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Complementary Spanish photovoltaic and Danish offshore wind pathways to cost-competitive renewable hydrogen

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ABSTRACT

This paper evaluates the techno-economic feasibility of large-scale green hydrogen production and export from Spain and Denmark by optimising renewable generation, electrolyser capacity, and hydrogen storage. We develop an integrated framework that minimizes the levelized cost of hydrogen (LCOH) while considering three storage technologies: liquid organic hydrogen carriers (LOHCs), salt caverns, and pressurised tanks. The approach combines country-specific optimisation with comparative technology assessment under future deployment assumptions and dual uncertainty (techno-economic and interannual). Results show that storage technology is the dominant cost driver, outweighing location-specific renewable energy characteristics. LOHC systems and salt caverns achieve comparably low LCOH values, offering competitive solutions depending on local geological constraints. In contrast, pressurised tanks entail substantially higher costs, making them suitable only for niche or short-term applications. A key finding is the seasonal complementarity between Spanish PV and Danish offshore wind: PV peaks in spring and summer, while offshore wind provides higher output in autumn and winter. Coordinating production and storage across both countries can reduce seasonal cost swings and improve export competitiveness under the European Hydrogen Backbone initiative. The proposed framework and sensitivity analysis offer strategic insights for designing hybrid hydrogen export systems and selecting appropriate storage technologies in regions with contrasting renewable profiles.

1. Introduction

The European Union (EU) has committed to achieving net-zero greenhouse gas emissions across its economy by 2050 [1]. This goal necessitates extensive electrification and the replacement of fossil-derived feedstocks with renewable alternatives. Green or renewable hydrogen [2], produced via electrolysis powered by renewable energy sources (RESs), offers a green solution to the transition by providing; (i) a carbon-free chemical energy carrier; (ii) long-duration storage for variable renewables [3]; and (iii) a flexible vector to decarbonise hard-to-electrify sectors such as heavy industry [4], long-haul transport, and aviation [5]. The EU has prioritised the development of renewable hydrogen as a central element of a climate agenda that promotes a shift away from fossil fuels [6]. Under the 2022 REPowerEU Strategy, the EU has set a target to domestically produce 10 million tonnes and import 10 million tonnes by 2030, as well as supply approximately 10% of the EU's total energy demand by 2050 [7].

Due to the disparity between renewable resources and hydrogen demand across countries in Europe, there is an emerging need for cross-border hydrogen exchange [8]. For example, the development of five European hydrogen corridors by 2030 has been proposed to facilitate the import and transport of hydrogen across the European continent [9]. Among potential hydrogen exporting countries, Spain and Denmark are considered promising given their substantial solar photovoltaic (PV) and offshore wind potential, respectively. Spain ranks among Europe's top PV performers, with average yields exceeding 1.7 MWh/kWp per year, as highlighted by Romero-Ramos et al. [10]. Denmark leads in offshore wind development, achieving capacity factors above 50% and aiming to achieve 4–6 GW of electrolysis capacity by 2030 [11].

The distinct offshore wind resource and solar resource profiles of Denmark and Spain, respectively, introduce different dynamics into their national energy systems. While there is potential competition between the two countries in the emerging hydrogen market, their renewable energy profiles may also offer complementary advantages. However, the European hydrogen market is still in its infancy, with uncertainty remaining about the optimal development pathways for

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renewable energy deployment, electrolysis capacity, and hydrogen storage infrastructure in both countries.

Several studies on European energy systems have examined cross-border hydrogen trading. Neumann et al. [12] adopted the PyPSA-Eur-Sec model to examine the benefit of a European hydrogen network in net-zero emission scenarios in 2030. Using Balmorel, the energy system optimisation model, Kountouris et al. [13] explored how hydrogen import hubs and European domestic production hubs could meet demand in Western and Central Europe through four hydrogen corridors. Some studies have also explored the country level implications in Europe. Münster et al. [14] examined and compared various hydrogen export scenarios for Denmark using five energy system modelling tools, while Back et al. [15] investigated the potential for hydrogen production from surplus electricity in Spain simulating the country's electricity system for the year 2040. While these studies provide valuable insights into the economic implications of hydrogen trading from a system-wide perspective, they fall short of delivering concrete cost estimates of hydrogen at the country level, especially the levelized cost of hydrogen (LCOH). Such information, however, is crucial for shaping the future European hydrogen market and for informing strategic planning and investment decisions in both export and import countries.

The LCOH estimates that have been made in the literature vary widely, largely due to the techno-economic uncertainties associated with green hydrogen production and transportation. Monte Carlo simulations performed by Wolf et al. [16] show that Spain could achieve LCOH values between 49.8–93.6 MEUR/TWh H_2 (1.66–3.12 €/kg) by 2050, outperforming other European and North African countries under PV-based production. Apostolou identified hydrogen selling prices in Denmark of between 108 and 450 MEUR/TWh H_2 (3.6 to 15 €/kg) as a feasible range under current market and technological conditions [17]. However, many studies rely on coarse temporal resolution, ignore storage infrastructure costs, or use static assumptions that are disconnected from 2050 policy-aligned technology forecasts.

Evidence shows that the LCOH is highly sensitive to certain key associated parameters, as well as the costs of renewable electricity, electrolysis and financing conditions [16]. Hydrogen storage is also an important factor as it is one of the key enablers of large-scale hydrogen deployment, particularly for balancing seasonal mismatches in the availability of renewables. Recent studies suggest that hydrogen production from surplus renewables in Spain could reach 17.3 TWh/year by 2040, with salt caverns offering a technically viable and geologically feasible long-duration storage solution [15]. In regions where underground storage is not feasible, technologies such as liquid organic hydrogen carriers (LOHCs) offer promising alternatives at ambient temperature and atmospheric pressure [7].

In addition to direct hydrogen use, the integration of hydrogen in synthetic fuel production through power-to-X (PtX) [18]becoming increasingly relevant, influencing overall hydrogen demand and consequently impacting the LCOH. Advances in electrolysis technologies, particularly solid oxide electrolysis cells (SOECs), are also expected to drive further cost reductions [19]. When coupled with industrial heat sources, SOECs can utilize waste heat, significantly reducing the electricity demand of SOEC-type electrolysers. This integration also supports the production of electricity-based sustainable aviation fuels (e-SAFs) with estimated production costs ranging from 0.5 to 1.1 €/L in Danish systems under favourable electricity pricing and oxygen valorisation conditions [20]. Existing modelling efforts often overlook these key system interactions when estimating the LCOH. Moreover, few studies have examined how resource-complementary countries, such as Spain and Denmark, could jointly develop hydrogen systems for both domestic supply and coordinated export strategies.

To address these gaps, this study introduces a country-level, high-resolution techno-economic framework to optimise renewable hydrogen systems for Spain and Denmark, focusing on export-oriented configurations. The main renewable resources (hourly distributions) of two countries with distinct RESs, Spain (PV) and Denmark (offshore wind), are compared for the year 2050 in a standalone mode. In this study, "standalone mode" refers to an off-grid configuration in which renewable generation, electrolysis and hydrogen storage operate as a self-contained system sized to meet the annual hydrogen export target without grid imports or external balancing. All mismatches between RES availability and electrolyser consumption are resolved through internal curtailment or storage. Using six years of hourly RES data and an exhaustive grid optimisation of RES, electrolyser and hydrogen storage capacities, we identify cost-minimizing system configurations while meeting a fixed annual demand. The LCOH in both countries is estimated and compared. The study incorporates a comprehensive sensitivity analysis using Latin hypercube sampling to reflect cost uncertainty, and evaluates three hydrogen storage technologies: salt caverns, pressurised tanks, and LOHCs.

By providing granular insights into seasonal performance, system costs and infrastructure trade-offs, this work contributes to current debates on the spatial and technological configuration of a future European hydrogen economy. Our findings aim to inform policymakers, investors and planners seeking to prioritise investments in scalable, cost-effective green hydrogen production hubs in Europe.

Unlike system-wide models such as PyPSA-Eur-Sec [12] or Balmorel [21], which focus on network-level hydrogen flows, our approach provides granular cost breakdowns (LCOH) and seasonal performance insights at the country level. This enables a detailed comparison of storage technologies and highlights the complementarities between Iberian PV and Danish offshore wind, offering a replicable blueprint for future European hydrogen hubs.

This study contributes to the literature by combining several novel elements within a unified framework: (i) a structured techno-economic optimisation of hydrogen supply chains under future deployment assumptions; (ii) a cross-country comparison between systems with contrasting RES profiles, highlighting their seasonal complementarity; (iii) an explicit evaluation of hydrogen storage technologies and their impact on LCOH; and (iv) a dual uncertainty analysis, combining parametric and interannual variability. These aspects distinguish this work from prior LCOH optimisation studies, which typically focus on single-country configurations or single-variable sensitivities.

2. Methods

This section describes the modelling framework developed to optimise renewable hydrogen production in Spain and Denmark under standalone, off-grid operation. The method integrates hourly renewable energy time series, techno-economic inputs, and an exhaustive capacity search to determine the combination of renewable generation, electrolysis and hydrogen storage that minimises the levelised cost of hydrogen while meeting the annual export target.

The framework is structured around four methodological principles. First, the system operates in standalone, off-grid mode: renewable generation, electrolysis and storage are dimensioned jointly to satisfy the annual hydrogen export requirement without grid imports or external balancing. Second, the optimisation relies on an exhaustive grid-search procedure, in which each combination of RES, electrolyser and storage capacities is evaluated against the hydrogen demand constraint. Third, the model uses hourly time-series inputs for RES availability, enabling an explicit representation of seasonal variability. Finally, techno-economic performance is quantified through a transparent LCOH formulation that consistently integrates CAPEX, OPEX, efficiency and lifetime parameters across all configurations.

2.1. Capacity optimisation framework and computational procedure

This study develops a strategy to optimize the installed RES, electrolysis, and storage capacities for wind- and solar-based hydrogen systems, as shown in Fig. 1. Historical hourly generation data from the Danish and Spanish transmission system operators (TSOs) (2019–2023)

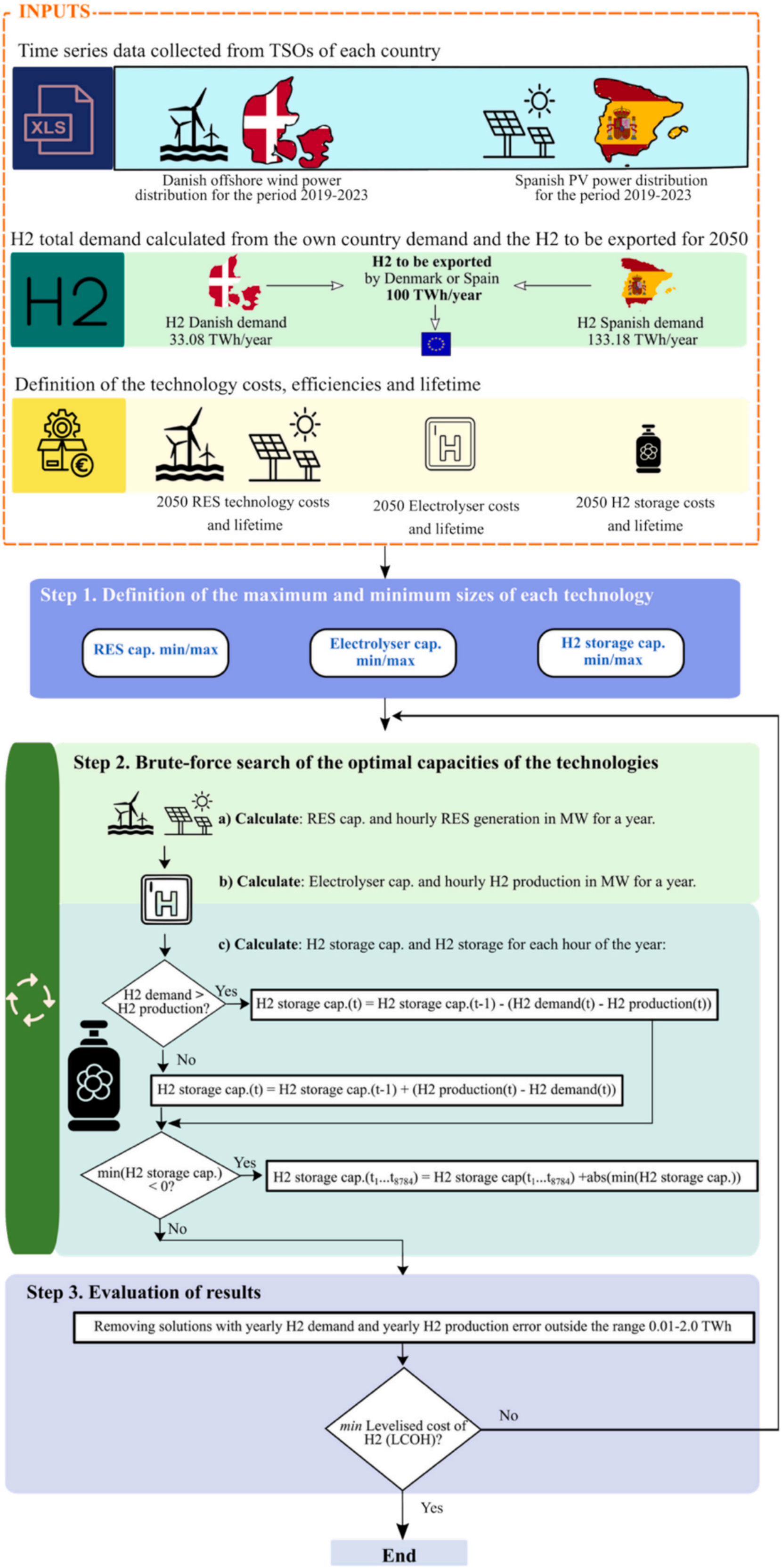

Fig. 1. Overall method used in this research.

