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D3.4. Techno-economic assessment of Blue Economy systems supporting the WindFloat

[Version 1.0]

STEP4WIND

Training network in floating wind energy

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Document History

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1	First draft	Omar S. Ibrahim		July, 15th 2024
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Disclaimer

The original deliverable title was based on a previous industry partner at the proposal writing stage of the project, with this deliverable supporting a specific product of theirs "WindFloat".

Since this partner is no longer part of the consortium, accordingly this deliverable is tackling the same research topic but in a generic approach, supporting no specific floating wind platform.

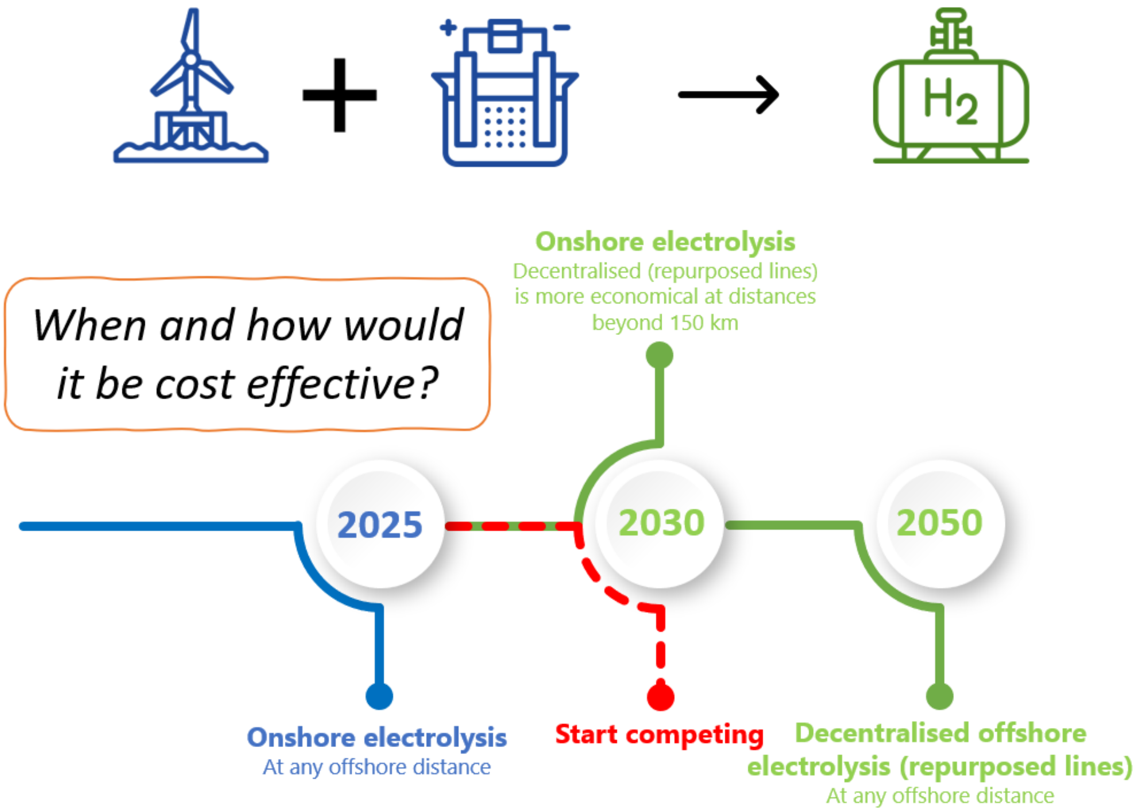
This deliverable is meant to get published as a journal publication, and hence another title is noted on the next page.

Can dedicated floating wind achieve cost-efficient hydrogen?

Highlights

- Dedicated floating wind can potentially offer cost efficient hydrogen by 2030.
- In 2025, onshore floating wind to hydrogen is the most cost-effective route.
- By 2030, decentralised floating wind hydrogen production with repurposed lines at distances beyond 150 km is more economical than onshore production.
- By 2050, decentralised floating wind hydrogen production with repurposed lines is the most economical route at any offshore distance.
- New offshore hydrogen pipelines might compete with repurposed from a reliability and longevity angle.

Graphical Abstract



Abstract

In light of the global efforts for increasing levels of renewables to meet the net zero targets, a clear role emerges for the high capacity factors floating offshore wind unlocking 80% of the global wind resources. This comes in parallel to the global projections for clean hydrogen expansion to effectively decarbonise particular sectors (heavy industries, long-haul transport, and aviation). This motivates to question if large-scale dedicated floating wind can offer a cost-competitive electrolytic hydrogen.

In an attempt to answer this question, this study undertakes techno-economic assessments for the most reasonable routes of coupling. This is conducted by examining different configurations: i) centralised onshore, ii) decentralised offshore with repurposed pipelines, iii) decentralised offshore with new pipelines, iv) centralised offshore with repurposed pipelines, and v) centralised offshore with new pipelines. The analysis incorporated a generic bottom-up modelling approach, where a range of future projections of the levelised cost of energy from floating offshore wind is considered through three time horizons: 2025, 2030, and 2050. The levelised cost of hydrogen (LCoH) is then estimated at 4 different generic offshore distances: 55 km, 100 km, 150 km, and 200 km, with a generic farm size of 2 GW.

Results suggest that for 2025, the onshore configuration is deemed the most cost-competitive one. The decentralised offshore configuration with repurposed offshore pipelines can start competing at a 150 km offshore distance by 2030. By 2050, the latter would be arguably the most economical route for all floating offshore distances. The analysis suggests floating wind could contribute to potentially cost-efficient hydrogen with continuous developments in technologies, as well as robust policy frameworks dictating the future hydrogen demand.

Keywords

Green hydrogen; Floating offshore wind; Floating wind to hydrogen; Techno-economic assessment; Levelised cost of hydrogen (LCoH)

Word Count

8325

Nomenclature Table

Acronyms

CAPEX - Capital Expenditure

CIP - Copenhagen Infrastructure Partners

DOE - Department of Energy

EU - European Union

GHG - Greenhouse Gas

HAR - Hydrogen Allocation Round

HVAC – high voltage alternating current

HVDC - high voltage direct current

IEA - International Energy Agency

IPCC - Intergovernmental Panel on Climate Change

LCoE – Levelised cost of energy

LCoH - Levelised cost of hydrogen

LOHC - Liquid Organic Hydrogen Carrier

NREL - National Renewable Energy Laboratory

O&G - Oil and Gas

O&M - Operation and Maintenance

OPEX - Operational Expenditure

PEM - Proton Exchange Membrane

RED - Renewable Energy Directive

TRL - Technology Readiness Levels

TSOs - Transmission System Operators

UK - United Kingdom

US - United States

Symbols and Indices

N_s - connection stages,

N_{CS} - number of connection slots

N_{WT} - number of wind turbines.

t - lifetime of the project in years,

E_t - amount of hydrogen produced

r - discount rate

1. Introduction

1.1. Context and background

The urgency of addressing the climate change pressing issues is only becoming increasingly palpable every year. According to the Intergovernmental Panel on Climate Change (IPCC) assessment report 6, projected long-term impacts are up to multiple times higher than what is currently observed. Climatic and non-climatic risks will increasingly interact, creating compound and cascading risks that are more complex and difficult to manage [1]. January 2024 was the warmest January on record globally, with an average surface air temperature of 13.14°C, 0.70°C above the 1991-2020 average for January and 0.12°C above the temperature of the previous warmest January, in 2020 [2].

In response to the ongoing magnified risk in question, countries have been ramping up their commitments to carbon neutrality. Notably, the European Union's (EU) Green Deal sets a target of reducing greenhouse gas emissions by at least 55% by 2030 compared to 1990 levels, in efforts to achieving carbon neutrality by 2050 [3]. Similarly, the United States (US) has pledged to achieve net-zero emissions by 2050, with interim goals aimed at cutting emissions by 50-52% by 2030 [4].

Renewable energy has been at the forefront of this transition trajectory, with solar and wind power experiencing a clear exponential growth [5]. Offshore wind has seen remarkable advancements despite the challenges of the ongoing supply chain disruptions, higher costs, and long permitting timelines (especially in Europe and North America) [5,6]. The global offshore wind market grew on average by 21% each year in the past decade, bringing total installations to 64.3 GW, which accounted for 7.1% of total global wind capacity as of the end of 2022 [6]. This is mainly due to the higher capacity factors they can achieve unlocking significant wind resources.

However, with this significant renewable energy (wind, PV, CSP, and biomass) grid penetration, the concern of curtailment[1] arises. This is of a particular concern in areas where major grid infrastructure investments and/or advanced market design and regulation are not keeping pace with the renewable energy deployment [7]. In 2022, the United Kingdom (UK) generated one-fourth of its electricity from wind power. However, most electricity demand is in the country’s southeast. This has led to increased curtailment due to transmission constrains with an amount reaching almost 4 TWh in 2022 [7]. Consequently, this reflects in an increased energy bill for homes and businesses. This creates an immediate need for investment in long duration energy storage and/or further grid development to accommodate this increased renewable energy penetration.

In tandem with the rise of renewable energy, hydrogen has emerged as a critical enabler of decarbonisation efforts, specifically for the hard-to-abate sectors. This includes for steel, chemicals, fertilisers, and long-haul transport, shipping and aviation [8,9]. According to the International Energy Agency (IEA), global hydrogen demand reached a historical high of 96 Mt in 2022, but it remains concentrated in the traditional applications [8]. It’s worth noting, low-emission hydrogen production remained below 1% of global hydrogen production in 2022 [8]. However, the number of announced projects for low-emission hydrogen production is rapidly expanding. Annual production of low-emission hydrogen could reach 38 Mt in 2030, if all announced projects are realised [8]. According to McKinsey & Company, by 2050 clean hydrogen demand could account for 125 up to 585 Mtpa of total hydrogen demand, with only between less than 1 and 50 Mtpa of demand being met by grey hydrogen [10].

To meet this ambition, offshore hydrogen production presents a compelling opportunity to capitalise on the synergies between (floating) offshore wind and hydrogen generation by unlocking significant wind resources [11–14].

[1] refers to the dispatch-down of renewable energy due to network or system reasons.

1.2. State of the art

Offshore hydrogen production has become an active research area recently. Recent studies have concluded the potential for offshore wind farms to serve as hubs for electrolysis-based hydrogen production, leveraging economies of scale to drive down costs and enhance efficiency [15–21]. This comes next to the opportunity of avoiding curtailments on the occasion hydrogen production is took place in a hybrid setting from those offshore wind farms. Few scientific publications investigated dedicated versus hybrid offshore wind systems, in a recent study I. Sorrenti et al. concluded that if the price of electricity from the wins farm is 40% higher than the current price of green electricity, the dedicated case will be cheaper [22].

