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

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5.1 Introduction

Today nearly 700 megawatts (MW) of concentrating solar power[1] (CSP) capacity is in operation worldwide, all in the United States and Spain. Over half of this capacity was built in southern California in the 1980s. In the past few years seven utility-scale plants have been built and more than ten gigawatts (GW) of capacity is under construction or under contract worldwide. Many new large-scale CSP plants, with signed power purchase agreements, are under development in the U.S. Southwest, and this trend is expected to accelerate as energy companies broaden their generation mix to include solar and strive to meet state renewable portfolio standards. Changing attitudes and policies toward solar power projects, recognition of CSP's capability of providing dispatchable energy, new power purchase agreements by major utilities, and over two gigawatts of planned new CSP capacity in Spain, indicate that the CSP industry is poised for rapid growth. The present robust mix of CSP backing—composed of diverse demonstrated technologies, a large number of experienced project developers, and increasing government R&D activity can provide momentum to overcome the challenges facing CSP as it heads for a mainstream role in the electricity portfolio. Those challenges include cost, financing, permitting and transmission.

CSP is of particular interest to utility companies due to its proven dispatch capability and solid long-term performance history. Most CSP technologies have the ability to integrate thermal energy storage and/or fossil fuel hybridization into the plant design, thus creating a firm energy resource that can be easily integrated with the electric grid. The current technology leaders expect cost reductions and increased operational flexibility. Although the current cost of electricity generated by CSP is high compared to traditional generation options, this cost is expected to decrease as the technologies mature and deployment increases. Furthermore the cost gap is expected to diminish when a carbon policy is established. Together with its unique capability to provide firm, dispatchable generation, CSP's prospects for low-cost conversion of abundant, domestic, clean fuel can make it an important contributor to national energy security and today's U.S. energy infrastructure.

[1] This may also be referred to as concentrating solar thermal power (CSTP)

5.2 TODAY'S CSP TECHNOLOGY

There are four demonstrated types of solar thermal power systems: parabolic trough, central receiver or power tower, dish/engine, and linear Fresnel reflector technology. All of these technologies involve a heat-driven engine, and the first two have demonstrated that they can be readily hybridized with fossil fuel and/or adapted to use thermal storage. Thermal energy storage is expected to play an increasingly important role over time due to its operational benefits including increased capacity factor.

5.2.1 TECHNOLOGY TYPES

Parabolic Trough

Parabolic trough systems are currently the most proven CSP technology due to a long commercial operating history starting in 1984 with the SEGS plants in the Mojave Desert of California, shown in Figure 5-1 and continued with Nevada Solar One and the several commercial trough plants in Spain.

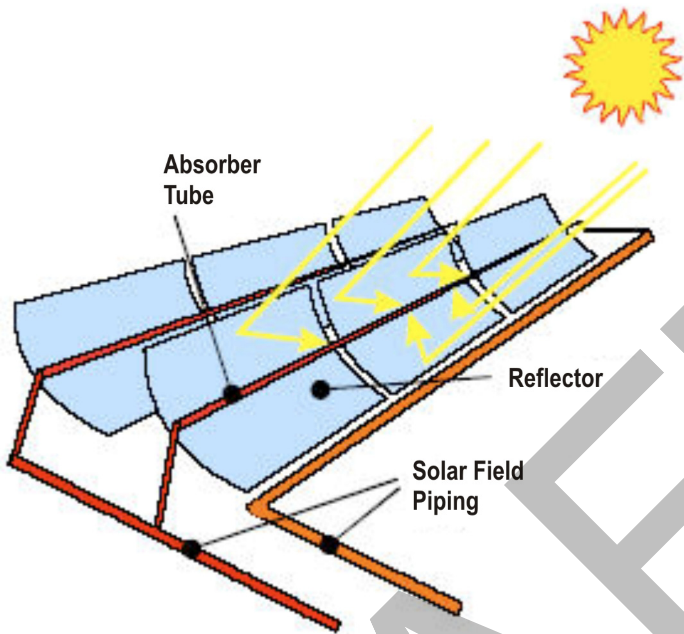
Figure 5-1. SEGS Parabolic Trough Plants in California's Mojave Desert

Parabolic trough power plants consist of large fields of mirrored parabolic trough collectors, a heat transfer fluid/steam generation system, a power system such as a Rankine steam turbine/generator, and optional thermal storage and/or fossil-fired backup systems. The use of thermal storage 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-derived electricity.

The solar field is made up of large modular arrays of single-axis-tracking solar collectors that are 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, as shown in 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 a heat transfer fluid (HTF) is heated to nearly 400ºC.

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

Figure 5-2. Parabolic Trough Field Components



transformed back into steam. Wet, dry, or hybrid cooling towers can be used for heat rejection from the condenser; the selection will influence water usage, cycle performance and cost.

