SunShot
U.S. Department of Energy

# SunShot Vision Study

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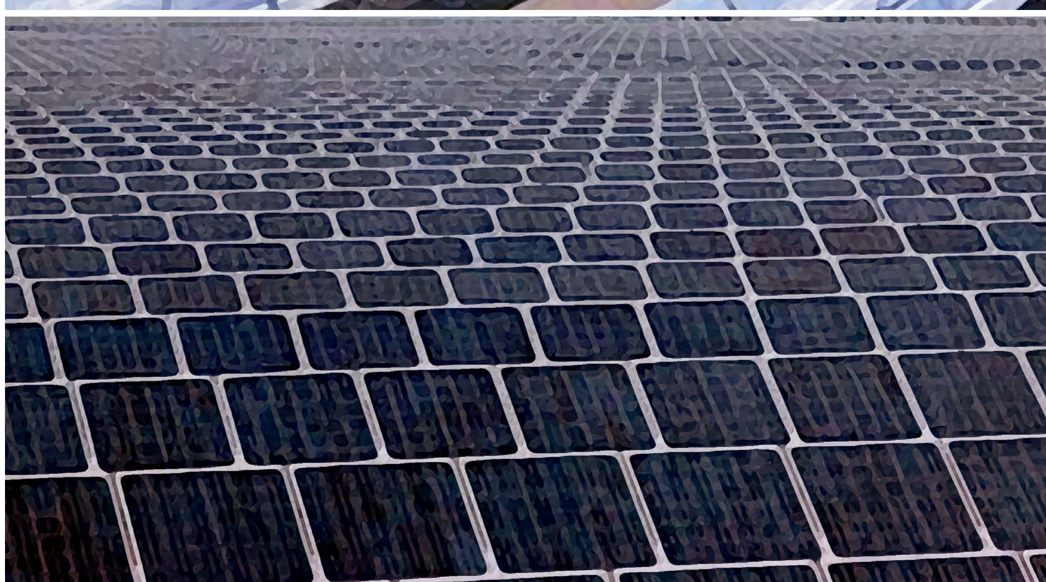


# 5. Concentrating Solar Power: Technologies, Cost, and Performance

## 5.1 INTRODUCTION

At the end of 2010, about 1,300 megawatts (MW) of concentrating solar power[50] (CSP) capacity was in operation worldwide, with 512 MW in the United States. More than half of the U.S. capacity was built in southern California in the 1980s. More recently, there has been increased interest in CSP technologies as a result of greater demand for renewable energy, government-supported research and development (R&D), and improved economics through policy initiatives. In the past few years, multiple utility-scale plants have been built, and almost 12 gigawatts (GW) of capacity were under construction or under contract worldwide during 2010. Of this total, almost 10 GW represented CSP plants with signed power purchase agreements (PPAs) under development in the U.S. Southwest (SEIA 2010).

CSP is composed of a diverse mix of technologies, at different stages of maturity, which convert sunlight into thermal energy and then use this thermal energy to generate electricity. A key characteristic of CSP is its built-in thermal inertia, which can provide stability in plant output during slight changes in solar radiation, such as when a cloud passes overhead. Because CSP uses thermal energy, it can also incorporate thermal energy storage (TES), fossil-fuel backup/hybridization, or both for higher levels of stability and dispatchability and increased duration of energy output. These attributes allow CSP plants to obtain capacity credits similar to those for fossil-fuel power systems and provide a firm energy resource that improves grid operations.

This chapter evaluates the current cost, performance, and potential of several CSP technologies. A detailed discussion of the opportunities for potential cost reductions to existing and emerging CSP technologies is provided. Key challenges to achieving the level of CSP growth envisioned in the SunShot scenario are evaluated, including potential materials-supply constraints as well as manufacturing scale-up issues. This analysis makes it clear that continued CSP technology advances and cost reductions, through both continued R&D investments and increased deployment activities, will be necessary for achieving the SunShot scenario. In particular, CSP's ability to provide firm, dispatchable power generation will play a critical role in enabling the U.S. electricity generation system to operate safely and reliably under the SunShot scenario's levels of solar technology deployment.

[50] CSP may also be called concentrating solar thermal power or solar thermal electric power.

## 5.2 TODAY'S CSP TECHNOLOGY

There are four demonstrated types of CSP systems: parabolic trough, linear Fresnel, power tower (also called central receiver), and dish/engine. All of these technologies involve converting sunlight into thermal energy for use in a heat-driven engine. The first three have been demonstrated in hybrid configurations with fossil-fuel technologies and/or adapted to use TES. These options provide operating flexibility and greater reliability. TES and hybridization are expected to play increasingly important roles as renewable energy contributions to the electric grid increase.

### 5.2.1 TECHNOLOGY TYPES

#### Parabolic Trough

Parabolic trough systems are currently the most proven CSP technology owing to a commercial operating history starting in 1984, with the Solar Energy Generating Systems (SEGS) plants in the Mojave Desert of California, and continuing with Nevada Solar One (Figure 5-1) and several recent commercial trough plants in Spain.

**Figure 5-1. Example of a Parabolic Trough Plant**

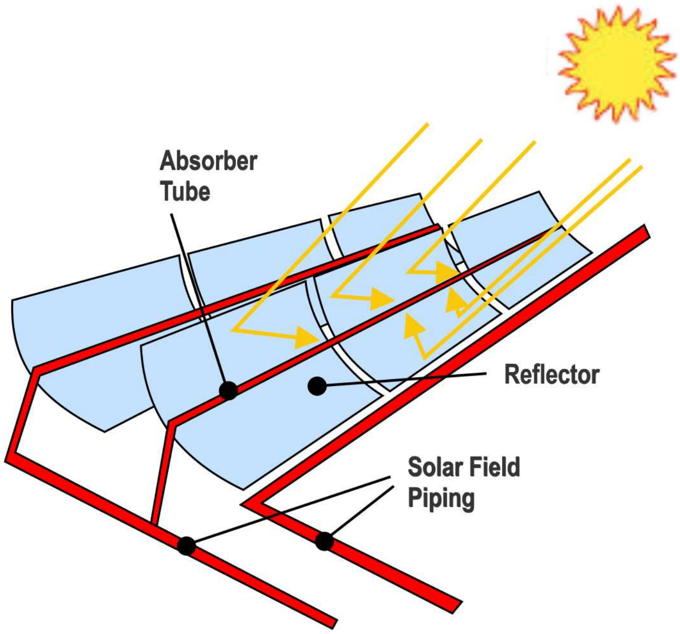
Source: EPRI (2010)

Parabolic trough power plants consist of large fields of mirrored parabolic trough collectors, a heat-transfer fluid (HTF)/steam-generation system, a power system such as a Rankine steam turbine/generator, and optional TES and/or fossil-fuel-fired backup systems. The use of TES results in both dispatchable generation and higher annual generation per unit of capacity, although the larger collector field and storage system lead to a higher upfront capital investment. Trough solar fields can also be deployed with fossil-fueled power plants to augment the steam cycle, improving performance by lowering the heat rate of the plant and either increasing power output or displacing fossil-fuel consumption.

The solar field is made up of large modular arrays of 1-axis[51] tracking solar collectors arranged in parallel rows, usually aligned on a north-south horizontal axis. Each solar collector has a linear parabolic-shaped reflector that focuses the direct-beam solar radiation onto a linear receiver (absorber tube) located at the focal line of the parabola (Figure 5-2). The collectors track the sun from east to west during the day, with the incident radiation continuously focused onto the linear receiver, within which an HTF is heated to approximately 390ºC.[52]

[51] Note that 1-axis tracking may also be referred to as "single-axis" tracking.
[52] To convert temperature to Fahrenheit, multiply the Celsius value by 1.8 and then add 32 degrees.

