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Chapter 4 Solar Thermal Energy

Chapter 4. Enabling Technologies: Solar Thermal Energy

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Executive Summary

Technology Overview and Features

Concentrating solar power (CSP) systems use focusing mirrors to capture and store solar energy in the form of heat. The stored heat, at temperatures approaching 600°C, can be released as needed and used to power a steam turbine for the dispatchable supply of renewable energy. As such, CSP complements inflexible renewables such as wind and photovoltaics, and offers an alternative to electricity storage systems such as batteries or pumped hydro storage.

The levelised cost of commercial CSP systems built in 2018 was USD 0.00185/kWhe, all of which had at least 4 hours and some had more than 8 hours of thermal energy storage. Costs are trending downward with a learning rate around 20%. Total global deployed capacity in 2018 was 5.48 GWe.

Optimal locations for CSP include Chile, southern Africa, north-western Australia, northern Africa, the Middle East, south-western North America and inland China.

Studies of 100% renewable energy scenarios indicate that it may be optimal to source 10–15% of electricity generation from CSP, with CSP playing the role of providing night-time electricity and adding robustness when a large fraction of generation is inflexible.

Important non-electricity applications of CSP are being developed, including water desalination and greenhouse horticulture. In the future, industrial production of fuels, reduced metals, lime, cement and ammonia may employ CSP as a source of high-temperature process heat.

Low-temperature solar thermal systems are used for small solar domestic hot water systems as well as in agriculture, mining, textiles and district heating.

Sustainable Development and Climate Adaptation Co-Benefits

In future decarbonised electricity networks and in some regions, CSP may become the primary source of night-time electricity, due to its low-cost high-capacity energy storage.

Compared to wet-cooled coal power stations, CSP plants today use only 10% of the water on a per-electricity-generated basis. Technologies are in development to drive water use further towards zero.

In arid regions, CSP can be used for the provision of desalinated seawater.

Process heat from CSP may be important in global efforts to decarbonise high-temperature and fossil-fuel-intensive industrial processes.

Concentrating solar power provides a long-term electricity supply with very low ongoing costs, bringing benefits in relation to energy autonomy and regional stability. CSP systems can be built with relatively high fractions of local content, and may be beneficial in national industrialisation, self-sufficiency and development efforts.

Low-temperature solar thermal collectors offer a relatively low-tech pathway to the reduction of emissions in developing areas.

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4.1 Introduction

Solar thermal technology provides a wide range of opportunities for climate-resilient global development. High-temperature concentrating solar thermal power (CSP) systems are used to generate flexible, dispatchable renewable electricity in large-scale grid-connected systems and could also soon be used as a heat source for industrial processes such as for desalinated water, fuels, chemical products and refined ores. Most CSP electricity systems include thermal energy storage units, allowing output to continue for hours after sunset. Solar thermal systems, which rely on heating up a working medium to operate, are distinct from solar photovoltaic (PV) technologies that directly convert solar photons into electric current. In addition to CSP, low-temperature solar thermal systems, used for domestic hot water and other applications, are briefly reviewed.

4.2 Concentrated Solar Thermal Energy

4.2.1 High-Level Description of CSP Systems

Concentrating solar thermal power systems work by focusing direct-beam solar radiation (sunlight) onto a receiver surface, where the heat is absorbed. The absorbed heat is transferred to a heat transfer medium (HTM), such as mineral oil, molten salt, water, or ceramic particles. The heat is transported via the HTM to the next part of the system, typically a thermal energy storage tank, and then typically used to drive a steam turbine power cycle where the heat is converted into electricity.

The light-focusing part of a CSP system, known as the collector or concentrator, is normally composed of curved or parabolic mirrors. These collectors are referred to as heliostats, troughs, dishes or linear Fresnel reflectors (LFRs) depending on the system type (described in §4.2.2). The mirrors need to be of high optical quality and also oriented with sufficient precision as the sun moves, so that the solar radiation can be focused onto a small receiver surface without excessive losses. Tracking systems are needed to ensure that light is continuously reflected onto the receiver as the sun moves. Solar radiation cannot be concentrated past certain optical and thermodynamic limits, dictated primarily by the angular size of the sun in the sky (Lovegrove and Pye 2012).

At the absorbing surface of the receiver, some of the energy will be lost by reflection. Then, as the absorbing surface becomes hot, further energy loss occurs due to re-radiation from the hot surface, and also due to convective air flows on the exterior surfaces. All three of these losses—reflection, re-radiation and convection—are proportional to the area of the receiver opening (the ‘aperture’), and hence the efficiency of the system overall can be increased if the concentration of light is as high as possible. Energy not lost by any of these mechanisms is transferred as heat to the HTM, which is then circulated out of the receiver and onward, typically to a thermal energy storage system.

Concentrating solar power systems usually include thermal energy storage capacity, in order to allow the supply of electricity to be matched to the demand. This storage typically involves two tanks containing an energy storage medium (ESM), usually a molten salt material. To ‘charge’ the storage, the ESM from the ‘cold’ tank is heated up inside a heat exchanger using the hot HTM from the receiver, and then pumped into the ‘hot’ tank. The typical molten salt ESM temperature range is from 290°C (‘cold’) to 565°C (‘hot’). To discharge the storage, the hot tank ESM is transferred through another heat exchanger in which water is boiled under pressure. The resulting steam is then passed to the steam turbine, and the ‘cold’ ESM is returned to the cold storage tank.

Power cycles in general, as well as steam turbine power cycles in particular, are more efficient when they have a higher temperature heat input. A simple steam power cycle includes a turbine, condenser, pump and boiler. In the CSP case, the boiler is provided by a heat exchanger connected to the thermal energy storage unit. Higher-efficiency power cycles are more complex, and typically include additional heat exchangers and turbine stages.

The above descriptions are reasonably general, but there are many variations in the types of CSP systems, both constructed and in development. For example, in many systems, the ESM and the HTM are the same medium, molten salt, which means that no heat exchanger is required to charge the storage tank. Not all systems provide storage, and in some cases the HTM in the receiver is water, which is directly transferred into the steam turbine. Other systems use a power cycle based on a gaseous working fluid (such as the Brayton cycle or Stirling cycle of a steam turbine), and there is no water involved. Yet other systems make use of melting/freezing or chemical reactions in the HTM or ESM, instead of simple sensible[1] heating and cooling, as a way to transfer and stored energy efficiently. Finally, CSP systems are sometimes hybridised with other conventional power systems, such as coal or gas power stations, allowing continuous or near-continuous supply of power.

The CSP systems described above are all used to produce electricity. However, a growing area of interest for CSP is in the provision of heat for other chemical and industrial processes (see §4.2.8).

Energy-intensive products that can be produced using CSP include liquid fuels, hydrogen, ammonia, zinc, iron/steel and cement, with processes for these and others under ongoing development.

