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Impact of Electricity Market Volatility on the Management of Hybrid Renewable Systems with Storage

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Abstract. This article analyzes the performance of a hybrid renewable energy system integrating photovoltaic and wind generation with Pumped Hydro Energy Storage (PHES) in the Spanish day-ahead electricity market. The methodology employs a simulation model based on generation profiles from Zaragoza, Spain, comparing two scenarios: 2019 (low volatility, average spread of 16.90 €/MWh) and 2025 (high volatility, average spread of 101.77 €/MWh). The results show that the high price spreads (the range between the lowest price and the highest price) of 2025 significantly incentivize PHES activity. Specifically, storage use increased fourfold compared to 2019, enabling an 85% reduction in grid imports during the summer quarter. Economically, the system faces significant seasonal disparity. In 2025, high purchase prices and lower solar availability during the winter (first quarter) result in a substantial net expenditure of 3.1 M€. Conversely, the system generates a net profit of 103.303 € during the summer (third quarter) by maximizing storage arbitrage and renewable self-consumption during peaks price periods. The study concludes that market daily spread acts as a catalyst for energy storage. Despite seasonal economic fluctuations, PHES remains an indispensable tool for mitigating high import costs and ensuring the stability of renewable hybrid systems in volatile markets.

Key words. Daily spreads, electricity market price, Pumped Hydro Storage.

1. Introduction

The global electrical system is currently undergoing a profound transformation process. In recent years, factors such as demand growth, renewable integration, rising financing costs, supply chain constraints, delays in grid development, and geopolitical pressures have triggered significant changes in electricity markets [1].

Globally, electricity consumption increased by nearly 4.3% in 2024, compared to 2.5% in 2023, with growth expected to continue at an annual rate of 3.9%, marking the onset of the "New Era of Electricity"[2].

In this context, renewable generation has taken on a central role. In Europe, wind and solar production have surpassed fossil fuels in the energy mix, reaching approximately 30%. In Spain, this expansion has had a notable impact on wholesale electricity prices, which were 32% (62 €/MWh) below the European Union average. Between 2019 and 2025, the country doubled its installed wind and solar capacity, adding more than 40 GW of new power [3].

This evolution has occurred within an environment marked by high volatility. The 2021–2023 period in Spain was characterized by an intense inflationary crisis, resulting from events such as the pandemic and the invasion of Ukraine, which caused unprecedented volatility peaks in energy markets [4]. Despite a 24% drop in the average electricity price in Spain in 2024, the Spanish electrical system began to exhibit new imbalances associated with increased price variability. During that year, the first instances of negative prices were recorded, a symptom of the lack of flexibility in managing energy surpluses [5]. Additionally, the April 2025 blackout significantly increased the reliance on natural gas to ensure grid stability, causing adjustment services to rise from 14% to 57% of the final electricity price by May 2025 [3].

Part of the literature analyzes the behavior of electricity markets in systems with high renewable energy penetration, focusing on price volatility and the emergence of negative prices. Article [6], which focuses on the Turkish market, shows that unexpected interruptions in wind power generation can cause sharp short-term price fluctuations. Furthermore, paper [7] examines the impact of renewables on extreme price volatility across 32 OECD (Organization for Economic Cooperation and Development) countries. Along the same lines, the authors of [8] conclude that negative prices are primarily a result of high renewable generation during periods of low demand, a situation worsened by the lack of system flexibility, grid congestion, and regulatory market distortions.

From a market design perspective, various studies analyze how the incorporation of storage systems contributes to reducing price differences. Specifically, study [9], utilizing a prediction model, estimates that by reaching 30 MWh of storage capacity, the PNIEC target, the daily price spread in the Spanish electricity market could be reduced from 70.68 €/MWh to 32.56 €/MWh. Other studies focus on PHES storage as a tool to capitalize on arbitrage opportunities and decrease energy dependency. In this area, article [10] studies the optimal management of a PHES plant on the Iberian Peninsula through stochastic models calibrated with historical and futures prices. The authors of [11] extend this approach to hybrid PHES-photovoltaic systems using simulated price scenarios. Finally, works [12] and [13] examine, respectively, the integration of electricity and hydrogen markets and the use of PHES in abandoned mines in Sweden.

Overall, the literature highlights the key role of energy storage as a tool for mitigating price volatility and improving the efficiency of the electricity system in a context of high renewable penetration.

Currently, the Spanish electricity market presents an apparently contradictory situation. On the one hand, it has some of the lowest average prices in Europe, which is favorable for consumers and businesses. On the other hand, there is growing intraday volatility, with sharp price fluctuations over short time intervals.