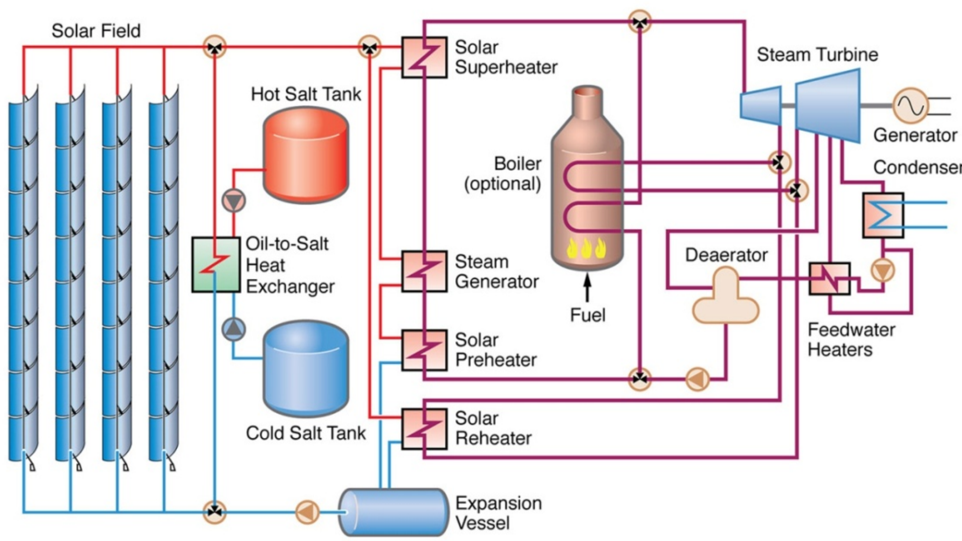
**Figure 5-2. Parabolic Trough Field Components**




Source: NREL

After circulation through the receivers, the HTF flows through a heat exchanger to generate high-pressure superheated steam (typically 100 bar at 370ºC). The superheated steam is fed to a conventional reheat steam turbine/generator to produce electricity. The spent steam from the turbine is condensed in a standard condenser and returned to the heat exchangers via condensate and feed-water pumps to be transformed back into steam. Wet, dry, or hybrid cooling towers can be used for heat rejection from the condenser; the selection will influence water use, cycle performance, and cost (see the water discussion in Chapter 7). Figure 5-3 shows a trough plant with a fossil-fuel-fired backup boiler and TES.

**Figure 5-3. Trough Plant Operation with Fossil-Fuel-Fired Backup System**




Source: EPRI (2010)

The current design-point solar-to-electric efficiency—the net efficiency in the ideal case when the sun is directly overhead—for a parabolic trough plant ranges from 24%–26%, and the overall annual average conversion efficiency is about 13%–15%. The design-point values represent an ideal case that is useful for comparing between different components, such as two different receiver designs. This metric is also used for evaluating photovoltaic (PV) panels. The annual average efficiency provides a better assessment of actual operation.

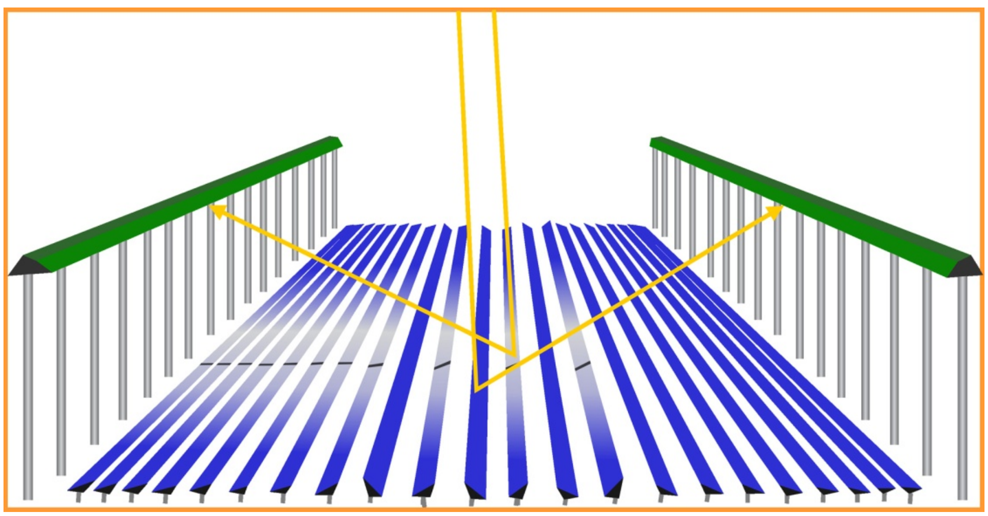
### Linear Fresnel

Linear Fresnel reflectors (LFRs) approximate the parabolic shape of a traditional trough collector with long, ground-level rows of flat or slightly curved reflectors that reflect the solar rays up onto an overhead linear receiver. Flat reflectors and fixed receivers lead to lower capital costs relative to a traditional trough-based plant, but LFR plants are less efficient on a solar-to-electricity basis. Recently, superheated steam at about 380°C has been demonstrated in an LFR plant, and there are proposals for producing steam at 450°C; higher operating temperatures enable higher efficiency. Because LFRs are in the demonstration phase of development, their relative energy cost compared with parabolic troughs remains to be established.



Compact LFR technology uses a design with two parallel receivers for each row of reflectors (Figure 5-4). This configuration minimizes blocking of adjacent reflectors and reduces required land area. Another advantage is that, depending on the position of the sun, the reflectors can be alternated to point at different receivers, thus improving optical efficiency.

**Figure 5-4. Compact Linear Fresnel Reflector Field**



Source: NREL

### Power Tower

Power towers (also called central receivers) are in the demonstration to early-commercialization stage of development. Because of their higher operating temperatures, power towers have the potential to achieve higher efficiency and lower-cost TES compared with current trough technology.

Power towers use heliostats—reflectors that rotate about both the azimuth and elevation axes—to reflect sunlight onto a central receiver. A large power tower plant can require from several thousand to more than one-hundred thousand heliostats, each under computer control. Because they typically constitute about 50% of the plant cost, it is important to optimize heliostat design. Heliostat size, weight, manufacturing volume, and performance are important design variables, and developers have selected different approaches to minimize cost. Some heliostat technology can be installed on relatively uneven land, with 5% or more slope, thereby reducing site-preparation costs for new projects. Figure 5-5 shows an example of a heliostat array and receiver.

**Figure 5-5. Example of a Power Tower and Heliostat Array**

Source: BrightSource (2010)



The two principal power tower technology concepts currently being pursued by developers are defined by the HTF in the receiver: steam or molten salt. Both concepts have unique operating characteristics, which are detailed below.

In direct-steam power towers, heliostats reflect sunlight onto a receiver on a tower, which is similar to a boiler in a conventional coal-fired power plant. The feed water, pumped from the power block, is evaporated and superheated in the receiver to produce steam, which feeds a turbine generator to generate electricity. Current steam conditions for direct-steam generation towers range from saturated steam at 250°C to superheated steam at over 550°C. Several characteristics of direct-steam power towers make them attractive: their straightforward design; use of conventional boiler technology, materials, and manufacturing techniques; high thermodynamic efficiency; and low parasitic power consumption. Short-duration direct-steam/water storage has been demonstrated at the 20-MW PS20 tower in Spain. Like many CSP technologies, steam towers can be hybridized with natural gas to provide additional operating flexibility and enhanced dispatchability. Figure 5-6 shows two examples of direct-steam receivers in operation.

**Figure 5-6. Examples of Direct Steam Receivers in Operation**

Source: eSolar (2010) (left) and BrightSource (2010) (right)



In a molten-salt power tower, salt at about 290°C is pumped from a cold storage tank to a receiver, where concentrated sunlight from the heliostat field heats the salt to about 565°C. The salt is typically a blend of sodium and potassium nitrate, which are ingredients sold commercially as fertilizer. The hot salt is held in a storage tank, and when electric power generation is required, hot salt is pumped to the steam generator, which produces high-pressure steam at nominal conditions of 100–150 bar and up to 540°C. The now-cooler salt from the steam generator is returned to the cold salt storage tank to complete the cycle. Owing to the negligible vapor pressure of the salt, both storage tanks are at atmospheric pressure. The steam is converted to electrical energy in a conventional steam turbine/generator. By placing the storage between the receiver and the steam generator, solar energy collection is decoupled from electricity generation. Thus, passing clouds that temporarily reduce direct-normal irradiance (DNI) do not affect turbine output. In addition, the TES could be less than half the cost of salt TES in trough plants because the larger temperature range across the storage system enables more energy to be stored per mass of salt. The combination of salt density, salt-specific heat, and temperature difference between the two tanks allows economic storage capacities of up to 15 hours of turbine operation at full load. Such a plant could run 24 hours per day, 7 days per week in the summer and part-load in the winter to achieve a 70% solar-only annual capacity factor. The Gemasolar plant in Spain is designed for such performance. Figure 5-7 shows a 43-MW thermal ($MW_t$) receiver at the 10-MW Solar Two central receiver demonstration project, which was completed in 1995 in Barstow, California.

The annual average solar-to-electric conversion efficiency of a power tower is about 14%–18%, with direct-steam towers slightly higher than molten-salt towers. The design-point efficiency is about 20%–24%. As discussed for troughs, annual average efficiency represents overall real-world performance, whereas design-point values are useful for comparing the performance of individual components. The choice of wet, dry, or hybrid cooling towers can influence water use, cycle performance, and cost (see Chapter 7).