FIGURE 4.1 HERE

Figure 4.1. Direct normal irradiance (DNI, kWh/m²y) at sites around the world. Optimal locations for CSP are Chile/Bolivia/Argentina, Australia, South Africa/Namibia and USA/Mexico. Other excellent locations include Spain, India, China, Morocco and Israel.

Source: DNI Solar Map © 2016 Solargis

4.2.1.1 Factors Determining CSP System Performance

Performance of a CSP system depends on direct normal irradiance (DNI), since only a direct beam (as opposed to diffuse radiation) can be focused using mirrors. A global map of the annual DNI is given in Figure 4.1, highlighting the excellent solar resource in many mid-latitude regions (red-purple). Around the equator, higher cloudiness reduces the annual DNI.

As with other power plants, the size of CSP systems is typically reported in terms of *nominal capacity* (also referred to as nameplate or rated capacity). This is the electrical power output when the plant is operating at full-speed design point conditions. The nominal capacity of a CSP plant is mostly constrained by the scale of the power block (turbine and generator). A representative range for the nominal capacity of CSP plants would be[2] 10–250 MWe.

The *capacity factor* of a CSP system is the ratio of the total energy generated by the power block over the course of the year, divided by the amount of power it could have produced had it been running at its nominal capacity for the whole time. A CSP system without any storage, similar to non-tracking PV, has a capacity factor of 20–25% (Branker et al. 2011; Romero and González-Aguilar 2014), which reflects the fact that there are only an average of 6 hours of sunlight each day, once seasonal variations

[1] 'Sensible' (as opposed to 'latent') heating is that which causes a detectable temperature rise, with no phase change.

[2] Nominal capacity is often written with units MWe—megawatts electrical. This is to differentiate from megawatts thermal (MWth), which would be used to refer to the rated capacity of, for example, a receiver or a boiler.

in day length as well as cloudy weather are accounted for. However, higher capacity factors for CSP up to 74% have been achieved through the addition of thermal energy storage (Romero and González-Aguilar 2014). A high overall capacity factor indicates a more cost-effective use of the power block, but this can only be achieved with the addition of storage and a larger collector area, which must be paid for in order to increase the capacity factor of the power block. The capacity factor can also be increased by oversizing the solar collector (see below), or by hybridising the CSP system so that the power block can also be operating using an alternative heat source, such as a gas-fired boiler. The annual output of the plant (expressed as megawatt-hours or gigawatt-hours per year: MWh/y or GWh/y) can then be obtained as the product of the nominal capacity (MW), the capacity factor, and the number of hours in a year.

FIGURE 4.2 HERE

Figure 4.2. Cosine efficiency of a heliostat describes whether mirrors face directly to the sun, presenting a large effective surface area, or whether they are oblique to the sun, presenting a relatively small effective area. Systems with high average cosine efficiency across their entire collector field throughout the year will require less total mirror area.

Source: Power from the Sun.

The size of the thermal energy storage in the CSP plant is normally communicated in terms of the numbers of hours of storage that the energy contained in the storage can run the power block at its nominal capacity. Storage systems as small as 30 minutes can be useful in improving system performance, since they allow the power block to continue operating through periods of patchy cloud. Storage of 3–6 hours allows a CSP system to preferentially target high-value evening demand, after sunset. Storage of approximately 15 hours allows the power block to be run continuously in summer months (Romero and González-Aguilar 2014) and delivers the lowest levelised cost of energy (see §4.2.1.2). Storage of more than 15 hours is technically easy to achieve, however does not yet appear to be valued sufficiently highly for deployment in commercial CSP projects.

The *field efficiency* of CSP systems is the ratio of the thermal output divided by the product of the DNI and the total mirror area. A major factor within the field efficiency is the *cosine efficiency*, which is the ratio of the effective mirror area of the solar field to the total mirror area, as shown in Figure 4.2. The field efficiency varies greatly as the sun moves daily and seasonally, and the main cause is cosine efficiency, which averages ~85% for most commercial system types. Other factors that affect the optical efficiency of a CSP system are mirror reflectivity losses, blocking, shading, atmospheric scattering, spillage and receiver reflection losses. Thermal losses that contribute to reducing the field efficiency include convection and re-radiation from the hot receiver surface, and heat loss in the pipework that conveys the HTM to the storage or power block.

The *solar multiple* is the ratio of the thermal energy rate delivered by the solar field at its design point (typically at solar noon in mid-summer or at equinox, in clear-sky conditions) to the thermal energy rate required in order to supply the power block at its nominal capacity. A solar multiple greater than one is typical, and (for a non-storage system) means that there will often be more power collected than can immediately be used in the power block. It is usually cost-effective to have a solar multiple of 1.2 or 1.3 for non-storage systems, even though that implies some 'dumping' of heat during peak conditions. For systems with storage, the solar multiple can be as high as 4.0, so that enough energy is gathered during the 6 hours of direct sunlight to run the power block for up to the full 24 hours of each day.

As mentioned above, the capacity factor can be increased not only by adding storage but also by hybridising the plant with other heat sources such as natural gas burners. The *solar fraction* is the ratio of solar thermal heat input at the absorber to the total of all heat inputs to the plant. It typically is measured as an average over a day or year. An example of a system with a solar fraction of 100% is the Crescent Dunes system in Nevada, USA. The Ain Beni Mathar plant in Morocco, on the other hand, is a large 472 MWe natural gas combined-cycle power plant with a relatively small solar field offsetting some gas consumption, with a solar fraction of 1.2% (World Bank 2014). The numerous Spanish CSP plants are mostly operated under rules that specify a minimum solar fraction of 85%.

The *power block efficiency* is the efficiency with which the thermal energy supplied to the power block is converted into electrical energy output. Values of 30–40% are typical. Systems with a higher inlet temperature will be more efficient, due to the second law of thermodynamics. Systems with a larger nominal capacity tend to be more efficient, because larger systems can cost-effectively incorporate more energy-saving features such as recuperators and feed-water heaters.

Because of seasonal variations in weather and the path of the sun through the sky, the performance of a CSP plant changes considerably throughout the year. For this reason, simulation of at least one full year of operation of the plant is essential in order to develop (or prove) an optimal system design. Annual performance calculations are made using weather data for the location in question, as well as simplified numerical models for each of the components in the system. Using such models, the combination of storage, power block, receiver and collector can be determined which gives the greatest return on investment.

