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About IRENA

The International Renewable Energy Agency (IRENA) is an intergovernmental organisation dedicated to renewable energy.

In accordance with its Statute, IRENA's objective is to "promote the widespread and increased adoption and the sustainable use of all forms of renewable energy". This concerns all forms of energy produced from renewable sources in a sustainable manner and includes bioenergy, geothermal energy, hydropower, ocean, solar and wind energy.

As of May 2012, the membership of IRENA comprised 158 States and the European Union (EU), out of which 94 States and the EU have ratified the Statute.

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Preface

Renewable power generation can help countries meet their sustainable development goals through provision of access to clean, secure, reliable and affordable energy.

Renewable energy has gone mainstream, accounting for the majority of capacity additions in power generation today. Tens of gigawatts of wind, hydropower and solar photovoltaic capacity are installed worldwide every year in a renewable energy market that is worth more than a hundred billion USD annually. Other renewable power technology markets are also emerging. Recent years have seen dramatic reductions in renewable energy technologies' costs as a result of R&D and accelerated deployment. Yet policy-makers are often not aware of the latest cost data.

International Renewable Energy Agency (IRENA) Member Countries have asked for better, objective cost data for renewable energy technologies. This working paper aims to serve that need and is part of a set of five reports on wind, biomass, hydropower, concentrating solar power and solar pholtovoltaics that address the current costs of these key renewable power technology options. The reports provide valuable insights into the current state of deployment, types of technologies available and their costs and performance. The analysis is based on a range of data sources with the objective of developing a uniform dataset that supports comparison across technologies of different cost indicators - equipment, project and levelised cost of electricity – and allows for technology and cost trends, as well as their variability to be assessed.

The papers are not a detailed financial analysis of project economics. However, they do provide simple, clear metrics based on up-to-date and reliable information which can be used to evaluate the costs and performance of different renewable power generation technologies. These reports help to inform the current debate about renewable power generation and assist governments and key decision makers to make informed decisions on policy and investment.

The dataset used in these papers will be augmented over time with new project cost data collected from IRENA Member Countries. The combined data will be the basis for forthcoming IRENA publications and toolkits to assist countries with renewable energy policy development and planning. Therefore, we welcome your feedback on the data and analysis presented in these papers, and we hope that they help you in your policy, planning and investment decisions.

Dolf Gielen

Director, Innovation and Technology

Contents

Key findings

1. **Concentrating solar power (CSP) plants** are capital intensive, but have virtually zero fuel costs. Parabolic trough plant without thermal energy storage have capital costs as low as USD 4 600/kW, but low capacity factors of between 0.2 and 0.25. Adding six hours of thermal energy storage increases capital costs to between USD 7 100/kW to USD 9 800/kW, but allows capacity factors to be doubled. Solar tower plants can cost between USD 6 300 and USD 10 500/kW when energy storage is between 6 and 15 hours. These plant can achieve capacity factors of 0.40 to as high as 0.80.

Table 1: CSP costs and performance in 2011

	Installed cost (2010 USD/kW)	Capacity factor (%)	O&M (2010 USD/kWh)	LCOE (2010 USD/kWh)
Parabolic trough			0.02 to 0.035	0.14 to 0.36
No storage	4 600	20 to 25		
6 hours storage	7 100 to 9 800	40 to 53		
Solar tower				0.17 to 0.29
6 to 7.5 hours storage	6 300 to 7 500	40 to 45		
12 to 15 hours storage	9 000 to 10 500	65 to 80		

Note: the levelised cost of electricity (LCOE) assumes a 10% cost of capital

2. **Operations and maintenance (O&M)** costs are relatively high for CSP plants, in the range USD 0.02 to USD 0.035/kWh. However, cost reduction opportunities are good and as plant designs are perfected and experience gained with operating larger numbers of CSP plants savings opportunities will arise.

3. **The levelised cost of electricity (LCOE)** from CSP plants is currently high. Assuming the cost of capital is 10%, the LCOE of parabolic trough plants today is in the range USD 0.20 to USD 0.36/kWh and that of solar towers between USD 0.17 and USD 0.29/kWh. However, in areas with excellent solar resources it could be as low as USD 0.14 to USD 0.18/kWh. The LCOE depends primarily on capital costs and the local solar resource. For instance, the LCOE of a given CSP plant will be around one-quarter lower for a direct normal irradiance of 2 700 kWh/m^2/year than for a site with 2 100 kWh/m^2/year.

4. **With just 1.9 GW of installed CSP capacity,** not enough data exists to identify a robust learning curve. However, the opportunities for cost reductions for CSP plant are good given that the commercial deployment of CSP is in its infancy. Capital cost reductions of 10% to 15% and modest reductions in O&M costs by 2015 could see the LCOE of parabolic trough plants decline to between USD 0.18 and USD 0.32/kWh by 2015 and that of solar tower plants to between USD 0.15 to USD 0.24/kWh.

5. **Cost reductions** will come from economies of scale in the plant size and manufacturing industry, learning effects, advances in R&D, a more competitive supply chain and improvements in the performance of the solar field, solar-to-electric efficiency and thermal energy storage systems. By 2020, capital cost reductions of 28% to 40% could be achieved and even higher reductions may be possible.

6. **Solar towers** might become the technology of choice in the future, because they can achieve very high temperatures with manageable losses by using molten salt as a heat transfer fluid. This will allow higher operating temperatures and steam cycle efficiency, and reduce the cost of thermal energy storage by allowing a higher temperature differential. Their chief advantage compared to solar photovoltaics is therefore that they could economically meet peak air conditioning demand and intermediate loads (in the evening when the sun isn't shining) in hot arid areas in the near future.

List of tables

List of figures

1. Introduction

Renewable energy technologies can help countries meet their policy goals for secure, reliable and affordable energy to expand electricity access and promote development. This paper is part of a series on the cost and performance of renewable energy technologies produced by IRENA. The goal of these papers is to assist government decision-making and ensure that governments have access to up-to-date and reliable information on the costs and performance of renewable energy technologies.

Without access to reliable information on the relative costs and benefits of renewable energy technologies it is difficult, if not impossible, for governments to arrive at an accurate assessment of which renewable energy technologies are the most appropriate for their particular circumstances. These papers fill a significant gap in information availability, because there is a lack of accurate, comparable, reliable and up-to-date data on the costs and performance of renewable energy technologies. The rapid growth in installed capacity of renewable energy technologies and the associated cost reductions mean that even data one or two years old can significantly overestimate the cost of electricity from renewable energy technologies. There is also a significant amount of perceived knowledge about the cost and performance of renewable power generation that is not accurate, or indeed even misleading. Conventions on how to calculate cost can influence the outcome significantly and it is imperative that these are well-documented.

The absence of accurate and reliable data on the cost and performance of renewable power generation technologies is therefore a significant barrier to the uptake of these technologies. Providing this information will help governments, policy-makers, investors and utilities make informed decisions about the role renewable can play in their power generation mix. This paper examines the fixed and variable cost components of concentrating solar power (CSP) plant, by country and region and provides the levelised cost of electricity for CSP power plants, given a number of key assumptions. This up-to-date analysis of the costs of generating electricity from CSP will allow a fair comparison of CSP with alternative generating technologies.[1]

1.1 DIFFERENT MEASURES OF COST

Cost can be measured in a number of different ways, and each way of accounting for the cost of power generation brings its own insights. The costs that can be examined include equipment costs (e.g. wind turbines, PV modules, solar reflectors), financing costs, total installed cost, fixed and variable operating and maintenance costs (O&M), fuel costs and the levelised cost of energy (LCOE).

The analysis of costs can be very detailed, but for comparison purposes and transparency, the approach used here is a simplified one. This allows greater scrutiny of the underlying data and assumptions, improving transparency and confidence in the analysis, as well as facilitating the comparison of costs by country or region for the same technologies in order to identify what are the key drivers in any differences.

The three indicators that have been selected are:

- Equipment cost (factory gate FOB and delivered at site CIF);
- Total installed project cost, including fixed financing costs[2]; and
- The levelised cost of electricity LCOE.

The analysis in this paper focuses on estimating the cost of CSP power generation from the perspective of a private investor, whether they are a state-owned electricity generation utility, an independent power generation promoter, or an individual or community

[1] IRENA, through its other work programmes, is also looking at the costs and benefits, as well as the macroeconmic impacts, of renewable power generation technologies. See WWW.IRENA.ORG for further details.

[2] Banks or other financial institutions will often charge a fee, such as a percentage of the total funds sought, to arrange the debt financing of a project. These costs are often reported separately under project development costs.

looking to invest in small-scale renewables (Figure 1.1). The analysis excludes the impact of government incentives or subsidies. However, the analysis does not take into account any CO2 pricing, nor the benefits of renewables in reducing other externalities (e.g. reduced local air pollution, contamination of natural environments). Similarly, the benefits of renewables being insulated from volatile fossil fuel prices have not been quantified. These issues are important, but are covered by other programmes of work at IRENA.

It is important to include clear definitions of the technology categories, where this is relevant, to ensure that cost comparisons can be correctly compared (e.g. parabolic troughs vs. solar towers with storage aren't like-for-like comparisons). Similarly, it is important to differentiate between the functionality and/or qualities of the renewable power generation technologies being investigated (e.g. concentrating solar power with and without thermal energy storage). It is important to ensure that system boundaries for costs are clearly set and that the available data are directly comparable. Other issues can also be important, such as cost allocation rules for combined heat and power plants, and grid connection costs.

The data used for the comparisons in this paper come from a variety of sources, such as business journals, industry associations, consultancies, governments, auctions and tenders. Every effort has been made to ensure that these data are directly comparable and are for the same system boundaries. Where this is not the case, the data have been corrected to a common basis using the best available data or assumptions. It is planned that these data will be complemented by detailed surveys of real world project data in forthcoming work by the agency.

An important point is that, although this paper tries to examine costs, strictly speaking, the data available are actually prices, and not even true market average prices, but price indicators. The difference between costs and prices is determined by the amount above, or below, the normal profit that would be seen in a competitive market. The rapid growth of renewables markets from a small base means that the market for renewable power generation technologies is rarely well-balanced. As a result, prices can rise significantly above costs in the short-term if supply is not expanding as fast as demand, while in times of excess supply, losses can occur and prices may be below production costs. This

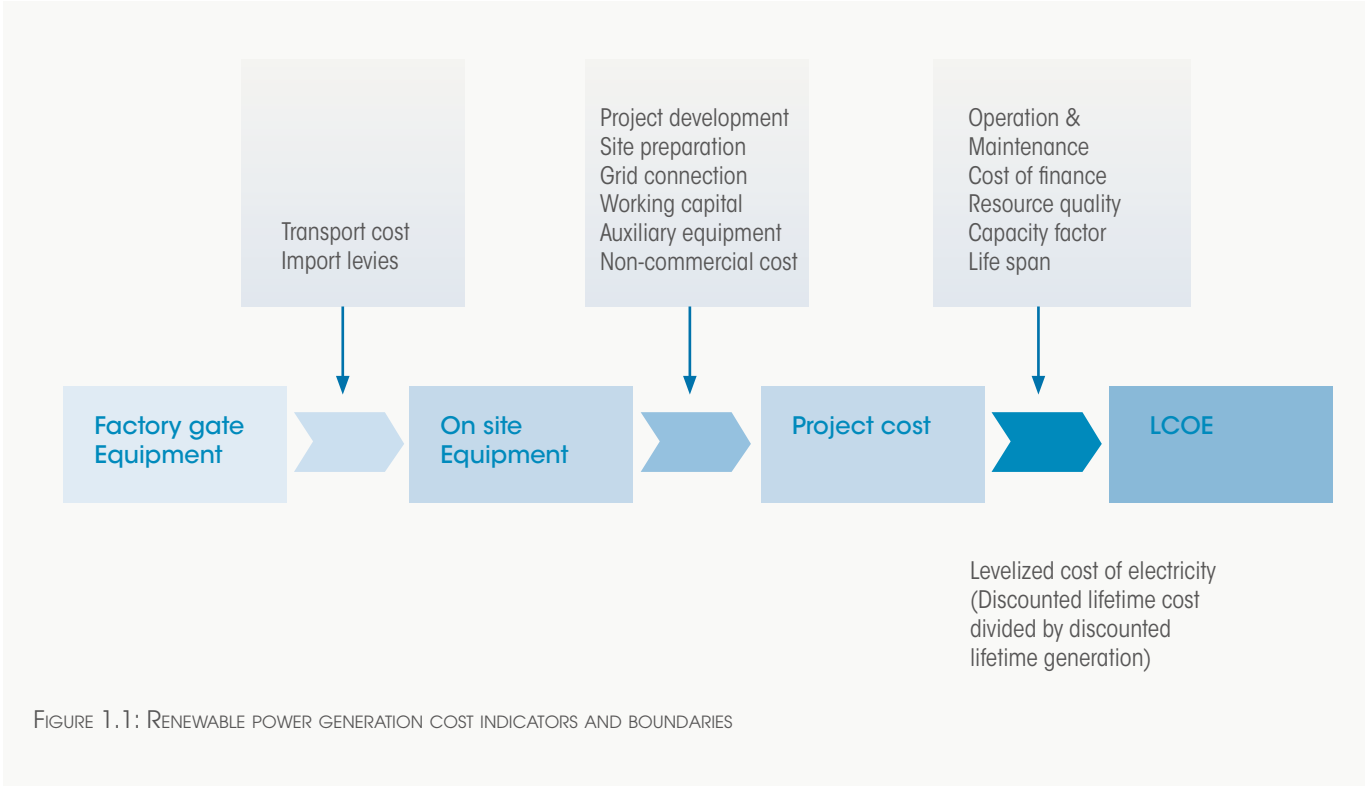

Figure 1.1: Renewable power generation cost indicators and boundaries

makes analysing the cost of renewable power generation technologies challenging and every effort is made to indicate whether current equipment costs are above or below their long-term trend.

The cost of equipment at the factory gate is often available from market surveys or from other sources. A key difficulty is often reconciling different sources of data to identify why data for the same period differ. The balance of capital costs in total project costs tends to vary even more widely than power generation equipment costs, as it is often based on significant local content, which depends on the cost structure of where the project is being developed. Total installed costs can therefore vary significantly by project, country and region, depending on a wide range of factors.

1.2 LEVELISED COST OF ELECTRICITY GENERATION

The LCOE of renewable energy technologies varies by technology, country and project based on the renewable energy resource, capital and operating costs, and the efficiency / performance of the technology. The approach used in the analysis presented here is based on a discounted cash flow (DCF) analysis. This method of calculating the cost of renewable energy technologies is based on discounting financial flows (annual, quarterly or monthly) to a common basis, taking into consideration the time value of money. Given the capital intensive nature of most renewable power generation technologies and the fact fuel costs are low, or often zero, the weighted average cost of capital (WACC), often also referred to as the discount rate, used to evaluate the project has a critical impact on the LCOE.

There are many potential trade-offs to be considered when developing an LCOE modeling approach. The approach taken here is relatively simplistic, given the fact that the model needs to be applied to a wide range of technologies in different countries and regions. However, this has the additional advantage that the analysis is transparent and easy to understand. In addition, more detailed LCOE analysis results in a significantly higher overhead in terms of the granularity of assumptions required. This often gives the impression of greater accuracy, but when it is not possible to robustly populate the model with assumptions, or to differentiate assumptions based on real world data, then the "accuracy" of the approach can be misleading.

The formula used for calculating the LCOE of renewable energy technologies is:

$$\text{LCOE} = \frac{\sum_{t=1}^{n} \frac{I_t + M_t + F_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{E_t}{(1+r)^t}}$$

Where:
LCOE = the average lifetime levelised cost of electricity generation;
I_t **=** investment expenditures in the year t;
M_t **=** operations and maintenance expenditures in the year t;
F_t **=** fuel expenditures in the year t;
E_t **=** electricity generation in the year t;
r = discount rate; and
n = life of the system.

All costs presented in this paper are real 2010 USD; that is to say, after inflation has been taken into account except where otherwise indicated.[3] The LCOE is the price of electricity required for a project where revenues would equal costs, including making a return on the capital invested equal to the discount rate. An electricity price above this would yield a greater return on capital, while a price below it would yielder a lower return on capital, or even a loss.

As already mentioned, although different cost measures are useful in different situations, the LCOE of renewable energy technologies is a widely used measure by which renewable energy technologies can be evaluated for modelling or policy development. Similarly, more detailed DCF approaches taking into account taxation, subsidies and other incentives are used by renewable energy project developers to assess the profitability of real world projects.

[3] An analysis based on nominal values with specific inflation assumptions for each of the cost components is beyond the scope of this analysis.

2. Concentrating solar power technologies

Concentrating solar power (CSP) is a power generation technology that uses mirrors or lenses[4] to concentrate the sun's rays and, in most of today's CSP systems, to heat a fluid and produce steam. The steam drives a turbine and generates power in the same way as conventional power plants. Other concepts are being explored and not all future CSP plants will necessarily use a steam cycle.

The innovative aspect of CSP is that it captures and concentrates the sun's energy to provide the heat required to generate electricity, rather than using fossil fuels or nuclear reactions. Another attribute of CSP plants is that they can be equipped with a heat storage system in order to generate electricity even when the sky is cloudy or after sunset. This significantly increases the CSP capacity factor[5] compared with solar photovoltaics and, more importantly, enables the production of dispatchable electricity, which can facilitate both grid integration and economic competitiveness.

CSP technologies therefore benefit from advances in solar concentrator and thermal storage technologies, while other components of the CSP plants are based on rather mature technologies and cannot expect to see rapid cost reductions.

CSP technologies are not currently widely deployed. A total of 354 MW[6] of capacity was installed between 1985 and 1991 in California and has been operating commercially since then. After a hiatus in interest between 1990 and 2000, interest in CSP has been growing over the past ten years. A number of new plants have been brought on line since 2006 (Muller-Steinhagen, 2011) as a result of declining investment costs and LCOE, as well as new support policies. Spain is now the largest producer of CSP electricity and there are several very large CSP plants planned or under construction in the United States and North Africa.

CSP plants can be broken down into two groups, based on whether the solar collectors concentrate the sun rays along a focal line or on a single focal point (with much higher concentration factors). *Line-focusing systems* include parabolic trough and linear Fresnel plants and have single-axis tracking systems. *Point-focusing systems* include solar dish systems and solar tower plants and include two-axis tracking systems to concentrate the power of the sun.

2.1 PARABOLIC TROUGH COLLECTOR TECHNOLOGY

The parabolic trough collectors (PTC) consist of solar collectors (mirrors), heat receivers and support structures. The parabolic-shaped mirrors are constructed by forming a sheet of reflective material into a parabolic shape that concentrates incoming sunlight onto a central receiver tube at the focal line of the collector. The arrays of mirrors can be 100 metres (m) long or more, with the curved aperture of 5 m to 6 m. A single-axis tracking mechanism is used to orient both solar collectors and heat receivers toward the sun (A.T. Kearney and ESTELA, 2010). PTC are usually aligned North-South and track the sun as it moves from East to West to maximise the collection of energy.

