The Economics of Concentrating Solar Power (CSP): Assessing Cost Competitiveness and Deployment Potential

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Abstract

A global transition to sustainable energy systems is underway, evident in the increasing proportion of renewables like solar and wind, which accounted for 10% of global power generation in 2020. The shift to a low-carbon economy will likely require a substantial increase in energy storage in the near future. In this context, concentrating solar power (CSP) is viewed as a promising renewable energy source in coming decades. However, high costs compared to other electricity generation methods remain a key barrier inhibiting wider deployment of CSP. Compared to solar PV and onshore wind alternatives, CSP cannot currently compete on levelized cost of electricity (LCoE). This review provides a comprehensive overview of the vital economic factors and considerations for large-scale CSP expansion. The current state of the market reveals over 9 GW of installed global CSP capacity in 2021, with rapid growth occurring in China, Chile, South Africa and the Middle East. Key economic parameters discussed include capital costs, capacity factors, operating expenses and LCoE. Installation costs for CSP declined by 50% over the past decade, falling to the current ranges of $3000-11000 per kW. Adding 6-15 hours of thermal energy storage at $20-60 per kWh is now considered economic. Capacity factors increased from 30% to 50% through larger storage capacities and higher operating temperatures. Operations and maintenance costs now range from $12-15 per kW-year. The resulting global weighted average LCoE for CSP plunged 68% from $0.31 per kWh in 2010 to $0.10 per kWh in 2020. Ongoing innovations in materials, components and systems can further reduce capital expenditures, enhance performance, and decrease LCoE. However, appropriate incentives and financing mechanisms remain vital to support continued CSP technology maturation and cost reductions. With its inherent transmission and storage capabilities, CSP can become a cost-competitive renewable energy source, but design optimizations and accurate economic appraisals are imperative for CSP to achieve its vast sustainability potential.

Key words: Concentrating solar power (CSP); Renewable energy; Capacity Factor; Levelized cost of electricity (LCoE)

1. Introduction

The recent 6th IPCC Assessment Report unequivocally states that, without immediate and deep greenhouse gas emission cuts across all sectors, limiting global warming to 1.5°C is now out of reach [1]. To achieve this temperature limit, a worldwide shift to more sustainable production and consumption systems is underway, especially visible in energy where solar PV and wind accounted for 12% of global electric power in 2022 [2]. Recent surges in the price of natural gas and coal in 2021-2022 have further weakened fossil fuel competitiveness, making solar and wind more attractive [3]. However, the intermittent nature of renewables like solar and wind poses grid stability challenges, as unexpected meteorological changes can drastically alter their output. Therefore, the steadily rising proportion of intermittent renewable energy raises concerns regarding the sustainability of our energy mix. Inflexible renewable energy systems disregard "capacity" and predominantly focus on preserving exploitable fossil fuels, but higher inflexible renewable fractions have undesirable consequences [4]. For instance, more inflexible renewables necessitate the construction of additional conventional backup plants like gas and coal, leading to more curtailments and subsequently higher electricity costs due to the increased costs of the overall system, as illustrated in **Fig. 1**.

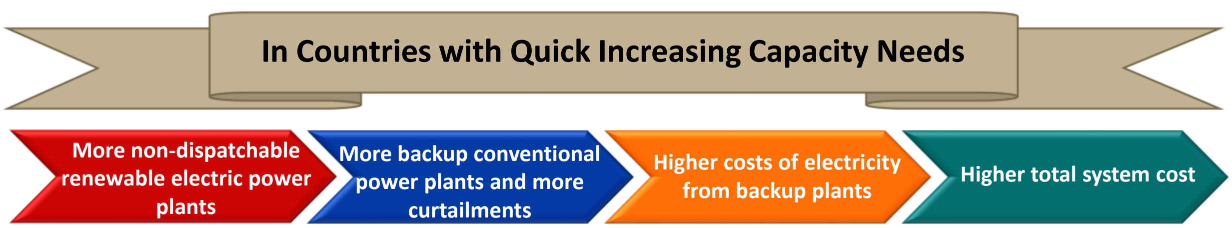

Fig. 1. Side-Effects of Having More Intermittent Renewable Energy in the System

However, this problem can be mitigated by increasing the proportion of transmissible renewables in the overall energy portfolio. It is widely believed that transitioning to a low-carbon economy will likely raise energy storage demand significantly. Concentrating solar power (CSP) can address both intermittency and storage needs by providing transmissible renewable electricity. CSP is among the most viable and promising renewable technologies that can scale up for rapid transition towards scenarios with extensive renewable energy usage [5]–[13]. One of the distinguishing features of CSP, setting it apart from its renewable counterparts, is its intrinsic compatibility with large-scale thermal storage facilities or hybrid subsystems. This symbiotic relationship enhances the technology's resilience against the inherent fluctuations of solar irradiance, thereby ensuring consistent power outputs—a prerequisite for seamless solar electricity-to-grid integration [14]. Incorporating thermal energy storage into CSP plants boosts transmissibility without significantly impacting the levelized electricity costs compared to CSP plants without storage [15], [16]. This enhancement bolsters CSP’s position as a valuable option for producing transmissible renewable electricity, suitable for bulk power generation, and this is particularly beneficial in balancing the intermittency of other renewable sources like wind and solar PV. Several strategic forecasts highlight CSP's indispensable role in shaping net zero energy systems. Corroborating this, the 'Net Zero by 2050' report of the International Energy Agency (IEA) projects exponential CSP growth, forecasting capacities of 73 GW, 281 GW, and 426 GW by 2030, 2040, and 2050, respectively [17]. Also, the International Renewable Energy Agency (IRENA) anticipates a rise to 52-83 GW of CSP capacity by 2030 [18]. Beyond large-scale, grid-connected power plants, CSP technologies hold immense potential for catering to niche applications like industrial process heat, combined heating/cooling/power, and water desalination. Furthermore, in the context of the developing world, CSP can transform household cooking and small-scale manufacturing. CSP's versatility is further elevated by its potential to facilitate the production of solar fuels, including but not limited to hydrogen and jet fuels, fortifying its significance in a low-carbon economy. CSP also aligns with climate change mitigation strategies, where the IEA emphasizes the necessity to remove CO_2 to limit the global warming below 2°C by the end of the century [19]. So, along with switching to renewable energy, we will need to remove CO_2 from the air. The high heat requirements for CO_2 capture thermo-chemistry can be met with CSP's unique solar thermal properties, positioning CSP to play a vital role in atmospheric CO_2 removal and climate change mitigation. However, CSP faces strong cost competition from other renewables, notably solar PV, pressing developers to pursue further cost reductions (**Fig. 2**). This imperative is intensified by the prevailing market dynamics characterized by high competition and the lack of tariffs that fairly reflect the intrinsic value of CSP's transmissibility. It is worth noting that while solar PV has significantly progressed down its experience curve, CSP remains a relatively immature technology with substantial untapped potential for further cost reductions [20]. In summation, while the technical prowess of CSP is a cornerstone of its potential, the economic dimensions associated with its deployment are equally vital. Economic factors will largely determine whether CSP reaches its expansive technical potential across power generation and innovative applications. Therefore, a holistic understanding of its costs, benefits, and economic challenges will determine CSP's trajectory in the global energy mix.

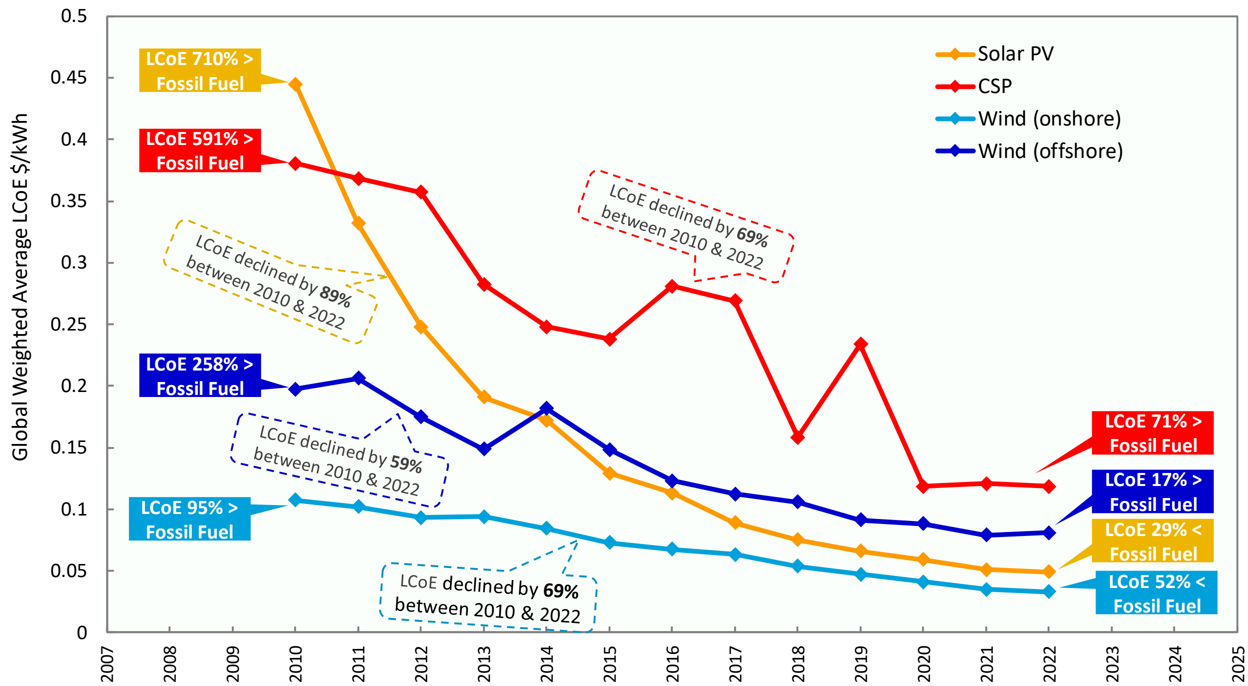

Fig. 2. Global weighted average LCOE and auction/PPA prices for CSP, onshore and offshore wind, and solar. Prepared by authors from IRENA Renewable Energy Cost Database [21]

1.1. Motivation, Objectives and Scope

While research on CSP technology has grown over the past decade, most published reviews approach CSP from a predominantly scientific and engineering perspective, analyzing performance, components, materials and configurations [22]–[31]. However, there is a gap in comprehensive techno-economic evaluations concerning the commercial viability and advances of CSP systems. This work aims to bridge this knowledge gap by providing a holistic assessment of the economic dimensions shaping CSP deployment, with a focus on developments in the last ten years. Data were gathered from academic and grey literature including journal papers, reports (e.g., IEA, IRENA), expert presentations, newsletters, technical documents and national statistics. As such, to be reliable, robust economic analysis should be based on real-world data of actual costs incurred to build and maintain CSP plants, and their actual electricity generation. Hence, additional insights will come from discussions with CSP industry stakeholders. Given the multitude of recent studies on CSP economics as well as ongoing R&D efforts, an updated synthesis is both timely and valuable. This paper examines key economic considerations and metrics including LCoE, capacity factors, O&M expenses, financing costs, and ancillary grid benefits that critically impact CSP's competitiveness and adoption. Emerging component innovations and cost reduction roadmaps are also explored from a commercial viability standpoint. While the scientific principles and engineering details of CSP systems have been extensively covered elsewhere, this assessment focuses uniquely on translating technical advances into economic insights. The intended audience spans experts and non-experts including researchers, industry practitioners, policymakers and other stakeholders interested in understanding the current status and trajectory of CSP economics. The scope encompasses installed commercial CSP facilities and near-term innovations likely to reach market deployment within 5-10 years. The time period examined spans 2011-2022, reflecting transformative changes in CSP economics over the past decade. Both component-level and system-level techno-economic perspectives are presented.

The manuscript is structured systematically to provide readers with a progressive understanding of the economic factors influencing CSP technologies and markets. Following the introduction, Section 2 summarizes the current status and growth trends in global CSP capacity over the past decade. Section 3 presents an overview of the main CSP technological configurations including parabolic troughs, solar towers, linear Fresnel reflectors and dish Stirling systems. With this background established, Section 4 delves into the pivotal economic parameters impacting CSP deployment using empirical project data and techno-economic modeling results from literature. Subsections provide in-depth examination of factors such as capital costs, capacity factors, operating expenses, levelized costs and financing challenges. Section 5 compiles and analyzes the LCoE ranges reported for CSP plants across numerous modeling studies to elucidate the effects on cost-competitiveness of design parameters like storage duration, solar field size and heat transfer fluids. Section 6 shifts the focus towards ongoing R&D aimed at lowering CSP costs through technological improvements in components like mirrors, receivers, thermal storage and heat transfer fluids. Section 7 offers conclusions and strategic insights into attaining the substantial cost reductions required for CSP to realize its immense promise in affordable clean energy generation.

In summary, this review offers a comprehensive techno-economic perspective on the current status and future outlook for CSP deployment at commercial scale. The work fills a valuable gap in the literature by providing a holistic overview of the economic considerations determining the trajectory of CSP amidst the global energy transition. With its technical prowess, continued cost decreases and unique grid-stabilizing attributes, CSP can fulfill a critical role in deeply decarbonized and sustainable energy systems. However, economic factors pose risks that require thorough investigation to elucidate CSP's future in the global energy mix. This review paper aims to deliver that requisite clarity.

2. Current status of the CSP market

As shown **Fig. 3**, the historical growth of the CSP market has been characterized over the past few decades by boom-bust cycles driven by shifting national policy support [32]. CSP experienced an initial wave of development in the 1980s in California, United States on the back of federal and state incentives. Between 1984-1991, nine CSP plants with 350 MW combined generation capacity were constructed in California. However, expiration of tax credits, waning policy support, and falling energy prices subsequently led to a bust period from 1995-2005 with no new CSP deployment. The second major boom for CSP came with the introduction of feed-in-tariffs (FITs) in Spain in 2007, which allowed project developers to secure 25-year contracts at a high fixed price per kWh generated or with a guaranteed premium added to wholesale market rates [33]. This incentive environment led to a boom in CSP construction, with around 50 plants totaling 2,300 MW capacity built across Spain from 2007 to 2013 [2]. Retrospectively, while the FIT enabled rapid scale-up, its fixed price structure did not encourage cost reductions or optimal generation timing. In January 2012 the Spanish government cancelled the FIT program for new applicants beyond the 2,304 MW allocated up to 2014 commissioning. Then in 2013, a retroactive law replaced the FIT for existing plants with a reduced 7.5% rate of return model based on a "reasonable profitability" criterion. This policy shift abruptly halted CSP expansion, as the fixed FIT pricing did not adapt to emerging cost improvements and provide incentives for optimal generation transmission. The Spanish FIT episode demonstrated that CSP deployment could ramp up rapidly given stable revenue assurances [34], but it also highlighted risks of over-incentivization without progressive tariff adjustment mechanisms. The next proliferation wave emerged as CSP expanded internationally beyond Spain through competitive auctions. Markets in the United States, South Africa, Morocco, Israel and the Middle East piloted projects, often incorporating thermal energy storage for transmissibility [4]. However, uncertainty around extending federal tax credits stalled US growth after a brief surge [16]. The latest CSP expansion is being spearheaded by China which instituted a national FIT program in 2016 to construct 1.35 GW capacity by 2018, aligned with their 13th Five-Year national Plan [35]. The boom-bust cycle showed that while targeted policy support can stimulate short-term growth, policy instability hampers long-term CSP deployment; sustained CSP expansion requires consistent frameworks that dynamically evolve with technology maturation.

