

Article

# A Comparison of Dispatchable RES Technoeconomics: Is There a Niche for Concentrated Solar Power?

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**Abstract:** Raising the penetration of renewable energy sources constitutes one of the main pillars of contemporary decarbonization strategies. Within this context, further progress is required towards the optimal exploitation of their potential, especially in terms of dispatchability, where the role of storage is considered vital. Although current literature delves into either storage per se or the integration of storage solutions in single renewable technologies, the comparative advantages of each technology remain underexplored. However, high-penetration solutions of renewable energy sources (RES) are expected to combine different technological options. Therefore, the conditions under which each technology outperforms their counterparts need to be thoroughly investigated, especially in cases where storage components are included. This paper aims to deal with this gap, by means of assessing the combination of three competing technologies, namely concentrated solar power (CSP), photovoltaics (PV) and offshore wind, with the storage component. The techno-economic assessment is based on two metrics; the levelized cost of electricity and the net present value. Considering the competition between the technologies and the impact storage may have, the paper's scope lies in investigating the circumstances, under which CSP could have an advantage against comparable technologies. Overall, PVs combined with storage prevail, as the most feasible technological option in the examined storage scenarios—with an LCOE lower than 0.11 €/kWh. CSP LCOE ranged between 0.1327–0.1513 €/kWh for high capacity factors and investment costs, thus larger storage components. Offshore wind—with a lower storage component—had an LCOE of 0.1402 €/kWh. Thus, CSP presents the potential to outperform offshore wind in cases where the latter technology is coupled with high storage requirements. CSP can be viewed as one of the options that could support European Union (EU) decarbonization scenarios. As such, an appropriate market design that takes into consideration and values CSP characteristics, namely dispatchability, is needed at the EU level.

**Keywords:** renewable energy sources; concentrated solar power; photovoltaics; wind energy; offshore wind; techno-economic assessment; levelized cost of electricity; net present value; sensitivity analysis; energy storage

## 1. Introduction

Efforts aiming at a decarbonized electricity supply have significantly intensified on a global scale in recent years [1–3]. The transition towards increased penetration of renewable energy sources (RES) is deemed pivotal [4] to boost the emergence of carbon-neutral economies [5–7]. In spite of the progress already achieved, more key interventions are required for the further deployment of renewables,

the efficient exploitation of their potential and the apt transformation of the electricity systems in the coming decade [8–10].

Renewable energy technologies such as offshore wind and solar photovoltaics (PV) comprise two of the most significant alternatives for the generation of low-carbon electricity. Their costs have undergone a significant reduction in recent decades. As a result, the respective market shares have risen [11–15]. Nonetheless, they are characterized by a noticeably lower level of flexibility than fossil fuels, due to their variable and intermittent power production [16]. Hence, raising the share of RES into the grid can be rather challenging—especially in terms of production and demand mismatches, as well as stability of supply [17–21]. Consequently, the role of energy storage in boosting the deployment of renewables is vital [22–25]. However, energy storage can have a strong influence on the costs of solar and wind electricity, in their effort to meet energy demand in high RES penetration scenarios [26–28]. As it is related to the intermittent operation of power plants, the incurrence of such additional costs should not be neglected [29,30].

On the contrary, concentrated solar power (CSP) with thermal energy storage (TES) differs significantly from the aforementioned technologies. Its energy production can be shifted over time and presents lower levels of variability, which can be attributed to the utilization of storage and thermal inertia [31–33]. Moreover, CSP with TES can provide steady capacity and generate electricity at time intervals of high net demand [34–36]. Dispatchability is regarded as a critical advantage that distinguishes CSP with TES from intermittent renewable energy sources in terms of energy quality. Nevertheless, its cost remains higher in comparison to competing technologies and its development remains uncertain [37,38].

The above-mentioned renewable energy technologies present a remarkable diversity in relation to costs and stability of electricity generation. No single technology can be identified as optimal in every aspect. As a result, future high-RES-penetration solutions are expected to combine different technological options [39,40]. Therefore, the evaluation of comparative assets of each technological option is of utmost importance. Although the existing literature is rich in studies delving into the challenges related to future low-carbon electricity systems, they explore either energy storage per se [41–44]—or the characteristics of a single RES technology combined with storage [45–50]. As a result, the circumstances, under which each RES technology outperforms their counterparts when energy storage is integrated, remain underexplored.

In an effort to investigate the circumstances under which CSP could have a niche against comparable technologies, this study deals also with this void by means of assessing competitive dispatchable RES technologies. These technologies could be utilized for the implementation of high RES penetration scenarios, especially in the frame of the long-term European decarbonization strategy for 2050. According to IRENA [51], solar PVs, offshore wind and CSP constitute by far the most cost-intensive RES technological options. The global weighted-average cost of electricity for PV, offshore wind and CSP are 0.085 \$/kWh, 0.127 \$/kWh and 0.185 \$/kWh, respectively. By contrast, onshore wind presents a noticeably lower cost, which is equal to 0.056 \$/kWh. Furthermore, another IRENA study states that many onshore wind projects commissioned in 2017 lie within the cost range of fossil-based electricity generation technologies [43]. However, the deployment of onshore wind is hindered by its high impact on the environment [52] and limited land availability [53,54]. In this context, the transition towards higher levels of RES penetration is expected to enable a case for CSP expansion. The rationale behind this is that when the system becomes highly dependent on variable sources, it requires sources capable of ramping up rapidly. In addition, investments on such dispatchable sources should be initiated when there is time ahead, so as to be available when variable sources have significantly increased their penetration rates [55]. Following consultation with industrial stakeholders, three technological options were selected for the current study—CSP, PV and offshore wind—all three combined with a storage component. More information on the storage component that has been considered is provided under Section 2.2. A detailed sensitivity analysis was conducted for all the parameters related to the levelized cost of electricity (LCOE) and net present value (NPV)

of these technologies. These parameters include the capital investment cost, storage related costs, the capacity factor, the discount rate and the annual fixed and variable operation and maintenance (O&M) costs. Drawing from the above, the main objective of this paper is to address the following question: under which circumstances can CSP have a competitive advantage against comparable technologies, until the rest of the conditions required for its deployment become more favorable?