were processed into normalized profiles: offshore wind for Denmark and solar PV for Spain, using publicly available datasets from Energinet [22] Red Electrica de España [23], respectively. In Denmark, offshore wind output is occasionally curtailed by market constraints or North German grid congestion, so these historical records may underestimate real potential during certain hours. Spatial interactions such as wake losses in offshore wind farms or aggregation effects in PV generation are not modelled in this study, as the framework operates on capacity-scale hourly profiles rather than spatially resolved layouts.

The analysis assesses whether each country can satisfy its own hydrogen demand and supply its share of the 100 TWh/yr export target under optimised RES, electrolyser, and storage capacities. To determine the optimal system sizing, minimum and maximum capacity bounds are defined for each technology, as illustrated in Step 1 of Fig. 1.

The lower bounds of renewable generation and electrolyser capacities are derived directly from the annual hydrogen production target defined in Section 2.3, which includes both domestic demand and a fixed export quota. This ensures that the minimum explored capacities are theoretically sufficient to meet the prescribed hydrogen output under ideal operating conditions. The upper bounds are set to ten times the corresponding minimum values in order to define a sufficiently wide exploration space for the exhaustive grid search, allowing the optimisation to capture both conservative and highly overdimensioned system configurations without imposing arbitrary technological constraints.

The assumed export volume is consistent with the European Hydrogen Backbone roadmap roadmap [24], which sizes each main cross-border hydrogen corridor at approximately 100 TWh/yr, ensuring coherence between the demand assumptions, the capacity bounds, and the planned European hydrogen transport infrastructure.

The core of the method involves an exhaustive grid search to find the optimal RES and electrolysis capacities, as shown in Step 2 of Fig. 1. For each combination of RES and electrolysis capacities, the required hydrogen storage capacity is derived endogenously from the hourly balance between production and demand, and the following calculations areperformed:

a) **RES generation:** The hourly RES generation was computed by multiplying a normalized annual average hourly generation profile and the assumed RES installed capacity for each scenario. The original datasets, obtained from the Danish and Spanish TSOs, contain real hourly power production values (in MW). These were processed by aggregating multiple years of data (2019–2023), grouped by month, day, and hour, and calculating the average hourly profile across the entire year. The resulting profile was then normalized to a maximum of 1, enabling scalable simulation of renewable generation under varying capacity assumptions in the optimization model.
b) **Electrolyser power demand:** The hourly electrolyser power consumption is limited by both its installed capacity and the available renewable electricity. At each hour, the electrolyser operates at its rated capacity when sufficient RES generation is available, and otherwise follows the available RES output. Any excess renewable electricity that cannot be absorbed by the electrolyser or hydrogen storage is curtailed.
c) **Hydrogen production:** The hydrogen production was determined based on the electrolyser power demand and the conversion efficiency.

The hourly hydrogen storage levels were computed based on the difference between constant hydrogen demand (which includes both domestic use and a flat export profile) and variable production. This simplification reflects an average annual target, though further studies could incorporate dynamic export demand scenarios. If the minimum hydrogen storage capacity was found to be less than zero at any point, it was adjusted to ensure all storage values were non-negative.

The LCOH was computed for each capacity combination. This involved calculating the capital expenditure (CAPEX) and operational expenditure (OPEX) for the RES, electrolyser, and hydrogen storage. Cost data for 2050 was used, including technology costs, efficiencies, and lifetimes (see Table 1).

The results were evaluated to identify the optimal solutions based on the minimum LCOH while ensuring hydrogen production met demand. As illustrated in Step 3 of Fig. 1, solutions with significant discrepancies between yearly hydrogen demand and production were removed.

The model iteratively evaluates all technically feasible combinations of renewable, electrolyser, and storage capacities. Infeasible configurations (those that fail to meet the annual hydrogen export target or violate system constraints) are discarded. This brute-force search across a discretised but sufficiently fine design space ensures that the global optimum is reliably identified. The dominant optimal solution refers to the configuration that consistently minimises the levelised cost of hydrogen (LCOH) across all simulated conditions.

Several figures were generated to visualize the results, including plots illustrating the relationships between the RES, electrolysis, and hydrogen storage capacities, and the LCOH. Seasonal LCOH variations were also analysed and presented.

Seasonal data was processed to account for variations in renewable energy production and hydrogen demand. This involved calculating the RES and electrolysis capacities for different seasons and assessing their impact on the LCOH.

2.2. Mathematical formulation of the optimisation problem

This section details the mathematical formulation of the optimisation problem, including the objective function, decision variables, constraints, and treatment of hourly renewable energy surpluses. The procedure combines an exhaustive capacity search with an endogenous derivation of hydrogen storage requirements, ensuring internal consistency between hourly operation and annual system sizing.

Table 1
Cost assumptions considered for the analysis.

Cost Assumption	Denmark	Spain	Unit	Source
Renewable Energy Source (RES) Costs				
Specific Investment Cost (SIC)	1.99 (Offshore wind)	0.35 (PV)	MEUR/MW	DEA [34], MITERD [31] IEA [30]
Useful Life Period	30	40	Years	DEA [34]
Fixed OPEX	0.0133	0.0232	(0–1)	DEA [34]
Variable OPEX	0	0	EUR/MWh	Incl. in fixed
Electrolyser Costs				
SIC	0.51	0.51	MEUR/MW	DEA [35]
Useful Life Period	25	25	Years	DEA [35],, MITERD [31], IEA [30]
Fixed OPEX	0.04	0.04	(0–1)	DEA [35,36]
Variable OPEX	0	0	EUR/MWh	DEA [35]
Efficiency of Electrolyser	0.696	0.696	(0–1)	DEA [35]
Hydrogen Storage Costs				
SIC	22.33	22.33	MEUR/GWh	DEA (tank) [33]
	1.28	1.28	MEUR/GWh	DEA (salt-cavern) [33]
	0.32	0.32	MEUR/GWh	DEA (LOHC) [33]
Fixed OPEX	0.0092	0.0092	(0–1)	DEA (tank) [33]
	0.02	0.02	(0–1)	DEA (salt-cavern) [33]
	0.0425	0.0425	(0–1)	DEA (LOHC) [33]
Useful Life Period	48	48	Years	Assumed
Variable OPEX	0.01	0.01	(0–1)	DEA [33]
Interest Discount Rate	0.03	0.03	(0–1)	Assumed

The optimisation identifies the combination of renewable generation and electrolysis capacities that minimises the levelised cost of hydrogen (LCOH). The decision variables are the installed capacities of RES, C_{RES}, and the installed capacities of electrolysers, C_{EL}. corresponding to the installed capacities of RES and electrolysers.

The storage capacity is not treated as an independent decision variable, but is derived endogenously as the minimum capacity required to balance hourly hydrogen production and a constant hydrogen demand over the year. This formulation avoids prescribing storage size ex ante and instead derives it directly from the temporal mismatch between production and demand, allowing storage to emerge as a system outcome rather than a design input.

2.2.1. Objective function

The optimisation problem aims to minimise the LCOH while satisfying the annual hydrogen demand constraint.

$$\min_{C_{RES},C_{EL}} LCOH$$

where the LCOH is defined as the ratio of total annualised system costs to total annual hydrogen production (Eq. (1)). The cost assessment includes the CAPEX and OPEX of renewable generation, electrolysis, and the endogenously determined hydrogen storage capacity (Section 2.3).

$$\text{LCOH} = \frac{\sum_i \left(CAPEX_i^{ann} + OPEX_i\right)}{H_{2,prod}} \tag{1}$$

where i denotes each system component (renewable generation, electrolysis, and hydrogen storage), $CAPEX_i^{ann}$ represents the annualised capital cost computed using a capital recovery factor based on the technology lifetime and discount rate, $OPEX_i$ includes fixed and variable operational expenditures, and $H_{2,prod}$ is the total annual hydrogen production. This formulation ensures internal consistency between investment decisions, operational performance, and the resulting hydrogen cost.

Throughout the manuscript, the LCOH is expressed in MEUR/TWh H_2 as the primary unit, consistent with the system-level formulation and export-oriented analysis.

2.2.2. Hourly operation constraints

Hourly renewable electricity generation is given by Eq.(2):

$$P_{RES}(t) = C_{RES} \cdot CF(t) \tag{2}$$

where $CF(t)$ is the normalised hourly capacity factor.

The electrolyser is assumed to operate at its rated capacity whenever sufficient RES is available and is limited otherwise (Eq. (3)), Additionally, the electrolyser is modelled as a continuously dispatchable unit, assumed to be infinitely divisible and capable of operating over the full load range without minimum stable load constraints. Effects related to modularity, part-load efficiency and degradation are neglected in order to preserve tractability at system level:

$$P_{EL}(t) = \min(C_{EL}, P_{RES}(t)) \tag{3}$$

with $P_{EL}(t) \geq 0$.

Hydrogen production follows the expression given by Eq. (4):

$$H_{prod}(t) = \eta_{EL} \cdot P_{EL}(t) \tag{4}$$

where η_{EL} is the electrical-to-hydrogen conversion efficiency of the electrolyser.

Hydrogen demand is modelled as a constant hourly profile over the year (Eq. (5)):

$$H_{dem}(t) = \frac{H_{target}}{N_h} \tag{5}$$

where H_{target} is the annual hydrogen requirement (domestic demand plus exports) and N_h is the number of hours in the representative year.

Hydrogen demand is represented as a flat hourly profile derived from the annual target demand. This simplification allows the analysis to focus on the effects of renewable variability and storage requirements, rather than demand-side dynamics.

The storage level evolves according to the hourly mass balance (Eq. (6)):

$$H_{STO}(t+1) = H_{STO}(t) + H_{prod}(t) - H_{dem}(t) \tag{6}$$

After computing the hourly storage level time series, the entire series is vertically shifted so that its minimum value equals zero. The required storage capacity is then obtained as the maximum value of the shifted series: $\max_t H_{STO}(t)$

Curtailment is implicitly allowed and given by Eq. (7):

$$P_{curt}(t) = P_{RES}(t) - P_{EL}(t) \geq 0 \tag{7}$$

Excess renewable electricity is implicitly curtailed whenever renewable generation exceeds electrolyser capacity. No grid export or alternative valorisation of surplus electricity is considered, in line with the standalone system assumption.

2.2.3. Annual hydrogen requirement

At the annual level, hydrogen production is required to match the prescribed target demand within a narrow tolerance. In the implementation, only configurations for which the annual balance $H_{prod,annual} - H_{target}$ lies within this tolerance are retained. Among the feasible configurations, the solution with the lowest LCOH is selected, ensuring consistency between hourly system operation and annual capacity sizing.

2.2.4. Search space discretisation

The optimisation uses an exhaustive grid search across predefined ranges for renewable generation and electrolyser capacities (C_{RES} and C_{EL}). These capacities vary from a minimum derived from the annual hydrogen demand to a maximum set at ten times this value. Both C_{RES} and C_{EL} are discretised into 500 equally spaced values, resulting in up to 250,000 candidate configurations per case study.

