6 CONCENTRATING SOLAR POWER

	2010	2013	2014	2010-2014 (% change)
New capacity additions (GW)	0.5	0.9	1.1	136%
Cumulative installed capacity (GW)	1.3	3.5	4.8	286%
Typical global total installed cost range (2014 USD/kW)	3 420 – 11 740	3 550 – 8 760	n.a.	n.a.
Global LCOE range (2014 USD/kWh)	0.33 – 0.44	0.19 – 0.39	0.20 – 0.35	n.a.

Notes: 2014 deployment data are estimates. n.a. = data not available or not enough data to provide a robust estimate.

Highlights

- CSP is in its infancy in terms of deployment compared to the other renewable power generation technologies, with 5 GW of CSP installed worldwide at the end of 2014.
- The current CSP market is dominated by parabolic trough technologies (around 85% of cumulative installed capacity). However, increasing numbers of solar towers are being built and offer the promise of lower electricity costs.
- CSP can integrate low-cost thermal energy storage in order to provide dispatchable electricity to the grid and capture peak market prices.
- The weighted average LCOE of CSP by region varied from a low of USD 0.20 in Asia to a high of USD 0.25/kWh in Europe in recent years, with the LCOE of individual projects varying significantly depending on location and level of storage.
- However, as costs are falling, recent projects are being built with LCOEs of USD 0.17/kWh, and power purchase agreements are being signed at even lower values where low-cost financing is available. Future cost reductions can be expected if deployment accelerates, but policy uncertainty is hurting growth prospects.
- Total CSP installed costs have ranged from USD 3 550 to USD 8 760/kW in 2013 and 2014. The wide variation is driven by different cost structures in different countries, but mostly reflects the wide variation between plants with and without energy storage and the amount of storage.

Introduction

Concentrating solar power (CSP) is a power generation technology that uses mirrors to concentrate the sun's rays and, in most of today's CSP systems, to heat a fluid that is used to produce steam. The steam is then used to drive a conventional steam turbine and generate power in the same way as conventional thermal power plants that use steam cycles. However, other concepts are being explored and not all future CSP plants will necessarily use a steam cycle.

CSP is at its infancy in terms of deployment, with total installed capacity at the end of 2014 of around 5 gigawatts (GW). New capacity additions in 2013 were estimated to have reached 0.9 GW, a new record. Total installed capacity has grown rapidly since 2010, but policy uncertainty has reduced growth prospects in key markets.

CSP plants can be divided into two groups, based on whether the solar collectors concentrate the sun's 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 and solar tower plants, and include two-axis tracking systems to concentrate the power of the sun.

Parabolic trough collectors (PTC) dominate the total installed capacity of CSP plants and consist of solar collectors (mirrors), heat receivers (tubes), heat transfer fluid and system, and support structures. A single-axis tracking mechanism is used to orient both solar collectors and heat receivers toward the sun (A.T. Kearney and ESTELA, 2010). Most existing parabolic troughs use synthetic oils as heat transfer fluid, which are stable up to around 360 to 400°C. High temperatures are an important development goal for all CSP plants as they improve the system's thermal storage performance and allow more efficient steam cycles to be used, thereby reducing the levelised cost of electricity (LCOE) from CSP plants.

Solar tower technologies use a ground-based field of mirrors (heliostats) that track the sun individually in two axes 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 then drives a thermodynamic cycle, in most cases a water-steam cycle, to generate electric power. 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. There are two proven types of solar tower concepts. Direct steam generation (DSG) plants have been developed by Abengoa and avoid the need and costs of a heat transfer fluid.

Table 6.1: A comparison of CSP technologies

	Parabolic trough	Solar tower	Linear Fresnel	Dish-Stirling
Maturity of technology	Commercially proven	Commercially proven	Early commericial projects	Demonstration projects
Operating temperature (°C)	350-400	250-565	250-350	550-750
Collector concentration	70-80 suns	> 1 000 suns	> 60 suns (depends on secondary reflector)	up to 10 000 suns
Receiver/absorber	Absorber attached to collector, moves with collector	External surface or cavity receiver, fixed	Fixed absorber, no evacuation secondary reflector	Absorber attached to collector moves with collector
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	Probably, but not proven

Table 6.2: Bottom up engineering estimates of different configurations of parabolic trough and solar power plants

	Heat transfer fluid	Solar mutiple	Storage (hours)	Capacity factor (%)	Cost (2014 USD/kW)
Parabolic trough	Synthetic oil	1.3	0	26	4 950
	Synthetic oil	1.3	0	23	7 688
	Synthetic oil	2	6	41	8 604
	Synthetic oil	2	6.3	47-48	9 626-10 552
	Synthetic oil	2	6	43	8 320
	Molten salt	2.8	4.5	50	7 936
		2.5	9	56	8 120
		3	13.4	67	9 826
Solar power	Molten salt		7.5		7 825
	Molten salt	1.8	6	43	6 772
	Molten salt	2.1	9	46	7 983
	Molten salt	1.8	6	48	8 025
	Molten salt	2	9	54	8 299
		3	12	68	9 742
		3	15	79	11 311

Sources: Fichtner, 2010; Hinkley, 2011; Kolb, 2011; Turchi, 2010a; and Turchi, 2010b.

