special case. The inverter is replaced at half the lifetime of the rest of the PV plant (at 12.5 years). The construction times for the plant are assumed to be less than one year for PV and all forms of DG, one year for wind and gas peaking plant, two years for wave farms, solar thermal and biomass plants, five years for nuclear and three years for all other plants. The fuel costs and fixed and variable operations and maintenance costs are from the ESM database. The discount rate is 7% and the cost of CO_2 transport and storage is fixed at $20/tonne for all CCS plants (Graham et al., 2008a, Graham et al., 2008c, Graham et al., 2008b).

The values used for the fixed and variable O&M cost are constant over time for fossil fuel plants, nuclear, hydro, conventional geothermal and hot fractured rocks but vary for all of the other plants, where they tend to decrease over time. There is no fixed O&M cost for rooftop PV. The transmission and distribution (T&D) cost is fixed over time but it varies by technology depending on the location of the resource (because of the requirement for new transmission infrastructure) (Graham et al., 2009).

The costs of all fossil fuels are assumed to increase over time. Global reserves of natural gas are more constrained than coal and the price of gas has tended to follow the oil price globally (Energy Information Administration, 2009a). Therefore, natural gas is treated differently in GALLM. The supply vs. price is segmented into an upward sloping step function so that high gas consumption increases the price. Uranium and biomass also have segmented supply vs. price curves because they are a limited resource, biomass in particular for Australia. There are 5 different segments in the model for each supply constrained fuel.

Table 8: Modelling assumptions and references for fossil-fuel based technologies

Technology	Capital cost ($/kW sent out)	Efficiency (%)	Capacity factor (%)	Variable O&M ($/MWh)	Fixed O&M ($/MWh)	References
Black coal, pf	1948	35.1	80	1.2	4.28	(Dave et al., 2008, Dave, 2009, Graham et al., 2008a, ACIL Tasman, 2008, McLennan Magasanik Associates, 2008a)
Black coal, IGCC	3004	41.0	80	1.5	6.28	(Belinski, 2009, Brinsmead et al., 2010, Graham et al., 2008a, ACIL Tasman, 2008, McLennan Magasanik Associates, 2008a)
Black coal with CCS	4348	25.2	80	2.7	7.13	(McLennan Magasanik Associates, 2008a, ACIL Tasman, 2008, Dave, 2009, Dave et al., 2008, Graham et al., 2008a, Rubin et al., 2007)
Brown coal, pf	2895	28.0	80	1.2	6.14	ACIL Tasman 2008; Dave, Do et al. 2008; Graham, Reedman et al. 2008; McLennan Magasanik Associates 2008; Dave 2009)
Brown coal, IGCC	3320	41.0	80	1.5	6.99	(Belinski, 2009, Brinsmead et al., 2010, Graham et al., 2008a, ACIL Tasman, 2008, McLennan Magasanik Associates, 2008a)
Brown coal with CCS	7380	17.0	80	2.7	7.85	(McLennan Magasanik Associates, 2008a, ACIL Tasman, 2008, Dave, 2009, Dave et al., 2008, Graham et al., 2008a, Rubin et al., 2007)
Gas open cycle	449	20.0	20	7.5	12.47	(Belinski, 2009, Brinsmead et al., 2010, Graham et al., 2008a, ACIL Tasman, 2008, McLennan Magasanik Associates, 2008a)

Gas combined cycle	892	49.0	80	4.85	2.85	(Belinski, 2009, Brinsmead et al., 2010, Graham et al., 2008a, ACIL Tasman, 2008, McLennan Magasanik Associates, 2008a)
Gas with CCS	2900	40.0	80	14.96	10.73	(McLennan Magasanik Associates, 2008a, ACIL Tasman, 2008, Graham et al., 2008a, Wearmouth, 2009, Statoil, 2009, Belinski, 2009, Rubin et al., 2007, Mints, 2007)
Nuclear	3971	34.0	80	2.0	4.99	(ACIL Tasman, 2008, Graham et al., 2008a, McLennan Magasanik Associates, 2008a, Belinski, 2009)