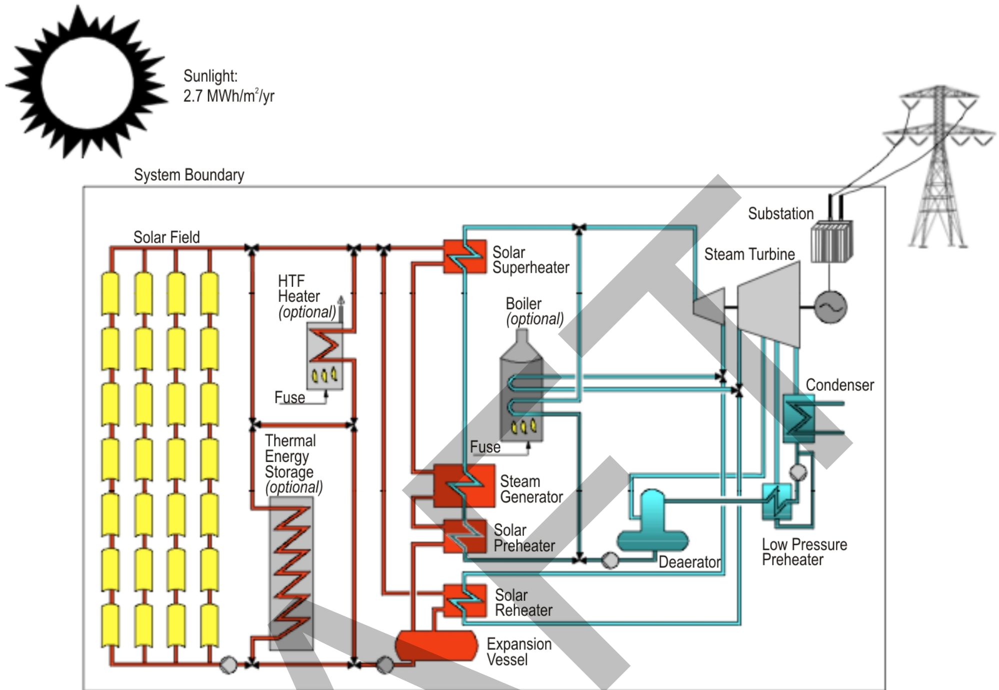
The current design point solar-to-electric efficiency (the net efficiency when the sun is directly overhead) for parabolic trough ranges from 24 to 26%.

A unique and very important characteristic of trough and power tower (discussed later) CSP plants is their ability to dispatch power beyond the daytime sun hours by incorporating highly efficient thermal energy storage (TES) systems (about 98% of the thermal energy placed into storage can be recovered). During summer months, for example, plants typically operate for up to 10 hours a day at full-rated electric output without thermal storage. However, significant additional full-load generation hours can be efficiently added or shifted if thermal storage is available, allowing a plant to also meet the morning and evening winter peaks. This requires increasing the size of the collector area in order to be able to produce excess thermal energy during the day, i.e., beyond what is needed to run the plant, which can be put into thermal energy storage for later use. Another method is to configure the systems as hybrid plants, that is, provide a secondary backup system to supplement the solar output during periods of low solar irradiance. Use of fossil fuels is typical, but use of renewable fuels such as biomass is also possible. This alternative hybrid approach allows solar plants to better match the utility system load profile. Figure 5-3 shows a schematic of a trough plant with optional fossil-fired boiler and thermal energy storage.

Power Tower

Power towers (also called central receivers) are in the demonstration to early-commercialization stage of development. Because of their higher operating

Figure 5-3. Plant Operation with Fossil-fired Backup System



temperatures, power towers have the potential to achieve higher efficiency and lower cost energy storage compared to today's trough technology.

Power towers use heliostats, which are mirrors that rotate about both the azimuth and elevation axes, to reflect sunlight on the central receiver. A large central receiver plant requires several thousand heliostats, each under computer control. Since they typically comprise about 50% of the plant cost it is important to optimize their 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 percent or more slope), thereby reducing cost requirements of site preparation for new projects. Figure 5-4 shows a heliostat array and receiver.

The two principle power tower technology concepts currently being pursued by developers, defined by the heat transfer fluid in the receiver: steam and molten salt. Both concepts have unique operating characteristics that are detailed below.

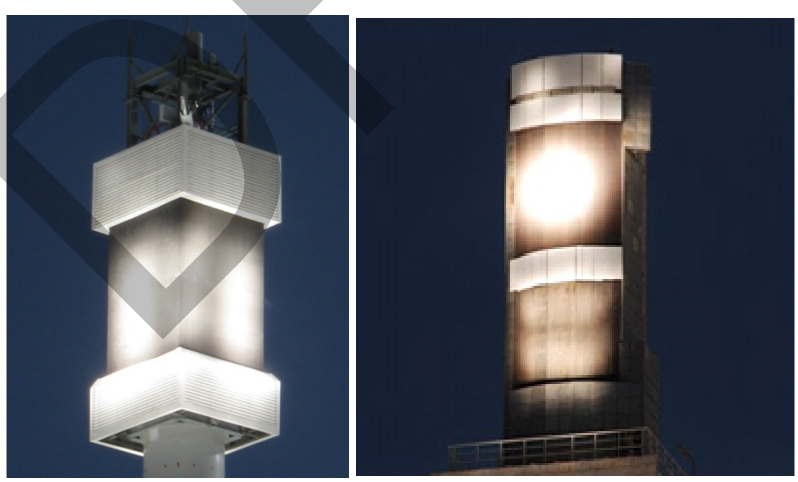
In direct steam power towers, heliostats reflect sunlight onto a receiver on a tower, which is similar to a boiler in a conventional coal-fired power plant. The feed water, pumped from the power block, is evaporated and superheated in the receiver to produce steam which feeds a turbine generator to generate electricity. In some concepts the receiver produces saturated steam which feeds a turbine generator. There are several characteristics of direct steam power towers that make them attractive: their straightforward design, high reliability, use of conventional boiler technology, materials, and manufacturing techniques, high thermodynamic efficiency, low parasitic power consumption, and lower perceived technology risk.

Figure 5-4. BrightSource 6 MWth Demonstration Facility near Dimona, Israel

Thermal storage for direct steam receiver technology can be incorporated primarily for short durations to buffer variable solar radiation during partly cloudy weather.

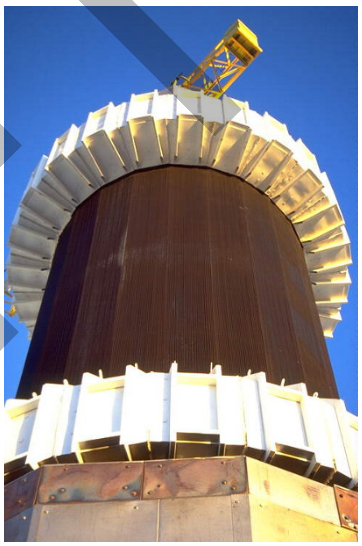
Figure 5-5 shows eSolar's (left) and BrightSource's (right) direct steam receivers in operation.

