Renewable Energy Technology Cost Review

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Executive Summary - Renewable Energy Technology Cost Review

This paper has undertaken a review of current and future costs of three forms of renewable energy technology, comparing data from a range of international and Australian-specific studies, taking care to compare data on the same basis of financial assumptions (discount rates) and resource quality. The purpose was to compare both the current costs, along with the rate of decrease, and the reason for differences between the studies. The Australian-specific datasets are the 'Australian Energy Generation Technology Costs' report by EPRI, and the 2010 dataset used by the Australian Energy Market Operator (AEMO), largely based on the EPRI data with a review from ACIL Tasman.

The assessment reviewed technical and economic parameters of wind, photovoltaic and solar thermal energy generation technologies, considering technology specific learning rates and cost reduction potentials. It includes a detailed exploration of the factors contributing to the learning rates and cost reductions.

Common financial assumptions (in particular discounting rates) are used, to provide a common basis of comparisons and analysis. These parameters were utilized in Levelised Cost of Energy (LCOE) calculations to develop cost outlooks, and compare the outlooks to other projections. Where relevant, LCOE is calculated from capital & operating cost data at a common renewable resource level, and includes the revenue generated from the sale of Renewable Energy Certificates, priced under a simplified assumption at an unchanging $50/MWh.

The international analyses tended to indicate cheaper costs for all of the solar and wind technologies than the AEMO dataset. Some of this difference can be attributed to the AEMO dataset's focus on the Australian-specific context of the technologies. However, especially in the case of the solar technologies (both PV and thermal), the rate of cost reduction expected from the global analyses is faster than that in the AEMO dataset. In both cases, AEMO costs in 2030 were higher than, and outside the range of, the 2020 costs from the international analyses.

The renewable technologies of PV and wind have historically shown that a large proportion of cost reductions have come from the learnings and economies of scale associated with large-scale global deployment, and not just improvements in technical efficiency. This is made particularly apparent when displaying a technology learning curve as a function of cumulative installed capacity, rather than time. Therefore any projection of a cost curve over time has an inherent assumption, whether explicit or not, of the expected growth in deployment of the technology.

With this in mind, when considering scenarios for new energy technology development and deployment, especially in the context of shifting away from greenhouse gas emitting energy sources, initial higher costs of renewable energy should not be considered a barrier to deployment. Rather, the focus should be on whether learning curves can give confidence that the technology is able to achieve desirable cost reductions within an acceptable timeframe, and how much the rate of deployment is expected to change the rate of cost reduction.

The key findings of this assessment are summarised below for each of the three technologies.

Photovoltaic

The installed capacity of photovoltaic has grown at rate of 40% over the last decade. As the industry has grown PV module prices declined along a well established learning curve, which has seen cost reductions of 22% for each doubling of cumulative capacity, over the last few decades. An excursion from this historical rate occurred due to supply bottlenecks and market dynamics from 2003 to the end of 2008. The learning curve has since returned towards the historic, and the global installation capacity increased to 10 Gigawatt-peak (GWp)/annum in 2010.

The International Energy Agency (IEA) and the EPIA expect further cost reduction with increased production capacities, improved supply chains and economies of scale. China has experienced a 20-fold increase in production capacity in four years, increased expansion of global production capacities for key components (including modules and inverters) and is continuing to exert downwards pressure on prices. A surge in silicon production capacity (a key commodity) has both alleviated supply constraints, and continued to increase. Technological cost reduction opportunities include improvements in efficiency for the different cell types. Based on these drivers, the IEA and EPIA have made cost projections using learning rates of 18%, slightly lower than the historical average of 22%.

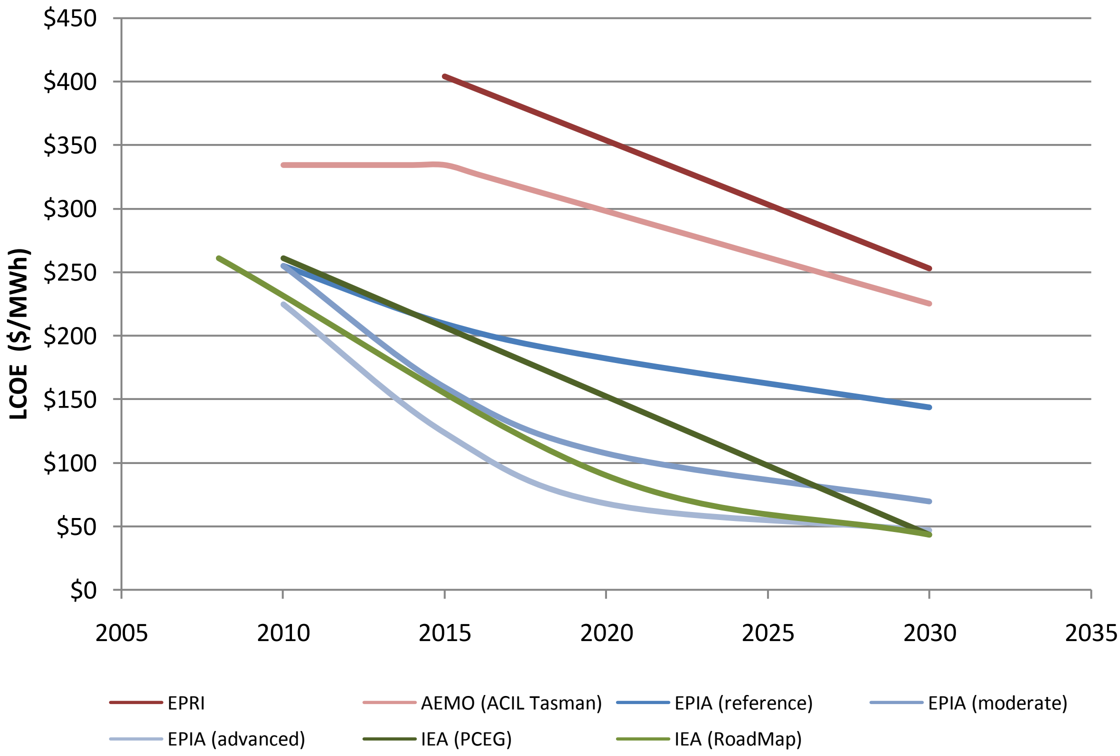

Figure 1: Solar photovoltaic cost projections (Direct Normal Irradiation = 2445 kWh/m2/yr)

The key findings are:

- The EPRI & AEMO data has higher starting costs compared to international studies
- The international studies, with the exception of the EPIA reference scenario, have slightly higher rates of cost reduction base on continuation of historical learning rates.

Wind

Wind energy generation has expanded rapidly in the previous decade 2000-2010, with installed capacity growing at 28% and doubling every 3 years. Wind capital costs have tracked along a learning curve as this capacity has grown, and the expectation of all of the studies reviewed is for the trend to continue as the expansion of the wind industry continues. Key commodity constraints and supply chain bottle necks have hampered cost reductions in the past few years. With larger scale (and largely automated) manufacturing, these bottlenecks have been alleviated. More recent developments have seen wind technology costs continue along historic learning rates. Incremental technological improvements represent a significant potential for cost reductions, with anticipated improvements resulting in larger, more efficient turbines.

The IEA and the Global Wind Energy Council (GWEC) expect that modest cost reductions will continue, due to economies of scale (as a result of continuing industry expansion, especially Chinese manufacturing), alongside stronger supply chains and technological improvements. The major technical cost reduction opportunities include increasing turbine size, hub height, and the elimination gearbox losses via the use of direct drive turbines.

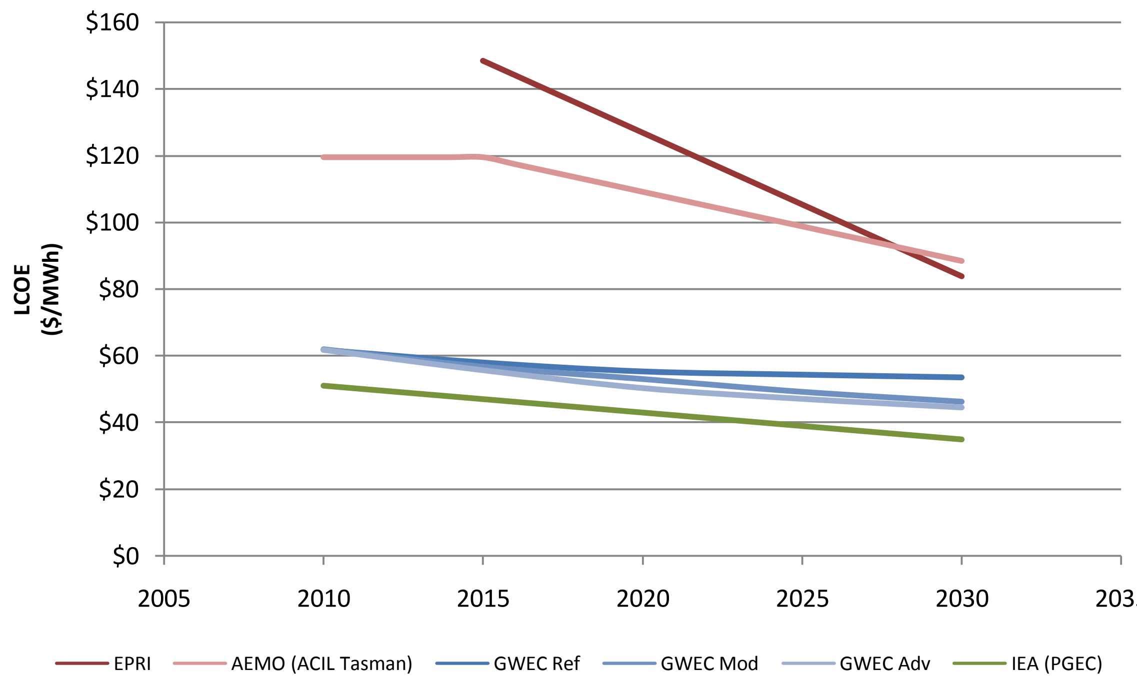

Figure 2: Wind power cost projections

The key findings are:

- The starting costs for the AEMO and EPRI results are higher than the international analyses. Some of this could likely be attributed to the Australian-specific context of these studies.
- The rate of cost decrease over time is similar for the studies, with the EPRI data showing the fastest rate of reduction, albeit from the highest starting point.

A useful next step of analysis would be to compare these costs against data available from current Australian wind power projects.

Concentrating Solar Thermal

For concentrating solar thermal (CST, or also known as CSP – concentrating solar power) technology, which is less mature than wind and solar PV, a range of sources indicate that there is significant cost reduction potential, from known technical improvements, economies of scale and industry learnings from continued deployment, similar to the observed learning rates of wind and PV. Importantly, the US DoE expects that around 50% of the potential cost reductions will be a result of industry scale and learnings, which will require the initial deployment of the technology at higher cost to allow these cost reductions to occur.

Primary studies reviewed include:

- The International Energy Agency's Concentrating Solar Power Roadmap
- The U.S. Department of Energy's CSP Program Power Tower Roadmap
- Solar Thermal Electricity 2025, by A.T. Kearney with the European Solar Thermal Electricity Association (ESTELA)

These each performed assessments of cost reductions for major plant components, taking into account expected growth and experience. The major opportunities include mass-manufacture of mirror components; implementation of higher temperature steam cycles and storage; scale-up of plant sizes; and convoy/experience effects on engineering and indirect overheads. Power tower (central receiver) solar thermal systems are expected to be cheaper than parabolic troughs.

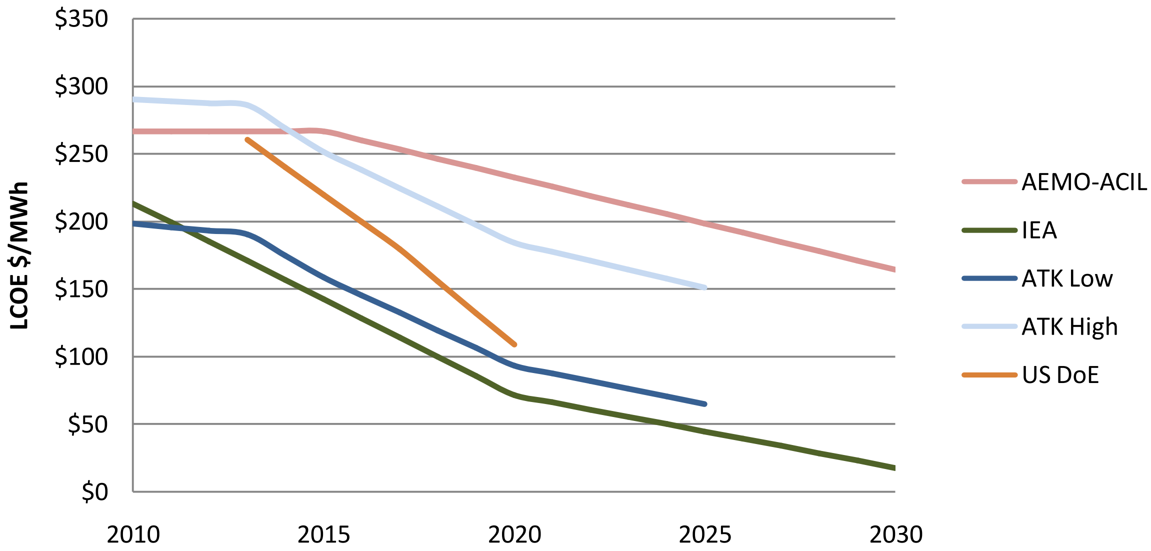

Figure 3: CST cost projections, at Direct Normal Irradiation of 2400 kWh/m2/yr.

The key findings are:

- The starting costs of the AEMO data is similar to the range from the international studies.
- The international studies indicate a faster rate of cost reduction to 2020. As discussed in the full report, AT Kearney has indicated that the low end of their range is more representative of real projects while the upper end represents a worst-case scenario.
- The rate of cost reduction 2020-2030 is similar for all analyses, though it is not clear why the AEMO data differs prior to 2020.
- Note that using a REC in the 2025-2030 timeframe delivers nonsensical results for IEA data.

Table of Contents

1. Introduction

This report assesses the recent developments in renewable energy generation technology, based on a range of analyses and reports from international sources. The primary objective is to review current cost outlooks, and compare the outlooks with those currently used by the Australian energy industry, in particular the dataset currently used by the Australian Energy Market Operator (AEMO), based on a the 'Australian Electricity Generation Technology Costs – Reference Case 2010' study carried out by EPRI for the Federal Department of Resources, Energy & Tourism. This study uses the 'Levelised Cost of Energy' metric to determine cost outlooks, and compare different cost projections.

The primary studies reviewed containing detailed cost information were:

Solar Photovoltaic

International Energy Agency – Projected Costs of Generating Electricity 2010

International Energy Agency – Technology Roadmap – Solar Photovoltaic Energy (2010)

European Photovoltaic Industry Association – Solar Generation 6 (2011)

Wind

International Energy Agency – Projected Costs of Generating Electricity 2010

Global Wind Energy Council – Global Wind Energy Outlook 2010

Concentrating Solar Thermal

International Energy Agency – Technology Roadmap - Concentrating Solar Power (2010)

Sandia National Laboratories (US Department of Energy) – Power Tower Cost Reduction Roadmap (2011)

AT Kearney Consulting with European Solar Thermal Electricity Association (ESTELA) – Solar Thermal Electricity 2025

Sargent & Lundy Consulting – Assessment of Parabolic Trough and Power Tower Solar Technology Cost and Performance Forecasts (2003)

2. The Levelised Cost of Energy

2.1. Introduction to LCOE

The Levelised Cost Of Energy (LCOE) is the most transparent metric used to measure electric power generating costs, and is widely used as a tool to compare the generation costs from differing sources. The LCOE is a measure of the marginal cost (the cost of producing one extra unit) of electricity, over an extended period, and is sometimes referred to as Long Run Marginal Cost or LRMC.

The LCOE is representative of the electricity price that would equalize cashflows (inflows and outflows) over the economic life time of an energy generating asset. It is the average electricity price needed for a *Net Present Value (NPV)* of zero when performing a discounted cash flow (DCF) analysis. With the average electricity price equal to the LCOE, an investor would breakeven and so receive a return equal to the discount rate on the investment.

The LCOE is determined by the point where the present value of the sum discounted revenues is equivalent to the discounted value of the sum of costs[1]:

$$\sum_{t=0}^{n} \frac{\mathrm{Revenue}}{(1+\mathrm{r})^{\mathrm{t}}} = \sum_{t=0}^{n} \frac{\mathrm{Costs}}{(1+\mathrm{r})^{\mathrm{t}}}$$

Where:

n	=	Project lifetime (yrs)
t	=	Year in which sale or cost is incured
r	=	Discount rate (%)

By definition this is the point at which the *Net Present Value* (summation of the *Present Values, PV,* of the cashflows) for a project is zero[2]:

$$NPV = \sum_{t=0}^{n} PV = 0$$

Where:

$$PV = \frac{EBIT\ (1-T)\ + DEP - CAPEX}{(1+r)^t}$$

And:

EBIT	=	Earnings Before Interest and Tax
DEP	=	Depreciation
CAPEX	=	Capital Expenditure
T	=	Corporate Tax rate (%)

2.2. Discount Rate:

One of the most important assumptions and input parameters is the discount rate. This input represents an appraisal of the *time value* of the money used in the investment. This value is dependent on the type of investor and their respective financial market, and is representative of the return expected (or the cost) of the particular capital. Money from the risk averse debt market maybe available at a nominal rate of 8%, where as the equity market, which takes on higher risk, will be available at a higher nominal rate of, say, 13%.

This discount rate is particularly important in the context of renewable energy generating assets, due to their inherent capital intensity. This can be contrasted with technologies with higher operating costs (for example open cycle gas turbines). Whilst the LCOE for these technologies is affected by the choice of discount rate, the impact is less pronounced and they are less sensitive to variations in the discount rate.

Typically, the initial investment comprises of a combination of both debt financing and equity financing. When this is the case, it is appropriate to use the *Weighted Average Cost of Capital (WACC)* as the effective discount rate. The WACC is calculated by weighting the individual costs by the proportion of each funding type[2]:

$$WACC = \frac{D \times k_d \times (1-T) + E \times k_e}{D + E}$$

Where:

D	=	Amount of Debt
k_d	=	Cost of Debt
E	=	Amount of Equity
k_e	=	Cost of Equity
T	=	Corporate Tax Rate

Tax is considered in our cash flow analysis, and all the cash flows are considered to be in real 2010 Australian Dollars. As such, a *post-tax*, *real* WACC is used. We use a discount rate of 8.1% to comply with the ATSE analysis, which assumes a 75-25 debt-equity split, and a real debt cost of 7.3% and a real, pre-tax equity cost of 17%. Given the sensitive nature of the discount rate, the same rate as ATSE analysis was used to enable a consistent basis, for comparison.

2.3. Other Financial Assumptions

Global Assumptions

Tax: The corporate tax rate is assumed to be 30% for the purposes of all cash-flow analysis.

Depreciation: The electric utility industry typically uses the *straight-line* method, which was used in this analysis. For a 25 year lifetime, the annual depreciation is 4%, and for a 30 year lifetime, the annual depreciation is 3.33%.

