SolarPACES 2023, 29th International Conference on Concentrating Solar Power, Thermal, and Chemical Energy Systems

Analysis and Simulation of CSP and Hybridized Systems

https://doi.org/10.52825/solarpaces.v2i.775

Published: 24 Jul. 2024

Techno-Economic Assessment of Electricity Generation From a Medium-Scale CSP-PV Hybrid Plant Using Long-Duration Storage

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Abstract. The South African electricity sector is transitioning from a single utility buyer model to an open market model due to increasing utility tariffs, the energy crisis, sustainability goals, and enabling legislation. As a result, the private sector is seeking to procure private power generation technologies, with solar photovoltaics (PV) and onshore wind being the primary choices. However, the integration of these technologies is limited due to their variability and lack of dispatchability. Concentrating solar power (CSP) tower technology combined with long-duration storage is gaining traction in high solar resource regions due to efficiency improvements and cost reductions. This paper evaluates a medium-scale CSP-PV hybrid plant's technical and economic feasibility in South Africa, focusing on cost savings, energy security, and sustainability. The study identifies a hybrid plant suitable for large power users, with independent power producers (IPPs) developing such a plant using non-recourse project finance and energy sold to large users through long-term power purchase agreements (PPA). The first-year PPA tariffs are determined using a typical project finance model developed for local market conditions. Depending on the plant design and the off-taker's utility tariff structure, the plant offers cost savings (and average tariffs) ranging from 9.25% (at 78 USD/MWh) to 17.58% (at 81 USD/MWh). Hybrid plants are expected to become more feasible and "bankable" with improving technology and decreasing costs in South Africa.

Keywords: Medium-Scale CSP, CSP-PV Hybrid, Grid Parity

1. Introduction

Due to rising tariffs, the energy crisis, sustainability aims, and enabling legislation, the South African electricity sector is swiftly shifting from a single utility buyer to an open market. As a result, the private sector is increasingly pursuing renewable private power generation, mainly from solar PV and onshore wind, due to low cost and risk. However, these sources' variability, lack of dispatchability, and the prohibitive expense of stationary batteries hinder widespread adoption.

CSP tower technology with extended storage is gaining global popularity due to efficiency gains and cost reductions [1]. It addresses renewables' dispatch and variability concerns through thermal energy storage, serving as an alternative to fossil fuel power generation [2].

Nevertheless, financing remains challenging due to perceived risk, high debt-risk premiums, and equity return expectations. These projects seem viable only for major energy-intensive users with solid credit ratings and balance sheets. The total installed cost for CSP projects are over five times the equivalent capacity for wind or PV, need multiple financiers and an aggregator (often the local grid), and have struggled to achieve financial close [3]. Conversely, a medium-scale 10 MWe plant suits single large power users. Due to the capital expenditure required, IPPs will likely develop such plants using typical non-recourse project finance to sell the energy to large power users through long-term PPAs. This paper assesses medium-scale CSP's feasibility in South Africa's private sector amid current market conditions.

2. Literature Survey

2.1 CSP technology and pricing trends

CSP technology costs dropped significantly in the last decade, with the global average Levelized Cost of Electricity (LCOE) down 68% from 2010 to 2021 [1] driven by reduced capital cost and higher capacity factors enabled by larger storage systems. Power tower plants with long-duration thermal energy storage are emerging as the standard CSP solution, surpassing parabolic trough [4]. In 2019, approx. 45% of CSP projects were power towers, representing 60% of installed capacity [5]. Several studies (e.g., [2],[6],[7]) suggest CSP-PV hybrid plants yield lower LCOE due to higher capacity factors and lower capital expenditure, highlighting the technologies' synergy. China's commitment is visible, as ten of its eleven power tower CSP plants under construction integrate PV [8].

CSP technology keeps advancing with cost reductions, but the perceived risk remains. Parabolic trough technology has seen more commercialisation, contributing to a negative perception of power towers [9]. However, recent power tower successes, often exceeding performance targets and ramping rates, suggest a potential shift in perception is possible. South Africa has vast CSP-suitable land, about 8.59% of its total [10], but its Integrated Resource Plan (IRP) lacks CSP expansion plans [11]. Due to complexity and remote sites, construction here takes 33 months on average [12]. South Africa has a high potential for localising the manufacture and assembly of CSP components, with a minimum of 50-60% of the plant's capital cost being sourced locally [13].

