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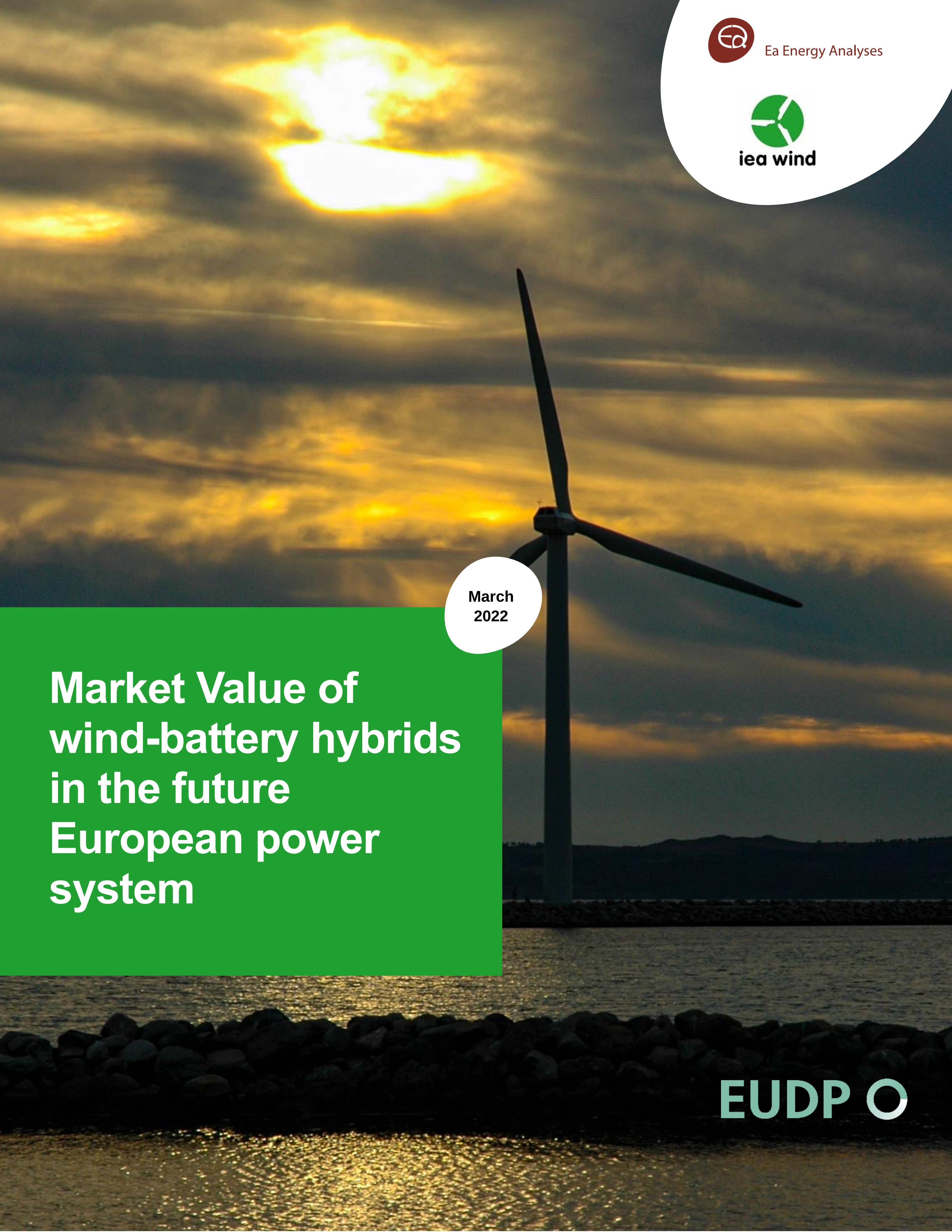

March 2022

Market Value of wind-battery hybrids in the future European power system

EUDP

Market Value of wind-battery hybrids in the future European power system

Prepared for the

IEA Wind TCP

Prepared by
Ea Energy Analyses

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List of Acronyms

CAPEX	Capital Expenditures
CF	Capacity Factor
CO2	Carbon Dioxide
EES	Electric Energy Storage
EV	Electric Vehicles
FLH	Full Load Hours
HSDC	Hyper-Scale Data Centers
HP	Heat Pumps
HWST	High Wind Speed Turbine
IEA	International Energy Agency
LCoE	Levelized Cost of Electricity
LWST	Low Wind Speed Turbines
MV	Market Value
NTC	Net Transfer Capacity
OEM	Original Equipment Manufacturer
PV	Photovoltaics
P2X	Power-to-X (where X can be hydrogen or other electrofuels)
RES	Renewable Energy Sources
SP	Specific Power
TCP	Technology Cooperation Program
VF	Value Factor
VRES	Variable Renewable Energy Sources

Executive Summary

The current development of technological cost for wind and solar, coupled with the increasing ambitions towards a fully decarbonised energy system, puts Variable Renewable Energy Sources (VRES) at the centre of the future power system. This will bring along a deep transformation of the whole system, including the need for more flexibility both on the demand side and the supply side.

Hybridisation of wind generators with storage has been one of the proposed solutions for a more flexible power supply and to sustain the revenues of wind generators, which could be jeopardised in a system with a very large wind power penetration and many hours with low prices.

The key objective of this study is to understand **to what extent can hybridising wind with battery storage increase the market value of wind in the European energy system** and to analyse **how this compares to the value obtained by other system options, such as deploying advanced wind turbines or standalone batteries.**

In order to do that, the Balmorel energy system model is used to simulate the development of the European energy system until 2050 under different future scenarios. Both capacity expansion optimisation and economic dispatch at an hourly level is simulated to reproduce the outcome of the day-ahead market.

The **key messages** that emerge from the study are the following:

1. Even in a system largely dominated by VRES, future need for storage for balancing and time-shifting services, being it standalone utility-scale batteries or a wind-hybrid setup, will largely depend on the evolution of the flexible demand, especially P2X. **Plan accordingly and consider long term profitability.**

2. Given the development of price profiles and a bit counterintuitively, hybridising wind power with storage is more profitable in solar-dominated countries. This is even more relevant as Northern Europe develops more P2X, which fits well with patterns of wind generation. **Plan for hybrid in central-south Europe rather than Northern Europe**.

3. Market value of wind is declining in a deep decarbonised future, but as more and more solar comes into the system from 2030, the drop is not that marked, and the relative revenue of wind stays higher compared to e.g. solar due to production during evenings and nights. **Hybridising wind with battery storage can increase the market value of wind by around 1-3 €/MWh on average** across countries and years (MV increase of 5% on average), but varies a lot by market (in Eastern Denmark the MV boost is 1% while in France it is 9%). Adding a 4h storage to a wind turbine performs better than adding 8 or 12h of storage, since it has the highest value boost and the lowest cost of the analysed options.

4. Even though hybridisation increases value seen in the market, the **cost of adding batteries outweigh the benefit, especially in the short-term**. Other options like using low wind speed turbines provide a similar value boost at a significant lower cost adder. Savings and synergies of co-locating batteries and turbines does not make up for this difference.

5. Day-ahead market does not seem to provide enough additional revenues to justify capital expenditure. However, **in some markets break-even is close and stacking other system services could appear to be enough to cover costs.** Whether additional revenue streams from e.g. reserve markets or reduced balancing costs can outweigh the coupling penalty is essential and is a topic that should be addressed in further studies.

6. **Standalone batteries can achieve higher revenues but building the hybrids to also allow charging from the grid can close the revenue gap**. The additional revenue for hybrid can also bring hybridisation closer to being competitive. This makes most sense in solar-dominated countries in central-south Europe, while in Northern Europe grid charging provide less additional revenues.

The overall recommendation based on the results of the study is to consider hybridising wind in countries where solar penetration is increasing with a faster pace, make sure to design the hybrids with around 4h of storage, and allow grid charging to take full advantage of the battery. If the potential wind asset is located in Northern Europe in regions with higher wind penetrations, adding storage to the turbine is less valuable and should be combined with other system services to guarantee a positive business case. Moreover, it is less relevant to design a bidirectional power flow, so grid charging can be avoided if this brings along capital savings. In a development phase, the alternative to using low wind speed turbines instead of adding storage might provide more value for the same extra capital expenditure.

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1 Introduction

1.1 Research Motivation and Previous Work

In May 2021, the International Energy Agency (IEA) released a roadmap for realising net-zero carbon dioxide (CO_2) emissions in the energy sector by 2050, aiming to achieve the global climate action goals of the Paris Agreement. The IEA stated that decarbonising the energy system will depend heavily on a power sector dominated by renewable generation, complemented by a rapid phase-out of coal, oil, and gas supply. In IEA's pathway to net-zero, almost 90% of the global electricity generation in 2050 will be generated from renewable sources, with **solar PV and wind taking up nearly 70% of total generation**. Consequently, flexibility measures, such as batteries, demand response, hydrogen-based fuels, and hydropower storage, will be required to ensure reliable supply while facilitating a carbon-free energy system [1].

Grid-level storage systems have long been indicated as one of the key flexibility providers in the future power systems. However, storage will have to compete with other potential sources of flexibility, like more flexible generators, demand-side response, and interregional transmission expansion. The future success of a specific flexibility measure will depend mainly on its cost reduction potential, which will be heavily influenced by future transmission expansion, future sector coupling, and future energy market design. Given the recent cost reductions in energy storage technologies, many studies have elaborated on the role of energy storage in the power system. In the light of the expected future increase in renewable energy shares in the European energy system, the need for utility-scale electrical energy storage has been tackled in [2]–[4]. Cebulla et al. found that the demand for electrical energy storage (EES) increases linearly in terms of power capacity and exponentially in terms of energy capacity with growing VRE shares [3].

The abundance of the variable renewable energy (VRE) resources, including wind energy, leads to **reducing electricity prices in the market during periods of high resource availability**, a phenomenon referred to as merit-order effect, with the consequence of reducing revenues of wind and solar generators (self-cannibalisation effect) [5]. With almost zero marginal cost, wind energy drives the market equilibrium towards lower prices in the generation hours of wind power plants, following the merit order effect [6]. With higher penetration rates, wind energy will continue to shift the residual load curve further to the left, causing an even larger price drop. The result is a polarisation of electricity prices, where high prices occur when wind resources are absent and low prices occur during periods of high wind availability. Consequently, wind power producers will face a lower market price in generation hours compared to the average annual price. This means that 1 MWh produced from wind power will on average be worth less than 1 MWh produces from a constant source [5].

The drop in the market value resulting from increasing VRE shares is detrimental to the competitiveness of wind energy, which is expected to play a crucial role in the decarbonisation of the power system. Consequently, this is already a critical issue in several regions today and is eventually expected to become so globally [5]. Several mitigation measures have been presented in literature, in particular the use of advanced turbine design for new wind power installations [5], [7]–[9]. This advanced turbine design, so-called low wind speed turbines (LWST), shift the generation profile towards lower wind speed hours in which market prices tend to be higher, therefore enhancing the market value of wind. However, as the market evolves and technologies develop, other measures to increase the value of wind, such as the integration of utility-scale storage, can become more favourable.

In recent years, several energy storage technologies, in particular lithium-ion (Li-ion) batteries, have achieved rapid technology advancement and cost reduction [10], leading to increasing interest in integrating utility-scale batteries into the grid. Many studies tackled the system value of utility-scale battery storage, concluding that its competitiveness relies on further cost reductions or additional revenue streams from other services than those offered solely by energy arbitrage [11]–[14]. Standalone utility-scale batteries can be integrated anywhere in the grid, they can also be co-located with wind or solar farms. The economic arguments for hybridising PV plants focus on opportunities to increase a project's market value and to reduce a project's costs.

Co-located batteries can enable wind producers to shift electricity selling from periods with low electricity prices to periods with higher prices, with perhaps even more flexibility than low wind speed turbines. To counter the merit order effect, the co-located batteries can be used to store excess wind power production. The increased volatility in wholesale prices associated with increasing levels of VRE output will make such energy arbitrage even more profitable. Several drivers of co-locating wind and battery systems have been identified, including construction savings relate to shared permitting and siting costs, potential transaction cost mitigation, better utilisation of transmission capacity, shared interconnection agreements, shared electrical and physical infrastructure, and operational synergies through co-optimisation [15]–[17]. Even though the present study focuses only on the European energy system, it is worth mentioning that hybrid systems in the U.S. (including both solar-hybrid and wind-hybrid) can benefit from policy incentives, such as a 30% investment tax credit (10% from 2022) [18].

There is an increasing interest from several unions and research laboratories in assessing the value of wind-storage hybrid power plants. Although WindEurope, National Renewable Energy Laboratory (NREL), and Lawrence Berkeley National Laboratory (LBNL) have recently addressed the benefits and market opportunities of these hybrid systems [15], [16], [19], the number of studies quantifying the impact of hybrid systems on the value of wind is still modest.

The IEA Wind TCP "Impacts of Wind Turbine Technology on the System Value of Wind in Europe" report, published in 2017, analysed the impact of different land-based wind turbine designs on grid integration and related system value and cost. The study addressed the potential benefits of wind turbine technologies that feature higher capacity factors, and it aimed to quantify the effects of different land-based wind turbine designs in the context of a projection of the European power system to 2030. The study analysed different scenarios for the future deployment of land-based wind turbines, with increasing hub heights and decreasing specific power (SP) ratings.[1]

It was found that when deploying turbines with higher hub heights and lower specific power ratings, the value factor of wind power increases significantly and by 2030, the market value (MV)

[1] Specific power (SP) is the ratio between the capacity rating and the rotor area. At equal capacity rating, lower specific power is achieved by increasing the diameter of the rotor.

of wind power in the wholesale market can be as much as 4.3 €/MWh (+10%) higher when using high-capacity-factor turbines relative to the lower capacity factor turbines.

When evaluating the economics of wind power installations, both cost and value perspectives should be considered. This is relevant for wind power developers and turbine manufacturers, as well as for policymakers designing renewable energy support schemes. The study also showed the importance of considering the technological development in land-based wind power when analysing the development of power systems and its potential contribution to cost-effective system development.

To expand on the previous work within the IEA Wind Task 26, the present study extends the time horizon to 2050 to look at a deep decarbonisation future, while focusing on analysing what could be the role of storage in connection with large wind deployment scenarios, whether hybridising wind generators with storage is economically viable and how it compares to advanced wind turbine design.

1.2 Research Questions

The study aims at answering the following main research questions:

To what extent can hybridising wind with battery storage increase the market value of wind in the European energy system?
How does this compare to the value obtained by other system options, such as deploying advanced wind turbines or standalone batteries?

Under the main research questions the following sub-questions have been tackled:

- What is the role of energy storage in the future European system?
- How does the potential value of hybrids change in solar-dominated vs wind-dominated countries across Europe?
- How does the market value of hybrids relate to that of independently sited standalone systems?

Thereby, the study contributes to three areas related to the integration of VRE in the European energy system: 1) estimating the development of the market value of wind towards 2050, 2) evaluating the impact of hybridisation on the market value of wind, and 3) determining the system value of hybrid configurations compared to independently sited installations.

1.3 Analysis Methodology and Focus

In this study, the Balmorel energy system model is used to simulate the development of the European energy system under different future scenarios. Balmorel is an optimisation model implemented as a linear programming optimisation problem, coded in GAMS (General Algebraic Modelling System), that can perform **day-ahead market simulations** with both optimised investments in new technologies (investment planning simulations), and economic dispatch simulations of the day-ahead market, where operation and market equilibrium is simulated at an hourly level. Balmorel is a bottom-up, partial equilibrium energy system optimisation model, with a detailed representation of the electricity and heat system. It can model multiple countries and it can simulate the day-ahead market with an hourly resolution, which is essential when considering systems with VRE and storage.

By 2050, the EU's climate neutrality target is assumed to be met, hence the time horizon for this study covers the **period from 2020 to 2050**, to look at how the market value of wind will evolve with increasing wind penetration and other system developments related to the decarbonisation of the energy sector.

The **geographical scope for this study includes nearly all of Europe**, with only the Balkan countries being excluded. The countries included in the simulations are Austria, Belgium, Czech Republic, Denmark, Estonia, Finland, France, Germany, Italy, Latvia, Lithuania, Luxembourg, Netherlands, Norway, Poland, Spain, Sweden, Switzerland, and the UK. From now on, the European energy system will be defined based on the above-mentioned countries.