4.2.1.2 The Levelised Cost of Energy (LCOE)

The levelised cost of energy (LCOE), for CSP as with other energy technologies, is the fixed price at which the generated energy must be sold over the lifetime of the plant in order for all capital and operational costs to be recouped, and for the project to thereby achieve a net present value of zero (Richert et al. 2012; Hernández-Moro and Martínez-Duart 2013). A key parameter in determining the levelised cost of energy is the weighted average cost of capital (WACC), also referred to as the discount rate, an aggregate of the financing costs (loan interest rate, investor dividends) for the project. Care must be taken when comparing LCOE values to ensure that similar assumptions for taxes, profit allowance, government subsidies and other incentives, and other costs and benefits are used in the different analyses. Levelised cost of energy is often criticised for being a poor measure of viability, especially for CSP technology, because, being based on a fixed constant sale price for all the generated electricity, it fails to recognise the value-adding opportunity for a CSP system to sell energy strategically when demand is high. A system optimised naively to give lowest LCOE may not always result in the most profitable configuration in real market conditions. This question is discussed further in §4.2.7. To lower the project risk, it is common for CSP plants to sign a power purchase agreement (PPA) with a duration of 20 years or more, to ensure a reliable income for the operational plant. Some discussion of the project benefits of signing a PPA are outlined by Jacobowitz (Jacobowitz and Google 2013). More recently, some project developers have proposed to operate with only a partial PPA, selling a fraction of their electricity into the much more variable but potentially more lucrative spot market.

4.2.2 Types of CSP Systems

Four basic types of CSP systems exist, based on two different ways of concentrating solar radiation (Figure 4.3). Trough and linear Fresnel systems (LFR) are *line-focusing* concentrators, while dish and tower systems are *point-focusing* concentrators. Line-focusing concentrators typically only use single-axis tracking systems, while point-focus systems require two-axis tracking systems. Point-focus systems concentrate their solar radiation onto much smaller spots, allowing these systems to achieve higher temperatures and greater efficiency compared to line-focus systems. However, point-focus systems are more complex in overall design, due to the additional tracking axis required for each reflector component.[3]

The receiver configuration varies for the different system types. Dish and trough systems have a moving receiver which is part of a single integrated tracking structure that also supports the mirrors. Tower and LFR systems have a fixed receiver, which remains stationary while the mirrors move independently. In tower systems, the mirrors are referred to as heliostats. In both cases, the moving-receiver system is more optically efficient (higher cosine efficiency) than the corresponding fixed-receiver system.

There are numerous trade-offs between the different CSP system types. Optical and thermal efficiency, operating temperature, structural cost, wind loads, cost of installation and cost of maintenance are all major factors. Trough systems have been most successful in the market to date, but towers are becoming increasingly commercially competitive. There is no clear winner yet though, and probably the best system type will be found to vary with location. For example, in hazy areas such as the Middle East, systems with a short distance between the mirror and the receiver are likely to perform better, since there will be lower light-scattering losses (atmospheric attenuation). For dish and LFR systems, commercial activity has recently been relatively limited.

4.2.3 Commercial Deployment of CSP Systems

Early development of CSP systems occurred in the 1980s and early 1990s, culminating in nine Solar Energy Generating System (SEGS) trough systems built in California with a total capacity of 354 MWe as well as several prototype-scale tower systems and a wide range of dish systems with a high-efficiency Stirling engine mounted at the focus. From the early 1990s there was a hiatus of 16 years for large system development, associated with (among other things) the gradually increased security of fossil fuel supplies that occurred after the 1979 oil crisis and the 1990 oil price spike.

However, in the mid-2000s, increased concern about anthropogenic climate change and national energy security led to renewed investment in CSP by governments and industry in several countries, especially Spain. The development in Spain was motivated by a Royal Decree mandating a strong feed-in tariff to support the construction of CSP systems up to a 50 MWe size limit. As a result, from 2002, the Spanish have led the world in the development of a new CSP industry, and the plants now operating there have been a net positive contribution to the Spanish economy despite the considerable cost (Ortega et al. 2013). Since the global financial crisis, progress in Spain has unfortunately slowed. In the USA, a policy of investment tax credits resulted in several much larger-scale projects being built there from 2008. Most recently, CSP development has been concentrated in South Africa, Morocco, the UAE, India, Chile and China, where a number of large systems are currently under construction.

As a result of these and numerous other global efforts to develop CSP, the deployment of CSP has grown rapidly, with a compound annual growth rate of 27% from 2008 to 2018, similar to that of PV (41%) and wind (17%) over the same period. A historical plot of the growth in deployed CSP capacity, including this recent growth, is shown in Figure 4.4. A good body of data on operational and in-development CSP systems is maintained in a database by the US National Renewable Energy Laboratory (NREL) and the International Energy Agency (IEA) Solar Power and Chemical Energy

3 One category of point concentrator not covered here is the Fresnel lens. Such concentrators have been used successfully with concentrating photovoltaic (CPV) systems, but have not been commercially adopted for CSP.

Systems (SolarPACES) network, and is the best publicly available resource for tracking CSP projects (NREL n.d.). A selection of some significant recent CSP plants is given in Table 4.1.

FIGURE 4.3 HERE

Figure 4.3. Different CSP system configurations. Top: line-focusing systems, (a) trough and (b) linear Fresnel reflector. Bottom: point-focusing systems, (c) dish and (d) tower system with heliostats.

Source: Romero, M. and Steinfeld, A. (2012).

4.2.4 Current Costs for CSP

It is challenging to obtain a full picture of the current costs of CSP technology. This is because CSP projects are very large commercial projects, and each one is a major investment for the companies involved. As a result, the solar resource, performance, loan terms, capital costs and profit margins for these projects are sensitive commercial information which, if leaked, will affect the market value of those companies, hence companies tend to keep these data secret. This situation is very different especially in the case of PV, where strong competition on price for domestic-scale PV installations have ensured that there is a very good understanding of cost reductions achieved. This section aims to review some of the limited sources of publicly available cost information relating to CSP systems, but it must be emphasised that a serious evaluation of CSP in any given location or market requires detailed analysis of all the local conditions.

FIGURE 4.4 HERE

Figure 4.4. Growth in the CSP sector (log-scale plot), compared to that of PV and wind. Triangles indicate systems known to be under construction/development.

Source: REN21.net, Global Wind Energy Council, CSP Guru, IEA, Bellini 2019.

A previous study which attempts to review all available primary sources on CSP system costs was Hinkley et al. (2013). The primary sources available include a study by Fichtner for the World Bank (Konstantin and Kretschmann 2010; Kulichenko and Wirth 2011), with emphasis on India, Morocco and South Africa, as well a comparative study focused on Australia by Hinkley et al. at CSIRO (the Commonwealth Scientific and Industrial Research Organisation: Hinkley et al. 2011), the tower cost reduction study by Kolb et al. at Sandia (Kolb et al. 2011) and the trough cost reduction study by Turchi et al. (Turchi 2010; Turchi et al. 2010) which incorporates a detailed review by engineering consulting firm Worley Parsons.

Table 4.1. A selection of significant CSP projects from around the world

Name (Type) ***Developer***	**Location**	**Commissioned**	**Nominal Capacity**	**Storage**	**Significance**
SEGS I–IX (trough) Luz Industries	California	1984–1990	354 MWe (total)	mineral oil (SEGS I only)	The first large-scale commercial CSP systems (nine units), now with over 30 years of operational and maintenance experience.