2.2 Techno-economic studies of small- to medium-scale CSP plants

Given the decreasing energy costs in utility-scale CSP, recent research on smaller-sized CSP shows promise in LCOE. A study by [14] explores distributed generation with small tower CSP plants using molten salt for storage and steam Rankine cycles. The study considers plant sizes ranging from 10-50 MWe and various tower materials, yielding LCOEs of 13.7 US¢/kWh to 16.7 US¢/kWh. The study concludes that CSP at these LCOEs would only be suitable for off-grid areas in the Australian context. Another study [15] examines a 10 MWe power tower with solid-state storage, using steam Rankine cycles, with a resulting LCOE of 9.4 US¢/kWh. These studies demonstrate the potential for small to medium-sized modular CSP plants for distributed generation. However, no studies have assessed their benefit in South Africa.

3. Modelling

3.1 Plant design assumptions

The following assumptions are made for the plant design: A 10 MWac PV and 10 MWe CSP capacity is selected, with the plants co-located in Upington, South Africa. The capacity fits a large South African mining or industrial sector power user. The off-taker is assumed to have a constant 10 MW baseload requirement over the year between 6 a.m. and 10 p.m. (i.e. peak and standard Time of Use (ToU) periods). The PV plant uses single-axis trackers. The CSP is power tower technology with molten salt as the heat transfer fluid, a direct two-tank salt thermal energy storage system, and an air-cooled steam Rankine cycle.

3.2 Power dispatch assumptions

Power dispatch is handled according to the following assumptions: The PV plant dispatches generated power immediately. The combined CSP and PV plants must aim to supply the entire load requirement between 6 a.m. and 10 p.m. if sufficient capacity exists. Between 10 p.m. and 6 a.m., some capacity is reserved to service the morning peak load. The excess energy is discarded if the TES reaches maximum capacity during any hour.

3.3 Financial and cost model assumptions

The following assumptions are made for the financial modelling: The power plant will be constructed using typical non-recourse project finance, and the energy will be wheeled from the IPP to a private off-taker in South Africa. Due to the high capital cost, the off-taker must enter into a PPA with the IPP for at least 20 years. Bankable PPAs in South Africa typically require that the off-taker conclude a take-or-pay agreement that necessitates the purchase of all the energy generated regardless of its use. As the market still considers power tower technology high-risk, debt premiums and equity hurdle rates are higher than those for solar PV and onshore wind. The minimum equity hurdle rate for a CSP project in the Southern African market is 15% ([16], [17]). Various heliostat options were considered. The Sunring heliostat ([18], [19]) was selected as the cheapest option at a total cost of $99.48/m². Steel truss towers are more suitable and cost-effective for smaller (≤ 20 MWe) CSP plants [14], with steel tower cost calculated according to [20]. The power cycle cost for a 10 MWe steam turbine is obtained from [15] and escalated, resulting in a specific cost of $1411.18/kWe. Installation and Operating costs are primarily based on [21]. All prices sourced from literature and vendors are adjusted for inflation to 2021 using [22] and [23].

Table 1. *Key financial model input assumptions for PV and CSP plants.*

Key Input	Unit	PV value	CSP value
O&M	% of CAPEX	1.0%	1.27%
Cash reserve	EBITDA	2.5%	1.5%
Maintenance reserve	months	6	6
Gearing	Debt as % of total	80%	75%
Tennor	Years from COD	16 a	18 a
Margin – constr.	bps	300	375
Margin – ops	bps	250	360
8yr Swap – constr.	bps	290	290
8yr Swap – ops	bps	290	290
Target DSCR	ratio	1.2	1.25
Target equity IRR	%	13%	15%