### Dish/Engine

**Figure 5-7. Example of a Molten-Salt Receiver**

Source: Sandia National Laboratories (2010)

Dish/engine CSP technology uses a collection of reflectors assembled in the shape of a parabolic dish to concentrate sunlight onto a receiver cavity at the focal point of the dish. Within the receiver, the heater head collects this solar energy, running an engine-driven generator to produce electricity. Similar to heliostats, all dishes rotate along two axes to track the sun for optimum capture of solar radiation. There are currently three major types of engines used at the core of dish/engine technology: kinematic Stirling engines, free-piston Stirling engines, and Brayton turbine-alternator based engines. Dishes have also been proposed with air receivers that feed hot air to a steam generator. Both kinematic and free-piston Stirling engines harness the thermodynamic Stirling cycle to convert solar thermal energy into electricity by using a working fluid, such as hydrogen or helium. Brayton systems use turbine-alternator engines with compressed hot air to produce electricity. Current dish/Stirling systems generate 3–30 kilowatts (kW) of electricity, depending on the size of the dish and the heat engine used. The first dish/Stirling commercial demonstration began operation in January 2010. Dish/Brayton systems have been proposed at sizes up to 200 kW.

Some dish/engine technology can be installed on relatively uneven land—with 5% or more slope—thereby reducing the cost of site preparation for new projects. Dish/engine systems are cooled by closed-loop systems (similar to an automobile engine), which, combined with the lack of a steam cycle, endow them with the lowest water use per megawatt-hour (MWh) among all the CSP technologies. As a modular technology, dish/engine systems are built to scale to meet the needs of each individual project site, potentially satisfying loads from kilowatts to gigawatts. This scalability makes dish/engine technology applicable for both distributed and utility-scale generation. Dish/Stirling systems have demonstrated the highest recorded CSP design-point solar-to-electric efficiency (31.4%) and have an estimated annual conversion efficiency in the low 20% range. Two types of dish/engine systems are shown in Figure 5-8.

## 5.2.2 COST AND PERFORMANCE

The current performance and cost of CSP plants varies by technology, configuration, solar resource, and financing parameters. However, it is possible to evaluate different plant designs and technologies in terms of a single index: the levelized cost of energy (LCOE). LCOE takes into account the available solar resource, upfront capital investment, plant capacity factor, operation and maintenance (O&M) costs, and financing parameters. LCOE is generally expressed in terms of cents per kilowatt-hour (kWh). Alternatively, the cost of a CSP plant can be expressed in terms of dollars per watt (W) or, more commonly, dollars per kilowatt. LCOE takes

**Figure 5-8. Examples of Dish/Engine Systems**

Sources: Stirling Energy Systems (SES) (2010) (left) and Infinia (2010) (right)

capacity factor and O&M costs into account, but dollars per kilowatt does not. For example, a 100-MW CSP plant can be built with TES and additional collector area to increase its capacity factor. This hypothetical design might generate 100% more energy per year and have a 60% higher installed cost than an alternative design without TES and additional collector area; such a plant would have a higher installed dollars-per-kilowatt cost but a lower LCOE than the alternative-design plant.

Assuming fixed financial inputs, the LCOE of a CSP plant can be reduced in two ways: 1) by lowering capital or O&M costs, and 2) by increasing annual performance. The capital equipment for a CSP plant involves solar components (e.g., solar collector field, heat-transfer piping, and TES system) and more-or-less conventional thermodynamic power-cycle components (e.g., pump, turbine, and generator). The O&M cost per megawatt-hour, of which staff is the largest contributor, decreases with an increase in plant size or co-location of multiple units at one site. Decreasing capital and operating costs can be achieved by technology advances and increased manufacturing volume and supply chain efficiency.

The performance of a CSP plant is characterized by its annual solar-to-electric conversion efficiency. This metric includes all of the energy losses that affect the annual electricity produced by the plant, including optical, thermal, and electrical parasitic losses, as well as forced and planned outages for maintenance. Although higher efficiency often costs more up front, it may more than pay for itself over the operating life of the plant. Also, plants with higher efficiency require less land to produce a given amount of electricity. In other cases, a slightly lower overall efficiency may be advantageous. For example, if the marginal cost of a heliostat is less than the return in revenue it provides, it may be worth adding heliostats—increasing the capacity factor, but lowering the efficiency, of the plant. Capacity factor is defined as the ratio of actual annual generation to the amount of generation had the plant operated at its nameplate capacity for the entire year. Capacity factors vary greatly between different locations, technologies, and plant configurations; for example, plants with TES achieve higher capacity factors because their power block can have more hours of operation. CSP plants with TES are likely to be more cost effective in the future as compared to plants without TES, because while the addition of low-cost TES does increase capital costs, it has the potential to reduce the LCOE.

One of the most recent utility-scale CSP plants built in the United States is the Nevada Solar One parabolic trough plant, which came on line in 2007 at a reported cost of about $4,100/kW ($266 million cost, nominal 64-MW capacity). Several similar-size trough plants have been built in Spain, including the Andasol plants that include TES; however, those project costs have not been disclosed. The estimated direct capital costs for building a CSP plant today are about $4,000–$8,500/kW. The upper end of the range reflects plants with TES, whereas the lower end includes no-TES troughs, direct-steam generation towers, and dish/engine systems (see Section 5.3.6 for more information). Plant capacity factors extend from 20%–28% for plants with no TES and 40%–50% for plants with 6–7.5 hours of TES. Larger amounts of TES and higher capacity factors are technically viable but subject to project economics. The LCOE varies greatly depending on the location, ownership, values of key financing terms, available financial incentives, and other factors. For locations in the southwestern United States, the LCOE is currently in the 12–18 cents/kWh range with a 30% investment tax credit (ITC).



## 5.3 Projected Technology and Cost Improvements to Existing and Emerging CSP Technologies

Anticipated reductions in the delivered cost of electricity from CSP plants will occur primarily from decreasing the upfront investment cost and improving performance. Reduced capital cost will be a consequence of manufacturing and installation scale-up as well as technology advancements through R&D aimed at cost reduction and performance improvements. A number of component- and system-level advancements are currently being pursued, which generally can be classified into five sub-systems: solar field, HTF, TES, cooling technology, and power block. Each of these sub-systems is discussed below, followed by a detailed discussion of current and projected cost improvements by sub-system.

### 5.3.1 Solar Field

The solar collector field (materials plus labor) represents the single largest capital investment in a CSP plant and thus represents the greatest potential for LCOE reduction among capital equipment costs. The key to reducing solar field costs is reducing the cost of the collector support structure, reflectors, and receivers.

The support structure must support the weight of the reflectors and have sufficient strength to keep the reflectors aligned, even during high-wind conditions. Survival wind loads (the maximum wind loads that structures must withstand), which vary by location, tend to drive the overall design of the collector. The support structures must also have sufficient torsional rigidity to minimize twisting. For the collectors, developers are working to reduce the amount of material and labor necessary to provide accurate optical performance. The choice of material also plays an important role in structural design: steel is stronger and stiffer than aluminum, but aluminum is lightweight, corrosion resistant, and more easily processed. Advanced collector designs that use integrated structural reflectors reduce the installation cost of both the structure and reflectors by making assembly of the solar field easier and faster. For troughs, several advanced frame designs are being evaluated, such as space frame, torque tube, and monocoque. Troughs are generally moving toward larger-aperture collectors to reduce total costs for piping, receivers, drives, and controls. For towers, heliostat sizes from 1–130 square meters ($m^2$) are being used. In addition, improvements in other collector components—such as drives, controls, and foundations —are needed to reduce the support structure cost further.



The optical performance of reflectors is also critical to minimizing LCOE, because it has an approximately one-to-one ratio with LCOE—i.e., a 1% increase in reflectance will cause a 1% reduction in LCOE. For CSP reflectors, it is important for the reflective surface to not only be highly reflective, but also to be highly specular; in other words, the reflector must not only reflect the sunlight, but also reflect it into a narrow cone angle that intercepts the receiver. Currently, most CSP plants use 4-millimeter (mm) second-surface silvered glass reflectors, and current glass reflectors have proven field performance and reflectivity values of about 93.5%. Costs may be reduced by moving from these heavy glass reflectors to lightweight thin glass, polymeric film, or coated aluminum reflectors. Figure 5-9 shows a recently installed parabolic trough system operating at SEGS-II as an example of a large-aperture trough that uses a silvered polymer reflector. Compared with glass reflectors, thin-film reflectors have the potential to provide a lightweight, high-reflectance, low-cost alternative, while also allowing a greater degree of design freedom and reduced breakability. Advanced reflectors are being developed to increase reflectivity to 95% or higher, but time is required to prove their long-term durability. Reflector coatings are being explored to increase durability and to reduce the amount of water used for cleaning.