For each capacity pair (C_{RES}, C_{EL}) the hourly system operation is simulated, the hydrogen storage trajectory is computed, and the required storage capacity C_{STO} is derived endogenously from the mismatch between hourly hydrogen production and demand. The corresponding LCOH is then calculated, and only configurations satisfying the annual hydrogen demand within the specified tolerance are retained for the selection of the cost-optimal solution.

2.3. Renewable resource time-series processing and demand definition

The projected 2050 hydrogen production was calculated by adding each country's internal demand derived from the sEEnergies 1.5 scenario (33.08 TWh/yr for Denmark [25] and 133.18 TWh/yr for Spain [26]). The European Hydrogen Backbone roadmap [24] sizes each main cross-border corridor at about 100 TWh/yr in its first stage [24,27]. Denmark and Spain are the designated supply hubs of the North Sea and Iberian corridors, respectively, owing to their comparable offshore-wind and solar potentials. Additionally, recent analyses support the ability of both hubs to supply exports of this scale: the Det Norske Veritas group projects Spanish exports of roughly 1.7 Mt H_2 (~57 TWh / yr) by 2050 [28], while Denmark's Power-to-X strategy (4–6 GW electrolysis by 2030 and planned North Sea energy islands) underpins comparable volumes [29]. Allocating one full corridor (around 100 TWh/yr) to each country is therefore consistent with both their export capability and the planned pipeline capacity. Adding this export quota to domestic demand from the sEEnergies 1.5 scenario yields 2050 production requirements of roughly 133 TWh/yr and 233 TWh/yr, respectively [22,23].

Data was collected from the TSO webpage or datacentre available for each country. More specifically, for Denmark the Danish offshore wind power distribution data was collected for the period 2019–2023 from the Energi Data Service of Energinet [22]. For Spain, Spanish PV power distribution data for the same period was collected from Red Electrica de España [23].

Fig. 2a shows a boxplot with the median and mean monthly offshore wind power generation in Denmark. A boxplot is a graphical representation that displays the distribution of a dataset, highlighting the median, quartiles, and potential outliers. In this figure, the highest average offshore wind power generation is in December at around 1400 MW, while the lowest is in June at around 400 MW. Offshore wind power generation is higher in the winter months (December, January, February) and lower in the summer months (June, July, August).

Fig. 2b shows the average monthly PV power generation in Spain. The boxplot shows that PV output is generally higher in the summer months (June, July, August) and lower in the winter months (December, January, February), indicating a significant seasonal variation.

2.4. Techno-economic assumptions and cost modelling

This section presents the techno-economic assumptions adopted in the model, which serve as the baseline for all simulations. These include the specific CAPEX, called the specific investment cost (SIC), technology lifetimes, OPEX, and energy conversion efficiencies for the main system components: RES, electrolyser, and hydrogen storage systems.

The selected baseline values are derived from the average projections for the year 2050, compiled from authoritative sources including the Danish Energy Agency (DEA), the Spanish Ministry for the Ecological Transition and the Demographic Challenge (MITERD), and the International Energy Agency (IEA) [30–35]. These values fall within the expected ranges for each technology, as summarised in Table 1.

For renewable electricity generation, the SIC is set at 1.99 MEUR/MW for offshore wind in Denmark and 0.35 MEUR/MW for utility-scale PV in Spain. These values are within the projected 2050 DEA range of 1.29–2.68 MEUR/MW for offshore wind and 0.25–0.59 MEUR/MW for PV [34], considering a weighted average of different configurations (rooftop, ground-mounted, and tracking). The useful life is assumed to be 30 years for offshore wind and 40 years for PV. Fixed OPEX costs are estimated at 1.33% of the CAPEX for Denmark and 2.32% of the CAPEX for Spain. No variable OPEX costs are included.

The SIC for electrolysers is set at 0.51 MEUR/MW, consistent with the 2050 control scenario DEA long-term projection of 0.23–1.33 MEUR/MW [35], covering alkaline, protein exchange membrane (PEM), and SOEC technologies. A lifetime of 25 years is assumed, which falls within the expected range of 14.1–25 years across the different technologies, acknowledging future improvements. Fixed OPEX costs are set at 4%, with no variable OPEX costs considered.

Electrolyser efficiency is assumed to be 69.6%, which aligns with the upper band of the average efficiency projections for 2050 (62.7%–77.2%) [35] and reflects progress in performance for alkaline and PEM technologies under commercial-scale deployment. A fixed O&M cost of 4% of CAPEX per year was assumed for alkaline electrolysis systems, covering both routine maintenance and periodic stack replacement. This value is consistent with the ranges reported by the Danish Energy Agency [35] and the Clean Hydrogen Strategic Research and Innovation Agenda [36], which cite 3–4% OPEX for AEC systems. While PEM electrolyzers typically report lower fixed OPEX values (~2%) [36], using a common 4% assumption ensures conservative estimates and avoids underrepresentation of long-term maintenance costs.

Hydrogen storage costs consider three infrastructure types: pressurised tank storage, salt cavern storage, and LOHC systems. The assumed CAPEX values are 22.33 MEUR/GWh for pressurised tanks, 1.28 MEUR/GWh for salt caverns, and 0.32 MEUR/GWh for LOHC systems, based on long-term projections from the Danish Energy Agency (DEA)[33]. Technical lifetimes were uniformly set to 48 years across all storage options to ensure consistent amortisation in the LCOH calculation. While DEA data reports a broad range of lifetimes (30 years for pressurised tanks, 20 years for LOHC, and 100 years for salt caverns) this standardisation facilitates comparability between technologies. Fixed OPEX costs, however, are differentiated to reflect operational characteristics: 0.92% of CAPEX for tanks, 2.13% for salt caverns, and 4.25% for LOHC. This structure accounts for the higher operational burden and degradation effects associated with LOHC systems, while maintaining internal consistency in cost representation. Variable OPEX is assumed at 1% of CAPEX for all cases.

A discount rate of 3% is uniformly applied across all technologies, consistent with socio-economic evaluation practices for long-term infrastructure investments [30–32,37].

2.5. Parametric sensitivity analysis under techno-economic uncertainty

Given the inherent uncertainty in long-term techno-economic projections, a structured sensitivity analysis was conducted to assess the robustness of the model outcomes against variations in investment and operational parameters. This analysis covers the three key elements of

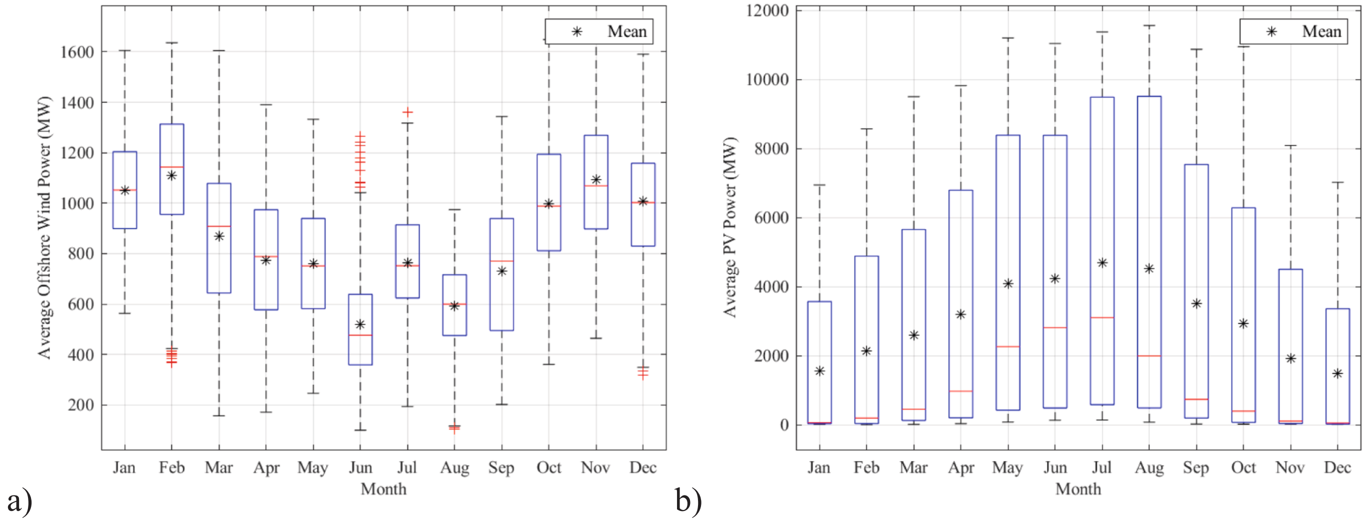

Fig. 2. Boxplots with: a) the monthly average offshore wind power produced in Denmark; and b) the monthly average PV power produced in Spain, during the period 2019–2023.

the hydrogen value chain: renewable power generation, water electrolysis, and hydrogen storage.

The parameter space was defined using the 2050 cost projections published by the DEA, supplemented with Spanish-specific data from MITERD and the IEA. For each technological component, the following attributes were considered: CAPEX/SIC, fixed and variable OPEX costs, technical lifetime, and (for electrolysers) conversion efficiency. Each parameter was associated with a reference value (DEA control), as well as lower and upper bounds reflecting realistic uncertainty intervals.

To explore this multidimensional uncertainty space, a Latin hypercube-style sampling method was applied to generate 30 independent scenarios. This technique partitions the uncertainty range of each parameter into equally probable intervals and selects a random sample from each one, ensuring complete coverage without clustering or redundancy. This approach, commonly used in energy system modelling [38], enables the generation of a representative set of scenarios that capture the full variability of plausible futures without requiring an exhaustive number of simulations.

Each of the 30 Monte Carlo scenarios consists of a unique, simultaneously perturbed set of parameter values. These are injected into the techno-economic model described in sections 2.1–2.4, replacing the control values. For each sampled parameter set, the complete optimisation procedure described in Section 2.2 is executed independently. The following computational workflow was applied:

a) Parameter injection: Sampled parameters are loaded into the model replacing baseline assumptions.
b) Capacity optimisation: A brute-force algorithm searches for the cost-optimal combination of renewable generation, electrolysis, and hydrogen storage capacities to satisfy the annual hydrogen demand.
c) Feasibility check: Configurations with a supply–demand imbalance greater than 0.01 TWh/year are discarded.
d) Post-processing: Valid outputs are stored and used to compute descriptive statistics, including the mean and standard deviation of the LCOH, critical excess energy produced, storage requirements, and renewable capacity shares.

The techno-economic input ranges and associated descriptors are summarised in Table 2, which lists the lower and upper bounds adopted, the DEA reference (control) values, and the mean and standard deviation of the 30 sampled values for each parameter.

This methodological framework allows identification of the influence of individual variables on system performance and to quantify the elasticity of LCOH with respect to cost and performance parameters. The resulting insights are analysed in Section 3.4.

For each capacity combination within each sensitivity scenario, hourly system operation is simulated under standalone conditions. Surplus renewable electricity is curtailed when generation exceeds electrolyser capacity, the hydrogen storage trajectory and the required storage capacity are derived endogenously from the mismatch between hourly production and demand, and the corresponding LCOH is computed. This ensures full consistency between the sensitivity analysis and the optimisation framework.

It is noted that the optimisation framework is applied independently to Spain and Denmark, and that no joint optimisation or cross-border energy exchange is explicitly modelled. The seasonal complementarity discussed in this work therefore emerges from a comparative analysis of independently optimised national systems, rather than from a coupled operational optimisation. Accordingly, this complementarity should be interpreted as a strategic planning insight rather than as an operationally coupled solution. The results indicate that independently optimised national export hubs can jointly contribute to a more balanced and stable European hydrogen supply when connected through shared hydrogen transport infrastructure.

Table 2
Techno-economic parameter ranges and descriptors used in the sensitivity analysis.