Table 9: Modelling assumptions and references for renewable technologies

Technology	Capital cost ($/kW sent out)	Efficiency (%)	Capacity factor (%)	Variable O&M ($/MWh)	Fixed O&M ($/MWh)	References
Hydro	3246	NA	20	2.0	19.98	(Graham et al., 2008a, ACIL Tasman, 2008, McLennan Magasanik Associates, 2008a)
Biomass	2924	26.0	45	3.0	12.54	(McLennan Magasanik Associates, 2008a, Graham et al., 2008a, ACIL Tasman, 2008)
Solar thermal	5898	NA	25	1.5	22.73	(McLennan Magasanik Associates, 2008a, Graham et al., 2008a, ACIL Tasman, 2008, Ritchie, 2009, European Commission, 2007, SolarPACES, 2009, Stoddard et al., 2006, Eichhammer et al., 2005, CSP Today, 2008, Ummel and Wheeler, 2008, World Bank and GEF, 2006, Wyld Group and McLennan Magasanik Associates, 2008, International Energy Agency, 2010c, Price et al., 2007, Price et al., 2002, Sargent and Lundy LLC Consulting Group, 2003, http://en.wikipedia.org/wiki/List_of_solar_thermal_power_stations, 2009, International Energy Agency, 2008b, Lazard, 2009, Flannery et al., 2009, Bloomfield and Laney, 2005, Williamson, 2010)
Hot fractured rocks	4633	NA	80	2.0	9.99	(McLennan Magasanik Associates, 2008a,

						Graham et al., 2008a, ACIL Tasman, 2008, Augustine et al., 2006, Cosgrove and Young, 2009, US Department of Energy, 2008, International Energy Agency, 2008b, MIT-led panel, 2006, McLennan Magasanik Associates, 2008b, Polsky et al., 2008, Brett and Millheim, 1986, Pinto et al., 2004b, Hance, 2005)
Conv. geothermal	2878	NA	80	2.0	9.99	(Cross and Freeman, 2009, International Energy Agency, 2007, Hance, 2005, Williamson, 2010, International Energy Agency, 2008b, International Energy Agency, 2008c)
Wave	7000	NA	50	17.0	15.13	(International Energy Agency, 2010a, International Energy Agency, 2010b, Dunnett and Wallace, 2009, Carbon Trust UK, 2006, Carnegie Wave Energy, 2010a, EPRI, 2006, Minerals Management Service, 2006, Clean Energy Council, 2010, Finnigan, 2009, International Energy Agency, 2008b)
Ocean current	5200	NA	35	17.0	21.61	(International Energy Agency, 2008b, International Energy Agency, 2010a)
Wind	1518 (DV); 1742 (AU); 1389	NA	29	1.6	13.73	(International Energy Agency, 2010a, Belinski, 2009, Brinsmead et al., 2010, Graham et al., 2008a, ACIL Tasman, 2008, McLennan Magasanik Associates, 2008a, Junginger et al., 2005, International Energy Agency, 2009, World Wind Energy Association, 2009, Cyranoski, 2009,

	(UN)					Koenemann, 2008a, Koenemann, 2008b, Milborrow, 2008)
PV rooftop	10529 (DV); 9960 (AU); 11858 (UN)	NA	20	2.14	0	(Watt, 2008, van der Zwaan and Rabl, 2003, van der Zwaan and Rabl, 2004, Mints, 2007, Navigant Consulting, 2006, Hoffmann, 2006, European Photovoltaic Industry Association, 2009, Earthscan, 2006, International Energy Agency, 2010b, International Energy Agency, 2010a, International Energy Agency, 2008b, International Energy Agency, 2010d, International Energy Agency, 2010e, European Photovoltaics Industry Association, 2010)
PV large scale	6969 (DV); 6615 (AU); 7867 (UN)	NA	20	1.5	11.33	As above

Table 10: Modelling fuel cost and emission assumptions

Fuel type	Cost of fuel ($/GJ)	Emissions (kgCO2/GJ)
Brown Coal	0.5	93.6
Black Coal	1.0	95.29
Natural gas	0.9	62.9
Biomass fuel	0.6	0
Uranium	0.7	0

12 APPENDIX C – SENSITIVITY ANALYSIS CHARTS

The projections of technology mix from the sensitivity analysis conducted in Section: 6.3are provided below.