In a techno-economic analysis domain, Dinh et al. [23] developed a geospatial method for estimating the levelised cost of hydrogen (LCoH) production from offshore wind. The model examined various foundation types (monopile, jacket and floating), to generate maps of LCoH production from offshore wind energy for Ireland. [24]. A. Rogeau et al. [17] analysed offshore wind for hydrogen production with a geospatial analysis at an European scale. The study concluded LCoH ranged falling from 4.5–7.5 €/kg in 2020 to 1.5–3.0 €/kg in 2050 as the costs of wind turbines and electrolysers continue to decrease. More specific to the scope of this paper, T.R. Lucas et al. [25] techno-economically examined the feasibility of considering floating wind for hydrogen production in comparison to the potential selling price back in 2019.

To the best of the authors' knowledge, this is the first paper to techno-economically examine dedicated floating offshore for hydrogen production in a generic approach, considering various time horizons, at different offshore distances. The upcoming sub-sections discuss the projected hydrogen targets and prices in EU, UK and US.

1.3. Beyond state of the art

1.3.1. Hydrogen targets

The EU has established ambitious hydrogen targets as part of its broader climate and energy strategies, aiming to significantly expand the production and use of renewable hydrogen by 2030 and beyond. These can be listed as follows:

- Electrolyser capacity: The EU aims to have 40 GW of renewable hydrogen electrolysers installed, capable of producing 10 million tonnes of renewable hydrogen annually [26].
- Industrial use: 42% of the hydrogen used in industry should be from renewable sources [27].
- Renewable fuels for transport: The Renewable Energy Directive (RED) III has either a 14.5% target of greenhouse gas (GHG) intensity reduction target for transport for 2030 or a 29% renewable energy target; member States may choose either target [28].

The UK government has set ambitious hydrogen targets as part of its strategy to achieve net zero carbon emissions by 2050. Key elements of the UK's hydrogen targets include:

- Production capacity: The UK aims to develop 10 GW of low-carbon hydrogen production capacity by 2030, with at least half of this coming from electrolytic hydrogen produced using renewable energy sources [29].
- Commercial projects: The UK government has already supported numerous commercial-scale green hydrogen production projects. For example, in December 2023, the UK announced support for projects representing 125 MW of production capacity and launched the second Hydrogen Allocation Round (HAR) aiming for an additional 875 MW [30].

The recent hydrogen targets for the US rather focus on substantial cost reductions and increased production of clean hydrogen to support national decarbonisation goals. Key targets include:

- Cost reduction: The US Department of Energy (DOE) aims to reduce the cost of clean hydrogen production to $2 per kilogram by 2026 and further to $1 per kilogram by 2031 [31].
- Electrolyser costs: By 2026, the DOE targets to bring down the costs of low-temperature electrolyser systems to $250 per kilowatt and high-temperature electrolyser systems to $500 per kilowatt [31].

1.3.2. Hydrogen price future projections

The LCoH depends on the technology and the levelised cost of energy (LCoE) source used, which has a significant regional influence. Projections for the future electrolytic LCoH are visualised in Figure 1 for the EU, UK, and US in 2025, 2030, and 2050 as a result of combining insights from [8,10,32–37]. The figure shows a significant decline over time due to advancements in technology and economies of scale, as well as ramped-up demand. The shaded area for each region represents the upper and lower boundaries for the projections with mid-point line for each. It's worth noting the EU is a fairly broad region, where some countries would have the potential of producing cheaper electrolytic renewable hydrogen over the others, due to the variation of the renewable energy sources abundance. Detailed figures are tabulated in the Appendix in Table 10.

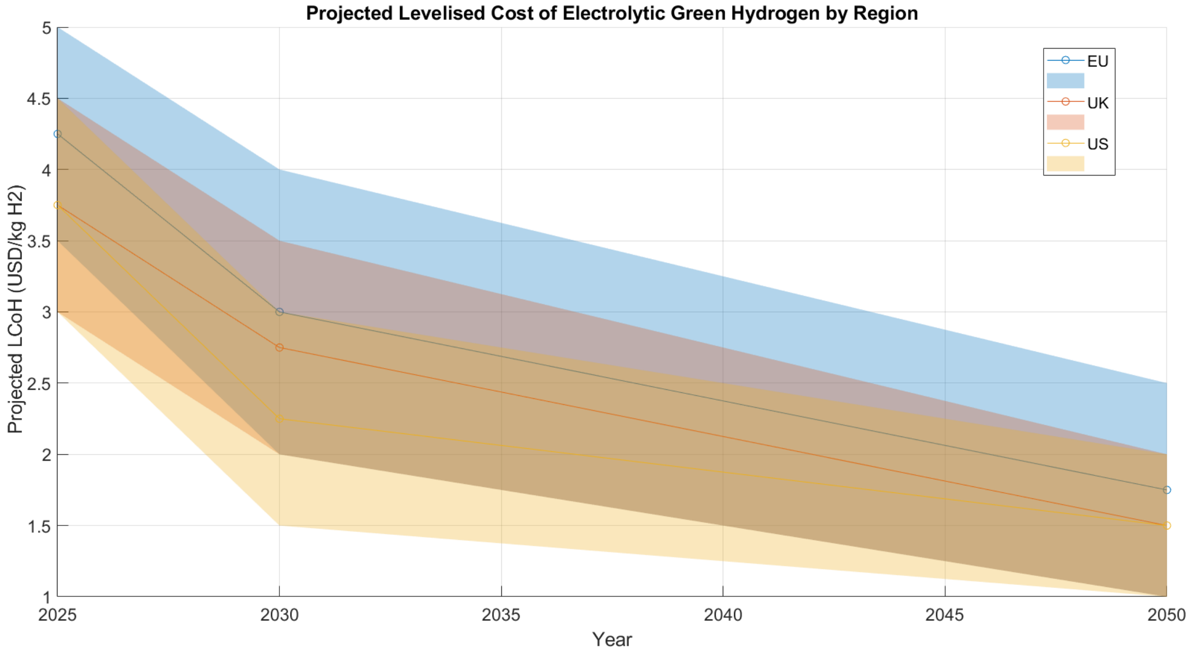


Figure 1 - Future projection of levelised cost of electrolytic green hydrogen 2025-2050 in the EU, UK, and US.

There is currently a number of projects with a different technology readiness levels (TRL) considering offshore hydrogen production. The "BrintØ" (Hydrogen Island) project by Copenhagen Infrastructure Partners (CIP) aims to deliver large-scale hydrogen production facilities at around 200 km off Denmark's west coast. At a full capacity of 10 GW, the island is expected to produce around 1 million tonnes of green hydrogen, corresponding to roughly 7% of Europe's expected hydrogen demand in 2030. This comes in the form of an artificial island to be connected to 10 GW of offshore wind [17].

Lhyfe's Sealhyfe Project in France had a pilot project with a 1 MW capacity to produce up to 400 kg of renewable green hydrogen daily. From 2026, a larger scale of 10 MW will be able to produce up to 4 tonnes per day of green hydrogen at sea, which will be exported ashore by pipeline, and then compressed and delivered to customers [18].

In a floating wind context, the UK's flagship Dolphyn project aims to demonstrate the feasibility of floating offshore hydrogen production at scale. This considers a 10 MW demonstrator scale by mid-2020's and a commercial larger scale (100-300 MW) by 2028 [19].

1.4. Objectives

In light of these trends and developments, this paper objective is to delve into the opportunities and challenges associated with floating offshore hydrogen production in a techno-economic analysis domain. By analysing current and future figures and insights, the authors aim to provide a comprehensive understanding of the role of floating offshore hydrogen in accelerating the transition to a sustainable, and investigate if it can offer a competitive LCoH.

This is examined through a generic bottom-up modelling approach utilising the future LCoE projections of floating wind in potential regions. The analysis includes for offshore distances of:

- 55 km
- 100 km
- 150 km
- 200 km

Through three time horizons:

- 2025
- 2030
- 2050

2. Methodology

A generic approach is used to techno-economically model large-scale dedicated floating wind to hydrogen. As the LCoE is a major contributing factor in the LCoH, the main basis of the modelling is the promising declining LCoE of floating wind in the three time horizons 2025, 2030, and 2050. Few parameters are generically adapted from literature and/or assumed, and other are sensitively analysed forming a conservative and an optimistic estimate for each configuration in each time horizon. A generic size of 2 GW is considered for all the three configurations proposed in our previous piece of work [38]. The distance from the shore is varied from 55-200 km to further understand how the distance via both submarine cables and pipelines impacts the LCoH in the three time horizons in the three configurations.

To maintain the generic approach with the fact the LCoEs incorporated are future projections rather than detailed techno-economic modelling, the modelling approach starts with the respective LCoE and adds or eliminates to the capital expenditure (CAPEX) and operational expenditure (OPEX) to reflect the modelled scenario. Detailed descriptions of the modelling hypothesis are presented throughout in Section 3. The open-access H2A lite national renewable energy laboratory (NREL) tool was used to conduct the techno-economic assessments for the three main configurations proposed in this paper.

2.1. Floating wind

Renewable electricity is the main cost driver for green hydrogen, followed by the cost of electrolyser [39]. Accordingly, achieving a competitive LCoH is dictated by achieving a competitive LCoE firstly. The LCoE is however inherently related to specific projects at specific locations. Yet, it is arguably the single most reliable metric to measure the viability of energy projects [39]. Accordingly, it was further used to examine the LCoH throughout this work.

As a higher TRL technology, bottom-fixed wind offers a lower LCoE in comparison to floating wind [40]. However, close to 80% of the world's offshore wind resource potential is in areas where the water depth is greater than 60 metres [41]. At such great depths, only floating wind is the viable solution. Capacity factors are however critical, as the LCoH depends on both; LCoE and run time [42]. An electrolysis facility relying solely on curtailed electricity is unlikely to be economically viable due to its low capacity factor, even if the electricity is considered to be free [43]. As such, each electrolyser must run at a high capacity factor in order to reduce the LCoH, hence the time required to recoup the initial investment.

Sites where only floating wind is viable come with abundant wind resources. Could even exceed 50% in regions with optimal wind conditions [40]. Consequently, floating wind is believed to be a potential source of reduced LCoH. This paper aims to generically investigate if dedicated floating wind to hydrogen could be a promising solution for the required global clean hydrogen expansion. Hence, no specific locations are considered for the techno-economic modelling; but rather the potential floating wind sites in general with anticipated declining LCoE.

In a recent study by Martinez et al. [44], it was found out that some reasonably low values (~95 €/MWh) can be achieved off Great Britain and Ireland, in the North Sea and off NW Spain. Similar values can also be achieved around the Gulf of Lion and the Aegean Sea [45]. Locations off Portugal present moderate values of the LCoE (~125 €/MWh). The northern Atlantic regions have low to moderate LCoE values, ranging from ~100 to ~135 €/MWh [44].

According to DNV [40], the LCoE for floating offshore wind in 2023 was USD 270/MWh, which was more than three times that of bottom-fixed offshore wind (USD 80/MWh). However, by 2032, they predict floating wind to cost only twice the amount of fixed offshore wind. By 2050 they further foresee cost reductions driven by volume increases and the advantages of experiential learning. With the global average LCoE for bottom-fixed offshore wind at around USD 51/MWh and floating offshore to be only at approximately USD 67/MWh.