Cost Assumption	Lower/ Upper (Denmark)	Lower/ Upper (Spain)	Control (DEA)	Mean (30 MC)	Units
Renewable Energy Source (RES) Costs					
RES Specific Investment Cost (SIC)	1.29 / 2.68	0.25 / 0.59	1.99 / 0.35	1.99 / 0.42	MEUR/ MW
Useful Life Period	25 / 40	40 / 40	30 / 40	32.5 / 40	Years
Fixed OPEX Cost	0.0103 / 0.0117	0.0117 / 0.0279	0.0133 / 0.0232	0.0122 / 0.0198	(0–1)
Variable OPEX Cost	0 / 0	0 / 0	0 / 0	0 / 0	EUR/ MWh
Electrolyser Costs					
Electrolyser SIC	0.22 / 1.32	0.22 / 1.32	0.51 / 0.51	0.77 / 0.77	MEUR/ MW
Electrolyser Lifetime	14.1 / 25	14.1 / 25	25 / 25	19.55 / 19.55	Years
Electrolyser Fixed OPEX	0.02 / 0.12	0.02 / 0.12	0.04 / 0.04	0.07 / 0.07	(0–1)
Electrolyser Efficiency	0.627 / 0.772	0.627 / 0.772	0.696 / 0.696	0.6995 / 0.6995	(0–1)
Hydrogen Storage Costs					
H_2 Storage SIC (Tank)	22.33 / 37.48	22.33 / 37.48	22.33 / 22.33	29.91 / 29.91	MEUR/ GWh
H_2 Storage SIC (Cavern)	1.06 / 1.91	1.06 / 1.91	1.28 / 1.28	1.49 / 1.49	MEUR/ GWh
H_2 Storage SIC (LOHC)	0.32 / 0.43	0.32 / 0.43	0.32 / 0.32		MEUR/ GWh
H_2 Storage Fixed OPEX (Tank)	0.0092 / 0.0092	0.0092 / 0.0092	0.0092 / 0.0092	0.0092 / 0.0092	(0–1)
H_2 Storage Fixed OPEX (Cavern)	0.0213 / 0.0213	0.0213 / 0.0213	0.0213 / 0.0213	0.0213 / 0.0213	(0–1)
H_2 Storage Fixed OPEX (LOHC)					(0–1)
H_2 Storage Variable OPEX (Cavern)	0.0113 / 0.0113	0.0113 / 0.0113	0.0113 / 0.0113	0.0113 / 0.0113	(0–1)
H_2 Storage Variable OPEX (LOHC)	0.0106 / 0.0106	0.0106 / 0.0106	0.0106 / 0.0106	0.0106 / 0.0106	(0–1)
Useful Life (Storage)	48 / 48	48 / 48	48 / 48	48 / 48	Years
Interest Discount Rate	0.03 / 0.03	0.03 / 0.03	0.03 / 0.03	0.03 / 0.03	(0–1)

3. Results and discussion

3.1. Analysis of the costs of PV-powered hydrogen generation in Spain

The costs associated with hydrogen generation driven by solar PV power in Spain are presented in this subsection. Unless otherwise stated, the results presented in this subsection correspond to the reference configuration assuming pressurised hydrogen tank storage, and average hourly profile for RES generation across the analysed years. Both annual and seasonal variations in costs and capacities for PV power, electrolysis, and hydrogen storage are presented. The main inputs and results are derived from the following data and visualized in Figs. 4 and 5.

The annual results reveal that the optimal PV power capacity is 223.26 GW, the optimal electrolyser capacity is 85.61 GW, and the optimal hydrogen storage capacity is 23.13 TWh (Table 3).

Tables 4 and 5 below summarize the key metrics by year and season. The LCOH is calculated to be 173.5 MEUR per TWh of hydrogen (for reference, 1 MEUR/TWh ≈ 0.033 €/kg H_2 on a lower-heating-value

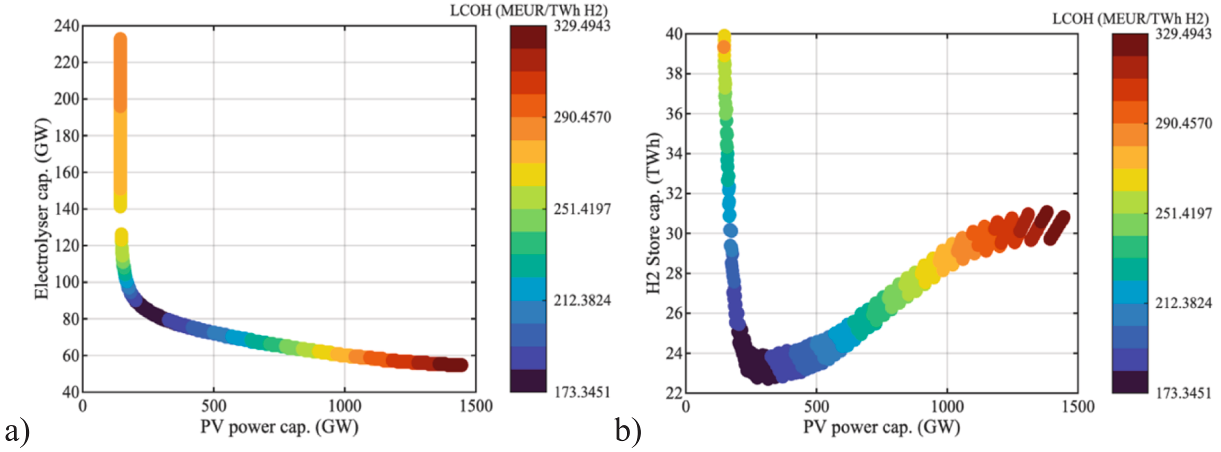

Fig. 3. Dominant cost-optimal feasible solutions for the Spanish PV-based hydrogen system obtained from the exhaustive grid-search optimisation. Each point represents a configuration that satisfies the annual hydrogen demand constraint and minimises the levelised cost of hydrogen (LCOH) within the explored design space. Panel (a) shows the relationship between installed PV power and electrolyser capacity, while panel (b) shows the relationship between installed PV power and the endogenously derived hydrogen storage capacity. Colours indicate the corresponding LCOH values. *The figure does not represent a Pareto front.*Fig. 4 presents the LCOH produced, measured in millions of euros per TWh of hydrogen (MEUR/TWh H2), for different periods: the entire year, winter, spring, summer, and autumn. The costs are broken down into three components: PV costs, electrolyser costs, and hydrogen storage costs. Additionally, a reference price from Energinet (60.5 MEUR/TWh H2 exported) is included (dashed line) for comparison. It can be seen that the cost of hydrogen production is strongly influenced by seasonal variations, with winter and autumn showing significantly higher costs primarily due to increased hydrogen storage expenses.

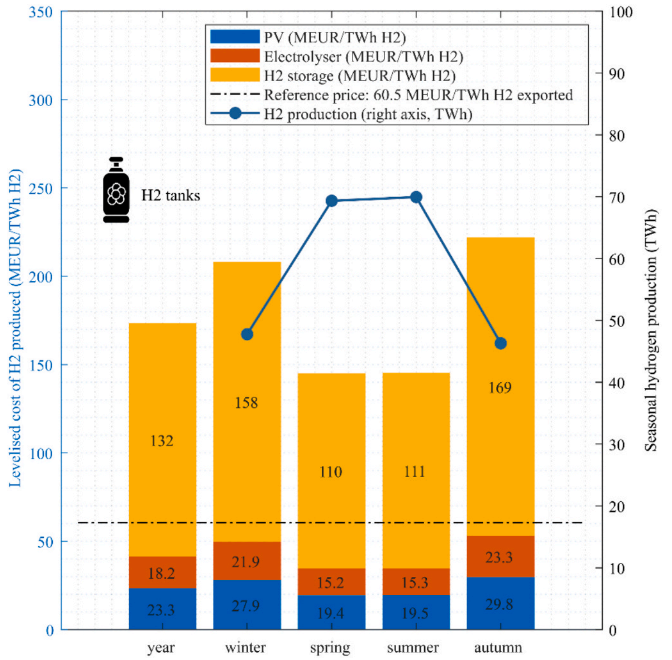

Fig. 4. Seasonal breakdown of the levelised cost of hydrogen (LCOH) for a PV-based hydrogen system in Spain. Stacked bars represent the contributions of PV generation, electrolysis, and hydrogen storage to the LCOH, while the dashed line denotes the reference export price. Seasonal hydrogen production (TWh) is shown on the secondary axis, highlighting intra-annual variability in hydrogen output.

(LHV) basis; thus 173.5 MEUR/TWh ≈ 5.7 €/kg). Annual hydrogen production is 233.26 TWh, closely matching the hydrogen demand of 233.18 TWh, with a minimal error of 0.14 TWh. The CAPEX and OPEX for RES are 3532.0 MEUR and 1894.1 MEUR, respectively. For electrolysers, the CAPEX is 2507.3 MEUR and the OPEX 1746.4 MEUR. Hydrogen storage incurs a CAPEX of 20437.7 MEUR and an OPEX of 10327.9 MEUR. The critical excess energy production (CEEP) is 205.2 TWh, and the capacity factor of the electrolyser is 0.45.

Fig. 3a and Fig. 3b show the relationship between PV power and electrolyser capacities and between PV power and hydrogen storage capacities, respectively, with the LCOH color-coded. Each point in the graphs represents a dominant optimal solution obtained from the brute-force procedure described earlier. Fig. 3a shows the set of dominant cost-optimal feasible configurations resulting from the optimisation. The lowest LCOH values occur for combinations of moderate PV capacity (below approximately 500 GW) and moderate electrolyser sizing, reflecting a system-level trade-off between renewable over-dimensioning, electrolyser utilisation and the resulting hydrogen storage requirement.. This suggests that achieving an optimal balance between PV power and storage is crucial for cost efficiency.

For the entire year, the LCOH is approximately 173.50 MEUR/TWh H2, broken down as follows: PV costs at 23.3 MEUR/TWh H2, electrolyser costs at 18.2 MEUR/TWh H2, and hydrogen storage costs at 132.0 MEUR/TWh H2 (Table 5 and Fig. 6). Spring and summer have the lowest costs, suggesting that optimizing PV capacity during these periods can be particularly cost effective. In all periods, the LCOH is higher than the reference price from Energinet for exported hydrogen at 60.5 MEUR/TWh H2, highlighting the challenge of meeting cost targets. The most substantial contributor to the LCOH is the cost of hydrogen storage, which remains consistently high across all periods. Therefore, it makes sense to focus efforts on reducing hydrogen storage costs and to analyse how these potential reductions might influence the overall costs.

3.2. Analysis of the costs of offshore wind-powered hydrogen generation in Denmark

This subsection presents the costs associated with hydrogen generation driven by offshore wind power in Denmark. Unless otherwise stated, the results presented in this subsection correspond to the reference configuration assuming pressurised hydrogen tank storage, and average hourly profile for RES generation across the analysed years. Both annual and seasonal variations in costs and capacities for offshore wind power, electrolysers, and hydrogen storage are provided. The main inputs and results are derived from the following data and visualized in Figs. 6 and 7.

The annual results show that the optimal offshore wind power capacity is 76.37 GW, the optimal electrolyser capacity is 22.55 GW, and the optimal hydrogen storage capacity is 2.25 TWh (Table 6).

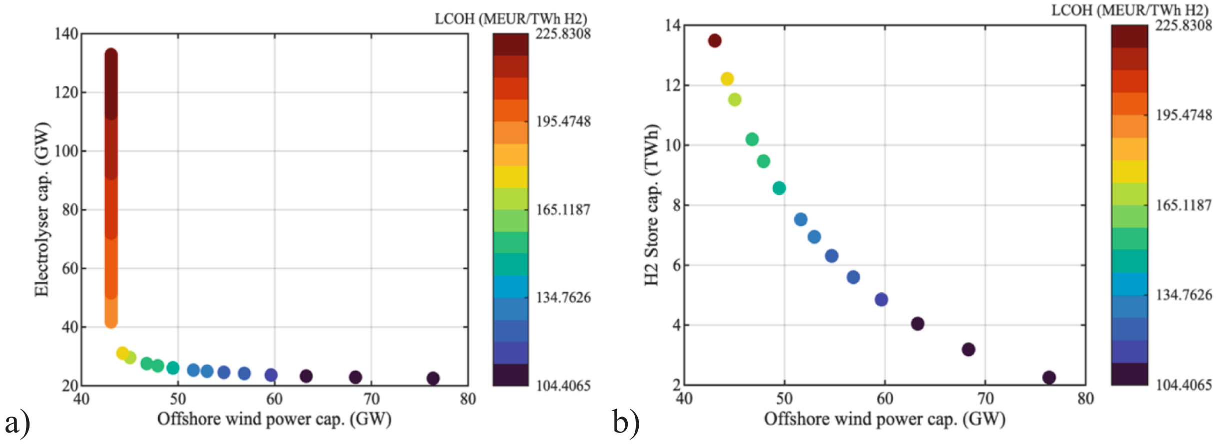

Fig. 5. Dominant cost-optimal feasible solutions for the Danish offshore-wind-based hydrogen system obtained from the exhaustive grid-search optimisation. Each point corresponds to a configuration that fulfils the annual hydrogen balance requirement and minimises the levelised cost of hydrogen (LCOH) among all feasible combinations. Panel (a) illustrates the relationship between offshore wind capacity and electrolyser capacity, while panel (b) shows the relationship between offshore wind capacity and the endogenously determined hydrogen storage capacity. Colours denote LCOH values. *The figure does not represent a Pareto front.*

Table 3
Optimal capacities obtained by the method for PV power (GW), electrolyser (GW) and hydrogen (H2) storage (TWh) in Spain.