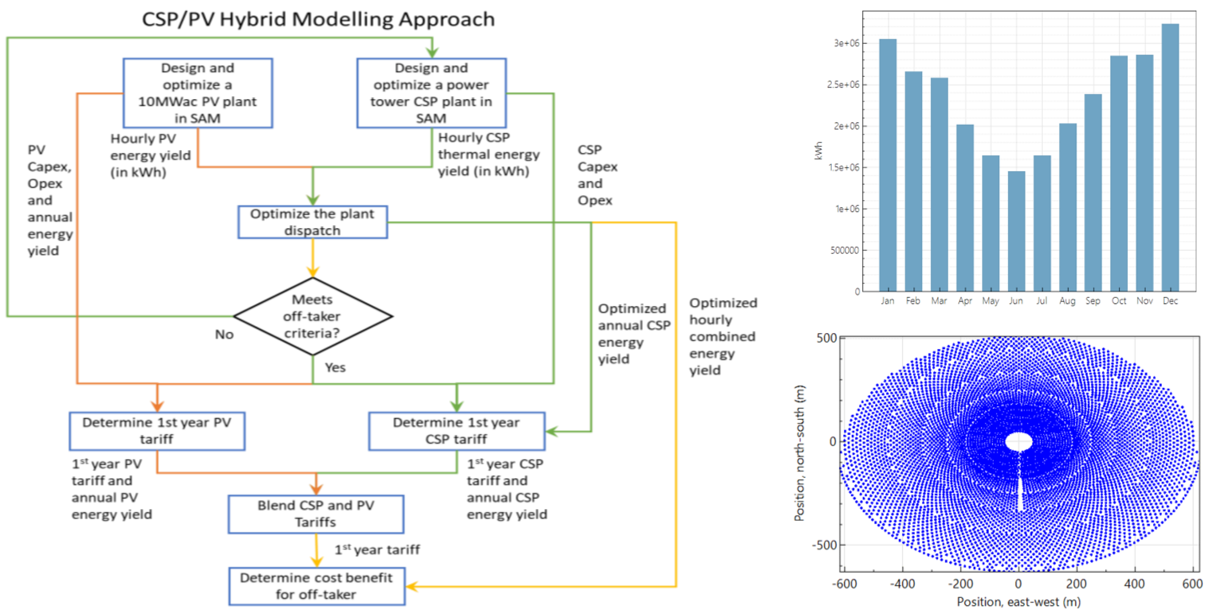

Figure 1. *CSP-PV hybrid modelling approach; PV monthly output and example CSP field layout are shown on the right.*

The PV and hybrid-ready CSP plants are each modelled separately in the USAID Southern African Energy Program (SAEP) IPP Financial Modelling Tool [24] to determine the PPA tariffs, given the different IRR expectations. Financial modelling parameters for the PV and CSP plants are shown in Table 1. For the sake of brevity, only the significant parameters are shown. Further details are available in [25]. The different PV and CSP plant tariffs are blended in proportion to the energy yields of the two plants to give a single first-year PPA tariff for the hybrid CSP-PV plant. Utility tariff escalation is predicted [25] based on historic escalation info by [26] at a nominal 8% over the long term.

3.4 General modelling approach

The techno-economic study assessed potential cost savings for the power user through a CSP-PV hybrid plant and accounts for market, technology, off-taker, and currency exchange rate risks. The power plants are designed with performance and cost optimised in the National Energy Laboratory's (NREL) System Advisor Model (SAM) [27]. The hourly dispatch of these power plants is optimised with an Excel-based tool according to the power user's baseload requirements. These first-year energy production figures and costs determine the first-year PPA tariffs using a typical project finance model developed for local market conditions. Considering these tariffs, together with the hourly generation profiles, the power user's hourly load requirement and their tariff regime, the cost-benefit to the power user is calculated over the first year and then estimated over the PPA term. The Net Present Value (NPV) is finally calculated, assuming a discount rate of 13%. Multiple configurations are assessed for user cost savings. The plant modelling process is shown in Figure 1.

4. Plant design details and simulation results

A typical 10 MWac PV plant is designed and optimised in SAM [27]. Weather data from the Climate.OneBuilding.Org repository [28] was imported into SAM. The size of the PV system is maximised as the PV tariff is considerably lower than the CSP tariff due to a significantly lower capital cost and low-risk funding profile. It is important to note that the energy generated in June through July (winter) is approximately half that of December through January. This high level of seasonality is an essential consideration in the design of the CSP plant for load following.

A 10 MWe CSP plant is designed around the PV plant to allow optimised baseload dispatch between 6 a.m. and 10 p.m. As a starting point, design point parameters for the CSP plant with Solar Multiple (SM) = 3.4 and Full Load Storage Hours (FLSH) = 16 hours are shown in Table 2. A parametric analysis is then conducted to optimise the SM and FLSH for the lowest first-year PPA price and LCOE. Considering the PV generation profile, it was judged that a minimum of 9 full-load hours of storage is required for the CSP plant.