Due to large differences in system characteristics and VRE generation patterns across Europe, the market value of wind and storage is expected to vary significantly from one country to another and similarly from one region to another. To capture these differences, analysed configurations have been allocated in countries with a distinctive energy mix. Figure 1 shows the map of Europe and elaborates on the countries and the regions where analysed configurations have been implemented. The countries in focus include Spain, France, the UK, Southwestern Norway and Southern Sweden, Denmark, and Germany.

The regions were selected to represent systems dominated by hydro (Norway), solar (Spain), systems with a fair share of both wind and solar (France, the UK, and Southern Sweden), wind-dominated systems (Eastern and Western Denmark and North-western Germany), and thermal-dominated systems (Southern Germany). As shown in Figure 1, nine different locations altogether have been assessed.

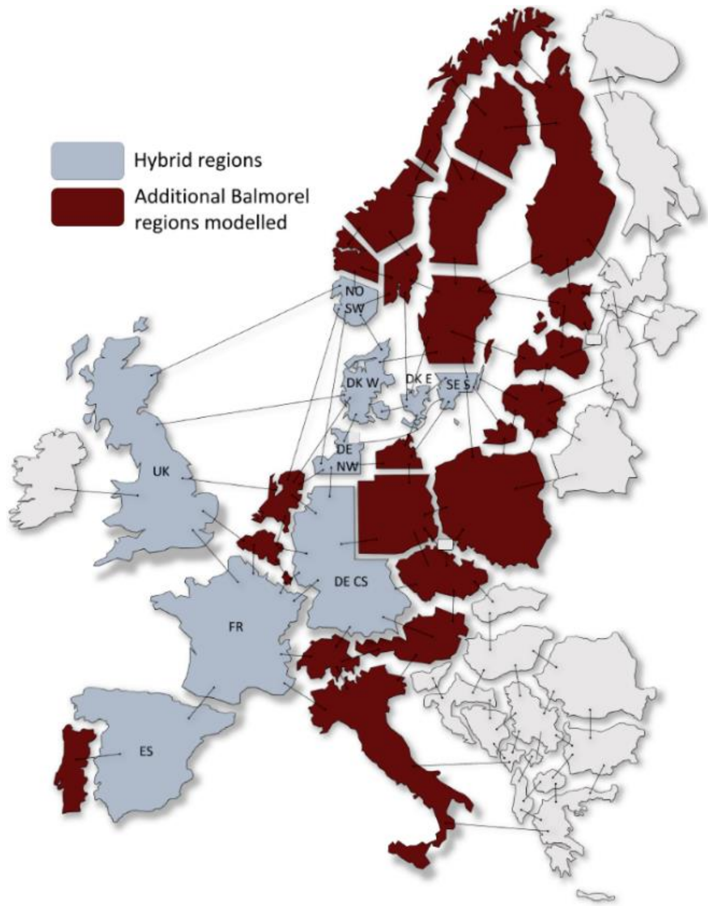

Figure 1. Map of the Balmorel regions where hybrid configurations have been implemented

Our **analysis is limited to the day-ahead market**, neglecting both the intra-day market, the balancing market, and forward and futures contracts. Consequently, the benefits and costs incurred in these markets are not considered. In our study, the balancing market has not been modelled, hence the value that batteries can gain from providing energy or capacity balancing services have not been quantified. Our study considers each region as an electrical "copper plate", therefore neither distributional power flows, congestions or bottlenecks are considered within the regions. Consequently, issues such as voltage and angle stability, as well as primary and secondary reserve management were not considered. Therefore, the value that energy storage units can provide in terms of ancillary services has not been quantified.

As each region is considered as an electrical "copper plate", the effect of **specific location hybrid configurations and standalone systems is not captured**. This reflects how the day-ahead market is structured in Europe and is in line with the scope of the analysis (sole focus on day-ahead market). However, standalone batteries would optimally be placed near congested areas and would potentially be able to provide additional grid services where most needed. Conversely, co-locating batteries with wind turbines, often installed in more remote areas, reduces the options to place storage optimally in the grid (as happens for stand-alone storage).

2 Modelled Scenarios and Assessment Framework

2.1 Scenario Setup

To begin, a reference time-aggregated investment optimisation run was performed, where generation and transmission capacity are optimised to satisfy energy demand and meet policy targets for long-term development of the power system at the lowest cost. This scenario is used to “set the scene” in terms of the optimal development of generation, transmission, and flexibility measures. This simulation for instance calculates the amount of storage needed to balance demand and supply, as well as the evolution of the power mixes in all countries and the locations of new wind and solar generators based on a least-cost approach.

Given the value of wind and storage highly depend on hourly operation, a set of hourly (day-ahead) optimisation runs for various technology scenarios are simulated, using results from the reference scenario as input. These scenarios can be defined as “marginal” for two reasons. Firstly, the evaluation of the revenues and market value of the various technologies are done in the system defined by the reference scenario. Secondly, the capacity of each technology added to the system is very small (i.e. marginal) compared to the rest of the system, so it will not affect dispatch and power price creation.

Technology scenarios have been designed considering the focus of the analysis, i.e. evaluating the value of hybrid wind plants compared to the value of advanced wind turbines (LWST) or standalone batteries.

For example, standalone batteries are evaluated based on three different scenarios, corresponding to Energy-to-Power ratios (E/P ratios[2]) of 4, 8, and 12 hours. E/P ratios were selected based on the discharge durations that Li-ion batteries are expected to reach in the future, allowing more energy to be stored and shifted in time.

2.2 Scenarios run

Three main set-ups have been developed to compare hybrid systems to standalone turbines:

1. The first scenario is a case in which a HWST is installed (specific power 300-270 W/m^2 between 2020 and 2050)
2. The second scenario represents the use of LWST (more advanced wind turbines, specific power 225-175 W/m^2 between 2020 and 2050)
3. The third set-up includes three scenarios (all with hybrid system configuration based on a HWST) representing different E/P ratios of 4, 8, and 12 hours, while capacity ratio between the turbine and the battery is fixed to 1/3 (corresponding to a turbine capacity of 3 MW and a battery power capacity of 1 MW).

[2] E/P ratio is the ratio between the energy storage capacity of a battery in MWh and the charge/discharge capacity in MW (assumed equal). It is expressed in hours (h).

In total, eight scenarios have been simulated for each of the nine locations across Europe (see Figure 2). For further elaboration on the turbine configurations, the battery configurations, and the cost assumptions used in the analysis, see Appendix I and II.

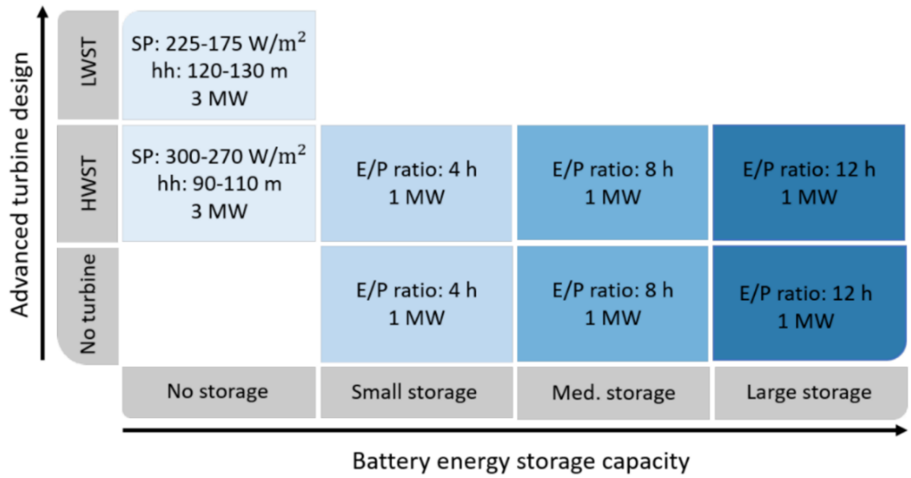

Figure 2. Overview of "marginal" technology scenarios simulated.

The key difference between how independent sited wind turbine and standalone batteries are modelled versus hybrid wind-battery systems is shown in Figure 3. The simulated hybrid battery is assumed to only be allowed to charge from the co-located wind turbine and not directly from the grid to differentiate it from a standalone battery located at the same region (charging from the grid). This type of operation could be the results of e.g. grid tariffs for electricity use for battery charging. In practice the sole option for charging the battery from the co-located wind turbine would likely not be the optimal setup.

In terms of the evaluation of revenues, sales are calculated based on wind generation profiles for standalone wind turbines. Sales of standalone batteries correspond to the difference between cost of charging (from wind turbines and any other technology in the system) and revenue of discharging. As hybrid wind-battery systems are not allowed to charge from the grid, sales are calculated by the final output profile given by both the wind turbine and the battery, rather than for each independent flow as for the standalone systems.

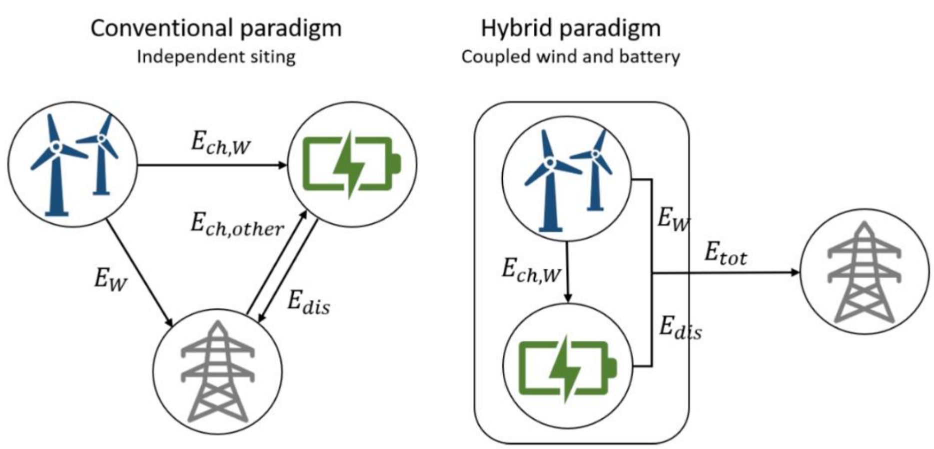

Figure 3. Description of independent sited system versus hybrid system. E = electricity flow (generation/charge/discharge)

On top of these key scenarios, two sensitivity analyses are performed:

- ***Highly flexible P2X:*** this sensitivity on the reference scenario is used to understand the role of utility-scale battery storage in the European power system in case hydrogen production becomes largely flexible.
- ***Grid charging hybrid****:* this set of sensitivities, simulated for the hybrid scenarios, allow the storage in the hybrid system to charge not only from the co-located turbine, but also from the grid.

2.3 Assessment Framework

To analyse the impact of the hybridisation of wind and to compare value provided by different configurations, four metrics have been used. The first two metrics, "Market Value (MV)" and "Levelized Cost of Electricity/Storage (LCOE/LCOS)", are used to evaluate how the value and cost of hybrid systems relate to high and low wind speed turbines across different markets in Europe. They also serve the purpose of defining the most cost-effective hybrid configuration, considering different energy-to-power (E/P) ratios. The third metric, "Value/Cost Adder", aims to quantify the additional value/cost of either adding the most favourable hybrid battery to the HWST or replacing the turbine with a LWST. Comparing the value adder to the cost adder illustrates the competitiveness of the different configurations. Lastly, a fourth metric was developed to assess the relative system value of hybrids compared to independently sited wind turbines and batteries, referred to as the "Coupling Penalty".

The Market Value of wind is expressed as the ratio between the revenue of wind power in the market and the total wind production (including curtailed energy) for a specific time span. To make accurate comparisons between different regions, it is convenient to study the relative market value, rather than the absolute market value. This is referred to as the Value Factor (VF) and is defined as the ratio between the market value in a certain market zone and the time-weighted average electricity price of that zone.

The value/cost adder can either be calculated for the hybrid plant or the LWST, given as the difference in market value (or levelized cost of electricity) relative to the standalone HWST.

$$Value\ adder = MW_{Hybrid/LWST} - MW_{HWST}$$

$$Cost\ adder = LCOE_{Hybrid/LWST} - LCOE_{HWST}$$

The competitiveness of hybrid systems and LWSTs can be evaluated by comparing the value adder to the cost adder. With a positive difference, the systems would provide higher monetary gain relative to the additional cost they impose. The coupling penalty aims to quantify the value loss associated with hybridisation compared to siting wind turbines and batteries independently. It is calculated by subtracting the market value of the hybrid plant from the market value of the independent wind turbine and battery.

$$Coupling\ penalty = MV_{HWST} + MW_{Battery} - MW_{Hybrid}$$

3 Key Results of the Analysis

The overall system results and economic evaluation of scenarios are based on the entire modelled area, as indicated in section 1.3. The results section starts with key messages regarding the role of energy storage in the future European power system, followed by a deep dive into the value of hybrid-wind compared to a standalone battery storage system and more advanced wind turbines.

3.1 Wind and solar will play a cardinal role in the future European power system, representing around 80% of total generation

The European energy system is progressing towards being highly VRE-dominated by 2050. As shown in Figure 4 and Table 1, the RES share is reaching 93% in 2050, of which VRES constitute 83% of total generation, which is in line with other studies on deep decarbonisation of the European system. Wind energy is estimated to account for more than 50% of the electricity generation in 2050 (30% onshore wind and 20% offshore wind), while solar shares are expected to increase from 4% in 2020 to 32% in 2050. Despite the lower contribution to the total generation, due to lower capacity factors, solar installed capacity will be the largest among all energy sources in the medium-long term. While still playing a role in 2050, nuclear will be gradually decommissioned, along with the almost-complete decommissioning of fossil fuel plants such as coal, lignite, and oil.

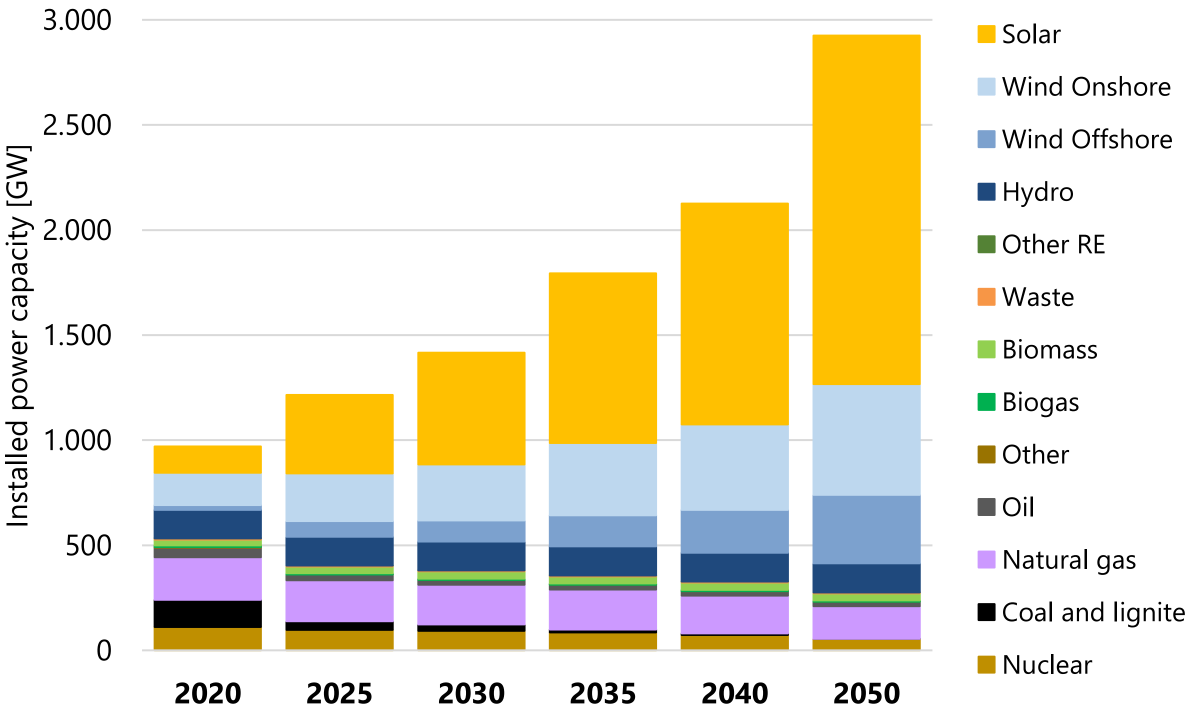

Figure 4. Installed power capacity development for the modelled European system

Table 1. Percentage of VRES, other RES, nuclear and non-RES from total generation from 2020 to 2050, with VRES split into solar and wind shares.