PV Power Capacity (GW)	Electrolyser Capacity (GW)	H2 Storage Capacity (TWh)
223.26	85.61	23.13

Tables 7 and 8 below summarize the key metrics by year and season. The LCOH obtained is 104.41 MEUR/TWh of H2. Annual hydrogen production is 133.07 TWh, closely matching the hydrogen demand of 133.08 TWh, with a minimal error of −0.006. The CAPEX and OPEX for offshore wind in Denmark are 7753.91 MEUR and 2021.33 MEUR, respectively. For electrolysers, the CAPEX is 660.53 MEUR and the OPEX 460.08 MEUR. For hydrogen storage, the CAPEX is 1991.55 MEUR and the OPEX 1006.40 MEUR. The CEEP is 147.92 TWh, and the electrolyser capacity factor is 0.97. The optimal capacities of PV and Offshore wind power (GW), electrolyser (GW) and LOHC hydrogen (H2) storage (TWh) are shown in Table 9.

Fig. 5a and 5b illustrate the relationship between offshore wind power and electrolyser capacities, and between offshore wind power and hydrogen storage capacities, respectively, with the LCOH color-coded. Each point in the graphs represents a dominant cost-optimal feasible configuration obtained from the exhaustive grid search under the annual hydrogen balance constraint. Fig. 5a shows that low-LCOH solutions cluster around combinations of moderate electrolyser sizing and offshore wind capacities within a limited range of the explored design space. Fig. 5b highlights how increasing offshore wind capacity reduces the required hydrogen storage volume, reflecting the mitigation of seasonal production–demand mismatches.

Although Fig. 5 may suggest that lower LCOH values could be achieved by further increasing renewable capacity while reducing hydrogen storage requirements, it should be noted that the figure does not represent the full optimisation landscape. Instead, it shows the dominant feasible solutions resulting from the exhaustive grid search after applying the annual hydrogen balance constraint and cost minimisation criteria. In the model, hydrogen storage capacity is derived endogenously from the hourly mismatch between production and demand. Reducing storage requirements is therefore only possible through RES overdimensioning, which in turn increases capital costs. As a result, configurations with very high RES capacities are penalised by increasing CAPEX and do not yield lower LCOH values once the full cost structure is accounted for. The apparent trend observed in Fig. 5 thus reflects the trade-off between renewable overcapacity and storage requirements, rather than indicating that the true optimum lies at the boundary of minimal storage.

Table 4
Key metrics by year and season – hydrogen production and efficiency for the Spanish system.

Period	LCOH (MEUR/TWh H2)	H2 production (TWh)	H2 demand (TWh)	Error (TWh)	CEEP (TWh)	Electrolyser capacity factor
Year	173.5	233.3	233.2	0.14	205.24	0.45
Winter	208.2	47.8	57.3	−9.6	22.83	0.37
Spring	145.0	69.3	58.0	11.4	70.07	0.53
Summer	145.3	69.9	58.6	11.3	87.65	0.53
Autumn	221.9	46.3	59.3	−13.0	24.69	0.35

Table 5
Key metrics by year and season – CAPEX, OPEX, and specific costs for the Spanish system.

Period	RES CAPEX (MEUR)	RES OPEX (MEUR)	Electrolyser CAPEX (MEUR)	Electrolyser OPEX (MEUR)	H2 storage CAPEX (MEUR)	H2 storage OPEX (MEUR)	RES cost (MEUR/TWh H2)	Electrolyser cost (MEUR/TWh H2)	H2 storage cost (MEUR/TWh H2)
Year	3532.0	1894.1	2507.3	1746.4	20437.7	10327.9	23.3	18.2	132.0
Winter	868.1	465.5	616.3	429.2	5023.3	2538.5	27.9	21.9	158.3
Spring	877.8	470.7	623.1	434.0	5079.2	2566.7	19.4	15.2	110.3
Summer	887.4	475.9	630.0	438.8	5135.0	2594.9	19.5	15.3	110.5
Autumn	897.1	481.1	636.8	443.6	5190.9	2623.1	29.8	23.3	168.8

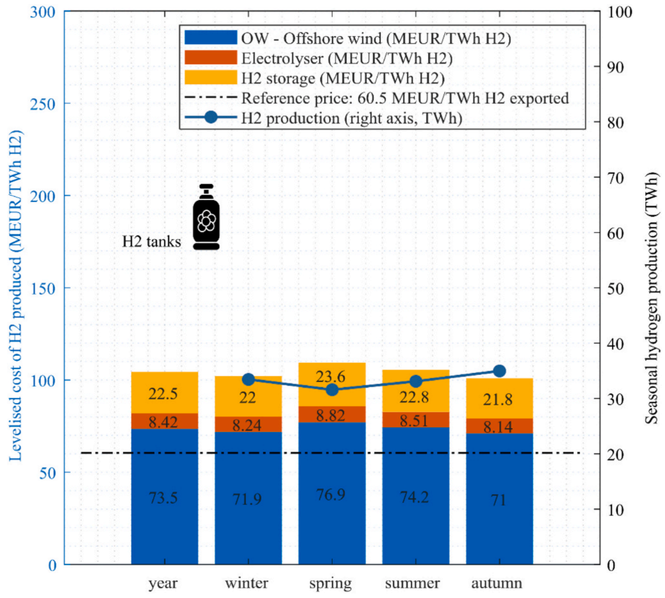

Fig. 6. Seasonal breakdown of the levelised cost of hydrogen (LCOH) for an offshore wind–based hydrogen system in Denmark. Stacked bars represent the contributions of offshore wind generation, electrolysis, and hydrogen storage to the LCOH, while the dashed line denotes the reference export price. Seasonal hydrogen production (TWh) is shown on the secondary axis, highlighting intra-annual variability in hydrogen output.

In Fig. 6 it is observed that, for the entire year, the LCOH is approximately 104.41 MEUR/TWh H2, broken down as follows: offshore wind costs at 73.46 MEUR/TWh H2, electrolyser costs at 8.42 MEUR/TWh H2, and hydrogen storage costs at 22.53 MEUR/TWh H2. Winter and autumn have the lowest costs, suggesting that optimizing offshore wind capacity during these periods can be particularly cost effective. In all periods, the LCOH is higher than the reference price from Energinet for exported hydrogen at 60.5 MEUR/TWh H2, highlighting the challenge of meeting cost targets.

3.3. *Analysis of the impact on the hydrogen production cost of potential storage costs reduction*

Fig. 7 quantifies how the LCOH responds when the storage SIC is evaluated using the upper- and lower-bound cost projections for each technology (obtained from the long-term DEA projections for 2050) [33]. Fig. 7a refers to the Spanish PV-based system, Fig. 7b to the Danish offshore-wind system.

For Spain, storage is by far the most dominant cost component in the tank-based H2 storage configurations (218 and 132 MEUR/TWh out of a total 262.4 and 173.34 MEUR/TWh, respectively). As the SIC decreases, the storage contribution collapses to around 2.33 MEUR/TWh and the total LCOH falls to roughly 40.34 MEUR/TWh, an 84.6% reduction relative to the upper cost projection for the tank configuration and well below the Energinet export reference of 60.5 MEUR/TWh. PV and electrolyser cost contributions remain practically unchanged (approximately 17.3–27.1 MEUR/TWh and roughly18.2–20.7 MEUR/TWh, respectively), confirming that storage CAPEX is the principal lever in a solar-dominated hydrogen production system.

For Denmark, storage costs are already modest thanks to the high capacity factor of offshore wind that minimizes seasonal imbalances. Nevertheless, reducing the SIC values lowers the storage term to roughly

Table 6
Optimal capacities obtained by the method for offshore wind power, electrolyser, and hydrogen storage in Denmark.

Offshore Wind Power Capacity (GW)	Electrolyser Capacity (GW)	H2 Storage Capacity (TWh)
76.37	22.55	2.25

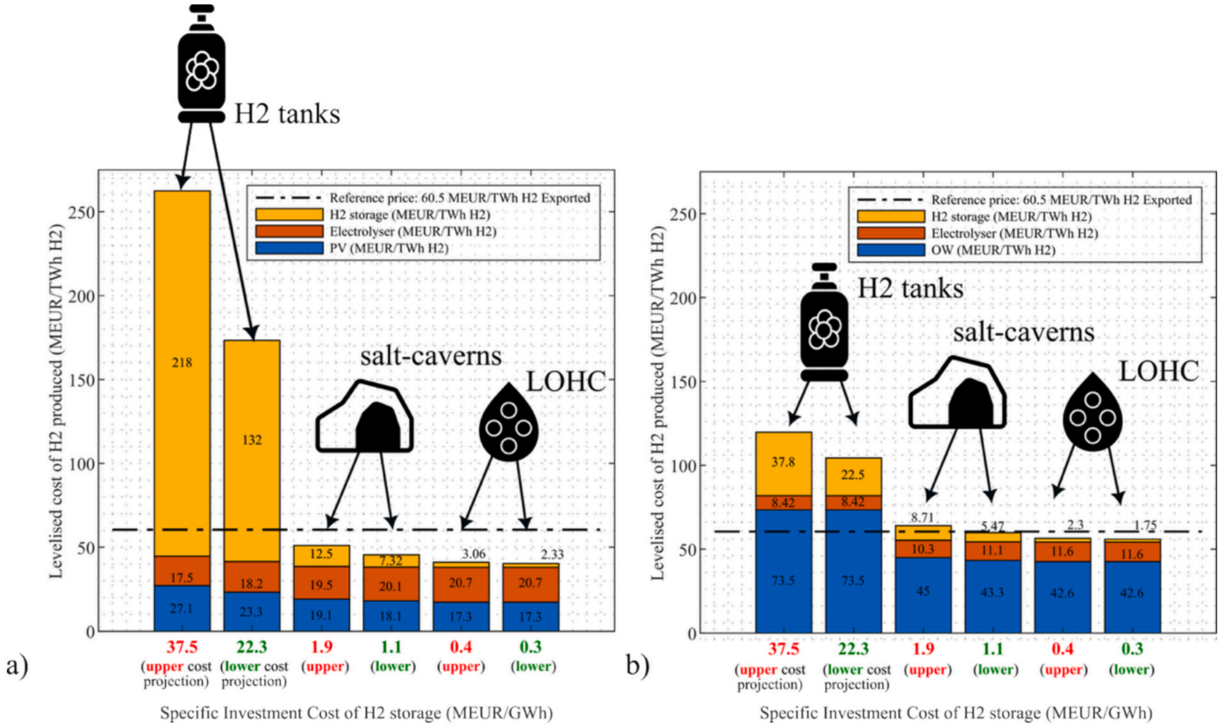

Fig. 7. Reduction of the yearly breakdown of the LCOH when the specific investment cost for hydrogen storage is reduced from 22.3 MEUR/GWh (lower estimated cost for hydrogen stored in tanks [33]) to 0.32 MEUR/GWh (lower estimated cost for hydrogen stored in LOHC in 2050 [33]) using: a) PV power in Spain; and b) offshore wind power in Denmark.

Table 7
Key metrics by year and season – hydrogen production and efficiency for the Danish system.

Period	LCOH (MEUR/TWh H2)	H2 Production (TWh)	H2 Demand (TWh)	Error (TWh)	CEEP (TWh)	Electrolyser Capacity Factor
Year	104.41	133.07	133.08	−0.006	147.92	0.97
Winter	102.13	33.44	32.72	0.712	49.71	0.99
Spring	109.36	31.57	33.09	−1.515	21.32	0.92
Summer	105.47	33.10	33.45	−0.354	21.91	0.95
Autumn	100.92	34.97	33.82	1.152	54.97	1.00

Table 8
Key metrics by year and season – CAPEX, OPEX, and specific costs for the Danish system.

