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Economic Impact of CSP Plants with Storage Addressing the Energy Transition in Locations with High Electricity Demand in Chile

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Abstract. This study explores the economic implications of hybrid plants combining photovoltaic (PV) and Concentrated Solar Power (CSP) technologies with energy storage in response to Chile's ongoing energy transition. Utilizing the System Advisor Model (SAM), six diverse locations were evaluated to assess energy generation profiles, calculate the Levelized Cost of Energy (LCOE), and analyze gross margins. The key finding is that higher solar multiples or storage capacities do not consistently lead to lower LCOE, primarily due to operational strategies aligning CSP generation profiles with PV. Notably, northern regions consistently yield higher gross margins despite occasional zero marginal costs, while areas near Santiago experience lower gross margins, with Salamanca presenting the lowest margin. This highlights the critical role of available solar resources in shaping economic outcomes.

Keywords: Hybrid Plants, Energy Transition, Levelized Cost of Energy (LCOE), Gross Margin, Chilean Electrical Market.

1. Introduction

Chile possesses exceptional renewable energy potential, with an evaluated capacity of 1800 GW in wind, solar, and hydraulic energy throughout the country [1]. Northern Chile offers optimal conditions, boasting minimal atmospheric attenuation and the highest annual direct solar radiation globally [2]. Over the past two decades, Chile's electric system has shifted from hydro-thermal to renewable-hydro composition, with a tripling of photovoltaic and wind capacity in the last decade [3]. Latin America's first concentrated solar power plant, Cerro Dominador, has been operational in the Antofagasta Region since 2021.

However, transmission lines in northern and central Chile are congested, limiting electricity utilization. Expanding transmission capacity is a lengthy process, necessitating 7 to 10 years for completion. An alternative solution involves establishing decentralized electricity production plants closer to consumption points to support the energy transition and decarbonization of the national electricity matrix. Chile's electricity demand divides into two customer types: regulated (connected power < 500 kW) and free (connected power > 5000 kW) customers. Those with 500 kW to 5000 kW can opt for regulated or free status, with regulated customers having less control over pricing but a fixed tariff.

This study quantifies and compares the LCOE, revenues, and expenses (gross margin) of a hybrid solar plant (PV+CSP) in six locations, considering marginal costs in Chile's electricity system in 2022 [4]. We highlight transmission congestion in the northern and central regions, comparing results in the high solar resource and high electrical demand north (mainly mining industry) with the central area (near the Metropolitan Region, representing 30% [5] of the national electricity demand, primarily due to high population density). The objective is to assess the economic impact of solar hybrid plants near high-consumption points, whether for regulated or free customers, reducing exposure to SPOT market price fluctuations while fulfilling contracts.

Recent data from the National Energy Commission [6] reveals Santiago and Antofagasta as the two cities with the highest electricity demand in Chile. Regulated customers in Santiago consume an average of 1,311 GWh annually, while those in Antofagasta consume 571 GWh per year, based on data from 2015 to 2022.

2. Methodology

To analyze the results of the hybrid plants, six locations were selected with high electricity demand to assess the impact of solar resources between northern and central Chile. Additionally, the influence of the generating facilities in each zone was considered, taking into account the marginal cost prices at the nearest busbars for each location. These six chosen locations span from the Arica Region in northern Chile to the Metropolitan Region in central Chile. All these locations are characterized by high electricity demand and are interconnected through the National Electric System. It was selected a 60 MWe plant size, taking into account land use restrictions in the target area (Metropolitan Region), where opportunity costs are higher compared to the northern region. Evaluating various locations across northern to central Chile allows us to assess CSP plant performance in different regions, demonstrating the techno-economic feasibility of implementing this technology.