% total generation	2020	2030	2040	2050
VRES	**19%**	**53%**	**74%**	**83%**
- *Solar*	*4%*	*18%*	*27%*	*32%*
- *Wind*	*15%*	*35%*	*47%*	*51%*
Hydro, biomass	20%	17%	13%	10%
Nuclear	23%	15%	9%	5%
Non-RES	38%	15%	4%	2%

3.2 Battery storage can act as an important flexibility measure, especially in solar-dominated countries

Battery storage's projected cost drop, coupled with the increase in VRE generation and the decommissioning of dispatchable generators, results in large utility-scale storage capacity deployment in Europe. The installed capacity, which is relatively low in 2030 (4 GW), grows to 140 GW in 2050, following the aforementioned steep increase in VRE generation. This large storage capacity will act as an important flexibility measure, helping balance demand and supply alongside other flexibility measures, such as hydropower (reservoirs and pumped hydro) and demand-side flexibility providers, such as P2X, smart EV charging, smart use of heat pumps and other domestic and industrial sources.

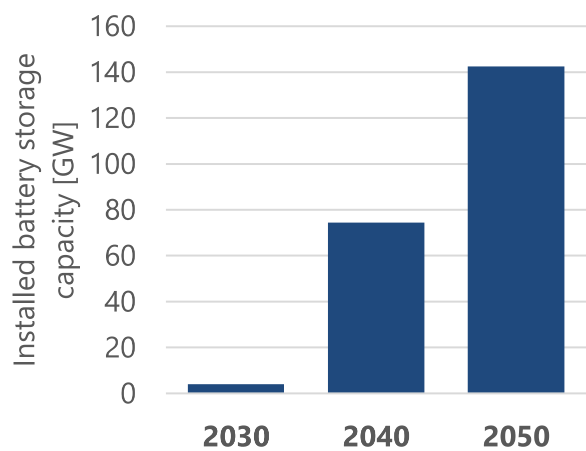

Figure 5. Development of installed capacity of grid-level battery storage in modelled area.

The largest deployment of batteries is seen in countries with high share of solar generation in their energy mix. Figure 6 shows the accumulated installed battery power capacity (GW) with respect to solar and wind generation shares in 2050 for selected countries. Generally speaking, the larger the generation of solar, the more utility-scale battery storage is installed in a country. It is the case, for example, in countries like Spain and France.

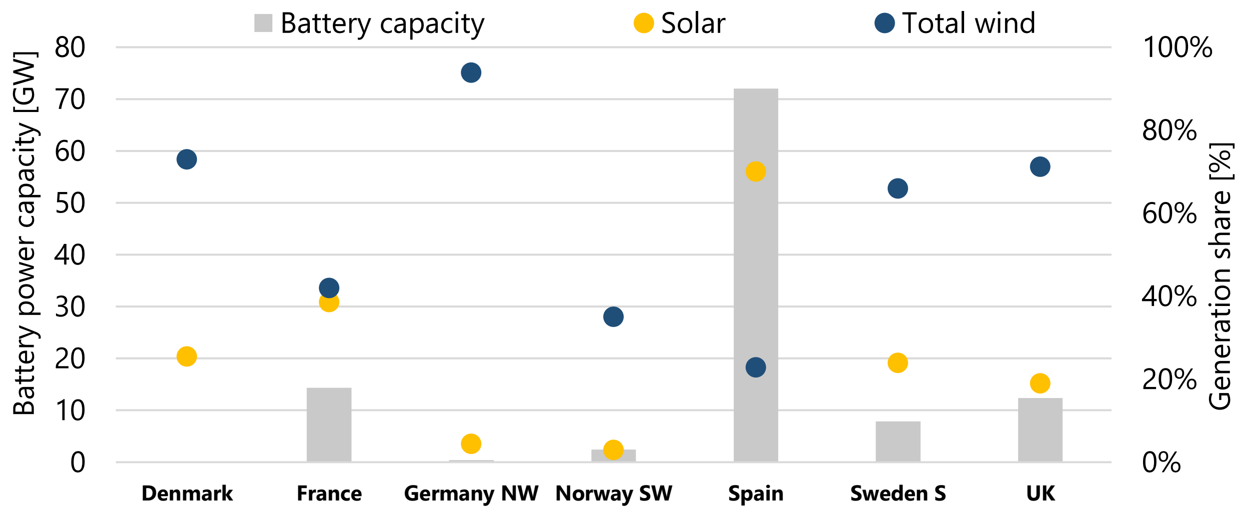

Figure 6. Battery power capacity with respect to solar and wind generation shares in 2050.

One of the key reasons for this development can be found by looking at electricity prices in selected European countries. Towards 2050, electricity prices are expected to be more volatile, often following the “duck curve” as solar share increases in most countries, notably Spain and France (see Figure 7). The concentration of solar power generation around the central part of the day, often beyond power demand level, depresses electricity prices, creating a predictable price variation and increasing price difference between the bottom and the peak, which is beneficial for storage.

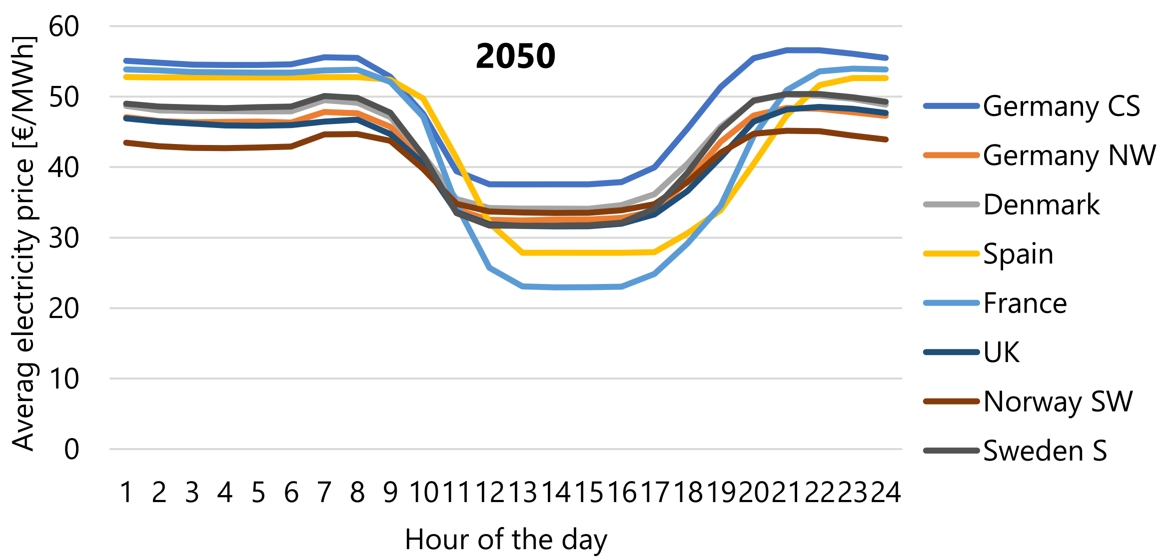

Figure 7. Average daily electricity price in 2050 for selected countries

This depression of electricity prices around midday follows the increase in solar power deployment over time, being already marked in 2030, but further increasing towards 2050 (Figure 8). This also results in increased periods where the electricity price is zero (or close to zero). Figure 9 shows, for example, that in France, hours with prices below 10 €/MWh goes from around 360 in 2030 to 1730 in 2050.

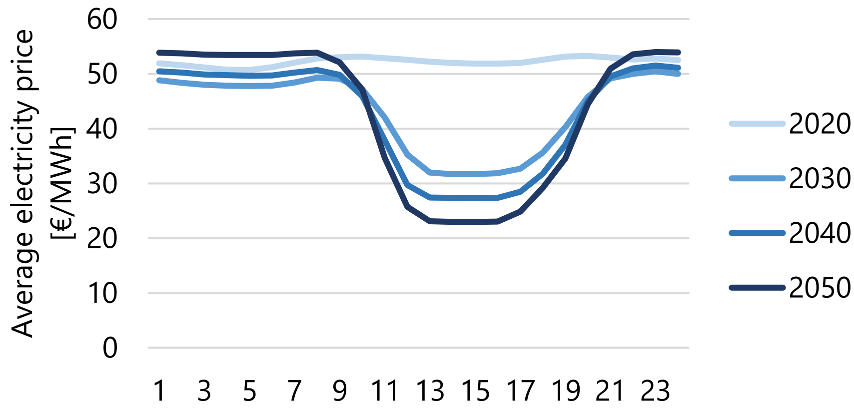

Figure 8. Daily average electricity price for France over the time horizon

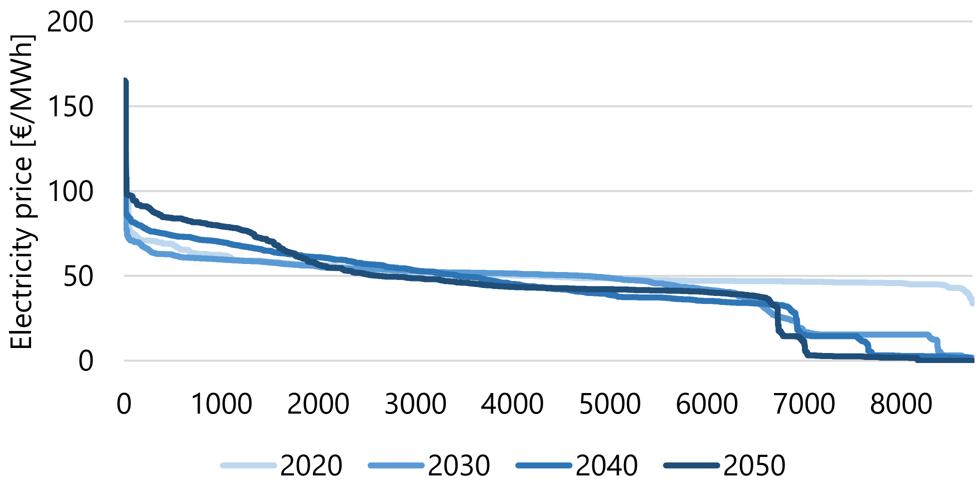

Figure 9. Daily average electricity price for France over the time horizon

The predictable daily generation pattern enables an increased number of storage cycles and allows battery storage to charge almost daily at very low prices and discharge in the night at higher prices, ultimately increasing storage revenues.

Figure 10 and Figure 11 respectively shows that battery market value increases with both increased solar generation shares and increased price volatility (the price standard deviation[3] is used as an indicator for the price volatility).

[3] Standard deviation is the statistical measure of market volatility, measuring how widely prices are dispersed from the average price. If prices trade in a narrow value range, the standard deviation will return a low value that indicates low volatility. Conversely, if prices swing more, then standard deviation returns a high value that indicates high volatility.

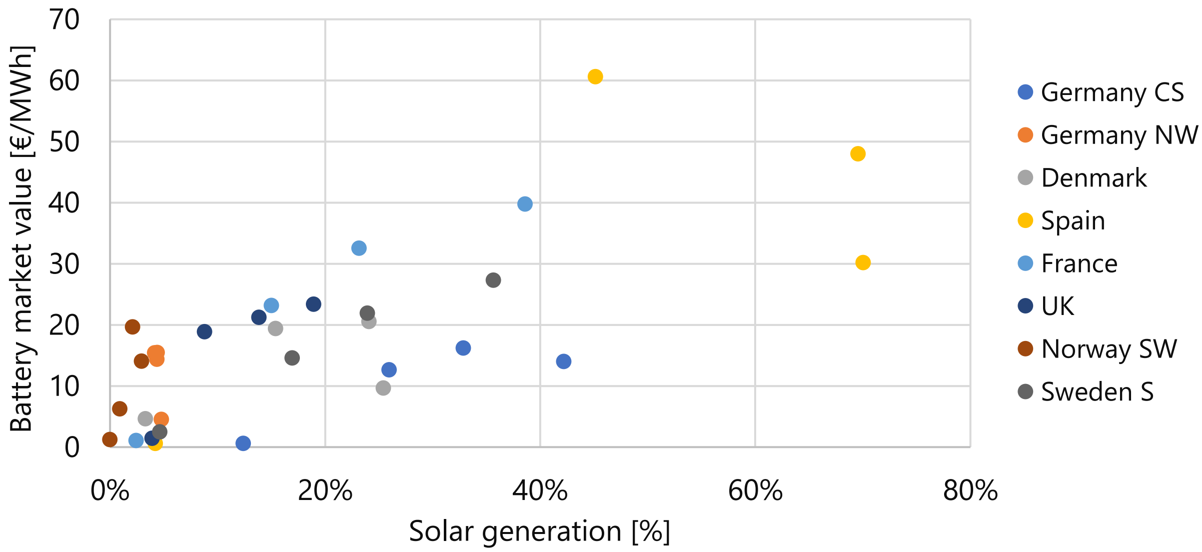

Figure 10. Battery market value in correlation with solar generation shares. Each point represents a decade from 2020 to 2050, given for each region

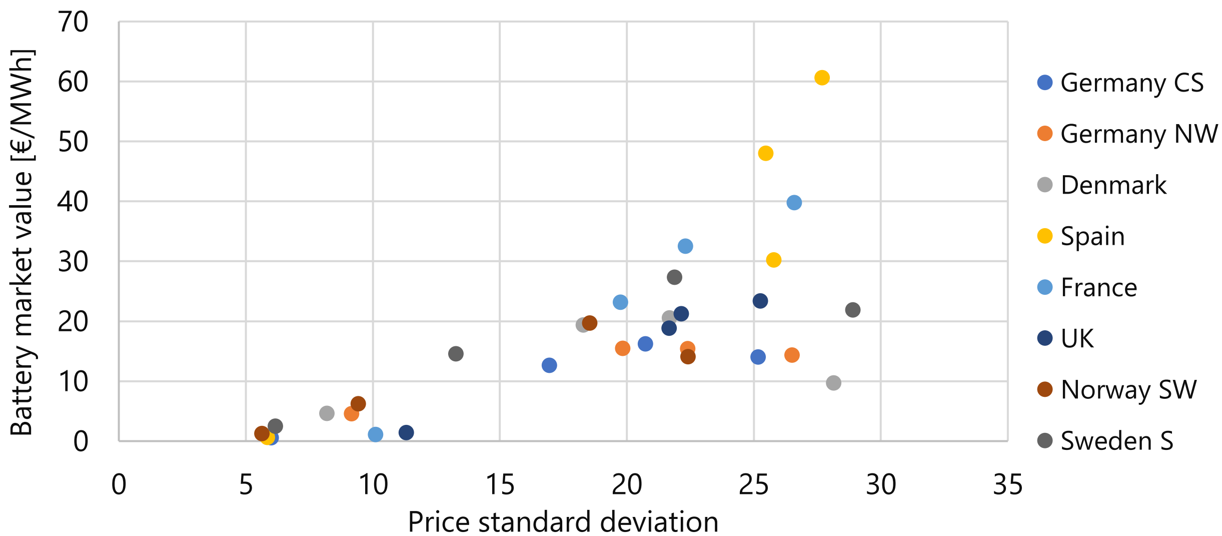

Figure 11. Battery market value in correlation with price volatility (price standard deviation). Each point represents a decade from 2020 to 2050, given for each region

3.3 Widespread penetration of flexible P2X can hinder battery storage development, especially in wind-dominated countries

As anticipated, besides utility-scale battery storage, other flexibility measures will contribute to balancing the supply and demand, mostly thanks to the development of more flexible demand.

To decarbonise the entire energy system by 2050, it is expected that the demand for electricity dedicated to hydrogen production will increase exponentially in the next 30 years, representing around 34% of the total power demand in 2050 (2,000 TWh). We collectively refer this portion of power demand as "P2X" where X can represent hydrogen directly used or converted to other electrofuels via synthesis with or without carbon. The production of hydrogen for P2X is done through electrolysis via an electrolyser that uses electricity to convert water into hydrogen (and oxygen).

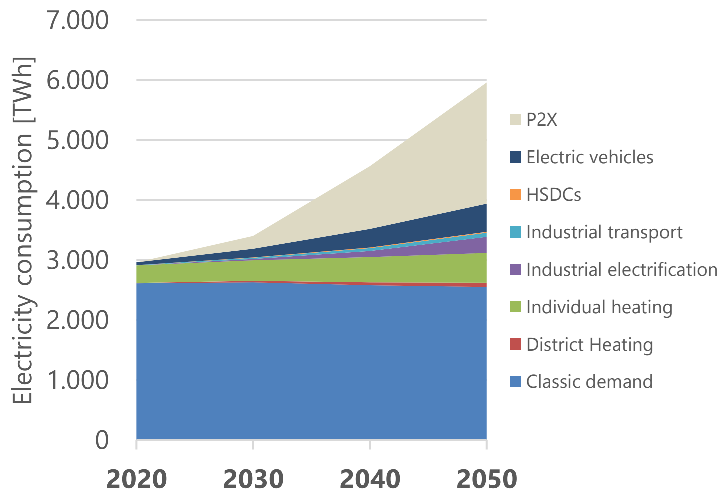

Figure 12. Evolution of power demand in Europe. P2X largely increases towards 2050.