Wiser et al. predicted a major decline for floating wind LCoE that was backed by an expert survey in 2020 [46]. Figure 2 demonstrates a median-scenario LCoE for the 2020 experts survey. The shaded area represents the 25th –75th percentile ranges of all responses, while the dashed line represents the median respondent.

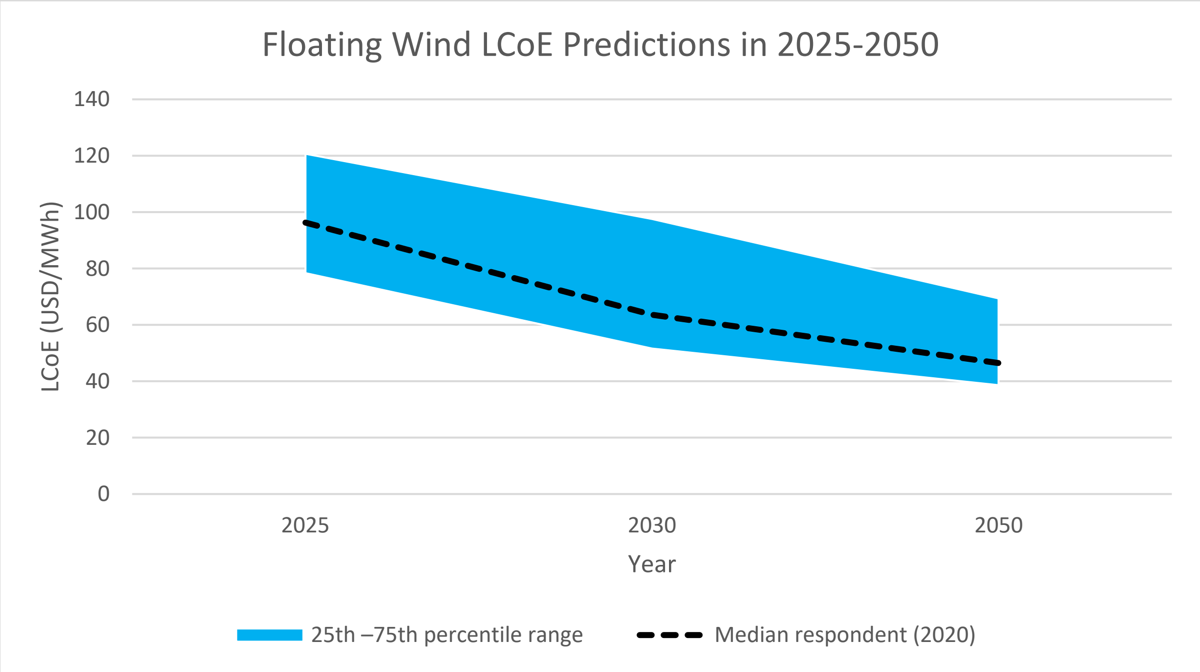


Figure 2 - Levelised Cost of Electricity (LCoE) for floating offshore wind over the period 2025 – 2050. (Adapted from Wiser et al. [46]*)*

Building on the previous discussion, three time horizons are considered for this work: 2025, 2030, and 2050. All USD figures are real 2019 US dollars. Table 1 adapts Wiser's ranges of future projections for floating wind.

Table 1 – Adapted Wiser's floating wind future LCoE projections.

Time horizon	**Lower boundary ($/MWh)**	**Upper boundary ($/MWh)**
2025	78.36	120.68
2030[2]	51.58	97.56
2050	38.62	69.40

The semi-submersible concept is receiving a great deal of attention due to the simplicity of the anchoring system and its fewer requirements regarding port infrastructure [44]. For simplicity, it is considered for all the configurations examined in this paper. Table 1's two boundaries represent the optimistic and conservative assumptions used in the techno-economic modelling. These LCoE values can be considered to be generally promising projected values for floating wind. Accordingly, that was used to represent a generic distance from the shore where a high voltage direct current (HVDC) export technology is the selected one representing the breakeven point over high voltage alternating current (HVAC). In agreement with the study conducted by

[2] 2030 is assumed to have the same projections as 2035.

Martinez et. al [47], the distance of 55 km is assumed as the base distance; and hence, it represents the lowest threshold of LCoE range in the analysis.

Three additional offshore distances were examined: 100, 150 and 200 km. The methodology implemented to account for these distances incorporated working out the additional submarine HVDC costs beyond 55 km to reflect in the resultant LCoH in case of onshore electrolysis. Whilst, for the offshore electrolysis, firstly, the HVDC costs of 55 km length are deducted from the CAPEX and OPEX, then the respective costs of submarine pipelines are added to the CAPEX and OPEX as well.

2.2. Electrolysis

There are three main technologies of electrolysers that use electricity (and heat) to produce hydrogen: alkaline, solid-oxide, and proton exchange membrane (PEM) electrolysis cells. Given the intermittent nature of wind generation with no gird connection, PEM electrolysis might be a potential candidate as it has the capability to operate under variable input electricity. Additionally, PEM electrolysers have a compact design (in case of integration on a floating wind turbine), high current density (up to 2 A/cm^2), operate at low temperatures (20–80 $^{\circ}$C), are expected to be low maintenance, and can efficiently deliver high purity gas [48].

Coupling floating wind with hydrogen production might incorporate either onshore or offshore electrolysis. For onshore electrolysis, the floating wind farm would have its energy exported to power an onshore electrolysis facility. This is relatively an established configuration for electrolysis and doesn't require neither unusual installation nor operation and maintenance (O&M) considerations. For offshore electrolysis, a decentralised or a centralised configuration might be incorporated. Full techno-economic analyses for all the configurations are presented later in this paper.

The stack specific energy consumption can be considered the main metric reflecting the projected development in electrolysers. The electrolyser capital costs per kilowatt used for this assessment are in line with the potential cost decrease for electrolysers as a function of deployed capacity, considering the cost corresponding to 5 TW of deployed capacity by the year 2050 [35]. Based on the deployment of electrolysers in the next decade envisaged in current announcements, the capital cost could decrease due to economies of scale and mass production.

Due to the novelty of offshore electrolysis, there is limited cost data or models available in literature. The hypothesis implemented in this paper incorporates the conventional electrolysers CAPEX and OPEX future projections obtained from literature and/or technical reports, with an added margin for offshore considerations. This is mainly quantified in the added costs required for installations, in addition to the different requirements in O&M. Hydrogen compression is accounted for separately.

Worth noting, the electrolysers performance in harsh offshore environments are still unpredictable and requires further research. This would have a direct effect on stack efficiencies, ideal electrolyser operational range, frequency of routine and major maintenance visits, which dictates the amount of hydrogen produced; directly reflecting on the techno-economics. Quantifying the offshore environment adaptation in this paper is dictated from trends of similar offshore applications and own assumptions.

Whether it's decentralised or centralised, the requirements for installation and O&M are assumed to be the same. Offshore installation would require vessels to transfer the equipment to the offshore site. The only difference between the two offshore configurations would be the additional costs required to set up a dedicated platform to accommodate the electrolysis facility in the centralised configuration. Theoretically, this can either be a vessel or platform, but building a platform is found to be a more cost-effective option than commissioning a vessel, and that's the considered methodology in the analysis.

Table 2 presents the CAPEX and OPEX assumptions used in this study for both the onshore and offshore electrolysis approaches. To assess the future cost reduction, a learning rate of 18% has been used for the electrolyser stack, representing about half of the system cost, and between 5-12% for the other components and the balance of plant [8].

Table 2 – Techno-economic assumptions (CAPEX and OPEX) for electrolysers for the three time horizons 2025, 2030 and 2050 with both conservative and optimistic scenarios.

	Parameter	**Unit**	**2025**		**2030**		**2050**	
			Conservative	**Optimistic**	**Conservative**	**Optimistic**	**Conservative**	**Optimistic**
CAPEX	Electrolysis system[3]	($/kW)[4]	810 [8]	720 [8]	688 [49]	384 [49]	326 [49]	134 [49]
	Additional costs to offshore installations[5]	% of installed onshore cost	50%		45%		40%	
	Offshore Platform (if centralised)	€	444,767,000 [50]					
OPEX & other parameters	System efficiency	(kWh/kg)	55 [51]		51 [51]		45 [35]	
	System lifetime	Years	30					
	Annual fixed OPEX	% of CAPEX	3%		1.5%		1.5%	
	Additional cost to offshore O&M[6]	% of CAPEX	2%		1%		1%	

[3] These values include installation costs.

[4] All $ values in this paper were changed to € using the average 2023 exchange rates with a factor of 0.9248.

[5] Authors assumptions.

[6] This includes for the required periodic maintenance, as well as the stack replacement visits.

	Stack lifetime	hours	50,000 – 80,000 [35]	80,000 – 100,000[4]	100,000 – 120,000 [35]
	Offshore Platform (if centralised)	€/a	6,532,000 [50]		

2.3. Energy export

For onshore electrolysis, power output of the farm is exported to the shore to power the onshore electrolysis facility. The energy export occurs through cables and involves both onshore and offshore substations. The LCoE ranges discussed in Section 2.1 are assumed to reflect all the associated electrical infrastructure including for the inter-array dynamic cables.

2.3.1. Inter-array cables

As inter-array cables are eliminated only in the decentralised configuration, it is worth discussing how they are arranged in a 2 GW farm. The inter-array grid is divided into 27 strands, each accommodating 5 turbines, with one strand accommodating only 1. The distance in the reference grid is 1 km between each turbine. Connecting inter-array cable lengths are assumed to be 1.4 km in length. To adjust for the operating water depth, this is added to the length [52]. Total inter-array cable length is then approximated to 256.7 km.

For offshore electrolysis, hydrogen is produced offshore with multiple off-take solutions. This includes for: (i) compressed hydrogen gas through pipelines, (ii) liquified hydrogen transported through vessels, (iii) hydrogen converted into ammonia and transported via vessels as well, and (iv) hydrogen combined with a liquid organic hydrogen carrier (LOHC) and exported in vessels [53]. For the scope of this work, compressed gas in pipelines is the selected methodology for offshore electrolysis. This is mainly due to the low operational costs and lifetimes of between 40 and 80 years [53,54].

2.3.2. Pipelines

The centralised configuration simply incorporates static pipelines connecting the wind farm to the shore. Whilst the decentralised configuration would require an earlier additional export step, where the produced hydrogen is collected from each wind turbine first via flexible pipelines or risers. The upcoming sections discuss the cost data used for both static and flexible pipelines.

2.3.3. Static pipelines

Static pipelines exporting compressed hydrogen gas from the farm to the shore could either be repurposed or new. Having dedicated pipelines for offshore hydrogen export is relatively a novel approach. In the oil and gas (O&G) domain, offshore steel pipelines exporting natural gas is however a well-established technology. In principle, these pipelines can be repurposed to export hydrogen instead. Generally, it's becoming a favourable route for O&G companies to repurpose their platforms and infrastructures for offshore wind, especially for how much direct decarbonisation this brings.