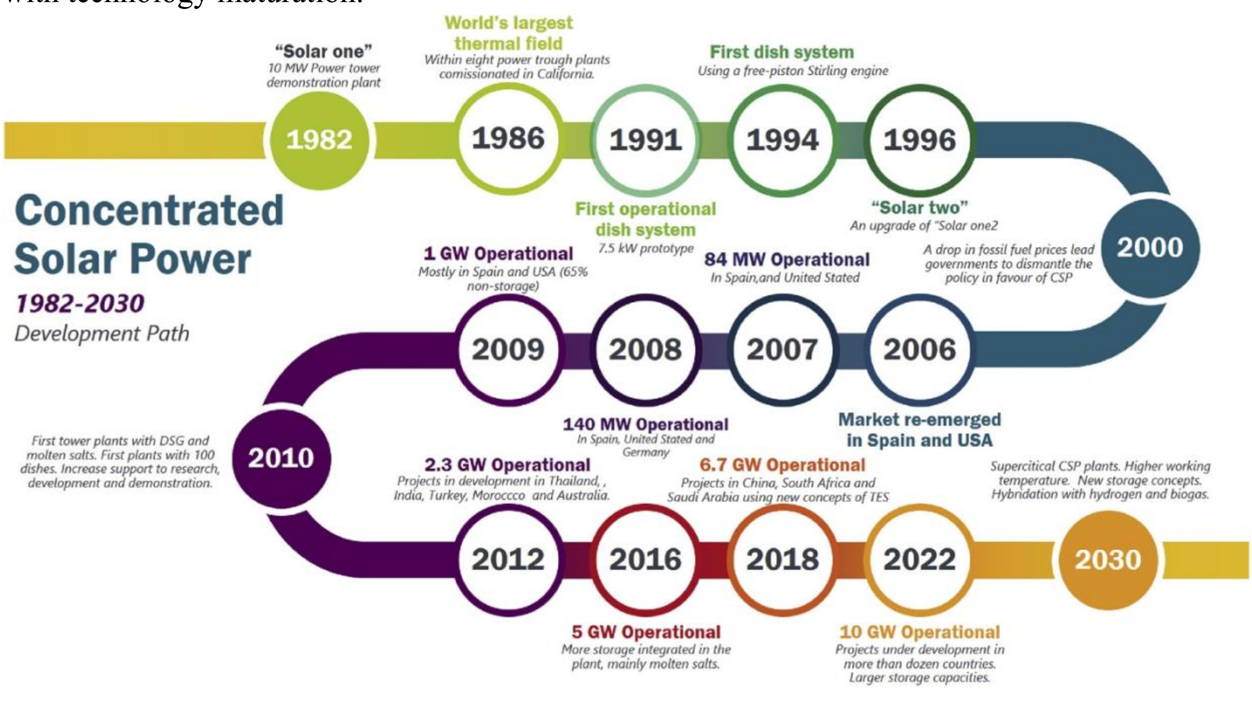

Fig. 3. Concentrated Solar Power development path from 1982 to 2030

As of 2021, the total global installed capacity of CSP plants stood at 6,475 MW [36] with an additional 4000 MW under construction. Estimates suggest a further pipeline of 8,472 MW in various stages of development, highlighting the growth potential for CSP technology. Over the past decade, CSP capacity has increased substantially from 1.2 GW in 2010 to over 6 GW by 2019. This expansion can be attributed to the feasibility of CSP for diverse applications when integrated with thermal energy storage and hybrid fossil power systems [37]. While the United States and Spain have been historical leaders in installed CSP, new markets are emerging rapidly including China, South Africa, Morocco, Chile, India and the Middle East. China alone has 30 CSP projects underway expected to add 3,000 MW capacity [38], [39]. Under supportive policy environments, CSP capacity could reach 1,089 GW globally by 2050 according to IEA forecasts [40]. Industry projections estimate CSP could provide 6-12% of global electricity by 2030 and 2050 respectively [41], [42]. Market expansion is projected across sunbelt countries as CSP competitiveness improves vis-à-vis conventional and other renewable power sources. If current growth momentum persists, CSP could foreseeably emerge as a critical transmissible renewable technology worldwide.

3. Overview of CSP technologies

CSP refers to a range of technologies that concentrate sunlight to generate high temperature heat, which is then used to drive a steam turbine or heat engine to generate electricity [5]. This differentiates CSP from traditional photovoltaic (PV) systems which convert sunlight directly into electricity through the photovoltaic effect. The schematic representation of the fundamental operational dynamics of CSP plants is depicted in **Fig. 3**. The fundamental components of a CSP plant comprise the solar field and the power block. In the solar field, mirrors or lenses concentrate incoming solar irradiation onto a focal point receiver. Different mirror configurations are used including parabolic troughs collectors (PTC), linear Fresnel reflectors (LFR), Parabolic dish reflectors (PDR), and heliostat tower systems (STP) [24]. The concentrated radiation heats up the receiver, which contains a working fluid that is pumped to the power block. The power block houses a heat exchanger that generates steam to run a turbine and produce electricity via a generator. Thermal energy storage (TES) systems can also be integrated, typically using molten salts, to store excess heat for later electricity generation [26]. By decoupling the collection and storage of solar energy, TES enables CSP plants to cost-effectively generate power on demand irrespective of sunlight conditions. The unique capability of CSP plants equipped with TES to store energy and flexibly shift output is a key advantage over intermittent renewable sources like solar PV and wind. TES configurations ranging from 6 -15 hours provide valuable generation and grid balancing services.

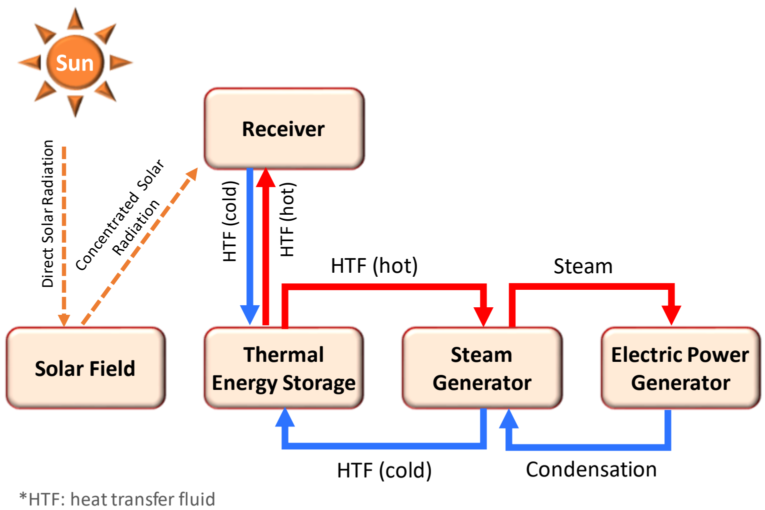

Fig. 3. Flow Diagram Highlighting the Sunlight-to-Electricity Transformation in CSP Technologies

There are four main CSP technologies currently available (**Fig. 4**): parabolic trough collectors (PTC), solar power towers (SPT), linear Fresnel reflectors (LFR), and parabolic dish collectors (PDC). PTC is the most mature technology, comprising almost 80% of existing CSP plants [43]. However, recent growth has shifted towards SPT plants. In PTC systems, sunlight is concentrated by parabolic mirrors onto a receiver tube running along the focal line. These generate operating temperatures up to 400°C using synthetic oils or molten salts as heat transfer fluids. SPT systems use a field of movable mirrors (heliostats) to focus sunlight onto a central receiver on a tower, enabling higher temperatures exceeding 1000°C. Heat transfer fluids include water/steam, molten salts, air, or liquid sodium. LFR systems concentrate sunlight onto fixed receivers using long parallel rows of flat or slightly curved mirrors. PDCs use dish-shaped reflectors to concentrate sunlight onto a receiver at the focal point, with individual modules typically sized 10-25 kW [43].

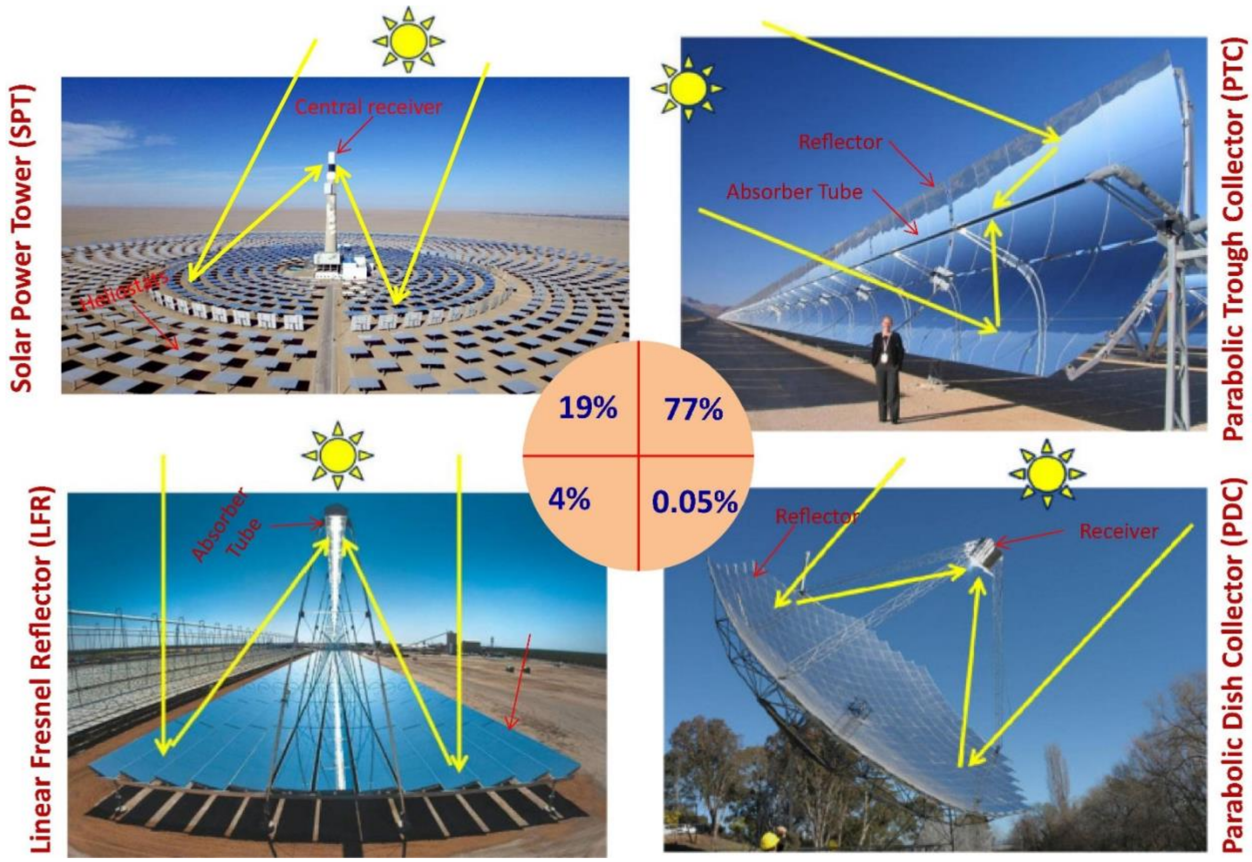

Fig. 4. Major CSP Technologies

4. Economic Aspects of CSPs Plants

The economic viability of concentrated solar power (CSP) plants is a critical factor determining their adoption and large-scale deployment. Key economic parameters influencing CSP competitiveness include capital costs, capacity factors, operation and maintenance (O&M) costs, and levelized cost of electricity (LCoE).

4.1. Capital Costs

The capital costs of CSP plants comprise the upfront investment required for site preparation, technology components like mirrors/receivers, power blocks, the balance of plant, and engineering/procurement/construction. Capacity-based capital costs ($/kW) indicate the total installed costs per unit power capacity. Several factors influence CSP capital costs including component costs, plant size, location, and storage duration. Unlike solar PV, CSP is very cost-sensitive to scale and favors large-scale power generation (generally ≥50 MW) to minimize energy production costs, which requires relatively large capital investments and financial risks (partly due to the relatively greater technical complexity of the technology) that not everyone can take up. In the early commercialization of CSP, adding thermal energy storage was often not economical, so its use was limited. But since around 2015, nearly all planned and installed CSP facilities include several hours of thermal storage, which enables electricity generation into the evening and nighttime hours. Integrating thermal storage is now viewed as a cost-effective way to increase capacity factors, improve project economics through higher utilization, and provide greater flexibility in generation scheduling. The average thermal storage capacity for commissioned CSP plants increased dramatically from 3.5 hours in 2010 to 11 hours by 2020 [21], [44], [45]. The 110 MW Cerro Dominador CSP project in Chile's Atacama Desert, which came online in 2021, set a new benchmark with 17.5 hours of thermal storage capacity. Recent projects in China average around 9 hours of storage. Considering these trends, it is likely that nearly all future CSP developments globally will incorporate substantial thermal energy storage.

The capital costs for building CSP plants globally have exhibited a declining trend over the past decade as tracked in **Fig. 5**, although substantial variability exists across different project sizes, technologies, and storage configurations. Comparing capital cost breakdowns across these parameters provides insights into key drivers and opportunities for reductions. Between 2010-2020, total installation costs for CSP plants worldwide halved from around $6,000-8,000 per kW to $3,000-4,000 per kW. This cost reduction occurred even as the size of integrated thermal energy storage (TES) systems expanded over the same period. Total capital costs for both PTC and SPT plants are dominated by the cost of the components that make up the solar field. This is particularly true for PTC plants, where it accounts for 39% of the total installed costs (**Fig. 6**). This includes expenses related to acquiring parabolic mirrors, support structures, drives and control systems to orientate mirrors, receivers and heat collection elements. For SPT plants, the solar field percentage is relatively lower at 28% of total capital costs. Higher proportions are incurred for the central receiver (18%) and power block (16%) in SPT facilities. The solar receiver design is more complex for SPT, given higher operating temperatures and the need for heat exchange optimization. The capital cost of a CSP project is influenced by the type of technology, the geographic location (quality of resources, local costs) and whether it use sites. Adding thermal energy storage (TES) increases capital costs by around 12-17% as per industry benchmarks, without raising nameplate capacity. However, TES increases the capacity factor of the project.

The total installation costs of concentrated solar power (CSP) plants have declined substantially over the past decade, driven by significant reductions in the costs of key components like the solar field and energy storage. In 2010, the solar field for a PTC plant cost an estimated $4503 per kW, accounting for 44% of total installed costs. By 2020, advances in trough technology had slashed solar field costs by 68% to just $1440 per kW, reducing its proportion of total installation costs to 30%. Meanwhile, other components like the power block and heat transfer fluid system decreased in absolute terms by 40-47% between 2010-2020, but these saw their percentages of total installation costs increase from 15% and 9% in 2010 to 19% and 11% in 2020, respectively. This highlights how dramatic solar field cost reductions have reshaped the balance of plant expenses for PTC facilities over the past decade. Similar trends were observed for SPT systems, with heliostat field costs falling 70% from US$ 5916/kW in 2011 to US$ 1768/kW in 2019. This dropped their proportion of the total installation cost of CSP from 31% to 28%. The cost of the STP's receiver fell by 71% between 2011 and 2019, from US$ 3069/kW to US$ 876/kW, with the receiver's proportion of total costs falling from 16% to 14%. The capital cost of recently completed commercial CSP projects ranges from $3216/kWh (in China) to $11717/kWh (in South Africa), depending on technology and storage duration (**Table 3**).

Overall, average global installation costs for CSP declined by around 58% from 2010 to 2022, from $10,358/kW to $4274/kW. Recently, two 150 MW STP plants completed in China, each with 13.8 storage hours achieved total installation costs of $4761-5713/kW. Importantly, adding thermal energy storage (TES) has not increased total installation costs, with recent plants integrating 8+ hours of TES at costs comparable to earlier installations without storage. Ongoing cost decreases can be attributed to technology improvements, economies of scale, and learning-by-doing as CSP deployment expands globally. If these trends continue, total CSP installation costs are projected to fall further, improving the competitiveness of CSP relative to conventional and other renewable generation. However, cost data remain geographically concentrated as deployment spreads to new markets. Additional installed project data, especially from emerging CSP leaders like China, will help refine understanding of current and future capital costs.