## 2. Methodology and Data

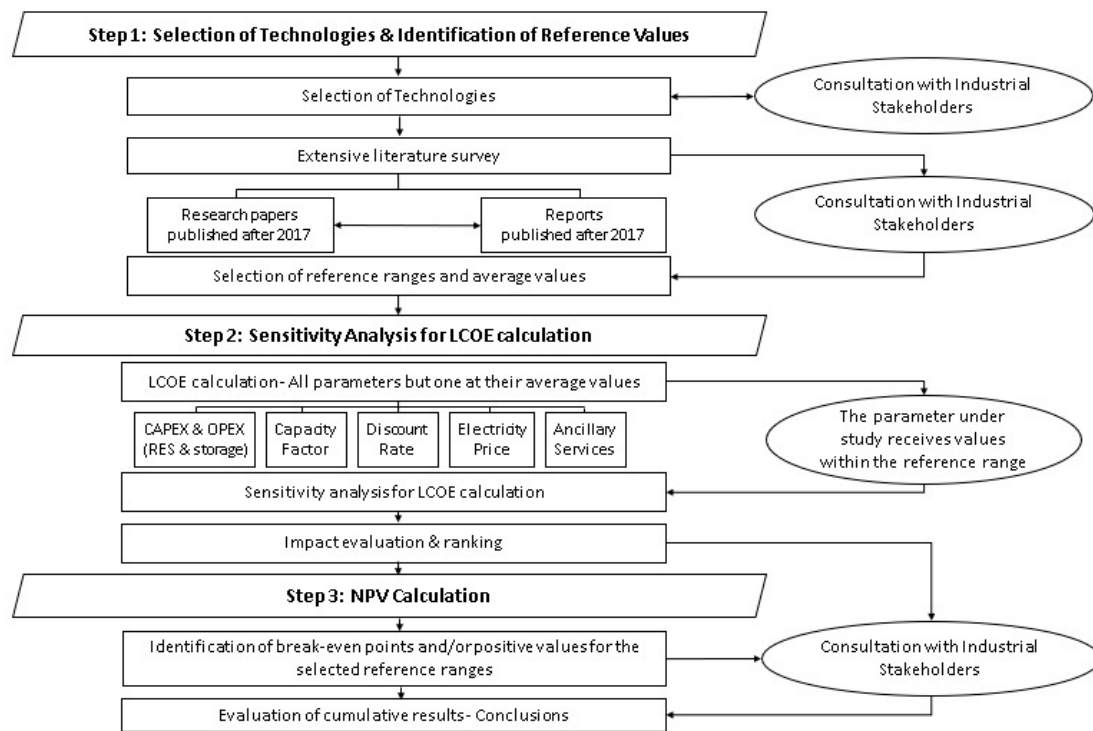
### 2.1. Adopted Approach

A comparison between NPV and internal rate of return (IRR) can point out the inverse relationship between them, whereas when comparing NPV, LCOE and return on investment (ROI) the results are unclear [56]. Newer projects are characterized by higher IRR in general, although IRR values can be significantly dependent on governmental grants and low-cost loans. On the other hand, projects with low LCOE may have a negative NPV or ROI. Consequently, no single metric can be regarded as adequately representative and reliable when comparing projects [57,58].

Critiques of LCOE are not uncommon in the literature. It has many times been characterized as a flawed metric for the assessment of the economic attractiveness of different renewable technologies against dispatchable, conventional ones [59–62]. In particular, the market value is not integrated in LCOE calculations, while also LCOE per se cannot provide a clear picture of the economic efficiency or competitiveness of a specific technology [63,64]. Given that higher penetration levels can lead to a decrease in the market value of variable renewable technologies, due to the intermittent nature of electricity generation, the use of LCOE can be even more difficult [65]. Furthermore, concerns have been also raised about the implications of heterogeneity on the economic assessment of electricity generating technologies with different market shares [66].

Nonetheless, this metric should not be abolished. Despite its drawbacks, it is still deemed able to serve as a useful and transparent comparison tool for energy generating technologies [67,68]. Targeted improvements though in applied techno-economic assessment methodologies are required [69–71]. Especially in cases of comparing electricity generation technologies that have different capacity factors, the sole use of LCOE does not suffice [72]. Considering that diverse renewable technologies and storage capacity scenarios are studied in the presented analysis, the NPV calculation offers an adequate counterpoint. NPV is appropriate for comparing projects of different sizes [73] and risk profiles [74], as well as for conducting sensitivity tests [75]. Henceforth, the techno-economic assessment of the examined technological options was based on LCOE and NPV, two complementary metrics.

During the first step of the adopted approach, the most representative scale for each one of the examined parameters is selected via consultation with industrial stakeholders. Based on the selected parameter average values, a sensitivity analysis is conducted. Along these lines, the current study aims to integrate the way these competing technologies are perceived by actors involved in the RES sector [76]. As a result, a correlation diagram is produced for different values of LCOE and the respecting parameters under study. The aim of this correlation diagram is to demonstrate the impact of each parameter's percentage change on the LCOE percentage change. The third step includes the NPV calculation corresponding to the low and high end of the reference range. The three selected technologies are techno-economically assessed in line with the approach graphically demonstrated in Figure 1.



**Figure 1.** Adopted approach for the comparative techno-economic analysis.

## 2.2. Assumptions

A common technical lifetime of 25 years has been assumed [77–79] for all three technologies, as well as a salvage value equal to zero [80,81]. Concerning the discount rate, Hermelink and de Jager [82] claim that a value of 5.7% represents the weighted average cost of capital (WACC) for energy projects implemented in Member States of the European Union (EU). The PRIMES model, utilized by the European Commission (EC) for the assessment of the energy and climate policy targets set for 2030, considered a discount rate equal to 9% for power generation projects [83]. Following consultation with industrial actors, a discount rate of 6–9% for projects realized in EU countries was deemed representative. Moreover, this discount rate range has been assumed the same for all three alternatives studied, although certain variations can be observed in real-life projects [84].

Regarding the revenues, only the wholesale electricity market price was adopted, and no power purchase agreement (PPA) price has been considered. The average electricity market price ranges has been reported in the past between 0.54–0.64 €/kWh [85] and 0.40 and 0.60 €/kWh [86]. In Schöniger and Resch [87], a reference value of 0.49 €/kWh has been considered for the electricity spot price in Spain. The quarterly reports by DG Energy for the second quarter of 2018 [88] and 2019 [89] present price ranges of 0.34–0.60 €/kWh and 0.34–0.64 €/kWh. Based on the above, the lowest and highest value of the electricity market price have been assumed to be 0.40 and 0.60 €/kWh accordingly, with 0.50 €/kWh considered for the average price.

In addition, considering that the dispatchable nature of renewable energy technologies combined with storage options may also contribute to the provision of ancillary services to the market, the NPV calculations have also integrated this price component, leading to additional revenues for them, especially in the frame of the transition towards high RES penetration scenarios. Typically, such services are paid by the transmission system operators (TSOs), mainly to conventional electricity producers [90,91]. It has been assumed that these services are also paid to dispatchable renewable electricity producers, who are in position to provide them by means of their storage capacity. To this end, CSP can be regarded as a fully dispatchable technology, receiving an amount of ancillary services corresponding to the total quantity of generated electricity. In contrast, two storage options are

investigated for PV and offshore wind; in these scenarios, only the quantity of electricity provided via storage is considered proper to receive the price of ancillary services.

As the EC has presented [85], grid charges to compensate for balancing services are paid by generators in a few countries—with the respective prices starting from 0.087 €/MWh in Sweden, raising to 2.81 €/MWh in Austria and reaching even 3.65 €/MWh in Bulgaria for wind and solar generators. According to ENTSO-E [92], the ancillary services' average cost in EU countries amounts to 2.5 €/MWh, which is the average price considered in this analysis, with a low end of 1 €/MWh and a high end of 4 €/MWh.

Market value is a concept referring to the price an asset would achieve in the marketplace and is mostly invoked in inefficient markets or cases of disequilibrium, where the existing market prices do not reflect the true underlying value [93]. As far as the market value is concerned, a first comparative analysis of the NPV is conducted based on a market value of 103%, in compliance with Schöniger and Resch [87], as typical of the present status for all three technologies. However, it should be noted that this market value was the outcome of a modeling analysis for CSP with storage, while the market values for the other two technologies without the storage component were calculated around 70%. Nevertheless, considering that the PV and offshore wind technologies studied are deemed to present a partly dispatchable behavior, besides the initial assessment with 103%, the behavior of both technologies assuming a market value of 100% is studied as well.

The EU decarbonization energy strategies in sight of 2050 will require an orientation towards higher penetration of RES technologies and thus the utilization of an appropriate portfolio. Inasmuch dispatchability is considered the most noticeable added value of CSP plants, thermal storage capacities of at least 8 h are regarded as necessary for the future [87]. Lastly, with regards to storage capacity selected for PVs and offshore wind, the utilization of Li-ion batteries has been assumed, as they constitute the most frequent kind of battery storage applications due to their high energy and power density [94–97].