**Figure 5-9. Parabolic Trough Undergoing Testing in Southern California**

Source: SkyFuel (2010)

Receivers have optical and thermal performance characteristics. The optical efficiency is a measure of the percentage of incoming DNI that is absorbed by the receiver, whereas the thermal efficiency is the proportion of energy absorbed by the receiver that is transferred to the HTF. Current solar selective coatings for receiver surfaces display high absorptivity of short-wave radiation (sunlight), but a challenge is to reduce the emissivity of long-wave radiation (infrared) while maintaining high absorptivity at high temperatures. Selective coatings for vacuum-jacketed trough receivers are fairly advanced, but tower receivers would benefit from new selective coatings that can withstand their higher temperatures and are resistant to oxidation.

For trough receivers in particular, receiver tubes in the field have exhibited a problem of hydrogen permeation from the HTF into the vacuum space, resulting in greatly increased heat loss. Solutions being studied to solve this problem include adjusting the amount and location of hydrogen getters, centrally removing the hydrogen, using an inert gas to block the motion of hydrogen, and deploying HTFs that do not generate hydrogen.

### 5.3.2 Heat-Transfer Fluid



A major focus of improved CSP performance is achieving higher operating temperatures to take advantage of increased thermal-to-electric conversion efficiencies and—for systems with TES—lower TES cost.

For commercial parabolic trough systems, the maximum operating temperature is limited by the HTF, currently a synthetic oil with a maximum operating temperature of approximately 390°C. Other limitations of this HTF include the cost of the fluid and the need for heat-exchange equipment to transfer thermal energy to the power cycle or storage system. Several parabolic trough companies are experimenting with alternative HTFs that would allow operation at much higher temperatures. Examples of HTFs currently under investigation include molten salts, water for direct-steam generation, organic silicones, ionic liquids, and polyaromatic napthalenes. In addition, researchers are investigating the incorporation of nanoparticles into many of these fluids to improve their heat capacity, heat-transfer rate, and/or thermal stability at high temperatures.

The maximum practical concentration ratio possible coupled with the lowest practical heat loss from the receiver tubes suggest an upper temperature limit of approximately 500°C for parabolic trough systems. Water/steam and molten-salt HTFs can be used at this temperature; however, there are concerns with the freezing temperature of molten salts as well as a need for salt-compatible components, such as flex-joints and valves. The salt currently used in tower projects and TES systems is a 40/60-weight-percent blend of potassium nitrate and sodium nitrate, which starts melting at 220°C. A small demonstration trough plant in Sicily is also currently running with this salt HTF. A shift to molten-salt HTFs running at 500°C is predicted to significantly reduce trough plant costs, primarily by improving thermal conversion efficiency, reducing TES costs, and reducing HTF system cost (piping, insulation, and fluid) (Turchi et al. 2010a). For this reason, considerable R&D efforts are underway to find lower-melting-point salts that are more attractive for use in commercial parabolic trough plants. However, lowering the melting point of salts typically requires the incorporation of more expensive salt components and hardware, and these tradeoffs must be weighed carefully. Efforts to address material compatibility are also underway, including new packing materials for ball joints and testing of both piping components and instrumentation. Direct-steam troughs have also been proposed and tested, but no commercial plants have yet been built owing to the greater control complexity of these systems.

In contrast to parabolic trough systems, molten salt and direct steam are currently used as the HTFs in power tower systems operating at temperatures near 565°C. This is possible because of the considerably smaller amount of piping required for the HTF in a tower system. Owing to higher concentration ratios associated with tower systems as compared with parabolic troughs, operating temperatures of 1,000°C or higher may be feasible, depending on the medium used for the HTF. Research efforts are investigating systems and materials capable of operating at these elevated temperatures. Systems that operate at moderately higher temperatures (600°C–700°C) may allow molten-salt and steam towers to adapt and use commercial supercritical steam turbines (as opposed to the current subcritical Rankine cycles).



The choice of HTF greatly influences whether a particular design can be integrated with TES. For example, although small amounts of steam can be stored in steam accumulators, such designs are not economically feasible at higher storage capacities. Steam-compatible options such as phase-change storage show promise but have yet to be demonstrated beyond pilot scale. Alternatively, molten-salt receivers can efficiently store the high-temperature salt HTF directly in tanks at a relatively low cost. Potential storage options are discussed in greater detail in the following section.

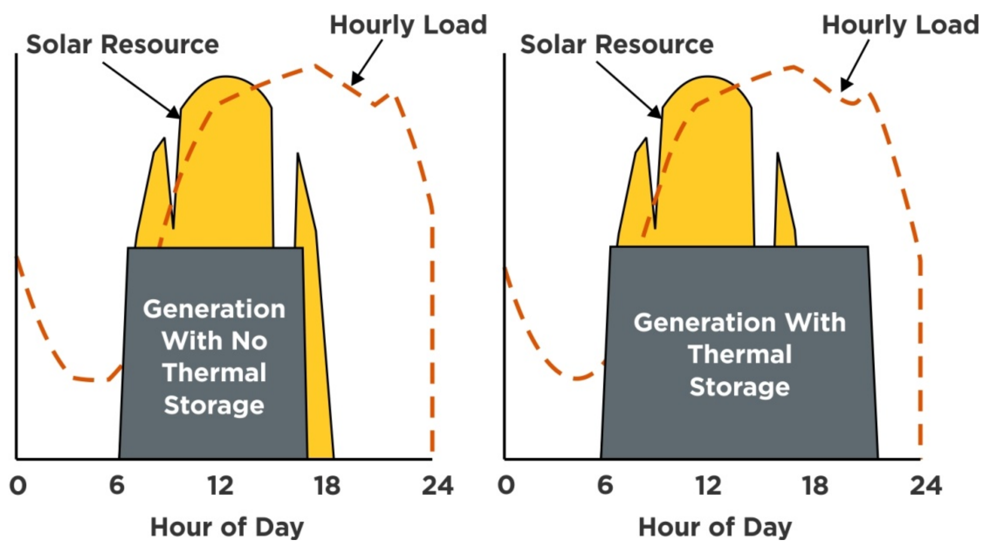
### 5.3.3 Thermal Energy Storage

A very important characteristic of CSP technologies is their ability to dispatch power beyond the daytime sun hours by incorporating TES systems. During summer months, for example, plants typically operate for up to 10 hours per day at full-rated electric output without TES. However, full-load generation hours can be added or shifted if TES is available, allowing for greater utilization of the power block and potentially reducing LCOE. Incorporating TES normally is accompanied by increasing the size of the collector area to produce excess thermal energy during the day that can be put into the TES system for later use. An alternative to TES that does not require collector-area expansion is to configure the systems as hybrid plants, i.e., provide a secondary backup system to supplement the solar output during periods of low solar irradiance. Use of natural gas is typical, but the use of renewable fuels such as biomass is also possible. Hybrid plants provide good dispatchability at relatively low cost and risk, albeit with a diluted solar contribution.

Large-scale TES systems have only recently appeared in commercial CSP plants. Plants with TES typically have collector fields that are much larger than the minimum size required to operate the power cycle at full load. The ratio of the collector-field thermal power to the power required to operate the power cycle at full load is termed the "solar multiple." For example, a system with a solar multiple of 1.0 means that the solar field delivers exactly the amount of energy required for the generator to produce the maximum rated power, or "nameplate capacity," for the plant's turbine at a defined insolation value—e.g., solar noon on the summer solstice. At all other times, the solar field would be delivering less power than required to run the turbine at maximum capacity. Even plants without explicit TES are designed with an oversized solar collector field (i.e., with a solar multiple greater than one) so that they can operate the turbine at its maximum power capacity (design point) for more hours of the year. The plant may need to reduce collection of some solar energy during summer afternoons, but the larger solar field allows for full-load operation for more total hours throughout the year. If TES is included, any excess heat from the collector field is sent to the TES system. When power is needed, the heat is extracted from the TES system and sent to the steam cycle. An example of a commercial plant with storage is Andasol 1 in Spain, which incorporates a two-tank molten-salt system. The 50-MW plant uses 28,500 metric tons (MT) of nitrate salts, offering a storage capacity of 1,000 $MW_t$, equivalent to about 7.5 hours of power production. The salt temperature ranges from 292°C in the cold tank to 386°C in the hot tank.

Additional capital investment is required to expand the collector area and add storage tanks so that a CSP plant may incorporate TES; however, these costs are offset by increasing the operational hours of the power block. If solar field and TES costs are low enough, the net effect is a decrease in LCOE. In addition, TES provides greater operating flexibility and enhances dispatchability, which provides additional value to the utility. Figure 5-10 shows how CSP plants with TES can tailor their output to match load curves, thereby maximizing value to the utility and revenue to the owner. TES allows CSP plants to extend and/or shift energy generation to coincide with peak load demands. The only current commercial TES option for parabolic trough, linear Fresnel, and power tower systems uses molten nitrate salt as the storage medium in a two-tank, sensible heat system. Two-tank, sensible heat TES tends to be highly efficient in both energy (energy stored is recovered) and exergy (energy stored is recovered at nearly the same temperature); roundtrip energy efficiencies of up to 98% were reported for the storage system at the Solar Two power tower demonstration (Pacheco 2002). The major limitation to two-tank, sensible TES is the amount of storage media required, especially at the lower operating temperatures used by current trough technology.