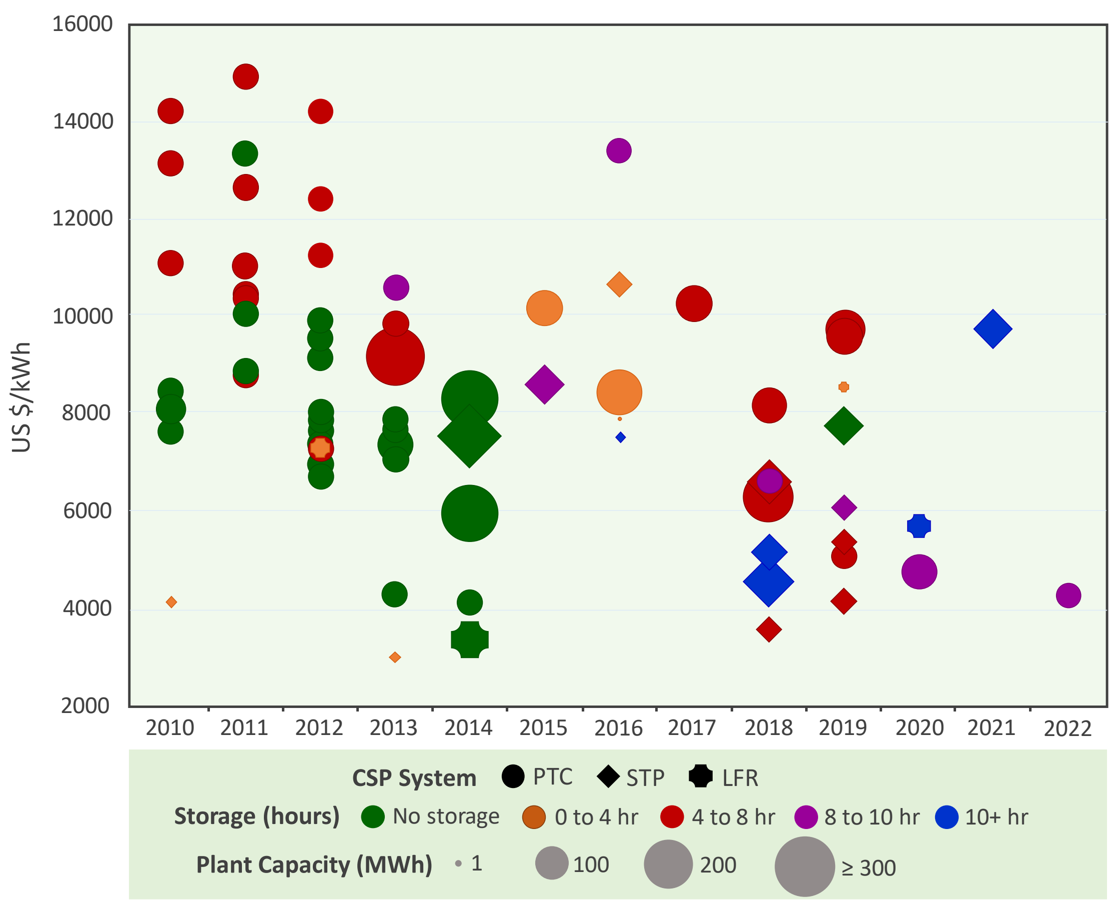

Fig. 5. CSP total installed costs ($/kWe) by project size, collector type, and thermal energy storage duration, 2010-2021. Prepared by Authors from IRENA Renewable Energy Cost Database [21] and CSP Guru, 2023 [46],

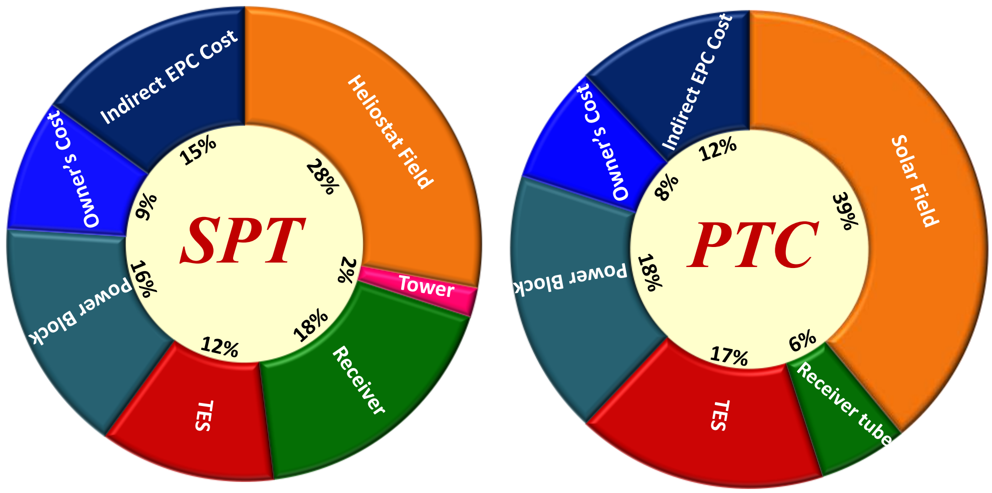

Fig. 6. Representative CSP total installed costs by component, 2020

Prepared by the authors based on the data in [21], [47]

4.2. Capacity Factor

In assessing the economic viability of CSP plants, the capacity factor emerges as a critical metric. The capacity factor of a CSP plant represents the ratio of the annual average electric power production of a CSP plant divided by the theoretical maximum annual electric power production of a CSP plant assuming it operates at its full rated capacity every hour of the year. Higher capacity factors indicate improved plant utilization and economics. Higher CSP capacity factors directly improve economics because of increased electricity generation without raised capital costs. Capacity factors are determined by the solar resource, power block reliability, and inclusion of TES. As CSP plants sometimes operate at less than rated power, the capacity factor is a measure of both how many hours in the year the CSP plant has operated and at what fraction of its total production. As capacity factors rise due to technological improvements, LCoE values decline substantially.

The formula for calculating capacity factor is given by:

$$\text{Capacity Factor} = \frac{\text{Annual electric power production (kWh/year)}}{\text{Plant rated capcity (kW) x 24 (hours/day) x 365 (days/year)}}$$

Global weighted average CSP capacity factors increased from 30% in 2011 to 50% in 2021, an increase of 66% over the decade (Fig. 7). Incorporating thermal energy storage (TES) boosts capacity factors by enabling generation after sunset. Over the last decade, falling costs for thermal energy storage and increased operating temperatures have been important developments in improving the economics of CSP [3]. Increased operating temperatures also improve capacity factors by raising solar field efficiency. Ongoing innovations to increase operating temperatures, optimize power blocks, and expand TES will further increase capacity factors. By optimizing the solar field area to minimize LCoE, a study by Wagner and Rubin [48] underscores this potential, demonstrating that the incorporation of a two-tank molten salt TES system into a 110 MW reference PTC plant in California can enhance the capacity factor of the plant from around 30% with no backup to up to 55% with 12 hours of storage. The capacity factor of future CSP plants are expected to reach 60% by 2030 [49].

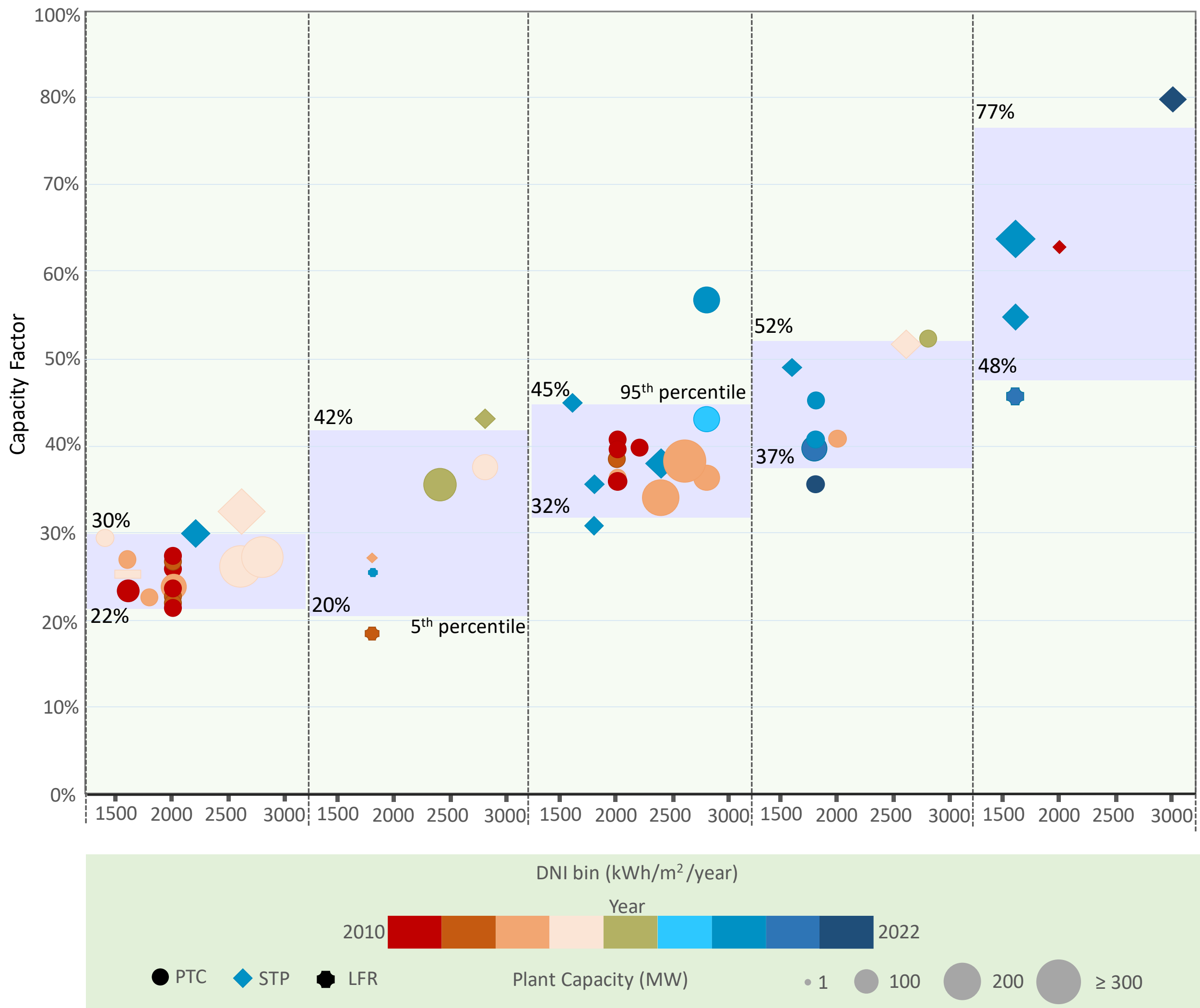

Fig. 7. Capacity factor trends for CSP plants by direct normal irradiance and storage duration, 2010-2022. Prepared by authors from IRENA Renewable Energy Cost Database [21] and CSP Guru, 2023 [46]

There are several important factors that influence the capacity factor of CSP plants:

4.2.1. Solar Resource Quality

The solar resource, measured by the direct normal irradiance (DNI), is the primary driver of a CSP plant's potential capacity factor. DNI quantifies the amount of solar radiation received per unit area on a surface held perpendicular to the sun's rays. Locations with higher DNI will enable a CSP plant to collect more thermal energy and convert more of that heat into electricity, resulting in a higher capacity factor. For example, regions with excellent solar resources like the Atacama Desert in Chile can achieve capacity factors upwards of 70-80% with current CSP technology. In contrast, regions with poorer solar resources may only allow capacity factors of 20-40%. Generally, capacity factors between 30-50% are typical for locations with good to excellent DNI levels between 2000-2800 kWh/m^2/year. As CSP technology continues to improve, capacity factors in lower DNI regions are also increasing.

4.2.2. Thermal Energy Storage

Incorporating thermal energy storage (TES) is critical for increasing capacity factors of CSP plants. TES allows thermal energy collected during periods of peak insolation to be stored and transmitted later when the solar input is reduced, enabling CSP plants to generate electricity well after sunset. Adding several hours of TES smooths the inherent variability of solar energy, better aligns generation with electricity demand curves that peak in the evening hours, and also boosts the capacity factor. The TES integration not only amplifies the capacity factor but also significantly diminishes the Levelized Cost of Energy (LCoE) — a paramount metric for gauging economic feasibility. Achieving this synergy necessitates intricate design optimization, an endeavor propelled by two intertwined goals: LCoE reduction and alignment with the operational mandates of grid controllers or stakeholders, who aim to capitalize on peak wholesale prices.

Modern CSP plants are increasingly being designed with 6-15 hours of TES capacity, compared to only 3-6 hours in early CSP plants. With sufficient TES, CSP capacity factors can reach 50-60% in regions with excellent DNI. Compared to CSP without storage which is limited to capacity factors of 20-25%, TES provides a dramatic boost in utilization. The amount of TES required to maximize capacity factor depends on the particular solar resource profile and desired generation schedule. More storage increases energy output but also adds costs, and so optimization studies are used to find the ideal storage capacity.

4.2.3. Heat Transfer Fluid and Storage Medium

The heat transfer fluid (HTF) used to collect and transport thermal energy through the solar field impacts system temperatures and storage efficiency. Historically, synthetic oils were common HTFs but had temperature limitations under 400°C. Modern CSP plants now favor molten salt HTFs which can reach temperatures of over 500°C. Higher temperatures enable more thermal energy storage in a fixed volume, reducing the size and cost of the TES system. Molten salts like sodium nitrate-potassium nitrate are also attractive storage mediums because they have high heat capacities and can retain thermal energy for many hours with minimal losses. The hot molten salt leaving the solar field can be directly routed to insulated storage tanks, avoiding costly heat exchangers between the HTF and storage medium. Avoiding this temperature change mitigates exergy losses. Higher temperature differentials between the hot and cold storage tanks also enable more thermal energy storage. Modern molten salt towers storing heat at 565°C and 285°C can achieve temperature differentials around 280°C compared to only 100-150°C for older synthetic oil-based parabolic troughs. Again, higher temperatures translate to more MWh stored per unit volume.

4.2.4. Trends in CSP Capacity Factors

Reviewing the capacity factors of global CSP plants over the past decade reveals several interesting trends. Average capacity factors have increased from around 30% in 2011 to over 40% as more plants incorporate larger TES capacities. In 2010, the weighted average capacity factor of newly commissioned CSP plants was 30%. By 2020, newly built plants achieved weighted average capacity factors of 42%, a 41% increase over the decade. Storage durations have also markedly increased, with ~80% of new CSP plants built between 2016 and 2020 having at least 4 hours of TES and 39% having eight or more hours, compared to an average of just 5 hours for plants built between 1984-2015. Longer storage durations directly enable higher capacity factors. In addition, larger plants unlock economies of scale, with projects shifting from early smaller 50 MW developments towards 100-150 MW scales that can spread fixed costs over more energy output. New CSP plants are also optimized for evening peaks when electricity prices are highest by using modeling tools to size the solar field and TES system to maximize generation during peak windows rather than at solar noon, reaching capacity factors on a peak-hour basis of 60-80%. Furthermore, increasing temperatures are enabling more thermal storage and higher capacity factors, with modern molten salt towers operating above 550°C compared to early synthetic oil-based parabolic troughs operating below 400°C. The higher temperatures create a larger temperature differential in the TES system, reducing the required storage volume for a set number of MWh. Finally, capacity factors are rising even in regions with mediocre solar resources. For example, between 2010 and 2013, newly built plants in regions averaging 2000-2800 kWh/m^2/year had capacity factors of 27-35%. However, by 2020 plants in similar DNI regions achieved weighted average capacity factors of 42% due to technology improvements like larger TES capacities.

The global weighted-average capacity factor of newly commissioned plants increased from 30% in 2011 to 50% in 2021 – an increase of 66% over the decade. The capacity factor of future CSP plants are expected to reach 60% by 2030 [49]. Over the last decade, falling costs for thermal energy storage and increased operating temperatures have been important developments in improving the economics of CSP [3]. Increased operating temperatures also lower the cost of storage, as higher heat transfer fluid (HTF) temperatures lower storage costs by increasing the energy stored for the same volume.

4.2.5. Economic Impact of High Capacity Factors

High CSP capacity factors have several direct economic benefits including improved financing terms, lower LCOE, and increased profitability. High capacity factors reduce financing costs per MWh, as lenders offer lower interest rates and equity investors provide higher valuations for projects with consistently high output, reducing overall financing expenses. Additionally, higher capacity factors spread fixed operating costs like labor, maintenance, and O&M over more MWh generated, which reduces LCoE. Increased energy sales and higher capacity payment revenue associated with more MWh generated during higher peak value periods also boost total project revenue. Furthermore, the smoother output profiles compared to variable renewables like PV reduce grid integration costs and provide firm capacity during evening peaks, displacing the need for new gas plants for peak periods. While adding TES and optimizing CSP plant designs increases upfront capital costs, the resulting boost in capacity factor and potential revenue justifies the larger initial investment. Sophisticated modeling and optimization tools allow developers to find the optimal tradeoffs between capacity factors and LCoE tailored to local energy markets.