The receiver comprises the absorber tube (usually metal) inside an evacuated glass envelope. The absorber tube is generally a coated stainless steel tube, with a spectrally selective coating that absorbs the solar (short wave) irradiation well, but emits very little infrared (long wave) radiation. This helps to reduce heat loss. Evacuated glass tubes are used because they help to reduce heat losses.

[4] The use of lenses remains a theoretical option, because no CSP plant today, or any planned in the near future, uses lenses.
[5] The capacity factor is the number of kWh produced in a year divided by the product of nominal capacity of the plant multiplied by 8 760 (the number of hours in a year).
[6] All capacity values in this paper are electrical, unless otherwise specified.

A heat transfer fluid (HTF) is circulated through the absorber tubes to collect the solar energy and transfer it to the steam generator or to the heat storage system, if any. Most existing parabolic troughs use synthetic oils as the heat transfer fluid, which are stable up to 400°C. New plants under demonstration use molten salt at 540°C either for heat transfer and/or as the thermal storage medium. High temperature molten salt may considerably improve the thermal storage performance.

At the end of 2010, around 1 220 MW of installed CSP capacity used the parabolic trough technology and accounted for virtually all of today's installed CSP capacity. As a result, parabolic troughs are the CSP technology with the most commercial operating experience (Turchi, et al., 2010).

2.2 LINEAR FRESNEL COLLECTOR TECHNOLOGY

Linear Fresnel collectors (LFCs) are similar to parabolic trough collectors, but use a series of long flat, or slightly curved, mirrors placed at different angles to concentrate the sunlight on either side of a fixed receiver (located several metres above the primary mirror field). Each line of mirrors is equipped with a single-axis tracking system and is optimised individually to ensure that sunlight is always concentrated on the fixed receiver. The receiver consists of a long, selectively-coated absorber tube.

Unlike parabolic trough collectors, the focal line of Fresnel collectors is distorted by astigmatism. This requires a mirror above the tube (a secondary reflector) to refocus the rays missing the tube, or several parallel tubes forming a multi-tube receiver that is wide enough to capture most of the focussed sunlight without a secondary reflector.

The main advantages of linear Fresnel CSP systems compared to parabolic trough systems are that:

- LFCs can use cheaper flat glass mirrors, which are a standard mass-produced commodity;
- LFCs require less steel and concrete, as the metal support structure is lighter. This also makes the assembly process easier;
- The wind loads on LFCs are smaller, resulting in better structural stability, reduced optical losses and less mirror-glass breakage; and.
- The mirror surface per receiver is higher in LFCs than in PTCs, which is important, given that the receiver is the most expensive component in both PTC and in LFCs.

These advantages need to be balanced against the fact that the optical efficiency of LFC solar fields (referring to direct solar irradiation on the cumulated mirror aperture) is lower than that of PTC solar fields due to the geometric properties of LFCs. The problem is that the receiver is fixed and in the morning and afternoon cosine losses are high compared to PTC. Despite these drawbacks, the relative simplicity of the LFC system means that it may be cheaper to manufacture and install than PTC CSP plants. However, it remains to be seen if costs per kWh are lower. Additionally, given that LFCs are generally proposed to use direct steam generation, adding thermal energy storage is likely to be more expensive.

2.3 SOLAR TOWER TECHNOLOGY

Solar tower technologies use a ground-based field of mirrors to focus direct solar irradiation onto a receiver mounted high on a central tower where the light is captured and converted into heat. The heat drives a thermo-dynamic cycle, in most cases a water-steam cycle, to generate electric power. The solar field consists of a large number of computer-controlled mirrors, called heliostats, that track the sun individually in two axes. These mirrors reflect the sunlight onto the central receiver where a fluid is heated up. Solar towers can achieve higher temperatures than parabolic trough and linear Fresnel systems, because more sunlight can be concentrated on a single receiver and the heat losses at that point can be minimised.[7]

Current solar towers use water/steam, air or molten salt to transport the heat to the heat-exchanger/steam-turbine system. Depending on the receiver design and the working fluid, the upper working temperatures can range from 250°C to perhaps as high 1 000°C for future plants, although temperatures of around 600°C will be the norm with current molten salt designs. The

[7] *In addition to power generation, solar towers could therefore also be used in many applications where high temperature heat or steam is required.*

typical size of today's solar tower plants ranges from 10 MW to 50 MW (Emerging Energy Research, 2010). The solar field size required increases with annual electricity generation desired, which leads to a greater distance between the receiver and the outer mirrors of the solar field. This results in increasing optical losses due to atmospheric absorption, unavoidable angular mirror deviation due to imperfections in the mirrors and slight errors in mirror tracking.

Solar towers can use synthetic oils or molten salt as the heat transfer fluid and the storage medium for the thermal energy storage. Synthetic oils limit the operating temperature to around 390°C, limiting the efficiency of the steam cycle. Molten salt raises the potential operating temperature to between 550 and 650°C, enough to allow higher efficiency supercritical steam cycles although the higher investment costs for these steam turbines may be a constraint. An alternative is direct steam generation (DSG), which eliminates the need and cost of heat transfer fluids, but this is at an early stage of development and storage concepts for use with DSG still need to be demonstrated and perfected.

Solar towers have a number of potential advantages, which mean that they could soon become the preferred CSP technology. The main advantages are that:

- The higher temperatures can potentially allow greater efficiency of the steam cycle and reduce water consumption for cooling the condenser;
- The higher temperature also makes the use of thermal energy storage more attractive in order to achieve schedulable power generation; and
- Higher temperatures will also allow greater temperature differentials in the storage system, reducing costs or allowing greater storage for the same cost.

The key advantage is the opportunity to use thermal energy storage to raise capacity factors and allow a flexible generation strategy to maximise the value of the electricity generated, as well as to achieve higher efficiency levels. Given this advantage and others, if costs can be reduced and operating experience gained, solar towers could potentially achieve significant market share in the future, despite PTC systems having dominated the market to date.

Solar tower technology is still under demonstration, with 50 MW scale plant in operation, but could in the long-run provide cheaper electricity than trough and dish systems (CSP Today, 2008). However, the lack of commercial experience means that this is by no means certain and deploying solar towers today includes significant technical and financial risks.

2.4 STIRLING DISH TECHNOLOGY

The Stirling dish system consists of a parabolic dish-shaped concentrator (like a satellite dish) that reflects direct solar irradiation onto a receiver at the focal point of the dish. The receiver may be a Stirling engine (dish/engine systems) or a micro-turbine. Stirling dish systems require the sun to be tracked in two axes, but the high energy concentration onto a single point can yield very high temperatures. Stirling dish systems are yet to be deployed at any scale.

Most research is currently focussed on using a Stirling engine in combination with a generator unit, located at the focal point of the dish, to transform the thermal power to electricity. There are currently two types of Stirling engines: Kinematic and free piston. Kinematic engines work with hydrogen as a working fluid and have higher efficiencies than free piston engines. Free piston engines work with helium and do not produce friction during operation, which enables a reduction in required maintenance.

The main advantages of Stirling dish CSP technologies are that:

- The location of the generator - typically, in the receiver of each dish - helps reduce heat losses and means that the individual dish-generating capacity is small, extremely modular (typical sizes range from 5 to 50 kW) and are suitable for distributed generation;
- Stirling dish technologies are capable of achieving the highest efficiency of all types of CSP systems;

- Stirling dishes use dry cooling and do not need large cooling systems or cooling towers, allowing CSP to provide electricity in water-constrained regions; and

- Stirling dishes, given their small foot print and the fact they are self-contained, can be placed on slopes or uneven terrain, unlike PTC, LFC and solar towers.

These advantages mean that Stirling dish technologies could meet an economically valuable niche in many regions, even though the levelised cost of electricity is likely to be higher than other CSP technologies. Apart from costs, another challenge is that dish systems cannot easily use storage. Stirling dish systems are still at the demonstration stage and the cost of mass-produced systems remains unclear. With their high degree of scalability and small size, stirling dish systems will be an alternative to solar photovoltaics in arid regions.

2.5 THE SOLAR RESOURCE, CSP PLANT DESIGN AND PERFORMANCE

CSP plants require abundant direct solar radiation in order to generate electricity, given that only strong direct sunlight can be concentrated to the temperatures required for electricity generation. This limits CSP to hot, dry regions. To be economic at present requires a CSP plant with direct normal irradiance levels (DNI) of 2 000 kWh/m^2/year or more, although there is no technical reason why CSP plants cannot run at lower levels.

CSP plants in areas with high DNI will have a lower LCOE, all else being equal, than one located in an area with a lower DNI. Higher levels of DNI have a strong impact, although not one-to-one, on the LCOE.

Globally; there a number of regions with an excellent solar resource that is suitable for CSP plants. They include North Africa, Middle East, Southern Africa, Australia, the Western United States and parts of South America (Figure 2.1). Good resources are much more widely distributed, but will not be as attractive for CSP plants until costs start to decline.

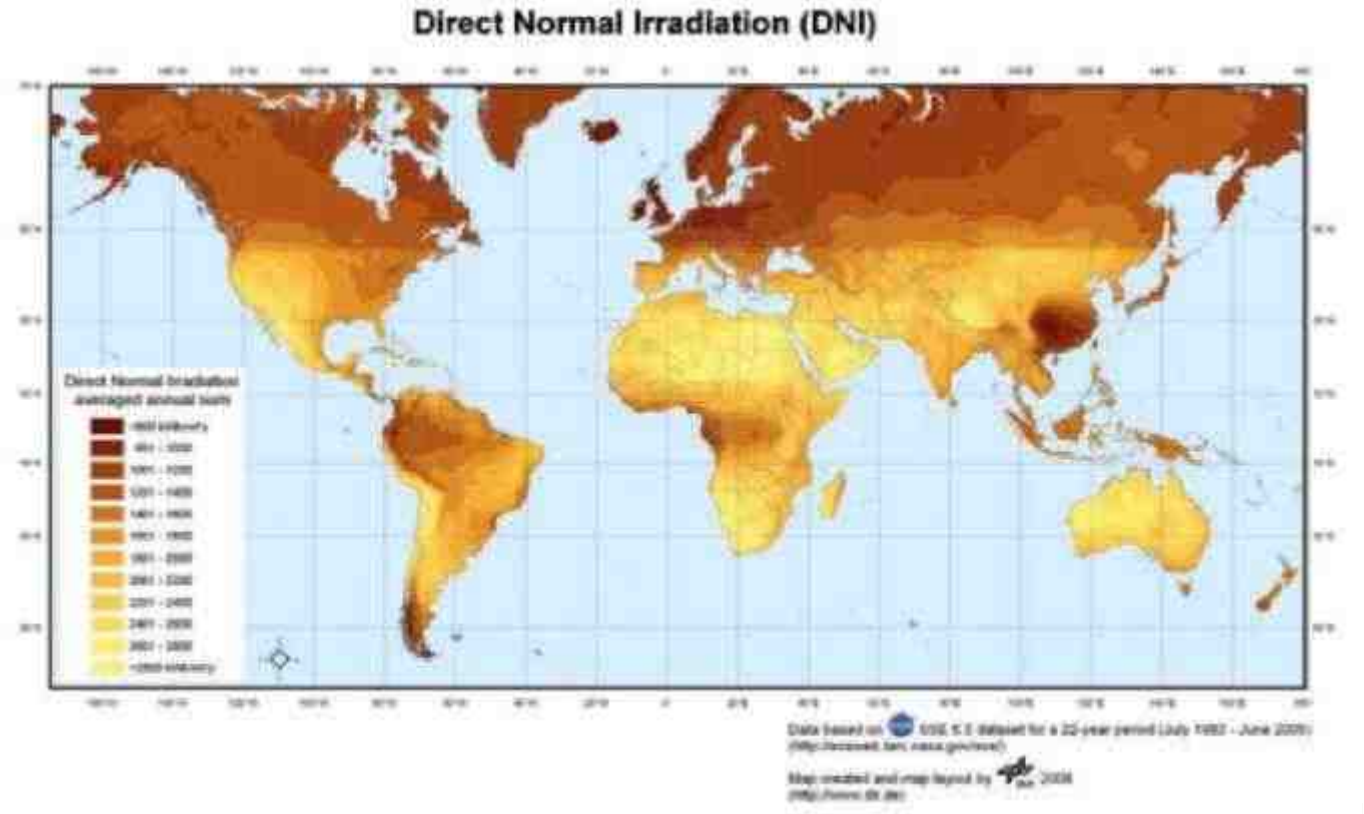

FIGURE 2.1: GLOBAL CSP RESOURCE MAP

Source: DLR.

Solar field sizing, thermal storage, capacity factors and the solar multiple

The parameters that determine the optimal plant design are many. An important consideration is the role of thermal energy storage. Thermal energy storage increases costs, but allows higher capacity factors, dispatchable generation when the sun is not shining and/or the maximisation of generation at peak demand times. Costs increase, because of the investment in thermal energy storage, but also if the solar field size is increased to allow operation of the plant and storage of solar heat to increase the capacity factor.

Although much depends on the design of the specific project and whether the storage is being used just to shift generation, or increase the capacity factor, the data currently available suggest that the incremental cost is economically justifiable, as CSP plants with storage have a similar or lower LCOE than those without. They also have lower O&M costs per kWh, because the fixed O&M costs, of which service staff is the largest contributor, are lower per megawatt as the plant size increases.

The solar multiple is an important parameter to optimise the plant design and the thermal energy needed to ensure that the power block is effectively utilised throughout the year. The solar multiple is the actual size of the solar field relative to what would be required to reach the rated electrical capacity at the design point. To guarantee that the power block is effectively used during the year, the solar multiple is usually larger than unity and is typically between 1.3 and 1.4. It can be even larger (up to 2.0) if the plant has a six-hour storage system.

NREL has developed a model for conducting performance and economic analysis of CSP plants. The model can compare various technology options and configurations in order to optimise the plant design. Figure 2.2 shows the relationship between capacity factor (20% to 60%) and thermal energy storage in hours (h) for different solar multiples in regions with a good solar resource. The trade-off between the incremental costs of the increased solar field and the storage system must be balanced against the anticipated increase in revenue that will accrue from higher production and the ability to dispatch power generation at times when the sun is not shining.

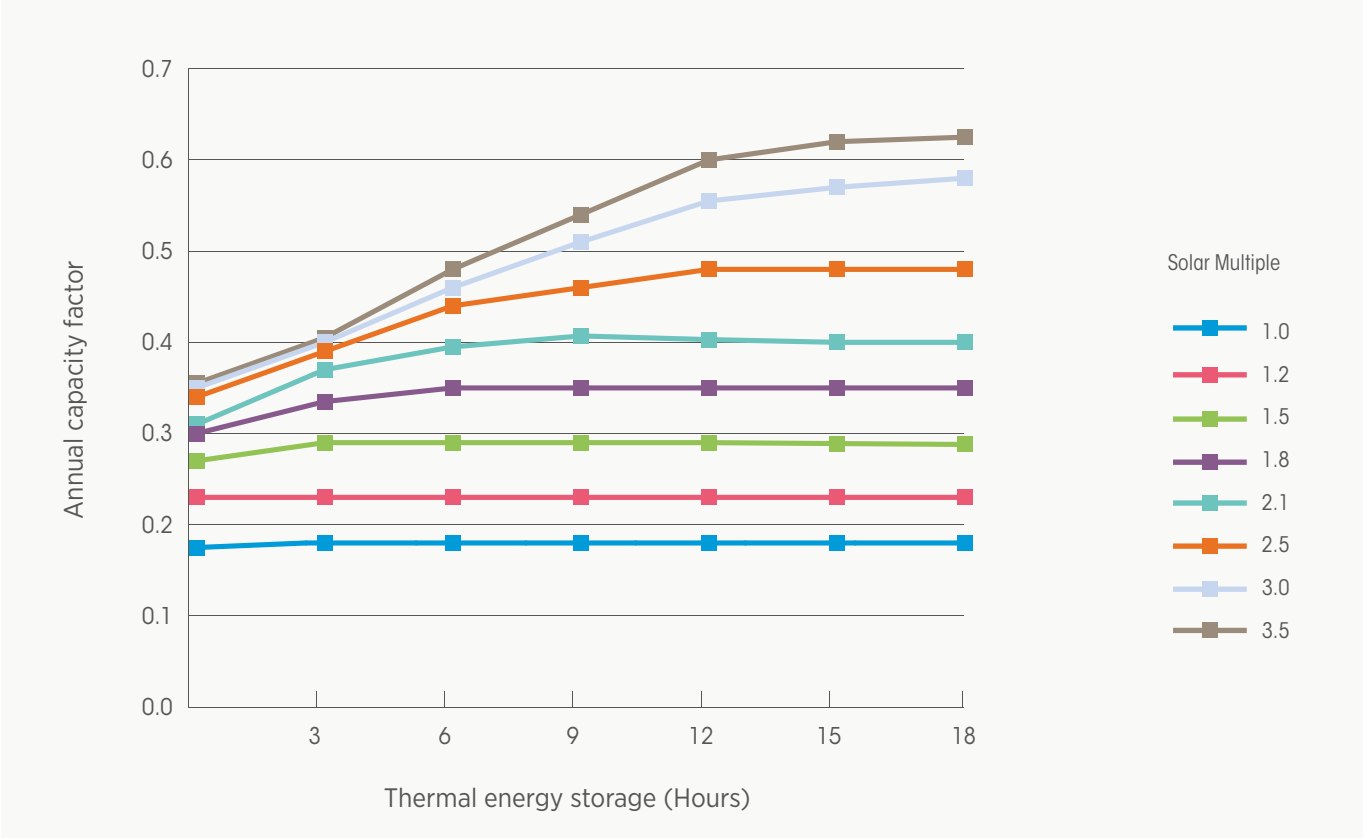

FIGURE 2.2: ANNUAL CAPACITY FACTOR FOR A 100 MW PARABOLIC TROUGH PLANT AS A FUNCTION OF SOLAR FIELD SIZE AND SIZE OF THERMAL ENERGY STORAGE

Source: Turchi, 2010a.

2.6 COMPARISON OF CSP TECHNOLOGIES

In Table 2.1 a comparison of the major features of the four main types of CSP technologies — Parabolic and Fresnel trough, Solar tower and Parabolic dish — are summarised. These CSP technologies differ significantly from one another, not only with regard to technical and economic aspects, but also in relation to their reliability, maturity and operational experience in utility scale conditions.

Parabolic trough plant are the most widely commercially deployed CSP plant, but are not a mature technology and improvements in performance and cost reductions are expected. Virtually all PTC systems currently deployed do not have thermal energy storage and only generate electricity during daylight hours.