Andasol 1 (oil trough) ACS Cobra	Andalucía, Spain	2008	50 MWe	7.5 hours molten salt	An early beneficiary of the Spanish feed-in tariff, and the first commercial system to use molten salt storage. Now part of a cluster of 3 co-located systems. See Figure 4.5.
Gemasolar (salt tower) SENER/Torresol Energy	Andalucía, Spain	2011	19.9 MWe	15 hours molten salt	First commercial molten salt tower system, and first solar power plant of any type to achieve 24-hour operation. See Figure 4.6.
Archimede (salt trough) ENEL	Sicily, Italy	2010	5 MWe equivalent	8 hours molten salt	The first direct salt-heating trough and first integrated solar combined-cycle system (ISCCS), where solar steam is injected into a fossil-fired combined-cycle power plant.
Ivanpah (steam tower) BrightSource	California, USA	2013	392 MWe	—	Largest tower system in the world, made up of three separate towers and heliostat fields in a single location. No storage.
Solana (trough) *Abengoa*	Arizona, USA	2013	250 MWe	6 hours molten salt	A very large trough system with storage. 2 × 140 MWe (gross) steam turbines.
Khi Solar One (steam tower) Abengoa	Northern Cape, South Africa	2016	50 MWe	2.7 hours saturated steam	Technologically ambitious plant with novel sandwich panel heliostats, dry updraft cooling tower and triple cavity receiver designs. Particularly high value-add in this region due to poor electricity

					infrastructure. See Figure 4.7.
Noor I, II, III (2 × trough, tower) ACWA/Aries/TSK	Ouarzazate, Morocco	2015–2018	143 MWe, 185 MWe, 150 MWe	3, 7 and 7.5 hours molten salt	Together form Ouarzazate Solar Power Station, the world's largest CSP plant at 510 MWe. Financed with loans from World Bank, German bank KfW, European Commission and European Investment Bank.
Jemalong (5 × sodium tower) Vast Solar	NSW, Australia	2019	1.1 MWe	liquid sodium	A demo plant based on modular ~1 MWth tower + field units interconnected with pipework carrying a liquid sodium HTM. See Figure 4.8.
Port Augusta (steam tower) Aalborg/eSolar/Sundrop Farms	Australia	2016	37 MWth	—	A first example of CSP hybridised with greenhouse-based food (tomato) production, providing power for water desalinisation and ventilation. See Figure 4.9.
Miraah (steam trough) Glasspoint	Oman	2017	100 MWth	—	Application of CSP for enhanced oil recovery (EOR) with reduced cost and 80% lower emissions. Troughs are encapsulated in a huge glasshouse to reduce wind loads and soiling. Full project is to be 1021 MWth in scale.
Dunhuang II (salt tower) Beijing Shouhang	Gansu, China	2018	100 MWe	11 hours molten salt	The first >100 MWe tower system in China, and a leader in the new wave of 20+ projects

					currently underway there since 2016.
Dhursar (linear Fresnel) Areva	Rajasthan, India	2014	125 MWe	—	Largest operational linear Fresnel CSP system to date.

Source: GSP Guru, NREL SolarPACES Database

FIGURE 4.5 HERE

Figure 4.5. Andasol 1, a Spanish 50 MWe trough system with molten salt thermal energy storage. Left: aerial view; centre: molten salt storage tanks; right: one of the parabolic trough collectors.

Source:

FIGURE 4.5 HERE

Figure 4.6. Gemasolar, at Fuentes de Andalucía in Spain. This 19.9 MWe system has 15 hours of thermal energy storage, allowing continuous 24-hour operation in summer months.sun

Source: Photo from l'energeek.

FIGURE 4.7 HERE

Figure 4.7. Khi Solar One. Left: 140 m² heliostats; centre: view of solar field, taken from the receiver; right: the tower, incorporating three cavity receivers.

Source: Photo courtesy of John Pye.

FIGURE 4.8 HERE

Figure 4.8. Jemalong Solar Thermal Station (left), developed by Vast Solar in central New South Wales, Australia. This modular system has five 1.25 MWth towers, 30 m high (right), with sodium as the HTM, connected to a single 1.2 MWe steam turbine.

Source: Photos from vastsolar.com.

FIGURE 4.9 HERE

Figure 4.9. Left: the Noor III plant near Ouarzazate, Morocco, has a 250 m high tower and 7400 heliostats, and is co-located with two large parabolic trough plants. Right: Sundrop Farms Port Augusta, a CSP plant installed to provide combined power and desalinated water for a commercial tomato greenhouse in South Australia.

Source: Photo of Noor III courtesy of SENER. Photo of Sundrop Farms courtesy of sundropfarms.com.

FIGURE 4.10 HERE

Figure 4.10. Relative breakdown of total installed costs for 100 MWe plants in South Africa. Left: parabolic trough with 13.4 hours of storage; right: a tower system with 15 hours of storage.

Source: Konstantin and Kretschmann (2010); replotted IRENA 2012.

4.2.4.1 Capital Costs

An indicative relative breakdown of capital costs (total installed costs) for two 100 MWe CSP plants with storage in the range 4.5–15 hours, located in South Africa, is given in Figure 4.10, based on data from a study by Fichtner commissioned by the World Bank (Konstantin and Kretschmann 2010).

A recent study of renewable energy project costs by the International Renewable Energy Agency (IRENA) reports that the global average of the total installed cost for CSP plants completed in 2018 was USD 5200/kWe (kilowatts electrical; IRENA 2019). Such costs vary greatly based on the amount of storage (in 2018, they all had at least 4 hours, and two had more than 8 hours), and are also sensitive to fluctuations in steel and glass prices, local wages, transport and the local solar resource (since the size of the solar field will need to be bigger in areas of lower annual DNI).

Concentrating solar power plants can be developed using a large share of local materials and components. A study by Deloitte commissioned by Protermosolar, the Spanish industry association for CSP, determined that for the plants built in Spain in 2010, over 70% of the total investment costs were domestic purchases (Deloitte 2011). In Africa, the recently operational Noor III plant in Morocco was planned with 35% local content, as a result of a strategy to help advance local industrial development (Moore 2018).

4.2.4.2 Operations and Maintenance (O&M) Costs

For a 100 Mwe trough system in South Africa, Fichtner estimated that the annual operations and maintenance (O&M) costs would vary between USD 15 and USD 18 per year, depending on the size of the storage system (Konstantin and Kretschmann 2010). This is approximately 2.0% of the system total installed costs each year. For the 100 Mwe tower systems in South Africa, the estimate was USD 14–18 per year, again depending on the amount of storage (Konstantin and Kretschmann 2010). This is approximately 1.9% of the system total installed costs each year.