In this context, the daily spread, defined as the difference between the maximum and minimum prices recorded on the same day in the electricity day-ahead market, has gained increasing relevance. In Spain, over the last year, there have been both price troughs at the lower end, reaching negative values, and peaks at the upper end, reaching 240 €/MWh. Historically, this spread was small, but recent energy crises and high renewable penetration have widened the price spread. As a result, this paper aims to conduct an in-depth analysis of the behavior of PV–Wind Hybrid System with PHES Storage, given price curves in the Spanish day-ahead market with different daily spreads.

The rest of the article is structured as follows: Section 2 presents the methodology. Section 3 analyzes the results obtained and Section 4 summarizes the main conclusions.

2. Methodology

This paper analyzes the optimal operation of a hybrid renewable energy system integrating photovoltaic (PV) and wind (W) generation with Pumped Hydro Energy Storage (PHES), which supply a constant electrical energy demand against wholesale market price curves with varying daily spreads.

For this purpose, generation profiles from plants located in Zaragoza, Spain, are utilized as the basis for the simulation model.

The system is mathematically modeled and optimized as a Mixed-Integer Non-Linear Programming (MINLP) problem to minimize total system costs using GAMS software. The methodology is based on the model described in article [14].

The objective function of the model minimizes the weekly net cost derived from the operation of the system (1), to meet a constant electricity demand (E_{dem}^{h}). It includes the operation and maintenance costs of renewable generation (C_{RE}^{h}), the costs resulting from the economic balance of energy exchange with the electricity market (C_{market}^{h}), and the costs associated with storage utilization (C_{PHES}^{h}). The h index indicates the calculation window, which, in this case, corresponds to 1 hour.

$$\min(OBJ) = \min\left[\sum_{h=1}^{168}\left(C_{RE}^{h} + C_{market}^{h} + C_{PHES}^{h}\right)\right] \quad (1)$$

For each hour of the week, the model calculates the renewable energy generated $(E_{pv}^{h}$ and $E_{w}^{h})$, along with its associated costs (C_{RE}^{h}) in (2).

$$C_{RE}^{h} = C_{PV}^{h} + C_{W}^{h} \quad (2)$$

With respect to grid interactions, the quantities of hourly imported (E_{imp}^{h}) and exported energy $(E_{\exp}^{h})$ are computed, as well as the associated costs and revenues. Costs arising from energy exchanges with the electricity market are quantified in (3), as the difference between import costs (energy purchased from the grid) and revenues generated from energy exports (energy sold to the grid).

$$C_{market}^{h} = C_{imp,market}^{h} - R_{\exp,market}^{h} \quad (3)$$

The main equations governing the behavior of pumped hydro storage consist of the constraints for pumping (4) and turbining (5) power limits, alongside the equation representing the energy balance in the upper reservoir of the PHES (6) and the equation that calculates the associated costs (7). Binary decision variables govern the operational models: pumping (I_{p}^{h}) and turbining (I_{t}^{h}). The model calculates hourly pumping energy and costs (E_{p}^{h}, C_{p}^{h}), turbine energy and costs (E_{t}^{h}, C_{t}^{h}), as well as stored energy (E_{PHES}^{h}) and startup costs (C_{start}^{h}).

$$\frac{P_{\min,p}^{h}}{\eta} \cdot I_{p}^{h} \cdot \Delta t \le E_{p}^{h} \le \frac{P_{\max,p}^{h}}{\eta} \cdot I_{p}^{h} \cdot \Delta t \quad (4)$$

$$P_{\min,t}^{h} \cdot \eta \cdot I_{t}^{h} \cdot \Delta t \le E_{t}^{h} \le P_{\max,t}^{h} \cdot \eta \cdot I_{t}^{h} \cdot \Delta t \quad (5)$$

$$E_{PHES}^{h} = E_{PHES}^{h-1} + E_{p}^{h} \cdot \eta - \frac{E_{t}^{h}}{\eta} \quad (6)$$

$$C_{PHES}^{h} = C_{p}^{h} + C_{t}^{h} + C_{start}^{h} \quad (7)$$

Finally, the energy balance of the system is presented as the difference between the energy generated and the energy consumed (8).

$$E_{pv}^{h} + E_{w}^{h} + E_{imp}^{h} + E_{t}^{h} - E_{dem}^{h} - E_{\exp}^{h} - E_{p}^{h} = 0 \quad (8)$$

Data used for model optimization are presented in Table I.