4.2.6. Future Outlook for CSP Capacity Factors

Recent technology trends including higher temperature operations, larger TES capacities, and optimized designs clearly demonstrate that CSP capacity factors can continue rising substantially. With thermal energy storage durations already at more than 10 hours in the latest plants, capacity factors exceeding 60% are achievable in excellent solar regions like Chile's Atacama Desert. Globally, average capacity factors for newly built CSP plants are expected to surpass 50% in the next 5 years. The capacity factor of future CSP plants are expected to reach 69% by 2030 [49]. Continued advances in molten salt storage mediums, improved power block flexibility, and growing plant sizes will also support higher capacity factors. Leveraging thermal storage to align generation with evening demand peaks can drive capacity factors calculated on peak hours to 70-90%, maximizing the value of CSP energy. Sophisticated modeling, optimization, and data analysis will enable increasingly tailored CSP plant designs. However, accurately predicting future CSP capacity factor trajectories requires the analysis of not just technical potential but also of the nonlinear interactions between capacity factors, CAPEX, LCoE, project revenue, and financing costs. There are open questions around the ideal capacity factor that minimizes LCoE or maximizes equity returns under different electricity market conditions. As with other renewables, deploying CSP in a thoughtful manner guided by techno-economic modeling will be critical in solving the complex multidimensional optimization challenge of affordable, reliable, and sustainable electricity generation.

4.3. Operations and Maintenance Costs

Operation and maintenance (O&M) expenses are a key determinant of the overall economic viability of CSP plants. Compared to other renewable energy technologies like solar photovoltaics (PV) and onshore wind, the O&M costs for CSP are substantially higher on both absolute and proportional bases. Higher O&M costs are driven by the greater mechanical and operational complexity inherent in CSP systems with large fields of mirrors, heat transfer systems, thermal storage, and conventional turbine generators. However, as the industry matures, O&M costs have declined through improved designs and economies of scale. The total O&M costs for a CSP plant encompass all the recurring expenditures required to operate and maintain the facility over its lifetime. This includes costs for regular maintenance of the solar field mirrors, receiver, heat transfer fluid system, thermal energy storage, power block, and balance of plant. Additional costs arise for plant operations staffing, insurance, spare parts inventory, and periodic component refurbishment or replacement. In general, O&M costs have both fixed and variable portions that scale with the net generating capacity and annual electricity production of the plant. The key factors influencing O&M costs for an individual CSP project include the solar field technology (i.e., PTC, STP, or LFR), quality of solar resource and annual DNI at the site location, hours of thermal energy storage capacity, power block type (steam turbine, combined cycle), plant capacity and design complexity, local labor costs for operations and maintenance personnel, and maturity of regional CSP supply chain and O&M expertise.

Reported O&M expenses for the first generations of utility-scale CSP plants still operating generally range \$0.02-0.04/kWh [50]–[54] but costs below \$0.02/kWh have now been achieved for newer facilities. For the early PTC-type CSP plants, frequent receiver tube and mirror glass replacements were major factors. Improvements in materials and manufacturing have increased receiver and mirror lifetimes by 2-4 times, drastically reducing these costs. Personnel are now often the biggest O&M expense, stemming from the labor-intensive nature of CSP operation. The number of full-time staff needed also depends on the solar field design, with simpler central receiver layouts requiring less personnel than complex parabolic trough arrays. Plants in lower-wage countries like India and Mexico have achieved total O&M costs below \$15/kW-yr (\$0.02/kWh). For the same plant capacity in the US and Europe, O&M costs range from \$25-\$35/kW-yr.

Advanced CSP designs incorporate features to boost reliability and reduce long-term O&M costs. PTC plants can use single-axis tracking for the mirrors to decrease motor/actuator maintenance compared to two-axis tracking. Larger aperture trough collectors concentrate sunlight onto fewer receiver tubes, reducing the number of components. Central receiver technologies allow 360-degree aiming strategies to mitigate localized wear and prolong receiver lifetime. Enclosed receivers also protect critical elements from harsh desert conditions. Using molten salt as both the heat transfer fluid and storage medium eliminates costly heat exchangers. Adaptive control schemes and automated monitoring techniques like drone infrared inspections will also lower future O&M costs. Detailed component degradation modeling enables the optimization of maintenance scheduling. Improved remote monitoring and early fault detection allows issues to be identified before significant damage occurs. Big data analytics can detect patterns and predict maintenance requirements before failures happen.

Recent industry trends show CSP O&M costs have substantial room for further improvement through supply chain maturation and design standardization to enable economies of scale for replacement parts and inventory. Improved components and more redundancy will increase maintenance intervals and extend lifetimes. Advanced materials like ceramics and polymers will enhance durability and cleaning efficiency. Drone and robotics automation will reduce manual labor requirements. Digitalization and analytical tools will shift maintenance from reactive to predictive. However, O&M costs still contribute a sizable fraction of a CSP plant's overall LCoE - typically 18-20% [44], [55]. This is 2-4 times higher than the O&M percentage for solar PV or onshore wind projects. The proportional impact is important when assessing competitiveness. Reducing O&M costs is imperative for lowering CSP LCoE. A 20% O&M reduction can increase the internal rate of return of CSP plants from 11.4% to 13.4% depending upon the type of CSP technology, e.g., PTC, SPT or LFR [56]. Thus, while continued technology learning and best practices will likely reduce absolute O&M costs moderately for future CSP plants, the relative O&M share of LCoE will remain significant compared to other renewable power generation.

The magnitude of O&M expenses must be weighed appropriately when evaluating the LCoE for CSP projects in various markets against alternative generation options. With realistic O&M assumptions, CSP with six or more hours of thermal energy storage can provide sustainable, transmissible electricity at highly competitive LCoE in high DNI regions. Reducing O&M costs through improved designs and maintenance strategies must be balanced against potential tradeoffs in performance and reliability. If value engineering with CSP plants is applied too aggressively to minimize short-term O&M outlays, it risks project availability and lifetime. Input from experienced O&M providers during project development is essential to avoid these pitfalls. While solar field and power block choices impact O&M costs, the amount of thermal energy storage capacity also plays a key role. Adding several hours of molten salt storage increases the O&M costs associated with the storage tanks, pumps, and heat exchangers. However, the generation benefit of thermal storage may justify the higher O&M expense. Overall, international experience demonstrates that best-in-class CSP projects can achieve O&M costs between $12-$18/kW-yr translating to $0.015 - $0.02/kWh in regions with excellent solar resources. Continued technological improvements should allow these benchmarks to be reached more widely. However, the inherent complexity of CSP plants compared to PV will likely preclude O&M costs dropping much below $0.01/kWh over the next decade.

4.4. Levelized Cost of Electricity (LCoE)

The levelized cost of energy (LCoE) has emerged as a pivotal economic metric for evaluating and comparing alternative power generation technologies. LCoE represents the per unit cost (on a per kWh basis) of building and operating a power plant over its lifetime. It enables an "apples-to-apples" comparison of technologies with different cost structures, plant lifetimes, capacities, and generation profiles. It represents the revenue needed for an investor to break even. Lower LCoE values indicate improved economic competitiveness. The most important parameters that determine the LCoE of CSP plants are [57]:

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

There is no single universally accepted LCoE formula. Various analytical models employ different mathematical expressions, terms and assumptions. At a high level, LCoE represents the ratio of total lifetime costs to total expected electrical output over the analysis period. But complexity arises in accurately estimating the numerator and denominator. Total plant costs encompass multiple variables like capital expenditures, operating expenses, fuel costs, financing costs etc. The useful plant lifetime over which costs are leveraged ranges from 20-30 years. Projected electricity generation depends on variables like solar resource, capacity factor, degradation etc. Assumptions around discount rates, debt interest rates, insurance rates etc. also vary. **Table 1** summarizes key LCoE equations from literature, identifying the main cost and performance parameters incorporated. Reviewing the range of LCoE formulas provides useful insights into the key factors affecting CSP economics and areas of variability across different analytical approaches.

Table 1. Variations of LCoE Formulations for CSP Systems in Literature

S.N.	LCoE Formula	Nomenclature	Ref.
1	LCoE expression uses by SAM (System Advisor Model by NREL) $LCoE = \frac{(FCR\ x\ CC + FOC)}{AEP} + VOC$	FCR: fixed charge rate CRF: capital recovery factor. PFF: project financing factor. CFF: construction financing factor. CC: capital cost, [$]. FOC: fixed operating cost, [$]. VOC: variable operating cost, [$/kWh].	[58]

	$FCR = CRF\ x\ PFF\ x\ CFF$	AEP: annual electricity production, [kWh].	
2	$$LCoE = \frac{crf\ x\ (K_{E,invest}) + K_{E,OM} + K_{E,fuel}}{E_{net}}$$ where $$crf = \frac{k_d\ x\ (1+k_d)^n}{(1+k_d)^n - 1} + K_{insurance}$$ $$K_{E,invest} = K_{E,direct} + K_{E,indirect}$$ $$K_{E,invest} = (1 + \%_{indirect}) + (K_{SP} + K_{SF} + K_{TES} + K_{T\&R} + K_{PB})$$ Useful Plant Life: 30 Year	crf: capital recovery factor $K_{E,invest}$: initial onetime capital costs $K_{E,OM}$: annual operation and management costs, $K_{E,fuel}$: tcost of required fuel, E_{net}: net electricity produced from the CSP plan K_d: real debt interest rate n: depreciation period or the lifetime of the plant $K_{insurance}$: annual insurance rate $K_{E,invest}$: total capital costs (investment) $K_{E,direct}$: direct costs $K_{E,indirect}$: indirect costs K_{SP}: site preparation cost K_{SF}: solar field cost K_{TES}: thermal storage cost $K_{T\&R}$: tower and receiver cost (for SPT) K_{PB}: power plant and balance of system costs	[59]
3	$$LCoE = \frac{PCI - \sum_{n=1}^{N} \frac{DEP + INT}{X} TR + \sum_{n=1}^{N} \frac{LP}{X} + \sum_{n=1}^{N} \frac{AO}{X}(1 - TR) - \frac{RV}{X}}{\sum_{n=1}^{N} \frac{Initial\ kWh\ x\ (1 - SDR)^n}{X}}$$ $$X = (1 + DR)^n$$	AO: annual operations cost DR: discount rate RV: residual value SDR: system degradation rate N: number of years the system is in operation. PCI: project cost minus any investment tax credit or grant DEP: depreciation INT: interest paid LP: loan payment TR: tax rate.	[60]
4	$$LCoE = \frac{C_t + L + \sum_{n=1}^{N}[(V+1)C_t(1+r)^{-n}]}{\sum_{n=1}^{N}[S\ x\ TF\ x\ \eta(1-DR)^n(1+r)^{-n}]}$$ Plant Life: 30 Year	C_t: Capital cost of the system installed in the year t between 2017 and 2050 L: Land cost V: Operation-maintenance cost (2%) I: Insurance cost (%) S: DNI (kWh m^{-2} $year^{-1}$) TF: Tracking factor (%) η: Performance factor DR: Degradation rate (0.2%) r: Discount rate (%) N: Lifetime of the system	[61]
5	$$LCoE = \frac{\left[C + L + \sum_{n=1}^{N} \frac{(OPEX + 1)\ x\ C}{(1+r)^n}\right]}{\left[\sum_{n=1}^{N} \frac{S\ x\ TF\ x\ \eta\ x\ (1-d)^n}{(1+r)^n}\right]}$$	En: annual energy production C: cost of the system L: cost of the required land S: available solar resource STF: tracking factor r: discount rate OPEX: operation and maintenance costs	[62]

		I: insurance costs d: annual degradation rate η: performance factor, which relates the amount of the utilized solar resource to the quantity of electricity produced N: economic lifetime of the system (years)	
6	$LCoE = \frac{C_I + \sum_{t=1}^{n}(C_{O\&M,t})}{\sum_{t=1}^{n}(E_t)}$ Plant Life: 30 Year	C_I: total capital cost (investment) $C_{O\&M,t}$: operation and maintenance cost in year t E_t: electricity generated in year t (kWh)	[63]
7	$LCoE = \frac{-C_o - \frac{\sum_{n=1}^{N} C_n}{(1-d_{nominal})^n}}{\frac{\sum_{n=1}^{N} Q_n}{(1-d_{real})^n}}$	Q_n: electricity produced (kWh) by the power plants in N years N: analysis period in years C_o: equity investment of the project N: analysis period C_n: annual cost of the project in number of years (inclusive of installation, operation and maintenance, financial costs and fees) $d_{nominal}$: nominal discount rate (the discount rate with inflation) d_{real}: real discount rate (the discount rate without inflation)	[64]
8	$LCoE = \frac{PMT(WACC, Life, Capex) + O\&M}{8766\ x\ CapFact\ x\ NamePlate}$ Useful Plant Life: 20 Year	PMT: annual capital payment, which includes interest repayments, WACC: weighted average cost of capital, assumed to be 7%, CapEx: as-built (present value) cost of the plant, including engineering, project management and contingency (in $/kW) O&M: annual operating and maintenance cost (in $/MWh), CapFact: annual average capacity factor of the plant NamePlate: design full-load capacity of the plant (in MW).	[65]
9	$LCoE = \frac{\sum_{t=1}^{t=n} \frac{I_t + M_t + F_t}{(1+r)^t}}{\sum_{t=1}^{t=n} \frac{E_t}{(1+r)^t}}$ $E_t = E_0\left(1 - \frac{DR}{100}\right)$ Useful Plant Life: 25 Year	It: investment expenditures in the year t which includes land cost, solar thermal collector system, thermal energy storage, power block system, labor cost, road construction, connection transmission line, substation M_t: O&M expenditures (2 to 3% of the investment cost) in the year t F_t: fuel expenditures in the year t (generally negligible for CSP) E_t: electricity generation in the year t E_0: electricity produced in the first year of the installation r: discount rate; (around 10%) n: life of the CSP plant DR: Degradation factor (for CSP plant, an annual output drop of 0.2% are	[66]

		considered mainly as a result of the degradation of the turbines)	
10	$$LCoE = \frac{\left[C + \sum_{n=1}^{N} \frac{(OM + I)\ x\ C}{(1 + r_r)^n}\right]}{\sum_{n=1}^{N} \frac{E\ x\ CF\ x\ 365\ x\ \eta\ x\ (1-d)^n}{(1+r_r)^n}}$$ $$r_r = \frac{(1 + r_n)}{(1 + u)} - 1$$	C: investment cost OM: operation and maintenance cost I: Insurance cost as a percentage of the investment cost E: energy storage capacity CF: capacity factor η: efficiency of converting heat into electricity d: annual degradation rate, %. r_r: real interest rate r_n: nominal interest rate u: inflation rate, %	[67]
11	$$LCoE = \frac{C_{invest}\left\{\frac{k_d\,(1+k_d)^n}{(1+k_d)^n - 1} + k_{insurance}\right\} + C_{O\&M}}{E}$$ Useful Plant Life: 30 Year	Kd: real debt interest (8%) $K_{insurance}$: annual insurance rate (1%) n: plant lifespan C_{invest}: total investment in the plant $C_{O\&M}$: cost of annual operation and maintenance E: annual electricity production	[68]
12	$$LCoE = \frac{L + S + A + K - W(1+r)^{-N} + \sum_{n=1}^{N} O\&M_n\,(1+r)^{-n}}{\sum_{n=1}^{N} E_n (1+r)^{-n}}$$	En: annual electricity production (kWh) in year n N: lifespan of the CSP plant r: discount rate O&M: operations and maintenance cost in year n J: investment cost over the construction period L: land cost (L), S: equipment procurement and installation cost A: civil works and auxiliary facilities cost K: interest payment over the construction period W: scrap value	[69]
13	$$LCoE = \frac{\sum_t \{(Investment_t + O\&M_t + Fuel_t + Others_t)(1+d)^{-t}\}}{\sum_t \{Electricity_t (1+d)^{-t}\}}$$	$Investment_t$: Investment expenditure in year t $O\&M_t$: Operation & maintenance expenditure in year t $Fuel_t$: Fuel expenditure in year t $Others_t$: Other expenditures in year t $Electricity_t$: Electrical energy generation in year t d: Discount rate	[70]
14	$$LCoE = \frac{\sum_{t=0}^{T} \frac{(I_t + O_t + M_t + F_t)}{(1+r)^t}}{\sum_{t=0}^{T} S_t \frac{(1-d)^t}{(1+r)^t}}$$	T: Life of the project in years T: Year t C_t: Net cost of project for t E_t: Energy produced for t I_t: Initial investment/cost of the system including construction, installation, etc. M_t: Maintenance costs for t O_t: Operation costs for t F_t: Interest expenditures for t	[71]

		R: Discount rate for t S_t: Yearly rated energy output for t (kWh/year D: Degradation rate	

The global weighted average LCoE of commissioned CSP plants fell by 68% over the period from 2010 to 2020, from $0.31/kWh to $0.098/kWh (**Fig. 8**). This resulted from lower capital costs, improved capacity factors, and reduced O&M expenses. Current LCoE ranges are $0.08-0.23/kWh for parabolic troughs, $0.09-0.2/kWh for solar towers, and ~$0.11/kWh for linear Fresnel plants (**Table 3**). Variability stems from technology, location, and storage duration. Higher solar resources and capacity factors reduce LCoE. Adding TES increases capital costs but boosts capacity factors, improving overall economics.