Figure 5-5. Direct Steam Receivers in Operation



In a molten salt power tower, salt at about 550°F (290°C) is pumped from a cold storage tank to a receiver where concentrated sunlight from the heliostat field heats the salt to about 1050°F (565°C). The hot salt is stored in a storage tank and when electric power generation is required, hot salt is pumped to the steam generator, which produces steam at a nominal temperature of about 1000°F (540°C). The now cooler salt from the steam generator is returned to the cold salt storage tank to complete the cycle. Both storage tanks are at atmospheric pressure. The steam is converted to electric energy in a conventional steam turbine power plant. By placing the storage between the receiver and the steam generator, solar energy collection is decoupled from electricity generation. Thus, cloud transients (passing clouds which temporarily reduce direct normal radiation) do not impact turbine output. In addition, the energy storage is about three times less expensive than trough plants because the higher temperature enables a smaller storage volume. The combination of salt density, salt specific heat, and temperature difference between the two tanks allows economic storage capacities up to 15 hours of turbine operation at full load. Such a plant would run 24/7 in the summer and part-load in the winter to achieve a 70% solar-only annual capacity factor. Similar to trough plants, power towers can be designed with an expanded collector area which enables the production of excess heat, i.e, in excess of the requirements of the power generator, that can be put into thermal energy storage.

Figure 5-6. 43 MWth Molten Salt Receiver at Solar Two



A photograph of the 43 MWth receiver at the 10 MW Solar Two central receiver demonstration project (completed in 1995 in Barstow, CA) is shown in Figure 5-6.

Linear Fresnel

Linear Fresnel reflectors (LFR) are in the demonstration phase of development. LFRs are expected to be lower cost compared to other CSP technologies, but they also are less efficient. The relative energy cost remains to be established.

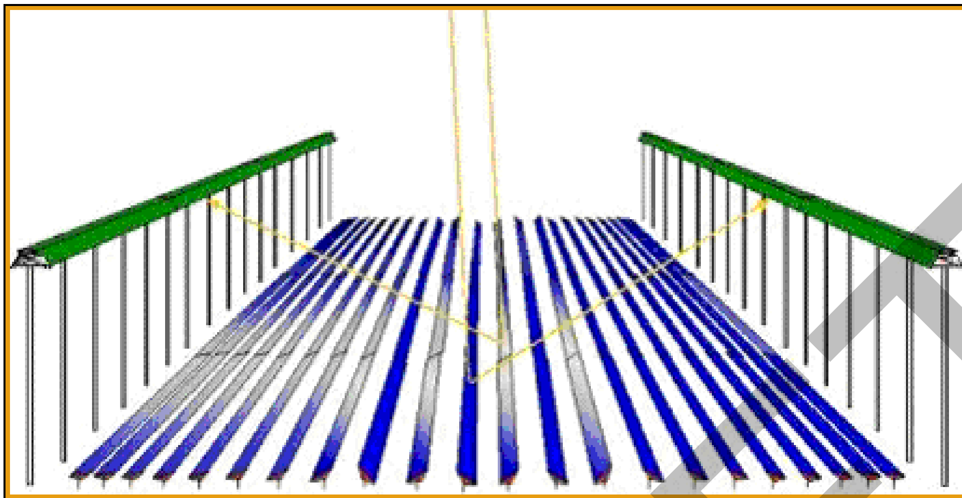
LFRs approximate the parabolic shape of a traditional trough collector with long, ground-level rows of flat or slightly curved mirrors that reflect the solar rays onto an overhead, downward-facing linear receiver. Simple designs of flat mirrors and fixed receivers lead to lower capital costs relative to a traditional trough, but the LFR plants are less efficient on a solar-to-electricity basis. Recently superheated steam has been demonstrated at about 720°F (380°C), and there are proposals for producing steam at 840°F (450°C).

LFR technology uses a compact design with two parallel receivers for each row of mirrors (see Figure 5-7). This configuration offers minimal mutual blocking of adjacent reflectors and minimizes ground usage. Another advantage is that, depending on the position of the sun, the mirrors can be alternated to point at different receivers, thus improving optical efficiency.

Dish

Dish technology is in the demonstration and early commercialization stage. Dish systems can achieve higher efficiencies than trough, tower, and LFR technologies.

Figure 5-7. Compact Linear Fresnel Reflector Field



The first dish Stirling commercial demonstration entered operation in January 2010, and significant deployments are expected in the next several years.

Dish CSP technology uses a collection of mirrors assembled in the shape of a parabolic dish to concentrate sunlight onto a fixed focal point. At the focal point, an engine collects this solar energy and converts it into electricity. All dishes rotate along two axes to track the sun for optimum capture of insolation. Current dish systems generate between 3 to 30 kilowatts of electricity, depending on the size of the dish and the heat engine utilized. There are currently three major types of engines at the core of dish technology: kinematic Stirling engines, free-piston Stirling engines, and Brayton turbine-alternator based engines. Both kinematic and free-piston Stirling engines harness the thermodynamic Stirling cycle to convert solar thermal energy into electricity through the employment of a working fluid, such as hydrogen or helium, to drive a pressure-based Stirling cycle engine. Closed-cycle Brayton systems use turbine/alternator engines with compressed hot air to produce electricity.

Some dish technology can be installed on relatively uneven land (with 5 percent or more slope), thereby reducing the cost of site preparation for new projects. Remote installations are possible due to negligible water requirements for mirror washing and the utilization of a closed loop or dry cooling system that does not consume water for cooling.

As a modular technology, dish systems are built to scale to fit the needs of each individual project site, potentially satisfying loads from kilowatts to gigawatts. This scalability makes dish technology applicable for both distributed and utility-scale energy generation sites. Dish Stirling systems have demonstrated the highest recorded CSP technology design-point solar to electric efficiency at 31%.