Case 1: No CCS

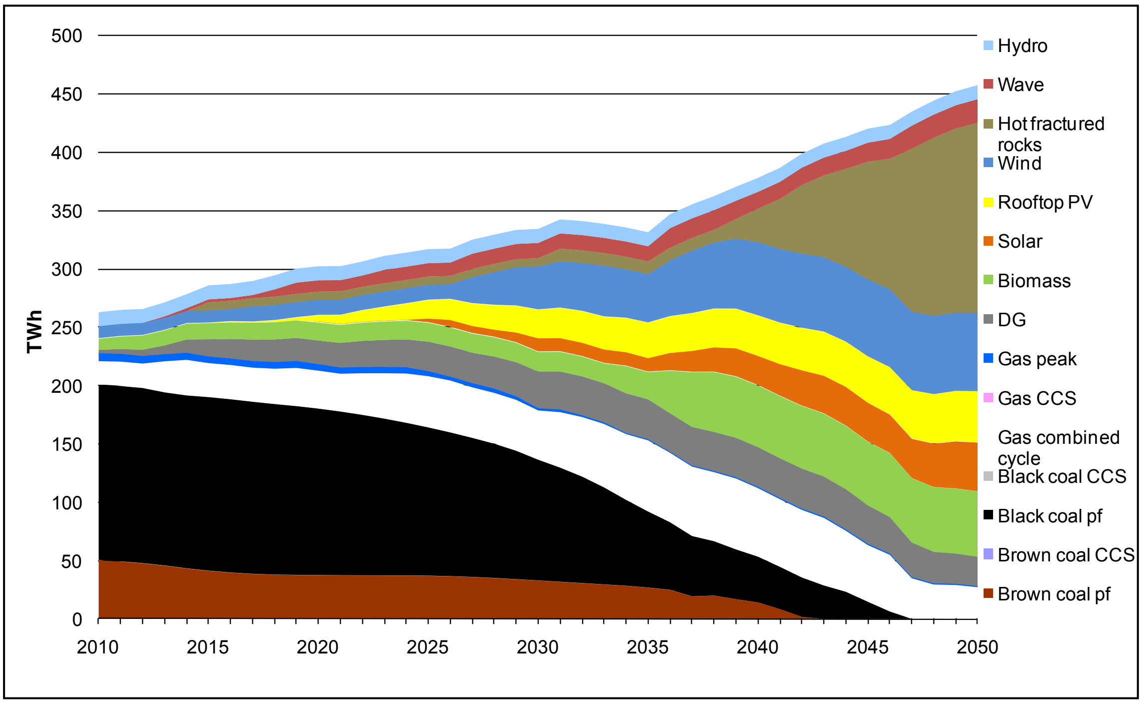

Figure 28: Projected electricity generation in Australia under CPRS-5 carbon price scenario with no CCS technologies allowed.

Case 2: Nuclear is allowed in Australia from 2018.

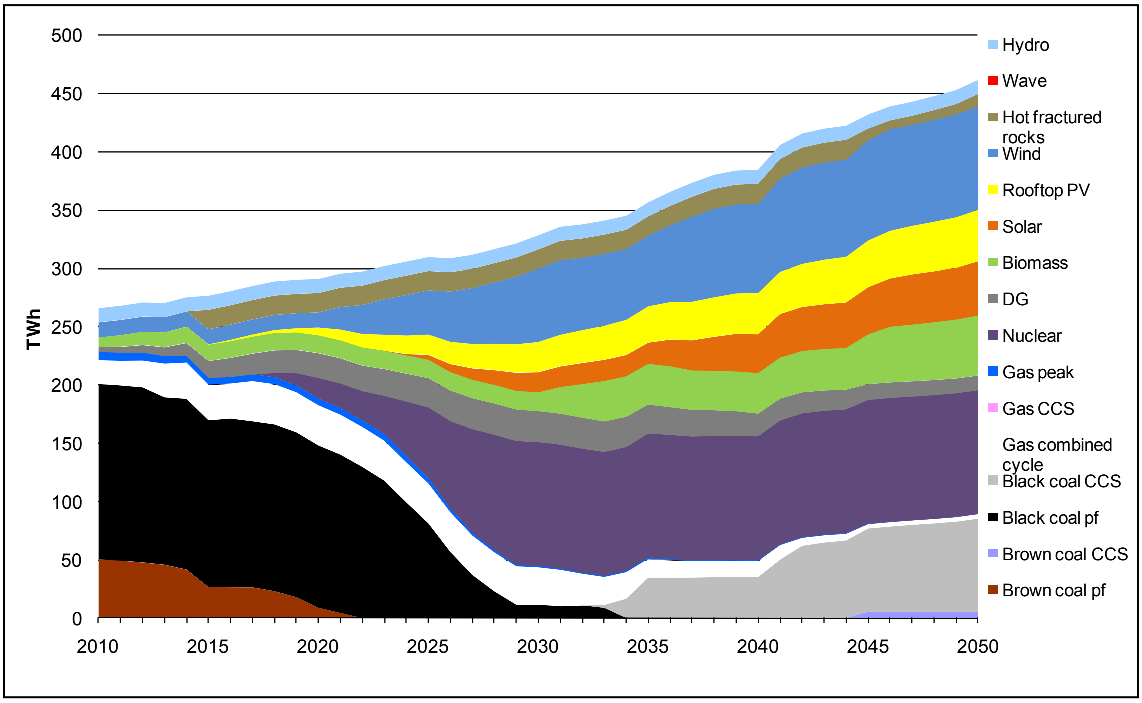

Figure 29: Projected electricity generation in Australia under Garnaut-25 carbon price scenario with nuclear allowed from 2018.