For the PV plant, It was selected a 60 MWe capacity with 1-axis tracking and an azimuth angle of 0° (south of the equator). It was considered an annual performance degradation rate of 0.60% for the PV plant components [7], along with 14% total system losses, primarily due to soiling, operational availability, and the system's life cycle, among other forms of degradation. In the case of the CSP plant, it was selected a 60 MWe capacity with an annual degradation rate of 0.20% [7]. Solar multiple (SM) parameters and thermal energy storage (TES) hours varied according to the configurations suggested by the ACSP and those proposed in the Ministry of Energy's PELP 2023-2027:

- CSP2: For Peak demand and part of the night, SM = 2.0 and TES=9.0 hrs.
- CSP3: For Peak and all-night demand, SM=2.5 and TES=13 hrs.

Figure 1(a) illustrates the distribution of available Direct Normal Irradiance (DNI) resources in Chile, spanning from the Arica region to the Metropolitan region. This map also highlights the locations of the CSP plants examined in this study, along with the nearest electrical substations and existing transmission lines. The 500 kV transmission line, depicted in blue, connects northern and central Chile, with congestion issues identified between SE Nueva Cardones and Polpaico [4]. Expanding transmission line capacity is a proposed solution, but it progresses slower than renewable projects. Increasing capacity and the number of transmission lines is a long-term strategy requiring several years for implementation. Therefore, this study evaluates the feasibility of generating energy through CSP plants located near major consumption points. Figure 1(b) provides a visualization of communal electricity demand in 2022 for regulated customers, along with the locations of key copper and iodine mines in northern Chile.

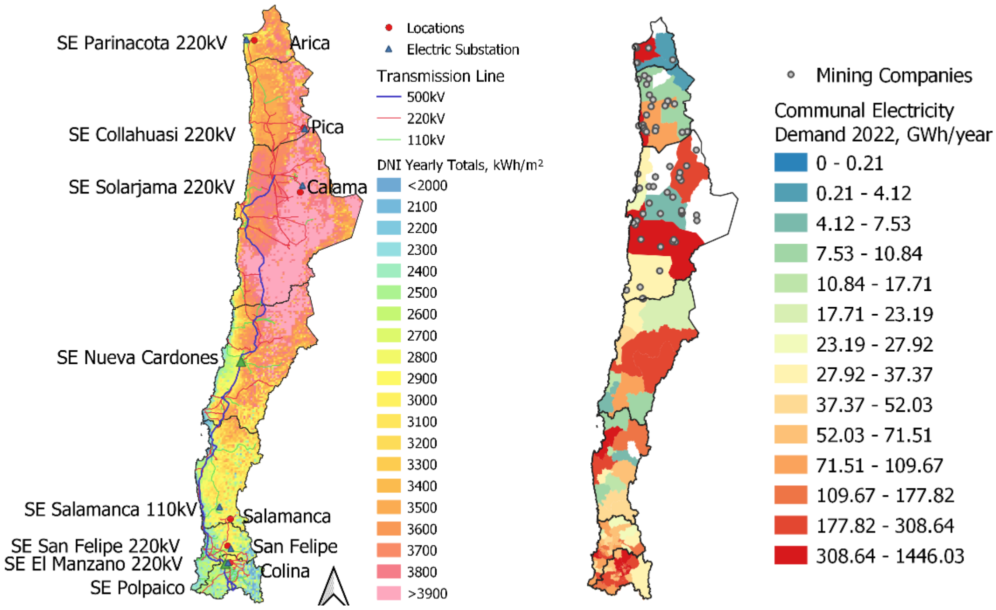

***Figure 1**. The left map (a) displays the CSP plant locations assessed in this study, along with the solar resource (DNI), electrical substations, and transmission lines. The right map (b) shows the communal electricity demand in 2022 and the mining facilities' location.*