Example dish systems are shown in Figure 5-8.

Figure 5-8. SES SunCatcherTM and INFINIA's POWERDISH

5.2.2 Cost and Performance

The current performance and cost of CSP plants varies by technology, configuration, solar resource, and financing parameters. It is possible to evaluate alternative plant designs and technologies in terms of a single index – the levelized cost of electricity (LCOE). The most important inputs for the LCOE calculation are the upfront capital investment; the plant capacity factor and DNI; O&M costs; and, financing parameters. One factor that influences the capital investment is the solar-to-electric efficiency. Plants with higher efficiency require less land and less mirror surface area to collect sunlight and produce electricity. Capacity factors vary greatly between different locations, technologies and plant configurations. For example, plants with thermal energy storage achieve higher capacity factors because they have more hours of operation. The trade-off is that the larger collector field and storage system for these plants leads to a higher upfront capital investment. Systems with storage are likely to be more cost effective in the future. The O&M cost, of which staff is the largest contributor, decreases with an increase in plant size and multiple units at one site.

Capital costs for today's CSP plants range from approximately $3200/kW to $6500/kW. The upper end of the range reflects plants with thermal energy storage. Storage is currently available for trough and molten salt towers, and the largest projects have about 6 to 7.5 hours of storage capacity. Plant capacity factors extend from 20-28% for plants with no storage to 30 -50% for plants with 6-7.5 hours of storage. The levelized cost of electricity varies greatly depending on the location, ownership, the values of key financing terms, available financial incentives, and other factors. For locations in the southwestern US, the LCOE is currently in the 14-20¢/kWh range with a 30% tax credit.

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. Reduction in capital cost will be a consequence of manufacturing and installation scale-up as well as technology advancements through R&D efforts aimed at cost reduction and performance improvements. A number of component and system level advancements are currently being pursued. These improvements can be generally classified into one of the various sub-systems discussed below.

5.3.1 SOLAR FIELD

The key to reducing solar field costs is reducing the cost of the collector support structure, mirrors, and receivers. Suppliers will offer lower prices for large orders and drop in price as volume increases. For the structures, developers are looking at reducing the amount of material and labor necessary to provide accurate optical performance. For mirrors, cost reduction may be accomplished by moving from heavy glass mirror reflectors to lightweight front-surface reflectors (thin film). Solar field components (drives, controls, support structures, heat collection elements, etc) can also be improved to increase the efficiency and reduce the delivered cost of energy. Advanced reflector coatings are under development to increase reflectivity (from current values of about 93.5% to 95% or higher) to support lowest cost and highest reflector efficiency. Coatings are also being explored to reduce the amount of water and frequency of cleaning required to maintain effectiveness. Advanced receiver cost reduction focuses on improving the reliability of the glass-to-metal seals (for trough receivers) and developing lower cost and higher performing coatings for trough, tower, and dish receivers. Advanced concentrator and heliostat designs that use integrated structural reflectors are expected to allow the cost of the structure and reflectors to be significantly reduced, thereby reducing installation costs by easier and faster assembly of the solar field.

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 that can take advantage of thermal storage, lower cost of thermal energy storage. For commercial parabolic trough systems the maximum operating temperature is limited by the heat transfer fluid, currently a synthetic oil with a maximum temperature of 390°C. Other limitations include the cost of the fluid, the need for heat exchange equipment to transfer thermal energy to the power cycle or storage system, and proper treatment of spills (the infrequent spills that occur at operating plants are readily treated by on-site bioremediation). Several parabolic trough companies are experimenting with alternative heat transfer fluids that would allow operation at much higher temperatures. However, due to the low concentrations intrinsic to parabolic trough systems (about 80 suns), an increase in solar field temperature will likely result in unacceptable thermal losses from the heat collection element at temperatures beyond 450-500°C. This suggests an upper practical limit on operating temperature in this range.

Alternative designs may incorporate higher temperature HTF. For example, several manufacturers are pursuing a higher concentration design with molten nitrate salt as its HTF, designed to operate at higher temperature (1020°F (550°C)), which can be more easily integrated into designs with thermal energy storage.

Due to higher concentration ratios associated with tower systems, operating temperatures as high as 1000°C may be practical depending on the medium used for the heat transfer fluid, e.g., air heat transfer fluid for solar Brayton cycles. Because today's tower designs are in the early stages of commercial development, each technology provider has a different approach for achieving a combination of low cost, high performance, and high market value. One of the most important considerations driving the system design is the choice of heat transfer fluid used in the receiver. Current options include water/steam, molten salt, or air. With higher operating temperatures (600^0C to 700^0C), supercritical steam turbines, which are commercially available can be used. Supercritical CO_2 may be an option when and if turbines are developed for future integration with solar plants. Molten salts with lower freeze temperatures would also be beneficial. The choice of heat transfer fluid greatly influences whether a particular design can be integrated with thermal energy storage. For example, while small amounts of steam can be stored in relatively small 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 hot and cold storage tanks at a relatively low cost.

5.3.3 Thermal Energy Storage

Large-scale storage systems only recently appeared in CSP plants. CSP can use relatively inexpensive and efficient heat storage to provide firm and dispatchable electricity to the grid. Thus, CSP plants can run after the sunset to match evening peak loads, or even round-the-clock if base-load production is required. Plants with thermal energy storage have collector fields that are larger than the minimum size required to operate a Rankine cycle at full load. The ratio of the collector field thermal power to the power required to operate the Rankine 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 energy required for the generator to produce maximum power under optimal solar conditions. A system with an oversized solar collector field, i.e., solar multiple greater than one, can operate closer to the design point for more hours of the year. The excess heat from the collector field is sent to thermal storage. When power is needed the heat is extracted from the storage system and sent to the steam cycle. An example of a deployed project with storage is the Andasol 1 plant in Spain which provides heat storage from a two-tank molten salt system, the basic commercially available technology. The 50 MW plant uses 28,500 metric tons of nitrate salts, offering a storage capacity of 1000 MWth, or about 7.5 hours of power production. The salt temperature ranges from 558°F (292°C) in the cold tank to 727°F (386°C) in the hot tank.