The PHES system uses reversible variable-speed machines. A constant efficiency of 90% is assumed for both work cycles to simplify the analysis, accounting for turbomachines (91-93% in turbine mode and 92-94% in pump mode), the motor-generator (97.5%), the transformer (99.5%), and hydraulic losses (2-2.5%), resulting in an overall cycle efficiency of approximately 81%.

The study is temporally disaggregated into four average weeks, representative of each quarter and season of the year: the first quarter (winter), the second (spring), the third (summer), and the fourth (autumn).

Table I. Study system data.

Parameter	Value
Demand	400 MW
Grid access capacity	400 MW
Energy Storage Capacity	5750 MWh
Maximum installed photovoltaic capacity	860 MW
Maximum wind power generation capacity	465 MW
Photovoltaic operation and maintenance cost	8 €/MWh
Wind operation and maintenance cost	15 €/MWh
Efficiency of the pumping/turbining cycle	0.9
Minimum power in pump mode	38.93 MW
Maximum power in pump mode	113.5 MW
Minimum power in turbine mode	33.96 MW
Maximum power in turbine mode	99 MW
Operation and maintenance costs in pump/turbine mode	3.5€/MWh
Reversible variable speed pump/turbine unit	4

The temporal resolution of the model is hourly, consistent with the level of detail in the data obtained from the Spanish daily market, which maintained this hourly frequency until October 2025.

Regarding wholesale electricity market prices, real data from the Spanish day-ahead market were employed, obtained from the Iberian Energy Market Operator (OMIE) [15]. The model distinguishes between acquisition costs and injection revenues. Purchase prices were calculated on an indexed basis, while a 7% tax on electricity generation was applied to the selling prices.

In order to capture the impact of current volatility, two different time scenarios are compared:

- Year 2019: Represents a low-volatility environment prior to the recent energy crises, with a reduced average spread of 16.90 €/MWh (see Table II). During this period, prices remained stable at approximately 50 €/MWh (see Fig. 1) without significant intra-day oscillations. Using this year as a baseline enables reliance on pre-disruption data (the pandemic and geopolitical conflicts), avoiding atypical demand distortions and ensuring a stable, representative baseline.
- Year 2025: Reflects the current market situation, characterized by high renewable penetration and strong daily volatility. As shown in Table II, the average daily spread surges to 101.77 €/MWh, reaching peaks exceeding 110 €/MWh during the third quarter

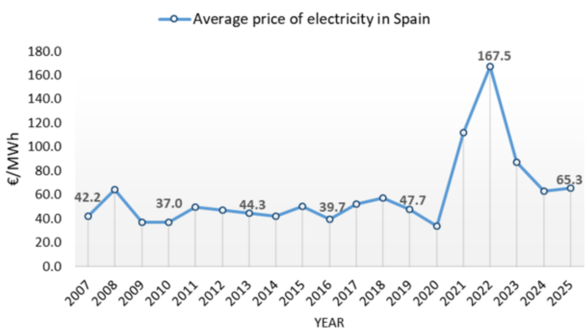

Fig. 1. Historical average price of electricity in Spain.

Table II presents the average grid electricity purchase and sale prices, as well as the average first, second, and fourth-level spreads for each quarter for both 2019 and 2025.

Table II. Average purchase and sale prices of electricity and average first, second, and fourth level spreads per quarter in 2019 and 2025 (€/MWh).

		P_{imp}	P_{exp}	spread1	spread2	spread4
2019	Q1	75.94	46.38	18.80	18.11	16.65
	Q2	66.23	45.57	15.63	14.80	13.17
	Q3	66.34	44.53	12.17	11.58	10.43
	Q4	60.30	40.78	20.98	20.13	18.16
	Average	67.20	44.32	16.90	16.15	14.60
2025	Q1	145.63	87.16	102.38	95.40	84.05
	Q2	69.06	30.08	95.13	90.26	79.49
	Q3	110.01	65.84	110.88	105.52	95.60
	Q4	103.30	60.59	98.70	93.45	83.58
	Average	107.00	60.92	101.77	96.16	85.68

This variability is visually illustrated in the price curve (Fig. 2), where 2025 (blue tones) exhibits deep valleys during the central hours and pronounced peaks at the beginning and end of the day, exceeding 140 €/MWh in summer, in contrast to the linearity observed in 2019 (orange tones).