Exchange Rates: In line with the Mid Year Economic Financial Outlook approach, the exchange rate is assumed to remain around the levels seen at the time the forecasts were prepared[3]. As of March 01 2011, a US$ exchange rate was $0.985[3] used, and an EU€ exchange rate of $0.70 was used[4].

Construction Period and Economic Lifetime

The construction period and economic lifetime can have a considerable affect on the levelised cost of generation. This is particularly important for protracted construction periods (lead times). The economic and lifetimes and construction periods used are presented in Table 1, and are based on the AEMO dataset[5]. The IEA reports wind construction periods of 1 year[1] (unlike AEMO), and the effects of this are explored in Appendix III.

Table 1: Construction periods and Economic Lifetimes

Technology	Construction Period	Economic Life Time
Wind	2 year	30 years
Solar PV	1 year	30 years
Solar Thermal	2 years	30 years

The Capacity Factor

In the case of renewable energy generators the assumed capacity factor of a facility has a significant impact on the LCOE. For renewable energy generators, the capacity factor is generally dependant on the quality of the renewable resource. In the interests of a consistent approach, constant capacity factors were used for each technology type. These capacities were based on reasonable resource qualities for Australian conditions, summarized below in Table 2, as used in the EPRI study[6].

Table 2: Capacity Factors

Technology	Resource Quailty	Capacity Factor
Wind	6.8 m/s	30%
Solar PV	2445 kWh/m^2/yr	20%
Solar Thermal	2400 kWh/m^2/yr	Varied by plant storage configuration

Technology Specific Inputs

The remaining parameters are specific to the technology type. These include capital cost, operation and maintenance costs, which are explored in the report.

To demonstrate the modelling, Appendix I shows the levelised costs calculated, and compares against the ATSE modelling results. The results for different technologies (Wind and CST), including the technology specific inputs, are included in the appendix.

3. Context: Fossil Fuel Levelised Costs Of Energy & Renewable Energy Certificates

The calculated LCOE's for the renewable energy technologies in this study are potentially misleading if not put in context with the cost of new entrant fossil generation. The LCOE's for two fossil fuel technologies, Pulverised Coal (PC) and Combined Cycle Gas Turbine (CCGT) were calculated to provide a reference frame, using the same financial parameters.

The data used to determine the LCOE was taken from the AEMO scenario 1 dataset[5], and included capital costs, thermal efficiencies, O&M costs, construction profiles and fuel price projections. The LCOE's are presented in Figure 4, with the upper and lower bounds of the LCOE represent the high and low fuel price estimates for the two technologies (the PC is assumed to be a black coal plant).

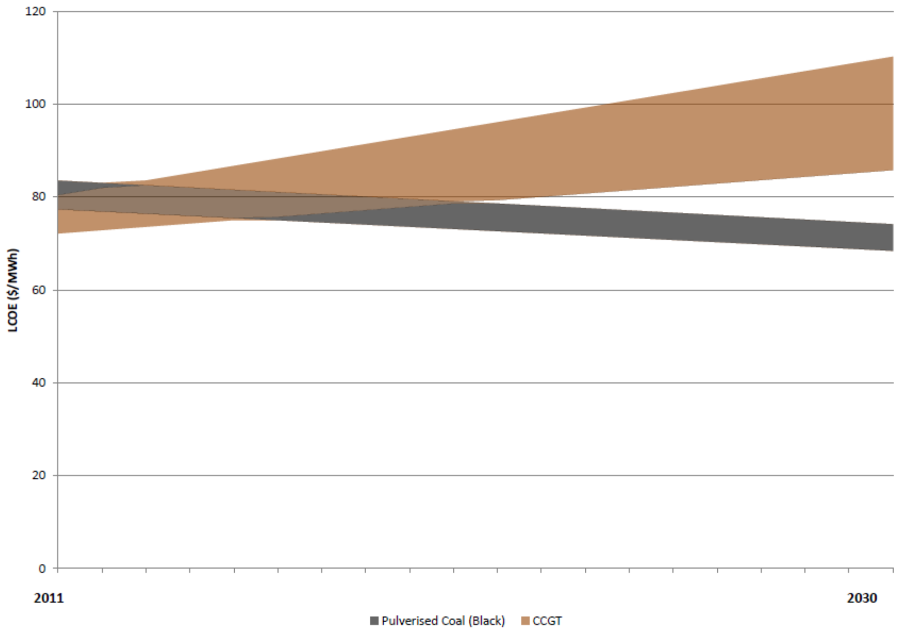

Figure 4: Levelised costs for fossil fuel power stations

Renewable Energy Certificates

The Large-scale Renewable Energy Target (LRET) scheme mandates that 41,000 GWhs of large-scale renewable electricity is supplied to the Australian electricity market by 2020, with targets for individual years up to 2020 that ramp up to the final target. The target is achieved by retailers purchasing Renewable Energy Certificates (RECs) from the generators, which have a dollar value per MWh of renewable energy generated. This certificate value is intended to bridge the gap between the fossil fuel electricity generation costs and the renewable energy electricity generation costs. For the purposes of this study, a constant $50/MWh REC value is used in the LCOE calculation. In reality, the scheme is a market mechanism and the price will vary, with the value of a REC should representing the difference between the LCOE of the least cost renewable energy on the market (likely wind power), and the wholesale fossil fuel generation cost. Therefore it is likely to be higher than $50/MWh in the short term, but could reduce to this price or lower in the long term. There are some cases in the international cost projections shown where using a REC towards the end of the cost curve actually delivers an LCOE lower than today's price of fossil electricity. In reality, if this occurs then the price of RECs will fall, and if the renewable technology reached parity with fossil fuels then the REC price would be zero.

4. Learning curves of energy generation technologies: an in-depth analysis

The analysis considers the factors and trends for learning rates in several renewable energy generation technologies. A useful forecast tool for the cost reductions of energy technologies is the 'Grubb' curve. At initial stages of technology conception, costs tend to be underestimated. As they reach the point of commercialisation and deployment, the costs tend to increase with comprehensive engineering assessments and real-world implementation. After the point of commercialisation, costs tend to reduce due to a combination of factors, and eventually cost reduction rates reduce as technologies mature. Different technologies can be mapped onto different segments of the curve.

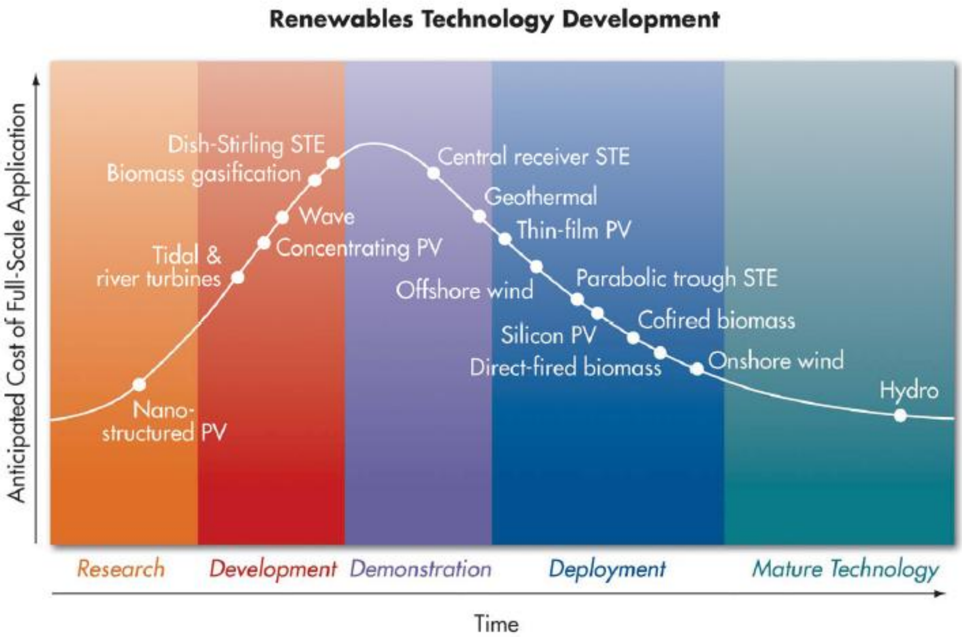

Figure 5: Grubb curve for renewable energy technologies, from EPRI (2010)

4.1. Learning rates

In many high-level analyses, the generic term 'learning rate' is used to describe the rate of costs reductions during commercial deployment. A range of specific factors contribute to reducing costs. These can be divided into two broad categories

Technological improvements – changes to the basic design of the technology.

'Learning by doing' – refers to the technical and management experience gained during the construction and operation of power plants leading to more streamlined, efficient methods of building and operating plants. A relevant example, is from SENER (Spanish engineering company) who has developed a type of parabolic trough mirror support strut that is simpler to manufacture and assemble, leading to a four-fold increase in the speed of mirror assembly for concentrating solar plants.

Technical efficiency – refers to Research & Development. Upgrading to state-of-the-art components, experience pushing operational envelopes or otherwise, the technology becomes overall more efficient by increasing output or decreasing wasted energy or materials. Upgrading from subcritical to supercritical steam turbines in thermal power plants, and incremental gains in the efficiency of photovoltaic cells are examples of technically efficiency improvements.

Economies of scale – increase in the size or volume of units results in lower costs per unit.

Economies of scale in the physical size of components – refers to the efficiency gains in construction, attributed to increased scale of industrial units. A 50 MW steam turbine requires the same complexity of piping, condensers, control systems and pressure relief systems as a 250MW turbine, with the main difference being the larger size of components for the larger turbine. On a per-MW basis, larger turbines are generally cheaper, the wind industry has demonstrated this with today's wind turbines an order of magnitude larger in output than 20 years ago. The effect is particularly important where the costs of design and construction are large relative to the raw material cost.

Economies of scale through large-volume manufacturing – refers to manufacturing efficiency gains achieved by producing very high volumes. When an industry reaches a scale where dedicated component factories can be built with the certainty of an ongoing market, unit costs come down significantly, as has been the case with solar PV and wind.

4.2. The Experience Curve and Learning Rate

The development and economics of renewable energy is sometimes illustrated by the use of the experience curve. Experience curves show that cumulative quantitative development of a product relates to the development of the specific costs.

Experience curves reflect the reduction in the cost of energy achieved with each doubling of capacity – known as the progress ratio. If the cumulative deployment of a technology doubles, the learning rate represents the achieved reduction in costs. The graph of the log of the costs versus the log of cumulative installed capacity will follow a straight line. This is well demonstrated by photovoltaic industry.

The progress ratio (P) is related to the Learning rate (L) by the following expression:

$$P = 1 - L$$

Historic data with steady learning rates allow for extrapolation into the future, and allow estimations of when a technology will reach as certain price level. It demonstrates the development that may be seen if the existing trends continue in the future.

The learning rate represents the effect of mass production (economies of scale) and the effect upon production costs without taking other causal relationships into account, such as the cost of raw materials or the demand-supply balance in a particular market (seller's or buyer's market).

5. Photovoltaic Technology

5.1. Introduction

Photovoltaic (PV) capacity has exhibited an average annual growth rate of 40% over the last decade (see Figure 6). The installed capacity almost increased by 50% between 2008 and 2009 from 15.7GW to 22.9 GW[7]. The EPIA expects the total installed capacity at the end of 2010 is to be between 32 and 38 GW.

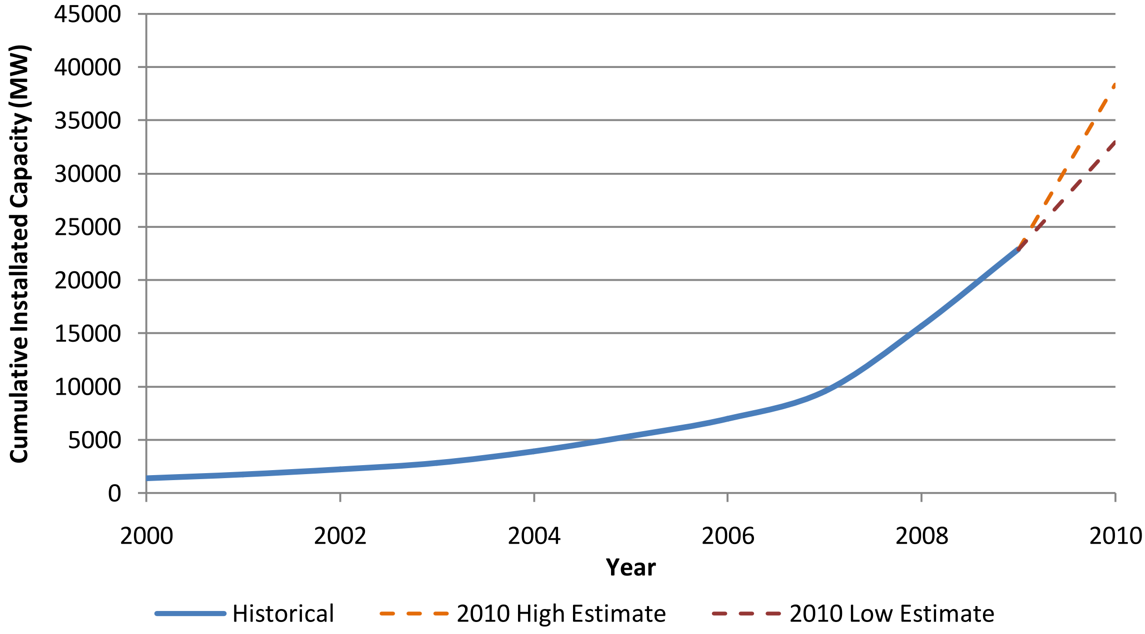

Figure 6: World Cumulative PV power installed[7]

Solar PV generates electricity through the direct conversion of sunlight. The basic building block of the PV system is the cell, which is a semi-conductor device which converts solar energy into direct current electricity. PV cells are interconnected to form the PV module.

There are many different types of PV cells. Single crystalline silicon and multi-crystalline silicon represent 85-90% of the PV market. Thin film PV cells represent 10%-15% of the PV market, and have many several different categories. Thin film cells less efficient, but cheaper, and crystalline silicon cell are more expensive.

Utility scale PV systems are generally built directly on the ground, and are typically between 1MW and 50MW in size. The module is combined with a ground based, mounting system, to create the solar collector array. The modules within the array are connected to an inverter, which converts the DC power into AC power, which is then transformed at a substation, for distribution in a high voltage transmission line.

1.1.1. Generation costs for PV Solar Power

The key parameters that govern the cost of PV power are the capital costs the solar resource and the discount rate. Other costs are the variable costs including operations and maintenance costs. Of these parameters, the capital cost is the most significant and provides the largest opportunity for cost reduction.

The capital costs themselves fall into one of two broad categories; the *module* and the *balance of system* (BOS). The *module* is the interconnected array of PV cells and incorporates feedstock silicon prices, cell processing and module assembly costs. The BOS includes structural system costs (structural installation, racks, site preparation and other attachments) and electrical system costs (the inverter, wiring and transformer and electrical installation costs). A breakdown of the costs for a ground mounted system as suggested by the Rocky Mountain Institute is illustrated below in Figure 7[8,9].

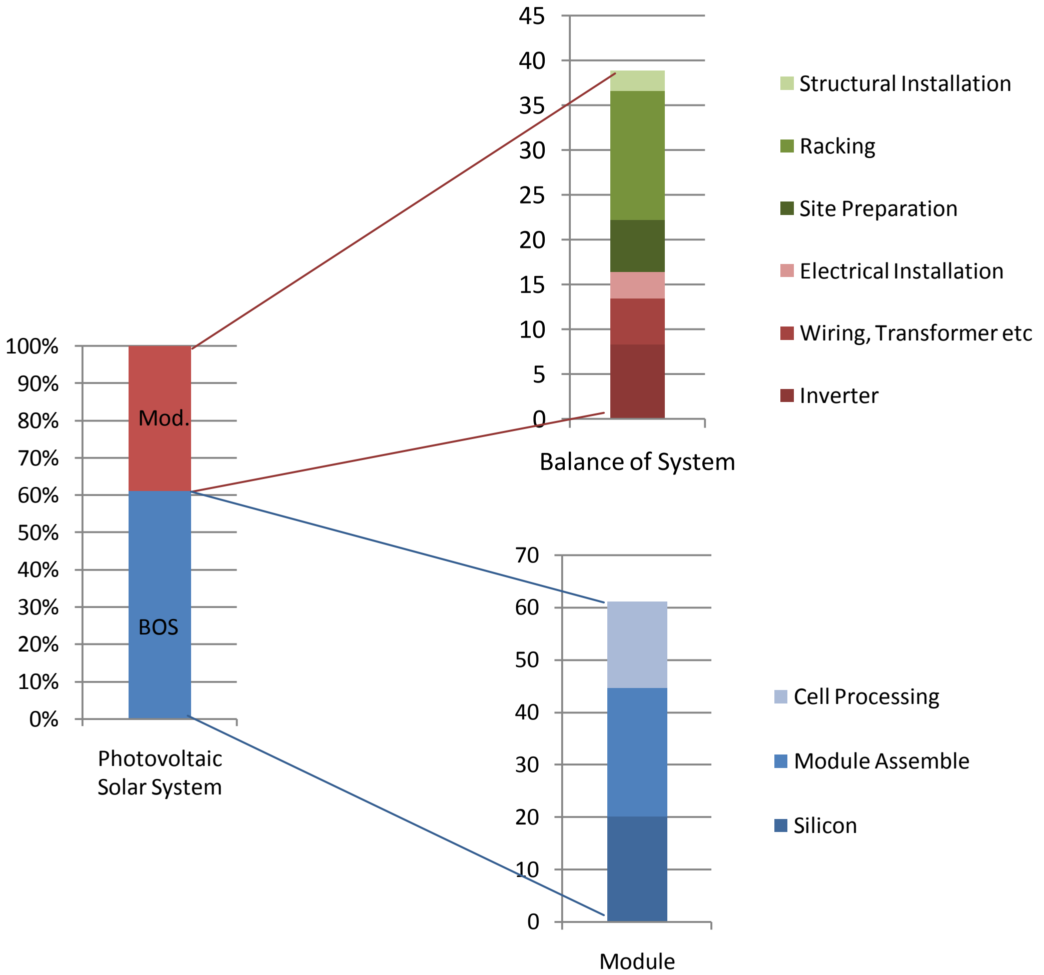

Figure 7: PV Solar System Cost Breakdown[8,9]

5.2. Historical Cost Reductions

As summarised by the EPIA, increase capacity has been associated with cost reductions. These reductions are a result of both technological improvements and the economies of scale. Both the module and balance of system components have experienced, or have the potential to experience, reductions as a result of both of these factors.

According to EPIA the general industry trend to fewer and larger vertically integrated multinationals has increased competition and price pressure[7], and lead to synergies between different parts of the supply chain.

The following analysis explores the cost reduction potentials for both module and balance of system components. Both technological and economies of scale effects are covered.

5.2.1. PV Module

The module cost reportedly represents 60% of the capital cost for a ground mounted system[8]. Experience curves for the module price display a historic learning rate of 22% (capital costs have reduced by 22% for each doubling of capacity), for the period from 1976 -2003[10] (Figure 8).