**Figure 5-10. Thermal Storage and Utility Demand**




Source: NREL

To reduce the cost of TES, industry and the U.S. Department of Energy (DOE) have made considerable investments in improvements and alternatives to two-tank, sensible TES. Examples of research topics include the following:

- Low-melting-point salt mixtures, which are identical to research efforts in HTFs
- Solid-media storage, such as graphite, concrete, or ceramics
- Phase-change material (PCM) systems, in which a solid, such as metal or salt, is melted, capturing a considerable amount of energy in the latent heat of the material
- Single-tank thermoclines, in which hot and cold molten salt are stored in one tank and separated by the difference in density between the hot and cold salt
- Thermochemical storage, in which energy is captured using a chemical reaction and, when needed, released by reversing the reaction
- Specially engineered additive materials such as dispersed nanoparticles within salts to increase heat capacity.

These TES options must be compatible with the corresponding HTF, because the most economical TES option is largely contingent on the HTF being used.

For most TES systems, the operational temperature range has an effect on the cost of storage. For example, molten-salt power tower plants can operate at higher temperatures and therefore can reduce the amount of salt required for TES by approximately a factor of three, for a given storage capacity, relative to a current parabolic trough plant.[53] This significant reduction in storage-material mass and the associated reduction in costs make it possible to economically add higher TES capacities. Longer-duration storage (~12 hours) makes near-baseload operation possible. However, at least for the near term, most troughs and towers likely will be built with low levels (6 hours or less) of storage owing to time-of-delivery rate schedules that pay more for peak-power electricity delivery. For example, the Nevada Solar One plant does not have a TES system, although it does provide about 30 minutes of storage via the extra HTF capacity held in the expansion tank.

The storage methods described above are largely focused on TES for parabolic trough, linear Fresnel, and power tower systems. The modular nature of dish/engine systems make them less suitable for large, centralized TES systems. However, several methods for incorporating better dispatchability into dish/engine technologies are being explored, including TES using PCMs and hybrid systems using fossil fuels to augment power production, similar to hybrid options in other CSP systems.

Although delivered cost of electricity, as measured by LCOE, is the most important cost metric for CSP, it does not fully capture the value of CSP as a dispatchable power source. Adding storage to a CSP plant adds value by decreasing variability, increasing predictability, and providing firm capacity during peak load when it is most valuable. CSP plants with TES can bid into ancillary services and capacity

[53] The mass of salt required is inversely proportional to the temperature differential in the storage system; thus, a tower operating from 290°C–565°C requires approximately three times less storage salt than a trough system operating from 300°C–390°C.

markets, where they exist, to realize additional revenue. Even in the absence of explicit markets, the greater capacity value of CSP with TES is recognized in resource planning, where CSP can be given additional consideration due to its dispatchability. This can be observed in the discussion about system dispatch in Section 3.2.6, where CSP is used to follow the significant variability of net load. This ability will become increasingly important to system planners and operators as they seek to maintain the reliability of the bulk power system while integrating large amounts of variable generation such as PV and wind.

### 5.3.4 Cooling Technology

All CSP systems require cooling, but they differ in their selection of cooling technology. Dish/engine systems are inherently air cooled, whereas trough, Fresnel, and power tower technologies can use wet, dry, or hybrid (a combination of wet and dry) cooling. The selection of cooling technology depends on economics, water availability, and policy. If available, wet cooling is often preferred and provides the lowest cost; however, some CSP developers have voluntarily opted for dry cooling to reduce water consumption. Chapter 7 provides additional discussion on the water use of CSP and other electricity-generating technologies.



CSP facilities need to be built in areas of high DNI, which generally translates into arid, desert areas where water is a scarce resource, making water use a major concern for CSP plants. A typical trough or power tower plant that employs wet cooling can consume 750–1,020 gallons of water to produce 1 MWh of solar electricity (see Chapter 7, Table 7-3). Several strategies can reduce the freshwater consumption of CSP plants: using dry cooling, using degraded water sources, capturing water that would otherwise be lost, and increasing thermal conversion efficiencies. Dry and hybrid cooling systems are commercial technologies that have the potential to reduce CSP water consumption by 40%–97%, depending on the generating technology and project location (see Chapter 7).

Compared with wet cooling, dry and hybrid cooling systems have a higher equipment cost and, depending on design, may have a performance penalty. Various studies have sought to define the cost and performance effects of dry cooling to minimize the impact on LCOE. For example, a recent analysis estimated that switching to dry cooling would raise the LCOE of a trough plant by 3%–8%, depending on location and plant design (Turchi et al. 2010b). The performance and cost penalty for power tower systems should be lower, because CSP technologies operating at higher temperatures experience smaller penalties as a result of using dry or hybrid cooling systems. Nevertheless, the importance of this issue may warrant additional research on indirect air cooling or other aspects to improve efficiencies and reduce costs for dry cooling. Examples of R&D efforts to reduce water use for wet or hybrid cooling include recovering water that is evaporated in cooling towers or using non-traditional sources for cooling water, such as treated saline groundwater, reclaimed water, or water produced from oil and gas extraction.

The effect of cooling technology on CSP system cost and performance varies by technology, location, and climate. Cooler climates make dry cooling more attractive, whereas the performance penalty is greatest for lower-temperature CSP systems in hot climates. Lastly, using TES systems enables some electricity production to be shifted to cooler evening hours, which offsets some of the penalties associated with dry or hybrid cooling systems (Sioshansi and Denholm 2010).

### 5.3.5 Power Block and Other Cost-Reduction Potential

The current CSP power block for trough, Fresnel, and power tower systems uses many conventional steam Rankine cycle components. It consists of a steam generator that feeds a subcritical Rankine cycle with reheat. The main cost-reduction potential in the current power block is correlated to increased size. For example, the SEGS units in California were built in the 1980s over a period of 7 years, with an increase in size from 14 to 80 MW. The recent Nevada Solar One plant is 64 MW, and several announced CSP plants exceed 200 MW. Increasing the size of the power block results in improved cycle efficiency and lower amortized O&M costs. Sargent & Lundy (2003) report a scaling factor of 0.7 for the power block, indicating that a doubling of gross turbine capacity results in only a 62% increase in power block cost (i.e., $2^{0.7} = 1.62$). However, some developers prefer to use multiple, smaller turbines within a single plant because this can yield higher annual availability. For the long term, alternative power cycles—such as supercritical steam, supercritical carbon dioxide ($CO_2$) Brayton, and air Brayton—are being investigated, which offer the potential to increase the efficiency and/or decrease the cost of the power block.

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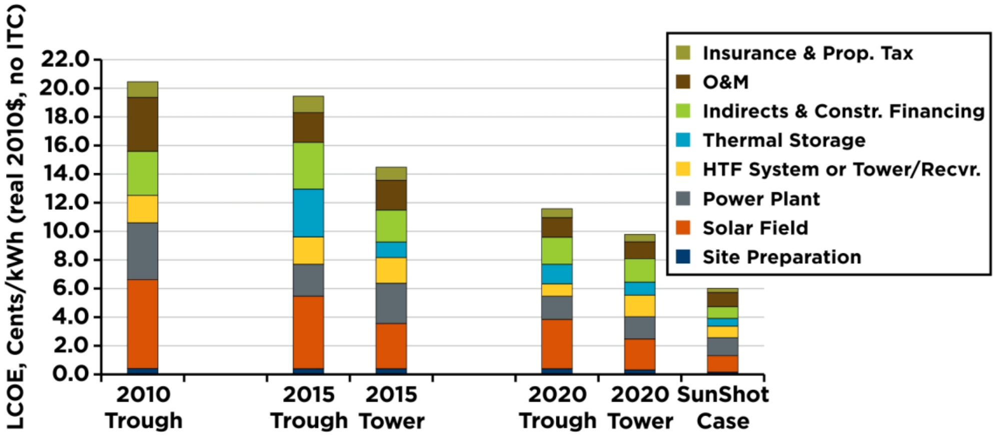
The next generation power cycle is likely the supercritical steam Rankine cycle, because this cycle readily exists at commercial utility-scale fossil plants. However, existing systems are 400 MW electric ($MW_e$) or larger and may need to be scaled down to better accommodate CSP systems. Operating at temperatures above 650°C may require advanced cycles such as supercritical $CO_2$ Brayton or air Brayton, which could provide high thermodynamic efficiencies compared with a traditional Rankine cycle. Commercial natural gas Brayton cycles currently exist; however, supercritical-$CO_2$ and air-Brayton systems do not currently exist beyond the pilot and demonstration scale, respectively. Research efforts are underway to better understand the feasibility of using Brayton cycles for CSP applications.