A number of studies have been conducted to investigate if the current tensile steel natural gas pipes are able to withstand pure hydrogen without modification; a conclusion may be drawn that it is not possible with high-pressure hydrogen at high mass flowrates, mainly due to the embrittlement challenges [55]. Not to mention, repurposed pipelines are unable to deliver ultimate levels of purity [56]. This is highly unlikely to create an issue at a transmission networks level, as further purification would anyway still be required depending on the required purity of the end-user. However, manufacturers claim there is no other difference in transporting natural gas or hydrogen apart from the embrittlement that might just need some modifications (special coating) to assure the robustness of the pipes [38,57]. Next to the cost benefits, repurposing natural gas pipelines for hydrogen export has a lower carbon footprint over commissioning a new pipeline. However, its durability and performance is one of the few areas that require further investigation. Whilst both remain competing, it’s argued that commissioning new pipelines adapted for hydrogen export might be an overall better option.

Various parameters dictate the design and hence the economics of pipelines such operating pressure and diameter, which are interdependent. The diameter of the export pipeline increases with the offshore distance and farm capacity, since more hydrogen would flow through the pipeline and the pressure drop is significant [38]. Consequently, the mass flowrate would dictate the operating pressure and hence the required diameter. Accordingly, it’s worth noting that designing the best fit pipeline is mostly project dependent. However, due to the novelty of the approach and lack of data, rough estimates are considered in this paper.

The European Hydrogen Backbone initiative which aims to investigate a large hydrogen infrastructure across Europe (both onshore and offshore) could be a close live example to the efforts done to commercialise offshore hydrogen pipelines. However, the scale of interest for dedicated farms for hydrogen production is far smaller than what it is in the European Hydrogen Backbone. However, insights from the “offshore low” scenario can still be adapted in this paper’s context. As for the diameter and for the scale in question, a diameter of 20 inch is assumed.

Offshore pipeline CAPEX are estimated in a simplified manner by applying a 1.7x multiplication factor to onshore pipelines of the same diameter [58]. This figure is based on typical offshore-onshore cost ratios seen in existing offshore natural gas pipelines.

Current estimations and empirical evidence from transmission system operators (TSOs) indicate that the capital cost of a newly built dedicated hydrogen pipeline will be 10-50% more expensive than its natural gas counterpart, though region-specific factors such as typical dimensioning of pipes affect this range. Range varies significantly depending on pipeline diameter. For larger diameters (36 inch or more), range is on the lower side whereas costs for smaller diameter pipelines can reach 150% [56].

Table 3 lists the cost assumptions used to account for the offshore hydrogen pipelines.

Table 3 - Cost assumptions used for estimating total investment, operating, and maintenance costs for offshore hydrogen pipelines.

Cost parameter	**Value**	**Unit**
Repurposed pipeline CAPEX	0.918[7] [47]	M€/km
New pipeline CAPEX	3.065[7] [47]	M€/km

[7] Adapted with a 1.7 onshore-offshore factor.

Pipeline O&M costs	0.8 [58]	€/year as % of CAPEX
Diameter	20	inch

2.3.4. Risers and manifolds

For the decentralised offshore configuration, flexible pipelines are required to collect the produced hydrogen from individual turbines before exporting it through the main static pipeline via manifolds. Both technologies are well established in the O&G domain. For risers, technically the same challenge exists with hydrogen embrittlement, yet for simplicity it is assumed the existing risers are well suited for hydrogen with no pre-requisite adaptation. Risers' length purely depends on the depth of water, i.e., the depth where the static pipelines are placed in the seabed. A generic depth of 200 m was assumed for all the configurations, and a factor of 1.5 x was used to work out the risers' length. For a 2 GW farm with 15 MW turbines and a total of 134 wind turbines, each with 300 m risers (1.5 x factor applied), resulting in a total of 40,200 m of risers for the whole farm.

As for the manifolds, sizing it is based on the number of connection slots it has. In this work the manifolds used are assumed to have 5 connections slots [17]. Table 4 lists the main cost parameters for risers and manifolds used in the analysis.

Table 4 - Main parameters values used for risers and manifold costs estimation.

Cost parameter	**Value**	**Unit**
Risers	1736.73 [59]	(€/m)
Manifolds (base+ miscellaneous)	2.453 [59]	M€

The total costs of manifolds would ideally include factors reflecting the pipelines diameter and number of connection slots as well other miscellaneous. For simplicity, such parameters are ignored in this study. The manifolds have a limited number of connection slots which means that the manifolds are cascaded into connection stages, as calculated by Equation (1) [17].

$$N_s = \log_{N_{CS}}(N_{WT}) \tag{1}$$

Where N_s is connection stages, N_{CS} is the number of connection slots and N_{WT} is the number of wind turbines. For the given farm, N_s is 3.

2.4. Desalination

For offshore electrolysis seawater is used, however, due to the required purity it undergoes desalination first. As a consequence of its low cost and constant improvement in membranes, reverse osmosis is becoming a popular desalination approach [60]. Portion of the resultant electricity from the wind farm is used for desalination and compression of hydrogen for pipeline transport. Whilst the production of 1 kg H_2 requires 0.009 m^3 of water, around 5 kWh/m^3 H_2O produced are associated with desalination. Therefore, for every kilogram of hydrogen, 1.35 kWh_{el} is required for desalination [50]. For its relatively minor impact on costs, desalination is economically ignored in the scope of this study.

2.5. Compression

When produced offshore and transported through pipelines, hydrogen encounters a pressure drop along the way. The longer the distance travelled, the more the drop. To compensate for this and ensure an efficient transport methodology with the hydrogen reaching the shore for storage at a reasonable pressure, the hydrogen gas has to get compressed beforehand. Whether production is centralised or decentralised, the approach is to have a centralised compression station that compresses hydrogen before getting exported through the main static subsea pipeline. Estimating costs for such a compression system at this scale is challenging mainly due to its novelty and lack of literature data.

Designing the compression station depends on the required mass flowrate of hydrogen, length of the pipeline, inlet pressure, and the required outlet pressure. The current gas networks utilise two types of compressors: reciprocating and centrifugal. A few-stage reciprocating compressor, or a multi-stage centrifugal compressor, or a combination of both. The electrolysers outlet pressure is 30 bars and the goal is to make sure hydrogen reaches the shore with a pressure of around 50 bars [61]. However, it is argued the current centrifugal compressor technology might not be fully optimised for hydrogen, mainly because of the low molecular weight of hydrogen. Higher circumferences are needed, which in turn, requires different advanced materials. To draw insights for the scope of this study; it's assumed that such compressors can be directly used for hydrogen.

According to the European Hydrogen Backbone initiative [56], for a 2 GW of hydrogen capacity with the given compression requirement, 6-9.2 MWe[8] compression station would be required for a distance of 200 km. A linear approach was employed to estimate the MWe size for the other distances (55, 100, and 150 km) examined in this paper.

Table 5 lists the main cost parameters used for the compressors' estimation.

Table 5 - Main parameters values used for compressors costs estimation.

Cost parameter	Value	Unit
Compression station CAPEX	2.2 [58]	M€/MWe
Compressor O&M costs	1.7 [58]	€/year as % of CAPEX

2.6. Storage

To realise this ambition of hydrogen volumes, a robust storage solution has to be implemented before distribution to the end user. Among the various hydrogen storage solutions, underground storage is considered one of the safest and most economical option [62]. As an onshore underground storage solution, salt caverns offer relative flexibility in operation with high pressures and high injection rates and withdrawal cycles [62–64]. To date, there are only a small number of underground storage facilities for pure hydrogen in operation globally, including salt caverns at three locations in Texas, US, and a single facility comprising three caverns at Teesside in the north-east of England, UK [65]. Worth noting, hydrogen storage in elliptically-shaped salt

[8] Input power for compressors.

caverns at a depth of 350 - 450 m and with a total volume of 210,000 m^3 has been in operation in Teesside since the 1970s [63,65].

The challenge with salt caverns is their geological availability at the first place. They have to exist with a reasonable proximity to the offshore locations considered for hydrogen production. In coherence with the potential locations discussed for floating wind in Section 2.1, the UK can offer a considerable potential. Using the gas cavern approach by Parkes et al. [66], current existing natural gas storage caverns in the UK would be capable of storing approximately 4.7 TWh of hydrogen after repurposing. Moreover, there are several additional projects undergoing planning, which if developed, would be capable of storing an additional 8.5 TWh of hydrogen [65]. Hydrogen storage (especially underground) is a stand-alone research area that is currently being developed at pace.

Hydrogen storage could either be a few days of buffer, or a long-term bulk storage. Both routes can have various viable solutions, with different cost ranges. In the future scenario of this up-scaled hydrogen production, the focus is mostly on the latter. The authors didn't include the storage component in this analysis due to the complexity of robustly modelling hydrogen storage. It has to be tied by the forecasted hydrogen demand for the given project/region to meaningfully estimate the required storage capacity and its cost implications,

2.7. Financial assumptions

The financial assumptions in a techno-economic analysis are generally dictated by the given country or region. However, since this work aims to deliver a generic analysis for such a system, own financial assumptions are implemented in the modelling. These are influenced by the regions of floating wind potential discussed in Section 2.1. This can be summarised in the discount rate, which has a range of 5-8% in this study. This parameter is used to express the risk of investment in a particular region. The lower end of the bracket is used for optimistic scenario, and the higher end of the bracket for the conservative one.

Some additional financial considerations would ideally be further considered in a real-life scenario, which would highly depend on the region the project is planned. This includes for: (i) Inflation rate, (ii) Insurance rate, (iii) Tax rate, (iv) Financing interest rate, and (v) Debt-equity ratio.

3. Configurations

This section includes a detailed description of the techno-economic modelling parameters considered for each of the configurations. The LCoH is the metric used to assess all the configurations. Equation (2) shows the formula which was used to calculate it.

$$LCoH = \frac{\sum_{t=0}^{t} \frac{CAPEX_t + OPEX_t}{(1+r)^t}}{\sum_{t=0}^{t} \frac{E_t}{(1+r)^t}} \quad (2)$$

Where; t is the lifetime of the project in years, E_t represents the energy produced or the amount of hydrogen produced (kg), and r is the discount rate. CAPEX and OPEX here represent both the floating wind system as well as the hydrogen production facility with all the associated components. However, in this paper's context the LCoE projections represent the floating wind component of the analysis and are directly fed to the model. Table 6 highlights the differences in main components between each of the configurations.

Table 6 - Comparison between the different components in the three configurations.

	Parameter	Centralised onshore	Decentralised offshore	Centralised offshore
Power conversion	Offshore substation	x		x
	Onshore substation	x		
Energy export	HVAC/HVDC	x		x
	Pipelines		x	x
	Dynamic cables	x		x
	Manifolds		x	
	Compressors		x	x
Hydrogen production	Desalination		x	x
	Offshore platform			x

3.1. Centralised onshore configuration

For this configuration, the LCoE range for each time horizon as discussed in Section 2.1 is applied. A generic range of offshore distances is examined (55–200 km). As the closest distance considered in the analysis is 55 km, the HVDC technology is the considered submarine cable. This comes in agreement with the breakeven point with HVAC reported for large offshore wind farms in [67].