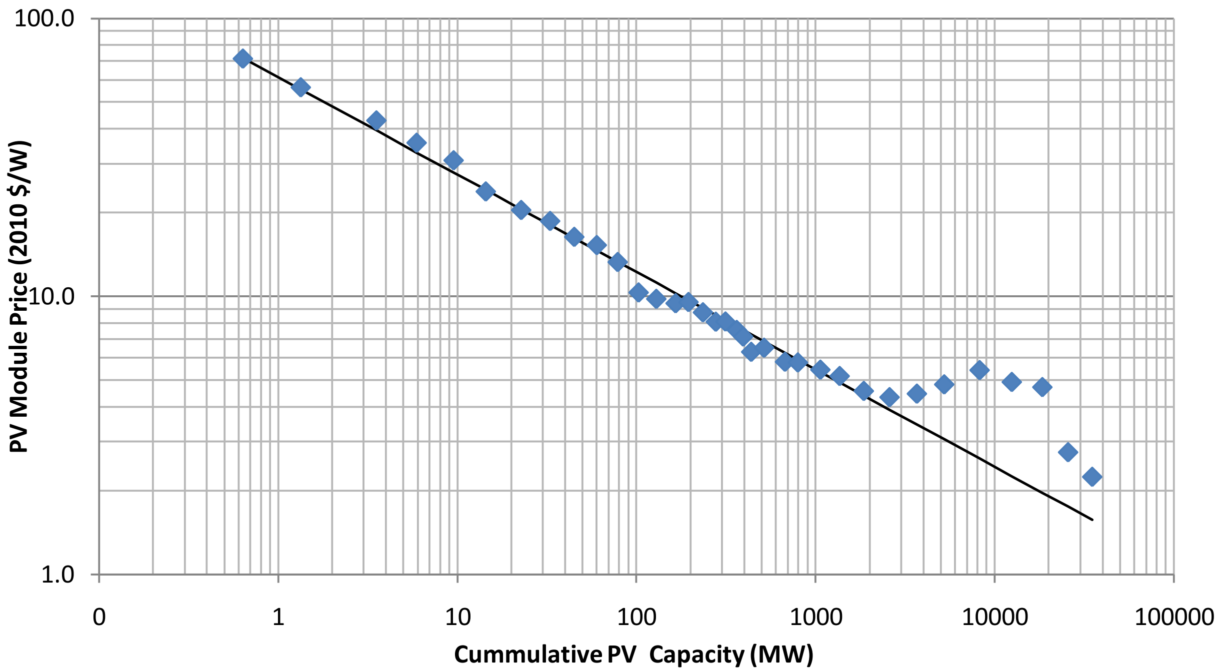

Figure 8: Historic Experience Curve for PV, with 22% Learning rate[10]

Departures from the historic learning rate from, 2003 to 2008, and have been attributed to varying PV industry market dynamics, supply chain issues and profit margins[10]. Since 2009 learning rates have approached the historic rates.

Technological Developments

Technological progress plays a large role in the development of PV technology, the chief focus being the improvement in the efficiency of conversion of sunlight to electricity. There is a range of PV devices, from low cost low efficiency cells to high cost high efficiency cells. Commercial PV modules fall broadly into two categories; wafer based crystalline silicon (c-Si) and thin film. Other emerging technologies, including concentrating PV and organic solar cells have a significant potential for performance increase and cost reduction, but are not explored here. Figure 9 below illustrates the different cost and performance of differing PV technologies[11].

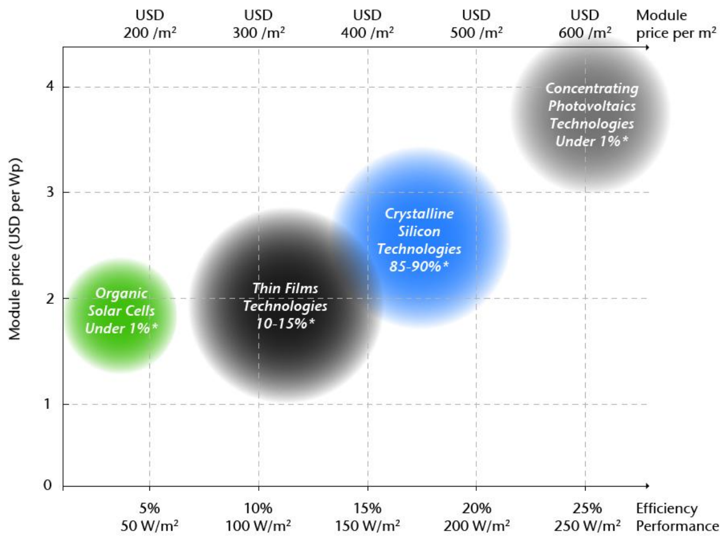

Figure 9: Performance and Price of different PV modules[11]

Module efficiencies range from 10% for thin film cells to as high 20% single crystalline cells and have an important impact on the cost through the entire module value chain and so are critical to determining module pricing[12]. Higher efficiencies result in higher power outputs per square meter, which is a significant consideration, given that many module cost inputs are priced on a per meter squared basis (e.g. glass).

A wide subset of technologies falls within the categories of Thin Film and Crystalline Silicon, characterised by the underlying physical properties of the semi-conductor used. Within these technologies, there is a further range of efficiencies, ranging from the theoretical, to the lab scale and finally production efficiencies. Figure 10 illustrates the module price reductions, that Lux Research expect to occur as a result of efficiency measures[12] for some of PV technologies. It should be noted that the relative apparent additional expense of the multi crystalline silicon technology (mc-Si), is partially offset by the lower area related system costs due to the higher conversion[12].

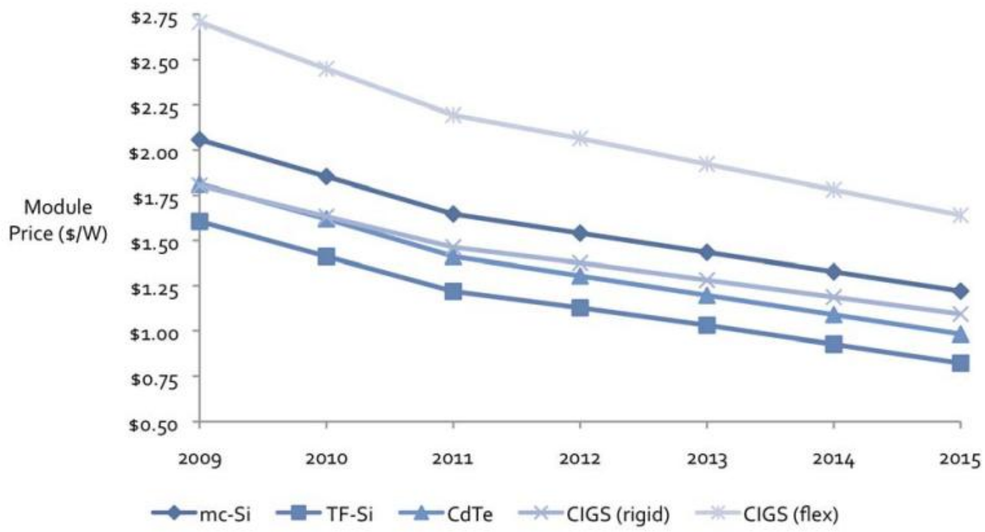

Figure 10: Module Pricing, driven by efficiency[12]

The Lux research analysis shows that as PV technology matures, the production efficiencies approach the improving lab scale efficiency. The lag that exists between commercial cells and lab cell efficiency has also been illustrated by Nemet (2006)[13]. Best practice production single crystalline silicon cells have achieved 20% efficiency, compared with lab level efficiencies of 25%[12]. The IEA PV Roadmap expects that general efficiency of production flat plate solar cells is expected to increase from 16% today to 25% in 2030[11], reducing the cost per kW by more 35%. Newer thin film technologies (beginning from a lower stating efficiency point) are expected to increase from to 15%-18% by 2030[11].

Economies of Scale and Volume Effects

The worldwide PV module production capacity is rapidly growing, with a total announced module production capacity (both crystalline and thin film) of 24 GW in 2009, meeting a global PV market expected to be 10GW in EPIA 'moderate' scenario*. The EPIA expects module production (both crystalline cell and thin film) production capacity is expected to grow with a compounded annual growth rate of around 22% for the next 5 years[7] (Figure 11).

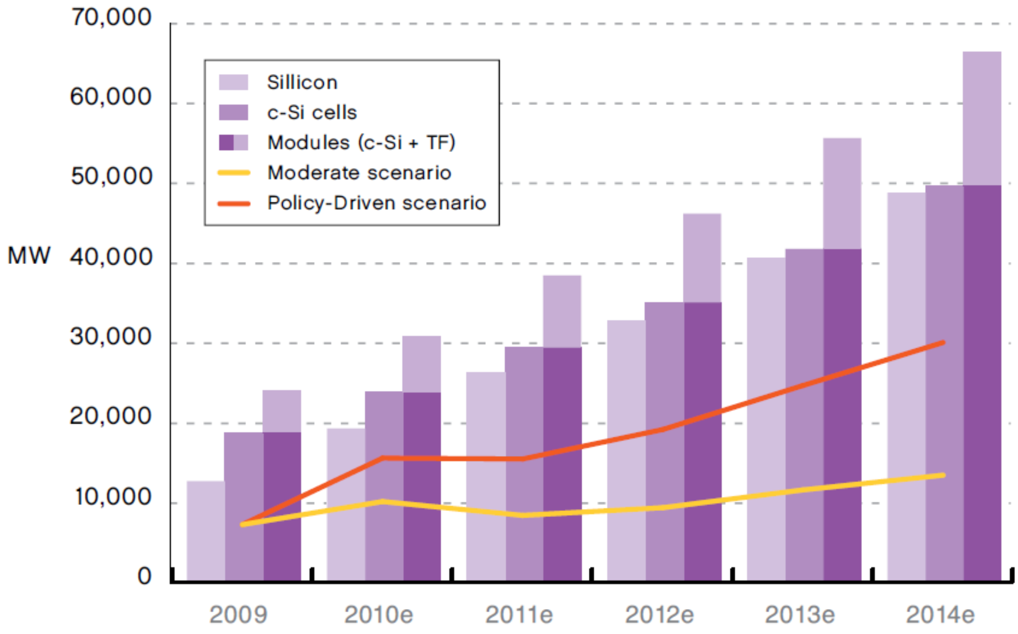

Figure 11: Production Capacity and Market Outlook projection[7]

The recent involvement of the China and Taiwanese manufactures is particularly significant. China's solar PV market has grown rapidly, experiencing a 20 fold increase in capacity in just four years[11]. Together, China and Taiwan now produce more than 50% of both crystalline silicon cells and modules[7], with China now leading the world in PV cells exports.

EPIA expects that the increased worldwide capacity and an increased inventory of PV modules will continue to exert downwards pressure on prices in the near term[14]. At present, production capacity now exceeds expected demand and there is significant pressure to reduce costs.

The large and successful players in the PV supply chain are, by necessity, becoming increasingly multinational and vertically integrated in their operations. According to the IEA, this well established trend will continue, as synergetic relationships and economies of scale lead to cost reduction[11].

* See Appendix II for scenario definitions

Upstream (Silicon Production) Trends

The current main source of silicon feedstock is virgin polysilicon. During early 2008 polysilicon production capacity lagged behind the rising demand, resulting in a significant price spike (to $500/kg)[15].

Silicon production capacity expanded in response to the production lag, according to the NREL[15]. EPIA and also attributes the growth to a response to the previous silicon shortages. The shortage was overcorrected, as a result of capacity expansions that were already in the pipeline, as new capacity was constructed. Production capacity outpaced demand in 2009 and the contract and forward prices for polysilicon declined to around $100 per kg. EPIA expects silicon production continue to grow at 30%.

Production of PV grade silicon feed stock was dominated by Germany, the US, Japan and Korea in 2009. However, there are many new entrants in the market (including numerous companies in China). This is expected to provide a more competitive supply / demand situation[14].

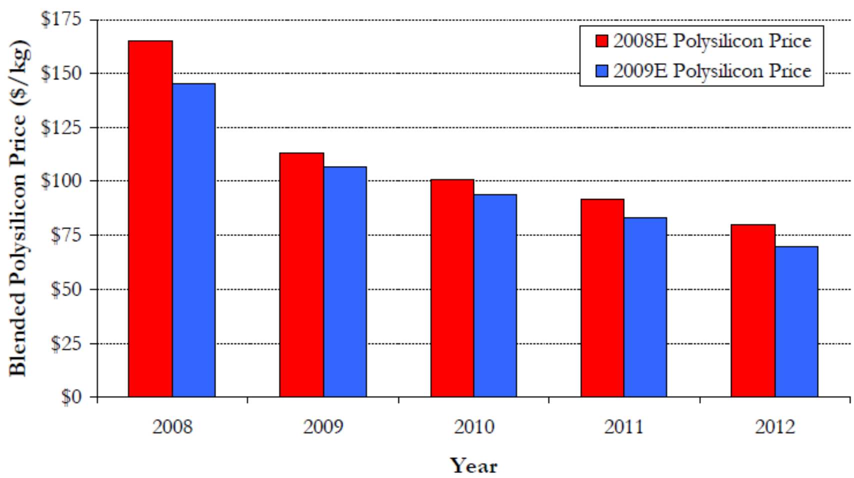

Figure 12: Forward Contract Prices for Polysilicon as charted by NREL study[15]

The NREL expects the price of silicon to decline continually in the near future[15], at a rate of about 12% per year from 2009 (see Figure 12). The current spot price is tracking below the contract prices, currently at $76 per kg, with $60/kg expected by the end of 2011[16]. Silicon production capacity is expected to continue growing at 30% p.a. from 2010 to 2014[7], putting further pressure on prices, as more competitive capacity is brought on line.

Novel methods of silicon production have achieved progress during recent years with several pilot plants being put into operation. Whilst these new production methods have not yet been introduced to the market, the IEA expects successful deployment will realise further cost reductions[11].

5.2.2. Balance of System (BOS)

The BOS costs largely depend on the nature of the installation, and can vary between 20% (for a simplified grid-connected system) to 70% (for an off-grid system)[14], with 40% representative of a standard ground mounted system[8]. The BOS costs and products are therefore an integral part to achieving system cost reductions.

The BOS cost reductions are arguably more complicated than Module cost reductions, as the costs are incurred by many different parties (installers, suppliers, regulators, utilities, building owners etc). The BOS industry is less vertically integrated and more fragmented than the module and upstream production industries. Because of this fragmented approach, there are literally hundreds of potential cost reduction pathways[8], and potential synergies available between the different BOS costs.

Figure 13 illustrates the potential cost savings, for the different BOS components according to the Rocky Mountain Institute.

Technological Developments

There is much potential for technological developments to optimise physical design and reduce BOS costs. There are many design strategies already being considered, however these strategies have not been widely taken up, and in some case have not been combined in an optimal manner.

> **Electrical Systems:** The inverters remain a key development point. The DC-AC inverters, which can contribute up to 10% to the system costs, offer a significant opportunity for breakthrough in technical design[8]. Inverters have been developed with larger rated capacities for the utility scale PV systems. New units simplify system design and installation and can help to increase energy yield[11], but are not yet being widely deployed.
>
> For some electrical systems, increasing integration between inverter processes and module electronics is possible. Specially designed BOS components may reduce cost downsizing or eliminating some components[8]. That is, BOS components can also reduce module components cost (with increased cooperation and integration between the module manufacturers and *BOS* manufacturers).
>
> **Structural Improvements:** Downsizing of the structural components enables considerable cost reductions. The structure cost, in particular the racking, can contribute up to 40% of BOS costs[8].
>
> Exposure to the wind forces is one of the factors affecting structural design; reducing exposure to wind can reduce the structural requirements. Efficient wind design (including spacing, spoiling and deflection could result in a 30% reduction in the system structural costs[8].
>
> Alternative approaches to reducing structural cost involve using the actual module as a structure. Racking systems could be significantly reduced by using the rigid glass as a part of the structural system[14].

Installation: Increased installation efficiency comes with experience, scale and learning. Automated equipment and higher levels of and preassembly, a result of economies of scale and standardisation, (see below) will further decrease installation costs. Estimations suggest such strategies could save up to 30% of labour time and costs[8]. For inverters, 'Plug and play' installations may become possible, which reduce the requirements of specialized labour[14].

Economies of Scale and Volume Effects

There is great cost reduction potential for the BOS industry as it develops, and adopts similar principles to those followed in the module industry. Larger (vertically integrated) multinationals can bring economy of scale reductions to fruition, and commoditize the BOS components. Already, increased production and new market players are supporting the price reduction of the BOS products[14].

Standardisation: An increased level of component standardisation can decrease cost and labour (and regulatory concerns). This standardisation of components can help drive economies of scale, and lead to high volume manufacturing. Pre-assembled components realised through the standardisation and resulting economies, can also offer cost savings in the installation phase.

High Volume: High volume manufacturing has the potential to significantly reduce component costs, as it has in the module production industry. Significant cost savings opportunities remain, as the BOS component manufactures are typically small (with small market share), and utilise materials that are not specifically design for use in the solar industry. Larger companies (and perhaps more vertically integrated) will see consolidation and increased volume, for reduced input. Significant cost reductions can be achieved by reducing material and labour requirements, whilst increasing the throughput.

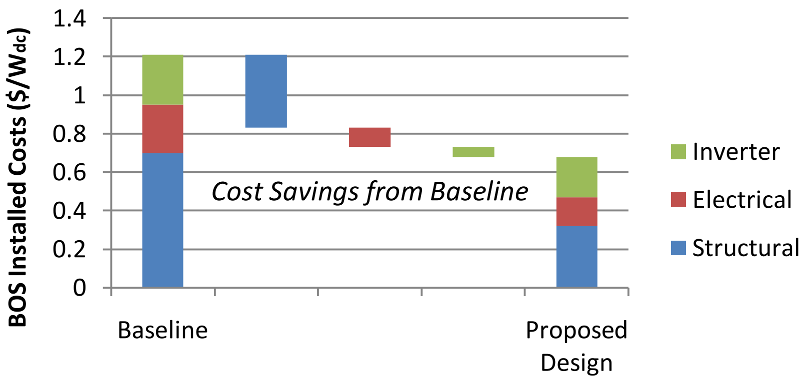

Figure 13: Near-Term Cost Savings[8]

5.3. Cost Projections

Based on these key costs drivers and cost reductions, projections of capital cost and hence levelised costs can be made. The EPIA and IEA have made cost projections based on these cost reductions out to 2030 and 2050 respectively. Each has multiple capital cost projections, corresponding to different scenarios with differing conditions (see Appendix II for details). Both the IEA and EPIA assume an 18% learning rate, which is less than the 22% learning rate experienced in the past.

The IEA reports the 2010 capital cost for utility scale PV facilities as $4060/kW and expects the capital costs of PV to drop by 70% to between $1220 and $1830 a kW[1]. It is with projected by the IEA that reductions in capital cost of 40% by 2015, and 50% by 2020 will occur.

EPIA reports the 2010 capital cost as being $3600/kW. They expect capital costs of $1380/kW in their moderate scenario, and $1060/kW in the more optimistic scenario by 2030. A capital cost reduction of 50% by 2020 will occur according to EPIA[17].

The EPRI analysis suggests the 2015 costs of PV are over $8000/kW for flat plate collector. A 35% reduction in capital costs $5500 / kW in 2030[6] is assumed to occur by EPRI (with the reduction to begin occurring in 2015). The EPRI report included qualitative discussion around the cost reduction; however there was no specific justification of 35% rate. This 2030 capital cost is within the range of the 2010 costs from IEA and EPIA.