The fractional breakdown of these O&M costs is fairly consistent between these different 100 Mwe systems as analysed by Fichtner. The averaged fractional breakdown in O&M costs, calculated from the Fichtner data, is shown in Figure 4.11.

FIGURE 4.11 HERE

Figure 4.11. An average breakdown of O&M costs for 100 Mwe trough and tower systems in South Africa. Fixed costs (field and storage, power block, personnel and insurance) dominate greatly over the other, variable, costs.

Source: Konstantin and Kretschmann (2010)

4.2.4.3 Financing Costs

Financing of CSP systems typically requires equity investment as well as a significant loan. The interest rate payable on the loan will depend greatly on the assessed risk of the project, and may be of the order of 6–8% per annum. The return required by equity investors will be higher, of the order of 12% per annum. In many locations, it is necessary for governments to provide various incentives such as investment tax credits, depreciation bonuses, carbon credits or others. Loan guarantees can also be a way to reduce the risk to lenders and investors, hence improving the economic feasibility of a project (Mendelsohn et al. 2012). For the most recent CSP projects, it has been suggested favourable financing with a weighted average cost of capital (WACC) as low as 3% must have been obtained (Lilliestam and Pitz-Paal 2018).

FIGURE 4.12 HERE

Figure 4.12. Variation of the LCOE for CSP systems as a function of the annual solar DNI. Estimates of DNI here are only approximate; newer data (see Figure 4.1) shows sites with 3600 kWh/m²y in Chile, and 2900 kWh/m²y in USA, South Africa and Australia.

Source: A.T. Kearney (2010)

In the Fichtner analysis discussed above, variations in carbon credit (USD 0–14 per tonne of carbon dioxide equivalent, or tCO_2e) and overall discount rate (6–8%) have the impact of varying the calculated LCOE in the range USD 0.17–0.22/kWh; these factors strongly affect the overall project feasibility calculation. The more recent report from IRENA gives the latest LCOE achieved in fully completed commercial projects in 2018 as USD 0.185/kWh (IRENA 2019). LCOE can be broken down into the component used to repay investors and lenders and the component used to cover O&M costs. As much as 80% of LCOE derives from amortisation of capital costs, with only 20% attributable to operations and maintenance costs (Pitz-Paal et al. 2005; Hinkley et al. 2013; Slaughter 2014).

4.2.4.4 Further Observations on Cost

Direct Normal Irradiance (DNI): (see Figure 4.1): DNI strongly affects the LCOE of a CSP system. The annual DNI affects the amount of electricity generated by a CSP system without altering the capital or operating cost. For example, high DNI in Chile causes the LCOE to be as much as 30% lower for plant installed there compared to an identical system in Spain (Figure 4.12). Many of the recent plants have been constructed in locations of higher DNI.

***Scale*:** Small CSP systems generally are unable to incorporate a highly efficient power block.[4] This results in the need for more collector area per unit of electrical energy delivered, and increases the LCOE. There is, however, an optimal size for CSP systems. For towers, atmospheric attenuation becomes a significant limitation (Ballestrín and Marzo 2012) and appears to have limited fields to a total collector area of the order of 1.30 km^2 (as in the 150 Mwe Noor III system), since heliostats in that system extend as far as ~1500 m from the receiver. For trough systems, a larger system incurs greater pumping and thermal losses through the larger collector field, and the largest fields to date have had a total collector area of 1.59 km^2 (250 Mwe Solana, Abengoa).

FIGURE 4.13 HERE

Figure 4.13. For a CSP system in any given location, the capacity factor (left) and the LCOE (right) are affected by the storage capacity and the solar multiple (see §4.2.1.1). In this example, the lowest LCOE is achieved with 12 hours storage and a solar multiple of 3.0.

Source: IRENA (2012)

Storage Capacity: The impact of storage capacity on the LCOE of CSP is not simple, because while storage has a major capital cost, it can also increase the capacity factor of the turbine, and reduce the amount of energy lost in turbine ramp-up and ramp-down cycling. When whole systems are optimised for LCOE, quite large storage systems of 12 hours or more are observed (Figure 4.13), with a correspondingly larger solar multiple then required to ensure that the storage capacity is efficiently utilised. This is a very important point: CSP systems with a specified power output typically show a lower LCOE with storage than without.

[4] The main driver here is the efficiency of steam Rankine cycle power blocks at larger scale. Larger power blocks gain large economies of scale due to the cost-effective addition of boiler feed-water heaters and reheat stages. A survey of coal-fired Rankine cycle power blocks in the 1970s showed the cost of power from systems with an average ~2 GWe output being as much as 10% cheaper than that from systems with an average ~200 MWe in size (Christensen and Greene 1976).

Local Wages and Transport Costs: LCOE is affected by variations in wages and transport costs from country to country. In some locations, it is necessary to pay a premium for workers in order for them to travel to the remote arid locations commonly associated with CSP systems.

Risk: The financial risk associated with CSP is also a major factor in the cost of developing CSP systems. As CSP systems become more accepted by banks and investors, the cost of financing will greatly reduce. This is one of the strongest factors affecting the energy cost from CSP systems.

Government Incentives: Governments can do a great deal to encourage the development of CSP in their region. Some options include loan de-risking (Mendelsohn et al. 2012), grant schemes, use of carbon credit revenues and funds for technical assistance (CSP Alliance 2014), or through feed-in tariffs and similar mechanisms that increase project profitability in a way somehow proportional to the higher cost of capital.

***The Golden Sunset*:** PPAs for CSP systems are typically agreed for a period of 20–25 years, corresponding to the expected lifetime of the plant. However, the SEGS systems in California, built during the 1980s, have now been operating for over 30 years in some cases. With all the loans now paid off, it has been profitable for the SEGS systems to continue to operate while selling power to the network for as little as USD 0.057/kWhe (Shahan 2013). As CSP technology matures, increasing commercial confidence about this end-of-life revenue should help to reduce the cost of CSP to consumers. Richert et al. give a good analysis of the impact of scale, location, storage capacity, government incentives and time-of-day pricing on the PPA price for CSP plants (Richert et al. 2012).

4.2.4.5 Learning Rates

The costs of many new technologies have been shown to decrease in a power-law relationship with the cumulative deployment of the technology. For most industries, learning rates are in the range 10–30% (Dutton and Thomas 1984). Lovegrove et al. (2012) reviewed other studies and found that PV and wind learning ratios were in the range 15–20%.

For CSP, establishing accurate learning rate estimates is challenging because little data from commercial plants is publicly released, and because there are so many variations due to location, incentives, etc., as noted in §4.2.4. In a recent study by Lilliestam et al. (2017), it was concluded that CSP learning rates are '18% or higher', significantly higher than the 5–15% assumed in 'most policy analyses'. Some well-known studies (Sargent and Lundy 2003; Pitz-Paal et al. 2005; Kolb et al. 2011) give breakdowns in cost reduction potential in CSP, and help to explain the changes that could be behind these recently observed savings.