Table 7 lists the cost parameters used for this configuration analysis through the three time horizons 2025, 2030, 2050 in both an optimistic and a conservative scenarios.

Table 7 - Centralised onshore configuration cost parameters.

Parameter	Unit	2025	2030	2050

		Conservative	Optimistic	Conservative	Optimistic	Conservative	Optimistic
Cost of electricity	(€/MWh)	111.6	72.45	90.22	47.7	64.18	35.72
Electrolysis CAPEX	(€/kW)	749.09 [8]	665.86 [8]	636.26 [49]	355.12 [49]	301.48 [49]	123.92[49]
System efficiency	(kWh/kg)	55 [51]		51 [51]		45 [35]	
System lifetime	Years	30					
Annual fixed OPEX[9]	% of CAPEX	3		1.5		1.5	
Annualised stack replacements	% of fixed OPEX	30					
Utilisation[10]	%	90					
Discount rate[11]	%	5-8					

3.2. Decentralised offshore configuration

The offshore configurations bring few changes to the system components in comparison to the onshore one. In the decentralised configuration, the energy export vector is pipelines rather than submarine cables. The same range of LCoE considered is applied within the NREL tool H2A Lite; however, it is followed by the adaptation required to reflect eliminating the electrical infrastructure, as well as adding the offshore hydrogen export components. That includes for:

- Omitting the submarine cable costs (inter-array and static)
- Omitting the offshore and onshore substations costs
- Adding the offshore pipelines costs (risers, manifolds, and static pipelines)
- Adding the anticipated additional costs with offshore electrolysers (installation and O&M)
- Adding compressors costs

[9] Authors own assumption.
[10] Annual average production or throughput as % of theoretically maximum throughput.
[11] 5% is used for the optimistic scenario and 8% is used for the conservative one.

For simplicity, these components' costs were assumed to be the same across the three time horizons.

Table 8 lists the detailed cost parameters used for the techno-economic modelling for the decentralised offshore configuration.

Table 8 - Decentralised offshore configuration cost parameters.

	Parameter	**Unit**	**2025**		**2030**		**2050**	
			Conservative	**Optimistic**	**Conservative**	**Optimistic**	**Conservative**	**Optimistic**
	Cost of electricity	(€/MWh)	111.6	72.45	90.22	47.7	64.18	35.72
Electrical infrastructure omission	Onshore HVDC substation (manufacturing and installation)	M€	84.35 [44]					
	Export HVDC cable (manufacture)	M€/km	1.168 [44]					
	Export HVDC cable (installation)	k€/km	637 [44]					
	Inter-array cables (manufacturing and installation)	k€/km	515.8 [44]					
	Offshore HVDC substation (manufacturing and installation)	M€	305.4 [44]					
Electrolysis	Electrolysis CAPEX	(€/kW)	749.09	665.86	636.26	355.12	301.48	123.92

	System efficiency	(kWh/kg)	55 [51]	51 [51]	45 [35]
	System lifetime	Years	30		
	Added CAPEX for offshore installation[12]	% of CAPEX	50	45	40
	Annual fixed OPEX	% of CAPEX	3	1.5	1.5
	Added fixed OPEX for offshore operation	% of CAPEX	1	0.5	0.5
Pipelines	Added CAPEX for new offshore pipelines	M€/km	3.065		
	Added CAPEX for repurposed offshore pipelines	M€/km	0.918		
	Added O&M costs for offshore pipelines	€/year as % of CAPEX	0.8		
	Added CAPEX for risers	M€	69.817		
	Manifolds	M€	7.359		

[12] All the offshore electrolysis consideration are a combination of authors own assumption and experts in the field.

Compression	Added CAPEX for the compression station	M€/MWe	2.2
	Added OPEX for the compression station	€/year as % of CAPEX	1.7
Others	Utilisation	%	90%
	Discount rate	%	5-8

3.3. Centralised offshore configuration

This configuration can be considered a hybrid configuration between the other two. Whilst it doesn't require neither manifolds nor risers for hydrogen collection at an individual wind turbines level, it would still require an offshore substation to capture the energy out of the farm and export it to the centralised electrolysis facility. Furthermore, it requires a dedicated offshore platform to accommodate the electrolysis facility. The range of LCoE mentioned in Section 2.1 is also applied and adapted to reflect eliminating the main export cables, the onshore substation, and inter-array cables, whilst it would still account for an offshore substation as well a short export cable from the farm to the electrolysis facility, in addition to the offshore hydrogen export infrastructure. That includes for:

- Omitting the main export submarine cable costs
- Omitting the onshore substations costs
- Adding the offshore static pipelines costs
- Adding the anticipated additional costs with offshore electrolysers (installation and O&M)
- Adding compressors costs

Table 9 lists the detailed cost parameters used for the techno-economic modelling for the centralised offshore configuration.

Table 9 - Centralised offshore configuration cost parameters.

	Parameter	**Unit**	**2025**		**2030**		**2050**	
			Conservative	**Optimistic**	**Conservative**	**Optimistic**	**Conservative**	**Optimistic**
	Cost of electricity	(€/MWh)	111.6	72.45	90.22	47.7	64.18	35.72

Electrical infrastructure omission	Onshore HVDC substation (manufacturing and installation)	M€	84.35 [44]					
	Export HVDC cable (manufacture)	M€/km	1.168 [44]					
	Export HVDC cable (installation)	k€/km	637 [44]					
Electrolysis	Electrolysis CAPEX	(€/kW)	749.09	665.86	636.26	355.12	301.48	123.92
	System efficiency	(kWh/kg)	55 [51]		51 [51]		45 [35]	
	System lifetime	Years	30					
	Added CAPEX for offshore installation	% of CAPEX	50		45		40	
	Annual fixed OPEX	% of CAPEX	3		1.5		1.5	
	Added fixed OPEX for offshore operation	% of CAPEX	1		0.5		0.5	
Pipelines	Added CAPEX for new offshore pipelines	M€/km	3.065					
	Added CAPEX for repurposed offshore pipelines	M€/km	0.918					
	Added O&M costs for offshore pipelines	€/year as % of CAPEX	0.8					

Compression	Added CAPEX for the compression station	M€/MWe	2.2
	Added OPEX for the compression station	€/year as % of CAPEX	1.7
Offshore Platform	Offshore Platform CAPEX	€	444,767,000
	Offshore Platform OPEX	€/a	6,532,000
Others	Utilisation	%	90%
	Discount rate	%	5-8

4. Results

This section presents the results of the techno-economic modelling conducted for the three configurations, with the different offshore distances examined over the three time horizons. To better understand the results, an arithmetic average value of the two runs (optimistic and conservative) is presented in this section throughout Figures 3-8. For each time horizon, Figures 3, 5, and 7 present the arithmetic average LCoH results against offshore distances for 2025, 2030 and 2050 respectively. Figures 4, 6, and 8 present the box and whisker, which show variation within the results for each configuration for 2025, 2030 and 2050 respectively. The line and the x within the box represent the median and the mean respectively. The upper and lower boundaries of the box represent the first (Q1) and third (Q3) quartiles of the dataset. Finally, the upper and lower whiskers represent the maximum and minimum values which are not outliers.

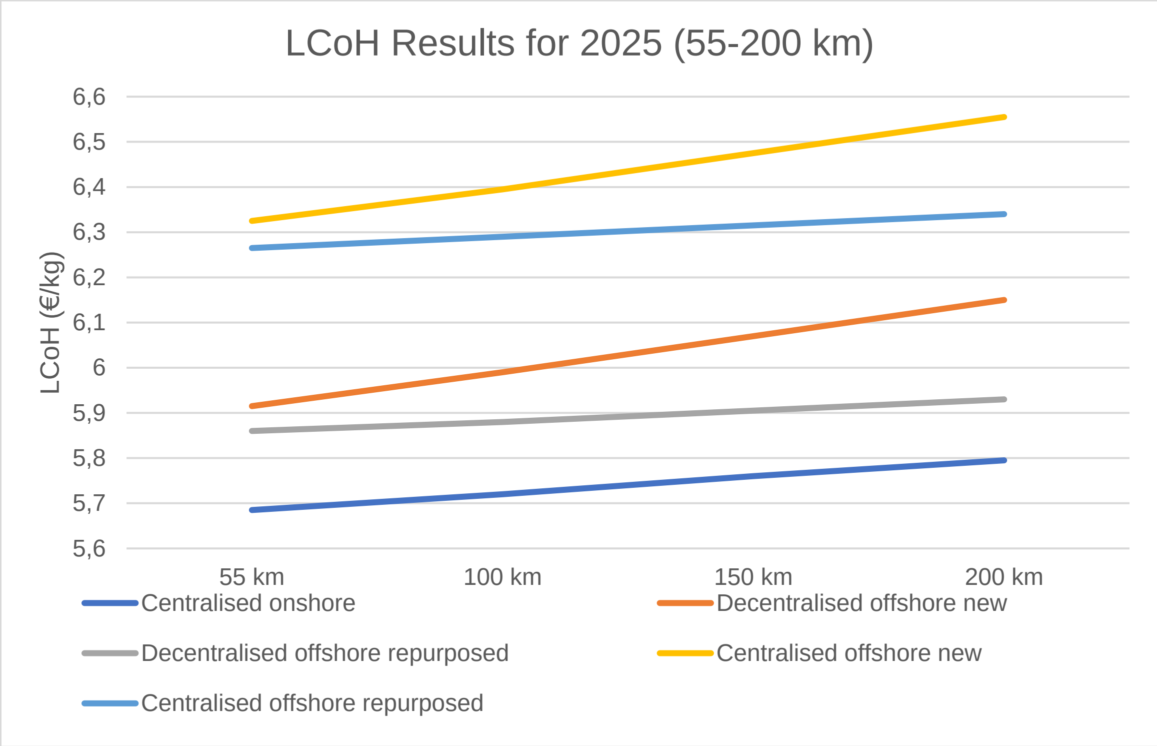


Figure 3 - LCoH arithmetic average values for 2025 (55-200 km).