Most CSP projects currently under construction or development are based on parabolic trough technology, as it is the most mature technology and shows the lowest development risk. Parabolic troughs and solar towers, when combined with thermal energy storage, can meet the requirements of utility-scale, schedulable power plant.

Solar tower and linear Fresnel systems are only beginning to be deployed and there is significant potential to reduce their capital costs and improve performance, particularly for solar towers. However, parabolic trough systems, with their longer operational experience of utility-size plants, represent a less flexible, but low-risk option today.

There is increased interest in solar towers operating at high temperatures using molten salt or other alternatives to synthetic oil as the heat transfer fluid and storage medium due to the potential for cost reduction, higher efficiency and expanded energy storage opportunities.

Solar towers using molten-salt as a high temperature heat transfer fluid and storage medium (or other high temperature medium) appear to be the most promising CSP technology for the future. This is based on their low energy storage costs, the high capacity factor achievable, greater efficiency of the steam cycle and their firm output capability.

While the levelised cost of electricity (LCOE) of parabolic trough systems does not tend to decline with higher capacity factors, the LCOE of solar towers tends to decrease as the capacity factor increases. This is mainly due to the significantly lower specific cost (up to three times lower) of the molten-salt energy storage in solar tower plants.

CSP technologies offer a great opportunity for local manufacturing, which can stimulate local economic development, including job creation. It is estimated that solar towers can offer more local opportunities than trough systems (Ernst & Young and Fraunhofer, 2010).

Table 2.1: Comparison of different CSP technologies




	Parabolic Trough	Solar Tower	Linear Fresnel	Dish-Stirling
Typical capacity (MW)	10-300	10-200	10-200	0.01-0.025
Maturity of technology	Commercially proven	Pilot commercial projects	Pilot projects	Demonstration projects
Key technology providers	Abengoa Solar, SolarMillennium, Sener Group, Acciona, Siemens, NextEra, ACS, SAMCA, etc.	Abengoa Solar, BrightSource, Energy, eSolar, SolarReserve, Torresol	Novatec Solar, Areva	
Technology development risk	Low	Medium	Medium	Medium
Operating temperature (°C)	350-550	250-565	390	550-750
Plant peak efficiency (%)	14-20	23-35*	18	30
Annual solar-to-electricity efficiency (net) (%)	11-16	7-20	13	12-25
Annual capacity factor (%)	25-28 (no TES) 29-43 (7h TES)	55 (10h TES)	22-24	25-28
Collector concentration	70-80 suns	>1 000 suns	>60 suns (depends on secondary reflector)	>1 300 suns
Receiver/absorber	Absorber attached to collector, moves with collector, complex design	External surface or cavity receiver, fixed	Fixed absorber, no evacuation secondary reflector	Absorber attached to collector, moves with collector
Storage system	Indirect two-tank molten salt at 380°C (dT=100K) or Direct two-tank molten salt at 550°C (dT=300K)	Direct two-tank molten salt at 550°C (dT=300K)	Short-term pressurised steam storage (<10 min)	No storage for Stirling dish, chemical storage under development
Hybridisation	Yes and direct	Yes	Yes, direct (steam boiler)	Not planned
Grid stability	Medium to high (TES or hybridisation)	High (large TES)	Medium (back-up firing possible)	Low
Cycle	Superheated Rankine steam cycle	Superheated Rankine steam cycle	Saturated Rankine steam cycle	Stirling
Steam conditions (°C/bar)	380 to 540/100	540/100 to 160	260/50	n.a.
Maximum slope of solar field (%)	<1-2	<2-4	<4	10% or more
Water requirement (m^3/MWh)	3 (wet cooling) 0.3 (dry cooling)	2-3(wet cooling) 0.25(dry cooling)	3 (wet cooling) 0.2 (dry cooling)	0.05-0.1 (mirror washing)
Application type	On-grid	On-grid	On-grid	On-grid/Off-grid
Suitability for air cooling	Low to good	Good	Low	Best
Storage with molten salt	Commercially available	Commercially available	Possible, but not proven	Possible, but not proven

*Note: * = upper limit is if the solar tower powers a combined cycle turbine.*

Sources: Based on Fichtner, 2010.

3. Global CSP market trends

The Luz Company of the United States built the "Solar Energy Generating Systems" (SEGS-I to SEGS-IX) in the Mohave Desert of southern California between 1985 and 1991. These parabolic trough plants are still in commercial operation today and have demonstrated the long-term viability of CSP. However, no other CSP plants were built between 1991 and 2006.

After more than 15 years, activity re-started with the construction of a 1 MW plant in Arizona, the solar tower plant "PS10" (11 MW) in Spain and a 64 MW plant in Nevada in 2006. Since then, many more plants have been completed. There are currently dozens of CSP plants under construction, and more than 20 GW under development worldwide. The two leading CSP markets are Spain and the United States, driven by government support schemes, such as tax incentives and renewable portfolio standards in the United States, and feed-in tariffs in Spain. Together, these two countries contain 90% of the current installed CSP capacity (Emerging Energy Research, 2010). Algeria, Egypt and Morocco have built or are building CSP plants that are integrated with natural gas combined-cycle plants. Australia, China, India, Iran, Israel, Italy, Jordan, Mexico and South Africa are developing large-scale CSP plant projects in coming years and the United Arab Emirates has already started construction on a project.

Today, CSP technologies are commercially deployed in the United States and Europe (Spain). The successful deployment in these countries is an example for others with abundant direct solar radiation and cheap land.

Some of the parabolic trough and solar tower plants already in operation have 6 to 7.5 hours of thermal storage capacity. Their capacity factors rise from 20% to 28% (with no storage) to 30% to 40%, with 6 to 7.5 hours of storage (Emerging Energy Research, 2010). In Spain, a 19-20 MW solar tower demonstration plant with 15 h molten-salt storage built by Gemasolar has recently started operation. It should allow almost 6 500 operation hours per year (74% capacity factor) (Emerging Energy Research, 2010). Several Integrated Solar Combined Cycle (ISCC) projects using solar and natural gas have been completed or are under development in Algeria, Egypt and Morocco; others are under construction in Italy and the USA. One small solar field (LFR) currently assists a large coal plant in Australia. (Ernst & Young and Fraunhofer, 2011; and CSP Today, 2008).

At the end of 2010, around 1 229 MW capacity of commercial CSP plants was in operation worldwide, of which 749 MW was installed in Spain, 509 MW in the United States and 4 MW in Australia (NREL, 2012). By the end of March 2012 the global installed capacity of CSP plant had increased to around 1.9 GW. Spain dominates the total installed capacity, with around 1 330 MW of installed capacity (AEIST, 2012). The United States has the second largest installed capacity, with 518 MW operational at the end of 2011 (Table 3.1).

Table 3.1: Utility-scale CSP capacity by country at the end of 2011/beginning of 2012

Country	Operating
USA	518
Spain	1 331
Algeria, Australia, France, Italy and Morocco	75

Source: AEIST, 2012; NREL, 2012; and Photon International, 2009.

Today, virtually all (94%) of installed CSP plants are based on parabolic trough systems, with an overall capacity of around 1.8 GW. Solar tower plants have an installed capacity of around 70 MW. There is around 31 MW of Fresnel reflector capacity in Spain and 4 MW in Australia (Photon International, 2009, NREL, 2012 and AEIST, 2012).

While still limited in terms of global installed capacity, CSP is clearly attracting considerable interest. At the beginning of 2012 Spain had around 873 MW of CSP power plants under construction and a further 271 MW

in the development pipeline. The United States has 518 MW operating, around 460 MW under construction and gigawatts of capacity being investigated for development (Ernst & Young and Fraunhofer, 2011).

The total capacity of projects that have filed for grid access in Spain exceeds 10 GW, although not all of these projects will break ground. Currently, several large CSP projects are under development in the MENA region, including an ISCC plant in Egypt (20 MW of solar thermal capacity) and a 100 MW parabolic trough plant in the United Arab Emirates (UAE) that should be completed by the end of 2012 (Ernst & Young and Fraunhofer, 2011).

The European Solar Industry Initiative projects total installed CSP capacity in Europe could grow to 30 GW by 2020 and 60 GW by 2030 (Emerging Energy Research, 2010). This represents 2.4% and 4.3% of projected EU-27 electricity capacity in 2020 and 2030 respectively. The IEA's CSP technology roadmap estimates that global CSP capacity could grow to 147 GW in 2020, with 50 GW in North America and 23 GW each in Africa and the Middle East if all the conditions of the roadmap are met. By 2030 total installed capacity of CSP plant in their analysis rises to 337 GW and then triples to 1 089 GW by 2050.

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4. The current cost of CSP

According to the IEA (IEA, 2010) and NREL (Sargent and Lundy, 2003), costs of CSP plants can be grouped into three distinct categories: investment costs (also called capital cost or CAPEX), operation and maintenance costs (O&M) and financing costs. In this analysis, financing costs are included in the CAPEX, as these data are often not available separately.

This section examines the cost of CSP technologies. The cost of electricity from CSP is currently higher than that of conventional fossil fuel technologies. However, cost reduction opportunities due to large-scale deployment and technology improvements are significant, and the LCOE is expected to come down.

4.1 CAPEX: CAPITAL INVESTMENT COST

Unlike power plants fired by fossil fuels, the LCOE of CSP plants is dominated by the initial investment cost, which accounts for approximately four-fifths of the total cost. The rest is the cost for operation and maintenance of the plant and for plant insurance.

The current CSP market is dominated by the parabolic trough technology. More than 80% of the CSP power plants in operation or under construction are based on this technology. As a consequence, most of the available cost information refers to parabolic trough systems. The cost data for parabolic trough systems are also the most reliable, although uncertainties still remain, because it is the most mature CSP technology.

The current investment cost for parabolic trough and solar tower plants without storage are between USD 4 500/kW and USD 7 150/kW (Hinkley, 2011; Turchi, 2010a and IRENA analysis).[8] CSP plants with thermal energy storage tend to be significantly more expensive, but allow higher capacity factors, the shifting of generation to when the sun does not shine and/or the ability to maximise generation at peak demand times.

The cost of parabolic trough and solar tower plants with thermal energy storage is generally between USD 5 000 and USD 10 500/kW (Table 4.1).

These cost ranges from the literature are not inconsistent with estimates of recent plant that have been commissioned in 2010 and 2011, or that are under construction. Figure 4.1 presents the estimated total installed capital costs, drawing on data in the media and various industry sources.[9] The data for parabolic trough systems without storage are at the higher end of the range identified in the literature, while that for plants with storage match quite closely data from the literature.

Although CSP plants with thermal energy storage have higher specific investment costs (USD/kW) due to the storage system and the larger solar field, the greater electricity generation will generally result in a lower electricity generation cost. Energy storage should therefore be looked at carefully, as it can reduce the cost of electricity generated by the CSP plant and increase electricity production (capacity factors).

The breakdown of the capital costs of two proposed CSP plants in South Africa (one a parabolic trough and the other a solar tower) is presented in Figure 4.2. These plants have very similar total capital investments of USD 914 million for the parabolic trough system and USD 978 million for the solar tower system. The capital costs for the solar field and receiver system are a larger percentage of the total costs in solar tower systems, while the thermal energy storage and power block costs are a smaller percentage.

[8] These costs compare to the estimated installed capital costs of the Californian SEGS Rankine-cycle trough systems operating since 1984 of USD 4 000/kW for a plant with a capacity of 30 MW and USD 3 000/kW for plant with a capacity 80 MW (Cohen, 1999).

[9] These data should be treated with caution and as order of magnitude estimates, as they are based predominantly on data that are of estimated project costs. It is not clear what is included in these cost estimates or whether or not there were cost overruns or savings by the time the project was completed.

Table 4.1: Capital costs and key characteristics of parabolic trough and solar tower plant

	Source	Heat transfer fluid	Solar multiple	Storage (hours)	Capacity factor (%)	Cost (2010 USD/kWe)
Parabolic trough	Turchi, 2010a	Synthetic oil	1.3	0	26	4 600
	Hinkley, 2011	Synthetic oil	1.3	0	23	7 144
	Turchi, 2010a	Synthetic oil	2	6	41	8 000
	Turchi, 2010b	Synthetic oil	2	6.3	47-48	8 950-9 810
	Hinkley, 2011	Synthetic oil	2	6	43	7 732
	Fichtner, 2010	Molten salt	2.8	4.5	50	7 380
			2.5	9	56	7 550
			3	13.4	67	9 140
Solar tower	Ernst and Young/ Fraunhofer, 2011	Molten salt		7.5		7 280
	Turchi, 2010a	Molten salt	1.8	6	43	6 300
	Kolb, 2011	Molten salt	2.1	9	48	7 427
	Hinkley, 2010	Molten salt	1.8	6	41	7 463
	Fichtner, 2010	Molten salt	2	9	54	7 720
			3	12	68	9 060
			3	15	79	10 520

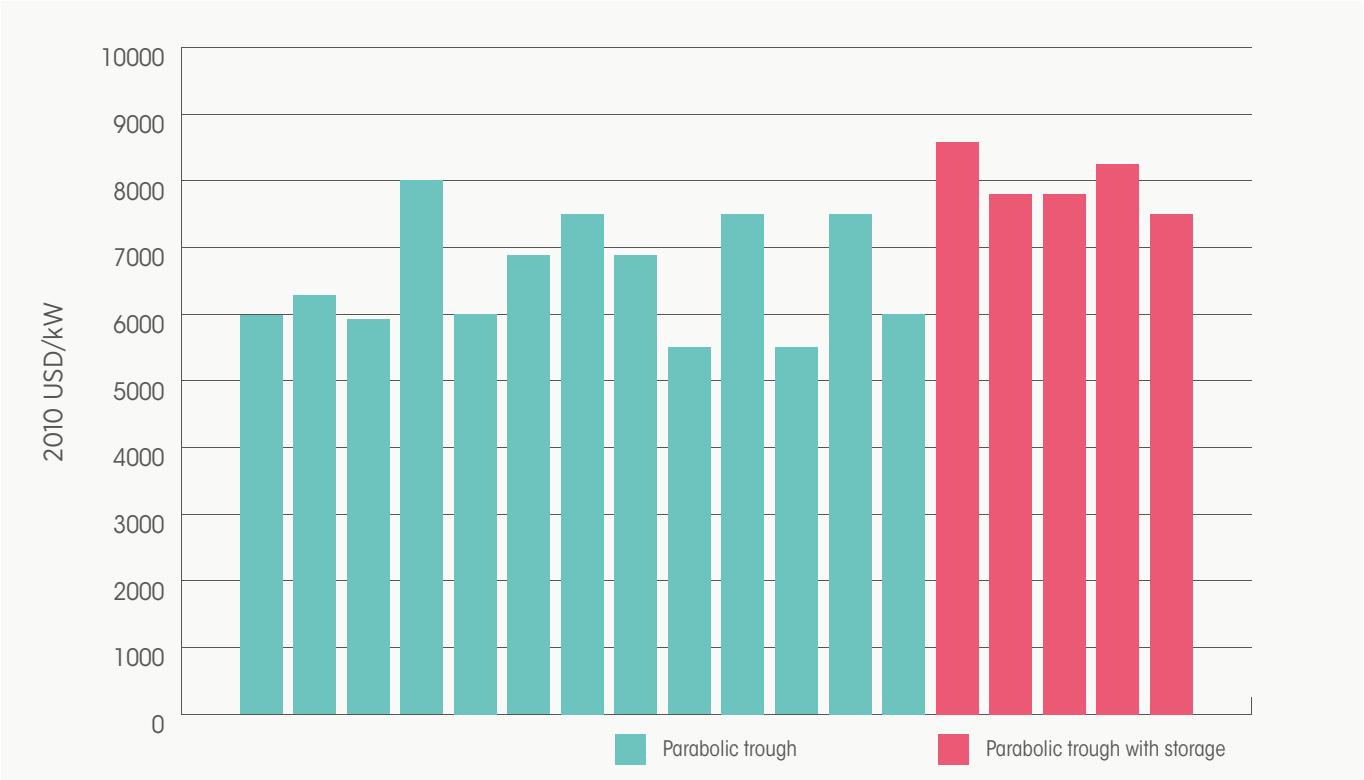


Figure 4.1: Total installed cost for parabolic trough plant commissioned or under construction in 2010 and 2011

Source: IRENA analysis.

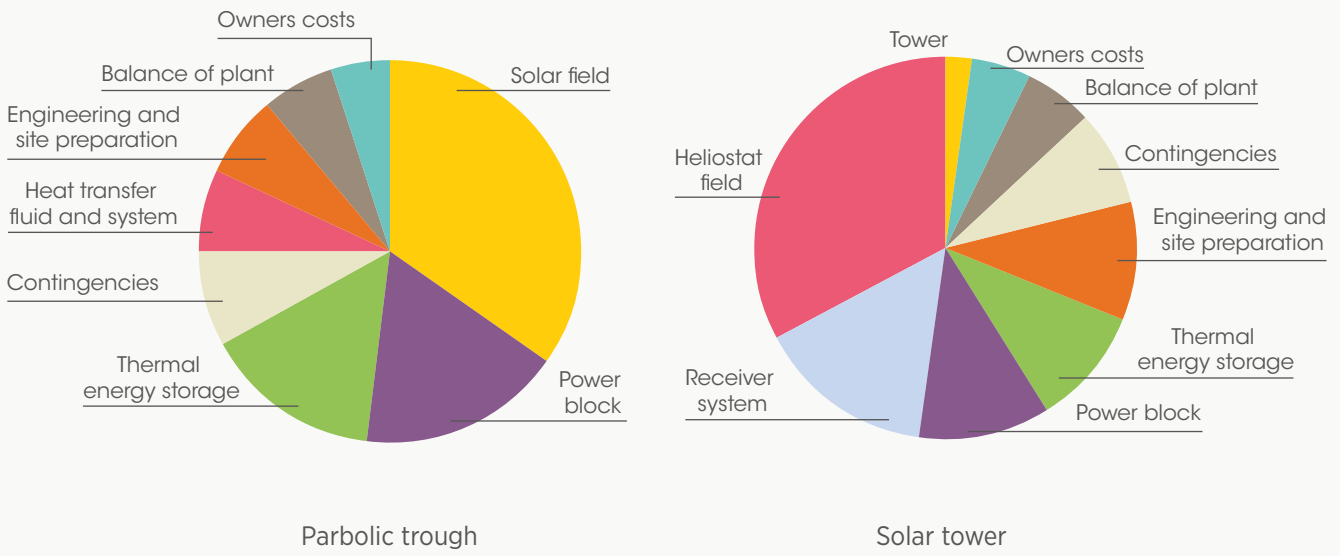


FIGURE 4.2: TOTAL INSTALLED COST BREAKDOWN FOR 100 MW PARABOLIC TROUGH AND SOLAR TOWER CSP PLANTS IN SOUTH AFRICA

Note: The parabolic trough system has 13.4 hours of thermal energy storage and the solar tower system 15 hours.