The analysis presented herein includes two storage scenarios for PVs and offshore wind. More specifically, the first scenario refers to a storage of 0.5 kW per 1 kW of installed RES-generation capacity, which can be considered realistic according to the available literature [48,98]. On the contrary, the storage capacity is doubled in the second scenario, becoming equal to 1 kW of storage per 1 kW of installed RES-generation capacity. In both scenarios, the following assumptions apply:

- An energy to power ratio (E/P ratio) constant at 4 h, as well as one full discharge cycle per day were considered [48];
- A life duration of 10 years was considered for current batteries; therefore, they will have to be replaced. Considering the technological advancements, the life duration of the new batteries is assumed to be 15 years, with a cost around 60% of the one currently taken into account [99].

It is evident though, that the above-mentioned options cannot compete with the dispatchability provided by CSP with thermal storage. Nonetheless, four hours of storage—corresponding to an E/P ratio equal to 4—comprise the optimal capacity which can be currently offered for such configurations, namely PV with storage and offshore wind with storage [98,100–102]. More specifically, the lead of 4-h batteries over batteries with a longer duration lies in their potential to achieve life-cycle cost parity with combustion turbines [103].

### 2.3. Data Selection

The data used were gathered by numerous reports/scientific articles, etc. and assumptions cannot be identical. However, through the extensive review conducted by the authors, the data ranges (min and max values, recent trends, etc.) were identified. Afterwards there was an extensive consultation with representatives of the industrial sector. In this respect, the data reference ranges for all the parameters used in the calculations have been discussed in detail and validated by industrial stakeholders & researchers within the framework of EU funded H2020 MUSTEC project.



The desk review for the data selected regarding the examined technological options is restricted to research papers and reports published after 2017. Thus, the comparative analysis is solely based on the most updated information, considering the significant cost reductions these technologies have experienced over the last decade. In reports where costs are expressed in USD and the conversion year is not explicitly mentioned, the conversion to euro has been conducted in line with the exchange rates applicable for the respective publication year.

### 2.3.1. CSP with Storage

All representative CSP projects selected by ESTELA in [104] include storage. The installed capacity cost for DEWA IV in Dubai—scheduled for operation in 2020—reached 4720 €/kW. Xina Solar One in South Africa—an installation that has been operational since 2017—had a cost of 7226 €/kW. The cost for Noor III in Morocco, launched in 2018, is 5380 €/kW. Lilliestam and Pitz-Paal [105] have pointed out that the cost of Aurora accounted for 2820 €/kW. In addition, Kost et al. [99] highlight that for CSP systems with a storage size of 8 h, the initial costs presented a range between 3600 and 4000 €/kW in early 2018. According to the estimates of Lazard [106], the capital investment costs for CSP range from 3370 €/kW to 8870 €/kW. IRENA [107], suggests a range between 2800 €/kW and 5930 €/kW for the global weighted average CSP investment costs in 2018. Moreover, Feldman et al. [108] claim that the current capital expenditure (CAPEX) of CSP projects for storage sizes of 6 to 16 h has been reduced to half compared to 2013–2015, ranging now from 3300 €/kW to 5400 €/kW. In particular, the CAPEX costs for 6 projects of the global CSP fleet (Khi Solar One, Noor III, Ashalim Plot B, Goldmud, Shouhang Dunhuang, Supcon Delingha), all of which would be in operation in 2018, started from as low as 3780 €/kW to 7890 €/kW. Concerning the future CSP fleet (Atacama 1, Aurora, DEWA CSP Unit 1, Redstone, Gansu Jinta and Yumen Huahai) with storage size of 8 to 18 h, expected to be operational in the period 2019–2021, the costs are varying from 3380 €/kW to 9850 €/kW.

As regards the capacity factor (CF) of CSP plants that went operational in 2018, values from 30% to 60% are deemed realistic, while the global weighted average CF has increased from 37% in 2017 to 45% in 2018, according to the analysis of IRENA [107]. As Lazard [106] mentions, a CF range of 43–52% can be regarded as representative of the status quo. As far as the O&M costs are concerned, Lilliestam and Pitz-Paal [105] estimate them around 1.5% of the installation costs. Therefore, assuming a range of 2800 to 6000 €/kW for the installation costs, based on the above referenced literature sources, O&M prices will be around 42 to 90 €/kW. However, Lazard [106] assumes a fixed O&M cost range of 66.5–70.9 €/kW and no variable O&M costs, whereas IRENA [107] suggests variable O&M costs of 1.7–3.4 eurocents per kWh. The parameters' values selected for this techno-economic assessment are summarized in the following Table (Table 1).

**Table 1.** Summary of data related to CSP with storage.

	Investment Cost (€/kW)		O&M Fixed Costs (€/kW)		O&M Variable Costs (€/kWh)		Capacity Factor (%)	
	Low	High	Low	High	Low	High	Low	High
	2800	6000	65	71	0.017	0.034	30	60
<b>Average</b>	4400		68		0.026		45	

### 2.3.2. PV with Storage

Concerning the installation costs for PV without storage, IRENA [51] accentuates the remarkable decline of 70–80% at the utility scale globally between 2010–2017, except for the United States (US), where the reduction is lower. Installation costs in these countries range between 995 €/kW and 1270 €/kW, while the significantly higher costs in US and Japan constitute the only exceptions. Similar trends are highlighted by a subsequent IRENA study [107], providing a range between 680–2330 €/kW for the installation costs at the global scale, with the global weighted average landing at 1025 €/kW.

As Feldman et al. [108] have mentioned, utility investment costs range between 1470–1915 €/kW. It should be noted that these costs are near the upper values of worldwide observed prices, considering the significant price deviation between the USA and the rest of the world, which is highlighted above. Furthermore, Fu et al. [42] refer to costs between 915–985 €/kW, depending on whether the fixed tilt or single axis tracker technology has been adopted. Kost et al. [99] mention costs between 600–800 €/kW, while Lazard [106] considers a cost range between 975–1220 €/kW and Yousif et al. [109] suggest a cost of 1200 €/kW. In addition, Lazard [48] provides an estimation regarding the total cost for a PV system including storage, to be between 1300–1830 €/kW. The consultation with industrial stakeholders led to the selection of a 600–1200 €/kW representative installation cost reference range for PV without storage in Europe.

Concerning the storage component, according to IRENA [43] prices of 117 to 1117 €/kWh are currently prevailing globally, depending on the Li-ion battery-type adopted. Costs between 322 and 760 €/kWh are mentioned by Fu et al. [98], while Mongird et al. [102] highlight a cost of 170 €/kWh. Furthermore, the studies conducted by Michas et al. and Stavrakas et al. consider a cost equal to 800 €/kWh [110,111]. Hence, a cost range of 200–900 €/kWh is adopted in this study, following consultation with industrial stakeholders. The values for PV fixed operation and maintenance costs vary in the available references. More precisely, Yousif et al. mention 29 €/kW annually, whereas IRENA refers to costs between 9–16.2 €/kW [51] and 9–17.1 €/kW [107]. Moreover, costs range between 13.7 and 16.4 €/kW according to Fu et al. [42] and Kost et al. [99] highlight prices between 15 and 20 €/kW. Regarding the fixed O&M costs of storage systems, the only price identified was mentioned by Mongird et al. [102] and ranged between 5 to 12 €/kW. The CF for PVs lies within a range of 21–32% according to Lazard [Lazard, 2017] and 13–27% with an average value of 18% according to IRENA [107]. Another analysis by IRENA suggests an average value amounting to 17.6% [51], whereas 17.5% is a representative value according to Fu et al. [42]. Moreover, Nikas et al. assume a CF equal to 22% [112]. Table (Table 2) below summarizes the data used for PVs with storage.