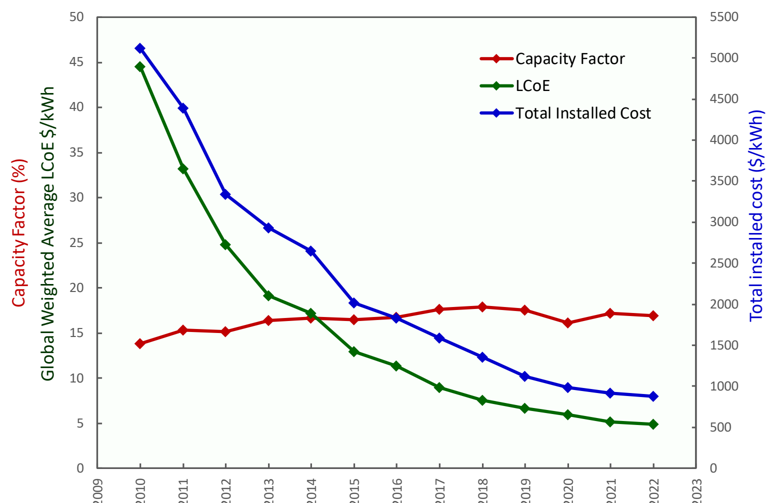

Fig. 8. Global weighted average total installed costs, capacity factors, and LCoE for CSP, 2010–2022. Prepared by authors based on IRENA Renewable Energy Cost Database [21] and CSP Guru, 2023 [46],

Initially, during the period from 2010 to 2012, Spain dominated the deployment of CSP plants, mostly consisting of PTC technology. Consequently, the global weighted average LCoE showed only a slight decline within a widening range as new projects came online. However, starting in 2013, the LCoE exhibited a clear downward trend as the market expanded, experience was gained, and more competitive procurement practices took effect. In addition to technology-learning effects, the shift in deployment to areas with higher Direct Normal Irradiance (DNI) contributed to this decline [72]. From 2016 to 2019, costs continued to decrease, and the commissioning of projects in China became noticeable. The estimated LCoEs for projects commissioned in China in 2018 and onwards ranged between $0.08/kWh and $0.14/kWh. On the other hand, projects commissioned in Morocco and South Africa during the same period tended to have higher costs. For projects commissioned between 2014 and 2017, the location in areas with high DNIs played a significant role in achieving increased capacity factors, resulting in lower LCoE values. The weighted average DNI for projects commissioned during this period was approximately 2,600 kWh/m²/year, which was 28% higher than during the period from 2010 to 2013. However, other factors besides DNI, such as technological advancements leading to plant configurations with higher storage capacities, also influenced the LCoE trends. Notably, CSP with low-cost thermal energy storage demonstrated its potential in integrating higher proportions of variable renewables in regions with favorable DNI.

Further LCoE reductions are expected, with target global weighted average LCoE reaching \$0.05/kWh by 2030. Continued capital cost reductions, improved capacity factors, lower O&M costs, and reduced financing expenses will drive this trend. However, appropriate policies and incentives will be needed to support ongoing CSP advancement and achieve these ambitious LCoE targets.

The economic data presented in **Tables 2** and **3** provide valuable insights into the cost trends and competitiveness challenges for CSP technologies. As shown in **Table 3**, the CSP levelized costs have reduced, probably as a result of the higher levels of irradiance of recent plant locations, lower total installed costs, larger thermal storage systems, and improved capacity factors. The LCoE for the current operating PTC-type CSP plants with 8 hours of thermal energy storage (TES) ranges from \$0.10/kWh in China to \$0.27/kWh in Spain. Similarly, the LCoE for SPT plants with 8 hours TES varies from \$0.08/kWh in China to \$0.15/kWh in Morocco. The LCoE for less mature LFR CSP plants is around \$0.11/kWh. As shown in **Fig. 9**, several factors have driven these significant LCoE reductions over the past decade: i) 50% lower installed costs, ii) 43% higher capacity factors from 30% to 44%, iii) 33% lower O&M costs, and iv) reduced weighted average cost of capital (WACC). Fig. 7 also breaks down the expected reduction in global weighted average LCoE by 49% from the base year 2021 to 2030. While early LCoE reductions resulted from deployments of CSP plants shifting to high direct normal irradiance (DNI) regions during 2013-2015, sustained cost reductions from 2016-2019 stemmed from technology maturation and CSP growth in China at \$0.08-0.13/kWh [72]. The accelerating cost reduction enhances the attractiveness of CSP to policymakers worldwide.

Table 2. Comparative Cost of CSP and alternative renewable energy technologies

Energy Technology	**Global Weighted-Average for Projects Commissioned in 2020**		
	Capital Cost (\$/kWh)	LCOE (\$/kWh)	Capacity Factor (%)
CSP	4581	0.108	42
Solar PV	883	0.057	16
Wind - Onshore	1355	0.041	36
Wind - Offshore	3185	0.084	40

Table. 3. Capital cost and LCOE for commercially operated CSP technologies

Project Name	**Country**	**Capacity** (MW)	**Start Year**	**Tech.**	**Capital Cost** $/kWh	**LCOE** $/kWh	**Storage** (hrs)	**HTF**	**TES**	**Turbine Eff.**
CEIC Dunhuang	China	100	2023	LFR	-	-	-	TO	MS	
Yumen Xinneng	China	50	2022	SPT	5395	0.11	9	MS	MS	43.7
Atacama I	Chile	110	2021	SPT	12727	-	17.5	MS	MS	
Shenzhen Jinfan Akesai	China	50	2021	SPT	6150	-	15	MS	MS	-
Shouhang Yumen	China	100	2021	SPT	4768	-	10	MS	MS	-
CSNP Urat	China	100	2020	PTC	4220	0.1	10	TO	MS	-
Ashalim Plot A	Israel	110	2019	PTC	9250	0.21	4.5	TO	TO	-
Ashalim Plot B	Israel	121	2019	SPT	7063	0.23		W	W	-
CEEC Hami	China	50	2019	SPT	4762	0.1	8	MS	MS	44
DCTC Dunhuang	China	50	2019	LFR	5064	0.1	15	MS	MS	-
Kathu Solar Park	S. Africa	100	2019	PTC	9179	0.16	5	TO	MS	-
LuNeng Haixi	China	50	2019	SPT	3316	0.09	12	MS	MS	-
Power China Gonghe	China	50	2019	SPT	3683	0.1	6	MS	MS	-
CGN Delingha	China	50	2018	PTC	5841	0.13	9	TO	MS	40
Huaqiang TeraSolar	China	15	2018	LFR	7033	0.12	14	W	W	-
Ilanga I	S. Africa	100	2018	PTC	7246	0.19	4.5	TO	MS	-
NOOR II	Morocco	200	2018	PTC	5596	0.16	7	TO	MS	-
NOOR III	Morocco	150	2018	SPT	5847	0.15	7	MS	MS	-
Shouhang Dunhuang -II	China	100	2018	SPT	4582	0.08	11	MS	MS	45
SUPCON Delingha	China	50	2018	SPT	3165	0.09	7	MS	MS	43
Xina Solar One	S. Africa	100	2018	SPT	8954	0.2	5.5	TO	TO	-
Bokpoort	S. Africa	50	2016	PTC	11717	0.22	9.3	TO	TO	-
Khi Solar One	S. Africa	50	2016	SPT	9332	0.22	2	W	W	-
Crescent Dunes	US	110	2015	PTC	9384	0.18	10	MS	MS	-
KaXu Solar One	S. Africa	100	2015	PTC	9031	0.24	2.5	TO	TO	-
NOOR I	Morocco	160	2015	PTC	7589	0.28	3	TO	TO	-
Dhursar	India	125	2014	LFR	2930	0.11		W		-
Genesis	USA	250	2014	PTC	5171	0.19		TO		-
Ivanpah	US	377	2014	SPT	6207	0.19		W		-
Megha	India	50	2014	PTC	2958	0.12		TO		-
Mojave	US	280	2014	PTC	6078	0.24		TO		-
Arenales	Spain	50	2013	PTC	9000	0.23	7	TO		-
Casablanca	Spain	50	2013	PTC	9905	0.27	7.5	TO	TO	-
Enerstar	Spain	50	2013	PTC	6460	0.28		TO		-

Godawari	India	50	2013	PTC	2914	0.11		TO		-
KVK Energy	India	100	2013	PTC			4	TO	MS	-
Shams 1	Abu Dhabi	100	2013	PTC	6483	0.27	None	TO		-
Solaben 1	Spain	50	2013	PTC	6890	0.3		TO		-
Solaben 6	Spain	50	2013	PTC	6574	0.28		TO		-
Solana	US	250	2013	PTC	8644	0.2	6	TO	MS	-
Termosol 1	Spain	50	2013	PTC	11756	0.28	9	TO	MS	-
Termosol 2	Spain	50	2013	PTC	11756	0.28	9	TO	MS	-
Aste 1A	Spain	50	2012	PTC	6705	0.17	8	TO	MS	-
Aste 1B	Spain	50	2012	PTC	6705	0.17	8	TO	MS	-
Astexol II	Spain	50	2012	PTC	6353	0.16	8	TO	MS	-
Extresol 3	Spain	50	2012	PTC	8564	0.23	7.5	TO	MS	38.1
*PTC - Solar Power Tower; PTC - Parabolic Trough Collector; LFR - Linear Fresnel Reflector; MS - Molten salt; STO - Synthetic Thermal Oil; HTF - Heat Transfer Fluid; TES - Thermal Energy Storage										

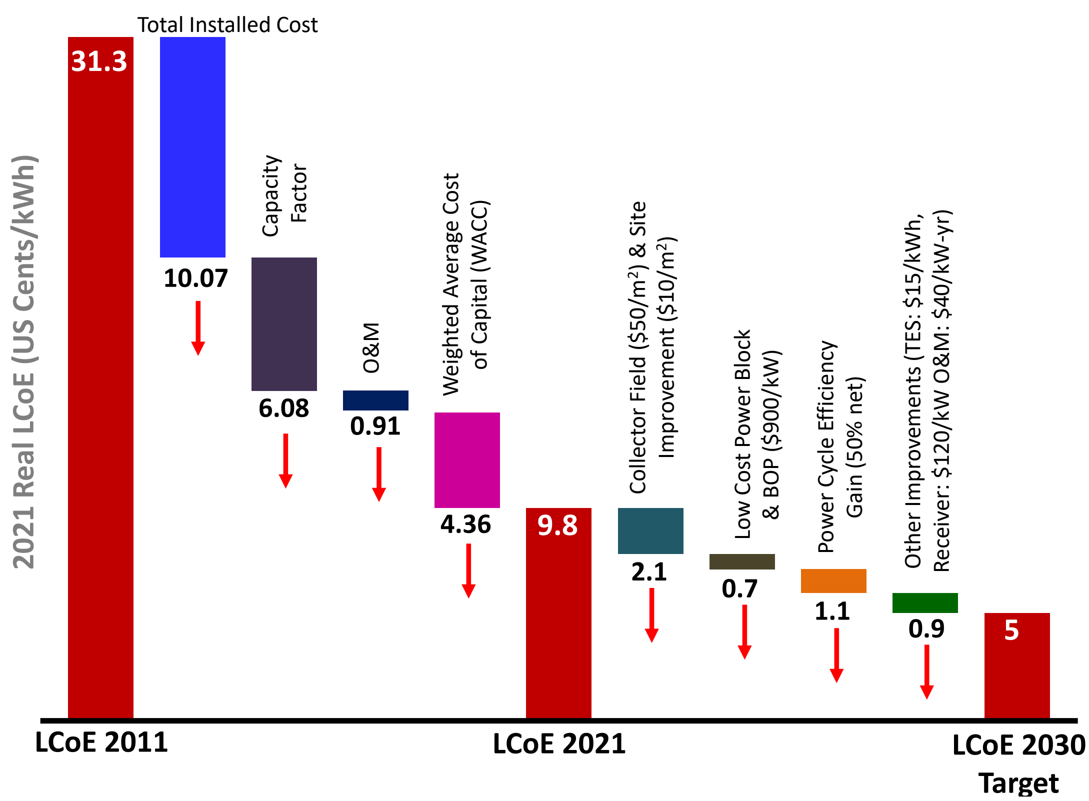

Fig. 9. Decomposition of the reduction in weighted average LCoE for CSP projects during the period 2011-2021 and future targets by 2030

However, LCoE comparisons between CSP plants must account for variability in assumptions around location, cost structures, plant configurations, incentives, time frames, etc. The auction database values in Fig. 8 illustrate this. Recent power purchase agreements (PPAs) have seen projects promising tariffs below \$0.10/kWh, much lower than older LCoE estimates, by securing low-cost, long-term financing to reduce LCoE. For instance, in September 2021, world record low bids of \$0.0339/kWh for the 390 MW Likana CSP project in Chile and \$0.073/kWh for the 700 MW DEWA CSP in Dubai were awarded. These companies likely signed PPAs above their LCoE, facilitated by low-cost extended financing which would lower their LCoE [49]. Such a low LCoE puts CSP on a par with offshore wind power. However, given that the global average costs of power generation from solar PV and onshore wind are now reaching fossil fuel cost parity, CSP must continue pushing down costs despite recent record project tariffs. New component technologies, especially for TES, are critical for attaining cost competitiveness. TES remains the missing link for CSP's technological and economic viability [26], [73]. Among CSP technologies, SPT has the highest potential for cost reductions and performance improvements with TES. The margin for improvement in SPT technology is higher and there are more under construction and development plants than for the rest of CSP technologies, due to their technical advantages [74]. SPT is likely to dominate future CSP growth [40], [74]–[78].

While CSP costs have fallen dramatically over the past decade, so have other renewables like solar PV (**Fig. 10**). However, CSP remains an immature technology with substantial potential for further cost cutting [20], [79]. Reducing CSP financing expenses will immediately improve competitiveness against PV and onshore wind, freeing up capital to accelerate technology innovation and grid parity. Ongoing projects rely on generous feed-in-tariffs (FITs) (e.g., CSP projects in China, Israel) and access to low-cost financing (e.g., CSP projects in the Middle East and Africa). While FITs and incentives have driven growth, CSP must transition to wholesale power markets. Low financing costs have a major impact on LCoE. Developing innovative public-private risk sharing instruments can attract lower costs and longer tenure investments. Debt sculpting aligns repayment with project cash flows. Securitization provides capital market access. With focused efforts on cutting-edge R&D, testing, commercialization and financing support, CSP can become a competitive clean energy technology.