As unit size increases, the per-megawatt-hour costs for balance of plant and O&M staffing decrease. For plants with multiple units, there is a cost reduction associated with shared infrastructure, such as substations and buildings, and O&M staffing (KJC Operating Co. 1994, Sargent & Lundy 2003). The average O&M cost for CSP is currently about 2.9 cents/kWh and drops to about 1.0 cent/kWh by 2020 in the SunShot target case defined below (Figure 5-11). The main drivers behind the O&M cost reduction are the increase in capacity factor and larger plant sizes. Potential areas for automation, such as reflector cleaning, are also being considered.

Parasitic power consumption can account for 10%–15% of gross turbine output in a CSP plant. Much of this consumption is due to pumping losses, and various options—including pressure-drop reduction, head-recovery, and joint minimization—are being explored to reduce this impact.

A promising low-cost market-entry strategy is augmentation of existing fossil-fired plants with CSP systems. Adding a solar component to an existing fossil-fired plant holds several distinct advantages, including reduction in capital and O&M costs through the use of existing power block hardware and O&M crews, respectively. Such projects have lower risk than stand-alone solar plants and benefit from existing

**Figure 5-11. Current and Projected Costs for CSP Trough and Tower Technologies, per Table 5-1**

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grid connections and inherent fossil backup. A joint study by the National Renewable Energy Laboratory (NREL) and the Electric Power Research Institute (EPRI) suggested that 10–20 GW of solar capacity could be added in the United States through solar augmentation of existing fossil plants (Turchi 2011).

## 5.3.6 Summary of Technology Improvements and Cost-Reduction Potential

In 2009, the DOE CSP subprogram set a goal to reduce the LCOE of CSP technology to 9 cents/kWh or less by 2020. In pursuit of this goal, two multi-year planning exercises—a parabolic trough roadmap and power tower roadmap—were initiated with representatives from the CSP industry, NREL, and Sandia National Laboratories (Kutscher et al. 2010, Kolb et al. 2011). The purpose of these documents was to describe the current technology, the technology improvement opportunities (TIOs) that exist, and the specific activities needed to advance CSP technology.

In 2011, DOE officially unveiled the SunShot Initiative, an aggressive R&D plan to make large-scale solar energy systems cost competitive without subsidies by the end of the decade. The SunShot Initiative takes a systems-level approach to revolutionary, disruptive (as opposed to incremental) technological advancements in the field of solar energy. The overarching goal of the SunShot Initiative is reaching cost parity with baseload energy rates, estimated to be 6 cents/kWh without subsidies, which would pave the way for rapid and large-scale adoption of solar electricity across the United States.

The SunShot Initiative's target for CSP is 6 cents/kWh or less. Although many of the TIOs identified in the roadmaps are applicable to the SunShot cost-reduction target, it is clear that an "extra step" is necessary to move from the roadmap goals to the SunShot targets. In other words, although the roadmaps laid out pathways to next-generation CSP technologies, SunShot requires even more advanced CSP technological breakthroughs.

Estimated current costs and projected future costs for roadmap and SunShot scenarios are presented in Table 5-1 and Figure 5-11. Current CSP costs are largely based on parabolic trough technology, which is the most mature CSP technology. Trough plants without TES are benchmarked by Nevada Solar One, whereas the Andasol plants in Spain represent the state-of-the-art for plants with TES.

Table 5-1 outlines representative cases for current and future CSP technology costs based on the DOE roadmap exercises. A SunShot target case, outlined later in this section, is also shown. The LCOE estimates for the different cases are presented in Figure 5-11. These values are based on the financial assumptions described in Chapter 8. No ITC is applied when calculating these LCOEs. Both the current and projected LCOE estimates for CSP technologies shown in Figure 5-11 are based on values shown in Table 5-1. The contingency percentage shown in Table 5-1 has been added to each direct cost category.

In Table 5-1 and Figure 5-11, 2010 costs are estimated based on a 100-MW parabolic trough plant with no TES, while the 2015 costs are based on a 250-MW parabolic trough plant with 6 hours of TES and a 100-MW molten-salt power tower plant with 6 hours of TES.[54] Both 2015 configurations are representative of current projects with existing PPAs. After 2015, salt-HTF trough and tower systems are assumed to be proven technologies with expanding deployment that leads to reduced costs via learning and manufacturing volume.

## Future Parabolic Troughs

The 2020 trough roadmap case is based on a 250-MW molten-salt HTF trough at a field temperature of 500°C, similar to the configuration being tested by Enel at the 5-MW Archimede demonstration in Sicily. The higher temperature improves power-cycle efficiency and dramatically lowers TES cost. Direct storage of the molten-salt HTF in a thermocline system is assumed, and no adjustment in the performance of the TES system is applied, which assumes improvement in the ability to maintain a sharply stratified thermocline and/or sliding pressure turbine operation with minimal efficiency impacts, as has been suggested by Kolb (2010). Advanced collector designs, employing novel reflector materials and larger-aperture troughs, account for the reduced solar field cost. Operating experience and manufacturing volume are also assumed to lower O&M and capital costs. The major challenge for this case is successful deployment of salt-HTF systems for troughs.

## Future Power Towers

The 2020 tower roadmap case is based on a 150-MW molten-salt HTF tower with a supercritical steam power cycle at 650°C. A slight power block cost increase is included based on the current ratio of subcritical-steam to supercritical-steam power blocks for coal plants.

[54] Although the 2015 power tower analysis presented in Table 5-1 and Figure 5-11 is based on a molten-salt power tower with several hours of TES, the predicted LCOEs for steam and molten-salt power tower technologies are nearly identical. Modeling a steam tower system with little to no storage results in an LCOE prediction within 1 cent/kWh of the 2015 tower values. In addition, much of the cost-reduction potential identified for molten-salt towers also applies to steam towers.

**Table 5-1. Current and Projected Costs and Performance Estimates for CSP Trough and Tower Technologies (Analysis with System Advisor Model Version 2010-11-09)**

| Case | 2010 Trough | 2015 Trough Roadmap | 2015 Tower Roadmap | 2020 Trough Roadmap | 2020 Tower Roadmap | 2020 SunShot Target |
|---|---|---|---|---|---|---|
| **Design Assumptions** | | | | | | |
| Technology | Oil-HTF trough | Oil-HTF trough | Salt tower | Salt-HTF trough | Salt tower | Supercrit. $CO_2$ combined cycle tower |
| Solar Multiple | 1.3 | 2.0 | 1.8 | 2.8 | 2.8 | 2.7 |
| TES (hours) | - | 6 | 6 | 12 | 14 | 14 |
| Plant Capacity (MW, net) | 100 | 250 | 100 | 250 | 150 | 200 |
| Power Cycle Gross Efficiency | 0.377 | 0.356 | 0.416 | 0.397 | 0.470 | 0.550 |
| Cooling Method | wet | dry | dry | dry | dry | dry |
| **Cost Assumptions** | | | | | | |
| Site Preparation ($/m²) | 20 | 20 | 20 | 20 | 20 | 10 |
| Solar Field ($/m²) | 295 | 245 | 165 | 190 | 120 | 75 |
| Power Plant ($/kW) | 940 | 875 | 1,140 | 875 | 1,050 | 880 |
| HTF Sys or Tower/Rcvr ($/m² or $/kW$_{th}$) | 90 | 90 | 180 | 50 | 170 | 110 |
| Thermal Storage ($/kWh$_{th}$) | - | 80 | 30 | 25 | 20 | 15 |
| Contingency | 10% | 10% | 10% | 10% | 10% | 10% |
| Indirect (% of direct costs + contingency) | 17.6% | 17.6% | 17.6% | 17.6% | 17.6% | 13% |
| Interest during Construction (% of overnight installed cost) | 6.0% | 6.0% | 6.0% | 6.0% | 6.0% | 6.0% |
| O&M ($/kW-yr) | 70 | 60 | 65 | 50 | 50 | 40 |
| **Performance and Cost** | | | | | | |
| Capacity Factor | 25.3% | 42.2% | 43.1% | 59.1% | 66.4% | 66.6% |
| Total Overnight Installed Cost ($/kW)[a] | 4,250 | 7,420 | 5,600 | 6,160 | 6,070 | 3,560 |
| Total Installed Cost ($/kW)[a] | 4,500 | 7,870 | 5,940 | 6,530 | 6,430 | 3,770 |
| LCOE (cents/kWh, real) [SunShot financial assumptions] | 20.4 | 19.4 | 14.4 | 11.6 | 9.8 | 6.0 |

Costs for trough and tower systems are based on analyses made in 2009 and 2010 dollars. No adjustments were made to these costs—net changes in labor and commodity prices for the period are assumed to be within the error of the analysis.