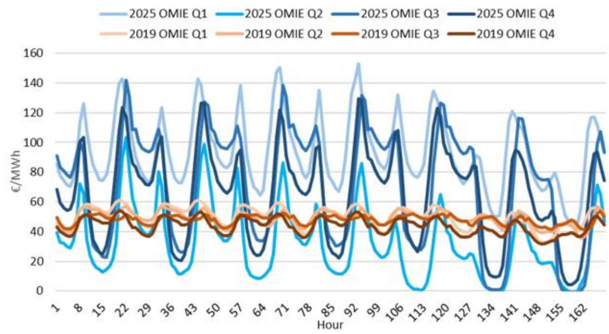

Fig. 2. Weekly average price curves for the electricity market (OMIE) by quarter in 2019 and 2025.

To further examine PHES storage management, this study considers not only the maximum spread (first-level) but also analyzes second and fourth-level spreads, defined as the differences between the second and fourth maximum and minimum prices, respectively. According to the data, in 2019, the second- and fourth-level spreads were not significantly different from the first-level spread, which remained below 17 €/MWh. Conversely, in 2025, a degradation of approximately 5 €/MWh at the second level and 12 €/MWh at the fourth level is observed relative to the primary spread; in these instances, the spreads do not reach the 100 €/MWh threshold.

The central research question of this study is whether the electricity market price profile, specifically its spread or variability, influences the behavior of a PHES storage model coupled with renewable generation (PV+W).

3. Results

The analysis focuses on determining how the magnitude of the price variability (spread) specifically affects the operational dispatch strategy and, consequently, the net economic performance of a system integrating photovoltaic and wind generation with pumped hydro energy storage, in the Spanish electricity market.

This section presents the results obtained after evaluating the system's behavior across the four selected average weeks. The analysis focuses on how the interaction between renewable generation and the price dynamics of the Spanish market conditions the system's operation, comparing the stability of 2019 with the high volatility of 2025.

A. Weekly analysis for the year 2025

This section studies the impact of price variability on the results obtained in the four average weeks of each quarter. Table III details the weekly results for each quarter, while Fig. 3 provides a graphical representation of the optimal hourly operation for each period of the year.

The first quarter (winter) is the period with the highest purchase price of the year (145.63 €/MWh). Despite the presence of wind generation (27,734 MWh), limited solar availability requires the import of 22,027 MWh. In this scenario, storage is necessary to arbitrate the spread of 102.38 €/MWh, allowing the system to manage energy surpluses to meet demand and minimize purchases during peak-price hours (see Fig 3A).

The second quarter (spring) presents a balanced combination of wind energy (29,771 MWh) and solar energy (47,043 MWh). With a price spread of 95.13 €/MWh, the system maintains minimal grid dependence, with imports limited to 2,911 MWh (see Fig 3B).

The third quarter (summer) stands out for having the highest photovoltaic generation, reaching approximately 59.8 MWh of solar energy. This high generation, combined with a maximum price spread of 110.8 €/MWh (the highest recorded in Table II), incentivizes the intensive use of PHES storage. During this quarter, grid imports are reduced to a minimum of 1.6 MWh, while exports reach only 12.4 MWh. As illustrated in the dispatch curves (Fig. 3C), the system capitalizes on price valleys, which reach 0 €/MWh, to pump 30.3 MWh. This energy is subsequently turbined (24.5 MWh) during price peaks, thereby minimizing the need for high-cost grid imports.

The fourth quarter (autumn) shows a spread of 98.70 €/MWh, with the system maintaining high storage activity, pumping 22,351 MWh. Although imports amount to 18,439 MWh, the use of PHES helps to manage the system in the face of purchase prices (see Fig 3D).