Case 3: Penetration of intermittent technologies is held fixed at 20% for Australia

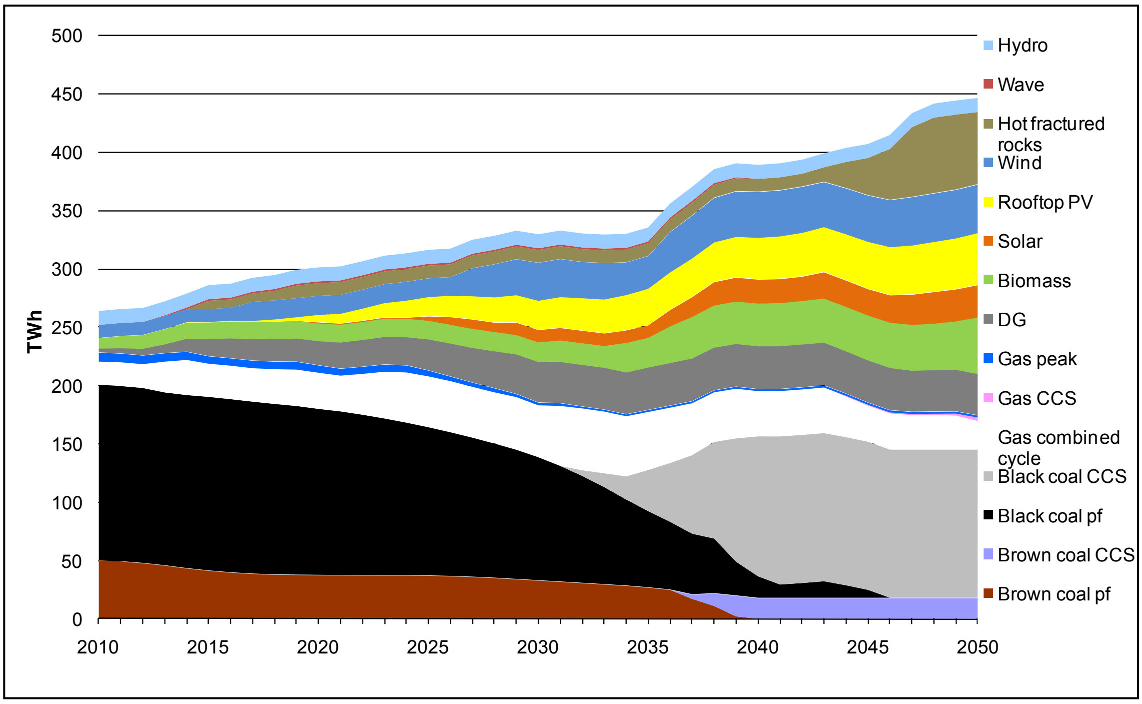

Figure 30: Projected electricity generation in Australia under CPRS-5 carbon price scenario under the intermittent case.