The AEMO data was taken from Scenario 1 of input assumptions to the 2010 NTNDP[5] modelling, representing the best-case data in the range of scenarios modelled. The AEMO data assumes that the capital cost for flat plat photovoltaics begins at $5118/kW in 2010 and linearly decreases (starting from 2015) to $3581/kW in 2030. The AEMO dataset is based on the EPRI analysis.

Residential scale PV installations are currently available in Australia at between approximately $4500/kW and $6500/kW[18]. This value excludes RECs and any other subsidies, and is in line with the international residential scale prices. As suggested by EPIA, utility scale investments are in a position to leverage volumes and lower negotiate prices[17]. Both the IEA and EPIA report lower prices for utility scale systems.

The projected LCOE for the different outlooks is presented in Figure 14.

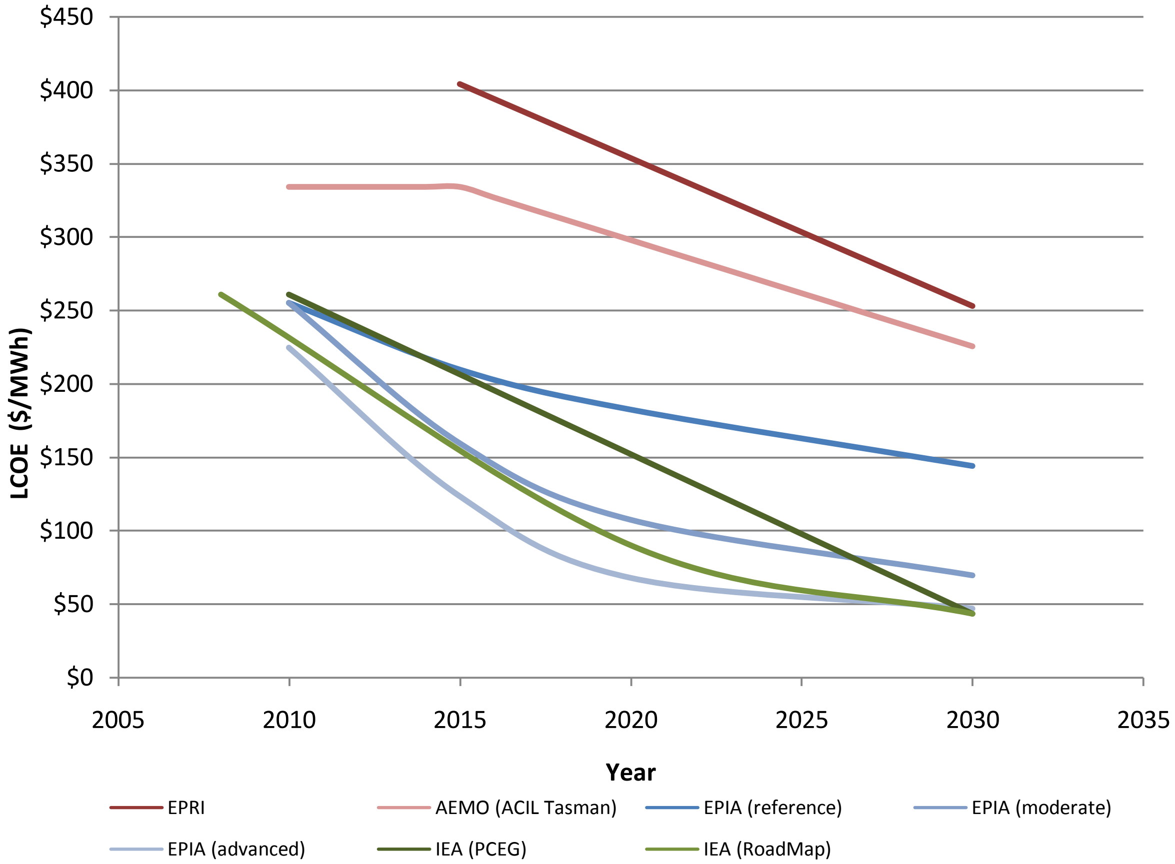

Figure 14: Comparison of PV LCOE's between different cost projections

A similar feature to all of the studies is the rate of cost reduction, (with the exception of the EPIA reference scenario). The key difference between the outlooks is primarily the starting point, from which the cost reduction occurs, (which is a result of differing current capital costs appraisals). LCOEs based on international studies are in the range of $274-$311, which are 25%-40% lower than AEMO LCOE at $384.

5.3.1. Key findings

- LCOE are in range of $225 - $404 / MWh, and are projected to continue along the learning curve between 18-22%.
- International based cost figures are 25%-40% lower than the Australian-specific studies.
- The capital cost data used in Australian specific studies are significantly higher (100% in the case of EPRI) than international numbers, (and residential scale numbers).

6. Wind Power

6.1. Introduction

The industry has experience an average growth rate of 28% over the past decade, and has doubled on average every 3 years. The total installed capacity was almost 160 GW at the end of 2009, and Global Wind Energy Council (GWEC) estimates that a further 30 GW was installed in 2010[19] (Figure 15).

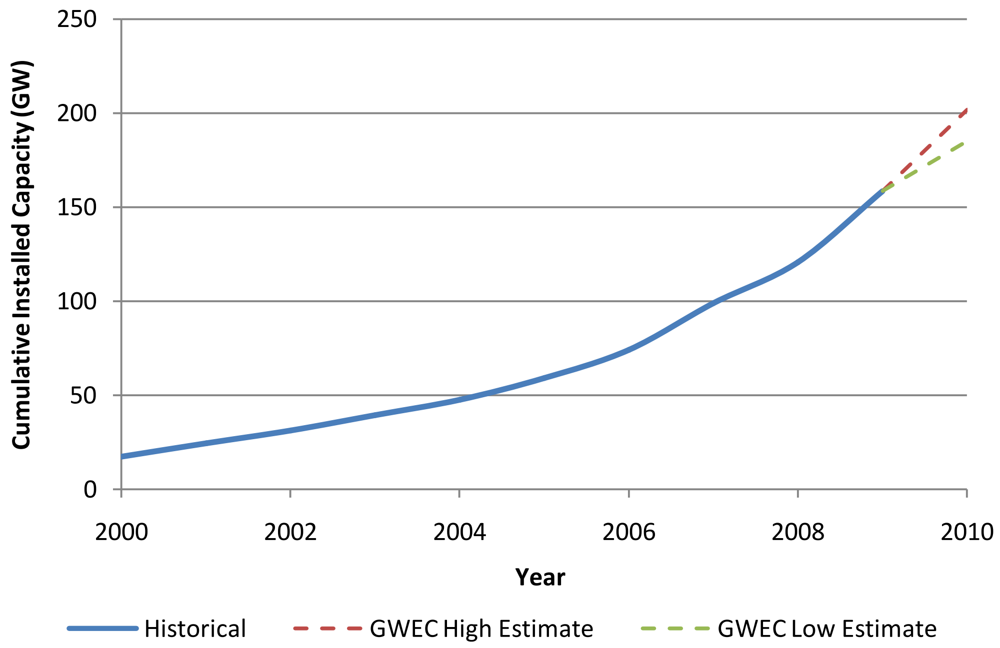

Figure 15: Cumulative Wind Power Installed Globally

Modern utility scale wind turbines are typically deployed in arrays of 50 – 150 turbines, known as 'wind farms'. The turbines generally have three-bladed rotors, between 80m – 125m in diameter, on top of a tower, typically between 80m – 130m high.

The wind force applied to the turbine blades drives a generator housed in the 'nacelle' on top of the tower. The rotor drive shaft is either directly connected to an annually generator (direct-drive turbine) or, more commonly, the shaft is connected to a gearbox. Transformers within the nacelle transform the power for distribution to the power collection system.

The individual turbines are connected to a power collection system (generally at medium voltage) and control system. At a substation the medium voltage power is transformed and connected to a high voltage transmission network. The land in between turbines may be used for other purposes; however road access, for both construction and O&M are required.

Turbine power is controlled by modifying the blade pitch (the angle of attack with respect to the relative wind) as the blades spin around the rotor hub, and the turbine is pointed into wind by rotating the nacelle around the tower.

6.1.1. Generation Costs for Wind Power

The key parameters that govern the cost for wind power are the capital costs, wind resource quality and the discount rate. Other costs are the variable costs including operations and maintenance costs. Of these parameters, the capital cost is the most significant and presents the largest potentials for cost reductions.

The capital costs of a wind power project are broken into several categories. These categories include the turbine cost, construction costs, grid connection costs and other capital cost. The construction costs include foundation work, road construction and buildings, and grid connection costs include cabling and substations. The turbine cost includes the production transportation and installation of the turbine itself (e.g. blades, transformer). A breakdown of the cost distribution can be found in Figure 16[20].

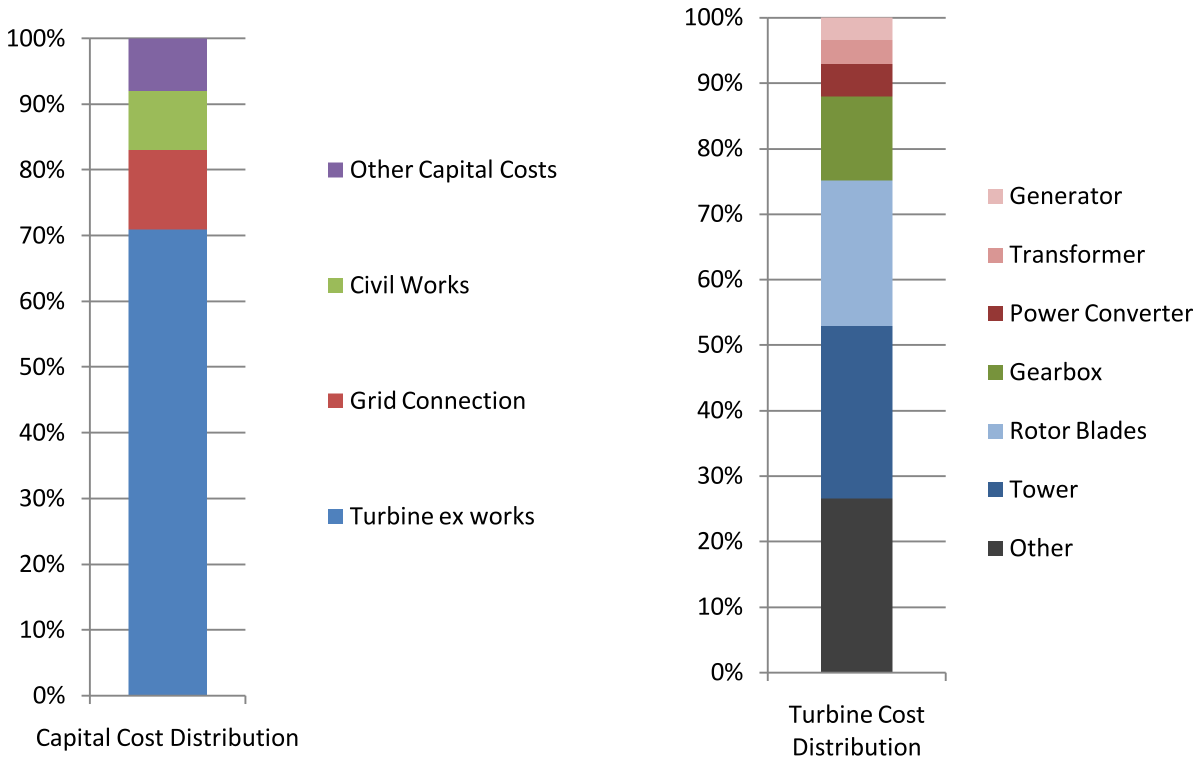

Figure 16: Capital Cost Distribution for a Wind Turbine (gearbox drive)[20]

The turbine cost can be further categorized into the major components. The EWEA have suggested a turbine cost breakdown representative of a gearbox driven turbine (as opposed to direct drive) in a European setting (Figure 16). The major cost items include the rotor blade, the tower and gearbox. The 'Balance of Tower' category includes other minor cost associated with the tower, such as the rotor hub, cabling, and rotor shaft.

6.2. Cost Reductions

Wind power has experienced cost reductions as capacities have expanded. Experience curves have been developed and learning rates of 10%[21] have been observed (based on historic records). The experience curve is for wind power capital cost is shown below in Figure 17, for European installations (with the data sets spanning roughly between 1990 and 2008).

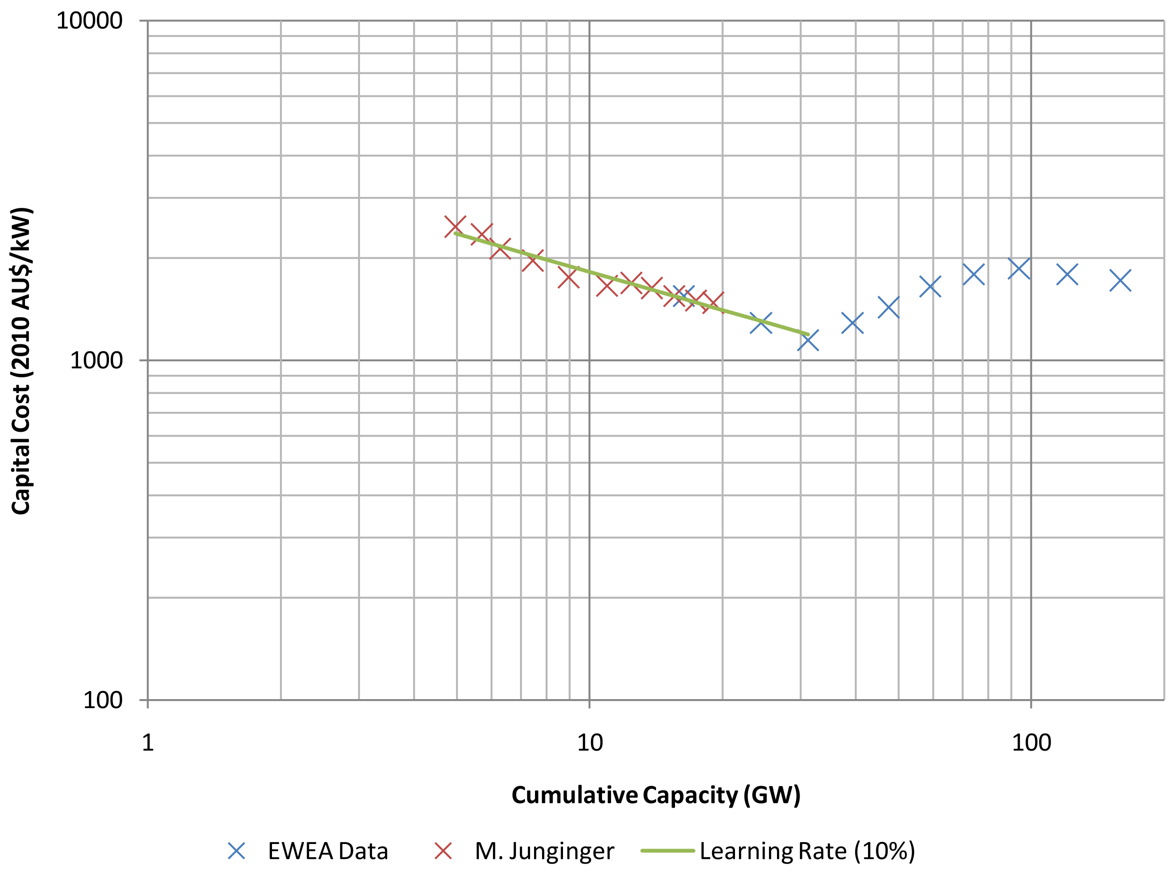

Figure 17: Historic Wind Experience curve, with Learning rate[22,23]

Supply-imbalances increased turbine prices from around 2004 according to Berkeley Labs. This imbalance occurred at the same time as a surge in steel and other base commodity prices, (and prices rose as cumulative capacity increased)[24]. According to the EWEA, some supply chain issues have resolved, and the learning rate has been returned to more historic values.

Figure 18 illustrates the cost data and projections, alongside two different learning rates (7% and 5%). The IEA projections incorporate a 7% learning rate[1], whilst the EWEA suggests a learning rate of 10% will occur (in line with historic observations[21]).

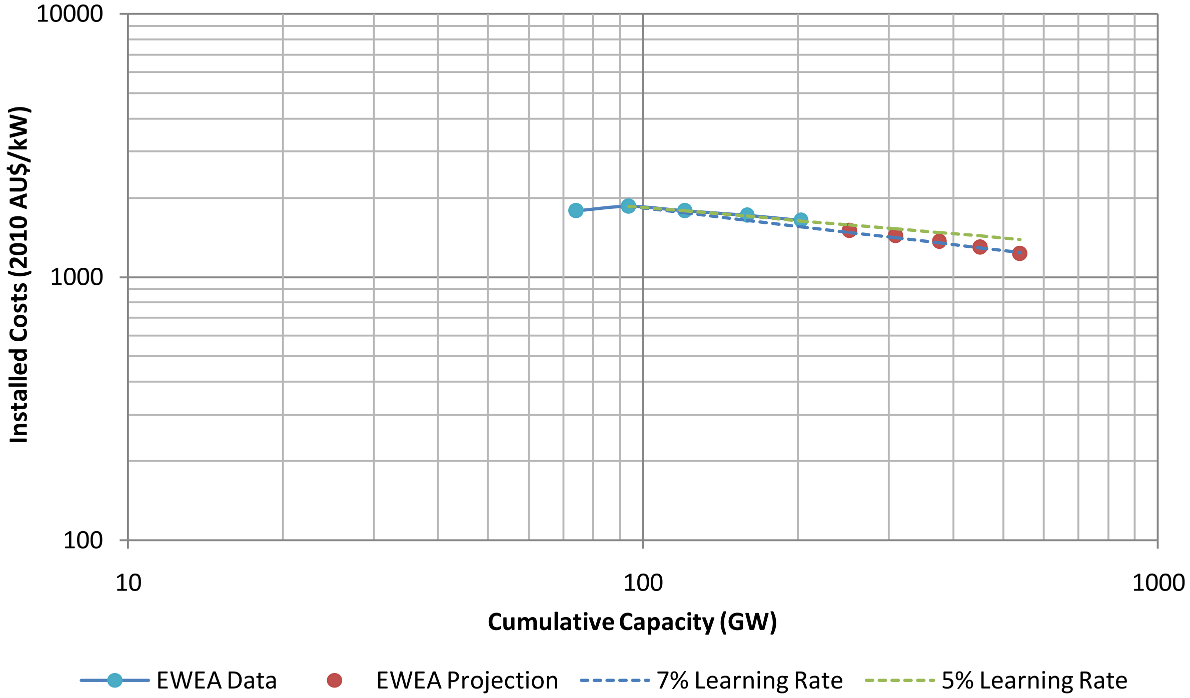

Figure 18: Recent Experience Curve, with projected learning rates and industry projections

The US DOE suggests that technology innovation (leading to reduction in O&M requirements; extending turbine lifespans; and reducing the cost of components) is a crucial driver for reducing the LCOE of wind power. Additionally, the opening of new markets and resulting economies of scale, as well as stronger supply chains, have the potential to yield further cost reductions.