[a] A project's "overnight installed cost" is the total direct and indirect costs that would be incurred if the project was built in an instant, that is, there are no additional costs for financing the construction period. A project's "total installed cost" is its overnight installed cost plus any financial costs incurred to cover payments made during the period between the start of construction and plant commissioning.

Direct storage of the molten-salt HTF in a thermocline system is assumed, and, as with troughs, no adjustment in performance of the TES system is applied. System availability increases and O&M cost reductions are due to increased operating experience. Improved heliostat designs, along with manufacturing experience and scale, account for the reduced solar field cost. The major challenge for this case is scale-down of supercritical steam turbomachinery from the 400-MW or larger scale currently deployed for coal plants to the 150-MW size proposed for CSP.

### SunShot Options

The 2020 SunShot case requires more aggressive advances in performance improvements and cost reductions than assumed by the roadmap cases. SunShot-level cost reductions likely include an increase in system efficiency by moving to higher-temperature operation (i.e., maximizing power-cycle efficiency) without sacrificing efficiency elsewhere in the system (i.e., minimizing optical and thermal efficiency losses). Likewise, reducing the cost of the solar field and developing high-temperature TES compatible with high-efficiency, high-temperature power cycles are critical to driving costs down further.

Reaching the SunShot cost target of 6 cents/kWh will require improvements to all subsystems within a CSP plant. The primary source of efficiency gains is the development and implementation of advanced power cycles, with the leading candidates for CSP applications being supercritical-$CO_2$ Brayton and air-Brayton power cycles. Although there are multiple potential pathways to reaching SunShot targets, the 2020 SunShot case presented in Table 5-1 is based on a 200-MW power tower utilizing a supercritical-$CO_2$-Brayton power cycle. Power towers may have the highest potential for achieving the SunShot target due to their combination of high optical concentration, high temperature, ease of TES integration, and ability to scale over a wide range of capacities. The development of these new CSP power blocks will require detailed modeling of power systems, followed by the development and testing of new turbomachinery, instrumentation, and heat exchanger designs. The 2020 SunShot case shown in Table 5-1 and Figure 5-11 assumes the deployment of a supercritical-$CO_2$ power cycle combined with a Rankine bottom cycle. A high-temperature salt serves as receiver HTF, and TES is provided by direct storage of the HTF in a thermocline. Fourteen hours of storage was selected as a value that minimizes LCOE for the assumed case conditions. Supercritical $CO_2$ power cycles are under development by a variety of academic, laboratory, and industry players for application to solar, advanced fossil, and other energy applications (Rochau 2011). Such a design offers the potential of high overall system efficiency while running at temperatures several hundred degrees lower than required for air-Brayton cycles, thereby lessening materials and thermal loss concerns.

Regardless of the power-cycle design, achieving the SunShot target will require significant reductions in collector costs while minimizing optical efficiency losses. It is essential to remove material weight from the solar field while maintaining adequate wind-load rigidity and optical accuracy. The primary cost components of heliostats include the reflector module, support structure and pylon, drive systems, wiring, and manufacturing infrastructure, all of which will need to be addressed. Proposed improvements include polymeric or thin-glass reflectors, anti-soiling coatings to maintain reflectivity while decreasing O&M costs, novel structures with significantly reduced material content, low-cost drives with wireless field controls, and highly automated manufacturing and installation procedures.

The development and testing of new solar receiver designs and materials will be necessary to accommodate the deployment of advanced, high-temperature power cycles. Air-Brayton systems running at temperatures of 1,000°C and higher may require volumetric receivers or designs with secondary concentrators; such designs are currently being investigated as part of the European Solugas project. Although supercritical-$CO_2$ systems will run at lower temperatures (600°C–800°C), they will still require the determination of compatible materials and receiver designs for high-pressure $CO_2$ systems. Selective receiver tube surface coatings that maintain high absorptivity while minimizing emissivity and are stable at high temperatures in air are needed for new receiver designs. Initial research suggests that candidate materials may be found among those originally investigated for trough receiver coatings.

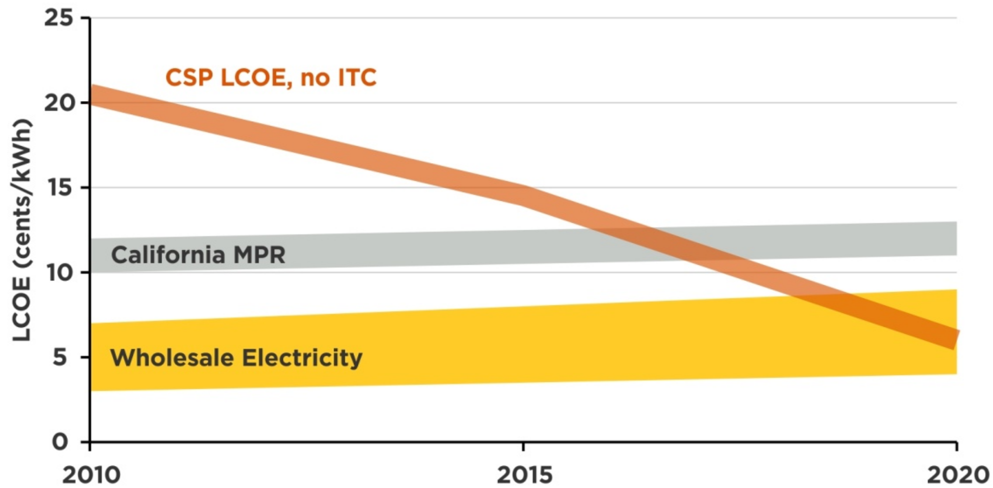


Lastly, as temperatures are increased and new HTFs are deployed, TES systems will need to advance to maintain the relatively high efficiency and low cost of current CSP TES systems. Supercritical steam and $CO_2$ are compatible with thermocline and two-tank storage concepts, but salts with stability and low corrosivity at the proposed higher temperatures may be required. Air-Brayton cycles in particular would benefit from low-cost solid-phase storage media or other novel TES concepts. Although the SunShot case presented in Table 5-1 and Figure 5-11 assumes a supercritical-$CO_2$ combined cycle with salt storage, alternative approaches are being considered and may prove a better fit.

The combined effect of lower capital costs, improved performance, and learning should lead to a rapid drop in LCOE by the end of the decade. Figure 5-12 shows the calculated decrease in LCOE if the CSP industry achieves the SunShot cost and performance targets presented above. The LCOE estimates in Figure 5-12 are based on the financial assumptions listed in Table 8-1 of Chapter 8, which are applied to both CSP and utility PV cases. In the near term, CSP with a 30% ITC is competitive with the solar-weighted California Market Price Referent (MPR). The California MPR represents the market price of electricity in California and is used as a benchmark to assess the above-market costs of renewable portfolio standard (RPS) contracts in California (CA PUC 2009). Solar weighting refers to the time-of-delivery credit applied to solar generation due to its good coincidence with peak load. When the 30% ITC expires at the end of 2016, CSP is projected to remain competitive with the California MPR. The LCOE projections shown in Figure 5-12 do not include any ITC, even though current U.S. law maintains a 10% ITC after 2016. This choice is made to be consistent with the SunShot Initiative's goal of making large-scale solar energy systems cost competitive without subsidies by the end of the decade.

Finally, although installed cost and LCOE are dominant metrics, they are not the sole criteria for technology selection. For example, CSP with TES is recognized to achieve close to 100% capacity value—much higher than wind or PV systems (Lew 2010). This dispatchability provides greater grid stability, especially as renewable generation penetration increases. As one example of this value, Arizona Public Service applied up to a 3 cents/kWh of credit to CSP for operational and capacity credit (APS 2009).

**Figure 5-12. Projected SunShot CSP LCOE (2010 U.S. Dollars, Real) versus Future Market Prices**




## 5.4 Materials and Manufacturing Requirements

The long-term availability of materials and manufacturing capacity is critical for increased deployment of CSP plants. The analysis here focuses on the most important raw materials needed for the SunShot scenario: aluminum, steel, glass, HTF, and molten salt. In general, these materials are not subject to rigid supply limits, but they are affected by changes in commodity prices. Manufacturing and supply chain issues are also considered.