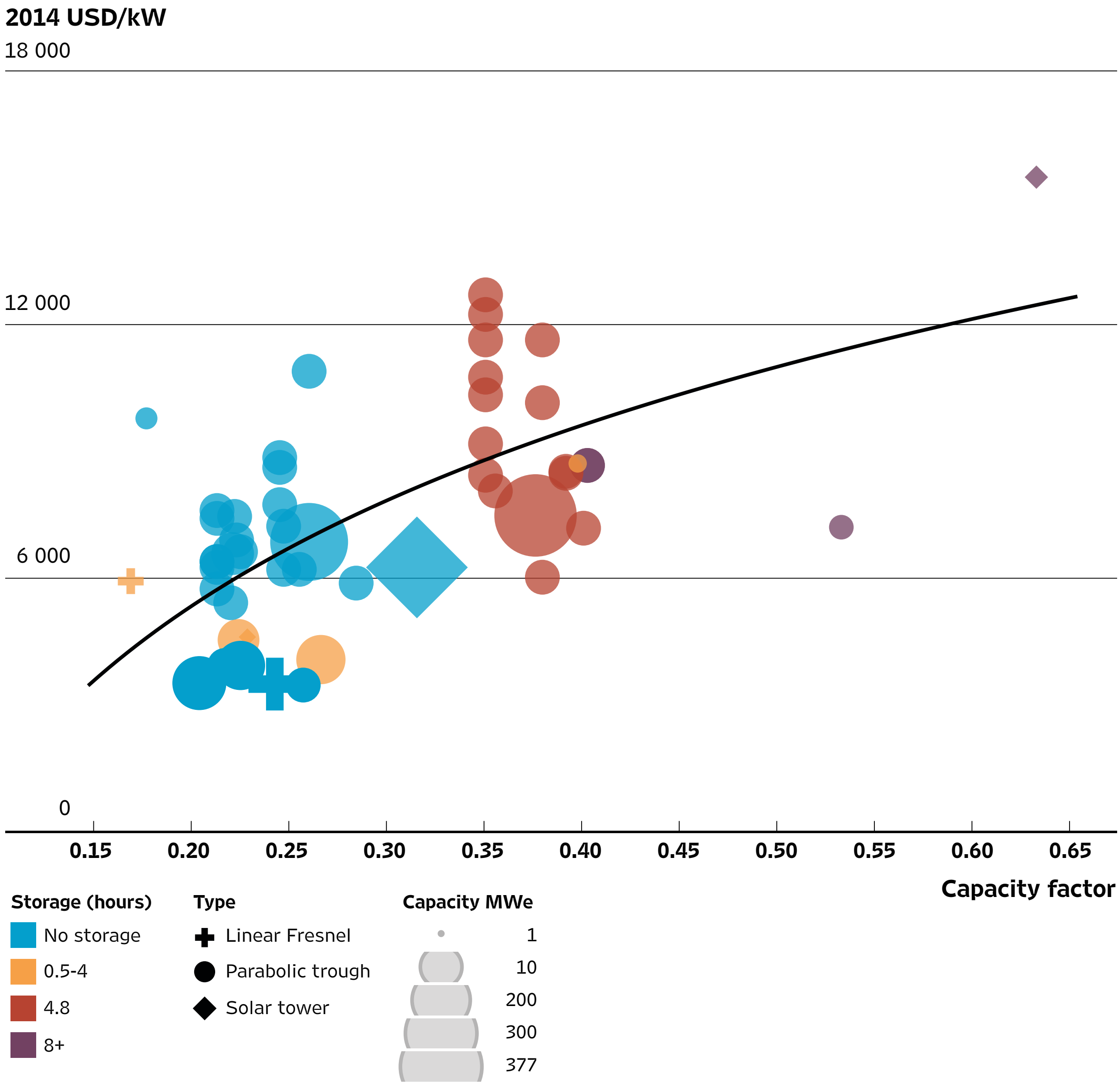
An alternative approach uses molten salts for the heat transfer fluid. By using molten salt as the heat transfer fluid the potential operating temperature could rise with more research and development (R&D) to between 550 and 650°C, sufficient to allow higher efficiency supercritical steam cycles. Although still at the R&D phase, supercritical cycles could improve efficiencies and lower the cost of thermal energy storage.

The key advantage of solar towers is their higher operating temperatures, which allow low-cost thermal energy storage to raise capacity factors and to achieve higher efficiency levels. This also allows a more flexible generation strategy to be pursued in order to maximise the value of the electricity generated. Given this and other advantages, 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.

Linear Fresnel collectors (LFCs) are similar to PTCs, but instead of parabolic mirrors LFCs use a series of long, flat or slightly curved mirrors placed at different angles on each side of a fixed receiver (located several metres above the primary mirror field) to concentrate sunlight on the receiver. The focal line of Fresnel collectors is somewhat distorted, unlike parabolic mirrors, and requires either that a mirror be installed above the receiver tube (a secondary reflector) to refocus any rays missing the tube, or several parallel tubes forming a multi-tube receiver that is wide enough to capture most of the focused sunlight without a secondary reflector. The advantage of LFCs is that they can use cheaper mirrors and lighter and less expensive support structures than PTC systems, resulting in lower capital costs than PTC systems. This is offset to some extent by their lower solar efficiency. As a result, there doesn't appear to be a clear advantage to either PTC or LFC systems at this stage of their development.

Solar dish systems consist 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. In order to convert this heat into electricity the receiver may incorporate a Stirling engine or a micro-turbine. This configuration avoids the need for a heat transfer fluid and cooling water. Stirling dish systems require the sun to be tracked in two axes,

Figure 6.1: Installed costs and capacity factors of CSP projects by their quantity of storage



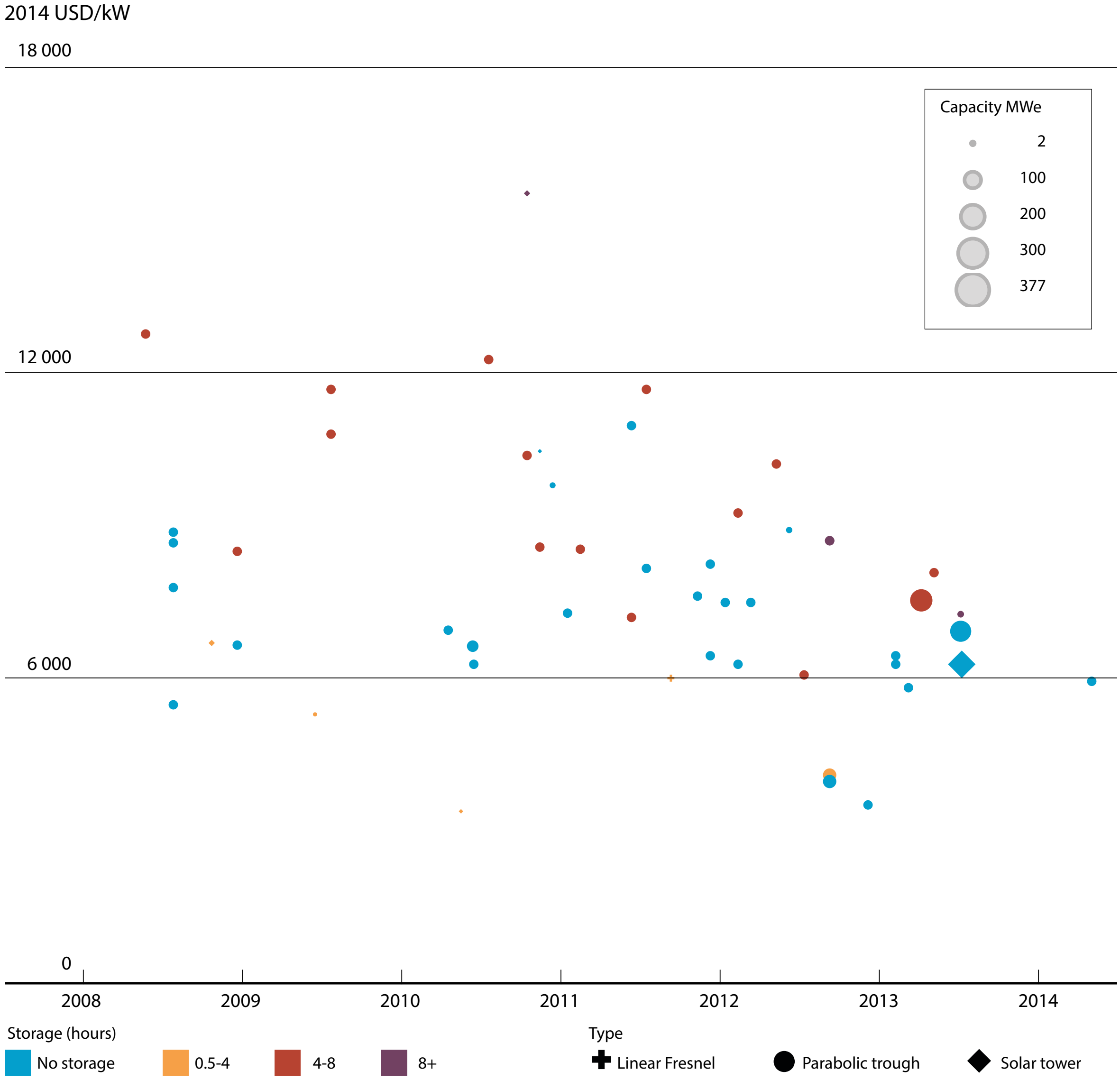
Sources: IRENA Renewable Cost Database; BNEF, 2014e; GlobalData, 2014; and NREL/SolarPACES, 2014.