It was employed the System Advisor Model (SAM) program to calculate the electricity generation for each plant. Specifically, used TES dispatch control was used for the hybrid plant's operation strategy. This approach prioritizes power generation from the photovoltaic plant over the CSP plant. Consequently, when the photovoltaic plant generates electricity, the CSP plant reduces or halts its electricity production and stores energy for use during periods of low or no solar radiation. For calculating the Levelized Cost of Energy (LCOE), it was applied a discount rate of 7% using Equation 1. The cost structure for the Solar Tower plant was obtained from ACSP [8], while for PV technology, the module cost structure was derived from the report issued by the Office of Energy Efficiency and Renewable Energy (EERE) for the 2030 scenario, aligning closely with the prices observed in recent Chilean tenders for PV technology [9]. The values used are presented in tables 1 and 2, corresponding to PV and CSP technology, respectively. Both technologies were evaluated with a lifetime of 30 years, as per NREL's Annual Technology Baseline [10].

***Table 1.** Cost distribution for economic evaluation of the 60 MWe PV power plant [9].*

Element	Value	Unit
Module	0,17	USD/W
Balance of system	0,1	USD/W
Installation labor	0,011	USD/W
PV Contingency	1%	-

$$LCOE = \frac{\sum_{i=0}^{N}\frac{CAPEX_i}{(1+t)^i}+\sum_{i=0}^{N}\frac{OPEX_i}{(1+t)^i}}{\sum_{i=0}^{N}\frac{Production_i}{(1+t)^i}} \quad (1)$$

Income and expenses for each simulated location were calculated to determine the gross margin for each hybrid plant. This analysis considered marginal electricity costs at the nearest substation [11] and a Power Purchase Agreement (PPA) for supplying 60 MWh of electricity in a 24/7 regime. It's important to note that achieving a positive economic outcome for selling electricity from the plant depends not only on the LCOE being greater than the PPA value but also on factors like marginal costs associated with the electric grid and the generation profile of the plant.

Table 2. *Cost distribution for economic evaluation of the 60 MWe CSP power plant [8].*

Element	Value	Unit
Site improvement cost	0,5	USD/m^2
Heliostat field cost	120	USD/m^2
Tower cost fixed	2 250 000	USD
Receiver Reference cost	72 100 000	USD
Thermal energy storage cost	20	USD/kWh$_t$
Balance of plant cost	200	USD/kW$_e$
Power Cycle Cost	700	USD/kW$_e$
Contingency CSP	5%	-

Equation 2 defines the gross margin of the hybrid plant, accounting for incomes and outcomes. The first income stems from the electricity generated by each hybrid plant ($E_{produced_i}$), injected into the grid at the marginal cost (CMg) of the injection point ($CMg_{produced_i}$). The second income corresponds to the energy associated with the PPA, representing the electricity committed for delivery to the client, marked by energy withdrawals from the grid to fulfill the PPA contract ($E_{retirement_i}$), using the PPA contract price as the energy value. Finally, the balance results in an economic outcome, corresponding to the energy drawn from the grid by the client under the PPA contract ($E_{retirement_i}$). This energy extraction considers a different energy value, corresponding to the marginal cost at the grid's extraction point ($CMg_{retirement_i}$).

$$\textbf{Gross Margin} = \sum_{i=1}^{8760} E_{produced_i} \cdot CMg_{produced_i} - \sum_{i=1}^{8760} E_{retirement_i} \cdot CMg_{retirement_i} + PPA \cdot \sum_{i=1}^{8760} E_{retirement_i} \tag{2}$$

Finally, a sensitivity analysis based on the PPA signing price is conducted. In Chile, due to the Regional Electric System's operation, the PPA value directly affects companies' financial results. It's important to note that generation companies in Chile (power-producing plants of any type) earn income not only from energy sales but also from power and auxiliary services. This study does not include these additional income possibilities.

Additionally, the scenario of injecting electricity in northern Chile was examined, specifically at the Solarjama 220 kV substation, and consuming it at the El Manzano 220 kV substation near Santiago. This analysis allows us to evaluate the impact of price differences at different nodes of the system, considering the 2022 marginal cost of generation values.