The future utilisation of electrolysers can be more or less flexible: if utilised flexibly, an electrolyser can contribute to the balancing of supply and demand, for example by increasing the demand when large amounts of wind and solar are available. How flexibly an electrolyser can function will ultimately depend on a combination of factors, such as technological limitations (e.g., on ramping, minimum loads, start-up time), economic incentives, and timing requirements from the demand side (i.e., when is hydrogen needed for a downstream plant creating electrofuels). Hydrogen storage can partly decouple these dynamics and allow to concentrate hydrogen production when more favourable for the power system, however, the round-trip efficiency of going from electricity to hydrogen and back to electricity is inferior to battery storage

In the simulations carried out, allowing the model to produce hydrogen more flexibly, by equipping it with hydrogen storage, leads to P2X technologies becoming the dominant source of flexibility by 2050. In this sensitivity case (*Highly flexible P2X*), battery storage will play a more limited role across Europe. Figure 13 shows the installed capacity of battery storage in focus countries in the reference scenario and in the *Highly flexible P2X* scenario. With advanced flexibility in electrolysers, the need for utility-scale battery storage, and thus its installed capacity in Europe, is reduced by around 33% from 141 GW to 95 GW in 2050.

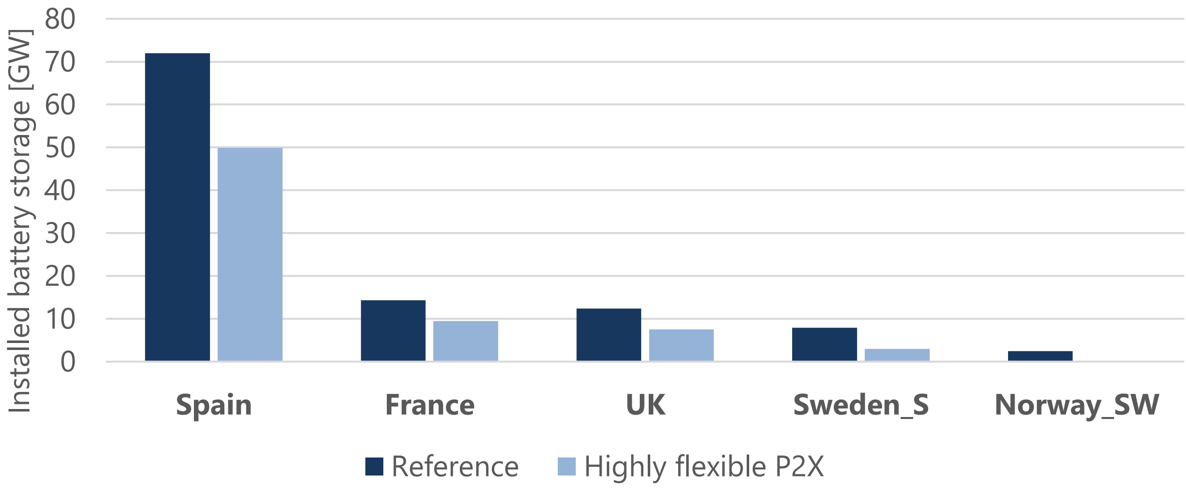

Figure 13. Installed capacity of battery storage under widespread and limited penetration of P2X.
Note: Germany and Denmark have installed capacities below 1 GW and are therefore not displayed.

Under this scenario, battery storage will be mainly present in countries with significant solar generation shares, while it will have an almost negligible role in wind-dominated countries, especially in countries with strong cross-national interconnections and more favourable flexibility measures.

To understand the sheer magnitude of the contribution of hydrogen to balance the supply and demand in the *Highly flexible P2X* scenario, the original power demand curve (inflexible) and the actual demand curve (flexible), after all flexibility measures are considered, are shown for an illustrative week in 2050 for Denmark West and France. This can be interpreted as a "flexibility dispatch", in which the demand-side flexibility offered by classic demand, P2X, industrial heating and EVs, as well as flexibility provided by utility-scale battery storage is included. Solid areas represent an increase in demand, mostly in correspondence to high VRES generation and low prices, while dashed areas illustrate situations in which the demand is reduced (higher price, lack of supply). Looking at both graphs it can be noted that P2X is the dominating source of flexibility in both solar- and wind-dominated countries. This is due to both the total size of P2X demand (largest of the demand contributors after classical demand) and the fact that electrolysers have a relatively high degree of flexibility compared to e.g. EVs and HPs, which need to follow certain limitations. With P2X providing all this flexibility and demand-supply balancing, the role for grid-level storage, including in the form of wind-storage hybrids, in the future European power system could be limited.

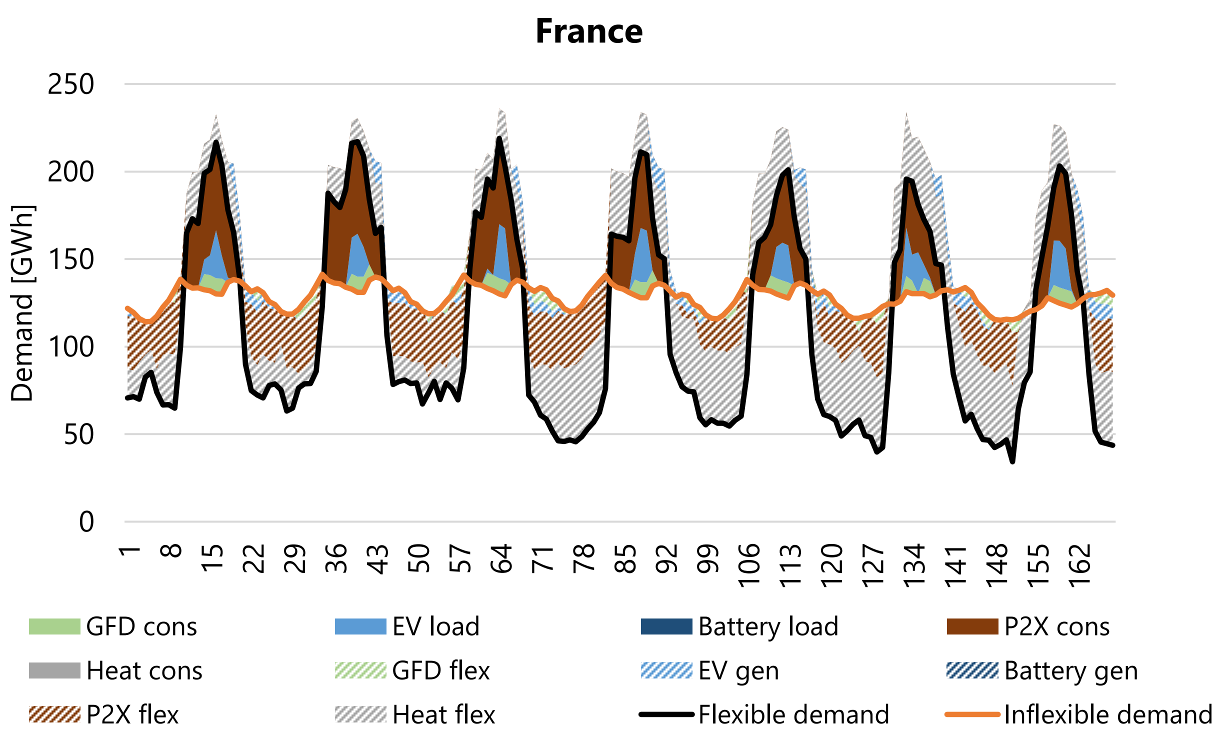

Figure 14. Inflexible and flexible demand with a breakdown of flexibility contribution accounting for the difference between the two demand curves in France (an illustrative week in 2050 under *Highly flexible P2X*)

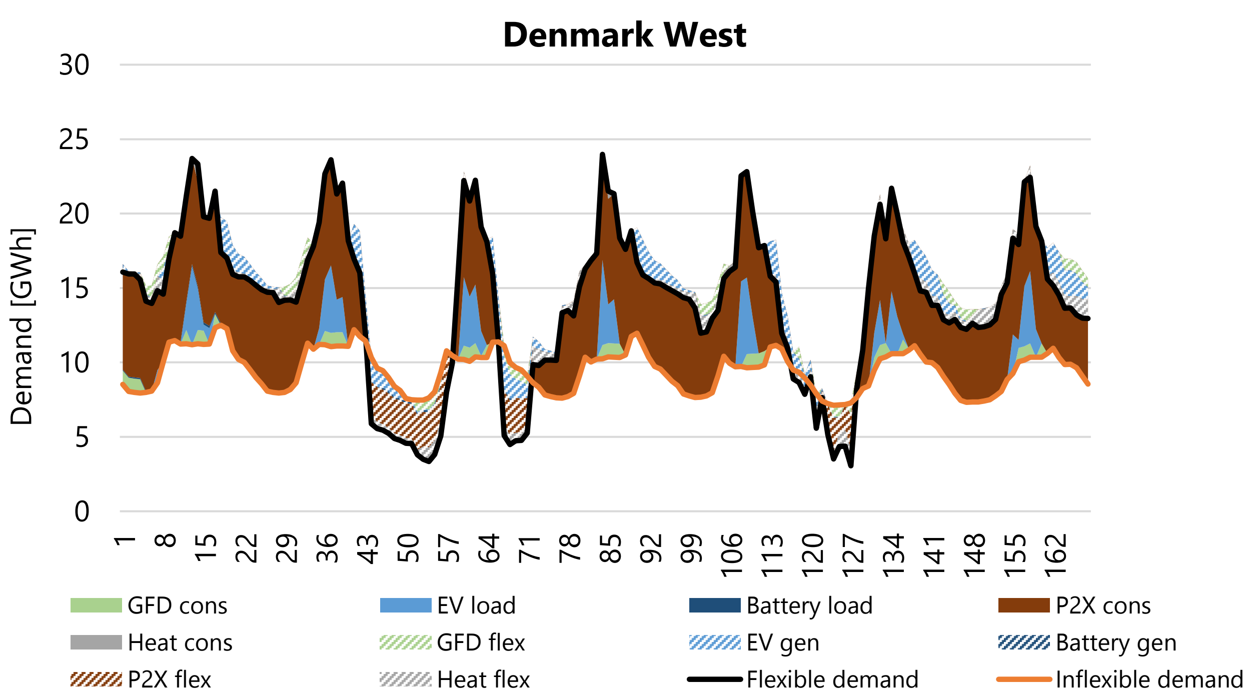

Figure 15. Inflexible and flexible demand with a breakdown of flexibility contribution accounting for the difference between the two demand curves in Denmark West (an illustrative week in 2050 under *Highly flexible P2X*)

3.4 Market value of wind declines in a high VRE system, but hybridizing wind can help boosting it

As described in the introduction, the development of the market value of wind with higher wind penetration has been explored in many studies. All studies point to a reduction of market value of wind as penetration increases, due to the self-cannibalization effect. Our previous work on low wind speed turbines [7] focused on the European system until 2030 underlining the same trend. In this study, the timeline is expanded towards 2050 and, while in most countries and regions the decreasing trend is still present, it can be noted that the value drop is less significant than in the decade 2020-2030 (Figure 16).

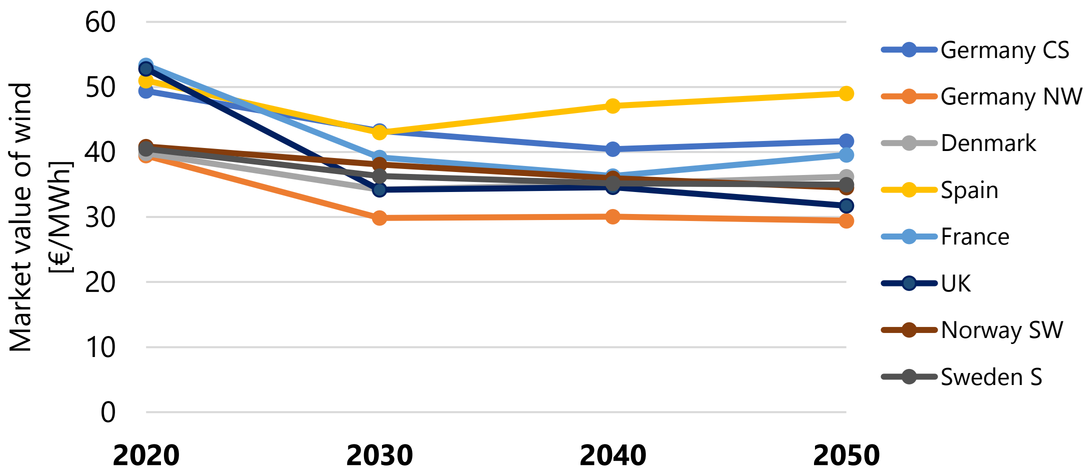

Figure 16. Market value of wind development towards 2050.

The mitigation of the market value drop beyond 2030 is due to a combination of factors such as increase in interconnection capacity, development of more flexible demand in terms of EV charging, heat pump use, end-demand flexibility, and P2X flexibility. This points to a power system development that can absorb a much larger VRES capacity without jeopardizing the revenues of RE generators.

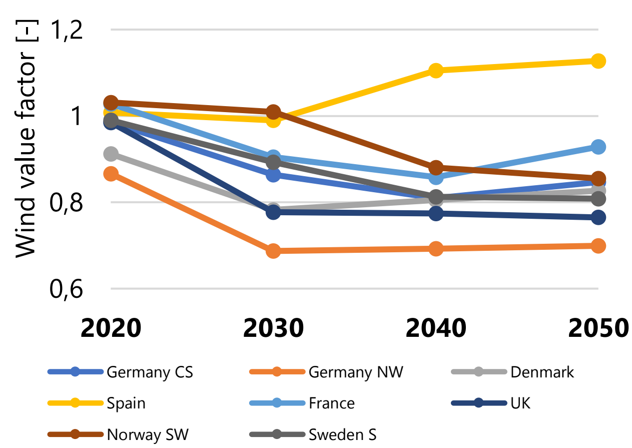

Figure 17. Wind value factor development.

On the other hand, one interesting factor is that the increase in the penetration of solar power depresses the prices in the central part of the day and slightly increases them during evening/nights. This has an indirect impact on wind since it tends to produce in hours where the price is not depressed. This helps mitigate the absolute market value drop and boost the wind value factors (market value relative to average electricity prices), as is shown in Figure 17.

The hybridisation of wind turbines with storage can increase the value of wind experienced by wind power. Figure 20 shows the increase in value in selected countries for the various battery configurations.

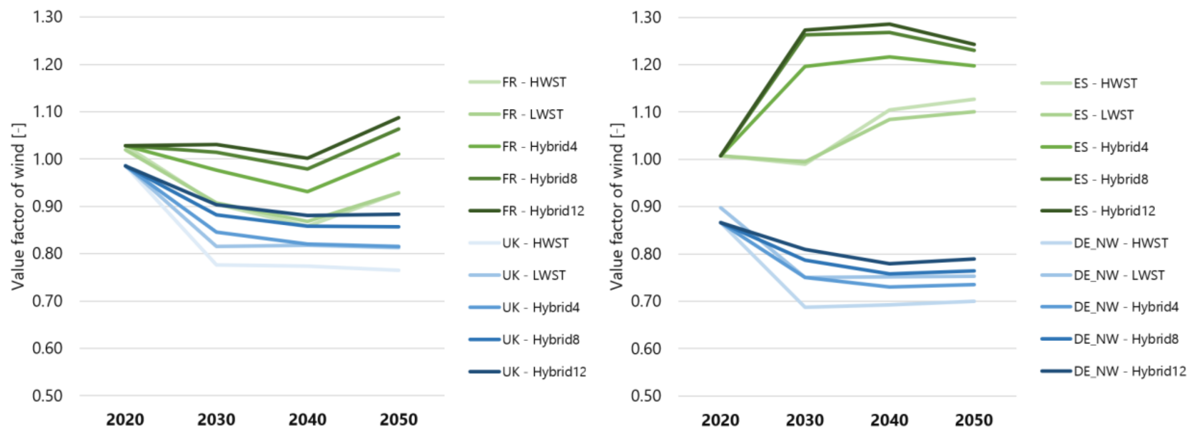

Figure 18. Value factor of HWST wind, LWST wind and hybrid with storage sizes (4h, 8h, 12h) in selected countries.