Although additional investment is required to expand the collector area and add storage tanks etc, the use of thermal storage ultimately reduces the cost of energy from the plant by increasing the capacity factor of the power block. Thermal energy storage can increase the plant capacity factors from about 25% in current solar-only plants to greater than 70%. The near term high-temperature storage option for both parabolic trough and tower systems uses molten nitrate salt as the storage medium in a two-tank system. For parabolic trough systems, while technically feasible as demonstrated by use in current commercial plants, the relatively low temperature difference between the hot and cold tank make this arrangement economically unattractive for the long term. Low melting point salt mixtures, solid media storage, single-tank thermoclines and engineered materials (e.g., storage materials with dispersed nanoparticles for increased heat capacity), are being investigated to improve the economics of storage for trough systems. For tower or parabolic trough systems using steam as the heat transfer fluid, steam compatible storage systems have yet to be demonstrated beyond the pilot scale and significant efforts are underway to make such systems commercially feasible.

Solar tower plants operate at higher temperatures and can reduce the amount of storage salt by about a factor of 3 relative to a trough plant. This very significant reduction in storage mass and associated costs makes it possible to add higher storage capacities. Very long term storage makes near-baseload operation possible. However, at least for the near term, troughs and towers will likely be built with lower levels of storage (approximately 6 hours) to maximize the rate of return for a given installation.

Several methods for energy storage are being explored to support dish technologies, including thermal energy storage utilizing phase-change materials, compressed air storage, and synergistic hybrid systems.

An important aspect of adding storage to a CSP plant is the increased value of produced energy. While delivered cost of energy is an important metric, it does not capture the value of being dispatchable. Adding storage to a CSP plant adds value by decreasing variability, increasing predictability, and by providing firm capacity. This can be observed in the system dispatch in Chapter 3 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

The need for cooling water may increase operational costs, or restrict CSP development where water availability is limited. Current wet-cooled CSP plants require 750-950 gallons/MWh (see Chapter 8 for additional discussion of water use.) There are several strategies for reducing freshwater consumption in thermoelectric power generation: dry cooling, use of degraded water sources, capturing water that would otherwise be lost, and increasing thermal conversion efficiencies. Dry and hybrid cooling systems have the potential to reduce water consumption by 40 to 97%, depending on the generating technology and project location, but at a higher cost and with a performance penalty. Additional research on indirect air-cooling or other improvements to improve efficiencies and reduce costs for dry cooling may be warranted. Examples of R&D efforts to reducing water use for wet or hybrid cooling includes recovering water that is evaporated in cooling towers or use of non-traditional sources for cooling water, such as treated saline groundwater, reclaimed water, or water produced from oil/gas extraction.

5.3.5 Power Block & Other Cost Reduction Potential

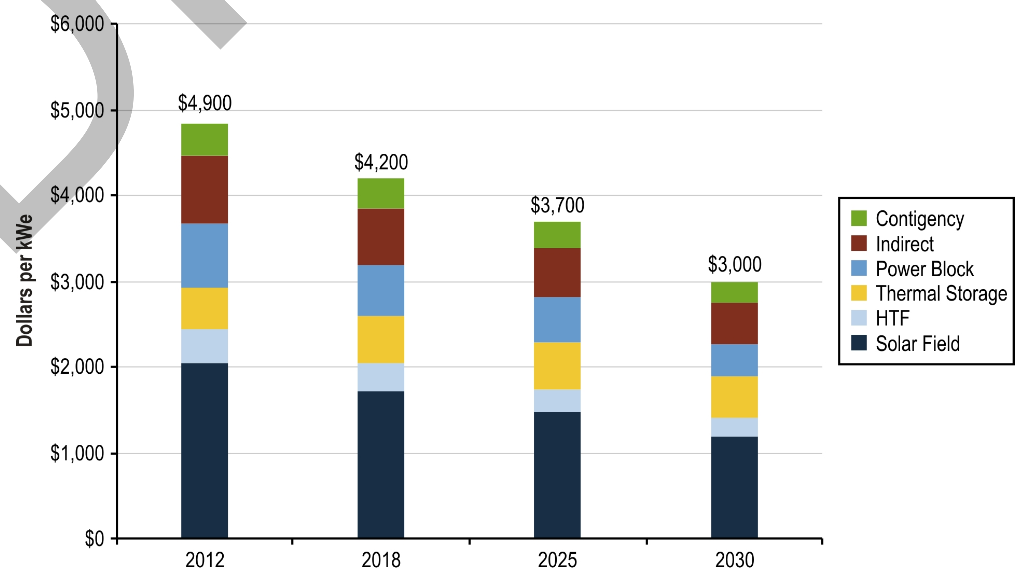
The primary power plant of choice for trough and tower systems remains the Rankine steam power cycle. The main cost reduction potential in the power block is due to increased size. For example the SEGS units in California were built in the 1980s over a period of 7 years with an increase in size from 14 to 80 MW. The recent Solar Nevada One plant is 64 MW and some announced CSP plants exceed 200 MW. Increasing the size of the power block results in improved cycle efficiency and lower amortized O&M costs, although, multiple turbines within a single plant can result in improved annual availability. For the long term, alternative power cycles (e.g., Brayton, supercritical steam, and supercritical CO_2) are all being investigated.