but the high energy concentration onto a single point can yield very high temperatures, helping to improve efficiency. Their advantages are their very modular nature, which allows for small-scale systems (10s of kW), the fact that they can be used on broken or sloped terrain and their very low water requirements. Their disadvantages are they are expensive relative to other CSP technologies and not dispatchable. Stirling dish systems are just beginning to be deployed at scale, with a 1 megawatt (MW) system at the Maricopa plant in Arizona, and a 1.5 MW system under construction in Utah, both in the United States.

CSP capital costs

Despite around 15 solar tower projects or more in operation, the current CSP market is dominated by PTC technologies, both in terms of number of projects and total installed capacity (around 85% of capacity). PTC technology's share of total installed capacity will decline slowly in the near future, as around one-third of the capacity of plants currently under construction are either solar tower projects or linear Fresnel systems (SolarPaces, 2014).

FIGURE 6.2: CSP INSTALLED COSTS BY PROJECT SIZE, COLLECTOR TYPE AND AMOUNT OF STORAGE; 2009 TO 2014



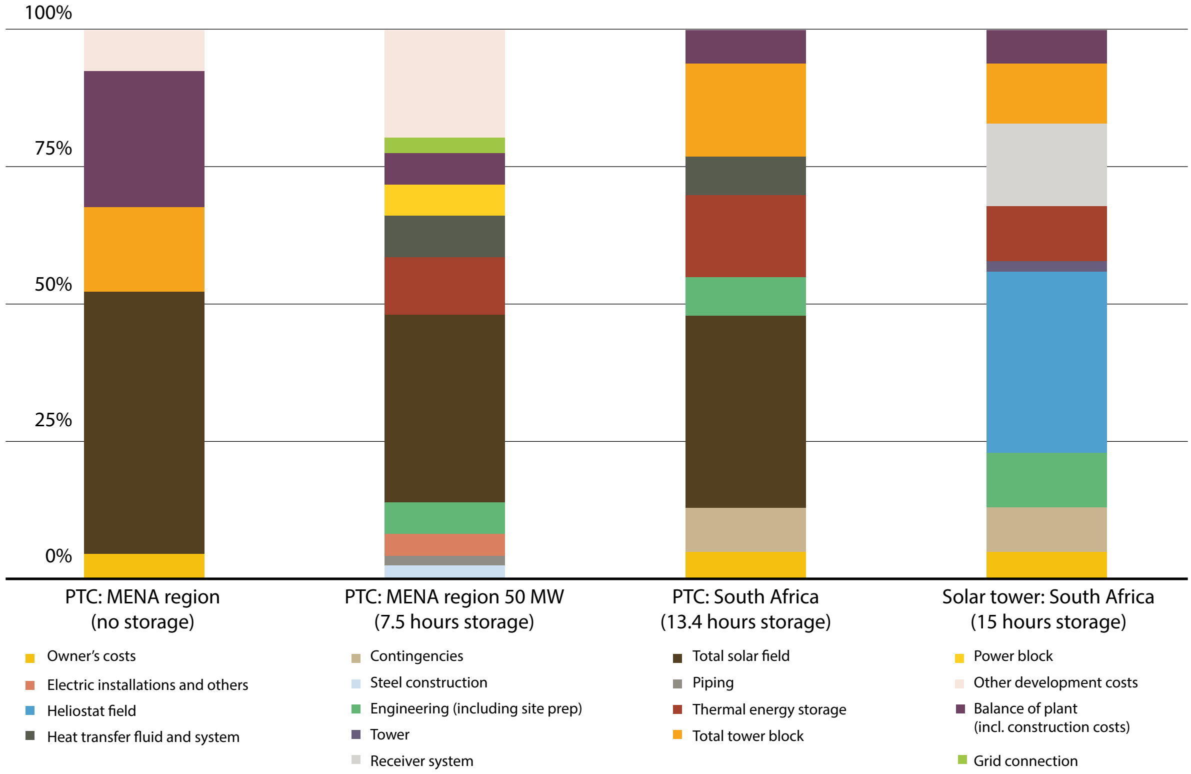
Sources: IRENA Renewable Cost Database; BNEF, 2014e; GlobalData, 2014; and NREL/SolarPACES, 2014.

The current situation means that, although solar towers are a very promising avenue for reducing the LCOE of CSP plants, most of the available operating experience and cost information refers to PTC systems. Limited cost data for solar tower systems at this early stage of their deployment means that it is difficult to draw robust conclusions about what their cost structure may look like once their deployment accelerates.

The current situation for PTC plants is somewhat clearer and current investment costs for PTC plants without storage in the OECD countries are typically between USD 4 600 and USD 8 000/kW, which compares reasonably closely with bottom-up, engineering cost estimates presented in Table 6.2.[25] PTC plants without storage in non-OECD countries have been able to achieve a lower cost structure, with capital costs between USD 3 500/kW and USD 7 300/kW. Current expectations are that, with experience and scale-up, notably in India, the installed cost could be reduced to as little as USD 3 100/kW (German CSP Association, 2014) for the next series of PTC plants without storage to come online.