Value of wind is increased more in countries like Spain and France than in Germany and the UK, in which LWST achieve almost the same results as adding a 4h battery. Overall, the largest boost occurs going from HWST to 4h hybrid, while 8h and 12h batteries have lower additional value increase. However, as shown in Figure 19, adding energy storage capacity is relatively expensive and does not pay off in any of the 8h and 12h cases, in all regions simulated, due to the high cost of adding energy storage capacity. For hybrids, it is therefore more cost-effective to install a 4h battery than larger sizes.

For standalone batteries (that can charge from the grid) it pays off in the longer term (towards 2050) to add more than 4h storage, and larger storages (12h) make sense in wind-dominated countries.

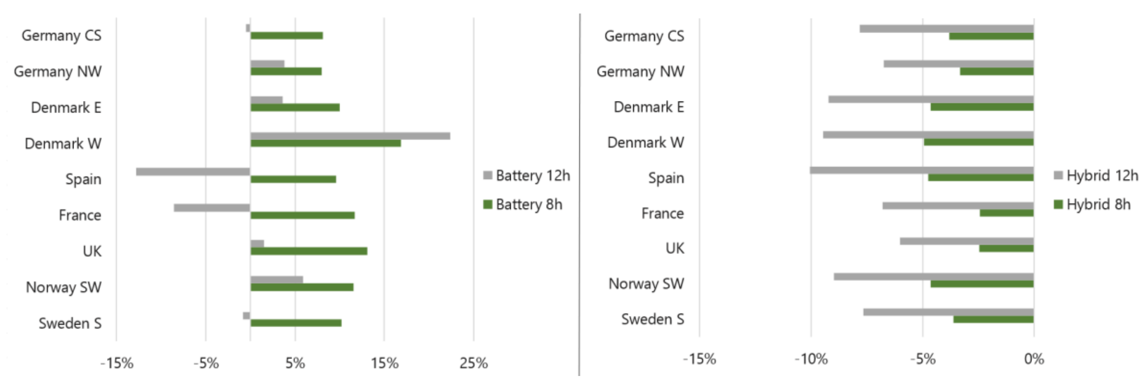

Figure 19. Percentage difference in benefit-cost ratio[4] of the 8h and 12h configuration compared to the 4h configuration for standalone batteries (left) and hybrids (right) in 2050.

[4] Used to determine the most cost-effective configuration, considering the monetary gain relative to the cost. It is calculated as the ratio between MV and LCOE.

Focusing on the 4h hybrid battery configuration, which is the most optimal given the cost-benefit ratio, value adders across regions can be seen in Figure 20. The highest value boost is achieved in 2030, when a large drop in the market value of wind is experienced and the system is not largely flexible yet. On the other hand, the value adder towards 2050 is reduced, as a more flexible system and larger power demand materialises and the need for adding storage to wind reduces.

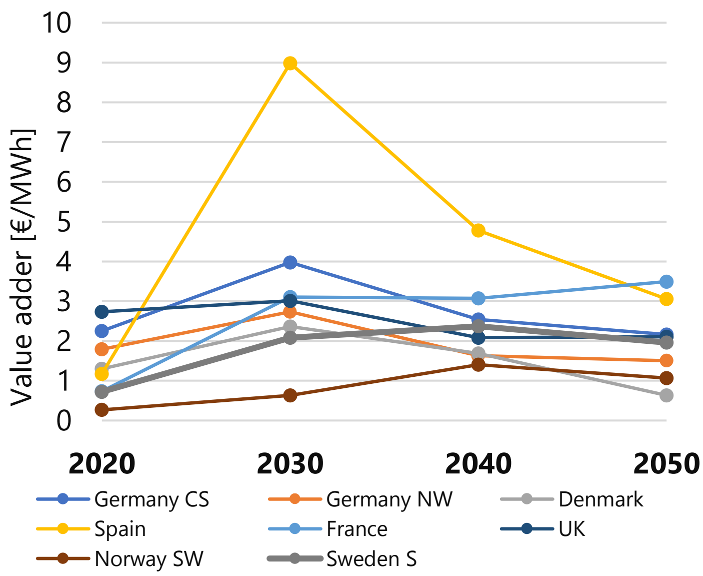

Figure 20. Value adder of 4h hybrids.

The smallest value adders are observed in Southwestern Norway, Denmark, and north-western Germany, while the largest adders are in Spain and France. From a value factor perspective, the mitigating effect of hybrids is largest in solar dominated countries (e.g., Spain and France). In 2030 in Spain a very large value of 9 €/MWh materialises, due to large solar deployment.

Value adders for the 4h hybrid are mostly in the range of 1-3 €/MWh in the period 2030-2050, corresponding to an average market value boost of 5% compared to a HWST (ranging from +1% to +9% in the regions analysed).

3.5 Hybridization of wind with storage present a better use case in solar-dominated countries

The ultimate role of storage, whether as a standalone or in a wind-storage hybrid, is to move energy from low price to high price. In the standalone battery, it is the energy bought at cheap price that is moved in time, while in a wind-storage hybrid (without grid charging, as the one we are simulating) it is the produced wind energy that can be stored and used at a later time. Towards 2050, many countries will have low prices occurring in correspondence with high solar generation, therefore wind hybrids are better in solar dominated countries.

As Figure 21 is showing, in a wind-dominated country like Denmark, due to the more constant nature of wind availability with longer periods of surplus and calm periods, the average daily battery behaviour includes both charging and discharging for all hours, for both standalone batteries and for the wind-storage hybrid. Meanwhile in France, the hybrid battery behaviour follows the daily pattern of solar generation (and prices), moving as much as possible of the wind generation from the central part of the day to the night. The possibility of charging directly from the grid (notably cheap solar generation), as opposed to simply moving around wind generation, brings higher value to the standalone battery in France. In short, these results show that compared to France, Denmark experiences lower average utilisation of both standalone and hybrid batteries.

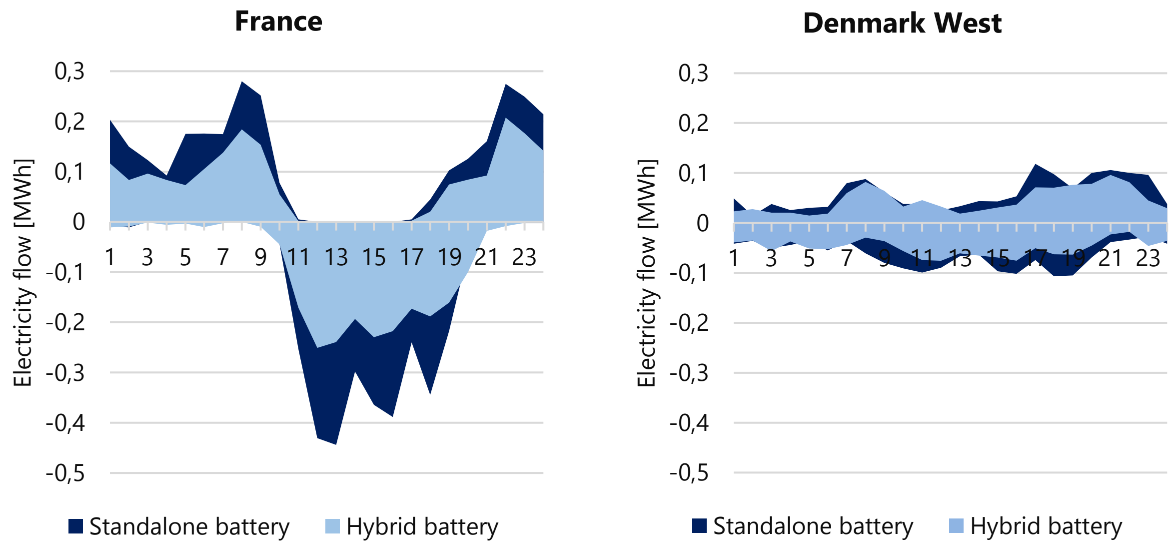

Figure 21. Average daily operation of 4h hybrid wind-battery and standalone battery for France and Western Denmark in 2050

Adding to this is the fact that having longer periods of low or surplus wind generation and less of a daily predictable pattern, the percentage of the year in which the battery is either fully charged or empty is higher in wind-dominated countries, leading to lower arbitrage opportunities and utilisation level of the battery. Table 2 shows that the regions with the highest wind generation share (e.g., Germany, Norway, and Denmark) have the lowest battery utilisation level, measured in terms of full cycles[5], while the regions with the highest solar generation share (e.g. Spain and France) have a higher battery utilisation level.

Table 2. Percentage of the year in which the State of Charge (SoC) is equal to 0 or 1 for each region, along with the number of full load cycles. Regions are ordered according to increasing full load cycles.

	Norway SW	Germany CS	Germany NW	Denmark E	Denmark W	Sweden S	UK	Spain	France
SoC = 0 [% of year]	29%	31%	34%	24%	27%	27%	26%	13%	20.6%
SoC = 1 [% of year]	24%	20%	30%	21%	27%	21%	27%	10%	21.6%
Full load cycles	224	235	270	278	286	385	446	511	513

Because of more volatile prices, hybrid wind-battery configurations are found to be more valuable in systems with higher solar share. In Figure 22 and Figure 23, the blue curve presents the total output from the hybrid in any given hour, corresponding to the sum of generation from the wind turbine and the battery, minus the loading of the battery. The green curve represents the output from the wind turbine, assuming no battery.

[5] Full cycles are here measured when a discharge rate above 90% of the total capacity of the battery is achieved.

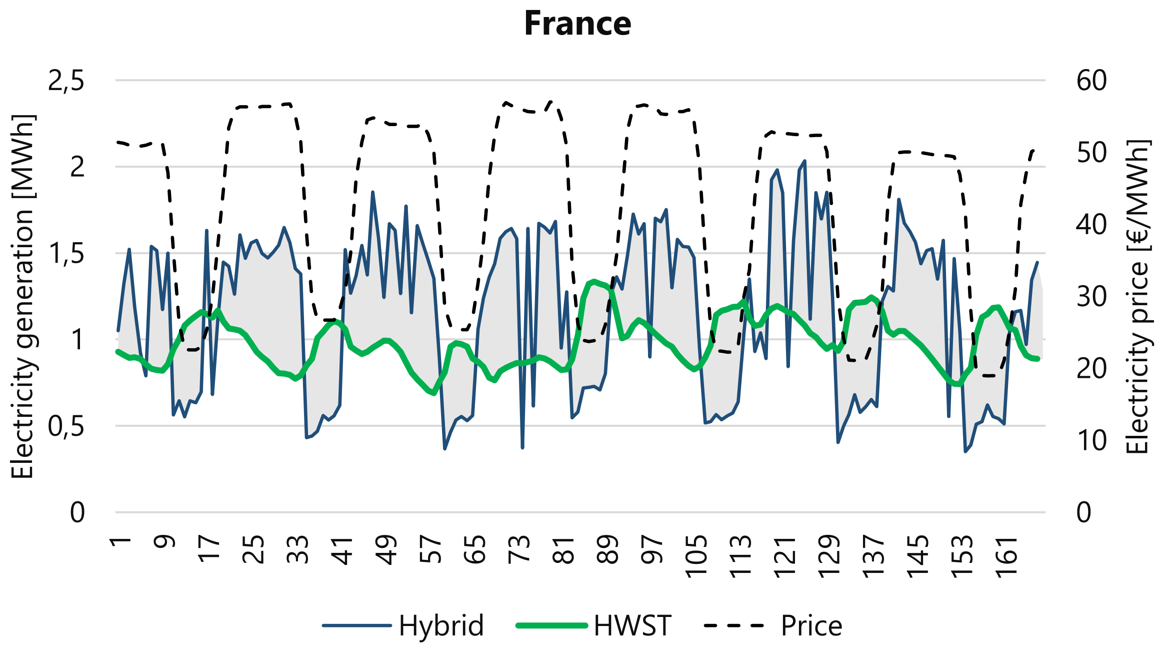

Figure 22. Average weekly generation of HWST and 4-hour hybrid for France in 2050, along with average price

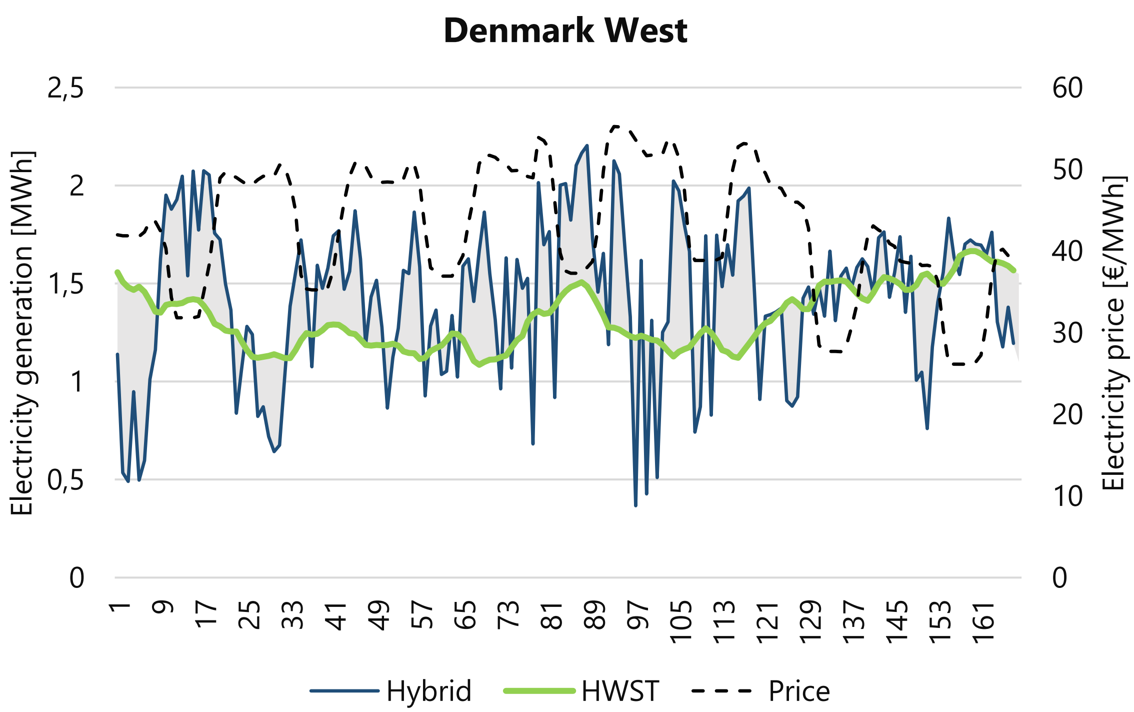

Figure 23. Average weekly generation of HWST and 4-hour hybrid for Denmark West in 2050, along with average price

3.6 Extra cost to equip wind turbines with storage is not justified by the increase in value obtained in the market. LWST represents better business case due to the significantly lower cost adders

One of the starting points of the study was that, similarly to LWST, adding storage to wind can modify the generation pattern by reducing generation at hours with lower prices and shifting it to hours with higher prices. LWSTs do this "by design" since they reduce the wind feed-in at high wind speeds (when a lot of other wind producers are feeding power to the grid, thus reducing price) and increase the generation at low wind speeds. The result of the analysis shows that batteries can also do that, but they modify the generation profile to a lower extent.

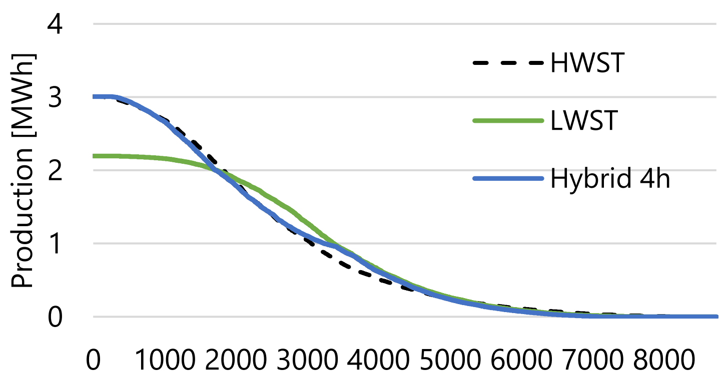

Figure 24. Difference of feed-in profile between LWST and 4h Hybrids (compared to original HWST profile).

However, even though the battery changed the generation pattern less, the dispatchability of storage creates a larger flexibility in choosing when to increase output, namely to peak price hours. As a result, compared to the LWST, the hybrid wind-battery can shift generation output to higher prices to a greater extent, leading to higher value adders (see Figure 25).