**Table 2.** Summary of data related to photovoltaics (PV) with storage.

	PV Investment Cost (€/kW)		PV Storage Cost (€/kWh)		PV O&M Fixed Costs (€/kW)		Storage O&M Fixed Costs (€/kW)		Capacity Factor (%)	
	Low	High	Low	High	Low	High	Low	High	Low	High
	600	1200	200	900	9	20	5	12	13	27
<b>Average</b>	900		550		14.5		8.5		20	

### 2.3.3. Offshore Wind with Storage

Concerning the total installed costs of offshore wind, IRENA [107] states that commissioned projects in 2018 underwent a 5% reduction compared to eight years ago. Furthermore, the global weighted average installation costs in 2018, no storage included, ranged from 2370 to 4580 €/kW, with Chinese projects presenting costs lower than 2500 €/kW, while the costs of European projects lied within 3400–5100 €/kW. Another study conducted by IRENA [51] highlights an installation cost equal to 4250 €/kW for offshore wind projects implemented in Europe in 2016, while Kost et al. [99] mention investment costs from 3100 to 4700 €/kW. Stehly et al. [113] present costs among 3850 and 4750 €/kW, whereas Yousif et al. [109] have considered a cost equal to 3215 €/kW. All things considered, a cost range between 3100–5100 €/kW will be assumed in this study. Installation and O&M costs related to battery storage are the same as the ones for PVs.

As far as the annual O&M costs of offshore wind projects are concerned, Stehly et al. [113] present prices ranging from 76 to 128 €/kW approximately for fixed O&M, while according to Yousif et al. [109] they amount to 66 €/kW. As IRENA highlights [51], prices for annual fixed and variable O&M costs range between 99–127 €/kW and 0.01–0.045 €/kWh respectively, whereas in the analysis conducted by Kost et al. [99] fixed O&M costs account for 100 €/kW and variable O&M costs amount to 0.005 €/kWh. As IRENA indicates, the CF in 2018 for offshore wind projects ranged from 25% to 50%, with a weighted

average equal to 43% [107]. In particular, the CFs of European projects exceeded 40% in 2017 and 2018, reaching even values of 55%, according to the same reference. Another analysis carried out by IRENA [51], arrived at a weighted average offshore capacity factor approximately equal to 42% for newly commissioned plants in 2017. Finally, the study conducted by Kost et al. [99] was based on a CF range between 37–52%. The consultation process with industrial stakeholders validated a capacity factor range between 40 and 55%, which was also selected in this study as indicative of European projects. The following Table (Table 3) summarizes the data selected for offshore wind with storage.

**Table 3.** Summary of data related to offshore wind with storage.

	Wind Investment Cost (€/kW)		Wind Storage Cost (€/kWh)		Wind O&M Fixed Costs (€/kW)		Wind O&M Variable Costs (€/kWh)		Storage O&M Fixed Costs (€/kW)		Capacity Factor (%)	
	Low	High	Low	High	Low	High	Low	High	Low	High	Low	High
	3100	5100	200	900	75	130	0.01	0.02	5	12	40	55
<b>Average</b>	4100		550		102.5		0.015		8.5		47.5	

### 3. Results

The correlation of the LCOE with the examined parameters, as well as the corresponding sensitivity analyses are presented in the current Section. More specifically, the illustrated results include the sensitivity analysis conducted for CSP with storage, as well as both storage scenarios examined for PV and offshore wind with storage. In each case, the parameter under study receives different values within the adopted range, while the rest of the parameters remain constant, at their average value.

Table 4 summarizes the average values and ranges for all parameters related to the analysis for CSP with storage. The first parameter examined for CSP is the investment cost, including the storage related costs. However, a different approach has been adopted in this case, given the interrelation of the CSP investment cost with the CF. To this end, the overall investment cost has been disaggregated for three specific ranges, each one of them corresponding to different CF values.

**Table 4.** Average values and sensitivity analysis ranges for concentrated solar power (CSP) with storage parameters.

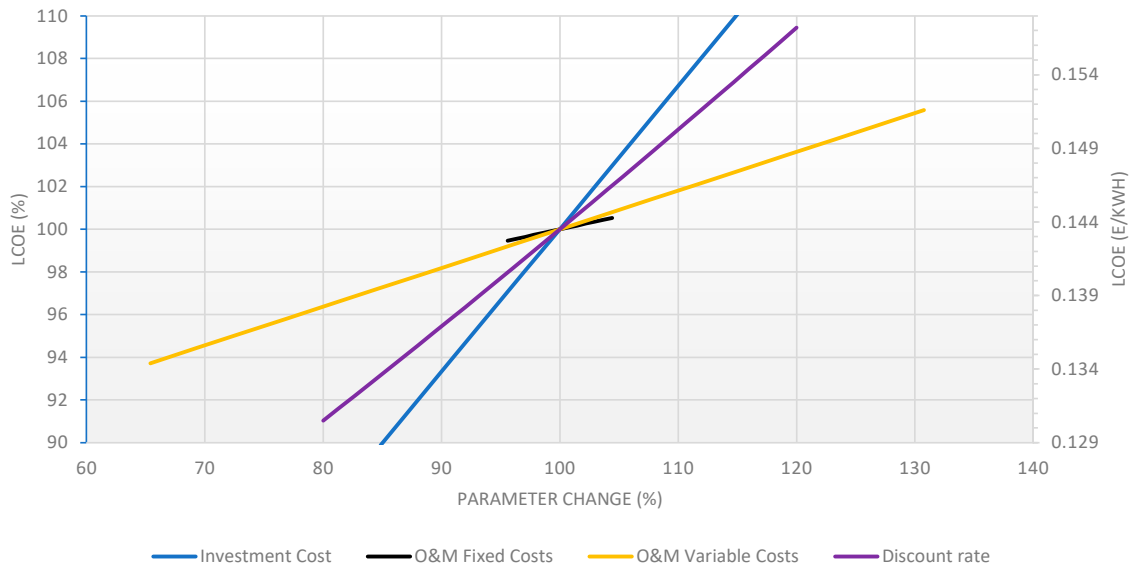
Investment Cost (€/kW)	O&M Fixed Costs (€/kW)	O&M Variable Costs (€/kWh)	Capacity Factor (%)	Discount Rate (%)	Electricity Price (€/kWh)	Ancillary Services (€/kWh)
<b>Average Values</b>						
4400	68	0.026	45	7.5	0.05	0.025
<b>Ranges</b>						
Increase of 200 € in three ranges:			Three ranges:			
<ul style="list-style-type: none"> <li>• 2800 ≤ Cost &lt; 4000</li> <li>• 4000 ≤ Cost &lt; 5000</li> <li>• 5000 ≤ Cost ≤ 6000</li> </ul>	Increase of 0.5 in the range of 65–71	Increase of 0.001 in the range of 0.017–0.034	<ul style="list-style-type: none"> <li>• 30 ≤ CF &lt; 40</li> <li>• 40 ≤ CF &lt; 50</li> <li>• 50 ≤ CF ≤ 60</li> </ul>	Increase of 0.1 in the range of 6–9	0.04–0.06	0.01–0.04

More precisely, in line with the CSP guru database [114] and IRENA [115], for a storage capacity of less than 6 h, the CF is considered between 30 to 40%. Accordingly, a CF range between 40 to 50% is considered for capacities between 6 and 9 h, while for 9 to 12 h, the CF parameter reaches 50–60%. The LCOE values for investment costs between 2800 and 4000 € and an average CF of 35% are calculated 0.13–0.1589 €/kWh. Assuming costs between 4000–5000 € and a CF of 45%, the LCOE is calculated 0.134–0.152 €/kWh, while for higher CFs (namely 55%) and costs ranging from 5000 € to 6000 €, the LCOE presents a range between 0.1327–0.1513 €/kWh.