[25] *This is a typical range, although three plants in the IRENA Renewable Cost Database have experienced higher costs – around USD 8 700 to USD 8 900/kW for two and USD 11 000/kW for one project. However, these are not representative projects and have therefore been excluded.*

Figure 6.3: Indicative breakdown of CSP installed costs by technology and amount of storage



Sources: IRENA Renewable Cost Database; Ernst & Young, ISE and ISI, 2011; and Fichtner, 2010.

CSP plants with thermal energy storage tend to have higher investment costs, but they allow higher capacity factors (Figure 6.1), dispatchability and typically lower LCOEs (particularly for molten salt solar towers). They also have the ability to shift generation to when the sun is not shining and/or the ability to maximise generation at peak demand times. There are a small number of PTC, linear Fresnel and solar tower projects around the world with modest storage capacity of between 0.5 and 4 hours. These plants have estimated installed capital costs of between USD 3 400 and USD 6 700/kW, but the small sample size (four plants) relative to the total number of projects in the IRENA Renewable Cost Database doesn't allow any firm conclusions about why this range is narrower than for PTC plants without storage. Given that few plants with these small levels of storage are ever likely to be built, the reasons may not become clearer, but at the same time the implications are less important if, as expected, CSP plants with more thermal energy storage become the norm.

The costs of PTC and solar tower plants with thermal energy storage of between 4 and 8 hours are typically between USD 6 800 and USD 12 800/kW for projects for which data are available. This cost range is wider than the bottom-up engineering estimates obtained from the available literature (Table 6.2) of between USD 6 400 and USD 10 000/kW. There is a slight downward trend in the installed costs for plants with 4 to 8 hours of storage over time, but with so few data points this is not statistically significant (Figure 6.2). A similar problem exists for the costs of projects with greater than 8 hours of storage, where first-of-a-kind commercial projects are only just now being deployed. Bottom-up engineering cost estimates suggest a range of around USD 7 600 to USD 10 700/kW. Two of the projects for which IRENA has data fall within this range. The third project – the Gemasolar solar tower project in Spain – was a first-of-a-kind solar tower project using high-temperature molten salt with a record-breaking 15 hours of storage (NREL/SolarPACES, 2014). This project broke new ground in CSP development and has provided invaluable technology insights and operating experience that will benefit future solar tower developments; however, it can't be considered representative from a cost perspective.

The total installed costs per kW of CSP plants since 2011 have been trending downwards as more industry experience has been gained. The scaling-up of plant sizes and a more challenging economic environment (including reductions in support measures) have seen installed costs for more recent projects trend lower than in the past. The limited data available suggest that caution should be applied in drawing any firm conclusions that cost reductions are becoming more generalised as the deployment of CSP grows, but the initial signs are very encouraging.

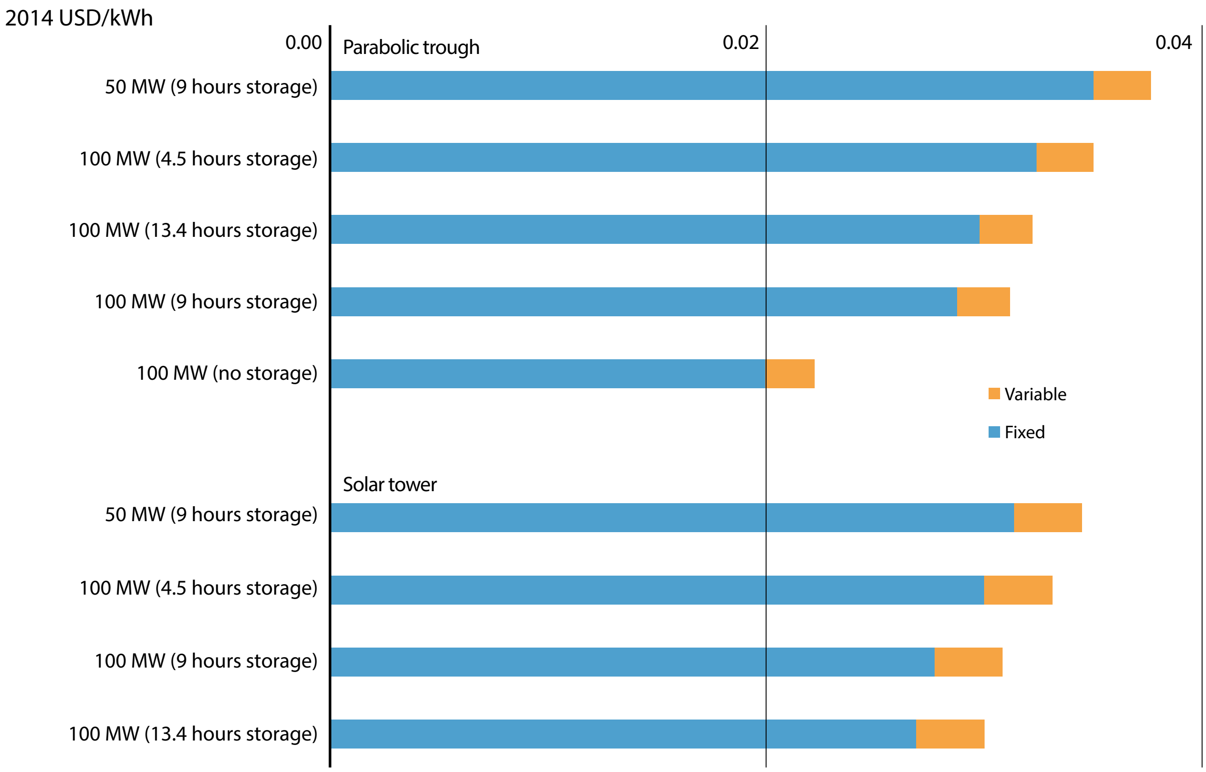
A summary of the breakdown of the capital costs for three parabolic trough plants and one solar tower plant is presented in Figure 6.3. The PTC and solar tower plants in South Africa have very similar total capital investments – USD 914 million for the parabolic trough system and USD 978 million for the solar tower system. The capital costs for the

Table 6.3: Total installed equipment cost breakdown for a PTC plant without storage in the Middle East and North Africa region

	Share (%)
Civil and Structural	**5**
Solar field preparation and other solar field civil work	1
Solar collector pylon foundations	2
Power block and balance of plant structures	2
Solar Field	**64**
Heat collection elements (HCE)	10
Reflectors	14
Metal support structures	20
Drives, electronic and controls	2
Heat transfer fluid (HTF) piping between collectors	1
HTF header piping	2
HTF fluid initial filling	3
Transport, erection and commissioning	11
Heat transfer fluid system, including solar heat exchangers	**9**
HTF heat exchangers and tanks	5
HTF pumps	2
Transport, erection and commissioning	2
Power Block	**23**
Steam turbine generators	7
Cooling system including condenser	7
Fuel gas system including back-up	1
Balance of plant	1
Wastewater treatment	0
Fire protection	1
Electrical and installation	4
Transport, erection & commissioning and other	2
Total	**100**

Source: IRENA Renewable Cost Database
Note: Some totals may not add up, due to rounding.