Figure 25 compares the value adders of 4h hybrid to those of LWST. For LWST, countries with high wind penetration shares, such as north-western Germany, Denmark, and the UK, benefit largely from moving production to hours of lower wind speeds. In contrast, Spain and, to some degree, France, obtain negative value adders. Different from hybrids, for which the highest adders are in solar-dominated countries, the mitigating effect of LWST has a greater impact in countries with high wind penetration.

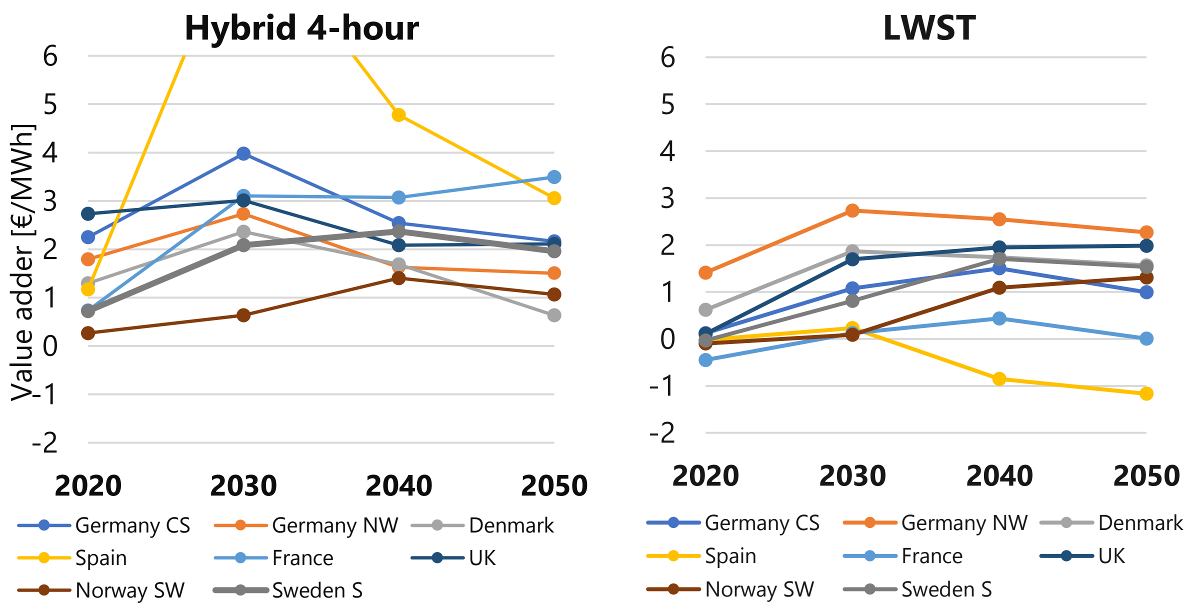

Figure 25. Value adders of 4-hour hybrid and LWST from 2020 to 2050, relative to the HWST.

Although hybrid systems in most locations provide higher market value, they also incur higher costs due to the installation of batteries. LWSTs can provide similar value gain to that of hybrids but at a substantially lower cost. Figure 26 shows the difference in LCOE (cost adder) for the hybrid and the LWST, relative to the HWST. It is worth mentioning that for hybrid the cost adder is relatively high in 2020 but reduces largely towards 2050. On the other hand, the cost adder for LWST is negative in many cases, mostly in areas with lower wind speeds, since using lower specific power turbines would reduce LCOE.

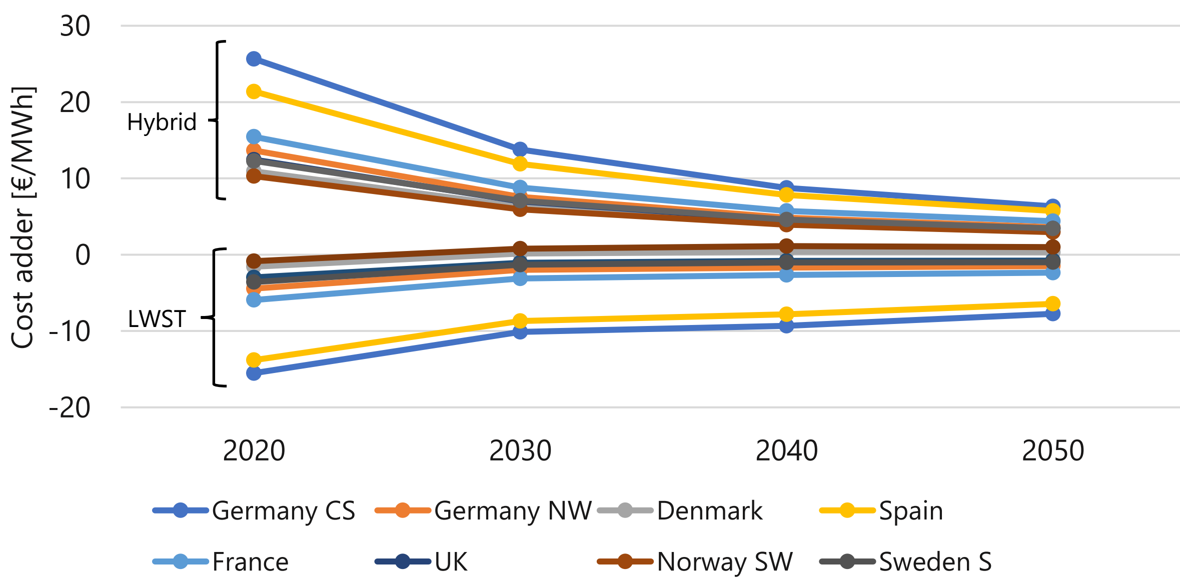

Figure 26. Difference in LCOE (cost adder) for the hybrid and LWST, relative to the HWST

Taking into consideration both the value adder and the cost adder, the cost-effectiveness of different configurations can be assessed relative to the HWST reference case (see Figure 27). The hybrid systems in all countries are neither competitive with the HWST, nor with the LWST. Even though hybrids in most locations gain a higher market value than standalone wind turbines, the added value (mostly in the range 1-3 €/MWh) is not sufficient to justify the cost of installing coupled batteries (cost adder 10-25 €/MWh in 2020, reduced to 3.5-6 €/MWh in 2050).

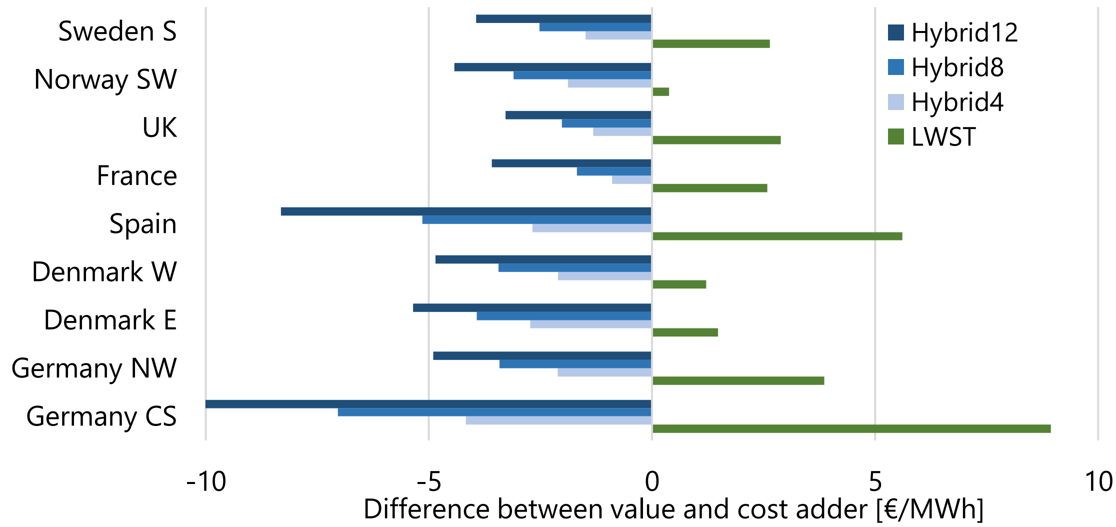

Figure 27. Competitiveness of the hybrid configurations and the LWST in 2050, defined as the difference between value and cost adder, relative to the HWST

In general terms, the drawback of hybrid systems is related to three coupling constraints of co-location: 1) restrictions on grid charging, 2) limitations on shared transmission capacity, and 3) reduced options for geographic siting of storage. Due to the lack of intra-zonal representation in Balmorel, only the impact of the two first constraints have been evaluated in this study.

The coupling penalty aims to quantify the "lost" value of hybridising wind turbines compared to having the same systems sited independently. It is calculated as the sum of the market value of wind and the standalone battery minus the market value of the wind-battery hybrid. In the simulation performed, the value ranges from 2-39 €/MWh, averaging at 19 €/MWh. The value increases over time, as it becomes more and more valuable to take advantage of low prices by charging from the grid. The highest coupling penalty is found in Spain, followed by France and the UK (Figure 28).

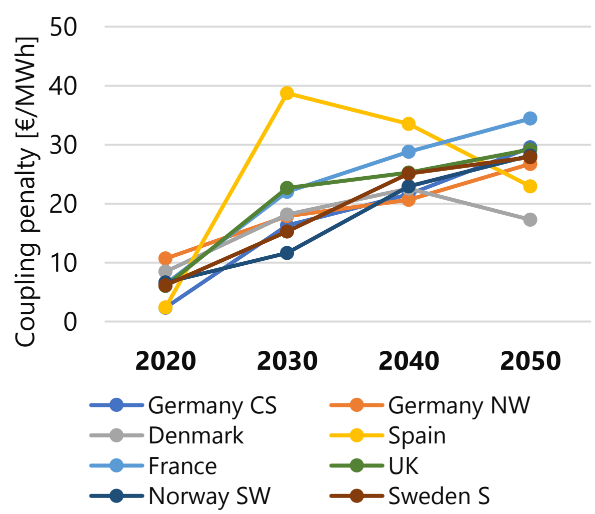

Figure 28. Coupling penalty of hybrid systems across markets and years.

It is worth mentioning that the coupling penalty does not consider the potential cost synergies of co-location. Hence, the economic attractiveness of hybrids will depend on whether potential synergy savings can outweigh the loss in value. Synergies include construction cost savings such as shared permitting and siting costs, shared electrical and physical infrastructure and shared interconnection agreements. With an estimate of synergy savings corresponding to 8% of capital cost (average at 2.4 €/MWh), which is a value mentioned in literature, standalone wind turbines (both HSWT and LWST) still show better business cases than hybrids (see Figure 29).

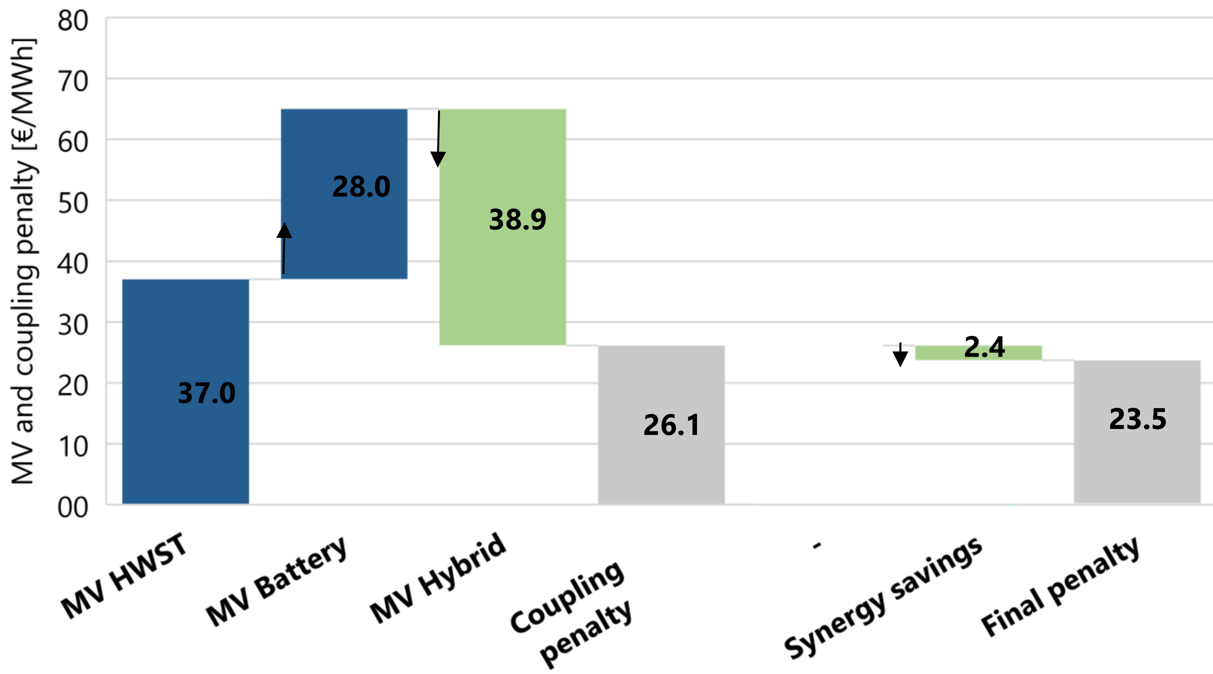

Figure 29. Breakdown of average coupling penalty in 2050, given as the difference in the market value of hybrid and standalone units.

3.7 Day-ahead market alone does not offer enough justification for hybrid wind-battery systems

As shown, the extra cost of hybridising wind power with battery storage is not balanced by additional revenues from providing time-shifting service in the day-ahead market. However, when looking at the long term (significantly lower battery cost), in some markets like France, the UK and Southern Sweden, the hybrid wind-battery systems are close to being competitive with the HWSTs, requiring additional cost reduction or revenue streams between 0.9-1.5 €/MWh (Figure 30).

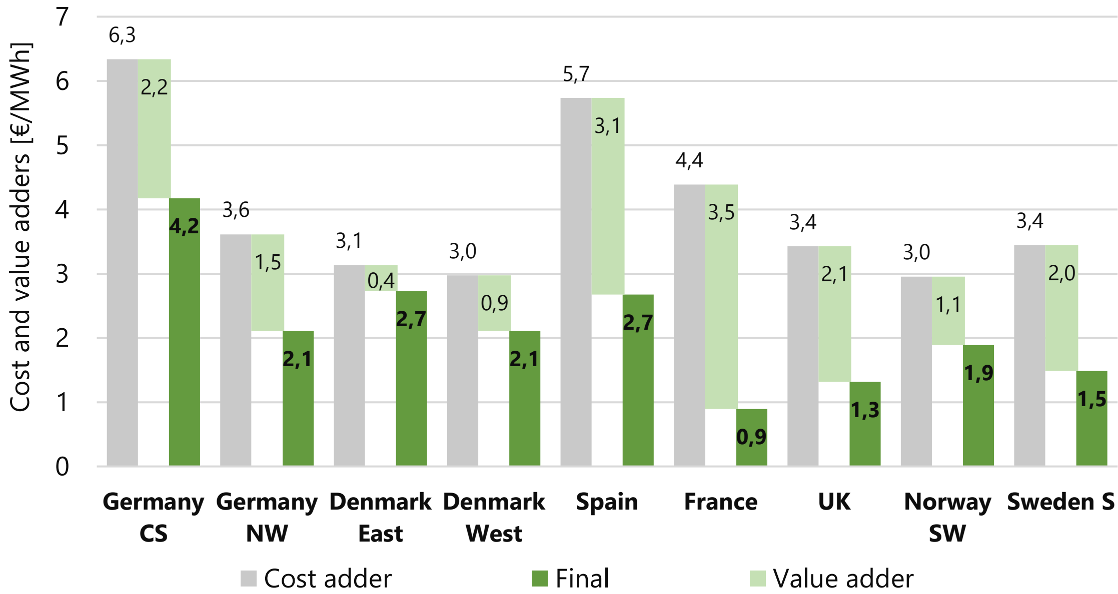

Figure 30. Breakdown with cost and value adder for the 4-hour hybrid relative to the HWST in 2050.

It is expected that batteries will offer ancillary services and reserve capacity in the future, promoted by the significant increase in VRE shares. While the day-ahead market alone does not offer enough justification for hybrid wind-battery systems, additional revenue streams (e.g., via balancing and ancillary services markets) can outweigh the cost adder and make hybrid-wind solutions more competitive in the market. Revenue streams can include reducing imbalance charges and penalties of wind producers by means of capacity firming. The regulatory structure for providing frequency response and reserve capacity may also benefit hybrid systems more, as the likelihood of meeting performance requirements is higher.