Source: Fichtner, 2010.

Cost breakdown for parabolic troughs

Looking at a wider range of parabolic trough projects, based on data from four sources, highlights that the solar field is by far the largest cost component and accounts for between 35% and 49% of the total installed costs of the projects evaluated (Fichtner, 2010; Turchi, 2010a; Turchi, 2010b; and Hinkley, 2011). However, care must be taken in interpreting these results, as the cost breakdown depends on whether the project has thermal energy storage or not. The share of the thermal energy storage system varies from as low as 9% for a plant with 4.5 hours storage, to 20% for a plant with 13.4 hours storage.[11] The heat transfer fluid is an important cost component and accounts for between 8% and 11% of the total costs in the projects examined.

A detailed breakdown of parabolic trough project costs is given in Table 4.2. This project, a turn-key 50 MW parabolic trough power plant similar to the Andasol plant in Spain, has storage capacity of 7.5 hours and is estimated to cost USD 364 million (€ 280 million) or USD 7 280/kW (Ernst & Young and Fraunhofer, 2011).

The solar field equipment (510 000 m^2) is the most capital-intensive part (38.5 %) of this parabolic trough system. The price of a solar collector is mainly determined by the cost of the metal support structure (10.7 % of the total plant cost), the receiver (7.1 %), the mirrors (6.4 %), the heat transfer system (5.4 %) and the heat transfer fluid (2.1 %). The thermal energy storage system accounts for 10% of total costs, with the salt and the storage tanks being the largest contributors to this cost.

Labour represents 17% of the project cost and is an area where local content can help reduce costs in developing countries.[12] Based on experience with Andasol 1, the site improvements, installation of the plant components and completion of the plant will require a workforce of around 500 people.

[11] This is for data from the same source, so is directly comparable. It should be noted that the other sources have a significantly higher specific cost for thermal energy storage, so care should be taken in comparing the data from the three sources.

[12] Labour in this table is only the direct labour during power plant construction, it excludes the labour for manufacturing of components.

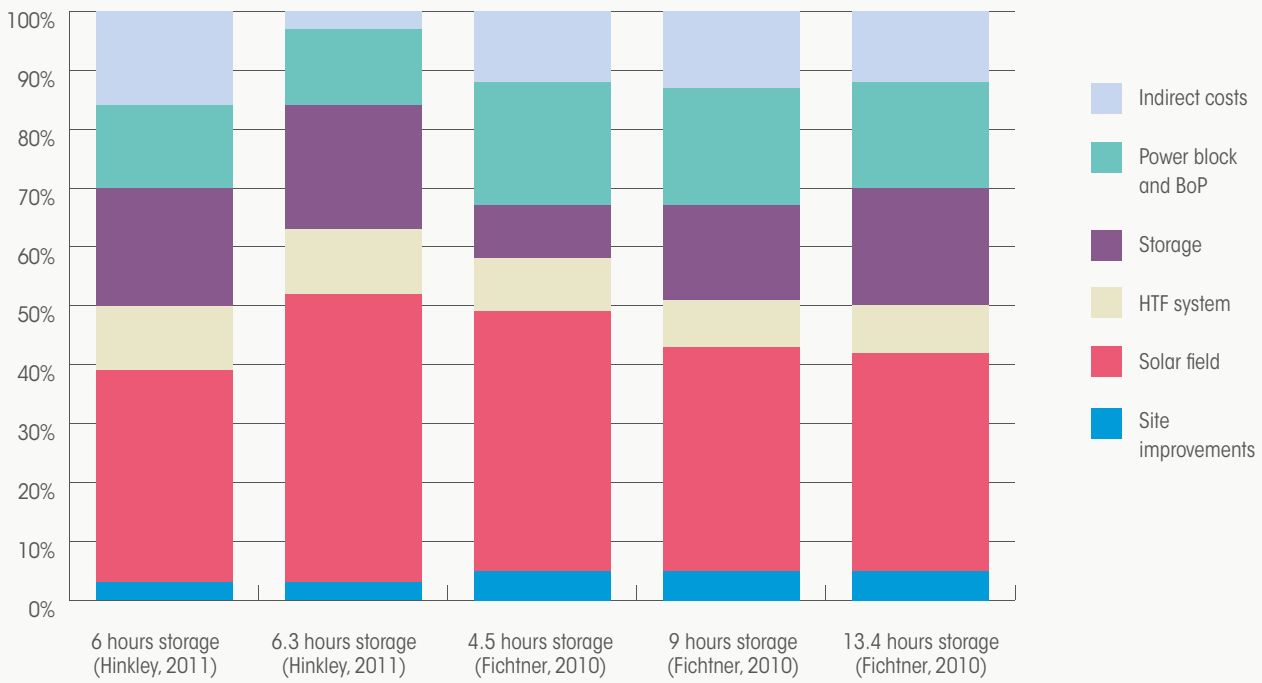


FIGURE 4.3: PARABOLIC TROUGH COST BREAKDOWN

Note: The data are for 100 MW net plants, except for Turchi, 2010.

Sources: Fichtner, 2010 and Hinkley, 2011.

There are opportunities for local manufacturing and services all along the value chain. The most promising components that could be locally manufactured or provided by developing countries are support structures, mirrors and receivers. While the key services that could be provided range from assembling and EPC to O&M.

Cost breakdown for solar towers

The cost breakdown for typical solar tower projects is different from that of parabolic trough systems. The most notable difference is in the cost of thermal energy storage (Figure 4.4). The higher operating temperature and temperature differential possible in the storage system significantly reduces the cost of thermal energy storage. In the analysis of a system with nine hours of storage, the thermal storage system of the solar tower project accounts for 8% of the total costs, while for the parabolic trough it is 16%. Given that the total costs are similar for the two projects, the absolute cost of nine hours of storage for the solar tower project is half that of the parabolic trough.

4.2 OPERATION AND MAINTENANCE COSTS

The operating costs of CSP plants are low compared to fossil fuel-fired power plants, but are still significant. The O&M costs of recent CSP plants are not publically available. However, a very detailed assessment of the O&M costs of the Californian SEGS plants estimated the O&M costs for these plants to be USD 0.04/kWh[13]. The replacement of receivers and mirrors, due to glass breakage, are a significant component of the O&M costs. The cost of mirror washing, including water costs, is also significant. Plant insurance is also an important expense and the annual cost for this can be between 0.5% to 1% of the initial capital cost.

The O&M maintenance costs of modern CSP plants are lower than the Californian SEGS plants, as technology improvements have reduced the requirement to replace mirrors and receivers. Automation has reduced the cost of other O&M procedures by as much as 30%. As a result of improved O&M procedures (both cost and plant performance), total O&M costs of CSP plants in the longer run are likely to be below USD 0.025/kWh (Cohen, 1999).[14]

[13] *The main findings of this analysis are summarised in Cohen, 1999.*
[14] *Without publically available data, however, this cannot be verified.*

Table 4.2: Breakdown of the investment cost of a 50 MW a parabolic trough power plant

	Cost (2010 USD million)	Share (%)
Labour cost: Site and solar field	62.4	17.1
Solar field	11.3	3.1
Site preparation and Infrastructure	21.2	5.8
Steel construction	9.1	2.5
Piping	6.4	1.8
Electric installations and others	14.4	4.0
Equipment: Solar field and HTF and system	140.3	38.5
Mirrors	23.1	6.4
Receivers	25.9	7.1
Steel construction	39.0	10.7
Pylons	3.9	1.1
Foundations	7.8	2.1
Trackers (hydaulics and electrical motors)	1.6	0.4
Swivel joints	2.6	0.7
HTF System (piping, insulation, heat exchanges, pumps)	19.5	5.4
Heat transfer fluid	7.8	2.1
Electronics, controls, electrical and solar equipment	9.1	2.5
Thermal storage system	38.4	10.5
Salt	18.6	5.1
Storage tanks	6.6	1.8
Insulation materials	0.7	0.2
Foundations	2.3	0.6
Heat exchanges	5.1	1.4
Pumps	1.6	0.4
Balance of system	3.5	1.0
Conventional plant components and plant system	52.0	14.3
Power block	20.8	5.7
Balance of plant	20.7	5.7
Grid connection	10.5	2.9
Others	71.0	19.5
Project development	10.5	2.9
Project management (EPC)	28.1	7.7
Financing	21.8	6.0
Other costs (allowances)	10.5	2.9
Total cost	364	100

Note: This analysis is for an Andasol-like power plant with a thermal storage capacity of 7.5 hours and a solar field size of 510 thousand m². Only key components are shown and prices will vary, depending on manufacturer, project size, market situation, country and other criteria.

Source: Ernst & Young and Fraunhofer, 2011.

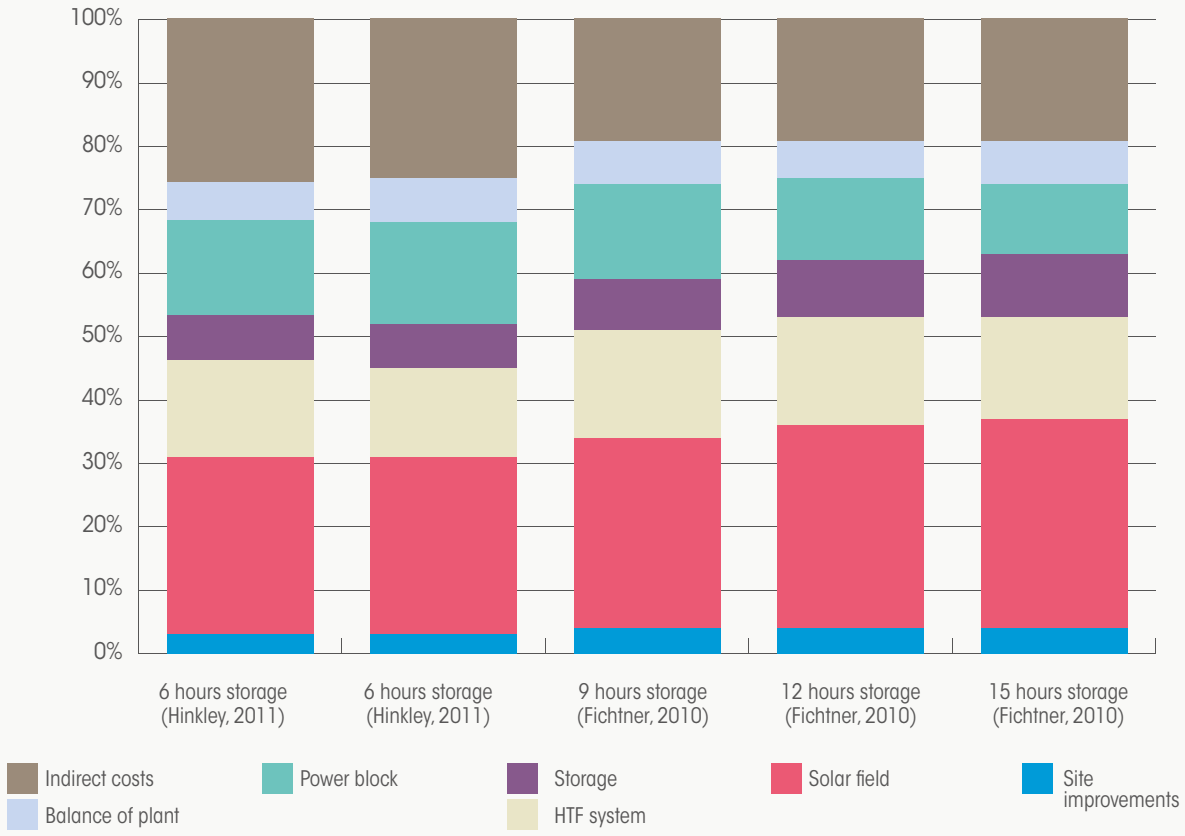


FIGURE 4.4: SOLAR TOWER COST BREAKDOWN

Note: The data are for 100 MW net plants.

Sources: Fichtner, 2010 and Hinkley, 2011.

It is currently estimated that a parabolic trough system in the United States would have O&M costs of around USD 0.015/kWh, comprised of USD 70/kW/year fixed and around USD 0.003/kWh in variable costs (Turchi, 2010b). However, this excludes insurance and potentially other costs also reported in other O&M cost estimates, so care should be taken in interpreting this value. Given that insurance alone typically adds 0.5% to 1%, a figure of USD 0.02/kWh to USD 0.03/kWh seems a robust estimate of the total O&M costs, including all other miscellaneous costs. For solar towers, the fixed O&M costs are estimated to be USD 65/kW/year (Turchi, 2010a)

The O&M costs of two proposed parabolic trough and solar tower projects in South Africa have estimated O&M costs (including insurance) of between USD 0.029 and USD 0.036/kWh. The parabolic troughs and solar tower plants experience important economies of scale in O&M costs relative to the level of thermal energy storage when moving from 4.5 hours to 9 hours storage, but adding more storage does not yield any significant reductions.

For the proposed 100 MW parabolic trough plant with nine hours of thermal energy storage, fixed O&M costs account for 92% of the total O&M costs of USD 14.6 million per year (Figure 4.5). The solar field and storage system accounts USD 4.7 million, insurance USD 3.8 million, staff costs USD 3.5 million and the power block for USD 2.5 million. The variable costs USD 1.2 million per year are dominated by miscellaneous consumables, which at USD 0.7 million, account for more than half of the total variable costs (Fichtner, 2010). In developed countries, personnel costs will be higher. For instance, personnel costs for a 100 MW parabolic trough plant in the United States would account for 45% of the total O&M costs, while it is 23% of the total costs in the proposed South African plant (Turchi, 2010b and Fichtner, 2010).

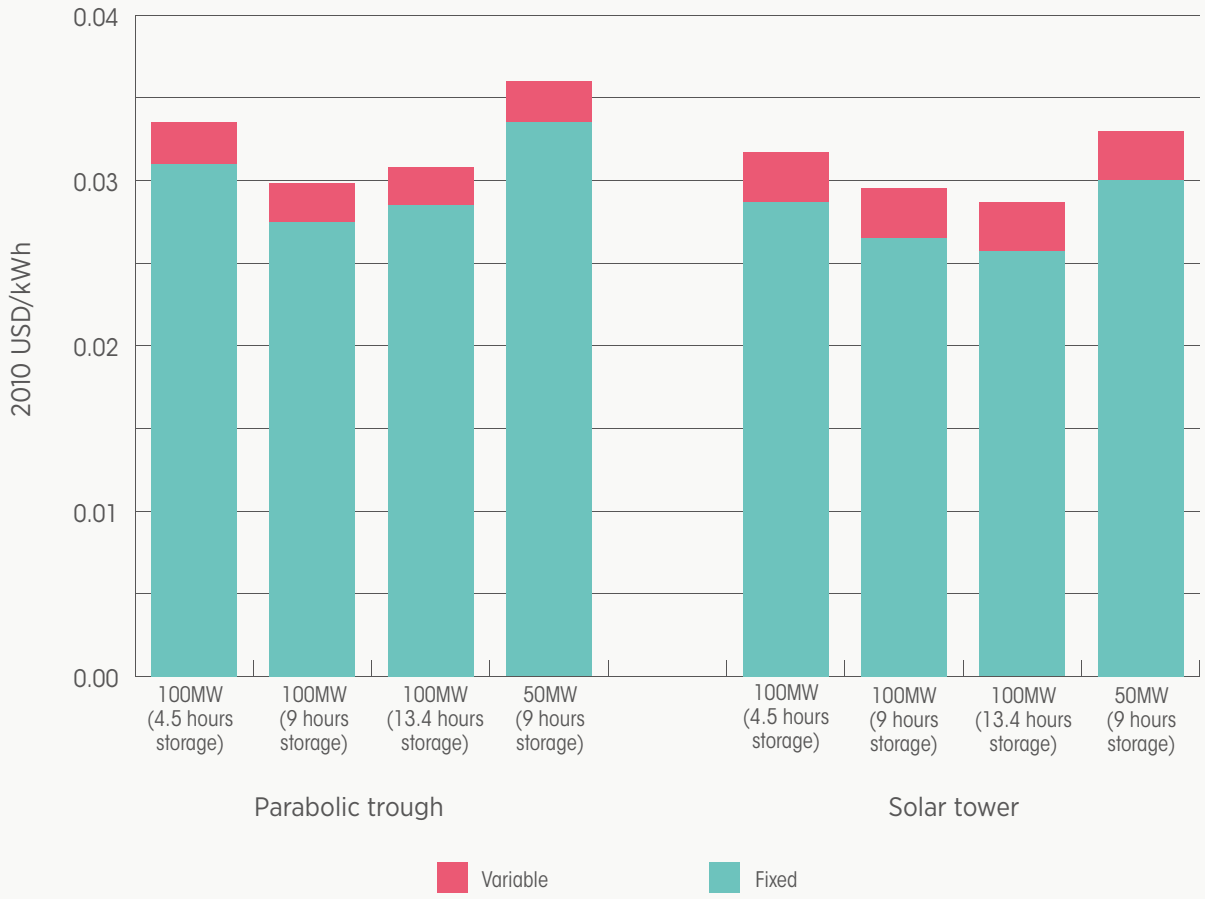


FIGURE 4.5: OPERATIONS AND MAINTENANCE COSTS FOR PARABOLIC TROUGH AND SOLAR TOWER PLANTS

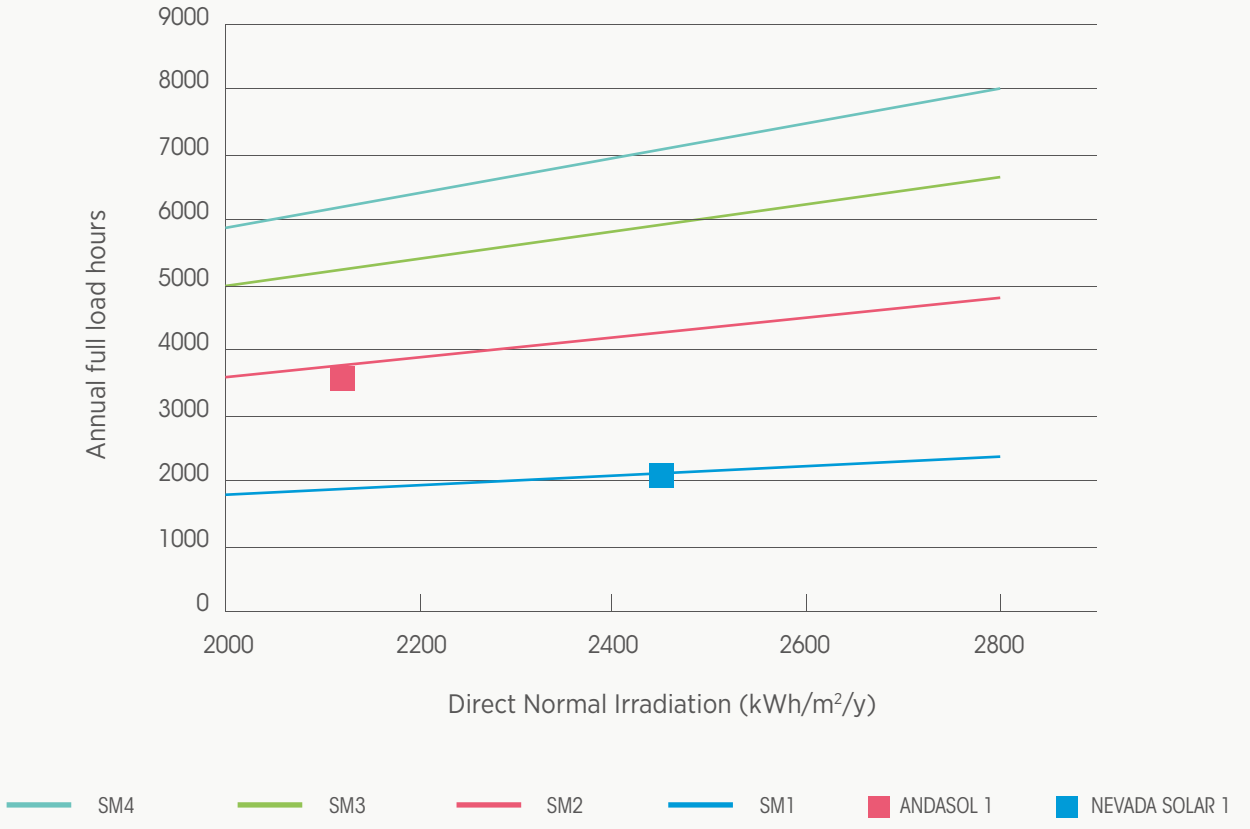
Source: Fichtner, 2010.