Case 4: Wave energy has a capacity factor of 0.5 in Australia

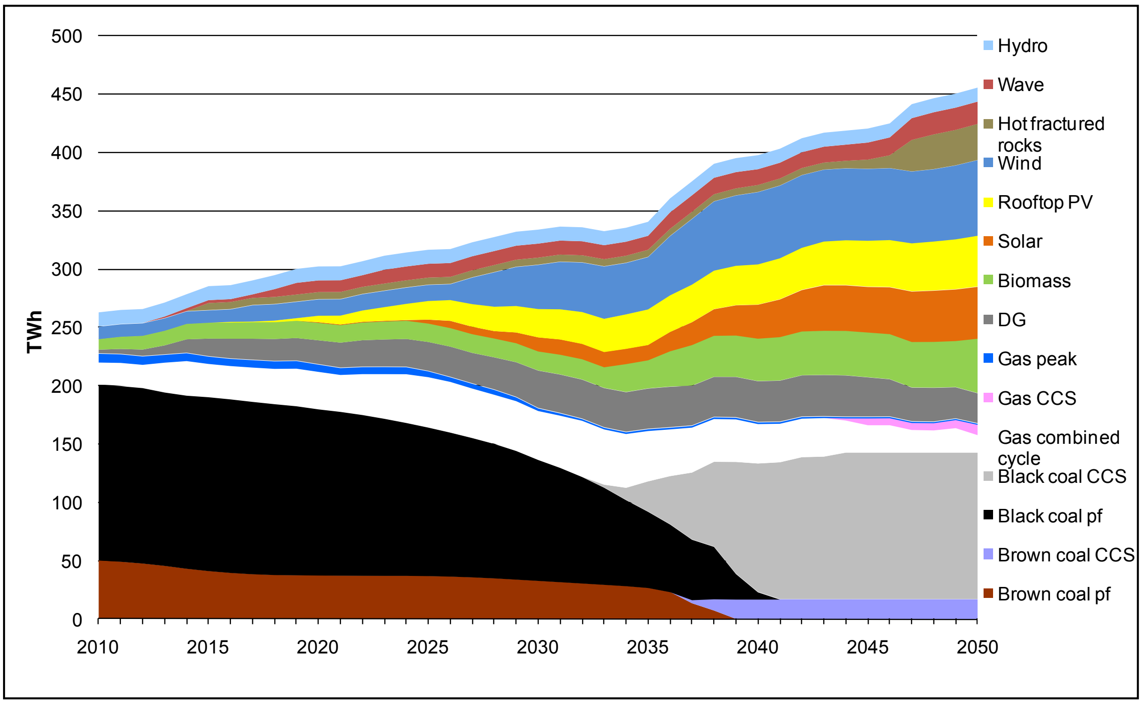

Figure 31: Projected electricity generation in Australia under CPRS-5 carbon price scenario under the solar thermal case.

Case 6: Lower cost HFR

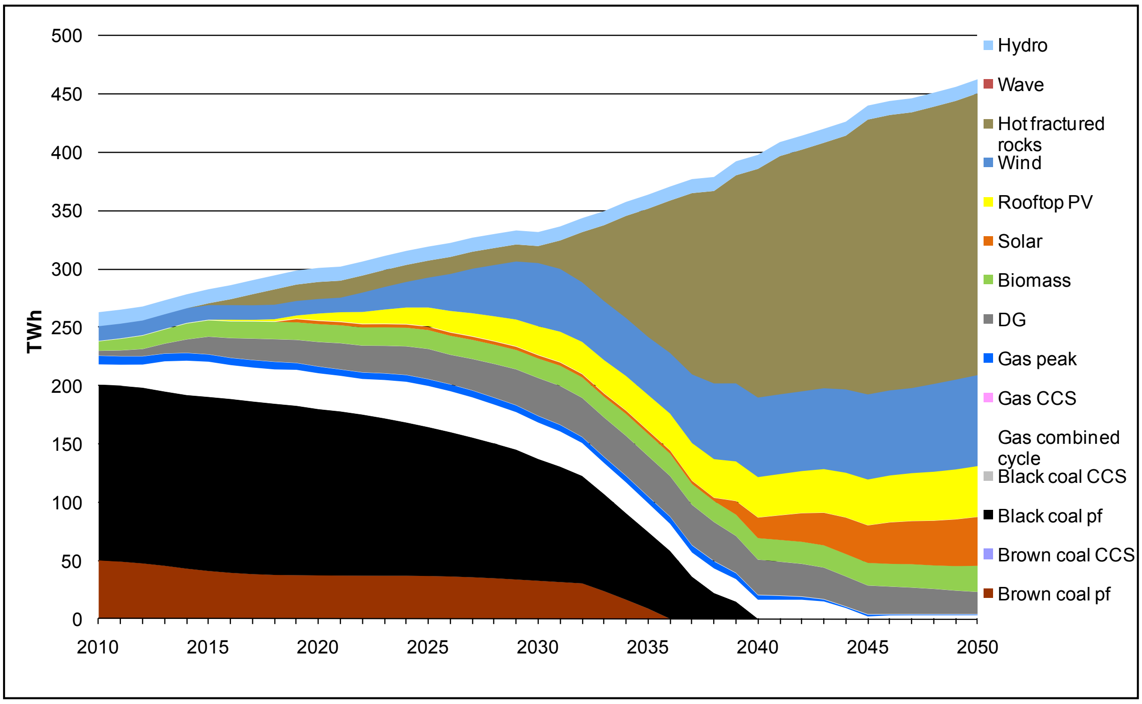

Figure 32: Projected electricity generation in Australia under CPRS-5 carbon price scenario under HFR case.