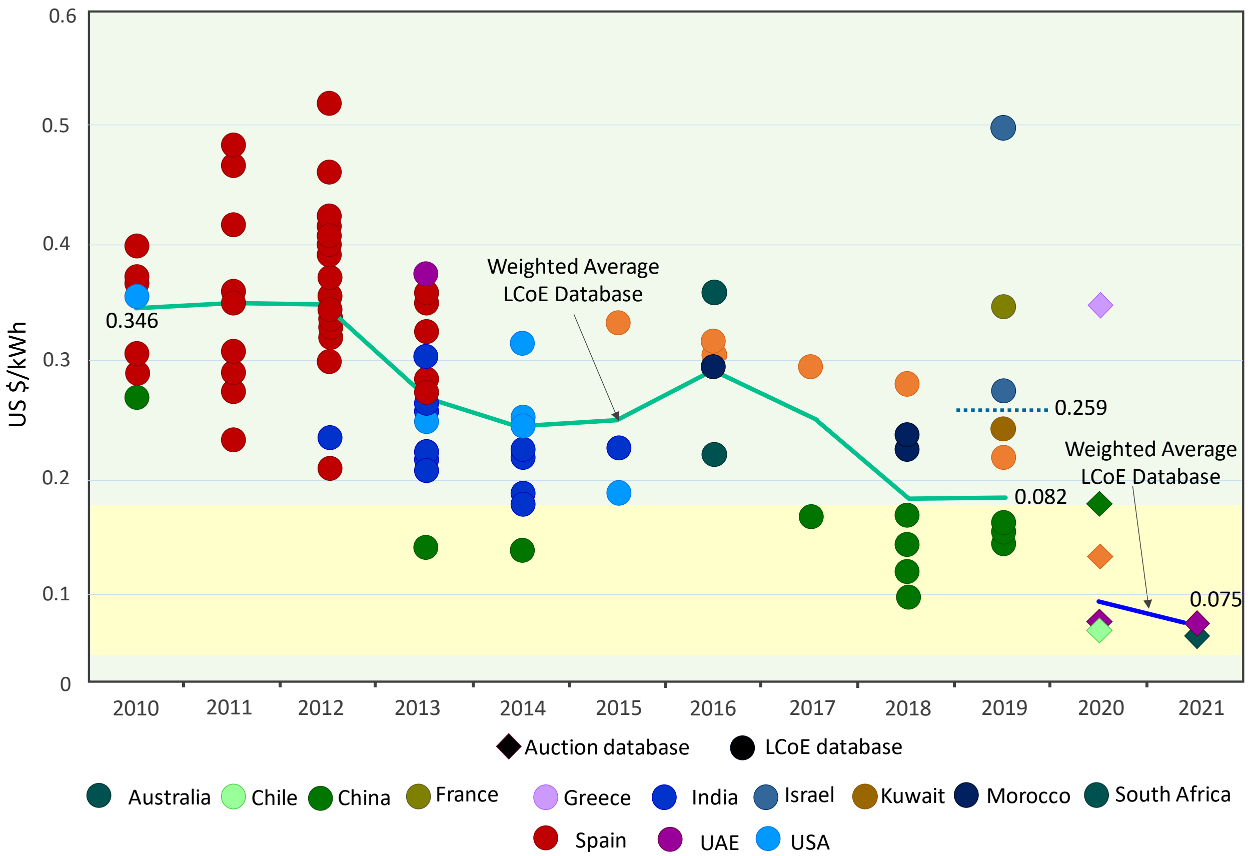

Fig 10. CSP project historical levelized cost of electricity and future plant auction prices ($/kWhe). Prepared by authors based on IRENA Renewable Energy Cost Database [44]

5. Key Findings from Previous LCoE Analyses of CSP Plants

Numerous studies have attempted to estimate the LCoE for CSP plants across different geographies and under various technological configurations. **Table 4** summarizes 45 studies that have analyzed the levelized cost of energy (LCoE) for various CSP plant configurations. The table includes details on the type of CSP technology examined (PTC, STP, or LFR), whether thermal energy storage (TES) was incorporated, the heat transfer fluid (HTF) and storage medium used, the system modeling approach, the plant capacity analyzed, the solar multiple, the storage hours, and the reported LCoE value and year. The calculated value of LCoE in these studies varies from a low of 0.05 $/kWh to as high as 0.64 $/kWh. This substantial variation can be attributed to a multitude of factors related to the technological configurations analyzed, modeling assumptions, geographic location, direct normal irradiance (DNI), plant capacity, financing conditions, capital costs, capacity factor, inclusion of thermal energy storage (TES) and other parameters [62], [80], [81]. For fair comparison, assumptions must be standardized [49]. Reviewing the findings from these previous techno-economic analyses provides useful insights into how researcher and design choices influence the projected competitiveness of CSP systems. Overall, these studies highlight that LCoE assessment of CSP plants is a multifaceted endeavor influenced by myriad of factors like plant configuration, scale, regional attributes and the choices in TES and HTF.

Table 4. Techno-Economic Studies of CSP systems in Literature

Study Reference	Baseline Year	Region	Capacity (MW)	Tools Used	CSP System	TES (hrs)	TES / HTF	LCoE (¢/kWh)	Takeaway Message
Asselineau et al. [82]	2023	USA	100 MW equipped with sCO2 Brayton Cycle η=51%	SAM + SolarPILOT + Solstice +	SPT	12	Liquid sodium / Chloride MS	5.49	LCoE comparative analysis for the four systems (i.e. 4x25 MW, 3x33 MW, 2x50 MW and 1x100 MW) show that the single large-scale 100 MW case leads to lower cost than multiple small-scale modules.
Mutume [83]	2023	Zimbabwe	600 MW	SAM	PTC	12	MS/Oil	14.7	LCoE analysis shows CSP-fossil fuel hybrid plants can reduce LCOE by 22% compared to stand-alone CSP plants, indicating hybridization improves financial viability.
						0	Oil	18.8	
Orangzeb et al. [84]	2023	Pakistan	100	SAM	PTC	12	MS/Oil	10.8	LCoE is significantly impacted by cheap workforce in Pakistan when compared to Western countries, influencing capital expenditure and maintenance costs.
Elfeky and Wang [85]	2023	Egypt	100	SAM	SPT	10	MS/MS	11.3	LCoE of PTC and STP system is calculated as 49.8% and 44% , respectively, higher compared to PV system
					PTC	8	MS/Oil	12.62	
Guccione and Guedez [86]	2023	Portugal	100	MoSES	STP	17	MS/MS	8.9	CSP-PV hybridization reduces LCoE by 22% for small-scale plants and 14% for large-scale plants compared to standalone CSP, demonstrating hybridization enhances cost-competitiveness across scales with greater benefits for small-scale CSP systems.
					PTC	16.2	MS/Oil	9.5	
Bayoumi et al. [87]	2022	Egypt	103	SAM	SPT	10	MS/MS	5.24	LCoE is reduced for SPT plants compared to PTC plants of the same capacity, due to approximately 20% higher annual power production and water consumption in the case of the SPT.
			102		PTC	10	MS/Oil	6.71	
Gamil et al. [88]	2022	Sudan	50	SAM	SPT	15	MS/MS	8.6	LCoE decreases as the plant capacity increases, leading to enhanced plant efficiency.
					PTC	15	MS/Oil	14.75	
Ahmad et al. [89]	2022	Pakistan	50	SAM	SPT	12	MS/MS	10.1	LCoE experiences a more pronounced impact from incremental changes in TES hours in PTC plants as compared to SPT plants, primarily due to high share of storage costs associated with PTC technology.
					PTC	12	MS/Oil	12.11	
Goyal et al. [90]	2021	India	100	SAM	STP	8	MS/MS	19.3	LCoE for all three CSP system types without TES was found to be approximately 11.5% lower than comparable CSP systems with energy storage.
					PTC	8	MS/Oil	15.2	
					LFR	8	MS/Oil	14.3	
Gutiérrez et al. [91]	2021	Spain	50	SAM	SPT	15	MS/MS	10.6	LCoE decreases with higher biomass shares in Hybrid CSP-Biomass Plant configurations, owing to reduced operating costs (cheap biomass) compared to TES.
					PTC	7.5	MS/Oil	11.6	
Xu et al. [92]	2021	China	50	-	SPT	6	MS/MS	14	LCoE analysis indicates that China is on the verge of achieving grid parity for CSP, with SPT emerging as the most promising technology.
					PTC	9	MS/Oil	17	
					LFR	-	-	14	

Guccione et al. [93]	2021	USA	100 MW equipped with sCO2 Cycle	SAM	STP	12	Chloride salt/ Sodium	7.3	LCoE reduction in STP plants can be achieved by reducing the size of the central receiver, a major contributor to the total installed cost, at the trade-off of employing larger and more costly sodium-chloride salt heat exchangers, without significantly impacting plant performance.
Rivera et al. [94]	2021	Honduras	50	SAM	SPT	10	MS/MS	11.01	The study projects an economic recovery period of less than 10 years for the CSP project, along with a positive Net Present Value (NPV), indicating its profitability
Augustine et al. [95]	2020	United States	100 MW equipped with sCO2 Brayton Cycle η=51%	SAM	SPT	14	MS/MS	10.9	LCOE can be further reduced by switching to a sodium-based receiver design compared to the molten salt design, but power cycle efficiency and TES tank costs remain challenges.
Bhuiyan et al. [96]	2020	Bangladesh	50	SAM	PTC	7	MS/Oil	9.86	LCoE favored molten salt CSP due to lower investment cost and higher capacity factor compared to thermal oil CSP.
						8	Oil/Oil	10.05	
Abaza et al. [97]	2020	Egypt	10	HYSYS, MATLAB & SAM	SPT	4	packed rock bed/Water	9.47	LCoE results suggest that small-scale CSP investments could boost market share, particularly in distributed energy generation.
Wang et al. [98]	2020	China	100	FVM	PTC	8	MS/MS	12.33	LCoE of PTC plants can be reduced by 8.67% by using molten salt as the heat transfer fluid instead of thermal oil and substituting the conventional solar receiver with a novel design that reduces radiation heat loss.
Tahir et al. [99]	2020	Pakistan	100	SAM	PTC	6	MS/MS	14.7	LCoE reaches its minimum value around 15 hrs TES capacity, increasing again beyond this point, indicating the advantage of larger TES capacity but also highlighting the need for optimizing TES capacity on a case-by-case basis.
Agyekum et al. [100]	2020	Ghana	100	SAM	SPT	12	MS/MS	14.2	LCoE is minimized with an optimal Solar Multiple (SM) of 1.4 to 1.9 for STP and 2.4 to 4 for PTC systems.
					PTC		MS/oil	27.21	
Soomro et al. [101]	2019	Pakistan	50	SAM	SPT	12	MS/MS	10.98	LCoE was reduced by wet cooling compared to dry cooling across all types of CSP technologies, resulting in a 10% LCoE reduction specifically for PTC plants.
					PTC	12	MS/Oil	3.69	
					LFR	12	MS/Oil	11.29	
Aly et al. [102]	2019	Tanzania	100	SAM	SPT	6	MS/MS	11.6 - 12.5	LCoE decreases with higher backup system capacity (natural gas turbine) but leads to higher annual fuel consumption and water usage.
					PTC	4	MS/Oil	13.0 - 14.4	
Islam et al. [103]	2019	Malaysia	-	RETScreen	STP	-	Water/Steam	20	LCoE in Malaysia could benefit from extending a feed-in tariff (FiT) rate to CSP plants, similar to solar PV.
			10		PTC	-	Oil/Oil	21.4	
Boujdaini et al. [104]	2019	Morocco	50	MATLAB	PTC	3	MS/oil	28	LCoE varies with solar field size and storage hours, reaching an optimal point with their precise combination.
Zhou et al. [51]	2019	China	100	SAM	SPT	8	MS/MS	15.8	The study found that higher solar multiples (SM) and longer thermal storage reduced operational costs and solar energy wastage; with optimal LCoE in the U.S. for SPT plants requiring an SM over 2.5 and 12 hours of storage, whereas in China, benefits leveled off at an SM of 1.6 -1.8 and 4 - 6 hours, discrepancy potentially influenced by the higher thermal energy storage costs for SPT compared to PTC plants in China needing further investigation.
					PTC	8	MS/Oil	15	

Hirbodi et al. [105]	2019	Iran	100	SAM	SPT	14	MS/MS	11.3	LCoE decreases with increasing TES capacity from 0 to 15 hr, but it slightly rises for a TES of 18 hours, highlighting the importance of optimizing TES capacity for specific CSP plants and conditions.
					PTC	14	MS/Oil	14.1	
Trabelsi et al. [106]	2018	Tunisia	50	SAM	PTC	7.5	Thermal Oil	18.97	LCoE for Molten Salt CSP plants is ~20% lower, coupled with ~6% higher energy efficiency compared to synthetic oil CSP plants.
							Molten Salt	15.18	
Pan et al. [107]	2018	South Africa	200	TRNSYS	SPT	9	MS/MS	10	LCoE decreases with increasing gross turbine capacities and overall system sizes, such as SM and TES, reaching its lowest levels at an SM of 3 and 15 hours of TES across all turbine capacities; however, for capacities of 175 MW and above, the need for large solar fields leads to high attenuation losses as heliostats are placed farther from the receiver, resulting in decreased solar field efficiency, increased LCoE, and a reduced capacity factor for plants with limitations on receiver rated thermal power.
					PTC	9	MS/Oil	12	
					PTC	9	MS/MS	11	
Ji et al. [108]	2018	China	50	MATLAB	SPT	9	MS/MS	14.2	LCoE of the PTC with 9 hour TES system is nearly 20% less than the LCoE without storage.
					PTC	9	MS/Oil	18.6	
Lou et al. [68]	2017	Spain		SAM	SPT	3	PCM/ steam	21.77	LCoE reduced by approximately 15% with a CSP plant size increase from 50 MW to 150 MW
Mihoub et al. [109]	2017	Algeria	50	SAM	SPT	8	MS/MS	23.57	LCoE reduces by 13% with lower interest rates and tax deductions
					PTC	8	MS/Oil	24.12	
Zhai et al. [110]	2017	Spain	19.9	EBSILON Profession al	SPT	6	MS/MS	21.7	LCoE drops by 22.6% in hybrid PV-CSP system vs. standalone CSP, but rises by 4.3% in hybrid PV-CSP vs. standalone PV.
Belgasim et al. [111]	2017	Libya	50	SAM	PTC	7.5	MS/Oil	24	LCoE for CSP plants in Libya can be made more competitive by reducing government subsidization for fossil fuels and electricity, ultimately increasing the profitability of CSP projects.
Zhuang et al. [61]	2017	China	100	SAM	SPT	6	MS/MS	20.88	LCoE is significantly influenced by high DNI, resulting in lower costs across various locations due to increased energy production, enhanced capacity factors, and more efficient TES systems.
Purohit et al. [112]	2016	India	50	SAM	SPT	0	MS/MS	12	LCoE for PTC plants is below the CERC's (Central Electricity Regulatory Commission, India) levelized tariff of INR 12.08/kWh in 142 out of 591 districts in India.
					PTC	0	MS/Oil	10.9	
					LFR	0	MS/Oil	16.8	
Balghouth i et al. [113]	2016	Tunisia	50	GREENI US (DLR)	PTC	7.5	MS/Oil	25.3	LCoE of CSP projects becomes economically competitive in Tunisia as the price of fossil fuel generated electricity increases.
Petrollese et al. [114]	2016	Morocco	1	SAM	LFR	8	Oil/Oil	64	LCoE is ~40% lower in hybrid CSP-PV system compared to CSP-only configuration
Olwig et al. [115]	2016	Tunisia	50	SAM	PTC	7.5	MS/Oil	17.57	LCoE is ~12.63% lower for wet cooling CSP plants compared to dry cooling, primarily due to decreased performance in the dry cooling system.
Boudaoud et al. [116]	2015	Algeria	20	SAM	SPT	8	MS/MS	63	LCoE decreases as storage capacity increases, driven by reduced investment costs in the storage system and larger solar field sizes.