4.3 THE IMPACT OF THE SOLAR RESOURCE ON ELECTRICITY GENERATION

CSP technologies, unlike PV technologies, require large (>5 kWh/m^2/day) direct normal irradiance (DNI) in order to function and be economic. This is unlike photovoltaic technologies that can use diffuse or scattered irradiance as well. The generation potential of a solar CSP plant is largely determined by the DNI. This obviously depends on average meteorological conditions over a year. However, the direct solar irradiance on any day will be determined by meteorological factors (e.g. cloud cover, humidity) and local environmental factors (e.g. local air pollution, dust). Tracking the sun provides a significantly greater energy yield for a given DNI than a fixed surface and this is why tracking is so important to CSP plants.

The relationship between DNI, energy output and the LCOE of electricity is strong. Sites with higher DNI will yield more energy, allow greater electricity generation and have a correspondingly lower LCOE (Figure 4.6). High DNI sites yield more electricity for a given solar multiple, but also make higher solar multiples attractive. The relationship between DNI and the capacity factor (full load hours) is stronger at higher solar multiples.

The practical impact on the LCOE of a given CSP plant, with identical design and capital costs, of higher DNI can be significant. For instance, the LCOE of an identical CSP plant will be around one-quarter lower in good sites in the United States, Algeria or South Africa where the DNI is around 2 700 kWh/m^2/year than for a site in Spain with a DNI of 2 100 kWh/m^2/year (A.T. Kearney and ESTELA, 2010).



4.6: Simplified model of full-load hours as a function of DNI and solar multiple (SM)

Note: SM1 refers to a solar multiple of one, SM2 to a solar multiple of 2, etc.

Source: Trieb, et al., 2009.

5. CSP cost reduction potentials

The opportunities for cost reductions for CSP plant are good. The commercial deployment of CSP is in its infancy and as experience is gained, R&D advances, plants get bigger, mass production of components occurs and increased competition in technology providers develops, costs will come down. However, significant investment in further R&D and deployment will be required to realise these cost reductions.

The key areas where cost reductions need to be achieved are in:

- The solar field: mass production and cheaper components, as well as improvements in design, can help to reduce costs.
- The heat transfer fluid: new heat transfer fluids and those capable of higher temperatures will help to improve storage possibilities and reduce costs. Direct steam generation is also a possibility, but requires further research.
- The storage system: This is closely tied to the heat transfer fluid, as higher temperatures, notably from solar towers, will reduce the cost of thermal energy storage.
- The power block: There is still room for cost reductions, although these will be more modest than for the other components.
- The balance of costs, including project development costs.

There are also areas where cost reductions will help improve the performance of CSP plants, helping to further reduce the LCOE of CSP plants. This is the case for the use of higher temperature HTF and cost reductions in thermal energy storage, which will allow higher solar-to-electric efficiencies and boost the capacity factors of plant by allowing more storage at a reasonable cost. This section focuses on capital cost reductions, but also discusses the importance of pursuing performance improvements.

5.1 RESEARCH AND DEVELOPMENT PRIORITIES FOR COST REDUCTION

A large number of R&D activities in the field of CSP are underway (ECOSTAR, 2005). Table 5.1 shows an excerpt of current R&D activities in the field of line-focusing collectors. All technology developments that are shown in Table 5.1 aim at improving CSP components and sub-systems with respect to cost and/or efficiency.

5.2 COST REDUCTION OF CSP COMPONENTS AND PERFORMANCE IMPROVEMENTS

The LCOE from CSP plants can be reduced by improving performance (efficiency) and reducing capital costs. There are specific capital cost reduction opportunities, while improvements in the performance of the CSP plant will reduce the “fuel cost”, for instance by reducing the size of the solar field for a given capacity.

Although CSP plants have a similar basic component breakdown (e.g. solar field, HTF, power block), the reality is that many of these components are materially different for each CSP technology. However, some of the cost reduction potentials are more generic, for instance from scaling up plant size and increased competition among technology suppliers. The following sections discuss the generic and technology-specific cost reduction opportunities.

Increasing plant size

CSP is only just beginning to be deployed at scale and, for a variety of reasons, many of the installed plant are relatively small. Increasing the scale of plants will be an important cost reduction driver and this is already happening in in the United States. Current parabolic

Table 5.1: Current R&D activities for parabolic trough CSP plants

Innovation	Today's state of the art	R&D goals	Solutions
New heat transfer fluids	Synthetic Oil	Higher temperatures, cost reductions, reduction of environmental risks	The use of molten salt will allow higher temperatures while direct steam generation (DSG) allows reduced water and no heat exchangers
New storage concepts	Molten salt	Cheaper storage materials, higher heat capacity, low freezing point, isothermal heat transfer (for evaporation)	Latent heat storage (for DSG), thermocline storage, new storage materials, such as concrete, sand or others
New mirror materials	Curved glass mirrors	Cost reductions and high reflectivity	Metallic reflectors, coated polymer film with integrated support
New collector concepts	PTC with 5-6 m apertures	Cost reductions, higher efficiency, high optical accuracy	Variety of collector substructures, different collector widths (1-10 m Fresnel Collectors), larger apertures for PTCs

Source: A.T. Kearney, 2010.

trough CSP projects under development in the United States have capacities of 140 MW to 250 MW (Ernst & Young and Fraunhofer, 2010), while solar tower projects are in the 100 to 150 MW scale for individual towers.

One artificial constraint in Spain has been the fact that the Spanish feed-in tariff law (RD-661/2007) stipulates a maximum electrical output of 50 MW for eligibility. However, in terms of economies of scale, 50 MW is not the optimal plant size.

The specific costs of a parabolic trough power plant with 7.5 h of storage can be cut by 12.1% if the plant size is increased from 50 MW to 100 MW and by 20.3% if it is increased from 50 MW to 200 MW (Figure 5.1). A similar analysis identified that increasing plant size from 50 MW to 120 MW could reduce capital costs by 13% (Nieto, 2009). The largest cost reductions come from the balance of plant, grid access, power block and project management costs. The project development and management are almost constant for each project size, so the specific costs decline significantly as the plant capacity increases. In contrast, the costs of the solar field and storage are directly related to the plant size, so only small economies can be expected.

The solar field: Mirrors, receivers and support structures

Key components to reduce the solar field cost are support structures, including foundations, mirrors and receivers. These costs will tend to decline over time as the overall volume increases. For the support structures, developers are looking at reducing the amount of material and labour necessary to provide accurate optical performance[15] and to meet the designed "survival wind speed". Given that the support structure and foundation can cost twice as much as the mirrors themselves, improvements here are very important.

For mirrors, cost reductions may be accomplished by moving from heavy silver-backed glass mirror reflectors to lightweight front-surface advanced reflectors (e.g. flexible aluminium sheets with a silver covering and silvered polymer thin film).[16] The advantages of thin-film reflectors are that they are potentially less expensive, will be lighter in weight and have a higher reflectance. They can also be used as part of the support structure. However, their long-term performance needs to be proven. Ensuring that the surface is resistant to repeated washing will require attention. In addition to these new reflectors, there is also work underway to produce thinner, lighter glass mirrors.

[15] Flexing of the support structures in windy conditions can have a negative impact on the concentration of sunlight on the receivers.
[16] Silver-backed glass mirrors are highly specular, that is to say they concentrate the sun's rays into a narrow cone to intersect the receiver. Any new reflector solutions need to also be highly specular.

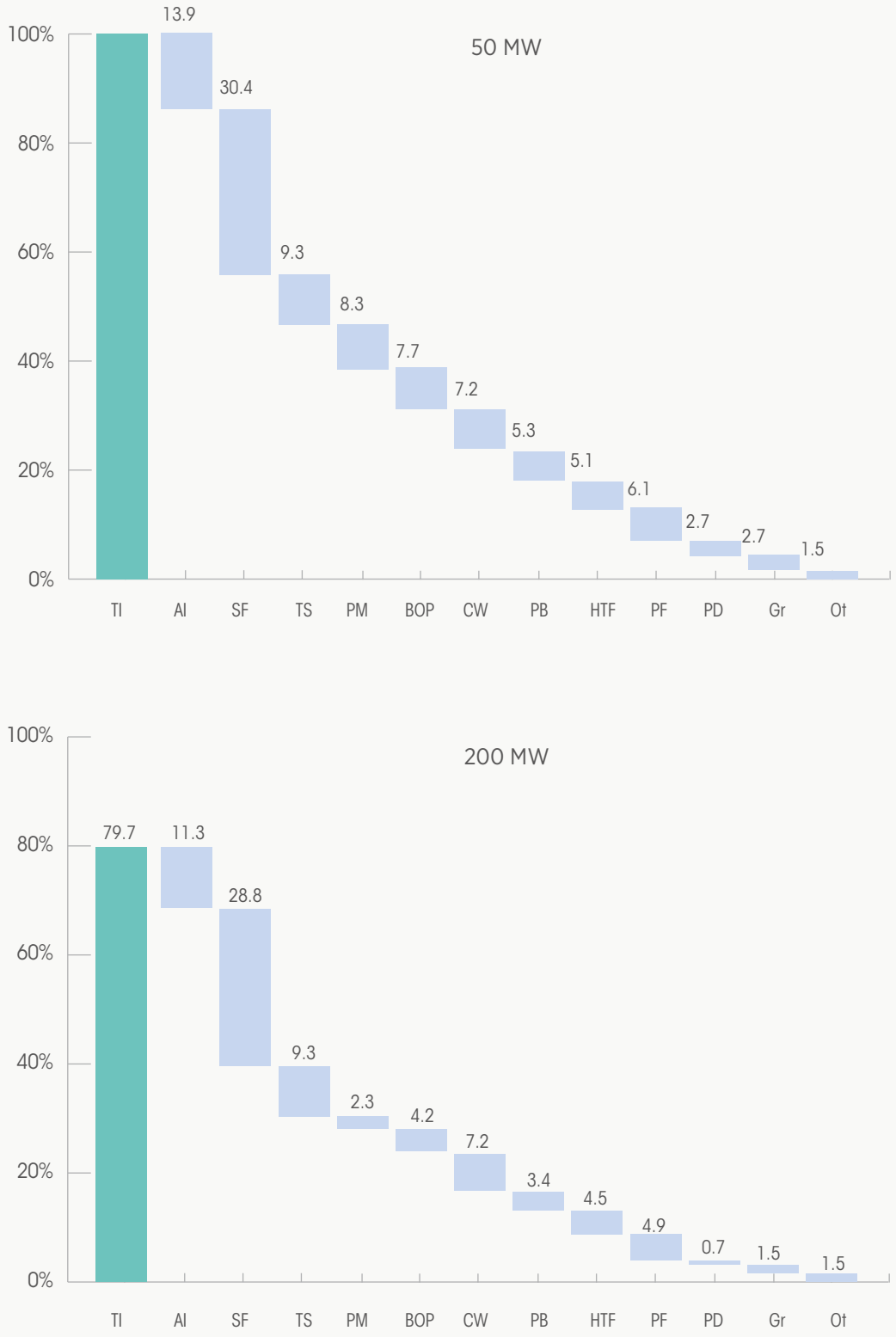


FIGURE 5.1: THE DECREASE IN COMPONENT COST WITH INCREASED PLANT SIZE FOR A PARABOLIC TROUGH PLANT

Abbreviations: Total Investment (TI), Allowances (AI), Solar Field (SF), Thermal Storage (TS), Project Management (PM), Balance of Plant (BOP), Civil Works (CW), Power Block (PB), Heat Transfer Fluid (HTF), Project Finance (PF), Project Development (PD), Grid Access (Gr), Other (Ot)

Source: Kistner, 2009.

Lighter mirrors will reduce support structure and foundation costs, while some thin-film mirror designs can even contribute part of the structural load themselves. For parabolic troughs, wider troughs with apertures close to 7 m are being developed and could offer cost reductions over current systems with a 5-6 m aperture.

Advanced reflector coatings are under development to increase reflectivity from current values of about 93.5% to 95% or higher. Coatings are also being explored to reduce water consumption and the frequency of cleaning required. Given that there is a one-to-one correlation between optical efficiency of the mirrors and receivers[17], and the LCOE of CSP plants, even these small improvements are important.

For the receivers, reducing the emittance of long wave radiation, while maintaining the high absorption of short wave radiation (sunlight) is being pursued to improve performance. This is important, because today's evacuated tube receivers can be designed to have virtually zero conduction and convection heat losses to the environment, meaning that radiation is the only important heat loss. Thus, the pursuit of selective coatings with very low, long-wave emittance is an important R&D goal, while these receivers will also need to be designed for cost-effective operation at higher temperatures. Improved diagnostic systems to help identify degraded receiver tubes will help maintain performance over time.

The use of an inert gas instead of a vacuum could result in lower cost receivers and would also help reduce or even eliminate hydrogen infiltration. The problem with current heat transfer fluids is that hydrogen can permeate into the evacuated tube and result in greatly increased heat rate losses. Given that a CSP plant with hydrogen infiltration in 50% of its receivers will produce electricity at USD 0.03/kWh more than one without, this is a serious cost issue.

For solar towers, the largest cost components of the solar field are the mirror modules, the drives and finally the foundation, pedestal and support structure. It is still not clear what size heliostats are optimal, or indeed if there is an optimal size (Kolb, 2010). Larger heliostats reduce the cost of wiring, drives, manufacturing and controls but have higher foundation, pedestal and support structure costs. Overall, larger heliostats appear to have a cost advantage, particularly if mass produced. Long-run costs could be as low as USD 137/m^2 for 148 m^2 heliostats that are produced at a rate of 50 000 per year. This compares to the estimate for today's cost at USD 196/m^2, and USD 237/m^2 for today's smaller 30 m^2 heliostats (Kolb, 2010). The trade-off is that smaller heliostats will have an improved optimal performance, which could reduce the cost gap by as much as USD 10/m^2.

For the mirrors, improving the optical efficiency is critical. Developing highly reflective surfaces with the required durability is the first step. At the same time, the development of better passive methods to reduce soiling and active cleaning measures with low water costs will help reduce O&M costs.

Solar field components, such as drives and controls, are expensive and cost reductions can be achieved. Future azimuth drives for solar tower heliostats should be lower in cost and have optimised controls to ensure the better focussing of the incoming solar radiation on the receiver. Reducing the specific costs of the foundations, pedestal and support structures can be achieved by having smaller heliostats, as the requirements to resist maximum wind speeds are lower, while stability is also improved, helping focusing. However, the remaining costs are higher, particularly for controls and wiring, but also for drives and installation. Better design tools will help optimise support structures and reduce material costs, but, as already noted, it is not yet clear if there will be an optimal size.

The solar tower receiver costs are dominated by the tower, around one-fifth of the cost, and the receiver around 60% of the cost (Kolb, 2010). Cost reductions are possible, but the focus will be on improving the performance of the receiver to reduce the LCOE of solar tower plants. An important opportunity is the increase in generating efficiency that can be achieved by moving to an ultra-supercritical Rankine cycle. This would require receivers that could provide outlet temperatures of 650°C and support higher internal temperatures. Improving solar absorptivity, reducing infrared emissivity and reducing thermal losses through optimised materials and designs will help reduce costs and improve performance. The use of direct steam receivers, rather than a heat transfer fluid in the receiver,

[17] The efficiency of the CSP system depends on the optical efficiency of the mirrors and receiver and the thermal efficiency of the receiver system and the heat transfer fluid. The optical efficiency is the percentage which determines what part of the incoming solar radiation which is absorbed by the receiver tube while the thermal efficiency is the percentage of that radiation transferred from the receiver to the heat transfer fluid and finally to the power block.

could yield LCOE reductions, but designs are currently based on conventional boilers and need to be adapted to CSP plants.

The overall cost reductions for parabolic trough solar fields, taking into account efforts in all areas, could be in the range 16% to 34% by 2020 (Kutscher, et. al., 2010). It is important to note that, all other things being equal, a given percentage improvement in the performance of the solar field will yield a 50% larger reduction in the base LCOE than the same percentage reduction in the cost of the solar field.

Heat transfer fluids

Higher operating temperatures will allow an increase in the electrical efficiency of CSP plants, reduce the cost of the thermal storage system (as a smaller storage volume is needed for a given amount of energy storage) and achieve higher thermal-to-electric efficiencies. Most current commercial plants use synthetic oil as the heat transfer fluid. This is expensive and the maximum operating temperature is around 390°C. The use of molten salt as the HTF can raise the operating temperature up to 550°C and improve thermal storage performance. In the solar towers, the higher concentration ratio could enable even higher operating temperatures. A temperature level of 600-700°C is compatible with commercial ultra-supercritical steam cycles that would allow the Rankine cycle efficiency to increase to 48%, compared with perhaps 42% to 43% for today's designs (Kolb, 2011). Super-critical carbon-dioxide is also being explored as a HTF to enable higher operating temperatures.

Higher temperatures than this would require the use of gas-based cooling and thermodynamic cycles. A number of design options (coolants, such as water, steam, salts, air, gases and various thermodynamic cycles) are being considered to exploit this potential.