13 APPENDIX D – SPECULATIVE TECHNOLOGICAL CHANGES

13.1 CONTEXT

In this section we examine some key energy technology areas that are not yet well established and which may never be widely established. We have selected them on the basis that they have a credible potential to make a significant impact on electricity production over the next two to five decades.

13.2 RESIDENTAIL AND COMMERCIAL BUILDING EFFICIENCY

Energy consumption and greenhouse gas reductions of up to 50% are quite feasible for existing and future office and domestic buildings. Both conventional and new technologies will contribute to these reductions with HVAC emissions and demand being reduced through trigeneration, natural gas fuel cells such as Blue Gen, passive heating and cooling, increased use of solar power to supplement heat pumps, and strategies analogous to trigeneration being applied to residential buildings through utilisation of the waste cooling or heating energy from HVAC systems integrated with appliances such as hot water supply. However, such savings could be offset by increased demand as the population increases.

13.3 CARBON SEQUESTRATION

Carbon capture and sequestration (CCS) is a well known process that is being developed for use with coal fired power stations and coal or gas to liquid fuel conversion. CCS has been taken into account in current energy economic projections. New methods of carbon sequestration, if accepted in a carbon accounting system, may significantly reduce the demand for low emissions technology. For example:

- Sequestration methods that add stable carbon to soil such as biochar[i]
- Iron fertilization to stimulate phytoplankton growth and thereby sequester carbon in the oceans[ii]
- Chemical scrubbing processes to remove CO2 from air, for example the artificial tree proposed by Klaus Lackner[iii] .

13.4 ALTERNATIVE METHODS FOR ELECTRICITY GENERATION FROM FOSSIL FUELS

It is becoming increasingly cost effective and efficient to generate electricity locally from natural gas using fuel cell technology. For example the commercially available 2KW BlueGen unit can reduce carbon dioxide production by 33 tonnes per year when compared against the equivalent power from a brown coal fuelled power station [iv].

Such technologies have the potential to significantly reduce building dependence on the electricity from coal fired power stations and as building density increases could supply a major proportion of commercial and residential buildings for which both solar how water and solar PV are not available.

13.5 ELECTRICITY GENERATION USING RENEWABLE ENERGY

The available resource for renewable energy in Australia is huge and becoming increasingly cost effective. However, renewable energy is limited in its application to about 30% of electricity supply by its intermittency. This could be greatly increased if any or all of the following were available:

- Better methods of energy storage e.g.
    - pumped hydro energy storage
    - improved electrochemical conversion methods where energy may be stored in anode, cathode or electrolyte materials
- Low loss grid interconnects to shunt renewable energy from its origin to its point of consumption
- Renewable energy resources with greater availability factors, such as ocean renewable energy.

Of all the renewable energy options solar photovoltaic technology shows perhaps the greatest potential for dramatic improvement with the economic model already projecting transitions between learning curves as a result of technology development.

13.5.1 SOLAR PHOTOVOLTAICS

Technology Description

Over recent years the main topic of research for conventional solar PV has been to increase efficiency levels and decrease costs. Efficiency levels have tended to creep up a percentage point or two each year in the laboratory to just over 40%[v], although commercial cells are tailing somewhat at around 15%[vi]. Although the silicon that is the dominant component of cells is widespread and easily obtainable, to purify it to the level required for PV is extremely expensive, so efforts have been made to identify ways of reducing the amount of silicon required, or to use other materials. Standard silicon wafers are also very brittle, meaning they require care (and thus expense) when manufacturing, in addition to being more prone to damage than other power generation systems. This is why even large-scale PV systems are an incredibly expensive way to produce electricity[vii]. Novel cell types which aim to avoid these problems have emerged from laboratories in recent years.

The California Institute of Technology[viii] (Caltech) cell consists of a dense array of short silicon wires (each 1 micron across, and 30-100 microns long). This design means incident photons get trapped and absorbed by the wires. With certain wavelengths absorption has been improved to 96%, with the average over the frequencies of sunlight that is useful to collect about 85%. Of those photons that are absorbed, 90-100% result in an electron which produces electricity - i.e. overall a fourfold increase over current cells[ix].The overall amount of silicon in the cell is also decreased to just 2% of the volume, with the remaining 98% being much cheaper polymer. Another advantage is that the cells are fairly flexible, especially compared with the brittleness of conventional flat wafers which means they are cheaper to manufacture. This should result in a cell that is not only four-five times more efficient at producing electricity over a given area, but a similar amount (or more) reduced in price to possibly under $250/kW, one-third less than the cheapest fossil-fuel system (advanced open cycle gas turbine)[x], with running costs for large-scale systems dropping to below 5 $/MWh[xi].