3. Results

Fig. 2 presents the LCOE values obtained for each of the examined hybrid plants across the six locations. As expected, the results demonstrate that the Calama site consistently exhibits the lowest LCOE, regardless of the plant configuration. This can be attributed to the significantly higher solar radiation levels in Calama, exceeding the solar resource available in the Metropolitan Region by 30%. Conversely, the figure illustrates that the LCOE increases as the sites move southward due to lower DNI values.

The lowest LCOE among the two evaluated hybrid plants in the Calama region is achieved by the PV plant with a solar tower and a storage capacity of 9 hours, featuring a solar multiple (SM) of 2.0, resulting in an LCOE of 55.57 USD/MWh. It is followed by the plant with an SM of 2.5 and a thermal energy storage (TES) capacity of 13 hours, resulting in an LCOE of 59.98 USD/MWh. Both of these cases are followed by the plants located in Arica and Parinacota. This outcome is influenced by the operational strategy of the hybrid plant, which optimizes the generation profile of the CSP plant based on the generation of the PV plant. Consequently, plants with higher TES capacity exhibit greater energy reduction, resulting in a 22% reduction in electricity generation for all simulated cases due to this operational strategy. As a result, hybrid plants simulated with 13 hours of storage demonstrate higher LCOE compared to other cases, in contrast to other studies [12].

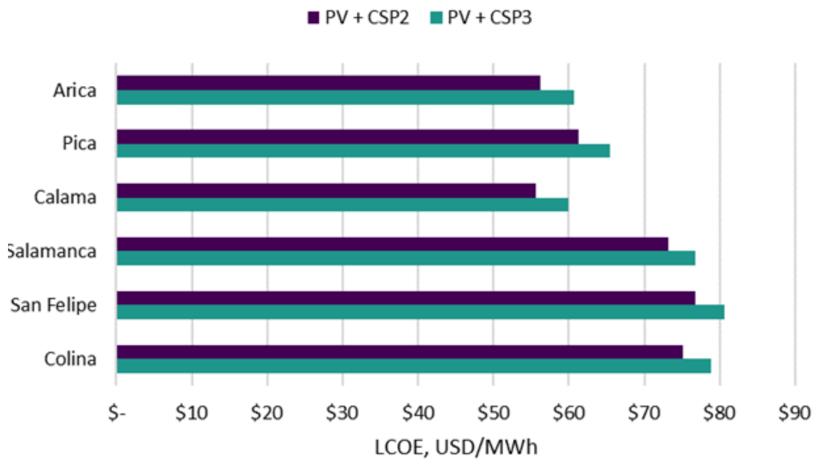

***Figure 2**. LCOE results according to location and type of hybrid plant.*

On the other hand, the locations of San Felipe and Colina exhibit the highest LCOEs compared to the other evaluated locations. In these two locations, the LCOE of the hybrid plant equipped with a 13-hour storage system is 5% higher than the most economically favorable scenario. Specifically, the most economically favorable scenario, with the lowest LCOE, is the hybrid plant configuration that includes a PV plant integrated with a CSP plant with 9 hours of storage and a solar multiple of 2.0.

However, generating companies in Chile should consider not only the cost of electricity production (LCOE) in their decisions but also the nodes (Substation, SE) to which the power plant is connected and the location where the customer will be supplied. This approach mitigates the distribution problems of the electricity generated and reduces the risk of being exposed to the SPOT market, with the PPA price becoming a key component. It is noteworthy that the valuation of Power Purchase Agreements (PPAs) can be established through diverse methods. Some organizations determine the PPA value based on the marginal cost of the system, factoring in additional costs due to significant fluctuations within the short-term market throughout the day and night. Alternatively, the valuation can be calculated as a percentage of energy generated at specific intervals or in blocks of energy during particular hours of the day. Thus, there are multiple ways to appraise the value of PPAs, and no single method for determining its value.