Figure 6.4: Operations and maintenance costs for parabolic trough and solar tower CSP plants



Sources: IRENA Renewable Cost Database and Fichtner, 2010.

solar field and receiver system represent a larger percentage of the total costs in solar tower systems than in PTC systems. This is because the solar tower project requires a larger solar field (solar multiple) in order to provide the heat for the larger storage system (15 hours) than was proposed for the PTC plant (13.4 hours). In contrast, because of the improved efficiency of the thermal energy storage system as a result of higher operating temperatures in the solar tower, the share of costs for the thermal energy storage system are lower in the solar tower plant. The total costs of CSP plants without thermal energy storage are dominated by the costs associated with the solar fields.

A detailed breakdown of the total installed equipment costs for a PTC plant is presented in Table 6.3. Within the solar field costs, which dominate the total, the metal support structures alone account for one-fifth of total installed costs and almost a third of the solar field costs. The reflectors, transportation to site, erection and commissioning, and the heat collection receivers each account for 10% or more of total equipment costs. After the solar field, it is the power block that accounts for the largest share of the total installed equipment costs.

In addition to their potential higher operating temperatures and improved efficiency for power generation and thermal energy storage, solar towers may offer greater economies of scale in the longer term. However, for current plants, both PTC and solar tower systems appear to offer economies of scale of around 10% when shifting from a 50 MW scale plant to a 100 MW scale plant (Fichtner, 2010). The breakdown of this reduction differs, with the 100 MW PTC plant having higher specific costs for the solar field and proportionately larger savings in specific costs for the other cost components than a solar tower plant.

Operations and maintenance costs for CSP plants

Virtually no data are available in the public domain on the actual operations and maintenance (O&M) costs of recently built CSP plants. However, a detailed assessment of the O&M costs of the pioneering Californian "Solar Electricity Generating

System" (SEGS) plants that were built between 1982 and 1990 estimated their O&M costs to be USD 0.04/kWh. One of the largest areas of expenditure was found to be the replacement of receivers and mirrors as a result of glass breakage (Cohen, 1999). Materials advances and new designs have helped to reduce the failure rate for receivers, but mirror breakage is still an important cost component. The cost of mirror washing, including water costs, is also significant. Plant insurance can also be a large expense and its annual cost can be between 0.5% and 1% of the initial capital cost, with even higher costs possible in particularly unsecure locations.[26]

The O&M costs of the recent CSP plants built in Spain, the United States and elsewhere are estimated to be lower than those of the Californian SEGS plants. Technology improvements have reduced the requirement to replace mirrors and receivers, while increased automation has reduced the cost of other maintenance procedures by as much as 30%. As a result, bottom-up engineering estimates of today's maintenance costs for a parabolic trough system in the United States are around USD 0.015/kWh, which comprises fixed costs of USD 70/kW/year and around USD 0.003/kWh in variable costs (Turchi, 2010b). For solar towers these costs are estimated at around USD 65/kW/year for the fixed costs (Turchi, 2010a). However, these estimates exclude insurance (typically 0.5% to 1% of total capital costs per year) and other potential costs also reported in total O&M cost estimates, so care should be taken in interpreting these values. Taking these points into consideration, the range of USD 0.02 to USD 0.04/kWh seems a robust estimate of the total O&M costs, including all other miscellaneous costs, but costs will vary significantly by plant size.

Two proposed PTC and solar tower projects in South Africa have estimated O&M costs (including insurance) of between USD 0.03 and USD 0.035/kWh for a 100 MW plant. A smaller 50 MW plant would have O&M costs of 7% higher for the PTC plant and 5% higher for the solar tower project (Fichtner, 2010). Parabolic trough systems and solar tower plants benefit from 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 of storage, although adding more storage does not yield any further significant reductions and even increases the O&M costs in the case of the parabolic trough plant.

Overall, given recent experience and as a result of improved O&M procedures, in the long run it should be possible to reduce total O&M costs of CSP plants to USD 0.025/kWh or less, even in OECD countries.

Capacity factors of CSP plants

Although the global solar resource is distributed widely, CSP technologies require large quantities (>5 kWh/m^2/day) of direct normal irradiance (DNI) in order to function and be economic. This is in contrast to solar photovoltaic technologies, which can also operate on diffuse or scattered irradiance as well. This reduces the number of regions where CSP can be used, or at least reduces their economic attractiveness. However, as already discussed, the advantages of CSP mean that it still has an important role to play.