Period	RES CAPEX (MEUR)	RES OPEX (MEUR)	Electrolyser CAPEX (MEUR)	Electrolyser OPEX (MEUR)	H2 Storage CAPEX (MEUR)	H2 Storage OPEX (MEUR)	RES Cost (MEUR/TWh H2)	Electrolyser Cost (MEUR/TWh H2)	H2 Storage Cost (MEUR/TWh H2)
Year	7753.91	2021.33	660.53	460.08	1991.55	1006.40	73.46	8.42	22.53
Winter	1905.82	496.82	162.35	113.08	489.50	247.36	71.86	8.24	22.04
Spring	1927.00	502.34	164.16	114.34	494.94	250.11	76.94	8.82	23.60
Summer	1948.19	507.86	165.96	115.60	500.38	252.86	74.21	8.51	22.76
Autumn	1969.37	513.39	167.76	116.85	505.82	255.61	71.00	8.14	21.78

Table 9
Optimal capacities obtained by the method after the analysis of the impact on the hydrogen production cost of potential storage costs reduction for PV and Offshore wind power (GW), electrolyser (GW) and LOHC hydrogen (H2) storage (TWh).

Country	RES Power Capacity (GW)	Electrolyser Capacity (GW)	LOHC H2 Storage Capacity (TWh)
Spain	173.3 (PV)	97.3	28.5
Denmark	44.3 (Offshore wind)	31.2	12.21

1.75 MEUR/TWh and encourages a downsizing of offshore wind capacity from 76.4 GW to ~ 45 GW. As a result, the LCOH drops from 119.7 MEUR/TWh to approximately 55.97 MEUR/TWh (around 53.2% reduction), bringing Denmark almost exactly to the Energinet benchmark.

Fig. 8 disaggregates the LOHC storage case (lower cost projection = 0.32 MEUR/GWh) by season. In Spain (Fig. 8a), the LCOH now ranges from around 32.70 MEUR/TWh in spring-summer to around 54.77 MEUR/TWh in winter-autumn, with the storage costs LCOH contribution never exceeding 4.25 MEUR/TWh. Thus, the system becomes export competitive for at least six months (two seasons) of the year. In Denmark (Fig. 8b), the annual average is roughly 55.97 MEUR/TWh, with winter and autumn at approximately 48.35 MEUR/TWh, while spring and summer reach 68.97 MEUR/TWh owing to a slightly lower wind output and the need for the additional handling of critical excess energy production.

The results show that shifting from pressurised tanks to LOHC is transformative for the Spanish PV pathway (cutting total hydrogen cost by two-thirds) and yields a substantial one-third saving in the Danish offshore wind case. The analysis underscores that (i) large-scale underground storage is a prerequisite for cost-competitive solar-driven hydrogen export; (ii) high capacity factor wind coupled with even modest cavern storage is sufficient to approach current Nordic price targets; and (iii) future research should prioritise detailed geospatial assessments of cavern potential and the integration of hybrid storage portfolios to further smooth seasonal cost swings.

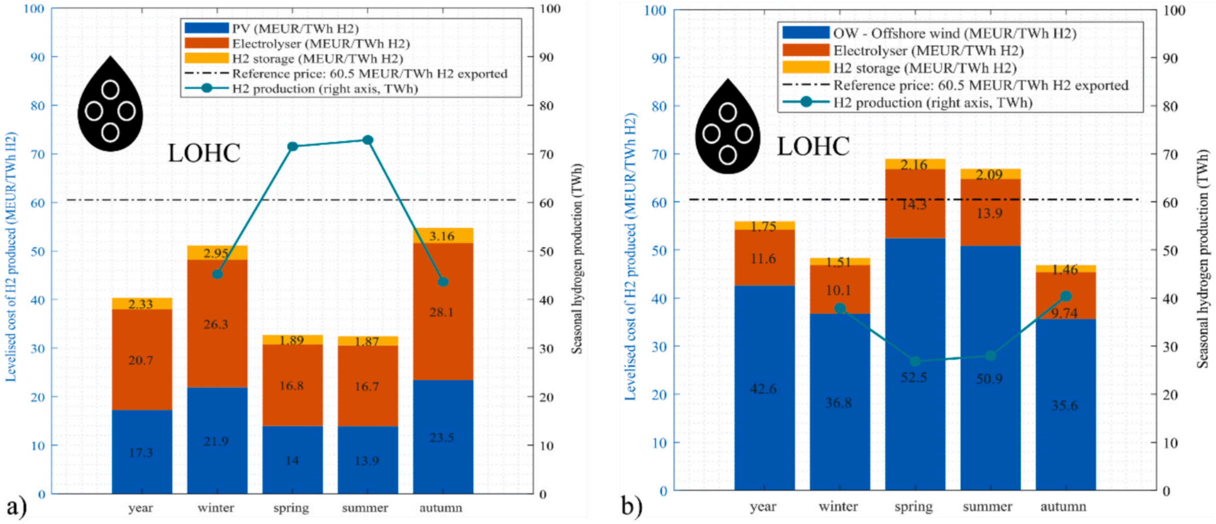

Fig. 8. Seasonal breakdown of the LCOH when the specific investment cost is 0.32 MEUR/GWh (lower estimated cost for LOHC-based hydrogen storage in 2050 [33]). Panel (a) shows the PV-based hydrogen system in Spain, and panel (b) the offshore wind–based hydrogen system in Denmark. Stacked bars represent the contributions of renewable electricity generation, electrolysis, and hydrogen storage to the LCOH, while the dashed line indicates the reference hydrogen export price. Seasonal hydrogen production (TWh) is shown on the secondary axis.

3.4. Sensitivity of hydrogen cost and system design to techno-economic parameters

This section evaluates the sensitivity of the LCOH and the overall system design to variations in techno-economic parameters. Using Latin hypercube sampling, 30 plausible and internally consistent scenarios were simulated for each configuration, reflecting uncertainties in investment costs, OPEX, lifetimes, efficiencies, and discount rates, based on the distributions in Table 2 [38]. All parameter ranges and probability distributions used to generate the scenarios are fully reported in Table 2. The objective of this analysis is not to assess individual scenarios in isolation, but to evaluate the robustness of the LCOH structure across a broad parameter space.

The analysis was conducted for both Denmark and Spain, considering three hydrogen storage technologies: salt caverns, compressed hydrogen gas tanks, and LOHC.

All parameter ranges and probability distributions used to generate the scenarios are fully reported in Table 2. The objective of this analysis is not to assess individual scenarios in isolation, but to evaluate the robustness of the LCOH structure across a broad parameter space.

The central purpose of Figs. 9 and 10 is to illustrate how uncertainty in techno-economic assumptions propagates through the system and is redistributed among renewable generation, electrolysis, and storage components, rather than to identify optimal or stable configurations on a scenario-by-scenario basis.

Fig. 9 shows the results for Denmark, where each bar represents the total levelized cost of hydrogen decomposed by contribution of each subsystem (renewables, electrolyser, and storage) for each scenario. The relatively narrow spread observed for pressurised tank systems (98–115 MEUR/TWh H2) reflects the dominant contribution of storage CAPEX under the adopted assumptions. In contrast, salt cavern and LOHC configurations exhibit a wider dispersion of LCOH values, indicating a stronger propagation of uncertainty in investment costs and lifetimes into the overall cost structure. For example, cavern-based systems span LCOH values between approximately 55 and 82 MEUR/TWh H_2, with noticeable variation in the storage contribution across scenarios.

Fig. 10 shows the results for Spain. The overall trends mirror those found for Denmark, although with generally lower LCOH values due to Spain's higher solar resource and lower assumed CAPEX for PV. Notably, LOHC configurations in Spain exhibit the lowest LCOH values of the entire analysis (as low as 42 MEUR/TWh H2)), highlighting their potential relevance in regions where underground storage options are limited or unavailable.

It should be noted that the scenarios shown in Figs. 9 and 10 are not intended to represent equally likely futures, nor to support a detailed causal interpretation of individual parameter combinations. Rather, the stacked representation is used to illustrate how uncertainty in technology-specific assumptions is redistributed among system components and reflected in the overall LCOH.. The corresponding ranges and central tendencies across scenarios are explicitly captured in aggregated form in Fig. 12. While the spread of results could be summarised by a representative value with an associated confidence interval, such an aggregated approach would obscure the internal structure of cost sensitivity that is central to the system-level interpretation pursued here.

To assess the effect of interannual variability, the model was re-run using the hourly renewable generation profiles for each individual year from 2019 to 2023, across all storage technologies and countries. Fig. 11 presents the resulting LCOH distributions per scenario. While absolute values vary across years due to weather-driven RES fluctuations, the overall cost hierarchy between technologies remains stable. This confirms that the use of an averaged profile offers robust insights while maintaining tractability.

The comparative summary provided in Fig. 12 offers a consolidated view of the LCOH distributions for both countries and all storage technologies, complementing the scenario-resolved results presented in Figs. 9 and 10. The lowest median LCOH values are found in Denmark with cavern and LOHC systems (around 63 MEUR/TWh H2), slightly above the Energinet reference export price (60.5 MEUR/TWh H2). Spain exhibits broader variability, particularly in tank configurations, which show LCOH values exceeding 200 MEUR/TWh H2 in some scenarios due to high CAPEX and poor storage utilization.

The results indicate that storage technology selection exerts a stronger impact on the final hydrogen cost than country-specific RES characteristics. As shown in Table 10 and Fig. 13, tank-based systems are consistently the most expensive option, with LCOH values reaching 108.7 MEUR/TWh (around 3.59 €/kg H_2) in Denmark and 201.9 MEUR/TWh (roughly 6.66 €/kg H_2) in Spain, despite offering design simplicity and short-term stability. By contrast, LOHC storage achieves the lowest costs in both countries—65.0 MEUR/TWh (around 2.15 €/kg H_2) in Denmark and 65.3 MEUR/TWh (around 2.16 €/kg H_2)—while salt caverns, where feasible, remain highly competitive with 69.6 MEUR/TWh (around 2.30 €/kg H_2) in Denmark and 71.9 MEUR/TWh (around 2.37 €/kg H_2), offering an effective trade-off between cost and flexibility. In Spain, LOHC outperforms caverns despite their similar costs because large-scale underground storage capacity is geographically limited and often far from coastal export hubs. LOHC systems, which operate at ambient conditions and integrate more flexibly with port infrastructure, offer lower logistical costs and simpler transport interfaces for export terminals compared to developing new cavern storage near PV-rich regions. From an interpretative standpoint, Figs. 9 and 10 should be read as robustness maps rather than detailed sensitivity decompositions. Their purpose is to show how uncertainty in techno-economic assumptions propagates differently across storage concepts and system components, rather than to attribute causality to individual parameters or scenarios.

Our results corroborate recent EU-wide assessments [15] that identified salt caverns as a key enabler for cost-competitive hydrogen supply. However, the inclusion of LOHC in our framework reveals comparable cost levels in geographies lacking suitable geology, extending the viability of hydrogen corridors beyond traditional storage assumptions.

This dual-storage insight expands the geographical feasibility of green hydrogen exports, especially for countries like Spain, where Back et al. [15] estimate up to 17.3 TWh/year of excess renewable electricity by 2040, with LOHC offering a viable pathway where cavern availability is regionally limited.

Moreover, our LCOH estimates for Spain fall within the probabilistic cost bands reported by Wolf et al. [16], confirming the cost leadership potential of PV-driven systems when paired with efficient storage technologies.

From a broader perspective, the results reinforce the importance of tailoring storage infrastructure to the specific geographic and economic conditions of each region. For export-oriented hydrogen systems, minimizing LCOH variability is key to securing long-term contracts and financing. While cavern-based solutions are ideal in Northern Europe, southern countries may benefit more from LOHC, especially as this technology matures and benefits from scale.

In the Danish case, our findings complement the techno-economic analysis of Apostolou et al. [17], who demonstrate the feasibility of hydrogen systems participating in both energy and transport markets under hydrogen selling prices ranging from 108 to 450 MEUR/TWh H_2 (3.6 to 15 €/kg). Our optimised offshore-wind-based configurations, featuring low seasonal volatility and stable LCOH values below 60.5 €/MWh (around 2.0 €/kg H_2) could thus enhance multi-sectoral value stacking in real deployments.