The Idaho National Laboratory[xii] (INL) and Microcontinuum Inc. cell has tiny loops of conducting metal stamped onto a sheet of plastic (nanoantennae), and as such is also cheap and flexible. Unlike conventional cells however, these are designed for turning infrared (heat) photons into electricity. Therefore, this cell has the advantage that it will create energy even when it is dark (in fact, even if underground). However, the level of energy produced will be substantially less in the dark, and there is less energy in an infrared photon than a visible photon, so overall less energy per unit area will be produced. However, the nanoantennae can theoretically transform 80% of the energy they receive into electricity, which is still four times more efficient than current solar cells.

State of Development

The Caltech researchers have already produced cells of a few square centimetres in size, and are now in the process of scaling them up to hundreds of square centimetres, the size of normal cells.

Although the INL cells are easily manufactured, the researchers have still not worked out a way to turn the currents produced in the nanoantennae into a form suitable for powering electrical appliances or charging batteries. This and other issues mean the cells are still at least a few years away from being commercialised.

Strengths and Challenges

The Caltech cell is potentially at least 20 times more cost effective than existing PV cells. This also makes it more efficient than wind turbines and competitive with producing electricity from coal. The potential flexibility and enhanced robustness of the cell also means that they can be installed just about anywhere there is sun. The challenge will be to get this technology into commercial production.

The INL cells could complement the Caltech cells, as they are also very efficient, but operate in a different spectral band. Their ability to produce electricity at all hours finally gives solar energy the ability to produce baseload power, although at much reduced levels when the Sun is not showing. The challenge will be to convert the energy harvested in the nanoantennae into useful power.

Priorities for Further Development and Demonstration

The priorities for future development with the Caltech cells will be to increase the effective cell size to the scales required for commercial production and to commercialise the technology. Given the challenges that have already been met with previous generations of solar PV technology that were much less efficient and harder to construct, it seems unlikely that this would be much of an issue, so it is quite possible that commercial quantities of this type of cell will be available before 2020.

The INL cell faces a few more challenges in terms of power harvesting and resonance effects, but it is still quite possible that commercial quantities will also be available by 2020. The move into harvesting non-visible parts of the spectrum is also likely to be extended – whilst infrared photons have less energy than those in the visible spectrum, ultraviolet light has more, and a substantial amount of ultraviolet light makes it through our atmosphere to the ground. As such cells making use of this energy could further extend the reach of solar cells.

Given the potentially flexible nature of these cells, there will also be extensive research in the future incorporating it into buildings, vehicles and even clothing, to power the increasing array of electrical devices that are appearing.

Disruptive Effect

With a twenty plus-fold improvement in energy production per unit price, and the ability to provide at least low levels of baseload power, these technologies have the potential to cause a major disruption in the energy production field worldwide, and especially in those countries that receive decent levels of sun year-round, such as Australia.

A large scale PV system could contain cells of both types utilising the INL cells' ability to produce power when the Caltech cells can't provides the equivalent of baseload power and power smoothing. Such units would be even more cost competitive than brown coal fired power. At the very least, these cells could certainly do away with the need for peaking power plants, and with a much higher level of power produced in urban environments could also do away with most of the need for centralised power production, although large-scale energy farms could make the provision of power to other nearby countries (e.g. Papua New Guinea and Indonesia) economically feasible.

These technologies could also give a major boost to vehicle electrification. With the dramatic reduction in price and increase in efficiency and flexibility, it would become cost-effective to coat the entire upper half of a vehicle with these cells. This would reduce the need for battery storage in the vehicle. Also, if these vehicles could then be left outside during the day and plugged into the grid they could contribute substantially to the energy requirements of business and industry.

13.6 NUCLEAR

Technology Description

Nuclear energy, from atomic fission of uranium supplies about 14% of the world's electricity[xiii] and is arguably a low greenhouse gas resource, provided the uranium is extracted from rich ore deposits. However, with current technology only 0.7% of the uranium, as U235, is fissionable contributing to energy production. Principal issues with this energy resource are:

Fuel availability

Hypothetically if uranium were used with current technology there is enough resource to supply all the world's energy needs for about 50 years. This could be increased by a factor of x400 if reactors were developed to efficiently use thorium, which is three times as available as uranium and where 100% of the fuel can be utilised compared with 0.7% for uranium. The largest resources for thorium are in Australia and India. India is the world leader in research towards thorium powered reactors[xiv]. An international research program 'The Generation IV International Forum' is developing fast neutron reactors that will be able to consume most of the uranium as fuel, extending the resource by a factor of x140 and greatly reducing the quantity and lifetime of waste[xv].