To establish the gross margin, the value of the PPA must be determined and strategically set to define the project's viability. This is a complex exercise. On the other hand, the LCOE represents the minimum value at which the power generating company can sell its energy. Therefore, Figure 3 shows the results of the gross margin obtained for each power plant at different sites under different PPA prices determined according to the average Marginal Cost for the year 2022 at each connection bus. The figure shows that Arica has the highest gross margin, considering a PPA value of 108.6 USD/MWh, with 35.4 million dollars for the PV and CSP2 configuration and 36.5 million dollars for the solar PV with CSP3 configuration. In contrast, the location with the lowest margin is Salamanca, with USD 23.5 million and USD 25.7 million, respectively. It is important to note that the results presented in Figure 3 only consider a portion of the revenues received by the power generation plants in Chile, as the study does not take into account the revenues from power (MW) and complementary services. Additionally, it should be mentioned that the marginal cost of the electricity system in Chile is affected by several factors that interact in a complex way, making it difficult to predict its value with certainty at any given time. These factors include the cost of the fuel used to generate energy, demand, and the availability of electricity in the country.

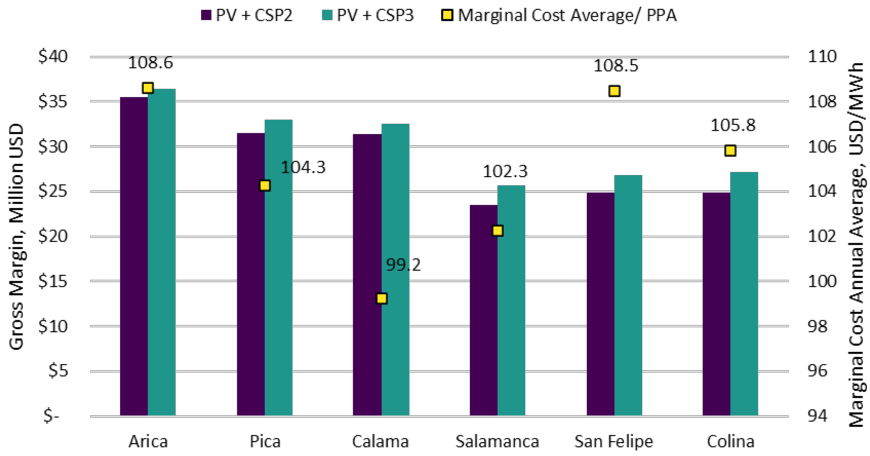

Figure 3. *Gross margin per energy of the different generating plants in the different locations with different PPA values according to the annual average Marginal Cost.*

An additional scenario for two hybrid plants is examined, involving different points of injection and consumption of electricity. This leads to variable marginal costs of the Chilean electricity system for both injection and consumption, impacting the plant's gross margin economically. To conduct this analysis, the hourly values of electricity generation for one year for both hybrid plants were considered, along with the hourly values of marginal costs for the year 2022 at the Solarjama 220 kV substation as an injection point and at the El Manzano 220 kV substation as a consumption point. The difference in marginal costs between the two substations results in different values for the injection and consumption of electricity, reflecting the different marginal cost caused by the high congestion of the power grid to evacuate electricity generally produced in the north of Chile and consumed in the central-south zone.

For the analysis, a different PPA price was used for each case since marginal costs for the generator are lower in the northern zone of Chile, leading to lower PPAs, due to the large installed capacity of renewable power plants. In the case of the central zone (Colina), the marginal cost is higher, and the installed renewable capacity is lower, resulting in a higher electricity sale price. In the case of the generator in the north delivering energy to a customer in Colina, an intermediate value should be offered because it is exposed to marginal costs at the point of consumption due to the high congestion of the Chilean transmission system connecting the north zone with the south zone. The PPA contract values used are set to supply 60 MWh of electricity on a 24/7 basis and are shown in Figure 4, along with the gross margin results for each case.