Furthermore, recent work by Abid et al. [20] shows that integrating hydrogen production with synthetic fuel manufacturing via SOEC electrolysis can reduce total electricity consumption through heat integration. While not modelled directly in this study, these synergies suggest that hydrogen hubs co-located with e-fuel synthesis facilities could further lower system costs and increase energy efficiency, especially in offshore wind-based systems where thermal by-products are available.

Future work should include additional techno-economic dimensions,

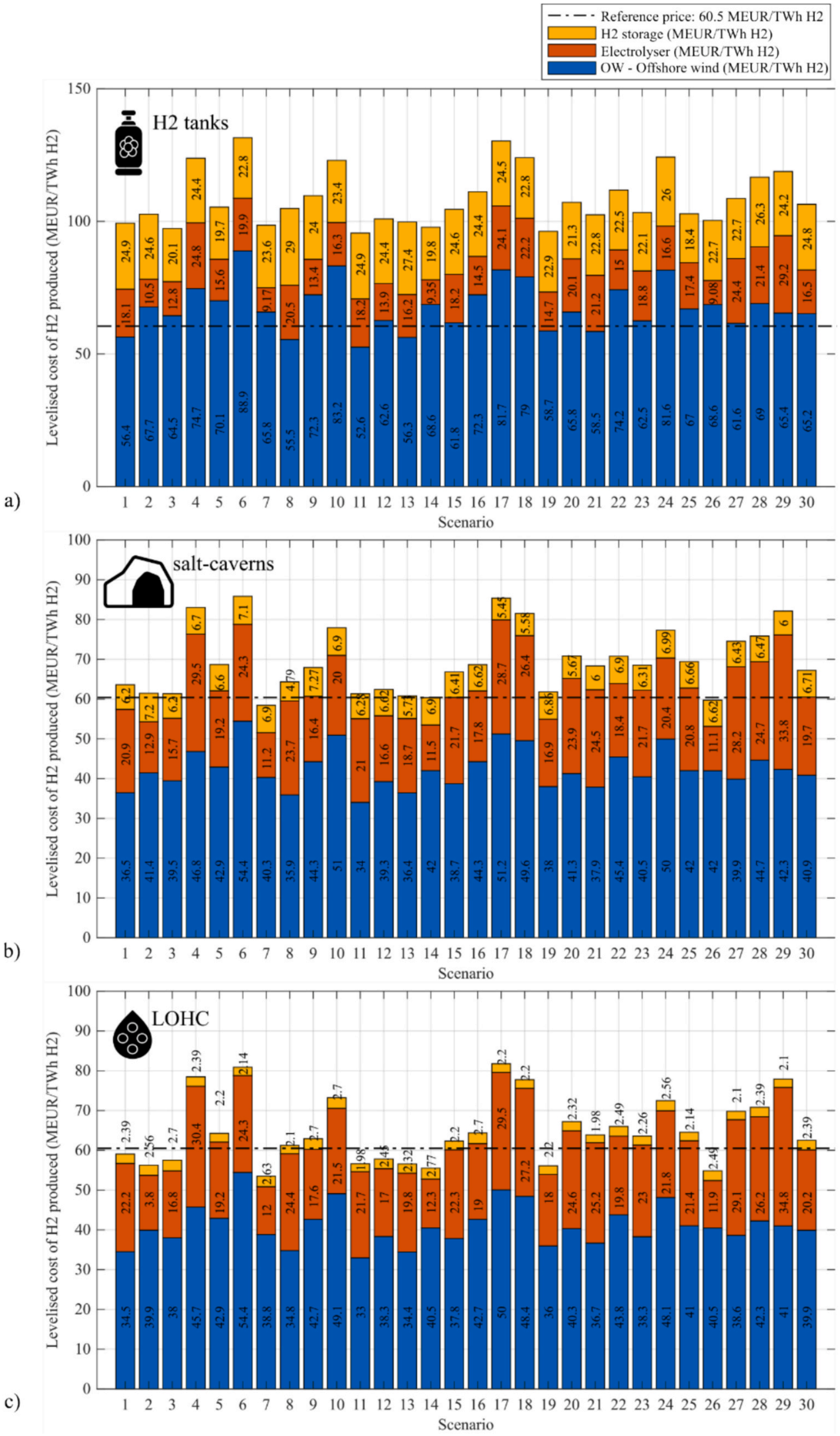

Fig. 9. Breakdown of the LCOH in Denmark across 30 Monte Carlo scenarios for each storage technology: (a) pressurised hydrogen tanks; (b) salt caverns; and (c) LOHC. Each stacked bar shows the contribution of offshore wind, electrolyser and storage infrastructure to the total LCOH. The reference export price (60.5 MEUR/TWh H2) is indicated for comparison.

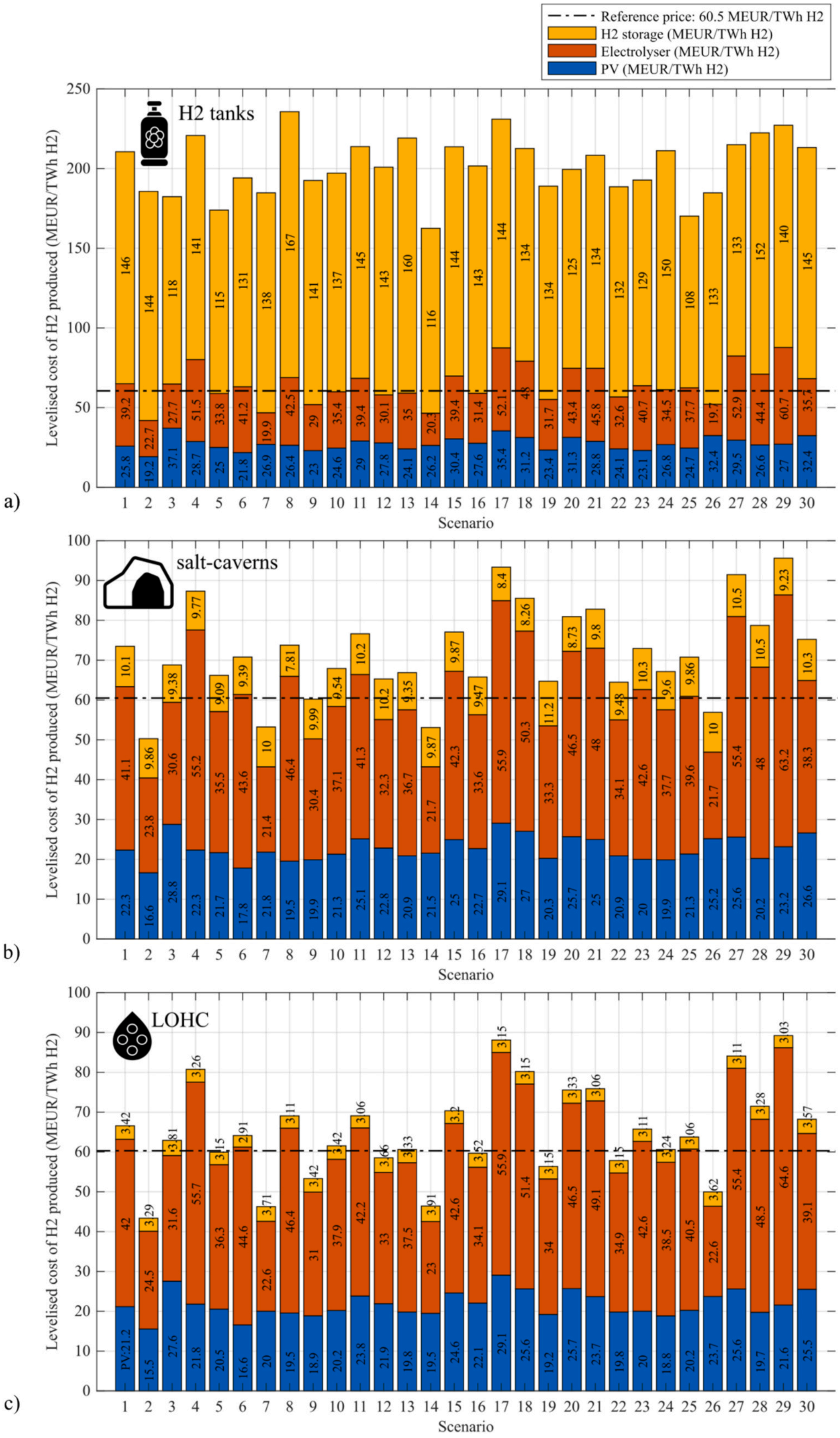

Fig. 10. Breakdown of the LCOH in Spain across 30 Monte Carlo scenarios for each storage technology: (a) pressurised hydrogen tanks; (b) salt caverns; and (c) LOHC. Variability in LCOH reflects the sensitivity of system design to techno-economic assumptions for RES, electrolyser and storage components.

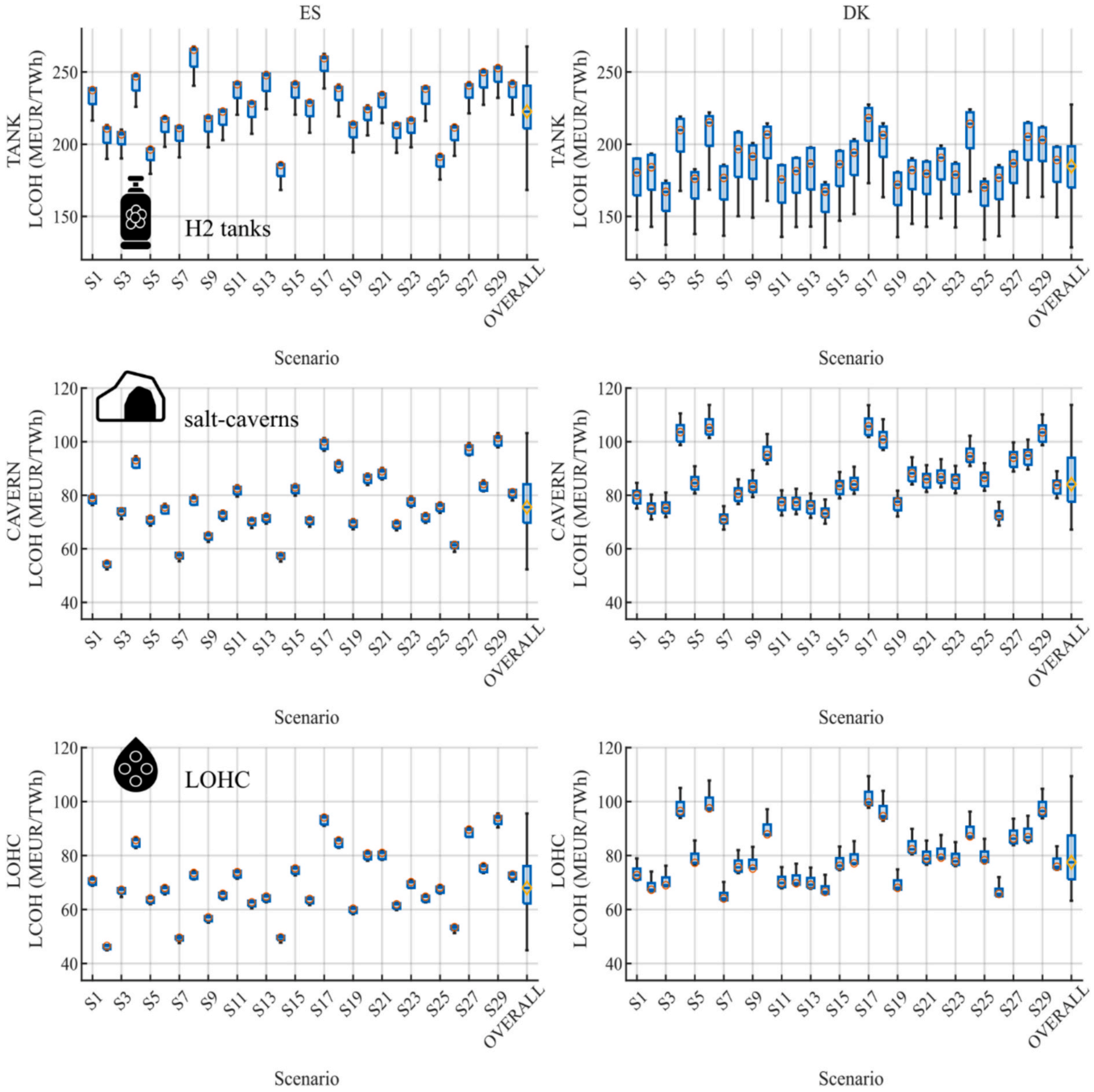

Fig. 11. Interannual LCOH variability across 30 Monte Carlo scenarios (S1–S30) for each storage technology in Spain (left) and Denmark (right), using annual renewable generation profiles from 2019 to 2023. Each box represents the LCOH distribution over 5 years for a given scenario. Circles denote median LCOH values across years.

such as ramping constraints, interannual RES variability and hydrogen demand uncertainty, to further refine investment strategies under risk. In particular, exploring the role of by-product valorisation (e.g. oxygen, heat) and sector coupling could unlock additional revenue streams and enhance system resilience under volatile market conditions. Additionally, a fully coupled optimisation including joint export constraints, shared hydrogen transport capacity, or coordinated storage utilisation across countries could further quantify these benefits and is identified as an important avenue for future research.