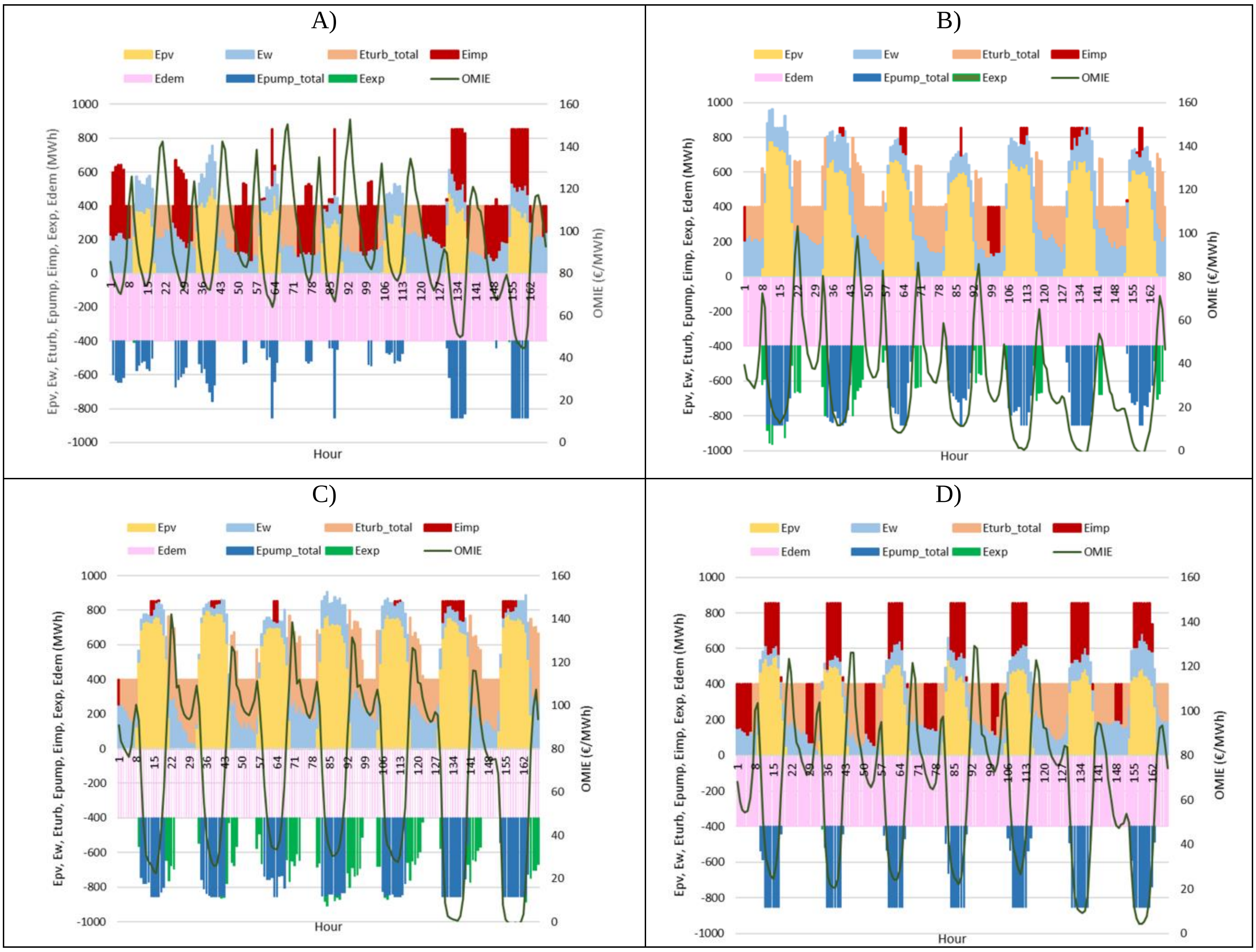

Fig. 3. Optimal hourly operation in one week of each quarter of the year. A) Q1: winter, B) Q2: spring, C) Q3: summer, D) Q4: autumn.

B. Comparison between 2019 and 2025

Table III shows the weekly results obtained in each quarter for both years. The results are analyzed below.

The comparison between 2019 and 2025 reveals that, despite having the same available renewable generation, the system's behavior varies drastically due to the market spread. In 2019, with an average spread of only 16.90 €/MWh, the incentive for arbitrage was scarce.

Table III. Weekly energy results for each quarter (MWh).

		E_{pv}	E_w	E_{imp}	E_{exp}	E_{pump}	E_{turb}
2019	Q1	20,148	27,734	21,571	218	10,712	8,677
	Q2	47,043	30,048	9,477	17,734	8,599	6,966
	Q3	59,807	24,030	10,795	26,309	5,914	4,790
	Q4	30,975	22,045	16,308	17	11,111	9,000
2025	Q1	20,148	27,734	22,027	10	14,207	11,508
	Q2	47,043	29,771	2,911	7,531	26,287	21,292
	Q3	59,807	23,891	1,629	12,364	30,339	24,575
	Q4	30,975	22,045	18,439	12	22,351	18,104

During the winter, the year 2025 presents an extremely high energy purchase price of 145.63 €/MWh, nearly double that of 2019. This economic pressure, combined with a spread that increases from 18.80 €/MWh to 102.38 €/MWh, forces the system to increase its storage activity, raising pumping from 10,712 MWh to 14,207 MWh to buffer against high grid costs.