6.2.1. Technology

Technology remains a key driver for the reduction in levelised electricity costs for wind, and is characterized by incremental reductions in the cost of energy, rather than by single leap. According to the US DOE, there is a general focus on the development of:

- Stronger and lighter materials
- Super conductor materials, for better electrically efficient generators
- Larger, more flexible rotors.

There is a long-term drive to develop larger turbines, which is a direct result of the desire to improve energy capture by accessing the stronger winds at higher elevations. Currently, the largest turbines are 7.5MW, and the IEA suggests 20MW turbines will be available by 2020[25]. The EPRI analysis in contrast assumes there will be an ultimate turbine size limit in the range 3-5MW[6]. Both the IEA and US DOE expect improvements through using advanced towers, advanced rotors, reduced energy losses and improvements to the drive train[25,26].

Throughout the past 20 years, average wind turbine ratings have grown almost linearly[26]. Each group of wind turbine designers has predicted that its latest machine is the largest that a wind turbine will ever be. However, turbine size has grown along the linear curve and has achieved reductions in life-cycle cost of energy[14]. According to the IEA Wind Roadmap, the key development points are the rotors, the blade, the tower and the drive train.

Blades: Blades typically account for 20% of the wind turbine costs[20]. Manufactures have typically tried to achieve two (contradictory) goals; increase blade length and reduce material volume (and cost). Longer blades increase the swept area, which increase the energy capture. However simply increasing the blade length without changing the design would make the blades heavier, and the blades would incur greater structural loads.

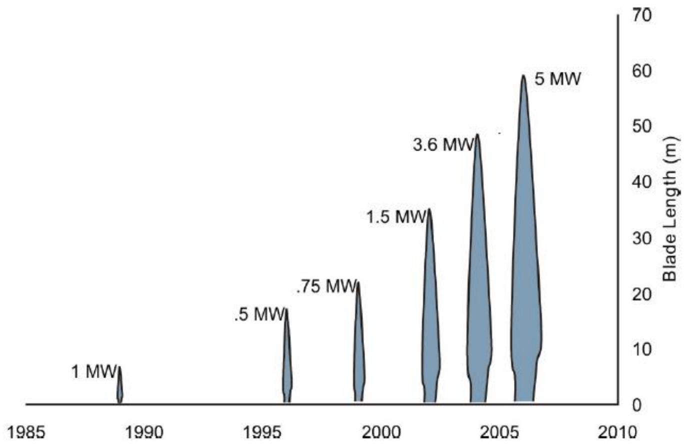

Figure 19: Blade Growth for US Blade Test Facilities[26]

Both the IEA and US DOE recognise the focus on advanced materials with higher strength to weight ratios, (for example carbon fibre). Blade length has continued to increase over time (see Figure 19), and will continue to increase as technological progress is made[26] according to US DOE. According to both the EWEA and IEA, blade lengths are anticipated to increase to approximately 125m by 2020.

Drive Train: Improvements that remove or reduce the fixed losses during low power generation are likely to have an important impact on raising the capacity factor and reducing cost. Parasitic losses when summed over the entire add up to significant numbers. These improvements include innovative power-electronic architectures and large-scale use of permanent-magnet generators. The IEA has identified the gearbox as a key development area (and efficiency loss point), and EWEA has noted clear a trend towards a simplification of the gearbox component, (e.g, one-stage gearboxes), and direct-drive turbines.

Direct drive systems, which avoid gear boxes altogether, (which represent up to 15% of the turbine cost) are receiving increased attention, according to the EWEA. These systems eliminate the gearbox (and thus gearbox failure) which have historically proved challenging[27], and utilise annual generators (see Figure 20 below), Direct-drive systems eliminate gear losses, increasing the system efficiency, whilst also and also reducing O&M cost[25]. Direct Drive systems do however use expensive rare earth metals (Neodymium) in the permanent magnets, which (partially) offsets the cost savings.

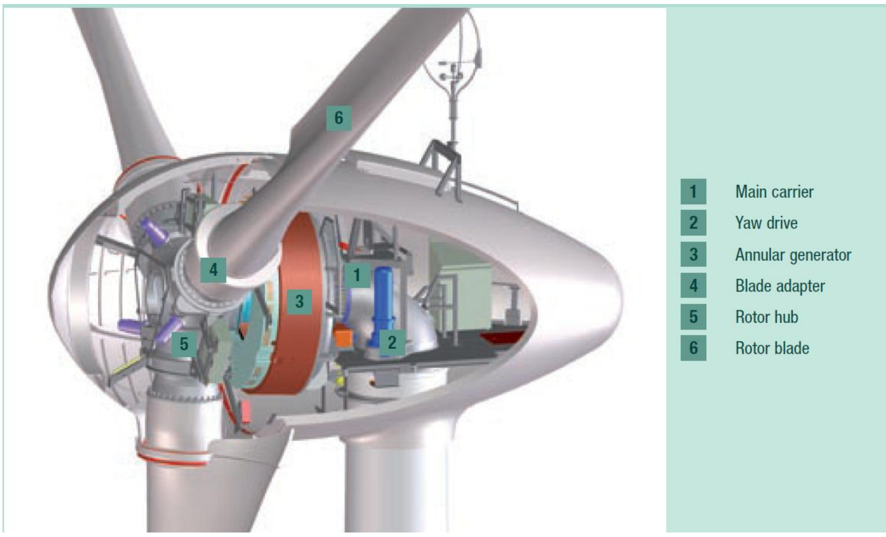

Figure 20: Enercon Direct Drive Turbine

Tower: Tower cost reductions could be achieved through lighter generators and other drive train components. This would reduce tower head mass (and thus structural requirement of the tower). New materials will also encourage a transition away from industry's current dependence on steel for taller towers[25] (which are expensive).

As placing the rotor at a higher elevation is beneficial it is highly likely that this component will be examined more closely in the future. The higher value of wind at higher elevations will drive development into turbines that sit on even higher towers. There is generally a trade off between higher winds speeds and against the additional capital expense of making the towers higher. Again, new materials (cheaper) materials will provide considerable cost reduction opportunities.

New tower erection technologies might play a role in O&M costs which will also help drive down the system cost of energy[25].

The US DOE quantifies the effects of the improvement in technology by determining the effective increase in capacity factor expected, (using a constant resource as a basis for comparison). For example, as hub heights increase, the energy extracted from an identical wind resource will also increase. The EWEA expects that the capacity factor achieved for a particular quality will increase over time, as a result of all the technological improvements[21]. A summary of the US DOE expected performance improvements for wind turbine, expressed in terms of capacity factors, is in Table 3[26].

Table 3: Potential improvements in capacity factor from advances in wind[26]

Technology	% increase of existing capacity factors		
	Best Case	**Expected**	**Worst Case**
Advanced tower concepts	+11%	+11%	+11%
Advanced rotors	+35%	+25%	+10%
Reduced energy losses and improved availability	+7%	+5%	+0%
Drive-train (gearboxes, generators and power electronics)	+8%	+4%	+0%

Capacity Factor: Previous studies (including the ACIL Tasman Review), estimate the capacity factor of successive wind deployments to continually decline over time, as the better wind resources are exhausted preferentially. Whilst this phenomenon is a reality, this simple analysis fails to incorporate the improvement in capacity factors as a result of technological improvements. These improvements will partially or completely offset the reduction in capacity that occurs as wind resources are depleted, according to the EWEA[21].

6.2.2. Wind Resource Assessment

Models are needed to predict wind patterns in difficult terrain and also wake effects for large wind farms. These factors can have serious implications for wind energy capture, and improved modelling is likely to better optimize the wind resource, and thus decrease levelised costs[25]. Increasing forecasting accuracy is also likely to improve the value of the wind energy (by helping produces meeting delivery targets).

6.2.3. Economies of Scale and Volume Effects

Industry growth over the past decades has given rise to bottlenecks in supply of key components, including labour[24]. The IEA reports that these issues have been addressed by accelerate automated, localised, large-scale manufacturing for economies of scale, (with an increased number of recyclable components)[25]. Now, overcapacity in the supply chain is putting considerable price pressures on manufacturers[28], according to the Bloomberg Wind Turbine Price analysis. Manufactures are continuing to reduce costs, and are displaying aggressive pricing, with recent decreases in wind turbine costs driven by new US manufacturing capacity[28].

An important development is the performance of China's wind sector, which managed to surprise even optimists in the industry. By the end of 2009, China had more than 80 wind turbine manufacturing business, and is readying itself to enter the international market[19], which GWEC expects to put further downward pressures on the wind turbine pricing.

On-site Manufacturing: To reduce transportation costs, concepts such as on-site manufacturing and segmented blades are also being explored. It might also be possible to segment moulds and move them into temporary buildings close to the site of a major wind installation so that the blades can be made close to, or actually at, the wind site.

Commodity Constraints: The use of rare-earth permanent magnets in generator rotors instead of wound rotors has several advantages (high energy density c.f. copper). However, according to the EWEA it increases the exposure to rare earth metal availability and supply constraints.

Installation experience: Installation experience of a country or jurisdiction can have a large impact on the development of wind projects. The EWEA reports that 'early' projects are often very time-consuming to establish, and it usually takes several years to adapt regulatory and administrative systems to deal with these new challenges. Grid connection procedures or multi-level spatial planning permission procedures tend to be both inefficient and unnecessarily costly in new wind energy markets[21]. Experience suggests that the "administration experience" curve is particularly steep for the first 1000MW installed, and that once authorities and grid operators have the experience and are used to the procedures, development can happen very fast[21]. This is a particularly relevant observation in the Australian context, has approximately only 2000MW of wind currently installed.

6.3. Cost Projections

GWEC and IEA have made cost projections based on these cost reductions. Each organisation has multiple projections, corresponding to different scenarios with differing conditions, and levelised cost projections were made based on these capital cost projections (see Appendix III for details).

The EWEA assumes that the cost trajectory will continue along an optimistic 10% learning rate for the next 5 year[21]. More conservative estimates were used but GWEC and the IEA, which assumes the cost trajectory will continue along at a 7% learning rate.

The IEA reports current capital cost for wind power to be $1725 /kW, and predicts capital cost to decline to $1420/kW by 2030[1].

The GWEC is reporting current capital cost of $1890/kw , and predict $1590/kW will occur by 2030 in their moderate scenario. The capital cost is expected to have reduced to $1790 by 2020.

The EPRI data suggests the 2015 capital costs for wind power is more than $3500/kW. It is assumed that capital costs will decrease by 35% by to around $2300 by 2030[6]. Again, The EPRI report included qualitative discussion around the cost reduction; however there was no specific justification of 35% rate (or the capital costs). The 2030 EPRI estimate is higher than all the GWEC and IEA estimates for 2010 capital costs.

The EPRI analysis is also basis for the AEMO dataset used (Scenario 1 of input assumptions to the 2010 NTNDP modelling)[5]. AEMO assume that the current capital cost for wind is $3018, which reduces to $2415 by 2030. The cost reductions occur after year 2015.

A recent media release from AGL suggests that the installed cost for McCarthur Wind Farm was around $2400/kW[29]. This is falls between the international and Australian specific studies. It is however roughly as low as (and in fact slightly lower than) the capital cost that AEMO project to be realised in 2030. However, further analysis of current data from Australian wind power projects is required and would be a useful next step.

The projected LCOE for the different outlooks is presented in Figure 21.

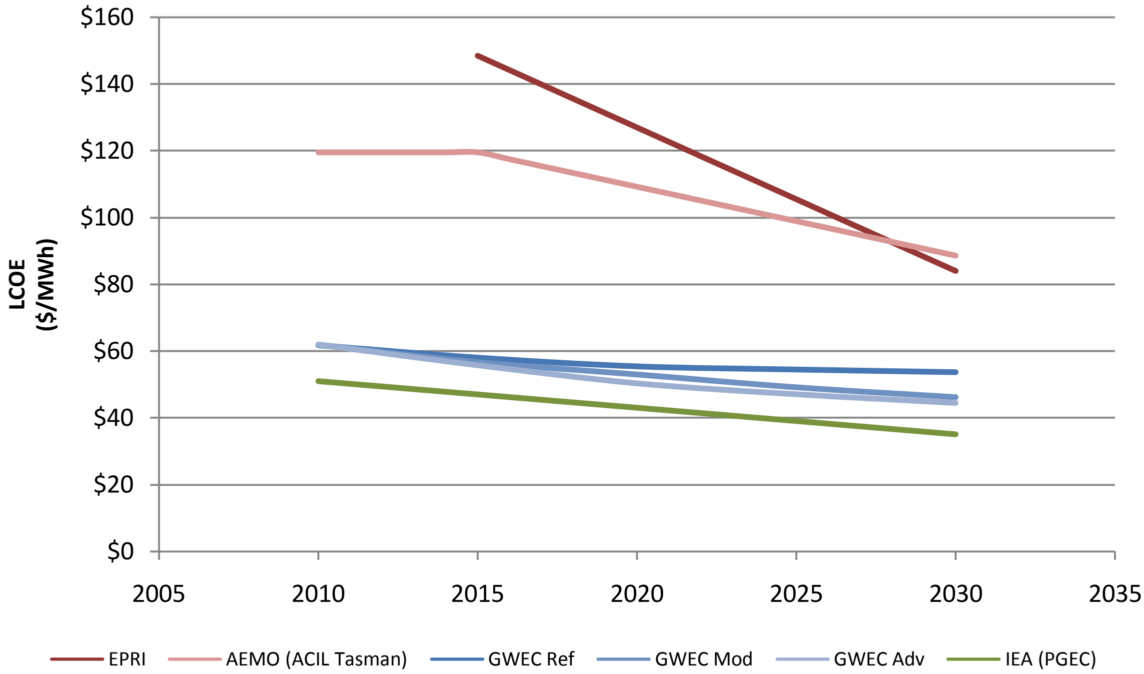

Figure 21: Comparison of Wind LCOE's between different cost projections

The cost of wind energy is at record lows. For the purposes of context, it should be noted that some projects in high wind resource areas (US, Brazil, Sweden and Mexico) are already displaying LCOE's of below $68/MWh[28] (2010 AUD). However, these projects would have high capacity factors, and cannot therefore be directly compared with the LCOE's presented above.

A similar feature to all of the studies is the rate of cost reduction, (with the exception of the EPRI analysis). Again, the key difference between the outlooks is primarily the current LCOE, which is a result of the different current capital costs used. LCOEs based on international studies are in the range of $90-$110, which are roughly 45%-50% lower than AEMO LCOE at $158.

6.3.1. Key findings

- LCOE are in range of $45-$135 / MWh, and are projected to continue along the learning curve at roughly 7%.
- International based LCOE figures are 50% lower than the Australian-specific studies.
- The capital cost data used in Australian specific studies are significantly higher than international numbers.

7. Concentrating solar power (CSP)

Comparison of solar thermal costs for the purpose of this review has primarily focused on towers, which while less mature than troughs, are considered by several independent analyses to have the greatest potential for lowest cost production of electricity. Sources of data have included:

- U.S. Department of Energy CSP Program: *Power Tower Technology Roadmap and Cost Reduction Plan*
- International Energy Agency: *Technology Roadmap Concentrating Solar Power*
- European Solar Thermal Electricity Association & A.T. Kearney Associates: *Solar Thermal Electricity 2025*
- Sargent & Lundy: *Assessment of Parabolic Trough and Power Tower Solar Technology Cost and Performance Forecasts*
- SolarReserve, tower developer (*publications and personal communications*)
- Abengoa Solar, tower developer (*publications and personal communications*)
- SENER/Torresol Energy, tower developer (*publications and personal communications*)

7.1. Comparison of projected costs of CSP from several analyses

The below graph shows cost projections from a range of organisations and studies reviewed. As discussed later, authors of the AT Kearney (ATK) study have indicated that realistic costs for towers lie at or near the lower end of their range shown.

These studies indicate that $120-160/MWh (not including RECs or other subsidies) by 2020 is achievable under expected global growth conditions. The IEA, AT Kearney and Sargent & Lundy study indicate that $100/MWh or less is achievable with greater or further growth and experience. Many of the factors leading to reduced costs for CSP are more a function of market size and economies of scale than just time. Therefore achieving the rate of cost reductions shown in the international datasets are dependent upon the projected deployment rates occurring, largely as a result of CSP-specific support policies.

The AEMO dataset has similar costs in the 2010-2015 timescale as the other analyses. However the rates of decrease for the international studies are higher up until 2020. Whilst the slightly higher starting cost for the AEMO dataset likely reflects Australian-specific conditions, the projected rate of reduction up to 2020 is lower than international analyses.

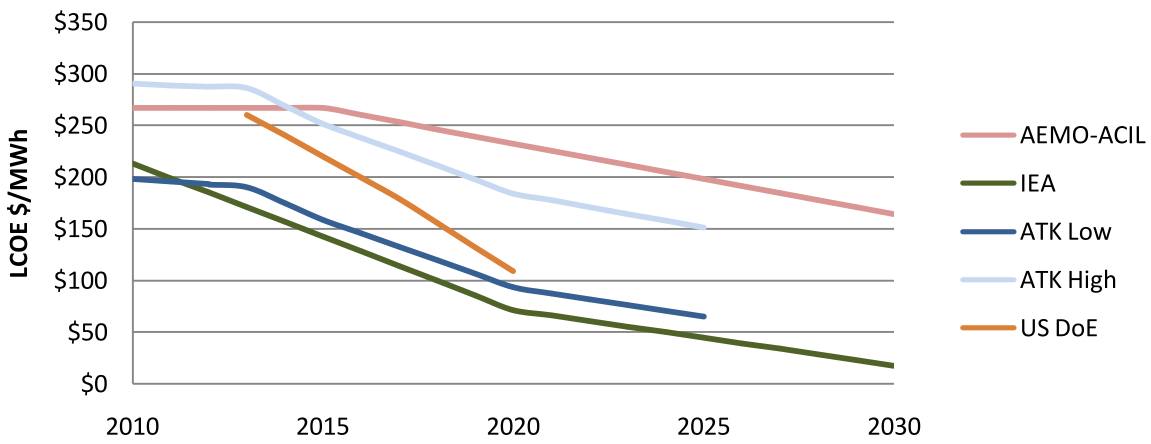

Figure 22: Comparison of LCOEs (with RECs) for CST from a range of studies. All calculated for DNI = 2400kWh/m2/year

7.2. Solar thermal power – introduction

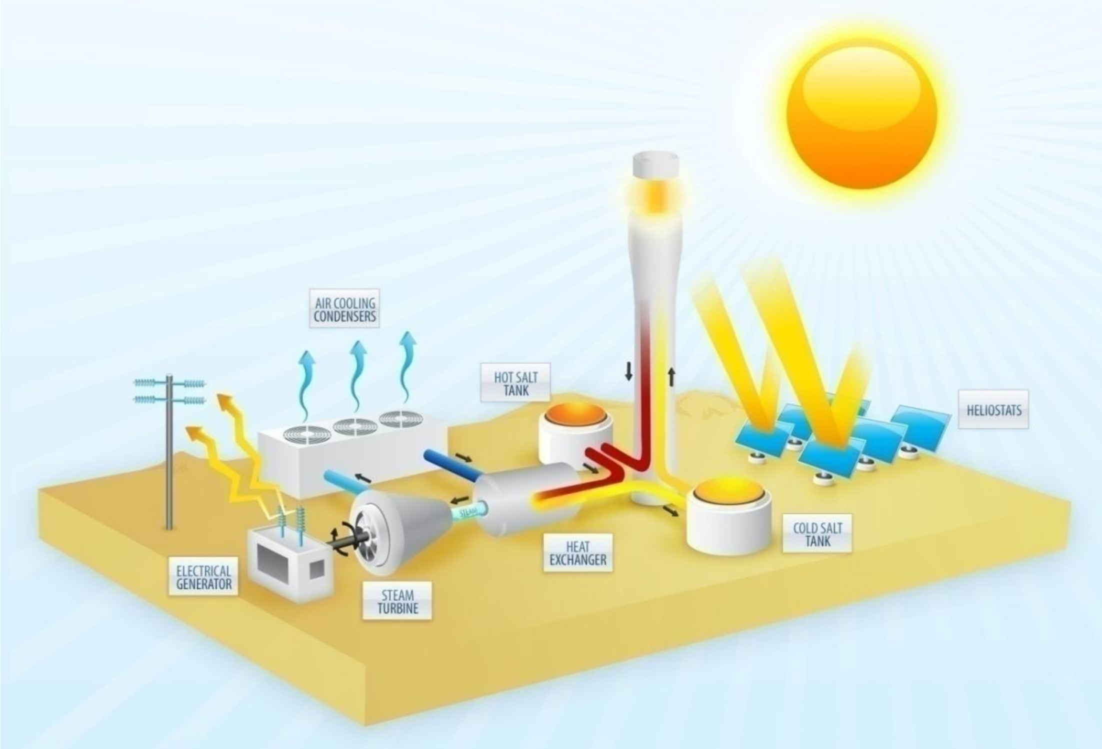

Figure 23: Diagram of solar thermal central receiver power tower - note in real plants there are hundreds to thousands of heliostats (Image: Sharon Wong 2010)

Solar thermal power, at its simplest, uses mirrors to concentrate the sun's rays to achieve temperatures in the order of several hundred degrees, hot enough to boil water, generate superheated steam and drive a conventional steam turbine in the same way that a fossil or nuclear thermal power plant works.