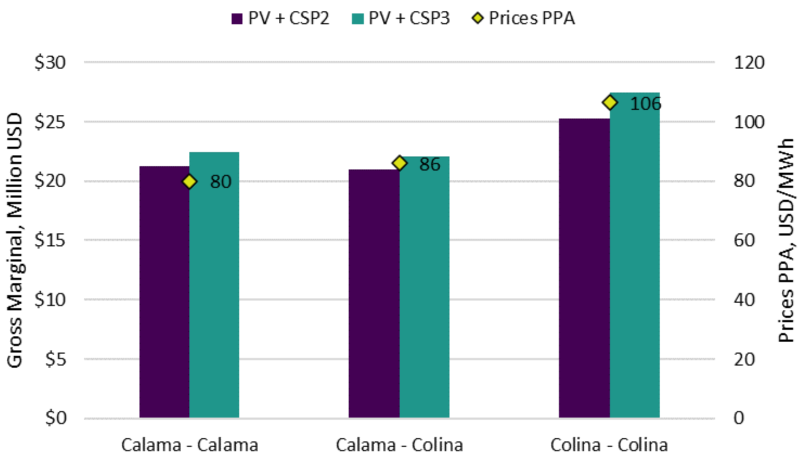

Figure 4. *Economic results of hybrid plants according to injection location and consumption location.*

Fig. 4 demonstrates that, for a price of 80 USD/MWh for the generator located in Calama at the Solarjama 220 kV busbar, the gross margin is 21.3 million dollars for the PV+CSP2 plant and 22.4 USD/MWh for the PV+CSP3 plant. In the case of the generator located in Colina, which injects its energy at El Manzano 220 kV, the energy sale price set is 106 USD/MWh (considered as the average market price), resulting in a gross margin of 25.2 and 27.5 million dollars for each of the plants. In the case of different injection points and electricity consumption, the PPA price analyzed is 86 USD/MWh (higher than the first case and lower than the second), resulting in lower gross margins for both hybrid plants, i.e., 21 and 22.1 million dollars, respectively. This is due to the exposure to the decoupling of the electricity system due to high renewable energy generation in the northern zone during sun hours and congestion in the transmission lines.

It is important to highlight that the marginal cost difference between all substations is directly related to the congestion problems affecting the Chilean electricity grid. During congestion times, the marginal cost of electricity tends to reach a value of 0 USD/MWh. For all the substations considered in this study, the percentage of annual hours in which the marginal cost is 0 USD/MWh was calculated. The results show that locations in northern Chile have the highest percentage of annual hours with marginal costs of 0 USD/MWh, specifically 26% for Calama, and 23% and 22% for Arica and Pica, respectively. In the case of Salamanca, located in the central zone but north of Santiago, it experiences marginal costs of 0 USD/MWh 21% of the time. Finally, for Colina and San Felipe, the percentage of annual hours with marginal costs equal to 0 USD/MWh is 18% in both cases. These results underscore the congestion problems along the electricity grid, with a more pronounced effect in northern Chile.

4. Conclusion

In summary, this study highlights that hybrid plant configurations with high solar multiples or storage capacity didn't necessarily result in lower Levelized Cost of Energy (LCOE), mainly due to the operational strategy aligning Concentrated Solar Power (CSP) plant generation with Photovoltaic (PV) plant generation.

Furthermore, analysis of gross margins at the same energy injection substation consistently showed that northern region configurations had higher margins, even during periods of zero marginal costs. Conversely, locations closer to Santiago de Chile had lower margins.

Additionally, scenarios considering different energy injection and consumption points revealed decreased gross margins due to varying marginal costs between substations.

In conclusion, generating electricity close to the point of consumption could mitigate uncertainties caused by different injection and consumption points, offering a potential solution to economic challenges linked to grid congestion in Chile.

Data availability statement

There is no relevant additional data to this article beyond the presented content.

Author contributions

Conceptualization, F.D., M.C., C.H., Investigation, C.H., Methodology C.H., Programming C.H., Writing - original draft C.H. and C.F., Writing - review & editing, C.H., M.C., Supervision, M.C. and F.D.

Competing interests

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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