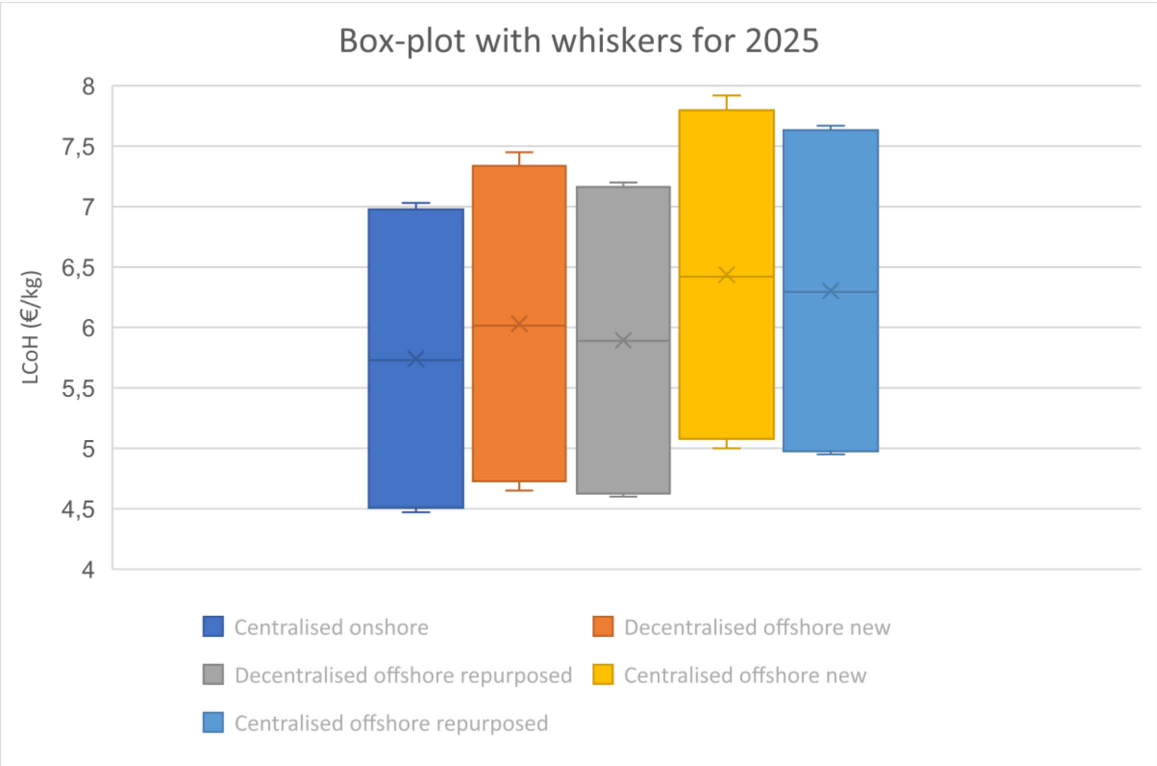


Figure 4 - Box and whiskers maximum and minimum arithmetic average LCoH values for all configurations for 2025.

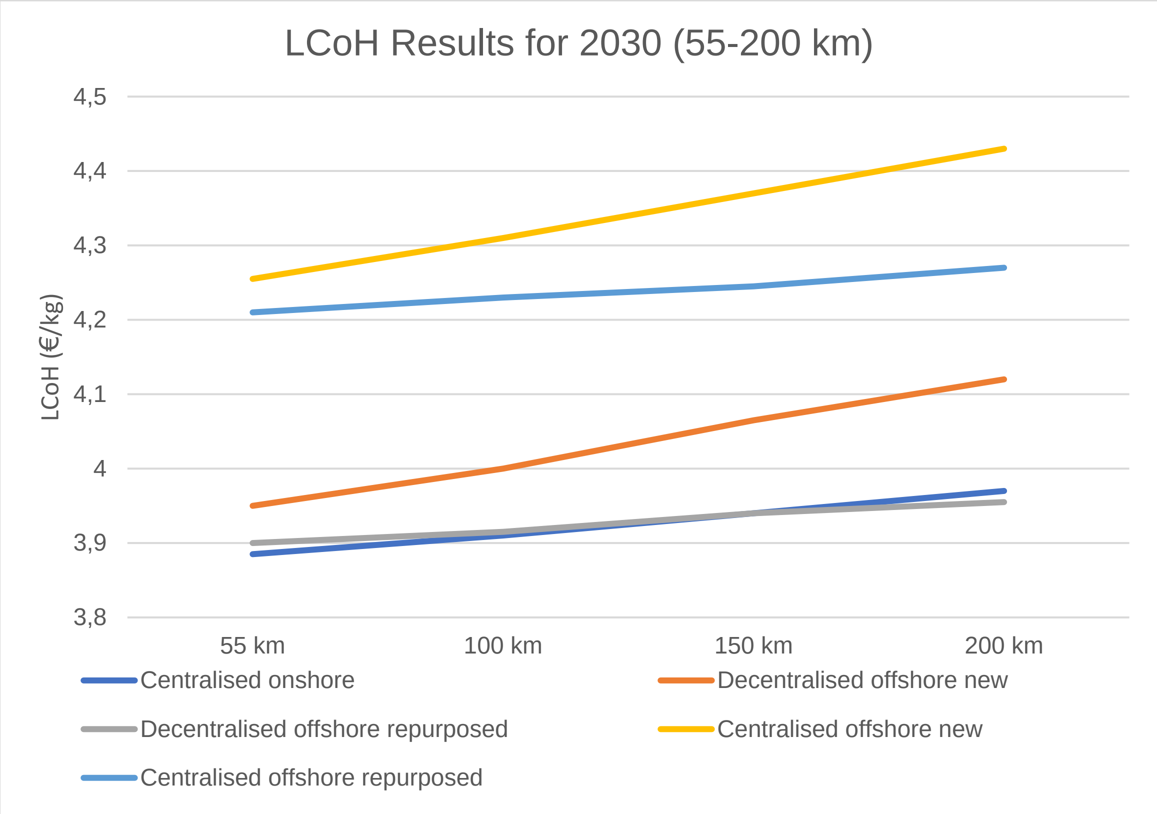


Figure 5 - LCoH arithmetic average values for 2030 (55-200 km).

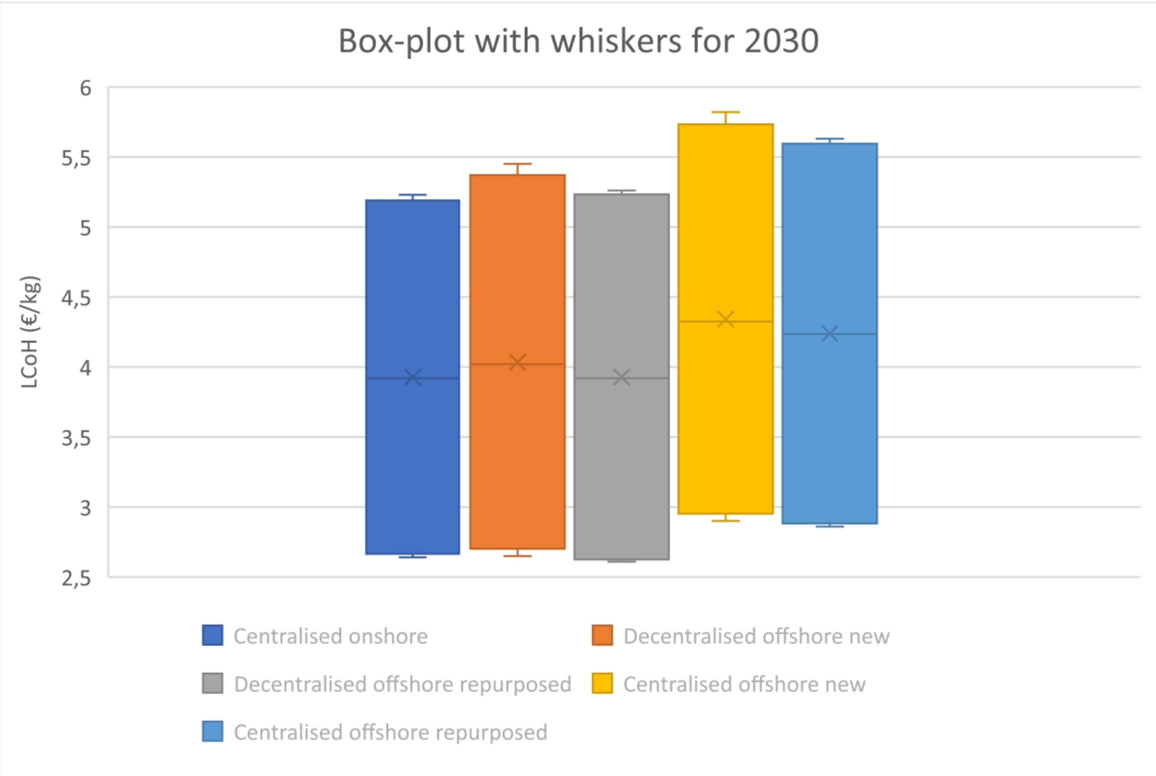


Figure 6 - Box and whiskers maximum and minimum arithmetic average LCoH values for all configurations for 2030.

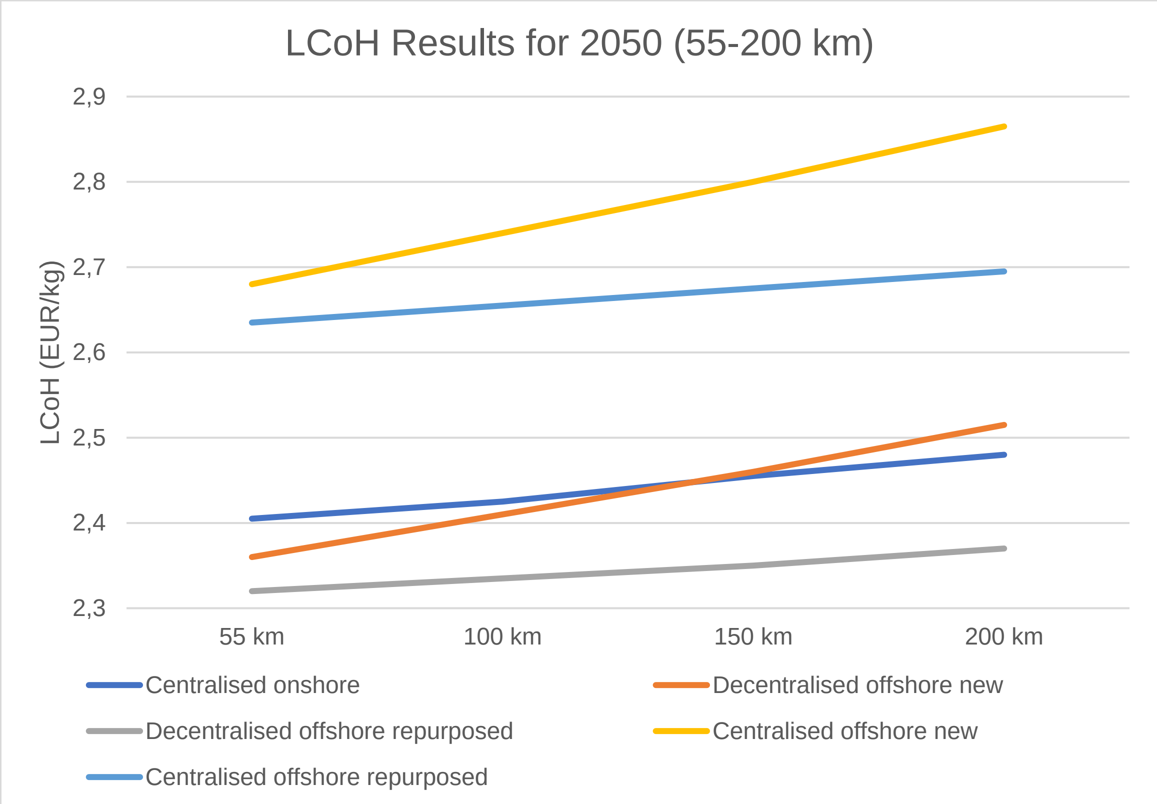


Figure 7 - LCoH arithmetic average values for 2050 (55-200 km).