The results should therefore not be interpreted as a definitive ranking of hydrogen storage technologies. Instead, they reveal a structural tendency: once storage investment costs fall below a certain threshold, the overall system cost becomes increasingly driven by renewable generation and electrolysis rather than by storage itself. This explains why scenarios based on LOHC and salt caverns yield comparable LCOH values despite their different CAPEX levels. Conversely, pressurised tank storage remains consistently more expensive, suggesting limited suitability for large-scale export-oriented systems. From this perspective, the proposed framework is particularly valuable as a screening tool to assess emerging storage technologies and to identify the cost domains that are most critical for system-level optimisation. In this sense, the framework is not intended to replace detailed project-level assessments, but to serve as a comparative screening tool that identifies which cost domains and infrastructure choices dominate system-level performance under uncertainty.

While our main results are based on averaged hourly RES profiles from 2019 to 2023, we acknowledge that this approach may attenuate interannual extremes in renewable availability and, consequently, underestimate the required storage capacity. To quantify this effect, we reran the optimisation model for each individual year (2019–2023) across all 30 scenarios, storage technologies, and countries. The resulting distributions of LCOH, presented in Fig. 11, reveal that although median values are generally robust, specific years can produce significantly higher or lower costs depending on the combination of RES availability and storage requirements. This variability is particularly pronounced in the pressurised tank cases due to their limited flexibility. These results

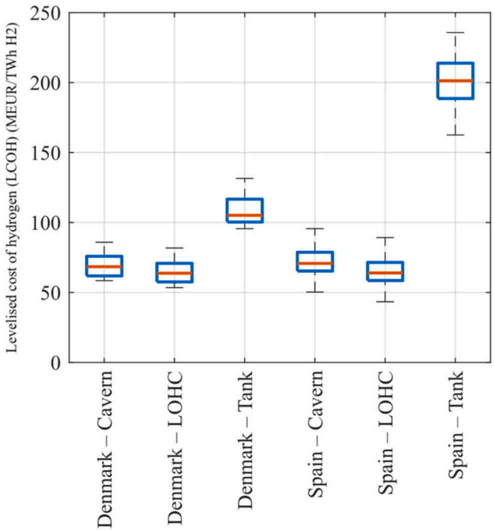

Fig. 12. Distribution of LCOH values obtained from 30 Monte Carlo scenarios for Denmark and Spain under the three hydrogen storage technologies. The boxplots explicitly capture central tendencies and dispersion, addressing the aggregated interpretation of uncertainty across scenarios, while highlighting differences in robustness between storage options and countries.

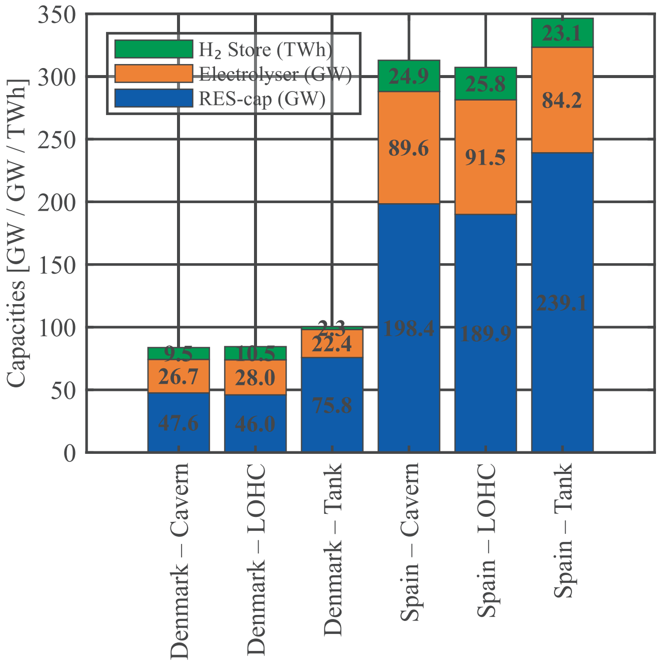

Fig. 13. Average capacities of the different technologies obtained from the 30 Monte Carlo scenarios, illustrating how uncertainty in techno-economic assumptions translates into distinct infrastructure sizing strategies across storage technologies and countries.

Table 10
Average LCOH obtained by the sensitivity analysis for RES (GW) (PV for Spain and offshore wind for Denmark), electrolyser (GW) and hydrogen (H2) storage (TWh) capacity.

Country – H2 Storage configuration	LCOH (MEUR/ TWh H2)	RES Capacity (GW)	Electrolyser Capacity (GW)	H2 Storage Capacity (TWh)
Denmark – Cavern	69.56	47.57	26.71	9.46
Denmark – LOHC	65.01	46.01	27.95	10.51
Denmark – Tank	108.67	75.76	22.37	2.25
Spain – Cavern	71.93	198.42	89.60	24.90
Spain – LOHC	65.33	189.94	91.47	25.84
Spain – Tank	201.89	239.12	84.24	23.05

confirm that year-specific fluctuations can meaningfully affect system design and economics. Therefore, we propose that future assessments adopt hybrid approaches combining multi-year averages with year-by-year stress tests to ensure robustness under variable climate and market conditions.

The sensitivity analysis indicates that the overall system configuration and the benefits of sector integration remain robust across a wide range of parameters. However, hydrogen storage costs exert a decisive influence on the magnitude of these benefits. In this study, the adopted cost assumptions (for example, 1.28 MEUR /GWh with a 48-year lifetime for cavern storage) are based on DEA datasets, whereas recent assessments [39] suggest higher capital requirements (around 3 MEUR /GWh) and shorter lifetimes (about 30 years), primarily due to the need for larger charging and discharging units and their shorter operational lifespan. In addition, the DEA reference values precede the recent inflationary period, implying that actual 2025 costs could be substantially higher. While LOHC systems show promising economic performance in specific contexts, their deployment may face practical constraints related to the handling, safety, and environmental risks of the carrier liquids. These aspects are not fully reflected in levelised cost metrics and warrant further dedicated investigation. These considerations highlight the importance of assessing scenarios with elevated storage costs, as future conditions may further reinforce the trends observed under the high-cost cases.

It is acknowledged that neglecting spatial interactions, such as wake losses in offshore wind farms or PV aggregation smoothing effects, introduces simplifications that may influence cost and sizing results. Wake effects in particular could lower the effective capacity factor of dense offshore wind deployments, requiring additional overcapacity or storage to meet the same hydrogen output targets. Conversely, spatial smoothing of PV output could marginally reduce short-term variability and associated storage needs. Incorporating these spatial effects into future work using geographically resolved generation models would provide a more refined assessment of system design and cost drivers.

3.5. Policy and infrastructure implications

The large-scale hydrogen export strategies proposed in this study will only succeed if supported by strong policy coordination and timely infrastructure deployment. Denmark's least-cost configuration requires approximately 10.5 TWh of LOHC storage, while Spain needs 25.8 TWh (roughly 0.6 Mt of dibenzyltoluene or similar carriers). Spain must therefore establish domestic LOHC production, recycling systems, and port infrastructure to handle hydrogenation and dehydrogenation processes. Incentive schemes similar to Germany's H_2Global could accelerate this supply chain.

Spain's optimal PV deployment (190–239 GW,around 400 GW DC-side) will require careful land-use planning (approximately 250,000 ha or 0.5% of national territory) and grid reinforcements, including upgrades to REE's 400 kV backbone, alongside advanced grid management to minimize curtailment. The seasonal complementarity between Spanish PV and Danish offshore wind suggests that a coordinated Iberian–Nordic export strategy could stabilise hydrogen costs throughout the year, leveraging each country's renewable strengths.

Achieving the 100 TWh/yr export target will depend on completing H_2Med and the North Sea corridors—designated as EU Projects of Common Interest—along with compression and interconnection stations. Long-term contracts, predictable regulations, and public–private partnerships will be essential to reduce risk and support emerging technologies like LOHC.

The combined use of a brute-force optimisation, a dual-layer uncertainty analysis, and a comparative cross-country perspective allows this work to bridge detailed modelling with strategic planning insights. These features extend its relevance beyond the specific case studies, offering methodological guidance for the design of hydrogen export systems in other regions with variable renewable resources.

4. Conclusions

This study introduces an integrated techno-economic framework for optimising renewable hydrogen systems designed for large-scale export from Spain and Denmark. The findings confirm that hydrogen storage technology is the most critical driver of cost, outweighing local RES characteristics.

LOHC systems achieve LCOH values of approximately 65 MEUR/TWh (equivalent to around 2.15 €/kg H_2) in both countries, making them a robust solution where geological storage is limited. Salt caverns, where feasible, are equally competitive at 69–72 MEUR/TWh (corresponding to approximately 2.3 €/kg H_2). Pressurised tanks are consistently less competitive, with LCOH above 108 MEUR/TWh (about 3.6 €/kg H_2) in Denmark and 200 MEUR/TWh (about 6.7 €/kg H_2) in Spain.

Comparative results reveal strong seasonal complementarity between Spanish PV and Danish offshore wind, reducing cost fluctuations and enabling more stable exports. This highlights the strategic value of a coordinated Iberian–Nordic hydrogen corridor under the European Hydrogen Backbone.

A global sensitivity analysis shows LCOH variations exceeding 30% due to uncertainties in CAPEX, lifetimes and storage costs. Reducing this uncertainty calls for targeted policy, innovation, and investment frameworks.

Our findings support broader system integration and sector coupling as enablers of efficiency and cost reduction. Future work should include coupled multi-country optimisation, cross-border hydrogen storage strategies, and the role of e-fuel by-products.

Storage costs remain a critical uncertainty, and projections suggest that rising costs and shorter lifetimes may strengthen the trends observed in high-cost scenarios. A hybrid export model combining PV-LOHC in Spain and offshore-wind-LOHC in Denmark emerges as the most cost-effective route to meet the 100 TWh/yr per-corridor target, offering a replicable strategy for future European hydrogen hubs.

While the absolute cost values presented are specific to Spain and Denmark, several conclusions are transferable. For instance, the relative cost-effectiveness of storage technologies under harmonised export assumptions and the strategic advantage of combining seasonally complementary regions can inform hydrogen planning in other country pairs with contrasting renewable profiles. These findings, though grounded in the Spanish and Danish contexts, offer broader insights for the design of hydrogen export corridors in regions with diverging renewable patterns.

Beyond the region-specific results, the methodological structure developed in this study provides a transferable framework for techno-economic optimisation of hydrogen systems under uncertainty, supporting the planning of future export corridors in diverse geographical contexts.

CRediT authorship contribution statement

Pedro Cabrera: Writing – review & editing, Writing – original draft, Visualization, Validation, Supervision, Software, Resources, Project administration, Methodology, Investigation, Funding acquisition, Formal analysis, Data curation, Conceptualization. **Peter Sorknæs:** Writing – review & editing, Validation, Methodology, Investigation, Formal analysis. **José A. Carta:** Writing – review & editing, Visualization, Validation, Software, Methodology, Investigation, Formal analysis. **Meng Yuan:** Writing – review & editing, Writing – original draft, Validation, Investigation, Formal analysis. **Henrik Lund:** Writing – review & editing, Validation, Supervision, Resources, Project administration, Methodology, Investigation, Funding acquisition, Formal analysis, Conceptualization.

Declaration of competing interest

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

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Data availability

Data will be made available on request.

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