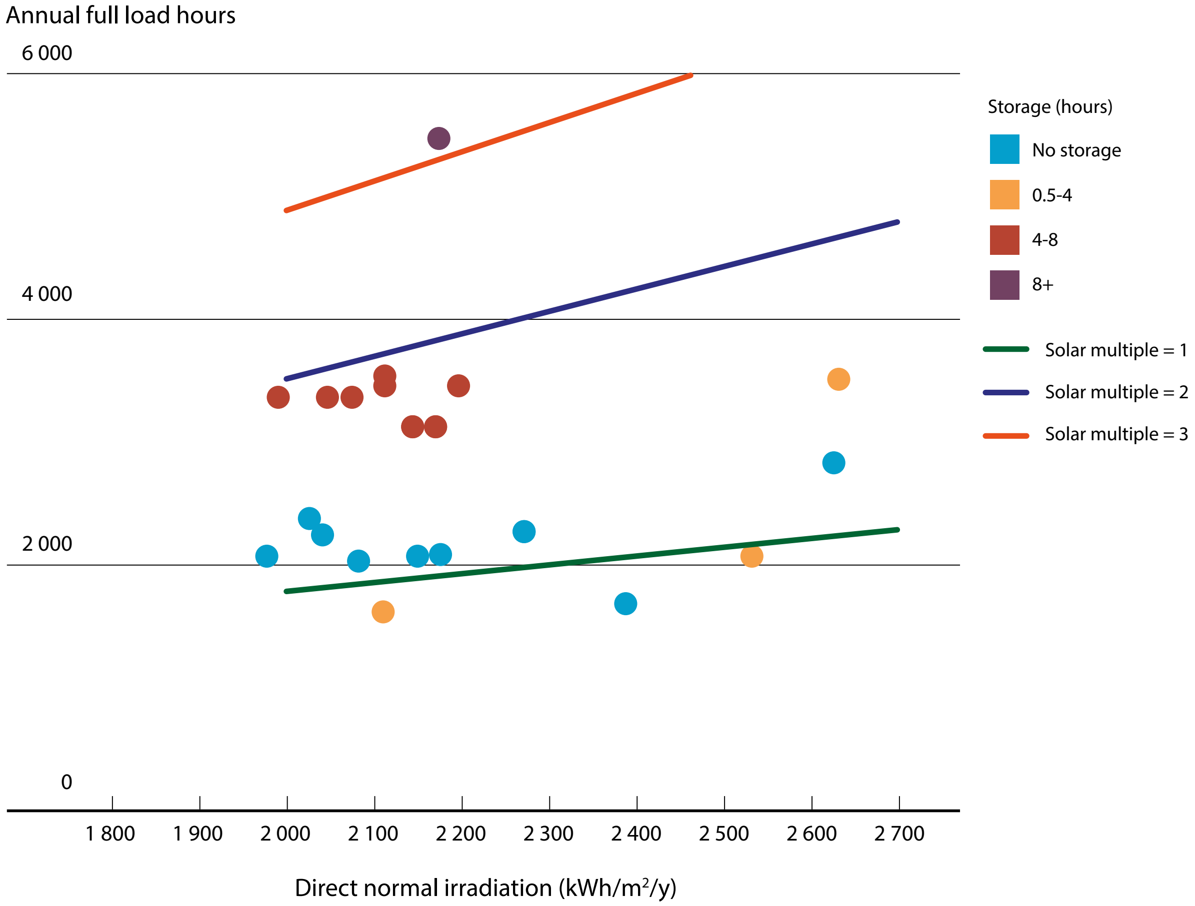
The generation potential of a solar CSP plant – and its competitiveness – are largely determined by the prevailing DNI. This depends on average meteorological conditions over a year. However, on any given day, the generation profile will often be strongly influenced by local meteorological factors (e.g. cloud cover, humidity) and local environmental factors (e.g. local air pollution, dust). The incorporation of thermal energy storage helps to smooth out these fluctuations in DNI over the day due to local, transient meteorological factors, and provide a more stable generation pattern or ability to meet peak demands as required.

Another important aspect for CSP is that tracking the sun provides a significantly greater energy yield for a given DNI than using a fixed surface, which is why tracking is so important to CSP plants. Unlike in solar photovoltaic technology, tracking is not merely an option to improve yield, but a necessity.

In theory, the relationship between DNI and energy output – and hence LCOE values – is strong. Sites with higher DNI will yield more energy, allow greater

[26] Local security issues will also raise capital costs slightly, due to the need for more secure enclosures, and will also raise operating costs as additional security personnel will be required.

FIGURE 6.5: FULL LOAD HOURS FOR CSP PROJECTS AS A FUNCTION OF DIRECT NORMAL IRRADIANCE AND STORAGE CAPACITY



Sources: IRENA Renewable Cost Database and Trieb et al., 2009.
Note: Full load hours, direct normal irradiance and storage capacity are individual project data. The solar multiples are generic estimates and not based on individual project data.

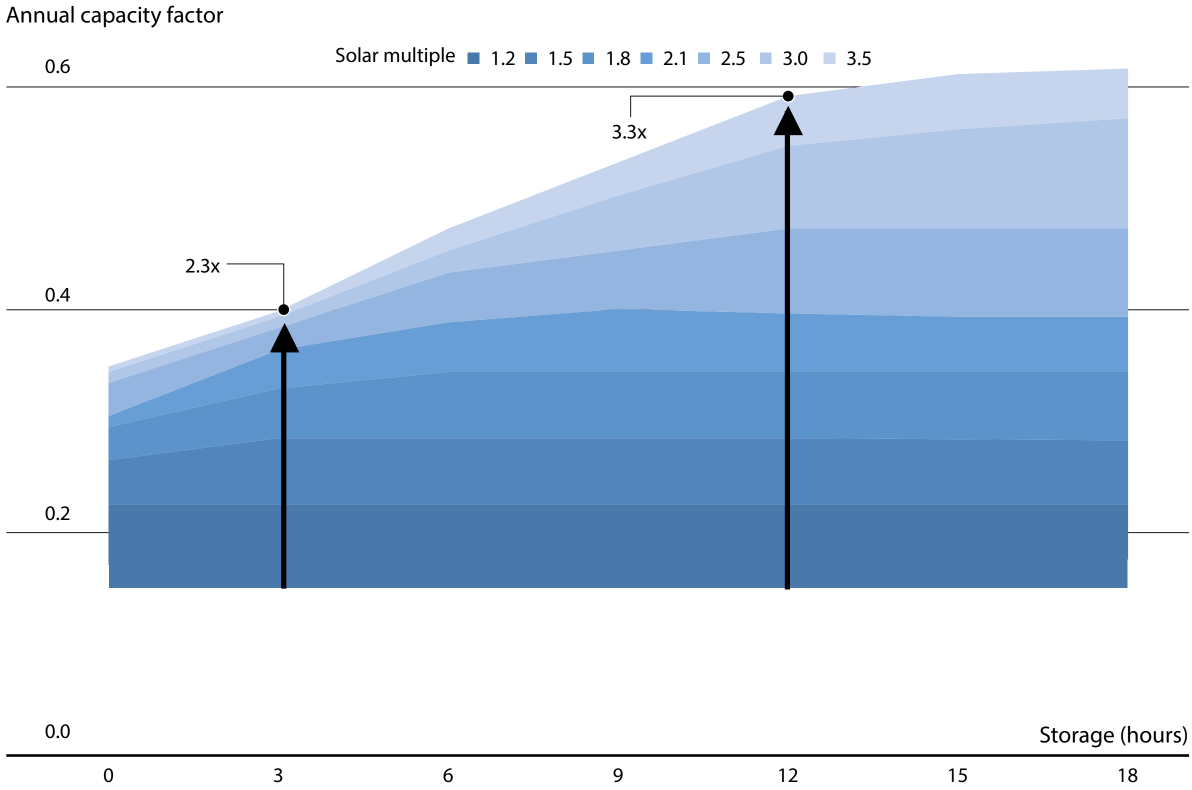
electricity generation and have a correspondingly lower LCOE. High DNI sites yield more electricity for a given solar multiple (the size of the collector field relative to what is required to drive the power block), but also make the concept of higher solar multiples to feed thermal energy stores more attractive.