There are a number of different mirror configurations available, such as parabolic troughs and paraboloidal dishes. This analysis however, will mainly focus on power towers, or central receiver plants, unless otherwise mentioned, as several analyses point towards power towers having the greatest potential for low cost power out of the solar thermal technologies[†].

The key components of a central receiver or power tower system are:

- Central receiver tower – a concrete or steel tower, over 100m tall. At the top of the tower is a receiver, consisting of rows of vertical tubes made out of a high-temperature alloy, in which heat is absorbed from rays of concentrated sunlight into a heat transfer fluid, commonly water (steam) or molten salt).
- Heliostat field – a heliostat has flat mirrors mounted on a pedestal which tracks the sun on both axes, reflecting the sun's light onto the receiver. A single heliostat can be up to 150m^2 in area, and a tower will have hundreds to thousands of heliostats, in the case of large systems fully surrounding the tower in 360^o.

[†] E.g. Sargent & Lundy LLC, 2003, IEA CSP Roadmap, 2010, discussion and full references in main report body.

- Thermal storage – storing energy as heat is incorporated into solar thermal systems as an intermediate step between energy collection and power generation. The most commercially proven system involves storing molten salt in insulated tanks, with an overnight roundtrip efficiency of 99.9%. There are other options being investigated, such as concrete storage, phase change materials and air-as-working-fluid ceramic storage, however these are not yet commercialised and will not form a part of this analysis.
- Steam generation – typically a series of industrial heat exchangers that heat, boil and superheat water to steam from the hot molten salt. Once used, the 'cold' molten salt, still liquid at 290°C, is circulated back to the cold tank for reuse.
- Power generation – through a Rankine cycle, superheated steam drives a conventional steam turbine generator to create electricity. Steam is condensed using either evaporative or dry-air cooling and recirculated as boiler feed water.
- Balance of Plant – BoP in this analysis refers to all other parts of the power plant. It includes but is not limited to control systems, electrical & pneumatic instrumentation, piping, support structures and buildings, land, cooling systems, fire protection, and safety systems.

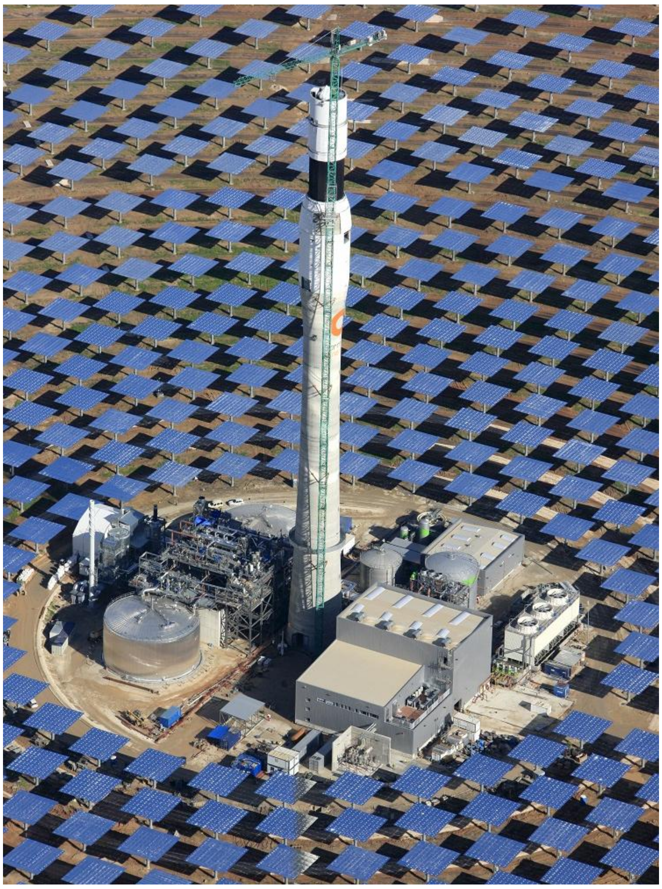

Figure 24: Gemasolar 17MW power tower near Cordoba, Spain, with enough molten salt storage for 15 hours of no-sun operation at full capacity. Image: Torresol/SENER 2011

Concentrating solar power plants of both parabolic trough and tower have been deployed commercially as of 2011, mostly in Spain, with many large projects under development in the U.S., and some projects operational and under development elsewhere in the Middle East and North Africa region[30]. As it is a less mature technology than wind & PV, historic cost curves are not available. This report has compared detailed cost curve projections from a range of sources.

Sargent & Lundy

One of the most detailed cost studies on concentrating solar thermal power available that gives a transparent analysis the effects of both technical improvements and economies of scale is the "*Assessment of Assessment of Parabolic Trough and Power Tower Solar Technology Cost and Performance Forecasts*"[31].

This was commissioned by the U.S. Department of Energy's office of Energy Efficiency and Renewable Energy (EERE) to perform a detailed cost assessment on the costs of solar thermal power towers up to 220MW. Sargent & Lundy are a power engineering consultancy with experience in a range of fossil, nuclear and renewable power projects. The study was based upon information provided by SunLab, the DoE's collaboration of the US National Laboratories with concentrating solar research (namely Sandia National Laboratories and the National Renewable Energy Laboratory), industry interviews and Sargent & Lundy's internal power engineering dataset.

The capital costs from the original data set have been converted to 2010 Australian dollars to recalculate the Levelised Cost of Energy. The DNI resource used is 2400 kWh/m2/year, representative of good quality Australian sites within close proximity to existing grids (see note on solar resource at the end of this report). The graph below shows the LCOE broken down into the portions contributed by ongoing O&M, and individual components of the capital expenditure.

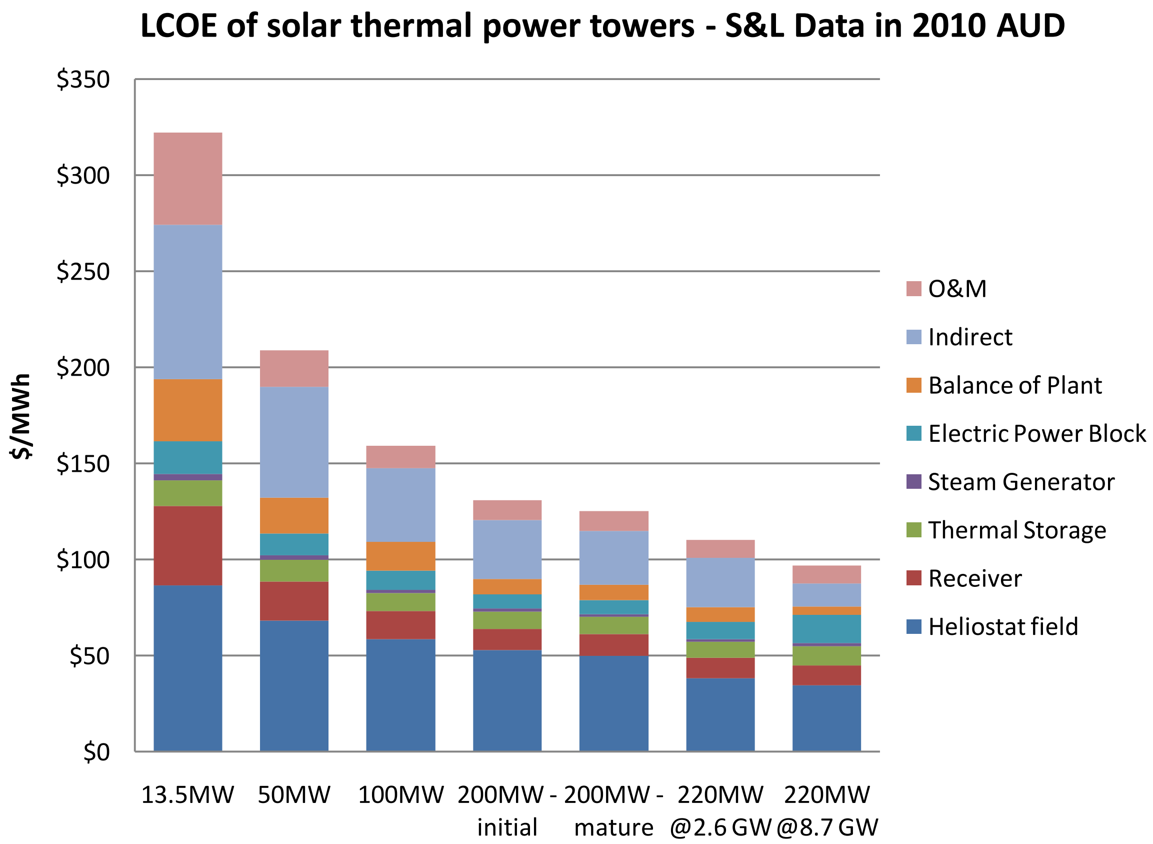

Figure 25: LCOE of CST central receiver calculated from Sargent & Lundy data (note - not inclusive of any REC price)

Especially at the beginning of the curve, there are large reductions from scale-up of a small 13.5MW plant to 50+ MW. Behind this analysis includes the projection of large-scale manufacturing on key components such as heliostats, receivers and storage, such that even the Solar 50 costs are representative of ‘nth-of-a-kind’ plants. The deployment scenario this is based upon is 2,600MW of cumulative capacity of various sized tower projects over a 16-year period, except for the last Solar 220 cost which is from a more advanced scenario where 8,700MW are deployed over the same timeframe. The ‘indirect’ cost component is inclusive of both contingency allowances, which Sargent & Lundy reduced for later instalments in the expectation that costs would become better known from deployment; as well as the overheads for design engineering and construction management, which would reduce over time as experience standardises designs and construction becomes more streamlined and repetitive.

Overall, the analysis broke down the main factors contributing to the cost reduction from the first-of-a-kind 13.5MW plant to the final 220MW plant into:

- 23% from technical improvements (e.g. higher efficiency turbines, optimised component design)
- 49% from economies of scale due to increasing plant sizes. It should be noted that this is a larger factor towards the start of the deployment scenario in scaling up from a first-of-a-kind 13.5MW plant to 50MW, and if the comparison was between 50MW and 200MW, the scaling factor would not be such a high proportion.
- 28% from volume production and ‘learning curve’ – i.e. the effects of mass-production of components such as heliostats and receiver panels, taking into account the scale of a larger market with multiple plants under concurrent construction.

The S&L study provides a useful benchmark for the relative reductions between first-of-a-kind plants to more mature ‘nth-of-a-kind’ plants. Overall, the LCOE reduction between the first and final plant is 66%, or to take a more conservative mid-range, 40% reductions between the 50MW and mature 200MW plant.

The data from the S&L study has not been compared to the other datasets, as the timescale is different (the 2,600 MW scenario included the first 50MW plant coming online in 2007, and the first 100MW plant in 2011, which has not occurred).

The US Department of Energy’s CSP program has very recently done a similar updated analysis, which takes into account cost information from a confidential industry survey of five power tower developers, as well as several non-confidential studies including an assessment of power tower costs from Abengoa Solar, a Spanish CSP developer. This aggregated data has led to an updated baseline cost for a first-of-a-kind tower plant in the U.S., along with future projections that to some extent take into account learnings and volume production, though not to the same level of detail as the S&L study. This study includes more up-to-date data on individual component costs which have been developed through the initial deployments of CST in Spain.

Sandia National Laboratories: Power Tower Technology Roadmap and Cost Reduction Plan

This report, produced by Sandia National Laboratories for the US Department of Energy (DoE)'s CSP Program and currently available in draft form, is the product of a joint DoE-industry working group which has collected cost data from a number of solar thermal power tower developers[32]. It has been aggregated to a standard set of component cost data, and an analysis on the potential for cost reduction for each key component has been carried out. The Roadmap has identified opportunities falling into the full range of learning rate factors that have the potential to reduce the LCOE from power towers by almost 50% by 2020:

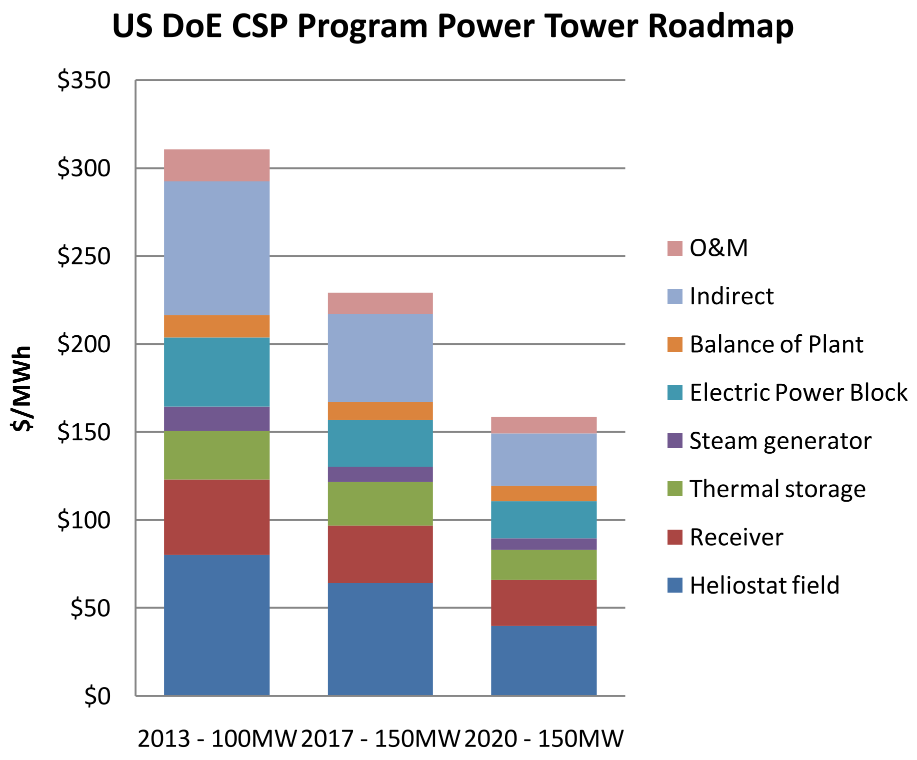

Figure 26: Projected LCOE breakdown from Sandia (2011) (note – not inclusive of any REC price)

Due to differences in the underlying plant designs shown, the '100MW' plant shown for 2013 is actually equivalent in size by mirror field and annual electricity output to a plant roughly halfway between the 50 and 100MW plants from the S&L study. Due to a range of factors, including increases in the costs of components such as power block and receiver, the updated costs are more expensive than prior projections. However it is also using component costs more suited to 'first-of-a-kind' plants with no factors for manufacturing volume and learnings, and a high factor for indirect costs and engineering overheads. Later plants take into account both improved efficiencies (such as supercritical steam turbines) and learning/volume effects on components.

7.3. Potential for cost reductions by component

Unique Components

Heliostats - Heliostats (mirrors) are the single largest outlay in a solar thermal power plant. As they are modular in nature, they are able to benefit from the effects of manufacturing volume reducing unit costs.

The graph in Figure 27 is data from a detailed bottom-up heliostat cost study performed by Sandia National Laboratories, based on data from a number of vendors at different rates of production. One representative 75-150MW CST tower plant will have just over 1 million square metres of heliostat area[33].

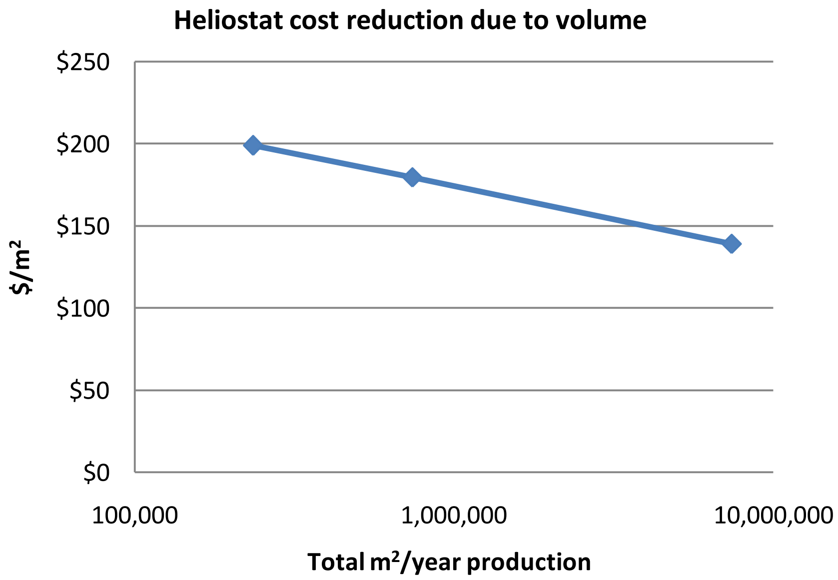

Figure 27: Heliostat cost curve as a function of production volume. Data from Sandia National Laboratories 'Heliostat Cost Reduction Study' via Power Tower Roadmap

Due to both reduced costs per unit and reduced field requirements due to higher efficiency plant operation, the US DoE Power Tower Roadmap expects that the contribution of heliostats to the levelised cost of electricity will almost halve by 2020.

Receiver – the high temperature receivers used for solar towers are the most unique component of the technology (and therefore is the main factor of technical risk), currently only produced by two companies – SENER (Spain) and Pratt & Whitney Rocketdyne (USA). Given the relatively small deployment of these components so far, it is reasonable to expect reductions in cost from learning and more regular manufacturing. Sargent & Lundy's original analysis indicated that a 10-15% learning rate on the receiver component in isolation is expected with a market of multiple plants per year[31]. This is in part due to the repetitive assembly of the receiver, which basically consists of dozens of panels each made of several dozen individual high-temperature metal tubes. It is also noted that the values of $200-150/kWt used for the 2013 receiver cost in the Power Tower Roadmap is higher than estimates from Abengoa ($125/kWt).