A comparable LCOE plot with the studied CSP parameters is presented under Figure 2. The LCOE price calculated for an average constant value of the CSP parameters is 0.1429 €/kWh. In regard with the parameters impacting on the LCOE, positive NPV values are achieved only by CSP plants equipped with at least 6 h of storage, when investment costs fall below 1995 €/kW. The impact of two additional parameters on the feasibility of a CSP project, namely of the electricity price and ancillary services,



was also studied. More precisely, negative NPV results were attained for an ancillary services cost of 0.025 €/kWh and a wholesale market price ranging between 0.04–0.06 €/kWh, as well as for a wholesale electricity price kept constant at 0.05 €/kWh and ancillary services of 0.01 to 0.04 €/kWh.



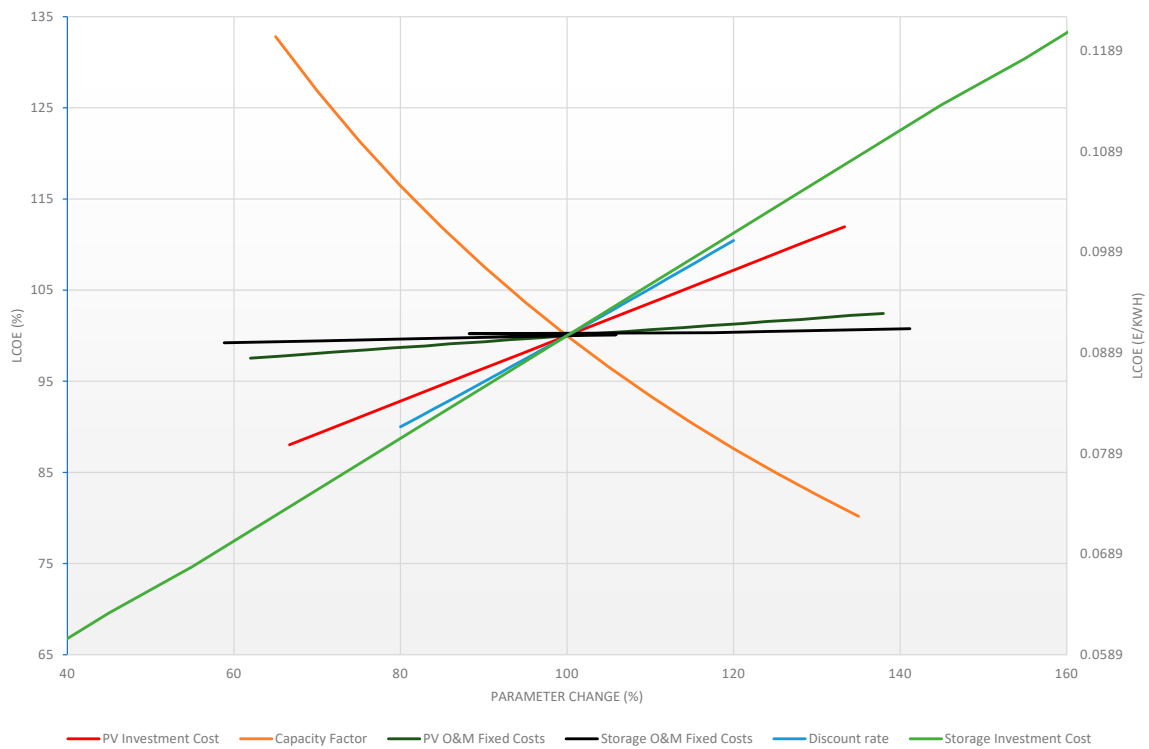
**Figure 2.** Levelized cost of electricity (LCOE) sensitivity analysis with all parameters for CSP plus storage.

The respective values and ranges for PV with storage are presented in Table 5.

**Table 5.** Average values and sensitivity analysis ranges for PV with storage parameters.

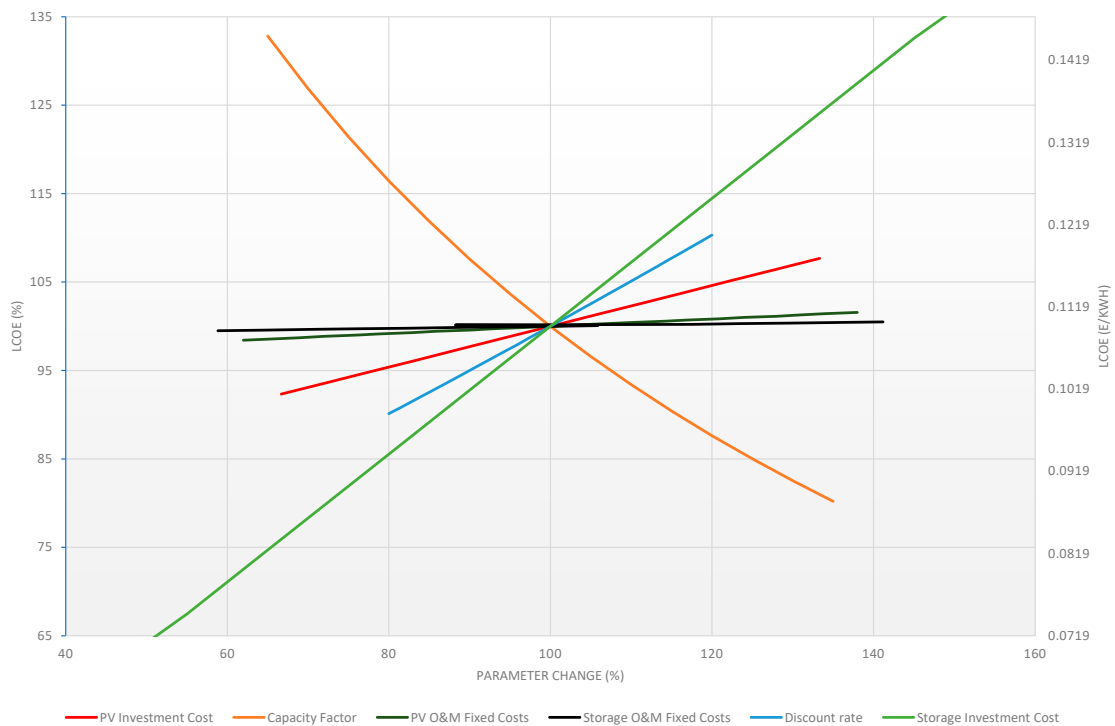
PV Investment Cost (€/kW)	PV Storage Cost (€/kWh)	PV O&M Fixed Costs (€/kW)	Storage O&M Fixed Costs (€/kW)	Capacity Factor (%)	Discount Rate (%)	Electricity Price (€/kWh)	Ancillary Services (€/kWh)
<b>Average Values</b>							
900	550	14.5	8.5	20	7.5	0.05	0.025
<b>Ranges</b>							
Increase of 50 in the range of 600–1200	Increase of 50 in the range of 200–900	Increase of 0.5 in the range of 9–20	Increase of 0.5 in the range of 5–12	Increase of 1% in the range of 13–27	Increase of 0.1 in the range of 6–9	0.04–0.06	0.01–0.04