The overall cost reductions for the HTF in parabolic trough CSP plants by moving from synthetic oil to molten salt could be on the order of 40% to 45% by 2020 and allow operating temperatures in the solar field to increase from 390°C to 500°C, with associated benefits from increased steam cycle efficiency (Kutscher, et. al., 2010).

An important issue is the cooling need of the CSP thermodynamic cycle, which may either increase the investment cost or constrain the CSP deployment where water availability is limited. Current wet-cooled CSP plants require around 2 100 to 3 000 litres/MWh (Turchi, 2010a and IEA, 2010), which is more than gas-fired power plants (800 litres/MWh), but the lower end of the range is similar to conventional coal-fired plants (2 000 litres/MWh). Strategies to reduce the freshwater consumption include: the use of dry cooling technology; the use of degraded water sources; the capture of water that would otherwise be lost; and increasing thermal conversion efficiencies. Dry cooling has by far the greatest potential to reduce water consumption. Dry cooling also has the advantage of reducing parasitic loads. Hybrid cooling is also an option where very high ambient temperatures would not allow adequate cooling. In hybrid systems the CSP plant is predominantly dry cooled; wet cooling is used when ambient temperatures rise to the point where dry cooling becomes inadequate.

Thermal energy storage

Today's state-of-the-art thermal energy storage solution for CSP plants is a two-tank molten salt thermal energy storage system. The salt itself is the most expensive component and typically accounts for around half of the storage system cost (Kolb, 2011), while the two tanks account for around a quarter of the cost. Improving the performance of the thermal energy system, its durability and increasing the storage temperature hot/cold differential will bring down costs.

For solar towers, increasing the hot temperature of the molten salt storage system should be possible (up to 650°C from around 560°C), but will require improvements in design and materials used. The development of heat transfer fluids that could support even higher temperatures would reduce storage costs even further and allow even higher efficiency, but it remains to be seen if this can be achieved at reasonable cost. If direct steam towers are developed, current storage solutions will need to be adapted, if the capacity factor is to be increased and some schedulable generation made available.

The cost reduction potential for thermal energy storage systems, when combined with increases in the operating temperature and hence temperature differential in the storage system, is significant. Thermal energy storage costs could be reduced by 38% to 69% by 2020 (Kutscher, et. al., 2010).

Balance of plant costs and other issues

Cost reductions in the power block will be driven largely by factors outside the CSP industry. However, cost reductions for the balance of plant should be possible, particularly for the molten salt steam generators in solar tower plants. Another important area for LCOE reductions is in reducing parasitic losses which can be quite high, with 10% thought to be achievable for future solar tower projects (Kolb, 2011), while for parabolic troughs, it is currently in the range of 13% to 15% (Kutscher, et. al., 2010).

There are relatively few CSP technology suppliers today given that the CSP industry is in its infancy and current suppliers have higher margins than the more mature and competitive PV industry (Ernst & Young and Fraunhofer, 2011). As the industry grows, the number of technology suppliers should increase and costs should come down with increased competition. Greater competition is also likely to help boost technology development and innovation.

5.3 OVERALL CAPITAL COST REDUCTION POTENTIAL

Recent analysis of cost reduction and deployment potential for CSP technologies has identified significant overall cost reduction potentials (IEA, 2010; Turchi, 2010a; Kutscher, 2010, Kolb, 2011). Figure 5.2 shows the expected reductions achievable for trough plants by 2017 and for solar tower plants by 2020. The various cost components are based on results from NRELs Solar Advisor Model (SAM) for a 100 MW plant located in Queensland (Hinkley, 2011). This reference plant has six hours of storage and uses dry cooling. Also shown at the top of the columns are the O&M costs (in USD/kW/year), which are likewise projected to decrease significantly.

For troughs, significant reductions are expected for thermal energy storage and the HTF system. This is expected to result from operating troughs at higher temperatures. This will allow a larger difference between the hot and cold fluid temperatures for both the HTF and storage medium, which will reduce HTF pumping requirements and also the volume and cost of the thermal storage system. Taking into account reductions in other areas, an overall reduction of 41% in the capital cost is projected.

For towers, the greatest reductions are expected in the cost of the solar field, which is predicted to fall by 40%. The overall reduction in capital cost projected for the generic plant solar tower plant is around 28%.

Overall capital cost reductions for parabolic trough plants by 2020 are estimated to be between 17% and 40% (Hinkley, 2011; and Kutscher, 2010). For solar towers the cost reduction potential could be as high as 28% on a like-for-like plant basis (Hinkley, 2011). Alternative analysis suggests that the evolution of costs and performance is a little more complex, with the possibility that capital costs might decline by between 10% and 20%, depending on the components by 2017, but, from an LCOE perspective, a better solution would be to have overall installed costs that are around the same as today, but use the cost reductions to increase the thermal energy storage and solar field size to increase the capacity factor from 48% to 65% (Kolb, 2011). Looking out slightly further to 2020 and assuming higher cost reductions (from one-fifth to one-third, depending on the components) and the switch to super-critical Rankine cycles, capital costs could be reduced by 24% and the capacity factor raised to 72% (Kolb, 2011).

In addition to industry expectations and bottom-up engineering-based estimates of cost reductions, cost reduction potentials can be derived by looking at the historical “experience curve” or “learning rate” for CSP. Learning curves estimate the percentage cost reduction for each doubling of the installed capacity. However, given the early stage of deployment of CSP technologies and the stop-start nature of the industry so far, the learning rate for CSP is highly uncertain. Estimates in the literature vary, but 8% to 10% have been suggested as a realistic, if perhaps slightly conservative, range (IEA, 2010 and Trieb, et al., 2009). This is an average figure; the learning rates for the solar field, HTF, thermal energy storage and the balance of plant will be higher than this, given they are the most innovative part of a CSP plant. The power block is based on mature technology and a lower learning rate than the average is expected (Viebahn et al., 2010).

Cost reductions by 2020, assuming a learning rate of between 8% and 10%, will depend on the rate of growth in CSP deployment. However, given the large number of CSP projects either under construction or soon to be constructed, cost reductions of as much as 30% to 40% maybe possible in an aggressive deployment scenario to 2020 (IEA, 2010). Given the uncertainty over cost

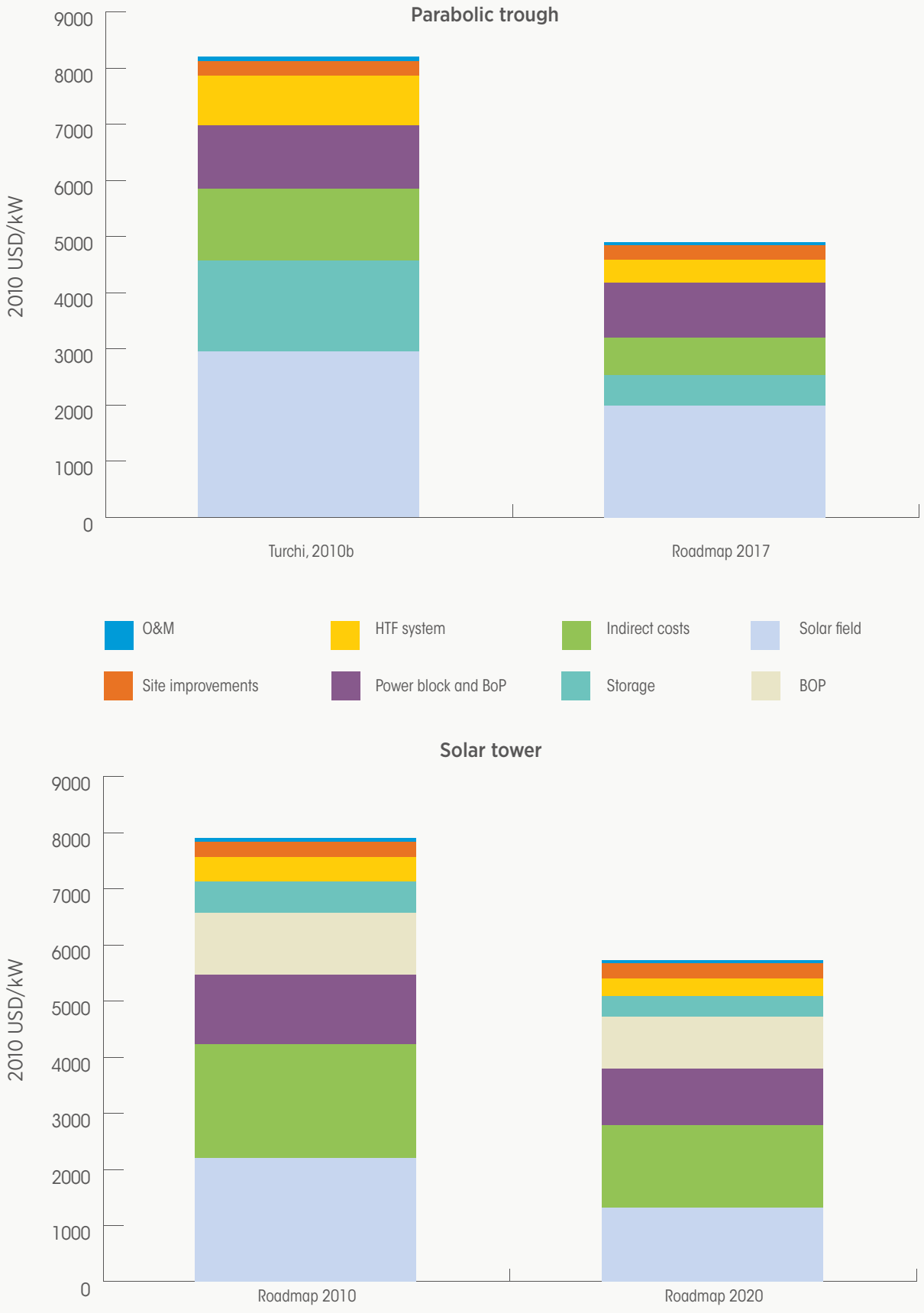


FIGURE 5.2: FORECAST COST REDUCTIONS FOR PARABOLIC TROUGH AND POWER TOWER CSP PLANT

Source: Hinkley, 2011.

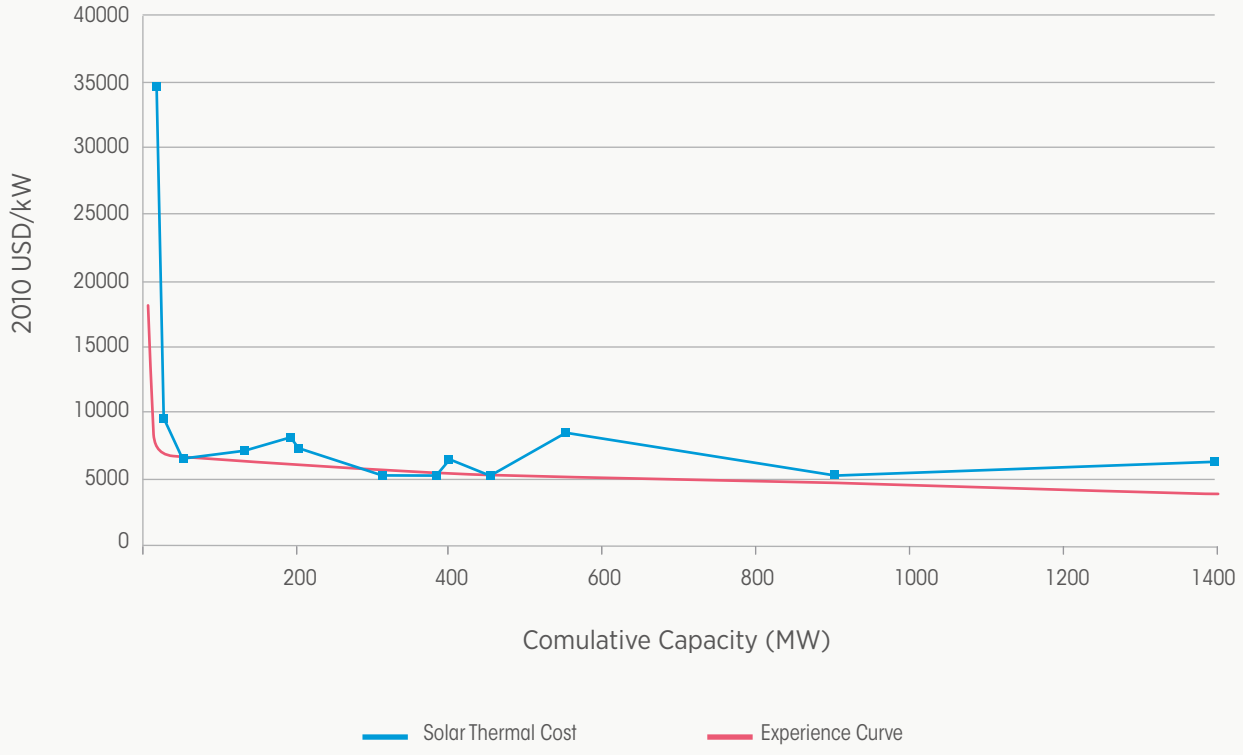


FIGURE 5.3: CSP HISTORICAL COST DATA, CUMULATIVE CAPACITY GROWTH AND EXPERIENCE CURVE

Source: Hayward, 2011.

reductions in the near term, overall cost reductions of 10% are assumed by 2015. This includes the impact of improved performance and higher thermal energy storage-increasing capacity factors. The cost reduction on a strictly like-for-like plant basis would be somewhat higher than this.

5.4 O&M COST REDUCTION POTENTIAL

The opportunities to reduce O&M costs are good. There is currently little long-term experience in operating CSP plants. It is only now that the lessons learned in California since the 1980s are beginning to be applied in today's designs. The key areas to address are:

- broken mirrors;
- receiver failure;
- more automation of maintenance activities/ better preventive maintenance; and
- plant designs that reduce O&M costs.

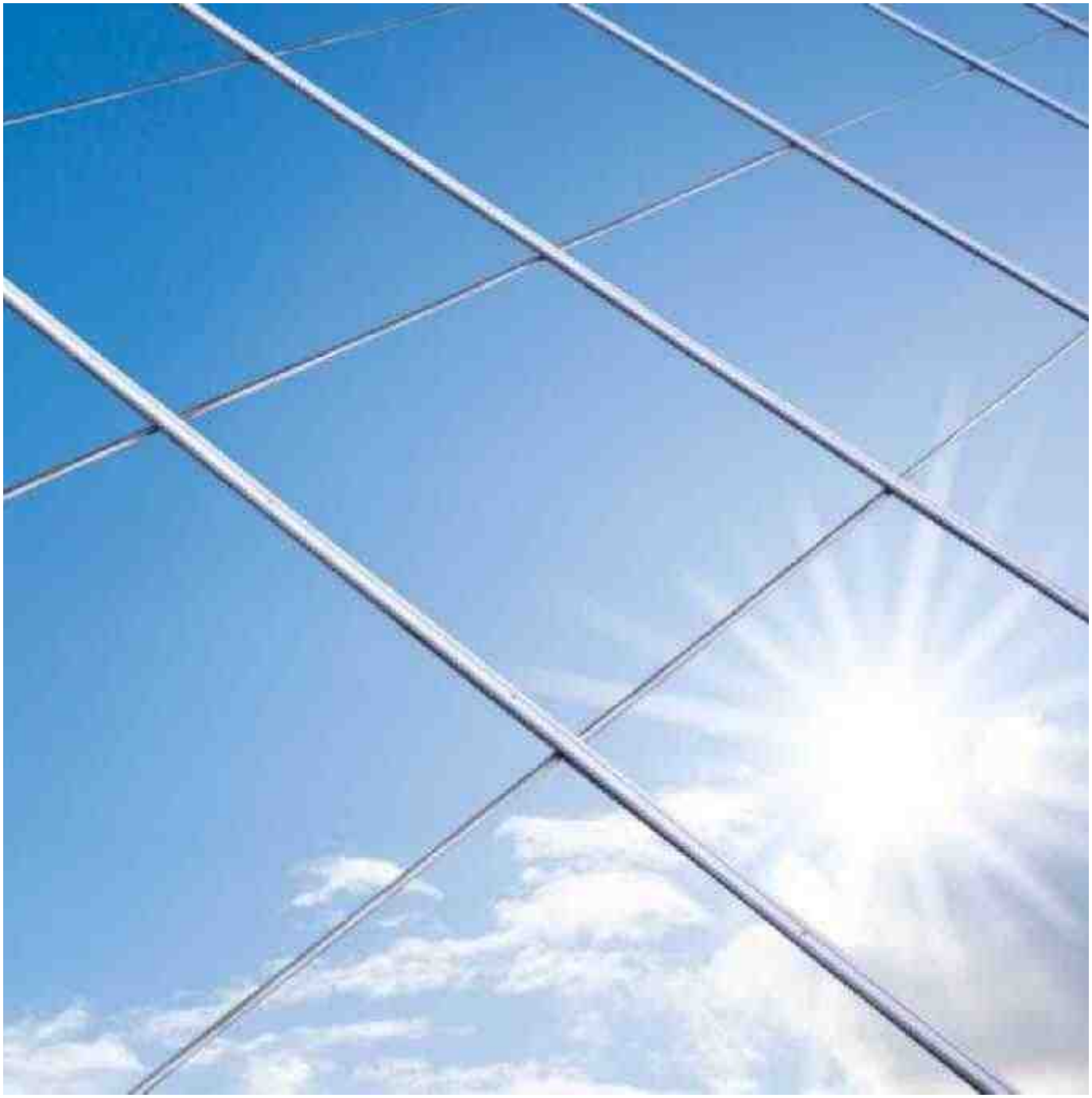
A significant problem with earlier plants was broken/ cracked mirrors or mirrors separating from their pads, with most of this damage coming from the effects of wind loads. This led to loss of reflectance, accounting for a fifth of all lost power production outages (Turchi, 2010b), so the costs are higher than just the O&M costs to fix or repair the mirrors. Reducing the rate of breakage and loss of reflectance can therefore help reduce costs significantly. This can be achieved with thin-film reflectors, laminated mirrors and reinforcing vulnerable reflectors (for instance at the edge of the solar field, where there is no mutual shelter from winds) (Turchi, 2010b).

Receiver failure in parabolic trough plants (i.e. breakage, hydrogen infiltration, vacuum loss and coating degradation) is another area that can be targeted for cost reduction. The SEGS plants were able to reduce breakage to 3.4%, but this still results in high costs in terms of replacement and lost output (Turchi, 2010b). More

robust receivers would help to reduce failures, but there currently is not enough data for new plants to identify the key causes of failure and allow improved designs. This is an area where ongoing research and monitoring of recent plants is warranted in order to identify the key failure mechanisms and how best to address them.