Storage – The potential for salt storage to become cheaper would mainly come from the technical improvement of expanding to higher temperatures, which requires less salt for a given amount of energy storage. In addition, some developers are actively pursuing and demonstrating thermocline storage systems which use a single tank instead of two, where the hot salt is layered on top of the cold salt. This has only been demonstrated experimentally, and needs to overcome a number of technical hurdles such as temperature gradient degradation, thermal ratcheting and scaleability. If it is proven at commercial scale, this has the potential to reduce storage costs by over 30%[34].

Generation components -

Components such as the steam turbine and power block are relatively standard thermal power equipment readily available from companies such as Siemens, GE and Alstom, which would not be expected to benefit further from learning-through-experience type effects. However due to the complexity of the design and assembly of the associated infrastructure of heat exchangers, piping, these components benefit from economies of scale of construction – i.e. the cost of power generation components does not scale linearly with the output of the plant[35].

It should be noted that when comparing the size of a solar thermal plant, the annual output (MWh/year) is a more useful measure than the size of the turbine, which can vary considerably depending on the desired operating regime. The US DoE Roadmap expects that power towers will be able to increase in thermal size at least double the current baseline size, which could result in capital savings per unit output of over 15%.

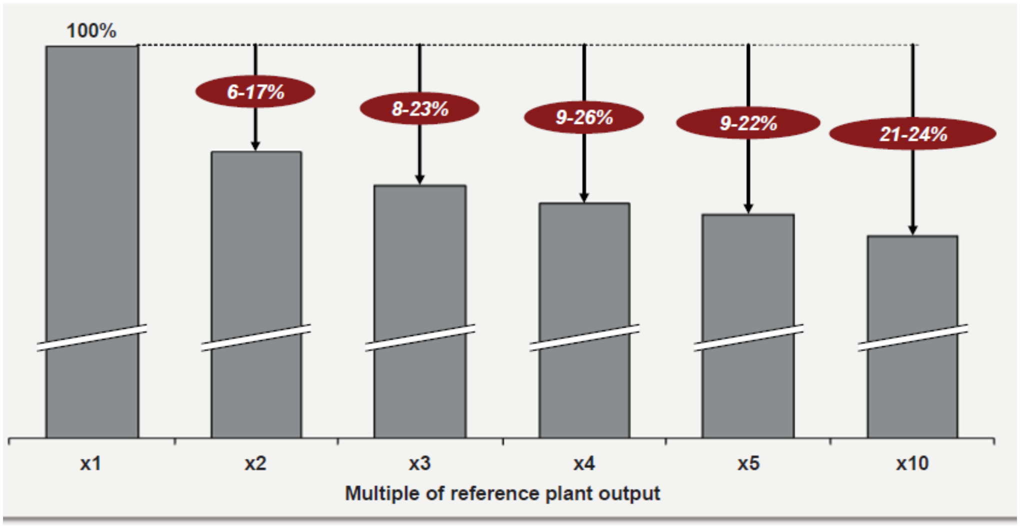

Figure 28: Capital cost reduction as a multiple of reference plant output. Source: AT Kearney & ESTELA (2010), data from industry sources and ATK analysis. Note this refers to all technologies – trough, tower, linear Fresnel, dish.

Technical improvements
Known improvements to the base technology used in power towers include:

Supercritical steam turbines - Expanding to higher operating temperatures for the salt and steam inlet conditions. Currently, the standard operating temperature for a tower is 540°C superheated steam. Superheated and supercritical steam turbines are operational in conventional fossil plants at temperatures of 600-610°C [36]. Reaching 600°C operating temperatures is expected for standard CSP development by 2020. It is possible that further R&D into higher temperature materials may push this to 640°C and above. As indicated by EPRI and the Sandia/US DoE Roadmap, this is expected to push gross steam turbine efficiencies as high as 48%[6].

Raising the temperature and operating regime (superheated to supercritical) of the steam turbines increases the efficiency of the power conversion cycle. As this is one of the largest sources of energy losses, an increase of 1-2% leads to significant performance improvement. However, in the current market supercritical turbines are not available under 400MW[37], approximately double the size required by a single large solar thermal tower. If the market for towers grows, there may be a greater incentive to produce supercritical turbines at these lower sizes. Standardisation of these products would then help reduce unit costs.

Indirect costs
Indirect costs consist of the extra fees and charges associated with developing and constructing a project on top of the 'hard' costs attributed to labour, materials and components. As the CST technology matures, contractors become more familiar with the construction process, and more modular standardised designs are used repeatedly, the indirect costs are expected to reduce[31]. It should also be pointed out that engineering, development and planning costs are mostly independent from the size of the plant, scaling non-linearly[38].

Engineering, procurement and construction management fees along with other project-related expenses can typically add another 30-35% or more on top of direct capital costs of a CST project, which ends up being a significant contributor to the levelised cost of electricity. This is most apparent for today's projects which are being conducted on one-off bases, with many projects still being first-of-a-kind for individual companies and contractors. It is expected that through learnings and modular design, indirect costs could be reduced to 20-25% of direct costs, which is what some power tower developers are expecting for near-term projects already[32,37,39]. If deployment occurs in an ad-hoc, non-continuous fashion, this has the potential to keep indirect costs high.

7.4. International Energy Agency (IEA) – Technology Roadmap – Concentrating Solar Power[40]

The IEA's CSP roadmap has taken into account the global expected growth in CSP, therefore is valuable for assessing the full effects of learning rates. The IEA's studies tend to focus on the metric of a 'progress ratio', the expected reduction in costs for each doubling of cumulative global capacity.

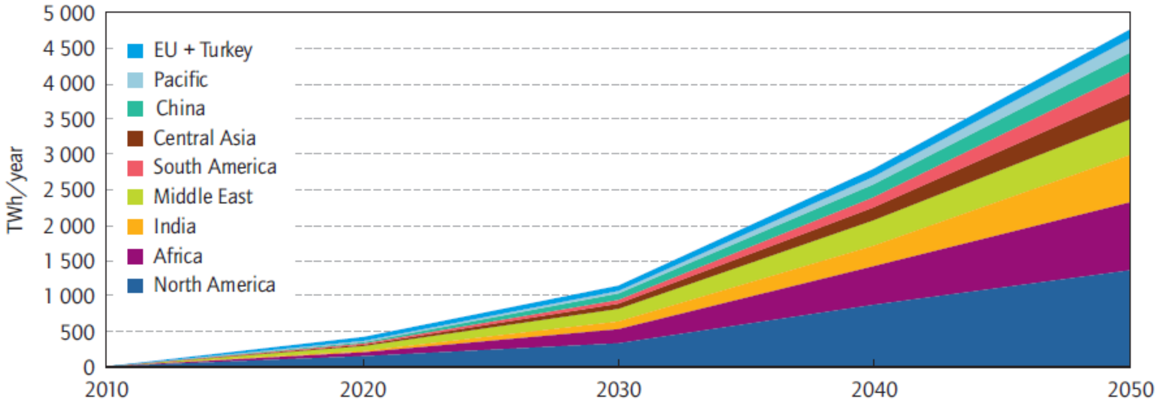

Figure 29: Global production of CSP under IEA Roadmap scenario (Source: IEA 2010)

The IEA Roadmap received expert input from over 30 CSP developers and research institutions worldwide to provide an updated assessment of the growth potential and costs of CSP under a growth forecast slightly higher than their *Energy Technology Perspectives BLUE Map* scenario, taking into account renewable incentive policies in countries with high CSP potential.

Under the growth scenario modelled, there would be 148GW of CSP capacity by 2020, producing 340TWh/yr of electricity which represents 1.3% of global electricity consumption. They expect that incentives and subsidies would be required much less for growth from 2020-2030, with installed capacity reaching 337GW by 2030 as the technology becomes competitive in many markets.

The IEA expects capital costs for troughs to fall by 30-40% over 2010-2020, whilst towers have even more potential with capital cost reductions of 40%-75% over the same period. This is consistent with the 10% learning rate and seven global doublings of capacity modelled by the Roadmap. This type of analysis is of course dependent upon the assumed deployment rate, which is dependent upon the individual stakeholder countries enacting the support policies the IEA's Roadmap recommends.

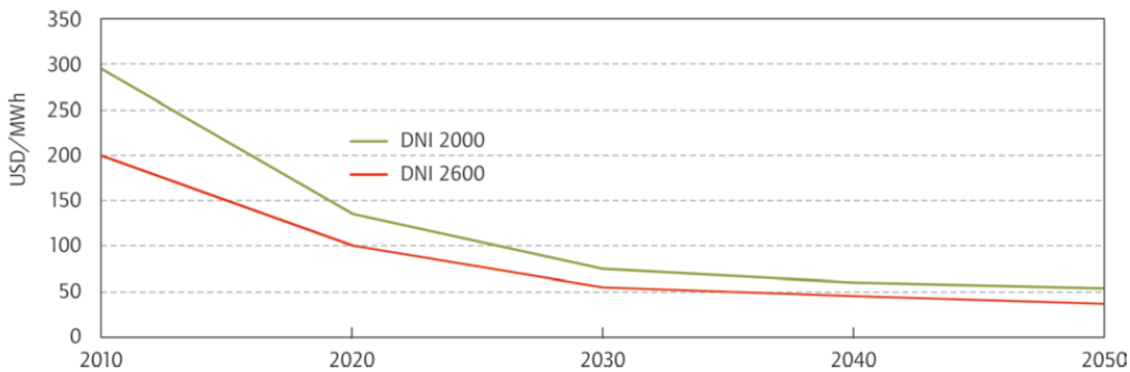

Figure 30: LCOE of CSP trough plants under IEA global growth scenario, at different DNI levels (Source: IEA 2010)

Under this scenario, the IEA expects that CSP in good solar resource locations will be competitive with intermediate power by 2020, and baseload power by 2025. The LCOE curve in Figure 30 is for trough plants, using slightly more conservative financial assumptions (10% WACC) than elsewhere in this paper, however the IEA analysis does not use a corporate tax rate – this is common for IEA analyses as tax conditions vary over their range of member countries. For the purposes of comparison with the other datasets, the IEA data shown in Figure 22 has been adjusted to normalise back to the 8.1% WACC, 30% tax rate used elsewhere.

7.5. ESTELA and AT Kearney Associates

In a similar vein to the U.S. DoE's CSP roadmap, the European Solar Thermal Electricity Association commissioned global consulting group AT Kearney to assess confidential data provided by over 20 CSP industry participants in Europe[38], particularly Spain, though many of these companies are operational elsewhere such as the United States.

The analysis took into account the market growth expected to occur in Europe and elsewhere under known policy incentives under a Business-As-Usual scenario. It conducted analysis of the technical efficiency and cost reductions expected from currently known improvements. Economies of scale were based on the aforementioned market growth rate, with a deployment of 30GW by 2020, and 60GW by 2025.

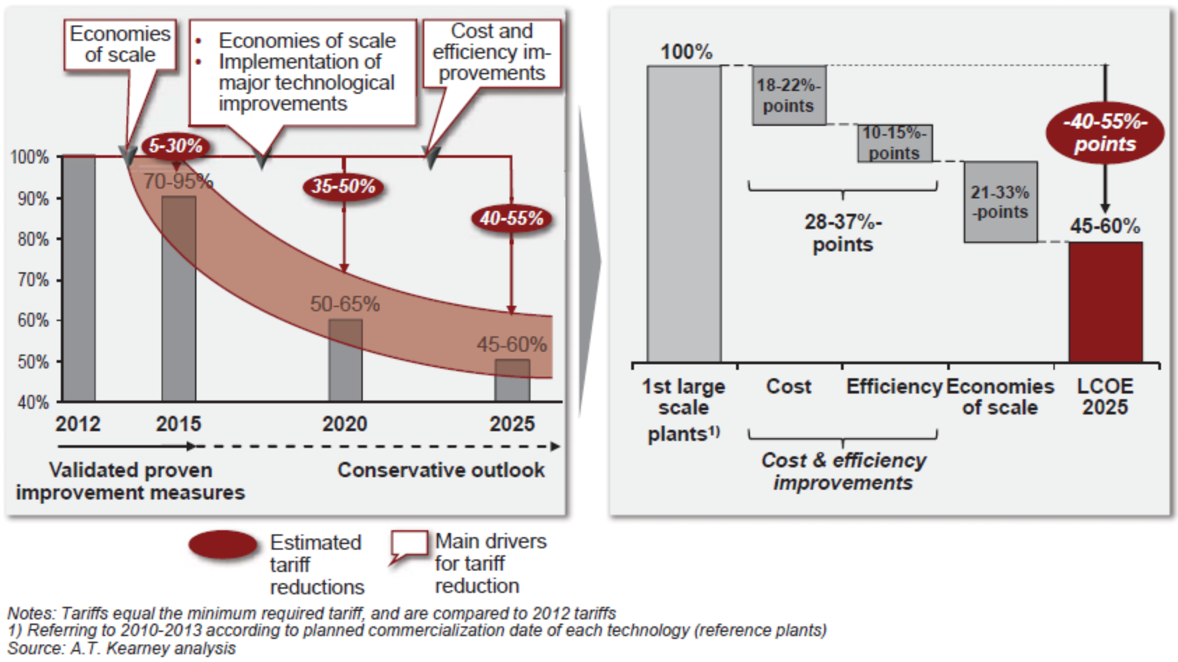

Figure 31: Summary of CSP cost reduction breakdown and timeline from AT Kearney analysis

The cost ranges given are inclusive of all solar thermal technologies – parabolic trough, dish, linear Fresnel and power tower. The aggregate result of the analysis is that cost reductions in LCOE of 35-50% are achievable by 2020, and 40-55% by 2025.

The category of 'cost' improvements in Figure 31 refers to reduced cost of individual components. As well as being inclusive of volume manufacturing effects, impacts such as the smoothing of nitrate salt prices due to market expansion are included. This is expected to contribute 18-22% of cost reduction potential.

The 'efficiency' category refers to technical efficiency improvements, in the case of power towers one of the main opportunities is increasing operating temperatures from 565°C to 600°C, which is possible with today's technology but not implemented in initial plants in the interest of keeping initial deployment low-risk[39]. As discussed earlier, higher temperatures both increasing the steam turbine efficiency, and lower the unit cost of salt storage by allowing greater storage of energy per unit volume of salt. Improved mirror efficiency is also a factor included in this analysis.

The 'economies of scale' portion takes into account both larger sizes for single plants, in the case of power towers up to 200MW, as well as the reduced engineering, construction management and planning cost overheads associated with larger plants, or multiple plants of a smaller size rolled out on a modular basis.

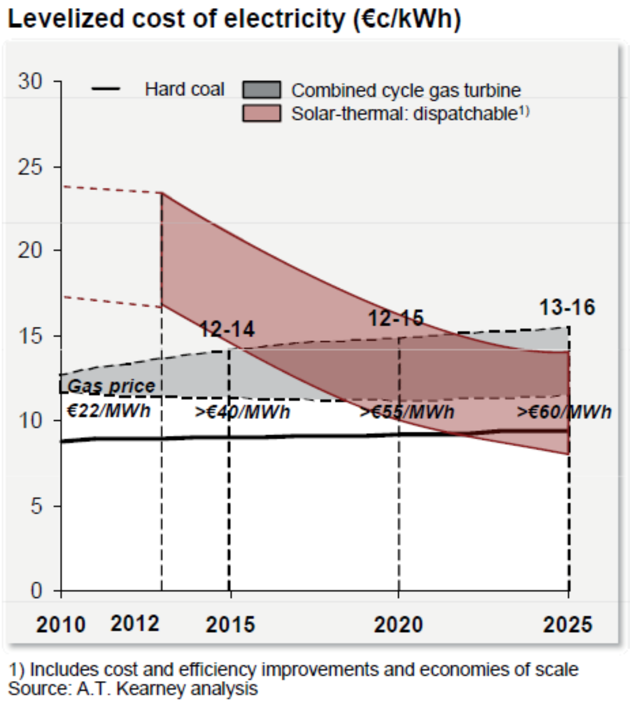

Figure 32: LCOE for solar thermal in Spain (Source: AT Kearney analysis)

The actual Levelised Cost of Energy projection range out to 2025 in Figure 32 is given for a reference solar thermal plant in Spain.

For the purposes of comparison in Figure 22, several adjustments have been made as outlined in the appendix IV.

The Eurocent/kWh figures shown have been converted to Australian dollars at the exchange rate of 1 AUD = 0.7 EUR, slightly below today's exchange rate. The financial parameters used a lifetime of 25 years, but a lower WACC of 6.9% post-tax, largely due to a low Return on Equity rate. Using the common WACC of 8.1% used elsewhere in this report would result in an LCOE 11-12% higher over the range shown, this adjustment has also been made (See Appendix 4 for further details).

Lastly, adjustment has been made to take into account the relatively low solar resource of the base plant that these calculations are derived from in Spain with 2084 kWh/m2/year. Australia's higher solar resource would result in approximately 13-15% lower LCOE from the same capital cost plant (comparison using DNI=2400).

Due to the nature of the AT Kearney-ESTELA study analyzing cost data from over 20 industry participants, exact data is confidential and not available for release, and the cost range shown represents all solar thermal technologies. However, updated information from the AT Kearney authors indicates that the upper range of costs shown represent a worst-case scenario, and that some solar thermal projects on the market are tracking at or even below the low end of the range given, indicating that this is the more realistic end of the cost projection. This seems to be especially the case for some current power tower technology projects[41].

7.6. AEMO dataset

For comparison, the cost data and future cost reduction projection currently used by the Australian Energy Market Operator has been used for a central receiver solar thermal plant with 6 hours of storage.

The capital cost quoted is $6,410/kW from 2010-2015, with an assumed capital cost reduction of 35% by 2030 to $4,166/kW. This is taken from Scenario 1 of input assumptions to the 2010 NTNDP modelling, representing the best-case data in the range of scenarios modelled[5]. It is based upon data from the EPRI report commissioned by the Department of Resource, Energy & Tourism[6], and reviewed by ACIL Tasman. The underlying data between AEMO and EPRI for this particular technology case are the same, therefore separate analysis for EPRI data has not been included as it would not give a different cost curve.

The factors of O&M and overall plant efficiency were constant over this period, with no allowance for reduction given in the data. The performance data from EPRI (capacity factors and annual solar-electric efficiency of 15.5%) have been used to calculate capacity factor for DNI = 2400 kWh/m2/year, to allow the same basis of comparison with the other datasets in this report.

DNI (kWh/m2/year)	Daily average DNI (kWh/m2/day)	Capacity Factor
1825	5	26.4%
2190	6	31.6%
2400	6.6	34.7%
2555	7	36.9%

8. Appendix I: LCOE Model Verification

The following two tables compare a sample of the model outputs against ATSE modeling results. A sample of four different sets of input variables, for the two different technologies, and can be found below.