For the system modelled in this study (considering only the energy market) the additional value offered by hybrids seems to be modest, with adders ranging from 0.3 €/MWh to 9 €/MWh, compared to $3-$22/MWh in the study of Fu et al. [17], which also included capacity market value.

The day-ahead zonal pricing system and market-coupling in Europe lead to less extreme price signals and price differentials across time and location compared to countries adopting nodal pricing (e.g., the U.S.). This can lead to a lower value of hybridisation, due to lower arbitrage opportunity for wind-hybrid in Europe. However, at the same time, decoupling wind generators and storage in a nodal market can lead to a more cost-effective solution since storage can be placed in a more suitable location and see different price signals in the day-ahead market than the wind turbine.

3.8 The option of charging from the grid can increase revenues of wind-storage hybrids, especially in solar-dominated countries

One of the assumptions in modelling hybrid wind systems in this study was that the battery would only be charged from the generation of the turbine, therefore not allowing storage to take direct additional advantage of particularly low prices in the market by charging from the grid. A set of sensitivity analyses on *Grid charging hybrids* are simulated, where the storage in the hybrid system is allowed to charge from the grid and not only from the co-located wind turbine.

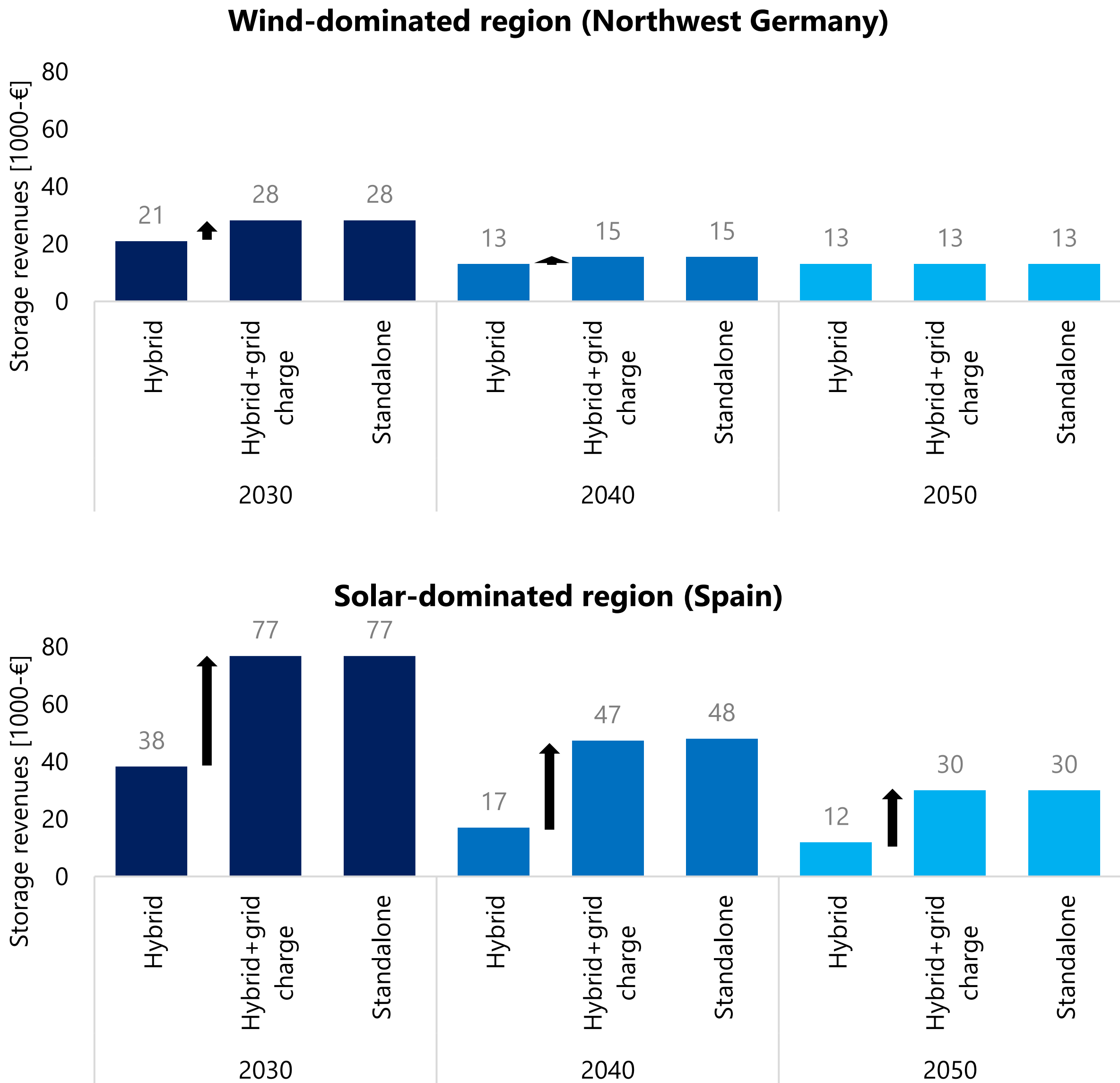

Figure 31. Storage revenues for hybrid (4h), hybrid with grid charge (4h) and standalone (4h). Black arrow shows the increase when adding grid charging to hybrid.

Figure 31 shows the revenue for the 4h battery in various cases: the battery inside the wind-storage hybrid in the reference case (no grid charging), in the sensitivity where grid charging is allowed, as well as in the standalone case. The revenues of the battery for the reference *Hybrid* case are the lowest across scenarios. Adding the opportunity for the storage to charge from the grid generally increases the revenues, bringing it close to the same level as a standalone battery.

It is interesting to note that in solar-dominated regions, the boost to the revenues by charging from the grid correspond to more than doubling the annual revenues, while in wind-dominated regions the increase is much more modest and grid charging has almost no value after 2030. This is related to the fact that in high wind regions there is a higher chance that when the price is close to zero, the wind turbine is producing so the battery can be charged with the generation from the hybrid, rather than charging from the grid.

The two key limitations of the hybrid setup compared to standalone were the restrictions on grid charging and the potential limitations on shared transmission capacity (i.e., storage and wind cannot unload energy at the same time since connection capacity is limited). In the study, a 3 MW turbine and a 1 MW storage were connected to the grid with 3 MW connection capacity. The fact that hybrid with grid charging performs so similarly to the standalone battery indicates that there is little to no impact from the fact that the wind asset and the battery have to share the same connection point. Further analyses could be performed to quantify how the outcome would change with a smaller or larger connection capacity.

Figure 32 shows the comparison between the cost adder and the value adder in 2050 when grid charging is allowed (compared to Figure 30 where it was not allowed). It can be noted that, while the difference between cost adder and value adder is only slightly reduced for most countries, for Spain the value boost from grid charging brings hybridisation close to competitiveness and for France, it makes it competitive considering the sole revenues from the day-ahead market.

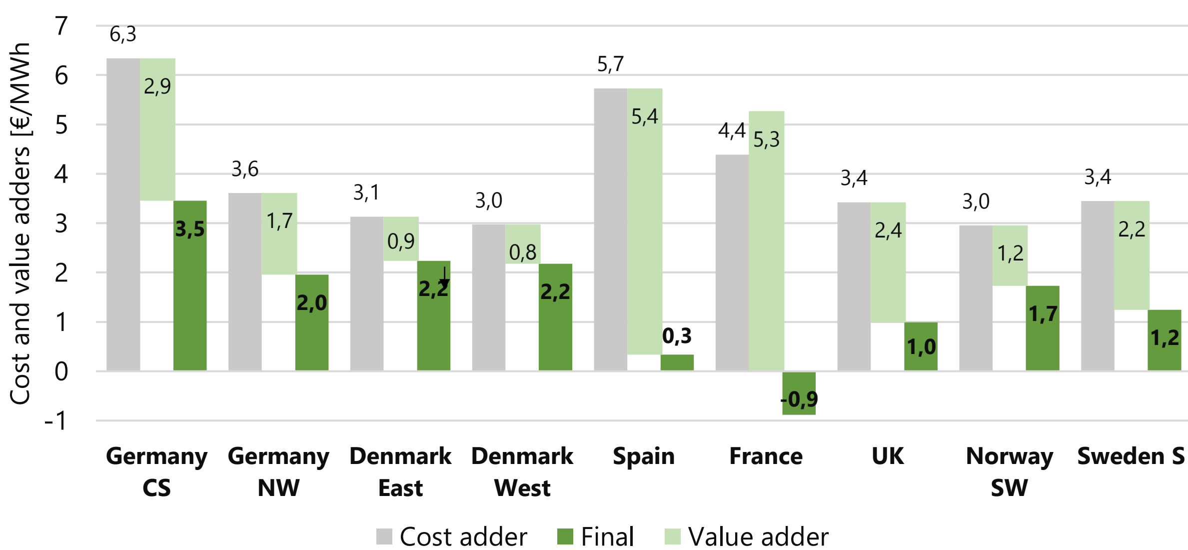

Figure 32. Breakdown with cost and value adder for the 4-hour hybrid with grid charging option relative to the HWST in 2050.

4 Recap and Recommendation

Below is a recap of the key messages of the analysis, and related recommendations:

1. Even in a system largely dominated by VRES, future need for storage for balancing and time-shifting services, being it standalone utility-scale batteries or in a wind-hybrid setup, will largely depend on the evolution of the flexible demand, especially P2X. **Plan accordingly and consider long term profitability.**

2. Given the development of price profiles, and a bit counterintuitively, hybridising wind power with storage is more profitable in solar-dominated countries. This is even more relevant as Northern Europe develops more P2X, which fits well with patterns of wind generation. **Plan for hybrid in central-south Europe rather than Northern Europe**.

3. Market value of wind is declining in a deep decarbonised future, but as more and more solar comes into the system from 2030, the drop is not that marked, and the relative revenue of wind stays higher compared to e.g. solar, due to production during evenings and nights. **Hybridising wind with battery storage can increase the market value of wind by around 1-3 €/MWh on average** across countries and years (MV increase of 5% on average), but varies a lot by market (in Eastern Denmark the MV boost is 1% while in France it is 9%). Adding a 4h storage to a wind turbine performs better than adding 8 or 12h of storage, since it has the highest value boost and the lowest cost of the analysed options.

4. Even though hybridisation increases value seen in the market, the **cost of adding batteries outweigh the benefit, especially in the short-term**. Other options like using low wind speed turbines provide a similar value boost at a significantly lower cost adder. Savings and synergies of co-locating batteries and turbines do not make up for this difference.

5. Day-ahead market does not seem to provide enough additional revenues to justify capital expenditure. However, **in some markets break-even is close and stacking other system services could turn out to be enough to cover costs.** Whether additional revenue streams from e.g. reserve markets or reduced balancing costs can outweigh the coupling penalty is essential, and is a topic that should be addressed in further studies.

6. **Standalone batteries can achieve higher revenues but building the hybrids to also allow charging from the grid can close the revenue gap**. The additional revenue for hybrid can also bring hybridisation closer to being competitive. This makes most sense in solar-dominated countries in central-south Europe, while in Northern Europe grid charging provide less additional revenues.

The overall recommendation based on the results of the study is to consider hybridising wind in countries where solar penetration is increasing with a faster pace, make sure to design the hybrids with around 4h of storage, and allow grid charging to take full advantage of the battery. If the potential wind asset is located in Northern Europe in regions with higher wind penetrations, adding storage to the turbine is less valuable and should be combined with other system services to guarantee a positive business case. Moreover, it is less relevant to design a bidirectional power flow, so grid charging can be avoided if this brings along capital savings. In a development phase, the alternative of using low wind speed turbines instead of adding storage might provide more value for the same extra capital expenditure.

Glossary

Specific power

It is defined as the ratio between the rated power of the turbine in W and the swept area expressed in m^2. Specific power is a crucial component in the definition of a wind technology since it directly affects the shape of the power curve and determines its production potential at different wind speeds.

$$SP = \frac{P_{rated}[W]}{\pi \cdot (D[m]/2)^2}$$

E/P ratio

E/P ratio is the ratio between the energy storage capacity of a battery in MWh and the charge/discharge capacity in MW (assumed equal). It is expressed in hours (h).

$$E/P\ ratio = \frac{Energy\ storage\ capacity\ [MWh]}{Discharge\ capacity\ [MW]}$$

Market Value of wind and storage

Expressed in €/MWh, it is the ratio between the revenue of wind power in the market in a certain time period and its potential production including curtailment. It represents the average revenue per energy unit of wind produced. In order to capture the characteristic seasonal variation of wind, market value is usually expressed in a yearly time frame.

$$MV_{g,z} = \frac{\sum_t^T p_{t,z} \cdot E_{t,g,z}}{\sum_t^T E_{t,g,z}} = \bar{p}_{g,z}$$

where:
t = timestep (1, …, T)
g = technology (land-based wind, offshore wind, solar, …)
z = market zone or country considered (DK1, DK2, France, …)
T = total timesteps in the period considered (8760 if a year is assumed)
E = potential energy production, including production that is curtailed
p = market price in the zone/country considered

The market value of storage is calculated similarly, however the revenue includes both sale of electricity and cost of charging. Moreover, energy production corresponds to the discharged electricity from the battery.

Value factor

This parameter is used to express the market value in relative terms, with respect to average day-ahead market price (time-weighted). It is the ratio between the market value in a certain market zone or country and the respective average wholesale electricity price. The value of wind represents the price "seen" by the wind producers in the market, with respect to average system price.

$$VF_{g,z} = \frac{\bar{p}_{g,z}}{\bar{p}_z} = \frac{(\sum_t^T p_{t,z} \cdot E_{t,g,z}) / \sum_t^T E_{t,g,z}}{\sum_t^T p_{t,z} / T}$$

where:
$\bar{p}_{g,z}$ *= technology weighted average price (i.e. Market Value)*
$\bar{p}_z$ *= average price in the market zone/country*

The value gap is further used to compare both the development in value factor for different time periods and the difference in value factor between technologies.

Levelized cost of electricity (or storage)

This parameter expresses the cost of the MWh generated during the lifetime of the plant, and it represents a life-cycle cost. It can be calculated as:

$$LCoE = \frac{I_0 + \sum_{t=1}^{N} \frac{V_t}{(1+i)^t}}{\sum_{t=1}^{N} \frac{E_t}{(1+i)^t}}$$

where:
I_0 *= overnight cost or Investment cost [€]*
N = technical lifetime of the plant [years]
V = variable cost including O&M, fuel, CO_2 *costs [€ in year t]*
E = electricity produced in the year t [kWh in year t]
i = real discount rate [%]

The levelized cost of storage (LCOS) uses the same metric but the electricity produced (E) is substituted by the total discharged energy from the battery.

Benefit-Cost ratio

Used to determine the most cost-effective configuration, taking into account the monetary gain relative to the cost. It is calculated as the ratio between MV and LCOE.

Value/cost adder

The value or cost adder is defined as the difference in market value or LCOE between two technologies. It is presented as the additional value or cost offered by a new scenario, relative to the reference scenario. A negative value adder indicates that the reference scenario provides higher value than the configuration being assessed. Conversely, a negative cost adder indicates a less expensive configuration compared to the reference. These metrics are defined as:

$$Value\ adder = MV_{scenario} - MV_{reference}$$
$$Cost\ adder = LCOE_{scenario} - LCOE_{reference}$$

Coupling penalty

The coupling penalty compares the value provided by hybrid configurations to that of standalone systems. For this work, it is calculated as the difference in market value between the hybrid configuration and the accumulated market value of the standalone wind and battery device. The value serves as a measure for quantifying the cost synergies required for making hybrid systems competitive to independently sited ones.

$$Coupling\ penalty\ =\ MV_{wind} + MV_{battery} - MV_{hybrid}$$

State of charge

The State of Charge (SoC) is the level of charge of a battery relative to its capacity. It acts as a measurement of the amount of energy available in the battery at a specific point in time, in which a value of 1 (100%) signifies that the battery is fully charged, while a value of 0 (0%) corresponds to an empty battery. In this work, the number of hours in which the battery has a SoC equal to 0 or 1 is calculated in order to give an indication of the utilisation level of the battery. This is assessed in combination with the full load cycles.

Full Load Cycles

By definition, a full load cycle occurs when the battery is discharged an amount that equals 100% of the power capacity. However, it does not necessarily have to be discharged from 100% to 0% in one charge. In this study, one full load cycle is defined by a discharge rate above 90% of capacity.

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Appendix I: Turbine and battery configuration

Turbine configuration

To consider future technology and cost development, in Balmorel each generation technology is defined for every 5- and 10-year period.