4.2.5 Environmental Impacts of CSP

4.2.5.1 Greenhouse Gas Emissions

Concentrating solar power technology offers a 96–98% reduction in greenhouse gas emissions compared to conventional coal generation, and a 92–96% reduction relative to natural gas. Emissions from CSP, PV and wind are all of similar magnitude, and further emissions reductions are expected to be realised through to 2050 (Viebahn et al. 2008; Viebahn et al. 2010; Viebahn et al. 2011; Burkhardt et al. 2011; Burkhardt et al. 2012).

4.2.5.2 Water Usage

Water use in CSP systems is an issue due the arid conditions typical of high-DNI locations. Conventional 'wet-cooled' CSP systems make use of recirculating evaporative cooling towers to cool the condenser in the steam Rankine power block, as with typical coal power stations, and consume large amounts of water, ~3 L/kWhe (Bracken et al. 2015). Increasingly, however, CSP systems are migrating to the use of 'dry cooling', where steam is condensed in large air-cooled condensers, either with natural-draft air flow as in Khi Solar One (South Africa), or with fan-forced air flow, as for example in Noor III (Morocco). These systems are estimated to have a total water use of below 300 mL/kWhe (Macknick et al. 2011). Dry cooling reduces water consumption greatly, but comes at the cost of 2–5% reduced electrical output, and a consequent 2.5–8% increase in LCOE, according to one study (Bracken et al. 2015).

A third option for cooling of CSP plants is hybrid cooling, employed in the recently operational Crescent Dunes tower system in the USA. In hybrid cooling, water is used only during the hottest weather periods, and the system runs using dry cooling at other times. These systems are estimated to use a total of ~1 L/kWhe of water (Macknick et al. 2011).

Aside from condenser cooling, water is also consumed by the power cycle itself for 'blowdown' of steam, to limit corrosion and scale within the various power cycle components (Cohen et al. 1999). Water consumption for power cycle blowdown is of the order of 100–200 mL/kWhe (Bracken et al. 2015). Finally, a very small amount of water is used to clean mirrors (Figure 4.14), to offset system performance losses due to gradually accumulated dust. Mirror cleaning water use is estimated to be 75–150 mL/kWhe (Vivar et al. 2010; Bracken et al. 2015). Future supercritical CO_2 power cycles for CSP would eliminate the steam blowdown water consumption, while next-generation ultrasonic mirror cleaning may also bring major savings.

FIGURE 4.14 HERE

Figure 4.14. A cleaning truck at the Khi Solar One power plant.

Source: Photo courtesy of John Pye.

4.2.5.3 Other Impacts

Concerns have been raised about the optical glare from CSP plants, and potential risk to aircraft and motorists. These issues can be managed through careful design and site selection, as well as by controlling where the heliostats are aimed when in 'standby' mode (Ho et al. 2014). Another community concern has been the risk to birds and bats. Following detailed studies, in particular in relation to the Ivanpah plant in California, it has been concluded that this risk is minor (Ho 2016; Ho et al. 2016), although future plant operators will certainly be expected to monitor this risk. Finally, arid landscapes can be home for certain animals which in some cases can be endangered, and require care or protection.

4.2.6 Resilience of CSP to Climate Change

As a potential solution to climate problems, it is critical that CSP systems themselves are able to withstand the effects of climate change while maintaining acceptable levels of output. Patt et al. (2013) reviewed CSP and PV technologies with regard to this issue, and found that areas of concern for CSP technology include: (1) increased downtime due to high wind; (2) reduced dry cooling effectiveness due to hotter ambient temperatures; (3) soiling of mirrors due to sand and dust and resulting increased cleaning costs; and (4) potentially prolonged periods of cloud, interrupting system output. The need for CSP systems to survive hail damage has been considered in several projects, but was not noted as an area of concern by Patt et al. (2013). The analysis concluded that the risks to CSP posed by climate change were surmountable, and not of major concern to the technology as a whole.

4.2.7 CSP in the Electricity Grid

A serious response to the risks of climate change requires the eventual elimination of electricity generation technologies that are net carbon emitters. Wind and PV, having achieved large cost reductions in recent years, will certainly contribute very significantly to this, but the limitation of these technologies is that they are 'inflexible'—they cannot adjust their supply to match a varying demand. This limitation of inflexible generation can be addressed through several strategies, discussed elsewhere in this book (see Chapter 7, which discusses energy storage, and Chapter 14, which discusses applications of solar thermal energy in industry and manufacturing), including centralised and distributed battery storage, centralised pumped hydroelectric energy storage, compressed air storage, and demand response.[5] CSP, with its integrated energy storage, offers an additional solution to the inflexible generation problem, and offers flexibility that helps to enable matching of time-varying demand and supply profiles. This flexibility in CSP systems has a value, which has been the subject of numerous studies in recent years.

4.2.7.1 The Role for CSP in a Future 100% Renewable Electricity Network

Recently, studies have sought to identify what would be required to transition to a completely renewable electricity network. Generally, these studies take projected costs for different technologies based on learning rates and seek to identify the lowest-cost balance of technologies that will meet anticipated demand. Jacobson et al. (2017) developed a 139-country 100% renewable energy scenario for the year 2050, and predicted 9.7% of annual power production would come from CSP, and that CSP would furthermore play a major role in providing peaking power capacity.

Elliston et al. (2013, 2014) completed an extensive analysis of the Australian National Electricity Market (NEM), which supplies electricity to the south-east part of Australia where the majority of the Australian population resides. After optimising the portfolio of PV, CSP, pumped hydro, hydro and biomass-fired gas turbines for lowest-cost generation while meeting the entire NEM demand, they found CSP would contribute significantly to the Australian generation mix, in the range of 7–13% of installed nominal capacity, and in the range 13–23% of generated energy. Subject to the cost assumptions of the Australian Energy Technology Assessments (AETA), the conclusions of Elliston et al. are that the cheapest electricity network that Australia could build in 2030, assuming a carbon tax of AUD 20/tCO_2, would arise from a network with no deployment of carbon capture and storage, in which at least 13% of the energy is provided from CSP.

These and other future 100% renewable scenarios (Cochran et al. 2014) are highly dependent on projections of cost reduction, and such projections are notoriously difficult. But on the basis of even conservative cost reduction predictions, it seems likely that CSP will have quite a significant role in meeting the needs of consumers as we seek to deploy lower-emission generation.

4.2.7.2 The Value of CSP in Existing Grids

Analysis of the benefits offered by CSP in existing grids tends to follow a different approach, where the value of CSP is quantified as an incremental modification of an existing network.