In spring, the most significant reduction in external dependency is observed. Grid imports falling from 9,477 MWh in 2019 to just 2,911 MWh in 2025. This shift is possible as the system triples its storage utilization, with pumping rising from 8,599 to 26,287 MWh, taking advantage of the fact that the price spread increases sixfold, from 15.63 €/MWh to 95.13 €/MWh.

During the summer, the 2025 scenario, characterized by a spread exceeding 100 €/MWh, causes the system to utilize storage four times more than in the previous period. This structural change results in an 85% reduction in energy imports and a 53% achieving a much more self-sufficient system that is less dependent on grid fluctuations. In 2025, the system prioritizes storage and self-consumption, driven by the emergence of zero-price valleys and peaks exceeding 140 €/MWh.

In autumn, the 2025 trend continues with a spread of 98.70 €/MWh, doubling the pumped energy compared to 2019, from. Although imports are slightly higher in 2025 (18,439 MWh), the system employs storage much more aggressively to manage price peaks that now reach 103.30 €/MWh

C. Economic analysis

From an economic perspective, Table IV presents the weekly financial results for each quarter. The columns display the costs associated with photovoltaic generation, wind generation, grid-purchased energy, pumped energy, and turbined energy, while the final column shows the revenues generated from energy sales to the grid.

In the first quarter (winter), the high grid purchase price and limited solar availability lead to a sharp increase in import costs, rising from 1,255,245 € in 2019 to 2,435,974 € in 2025 (+94%), despite a reduction in the volume of imported energy. To mitigate this effect, the system increases pumping costs by 32%, from 37,492 € to 49,726 €, leveraging a 102.38 €/MWh spread to meet demand during peak hours. Consequently, total costs increase by 63%, while revenues drop by 92%, resulting in a 64% increase in net cost.

In the second quarter (spring), import costs decrease by 76% due to a significant increase in pumping, the cost of which triples to 92,004 €. Export revenues decrease by 44%, reflecting a prioritization of storage over direct sales. Overall, total costs fall by 22%, although the net cost rises slightly by 11%.

In the third quarter (summer), the import cost is reduced from 606,021 € to 88,156 €. Pumping and turbining costs increase by 413% compared to 2019, which enables export revenues of 1,220,695 €. Consequently, the system shifts from a net cost of 274,172 € to a net profit of 103,030 €, demonstrating the potential of storage to generate profitability.

In the fourth quarter (autumn), pumping costs double, rising from 38,890 € to 78,227 €, while the import cost increases by 66%. Total costs grow by 42% and revenues increase by 12%, leading to a 57% increase in net cost.

Table IV. Weekly financial results for each quarter (€).

		C_{pv}	C_w	C_{imp}	C_{pump}	C_{turb}	R_{exp}
2019	Q1	161,185	416,016	1,255,245	37,492	30,369	11,473
	Q2	376,344	450,718	552,869	30,098	24,379	855,573
	Q3	478,460	360,454	606,021	20,698	16,766	1,208,646
	Q4	247,801	330,673	824,752	38,890	31,501	785
2025	Q1	161,185	416,016	2,435,974	49,726	40,278	874
	Q2	376,344	446,558	134,478	92,004	74,524	481,000
	Q3	478,460	358,371	88,156	106,187	86,011	1,220,695
	Q4	247,801	330,673	1,372,484	78,227	63,364	879

4. Conclusion

The results of this study confirm that electricity market volatility is a key driver for the integration and intensive use of energy storage systems. The comparison between scenarios shows that the high daily price spreads observed in 2025 led to a fourfold increase in PHES operation compared to the more stable market conditions of 2019.

From an operational perspective, the optimized management of a hybrid system PV+W with PHES significantly reduces dependence on the grid. This effect is particularly evident in the summer of 2025, when the system cut energy imports by 85% by exploiting solar surpluses and price variability. The PHES effectively operated by pumping during minimum price, and generating during peak prices.

Economically, although the system remains exposed to seasonal imbalances, such as the net winter cost of 3.1 million € driven by high electricity prices and low solar availability, it also demonstrates clear profitability potential. In the summer of 2025, the system shifted from a net cost to a net profit of 103,030 €, confirming that storage enables renewable surpluses to be monetized through arbitrage.

Overall, daily differences in electricity prices have become a determining factor for economic viability, rather than a secondary factor. Despite seasonal variability, PHES proves to be an essential asset for reducing import costs and improving renewable self-consumption.

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