Desai et al. [117]	2015	India	50	Engineering Equation Solver	PTC	-	oil	18.8	LCoE decreases with higher turbine inlet temperatures, larger plant size, and improvements in the Rankine cycle.
Dieckmann et al. [118]	2015	Morocco	150	In-house simulation tools	SPT	9	MS/MS	16.6	LCoE expected to decrease by 37% (PTC) and 43% (SPT) by 2025.
			160		PTC	7.5	MS/Oil	16.1	
Liqreina and Qoaide [119]	2013	Jordan	50	Greenius	PTC (wet cooling)	7.5	MS/Oil	15.55	LCoE is reduced by 18.8% when employing dry cooling in a PTC plant compared to the same PTC plant with wet cooling.
					PTC (dry cooling)	6.3		13.83	
Flueckiger et al. [120]	2013	USA	100	DELSOL	SPT	16	MS (single tank thermocline)	12.2	LCoE is minimized when a solar multiple of 3 (from options including 1, 2, 3, & 4) and a TES capacity of 14 hours are employed.
Krishnamurthy et al. [121]	2012	India	50	In-house simulation tool	PTC	7.5	Oil/Oil	14 - 15	LCoE experiences a sharp cost reduction initially with up to 5 hours of storage, followed by a gradual decrease as storage hours increase.
Köberle et al. [122]	2010	S. America & N. Africa	100	In-house simulation tools	PTC	6	MS/Oil	18	LCoE could potentially reach $0.06/kWh by 2050 with a 20% increase in learning rates for CSP technology.
Janjai et al. [123]	2011	Thailand	10	TRNSYS	SPT	2	Rock-bed/air	35	LCoE of PTC plant is found to be than SPT plant.
					PTC	2	Steam/Oil	30	

Notes:
FVM: Finite Volume Method; HTF: Heat Transfer Fluid; LFR: Linear Fresnel Reflector; MS: Molten Salt; MoSES: Modeling of Solar Energy Systems; MW: Megawatt; PTC: Parabolic Trough Collector; SAM: System Advisor Model; SPT: Solar Power Tower; TES: Thermal Energy Storage; TRNSYS: Transient System Simulation Program

5.1.1. Scale and System Configuration

The size of a CSP system is a major factor influencing capital and operating costs and therefore the overall LCoE from the plant. Larger plant sizes provide opportunities to improve cost efficiencies through scaling effects in multiple areas [124], [125]. There are several mechanisms through which increasing scale drives down CSP costs. First, key plant components and subsystems demonstrate a power law relationship between size and cost. As the physical dimensions increase, the specific cost per unit of capacity decreases. Equipment costs do not scale linearly with size, but follow an empirical power law relationship [124], [125]: (i) Power Block Cost/kWhe ~ (System Size)^(-0.3145), (ii) BOP Cost/kWhe ~ (System Size)^(-0.1896). These exponents indicate that doubling plant size reduces BOS $/kW by around 15% and power block $/kW by 20%. Second, the thermal efficiency of steam turbines degrades nonlinearly as size decreases. To maintain net plant efficiency, all thermal subsystem capacities must increase to offset turbine efficiency losses in smaller plants. This further raises the specific capital costs for reduced-scale facilities. Third, indirect fixed costs like development, engineering, construction management and plant commissioning show limited variability with plant size (nearly the same for a 20 MWh system as for a 100 MWh system). Fourth, larger plants necessitate the procurement of materials and components in bulk, leading to potential cost savings. Additionally, contractual arrangements for larger projects often permit a better negotiation leeway with suppliers, translating to cost reductions. Overall capital costs per kW for a 250 MW CSP SPT plant could be 25-35% lower than for a 50 MW SPT plant.

O&M costs also depend on size, with only moderate staffing increases needed for much larger plants, reducing the cost per kWh. Most O&M activities like mirror cleaning, equipment maintenance, and plant monitoring require a relatively fixed team size, even as generating capacity expands. Existing 50 MW Spanish PTC type CSP plants require 40-47 full-time staff annually [126], [127]. While detailed engineering analyses are needed, studies suggest O&M costs may be cut in half when moving from a 50 MW to 250 MW CSP plant [126], [127].

However, it is crucial to note that while larger plants can achieve economies of scale, they also entail greater risks. Very large plants can also introduce construction and operational complexities that may counteract some benefits. Any technical or operational setbacks in a large plant can lead to significant losses. Optimizing plant size is an important consideration during CSP project development and design. In addition, land availability, transmission infrastructure, and electricity demand may impose practical limits on optimally scaling up plant size. Land is a key constraint, as the solar field for a 100 MW parabolic trough plant already requires approximately 3 km^2 [24]. Siting larger plants to access high quality solar resources therefore requires sufficient suitable land with minimal shading, which favors deserts and arid regions with low population densities. The cost analysis must also consider the availability of transmission infrastructure to deliver electricity from these remote sites to load centers. Most studies examined in **Table 4** analyze plants in the 50-100 MW range, likely reflecting expectations of commercially viable plant sizes. New larger aperture CSP technologies may provide opportunities for further economies of scale. Many components of CSP systems exhibit economies of scale, including the solar field, power block, and TES system. As such, the per-kilowatt capital costs tend to be lower for larger plants. For example, Lou et al. [68] estimate the LCoE for a 150 MW SPT could be 15% lower than for a 50 MW plant on a per kilowatt basis. Asselineau et al. [82] provided a critical insight into scale aspect of CSP by comparing the LCoE across different CSP configurations. Their study elucidated that a single large-scale CSP plant of 100 MW tends to have a reduced LCoE compared to multiple smaller modules, for instance, four modules of 25 MW each. In terms of system configuration, most of the studies in **Table 4** show that the choice of CSP system — whether PTC, SPT or LFR — distinctly impacts the LCoE. In terms of system configurations, Bayoumi et al. [87] observed in Egypt that Solar Power Tower (SPT) plants boast a lower LCoE compared to Parabolic Trough Collector (PTC) plants of identical capacity. This advantage is attributed to the SPT plants' approximately 20% higher annual power production and water consumption. Gamil et al. [88] made a similar observation in Sudan, emphasizing that increasing plant capacity can lead to a decrease in LCoE, thus enhancing overall plant efficiency.

5.1.2. Regional Attributes

The LCoE of CSP plants is inherently influenced by the geographical region. For instance, the study by Orangzeb et al. [84] emphasizes the significant LCoE advantage leveraged by a cheap workforce in Pakistan compared to Western countries. This has a cascading effect on capital expenditure and maintenance costs, making CSP plants in regions with lower labor costs potentially more economically viable. In addition, the availability of solar radiation for power generation depends on location and so it is a critical factor influencing CSP LCoE, as higher direct normal irradiance (DNI) yields lower LCoE [80]. This drives siting of CSP plants in deserts and arid regions with excellent solar resources, such as the southwestern United States and Northern Africa. However, available land and transmission infrastructure also play important roles in site selection. Proximity to transmission lines is particularly desirable to minimize transmission-related losses, wheeling charges, and infrastructure costs. Land slope and geology must also permit site development at reasonable costs. Prior human activity and ecosystem value may also constrain viable sites. Overall, while higher DNI drives CSP developments towards solar-rich but transmission-remote desert areas, LCoE is not the only siting factor. The potential value of CSPs' dispatchability, land constraints, infrastructure factors, and environmental restrictions also shape viable locations. More holistic assessments are needed to site CSPs optimally as part of broader renewable energy systems.

Further compounding these regional variations are the infrastructural disparities. The availability and quality of infrastructure, be it roads for transporting materials or grids for transmitting the generated power, can sway the LCoE [128]. Regions with well-developed infrastructure can expedite project timelines, reduce transportation and logistical costs, and ensure efficient power transmission, all of which can contribute to a lower LCoE [129]. Another dimension to consider is the regulatory and policy environment. Governments and regulatory bodies can wield significant influence over the LCoE through policy instruments, subsidies, and incentives. For instance, regions with favorable policies promoting renewable energy adoption might offer tax breaks, capital subsidies, or feed-in tariffs that can substantially reduce the LCoE of CSP plants [130]. Conversely, in regions where the policy framework is still nascent or non-supportive, the LCoE might be higher due to the lack of such incentives. Financial mechanisms and market structures also play their part. The availability of affordable financing, the interest rates prevalent in a region, and the broader economic climate can influence the capital costs associated with setting up CSP plants [131], [132]. In economies where there is a robust ecosystem of green financing, coupled with a history of backing renewable energy ventures, the financial costs associated with CSP projects might be lower.

Beyond the tangible factors, the socio-cultural fabric of a region can play a subtle yet significant role. Public acceptance and community support can expedite project approvals, reduce litigations, and foster a conducive environment for the smooth execution of CSP projects. Regions with a history of community protests or opposition to energy projects might experience delays, leading to increased project durations and, consequently, higher LCoE [10]. Bayoumi et al.'s study [3] in Egypt offers another perspective on regional variations. While the study primarily focused on comparing the LCoE between different CSP configurations, it inadvertently highlighted the role of regional factors. Egypt, with its abundant sunlight, strategic geographic location, and a national push towards renewable energy, emerges as a favorable destination for CSP installations. The relatively lower LCoE figures, as compared to global averages, can be attributed not just to the technical efficiencies but also to the regional advantages that Egypt offers. In synthesizing these observations, it becomes evident that the economic assessment of CSP plants cannot be divorced from the regional context. The interplay of local economic conditions, infrastructural readiness, policy frameworks, financial mechanisms, and socio-cultural dynamics shapes the LCoE in profound ways. As the global community strides towards a sustainable energy future, recognizing and navigating these regional variations will be instrumental in harnessing the true potential of CSP plants.

5.1.3. Thermal Energy Storage (TES) and Heat Transfer Fluid (HTF)

Thermal Energy Storage (TES) systems significantly influence the LCoE of CSP plants. The inclusion of TES systems enables CSP plants to better align production with peak demand periods, enhancing their value and competitiveness [133]. The juxtaposition of varied TES durations and HTF mediums, from molten salt (MS) to oil, elucidates their economic implications. While longer TES durations enable extended energy transmission beyond sunlight hours, the choice of HTF impacts the operational efficiency and plant maintenance. Many studies have found that adding TES increases the LCoE of CSP plants but also increases the capacity factor and dispatchability. For example, Ji et al. [108] report that adding 9 hours of TES using a two-tank molten salt system decreases the LCoE of a 50 MW parabolic trough plant by 20% compared with a similar CSP plant without storage. Ahmad et al. [89] pointed out that the LCoE is more susceptible to variations in TES hours in PTC plants compared to SPT plants, largely due to the high proportion of costs associated with TES in PTC plants. However, the high cost of molten salt TES systems also increases capital costs [90], [134]. Estimates indicate for 10 hours of molten salt TES can increase actualized construction costs of PTC plant by about 39% and the cost of the SPT plant by about 52% [135]. Thus, an optimal tradeoff needs to be achieved between additional generation capability and higher investment costs when sizing the TES subsystem. The optimal configuration depends on the CSP cost, the CSP generation profile value, and financing assumptions.

The choice of Heat Transfer Fluids (HTF) and thermal energy storage medium can also influence the LCoE of CSP plants. Specifically, the selection between molten salt (MS) and thermal oil as the HTF impacts plant efficiency and consequently the LCoE. For example, Asselineau et al. [82], found that using liquid sodium paired with chloride molten salt offered a different performance compared to traditional molten salt or oil HTF pairings. Comparing oil and molten salt HTF for an SPT plant, Trabelsi et al. [106] reported approximately 20% lower LCoE and 6% higher energy efficiency for molten salt versus thermal oil. For a 100 MW SPT in China, Zhuang et al. [61]

analyzed four molten salt options - traditional nitrate (molten salt), chloride, fluoride, and carbonate eutectics. Their results showed the traditional nitrate molten salt (60-40 wt% $NaNO_3$-KNO_3) yielded a lower LCoE compared to the other three salt mixtures studied. In summary, the interwoven dynamics of HTF, thermal energy storage medium and TES in CSP plants hold profound economic implications. Their choices and efficiencies can either elevate CSP plants to the pinnacle of renewable energy sources or relegate them to the annals of economic unviability. As the energy landscape shifts towards sustainability, and as innovations in materials and storage technologies emerge, the economic assessment of CSP plants will remain an ever-evolving tapestry, with HTF and TES at its heart.

5.1.4. Reflection on LCoE Values reported in Literature

A major shortcoming evident from the results of the studies in **Table 4** is that many studies rely predominantly on projected or estimated input parameters as opposed to using real empirical data from operating CSP plants. Compared to the LCoE range of \$0.08-0.28/kWh for real-world plants listed in **Table 3**, many of the modeled projections seem overly optimistic. The simplified modeling assumptions likely do not account for full plant integration challenges, site-specific factors like grid connection costs, and component degradation affecting performance over time for actual plants. This probably explains why many of the projected LCoE values seem optimistic compared to those from operational facilities. Independent validation of these projections via operational data from commercial CSP facilities can improve modeling accuracy.

The results of many studies presented in **Table 4** can be considered scientifically poor and irrational when compared to real world LCoE values reported in **Table 3**. For instance, the study by Tahir et al. [99] models molten salt usage in conventional parabolic trough receivers to estimate LCoE of \$0.12/kWh in Pakistan. However, molten salt operation above 565°C causes massive heat losses that erode the solar-to-thermal efficiency of commercial parabolic trough technology designed for lower temperature oils up to 400 °C [24], [136]. Similarly, the payback period estimates of 0.93 years for LFR systems and 17.17 years for SPT systems without storage in India by Goyal et al. [90] appear unrealistically optimistic and impractical when benchmarked against real-world data. As shown in **Table 3**, there is no major difference in the total installed cost between LFR and SPT technologies per MW of plant capacity. The global weighted average installed costs are around \$5500-6500/kW for both technologies. With such high upfront investments required, a payback period of less than 1 year for a 100 MW LFR plant is practically impossible.

6. Future Cost Reduction Trends

Current theory explains that growth improves costs because growth increases the likelihood of fundamental technological advances, incremental learning by doing, economies of scale in manufacturing, and standardization [1, 2]. As a technology is deployed more widely, costs tend to drop due to increases in: fundamental technological advances arising from greater R&D investments and knowledge stock enabling incremental and breakthrough innovations; learning-by-doing as manufacturers optimize fabrication, supply chains, and assembly from real-world experience; economies of scale through lower input costs, efficient specialized equipment, and spreading fixed costs with higher production volumes; and standardization of common components, logistics, and plant designs boosting productivity. Together, these interlinked learning mechanisms result in lower costs as deployment expands. A common technique used to analyze the cost trajectory of a technology as it scales up is "Progress Ratio" or learning curve [137]–[141]. Progress Ratio is the factor by which the cost decreases each time the total installed capacity of a specific energy technology doubles. For instance, a progress ratio of 80% indicates a 20% cost reduction with each doubling of installed capacity. In the case of CSP, it is anticipated that the Progress Ratio would range from 80% to 90%, resulting in a cost reduction of 10% to 20% with each doubling of capacity [139], [142]. This reflects the relatively high potential for continued learning advances across the value chain, from materials and components to plant operation. Assuming an optimal Progress Ratio of 85% (15% cost reduction per doubling), the levelized cost of CSP could plausibly decrease by 40-50% by 2030. Realizing these reductions involves scaling up deployment, implementing continued technology improvements, and overcoming non-technical barriers.

"Learning curve" predictions for Cost Reduction Potential of Energy Technology

Current theory explains that increasing deployment leads to lower costs through several interlinked mechanisms, including fundamental technological breakthroughs, incremental learning-by-doing, economies of scale in manufacturing, and standardization [143]–[146]. A simple mathematical relationship, or "learning curve", to model how costs are expected to decline as installed capacity increases for a given technology can be written as:

$$C_2 = C_1 \, x \, PR^{\log_2 Q_2/Q_1}$$

where C_1 and C_2 are the costs at installed capacities Q_1 and Q_2, respectively, and PR is the progress ratio (as a decimal, e.g., 0.85 for 85%).

In the case of CSP, it is anticipated that the Progress Ratio would range from 80% to 90%, resulting in a cost reduction of 10% to 20% with each doubling of capacity [139], [142], [144]. This reflects the relatively high potential for continued advances across the CSP value chain, from materials and components to plant operation. By assuming an optimal Progress Ratio of 15%, it is reasonable to expect a reduction in the LCoE of approximately 40% to 50% by the year 2030.

Fig. 11 illustrates the global weighted-average trends of Levelized Cost of Energy (LCoE) for utility-scale solar PV, CSP, and onshore and offshore wind installations. The chart presents these variables on a logarithmic scale (log-log), allowing us to observe the learning rate of these technologies through the slope of a straight line. From 2010 to 2022, the LCoE learning rate for CSP's total installed costs was estimated to be 36.7%, which is twice the learning rate for total installed costs (18.1%) [21]. This significant improvement in CSP can be attributed to technological advances that have increased typical thermal energy storage from 6 hours to 9-15 hours, now being the economic optimum, depending on resource quality and market factors. Over the same period, CSP's progress ratio (PR) of 36.7% far exceeds that of offshore wind (21.2%) but fell slightly below solar PV (38.2%). If these learning curves continue into the future, Figure X suggests that, above around 10 GW of installed CSP capacity, it will likely achieve a lower LCoE than any other renewable power generation technology at comparable cumulative capacity.