As unit size increases there is a cost reduction with the balance of plant and O&M staffing. For plants with multiple units there is a cost reduction associated with shared infrastructure (substations, buildings, etc.) and O&M staffing (KJC 1994; Sargent & Lundy 2001). The average O&M cost for CSP is currently about 2.9¢ per kWh and is expected to be about 1.2¢ per kWh in 2030. The main drivers behind the O&M cost reduction are the increase in capacity factor and larger plant sizes.

5.3.6 Summary of Technology Improvements and Cost Reduction Potential

Reducing the cost of delivered energy from CSP will result from both capital cost reductions and technology improvements. Figure 5-9 summarizes the capital cost

Figure 5-9. Current and Projected Future Cost of CSP Plants



reduction potential for an assumed mix of CSP technologies that changes over time as the technologies mature. The values shown in the tables and figures below represent weighted averages for the changing mix of CSP technologies.

Figure 5-9 shows that the majority of CSP costs (40-42%) are from the solar field, followed by indirect[2] (16%) costs, power block (13-15%), and thermal storage (10-16%). Heat transfer fluid and contingency account for roughly 8% each. The reduction in delivered cost depends on the interaction between cost reduction, technology improvement and efficiency increase.

Any increase in solar-to-electric efficiency results in a decrease in the field size per installed capacity and hence a decrease in the overall capital cost. For example increasing the solar-to-electric efficiency from 16% to 18.5% will decrease the size of the solar field by about 15%, thus reducing the installed cost. As plant size[3] increases the capital cost will be reduced by scale-up of unit power blocks and other economies of scale. Constructing multiple units at a single plant site can also lead to cost reduction through consolidation of infrastructure, staffing, and project development costs. Note: changes in commodity prices (steel, aluminum, glass, etc.) were not included in the potential cost reduction, and commodity prices were fixed at current prices (2009$).

Indirect costs scale directly with system price for comparable purposes but are dependent on the contracting approach and labor cost, and will decrease proportionally. 2018 cost reductions are driven by reduced solar field, storage and power block costs. 2025 cost reductions represent further solar field and thermal storage cost reductions (storage for towers is more economical than for trough, and tower deployment is expected to increase over time), reduced HTF costs, and increased efficiency due to higher operating temperatures. 2030 cost reductions represent a further reduction in storage costs from representing the transition from a two-tank molten salt system to lower cost options current under development (thermoclines, phase change materials, solid media), and increased power block efficiencies and reduced costs from a transition to supercritical steam or CO_2 .

Plant capacity factor varies significantly between the technologies and are expected to gradually increase through the 2030 time period. Figure 5-10 shows the expected increase in capacity factors for each technology over time as thermal energy storage technology matures and deploys, and as plant operating techniques improve. The assumed percentage of new plants with and without storage is shown in the text box in Figure 5-10.

Expectations for technology improvements over time for the mix of assumed CSP technologies are summarized in Table 5-1. The average plant size doubles by 2030. Despite the increasing number of plants with thermal energy storage, plant capital cost decreases by almost 40% by 2030, from \$4900/kW to \$3000/kW. The reduction in capital cost occurs, in part, because the average solar-to-electric efficiency increases by over 16%. This improvement is revealed in the amount of surface area required for the solar field, which decreases by about 15%. The

[3] Includes engineering, EPC fee, EPC G&A, Owner's Cost, sales tax, etc.
[3] [3] Depending on the technology, plant size may consist of several units or modules of units (for dish).