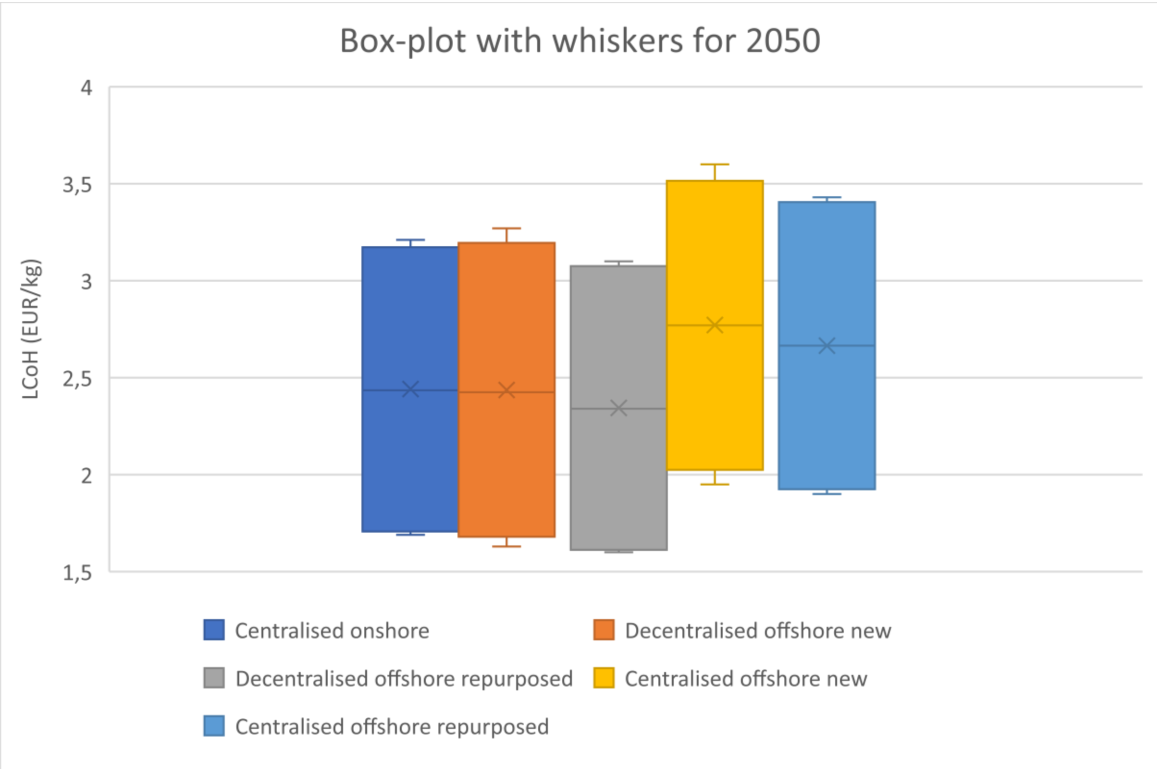


Figure 8 - Box and whiskers maximum and minimum arithmetic average LCoH values for all configurations for 2050.

Throughout Figures 3-8 the following observations can be made:

- In 2025, it is more economical to produce hydrogen from electricity transported to shore (via HVDC) than producing it offshore at any distance.
- Comparing repurposed to new pipelines (decentralised or centralised), it can be noticed that the difference in LCoH increases as the offshore distance increases.
- In 2030, a break-even point at a 150 km offshore distance can be noticed between the onshore configuration and the decentralised offshore configuration (with repurposed pipelines).
- In 2050, the decentralised offshore configuration (with repurposed pipelines) at all offshore distances is the most economical route. Additionally, the decentralised offshore configuration (with new pipelines) stands more economical than the onshore configuration till a break-even point of an offshore distance of around 142 km.
- Whilst the LCoH results of the centralised offshore configuration look promising from a general point of view, they aren't competing (even with repurposed pipelines) with any of the other two configurations at any distance nor a time horizon.

Detailed results for each time horizon in the optimistic and conservative runs are both further tabulated and graphically presented in the Appendix.

5. Discussion

This study is investigating if floating offshore wind farms dedicated for hydrogen production can be a potential route for achieving a cost-effective green hydrogen. However, from an investor's perspective, the dedicated wind farms approach prevents electricity from being used for other purposes. In other words, there is a missed opportunity to sell electricity in an energy markets domain when prices are high and produce hydrogen when they are low. This could bring a different lens on the assessment and expand the relevance of onshore hydrogen production and the hybrid mode rather than a dedicated one.

Comparing onshore to offshore hydrogen production, the latter might have a promising economical potential in the near future. Nevertheless, offshore electrolysis is expected to be more economical for far-from-shore sites than its onshore counterpart and should be considered in the bigger picture. Along similar lines, looking at the decentralised and the centralised offshore configurations, with the latter showing less economical potential; it is worth noting the electrolyser technology considered for all the three configurations was assumed to be the same. This doesn't account for the potential capital costs savings in the centralised configuration (onshore too), where the compact size of the electrolyser stack is not as important as it is in the offshore decentralised configuration. On this occasion, cheaper technologies than PEM could bring a different lens to the analysis. Additionally, as for the pipelines, whilst there are economic and environmental benefits from incorporating repurposed offshore pipelines, its technical performance and durability remains unclear and would require further investigation.

The projected developments and upscaling of floating offshore wind potential sites (in deep waters) is a crucial element to their LCoE reductions, which in turn is the base element of achieving cost efficient hydrogen from floating wind. The development and future projected costs of the electrolysis technologies come next. From an economy lens, the recent global inflation and increase in labour cost have had a considerable impact on projects under development, whose first cost estimates have been revised upwards in several cases. This not just directly impacts all the future cost projections, but also causes potential disturbance for developers, affecting the anticipated upscaling of projects at the first place. Consequently, impacting the anticipated cost reductions. For example, the cost of Saudi Arabia's NEOM Green Hydrogen project has risen from $ 5 billion to $ 8.5 billion, according to a statement from the beginning of 2023, due to inflation, and supply chain-related cost increase. Similarly, the German Bad Lauchstädt Energy Park project has seen costs rise by 50% from the first estimate [8].

6. Conclusions

This paper techno-economically investigated the route of producing hydrogen from dedicated large-scale floating offshore wind farms. This is based on the anticipated reductions of LCoEs of floating wind given the projected global upscaling in floating wind potential sites, coupled with the future electrolysis technologies development, which comes with a significant cost reduction.

The paper examined three main configurations: onshore centralised, offshore decentralised, as well as offshore centralised. The offshore configurations considered both repurposed and new offshore pipelines as the hydrogen export vector.

6.1. Findings and contribution

Looking at the results presented in Section 4, the following conclusions can be drawn:

1. In 2025, for the given capacity (2 GW), producing hydrogen onshore via HVDC cables for offshore distances further than 55 km seems to be the most economically attractive configuration.
2. From 2030 onwards, at distances beyond 150 km, producing hydrogen offshore in a decentralised configuration (with repurposed pipelines) could be more economical than onshore. This is mainly due to the anticipated reduction in electrolyser costs, which means that the additional cost of installing the electrolyser offshore is offset by the lower cost of transporting it via pipelines.
3. In 2050, even at relatively short distances as 55 km, producing hydrogen offshore (with repurposed pipelines) seems to be more promising than producing it onshore. The decentralised offshore configuration with new pipelines then ranks next to that with repurposed ones up until a break-even point of around 142 km with the onshore configuration.
4. Producing hydrogen in a centralised offshore setting seems to be the least economically attractive at all offshore distances, through all time horizons with both repurposed and new pipelines. This is mainly due to the added costs of having a dedicated platform accommodating the hydrogen production facility. However, it’s worth noting it might have other advantages as utilising spar floating platforms in sites of significant water depth, and/or the potential of utilising cost-competitive electrolysis technologies given the relative flexibility with stacks size in comparison to the decentralised configuration.

Figure 9 is a modified version of Figure 1 with hydrogen from floating wind costs projections added. The range of values considered is based on the generic shortest distance considered for floating wind in the analysis, which is 55 km. The lower boundary represents the most cost competitive route for the given year in the optimistic scenario, while the upper boundary represents the least cost competitive route for the same given year at the same offshore distance in the conservative scenario.

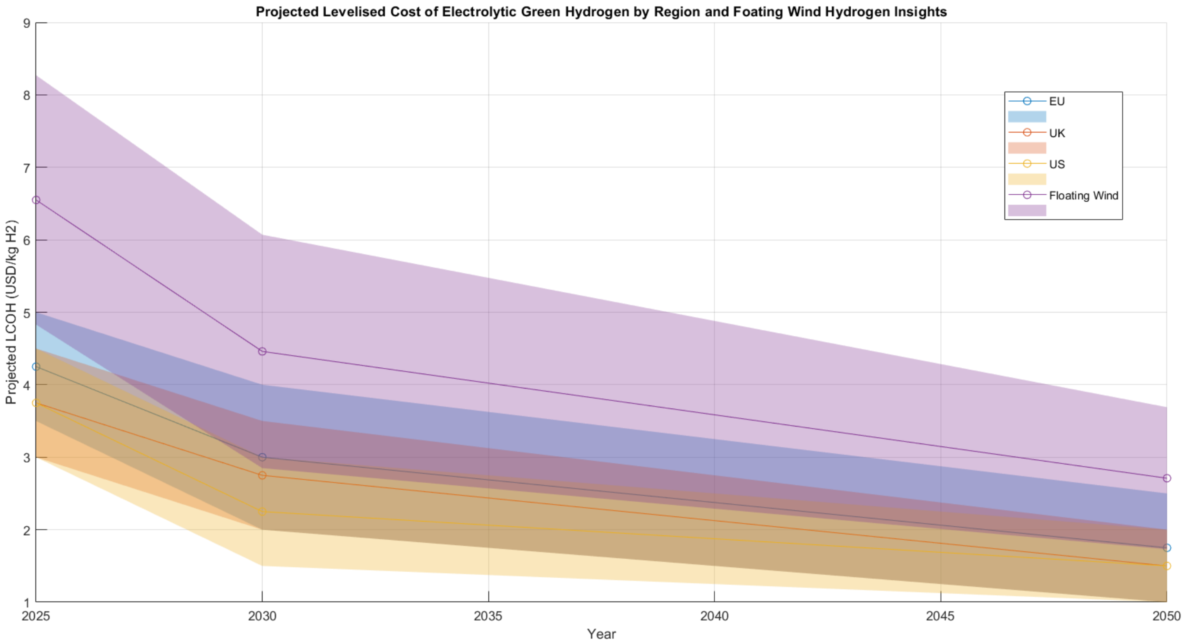


Figure 9 - Projected green hydrogen levelised costs and hydrogen from floating wind insights in 2025, 2030, and 2050.