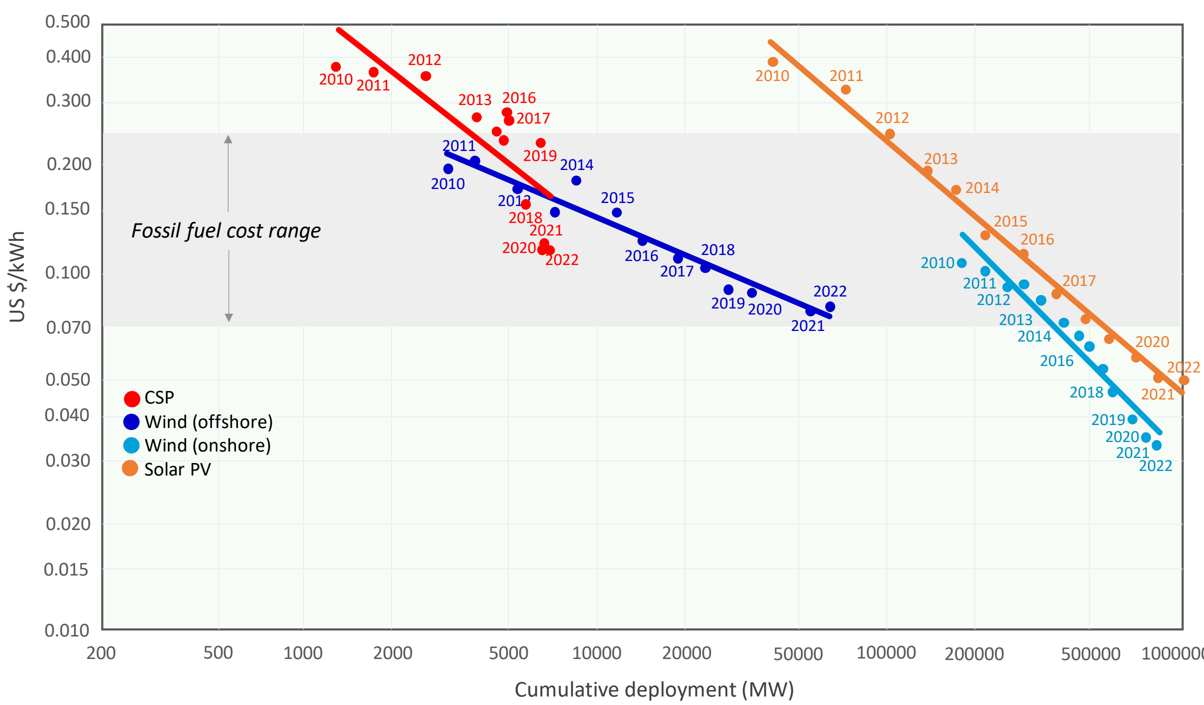

Fig. 11. The global weighted average LCoE learning curve (Logarithmic scale) trends for CSP, solar PV, onshore and offshore wind, 2010-2022. Adapted from: [21]

6.1. R&D Priorities for Enhancing Economic Performance of CSP

The advance of CSP technology is driven by ongoing research and development (R&D) efforts with two primary objectives: refining existing technology (evolutionary R&D) and pushing the boundaries to develop next-generation CSP systems (step-change R&D). To ensure effective coordination and alignment of R&D priorities, the global CSP community has established the IEA Solar Power and Chemical Energy Systems (SolarPACES) program, which includes active participation from countries engaged in CSP research. The collective efforts of researchers, industry experts, and policymakers within the global CSP community, facilitated by programs such as SolarPACES, play a pivotal role in driving the progress and growth of the CSP sector. In the context of CSP and other emerging energy technologies, technical R&D endeavors aim to enhance economic performance by addressing several key areas. These areas include reducing construction costs, enhancing energy conversion efficiency, minimizing O&M costs, and expanding the market value and range of applications for CSP technology. To prioritize these R&D efforts, this study incorporates suggestions from the reviewed sources, supplemented by valuable insights from R&D professionals with direct experience in the field. **Table 5** provides an overview of the technical challenges associated with various components of CSP systems and proposes corresponding R&D efforts to overcome these challenges. By addressing these research areas, the CSP industry can unlock the full potential of CSP and solidify its position as a key player in the global energy landscape.

Table 5. CSP Technical challenges and efforts to overcome them [24], [28], [66], [133], [139], [147], [148]

Component of CSP Plant	**Specific Requirements**	**Challenges/ issues**	**Required Improvement/Technology shift proposed for Cost Reduction**
Mirrors	▪ High reflectivity ▪ Resistance to environmental degradation ▪ Easy maintenance ▪ Durability for 30+ years ▪ Resistance to dust and soiling ▪ Low cost per m2	▪ Glass thickness must be optimized. ▪ Transition piece between back of mirror & structure needs improvement. ▪ Mirror prices can be prohibitive. ▪ The reflecting layer, collector frames, & glue used on mounting pads degradation.	▪ Development of cost-effective reflective materials (e.g., standardized dimensions, thinner glass mirrors) ▪ Improved reflective materials (e.g., aluminized polymer films) to increase efficiency and durability ▪ Large dimensions (for PTC plants, larger dimensions reduce the total number of rows in the same solar field, leading to capital cost savings. Similarly, in STP plants, fewer tracking devices are needed

			due to the larger size, which lowers the tracking cost per square meter). ▪ Improved manufacturing processes (e.g., production automation) ▪ Develop anti-soiling coatings ▪ Automated mirror cleaning systems.
Support Structures	▪ Strength to withstand high wind loads, ▪ Cost effective lightweight ▪ Resistance to corrosion ▪ Allow easy mirror cleaning and accurate mirror positioning	▪ Trade-offs between rigidity & cost. ▪ Long-term durability due to corrosion. ▪ Costly assembly by hand. ▪ For parabolic troughs: wider apertures, simplified installation. ▪ For tower plantsr heliostats with cheaper actuators, smaller heliostats - possibly preassembled	▪ Use of advanced materials with higher strength-to-weight ratio e.g., composites ▪ Self-supporting structures for mirrors. ▪ Modular designs for mass production and rapid installation ▪ Pre-fabricated supports for rapid installation ▪ Optimized structural designs
Receiver	▪ High thermal efficiency ▪ Withstand high temperatures and thermal stresses ▪ Long operational lifetime ▪ Efficient heat transfer ▪ High thermal conductivity ▪ Resistance to thermal stresses	▪ Central receiver towers are not standardized. ▪ Excessive con- centration on a single element is a risk. ▪ Corrosion due to use of molten salts is possible. ▪ Hydrogen can permeate parabolic trough units due to degradation of heat transfer fluid. ▪ Corrosion of steel tubes ▪ Need for more absorptive receivers to the visible spectrum of solar light; low thermal emittance. ▪ Able to work at higher temperatures to improve efficiencies.	▪ Advanced coatings for increased heat absorption ▪ Improved materials for longevity under high thermal stresses (e.g., ceramics, alloys) ▪ Improved design for uniform heating and less subject to thermal stress ▪ Enhanced heat exchange designs ▪ Lower cost manufacturing techniques. ▪ Corrosion resistant receivers.
Tracking & Drive Mechanism	▪ Precision sun tracking, ▪ Reliable drive systems with durable mechanical parts ▪ Low maintenance ▪ Robustness against environmental factors (wind, dust) ▪ Accurate solar tracking	▪ Difficulty maintaining tracking accuracy over time ▪ Calibration and alignment difficulties (small deviations can lead to significant efficiency losses). ▪ Frequent manual adjustments required	▪ Implementation of advanced control algorithms for optimal solar tracking (e.g., automated and self-correcting tracking algorithms ▪ Lower torque drives ▪ Use of low-cost sensors ▪ Integrated drives, possibly without hydraulics. ▪ Integration of AI and machine learning for predictive

		▪ Environmental interferences (e.g. wind might cause misalignment, dust can obscure sensors) ▪ Complexity in system integration (sensors, drives, controllers) making troubleshooting and maintenance more challenging.	maintenance and system optimization
Heat Transfer Fluid (HTF)	▪ High thermal/chemical stability ▪ Efficient heat transfer ▪ Low viscosity at operational temperatures ▪ Low freezing point ▪ Non-toxicity and low corrosion ▪ High heat capacity ▪ Low pumping power ▪ Cost-effectiveness ▪ High lifecycle and recyclability	▪ Fluid is toxic, flammable, & inefficient ▪ Ambient air temperature & degradation pose issues. ▪ All central receiver tower's circuit elements are subject to freezing & corrosion.	▪ Exploration of new higher temperature fluids with improved thermal stability, lower frizzing point and lower costs ▪ Improved lifecycle and recyclability ▪ Enhance heat transfer properties (e.g., nanofluids, ionic liquids) ▪ Advanced thermal oils
Thermal Energy Storage (TES) system	▪ High energy storage density ▪ Long-term thermal stability ▪ Low cost ▪ Efficient charging/discharging cycles with high cyclic durability ▪ Compatibility with HTF ▪ Low energy losses ▪ Low corrosion potential	▪ Substantial backup energy required because molten salt cannot remain frozen. ▪ Need for more reliable, corrosion resistant, longer-lived systems. ▪ Concerns regarding parasitic use & costs of antifreeze fuel. ▪ Expensive molten salts used as storage medium.	▪ Exploration of alternative storage mediums (e.g., advanced encapsulated phase change materials, particle storage, thermocline storage) ▪ Alternative molten salt compositions for better performance (e.g., chloride salt) ▪ Improved purity of molten salt for reduced corrosion ▪ Improved integration with CSP system for optimized charging/discharging ▪ Improved insulation methods ▪ Modular design for scalability ▪ Optimized storage sizing ▪ Improved heat retention capabilities ▪ Enhanced safety and environmental profiles ▪ Thermo-chemical reactions to store energy
Power Turbine	▪ High thermal-to-electric efficiency at varying loads	▪ Thermal to electric technologies are inefficient.	▪ Higher efficiency turbines optimized for CSP operating conditions.

	▪ Rapid startup and load following capabilities ▪ Reliability, ▪ Low maintenance ▪ Integration with CSP system ▪ Low maintenance	▪ Small steam turbines reduce efficiency. ▪ Daily start-up & shutdown processes shorten the life span. ▪ Excessive water consumption	▪ For Rankine, develop new materials able to work at 6020 psi & 700ºC. ▪ Switch from Rankine to Brayton or other cycles to improve efficiency ▪ Switch to alternative working fluids such as supercritical CO2 ▪ Improved control algorithms ▪ Durability improvements to reduce maintenance
HTF Pumps	▪ Capability to handle high temperature fluids ▪ Resistance to HTF degradation ▪ Design should permit wide fluctuations in operating conditions expected in CSP plants ▪ Efficiency in circulation ▪ Reliability, ▪ Efficient fluid pumping with long operational lifetime	▪ Seal and gasket degradation at high temperatures leading to leaks ▪ Low efficiency due to inflexibility of traditional pump designs to cater to the variable operating conditions inherent in CSP operations ▪ Frequent maintenance and short seal lifetimes causing potential downtime.	▪ Advanced pump designs for reduced wear, reduced leaks and increased lifespan e.g., magnetically driven pumps ▪ Variable frequency drives to Integrate with system controls for optimal operation ▪ Durable sealing materials for high temperature HTF ▪ Improved reliability and longer lifetime
Land Use	▪ Efficient land utilization ▪ Low land acquisition costs ▪ Access to water resources ▪ Minimization of environmental impact ▪ Flexible layout to accommodate different CSP technologies (PTC, SPT, LFR) ▪ Land with suitable topography (minimal grading required)	▪ Limitations on plant size due to land availability ▪ High land costs in densely populated areas ▪ Remote locations of ideal CSP sites leading to increased infrastructure costs ▪ Conflicts with other land uses (agriculture, conservation) ▪ High water usage competing with other demands (e.g. agriculture) ▪ Potential disruption to local ecosystems and habitats	▪ Land optimization strategies and compact plant designs ▪ Hybridization with PV to reduce land use ▪ Co-location with industries needing process heat ▪ Lower water consumption through dry or hybrid cooling
Water Use	▪ Minimized water consumption ▪ Sustainable water sourcing ▪ High efficiency in cooling processes	▪ Traditional wet-cooling methods consume significant amounts of water ▪ Competition with other water users in arid regions	▪ Advanced dry cooling technologies (e.g., adiabatic coolers) ▪ Use of degraded/non-potable water sources ▪ Implementation of dry cooling techniques where feasible

		▪ Constraints on plant location due to water access ▪ Water scarcity in many regions where CSP plants are most effective	▪ Design of closed-loop systems to minimize evaporation losses ▪ Integration of desalination processes with CSP to utilize waste heat and provide clean water

7. Conclusion

This review has provided a comprehensive overview of the key economic considerations vital for evaluating the current status and future potential of concentrated solar power (CSP) technologies. The analysis of real-world data on capital costs, capacity factors, O&M expenses, and LCoE reveals that, while costs have declined substantially, ongoing innovations and strategic policy support will be imperative for CSP to achieve its immense promise as an affordable and sustainable renewable energy solution. The following key points can be drawn from this synthesis of the techno-economic research literature and industry data on CSP installations globally.

- Total installed capital costs for CSP plants have exhibited a distinct downward trajectory, falling by around 50% over the past decade. This resulted primarily from dramatic improvements in the solar field and thermal energy storage, which constitute the largest proportion of plant costs. Further cost reductions of the order of 30-40% by 2030 seem feasible through continuing R&D, manufacturing scale-up, supply chain development, and technology standardization. However, appropriately tailored incentives and financing mechanisms are needed during this period to support ongoing capacity growth and cost cutting. Sustained policy support has proven decisive in maturing other renewables like wind and solar PV. CSP likewise requires consistent backing to navigate "valleys of death" as it progresses down the experience curve.
- The inclusion of larger thermal energy storage capacities has significantly boosted capacity factors for modern CSP plants while moderately increasing installed costs. With 6+ hours of molten salt storage now commonplace, capacity factors approaching 60% are being achieved in high solar resource regions. Along with improved system optimization, larger storage volumes enable generation to be shifted towards evening peaks when power prices and demand are highest. While adding storage raises CAPEX, the values of transmissibility and increased utilization generally justify the higher investment. Overall, thermal energy storage is now universally viewed as economically attractive for maximizing revenue and competitiveness. Further advances in storage materials, systems, and integration will support even higher capacity factors exceeding 60%.
- Enhanced system designs, economies of scale, and accumulated experience have helped lower fixed O&M costs by about 33% over the past decade. However, at around 20% of LCoE, the O&M cost percentage for CSP remains 2-4 times higher than solar PV or onshore wind. This highlights the greater complexity inherent in CSP plants. While continued incremental

improvements will further reduce O&M costs, they are unlikely to reach PV levels. Hence O&M expenses will continue to represent a significant proportion of LCoE for CSP. Advanced control schemes, drone inspections, and big data analytics can shift maintenance from reactive to predictive, optimizing O&M outlays. But the tradeoffs between O&M costs and reliability warrant careful consideration.

- The levelized cost of electricity (LCoE) from CSP has declined substantially from an average of $0.31/kWh in 2010 to today's range of $0.08-0.15/kWh for plants with 6+ hours of thermal storage capacity. This 68% LCoE reduction resulted from lower capital costs, improved capacity factors, and reduced O&M expenses, as discussed above. However, while capital expenses have halved due to factors like economies of scale and technology learning, the LCoE remains above solar PV and onshore wind. Significant further cost reductions of the order of 40-60% are required for CSP to firmly establish grid parity across geographies and electricity markets. Attaining LCoE between $0.04-0.06/kWh can unlock CSP's vast potential. Our findings suggest this ambitious, yet achievable, target can be met by 2030 through coordinated advances across multiple fronts. First and foremost, continued deployment is essential to drive down costs along the experience curve. Global CSP capacity exceeds 6 GW but remains an immature technology with substantial room for growth. Expanding installations will enable further economies of scale, supply chain development, knowledge gains and R&D investment. China's recent CSP expansion highlights the potential. Strategic deployment incentives will be vital during this scale-up phase. Feed-in-tariffs, auction schemes and tax credits can stimulate cost-competitive growth.

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