The practical impact of higher DNI on the LCOE of CSP plants with identical design and capital costs is significant. For instance, the LCOE of identical CSP plants will be around one-quarter lower for 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).

However, given the range of technology solutions and the relatively modest number of projects for which data are available, the empirical evidence suggests that many other variables are in play in the real world that can affect this result. The available data suggest that these factors can predominate over even relatively significant DNI ranges. For plants without storage, there is not enough evidence to conclude whether other factors are dominating over the resource, as the expected positive relationship yield with a solar multiple of one is modest (Figure 6.5).

However, for plants with significant amounts of storage (4 to 8 hours) and larger solar multiples, a stronger positive expected relationship exists. The limited data, although not sufficiently numerous to prove statistically relevant, suggest that, for this early stage of deployment of CSP, differences in technologies, design solutions, actual solar multiples, operation and local meteorological conditions can negate the expected positive relationship between DNI and capacity factor over a significant DNI range (e.g. between 1 950 and 2 200 kWh/m^2/year). Given that CSP deployment is in its infancy, the expectation is

FIGURE 6.6: CAPACITY FACTOR FOR A 100 MW PTC PLANT AS A FUNCTION OF SOLAR MULTIPLE AND THERMAL ENERGY STORAGE



Sources: Based on IRENA Renewable Cost Database and Trieb et al., 2009.

that with increased deployment and replication of plant designs in numerous different locations, the positive relationship between DNI and output will emerge.[27]

Figure 6.6 shows the relationship between capacity factor and thermal energy storage in hours (h) for different solar multiples in regions with a good solar resource. Increasing the solar multiple (e.g. having a larger solar field relative to the power block capacity) will significantly increase solar field costs and introduce thermal energy storage system costs if going from a design with no storage. An important consideration, therefore, is the likely yield for the additional investment. The analysis in Figure 6.6 suggests that the relative increase in output when moving from lower solar multiples to higher ones is significantly larger as the size of storage is increased. The decision about what solar multiple and level of storage to develop for a given plant will depend on the additional costs of expanding the solar field and the cost of thermal energy storage, relative to the additional value unlocked by the greater ability to schedule dispatch in peak periods.

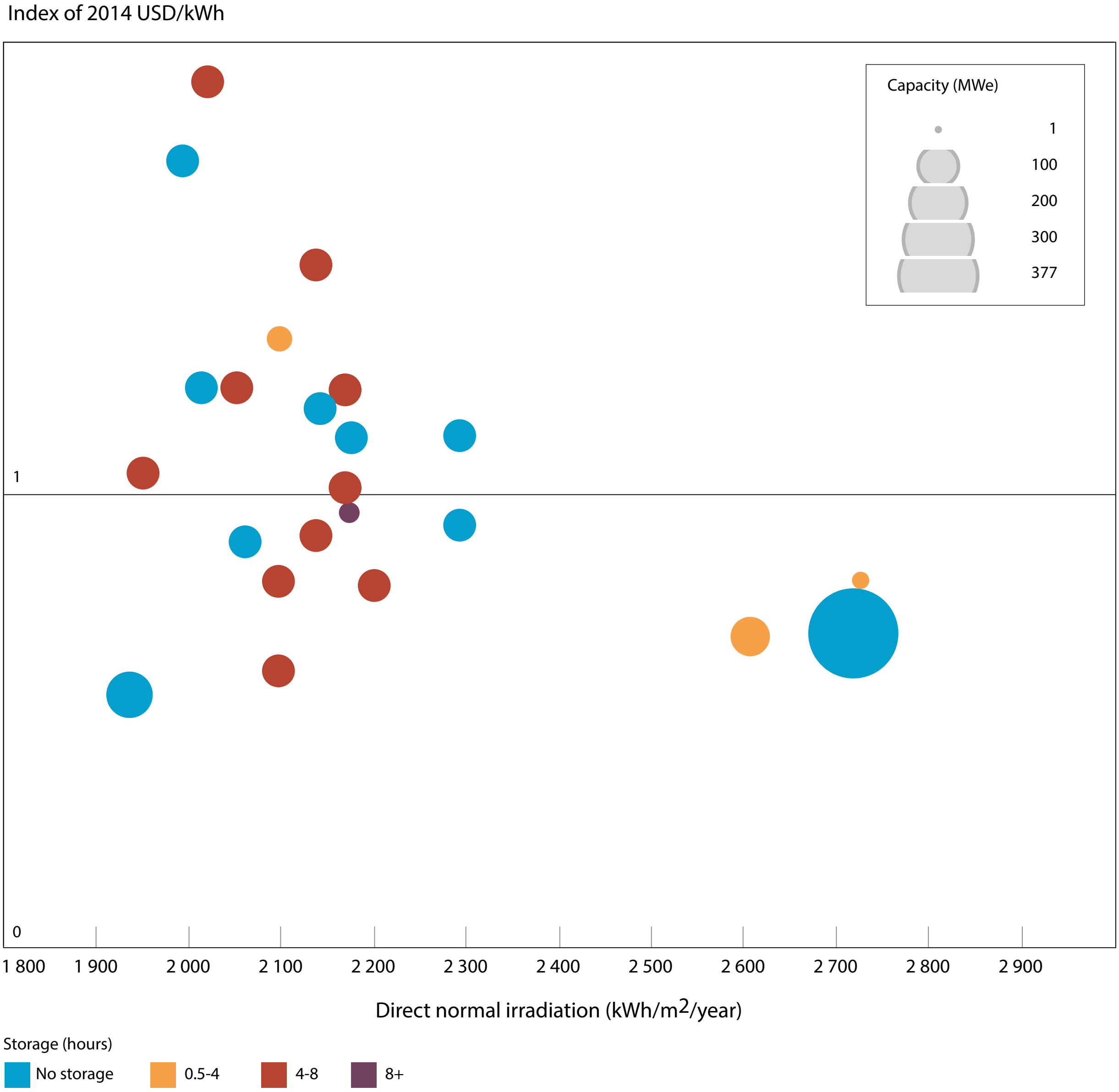
[27] *Additional data on the technical specifications of the existing plants would be needed in order to come to a conclusion about the exact reasons for the current distribution of capacity factors at different DNI levels and is beyond the scope of this report.*

It is important to remember that the calculations for the LCOE of CSP assume that all electricity generated has the same value. However, this is not the case, so plants with higher storage levels are likely to provide more flexibility to capture the increased value of peak prices. For instance, CSP with thermal energy storage has been estimated to provide between 26% and 41% more value when added to a model of the Colorado and Wyoming electricity system than a "flat block" of power generation (Denholm and Hummon, 2012).