The chart suggests floating wind could contribute to potentially cost-efficient hydrogen closely matching the future LCoH projections in the EU, UK and US in the three time horizons analysed. This potential would however be highly driven by firstly achieving the forecasted hydrogen demand in these regions, which is dictated by policy and regulations in place. The large-scale hydrogen production requirement then comes next with the ramp-up need, and hence unlocking the high capacity factors floating wind potential.

6.2. Future work

Despite the contributions of this work, some future work should be further carried out to deepen the analysis:

- The electrolysers CAPEX and OPEX used in the analysis are general future projections rather than technology specific. For a more robust analysis for decentralised versus centralised configurations, considering different electrolysers technologies (PEM for decentralised and Alkaline for onshore/offshore centralised).
- Depending on the geological features of the given project, hydrogen storage could be included in the analysis.
- Decommissioning costs of the hydrogen production facility should also be included in the analysis.
- Given the analysis is conducted for a given region, a more comprehensive and definite discount rate could be applied. Furthermore; tax rates, potential incentives, and/or subsidies in place.
- Given a more robust understanding of offshore pipelines (repurposed or new), a more comprehensive analysis could be further developed to reflect the projected development in their costs over the different time horizons tackled in this paper.
- Other offshore hydrogen export vectors such as tankers could be included in the analysis, which potentially would require an additional layer of hydrogen storage analysis. The hydrogen produced could be transported liquefied or as ammonia.
- On the occasion of onshore production, which would ideally be a hybrid setting with grid connection, the potential cost of connecting to existing infrastructure should be considered. This is especially important in remote areas where such costs could be significant.

- On the occasion of having a wind farm (or a more than a farm), with a capacity exceeding 2 GW, a whole new infrastructure of HVDC would need to be built. This would impact the competitivity of the onshore production even in the near future given this large scale.
- A more detailed future analysis for floating wind comparing the different floaters against different depths would bring a higher level of understanding of understanding, especially for decentralised against centralised offshore configurations with a given site depth.
- The electrical infrastructure as well as the offshore hydrogen export infrastructure costs assumptions would ideally get different values for the three time horizons in question.
- The ports infrastructure availability is a main driver to realise such a system, having a risk assessment layer for this would robustly enhance the analysis.

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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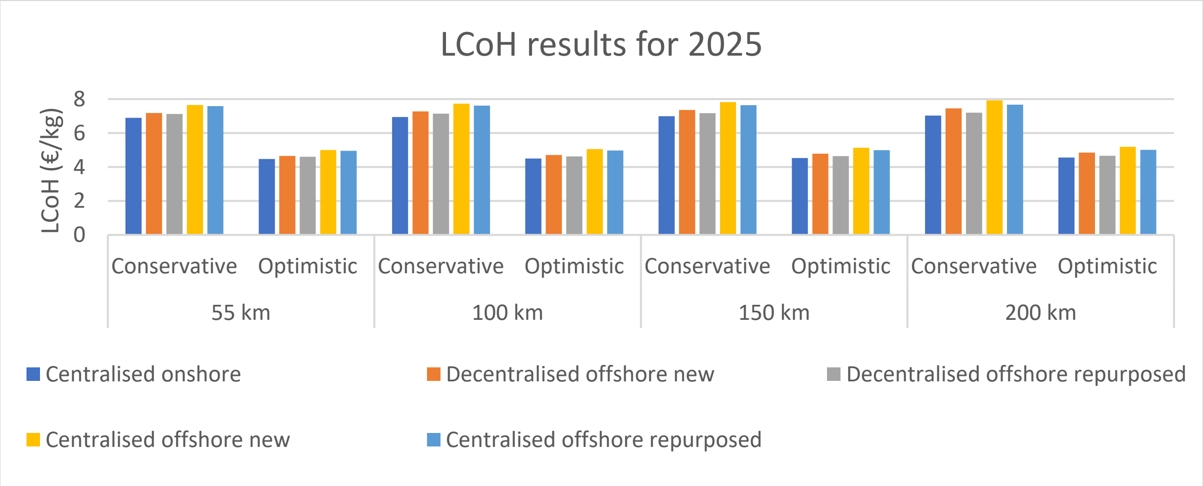
Appendix

1.1. Figures

2025



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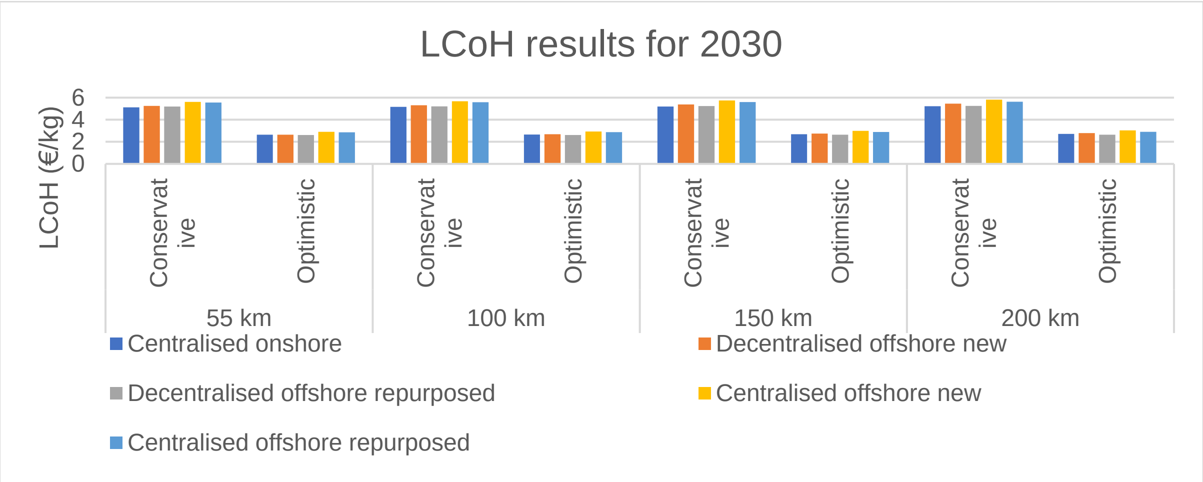
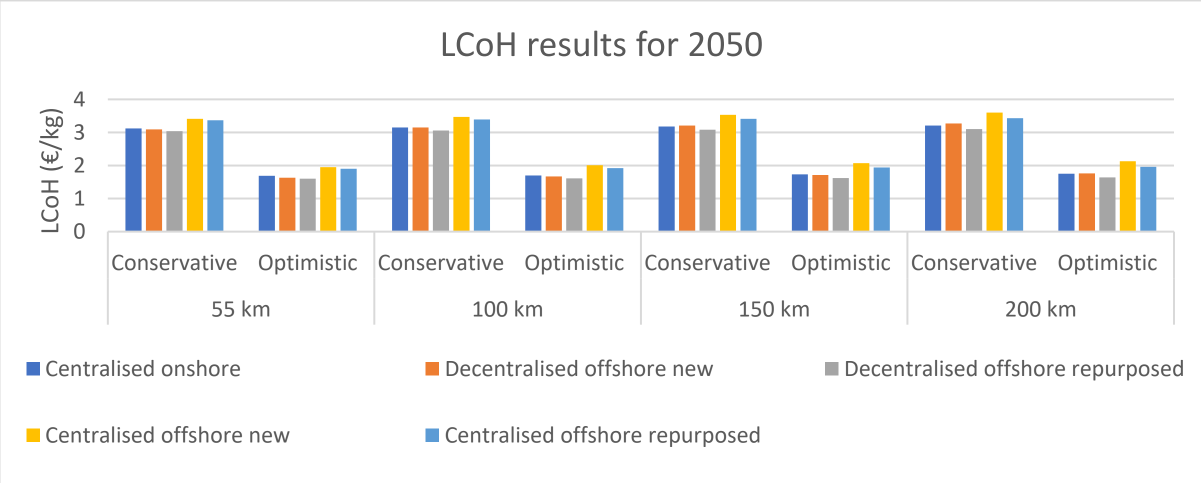


2050



1.2. Tables

Table 10 - Electrolytic green hydrogen future cost projections in the EU, UK, and US.

Region	**Projected LCoH (USD/kg H2)**			**Sources**
	2025	**2030**	**2050**	
EU	3.5 - 5.0	2.0 - 4.0	1.0 - 2.5	[8,10,32–36]
UK	3.0 - 4.5	2.0 - 3.5	1.0 - 2.0	[8,10,32–36]
US	3.0 - 4.5	1.5 - 3.0	1.0 - 2.0	[8,10,32–37]

Table 11 - LCoH results for 2025 for the three configurations, both conservative and optimistic runs.

	55 km		**100 km**		**150 km**		**200 km**	
Configurations	**Conservative**	**Optimistic**	**Conservative**	**Optimistic**	**Conservative**	**Optimistic**	**Conservative**	**Optimistic**
Centralised onshore	6.9	4.47	6.94	4.5	6.99	4.53	7.03	4.56

Decentralised offshore new	7.18	4.65	7.27	4.71	7.36	4.78	7.45	4.85
Decentralised offshore repurposed	7.12	4.6	7.14	4.62	7.17	4.64	7.2	4.66
Centralised offshore new	7.65	5	7.73	5.06	7.82	5.13	7.92	5.19
Centralised offshore repurposed	7.58	4.95	7.61	4.97	7.64	4.99	7.67	5.01

Table 12 - LCoH results for 2030 for the three configurations, both conservative and optimistic runs.

	55 km		**100 km**		**150 km**		**200 km**	
Configurations	**Conservative**	**Optimistic**	**Conservative**	**Optimistic**	**Conservative**	**Optimistic**	**Conservative**	**Optimistic**
Centralised onshore	5.13	2.64	5.16	2.66	5.2	2.68	5.23	2.71
Decentralised offshore new	5.25	2.65	5.31	2.69	5.39	2.74	5.45	2.79
Decentralised offshore repurposed	5.19	2.61	5.21	2.62	5.24	2.64	5.26	2.65
Centralised offshore new	5.61	2.9	5.68	2.94	5.75	2.99	5.82	3.04

Centralised offshore repurposed	5.56	2.86	5.58	2.88	5.6	2.89	5.63	2.91

Table 13 - LCoH results for 2050 for the three configurations, both conservative and optimistic runs.

	55 km		**100 km**		**150 km**		**200 km**	
Configurations	**Conservative**	**Optimistic**	**Conservative**	**Optimistic**	**Conservative**	**Optimistic**	**Conservative**	**Optimistic**
Centralised onshore	3.12	1.69	3.15	1.7	3.18	1.73	3.21	1.75
Decentralised offshore new	3.09	1.63	3.15	1.67	3.21	1.71	3.27	1.76
Decentralised offshore repurposed	3.04	1.6	3.06	1.61	3.08	1.62	3.1	1.64
Centralised offshore new	3.41	1.95	3.47	2.01	3.53	2.07	3.6	2.13
Centralised offshore repurposed	3.37	1.9	3.39	1.92	3.41	1.94	3.43	1.96