More automation of maintenance activities and better real-time diagnostics could help reduce O&M costs, as well as improve performance. For example, automated washing of only those mirrors with known degraded performance could help reduce costs. Improved plant designs that also aim to minimise O&M costs will evolve as operating experience with the new generation of CSP plants emerges.

Overall cost reduction potentials for O&M costs could be in the range of 35% by 2020 for parabolic trough plant and 23% for solar towers (Turchi, 2010a). Given these figures, it is assumed that O&M costs could be reduced by between 5% and 10% by 2015.



6. The levelised cost of electricity from CSP

The first SEGS plants that have been operating in California since 1984 are estimated to have LCOEs of between USD 0.11 to USD 0.18/kWh. However, current materials and engineering costs are significantly higher than they were during the period of their construction and these are not necessarily a good guide to the current LCOE of CSP plants.

The most important parameters that determine the LCOE of CSP plants are:

- The initial investment cost, including site development, components and system costs, assembly, grid connection and financing costs;
- The plant's capacity factor and efficiency;
- The local DNI at the plant site;
- The O&M costs (including insurance) costs; and
- The cost of capital, economic lifetime, etc.

The economics of CSP and other renewable technologies are, with the exception of biomass, substantially different from that of fossil fuel power technologies. Renewables have, in general, high upfront investment costs, modest O&M costs and very low or no fuel costs. Conventional fossil fuel power tends to have lower upfront costs and high (if not dominant) fuel costs, which are very sensitive to the price volatility of the fossil fuel markets. In contrast, renewable technologies are more sensitive to change in the cost of capital and financing conditions.

Solar tower projects are currently considered more risky by financiers due to their less mature status. However, in the longer-term, greater experience with solar towers will reduce this risk premium and convergence is likely to occur in financing costs. The analysis presented here, as in the other papers in this series, assumes a standard 10% cost of capital for all the technologies evaluated. The LCOE of CSP plants from a developer's perspective will therefore differ from that presented here, due to differences in local conditions and developers' and lenders' perceptions of risk.

The impact of the solar resource and plant design decisions on the LCOE of CSP plants

It is important to note that the LCOE of CSP plants is strongly correlated with the DNI. Assuming a base of 2 100 kWh/m^2/year (a typical value for Spain), the estimated LCOE of a CSP plant is expected to decline by 4.5% for every 100 kWh/m^2/year that the DNI exceeds 2 100 (Figure 6.1).

An important consideration in the design of CSP plant is the amount of thermal energy storage and the size of the solar multiple. Various combinations of these two parameters yield different LCOE results (Figure 6.2). Thermal storage allows CSP to achieve higher capacity factors and dispatch generation when the sun is not shining. This can make CSP a competitor for conventional base- or intermediate-load power plants. A large-scale example of this technology is the 280 MW Solana 1 power plant under construction by Abengoa for the Arizona Public Service Co, United States.

However, for a given plant, the minimum range of LCOE can be achieved by varying the thermal energy storage and solar multiple values (Figure 6.2). This analysis suggests that the minimum LCOE is achieved with a solar multiple of 3 and 12 hours energy storage. However, there is relatively little difference between a plant with a solar multiple of 1.5 and no thermal energy storage, a solar multiple of 2 and 6 hours energy storage, and a plant with a solar multiple of 3 and 12 hours energy storage. Choosing what plant design is optimal will depend significantly on the project's specifics. However, one important factor to consider is that this assumes all electricity generated has the same value. If this is not the

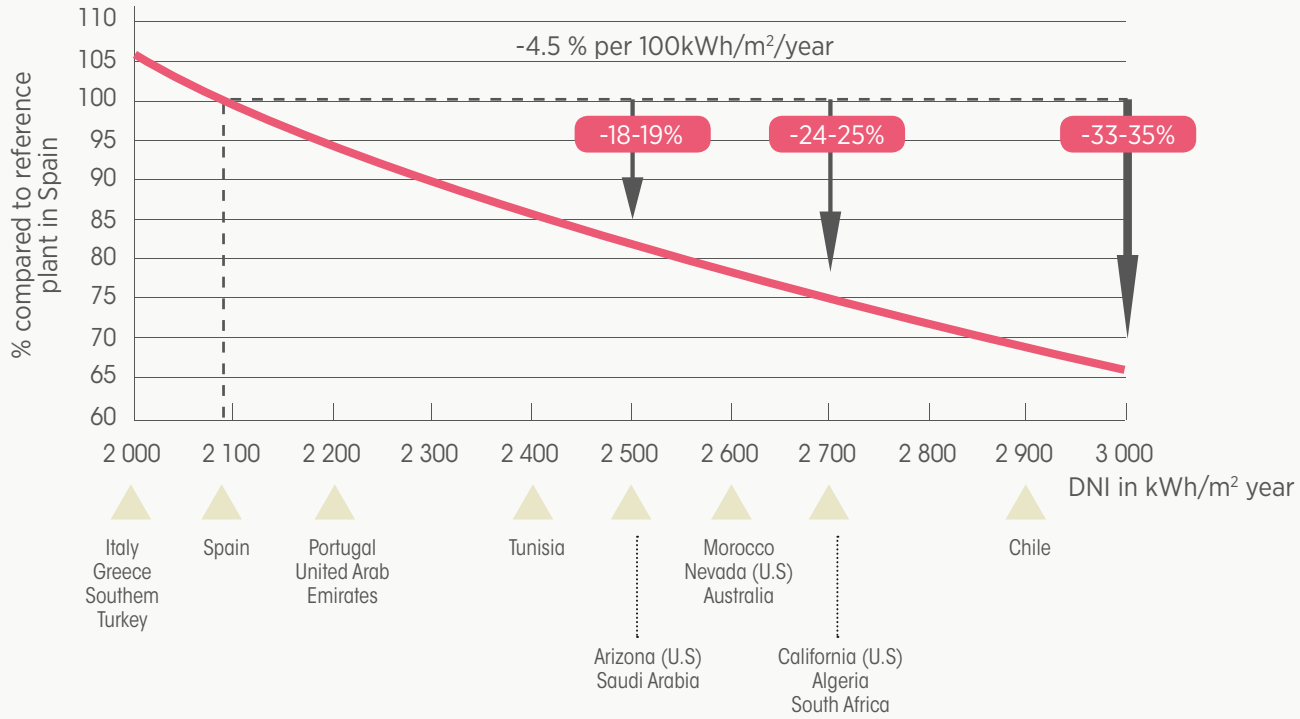


FIGURE 6.1: THE LCOE OF CSP PLANTS AS A FUNCTION OF DNI

Source: A.T. Kearney and ESTELA, 2010.

case, then plants with higher storage levels are likely to provide more flexibility to capture this increased value. This picture will evolve over time as thermal energy storage costs decline. Lower storage costs, particularly for solar tower projects, will result in a lower LCOE for plants with higher storage.

6.1 THE CURRENT LEVELISED COST OF ELECTRICITY FROM CSP

The current LCOE of CSP plants varies significantly by project and solar resource. Table 6.1 presents the range of estimates for CSP from different sources. Parabolic trough systems are estimated to have an LCOE of between USD 0.20 and USD 0.33/kWh at present, depending on their location, whether they include energy storage and the particulars of the project. These ranges broadly agree with the limited data that are available for recent CSP projects that have been commissioned, or will come online in the near future (Figure 6.3). However, the results need to be treated with caution, given that there are relatively few projects, and not all of the data on the actual costs of recent projects is in the public domain.

Solar tower systems are estimated to have an LCOE of between USD 0.16 and USD 0.27/kWh at present, depending on their location, the size of the thermal energy storage and the particulars of the project.

An important aspect of adding storage to a CSP plant in the context of the profitability of the project is the anticipated increased value of produced energy. This will depend on the existing electricity system, usage patterns and the structure of the electricity market. Adding storage to a CSP plant adds value by decreasing variability, increasing predictability and by providing firm capacity. Where peak demand and prices received coincide with the production of a CSP plant, little or no storage may be justified. In contrast, where early evening

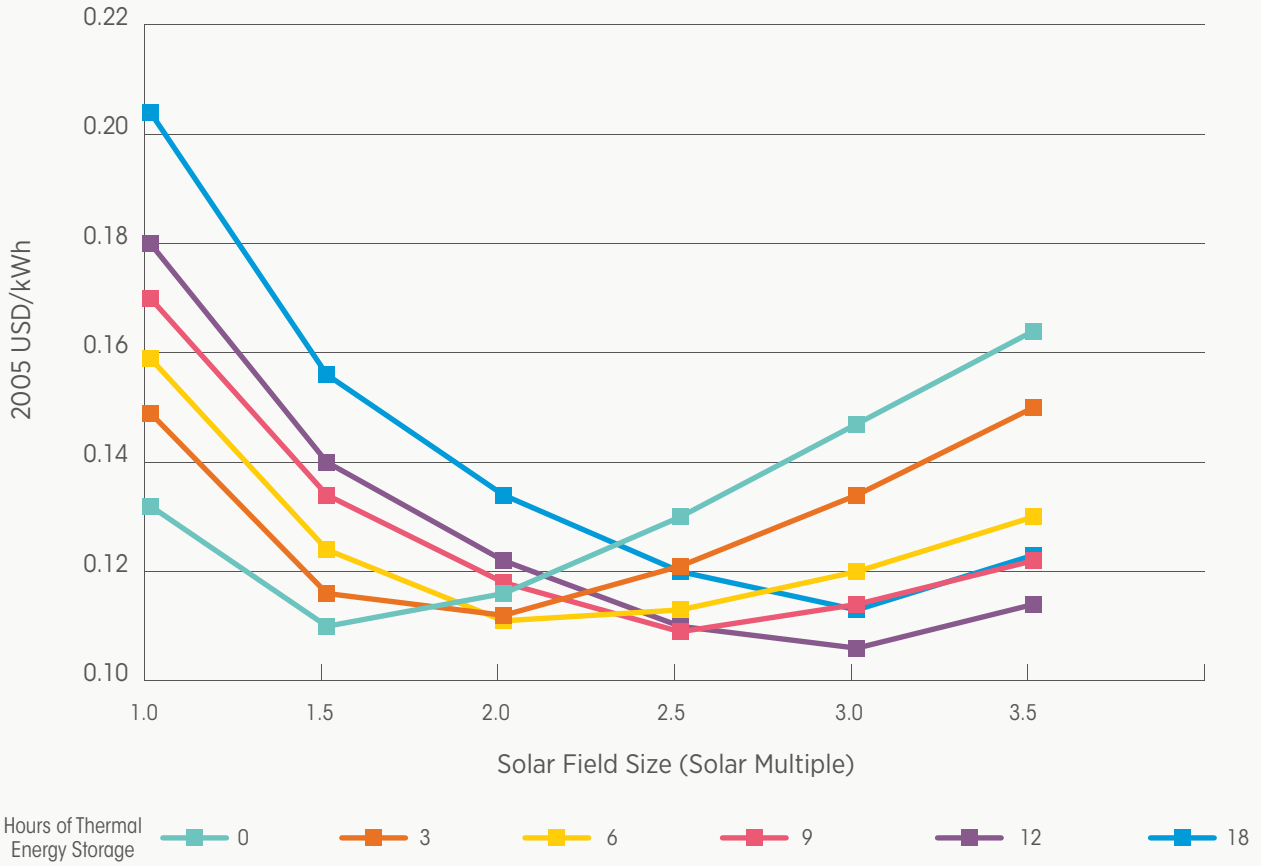


FIGURE 6.2: LEVELISED COST OF ELECTRICITY FOR 100 MW PARABOLIC TROUGH PLANT AS A FUNCTION OF THE SIZE OF THE SOLAR FIELD AND THERMAL STORAGE

Source: Anders, 2005.

peaks occur, storage allows CSP plant to be dispatched at this time of higher value electricity demand. The value of the ability to dispatch a CSP plant's generation into peak demand periods is very country- and project-specific, but the overall increase in value can be in the range of USD 0.015 to USD 0.065/kWh (Richter, 2011).

In Spain, a number of 50 MW CSP units are planned, based on an estimated LCOE of approximately USD 0.30 to USD 0.35/kWh. Other technologies, such as the solar tower and Stirling dish systems, are currently planned for significantly smaller scales of up to 15 MW. For these small systems, the LCOE is significantly higher. The cost of electricity production by parabolic trough systems is currently on the order of USD 0.23 to USD 0.26/kWh (€ 0.18 to € 0.20/kWh) for Southern Europe, where the DNI is 2 000 kWh/m^2/year (CSP Today, 2008).

The LCOE of parabolic trough plants and solar tower plants is dominated by the initial capital investment (Figure 6.4). The analysis of CSP options for South Africa suggests 84% of the LCOE of both parabolic troughs and solar towers will be accounted for by the initial capital investment. The fixed operations and maintenance costs account for 10% to 11% of the LCOE and personnel costs for 4% to 5% of the total LCOE.

Substantial cost reductions for the LCOE of CSP plants can be expected by 2020, given that several GW of CSP power plants are under construction, announced or in the pipeline for 2020. With aggressive deployment policies, this will lead to significant cost reductions from learning effects. Additional reductions in the LCOE of CSP plants will come from the impact of greater R&D investment, greater operational experience and the scaling-up of plants.

The LCOE of parabolic trough systems could decline by between 38% and 50% by 2020 (Table 6.1). This is driven by improvements in performance and capital

Table 6.1: Estimated LCOE for parabolic trough and solar tower projects in 2011 and 2020

	2011		2020		
CSP type and source	**Low estimate**	**High estimate**	**Low estimate**	**High estimate**	**Notes**
			(2010 USD/kWh)		
Parabolic trough					
IEA, 2010	0.20	0.295	0.10	0.14	Large plant, 10% discount rate
Fichtner, 2010	0.22	0.24			Proposed plant in South Africa. 8% discount rate. Lower end is for 100 MW plant with storage
	0.33	0.36			LCOE for India, lower value is for wet-cooled and higher value for dry-cooled
	0.22	0.23			LCOE for Morocco, lower value is for wet-cooled and higher value for dry-cooled
Based on Kutscher, et al., 2010	0.22		0.10	0.11	Data for the United States, adjusted to exclude impact of tax credits
Hinkley, et al., 2011	0.21		0.13		Data for a 100 MW plant in Queensland, Australia. 7% discount rate.
Solar Tower					
Fichtner, 2010	0.185	0.202			Proposed plant in South Africa. 8% discount rate. Lower end is for 100 MW plant with storage
	0.27	0.28			LCOE for India, lower value is for wet-cooled and higher value for dry-cooled
	0.22	0.23			LCOE for Morocco, lower value is for wet-cooled and higher value for dry-cooled
Kolb, et al., 2010	0.16	0.17	0.08	0.09	Data for the United States, adjusted to exclude impact of tax credits
Hinkley, et al., 2011	0.21		0.16		Data for a 100 MW plant in Queensland, Australia. 7% discount rate.
Parabolic trough and solar towers					
A.T. Kearney, 2010	0.23	0.32	0.13	0.16	

cost reductions. The LCOE of solar tower projects could decline by between 30% and 50% by 2020. The lower end of this range is somewhat less than for parabolic troughs, given the less mature status of this technology.

By 2025 a survey of industry expectations and analysis of the bottom-up technology cost reduction potential highlights potentially larger cost reductions for CSP plants (Figure 6.5). Economies of scale in manufacturing and project development are expected to offer the largest cost reduction potential, followed by capital cost reductions and performance improvements.

6.2 THE LCOE OF CSP PLANTS: 2011 TO 2015

The estimated cost of CSP plant varies significantly, depending on the capacity factor, which in turn depends on the quality of the solar resource, thermal energy storage levels and the technical characteristics of the CSP plant.

Based on the data and analysis presented earlier, CSP plant capital costs vary significantly, depending on the level of energy storage. For parabolic trough plants without thermal energy storage, costs could be as low as