Concerning the first storage scenario for PVs, the cumulative results of the sensitivity analysis are presented in Figure 3. Considering average values for all studied parameters, the LCOE price is 0.0906 €/kWh. Moreover, NPV calculations returned negative results for all the studied parameters. In addition, the break-even points identified did not correspond to realistic parameter values. Positive NPV values have been attained for both market values considered (103% and 100% for PV electricity), for unrealistic storage costs (<24 €/kWh for 103% and 21 €/kWh for 100%, respectively). As far as the CF is concerned, break even value for the NPV is 47% for market values of 103% and 48% for a market value of 100%, therefore positive values can be identified for CFs over these values. NPV calculations have also led to negative values for a constant cost of ancillary services at 0.025 €/kWh and a wholesale market price ranging between 0.04–0.06 €/kWh. The NPV values are positive only for more than twice the value of average wholesale electricity prices, namely higher than 0.1185 €/kWh and 0.1188 €/kWh, if market values of 103% and 100%, respectively are considered.



**Figure 3.** LCOE sensitivity analysis with all parameters for PV plus storage (Scenario 1).

Accordingly, the results of the second storage scenario for PVs are illustrated in Figure 4. The LCOE is calculated equal to 0.1091 €/kWh, considering average values for all the investigated parameters. No positive NPV values were identified for this scenario as well.



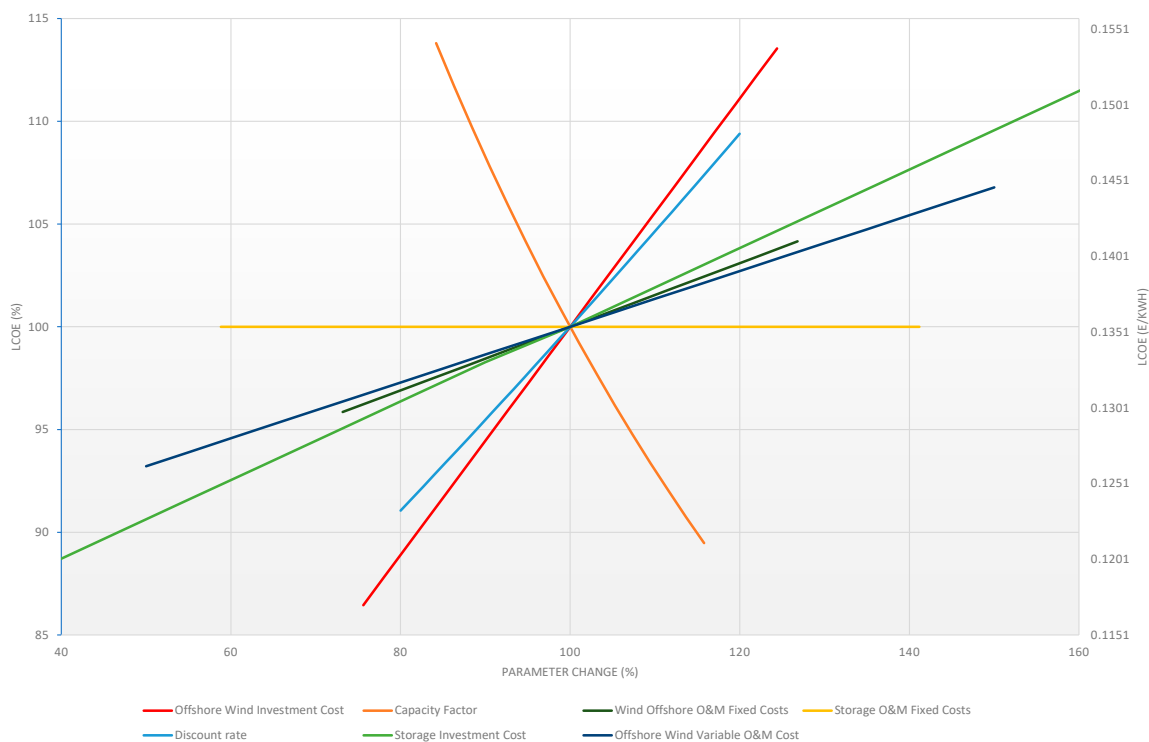
**Figure 4.** LCOE sensitivity analysis with all parameters for PV plus storage (Scenario 2).

Likewise, the average values and ranges corresponding to the scenarios studied for offshore wind with storage are summarized in Table 6.

**Table 6.** Average values and sensitivity analysis ranges for offshore wind with storage parameters.

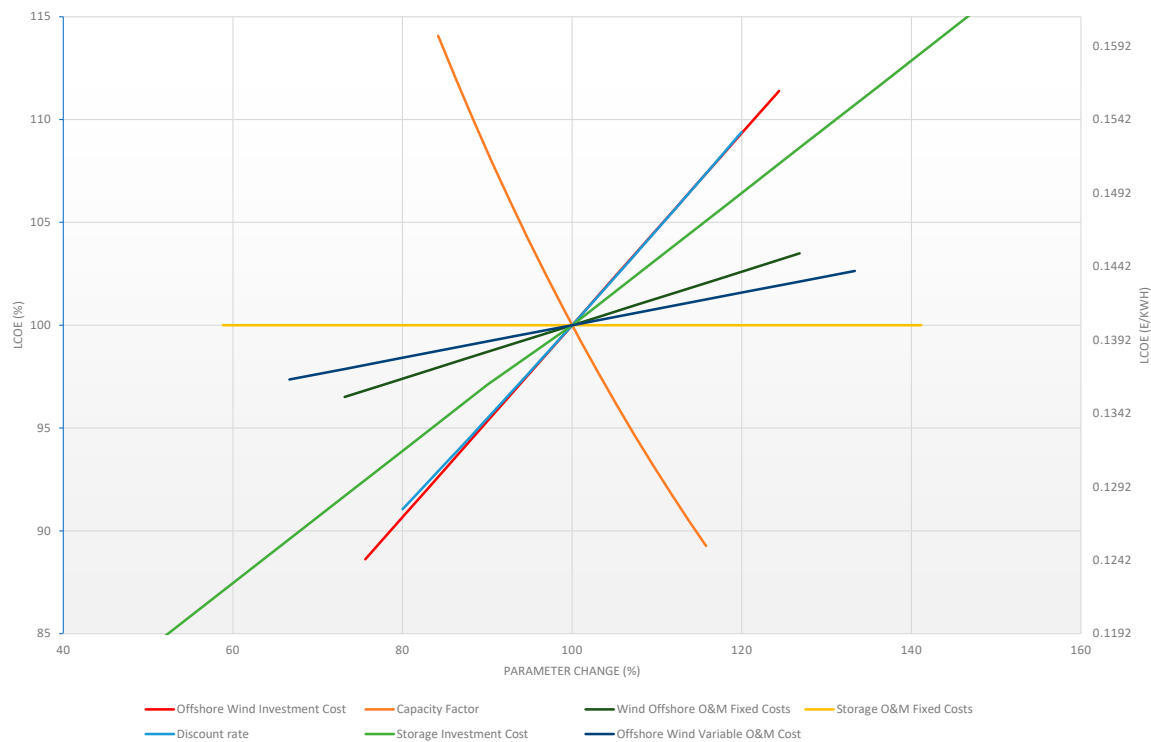
Wind Investment Cost (€/kW)	Wind Storage Cost (€/kWh)	Wind O&M Fixed Costs (€/kW)	Wind O&M Variable Costs (€/kWh)	Storage O&M Fixed Costs (€/kW)	Capacity Factor (%)	Discount Rate (%)	Electricity Price (€/kWh)	Ancillary Services (€/kWh)
<b>Average Values</b>								
4100	550	102.5	0.015	8.5	47.5	7.5	0.05	0.025
<b>Ranges</b>								
Increase of 100 in the range of 3100–5100	Increase of 50 in the range of 200–900	Increase of 5 in the range of 75–130	Increase of 0.001 in the range of 0.01–0.02	Increase of 0.5 € in the range of 5–12	Increase of 1 in the range of 40–55	Increase of 0.1 in the range of 6–9	0.04–0.06	0.01–0.04