THE LEVELISED COST OF ELECTRICITY OF CSP

CSP is at the beginning of its commercial deployment in terms of installed capacity, with only wave and ocean technologies having less installed capacity. The costs of CSP plants are therefore expected to come down and their performance is expected to improve as the industry scales

Figure 6.7: Index of the levelised cost of electricity as a function of direct normal irradiance for a range of CSP projects



Source: IRENA Renewable Cost Database.

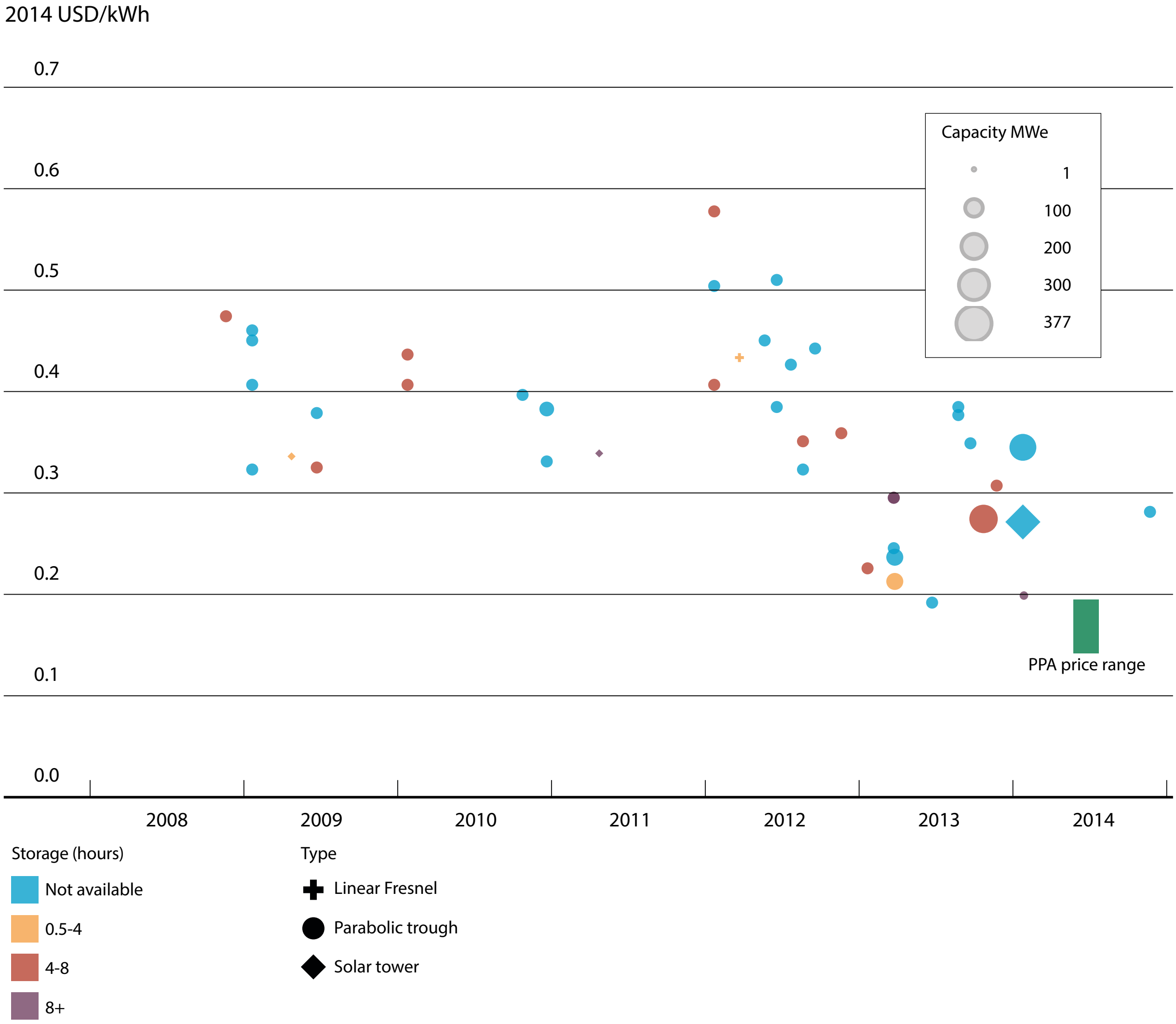
up, operating experience improves, technology improvements are deployed and a larger and more competitive supply chain develops, both locally and globally.

The key assumptions behind the LCOE costs not otherwise discussed in this chapter are the economic life of the plant and the weighted average cost of capital (WACC). All the calculations in this section assume a 25-year economic life and a WACC of 7.5% in OECD countries and China, and 10% elsewhere unless otherwise stated.

Although capacity factors did not exhibit a strong correlation relative to the solar DNI resource, this is not the case for the LCOE. For the limited subset of projects in the IRENA Renewable Cost Database for which complete data exist, there is the expected correlation between the DNI and project LCOE for plants without storage (Figure 6.7). Care needs to be taken in coming to any firm conclusions given the limited data available and the fact that not enough technical data are available to control for design characteristics other than project size and storage.

The evolution of the LCOE between 2008 and 2014 is presented in Figure 6.8. There was little change in the LCOE range for CSP projects between 2008 and 2012, although the range widened and

Figure 6.8: The levelised cost of electricity for CSP projects, 2008 to 2014



Source: IRENA Renewable Cost Database.

grew somewhat with the burst in growth in 2012. Between 2012 and 2014, the LCOE of the projects in the IRENA Renewable Cost Database and other sources has trended downwards. The LCOE for recent parabolic trough plants without storage is in the range of USD 0.19/kWh to USD 0.38/kWh. Adding storage narrows this range to USD 0.20 to USD 0.36/kWh. The fact that recent power purchase agreement (PPA) prices where no direct subsidies are supplied have been between USD 0.14 to 0.19/kWh suggests that government guarantees and development financing have been able to reduce financing costs for some CSP plants to below a 7.5% WACC.

With few data points available for large-scale solar towers, current estimates of project LCOEs fall within the expected range from bottom-up engineering estimates (Figure 6.8).