Waste products

Currently nuclear waste remains highly radioactive for up to hundreds of thousands of years. By consuming the waste as fuel Generation IV reactors have the potential to reduce the amount of waste they produce as well as remove pre-existing waste products. In addition the radioactivity lifetimes can be reduced by several orders of magnitude to tens or a few hundred years.

Reactor Safety
Research is ongoing into reactor safety and the track record is improving significantly. However, the Generation IV reactors will bring their own safety challenges.

Weapons Proliferation
It is hard to see how this can be avoided no matter how well guarded or fail safe a particular nuclear fission technology may be. A world that relies to a great degree on fission reactors will require a broad base of associated technologists and the presence of this skill base increases the probability that these skills will be applied to the production of nuclear weapons.

Fusion
Nuclear energy is produced from fusion reactors by combining atoms under intense temperature and pressure to produce new atoms of higher atomic number. Well known reactions being researched for producing net energy include: i) those that produce significant levels of neutrons: deuterium with itself or with tritium or helium and ii) the so called ‘aneutronic’ reactions of hydrogen with lithium or with boron.

The two most well known and most highly funded programs of research for fusion reactors are i) the ITER Tokamak, which uses a toroidal structure to confine a plasma required to produce fusion ii) The National Ignition Facility at Lawrence Livermore laboratories, which uses the force and temperature generated by a cluster of laser beams simultaneously colliding with the fuel pellet. These programs aim for commercial power generation within three or more decades. Less well known are a cluster of smaller ‘aneutronic’ fusion programs that are well founded in scientific theory but with considerable risk by virtue of their relatively small scale. This same small scale is argued to be a reason why such research may prove rapidly realisable as a commercial product should the technique be effectively demonstrated. The aneutronic fusion reactions have the additional advantage that the energy released can be converted to electricity without an intermediate thermal stage. A relatively well known example is the ‘Focus Fusion’ project.

There are frequent claims that the fuel for fusion reactions is effectively limitless. This ignores the need for co-reactants such as lithium either in its own right or to produce tritium; or boron. These elements while abundant are also in great demand for many applications. The principle advantages of the fusion reactor program are:

- A fuel resource with long term prospects
- The intrinsic safety of the reactors
- The incompatibility of the industrial infrastructure that supports the technology with the production of nuclear weapons.

Fusion/Fission Hybrids
These are devices that use the neutrons from fusion reactors to create long lived fuel resources for fission reactors. Arguably they have the advantages and disadvantages of both fission and fusion technologies. They are not likely to reduce the risk of weapons proliferation at least according to the argument presented above.

13.7 IN SUMMARY

It would be virtually impossible for a mathematical model of the economy to predict what effect some of these speculative technologies would have upon the world; you would be served better by reading an assortment of science fiction novels by leading authors. However, they could very well make every other source of power generation, and conventional fuel supply, redundant within the space of a few years, which would have a dramatic impact upon the economy of the world *never* seen previously.

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[i] http://www.csiro.edu.au/files/files/pwiv.pdf
[ii] http://cdiac2.esd.ornl.gov/ocean.html
[iii] http://www.earth.columbia.edu/articles/view/2523

[iv] 'Comparison of the BlueGen Fuel Cell Unit with other means of providing Electricity and Heat to Australian Homes'; Peter K. Campbell; Report R722-12-2/1/F1.4; for Ceramic Fuel Cells Limited http://www.cfcl.com.au/

[v] http://www.technologyreview.com/Energy/18910/
[vi] http://www.renewableenergyworld.com/rea/news/article/2009/04/ecn-reaches-16-4-efficiency-with-multi-crystalline-pv
[vii] http://www.jcmiras.net/surge/p130.htm
[viii] http://media.caltech.edu/press_releases/13325
[ix] http://www.nature.com/nmat/journal/v9/n3/full/nmat2701.html
http://www.stanford.edu/group/cui_group/papers/nmat2701.pdf
http://www.rsc.org/chemistryworld/News/2010/February/14021001.asp
[x] http://www.jcmiras.net/surge/p130.htm
[xi] http://www.unenergy.org/Popup%20pages/Comparecosts.html
[xii] https://inlportal.inl.gov/portal/server.pt?open=514&objID=1269&mode=2&featurestory=DA_101047
[xiii] International Energy Agency (2010), "World Energy Outlook 2010", OECD, France.
[xiv] http://www.world-nuclear.org/info/inf62.html
[xv] http://www.gen-4.org/

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