Table 2. *SAM design parameters for unhybridised 10 MWe CSP power tower plant.*

Heliostats and solar field			**Receiver**		
Solar Multiple		3.4	Receiver height	m	6.77
Heliostat width	m	8.4	Receiver diameter	m	6.55
Heliostat height	m	3.2	Number of panels		20
Site Improvement Cost	$/m²	16	**TES and power cycle**		
Heliostat Field Cost	$/m²	83.48	Full load hours of storage	hours	16
Heliostats		6603	TES thermal capacity	MWth	388
Total land area	acres	314	Design turbine gross output	MWe	10
Total heliostat reflective area	m²	178043	Cycle thermal efficiency	%	41.2
Tower height	m	68.4	Cycle thermal power	MWth	24.27

Table 3. *Main performance and cost parameters for optimal hybrid CSP-PV plant.*

Metric	**Unit**	**PV value**	**CSP value†**
Capacity (AC)	MW	10.00 / 11.94 DC	10.00
Net generation	MWh	28 110 *	33 491
Capacity factor	%	32% Y1	38%
Energy yield in	kWh/kW	2 377 Y1	6 189
Total installed cost	mi USD	7.735	53.838
Specific capex	USD/kWp	647.5	5384
PPA tariff (Y1)	USD/MWh	44	117

* Year 1 (Y1), followed by 0.5%/a degradation
† SM=1.6, FLSH=9hr, the NPV-optimal hybrid case

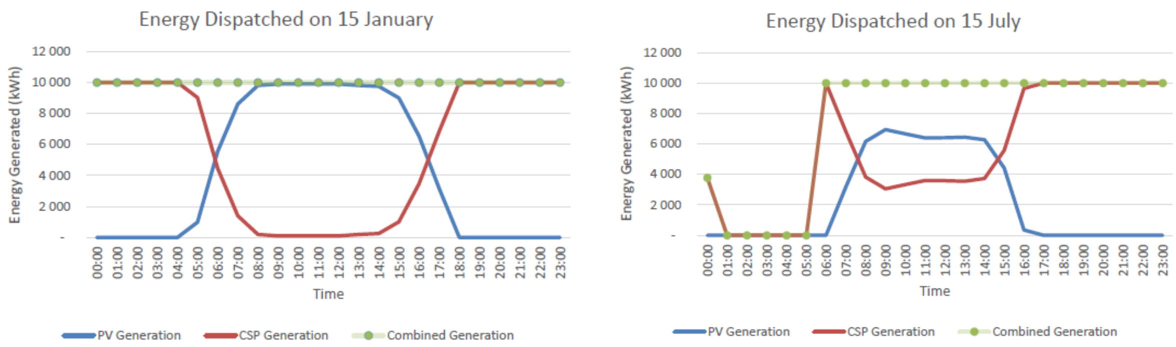

Figure 2*: Optimised hybrid CSP-PV dispatch profiles for sample summer and winter days.*

The primary performance and cost parameters for the optimal hybrid CSP-PV plant are shown in Table 3. For illustrative purposes, Figure 2 shows the optimised power dispatch profiles for a plant configuration with SM = 2.2 and FLSH = 14 hours for a representative summer (January) and winter (July) day. For the summer day, the figure shows that the plant can supply the required 10 MWe baseload for 24 hours. For the winter day, the combined contributions of the CSP and PV plants can serve the 10 MWe requirement between 6 a.m. and 10 p.m., but no output is possible during the early morning hours. The dispatch optimiser is used later to calculate the performance of several hybrid plant configurations.

4. Results

The financial modelling of the 10 MWac PV plant in the South African context was performed considering key input assumptions detailed in Table 1. The net generation in the first year was obtained from the SAM PV plant design (see Table 3), adjusted for plant availability, and derated at a rate of 0.5% from the second year onwards. The plant CAPEX was determined based on the competitive nature of the South African PV market. Various sources indicated PV costs ranging from $533/kWp to $670/kWp, and the top end of the cost scale was used for the financial model. The results revealed that the PV plant could be funded with a minimum tariff of 44 USD/MWh to achieve an equity hurdle rate of 13%.

The financial modelling of the 10 MWe CSP plant was conducted for different solar multiples and thermal storage capacities, considering the first-year PPA tariffs that would achieve an equity hurdle rate of 15%. These tariffs were determined based on the CSP installation costs, yields, and other parameters, as shown in Tables 1-3. While not presented here due to limited space, [25] shows that a standalone medium-scale CSP plant is still too costly for an off-taker in the private sector in South Africa, with PPA tariffs exceeding utility tariffs.