Denholm, Mehos and co-workers (Denholm and Mehos 2011; Denholm et al. 2013; Jorgensen et al. 2013; Denholm et al. 2014; Jorgenson et al. 2014) define the value to the grid from two aspects. First, *operational value* relates to the reduction of operating costs from the pre-existing part of the electricity

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[5] 'Dumping' (throwing away PV- or wind-generated power without sending it to the grid) and 'load shedding' (disconnecting customers from the grid in a controlled way, in order to avoid blackouts) are also options, albeit far less palatable.

network before and after the addition of new plants. When a new CSP plant is added, it reduces the fuel use in existing fossil-fired plants, it reduces the O&M costs on the existing network, and it reduces the costs associated with start-ups during periods of varying demand. It also reduces the carbon taxes for the plant, if applicable, corresponding to those periods of operation.

Second, *capacity value* relates to the fact that a new CSP plant eliminates the need for at least a part of a pre-existing power plant. This is determined by considering the hours of peak demand on the whole network, and considering whether the CSP plant is likely to be operational during those hours in the year. It is found that CSP plants typically are able to operate at a close to 100% capacity factor at peak times for the electricity network considered. Hence the capacity value for CSP is high, and the annualised cost of an existing plant on the network can be included in the value that the new CSP plant provides.

Denholm et al. (2014) considered the case of the desert south-west USA, the region where most of the CSP plants built in that country have been located up to now. Calculating the operational and capacity value for several options, they concluded that CSP plant has a value of USD 0.08–0.12/kWh (Figure 4.15). Jorgensen et al. (2013) considered the best way to configure a CSP plant having a fixed collector field size. They considered variations in solar multiple and storage capacity and found that the configuration giving the greatest value is that with a small solar multiple (hence a large power block, if the collector field is fixed) and only 6 hours of storage. This is because 6 hours of storage is enough for the peak demand times to be met, and the larger power block size maximises capacity and operational value. Solar Dynamics LLC recently proposed that even higher value in the grid (perhaps up to USD 0.17/kWh) could be gained from 'CSP peaker' systems with 3 hours of storage and a solar multiple of just 0.5 (Price 2017).

FIGURE 4.15 HERE

Figure 4.15. (a) Capacity value (displaced amortised capital of installed plants) and operational value (displaced emissions, start + O&M, fuel) for new baseload, PV and CSP plants installed in south-west USA. As there is a range of estimates for the amortised capital cost of installed plants, the plot shows both high and low capital costs as separate bars. (b) Relationship between total plant value and storage size and solar multiple.

Source: Denholm et al. (2014)

From these analyses it is clear that CSP plants cannot be designed on the basis of LCOE alone. Project developers should consider that a low-LCOE plant will not necessarily be the most valuable choice for the local electricity network, and that in fact the local electricity network may be prepared to pay a premium price for a different type of system that provides greater capacity or operational value to the network as a whole. Policymakers can help to ensure that project developers are given incentives to provide the greatest value to the grid, but must ensure that this is not done with too detrimental an impact on the cost of plants being proposed.

The situation analysed for the USA could likely be quite different in developing countries with less extensive electricity networks. In places where there is growing demand and insufficient generation, there will be a high capacity value derived from the installation of CSP with substantial amounts of storage. Photovoltaic systems without storage, though cheaper, will not help greatly in the urgent need to supply reliable power at the times it is needed. For these locations, combined CSP and PV plants are being developed, offering a degree of firm capacity at a more competitive cost (Green et al. 2015; Platzer 2015).

4.2.8 Other Markets for CSP

Up to now, commercial development of CSP has been mainly focused on electricity generation. However, there is a growing effort to find ways to apply CSP technology to other energy needs in society. These include the production of transport fuels and the supply of industrial process heat for a wide range of industries. This section provides a brief overview of the activities and opportunities in these areas, and the current research efforts.

4.2.8.1 Water Desalination

A major environmental problem today is the unsustainable extraction of groundwater for use in agriculture and cities (see Chapter 12). Desalination already provides 1% of the world's drinking water, and as demand grows and natural sources are depleted, this fraction will continue to grow. As of 2015, 18 000 desalination units were installed worldwide, with a total capacity of 87 million m^3 per day; 44% of that capacity is in the high-DNI region of the Middle East (Voutchkov 2016). Outside the Middle East, desalination is mostly via the high-pressure process of reverse osmosis, whereas in the Middle East, low fuel costs have led to greater use of distillation (thermal) systems (Voutchkov 2016). The cost of fossil fuel–powered desalinated water is claimed to be USD 0.8–1.2/m^3 as of 2016 (Voutchkov 2016).

Concentrating solar power shows excellent potential as a replacement for fossil fuels in powering large-scale desalination systems and was recently estimated to be capable of providing clean water for below EUR 1/m^3 (= USD 0.78/m^3 as of 2012) (Lienhard et al. 2012). There is strong opportunity for hybridisation here, since the CSP plant can first produce electricity, and then make use of waste heat from the power block to drive the thermal desalination system.

Recently, a large-scale hybrid desalination system of this type has been built as part of an integrated greenhouse agriculture project in arid land. Sundrop Farms, in Port Augusta, South Australia, has installed a 20 ha greenhouse facility alongside a 39 MWth CSP tower system and a water treatment system, to grow tomatoes using seawater (see Table 4.1 and Figure 4.9) (Staight 2016). The system provides power and water for the plant, and the developers of this system are planning to build several further systems in coming years.

4.2.8.2 Solar Fuels

A significant and growing area of research relates to the use of CSP in production of transport fuels (Steinfeld 2005; Romero and Steinfeld 2012). Fluids that could play the role of future transport fuels include hydrogen, methane, methanol, dimethyl ether, ammonia and synthesised 'drop-in' fuels.

Hydrogen produced using solar energy needs only water as a feedstock. Two leading approaches are water electrolysis using PV or CSP electricity, and thermochemical water splitting. Electrolysis is already well established commercially but costly, in part due to relatively low efficiency. Thermochemical water splitting, meanwhile, is being heavily researched because of its potential to achieve up to 45% solar-to-fuel conversion efficiency, higher than the ~30% possible for PV or CSP-driven electrolysis (Wang et al. 2012). Thermochemical water splitting makes use of metal oxides which are reduced using solar thermal heat input, releasing oxygen. The reduced oxides are then re-oxidised with the addition of water at high temperature. This second reaction releases hydrogen, and the entire two-step process occurs at temperatures of 900°C or more, depending on the metal oxide material chosen. There are numerous challenges to be overcome in order for thermochemical water splitting to be successful commercially, including heat transfer, chemical conversion, material stability and others.