Two turbine technologies have been selected: a low wind speed turbine (LWST) and a high wind speed turbine (HWST). The technological parameters of the wind turbines have then been defined. The characteristics of the two turbine technologies for 2020 and 2050 are presented in Table 3. The HWST is characterised by a higher specific power (SP) and lower hub height. The trend corresponds to decreasing specific power for both turbines, while hub heights increase to accommodate larger rotors. The HWST has traditionally been installed in the energy system and is therefore considered as the reference case.

Table 3 Specific power and hub height for the two turbine technologies in 2020 and 2050.

	Specific Power [W/m2]		**Hub Height [m]**	
Turbine Type	HWST	LWST	HWST	LWST
2020	300	225	90	120
2050	270	175	110	130

As only marginal values are to be considered, a HWST capacity of 3 MW is assumed. In order to accurately compare the market value of high wind and low wind speed turbines, different energy capacities are defined for the two turbine technologies, on the basis of different full load hours. As the LWST can generate more at low wind speeds, the installed capacity needed to ensure the same yearly production level is lower. The capacity does, however, differ across regions and years, as wind resources are site-specific and continuous development in turbine technology leads to improved capacity factors for future turbines. Table 4 presents the average wind speed for each region, along with the full load hours and respective capacities of the HWST and LWST needed to achieve the same production levels in 2050.

Table 4 Average wind speed for each region, full load hours of the LWST and HWST available for investments in 2050 and the respective capacity required for the LWST to produce the same levels as the 3 MW HWST.

	DE_CS	DE_NW	DK_E	DK_W	UK	ES	FR	NO_SW	SE_S
Average wind speed [m/s]	6.06	7.47	8.13	8.33	7.88	6.39	7.12	8.17	7.76
Capacity HWST [MW]	3	3	3	3	3	3	3	3	3
FLH HWST [h]	1829	3192	3730	3861	3438	2150	2766	3850	3398
Capacity LWST [MW]	2.00	2.23	2.37	2.38	2.28	2.00	2.19	2.45	2.26
FLH LWST [h]	2748	4302	4728	4865	4534	3231	3790	4724	4515

Battery configuration

The energy system has been modelled with a fixed energy-to-power (E/P) ratio of 4-hour for all standalone batteries. It is acknowledged that such a fixed ratio for all countries will not result in the optimal solution and that allowing for an additional 1MW of battery power capacity might opt for a different ratio. Due to the restriction on charging only from the wind turbine, coupled batteries are expected to obtain a different operational pattern compared to independently sited ones. Hence, three different configurations have been implemented for both standalone and coupled batteries to evaluate the benefits of larger storage volumes in different systems and across years, and to determine the most cost-effective E/P ratio. Each battery is installed with a power capacity of 1 MW and an E/P ratio of 4, 8 and 12 hours, respectively.

Appendix II: Cost assumptions

Figure 33 shows the investment cost assumptions and development for the two wind turbines and the three battery capacities, given in real 2020 prices. The costs are calculated for the respective capacities, corresponding to 3 MW for the HWST, and 4 MWh, 8 MWh and 12 MWh for the three respective batteries. As the capacity of the LWST changes according to region and year, the average capacity of 2.24 MW is used. Firstly, the cost of the HWST is higher due to the larger capacity needed to obtain the same generation levels as the LWST. Moreover, the cost differences decline towards 2050 following the change in technology parameters, in which the cost of the LWST is reduced at a lower rate than that of the HWST. For the three battery configurations, the smaller volume capacities will naturally lead to lower investment costs. Also here, a tendency towards more coincident investment costs towards 2050 can be observed.

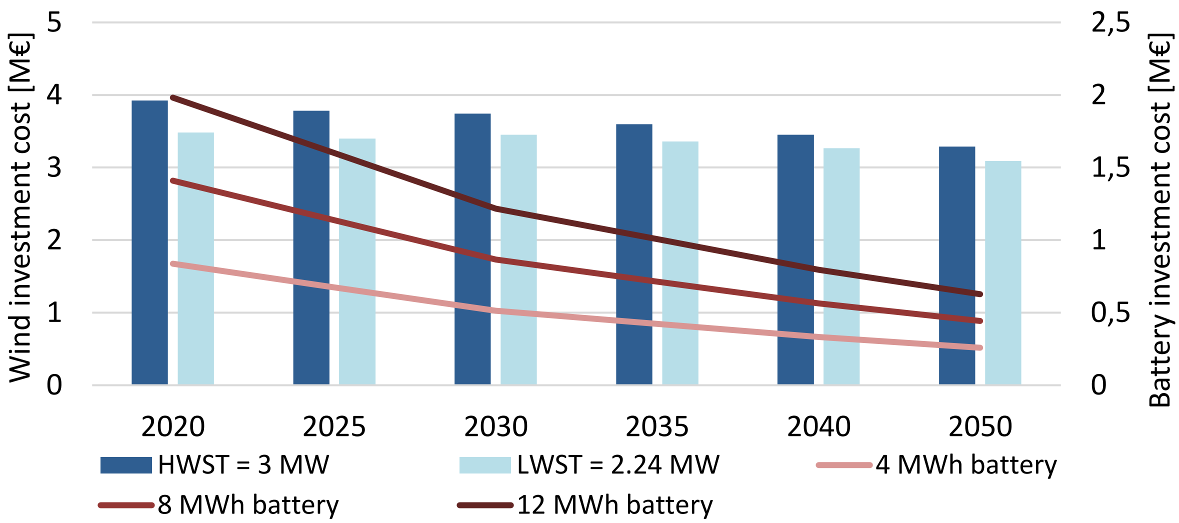

Figure 33 Investment cost assumptions for wind turbines and batteries used in the model.

Appendix III: Flexibility measures included in the Balmorel model

With the energy system evolving towards a future VRES-dominant one, the need for flexibility to ensure balance between demand and supply becomes increasingly important. Hence, energy storage is playing a crucial role as flexibility provider, while also offering several other benefits to the system. However, system flexibility can also be provided through other measures, such as strengthening inter-regional transmission connections or increasing demand-side response. These are all competing measures in terms of capacity investments, and their deployment will therefore impact the need and the extent for battery storage in the system.

The most important sources of flexibility included in the Balmorel model are:

General flexibility from end-users
Demand-side flexibility can be offered in terms of flexible electricity consumption from end-users, such as residential, commercial, and industrial sectors. To account for this, a certain percentage of the average classical demand is allowed to be increased or decreased by the means of a virtual storage.

Industrial heating
Electrification of the industry heat sector, by means of heat pumps and electric boilers, is also seen as a promising solution for increasing flexibility. By replacing other boilers in periods of high VRE supply and corresponding low electricity prices, electricity demand increases, leading to higher prices and hence VRE market value.

Smart charging of electric vehicles
The expanding fleet of electric vehicles will increase electricity consumption in the long term, and it will also provide an additional source of flexibility. In the model, the EV batteries act as a virtual storage for which consumption from the grid can either increase, by charging outside natural patterns, or decrease, by refraining from charging. For each country, the amount of charge, discharge and volume capacity is limited by a fraction of the total EV capacity.

Production of Power-to-X
A certain amount of electricity is consumed to produce and cover the demand of Power-to-X (P2X). The model does however provide the option of shifting production to hours of low electricity prices, by the means of hydrogen storage. This provides another source of flexibility to the system, which increases as the demand for P2X expands. The P2X electricity consumption can also be redistributed between countries, which provides additional flexibility.

Appendix IV: Balmorel Implementation

Being a marginal study, implementing the defined configurations within the nine locations should have a minimal impact on the overall energy system and price, as well as on a regional or a country level. To be able to evaluate the marginal value of these minor configurations, so-called "fictional" regions have been developed. These regions are created exogenously in the model after the investment optimisation is performed and involve no other generation technologies or demand. Each region is connected to its respective main region, including only the capacity of the wind and/or battery unit for the different scenarios. Electricity produced in the fictional region is used to cover the demand of the main region, and it follows the price formation at this level.

The implementation of the standalone batteries and the hybrid systems differ due to different grid connection characteristics. Each fictional region is connected to the main region by a transmission line, sized according to the power capacity of the wind turbine (3 MW). To ensure that technologies within the fictional region are considered equal to those in the main region, the transmission line is neither subject to losses nor costs. For the standalone battery, the line is defined two-ways, allowing both sales and purchase of electricity from the grid. In contrast, the fictional regions with either standalone turbines or hybrids have one transmission line defined only for the export of electricity, meaning that the hybrid battery is only eligible to charge from the wind turbine.

The set-up of the fictional regions with 1) a standalone battery, 2) a single turbine (HWST or LWST), and 3) a single HWST with a battery, is graphically presented in Figure 34 where Southern Germany is used as an illustrative example, but the same configurations apply for all nine locations.

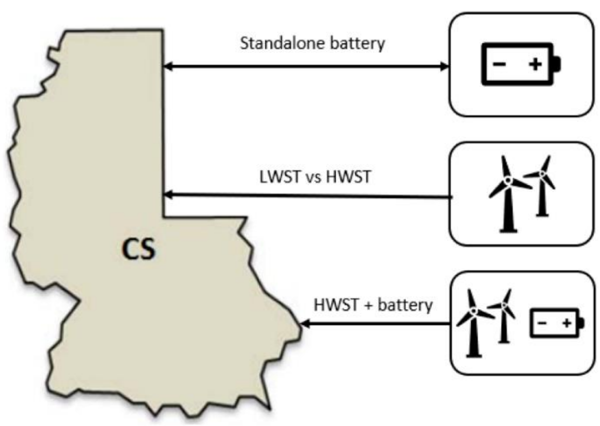

Figure 34. Connection of fictional region with different configurations to main region

Firstly, an aggregated investment optimisation run was performed, where generation and transmission capacity are planned and optimised to satisfy energy demand and meet policy targets for emissions and renewable penetration levels at lowest cost. As the value of wind and storage highly depend on hourly operation, another hourly (day-ahead) optimisation run was performed which replicated the principles of the day-ahead markets in Europe, where bids are scheduled according to the merit order curve and generators are dispatched based on their marginal cost

Appendix V: Limitations of the marginal case study

Due to the complexity of the study and the need for investment optimisation, the use of unit commitment has not been feasible. The model therefore only includes economic dispatch, lacking constraints related to minimum/maximum up- and downtime and ramp limitations of the power plants. Adding these elements could provide additional value to batteries.

Assuming perfect foresight of VRE production, hydro inflow and demand levels remove the uncertainty of these parameters. Assuming perfect foresight presents in a way the maximum arbitrage revenue that can be obtained by batteries, as complete certainty about market prices leads to artificially high efficiency.

Besides energy arbitrage, battery energy storage can also earn revenues from participating in the balancing market. However, the additional value depends on the VRE penetration and flexibility needs in the market, which differs across Europe. The potential increases with higher price volatility, indicating more frequent dispatch of reserve capacity. Even though this revenue stream has not been possible to quantify in this work, it is expected that batteries to a greater extent will take part in offering ancillary services and reserve capacity in the future, promoted by the increase in VRE shares. For battery coupled systems, this also includes reducing imbalance charges and penalties of wind producers by means of capacity firming. Nevertheless, including balancing markets in the model is expected to benefit standalone batteries more, owing to the coupling constraints of the hybrid.

One of the main limitations of the marginal case study is related to the system on which it is established. Being a marginal study, hybrids are installed exogenously after the system has been optimised, meaning the balance of supply and demand is secured. Consequently, the system is almost saturated with batteries, and the value of adding a hybrid system is, therefore, lower compared to a system in need of flexibility. The storage value adder of hybrids from 2035 and onwards might therefore be underrepresented, because of increasing system battery capacity.

In this study, the transmission limit of the hybrid configuration has been restricted by the maximum capacity of the VRE. Consequently, if the turbine produced at maximum capacity, the battery would not be able to sell additional energy. [20] show that for the U.S. system, increasing the POI capacity to the total capacity of the wind and battery device could provide additional value, in their case $1.6/MWh. However, considering the load duration curve of the hybrid versus HWST presented in this study, the hybrid battery mainly increases output at periods of lower wind production. Accordingly, the POI capacity is rarely restricting output. Hence, in this study, the impact of different POI capacities has not been quantified.

For simplicity reasons, a turbine rating of 3 MW for the HWST is assumed for all years up to 2050. With continuous development in turbine technology, it is acknowledged that larger capacity turbines will likely enter the market in years to come. Cycle induced degradation of batteries are not accounted for in the model. If a degradation penalty were to be imposed on the battery operation, the value adders of both standalone batteries and hybrids would decrease. However, the difference would likely be greater for standalone batteries due to more frequent charge and discharge, especially in high-volatile countries.

Appendix VI: Balmorel analysis and model framework

Balmorel is a bottom-up, partial equilibrium energy system optimisation model, with a detailed characterisation of the electricity and heat system. Balmorel is implemented as a mainly linear programming optimisation problem [21]. It is coded in GAMS (General Algebraic Modelling System), a high-level modelling system for mathematical programming and optimisation. The analytical framework can vary between short-term and long-term perspectives, depending on the assumptions made concerning the existing capital stock. For this work, a medium-term perspective is used [22], in which existing infrastructure is given, but the system can adapt to evolving conditions through endogenous investments and decommissioning. The Balmorel simulations executed are based on an existing model configuration, developed throughout the years by Ea Energy Analyses. The model includes both existing policies and targets, as well as future projections for renewable energy commissioning and transmission expansion.

Simulation process and time resolution

Three successive simulation layers have been executed, namely investment optimisation, full-year optimisation and day-ahead optimisation. These refer to three different so-called ”Balbase (Bb)” options. The sequence of simulations along with respective time resolutions is illustrated in Figure 35.

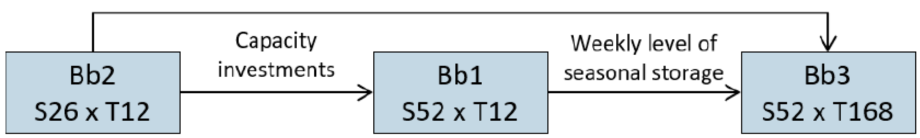

Figure 35 Sequence of simulations with respective time resolution. S = weeks, T = hours.

With a medium-term approach, the model first performs an investment optimisation (Bb2) where generation and transmission capacities are planned and optimised in order to satisfy energy demand and meet policy targets for emissions and renewable penetration levels at the lowest cost. The investment into additional capacity, as well as decommissioning of existing non-competitive units, are optimised for each decade from 2020 to 2050. The model converges to the optimal solution by means of linear programming, meaning no binary or integer variables are considered. In addition, due to the high computational power required to run investment simulations over a long-term horizon, the time resolution has been reduced. This is achieved through time-aggregation, where one year is composed of 26 weeks and each week consists of 12 hours. Consequently, the hourly resolution of one year is aggregated down to 312 hours.

The full-year optimisation run (Bb1) simulates one year at a time, taking the capacity investments from the Bb2 run as exogenous parameters. The purpose of the run is to accurately model long-term operational decisions that cannot be optimised for in the short-term day-ahead optimisation. This includes planned maintenance of thermal generators, as well as the use of hydro reservoirs and other seasonal storage. As capacity investments are fixed in the Bb1 optimisation, a more detailed time resolution is feasible. The number of weeks simulated is therefore doubled, including each of the 52 weeks of a year. One week is still aggregated to 12 hours, resulting in a total of 624 hours.

Due to the highly fluctuating nature of VRES, the temporal resolution of the investment and full-year optimisation is not sufficient to accurately model the impact of renewables on the energy system, as well as the market value of these energy sources. In addition, the value of storage highly depends on the price volatility from hour to hour, as the battery will charge in hours of high price and discharge in hours of low price.

To capture the complex interaction between renewables, conventional generators, storage, distribution and consumption, an hourly resolution is required. A third optimisation is therefore performed for the hourly energy dispatch (Bb3), where the capacities optimised for in the investment simulation are fixed. The hourly (day-ahead) optimisation also relies on the results of the full-year optimisation, which determines the availability of the units and the initial storage content that can be utilised at the beginning of each week. With regard to time resolution, one year is assumed to consist of 52 weeks, corresponding to 8736 hours. The optimisation run replicates the principles of the day-ahead markets in Europe, where bids are scheduled according to the merit order curve and generators are dispatched based on their marginal cost. In addition to determining the supply of each generator, the market-clearing price for each hour and each region correspond to the shadow price of the energy balance constraint of that region. Finally, the analysis is limited to the day ahead market, neglecting both the intra-day market, the balancing market and forward and futures contracts.