As far as offshore wind is concerned, the results of the first storage scenario are demonstrated in Figure 5. The LCOE price calculated for constant average values of the studied parameters is 0.1354 €/kWh. In this case, negative NPV values were identified for all the examined parameters. Furthermore, the break-even point for offshore wind values was identified for remarkably high wholesale electricity prices (0.1547 €/kWh and 0.1548 €/kWh for market values of 103% and 100%, respectively).



**Figure 5.** LCOE sensitivity analysis with all parameters for offshore wind plus storage (Scenario 1).

Finally, the results of the second storage scenario for offshore wind are depicted in Figure 6. If average values are considered for all the parameters, the LCOE price is equal to 0.1402 €/kWh. All NPV values calculated were negative in this case as well.



**Figure 6.** LCOE sensitivity analysis with all parameters for offshore wind plus storage (Scenario 2).

#### 4. Discussion

As the related analysis indicates, the LCOE values for CSP projects are expected to vary between approximately 0.13 and 0.159 €/kWh—depending on the existing variations in storage capacities. Moreover, higher capacity factors and investment costs are expected to lead to a downward trend of LCOE. The break-even point for NPV has been identified at investment costs equal to 1995 €/kW. These results are in compliance with the ones presented in the CSP study of Lilliestam [116], as the elicited LCOE prices lie within the above range for recent projects. In addition, the high learning rates of CSP projects with large storage capacities, reaching up to 43% approximately in the case of parabolic trough plants, can set the groundwork for the emergence of investment costs below 2000 €/kW in the coming years. By contrast, the impact of fixed O&M costs can be deemed negligible; a 65–71 €/kW range in their values lead to a range between 0.1421 and 0.1437 €/kWh for LCOE (Figure 2), namely a 4.4% change in fixed O&M costs results in a 0.5% change in LCOE.

However, the impact of variable O&M costs and the discount rate cannot be neglected. According to the current study, a range between 0.017 and 0.034 €/kWh for O&M variable costs can result in a 0.134–0.154 €/kWh range for LCOE. As the sensitivity analysis in Figure 2 demonstrates, a 35% change in this parameter causes a 6% change in the LCOE value. Accordingly, for values between 6–9% for the discount rate, the LCOE values are calculated to lie within a range of 0.1301–0.1564 €/kWh, namely a 20% change in the discount rate leads to 9% differentiation for LCOE. All NPV calculations, except for the ones related to the impact of investment costs, resulted in negative prices. As can be clearly seen in Figure 2, the CSP parameter with the strongest impact on the LCOE is the investment cost, followed by the discount rate and variable O&M costs, whereas the impact of fixed O&M costs is inappreciable. Finally, the LCOE price corresponding to the average values of the studied parameters is equal to 0.1429 €/kWh, which is the highest LCOE price identified in the presented analysis.

Concerning the first scenario for PV with storage, as expected, the impact of the investment cost on LCOE is very high. More precisely, for a PV cost ranging between 600–1200 €/kW, the LCOE values lie within a 0.0798–0.1015 €/kWh range, namely a 33% parameter change leads to a 12% change in LCOE. Negative NPV prices are reasonable in this case, given the low prices of wholesale electricity

and ancillary services. The influence exerted by storage investment costs on the LCOE is even more significant. As Figure 3 shows, for parameter values between 200 and 900 €/kW, the respective LCOE values range from 0.0585 to 0.1228 €/kWh, corresponding to a 35% LCOE change for a 64% change in the parameter values. The positive NPV values achieved do not correspond to current market prices, hence this option cannot be considered viable. The impact of fixed O&M costs for both PV and storage cannot be regarded as significant, given that parameter changes of approximately 40% have resulted in LCOE changes between 1–2%. As expected, negative NPV values were returned in both cases. On the contrary, the impact of the CF is remarkable, as LCOE prices range between 0.1203 and 0.0727 €/kWh for a CF range from 13% to 27%, namely a 35% change in the values of the parameter results in a 33% change in LCOE values. However, CF values achieving the NPV break point cannot be regarded as attainable. The impact of the discount rate is considerable, but not so substantial in order to return positive NPV values. More specifically, considering a 6–9% range for the discount rate, the LCOE ranges between 0.082–0.10 €/kWh, namely a variation of 20% in the discount rate leads to almost 10% change of the LCOE.

Concerning the first PV plus storage scenario, Figure 3 shows that the CF and the storage investment cost constitute the two most important parameters, followed by the discount rate and the PV investment cost, while the impact of the fixed O&M costs for the PV and the storage components is negligible. The LCOE price corresponding to the average values of all parameters is 0.0906 €/kWh. In the second scenario, the respective LCOE price is equal to 0.1091 €/kWh. Nonetheless, the overall picture remains the same according to Figure 4, given that there are no differentiations in the ranking of the parameters, as far as their impact on LCOE is concerned. Overall, the LCOE prices achieved in the case of PV plus storage are by far the lowest ones in this analysis. The above-mentioned outcomes are deemed tenable according to the existing literature, given that PVs constitute a considerably mature [117,118] and cost-competitive technological option [119]; as a result, the impact of storage is expected to be dominant [120].

Concerning the first scenario for offshore wind coupled with storage, the LCOE lies within a range between 0.1171 and 0.1538 €/kWh for offshore wind investment costs between 3100 and 5100 €/kW, according to Figure 5. These results indicate that a change of 24% in the parameter values leads to a 14% change in LCOE. The values calculated are in line with the studies conducted by IRENA, according to which the global weighted LCOE accounted for 0.126 €/kWh in 2016 [51], landing at 0.107 €/kWh in 2018 [107], including also an investment cost for storage. Moreover, the same Figure shows that for storage investment costs between 200–900 €/kWh the LCOE ranges between 0.1191–0.1518 €/kWh, namely a 64% variation of the parameter impacts on the LCOE price by approximately 12%. Regarding both fixed and variable offshore wind O&M costs, their impact on LCOE is deemed weak. More precisely, in the case of fixed costs, LCOE presents a variation by slightly over 4% for a parameter change up to 27%, while in the case of variable costs, a 33% change in the parameter value results in a 3% change in LCOE. Furthermore, the impact of fixed O&M costs for the storage component is regarded as inappreciable, as can be clearly seen in Figure 5. On the contrary, the impact of the CF is rather significant, as the LCOE receives values from 0.154 to 0.121 €/kWh, corresponding to a 40–55% range for the CF. The sensitivity analysis shows that a 16% change in the parameter's value results in an almost equal variation of the LCOE, namely 14%. By contrast, the discount rate presents an intermediate impact; more specifically, a parameter variation equal to 20% leads to a 9% change in the LCOE value. No positive NPV values have been identified for the above parameters. As offshore wind constitutes a rather capital-intensive technological option [121] and the storage component is expected to incur additional costs, such results can be considered reasonable.