CST Sample Calculations (not inclusive of RECs):

Capex	Opex	CF	LCOE - MEI	LCOE-ATSE	Difference
$6,410	$73	35%	**$309.90**	**$309**	0.291%
$5,662	$73	35%	**$276.54**	**$276**	0.196%
$4,914	$73	35%	**$243.19**	**$243**	0.078%
$4,166	$73	35%	**$209.83**	**$209**	0.397%

Wind Sample Calculations (not inclusive of RECs):

Capex	Opex	CF	LCOE - MEI	LCOE-ATSE	Difference
$3,018	$37	30%	**$169.57**	**$169**	0.337%
$2,817	$37	30%	**$159.22**	**$159**	0.138%
$2,616	$37	30%	**$148.86**	**$148**	0.581%
$2,415	$37	30%	**$138.51**	**$138**	0.370%

9. Appendix II: Photovoltaic

Capital Costs

Table 4 lists the Capital Costs used in the LCOE calculation. All values are in 2010 AU$/kW.

Table 4: Capital Expenses for the relevant datasets

	EPIA[17]			IEA		AEMO[5] (ACIL Tasman)	EPRI[6]
	Reference*	Advanced*	Paradigm Shift*	PCEG[1]	RoadMap[11]		
2010	$4,000	$4,000	$3,571	$4,061	$4,061	$5,115	-
2015	$3,357	$2,650	$2,143	-	-	$5,115	$8,459
2020	$2,971	$1,914	$1,359	-	$1,827	$4,604	-
2030	$2,429	$1,380	$1,063	$1,218	$1,218	$3,581	$5,498

Levelised Costs of Energy

Table 5 list the calculated LCOE's for the different data sets. All values are in 2010 AU$/MWh.

Table 5: Calculated LCOE's for the relevant data sets

	EPIA			IEA		AEMO (ACIL Tasman)	EPRI
	Reference	Advanced	Paradigm Shift	PCEG	RoadMap		
2010	$305	$305	$275	$311**	$311	$384	-
2015	$260	$210	$174	-	-	$384	$454
2020	$232	$157	$118	-	$140	$348	-
2030	$194	$120	$97	$93	$93	$312	$303

* The EPIA reference scenario is based Reference scenario is based on the Reference scenario in the International Energy Agency's 2009 World Energy Outlook (WEO 2009) analysis. The EPIA advanced scenario foresees the 'ability to deploy PV faster, in line with market developments' and can be seen as a continuation of current support measures. The Paradigm shift scenario estimates the 'full potential of PV in the next 40 years'.

**This is value is actually a cost for 2008 (not 2010), but was placed here to fit in the table.

10. Appendix III: Wind

1.1.1. *Experience Curves*

The wind experience curve was constructed from two sets of data; an 'historic' set based on the installation of wind farms in Spain between 1990 and 2001[22], and a 'current' set based on aggregated numbers from the European Wind Energy Agency between 2000 and 2010[23]. The historic set was reported in 2001 Euro's, whilst the EWEA set was report in 2005 Euro's. The data was inflated and converted to 2010 Australian dollars to provide a consistent and relevant basis of comparison. The original data can be found below:

Historic Data[22]		Current Data[23]	
Cumulative Capacity (MW)	Cost (2010 $/kWh)	**Cumulative Capacity (MW)**	Cost (2010 $/kWh)
4966	2467	**16357**	1540
5709	2342	**24448**	1286
6271	2127	**31248**	1143
7443	1962	**39431**	1286
8975	1752	**47620**	1429
10960	1654	**59091**	1643
12449	1686	**74133**	1786
13848	1628	**93802**	1857
15561	1543	**120791**	1786
17434	1493	**159134**	1714
19058	1473		

Log-Log plots of the transformed data were constructed to represent the experience curves. The progress ratios and hence learning rates can be derived from this plot.

The most recent EWEA data, and EWEA projections for the medium term were also plotted alongside two different learning rates (5% and 7%). This illustrates how the EWEA projections fit in with different learning rate projections (e.g. the IEA projection of a learning rate of 7%[1]). It should be noted that a different (but more aggressive) EWEA projection suggests a 10% learning rate could be achieved.

Capital Costs

Table 6 lists the Capital Costs used in the LCOE calculation. All values are in 2010 AU$/kW.

Table 6: Capital Expenses for the relevant datasets

	GWEC[19]			IEA[1]	AEMO[5] (ACIL Tasman)	EPRI[6]
	Reference*	Moderate*	Advanced*			
2010	$1896	$1899	$1897	$1725	$3018	-
2015	$1823	$1797	$1779	-	$3018	$3577
2020	$1771	$1726	$1674	-	$2817	-
2025	$1753	$1651	$1611	-	$2616	-
2030	$1737	$1594	$1561	$1421	$2415	$2325

Levelised Costs of Energy

Table 7 list the calculated LCOE's for the different data sets. All values are in 2010 AU$/MWh.

Table 7: Calculated LCOE's for the relevant data sets

	GWEC			IEA	AEMO (ACIL Tasman)	EPRI
	Reference	Moderate	Advanced			
2010	$62	$62	$62	$51	$119	-
2015	$58	$57	$56	-	$119	$148
2020	$55	$53	$50	-	$109	-
2025	$54	$49	$47	-	$98	-
2030	$54	$46	$45	$35	$88	$84

*The GWEC reference scenario is based on the projections in the IEA World Energy Outlook. The Moderate scenario takes in to account all policy measures already in place around the world. The advanced scenario is a 'best case scenario', if the industry were given the 'political commitment and encouragement it deserves'[19].

Sensitivities

Construction Period

It was assumed the construction period for a wind farm was two years, in line with the AEMO dataset[5]. The IEA projects that wind farm projects would have a 1 yr construction period[1], which results in different LCOE's. The impact of variation of construction period on the LCOE is illustrated in Figure 33 (GWEC moderate scenario), and the LCOE results assuming 1 year construction are displayed in Table 8.

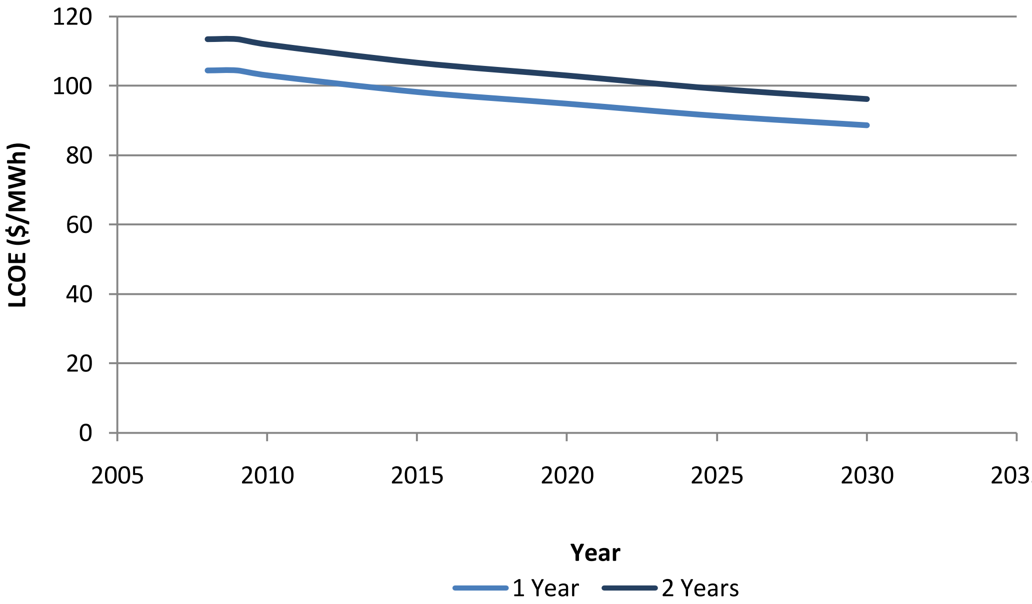

Figure 33: Construction Period Sensitivity, GWEC moderate scenario, (excluding REC revenue)

Table 8: Calculated LCOE's, assuming 1 year construction

	GWEC			IEA	AEMO (ACIL Tasman)	EPRI
	Reference	Moderate	Advanced			
2010	$53	$53	$53	$73	$105	-
2015	$49	$48	$47	-	$105	$132
2020	$47	$45	$42	-	$96	-
2025	$46	$41	$40	-	$87	-
2030	$45	$39	$37	$29	$77	$83

11. Appendix IV: Concentrating Solar Thermal

1.1.1. Costs

The tables below list the costs used in the LCOE calculations. All values are in 2010 AU$/kW unless explicitly stated otherwise, converted at foreign exchange rates of 1USD = 0.985AUD, and 1EUR = 0.7AUD. LCOEs are inclusive of $50/MWh REC.

	AEMO 2010 (ACIL Tasman) – Scenario 1			
	Capex ($/kW)	O&M ($/kW/yr)	Annual Solar-Electric Efficiency	LCOE ($/MWh)
2010	$6,410	$73	15.5%	$267
2015	$6,410	$73	15.5%	$267
2020	$5,662	$73	15.5%	$233
2025	$4,914	$73	15.5%	$198
2030	$4,166	$73	15.5%	$164

	US DoE Power Tower Roadmap			
	Capex ($/kW)	O&M ($/kW/yr)	Annual Solar-Electric Efficiency	LCOE ($/MWh)
2013	$7,540	$66	14.8%	$260
2017	$7,516	$58	15.7%	$179
2020	$5,763	$51	17.8%	$109

International Energy Agency data was available as a final LCOE. It has been converted to Australian dollars taking into account factors to allow for different tax rates and WACC used.

	IEA CSP Roadmap – DNI 2400	
	LCOE (US$/MWh, no REC)	LCOE (AU$/MWh adjusted, with REC)
2010	$295	$213
2020	$136	$72
2030	$76	$18
WACC	10%	8.1%
Tax Rate	0	30%

Under the high end of the range of sensitivity analyses in Figure 34, the tax rate of 30% increased the LCOE by 28% relative to zero tax. Therefore this factor has been applied to the IEA data. Changing the WACC from 10% to 8.1% lowered the LCOE by 18% (Figure 35), which has also been applied.

	AT Kearney - High		AT Kearney - Low	
	LCOE (EU$/MWh, no REC)	LCOE (AU$/MWh adjusted, with REC)	LCOE (EU$/MWh, no REC)	LCOE (AU$/MWh adjusted, with REC)
2010	€238	$290	€174	$198
2013	€235	$286	€168	$190
2015	€211	$252	€146	$158
2020	€164	$184	€100	$93
2025	€141	$151	€80	$65

The AT Kearney analysis used a post-tax WACC of 6.9%, while under a range of scenarios, using 8.1% delivers an LCOE 15% higher (Figure 35). This adjustment has been made to convert the AT Kearney data, along with a factor to allow for the lower DNI of 2084 kWh/m2/year compared to 2400 (13% lower LCOE), this relationship is shown in Figure 36.

LCOE sensitivities

Sensitivity analyses have been carried out on a range of plant costs and configurations under different financial parameters to assess the effect on the LCOE of varying key parameters such as the WACC, tax rate, and DNI resource. As the figures below show, the relative effect of the varying these parameters is fairly constant even under varying other financial and cost parameters at the same time.

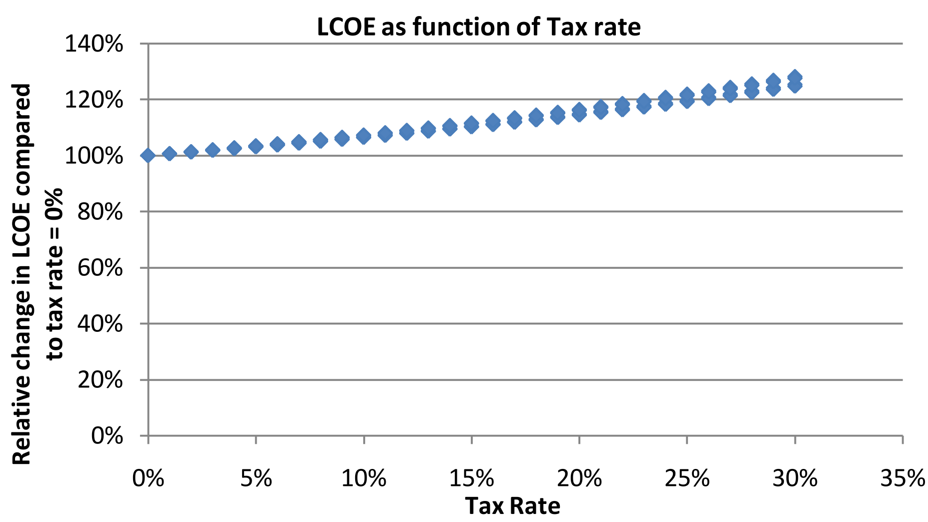

Figure 34: LCOE as a function of corporate tax rate for solar thermal power. 186 data points are shown, which include a range of varying capital and operating costs, and resource levels.

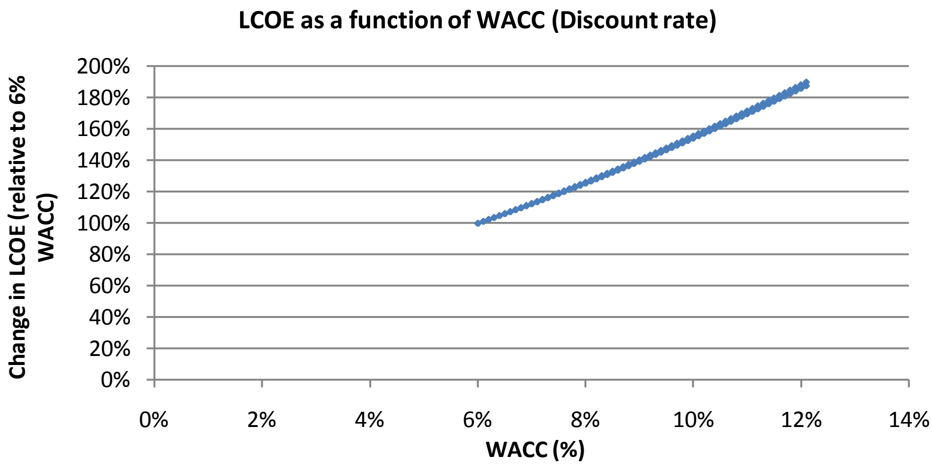

Figure 35: LCOE as a function of varying WACC for solar thermal power. 186 data points are shown, which also include a range of varying capital and operating costs, and resource levels.

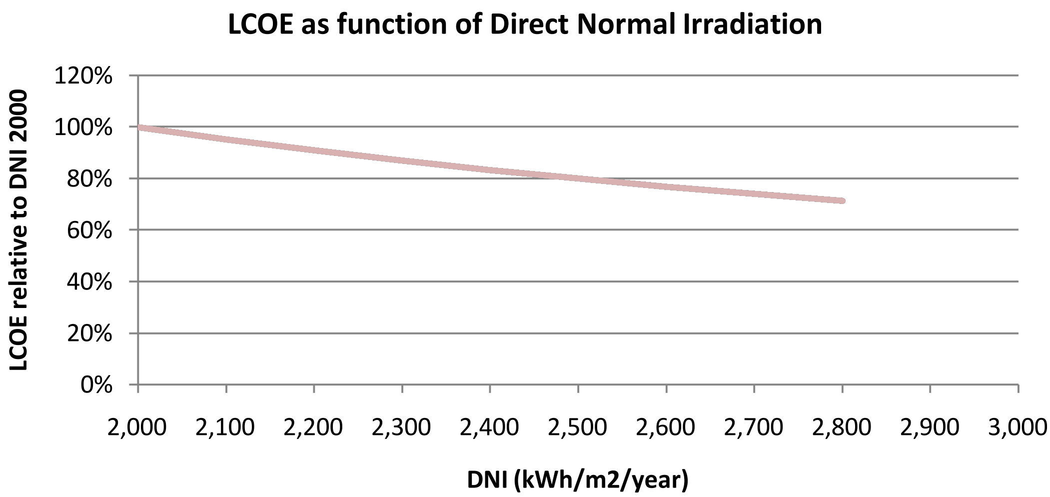

Figure 36: LCOE as a function of DNI. 20 different cases are shown which also include varying capital and operating costs, and annual solar-to-electric efficiencies.

12. Appendix V: Solar Resource

The available solar radiation at any given location has a significant effect on the LCOE for solar technologies, as this essentially governs the total energy output and capacity factor for a given installation. There are several ways of measuring solar resource:

- Global Horizontal Irradiation (GHI) measures the energy received on a surface parallel to the surface of the Earth (i.e. flat on the ground).
- Direct Normal Irradiation (DNI) measures the energy received on a surface angled at a normal (i.e. perpendicular) to the sun at any point in time.

For assessing solar energy technologies, DNI is the relevant resource type to use. When calculating output, factors such as the angle of a fixed collector or the tracking of a moving collector can be taken into account.

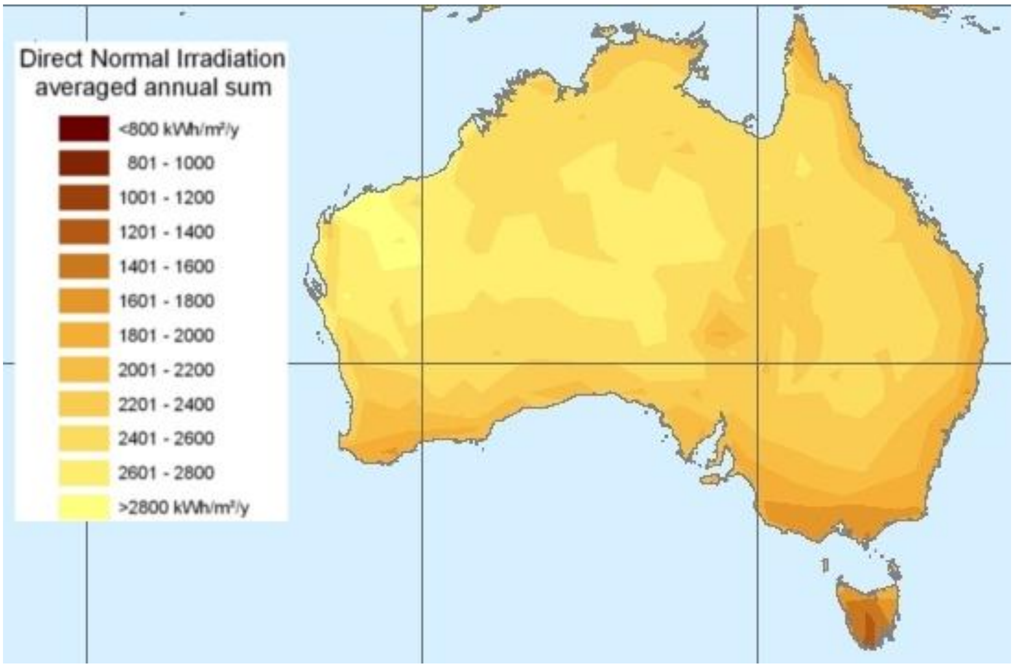

Figure 37: Direct Normal Irradiation resource for Australia. Adapted from DLR[42]

For Australia, as can be seen from Figure 37, the DNI over most of Australia is over 2000 kWh/m2/year (5.48 kWh/m2/day average). There are many areas in central NSW, central QLD, South Australia and Western Australia with average DNI around 2400, whilst still in close proximity to the existing electricity grid. Therefore for the purposes of the solar thermal power analysis in this report, all calculations have been done on the basis of DNI = 2400 kWh/m2/year.

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