### 5.4.1 Materials

Table 5-2 provides the construction material breakdown for a 100-MW parabolic trough plant with 6 hours of TES and a solar multiple of 2.2, i.e., for 2010 technology design and performance characteristics as adapted from Burkhardt et al. (2010), which assumes a 103-MW plant with 6.3 hours of TES. The estimates shown in Table 5-2 do not include commonly available construction materials such as gravel, asphalt, and various plastics, which may be used in significant volumes in CSP plants but generally are not subject to supply constraints. The baseline plant depicted in Table 5-2 generates approximately 426,000 MWh of net energy per year.

Table 5-3 uses the data in Table 5-2 to provide a preliminary estimate of the annual material requirements for CSP assuming the SunShot targets are met. The SunShot scenario assumes peak annual U.S. CSP installations of 4 GW. Similar to the baseline plant shown in Table 5-2, in order to be conservative, a 100-MW trough plant capacity is assumed, although the solar multiple and hours of TES have been increased to 2.8 and 12, respectively. In addition, material requirements have been adjusted to account for the estimated efficiency improvements in the SunShot case. Whereas Table 5-2 is for a parabolic trough plant, Table 5-3 assumes a mix of CSP technologies. This scenario assumes that the transition to next-generation CSP technologies includes higher-temperature operation and a transition away from synthetic oil as an HTF.

**Table 5-2. Construction Materials for Nominal 100-MW Parabolic Trough Plant with 6 Hours of TES**

| Material | Trough Plant Subsystem (MT) | | | | |
|---|---|---|---|---|---|
| | Solar Field | HTF System | Power Block | Thermal Storage | Total |
| Aluminum | 16 | 51 | 18 | 0 | 86 |
| Other Non-Ferrous Metal | 68 | 6 | 66 | 2 | 142 |
| Steel and Iron | 17,556 | 3,346 | 2,277 | 3,654 | 26,833 |
| Glass | 10,971 | - | 11 | 0 | 10,982 |
| Concrete | 27,184 | 5,709 | 18,738 | 9,339 | 60,970 |
| Synthetic Oil | 0 | 4,146 | 0 | 0 | 4,146 |
| Nitrate Salts | 0 | 0 | 0 | 57,328 | 57,328 |

Source: Adapted from Burkhardt et al. (2010)



**Table 5-3. Projected Annual Material Requirements for CSP Assuming Maximum SunShot (4 GW/year) U.S. Deployment**

| Scenario | Material Requirements (MT) | | | | |
|---|---|---|---|---|---|
| | Glass | Aluminum | Steel and Iron | Synthetic Oil | Molten Salt |
| SunShot | 360,000 | 2,700 | 840,000 | — | 1,000,000 |

Glass for CSP reflectors is manufactured via a float glass process. Global production of common float glass in 2007 was approximately 44 million MT, while global production capacity was estimated at 65 million MT (AGC Flat Glass 2010). U.S. production of float glass in 2007 was approximately 5.5 million MT, with additional available capacity of approximately 0.5 million MT (Headley 2008). Based on this standard float glass capacity, the glass requirements in the SunShot case correspond to approximately 7% of 2007 U.S. production or less than 1% of 2007 global production. However, CSP plants use low-iron glass, which is produced through a similar process as common float glass, but with specific feedstock sand and rigorous contamination requirements. Current production of low-iron glass is limited by relatively low demand, which in turn leads to reduced production runs and increased cost. Increased demand for low-iron glass would result in the operation of dedicated production lines and reduced costs.

Although glass is clearly not a constraint on increased CSP deployment, it is possible that non-glass reflectors—such as reflective films laminated onto aluminum sheets—may be used in commercial CSP facilities as the technology continues to mature. If all CSP were to use non-glass films as reflectors, approximately 40 million $m^2$ of reflecting material would be required on an annual basis. This volume is roughly half of the current production volume of solar-control window film (which requires a similar production process) of approximately 80 million $m^2$ annually.

The SunShot scenario relies primarily on steel for the solar field structures, with additional steel needed for HTF piping, molten-salt storage tanks, heat exchangers, and the power block. The peak steel requirement in the SunShot scenario is less than 1 million MT/year, or approximately 1% of the 84 million MT of U.S. steel production in 2008 (Fenton 2010).

Aluminum can serve as a replacement material for a significant fraction of the structural steel in CSP plants and can also be used as the reflector material in CSP plants using thin-film reflectors. Each MW of solar collector field using aluminum-based structures would require approximately 50 MT of aluminum with a solar multiple of two. An additional 22–29 MT/MW would be required for plants using coated aluminum or thin-film laminated reflectors. A deployment scenario including a shift to aluminum would reduce steel requirements in Table 5-3 by approximately 50%; however, it would also require approximately 300,000 MT of aluminum per year for SunShot scenario deployment. Aluminum production in the United States in 2008 was approximately 2.4 million MT, with another 4.1 million MT imported (Fenton 2010). Thus, a deployment scenario including a shift to aluminum could require up to 5% of current annual U.S. aluminum use.



The current HTF for existing parabolic trough systems consists of a eutectic mixture of diphenyl oxide and biphenyl. This fluid type is widely used in large volumes in the global chemical industry, and there appears to be no supply constraints. Regardless, the SunShot scenario assumes a shift away from synthetic oil as an HTF to other materials that can operate at higher temperatures, such as molten salt.

Molten salt is currently used as the TES medium in most CSP storage system designs and as the HTF in salt-receiver power towers. Much of the world's nitrate salts are derived from deposits in the Atacama region of Chile. Proven reserves are 29.4 million MT, although this figure is based on exploration of only 16% of total reserves (SQM 2009). Burkhardt et al. (2010) estimate that the nitrate salt requirement for a thermocline storage system is approximately 32% of the two-tank system assumed in Table 5-2 and that higher-temperature TES would reduce this requirement even further. As a result, Table 5-3 assumes a MT/MW nitrate salt requirement equal to approximately 22% of the requirement in Table 5-2. For SunShot scenario total deployment levels, the cumulative required salt is roughly two-thirds of proven Chilean reserves. Although alternative salts for storage and/or HTFs could be used, the use of nitrate salts is still feasible. If nitrates remain the salt of choice, it is possible that increased CSP deployment would require expansion of nitrate salt production, possibly including synthetic production via the Haber-Bosch process, which is used worldwide for fertilizer production.

### 5.4.2 Manufacturing and Supply Chain

The CSP supply chain is overwhelmingly domestic, from materials to manufacturing. Most, if not all, materials necessary to build a CSP plant can be found in the United States. However, substantial increases in the manufacturing capacity of CSP components will be required to achieve the SunShot scenario. CSP plants require a number of components; some are similar to other industrial components and others are unique to the industry. In addition to the structural and reflector components, CSP plants require manufacturing of receiver components and the power block.

Reflectors are manufactured from readily available materials. The current manufacturing capacity is consistent with the requirements for facilities under construction or scheduled for construction in the near term. It takes approximately 1 year to construct a glass reflector manufacturing line. Therefore, as the demand for reflectors increases, the reflector industry should be able to ramp up production quickly enough to meet demand. As a result, the availability of reflectors should not be a bottleneck to achieving the SunShot scenario.

Receiver tubes for parabolic troughs and linear Fresnel plants are fabricated from readily available materials such as glass tubing, stainless-steel tubing, and steel bellows. Although the materials are basic, manufacturing high-quality receivers does require expertise and specialized processes. This could create short-term constraints on scaling-up manufacturing of receivers. The current manufacturing capacity, however, is adequate to meet the demands for facilities currently under construction and scheduled for construction in the near term. Experience with current manufacturers of receiver tubes shows that significant manufacturing lines can be brought to production in approximately 1–2 years.



Power tower receivers are similar in design to standard industrial boiler equipment. All developed countries and many developing countries have boiler manufacturing capabilities and are capable of fabricating components such as steam boilers and pressure vessels. Boilers and turbines to be used in CSP plants will replace similar products that would have been manufactured for fossil-fuel power systems. The manufacturing capability that exists to build conventional fossil-fuel boilers can be readily adapted to fabricate multiple gigawatts per year of steam or molten-salt receivers. A good example of this adaptation is the steam receivers fabricated for the Sierra Sun Tower in Lancaster, California. These receivers were manufactured by two separate conventional boiler shops in the United States without significant changes to the shop floor or development of new manufacturing techniques.

In a dish/engine system, the receiver and power block subsystems are well integrated into a single unit. Dish/Stirling engines use materials and manufacturing processes common to the automotive industry that allow for efficient mass production.

For parabolic trough, power tower, and linear Fresnel systems, the current power block is very similar to those used in conventional fossil-fired plants, thus, manufacturing capabilities for these power blocks and other system components are available worldwide. The development of new turbomachinery—such as that required for new supercritical-$CO_2$ or air-Brayton solar turbines—will also use materials and manufacturing processes common to the existing gas and steam turbine industries.

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