As Figure 5 shows, the strongest impact on the LCOE is presented by the CF, while the second most pivotal parameters are the wind investment cost and the discount rate. The impact of the storage investment cost and the offshore wind O&M costs (both fixed and variable) is less significant, whereas the impact of the storage O&M fixed costs is negligible. The LCOE price calculated for an average value at all parameters is 0.1354 €/kWh in the first storage scenario. This price is significantly



higher than the ones corresponding to PV with storage, although it does not exceed the LCOE price of CSP. Nonetheless, the LCOE price achieved in the second storage scenario for offshore wind is equal to 0.1402 €/kWh, thus becoming comparable to CSP. Concerning the impact of the studied parameters on LCOE, no differentiations have occurred in their ranking, as can be clearly seen in Figure 6.

Overall, achievable positive NPV values were identified only in the case of a CSP plus storage investment cost lower than 1995 €/kW. Positive NPV values achieved by PVs with storage, corresponded either to investment costs below 21–24 €/kWh or CF values exceeding 47%. Hence, they cannot be regarded as feasible. Nevertheless, such an outcome does not imply that positive NPV values cannot be observed in real-life projects for these technologies, but rather indicates that the optimal values of the examined parameters are required. Such an analysis lies beyond the scope of the present study, which is based on reference values, provided by the international literature.

Concerning the LCOE sensitivity analysis, the largest range in the calculated values is experienced for PV coupled with storage, followed by offshore wind with storage. The lowest range achieved in this analysis is attributed to CSP. As regards PV, this result is expected, given the wider impact of storage cost compared to offshore wind and CSP, mainly due to the low investment cost of PV [122–124]. The second largest LCOE range presented by offshore wind can be deemed an equally reasonable result; in this case, a relatively weaker impact of storage cost is expected, due to the higher investment costs characterizing the specific technological option [125–127]. Therefore, it is evident that the regulating parameter in the LCOE range of these technologies is the storage cost applied.

All things considered, PVs coupled with storage constitute the predominant technological option in both storage scenarios, presenting noticeably lower LCOE values compared to their counterparts. For storage capacities of 0.5 kW per 1 kW of installed generation capacity or less, PVs are followed by offshore wind with storage, while CSP land at the third place. However, when the storage requirements are doubled, the LCOE of offshore wind with four hours of storage becomes comparable to CSP (0.1402 €/kWh for offshore wind against 0.1327–0.1513 €/kWh for CSP with higher CAPEX and thus bigger storage component than 4 h). Besides this, the particular traits of CSP should be considered, namely the remarkably high learning rates, the downward trends related to the LCOE as well as the comparatively higher storage capacities offered. Taking into account all of the above, it is expected that CSP can outperform offshore wind coupled with storage in high RES penetration (and thus high storage scenarios), both in terms of dispatchability and financial feasibility. Furthermore, in the current analysis only CSP plants equipped with at least six hours of storage presented positive NPV values. This conclusion is validated by the analysis carried out by Lovegrove et al. [128], which points out the competitiveness of CSP plus storage against other dispatchable RES technologies in cases of storage requirements exceeding six hours. Nonetheless, it should be noted that the exact value of the storage capacity threshold, beyond which CSP presents a lead over competing technologies, is significantly determined by the respective assumptions regarding the related costs and discount rates.

## 5. Conclusions

As the clean energy transition goals become more ambitious, it is evident that the contribution of energy storage to fostering the penetration of renewables will be vital. In this context, the main challenge lies in optimizing the exploitation of RES potential, while at the same time addressing the impact of additional incurred costs of storage technologies [129], especially in regard with the initial investment costs [110]. As already mentioned, although solar PVs, offshore wind and CSP plus storage present remarkable differences, the existing literature either delves into these technologies partially or investigates the features of energy storage itself.

Concerning the competitiveness of dispatchable renewables, this study did not aim to identify an optimum technology, but rather to assess the contributing parameters and accent the conditions under which the added value of CSP's dispatchable nature can really provide a competitive advantage against other comparable technologies, so as to preserve its position until a more advantageous situation emerges for its development. In this framework, PV and offshore wind combined with two different

storage options were reviewed and comparatively assessed. In this frame, the comparative analysis of the above-mentioned technologies was based on two complementary metrics; LCOE and NPV. Nevertheless, the elicited conclusions should be treated as a revealing qualitative trend—and not absolute values per se—given that the respective analysis relied on average ranges of data stemming from studies published after 2017.

More specifically, as the sensitivity analysis indicates, the impact of the investment cost on the LCOE of CSP is predominant, followed by the discount rate and the variable O&M costs. On the other hand, the influence of the fixed O&M costs was noticeably weaker. It should be pointed out, though, that CSP presented a high LCOE price, compared to PV and the first storage scenario for offshore wind. By contrast, the LCOE of PV in the first storage scenario is the lowest and depends mainly on the capacity factor and the storage investment cost, whereas the discount rate and the PV investment cost were attributed an intermediate impact. On the other hand, fixed O&M costs for both the PV and storage components affected the LCOE the least. When equipped with the storage capacity of the second scenario, the picture remains similar, besides a slight increase of the LCOE. The LCOE price of offshore wind in the first storage scenario lies between the ones achieved by PV and CSP. However, when the storage capacity is doubled, the LCOE price becomes comparable to CSP. In both cases, it is heavily influenced by the capacity factor, the wind investment cost and the discount rate. The impact of storage, fixed O&M and variable O&M costs is lower, while the impact of storage O&M fixed costs can be deemed inappreciable.

Overall, the lowest LCOE values were achieved by PV with storage in both scenarios, whereas the highest ones by CSP in the first scenario and by offshore wind in the second storage scenario. Furthermore, the LCOE range of PV with storage was by far the largest, while CSP presented the lowest range achieved in this analysis. Regarding the competitiveness of the investigated technologies, PVs prevail in both storage scenarios. As far as the comparative assets of CSP with storage are concerned, the specific technological option has the potential to outperform offshore wind with storage in cases of high storage requirements. Consequently, high RES penetration is expected to result in the emergence of beneficial niches for CSP.

The main limitation of the present study lies in the utilization of value ranges provided by recent literature. Therefore, the elicited results reflect only the current status quo in EU countries as far as the RES penetration levels are concerned. Thus, value deviations emerging in 100% RES penetration scenarios have not been explored. However, significant raises in RES penetration are expected to lead to an increase in total generation costs [130,131], given that integration costs are higher for intermittent RES [132]. In addition, the predominance of volatile energy sources in such scenarios is expected to cause price fluctuations and spikes [133]. Considering the need for greater flexibility in 100% RES scenarios, the role of energy storage is also deemed pivotal; bulk energy storage options are characterized by high costs [134,135], as well as the extensive integration of fast-response units is expected to increase electricity prices [136].

Within this context, the performance of 100% RES electricity systems will mainly depend on the ratio of the exploited electricity generation technologies, especially on the contextually prevalent one [137,138]. In regard with future research prospects, investigating the impact of competing RES technologies on 100% RES systems is recommended. In particular, the authors urge for more studies to explore the deviations caused by different technology ratios in such systems, especially in terms of costs, prices, flexibility and storage requirements. Shedding light on how these parameters are influenced will contribute to more targeted design and implementation efforts towards low-carbon electricity systems.

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