Table 4. *CSP-PV hybrid plant solution alternatives (extract from [25])*

SM	**FLSH**	**NPV@13% of savings** (lowest utility tariff)	**Y1 CSP-PV blended tariff**	**Y1 weighted CSP-PV and utility ToU**	**%Heat energy dumped**	**%Annual Unmet demand**	**%Unmet demand in winter months**	**%Off-peak from utility ToU**
-	h	mi USD	USD/MWh	USD/MWh	%	%	%	%
1.6	9	32.504	83.92	81.18	19.00%	7.20%	16.96%	44.80%
	10	*32.518**	83.69	81.28	14.00%	7.19%	16.96%	49.42%
	11	32.509	*83.54*†	81.61	10.00%	7.19%	16.96%	53.18%
	12	32.394	83.59	82.02	7.00%	7.19%	16.96%	56.41%
	14	32.043	83.97	82.80	2.00%	7.18%	16.96%	60.62%
	16	31.267	85.17	83.77	2.00%	7.16%	16.96%	60.93%
2.4	9	28.897	92.80	86.61	38.97%	2.05%	3.72%	50.02%
	10	29.421	91.89	86.65	34.22%	1.79%	2.91%	56.63%
	11	29.867	90.85	86.68	29.71%	1.68%	2.62%	63.04%
	12	30.429	89.56	86.66	24.46%	1.65%	2.53%	70.56%
	14	31.109	87.99	86.85	16.25%	1.62%	2.52%	82.31%
	16	30.482	88.79	87.73	15.25%	1.52%	2.52%	83.58%

* Maximum NPV for minimum tariff case at 1.6 SM, 10 FLSH
† Minimum Y1 CSP-PV blended tariff case at 1.6 SM, 11 FLSH

The concept of tariff blending was introduced to combine the PV and CSP contributions to create blended tariffs for hybrid CSP-PV plants. The PV contribution remained fixed, and the CSP first-year tariff and annual generation varied for different scenarios and utility tariff structures. According to [25], the optimisation target should be NPV, not first-year ToU-weighted tariff. The first-year ToU-weighted tariff averages CSP-PV hybrid plant costs with the utility's ToU tariff for unmet demand. The ToU-weighted tariff does not correspond with the NPV throughout the 20-year PPA period since the utility's ToU rate rises above inflation. Thus, the hybrid CSP-PV plant should supply more energy in later years when utility prices are higher, but the first-year ToU-weighted tariff is not the minimum.

The results demonstrate a substantial cost-saving for the hybrid plant compared to supplying all energy needs by the utility. First-year annual energy cost savings of 10.62% to 17.58% for the highest utility tariff and 0.06% to 9.85% for the lowest utility tariff are achieved, depending on the design. With SM =1.6, 10 hours of storage maximises the NPV for the costliest tariff structure and 11 hours minimises the year-1 blended tariff (Table 4). Increasing SM and FLSH reduces annual unmet demand from 7.2% to 1.5% (17% to 2.5% for winter months). If energy security is a consideration, the plant design is based on how much unmet demand the off-taker is willing to accept, understanding that the lower the unmet demand, the smaller the savings, with all cases NPV-positive.

The research findings indicate that hybrid CSP-PV solutions could offer competitive solutions for the private off-take market. However, it must be acknowledged that forecasted savings are based on predicted inflation and utility escalations over the PPA term. The degree of savings depends on the off-taker's current tariff structure and energy security requirements. [25] provides further insights into the factors influencing the choice of plant design and highlights the complex relationship between tariffs, energy supply, and savings over the PPA term.

5. Conclusion

This study assessed the viability of a 10 MW molten salt power tower plant for the private off-take market in South Africa, focusing on the plant's capacity to address peak and standard load requirements from 6 a.m. to 10 p.m. The CSP tariff is affected by technology and off-taker risk, leading to a high equity hurdle rate and debt risk premium. Despite a 68% cost reduction since 2010, CSP facilities are capital-intensive, and a standalone CSP plant does not achieve grid parity at the 10 MWe scale in South Africa. The investigation instead argued for a CSP-PV hybrid approach. By blending the dispatchability and long-duration storage of CSP with the low cost of solar PV, this hybrid model exhibits a significantly lower tariff structure that achieves local grid parity and offers a positive return to the developer.

This study underscores the need for a nuanced evaluation considering long-term NPV and acceptable unmet demand levels rather than a singular focus on initial PPA tariffs. It offers insights into the intricate balance between cost-efficiency and sustainable energy solutions in a landscape of evolving technologies and shifting market dynamics.

Data availability statement

The Excel-based tools are available on SUNscholarData at DOI: 10.25413/sun.24064041.v1. Reference [25] is also available upon reasonable request from the authors.

Author contributions

Investigation by Annitta Attieh, writing by Craig McGregor and Johannes Pretorius, review and edit by Jaap Hoffmann.

Competing interests

The authors declare that they have no competing interests.

Funding

This work is partially funded by the Department of Science and Innovation of South Africa, via the Solar Thermal Energy Research Group (STERG) within the Mechanical & Mechatronic Engineering department at Stellenbosch University.

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