Hydrogen itself is not an ideal fuel because, in order to be transported with reasonable volumetric energy density, it requires either high pressure (>200 bar) or cryogenic cooling, or else more complex storage techniques such as chemical storage in metal hydrides. Instead of transporting hydrogen directly, one option is to convert the hydrogen into ammonia (NH_3) using nitrogen from the air. Ammonia can be transported at much lower pressure (~10 bar), and still has very good energy density, and can be either burnt as a fuel or processed into other useful chemicals (Zamfirescu and Dincer 2008). Ammonia is still a dangerous material however, and safety systems would need to be developed or adapted if it were to be adopted as a mass-market fuel.

'Drop-in' solar fuels are synthesised to have a chemical composition close to conventional fossil fuels such as kerosene, gasoline and diesel, all of which are liquid hydrocarbons. Most commonly, this is proposed via the commercially mature Fischer-Tropsch (FT) process, which requires syngas (hydrogen mixed with carbon monoxide) as its input. This syngas can be produced in a number of ways, including via high-temperature solar-driven gasification of biomass (Hertwich and Zhang 2009) or, as recently demonstrated, via CSP-assisted direct air capture of CO_2 (ETH Zurich 2019). One challenge with such processes is that conventional FT synthesis reactors are big and heavy and not suitable for daily ramp-up and ramp-down as would be preferable when powered from syngas that is produced only during sunlight hours (Hinkley, Naughton, Pye, Saw et al. 2015). Smaller and lighter FT reactors with potential for integration with solar fuels systems are under development (Cao et al. 2009). Other challenges exist with gasification, such as char and tar formation, and availability of high-temperature materials for the gasification reactor. 'Drop-in' synthetic fuels are attractive because they can immediately be integrated with existing infrastructure, and have a market value far higher than other easier-to-produce fuels such as methane. Apart from biomass gasification, solar syngas can also be produced from fossil fuels through steam methane reforming (reacting methane and steam at high temperature, using CSP heat input) and coal gasification (again using CSP as the heat input) (Zedtwitz and Steinfeld 2003; Agrafiotis et al. 2014). These processes are closer to maturity, but result in a fuel with only a modest solar fraction, ~25% (Zedtwitz and Steinfeld 2003). Such processes could be helpful in a transition to a lower-emissions economy, but, on their own, they will not be sufficient for us to achieve our longer-term global emission reductions targets. On the other hand, large-scale adoption of carbon-neutral solar biofuels will require very large quantities of biomass, production of which will strain our precious water and land resources.

As Lovegrove points out (2013), the cost of heat from a CSP plant (~AUD 7.50/GJ, 2013 estimates) plus the cost of carbonaceous material (~AUD 2.50/GJ for brown coal, including an AUS 23/tCO_2e carbon tax; or ~AUD 0.80/GJ for bagasse) is much less than the cost of diesel (AUD 26.03/GJ, excise free) or oil (AUD 17.88/GJ). There appears, then, to be strong potential to produce solar fuels from carbonaceous materials at a cost that is competitive with conventional fuels. An extensive road-mapping exercise by the IEA SolarPACES organisation is currently nearing completion, which aims to identify the most promising concepts and required research for development of solar fuels processes at commercial scales (Hinkley, Naugthon, Pye, Lipiński et al. 2015).

4.2.8.3 Industrial Process Heat

As efforts are made to achieve reductions in global greenhouse gas emissions, there will need to be major changes to the current practices of providing heat to industrial processes using fossil fuels, currently mostly natural gas and coal. Many of these processes operate at high temperature and replacing them with renewable alternatives is challenging.

Eglinton et al. (2013) reviewed a wide range of high-temperature industrial processes, including in mineral processing and metallurgy. Lab-scale and demonstration-scale experiments have been conducted for several of these processes, including solar zinc reduction and calcination of lime for cement production. Currently, these CSP-driven processes are not commercially viable, but these remain active areas of research. A more recent review of the application of CSP to powering chemical processes is given by Bader and Lipiński (2017).

Considering the broader use of natural gas in industrial processes in the Australian context, Lovegrove et al. (2015) observed a wide range of sectors requiring process heat at temperatures in the range 250–800°C where CSP could potentially provide input. This range of temperatures is highly compatible with current commercial CSP collector technology. Significant sectors include pulp and paper manufacturing, food manufacturing and chemical production. Lovegrove observes, however, that the current relative costs of CSP and natural gas make adoption of CSP in these areas difficult, and that low-temperature solar thermal technologies are closer to viability.

4.3 Low-Temperature Solar Thermal Systems

Although the emphasis of this chapter has been on high-temperature CSP systems, there is a large number and a wide range of systems that provide solar thermal heat for lower-temperature applications.

As of 2018, the IEA estimates that there were 480 GWth of non-concentrating solar thermal collectors installed globally (Weiss and Spörk-Dür 2019). Systems as large as 27 MWth have been installed in recent years for applications in agriculture, mining, textiles and district heating. In addition to these large systems, this sector remains dominated by solar domestic hot water systems, which are either flat plate or evacuated tube systems, and represent ~80% of the total installed capacity globally. Large non-concentrating solar thermal systems continue to be installed and numerous applications in the area of industrial process heat and in agriculture/crop drying have been highlighted by the IEA and IRENA (Kempener et al. 2015). Strong potential for low-temperature solar thermal collectors to cost-effectively replace natural-gas-fired industrial process heat was also highlighted by Lovegrove et al. (2015).

Solar cookers are a low-cost technology with relevance to developing regions. An insulated box receives solar radiation, usually slightly concentrated using one or more manually adjusted reflectors. Food to be cooked is placed inside the box and cooked at temperatures of the order of 90–100°C. Such cookers tend not to completely displace firewood and other fuels, but field trials from South Africa suggest that owners use them regularly and reduce their fuel use by ~40% (Wentzel and Pouris 2007).

Finally, various passive and active techniques use solar thermal energy to lower or eliminate building heating requirements. Active solar hot air collectors can be placed on roofs, Trombe walls can be incorporated into building facades and well-insulated buildings with good solar orientation (‘passive houses’) can greatly reduce energy demand from other sources.

4.4 Conclusion

To conclude, solar thermal technologies are growing strongly and have an important role to play in the provision of dispatchable renewable electricity, hot water for domestic and industrial use, and heat for industrial processes, and in the production of solar fuels. Large-scale CSP systems are being developed and constructed currently in Morocco, China, the UAE, Chile, Australia and South Africa, and appear to indicate that CSP is now either at—or very close to—commercial competitiveness in these specific markets where the DNI solar resource is high, and where electricity network constraints, fuel costs or trade barriers limit the use of alternative energy sources. Learning rates in this industry are strong. Next-generation systems currently in development are seeking to reduce costs by incorporating higher-efficiency supercritical CO_2 turbines, cheaper particle-based energy storage, new salt formulations for higher-temperature storage, phase-change energy storage materials, liquid metal heat transfer fluids and other innovations. With its cost-effective energy storage technology, CSP is projected to play a significant and stabilising role in the future electricity grid alongside other renewables, and it has been shown to carry a higher value than other non-flexible renewables as a result.

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