Figure 5-10. Current and Projected Capacity Factors for CSP Plants

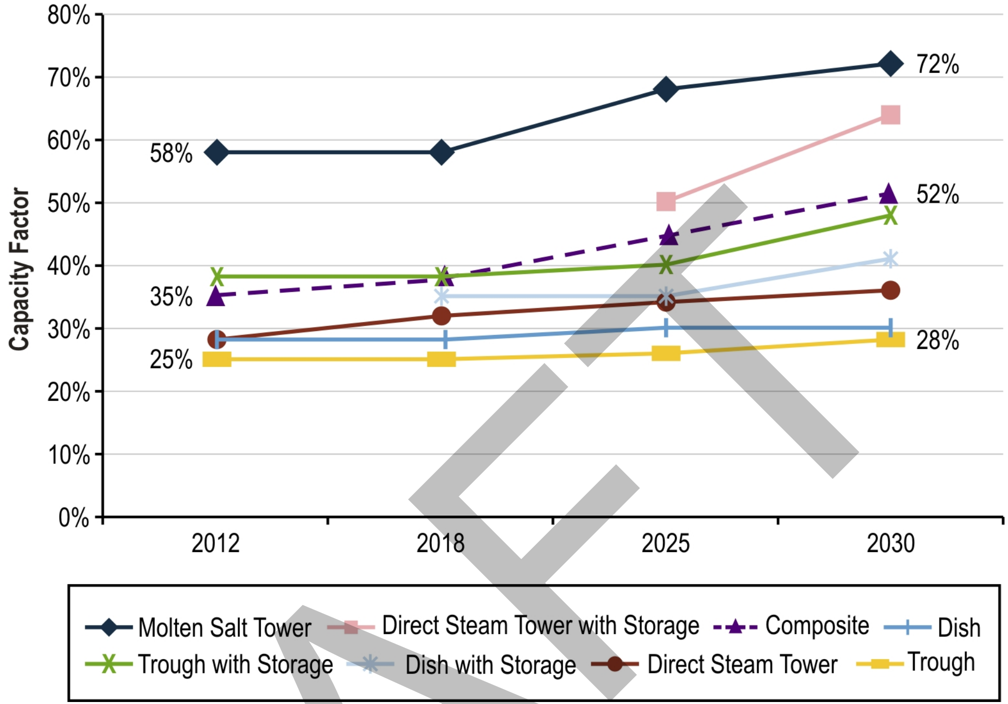


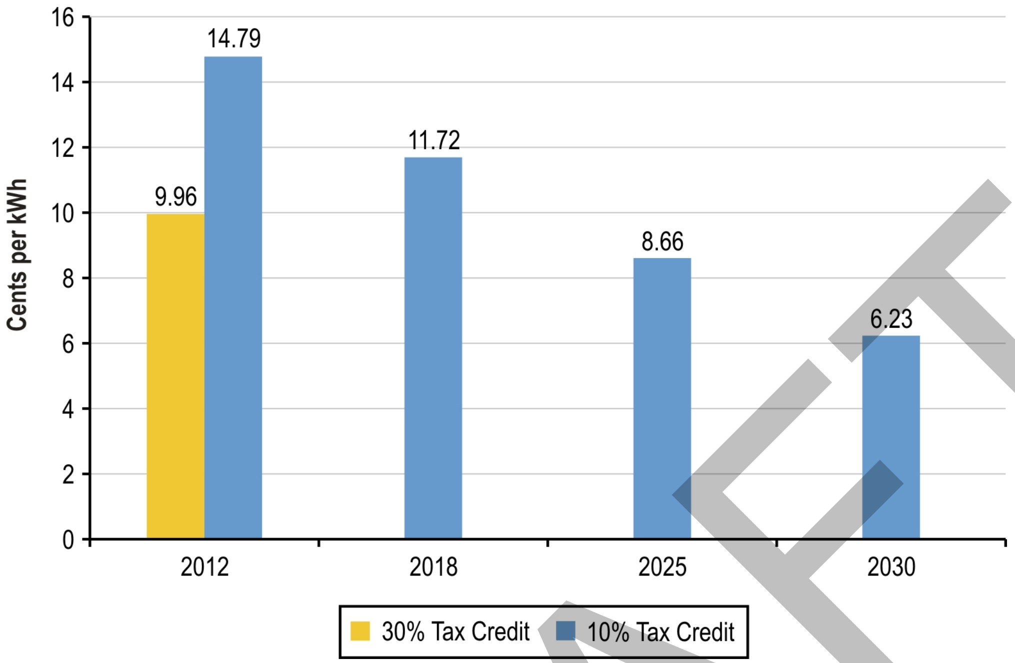
Table 5-1. Summary of Expected Technology Advancement for Composite CSP Plant

Year	Average Plant Capacity MW_{net}	Average Capital Cost $/kW	Average Capacity Factor %	Range of Capacity Factor %	Average Solar-to-Electric (Net) Efficiency %	Avg. Reflector Area m^2/MWh
2010 to 2015	200	4900	32.3%	25-58%	15.8%	2.55
2015 to 2020	250	4200	37.7%	25-58%	16.7%	2.41
2020 to 2025	300	3700	43.6%	26-68%	17.5%	2.29
2025 to 2030	400	3000	50.7%	28-72%	18.4%	2.17

average capacity factor for new CSP plants increases by a factor of 3 as plants with thermal energy storage achieve capacity factors as high as 72%.

The combined effect of lowering capital costs and increasing plant capacity factors leads to a rapid drop in LCOE over the next 20 years. Figure 5-11 shows the calculated decrease in LCOE if the industry achieves the capital costs and capacity factors presented above. The estimates are based on the following assumptions: capital cost is financed based on 55% equity and 45% debt: 20 year repayment period; discount rates (adjusted to real value) of 7.52%, MACRS at 5-years,

Figure 5-11. Breakdown of LCOE for CSP Composite Mix of Technologies



composite corporate income tax of 40.2%, and construction period financing (AFUDC) at 2.44%.

Experience curves can be used to compare the cost reductions assumed in Table 5-1 with the solar vision scenarios. Moving from the current level of 0.7 GW installed CSP capacity worldwide in 2010 to 63 GW installed in just the US in 2030 (20% deployment) will require about seven doublings of capacity. In order to achieve the expected reduction in cost based on this deployed capacity, a progress ratio of 0.88 is required. Although progress ratios should be evaluated at the global scale, the assumption of US-only growth reflects a conservative estimate of the learning curve. For comparison, wind technology has shown a progress ratio of 0.92 in Denmark and 0.94 in Germany (Neij 2003) and PV is 0.80 (see Chapter 4). The Enermodal study projected the experience curve for trough and tower technologies between 85% and 92%. (Enermodal Engineering Limited 1999).

5.4 MATERIALS AND MANUFACTURING

5.4.1 RAW MATERIALS REQUIREMENTS

The long-term availability of materials and equipment is critical for building CSP plants. This analysis focused on the most important raw materials that would be needed for the 10% and 20% solar scenarios – aluminum, steel, glass, heat transfer fluid and molten salt. In general, these materials are not subject to rigid supply limits, but they are affected by changes in commodity prices. This section discusses the amount of material that will be required for the two scenarios.

Table 5-2 provides material breakdown for a parabolic trough plant. The solar vision scenario assumes a transition to a mix of plant types, using a variety of materials. Table 5-3 shows the amount of material required on per-MWh (annual production) basis for the assumed mix of CSP technologies characterized in section 5.3.6. Table 5-4 provides the total annual material requirements in 2030.