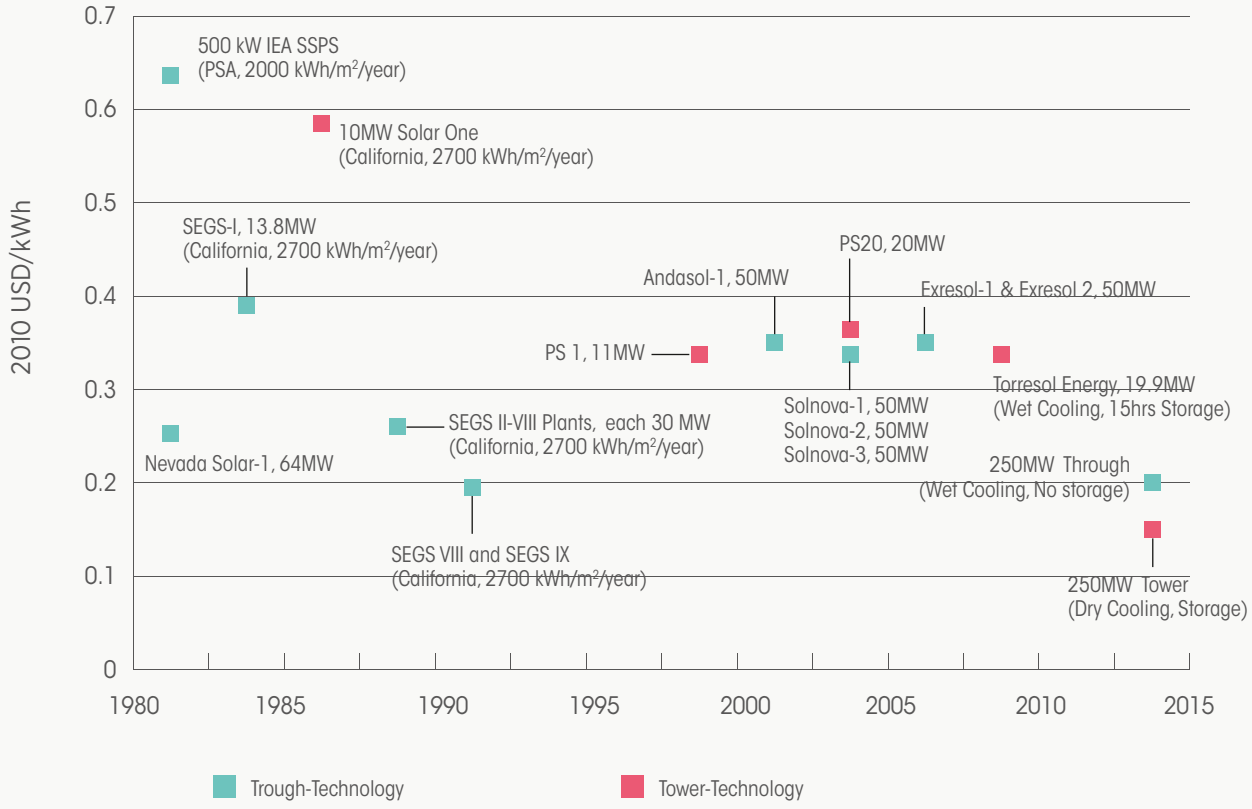


FIGURE 6.3: ESTIMATED LCOE FOR EXISTING AND PROPOSED PARABOLIC TROUGH AND SOLAR TOWER CSP PLANTS

Source: IRENA analysis

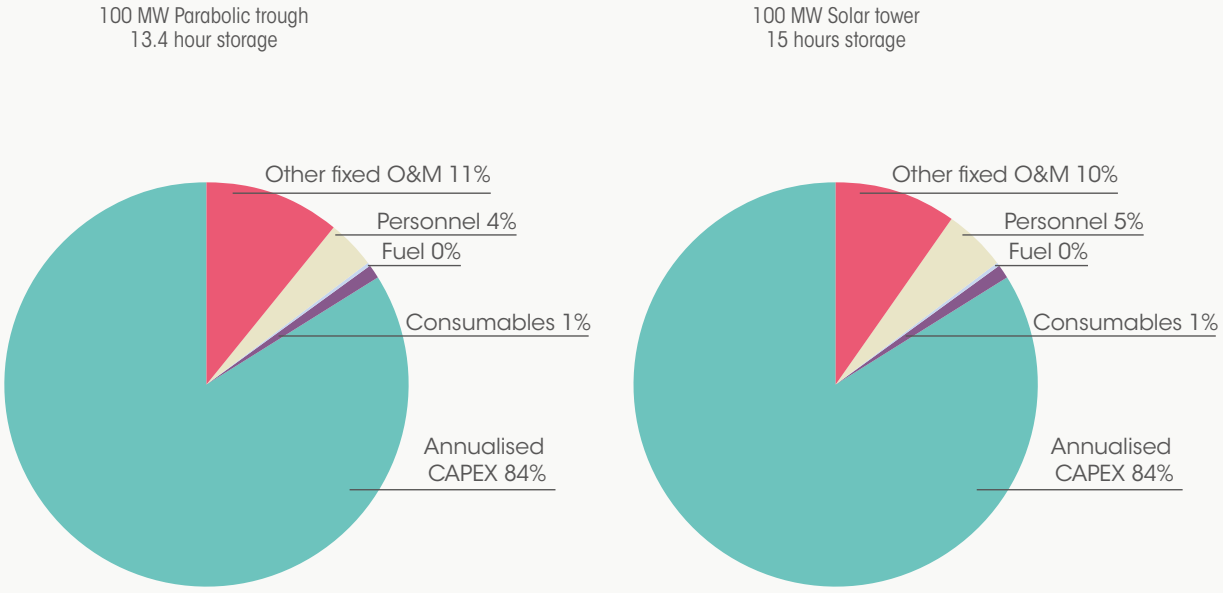


FIGURE 6.4: LCOE BREAKDOWN FOR A PARABOLIC TROUGH AND SOLAR TOWER PLANT IN SOUTH AFRICA

Source: Fichtner, 2010.

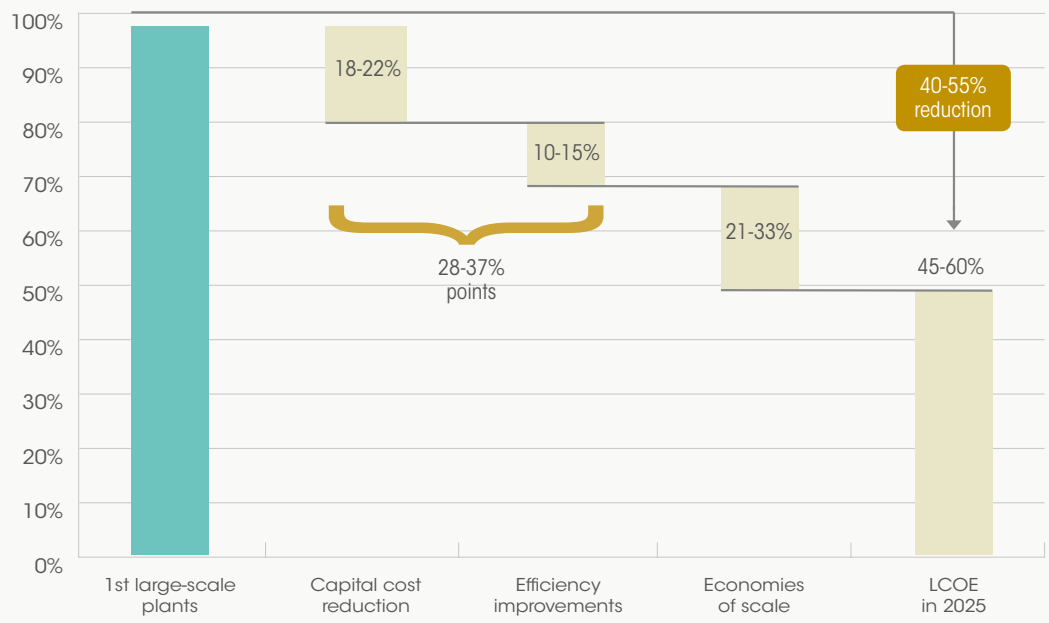


FIGURE 6.5: BREAKDOWN OF LCOE REDUCTIONS FOR CSP PLANT BY 2025

Source: A.T. Kearney and ESTELA, 2010.

USD 4 600/kW, but the capacity factor is likely to be just 0.2 to 0.25 (Table 6.2). The total installed capital costs of parabolic trough plant with six hours energy storage is estimated to be in the range USD 7 100 to USD 9 800/kW. These plants will have much higher capacity factors in the range of 40% to 53%.

Solar tower projects, given their potential for higher operating temperatures and therefore cheaper storage and higher performance, tend to be designed with higher thermal energy storage. Solar tower projects with thermal energy storage of 6 to 7.5 hours are estimated to cost USD 6 300 to USD 7 500/kW and have capacity factors between 40% and 45%. Solar tower projects with nine hours energy storage have costs of between USD 7 400 to USD 7 700/kW and have capacity factors between 45% and 55%. Increasing energy storage to between 12 and 15 hours increases the specific costs to USD 9 000 to USD 10 500/kW and could increase the capacity factor to between 65% and 80%.

Given the very early stage of development of linear Fresnel collectors and Stirling dish systems, capital costs and LCOE estimates for these technologies are not presented in this analysis.

The LCOE for parabolic trough plant is presented in Figure 6.6. High and low assumptions for the capital costs and capacity factor are taken from Table 6.1 and are based on the data presented in Section 4 for 2011. The analysis assumes 0.5% per year for insurance, 0.4% degradation in the solar field performance per year and O&M cost escalation at the rate of 1% per year. The LCOE of parabolic trough CSP plants without thermal energy storage is estimated to be between USD 0.30 and USD 0.37/kWh and could decline to between USD 0.26 and USD 0.34/kWh by 2015. Parabolic trough plants with six hours of thermal energy storage have an estimated LCOE of between USD 0.21 to USD 0.37/kWh, depending on the capital costs and capacity factor achieved. By 2015, the LCOE for these plants could fall to between USD 0.18 and USD 0.31/kWh.

The estimated LCOE of solar tower CSP with 6 to 7.5 hours of storage in 2011 is estimated to be between USD 0.22 and USD 0.29/kWh (Figure 6.7). For solar tower plants with 12 to 15 hours of storage, the LCOE drops to between USD 0.17 and USD 0.24/kWh. By 2015, capital cost reductions, performance improvements and lower O&M costs could reduce the LCOE of plants with 6 to 7.5 hours of storage to between USD 0.17 and USD 0.24/kWh.

TABLE 6.2: TOTAL INSTALLED COST FOR PARABOLIC TROUGH AND SOLAR TOWERS, 2011 AND 2015

	2011		2015	
	2010 USD/kW	Capacity factor (%)	2010 USD/kW	Capacity factor (%)
Parabolic trough				
No storage	4 600	20 to 25	3 900 to 4 100	20 to 25
6 hours storage	7 100 to 9 800	40 to 53	6 300 to 8 300	40 to 53
Solar tower				
6 to 7.5 hours storage	6 300 to 7 500	40 to 45	5 700 to 6 400	40 to 53
12 to 15 hours storage	9 000 to 10 500	65 to 80	8 100 to 9 000	65 to 80

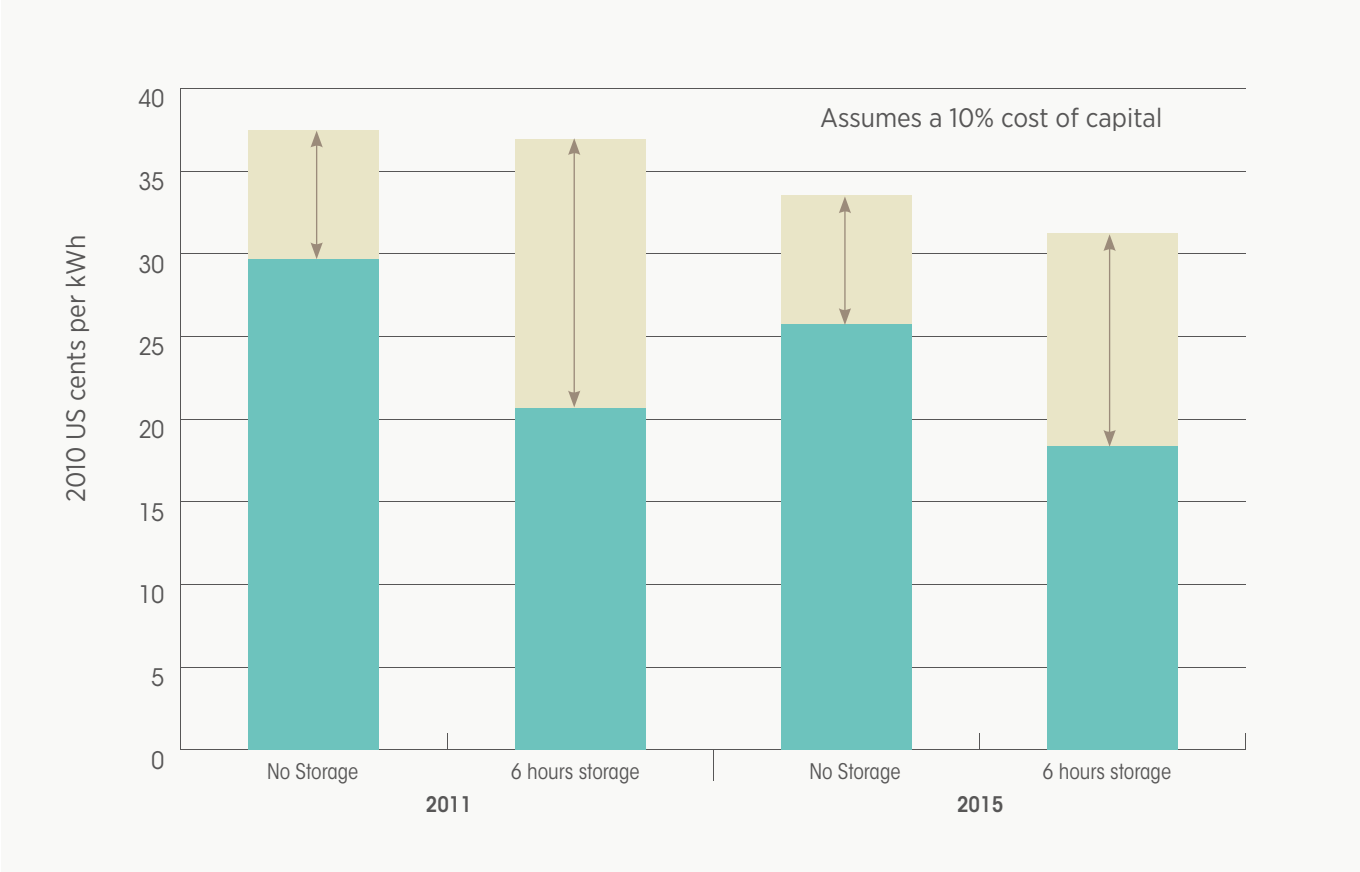


FIGURE 6.6: LCOE OF PARABOLIC TROUGH CSP PLANT, 2011 AND 2015

Note: The LCOE numbers are based on a 10% discount rate, higher or lower rates will have a significant impact on the LCOE.

For plants with 12 to 15 hours of storage, the LCOE could decline to between USD 0.15 and USD 0.21/kWh by 2015.

Solar towers, therefore, have the potential to reduce their costs to the point at which they can compete with conventional technologies for providing intermediate load and peak afternoon air conditioning loads in hot, arid climates in the short- to medium-term, with further cost reductions to 2020 further improving their competiveness.

Sensitivity to the discount rate used

The analysis in this section assumes that the average cost of capital for a project is 10%. However, the cost of debt and the required return on equity, as well as the ratio of debt-to-equity varies between individual projects and countries. This can have a significant impact on the average cost of capital and the LCOE of a CSP project.

In the United States, the required return on equity for CSP projects for which data was available between the

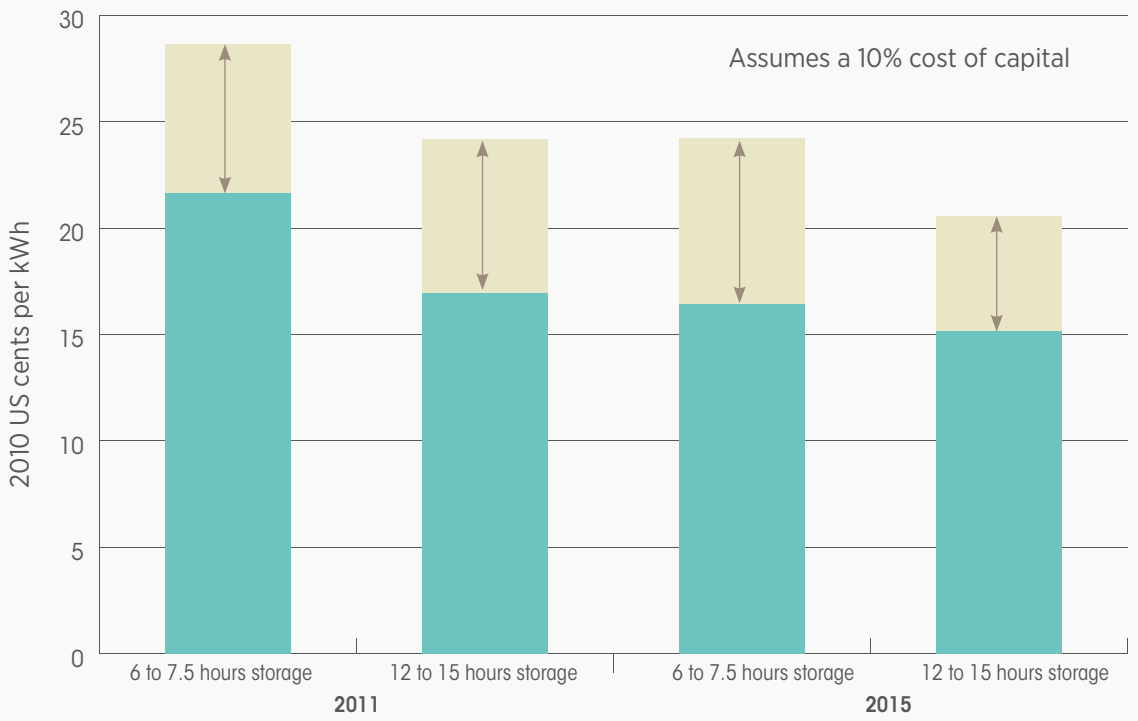


FIGURE 6.7: LCOE OF SOLAR TOWER CSP PLANT, 2011 AND 2015

Note: The LCOE numbers are based on a 10% discount rate, higher or lower rates will have a significant impact on the LCOE.

fourth quarter of 2009 and the fourth quarter of 2010, inclusive, ranged from a low of 7% to a high of 15%. While the quarterly average cost of debt ranged from a low of 4.4% to a high of 11%.[18] Making the simplifying assumptions that the debt-to-equity ratio is between 50% and 80% and that debt maturity matches project length results in project discount rates of between 5.5% and 12.8%.[19]

Table 6.3 presents the impact of varying the discount rate between 5.5% and 14.5% for CSP projects. The LCOE of a parabolic trough plant with 6 hours storage is around 30% lower when the discount rate is 5.5% instead of 10%. Increasing the discount rate from 10% to 12.8% increases the LCOE of a parabolic trough plant by around one-fifth, depending on the capacity factor. Increasing the discount rate to 14.5% increases the LCOE by around 30%.

TABLE 6.3: LCOE OF CSP PARABOLIC TROUGH AND SOLAR TOWER PROJECTS UNDER DIFFERENT DISCOUNT RATE ASSUMPTIONS

	Paraboloic trough plant (6 hours storage, USD 8 000/kW)		Solar tower plant (12-15 hours storage, USD 10 000/kW)	
Capacity factor	**40%**	**53%**	**65%**	**80%**
	2010 USD/kWh			
10% discount rate	0.31	0.23	0.23	0.19
5.5% discount rate	0.22	0.16	0.16	0.13
12.8% discount rate	0.37	0.28	0.28	0.23
14.5% discount rate	0.40	0.30	0.31	0.25

Note: Assumes USD 70/kW/year for O&M, 0.5% insurance and a 25 year economic life.

[18] *This data comes from the Renewable Energy Financing Tracking Initiative database and was accessed in November 2011. See https://financere.nrel.gov/finance/REFTI*

[19] *These assumptions aren't representative of how projects are structured, but in the absence of comprehensive data are used for illustrative purposes.*

For solar towers with 12 to 15 hours storage, decreasing the discount rate from 10% to 5.5% reduces the LCOE by between 30% and 32%. Increasing the discount rate to 12.8% increases the LCOE by 21% to 22%, while increasing the discount rate to 14.5% increases the LCOE by between 32% and 35%. This simple comparison shows that reducing the risks associated with CSP projects and ensuring that favourable financing terms can be accessed will have a significant impact on the competitiveness of CSP projects.

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Acronyms

BoP	Balance of plant
CAPEX	Capital expenditure
CIF	Cost, insurance and freight
CSP	Concentrating solar power
DCF	Discounted cash flow
DNI	Direct normal irradiance
DSG	Direct steam generation
EU-27	The 27 European Union member countries
FOB	Free-on-board
GHG	Greenhouse gas
GW	Gigawatt
HTF	Heat transfer fluid
ISCC	Integrated solar combined cycle
kW	Kilowatt
kWh	kilowatt hour
LFC	Linear Fresnel collector
MENA	Middle East and North Africa
MW	Megawatt
MWh	Megawatt hour
LCOE	Levelised cost of energy
O&M	Operating and maintenance
OPEX	Operation and maintenance expenditure
PTC	Parabolic trough collector
R&D	Research and Development
USD	United States dollar
WACC	Weighted average cost of capital

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