Table 5-2. Construction Materials for Nominal 100 MW Parabolic Trough Plant with 6 Hours Thermal Energy Storage

Year	Trough Plant Subsystem (metric tons)				
	Solar Field	HTF System	Power Block	Thermal Storage	Total (metric tons)
Aluminum		2		74	**77**
Glass	9,806	1		181	**10,351**
Calcium silicate (insulation)		66	31	155	**252**
Mineral wool	442			568	**1010**
Steel and iron	20,747	787	303	3,407	**25,244**
Concrete	28,590			10,277	**38,867**
Copper	56	6	59		**122**
Nickel	1				**1**
Nitrate salts				51,200	**51,200**
Nitrogen		18		429	**447**
Plastic and rubber	22	2	12		**36**
Synthetic oil (Therminol™)		4,271			**4,271**

Table 5-3. Material Requirements for Composite CSP Plant

Year	Glass, lb/MWh	Reflecting Film, m^2/MWh	Aluminum, lb/MWh	Steel, lb/MWh	HTF, gal/MWh	Molten Salt, lb/MWh
2010 to 2015	53.4	2.60	18.7	64	1.02	95.7
2015 to 2020	49.8	2.42	35.6	61	0.94	95.7
2020 to 2025	47.6	2.32	34	59	0.90	90.0
2025 to 2030	45.2	2.20	32.4	55	0.86	85.8

Table 5-4. Annual Material Requirements in 2030 for 10% and 20% Scenarios

Scenario	Glass, tons/yr	Reflecting Film, million m^2	Aluminum, tons	Steel, tons	HTF, million gal	Molten Salt, tons
10%	516,000	50.2	370,000	627,000	19.6	978,000
20%	808,000	78.6	579,000	983,000	30.7	1,531,000

Glass is used primarily for the mirrors which are manufactured from standard float glass. There are currently more than 260 float glass plants worldwide with an output ranging from 600 tons/day to 1000 tons/day. The 20% by 2030 case would require

2 to 3 float glass lines. The CSP requirement at the peak will consume about 1% of the current worldwide float glass capacity.

Non-glass mirrors, either with reflective films (usually laminated onto aluminum sheets) will be used for parabolic trough plants as the technology matures and will be 50% of the reflecting surface material in 2030. The CSP requirement at the peak will require about 13.2 million m^2 of non-glass reflecting material. This is comparable to the current production volume of solar control window film (which requires a similar production process) of approximately 80 million square meters annually. This production capacity of window film was put in place within just a 15 to 20 year timeframe.

Aluminum is used for reflectors and also is used as the primary structural material in several space frame designs in the form of extrusions, especially for parabolic troughs. Each MW of parabolic troughs using aluminum framing will typically require about 25 tons of aluminum for the space frame structure (for a solar multiple of 1.0). This requirement scales with the solar multiple, so a plant with a solar multiple of 2.0 requires about 50 tons per MW. Aluminum production in the U.S. in 2008 was about 2.7 million tons, with another 4.5 million tons imported (Fenton 2010). The CSP requirement at the peak is about 8% of current US use.

Aluminum is also required for CSP plants using non-glass mirrors, either with reflective films (usually laminated onto aluminum sheets), polished aluminum or coated aluminum. Each MW of CSP using non-glass reflectors will typically require 4,000 to 6,000 square meters of reflector area (for a solar multiple of 1.0), depending on many factors such as reflectance, solar device efficiency, and thermal conversion efficiency. Using a typical aluminum sheet thickness of 1 mm a plant solar multiple of 2.0 would require 24 and 32 tons per MW.

The amount of steel for the power block will be the same as similarly sized fossil fueled power plants. Additional steel for a CSP plant will be required for heliostat and dish structures, HTF piping for the parabolic trough solar field, some parabolic trough structure designs, tower structures, receivers, molten salt storage tanks, and heat exchangers. Steel production in the U.S. was 92 million tons in 2008 (Fenton 2010). The CSP requirement at the peak is less than 1% of 2008 U.S. production.

The analysis assumes synthetic oil is used as the HTF for parabolic trough through 2030, although alternative fluids could gradually replace it. The current generation of organic heat transfer fluids for existing parabolic trough systems consists of a eutectic mixture of the synthetics diphenyl oxide / biphenyl, known by trade names Therminol VP-1 and Dowtherm-A. This fluid type is widely used worldwide in large volumes in the chemical industry. Both of these components are made by the petrochemical industry so raw materials are not expected to be an issue.

Molten salt is associated with thermal energy storage. Much of the world's nitrate salts are derived from salt brines in the Alta Cama region of Chile. Documented reserves of this brine yield a reserve of 29.4 million metric tons (32.4 tons). The cumulative amount of molten salt for the 20% deployment scenario is about 18 million tons, which is about 60% of the reserve. This use, combined with international requirements, indicates the likely need to utilize other regions which can also add to the reservoir of available salt.

5.4.2 Manufacturing and Supply Chain

Substantial increases in the manufacturing capacity of CSP components will be required to achieve the Solar Vision scenarios. CSP plants require a number of components, some of which are similar to other industrial components, others which are unique to the industry. In addition to the structural and mirror components, CSP plants require manufacturing of receiver components and the power block.

Receiver tubes are fabricated from readily available materials such as glass tubing, stainless steel tubing and steel bellows. The current manufacturing capacity is adequate to meet the demands for facilities currently under construction and planned in the near term. SCHOTT and Solel are currently the suppliers for the trough industry. For example SCHOTT's current manufacturing capacity is approximately 1 GW/year, and can be readily expanded as demand increases. A new production facility in Albuquerque, NM constructed two receiver tube manufacturing lines and brought them to full production in 14 months. These two lines produce enough receiver tubes each year to supply 400 MW of trough plants. The availability of receiver tubes should not present a bottleneck to achieve the 20% by 2030 scenario.

Manufacturing capability for power block and other system components is available worldwide. Tower, trough and LFR plants produce steam to provide the energy in a Rankine cycle to operate a steam turbine generator. All developed countries and many developing countries have boiler manufacturing capabilities and can fabricate components such as steam boilers and pressure vessels. For example, in the U.S. over 5 GW of coal capacity has been added in the United States in the past three years and 20 GW is under construction. The manufacturing capability that exists to build conventional fossil fuel boilers can be adapted readily to fabricate multiple GW per year of steam or molten salt receivers. A good example of this adaptation is the steam receivers fabricated for eSolar's Sierra Generating Station in Lancaster, CA. These receivers were manufactured by two separate conventional boiler shops in the United States without significant changes to the shop floor or development of unique manufacturing techniques. Similarly, dish Stirling engines utilize common materials and manufacturing processes for efficient mass-production.

5.5 References

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